Q3 2017 YTD GAAP EPS Reconciliation

Nine Months Ended September 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP Earnings (Loss) Per Share	**$0.51**	**$0.47**	**$0.35**	**$0.24**	**$0.38**	**$0.06**	**$2.01**
Mark-to-market impact of economic hedging activities	0.10	-	-	-	-	-	0.10
Unrealized gains related to NDT fund investments	(0.22)	-	-	-	-	-	(0.22)
Amortization of commodity contract intangibles	0.03	-	-	-	-	-	0.03
Merger and integration costs	0.05	-	-	-	(0.01)	-	0.04
Merger commitments	(0.02)	-	-	-	(0.06)	(0.06)	(0.15)
Long-lived asset impairments	0.31	-	-	-	-	-	0.31
Plant retirements and divestitures	0.15	-	-	-	-	-	0.15
Reassessment of state deferred income taxes	0.02	-	-	-	-	(0.06)	(0.04)
Cost management program	0.02	-	-	-	-	-	0.03
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
Asset retirement obligation	-	-	-	-	-	-	-
Tax settlements	(0.01)	-	-	-	-	-	(0.01)
Bargain purchase gain	(0.25)	-	-	-	-	-	(0.25)
CENG noncontrolling interest	0.08	-	-	-	-	-	0.08
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.76**	**$0.50**	**$0.35**	**$0.25**	**$0.31**	**($0.12)**	**$2.05**

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Exelon.

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GAAP to Operating Adjustments

- **Exelon's 2017 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:**
  - Mark-to-market adjustments from economic hedging activities
  - Unrealized gains from NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
  - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the ConEdison Solutions and FitzPatrick acquisition dates
  - Certain merger and integration costs associated with the PHI and FitzPatrick acquisitions
  - Adjustments to reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions
  - Impairments as a result of the ExGen Texas Power, LLC assets held for sale
  - Plant retirements and divestitures at Generation
  - Non-cash impact of the remeasurement of state deferred income taxes, related to changes in statutory tax rates and changes in forecasted apportionment
  - Costs incurred related to a cost management program
  - Certain adjustments related to Exelon's like-kind exchange tax position
  - Non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units
  - Benefits related to the favorable settlement of certain income tax positions related to PHI's unregulated business interests
  - The excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition
  - Generation's noncontrolling interest, primarily related to CENG exclusion items

Exelon.

GAAP to Non-GAAP Reconciliations

YE 2017 Exelon FFO Calculation ($M)[1,2,10,11]	
GAAP Operating Income	$3,500
Depreciation & Amortization	$3,350
EBITDA	$6,850
+/- Non-operating activities and nonrecurring items[3]	$450
- Interest Expense	($1,450)
+ Current Income Tax (Expense)/Benefit	$325
+ Nuclear Fuel Amortization	$1,075
+/- Other S&P Adjustments[4]	$350
= FFO (a)	**$7,600**

YE 2017 Exelon Adjusted Debt Calculation ($M)[1,2,10]	
Long-Term Debt (including current maturities)	$32,050
Short-Term Debt	$1,125
+ PPA Imputed Debt[5]	$350
+ Operating Lease Imputed Debt[6]	$875
+ Pension/OPEB Imputed Debt[7]	$4,100
- Off-Credit Treatment of Debt[8]	($1,725)
- Surplus Cash Adjustment[9]	($600)
+/- Other S&P Adjustments[4]	($650)
= Adjusted Debt (b)	**$35,525**

YE 2017 Exelon FFO/Debt[1,2]		
FFO (a) / Adjusted Debt (b)	=	21%

(1) All amounts rounded to the nearest $25M
(2) Calculated using S&P Methodology. Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment.
(3) Reflects impact of operating adjustments on GAAP EBITDA
(4) Includes other adjustments as prescribed by S&P
(5) Reflects present value of net capacity purchases
(6) Reflects present value of minimum future operating lease payments
(7) Reflects after-tax unfunded pension/OPEB
(8) Includes non-recourse project debt
(9) Applies 75% of excess cash against balance of LTD
(10) Reflects removal of EGTP
(11) Reflects delay in Illinois ZEC revenue recognition from 2017 to 2018

Exelon.

GAAP to Non-GAAP Reconciliations

YE 2017 ExGen Net Debt Calculation ($M)[1,3]	
Long-Term Debt (including current maturities)	$8,775
Short-Term Debt	$350
- Surplus Cash Adjustment	($300)
= Net Debt (a)	**$8,825**

YE 2017 ExGen Net Debt Calculation ($M)[1,3]	
Long-Term Debt (including current maturities)	$8,775
Short-Term Debt	$350
- Surplus Cash Adjustment	($300)
- Nonrecourse Debt	($1,925)
= Net Debt (a)	**$6,900**

YE 2017 ExGen Operating EBITDA Calculation ($M)[1,3,4]	
GAAP Operating Income	$775
Depreciation & Amortization	$1,375
EBITDA	$2,150
+/- Non-operating activities and nonrecurring items[2]	$725
= Operating EBITDA (b)	**$2,875**

YE 2017 ExGen Operating EBITDA Calculation ($M)[1,3,4]	
GAAP Operating Income	$775
Depreciation & Amortization	$1,375
EBITDA	$2,150
+/- Non-operating activities and nonrecurring items[2]	$725
- EBITDA from projects financed by nonrecourse debt	($250)
= Operating EBITDA (b)	**$2,625**

YE 2017 Book Debt / EBITDA		
Net Debt (a) / Operating EBITDA (b)	=	3.1x

YE 2017 Recourse Debt / EBITDA		
Net Debt (a) / Operating EBITDA (b)	=	2.6x

(1) All amounts rounded to the nearest $25M
(2) Reflects impact operating adjustments on GAAP EBITDA
(3) Reflects removal of EGTP
(4) Reflects delay in Illinois ZEC revenue recognition from 2017 to 2018

Exelon.

GAAP to Non-GAAP Reconciliations

Q3 2017 Operating ROE Reconciliation ($M)[1]	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)[1]	$85	$114	$210	$1,281	$1,690
Operating Exclusions	($23)	($12)	($25)	$34	($25)
Adjusted Operating Earnings[1]	$63	$103	$185	$1,315	$1,665
Average Equity	$1,061	$1,323	$2,419	$12,750	$17,554
Operating ROE (Adjusted Operating Earnings/Average Equity)	**5.9%**	**7.8%**	**7.7%**	**10.3%**	**9.5%**

Q2 2017 Operating ROE Reconciliation ($M)[1]	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)[1]	$91	$127	$203	$1,132	$1,548
Operating Exclusions	($25)	($32)	($29)	$186	$105
Adjusted Operating Earnings[1]	$66	$95	$174	$1,318	$1,653
Average Equity	$1,039	$1,300	$2,390	$12,308	$17,038
Operating ROE (Adjusted Operating Earnings/Average Equity)	**6.4%**	**7.3%**	**7.3%**	**10.7%**	**9.7%**

(1) ACE, Delmarva, and Pepco represents full year of earnings

Exelon.

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GAAP to Non-GAAP Reconciliations

2017 Adjusted Cash from Ops Calculation ($M)[1]	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flows provided by operating activities (GAAP)	$1,375	$750	$775	$1,175	$3,400	($250)	$7,225
Other cash from investing activities	-	-	-	-	($275)	-	($275)
Intercompany receivable adjustment	($350)	-	-	-	-	$350	-
Counterparty collateral activity	-	-	-	-	$200	-	$200
Adjusted Cash Flow from Operations	**$1,025**	**$750**	**$775**	**$1,175**	**$3,350**	**$75**	**$7,150**

2017 Cash From Financing Calculation ($M)[1]	ComEd	PECO	BGE	PHI	ExGen	Other	Exelon
Net cash flow provided by financing activities (GAAP)	$825	$175	$150	$125	($300)	$400	$1,375
Dividends paid on common stock	$425	$300	$200	$325	$650	($675)	$1,225
Intercompany receivable adjustment	$350	-	-	-	-	($350)	-
Financing Cash Flow	**$1,600**	**$475**	**$350**	**$450**	**$350**	**($625)**	**$2,625**

Exelon Total Cash Flow Reconciliation[1]	2017
GAAP Beginning Cash Balance	**$650**
Adjustment for Cash Collateral Posted	$400
Adjusted Beginning Cash Balance[3]	$1,050
Net Change in Cash (GAAP)[2]	$400
Adjusted Ending Cash Balance[3]	$1,450
Adjustment for Cash Collateral Posted	($625)
GAAP Ending Cash Balance	**$825**

(1) All amounts rounded to the nearest $25M. Items may not sum due to rounding.
(2) Represents the GAAP measure of net change in cash, which is the sum of cash flow from operations, cash from investing activities, and cash from financing activities. Figures reflect cash capital expenditures and CENG fleet at 100%.
(3) Adjusted Beginning and Ending cash balances reflect GAAP Beginning and End Cash Balances excluding counterparty collateral activity

Exelon.

GAAP to Non-GAAP Reconciliations

ExGen Adjusted O&M Reconciliation ($M)[1]	2017	2018	2019	2020
GAAP O&M	**$6,325**	**$5,300**	**$5,150**	**$5,025**
Decommissioning[2]	25	50	50	50
TMI Retirement	(75)	-	-	-
EGTP Impairment	(450)	-	-	-
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses[3]	(425)	(325)	(325)	(325)
O&M for managed plants that are partially owned	(425)	(425)	(400)	(425)
Other	(125)	(25)	(25)	(25)
Adjusted O&M (Non-GAAP)	**$4,850**	**$4,600**	**$4,450**	**$4,300**

2017-2020 ExGen Free Cash Flow Calculation ($M)[1]	
Cash from Operations (GAAP)	$15,150
Other Cash from Investing and Activities	($650)
Baseline Capital Expenditures[4]	($4,025)
Nuclear Fuel Capital Expenditures	($3,625)
Free Cash Flow before Growth CapEx and Dividend	**$6,825**

(1) All amounts rounded to the nearest $25M. Items may not sum due to rounding.
(2) Reflects earnings neutral O&M
(3) Reflects the direct cost of sales of certain businesses, which are included in Total Gross Margin*
(4) Baseline capital expenditures refer to maintenance and required capital expenditures necessary for day-to-day plant operations and includes merger commitments

Exelon.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

November 4, 2016
Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201 (410) 234-5000	52-0280210
001-31403	**PEPCO HOLDINGS LLC** **(a Delaware limited liability company)** 701 Ninth Street, N.W. Washington, D.C. 20068 (202)872-2000	52-2297449
001-01072	**POTOMAC ELECTRIC POWER COMPANY** **(a District of Columbia and Virginia corporation)** 701 Ninth Street, N.W. Washington, D.C. 20068 (202)872-2000	53-0127880
001-01405	**DELMARVA POWER & LIGHT COMPANY** **(a Delaware and Virginia corporation)** 500 North Wakefield Drive, 2 nd Floor Newark, DE 19702 (202)872-2000	51-0084283
001-03559	**ATLANTIC CITY ELECTRIC COMPANY** **(a New Jersey corporation)**	21-0398280

500 North Wakefield Drive, 2 nd Floor
Newark, DE 19702
(202)872-2000

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 7 – Regulation FD

Item 7.01. Regulation FD Disclosure.

On November 7-8, 2016, Exelon Corporation (Exelon) will participate in the Edison Electric Institute (EEI) conference. During the conference, Exelon will re-affirm its 2016 adjusted (non-GAAP) operating earnings guidance range of $2.55—$2.75 per share, as disclosed in its third quarter 2016 earnings release and the slides for its earnings call, as furnished to the SEC in the Current Report on Form 8-K on October 26, 2016. The materials Exelon will discuss at the conference have been previously furnished to the SEC in either that 8-K or in the 8-K furnished on August 10, 2016 with the materials for Exelon's Analyst Day presentation. The slides for the EEI conference have been posted on Exelon's website, www.exeloncorp.com , on the Investor Relations page.

* * * * *

This combined Current Report on Form 8-K is being furnished separately by Exelon, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC (PHI), Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants). Information contained herein relating to any individual Registrant has been furnished by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

This report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Registrants include those factors discussed herein, as well as the items discussed in (1) Exelon's 2015 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23; (2) PHI's 2015 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 16; (3) Exelon's Third Quarter 2016 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18 and (4) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Jonathan W. Thayer

Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright

Bryan P. Wright
Senior Vice President and Chief Financial Officer
Exelon Generation Company, LLC

COMMONWEALTH EDISON COMPANY

/s/ Joseph R. Trpik, Jr.

Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer
Commonwealth Edison Company

PECO ENERGY COMPANY

/s/ Phillip S. Barnett

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
PECO Energy Company

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ David M. Vahos

David M. Vahos
Senior Vice President, Chief Financial Officer and Treasurer
Baltimore Gas and Electric Company

PEPCO HOLDINGS LLC

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer,
Pepco Holdings LLC

POTOMAC ELECTRIC POWER COMPANY

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer,
Potomac Electric Power Company

DELMARVA POWER & LIGHT COMPANY

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer,
Delmarva Power & Light Company

ATLANTIC CITY ELECTRIC COMPANY

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer,
Atlantic City Electric Company

November 4, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

November 6, 2017

Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
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001-01072	**POTOMAC ELECTRIC POWER COMPANY** **(a District of Columbia and Virginia corporation)** 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	53-0127880

001-01405	**DELMARVA POWER & LIGHT COMPANY** **(a Delaware and Virginia corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
001-03559	**ATLANTIC CITY ELECTRIC COMPANY** **(a New Jersey corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	21-0398280

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

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☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether any of the registrants are emerging growth companies as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if any of the registrants have elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Section 7 - Regulation FD
Item 7.01. Regulation FD Disclosure.

On November 6-8, 2017, Exelon Corporation (Exelon) will participate in the Edison Electric Institute (EEI) conference. During the conference, Exelon will re-affirm its 2017 adjusted (non-GAAP) operating earnings guidance range of $2.55—$2.75 per share, as disclosed in its third quarter 2017 earnings release and the slides for its earnings call, as furnished to the SEC in the Current Report on Form 8-K on November 2, 2017. Attached as Exhibits 99.1 and 99.2 to this Current Report on Form 8-K are the presentation slides and handouts to be used at the conference.

Section 9 - Financial Statements and Exhibits
Item 9.01. Financial Statements and Exhibits

(d) Exhibits.

Exhibit No.	Description
99.1	EEI presentation slides
99.2	Tax rate and utility asset projections at current plan

* * * * *

This Current Report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from these forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein as well as those discussed in (1) Exelon's 2016 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 24; (2) Exelon's Third Quarter 2017 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18 and (3) other factors discussed in filings with the Securities and Exchange Commission by the registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Current Report. None of the registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Current Report.

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Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer
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/s/ Bryan P. Wright

Bryan P. Wright
Senior Vice President and Chief Financial Officer
Exelon Generation Company, LLC

COMMONWEALTH EDISON COMPANY

/s/ Gerald J. Kozel

Gerald J. Kozel

Vice President, Controller
Commonwealth Edison Company

PECO ENERGY COMPANY

/s/ Phillip S. Barnett

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
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Senior Vice President, Chief Financial Officer and Treasurer
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ATLANTIC CITY ELECTRIC COMPANY

/s/ Donna J. Kinzel

Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer
Atlantic City Electric Company

November 6, 2017

EXHIBIT INDEX

Exhibit No.	Description
99.1	EEI presentation slides
99.2	Tax rate and utility asset projections at current plan

EEI Financial Conference

November 2017

Exelon.

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Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2016 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 24, Commitments and Contingencies; (2) Exelon's Third Quarter 2017 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (2) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this press release. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Exelon.

Non-GAAP Financial Measures

Exelon reports its financial results in accordance with accounting principles generally accepted in the United States (GAAP). Exelon supplements the reporting of financial information determined in accordance with GAAP with certain non-GAAP financial measures, including:

- ***Adjusted operating earnings*** exclude certain costs, expenses, gains and losses and other specified items, including mark-to-market adjustments from economic hedging activities, unrealized gains and losses from nuclear decommissioning trust fund investments, merger and integration related costs, impairments of certain long-lived assets, certain amounts associated with plant retirements and divestitures, costs related to a cost management program and other items as set forth in the reconciliation in the Appendix
- ***Adjusted operating and maintenance expense*** excludes regulatory operating and maintenance costs for the utility businesses and direct cost of sales for certain Constellation and Power businesses, decommissioning costs that do not affect profit and loss, the impact from operating and maintenance expense related to variable interest entities at Generation, EDF's ownership of O&M expenses, and other items as set forth in the reconciliation in the Appendix
- ***Total gross margin*** is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, JExel Nuclear JV, variable interest entities, and net of direct cost of sales for certain Constellation and Power businesses
- ***Adjusted cash flow from operations*** primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures, net merger and acquisitions, and equity investments
- ***Free cash flow*** primarily includes net cash flows from operating activities and net cash flows from investing activities excluding certain capital expenditures, net merger and acquisitions, and equity investments
- ***Operating ROE*** is calculated using operating net income divided by average equity for the period. The operating income reflects all lines of business for the utility business (Electric Distribution, Gas Distribution, Transmission).
- ***EBITDA*** is defined as earnings before interest, taxes, depreciation and amortization. Includes nuclear fuel amortization expense.
- ***Revenue net of purchased power and fuel expense*** is calculated as the GAAP measure of operating revenue less the GAAP measure of purchased power and fuel expense

Due to the forward-looking nature of some forecasted non-GAAP measures, information to reconcile the forecasted adjusted (non-GAAP) measures to the most directly comparable GAAP measure may not be currently available, as management is unable to project all of these items for future periods

Exelon.

Non-GAAP Financial Measures Continued

This information is intended to enhance an investor's overall understanding of period over period financial results and provide an indication of Exelon's baseline operating performance by excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods.

These non-GAAP financial measures are not a presentation defined under GAAP and may not be comparable to other companies' presentation. Exelon has provided these non-GAAP financial measures as supplemental information and in addition to the financial measures that are calculated and presented in accordance with GAAP. These non-GAAP measures should not be deemed more useful than, a substitute for, or an alternative to the most comparable GAAP measures provided in the materials presented.

Non-GAAP financial measures are identified by the phrase "non-GAAP" or an asterisk. Reconciliations of these non-GAAP measures to the most comparable GAAP measures are provided in the appendices and attachments to this presentation, except for the reconciliation for total gross margin, which appears on slide 45 of this presentation.

Exelon: An Industry Leader

Note: All numbers reflect year-end 2016; revenue accounts for PHI as of the merger effective date of March 24, 2016 through December 31, 2016.

Exelon.

The Exelon Value Proposition

- **Regulated Utility Growth** with utility EPS rising 6-8% annually from 2017-2020 and rate base growth of 6.5%, representing an expanding majority of earnings
- **ExGen's strong free cash generation** will support utility growth while also reducing debt by ~$3B over the next 4 years
- **Optimizing ExGen value by:**
  - Seeking fair compensation for the zero-carbon attributes of our fleet;
  - Closing uneconomic plants;
  - Monetizing assets; and
  - Maximizing the value of the fleet through our generation to load matching strategy
- **Strong balance sheet is a priority** with all businesses comfortably meeting investment grade credit metrics through the 2020 planning horizon
- **Capital allocation priorities targeting:**
  - Organic utility growth;
  - Return of capital to shareholders with 2.5% annual dividend growth through 2018(1),
  - Debt reduction; and
  - Modest contracted generation investments

(1) Quarterly dividends are subject to declaration by the board of directors

Exelon.

Exelon Utilities Overview

$31.7B
2016 Rate Base

$15.1B
In Revenue

24.9
Thousand mi²
Combined
Service Territory

8.5 M
Smart Meters
Installed

Note: All numbers reflect year-end 2016; revenue number accounts for PHI revenue as of March 24, 2016 merger date.

Exelon.

S1-SSA-0009 - 10026

Exelon Utilities are an Industry Leader

US Utility Customers (millions)

Total Capital Expenditures 2017-2019 ($B)[1]

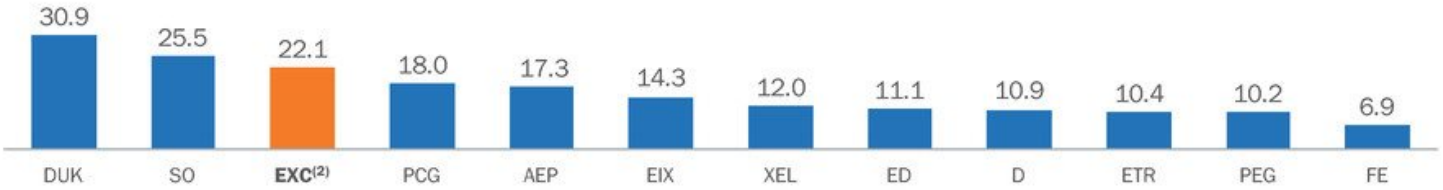

Total Utility Rate Base ($B)[1]

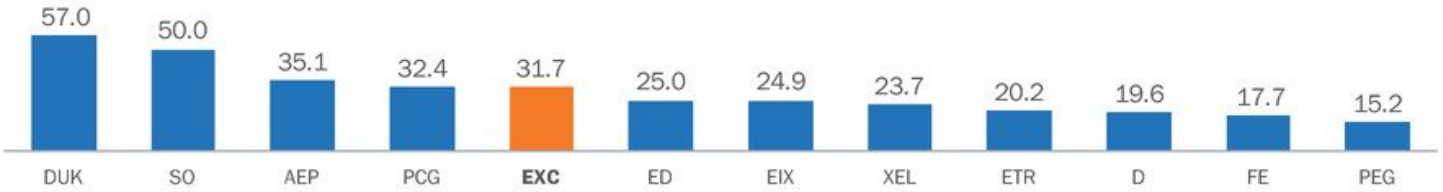

Source: Company Filings
(1) Includes utility and generation
(2) $23B includes $15.2B of utility capital expenditures and $6.9B of generation capital expenditures

Exelon.

Our Capital Plan Drives Stable Earnings Growth

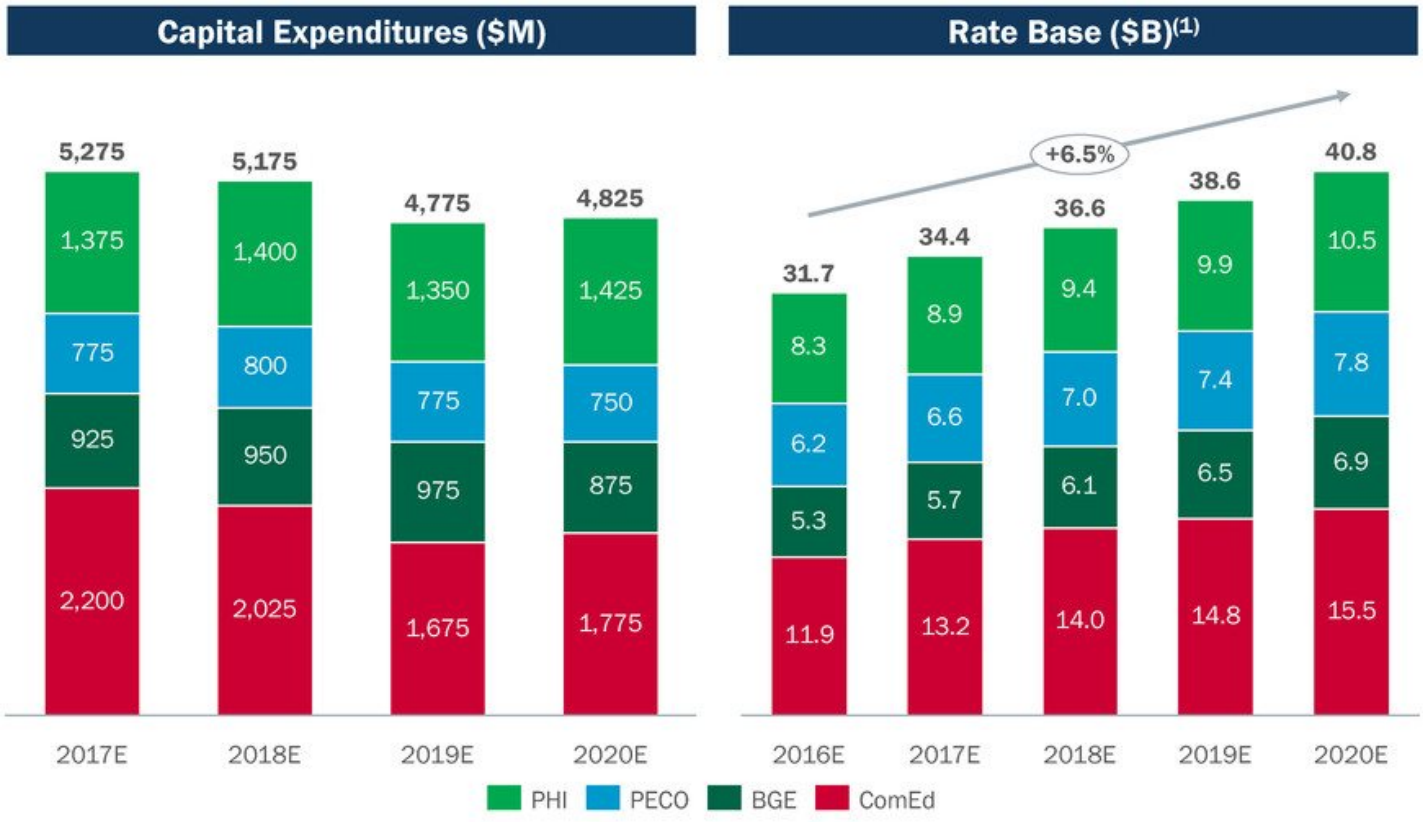

Over $20B of capital is being invested at utilities from 2017-2020 to improve reliability

Note: CapEx numbers are rounded to nearest $25M and numbers may not add due to rounding
(1) Rate base reflects year-end estimates

Exelon.

Utility CapEx Update

2017 Exelon Utilities CapEx Spend ($M)

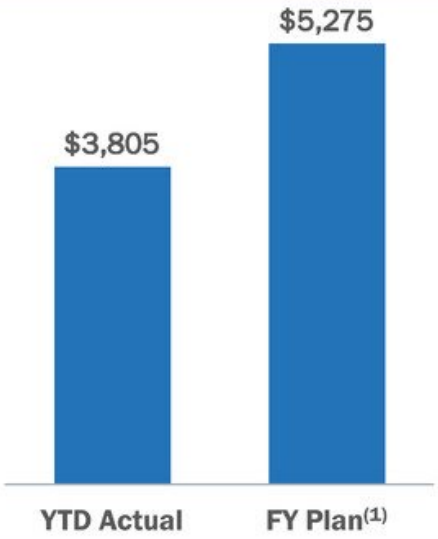

Notable Projects

- **Pepco's Waterfront Substation**
  - $182 million invested to date. Expected completion by end of 2017
  - Part of "Capital Grid" project
  - Replaces aging infrastructure and improves substation performance
  - Will support existing customers and planned development in the Capitol Riverfront and Southwest Waterfront areas
- **ComEd's Grand Prairie Gateway transmission line**
  - $203 million investment
  - 60-mile, 345kV line through four northern Illinois counties
  - Energized April 2017
  - Estimated customer savings of $121 to $325 million, net of construct costs, within the first 15 years
  - Reduces carbon emissions by nearly 500,000 tons within the first 15 years

Exelon Utilities on track to meet their 2017 capital investment commitments to the benefit of customers

(1) FY Plan rounded to the nearest $25M

Exelon.

Proven Track Record of Improving Operational Performance

Operations	Metric	At CEG Merger (2012)			2015	Q3 2017			
		BGE	ComEd	PECO	PHI	BGE	ComEd	PECO	PHI
Electric Operations	OSHA Recordable Rate								
	2.5 Beta SAIFI (Outage Frequency)(1)								
	2.5 Beta CAIDI (Outage Duration)								
Customer Operations	Customer Satisfaction				N/A				
	Service Level % of Calls Answered in <30 sec								
	Abandon Rate								
Gas Operations	Percent of Calls Responded to in <1 Hour		No Gas Operations				No Gas Operations		
Overall Rank	Electric Utility Panel of 24 Utilities(2)	23rd	2nd	2nd	18th				

Performance Quartiles: Q1 | Q2 | Q3 | Q4

Exelon Utilities has identified and transferred best practices at each of its utilities to improve operating performance in areas such as:

- System Performance
- Emergency Preparedness
- Corrective and Preventive Maintenance

(1) 2.5 Beta SAIFI is YE projection
(2) Ranking based on results of five key industry performance indicators – CAIDI, SAIFI, Safety, Customer Satisfaction, and Cost per Customer

Exelon.

Formulaic Mechanisms Cover Bulk of Rate Base Growth

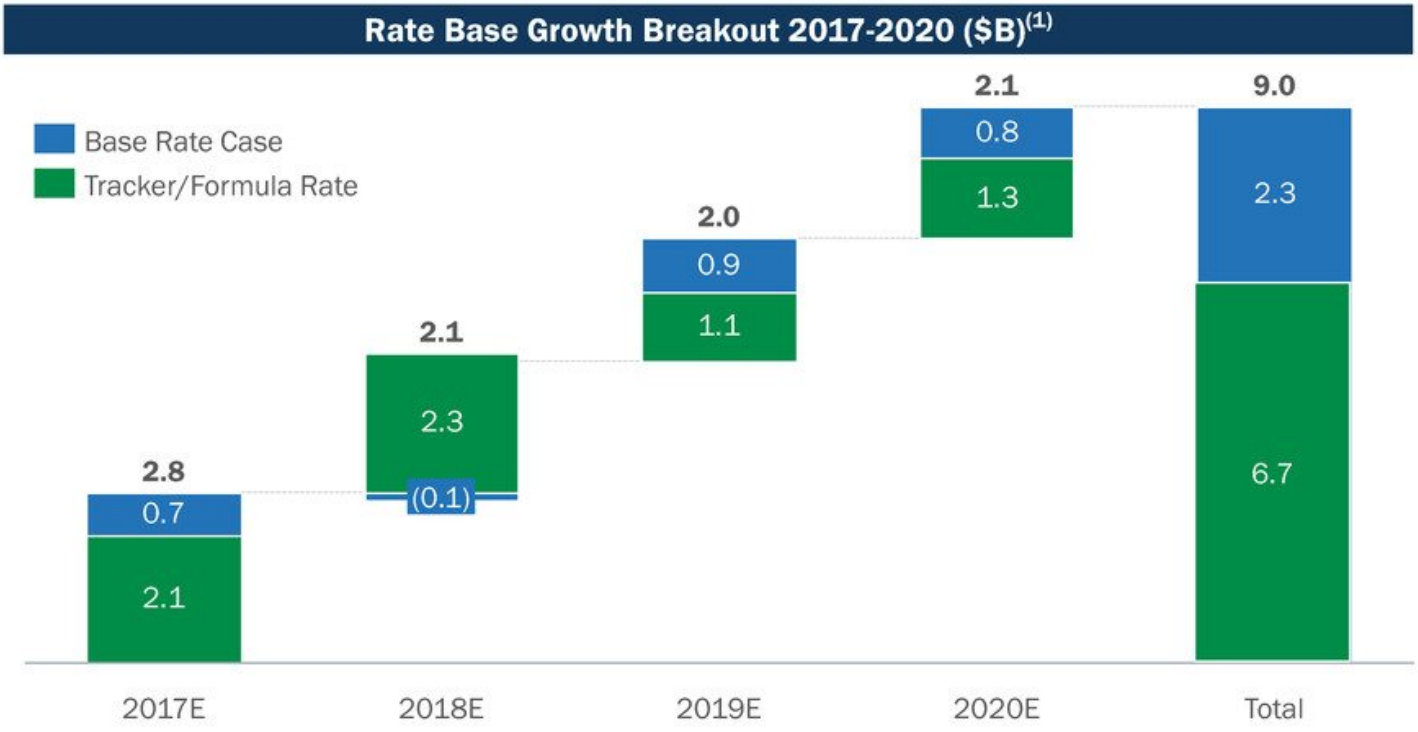

Of the approximately $9.0 billion of rate base growth Exelon Utilities forecasts over the next 4 years, ~75% will be recovered through existing formula and tracker mechanisms

Note: Numbers may not add due to rounding
(1) Assumes PECO transmission formula rate beginning in 2018; base rate base decrease due to reclassification of transmission rate base growth at PECO

Exelon.

Trailing 12 Month ROE vs Allowed ROE

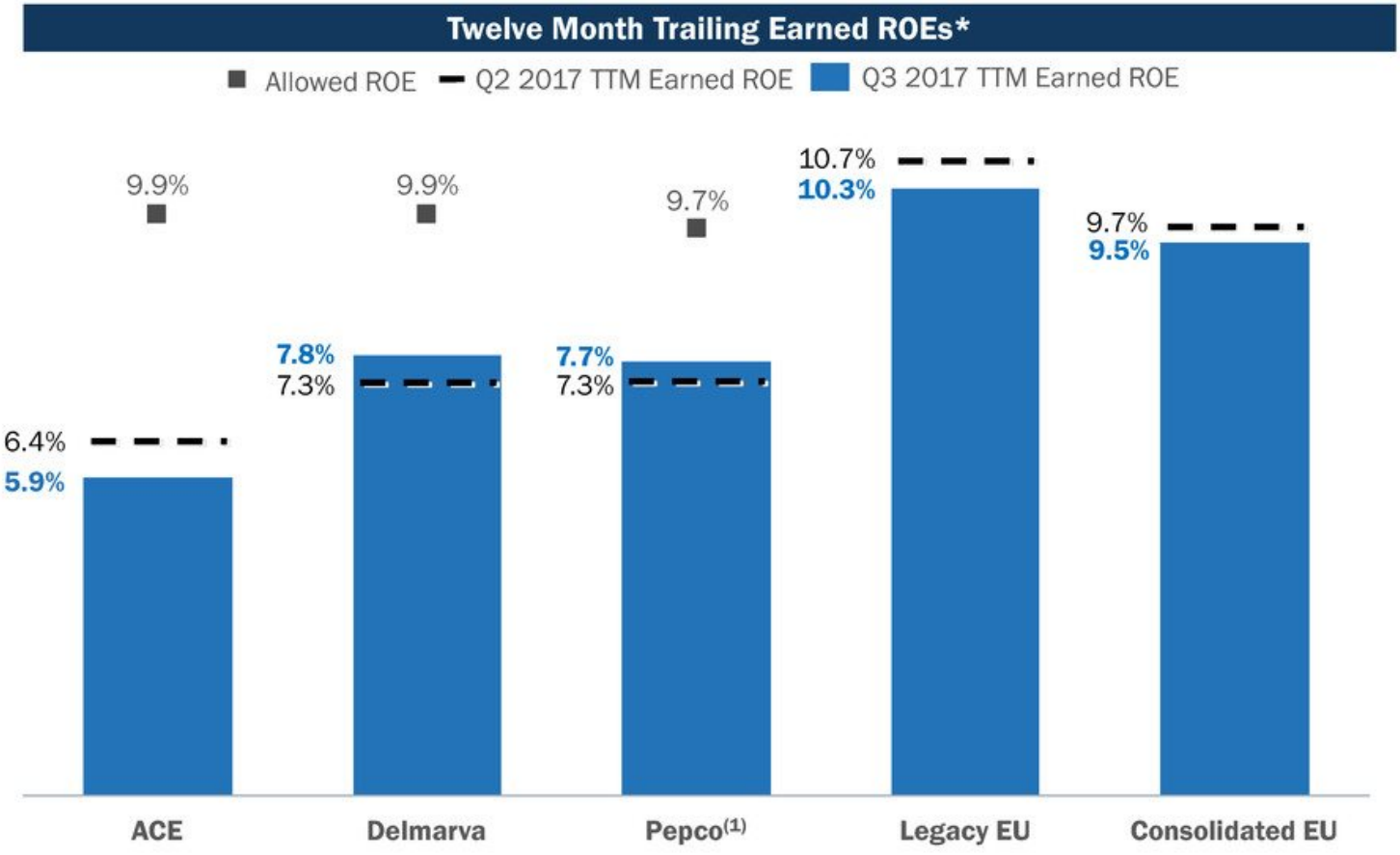

Note: Represents the period from 10/1/2016 to 9/30/2017. ROEs represent weighted average across all lines of business (Electric Distribution, Gas Distribution, and Transmission).

(1) Pepco MD Distribution allowed ROE is based on authorized ROE of 9.55% for the rates that were in effect during the trailing twelve month period. The order issued on 10/20/17 authorized an ROE of 9.50%.

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Exelon Utilities' Distribution Rate Case Updates

Pepco DC Order	
Authorized Revenue Requirement Increase[1]	$36.9M
Authorized ROE	9.50%
Common Equity Ratio	49.14%
Order Received	7/25/17

ACE NJ Order	
Authorized Revenue Requirement Increase[1]	$43.0M
Authorized ROE	9.60%
Common Equity Ratio	50.47%
Order Received	9/22/17

Pepco MD Order	
Authorized Revenue Requirement Increase[1]	$32.4M
Authorized ROE	9.50%
Common Equity Ratio	50.15%
Order Received	10/20/17

ComEd Filing	
Requested Revenue Requirement Increase[1]	$95.6M[2]
Requested ROE	8.40%
Requested Common Equity Ratio	45.89%
Order Expected	Q4 2017

Delmarva MD Filing	
Requested Revenue Requirement Increase[1]	$21.6M[4]
Requested ROE	10.10%
Requested Common Equity Ratio	50.68%
Order Expected	2/14/18

Delmarva DE Electric Filing	
Requested Revenue Requirement Increase[1,3]	$31.2M
Requested ROE	10.10%
Requested Common Equity Ratio	50.52%
Order Expected	Q3 2018

Delmarva DE Gas Filing	
Requested Revenue Requirement Increase[1,3]	$12.9M
Requested ROE	10.10%
Requested Common Equity Ratio	50.52%
Order Expected	Q3 2018

(1) Revenue requirement includes changes in depreciation and amortization expense where applicable, which have no impact on pre-tax earnings
(2) Amount represents ComEd's position filed in Rebuttal testimony on July 21, 2017
(3) As permitted by Delaware law, Delmarva Power will implement interim rate increases of $2.5M in Q3 2017 and will implement full allowable rates on March 17, 2018, subject to refund
(4) Amount represents adjusted requested revenue requirement filed on September 28, 2017

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Exelon Utilities EPS Growth of 6-8% to 2020

Exelon Utilities Operating Earnings 2017-2020

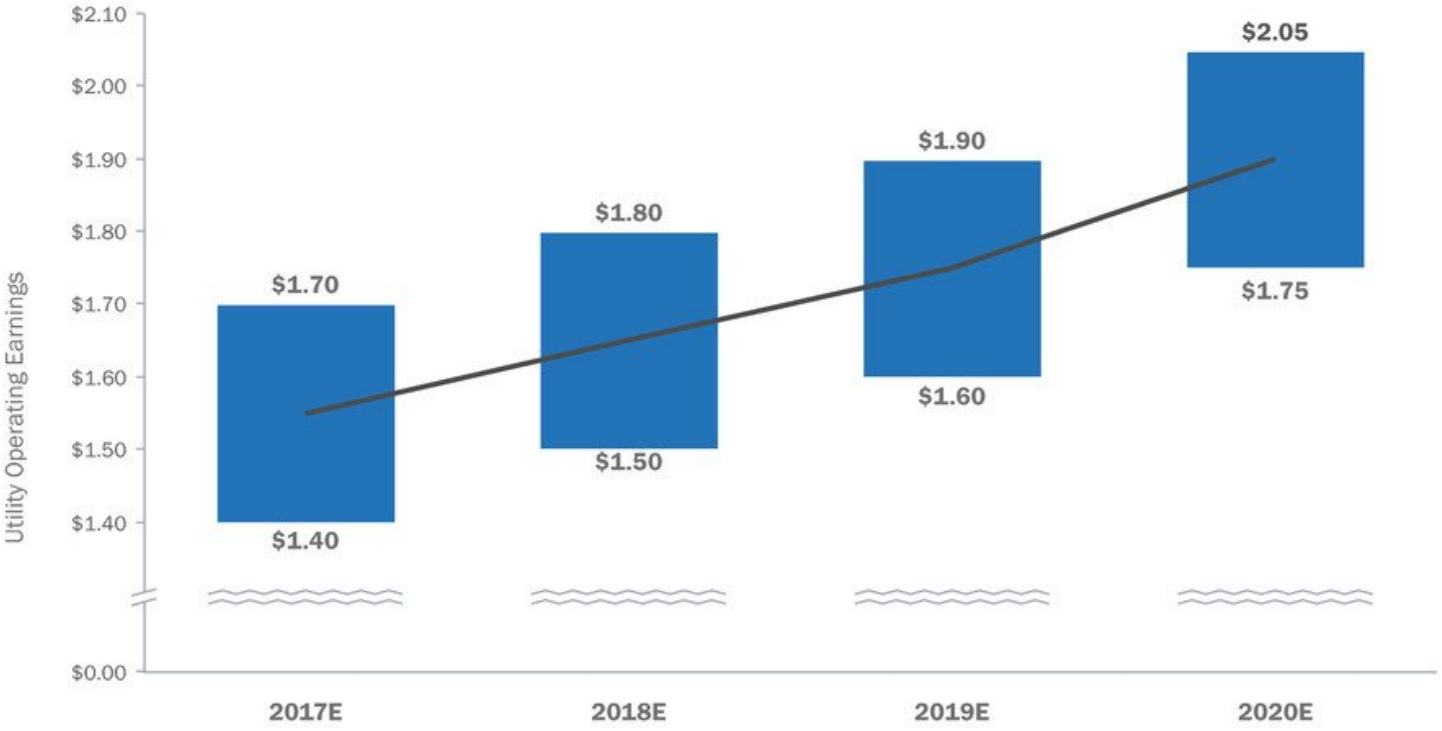

Rate base growth combined with PHI ROE improvement drives EPS growth

Note: Reflects GAAP operating earnings except for 2017. 2017 GAAP EPS range would be $1.35 to $1.65. 2017 adjusted (non-GAAP) operating earnings include adjustments to exclude $0.05 for merger commitments and integration costs. Includes after-tax interest expense held at Corporate for debt associated with existing utility investment.

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Exelon Generation Overview

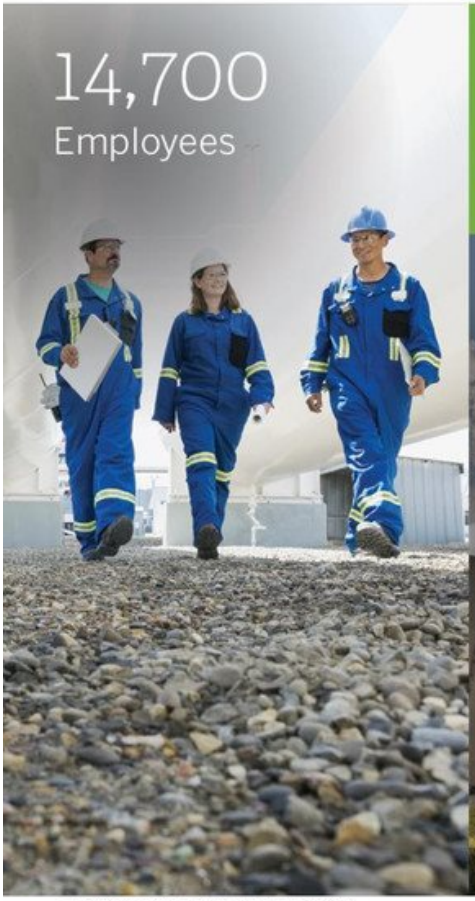

#1
Lowest carbon intensity among large power generators

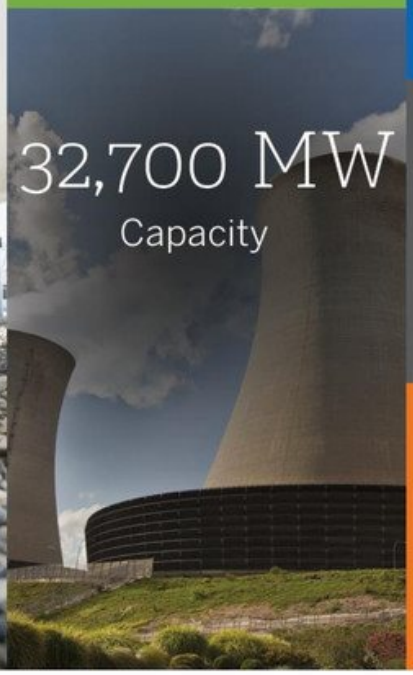

#1
Retail electricity provider in the country

205 TWh
Customer Load Served

94.6%
Nuclear Capacity Factor in 2016

97.2%
Gas and Hydro Dispatch Match in 2016

8th
largest gas provider

203 TWh
Generation Output

Note: All numbers reflect year-end 2016

Exelon.

Constellation Overview

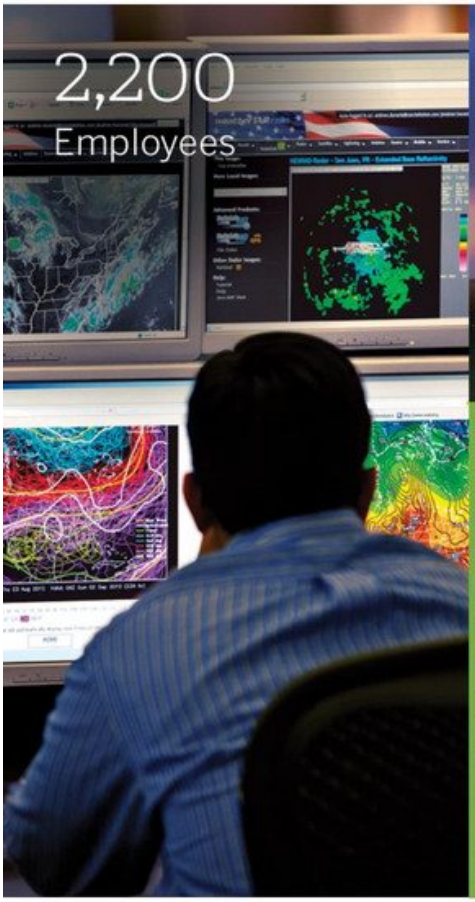

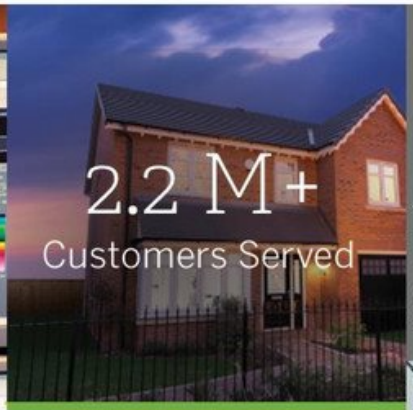

#1 Retail
Retail Electricity Provider in the U.S
Among the top 10 largest gas providers in the U.S.

1.6 TCF
Gas Delivered

In 2016, procured
2.9 million
RECs for customers, enabling them to avoid approximately
1.51 million[1]
metric tons of GHG emissions and support the development of renewable power generation

48
Operate in 48 States

27,000
Volunteer Hours

Note: All numbers reflect year-end 2016
(1) As calculated based on the national average generation supply mix used in EPA eGRID2014.

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Exelon Generation: Gross Margin Update

	September 30, 2017			Change from June 30, 2017		
Gross Margin Category ($M)[1]	**2017**	**2018**	**2019**	**2017**	**2018**	**2019**
Open Gross Margin[2,5] (including South, West, Canada hedged gross margin)	$3,600	$3,900	$3,700	$(150)	$(100)	$(100)
Capacity and ZEC Revenues[2,5,6]	$1,700	$2,300	$2,000	$(150)	$100	$(50)
Mark-to-Market of Hedges[2,3]	$2,150	$650	$450	$250	$100	$50
Power New Business / To Go	$100	$700	$850	$(100)	$(150)	$(100)
Non-Power Margins Executed	$350	$200	$100	$50	$50	-
Non-Power New Business / To Go	$100	$300	$400	$(50)	$(50)	-
Total Gross Margin*[4,5]	**$8,000**	**$8,050**	**$7,500**	**$(150)**	**$(50)**	**$(200)**

Recent Developments

- Delay in recognition of Illinois ZEC revenues lowers the Capacity and ZEC Revenues line in 2017 by $150M and increases the 2018 line by $150M – see slide 19 for details
- Excluding impact of Illinois ZEC timing:
  - In 2017, $50M reduction in Power New Business targets
  - In both 2018 and 2019, $100M reduction due to lower power and capacity prices and $100M reduction to Power New Business Targets
- Behind ratable hedging position reflects the upside we see in power prices
  - ~11-14% behind ratable in 2018 when considering cross commodity hedges

(1) Gross margin categories rounded to nearest $50M
(2) Excludes EDF's equity ownership share of the CENG Joint Venture
(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(4) Based on September 30, 2017, market conditions
(5) Reflects TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.
(6) 2018 includes $150M of IL ZEC revenues associated with 2017 production

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ExGen Forward Total Gross Margin* Walk: Q3 2017 vs. Q2 2017

FY 2017 ($M)[1,3,4]

FY 2018 ($M)[1,3,4]

FY 2019 ($M)[1,3,4]

Key Takeaways

- Change in timing of Illinois ZEC contract finalization results in 2017 reduction of $150M on a rounded basis and 2018 increase of $150M
- Aggressive bidding by market participants in a low volatility period is pressuring Wholesale margins and limiting C&I Retail growth; reduce Power New Business To Go by $100M in 2018 and 2019 to reflect continuation of current, low discipline market bidding behavior
- Lower energy prices reduce Open Gross Margin by $50M in 2018 and 2019; October price recovery offsets 2019 declines
- Lower observed capacity prices in NY and MISO reduce Capacity Revenues by $50M on a rounded basis in 2018 and 2019

(1) Gross margin categories rounded to nearest $50M
(2) Excludes EDF's equity ownership share of the CENG Joint Venture
(3) Based on September 30, 2017, market conditions
(4) Reflects TMI and Oyster Creek retirements in September 2019 and December 2019, respectively
(5) 2018 includes $150M of IL ZEC revenues associated with 2017 production

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Forward Market Liquidity

Overall liquidity is declining

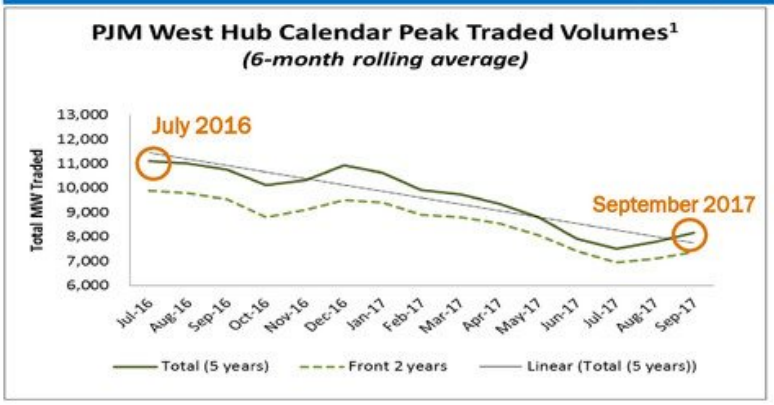

Total calendar peak traded volumes for the rolling 5-year window have been trending lower over the past year

Calendar peak traded volumes beyond prompt year +1 account for less than 10% of total traded volumes

** Please note that hedging strategy utilizes various price points (i.e. NIHUB, ERCOT), channels to market (i.e. Origination, Mid-Marketing, Retail, OTC), products (i.e. calendar, seasonal), and other exchanges*

Limited liquidity in the outer years

September 2016 PJM West Hub Calendar Peak Traded Volumes(1) (by year)

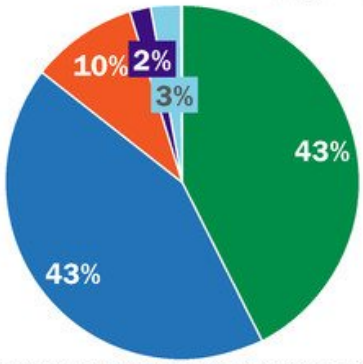

September 2017 PJM West Hub Calendar Peak Traded Volumes(1) (by year)

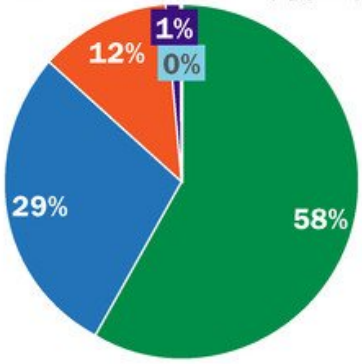

(1) Total monthly traded volumes for rolling prompt year + 4 years on ICE and NASDAQ Exchanges only

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Exelon's Policy Priorities

Resiliency and Energy Market Reform

Price Formation

- PJM has stated that it is prepared to implement its reforms allowing all resources to set LMP by mid-2018
- "FERC should expedite its efforts with states, RTO/ISOs, and other stakeholders to improve energy price formation in centrally-organized wholesale electricity markets." – DOE Staff Report, August 2017
- The Commission should focus "first and foremost on the optimization of price formation in the energy and ancillary service markets." Ill. Commerce Comm'n Comments at 7
- "PJM staff is proposing to reform the existing pricing model in order to ensure that the cost of serving load is reflected in LMP to the fullest extent possible... This follows the principles of sound market design." - William W. Hogan, October 23, 2017

Resiliency

- "Accurately valuing resilience is not a zero-sum game. Compensating base-load generation does not equate to destruction of markets. On the contrary, I think it's a step toward accurately pricing contributions of all market participants." – FERC Chairman Neil Chatterjee, October 13, 2017
- "The unknowns are what we're going to have to deal with: if there was a physical attack, if you had [an explosion like the one on the Spectra pipeline that wasn't] fixed in a timely manner heading into the winter heating season, central Pennsylvania would have had potential issues. . . So now the conversation's gotten broader around these cascading events, and then how do you price resiliency? That conversation needs to take place." FERC Commissioner Rob Powelson, October 27, 2017
- "We used to talk about equipment failure and outages caused by storms. Now, the threat profile has changed, the considerations are broader. There could be intentional attacks – cyber or physical. Those concerns lead us beyond reliability and into resilience." PJM CEO and President Andrew L. Ott, September 20, 2017

Exelon recommends that FERC:

1. Immediately require PJM to submit its energy price formation proposal
2. Require the affected RTOs to submit detailed information on the grid's vulnerabilities to enable the development of a design basis threat analysis that can inform cost-effective market reforms, and
3. State that it will not interfere with state programs that value resilient resources like nuclear plants

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ZEC Updates

New York ZEC Legal Challenges

Federal Case:

- Case dismissed on July 25 and judgment entered on July 27
- "The ZEC program does not thwart the goal of an efficient energy market; rather, it encourages through financial incentives the production of clean energy."
- On August 24, the plaintiffs appealed to the US Court of Appeals for the 2nd Circuit
- Briefing schedule:
  - Plaintiff-Appellant Opening Brief filed October 13
  - Reply Briefs due December 1
  - Oral arguments will then follow

State Case:

- Motions to dismiss procedural challenges filed in NY State court were briefed in 1Q17
- The court heard oral arguments on June 19
- Currently awaiting decision; next step determined by outcome

IL ZEC Legal Challenges

- Both cases dismissed and judgment entered July 14
- "The ZEC program does not conflict with the Federal Power Act."
- On July 17, both sets of plaintiffs appealed to the US Court of Appeals for the 7th Circuit
- On July 18, the 7th Circuit consolidated the appeals and set a briefing schedule:
  - Plaintiff-Appellant Opening Brief filed August 28
  - Reply Briefs due December 12
  - Oral arguments will then follow

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Exelon Policy Priorities

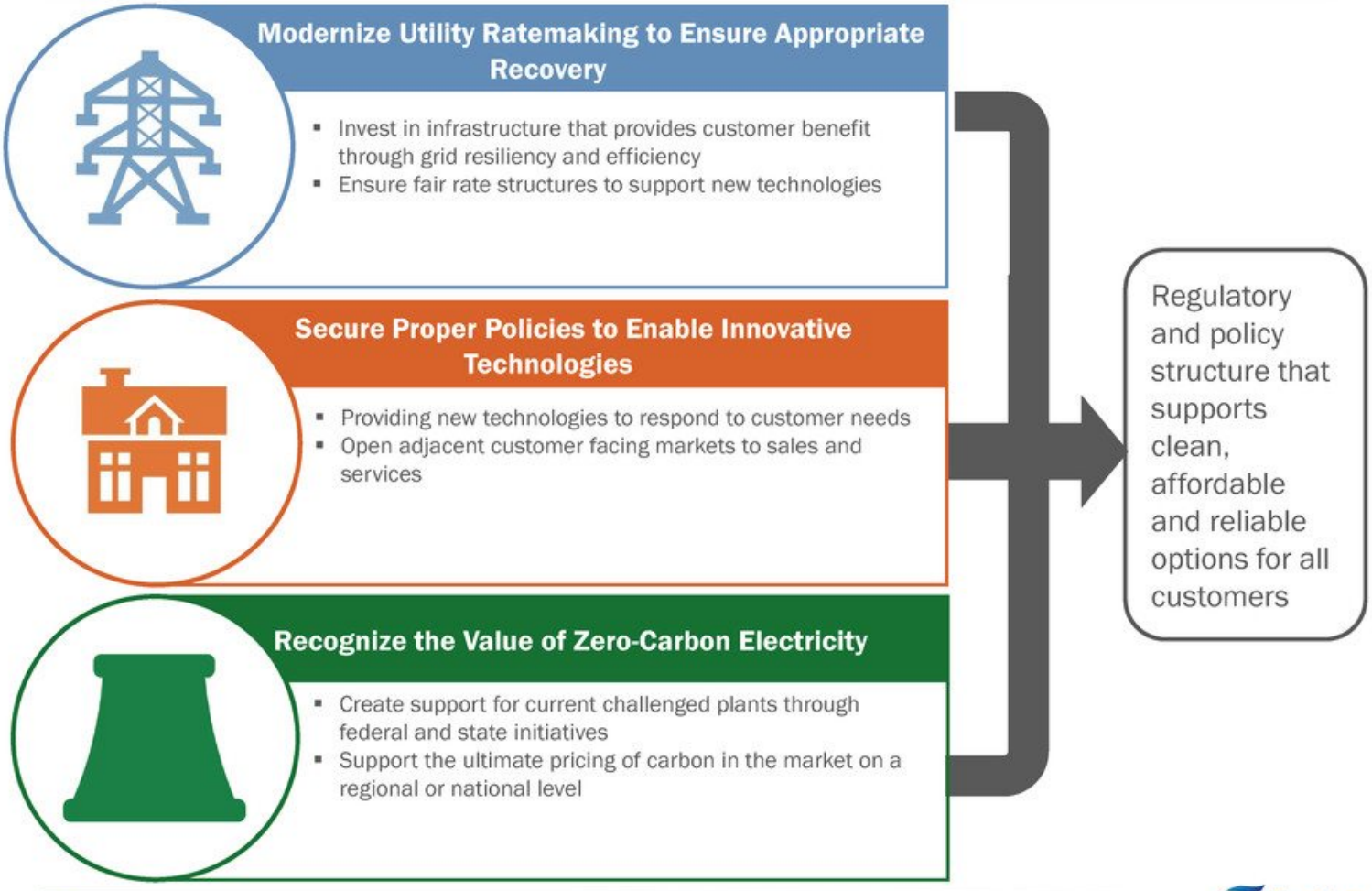

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Our Carbon Policy Principles

- **Exelon believes in our nation's ability to transition the generation fleet to a zero-carbon future while maintaining affordable and reliable electric service for consumers**
- For the foreseeable future, the most cost-effective carbon solution for our customers will be the continued operation of our nation's nuclear fleet
- Exelon believes competitive markets produce superior results for consumers and drive innovation. However, those markets do not currently incorporate appropriate pricing for environmental attributes.
- **Exelon is pursuing a two-part strategy for moving toward a more competitive treatment of CO_2 emissions:**
  - **First, we must maintain nuclear units that provide a cost-effective form of CO_2 abatement.** The New York ZEC program demonstrates that as long as the clean energy payment required to maintain operations at existing nuclear units is lower than the social cost of CO_2 emissions and the cost of CO_2 abatement being paid to other zero carbon resources, maintaining nuclear capacity should be selected as the most competitive source of CO_2 abatement.
  - **Second, we must continue to work toward a technology neutral price of CO_2 abatement.** Exelon is pursuing approaches to reflect a uniform price on CO_2 in wholesale markets as an eventual substitute for technology-specific subsidies. As these approaches are phased in, the ZEC programs have been designed to automatically reduce ZEC payments in response to higher energy prices.

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Financial Overview

Strong Third Quarter Results

Q3 2017 EPS Results

- GAAP earnings were $0.85/share in Q3 2017 vs. $0.53/share in Q3 2016
- Adjusted operating earnings* were $0.85/share in Q3 2017 vs. $0.91/share in Q3 2016, at the mid-point of our guidance range of $0.80-$0.90/share

Note: Amounts may not sum due to rounding
* Refer to pages 3 and 4 for information regarding non-GAAP financial measures

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Narrowing 2017 Adjusted Operating Earnings* Guidance Range

(1) 2017 earnings guidance based on expected average outstanding shares of 949M. Earnings guidance for OpCos may not sum up to consolidated EPS guidance.
(2) Revised guidance reflects delay in Illinois ZEC revenue recognition for 2017 until 2018, shifting $0.09 of EPS

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Cost Management is Integral to Our Business Strategy

ExGen and BSC Cost Reductions Since Constellation Merger

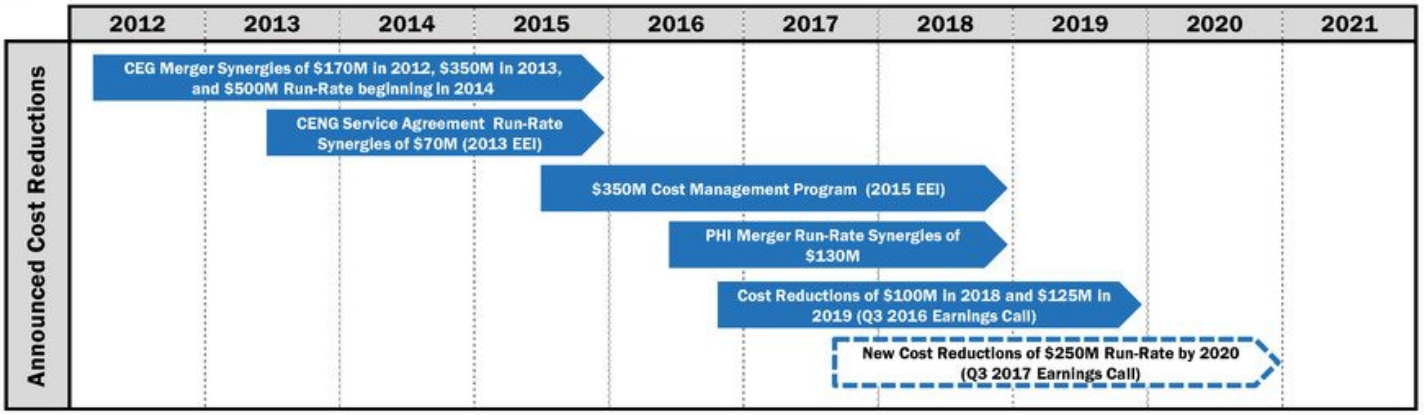

ExGen Forecast O&M* Q3 2017 ($M)(1)

(1) Adjusted for TMI retirement and removal of EGTP, net of other expenses

ExGen Forecast O&M*: Q3 2017 vs. Q4 2016(1)

ExGen O&M ($M)	2017	2018	2019	2020	2017-2020 CAGR
Q4 2016 O&M	$4,850	$4,725	$4,725	$4,775	- 0.5%
EGTP & TMI	($0)	($50)	($125)	($225)	-
Q4 '16 O&M, Net of EGTP & TMI	**$4,850**	**$4,675**	**$4,600**	**$4,550**	**-2.1%**
Cost Savings	($0)	($75)	($150)	($250)	-
Q3 2017 O&M	**$4,850**	**$4,600**	**$4,450**	**$4,300**	**-3.9%**

Exelon.

ExGen's Strong Free Cash Flow Supports Utility Growth and Debt Reduction

2017-2020 Exelon Generation Free Cash Flow* and Uses of Cash ($B)

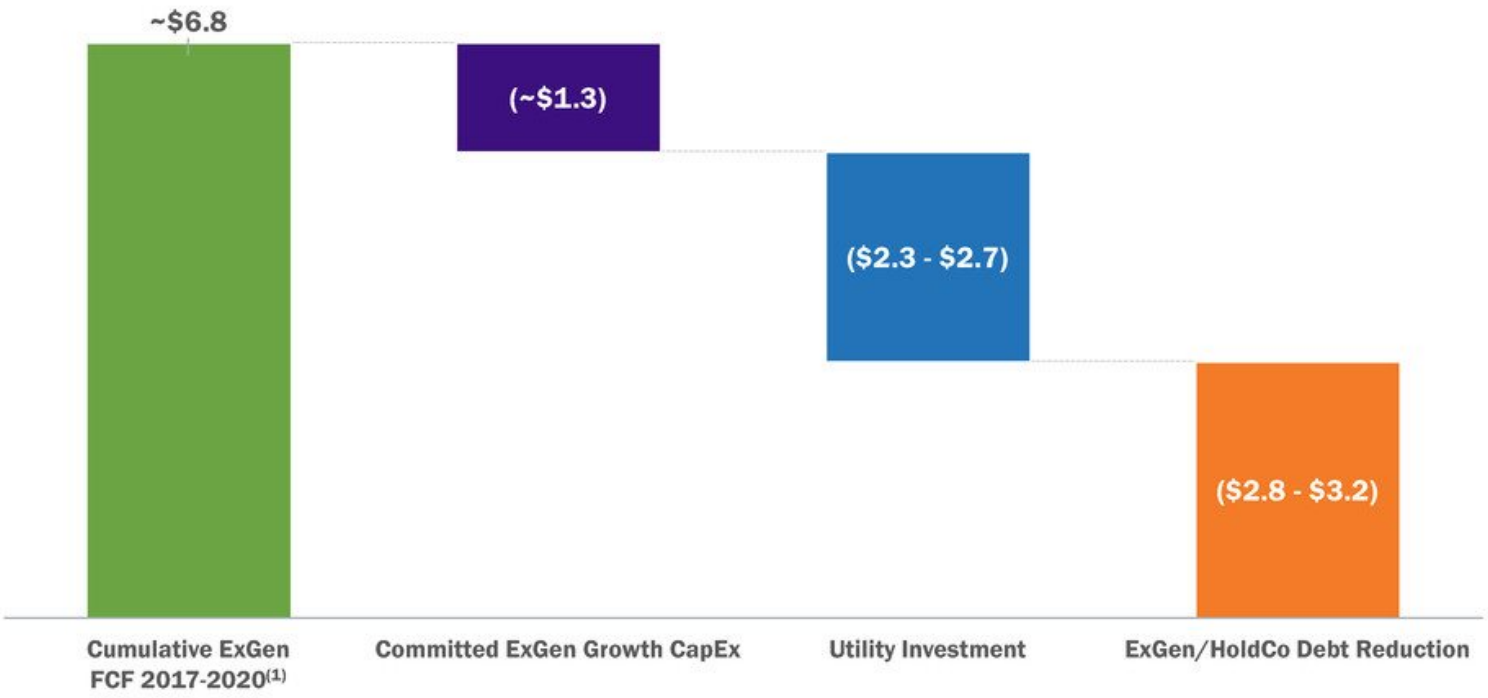

Redeploying Exelon Generation's free cash flow to maximize shareholder value

(1) Sources include change in margin, tax parent benefit, equity investments, and acquisitions and divestitures

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Maintaining Strong Investment Grade Credit Ratings is a Top Financial Priority

Exelon S&P FFO/Debt %*(1,4,6,7)

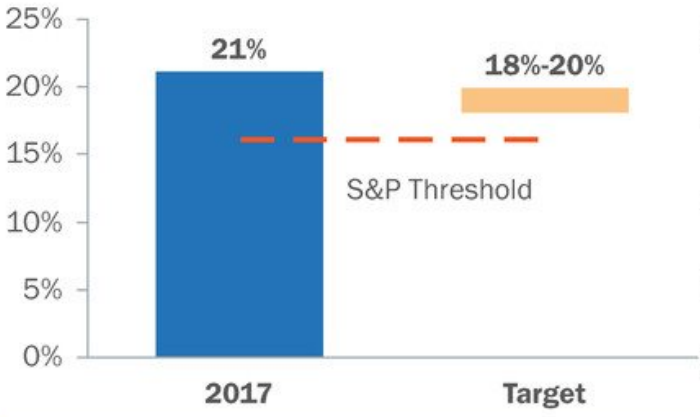

ExGen Debt/EBITDA Ratio*(5,6,7)

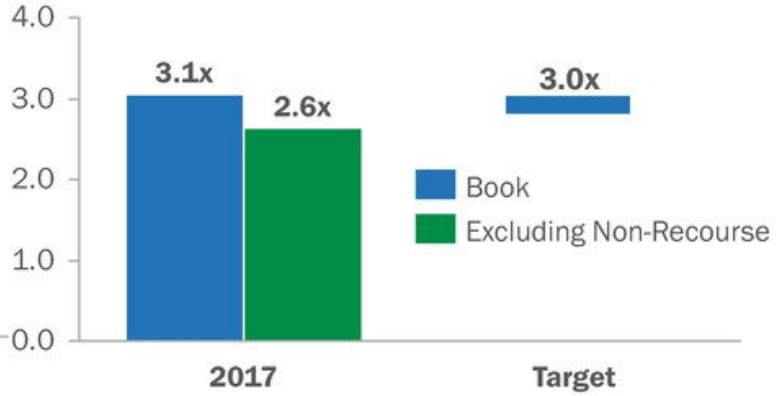

Credit Ratings by Operating Company

Current Ratings(2,3)	ExCorp	ExGen	ComEd	PECO	BGE	ACE	DPL	Pepco
Moody's	Baa2	Baa2	A1	Aa3	A3	A3	A2	A2
S&P	BBB-	BBB	A-	A-	A-	A	A	A
Fitch	BBB	BBB	A	A	A-	A-	A	A-

(1) Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment
(2) Current senior unsecured ratings as of October 24, 2017, for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd, PECO, ACE, DPL, and Pepco
(3) All ratings have a "Stable" outlook
(4) Exelon Corp downgrade threshold (red dotted line) is based on the S&P Exelon Corp Summary Report; represents minimum level to maintain current Issuer Credit Rating of BBB at Exelon Corp
(5) Reflects net book debt (YE debt less cash on hand) / adjusted operating EBITDA*
(6) Reflects removal of EGTP
(7) Reflects delay in Illinois ZEC revenue recognition from 2017 to 2018

Exelon.

Theoretical Dividend Affordability from Utility less HoldCo[1,2]

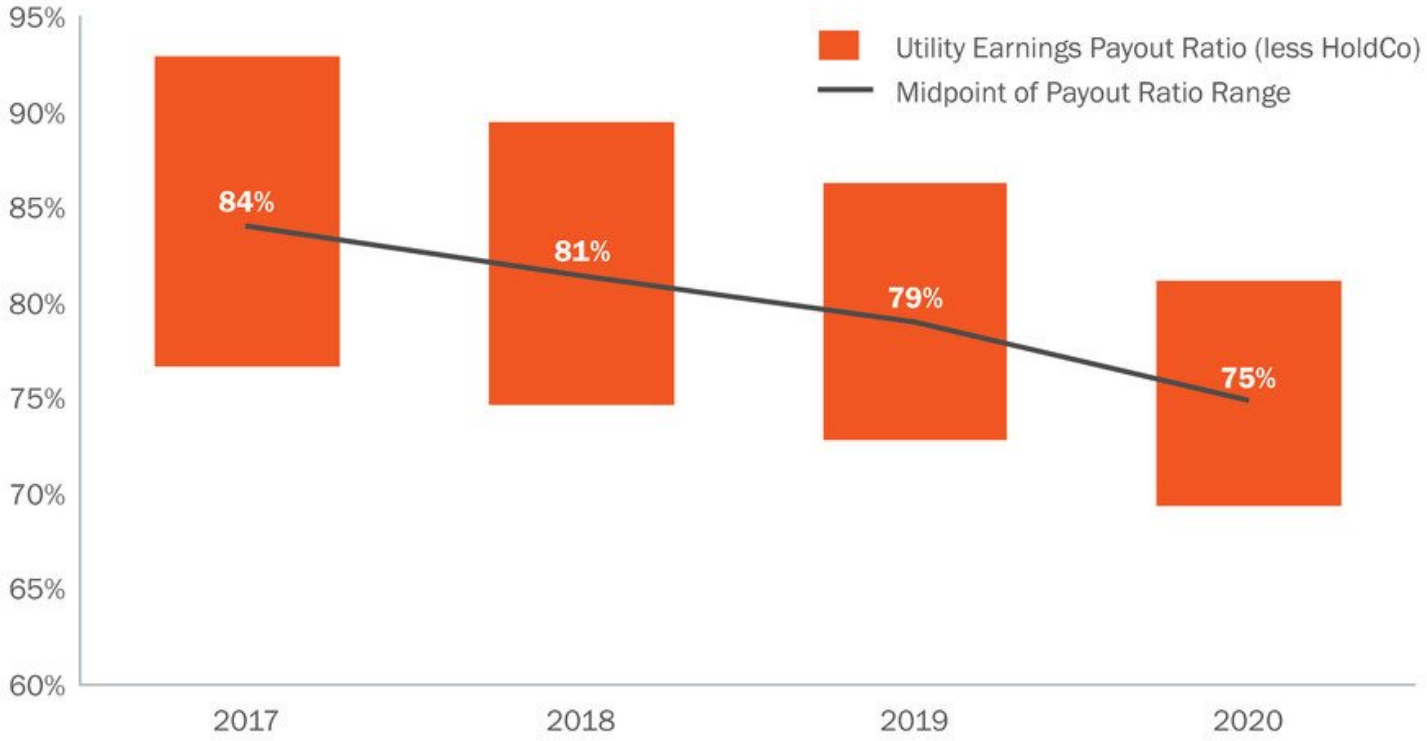

Utility less HoldCo payout ratio falling consistently even as dividend grows

(1) Chart is illustrative and shows theoretical payout ratio if utilities supported 100% of the external dividend and interest expense at HoldCo. Currently, the utilities have a payout ratio of 70% which covers the majority of the external dividend and interest expense at HoldCo with ExGen covering the remainder.
(2) Board of directors has approved a policy of 2.5% per year dividend increase through 2018. For illustrative purposes only, the chart assumes the dividend continues to increase 2.5% per year through 2020, although the board has not yet established dividend policy for periods after 2018. Quarterly dividends are subject to declaration by the board of directors.

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Recognition for Stewardship and Employee Engagement

Supplier Diversity: Exelon is the only utility and energy company to be inducted into the Billion Dollar Roundtable, which recognizes corporations that have achieved spending of $1 billion with minority and women-owned suppliers; our 2016 spend was nearly $2B

Civic 50: Points of Light named Exelon utility sector leader in its annual ranking of the nation's most community-minded public and private companies

Top 50 Companies for Diversity: National recognition from DiversityInc, first year in Top 50 after being named a DiversityInc "Top Utility" in 2015 and 2016

Best Places to Work in 2017: Ranked No. 18 on Indeed.com survey of Fortune 500 companies based on employee reviews

CEO Action for Diversity & Inclusion™: Joined 150 leading companies in the largest CEO-driven business commitment to advance diversity and inclusion

Top 50 Most Energy-Efficient Utilities: American Council for an Energy-Efficient Economy ranks BGE and ComEd in the top 10 with PECO also making the list

Lowest Carbon Emissions: 2017 Air Emissions Benchmarking Report notes Exelon's generation fleet had the lowest carbon dioxide emissions of the top 20 privately held and investor-owned energy producers

HeForShe: In continuing its commitment to gender equality, Exelon joined the United Nations HeForShe campaign, which provides a platform on which men can engage and become change agents for gender equality

Hurricane Support

- More than 2,200 employees, contractors and support personnel from Exelon's six utilities mobilized to assist residents in the southeastern U.S. impacted by Hurricane Irma
  - Exelon teams shared our experience with severe weather restoration efforts and industry-leading best practices to lead one of the largest contingents of support nationally
  - Crews deployed for more than two weeks helping to restore power to nearly eight million customers in Florida and Georgia
- Approximately 250 Exelon employee volunteers logged over 1,300 hours for disaster relief activities
- Exelon and its employees contributed approximately $820,000 in disaster relief

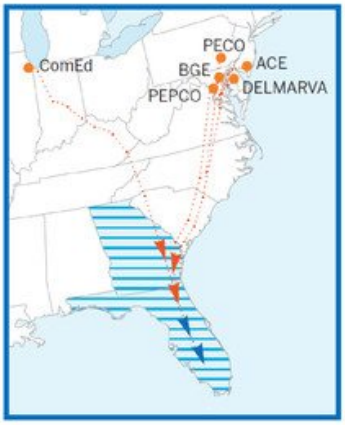

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Appendix

Exelon Debt Maturity Profile(1)

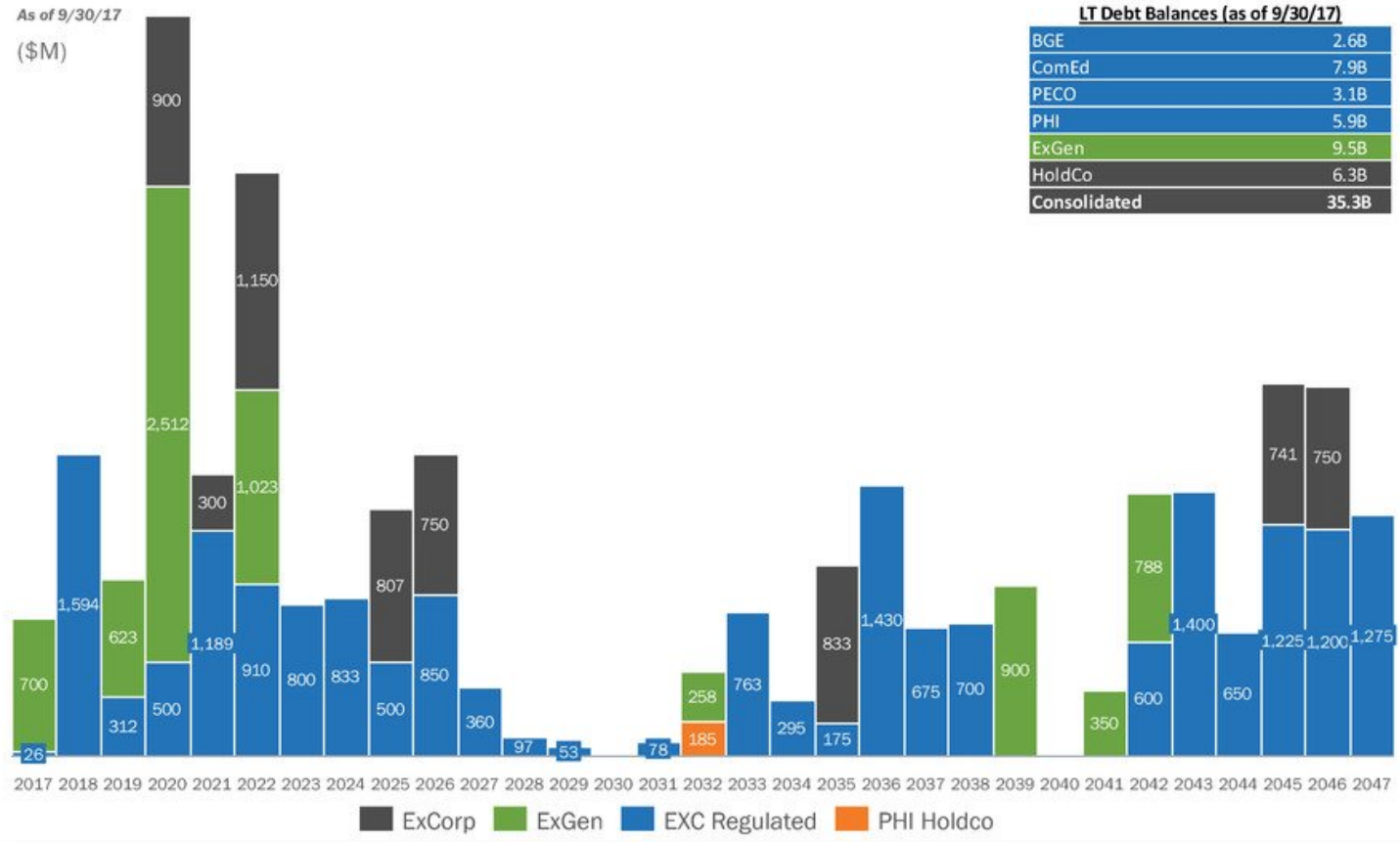

Exelon's weighted average LTD maturity is approximately 14 years

(1) ExGen debt includes legacy CEG debt; Excludes securitized debt and non-recourse debt

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Capacity Market: PJM

PJM Capacity Revenues[1,2,3]

(1) Revenues reflect capacity cleared in Base, CP transitional & incremental auctions and are for calendar years
(2) Revenues reflect owned and contracted generation
(3) Reflects 50.01% ownership at CENG
(4) Volumes at ownership and rounded

Cleared Volumes (MW)[4]	2019/2020 CP	2019/2020 Price	2019/2020 Base	2019/2020 Price	2020/2021 CP	2020/2021 Price
Comed						
Nuclear	6,925	$203	-	$183	8,075	$188
Fossil/Other	-	$203	50	$183	-	$188
Subtotal	**6,925**		**50**		**8,075**	
EMAAC						
Nuclear	4,375	$120	-	$100	4,350	$188
Fossil/Other	1,525	$120	1,675	$100	2,325	$188
Subtotal	**5,900**		**1,675**		**6,675**	
SWMAAC						
Nuclear	850	$100	-	$80	850	$86
Fossil/Other	-	$100	-	$80	-	$86
Subtotal	**850**		**-**		**850**	
MAAC						
Nuclear	-		-		-	$86
Fossil/Other	-		-		225	$86
Subtotal	**-**		**-**		**225**	
BGE						
Nuclear	-	$100	-	$80	-	$86
Fossil/Other	375	$100	225	$80	375	$86
Subtotal	**375**		**225**		**375**	
Rest of RTO						
Nuclear	-	$100	-	$80	-	$77
Fossil/Other	275	$100	75	$80	-	$77
Subtotal	**275**		**75**		**-**	
PJM Total						
Nuclear	12,150		-		13,275	
Fossil/Other	2,175		2,025		2,925	
Grand Total	**14,325**		**2,025**		**16,200**	

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Portfolio Management Strategy

Strategic Policy Alignment

- Aligns hedging program with financial policies and financial outlook
  - Establish minimum hedge targets to meet financial objectives of the company (dividend, credit rating)
  - Hedge enough commodity risk to meet future cash requirements under a stress scenario

Three-Year Ratable Hedging

- Ensure stability in near-term cash flows and earnings
  - Disciplined approach to hedging
  - Tenor aligns with customer preferences and market liquidity
  - Multiple channels to market that allow us to maximize margins
  - Large open position in outer years to benefit from price upside

Bull / Bear Program

- Ability to exercise fundamental market views to create value within the ratable framework
  - Modified timing of hedges versus purely ratable
  - Cross-commodity hedging (heat rate positions, options, etc.)
  - Delivery locations, regional and zonal spread relationships

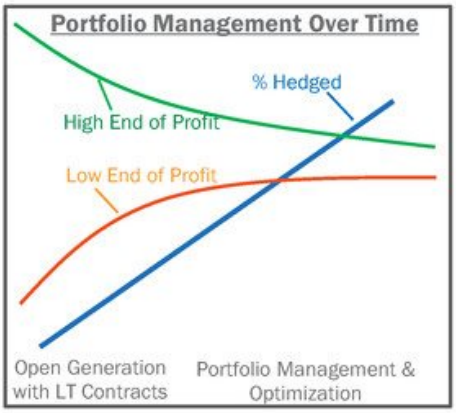

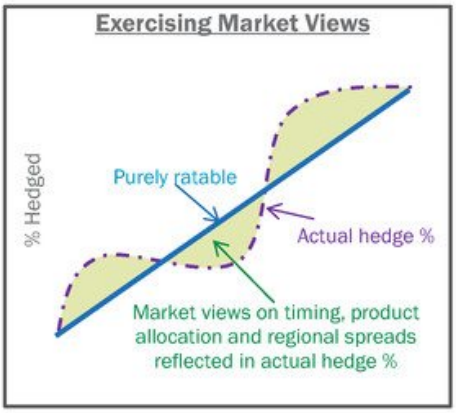

Protect Balance Sheet | **Ensure Earnings Stability** | **Create Value**

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Components of Gross Margin Categories

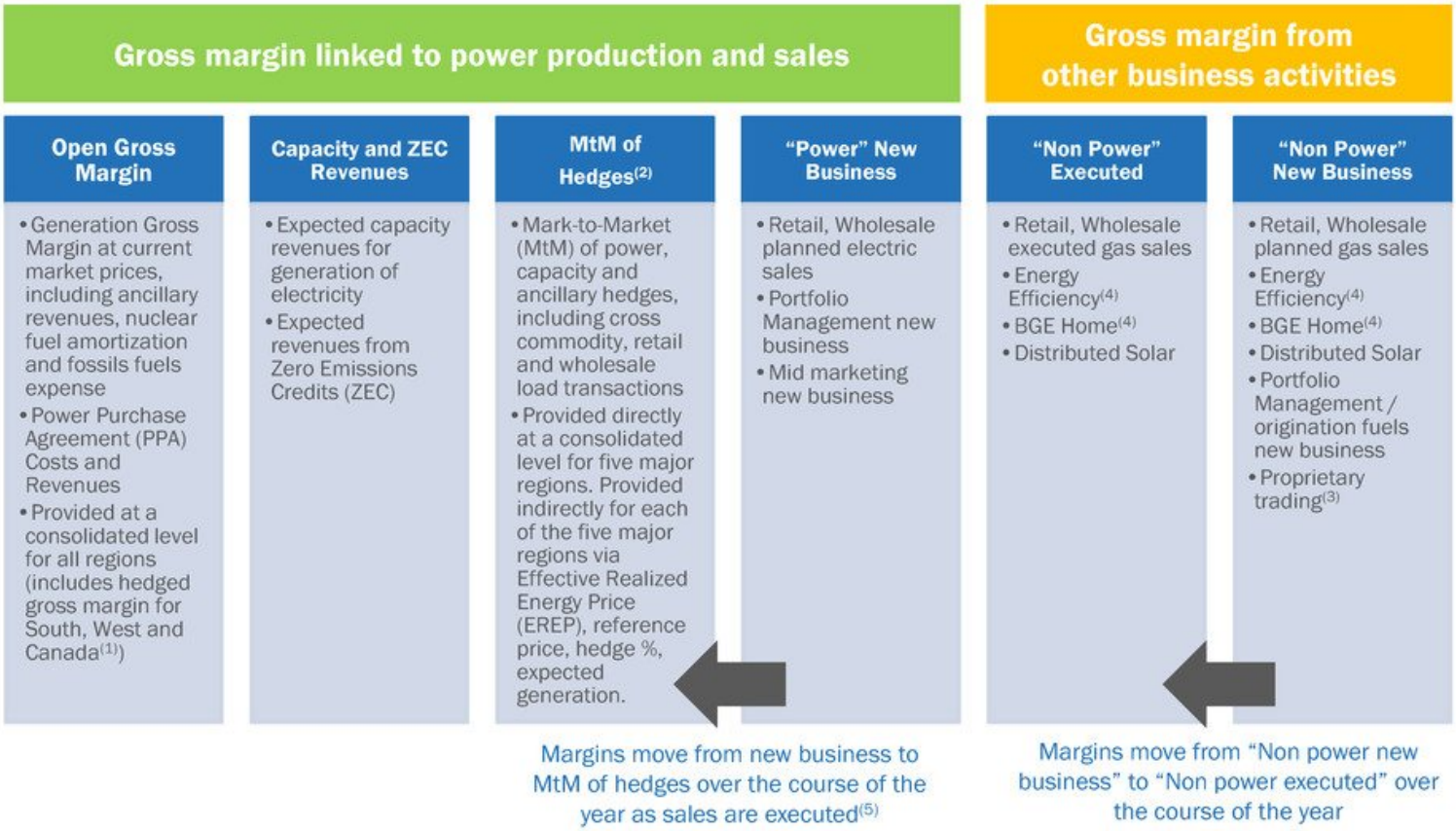

(1) Hedged gross margins for South, West & Canada region will be included with Open Gross Margin; no expected generation, hedge %, EREP or reference prices provided for this region
(2) MtM of hedges provided directly for the five larger regions; MtM of hedges is not provided directly at the regional level but can be easily estimated using EREP, reference price and hedged MWh
(3) Proprietary trading gross margins will generally remain within "Non Power" New Business category and only move to "Non Power" Executed category upon management discretion
(4) Gross margin for these businesses are net of direct "cost of sales"
(5) Margins for South, West & Canada regions and optimization of fuel and PPA activities captured in Open Gross Margin

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ExGen Disclosures

Gross Margin Category ($M)[1]	2017	2018	2019
Open Gross Margin (including South, West & Canada hedged GM)[2,5]	$3,600	$3,900	$3,700
Capacity and ZEC Revenues[2,5,6]	$1,700	$2,300	$2,000
Mark-to-Market of Hedges[2,3]	$2,150	$650	$450
Power New Business / To Go	$100	$700	$850
Non-Power Margins Executed	$350	$200	$100
Non-Power New Business / To Go	$100	$300	$400
Total Gross Margin*[4,5]	**$8,000**	**$8,050**	**$7,500**

Reference Prices[4]	2017	2018	2019
Henry Hub Natural Gas ($/MMBtu)	$3.14	$3.05	$2.89
Midwest: NiHub ATC prices ($/MWh)	$26.52	$27.45	$26.36
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$28.81	$30.77	$29.22
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	($0.78)	$1.22	$2.65
New York: NY Zone A ($/MWh)	$24.38	$27.29	$26.67
New England: Mass Hub ATC Spark Spread ($/MWh) *ALQN Gas, 7.5HR, $0.50 VOM*	$4.36	$3.99	$4.24

(1) Gross margin categories rounded to nearest $50M
(2) Excludes EDF's equity ownership share of the CENG Joint Venture
(3) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(4) Based on September 30, 2017, market conditions
(5) Reflects ownership of FitzPatrick as of April 1, 2017, and TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.
(6) 2018 includes $150M of IL ZEC revenues associated with 2017 production

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Generation and Hedges	2017	2018	2019
Exp. Gen (GWh)[1]	**200,200**	**199,300**	**202,000**
Midwest	95,900	95,800	97,000
Mid-Atlantic[2,6]	60,700	60,500	59,000
ERCOT	17,800	19,500	20,800
New York[2,6]	14,700	15,500	16,600
New England	11,100	8,000	8,600
% of Expected Generation Hedged[3]	**98%-101%**	**79%-82%**	**45%-48%**
Midwest	97%-100%	74%-77%	41%-44%
Mid-Atlantic[2,6]	98%-101%	90%-93%	51%-54%
ERCOT	97%-100%	77%-80%	44%-47%
New York[2,6]	99%-102%	71%-74%	43%-46%
New England	103%-106%	86%-89%	52%-55%
Effective Realized Energy Price ($/MWh)[4]			
Midwest	$33.00	$29.50	$29.50
Mid-Atlantic[2,6]	$44.00	$37.00	$39.00
ERCOT[5]	$11.00	$3.50	$3.50
New York[2,6]	$41.50	$37.50	$32.00
New England[5]	$20.00	$2.50	$3.00

(1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 15 refueling outages in 2017, 15 in 2018, and 11 in 2019 at Exelon-operated nuclear plants and Salem. Expected generation assumes capacity factors of 93.4%, 93.2% and 94.7% in 2017, 2018, and 2019, respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2018 and 2019 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years.

(2) Excludes EDF's equity ownership share of CENG Joint Venture

(3) Percent of expected generation hedged is the amount of equivalent sales divided by expected generation. Includes all hedging products, such as wholesale and retail sales of power, options and swaps.

(4) Effective realized energy price is representative of an all-in hedged price, on a per MWh basis, at which expected generation has been hedged. It is developed by considering the energy revenues and costs associated with our hedges and by considering the fossil fuel that has been purchased to lock in margin. It excludes uranium costs, RPM capacity and ZEC revenues, but includes the mark-to-market value of capacity contracted at prices other than RPM clearing prices including our load obligations. It can be compared with the reference prices used to calculate open gross margin in order to determine the mark-to-market value of Exelon Generation's energy hedges.

(5) Spark spreads shown for ERCOT and New England

(6) Reflects ownership of FitzPatrick as of April 1, 2017, and TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.

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ExGen Hedged Gross Margin* Sensitivities

Gross Margin* Sensitivities (with existing hedges)[1]	2017	2018	2019
Henry Hub Natural Gas ($/MMBtu)			
+ $1/MMBtu	$(20)	$140	$515
- $1/MMBtu	$(10)	$(210)	$(500)
NiHub ATC Energy Price			
+ $5/MWh	-	$120	$265
- $5/MWh	-	$(115)	$(265)
PJM-W ATC Energy Price			
+ $5/MWh	-	$10	$150
- $5/MWh	$5	$(40)	$(145)
NYPP Zone A ATC Energy Price			
+ $5/MWh	-	$25	$40
- $5/MWh	-	$(20)	$(45)
Nuclear Capacity Factor			
+/- 1%	+/- $10	+/- $35	+/- $35

(1) Based on September 30, 2017, market conditions and hedged position; gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically; power price sensitivities are derived by adjusting the power price assumption while keeping all other price inputs constant; due to correlation of the various assumptions, the hedged gross margin impact calculated by aggregating individual sensitivities may not be equal to the hedged gross margin impact calculated when correlations between the various assumptions are also considered; sensitivities based on commodity exposure which includes open generation and all committed transactions; excludes EDF's equity share of CENG Joint Venture

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ExGen Hedged Gross Margin* Upside/Risk

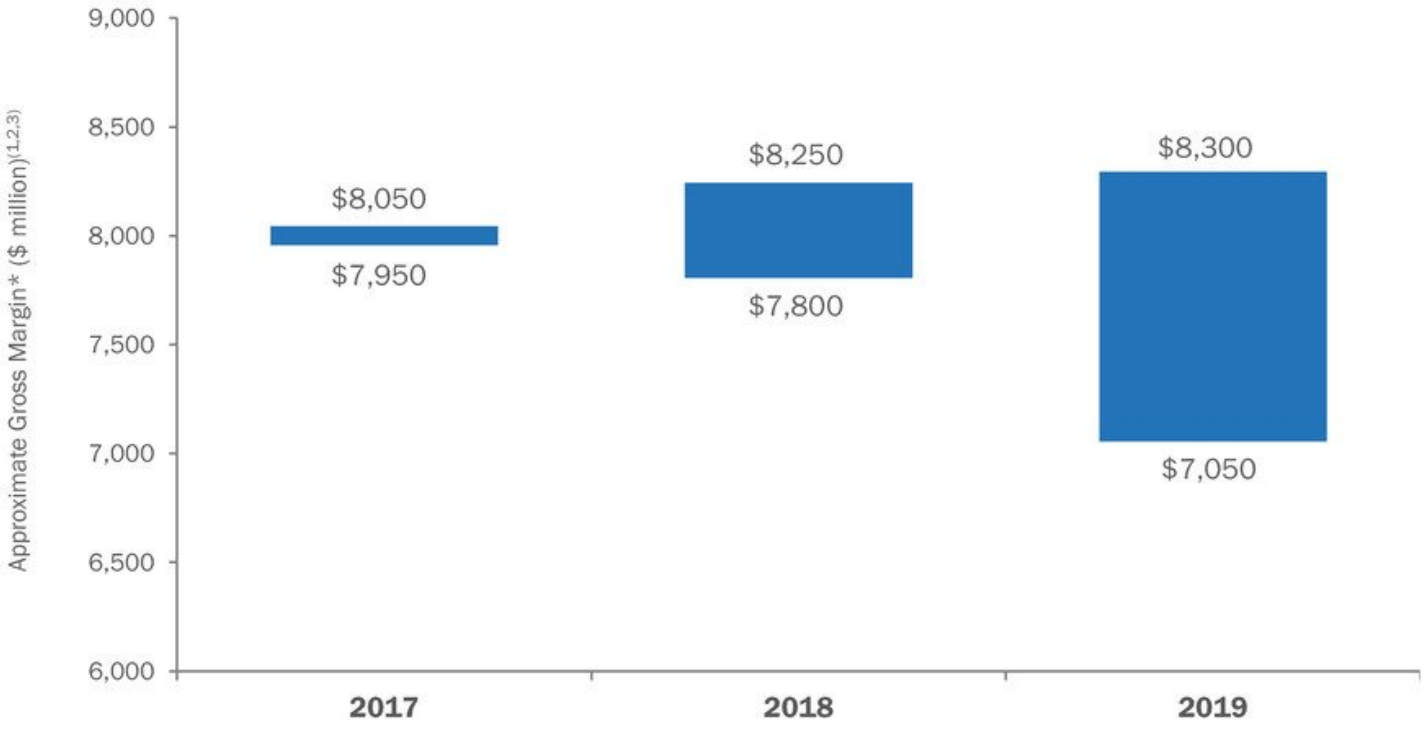

(1) Represents an approximate range of expected gross margin, taking into account hedges in place, between the 5th and 95th percent confidence levels assuming all unhedged supply is sold into the spot market; approximate gross margin ranges are based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes; these ranges of approximate gross margin in 2018 and 2019 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years; the price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of September 30, 2017

(2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions

(3) Reflects ownership of FitzPatrick as of April 1, 2017, and TMI and Oyster Creek retirements in September 2019 and December 2019, respectively. EGTP removal impacts partial year 2017 and full year 2018 and 2019.

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Illustrative Example of Modeling Exelon Generation 2018 Gross Margin*

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	← $3.9 billion →					
(B)	Capacity and ZEC	← $2.3 billion →					
(C)	Expected Generation (TWh)	95.8	60.5	19.5	15.5	8.0	
(D)	Hedge % (assuming mid-point of range)	75.5%	91.5%	78.5%	72.5%	87.5%	
(E=C*D)	Hedged Volume (TWh)	72.3	55.4	15.3	11.2	7.0	
(F)	Effective Realized Energy Price ($/MWh)	$29.50	$37.00	$3.50	$37.50	$2.50	
(G)	Reference Price ($/MWh)	$27.45	$30.77	$1.22	$27.29	$3.99	
(H=F-G)	Difference ($/MWh)	$2.05	$6.23	$2.28	$10.21	($1.49)	
(I=E*H)	Mark-to-Market value of hedges ($ million)(1)	$150	$345	$35	$115	($10)	
(J=A+B+I)	Hedged Gross Margin ($ million)	$6,850					
(K)	Power New Business / To Go ($ million)	$700					
(L)	Non-Power Margins Executed ($ million)	$200					
(M)	Non-Power New Business / To Go ($ million)	$300					
(N=J+K+L+M)	Total Gross Margin*	$8,050 million					

(1) Mark-to-market rounded to the nearest $5 million

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Additional ExGen Modeling Data

Total Gross Margin Reconciliation (in $M)[1]	2017	2018	2019
Revenue Net of Purchased Power and Fuel Expense*[2,3]	**$8,575**	**$8,575**	**$8,025**
Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at merger date	$50	-	-
Other Revenues[4]	$(150)	$(200)	$(200)
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses	$(475)	$(325)	$(325)
Total Gross Margin* (Non-GAAP)	**$8,000**	**$8,050**	**$7,500**

Key ExGen Modeling Inputs (in $M)[1,5]	2017
Other[6]	$175
Adjusted O&M*	$(4,850)
Taxes Other Than Income (TOTI)[7]	$(400)
Depreciation & Amortization[8]	$(1,075)
Interest Expense[9]	$(400)
Effective Tax Rate	**32.0%**

(1) All amounts rounded to the nearest $25M
(2) ExGen does not forecast the GAAP components of RNF separately, as to do so would be unduly burdensome. RNF also includes the RNF of our proportionate ownership share of CENG.
(3) Excludes the Mark-to-Market impact of economic hedging activities due to the volatility and unpredictability of the future changes to power prices
(4) Other Revenues reflects primarily revenues from Exelon Nuclear Partners, JExel Nuclear JV, variable interest entities, funds collected through revenues for decommissioning the former PECO nuclear plants through regulated rates, and gross receipts tax revenues
(5) ExGen amounts for O&M, TOTI, Depreciation & Amortization; excludes EDF's equity ownership share of the CENG Joint Venture
(6) Other reflects Other Revenues excluding gross receipts tax revenues, nuclear decommissioning trust fund earnings from unregulated sites, and the minority interest in ExGen Renewables JV and Bloom
(7) TOTI excludes gross receipts tax of $125M
(8) Excludes P&L neutral decommissioning depreciation
(9) Interest expense includes impact of reduced capitalized interest due to Texas CCGT plants in service as of May and June of 2017. Capitalized interest will be an additional ~$25M lower in 2018 as well due to this.

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Appendix

Reconciliation of Non-GAAP Measures

Q3 2016 QTD GAAP EPS Reconciliation

Three Months Ended September 30, 2016	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2016 GAAP Earnings (Loss) Per Share	**$0.25**	**$0.04**	**$0.13**	**$0.06**	**$0.18**	**($0.13)**	**$0.53**
Mark-to-market impact of economic hedging activities	(0.06)	-	-	-	-	-	(0.06)
Unrealized gains related to NDT fund investments	(0.07)	-	-	-	-	-	(0.07)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.01	-	-	-	-	-	0.01
Merger commitments	-	-	-	-	(0.04)	0.05	0.01
Long-Lived asset impairments	0.01	-	-	-	-	-	0.01
Plant retirements and divestitures	0.22	-	-	-	-	-	0.22
Cost management program	0.01	-	-	-	-	-	0.01
Like-kind exchange tax position	-	0.16	-	-	-	0.05	0.21
CENG noncontrolling interest	0.03	-	-	-	-	-	0.03
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.41**	**$0.20**	**$0.13**	**$0.06**	**$0.14**	**$(0.03)**	**$0.91**

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Exelon.

Q3 2017 QTD GAAP EPS Reconciliation

Three Months Ended September 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP (Loss) Earnings Per Share	**$0.32**	**$0.20**	**$0.12**	**$0.06**	**$0.16**	**($0.00)**	**$0.85**
Mark-to-market impact of economic hedging activities	(0.05)	-	-	-	-	-	(0.05)
Unrealized gains related to NDT fund investments	(0.07)	-	-	-	-	-	(0.07)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.01	-	-	-	(0.01)	-	-
Long-lived asset impairments	0.03	-	-	-	-	-	0.03
Plant retirements and divestitures	0.08	-	-	-	-	-	0.08
Cost management program	0.01	-	-	-	-	-	0.01
Reassessment of state deferred income taxes	0.02	-	-	-	-	(0.04)	(0.02)
Bargain purchase gain	(0.01)	-	-	-	-	-	(0.01)
CENG noncontrolling interest	0.02	-	-	-	-	-	0.02
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.36**	**$0.19**	**$0.12**	**$0.07**	**$0.15**	**($0.04)**	**$0.85**

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

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Q3 2016 YTD GAAP EPS Reconciliation

Nine Months Ended September 30, 2016	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2016 GAAP Earnings (Loss) Per Share	**$0.58**	**$0.32**	**$0.37**	**$0.20**	**($0.10)**	**$(0.37)**	**$1.00**
Mark-to-market impact of economic hedging activities	0.07	-	-	-	-	-	0.07
Unrealized gains related to NDT fund investments	(0.13)	-	-	-	-	-	(0.13)
Amortization of commodity contract intangibles	0.01	-	-	-	-	-	0.01
Merger and integration costs	0.02	-	-	-	0.04	0.04	0.10
Merger commitments	-	-	-	-	0.26	0.17	0.43
Long-lived asset impairments	0.11	-	-	-	-	-	0.11
Plant retirements and divestitures	0.37	-	-	-	-	-	0.37
Reassessment of state deferred income taxes	0.01	-	-	-	-	(0.01)	-
Cost management program	0.02	-	-	-	-	-	0.03
Like-kind exchange tax position	-	0.16	-	-	-	0.05	0.21
CENG noncontrolling interest	0.04	-	-	-	-	-	0.04
2016 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$1.10**	**$0.48**	**$0.37**	**$0.20**	**$0.20**	**$(0.11)**	**$2.24**

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

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Q3 2017 YTD GAAP EPS Reconciliation

Nine Months Ended September 30, 2017	ExGen	ComEd	PECO	BGE	PHI	Other	Exelon
2017 GAAP Earnings (Loss) Per Share	**$0.51**	**$0.47**	**$0.35**	**$0.24**	**$0.38**	**$0.06**	**$2.01**
Mark-to-market impact of economic hedging activities	0.10	-	-	-	-	-	0.10
Unrealized gains related to NDT fund investments	(0.22)	-	-	-	-	-	(0.22)
Amortization of commodity contract intangibles	0.03	-	-	-	-	-	0.03
Merger and integration costs	0.05	-	-	-	(0.01)	-	0.04
Merger commitments	(0.02)	-	-	-	(0.06)	(0.06)	(0.15)
Long-lived asset impairments	0.31	-	-	-	-	-	0.31
Plant retirements and divestitures	0.15	-	-	-	-	-	0.15
Reassessment of state deferred income taxes	0.02	-	-	-	-	(0.06)	(0.04)
Cost management program	0.02	-	-	-	-	-	0.03
Like-kind exchange tax position	-	0.02	-	-	-	(0.05)	(0.03)
Asset retirement obligation	-	-	-	-	-	-	-
Tax settlements	(0.01)	-	-	-	-	-	(0.01)
Bargain purchase gain	(0.25)	-	-	-	-	-	(0.25)
CENG noncontrolling interest	0.08	-	-	-	-	-	0.08
2017 Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$0.76**	**$0.50**	**$0.35**	**$0.25**	**$0.31**	**($0.12)**	**$2.05**

NOTE: All amounts shown are per Exelon share and represent contributions to Exelon's EPS. Amounts may not add due to rounding.

Exelon.

GAAP to Operating Adjustments

- **Exelon's 2017 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:**
  - Mark-to-market adjustments from economic hedging activities
  - Unrealized gains from NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
  - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the ConEdison Solutions and FitzPatrick acquisition dates
  - Certain merger and integration costs associated with the PHI and FitzPatrick acquisitions
  - Adjustments to reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions
  - Impairments as a result of the ExGen Texas Power, LLC assets held for sale
  - Plant retirements and divestitures at Generation
  - Non-cash impact of the remeasurement of state deferred income taxes, related to changes in statutory tax rates and changes in forecasted apportionment
  - Costs incurred related to a cost management program
  - Certain adjustments related to Exelon's like-kind exchange tax position
  - Non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units
  - Benefits related to the favorable settlement of certain income tax positions related to PHI's unregulated business interests
  - The excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition
  - Generation's noncontrolling interest, primarily related to CENG exclusion items

Exelon.

GAAP to Non-GAAP Reconciliations

YE 2017 Exelon FFO Calculation ($M)[1,2,10,11]	
GAAP Operating Income	$3,500
Depreciation & Amortization	$3,350
EBITDA	$6,850
+/- Non-operating activities and nonrecurring items[3]	$450
- Interest Expense	($1,450)
+ Current Income Tax (Expense)/Benefit	$325
+ Nuclear Fuel Amortization	$1,075
+/- Other S&P Adjustments[4]	$350
= FFO (a)	**$7,600**

YE 2017 Exelon Adjusted Debt Calculation ($M)[1,2,10]	
Long-Term Debt (including current maturities)	$32,050
Short-Term Debt	$1,125
+ PPA Imputed Debt[5]	$350
+ Operating Lease Imputed Debt[6]	$875
+ Pension/OPEB Imputed Debt[7]	$4,100
- Off-Credit Treatment of Debt[8]	($1,725)
- Surplus Cash Adjustment[9]	($600)
+/- Other S&P Adjustments[4]	($650)
= Adjusted Debt (b)	**$35,525**

YE 2017 Exelon FFO/Debt[1,2]		
FFO (a) / Adjusted Debt (b)	=	21%

(1) All amounts rounded to the nearest $25M
(2) Calculated using S&P Methodology. Due to ring-fencing, S&P deconsolidates BGE from Exelon and analyzes solely as an equity investment.
(3) Reflects impact of operating adjustments on GAAP EBITDA
(4) Includes other adjustments as prescribed by S&P
(5) Reflects present value of net capacity purchases
(6) Reflects present value of minimum future operating lease payments
(7) Reflects after-tax unfunded pension/OPEB
(8) Includes non-recourse project debt
(9) Applies 75% of excess cash against balance of LTD
(10) Reflects removal of EGTP
(11) Reflects delay in Illinois ZEC revenue recognition from 2017 to 2018

Exelon.

GAAP to Non-GAAP Reconciliations

YE 2017 ExGen Net Debt Calculation ($M)[1,3]	
Long-Term Debt (including current maturities)	$8,775
Short-Term Debt	$350
- Surplus Cash Adjustment	($300)
= Net Debt (a)	**$8,825**

YE 2017 ExGen Net Debt Calculation ($M)[1,3]	
Long-Term Debt (including current maturities)	$8,775
Short-Term Debt	$350
- Surplus Cash Adjustment	($300)
- Nonrecourse Debt	($1,925)
= Net Debt (a)	**$6,900**

YE 2017 ExGen Operating EBITDA Calculation ($M)[1,3,4]	
GAAP Operating Income	$775
Depreciation & Amortization	$1,375
EBITDA	$2,150
+/- Non-operating activities and nonrecurring items[2]	$725
= Operating EBITDA (b)	**$2,875**

YE 2017 ExGen Operating EBITDA Calculation ($M)[1,3,4]	
GAAP Operating Income	$775
Depreciation & Amortization	$1,375
EBITDA	$2,150
+/- Non-operating activities and nonrecurring items[2]	$725
- EBITDA from projects financed by nonrecourse debt	($250)
= Operating EBITDA (b)	**$2,625**

YE 2017 Book Debt / EBITDA		
Net Debt (a) / Operating EBITDA (b)	=	3.1x

YE 2017 Recourse Debt / EBITDA		
Net Debt (a) / Operating EBITDA (b)	=	2.6x

(1) All amounts rounded to the nearest $25M
(2) Reflects impact operating adjustments on GAAP EBITDA
(3) Reflects removal of EGTP
(4) Reflects delay in Illinois ZEC revenue recognition from 2017 to 2018

Exelon.

GAAP to Non-GAAP Reconciliations

Q3 2017 Operating ROE Reconciliation ($M)[1]	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)[1]	$85	$114	$210	$1,281	$1,690
Operating Exclusions	($23)	($12)	($25)	$34	($25)
Adjusted Operating Earnings[1]	$63	$103	$185	$1,315	$1,665
Average Equity	$1,061	$1,323	$2,419	$12,750	$17,554
Operating ROE (Adjusted Operating Earnings/Average Equity)	**5.9%**	**7.8%**	**7.7%**	**10.3%**	**9.5%**

Q2 2017 Operating ROE Reconciliation ($M)[1]	ACE	Delmarva	Pepco	Legacy EXC	Consolidated EU
Net Income (GAAP)[1]	$91	$127	$203	$1,132	$1,548
Operating Exclusions	($25)	($32)	($29)	$186	$105
Adjusted Operating Earnings[1]	$66	$95	$174	$1,318	$1,653
Average Equity	$1,039	$1,300	$2,390	$12,308	$17,038
Operating ROE (Adjusted Operating Earnings/Average Equity)	**6.4%**	**7.3%**	**7.3%**	**10.7%**	**9.7%**

(1) ACE, Delmarva, and Pepco represents full year of earnings

Exelon.

GAAP to Non-GAAP Reconciliations

ExGen Adjusted O&M Reconciliation ($M)[1]	2017	2018	2019	2020
GAAP O&M	**$6,325**	**$5,300**	**$5,150**	**$5,025**
Decommissioning[2]	25	50	50	50
TMI Retirement	(75)	-	-	-
EGTP Impairment	(450)	-	-	-
Direct cost of sales incurred to generate revenues for certain Constellation and Power businesses[3]	(425)	(325)	(325)	(325)
O&M for managed plants that are partially owned	(425)	(425)	(400)	(425)
Other	(125)	(25)	(25)	(25)
Adjusted O&M (Non-GAAP)	**$4,850**	**$4,600**	**$4,450**	**$4,300**

2017-2020 ExGen Free Cash Flow Calculation ($M)[1]	
Cash from Operations (GAAP)	$15,150
Other Cash from Investing and Activities	($650)
Baseline Capital Expenditures[4]	($4,025)
Nuclear Fuel Capital Expenditures	($3,625)
Free Cash Flow before Growth CapEx and Dividend	**$6,825**

(1) All amounts rounded to the nearest $25M. Items may not sum due to rounding.
(2) Reflects earnings neutral O&M
(3) Reflects the direct cost of sales of certain businesses, which are included in Total Gross Margin*
(4) Baseline capital expenditures refer to maintenance and required capital expenditures necessary for day-to-day plant operations and includes merger commitments

Exelon.

Tax Rate and Utility Asset Projections at Current Plan

Tax Rate Expectations[1]	2018	2019	2020
ExGen Tax Rate	33%	28%	27%
Consolidated Tax Rate	34%	33%	34%
Consol. Cash Tax Rate	1%	6%	28%

Key Highlights

- ExGen's effective tax rate declines due to its declining pre-tax income relative to the tax credits it generates, which remain relatively constant
- Exelon's consolidated tax rate remains reasonably constant as growing earnings from the Utilities at a higher effective tax rate offset the declining tax rate at ExGen

Exelon Utilities Asset Projections ($B)[2]	2018	2019	2020
Rate Base	36.6	38.6	40.8
Deferred Tax Liabilities	14.4	15.2	15.7

Key Highlights

- Deferred tax liabilities are growing at a slowing rate through 2020 as percentage of new investment impacted by bonus depreciation declines

Note: tax rates and liabilities are based on the current tax code before the effect of any reforms that may be adopted
(1) Rounded to the nearest 1%
(2) All numbers reflect year-end 2016

Exelon.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

November 7, 2017

Date of Report (Date of earliest event reported)

Commission File Number	Name of Registrant; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether any of the registrants are emerging growth companies as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if any of the registrants have elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Section 8.01 - Other Events

As previously disclosed, Exelon Generation Company, LLC (“Generation”) has been considering its strategic options with respect to its wholly-owned indirect subsidiary, ExGen Texas Power, LLC (“EGTP”). On May 2, 2017, EGTP entered into a Consent, Waiver and Amendment Agreement (“Consent Agreement”) with the lenders of its $675 million non-recourse senior secured loan due September 18, 2021. Among other things, the Consent Agreement permitted EGTP to draw on its revolving credit facility and initiate an orderly sales process to sell the assets of its wholly-owned subsidiaries (collectively with EGTP, the “Debtors”), the proceeds from which will first be used to pay the administrative costs of the sale, the normal and ordinary costs of operating the plants, and repayment of the secured debt of EGTP. As a result, Exelon Corporation ("Exelon") and Generation classified certain of EGTP's assets and liabilities as held for sale at their respective fair values less costs to sell and recorded associated pre-tax impairment charges of $418 million and $40 million in the second and third quarter of 2017, respectively.

In connection with this orderly sales process, on November 7, 2017, the Debtors filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code (the “Bankruptcy Code”) in the United States Bankruptcy Court for the District of Delaware (the “Bankruptcy Court”, and the petitions for relief therein, the “Chapter 11 Filings”).

The Debtors are seeking Bankruptcy Court authorization to jointly administer the Chapter 11 cases (the “Chapter 11 Cases”) under the caption “In re ExGen Texas Power LLC, et al.” Case No. 17-12377. The Debtors will continue to manage their assets and operate their businesses as “debtors in possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court.

As a result of the bankruptcy filing, Exelon and Generation determined that EGTP’s assets and liabilities (including its nonrecourse senior secured term loan, revolving credit facility and various interest rate and commodity swaps), of which the assets were classified as held for sale at September 30, 2017, will be deconsolidated from Exelon’s and Generation’s consolidated financial statements as of November 7, 2017. Exelon and Generation estimate that a pre-tax gain upon deconsolidation ranging from $125 to $200 million will be recognized in the fourth quarter of 2017.

Concurrently with the Chapter 11 Filings, Generation entered into an asset purchase agreement to acquire one of EGTP’s generating plants, the Handley Generating Station, for approximately $60 million, subject to an adjustment for fuel oil and assumption of certain liabilities. In the Chapter 11 Filings, EGTP has requested that the proposed acquisition of the Handley Generating Station be consummated through a court-approved and supervised sales process. The consummation of the acquisition is subject to the approval of the asset purchase agreement by the Bankruptcy Court following a sale process, and the confirmation of a plan of reorganization in the bankruptcy cases.

* * * * *

This Current Report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from these forward-looking statements made by Exelon Corporation and Exelon Generation Company, LLC (Registrants) include those factors discussed herein as well as those discussed in (1) Exelon's 2016 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 24; (2) Exelon's Third Quarter 2017 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; (3) other factors discussed in filings with the Securities and Exchange Commission by the registrants; and (4) the following important factors, among others:

- the Debtors’ ability to obtain the approval of the Bankruptcy Court with respect to motions filed in the Chapter 11 Cases and the outcomes of Bankruptcy Court rulings and the Chapter 11 Cases in general; and
- the actions and decisions of creditors, regulators and other third parties that have an interest in the Chapter 11 Cases.

Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Current Report. None of the registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Current Report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Jonathan W. Thayer

Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright

Bryan P. Wright
Senior Vice President and Chief Financial Officer
Exelon Generation Company, LLC

November 7, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

November 8, 2013
Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201 (410) 234-5000	52-0280210

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

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☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 7 – Regulation FD

Item 7.01. Regulation FD Disclosure.

On November 11-12, 2013, Exelon Corporation (Exelon) will participate in the Edison Electric Institute Financial Conference. Attached as Exhibit 99.1 to this Current Report on Form 8-K are the presentation slides and handouts to be used at the conference.

Section 9 – Financial Statements and Exhibits

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits* .

Exhibit No.	Description
99.1	Presentation slides and handouts

* * * * *

This combined Form 8-K is being furnished separately by Exelon, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, and Baltimore Gas and Electric Company (Registrants). Information contained herein relating to any individual Registrant has been furnished by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

This Current Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) Exelon's 2012 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 19; (2) Exelon's Third Quarter 2013 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Current Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Current Report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Jonathan W. Thayer
Jonathan W. Thayer
Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright
Bryan P. Wright
Senior Vice President and Chief Financial Officer Exelon Generation Company, LLC

COMMONWEALTH EDISON COMPANY

/s/ Joseph R. Trpik, Jr.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer
Commonwealth Edison Company

PECO ENERGY COMPANY

/s/ Phillip S. Barnett
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
PECO Energy Company

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ Carim V. Khouzami
Carim V. Khouzami
Senior Vice President, Chief Financial Officer and Treasurer
Baltimore Gas and Electric Company

November 8, 2013

EXHIBIT INDEX

Exhibit No.	Description
99.1	Presentation slides and handouts

Exhibit 99.1

Edison Electric Institute Financial Conference

November 11 –12, 2013

S1-SSA-0009 - 10086

Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company and Exelon Generation Company, LLC (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2012 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 19; (2) Exelon's Third Quarter 2013 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Setting the Context

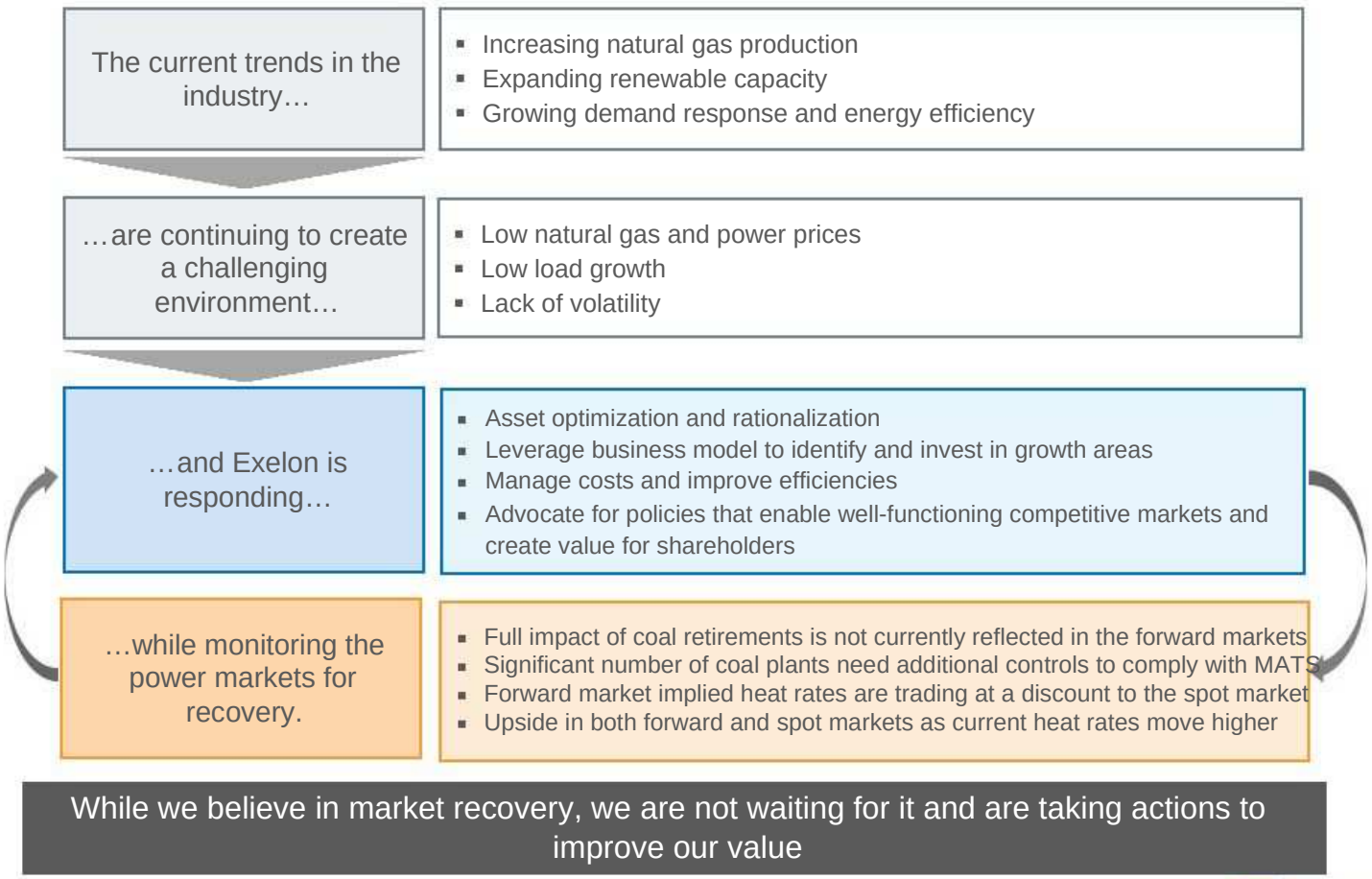

While we believe in market recovery, we are not waiting for it and are taking actions to improve our value

Exelon.

S1-SSA-0009 - 10088

Exelon's Strategic Response to the Current Environment

Asset Optimization

Review Solutions from All Angles

- Infrastructure
- Commercial
- Policy
- Legal

Scenarios for Optimization

- Cost and productivity enhancement
- Operations improvement
- Transmission
- PPAs
- Sale
- Retirement

Growth Investments

Utilities

- Invest $15 billion across the planning period
- Upgrade aging infrastructure
- Invest in infrastructure and new technologies
- Provide stable earnings growth

ExGen

- Invest in renewables and expand footprint in the natural gas business to diversify
- Maintain retail pricing discipline
- Bolster presence in core regions
- Research and invest in emerging technologies

Cost Management

Our Record

- Record of managing costs
- $550 million in merger synergies
- Reduced 2013 ExGen O&M by $150 million
- CENG annual projected synergies of $50-70 million(1)

Continued Focus

- Expand cost management efforts
- Efficiency gains through productivity and technology enhancements
- Share best practices across the utilities

We are biased towards action while we leverage our competencies and strengths to influence our financial future

(1) At 100% ownership, Exelon share is 50%

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Advocating for Public Policy to Enhance Customer and Shareholder Value

Regulatory / Policy Actions

Market Policy

PJM:
- Engaged in stakeholder process regarding PJM reliance on planned resources
- Minimum Offer Price Rule (MOPR) Reform
- Demand Response Reforms

ERCOT:
- Resource adequacy

New England:
- Energy and capacity market reforms

RGGI:
- New Model Rule

Federal Policy

Subsidies:
- Leading voice against extension of the Production Tax Credit and other electric generation subsidies

EPA Regulations:
- Mercury and Air Toxics Standards (MATS)
- Greenhouse gases (new and existing sources)
- 316(b)

State Policy

Oppose Subsidized Generation:
- IL: Defeated Taylorsville Energy Project Subsidy legislation
- MA: Opposed Footprint Power Subsidy legislation
- NJ: Won LCAPP Court decision

Infrastructure & Ratemaking Improvements:
- IL: Energy Infrastructure and Modernization Legislation (Senate Bill 9)
- MD/PA: Policies to speed recovery for gas and infrastructure investments

Exelon.

Investing in a Stronger Future

Core Strength	Strategic Focus and Actions
Strong Balance Sheet	Solid financial footing and investment grade credit rating will allow us to grow in challenging times.
Utility Investment	Significant infrastructure and technology enhancements under regulatory structures that allow a fair rate of return.
Operating Excellence	Generating fleet will continue unwavering focus on world class performance.
Asset Optimization	Disciplined fleet evaluation will drive strategic decisions to unlock value, improve cash flow and grow earnings.
Portfolio Management	Enhance the value of our portfolio through implementation of our fundamental view and disciplined retail pricing.
Well-Crafted Public Policies	Advocate for policies that strengthen competitive markets, limit subsidies and enhance the value of clean generation.

Exelon.

Financial Update

S1-SSA-0009 - 10092

2013 Operating Earnings Guidance

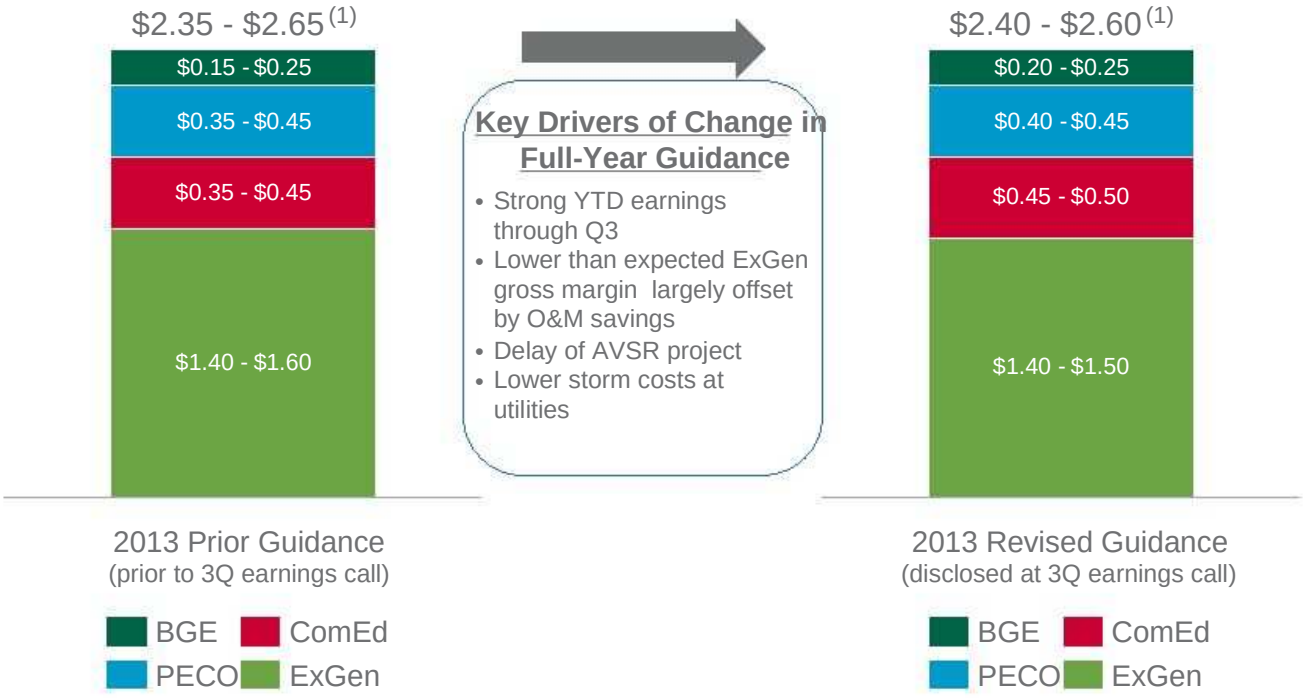

(1) Earnings guidance for OpCos may not add up to consolidated EPS guidance. Refer to slide 15 for a list of adjustments from GAAP EPS to adjusted (non - GAAP) operating EPS.

Exelon

S1-SSA-0009 - 10093

Capital Expenditure Expectations

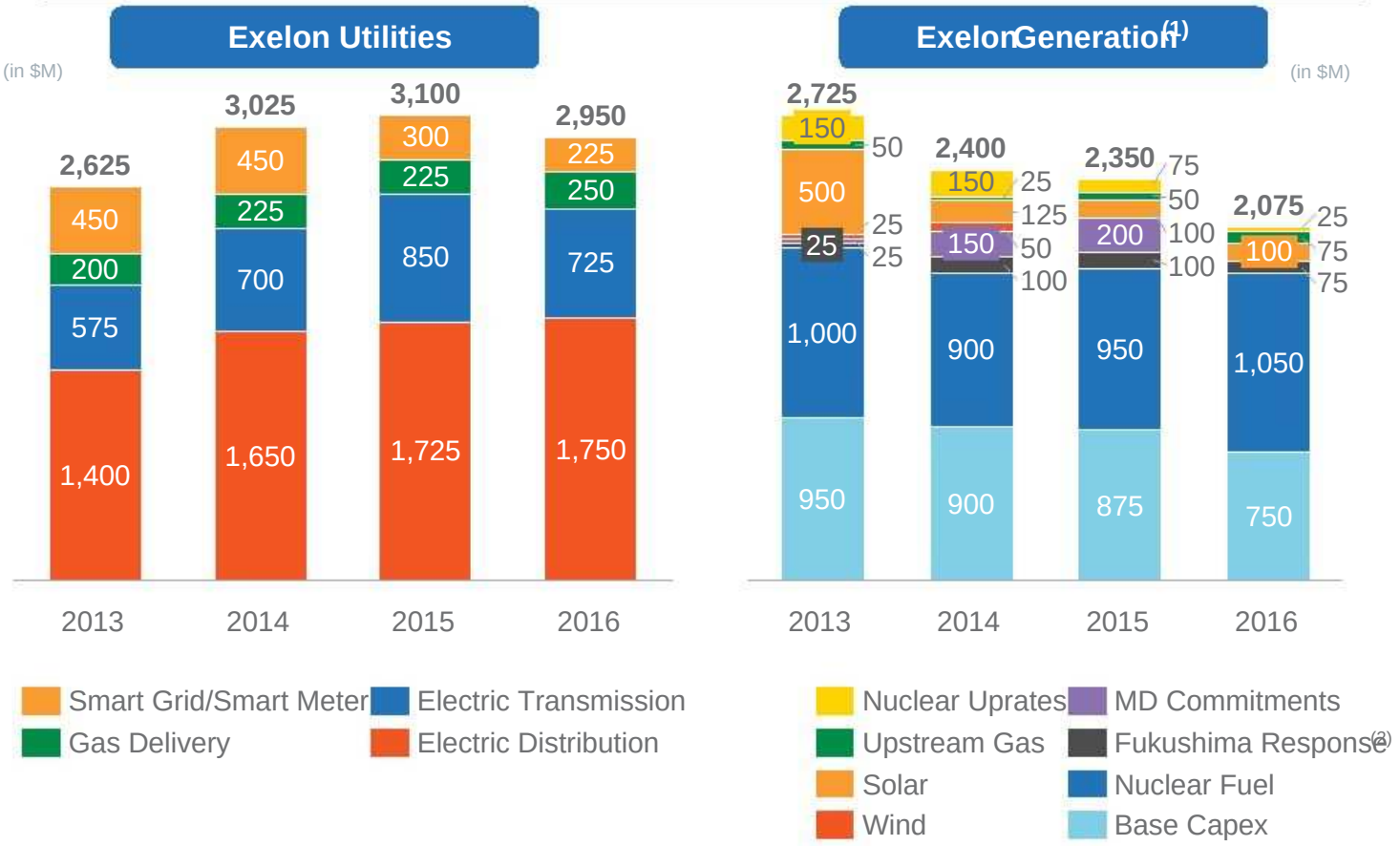

(1) Excludes CENG

(2) Fukushima Response spend excludes Salem, which is included in Base CapEx

Exelon

S1-SSA-0009 - 10094

2013 Projected Sources and Uses of Cash

($ in millions)	BGE	ComEd	PECO	ExGen	Exelon[6]	As of 2Q13	Delta
Beginning Cash Balance[1]					1,575	1,575	--
Cash Flow from Operations[2]	575	1,075	650	3,550	5,775	5,550	225
CapEx (excluding other items below):	(500)	(1,300)	(375)	(1,000)	(3,275)	(3,300)	25
Nuclear Fuel	n/a	n/a	n/a	(1,000)	(1,000)	(1,000)	–
Dividend[3]					(1,250)	(1,250)	–
Nuclear Uprates	n/a	n/a	n/a	(150)	(150)	(150)	–
Wind	n/a	n/a	n/a	(25)	(25)	(25)	–
Solar	n/a	n/a	n/a	(500)	(500)	(550)	50
Upstream	n/a	n/a	n/a	(50)	(50)	(50)	–
Utility Smart Grid/Smart Meter	(125)	(150)	(175)	n/a	(450)	(450)	–
Net Financing (excluding Dividend):							
Debt Issuances	300	350	550	–	1,200	1,200	–
Debt Retirements[4]	(400)	(250)	(500)	(450)	(1,600)	(1,600)	–
Project Finance/Federal Financing Bank Loan	n/a	n/a	n/a	850	850	1,025	(175)
Other[5]	75	350	(75)	(125)	325	300	25
Ending Cash Balance[1]					1,425	1,275	150

(1) Exelon beginning cash balance as of 1/1/13. Excludes counterparty collateral activity.
(2) Cash Flow from Operations primarily includes net cash flows provided by operating activities and net cash flows used in investing activities other than capital expenditures.
(3) Dividends are subject to declaration by the Board of Directors.
(4) Includes PECO's $210 million Accounts Receivable (A/R) Agreement with Bank of Tokyo and excludes BGE's current portion of its rate stabilization bonds
(5) "Other" includes proceeds from options, redemption of PECO preferred stock and expected changes in short-term debt, including money pool activity.
(6) Includes cash flow activity from Holding Company, eliminations, and other corporate entities.

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Commitment to Investment Grade

Value of Investment Grade

- Maintain key credit metrics above target ranges under both market and stress conditions to maintain investment grade ratings
- Shareholder value of maintaining investment grade:
  - Increases ability to participate in commercial business opportunities
  - Lowers collateral requirements
  - Reliable and cost efficient access to the capital markets
  - Increases business and financial flexibility

Current Ratings & Targets

Current Ratings (1) (2)

	Moody's	S&P	Fitch
Corp	Baa2	BBB-	BBB+
ComEd	A3	A-	BBB+
PECO	A1	A-	A
BGE	Baa1	A-	BBB+
Generation	Baa1	BBB	BBB+

Credit Metric Targets Supportive of Mid-High BBB/Baa Ratings (3)

- FFO/Debt > 30% in base case and 27% in stress case
- RCF/Debt > 20%
- Positive Moody's FCF

(1) Current senior unsecured ratings for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd and PECO as of September 25, 2013.
(2) All ratings at S&P and Moody's have a stable outlook. On August 23rd, BGE was upgraded one notch to A- as part of S&P's annual review. All other entities were affirmed. Additionally, on February 8th, Fitch affirmed all ratings for Exelon and subs and placed ComEd on positive outlook.
(3) Credit metric target ranges are for ExGen and include the debt obligations of Exelon Corp.

Exelon remains committed to maintaining investment grade ratings

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Pension and OPEB Forecast

Current Forecast:

- The table below provides the combined company's forecasted 2014 and 2015 pension and OPEB expense and contributions

	2014		2015	
(in $M)	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]
Pension[3][4]	$335	$275	$315	$175
OPEB[3][4]	$165	$210	$160	$200
Total	$500	$485	$475	$375

(1) Pension and OPEB expenses assume an ~ 25% capitalization rate.
(2) Contributions shown in the table above are based on the current contribution policy for the plans and include both amounts contributed to trusts and paid from corporate assets.
(3) Expected return on assets for pension is 7.00% and for OPEB is 6.45% (2014 and 2015). Amounts above assume an actual return on assets for pension and OPEB in 2013 of 4.88% and 8.00%, respectively.
(4) Projected 12/31/13 pension and OPEB discount rates are 4.80% and 4.92%, respectively.

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2014 Pension and OPEB Sensitivities

- Tables below provide sensitivities for the combined company's 2014 pension and OPEB expense and contributions[1] under various discount rate and S&P 500 asset return scenarios

	2014 Pension Sensitivity[2] (in $M)					
	S&P Returns in Q4 2013[3]					
	10%		0%		-10%	
Discount Rate at 12/31/13	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]
Baseline Discount Rate[4]	$325	$275	$335	$275	$350	$275
+50 bps	$295	$25	$300	$275	$315	$275
- 50bps	$365	$275	$380	$275	$390	$275

	2014 OPEB Sensitivity[2] (in $M)					
	S&P Returns in Q4 2013[3]					
	10%		0%		-10%	
Discount Rate at 12/31/13	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]
Baseline Discount Rate[4]	$155	$195	$165	$210	$180	$225
+50 bps	$135	$180	$150	$185	$160	$200
- 50bps	$180	$220	$190	$235	$200	$250

(1) Contributions shown in the table above are based on the current contribution policy and include the impact of pension funding relief.
(2) Pension and OPEB expenses assume an ~ 25% capitalization rate in 2014.
(3) Final 2013 asset return for pension and OPEB will depend in part on overall equity market returns for Q4 2013 as proxied by the S&P 500. The amounts above reflect YTD S&P returns through September 30, 2013.
(4) The baseline discount rates reflect projected 12/31/13 pension and OPEB discount rates of 4.80% and 4.92%, respectively.

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Additional 2013 ExGen and CENG Modeling

P&L Item	2013 Estimate
ExGen Model Inputs[1]	
O&M[2]	$4,275M
Taxes Other Than Income (TOTI)[3]	$300M
Depreciation & Amortization[4]	$825M
Interest Expense	$350M
CENG Model Inputs (at ownership)[5]	
Gross Margin	Included in ExGen Disclosures
O&M/TOTI	$400M - $450M
Depreciation & Amortization/Accretion of Asset Retirement Obligations	$100M - $150M
Capital Expenditures	$75M - $125M
Nuclear Fuel Capital Expenditures	$100M - $150M

(1) ExGen amounts for O&M, TOTI and Depreciation & Amortization exclude the impacts of CENG. CENG impact is reflected in "Equity earnings of unconsolidated affiliates" in the Income Statement.
(2) ExGen O&M excludes P&L neutral decommissioning costs and the impact from O&M related to entities consolidated solely as a result of the application of FIN 46R.
(3) TOTI excludes gross receipts tax for retail.
(4) ExGen Depreciation & Amortization excludes the impact of P&L neutral decommissioning.
(5) The CENG model inputs are intended to support Exelon's guidance range and do not represent CENG's final estimates.

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Debt Maturity Schedule

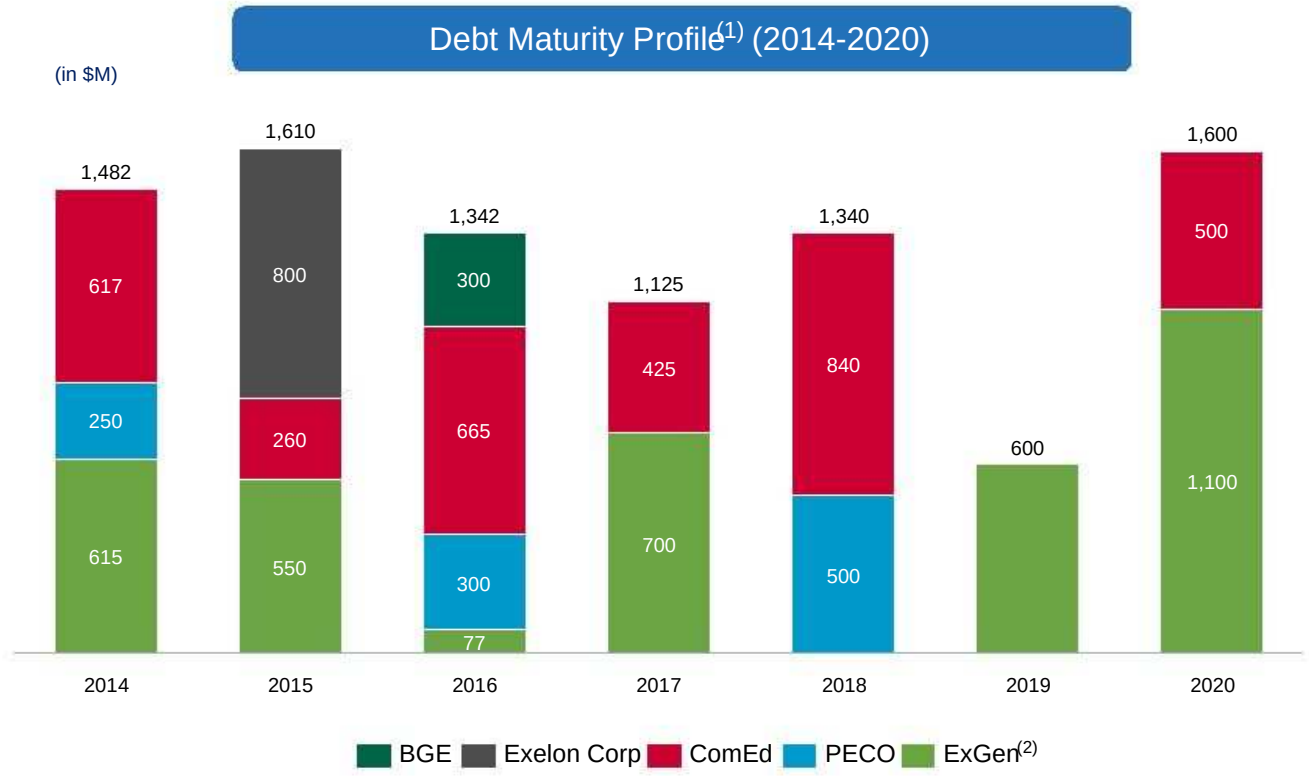

(1) As of 9/30/13
(2) Includes $550M in 2015 and 2020 of inter-company loan agreements between Exelon and Exelon Generation that mirror the terms and amounts of the third party obligations of Exelon.

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GAAP to Operating Adjustments

- **Exelon's 2013 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:**
  - Mark-to-market adjustments from economic hedging activities
  - Unrealized gains and losses from NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
  - Financial impacts associated with the sale or retirement of generating stations
  - Financial impacts associated with the increase in certain decommissioning obligations for spent nuclear fuel at retired nuclear units and increased retirement obligations for retired fossil power plants
  - Certain costs incurred associated with the Constellation merger and integration initiatives
  - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the merger date
  - Non-cash amortization of certain debt recorded at fair value at the merger date, which was retired in the second quarter of 2013
  - Non-cash charge to earnings resulting from the remeasurement of Exelon's like-kind exchange tax position
  - Non-cash charge to earnings related to the cancellation of previously capitalized nuclear uprate projects and the impairment of certain wind generating assets
  - Other unusual items

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Exelon Utilities

S1-SSA-0009 - 10102

ComEd April 2013 Distribution Formula Rate Updated Filing

The 2013 distribution formula rate filing establishes the net revenue requirement used to set the rates that will take effect in January 2014 after the ICC's review. The filing was updated to reflect the impact of Senate Bill 9. There are two components to the annual distribution formula rate filing:

- Filing Year: Based on prior year costs (2012) and current year (2013) projected plant additions.
- Annual Reconciliation: For the prior calendar year (2012), this amount reconciles the revenue requirement reflected in rates during the prior year (2012) in effect to the actual costs for that year. The annual reconciliation impacts cash flow in the following year (2014) but the earnings impact has been recorded in the prior year (2012) as a regulatory asset.

Docket #	13-0318
Filing Year	**2012 Calendar Year Actual Costs and 2013 Projected Net Plant Additions** are used to set the rates for calendar year 2014. Rates currently in effect (docket 13-0386) for calendar year 2013 were based on 2011 actual costs and 2012 projected net plant additions and reflect the impacts of PA 98-0015 (SB9).
Reconciliation Year	**Reconciles Revenue Requirement reflected in rates during 2012 to 2012 Actual Costs Incurred.** Revenue requirement for 2012 is based on dockets 10-0467, 11-0721 May Order and 11-0721 October Re-hearing Order.
Common Equity Ratio	~ **45%** for both the filing and reconciliation year
ROE	**8.72%** for both the filing and reconciliation year (2012 30-yr Treasury Yield of 2.92% + 580 basis point risk premium). For 2013 and 2014, the actual allowed ROE reflected in net income will ultimately be based on the average of the 30-year Treasury Yield during the respective years plus 580 basis point spread.
Requested Rate of Return	~ **7%** for the both the filing and reconciliation year
Rate Base	**$6,702 million**– Filing year (represents projected year-end rate base using 2012 actual plus 2013 projected capital additions). 2013 and 2014 earnings will reflect 2013 and 2014 year-end rate base respectively. **$6,389 million** - Reconciliation year (represents year-end ate base for 2012)
Revenue Requirement Increase [1]	**$353M** ($191M is due to the 2012 reconciliation, $162M relates to the filing year). The 2012 reconciliation impact on net income was recorded in 2012 as a regulatory asset. This increase also reflects the decrease in 2013 rates as a result of Senate Bill 9.
Timeline	• 04/29/13 Filing Date • 240 Day Proceeding • ICC order by year end; rates effective January 2014

Given the retroactive ratemaking provision in the EIMA legislation, ComEd net income during the year will be based on actual costs with a regulatory asset/liability recorded to reflect any under/over recovery reflected in rates. Revenue Requirement in rate filings impacts cash flow.

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BGE Rate Case

Rate Case Request	Electric	Gas
Docket #	9326	
Test Year	August 2012 –July 2013	
Common Equity Ratio	51.1%	
Requested Returns	ROE: 10.5%; ROR: 7.87%	ROE: 10.35%; ROR: 7.79%
Rate Base	$2.8B	$1.0B
Revenue Requirement Increase	$82.6M	$24.4M
Proposed Distribution Price Increase as % of overall bill	2%	3%

Timeline

- 5/17/13: BGE filed application with the MDPSC seeking increases in gas & electric distribution base rates
- 8/5/13: Staff/Intervenors file direct testimony
- 8/23/13: Update 8 months actual/4 month estimated test period data with actuals for last 4 months (March -July 2013)
- 9/17/13: BGE and staff/intervenors file rebuttal testimony
- 10/3/13: Staff/Intervenors and BGE file surrebuttal testimony
- 10/18/13 – 10/29/13: Hearings
- 11/12/13: Initial Briefs
- 11/22/13: Reply Briefs
- 12/13/13: Final Order
- New rates are in effect shortly after the final order

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ComEd Load

Weather-Normalized Load YoY Growth

Economic Forecast of Drivers that Influence Load

Driver or Indicator	2014 Outlook
Gross Metro Product (GMP)	2.2% growth in GMP reflects overall better economic conditions than the slow growth in 2013 (Manufacturing and Professional Business Services employment accelerate in 2014)
Employment	1.4% increase in total employment is expected for 2014, which is consistent with the past three years
Manufacturing	Manufacturing employment is expected to grow 1.4% in 2014. This is a significant improvement over the 0.7% growth in 2012 and the 0.4% growth in 2013
Households	Household formations are expected to increase 0.4% in 2014. This is a slight improvement over the 0.3% realized in the past couple of years
Energy Efficiency	Continued expansion of EE program expected to reduce usage in 2014 by approximately 1.2%

Moderate growth economy and energy efficiency initiatives will continue to impact load growth

Notes: 2012 data is not adjusted for leap year. Source of 2014 economic outlook data is Global Insight (July 2013).

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S1-SSA-0009 - 10105

PECO Load

Weather-Normalized Load YoY Growth

Economic Forecast of Drivers that Influence Load

Driver or Indicator	2014 Outlook
Gross Metro Product (GMP)	GMP projected to grow at 2.1% for 2014, vs. pre-recession average of 2.5%
Resident Employment	Resident Employment outlook is 1.0% in 2014 vs. 0.8% in 2013
Manufacturing Employment	Manufacturing employment is expected to grow at 1.1%. Philadelphia has had negative growth from 2000 to 2013
Households	Household growth is expected to be 0.7%, strongest growth since 2010
Energy Efficiency	Deemed Energy Efficiency impact forecasted to be ~1% reduction in usage in 2014

Moderately strong economic recovery will drive sales in 2014, but this will be partially offset by on-going energy efficiency initiatives

Notes: 2012 data is not adjusted for leap year. Source of 2013 economic outlook data is Global Insight (August 2013)

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S1-SSA-0009 - 10106

BGE Load

Weather-Normalized Load YoY Growth

Economic Forecast of Drivers that Influence Load

Driver or Indicator	2014 Outlook
Gross Metro Product (GMP)	GMP is projected to grow at 2.4% for 2014.
Employment	1.4% growth projected. BGE's decoupled non-rate case revenue growth is primarily driven by customer growth. The main driver for customer growth is employment.
Manufacturing	Manufacturing employment is expected to be fairly flat to 2013 levels in 2014
Households	Household growth is projected to be 0.9%, the same as 2013.
Energy Efficiency	Continued expansion of EE programs will partially offset growth seen due to improvements in economic conditions.

2014 is expected to be another transition year for the Baltimore economy with continued slow to moderate growth

Notes: 2012 Data is not adjusted for leap year. Source of 2014 economic outlook data is Global Insight (August 2013).

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S1-SSA-0009 - 10107

Exelon Utilities: Rate Base(1) and ROE Targets

ComEd

($ in billions)

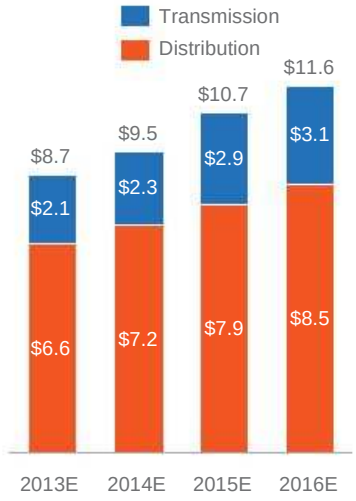

	2013E	Long-Term Target
Equity Ratio	~45%	~53%(2)
Earned ROE	8 -9%	Based on 30-yr. US Treasury(3)

PECO

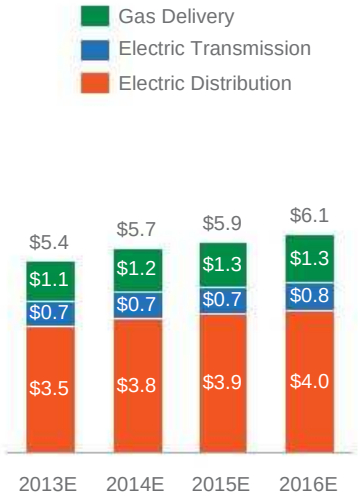

	2013E	Long-Term Target
Equity Ratio	~56%	~53%
Earned ROE	11.5 – 12.5%	≥10%

BGE

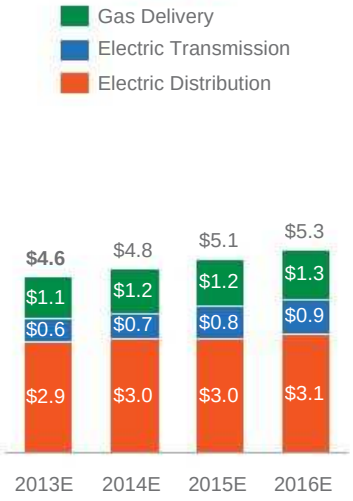

	2013E	Long-Term Target
Equity Ratio	~49%	~53%(4)
Earned ROE	8.0-8.5%	≥10%

Continued investment in Utilities will provide stable earnings growth

(1) ComEd and PECO rate base represents end-of-year; and BGE rate base represents a trailing 13-month average. Numbers may not add due to rounding.
(2) Equity component for distribution rates will be the actual capital structure adjusted for goodwill.
(3) Earned ROE will reflect the weighted average of 11.5% allowed transmission ROE and distribution ROE resulting from 30-year Treasury plus 580 basis points for each calendar year.
(4) Per MDPSC merger commitment, BGE is precluded from paying dividends through 2014. Per MDPSC orders, BGE cannot pay out a dividend to its parent company if said dividend would cause BGE's equity ratio to fall below 48%.

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S1-SSA-0009 - 10108

Capital Expenditures

($ in millions)

(1) Smart Meter/Smart Grid CapEx net of proceeds from U.S. Department of Energy (DOE) grant. For BGE, includes CapEx from Smart Energy Savers program of ~$10M per year.

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S1-SSA-0009 - 10109

Regulatory Schedule

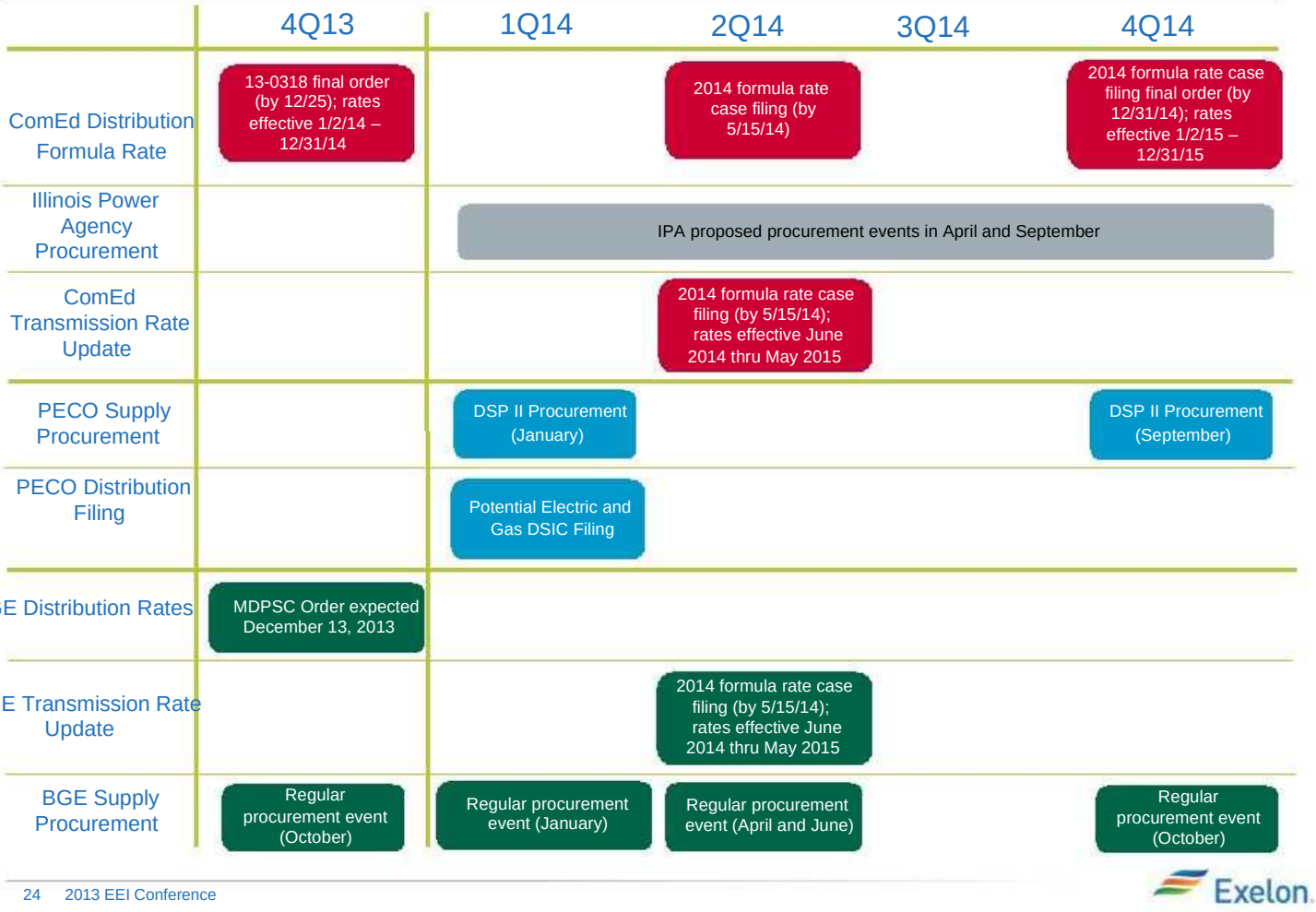

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S1-SSA-0009 - 10110

Constellation℠
An Exelon Company

S1-SSA-0009 - 10111

Commercial Business Overview

Scale, Scope and Flexibility Across the Energy Value Chain

Development and exploration of natural gas and liquids properties

12 assets in seven states

~255 BCFe of proved Reserves[1]

Leading merchant power generation portfolio in the U.S.

~35 GW of owned generation capacity[2]

Clean portfolio, well positioned for evolving regulatory requirements

Industry-leading wholesale and retail sales and marketing platform

~150 TWh of load and ~410 BCF of gas delivered[3]

~ 1 million residential and 100,000 business and public sector customers

One of the largest and most experienced Energy Management providers

~2,000 MW of Load Response under contract[4]

Over 4,000 energy savings projects implemented across the U.S.

Benefiting from scale, scope and flexibility across the value chain

(1) Estimated proved reserves as of 12/31/2012. Includes Natural Gas (NG), NGL Liquids (NGL) and Oil. NGL and Oil are converted to BCFe at a ratio of 6:1.
(2) Total owned generation capacity as of 9/30/2013.
(3) Expected for 2013 as of 9/30/2013. Electric load and gas includes fixed price and indexed products.
(4) Load Response estimate as of 9/30/2013.

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S1-SSA-0009 - 10112

Generation and Load Match

Generation Capacity, Expected Generation and Expected Load

2014 in TWh(1,2)

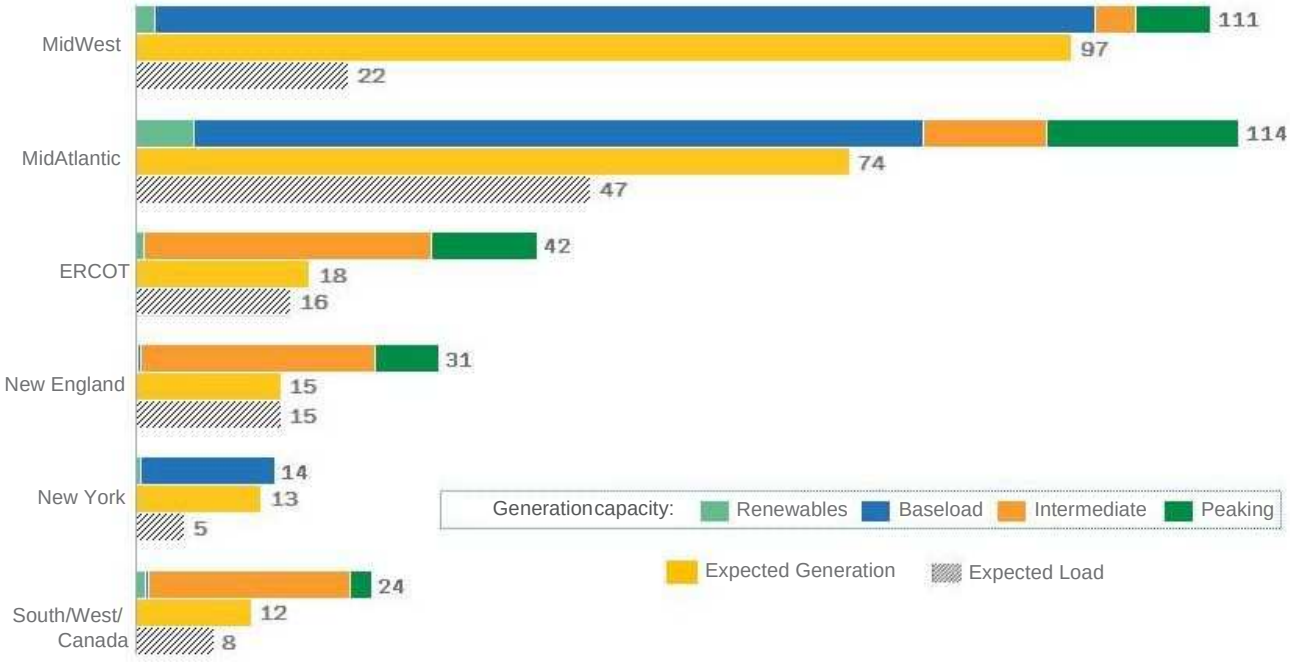

The combination establishes an industry-leading platform with regional diversification of the generation fleet and customer-facing load business

(1) Owned and contracted generation capacity converted from MW to MWh assuming 100% capacity factor for all technology types, except for renewable capacity which is shown at estimated capacity factor.
(2) Expected generation and load shown in the chart above will not tie out with load volume and ExGen disclosures. Load shown above does not include indexed products and generation reflects a net owned and contracted position. Estimates as of 9/30/2013.

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Electric Load Serving Business: Growth Target

Commercial Load[1]

2013 – 2016 TWh

(1) Numbers and percentages are rounded to the nearest 5
(2) Index load expected to be 20% to 30% of total forecasted retail load

Focus on disciplined pricing and maximizing margin potential through all channels to market

Load Split by Customer Class

(2013 TWh)

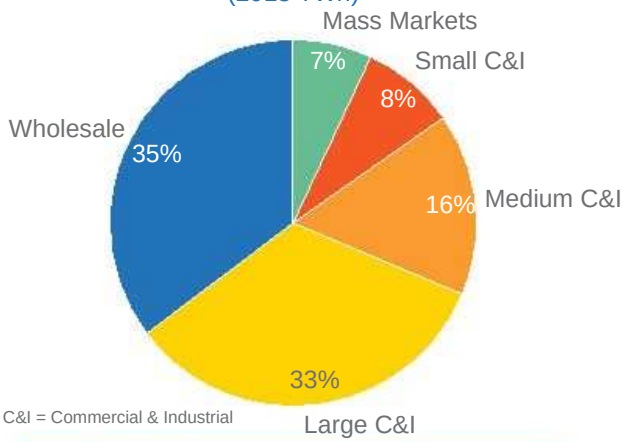

C&I = Commercial & Industrial

Customer Type	Load Size
Mass Markets	<1,000 MWhs per year
Small C&I	1,001-5,000 MWhs per year
Medium C&I	5,001-25,000 MWhs per year
Large C&I	>25,000 MWhs per year

A diverse set of customers enhances margin opportunities from a sales and portfolio management standpoint

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Electric Load Serving Business: Strategy

Total U.S. Power Market in 2013

Estimated Load ~ 3,700 TWh[1)]

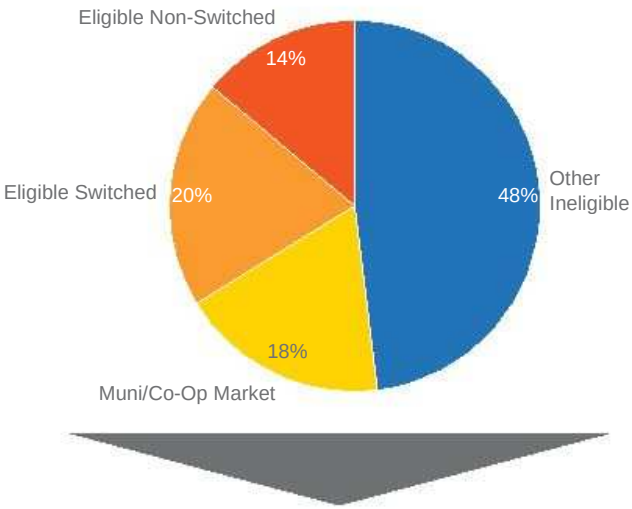

Through retail and wholesale channels, Constellation currently serves 150 TWhs, or approximately 4%, of total U.S. power demand

Expected Total Competitive Market Growth

- Underlying load growth
  - Approx. 1% load growth across the U.S.
- Switched market expected to grow by approximately 5% in C&I from 2013-2016
- Switched market expected to grow by approximately 3% in Residential from 2013-2016

Strategy to Grow

- Improve market share in existing markets
- Cross sell suite of products to existing customers
  - Create more value with customers
  - Utilize data and technology to expand product offerings
  - Achieve higher renewal rates
  - Distinguish our brand
- Leverage operational efficiency

Constellation is well positioned in a U.S. market where capacityavailable for competitive supply has room to grow

(1) Source: EIA, KEMA and internal estimates.

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Capacity Markets

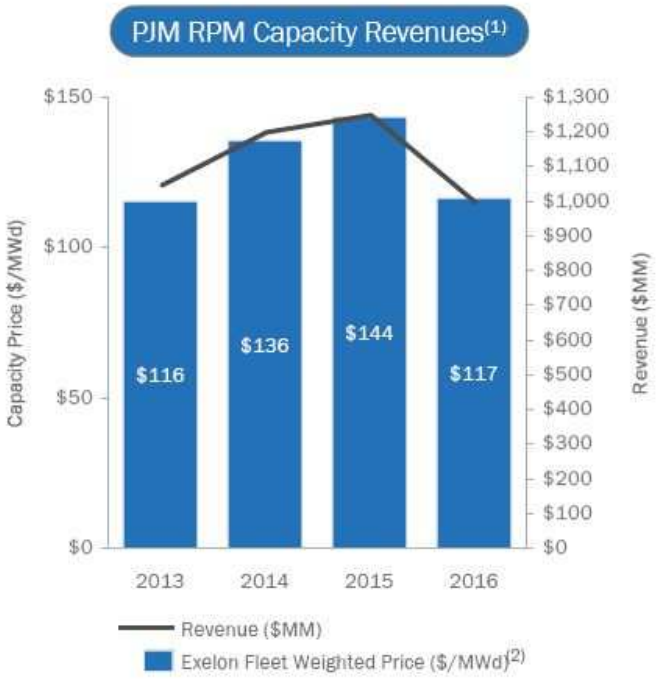

		2012/ 2013	2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017
PJM(3,8)						
RTO	*Capacity*	12,800	11,500	11,500	11,500	11,250
	Price	$16	$28	$126	$136	$59
EMAAC	*Capacity*(4)	9,100	9,100	9,100	9,100	9,100
	Price	$140	$245	$137	$168	$119
MAAC	*Capacity*	2,600	2,700	2,700	2,700	2,700
	Price	$133	$226	$137	$168	$119
SWMAAC	*Capacity*(5)	1,800	1,800	1,800	1,800	1,800
	Price	$133	$226	$137	$168	$119
Average Exelon		$78	$142	$132	$153	$92
New England(6)						
NEMA	*Capacity*	2,100	2,100	2,100	2,100	2,100
	Price	$85(7)	$85(7)	$107	$114	$219
Rest of Pool	*Capacity*	735	735	735	735	735
	Price	$85(7)	$85(7)	$95(7)	$104(7)	$90
NYISO(8)						
Rest of Pool	*Capacity*	1,100	1,100	1,100	1,100	1,100
MISO(9)						
AMIL	*Capacity*	1,100	1,100	1,100	1,100	1,100

RTO = Regional Transmission Organization, MAAC = Mid-Atlantic Area Council, EMAAC = Eastern Mid-Atlantic Area Council, SWMAAC = South West Mid-Atlantic Area Council, NEMA = North East Massachusetts; SEMA = North East Massachusetts, AMIL = Ameren Illinois.

(1) Revenues reflect capacity cleared in base and incremental auctions and are for calendar years. Revenue rounded to nearest $50M.
(2) Weighted average $/MW-Day would apply if all owned generation cleared.
(3) Reflects owned and contracted generation Installed Capacity (ICAP) adjusted for mid-year PPA roll offs.
(4) ICAP is net of Eddystone 1&2, Cromby 1&2 and Schuylkill 1 (total ~ 1,100 MW).
(5) ICAP is net of units to be divested (Brandon Shores, Wagner & Crane ~2,648 MW; Constellation offered these units in PY11/12 - PY 15/16 auctions) and Riverside 6 CT (~115MW).
(6) Reflects Qualified Summer Capacity including owned and contracted units.
(7) Price is pro-rated for auctions that clear at the floor price and there is more capacity procured than suggested by the reliability requirement.
(8) Reflects 50.01% ownership in CENG.
(9) Does not include wind under PPA.

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S1-SSA-0009 - 10116

Retail and Wholesale Gas

Retail Gas

Portfolio Size:

- 410 Bcf expected to be served in 2013 with moderate growth thereafter
- Month by month renewals, with high retention rates

Market Potential:

- All states are competitive markets with an estimated total market size of 15,000 Bcf, of which 7,500 Bcf is currently switched

Growth Strategy and Objectives:

- Looking to grow Northeast gas markets as well as ONEOK territories

Wholesale Gas

Portfolio Size:

- 8 Bcf wholesale storage
- 450,000 MMBtu's per day of term transport
- Over 1 Bcf/day of plant supply
- ~4Bcf/day of NG flows to meet growing customer business, asset optimization, and plant supply

Growth Strategy and Objectives:

- Continue to expand wholesale presence to complement power assets
- Increase market knowledge of regional and basis transport information to assist power forecasting
- Continue to expand physically based customer business
- Continue to grow NG asset portfolio that complements customer business & plant supply requirements

(1) Estimate as of 9/30/2013.

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Upstream E&P Assets

Investment Thesis

- Our Upstream Gas business achieves strong returns (>12% IRR)
- $125m (~62% utilized) Reserve Based Lending (RBL) facility in place
  - Receives off-balance sheet treatment from S&P
- Provides valuable market intelligence in complex natural gas markets

Forecasted Production

	2013	2014	2015	2016
Net Daily Prod (MMcfe / day)	55 - 70	45 - 60	45 - 60	60 - 75

Current Portfolio Of Investments

Mississippi lime (OK)	Floyd shale (AL)
Hunton dewatering (OK)	Ohio shale (OH)
Woodford shale (OK)	Woodbine shale (TX)
Fayetteville shale (AR)	Trenton Black River (MI)
Haynesville shale (LA)	Barnett shale (TX)

Estimated Net Proved Reserves (as of 12/31/12)[3]	Average Net Daily Production (Q2 2013)[4]
255 Bcfe	61.0 MMcfe

(1) Oil/NGL conversion to gas is 6:1.
(2) Constellation does not operate any of its properties.
Note: E&P = Exploration and Production
(3) 12/31/12 Year end reserves excluding Eagle Ford
(4) Net daily production as of Q2 2013 excluding Eagle Ford

Exelon

Energy Price Upside - NIHub

Key Drivers
- Year over year increases in fuel prices
- Current and future coal retirements
- Higher variable unit costs due to MATS
- Modest load growth
- Offset by new generation (gas and renewable)

Other factors (not included)
- Demand Response energy bidding
- Increased variable costs due to RGGI
- Scarcity pricing

- The charts above illustrates NIHub prices from 2011 to 2016 (realized through 2013) and NYMEX natural gas for the same time period
- In 2012 we saw low prices in the natural gas and power markets.
  - Natural gas prices settled $2.75 for the year and NIHub ATC prices settled ~$29.00. The forward market for NIHub continues to trade between $30.50 and $31.00 even though forward natural gas prices are between $1.00 - $1.50 per MMBtu higher than the spot levels we saw in 2012.

We continue to believe there is $4 of upside in NiHub energy prices in 2015/2016 driven by several factors including compliance with environmental regulations

Exelon

Exelon Generation Disclosures

September 30, 2013
(As disclosed in Third Quarter 2013 Earnings materials)

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Portfolio Management Strategy

Strategic Policy Alignment

- Aligns hedging program with financial policies and financial outlook
  - Establish minimum hedge targets to meet financial objectives of the company (dividend, investment-grade credit rating)
  - Hedge enough commodity risk to meet future cash requirements under a stress scenario

Three-Year Ratable Hedging

- Ensure stability in near-term cash flows and earnings
  - Disciplined approach to hedging
  - Tenor aligns with customer preferences and market liquidity
  - Multiple channels to market that allow us to maximize margins
  - Large open position in outer years to benefit from price upside

Bull / Bear Program

- Ability to exercise fundamental market views to create value within the ratable framework
  - Modified timing of hedges versus purely ratable
  - Cross-commodity hedging (heat rate positions, options, etc.)
  - Delivery locations, regional and zonal spread relationships

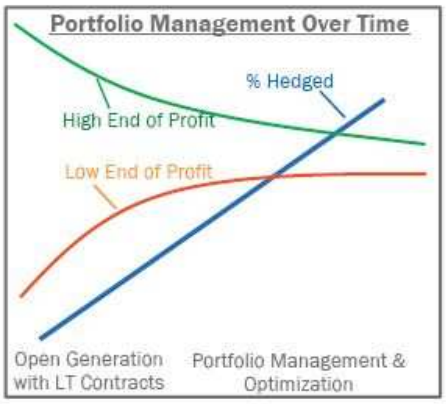

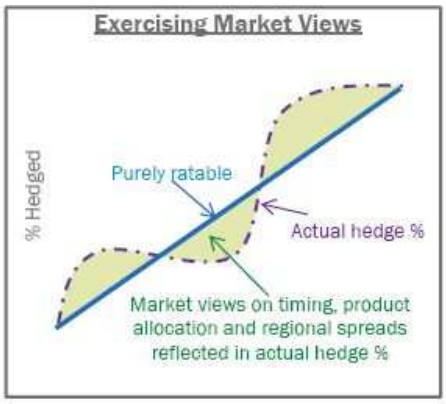

Protect Balance Sheet | **Ensure Earnings Stability** | **Create Value**

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Components of Gross Margin Categories

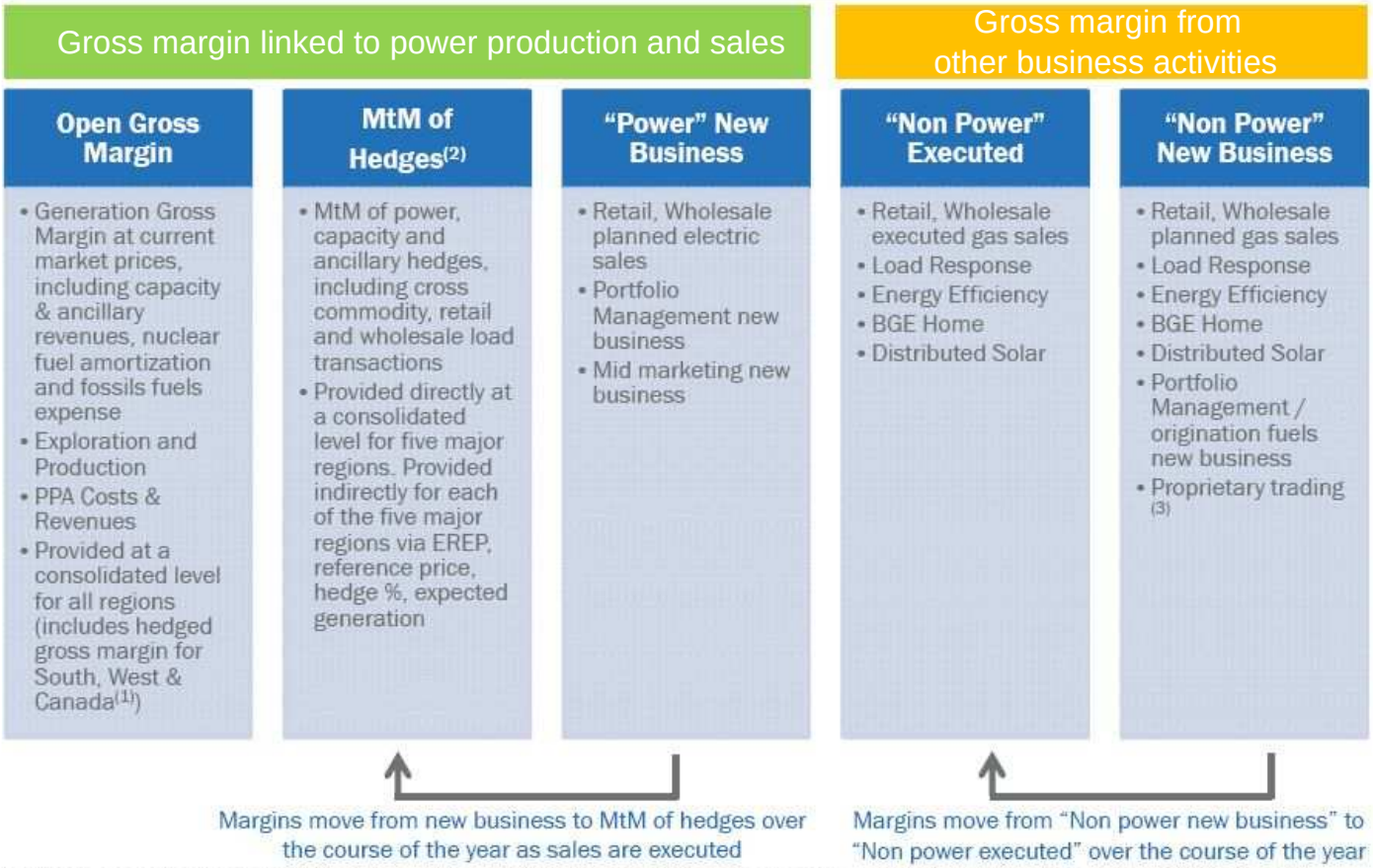

(1) Hedged gross margins for South, West & Canada region will be included with Open Gross Margin, and no expected generation, hedge %, EREP or reference prices provided for this region.
(2) MtM of hedges provided directly for the five larger regions. MtM of hedges is not provided directly at the regional level but can be easily estimated using EREP, reference price and hedged MWh.
(3) Proprietary trading gross margins will remain within "Non Power" New Business category and not move to "Non power" executed category.

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ExGen Disclosures

Gross Margin Category ($M)[1,2]	2013	2014	2015	2016
Open Gross Margin (including South, West & Canada hedged GM)[3]	$5,600	$5,650	$5,800	$5,800
Mark to Market of Hedges[3,4]	$1,700	$900	$450	$250
Power New Business/ To Go	$50	$500	$750	$750
Non-Power Margins Executed[5]	$400	$200	$100	$100
Non-Power New Business/ To Go[5]	$200	$400	$500	$500
Total Gross Margin	**$7,950**	**$7,650**	**$7,600**	**$7,400**

Reference Prices[6]	2013	2014	2015	2016
Henry Hub Natural Gas ($/MMbtu)	$3.65	$3.86	$4.06	$4.17
Midwest: NiHub ATC prices ($/MWh)	$31.18	$30.25	$30.47	$30.99
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$37.58	$37.19	$37.53	$38.13
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	$1.09	$6.30	$8.18	$7.13
New York: NY Zone A ($/MWh)	$37.07	$35.54	$35.70	$36.07
New England: Mass Hub ATC Spark Spread($/MWh) *ALQN Gas, 7.5HR, $0.50 VOM*	$3.70	$4.88	$3.69	$2.33

(1) Gross margin rounded to nearest $50M.
(2) Gross margin does not include revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners and entities consolidated solely as a result of the application of FIN 46R.
(3) Includes CENG Joint Venture.
(4) Mark to Market of Hedges assumes mid-point of hedge percentages.
(5) Any changes to new business estimates for our non-power business are presented as revenue less costs of sales.
(6) Based on September 30, 2013 market conditions.

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ExGen Disclosures

Generation and Hedges	2013	2014	2015	2016
Exp. Gen (GWh)[1]	214,700	215,500	209,400	211,000
Midwest	97,200	96,900	96,400	97,400
Mid-Atlantic[2]	74,500	73,600	70,100	71,400
ERCOT	13,200	17,800	19,600	19,400
New York[2]	14,000	12,500	9,300	9,300
New England	15,800	14,700	14,000	13,500
% of Expected Generation Hedged[3]	97-100%	84-87%	48-51%	19-22%
Midwest	97-100%	85-88%	47-50%	16-19%
Mid-Atlantic[2]	97-100%	90-93%	56-59%	21-24%
ERCOT	92-95%	81-84%	39-42%	31-34%
New York[2]	98-101%	87-90%	54-57%	19-22%
New England	95-98%	49-52%	22-25%	7-10%
Effective Realized Energy Price ($/MWH)[4]				
Midwest	$37.00	$33.50	$33.00	$34.00
Mid-Atlantic[2]	$49.00	$45.00	$45.00	$49.00
ERCOT[5]	$24.00	$11.00	$9.50	$6.50
New York[2]	$32.00	$37.00	$42.50	$39.50
New England[5]	$6.00	$3.50	$2.00	$5.50

(1) Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted for capacity. Expected generation is based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 12 refueling outages in 2013, 14 refueling outages in 2014 and 2015 and 12 refueling outages in 2016 at Exelon-operated nuclear plants, Salem and CENG. Expected generation assumes capacity factors of 94.1%, 93.7%, 93.3%, and 94.4% in 2013, 2014, 2015 and 2016 at Exelon-operated nuclear plants excluding Salem and CENG. These estimates of expected generation in 2014, 2015 and 2016 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years. (2) Includes CENG Joint Venture. (3) Percent of expected generation hedged is the amount of equivalent sales divided by expected generation. Includes all hedging products, such as wholesale and retail sales of power, options and swaps. Uses expected value on options. (4) Effective realized energy price is representative of an all-in hedged price, on a per MWh basis, at which expected generation has been hedged. It is developed by considering the energy revenues and costs associated with our hedges and by considering the fossil fuel that has been purchased to lock in margin. It excludes uranium costs and RPM capacity revenue, but includes the mark-to-market value of capacity contracted at prices other than RPM clearing prices including our load obligations. It can be compared with the reference prices used to calculate open gross margin in order to determine the mark-to-market value of Exelon Generation's energy hedges. (5) Spark spreads shown for ERCOT and New England.

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ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (With Existing Hedges) [1, 2,3]	2013	2014	2015	2016
Henry Hub Natural Gas ($/MMbtu)				
+ $1/MMbtu	$10	$110	$370	$575
-$1/MMbtu	$0	$(45)	$(305)	$(550)
NiHub ATC Energy Price				
+ $5/MWh	$0	$65	$325	$450
-$5/MWh	$0	$(60)	$(325)	$(450)
PJM-W ATC Energy Price				
+ $5/MWh	$0	$35	$175	$290
-$5/MWh	$0	$(35)	$(170)	$(280)
NYPP Zone A ATC Energy Price				
+ $5/MWh	$0	$5	$20	$35
-$5/MWh	$0	$(10)	$(20)	$(35)
Nuclear Capacity Factor				
+/- 1%	+/- $10	+/- $40	+/- $45	+/- $45

(1) Based on September 30, 2013 market conditions and hedged position. Gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically. Power prices sensitivities are derived by adjusting the power price assumption while keeping all other prices inputs constant. Due to correlation of the various assumptions, the hedged gross margin impact calculated by aggregating individual sensitivities may not be equal to the hedged gross margin impact calculated when correlations between the various assumptions are also considered. (2) Sensitivities based on commodity exposure which includes open generation and all committed transactions. (3) Includes CENG Joint Venture.

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Exelon Generation Hedged Gross Margin Upside/Risk

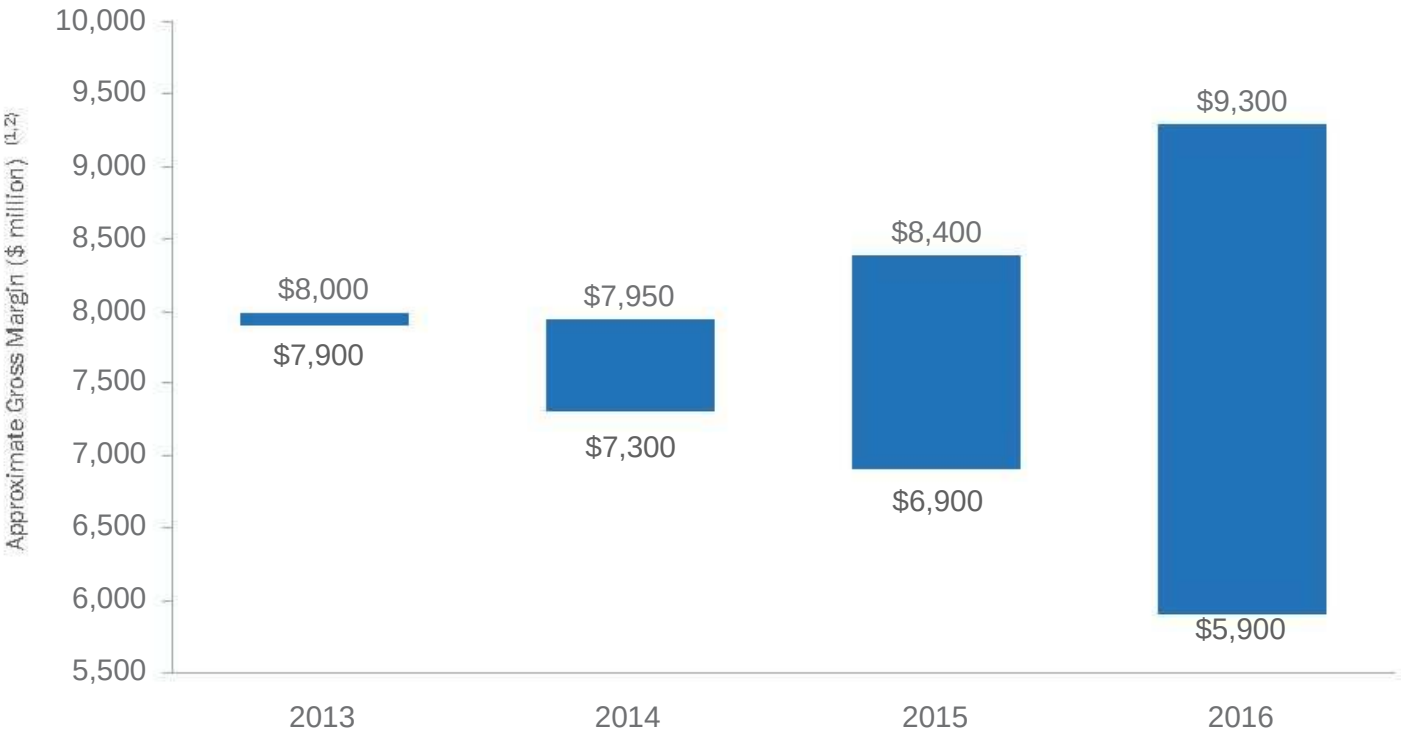

(1) Represents an approximate range of expected gross margin, taking into account hedges in place, between the 5th and 95th percent confidence levels assuming all unhedged supply is sold into the spot market. Approximate gross margin ranges are based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes. These ranges of approximate gross margin in 2014, 2015 and 2016 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years. The price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of September 30, 2013 (2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions.

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Illustrative Example of Modeling Exelon Generation 2014 Gross Margin

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	← $5.65 billion →					
(B)	Expected Generation (TWh)	96.9	73.6	17.8	12.5	14.7	
(C)	Hedge % (assuming mid-point of range)	86.5%	91.5%	82.5%	88.5%	50.5%	
(D=B*C)	Hedged Volume (TWh)	83.8	67.3	14.7	11.1	7.4	
(E)	Effective Realized Energy Price ($/MWh)	$33.50	$45.00	$11.00	$37.00	$3.50	
(F)	Reference Price ($/MWh)	$30.25	$37.19	$6.30	$35.54	$4.88	
(G=E-F)	Difference ($/MWh)	$3.25	$7.81	$4.70	$1.46	$(1.38)	
(H=D*G)	Mark-to-market value of hedges ($ million)(1)	$275 million	$525 million	$70 million	$15 million	$(10) million	
(I=A+H)	Hedged Gross Margin ($ million)	$6,550 million					
(J)	Power New Business / To Go ($ million)	$500 million					
(K)	Non-Power Margins Executed ($ million)	$200 million					
(L)	Non-Power New Business / To Go ($ million)	$400 million					
(N=I+J+K+L)	Total Gross Margin	$7,650 million					

(1) Mark-to-market rounded to the nearest $5 million.

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Constellation Energy Nuclear Group (CENG) Background

As a result of Exelon's equity interest in CENG, CENG gross margins and earnings are reflected in ExGen disclosures and other financial statements. The following is information related to PPA contracts between CENG and 3rd parties and the PPA between CENG and its equity parents.

	Calvert 1&2	NMP 1	NMP 2 (1)	Ginna(2)	
Ownership Interest					
Total Plant Capacity	1,756 MW	617 MW	1,279 MW	577 MW	
Ownership Split	100% CENG	100% CENG	82% CENG / 18% LIPA	100% CENG	
ExGen Ownership (50.01% of CENG)	878 MW	308 MW	524 MW	288 MW	
PPA structure (% output)					
CENG Legacy PPA with Utilities	-	-	See footnote 1	90% < June 2014	0% > June 2014
CENG PPA with Parents	100%	100%	100%	10% < June 2014	100% > June 2014

CENG PPA with Parents				
5 year contract extendable at end of each year for additional year - Market based pricing and monthly, rolling 3 year hedge profile (100%, 60%, 30%)				
	2012	2013	2014	2015
(% of uncommitted output)				
EDF Trading	15	15	15	N.A.
ExGen	85	85	85	N.A.

(1) Nine Mile Point 2 (NMP) has a revenue sharing agreement (via a call option type contract) on 80% of the output.
(2) Ginna Legacy PPA at $44/MWh; CENG PPA with parents (ExGen, EDF) at close to market prices and designed to maintain a monthly ratable profile for CENG.

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Constellation Energy Nuclear Group (CENG) Background

ExGen Disclosures
Forward Estimates

- ExGen forward disclosures reflect the gross position that accrues to ExGen from ownership interest in CENG and PPA with CENG as of a certain date
- **Open Gross Margin:** Reflects proportionate share of CENG revenues and fuel costs, market value of PPA less PPA costs paid by ExGen to CENG
- **MtM of Hedges:** Reflects MtM of any hedges placed by ExGen for managing position arising from ownership interests or PPAs with CENG
- **Expected Generation:** Reflects proportionate ownership in CENG and generation associated with PPA between CENG and ExGen.
- **Hedge Percentage:** Reflects hedges placed by ExGen to hedge exposure arising from CENG position (owned or contracted)
- **Effective Realized Energy Price:** Reflects MtM and hedges from CENG position (owned or contracted)

Financial Statements
(10-Q, 10-K, Earnings Release tables)
Actuals

- ExGen actuals reflect equity method accounting treatment for ownership interest in CENG and regular treatment for PPA between ExGen and CENG.
- **RnF:** Includes net PPA gross margin (revenues less costs) between ExGen and CENG. CENG earnings or gross margin are not included, and are instead shown under "CENG equity earnings" on the income statement.
- **Total Supply:** Includes only the generation corresponding to the PPA between ExGen and CENG.
- **Average Margins ($/MWh):** Includes only margins corresponding to PPA between ExGen and CENG as well as any hedges placed by ExGen

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S1-SSA-0009 - 10129

Generation

Exelon Generation Fleet

National Scope

- Power generation assets in 20 states and Canada
- Low-cost generation capacity provides unparalleled leverage to rising commodity prices

Large and Diverse

- 35 GW of diverse generation(1)
  - 19 GW of Nuclear
  - 10 GW of Gas
  - 2 GW of Hydro
  - 2 GW of Oil
  - 1 GW of Coal
  - 1 GW of Wind/Solar/Other

Clean

- One of nation's cleanest fleets as measured by CO2, SO2 and NOx intensity
- Less than 5% of generation capacity will require capital expenditures to comply with Air Toxic rules

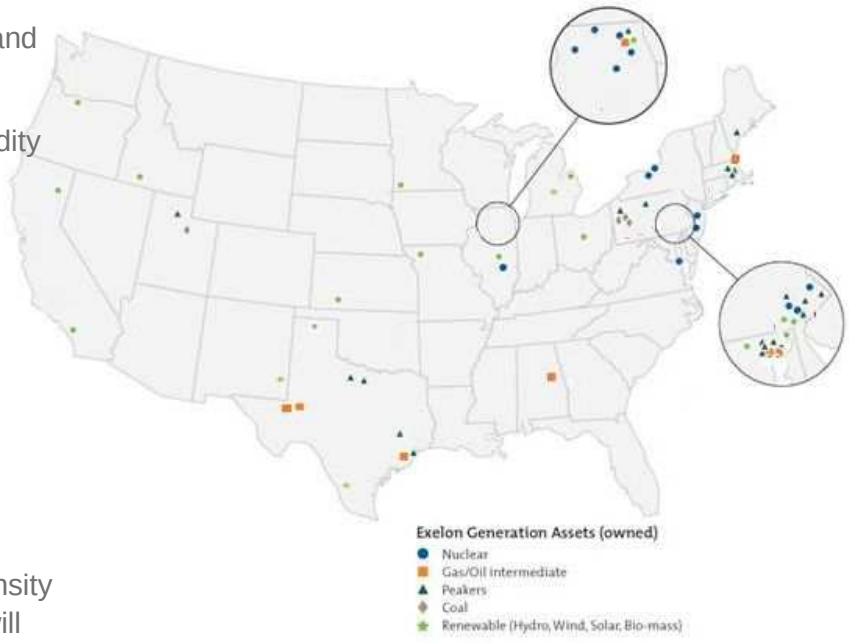

A clean and diverse portfolio that is well positioned for environmental upside from EPA regulations

(1) Total owned generation capacity as of 9/30/2013. Nuclear capacity reflects EXC ownership of CENG and Salem.

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Executing on Generation Development and Growth Projects

Solar

- Antelope Valley Solar Ranch Project One
  - Large scale solar project that will be 230 MW once fully operational
    - 128 MW currently online, additional 54 MW by Fall 2013
    - 48 MW by first half of 2014
  - Initial investment fully recovered by 2015
  - 25-year PPA for entire output with Pacific Gas & Electric
  - Cashflow and EPS accretive in 2013

Wind

- Six projects completed in 2012, added 404 MWs to the wind portfolio
  - All projects done under long-term PPAs with anticipated payback in approximately 10 years
- 45.6 MW wind farm in Michigan to be built in 2014

Nuclear Uprates

- Peach Bottom Extended Power Uprate
  - Adding 130 MW
  - Online dates of 65 MW in Q1 2015 and 65 MW in Q1 2016

Expanding the contracted renewable portfolio of Solar and Wind while adding incremental MWs to our existing nuclear fleet

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Exelon Nuclear Fleet Overview (including CENG and Salem)

	Plant Location	Type/ Containment	Water Body	License Extension Status / License Expiration[1]	Ownership	Spent Fuel Storage/ Date to lose full core discharge capacity[2]
Midwest	Braidwood, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Kankakee River	Filed application in May 2013 (decision expected in 2015)/ 2026, 2027	100%	Dry Cask
	Byron, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Rock River	Filed application in May 2013 (decision expected in 2015)/ 2024, 2026	100%	Dry Cask
	Clinton, IL (Unit 1)	BWR Concrete/Steel Lined / Mark III	Clinton Lake	2026	100%	Dry Cask (2016)
	Dresden, IL (Units 2 and 3)	BWR Steel Vessel / Mark I	Kankakee River	Renewed / 2029, 2031	100%	Dry Cask
	LaSalle, IL (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Illinois River	2022, 2023	100%	Dry Cask
	Quad Cities, IL (Units 1 and 2)	BWR Steel Vessel / Mark I	Mississippi River	Renewed / 2032	75% Exelon, 25% Mid-American Holdings	Dry Cask
Mid-Atlantic	Calvert Cliffs, MD (Units 1and 2)	PWR Concrete/Steel Lined	Chesapeake Bay	Renewed / 2034, 2036	100% CENG[4]	Dry Cask
	R.E. Ginna, NY (Unit 1)	PWR Concrete/Steel Lined	Lake Ontario	Renewed / 2029	100% CENG[4]	Dry Cask
	Limerick, PA (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Schuylkill River	Filed application in June 2011 (decision expected in 2015) / 2024, 2029	100%	Dry Cask
	Nine Mile Point, NY (Units 1 and 2)	BWR Steel Vessel / Mark I Concrete/Steel Vessel/ Mark II	Lake Ontario	Renewed / 2029, 2046	100% CENG[4] / 82% CENG[4], 18% Long Island Power Authority	Dry Cask
	Oyster Creek, NJ (Unit 1)	BWR Steel Vessel / Mark I	Barnegat Bay	Renewed / 2029[3]	100%	Dry Cask
	Peach Bottom, PA (Units 2 and 3)	BWR Steel Vessel / Mark I	Susquehanna River	Renewed / 2033, 2034	50% Exelon, 50% PSEG	Dry Cask
	TMI, PA (Unit 1)	PWR Concrete/Steel Lined	Susquehanna River	Renewed / 2034	100%	2023
	Salem, NJ (Units 1 and 2)	PWR Concrete/Steel Lined	Delaware River	Renewed / 2036, 2040	42.6% Exelon, 57.4% PSEG	Dry Cask

(1) Operating license renewal process takes approximately 4-5 years from commencement until completion of NRC review.
(2) The date for loss of full core reserve identifies when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core. Dry cask storage will be in operation at those sites prior to losing full core discharge capacity in their on-site storage pools.
(3) On December 8, 2010, Exelon announced that it will permanently cease generation operations at Oyster Creek by December 31, 2019. Oyster Creek's current NRC license expires in 2029.
(4) Exelon Generation has a 50.01% ownership interest in CENG (Constellation Energy Nuclear Group, LLC). Electricite de France SA (EDF) has a 49.99% ownership interest in CENG.

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World Class Nuclear Operator(1)

Nuclear Production Cost ($/MWh)(2)

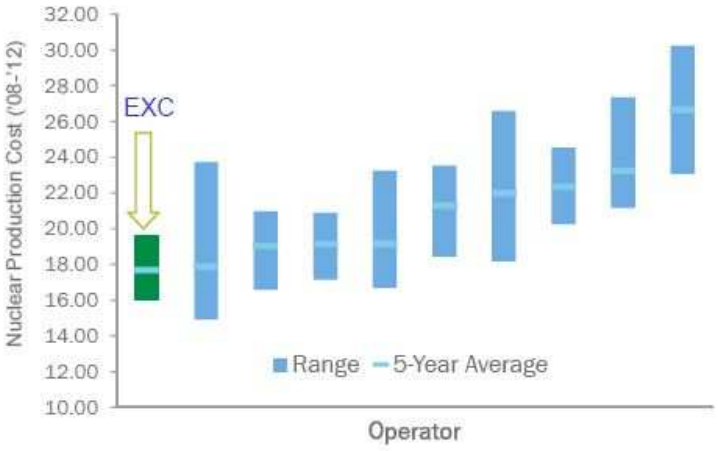

Capacity Factor (%)(3)

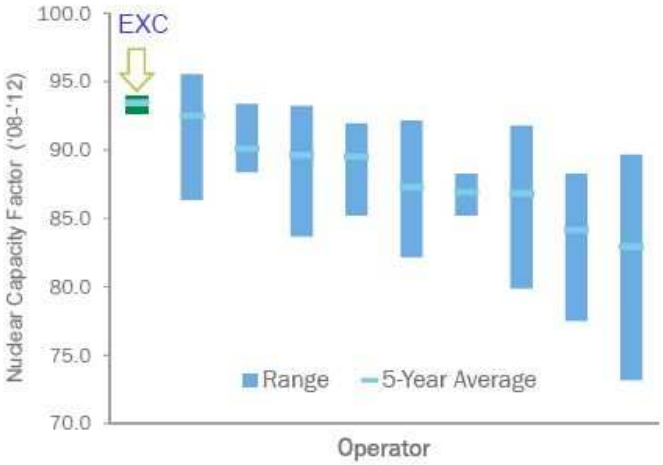

Among major nuclear plant fleet operators, Exelon is consistently one of the lowest-cost and most efficient producers of electricity in the nation

(1) Exelon fleet averages exclude Salem and CENG

(2) Source: 2012 Electric Utility Cost Group (EUCG) survey. Includes Fuel Cost plus Direct O&M divided by net generation.

(3) Source: Platts Nuclear News, Nuclear Energy Institute and Energy Information Administration (Department of Energy).

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Nuclear Output and Refueling Outages

Nuclear Output (1)

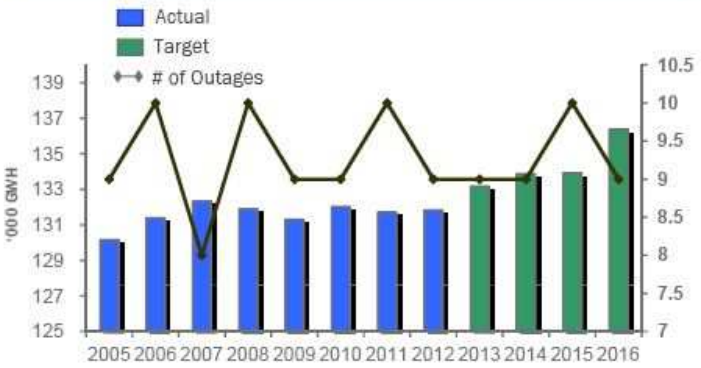

(1) Net nuclear generation data at ownership excluding Salem and CEN G. 2016 includes Clinton Refueling Only outage of shortened duration.

Fleet Average Refueling Outage Duration (Days)(1)

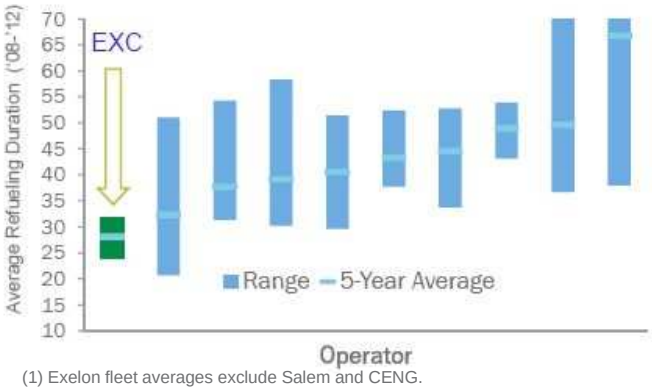

(1) Exelon fleet averages exclude Salem and CENG.

Nuclear Refueling Cycle

- All Exelon owned units on a 24 month cycle except for Braidwood U1/U2, Byron U1/U2 and Salem U1/U2, which are on 18 month cycles
- Starting in 2015 Clinton is on annual cycles

2013 Refueling Outage Impact

- 10 planned refueling outages, including 1 at Salem
- Exelon completed 4 refueling outages in the Spring with an average duration of 24 days
- Salem completed 1 refueling outage in the Spring
- 5 Exelon planned Fall refueling outages (Braidwood 1, Peach Bottom 3, Clinton, Three Mile Island and Dresden 2)

2014 Refueling Outage Impact

- 11 planned refueling outages, including 2 at Salem
- 5 Exelon planned Spring refueling outages and 4 planned Fall refueling outages
- 1 Salem planned Spring refueling outage and 1 planned Fall refueling outage

Exelon

Nuclear Fuel Costs(1)

Projected Exelon (100%) Uranium Demand

2013 – 2016: 100% hedged in volume
2017: ~80% hedged in volume
2018: ~50% hedged in volume

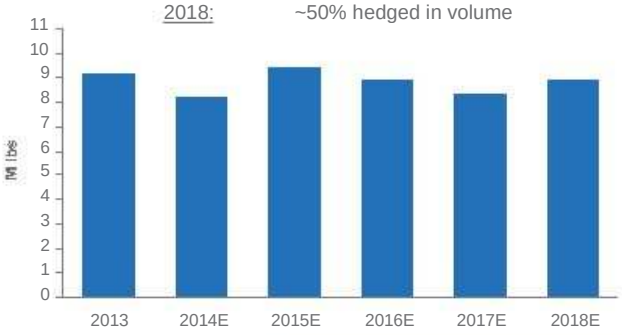

Components of Fuel Expense in 2013

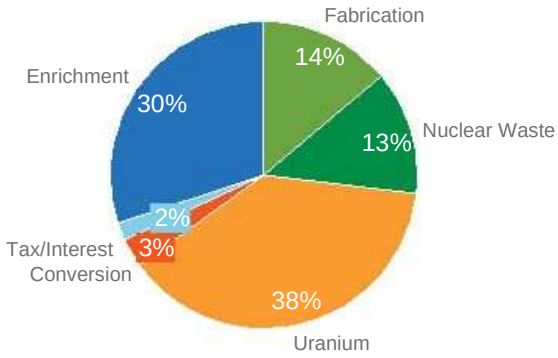

Projected Total Nuclear Fuel Spend(2)

(1) All charts exclude Salem and CENG.
(2) At ownership, excluding Salem and CENG. Excludes costs reimbursed under the settlement agreement with the DOE.

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Constellation Energy Nuclear Group (CENG) Operating Services Agreement

- **Agreement signed between Exelon and EDF, with expected close in 2014 (first quarter or early second quarter)**
- **Nuclear Operating services agreement**
  - Integrate CENG and their 3 plants into Exelon Nuclear with transfer of operating licenses
  - Utilize Exelon Nuclear Management Model to improve plant performance
  - Leverage scale and obtain cost efficiencies of running a larger, integrated fleet
    - Expect cost synergies of $50-$70M at 100% ownership
- **Loan to CENG and distributions to EDF/Exelon Generation**
  - Exelon Generation $400M loan to CENG at 5.25% annual interest rate
  - CENG $400M special distribution to EDF
  - Exelon Generation to receive preferred distributions from CENG's available cash flows until loan is fully repaid
  - Exelon Generation also to receive aggregate distributions of $400M plus a return of 8.5% per annum from the date of the special dividend
- **Option provision for EDF to sell its 49.99% interest in CENG to Exelon Generation**
  - Exercisable from January 2016 to June 2022, priced at fair market value
- **Indemnify EDF in the event of a future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations**
  - Given Exelon's size and past performance, no material impact to premiums

Leverages Exelon's best-in-class operations, scale and low-cost fleet to add value

Exelon

S1-SSA-0009 - 10137

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

November 9, 2015
Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** **10 South Dearborn Street** **P.O. Box 805379** **Chicago, Illinois 60680-5379** **(800) 483-3220**	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** **300 Exelon Way** **Kennett Square, Pennsylvania 19348-2473** **(610) 765-5959**	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** **440 South LaSalle Street** **Chicago, Illinois 60605-1028** **(312) 394-4321**	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** **P.O. Box 8699** **2301 Market Street** **Philadelphia, Pennsylvania 19101-8699** **(215) 841-4000**	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** **2 Center Plaza** **110 West Fayette Street** **Baltimore, Maryland 21201** **(410) 234-5000**	52-0280210

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 7 – Regulation FD

Item 7.01. Regulation FD Disclosure.

On November 8-11, 2015, Exelon Corporation (Exelon) will participate in the Edison Electric Institute Financial Conference. Attached as Exhibit 99.1 to this Current Report on Form 8-K are the presentation slides and handouts to be used at the conference.

Section 9 – Financial Statements and Exhibits

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits* .

Exhibit No.	Description
99.1	Presentation slides and handouts

* * * * *

This combined Form 8-K is being furnished separately by Exelon, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, and Baltimore Gas and Electric Company (Registrants). Information contained herein relating to any individual Registrant has been furnished by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

This Current Report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from these forward-looking statements include those discussed herein as well as those discussed in (1) Exelon's 2014 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; (2) Exelon's Third Quarter 2015 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 19; and (3) other factors discussed in filings with the Securities and Exchange Commission by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Current Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Current Report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Jonathan W. Thayer
Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright
Bryan P. Wright
Senior Vice President and Chief Financial Officer Exelon Generation Company, LLC

COMMONWEALTH EDISON COMPANY

/s/ Joseph R. Trpik, Jr.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer
Commonwealth Edison Company

PECO ENERGY COMPANY

/s/ Phillip S. Barnett
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
PECO Energy Company

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ David M. Vahos
David M. Vahos
Vice President, Chief Financial Officer and Treasurer
Baltimore Gas and Electric Company

November 9, 2015

EXHIBIT INDEX

Exhibit No.	Description
99.1	Presentation slides and handouts

Exhibit 99.1

Edison Electric Institute Financial Conference

November 8–11, 2015

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Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company and Exelon Generation Company, LLC (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2014 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; (2) Exelon's Third Quarter 2015 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 19; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

2015: An Exceptional Year of Performance

Our utilities are performing at their best levels, our generation business is world class and our Constellation business maximizes its value. We will deliver earnings between $2.40 - $2.60[1] per share.

- On track to invest $3.7 billion this year to make the grid smarter, more reliable, and more resilient
- Exceeding $ 1 billion in net income this year at Exelon Utilities
- Constructive regulatory environments across our jurisdictions
  - PECO rate case settlement
  - ComEd formula rate
  - Recent BGE unanimous rate case settlement
- Industry leading operational excellence
  - 1st Quartile SAIFI performance
  - 1st Quartile CAIDI performance at ComEd and PECO, 2nd Quartile at BGE
  - 1st Quartile Customer Satisfaction
  - Top Decile Gas Odor Response
- Successful generation to load matching strategy is protecting earnings
- Active role in policy development to deliver Capacity Performance construct
- #1 Provider of retail electricity, serving 34 TWhs more than our nearest competitor
- Top 10 marketer of natural gas
- World Class Operator
  - 2015 Nuclear capacity factor through 3Q: 93.8%
  - 2015 Power dispatch match through 3Q: 98.7%
  - 2015 Renewables energy capture 3Q: 95.6%

(1) Represents adjusted (non-GAAP) operating earnings. Refer to slide 31 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating earnings

Exelon.

Looking Ahead

- The Exelon Strategy

- Addressing Key Immediate Issues
  1) Capital Allocation
  2) Pepco Holdings Acquisition
  3) Extending Clinton One Year
  4) Cost Management Initiative

- The Foundation for Exelon's Growth

Exelon.

The Exelon Strategy

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Our Key Objectives

Employ our integrated model to deliver stable growth, sustainable earnings and an attractive dividend

- Stable Growth – Grow ourregulated and contracted businesses and optimize our existing generation portfolio
- Sustainable Earnings – Utilities, contracted assets, and balanced generation to load strategy profits are an engine for predictable earnings and our generation business positions us to capture market upside
- Attractive Dividend – Dividend will be covered by the utilities, insulated from the earnings volatility of the generation business

Exelon

How We Will Meet Our Objectives

We will produce stable earnings growth of 3 - 5% per year from 2015 to 2018[1]

- Investing more than $18 billion in Exelon's current utilities through 2020 to modernize the grid and better serve our customers ($11 billion from 2016-2018)

We will sustainearnings growth while also preserving the benefit of market upside through:

- Ensuring operating excellence across every business
- Shifting our earnings mix to be more regulated through investments in Exelon's utilities and the acquisition of Pepco Holdings (Expect earnings to be ~60% regulated in 2018)
- Effectively managing our costs
- Growing the amount of contracted assets in our Exelon Generation portfolio
- Maximizing the value of our generation fleet and customer base through our proven generation to load matching strategy
- Hedging our generation in a manner that preserves upside from our fundamental price view

We will continue to deliver an attractivedividend of $1.24 per share[2]

- Targeting dividend funding entirely from regulated utilities
- Our business mix protects our dividend regardless of changing phases of the commodities cycle

(1) Growth target is a net income compounded annual growth rate (CAGR), assumes September 30, 2015 market prices, and does not include our fundamental market view of prices
(2) Dividends are subject to declaration by the Exelon Board of Directors

Exelon.

We Are Well Down the Path of Delivering on Our Key Objectives

	2011 (Pre-CEG Merger)	2014 (Post-CEG Merger)	2018 (Post-PHI Merger)
Top Performing Utilities	• 5.4M Electric Customers • 0.5M Gas Customers • $791M Net Income(1) • $13B Rate Base • 6,054 Miles of Transmission Lines	• 6.7M Electric Customers • 1.2M Gas Customers • $962M Net Income(1) • $20B Rate Base • 7,435 Miles of Transmission Lines	• 8.6M Electric Customers • 1.3M Gas Customers • $1.5B-1.7B Net Income(1,2) • $38B Rate Base • ~12,000 Miles of Transmission Lines
World Class Generator	• 25,544 MW (Total Capacity) • 67% Nuclear • 151 TWh Generation	• 32,753 MW (Total Capacity) • 59% Nuclear(3) • 205 TWh Generation	• 34,800 MW (Total Capacity) • 56% Nuclear(3) • 206 TWh Generation
Preeminent Competitive Energy Company	• 4 States • ~59 TWh/yr • <1 Bcf of Gas per day	• 48 States, DC & Canada • ~155 TWh/yr • 4-6 Bcf of Gas per day	• 48 States, DC, & Canada • ~210 TWh/yr • 6-8 Bcf of Gas
Transforming the Business Mix	2011 Earnings (1) • 29% Utilities • 71% Generation	2014 Earnings (1) • 47% Utilities • 53% Generation	2018 Earnings (1,4) • ~60% Utilities • ~40% Generation

(1) Represents adjusted (non-GAAP) operating earnings. Refer to slide 31 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating earnings.
(2) Includes after-tax interest expense of (~$150M) for debt held at Corporate related to utility investment
(3) Includes CENG at ownership; does not assume put exercised
(4) Based on September 30, 2015 market prices

Exelon.

Addressing Key Immediate Issues

1) Capital Allocation
2) Pepco Holdings Acquisition
3) Extending Clinton One Year
4) Cost Management Initiative

Capital Allocation

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Delivering Value to Shareholders Through a Principled Capital Allocation Policy

- Everycapital decisionis made to maximize value to our customers and shareholders
- We are h arvesting free cash flow from Exelon Generation to:
  - First, invest in utilities where we can earn an appropriate return,
  - Invest in contracted assets where we can meet return thresholds, and/or
  - Return capital to shareholders by retiring debt, repurchasing our shares, or increasing our dividend if required investment returns are not met
- We are committed to maintaining an attractive dividend
- Our strong balance sheet underpins our capital allocation policy

Exelon.

Redeploying Exelon Generation's Free Cash Flow to Maximize Shareholder Value

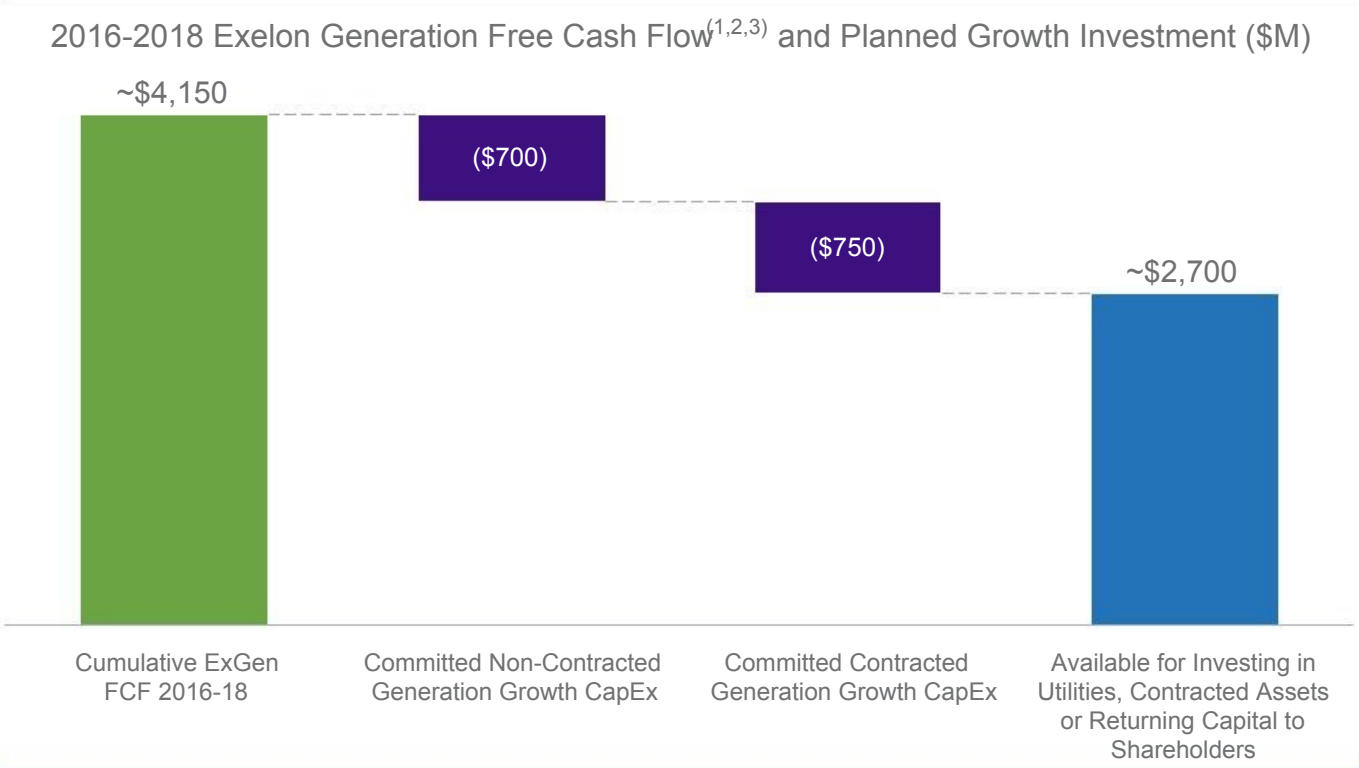

If investments do not meet our thresholds, we will return capital to shareholders

(1) Free Cash Flow = Adjusted Cash Flow from Operations less Base CapEx and Nuclear Fuel. Free Cash Flow is midpoint of a range based on September 30, 2015 market prices. Adjusted Cash Flow From Operations (non-GAAP) primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures. Reconciliation of Free Cash Flow to GAAP can be found on slide 32.
(2) Does not include an extension of bonus depreciation. A two year extension of bonus depreciation would add ~$200 million of Free Cash Flow
(3) Does not include impacts of PHI, which would decrease Free Cash Flow by (~$100M)

Exelon.

Capital Allocation —Disciplined Commitment to Growth

We will prioritize investment in assets that minimize earnings volatility and support stable earnings growth

Exelon Utilities

- Investing in utility infrastructure to benefit our customers by making the grid smarter, more reliable, and more resilient
  - $18 billion from 2016 to 2020 (existing Exelon Utilities)
  - $25 billion from 2016 to 2020 (including PHI)
- Targeting long-term ROE of 10%
- Growing existing rate base from $22 billion in 2015 to $28 billion in 2018
- Earnings CAGR of 7-9% from 2015-2018

Exelon Generation

- Going forward, we will invest in assets with contracted cash flows
  - We are reviewing development opportunities that may result in investment of $2.8 billion from 2016 through 2020
  - Approximately half of any growth investment will be funded through structured financing
- Projects must earn attractive return (> 10% ROE)

No incremental equity issuance needed to fund investment

Note: Including PHI would increase combined rate base by $10 billion in 2018; Exelon Utilities 2016-2018 capital investment is $11 billion for existing Exelon utilities ($15 billion including PHI); Exelon Generation 2016-2018 investment opportunities total $1.6 billion

Exelon.

Pepco Holdings Acquisition

S1-SSA-0009 - 10155

PHI Acquisition Increases Sustainability of Earnings Growth

Projected Earnings Accretion at Various Earned ROE Levels(1,2,3)

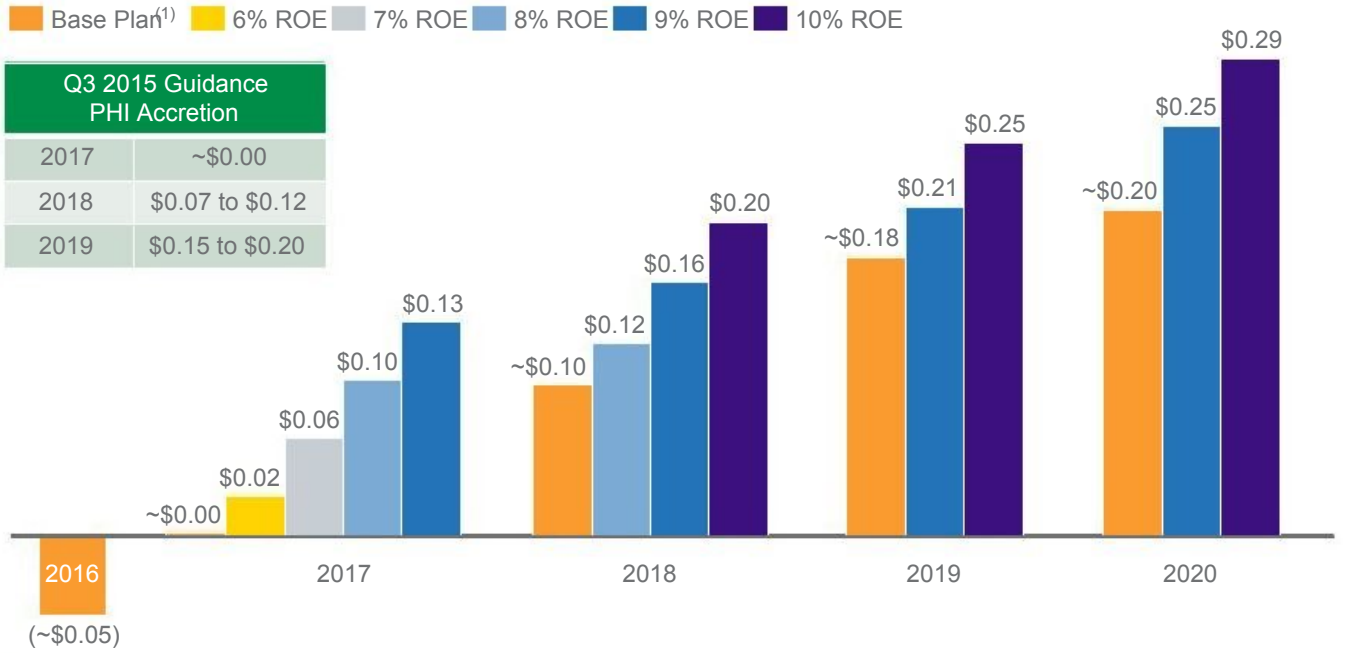

Operational improvements should drive enhanced regulatoryoutcomes, positively impacting EPS

(1) Base Plan accretion figures represent midpoint of updated guidance range from Q3 2015 earnings call and reflect current PHI business plan
(2) Chart above illustrates accretion at various weighted average distribution earned ROEs for PHI
(3) Accretion is measured against Exelon standalone plan, which excludes the impact of PHI acquisition debt and equity
Note: Represents adjusted (non-GAAP) operating earnings. Refer to slide 31 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating earnings

Exelon.

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BGE: A Proven Track Record of Enhancing Utility Value

Delivering value to our customers and regulators by improving reliability while providing investors with predictable cost recovery and earnings growth

SAIFI and Customer Satisfaction Index

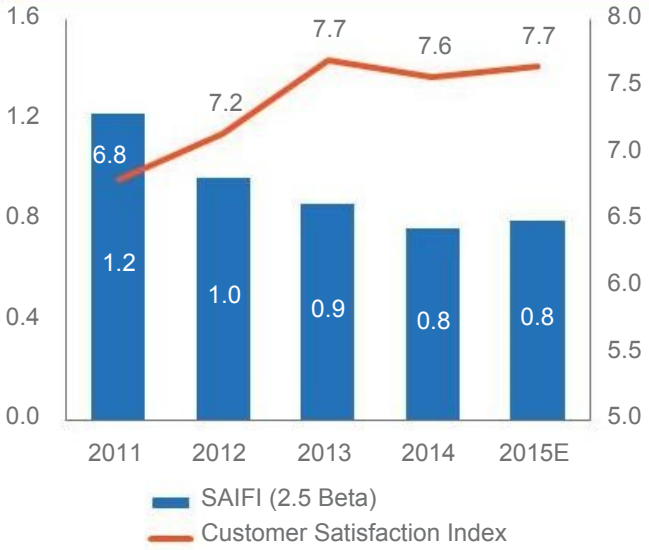

- Increased reliability by 10% per year and customer satisfaction by 3% per year

Operating ROE (%) and Net Income ($M)

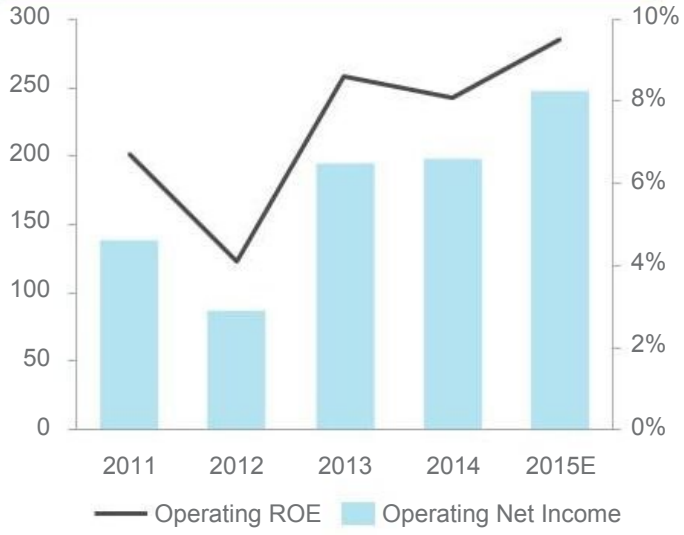

- Increased ROE by more than 250 basis points from 2011 to 2015 and grew net income 15% annually over same period
- Continued system investments in reliability and safety necessitate continued rate cases for capital recovery

Note: 2012 ROE and Net Income normalized by excluding one-time $112M rate credit as part of EXC-CEG merger. Operating net income represents adjusted (non-GAAP) operating earnings. Refer to slide 31 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating earnings

Exelon.

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Extending Clinton One Year

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We Will Continue to Operate Clinton for Another Year

"If we do not see a path to sustain profitability for these units . . . we will be forced to retire them." – – *Chris Crane, July 31, 2014*

What has changed in 2015?

- Recent upward movement in MISO capacity prices -- $150/MWd in MISO 2015 auction and Illinois Power Authority Zone 4 procurement auction
- Fleet capacity revenue uplift due to Capacity Performance of $1.4B, beyond our expectations; MISO will now consider similar market reforms
- EPA's Clean Power Plan finalized. Development of Illinois compliance program in 2016, could facilitate significant upside from implementation
- Legislative engagement on Illinois Low Carbon Portfolio Standard. Resolution of budget crisis should facilitate legislative consideration in 2016
- Improved operating efficiency and agile nuclear fuel procurement strategy
- Over the last 2 years Clinton has deferred approximately $100M of strategic capital, minimizing the cost of maintaining the optionality at Clinton
- Significant potential NiHub upside in the out-years not yet reflected in illiquid forward markets

Exelon.

More Progress Necessary for Clinton to Operate Beyond 2017

1) MISO Reforms:

- MISO iscommitted to evaluate Zone 4 market design
- Illinois Commerce Commission is holding workshops to examine potential fixes to address Zone 4
- Reforms must provide strong revenues like the PJM reforms effectuated

2) Areas of Additional Progress Needed:

- Passage of Low Carbon Portfolio Standard
- Illinois implementation of EPA's Clean Power Plan must fully recognize the value of Clinton

Exelon.

Cost Management Initiative

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The Sustainability and Growth of Our Earnings Will be Supported by an Aggressive Cost Management Program

- Exelon has launched a cost management program across to provide sustainable improvement to the Company's earnings trajectory
- The initiative will achieve $300 – $350 million of annual cost savings at Exelon Generation and Corporate
- Estimated EPS benefit of $ 0.13 to $0.18(2)
- An additional $50 million of nuclear fuel savings already reflected in hedge disclosures
- Savings to begin in 2016 and will be fully realized in 2018

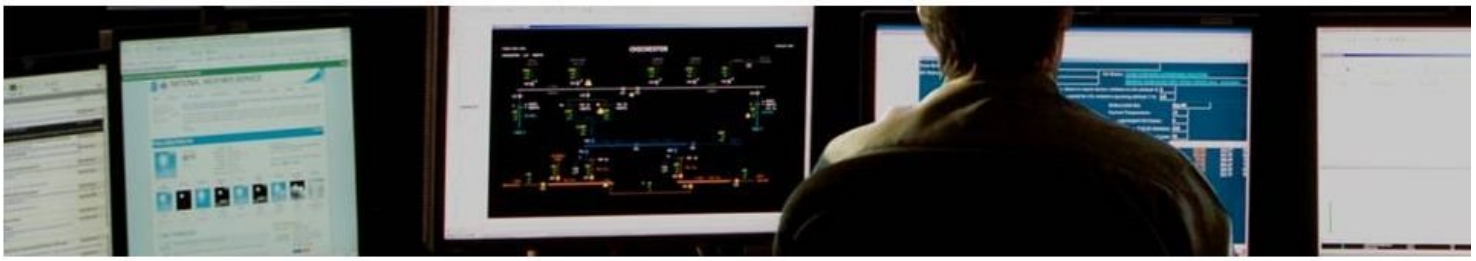

(1) Based on projected 2018 share count of 965M shares, which assumes PHI merger closes
(2) Represents adjusted (non-GAAP) operating earnings. Refer to slide 31 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating earnings

Exelon.

Financial Data

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The Foundation for Exelon's Growth

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2015 Operating Earnings Guidance

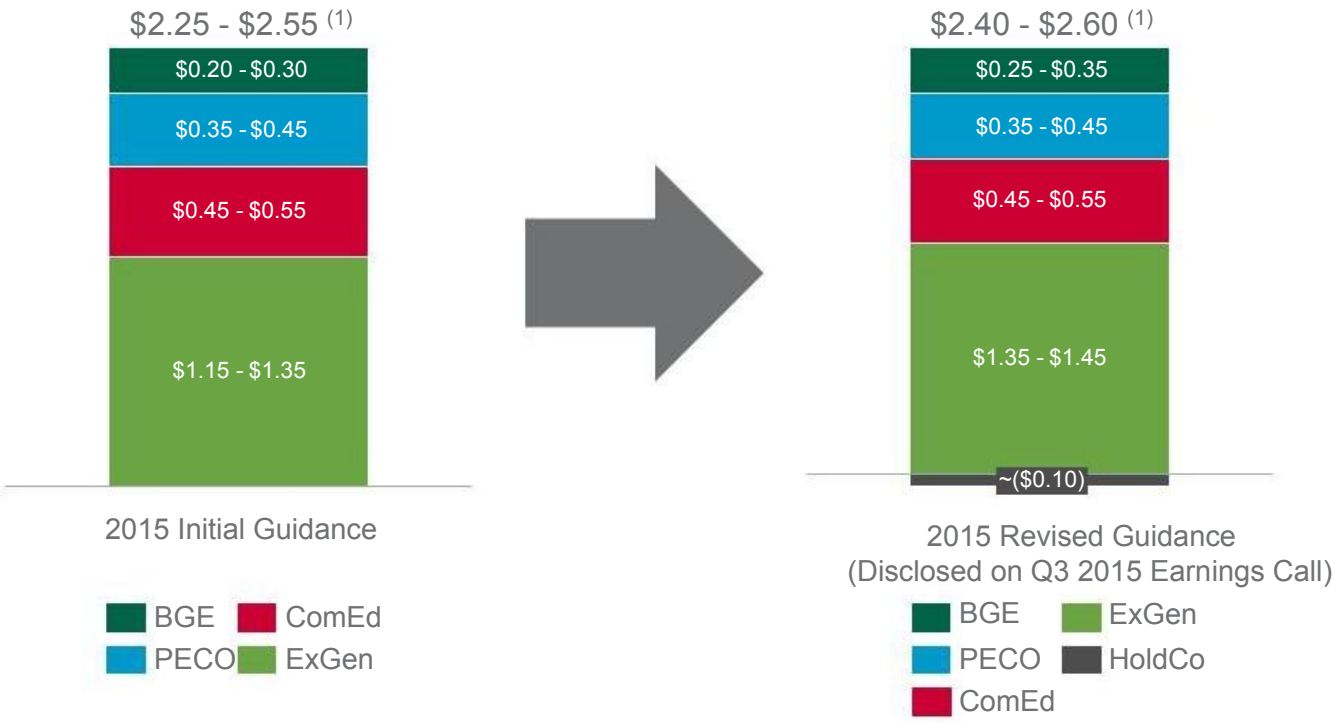

(1) Earnings guidance for OpCos may not add up to consolidated EPS guidance. Represents adjusted (non-GAAP) operating earnings. Refer to slide 31 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating earnings

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Our Capital Plan Drives Stable Earnings Growth

Exelon Utilities ($M)

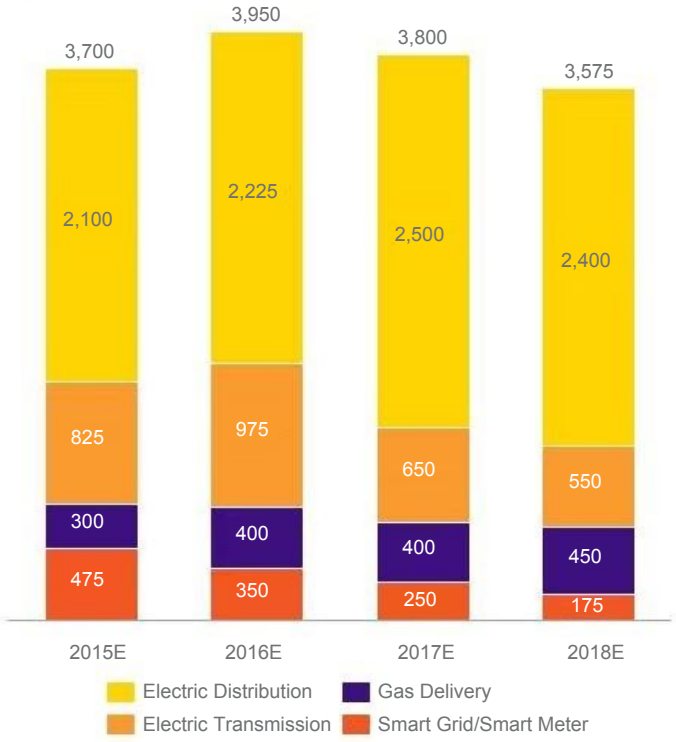

Exelon Generation($M)[1)]

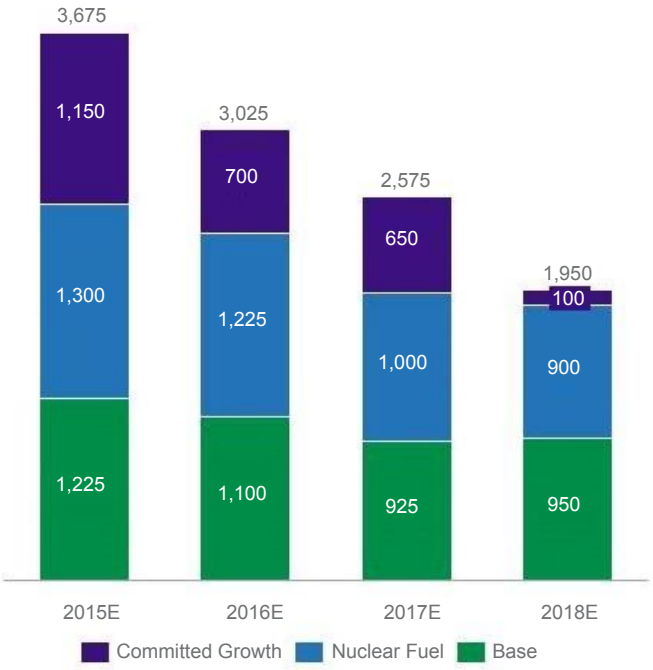

Note: Numbers rounded to nearest $25M
(1) Figures reflect cash CapEx and CENG fleet at 100%; 2014 EEI presentation showed CENG fleet at ownership; Does not include potential pipeline of contracted generation growth mentioned on slides 11 and 12

Exelon.

S1-SSA-0009 - 10166

Exelon's Existing Utilities Drive Stable Earnings Growth

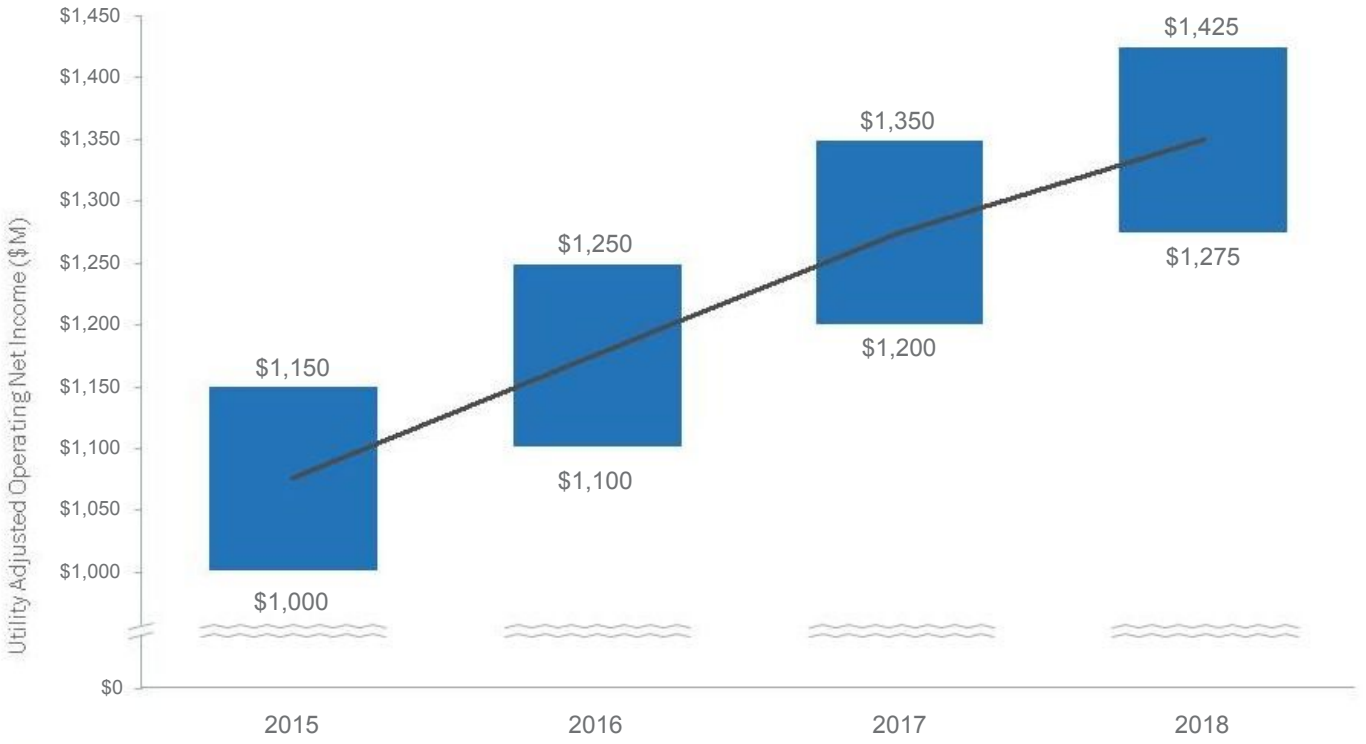

Projected average earnings growth of ~7-9% per year from 2015-2018

Note: Does not include PHI net income and represents adjusted (non-GAAP) operating earnings. Refer to slide 31 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating earnings. Does not include an extension of bonus depreciation. Impact of a 2-year bonus depreciation extension for 2015 and 2016 would be ~($10M) in 2015 and ~($25M) a year in 2016-2018. Excludes after-tax interest expense held at Corporate for debt associated with existing utility investment, which is (~$25M) a year.

Exelon.

Continued Focus on Our Balance Sheet

Our strong balance sheet supports our disciplined commitment to growth

Exelon Consolidated[1] FFO/Debt

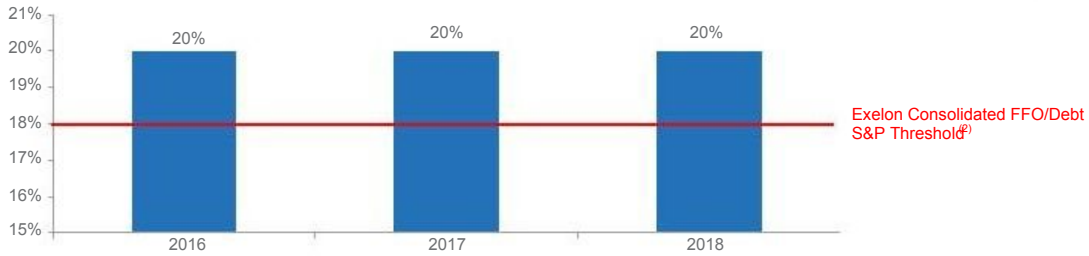

Solid investment grade credit ratings are a financial priority

Current Ratings [3,4]	ExCorp	ComEd	PECO	BGE	ExGen	Recent Commentary
Moody's	Baa2	A2	Aa3	A3	Baa2	" Exelon maintains a strong consolidated financial profile…which should produce steady ratios of cash flow to debt in the low 20% range which, when combined with adequate liquidity reserves and a growing focus on regulated investment opportunities, positions Exelon firmly within its current rating category." Moody's Issuer Comment, June 11, 2015
S&P	BBB-	A-	A-	A-	BBB	" ExGergenerates a significant portion of earnings from its retail operations. Through retail and wholesale channels, ExGen now provides nearly 5% of total U.S. power demand, and enjoys regional diversity. The company's generation units are well positioned to grow where capacity available for competitive supply has room to grow. We expect these incremental revenue streams to make the consolidated Exelon somewhat more resilient to commodity prices." S&P Summary Analysis; March 9, 2015
Fitch	BBB+	A-	A	A-	BBB	" The majority of capital investment is allocated to EXC's three utility subsidiaries, which should provide a more stable earnings base." Fitch Full Ratings Report; October 15, 2015 "Exgen's financial position has stabilized in recent years, and remains solidly within the investment-grade category. " Fitch Full Ratings Report; September 11, 2015

(1) Metrics include PHI financing. Because of ring-fencing, S&P deconsolidates BGE's and PHI's financial profile from Exelon and analyzes them solely as equity investments
(2) Exelon Consolidated threshold of 18% is based on the S&P Exelon Corp Summary Report published on August 5, 2015
(3) Current senior unsecured ratings as of 11/3/2015 for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd and PECO
(4) All ratings are "Stable" outlook, except for at Fitch, which has ComEd on "Positive" and Exelon on "Ratings Watch Negative," and Moody's, which has ComEd on "Positive" outlook

Exelon.

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Exelon-PHI Debt Maturity Profile(1)

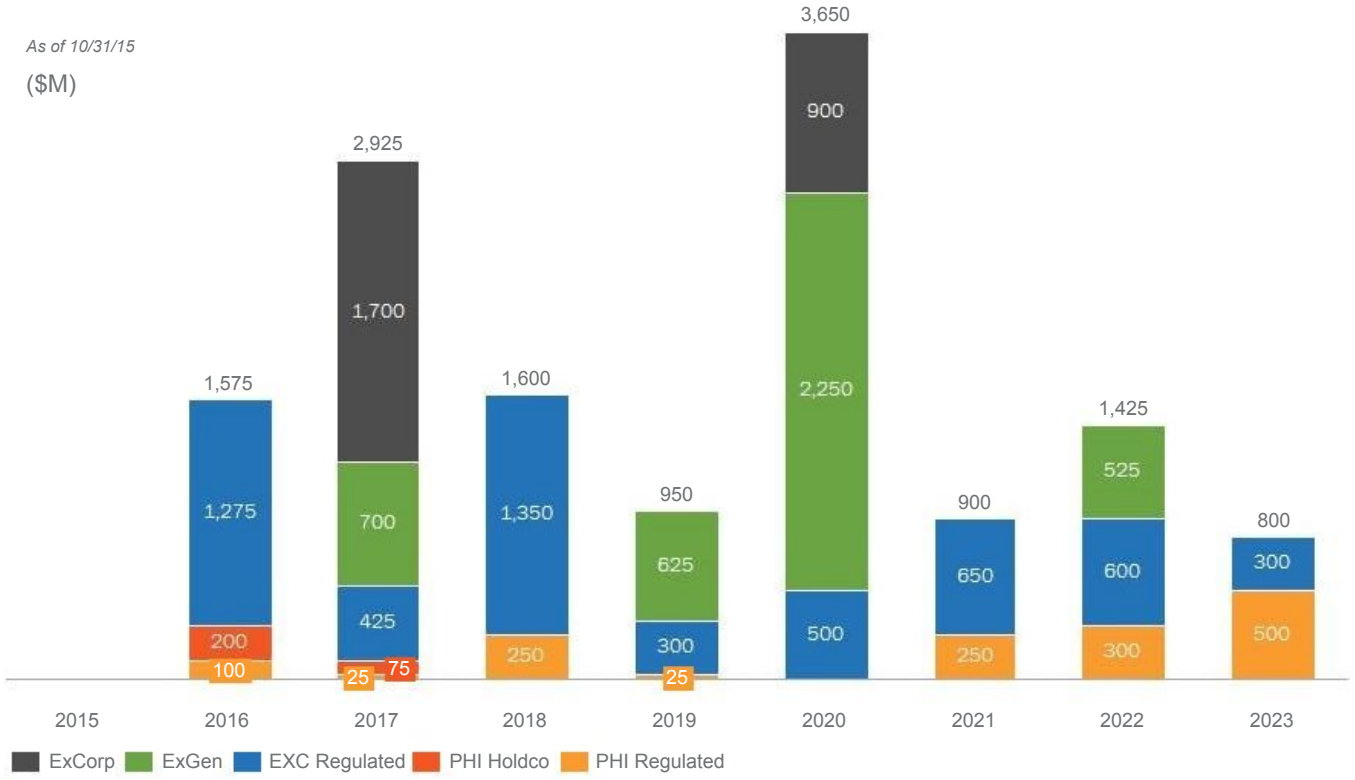

Debt Exchange Underway on Exelon Corp Notes due 2025, 2035 and 2045

(1) ExCorp debt includes acquisition debt, including $1,150M mandatory convertible units remarketing in 2017; ExGen debt includes legacy CEG debt; Excludes securitized debt and non-recourse debt

Exelon.

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EPS Sensitivities

		2015	2016	2017	2018	Fully Open
ExGen EPS Impact[1]	Henry Hub Natural Gas					
	+$1/MMBtu	($0.00)	$0.08	$0.31	$0.46	$0.56
	-$1/MMBtu	$0.01	($0.08)	($0.30)	($0.46)	($0.55)
	NiHub ATC Energy Price					
	+$5/MWh	($0.00)	$0.07	$0.19	$0.28	$0.31
	-$5/MWh	$0.00	($0.07)	($0.19)	($0.28)	($0.31)
	PJM-W ATC Energy Price					
	+$5/MWh	($0.00)	$0.03	$0.09	$0.16	$0.19
	-$5/MWh	$0.00	($0.03)	($0.09)	($0.16)	($0.19)
	PJM Capacity Market[2]					
	+$10/MW-day					$0.04
	-$10/MW-day					($0.04)
ComEd EPS Impact	30 Year Treasury Rate					
	+50 basis points		$0.02	$0.03	$0.03	
	-50 basis points		($0.02)	($0.03)	($0.03)	
	Share Count[3] (millions)	893	927	947	965	

(1) Based on September 30, 2015 market conditions and hedged position. Gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically. Power prices sensitivities are derived by adjusting the power price assumption while keeping all other price inputs constant. Due to correlation of the various assumptions, the EPS impact calculated by aggregating individual sensitivities may not be equal to the EPS impact calculated when correlations between the various assumptions are also considered. Represents adjusted (non-GAAP) operating earnings. Refer to slide 31 for a list of adjustments from GAAP EPS to adjusted (non-GAAP) operating earnings

(2) Assumes 2018/2019 auction cleared volumes

(3) Share count used to calculated EPS impact assumes PHI transaction closes

Exelon.

Modeling Combined Exelon & Pepco Holdings Pro Forma EPS

	2016	2017	2018	Source of Data
Exelon Utilities Net Income ($M)	$1,175	$1,275	$1,350	Model using midpoint of NetIncome guidance from slide 25
ExelonGeneration Net Income ($M)	$X,XXX	$X,XXX	$X,XXX	Model using Gross Margin disclosure from slide 45
Corporate Net Income ($M)	($25)	($25)	($25)	Model using interestexpense information in note on slide 25
Exelon Standalone Net Income ($M)	$X,XXX	$X,XXX	$X,XXX	
Standalone Share Count (millions)	877	881	886	Approximate sharecount when PHI equity issuance is excluded
Standalone EPS	$X.XX	$X.XX	$X.XX	TakeExelon standalone Net Income and divide by standalone share count
PHI Accretion Guidance	($0.05)	$0.00	$0.10	Midpoint of Q3 2015 guidance for PHI accretion f rom slide 14
Pro Forma EPS	$X.XX	$X.XX	$X.XX	Take Exelonstandalone Net Income and add PHI accretion
Pro Forma Share Count (millions)	927	947	965	From slide 28

Exelon.

Pension and OPEB Update

Pension Funded Status: % Funded(1)

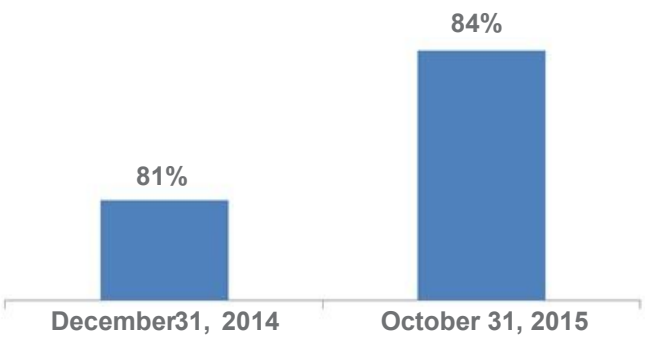

Pension Unfunded Status ($B)

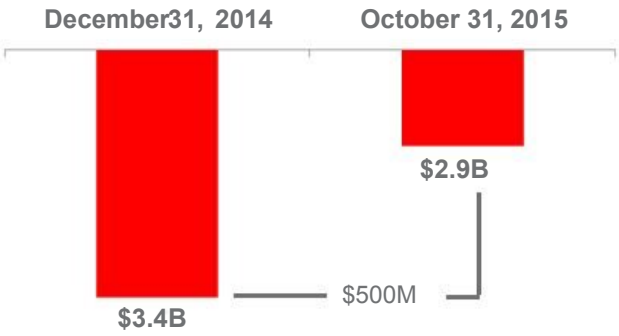

- Exelon's pension funding and investment strategies have continued to drive improvements in the overall funded status of Exelon's pension plans
- Given the continued improvements in the funded status of the Exelon Corporation Retirement Program (ECRP), traditional defined benefit plan (87% funded at October 31, 2015), and its positive exposure to an improving rate environment; Exelon is evaluating opportunities to optimize our pension contribution strategy going forward
- Exelon's standard Pension/OPEB assumptions and sensitivities will be provided as part of Q4 2015 earnings disclosures

Note: October 2015 numbers are preliminary estimates and are subject to change

(1) Assets as a % of PBO Liability

Exelon.

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GAAP to Operating Adjustments

- Exelon's 2015 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:
  - Mark-to-market adjustments from economic hedging activities
  - Unrealized losses from NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
  - Certain costs incurred associated with the Integrys and pending Pepco Holdings, Inc. acquisitions
  - Mark-to-market adjustments from forward-starting interest rate swaps related to anticipated financing for the pending PHI acquisition
  - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the date of acquisition of Integrys in 2014
  - Non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units
  - Impairment of investment in long-term generating leases
  - Favorable settlement of certain income tax positions on Constellation's pre-acquisition tax returns
  - Generation's non-controlling interest related to CENG exclusion items
  - Other unusual items

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Free Cash Flow GAAP to Non-GAAP Reconciliation

2016-2018 ExGen Free Cash Flow Calculation ($M)	2016-2018 Estimate
Adjusted Cash from Operations[1]	$10,250
Non-Growth Capital Expenditures	($2,975)
Nuclear Fuel Capital Expenditures	($3,125)
Free Cash Flow before Growth CapEx and Dividend	$4,150

(1) Adjusted Cash Flow From Operations (non-GAAP) primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures

Exelon.

S1-SSA-0009 - 10174

Exelon Utilities

S1-SSA-0009 - 10175

Operational Excellence Drives Value for Customers, Communities, and Shareholders

Operations	Metric	At CEG Merger (2012)			Post CEG Merger (2015)		
		BGE	PECO	ComEd	BGE	PECO	ComEd
Electric Operations	OSHA Recordable Rate						
	OSHA Severity Rate						
	2.5 Beta SAIFI (Outage Frequency)						
	2.5 Beta CAIDI (Outage Duration)						
Customer Operations	Customer Satisfaction						
	Service Level % of Calls Answered in <30 sec						
	Abandon Rate						
Gas Operations	Percent of Calls Responded to in <1 Hour			No Gas Operations			No Gas Operation s
	3rd Party Damages per 1000 Gas Locates						
Overall Rank	Electric Utility Panel of 24 Utilities	23rd	2nd	2nd	2nd	2nd	2nd

Exelon Utilities has identified and transferred best practices at each of its utilities to improve operating performance in areas such as:

- System Performance
- Emergency Preparedness
- Corrective and Preventive Maintenance

Performance Quartiles

Q1	Q2
Q3	Q4

Exelon

Exelon Utilities: Capital Plan

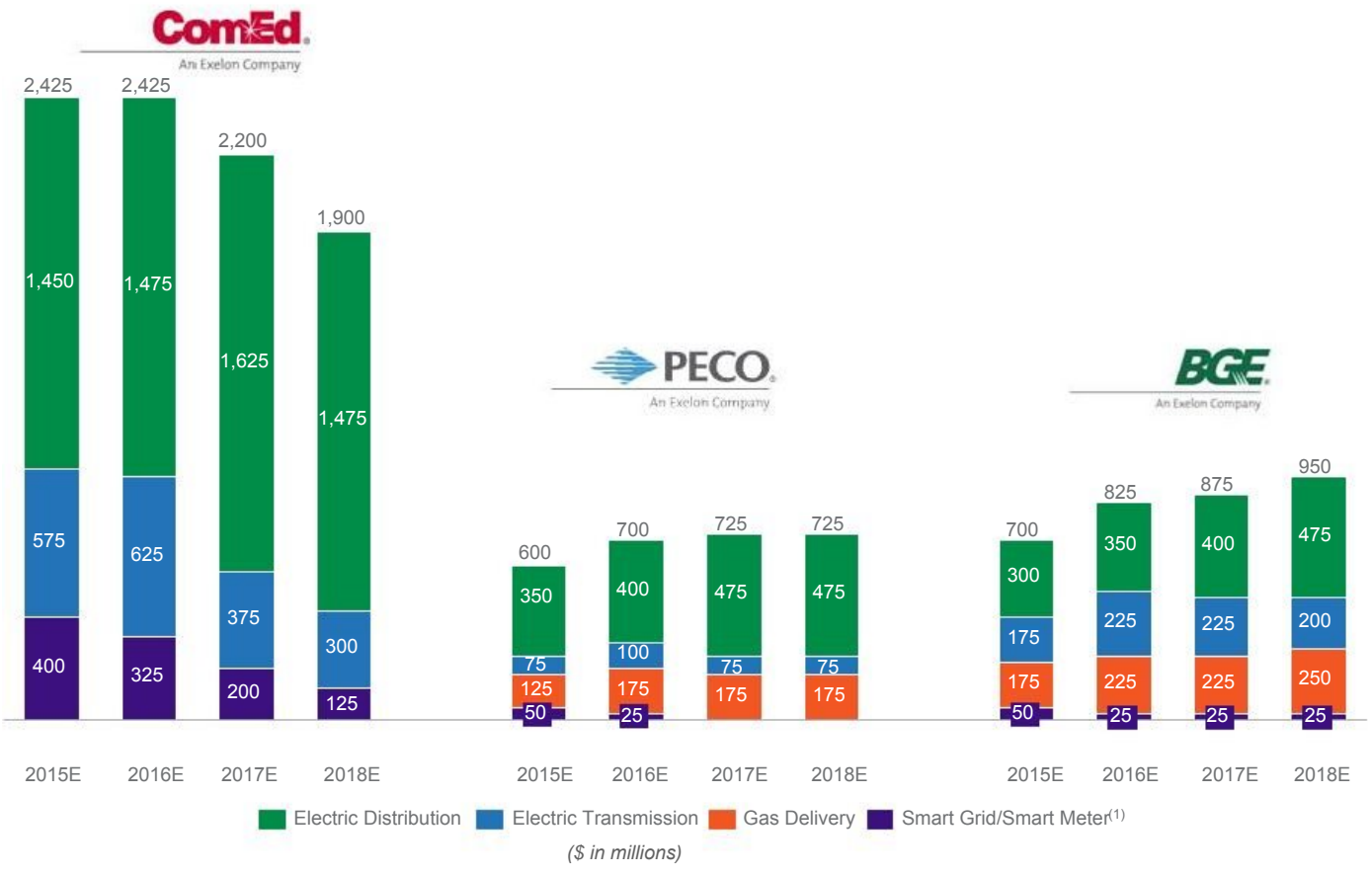

(1) Smart Meter/Smart Grid CapEx net of proceeds from U.S. Department of Energy (DOE) grant; For BGE, includes CapEx from Smart Energy Savers program of ~$10M per year

Exelon

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Exelon Utilities: Rate Base[1,4] and ROE Targets

	2015E	Long-Term Target
Equity Ratio	~46%	~50-53%(2)
Earned ROE	~8%	Based on 30-yr US Treasury(3)

	2015E	Long-Term Target
Equity Ratio	54%	~50-53%
Earned ROE	11-12%	≥ 10%

	2015E	Long-Term Target
Equity Ratio	52%	~50-53%
Earned ROE	9-10%	≥ 10%

(1) ComEd, PECO and BGE rate base represents end-of-year. Numbers may not add due to rounding
(2) Equity component for distribution rates will be the actual capital structure adjusted for goodwill
(3) Earned ROE will reflect the weighted average of 11.5% allowed transmission ROE and distribution ROE resulting from 30-year Treasury plus 580 basis points for each calendar year
(4) Rate base does not include extension of bonus depreciation

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Exelon Utilities Load

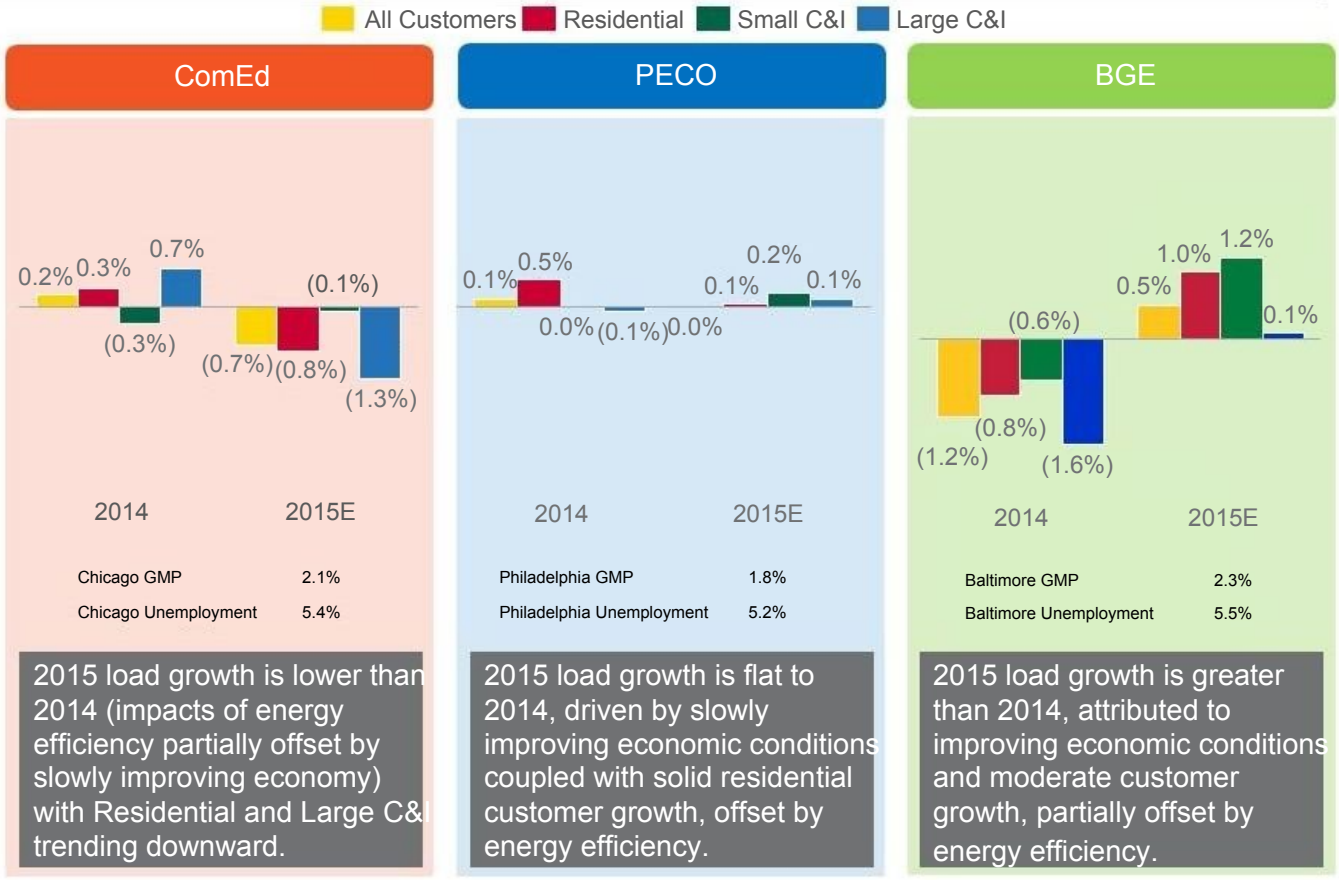

Notes: Data is weather normalized. Source of economic outlook data is IHS (September 2015). Assumes 2015 GDP of 2.5% and U.S. unemployment of 5.1%.
ComEd has the ROE collar as part of the distribution formula rate and BGE is decoupled which mitigates the load risk. QTD and YTD actual data can be found in earnings release tables.
BGE amounts have been adjusted for prior quarter true-ups.

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ComEd April 2015 Distribution Formula Rate

The 2015 distribution formula rate filing establishes the net revenue requirement used to set the rates that will take effect in January 2016 after the Illinois Commerce Commission's (ICC's) review. There are two components to the annual distribution formula rate filing:

- Filing Year: Based on prior year costs (2014) and current year (2015) projected plant additions.
- Annual Reconciliation: For the prior calendar year (2014), this amount reconciles the revenue requirement reflected in rates during the prior year (2014) in effect to the actual costs for that year. The annual reconciliation impacts cash flow in the following year (2016) but the earnings impact has been recorded in the prior year (2014) as a regulatory asset.

Docket #	15-0287
Filing Year	2014 Calendar Year Actual Costs and 2015 Projected Net Plant Additions are used to set the rates for calendar year 2016. Rates currently in effect (docket 14-0312) for calendar year 2015 were based on 2013 actual costs and 2014 projected net plant additions
Reconciliation Year	Reconciles Revenue Requirement reflected in rates during 2014 to 2014 Actual Costs Incurred. Revenue requirement for 2014 is based on docket 13-0318 (2012 actual costs and 2013 projected net plant additions) approved in December 2013 and reflects the impacts of PA 98-0015 (SB9)
Common Equity Ratio	~ 46% for both the filing and reconciliation year
ROE	9.14% for the filing year (2014 30-yr Treasury Yield of 3.34% + 580 basis point risk premium) and 9.09% for the reconciliation year (2014 30-yr Treasury Yield of 3.34% + 580 basis point risk premium – 5 basis points performance metrics penalty). For 2015 and 2016, the actual allowed ROE reflected in net income will ultimately be based on the average of the 30-year Treasury Yield during the respective years plus 580 basis point spread, absent any metric penalties
Requested Rate of Return	~ 7% for both the filing and reconciliation years
Rate Base(1)	$8,277 million – Filing year (represents projected year-end rate base using 2014 actual plus 2015 projected capital additions). 2015 and 2016 earnings will reflect 2015 and 2016 year-end rate base respectively. $7,082 million - Reconciliation year (represents year-end rate base for 2014)
Revenue Requirement Decrease(1)	$55M decrease ($145M decrease due to the 2014 reconciliation offset by a $90M increase related to the filing year). The 2014 reconciliation impact on net income was recorded in 2014 as a regulatory asset.
Timeline	• 04/15/15 Filing Date • 240 Day Proceeding • ICC order expected to be issued by December 11, 2015

Given the retroactive ratemaking provision in the Energy Infrastructure Modernization Act legislation, ComEd net income during the year will be based on actual costs with a regulatory asset/liability recorded to reflect any under/over recovery reflected in rates. Revenue Requirement in rate filings impacts cash flow

Note: Disallowance of any items in the 2015 distribution formula rate filing could impact 2015 earnings in the form of a regulatory asset adjustment

(1) Amounts represent ComEd's position filed in surrebuttal testimony on August 20, 2015

Exelon.

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PECO Electric Distribution Rate Case & Proposed Settlement

Docket #	R-2015-2468981
Test Year	2016 Calendar Year
Requested Revenue Requirement	$190M
Requested Common Equity Ratio[1]	53.36%
Requested Rate of Return	ROE: 10.95%; ROR: 8.19%
Proposed Rate Base	$4.1B
Proposed Revenue Requirement Settlement Increase	$127M
Authorized Returns[2]	N/A
System Average Increase as % of overall bill	2.9%
Timeline	• 3/27/15 – PECO filed electric distribution rate case with PaPUC • 9/10/15 Settlement filed with all intervening parties • 10/28/15 – ALJ issued Recommended Decision that settlement be approved • December 2015 – PUC Decision • Increased rates effective on January 1, 2016

The proposed Revenue Requirement increase of $127M represents 67% of the Company's original proposal

(1) Reflects PECO's expected capital structure as of 12/31/2016
(2) Due to the "black box" nature of the settlement, Authorized Return was not agreed upon by the parties in determining the ultimate revenue requirement increase

Exelon.

PECO Electric LTIIP System 2020

- PECO filed its Electric Long Term Infrastructure Improvement Plan ("LTIIP") along with its associated recovery mechanism the Distribution System Improvement Charge ("DSIC") on March 27, 2015 (with Electric Distribution Rate Case)
  - LTIIP includes $275 million in incremental capital spending from 2016-2020 focusing on the following areas:
    - Cable Replacement
    - Storm Hardening Programs
    - Substation replacement and upgrades
  - DSIC mechanism will allow recovery of eligible LTIIP spend between rate cases if the electric distribution ROE falls below the DSIC ROE established by PaPUC. The current Electric DSIC ROE is 10.0%.
  - Approved on 10/22/15
- PECO also proposed the concept of constructing one or more pilot microgrid projects as part of a future LTIIP update ($50-$100M). The objective is to evaluate and test emerging microgrid technologies that could enhance reliability and resiliency by replacing obsolete infrastructure as an alternative to traditional solutions.

LTIIP guarantees at least 10% ROE on capital improvements made on behalf of PECO customers

Exelon.

PHI Capital Plan and Rate Base

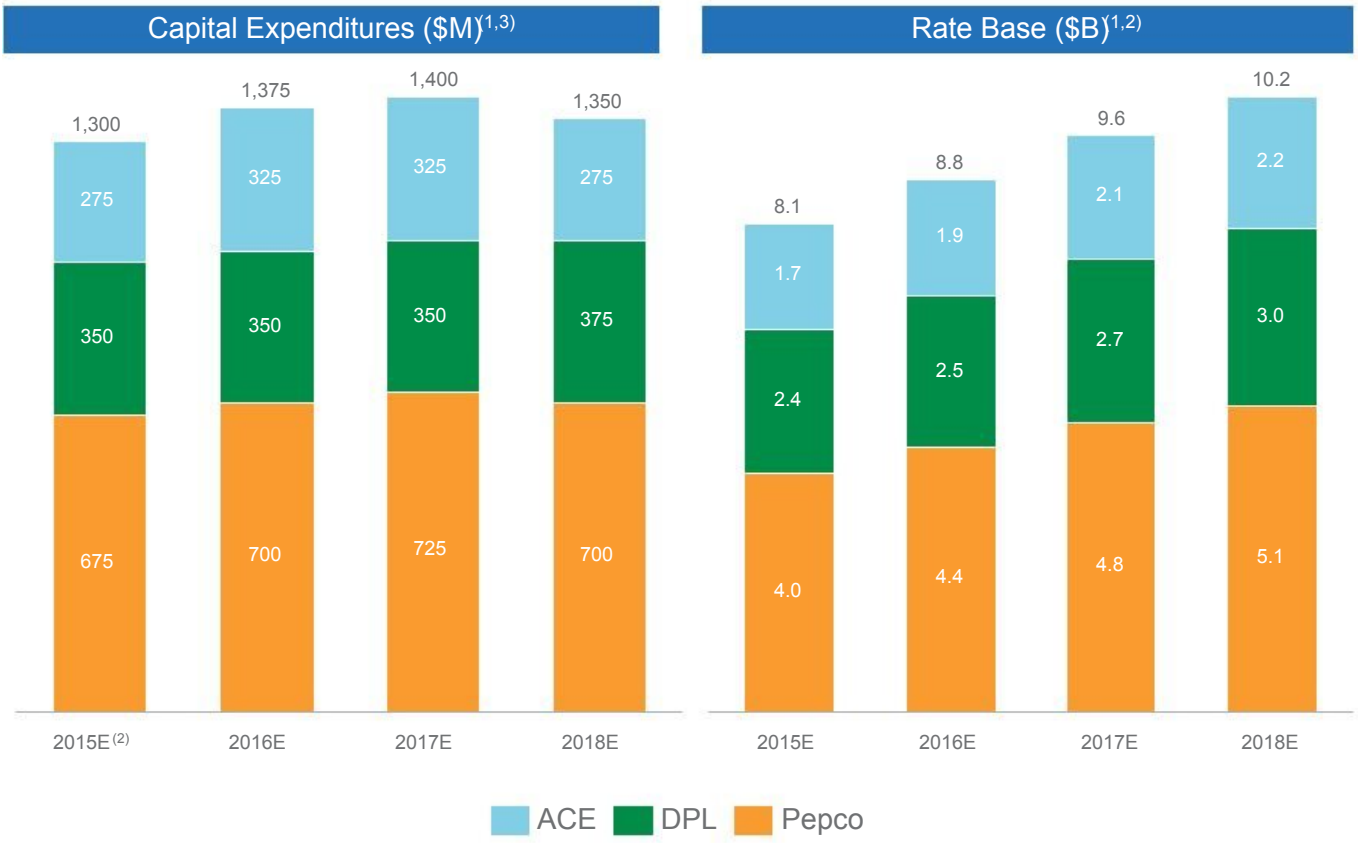

(1) Source: PHI Third Quarter Earnings Materials 10/31/14
(2) Denotes year end rate base
(3) CapEx numbers rounded to nearest $25M; totals might not add due to rounding

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Pepco Holdings: DCPSC Procedural Timeline

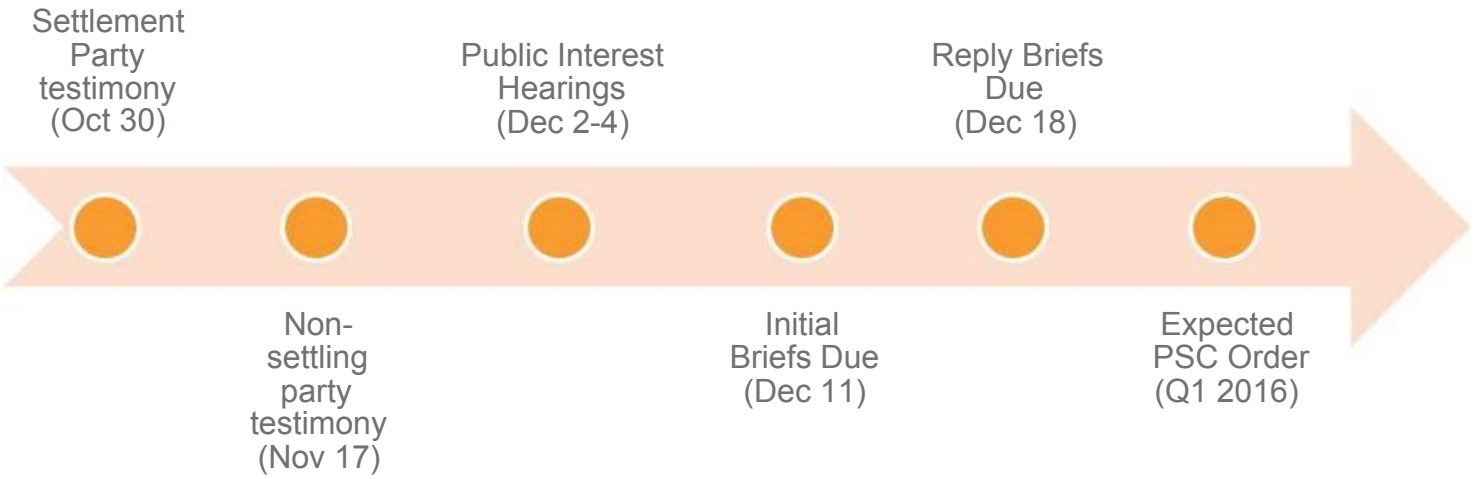

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Exelon Generation

S1-SSA-0009 - 10185

Our Generation to Load Strategy Delivers Sustainable Earnings in Volatile Markets

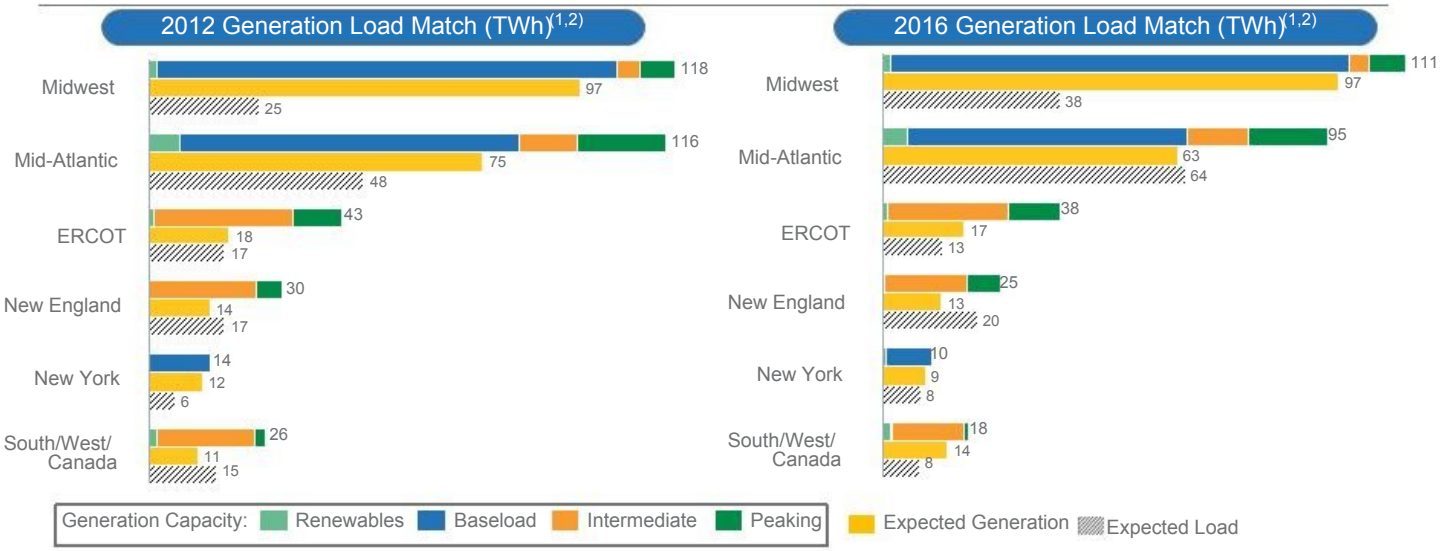

- Since the Constellation merger, we have improved our generation to load match through growing our customer load business, both organically and through disciplined acquisitions like Integrys
- This strategy and hedging with a fundamentals driven approach has meaningfully benefitted earnings over the last two years
- High volatility : We captured higher prices for our generation during periods of extreme weather while managing our load obligations. During periods of high volatility, generation availability is of utmost importance. During the polar vortex of 2014, our 2 GW of peaking capability created significant value in the energy and ancillary markets. During the polar vortex, we made ~$100 million (3)
- Low volatility : During periods of low volatility, we captured higher margins as we realized a lower cost to serve our customers and we optimized the value of our dispatchable fleet through load sales. This year alone, we have made ~$250 million as result of lower cost to serve load
- Generation to Load match also provides us with an important channel to market for our hedging activities which is important in times of low liquidity and in places where there is not an active market

(1) Owned and contracted generation capacity converted from MW to MWh assuming 100% capacity factor (CF) for all technology types, except for renewable capacity which is shown at estimated CF
(2) Expected generation and load shown in the chart above will not tie out with load volume and ExGen disclosures; Load shown above does not include indexed products and generation reflects a net owned and contracted position; Estimates as of 9/30/2015
(3) Excludes the impact of plant outages, primarily at Calvert Cliffs prior to us operating the plant

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Exelon Generation –Optimizing the Portfolio and Positioning it for Market Upside

Gross Margin Category ($M)[1]	2015	2016	2017	2018
Open Gross Margin(including South, West, & Canada hedged GM)[3]	$5,150	$5,650	$5,800	$6,100
Mark-to-Market of Hedges[3,4]	$2,200	$1,200	$750	$250
Power New Business / To Go	$50	$500	$800	$1,000
Non-Power Margins Executed	$400	$200	$100	$50
Non-Power New Business / To Go	$50	$250	$350	$450
Total Gross Margin[2]	$7,850	$7,800	$7,800	$7,850

- Capacity Performance added approximately $1B in gross margin over the 2016 to 2018 period
- Timing of hedge decisions creates value
  - Positioning portfolio to reflect our fundamental views– currently carrying a larger open position in 2017 and 2018
  - Intra-year hedging flexibility to take advantage of volatility
- Using cross-commodity spreads in NiHub: 7-10% of the portfolio in 2017 is in cross-commodity hedges and 3 - 6% in 2018

(1) Gross margin categories rounded to nearest $50M

(2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses

(3) Excludes EDF's equity ownership share of the CENG Joint Venture

(4) Mark-to-Market of Hedges assumes mid-point of hedge percentages

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Electric Load Serving Business: Market Landscape

Constellation Active Retail Electric Markets

Total U.S. Power Market 2015 (3,725 TWhload)(1)

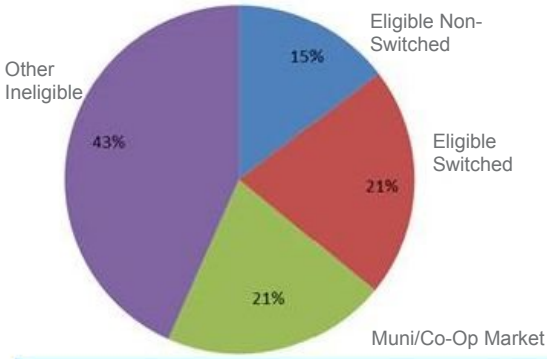

Market Landscape(1)

Improved competitive landscape observed across many markets

- Conditions have improved in many markets as impacts of the Polar Vortex have played out
- Some suppliers have taken steps to reduce exposure to weather-sensitive customer loads following the Polar Vortex

Retail transactions and new entrant activity down in 2015

- M&A, exits and divestiture activity down from 2014 levels
- Fewer new entrants have entered the market in 2015

Existing suppliers continue to expand market footprint and product portfolio

- Several existing suppliers have expanded into new states
- Energy efficiency and distributed energy among most popular for cross-selling opportunities

Competitive retail market expected to grow modestly over the next five years (2015-2019)

- C&I switched market to grow by about 8%
- Residential switched market to grow by about 7%

Constellation is the #1 Provider of Retail Electricity in the United States

(1) Sources are EIA, DNV GL, and internal estimates

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Our Electric Load Serving Business Provides Sustainable Earnings and Stable Earnings Growth

2014 EEI
Commercial Load Projections (1,3)
2015 – 2017 TWh

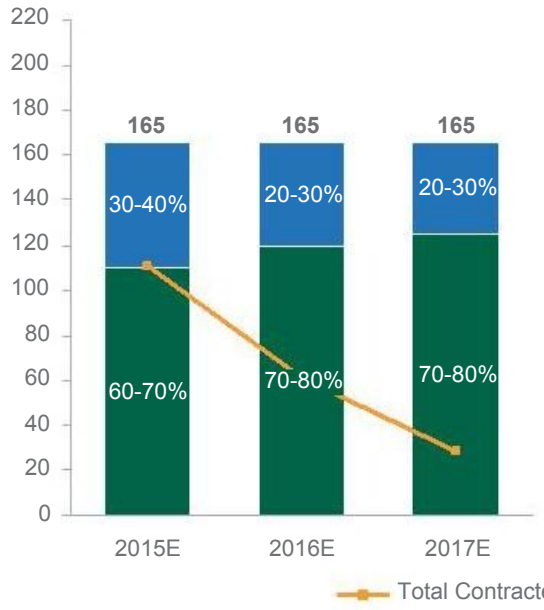

2015 EEI
Commercial Load Projections(1)
2015 – 2018 TWh

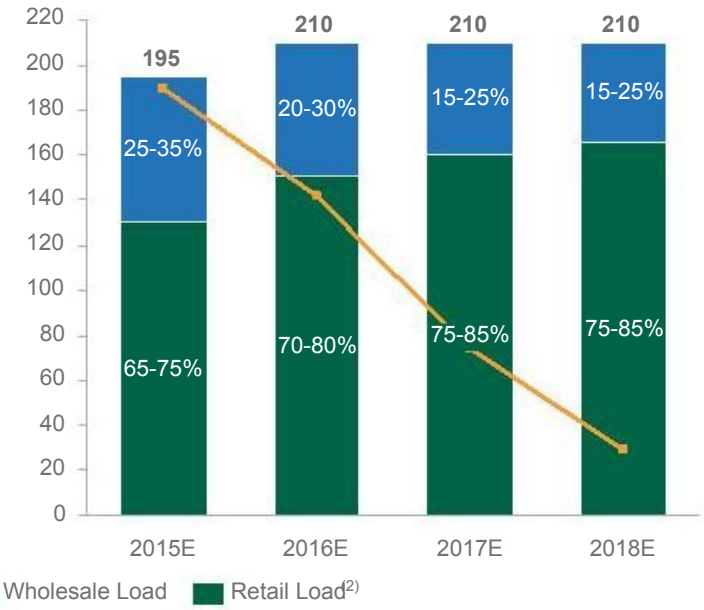

Total Contracted | Wholesale Load | Retail Load(2)

Our growing load business provides a channel to market that reduces the reliance on lower margin over-the-counter products

(1) Numbers and percentages are rounded to the nearest 5
(2) Index load expected to be 25% to 35% of total forecasted retail load
(3) Excludes Integrys acquisition completed in November 2014

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Our NiHubStrategy Recognizes the Lack of Liquidity and Disconnect Between our Fundamental View of Prices

Forward market heat rates expanded again through 2015

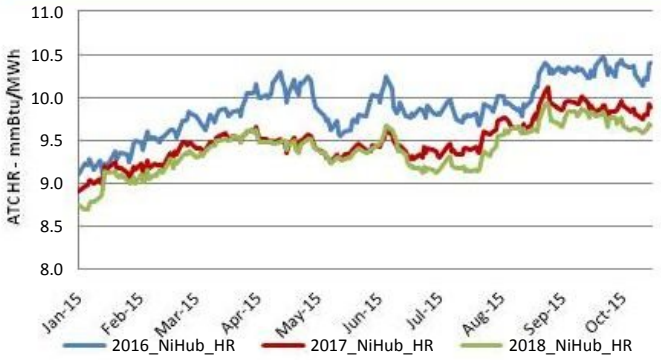

- Our portfolio is positioned to take advantage of expected volatility and power price upside
  - 2017-2018 average upside of $2 - $3/ MWh
- Power exposure in NiHubabove purely ratable:
  - 17-20% behind ratable in 2017
  - 13-15% behind ratable in 2018
- The increased reliance on natural gas as coal plants retire has impacted prices
- Our PJM forecast includes 20+GW of new CCGTs, full compliance with state renewables requirements and essentially flat load growth, in addition to coal retirements

Incremental coal retirements will lead to continued volatility and higher dispatch costs, creating $2-$3/MWh of power price upside in NiHubin 2017-2018

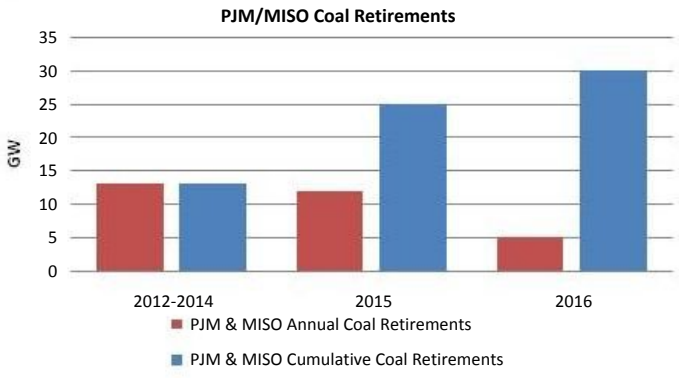

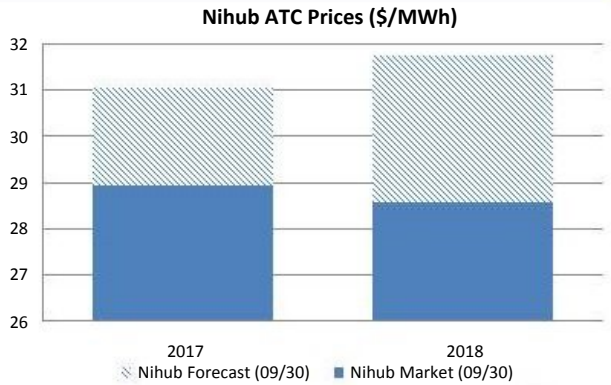

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Capacity Markets: PJM

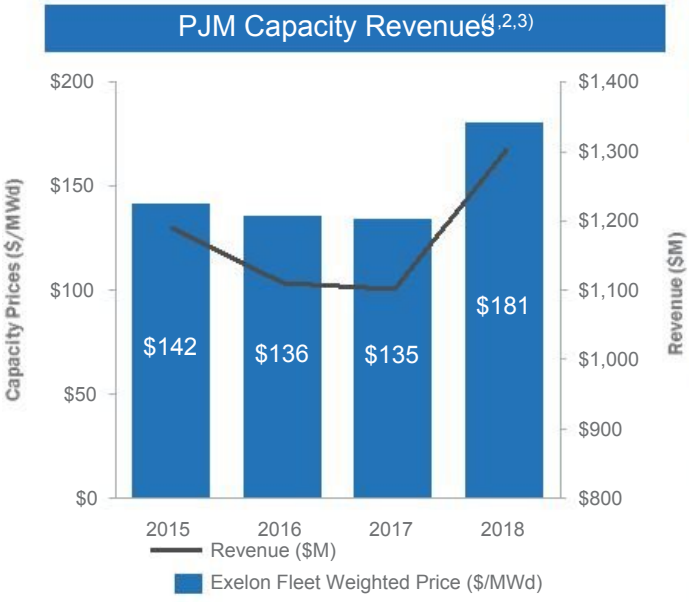

Cleared Volumes (MWs)(4)	16/17 Transition Auction		17/18 Transition Auction		18/19 Base Auction			
	CP	Price	CP	Price	CP	Price	Base	Price
ComEd								
Fossil/Other	-	$134.00	-	$151.50	-	$215.00	25	$200.21
Nuclear	9,950	$134.00	9,975	$151.50	8,625	$215.00	-	$200.21
Total	9,950	$134.00	9,975	$151.50	8,625	$215.00	25	$200.21
EMAAC								
Fossil/Other	25	$134.00	850	$151.50	2,075	$225.42	1,050	$210.63
Nuclear	3,950	$134.00	4,950	$151.50	4,325	$225.42	-	$210.63
Total	3,975	$134.00	5,800	$151.50	6,400	$225.42	1,050	$210.63
SWMAAC								
Fossil/Other	-	$134.00	-	$151.50	-	$164.77	-	$149.98
Nuclear	425	$134.00	825	$151.50	850	$164.77	-	$149.98
Total	425	$134.00	825	$151.50	850	$164.77	-	$149.98
BGE								
Fossil/Other	75	$134.00	150	$151.50	300	$164.77	425	$149.98
Nuclear	-	$134.00	-	$151.50	-	$164.77	-	$149.98
Total	75	$134.00	150	$151.50	300	$164.77	425	$149.98
Rest of MAAC/RTO								
Fossil/Other	-	$134.00	-	$151.50	265	$164.77	50	$149.98
Nuclear	775	$134.00	800	$151.50	-	$164.77	-	$149.98
Total	775	$134.00	800	$151.50	265	$164.77	50	$149.98
GRAND TOTAL								
Fossil/Other	100		1,000		2,640		1,550	
Nuclear	15,100		16,550		13,800		-	
Total	15,200		17,550		16,440		1,550	

(1) Revenues reflect capacity cleared in Base, CP transitional & incremental auctions and are for calendar years
(2) Revenues reflect owned and contracted generation
(3) Reflects 50.01% ownership at CENG
(4) Volumes at ownership. Rounded.

Exelon

Capacity Markets: ISO-NE, NYISO, MISO

	2015/2016	2016/2017	2017/2018	2018/2019
ISO-NE[1]				
NEMA				
Capacity[3] (MW)	2,100	2,100	2,100	2,100
Price ($/MWd)	$104	$222	$500	$318
SEMA				
Capacity[3] (MW)	35	35	35	230
Price ($/MWd)	$104	$105	$234	$557
NYISO[2]				
Capacity[3] (MW)	1,100	1,100	1,100	1,100
MISO				
Zone 4				
Capacity[3] (MW)	1,100	1,100	1,100	1,100
Price ($/MWd)[4]	$150			

(1) ISO-NE: ISO New England; NEMA: Northeastern Massachusetts and Boston; SEMA: Southeastern Massachusetts
(2) NYISO: New York Independent System Operator
(3) Represents offered capacity at ownership
(4) AMIL: Ameren Illinois AMIL capacity price represents PRA auction clearing price for Zone 4 in $/MWd

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Natural Gas Marketing Platform

Active Natural Gas Markets

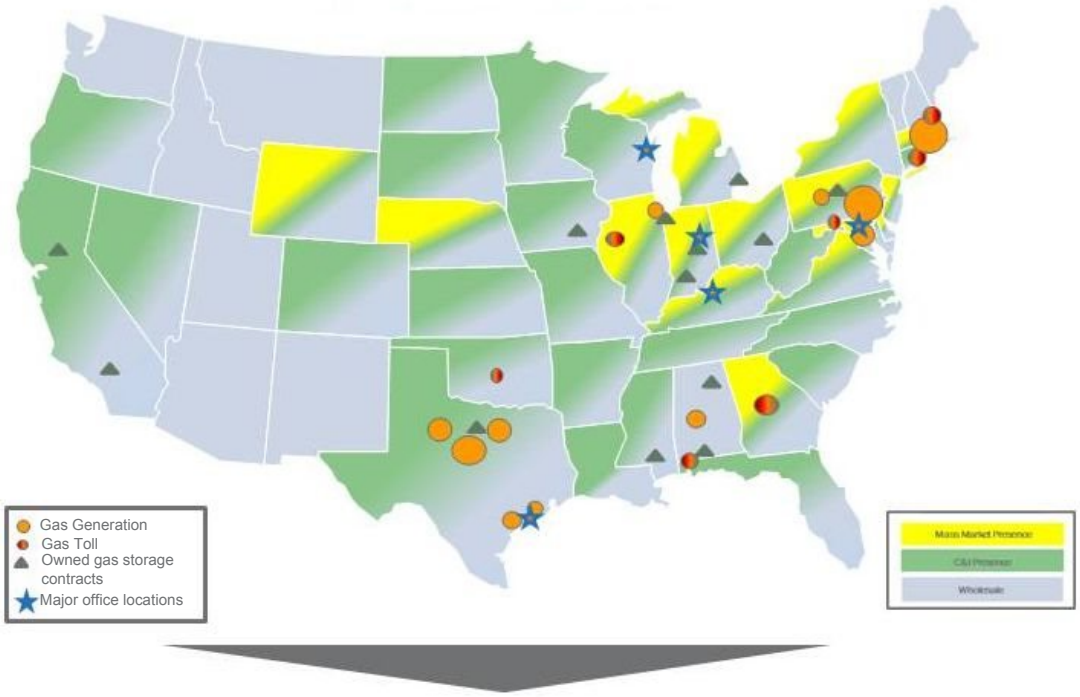

Supply	~4-6 Bcf per day delivered in competitive markets growing to 6-8 Bcf by 2018
Transportation	Active shipper on more than 45 interstate pipelines on a daily basis
Trading	Active participant in all major supply basins, markets, and trading points in North America
Volume Management	Schedule, nominate and balance behind more than 120 LDCs

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EPA Clean Power Plan: Compliance Pathways

Mass Budget

- States distribute allowances equal to the number of CO2 emissions allowed
- At the end of each compliance period, affected electric generating units (EGUs) must surrender allowances equal to their emissions
- States may allow affected EGUs to buy or sell allowances with other parties

One **allowance** = one ton of CO2 emissions

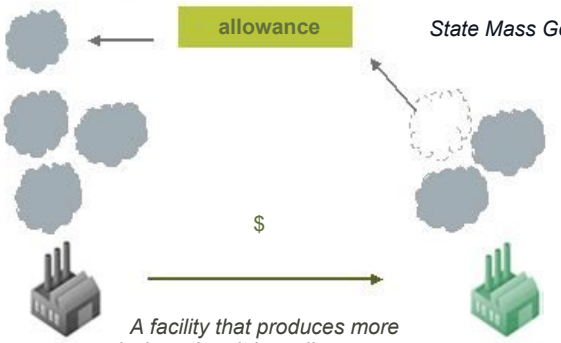

A facility that produces more emissions than it has allowances may purchase allowances from another facility that has extra allowances

Emissions Rate

- Emission rate credits (ERCs) are created when incremental nuclear or incremental renewables generate electricity
- Emitting generators must purchase sufficient ERCs to reduce their emission rate to the target level

State Rate Standard: 1,000 lb/MW h

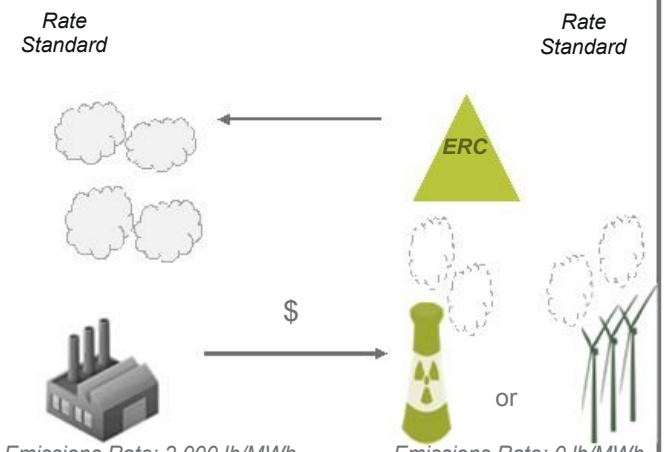

Exelon recommends that states adopt mass-based plans that include both existing and new units because that is the best way to level the playing field and ensure that clean resources like nuclear receive value for the carbon-free, always-on electricity that Exelon provides. It is also the best way to minimize overall costs to consumers and preserve electric reliability while achieving verifiable carbon reductions

Exelon.

S1-SSA-0009 - 10194

Exelon Nuclear Fleet Overview (including CENG and Salem)

	Plant Location	Type/ Containment	Net Generation Capacity (MW)[5]	License Extension Status / License Expiration[1]	Ownership	Spent Fuel Storage/ Date to lose full core discharge capacity[2]
Midwest	Braidwood, IL (Units 1 and 2)	PWR Concrete/Steel Lined	2,389	Filed application in May 2013 (decision expected in early 2016)/ 2026, 2027	100%	Dry Cask
	Byron, IL (Units 1 and 2)	PWR Concrete/Steel Lined	2,347	Filed application in May 2013 (decision expected in 2015)/ 2024, 2026	100%	Dry Cask
	Clinton, IL (Unit 1)	BWR Concrete/Steel Lined / Mark III	1,069	2026	100%	Dry Cask (2016)
	Dresden, IL (Units 2 and 3)	BWR Steel Vessel / Mark I	1,845	Renewed / 2029, 2031	100%	Dry Cask
	LaSalle, IL (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	2,320	Filed application December 2014 (decision expected 2017)/2022, 2023	100%	Dry Cask
	Quad Cities, IL (Units 1 and 2)	BWR Steel Vessel / Mark I	1,403	Renewed / 2032	75% Exelon, 25% Mid-American Holdings	Dry Cask
Mid-Atlantic	Limerick, PA (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	2,317	Renewed / 2044, 2049	100%	Dry Cask
	Oyster Creek, NJ (Unit 1)	BWR Steel Vessel / Mark I	625	Renewed / 2029(3)	100%	Dry Cask
	Peach Bottom, PA (Units 2 and 3)	BWR Steel Vessel / Mark I	1,221	Renewed / 2033, 2034	50% Exelon, 50% PSEG	Dry Cask
	TMI, PA (Unit 1)	PWR Concrete/Steel Lined	837	Renewed / 2034	100%	2023
	Salem, NJ (Units 1 and 2)	PWR Concrete/Steel Lined	1,005	Renewed / 2036, 2040	42.6% Exelon, 57.4% PSEG	Dry Cask
CENG	Calvert Cliffs, MD (Units 1and 2)	PWR Concrete/Steel Lined	878	Renewed / 2034, 2036	100% CENG(4)	Dry Cask
	R.E. Ginna, NY (Unit 1)	PWR Concrete/Steel Lined	288	Renewed / 2029	100% CENG(4)	Dry Cask
	Nine Mile Point, NY (Units 1 and 2)	BWR Steel Vessel / Mark I Concrete/Steel Vessel/ Mark II	838	Renewed / 2029, 2046	100% CENG[4] / 82% CENG[4], 18% Long Island Power Authority	Dry Cask

(1) Operating license renewal process takes approximately 4-5 years from commencement until completion of NRC review
(2) The date for loss of full core reserve identifies when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core; Dry cask storage will be in operation at those sites prior to losing full core discharge capacity in their on-site storage pools
(3) On December 8, 2010, Exelon announced that it will permanently cease generation operations at Oyster Creek by December 31, 2019; Oyster Creek's current NRC license expires in 2029
(4) Exelon Generation has a 50.01% ownership interest in CENG. EDF has a 49.99% ownership interest in CENG.
(5) Net generation capacity is stated at proportionate ownership share. Based on 2015 projected full year

Exelon.

World Class Nuclear Operator(1)

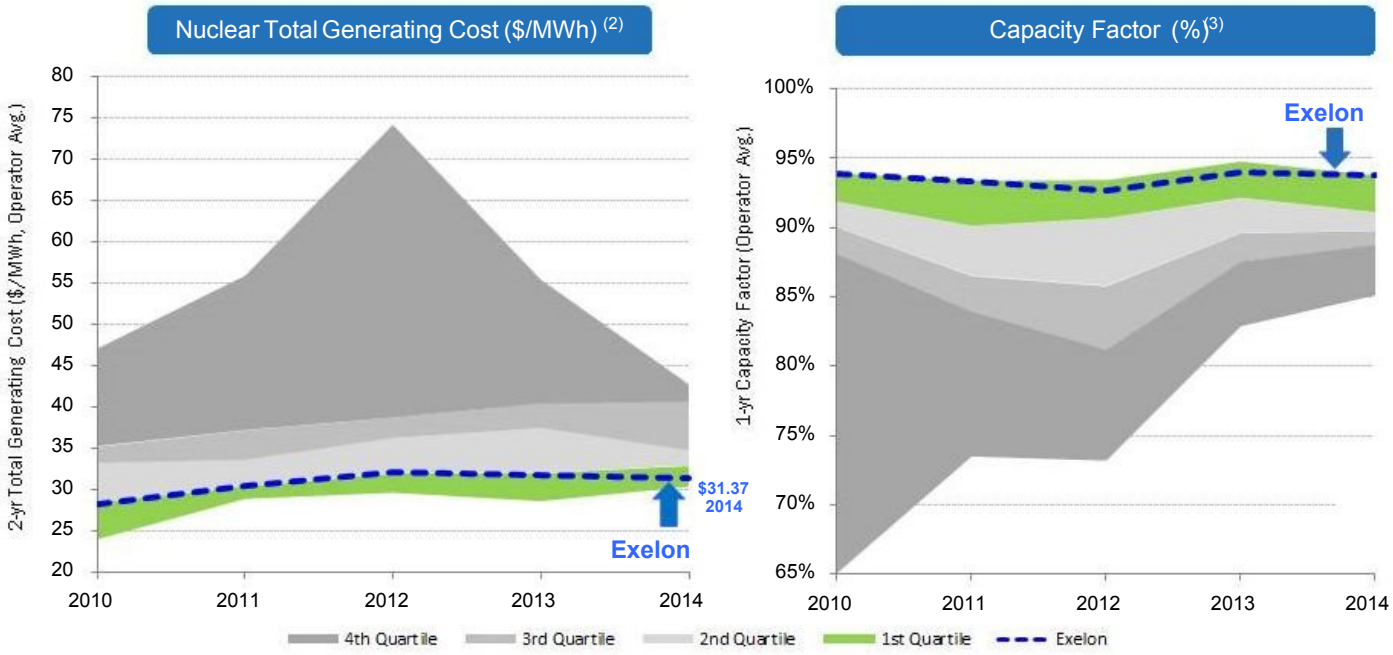

- Exelon is consistently one of the lowest-cost and most efficient producers of electricity in the nation
- Over the next five years, Exelon Nuclear projects a negative cost CAGR, while maintaining strong generation performance

(1) 2010 – 2013 Exelon fleet averages exclude Salem, Ft. Calhoun, and CENG; 2014 Exelon fleet averages exclude Salem and Ft. Calhoun
(2) Total Generating Cost is defined as cost to produce one MWh of energy, including fuel, materials, labor, contracting, capital expenditures, insurance and the majority of overhead expenses including benefit costs associated with labor but excludes property taxes, unit contingent costs and risks, costs due to unknown future regulatory changes, and suspended DOE nuclear waste storage fee (effective May 2014)
(3) Source: Platts Nuclear News, Nuclear Energy Institute and Energy Information Administration (Department of Energy)

Exelon.

Nuclear Output and Refueling Outages

Nuclear Output

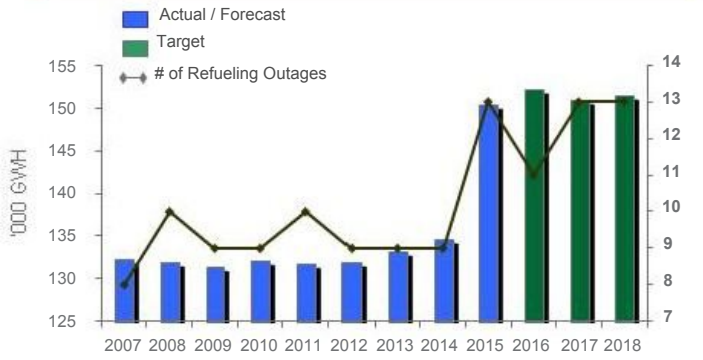

Net nuclear generation data at ownership excluding Salem for all years
CENG excluded in years 2007–2014 but included in 2015 and beyond
2016 and 2018 include Clinton Refueling Only outage of shortened duration

Fleet Average Refueling Outage Duration (Days)

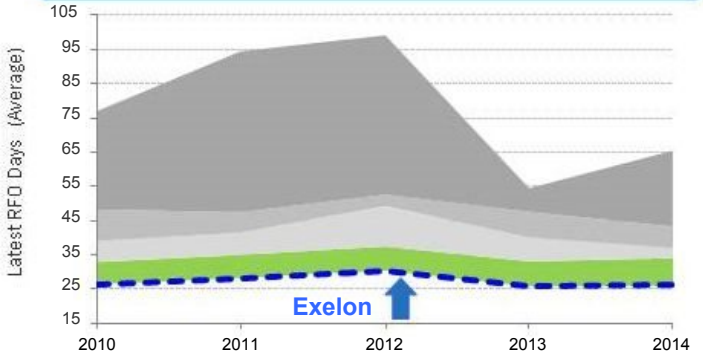

2010-2013 Exelon fleet averages exclude Salem and CENG. 2014 Exelon fleet average excludes Salem

Nuclear Refueling Cycle

- All Exelon-owned units are on a 24 month cycle except for Braidwood U1/U2, Byron U1/U2, Ginna, and Salem U1/U2, which are on 18 month cycles
- Starting in 2015 Clinton is on annual cycles

2015 Refueling Outage Impact

- 14 planned refueling outages, including 1 at Salem
  - 7 spring refueling outages and 6 fall refueling outages
  - 1 Salem fall refueling outage

2016 Refueling Outage Impact

- 12 planned refueling outages, including 1 at Salem
  - 7 spring refueling outages and 4 fall refueling outages
  - 1 Salem spring refueling outage

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Nuclear Fuel Costs[1]

Projected Exelon Uranium Demand[2]

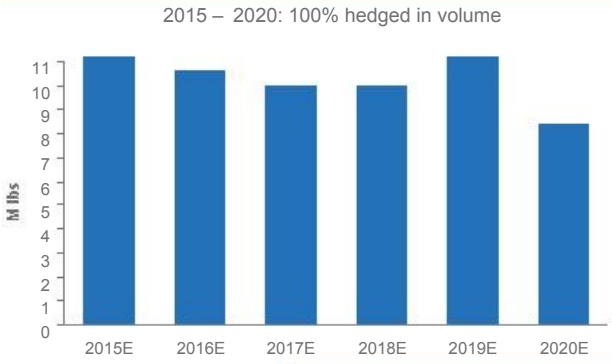

Components of Fuel Expense in 2015

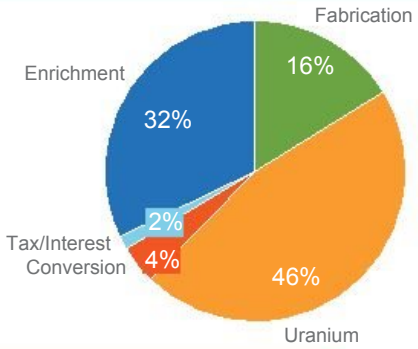

Projected Total Nuclear Fuel Spend [3]

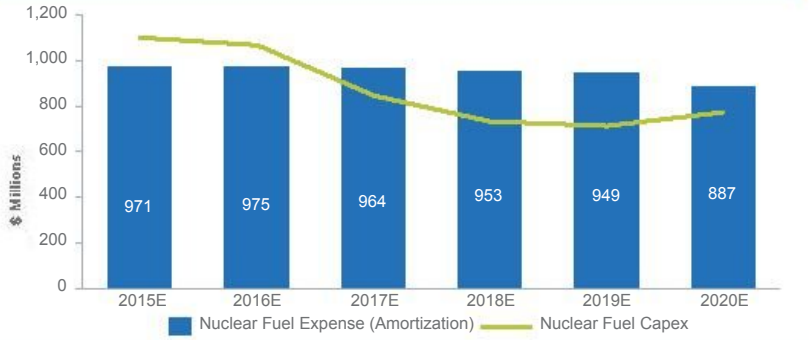

Over the last year, Exelon has reduced capital requirements for nuclear fuel by ~$265M (2015 to 2019)

(1) All charts exclude Salem
(2) Includes 100% of requirements
(3) CENG included at ownership. Including Salem and 100% of CENG total cash capital expenditures are $1.3B, $1.2B, $1.0B, $0.9B, $0.9B, and $0.9B for 2015 - 2020

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S1-SSA-0009 - 10198

Constellation Energy Nuclear Group (CENG) Operating Service Agreement Terms

- Nuclear Operating services agreement
  - Integrated CENG and their 3 plants into Exelon Nuclear with transfer of operating licenses
- Loan to CENG and distributions to EDF/Exelon Generation
  - CENG $400M special distribution paid to EDF on April 1, 2014
  - Exelon Generation made $400M loan to CENG at 5.25% annual interest rate to fund special distribution to EDF (As of September 30, 2015, the loan balance, including interest, was $296M)
  - Exelon Generation receives priority payment from CENG's available cash flows until loan is fully repaid
  - Exelon Generation also entitled to receive aggregate preferred distributions of $400M plus a return of 8.5% per annum from April 1, 2014 (No amounts have been paid on this special distribution)
- Option for EDF to sell its 49.99% interest in CENG to Exelon Generation
  - Exercisable from January 2016 to June 2022
  - Process and timeline allows for possible negotiated agreement on price
  - If no negotiated agreement on price, price is determined by arbitration process to determine fair market value
  - Arbitration process could take up to 10 months or longer before binding decision is made on price
  - Price would be adjusted for EDF share of remaining loan balance and special distribution to Exelon Generation
  - Regulatory approvals could take several months but might run concurrently with arbitration process
  - Exelon has limited rights to defer closing up to 6 months

Exelon Fossil Generation Fleet Overview

	Station	Location	Number of Units	Primary Fuel Type	Percent Owned[1]	Net Generation Capacity (MW)[2]
ERCOT	Colorado Bend	Wharton, TX	6	Gas		498
	Handley 3	Fort Worth, TX	1	Gas		395
	Handley 4, 5	Fort Worth, TX	2	Gas		870
	LaPorte	Laporte, TX	4	Gas		152
	Mountain Creek 6, 7	Dallas, TX	2	Gas		240
	Mountain Creek 8	Dallas, TX	1	Gas		565
	Wolf Hollow 1, 2, 3	Granbury, TX	3	Gas		704
Mid-Atlantic	Chester	Chester, PA	3	Oil		39
	Conowingo	Darlington, MD	11	Hydro		572
	Croydon	West Bristol, PA	8	Oil		391
	Delaware	Philadelphia, PA	4	Oil		56
	Eddystone	Eddystone, PA	4	Oil		60
	Eddystone3, 4	Eddystone, PA	2	Oil/Gas		760
	Fairless Hills	Fairless Hills, PA	2	Landfill Gas		60
	Falls	Morrisville, PA	3	Oil		51
	Gould Street	Baltimore, MD	1	Gas		97
	Handsome Lake	Kennerdell, PA	5	Gas		268
	Moser	Lower PottsgroveTwp., PA	3	Oil		51
	Muddy Run	Drumore, PA	8	Hydro		1070
Mid-Atlantic	Notch Cliff	Baltimore, MD	8	Gas		118
	Pennsbury	Morrisville, PA	2	Landfill Gas		6
	Perryman[3]	Belcamp, MD	6	Oil/Gas		463
	Philadelphia Road	Baltimore, MD	4	Oil		61
	Richmond	Philadelphia, PA	2	Oil		98
	Riverside[4]	Baltimore, MD	3	Oil/Gas		113
	Salem	Lower Alloways Creek Twp, NJ	1	Oil	42.59	16
	Schuylkill	Philadelphia, PA	2	Oil		30
	Southwark	Philadelphia, PA	4	Oil		52
	Westport	Baltimore, MD	1	Gas		116
Midwest	Southeast Chicago	Chicago, IL	8	Gas		296
New England	Framingham	Framingham, MA	3	Oil		33
	Medway	West Medway, MA	3	Oil/Gas		117
	Mystic 7	Charlestown, MA	1	Oil/Gas		575
	Mystic 8, 9	Charlestown, MA	2	Gas		1418
	Mystic Jet	Charlestown, MA	1	Oil		9
	New Boston	South Boston, MA	1	Oil		16
	Wyman	Yarmouth, ME	1	Oil	5.9	36
Other	Grand Prairie	Alberta, Canada	1	Gas		75
	Hillabee	Alexander City, AL	1	Gas		722
	Sunnyside	Sunnyside, UT	1	Waste Coal	50	26

(1) 100%, unless otherwise indicated
(2) Fossil/Hydro Capacity values shown represent summer ratings as of September 2015. Net Generation Capacity (MW) is stated at proportionate ownership share
(3) Includes Perryman 2 (51MW), which will retire on in Q1 2016. Includes Perryman 6 (110MW) that went COD in June 2015
(4) Includes Riverside 4 (74MW), which is scheduled for retirement in May 2016

Exelon.

Summer Texas Heat Brings Return of Volatility to ERCOT

ERCOT Weather: July-September

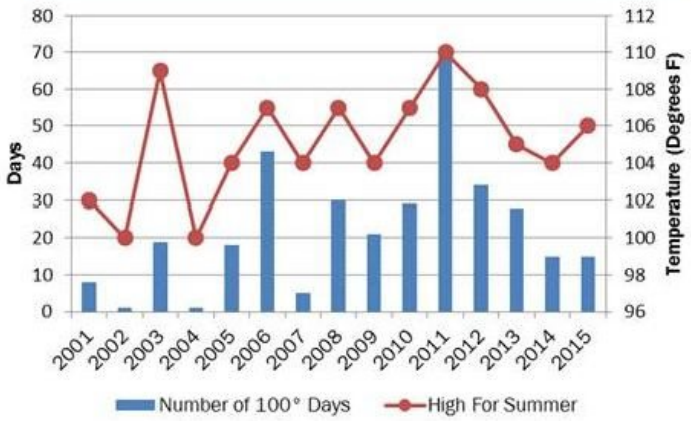

ERCOT Scarcity Indicators: July-September

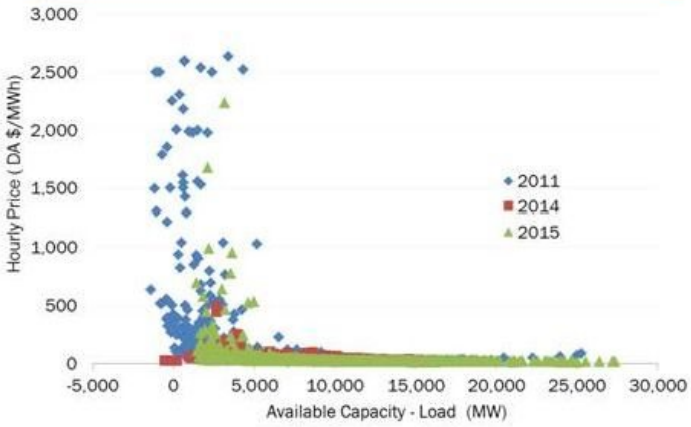

Demand is Growing

- Summer 2015 was hot; record load pushed summer 2015 spot power prices up and led summer forwards higher
- Average demand in ERCOT has risen 2-3% in 2015 from 2014
- Reserve margins reserve were as much as 10% lower than projected, falling below 4 GW in August

Generation assets will be valuable going forward

- Wind generation is forecasted to grow from 13 GW today to nearly 20 GW by 2020, which will increase volatility of the ERCOT dispatch stack
- New gas generation development has slowed – with 600MW of peakers in 2016 and Exelon CCGTs in 2017 the only visible gas additions through 2018
- The Public Utilities Commission of Texas has requested that ERCOT examine the Operating Reserve Demand Curve

Exelon captured ~$20M of value from this summer's volatility and our new CCGTs wil be well positioned to replicate this success

Exelon.

S1-SSA-0009 - 10201

Texas CCGTs: Unique Opportunity to Grow in ERCOT

ERCOT Dispatch

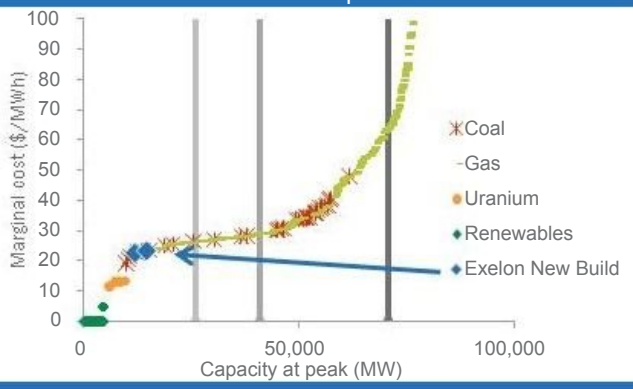

Key Facts	
Sites	Wharton County and Granbury, TX
Total Capacity	~2,200MW
Construction Cost	$1,475M (~$700/kW); $700M remaining
Heat Rate	~6,500 mmBtu/MWh
EPC / OEMs	Zachry/ GE and Alstom
Cooling System	Air Cooled
Commercial Operation	By Summer 2017
Expected Economics	
ROE	> 12%

Key Messages

Efficient
- Two of the cleanest, most efficient Combined Cycle Gas Turbines (CCGT) in the nation

Cost Effective
- Simplified design provides for easier construction and maintenance, making these units among the most predictable and least costly to operate and maintain in the industry

Environmental
- Plants use air cooling which mitigates water constraint issues

Versatile
- Ramp rate of 100 MW/minute can respond quickly to depressed wind or unexpected outages (market ramp rate ~50 MW/minute)
- Capacity factor will average 75-85%

Constructive Market
- Demand continues to grow at more than 1% per year, which results in the need for roughly 700MW of incremental capacity every year and potential for real-time prices to go to $9,000/MWh
- New units should see sustainably high spark spreads and returns, especially if natural gas prices recover
- Potential for coal units in the state to add costly controls or shutdown could further boost returns as the Mercury & Air Toxics (MATS) and Regional Haze rules take effect

Exelon.

Exelon Renewable Generation Fleet Overview

	Station	Location	Number of Units	Primary Fuel Type	Percent Owned[1]	Net Generation Capacity (MW)[2]
ERCOT/SPP	EXC Wind 1,2,3,4	Hansford Co., TX	62	Wind		110
	EXC Wind 5,6	Sherman Co., TX	16	Wind		20
	EXC Wind 7,8,9,10,11	Moore Co., TX	40	Wind		50
	High Plains	Moore Co., TX	8	Wind	99.5	10
	Whitetail	Webb, TX	57	Wind		91
Mid-Atlantic	Conowingo	Hartford Co., MD	11	Hydroelectric		572
	Criterion	Oakland, MD	28	Wind		70
	Fairless	Falls Twp, PA	2	Landfill Gas		60
	Fourmile	Garrett Co., MD	16	Wind		40
	Muddy Run	Lancaster Co., PA	8	Hydro		1,070
	Pennsbury	Falls Twp, PA	2	Landfill Gas		6
West	Antelope Valley Solar Ranch	LA Country., CA	1	Solar		242
	Cassia	Twin Falls Co., ID	14	Wind		29
	Echo I	Umatilla Co., OR	21	Wind	99	35
	Echo II	Morrow Co., OR	10	Wind		20
	Echo III	Morrow Co., OR	6	Wind	99	10
	High Mesa	Twin Fall Co., ID	19	Wind		40
	Mountain Home	Elsmore Co., ID	20	Wind		42
	Threemile Canyon	Morrow Co., OR	6	Wind		10
	Tuana Springs	Twin Fall Co., ID	8	Wind		17
	Wildcat	Lea, NM	13	Wind		27

	Station	Location	Number of Units	Primary Fuel Type	Percent Owned[1]	Net Generation Capacity (MW)[2]
Midwest	AgriWind	Bureau Co., IL	4	Wind	99	8
	Beebe 1A & 1B	Gratiot, MI	55	Wind		131
	Blue Breezes/Moore	Blue Earth, MN	2	Wind		3
	Cisco	Jackson Co., MN	4	Wind	99	8
	Cowell	Pipestone Co., MN	1	Wind	99	2
	CP Windfarm	Faribault Co., MN	2	Wind		4
	Ewington	Jackson Co. MN	10	Wind	99	21
	EXC City Solar	Cook Co., IL	1	Solar		8
	Harvest I & II	Huron Co. MI	65	Wind		112
	Marshall	Lyon Co., MN	9	Wind	99	19
	Michigan Wind I	Bingham Township, MI	46	Wind		69
	Michigan Wind II	Minden City, MI	50	Wind		90
	Norgaard	Lincoln Co. MN	7	Wind	99	9
	Wolf	Nobles Co., MN	5	Wind	99	6
Other	Bluegrass Ridge	Gentry Co., MO	27	Wind		57
	Conception	Nodaway Co., MO	24	Wind		50
	Cow Branch	Atchinson Co., MO	24	Wind		50
	Greensburg	Kiowa Co., KS	10	Wind		13
	Loess Hills	Atchinson Co., MO	4	Wind		5
	Shooting Star	Kiowa Co., KS	65	Wind		104

(1) 100%, unless otherwise indicated
(2) Fossil/Hydro Capacity values shown represent summer ratings as of September 2015. Net Generation Capacity (MW) is stated at proportionate ownership share
(3) Constellation Solar is an operation that constructs, owns, and operates solar facilities at various customer locations.

Exelon

S1-SSA-0009 - 10203

Exelon Generation Disclosures

September 30, 2015

Exelon

S1-SSA-0009 - 10204

Portfolio Management Strategy

Strategic Policy Alignment

- Aligns hedging program with financial policies and financial outlook
- Establish minimum hedge targets to meet financial objectives of the company (dividend, credit rating)
- Hedge enough commodity risk to meet future cash requirements under a stress scenario

Three-Year Ratable Hedging

- Ensure stability in near-term cash flows and earnings
  - Disciplined approach to hedging
  - Tenor aligns with customer preferences and market liquidity
  - Multiple channels to market that allow us to maximize margins
  - Large open position in outer years to benefit from price upside

Bull / Bear Program

- Ability to exercise fundamental market views to create value within the ratable framework
  - Modified timing of hedges versus purely ratable
  - Cross-commodity hedging (heat rate positions, options, etc.)
  - Delivery locations, regional and zonal spread relationships

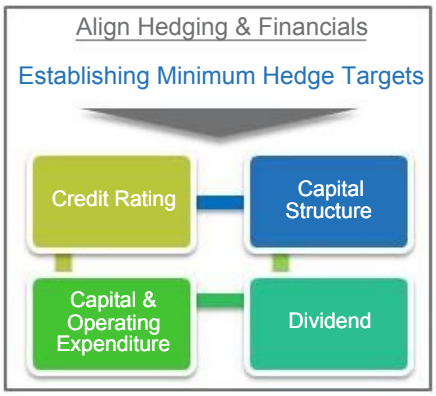

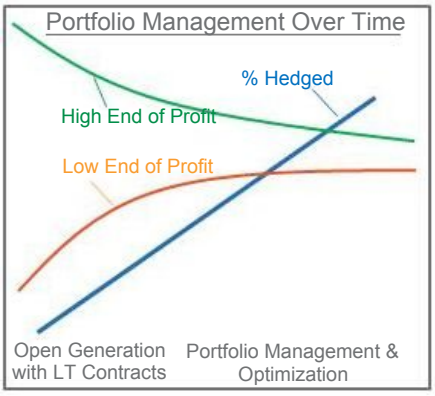

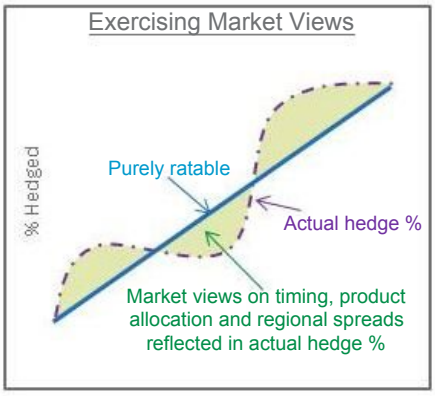

Protect Balance Sheet | **Ensure Earnings Stability** | **Create Value**

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S1-SSA-0009 - 10205

Components of Gross Margin Categories

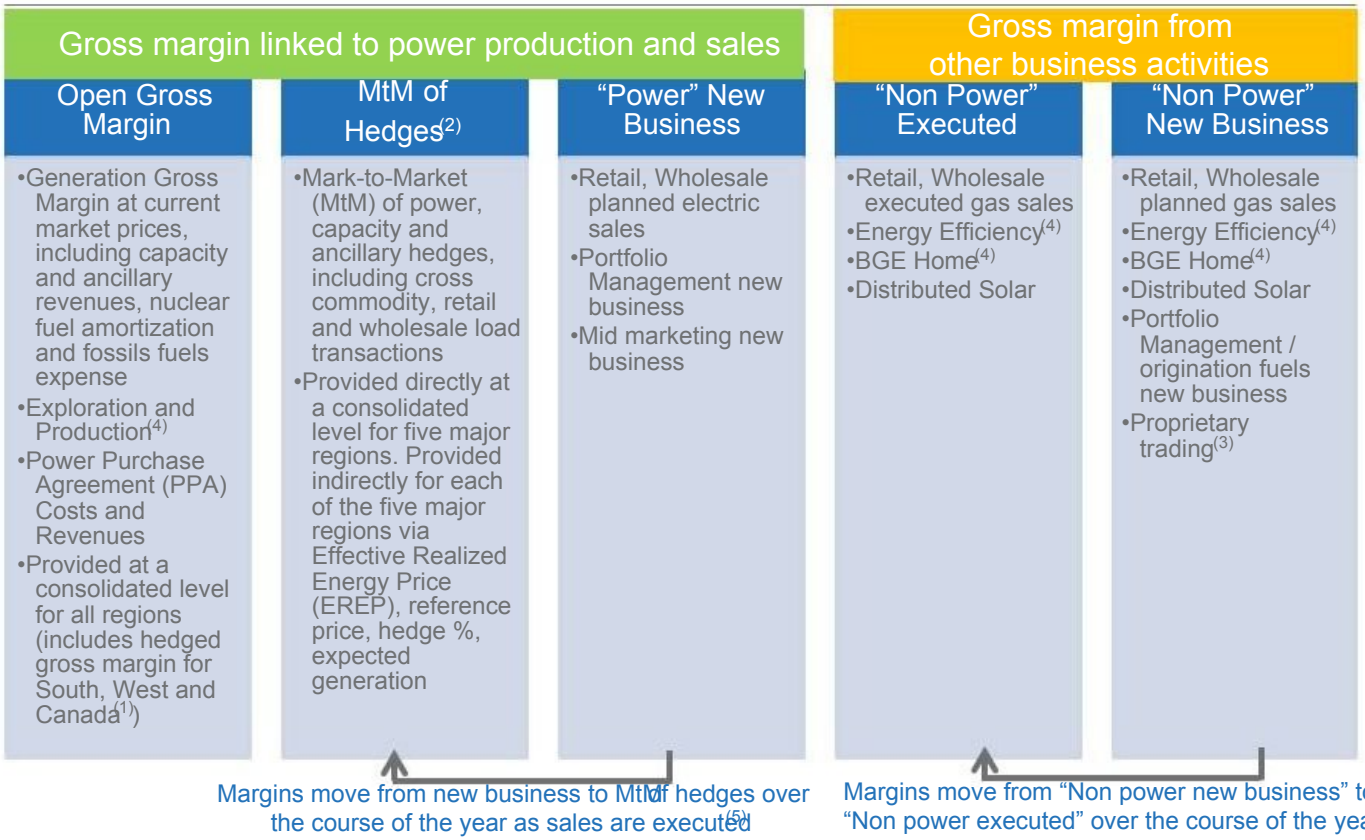

(1) Hedged gross margins for South, West & Canada region will be included with Open Gross Margin, and no expected generation, hedge %, EREP or reference prices provided for this region
(2) MtM of hedges provided directly for the five larger regions; MtM of hedges is not provided directly at the regional level but can be easily estimated using EREP, reference price and hedged MWh
(3) Proprietary trading gross margins will generally remain within "Non Power" New Business category and only move to "Non Power" Executed category upon management discretion
(4) Gross margin for these businesses are net of direct "cost of sales"
(5) Margins for South, West & Canada regions and optimization of fuel and PPA activities captured in Open Gross Margin

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S1-SSA-0009 - 10206

ExGen Disclosures

Gross Margin Category ($M)[1]	2015	2016	2017	2018
Open Gross Margin (including South, West & Canada hedged GM)[3]	$5,150	$5,650	$5,800	$6,100
Mark-to-Market of Hedges[3,4]	$2,200	$1,200	$750	$250
Power New Business / To Go	$50	$500	$800	$1,000
Non-Power Margins Executed	$400	$200	$100	$50
Non-Power New Business / To Go	$50	$250	$350	$450
Total Gross Margin [2]	$7,850	$7,800	$7,800	$7,850

Reference Prices[5]	2015	2016	2017	2018
Henry Hub Natural Gas ($/MMbtu)	$2.75	$2.80	$2.99	$3.05
Midwest: NiHub ATC prices ($/MWh)	$28.80	$29.58	$28.95	$28.57
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$37.05	$36.82	$35.36	$33.99
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	$3.12	$4.62	$4.47	$3.83
New York: NY Zone A ($/MWh)	$33.55	$33.52	$33.22	$32.70
New England: Mass Hub ATC Spark Spread ($/MWh) *ALQN Gas, 7.5HR, $0.50 VOM*	$5.57	$9.33	$10.73	$11.84

(1) Gross margin categories rounded to nearest $50M
(2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses.
(3) Excludes EDF's equity ownership share of the CENG Joint Venture
(4) Mark-to-Market of Hedges assumes mid-point of hedge percentages
(5) Based on September 30, 2015 market conditions

Exelon.

S1-SSA-0009 - 10207

ExGenDisclosures

Generation and Hedges	2015	2016	2017	2018
Exp. Gen (GWh)[1]	186,700	199,400	205,300	206,200
Midwest	96,600	97,300	95,700	96,200
Mid-Atlantic[2]	61,700	63,100	61,200	60,500
ERCOT	11,600	17,200	26,400	31,100
New York[2]	9,300	9,300	9,200	9,100
New England	7,500	12,500	12,800	9,300
% of Expected Generation Hedged[3]	**97%-100%**	**81%-84%**	**51%-54%**	**20%-23%**
Midwest	97%-100%	79%-82%	45%-48%	15%-18%
Mid-Atlantic[2]	95%-98%	84%-87%	57%-60%	26%-29%
ERCOT	99%-102%	86%-89%	65%-68%	25%-28%
New York[2]	94%-97%	72%-75%	46%-49%	30%-33%
New England	115%-118%	81%-84%	37%-40%	11%-14%
Effective Realized Energy Price ($/MWh)[4]				
Midwest	$36.00	$34.50	$34.50	$34.50
Mid-Atlantic[2]	$51.50	$47.00	$45.50	$45.00
ERCOT[5]	$23.50	$11.00	$7.50	$2.50
New York[2]	$47.50	$45.50	$42.00	$35.00
New England[5]	$42.00	$20.00	$18.00	$11.00

(1) Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 12 refueling outages in 2016, 15 in 2017, and 14 in 2018 at Exelon-operated nuclear plants, and Salem. Expected generation assumes capacity factors of 94.1%, 93.3% and 93.7% in 2016, 2017 and 2018 respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2016, 2017 and 2018 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years

(2) Excludes EDF's equity ownership share of CENG Joint Venture

(3) Percent of expected generation hedged is the amount of equivalent sales divided by expected generation. Includes all hedging products, such as wholesale and retail sales of power, options and swaps

(4) Effective realized energy price is representative of an all-in hedged price, on a per MWh basis, at which expected generation has been hedged. It is developed by considering the energy revenues and costs associated with our hedges and by considering the fossil fuel that has been purchased to lock in margin. It excludes uranium costs and RPM capacity revenue, but includes the mark-to-market value of capacity contracted at prices other than RPM clearing prices including our load obligations. It can be compared with the reference prices used to calculate open gross margin in order to determine the mark-to-market value of Exelon Generation's energy hedges

(5) Spark spreads shown for ERCOT and New England

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ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (With Existing Hedges)[1]	2015	2016	2017	2018
Henry Hub Natural Gas ($/Mmbtu)				
+ $1/Mmbtu	-	$110	$445	$690
- $1/Mmbtu	$20	$(115)	$(430)	$(680)
NiHub ATC Energy Price				
+ $5/MWh	-	$100	$275	$410
- $5/MWh	-	$(95)	$(275)	$(410)
PJM-W ATC Energy Price				
+ $5/MWh	-	$45	$130	$235
- $5/MWh	-	$(40)	$(125)	$(230)
NYPP Zone A ATC Energy Price				
+ $5/MWh	-	$10	$25	$30
- $5/MWh	-	$(10)	$(25)	$(30)
Nuclear Capacity Factor				
+/- 1%	+/- $10	+/- $40	+/- $40	+/- $40

(1) Based on September 30, 2015 market conditions and hedged position; Gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically; Power prices sensitivities are derived by adjusting the power price assumption while keeping all other prices inputs constant; Due to correlation of the various assumptions, the hedged gross margin impact calculated by aggregating individual sensitivities may not be equal to the hedged gross margin impact calculated when correlations between the various assumptions are also considered; Sensitivities based on commodity exposure which includes open generation and all committed transactions; Excludes EDF's equity share of CENG Joint Venture

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ExGen Hedged Gross Margin Upside/Risk

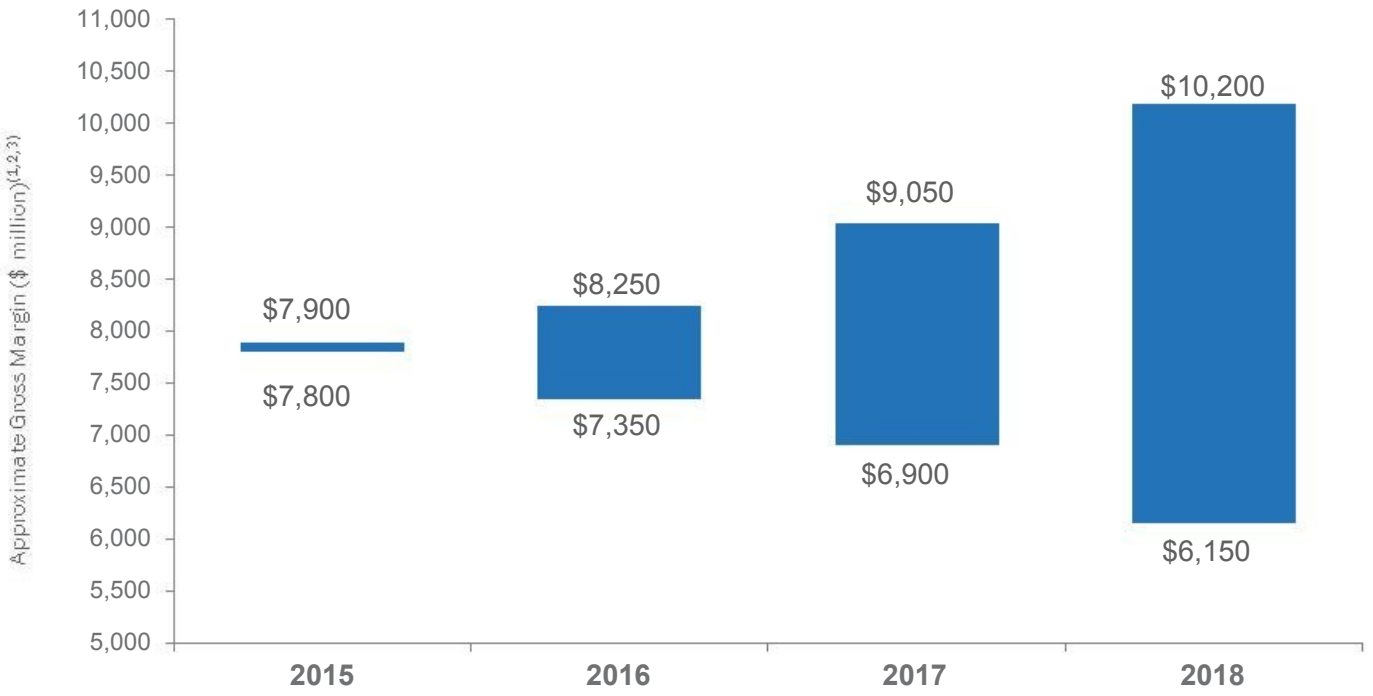

(1) Represents an approximate range of expected gross margin, taking into account hedges in place, between the 5th and 95th percent confidence levels assuming all unhedged supply is sold into the spot market; Approximate gross margin ranges are based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes; These ranges of approximate gross margin in 2016, 2017 and 2018 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years; The price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of September 30, 2015

(2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions

(3) Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners, operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses. Excludes EDF's equity ownership share of the CENG Joint Venture

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Illustrative Example of Modeling Exelon Generation 2016 Gross Margin

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	← $5.65 billion →					
(B)	Expected Generation (TWh)	97.3	63.1	17.2	9.3	12.5	
(C)	Hedge % (assuming mid-point of range)	80.5%	85.5%	87.5%	73.5%	82.5%	
(D=B*C)	Hedged Volume (TWh)	78.3	54.0	15.1	6.8	10.3	
(E)	Effective Realized Energy Price ($/MWh)	$34.50	$47.00	$11.00	$45.50	$20.00	
(F)	Reference Price ($/MWh)	$29.58	$36.82	$4.62	$33.52	$9.33	
(G=E-F)	Difference ($/MWh)	$4.92	$10.18	$6.38	$11.98	$10.67	
(H=D*G)	Mark-to-market value of hedges ($ million)[1]	$385	$550	$95	$80	$110	
(I=A+H)	Hedged Gross Margin ($ million)	$6,850					
(J)	Power New Business / To Go ($ million)	$500					
(K)	Non-Power Margins Executed ($ million)	$200					
(L)	Non-Power New Business / To Go ($ million)	$250					
(N=I+J+K+L)	Total Gross Margin[2]	$7,800 million					

(1) Mark-to-market rounded to the nearest $5 million
(2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners operating services agreement with Fort Calhoun and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses

Exelon.

S1-SSA-0009 - 10211

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

November 10, 2014
Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201 (410) 234-5000	52-0280210

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 7 – Regulation FD

Item 7.01. Regulation FD Disclosure.

On November 11-13, 2014, Exelon Corporation (Exelon) will participate in the Edison Electric Institute Financial Conference. Attached as Exhibit 99.1 to this Current Report on Form 8-K are the presentation slides and handouts to be used at the conference.

Section 9 – Financial Statements and Exhibits

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits* .

Exhibit No.	Description
99.1	Presentation slides and handouts

* * * * *

This combined Form 8-K is being furnished separately by Exelon, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, and Baltimore Gas and Electric Company (Registrants). Information contained herein relating to any individual Registrant has been furnished by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

This presentation includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from these forward-looking statements include those discussed herein as well as those discussed in (1) Exelon's 2013 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; (2) Exelon's Third Quarter 2014 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (3) other factors discussed in filings with the Securities and Exchange Commission by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Jonathan W. Thayer
Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright
Bryan P. Wright
Senior Vice President and Chief Financial Officer Exelon Generation Company, LLC

COMMONWEALTH EDISON COMPANY

/s/ Joseph R. Trpik, Jr.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer
Commonwealth Edison Company

PECO ENERGY COMPANY

/s/ Phillip S. Barnett
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
PECO Energy Company

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ David M. Vahos
David M. Vahos
Vice President, Chief Financial Officer and Treasurer
Baltimore Gas and Electric Company

November 10, 2014

EXHIBIT INDEX

Exhibit No.	Description
99.1	Presentation slides and handouts

Exhibit 99.1

Edison Electric Institute Financial Conference

November 12 –13, 2014

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Cautionary Statements Regarding Forward-Looking Information

This presentation contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company and Exelon Generation Company, LLC (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2013 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; (2) Exelon's Third Quarter 2014 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this presentation. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this presentation.

Our Strategy

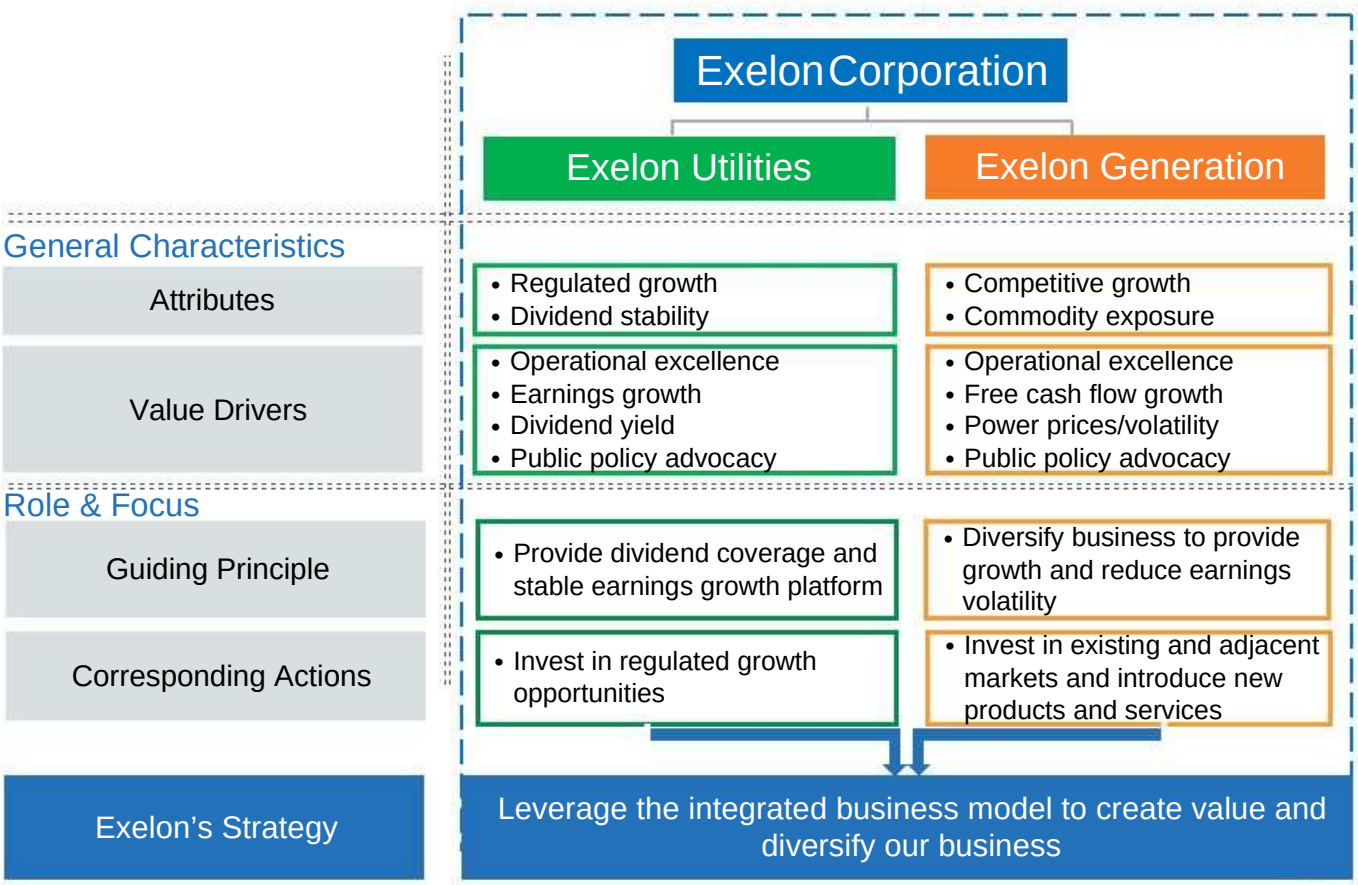

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Driving Value at Exelon Utilities

Providing Material EPS Accretion(1)

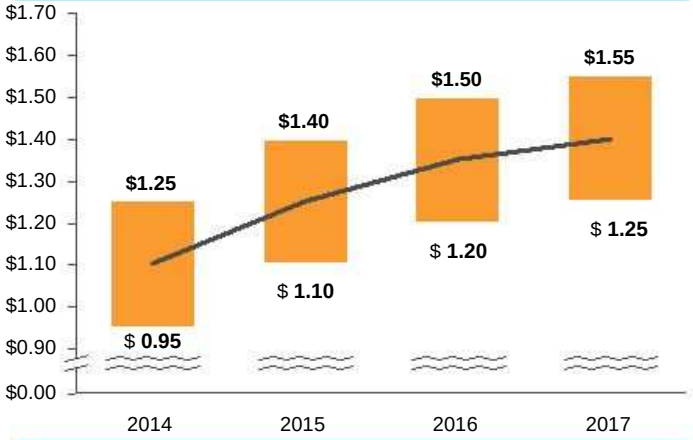

Significant Rate Base Growth(2)

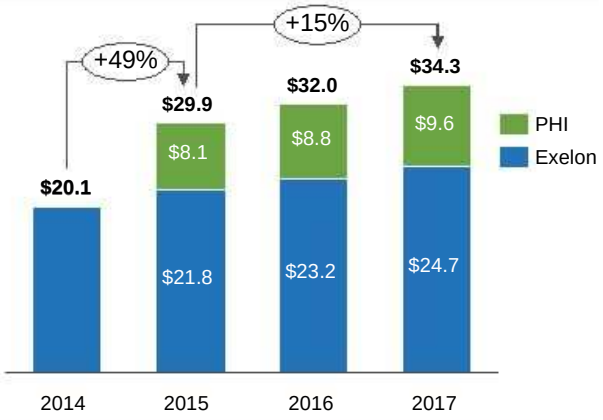

Operational Excellence

- Continue first quartile operating performance in areas such as reliability and customer satisfaction
- Achieve financial performance targets
- Leverage standardization, common platforms and best practices across operating companies
- Improved operational performance at ComEd, PECO and BGE since the merger

Creating the Leading Mid-Atlantic Utility

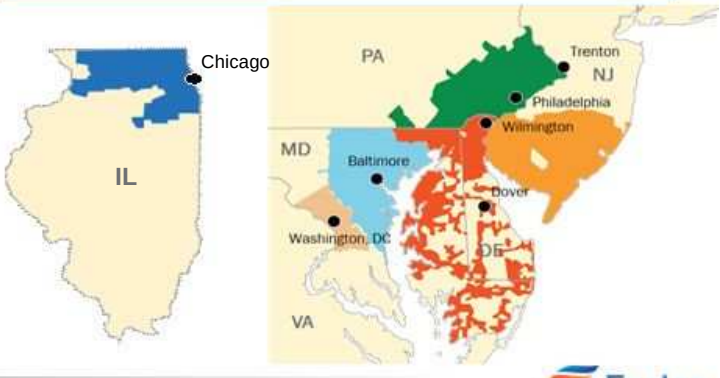

(1) Earnings guidance is for Exelon Utilities only and does not include PHI utilities
(2) Denotes year end rate base

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Driving Value at Exelon Generation

Guiding Principles:

Preserve the value of our core business . . .

- Operate the nuclear fleet safely and reliably
- Provide clean, reliable and affordable energy
- Manage portfolio through hedging and generation to load matching

. . . while strategically growing and diversifying the business

- Leverage competencies for growth
- Identify and capitalize on emerging trends and technologies by being a first mover
- Invest in business diversification to position the company for the future
- Use full arsenal of financing tools

Taking action to create value today while preparing for a different future

Exelon.

S1-SSA-0009 - 10220

IL - Market Based Solution

Possible Market Based Solutions

Clean Energy Standard

- Illinois could enact legislation to create a Clean Energy Standard (CES)
- A CES is a requirement that all customers purchase a minimum percentage of "clean" generation. The concept is similar to a Renewable Portfolio Standard with the distinction that the set of resources which qualify under the CES include all zero or low CO_2 emission generators
- Clean energy credits would be traded in a similar fashion to how renewable energy credits (RECs) are traded today

Carbon Trading Program

- Illinois could enact legislation to create a carbon trading program or join an existing program like the Regional Greenhouse Gas Initiative (RGGI)
- Carbon trading programs put a cap on carbon emissions and each fossil fuel generator must submit a carbon allowance for each tonne of carbon the plant emits
- These allowances are traditionally auctioned with the proceeds going to the state treasury. Some of the funds may be provided to customers to offset any rate impacts or dedicated to other energy-related programs

Benefits of Exelon's Fleet to Illinois

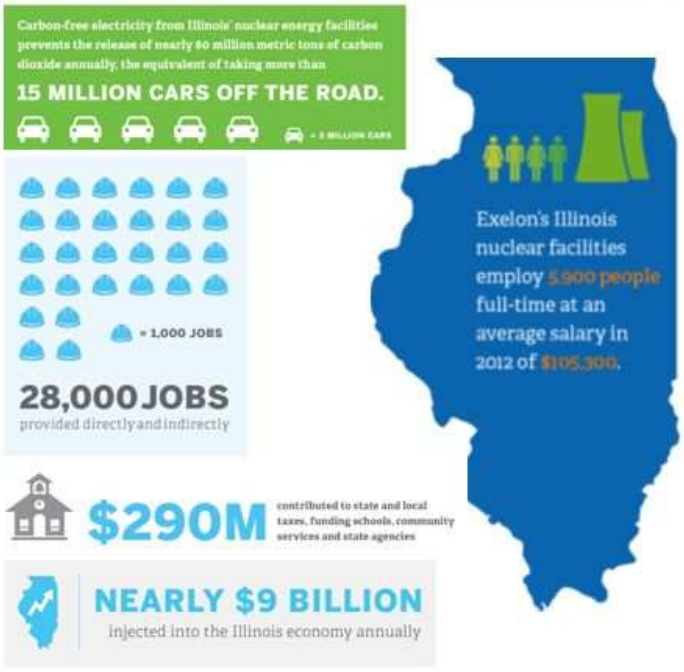

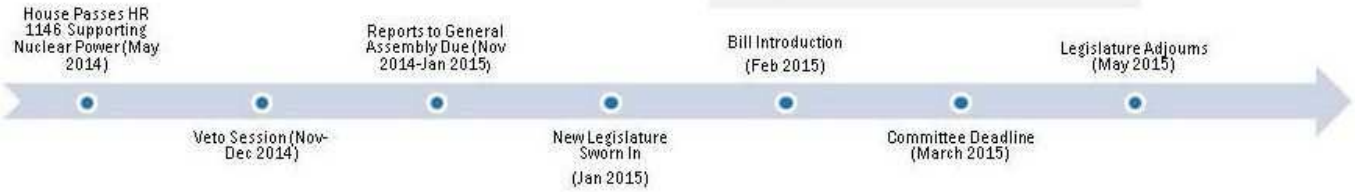

Note: 2015 Legislative timeline is illustrative

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Exelon is positioned for a strong future

Core Strength	Strategic Actions
Strong Integrated Business Model	We leverage our core competencies to grow our regulated and competitive businesses while expanding to adjacent markets
Operational Excellence	We operate our nuclear fleet at world class levels, and deliver first quartile performance at the utilities
Financial Strength	We maintain a strong balance sheet and the ability to raise and deploy capital for growth
Portfolio Optimization	We manage commodity market volatility and optimize earnings through our hedging strategy
Strategic Diversification	We diversify our business to capitalize on evolving industry trends over the long term
Public Policy Advocacy	We advocate for policies that strengthen competitive markets, value the grid and enhance the value of clean, reliable generation

Exelon

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Key Developments

Capacity Performance (CP) Impact on PJM Fleet

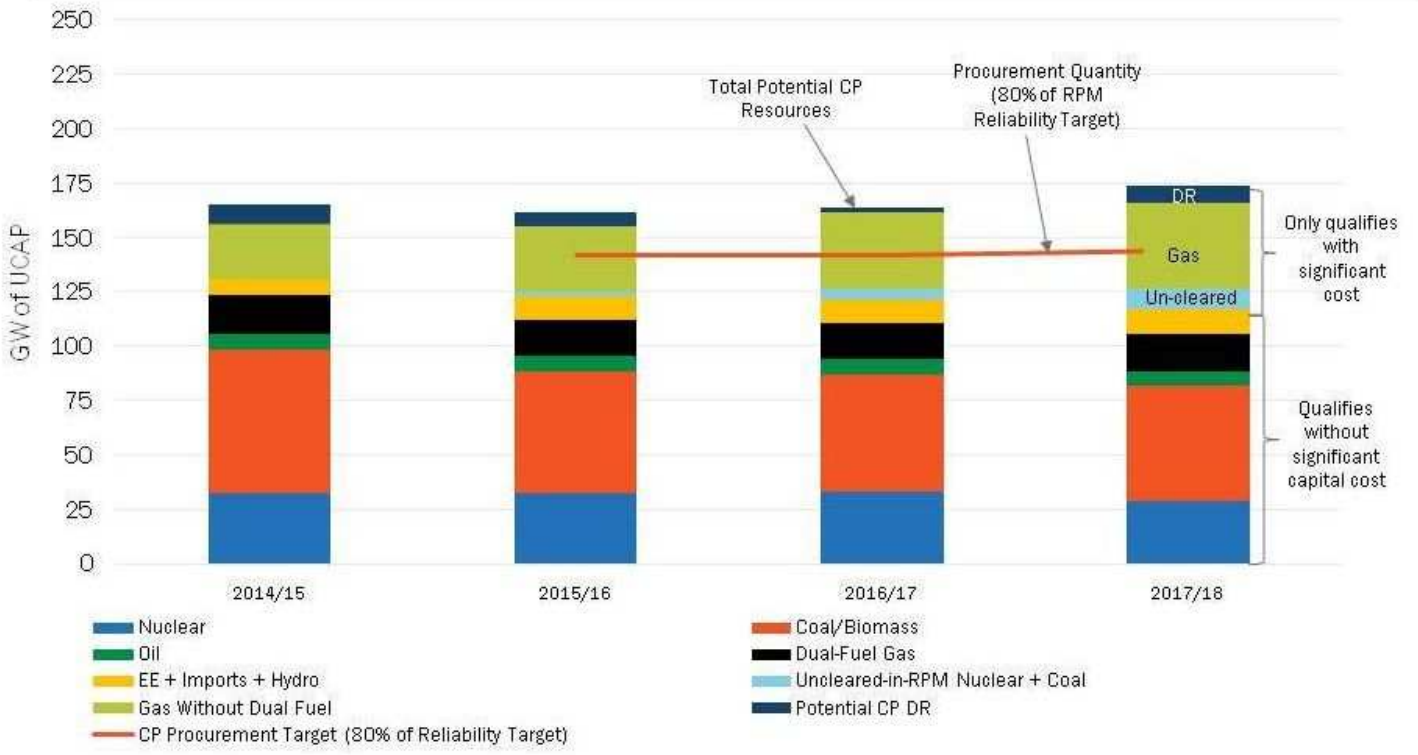

Exelon's fleet is well positioned to benefit from Capacity Performance due to significant investments in reliability

Source: NorthBridge Analysis; includes FRR resources/Loads; PJM proposal is to fully procure CP for 2016/17 and 2017/18 but to incrementally procure up to 10 GW of base capacity for 2015/16. Potential 2015/16 all-in CP procurement quantity shown for comparison purposes.

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Asset Divestitures --$ 1.4 Billion in Proceeds to Date

To date, Exelon has signed definitive agreements on five non-core assets representing a total of nearly $1.4 billion of after-tax sales proceeds upon closings; This excludes proceeds from Hillabee, which is currently on the market

(1) Represents EXC's portion of the asset
Note: CF: Capacity Factor through September 2014; Safe Harbor capacity factor through July 2014

Exelon.

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ExGen Disclosures – Asset Sale Impacts

Gross Margin Category ($M)[1]	2015	2016	2017
Open Gross Margin (including South, West & Canada hedged GM)[3]	6,750	6,500	6,650
Mark to Market of Hedges[3,4]	-	150	150
Power New Business / To Go	400	550	750
Non-Power Margins Executed	100	50	50
Non-Power New Business / To Go	300	350	350
Total Gross Margin[2,5]	7,550	7,600	7,950
Impact of Removing Keystone / Conemaugh	(150)	(100)	(100)
Pro-forma Total Gross Margin excluding Keystone / Conemaugh	7,400	7,500	7,850
Impact of Announced Assets Sales During 2014 [1]	**2015**	**2016**	**2017**
OGM Impact Q2 (Safe Harbor)	(50)	(50)	(50)
OGM Impact Q3 (Fore River, Quail Run, West Valley)	(100)	(100)	(100)
OGM Impact Q4 (Keystone / Conemaugh)	(150)	(100)	(100)
Total Impact to OGM from Announced Asset Sales	(300)	(250)	(250)
O&M	100	100	100
D&A	100	100	100
EBIT	(100)	(50)	(50)
CapEx	(50)	(50)	(100)
EPS Reduction[6]	($0.06-$0.08)	($0.02-$0.04)	($0.02-$0.04)

(1) Rounded to nearest $50M

(2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses

(3) Excludes EDF's equity ownership share of the CENG Joint Venture

(4) Mark to Market of Hedges assumes mid-point of hedge percentages

(5) Reflects the divestiture impact of Fore River, Quail Run and West Valley. Does not include divestiture of Keystone/Conemaugh or the Integrys Acquisition

(6) EPS impact does not include impact of investing the proceeds from the sale. As a reminder these sales were included in the accretion calculation for the PHI transaction

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State of the Art Combined Cycles in ERCOT

ERCOT Dispatch

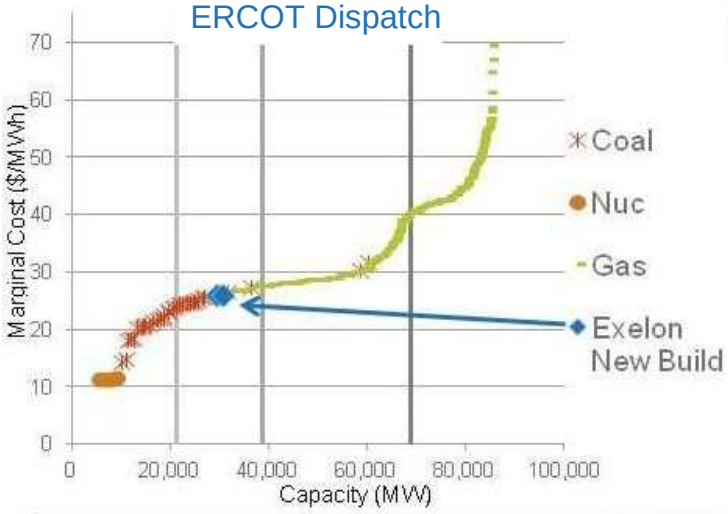

Key Facts	
Sites	Wharton County, TX Granbury, TX
Total Capacity	~2,200MW (Wolf Hollow: 1,085MW / Colorado Bend: 1,104MW)
Construction Cost	~$700/kW
Heat Rate	~6,500 mmBtu/MWh
OEMs	GE and Alstom
EPC	Zachry
Cooling System	Air Cooled
Construction Start	2015
Commercial Operation	By Summer 2017

- **Efficient:** Two of the cleanest, most efficient Combined Cycle Gas Turbines (CCGT) in the nation
- **Cost Effective:** Simplified design provides for easier construction and maintenance, making these units among the most predictable and least costly to operate and maintain in the industry
- **Environmental:** Plants use air cooling which mitigates water constraint issues
- **Fast Ramp:** 100 MW/Minute ramp rate (market ramp rate ~50 MW/minute)

Exelon

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Distributed Energy Platform

Distributed Energy is a Fast Growing Business

- On-site generation, including solar, quadrupled since 2006 *(Wall Street Journal 2013)*
- US C&I customers are spending ~$5-6 billion per year on self-generation and energy efficiency programs *(Bloomberg 2013)*
- Revenues from Distributed Generation are expected to reach $12.7 billion by 2018 *(Pike Research, Navigant, 2012)*

Distributed Energy Supports Exelon's Strategy:

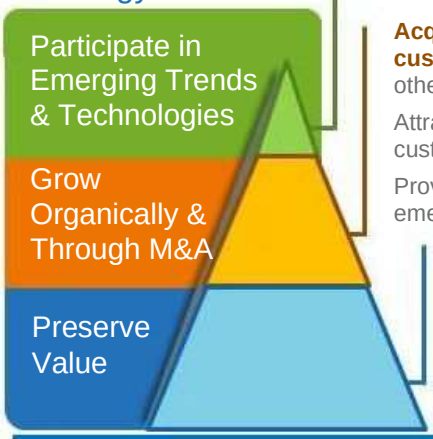

Commercializing emerging and potentially disruptive energy technologies to diversify existing technology base

Acquiring long term retail customers through a PPA or other long-term agreement

Attract and acquire new customers with unique offering

Provides adaptive growth within an emerging market sector

Bolstering existing relationships with customers to help achieve reliability or sustainability objectives

Integrating supply & demand side solutions

Key Attributes of Financial Value

Co-Generation
- Design, build and operate energy assets
- Provides renewable energy value or credits, if applicable
- Long-term O&M agreements

Owned Assets additional attributes:
- Long-term customer PPA (usually @ fixed price)
- Provides tax incentives, if applicable

Solar
- ~ 200 MW of Retail Solar Projects in operation or under construction
- Long-term customer PPA (usually @ fixed price)
- Provides renewable energy value or credits, if applicable
- Provides tax incentives, if applicable

Energy Efficiency
- Over 1,000 energy saving projects implemented
- ~ 50 MW conserved by customers
- More than $1 billion in projects 3rd party customer financed

Fuel Cell
- Provide equity financing for 21 MW of Bloom Energy fuel cell projects at 75 commercial facilities including AT&T
- Provides renewable energy value or credits, if applicable
- Provides tax incentives, if applicable

Backup Generation
- Own and operate energy assets as a service to retail customers
- Bundled service offering with long-term customer agreements through grid power supply & LR programs
- Load Response market -based value creation (e.g., LR Programs)

Battery Storage
- Own and operate energy assets as a service to retail customers
- Bundled service offering with long-term customer agreements through grid power supply & LR programs
- Load Response market based value creation (e.g., ancillary services)

CNG
- Own and operate CNG facilities
- Leverage retail gas supply and risk management expertise
- Long-term customer off-take agreement(s)

Invested more than $1 billion of capital with projects averaging returns of 8% - 12%, and well positioned for growth

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S1-SSA-0009 - 10228

Financial Update

S1-SSA-0009 - 10229

Financing Strategy

On Balance Sheet Debt supports core business and/or strategic assets
- Senior Unsecured Notes
- Utility First Mortgage Bonds

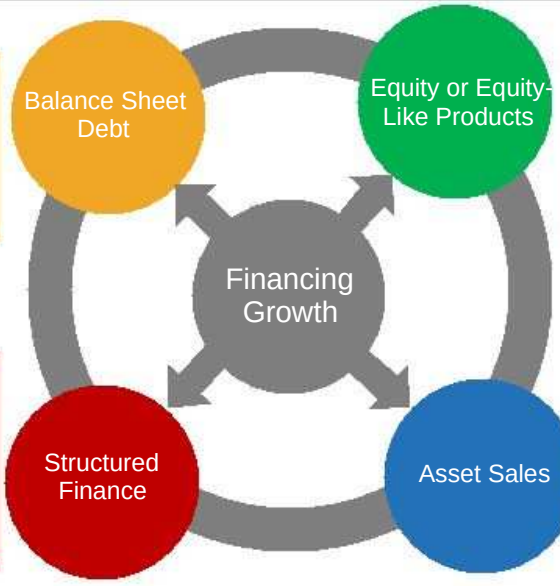

Equity or Equity-Like Products support growth projects (both on-going and strategic M&A)
- Mandatory Convertible Units
- Marketed Follow-On Offerings

Structured Financing supports non-core assets that generate consistent cash flows
- Project Financing
- Asset Based Lending
- Joint Venture/Equity Partner

Proceeds from asset sales support
- Reinvestment of Free Cash Flow
- Strategic Diversification

- Our financing strategy incorporates a broad range of financial products, from the standard corporate-style products (such as corporate debt and equity), to alternative structures such as project financing, partnership structures and other arrangements
- We employ a wide variety of financing tools that will enable us to access capital to grow on both the regulated and unregulated sides of the business

Exelon.

Exelon's Strategic and Financial Decisions Enable Growth Across the Enterprise

A broad spectrum of financing alternatives beyond the core financing options can be used to fund growth

- Monetize assets in the portfolio via project finance (Nearly $3B over past 3 years)
- Sell assets which are worth more to others ($1.0-$1.5B after-tax in 2014-15)
- Other financing structures (joint ventures, minority partners, etc.) could be used based on opportunity

Incremental Sources of Cash

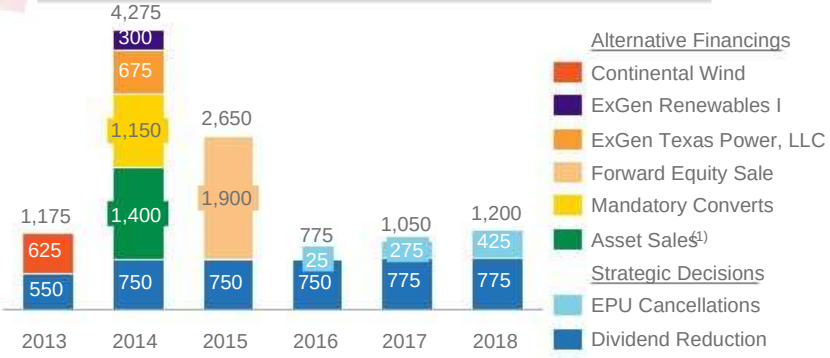

(1) Includes Safe Harbor, Fore River, Quail Run, West Valley and Keystone Conemaugh.
Note: Does not include future Hillabee proceeds

Exelon	
1.	Constellation
2.	BGE
3.	Utility Rate Base
4.	Retail Acquisitions
5.	Wind
6.	Annova LNG
7.	ERCOT New Build
8.	Pepco Holdings
9.	Distributed Energy

Strategic and Diversified Deployment

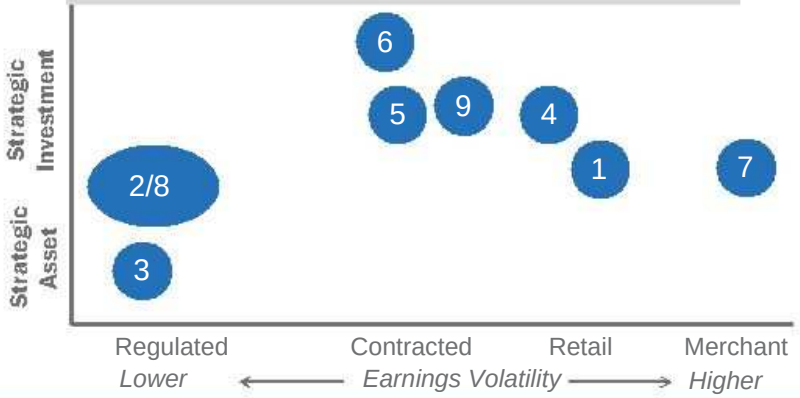

Exelon has a proven ability to finance growth

Exelon.

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Over the Last Three Years, Exelon Has Raised Nearly $3 Billion through Project Financing

- Exelon uses project financing to:
  - Maintain upside reward of the project while mitigating the downside risk
  - Enhance corporate credit metrics and strengthen the balance sheet via non-recourse financing vehicles
  - Provide different and new sources of liquidity that Exelon would not typically be able to access corporately
  - Maximize Exelon's returns on its strategic investments

Antelope Valley Solar Ranch

- 230 MW photovoltaic solar generating plant in Lancaster, CA
- $646 MM Senior Secured Bond –due January 2037 with a DOE Loan Guaranty

Continental Wind

- 667 MW of wind spread across 13 projects and five wind regimes
- $613MM Senior Secured 144a Project Bond –due February 2033 and $141MM Senior Secured LC and Working Capital Facilities – due February 2021
- Deal of the Year
  - *Project Finance ' s* 2013 North American Portfolio Power Deal of the Year
  - *Project Finance & Risk ' s* 2013 Project Finance Renewable Deal of the Year

ExGen Renewables

- HoldCo financing of Continental's distributions to further maximize our returns on our wind investments
- $300MM Senior Secured Team Loan B –due February 2021

ExGen Texas Power

- 3,476 MW ERCOT conventional power portfolio consisting of CCGTs and Simple Cycles
- $675MM Senior Secured Term Loan B –due September 2021
- One of the largest non-corporate, single-tranche term loan B issuances in the power sector in 2014

Exelon.

2014 Operating Earnings Guidance

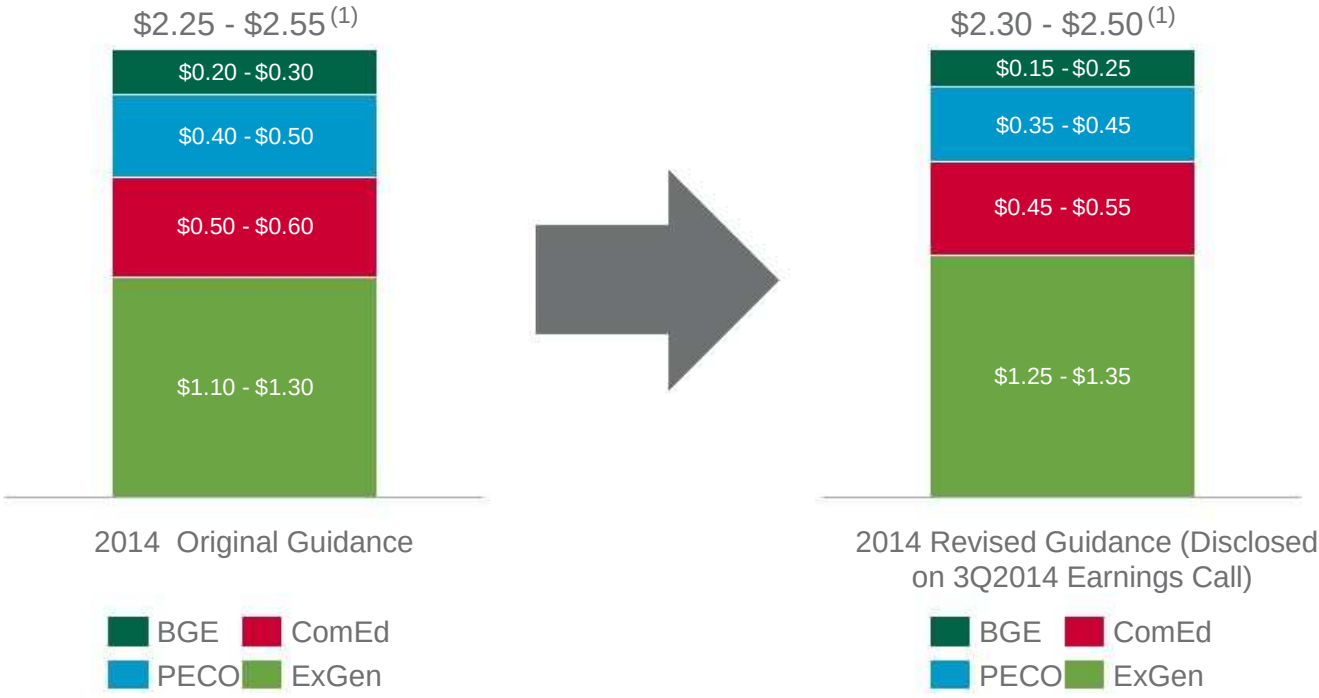

(1) Earnings guidance for OpCos may not add up to consolidated EPS guidance. Refer to **slide 24** for a list of a djustments from GAAP EPS to adjusted (non - GAAP) operating EPS

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EPS Sensitivities

		2015	2016	2017	Fully Open
ExGen EPS Impact[1]	Henry Hub Natural Gas				
	+$1/MMBtu	$0.10	$0.37	$0.66	$0.88
	-$1/MMBtu	($0.05)	($0.34)	($0.59)	($0.87)
	NiHub ATC Energy Price				
	+$5/MWh	$0.07	$0.22	$0.31	$0.36
	-$5/MWh	($0.07)	($0.22)	($0.31)	($0.36)
	PJM-W ATC Energy Price				
	+$5/MWh	$0.03	$0.14	$0.21	$0.27
	-$5/MWh	($0.02)	($0.13)	($0.20)	($0.27)
	PJM Capacity Market[2]				
	+$10/MW-day				$0.05
	-$10/MW-day				($0.05)
ComEd EPS Impact	30 Year Treasury Rate				
	+25 basis points	$0.01	$0.01	$0.01	$0.01
	-25 basis points	($0.01)	($0.01)	($0.01)	($0.01)
	Share Count *(millions)*[3]	870	872	892	910

(1) Based on September 30, 2014 market conditions and hedged position. Gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically. Power prices sensitivities are derived by adjusting the power price assumption while keeping all other price inputs constant. Due to correlation of the various assumptions, the EPS impact calculated by aggregating individual sensitivities may not be equal to the EPS impact calculated when correlations between the various assumptions are also considered.
(2) Assumes 2017/2018 auction cleared volumes
(3) Does not include shares assumed to be issued via forward equity sale in connection with PHI acquisition

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Capital Expenditure Expectations ($M)

(1) At Ownership
Note: Numbers rounded to nearest $25m

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2014 Projected Sources and Uses of Cash

Projected Sources & Uses[1]

($ in millions)	BGE	ComEd	PECO	ExGen	Exelon[3]	As of 2Q14	Variance
Beginning Cash Balance[2]					**1,475**	**1,475**	**--**
Adjusted Cash Flow from Operations[4]	675	1,600	650	4,550	7,475	6,975	500
CapEx (excluding other items below):	(550)	(1,475)	(500)	(1,275)	(3,700)	(3,450)	(250)
Nuclear Fuel	n/a	n/a	n/a	(1,000)	(1,000)	(1,000)	--
Dividend[5]					(1,075)	(1,075)	--
Nuclear Uprates	n/a	n/a	n/a	(150)	(150)	(150)	--
Wind	n/a	n/a	n/a	(75)	(75)	(75)	--
Solar	n/a	n/a	n/a	(200)	(200)	(200)	--
Upstream	n/a	n/a	n/a	(75)	(75)	(50)	(25)
Utility Smart Grid/Smart Meter	(75)	(275)	(150)	n/a	(525)	(525)	--
Net Financing (excluding Dividend):							
Debt Issuances	--	900	300	--	1,200	1,250	(50)
Debt Retirements	--	(625)	(250)	(525)	(1,375)	(1,375)	--
Project Finance/Federal Financing Bank Loan	n/a	n/a	n/a	1,050	1,050	875	175
Other Financing[6]	(75)	175	100	(375)	575	575	--
Ending Cash Balance[2]					**3,600**	**3,250**	**350**

(1) All amounts rounded to the nearest $25M.

(2) Excludes counterparty collateral of $134 million at 12/31/2013. In addition, the 12/31/2014 ending cash balance does not include collateral.

(3) Includes cash flow activity from Holding Company, eliminations, and other corporate entities. CapEx for Exelon is shown net of $325M CPS early lease termination fee, and ($125M) purchase of PHI preferred stock.

(4) Adjusted Cash Flow from Operations (non-GAAP) primarily includes net cash flows from operating activities and net cash flows from investing activities excluding capital expenditures of $5.7B for 2014.

(5) Dividends are subject to declaration by the Board of Directors.

(6) "Other Financing" primarily includes CENG distribution to EDF, expected changes in short-term debt, and proceeds from issuance of mandatory convertible units.

Key Messages[1]

- Cash from Operations is projected to be $7,475M vs. 2Q14E of $6,975M for a $500M variance. This variance is driven by:
  - $625M Net proceeds from divestitures
  - $175M Income taxes and settlements
  - $125M Reclassification of PHI preferred stock purchase
  - ($325M) Integrys acquisition, including working capital
  - ($100M) Working capital at Utilities
- Cash from Investing activities is projected to be ($5,725M) vs. 2Q14E of ($5,450M) for a ($275M) variance. This variance is driven by:
  - ($125M) ExGen development
  - ($125M) Reclassification of PHI preferred stock purchase
  - ($25M) Upstream
- Cash from Financing activities is projected to be $375M vs. 2Q14E of $250M for a $125M variance. This variance is driven by:
  - $175M Incremental project financing at ExGen
  - ($50M) Decreased ComEd long term debt requirements
  - ($25M) Decrease in projected commercial paper financings

Exelon

Pension and OPEB Contributions and Expense

	2015		2016	
(in $M)	Pre-tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]
Pension[3][4]	$375	$515	$325	$565
OPEB[3][4]	$5	$30	$5	$35
Total	$380	$545	$330	$600

(1) Pension and OPEB expenses assume a ~27% and ~28% capitalization rate in 2015 and 2016, respectively
(2) Contributions shown in the table above are based on the current contribution policy, which for the pension includes a discretionary component of $250M
(3) Expected return on assets for pension is 7.00% and for OPEB is 6.59%
(4) Projected 12/31/14 pension and OPEB discount rates are 4.28% and 4.26%, respectively, for the majority of plans

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2015 Pension and OPEB Sensitivities

- Tables below provide sensitivities for the combined company's 2015 pension and OPEB expense and contributions[1] under various discount rate and S&P 500 asset return scenarios

	2015 Pension Sensitivity[2] (in $M)					
	S&P Returns in Q4 2014[3]					
	10%		0%		-10%	
Discount Rate at 12/31/14	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]
Baseline Discount Rate[4]	$365	$505	$375	$515	$390	$520
+50 bps	$345	$265	$345	$520	$355	$525
-50bps	$400	$490	$410	$495	$425	$505

	2015 OPEB Sensitivity[2] (in $M)					
	S&P Returns in Q4 2014[3]					
	10%		0%		-10%	
Discount Rate at 12/31/14	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]	Pre-Tax Expense[1]	Contributions[2]
Baseline Discount Rate[4]	$0	$30	$5	$30	$25	$35
+50 bps	($10)	$30	$0	$30	$10	$30
-50bps	$10	$30	$25	$35	$35	$50

(1) Contributions shown in the table above are based on the current contribution policy which for the pension includes a discretionary component of $250M
(2) Pension and OPEB expenses assume an ~ 27% capitalization rate in 2015
(3) Final 2014 asset return for pension and OPEB will depend in part on overall equity market returns for Q4 2014 as proxied by the S&P500 ; The amounts above reflect YTD asset returns through September 30 , 2014
(4) The baseline discount rates reflect projected 12/31/14 pension and OPEB discount rates of 4.28% and 4.26%, respectively, for the majority of plans

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Exelon-PHI Debt Maturity Profile(1)

As of 10/31/14

Current Ratings (2)(3)	Moody's	S&P	Fitch
Corp	Baa2	BBB-	BBB+
ComEd	A2	A-	A-
PECO	Aa3	A-	A
BGE	A3	A-	BBB+
Generation	Baa2	BBB	BBB+

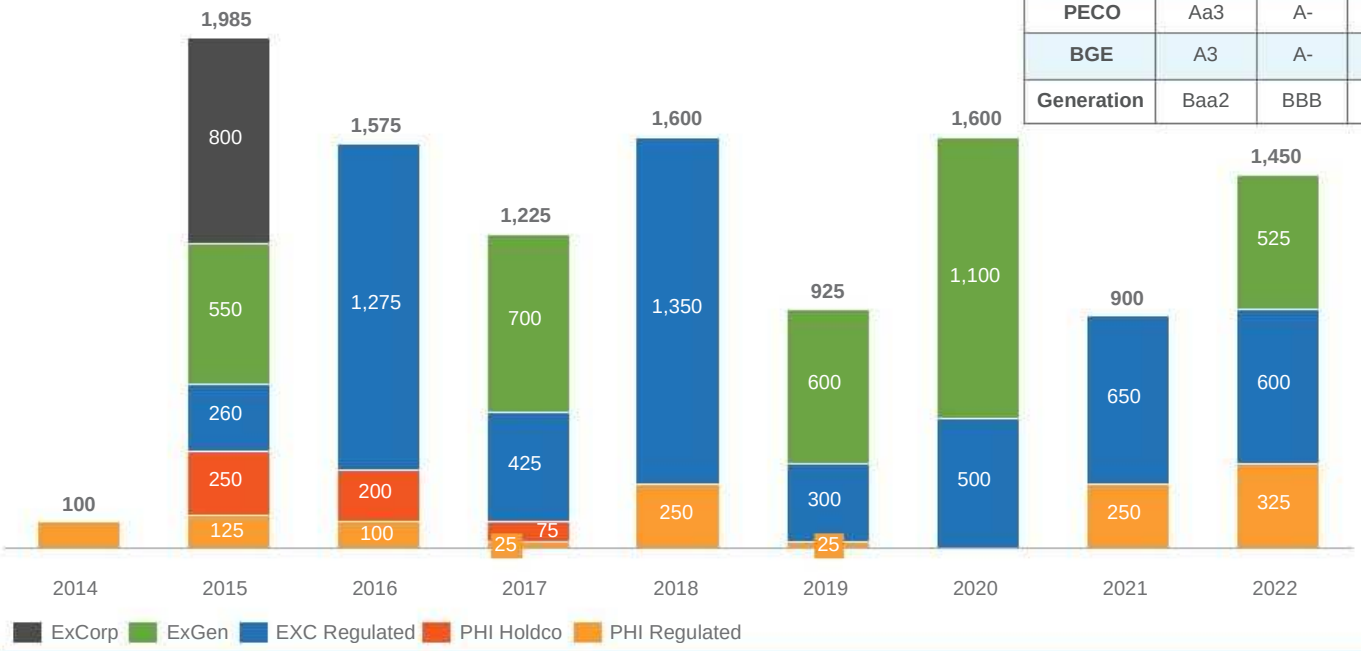

Manageable debt maturity profile

(1) ExGen debt includes legacy CEG debt; EXC Regulated includes capital trust securities; Excludes PHI unregulated debt, which totals $25M; Excludes acquisition debt and non-recourse debt; (2) Current senior unsecured ratings for Exelon, Exelon Generation and BGE and senior secured ratings for ComEd and PECO (3) All ratings are "Stable" outlook, except for at Fitch, which has BGE on "Positive" and Exelon and ExGen on "Ratings Watch Negative"

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GAAP to Operating Adjustments

- Exelon's 2014 adjusted (non-GAAP) operating earnings excludes the earnings effects of the following:
  - Mark-to-market adjustments from economic hedging activities
  - Unrealized gains and losses from NDT fund investments to the extent not offset by contractual accounting as described in the notes to the consolidated financial statements
  - Financial impacts associated with the increase and decrease in certain decommissioning obligations
  - Financial impacts associated with the sale of interests in generating stations
  - Non-cash charge to earnings related to the cancellation of previously capitalized nuclear uprate projects and the impairment of certain wind generating assets and certain assets held for sale
  - Gain recorded upon consolidation of CENG
  - Certain costs incurred associated with the Constellation, CENG merger, and Pepco Holdings, Inc. merger and integration initiatives
  - Non-cash amortization of intangible assets, net, related to commodity contracts recorded at fair value at the merger date for 2014
  - Favorable settlements of certain income tax positions on Constellation's 2009-2012 tax returns
  - CENG interest not owned by Generation, where applicable

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Exelon Utilities

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Exelon Utilities Strategy

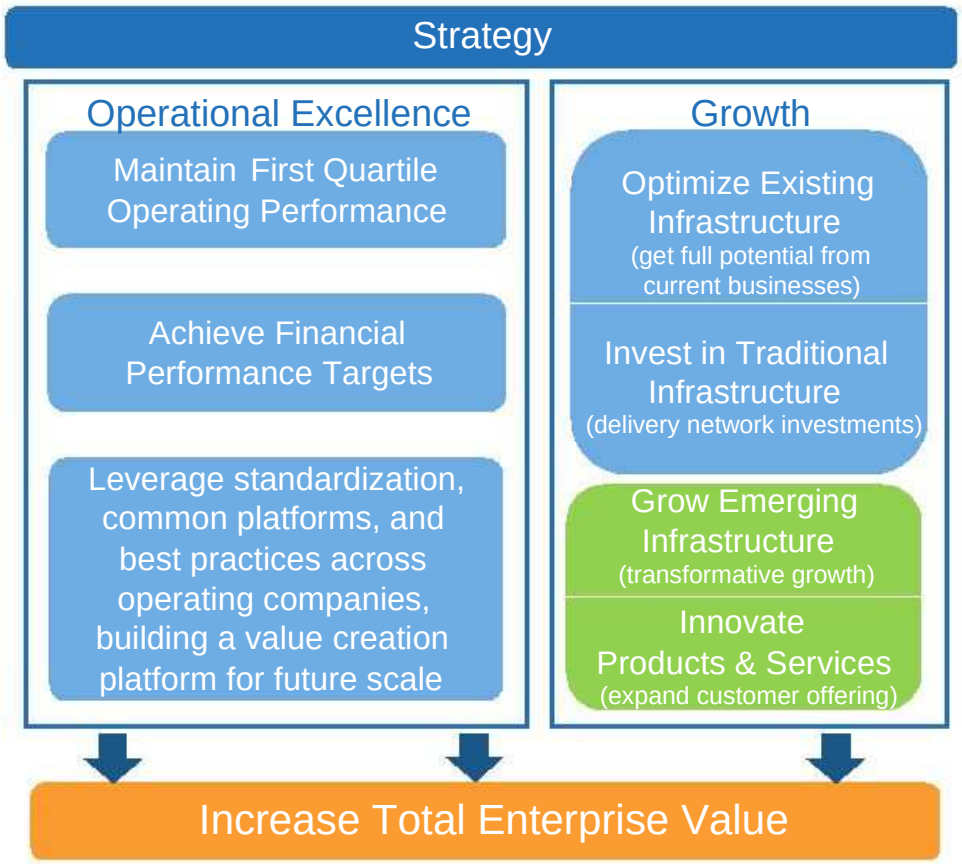

Exelon

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Leveraging Best Practices for Operational Excellence

Performance Quartiles: Q1 | Q2 | Q3 | Q4

Operations	Metric	At Merger (2012) BGE	At Merger (2012) PECO	At Merger (2012) ComEd	Post Merger (2014) BGE	Post Merger (2014) PECO	Post Merger (2014) ComEd
Electric Operations	OSHA Recordable Rate						
	OSHA Severity Rate						
	2.5 Beta SAIFI						
	2.5 Beta CAIDI						
Customer Operations	Customer Satisfaction (MSI)						
	Service Level % of Calls Answered in <30 Sec						
	Abandon Rate						
	Calls per Customer						
Gas Operations	Percent of Calls Responded to in <=1 Hour			*No Gas Operations*			*No Gas Operations*
	3rd Party Damages per 1,000 Gas Locates						

Exelon Utilities has identified and transferred best practices at each of its utilities to improve operating performance in areas such as:

- System Performance
- Emergency Preparedness
- Corrective and Preventive Maintenance

Exelon.

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Capital Expenditures

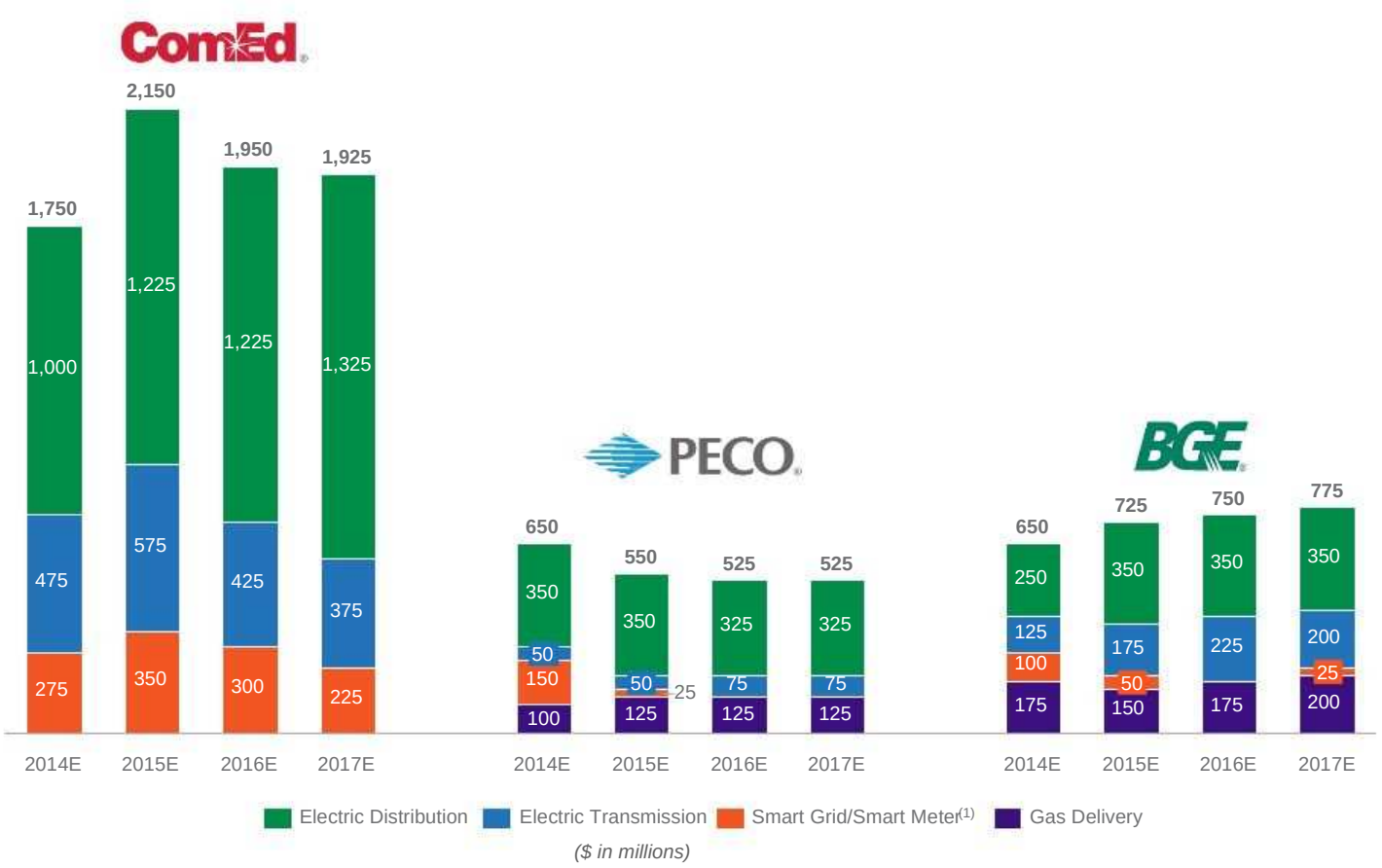

(1) SmartMeter/Smart Grid CapEx net of proceeds from U.S. Department of Energy (DOE) grant; For BGE includes CapEx from Smart Energy Savers program of ~$10M per year

Exelon

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Exelon Utilities: Rate Base[1] and ROE Targets

ComEd

($ in billions)

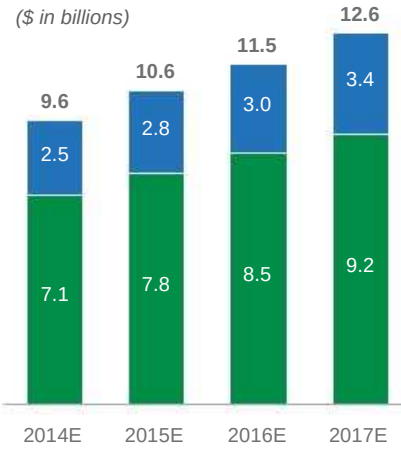

	2014E	Long-Term Target
Equity Ratio	~46%	~53%[2]
Earned ROE	8-9%	Based on 30-yr US Treasury[3]
Rate Case	Annual Formula Rate Filing	

PECO

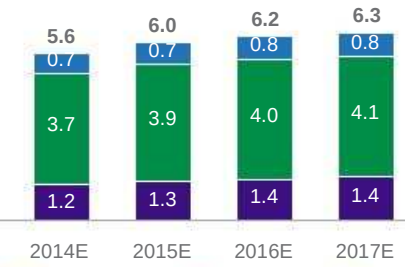

	2014E	Long-Term Target
Equity Ratio	56%	~53%
Earned ROE	11-12%	≥ 10%
Rate Case	Possible 2015-2016	

BGE

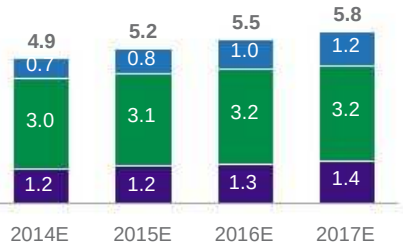

	2014E	Long-Term Target
Equity Ratio	52%	~53%[4]
Earned ROE	7-8%	≥ 10%
Rate Case	2015	

Transmission Distribution Gas

Continued investment in utilities will provide stable earnings growth

(1) ComEd, PECO and BGE rate base represents end-of-year. Numbers may not add due to rounding
(2) Equity component for distribution rates will be the actual capital structure adjusted for goodwill
(3) Earned ROE will reflect the weighted average of 11.5% allowed transmission ROE and distribution ROE resulting from 30-year Treasury plus 580 basis points for each calendar year
(4) Per MDPSC merger commitment, BGE is precluded from paying dividends through 2014

Exelon

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Rate Base Growth

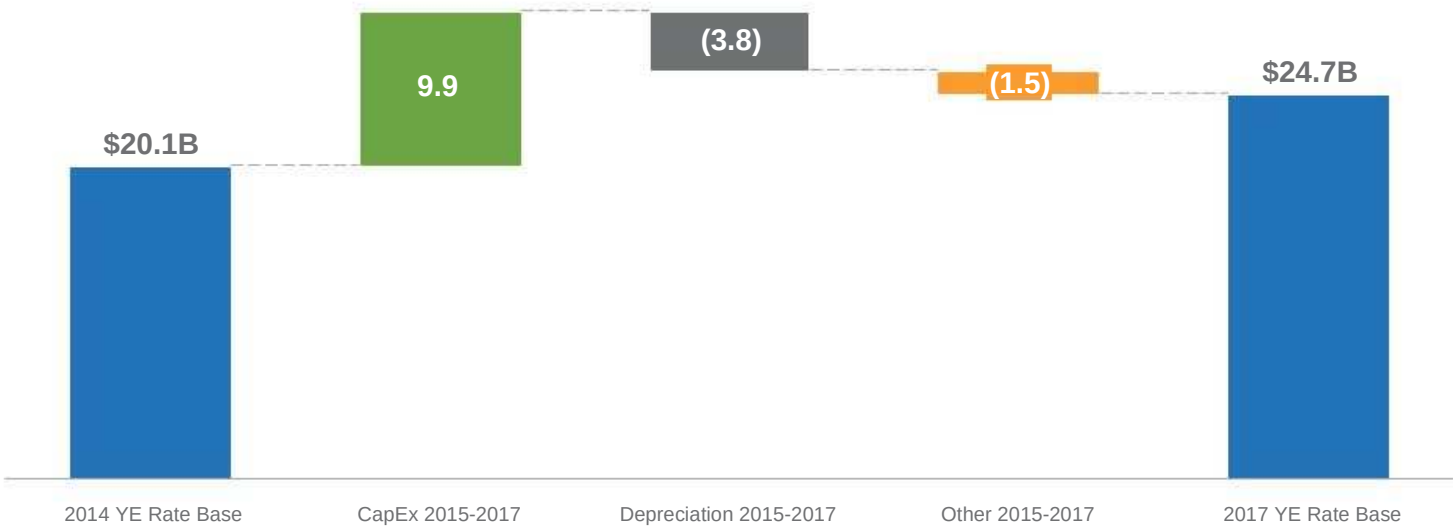

Utility CapEx spend outpaces depreciation, thereby growing rate base and earnings

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Exelon Utility 2014-17 Adjusted Operating EPS Guidance

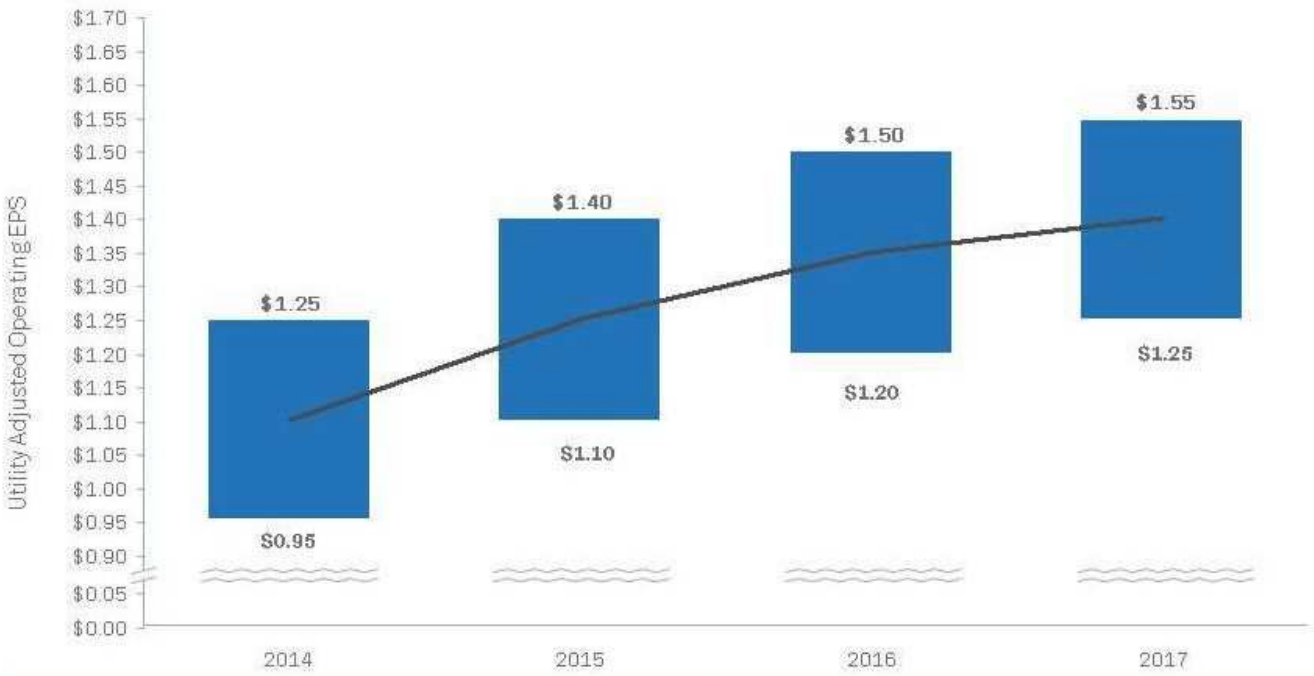

By investing $16B in capital and improving earned ROEs, Exelon Utilities will provide average earnings growth of ~8% per year from 2014-2017

Exelon.

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Grand Prairie Gateway Transmission Line

Key Facts

- Line : 60 mile, 345 kV transmission line connecting ComEd's Byron and Wayne substations alleviating identified congestion and enhancing reliability
- Cost: $260 million
- Customer Savings: $250 million within the first 15 years of operation – net of all costs
- Recovery Mechanism: FERC-filed transmission rate of 11.5% and construction work in progress and abandonment recovery
- Construction : Scheduled to begin Q2 2015
- In Service Date: Q2 2017
- Environmental Benefits: 735,000 pounds of carbon dioxide (CO2) reduced over the first 15 years

Exelon

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ComEd April 2014 Distribution Formula Rate

The 2014 distribution formula rate filing establishes the net revenue requirement used to set the rates that will take effect in January 2015 after the Illinois Commerce Commission's (ICC's) review. There are two components to the annual distribution formula rate filing:

- Filing Year: Based on prior year costs (2013) and current year (2014) projected plant additions.
- Annual Reconciliation: For the prior calendar year (2013), this amount reconciles the revenue requirement reflected in rates during the prior year (2013) in effect to the actual costs for that year. The annual reconciliation impacts cash flow in the following year (2015) but the earnings impact has been recorded in the prior year (2013) as a regulatory asset.

Docket #	**14-0312**
Filing Year	**2013 Calendar Year Actual Costs and 2014 Projected Net Plant Additions** are used to set the rates for calendar year 2015. Rates currently in effect (docket 13-0318) for calendar year 2014 were based on 2012 actual costs and 2013 projected net plant additions
Reconciliation Year	**Reconciles Revenue Requirement reflected in rates during 2013 to 2013 Actual Costs Incurred.** Revenue requirement for 2013 is based on docket 13-0386 filed in June 2013 and reflect the impacts of PA98-0015 (SB9)
Common Equity Ratio	**~ 46%** for both the filing and reconciliation year
ROE	**9.25%** for the filing year (2013 30-yr Treasury Yield of 3.45% + 580 basis point risk premium) and **9.20%** for the reconciliation year (2013 30-yr Treasury Yield of 3.45% + 580 basis point risk premium – 5 basis points performance metrics penalty). For 2014 and 2015, the actual allowed ROE reflected in net income will ultimately be based on the average of the 30-year Treasury Yield during the respective years plus 580 basis point spread, absent any metric penalties
Requested Rate of Return	**~ 7%** for both the filing and reconciliation years
Rate Base(1)	**$7,369 million** – Filing year (represents projected year-end rate base using 2013 actual plus 2014 projected capital additions). 2014 and 2015 earnings will reflect 2014 and 2015 year-end rate base respectively. $6,596 million - Reconciliation year (represents year-end rate base for 2013)
Revenue Requirement Increase(1)	**$269M** ($96M is due to the 2013 reconciliation, $173M relates to the filing year). The 2013 reconciliation impact on net income was recorded in 2013 as a regulatory asset.
Timeline	• 04/16/14 Filing Date • 240 Day Proceeding • ALJ Proposed Order issued on 10/15/14 proposes a $239M revenue requirement increase • ICC order expected by December 12, 2014

Given the retroactive ratemaking provision in the Energy Infrastructure Modernization Act (EIMA) legislation, ComEd net income during the year will be based on actual costs with a regulatory asset/liability recorded to reflect any under/over recovery reflected in rates. Revenue Requirement in rate filings impacts cash flow.

(1) Amounts represent ComEd's position filed in rebuttal testimony on July 23, 2014

Note: Disallowance of any items in the 2014 distribution formula rate filing could impact 2014 earnings in the form of a regulatory asset adjustment

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BGE Rate Case Settlement

	Electric	Gas
Docket #	9355	
Test Year	September 2013 August 2014	
Common Equity Ratio[2]	52.3%	
Authorized Returns[1][3]	ROE: 9.75%; ROR: 7.46%	ROE: 9.65%; ROR: 7.41%
Requested Rate of Return	7.93%	7.88%
Proposed Rate Base (adjusted)[1][4]	$2.9B	$1.2B
Revenue Requirement Increase	$22.0M	$38.0M
Distribution Increase as % of overall bill	1%	5%
Timeline	• 07/02/14 BGE filed application with the MDPSC seeking increases in electric & gas distribution base rates • 210 Day Proceeding • 7/08/14 – Case delegated to the Public Utility Law Judge Division • 10/17/14 – BGE filed unanimous "black box" settlement with MD PSC • Settlement must be approved by the MD PSC • If approved, new rates are expected to be effective no sooner than the middle of December 2014	

First BGE rate case settlement agreement since 1999

(1) Due to the "black box" nature of the settlement, the Common Equity Ratio, Authorized Returns, and Proposed Rate Base (adjusted) were not agreed upon by the parties in determining the ultimate revenue requirement increase
(2) Reflects BGE's actual capital structure as of 8/31/2014
(3) ROE and ROR stated in the settlement only apply to AFUDC and carrying costs on regulatory assets
(4) BGE's Proposed Adjusted rate base

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ComEd Load

Weather-Normalized Load Growth

Economic Forecast of Drivers that Influence Load

Driver or Indicator	2015 Outlook
Gross Metro Product (GMP)	2.3% growth in real GMP reflects overall better economic conditions than the slower growth in 2014 (Manufacturing and Professional Business Services employment accelerate in 2015)
Employment	1.3% increase in total employment is expected for 2015, which is consistent with the average growth for the past three years
Manufacturing	Manufacturing employment is expected to grow 1.4% in 2015. This is a significant improvement over the (0.4%) decline in 2013 and the (1.1%) decline in 2014
Households	Household formations are expected to increase 0.7% in 2015 which is slightly higher than the expected increase of 0.6% in 2014
Energy Efficiency	Continued expansion of EE program expected to reduce usage in 2015 by approximately 1.2%

Improving economic conditions and energy efficiency initiatives will continue to impact load growth

Notes: 2013 data is not adjusted for leap year. Source of 2015 economic outlook data is IHS Economics (September 2014). (C&I = Commercial and Industrial)

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PECO Load

Weather-Normalized Load Growth

Economic Forecast of Drivers that Influence Load

Driver or Indicator	2015 Outlook
Gross Metro Product (GMP)	GMP projected to grow at 2.5% for 2015, the same as prerecession levels
Resident Employment	Resident employment outlook is 1.7% in 2015 vs. 1.3% in 2014
Manufacturing Employment	Manufacturing employment is expected to grow at 1.7%. Philadelphia has had negative growth from 2000 to 2014
Households	Household growth is expected to be 0.7%, strongest growth since 2008, and at the same level as 2014
Energy Efficiency	Deemed Energy Efficiency impact forecasted to be ~0.9% reduction in usage in 2015

Moderately strong economic recovery will drive sales in 2015, partially offset by on-going energy efficiency initiatives

Notes: 2013 data is not adjusted for leap year. Source of 2015 economic outlook data is IHS Economics (September 2014). (C&I = Commercial and Industrial)

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BGE Load

Weather-Normalized Load Growth

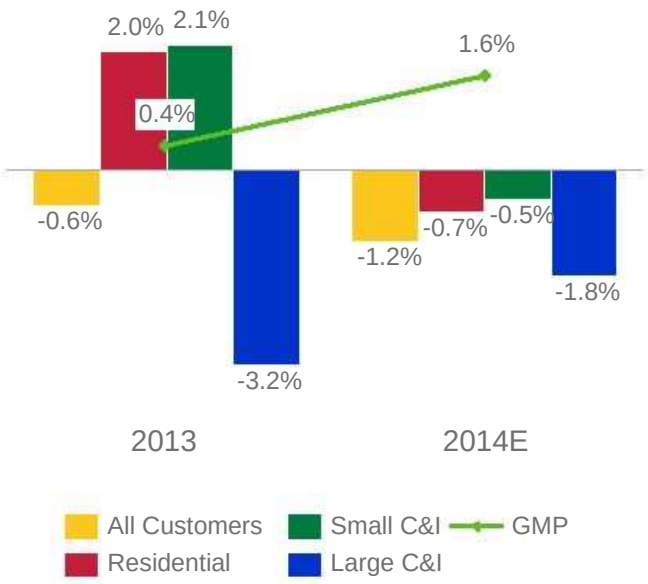

Economic Forecast of Drivers that Influence Load

Driver or Indicator	2015 Outlook
Gross Metro Product (GMP)	GMP is projected to grow at 2.6% for 2015
Employment	2.1% growth projected. BGE's decoupled non-rate case revenue growth is primarily driven by customer growth. The main driver for customer growth is employment
Manufacturing	Manufacturing employment is expected to be fairly flat to 2014 levels in 2015
Households	Household growth is projected to be 0.8%, almost flat to 2014
Energy Efficiency	Continued expansion of EE programs will partially offset growth seen due to improvements in economic conditions

Moderately strong economic recovery will drive sales in 2015, partially offset by energy efficiency initiatives

Notes: 2013 data is not adjusted for leap year. Source of 2015 economic outlook data is IHS Economics (September 2014). (C&I = Commercial and Industrial)

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PHI Acquisition

S1-SSA-0009 - 10254

Delivering Value to PHI's Customers and Communities

Joining a family of large urban utilities with distinguished emergency response capabilities will benefit PHI utilities and their customers during major storms, while helping to reduce costs

Exelon will provide **$100 million** for a Customer Investment Fund to be utilized across the PHI utilities' service territories as each public service commission deems appropriate for customer benefits

Exelon shares PHI's commitment to the local communities it serves. Exelon has committed to provide **$50 million** over 10 years to charitable organizations and programs in the communities the PHI utilities serve – exceeding PHI's 2013 contribution levels

Combined with reliability improvement projects already announced by PHI and underway (including the project to bury distribution lines in Washington, D.C.), the merger commitments are expected to produce approximately 11,000 to 14,000 new indirect jobs in the region and between **$1.0 billion to $1.3 billion** in benefits to the economies of Delaware, Maryland, New Jersey and Washington, D.C.

PHI Acquisition Will Create the Leading Mid-Atlantic Utility

Operating Statistics

Exelon. | Pepco Holdings Inc

Commonwealth Edison	
Customers:	3,800,000
Service Territory:	11,400 sq. miles
Peak Load:	23,753 MW
2013 Rate Base:	$8.7 bn

Potomac Electric Power	
Customers:	801,000
Service Territory:	640 sq. miles
Peak Load:	6,674 MW
2013 Rate Base:	$3.4 bn

PECO Energy	
Customers:	2,100,000
Service Territory:	2,100 sq. miles
Peak Load:	8,983 MW
2013 Rate Base:	$5.4 bn

Atlantic City Electric	
Customers:	545,000
Service Territory:	2,700 sq. miles
Peak Load:	2,797 MW
2013 Rate Base:	$1.6 bn

Baltimore Gas & Electric	
Customers:	1,900,000
Service Territory:	2,300 sq. miles
Peak Load:	7,236 MW
2013 Rate Base:	$4.6 bn

Delmarva Power & Light	
Customers:	632,000
Service Territory:	5,000 sq. miles
Peak Load:	4,121 MW
2013 Rate Base:	$2.0 bn

Source: Company filings.
Note: Operational statistics as of 12/31/2013

Combined Service Territory

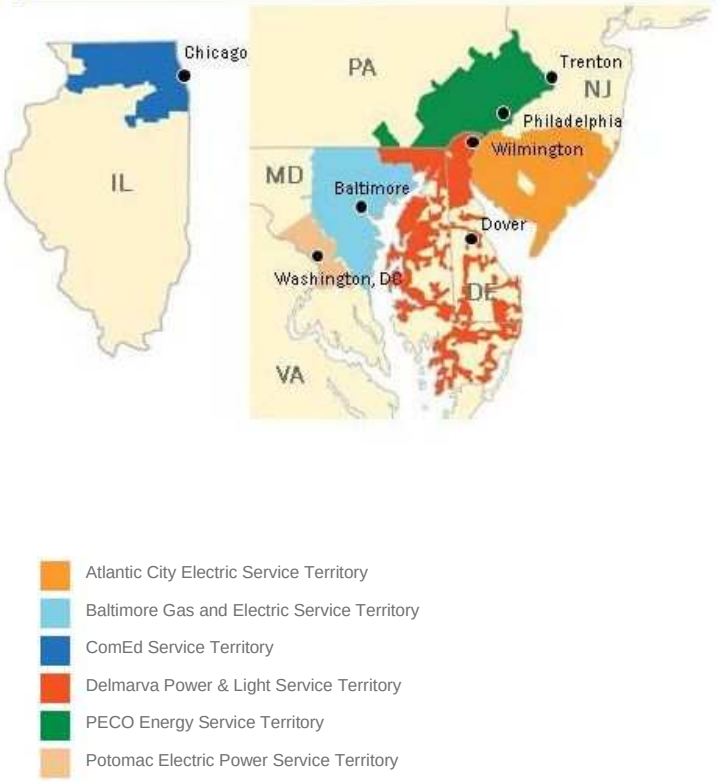

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Transaction Economics

Earnings Accretive First Full Year[1]

Rate Base Growth ($B)[2]

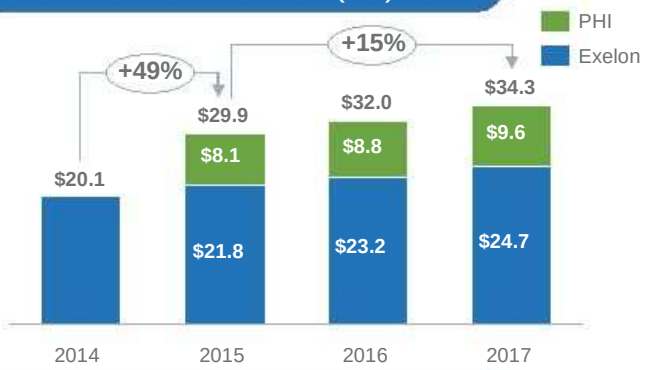

Exelon Consolidated S&P FFO/Debt

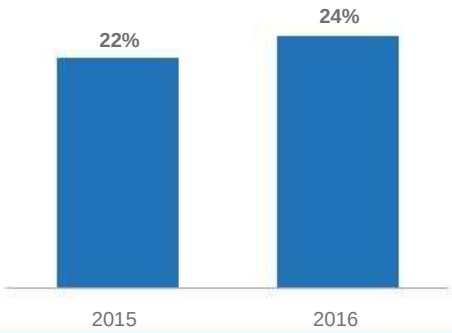

2016-2017 Operating Earnings

Pro Forma Business Mix

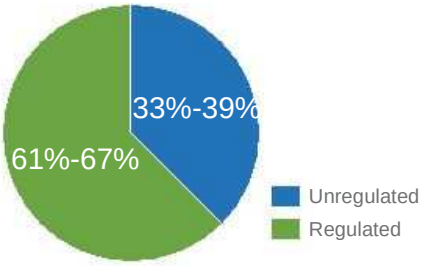

The transaction is EPS accretive, adds to rate base growth and further strengthens our financials

(1) Assumes funding mix of assumed debt, new debt, asset sales and equity issuance with appropriate discount to market price. (2) Reflects year end rate base

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PHI: Capital Expenditures and Rate Base

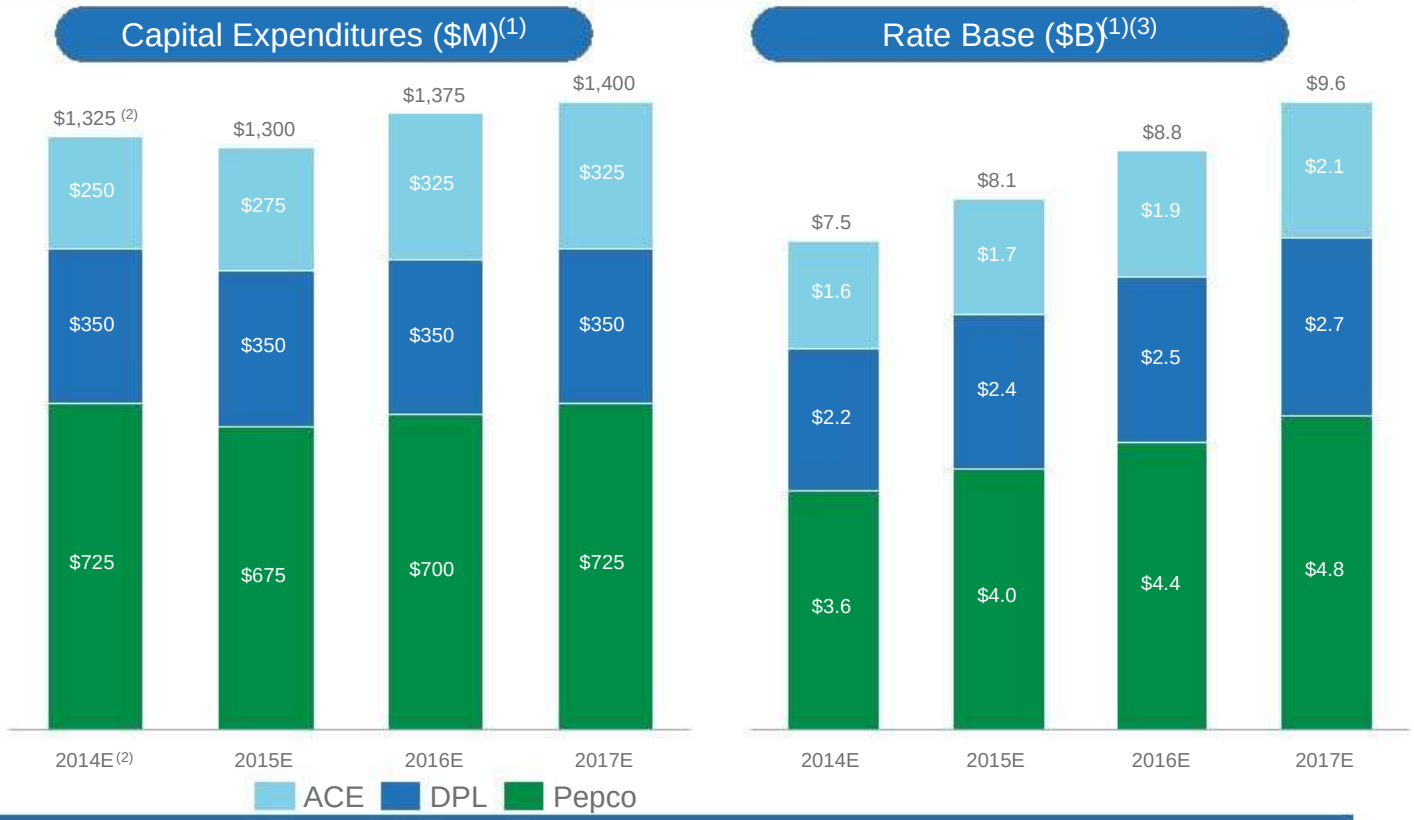

Strong rate base growth will provide stable utility earnings growth

(1) Source: PHI Third Quarter Earnings Materials 10/31/14
(2) Source for 2014 CapEx is PHI 2014 Analyst Day Conference Presentation 03/21/14 and PHI First Quarter 2014 Earnings Materials 05/07/14
(3) Denotes year end rate base
Note: CapEx numbers rounded to nearest $25M; totals might not add due to rounding

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Opportunity for ROE Improvement at PHI Utilities

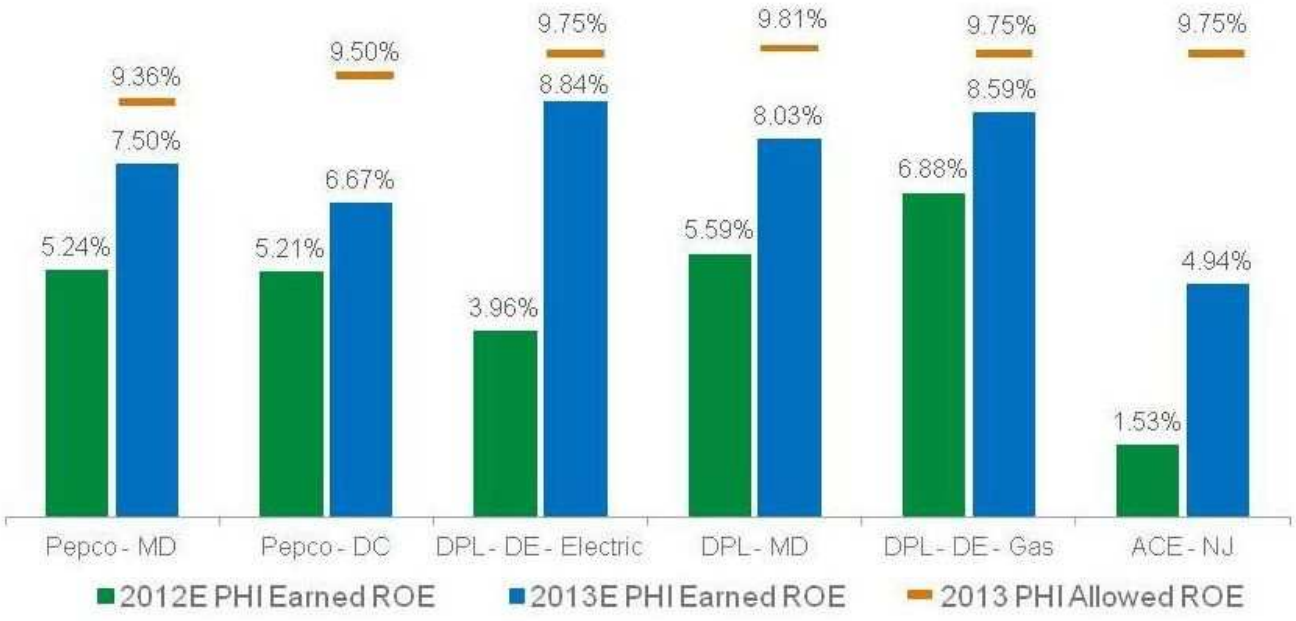

Source: Pepco Holdings Inc. 2014 Analyst Conference Presentation, 3/21/14

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Regulatory Approval Timeline Supports a Q2/Q3 2015 Close

Jurisdiction	Application Filing	Key Regulatory Milestones	Approved
Virginia (Case No. PUE-2014-00048)	3-Jun	Approved October 7, 2015	✓
Federal Energy Regulatory Commission (FERC) (Docket No. EC14-96-000)	30-May		
Department of Justice (DOJ)	6-Aug	Request for additional information received October 9	
Delaware (Docket 14-193)	18-Jun	Pre-Hearing Briefs: Feb 11, 2015 Hearings: Feb 18 20, 2015 Final Order: Mar 10, 2015	
New Jersey (Docket No. EM14060581)	18-Jun	Hearings: Jan 12 16, 2015 Briefs: Feb 6, 2015 Reply Briefs: March 3, 2015	
Maryland (Case No 9361)	19-Aug	Hearings: Jan 26 Feb 6, 2015 Briefs: Feb 27, 2015 Reply Briefs: March 13, 2015 Statutory Deadline: April 1, 2015	
District of Columbia (Formal Case No. 1119)	18-Jun	Hearings: Feb 9 13, 2015 Briefs: March 12, 2015 Reply Briefs: March 26, 2015	

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Constellation℠
An Exelon Company

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Commercial Business Overview

Scale, Scope and Flexibility Across the Energy Value Chain

Development and exploration of natural gas and liquids properties

9 assets in six states

~165 BCFe of proved Reserves[1]

Leading merchant power generation portfolio in the U.S.

~32 GW of owned generation capacity[2]

Clean portfolio, well positioned for evolving regulatory requirements

Industry-leading wholesale and retail sales and marketing platform

~150 TWh of load and ~500 BCF of retail gas delivered[3]

~ 1 million residential and 100,000 business and public sector customers

One of the largest and most experienced Energy Management providers

Over 4,000 energy savings projects implemented across the U.S.

A growing Distributed Energy platform with over $1B of investment to date

Benefiting from scale, scope and flexibility across the value chain

(1) 12/31/13 year-end reserves based upon assets owned as of 9/30/14 . Includes Natural Gas (NG), NG Liquids (NGL) and Oil. NG and Oil are converted to BCFe at a ratio of 6:1.
(2) Total owned generation capacity as of 9/30/2014, less capacity for announced divestitures of Fore River, Quail Run, West Valley, and Keystone Conemaugh
(3) Expected for 2014 as of 9/30/2014. Electric load and gas includes fixed price and indexed products
Note: Does not include the impact of Integrys acquisition

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Generation to Load Match

Generation Capacity, Expected Generation and Expected Load

2015 in TWH[1,2]

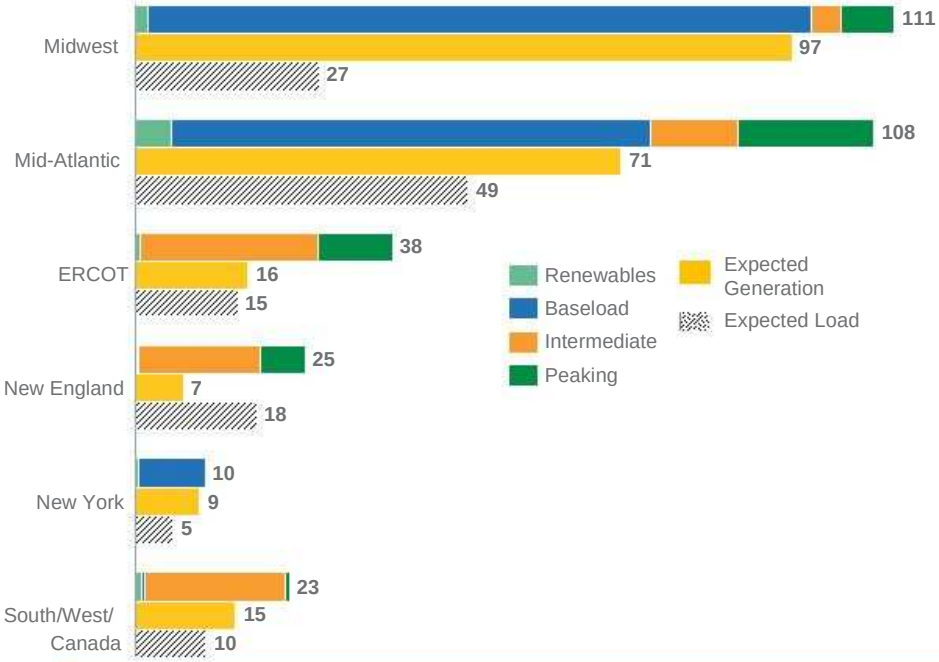

Generation to Load match provides portfolio management benefits in differing volatility and price environments

- During the first quarter, our nuclear baseload generation fleet, in combination with our dispatchable fleet, allowed us to take advantage of the high volatility/price environment while managing load obligations
- During the third quarter, we were able to realize lower costs to serve our load due to the low volatility/price environment

Industry-leading platform with regional diversification of the generation fleet and customer-facing load business

(1) Owned and contracted generation capacity converted from MW to MWh assuming 100% capacity factor (CF) for all technology types, except for renewable capacity which is shown at estimated CF
(2) Expected generation and load shown in the chart above will not tie out with load volume and ExGen disclosures; Load shown above does not include indexed products and generation reflects a net owned and contracted position; Estimates as of 9/30/2014

Note: Includes divestitures for Safe Harbor, Fore River, Quail Run, and West Valley; Does not include impact of Keystone/Conemaugh divestiture or the Integrys acquisition

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Electric Load Serving Business: Growth Targets(1)

Commercial Load

2014 – 2017 TWh

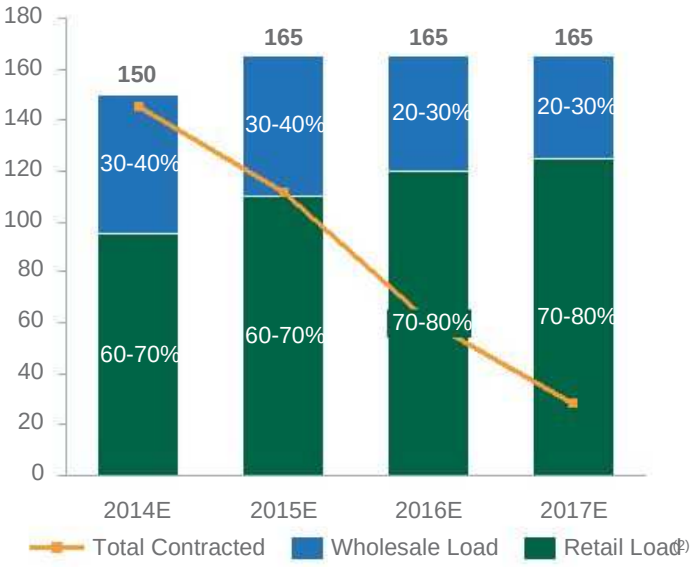

Note: Index load expected to be 20% to 30% of total forecasted retail load

Expected growth in volumes and margins on the back of a sustainable platform

Load Split by Customer Class

(2014 TWh)

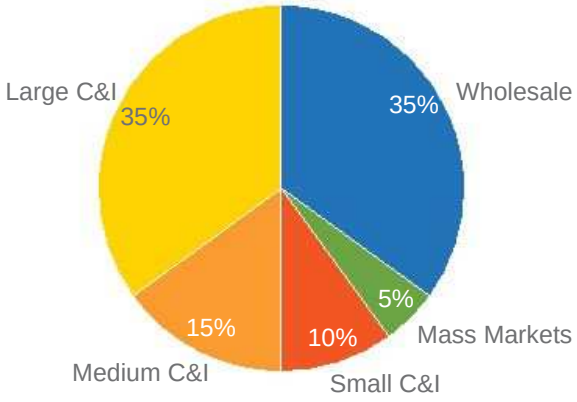

C&I = Commercial & Industrial

Customer Type	Load Size
Mass Markets	<1,000 MWhs per year
Small C&I	1,001-5,000 MWhs per year
Medium C&I	5,001-25,000 MWhs per year
Large C&I	>25,000 MWhs per year

A diverse set of customers enhances portfolio management opportunities

(1) Does not include Integrys acquisition

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Electric Load Serving Business: Market Landscape

Constellation Active Retail Electric Markets (1)

Total U.S. Power Market 2014 (~3,700 TWh load) (2)

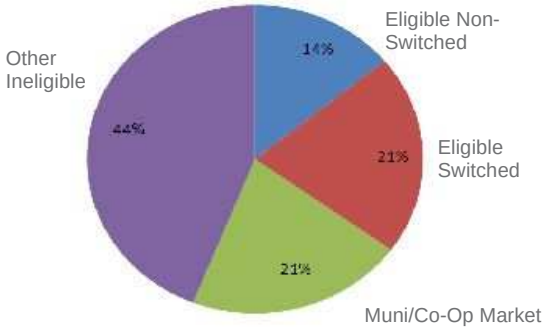

Market Landscape (2)

Conditions have improved in many markets as impacts of the Polar Vortex have played out

- During 2014, we have experienced improved margins, contract tenors, and renewal rates

Competitive Retail Market Expected to Grow Faster Than Overall Market 2014-2017

- Underlying 1% load growth across the U.S.
- C&I switched market to grow by about 8%
- Residential switched market to grow by about 7%

Retail Mergers & Acquisitions Activity has Increased

- EXC has been active in evaluating opportunities, and acquired Integrys Energy Services earlier this year
- 34 deals announced 2014 YTD, compared to 27 deals in 2013, and 23 deals in 2012

Existing suppliers continue to expand market footprint and product portfolio

- Existing suppliers entered 23 new markets in 2014 YTD
- Energy efficiency among most popular for cross-selling opportunities

Improving market driving higher margins and better contract terms

(1) Does not include Integrys acquisition (2) Sources are EIA, DNV GL, and internal estimates

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Natural Gas Serving Business: Marketing Platform

Constellation Active Natural Gas Markets

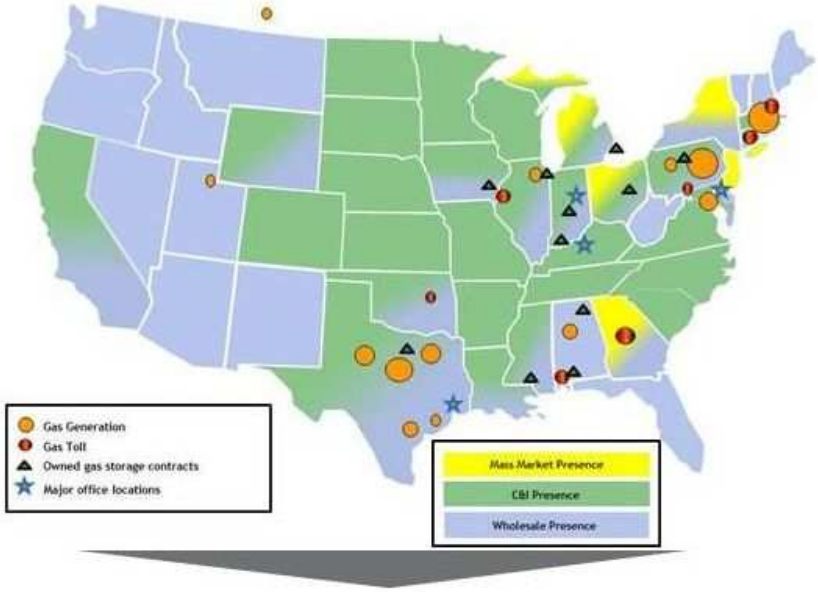

Supply	~4-6 Bcf per day delivered in competitive markets
Transportation	Active shipper on more than 45 interstate pipelines on a daily basis
Trading	Active participant in all major supply basins, markets, and trading points in North America
Volume Management	Schedule, nominate and balance behind more than 100 LDCs

Market Landscape 2014 -2015(1)

The Polar Vortex provided multiple supply opportunities across the US for natural gas

Nature Gas markets continue to grow on both the consumption and supply side

- Lead by the industrial section, gas consumption is expected to increase by 1.6% in 2014
- EXC expanded it's gas marketing presence through the Integyrs and ETC ProLiance acquisitions

Growing domestic production impacting imports

- Continued downward pressure on natural gas imports from Canada
- Mexican exports, specifically from Eagle Ford, are expected to increase due to growing demand in the electric power sector

LNG imports and exports

- Higher prices in Europe and Asia more attractive to sellers than low US prices
- LNG exports are still a very small part of the total picture; however, the United States will remain a net importer of natural gas because of pipeline imports from Canada

Gas Storage and Pipeline Investment

- Gas inventories continue to drop year over year. Currently 373 BCF lower than last year driving storage opportunities
- Investment in new pipelines supporting key production areas continue grow supported by multiple parties (Equity, LDCs)

Top 10 US Gas Marketer with a growing presence

(1) Source: EIA and internal estimates

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Integrys Energy Services Acquisition

Increases Gas and Power Scale

- Significantly increases natural gas portfolio by 150 bcf annually
- Increases power load by 15 TWh

Generation to Load Matching

- Many of the power customers served by Integrys are in regions where Exelon owns significant generation, providing generation to load match benefit
- Mitigates risk of hedging in illiquid markets

Customers

- Adds 1.2 million customers, bringing the total Constellation customer base to approximately 2.5 million homes and businesses

integrys energy services

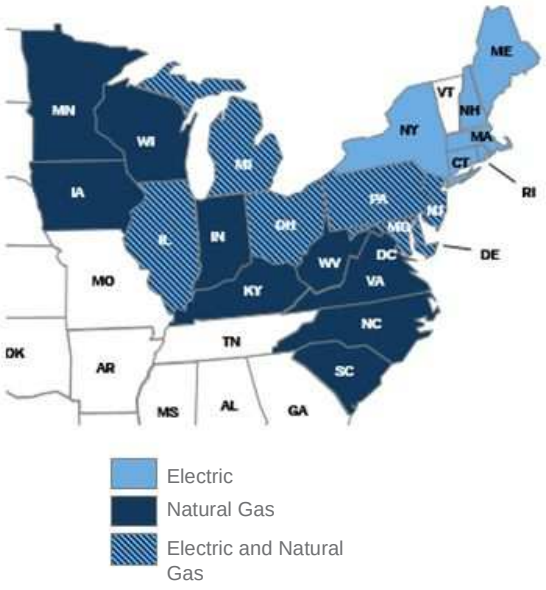

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Upstream E&P Assets

Investment Thesis

- Our Upstream Gas business achieves strong returns (>16% after-tax IRR)
- $110m (~70% utilized) Reserve Based Lending (RBL) facility in place
  - Non-recourse treatment at S&P
- Provides valuable market intelligence in complex natural gas markets

Forecasted Production

	2014	2015	2016	2017
Net Daily Prod (MMcfe / day)	50-55	40-55	35-50	40-55

Current Portfolio Of Investments

Mississippi Lime (OK)
Hunton Dewatering (OK)
Woodford Shale (OK)
Fayetteville Shale (AR)
Haynesville Shale (LA)
Floyd Shale (AL)
Woodbine Shale (TX)
Trenton Black River (MI)
Barnett Shale (TX)

Estimated Net Proved Reserves (as of 12/31/13) (1)	Average Net Daily Production (as of Q2 2014)
165 Bcfe	55 MMcfe

(1) 12/31/13 year-end reserves based upon assets owned as-of 9/30/14.

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Mid-Atlantic Gas Basis: Improves Starting 2017

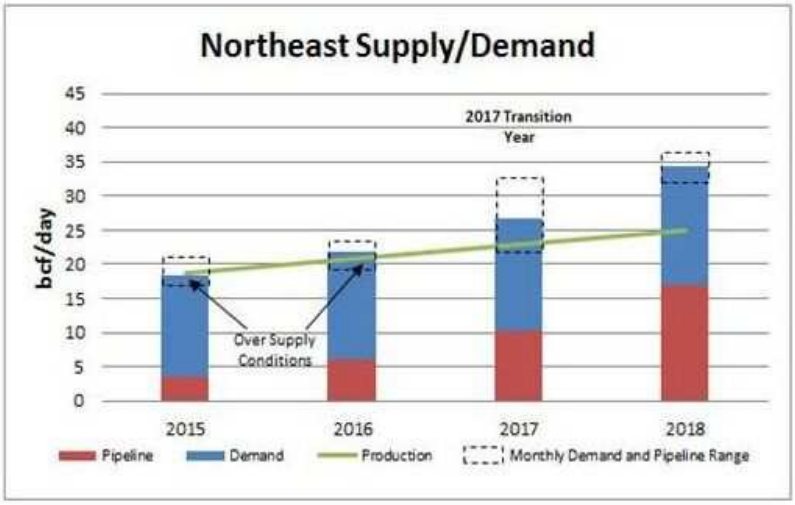

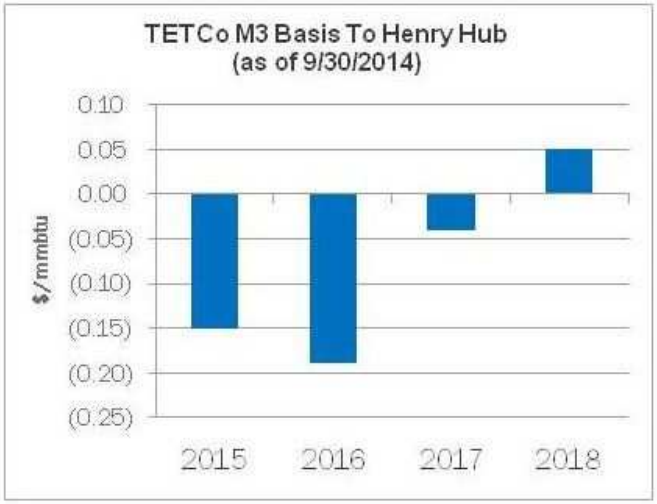

- Northeastern U.S. gas production is projected to approach 25 bcf/day by 2018, up from 19 bcf/day in 2015
- Regional demand is projected to reach 18 bcf/day by 2018, up from 15 bcf/day in 2015
- Based upon public announcements, we expect 19 bcf/day of pipeline takeaway capacity by 2018
- Pipeline projects are underway adding takeaway capacity. 2017 is a transition year where timing of pipeline expansions (~9 bcf/day) will play a role in determining local gas prices, but should be more balanced than in prior years. This is consistent with the current forward market which indicates an improving Mid-Atlantic natural gas basis
- Additional pipeline capacity and regional demand will stabilize basis discounts in non winter months and reduce price spikes in the winter

Pipeline capacity expansions and regional demand should balance higher gas production starting in mid-2017, improving Mid-Atlantic gas basis

Notes: Values represent annual averages; Demand includes storage

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Northeast Gas Pipeline Expansion Projects

Pipeline	Project	Estimated Inservice Date	States	Volume (MCF/day)	Cumulative Volume
ANR	ANR Lebanon Lateral	Jan-14	OH	350	350
Tennessee Gas Pipeline	Utica Backhaul	Apr-14	PA -> LA	500	850
Rockies Express Pipeline	Rockies Express Pipeline Reversal	Jun-14	OH	200	1,050
Columbia Gas Transmission	Smithfield III (West Side Expansion)	Nov-14	PA, WV -> KY	444	1,494
TETCO	TEAM South	Nov-14	PA, OH South	300	1,794
TETCO	TEAM 2014	Nov-14	PA, OH South	300	2,094
Dominion	Western Access (Natrium to Market) *	Nov-14	OH	300	2,094
Rockies Express Pipeline	Reversal II (Antero)	Jan-15	OH -> IL	400	2,494
Rockies Express Pipeline	Reversal III (Market)	Jun-15	OH -> IL	1,200	3,694
TETCO	Ohio Pipeline Energy Network (OPEN)	Nov-15	OH	550	4,244
TETCO	Uniontown to Gas City	Nov-15	PA, OH, IN	425	4,669
ANR	ANR Glen Karn 2015 *	Nov-15	OH	400	4,669
Tennessee Gas Pipeline	Niagara Expansion	Nov-15	NY -> CAN	158	4,827
National Fuel Gas	Northern Access *	Nov-15	NY -> CAN	140	4,827
Tennessee Gas Pipeline	Broad Run Flexibility	Nov-15	WV -> LA	590	5,417
Transco	Leidy Southeast	Dec-15	PA, NJ	525	5,942
TETCO	Gulf Market Expansion	Nov-16	OH -> LA	350	6,292
National Fuel Gas	Northern Access 2016	Nov-16	NY -> CAN	250	6,542
Energy Transfer Partners	Rover ^	Jun-17	PA -> MI, CAN	2,200	8,742
Columbia Gas Transmission	Cameron Access Project	Jul-17	KY -> LA	800	9,542
Transco	Atlantic Sunrise	Jul-17	PA -> AL	1,700	11,242
Tennessee Gas Pipeline	Southwest Louisiana Supply	Jul-17	OH, PA -> LA	900	12,142
Spectra Energy	NEXUS Gas Transmission ^	Nov-17	OH, MI	1,000	13,142
Columbia Gas Transmission	Rayne XPress	Nov-17	KY to LA	600	13,742
Rockies Express Pipeline	Expansion IV ^	Nov-17	OH -> IL	1,000	14,742
TETCO	Adair Southwest	Nov-17	OH -> TN	200	14,942
TETCO	Access South	Nov-17	OH -> MS	320	15,262
Transco	Dalton Expansion	Nov-17	NJ -> GA	448	15,710
Tennessee Gas Pipeline	Broad Run Expansion	Nov-17	WV -> LA	200	15,910
Dominion	Atlantic Coast Pipeline %	Jul-18	WV -> NC	1,500	17,410
Transco	Western Marcellus Pipeline %	Nov-18	WV -> NC	1,500	18,910

**Note: Western Access, Glen Karn & Northern Access are complementary to Lebanon, Union Gas City, and Niagara Expansion*

^, % Note: Competing projects

Almost 19 bcf/day of pipeline expansion projects have been announced for completion by the end of 2018

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Power Markets - NiHub

Forward markets continued their upward trend through 2014

- During 2014, strong spot prices have started to reflect the changing nature of the grid in PJM and new reliance on different resources such as NG supply, demand response, and oil peakers
- As a result, we have seen stronger forward power and heat rate curves
- Our portfolio is positioned to take advantage of expected volatility and power price upside
  - 2015 seasonal upside in the second half of the year, especially at NIHUB off peak
  - 2016-2017 average upside of $2-$3/MWh

Expect continued volatility due to incremental coal retirements in the second half of 2015

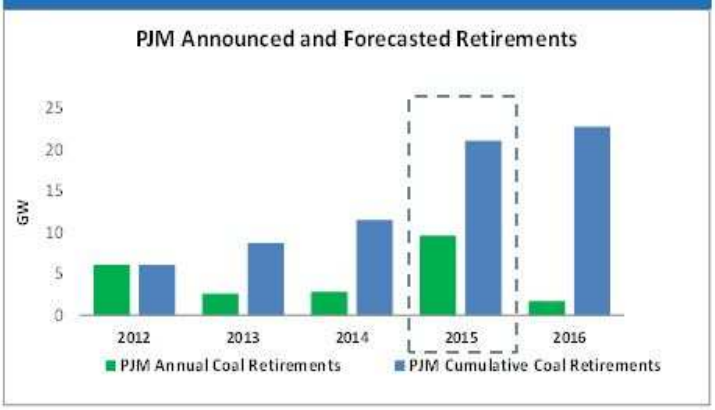

$2-$3/MWh power price upside in 2016-2017 due to higher dispatch costs and a modest increase in load

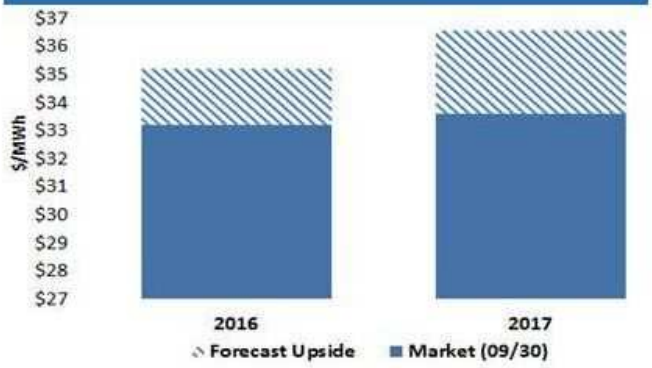

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Capacity Markets

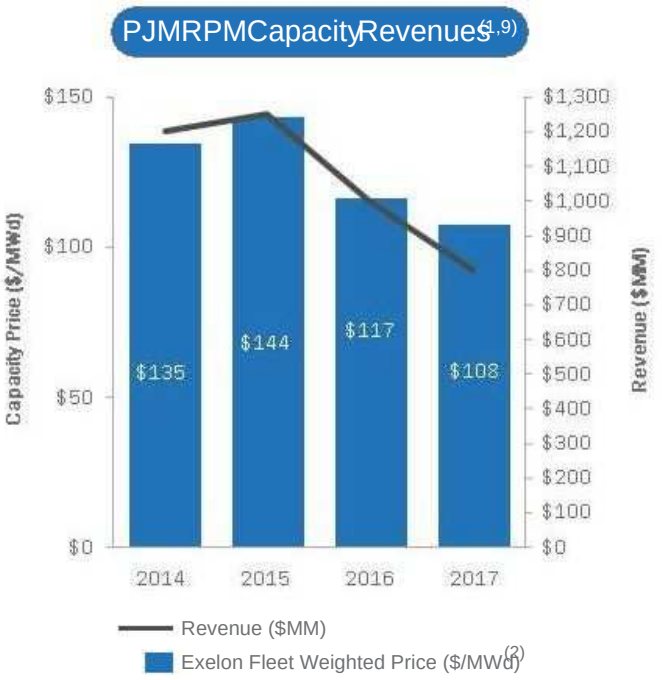

		2013/ 2014	2014/ 2015	2015/ 2016	2016/ 2017	2017/ 2018
PJM (3,8,9)						
ComEd	*Capacity*	N/A	N/A	N/A	N/A	10,900
	Price	N/A	N/A	N/A	N/A	$120
RTO	*Capacity*	11,500	11,500	11,500	11,250	0
	Price	$28	$126	$136	$59	$120
EMAAC	*Capacity (4)*	8,900	8,900	8,900	8,900	8,300
	Price	$245	$137	$168	$119	$120
MAAC	*Capacity (5)*	2,300	2,300	2,300	2,300	2,300
	Price	$226	$137	$168	$119	$120
SWMAAC	*Capacity (6)*	1,800	1,800	1,800	1,800	900
	Price	$226	$137	$168	$119	$120
BGE	*Capacity*	N/A	N/A	N/A	N/A	900
	Price	N/A	N/A	N/A	N/A	$120
Average Exelon		*$140*	*$132*	*$153*	*$91*	*$120*
New England (7)						
NEMA	*Capacity*	2,100	2,100	2,100	2,100	2,100
	Price	$98	$107	$114	$219	$493
Rest of Pool	*Capacity*	735	445	35	35	35
	Price	$85 (8)	$95 (8)	$104 (8)	$90	$231
NYISO (9)						
Rest of Pool	*Capacity*	1,100	1,100	1,100	1,100	1,100
MISO (10)						
AMIL	*Capacity*	1,100	1,100	1,100	1,100	1,100
	Price	N/A	N/A	N/A	1	17

(1) Revenues reflect capacity cleared in base and incremental auctions and are for calendar years. Revenue rounded to nearest $50M
(2) Weighted average $/MW-Day would apply if all owned generation cleared
(3) Reflects owned and contracted generation Installed Capacity (ICAP) adjusted for mid-year PPA roll offs
(4) ICAP is net of Eddystone 1&2, Cromby 1&2 and Schuykill 1 (total ~ 1,100 MW)
(5) ICAP is net of Safe Harbor divestiture (total ~300 MW); Impact of Keystone Conemaugh diestiture not included
(6) ICAP is net of units divested (Brandon Shores, Wagner & Crane ~2,648 MW; and Riverside 6 CT (~115MW)
(7) Reflects Qualified Summer Capacity including owned and contracted units; excludes Fore River after 14/15
(8) Price is pro-rated for auctions that clear at the floor price and there is more capacity procured than suggested by the reliability requirement
(9) Reflects 50.01% ownership in CENG
(10) Does not include wind under PPA

RTO = Regional Transmission Organization, MAAC = Mid-Atlantic Area Council, EMAAC = Eastern Mid-Atlantic Area Council, SWMAAC = South West Mid-Atlantic Area Council, NEMA = North East Massachusetts; SEMA = Southeast Massachusetts, AMIL = Ameren Illinois.

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PJM – Working to Address Reliability

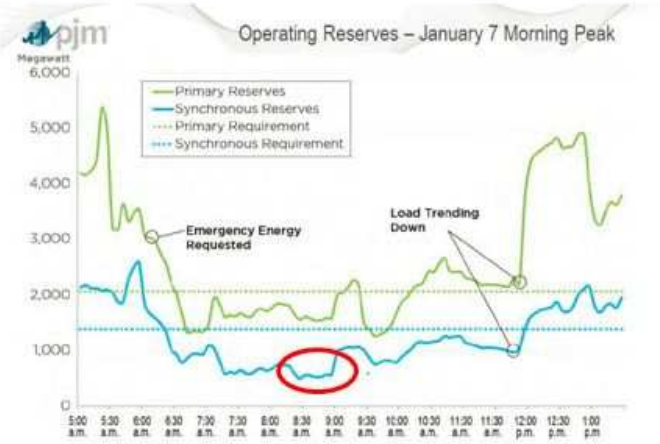

Source: PJM Interconnection, "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather" May 9, 2014, slide 10.

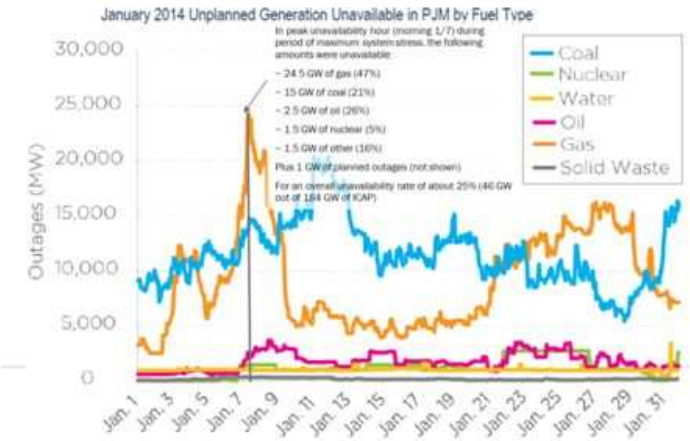

Source: PJM Interconnection, Response to Committee Questions of U.S. House of Representatives Committee on Energy and Commerce, April 18, 2014, Figure 4.

The polar vortex in the winter of 2014 highlighted generator reliability concerns that PJM is now working to address

Source: Northbridge Analysis based on PJM data

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PJM's Proposed Solution - Capacity Performance Proposal

- PJM recognizes that generation resources procured through its existing forward capacity market (RPM) may not be sufficient to meet future load conditions, especially winter peak
  - Additionally, current revenues and penalty structures are insufficient to provide incentives for necessary investment to maintain highly available capacity
- PJM released a revised "Capacity Performance" proposal on October 7, 2014 revamping initial reform concepts suggested in August
  - The Capacity Performance concept reforms are intended to encourage commitment of capacity resources that have secure fuel and other performance characteristics to provide PJM confidence that units will be available when dispatched to meet peak summer and winter load
  - PJM proposes to increase the capacity market offer cap to Net CONE, and to substantially raise penalties for performance failure
  - PJM suggests transition mechanisms for delivery years in which it has already made forward capacity procurements (2015-16, 2016-17, and 2017-18)
  - PJM proposes a method of integrating "wholesale" demand response through PJM Load Serving Entities in a manner that would clear by adjusting the RPM demand curve

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Capacity Performance Impact on PJM Fleet

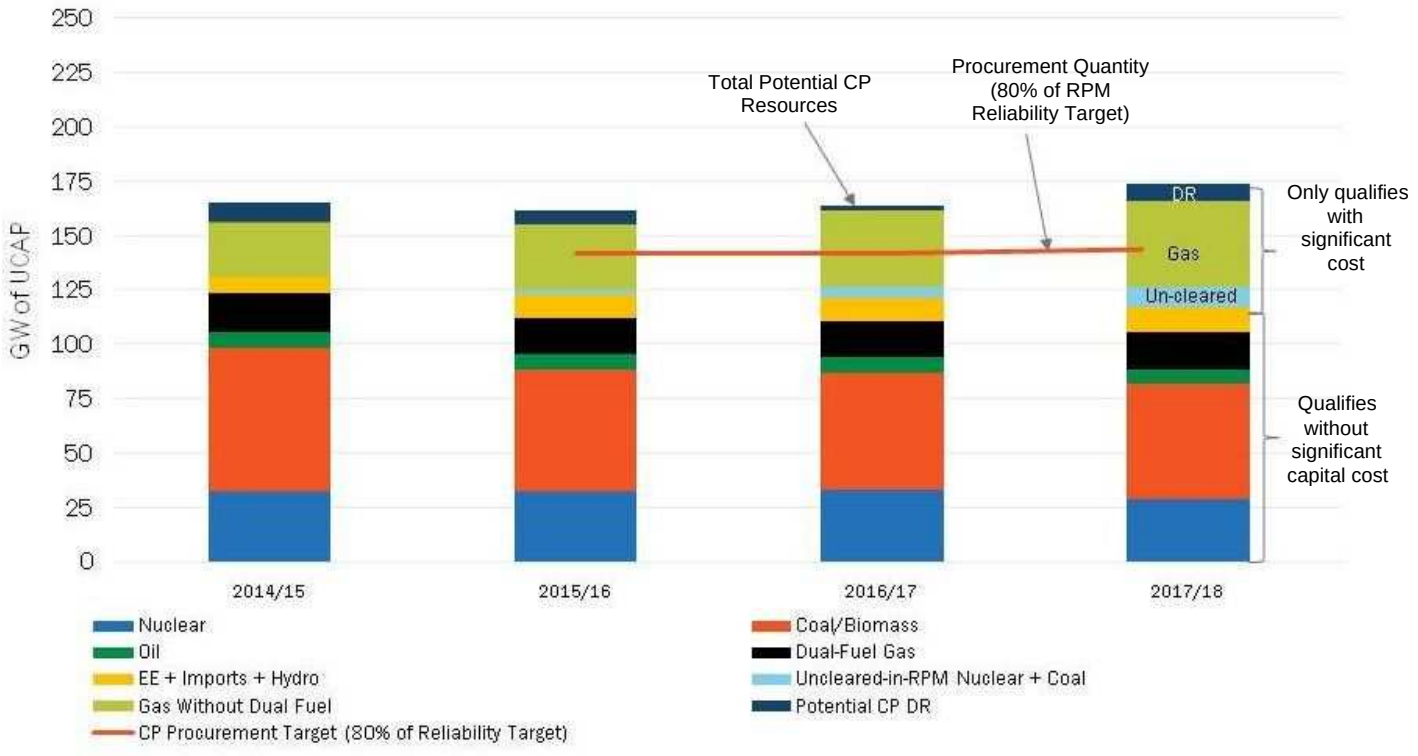

Exelon's fleet is well positioned to benefit from Capacity Performance due to significant investment in reliability

Source: NorthBridge Analysis; Includes FRR resources/Loads; PJM proposal is to fully procure CP for 2016/17 and 2017/18 but to incrementally procure up to 10 GW of base capacity for 2015/16; Potential 2015/16 all-in CP procurement quantity shown for comparison purposes

Exelon.

Exelon Generation Disclosures

As of September 30, 2014

Portfolio Management Strategy

Strategic Policy Alignment

- Aligns hedging program with financial policies and financial outlook
- Establish minimum hedge targets to meet financial objectives of the company (dividend, investment-grade credit rating)
- Hedge enough commodity risk to meet future cash requirements under a stress scenario

Three-Year Ratable Hedging

- Ensure stability in near-term cash flows and earnings
- Disciplined approach to hedging
- Tenor aligns with customer preferences and market liquidity
- Multiple channels to market that allow us to maximize margins
- Large open position in outer years to benefit from price upside

Bull / Bear Program

- Ability to exercise fundamental market views to create value within the ratable framework
  - Modified timing of hedges versus purely ratable
  - Cross-commodity hedging (heat rate positions, options, etc.)
  - Delivery locations, regional and zonal spread relationships

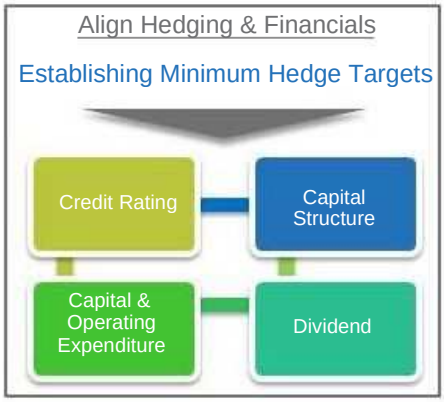

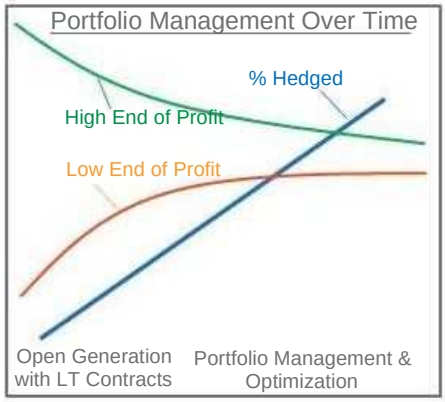

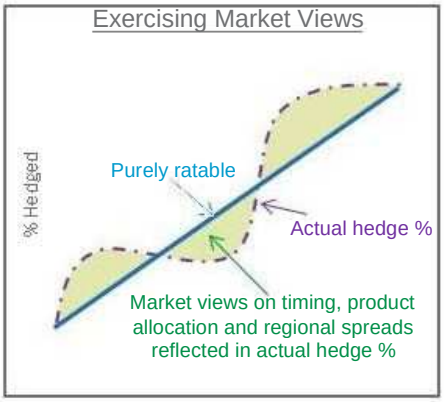

Protect Balance Sheet | **Ensure Earnings Stability** | **Create Value**

Note: Hedge strategy has not changed as a result of recent and pending asset divestitures

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Components of Gross Margin Categories

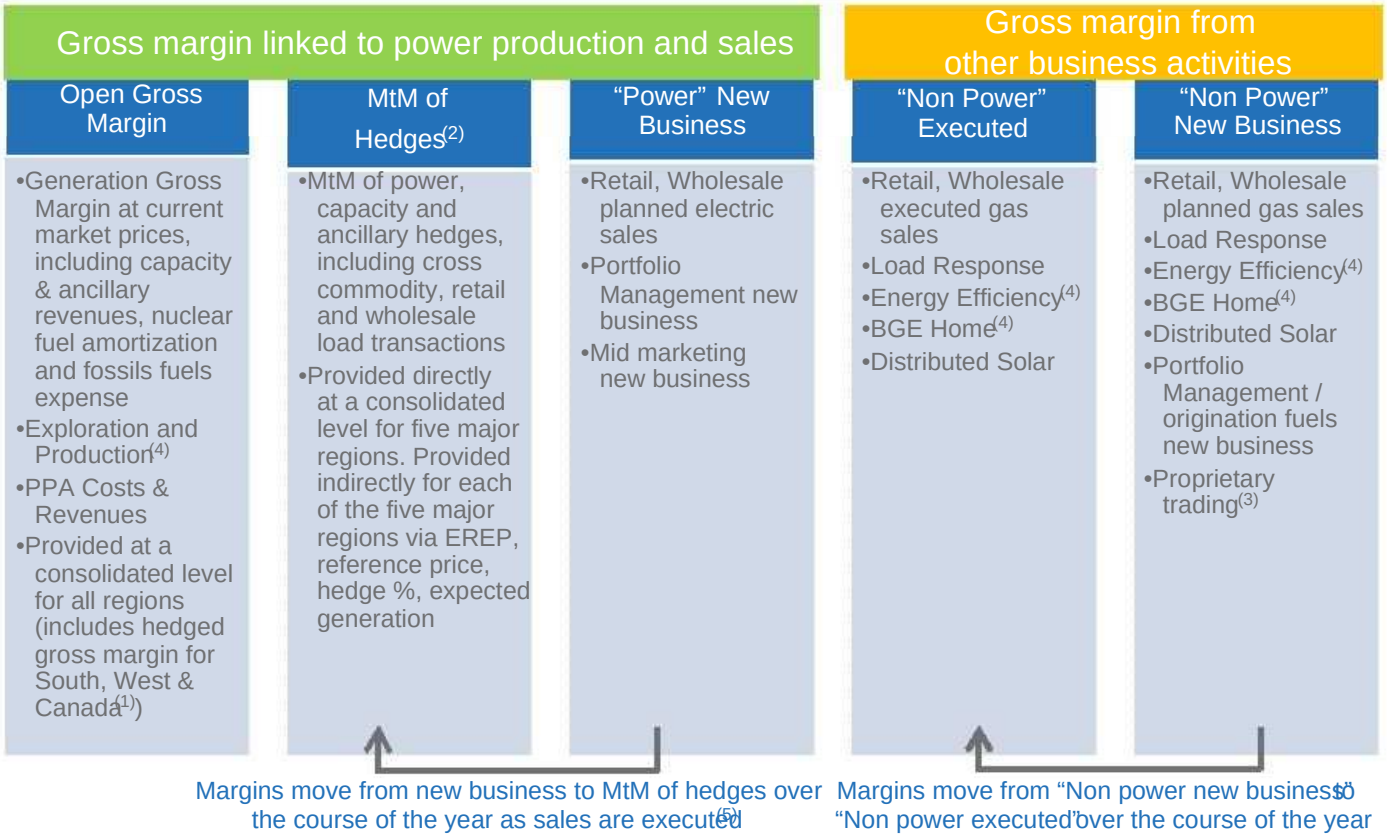

(1) Hedged gross margins for South, West & Canada region will be included with Open Gross Margin and no expected generation, hedge %, EREP or reference prices provided for this region
(2) MtM of hedges provided directly for the five larger regions; MtM of hedges is not provided directly at the regional level but can be easily estimated using EREP, reference price and hedged MWh
(3) Proprietary trading gross margins will generally remain within "Non Power" New Business category and only move to "Non Power" Executed category upon management discretion
(4) Gross margin for these businesses are net of direct "cost of sales"
(5) Margins for South, West & Canada regions and optimization of fuel and PPA activities captured in Open Gross Margin

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ExGen Disclosures

Gross Margin Category ($M)[1]	2014	2015	2016	2017
Open Gross Margin (including South, West & Canada hedged GM)[6]	7,300	6,750	6,500	6,650
Mark to Market of Hedges[3,4]	(350)	-	150	150
Power New Business / To Go	50	400	550	750
Non-Power Margins Executed	350	100	50	50
Non-Power New Business / To Go	50	300	350	350
Total Gross Margin[2,6]	**7,400**	**7,550**	**7,600**	**7,950**

Reference Prices[5]	2014	2015	2016	2017
Henry Hub Natural Gas ($/MMbtu)	$4.44	$4.00	$4.08	$4.22
Midwest: NiHub ATC prices ($/MWh)	$39.45	$33.70	$33.21	$33.62
Mid-Atlantic: PJM-W ATC prices ($/MWh)	$51.38	$42.75	$40.69	$40.06
ERCOT-N ATC Spark Spread ($/MWh) *HSC Gas, 7.2HR, $2.50 VOM*	$3.02	$6.47	$6.14	$6.27
New York: NY Zone A ($/MWh)	$49.00	$42.14	$38.94	$38.37
New England: Mass Hub ATC Spark Spread($/MWh) *ALQN Gas, 7.5HR, $0.50 VOM*	$3.04	$8.95	$7.64	$5.48

(1) Gross margin categories rounded to nearest $50M
(2) Total Gross Margin (Non-GAAP) defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners and variable interest entities. Total Gross Margin is also net of direct cost of sales for certain Constellation businesses.
(3) Excludes EDF's equity ownership share of the CENG Joint Venture
(4) Mark to Market of Hedges assumes mid-point of hedge percentages
(5) Based on September 30, 2014 market conditions
(6) Reflects the divestiture impact of Fore River, Quail Run and West Valley. Does not include divestiture of Keystone/Conemaugh or the Integrys acquisition

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ExGen Disclosures

Generation and Hedges[6]	2014	2015	2016	2017
Exp. Gen (GWh)[1]	205,300	200,800	202,200	205,000
Midwest	97,000	96,600	97,500	95,800
Mid-Atlantic[2]	74,300	71,300	72,100	68,900
ERCOT	11,400	16,400	16,900	25,300
New York[2]	12,700	9,400	9,300	9,300
New England	9,900	7,100	6,400	5,700
% of Expected Generation Hedged[3]	98-101%	86-89%	55-58%	27-30%
Midwest	97-100%	83-86%	49-52%	20-23%
Mid-Atlantic[2]	98-101%	88-91%	55-58%	28-31%
ERCOT	101-104%	99-102%	82-85%	46-49%
New York[2]	98-101%	87-90%	62-65%	42-45%
New England	102-105%	82-85%	62-65%	25-28%
Effective Realized Energy Price ($/MWh)[4]				
Midwest	$36.50	$33.50	$34.50	$36.00
Mid-Atlantic[2]	$48.50	$42.50	$43.00	$46.50
ERCOT[5]	$20.00	$8.50	$5.50	$6.00
New York[2]	$42.50	$42.50	$40.00	$38.50
New England[5]	$6.00	$11.50	$4.50	($2.50)

(1) Expected generation is the volume of energy that best represents our financial exposure through owned or contracted for capacity. Expected generation is based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Expected generation assumes 14 refueling outages in 2014 and 2015, 12 in 2016, and 15 in 2017 at Exelon-operated nuclear plants, and Salem. Expected generation assumes capacity factors of 93.6%, 93.5%, 94.1% and 93.4% in 2014, 2015 , 2016 and 2017 respectively at Exelon-operated nuclear plants, at ownership. These estimates of expected generation in 2015, 2016 and 2017 do not represent guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years. (2) Excludes EDF's equity ownership share of CENG Joint Venture. (3) Percent of expected generation hedged is the amount of equivalent sales divided by expected generation. Includes all hedging products, such as wholesale and retail sales of power, options and swaps. (4) Effective realized energy price is representative of an all-in hedged price, on a per MWh basis, at which expected generation has been hedged. It is developed by considering the energy revenues and costs associated with our hedges and by considering the fossil fuel that has been purchased to lock in margin. It excludes uranium costs and RPM capacity revenue, but includes the mark-to-market value of capacity contracted at prices other than RPM clearing prices including our load obligations. It can be compared with the reference prices used to calculate open gross margin in order to determine the mark-to-market value of Exelon Generation's energy hedges. (5) Spark spreads shown for ERCOT and New England. (6) Reflects the divestiture impact of Fore River, Quail Run and West Valley. Does not include divestitures of Keystone/Conemaugh or the Integrys acquisition

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ExGen Hedged Gross Margin Sensitivities

Gross Margin Sensitivities (With Existing Hedges)[1]	2014	2015	2016	2017
Henry Hub Natural Gas ($/MMbtu)				
+ $1/Mmbtu	$15	$120	$440	$830
- $1/Mmbtu	$10	$(60)	$(400)	$(750)
NiHub ATC Energy Price				
+ $5/MWh	$-	$85	$265	$390
- $5/MWh	$-	$(85)	$(260)	$(390)
PJM-W ATC Energy Price				
+ $5/MWh	$(5)	$30	$165	$260
- $5/MWh	$5	$(25)	$(155)	$(255)
NYPP Zone A ATC Energy Price				
+ $5/MWh	$-	$5	$15	$25
- $5/MWh	$-	$(10)	$(20)	$(25)
Nuclear Capacity Factor				
+/- 1%	+/- $15	+/- $50	+/- $45	+/- $45

(1) Based on September 30, 2014 market conditions and hedged position; Gas price sensitivities are based on an assumed gas-power relationship derived from an internal model that is updated periodically; Power prices sensitivities are derived by adjusting the power price assumption while keeping all other prices inputs constant; Due to correlation of the various assumptions, the hedged gross margin impact calculated by aggregating individual sensitivities may not be equal to the hedged gross margin impact calculated when correlations between the various assumptions are also considered; Sensitivities based on commodity exposure which includes open generation and all committed transactions; Excludes EDF's equity share of CENG Joint Venture; Reflects the divestiture impact of Fore River, Quail Run and West Valley; Does not include divestiture of Keystone/Conemaugh or the Integrys acquisition

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Exelon Generation Hedged Gross Margin Upside/Risk

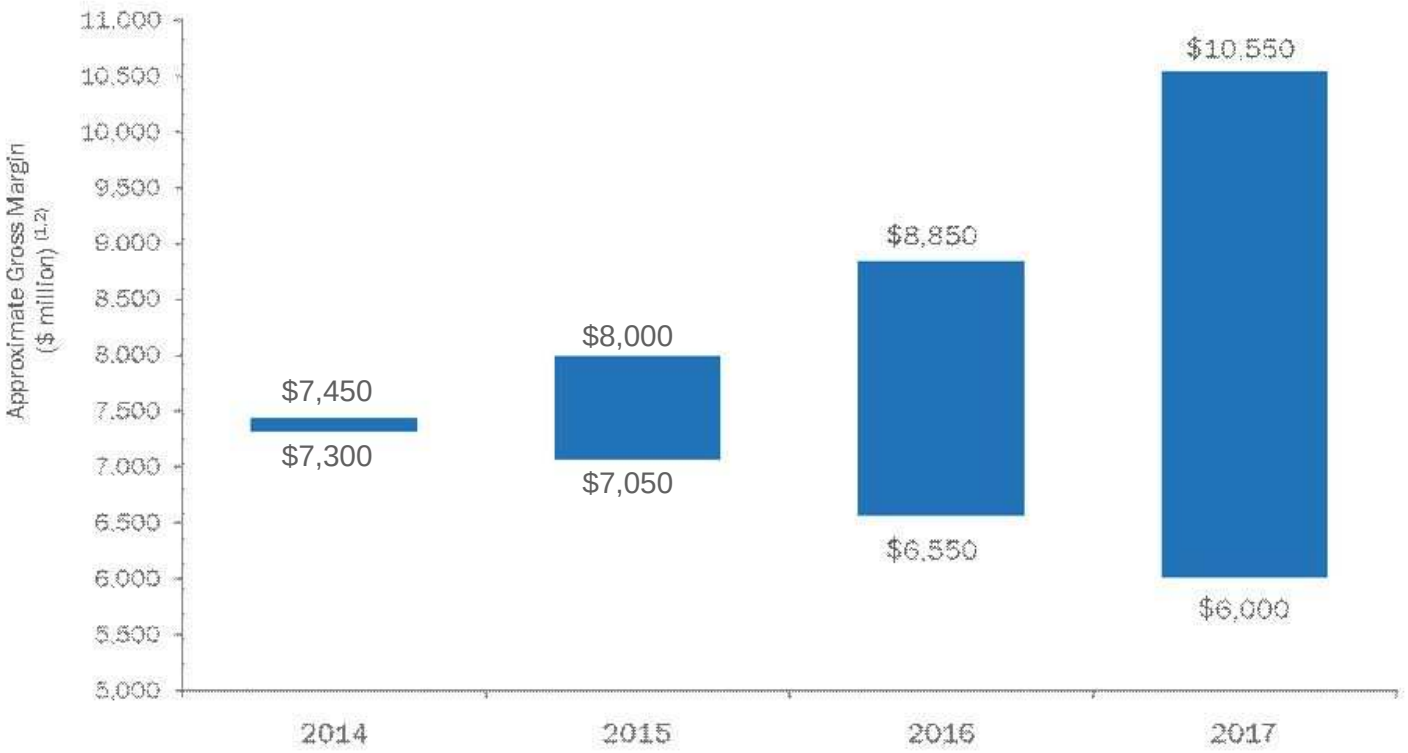

(1) Represents an approximate range of expected gross margin, taking into account hedges in place, between the 5th and 95th percent confidence levels assuming all unhedged supply is sold into the spot market; Approximate gross margin ranges are based upon an internal simulation model and are subject to change based upon market inputs, future transactions and potential modeling changes; These ranges of approximate gross margin in 2015, 2016 and 2017 do not represent earnings guidance or a forecast of future results as Exelon has not completed its planning or optimization processes for those years; The price distributions that generate this range are calibrated to market quotes for power, fuel, load following products, and options as of September 30, 2014

(2) Gross Margin Upside/Risk based on commodity exposure which includes open generation and all committed transactions

Note: Reflects the divestiture impact of Fore River, Quail Run and West Valley; Does not include divestiture of Keystone/Conemaugh or the Integrys acquisition

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Illustrative Example of Modeling Exelon Generation 2015 Gross Margin

Row	Item	Midwest	Mid-Atlantic	ERCOT	New York	New England	South, West & Canada
(A)	Start with fleet-wide open gross margin	← $6.75 billion →					
(B)	Expected Generation (TWh)	97.0	71.3	16.4	9.4	7.1	
(C)	Hedge % (assuming mid-point of range)	84.5%	89.5%	100.5%	88.5%	83.5%	
(D=B*C)	Hedged Volume (TWh)	82.0	63.8	16.4	8.3	5.9	
(E)	Effective Realized Energy Price ($/MWh)	$33.50	$42.50	$8.50	$42.50	$11.50	
(F)	Reference Price ($/MWh)	$33.70	$42.75	$6.47	$42.14	$8.95	
(G=E-F)	Difference ($/MWh)	$(0.20)	$(0.25)	$2.03	$0.36	$2.55	
(H=D*G)	Mark-to-market value of hedges ($ million)(1)	$(15) million	$(15) million	$30 million	$5 million	$15 million	
(I=A+H)	Hedged Gross Margin ($ million)	$6,750 million					
(J)	Power New Business / To Go ($ million)	$400 million					
(K)	Non-Power Margins Executed ($ million)	$100 million					
(L)	Non-Power New Business / To Go ($ million)	$300 million					
(N=I+J+K+L)	Total Gross Margin(2)	$7,550 million					

(1) Mark-to-market rounded to the nearest $5 million
(2) Total Gross Margin (Non-GAAP) is defined as operating revenues less purchased power and fuel expense, excluding revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners and variable interest entities; Total Gross Margin is also net of direct cost of sales for certain Constellation businesses.
Note: Reflects the divestiture impact of Fore River, Quail Run and West Valley; Does not include divestiture of Keystone/Conemaugh

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Generation

Exelon Generation Fleet

National Scope

- Power generation assets in 20 states and Canada
- Low-cost generation capacity provides unparalleled leverage to rising commodity prices

Large and Diverse

- 32 GW of diverse generation[1]
  - 19 GW of Nuclear
  - 8 GW of Gas
  - 2 GW of Hydro
  - 2 GW of Oil
  - 1 GW of Wind/Solar/Other

Clean

- One of nation's cleanest fleets as measured by CO_2, SO_2 and NO_x intensity
- Less than 5% of generation capacity will require capital expenditures to comply with Air Toxic rules

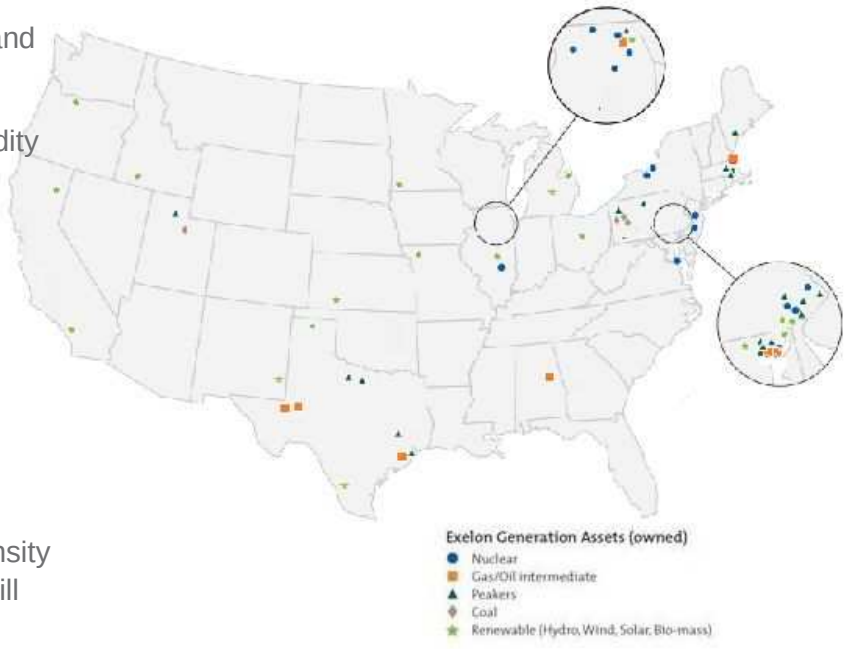

A clean and diverse portfolio that is well positioned for environmental upside from EPA regulations

(1) Reflects owned generation less announced divestitures of Fore River, Quail Run and West Valley and Keystone Conemaugh

Exelon

Exelon Nuclear Fleet Overview (including CENG and Salem)

	Plant Location	Type/ Containment	Water Body	License Extension Status / License Expiration (1)	Ownership	Spent Fuel Storage/ Date to lose full core discharge capacity (2)
Midwest	Braidwood, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Kankakee River	Filed application in May 2013 (decision expected in 2015)/ 2026, 2027	100%	Dry Cask
	Byron, IL (Units 1 and 2)	PWR Concrete/Steel Lined	Rock River	Filed application in May 2013 (decision expected in 2015)/ 2024, 2026	100%	Dry Cask
	Clinton, IL (Unit 1)	BWR Concrete/Steel Lined / Mark III	Clinton Lake	2026	100%	Dry Cask (2016)
	Dresden, IL (Units 2 and 3)	BWR Steel Vessel / Mark I	Kankakee River	Renewed / 2029, 2031	100%	Dry Cask
	LaSalle, IL (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Illinois River	Application will be filed Dec 2014(decision expected 2017)/2022, 2023	100%	Dry Cask
	Quad Cities, IL (Units 1 and 2)	BWR Steel Vessel / Mark I	Mississippi River	Renewed / 2032	75% Exelon, 25% Mid-American Holdings	Dry Cask
Mid-Atlantic	Limerick, PA (Units 1 and 2)	BWR Concrete/Steel Lined / Mark II	Schuylkill River	Renewed/ 2044, 2049 (5)	100%	Dry Cask
	Oyster Creek, NJ (Unit 1)	BWR Steel Vessel / Mark I	Barnegat Bay	Renewed / 2029(3)	100%	Dry Cask
	Peach Bottom, PA (Units 2 and 3)	BWR Steel Vessel / Mark I	Susquehanna River	Renewed / 2033, 2034	50% Exelon, 50% PSEG	Dry Cask
	TMI, PA (Unit 1)	PWR Concrete/Steel Lined	Susquehanna River	Renewed / 2034	100%	2023
	Salem, NJ (Units 1 and 2)	PWR Concrete/Steel Lined	Delaware River	Renewed / 2036, 2040	42.6% Exelon, 57.4% PSEG	Dry Cask
CENG	Calvert Cliffs, MD (Units 1and 2)	PWR Concrete/Steel Lined	Chesapeake Bay	Renewed / 2034, 2036	100% CENG(4)	Dry Cask
	R.E. Ginna, NY (Unit 1)	PWR Concrete/Steel Lined	Lake Ontario	Renewed / 2029	100% CENG(4)	Dry Cask
	Nine Mile Point, NY (Units 1 and 2)	BWR Steel Vessel / Mark I Concrete/Steel Vessel/ Mark II	Lake Ontario	Renewed / 2029, 2046	100% CENG(4) / 82% CENG(4), 18% Long Island Power Authority	Dry Cask

(1) Operating license renewal process takes approximately 4--5 years from commencement until completion of NRC review
(2) The date for loss of full core reserve identifies when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core; Dry cask storage will be in operation at those sites prior to losing full core discharge capacity in their on-site storage pools
(3) On December 8, 2010, Exelon announced that it will permanently cease generation operations at Oyster Creek by December 31, 2019. Oyster Creek's current NRC license expires in 2029
(4) Exelon Generation has a 50.01% ownership interest in CENG (Constellation Energy Nuclear Group, LLC). Electricite de France SA (EDF) has a 49.99% ownership interest in CENG
(5) Limerick Received a 20 year license renewal in October 2014

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World Class Nuclear Operator[1]

Nuclear Production Cost ($/MWh)[2]

Capacity Factor (%)[3]

Exelon is consistently one of the lowest-cost and most efficient producers of electricity in the nation

(1) Exelon fleet averages exclude Salem and CENG
(2) Source: 2013 Electric Utility Cost Group (EUCG) survey. Includes Fuel Cost plus Direct O&M divided by net generation
(3) Source: Platts Nuclear News, Nuclear Energy Institute and Energy Information Administration (Department of Energy)

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Nuclear Output and Refueling Outages

Nuclear Output

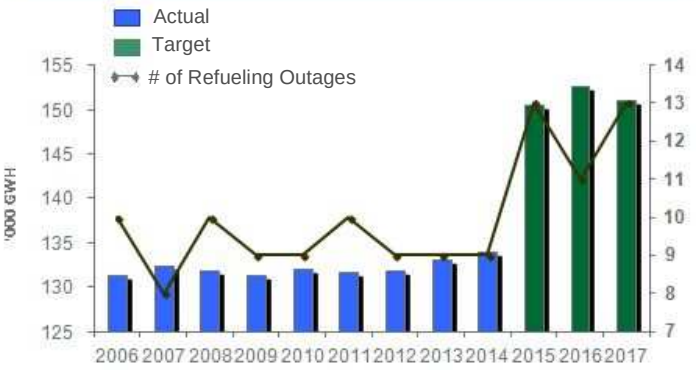

Net nuclear generation data at ownership excluding Salem for all years
CENG excluded thru 2006 2014, but included in 2015 and beyond at ownership
2016 includes Clinton Refueling Only outage of shortened duration.

Fleet Average Refueling Outage Duration (Days)

Exelon fleet averages exclude Salem and CENG

Nuclear Refueling Cycle

- All Exelon-owned units are on a 24 month cycle except for Braidwood U1/U2, Byron U1/U2, Ginna, and Salem U1/U2, which are on 18 month cycles
- Starting in 2015 Clinton will be on annual cycles

2014 Refueling Outage Impact (Includes CENG)

- 14 planned refueling outages, including 2 at Salem
  - 8 spring refueling outages (average duration of 25 days)
  - 4 fall refueling outages
  - Salem -1 refueling outage in the spring and 1 in the fall

2015 Refueling Outage Impact

- 14 planned refueling outages, including 1 at Salem
  - 7 spring refueling outages and 6 Fall refueling outages
  - 1 Salem fall refueling outage

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Nuclear Fuel Costs[1]

Projected Exelon Uranium Demand

2014 – 2016: 100% hedged in volume
2017: ~96% hedged in volume
2018: ~87% hedged in volume
2019: ~64% hedged in volume

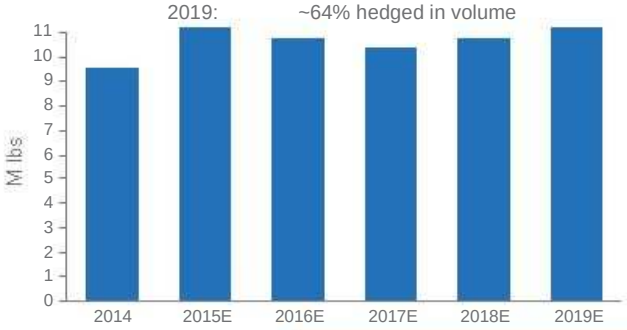

Components of Fuel Expense in 2014

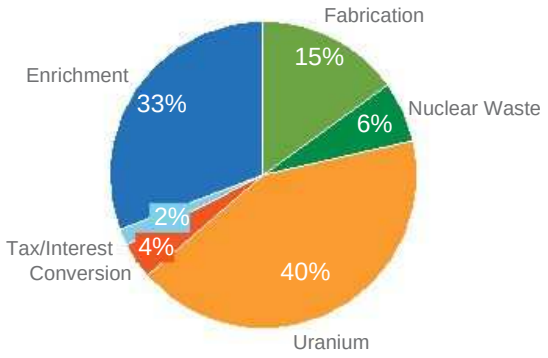

Projected Total Nuclear Fuel Spend[2]

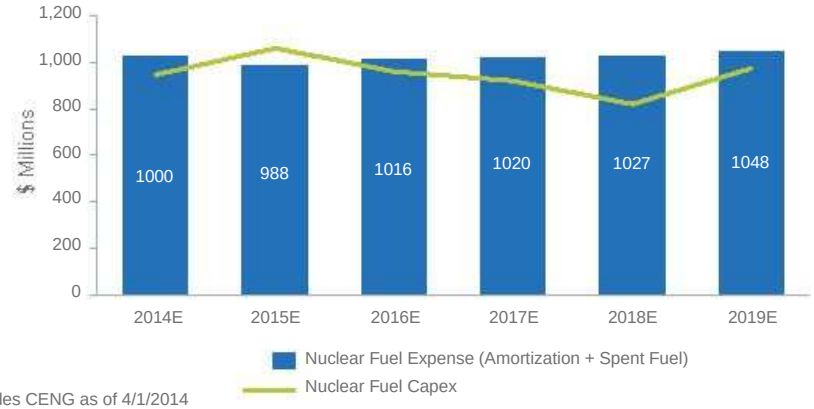

(1) All charts exclude Salem. Includes CENG as of 4/1/2014
(2) At ownership. Excludes costs reimbursed under the settlement agreement with the DOE

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Exelon Power Fleet Overview (owned generation, excludes wind and solar)

	Station	Location	Number of Units	Primary Fuel Type	Percent Owned[1]	Net Generation Capacity (MW)[2]
ERCOT	Colorado Bend	Wharton, TX	1	Gas		498
	Handley 3	Fort Worth, TX	1	Gas		395
	Handley 4, 5	Fort Worth, TX	2	Gas		870
	LaPorte	Laporte, TX	4	Gas		152
	Mountain Creek 6, 7	Dallas, TX	2	Gas		240
	Mountain Creek 8	Dallas, TX	1	Gas		565
	Wolf Hollow 1, 2, 3	Granbury, TX	3	Gas		704
Mid-Atlantic	Chester	Chester, PA	3	Oil		39
	Colver	Colver Twp., PA	1	Waste Coal	25	26
	Conowingo	Darlington, MD	11	Hydro		572
	Croydon	West Bristol, PA	8	Oil		391
	Delaware	Philadelphia, PA	4	Oil		56
	Eddystone	Eddystone, PA	4	Oil		60
	Eddystone 3, 4	Eddystone, PA	2	Oil/Gas		760
	Fairless Hills	Fairless Hills, PA	2	Landfill Gas		60
	Falls	Morrisville, PA	3	Oil		51
	Gould Street	Baltimore, MD	1	Gas		97
	Handsome Lake	Kennerdell, PA	5	Gas		268
	Moser	Lower PottsgroveTwp., PA	3	Oil		51
Mid-Atlantic	Muddy Run	Drumore, PA	8	Hydro		1070
	Notch Cliff	Baltimore, MD	8	Gas		118
	Pennsbury	Morrisville, PA	2	Landfill Gas		6
	Perryman	Belcamp, MD	5	Oil/Gas		353
	Philadelphia Road	Baltimore, MD	4	Oil		61
	Richmond	Philadelphia, PA	2	Oil		98
	Riverside	Baltimore, MD	3	Oil/Gas		113
	Salem	Lower Alloways Creek Twp, NJ	1	Oil	42.59	16
	Schuylkill	Philadelphia, PA	2	Oil		30
	Southwark	Philadelphia, PA	4	Oil		52
	Westport	Baltimore, MD	1	Gas		115
Midwest	Southeast Chicago	Chicago, IL	8	Gas		296
New England	Framingham	Framingham, MA	3	Oil		33
	Medway	West Medway, MA	3	Oil/Gas		117
	Mystic 7	Charlestown, MA	1	Oil/Gas		575
	Mystic 8, 9	Charlestown, MA	2	Gas		1418
	Mystic Jet	Charlestown, MA	1	Oil		9
	New Boston	South Boston, MA	1	Oil		16
	Wyman	Yarmouth, ME	1	Oil	5.9	36
Other	Grand Prairie	Alberta, Canada	1	Gas		75
	Hillabee	Alexander City, AL	1	Gas		670
	Sunnyside	Sunnyside, UT	1	Waste Coal	50	26

(1) 100%, unless otherwise indicated
(2) Fossil/Hydro Capacity values shown represent summer ratings. Net Generation Capacity (MW) is stated at proportionate ownership share

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Investment in New Generation Technology

Exelon is investing in an innovative, carbon-free, gas-fired technology through an investment in NET Power to support the development of an 11.4MWe demonstration facility to prove the technology

NET Power's system has the potential to transform both the electricity and the oil and gas markets. Using a novel, supercritical CO_2 - power cycle known as the Allam Cycle, the technology is projected to match or lower the current cost of electricity from natural gas generation technologies while also capturing all carbon dioxide emissions. The system produces carbon dioxide as a low-cost, pipeline-quality by-product as opposed to a gas emitted through a stack in conventional power plants. The produced CO_2 is ready for sequestration or use in enhanced oil recovery.

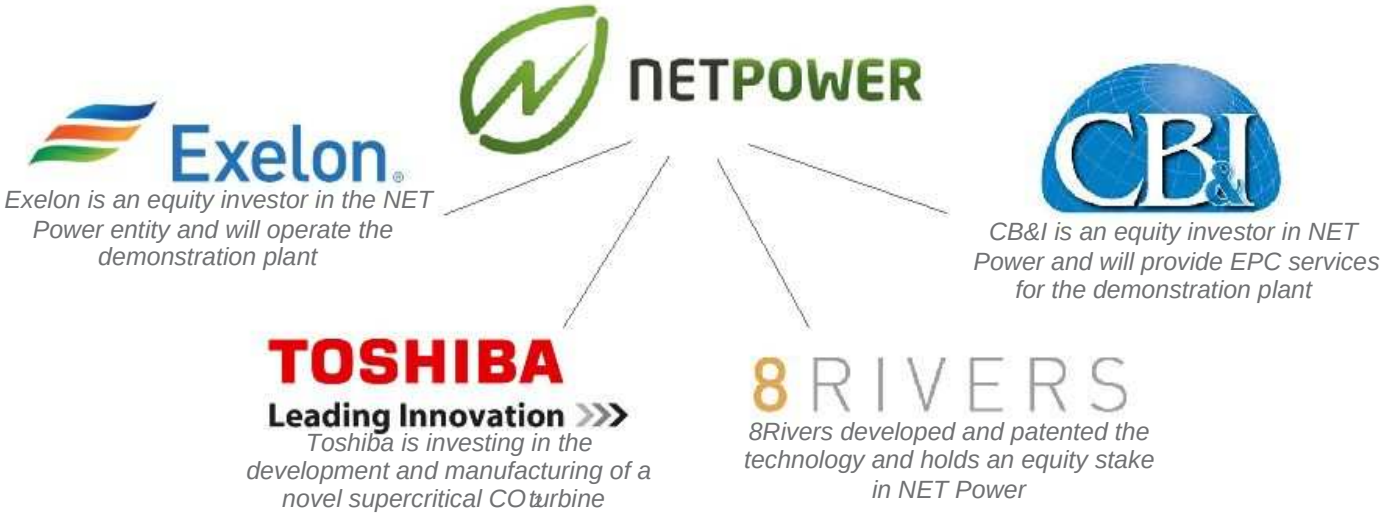

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) November 18, 2016

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 1 – Registrant's Business and Operations

Item 1.01 Entry into a Material Definitive Agreement.

On November 18, 2016, two subsidiaries of Constellation Energy Nuclear Group, LLC (CENG) and a subsidiary of Entergy Corporation entered into three separate agreements with the New York State Energy Research & Development Authority (NYSERDA) for the procurement of Zero Emission Credits (ZECs) pursuant to the August 1, 2016, New York Public Service Commission order approving the New York Clean Energy Standard (NYSERDA Agreements). The objective of the program is to preserve the environmental attributes of zero-emissions nuclear-powered generating facilities.

The NYSERDA Agreements extend from April 1, 2017 through March 31, 2029. Under the NYSERDA Agreements, ZECs will be procured in six, two-year tranches. Pricing for each tranche will be administratively determined based on the USIWG Social Cost of Carbon (escalating over the term), less a fixed baseline for carbon pricing already captured through the Regional Greenhouse Gas Initiative ($10.41/short ton). Pricing for Tranche 1 is $17.48/MWh.

The quantity of ZECs to be purchased by NYSERDA each year under all three NYSERDA Agreements is capped at an amount that represents the verifiable historic contribution the facility has made to the clean energy resource mix. Each Load Serving Entity is required to purchase an amount of ZECs equivalent to its load ratio share of the total electric energy load in the New York Control Area. Cost recovery from ratepayers will be incorporated into the commodity charges on customer bills.

The description of the NYSERDA Agreements referred to above is not complete and is qualified in its entirety by reference to the agreements. Copies of the two NYSERDA Agreements with subsidiaries of CENG are attached as exhibits 10.1 and 10.2, respectively, which are incorporated herein by reference.

Section 9 – Financial Statements and Exhibits

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits.*

Exhibit No.	Description
10.1	Execution Version—ZEC Standard Contract by and between the NYSERDA and Nine Mile Point Nuclear Station, LLC dated Nov. 18, 2016
10.2	Execution Version—ZEC Standard Contract by and between the NYSERDA and R. E. Ginna Nuclear Power Plant, LLC dated Nov. 18, 2016

* * * * *

Cautionary Statements Regarding Forward-Looking Information

This report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation and Exelon Generation Company, LLC include those factors discussed herein, as well as the items discussed in (1) Exelon's 2015 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23; (2) Pepco Holdings, Inc.'s 2015 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 16; (3) Exelon's Third Quarter 2016 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18 and (4) other factors discussed in filings with the SEC by Exelon and Generation. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this report. Exelon and Generation do not undertake any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this report.

* * * * *

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Jonathan W. Thayer
Jonathan W. Thayer
Senior Executive Vice President and
Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright
Bryan P. Wright
Senior Vice President and
Chief Financial Officer
Exelon Generation Company, LLC

November 18, 2016

EXHIBIT INDEX

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ZEC STANDARD CONTRACT

BY AND BETWEEN

THE NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

AND

NINE MILE POINT NUCLEAR STATION, LLC

Dated: November 18, 2016

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This Agreement is entered into as of November 18, 2016 (the "Contract Date") by and between the New York State Energy Research and Development Authority ("NYSERDA"), a public benefit corporation, having a principal business address of 17 Columbia Circle, Albany, New York 12203, and Nine Mile Point Nuclear Station, LLC ("Seller"), a Delaware limited liability company, having a principal business address of 1310 Point Street, Baltimore, MD 21231. NYSERDA and Seller are each referred to herein as a "Party" and are collectively referred to herein as the "Parties." All capitalized terms shall have the meanings ascribed to them in this Agreement.

RECITALS

WHEREAS, on August 1, 2016 the New York State Public Service Commission ("PSC" or the "Commission") adopted a Clean Energy Standard ("CES") program that is intended to achieve the State of New York's environmental, public health, climate policy and economic goals, and to preserve carbon-free attributes of certain existing nuclear generation resources as a bridge to the clean energy future (Case 15-E-0302; Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard , "Order Adopting a Clean Energy Standard," issued and effective August 1, 2016) (the "CES Order"); and

WHEREAS, the CES Order established, as part of the CES, a ZEC Program (as defined below), and established a mechanism for the purchase by NYSERDA of the ZECs (as defined below) of eligible nuclear zero-carbon electric generating facilities that elect to participate in the ZEC Program where a public necessity to encourage the continued creation of the attributes is demonstrated; and

WHEREAS, in accordance with criteria set forth in the CES Order, the Commission has found that there is a public necessity to provide ZEC payments to three nuclear facilities, including the Facility (as defined below); and

WHEREAS, Seller has elected for the Facility to participate in the ZEC Program; and

WHEREAS, the CES Order provides a price to be paid by NYSERDA to Seller for each ZEC delivered to NYSERDA during Tranche 1 (as defined below), and a methodology for the calculation and determination of the price in subsequent Tranches; and

WHEREAS, the CES Order imposes an obligation on each Load Serving Entity to invest in the preservation of certain existing at-risk nuclear zero-emissions attributes to serve their retail customers and accordingly directs LSEs to enter into a contractual relationship with NYSERDA for the purchase of ZECs during each ZEC Program year based on initial forecasts of load and a balancing reconciliation at the end of each program year; and

WHEREAS, NYSERDA anticipates that it will enter into backstop agreements (each, a "Backstop Agreement") with each electric distribution company ("EDC"), as proposed in NYSERDA's Petition filed with the Commission on August 25, 2016 and any Commission order related to that Petition, to guarantee that each LSE covers its obligation to buy from NYSERDA the quantity of ZECs required by the CES Order such that NYSERDA is assured that each ZEC purchased from Seller will be sold to LSEs; and

WHEREAS, Seller agrees to sell to NYSERDA, and NYSERDA agrees to purchase from Seller, ZECs associated with the generation of energy by the Facility and pursuant to the ZEC Program, on the terms and subject to the conditions set forth herein; and

WHEREAS, the Parties recognize that the 12-year Contract Term (as defined below) is an essential item of this Agreement and that Seller has made and will make significant investments in the Facility in reliance upon the existence of such Contract Term.

NOW, THEREFORE, for and in consideration of the premises, the mutual promises and agreements set forth herein and other good and valuable consideration, the receipt, sufficiency and adequacy of which are hereby acknowledged, NYSERDA and Seller, each intending to be legally bound, agree as follows:

Article I

Definitions

The terms defined in this Article I, whenever used in this Agreement (including in any Exhibit hereto), shall have the respective meanings indicated below for all purposes of this Agreement (each such meaning to be equally applicable to the singular and the plural forms of the respective terms so defined). All references herein to a Section, Article or Exhibit are to a Section, Article or Exhibit of or to this Agreement, unless otherwise indicated. The words "hereby", "herein", "hereof", "hereunder" and words of similar import refer to this Agreement as a whole (including any Exhibit) and not merely to the specific section, paragraph or clause in which such word appears. The words "include", "includes", and "including" shall be deemed, in every instance, to be followed by the phrase "without limitation." Whenever the context may require, any pronoun shall include the corresponding masculine, feminine and neuter forms. Except as otherwise expressly provided herein, all references to "dollars" and "$" shall be deemed references to the lawful money of the United States of America.

" Agreement " means this ZEC Standard Contract, including Exhibits A (Standard Terms and Conditions For All NYSERDA Agreements); B (NYSERDA Prompt Payment Policy Statement); C (Certification Form); and D (Zero Emissions Credit Pricing), all of which are incorporated herein and made part hereof.

" Annual ZEC Cap Amount " means either (i) 20,603,028 ZECs, if the FitzPatrick Facility is in Commercial Operation but is not included in the Nuclear Group, and the Nuclear Group consists of the Facility and the Ginna Facility, (ii) 18,412,000 ZECs, if a Permanent Cessation of Operations occurs with respect to the FitzPatrick Facility prior to the FitzPatrick Facility becoming included in the Nuclear Group and the Nuclear Group consists of only the Facility and the Ginna Facility, or (iii) 27,618,000 ZECs, if the Nuclear Group consists of the Facility, the Ginna Facility and the FitzPatrick Facility, subject to adjustment pursuant to Section 5.2.

" Annual ZEC Cap Reduction Amount " means 666,666 ZECs, if the Nuclear Group consists of the Facility and the Ginna Facility, and 1,000,000 ZECs, if the Nuclear Group consists of the Facility, the Ginna Facility and the FitzPatrick Facility.

" Applicable Law " means all applicable provisions of all constitutions, treaties, statutes, laws (including the common law), rules, regulations, ordinances, and codes and any order, writ, injunction, decree, judgment, award, decision or determination of any court or any federal, state, municipal or other governmental department, commission, board, bureau, agency, authority or instrumentality, including the NYISO tariff.

" Backstop Agreement " has the meaning set forth in the recitals to this Agreement.

" Business Day " means a day on which Federal Reserve member banks are open for business. A Business Day will begin at 8:00 a.m. and end at 5:00 p.m. Eastern Prevailing Time.

" Certificate " means a certificate as defined in the NYGATS Operating Rules.

" Cessation Tranche Reduction Amount " means 18,412,000 ZECs reduced for a full Tranche which shall be pro-rated for the remaining facilities within a Tranche from the date any facility undergoes a Permanent Cessation of Operations.

" Cessation ZEC Reduction Amount " means 9,206,000 ZECs reduced for a full Contract Year which shall be pro-rated for the remaining facilities within a Contract Year from the date any facility undergoes a Permanent Cessation of Operations.

" Claiming Party " has the meaning set forth in Section 14.2.

" Commercial Operation " means a state of operations under which the Facility is physically generating electric energy, consistent with Good Utility Practice, subject to outages that are consistent with Good Utility Practice, including refueling, planned, and forced outages.

" Common Ownership " means two or more generation facilities being owned, in whole or in part, directly or indirectly, by the same ultimate parent entity or entities.

" Contract Date " has the meaning set forth in the preamble of this Agreement.

" Contract Term " means a term commencing on April 1, 2017 and continuing through March 31, 2029, subject to adjustments pursuant to Article IV (Payment) and Article V (Adjustments).

The Contract Term will be administered in six two-Contract Year Tranches, as follows:

Tranche	1:	April	1,	2017	– March 31,	2019
Tranche	2:	April	1,	2019	– March 31,	2021
Tranche	3:	April	1,	2021	– March 31,	2023
Tranche	4:	April	1,	2023	– March 31,	2025
Tranche	5:	April	1,	2025	– March 31,	2027
Tranche	6:	April	1,	2027	– March 31,	2029

" Contract Year " means a 12-month period commencing on April 1, 2017 and each subsequent 12-month period commencing on an anniversary thereof during the Contract Term.

" EDC " has the meaning set forth in the recitals to this Agreement.

" Effective Date " means the date on which ZEC Standard Contracts have been executed by NYSERDA and each of the owners of the Facility, the FitzPatrick Facility and the Ginna Facility.

" Enjoined " or " Enjoinment " means if any court issues a final, non-appealable order, writ, injunction, decree, judgment, award, decision or determination that invalidates or permanently terminates the ZEC Program or otherwise permanently enjoins, impedes or prevents any Party from participating in the ZEC Program or fulfilling its material obligations under this Agreement, as applicable.

" ESCO " means an "energy service company" making sales of electricity in the State of New York.

" Extended Force Majeure Event " has the meaning set forth in Section 14.3(a).

" Facility " means the Nine Mile Point nuclear facility consisting of the Nine Mile Unit 1 and Unit 2 facilities, located in Oswego, New York (PTID 23575 and 23744, respectively).

" Facility Revenue Meters " means (i) the two meters on the high side of the Unit 1 main generator (Gen PTID: 23575) step-up transformers just prior to the Unit 1 main output breakers R915 and R925 and (ii) the two meters on the high side of the Unit 2 main generator (Gen PTID: 23744) step-up transformers just prior to the Unit 2 main output breakers R230 and R925, which are the meters for the Facility designated by the NYISO for measuring the output of the Facility that is referenced in Article V of the NYGATS Operating Rules as the Facility's "Revenue-Quality Meter."

" Final CES Order " has the meaning set forth in Section 13.3.

" FitzPatrick Facility " means the James A. FitzPatrick nuclear generation facility located in Scriba, New York (PTID 23598).

" Force Majeure Event " has the meaning set forth in Section 14.1.

" Force Majeure Remedy Plan " has the meaning set forth in Section 14.3(a).

" Ginna Facility " means the R.E. Ginna nuclear generation facility located in Ontario, New York (PTID 23603).

" Good Utility Practice " means any of the practices, methods or acts engaged in or approved by a significant portion of the electric utility or the nuclear electric power generation industry in the United States during the relevant time period, or any of the practices, methods or acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was

made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice or method, or act to the exclusion of all others, but rather to delineate acceptable practices, methods, or acts generally accepted in the region.

" Governmental Authority " Any federal, state, local, municipal, judicial or other government or any other governmental, quasi-governmental, regulatory or administrative agency, commission, court or other authority (including for federal purposes the NYISO) lawfully exercising or entitled to exercise any administrative, executive, judicial, legislative, police, policy, regulatory or taxing authority or power.

" Load-Serving Entity " or " LSE " means any entity or individual that sells retail commodity electricity supply to an end-use customer located in New York State, including any ESCO and each electric distribution company regulated by the PSC, serving in their roles as electric commodity supplier of last resort, jurisdictional municipal utilities, community choice aggregators not otherwise served by an ESCO, customers purchasing power directly from the NYISO, and the Long Island Power Authority and the New York Power Authority to the extent the Long Island Power Authority and the New York Power Authority have voluntarily agreed to act as LSEs.

" LSE Agreement " means a contract between NYSERDA and an LSE as contemplated in the CES Order, pursuant to which NYSERDA shall sell, and LSEs shall purchase, ZECs.

" MWh " means a unit for measuring power that is equivalent to 1,000 kilowatts of electricity used continuously for one hour.

" NRC " means the U.S. Nuclear Regulatory Commission and any successor agency thereto.

" Nuclear Group " means a group of nuclear generating facilities in New York State, consisting of the Facility and the Ginna Facility; provided that the "Nuclear Group" shall also include the FitzPatrick Facility if the FitzPatrick Facility comes under Common Ownership with the Facility and the Ginna Facility.

" NYGATS " means the New York Generation Attribute Tracking System, established by NYSERDA pursuant to the Public Authorities Law.

" NYGATS Operating Rules " means the rules, as may be amended from time to time, that govern the operation of the NYGATS by NYSERDA and its designated NYGATS Administrator, and the participation in and use of the NYGATS by users.

" NYISO " means the New York Independent System Operator, Inc.

" NYISO Rules " means the NYISO tariff, and all NYISO manuals, rules, procedures, agreements or other documents governing the participation of market participants in the NYISO markets as in effect from time to time.

" NYSERDA Prompt Payment Policy " has the meaning set forth in Exhibit B.

" NYSERDA ZEC Account " means the account established in NYGATS into which Seller shall deliver (by designation for transfer in accordance with the NYGATS Operating Rules) ZECs under the terms and conditions of this Agreement.

" Non-Claiming Party " has the meaning set forth in Section 14.2.

" Permanent Cessation of Operations " means the date upon which the Facility actually permanently shuts down and ceases operations following the filing of a Notice of Permanent Cessation of Operations with respect to a specific nuclear generation facility with the NRC pursuant to 10 C.F.R. Section 50.82(a)(1)(i).

" Public Authorities Law " means the Public Authority Act codified in the Consolidated Laws of New York at Public Authorities Law Sec. 1000 *et seq.*

" Seller ZEC Account " means the account established in the NYGATS for the deposit with NYGATS of ZECs created under the NYGATS Operating Rules for the Facility from which account Seller shall deliver ZECs(by designation for transfer in accordance with the NYGATS Operating Rules) to the NYSERDA ZEC Account under the terms and conditions of this Agreement.

" Threshold Amount " has the meaning set forth in Section 5.2(a).

" Tranche " means a two-Contract Year period for the sale of the ZECs, as set forth in the definition of "Contract Term" above.

" Tranche Cap Amount " means: (i) 41,206,056 ZECs, if the FitzPatrick Facility is in Commercial Operation and the Nuclear Group consists of the Facility and the Ginna Facility, (ii) 36,824,000 ZECs, if a Permanent Cessation of Operations occurs with respect to the FitzPatrick Facility prior to the FitzPatrick Facility becoming part of the Nuclear Group, and (iii) 55,236,000 ZECs, if the Nuclear Group consists of the Facility, the Ginna Facility and the FitzPatrick Facility.

" Tranche Cap Reduction Amount " means 1,333,333 ZECs, if the Nuclear Group consists of the Facility and the Ginna Facility, and 2,000,000 ZECs, if the Nuclear Group consists of the Facility, the Ginna Facility and the FitzPatrick Facility.

" ZEC Price " means the price that NYSERDA shall pay for each ZEC delivered by Seller (by designation for transfer in accordance with the NYGATS Operating Rules) to the NYSERDA ZEC Account during the Contract Term. The ZEC Price shall be as provided in Exhibit D.

" ZEC Program " means the zero-emissions credit requirement program as established by the PSC through the CES Order and administered by NYSERDA and its designated NYGATS administrator in accordance with the NYGATS Operating Rules.

" ZEC Quantity " means, with respect to any Contract Year, the lesser of (a) the quantity of ZECs produced by the Nuclear Group in such Contract Year and (b) the Annual ZEC Cap Amount that applies to the Nuclear Group for such Contract Year, subject to adjustments pursuant to Article IV (Payment) and Article V (Adjustments).

" Zero Carbon Electric Generating Facility " means an electric generating facility that uses energy released in the course of nuclear fission to generate electricity.

" Zero Emissions Credit " or "ZEC " means a credit for the zero-emissions attributes of one (1) MWh of electric energy production by an eligible Zero Carbon Electric Generating Facility, such as the Facility, represented by a Certificate, which credit is purchased by NYSERDA or a LSE from Seller to reduce carbon consumption by retail electric consumers in New York State, such purchases to be accomplished through NYGATS pursuant to the NYGATS Operating Rules.

Article II

Purchase and Sale of Rights to ZECs

Section 2.1. Eligibility . The Parties' respective obligations under this Agreement are expressly conditioned on the eligibility of Seller's Facility under the ZEC Program, as of the Effective Date.

Section 2.2. ZEC Sales . On the terms and subject to the conditions and provisions of this Agreement, Seller shall sell, assign, transfer, convey, and deliver to NYSERDA, and NYSERDA shall purchase, confirm transfer, and receive from Seller, all right, title and interest in ZECs measured at the Facility Revenue Meters and created in the Seller ZEC Account by NYGATS during the Contract Term at the ZEC Price and in accordance with the NYGATS Operating Rules. With respect to each Contract Year during the Contract Term, NYSERDA shall purchase from Seller such ZECs, up to the ZEC Quantity among the applicable Nuclear Group for such Contract Year, but shall not be obligated to purchase such ZECs over and above such ZEC Quantity. Seller shall, for the duration of the Contract Term, and subject to the terms and conditions of this Agreement, produce zero-emissions attributes, and, upon receipt of ZECs in the Seller ZEC Account, transfer such ZECs to the NYSERDA ZEC Account. For the avoidance of doubt, and except as set forth in Section 2.5, ZECs are the only product Seller is selling and NYSERDA is buying from Seller under this Agreement. Seller is not selling and NYSERDA is not purchasing any electricity or any capacity, energy, or ancillary services or other products or attributes (other than ZECs) associated with the Facility.

Section 2.3. ZEC Rights and Use . Such right, title and interest shall include perpetual and exclusive rights to all ZECs transferred under this Agreement, including the exclusive rights to claim or represent, consistent with New York State Environmental Disclosure rules: (a) that the ZECs are associated with energy that was generated by the Facility; and (b) that New York State and or the ZEC Program is responsible for the environmental benefits including reductions in emissions and/or other pollution or any other environmental benefit resulting from the generation of the energy associated with ZECs purchased hereunder.

Section 2.4. Risk of Loss . Title and risk of loss of ZECs will transfer from Seller to NYSERDA upon completion of (a) delivery by Seller of such ZECs into the NYSERDA ZEC Account (by designation for transfer in accordance with the NYGATS Operating Rules) and (b) receipt by NYSERDA of such ZECs into the NYSERDA ZEC Account (by confirmation of the transfer in accordance with the NYGATS Operating Rules). Each Party is responsible for completing all actions it is required to undertake in NYGATS to establish its respective ZEC

account and to cause the transfer of each ZEC in accordance with the NYGATS Operating Rules. Seller shall deliver all right, title and interest in and to the ZECs (by designation for transfer in accordance with the NYGATS Operating Rules) free and clear of all liens, judgments, encumbrances and restrictions created by or on behalf of Seller or any party claiming through Seller.

Section 2.5. Other Attributes . In the event that the Facility becomes eligible for credits under any emission-trading, emissions recordation or other carbon emissions reduction regime other than the CES, NYSERDA may request that Seller take reasonable actions necessary to apply for and secure such title to such credits, to the maximum extent to which the Facility is entitled. Seller shall provide NYSERDA with evidence of taking such actions. NYSERDA and Seller shall reasonably cooperate to cause title to such credits to be conveyed to NYSERDA after such title is secured by Seller.

Section 2.6. Equivalent Programs . This Agreement may be modified or terminated by the Commission if there is a national, NYISO, or other program instituted that pays for or internalizes the value of the Facility's zero-emissions attributes in a manner that adequately replicates the economics of the ZEC Program such that the Commission in its sole discretion is satisfied that the zero-emissions attributes are no longer at risk and that discontinuing the ZEC Program can be done in a manner that is fair to both the Facility owners and the New York State ratepayers. Nothing herein shall require NYSERDA or Seller to take any action violative of Applicable Law or an order of court of competent jurisdiction.

Section 2.7. NYSERDA Assignment of ZECs . NYSERDA shall be free to sell, assign or transfer to any entity, or otherwise encumber, any of the ZECs NYSERDA has acquired under this Agreement, at any time and from time to time, and on such terms and conditions as NYSERDA may desire; *provided* , *however,* NYSERDA's actions must at all times be in accordance with the CES Order.

Section 2.8. Opinions . Within thirty (30) days after the Seller receives written notice from NYSERDA stating that the Effective Date has been achieved, each Party shall deliver to the other Party an opinion of counsel (which may be an opinion of its in-house counsel) containing the opinions supporting the Seller's and NYSERDA's representations and warranties set forth in Sections 9.1(a), (b) and (c) and Sections 10.1(a), (b), (c) and (d), respectively, subject to customary assumptions, qualifications and exceptions.

Section 2.9. ZEC Sales to LSEs . To the extent permitted by the Commission and the CES Order, Seller may sell ZECs directly to LSEs. The Parties shall undertake good faith efforts to negotiate required amendments to this Agreement to account for such ZEC sales by Seller to LSEs.

Article III

ZEC Qualification; Operating Condition

Section 3.1. ZEC Qualification . The Facility's electric generation production shall be measured by the Facility Revenue Meters. Such measurement shall be used as a basis for

determining pursuant to the ZEC Program the amount of ZECs related to such generation to be created and recorded in NYGATS. NYSERDA shall track (a) ZECs through NYGATS and NYSERDA's program administrator and (b) the contribution of such ZECs toward reducing carbon consumption by retail electric consumers in New York State.

Section 3.2. Obligation to Maintain Good Operating Condition . For the duration of the Contract Term, Seller shall: (a) comply with applicable NRC requirements (including insurance requirements); (b) maintain the Facility in Commercial Operation in good operating condition in accordance with Good Utility Practice; and (c) operate the Facility in compliance with the NYISO Rules.

Article IV

Payment

Section 4.1. Invoices . Seller shall submit invoices to NYSERDA on a quarterly basis throughout the Contract Term for ZECs created in the Seller ZEC Account by NYGATS for the preceding three (3) month period in accordance with the NYGATS Operating Rules and delivered (by designation for transfer in accordance with the NYGATS Operating Rules) to the NYSERDA ZEC Account. Each invoice shall be accompanied by a CERTIFICATION FORM, the form of which is set forth as Exhibit C, setting forth the ZECs to be delivered. Invoices shall not be submitted before the fifteenth (15) day of the month following the close of each quarter; invoices submitted prior to the fifteenth (15) day of the month following the close of each quarter shall not be considered proper invoices for purposes of NYSERDA's Prompt Payment Policy. Invoices shall be submitted electronically to NYSERDA's online invoice system at https://services.nyserda.ny.gov/Invoices/ with a copy to the Office of the General Counsel at general.counsel@nyserda.ny.gov. Such invoices shall make reference to the Agreement number shown on page 1 of this Agreement. Such invoices shall include a statement of the amount due and payable by NYSERDA to Seller, which amount shall be calculated in accordance with Section 4.2.

Section 4.2. Payment . NYSERDA will confirm receipt of ZECs in accordance with the NYGATS Operating Rules and make payment to Seller for ZECs delivered, subject to true-up pursuant to Article V. NYSERDA will not confirm receipt and will not pay, with respect to any Contract Year, for ZECs in excess of the applicable ZEC Quantity. The amounts payable shall be calculated as the multiplicative product of (a) the applicable ZEC Price; and (b) the number of ZECs delivered by Seller up to the applicable ZEC Quantity (by designation for transfer in accordance with the NYGATS Operating Rules) to the NYSERDA ZEC Account prior to the date on invoice.

Section 4.3. Prompt Payment Policy . NYSERDA will make payments to the Seller in accordance with and subject to its Prompt Payment Policy Statement, attached hereto as Exhibit B. Such payments shall be made by wire transfer to an account designated by the Seller.

Section 4.4. Limitation on ZEC Purchase Obligation . Notwithstanding any other provision in this Agreement to the contrary, Seller acknowledges that NYSERDA's ability to make payments hereunder is limited to the amount NYSERDA realizes from ZEC sales transactions to LSEs, which obligations will be guaranteed by agreements NYSERDA anticipates entering into with each EDC, in accordance with the CES Order; provided, however, that if so authorized by the Commission, NYSERDA shall use available funds which NYSERDA has rights to use, in accordance with the Commission's authorization to make payments hereunder if the proceeds from such ZEC sales transactions are not sufficient to cover NYSERDA's payment obligations hereunder. Notwithstanding NYSERDA's obligation pursuant to Section 4.5 to enforce agreements to ensure that it can meet its obligations hereunder, NYSERDA shall not be obligated to purchase ZECs to the extent it does not have sufficient funds (from those referenced in the immediately preceding sentence) to do so, including in the event that NYSERDA, LSEs or EDCs are precluded by a court of competent jurisdiction from fulfilling their respective obligations under the ZEC Program. In the event that NYSERDA suffers a cash shortfall in the manner described in this Section 4.4, NYSERDA shall, subject to Applicable Law, use its sole discretion in purchasing reduced ZECs pro rata across all of the facilities to the extent possible.

Section 4.5. LSE Agreements . NYSERDA shall use commercially reasonable efforts, as authorized by the Commission, to enter into and maintain LSE Agreements in sufficient numbers and with sufficient pricing and on such other terms and conditions as NYSERDA may determine necessary or appropriate to enable NYSERDA to fulfill its payment obligations under this Agreement. Subject to Applicable Law, NYSERDA shall use commercially reasonable efforts to enforce its rights and remedies under each of its LSE Agreements and under any related EDC guarantee commitments.

Article V

Adjustments

Section 5.1. True-Up Adjustments . NYSERDA may adjust, including by means of set-off, payments to subsequent invoices consistent with adjustments by NYGATS based on actual metered electric energy production data from the Facility Revenue Meters, associated ZEC creation data and the number of ZECs delivered and received; provided , however , NYSERDA's right to a specific payment adjustment under this Section 5.1 shall expire three (3) years after the issuance of Seller's invoice to which such payment adjustment relates.

Section 5.2. Other Adjustments . NYSERDA may also make the following adjustments under the following circumstances:

(a) Failure to Produce . If during any Tranche, the Nuclear Group fails to generate in the aggregate an amount of electric energy sufficient to support the creation of ZECs pursuant to the ZEC Program in an amount equal to at least eighty-five percent (85%) of the applicable Tranche Cap Amount (the "Threshold Amount"), then the Annual ZEC Cap Amount and the Tranche Cap Amount applicable to the Nuclear Group in the immediately subsequent Tranche shall decrease by the applicable Annual ZEC Cap Reduction Amount and the applicable Tranche Cap

Reduction Amount, respectively. If, during any subsequent Tranche, the Nuclear Group generates in the aggregate an amount of electric energy sufficient to support the creation of ZECs pursuant to the ZEC Program in an amount at or above the new lower cap and obligation, the Annual ZEC Cap Amount and Tranche Cap Amount will be restored for the Nuclear Group in subsequent Tranches. Subject to Sections 2.2, 3.2 and 12.1(b), but notwithstanding any other provision in this Agreement to the contrary, the cap reductions described in this Section 5.2(a) shall be NYSERDA's sole remedy for Seller's failure to produce the Threshold Amount and transfer ZECs to the NYSERDA ZEC Account, in accordance with the terms of this Agreement, through the Contract Term;

(b) Permanent Cessation of Operations. As of the Contract Date, the Nuclear Group consists of the Facility and the Ginna Facility. If, during the Contract Term, a Permanent Cessation of Operations occurs with respect to (a) the FitzPatrick Facility or (b) the Ginna Facility, then, NYSERDA shall make any payments due to such facility in accordance with obligations hereunder already performed by such facility. If a Permanent Cessation of Operations occurs with respect to the FitzPatrick Facility prior to the FitzPatrick Facility becoming part of the Nuclear Group, then, effective on the date of the facility's Permanent Cessation of Operations, the Annual ZEC Cap Amount and the Tranche Cap Amount shall be modified in accordance with their respective definitions in Article I. If a Permanent Cessation of Operations occurs with respect to (a) the FitzPatrick Facility after the FitzPatrick Facility becomes part of the Nuclear Group or (b) the Ginna Facility, then effective on the date of the facility's Permanent Cessation of Operations, the Annual ZEC Cap Amount and the Tranche Cap Amount shall be reduced by the Cessation ZEC Reduction Amount and Cessation Tranche Reduction Amount, respectively. Solely for the purpose of determining the Cessation ZEC Reduction Amount and Cessation Tranche Reduction Amount, if either Unit 1 or Unit 2 of the Facility has a Permanent Cessation of Operations, it will be treated as if the entire Facility has a Permanent Cessation of Operations. For purposes of clarity, if a Permanent Cessation of Operations occurs at only Unit 1 or Unit 2 of the Facility, this Agreement shall not terminate, and Seller shall continue to sell, and Buyer shall continue to purchase, ZECs hereunder;

(c) Other Programs. This Agreement may be modified or terminated if there is a national, NYISO, or other program instituted that pays for or internalizes the value of the Facility's zero-emissions attributes in a manner that adequately replicates the economics of the ZEC Program such that the Commission in its sole discretion is satisfied that the zero-emissions attributes are no longer at risk and that discontinuing the mechanism can be done in a manner that is fair to both the Facility owners and the New York State ratepayers. Nothing herein shall require NYSERDA or Seller to take any action violative of Applicable Law or an order of court of competent jurisdiction; and

(d) LSE Agreements. If, during the Contract Term, the Seller enters into an agreement with an LSE for the sale of ZECs, the Annual ZEC Cap Amount and the Tranche Cap Amount, as the case may be, shall be reduced by the same

number of ZECs that Seller contracts to sell to the LSE; *provided* that, for the Tranche in which the effective date of such contract occurs, such modifications shall be made on a pro rata basis.

Article VI

Records and Reports

Section 6.1. Additional Documents . Within ten (10) Business Days after Seller receives written notice from NYSERDA stating that the Effective Date has been achieved, Seller shall provide to NYSERDA:

(a) certificates, dated as of the most recent practicable date prior to delivery of the opinion referenced in Section 2.8, issued by the Maryland Secretary of State confirming the corporate good standing of the Seller; and

(b) a certificate of an appropriate officer of the Seller in form and substance reasonably satisfactory to NYSERDA and certifying: (i) the names and signatures of the officers of the Seller authorized to sign any documents to be delivered hereunder; and (ii) the accuracy and completeness of resolutions of the Seller, authorizing and approving all matters in connection with the transactions contemplated thereby.

Seller shall promptly provide NYSERDA with updated and corrected versions of the above-referenced certificates upon any change in the information provided therein.

Section 6.2. Maintenance of Records . The Seller shall keep, maintain, and preserve at its principal office throughout the term of the Agreement and for a period of seven (7) years following the expiration of this Agreement, full and detailed books, accounts, and records pertaining to Seller's performance under the Agreement.

Article VII

Audit; Alternative Pricing Source

Section 7.1. Audit . NYSERDA shall have the right from time to time and at all reasonable times during the Contract Term and such period thereafter, upon reasonable notice to Seller, to inspect and audit any and all books, accounts and records pertaining to Seller's performance under this Agreement, at the office or offices of the Seller where they are then being kept, maintained and preserved. If such books, accounts and records are not kept at an office within the State of New York, within a reasonable time of a request by NYSERDA, Seller shall make such books, accounts and records available to NYSERDA at NYSERDA's offices or at an agreed upon location within the State of New York. Any payment made under this Agreement shall be subject to retroactive adjustment (reduction or increase) regarding amounts included therein which are found by NYSERDA on the basis of any audit of the Seller by an agency of the United States, the State of New York or NYSERDA not to constitute a properly invoiced amount.

Section 7.2. Alternative Pricing Source . If any of the prices utilized in Exhibit D of this Agreement fail to be announced or published by the relevant provider, or are otherwise unavailable on a temporary or permanent basis, promptly upon becoming aware of such circumstances, the Parties shall negotiate in good faith to agree upon a mutually acceptable alternative pricing source, index or calculation method that most closely approximates the discontinued prices, subject to Commission authorization as necessary.

Article VIII

Assignments

Section 8.1. General Restrictions . Except as specifically provided under Section 8.2, the assignment, transfer, conveyance, subcontracting or other disposal of this Agreement or any of the Seller's rights, obligations, interests or responsibilities hereunder, in whole or in part, without the express prior consent (not to be unreasonably withheld, conditioned or delayed) in writing of NYSERDA shall be void and of no effect as to NYSERDA. Seller agrees to compensate NYSERDA for NYSERDA's reasonable costs and expenses incurred by its use of outside attorneys, consultants, accountants and advisors in connection with this Agreement in response to Seller's requests made pursuant to this Section 8.1. NYSERDA shall provide an invoice to Seller for such charges, with appropriate documentation, and Seller shall pay such invoice within thirty (30) Days.

Section 8.2. Permitted Assignments . Notwithstanding the general restriction in Section 8.1:

(a) Seller may, without NYSERDA's prior written consent, grant a security interest in or conditionally assign this Agreement as collateral in connection with financing arrangements; provided that Seller provides prompt notice to NYSERDA of such collateral assignment;

(b) Seller may, without NYSERDA's prior written consent, assign, transfer or convey Seller's rights, obligations, interests or responsibilities hereunder pursuant to an assignment or transfer of Seller's license to operate approved by the NRC; and

(c) any change in ownership or control of Seller or a direct or indirect parent of Seller shall not require the prior written consent of NYSERDA; *provided* that Seller shall provide NYSERDA with any NRC or Commission filings with respect to such change in ownership or control promptly after such filings have been submitted to the NRC or the Commission.

Article IX

Seller's Representations and Warranties

Section 9.1. As a material inducement to NYSERDA to enter into this Agreement, Seller makes the following representations and warranties, as of the Effective Date, all of which shall survive the execution and delivery of this Agreement and any termination:

(a) (1) that Seller is a limited liability company duly organized, validly existing and in good standing under the laws of the jurisdiction of its organization; (2) has all requisite limited liability company power, and has all material governmental permits necessary to own its assets or lease and operate its properties and carry on its business as now being or as proposed to be conducted, to construct, finance, own, maintain and operate the Facility, to execute and deliver this Agreement, and to consummate the transactions contemplated herein; and (3) is qualified to do business and is in good standing in all jurisdictions in which the nature of the business conducted by it makes such qualification necessary;

(b) that the execution, delivery and performance by Seller, the entry into this Agreement by Seller, and the consummation of the transactions contemplated by this Agreement: (1) have been duly authorized by all requisite limited liability company action (including any required action of its members); and (2) will not (i) violate any applicable provision of law, statute, rule, regulation or order of any governmental agency or any provision of the limited liability company agreement or other governing documents of Seller; (ii) violate, conflict with, result in a breach of or constitute (alone or with notice or lapse of time or both) a default or an event of default under any indenture, agreement (including the respective limited liability company agreements of Seller), mortgage, deed of trust, note, lease, contract or other instrument to which Seller is a party or by which it or any of its property is bound; or (iii) result in the creation or imposition of any lien upon any property or assets of the Seller;

(c) that this Agreement has been duly executed and delivered by Seller and constitutes the legal, valid and binding obligation of Seller enforceable against Seller in accordance with the terms thereof; and

(d) that Seller is in compliance with Applicable Law that may in any way affect the performance of this Agreement, except where the failure to so comply would not result in a material adverse effect on Seller's ability to perform its material obligations hereunder.

Article X

NYSERDA's Representations and Warranties

Section 10.1. As a material inducement to Seller to enter into this Agreement, NYSERDA makes the following representations and warranties, as of the Effective Date, all of which shall survive the execution and delivery of this Agreement and any termination:

(a) that NYSERDA is an instrumentality of the State of New York and a public authority and public benefit corporation, created under the New York State Public Authorities Law, validly existing and in good standing under the laws of the State of New York;

(b) that NYSERDA has all necessary power and authority to execute and deliver this Agreement and all other agreements contemplated herein and hereby and to consummate the transactions contemplated hereby and thereby. The execution and delivery by NYSERDA of this Agreement and all other agreements contemplated herein and hereby and the consummation of the transactions contemplated hereby and thereby have been or, if not yet executed and delivered, will be when executed and delivered, and no other actions or proceedings on the part of NYSERDA are necessary to authorize this Agreement or any other agreement contemplated herein and hereby or the consummation of the transactions contemplated hereby and thereby;

(c) that the execution, delivery and performance by NYSERDA of this Agreement will not (1) violate any applicable provision of law, statute, rule, regulation or order of any governmental agency or, any provision of the Public Authorities Law; (2) violate, conflict with, result in a material breach of or constitute (alone or with notice or lapse of time or both) a material default or event of default under any indenture, agreement, mortgage, deed of trust, note, lease, contract or other instrument to which NYSERDA is a party or by which NYSERDA or any of its property is bound; (3) result in the creation or imposition of any lien upon any property or assets of NYSERDA; or (4) require any consent or approval of, registration or filing with, or any other action by, any Governmental Authority, except such as have been obtained or made and are in full force and effect. This Agreement will not conflict with any other agreement or contract to which NYSERDA is a party;

(d) that this Agreement has been duly executed and delivered by NYSERDA and constitutes the legal, valid and binding obligation of NYSERDA enforceable against NYSERDA in accordance with the terms thereof;

(e) that NYSERDA is familiar with and in compliance with Applicable Law, except where the failure to so comply would not result in a material adverse effect on NYSERDA's ability to perform its material obligations hereunder; and

(f) that there is no action, suit or claim at law or in equity, or before or by a Governmental Authority pending or, to the best knowledge of NYSERDA after due inquiry, threatened against NYSERDA or affecting any of its properties or assets which could reasonably be expected to result in a material adverse effect on NYSERDA's ability to perform its obligations.

Article XI

Indemnification

Section 11.1. Indemnification . Seller shall protect, indemnify and hold harmless NYSERDA and their respective officials, trustees, officers, directors, employees, agents, representatives and contractors from and against all liabilities, losses, claims, damages, judgments, penalties, causes of action, costs and expenses (including reasonable attorneys' and/or experts' fees and expenses) imposed upon or incurred by or asserted against NYSERDA resulting from, arising out of or relating to Seller's material breach of this Agreement. The obligations of Seller under this Article shall survive any expiration or Termination of this Agreement, and shall not be limited by any enumeration herein of required insurance coverage.

Article XII

Events of Default

Section 12.1. Event of Default . For the purposes of this Agreement, "Event of Default" shall mean any of the following:

(a) Representations and Warranties . Any representation or warranty made in this Agreement that shall prove to have been false or misleading in any material respect as of the time made or deemed to be made;

(b) Other Obligations . A Party shall default in the performance of any of its obligations under Sections 2.2, 2.4, 3.2, 4.2, 6.2 and 7.1 of this Agreement and such default shall continue unremedied for a period of thirty (30) days after the defaulting Party receives notice thereof;

(c) Voluntary Proceedings . A Party shall (i) apply for or consent to the appointment of, or the taking of possession by, a receiver, custodian, trustee or liquidator of itself or of all or a substantial part of its property; (ii) make a general assignment for the benefit of its creditors; (iii) commence a voluntary case under the United States Bankruptcy Code; (iv) file a petition seeking to take advantage of any other law relating to bankruptcy, insolvency, reorganization, winding-up, or composition or readjustment of debts; (v) fail to convert in a timely and appropriate manner, or acquiesce in writing to, any petition filed against it in an involuntary case under the United States Bankruptcy Code; (vi) cancel this Agreement, or sell ZECs to a third party (whether by a Party or a receiver, custodian, trustee or liquidator) other than NYSERDA or (subject to Section 2.9) an LSE; or (vii) take any corporate action for the purpose of effecting any of the foregoing;

(d) Involuntary Proceedings. A proceeding or case shall be commenced against a Party, without its application or consent, in any court of competent jurisdiction, seeking (i) its liquidation, reorganization, dissolution or winding-up, or the composition or readjustment of its debts; (ii) the appointment of a trustee, receiver, custodian, liquidator or the like of all or any substantial part of its assets; (iii) similar relief under any law relating to bankruptcy, insolvency, reorganization, winding-up, or composition or adjustment of debts, and such proceeding or case shall continue undismissed, or an order, judgment or decree approving or ordering any of the foregoing shall be entered and continue unstayed and in effect, for a period of sixty (60) or more days; or an order for relief against a Party, shall be entered in an involuntary case under the Bankruptcy Code; or (iv) as part of such a proceeding, a Party, receiver, custodian, trustee or liquidator shall cancel this Agreement, or sell ZECs to a third party other than NYSERDA or (subject to the terms of Section 2.9) an LSE;

(e) Unauthorized Transfer. The transfer of any ZEC included in the ZEC Quantity by Seller to any transferee other than NYSERDA or an LSE as permitted by the Commission; or

(f) Abandonment/Cessation of Commercial Operation. Seller's failure to maintain Commercial Operation, Seller's abandonment of the Facility or a Permanent Cessation of Operations with respect to the Facility.

Section 12.2. Effect of an Event of Default. In addition to any other remedy available to it under this Agreement or under Applicable Law, upon any occurrence of an Event of Default, the non-defaulting Party shall be entitled to suspend performance of its obligations under this Agreement until the earlier of such time as (a) such Event of Default has been cured or (b) the non-defaulting Party has elected to terminate this Agreement pursuant to Article XIII below.

Article XIII

Termination

Section 13.1. Termination. This Agreement may be terminated:

(a) at any time by the non-defaulting Party if an Event of Default occurs and continues unremedied following any applicable notice and cure period;

(b) at any time by the mutual written consent of Seller and NYSERDA;

(c) unless otherwise mutually agreed upon by NYSERDA and Seller in writing, on the expiration of the Contract Term (subject to Section 15.3 of this Agreement);

(d) by Seller, in the event that the ZEC Price becomes zero dollars ($0) at any time during the Contract Term; or

(e) by Seller or NYSERDA upon Enjoinment.

Section 13.2. Sale of FitzPatrick Facility . Unless the Commission orders otherwise prior to the commencement of Tranche 2, should Seller fail to reasonably demonstrate to NYSERDA, on or before September 1, 2018, that the FitzPatrick Facility has been purchased and that title to the FitzPatrick Facility has passed to a third party licensee unaffiliated with the current owner of the FitzPatrick Facility, this Agreement may be terminated by NYSERDA by providing written notice thereof to Seller on or at any time after September 2, 2018, but before April 1, 2019, pursuant to which the Parties' respective obligations shall terminate at the end of Tranche 1 with no further payment or performance obligation; provided that NYSERDA shall make any payments due in accordance with obligations hereunder already performed (such termination right defined herein as the "FitzPatrick Condition"). Seller has requested clarification or rehearing from the Commission that the FitzPatrick Condition does not apply to the procurement of ZECs from the Facility.

Section 13.3. Final Order . If one or more proceedings are commenced or pending by or before any Governmental Authority seeking to modify, terminate, amend, alter, avoid or invalidate any of the CES Order related to this Agreement or this Agreement, or any material provision thereof, the Parties shall continue to perform all of their respective obligations hereunder until such time that the Commission's decision on the CES Order and ZEC Program is final and non-appealable ("Final CES Order"). If a Final CES Order by the Commission has the effect of materially changing the original economic benefits of the ZEC Program or this Agreement for a Party (but not Enjoining the ZEC Program), the Parties shall negotiate in good faith to amend this Agreement to conform to the Final CES Order in order to effectuate as closely as reasonably possible the intent of the Parties hereunder on the Effective Date and preserve the original economic benefit to the Parties under this Agreement, subject to Commission approval as necessary. In the event that the Parties are not able to reach a mutually acceptable agreement, either Party, at its reasonable discretion, may terminate this Agreement. In the event the ZEC Program is Enjoined, either Party may terminate this Agreement pursuant to Section 13.1(e) and neither Party shall be required thereafter to perform any of the obligations under this Agreement. Notwithstanding any provision of this Section 13.3 to the contrary, nothing in this Section 13.3 shall affect the authority of the Commission to take any action pursuant to Sections 2.6 and 5.2(c) of this Agreement.

Section 13.4. Change in Law . Except as provided in Section 13.3 of this Agreement, the Parties agree that their respective obligations under this Agreement shall continue unmodified in full force and effect for the Contract Term in the event that a non-judicial Governmental Authority of the State of New York, including the Commission, modifies, terminates, amends, alters, avoids or invalidates the CES Order or the Final CES Order. Further, if any other Applicable Law has the effect of materially changing the original economic benefits of this Agreement for a Party or the economics of owning and operating the Facility, the Parties shall negotiate in good faith to amend this Agreement to conform to such new Applicable Law in order to effectuate as closely as reasonably possible the intent of the Parties hereunder on the Effective Date and preserve the original economic benefit to the Parties under this Agreement, subject to Commission approval as necessary. In the event that the Parties are not able to reach a mutually acceptable agreement, either Party, at its reasonable discretion, may terminate this Agreement. Notwithstanding any provision of this Section 13.4 to the contrary, nothing in this Section 13.4 shall affect the authority of the Commission to take any action pursuant to Sections 2.6 and 5.2(c) of this Agreement.

Section 13.5. Material Adverse Change . Seller shall promptly notify NYSERDA if it becomes aware of any damage to or loss of use of the Facility that could reasonably be expected to materially adversely affect the Facility and its ability to generate electricity and pursuant to the ZEC Program the subsequent creation of ZECs related to such generation. In the event of (a) the unavailability, interruption, breakdown or failure of equipment at the Facility or (b) other similar material adverse change to the operating condition of the Facility that, with respect to either or both of the events or conditions described in the preceding clause (a) or (b), could reasonably be expected to cost more than Forty Million Dollars ($40,000,000), as demonstrated by an independent engineering report provided by Seller, to repair or replace in accordance with Good Utility Practice and Seller's standard operating procedures, Seller may, at its sole option, terminate this Agreement with no further payment or performance obligation; provided that NYSERDA shall make any payments due in accordance with obligations hereunder already performed. For the avoidance of doubt, the Forty Million Dollar ($40,000,000) threshold set forth above must be for costs above Seller's previously forecasted budget and must pertain to capital costs, including costs associated with construction, repair, parts and equipment.

Article XIV

Force Majeure

Section 14.1. Force Majeure . Neither Party hereto shall be liable for any failure or delay in the performance of its respective obligations hereunder (other than payment obligations) if and to the extent that such delay or failure is due to a cause or circumstance beyond the reasonable control of such party, including acts of God or the public enemy, expropriation or confiscation of land or facilities, acts of war, rebellion or sabotage or damage resulting therefrom, fires, floods, storms or weather of unusual severity, unavailability of NYGATS, explosions, accidents, riots, or strikes (a "Force Majeure Event"). Compliance with Applicable Law shall not constitute a Force Majeure Event and shall be addressed in Section 13.4. The suspension of performance due to a Force Majeure Event shall be of no greater scope or amount and of no longer duration than is required by such Force Majeure Event and the Claiming Party shall not be construed to be in default with respect to any obligation hereunder for so long as, but only to the extent that, failure to perform such obligation is due to a Force Majeure Event. No Force Majeure Event shall extend this Agreement beyond the Term.

Section 14.2. Due Diligence . A Party claiming a Force Majeure Event ("Claiming Party") shall: (a) provide oral notice as promptly as practicable followed by written notice to the other Party ("Non-Claiming Party") within two (2) Business Days after such Claiming Party becomes aware of such Force Majeure Event, giving the Non-Claiming Party a detailed written explanation of the event and an estimate of its expected duration and probable effect on the performance of the Claiming Party's obligations hereunder; (b) use commercially reasonable efforts in accordance with Good Utility Practice to remedy the condition that prevents performance and to mitigate the effects of same in order to continue to perform its obligations under this Agreement; and (c) provide the Non-Claiming Party with weekly status reports of all efforts to mitigate and remedy the Force Majeure Event.

Section 14.3. Extended Force Majeure Events .

(a) If the Claiming Party has reason to believe that a Force Majeure Event will prevent it from performing its obligations under this Agreement for one (1) month or longer ("Extended Force Majeure Event"), it shall notify the Non-Claiming Party in writing within fifteen (15) days from the beginning of said Force Majeure Event and shall submit a plan to remedy the impact of such Force Majeure Event(s) (a "Force Majeure Remedy Plan") to the Non-Claiming Party within ten (10) days of such notification.

(b) While the Force Majeure Remedy Plan is in effect, the Claiming Party shall provide (i) weekly status reports notifying the Non-Claiming Party of the steps which have been taken to remedy the Extended Force Majeure Event, and (ii) the expected remaining duration of its inability to perform hereunder.

Section 14.4. Right to Terminate or Discontinue Obligations .

Either Party upon written notice to the other Party may terminate this Agreement if the Claiming Party remains unable to perform its material obligations hereunder due to a Force Majeure Event for twenty-four (24) consecutive months following the date of such Force Majeure Event; provided, that neither Party shall be entitled to terminate this Agreement until twenty four (24) months after the date of such Force Majeure Event provided that the Party affected by the Force Majeure Event (a) has commenced to remedy the Force Majeure Event and (b) is diligently pursuing such remedy; and (c) if such remedy can be reasonably completed within twenty four (24) consecutive Months following the date of such Force Majeure Event.

Section 14.5. Liability Following Termination .

Upon termination of this Agreement as provided in Section 14.4, the Parties shall have no further liability or obligation to each other as a consequence of such termination, except for any obligation accruing prior to the occurrence of such Force Majeure Event.

Article XV

Additional Provisions

Section 15.1. Forward Contract . Each Party represents and warrants to the other, as of the date of each sale and purchase of ZECs (each "transaction") hereunder that it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code, that this Agreement and each transaction is a "forward contract" or a "commodity contract" within the meaning of the United States Bankruptcy Code, and that the remedies identified in this Agreement shall be "contractual rights" as provided for in 11 U.S.C. § 556 as that provision may be amended from time to time. Each Party represents to the other, as of the date of each transaction, that: (a) it is a commercial market participant with respect to ZECs and is entering into the transaction in connection with its commercial business; (b) it intends, as of the date of the transaction, to make or take physical delivery of ZECs, which are nonfinancial commodities; and (c) that the transaction is not a "swap" under the Commodity Exchange Act and the CFTC regulations, interpretations and guidance promulgated thereunder.

Section 15.2. Taxes. Seller shall be responsible for and obligated to pay all present and future taxes, fees and levies that may be assessed by any entity upon the Seller's delivery of ZECs to NYSERDA, or with respect to the creation of the ZECs and/or the energy with which they are associated, and, if any, for the registration of the Facility in the NYGATS and the delivery of the ZEC Certificates.

Section 15.3. Term. Unless earlier terminated pursuant to the terms hereof, this Agreement shall commence on the Effective Date and expire upon the expiration of the Contract Term, provided that payment has been made for all ZECs for which payment is properly due. Upon such date or upon earlier termination of this Agreement under Article XIII, neither Party shall have any further obligation to the other, except that Sections 15.1, 18.1, 18.2, 18.3, 18.4 **,** and NYSERDA's payment obligation under Article IV shall survive.

Section 15.4. Waiver. Either Party to this Agreement may (a) extend the time for the performance of any of the obligations or other acts of the other Party, (b) waive any inaccuracies in the representations and warranties of the other Party contained herein or in any document delivered by the other Party pursuant hereto or (c) waive compliance with any of the agreements or conditions of the other party contained herein. Any such extension or waiver shall be valid only if set forth in an instrument in writing signed by the Party to be bound thereby. Any waiver of any term or condition shall not be construed as a waiver of any subsequent breach or a subsequent waiver of the same term or condition, or a waiver of any other term or condition, of this Agreement. No provision of this Agreement will be deemed to have been waived unless the waiver is in writing, and no delay by either Party in exercising its rights hereunder, including the right to terminate this Agreement, shall be deemed to constitute or evidence any waiver by either Party of any right hereunder. The rights granted in this Agreement are cumulative of every other right or remedy that the enforcing Party may otherwise have at law or in equity or by statute.

Section 15.5. Independent Contractor. The status of the Seller under this Agreement shall be that of an independent contractor and not that of an agent, and in accordance with such status, Seller and its respective officers, agents, employees, representatives and servants shall at all times during the term of this Agreement conduct themselves in a manner consistent with such status and by reason of this Agreement shall neither hold themselves out as, nor claim to be acting in the capacity of, officers, employees, agents, representatives or servants of NYSERDA nor make any claim, demand or application for any right or privilege applicable to NYSERDA, including rights or privileges derived from workers' compensation coverage, unemployment insurance benefits, social security coverage and retirement membership or credit.

Section 15.6. Severability. If any provision of this Agreement shall be declared by any court of competent jurisdiction to be illegal, void or unenforceable, all other provisions of this Agreement shall not be affected and shall remain in full force and effect. If any provision of this Agreement is so broad as to be unenforceable, that provision shall be interpreted to be only so broad as will enable it to be enforced.

Section 15.7. Seller Expense. Seller shall, at its own expense, make all arrangements necessary to register the Facility and transfer ZECs to NYSERDA through NYGATS in accordance with the NYGATS Operating Rules.

Section 15.8. Further Assurances. Each Party shall execute and deliver to the other Party any instrument or other document reasonably requested by the other Party to give effect to the agreement of the Parties reflected herein.

Section 15.9. Waiver of Relief from Contract. Neither Party shall unilaterally seek to obtain from any Governmental Authority any relief changing the ZEC Price, each Party's obligations or any other economic terms and conditions of this Agreement. To the extent that any non-Party shall seek such relief, the Parties further covenant not to support such action.

Section 15.10. Governing Law; Venue. This Agreement shall be governed by, and construed in accordance with the laws of the State of New York applicable to contracts executed and to be performed in New York State without regard to its conflicts of laws principles. The parties irrevocably acknowledge and accept that all actions arising under or relating to this Agreement, and the transactions contemplated hereby and thereby shall be brought exclusively in a United States District Court or New York State Court located in Albany, New York having subject matter jurisdiction over such matters, and each of the Parties hereby consents to and accepts such personal jurisdiction of, and waives any objection as to the laying of venue in, such courts for purposes of such action.

Section 15.11. Laws of the State of New York. Seller shall comply with all of the requirements set forth in Exhibit A hereto.

Section 15.12. No Third Party Beneficiaries. Nothing herein is intended to or should be construed to create any rights of any kind whatsoever in third persons not parties to this Agreement.

Article XVI

Notices, Entire Agreement, Amendment, Counterparts, Good Faith Negotiation

Section 16.1 . Notices.

(a) All notices, requests, consents, approvals and other communications which may or are required to be given by either party to the other under this Agreement shall be in writing and shall be transmitted either:

(1) via certified or registered United States mail, return receipt requested;

(2) by personal delivery;

(3) by expedited delivery service; or

(4) by e-mail, return receipt requested.

Such notices shall be addressed as follows, or to such different addresses as the Parties may from time-to-time designate as set forth in paragraph (c) below:

To Seller:

Nine Mile Point Nuclear Station, LLC
c/o Exelon Generation Company, LLC
1310 Point Street
Baltimore, MD 21231
Attn: General Counsel
E:mail Address: david.dardis@constellation.com

To NYSERDA:	NYSERDA Attn: Office of the General Counsel 17 Columbia Circle Albany, New York 12203-6399 E:mail address: pete.keane@nyserda.ny.gov
With a copy to:	NYSERDA Attn: Peter Keane 17 Columbia Circle Albany, New York 12203-6399

(b) Any such notice shall be deemed to have been given either at the time of personal delivery or, in the case of expedited delivery service or certified or registered United States mail, as of the date of first attempted delivery at the address and in the manner provided herein, or in the case of facsimile transmission or email, upon receipt of an email acknowledgement of receipt.

(c) The Parties may, from time to time, specify any new or different address in the United States as their address for purpose of receiving notice under this Agreement by giving fifteen (15) days' written notice to the other Party sent in accordance herewith. The Parties agree to mutually designate individuals as their respective representatives for the purposes of receiving notices under this Agreement. Additional individuals may be designated in writing by the Parties for purposes of implementation and administration/billing, resolving issues and problems and/or for dispute resolution.

Section 16.2. Entire Agreement; Amendment. This Agreement embodies the entire agreement and understanding between NYSERDA and the Seller and supersedes all prior agreements and understandings relating to the subject matter hereof. Except as otherwise expressly provided for herein, this Agreement may be amended, modified, changed, waived, discharged or terminated only by an instrument in writing, signed by the Party against which enforcement of such amendment, modification, change, waiver, discharge or termination is sought.

Section 16.3. Counterparts. This Agreement may be executed in counterparts each of which shall be deemed an original, but all of which taken together shall constitute one and the same instrument.

Section 16.4. Good Faith Negotiation. Both Parties agree that, should any dispute arise during the term of this Agreement, the Parties will make a good faith though non-binding effort to reconcile any difference or dispute before the filing of an action in any court.

Article XVII

Publicity

Section 17.1. Publicity. On or prior to the Effective Date, the Parties will collaborate with regard to the preparation and issuance of any initial press release or public announcement with respect to the Parties' entry into this Agreement.

Article XVIII

Confidentiality

Section 18.1. Seller will be required to waive confidentiality, as to NYSERDA and the NYGATS, for the direct transfer to NYSERDA of data pertinent to the verification of ZEC creation.

Section 18.2. Freedom of Information Law. Seller acknowledges that NYSERDA is subject to and must comply with the requirements of New York's Freedom of Information Law ("FOIL;" see Public Officers' Law Article 6).

Section 18.3. Claim of Confidentiality. Information of any tangible form including any document that Seller wishes to be protected from disclosure to third parties, must be marked "Confidential" or "Proprietary" at the time such information is provided to NYSERDA.

Section 18.4. Trade Secrets/Commercial Information. The FOIL Law (Public Officers Law § 87(d)(2)) provides an exception to disclosure for records or portions thereof that "are trade secrets or are submitted to an agency by a commercial enterprise or derived from information obtained from a commercial enterprise and which if disclosed would cause substantial injury to the competitive position of the subject enterprise. " If NYSERDA receives a request from a third party for information or a document received from Seller and which has been marked "Confidential" or "Proprietary," NYSERDA will process such request under the procedures provided by NYSERDA's FOIL regulations.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed and delivered by their duly authorized representatives.

Nine Mile Point Nuclear Station, LLC

By: /s/ Bruce Wilson

Name: Bruce Wilson

Title Secretary

New York State Energy Research And Development Authority

By: /s/ John B. Rhodes

Title President and CEO

STATE OF _____)

) SS:

COUNTY OF _____)

On the _____day of _____, 20 _____, before me, the undersigned, personally appeared _____, personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her/their signature(s) on the instrument, the individual(s), or the person on behalf of which the individual(s) acted, executed the instrument.

_____

Notary

[Signature Page to ZEC Standard Agreement (Nine Mile Point)]

EXHIBIT A

REVISED 5/12

STANDARD TERMS AND CONDITIONS
FOR ALL NYSERDA AGREEMENTS

(Based on Standard Clauses for New York State Contracts and Tax Law Section 5-a)

The parties to the Agreement agree to be bound by the following clauses which are hereby made a part of the Agreement:

1. NON-DISCRIMINATION REQUIREMENTS. To the extent required by Article 15 of the Executive Law (also known as the Human Rights Law) and all other State and Federal statutory and constitutional non-discrimination provisions, the Contractor will not discriminate against any employee or applicant for employment because of race, creed, color, sex, national origin, sexual orientation, age, disability, genetic predisposition or carrier status, or marital status. Furthermore, in accordance with Section 220-e of the Labor Law, if this is an Agreement for the construction, alteration or repair of any public building or public work or for the manufacture, sale or distribution of materials, equipment or supplies, and to the extent that this Agreement shall be performed within the State of New York, Contractor agrees that neither it nor its subcontractors shall, by reason of race, creed, color, disability, sex or national origin: (a) discriminate in hiring against any New York State citizen who is qualified and available to perform the work; or (b) discriminate against or intimidate any employee hired for the performance of work under this Agreement. If this is a building service Agreement as defined in Section 230 of the Labor Law, then, in accordance with Section 239 thereof, Contractor agrees that neither it nor its subcontractors shall, by reason of race, creed, color, national origin, age, sex or disability: (a) discriminate in hiring against any New York State citizen who is qualified and available to perform the work; or (b) discriminate against or intimidate any employee hired for the performance of work under this contract. Contractor is subject to fines of $50.00 per person per day for any violation of Section 220-e or Section 239 as well as possible termination of this Agreement and forfeiture of all moneys due hereunder for a second subsequent violation.

2. WAGE AND HOURS PROVISIONS. If this is a public work Agreement covered by Article 8 of the Labor Law or a building service Agreement covered by Article 9 thereof, neither Contractor's employees nor the employees of its subcontractors may be required or permitted to work more than the number of hours or days stated in said statutes, except as otherwise provided in the Labor Law and as set forth in prevailing wage and supplement schedules issued by the State Labor Department. Furthermore, Contractor and its subcontractors must pay at least the prevailing wage rate and pay or provide the prevailing supplements, including the premium rates for overtime pay, as determined by the State Labor Department in accordance with the Labor Law. Additionally, effective April 28, 2008, if this is a public work contract covered by Article 8 of the Labor Law, the Contractor understands and agrees that the filing of payrolls in a manner consistent with Subdivision 3-a of Section 220 of the Labor Law shall be a condition precedent to payment by NYSERDA of any NYSERDA-approved sums due and owing for work done upon the project.

3. NON-COLLUSIVE BIDDING REQUIREMENT . In accordance with Section 2878 of the Public Authorities Law, if this Agreement was awarded based upon the submission of bids, Contractor warrants, under penalty of perjury, that its bid was arrived at independently and without collusion aimed at restricting competition. Contractor further warrants that, at the time Contractor submitted its bid, an authorized and responsible person executed and delivered to NYSERDA a non-collusive bidding certification on Contractor's behalf.

4. INTERNATIONAL BOYCOTT PROHIBITION . If this Agreement exceeds $5,000, the Contractor agrees, as a material condition of the Agreement, that neither the Contractor nor any substantially owned or affiliated person, firm, partnership or corporation has participated, is participating, or shall participate in an international boycott in violation of the Federal Export Administration Act of 1979 (50 USC App. Sections 2401 et seq.) or regulations thereunder. If such Contractor, or any of the aforesaid affiliates of Contractor, is convicted or is otherwise found to have violated said laws or regulations upon the final determination of the United States Commerce Department or any other appropriate agency of the United States subsequent to the Agreement's execution, such Agreement, amendment or modification thereto shall be rendered forfeit and void. The Contractor shall so notify NYSERDA within five (5) Business Days of such conviction, determination or disposition of appeal. (See and compare Section 220-f of the Labor Law, Section 139-h of the State Finance Law, and 2 NYCRR 105.4).

5. SET-OFF RIGHTS . NYSERDA shall have all of its common law and statutory rights of set-off. These rights shall include, but not be limited to, NYSERDA's option to withhold for the purposes of set-off any moneys due to the Contractor under this Agreement up to any amounts due and owing to NYSERDA with regard to this Agreement, any other Agreement, including any Agreement for a term commencing prior to the term of this Agreement, plus any amounts due and owing to NYSERDA for any other reason including, without limitation, tax delinquencies, fee delinquencies or monetary penalties relative thereto.

6. PROPRIETARY INFORMATION . Notwithstanding any provisions to the contrary in the Agreement, Contractor and NYSERDA acknowledge and agree that all information, in any format, submitted to NYSERDA shall be subject to and treated in accordance with the NYS Freedom of Information Law ("FOIL," Public Officers Law, Article 6). Pursuant to FOIL, NYSERDA is required to make available to the public, upon request, records or portions thereof which it possesses, unless that information is statutorily exempt from disclosure. Therefore, unless the Agreement specifically requires otherwise, Contractor should submit information to NYSERDA in a non-confidential, non-proprietary format. FOIL does provide that NYSERDA may deny access to records or portions thereof that "are trade secrets or are submitted to an agency by a commercial enterprise or derived from information obtained from a commercial enterprise and which if disclosed would cause substantial injury to the competitive position of the subject enterprise." [See Public Officers Law, § 87(2)(d)]. Accordingly, if the Agreement specifically requires submission of information in a format Contractor considers a proprietary and/or confidential trade secret, Contractor shall fully identify and plainly label the information "confidential" or "proprietary" at the time of disclosure. By so marking such information, Contractor represents that the information has actual or potential specific commercial or competitive value to the competitors of Contractor. Without limitation, information will not be considered confidential or proprietary if it is or has been (i) generally known or available from other sources without obligation concerning its confidentiality; (ii) made available by the owner

to others without obligation concerning its confidentiality; or (iii) already available to NYSERDA without obligation concerning its confidentiality. In the event of a FOIL request, it is NYSERDA's policy to consider records as marked above pursuant to the trade secret exemption procedure set forth in 21 New York Codes Rules & Regulations § 501.6 and any other applicable law or regulation. However, NYSERDA cannot guarantee the confidentiality of any information submitted. More information on FOIL, and the relevant statutory law and regulations, can be found at the website for the Committee on Open Government (http://www.dos.state.ny.us/coog/foil2.html) and NYSERDA's Regulations, Part 501 (http://www.nyserda.ny.gov/About/New-York-State-Regulations.aspx).

7. IDENTIFYING INFORMATION AND PRIVACY NOTIFICATION . (a) FEDERAL EMPLOYER IDENTIFICATION NUMBER and/or FEDERAL SOCIAL SECURITY NUMBER. As a condition to NYSERDA's obligation to pay any invoices submitted by Contractor pursuant to this Agreement, Contractor shall provide to NYSERDA its Federal employer identification number or Federal social security number, or both such numbers when the Contractor has both such numbers. Where the Contractor does not have such number or numbers, the Contractor must give the reason or reasons why the payee does not have such number or numbers.

(b) PRIVACY NOTIFICATION **.** The authority to request the above personal information from a seller of goods or services or a lessor of real or personal property, and the authority to maintain such information, is found in Section 5 of the State Tax Law. Disclosure of this information by Contractor to the State is mandatory. The principal purpose for which the information is collected is to enable the State to identify individuals, businesses and others who have been delinquent in filing tax returns or may have understated their tax liabilities and to generally identify persons affected by the taxes administered by the Commissioner of Taxation and Finance. The information will be used for tax administration purposes and for any other purpose authorized by law.

8. CONFLICTING TERMS . In the event of a conflict between the terms of the Agreement (including any and all attachments thereto and amendments thereof) and the terms of this Exhibit A, the terms of this Exhibit A shall control.

9. GOVERNING LAW . This Agreement shall be governed by the laws of the State of New York except where the Federal supremacy clause requires otherwise.

10. NO ARBITRATION . Disputes involving this Agreement, including the breach or alleged breach thereof, may not be submitted to binding arbitration (except where statutorily required) without the NYSERDA's written consent, but must, instead, be heard in a court of competent jurisdiction of the State of New York.

11. SERVICE OF PROCESS . In addition to the methods of service allowed by the State Civil Practice Law and Rules ("CPLR"), Contractor hereby consents to service of process upon it by registered or certified mail, return receipt requested. Service hereunder shall be complete upon Contractor's actual receipt of process or upon NYSERDA's receipt of the return thereof by the United States Postal Service as refused or undeliverable. Contractor must promptly notify NYSERDA, in writing, of each and every change of address to which service of process can be made. Service by NYSERDA to the last known address shall be sufficient. Contractor will have thirty (30) calendar days after service hereunder is complete in which to respond.

12. CRIMINAL ACTIVITY. If subsequent to the effectiveness of this Agreement, NYSERDA comes to know of any allegation previously unknown to it that the Contractor or any of its principals is under indictment for a felony, or has been, within five (5) years prior to submission of the Contractor's proposal to NYSERDA, convicted of a felony, under the laws of the United States or Territory of the United States, then NYSERDA may exercise its stop work right under this Agreement. If subsequent to the effectiveness of this Agreement, NYSERDA comes to know of the fact, previously unknown to it, that Contractor or any of its principals is under such indictment or has been so convicted, then NYSERDA may exercise its right to terminate this Agreement. If the Contractor knowingly withheld information about such an indictment or conviction, NYSERDA may declare the Agreement null and void and may seek legal remedies against the Contractor and its principals. The Contractor or its principals may also be subject to penalties for any violation of law which may apply in the particular circumstances. For a Contractor which is an association, partnership, corporation, or other organization, the provisions of this paragraph apply to any such indictment or conviction of the organization itself or any of its officers, partners, or directors or members of any similar governing body, as applicable.

13. PERMITS. It is the responsibility of the Contractor to acquire and maintain, at its own cost, any and all permits, licenses, easements, waivers and permissions of every nature necessary to perform the work.

14. PROHIBITION ON PURCHASE OF TROPICAL HARDWOODS. The Contractor certifies and warrants that all wood products to be used under this Agreement will be in accordance with, but not limited to, the specifications and provisions of State Finance Law Section 165 (Use of Tropical Hardwoods), which prohibits purchase and use of tropical hardwoods, unless specifically exempted by NYSERDA.

15. OMNIBUS PROCUREMENT ACT OF 1992. It is the policy of New York State to maximize opportunities for the participation of New York State business enterprises, including minority and women-owned business enterprises as bidders, subcontractors and suppliers on its procurement contracts.

Information on the availability of New York State subcontractors and suppliers is available from:

NYS Department of Economic Development
Division for Small Business
625 Broadway
Albany, New York 12207
Telephone: 518-292-5200
Fax: 518-292-5884
http://www.esd.ny.gov
http://www.esd.ny.gov

A directory of certified minority and women-owned business enterprises is available from:

NYS Department of Economic Development
Division of Minority and Women's Business Development
625 Broadway
Albany, New York 12207
Telephone: 518-292-5200
Fax: 518-292-5803
http://www.empire.state.ny.us

The Omnibus Procurement Act of 1992 requires that by signing this Agreement, Contractors certify that whenever the total amount is greater than $1 million:

(a) The Contractor has made reasonable efforts to encourage the participation of New York State Business Enterprises as suppliers and subcontractors, including certified minority and women-owned business enterprises, on this project, and has retained the documentation of these efforts to be provided upon request to the State;

(b) The Contractor has complied with the Federal Equal Opportunity Act of 1972 (P.L. 92-261), as amended;

(c) The Contractor agrees to make reasonable efforts to provide notification to New York State residents of employment opportunities on this project through listing any such positions with the Job Service Division of the New York State Department of Labor, or providing such notification in such manner as is consistent with existing collective bargaining contracts or agreements. The Contractor agrees to document these efforts and to provide said documentation to the State upon request; and

(d) The Contractor acknowledges notice that the State may seek to obtain offset credits from foreign countries as a result of this contract and agrees to cooperate with the State in these efforts.

16. RECIPROCITY AND SANCTIONS PROVISIONS . Bidders are hereby notified that if their principal place of business is located in a country, nation, province, state or political subdivision that penalizes New York State vendors, and if the goods or services they offer will be substantially produced or performed outside New York State, the Omnibus Procurement Act 1994 and 2000 amendments (Chapter 684 and Chapter 383, respectively) require that they be denied contracts which they would otherwise obtain. NOTE: As of May 15, 2002, the list of discriminatory jurisdictions subject to this provision includes the states of South Carolina, Alaska, West Virginia, Wyoming, Louisiana and Hawaii. Contact NYS Department of Economic Development for a current list of jurisdictions subject to this provision.

17. COMPLIANCE WITH NEW YORK STATE INFORMATION SECURITY BREACH AND NOTIFICATION ACT . Contractor shall comply with the provisions of the New York State Information Security Breach and Notification Act (General Business Law Section 899-aa; State Technology Law Section 208).

18. PROCUREMENT LOBBYING. To the extent this Agreement is a "procurement contract" as defined by State Finance Law Sections 139-j and 139-k, by signing this Agreement the Contractor certifies and affirms that all disclosures made in accordance with State Finance Law Sections 139-j and 139-k are complete, true and accurate. In the event such certification is found to be intentionally false or intentionally incomplete, NYSERDA may terminate the agreement by providing written notification to the Contractor in accordance with the terms of the agreement.

19. COMPLIANCE WITH TAX LAW SECTION 5-a. The following provisions apply to Contractors that have entered into agreements in an amount exceeding $100,000 for the purchase of goods and services:

(a) Before such agreement can take effect, the Contractor must have on file with the New York State Department of Taxation and Finance a Contractor Certification form (ST-220-TD).

(b) Prior to entering into such an agreement, the Contractor is required to provide NYSERDA with a completed Contractor Certification to Covered Agency form (Form ST-220-CA).

(c) Prior to any renewal period (if applicable) under the agreement, the Contractor is required to provide NYSERDA with a completed Form ST-220-CA.

Certifications referenced in paragraphs (b) and (c) above will be maintained by NYSERDA and made a part hereof and incorporated herein by reference.

NYSERDA reserves the right to terminate this agreement in the event it is found that the certification filed by the Contractor in accordance with Tax Law Section 5-a was false when made.

20. IRANIAN ENERGY SECTOR DIVESTMENT. In accordance with Section 2879-c of the Public Authorities Law, by signing this contract, each person and each person signing on behalf of any other party certifies, and in the case of a joint bid or partnership each party thereto certifies as to its own organization, under penalty of perjury, that to the best of its knowledge and belief that each person is not on the list created pursuant to paragraph (b) of subdivision 3 of section 165-a of the State Finance Law (See www.ogs.ny.gov/about/regs/ida.asp).

EXHIBIT B

NYSERDA PROMPT PAYMENT POLICY STATEMENT

504.1. Purpose and Applicability . (a) The purpose of this Exhibit is to provide a description of Part 504 of NYSERDA's regulations, which consists of NYSERDA's policy for making payment promptly on amounts properly due and owing by NYSERDA under this Agreement. The section numbers used in this document correspond to the section numbers appearing in Part 504 of the regulations. [1]

(b) This Exhibit applies generally to payments due and owing by the NYSERDA to the Contractor pursuant to this Agreement. However, this Exhibit does not apply to Payments due and owing when NYSERDA is exercising a Set-Off against all or part of the Payment, or if a State or Federal law, rule or regulation specifically requires otherwise.

504.2. Definitions . Capitalized terms not otherwise defined in this Exhibit shall have the same meaning as set forth earlier in this Agreement. In addition to said terms, the following terms shall have the following meanings, unless the context shall indicate another or different meaning or intent:

(a) "Date of Payment" means the date on which NYSERDA requisitions a check from its statutory fiscal agent, the Department of Taxation and Finance, to make a Payment.

(b) "Designated Payment Office" means the Office of NYSERDA's Controller, located at 17 Columbia Circle, Albany, New York 12203.

(c) "Payment" means payment properly due and owing to Contractor pursuant to Article IV, Exhibit B of this Agreement.

(d) "Prompt Payment" means a Payment within the time periods applicable pursuant to Sections 504.3 through 504.5 of this Exhibit in order for NYSERDA not to be liable for interest pursuant to Section 504.6.

(e) "Payment Due Date" means the date by which the Date of Payment must occur, in accordance with the provisions of Sections 504.3 through 504.5 of this Exhibit, in order for NYSERDA not to be liable for interest pursuant to Section 504.6.

(f) "Proper Invoice" means a written request for Payment that is submitted by a Contractor setting forth the description, price or cost, and quantity of goods, property or services delivered or rendered, in such form, and supported by such other substantiating documentation, as NYSERDA may reasonably require, including but not limited to any requirements set forth in Exhibits A or B to this Agreement; and addressed to NYSERDA's Controller, marked "Attention: Accounts Payable," at the Designated Payment Office.

(g)(1) "Receipt of an Invoice" means:

[1] This is only a summary; the full text of Part 504 can be accessed at: http://www.nyserda.ny.gov/en/About/~/media/Files/About/Contact/NYSERDARegulations.ashx

(i) if the Payment is one for which an invoice is required, the later of:

(a) the date on which a Proper Invoice is actually received in the Designated Payment Office during normal business hours; or

(b) the date by which, during normal business hours, NYSERDA has actually received all the purchased goods, property or services covered by a Proper Invoice previously received in the Designated Payment Office.

(ii) if the Agreement provides that a Payment will be made on a specific date or at a predetermined interval, without having to submit a written invoice the 30th calendar day, excluding legal holidays, before the date so specified or predetermined.

(2) For purposes of this subdivision, if the Agreement requires a multifaceted, completed or working system, or delivery of no less than a specified quantity of goods, property or services and only a portion of such systems or less than the required goods, property or services are working, completed or delivered, even though the Contractor has invoiced NYSERDA for the portion working, completed or delivered, NYSERDA will not be in Receipt of an Invoice until the specified minimum amount of the systems, goods, property or services are working, completed or delivered.

(h) "Set-off" means the reduction by NYSERDA of a payment due a Contractor by an amount equal to the amount of an unpaid legally enforceable debt owed by the Contractor to NYSERDA.

504.3. Prompt Payment Schedule. Except as otherwise provided by law or regulation or in Sections 504.4 and 504.5 of this Exhibit, the Date of Payment by NYSERDA of an amount properly due and owing under this Agreement shall be no later than thirty (30) calendar days, excluding legal holidays, after Receipt of a Proper Invoice.

504.4. Payment Procedures.

(a) Unless otherwise specified in this Agreement, a Proper Invoice submitted by the Contractor to the Designated Payment Office shall be required to initiate payment for goods, property or services. As soon as any invoice is received in the Designated Payment Office during normal business hours, such invoice shall be date-stamped. The invoice shall then promptly be reviewed by NYSERDA.

(b) NYSERDA shall notify the Contractor within fifteen (15) calendar days after Receipt of an Invoice of:

(1) any defects in the delivered goods, property or services;

(2) any defects in the invoice; or

(3) suspected improprieties of any kind.

(c) The existence of any defects or suspected improprieties shall prevent the commencement of the time period specified in Section 504.3 until any such defects or improprieties are corrected or otherwise resolved.

(d) If NYSERDA fails to notify a Contractor of a defect or impropriety within the fifteen (15) calendar day period specified in subdivision (b) of this section, the sole effect shall be that the number of days allowed for Payment shall be reduced by the number of days between the 15th day and the day that notification was transmitted to the Contractor. If NYSERDA fails to provide reasonable grounds for its contention that a defect or impropriety exists, the sole effect shall be that the Payment Due Date shall be calculated using the original date of Receipt of an Invoice.

(e) In the absence of any defect or suspected impropriety, or upon satisfactory correction or resolution of a defect or suspected impropriety, NYSERDA shall make Payment, consistent with any such correction or resolution and the provisions of this Exhibit.

504.5. Exceptions and Extension of Payment Due Date . NYSERDA has determined that, notwithstanding the provisions of Sections 504.3 and 504.4 of this Exhibit, any of the following facts or circumstances, which may occur concurrently or consecutively, reasonably justify extension of the Payment Due Date:

(a) If this Agreement provides Payment will be made on a specific date or at a predetermined interval, without having to submit a written invoice, if any documentation, supporting data, performance verification, or notice specifically required by this Agreement or other State or Federal mandate has not been submitted to NYSERDA on a timely basis, then the Payment Due Date shall be extended by the number of calendar days from the date by which all such matter was to be submitted to NYSERDA and the date when NYSERDA has actually received such matter.

(b) If an inspection or testing period, performance verification, audit or other review or documentation independent of the Contractor is specifically required by this Agreement or by other State or Federal mandate, whether to be performed by or on behalf of NYSERDA or another entity, or is specifically permitted by this Agreement or by other State or Federal provision and NYSERDA or other entity with the right to do so elects to have such activity or documentation undertaken, then the Payment Due Date shall be extended by the number of calendar days from the date of Receipt of an Invoice to the date when any such activity or documentation has been completed, NYSERDA has actually received the results of such activity or documentation conducted by another entity, and any deficiencies identified or issues raised as a result of such activity or documentation have been corrected or otherwise resolved.

(c) If an invoice must be examined by a State or Federal agency, or by another party contributing to the funding of the Contract, prior to Payment, then the Payment Due Date shall be extended by the number of calendar days from the date of Receipt of an Invoice to the date when the State or Federal agency, or other contributing party to the Contract, has completed the inspection, advised NYSERDA of the results of the inspection, and any deficiencies identified or issues raised as a result of such inspection have been corrected or otherwise resolved.

(d) If appropriated funds from which Payment is to be made have not yet been appropriated or, if appropriated, not yet been made available to NYSERDA, then the Payment Due Date shall be extended by the number of calendar days from the date of Receipt of an Invoice to the date when such funds are made available to NYSERDA.

504.6. Interest Eligibility and Computation. If NYSERDA fails to make Prompt Payment, NYSERDA shall pay interest to the Contractor on the Payment when such interest computed as provided herein is equal to or more than ten dollars ($10.00). Interest shall be computed and accrue at the daily rate in effect on the Date of Payment, as set by the New York State Tax Commission for corporate taxes pursuant to Section 1096(e)(1) of the Tax Law. Interest on such a Payment shall be computed for the period beginning on the day after the Payment Due Date and ending on the Date of Payment.

504.7. Sources of Funds to Pay Interest. Any interest payable by NYSERDA pursuant to Exhibit shall be paid only from the same accounts, funds, or appropriations that are lawfully available to make the related Payment.

504.8. Incorporation of Prompt Payment Policy Statement into Contracts. The provisions of this Exhibit shall apply to all Payments as they become due and owing pursuant to the terms and conditions of this Agreement, notwithstanding that NYSERDA may subsequently amend its Prompt Payment Policy by further rulemaking.

504.9. Notice of Objection. Contractor may object to any action taken by NYSERDA pursuant to this Exhibit that prevents the commencement of the time in which interest will be paid by submitting a written notice of objection to NYSERDA. Such notice shall be signed and dated and concisely and clearly set forth the basis for the objection and be addressed to the Vice President, New York State Energy Research and Development Authority, at the notice address set forth in Exhibit B to this Agreement. The Vice President of NYSERDA, or his or her designee, shall review the objection for purposes of affirming or modifying NYSERDA's action. Within fifteen (15) working days of the receipt of the objection, the Vice President, or his or her designee, shall notify the Contractor either that NYSERDA's action is affirmed or that it is modified or that, due to the complexity of the issue, additional time is needed to conduct the review; provided, however, in no event shall the extended review period exceed thirty (30) working days.

504.10. Judicial Review. Any determination made by NYSERDA pursuant to this Exhibit that prevents the commencement of the time in which interest will be paid is subject to judicial review in a proceeding pursuant to Article 78 of the Civil Practice Law and Rules. Such proceedings shall only be commenced upon completion of the review procedure specified in Section 504.9 of this Exhibit or any other review procedure that may be specified in this Agreement or by other law, rule, or regulation.

504.11. Court Action or Other Legal Processes.

(a) Notwithstanding any other law to the contrary, the liability of NYSERDA to make an interest payment to a Contractor pursuant to this Exhibit shall not extend beyond the date of a notice of intention to file a claim, the date of a notice of a claim, or the date commencing a legal action for the payment of such interest, whichever occurs first.

(b) With respect to the court action or other legal processes referred to in subdivision (a) of this section, any interest obligation incurred by NYSERDA after the date specified therein pursuant to any provision of law other than Public Authorities Law Section 2880 shall be determined as prescribed by such separate provision of law, shall be paid as directed by the court, and shall be paid from any source of funds available for that purpose.

EXHIBIT C

CERTIFICATION FORM

NYSERDA Agreement No. _____

Name of Seller: _____

Name of Facility: _____

Invoice Number: _____

Serial Number(s): _____

Total Number of ZECs: _____

Terms used in this Certificate are used with the meanings given to such terms in the referenced NYSERDA Agreement.

Seller certifies that, to Seller's knowledge, all of the information provided on the attached invoice requesting payment from NYSERDA is true and accurate; that the ZECs delivered by Seller (identified by the serial number(s) above) by designation for transfer to NYSERDA in accordance with the NYGATS Operating Rules are free and clear of all liens, judgments, encumbrances and similar restrictions created by or on behalf of Seller or any party claiming through Seller, and have not otherwise been, nor will be, sold, retired, claimed or represented by or on behalf of Seller or any party claiming through Seller, as part of electricity output or sales, or used by or on behalf of Seller or any party claiming through Seller, to satisfy obligations in any other jurisdiction.

Seller further certifies that all representations and warranties of the Seller set forth in Section 15.1 of the NYSERDA Agreement are true and correct on the date hereof as though made on the date hereof, other than such representations and warranties that are expressly effective as of an earlier date, in which case, such representations and warranties continue to be true and correct as of such date.

Quarterly Invoice Date: _____
By: _____

EXHIBIT D
ZERO EMISSIONS CREDIT PRICING

The ZEC Price will be determined in six, 2-year Tranches, as follows:

Tranche 1: April 1, 2017 – March 31, 2019
Tranche 2: April 1, 2019 – March 31, 2021
Tranche 3: April 1, 2021 – March 31, 2023
Tranche 4: April 1, 2023 – March 31, 2025
Tranche 5: April 1, 2025 – March 31, 2027
Tranche 6: April 1, 2027 – March 31, 2029

For Tranche 1, the ZEC Price shall be $17.48.

For Tranches 2 through 6, the ZEC Price shall be as calculated by NYSERDA in consultation with DPS staff, calculated for the relevant Tranche t using the following formula:

$ZEC\ Price_t = Max(0, Base\ ZEC\ Price_t - Max(0, (Energy\ Forward\ Index_t + Capacity\ Forward\ Index_t - Zone\ A\ Reference\ Price_t)))$; where

- $Base\ ZEC\ Price_t$ shall be determined as follows for each Tranche:
  - For Tranche 2, the Base ZEC Price shall be $19.59
  - For Tranche 3, the Base ZEC Price shall be $21.38
  - For Tranches 4 through 6, the Base ZEC Price shall be determined using the following formula:

    $Base\ ZEC\ Price_t = Net\ CO2\ Externality_t \times (0.53846—(0.00491 \times Max(0, Min(26.704, (Incremental\ Renewable\ Generation_t / 1{,}000{,}000)) - 8.704)))$; where

    Net CO2 Externality shall be equal to 44.26 for Tranche 4, 49.13 for Tranche 5, and 54.13 for Tranche 6

    Incremental Renewable Generation shall be the total amount, denominated in megawatt-hours, of Renewable Energy Credits ("RECs") qualified to serve Tier 1 of the New York Renewable Energy Standard (i.e. new renewable resources of all types beginning commercial operation on or after January 1 st , 2015 that are eligible to satisfy the Renewable Energy Standard) generated in calendar years 2022, 2024, and 2026 as reported by the New York Generation Attribute Tracking System. The Incremental Renewable Generation for calendar year 2022 will be utilized in determining the Base ZEC Price for Tranche 4, the Incremental Renewable Generation for calendar year 2024 will be utilized in determining the Base ZEC Price for Tranche 5, and the Incremental Renewable Generation for calendar year 2026 will be utilized in determining the Base ZEC Price for Tranche 6.

- Energy Forward Index $_t$ shall be the average NYISO Zone A energy price forecast for the period covered by the Tranche, developed using futures prices reported on the Intercontinental Exchange ("ICE") as follows:

  1) for each trading day during the calendar year preceding each Tranche, On-Peak Monthly Forward Energy Prices and Off-Peak Monthly Forward Energy Prices for the 24 months of the Tranche will be separately averaged, yielding separate average on-peak and off-peak Tranche energy prices for each trading day;

  2) each trading day's average Tranche on-peak and off-peak energy prices (developed in step 1) will be time-weight averaged based on the number of on-peak and off peak hours in the Tranche, yielding a single average all-hours energy price for the Tranche for each trading day;

  3) the average Tranche all-hours energy prices for each of the trading days during the calendar year preceding each Tranche (developed in step 2) will be averaged, yielding the NYISO Zone A energy price forecast for the Tranche expressed in dollars per MWh.

- Capacity Forward Index $_t$ shall be the average NYISO Rest of the State capacity price forecast for the period covered by the Tranche, developed using futures prices reported on the New York Mercantile Exchange ("NYMEX") as follows:

  1) for each trading day during the final 6 months of the calendar year preceding each Tranche, NYMEX Rest of the State Capacity Calendar-Month settled futures prices for the first 12 months of the Tranche will be averaged, yielding a separate average annualized capacity price for each trading day

  2) the average annualized capacity prices for each of the trading days during the final six months of the calendar year preceding each Tranche (developed in step 1) will be averaged, yielding a single average annualized capacity price for the Tranche, expressed in dollars per kilowatt-month

  3) the average annualized capacity price developed in step 2 will be multiplied by 1.3699 to yield an average annualized capacity price for the Tranche expressed in dollars per MWh.

- Zone A Reference Price $_t$ shall be determined as follows for each Tranche:
  - For Tranche 2, the Zone A Reference Price shall be $39
  - For Tranche 3, the Zone A Reference Price shall be $39
  - For Tranches 4 through 6, the Zone A Reference Price shall be determined using the following formula:

    Zone A Reference Price $_t$ = $39 + Energy Basis Adjustment; where

    Energy basis adjustment is determined as follows:

    1) the simple average hourly day-ahead energy price over the six-year period covering calendar years 2017 through 2022 will be calculated using historic price data reported by the New York ISO for New York Zone A ("WEST (ZONE A)"), the R.E. Ginna nuclear unit generation bus ("GINNA _____"), the R.A. FitzPatrick nuclear unit generation bus ("FITZPATRICK _____"), the Nine Mile Point 1 nuclear unit generation bus ("NINE_MILE_1"), and the Nine Mile Point 2 nuclear unit generation bus ("NINE_MILE_2")

    2) each of the five six-year historical average nuclear unit generation bus energy prices will be subtracted from the six-year historical average Zone A energy price to calculate five unit-specific historic energy price basis differentials with Zone A

    3) the five unit-specific historic energy price basis differentials calculated in step 2 will be weighted by their actual six-year cumulative energy output over the 2017 through 2022 period to determine a single weighted-average historic energy basis differential, denominated in dollars per MWh.

    4) if the weighted-average historic energy basis differential calculated in step 3 is between $5 per MWh and $7 per MWh, the Energy Basis Adjustment shall be $0 per MWh

    5) If the weighted-average historic energy basis differential calculated in step 3 is less than $5 per MWh, the Energy Basis Adjustment shall be equal to the weighted-average historic energy basis differential minus $5 per MWh

    6) If the weighted-average historic energy basis differential calculated in step 3 is greater than $7 per MWh, the Energy Basis Adjustment shall be equal to the weighted-average historic energy basis differential minus $7 per MWh.

If the foregoing calculation yields a negative number, the ZEC Price shall be deemed to equal zero ($0).

Example Calculations:

Example 1:

Assumptions
Tranche 2
Energy Forward Index = $42
Capacity Forward Index = $7

Resulting ZEC Price
Base ZEC Price = $19.59
ZEC Price = $19.59 – ($42 + $7 – $39) = $9.59

Example 2:

Assumptions
Tranche 4
Energy Forward Index = $42
Capacity Forward Index = $7
Incremental Renewable Generation = 8,000,000
Energy Basis Adjustment = $0

Resulting ZEC Price
Base ZEC Price = 44.26 x (0.53846 – (.00491 x 0)) = $23.83
ZEC Price = $23.83 – ($42 + $7 – $39) = $13.83

Example 3:

Assumptions
Tranche 4
Energy Forward Index = $42
Capacity Forward Index = $7
Incremental Renewable Generation = 13,000,000
Energy Basis Adjustment = $0

Resulting ZEC Price
Base ZEC Price = 44.26 x (0.53846 – (.00491 x (13,000,000 / 1,000,000 – 8.704)) = $22.90
ZEC Price = $22.90 – ($42 + $7 – $39) = $12.90

ZEC STANDARD CONTRACT

BY AND BETWEEN

THE NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

AND

R.E. GINNA NUCLEAR POWER PLANT, LLC

DATED: NOVEMBER 18, 2016

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This Agreement is entered into as of November 18, 2016 (the "Contract Date") by and between the New York State Energy Research and Development Authority ("NYSERDA"), a public benefit corporation, having a principal business address of 17 Columbia Circle, Albany, New York 12203, and R. E. Ginna Nuclear Power Plant, LLC ("Seller"), a Maryland limited liability company, having a principal business address of 1310 Point Street, Baltimore, MD 21231. NYSERDA and Seller are each referred to herein as a "Party" and are collectively referred to herein as the "Parties." All capitalized terms shall have the meanings ascribed to them in this Agreement.

RECITALS

WHEREAS, on August 1, 2016 the New York State Public Service Commission ("PSC" or the "Commission") adopted a Clean Energy Standard ("CES") program that is intended to achieve the State of New York's environmental, public health, climate policy and economic goals, and to preserve carbon-free attributes of certain existing nuclear generation resources as a bridge to the clean energy future (Case 15-E-0302; Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard , "Order Adopting a Clean Energy Standard," issued and effective August 1, 2016) (the "CES Order"); and

WHEREAS, the CES Order established, as part of the CES, a ZEC Program (as defined below), and established a mechanism for the purchase by NYSERDA of the ZECs (as defined below) of eligible nuclear zero-carbon electric generating facilities that elect to participate in the ZEC Program where a public necessity to encourage the continued creation of the attributes is demonstrated; and

WHEREAS, in accordance with criteria set forth in the CES Order, the Commission has found that there is a public necessity to provide ZEC payments to three nuclear facilities, including the Facility (as defined below); and

WHEREAS, Seller has elected for the Facility to participate in the ZEC Program; and

WHEREAS, the CES Order provides a price to be paid by NYSERDA to Seller for each ZEC delivered to NYSERDA during Tranche 1 (as defined below), and a methodology for the calculation and determination of the price in subsequent Tranches; and

WHEREAS, the CES Order imposes an obligation on each Load Serving Entity to invest in the preservation of certain existing at-risk nuclear zero-emissions attributes to serve their retail customers and accordingly directs LSEs to enter into a contractual relationship with NYSERDA for the purchase of ZECs during each ZEC Program year based on initial forecasts of load and a balancing reconciliation at the end of each program year; and

WHEREAS, NYSERDA anticipates that it will enter into backstop agreements (each, a "Backstop Agreement") with each electric distribution company ("EDC"), as proposed in NYSERDA's Petition filed with the Commission on August 25, 2016 and any Commission order related to that Petition, to guarantee that each LSE covers its obligation to buy from NYSERDA the quantity of ZECs required by the CES Order such that NYSERDA is assured that each ZEC purchased from Seller will be sold to LSEs; and

WHEREAS, Seller agrees to sell to NYSERDA, and NYSERDA agrees to purchase from Seller, ZECs associated with the generation of energy by the Facility and pursuant to the ZEC Program, on the terms and subject to the conditions set forth herein; and

WHEREAS, the Parties recognize that the 12-year Contract Term (as defined below) is an essential item of this Agreement and that Seller has made and will make significant investments in the Facility in reliance upon the existence of such Contract Term.

NOW, THEREFORE, for and in consideration of the premises, the mutual promises and agreements set forth herein and other good and valuable consideration, the receipt, sufficiency and adequacy of which are hereby acknowledged, NYSERDA and Seller, each intending to be legally bound, agree as follows:

Article I

Definitions

The terms defined in this Article I, whenever used in this Agreement (including in any Exhibit hereto), shall have the respective meanings indicated below for all purposes of this Agreement (each such meaning to be equally applicable to the singular and the plural forms of the respective terms so defined). All references herein to a Section, Article or Exhibit are to a Section, Article or Exhibit of or to this Agreement, unless otherwise indicated. The words “hereby”, “herein”, “hereof”, “hereunder” and words of similar import refer to this Agreement as a whole (including any Exhibit) and not merely to the specific section, paragraph or clause in which such word appears. The words “include”, “includes”, and “including” shall be deemed, in every instance, to be followed by the phrase “without limitation.” Whenever the context may require, any pronoun shall include the corresponding masculine, feminine and neuter forms. Except as otherwise expressly provided herein, all references to “dollars” and “$” shall be deemed references to the lawful money of the United States of America.

“ Agreement ” means this ZEC Standard Contract, including Exhibits A (Standard Terms and Conditions For All NYSERDA Agreements); B (NYSERDA Prompt Payment Policy Statement); C (Certification Form); and D (Zero Emissions Credit Pricing), all of which are incorporated herein and made part hereof.

“ Annual ZEC Cap Amount ” means either (i) 20,603,028 ZECs, if the FitzPatrick Facility is in Commercial Operation but is not included in the Nuclear Group, and the Nuclear Group consists of the Facility and the Nine Mile Facility, (ii) 18,412,000 ZECs, if a Permanent Cessation of Operations occurs with respect to the FitzPatrick Facility prior to the FitzPatrick Facility becoming included in the Nuclear Group and the Nuclear Group consists of only the Facility and the Nine Mile Facility, or (iii) 27,618,000 ZECs, if the Nuclear Group consists of the Facility, the Nine Mile Facility and the FitzPatrick Facility, subject to adjustment pursuant to Section 5.2.

" Annual ZEC Cap Reduction Amount " means 666,666 ZECs, if the Nuclear Group consists of the Facility and the Nine Mile Facility, and 1,000,000 ZECs, if the Nuclear Group consists of the Facility, the Nine Mile Facility and the FitzPatrick Facility.

" Applicable Law " means all applicable provisions of all constitutions, treaties, statutes, laws (including the common law), rules, regulations, ordinances, and codes and any order, writ, injunction, decree, judgment, award, decision or determination of any court or any federal, state, municipal or other governmental department, commission, board, bureau, agency, authority or instrumentality, including the NYISO tariff.

" Backstop Agreement " has the meaning set forth in the recitals to this Agreement.

" Business Day " means a day on which Federal Reserve member banks are open for business. A Business Day will begin at 8:00 a.m. and end at 5:00 p.m. Eastern Prevailing Time.

" Certificate " means a certificate as defined in the NYGATS Operating Rules.

" Cessation Tranche Reduction Amount " means 18,412,000 ZECs reduced for a full Tranche which shall be pro-rated for the remaining facilities within a Tranche from the date any facility undergoes a Permanent Cessation of Operations.

" Cessation ZEC Reduction Amount " means 9,206,000 ZECs reduced for a full Contract Year which shall be pro-rated for the remaining facilities within a Contract Year from the date any facility undergoes a Permanent Cessation of Operations.

" Claiming Party " has the meaning set forth in Section 14.2.

" Commercial Operation " means a state of operations under which the Facility is physically generating electric energy, consistent with Good Utility Practice, subject to outages that are consistent with Good Utility Practice, including refueling, planned, and forced outages.

" Common Ownership " means two or more generation facilities being owned, in whole or in part, directly or indirectly, by the same ultimate parent entity or entities.

" Contract Date " has the meaning set forth in the preamble of this Agreement.

" Contract Term " means a term commencing on April 1, 2017 and continuing through March 31, 2029, subject to adjustments pursuant to Article IV (Payment) and Article V (Adjustments).

The Contract Term will be administered in six two-Contract Year Tranches, as follows:

Tranche	1:	April	1,	2017	– March	31,	2019
Tranche	2:	April	1,	2019	– March	31,	2021
Tranche	3:	April	1,	2021	– March	31,	2023
Tranche	4:	April	1,	2023	– March	31,	2025
Tranche	5:	April	1,	2025	– March	31,	2027
Tranche	6:	April	1,	2027	– March	31,	2029

" Contract Year " means a 12-month period commencing on April 1, 2017 and each subsequent 12-month period commencing on an anniversary thereof during the Contract Term.

" EDC " has the meaning set forth in the recitals to this Agreement.

" Effective Date " means the date on which ZEC Standard Contracts have been executed by NYSERDA and each of the owners of the Facility, the FitzPatrick Facility and the Nine Mile Facility.

" Enjoined " or " Enjoinment " means if any court issues a final, non-appealable order, writ, injunction, decree, judgment, award, decision or determination that invalidates or permanently terminates the ZEC Program or otherwise permanently enjoins, impedes or prevents any Party from participating in the ZEC Program or fulfilling its material obligations under this Agreement, as applicable.

" ESCO " means an "energy service company" making sales of electricity in the State of New York.

" Extended Force Majeure Event " has the meaning set forth in Section 14.3(a).

" Facility " means the R.E. Ginna nuclear facility located in Ontario, New York (PTID 23603).

" Facility Revenue Meter " means the meter on the high side of the main generator step-up transformer of the busbar of the Facility (Gen PTID: 23603), which is the meter for the Facility designated by the NYISO for measuring the output of the Facility that is referenced in Article V of the NYGATS Operating Rules as the Facility's "Revenue-Quality Meter."

" Final CES Order " has the meaning set forth in Section 13.3.

" FitzPatrick Facility " means the James A. FitzPatrick nuclear generation facility located in Scriba, New York (PTID 23598).

" Force Majeure Event " has the meaning set forth in Section 14.1.

" Force Majeure Remedy Plan " has the meaning set forth in Section 14.3(a).

" Good Utility Practice " means any of the practices, methods or acts engaged in or approved by a significant portion of the electric utility or the nuclear electric power generation industry in the United States during the relevant time period, or any of the practices, methods or acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice or method, or act to the exclusion of all others, but rather to delineate acceptable practices, methods, or acts generally accepted in the region.

" Governmental Authority " Any federal, state, local, municipal, judicial or other government or any other governmental, quasi-governmental, regulatory or administrative agency, commission, court or other authority (including for federal purposes the NYISO) lawfully exercising or entitled to exercise any administrative, executive, judicial, legislative, police, policy, regulatory or taxing authority or power.

" Load-Serving Entity " or " LSE " means any entity or individual that sells retail commodity electricity supply to an end-use customer located in New York State, including any ESCO and each electric distribution company regulated by the PSC, serving in their roles as electric commodity supplier of last resort, jurisdictional municipal utilities, community choice aggregators not otherwise served by an ESCO, customers purchasing power directly from the NYISO, and the Long Island Power Authority and the New York Power Authority to the extent the Long Island Power Authority and the New York Power Authority have voluntarily agreed to act as LSEs.

" LSE Agreement " means a contract between NYSERDA and an LSE as contemplated in the CES Order, pursuant to which NYSERDA shall sell, and LSEs shall purchase, ZECs.

" MWh " means a unit for measuring power that is equivalent to 1,000 kilowatts of electricity used continuously for one hour.

" Nine Mile Facility " means the Nine Mile Point nuclear generation facility, consisting of the Nine Mile Unit 1 and Unit 2 facilities, located in Oswego, New York (PTID 23575 and 23744, respectively).

" NRC " means the U.S. Nuclear Regulatory Commission and any successor agency thereto.

" Nuclear Group " means a group of nuclear generating facilities in New York State, consisting of the Facility and the Nine Mile Facility; provided that the "Nuclear Group" shall also include the FitzPatrick Facility if the FitzPatrick Facility comes under Common Ownership with the Facility and the Nine Mile Facility.

" NYGATS " means the New York Generation Attribute Tracking System, established by NYSERDA pursuant to the Public Authorities Law.

" NYGATS Operating Rules " means the rules, as may be amended from time to time, that govern the operation of the NYGATS by NYSERDA and its designated NYGATS Administrator, and the participation in and use of the NYGATS by users.

" NYISO " means the New York Independent System Operator, Inc.

" NYISO Rules " means the NYISO tariff, and all NYISO manuals, rules, procedures, agreements or other documents governing the participation of market participants in the NYISO markets as in effect from time to time.

" NYSERDA Prompt Payment Policy " has the meaning set forth in Exhibit B.

" NYSERDA ZEC Account " means the account established in NYGATS into which Seller shall deliver (by designation for transfer in accordance with the NYGATS Operating Rules) ZECs under the terms and conditions of this Agreement.

" Non-Claiming Party " has the meaning set forth in Section 14.2.

" Permanent Cessation of Operations " means the date upon which the Facility actually permanently shuts down and ceases operations following the filing of a Notice of Permanent Cessation of Operations with respect to a specific nuclear generation facility with the NRC pursuant to 10 C.F.R. Section 50.82(a)(1)(i).

" Public Authorities Law " means the Public Authority Act codified in the Consolidated Laws of New York at Public Authorities Law Sec. 1000 *et seq.*

" Seller ZEC Account " means the account established in the NYGATS for the deposit with NYGATS of ZECs created under the NYGATS Operating Rules for the Facility from which account Seller shall deliver ZECs(by designation for transfer in accordance with the NYGATS Operating Rules) to the NYSERDA ZEC Account under the terms and conditions of this Agreement.

" Threshold Amount " has the meaning set forth in Section 5.2(a).

" Tranche " means a two-Contract Year period for the sale of the ZECs, as set forth in the definition of "Contract Term" above.

" Tranche Cap Amount " means: (i) 41,206,056 ZECs, if the FitzPatrick Facility is in Commercial Operation and the Nuclear Group consists of the Facility and the Nine Mile Facility, (ii) 36,824,000 ZECs, if a Permanent Cessation of Operations occurs with respect to the FitzPatrick Facility prior to the FitzPatrick Facility becoming part of the Nuclear Group, and (iii) 55,236,000 ZECs, if the Nuclear Group consists of the Facility, the Nine Mile Facility and the FitzPatrick Facility.

" Tranche Cap Reduction Amount " means 1,333,333 ZECs, if the Nuclear Group consists of the Facility and the Nine Mile Facility, and 2,000,000 ZECs, if the Nuclear Group consists of the Facility, the Nine Mile Facility and the FitzPatrick Facility.

" ZEC Price " means the price that NYSERDA shall pay for each ZEC delivered by Seller (by designation for transfer in accordance with the NYGATS Operating Rules) to the NYSERDA ZEC Account during the Contract Term. The ZEC Price shall be as provided in Exhibit D.

" ZEC Program " means the zero-emissions credit requirement program as established by the PSC through the CES Order and administered by NYSERDA and its designated NYGATS administrator in accordance with the NYGATS Operating Rules.

" ZEC Quantity " means, with respect to any Contract Year, the lesser of (a) the quantity of ZECs produced by the Nuclear Group in such Contract Year and (b) the Annual ZEC Cap Amount that applies to the Nuclear Group for such Contract Year, subject to adjustments pursuant to Article IV (Payment) and Article V (Adjustments).

" Zero Carbon Electric Generating Facility " means an electric generating facility that uses energy released in the course of nuclear fission to generate electricity.

" Zero Emissions Credit " or " ZEC " means a credit for the zero-emissions attributes of one (1) MWh of electric energy production by an eligible Zero Carbon Electric Generating Facility, such as the Facility, represented by a Certificate, which credit is purchased by NYSERDA or a LSE from Seller to reduce carbon consumption by retail electric consumers in New York State, such purchases to be accomplished through NYGATS pursuant to the NYGATS Operating Rules.

Article II

Purchase and Sale of Rights to ZECs

Section 2.1. Eligibility . The Parties' respective obligations under this Agreement are expressly conditioned on the eligibility of Seller's Facility under the ZEC Program, as of the Effective Date.

Section 2.2. ZEC Sales . On the terms and subject to the conditions and provisions of this Agreement, Seller shall sell, assign, transfer, convey, and deliver to NYSERDA, and NYSERDA shall purchase, confirm transfer, and receive from Seller, all right, title and interest in ZECs measured at the Facility Revenue Meter and created in the Seller ZEC Account by NYGATS during the Contract Term at the ZEC Price and in accordance with the NYGATS Operating Rules. With respect to each Contract Year during the Contract Term, NYSERDA shall purchase from Seller such ZECs, up to the ZEC Quantity among the applicable Nuclear Group for such Contract Year, but shall not be obligated to purchase such ZECs over and above such ZEC Quantity. Seller shall, for the duration of the Contract Term, and subject to the terms and conditions of this Agreement, produce zero-emissions attributes, and, upon receipt of ZECs in the Seller ZEC Account, transfer such ZECs to the NYSERDA ZEC Account. For the avoidance of doubt, and except as set forth in Section 2.5, ZECs are the only product Seller is selling and NYSERDA is buying from Seller under this Agreement. Seller is not selling and NYSERDA is not purchasing any electricity or any capacity, energy, or ancillary services or other products or attributes (other than ZECs) associated with the Facility.

Section 2.3. ZEC Rights and Use . Such right, title and interest shall include perpetual and exclusive rights to all ZECs transferred under this Agreement, including the exclusive rights to claim or represent, consistent with New York State Environmental Disclosure rules: (a) that the ZECs are associated with energy that was generated by the Facility; and (b) that New York State and or the ZEC Program is responsible for the environmental benefits including reductions in emissions and/or other pollution or any other environmental benefit resulting from the generation of the energy associated with ZECs purchased hereunder.

Section 2.4. Risk of Loss . Title and risk of loss of ZECs will transfer from Seller to NYSERDA upon completion of (a) delivery by Seller of such ZECs into the NYSERDA ZEC Account (by designation for transfer in accordance with the NYGATS Operating Rules) and (b) receipt by NYSERDA of such ZECs into the NYSERDA ZEC Account (by confirmation of the transfer in accordance with the NYGATS Operating Rules). Each Party is responsible for completing all actions it is required to undertake in NYGATS to establish its respective ZEC

account and to cause the transfer of each ZEC in accordance with the NYGATS Operating Rules. Seller shall deliver all right, title and interest in and to the ZECs (by designation for transfer in accordance with the NYGATS Operating Rules) free and clear of all liens, judgments, encumbrances and restrictions created by or on behalf of Seller or any party claiming through Seller.

Section 2.5 . Other Attributes . In the event that the Facility becomes eligible for credits under any emission-trading, emissions recordation or other carbon emissions reduction regime other than the CES, NYSERDA may request that Seller take reasonable actions necessary to apply for and secure such title to such credits, to the maximum extent to which the Facility is entitled. Seller shall provide NYSERDA with evidence of taking such actions. NYSERDA and Seller shall reasonably cooperate to cause title to such credits to be conveyed to NYSERDA after such title is secured by Seller.

Section 2.6 . Equivalent Programs . This Agreement may be modified or terminated by the Commission if there is a national, NYISO, or other program instituted that pays for or internalizes the value of the Facility's zero-emissions attributes in a manner that adequately replicates the economics of the ZEC Program such that the Commission in its sole discretion is satisfied that the zero-emissions attributes are no longer at risk and that discontinuing the ZEC Program can be done in a manner that is fair to both the Facility owners and the New York State ratepayers. Nothing herein shall require NYSERDA or Seller to take any action violative of Applicable Law or an order of court of competent jurisdiction.

Section 2.7 . NYSERDA Assignment of ZECs . NYSERDA shall be free to sell, assign or transfer to any entity, or otherwise encumber, any of the ZECs NYSERDA has acquired under this Agreement, at any time and from time to time, and on such terms and conditions as NYSERDA may desire; *provided* , *however,* NYSERDA's actions must at all times be in accordance with the CES Order.

Section 2.8 . Opinions . Within thirty (30) days after the Seller receives written notice from NYSERDA stating that the Effective Date has been achieved, each Party shall deliver to the other Party an opinion of counsel (which may be an opinion of its in-house counsel) containing the opinions supporting the Seller's and NYSERDA's representations and warranties set forth in Sections 9.1(a), (b) and (c) and Sections 10.1(a), (b), (c) and (d), respectively, subject to customary assumptions, qualifications and exceptions.

Section 2.9 . ZEC Sales to LSEs . To the extent permitted by the Commission and the CES Order, Seller may sell ZECs directly to LSEs. The Parties shall undertake good faith efforts to negotiate required amendments to this Agreement to account for such ZEC sales by Seller to LSEs.

Article III

ZEC Qualification; Operating Condition

Section 3.1 . ZEC Qualification . The Facility's electric generation production shall be measured by the Facility Revenue Meter. Such measurement shall be used as a basis for

determining pursuant to the ZEC Program the amount of ZECs related to such generation to be created and recorded in NYGATS. NYSERDA shall track (a) ZECs through NYGATS and NYSERDA's program administrator and (b) the contribution of such ZECs toward reducing carbon consumption by retail electric consumers in New York State.

Section 3.2 . Obligation to Maintain Good Operating Condition . For the duration of the Contract Term, Seller shall: (a) comply with applicable NRC requirements (including insurance requirements); (b) maintain the Facility in Commercial Operation in good operating condition in accordance with Good Utility Practice; and (c) operate the Facility in compliance with the NYISO Rules.

Article IV

Payment

Section 4.1 . Invoices . Seller shall submit invoices to NYSERDA on a quarterly basis throughout the Contract Term for ZECs created in the Seller ZEC Account by NYGATS for the preceding three (3) month period in accordance with the NYGATS Operating Rules and delivered (by designation for transfer in accordance with the NYGATS Operating Rules) to the NYSERDA ZEC Account. Each invoice shall be accompanied by a CERTIFICATION FORM, the form of which is set forth as Exhibit C, setting forth the ZECs to be delivered. Invoices shall not be submitted before the fifteenth (15) day of the month following the close of each quarter; invoices submitted prior to the fifteenth (15) day of the month following the close of each quarter shall not be considered proper invoices for purposes of NYSERDA's Prompt Payment Policy. Invoices shall be submitted electronically to NYSERDA's online invoice system at https://services.nyserda.ny.gov/Invoices/ with a copy to the Office of the General Counsel at general.counsel@nyserda.ny.gov. Such invoices shall make reference to the Agreement number shown on page 1 of this Agreement. Such invoices shall include a statement of the amount due and payable by NYSERDA to Seller, which amount shall be calculated in accordance with Section 4.2.

Section 4.2 . Payment . NYSERDA will confirm receipt of ZECs in accordance with the NYGATS Operating Rules and make payment to Seller for ZECs delivered, subject to true-up pursuant to Article V. NYSERDA will not confirm receipt and will not pay, with respect to any Contract Year, for ZECs in excess of the applicable ZEC Quantity. The amounts payable shall be calculated as the multiplicative product of (a) the applicable ZEC Price; and (b) the number of ZECs delivered by Seller up to the applicable ZEC Quantity (by designation for transfer in accordance with the NYGATS Operating Rules) to the NYSERDA ZEC Account prior to the date on invoice.

Section 4.3 . Prompt Payment Policy . NYSERDA will make payments to the Seller in accordance with and subject to its Prompt Payment Policy Statement, attached hereto as Exhibit B. Such payments shall be made by wire transfer to an account designated by the Seller.

Section 4.4 . Limitation on ZEC Purchase Obligation . Notwithstanding any other provision in this Agreement to the contrary, Seller acknowledges that NYSERDA's ability to make payments hereunder is limited to the amount NYSERDA realizes from ZEC sales transactions to LSEs, which obligations will be guaranteed by agreements NYSERDA anticipates entering into with each EDC, in accordance with the CES Order; provided, however, that if so authorized by the Commission, NYSERDA shall use available funds which NYSERDA has rights to use, in accordance with the Commission's authorization to make payments hereunder if the proceeds from such ZEC sales transactions are not sufficient to cover NYSERDA's payment obligations hereunder. Notwithstanding NYSERDA's obligation pursuant to Section 4.5 to enforce agreements to ensure that it can meet its obligations hereunder, NYSERDA shall not be obligated to purchase ZECs to the extent it does not have sufficient funds (from those referenced in the immediately preceding sentence) to do so, including in the event that NYSERDA, LSEs or EDCs are precluded by a court of competent jurisdiction from fulfilling their respective obligations under the ZEC Program. In the event that NYSERDA suffers a cash shortfall in the manner described in this Section 4.4, NYSERDA shall, subject to Applicable Law, use its sole discretion in purchasing reduced ZECs pro rata across all of the facilities to the extent possible.

Section 4.5 . LSE Agreements . NYSERDA shall use commercially reasonable efforts, as authorized by the Commission, to enter into and maintain LSE Agreements in sufficient numbers and with sufficient pricing and on such other terms and conditions as NYSERDA may determine necessary or appropriate to enable NYSERDA to fulfill its payment obligations under this Agreement. Subject to Applicable Law, NYSERDA shall use commercially reasonable efforts to enforce its rights and remedies under each of its LSE Agreements and under any related EDC guarantee commitments.

Article V

Adjustments

Section 5.1. True-Up Adjustments . NYSERDA may adjust, including by means of set-off, payments to subsequent invoices consistent with adjustments by NYGATS based on actual metered electric energy production data from the Facility Revenue Meter, associated ZEC creation data and the number of ZECs delivered and received; provided, however, NYSERDA's right to a specific payment adjustment under this Section 5.1 shall expire three (3) years after the issuance of Seller's invoice to which such payment adjustment relates.

Section 5.2. Other Adjustments . NYSERDA may also make the following adjustments under the following circumstances:

(a) Failure to Produce . If during any Tranche, the Nuclear Group fails to generate in the aggregate an amount of electric energy sufficient to support the creation of ZECs pursuant to the ZEC Program in an amount equal to at least eighty-five percent (85%) of the applicable Tranche Cap Amount (the "Threshold Amount"), then the Annual ZEC Cap Amount and the Tranche Cap Amount applicable to the Nuclear Group in the immediately subsequent Tranche shall decrease by the applicable Annual ZEC Cap Reduction Amount and the applicable Tranche Cap

Reduction Amount, respectively. If, during any subsequent Tranche, the Nuclear Group generates in the aggregate an amount of electric energy sufficient to support the creation of ZECs pursuant to the ZEC Program in an amount at or above the new lower cap and obligation, the Annual ZEC Cap Amount and Tranche Cap Amount will be restored for the Nuclear Group in subsequent Tranches. Subject to Sections 2.2, 3.2 and 12.1(b), but notwithstanding any other provision in this Agreement to the contrary, the cap reductions described in this Section 5.2(a) shall be NYSERDA's sole remedy for Seller's failure to produce the Threshold Amount and transfer ZECs to the NYSERDA ZEC Account, in accordance with the terms of this Agreement, through the Contract Term;

(b) Permanent Cessation of Operations. As of the Contract Date, the Nuclear Group consists of the Facility and the Nine Mile Facility. If, during the Contract Term, a Permanent Cessation of Operations occurs with respect to (a) the FitzPatrick Facility or (b) the Nine Mile Facility, then, NYSERDA shall make any payments due to such facility in accordance with obligations hereunder already performed by such facility. If a Permanent Cessation of Operations occurs with respect to the FitzPatrick Facility prior to the FitzPatrick Facility becoming part of the Nuclear Group, then, effective on the date of the facility's Permanent Cessation of Operations, the Annual ZEC Cap Amount and the Tranche Cap Amount shall be modified in accordance with their respective definitions in Article I. If a Permanent Cessation of Operations occurs with respect to (a) the FitzPatrick Facility after the FitzPatrick Facility becomes part of the Nuclear Group or (b) the Nine Mile Facility, then effective on the date of the facility's Permanent Cessation of Operations, the Annual ZEC Cap Amount and the Tranche Cap Amount shall be reduced by the Cessation ZEC Reduction Amount and Cessation Tranche Reduction Amount, respectively. For the purposes of this Section 5.2(b), the Permanent Cessation of Operations of either Unit 1 or Unit 2 of the Nine Mile Facility shall constitute the Permanent Cessation of Operations of the entire Nine Mile Facility;

(c) Other Programs. This Agreement may be modified or terminated if there is a national, NYISO, or other program instituted that pays for or internalizes the value of the Facility's zero-emissions attributes in a manner that adequately replicates the economics of the ZEC Program such that the Commission in its sole discretion is satisfied that the zero-emissions attributes are no longer at risk and that discontinuing the mechanism can be done in a manner that is fair to both the Facility owners and the New York State ratepayers. Nothing herein shall require NYSERDA or Seller to take any action violative of Applicable Law or an order of court of competent jurisdiction; and

(d) LSE Agreements. If, during the Contract Term, the Seller enters into an agreement with an LSE for the sale of ZECs, the Annual ZEC Cap Amount and the Tranche Cap Amount, as the case may be, shall be reduced by the same number of ZECs that Seller contracts to sell to the LSE; *provided* that, for the Tranche in which the effective date of such contract occurs, such modifications shall be made on a pro rata basis.

Article VI

Records and Reports

Section 6.1. Additional Documents . Within ten (10) Business Days after Seller receives written notice from NYSERDA stating that the Effective Date has been achieved, Seller shall provide to NYSERDA:

(a) certificates, dated as of the most recent practicable date prior to delivery of the opinion referenced in Section 2.8, issued by the Maryland Secretary of State confirming the corporate good standing of the Seller; and

(b) a certificate of an appropriate officer of the Seller in form and substance reasonably satisfactory to NYSERDA and certifying: (i) the names and signatures of the officers of the Seller authorized to sign any documents to be delivered hereunder; and (ii) the accuracy and completeness of resolutions of the Seller, authorizing and approving all matters in connection with the transactions contemplated thereby.

Seller shall promptly provide NYSERDA with updated and corrected versions of the above-referenced certificates upon any change in the information provided therein.

Section 6.2. Maintenance of Records . The Seller shall keep, maintain, and preserve at its principal office throughout the term of the Agreement and for a period of seven (7) years following the expiration of this Agreement, full and detailed books, accounts, and records pertaining to Seller's performance under the Agreement.

Article VII

Audit; Alternative Pricing Source

Section 7.1. Audit . NYSERDA shall have the right from time to time and at all reasonable times during the Contract Term and such period thereafter, upon reasonable notice to Seller, to inspect and audit any and all books, accounts and records pertaining to Seller's performance under this Agreement, at the office or offices of the Seller where they are then being kept, maintained and preserved. If such books, accounts and records are not kept at an office within the State of New York, within a reasonable time of a request by NYSERDA, Seller shall make such books, accounts and records available to NYSERDA at NYSERDA's offices or at an agreed upon location within the State of New York. Any payment made under this Agreement shall be subject to retroactive adjustment (reduction or increase) regarding amounts included therein which are found by NYSERDA on the basis of any audit of the Seller by an agency of the United States, the State of New York or NYSERDA not to constitute a properly invoiced amount.

Section 7.2. Alternative Pricing Source . If any of the prices utilized in Exhibit D of this Agreement fail to be announced or published by the relevant provider, or are otherwise

unavailable on a temporary or permanent basis, promptly upon becoming aware of such circumstances, the Parties shall negotiate in good faith to agree upon a mutually acceptable alternative pricing source, index or calculation method that most closely approximates the discontinued prices, subject to Commission authorization as necessary.

Article VIII

Assignments

Section 8.1. General Restrictions . Except as specifically provided under Section 8.2, the assignment, transfer, conveyance, subcontracting or other disposal of this Agreement or any of the Seller's rights, obligations, interests or responsibilities hereunder, in whole or in part, without the express prior consent (not to be unreasonably withheld, conditioned or delayed) in writing of NYSERDA shall be void and of no effect as to NYSERDA. Seller agrees to compensate NYSERDA for NYSERDA's reasonable costs and expenses incurred by its use of outside attorneys, consultants, accountants and advisors in connection with this Agreement in response to Seller's requests made pursuant to this Section 8.1. NYSERDA shall provide an invoice to Seller for such charges, with appropriate documentation, and Seller shall pay such invoice within thirty (30) Days.

Section 8.2. Permitted Assignments . Notwithstanding the general restriction in Section 8.1:

(a) Seller may, without NYSERDA's prior written consent, grant a security interest in or conditionally assign this Agreement as collateral in connection with financing arrangements; provided that Seller provides prompt notice to NYSERDA of such collateral assignment;

(b) Seller may, without NYSERDA's prior written consent, assign, transfer or convey Seller's rights, obligations, interests or responsibilities hereunder pursuant to an assignment or transfer of Seller's license to operate approved by the NRC; and

(c) any change in ownership or control of Seller or a direct or indirect parent of Seller shall not require the prior written consent of NYSERDA; provided that Seller shall provide NYSERDA with any NRC or Commission filings with respect to such change in ownership or control promptly after such filings have been submitted to the NRC or the Commission.

Article IX

Seller's Representations and Warranties

Section 9.1. As a material inducement to NYSERDA to enter into this Agreement, Seller makes the following representations and warranties, as of the Effective Date, all of which shall survive the execution and delivery of this Agreement and any termination:

(a) (1) that Seller is a limited liability company duly organized, validly existing and in good standing under the laws of the jurisdiction of its organization; (2) has all requisite limited liability company power, and has all material governmental permits necessary to own its assets or lease and operate its properties and carry on

its business as now being or as proposed to be conducted, to construct, finance, own, maintain and operate the Facility, to execute and deliver this Agreement, and to consummate the transactions contemplated herein; and (3) is qualified to do business and is in good standing in all jurisdictions in which the nature of the business conducted by it makes such qualification necessary;

(b) that the execution, delivery and performance by Seller, the entry into this Agreement by Seller, and the consummation of the transactions contemplated by this Agreement: (1) have been duly authorized by all requisite limited liability company action (including any required action of its members); and (2) will not (i) violate any applicable provision of law, statute, rule, regulation or order of any governmental agency or any provision of the limited liability company agreement or other governing documents of Seller; (ii) violate, conflict with, result in a breach of or constitute (alone or with notice or lapse of time or both) a default or an event of default under any indenture, agreement (including the respective limited liability company agreements of Seller), mortgage, deed of trust, note, lease, contract or other instrument to which Seller is a party or by which it or any of its property is bound; or (iii) result in the creation or imposition of any lien upon any property or assets of the Seller;

(c) that this Agreement has been duly executed and delivered by Seller and constitutes the legal, valid and binding obligation of Seller enforceable against Seller in accordance with the terms thereof; and

(d) that Seller is in compliance with Applicable Law that may in any way affect the performance of this Agreement, except where the failure to so comply would not result in a material adverse effect on Seller's ability to perform its material obligations hereunder.

Article X

NYSERDA's Representations and Warranties

Section 10.1. As a material inducement to Seller to enter into this Agreement, NYSERDA makes the following representations and warranties, as of the Effective Date, all of which shall survive the execution and delivery of this Agreement and any termination:

(a) that NYSERDA is an instrumentality of the State of New York and a public authority and public benefit corporation, created under the New York State Public Authorities Law, validly existing and in good standing under the laws of the State of New York;

(b) that NYSERDA has all necessary power and authority to execute and deliver this Agreement and all other agreements contemplated herein and hereby and to consummate the transactions contemplated hereby and thereby. The execution and delivery by NYSERDA of this Agreement and all other agreements contemplated herein and hereby and the consummation of the transactions

contemplated hereby and thereby have been or, if not yet executed and delivered, will be when executed and delivered, and no other actions or proceedings on the part of NYSERDA are necessary to authorize this Agreement or any other agreement contemplated herein and hereby or the consummation of the transactions contemplated hereby and thereby;

(c) that the execution, delivery and performance by NYSERDA of this Agreement will not (1) violate any applicable provision of law, statute, rule, regulation or order of any governmental agency or, any provision of the Public Authorities Law; (2) violate, conflict with, result in a material breach of or constitute (alone or with notice or lapse of time or both) a material default or event of default under any indenture, agreement, mortgage, deed of trust, note, lease, contract or other instrument to which NYSERDA is a party or by which NYSERDA or any of its property is bound; (3) result in the creation or imposition of any lien upon any property or assets of NYSERDA; or (4) require any consent or approval of, registration or filing with, or any other action by, any Governmental Authority, except such as have been obtained or made and are in full force and effect. This Agreement will not conflict with any other agreement or contract to which NYSERDA is a party;

(d) that this Agreement has been duly executed and delivered by NYSERDA and constitutes the legal, valid and binding obligation of NYSERDA enforceable against NYSERDA in accordance with the terms thereof;

(e) that NYSERDA is familiar with and in compliance with Applicable Law, except where the failure to so comply would not result in a material adverse effect on NYSERDA's ability to perform its material obligations hereunder; and

(f) that there is no action, suit or claim at law or in equity, or before or by a Governmental Authority pending or, to the best knowledge of NYSERDA after due inquiry, threatened against NYSERDA or affecting any of its properties or assets which could reasonably be expected to result in a material adverse effect on NYSERDA's ability to perform its obligations.

Article XI

Indemnification

Section 11.1. Indemnification . Seller shall protect, indemnify and hold harmless NYSERDA and their respective officials, trustees, officers, directors, employees, agents, representatives and contractors from and against all liabilities, losses, claims, damages, judgments, penalties, causes of action, costs and expenses (including reasonable attorneys' and/or experts' fees and expenses) imposed upon or incurred by or asserted against NYSERDA resulting from, arising out of or relating to Seller's material breach of this Agreement. The obligations of Seller under this Article shall survive any expiration or Termination of this Agreement, and shall not be limited by any enumeration herein of required insurance coverage.

Article XII

Events of Default

Section 12.1. Event of Default . For the purposes of this Agreement, "Event of Default" shall mean any of the following:

(a) Representations and Warranties . Any representation or warranty made in this Agreement that shall prove to have been false or misleading in any material respect as of the time made or deemed to be made;

(b) Other Obligations . A Party shall default in the performance of any of its obligations under Sections 2.2, 2.4, 3.2, 4.2, 6.2 and 7.1 of this Agreement and such default shall continue unremedied for a period of thirty (30) days after the defaulting Party receives notice thereof;

(c) Voluntary Proceedings . A Party shall (i) apply for or consent to the appointment of, or the taking of possession by, a receiver, custodian, trustee or liquidator of itself or of all or a substantial part of its property; (ii) make a general assignment for the benefit of its creditors; (iii) commence a voluntary case under the United States Bankruptcy Code; (iv) file a petition seeking to take advantage of any other law relating to bankruptcy, insolvency, reorganization, winding-up, or composition or readjustment of debts; (v) fail to convert in a timely and appropriate manner, or acquiesce in writing to, any petition filed against it in an involuntary case under the United States Bankruptcy Code; (vi) cancel this Agreement, or sell ZECs to a third party (whether by a Party or a receiver, custodian, trustee or liquidator) other than NYSERDA or (subject to Section 2.9) an LSE; or (vii) take any corporate action for the purpose of effecting any of the foregoing;

(d) Involuntary Proceedings . A proceeding or case shall be commenced against a Party, without its application or consent, in any court of competent jurisdiction, seeking (i) its liquidation, reorganization, dissolution or winding-up, or the composition or readjustment of its debts; (ii) the appointment of a trustee, receiver, custodian, liquidator or the like of all or any substantial part of its assets; (iii) similar relief under any law relating to bankruptcy, insolvency, reorganization, winding-up, or composition or adjustment of debts, and such proceeding or case shall continue undismissed, or an order, judgment or decree approving or ordering any of the foregoing shall be entered and continue unstayed and in effect, for a period of sixty (60) or more days; or an order for relief against a Party, shall be entered in an involuntary case under the Bankruptcy Code; or (iv) as part of such a proceeding, a Party, receiver, custodian, trustee or liquidator shall cancel this Agreement, or sell ZECs to a third party other than NYSERDA or (subject to the terms of Section 2.9) an LSE;

(e) Unauthorized Transfer. The transfer of any ZEC included in the ZEC Quantity by Seller to any transferee other than NYSERDA or an LSE as permitted by the Commission; or

(f) Abandonment/Cessation of Commercial Operation. Seller's failure to maintain Commercial Operation, Seller's abandonment of the Facility or a Permanent Cessation of Operations with respect to the Facility.

Section 12.2. Effect of an Event of Default. In addition to any other remedy available to it under this Agreement or under Applicable Law, upon any occurrence of an Event of Default, the non-defaulting Party shall be entitled to suspend performance of its obligations under this Agreement until the earlier of such time as (a) such Event of Default has been cured or (b) the non-defaulting Party has elected to terminate this Agreement pursuant to Article XIII below.

Article XIII

Termination

Section 13.1. Termination. This Agreement may be terminated:

(a) at any time by the non-defaulting Party if an Event of Default occurs and continues unremedied following any applicable notice and cure period;

(b) at any time by the mutual written consent of Seller and NYSERDA;

(c) unless otherwise mutually agreed upon by NYSERDA and Seller in writing, on the expiration of the Contract Term (subject to Section 15.3 of this Agreement);

(d) by Seller, in the event that the ZEC Price becomes zero dollars ($0) at any time during the Contract Term; or

(e) by Seller or NYSERDA upon Enjoinment.

Section 13.2. Sale of FitzPatrick Facility. Unless the Commission orders otherwise prior to the commencement of Tranche 2, should Seller fail to reasonably demonstrate to NYSERDA, on or before September 1, 2018, that the FitzPatrick Facility has been purchased and that title to the FitzPatrick Facility has passed to a third party licensee unaffiliated with the current owner of the FitzPatrick Facility, this Agreement may be terminated by NYSERDA by providing written notice thereof to Seller on or at any time after September 2, 2018, but before April 1, 2019, pursuant to which the Parties' respective obligations shall terminate at the end of Tranche 1 with no further payment or performance obligation; provided that NYSERDA shall make any payments due in accordance with obligations hereunder already performed (such termination right defined herein as the "FitzPatrick Condition"). Seller has requested clarification or rehearing from the Commission that the FitzPatrick Condition does not apply to the procurement of ZECs from the Facility.

Section 13.3. Final Order. If one or more proceedings are commenced or pending by or before any Governmental Authority seeking to modify, terminate, amend, alter, avoid or

invalidate any of the CES Order related to this Agreement or this Agreement, or any material provision thereof, the Parties shall continue to perform all of their respective obligations hereunder until such time that the Commission's decision on the CES Order and ZEC Program is final and non-appealable ("Final CES Order"). If a Final CES Order by the Commission has the effect of materially changing the original economic benefits of the ZEC Program or this Agreement for a Party (but not Enjoining the ZEC Program), the Parties shall negotiate in good faith to amend this Agreement to conform to the Final CES Order in order to effectuate as closely as reasonably possible the intent of the Parties hereunder on the Effective Date and preserve the original economic benefit to the Parties under this Agreement, subject to Commission approval as necessary. In the event that the Parties are not able to reach a mutually acceptable agreement, either Party, at its reasonable discretion, may terminate this Agreement. In the event the ZEC Program is Enjoined, either Party may terminate this Agreement pursuant to Section 13.1(e) and neither Party shall be required thereafter to perform any of the obligations under this Agreement. Notwithstanding any provision of this Section 13.3 to the contrary, nothing in this Section 13.3 shall affect the authority of the Commission to take any action pursuant to Sections 2.6 and 5.2(c) of this Agreement.

Section 13.4. Change in Law . Except as provided in Section 13.3 of this Agreement, the Parties agree that their respective obligations under this Agreement shall continue unmodified in full force and effect for the Contract Term in the event that a non-judicial Governmental Authority of the State of New York, including the Commission, modifies, terminates, amends, alters, avoids or invalidates the CES Order or the Final CES Order. Further, if any other Applicable Law has the effect of materially changing the original economic benefits of this Agreement for a Party or the economics of owning and operating the Facility, the Parties shall negotiate in good faith to amend this Agreement to conform to such new Applicable Law in order to effectuate as closely as reasonably possible the intent of the Parties hereunder on the Effective Date and preserve the original economic benefit to the Parties under this Agreement, subject to Commission approval as necessary. In the event that the Parties are not able to reach a mutually acceptable agreement, either Party, at its reasonable discretion, may terminate this Agreement. Notwithstanding any provision of this Section 13.4 to the contrary, nothing in this Section 13.4 shall affect the authority of the Commission to take any action pursuant to Sections 2.6 and 5.2(c) of this Agreement.

Section 13.5. Material Adverse Change . Seller shall promptly notify NYSERDA if it becomes aware of any damage to or loss of use of the Facility that could reasonably be expected to materially adversely affect the Facility and its ability to generate electricity and pursuant to the ZEC Program the subsequent creation of ZECs related to such generation. In the event of (a) the unavailability, interruption, breakdown or failure of equipment at the Facility or (b) other similar material adverse change to the operating condition of the Facility that, with respect to either or both of the events or conditions described in the preceding clause (a) or (b), could reasonably be expected to cost more than Forty Million Dollars ($40,000,000), as demonstrated by an independent engineering report provided by Seller, to repair or replace in accordance with Good Utility Practice and Seller's standard operating procedures, Seller may, at its sole option, terminate this Agreement with no further payment or performance obligation; provided that NYSERDA shall make any payments due in accordance with obligations hereunder already performed. For the avoidance of doubt, the Forty Million Dollar ($40,000,000) threshold set forth above must be for costs above Seller's previously forecasted budget and must pertain to capital costs, including costs associated with construction, repair, parts and equipment.

Article XIV

Force Majeure

Section 14.1. Force Majeure . Neither Party hereto shall be liable for any failure or delay in the performance of its respective obligations hereunder (other than payment obligations) if and to the extent that such delay or failure is due to a cause or circumstance beyond the reasonable control of such party, including acts of God or the public enemy, expropriation or confiscation of land or facilities, acts of war, rebellion or sabotage or damage resulting therefrom, fires, floods, storms or weather of unusual severity, unavailability of NYGATS, explosions, accidents, riots, or strikes (a "Force Majeure Event"). Compliance with Applicable Law shall not constitute a Force Majeure Event and shall be addressed in Section 13.4. The suspension of performance due to a Force Majeure Event shall be of no greater scope or amount and of no longer duration than is required by such Force Majeure Event and the Claiming Party shall not be construed to be in default with respect to any obligation hereunder for so long as, but only to the extent that, failure to perform such obligation is due to a Force Majeure Event. No Force Majeure Event shall extend this Agreement beyond the Term.

Section 14.2. Due Diligence . A Party claiming a Force Majeure Event ("Claiming Party") shall: (a) provide oral notice as promptly as practicable followed by written notice to the other Party ("Non-Claiming Party") within two (2) Business Days after such Claiming Party becomes aware of such Force Majeure Event, giving the Non-Claiming Party a detailed written explanation of the event and an estimate of its expected duration and probable effect on the performance of the Claiming Party's obligations hereunder; (b) use commercially reasonable efforts in accordance with Good Utility Practice to remedy the condition that prevents performance and to mitigate the effects of same in order to continue to perform its obligations under this Agreement; and (c) provide the Non-Claiming Party with weekly status reports of all efforts to mitigate and remedy the Force Majeure Event.

Section 14.3. Extended Force Majeure Events .

(a) If the Claiming Party has reason to believe that a Force Majeure Event will prevent it from performing its obligations under this Agreement for one (1) month or longer ("Extended Force Majeure Event"), it shall notify the Non-Claiming Party in writing within fifteen (15) days from the beginning of said Force Majeure Event and shall submit a plan to remedy the impact of such Force Majeure Event(s) (a "Force Majeure Remedy Plan") to the Non-Claiming Party within ten (10) days of such notification.

(b) While the Force Majeure Remedy Plan is in effect, the Claiming Party shall provide (i) weekly status reports notifying the Non-Claiming Party of the steps which have been taken to remedy the Extended Force Majeure Event, and (ii) the expected remaining duration of its inability to perform hereunder.

Section 14.4. Right to Terminate or Discontinue Obligations .

Either Party upon written notice to the other Party may terminate this Agreement if the Claiming Party remains unable to perform its material obligations hereunder due to a Force Majeure Event for twenty-four (24) consecutive months following the date of such Force Majeure Event; provided, that neither Party shall be entitled to terminate this Agreement until twenty four (24) months after the date of such Force Majeure Event provided that the Party affected by the Force Majeure Event (a) has commenced to remedy the Force Majeure Event and (b) is diligently pursuing such remedy; and (c) if such remedy can be reasonably completed within twenty four (24) consecutive Months following the date of such Force Majeure Event.

Section 14.5. Liability Following Termination .

Upon termination of this Agreement as provided in Section 14.4, the Parties shall have no further liability or obligation to each other as a consequence of such termination, except for any obligation accruing prior to the occurrence of such Force Majeure Event.

Article XV

Additional Provisions

Section 15.1. Forward Contract . Each Party represents and warrants to the other, as of the date of each sale and purchase of ZECs (each "transaction") hereunder that it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code, that this Agreement and each transaction is a "forward contract" or a "commodity contract" within the meaning of the United States Bankruptcy Code, and that the remedies identified in this Agreement shall be "contractual rights" as provided for in 11 U.S.C. § 556 as that provision may be amended from time to time. Each Party represents to the other, as of the date of each transaction, that: (a) it is a commercial market participant with respect to ZECs and is entering into the transaction in connection with its commercial business; (b) it intends, as of the date of the transaction, to make or take physical delivery of ZECs, which are nonfinancial commodities; and (c) that the transaction is not a "swap" under the Commodity Exchange Act and the CFTC regulations, interpretations and guidance promulgated thereunder.

Section 15.2. Taxes . Seller shall be responsible for and obligated to pay all present and future taxes, fees and levies that may be assessed by any entity upon the Seller's delivery of ZECs to NYSERDA, or with respect to the creation of the ZECs and/or the energy with which they are associated, and, if any, for the registration of the Facility in the NYGATS and the delivery of the ZEC Certificates.

Section 15.3. Term . Unless earlier terminated pursuant to the terms hereof, this Agreement shall commence on the Effective Date and expire upon the expiration of the Contract Term, provided that payment has been made for all ZECs for which payment is properly due. Upon such date or upon earlier termination of this Agreement under Article XIII, neither Party shall have any further obligation to the other, except that Sections 15.1, 18.1, 18.2, 18.3, 18.4, and NYSERDA's payment obligation under Article IV shall survive.

Section 15.4. Waiver . Either Party to this Agreement may (a) extend the time for the performance of any of the obligations or other acts of the other Party, (b) waive any inaccuracies in the representations and warranties of the other Party contained herein or in any document delivered by the other Party pursuant hereto or (c) waive compliance with any of the agreements or conditions of the other party contained herein. Any such extension or waiver shall be valid only if set forth in an instrument in writing signed by the Party to be bound thereby. Any waiver of any term or condition shall not be construed as a waiver of any subsequent breach or a subsequent waiver of the same term or condition, or a waiver of any other term or condition, of this Agreement. No provision of this Agreement will be deemed to have been waived unless the waiver is in writing, and no delay by either Party in exercising its rights hereunder, including the right to terminate this Agreement, shall be deemed to constitute or evidence any waiver by either Party of any right hereunder. The rights granted in this Agreement are cumulative of every other right or remedy that the enforcing Party may otherwise have at law or in equity or by statute.

Section 15.5. Independent Contractor . The status of the Seller under this Agreement shall be that of an independent contractor and not that of an agent, and in accordance with such status, Seller and its respective officers, agents, employees, representatives and servants shall at all times during the term of this Agreement conduct themselves in a manner consistent with such status and by reason of this Agreement shall neither hold themselves out as, nor claim to be acting in the capacity of, officers, employees, agents, representatives or servants of NYSERDA nor make any claim, demand or application for any right or privilege applicable to NYSERDA, including rights or privileges derived from workers' compensation coverage, unemployment insurance benefits, social security coverage and retirement membership or credit.

Section 15.6. Severability . If any provision of this Agreement shall be declared by any court of competent jurisdiction to be illegal, void or unenforceable, all other provisions of this Agreement shall not be affected and shall remain in full force and effect. If any provision of this Agreement is so broad as to be unenforceable, that provision shall be interpreted to be only so broad as will enable it to be enforced.

Section 15.7. Seller Expense . Seller shall, at its own expense, make all arrangements necessary to register the Facility and transfer ZECs to NYSERDA through NYGATS in accordance with the NYGATS Operating Rules.

Section 15.8. Further Assurances . Each Party shall execute and deliver to the other Party any instrument or other document reasonably requested by the other Party to give effect to the agreement of the Parties reflected herein.

Section 15.9. Waiver of Relief from Contract . Neither Party shall unilaterally seek to obtain from any Governmental Authority any relief changing the ZEC Price, each Party's obligations or any other economic terms and conditions of this Agreement. To the extent that any non-Party shall seek such relief, the Parties further covenant not to support such action.

Section 15.10. Governing Law; Venue . This Agreement shall be governed by, and construed in accordance with the laws of the State of New York applicable to contracts executed and to be performed in New York State without regard to its conflicts of laws principles. The parties irrevocably acknowledge and accept that all actions arising under or relating to this

Agreement, and the transactions contemplated hereby and thereby shall be brought exclusively in a United States District Court or New York State Court located in Albany, New York having subject matter jurisdiction over such matters, and each of the Parties hereby consents to and accepts such personal jurisdiction of, and waives any objection as to the laying of venue in, such courts for purposes of such action.

Section 15.11. Laws of the State of New York . Seller shall comply with all of the requirements set forth in Exhibit A hereto.

Section 15.12. No Third Party Beneficiaries . Nothing herein is intended to or should be construed to create any rights of any kind whatsoever in third persons not parties to this Agreement.

Article XVI

Notices, Entire Agreement, Amendment, Counterparts, Good Faith Negotiation

Section 16.1. Notices.

(a) All notices, requests, consents, approvals and other communications which may or are required to be given by either party to the other under this Agreement shall be in writing and shall be transmitted either:

(1) via certified or registered United States mail, return receipt requested;

(2) by personal delivery;

(3) by expedited delivery service; or

(4) by e-mail, return receipt requested.

Such notices shall be addressed as follows, or to such different addresses as the Parties may from time-to-time designate as set forth in paragraph (c) below:

To Seller:	R. E. Ginna Nuclear Power Plant, LLC c/o Exelon Generation Company, LLC 1310 Point Street Baltimore, MD 21231 Attn: General Counsel E:mail Address: david.dardis@constellation.com
To NYSERDA:	NYSERDA Attn: Office of the General Counsel 17 Columbia Circle Albany, New York 12203-6399 E:mail address: pete.keane@nyserda.ny.gov
With a copy to:	NYSERDA Attn: Peter Keane 17 Columbia Circle Albany, New York 12203-6399

(b) Any such notice shall be deemed to have been given either at the time of personal delivery or, in the case of expedited delivery service or certified or registered United States mail, as of the date of first attempted delivery at the address and in the manner provided herein, or in the case of facsimile transmission or email, upon receipt of an email acknowledgement of receipt.

(c) The Parties may, from time to time, specify any new or different address in the United States as their address for purpose of receiving notice under this Agreement by giving fifteen (15) days' written notice to the other Party sent in accordance herewith. The Parties agree to mutually designate individuals as their respective representatives for the purposes of receiving notices under this Agreement. Additional individuals may be designated in writing by the Parties for purposes of implementation and administration/billing, resolving issues and problems and/or for dispute resolution.

Section 16.2. Entire Agreement; Amendment . This Agreement embodies the entire agreement and understanding between NYSERDA and the Seller and supersedes all prior agreements and understandings relating to the subject matter hereof. Except as otherwise expressly provided for herein, this Agreement may be amended, modified, changed, waived, discharged or terminated only by an instrument in writing, signed by the Party against which enforcement of such amendment, modification, change, waiver, discharge or termination is sought.

Section 16.3. Counterparts . This Agreement may be executed in counterparts each of which shall be deemed an original, but all of which taken together shall constitute one and the same instrument.

Section 16.4. Good Faith Negotiation . Both Parties agree that, should any dispute arise during the term of this Agreement, the Parties will make a good faith though non-binding effort to reconcile any difference or dispute before the filing of an action in any court.

Article XVII

Publicity

Section 17.1. Publicity . On or prior to the Effective Date, the Parties will collaborate with regard to the preparation and issuance of any initial press release or public announcement with respect to the Parties' entry into this Agreement.

Article XVIII

Confidentiality

Section 18.1. Seller will be required to waive confidentiality, as to NYSERDA and the NYGATS, for the direct transfer to NYSERDA of data pertinent to the verification of ZEC creation.

Section 18.2. Freedom of Information Law . Seller acknowledges that NYSERDA is subject to and must comply with the requirements of New York's Freedom of Information Law ("FOIL;" see Public Officers' Law Article 6).

Section 18.3. Claim of Confidentiality . Information of any tangible form including any document that Seller wishes to be protected from disclosure to third parties, must be marked "Confidential" or "Proprietary" at the time such information is provided to NYSERDA.

Section 18.4. Trade Secrets/Commercial Information . The FOIL Law (Public Officers Law § 87(d)(2)) provides an exception to disclosure for records or portions thereof that "are trade secrets or are submitted to an agency by a commercial enterprise or derived from information obtained from a commercial enterprise and which if disclosed would cause substantial injury to the competitive position of the subject enterprise ." If NYSERDA receives a request from a third party for information or a document received from Seller and which has been marked "Confidential" or "Proprietary," NYSERDA will process such request under the procedures provided by NYSERDA's FOIL regulations.

[Signature Page Follows]

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed and delivered by their duly authorized representatives.

R. E. Ginna Nuclear Power Plant, LLC

By: /s/ Bruce Wilson

Name: Bruce Wilson

Title Secretary

New York State Energy Research And Development Authority

By: /s/ John B. Rhodes

Title President and CEO

STATE OF _____)

) SS:

COUNTY OF _____)

On the _____day of _____, 20 __, before me, the undersigned, personally appeared _____, personally known to me or proved to me on the basis of satisfactory evidence to be the individual(s) whose name(s) is (are) subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their capacity(ies), and that by his/her/their signature(s) on the instrument, the individual(s), or the person on behalf of which the individual(s) acted, executed the instrument.

_____

Notary

[Signature Page to ZEC Standard Agreement (Ginna)]

EXHIBIT A

REVISED 5/12

STANDARD TERMS AND CONDITIONS
FOR ALL NYSERDA AGREEMENTS

(Based on Standard Clauses for New York State Contracts and Tax Law Section 5-a)

The parties to the Agreement agree to be bound by the following clauses which are hereby made a part of the Agreement:

1. NON-DISCRIMINATION REQUIREMENTS. To the extent required by Article 15 of the Executive Law (also known as the Human Rights Law) and all other State and Federal statutory and constitutional non-discrimination provisions, the Contractor will not discriminate against any employee or applicant for employment because of race, creed, color, sex, national origin, sexual orientation, age, disability, genetic predisposition or carrier status, or marital status. Furthermore, in accordance with Section 220-e of the Labor Law, if this is an Agreement for the construction, alteration or repair of any public building or public work or for the manufacture, sale or distribution of materials, equipment or supplies, and to the extent that this Agreement shall be performed within the State of New York, Contractor agrees that neither it nor its subcontractors shall, by reason of race, creed, color, disability, sex or national origin: (a) discriminate in hiring against any New York State citizen who is qualified and available to perform the work; or (b) discriminate against or intimidate any employee hired for the performance of work under this Agreement. If this is a building service Agreement as defined in Section 230 of the Labor Law, then, in accordance with Section 239 thereof, Contractor agrees that neither it nor its subcontractors shall, by reason of race, creed, color, national origin, age, sex or disability: (a) discriminate in hiring against any New York State citizen who is qualified and available to perform the work; or (b) discriminate against or intimidate any employee hired for the performance of work under this contract. Contractor is subject to fines of $50.00 per person per day for any violation of Section 220-e or Section 239 as well as possible termination of this Agreement and forfeiture of all moneys due hereunder for a second subsequent violation.

2. WAGE AND HOURS PROVISIONS. If this is a public work Agreement covered by Article 8 of the Labor Law or a building service Agreement covered by Article 9 thereof, neither Contractor's employees nor the employees of its subcontractors may be required or permitted to work more than the number of hours or days stated in said statutes, except as otherwise provided in the Labor Law and as set forth in prevailing wage and supplement schedules issued by the State Labor Department. Furthermore, Contractor and its subcontractors must pay at least the prevailing wage rate and pay or provide the prevailing supplements, including the premium rates for overtime pay, as determined by the State Labor Department in accordance with the Labor Law. Additionally, effective April 28, 2008, if this is a public work contract covered by Article 8 of the Labor Law, the Contractor understands and agrees that the filing of payrolls in a manner consistent with Subdivision 3-a of Section 220 of the Labor Law shall be a condition precedent to payment by NYSERDA of any NYSERDA-approved sums due and owing for work done upon the project.

3. NON-COLLUSIVE BIDDING REQUIREMENT . In accordance with Section 2878 of the Public Authorities Law, if this Agreement was awarded based upon the submission of bids, Contractor warrants, under penalty of perjury, that its bid was arrived at independently and without collusion aimed at restricting competition. Contractor further warrants that, at the time Contractor submitted its bid, an authorized and responsible person executed and delivered to NYSERDA a non-collusive bidding certification on Contractor's behalf.

4. INTERNATIONAL BOYCOTT PROHIBITION . If this Agreement exceeds $5,000, the Contractor agrees, as a material condition of the Agreement, that neither the Contractor nor any substantially owned or affiliated person, firm, partnership or corporation has participated, is participating, or shall participate in an international boycott in violation of the Federal Export Administration Act of 1979 (50 USC App. Sections 2401 et seq.) or regulations thereunder. If such Contractor, or any of the aforesaid affiliates of Contractor, is convicted or is otherwise found to have violated said laws or regulations upon the final determination of the United States Commerce Department or any other appropriate agency of the United States subsequent to the Agreement's execution, such Agreement, amendment or modification thereto shall be rendered forfeit and void. The Contractor shall so notify NYSERDA within five (5) Business Days of such conviction, determination or disposition of appeal. (See and compare Section 220-f of the Labor Law, Section 139-h of the State Finance Law, and 2 NYCRR 105.4).

5. SET-OFF RIGHTS . NYSERDA shall have all of its common law and statutory rights of set-off. These rights shall include, but not be limited to, NYSERDA's option to withhold for the purposes of set-off any moneys due to the Contractor under this Agreement up to any amounts due and owing to NYSERDA with regard to this Agreement, any other Agreement, including any Agreement for a term commencing prior to the term of this Agreement, plus any amounts due and owing to NYSERDA for any other reason including, without limitation, tax delinquencies, fee delinquencies or monetary penalties relative thereto.

6. PROPRIETARY INFORMATION . Notwithstanding any provisions to the contrary in the Agreement, Contractor and NYSERDA acknowledge and agree that all information, in any format, submitted to NYSERDA shall be subject to and treated in accordance with the NYS Freedom of Information Law ("FOIL," Public Officers Law, Article 6). Pursuant to FOIL, NYSERDA is required to make available to the public, upon request, records or portions thereof which it possesses, unless that information is statutorily exempt from disclosure. Therefore, unless the Agreement specifically requires otherwise, Contractor should submit information to NYSERDA in a non-confidential, non-proprietary format. FOIL does provide that NYSERDA may deny access to records or portions thereof that "are trade secrets or are submitted to an agency by a commercial enterprise or derived from information obtained from a commercial enterprise and which if disclosed would cause substantial injury to the competitive position of the subject enterprise." [See Public Officers Law, § 87(2)(d)]. Accordingly, if the Agreement specifically requires submission of information in a format Contractor considers a proprietary and/or confidential trade secret, Contractor shall fully identify and plainly label the information "confidential" or "proprietary" at the time of disclosure. By so marking such information, Contractor represents that the information has actual or potential specific commercial or competitive value to the competitors of Contractor. Without limitation, information will not be considered confidential or proprietary if it is or has been (i) generally known or available from other sources without obligation concerning its confidentiality; (ii) made available by the owner

to others without obligation concerning its confidentiality; or (iii) already available to NYSERDA without obligation concerning its confidentiality. In the event of a FOIL request, it is NYSERDA's policy to consider records as marked above pursuant to the trade secret exemption procedure set forth in 21 New York Codes Rules & Regulations § 501.6 and any other applicable law or regulation. However, NYSERDA cannot guarantee the confidentiality of any information submitted. More information on FOIL, and the relevant statutory law and regulations, can be found at the website for the Committee on Open Government (http://www.dos.state.ny.us/coog/foil2.html) and NYSERDA's Regulations, Part 501 (http://www.nyserda.ny.gov/About/New-York-State-Regulations.aspx).

7. IDENTIFYING INFORMATION AND PRIVACY NOTIFICATION . (a) FEDERAL EMPLOYER IDENTIFICATION NUMBER and/or FEDERAL SOCIAL SECURITY NUMBER. As a condition to NYSERDA's obligation to pay any invoices submitted by Contractor pursuant to this Agreement, Contractor shall provide to NYSERDA its Federal employer identification number or Federal social security number, or both such numbers when the Contractor has both such numbers. Where the Contractor does not have such number or numbers, the Contractor must give the reason or reasons why the payee does not have such number or numbers.

(b) PRIVACY NOTIFICATION. The authority to request the above personal information from a seller of goods or services or a lessor of real or personal property, and the authority to maintain such information, is found in Section 5 of the State Tax Law. Disclosure of this information by Contractor to the State is mandatory. The principal purpose for which the information is collected is to enable the State to identify individuals, businesses and others who have been delinquent in filing tax returns or may have understated their tax liabilities and to generally identify persons affected by the taxes administered by the Commissioner of Taxation and Finance. The information will be used for tax administration purposes and for any other purpose authorized by law.

8. CONFLICTING TERMS . In the event of a conflict between the terms of the Agreement (including any and all attachments thereto and amendments thereof) and the terms of this Exhibit A, the terms of this Exhibit A shall control.

9. GOVERNING LAW . This Agreement shall be governed by the laws of the State of New York except where the Federal supremacy clause requires otherwise.

10. NO ARBITRATION . Disputes involving this Agreement, including the breach or alleged breach thereof, may not be submitted to binding arbitration (except where statutorily required) without the NYSERDA's written consent, but must, instead, be heard in a court of competent jurisdiction of the State of New York.

11. SERVICE OF PROCESS . In addition to the methods of service allowed by the State Civil Practice Law and Rules ("CPLR"), Contractor hereby consents to service of process upon it by registered or certified mail, return receipt requested. Service hereunder shall be complete upon Contractor's actual receipt of process or upon NYSERDA's receipt of the return thereof by the United States Postal Service as refused or undeliverable. Contractor must promptly notify NYSERDA, in writing, of each and every change of address to which service of

process can be made. Service by NYSERDA to the last known address shall be sufficient. Contractor will have thirty (30) calendar days after service hereunder is complete in which to respond.

12. CRIMINAL ACTIVITY. If subsequent to the effectiveness of this Agreement, NYSERDA comes to know of any allegation previously unknown to it that the Contractor or any of its principals is under indictment for a felony, or has been, within five (5) years prior to submission of the Contractor's proposal to NYSERDA, convicted of a felony, under the laws of the United States or Territory of the United States, then NYSERDA may exercise its stop work right under this Agreement. If subsequent to the effectiveness of this Agreement, NYSERDA comes to know of the fact, previously unknown to it, that Contractor or any of its principals is under such indictment or has been so convicted, then NYSERDA may exercise its right to terminate this Agreement. If the Contractor knowingly withheld information about such an indictment or conviction, NYSERDA may declare the Agreement null and void and may seek legal remedies against the Contractor and its principals. The Contractor or its principals may also be subject to penalties for any violation of law which may apply in the particular circumstances. For a Contractor which is an association, partnership, corporation, or other organization, the provisions of this paragraph apply to any such indictment or conviction of the organization itself or any of its officers, partners, or directors or members of any similar governing body, as applicable.

13. PERMITS. It is the responsibility of the Contractor to acquire and maintain, at its own cost, any and all permits, licenses, easements, waivers and permissions of every nature necessary to perform the work.

14. PROHIBITION ON PURCHASE OF TROPICAL HARDWOODS. The Contractor certifies and warrants that all wood products to be used under this Agreement will be in accordance with, but not limited to, the specifications and provisions of State Finance Law Section 165 (Use of Tropical Hardwoods), which prohibits purchase and use of tropical hardwoods, unless specifically exempted by NYSERDA.

15. OMNIBUS PROCUREMENT ACT OF 1992. It is the policy of New York State to maximize opportunities for the participation of New York State business enterprises, including minority and women-owned business enterprises as bidders, subcontractors and suppliers on its procurement contracts.

Information on the availability of New York State subcontractors and suppliers is available from:

NYS Department of Economic Development
Division for Small Business
625 Broadway
Albany, New York 12207
Telephone: 518-292-5200
Fax: 518-292-5884
http://www.esd.ny.gov
http://www.esd.ny.gov

A directory of certified minority and women-owned business enterprises is available from:

NYS Department of Economic Development
Division of Minority and Women's Business Development
625 Broadway
Albany, New York 12207
Telephone: 518-292-5200
Fax: 518-292-5803
http://www.empire.state.ny.us

The Omnibus Procurement Act of 1992 requires that by signing this Agreement, Contractors certify that whenever the total amount is greater than $1 million:

(a) The Contractor has made reasonable efforts to encourage the participation of New York State Business Enterprises as suppliers and subcontractors, including certified minority and women-owned business enterprises, on this project, and has retained the documentation of these efforts to be provided upon request to the State;

(b) The Contractor has complied with the Federal Equal Opportunity Act of 1972 (P.L. 92-261), as amended;

(c) The Contractor agrees to make reasonable efforts to provide notification to New York State residents of employment opportunities on this project through listing any such positions with the Job Service Division of the New York State Department of Labor, or providing such notification in such manner as is consistent with existing collective bargaining contracts or agreements. The Contractor agrees to document these efforts and to provide said documentation to the State upon request; and

(d) The Contractor acknowledges notice that the State may seek to obtain offset credits from foreign countries as a result of this contract and agrees to cooperate with the State in these efforts.

16. RECIPROCITY AND SANCTIONS PROVISIONS . Bidders are hereby notified that if their principal place of business is located in a country, nation, province, state or political subdivision that penalizes New York State vendors, and if the goods or services they offer will be substantially produced or performed outside New York State, the Omnibus Procurement Act 1994 and 2000 amendments (Chapter 684 and Chapter 383, respectively) require that they be denied contracts which they would otherwise obtain. NOTE: As of May 15, 2002, the list of discriminatory jurisdictions subject to this provision includes the states of South Carolina, Alaska, West Virginia, Wyoming, Louisiana and Hawaii. Contact NYS Department of Economic Development for a current list of jurisdictions subject to this provision.

17. COMPLIANCE WITH NEW YORK STATE INFORMATION SECURITY BREACH AND NOTIFICATION ACT . Contractor shall comply with the provisions of the New York State Information Security Breach and Notification Act (General Business Law Section 899-aa; State Technology Law Section 208).

18. PROCUREMENT LOBBYING. To the extent this Agreement is a "procurement contract" as defined by State Finance Law Sections 139-j and 139-k, by signing this Agreement the Contractor certifies and affirms that all disclosures made in accordance with State Finance Law Sections 139-j and 139-k are complete, true and accurate. In the event such certification is found to be intentionally false or intentionally incomplete, NYSERDA may terminate the agreement by providing written notification to the Contractor in accordance with the terms of the agreement.

19. COMPLIANCE WITH TAX LAW SECTION 5-a. The following provisions apply to Contractors that have entered into agreements in an amount exceeding $100,000 for the purchase of goods and services:

(a) Before such agreement can take effect, the Contractor must have on file with the New York State Department of Taxation and Finance a Contractor Certification form (ST-220-TD).

(b) Prior to entering into such an agreement, the Contractor is required to provide NYSERDA with a completed Contractor Certification to Covered Agency form (Form ST-220-CA).

(c) Prior to any renewal period (if applicable) under the agreement, the Contractor is required to provide NYSERDA with a completed Form ST-220-CA.

Certifications referenced in paragraphs (b) and (c) above will be maintained by NYSERDA and made a part hereof and incorporated herein by reference.

NYSERDA reserves the right to terminate this agreement in the event it is found that the certification filed by the Contractor in accordance with Tax Law Section 5-a was false when made.

20. IRANIAN ENERGY SECTOR DIVESTMENT. In accordance with Section 2879-c of the Public Authorities Law, by signing this contract, each person and each person signing on behalf of any other party certifies, and in the case of a joint bid or partnership each party thereto certifies as to its own organization, under penalty of perjury, that to the best of its knowledge and belief that each person is not on the list created pursuant to paragraph (b) of subdivision 3 of section 165-a of the State Finance Law (See www.ogs.ny.gov/about/regs/ida.asp).

EXHIBIT B

NYSERDA PROMPT PAYMENT POLICY STATEMENT

504.1. Purpose and Applicability . (a) The purpose of this Exhibit is to provide a description of Part 504 of NYSERDA's regulations, which consists of NYSERDA's policy for making payment promptly on amounts properly due and owing by NYSERDA under this Agreement. The section numbers used in this document correspond to the section numbers appearing in Part 504 of the regulations. [1]

(b) This Exhibit applies generally to payments due and owing by the NYSERDA to the Contractor pursuant to this Agreement. However, this Exhibit does not apply to Payments due and owing when NYSERDA is exercising a Set-Off against all or part of the Payment, or if a State or Federal law, rule or regulation specifically requires otherwise.

504.2. Definitions . Capitalized terms not otherwise defined in this Exhibit shall have the same meaning as set forth earlier in this Agreement. In addition to said terms, the following terms shall have the following meanings, unless the context shall indicate another or different meaning or intent:

(a) "Date of Payment" means the date on which NYSERDA requisitions a check from its statutory fiscal agent, the Department of Taxation and Finance, to make a Payment.

(b) "Designated Payment Office" means the Office of NYSERDA's Controller, located at 17 Columbia Circle, Albany, New York 12203.

(c) "Payment" means payment properly due and owing to Contractor pursuant to Article IV, Exhibit B of this Agreement.

(d) "Prompt Payment" means a Payment within the time periods applicable pursuant to Sections 504.3 through 504.5 of this Exhibit in order for NYSERDA not to be liable for interest pursuant to Section 504.6.

(e) "Payment Due Date" means the date by which the Date of Payment must occur, in accordance with the provisions of Sections 504.3 through 504.5 of this Exhibit, in order for NYSERDA not to be liable for interest pursuant to Section 504.6.

(f) "Proper Invoice" means a written request for Payment that is submitted by a Contractor setting forth the description, price or cost, and quantity of goods, property or services delivered or rendered, in such form, and supported by such other substantiating documentation, as NYSERDA may reasonably require, including but not limited to any requirements set forth in Exhibits A or B to this Agreement; and addressed to NYSERDA's Controller, marked "Attention: Accounts Payable," at the Designated Payment Office.

(g)(1) "Receipt of an Invoice" means:

[1] This is only a summary; the full text of Part 504 can be accessed at: http://www.nyserda.ny.gov/en/About/~/media/Files/About/Contact/NYSERDARegulations.ashx

(i) if the Payment is one for which an invoice is required, the later of:

(a) the date on which a Proper Invoice is actually received in the Designated Payment Office during normal business hours; or

(b) the date by which, during normal business hours, NYSERDA has actually received all the purchased goods, property or services covered by a Proper Invoice previously received in the Designated Payment Office.

(ii) if the Agreement provides that a Payment will be made on a specific date or at a predetermined interval, without having to submit a written invoice the 30th calendar day, excluding legal holidays, before the date so specified or predetermined.

(2) For purposes of this subdivision, if the Agreement requires a multifaceted, completed or working system, or delivery of no less than a specified quantity of goods, property or services and only a portion of such systems or less than the required goods, property or services are working, completed or delivered, even though the Contractor has invoiced NYSERDA for the portion working, completed or delivered, NYSERDA will not be in Receipt of an Invoice until the specified minimum amount of the systems, goods, property or services are working, completed or delivered.

(h) "Set-off" means the reduction by NYSERDA of a payment due a Contractor by an amount equal to the amount of an unpaid legally enforceable debt owed by the Contractor to NYSERDA.

504.3. Prompt Payment Schedule. Except as otherwise provided by law or regulation or in Sections 504.4 and 504.5 of this Exhibit, the Date of Payment by NYSERDA of an amount properly due and owing under this Agreement shall be no later than thirty (30) calendar days, excluding legal holidays, after Receipt of a Proper Invoice.

504.4. Payment Procedures.

(a) Unless otherwise specified in this Agreement, a Proper Invoice submitted by the Contractor to the Designated Payment Office shall be required to initiate payment for goods, property or services. As soon as any invoice is received in the Designated Payment Office during normal business hours, such invoice shall be date-stamped. The invoice shall then promptly be reviewed by NYSERDA.

(b) NYSERDA shall notify the Contractor within fifteen (15) calendar days after Receipt of an Invoice of:

(1) any defects in the delivered goods, property or services;

(2) any defects in the invoice; or

(3) suspected improprieties of any kind.

(c) The existence of any defects or suspected improprieties shall prevent the commencement of the time period specified in Section 504.3 until any such defects or improprieties are corrected or otherwise resolved.

(d) If NYSERDA fails to notify a Contractor of a defect or impropriety within the fifteen (15) calendar day period specified in subdivision (b) of this section, the sole effect shall be that the number of days allowed for Payment shall be reduced by the number of days between the 15th day and the day that notification was transmitted to the Contractor. If NYSERDA fails to provide reasonable grounds for its contention that a defect or impropriety exists, the sole effect shall be that the Payment Due Date shall be calculated using the original date of Receipt of an Invoice.

(e) In the absence of any defect or suspected impropriety, or upon satisfactory correction or resolution of a defect or suspected impropriety, NYSERDA shall make Payment, consistent with any such correction or resolution and the provisions of this Exhibit.

504.5. Exceptions and Extension of Payment Due Date . NYSERDA has determined that, notwithstanding the provisions of Sections 504.3 and 504.4 of this Exhibit, any of the following facts or circumstances, which may occur concurrently or consecutively, reasonably justify extension of the Payment Due Date:

(a) If this Agreement provides Payment will be made on a specific date or at a predetermined interval, without having to submit a written invoice, if any documentation, supporting data, performance verification, or notice specifically required by this Agreement or other State or Federal mandate has not been submitted to NYSERDA on a timely basis, then the Payment Due Date shall be extended by the number of calendar days from the date by which all such matter was to be submitted to NYSERDA and the date when NYSERDA has actually received such matter.

(b) If an inspection or testing period, performance verification, audit or other review or documentation independent of the Contractor is specifically required by this Agreement or by other State or Federal mandate, whether to be performed by or on behalf of NYSERDA or another entity, or is specifically permitted by this Agreement or by other State or Federal provision and NYSERDA or other entity with the right to do so elects to have such activity or documentation undertaken, then the Payment Due Date shall be extended by the number of calendar days from the date of Receipt of an Invoice to the date when any such activity or documentation has been completed, NYSERDA has actually received the results of such activity or documentation conducted by another entity, and any deficiencies identified or issues raised as a result of such activity or documentation have been corrected or otherwise resolved.

(c) If an invoice must be examined by a State or Federal agency, or by another party contributing to the funding of the Contract, prior to Payment, then the Payment Due Date shall be extended by the number of calendar days from the date of Receipt of an Invoice to the date when the State or Federal agency, or other contributing party to the Contract, has completed the inspection, advised NYSERDA of the results of the inspection, and any deficiencies identified or issues raised as a result of such inspection have been corrected or otherwise resolved.

(d) If appropriated funds from which Payment is to be made have not yet been appropriated or, if appropriated, not yet been made available to NYSERDA, then the Payment Due Date shall be extended by the number of calendar days from the date of Receipt of an Invoice to the date when such funds are made available to NYSERDA.

504.6. Interest Eligibility and Computation. If NYSERDA fails to make Prompt Payment, NYSERDA shall pay interest to the Contractor on the Payment when such interest computed as provided herein is equal to or more than ten dollars ($10.00). Interest shall be computed and accrue at the daily rate in effect on the Date of Payment, as set by the New York State Tax Commission for corporate taxes pursuant to Section 1096(e)(1) of the Tax Law. Interest on such a Payment shall be computed for the period beginning on the day after the Payment Due Date and ending on the Date of Payment.

504.7. Sources of Funds to Pay Interest. Any interest payable by NYSERDA pursuant to Exhibit shall be paid only from the same accounts, funds, or appropriations that are lawfully available to make the related Payment.

504.8. Incorporation of Prompt Payment Policy Statement into Contracts. The provisions of this Exhibit shall apply to all Payments as they become due and owing pursuant to the terms and conditions of this Agreement, notwithstanding that NYSERDA may subsequently amend its Prompt Payment Policy by further rulemaking.

504.9. Notice of Objection. Contractor may object to any action taken by NYSERDA pursuant to this Exhibit that prevents the commencement of the time in which interest will be paid by submitting a written notice of objection to NYSERDA. Such notice shall be signed and dated and concisely and clearly set forth the basis for the objection and be addressed to the Vice President, New York State Energy Research and Development Authority, at the notice address set forth in Exhibit B to this Agreement. The Vice President of NYSERDA, or his or her designee, shall review the objection for purposes of affirming or modifying NYSERDA's action. Within fifteen (15) working days of the receipt of the objection, the Vice President, or his or her designee, shall notify the Contractor either that NYSERDA's action is affirmed or that it is modified or that, due to the complexity of the issue, additional time is needed to conduct the review; provided, however, in no event shall the extended review period exceed thirty (30) working days.

504.10. Judicial Review. Any determination made by NYSERDA pursuant to this Exhibit that prevents the commencement of the time in which interest will be paid is subject to judicial review in a proceeding pursuant to Article 78 of the Civil Practice Law and Rules. Such proceedings shall only be commenced upon completion of the review procedure specified in Section 504.9 of this Exhibit or any other review procedure that may be specified in this Agreement or by other law, rule, or regulation.

504.11. Court Action or Other Legal Processes.

(a) Notwithstanding any other law to the contrary, the liability of NYSERDA to make an interest payment to a Contractor pursuant to this Exhibit shall not extend beyond the date of a notice of intention to file a claim, the date of a notice of a claim, or the date commencing a legal action for the payment of such interest, whichever occurs first.

(b) With respect to the court action or other legal processes referred to in subdivision (a) of this section, any interest obligation incurred by NYSERDA after the date specified therein pursuant to any provision of law other than Public Authorities Law Section 2880 shall be determined as prescribed by such separate provision of law, shall be paid as directed by the court, and shall be paid from any source of funds available for that purpose.

EXHIBIT C

CERTIFICATION FORM

NYSERDA Agreement No. _____

Name of Seller: _____

Name of Facility: _____

Invoice Number: _____

Serial Number(s): _____

Total Number of ZECs: _____

Terms used in this Certificate are used with the meanings given to such terms in the referenced NYSERDA Agreement.

Seller certifies that, to Seller's knowledge, all of the information provided on the attached invoice requesting payment from NYSERDA is true and accurate; that the ZECs delivered by Seller (identified by the serial number(s) above) by designation for transfer to NYSERDA in accordance with the NYGATS Operating Rules are free and clear of all liens, judgments, encumbrances and similar restrictions created by or on behalf of Seller or any party claiming through Seller, and have not otherwise been, nor will be, sold, retired, claimed or represented by or on behalf of Seller or any party claiming through Seller, as part of electricity output or sales, or used by or on behalf of Seller or any party claiming through Seller, to satisfy obligations in any other jurisdiction.

Seller further certifies that all representations and warranties of the Seller set forth in Section 15.1 of the NYSERDA Agreement are true and correct on the date hereof as though made on the date hereof, other than such representations and warranties that are expressly effective as of an earlier date, in which case, such representations and warranties continue to be true and correct as of such date.

Quarterly Invoice Date: _____

By: _____

EXHIBIT D
ZERO EMISSIONS CREDIT PRICING

The ZEC Price will be determined in six, 2-year Tranches, as follows:

Tranche 1: April 1, 2017 – March 31, 2019
Tranche 2: April 1, 2019 – March 31, 2021
Tranche 3: April 1, 2021 – March 31, 2023
Tranche 4: April 1, 2023 – March 31, 2025
Tranche 5: April 1, 2025 – March 31, 2027
Tranche 6: April 1, 2027 – March 31, 2029

For Tranche 1, the ZEC Price shall be $17.48.

For Tranches 2 through 6, the ZEC Price shall be as calculated by NYSERDA in consultation with DPS staff, calculated for the relevant Tranche t using the following formula:

$ZEC\ Price_t = Max(0, Base\ ZEC\ Price_t - Max(0, (Energy\ Forward\ Index_t + Capacity\ Forward\ Index_t - Zone\ A\ Reference\ Price_t)))$; where

- $Base\ ZEC\ Price_t$ shall be determined as follows for each Tranche:
  - For Tranche 2, the Base ZEC Price shall be $19.59
  - For Tranche 3, the Base ZEC Price shall be $21.38
  - For Tranches 4 through 6, the Base ZEC Price shall be determined using the following formula:

    $Base\ ZEC\ Price_t = Net\ CO2\ Externality_t \times (0.53846 - (0.00491 \times Max(0, Min(26.704, (Incremental\ Renewable\ Generation_t / 1{,}000{,}000)) - 8.704)))$; where

    Net CO2 Externality shall be equal to 44.26 for Tranche 4, 49.13 for Tranche 5, and 54.13 for Tranche 6

    Incremental Renewable Generation shall be the total amount, denominated in megawatt-hours, of Renewable Energy Credits ("RECs") qualified to serve Tier 1 of the New York Renewable Energy Standard (i.e. new renewable resources of all types beginning commercial operation on or after January 1 st , 2015 that are eligible to satisfy the Renewable Energy Standard) generated in calendar years 2022, 2024, and 2026 as reported by the New York Generation Attribute Tracking System. The Incremental Renewable Generation for calendar year 2022 will be utilized in determining the Base ZEC Price for Tranche 4, the Incremental Renewable Generation for calendar year 2024 will be utilized in determining the Base ZEC Price for Tranche 5, and the Incremental Renewable Generation for calendar year 2026 will be utilized in determining the Base ZEC Price for Tranche 6.

- Energy Forward Index $_t$ shall be the average NYISO Zone A energy price forecast for the period covered by the Tranche, developed using futures prices reported on the Intercontinental Exchange ("ICE") as follows:

  1) for each trading day during the calendar year preceding each Tranche, On-Peak Monthly Forward Energy Prices and Off-Peak Monthly Forward Energy Prices for the 24 months of the Tranche will be separately averaged, yielding separate average on-peak and off-peak Tranche energy prices for each trading day;

  2) each trading day's average Tranche on-peak and off-peak energy prices (developed in step 1) will be time-weight averaged based on the number of on-peak and off peak hours in the Tranche, yielding a single average all-hours energy price for the Tranche for each trading day;

  3) the average Tranche all-hours energy prices for each of the trading days during the calendar year preceding each Tranche (developed in step 2) will be averaged, yielding the NYISO Zone A energy price forecast for the Tranche expressed in dollars per MWh.

- Capacity Forward Index $_t$ shall be the average NYISO Rest of the State capacity price forecast for the period covered by the Tranche, developed using futures prices reported on the New York Mercantile Exchange ("NYMEX") as follows:

  1) for each trading day during the final 6 months of the calendar year preceding each Tranche, NYMEX Rest of the State Capacity Calendar-Month settled futures prices for the first 12 months of the Tranche will be averaged, yielding a separate average annualized capacity price for each trading day

  2) the average annualized capacity prices for each of the trading days during the final six months of the calendar year preceding each Tranche (developed in step 1) will be averaged, yielding a single average annualized capacity price for the Tranche, expressed in dollars per kilowatt-month

  3) the average annualized capacity price developed in step 2 will be multiplied by 1.3699 to yield an average annualized capacity price for the Tranche expressed in dollars per MWh.

- Zone A Reference Price $_t$ shall be determined as follows for each Tranche:
  - For Tranche 2, the Zone A Reference Price shall be $39
  - For Tranche 3, the Zone A Reference Price shall be $39
  - For Tranches 4 through 6, the Zone A Reference Price shall be determined using the following formula:

    Zone A Reference Price $_t$ = $39 + Energy Basis Adjustment; where

    Energy basis adjustment is determined as follows:

    1) the simple average hourly day-ahead energy price over the six-year period covering calendar years 2017 through 2022 will be calculated using historic price data reported by the New York ISO for New York Zone A ("WEST (ZONE A)"), the R.E. Ginna nuclear unit generation bus ("GINNA _____"), the R.A. FitzPatrick nuclear unit generation bus ("FITZPATRICK _____"), the Nine Mile Point 1 nuclear unit generation bus ("NINE_MILE_1"), and the Nine Mile Point 2 nuclear unit generation bus ("NINE_MILE_2")

    2) each of the five six-year historical average nuclear unit generation bus energy prices will be subtracted from the six-year historical average Zone A energy price to calculate five unit-specific historic energy price basis differentials with Zone A

    3) the five unit-specific historic energy price basis differentials calculated in step 2 will be weighted by their actual six-year cumulative energy output over the 2017 through 2022 period to determine a single weighted-average historic energy basis differential, denominated in dollars per MWh.

    4) if the weighted-average historic energy basis differential calculated in step 3 is between $5 per MWh and $7 per MWh, the Energy Basis Adjustment shall be $0 per MWh

    5) If the weighted-average historic energy basis differential calculated in step 3 is less than $5 per MWh, the Energy Basis Adjustment shall be equal to the weighted-average historic energy basis differential minus $5 per MWh

    6) If the weighted-average historic energy basis differential calculated in step 3 is greater than $7 per MWh, the Energy Basis Adjustment shall be equal to the weighted-average historic energy basis differential minus $7 per MWh.

If the foregoing calculation yields a negative number, the ZEC Price shall be deemed to equal zero ($0).

Example Calculations:

Example 1:

Assumptions
Tranche 2
Energy Forward Index = $42
Capacity Forward Index = $7

Resulting ZEC Price
Base ZEC Price = $19.59
ZEC Price = $19.59 – ($42 + $7 – $39) = $9.59

Example 2:

Assumptions
Tranche 4
Energy Forward Index = $42
Capacity Forward Index = $7
Incremental Renewable Generation = 8,000,000
Energy Basis Adjustment = $0

Resulting ZEC Price
Base ZEC Price = 44.26 x (0.53846 – (.00491 x 0)) = $23.83
ZEC Price = $23.83 – ($42 + $7 – $39) = $13.83

Example 3:

Assumptions
Tranche 4
Energy Forward Index = $42
Capacity Forward Index = $7
Incremental Renewable Generation = 13,000,000
Energy Basis Adjustment = $0

Resulting ZEC Price
Base ZEC Price = 44.26 x (0.53846 – (.00491 x (13,000,000 / 1,000,000 – 8.704)) = $22.90
ZEC Price = $22.90 – ($42 + $7 – $39) = $12.90

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

November 28, 2017

Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether any of the registrants are emerging growth companies as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if any of the registrants have elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 1.01. Entry into a Material Definitive Agreement

On November 28, 2017, ExGen Renewables IV, LLC (the " ***Borrower*** ") (an indirect subsidiary of Exelon Corporation and Exelon Generation Company, LLC (the " ***Sponsor*** ")) successfully completed the closing of a $850 million senior secured term loan credit facility established pursuant to a Credit Agreement, dated as of November 28, 2017 (the " ***Credit Agreement*** "), among the Borrower, ExGen Renewables IV Holding, LLC (" ***Holdings*** "), the lenders party, Morgan Stanley Senior Funding, Inc., as administrative agent, and Wilmington Trust, National Association, as the depositary bank and collateral agent, and the other agents party thereto.

The Borrower's obligations under the Credit Agreement are fully and unconditionally guaranteed by Holdings (the Borrower's direct parent) and ExGen Renewables Holdings, LLC (" ***ExGen Holdings*** "; and together with the Borrower and Holdings, the " ***Loan Parties*** "), a direct subsidiary of the Borrower. Holdings and ExGen Holdings guarantee the obligations of the Borrower with respect to the Credit Agreement and the other Loan Documents (as defined in the Credit Agreement, the " ***Loan Documents*** "). The obligations of the Loan Parties under the Credit Agreement and the other Loan Documents are secured by collateral (as defined in the Credit Agreement) owned or held by the Loan Parties as and to the extent provided for in the Credit Agreement and the other Loan Documents.

The term loans (the " ***Term Facility*** ") were made pursuant to the Credit Agreement in a single borrowing of $850 million on November 28, 2017. The Borrower received net proceeds of approximately $785 million from the Term Facility, after deducting original discount and estimated costs, fees and expenses incurred in connection with the execution and delivery of the Credit Agreement and the transactions contemplated thereby. It is expected that the Borrower will distribute the net proceeds from the offering to the Sponsor for its general corporate purposes.

The interest rate on the Term Facility will accrue interest at a rate equal to the LIBOR Rate (as defined in the Credit Agreement) *plus* 3.00% or Base Rate (as defined in the Credit Agreement) *plus* 2.00%.

The interest rate on the Term Facility is payable quarterly in arrears on each Quarterly Payment Date and on the Maturity Date (each, as defined in the Credit Agreement), commencing on February 28, 2018. The Term Facility is scheduled to mature, and the principal of the Term Facility is due and payable, on November 28, 2024, seven (7) years after the Closing Date (as defined in the Credit Agreement).

The Credit Agreement contains provisions for acceleration of the maturity and mandatory prepayment of the Term Facility and other obligations thereunder upon the occurrence of certain stated events and also for optional prepayments on account of principal of the Term Facility prior to the maturity thereof upon the terms and conditions specified therein. In addition, the Credit Agreement and the other Loan Documents contain customary covenants by the Borrower and Holdings (on their own behalf and, in certain circumstances, on behalf of their subsidiaries) and default provisions for the benefit of the lenders.

Item 2.03. Creation of a Direct Financial Obligation or an Obligation under an Off-Balance Sheet Arrangement of a Registrant.

On November 28, 2017, the Borrower successfully completed the closing of an $850.0 million senior secured term loan credit facility established pursuant to the Credit Agreement. See Item 1.01 for information regarding the Credit Agreement.

* * * * *

This combined Form 8-K is being furnished separately by Exelon Corporation and Exelon Generation Company, LLC (the " ***Registrants*** "). Information contained herein relating to any individual Registrant has been furnished by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

This Current Report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from these forward-looking statements include those discussed herein as well as those discussed in (1) Registrants' 2016 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 24; (2) Registrants' Third Quarter 2017 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (3) other factors discussed in filings with the Securities and Exchange Commission by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Current Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Current Report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Jonathan W. Thayer

Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright

Bryan P. Wright
Senior Vice President and Chief Financial Officer
Exelon Generation Company, LLC

November 30, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) December 9, 2013

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

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☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 7 – Regulation FD

Item 7.01. Regulation FD Disclosure.

Exelon Corporation (Exelon) and Exelon Generation Company, LLC (Exelon Generation) are revising the non-GAAP presentation definitions previously used in earnings release and investor conference presentations for Exelon Generation Gross Margin, Operating and Maintenance (O&M) and Depreciation & Amortization (D&A). Direct costs incurred to generate revenues (Cost of Sales) of certain Constellation businesses including Energy Efficiency, BGE Home and Exploration and Production were previously included in O&M or D&A. To better reflect the scale of these businesses and reduce the volatility in the Gross Margin disclosures resulting from only capturing changes in revenue, Exelon will include Cost of Sales for those businesses in Gross Margin and remove those costs from O&M or D&A. While these changes are material to the individual categories being disclosed, there is no impact to the overall results for Exelon or Exelon Generation. Attached as Exhibit 99.1 to this Current Report on Form 8-K are the presentation slides for the disclosure format change including the amounts being adjusted and a comparison of presentation methodologies for the September 30, 2013 amounts.

Section 9 – Financial Statements and Exhibits

Item 9.01. Financial Statements and Exhibits.

(d) *Exhibits* .

Exhibit No.	Description
99.1	Presentation supporting disclosure changes

* * * * *

This combined Form 8-K is being furnished separately by Exelon Corporation and Exelon Generation Company, LLC (the "Registrants"). Information contained herein relating to any individual Registrant has been furnished by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

This Current Report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from these forward-looking statements include those discussed herein as well as those discussed in (1) Registrants' 2012 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 19; (2) Registrants' Third Quarter 2013 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (3) other factors discussed in filings with the Securities and Exchange Commission by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Current Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Current Report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Jonathan W. Thayer
Jonathan W. Thayer
Executive Vice President and Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright
Bryan P. Wright
Senior Vice President and Chief Financial Officer Exelon Generation Company, LLC

December 9, 2013

EXHIBIT INDEX

Exhibit No.	Description
99.1	Presentation supporting disclosure changes

Change to Format of Exelon Generation Disclosures

All numbers as of September 30, 2013

Change to Format of Exelon Generation Disclosures – Gross Margin, O&M and Depreciation & Amortization Definitions

- Direct costs incurred to generate revenues ("Cost of Sales") for certain Constellation businesses (Energy Efficiency, BGE Home and Upstream) have been included in O&M or Depreciation & Amortization ("D&A") in previous Exelon Generation disclosures
  - Cost of Sales previously included in O&M and D&A is approximately $250M - $300M/year

- Including the Cost of Sales in Gross Margin better reflects the scale of these Constellation businesses while reducing volatility in disclosures resulting from only capturing changes in revenue

- Beginning with Q4 2013 Exelon Generation disclosure, Exelon is revising Gross Margin to include "Cost of Sales" for certain Constellation businesses; while simultaneously reducing O&M and D&A by an equal amount

- Effect of revised format:

Gross Margin	lowered by	$250M - $300M
O&M/D&A	lowered by	$250M - $300M
Net Change to EBIT		$0

Exelon.

Impacted Components of Gross Margin Categories

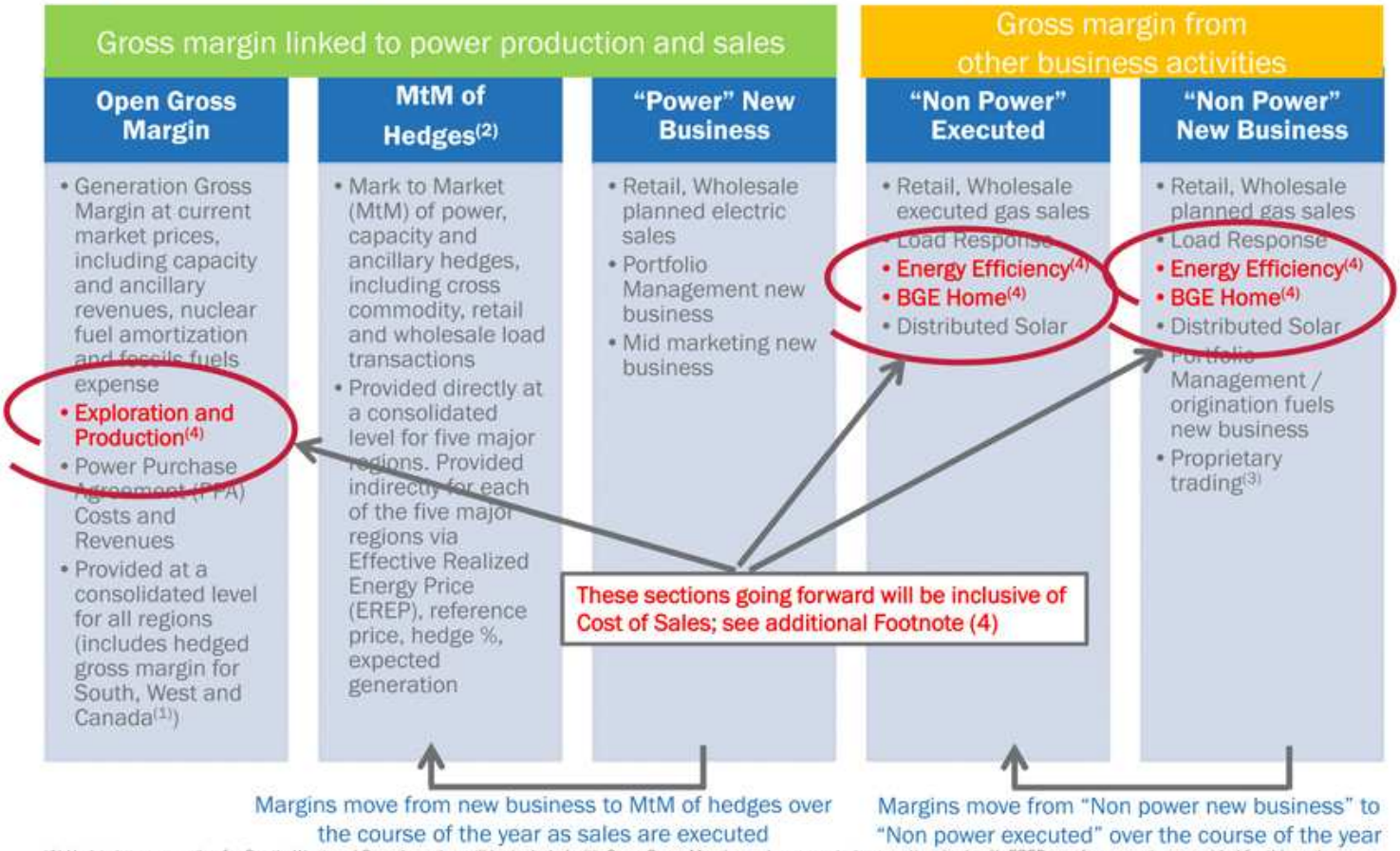

(1) Hedged gross margins for South, West and Canada region will be included with Open Gross Margin, and no expected generation, hedge %, EREP or reference prices provided for this region.
(2) MtM of hedges provided directly for the five larger regions. MtM of hedges is not provided directly at the regional level but can be easily estimated using EREP, reference price and hedged MWh.
(3) Proprietary trading gross margins will remain within "Non Power" New Business category and not move to "Non Power" Executed category.
(4) Gross margin for these businesses are net of direct "Cost of Sales".

Exelon.

ExGen Disclosures – Previous and Revised Presentations

Gross Margin Category ($M) [1,2] (as presented in EEI presentation slide 37)	2013	2014	2015	2016
Open Gross Margin (including South, West & Canada hedged GM) [3]	$5,600	$5,650	$5,800	$5,800
Mark to Market of Hedges [3,4]	$1,700	$900	$450	$250
Power New Business / To Go	$50	$500	$750	$750
Non-Power Margins Executed [5]	$400	$200	$100	$100
Non-Power New Business / To Go [5]	$200	$400	$500	$500
Total Gross Margin	$7,950	$7,650	$7,600	$7,400

	Sept 30, 2013 – Revised presentation				Change from previous presentation			
Gross Margin Category ($M)	2013	2014	2015	2016	2013	2014	2015	2016
Open Gross Margin (including South, West, Canada hedged gross margin)	$5,550	$5,600	$5,750	$5,700	($50)	($50)	($50)	($100)
Mark-to-Market of Hedges	$1,700	$900	$450	$250	0	0	0	0
Power New Business / To Go	$50	$500	$750	$750	0	0	0	0
Non-Power Margins Executed	$300	$100	$50	$50	($100)	($100)	($50)	($50)
Non-Power New Business / To Go	$100	$300	$350	$350	($100)	($100)	($150)	($150)
Total Gross Margin	$7,700	$7,400	$7,350	$7,100	($250)	($250)	($250)	($300)

(1) Gross margin (net of direct "cost of sales") rounded to nearest $50M.

(2) Gross margin does not include revenue related to decommissioning, gross receipts tax, Exelon Nuclear Partners and entities consolidated solely as a result of the application of FIN 46R.

(3) Includes CENG Join

(4) Mark to Market of Hedges assumes mid-point of hedge percentages.

(5) Any changes to new business estimates for our non-power business are presented as revenue less costs of sales.

(6) Based on September 30, 2013 market conditions.

These reductions shown in gross margin, are offset by commensurate reductions in O&M and D&A; There is no impact on net income

Exelon.

Additional 2013 ExGen and CENG Modeling – Previous and Revised Presentations

P&L Item	2013 Estimate	
ExGen Model Inputs[1]	EEI Slide 13 presentation	Revised presentation
O&M[2]	$4,275M	$4,075M
Taxes Other Than Income (TOTI)[3]	$300M	No change
Depreciation & Amortization[4]	$825M	$775M
Interest Expense	$350M	No change
CENG Model Inputs (at ownership)[5]		
Gross Margin	n ExGen Disclosures	No change
O&M/TOTI	400M - $450M	No change
Depreciation & Ar Asset Retirement	100M - $150M	No change
Capital Expenditures	$75M - $125M	No change
Nuclear Fuel Capital Expenditure	$100M - $150M	No change

Reduced O&M ~$200M and D&A ~$50M. Footnotes (2) and (4) have been updated to reflect new definition

(1) ExGen amounts for O&M, TOTI and Depreciation & Amortization exclude the impacts of CENG. CENG impact is reflected in "Equity earnings of unconsolidated affiliates" in the Income Statement.
(2) ExGen O&M excludes costs of sales for certain Constellation businesses, P&L neutral decommissioning costs and the impact from O&M related to entities consolidated solely as a result of the application of FIN 46R.
(3) TOTI excludes gross receipts tax for retail.
(4) ExGen Depreciation & Amortization excludes costs of sales for certain Constellation businesses and the impact of P&L neutral decommissioning.
(5) The CENG model inputs are intended to support Exelon's guidance range and do not represent CENG's final estimates.

Exelon.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

December 7, 2016
Date of Report (Date of earliest event reported)

Commission File Number	Exact Name of Registrant as Specified in Its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Section 2 – Financial Information

Item 2.05 Costs Associated with Exit or Disposal Activities

Item 8.01 Other Information

As previously disclosed, on June 2, 2016, Exelon Corporation (Exelon) announced that Exelon Generation Company, LLC (Generation) would permanently cease generation operations at Clinton Nuclear Generating Station (Clinton) on June 1, 2017 and at Quad Cities Nuclear Power Station (Quad Cities) on June 1, 2018.

On December 7, 2016, the Future Energy Jobs Bill (Bill) was signed into law by the Governor of Illinois. The Bill includes a Zero Emission Standard (ZES) providing compensation in the form of a Zero Emission Credit (ZEC) targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet specific eligibility criteria. Exelon and Generation now expect the Clinton and Quad Cities plants, if selected in the Illinois Power Authority process, to continue operation for at least another 10 years as a result of this legislation.

The ZES will have a 10-year duration commencing on June 1, 2017 and Generation will directly contract with Illinois utilities for the procurement of the ZECs based upon the number of MWh produced by eligible facilities, subject to specified caps. The ZEC price will be based upon the current social cost of carbon as determined by the federal government and is initially established at $16.50 per MWh of production, subject to future adjustments based on specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices.

Pursuant to this development, in December 2016 Exelon and Generation will reverse approximately $120 million of certain one-time charges initially recorded in June 2016 associated with early retirement primarily for employee-related costs and a materials and supplies inventory reserve adjustment, among other items.

In addition to these one-time charges, there will be ongoing annual financial impacts stemming from extending the previously shortened expected economic useful life of Clinton and Quad Cities on a prospective basis starting on December 7, 2016 primarily related to depreciation of plant assets (including any asset retirement costs (ARC)), amortization of nuclear fuel, and changes to asset retirement obligation (ARO) accretion expense. Exelon and Generation continue to assess the impacts on the ARO and ARC associated with the changes in decommissioning timing and cost assumptions to reflect a later retirement date. While these impacts have not yet been quantified, Exelon and Generation expect lower ARC depreciation and ARO accretion prospectively. In addition, the following table summarizes the estimated amount and timing of expected future decreases to the other non-cash expense items most recently disclosed within Management’s Discussion and Analysis of our third quarter Form 10-Q.

(in millions)

	2016 [a]	2017 [b]	2018 [c]
Income statement expenses (pre-tax):			
Depreciation and Amortization			
Accelerated non-ARC depreciation [d]	($ 45)	($470)	($140)
Accelerated nuclear fuel amortization	($ 10)	($ 85)	($ 20)

(a) From December 7, 2016 to December 31, 2016.
(b) From January 1, 2017 to May 31, 2017 for Clinton and full year for Quad Cities.
(c) From January 1, 2018 to May 31, 2018 for Quad Cities.
(d) Includes the accelerated depreciation of plant assets excluding any ARC and assumes an estimated useful life commensurate with the end of the ZES for Clinton and consistent with the current operating license expiration for Quad Cities.

Exelon and Generation are continuing to assess the impact on Nuclear Regulatory Commission (NRC) minimum funding requirements for Clinton and Quad Cities. While these impacts have not yet been quantified, Exelon and Generation expect that given the later commencement of decommissioning activities and a longer time period over which the nuclear decommissioning trust fund (NDTF) investments can appreciate in value, it is more likely than not that both Clinton and Quad Cities will either meet the NRC minimum funding requirements or, if not, not meet the NRC minimum funding requirements by only a small margin. A shortfall could require Exelon to post parental guarantees for Generation's obligations. However, the amount of required guarantees, if any, will ultimately be dependent on the decommissioning approach adopted at each site, the associated level of costs, and the decommissioning trust fund investment performance going forward. Generation is financially responsible for the decommissioning obligations related to Clinton and Quad Cities and cannot collect funds from Illinois customers related to decommissioning costs for either plant.

Exelon and Generation will continue to assess the financial implications of the adjustments to the ARC and ARO as well as the NRC minimum funding requirements and will disclose those impacts in its upcoming Form 10-K.

In addition to the ZES providing compensation in the form of zero emission credits to eligible nuclear facilities, the Bill, which is effective June 1, 2017, also includes (1) an expansion of the Renewable Portfolio Standard requiring Commonwealth Edison Company (ComEd) procurement of renewable energy credits for all customers by June 2019, (2) incentives for low-income solar distributed generation and community solar programs, which will be funded by an existing Renewable Energy Resources Fund and ongoing Renewable Portfolio Standards collections (3) new cumulative annual energy efficiency megawatt-hours (MWhs) savings goals for ComEd, which are designed to achieve 21.5% of cumulative annual savings by 2030, as compared to an estimated cumulative annual savings of 6.5% at the end of 2017, with the option to defer energy efficiency costs as a regulatory asset and earn a return equal to ComEd's weighted average cost of capital, subject to certain return on equity adjustments, (4) non-recoverable contributions by ComEd to low income energy assistance programs of $10 million per year for 5 years, (5) rebates to commercial

customers who own or operate distributed generation and for community solar projects, (6) revisions to the existing net metering statute to transition to energy only netting once the 5% net metering cap is reached, mandate net metering for community generation projects, and establish billing procedures for subscribers to those projects, (7) increased funding and scope of on-bill financing programs, and (8) rate caps for residential and commercial and industrial customers that limit potential increases due to the Bill. The Bill also extends the sunset date for the Illinois Energy Infrastructure Modernization Act, which established ComEd's performance-based distribution formula, from 2019 to 2022, allows ComEd to revise its distribution formula to eliminate the ROE collar beginning with the reconciliation performed for the 2017 calendar year and allows ComEd to implement a revenue balancing adjustment tariff if its distribution formula rate were to terminate.

Eliminating the ROE collar in ComEd's distribution formula or implementing a revenue balancing adjustment tariff will eliminate any unfavorable or favorable impacts of weather or load from ComEd's electric distribution revenues beginning with the reconciliation performed for the 2017 calendar year. With the exception of the $50 million of contributions to low income energy assistance programs discussed above, ComEd will recover from customers the costs it incurs pursuant to the Bill either through its distribution formula or other separate recovery mechanisms. ComEd may defer energy efficiency costs as a separate regulatory asset that will be recovered and amortized over the weighted average life of the related energy efficiency measures as filed with and approved by the Illinois Commerce Commission. ComEd will earn a return on the energy efficiency regulatory asset at a rate equal to its weighted average cost of capital, which is based on a year-end capital structure and calculated using the same methodology applicable to ComEd's distribution formula rate. Through December 31, 2030, the return on equity that ComEd earns on its energy efficiency regulatory asset is subject to a maximum downward or upward adjustment of 200 basis points if ComEd falls short of or exceeds its cumulative annual savings goal. ComEd does not expect the Bill to have financial statement impacts until 2017.

* * * * *

Cautionary Statements Regarding Forward-Looking Information

This report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon, Generation and ComEd (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2015 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial

Statements and Supplementary Data: Note 23; (2) Exelon's Third Quarter 2016 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18 and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this report.

* * * * *

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, each Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

EXELON CORPORATION

/s/ Jonathan W. Thayer

Jonathan W. Thayer
Senior Executive Vice President and
Chief Financial Officer
Exelon Corporation

EXELON GENERATION COMPANY, LLC

/s/ Bryan P. Wright

Bryan P. Wright
Senior Vice President and
Chief Financial Officer
Exelon Generation Company, LLC

COMMONWEALTH EDISON COMPANY

/s/ Joseph R. Trpik, Jr.

Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer
Commonwealth Edison Company

December 13, 2016

8-Ks (PEG)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K/A

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) December 15, 2015

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza, P.O. Box 1171
Newark, New Jersey 07101-1171
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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On December 15, 2015, Public Service Enterprise Group Incorporated ("PSEG" or the "Company") elected Mr. Willie A. Deese to its Board of Directors, effective February 16, 2016, for a term ending at the 2016 Annual Meeting of Stockholders. The Current Report on Form 8-K filed by the Company with the Securities and Exchange Commission on December 16, 2015 is being amended hereby to report Mr. Deese's appointment as a member of various committees of the Board of Directors.

Item 5.02. Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers

On February 16, 2016, the PSEG Board of Directors appointed Mr. Willie A. Deese to the PSEG Corporate Governance Committee and Organization and Compensation Committee, effective immediately.

S1-SSA-0009 - 10403

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: February 16, 2016

S1-SSA-0009 - 10404

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) March 10, 2015

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza, P.O. Box 1171
Newark, New Jersey 07101-1171
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)
http://www.pseg.com

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

(Exact name of registrant as specified in its charter)

New Jersey	001-00973	22-1212800
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza, P.O. Box 570
Newark, New Jersey 07101-0570
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)
http://www.pseg.com

PSEG POWER LLC

(Exact name of registrant as specified in its charter)

Delaware	001-34232	22-3663480
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

S1-SSA-0009 - 10405

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80 Park Plaza
Newark, New Jersey 07102-4194
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)
http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

- ☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
- ☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
- ☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
- ☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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The information contained in Item 7.01 Regulation FD Disclosure in this combined Form 8-K is separately furnished, as noted, by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is provided by such company on its own behalf and in connection with its respective Form 8-K. PSE&G and Power each makes representations only as to itself and makes no other representations whatsoever as to any other company. The materials furnished as Exhibits 99 and 99.1 are available on the pseg.com website under the investor tab, or at http://investor.pseg.com.

Item 7.01 Regulation FD Disclosure

PSEG, PSE&G and Power

On March 11, 2015, PSEG is presenting at the Barclays Select Series Conference in Zurich, Switzerland as well as participating on March 12-13, 2015 in a series of investor meetings sponsored by Barclays Capital in Copenhagen, Denmark and Stockholm, Sweden. The attachment, which is furnished as Exhibit 99 to this Form 8-K, represents those discussion materials being used in which we are reaffirming earnings guidance previously furnished on Form 8-K. The complete meeting materials will be available on our website www.pseg.com.

Item 9.01 Financial Statements and Exhibits

Exhibit 99. Discussion Materials for March 11-13, 2015 investor meetings.

S1-SSA-0009 - 10407

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
STUART J. BLACK
Vice President and Controller
(Principal Accounting Officer)

Date: March 10, 2015

S1-SSA-0009 - 10408

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /s/ Stuart J. Black
STUART J. BLACK
Vice President and Controller
(Principal Accounting Officer)

Date: March 10, 2015

S1-SSA-0009 - 10409

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /s/ Stuart J. Black
STUART J. BLACK
Vice President and Controller
(Principal Accounting Officer)

Date: March 10, 2015

S1-SSA-0009 - 10410

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Forward-Looking Statement

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and transmission planning,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- any deterioration in our credit quality or the credit quality of our counterparties,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as for transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies, and
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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GAAP Disclaimer

PSEG presents Operating Earnings in addition to its Net Income reported in accordance with accounting principles generally accepted in the United States (GAAP). Operating Earnings is a non-GAAP financial measure that differs from Net Income because it excludes gains or losses associated with Nuclear Decommissioning Trust (NDT), Mark-to-Market (MTM) accounting, and other material one-time items. PSEG presents Operating Earnings because management believes that it is appropriate for investors to consider results excluding these items in addition to the results reported in accordance with GAAP. PSEG believes that the non-GAAP financial measure of Operating Earnings provides a consistent and comparable measure of performance of its businesses to help shareholders understand performance trends. This information is not intended to be viewed as an alternative to GAAP information. The last slide in this presentation includes a list of items excluded from Net Income to reconcile to Operating Earnings, with a reference to those slides included on each of the slides where the non-GAAP information appears.

These materials and other financial releases can be found on the pseg.com website under the investor tab, or at http://investor.pseg.com/

S1-SSA-0009 - 10412

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Operating Earnings

Disciplined investment program and focus on operational excellence have supported growth

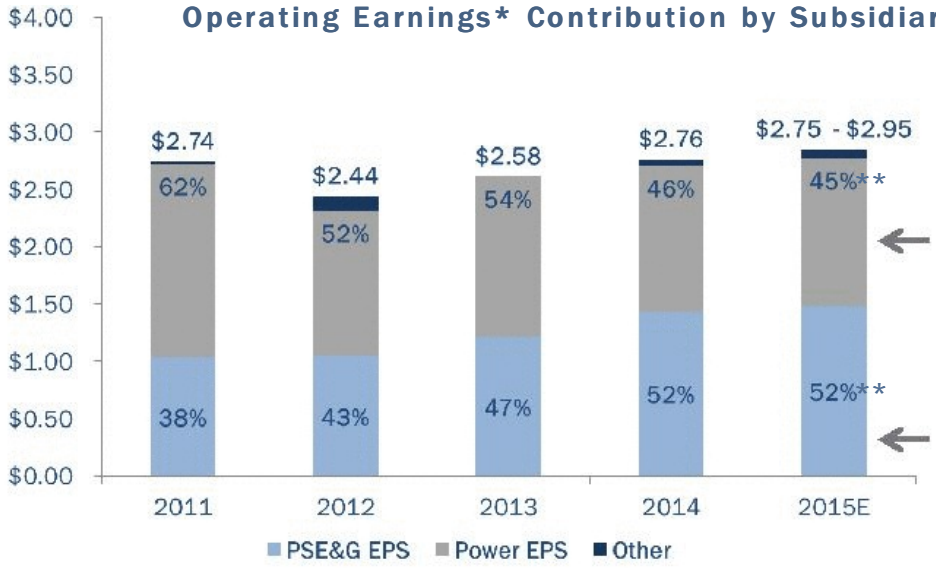

Power's diverse fuel mix and dispatch flexibility continue to generate strong earnings and free cash flow in low price environment

PSE&G's investment program has driven double digit compound annual earnings growth since 2010

PSEG

*SEE SLIDE A FOR ITEMS EXCLUDED FROM INCOME FROM CONTINUING OPERATIONS/ NET INCOME TO RECONCILE TO OPERATING EARNINGS. E=ESTIMATE
** 2015 PERCENTS USE MIDPOINT OF EARNINGS GUIDANCE.

S1-SSA-0009 - 10413

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PSE&G's 2015 operating earnings

expected to benefit from increased investment in Transmission

PSEG

*SEE SLIDE A FOR ITEMS EXCLUDED FROM NET INCOME TO RECONCILE TO OPERATING EARNINGS. E =ESTIMATE. DATA AS OF MARCH 2, 2015.

S1-SSA-0009 - 10414

Source: PUBLIC SERVICE ENTERPRISE GROUP INC, 8-K, March 10, 2015

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Power's 2015 operating earnings

maintain solid performance

Power Operating Earnings*
($ Millions)

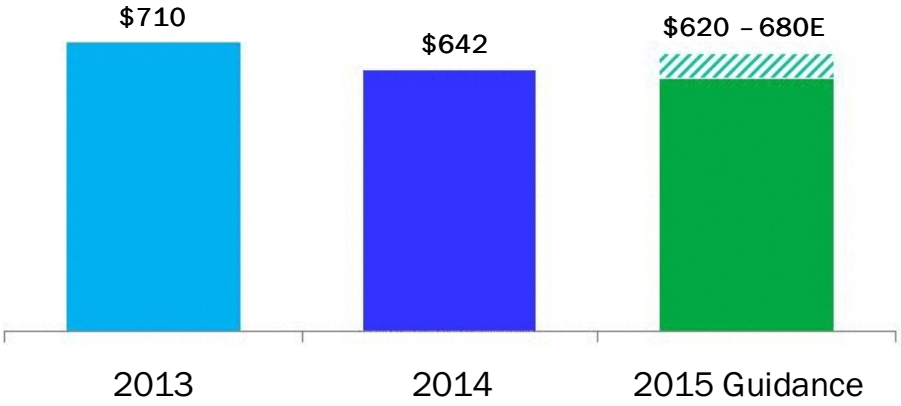

2015 Observations

- 75-80% hedged at $52/MWh
- Increase in average hedge price for energy helps mitigate reset in capacity price and volume

S1-SSA-0009 - 10415

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Increasing PSE&G earnings with stable contribution from Power

PSEG Operating Earnings			
$ Millions (except EPS)	**2013**	**2014**	**2015E**
PSE&G	$612	$725	$735 - $775
PSEG Power	$710	$642	$620 - $680
Enterprise/Other	($13)	$33	$40 - $45
Operating Earnings*	$1,309	$1,400	$1,395 - $1,500
*Operating EPS**	**$2.58**	**$2.76**	**$2.75 - $2.95**
Regulated % of Earnings	**47%**	**52%**	**52% (1)**

PSEG

(1) REPRESENTS MID POINT OF GUIDANCE
*SEE SLIDE A FOR ITEMS EXCLUDED FROM INCOME FROM CONTINUING OPERATIONS/NET INCOME TO RECONCILE TO OPERATING EARNINGS. E= ESTMATE.

S1-SSA-0009 - 10416

Source: PUBLIC SERVICE ENTERPRISE GROUP INC, 8-K, March 10, 2015
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PSEG Summary

- Our 2014 earnings of $2.76 exceeded our revised operating earnings guidance of $2.60 - $2.75 per share
- Continued third year of anticipated positive earnings trend in 2015 with operating earnings guidance of $2.75 to $2.95 per share
- Continued 5th straight year of expected double digit, 5 year growth in rate base
- Anticipated high single digit earnings growth at PSE&G on three-year basis from 2014 to 2017, driven by transmission investments and planned programs
- Power's continued focus on operational excellence, market expertise and financial strength delivers value in current price environment
- Strong Balance Sheet and Cash Flow support full capital program and new potential opportunities without the need for equity
- Our $0.08 per share dividend increase is consistent with our long history of returning cash to the shareholder through the common dividend, with potential for consistent and sustainable growth

S1-SSA-0009 - 10417

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Items Excluded from Income from Continuing Operations/Net Income to Reconcile to Operating Earnings

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Reconciling Items, net of tax	For the Year Ended December 31, 2014	2013	2012	2011	2010	2009
Earnings Impact ($ Millions)			(Unaudited)			
Operating Earnings	$ 1,400	$ 1,309	$ 1,236	$ 1,389	$ 1,584	$ 1,567
Gain (Loss) on Nuclear Decommissioning Trust (NDT) Fund Related Activity (PSEG Power)	68	40	52	50	46	9
Gain (Loss) on Mark-to-Market (MTM) [a] (PSEG Power)	66	(74)	(10)	107	(1)	(11)
Lease Transaction Activity (PSEG Enterprise/Other)	-	-	36	(173)	-	29
Storm O&M (PSEG Power)	(16)	(32)	(39)	-	-	-
Market Transition Charge Refund (PSE&G)	-	-	-	-	(72)	-
Gain (Loss) on Asset Sales and Impairments (PSEG Enterprise/Other)	-	-	-	34	-	-
Income from Continuing Operations	$ 1,518	$ 1,243	$ 1,275	$ 1,407	$ 1,557	$ 1,594
Discontinued Operations	-	-	-	96	7	(2)
Net Income	$ 1,518	$ 1,243	$ 1,275	$ 1,503	$ 1,564	$ 1,592
Fully Diluted Average Shares Outstanding (in Millions)	508	508	507	507	507	507
Per Share Impact (Diluted)						
Operating Earnings	$ 2.76	$ 2.58	$ 2.44	$ 2.74	$ 3.12	$ 3.09
Gain (Loss) on NDT Fund Related Activity (PSEG Power)	0.13	0.08	0.10	0.10	0.09	0.02
Gain (Loss) on MTM [a] (PSEG Power)	0.13	(0.14)	(0.02)	0.21	-	(0.02)
Lease Transaction Activity (PSEG Enterprise/Other)	-	-	0.07	(0.34)	-	0.05
Storm O&M (PSEG Power)	(0.03)	(0.07)	(0.08)	-	-	-
Market Transition Charge Refund (PSE&G)	-	-	-	-	(0.14)	-
Gain (Loss) on Asset Sales and Impairments (PSEG Enterprise/Other)	-	-	-	0.06	-	-
Income from Continuing Operations	$ 2.99	$ 2.45	$ 2.51	$ 2.77	$ 3.07	$ 3.14
Discontinued Operations	-	-	-	0.19	0.01	-
Net Income	$ 2.99	$ 2.45	$ 2.51	$ 2.96	$ 3.08	$ 3.14

[a] Includes the financial impact from positions with forward delivery months.

S1-SSA-0009 - 10418

Source: PUBLIC SERVICE ENTERPRISE GROUP INC, 8-K, March 10, 2015

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) March 31, 2014

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza, P.O. Box 1171
Newark, New Jersey 07101-1171
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 5.02 Departure of Directors or Certain Officers; Election of Directors: Appointment of Certain Officers; Compensatory Arrangements of Certain Officers

On March 31, 2014, Lon Bouknight, Jr., Executive Vice President and General Counsel of each of Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power), Public Service Electric and Gas Company (PSE&G) and PSEG Services Corporation (Services) notified the registrant of his intention to retire from each of his positions, effective in the third quarter of 2014.

Item 9.01 Financial Statements and Exhibits

Exhibit 99 Press Release dated April 1, 2014

S1-SSA-0009 - 10420

Source: PUBLIC SERVICE ENTERPRISE GROUP INC, 8-K, April 02, 2014 Powered by Morningstar® Document Research℠

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Derek M. DiRisio
Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: April 2, 2014

S1-SSA-0009 - 10421

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EXHIBIT 99

Media Relations

Public Service Enterprise Group
80 Park Plaza, T6
Newark, NJ 07102

FOR IMMEDIATE RELEASE
April 1, 2014

CONTACT: Paul Rosengren
973-430-5911

Lon Bouknight, PSEG General Counsel, To Retire

Tamara Linde to Be Named General Counsel

Courtney McCormick Promoted to VP and Deputy General Counsel

(Newark – April 1, 2014) — PSEG announced today that Lon Bouknight, Jr. executive vice president and general counsel, will be retiring in the third quarter of 2014. Tamara Linde, currently vice president - regulatory, will be promoted to executive vice president and general counsel upon Bouknight's retirement.

"Lon brought a wealth of experience as a general counsel to PSEG when he joined us four years ago. He effectively led our legal team at a critical time in our company's history and diligently mentored his successor," said Ralph Izzo - president, chairman and CEO of PSEG. "He gave sage counsel to the PSEG Board of Directors and our executive team. I want to thank him personally and on behalf of the entire company. We wish him well in retirement." Bouknight had been a partner at Steptoe and Johnson before joining PSEG and prior to that had been executive vice president and general counsel at Edison International.

Linde joined the PSEG legal department in 1990. She was appointed vice president - regulatory in 2006 and has led the company's federal and state regulatory functions, as well as managed corporate, environmental and labor/employment practices within the company. She has served as regulatory counsel on many of the company's most important initiatives in recent years.

"Tammy is a strong leader and excellent lawyer who thoroughly understands our business and the environment in which we operate. I am pleased to announce her promotion and know that she can continue to build on Lon's successes in leading our outstanding internal legal team," said Izzo. Bouknight will support Linde and her team through the transition.

PSEG also announced that Courtney McCormick has been named vice president, deputy general counsel and corporate secretary. Since joining PSEG in 2008, McCormick has held several roles, most recently as corporate secretary and general corporate counsel. She also oversees shareholder services, corporate records management and legal administration functions. McCormick had worked at the law firms of King & Spalding LLP as well as Pillsbury Winthrop LLP before joining PSEG. She will report to Linde.

Public Service Enterprise Group (NYSE:PEG) is a publicly traded diversified energy company with annual revenues of $10 billion. Its operating subsidiaries are: PSEG Power, Public Service Electric and Gas Company (PSE&G) and PSEG Long Island. # # #

Source: PUBLIC SERVICE ENTERPRISE GROUP INC, 8-K, April 02, 2014 Powered by Morningstar® Document Research℠
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) April 15, 2014

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza, P.O. Box 1171
Newark, New Jersey 07101-1171
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 5.07 Submission of Matters to a Vote of Security Holders

Our Annual Meeting of Stockholders was held on April 15, 2014. Proxies for the meeting were solicited by us pursuant to Regulation 14A under the Securities Act of 1934. There was no solicitation of proxies in opposition to management's nominees as listed in the proxy statement.

All of management's nominees were elected to the Board of Directors.

The advisory vote on executive compensation was approved.

The amendments to our Certificate of Incorporation and/or By-Laws to eliminate

- supermajority voting requirements for certain business combinations,
- supermajority voting requirements to remove a director without cause, and
- supermajority voting requirement to make certain amendments to our By-Laws

failed to receive the required affirmative vote of 80% of the number of shares outstanding and eligible to vote and were not approved.

The appointment of Deloitte & Touche LLP as Independent Auditor was ratified.

Final results of the voting are provided below:

Proposal 1:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Election of Directors				
Terms expiring in 2015				
Albert R. Gamper, Jr.	369,729,024	4,793,690	2,349,280	73,587,487
William V. Hickey	371,273,245	3,310,942	2,287,807	73,587,487
Ralph Izzo	361,986,108	8,860,324	6,025,562	73,587,487
Shirley Ann Jackson	350,025,650	24,567,436	2,278,908	73,587,487
David Lilley	371,969,210	2,557,909	2,344,875	73,587,487
Thomas A. Renyi	366,354,325	8,166,048	2,351,621	73,587,487
Hak Cheol Shin	371,663,392	2,803,430	2,405,172	73,587,487
Richard J.Swift	353,279,307	21,209,810	2,382,877	73,587,487
Susan Tomasky	371,877,408	2,720,346	2,274,240	73,587,487
Alfred W. Zollar	372,376,664	2,177,358	2,317,972	73,587,487

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Proposal 2:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Advisory Vote on Executive Compensation	355,065,144	17,220,508	4,586,342	73,587,487

Proposal 3(a):	Votes For	Votes Against	Abstentions	Broker Non-Votes
Approval of Amendment to Eliminate Supermajority for Certain Business Combinations	366,767,136	6,312,006	3,792,144	73,588,195

Proposal 3(b):	Votes For	Votes Against	Abstentions	Broker Non-Votes
Approval of Amendment to Eliminate Supermajority to Remove a Director Without Cause	367,375,061	5,785,881	3,710,344	73,588,195

Proposal 3(c):	Votes For	Votes Against	Abstentions	Broker Non-Votes
Approval of Amendment to Eliminate Supermajority to Make Certain Amendments to By-Laws	366,532,486	6,599,478	3,739,322	73,588,195

Proposal 4:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Ratification of Appointment of Deloitte & Touche LLP as Independent Auditor	440,889,817	6,546,246	3,023,418	N/A

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Derek M. DiRisio
Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: April 17, 2014

S1-SSA-0009 - 10426

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) April 16, 2013

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza, P.O. Box 1171
Newark, New Jersey 07101-1171
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

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☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 5.07 Submission of Matters to a Vote of Security Holders

Our Annual Meeting of Stockholders was held on April 16, 2013. Proxies for the meeting were solicited by us pursuant to Regulation 14A under the Securities Act of 1934. There was no solicitation of proxies in opposition to management's nominees as listed in the proxy statement.

All of management's nominees were elected to the Board of Directors.

The advisory vote on executive compensation was approved.

The amendment and restatement of the 2004 Long-Term Incentive Plan was approved.

The amendment and restatement of the Employee Stock Purchase Plan was approved.

The appointment of Deloitte & Touche LLP as Independent Auditor was ratified.

The stockholder proposal on the simple majority vote requirement was approved. The stockholder proposal received the support of more than a majority of the votes cast. In the coming months our Board of Directors will take into careful consideration the results of this vote in determining how best to address the concerns raised in the proposal, including any recommendations the Board may make regarding amendments to our Certificate of Incorporation and By-Laws.

Final results of the voting are provided below:

Proposal 1:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Election of Directors				
Terms expiring in 2014				
Albert R. Gamper, Jr.	368,406,953	5,047,803	2,172,663	73,507,962
William V. Hickey	362,486,586	11,041,033	2,099,800	73,507,962
Ralph Izzo	363,571,842	8,011,304	4,044,273	73,507,962
Shirley Ann Jackson	329,870,940	43,713,104	2,043,375	73,507,962
David Lilley	366,420,726	7,133,018	2,073,675	73,507,962
Thomas A. Renyi	363,169,813	10,155,149	2,302,457	73,507,962
Hak Cheol Shin	369,445,907	3,730,177	2,451,335	73,507,962
Richard J.Swift	341,382,749	31,958,608	2,286,062	73,507,962
Susan Tomasky	368,764,811	4,678,175	2,184,433	73,507,962
Alfred W. Zollar	369,712,267	3,630,033	2,285,119	73,507,962

S1-SSA-0009 - 10428

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Proposal 2:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Advisory Vote on Executive Compensation	352,119,461	19,432,411	4,075,547	73,507,962

Proposal 3:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Approval of Amendment and Restatement of 2004 Long-Term Incentive Plan	354,422,786	17,664,452	3,540,181	73,507,962

Proposal 4:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Approval of Amendment and Restatement of Employee Stock Purchase Plan	366,217,762	6,518,813	2,890,844	73,507,962

Proposal 5:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Ratification of Appointment of Deloitte & Touche LLP as Independent Auditor	439,750,253	6,862,713	2,522,415	N/A

Proposal 6:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Stockholder proposal on simple majority vote requirement	230,834,134	140,545,073	4,248,087	73,508,087

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Derek M. DiRisio
Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: April 18, 2013

S1-SSA-0009 - 10430

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) April 18, 2017

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).
Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act ☐

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Item 5.07 Submission of Matters to a Vote of Security Holders

The Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated (PSEG) was held on April 18, 2017. Proxies for the meeting were solicited by PSEG pursuant to Regulation 14A under the Securities Act of 1934. There was no solicitation of proxies in opposition to management's nominees as listed in the proxy statement.

All of management's nominees were elected to the Board of Directors.

The advisory vote on executive compensation was approved.

The stockholders have recommended in the advisory vote on the frequency of future advisory votes on executive compensation that such votes be held every year. Based on that result and consistent with its own recommendation, the Board of Directors has determined that PSEG's stockholders will continue to be presented with the opportunity to cast an advisory vote on executive compensation at the Annual Meeting of Stockholders to be held in each year beginning in 2018 and continuing through the earlier of 2023 or the next Annual Meeting at which an advisory vote on the frequency of the advisory vote on executive compensation is presented to stockholders.

The appointment of Deloitte & Touche LLP as PSEG's independent auditor was ratified.

Final results of the voting are provided below:

Proposal 1:
Election of Directors

Terms expiring in 2018	**Votes For**	**Votes Against**	**Abstentions**	**Broker Non-Votes**
Willie A. Deese	375,340,842	2,837,580	1,446,709	70,110,190
Albert R. Gamper, Jr.	362,416,064	15,751,938	1,457,129	70,110,190
William V. Hickey	363,619,758	14,549,061	1,456,312	70,110,190
Ralph Izzo	340,688,776	33,175,683	5,760,672	70,110,190
Shirley Ann Jackson	355,182,444	22,944,385	1,498,302	70,110,190
David Lilley	374,437,438	3,677,537	1,510,156	70,110,190
Thomas A. Renyi	361,187,018	16,936,034	1,502,079	70,110,190
Hak Cheol Shin	375,745,994	2,437,831	1,441,306	70,110,190
Richard J. Swift	312,210,568	65,892,028	1,522,535	70,110,190
Susan Tomasky	375,551,594	2,710,664	1,362,873	70,110,190
Alfred W. Zollar	375,302,843	2,866,612	1,455,676	70,110,190

Proposal 2:	**Votes For**	**Votes Against**	**Abstentions**	**Broker Non-Votes**
Advisory Vote on the Approval of Executive Compensation	337,202,570	39,528,570	2,892,891	70,111,290

Proposal 3:	**1 Year**	**2 Years**	**3 Years**	**Abstentions**	**Broker Non-Votes**
Advisory Vote on the Frequency of Future Advisory Votes of Executive Compensation	323,963,929	3,236,589	49,811,999	2,611,514	70,111,290

Proposal 4:	**Votes For**	**Votes Against**	**Abstentions**	**Broker Non-Votes**
Ratification of Appointment of Deloitte & Touche LLP as Independent Auditor	433,511,648	14,344,889	1,878,784	0

S1-SSA-0009 - 10432

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 20, 2017

S1-SSA-0009 - 10433

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) April 17, 2018

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)
http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act ☐

Source: PUBLIC SERVICE ENTERPRISE GROUP INC, 8-K, April 20, 2018 Powered by Morningstar® Document Research℠
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Item 5.07 Submission of Matters to a Vote of Security Holders

The Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated (PSEG) was held on April 17, 2018. Proxies for the meeting were solicited by PSEG pursuant to Regulation 14A under the Securities Act of 1934. There was no solicitation of proxies in opposition to management's nominees as listed in the proxy statement.

All of management's nominees were elected to the Board of Directors.

The advisory vote on executive compensation was approved.

The appointment of Deloitte & Touche LLP as PSEG's independent auditor was ratified.

Final results of the voting are provided below:

Proposal 1:
Election of Directors

Terms expiring in 2019	Votes For	Votes Against	Abstentions	Broker Non-Votes
Willie A. Deese	382,097,089	2,788,505	1,540,588	69,331,376
William V. Hickey	376,225,606	8,687,254	1,513,322	69,331,376
Ralph Izzo	360,836,424	22,840,861	2,748,897	69,331,376
Shirley Ann Jackson	367,245,468	17,685,437	1,495,277	69,331,376
David Lilley	381,785,722	3,026,693	1,613,767	69,331,376
Barry H. Ostrowsky	381,890,107	2,969,064	1,567,011	69,331,376
Thomas A. Renyi	369,454,705	15,359,394	1,612,083	69,331,376
Hak Cheol (H.C.) Shin	381,188,150	3,626,131	1,611,901	69,331,376
Richard J. Swift	306,293,051	78,556,158	1,576,973	69,331,376
Susan Tomasky	382,875,388	2,101,361	1,449,433	69,331,376
Alfred W. Zollar	382,706,229	2,156,547	1,563,406	69,331,376

Proposal 2:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Advisory Vote on the Approval of Executive Compensation	356,367,405	26,829,826	3,228,386	69,331,941

Proposal 3:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Ratification of Appointment of Deloitte & Touche LLP as Independent Auditor	438,737,387	15,327,587	1,692,584	0

S1-SSA-0009 - 10435

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 20, 2018

S1-SSA-0009 - 10436

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) April 21, 2015

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza, P.O. Box 1171
Newark, New Jersey 07101-1171
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 7.01 Regulation FD Disclosure

On April 21, 2015, PSEG is holding its Annual Meeting of Stockholders in Newark, NJ. In his remarks at the Annual Meeting, Ralph Izzo, Chairman of the Board, President and Chief Executive Officer will be reaffirming that for 2015 PSEG is projecting a third consecutive year of earnings growth. PSEG has previously furnished on Form 8-K earnings guidance for 2015 of $2.75 - $2.95 per share.

S1-SSA-0009 - 10438

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 21, 2015

S1-SSA-0009 - 10439

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) April 21, 2015

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza, P.O. Box 1171
Newark, New Jersey 07101-1171
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 5.07 Submission of Matters to a Vote of Security Holders

Our Annual Meeting of Stockholders was held on April 21, 2015. Proxies for the meeting were solicited by us pursuant to Regulation 14A under the Securities Act of 1934. There was no solicitation of proxies in opposition to management's nominees as listed in the proxy statement.

All of management's nominees were elected to the Board of Directors.

The advisory vote on executive compensation was approved.

The appointment of Deloitte & Touche LLP as Independent Auditor was ratified.

Final results of the voting are provided below:

Proposal 1:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Election of Directors				
Terms expiring in 2016				
Albert R. Gamper, Jr.	369,494,100	6,496,968	3,316,961	69,204,024
William V. Hickey	370,521,445	6,253,541	2,533,043	69,204,024
Ralph Izzo	350,195,759	23,010,774	6,101,496	69,204,024
Shirley Ann Jackson	343,858,411	32,868,030	2,581,588	69,204,024
David Lilley	374,573,603	2,096,869	2,637,557	69,204,024
Thomas A. Renyi	368,004,701	8,674,559	2,628,769	69,204,024
Hak Cheol Shin	374,535,711	2,129,475	2,642,843	69,204,024
Richard J.Swift	345,672,712	30,268,609	3,366,708	69,204,024
Susan Tomasky	374,018,786	2,759,622	2,529,621	69,204,024
Alfred W. Zollar	373,698,228	2,887,811	2,721,990	69,204,024
Proposal 2:				
Advisory Vote on the Approval of Executive Compensation	353,694,934	21,278,316	4,334,779	69,204,024
Proposal 3:				
Ratification of Appointment of Deloitte & Touche LLP as Independent Auditor	438,876,256	6,643,634	2,992,163	N/A

S1-SSA-0009 - 10441

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 23, 2015

S1-SSA-0009 - 10442

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) April 19, 2016

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza, P.O. Box 1171
Newark, New Jersey 07101-1171
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)
http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 5.07 Submission of Matters to a Vote of Security Holders

The Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated was held on April 19, 2016. Proxies for the meeting were solicited by us pursuant to Regulation 14A under the Securities Act of 1934. There was no solicitation of proxies in opposition to management's nominees as listed in the proxy statement.

All of management's nominees were elected to the Board of Directors.

The compensation of the named executive officers as disclosed in the proxy statement was approved on an advisory basis.

The appointment of Deloitte & Touche LLP as Independent Auditor was ratified.

Final results of the voting are provided below:

Proposal 1:	Votes For	Votes Against	Abstentions	Broker Non-Votes
Election of Directors				
Terms expiring in 2017				
Willie A. Deese	376,904,948	5,282,344	1,402,989	67,277,314
Albert R. Gamper, Jr.	372,987,631	8,160,181	2,442,469	67,277,314
William V. Hickey	375,292,772	6,975,900	1,321,609	67,277,314
Ralph Izzo	349,667,716	29,449,624	4,472,941	67,277,314
Shirley Ann Jackson	370,300,018	11,988,439	1,301,824	67,277,314
David Lilley	379,988,583	2,283,309	1,318,389	67,277,314
Thomas A. Renyi	375,258,182	6,896,325	1,435,774	67,277,314
Hak Cheol Shin	380,095,388	2,087,856	1,407,037	67,277,314
Richard J.Swift	329,619,224	51,496,674	2,474,383	67,277,314
Susan Tomasky	380,227,494	2,043,268	1,319,519	67,277,314
Alfred W. Zollar	379,995,161	2,214,412	1,380,708	67,277,314
Proposal 2:				
Advisory Vote on the Approval of Executive Compensation	345,829,085	34,207,864	3,552,615	67,278,031
Proposal 3:				
Ratification of Appointment of Deloitte & Touche LLP as Independent Auditor	443,311,916	5,945,066	1,610,613	N/A

S1-SSA-0009 - 10444

Source: PUBLIC SERVICE ENTERPRISE GROUP INC, 8-K, April 25, 2016 Powered by Morningstar® Document Research℠

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 25, 2016

S1-SSA-0009 - 10445

Source: PUBLIC SERVICE ENTERPRISE GROUP INC, 8-K, April 25, 2016 Powered by Morningstar® Document Research℠

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) May 9, 2017

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

(Exact name of registrant as specified in its charter)

New Jersey	001-00973	22-1212800
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

S1-SSA-0009 - 10446

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 8-K, May 10, 2017 Powered by Morningstar® Document Research℠

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☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether any of the registrants is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act ☐

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 8-K, May 10, 2017 Powered by Morningstar® Document Research℠

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The information contained in Item 8.01. Other Events in this Form 8-K is separately filed, as noted, by Public Service Enterprise Group Incorporated (PSEG) and Public Service Electric and Gas Company (PSE&G). Information contained herein relating to any individual company is provided by such company on its own behalf and in connection with its respective Form 8-K. PSE&G makes representations only as to itself and makes no other representations whatsoever as to any other company.

Item 8.01. Other Events

On May 9, 2017, the New Jersey Boroughs of Milltown, Park Ridge and South River submitted a joint complaint to the Federal Energy Regulatory Commission (FERC) against PSE&G alleging that the current base return on equity (ROE) of 11.18% used in PSE&G's transmission formula rates is unjust and unreasonable and should be reduced to 8.3%. As an alternative request, the complaint asks FERC to set the matter for hearing and settlement procedures. Finally, the complaint requests that FERC establish May 9, 2017 as the refund effective date for the relief sought.

Since the complaint was filed under section 206 of the Federal Power Act, there is no prescribed timeframe in which FERC must act. We cannot predict the timing or final outcome of this matter, but the ultimate resolution of this matter could be material to the results of operations and financial condition of PSEG and PSE&G.

Forward-Looking Statements

The statements contained in this Current Report on Form 8-K that are not purely historical, are "forward-looking statements" within the meaning of The Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K filed with the Securities and Exchange Commission (SEC), and available on our website: http://investor.pseg.com/sec-filings. All of the forward-looking statements made in this Current Report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business, prospects, financial condition, results of operations or cash flows. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this Current Report apply only as of the date hereof. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even in light of new information or future events, unless otherwise required by applicable securities laws.

S1-SSA-0009 - 10448

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: May 10, 2017

S1-SSA-0009 - 10449

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 8-K, May 10, 2017 Powered by Morningstar® Document Research℠
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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /s/ Stuart J. Black
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: May 10, 2017

S1-SSA-0009 - 10450

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) June 19, 2017

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act ☐

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Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers.

On June 23, 2017, Public Service Enterprise Group Incorporated ("PSEG") announced that Ralph LaRossa has been elected as President and Chief Operating Officer of PSEG Power LLC ("Power"), effective October 2, 2017. As previously announced, William Levis will retire from his position as President and Chief Operating Officer of Power, which retirement will become effective at the end of October 1, 2017.

Mr. LaRossa, 54, has served as President and Chief Operating Officer of Public Service Electric and Gas Company ("PSE&G") since 2006. He is the Chairman of the Board of PSEG Long Island LLC ("PSEG LI"). Mr. LaRossa joined PSE&G in 1985 as an associate engineer and advanced through a variety of management positions in the utility's gas and electric operations. In connection with Mr. LaRossa's election as President and Chief Operating Officer of Power, Mr. LaRossa was awarded a retention grant under PSEG's Long-Term Incentive Plan ("LTIP") of $3,000,000, payable in February 2018, concurrent with PSEG's annual grant of awards under the LTIP, in equal amounts of restricted stock units ("RSUs") and performance share units ("PSUs"). The award is subject to Mr. LaRossa's active employment at the time of the grant. The RSUs and PSUs will vest in January 2021 and December 2020, respectively, and are not subject to acceleration of vesting for retirement eligibility, retirement, or voluntary termination. There were no changes to Mr. LaRossa's base salary, annual incentive target or long-term incentive target.

Item 8.01 Other Events.

Also on June 23, 2017, PSEG announced the election of David M. Daly to succeed Mr. LaRossa as President and Chief Operating Officer of PSE&G and Chairman of the Board of PSEG LI, effective October 2, 2017. Daly, 55, was named President and Chief Operating Officer of PSEG LI in October 2013 and has overseen the transition to PSEG management of PSEG LI. Prior to his appointment, Daly served as Vice President-Asset Management and Centralized Services at PSE&G. Initially hired at PSE&G in 1983, Daly has held a variety of positions in utility operations and support services.

Item 9.01 Financial Statements and Exhibits.

Exhibit 99 Press Release dated June 23, 2017

S1-SSA-0009 - 10452

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
STUART J. BLACK
Vice President and Controller
(Principal Accounting Officer)

Date: June 23, 2017

S1-SSA-0009 - 10453

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Investor News **NYSE: PEG**

For further information, contact:

- Kathleen A. Lally, Vice President – Investor Relations Phone: 973-430-6565
- Carlotta Chan, Manager – Investor Relations Phone: 973-430-6596

RALPH LAROSSA ELECTED PRESIDENT AND COO OF PSEG POWER

Takes over from retiring PSEG Power President & COO William Levis

DAVID M. DALY ELECTED PRESIDENT AND COO OF PSE&G

(Newark – June 23, 2017) Public Service Enterprise Group (NYSE:PEG) announced today the election of Ralph LaRossa as President and Chief Operating Officer (COO) of PSEG's merchant generation business, PSEG Power effective October 2, 2017. LaRossa is currently President and COO of PSEG's utility business, Public Service Electric and Gas Company (PSE&G). In his new role, LaRossa succeeds Bill Levis who in December 2016 had announced his plans to retire.

PSEG also announced David M. Daly has been elected to succeed Ralph LaRossa as President and COO of PSE&G effective October 2, 2017. Daly will also assume the role of Chairman of the Board of PSEG Long Island currently held by Ralph LaRossa. Daly is currently President and COO of PSEG Long Island.

LaRossa, 54, was elected President and COO of PSE&G in October 2006. Since then, he has successfully led the utility through significant growth in its transmission and distribution businesses which now account for more than two-thirds of PSEG's consolidated annual revenues, with a culture focused on safety and compliance. LaRossa also led PSEG's efforts to garner a 12-year contract to manage the LIPA transmission and distribution system, which is now in its fourth year.

Ralph Izzo, Chairman, President and Chief Executive Officer of PSEG, said "In his career at PSE&G, Ralph has demonstrated the right skills to step into this key leadership role. For the past decade, Ralph has successfully led PSE&G through the largest capital program in its history. During this period he led the recovery from Superstorm Sandy and maintained a focus on operational reliability and the needs of our customers. Ralph has demonstrated strong leadership and is respected across PSEG and the industry as he assumes this role at PSEG Power." Izzo said the timing of the appointments in advance of the effective date allows ample opportunity for a smooth transition in executive leadership at PSEG Power and PSE&G. Izzo added, "Moreover, the broadening of Ralph's background is consistent with our long-term succession planning efforts."

Izzo also noted, "Dave has demonstrated strong leadership capabilities at PSEG Long Island, and has been instrumental in achieving improvements in utility operations and customer satisfaction. I am confident that under Dave, the PSE&G team will continue to meet customer expectations by maintaining a focus on service quality through programs that modernize and upgrade the system".

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Reacting to his new responsibilities, LaRossa said "I thoroughly appreciate the trust that Ralph Izzo and the Board have placed in me. I look forward to this new role working with the dedicated men and women of PSEG Power. I will do this with a close eye on operating safely and efficiently as we complete construction of PSEG Power's three new gas-fired combined cycle generators."

Daly, in reacting to his appointment, said "This is an extraordinary honor. I look forward to working with the great men and women of PSE&G, and plan to maintain our commitment to shareholder value, safe and reliable service and the highest levels of community involvement."

Mr. LaRossa joined PSE&G in 1985 as an associate engineer and advanced through a variety of management positions in the utility's gas and electric operations. In addition to his role at PSE&G, on January 1, 2014, Mr. LaRossa was appointed Chairman of the Board of PSEG Long Island, a subsidiary of PSEG. He is a graduate of Stevens Institute of Technology and has completed the Harvard Business School's Program for Management Development.

Daly, 55, was named President and COO of PSEG Long Island in October 2013, and has overseen the transition to PSEG management of PSEG Long Island. Prior to his appointment, Daly served as vice president-asset management and centralized services at PSE&G. Initially hired at PSE&G in 1983, Daly has held a variety of positions in utility operations and support services. He has an electrical engineering degree from the State University of New York Maritime College, and a Master of Business Administration from Rutgers University.

"Bill Levis's leadership at PSEG Power occurred during a time when the industry faced tremendous challenges. I greatly value his contribution to our success during these past 10 years," said Izzo. "I, along with the rest of the company, thank him and wish him well in his retirement."

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Public Service Enterprise Group (NYSE: PEG) is a publicly traded diversified energy company with annual revenues of $9.1 billion. Its operating subsidiaries are: Public Service Electric and Gas Company (PSE&G), PSEG Power, and PSEG Long Island. www.pseg.com.

Public Service Electric and Gas Company (PSE&G) is New Jersey's oldest and largest regulated gas and electric delivery utility, serving nearly three-quarters of the state's population. PSE&G is the winner of the ReliabilityOne Award for superior electric system reliability.

PSEG Power LLC is an independent power producer that generates and sells electricity in the PJM, New York and New England wholesale power markets.

Forward-Looking Statements

The statements contained in this communication about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical, are "forward-looking statements" within the meaning of The Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as

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assumptions made by and information currently available to management. When used herein, the words “anticipate,” “intend,” “estimate,” “believe,” “expect,” “plan,” “should,” “hypothetical,” “potential,” “forecast,” “project,” variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K filed with the Securities and Exchange Commission (SEC), and available on our website: http://investor.pseg.com/sec-filings. All of the forward-looking statements made in this communication are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business, prospects, financial condition, results of operations or cash flows. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this communication apply only as of the date hereof. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even in light of new information or future events, unless otherwise required by applicable securities laws.

From time to time, PSEG, PSE&G and PSEG Power release important information via postings on their corporate website at http://investor.pseg.com. Investors and other interested parties are encouraged to visit the corporate website to review new postings. The “Email Alerts” link at http://investor.pseg.com may be used to enroll to receive automatic email alerts and/or Really Simple Syndication (RSS) feeds regarding new postings.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) October 20, 2017

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

(Exact name of registrant as specified in its charter)

New Jersey	001-00973	22-1212800
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

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☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether any of the registrants is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act ☐

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The information contained in Item 7.01 Regulation FD Disclosure in this combined Form 8-K is separately furnished, as noted, by Public Service Enterprise Group Incorporated and Public Service Electric and Gas Company ("PSE&G"). Information contained herein relating to any individual company is provided by such company on its own behalf and in connection with its respective Form 8-K. PSE&G makes representations only as to itself and makes no other representations whatsoever as to any other company.

Item 7.01 Regulation FD Disclosure

Following discussions with Rate Counsel and the staff of the New Jersey Board of Public Utilities (the "BPU"), and as approved by the BPU at its October 20, 2017 meeting, the deadline for filing PSE&G's distribution rate case was deferred from November 1, 2017 to December 1, 2017. The filing will now be based upon three months of actual data and nine months of forecasted data. PSE&G is required to file a distribution base rate case as a result of its Energy Strong Order from the BPU.

S1-SSA-0009 - 10459

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
STUART J. BLACK
Vice President and Controller
(Principal Accounting Officer)

Date: October 20, 2017

S1-SSA-0009 - 10460

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /s/ Stuart J. Black
STUART J. BLACK
Vice President and Controller
(Principal Accounting Officer)

Date: October 20, 2017

S1-SSA-0009 - 10461

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) October 18, 2013

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza, P.O. Box 1171
Newark, New Jersey 07101-1171
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 5.02 Departure of Directors or Certain Officers; Election of Directors: Appointment of Certain Officers; Compensatory Arrangements of Certain Officers

On October 18, 2013, Randall E. Mehrberg, Executive Vice President of Public Service Enterprise Group Incorporated (PSEG) and President and Chief Operating Officer of PSEG's wholly owned subsidiary, PSEG Energy Holdings LLC, notified us of his intention to resign from all positions effective December 1, 2013.

S1-SSA-0009 - 10463

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Derek M. DiRisio
Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: October 21, 2013

S1-SSA-0009 - 10464

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): November 2, 2017

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Exact name of registrant as specified in its charter)

New Jersey	**001-09120**	**22-2625848**
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)
973-430-7000
(Registrant's telephone number, including area code)
http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company [ ]

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

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Item 8.01. Other Events

On November 6, 2017, Public Service Enterprise Group Incorporated ("PSEG") completed a public offering of $700.0 million aggregate principal amount of its 2.650% Senior Notes due 2022 (the "Notes"). The Notes were offered and sold by PSEG pursuant to a registration statement on Form S-3 (File No. 333-200352) (the "Registration Statement") and the related Prospectus dated November 18, 2014 and Prospectus Supplement dated November 2, 2017. The Notes were issued pursuant to an underwriting agreement (the "Underwriting Agreement"), dated November 2, 2017, between PSEG and Barclays Capital Inc., J.P. Morgan Securities LLC and Morgan Stanley & Co. LLC, as representatives of the several underwriters named therein (the "Underwriters"). Pursuant to the Underwriting Agreement and subject to the terms and conditions expressed therein, PSEG agreed to sell the Notes to the Underwriters, and the Underwriters agreed to purchase the Notes for resale to the public. The Underwriting Agreement is filed as Exhibit 1 hereto. The Notes are governed by an indenture, dated as of November 1, 1998 (the "Indenture"), between PSEG and U.S. Bank National Association, as successor trustee. The Indenture and the form of Note are filed as Exhibits 4-1 and 4-2 hereto, respectively. The Underwriting Agreement, Indenture and the form of Note are incorporated by reference into the Registration Statement.

In connection with the offering of the Notes, PSEG is filing herewith as Exhibit 5 an opinion of Shawn P. Leyden, Vice President and Deputy General Counsel of PSEG Services Corporation, addressing the legality of the Notes. Such opinion is incorporated by reference into the Registration Statement.

Item 9.01. Financial Statements and Exhibits

Exhibit 1	Underwriting Agreement, dated November 2, 2017, between PSEG and Barclays Capital Inc., J.P. Morgan Securities LLC and Morgan Stanley & Co. LLC, as representatives of the several underwriters named therein.
Exhibit 4-1	Indenture dated as of November 1, 1998 between PSEG and U.S. Bank National Association (as successor to First Union National Bank), as Trustee (incorporated by reference to Exhibit 4(f) to the Annual Report on Form 10-K for the year ended December 31, 1998, File No. 001-09120).
Exhibit 4-2	Form of Note.
Exhibit 5	Opinion of Shawn P. Leyden, Vice President and Deputy General Counsel of PSEG Services Corporation, addressing the legality of the Notes.
Exhibit 23	Consent of Shawn P. Leyden, Vice President and Deputy General Counsel of PSEG Services Corporation (included in Exhibit 5).

S1-SSA-0009 - 10466

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: November 6, 2017

S1-SSA-0009 - 10467

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Exhibit 1

EXECUTION VERSION

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(a New Jersey corporation)

$700,000,000 2.650% Senior Notes due 2022

UNDERWRITING AGREEMENT

November 2, 2017

BARCLAYS CAPITAL INC.
J.P. MORGAN SECURITIES LLC
MORGAN STANLEY & CO. LLC

c/o Barclays Capital Inc.
745 Seventh Avenue
New York, New York 10019

As Representatives of the several Underwriters

Ladies and Gentlemen:

Public Service Enterprise Group Incorporated, a New Jersey corporation (the "**Company**"), proposes to issue and sell to the several underwriters named in Schedule 1 hereto (the "**Underwriters,**" which term shall include any underwriter substituted as hereinafter provided in Section 10), acting severally and not jointly, the respective principal amounts set forth in such Schedule 1 of $700,000,000 aggregate principal amount of the Company's 2.650% Senior Notes due 2022 (the "**Securities**"). Barclays Capital Inc., J.P. Morgan Securities LLC and Morgan Stanley & Co. LLC have agreed to act as representatives of the several Underwriters (in such capacity, the "**Representatives**") in connection with the offering and sale of the Securities.

The Securities will be issued pursuant to the provisions of an Indenture dated as of November 1, 1998, as amended and supplemented by the First Supplemental Indenture, dated as of September 10, 2002, and the Second Supplemental Indenture, dated as of July 27, 2005 (collectively, the **"Indenture"**), between the Company and U.S. Bank National Association (as successor trustee to First Union National Bank), as trustee (the **"Trustee"**).

The Company has filed with the Securities and Exchange Commission (the "**Commission**") a registration statement on Form S-3 (No. 333-200352), which contains a base prospectus (the "**Base Prospectus**"), to be used in connection with the public offering and sale of certain securities by the Company, including the Securities, under the Securities Act of 1933, as amended (the "**1933 Act**"), and the offering thereof from time to time in accordance with Rule 415 of the rules and regulations of the Commission under the 1933 Act (the "**1933 Act Regulations**"). Such registration statement, including the financial statements, exhibits and schedules thereto, in the form in which it became effective under the 1933 Act, including any required information deemed to be a part thereof at the time of effectiveness pursuant to

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Rule 430B of the 1933 Act Regulations ("**Rule 430B**"), is called the "**Registration Statement**." The term "**Prospectus**" shall mean the final prospectus supplement relating to the Securities, together with the Base Prospectus, that is first filed pursuant to Rule 424(b) of the 1933 Act Regulations ("**Rule 424(b)**") after the date and time that this Agreement is executed (the "**Execution Time**") by the parties hereto. The term "**preliminary prospectus**" shall mean any preliminary prospectus supplement relating to the Securities, together with the Base Prospectus, that is first filed with the Commission pursuant to Rule 424(b). Any reference herein to the Registration Statement, any preliminary prospectus or the Prospectus shall be deemed to refer to and include the documents that are or are deemed to be incorporated by reference therein pursuant to Item 12 of Form S-3 under the 1933 Act prior to the Applicable Time (as defined below). For purposes of this Agreement, all references to the Registration Statement, any preliminary prospectus or the Prospectus or to any amendment or supplement to any of the foregoing shall be deemed to include any copy filed with the Commission pursuant to its Electronic Data Gathering, Analysis and Retrieval system ("**EDGAR**").

All references in this Agreement to financial statements and schedules and other information which is "contained," "included" or "stated" (or other references of like import) in the Registration Statement, any preliminary prospectus or the Prospectus or any amendment or supplement thereto shall be deemed to mean and include all such financial statements and schedules and other information which is or is deemed to be incorporated by reference in or otherwise deemed by the 1933 Act Regulations to be a part of or included in the Registration Statement, any preliminary prospectus or the Prospectus or any amendment or supplement thereto, as the case may be, on or before the effective date of the Registration Statement or the date of such preliminary prospectus or the Prospectus or such amendment or supplement, as the case may be; and all references in this Agreement to amendments or supplements to the Registration Statement, any preliminary prospectus or the Prospectus shall be deemed to mean and include the filing of any document under the Securities Exchange Act of 1934, as amended (the "**1934 Act**"), which is or is deemed to be incorporated by reference in or otherwise deemed by the 1933 Act Regulations to be a part of or included in the Registration Statement, such preliminary prospectus or the Prospectus, as the case may be, at the time of such amendment or supplement.

SECTION 1. Representations and Warranties.

(a) Representations and Warranties. The Company represents and warrants to each Underwriter, as of the date hereof, as of the Applicable Time and as of the Closing Time (as defined below) (in each case, a "**Representation Date**"), as follows:

(1) Compliance with Registration Requirements. The Company meets the requirements for use of Form S-3 under the 1933 Act. The Registration Statement became effective upon filing with the Commission under Rule 462(e) of the 1933 Act Regulations ("**Rule 462(e)**") on November 18, 2014 and any post-effective amendment thereto also became effective upon filing under Rule 462(e). No stop order suspending the effectiveness of the Registration Statement or preventing or suspending the use of any prospectus has been issued under the 1933 Act and no proceedings for that purpose or pursuant to Section 8A of the 1933 Act against the Company or related to the offering of the Securities have been instituted or are pending or, to the knowledge of the Company,

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are contemplated by the Commission, any request on the part of the Commission for additional information has been complied with, and no notice of objection of the Commission to the use of the Registration Statement or any post-effective amendment thereto pursuant to Rule 401(g)(2) of the 1933 Act Regulations has been received by the Company. In addition, the Indenture has been duly qualified under the Trust Indenture Act of 1939, as amended (the "**1939 Act**").

At the respective times the Registration Statement and any post-effective amendments thereto became effective and as of each Representation Date, the Registration Statement and any amendments thereto complied, complies and will comply in all material respects with the requirements of the 1933 Act and the 1933 Act Regulations and the 1939 Act and the rules and regulations of the Commission under the 1939 Act (the "**1939 Act Regulations**"), and did not, does not and will not contain an untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary to make the statements therein not misleading; provided, that the Company makes no representation or warranty with respect to the Underwriter Information (as defined below).

The Prospectus and each amendment or supplement thereto, if any, at the time the Prospectus or any such amendment or supplement is issued and at the Closing Time, complied, complies and will comply in all material respects with the requirements of the 1933 Act and the 1933 Act Regulations, and neither the Prospectus nor any amendment or supplement thereto included, includes or will include an untrue statement of a material fact or omitted, omits or will omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading; provided, that the Company makes no representation or warranty with respect to the Underwriter Information.

Each preliminary prospectus and any amendment thereto complied when so filed in all material respects with the 1933 Act and the 1933 Act Regulations and each preliminary prospectus and the Prospectus delivered or made available to the Underwriters for use in connection with the offering of the Securities was and will be, at the time of such delivery, identical to the electronically transmitted copies thereof filed with the Commission pursuant to EDGAR, except to the extent permitted by Regulation S-T.

As of the Applicable Time, neither (x) the General Disclosure Package (as defined below) nor (y) any individual Issuer Limited Use Free Writing Prospectus (as defined below), when considered together with the General Disclosure Package, included any untrue statement of a material fact or omitted to state any material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading; provided that the Company makes no representation or warranty with respect to the Underwriter Information.

As used in this subsection and elsewhere in this Agreement:

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"**Applicable Time**" means 3:15 P.M. (New York City time) on November 2, 2017 or such other time as agreed by the Company and the Representatives.

"**General Disclosure Package**" means (i) the Issuer General Use Free Writing Prospectus(es) (as defined below) relating to the Securities issued at or prior to the Applicable Time, including the Final Term Sheet (as defined below) attached as Schedule 3 hereto, and (ii) the most recent preliminary prospectus (including any documents incorporated therein by reference) that is distributed to investors prior to the Applicable Time, all considered together.

"**Issuer Free Writing Prospectus**" means any "issuer free writing prospectus," as defined in Rule 433 of the 1933 Act Regulations ("**Rule 433**"), relating to the Securities that (i) is required to be filed with the Commission, (ii) is a "road show that is a written communication" within the meaning of Rule 433(d)(8)(i), whether or not required to be filed with the Commission or (iii) is exempt from filing pursuant to Rule 433(d)(5)(i) because it contains a description of the Securities or of the offering thereof that does not reflect the final terms, in each case in the form filed or required to be filed with the Commission or, if not required to be filed, in the form retained in the Company's records pursuant to Rule 433(g).

"**Issuer General Use Free Writing Prospectus**" means any Issuer Free Writing Prospectus that is intended for general distribution to prospective investors, as evidenced by its being specified in Schedule 2-A hereto.

"**Issuer Limited Use Free Writing Prospectus**" means any Issuer Free Writing Prospectus that is not an Issuer General Use Free Writing Prospectus and that is specified in Schedule 2-B hereto.

Each Issuer Free Writing Prospectus, as of its issue date and at all subsequent times through the completion of the offering and sale of the Securities under this Agreement or until any earlier date that the Company notified or notifies you as described in Section 3(e), did not, does not and will not include any information that conflicted, conflicts or will conflict with the information contained in the Registration Statement or the Prospectus. The Company has complied with the requirements of Rule 164 and Rule 433 of the 1933 Act Regulations with respect to each Issuer Free Writing Prospectus.

(2) Status as a Well-Known Seasoned Issuer. Since the time of initial filing of the Registration Statement, the Company has been, and continues to be, a "well known seasoned issuer" as defined in Rule 405 of the 1933 Act Regulations ("**Rule 405**").

(3) Status as Non-Ineligible Issuer. At the earliest time that the Company or another offering participant made a *bona fide* offer (within the meaning of Rule 164(h)(2) of the 1933 Act Regulations) of the Securities and at each Representation Date, the Company was not and is not an "ineligible issuer," as defined in Rule 405.

(4) Incorporated Documents. The documents incorporated or deemed to be incorporated by reference in the Registration Statement, the General Disclosure Package or the Prospectus, at the time they were or hereafter are filed with the Commission,

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complied and will comply in all material respects with the requirements of the 1934 Act and the rules and regulations of the Commission thereunder (the "**1934 Act Regulations**") and, when read together with the other information in the Registration Statement, the General Disclosure Package or the Prospectus, as the case may be, (a) at the time the Registration Statement originally became effective and (b) at each Representation Date, did not, does not and will not include an untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading.

(5) Independent Accountants. The accountants who certified the financial statements and any supporting schedules thereto included in the Registration Statement, the General Disclosure Package or the Prospectus are independent public accountants as required by the 1933 Act and the 1933 Act Regulations and the Public Company Accounting Oversight Board (United States).

(6) Financial Statements. The financial statements of the Company included or incorporated by reference in the Registration Statement, the General Disclosure Package or the Prospectus, together with the related schedules and notes, as well as those financial statements, schedules and notes of any other entity included or incorporated by reference therein, present fairly the financial position of the Company and its consolidated subsidiaries, or such other entity, as the case may be, at the dates indicated and the statement of operations, member's equity and cash flows of the Company and its consolidated subsidiaries, or such other entity, as the case may be, for the periods specified. Such financial statements have been prepared in conformity with U.S. generally accepted accounting principles ("**GAAP**") applied on a consistent basis throughout the periods involved. Except as otherwise included or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus, neither pro forma financial statements of the Company nor the financial statements of any entity other than the Company are required to be included in the Registration Statement, the General Disclosure Package or the Prospectus under the 1933 Act, the 1933 Act Regulations, the 1934 Act or the 1934 Act Regulations. The supporting schedules, if any, included or incorporated by reference in the Registration Statement, the General Disclosure Package or the Prospectus present fairly in accordance with GAAP the information required to be stated therein. The Company's ratios of earnings to fixed charges included or incorporated by reference in the Registration Statement (including Exhibit 12), the General Disclosure Package or the Prospectus have been calculated in compliance with Item 503(d) of Regulation S-K of the 1933 Act Regulations. The selected financial data and the summary financial information included or incorporated by reference in the Registration Statement, the General Disclosure Package or the Prospectus present fairly the information shown therein and have been compiled on a basis consistent with that of the audited financial statements included or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus. All disclosures contained in the Registration Statement, the General Disclosure Package or the Prospectus, if any, regarding "non-GAAP financial measures" (as such term is defined by the rules and regulations of the Commission) comply with Regulation G under the 1934 Act and Item 10 of Regulation S-K of the 1933 Act

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Regulations, to the extent applicable. The interactive data in eXtensible Business Reporting Language included or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus fairly presents the information called for in all material respects and has been prepared in accordance with the Commission's rules and guidelines applicable thereto.

(7) No Material Adverse Change in Business. The Company has not sustained since the date of the latest audited financial statements included or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus any material loss from fire, explosion, flood, accident or other calamity not fully covered by insurance, otherwise than as set forth or contemplated in the Registration Statement, the General Disclosure Package and the Prospectus. Since the respective dates as of which information is given in the Registration Statement, the General Disclosure Package or the Prospectus, except as otherwise stated therein, (A) there has been no material adverse change, or any development involving a prospective material adverse change, in the general affairs, financial condition, earnings or business affairs of the Company and its subsidiaries (each such subsidiary, a "**Subsidiary**" and, collectively, the "**Subsidiaries**"), considered as one enterprise, whether or not arising in the ordinary course of business (a "**Material Adverse Change**"); (B) there have been no transactions entered into by the Company or any of its Subsidiaries, other than those arising in the ordinary course of business, which are material with respect to the Company and its Subsidiaries considered as one enterprise; (C) other than, in the case of the Company, regular dividends on the Company's common stock or preferred stock, in amounts per share that are consistent with past practice or the applicable charter document or supplement thereto, respectively, or, in the case of any of the Company's Subsidiaries, to the Company, there has been no dividend or distribution of any kind declared, paid or made by the Company or any of its Subsidiaries on any class of its capital stock; and (D) there has not been any material change in the capital stock (other than upon exercise of outstanding stock options, upon conversion of convertible securities outstanding as of the date of the most recent balance sheet incorporated by reference into the Registration Statement, the General Disclosure Package and the Prospectus or pursuant to the Company's employee or director compensation and benefit plans or the Company's dividend reinvestment and stock purchase plan) or long-term debt of the Company and its Subsidiaries considered as one enterprise.

(8) Good Standing of the Company. The Company has been duly incorporated, is validly existing as a corporation in good standing under the laws of the jurisdiction of its incorporation, has the requisite power and authority to own its property and to conduct its business as described in the Registration Statement, the General Disclosure Package and the Prospectus and is duly qualified to transact business and is in good standing in each jurisdiction in which the conduct of its business or its ownership or leasing of property requires such qualification, except to the extent that the failure to be so qualified or be in good standing would not result in a Material Adverse Change.

(9) Good Standing of Significant Subsidiaries. Each Subsidiary of the Company which is a significant subsidiary, as defined in Rule 405 (each, a "**Significant Subsidiary**"), has been duly incorporated or organized, is validly existing as a

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corporation or limited liability company in good standing under the laws of the jurisdiction of its incorporation or organization, has the requisite power and authority to own its property and to conduct its business as described in the Registration Statement, the General Disclosure Package and the Prospectus and is duly qualified to transact business and is in good standing in each jurisdiction in which the conduct of its business or its ownership or leasing of property requires such qualification, except to the extent that the failure to be so qualified or be in good standing would not result in a Material Adverse Change. All of the issued shares of capital stock or other equity interests of each Significant Subsidiary have been duly and validly authorized and issued, are fully paid and non-assessable and are owned directly by the Company or a direct wholly-owned Subsidiary of the Company, as the case may be, free and clear of all liens, encumbrances, equities or claims. None of the outstanding shares of capital stock or other equity interests of any Significant Subsidiary were issued in violation of preemptive or other similar rights of any security holder of such Significant Subsidiary.

(10) Capitalization. The authorized, issued and outstanding shares of capital stock of the Company are as set forth in the Company's most recent Annual Report on Form 10-K or, if applicable, subsequent Quarterly Report on Form 10-Q (except for subsequent issuances thereof, if any, pursuant to reservations, agreements or employee benefit plans or pursuant to the exercise of convertible securities or options, in each case which are referred to in the Registration Statement, the General Disclosure Package and the Prospectus). Such shares of capital stock have been duly authorized and validly issued by the Company and are fully paid and non-assessable and none of such shares of capital stock of the Company were issued in violation of preemptive or other similar rights of any security holder of the Company.

(11) Authorization of this Agreement. This Agreement has been duly authorized, executed and delivered by the Company.

(12) Authorization of Securities. The Securities have been duly authorized by the Company for issuance and sale pursuant to this Agreement. At the Closing Time, the Securities will have been duly executed by the Company and, when authenticated in the manner provided for in the Indenture and delivered against payment of the requisite consideration therefor, will constitute valid and legally binding obligations of the Company, enforceable against the Company in accordance with their terms, except as the enforcement thereof may be limited by bankruptcy, insolvency (including, without limitation, all laws relating to fraudulent transfers), reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally or by general equitable principles (regardless of whether enforcement is considered in a proceeding in equity or at law), and except further as enforcement thereof may be limited by requirements that a claim with respect to any debt securities payable in a foreign or composite currency (or a foreign or composite currency judgment in respect of such claim) be converted into U.S. dollars at a rate of exchange prevailing on a date determined pursuant to applicable law or by governmental authority to limit, delay or prohibit the making of payments outside the United States. The Securities will be in the form contemplated by, and each registered holder thereof will be entitled to the benefits of, the Indenture.

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(13) Authorization of the Indenture. The Indenture has been duly authorized, executed and delivered by the Company and constitutes a valid and legally binding agreement of the Company, enforceable against the Company in accordance with its terms, except as the enforcement thereof may be limited by bankruptcy, insolvency (including, without limitation, all laws relating to fraudulent transfers), reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally or by general equitable principles (regardless of whether enforcement is considered in a proceeding in equity or at law), and except further as enforcement thereof may be limited by requirements that a claim with respect to any debt securities issued or issuable under the Indenture that are payable in a foreign or composite currency (or a foreign or composite currency judgment in respect of such claim) be converted into U.S. dollars at a rate of exchange prevailing on a date determined pursuant to applicable law or by governmental authority to limit, delay or prohibit the making of payments outside the United States.

(14) Descriptions of the Securities and the Indenture. The Indenture conforms, and, upon issuance, the Securities will conform, in all material respects to the statements relating thereto contained in the Registration Statement, the General Disclosure Package and the Prospectus and will be substantially in the forms filed or incorporated by reference, as the case may be, as an exhibit to the Registration Statement.

(15) Absence of Defaults and Conflicts. Neither the Company nor any of its Subsidiaries is in violation of its certificate of incorporation or by-laws or other organizational documents or in default in the performance or observance of any obligation, agreement, covenant or condition contained in any contract, indenture, mortgage, deed of trust, loan or credit agreement, note, lease or other agreement or instrument to which the Company or any of its Subsidiaries is a party or by which it or any of them may be bound, or to which any of the assets, properties or operations of the Company or any of its Subsidiaries is subject (collectively, "**Agreements and Instruments**"), except for such defaults that would not result in a Material Adverse Change. The execution, delivery and performance of this Agreement, the Indenture, the Securities and any other agreement or instrument entered into or issued or to be entered into or issued by the Company in connection with the transactions contemplated hereby or thereby or in the Registration Statement, the General Disclosure Package and the Prospectus and the consummation of the transactions contemplated herein and in the Registration Statement, the General Disclosure Package and the Prospectus (including the issuance and sale of the Securities and the use of the proceeds from the sale of the Securities as described therein) and compliance by the Company with its obligations hereunder and thereunder have been duly authorized by all necessary corporate action and do not and will not, whether with or without the giving of notice or passage of time or both, conflict with or constitute a breach of, or default or Repayment Event (as defined below) under, or result in the creation or imposition of any lien, charge or encumbrance upon any assets, properties or operations of the Company or any of its Subsidiaries pursuant to, any Agreements and Instruments, nor will such action result in any violation of the provisions of the certificate of incorporation or by-laws or other organizational documents of the Company or any of its Subsidiaries or any applicable law, statute, rule, regulation, judgment, order, writ or decree of any government, government

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instrumentality or court, domestic or foreign, having jurisdiction over the Company or any of its Subsidiaries or any of their assets, properties or operations. As used herein, a "**Repayment Event**" means any event or condition which gives the holder of any note, debenture or other evidence of indebtedness (or any person acting on such holder's behalf) the right to require the repurchase, redemption or repayment of all or a portion of such indebtedness by the Company or any of its Subsidiaries.

(16) Absence of Labor Dispute. Other than as set forth in or contemplated by the Registration Statement, the General Disclosure Package and the Prospectus, no labor dispute with the employees of the Company or any of its Subsidiaries exists or, to the knowledge of the Company, is imminent, and the Company does not have actual knowledge of any existing or imminent labor disturbance by the employees of any of its or any Subsidiary's principal suppliers, manufacturers, customers or contractors, which, in either case, may reasonably be expected to result in a Material Adverse Change.

(17) Absence of Proceedings. Other than as set forth in or contemplated by the Registration Statement, the General Disclosure Package and the Prospectus, there is no action, suit, proceeding, inquiry or investigation before or brought by any court or governmental agency or body, domestic or foreign, now pending, or, to the knowledge of the Company, threatened, against or affecting the Company or any of its Subsidiaries which is required to be disclosed in the Registration Statement, the General Disclosure Package and the Prospectus (other than as stated in the Registration Statement, the General Disclosure Package and the Prospectus), or which might reasonably be expected to result in a Material Adverse Change, or which might reasonably be expected to materially and adversely affect the consolidated assets, properties or operations thereof or the consummation of the transactions contemplated under the Registration Statement, the General Disclosure Package and the Prospectus, this Agreement, the Securities or the Indenture, or the performance by the Company of its obligations hereunder and thereunder. The aggregate of all pending legal or governmental proceedings to which the Company or any of its Subsidiaries is a party or of which any of their respective assets, properties or operations is the subject which are not described in the Registration Statement, the General Disclosure Package and the Prospectus, including ordinary routine litigation incidental to the business, could not reasonably be expected to result in a Material Adverse Change.

(18) Accuracy of Exhibits. There are no contracts or documents which are required under the 1933 Act, the 1933 Act Regulations, the 1934 Act or the 1934 Act Regulations to be described in the Registration Statement, the General Disclosure Package, the Prospectus or the documents incorporated by reference therein or to be filed as exhibits thereto which have not been so described or filed as required.

(19) Absence of Further Requirements. No filing with, or authorization, approval, consent, license, order, registration, qualification or decree of, any court or governmental authority or agency, domestic or foreign, is necessary or required for the due authorization, execution and delivery by the Company of this Agreement, the Indenture, the Securities or for the performance by the Company of the transactions contemplated under the Registration Statement, the General Disclosure Package, the

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Prospectus, this Agreement, the Securities or the Indenture, except the registration of the Securities under the 1933 Act, the qualification of the Indenture under the 1939 Act and such consents, approvals, registrations or qualifications as may be required under state securities or Blue Sky laws in connection with the issuance and sale of the Securities and except such as have been already made, obtained or rendered, as applicable.

(20) Possession of Licenses and Permits. The Company and its Subsidiaries possess such permits, licenses, approvals, consents and other authorizations (collectively, "**Governmental Licenses**") issued by the appropriate federal, state, local or foreign regulatory agencies or bodies necessary to conduct the business now operated by them, except where the failure so to possess such Governmental Licenses would not, singly or in the aggregate, result in a Material Adverse Change. The Company and its Subsidiaries are in compliance with the terms and conditions of all such Governmental Licenses, except where the failure so to comply would not, singly or in the aggregate, result in a Material Adverse Change. All of the Governmental Licenses are valid and in full force and effect, except where the invalidity of such Governmental Licenses or the failure of such Governmental Licenses to be in full force and effect would not result in a Material Adverse Change. Neither the Company nor any of its Subsidiaries has received any notice of proceedings relating to the revocation or modification of any such Governmental Licenses which, singly or in the aggregate, if the subject of an unfavorable decision, ruling or finding, would result in a Material Adverse Change.

(21) Title to Property. The Company and its Subsidiaries have good and marketable title to all real property owned by the Company and its Subsidiaries and good title to all other properties owned by them, in each case, free and clear of all mortgages, pledges, liens, security interests, claims, restrictions or encumbrances of any kind, except (A) as otherwise stated in the Registration Statement, the General Disclosure Package and the Prospectus or (B) those which do not, singly or in the aggregate, materially affect the value of the properties owned by the Company and its Subsidiaries considered as one enterprise and do not interfere in any material respect with the use made and proposed to be made of such properties. All of the leases and subleases material to the business of the Company and its Subsidiaries considered as one enterprise, and under which the Company or any of its Subsidiaries holds properties, are in full force and effect, and neither the Company nor any of its Subsidiaries has received any notice of any material claim of any sort that has been asserted by anyone adverse to the rights of the Company or any of its Subsidiaries under any of the leases or subleases mentioned above, or affecting or questioning the rights of the Company or such Subsidiary of the continued possession of the leased or subleased premises under any such lease or sublease.

(22) Insurance. The Company and its Subsidiaries have in full force and effect insurance with insurers believed to be reputable by the Company, covering their assets, properties, operations, personnel and business against such losses, damage, risks and hazards as are adequate in accordance with customary industry practice to protect the Company and its Subsidiaries considered as one enterprise.

(23) Commodity Exchange Act. The Securities will be excluded or exempted under, or beyond the purview of, the Commodity Exchange Act, as amended (the

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"**Commodity Exchange Act**"), and the rules and regulations of the Commodity Futures Trading Commission under the Commodity Exchange Act (the "**Commodity Exchange Act Regulations**").

(24) Investment Company Act. The Company is not, or upon the issuance and sale of the Securities as herein contemplated and the application of the net proceeds therefrom as described in the Registration Statement, the General Disclosure Package and the Prospectus will not be, an "investment company" within the meaning of the Investment Company Act of 1940, as amended (the "**1940 Act**").

(25) Environmental Laws. Except as otherwise stated in the Registration Statement, the General Disclosure Package and the Prospectus or except as would not, singly or in the aggregate, result in a Material Adverse Change, (A) neither the Company nor any of its Subsidiaries is in violation of any federal, state, local or foreign statute, law, rule, regulation, ordinance, code, policy or rule of common law or any judicial or administrative interpretation thereof, including any judicial or administrative order, consent, decree or judgment, relating to pollution or protection of human health, the environment (including, without limitation, ambient air, surface water, groundwater, land surface or subsurface strata) or wildlife, including, without limitation, laws and regulations relating to the release or threatened release of chemicals, pollutants, contaminants, wastes, toxic substances, hazardous substances, petroleum or petroleum products (collectively, "**Hazardous Materials**") or to the manufacture, processing, distribution, use, treatment, storage, disposal, transport or handling of Hazardous Materials (collectively, "**Environmental Laws**"), (B) the Company and its Subsidiaries have all permits, authorizations and approvals required under any applicable Environmental Laws and are each in compliance with their requirements, (C) there are no pending or threatened administrative, regulatory or judicial actions, suits, demands, demand letters, claims, liens, notices of noncompliance or violation, investigation or proceedings relating to any Environmental Law against the Company or any of its Subsidiaries and (D) there are no events or circumstances known to the Company that might reasonably be expected to form the basis of an order for clean-up or remediation, or an action, suit or proceeding by any private party or governmental body or agency, against or affecting the Company or any of its Subsidiaries relating to Hazardous Materials or any Environmental Laws.

(26) Patriot Act. The Company will apply the net proceeds received from the offering and sale of the Securities as described in the Registration Statement, the General Disclosure Package and the Prospectus and, to the knowledge of the Company, none of such net proceeds will be used to further any action in violation or contravention of the U.S.A. Patriot Act or otherwise violate or contravene the rules, regulations or policies of the U.S. Office of Foreign Assets Control.

(27) Internal Control Over Financial Reporting. The Company and each of its Subsidiaries maintains a system of internal accounting controls sufficient to provide reasonable assurances that (i) transactions are executed in accordance with management's general or specific authorization; (ii) transactions are recorded as necessary to permit preparation of financial statements in conformity with GAAP and to maintain

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accountability for assets; (iii) access to assets is permitted only in accordance with management's general or specific authorization; (iv) the recorded accountability for assets is compared with the existing assets at reasonable intervals and appropriate action is taken with respect to any differences; and (v) the interactive data in eXtensible Business Reporting Language included or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus fairly presents the information called for in all material respects and is prepared in accordance with the Commission's rules and guidelines applicable thereto. Except as described in the Registration Statement, the General Disclosure Package and the Prospectus, since the end of the Company's most recent audited fiscal year, there has been (A) no material weakness in any such party's internal control over financial reporting (whether or not remediated) and (B) no change in any such party's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, such internal control over financial reporting.

(28) Disclosure Controls and Procedures. The Company employs disclosure controls and procedures that are designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the 1934 Act is recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms and is accumulated and communicated to the Company's management, including its principal executive officer or officers and principal financial officer or officers, as appropriate, to allow timely decisions regarding disclosure.

(29) Compliance with the Sarbanes-Oxley Act. There is and has been no failure on the part of the Company or any of the Company's directors or officers, in their capacities as such, to comply in all material respects with any provision of the Sarbanes-Oxley Act of 2002 and the rules and regulations promulgated in connection therewith, including Section 402 related to loans and Sections 302 and 906 related to certifications.

(30) Pending Proceedings and Examinations. The Registration Statement is not the subject of a pending proceeding or examination under Section 8(d) or 8(e) of the 1933 Act, and the Company is not the subject of a pending proceeding under Section 8A of the 1933 Act in connection with the offering and sale of the Securities.

(31) No Unlawful Contributions or Other Payments. Neither the Company nor any of its Subsidiaries nor, to the knowledge of the Company, any director, officer, agent, employee or affiliate of the Company or any of its Subsidiaries is aware of or has taken any action, directly or indirectly, that would result in a violation by such persons of the Foreign Corrupt Practices Act of 1977, as amended, and the rules and regulations thereunder (the "**FCPA**"), including, without limitation, making use of the mails or any means or instrumentality of interstate commerce corruptly in furtherance of an offer, payment, promise to pay or authorization of the payment of any money, or other property, gift, promise to give, or authorization of the giving of anything of value to any "foreign official" (as such term is defined in the FCPA) or any foreign political party or official thereof or any candidate for foreign political office, in contravention of the FCPA, and the Company, its Subsidiaries and, to the knowledge of the Company, its affiliates have conducted their businesses in compliance with the FCPA and have

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instituted and maintain policies and procedures designed to ensure, and which are reasonably expected to continue to ensure, continued compliance therewith.

(32) No Conflict with Money Laundering Laws. The operations of the Company and its Subsidiaries are and have been conducted at all times in compliance with applicable financial recordkeeping and reporting requirements of the Currency and Foreign Transactions Reporting Act of 1970, as amended, the money laundering statutes of all applicable jurisdictions, the rules and regulations thereunder and any related or similar rules, regulations or guidelines issued, administered or enforced by any governmental agency (collectively, the "**Money Laundering Laws**") and no action, suit or proceeding by or before any court or governmental agency, authority or body or any arbitrator involving the Company or any of its Subsidiaries with respect to the Money Laundering Laws is pending or, to the knowledge of the Company, threatened.

(33) OFAC. Neither the Company nor any of its Subsidiaries, nor, to the knowledge of the Company, any director, officer, agent or employee of the Company or any of its Subsidiaries is currently the subject of any sanctions administered or enforced by the Office of Foreign Assets Control of the U.S. Department of the Treasury or the U.S. Department of State.

(b) Officers' Certificates. Any certificate signed by any officer of the Company or any of its Subsidiaries and delivered to any Underwriter or to counsel for the Underwriters in connection with the offering of the Securities shall be deemed a representation and warranty by the Company to each Underwriter as to the matters covered thereby on the date of such certificate.

SECTION 2. Sale and Delivery to Underwriters; Closing.

(a) The Securities. On the basis of the representations, warranties and agreements herein contained, and upon the terms but subject to the conditions herein set forth, the Company agrees to sell to each Underwriter, severally and not jointly, and each Underwriter agrees, severally and not jointly, to purchase from the Company the aggregate principal amount of the Securities set forth opposite the names of the Underwriters on Schedule 1 at a purchase price of 99.273% of the aggregate principal amount of the Securities, plus accrued interest thereon, if any, from November 6, 2017 to the Closing Time. The Securities and the offering thereof will have the terms specified in the Final Term Sheet referred to in Section 3(b).

(b) Payment. The Company will deliver against payment of the purchase price set forth in Section 2(a) the Securities in the form of permanent global securities (the "**Global Securities**") deposited with the Trustee as custodian for The Depository Trust Company ("**DTC**") and registered in the name of Cede & Co., as nominee for DTC. Interests in any permanent Global Securities will be held only in book-entry form through DTC, except in the limited circumstances described in the General Disclosure Package. Payment for the Securities shall be made by the Underwriters in immediately available funds by wire transfer to an account specified by the Company drawn to the order of the Company at the office of the Company, 80 Park Plaza, Newark, New Jersey 07102, or at such other place as shall be agreed upon by the Representatives and the Company, at 9:00 A.M. (New York City time) on November 6, 2017, or

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such other time and date as the Representatives and the Company shall mutually agree (the time and date of such closing are called (unless postponed in accordance with the provisions of Section 10 hereof) the "**Closing Time**"), against delivery to the Trustee as custodian for DTC of the Global Securities representing all of the Securities.

It is understood that each Underwriter has authorized the Representatives, for their accounts, to accept delivery of, receipt for, and make payment of the purchase price for, the Securities which it has severally agreed to purchase. Each Representative, individually and not as representative of the Underwriters, may (but shall not be obligated to) make payment of the purchase price for the Securities to be purchased by any Underwriter whose funds have not been received by the Closing Time, but such payment shall not relieve such Underwriter from its obligations hereunder.

(c) Denominations; Registration. The Securities shall be in such denominations and registered in such names as the Representatives may request in writing at least one full business day prior to the Closing Time. The Securities will be made available for examination by the Representatives in The City of New York not later than 9:00 A.M. (New York City time) on the business day prior to the Closing Time.

SECTION 3. Covenants of the Company. The Company covenants with each Underwriter as follows:

(a) Compliance with Securities Regulations and Commission Requests. The Company, subject to Section 3(b), will comply with the requirements of Rule 430B and, during the Prospectus Delivery Period (as defined below), will notify the Representatives promptly, and confirm the notice in writing, (i) of the effectiveness of any post-effective amendment to the Registration Statement or of a new registration statement relating to the Securities or the filing of any supplement or amendment to the Prospectus or any preliminary prospectus, (ii) of the receipt of any comments from the Commission, (iii) of any request by the Commission for any amendment to the Registration Statement or the filing of a new registration statement or any amendment or supplement to the Prospectus or any preliminary prospectus or any document incorporated by reference therein or otherwise deemed to be a part thereof or for additional information, (iv) of the issuance by the Commission of any stop order suspending the effectiveness of the Registration Statement or such new registration statement, or notice objecting to its use pursuant to Rule 401(g)(2) of the 1933 Act Regulations, or of any order preventing or suspending the use of any preliminary prospectus or the Prospectus, or of the suspension of the qualification of the Securities for offering or sale in any jurisdiction, or of the initiation or threatening of any proceedings for any of such purposes or of any examination pursuant to Section 8(e) of the 1933 Act concerning the Registration Statement and (v) if the Company becomes the subject of a proceeding under Section 8A of the 1933 Act in connection with the offering of the Securities. The Company will promptly effect the filings necessary pursuant to Rule 424(b), in the manner and within the time period required by Rule 424(b) (without reliance on Rule 424(b)(8)), and will take such steps as it deems necessary to ascertain promptly whether the Prospectus transmitted for filing under Rule 424(b) was received for filing by the Commission and, in the event that it was not, the Company will promptly file the Prospectus. The Company will make every reasonable effort to prevent the issuance of any stop order and, if any stop order is issued, promptly to use its best efforts to obtain its withdrawal.

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The Company agrees to pay the required Commission filing fees relating to the offering of the Securities within the time required by and in accordance with Rule 456(b)(1) and 457(r) of the 1933 Act Regulations.

(b) Filing of Amendments and 1934 Act Documents; Preparation of Final Term Sheet. During such period beginning on the date of this Agreement and ending on the later of the Closing Time or such date as, in the opinion of counsel for the Underwriters, the Prospectus is no longer required by law to be delivered in connection with sales of the Securities by an Underwriter or dealer, including in circumstances where such requirement may be satisfied pursuant to Rule 172 of the 1933 Act Regulations (the "**Prospectus Delivery Period**"), the Company will give the Representatives notice of its intention to file or prepare any amendment to the Registration Statement or a new registration statement relating to the Securities or any amendment, supplement or revision to any preliminary prospectus or to the Prospectus, whether pursuant to the 1933 Act, the 1934 Act or otherwise, will furnish the Representatives with copies of any such documents a reasonable amount of time prior to such proposed filing or use, as the case may be, and will not file or use any such document of which the Representatives or counsel for the Underwriters shall reasonably disapprove. The Company has given the Representatives notice of any filings made pursuant to the 1934 Act or the 1934 Act Regulations within 48 hours prior to the Applicable Time; the Company will give the Representatives notice of its intention to make any such filing from the Applicable Time to the Closing Time and will furnish the Representatives with copies of any such documents a reasonable amount of time prior to such proposed filing and will not file or use any such document to which the Representatives or counsel for the Underwriters shall object. The Company will prepare a final term sheet (the "**Final Term Sheet**") reflecting the final terms of the Securities, in form and substance satisfactory to the Underwriters and attached as Schedule 3 hereto, and will file such Final Term Sheet pursuant to Rule 433(d) within the time required by such rule. The Final Term Sheet is an Issuer Free Writing Prospectus for purposes of this Agreement.

(c) Delivery of Registration Statement. The Company has furnished or will deliver to the Representatives and counsel for the Underwriters, in such quantities as the Representatives may reasonably request, without charge, signed copies of the Registration Statement as originally filed and any amendment thereto (including exhibits filed therewith or incorporated by reference therein and documents incorporated or deemed to be incorporated by reference therein or otherwise deemed to be a part thereof) and signed copies of all consents and certificates of experts, and will also deliver to the Representatives, without charge, a conformed copy of the Registration Statement as originally filed and any amendment thereto (without exhibits) for each of the Underwriters. The Registration Statement and any amendment thereto furnished to the Underwriters will be identical to any electronically transmitted copies thereof filed with the Commission pursuant to EDGAR, except to the extent permitted by Regulation S-T.

(d) Delivery of Prospectuses. The Company will deliver to each Underwriter, without charge, as many copies of each preliminary prospectus and any amendment or supplement thereto as such Underwriter may reasonably request, and the Company hereby consents to the use of such copies for purposes permitted by the 1933 Act. The Company will furnish to each Underwriter, without charge, during the Prospectus Delivery Period, such number of copies of the Prospectus (as amended or supplemented) as such Underwriter may reasonably request. Each preliminary prospectus and the Prospectus and any amendments or supplements thereto

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furnished to the Underwriters will be identical to any electronically transmitted copies thereof filed with the Commission pursuant to EDGAR, except to the extent permitted by Regulation S-T.

(e) Continued Compliance with Securities Laws. The Company will comply with the 1933 Act and the 1933 Act Regulations, the 1934 Act and the 1934 Act Regulations and the 1939 Act and the rules and regulations of the Commission under the 1939 Act so as to permit the completion of the distribution of the Securities as contemplated in this Agreement and in the Registration Statement, the General Disclosure Package and the Prospectus. If at any time during the Prospectus Delivery Period, any event shall occur or condition shall exist as a result of which it is necessary, in the opinion of counsel for the Underwriters or for the Company, to amend the Registration Statement in order that the Registration Statement will not contain an untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary to make the statements therein not misleading or to amend or supplement the General Disclosure Package or the Prospectus in order that such General Disclosure Package or the Prospectus, as the case may be, will not include an untrue statement of a material fact or omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances existing at the Applicable Time or at the time it is delivered or conveyed to a purchaser, not misleading, or if it shall be necessary, in the opinion of such counsel, at any such time to amend the Registration Statement, to file a new registration statement or to amend or supplement the General Disclosure Package or the Prospectus in order to comply with the requirements of the 1933 Act or the 1933 Act Regulations, the Company will: (i) promptly prepare and file with the Commission, subject to Sections 3(b) and 3(k), such amendment or supplement or new registration statement as may be necessary to correct such statement or omission or to make the Registration Statement, the General Disclosure Package or the Prospectus comply with such requirements; (ii) use their best efforts to have such amendment or new registration statement (if it is not an automatic shelf registration statement) declared effective as soon as practicable; and (iii) furnish to the Underwriters, without charge, such number of copies of such amendment or supplement or new registration statement as the Underwriters may reasonably request. If, prior to the completion of the public offer and sale of the Securities, at any time following the issuance of an Issuer Free Writing Prospectus there occurred or occurs an event or development as a result of which such Issuer Free Writing Prospectus conflicted or would conflict with the information then contained in the Registration Statement, any preliminary prospectus or the Prospectus or included or would include an untrue statement of a material fact or omitted or would omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances prevailing at that subsequent time, not misleading, the Company will promptly (i) notify the Representatives and (ii) either (1) amend or supplement such Issuer Free Writing Prospectus to eliminate or correct such conflict, untrue statement or omission or (2) file a report with the Commission under the 1934 Act that corrects such untrue statement or omission and notify the Representatives in writing that such Issuer Free Writing Prospectus shall no longer be used.

(f) Blue Sky Qualifications. The Company will use its best efforts, in cooperation with the Underwriters, to qualify the Securities for offering and sale under the applicable securities laws of such states and other jurisdictions (domestic or foreign) as the Representatives may designate and to maintain such qualifications in effect for a period of not less than one year from the date of this Agreement; provided, however, that the Company shall not be obligated to file

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any general consent to service of process or to qualify as a foreign corporation or as a dealer in securities in any jurisdiction in which it is not so qualified or to subject itself to taxation in respect of doing business in any jurisdiction in which it is not otherwise so subject. In each jurisdiction in which the Securities have been so qualified, the Company will file such statements and reports as may be required by the laws of such jurisdiction to continue such qualification in effect for a period of not less than one year from the date of this Agreement.

(g) Earnings Statement. The Company will timely file such reports pursuant to the 1934 Act as are necessary in order to make generally available to its security holders as soon as practicable an earnings statement for the purposes of, and to provide the benefits contemplated by, the last paragraph of Section 11(a) of the 1933 Act; provided, that the Company will be deemed to have furnished such statement to its security holders to the extent it is filed on EDGAR.

(h) Use of Proceeds. The Company will use the net proceeds received by it from the sale of the Securities in the manner specified in the Registration Statement, the General Disclosure Package and the Prospectus under "Use of Proceeds."

(i) Restriction on Sale of Securities. Between the date of this Agreement and the Closing Time, the Company will not, without the prior written consent of the Representatives, directly or indirectly, issue, sell, offer or contract to sell, grant any option for the sale of, or otherwise dispose of, the Securities.

(j) Reporting Requirements. The Company, during the Prospectus Delivery Period, will file all documents required to be filed with the Commission pursuant to the 1934 Act within the time periods required by the 1934 Act and the 1934 Act Regulations.

(k) Permitted Free Writing Prospectuses. The Company represents and agrees that, unless it obtains the prior consent of the Representatives, and each Underwriter represents and agrees that, unless it obtains the prior consent of the Representatives and the prior consent of the Company, it has not made and will not make any offer relating to the Securities that would constitute an "issuer free writing prospectus," as defined in Rule 433, or that would otherwise constitute a "free writing prospectus," as defined in Rule 405, required to be filed with the Commission; provided, however, that the Underwriters are authorized to use any free writing prospectus that contains substantially only information specified in the Final Term Sheet. Any such free writing prospectus consented to by the Company and the Representatives is hereinafter referred to as a "**Permitted Free Writing Prospectus**." The Company represents that it has treated or agrees that it will treat each Permitted Free Writing Prospectus as an "issuer free writing prospectus," as defined in Rule 433, and has complied and will comply with the requirements of Rule 433 applicable to each and every Permitted Free Writing Prospectus, including timely filing with the Commission where required, legending and record keeping.

(l) Renewal of Registration Statement. If, immediately prior to the third anniversary of the initial effective date of the Registration Statement (the "**Renewal Date**"), any of the Securities remain unsold by the Underwriters, the Company will, prior to the Renewal Date and subject to Section 3(b), file, if it has not already done so and is eligible to do so, a new automatic shelf registration statement relating to the Securities. If no longer eligible to file an automatic

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shelf registration statement, the Company will, prior to the Renewal Date and subject to Section 3(b), if it has not already done so, file a new shelf registration statement relating to the Securities and will use its reasonable best efforts to cause such registration statement to be declared effective within 180 days after the Renewal Date, and will take all other reasonable actions necessary or appropriate to permit the public offering and sale of the Securities to continue as contemplated in the expired registration statement relating to the Securities. References herein to the "**Registration Statement**" shall include such new automatic shelf registration statement or shelf registration statement, as the case may be.

(m) Notice of Inability to Use Automatic Shelf Registration Statement Form. If, at any time during the Prospectus Delivery Period, the Company receives from the Commission a notice pursuant to Rule 401(g)(2) of the 1933 Act Regulations or otherwise ceases to be eligible to use the automatic shelf registration statement form, the Company will (i) promptly notify the Representatives, (ii) promptly file a new registration statement or post-effective amendment on the proper form relating to the Securities, in a form satisfactory to the Representatives, (iii) use its reasonable best efforts to cause such registration statement or post-effective amendment to be declared effective and (iv) promptly notify the Representatives of such effectiveness. The Company will take all other action necessary or appropriate to permit the public offering and sale of the Securities to continue as contemplated in the registration statement that was the subject of the Rule 401(g)(2) notice or for which the Company has otherwise become ineligible. References herein to the Registration Statement shall include such new registration statement or post-effective amendment, as the case may be.

SECTION 4. Payment of Expenses. *(a) Expenses*. The Company will pay all expenses incident to the performance of its obligations under this Agreement, including (i) the preparation, printing and filing of the Registration Statement (including financial statements and exhibits) and any amendment thereto, (ii) the preparation, printing and delivery to the Underwriters of this Agreement, the Indenture and such other documents as may be required in connection with the offering, purchase, sale, issuance or delivery of the Securities, (iii) the preparation, issuance and delivery of the Securities to the Underwriters, including any transfer taxes and any stamp or other duties payable upon the sale, issuance or delivery of the Securities to the Underwriters, (iv) the fees and disbursements of counsel to the Company, accountants and other advisors or agents (including transfer agents and registrars), as well as the fees and disbursements of the Trustee and its counsel, (v) the qualification of the Securities under state securities laws in accordance with the provisions of Section 3(f) hereof, including filing fees and the reasonable fees and disbursements of counsel for the Underwriters in connection therewith and in connection with the preparation, printing and delivery of the Blue Sky Survey, and any amendment thereto, (vi) the printing and delivery to the Underwriters of copies of the Registration Statement, each preliminary prospectus, any Issuer Free Writing Prospectus and the Prospectus and any amendments or supplements thereto, (vii) the fees charged by nationally recognized statistical rating organizations for the rating of the Securities, (viii) the filing fees incident to, and the reasonable fees and disbursements of counsel to the Underwriters in connection with, the review, if any, by the Financial Industry Regulatory Authority ("**FINRA**") of the terms of the sale of the Securities, (ix) all fees and expenses in connection with making the Securities eligible for clearance, settlement and trading through the facilities of DTC, and (x) all other costs and expenses incident to the performance of the obligations of the Company hereunder for which provision is not otherwise made in this Section. It is understood, however, that except as

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provided in this Section, Section 5(j), Section 6, Section 7 and Section 9(b), the Underwriters will pay all of their costs and expenses, including fees and disbursements of their counsel, transfer taxes payable on resale of any of the Securities by them and any advertising expenses connected with any offers they may make.

(b) Termination of Agreement. If this Agreement is terminated by the Representatives in accordance with the provisions of Section 5 hereof, the Company shall reimburse the Underwriters for all of their out of pocket expenses, including the reasonable fees and disbursements of counsel for the Underwriters.

SECTION 5. Conditions of Underwriters' Obligations. The obligations of the Underwriters to purchase and pay for the Securities pursuant to this Agreement are subject to the accuracy of the representations and warranties of the Company contained in Section 1 hereof or in certificates of any officer of the Company or any of its Subsidiaries delivered pursuant to the provisions hereof, to the performance by the Company of its covenants and other obligations hereunder, and to the following further conditions:

(a) Effectiveness of Registration Statement. At Closing Time, (i) the Registration Statement shall have been filed by the Company with the Commission not earlier than three years prior to the date hereof and shall have become effective upon filing in accordance with Rule 462(e), and no stop order suspending the effectiveness of the Registration Statement shall have been issued under the 1933 Act and no proceedings for that purpose or pursuant to Section 8A of the 1933 Act against the Company or related to the offering of the Securities shall have been instituted or be pending or threatened by the Commission, any request on the part of the Commission for additional information shall have been complied with to the reasonable satisfaction of counsel for the Underwriters, and no notice of objection of the Commission to the use of such form of registration statement or any post-effective amendment thereto pursuant to Rule 401(g)(2) of the 1933 Act Regulations shall have been received by the Company, (ii) each preliminary prospectus and the Prospectus shall have been filed with the Commission in the manner and within the time period required by Rule 424(b) without reliance on Rule 424(b)(8) (or a post-effective amendment providing such information shall have been filed and become effective in accordance with the requirements of Rule 430B) and (iii) the Final Term Sheet and any other material required to be filed by the Company pursuant to Rule 433(d) shall have been filed with the Commission within the applicable time periods prescribed for such filings under such Rule 433.

(b) Opinion of Counsel for Company. At Closing Time, the Representatives shall have received the favorable opinion, dated as of Closing Time, of either Tamara L. Linde, Esquire, Executive Vice President and General Counsel of the Company, or Shawn P. Leyden, Esquire, Vice President and Deputy General Counsel of PSEG Services Corporation, in form and substance satisfactory to counsel for the Underwriters, together with signed or reproduced copies of such letter for each of the other Underwriters, to the effect set forth in Exhibit A hereto and to such further effect as counsel to the Underwriters may reasonably request.

(c) Opinion of Counsel for Underwriters. At Closing Time, the Representatives shall have received the favorable opinion, dated as of Closing Time, of Sidley Austin llp, counsel for the Underwriters, together with signed or reproduced copies of such letter for each of the other

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Underwriters, in form and substance satisfactory to the Representatives. In giving such opinion, such counsel may rely, as to all matters governed by the laws of the State of New Jersey, upon the opinion, dated as of Closing Time, of either Tamara L. Linde, Esquire, Executive Vice President and General Counsel of the Company, or Shawn P. Leyden, Esquire, Vice President and Deputy General Counsel of the Company, and as to all matters governed by the laws of other jurisdictions other than the law of the State of New York and the federal law of the United States, upon the opinions of counsel satisfactory to the Representatives. Such counsel may also state that, insofar as such opinion involves factual matters, they have relied, to the extent they deem proper, upon certificates of officers of the Company and its Subsidiaries and certificates of public officials.

(d) Officer's Certificate. At Closing Time, there shall not have been, since the date of this Agreement or since the respective dates as of which information is given in the Registration Statement, the General Disclosure Package or the Prospectus, any Material Adverse Change, and the Representatives shall have received a certificate of the Chairman, the President or any Vice President of the Company, dated as of Closing Time, to the effect that (i) there has been no such Material Adverse Change, (ii) the representations and warranties in Section 1(a) are true and correct with the same force and effect as though expressly made at and as of the Closing Time, (iii) the Company has complied with all agreements contained in this Agreement and satisfied all conditions on its part to be performed or satisfied at or prior to the Closing Time, and (iv) no stop order suspending the effectiveness of the Registration Statement has been issued and no proceedings for that purpose or pursuant to Section 8A of the 1933 Act against the Company or relating to the offering have been instituted, are pending or, to the best of such officer's knowledge, are threatened by the Commission.

(e) Accountant's Comfort Letter. At the Execution Time, the Representatives shall have received from Deloitte & Touche LLP, independent registered public accountants for the Company, a letter, dated as of the date hereof addressed to the Underwriters, in form and substance satisfactory to the Representatives, together with signed or reproduced copies of such letter for each of the other Underwriters, with respect to the audited and unaudited financial statements and certain financial information contained or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus.

(f) Bring-down Comfort Letter. At Closing Time, the Representatives shall have received from Deloitte & Touche LLP, independent registered public accountants for the Company, a letter, dated as of Closing Time addressed to the Underwriters, in form and substance satisfactory to the Representatives, together with signed or reproduced copies of such letter for each of the other Underwriters to the effect that they reaffirm the statements made in the letter furnished pursuant to subsection (e) of this Section 5, except that the specified date referred to shall be a date not more than three business days prior to the Closing Time.

(g) Ratings. At Closing Time, the Securities shall have the ratings accorded by any "nationally recognized statistical rating organization," as defined in Section 3(a)(62) of the 1934 Act, as specified in the Final Term Sheet, and the Company shall have delivered to the Representatives a letter, dated as of such date, from each such rating organization, or other evidence satisfactory to the Representatives, confirming that the Securities have such ratings. Since the Execution Time, there shall not have occurred a downgrading in, or withdrawal of, the

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rating assigned to the Securities or any of the Company's other securities by any such rating organization, and no such rating organization shall have publicly announced or given notice of any intended or potential decrease in or withdrawal of any such rating or of a possible change in any such rating that does not indicate the direction of the possible change.

(h) No Objection. If the Registration Statement or the offering of the Securities has been filed with FINRA for review, FINRA shall not have raised any objection with respect to the fairness and reasonableness of the underwriting terms and arrangements.

(i) Additional Documents. At Closing Time, counsel for the Underwriters shall have been furnished with such documents and opinions as they may require for the purpose of enabling them to pass upon the issuance and sale of the Securities as herein contemplated, or in order to evidence the accuracy of any of the representations or warranties, or the fulfillment of any of the conditions, herein contained; and all proceedings taken by the Company in connection with the issuance and sale of the Securities as herein contemplated shall be satisfactory in form and substance to the Representatives and counsel for the Underwriters.

(j) Termination. If any condition specified in this Section 5 shall not have been fulfilled when and as required to be fulfilled, this Agreement may be terminated by the Representatives by notice to the Company at any time at or prior to the Closing Time, and such termination shall be without liability of any party to any other party except as provided in Section 4 and except that Sections 1, 6, 7, 8 and 14 shall survive any such termination and remain in full force and effect.

SECTION 6. Indemnification.

(a) Indemnification of Underwriters. The Company agrees to indemnify and hold harmless each Underwriter and their respective partners, directors and officers and each person, if any, who controls any Underwriter (collectively, "**Underwriter Indemnified Parties**") within the meaning of Section 15 of the 1933 Act or Section 20 of the 1934 Act as follows:

(i) against any and all loss, liability, claim, damage and expense whatsoever, as incurred, arising out of any untrue statement or alleged untrue statement of a material fact contained in the Registration Statement (or any amendment thereto) or the omission or alleged omission therefrom of a material fact required to be stated therein or necessary to make the statements therein not misleading or arising out of any untrue statement or alleged untrue statement of a material fact contained in any preliminary prospectus, any Issuer Free Writing Prospectus or the Prospectus (or any amendment or supplement thereto) or in any "issuer information" (as defined in Rule 433) of the Company that is filed or required to be filed under Rule 433(d) or the omission or alleged omission therefrom of a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading;

(ii) against any and all loss, liability, claim, damage and expense whatsoever, as incurred, to the extent of the aggregate amount paid in settlement of any litigation, or any investigation or proceeding by any governmental agency or body, commenced or threatened, or of any claim whatsoever based upon any such untrue statement or omission

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referred to in subsection (i) above or any alleged untrue statement or omission, if such settlement is effected with the written consent of the Company; and

(iii) against any and all expense whatsoever, as incurred, reasonably incurred in investigating, preparing or defending against any litigation, or any investigation or proceeding by any governmental agency or body, commenced or threatened, or any claim whatsoever based upon any such untrue statement or omission, or any such alleged untrue statement or omission, to the extent that any such expense is not paid under (i) or (ii) above;

provided, however, that this indemnity agreement shall not apply to any loss, liability, claim, damage or expense to the extent arising out of any untrue statement or omission or alleged untrue statement or omission made in reliance upon and in conformity with written information furnished to the Company by any Underwriter through the Representatives expressly for use in the Registration Statement (or any amendment thereto) or any preliminary prospectus, any Issuer Free Writing Prospectus or the Prospectus (or any amendment or supplement thereto) or made in reliance upon the Trustee's Statement of Eligibility filed as an exhibit to the Registration Statement. The Company and the Underwriters hereby acknowledge and agree that the only written information furnished to the Company by any Underwriter through the Representatives expressly for use in the Registration Statement (or any amendment thereto) or any preliminary prospectus, any Issuer Free Writing Prospectus or the Prospectus (or any amendment or supplement thereto) are the statements set forth in the (x) first, second and third sentences of the third paragraph, (y) second sentence of the fifth paragraph and (z) first, second, third, fourth and sixth sentences of the sixth paragraph, in each case under the caption "Underwriting" in the Prospectus (collectively, the "**Underwriter Information**").

(b) In no case shall the Company be liable under the indemnity agreement set forth in Section 6(a) hereof with respect to any claim made against any Underwriter Indemnified Party unless such party shall be notified in writing of the nature of the claim promptly after the assertion thereof, but failure to so notify such party shall not relieve it from any liability which it may have otherwise than on account of said indemnity agreement. The Company shall be entitled to participate at its own expense in the defense, or, if the Company so elects, within a reasonable time after receipt of such notice, to assume the defense of any suit brought to enforce any such claim, but if they so elect to assume the defense, such defense shall be conducted by counsel chosen by the Company and approved by the Underwriter Indemnified Parties who are party to such suit, which approval shall not be unreasonably withheld. In the event that the Company elects to assume the defense of any such suit and retain such counsel, the Underwriter Indemnified Parties who are party to such suit shall bear the fees and expenses of any additional counsel thereafter retained by them. In the event that the parties to any such action (including impleaded parties) include the Company and one or more Underwriters and any such Underwriter shall have been advised by counsel chosen by it and satisfactory to the Company, as the case may be, that there may be one or more legal defenses available to it which are different from or additional to those available to the Company, the Company shall not have the right to assume the defense of such action on behalf of such Underwriter and the Company will reimburse, without duplication, such Underwriter Indemnified Parties as aforesaid for the reasonable fees and expenses of any counsel retained by them, it being understood that the Company shall not, in connection with any one action or separate but similar or related actions in

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the same jurisdiction arising out of the same general allegations or circumstances, be liable for the reasonable fees and expenses of more than one separate firm of attorneys for all such Underwriter Indemnified Parties, which firm shall be designated by the Representatives in writing. The Company agrees to notify the Representatives promptly after the assertion of any claim against it, any of its directors, any of its officers who signed the Registration Statement, or any person who controls the Company within the meaning of Section 15 of the 1933 Act or Section 20 of the 1934 Act, in connection with the offering and sale of the Securities.

(c) Indemnification of the Company, Directors and Officers. The Underwriters, severally and not jointly, agree to indemnify and hold harmless the Company, its directors, each of its officers who signed the Registration Statement, and each person, if any, who controls the Company within the meaning of Section 15 of the 1933 Act or Section 20 of the 1934 Act against any and all loss, liability, claim, damage and expense described in the indemnity contained in subsection (a) of this Section, as incurred, but only with respect to untrue statements or omissions, or alleged untrue statements or omissions, made in the Registration Statement (or any amendment thereto) or any preliminary prospectus, any Issuer Free Writing Prospectus or the Prospectus (or any amendment or supplement thereto) in reliance upon and in conformity with the Underwriter Information. In case any action shall be brought against the Company or any person so indemnified based on the Registration Statement (or any amendment thereto) or such preliminary prospectus, such Issuer Free Writing Prospectus or the Prospectus (or any amendment or supplement thereto) and in respect of which indemnity may be sought against any Underwriter, such Underwriter shall have the rights and duties given to the Company, and the Company and each person so indemnified shall have the rights and duties given to the Underwriters by the provisions of Section 6(b) hereof.

(d) The indemnity agreements contained in this Section 6 shall remain operative and in full force and effect, regardless of any investigation made by or on behalf of the Company or any Underwriter Indemnified Parties, and shall survive the delivery of the Securities to the Underwriters.

(e) Settlement. No indemnifying party shall, without the prior written consent of the indemnified parties, settle or compromise or consent to the entry of any judgment with respect to any litigation, or any investigation or proceeding by any governmental agency or body, commenced or threatened, or any claim whatsoever in respect of which indemnification or contribution could be sought under this Section 6 or Section 7 hereof (whether or not the indemnified parties are actual or potential parties thereto), unless such settlement, compromise or consent (i) includes an unconditional release of each indemnified party from all liability arising out of such litigation, investigation, proceeding or claim and (ii) does not include a statement as to or an admission of fault, culpability or a failure to act by or on behalf of any indemnified party.

SECTION 7. Contribution. In order to provide for just and equitable contribution in circumstances in which the indemnity agreement provided for in Section 6 is for any reason held to be unenforceable by the indemnified parties although applicable in accordance with its terms, the Company and the Underwriters shall contribute to the aggregate losses, liabilities, claims, damages and expenses of the nature contemplated by said indemnity agreements incurred by the Company and the Underwriters, in such proportions that the Underwriters are responsible for that

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portion represented by the percentage that the total underwriting discount appearing on the cover page of the Prospectus relating to the Securities bears to the aggregate initial public offering price appearing thereon and the Company is responsible for the balance; provided, however, that (i) no Underwriter shall be required to contribute any amount in excess of the amount by which the total discount or commission received by such Underwriter in connection with the offering of the Securities exceeds the amount of any damages which such Underwriter has otherwise been required to pay by reason of any applicable untrue or alleged untrue statement or omission or alleged omission and (ii) no person guilty of fraudulent misrepresentation (within the meaning of Section 11(f) of the 1933 Act) shall be entitled to contribution from any person who was not guilty of such fraudulent misrepresentation. For purposes of this Section, each Underwriter Indemnified Party shall have the same rights to contribution as the Underwriters, and each director of the Company, each officer of the Company who signed the Registration Statement, and each person, if any, who controls the Company within the meaning of Section 15 of the 1933 Act or Section 20 of the 1934 Act shall have the same rights to contribution as the Company. The Underwriters' respective obligations to contribute pursuant to this Section 7 are several in proportion to their respective underwriting obligations, and not joint.

SECTION 8. Representations, Warranties and Agreements to Survive Delivery. All representations, warranties and agreements contained in this Agreement or in certificates of officers of the Company or any of its Subsidiaries submitted pursuant hereto or thereto shall remain operative and in full force and effect, regardless of any investigation made by or on behalf of any Underwriter or controlling person, or by or on behalf of the Company, and shall survive delivery of and payment for the Securities.

In all dealings hereunder, the Representatives shall act on behalf of each of the Underwriters, and the parties hereto shall be entitled to act and rely upon any statement, request, notice or agreement on behalf of any Underwriter made or given by the Representatives or by the Representatives on behalf of the Underwriters.

SECTION 9. Termination.

(a) The Representatives may terminate this Agreement, by notice to the Company, at any time at or prior to the Closing Time, (i) if there has been, since the time of execution of this Agreement or since the respective dates as of which information is given in the Registration Statement, the General Disclosure Package or the Prospectus, any Material Adverse Change, or (ii) if there has occurred any material adverse change in the financial markets in the United States, any outbreak of hostilities or escalation thereof or other calamity or crisis or any change or development involving a prospective change in national or international political, financial or economic conditions, in each case the effect of which is such as to make it, in the judgment of the Underwriters, impracticable or inadvisable to market the Securities or to enforce contracts for the sale of the Securities, or (iii) if trading in any securities of the Company has been suspended or materially limited by the Commission or the New York Stock Exchange, or if trading generally on the NYSE MKT or the New York Stock Exchange or in the Nasdaq Stock Market has been suspended or materially limited, or minimum or maximum prices for trading have been fixed, or maximum ranges for prices have been required, by any of said exchanges or by such system or by order of the Commission, FINRA or any other governmental authority, or a material disruption has occurred in commercial banking or settlement or clearance services in the

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United States, or (iv) if a banking moratorium has been declared by either federal or New York authorities or (v) if the rating accorded the Securities or any debt securities or other security of the Company by any nationally recognized statistical rating organization shall have been decreased or withdrawn or any such rating organization has publicly announced or given notice of any intended or potential decrease in or withdrawal of any such rating or of a possible change in any such rating that does not indicate the direction of the possible change.

(b) Liabilities. If this Agreement is terminated pursuant to this Section 9, such termination shall be without liability of any party to any other party except as provided in Section 4 hereof, and provided further that Sections 1, 6, 7, 8 and 14 shall survive such termination and remain in full force and effect.

SECTION 10. Default by One or More of the Underwriters. If one or more of the Underwriters shall fail at the Closing Time to purchase the Securities which it or they are obligated to purchase hereunder (the unpurchased securities, the "**Defaulted Securities**"), then the Representatives shall have the right, within 36 hours thereafter, to make arrangements for one or more of the non-defaulting Underwriters, or any other underwriters, to purchase all, but not less than all, of the Defaulted Securities in such amounts as may be agreed upon and upon the terms herein set forth; if, however, the Representatives shall not have completed such arrangements within such 36-hour period, then:

(a) if the aggregate principal amount of Defaulted Securities does not exceed 10% of the aggregate principal amount of Securities to be purchased on such date, the non-defaulting Underwriters shall be obligated, severally and not jointly, to purchase the full amount thereof in the proportions that their respective underwriting obligations under this Agreement bear to the underwriting obligations of all non-defaulting Underwriters; or

(b) if the aggregate principal amount of Defaulted Securities exceeds 10% of the aggregate principal amount of Securities to be purchased on such date, this Agreement shall terminate with respect to the Securities without liability on the part of any non-defaulting Underwriter.

No action taken pursuant to this Section 10 shall relieve any defaulting Underwriter from liability in respect of its default.

In the event of any such default which does not result in a termination of this Agreement, either the Representatives, on the one hand, or the Company, on the other, shall have the right to postpone the Closing Time for a period not exceeding seven days in order to effect any required changes in the Registration Statement, the General Disclosure Package or the Prospectus or in any other documents or arrangements.

SECTION 11. No Advisory or Fiduciary Relationship. The Company acknowledges and agrees that (a) the purchase and sale of the Securities pursuant to this Agreement, including the determination of the public offering price of the Securities and any related discounts and commissions, is an arm's-length commercial transaction among the Company, on the one hand, and the Underwriters, on the other hand, (b) in connection with the offering contemplated by this

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Agreement and the process leading to such transaction, each Underwriter is and has been acting solely as a principal and is not the agent or fiduciary of the Company, or its stockholders, creditors, employees or any other party, (c) no Underwriter has assumed or will assume an advisory or fiduciary responsibility in favor of the Company with respect to the offering contemplated hereby or the process leading thereto (irrespective of whether such Underwriter has advised or is currently advising the Company on other matters) and no Underwriter has any obligation to the Company with respect to the offering contemplated by this Agreement except the obligations expressly set forth in this Agreement, (d) the Underwriters and their respective affiliates may be engaged in a broad range of transactions that involve interests that differ from those of the Company and (e) no Underwriter has provided any legal, accounting, regulatory or tax advice with respect to the offering contemplated by this Agreement and the Company has consulted its own legal, accounting, regulatory and tax advisors to the extent it deemed appropriate.

SECTION 12. Notices. All notices and other communications hereunder shall be in writing and shall be deemed to have been duly given if mailed or transmitted by any standard form of telecommunication. Notices to the Underwriters shall be directed to the Representatives c/o Barclays Capital Inc., 745 Seventh Avenue, New York, New York 10019, Attention: Syndicate Registration, Telecopy: (636) 834-8133; J.P. Morgan Securities LLC, 383 Madison Avenue, 3rd Floor, New York, New York 10179, Attention: Investment Grade Syndicate Desk, Telecopy: (212) 834-6081; Morgan Stanley & Co. LLC, 1585 Broadway, 29th Floor, New York, New York 10036, Attention: Investment Banking Division, Facsimile 212-507-8999, and notices to the Company shall be directed to it at 80 Park Plaza, P.O. Box 1171, Newark, New Jersey 07101, attention of Tamara L. Linde, Esq.

SECTION 13. Parties. This Agreement shall inure to the benefit of and be binding upon the Company and the Underwriters and their respective successors. Nothing expressed or mentioned in this Agreement is intended or shall be construed to give any person, firm or corporation, other than the Underwriters, the Company and their respective successors and the controlling persons and officers and directors referred to in Sections 6 and 7 and their heirs and legal representatives, any legal or equitable right, remedy or claim under or in respect of this Agreement or any provision herein or therein contained. This Agreement and all conditions and provisions hereof and thereof are intended to be for the sole and exclusive benefit of the parties hereto and thereto and their respective successors, and said controlling persons and officers and directors and their heirs and legal representatives, and for the benefit of no other person, firm or corporation. No purchaser of Securities from any Underwriter shall be deemed to be a successor by reason merely of such purchase.

SECTION 14. GOVERNING LAW AND TIME. THIS AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK. SPECIFIED TIMES OF DAY REFER TO NEW YORK CITY TIME.

SECTION 15. Patriot Act. In accordance with the requirements of the USA Patriot Act (Title III of Pub. L. 107-56 (signed into law October 26, 2001)), the Underwriters are required to obtain, verify and record information that identifies their respective clients, including the Company, which information may include the name and address of their respective clients, as

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well as other information that will allow the Underwriters to properly identify their respective clients.

SECTION 16. Counterparts. This Agreement may be signed in one or more counterparts, each of which shall constitute an original and all of which together shall constitute one and the same agreement.

SECTION 17. Effect of Headings. The Article and Section headings herein are for convenience only and shall not affect the construction hereof.

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If the foregoing is in accordance with your understanding of our agreement, please sign and return to the Company a counterpart hereof, whereupon this Agreement, along with all counterparts, will become a binding agreement in accordance with its terms.

Very truly yours,

Public Service Enterprise Group Incorporated

By: /s/ Bradford Huntington
Name: Bradford Huntington
Title: Vice President and Treasurer

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Confirmed and accepted as of the
date first above written:

BARCLAYS CAPITAL INC.

By: /s/ Robert Stowe
Name: Robert Stowe
Title: Managing Director

J.P. MORGAN SECURITIES LLC

By: /s/ Som Bhattacharyya
Name: Som Bhattacharyya
Title: Executive Director

MORGAN STANLEY & CO. LLC

By: /s/ Yurij Slyz
Name: Yurij Slyz
Title: Executive Director

Acting on behalf of themselves and as representatives
of the other named Underwriters

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SCHEDULE 1

Underwriters and Principal Amount of Securities

Underwriters	Aggregate Principal Amount of the Securities to be Purchased
Barclays Capital Inc.	$ **109,900,000**
J.P. Morgan Securities LLC	**109,900,000**
Morgan Stanley & Co. LLC	**109,900,000**
CIBC World Markets Corp.	**84,000,000**
RBC Capital Markets, LLC	**84,000,000**
TD Securities (USA) LLC	**84,000,000**
BNY Mellon Capital Markets, LLC	**33,600,000**
PNC Capital Markets LLC	**33,600,000**
U.S. Bancorp Investments, Inc.	**33,600,000**
Loop Capital Markets LLC	**17,500,000**
Total	$ **700,000,000**

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SCHEDULE 2-A

Schedule of Issuer Free Writing Prospectuses included in the General Disclosure Package

1. The Final Term Sheet attached as Schedule 3 to this Agreement.

SCHEDULE 2-B

Issuer Limited Use Free Writing Prospectuses

1. None.

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SCHEDULE 3

Filed Pursuant to Rule 433
dated November 2, 2017
Relating to
Preliminary Prospectus Supplement
dated November 2, 2017 and
Prospectus dated November 18, 2014
Registration Statement No. 333-200352

Final Term Sheet

$700,000,000

Public Service Enterprise Group Incorporated

2.650% Senior Notes due 2022

November 2, 2017

Issuer:	Public Service Enterprise Group Incorporated
Trade Date:	November 2, 2017
Settlement Date:	November 6, 2017 (T+2)
Proceeds to Issuer Before Expenses:	$694,911,000
Security:	2.650% Senior Notes due 2022 (the "Notes")
Ratings*:	
Security Type:	Senior Unsecured Fixed Rate Notes
Principal Amount:	$700,000,000
Maturity Date:	November 15, 2022
Coupon:	2.650% per annum
Interest Payment Dates:	The 15th of each May and November, beginning May 15, 2018
Redemption Provisions:	At any time prior to October 15, 2022 (one month prior to the maturity date), at a price equal to the greater of (a) 100% of the principal amount of the Notes being redeemed and (b) the sum of the present values of the remaining scheduled payments of principal of and interest on the Notes being redeemed that would be due if the Notes matured on October 15, 2022, exclusive of accrued interest to the redemption date, discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the treasury rate plus 12.5 basis points (0.125%), plus any accrued and unpaid interest on the principal amount of the Notes being redeemed to,

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	but excluding, the redemption date.
	At any time on or after October 15, 2022, at a price equal to 100% of the principal amount of the Notes being redeemed, plus any accrued and unpaid interest on the principal amount of the Notes being redeemed to, but excluding, the redemption date.
Benchmark Treasury:	2.000% due October 31, 2022
Benchmark Treasury Yield:	1.997%
Re-offer Spread to Benchmark:	68 basis points
Re-offer Yield:	2.677%
Price to Public:	99.873% of Principal Amount
CUSIP / ISIN:	744573AL0 / US744573AL05
Joint Book-Running Managers:	Barclays Capital Inc. J.P. Morgan Securities LLC Morgan Stanley & Co. LLC CIBC World Markets Corp. RBC Capital Markets, LLC TD Securities (USA) LLC
Co-Managers:	BNY Mellon Capital Markets, LLC PNC Capital Markets LLC U.S. Bancorp Investments, Inc. Loop Capital Markets LLC

***** Note: A securities rating is not a recommendation to buy, sell or hold securities and may be subject to revision, suspension or withdrawal at any time. Each credit rating should be evaluated independently of any other credit rating.

The Issuer has filed a registration statement (including a prospectus) and a preliminary prospectus supplement with the SEC for the offering to which this communication relates. Before you invest, you should read the prospectus in that registration statement, the preliminary prospectus supplement and the other documents the Issuer has filed with the SEC for more complete information about the Issuer and the offering. You may get these documents for free by visiting EDGAR on the SEC's website at www.sec.gov. Alternatively, any underwriter or any dealer participating in the offering will arrange to send you these documents if you request them by calling Barclays Capital Inc. toll-free at 1-888-603-5847, J.P. Morgan Securities LLC collect at 1-212-834-4533 or Morgan Stanley & Co. LLC toll-free at 1-866-718-1649.

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EXHIBIT A

FORM OF OPINION OF COUNSEL FOR THE COMPANY
TO BE DELIVERED PURSUANT TO
SECTION 5(b)

On the basis of the foregoing and of my examination and consideration of such other legal and factual matters as I have deemed appropriate, I am of the opinion that:

(i) The Company has been duly incorporated and is validly existing as a corporation in good standing under the laws of the State of New Jersey and has the requisite power and authority to own, lease and operate its properties, to conduct its business as described in the Registration Statement, the General Disclosure Package (as defined in Annex A hereto), and the Prospectus and to enter into and perform its obligations under, or as contemplated under, the Underwriting Agreement.

(ii) Each Significant Subsidiary has been duly incorporated or organized and is validly existing as a corporation or limited liability company in good standing under the laws of the jurisdiction of its incorporation or organization, has the requisite power and authority to own, lease and operate its properties and to conduct its business as described in the Registration Statement, the General Disclosure Package and the Prospectus.

(iii) To the best of my knowledge, the Company and each Significant Subsidiary is duly qualified as a foreign corporation or limited liability company to transact business and is in good standing in each jurisdiction in which such qualification is required, whether by reason of the ownership or leasing of property or the conduct of business, except where the failure to so qualify and be in good standing would not have a material adverse effect on the financial condition, business or properties of the Company and its Subsidiaries considered as one enterprise.

(iv) The authorized, issued and outstanding shares of capital stock of the Company is as set forth in the Company's Annual Report on Form 10-K for the year ended December 31, 2016 and subsequent Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 (except for subsequent issuances thereof, if any, pursuant to reservations, agreements or employee benefit plans referred to in the Registration Statement, the General Disclosure Package and the Prospectus or pursuant to the exercise of convertible securities or options referred to in the Registration Statement, the General Disclosure Package and the Prospectus). Such shares of capital stock have been duly authorized and validly issued by the Company and are fully paid and non-assessable, and none of such shares of capital stock were issued in violation of preemptive or other similar rights of any security holder of the Company.

(v) All of the shares of capital stock or other equity interests of each Significant Subsidiary have been duly and validly authorized and issued, are fully paid and non-assessable (except in the case of a limited liability company), and are owned directly by the Company or another Subsidiary, as the case may be, free and clear

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of all liens, encumbrances, equities or claims. None of the outstanding shares of capital stock or other equity interests of any Significant Subsidiary were issued in violation of preemptive or other similar rights of any security holder of such Significant Subsidiary.

(vi) The Underwriting Agreement has been duly authorized, executed and delivered by the Company.

(vii) The Indenture has been duly authorized, executed and delivered by the Company and (assuming the Indenture has been duly authorized, executed and delivered by the Trustee) constitutes a valid and legally binding agreement of the Company, enforceable against each of them in accordance with its terms, subject to applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium and similar laws affecting creditors' rights and remedies generally, and subject, as to enforceability, to general principles of equity, including principles of commercial reasonableness, good faith and fair dealing (regardless of whether enforcement is sought in a proceeding at law or in equity).

(viii) The Securities have been duly authorized and executed by the Company pursuant to the Underwriting Agreement and, when delivered pursuant to the provisions of the Underwriting Agreement and the Indenture against the requisite payment therefor (assuming the due authentication thereof by the Trustee), will constitute valid and legally binding obligations of the Company enforceable against the Company in accordance with their terms, subject to applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium and similar laws affecting creditors' rights and remedies generally, and subject, as to enforceability, to general principles of equity, including principles of commercial reasonableness, good faith and fair dealing (regardless of whether enforcement is sought in a proceeding at law or in equity). The registered holders of the Securities will be entitled to the benefit of the Indenture.

(ix) The statements in (i) the Registration Statement, the General Disclosure Package and the Prospectus under the captions "Description of the Senior Notes" and "Description of the Senior and Subordinated Debt Securities," (ii) the Company's Annual Report on Form 10-K for the year ended December 31, 2016, under the captions (A) Part I, Item 1. Business – Regulatory Issues, (B) Part I, Item 1. Business – Environmental Matters, and (C) Part I, Item 3. Legal Proceedings and (iii) the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 under the caption Part II, Item 1. Legal Proceedings and Part II, Item 5. Other Information, in each case including the information incorporated by reference in such section and insofar as such statements constitute summaries of the legal matters, documents or proceedings referred to therein, fairly summarize the matters referred to therein in all material respects.

(x) The Indenture has been duly qualified under the Trust Indenture Act of 1939, as amended, and the regulations thereunder (the "1939 Act").

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(xi) The Registration Statement is effective under the 1933 Act and, to the best of my knowledge, no stop order suspending the effectiveness of the Registration Statement or the use of any prospectus relating to the Securities has been issued under the 1933 Act or proceedings therefor initiated or threatened by the SEC or any other governmental agency or authority.

(xii) The Registration Statement (except for the financial statements and the related notes thereto, the financial statement schedules or the financial or accounting data incorporated by reference therein or Exhibits 25-1 and 25-2 thereto, as to which I express no opinion), as of its most recent effective date pursuant to Rule 430B(f)(2), and the Prospectus (except for the financial statements and the related notes thereto, the financial statement schedules or the financial or accounting data incorporated by reference therein, as to which I express no opinion), as of November 2, 2017, appeared on their face to be appropriately responsive, in all material respects relevant to the offering of the Securities, to the applicable requirements of the 1933 Act;

(xiii) Each document filed pursuant to the Securities Exchange Act of 1934 and the regulations thereunder (the "1934 Act") and incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus appeared on its face, at the time it was filed, to be appropriately responsive in all material respects with the applicable requirements of the 1934 Act.

(xiv) To the best of my knowledge, none of the Company nor any Significant Subsidiary is in violation of its certificate of incorporation or by-laws or other organizational documents, or in default in the performance or observance of any obligation, agreement, covenant or condition contained in any material contract, indenture, mortgage, loan agreement, note or lease to which it is a party or by which it or any its properties may be bound.

(xv) The execution and delivery of the Underwriting Agreement, the Indenture and the Securities, and the consummation by the Company of the transactions contemplated thereby, will not conflict with, violate or constitute a breach of, or default under, or, except as contemplated thereby, result in the creation or imposition of: (A) any lien, charge or encumbrance upon any property or assets of the Company or any Significant Subsidiary pursuant to, any contract, indenture, mortgage, loan agreement, note, lease or other instrument known to me and to which the Company or any Significant Subsidiary is a party or by which it may be bound or to which any of the property or assets of the Company or any Significant Subsidiary is subject; (B) any law, administrative regulation or administrative or court decree known to me to be applicable to the Company or any Significant Subsidiary of any court or governmental agency, authority or body or any arbitrator having jurisdiction over the Company or any Significant Subsidiary (other than federal and state securities or blue sky laws, as to which I express no opinion in this paragraph), or (C) the

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certificate of incorporation or by-laws or other organizational documents of the Company or any Significant Subsidiary.

(xvi) No consent, approval, waiver, license or authorization or other action by or filing with any New York, New Jersey or federal governmental authority is required in connection with the execution and delivery by the Company of the Underwriting Agreement, the Indenture and the Securities, the consummation by the Company of the transactions contemplated thereby or the performance by the Company of its obligations thereunder, except for filings and other actions required pursuant to the 1933 Act and/or the 1934 Act and the rules and regulations thereunder and federal and state securities or blue sky laws, as to which I express no opinion in this paragraph.

(xvii) To the best of my knowledge, except as disclosed in the Registration Statement, the General Disclosure Package and the Prospectus, there is not pending or threatened any action, suit, proceeding, inquiry or investigation to which the Company or any Subsidiary is a party or to which the assets, properties or operations of the Company or any Subsidiary is subject, before or by any court or governmental agency or body, domestic or foreign, which might reasonably be expected to result in a Material Adverse Change or which might reasonably be expected to materially and adversely affect the assets, properties or operations thereof or the consummation of the transactions contemplated under the Underwriting Agreement, the Securities or the Indenture or the performance by the Company of its obligations thereunder.

(xviii) The Company is not, and immediately after giving effect to the sale of the Securities and the application of the proceeds thereof as described in the Prospectus will not be, an "investment company" under the Investment Company Act of 1940, as amended.

(xix) The Securities, upon issuance, will be excluded or exempted under, or beyond the purview of, the Commodity Exchange Act and the Commodity Exchange Act Regulations.

I have generally reviewed the Registration Statement, the General Disclosure Package and the Prospectus and discussed the information therein with certain officers and employees of the Company, but without independent check or verification except as indicated above, and no facts have come to my attention that would lead me to believe that:

(1) the Registration Statement, at the time it originally became effective under the 1933 Act or as of each "new effective date" with respect to the Securities and the Underwriters pursuant to, and within the meaning of, Rule 430B(f)(2) under the 1933 Act, contained an untrue statement of a material fact or omitted to state a material fact required to be stated therein or necessary to make the statements therein not misleading;

(2) the General Disclosure Package, as of 3:15 p.m. (Eastern Time) on November 2,

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2017, contained an untrue statement of a material fact or omitted to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading; or

(3) the Prospectus, as of the date of the Prospectus Supplement or as of the date hereof, included or includes an untrue statement of a material fact or omitted or omits to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading.

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GLOBAL NOTE

UNLESS THIS CERTIFICATE IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY (55 WATER STREET, NEW YORK, NEW YORK) (THE "DEPOSITORY") TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE OR PAYMENT, AND SUCH CERTIFICATE ISSUED IS REGISTERED IN THE NAME OF CEDE & CO., OR SUCH OTHER NAME AS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY, ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL, SINCE THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

UNLESS AND UNTIL THIS CERTIFICATE IS EXCHANGED IN WHOLE OR IN PART FOR NOTES IN CERTIFICATED FORM, THIS CERTIFICATE MAY NOT BE TRANSFERRED EXCEPT AS A WHOLE BY THE DEPOSITORY TO A NOMINEE THEREOF OR BY A NOMINEE THEREOF TO THE DEPOSITORY OR ANOTHER NOMINEE OF THE DEPOSITORY OR BY THE DEPOSITORY OR ANY SUCH NOMINEE TO A SUCCESSOR OF THE DEPOSITORY OR A NOMINEE OF SUCH SUCCESSOR.

CUSIP NO. 744573 AL0 $
No. R-01

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
2.650% Senior Note due 2022

GLOBAL NOTE

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED, a New Jersey corporation (herein referred to as the "Company," which term includes any successor corporation under the Indenture hereinafter referred to), for value received, hereby promises to pay to Cede & Co., or registered assigns, the principal sum of $ on November 15, 2022 (the "Stated Maturity Date"), unless redeemed in accordance with the provisions of this Global Note, and to pay interest on the outstanding principal amount of this Global Note from November 6, 2017, semi-annually in arrears on May 15 and November 15 of each year, beginning on May 15, 2018 (each, an "Interest Payment Date") at 2.650% per annum until the principal hereof is paid or duly provided for. Interest payable on each Interest Payment Date will include interest accrued from and including November 6, 2017 or from and including the most recent Interest Payment Date to which interest has been paid or duly provided for, as the case may be, to, but excluding, such Interest Payment Date. Interest will be computed based on a 360-day year consisting of twelve 30-day months.

The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, except as provided below, be paid to the person (the "Holder") in whose name this Global Note (or one or more Predecessor Securities) is registered at the close of business on the fifteenth day (whether or not a Business Day (as defined below)) immediately preceding the applicable Interest Payment Date (a "Regular Record Date"). Any such interest not so punctually paid or duly provided for ("Defaulted Interest") will forthwith cease to be payable to the Holder on such Regular Record Date and may either be paid to the person in whose name this Global Note (or one or more Predecessor Securities) is registered at the close of business on a special record date (the "Special Record Date") for the payment of such Defaulted Interest to be fixed by the Trustee hereinafter referred to, notice whereof shall be

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given to the Holder of this Global Note not less than ten days prior to such Special Record Date, or may be paid at any time in any other lawful manner, all as more fully provided in the Indenture.

For purposes of this Global Note, "Business Day" means each Monday, Tuesday, Wednesday, Thursday and Friday which is not a day on which banking institutions in Newark, New Jersey and The City of New York are authorized or obligated by law or executive order to close.

Payments of principal, premium, if any, and interest with respect to this Global Note will be made in such coin or currency of the United States of America as at the time of payment is legal tender for the payment of public and private debts. Payment of the principal of and any premium on this Global Note on the Stated Maturity Date or date of earlier redemption will be made in immediately available funds against presentation of this Global Note at the office or agency of the Company maintained for that purpose in the Borough of Manhattan, The City of New York. Payments of interest on an Interest Payment Date will be made, at the option of the Company, by check mailed to the Holder entitled thereto at the applicable address appearing in the Security Register or by transfer of immediately available funds to an account maintained by the payee with a bank located in the United States of America; provided, however, that so long as Cede & Co. is the Holder of this Global Note, payments of interest on an Interest Payment Date will be made in immediately available funds.

Any payment of principal, premium or interest required to be made with respect to this Global Note on a day that is not a Business Day need not be made on such day, but may be made on the next succeeding Business Day with the same force and effect as if made on such day and no additional interest shall be payable on the next succeeding Business Day as a result of such delayed payment.

General. This Global Note is one of the duly authorized series of securities of the Company (the "Securities"), issued or to be issued under the Indenture, dated as of November 1, 1998 (together with all amendments and supplements thereto, the "Indenture"), between the Company and U.S. Bank National Association, as successor trustee (the "Trustee"), to which Indenture reference is hereby made for a statement of the respective rights, limitations of rights, duties and immunities thereunder of the Company, the Trustee and each of the Holders of the Securities and of the terms upon which the Securities are, and are to be, authenticated and delivered and transferred. This Global Note is one of the duly authorized series of Securities designated as the “2.650% Senior Notes due 2022” (collectively, the “Notes”). The Notes will be limited to $700,000,000 aggregate principal amount, except as permitted in the Indenture, and will be subject, without the consent of the Holders of any series of Securities under the Indenture, to the issuance of additional Notes in the future having the same terms, other than the date of original issuance and the date on which interest begins to accrue, so as to form one series with the Notes. All terms used in this Global Note, which are not defined herein shall have the meanings given to them in the Indenture.

Events of Default. If an Event of Default with respect to the Notes shall have occurred and be continuing, the principal of the Notes may be declared due and payable in the manner and with the effect provided in the Indenture.

As used in this Global Note and the Indenture, the term “Event of Default” wherever used with respect to the Notes means any one of the events described under Article Five, Section 501 of the Indenture or the following event:

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an event of default shall have occurred and be continuing with respect to indebtedness for borrowed money of the Company in excess of $75,000,000 and such event of default shall have been accelerated, and such acceleration shall not be rescinded or annulled within ten days after written notice thereof shall have been given to the Company by the Trustee or to the Company and the Trustee by the Holders of at least 25% in aggregate principal amount of the Notes then Outstanding; *provided*, *however*, that if such event of default with respect to such other indebtedness shall be remedied or cured by the Company, or waived by the holders of such other indebtedness, then the Event of Default hereunder by reason thereof shall be deemed likewise to have been thereupon remedied, cured or waived without further action upon the part of either the Trustee or any of the Holders of the Notes; and *provided, further*, that, subject to the provisions of Section 601 of the Indenture, the Trustee shall not be charged with knowledge of any such event of default or any remedy, cure or waiver thereof or any such acceleration unless written notice thereof shall have been given to the Trustee by the Company, by a holder or an agent of such other indebtedness or by the Trustee then acting under this Indenture with respect to such other series of Securities or under any other indenture or instrument, as the case may be, under which such event of default shall have occurred, or by the Holders of at least twenty-five percent in aggregate principal amount of the Notes at the time Outstanding;

in each case whatever the reason for such Event of Default and whether or not it shall be voluntary or involuntary or be effected by operation of law or pursuant to any judgment, decree or order of any court or any order, rule or regulation of any administrative or governmental body.

Sinking Fund. This Global Note will not be entitled to the benefit of, or be subject to, any sinking fund.

Optional Redemption. This Global Note (or portion hereof) will be redeemable at the option of the Company, in whole or in part at any time prior to October 15, 2022, on at least 10 days but not more than 60 days prior written notice mailed to the Holder hereof, at a price (the "Make-Whole Redemption Price") equal to the greater of (i) 100% of the principal amount of this Global Note (or portion hereof) to be redeemed, and (ii) the sum of the present values of the remaining scheduled payments of principal of and interest on this Global Note (or portion hereof) to be redeemed that would be due if this Global Note matured on October 15, 2022, exclusive of accrued interest to the date of redemption (each, a “Make-Whole Redemption Date”), discounted to such Make-Whole Redemption Date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined below) plus 12.5 basis points, plus, in either case, any accrued and unpaid interest thereon to, but excluding, such Make-Whole Redemption Date.

This Global Note (or a portion thereof) will be redeemable at the option of the Company, in whole or in part, at any time on or after October 15, 2022, on at least 10 days but not more than 60 days prior written notice mailed to the Holder hereof, at a price (the “Par Redemption Price”) equal to 100% of the principal amount of this Global Note (or portion hereof) to be redeemed, plus any accrued and unpaid interest thereon to, but excluding, the date of redemption (each, a “Par Redemption Date”).

If money sufficient to pay the Make-Whole Redemption Price of this Global Note (or portion hereof) to be redeemed on a Make-Whole Redemption Date is deposited with the Trustee or a Paying Agent on or before such Make-Whole Redemption Date and certain other

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conditions are satisfied, then on and after such Make-Whole Redemption Date, interest will cease to accrue on this Global Note (or such portion hereof) called for redemption.

If money sufficient to pay the Par Redemption Price of this Global Note (or portion hereof) to be redeemed on a Par Redemption Date is deposited with the Trustee or a Paying Agent on or before such Par Redemption Date and certain other conditions are satisfied, then on and after such Par Redemption Date, interest will cease to accrue on this Global Note (or such portion hereof) called for redemption.

For purposes of the foregoing, the following definitions apply:

"Comparable Treasury Issue" means, with respect to any Make-Whole Redemption Date for this Global Note (or portion hereof) to be redeemed, the United States Treasury security selected by the Independent Investment Banker (as defined below) as having the maturity comparable to the remaining term of this Global Note (or portion hereof) to be redeemed (assuming that this Global Note matured on October 15, 2022) that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of this Global Note (or portion hereof) to be redeemed.

"Comparable Treasury Price" means, with respect to any Make-Whole Redemption Date for this Global Note (or portion hereof) to be redeemed, (a) the average of three Reference Treasury Dealer Quotations (as defined below) for the Make-Whole Redemption Date for this Global Note (or portion hereof) to be redeemed, after excluding the highest and lowest of five Reference Treasury Dealer Quotations, or, (b) if the Independent Investment Banker obtains fewer than five Reference Treasury Dealer Quotations, the average of all Reference Treasury Dealer Quotations obtained.

"Independent Investment Banker" means one of the Reference Treasury Dealers appointed by the Company after consultation with the Trustee.

"Reference Treasury Dealer" means each of Barclays Capital Inc., J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC, RBC Capital Markets, LLC and TD Securities (USA) LLC, and their respective affiliates or successors, *provided* that if any of the foregoing shall cease to be a primary U.S. government securities dealer in the United States (a “Primary Treasury Dealer”), the Company will substitute therefor another Primary Treasury Dealer.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any Make-Whole Redemption Date, the average, as determined by the Independent Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Independent Investment Banker by such Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding such Make-Whole Redemption Date.

"Treasury Rate" means, with respect to any Make-Whole Redemption Date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such Make-Whole Redemption Date. The Treasury Rate will be calculated by the Company on the third Business Day preceding the Make-Whole Redemption Date. The Trustee shall not be responsible for any such calculation.

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Reports. So long as this Global Note remains Outstanding, the Company will file with the Trustee, within 30 days of filing them with the Securities and Exchange Commission (the "SEC"), copies of the current, quarterly and annual reports and of the information, documents and other reports (or copies of such portions of any of the foregoing as the SEC may by rules and regulations prescribe) that the Company is required to file with the SEC pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act"). If the Company is not subject to the requirements of Section 13 or Section 15(d) of the Exchange Act and this Global Note remains Outstanding, the Company must nevertheless file with the SEC (if permitted) and the Trustee, on the date upon which the Company would have been required to file with the SEC, current, quarterly and annual financial statements, including any notes thereto (and with respect to annual reports, an auditor's report by a firm of established national reputation, upon which the Trustee may conclusively rely), and a "Management's Discussion and Analysis of Financial Condition and Results of Operations," both comparable to that which the Company would have been required to include in such current, quarterly and annual reports, information, documents or other reports on Forms 8-K, 10-Q and 10-K if the Company was subject to the requirements of Section 13 or 15(d) of the Exchange Act; provided that the Company will not be required to register under the Exchange Act by virtue of this provision, if not otherwise required to do so.

Modification and Waivers; Obligations of the Company Absolute. The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders of the Securities of each series. Such amendment may be effected under the Indenture at any time by the Company and the Trustee with the consent of the Holders of a majority in aggregate principal amount of all Securities issued under the Indenture at the time Outstanding and affected thereby. The Indenture also contains provisions permitting the Holders of a majority in aggregate principal amount of the Securities of each series at the time Outstanding, on behalf of the Holders of all Outstanding Securities of such series, to waive compliance by the Company with certain provisions of the Indenture and certain past defaults under the Indenture and their consequences. Any such consent or waiver shall be conclusive and binding upon the Holder of this Global Note and upon all future Holders of this Global Note and of any Note issued upon the registration of transfer hereof or in exchange hereof or in lieu hereof, whether or not notation of such consent or waiver is made upon this Note.

No reference herein to the Indenture and no provision of this Global Note or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal, premium, if any, and interest with respect to this Global Note at the times, place and rate, and in the coin or currency herein prescribed.

Defeasance. The Indenture contains provisions for defeasance at any time of the entire indebtedness of the Company on this Global Note, upon compliance by the Company with certain conditions set forth in the Indenture, which provisions apply to this Global Note.

Authorized Denominations. The Notes are issuable only in registered form without coupons in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

Registration of Transfer or Exchange of this Global Note. As provided in the Indenture and subject to certain limitations herein and therein set forth, the transfer of this Global Note is registrable in the Security Register upon surrender of this Global Note for registration of transfer at the office or agency of the Company in any place where the principal

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of (and premium, if any) and interest on this Global Note are payable, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Security Registrar duly executed by, the Holder hereof or his attorney duly authorized in writing, and thereupon one or more new Global Notes of this series of like tenor, of authorized denominations and for the same aggregate principal amount, will be issued to the designated transferee or transferees.

As provided in the Indenture and subject to certain limitations herein and therein set forth, the Global Notes are exchangeable for a like aggregate principal amount of Global Notes of different authorized denominations, as requested by the Holders surrendering the same.

This Global Note is a "Security in global form" within the meaning of the Indenture. If The Depository Trust Company is at any time unwilling, unable or ineligible to continue as depository and a successor depository is not appointed by the Company within 90 days or an Event of Default under the Indenture has occurred and is continuing, the Company will issue Notes in certificated form in exchange for this Global Note. In addition, the Company may at any time determine not to have Notes represented by one or more Securities in global form and, in such event, will issue Notes in certificated form in exchange in whole for this Global Note. In any such instance, an owner of a beneficial interest in this Global Note will receive Notes in certificated form equal in principal amount to such beneficial interest and to have such Notes registered in its name. Notes so issued in certificated form will be issued in denominations of $2,000 and integral multiples of $1,000 in excess thereof and will be issued in registered form only, without coupons.

No service charge shall be made for any such registration of transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

Prior to due presentment of this Global Note for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the Holder of this Global Note as the owner hereof for all purposes, whether or not this Global Note be overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

Governing Law. This Global Note shall be governed by and construed in accordance with the law of the State of New Jersey.

Unless the certificate of authentication hereon has been executed by the Trustee by manual signature, this Global Note shall not be entitled to any benefit under the Indenture or be valid or obligatory for any purpose.

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IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed under its facsimile corporate seal.

PUBLIC SERVICE ENTERPRISE GROUP
INCORPORATED

Dated: November 6, 2017

By: _____
Vice President and Treasurer

Attest: _____
Secretary

TRUSTEE'S CERTIFICATE OF AUTHENTICATION

This is one of the Securities of the series designated therein referred to in the within-mentioned Indenture.

U.S. BANK NATIONAL ASSOCIATION,
as Trustee

Dated: November 6, 2017

By: _____
Authorized Signatory

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ASSIGNMENT FORM

To assign this Security, fill in the form below:
I or we assign and transfer this Security to

(Insert assignee's soc. sec. or tax I.D. No.)

(Print or type assignee's name, address and zip code)

and irrevocably appoint _____ agent to transfer this Security on the books of the Company. The agent may substitute another to act for him.

Dated: _____ Signed _____

(Sign exactly as your name appears on the other side of this Security)

Signature Guarantee: _____

Dated: _____ Signed _____

(Sign exactly as your name appears on the other side of this Security)

Signature Guarantee: _____

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Exhibit 5

Shawn P. Leyden
Vice President & Deputy General Counsel

PSEG Services Corporation
80 Park Plaza, T19, Newark, NJ 07102-4194
tel: 973.430.7698 fax: 973.643.8385
email: shawn.leyden@pseg.com

November 6, 2017

Public Service Enterprise Group Incorporated
80 Park Plaza
P.O. Box 1171
Newark, NJ 07102

Re: Public Service Enterprise Group Incorporated
Registration Statement on Form S-3 (No. 333-200352)

Ladies and Gentlemen:

This opinion is furnished in connection with the issuance and sale by Public Service Enterprise Group Incorporated (the "Company") of $700,000,000 aggregate principal amount of its 2.650% Senior Notes due 2022 (the "Notes") pursuant to (i) the Company's Registration Statement on Form S-3, Registration No. 333-200352 (the "Registration Statement"); (ii) the base prospectus constituting a part of the Registration Statement, dated November 18, 2014 (the "Base Prospectus"), relating to the offering from time to time of certain debt securities of the Company, among other securities, pursuant to Rule 415 promulgated under the Securities Act of 1933, as amended (the "Act"); and (iii) the prospectus supplement, dated November 2, 2017 (the "Prospectus Supplement" and together with the Base Prospectus, the "Prospectus"). The Notes were issued under the Indenture, dated as of November 1, 1998 (as amended and supplemented to the date hereof, the "Indenture"), between the Company and U.S. Bank National Association, as trustee (the "Trustee").

I have examined the Registration Statement, the Prospectus, the Indenture, the global certificates representing the Notes and such other agreements, instruments, documents and records and such certificates or comparable documents of public officials which I deemed relevant and necessary for the basis of the opinion hereinafter expressed. In such examination, I have assumed the following: (a) the authenticity of original documents and the genuineness of all signatures; (b) the conformity to the originals of all documents submitted to me as copies; and (c) the truth, accuracy, and completeness of the information, representations, and warranties contained in the records, documents, instruments, and certificates I have reviewed.

Based on such examination, I am of the opinion that the Notes, assuming the due authentication thereof by the Trustee pursuant to the Indenture, constitute valid and binding obligations of the Company, enforceable against the Company in accordance with their terms, subject to applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium

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and similar laws affecting creditors' rights and remedies generally and to general principles of equity, including principles of commercial reasonableness, good faith and fair dealing (regardless of whether enforcement is sought in a proceeding at law or in equity).

The foregoing opinion is given as of the date hereof and is limited to matters arising under laws of the State of New Jersey as in effect on the date hereof and I express no opinion as to the effect on the matters covered by this letter of the laws of any other jurisdiction. I hereby consent to the incorporation by reference of this letter as an exhibit to the Registration Statement and to the use of my name wherever it appears in the Registration Statement. In giving such consent, I do not thereby admit that I am within the category of persons whose consent is required by Section 7 of the Act or the related rules and regulations of the Securities and Exchange Commission issued thereunder with respect to any part of the Registration Statement, including this letter as an exhibit or otherwise.

Very truly yours,

/s/ Shawn P. Leyden

Shawn P. Leyden
Vice President and Deputy General Counsel
PSEG Services Corporation

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): November 3, 2016

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Exact name of registrant as specified in its charter)

New Jersey	**001-09120**	**22-2625848**
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)
973-430-7000
(Registrant's telephone number, including area code)
http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 8.01. Other Events

On November 8, 2016, Public Service Enterprise Group Incorporated ("PSEG") completed a public offering of $400.0 million aggregate principal amount of its 1.600% Senior Notes due 2019 (the "2019 Notes") and $300.0 million aggregate principal amount of its 2.000% Senior Notes due 2021 (the "2021 Notes" and together with the 2019 Notes, the "Notes"). The Notes were offered and sold by PSEG pursuant to a registration statement on Form S-3 (File No. 333-200352) (the "Registration Statement") and the related Prospectus dated November 18, 2014 and Prospectus Supplement dated November 3, 2016. The Notes were issued pursuant to an underwriting agreement (the "Underwriting Agreement"), dated November 3, 2016, between PSEG and Barclays Capital Inc., J.P. Morgan Securities LLC and RBC Capital Markets, LLC, as representatives of the several underwriters named therein (the "Underwriters"). Pursuant to the Underwriting Agreement and subject to the terms and conditions expressed therein, PSEG agreed to sell the Notes to the Underwriters, and the Underwriters agreed to purchase the Notes for resale to the public. The Underwriting Agreement is filed as Exhibit 1 hereto. The Notes are governed by an indenture, dated as of November 1, 1998 (the "Indenture"), between PSEG and U.S. Bank National Association, as successor trustee. The Indenture, the form of 2019 Note and the form of 2021 Note are filed as Exhibits 4-1, 4-2 and 4-3 hereto, respectively. The Underwriting Agreement, Indenture, the form of 2019 Note and the form of 2021 Note are incorporated by reference into the Registration Statement.

In connection with the offering of the Notes, PSEG is filing herewith as Exhibit 5 an opinion of Shawn P. Leyden, Vice President and Deputy General Counsel of PSEG Services Corporation, addressing the legality of the Notes. Such opinion is incorporated by reference into the Registration Statement.

Item 9.01. Financial Statements and Exhibits

Exhibit 1	Underwriting Agreement, dated November 3, 2016, between PSEG and Barclays Capital Inc., J.P. Morgan Securities LLC and RBC Capital Markets, LLC, as representatives of the several underwriters named therein.
Exhibit 4-1	Indenture dated as of November 1, 1998 between PSEG and U.S. Bank National Association (as successor to First Union National Bank), as Trustee (incorporated by reference to Exhibit 4(f) to the Annual Report on Form 10-K for the year ended December 31, 1998, File No. 001-09120).
Exhibit 4-2	Form of 2019 Note.
Exhibit 4-3	Form of 2021 Note.
Exhibit 5	Opinion of Shawn P. Leyden, Vice President and Deputy General Counsel of PSEG Services Corporation, addressing the legality of the Notes.
Exhibit 23	Consent of Shawn P. Leyden, Vice President and Deputy General Counsel of PSEG Services Corporation (included in Exhibit 5).

S1-SSA-0009 - 10517

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: November 8, 2016

S1-SSA-0009 - 10518

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Exhibit 1

EXECUTION VERSION

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(a New Jersey corporation)

$400,000,000 1.600% Senior Notes due 2019

$300,000,000 2.000% Senior Notes due 2021

UNDERWRITING AGREEMENT

November 3, 2016

BARCLAYS CAPITAL INC.
J.P. MORGAN SECURITIES LLC
RBC CAPITAL MARKETS, LLC

c/o J.P. Morgan Securities LLC
383 Madison Avenue
New York, New York 10179

As Representatives of the several Underwriters

Ladies and Gentlemen:

Public Service Enterprise Group Incorporated, a New Jersey corporation (the "**Company**"), proposes to issue and sell to the several underwriters named in Schedule 1 hereto (the "**Underwriters,**" which term shall include any underwriter substituted as hereinafter provided in Section 10), acting severally and not jointly, the respective principal amounts set forth in such Schedule 1 of (i) $400,000,000 aggregate principal amount of the Company's 1.600% Senior Notes due 2019 (the "**2019 Notes**") and (ii) $300,000,000 aggregate principal amount of the Company's 2.000% Senior Notes due 2021 (the "**2021 Notes**" and, together with the 2019 Notes, the "**Securities**"). Barclays Capital Inc. ("**Barclays**"), J.P. Morgan Securities LLC ("**J.P. Morgan**") and RBC Capital Markets, LLC ("**RBC Capital Markets**") have agreed to act as representatives of the several Underwriters (in such capacity, the "**Representatives**") in connection with the offering and sale of the Securities.

The Securities will be issued pursuant to the provisions of an Indenture dated as of November 1, 1998, as amended and supplemented by the First Supplemental Indenture, dated as of September 10, 2002, and the Second Supplemental Indenture, dated as of July 27, 2005 (collectively, the **"Indenture"**), between the Company and U.S. Bank National Association (as successor trustee to First Union National Bank), as trustee (the **"Trustee"**).

The Company has filed with the Securities and Exchange Commission (the "**Commission**") a registration statement on Form S-3 (No. 333-200352), which contains a base prospectus (the "**Base Prospectus**"), to be used in connection with the public offering and sale of certain securities by the Company, including the Securities, under the Securities Act of 1933, as amended (the "**1933 Act**"), and the offering thereof from time to time in accordance with Rule 415 of the rules and regulations of the Commission under the 1933 Act (the "**1933 Act Regulations**"). Such registration statement, including the financial statements, exhibits and

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schedules thereto, in the form in which it became effective under the 1933 Act, including any required information deemed to be a part thereof at the time of effectiveness pursuant to Rule 430B of the 1933 Act Regulations ("**Rule 430B**"), is called the "**Registration Statement**." The term "**Prospectus**" shall mean the final prospectus supplement relating to the Securities, together with the Base Prospectus, that is first filed pursuant to Rule 424(b) of the 1933 Act Regulations ("**Rule 424(b)**") after the date and time that this Agreement is executed (the "**Execution Time**") by the parties hereto. The term "**preliminary prospectus**" shall mean any preliminary prospectus supplement relating to the Securities, together with the Base Prospectus, that is first filed with the Commission pursuant to Rule 424(b). Any reference herein to the Registration Statement, any preliminary prospectus or the Prospectus shall be deemed to refer to and include the documents that are or are deemed to be incorporated by reference therein pursuant to Item 12 of Form S-3 under the 1933 Act prior to the Applicable Time (as defined below). For purposes of this Agreement, all references to the Registration Statement, any preliminary prospectus or the Prospectus or to any amendment or supplement to any of the foregoing shall be deemed to include any copy filed with the Commission pursuant to its Electronic Data Gathering, Analysis and Retrieval system ("**EDGAR**").

All references in this Agreement to financial statements and schedules and other information which is "contained," "included" or "stated" (or other references of like import) in the Registration Statement, any preliminary prospectus or the Prospectus or any amendment or supplement thereto shall be deemed to mean and include all such financial statements and schedules and other information which is or is deemed to be incorporated by reference in or otherwise deemed by the 1933 Act Regulations to be a part of or included in the Registration Statement, any preliminary prospectus or the Prospectus or any amendment or supplement thereto, as the case may be, on or before the effective date of the Registration Statement or the date of such preliminary prospectus or the Prospectus or such amendment or supplement, as the case may be; and all references in this Agreement to amendments or supplements to the Registration Statement, any preliminary prospectus or the Prospectus shall be deemed to mean and include the filing of any document under the Securities Exchange Act of 1934, as amended (the "**1934 Act**"), which is or is deemed to be incorporated by reference in or otherwise deemed by the 1933 Act Regulations to be a part of or included in the Registration Statement, such preliminary prospectus or the Prospectus, as the case may be, at the time of such amendment or supplement.

SECTION 1. Representations and Warranties.

(a) Representations and Warranties. The Company represents and warrants to each Underwriter, as of the date hereof, as of the Applicable Time and as of the Closing Time (as defined below) (in each case, a "**Representation Date**"), as follows:

(1) Compliance with Registration Requirements. The Company meets the requirements for use of Form S-3 under the 1933 Act. The Registration Statement became effective upon filing with the Commission under Rule 462(e) of the 1933 Act Regulations ("**Rule 462(e)**") on November 18, 2014 and any post-effective amendment thereto also became effective upon filing under Rule 462(e). No stop order suspending the effectiveness of the Registration Statement or preventing or suspending the use of any prospectus has been issued under the 1933 Act and no proceedings for that purpose or

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pursuant to Section 8A of the 1933 Act against the Company or related to the offering of the Securities have been instituted or are pending or, to the knowledge of the Company, are contemplated by the Commission, any request on the part of the Commission for additional information has been complied with, and no notice of objection of the Commission to the use of the Registration Statement or any post-effective amendment thereto pursuant to Rule 401(g)(2) of the 1933 Act Regulations has been received by the Company. In addition, the Indenture has been duly qualified under the Trust Indenture Act of 1939, as amended (the "**1939 Act**").

At the respective times the Registration Statement and any post-effective amendments thereto became effective and as of each Representation Date, the Registration Statement and any amendments thereto complied, complies and will comply in all material respects with the requirements of the 1933 Act and the 1933 Act Regulations and the 1939 Act and the rules and regulations of the Commission under the 1939 Act (the "**1939 Act Regulations**"), and did not, does not and will not contain an untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary to make the statements therein not misleading; provided, that the Company makes no representation or warranty with respect to the Underwriter Information (as defined below).

The Prospectus and each amendment or supplement thereto, if any, at the time the Prospectus or any such amendment or supplement is issued and at the Closing Time, complied, complies and will comply in all material respects with the requirements of the 1933 Act and the 1933 Act Regulations, and neither the Prospectus nor any amendment or supplement thereto included, includes or will include an untrue statement of a material fact or omitted, omits or will omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading; provided, that the Company makes no representation or warranty with respect to the Underwriter Information.

Each preliminary prospectus and any amendment thereto complied when so filed in all material respects with the 1933 Act and the 1933 Act Regulations and each preliminary prospectus and the Prospectus delivered or made available to the Underwriters for use in connection with the offering of the Securities was and will be, at the time of such delivery, identical to the electronically transmitted copies thereof filed with the Commission pursuant to EDGAR, except to the extent permitted by Regulation S-T.

As of the Applicable Time, neither (x) the General Disclosure Package (as defined below) nor (y) any individual Issuer Limited Use Free Writing Prospectus (as defined below), when considered together with the General Disclosure Package, included any untrue statement of a material fact or omitted to state any material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading; provided that the Company makes no representation or warranty with respect to the Underwriter Information.

As used in this subsection and elsewhere in this Agreement:

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"**Applicable Time**" means 4:35 P.M. (New York City time) on November 3, 2016 or such other time as agreed by the Company and the Representatives.

"**General Disclosure Package**" means (i) the Issuer General Use Free Writing Prospectus(es) (as defined below) relating to the Securities issued at or prior to the Applicable Time, including the Final Term Sheet (as defined below) attached as Schedule 3 hereto, and (ii) the most recent preliminary prospectus (including any documents incorporated therein by reference) that is distributed to investors prior to the Applicable Time, all considered together.

"**Issuer Free Writing Prospectus**" means any "issuer free writing prospectus," as defined in Rule 433 of the 1933 Act Regulations ("**Rule 433**"), relating to the Securities that (i) is required to be filed with the Commission, (ii) is a "road show that is a written communication" within the meaning of Rule 433(d)(8)(i), whether or not required to be filed with the Commission or (iii) is exempt from filing pursuant to Rule 433(d)(5)(i) because it contains a description of the Securities or of the offering thereof that does not reflect the final terms, in each case in the form filed or required to be filed with the Commission or, if not required to be filed, in the form retained in the Company's records pursuant to Rule 433(g).

"**Issuer General Use Free Writing Prospectus**" means any Issuer Free Writing Prospectus that is intended for general distribution to prospective investors, as evidenced by its being specified in Schedule 2-A hereto.

"**Issuer Limited Use Free Writing Prospectus**" means any Issuer Free Writing Prospectus that is not an Issuer General Use Free Writing Prospectus and that is specified in Schedule 2-B hereto.

Each Issuer Free Writing Prospectus, as of its issue date and at all subsequent times through the completion of the offering and sale of the Securities under this Agreement or until any earlier date that the Company notified or notifies you as described in Section 3(e), did not, does not and will not include any information that conflicted, conflicts or will conflict with the information contained in the Registration Statement or the Prospectus. The Company has complied with the requirements of Rule 164 and Rule 433 of the 1933 Act Regulations with respect to each Issuer Free Writing Prospectus.

(2) Status as a Well-Known Seasoned Issuer. Since the time of initial filing of the Registration Statement, the Company has been, and continues to be, a "well known seasoned issuer" as defined in Rule 405 of the 1933 Act Regulations ("**Rule 405**").

(3) Status as Non-Ineligible Issuer. At the earliest time that the Company or another offering participant made a *bona fide* offer (within the meaning of Rule 164(h)(2) of the 1933 Act Regulations) of the Securities and at each Representation Date, the Company was not and is not an "ineligible issuer," as defined in Rule 405.

(4) Incorporated Documents. The documents incorporated or deemed to be incorporated by reference in the Registration Statement, the General Disclosure Package or the Prospectus, at the time they were or hereafter are filed with the Commission,

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complied and will comply in all material respects with the requirements of the 1934 Act and the rules and regulations of the Commission thereunder (the "**1934 Act Regulations**") and, when read together with the other information in the Registration Statement, the General Disclosure Package or the Prospectus, as the case may be, (a) at the time the Registration Statement originally became effective and (b) at each Representation Date, did not, does not and will not include an untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading.

(5) Independent Accountants. The accountants who certified the financial statements and any supporting schedules thereto included in the Registration Statement, the General Disclosure Package or the Prospectus are independent public accountants as required by the 1933 Act and the 1933 Act Regulations and the Public Company Accounting Oversight Board (United States).

(6) Financial Statements. The financial statements of the Company included or incorporated by reference in the Registration Statement, the General Disclosure Package or the Prospectus, together with the related schedules and notes, as well as those financial statements, schedules and notes of any other entity included or incorporated by reference therein, present fairly the financial position of the Company and its consolidated subsidiaries, or such other entity, as the case may be, at the dates indicated and the statement of operations, member's equity and cash flows of the Company and its consolidated subsidiaries, or such other entity, as the case may be, for the periods specified. Such financial statements have been prepared in conformity with U.S. generally accepted accounting principles ("**GAAP**") applied on a consistent basis throughout the periods involved. Except as otherwise included or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus, neither pro forma financial statements of the Company nor the financial statements of any entity other than the Company are required to be included in the Registration Statement, the General Disclosure Package or the Prospectus under the 1933 Act, the 1933 Act Regulations, the 1934 Act or the 1934 Act Regulations. The supporting schedules, if any, included or incorporated by reference in the Registration Statement, the General Disclosure Package or the Prospectus present fairly in accordance with GAAP the information required to be stated therein. The Company's ratios of earnings to fixed charges included or incorporated by reference in the Registration Statement (including Exhibit 12), the General Disclosure Package or the Prospectus have been calculated in compliance with Item 503(d) of Regulation S-K of the 1933 Act Regulations. The selected financial data and the summary financial information included or incorporated by reference in the Registration Statement, the General Disclosure Package or the Prospectus present fairly the information shown therein and have been compiled on a basis consistent with that of the audited financial statements included or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus. All disclosures contained in the Registration Statement, the General Disclosure Package or the Prospectus, if any, regarding "non-GAAP financial measures" (as such term is defined by the rules and regulations of the Commission) comply with Regulation G under the 1934 Act and Item 10 of Regulation S-K of the 1933 Act

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Regulations, to the extent applicable. The interactive data in eXtensible Business Reporting Language included or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus fairly presents the information called for in all material respects and has been prepared in accordance with the Commission's rules and guidelines applicable thereto.

(7) No Material Adverse Change in Business. The Company has not sustained since the date of the latest audited financial statements included or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus any material loss from fire, explosion, flood, accident or other calamity not fully covered by insurance, otherwise than as set forth or contemplated in the Registration Statement, the General Disclosure Package and the Prospectus. Since the respective dates as of which information is given in the Registration Statement, the General Disclosure Package or the Prospectus, except as otherwise stated therein, (A) there has been no material adverse change, or any development involving a prospective material adverse change, in the general affairs, financial condition, earnings or business affairs of the Company and its subsidiaries (each such subsidiary, a "**Subsidiary**" and, collectively, the "**Subsidiaries**"), considered as one enterprise, whether or not arising in the ordinary course of business (a "**Material Adverse Change**"); (B) there have been no transactions entered into by the Company or any of its Subsidiaries, other than those arising in the ordinary course of business, which are material with respect to the Company and its Subsidiaries considered as one enterprise; (C) other than, in the case of the Company, regular dividends on the Company's common stock or preferred stock, in amounts per share that are consistent with past practice or the applicable charter document or supplement thereto, respectively, or, in the case of any of the Company's Subsidiaries, to the Company, there has been no dividend or distribution of any kind declared, paid or made by the Company or any of its Subsidiaries on any class of its capital stock; and (D) there has not been any material change in the capital stock (other than upon exercise of outstanding stock options, upon conversion of convertible securities outstanding as of the date of the most recent balance sheet incorporated by reference into the Registration Statement, the General Disclosure Package and the Prospectus or pursuant to the Company's employee or director compensation and benefit plans or the Company's dividend reinvestment and stock purchase plan) or long-term debt of the Company and its Subsidiaries considered as one enterprise.

(8) Good Standing of the Company. The Company has been duly incorporated, is validly existing as a corporation in good standing under the laws of the jurisdiction of its incorporation, has the requisite power and authority to own its property and to conduct its business as described in the Registration Statement, the General Disclosure Package and the Prospectus and is duly qualified to transact business and is in good standing in each jurisdiction in which the conduct of its business or its ownership or leasing of property requires such qualification, except to the extent that the failure to be so qualified or be in good standing would not result in a Material Adverse Change.

(9) Good Standing of Significant Subsidiaries. Each Subsidiary of the Company which is a significant subsidiary, as defined in Rule 405 (each, a "**Significant Subsidiary**"), has been duly incorporated or organized, is validly existing as a

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corporation or limited liability company in good standing under the laws of the jurisdiction of its incorporation or organization, has the requisite power and authority to own its property and to conduct its business as described in the Registration Statement, the General Disclosure Package and the Prospectus and is duly qualified to transact business and is in good standing in each jurisdiction in which the conduct of its business or its ownership or leasing of property requires such qualification, except to the extent that the failure to be so qualified or be in good standing would not result in a Material Adverse Change. All of the issued shares of capital stock or other equity interests of each Significant Subsidiary have been duly and validly authorized and issued, are fully paid and non-assessable and are owned directly by the Company or a direct wholly-owned Subsidiary of the Company, as the case may be, free and clear of all liens, encumbrances, equities or claims. None of the outstanding shares of capital stock or other equity interests of any Significant Subsidiary were issued in violation of preemptive or other similar rights of any security holder of such Significant Subsidiary.

(10) Capitalization. The authorized, issued and outstanding shares of capital stock of the Company are as set forth in the Company's most recent Annual Report on Form 10-K or, if applicable, subsequent Quarterly Report on Form 10-Q (except for subsequent issuances thereof, if any, pursuant to reservations, agreements or employee benefit plans or pursuant to the exercise of convertible securities or options, in each case which are referred to in the Registration Statement, the General Disclosure Package and the Prospectus). Such shares of capital stock have been duly authorized and validly issued by the Company and are fully paid and non-assessable and none of such shares of capital stock of the Company were issued in violation of preemptive or other similar rights of any security holder of the Company.

(11) Authorization of this Agreement. This Agreement has been duly authorized, executed and delivered by the Company.

(12) Authorization of Securities. The Securities have been duly authorized by the Company for issuance and sale pursuant to this Agreement. At the Closing Time, the Securities will have been duly executed by the Company and, when authenticated in the manner provided for in the Indenture and delivered against payment of the requisite consideration therefor, will constitute valid and legally binding obligations of the Company, enforceable against the Company in accordance with their terms, except as the enforcement thereof may be limited by bankruptcy, insolvency (including, without limitation, all laws relating to fraudulent transfers), reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally or by general equitable principles (regardless of whether enforcement is considered in a proceeding in equity or at law), and except further as enforcement thereof may be limited by requirements that a claim with respect to any debt securities payable in a foreign or composite currency (or a foreign or composite currency judgment in respect of such claim) be converted into U.S. dollars at a rate of exchange prevailing on a date determined pursuant to applicable law or by governmental authority to limit, delay or prohibit the making of payments outside the United States. Each series of Securities will be in the form contemplated by, and each registered holder thereof will be entitled to the benefits of, the Indenture.

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(13) Authorization of the Indenture. The Indenture has been duly authorized, executed and delivered by the Company and constitutes a valid and legally binding agreement of the Company, enforceable against the Company in accordance with its terms, except as the enforcement thereof may be limited by bankruptcy, insolvency (including, without limitation, all laws relating to fraudulent transfers), reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally or by general equitable principles (regardless of whether enforcement is considered in a proceeding in equity or at law), and except further as enforcement thereof may be limited by requirements that a claim with respect to any debt securities issued or issuable under the Indenture that are payable in a foreign or composite currency (or a foreign or composite currency judgment in respect of such claim) be converted into U.S. dollars at a rate of exchange prevailing on a date determined pursuant to applicable law or by governmental authority to limit, delay or prohibit the making of payments outside the United States.

(14) Descriptions of the Securities and the Indenture. The Indenture conforms, and, upon issuance, the Securities will conform, in all material respects to the statements relating thereto contained in the Registration Statement, the General Disclosure Package and the Prospectus and will be substantially in the forms filed or incorporated by reference, as the case may be, as an exhibit to the Registration Statement.

(15) Absence of Defaults and Conflicts. Neither the Company nor any of its Subsidiaries is in violation of its certificate of incorporation or by-laws or other organizational documents or in default in the performance or observance of any obligation, agreement, covenant or condition contained in any contract, indenture, mortgage, deed of trust, loan or credit agreement, note, lease or other agreement or instrument to which the Company or any of its Subsidiaries is a party or by which it or any of them may be bound, or to which any of the assets, properties or operations of the Company or any of its Subsidiaries is subject (collectively, "**Agreements and Instruments**"), except for such defaults that would not result in a Material Adverse Change. The execution, delivery and performance of this Agreement, the Indenture, the Securities and any other agreement or instrument entered into or issued or to be entered into or issued by the Company in connection with the transactions contemplated hereby or thereby or in the Registration Statement, the General Disclosure Package and the Prospectus and the consummation of the transactions contemplated herein and in the Registration Statement, the General Disclosure Package and the Prospectus (including the issuance and sale of the Securities and the use of the proceeds from the sale of the Securities as described therein) and compliance by the Company with its obligations hereunder and thereunder have been duly authorized by all necessary corporate action and do not and will not, whether with or without the giving of notice or passage of time or both, conflict with or constitute a breach of, or default or Repayment Event (as defined below) under, or result in the creation or imposition of any lien, charge or encumbrance upon any assets, properties or operations of the Company or any of its Subsidiaries pursuant to, any Agreements and Instruments, nor will such action result in any violation of the provisions of the certificate of incorporation or by-laws or other organizational documents of the Company or any of its Subsidiaries or any applicable law, statute, rule, regulation, judgment, order, writ or decree of any government, government

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instrumentality or court, domestic or foreign, having jurisdiction over the Company or any of its Subsidiaries or any of their assets, properties or operations. As used herein, a "**Repayment Event**" means any event or condition which gives the holder of any note, debenture or other evidence of indebtedness (or any person acting on such holder's behalf) the right to require the repurchase, redemption or repayment of all or a portion of such indebtedness by the Company or any of its Subsidiaries.

(16) Absence of Labor Dispute. Other than as set forth in or contemplated by the Registration Statement, the General Disclosure Package and the Prospectus, no labor dispute with the employees of the Company or any of its Subsidiaries exists or, to the knowledge of the Company, is imminent, and the Company does not have actual knowledge of any existing or imminent labor disturbance by the employees of any of its or any Subsidiary's principal suppliers, manufacturers, customers or contractors, which, in either case, may reasonably be expected to result in a Material Adverse Change.

(17) Absence of Proceedings. Other than as set forth in or contemplated by the Registration Statement, the General Disclosure Package and the Prospectus, there is no action, suit, proceeding, inquiry or investigation before or brought by any court or governmental agency or body, domestic or foreign, now pending, or, to the knowledge of the Company, threatened, against or affecting the Company or any of its Subsidiaries which is required to be disclosed in the Registration Statement, the General Disclosure Package and the Prospectus (other than as stated in the Registration Statement, the General Disclosure Package and the Prospectus), or which might reasonably be expected to result in a Material Adverse Change, or which might reasonably be expected to materially and adversely affect the consolidated assets, properties or operations thereof or the consummation of the transactions contemplated under the Registration Statement, the General Disclosure Package and the Prospectus, this Agreement, the Securities or the Indenture, or the performance by the Company of its obligations hereunder and thereunder. The aggregate of all pending legal or governmental proceedings to which the Company or any of its Subsidiaries is a party or of which any of their respective assets, properties or operations is the subject which are not described in the Registration Statement, the General Disclosure Package and the Prospectus, including ordinary routine litigation incidental to the business, could not reasonably be expected to result in a Material Adverse Change.

(18) Accuracy of Exhibits. There are no contracts or documents which are required under the 1933 Act, the 1933 Act Regulations, the 1934 Act or the 1934 Act Regulations to be described in the Registration Statement, the General Disclosure Package, the Prospectus or the documents incorporated by reference therein or to be filed as exhibits thereto which have not been so described or filed as required.

(19) Absence of Further Requirements. No filing with, or authorization, approval, consent, license, order, registration, qualification or decree of, any court or governmental authority or agency, domestic or foreign, is necessary or required for the due authorization, execution and delivery by the Company of this Agreement, the Indenture, the Securities or for the performance by the Company of the transactions contemplated under the Registration Statement, the General Disclosure Package, the

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Prospectus, this Agreement, the Securities or the Indenture, except the registration of the Securities under the 1933 Act, the qualification of the Indenture under the 1939 Act and such consents, approvals, registrations or qualifications as may be required under state securities or Blue Sky laws in connection with the issuance and sale of the Securities and except such as have been already made, obtained or rendered, as applicable.

(20) Possession of Licenses and Permits. The Company and its Subsidiaries possess such permits, licenses, approvals, consents and other authorizations (collectively, "**Governmental Licenses**") issued by the appropriate federal, state, local or foreign regulatory agencies or bodies necessary to conduct the business now operated by them, except where the failure so to possess such Governmental Licenses would not, singly or in the aggregate, result in a Material Adverse Change. The Company and its Subsidiaries are in compliance with the terms and conditions of all such Governmental Licenses, except where the failure so to comply would not, singly or in the aggregate, result in a Material Adverse Change. All of the Governmental Licenses are valid and in full force and effect, except where the invalidity of such Governmental Licenses or the failure of such Governmental Licenses to be in full force and effect would not result in a Material Adverse Change. Neither the Company nor any of its Subsidiaries has received any notice of proceedings relating to the revocation or modification of any such Governmental Licenses which, singly or in the aggregate, if the subject of an unfavorable decision, ruling or finding, would result in a Material Adverse Change.

(21) Title to Property. The Company and its Subsidiaries have good and marketable title to all real property owned by the Company and its Subsidiaries and good title to all other properties owned by them, in each case, free and clear of all mortgages, pledges, liens, security interests, claims, restrictions or encumbrances of any kind, except (A) as otherwise stated in the Registration Statement, the General Disclosure Package and the Prospectus or (B) those which do not, singly or in the aggregate, materially affect the value of the properties owned by the Company and its Subsidiaries considered as one enterprise and do not interfere in any material respect with the use made and proposed to be made of such properties. All of the leases and subleases material to the business of the Company and its Subsidiaries considered as one enterprise, and under which the Company or any of its Subsidiaries holds properties, are in full force and effect, and neither the Company nor any of its Subsidiaries has received any notice of any material claim of any sort that has been asserted by anyone adverse to the rights of the Company or any of its Subsidiaries under any of the leases or subleases mentioned above, or affecting or questioning the rights of the Company or such Subsidiary of the continued possession of the leased or subleased premises under any such lease or sublease.

(22) Insurance. The Company and its Subsidiaries have in full force and effect insurance with insurers believed to be reputable by the Company, covering their assets, properties, operations, personnel and business against such losses, damage, risks and hazards as are adequate in accordance with customary industry practice to protect the Company and its Subsidiaries considered as one enterprise.

(23) Commodity Exchange Act. The Securities will be excluded or exempted under, or beyond the purview of, the Commodity Exchange Act, as amended (the

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"**Commodity Exchange Act**"), and the rules and regulations of the Commodity Futures Trading Commission under the Commodity Exchange Act (the "**Commodity Exchange Act Regulations**").

(24) Investment Company Act. The Company is not, or upon the issuance and sale of the Securities as herein contemplated and the application of the net proceeds therefrom as described in the Registration Statement, the General Disclosure Package and the Prospectus will not be, an "investment company" within the meaning of the Investment Company Act of 1940, as amended (the "**1940 Act**").

(25) Environmental Laws. Except as otherwise stated in the Registration Statement, the General Disclosure Package and the Prospectus or except as would not, singly or in the aggregate, result in a Material Adverse Change, (A) neither the Company nor any of its Subsidiaries is in violation of any federal, state, local or foreign statute, law, rule, regulation, ordinance, code, policy or rule of common law or any judicial or administrative interpretation thereof, including any judicial or administrative order, consent, decree or judgment, relating to pollution or protection of human health, the environment (including, without limitation, ambient air, surface water, groundwater, land surface or subsurface strata) or wildlife, including, without limitation, laws and regulations relating to the release or threatened release of chemicals, pollutants, contaminants, wastes, toxic substances, hazardous substances, petroleum or petroleum products (collectively, "**Hazardous Materials**") or to the manufacture, processing, distribution, use, treatment, storage, disposal, transport or handling of Hazardous Materials (collectively, "**Environmental Laws**"), (B) the Company and its Subsidiaries have all permits, authorizations and approvals required under any applicable Environmental Laws and are each in compliance with their requirements, (C) there are no pending or threatened administrative, regulatory or judicial actions, suits, demands, demand letters, claims, liens, notices of noncompliance or violation, investigation or proceedings relating to any Environmental Law against the Company or any of its Subsidiaries and (D) there are no events or circumstances known to the Company that might reasonably be expected to form the basis of an order for clean-up or remediation, or an action, suit or proceeding by any private party or governmental body or agency, against or affecting the Company or any of its Subsidiaries relating to Hazardous Materials or any Environmental Laws.

(26) Patriot Act. The Company will apply the net proceeds received from the offering and sale of the Securities as described in the Registration Statement, the General Disclosure Package and the Prospectus and, to the knowledge of the Company, none of such net proceeds will be used to further any action in violation or contravention of the U.S.A. Patriot Act or otherwise violate or contravene the rules, regulations or policies of the U.S. Office of Foreign Assets Control.

(27) Internal Control Over Financial Reporting. The Company and each of its Subsidiaries maintains a system of internal accounting controls sufficient to provide reasonable assurances that (i) transactions are executed in accordance with management's general or specific authorization; (ii) transactions are recorded as necessary to permit preparation of financial statements in conformity with GAAP and to maintain

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accountability for assets; (iii) access to assets is permitted only in accordance with management's general or specific authorization; (iv) the recorded accountability for assets is compared with the existing assets at reasonable intervals and appropriate action is taken with respect to any differences; and (v) the interactive data in eXtensible Business Reporting Language included or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus fairly presents the information called for in all material respects and is prepared in accordance with the Commission's rules and guidelines applicable thereto. Except as described in the Registration Statement, the General Disclosure Package and the Prospectus, since the end of the Company's most recent audited fiscal year, there has been (A) no material weakness in any such party's internal control over financial reporting (whether or not remediated) and (B) no change in any such party's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, such internal control over financial reporting.

(28) Disclosure Controls and Procedures. The Company employs disclosure controls and procedures that are designed to ensure that information required to be disclosed by the Company in the reports that it files or submits under the 1934 Act is recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms and is accumulated and communicated to the Company's management, including its principal executive officer or officers and principal financial officer or officers, as appropriate, to allow timely decisions regarding disclosure.

(29) Compliance with the Sarbanes-Oxley Act. There is and has been no failure on the part of the Company or any of the Company's directors or officers, in their capacities as such, to comply in all material respects with any provision of the Sarbanes-Oxley Act of 2002 and the rules and regulations promulgated in connection therewith, including Section 402 related to loans and Sections 302 and 906 related to certifications.

(30) Pending Proceedings and Examinations. The Registration Statement is not the subject of a pending proceeding or examination under Section 8(d) or 8(e) of the 1933 Act, and the Company is not the subject of a pending proceeding under Section 8A of the 1933 Act in connection with the offering and sale of the Securities.

(31) No Unlawful Contributions or Other Payments. Neither the Company nor any of its Subsidiaries nor, to the knowledge of the Company, any director, officer, agent, employee or affiliate of the Company or any of its Subsidiaries is aware of or has taken any action, directly or indirectly, that would result in a violation by such persons of the Foreign Corrupt Practices Act of 1977, as amended, and the rules and regulations thereunder (the "**FCPA**"), including, without limitation, making use of the mails or any means or instrumentality of interstate commerce corruptly in furtherance of an offer, payment, promise to pay or authorization of the payment of any money, or other property, gift, promise to give, or authorization of the giving of anything of value to any "foreign official" (as such term is defined in the FCPA) or any foreign political party or official thereof or any candidate for foreign political office, in contravention of the FCPA, and the Company, its Subsidiaries and, to the knowledge of the Company, its affiliates have conducted their businesses in compliance with the FCPA and have

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instituted and maintain policies and procedures designed to ensure, and which are reasonably expected to continue to ensure, continued compliance therewith.

(32) No Conflict with Money Laundering Laws. The operations of the Company and its Subsidiaries are and have been conducted at all times in compliance with applicable financial recordkeeping and reporting requirements of the Currency and Foreign Transactions Reporting Act of 1970, as amended, the money laundering statutes of all applicable jurisdictions, the rules and regulations thereunder and any related or similar rules, regulations or guidelines issued, administered or enforced by any governmental agency (collectively, the "**Money Laundering Laws**") and no action, suit or proceeding by or before any court or governmental agency, authority or body or any arbitrator involving the Company or any of its Subsidiaries with respect to the Money Laundering Laws is pending or, to the knowledge of the Company, threatened.

(33) OFAC. Neither the Company nor any of its Subsidiaries, nor, to the knowledge of the Company, any director, officer, agent or employee of the Company or any of its Subsidiaries is currently the subject of any sanctions administered or enforced by the Office of Foreign Assets Control of the U.S. Department of the Treasury or the U.S. Department of State.

(b) Officers' Certificates. Any certificate signed by any officer of the Company or any of its Subsidiaries and delivered to any Underwriter or to counsel for the Underwriters in connection with the offering of the Securities shall be deemed a representation and warranty by the Company to each Underwriter as to the matters covered thereby on the date of such certificate.

SECTION 2. Sale and Delivery to Underwriters; Closing.

(a) The Securities. On the basis of the representations, warranties and agreements herein contained, and upon the terms but subject to the conditions herein set forth, the Company agrees to sell to each Underwriter, severally and not jointly, and each Underwriter agrees, severally and not jointly, to purchase from the Company the aggregate principal amount of the Securities of each series set forth opposite the names of the Underwriters on Schedule 1 at a purchase price of 99.533% of the aggregate principal amount of the 2019 Notes, plus accrued interest thereon, if any, from November 8, 2016 to the Closing Time and 99.210% of the aggregate principal amount of the 2021 Notes, plus accrued interest thereon, if any, from November 8, 2016 to the Closing Time, respectively. The Securities of each series and the offering thereof will have the terms specified in the Final Term Sheet referred to in Section 3(b).

(b) Payment. The Company will deliver against payment of the respective purchase prices set forth in Section 2(a) each series of Securities in the form of permanent global securities (the "**Global Securities**") deposited with the Trustee as custodian for The Depository Trust Company ("**DTC**") and registered in the name of Cede & Co., as nominee for DTC. Interests in any permanent Global Securities will be held only in book-entry form through DTC, except in the limited circumstances described in the General Disclosure Package. Payment for the Securities shall be made by the Underwriters in immediately available funds by wire transfer to an account specified by the Company drawn to the order of the Company at the office of the

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Company, 80 Park Plaza, Newark, New Jersey 07102, or at such other place as shall be agreed upon by the Representatives and the Company, at 9:00 A.M. (New York City time) on November 8, 2016, or such other time and date as the Representatives and the Company shall mutually agree (the time and date of such closing are called (unless postponed in accordance with the provisions of Section 10 hereof) the "**Closing Time**"), against delivery to the Trustee as custodian for DTC of the Global Securities representing all of the Securities.

It is understood that each Underwriter has authorized the Representatives, for their accounts, to accept delivery of, receipt for, and make payment of the respective purchase prices for, the Securities which it has severally agreed to purchase. Each Representative, individually and not as representative of the Underwriters, may (but shall not be obligated to) make payment of the respective purchase prices for the Securities to be purchased by any Underwriter whose funds have not been received by the Closing Time, but such payment shall not relieve such Underwriter from its obligations hereunder.

(c) Denominations; Registration. The Securities shall be in such denominations and registered in such names as the Representatives may request in writing at least one full business day prior to the Closing Time. The Securities will be made available for examination by the Representatives in The City of New York not later than 9:00 A.M. (New York City time) on the business day prior to the Closing Time.

SECTION 3. Covenants of the Company. The Company covenants with each Underwriter as follows:

(a) Compliance with Securities Regulations and Commission Requests. The Company, subject to Section 3(b), will comply with the requirements of Rule 430B and, during the Prospectus Delivery Period (as defined below), will notify the Representatives promptly, and confirm the notice in writing, (i) of the effectiveness of any post-effective amendment to the Registration Statement or of a new registration statement relating to the Securities or the filing of any supplement or amendment to the Prospectus or any preliminary prospectus, (ii) of the receipt of any comments from the Commission, (iii) of any request by the Commission for any amendment to the Registration Statement or the filing of a new registration statement or any amendment or supplement to the Prospectus or any preliminary prospectus or any document incorporated by reference therein or otherwise deemed to be a part thereof or for additional information, (iv) of the issuance by the Commission of any stop order suspending the effectiveness of the Registration Statement or such new registration statement, or notice objecting to its use pursuant to Rule 401(g)(2) of the 1933 Act Regulations, or of any order preventing or suspending the use of any preliminary prospectus or the Prospectus, or of the suspension of the qualification of the Securities for offering or sale in any jurisdiction, or of the initiation or threatening of any proceedings for any of such purposes or of any examination pursuant to Section 8(e) of the 1933 Act concerning the Registration Statement and (v) if the Company becomes the subject of a proceeding under Section 8A of the 1933 Act in connection with the offering of the Securities. The Company will promptly effect the filings necessary pursuant to Rule 424(b), in the manner and within the time period required by Rule 424(b) (without reliance on Rule 424(b)(8)), and will take such steps as it deems necessary to ascertain promptly whether the Prospectus transmitted for filing under Rule 424(b) was received for filing by the Commission and, in the event that it was not, the Company will promptly file the

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Prospectus. The Company will make every reasonable effort to prevent the issuance of any stop order and, if any stop order is issued, promptly to use its best efforts to obtain its withdrawal. The Company agrees to pay the required Commission filing fees relating to the offering of the Securities within the time required by and in accordance with Rule 456(b)(1) and 457(r) of the 1933 Act Regulations.

(b) Filing of Amendments and 1934 Act Documents; Preparation of Final Term Sheet. During such period beginning on the date of this Agreement and ending on the later of the Closing Time or such date as, in the opinion of counsel for the Underwriters, the Prospectus is no longer required by law to be delivered in connection with sales of the Securities by an Underwriter or dealer, including in circumstances where such requirement may be satisfied pursuant to Rule 172 of the 1933 Act Regulations (the "**Prospectus Delivery Period**"), the Company will give the Representatives notice of its intention to file or prepare any amendment to the Registration Statement or a new registration statement relating to the Securities or any amendment, supplement or revision to any preliminary prospectus or to the Prospectus, whether pursuant to the 1933 Act, the 1934 Act or otherwise, will furnish the Representatives with copies of any such documents a reasonable amount of time prior to such proposed filing or use, as the case may be, and will not file or use any such document of which the Representatives or counsel for the Underwriters shall reasonably disapprove. The Company has given the Representatives notice of any filings made pursuant to the 1934 Act or the 1934 Act Regulations within 48 hours prior to the Applicable Time; the Company will give the Representatives notice of its intention to make any such filing from the Applicable Time to the Closing Time and will furnish the Representatives with copies of any such documents a reasonable amount of time prior to such proposed filing and will not file or use any such document to which the Representatives or counsel for the Underwriters shall object. The Company will prepare a final term sheet (the "**Final Term Sheet**") reflecting the final terms of the Securities, in form and substance satisfactory to the Underwriters and attached as Schedule 3 hereto, and will file such Final Term Sheet pursuant to Rule 433(d) within the time required by such rule. The Final Term Sheet is an Issuer Free Writing Prospectus for purposes of this Agreement.

(c) Delivery of Registration Statement. The Company has furnished or will deliver to the Representatives and counsel for the Underwriters, in such quantities as the Representatives may reasonably request, without charge, signed copies of the Registration Statement as originally filed and any amendment thereto (including exhibits filed therewith or incorporated by reference therein and documents incorporated or deemed to be incorporated by reference therein or otherwise deemed to be a part thereof) and signed copies of all consents and certificates of experts, and will also deliver to the Representatives, without charge, a conformed copy of the Registration Statement as originally filed and any amendment thereto (without exhibits) for each of the Underwriters. The Registration Statement and any amendment thereto furnished to the Underwriters will be identical to any electronically transmitted copies thereof filed with the Commission pursuant to EDGAR, except to the extent permitted by Regulation S-T.

(d) Delivery of Prospectuses. The Company will deliver to each Underwriter, without charge, as many copies of each preliminary prospectus and any amendment or supplement thereto as such Underwriter may reasonably request, and the Company hereby consents to the use of such copies for purposes permitted by the 1933 Act. The Company will furnish to each Underwriter, without charge, during the Prospectus Delivery Period, such number of copies of

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the Prospectus (as amended or supplemented) as such Underwriter may reasonably request. Each preliminary prospectus and the Prospectus and any amendments or supplements thereto furnished to the Underwriters will be identical to any electronically transmitted copies thereof filed with the Commission pursuant to EDGAR, except to the extent permitted by Regulation S-T.

(e) Continued Compliance with Securities Laws. The Company will comply with the 1933 Act and the 1933 Act Regulations, the 1934 Act and the 1934 Act Regulations and the 1939 Act and the rules and regulations of the Commission under the 1939 Act so as to permit the completion of the distribution of the Securities as contemplated in this Agreement and in the Registration Statement, the General Disclosure Package and the Prospectus. If at any time during the Prospectus Delivery Period, any event shall occur or condition shall exist as a result of which it is necessary, in the opinion of counsel for the Underwriters or for the Company, to amend the Registration Statement in order that the Registration Statement will not contain an untrue statement of a material fact or omit to state a material fact required to be stated therein or necessary to make the statements therein not misleading or to amend or supplement the General Disclosure Package or the Prospectus in order that such General Disclosure Package or the Prospectus, as the case may be, will not include an untrue statement of a material fact or omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances existing at the Applicable Time or at the time it is delivered or conveyed to a purchaser, not misleading, or if it shall be necessary, in the opinion of such counsel, at any such time to amend the Registration Statement, to file a new registration statement or to amend or supplement the General Disclosure Package or the Prospectus in order to comply with the requirements of the 1933 Act or the 1933 Act Regulations, the Company will: (i) promptly prepare and file with the Commission, subject to Sections 3(b) and 3(k), such amendment or supplement or new registration statement as may be necessary to correct such statement or omission or to make the Registration Statement, the General Disclosure Package or the Prospectus comply with such requirements; (ii) use their best efforts to have such amendment or new registration statement (if it is not an automatic shelf registration statement) declared effective as soon as practicable; and (iii) furnish to the Underwriters, without charge, such number of copies of such amendment or supplement or new registration statement as the Underwriters may reasonably request. If, prior to the completion of the public offer and sale of the Securities, at any time following the issuance of an Issuer Free Writing Prospectus there occurred or occurs an event or development as a result of which such Issuer Free Writing Prospectus conflicted or would conflict with the information then contained in the Registration Statement, any preliminary prospectus or the Prospectus or included or would include an untrue statement of a material fact or omitted or would omit to state a material fact necessary in order to make the statements therein, in the light of the circumstances prevailing at that subsequent time, not misleading, the Company will promptly (i) notify the Representatives and (ii) either (1) amend or supplement such Issuer Free Writing Prospectus to eliminate or correct such conflict, untrue statement or omission or (2) file a report with the Commission under the 1934 Act that corrects such untrue statement or omission and notify the Representatives in writing that such Issuer Free Writing Prospectus shall no longer be used.

(f) Blue Sky Qualifications. The Company will use its best efforts, in cooperation with the Underwriters, to qualify the Securities for offering and sale under the applicable securities laws of such states and other jurisdictions (domestic or foreign) as the Representatives may

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designate and to maintain such qualifications in effect for a period of not less than one year from the date of this Agreement; provided, however, that the Company shall not be obligated to file any general consent to service of process or to qualify as a foreign corporation or as a dealer in securities in any jurisdiction in which it is not so qualified or to subject itself to taxation in respect of doing business in any jurisdiction in which it is not otherwise so subject. In each jurisdiction in which the Securities have been so qualified, the Company will file such statements and reports as may be required by the laws of such jurisdiction to continue such qualification in effect for a period of not less than one year from the date of this Agreement.

(g) Earnings Statement. The Company will timely file such reports pursuant to the 1934 Act as are necessary in order to make generally available to its security holders as soon as practicable an earnings statement for the purposes of, and to provide the benefits contemplated by, the last paragraph of Section 11(a) of the 1933 Act; provided, that the Company will be deemed to have furnished such statement to its security holders to the extent it is filed on EDGAR.

(h) Use of Proceeds. The Company will use the net proceeds received by it from the sale of the Securities in the manner specified in the Registration Statement, the General Disclosure Package and the Prospectus under "Use of Proceeds."

(i) Restriction on Sale of Securities. Between the date of this Agreement and the Closing Time, the Company will not, without the prior written consent of the Representatives, directly or indirectly, issue, sell, offer or contract to sell, grant any option for the sale of, or otherwise dispose of, the Securities.

(j) Reporting Requirements. The Company, during the Prospectus Delivery Period, will file all documents required to be filed with the Commission pursuant to the 1934 Act within the time periods required by the 1934 Act and the 1934 Act Regulations.

(k) Permitted Free Writing Prospectuses. The Company represents and agrees that, unless it obtains the prior consent of the Representatives, and each Underwriter represents and agrees that, unless it obtains the prior consent of the Representatives and the prior consent of the Company, it has not made and will not make any offer relating to the Securities that would constitute an "issuer free writing prospectus," as defined in Rule 433, or that would otherwise constitute a "free writing prospectus," as defined in Rule 405, required to be filed with the Commission; provided, however, that the Underwriters are authorized to use any free writing prospectus that contains substantially only information specified in the Final Term Sheet. Any such free writing prospectus consented to by the Company and the Representatives is hereinafter referred to as a "**Permitted Free Writing Prospectus**." The Company represents that it has treated or agrees that it will treat each Permitted Free Writing Prospectus as an "issuer free writing prospectus," as defined in Rule 433, and has complied and will comply with the requirements of Rule 433 applicable to each and every Permitted Free Writing Prospectus, including timely filing with the Commission where required, legending and record keeping.

(l) Renewal of Registration Statement. If, immediately prior to the third anniversary of the initial effective date of the Registration Statement (the "**Renewal Date**"), any of the Securities remain unsold by the Underwriters, the Company will, prior to the Renewal Date and

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subject to Section 3(b), file, if it has not already done so and is eligible to do so, a new automatic shelf registration statement relating to the Securities. If no longer eligible to file an automatic shelf registration statement, the Company will, prior to the Renewal Date and subject to Section 3(b), if it has not already done so, file a new shelf registration statement relating to the Securities and will use its reasonable best efforts to cause such registration statement to be declared effective within 180 days after the Renewal Date, and will take all other reasonable actions necessary or appropriate to permit the public offering and sale of the Securities to continue as contemplated in the expired registration statement relating to the Securities. References herein to the "**Registration Statement**" shall include such new automatic shelf registration statement or shelf registration statement, as the case may be.

(m) Notice of Inability to Use Automatic Shelf Registration Statement Form. If, at any time during the Prospectus Delivery Period, the Company receives from the Commission a notice pursuant to Rule 401(g)(2) of the 1933 Act Regulations or otherwise ceases to be eligible to use the automatic shelf registration statement form, the Company will (i) promptly notify the Representatives, (ii) promptly file a new registration statement or post-effective amendment on the proper form relating to the Securities, in a form satisfactory to the Representatives, (iii) use its reasonable best efforts to cause such registration statement or post-effective amendment to be declared effective and (iv) promptly notify the Representatives of such effectiveness. The Company will take all other action necessary or appropriate to permit the public offering and sale of the Securities to continue as contemplated in the registration statement that was the subject of the Rule 401(g)(2) notice or for which the Company has otherwise become ineligible. References herein to the Registration Statement shall include such new registration statement or post-effective amendment, as the case may be.

SECTION 4. Payment of Expenses. *(a) Expenses*. The Company will pay all expenses incident to the performance of its obligations under this Agreement, including (i) the preparation, printing and filing of the Registration Statement (including financial statements and exhibits) and any amendment thereto, (ii) the preparation, printing and delivery to the Underwriters of this Agreement, the Indenture and such other documents as may be required in connection with the offering, purchase, sale, issuance or delivery of the Securities, (iii) the preparation, issuance and delivery of the Securities to the Underwriters, including any transfer taxes and any stamp or other duties payable upon the sale, issuance or delivery of the Securities to the Underwriters, (iv) the fees and disbursements of counsel to the Company, accountants and other advisors or agents (including transfer agents and registrars), as well as the fees and disbursements of the Trustee and its counsel, (v) the qualification of the Securities under state securities laws in accordance with the provisions of Section 3(f) hereof, including filing fees and the reasonable fees and disbursements of counsel for the Underwriters in connection therewith and in connection with the preparation, printing and delivery of the Blue Sky Survey, and any amendment thereto, (vi) the printing and delivery to the Underwriters of copies of the Registration Statement, each preliminary prospectus, any Issuer Free Writing Prospectus and the Prospectus and any amendments or supplements thereto, (vii) the fees charged by nationally recognized statistical rating organizations for the rating of the Securities, (viii) the filing fees incident to, and the reasonable fees and disbursements of counsel to the Underwriters in connection with, the review, if any, by the Financial Industry Regulatory Authority ("**FINRA**") of the terms of the sale of the Securities, (ix) all fees and expenses in connection with making the Securities eligible for clearance, settlement and trading through the facilities of DTC, and (x) all other costs and

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expenses incident to the performance of the obligations of the Company hereunder for which provision is not otherwise made in this Section. It is understood, however, that except as provided in this Section, Section 5(j), Section 6, Section 7 and Section 9(b), the Underwriters will pay all of their costs and expenses, including fees and disbursements of their counsel, transfer taxes payable on resale of any of the Securities by them and any advertising expenses connected with any offers they may make.

(b) Termination of Agreement. If this Agreement is terminated by the Representatives in accordance with the provisions of Section 5 hereof, the Company shall reimburse the Underwriters for all of their out of pocket expenses, including the reasonable fees and disbursements of counsel for the Underwriters.

SECTION 5. Conditions of Underwriters' Obligations. The obligations of the Underwriters to purchase and pay for the Securities pursuant to this Agreement are subject to the accuracy of the representations and warranties of the Company contained in Section 1 hereof or in certificates of any officer of the Company or any of its Subsidiaries delivered pursuant to the provisions hereof, to the performance by the Company of its covenants and other obligations hereunder, and to the following further conditions:

(a) Effectiveness of Registration Statement. At Closing Time, (i) the Registration Statement shall have been filed by the Company with the Commission not earlier than three years prior to the date hereof and shall have become effective upon filing in accordance with Rule 462(e), and no stop order suspending the effectiveness of the Registration Statement shall have been issued under the 1933 Act and no proceedings for that purpose or pursuant to Section 8A of the 1933 Act against the Company or related to the offering of the Securities shall have been instituted or be pending or threatened by the Commission, any request on the part of the Commission for additional information shall have been complied with to the reasonable satisfaction of counsel for the Underwriters, and no notice of objection of the Commission to the use of such form of registration statement or any post-effective amendment thereto pursuant to Rule 401(g)(2) of the 1933 Act Regulations shall have been received by the Company, (ii) each preliminary prospectus and the Prospectus shall have been filed with the Commission in the manner and within the time period required by Rule 424(b) without reliance on Rule 424(b)(8) (or a post-effective amendment providing such information shall have been filed and become effective in accordance with the requirements of Rule 430B) and (iii) the Final Term Sheet and any other material required to be filed by the Company pursuant to Rule 433(d) shall have been filed with the Commission within the applicable time periods prescribed for such filings under such Rule 433.

(b) Opinion of Counsel for Company. At Closing Time, the Representatives shall have received the favorable opinion, dated as of Closing Time, of either Tamara L. Linde, Esquire, Executive Vice President and General Counsel of the Company, or Shawn P. Leyden, Esquire, Vice President and Deputy General Counsel of PSEG Services Corporation, in form and substance satisfactory to counsel for the Underwriters, together with signed or reproduced copies of such letter for each of the other Underwriters, to the effect set forth in Exhibit A hereto and to such further effect as counsel to the Underwriters may reasonably request.

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(c) Opinion of Counsel for Underwriters. At Closing Time, the Representatives shall have received the favorable opinion, dated as of Closing Time, of Sidley Austin llp, counsel for the Underwriters, together with signed or reproduced copies of such letter for each of the other Underwriters, in form and substance satisfactory to the Representatives. In giving such opinion, such counsel may rely, as to all matters governed by the laws of the State of New Jersey, upon the opinion, dated as of Closing Time, of either Tamara L. Linde, Esquire, Executive Vice President and General Counsel of the Company, or Shawn P. Leyden, Esquire, Vice President and Deputy General Counsel of the Company, and as to all matters governed by the laws of other jurisdictions other than the law of the State of New York and the federal law of the United States, upon the opinions of counsel satisfactory to the Representatives. Such counsel may also state that, insofar as such opinion involves factual matters, they have relied, to the extent they deem proper, upon certificates of officers of the Company and its Subsidiaries and certificates of public officials.

(d) Officer's Certificate. At Closing Time, there shall not have been, since the date of this Agreement or since the respective dates as of which information is given in the Registration Statement, the General Disclosure Package or the Prospectus, any Material Adverse Change, and the Representatives shall have received a certificate of the Chairman, the President or any Vice President of the Company, dated as of Closing Time, to the effect that (i) there has been no such Material Adverse Change, (ii) the representations and warranties in Section 1(a) are true and correct with the same force and effect as though expressly made at and as of the Closing Time, (iii) the Company has complied with all agreements contained in this Agreement and satisfied all conditions on its part to be performed or satisfied at or prior to the Closing Time, and (iv) no stop order suspending the effectiveness of the Registration Statement has been issued and no proceedings for that purpose or pursuant to Section 8A of the 1933 Act against the Company or relating to the offering have been instituted, are pending or, to the best of such officer's knowledge, are threatened by the Commission.

(e) Accountant's Comfort Letter. At the Execution Time, the Representatives shall have received from Deloitte & Touche LLP, independent registered public accountants for the Company, a letter, dated as of the date hereof addressed to the Underwriters, in form and substance satisfactory to the Representatives, together with signed or reproduced copies of such letter for each of the other Underwriters, with respect to the audited and unaudited financial statements and certain financial information contained or incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus.

(f) Bring-down Comfort Letter. At Closing Time, the Representatives shall have received from Deloitte & Touche LLP, independent registered public accountants for the Company, a letter, dated as of Closing Time addressed to the Underwriters, in form and substance satisfactory to the Representatives, together with signed or reproduced copies of such letter for each of the other Underwriters to the effect that they reaffirm the statements made in the letter furnished pursuant to subsection (e) of this Section 5, except that the specified date referred to shall be a date not more than three business days prior to the Closing Time.

(g) Ratings. At Closing Time, the Securities shall have the ratings accorded by any "nationally recognized statistical rating organization," as defined in Section 3(a)(62) of the 1934 Act, as specified in the Final Term Sheet, and the Company shall have delivered to the

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Representatives a letter, dated as of such date, from each such rating organization, or other evidence satisfactory to the Representatives, confirming that the Securities have such ratings. Since the Execution Time, there shall not have occurred a downgrading in, or withdrawal of, the rating assigned to the Securities or any of the Company's other securities by any such rating organization, and no such rating organization shall have publicly announced or given notice of any intended or potential decrease in or withdrawal of any such rating or of a possible change in any such rating that does not indicate the direction of the possible change.

(h) No Objection. If the Registration Statement or the offering of the Securities has been filed with FINRA for review, FINRA shall not have raised any objection with respect to the fairness and reasonableness of the underwriting terms and arrangements.

(i) Additional Documents. At Closing Time, counsel for the Underwriters shall have been furnished with such documents and opinions as they may require for the purpose of enabling them to pass upon the issuance and sale of the Securities as herein contemplated, or in order to evidence the accuracy of any of the representations or warranties, or the fulfillment of any of the conditions, herein contained; and all proceedings taken by the Company in connection with the issuance and sale of the Securities as herein contemplated shall be satisfactory in form and substance to the Representatives and counsel for the Underwriters.

(j) Termination. If any condition specified in this Section 5 shall not have been fulfilled when and as required to be fulfilled, this Agreement may be terminated by the Representatives by notice to the Company at any time at or prior to the Closing Time, and such termination shall be without liability of any party to any other party except as provided in Section 4 and except that Sections 1, 6, 7, 8 and 14 shall survive any such termination and remain in full force and effect.

SECTION 6. Indemnification.

(a) Indemnification of Underwriters. The Company agrees to indemnify and hold harmless each Underwriter and their respective partners, directors and officers and each person, if any, who controls any Underwriter (collectively, "**Underwriter Indemnified Parties**") within the meaning of Section 15 of the 1933 Act or Section 20 of the 1934 Act as follows:

(i) against any and all loss, liability, claim, damage and expense whatsoever, as incurred, arising out of any untrue statement or alleged untrue statement of a material fact contained in the Registration Statement (or any amendment thereto) or the omission or alleged omission therefrom of a material fact required to be stated therein or necessary to make the statements therein not misleading or arising out of any untrue statement or alleged untrue statement of a material fact contained in any preliminary prospectus, any Issuer Free Writing Prospectus or the Prospectus (or any amendment or supplement thereto) or in any "issuer information" (as defined in Rule 433) of the Company that is filed or required to be filed under Rule 433(d) or the omission or alleged omission therefrom of a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading;

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(ii) against any and all loss, liability, claim, damage and expense whatsoever, as incurred, to the extent of the aggregate amount paid in settlement of any litigation, or any investigation or proceeding by any governmental agency or body, commenced or threatened, or of any claim whatsoever based upon any such untrue statement or omission referred to in subsection (i) above or any alleged untrue statement or omission, if such settlement is effected with the written consent of the Company; and

(iii) against any and all expense whatsoever, as incurred, reasonably incurred in investigating, preparing or defending against any litigation, or any investigation or proceeding by any governmental agency or body, commenced or threatened, or any claim whatsoever based upon any such untrue statement or omission, or any such alleged untrue statement or omission, to the extent that any such expense is not paid under (i) or (ii) above;

provided, however, that this indemnity agreement shall not apply to any loss, liability, claim, damage or expense to the extent arising out of any untrue statement or omission or alleged untrue statement or omission made in reliance upon and in conformity with written information furnished to the Company by any Underwriter through the Representatives expressly for use in the Registration Statement (or any amendment thereto) or any preliminary prospectus, any Issuer Free Writing Prospectus or the Prospectus (or any amendment or supplement thereto) or made in reliance upon the Trustee's Statement of Eligibility filed as an exhibit to the Registration Statement. The Company and the Underwriters hereby acknowledge and agree that the only written information furnished to the Company by any Underwriter through the Representatives expressly for use in the Registration Statement (or any amendment thereto) or any preliminary prospectus, any Issuer Free Writing Prospectus or the Prospectus (or any amendment or supplement thereto) are the statements set forth in the (x) first, second and third sentences of the third paragraph, (y) second sentence of the fifth paragraph and (z) first, second, third, fourth and sixth sentences of the sixth paragraph, in each case under the caption "Underwriting" in the Prospectus (collectively, the "**Underwriter Information**").

(b) In no case shall the Company be liable under the indemnity agreement set forth in Section 6(a) hereof with respect to any claim made against any Underwriter Indemnified Party unless such party shall be notified in writing of the nature of the claim promptly after the assertion thereof, but failure to so notify such party shall not relieve it from any liability which it may have otherwise than on account of said indemnity agreement. The Company shall be entitled to participate at its own expense in the defense, or, if the Company so elects, within a reasonable time after receipt of such notice, to assume the defense of any suit brought to enforce any such claim, but if they so elect to assume the defense, such defense shall be conducted by counsel chosen by the Company and approved by the Underwriter Indemnified Parties who are party to such suit, which approval shall not be unreasonably withheld. In the event that the Company elects to assume the defense of any such suit and retain such counsel, the Underwriter Indemnified Parties who are party to such suit shall bear the fees and expenses of any additional counsel thereafter retained by them. In the event that the parties to any such action (including impleaded parties) include the Company and one or more Underwriters and any such Underwriter shall have been advised by counsel chosen by it and satisfactory to the Company, as the case may be, that there may be one or more legal defenses available to it which are different from or additional to those available to the Company, the Company shall not have the right to

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assume the defense of such action on behalf of such Underwriter and the Company will reimburse, without duplication, such Underwriter Indemnified Parties as aforesaid for the reasonable fees and expenses of any counsel retained by them, it being understood that the Company shall not, in connection with any one action or separate but similar or related actions in the same jurisdiction arising out of the same general allegations or circumstances, be liable for the reasonable fees and expenses of more than one separate firm of attorneys for all such Underwriter Indemnified Parties, which firm shall be designated by the Representatives in writing. The Company agrees to notify the Representatives promptly after the assertion of any claim against it, any of its directors, any of its officers who signed the Registration Statement, or any person who controls the Company within the meaning of Section 15 of the 1933 Act or Section 20 of the 1934 Act, in connection with the offering and sale of the Securities.

(c) Indemnification of the Company, Directors and Officers. The Underwriters, severally and not jointly, agree to indemnify and hold harmless the Company, its directors, each of its officers who signed the Registration Statement, and each person, if any, who controls the Company within the meaning of Section 15 of the 1933 Act or Section 20 of the 1934 Act against any and all loss, liability, claim, damage and expense described in the indemnity contained in subsection (a) of this Section, as incurred, but only with respect to untrue statements or omissions, or alleged untrue statements or omissions, made in the Registration Statement (or any amendment thereto) or any preliminary prospectus, any Issuer Free Writing Prospectus or the Prospectus (or any amendment or supplement thereto) in reliance upon and in conformity with the Underwriter Information. In case any action shall be brought against the Company or any person so indemnified based on the Registration Statement (or any amendment thereto) or such preliminary prospectus, such Issuer Free Writing Prospectus or the Prospectus (or any amendment or supplement thereto) and in respect of which indemnity may be sought against any Underwriter, such Underwriter shall have the rights and duties given to the Company, and the Company and each person so indemnified shall have the rights and duties given to the Underwriters by the provisions of Section 6(b) hereof.

(d) The indemnity agreements contained in this Section 6 shall remain operative and in full force and effect, regardless of any investigation made by or on behalf of the Company or any Underwriter Indemnified Parties, and shall survive the delivery of the Securities to the Underwriters.

(e) Settlement. No indemnifying party shall, without the prior written consent of the indemnified parties, settle or compromise or consent to the entry of any judgment with respect to any litigation, or any investigation or proceeding by any governmental agency or body, commenced or threatened, or any claim whatsoever in respect of which indemnification or contribution could be sought under this Section 6 or Section 7 hereof (whether or not the indemnified parties are actual or potential parties thereto), unless such settlement, compromise or consent (i) includes an unconditional release of each indemnified party from all liability arising out of such litigation, investigation, proceeding or claim and (ii) does not include a statement as to or an admission of fault, culpability or a failure to act by or on behalf of any indemnified party.

SECTION 7. Contribution. In order to provide for just and equitable contribution in circumstances in which the indemnity agreement provided for in Section 6 is for any reason held

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to be unenforceable by the indemnified parties although applicable in accordance with its terms, the Company and the Underwriters shall contribute to the aggregate losses, liabilities, claims, damages and expenses of the nature contemplated by said indemnity agreements incurred by the Company and the Underwriters, in such proportions that the Underwriters are responsible for that portion represented by the percentage that the total underwriting discounts appearing on the cover page of the Prospectus relating to the Securities bears to the respective aggregate initial public offering prices appearing thereon and the Company is responsible for the balance; provided, however, that (i) no Underwriter shall be required to contribute any amount in excess of the amount by which the total discount or commission received by such Underwriter in connection with the offering of the Securities exceeds the amount of any damages which such Underwriter has otherwise been required to pay by reason of any applicable untrue or alleged untrue statement or omission or alleged omission and (ii) no person guilty of fraudulent misrepresentation (within the meaning of Section 11(f) of the 1933 Act) shall be entitled to contribution from any person who was not guilty of such fraudulent misrepresentation. For purposes of this Section, each Underwriter Indemnified Party shall have the same rights to contribution as the Underwriters, and each director of the Company, each officer of the Company who signed the Registration Statement, and each person, if any, who controls the Company within the meaning of Section 15 of the 1933 Act or Section 20 of the 1934 Act shall have the same rights to contribution as the Company. The Underwriters' respective obligations to contribute pursuant to this Section 7 are several in proportion to their respective underwriting obligations, and not joint.

SECTION 8. Representations, Warranties and Agreements to Survive Delivery. All representations, warranties and agreements contained in this Agreement or in certificates of officers of the Company or any of its Subsidiaries submitted pursuant hereto or thereto shall remain operative and in full force and effect, regardless of any investigation made by or on behalf of any Underwriter or controlling person, or by or on behalf of the Company, and shall survive delivery of and payment for the Securities.

In all dealings hereunder, the Representatives shall act on behalf of each of the Underwriters, and the parties hereto shall be entitled to act and rely upon any statement, request, notice or agreement on behalf of any Underwriter made or given by the Representatives or by the Representatives on behalf of the Underwriters.

SECTION 9. Termination.

(a) The Representatives may terminate this Agreement, by notice to the Company, at any time at or prior to the Closing Time, (i) if there has been, since the time of execution of this Agreement or since the respective dates as of which information is given in the Registration Statement, the General Disclosure Package or the Prospectus, any Material Adverse Change, or (ii) if there has occurred any material adverse change in the financial markets in the United States, any outbreak of hostilities or escalation thereof or other calamity or crisis or any change or development involving a prospective change in national or international political, financial or economic conditions, in each case the effect of which is such as to make it, in the judgment of the Underwriters, impracticable or inadvisable to market the Securities or to enforce contracts for the sale of the Securities, or (iii) if trading in any securities of the Company has been suspended or materially limited by the Commission or the New York Stock Exchange, or if trading

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generally on the NYSE MKT or the New York Stock Exchange or in the Nasdaq Stock Market has been suspended or materially limited, or minimum or maximum prices for trading have been fixed, or maximum ranges for prices have been required, by any of said exchanges or by such system or by order of the Commission, FINRA or any other governmental authority, or a material disruption has occurred in commercial banking or settlement or clearance services in the United States, or (iv) if a banking moratorium has been declared by either federal or New York authorities or (v) if the rating accorded the Securities or any debt securities or other security of the Company by any nationally recognized statistical rating organization shall have been decreased or withdrawn or any such rating organization has publicly announced or given notice of any intended or potential decrease in or withdrawal of any such rating or of a possible change in any such rating that does not indicate the direction of the possible change.

(b) Liabilities. If this Agreement is terminated pursuant to this Section 9, such termination shall be without liability of any party to any other party except as provided in Section 4 hereof, and provided further that Sections 1, 6, 7, 8 and 14 shall survive such termination and remain in full force and effect.

SECTION 10. Default by One or More of the Underwriters. If one or more of the Underwriters shall fail at the Closing Time to purchase the Securities of either series which it or they are obligated to purchase hereunder (the unpurchased securities of such series, the "**Defaulted Securities**"), then the Representatives shall have the right, within 36 hours thereafter, to make arrangements for one or more of the non-defaulting Underwriters, or any other underwriters, to purchase all, but not less than all, of the Defaulted Securities in such amounts as may be agreed upon and upon the terms herein set forth; if, however, the Representatives shall not have completed such arrangements within such 36-hour period, then:

(a) if the aggregate principal amount of Defaulted Securities does not exceed 10% of the aggregate principal amount of Securities of such series to be purchased on such date, the non-defaulting Underwriters shall be obligated, severally and not jointly, to purchase the full amount thereof in the proportions that their respective underwriting obligations under this Agreement bear to the underwriting obligations of all non-defaulting Underwriters; or

(b) if the aggregate principal amount of Defaulted Securities exceeds 10% of the aggregate principal amount of Securities of such series to be purchased on such date, this Agreement shall terminate with respect to the Securities of such series without liability on the part of any non-defaulting Underwriter.

No action taken pursuant to this Section 10 shall relieve any defaulting Underwriter from liability in respect of its default.

In the event of any such default which does not result in a termination of this Agreement, either the Representatives, on the one hand, or the Company, on the other, shall have the right to postpone the Closing Time for a period not exceeding seven days in order to effect any required changes in the Registration Statement, the General Disclosure Package or the Prospectus or in any other documents or arrangements.

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SECTION 11. No Advisory or Fiduciary Relationship. The Company acknowledges and agrees that (a) the purchase and sale of the Securities pursuant to this Agreement, including the determination of the respective public offering prices of the Securities and any related discounts and commissions, is an arm's-length commercial transaction among the Company, on the one hand, and the Underwriters, on the other hand, (b) in connection with the offering contemplated by this Agreement and the process leading to such transaction, each Underwriter is and has been acting solely as a principal and is not the agent or fiduciary of the Company, or its stockholders, creditors, employees or any other party, (c) no Underwriter has assumed or will assume an advisory or fiduciary responsibility in favor of the Company with respect to the offering contemplated hereby or the process leading thereto (irrespective of whether such Underwriter has advised or is currently advising the Company on other matters) and no Underwriter has any obligation to the Company with respect to the offering contemplated by this Agreement except the obligations expressly set forth in this Agreement, (d) the Underwriters and their respective affiliates may be engaged in a broad range of transactions that involve interests that differ from those of the Company and (e) no Underwriter has provided any legal, accounting, regulatory or tax advice with respect to the offering contemplated by this Agreement and the Company has consulted its own legal, accounting, regulatory and tax advisors to the extent it deemed appropriate.

SECTION 12. Notices. All notices and other communications hereunder shall be in writing and shall be deemed to have been duly given if mailed or transmitted by any standard form of telecommunication. Notices to the Underwriters shall be directed to the Representatives c/o J.P. Morgan Securities LLC, 383 Madison Avenue, 3rd Floor, New York, New York 10179, Attention: Investment Grade Syndicate Desk, Telecopy: (212) 834-6081; Barclays Capital Inc., 745 Seventh Avenue, New York, New York 10019, Attention: Syndicate Registration, Telecopy: (636) 834-8133; RBC Capital Markets, LLC, 200 Vesey Street, New York, New York, 10281, Attention: DCM Transaction Management, Telecopy: (212) 658-6137, and notices to the Company shall be directed to it at 80 Park Plaza, P.O. Box 1171, Newark, New Jersey 07101, attention of Tamara L. Linde, Esq.

SECTION 13. Parties. This Agreement shall inure to the benefit of and be binding upon the Company and the Underwriters and their respective successors. Nothing expressed or mentioned in this Agreement is intended or shall be construed to give any person, firm or corporation, other than the Underwriters, the Company and their respective successors and the controlling persons and officers and directors referred to in Sections 6 and 7 and their heirs and legal representatives, any legal or equitable right, remedy or claim under or in respect of this Agreement or any provision herein or therein contained. This Agreement and all conditions and provisions hereof and thereof are intended to be for the sole and exclusive benefit of the parties hereto and thereto and their respective successors, and said controlling persons and officers and directors and their heirs and legal representatives, and for the benefit of no other person, firm or corporation. No purchaser of Securities from any Underwriter shall be deemed to be a successor by reason merely of such purchase.

SECTION 14. GOVERNING LAW AND TIME. THIS AGREEMENT SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK. SPECIFIED TIMES OF DAY REFER TO NEW YORK CITY TIME.

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SECTION 15. Patriot Act. In accordance with the requirements of the USA Patriot Act (Title III of Pub. L. 107-56 (signed into law October 26, 2001)), the Underwriters are required to obtain, verify and record information that identifies their respective clients, including the Company, which information may include the name and address of their respective clients, as well as other information that will allow the Underwriters to properly identify their respective clients.

SECTION 16. Counterparts. This Agreement may be signed in one or more counterparts, each of which shall constitute an original and all of which together shall constitute one and the same agreement.

SECTION 17. Effect of Headings. The Article and Section headings herein are for convenience only and shall not affect the construction hereof.

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If the foregoing is in accordance with your understanding of our agreement, please sign and return to the Company a counterpart hereof, whereupon this Agreement, along with all counterparts, will become a binding agreement in accordance with its terms.

Very truly yours,

Public Service Enterprise Group Incorporated

By: /s/ Bradford Huntington
Name: Bradford Huntington
Title: Vice President and Treasurer

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Confirmed and accepted as of the
date first above written:

BARCLAYS CAPITAL INC.

By: /s/ Robert A. Stowe
Name: Robert A. Stowe
Title: Managing Director

J.P. MORGAN SECURITIES LLC

By: /s/ Som Bhattacharyya
Name: Som Bhattacharyya
Title: Vice President

RBC CAPITAL MARKETS, LLC

By: /s/ Scott G. Primrose
Name: Scott G. Primrose
Title: Authorized Signatory

Acting on behalf of themselves and as representatives
of the other named Underwriters

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SCHEDULE 1

Underwriters and Principal Amount of Securities

Underwriters	Aggregate Principal Amount of 2019 Notes to be Purchased	Aggregate Principal Amount of 2021 Notes to be Purchased
Barclays Capital Inc.	$ 73,000,000	$ 54,750,000
J.P. Morgan Securities LLC	73,000,000	54,750,000
RBC Capital Markets, LLC	73,000,000	54,750,000
Scotia Capital (USA) Inc.	48,000,000	36,000,000
Wells Fargo Securities, LLC	48,000,000	36,000,000
CIBC World Markets Corp.	24,000,000	18,000,000
Citigroup Global Markets Inc.	24,000,000	18,000,000
TD Securities (USA) LLC	24,000,000	18,000,000
MFR Securities, Inc.	13,000,000	9,750,000
Total	$ 400,000,000	$ 300,000,000

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SCHEDULE 2-A

Schedule of Issuer Free Writing Prospectuses included in the General Disclosure Package

1. The Final Term Sheet attached as Schedule 3 to this Agreement.

SCHEDULE 2-B

Issuer Limited Use Free Writing Prospectuses

1. Investor Presentation, dated November 3, 2016

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SCHEDULE 3

Filed Pursuant to Rule 433
dated November 3, 2016
Relating to
Preliminary Prospectus Supplement
dated November 3, 2016 and
Prospectus dated November 18, 2014
Registration Statement No. 333-200352

Final Term Sheet

$700,000,000

Public Service Enterprise Group Incorporated

$400,000,000 1.600% Senior Notes due 2019
$300,000,000 2.000% Senior Notes due 2021

November 3, 2016

Issuer:	Public Service Enterprise Group Incorporated	
Trade Date:	November 3, 2016	
Settlement Date:	November 8, 2016	
Proceeds to Issuer Before Expenses:	$695,762,000	
Security:	1.600% Senior Notes due 2019	2.000% Senior Notes due 2021
Ratings*:		
Security Type:	Senior Unsecured Fixed Rate Notes	Senior Unsecured Fixed Rate Notes
Principal Amount:	$400,000,000	$300,000,000
Maturity Date:	November 15, 2019	November 15, 2021
Coupon:	1.600% per annum	2.000% per annum
Interest Payment Dates:	The 15th of each May and November, beginning May 15, 2017	The 15th of each May and November, beginning May 15, 2017
Redemption Provisions:	At any time prior to the maturity date, at a price equal to the greater of (a) 100% of the principal amount of the 2019 Senior Notes being redeemed and (b) the sum of the present values of the remaining	At any time prior to October 15, 2021, at a price equal to the greater of (a) 100% of the principal amount of the 2021 Senior Notes being redeemed and (b) the sum of the present values of the remaining

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	scheduled payments of principal of and interest on the 2019 Senior Notes being redeemed that would be due on the maturity date, exclusive of accrued interest to the redemption date, discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the treasury rate plus 15 basis points (0.15%), plus any accrued and unpaid interest on the principal amount of the 2019 Senior Notes being redeemed to, but excluding, the redemption date.	scheduled payments of principal of and interest on the 2021 Senior Notes being redeemed that would be due if the 2021 Senior Notes matured on October 15, 2021, exclusive of accrued interest to the redemption date, discounted to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the treasury rate plus 15 basis points (0.15%), plus any accrued and unpaid interest on the principal amount of the 2021 Senior Notes being redeemed to, but excluding, the redemption date. At any time on and after October 15, 2021, at a price equal to 100% of the principal amount of the 2021 Senior Notes being redeemed, plus any accrued and unpaid interest on the principal amount of the 2021 Senior Notes being redeemed to, but excluding, the redemption date.
Benchmark Treasury:	1.000% due October 15, 2019	1.250% due October 31, 2021
Benchmark Treasury Yield:	0.960%	1.260%
Re-offer Spread to Benchmark:	68 basis points	78 basis points
Re-offer Yield:	1.640%	2.040%
Price to Public:	99.883% of Principal Amount	99.810% of Principal Amount
CUSIP / ISIN:	744573 AJ5 / US744573AJ58	744573 AK2 / US744573AK22
Joint Book-Running Managers:	Barclays Capital Inc. J.P. Morgan Securities LLC RBC Capital Markets, LLC Scotia Capital (USA) Inc. Wells Fargo Securities LLC	Barclays Capital Inc. J.P. Morgan Securities LLC RBC Capital Markets, LLC Scotia Capital (USA) Inc. Wells Fargo Securities LLC
Co-Managers:	CIBC World Markets Corp. Citigroup Global Markets Inc. MFR Securities, Inc. TD Securities (USA) LLC	CIBC World Markets Corp. Citigroup Global Markets Inc. MFR Securities, Inc. TD Securities (USA) LLC

* Note: A securities rating is not a recommendation to buy, sell or hold securities and may be subject to revision, suspension or withdrawal at any time. Each credit rating should be evaluated independently of any other credit rating.

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The Issuer has filed a registration statement (including a prospectus) and a preliminary prospectus supplement with the SEC for the offering to which this communication relates. Before you invest, you should read the prospectus in that registration statement, the preliminary prospectus supplement and the other documents the Issuer has filed with the SEC for more complete information about the Issuer and the offering. You may get these documents for free by visiting EDGAR on the SEC's website at www.sec.gov. Alternatively, any underwriter or any dealer participating in the offering will arrange to send you these documents if you request them by calling Barclays Capital Inc. toll-free at 1-888-603-5847, J.P. Morgan Securities LLC collect at 1-212-834-4533 or RBC Capital Markets, LLC toll-free at 1-866-375-6829.

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EXHIBIT A

FORM OF OPINION OF COUNSEL FOR THE COMPANY
TO BE DELIVERED PURSUANT TO
SECTION 5(b)

On the basis of the foregoing and of my examination and consideration of such other legal and factual matters as I have deemed appropriate, I am of the opinion that:

(i) The Company has been duly incorporated and is validly existing as a corporation in good standing under the laws of the State of New Jersey and has the requisite power and authority to own, lease and operate its properties, to conduct its business as described in the Registration Statement, the General Disclosure Package (as defined in Annex A hereto), and the Prospectus and to enter into and perform its obligations under, or as contemplated under, the Underwriting Agreement.

(ii) Each Significant Subsidiary has been duly incorporated or organized and is validly existing as a corporation or limited liability company in good standing under the laws of the jurisdiction of its incorporation or organization, has the requisite power and authority to own, lease and operate its properties and to conduct its business as described in the Registration Statement, the General Disclosure Package and the Prospectus.

(iii) To the best of my knowledge, the Company and each Significant Subsidiary is duly qualified as a foreign corporation or limited liability company to transact business and is in good standing in each jurisdiction in which such qualification is required, whether by reason of the ownership or leasing of property or the conduct of business, except where the failure to so qualify and be in good standing would not have a material adverse effect on the financial condition, business or properties of the Company and its Subsidiaries considered as one enterprise.

(iv) The authorized, issued and outstanding shares of capital stock of the Company is as set forth in the Company's Annual Report on Form 10-K for the year ended December 31, 2015 and subsequent Quarterly Report on Form 10-Q for the quarter ended September 30, 2016 (except for subsequent issuances thereof, if any, pursuant to reservations, agreements or employee benefit plans referred to in the Registration Statement, the General Disclosure Package and the Prospectus or pursuant to the exercise of convertible securities or options referred to in the Registration Statement, the General Disclosure Package and the Prospectus). Such shares of capital stock have been duly authorized and validly issued by the Company and are fully paid and non-assessable, and none of such shares of capital stock were issued in violation of preemptive or other similar rights of any security holder of the Company.

(v) All of the shares of capital stock or other equity interests of each Significant Subsidiary have been duly and validly authorized and issued, are fully paid and non-assessable (except in the case of a limited liability company), and are owned directly by the Company or another Subsidiary, as the case may be, free and clear

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of all liens, encumbrances, equities or claims. None of the outstanding shares of capital stock or other equity interests of any Significant Subsidiary were issued in violation of preemptive or other similar rights of any security holder of such Significant Subsidiary.

(vi) The Underwriting Agreement has been duly authorized, executed and delivered by the Company.

(vii) The Indenture has been duly authorized, executed and delivered by the Company and (assuming the Indenture has been duly authorized, executed and delivered by the Trustee) constitutes a valid and legally binding agreement of the Company, enforceable against each of them in accordance with its terms, subject to applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium and similar laws affecting creditors' rights and remedies generally, and subject, as to enforceability, to general principles of equity, including principles of commercial reasonableness, good faith and fair dealing (regardless of whether enforcement is sought in a proceeding at law or in equity).

(viii) The Securities have been duly authorized and executed by the Company pursuant to the Underwriting Agreement and, when delivered pursuant to the provisions of the Underwriting Agreement and the Indenture against the requisite payment therefor (assuming the due authentication thereof by the Trustee), will constitute valid and legally binding obligations of the Company enforceable against the Company in accordance with their terms, subject to applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium and similar laws affecting creditors' rights and remedies generally, and subject, as to enforceability, to general principles of equity, including principles of commercial reasonableness, good faith and fair dealing (regardless of whether enforcement is sought in a proceeding at law or in equity). The registered holders of the Securities will be entitled to the benefit of the Indenture.

(ix) The statements in (i) the Registration Statement, the General Disclosure Package and the Prospectus under the captions "Description of the Senior Notes" and "Description of the Senior and Subordinated Debt Securities," (ii) the Company's Annual Report on Form 10-K for the year ended December 31, 2015, under the captions (A) Part I, Item 1. Business – Regulatory Issues, (B) Part I, Item 1. Business – Environmental Matters, and (C) Part I, Item 3. Legal Proceedings and (iii) the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2016 under the caption Part II, Item 1. Legal Proceedings and Part II, Item 5. Other Information, in each case including the information incorporated by reference in such section and insofar as such statements constitute summaries of the legal matters, documents or proceedings referred to therein, fairly summarize the matters referred to therein in all material respects.

(x) The Indenture has been duly qualified under the Trust Indenture Act of 1939, as amended, and the regulations thereunder (the "1939 Act").

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(xi) The Registration Statement is effective under the 1933 Act and, to the best of my knowledge, no stop order suspending the effectiveness of the Registration Statement or the use of any prospectus relating to the Securities has been issued under the 1933 Act or proceedings therefor initiated or threatened by the SEC or any other governmental agency or authority.

(xii) The Registration Statement (except for the financial statements and the related notes thereto, the financial statement schedules or the financial or accounting data incorporated by reference therein or Exhibits 25-1 and 25-2 thereto, as to which I express no opinion), as of its most recent effective date pursuant to Rule 430B(f)(2), and the Prospectus (except for the financial statements and the related notes thereto, the financial statement schedules or the financial or accounting data incorporated by reference therein, as to which I express no opinion), as of November 3, 2016, appeared on their face to be appropriately responsive, in all material respects relevant to the offering of the Securities, to the applicable requirements of the 1933 Act;

(xiii) Each document filed pursuant to the Securities Exchange Act of 1934 and the regulations thereunder (the "1934 Act") and incorporated by reference in the Registration Statement, the General Disclosure Package and the Prospectus appeared on its face, at the time it was filed, to be appropriately responsive in all material respects with the applicable requirements of the 1934 Act.

(xiv) To the best of my knowledge, none of the Company nor any Significant Subsidiary is in violation of its certificate of incorporation or by-laws or other organizational documents, or in default in the performance or observance of any obligation, agreement, covenant or condition contained in any material contract, indenture, mortgage, loan agreement, note or lease to which it is a party or by which it or any its properties may be bound.

(xv) The execution and delivery of the Underwriting Agreement, the Indenture and the Securities, and the consummation by the Company of the transactions contemplated thereby, will not conflict with, violate or constitute a breach of, or default under, or, except as contemplated thereby, result in the creation or imposition of: (A) any lien, charge or encumbrance upon any property or assets of the Company or any Significant Subsidiary pursuant to, any contract, indenture, mortgage, loan agreement, note, lease or other instrument known to me and to which the Company or any Significant Subsidiary is a party or by which it may be bound or to which any of the property or assets of the Company or any Significant Subsidiary is subject; (B) any law, administrative regulation or administrative or court decree known to me to be applicable to the Company or any Significant Subsidiary of any court or governmental agency, authority or body or any arbitrator having jurisdiction over the Company or any Significant Subsidiary (other than federal and state securities or blue sky laws, as to which I express no opinion in this paragraph), or (C) the

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certificate of incorporation or by-laws or other organizational documents of the Company or any Significant Subsidiary.

(xvi) No consent, approval, waiver, license or authorization or other action by or filing with any New York, New Jersey or federal governmental authority is required in connection with the execution and delivery by the Company of the Underwriting Agreement, the Indenture and the Securities, the consummation by the Company of the transactions contemplated thereby or the performance by the Company of its obligations thereunder, except for filings and other actions required pursuant to the 1933 Act and/or the 1934 Act and the rules and regulations thereunder and federal and state securities or blue sky laws, as to which I express no opinion in this paragraph.

(xvii) To the best of my knowledge, except as disclosed in the Registration Statement, the General Disclosure Package and the Prospectus, there is not pending or threatened any action, suit, proceeding, inquiry or investigation to which the Company or any Subsidiary is a party or to which the assets, properties or operations of the Company or any Subsidiary is subject, before or by any court or governmental agency or body, domestic or foreign, which might reasonably be expected to result in a Material Adverse Change or which might reasonably be expected to materially and adversely affect the assets, properties or operations thereof or the consummation of the transactions contemplated under the Underwriting Agreement, the Securities or the Indenture or the performance by the Company of its obligations thereunder.

(xviii) The Company is not, and immediately after giving effect to the sale of the Securities and the application of the proceeds thereof as described in the Prospectus will not be, an "investment company" under the Investment Company Act of 1940, as amended.

(xix) The Securities, upon issuance, will be excluded or exempted under, or beyond the purview of, the Commodity Exchange Act and the Commodity Exchange Act Regulations.

I have generally reviewed the Registration Statement, the General Disclosure Package and the Prospectus and discussed the information therein with certain officers and employees of the Company, but without independent check or verification except as indicated above, and no facts have come to my attention that would lead me to believe that:

(1) the Registration Statement, at the time it originally became effective under the 1933 Act or as of each "new effective date" with respect to the Securities and the Underwriters pursuant to, and within the meaning of, Rule 430B(f)(2) under the 1933 Act, contained an untrue statement of a material fact or omitted to state a material fact required to be stated therein or necessary to make the statements therein not misleading;

(2) the General Disclosure Package, as of 4:35 p.m. (Eastern Time) on November 3, 2016, contained an untrue statement of a material fact or omitted to state a

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material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading; or

(3) the Prospectus, as of the date of the Prospectus Supplement or as of the date hereof, included or includes an untrue statement of a material fact or omitted or omits to state a material fact necessary in order to make the statements therein, in the light of the circumstances under which they were made, not misleading.

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Exhibit 4-2

GLOBAL NOTE

UNLESS THIS CERTIFICATE IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY (55 WATER STREET, NEW YORK, NEW YORK) (THE "DEPOSITORY") TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE OR PAYMENT, AND SUCH CERTIFICATE ISSUED IS REGISTERED IN THE NAME OF CEDE & CO., OR SUCH OTHER NAME AS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY, ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL, SINCE THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

UNLESS AND UNTIL THIS CERTIFICATE IS EXCHANGED IN WHOLE OR IN PART FOR NOTES IN CERTIFICATED FORM, THIS CERTIFICATE MAY NOT BE TRANSFERRED EXCEPT AS A WHOLE BY THE DEPOSITORY TO A NOMINEE THEREOF OR BY A NOMINEE THEREOF TO THE DEPOSITORY OR ANOTHER NOMINEE OF THE DEPOSITORY OR BY THE DEPOSITORY OR ANY SUCH NOMINEE TO A SUCCESSOR OF THE DEPOSITORY OR A NOMINEE OF SUCH SUCCESSOR.

CUSIP NO. 744573 AJ5 $400,000,000

No. R-01

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
1.600% Senior Note due 2019

GLOBAL NOTE

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED, a New Jersey corporation (herein referred to as the "Company," which term includes any successor corporation under the Indenture hereinafter referred to), for value received, hereby promises to pay to Cede & Co., or registered assigns, the principal sum of $400,000,000 on November 15, 2019 (the "Stated Maturity Date"), unless redeemed in accordance with the provisions of this Global Note, and to pay interest on the outstanding principal amount of this Global Note from November 8, 2016, semi-annually in arrears on May 15 and November 15 of each year, beginning on May 15, 2017 (each, an "Interest Payment Date") at 1.600% per annum until the principal hereof is paid or duly provided for. Interest payable on each Interest Payment Date will include interest accrued from and including November 8, 2016 or from and including the most recent Interest Payment Date to which interest has been paid or duly provided for, as the case may be, to, but excluding, such Interest Payment Date. Interest will be computed based on a 360-day year consisting of twelve 30-day months.

The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, except as provided below, be paid to the person (the "Holder") in whose name this Global Note (or one or more Predecessor Securities) is registered at the close of business on the fifteenth day (whether or not a Business Day (as defined below)) immediately preceding the applicable Interest Payment Date (a "Regular Record Date"). Any such interest not so punctually paid or duly provided for ("Defaulted Interest") will forthwith cease to be payable to the Holder on such Regular Record Date and may either be paid to the person in whose name this Global Note (or one or more Predecessor Securities) is registered at the close of business on a special record date (the "Special Record Date") for the payment of such Defaulted Interest to be fixed by the Trustee hereinafter referred to, notice whereof shall be

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given to the Holder of this Global Note not less than ten days prior to such Special Record Date, or may be paid at any time in any other lawful manner, all as more fully provided in the Indenture.

For purposes of this Global Note, "Business Day" means each Monday, Tuesday, Wednesday, Thursday and Friday which is not a day on which banking institutions in Newark, New Jersey and The City of New York are authorized or obligated by law or executive order to close.

Payments of principal, premium, if any, and interest with respect to this Global Note will be made in such coin or currency of the United States of America as at the time of payment is legal tender for the payment of public and private debts. Payment of the principal of and any premium on this Global Note on the Stated Maturity Date or date of earlier redemption will be made in immediately available funds against presentation of this Global Note at the office or agency of the Company maintained for that purpose in the Borough of Manhattan, The City of New York. Payments of interest on an Interest Payment Date will be made, at the option of the Company, by check mailed to the Holder entitled thereto at the applicable address appearing in the Security Register or by transfer of immediately available funds to an account maintained by the payee with a bank located in the United States of America; provided, however, that so long as Cede & Co. is the Holder of this Global Note, payments of interest on an Interest Payment Date will be made in immediately available funds.

Any payment of principal, premium or interest required to be made with respect to this Global Note on a day that is not a Business Day need not be made on such day, but may be made on the next succeeding Business Day with the same force and effect as if made on such day and no additional interest shall be payable on the next succeeding Business Day as a result of such delayed payment.

General. This Global Note is one of the duly authorized series of securities of the Company (the "Securities"), issued or to be issued under the Indenture, dated as of November 1, 1998 (together with all amendments and supplements thereto, the "Indenture"), between the Company and U.S. Bank National Association, as successor trustee (the "Trustee"), to which Indenture reference is hereby made for a statement of the respective rights, limitations of rights, duties and immunities thereunder of the Company, the Trustee and each of the Holders of the Securities and of the terms upon which the Securities are, and are to be, authenticated and delivered and transferred. This Global Note is one of the duly authorized series of Securities designated as the “1.600% Senior Notes due 2019” (collectively, the “Notes”). The Notes will be limited to $400,000,000 aggregate principal amount, except as permitted in the Indenture, and will be subject, without the consent of the Holders of any series of Securities under the Indenture, to the issuance of additional Notes in the future having the same terms, other than the date of original issuance and the date on which interest begins to accrue, so as to form one series with the Notes. All terms used in this Global Note, which are not defined herein shall have the meanings given to them in the Indenture.

Events of Default. If an Event of Default with respect to the Notes shall have occurred and be continuing, the principal of the Notes may be declared due and payable in the manner and with the effect provided in the Indenture.

As used in this Global Note and the Indenture, the term “Event of Default” wherever used with respect to the Notes means any one of the events described under Article Five, Section 501 of the Indenture or the following event:

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an event of default shall have occurred and be continuing with respect to indebtedness for borrowed money of the Company in excess of $75,000,000 and such event of default shall have been accelerated, and such acceleration shall not be rescinded or annulled within ten days after written notice thereof shall have been given to the Company by the Trustee or to the Company and the Trustee by the Holders of at least 25% in aggregate principal amount of the Notes then Outstanding; *provided*, *however*, that if such event of default with respect to such other indebtedness shall be remedied or cured by the Company, or waived by the holders of such other indebtedness, then the Event of Default hereunder by reason thereof shall be deemed likewise to have been thereupon remedied, cured or waived without further action upon the part of either the Trustee or any of the Holders of the Notes; and *provided, further*, that, subject to the provisions of Section 601 of the Indenture, the Trustee shall not be charged with knowledge of any such event of default or any remedy, cure or waiver thereof or any such acceleration unless written notice thereof shall have been given to the Trustee by the Company, by a holder or an agent of such other indebtedness or by the Trustee then acting under this Indenture with respect to such other series of Securities or under any other indenture or instrument, as the case may be, under which such event of default shall have occurred, or by the Holders of at least twenty-five percent in aggregate principal amount of the Notes at the time Outstanding;

in each case whatever the reason for such Event of Default and whether or not it shall be voluntary or involuntary or be effected by operation of law or pursuant to any judgment, decree or order of any court or any order, rule or regulation of any administrative or governmental body.

Sinking Fund. This Global Note will not be entitled to the benefit of, or be subject to, any sinking fund.

Optional Redemption. This Global Note (or portion hereof) will be redeemable at the option of the Company, in whole or in part at any time prior to the Stated Maturity Date, on at least 10 days but not more than 60 days prior written notice mailed to the Holder hereof, at a price (the "Make-Whole Redemption Price") equal to the greater of (i) 100% of the principal amount of this Global Note (or portion hereof) to be redeemed, and (ii) the sum of the present values of the remaining scheduled payments of principal of and interest on this Global Note (or portion hereof) to be redeemed, exclusive of accrued interest to the date of redemption (each, a “Make-Whole Redemption Date”), discounted to such Make-Whole Redemption Date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined below) plus 15 basis points, plus, in either case, any accrued and unpaid interest thereon to, but excluding, such Make-Whole Redemption Date.

If money sufficient to pay the Make-Whole Redemption Price of this Global Note (or portion hereof) to be redeemed on a Make-Whole Redemption Date is deposited with the Trustee or a Paying Agent on or before such Make-Whole Redemption Date and certain other conditions are satisfied, then on and after such Make-Whole Redemption Date, interest will cease to accrue on this Global Note (or such portion hereof) called for redemption.

For purposes of the foregoing, the following definitions apply:

"Comparable Treasury Issue" means, with respect to any Make-Whole Redemption Date for this Global Note (or portion hereof) to be redeemed, the United States Treasury security selected by the Independent Investment Banker (as defined below) as having the maturity

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comparable to the remaining term of this Global Note (or portion hereof) to be redeemed that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of this Global Note (or portion hereof) to be redeemed.

"Comparable Treasury Price" means, with respect to any Make-Whole Redemption Date for this Global Note (or portion hereof) to be redeemed, (a) the average of three Reference Treasury Dealer Quotations (as defined below) for the Make-Whole Redemption Date for this Global Note (or portion hereof) to be redeemed, after excluding the highest and lowest of five Reference Treasury Dealer Quotations, or, (b) if the Independent Investment Banker obtains fewer than five Reference Treasury Dealer Quotations, the average of all Reference Treasury Dealer Quotations obtained.

"Independent Investment Banker" means one of the Reference Treasury Dealers appointed by the Company after consultation with the Trustee.

"Reference Treasury Dealer" means each of Barclays Capital Inc., J.P. Morgan Securities LLC, RBC Capital Markets, LLC, Scotia Capital (USA) Inc. and Wells Fargo Securities, LLC, and their respective affiliates or successors, *provided* that if any of the foregoing shall cease to be a primary U.S. government securities dealer in the United States (a “Primary Treasury Dealer”), the Company will substitute therefor another Primary Treasury Dealer.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any Make-Whole Redemption Date, the average, as determined by the Independent Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Independent Investment Banker by such Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding such Make-Whole Redemption Date.

"Treasury Rate" means, with respect to any Make-Whole Redemption Date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such Make-Whole Redemption Date. The Treasury Rate will be calculated by the Company on the third Business Day preceding the Make-Whole Redemption Date. The Trustee shall not be responsible for any such calculation.

Reports. So long as this Global Note remains Outstanding, the Company will file with the Trustee, within 30 days of filing them with the Securities and Exchange Commission (the "SEC"), copies of the current, quarterly and annual reports and of the information, documents and other reports (or copies of such portions of any of the foregoing as the SEC may by rules and regulations prescribe) that the Company is required to file with the SEC pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (the “Exchange Act”). If the Company is not subject to the requirements of Section 13 or Section 15(d) of the Exchange Act and this Global Note remains Outstanding, the Company must nevertheless file with the SEC (if permitted) and the Trustee, on the date upon which the Company would have been required to file with the SEC, current, quarterly and annual financial statements, including any notes thereto (and with respect to annual reports, an auditor's report by a firm of established national reputation, upon which the Trustee may conclusively rely), and a "Management's Discussion and Analysis of Financial Condition and Results of Operations," both comparable to that which the Company would have been required to include in such current, quarterly and annual reports,

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information, documents or other reports on Forms 8-K, 10-Q and 10-K if the Company was subject to the requirements of Section 13 or 15(d) of the Exchange Act; provided that the Company will not be required to register under the Exchange Act by virtue of this provision, if not otherwise required to do so.

Modification and Waivers; Obligations of the Company Absolute. The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders of the Securities of each series. Such amendment may be effected under the Indenture at any time by the Company and the Trustee with the consent of the Holders of a majority in aggregate principal amount of all Securities issued under the Indenture at the time Outstanding and affected thereby. The Indenture also contains provisions permitting the Holders of a majority in aggregate principal amount of the Securities of each series at the time Outstanding, on behalf of the Holders of all Outstanding Securities of such series, to waive compliance by the Company with certain provisions of the Indenture and certain past defaults under the Indenture and their consequences. Any such consent or waiver shall be conclusive and binding upon the Holder of this Global Note and upon all future Holders of this Global Note and of any Note issued upon the registration of transfer hereof or in exchange hereof or in lieu hereof, whether or not notation of such consent or waiver is made upon this Note.

No reference herein to the Indenture and no provision of this Global Note or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal, premium, if any, and interest with respect to this Global Note at the times, place and rate, and in the coin or currency herein prescribed.

Defeasance. The Indenture contains provisions for defeasance at any time of the entire indebtedness of the Company on this Global Note, upon compliance by the Company with certain conditions set forth in the Indenture, which provisions apply to this Global Note.

Authorized Denominations. The Notes are issuable only in registered form without coupons in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

Registration of Transfer or Exchange of this Global Note. As provided in the Indenture and subject to certain limitations herein and therein set forth, the transfer of this Global Note is registrable in the Security Register upon surrender of this Global Note for registration of transfer at the office or agency of the Company in any place where the principal of (and premium, if any) and interest on this Global Note are payable, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Security Registrar duly executed by, the Holder hereof or his attorney duly authorized in writing, and thereupon one or more new Global Notes of this series of like tenor, of authorized denominations and for the same aggregate principal amount, will be issued to the designated transferee or transferees.

As provided in the Indenture and subject to certain limitations herein and therein set forth, the Global Notes are exchangeable for a like aggregate principal amount of Global Notes of different authorized denominations, as requested by the Holders surrendering the same.

This Global Note is a “Security in global form” within the meaning of the Indenture. If The Depository Trust Company is at any time unwilling, unable or ineligible to continue as depository and a successor depository is not appointed by the Company within 90 days or an Event of

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Default under the Indenture has occurred and is continuing, the Company will issue Notes in certificated form in exchange for this Global Note. In addition, the Company may at any time determine not to have Notes represented by one or more Securities in global form and, in such event, will issue Notes in certificated form in exchange in whole for this Global Note. In any such instance, an owner of a beneficial interest in this Global Note will receive Notes in certificated form equal in principal amount to such beneficial interest and to have such Notes registered in its name. Notes so issued in certificated form will be issued in denominations of $2,000 and integral multiples of $1,000 in excess thereof and will be issued in registered form only, without coupons.

No service charge shall be made for any such registration of transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

Prior to due presentment of this Global Note for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the Holder of this Global Note as the owner hereof for all purposes, whether or not this Global Note be overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

Governing Law. This Global Note shall be governed by and construed in accordance with the law of the State of New Jersey.

Unless the certificate of authentication hereon has been executed by the Trustee by manual signature, this Global Note shall not be entitled to any benefit under the Indenture or be valid or obligatory for any purpose.

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IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed under its facsimile corporate seal.

PUBLIC SERVICE ENTERPRISE GROUP
INCORPORATED

Dated: November 8, 2016

By: _____
Vice President and Treasurer

Attest:

_____
Secretary

TRUSTEE'S CERTIFICATE OF AUTHENTICATION

This is one of the Securities of the series designated therein referred to in the within-mentioned Indenture.

U.S. BANK NATIONAL ASSOCIATION,
as Trustee

Dated: November 8, 2016

By: _____
Authorized Signatory

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ASSIGNMENT FORM

To assign this Security, fill in the form below:
I or we assign and transfer this Security to

(Insert assignee's soc. sec. or tax I.D. No.)

(Print or type assignee's name, address and zip code)

and irrevocably appoint _____ agent to transfer this Security on the books of the Company. The agent may substitute another to act for him.

Dated: _____ Signed: _____

(Sign exactly as your name appears on the other side of this Security)

Signature Guarantee: _____

Dated: _____ Signed: _____

(Sign exactly as your name appears on the other side of this Security)

Signature Guarantee: _____

S1-SSA-0009 - 10565

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Exhibit 4-3

GLOBAL NOTE

UNLESS THIS CERTIFICATE IS PRESENTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY TRUST COMPANY (55 WATER STREET, NEW YORK, NEW YORK) (THE "DEPOSITORY") TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED OR ITS AGENT FOR REGISTRATION OF TRANSFER, EXCHANGE OR PAYMENT, AND SUCH CERTIFICATE ISSUED IS REGISTERED IN THE NAME OF CEDE & CO., OR SUCH OTHER NAME AS REQUESTED BY AN AUTHORIZED REPRESENTATIVE OF THE DEPOSITORY, ANY TRANSFER, PLEDGE OR OTHER USE HEREOF FOR VALUE OR OTHERWISE BY OR TO ANY PERSON IS WRONGFUL, SINCE THE REGISTERED OWNER HEREOF, CEDE & CO., HAS AN INTEREST HEREIN.

UNLESS AND UNTIL THIS CERTIFICATE IS EXCHANGED IN WHOLE OR IN PART FOR NOTES IN CERTIFICATED FORM, THIS CERTIFICATE MAY NOT BE TRANSFERRED EXCEPT AS A WHOLE BY THE DEPOSITORY TO A NOMINEE THEREOF OR BY A NOMINEE THEREOF TO THE DEPOSITORY OR ANOTHER NOMINEE OF THE DEPOSITORY OR BY THE DEPOSITORY OR ANY SUCH NOMINEE TO A SUCCESSOR OF THE DEPOSITORY OR A NOMINEE OF SUCH SUCCESSOR.

CUSIP NO. 744573 AK2 $300,000,000

No. R-01

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
2.000% Senior Note due 2021

GLOBAL NOTE

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED, a New Jersey corporation (herein referred to as the "Company," which term includes any successor corporation under the Indenture hereinafter referred to), for value received, hereby promises to pay to Cede & Co., or registered assigns, the principal sum of $300,000,000 on November 15, 2021 (the "Stated Maturity Date"), unless redeemed in accordance with the provisions of this Global Note, and to pay interest on the outstanding principal amount of this Global Note from November 8, 2016, semi-annually in arrears on May 15 and November 15 of each year, beginning on May 15, 2017 (each, an "Interest Payment Date") at 2.000% per annum until the principal hereof is paid or duly provided for. Interest payable on each Interest Payment Date will include interest accrued from and including November 8, 2016 or from and including the most recent Interest Payment Date to which interest has been paid or duly provided for, as the case may be, to, but excluding, such Interest Payment Date. Interest will be computed based on a 360-day year consisting of twelve 30-day months.

The interest so payable, and punctually paid or duly provided for, on any Interest Payment Date will, except as provided below, be paid to the person (the "Holder") in whose name this Global Note (or one or more Predecessor Securities) is registered at the close of business on the fifteenth day (whether or not a Business Day (as defined below)) immediately preceding the applicable Interest Payment Date (a "Regular Record Date"). Any such interest not so punctually paid or duly provided for ("Defaulted Interest") will forthwith cease to be payable to the Holder on such Regular Record Date and may either be paid to the person in whose name this Global Note (or one or more Predecessor Securities) is registered at the close of business on a special record date (the "Special Record Date") for the payment of such Defaulted Interest to be fixed by the Trustee hereinafter referred to, notice whereof shall be

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given to the Holder of this Global Note not less than ten days prior to such Special Record Date, or may be paid at any time in any other lawful manner, all as more fully provided in the Indenture.

For purposes of this Global Note, "Business Day" means each Monday, Tuesday, Wednesday, Thursday and Friday which is not a day on which banking institutions in Newark, New Jersey and The City of New York are authorized or obligated by law or executive order to close.

Payments of principal, premium, if any, and interest with respect to this Global Note will be made in such coin or currency of the United States of America as at the time of payment is legal tender for the payment of public and private debts. Payment of the principal of and any premium on this Global Note on the Stated Maturity Date or date of earlier redemption will be made in immediately available funds against presentation of this Global Note at the office or agency of the Company maintained for that purpose in the Borough of Manhattan, The City of New York. Payments of interest on an Interest Payment Date will be made, at the option of the Company, by check mailed to the Holder entitled thereto at the applicable address appearing in the Security Register or by transfer of immediately available funds to an account maintained by the payee with a bank located in the United States of America; provided, however, that so long as Cede & Co. is the Holder of this Global Note, payments of interest on an Interest Payment Date will be made in immediately available funds.

Any payment of principal, premium or interest required to be made with respect to this Global Note on a day that is not a Business Day need not be made on such day, but may be made on the next succeeding Business Day with the same force and effect as if made on such day and no additional interest shall be payable on the next succeeding Business Day as a result of such delayed payment.

General. This Global Note is one of the duly authorized series of securities of the Company (the "Securities"), issued or to be issued under the Indenture, dated as of November 1, 1998 (together with all amendments and supplements thereto, the "Indenture"), between the Company and U.S. Bank National Association, as successor trustee (the "Trustee"), to which Indenture reference is hereby made for a statement of the respective rights, limitations of rights, duties and immunities thereunder of the Company, the Trustee and each of the Holders of the Securities and of the terms upon which the Securities are, and are to be, authenticated and delivered and transferred. This Global Note is one of the duly authorized series of Securities designated as the “2.000% Senior Notes due 2021” (collectively, the “Notes”). The Notes will be limited to $300,000,000 aggregate principal amount, except as permitted in the Indenture, and will be subject, without the consent of the Holders of any series of Securities under the Indenture, to the issuance of additional Notes in the future having the same terms, other than the date of original issuance and the date on which interest begins to accrue, so as to form one series with the Notes. All terms used in this Global Note, which are not defined herein shall have the meanings given to them in the Indenture.

Events of Default. If an Event of Default with respect to the Notes shall have occurred and be continuing, the principal of the Notes may be declared due and payable in the manner and with the effect provided in the Indenture.

As used in this Global Note and the Indenture, the term “Event of Default” wherever used with respect to the Notes means any one of the events described under Article Five, Section 501 of the Indenture or the following event:

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an event of default shall have occurred and be continuing with respect to indebtedness for borrowed money of the Company in excess of $75,000,000 and such event of default shall have been accelerated, and such acceleration shall not be rescinded or annulled within ten days after written notice thereof shall have been given to the Company by the Trustee or to the Company and the Trustee by the Holders of at least 25% in aggregate principal amount of the Notes then Outstanding; *provided*, *however*, that if such event of default with respect to such other indebtedness shall be remedied or cured by the Company, or waived by the holders of such other indebtedness, then the Event of Default hereunder by reason thereof shall be deemed likewise to have been thereupon remedied, cured or waived without further action upon the part of either the Trustee or any of the Holders of the Notes; and *provided, further*, that, subject to the provisions of Section 601 of the Indenture, the Trustee shall not be charged with knowledge of any such event of default or any remedy, cure or waiver thereof or any such acceleration unless written notice thereof shall have been given to the Trustee by the Company, by a holder or an agent of such other indebtedness or by the Trustee then acting under this Indenture with respect to such other series of Securities or under any other indenture or instrument, as the case may be, under which such event of default shall have occurred, or by the Holders of at least twenty-five percent in aggregate principal amount of the Notes at the time Outstanding;

in each case whatever the reason for such Event of Default and whether or not it shall be voluntary or involuntary or be effected by operation of law or pursuant to any judgment, decree or order of any court or any order, rule or regulation of any administrative or governmental body.

Sinking Fund. This Global Note will not be entitled to the benefit of, or be subject to, any sinking fund.

Optional Redemption. This Global Note (or portion hereof) will be redeemable at the option of the Company, in whole or in part at any time prior to October 15, 2021, on at least 10 days but not more than 60 days prior written notice mailed to the Holder hereof, at a price (the "Make-Whole Redemption Price") equal to the greater of (i) 100% of the principal amount of this Global Note (or portion hereof) to be redeemed, and (ii) the sum of the present values of the remaining scheduled payments of principal of and interest on this Global Note (or portion hereof) to be redeemed that would be due if this Global Note matured on October 15, 2021, exclusive of accrued interest to the date of redemption (each, a “Make-Whole Redemption Date”), discounted to such Make-Whole Redemption Date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined below) plus 15 basis points, plus, in either case, any accrued and unpaid interest thereon to, but excluding, such Make-Whole Redemption Date.

This Global Note (or a portion thereof) will be redeemable at the option of the Company, in whole or in part, at any time on or after October 15, 2021, on at least 10 days but not more than 60 days prior written notice mailed to the Holder hereof, at a price (the “Par Redemption Price”) equal to 100% of the principal amount of this Global Note (or portion hereof) to be redeemed, plus any accrued and unpaid interest thereon to, but excluding, the date of redemption (each, a “Par Redemption Date”).

If money sufficient to pay the Make-Whole Redemption Price of this Global Note (or portion hereof) to be redeemed on a Make-Whole Redemption Date is deposited with the Trustee or a Paying Agent on or before such Make-Whole Redemption Date and certain other

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conditions are satisfied, then on and after such Make-Whole Redemption Date, interest will cease to accrue on this Global Note (or such portion hereof) called for redemption.

If money sufficient to pay the Par Redemption Price of this Global Note (or portion hereof) to be redeemed on a Par Redemption Date is deposited with the Trustee or a Paying Agent on or before such Par Redemption Date and certain other conditions are satisfied, then on and after such Par Redemption Date, interest will cease to accrue on this Global Note (or such portion hereof) called for redemption.

For purposes of the foregoing, the following definitions apply:

"Comparable Treasury Issue" means, with respect to any Make-Whole Redemption Date for this Global Note (or portion hereof) to be redeemed, the United States Treasury security selected by the Independent Investment Banker (as defined below) as having the maturity comparable to the remaining term of this Global Note (or portion hereof) to be redeemed (assuming that this Global Note matured on October 15, 2021) that would be utilized, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities of comparable maturity to the remaining term of this Global Note (or portion hereof) to be redeemed.

"Comparable Treasury Price" means, with respect to any Make-Whole Redemption Date for this Global Note (or portion hereof) to be redeemed, (a) the average of three Reference Treasury Dealer Quotations (as defined below) for the Make-Whole Redemption Date for this Global Note (or portion hereof) to be redeemed, after excluding the highest and lowest of five Reference Treasury Dealer Quotations, or, (b) if the Independent Investment Banker obtains fewer than five Reference Treasury Dealer Quotations, the average of all Reference Treasury Dealer Quotations obtained.

"Independent Investment Banker" means one of the Reference Treasury Dealers appointed by the Company after consultation with the Trustee.

"Reference Treasury Dealer" means each of Barclays Capital Inc., J.P. Morgan Securities LLC, RBC Capital Markets, LLC, Scotia Capital (USA) Inc. and Wells Fargo Securities, LLC, and their respective affiliates or successors, *provided* that if any of the foregoing shall cease to be a primary U.S. government securities dealer in the United States (a “Primary Treasury Dealer”), the Company will substitute therefor another Primary Treasury Dealer.

"Reference Treasury Dealer Quotations" means, with respect to each Reference Treasury Dealer and any Make-Whole Redemption Date, the average, as determined by the Independent Investment Banker, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the Independent Investment Banker by such Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding such Make-Whole Redemption Date.

"Treasury Rate" means, with respect to any Make-Whole Redemption Date, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, assuming a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such Make-Whole Redemption Date. The Treasury Rate will be calculated by the Company on the third Business Day preceding the Make-Whole Redemption Date. The Trustee shall not be responsible for any such calculation.

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Reports. So long as this Global Note remains Outstanding, the Company will file with the Trustee, within 30 days of filing them with the Securities and Exchange Commission (the "SEC"), copies of the current, quarterly and annual reports and of the information, documents and other reports (or copies of such portions of any of the foregoing as the SEC may by rules and regulations prescribe) that the Company is required to file with the SEC pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (the “Exchange Act”). If the Company is not subject to the requirements of Section 13 or Section 15(d) of the Exchange Act and this Global Note remains Outstanding, the Company must nevertheless file with the SEC (if permitted) and the Trustee, on the date upon which the Company would have been required to file with the SEC, current, quarterly and annual financial statements, including any notes thereto (and with respect to annual reports, an auditor's report by a firm of established national reputation, upon which the Trustee may conclusively rely), and a "Management's Discussion and Analysis of Financial Condition and Results of Operations," both comparable to that which the Company would have been required to include in such current, quarterly and annual reports, information, documents or other reports on Forms 8-K, 10-Q and 10-K if the Company was subject to the requirements of Section 13 or 15(d) of the Exchange Act; provided that the Company will not be required to register under the Exchange Act by virtue of this provision, if not otherwise required to do so.

Modification and Waivers; Obligations of the Company Absolute. The Indenture permits, with certain exceptions as therein provided, the amendment thereof and the modification of the rights and obligations of the Company and the rights of the Holders of the Securities of each series. Such amendment may be effected under the Indenture at any time by the Company and the Trustee with the consent of the Holders of a majority in aggregate principal amount of all Securities issued under the Indenture at the time Outstanding and affected thereby. The Indenture also contains provisions permitting the Holders of a majority in aggregate principal amount of the Securities of each series at the time Outstanding, on behalf of the Holders of all Outstanding Securities of such series, to waive compliance by the Company with certain provisions of the Indenture and certain past defaults under the Indenture and their consequences. Any such consent or waiver shall be conclusive and binding upon the Holder of this Global Note and upon all future Holders of this Global Note and of any Note issued upon the registration of transfer hereof or in exchange hereof or in lieu hereof, whether or not notation of such consent or waiver is made upon this Note.

No reference herein to the Indenture and no provision of this Global Note or of the Indenture shall alter or impair the obligation of the Company, which is absolute and unconditional, to pay the principal, premium, if any, and interest with respect to this Global Note at the times, place and rate, and in the coin or currency herein prescribed.

Defeasance. The Indenture contains provisions for defeasance at any time of the entire indebtedness of the Company on this Global Note, upon compliance by the Company with certain conditions set forth in the Indenture, which provisions apply to this Global Note.

Authorized Denominations. The Notes are issuable only in registered form without coupons in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

Registration of Transfer or Exchange of this Global Note. As provided in the Indenture and subject to certain limitations herein and therein set forth, the transfer of this Global Note is registrable in the Security Register upon surrender of this Global Note for

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registration of transfer at the office or agency of the Company in any place where the principal of (and premium, if any) and interest on this Global Note are payable, duly endorsed by, or accompanied by a written instrument of transfer in form satisfactory to the Company and the Security Registrar duly executed by, the Holder hereof or his attorney duly authorized in writing, and thereupon one or more new Global Notes of this series of like tenor, of authorized denominations and for the same aggregate principal amount, will be issued to the designated transferee or transferees.

As provided in the Indenture and subject to certain limitations herein and therein set forth, the Global Notes are exchangeable for a like aggregate principal amount of Global Notes of different authorized denominations, as requested by the Holders surrendering the same.

This Global Note is a "Security in global form" within the meaning of the Indenture. If The Depository Trust Company is at any time unwilling, unable or ineligible to continue as depository and a successor depository is not appointed by the Company within 90 days or an Event of Default under the Indenture has occurred and is continuing, the Company will issue Notes in certificated form in exchange for this Global Note. In addition, the Company may at any time determine not to have Notes represented by one or more Securities in global form and, in such event, will issue Notes in certificated form in exchange in whole for this Global Note. In any such instance, an owner of a beneficial interest in this Global Note will receive Notes in certificated form equal in principal amount to such beneficial interest and to have such Notes registered in its name. Notes so issued in certificated form will be issued in denominations of $2,000 and integral multiples of $1,000 in excess thereof and will be issued in registered form only, without coupons.

No service charge shall be made for any such registration of transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge payable in connection therewith.

Prior to due presentment of this Global Note for registration of transfer, the Company, the Trustee and any agent of the Company or the Trustee may treat the Holder of this Global Note as the owner hereof for all purposes, whether or not this Global Note be overdue, and neither the Company, the Trustee nor any such agent shall be affected by notice to the contrary.

Governing Law. This Global Note shall be governed by and construed in accordance with the law of the State of New Jersey.

Unless the certificate of authentication hereon has been executed by the Trustee by manual signature, this Global Note shall not be entitled to any benefit under the Indenture or be valid or obligatory for any purpose.

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IN WITNESS WHEREOF, the Company has caused this instrument to be duly executed under its facsimile corporate seal.

PUBLIC SERVICE ENTERPRISE GROUP
INCORPORATED

Dated: November 8, 2016

By: _____
Vice President and Treasurer

Attest:

_____
Secretary

TRUSTEE'S CERTIFICATE OF AUTHENTICATION

This is one of the Securities of the series designated therein referred to in the within-mentioned Indenture.

U.S. BANK NATIONAL ASSOCIATION,
as Trustee

Dated: November 8, 2016

By: _____
Authorized Signatory

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ASSIGNMENT FORM

To assign this Security, fill in the form below:
I or we assign and transfer this Security to

(Insert assignee's soc. sec. or tax I.D. No.)

(Print or type assignee's name, address and zip code)

and irrevocably appoint _____ agent to transfer this Security on the books of the Company. The agent may substitute another to act for him.

Dated: _____ Signed: _____

(Sign exactly as your name appears on the other side of this Security)

Signature Guarantee: _____

Dated: _____ Signed: _____

(Sign exactly as your name appears on the other side of this Security)

Signature Guarantee: _____

S1-SSA-0009 - 10573

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Exhibit 5

Shawn P. Leyden
Vice President and
Deputy General Counsel

PSEG Services Corporation
80 Park Plaza, T5, Newark, NJ 07102-4194
tel: 973-430-8058 fax: 973-639-0741

November 8, 2016

Public Service Enterprise Group Incorporated
80 Park Plaza
P.O. Box 1171
Newark, NJ 07102

Re: Public Service Enterprise Group Incorporated
Registration Statement on Form S-3 (No. 333-200352)

Ladies and Gentlemen:

This opinion is furnished in connection with the issuance and sale by Public Service Enterprise Group Incorporated (the "Company") of $400,000,000 aggregate principal amount of its 1.600% Senior Notes due 2019 and $300,000,000 aggregate principal amount of its 2.000% Senior Notes due 2021 (collectively, the "Notes") pursuant to (i) the Company's Registration Statement on Form S-3, Registration No. 333-200352 (the "Registration Statement"); (ii) the base prospectus constituting a part of the Registration Statement, dated November 18, 2014 (the "Base Prospectus"), relating to the offering from time to time of certain debt securities of the Company, among other securities, pursuant to Rule 415 promulgated under the Securities Act of 1933, as amended (the "Act"); and (iii) the prospectus supplement, dated November 3, 2016 (the "Prospectus Supplement" and together with the Base Prospectus, the "Prospectus"). The Notes were issued under the Indenture, dated as of November 1, 1998 (as amended and supplemented to the date hereof, the "Indenture"), between the Company and U.S. Bank National Association, as trustee (the "Trustee").

I have examined the Registration Statement, the Prospectus, the Indenture, the global certificates representing the Notes and such other agreements, instruments, documents and records and such certificates or comparable documents of public officials which I deemed relevant and necessary for the basis of the opinion hereinafter expressed. In such examination, I have assumed the following: (a) the authenticity of original documents and the genuineness of all signatures; (b) the conformity to the originals of all documents submitted to me as copies; and (c) the truth, accuracy, and completeness of the information, representations, and warranties contained in the records, documents, instruments, and certificates I have reviewed.

Based on such examination, I am of the opinion that the Notes, assuming the due authentication thereof by the Trustee pursuant to the Indenture, constitute valid and binding obligations of the Company, enforceable against the Company in accordance

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with their terms, subject to applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium and similar laws affecting creditors' rights and remedies generally and to general principles of equity, including principles of commercial reasonableness, good faith and fair dealing (regardless of whether enforcement is sought in a proceeding at law or in equity).

The foregoing opinion is given as of the date hereof and is limited to matters arising under laws of the State of New Jersey as in effect on the date hereof and I express no opinion as to the effect on the matters covered by this letter of the laws of any other jurisdiction. I hereby consent to the incorporation by reference of this letter as an exhibit to the Registration Statement and to the use of my name wherever it appears in the Registration Statement. In giving such consent, I do not thereby admit that I am within the category of persons whose consent is required by Section 7 of the Act or the related rules and regulations of the Securities and Exchange Commission issued thereunder with respect to any part of the Registration Statement, including this letter as an exhibit or otherwise.

Very truly yours,

/s/ Shawn P. Leyden

Shawn P. Leyden
Vice President and Deputy General Counsel
PSEG Services Corporation

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): November 8, 2018

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)
http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act ☐

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Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers.

Hak Cheol (H.C.) Shin, a director of Public Service Enterprise Group Incorporated (PSEG), has notified PSEG that he intends to resign from the PSEG Board of Directors effective December 31, 2018. An announcement has been made by LG Chem, Ltd. that Mr. Shin will be appointed as its Vice Chairman and CEO. Mr. Shin's resignation is not the result of any disagreement with PSEG or any matter relating to PSEG's operations, policies or practices.

S1-SSA-0009 - 10577

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: November 14, 2018

S1-SSA-0009 - 10578

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) November 21, 2017

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

(Exact name of registrant as specified in its charter)

New Jersey	001-00973	22-1212800
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Indicate by check mark whether any of the registrants is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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The information contained in Item 8.01 Other Events in this combined Form 8-K is separately filed, as noted, by Public Service Enterprise Group Incorporated and Public Service Electric and Gas Company ("PSE&G"). Information contained herein relating to any individual company is provided by such company on its own behalf and in connection with its respective Form 8-K. PSE&G makes representations only as to itself and makes no other representations whatsoever as to any other company.

Item 8.01 Other Events

The New Jersey Board of Public Utilities (the "BPU"), at its November 21, 2017 meeting, approved an extension of the deadline for filing PSE&G's distribution base rate case proceeding to February 1, 2018. The filing will now be based upon five months of actual data and seven months of forecasted data. PSE&G is required to file a distribution base rate case as a result of its Energy Strong Order from the BPU.

S1-SSA-0009 - 10581

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
STUART J. BLACK
Vice President and Controller
(Principal Accounting Officer)

Date: November 21, 2017

S1-SSA-0009 - 10582

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /s/ Stuart J. Black
STUART J. BLACK
Vice President and Controller
(Principal Accounting Officer)

Date: November 21, 2017

S1-SSA-0009 - 10583

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) December 15, 2015

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza, P.O. Box 1171
Newark, New Jersey 07101-1171
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 5.02. Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers

On December 15, 2015, Public Service Enterprise Group Incorporated (PSEG) elected Mr. Willie A. Deese to its Board of Directors, effective February 16, 2016, for a term ending at the 2016 Annual Meeting of Stockholders. Mr. Deese has not been appointed to any committees at this time.

Mr. Deese has been Executive Vice President of Merck & Co. Inc. since January 2008 and has served as President of Merck Manufacturing Division since May 2005. He joined Merck & Co. in 2004 as Senior Vice President of Global Procurement.

Mr. Deese also serves as a Director of DENTSPLY International Inc., a dental equipment and supplies manufacturing company, and CDK Global, Inc., a provider of integrated technology solutions for automotive and heavy equipment dealerships.

Item 5.03. Amendment to Articles of Incorporation or Bylaws; Change in Fiscal Year

On December 15, 2015, the Board of Directors of PSEG approved, effective on that date, amendments to the By-Laws of PSEG to adopt a proxy access by-law that will allow PSEG to include in its proxy materials candidates nominated by a shareholder pursuant to certain conditions set forth within the By-Laws amended as of December 15, 2015.

Item 9.01 Financial Statements and Exhibits

Exhibit 99. Press Release dated December 16, 2015

Exhibit 99.1. By-Laws of Public Service Enterprise Group Incorporated, as in effect December 15, 2015

S1-SSA-0009 - 10585

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: December 16, 2015

S1-SSA-0009 - 10586

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EXHIBIT 99

Media Relations

Public Service Enterprise Group
80 Park Plaza, T6
Newark, NJ 07102

FOR IMMEDIATE RELEASE
December 16, 2015

CONTACT: **Mike Jennings**
973-430-6406
Michael.Jennings@pseg.com

PSEG ELECTS WILLIE A. DEESE TO BOARD OF DIRECTORS

Executive Vice President and President, Merck & Co. Manufacturing Division

(December 16, 2015 – Newark, NJ) – Public Service Enterprise Group (PSEG) today announced that Willie A. Deese has been elected to its Board of Directors, effective February 16, 2016.

Deese has been Executive Vice President of Merck & Co. Inc. since January 2008 and has served as President of Merck Manufacturing Division since May 2005. He oversees a network of over 55 manufacturing sites in more than 22 countries. Deese joined Merck & Co. in 2004 as Senior Vice President of Global Procurement.

"Willie's extensive experience in leading manufacturing and procurement operations will be a tremendous asset to our Board," said Ralph Izzo, PSEG's Chairman, President and Chief Executive Officer. "His skills, knowledge and counsel will be invaluable as we continue to focus on operational excellence and driving down costs in an increasingly competitive energy marketplace."

During his career, Deese has served in several leadership positions, including Senior Vice President and Director of Purchasing at SmithKline Beecham Pharmaceuticals in Philadelphia, Pennsylvania and Vice President of Purchasing at Kaiser Permanente in Oakland, California. He also led the integration of Glaxo and SmithKline procurement organizations during their merger and became Senior Vice President, Global Procurement and Logistics at GlaxoSmithKline.

He is Former Chairman of the North Carolina A&T State University Board of Trustees and has been named as one of the "100 Most Powerful Executives in Corporate America" by Black Enterprise Magazine.

Currently, Deese sits on the board of directors of DENSTPLY International Inc., a dental equipment and supplies manufacturing company, and CDK Global, Inc., a provider of integrated technology solutions for automotive and heavy equipment dealerships.

# # #

Public Service Enterprise Group (NYSE: PEG) is a publicly traded diversified energy company with annual revenues of approximately $11 billion. Its operating subsidiaries are: Public Service Electric and Gas Company (PSE&G), PSEG Power, and PSEG Long Island.

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BY-LAWS

OF

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

As in effect

December 15, 2015

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BY-LAWS
OF
PUBLIC SERVICE ENTERPRISE GROUP
INCORPORATED

ARTICLE I.

DIRECTORS.

SECTION 1. (a) Number, election and terms. Except as otherwise fixed by or pursuant to the provisions of Article 3 of the Certificate of Incorporation relating to the rights of the holders of any class or series of stock having a preference over the Common Stock as to dividends or upon liquidation to elect additional directors under specified circumstances, the number of the directors of the corporation shall be fixed from time to time by the Board of Directors but shall not be less than 3 nor more than 16. The directors, other than those who may be elected by the holders of any class or series of stock having a preference over the Common Stock as to dividends or upon liquidation, shall hold office for a term expiring at the next annual meeting of the stockholders of the corporation or until their respective successors are elected and qualified; provided, however, that directors elected to terms expiring at the 2010 annual meeting of stockholders shall continue to hold office until their respective successors are elected and qualified. As used in these By-Laws, the term "entire Board" means the total number of directors which the corporation would have if there were no vacancies.

(b) Stockholder nomination of director candidates. Advance notice of stockholder nominations for election of directors shall be given in the manner provided in Article IX, Section 9 of these By-Laws.

(c) Newly created directorships and vacancies. Except as otherwise provided for or fixed by or pursuant to the provisions of Article 3 of the Certificate of Incorporation relating to the rights of the holders of any class or series of stock having a preference over the Common Stock as to dividends or upon liquidation to elect directors under specified circumstances, newly created directorships resulting from any increase in the number of directors and any vacancies on the Board of Directors resulting from death, resignation, disqualification, removal or other cause shall be filled by the affirmative vote of a majority of the remaining directors then in office, even though less than a quorum of the Board of Directors. Any director elected in accordance with the preceding sentence shall hold office until the next succeeding annual meeting of stockholders and until such director's successor shall have been elected and qualified. No decrease in the number of directors constituting the Board of Directors shall shorten the term of any incumbent director.

(d) Removal and Suspension. Subject to the rights of any class or series of stock having a preference over the Common Stock as to dividends or upon liquidation to elect directors under specified circumstances, any director may be removed from office without cause only by the affirmative vote of the holders of 80% of the combined voting power of the then outstanding

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shares of stock entitled to vote generally in the election of directors, voting together as a single class. The Board of Directors, by the affirmative vote of a majority of the directors in office, may remove a director or directors for cause where, in the judgment of such majority, the continuation of the director or directors in office would be harmful to the corporation and may suspend the director or directors for a reasonable period pending final determination that cause exists for such removal.

(e) Inclusion of stockholder director nominations in the corporation's proxy materials. The corporation shall include in its proxy statement for an annual meeting of stockholders the name, together with the Required Information (as defined below), of any person nominated for election ("Stockholder Nominee") in a timely notice, as set forth below, delivered by one or more stockholders who at the time of the request is delivered satisfy the ownership and other requirements of this Section 1(e) (such stockholder or stockholders, the "Eligible Stockholder"), and who expressly elect at the time of providing such written notice to have its nominee included in the corporation's proxy materials. To be timely, a stockholder's proxy access notice, which shall include the Required Information, must be delivered to and received by the Secretary no earlier than 150 days and no later than 120 days prior to the anniversary of the mailing date of the corporation's proxy statement in the prior year.

(1) For purposes of this Section 1(e), the "Required Information" that the corporation will include in its proxy statement is (i) information concerning the Stockholder Nominee and the Eligible Stockholder that, as determined by the corporation, is required to be disclosed in a proxy statement filed pursuant to the proxy rules of the Securities and Exchange Commission ("SEC"), (ii) if the Eligible Stockholder so elects, a Statement (as defined below), and (iii) any direct or indirect compensation and other monetary arrangement and understandings between the Stockholder Nominee and Eligible Stockholder related thereto. The corporation may in its sole discretion solicit against, and include in the proxy statement its own statement or other information relating to, any Eligible Stockholder and/or Stockholder Nominee, including any information provided to the corporation with respect to the foregoing.

(2) The number of Stockholder Nominees (including Stockholder Nominees that were submitted by an Eligible Stockholder for inclusion in the corporation's proxy materials pursuant to this Section 1(e) but either are subsequently withdrawn or that the Board of Directors decides to nominate) appearing in the corporation's proxy materials with respect to a meeting of stockholders shall not exceed 25% of the number of directors in office as of the last day on which notice of a nomination may be delivered pursuant to this Section 1(e), or if such amount is not a whole number, the closest whole number below 25%. In the event that the number of Stockholder Nominees submitted pursuant to this Section 1(e) exceeds this maximum number, each Eligible Stockholder shall select one Stockholder Nominee for inclusion in the corporation's proxy materials until the maximum number is reached, going in the order of the number (largest to smallest) of shares of the corporation's Common Stock that each Eligible Stockholder owns as disclosed in the written notice of the nomination submitted to the corporation. If the maximum number is not reached after each Eligible Stockholder has selected one Stockholder Nominee, this selection process shall continue as many times as necessary, following the same order each time, until the maximum number is reached.

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(3) An Eligible Stockholder must have owned (as defined below) 3% or more of the corporation's outstanding Common Stock continuously for at least three years (the "Required Shares") as of both the date the written notice of the nomination is delivered to and received by the corporation in accordance with this Section 1(e) and the record date for determining stockholders entitled to vote at the meeting and must continue to own the Required Shares through the meeting date. For purposes of satisfying the foregoing ownership requirement, (i) the shares of Common Stock owned by one or more stockholders, or by the person or persons who own shares of the corporation's Common Stock and on whose behalf any stockholder is acting, may be aggregated, provided that the number of stockholders and other persons whose ownership of shares is aggregated for such purpose shall not exceed twenty, and (ii) a group of funds under common management and investment control shall be treated as one stockholder or person for this purpose. Within the time period specified in this Section 1(e) for providing notice of a nomination, an Eligible Stockholder must provide the following information in writing to the Secretary: (i) one or more written statements from the record holder of the shares (and from each intermediary through which the shares are or have been held during the requisite three-year holding period) verifying that, as of a date within seven calendar days prior to the date the written notice of the nomination is delivered to and received by the corporation, the Eligible Stockholder owns, and has owned continuously for the preceding three years, the Required Shares, and the Eligible Stockholder's agreement to provide, within five business days after the record date for the meeting, written statements from the record holder and intermediaries verifying the Eligible Stockholder's continuous ownership of the Required Shares through the record date, (ii) the written consent of each Stockholder Nominee to be named in the proxy statement as a nominee and to serve as a director if elected, and such consent shall include an affirmative representation that the Stockholder Nominee will comply with all of the corporation's policies and guidelines applicable to directors, including the confidentiality provision of the Standards of Integrity, which prohibits the disclosure of the corporation's confidential information, (iii) a copy of the Schedule 14N that has been filed with the SEC as required by Rule 14a-18 under the Securities Exchange Act of 1934, as may be amended ("Exchange Act"), (iv) a statement as to whether the Stockholder Nominee (a) is an officer or director of a public utility as defined in Section 305 of the Federal Power Act of 1935, as may be amended and (b) has any relationship, or any immediate family member has any relationship, with (x) the firm selected by the company to serve as its independent auditor and (y) the firm selected by the Board to serve as its independent compensation consultant, (v) a representation that the Eligible Stockholder (including each member of any group of stockholders that together is an Eligible Stockholder hereunder) (a) acquired the Required Shares in the ordinary course of business and not with the intent to change or influence control at the corporation, and does not presently have such intent, (b) has not nominated and will not nominate for election to the Board of Directors at the meeting any person other than the Stockholder Nominee(s) being nominated pursuant to this Section 1(e), (c) has not engaged and will not engage in, and has not and will not be, a "participant" in another person's "solicitation" within the meaning of Rule 14a-1(l) under

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the Exchange Act in support of the election of any individual as a director at the meeting other than its Stockholder Nominee or a nominee nominated by the Board, (d) will not distribute to any stockholder any form of proxy for the meeting other than the form distributed by the corporation, (e) intends to continue to own the Required Shares through the date of the meeting, and (f) will provide facts, statements and other information in all communications with the corporation and its stockholders that are or will be true and correct in all material respects and do not and will not omit to state a material fact necessary in order to make the statements made, in light of the circumstances under which they were made, not misleading, (vi) a description of the amount and terms of any direct or indirect compensation and other monetary arrangement and understandings between the Stockholder Nominee and Eligible Stockholder related to the proxy access nomination, (vii) an undertaking that the Eligible Stockholder agrees to (a) assume all liability stemming from any legal or regulatory violation arising out of the Eligible Stockholder's communications with the corporation's stockholders or out of the information that the Eligible Stockholder provided to the corporation, (b) indemnify and hold harmless the corporation and each of its directors, officers and employees individually against any liability, loss or damages in connection with any threatened or pending action, suit or proceeding, whether legal, administrative or investigative, against the corporation or any of its directors, officers or employees arising out of any nomination submitted by the Eligible Stockholder pursuant to this Section 1(e), and (c) comply with all other applicable laws, rules, regulations and listing standards with respect to any solicitation in connection with the meeting, and (viii) an undertaking that the Stockholder Nominee will complete a directors and officers questionnaire at the time such questionnaire is distributed to the nominees nominated by the Board and will provide such other information as may be reasonably requested by the Board in order to assess the compliance by the Stockholder Nominee with the requirements and conditions for inclusion of the Stockholder Nominee's name in its proxy materials. The inspector of elections shall not give effect to the Eligible Stockholder's votes with respect to the election of directors if the Eligible Stockholder does not comply with each of the representations noted above.

(4) For purposes of this Section 1(e), an Eligible Stockholder shall be deemed to "own" only those outstanding shares of the corporation's Common Stock as to which the stockholder possesses both (i) the full voting and investment rights pertaining to the shares and (ii) the full economic interest in (including the opportunity for profit and risk of loss on) such shares; provided that the number of shares calculated in accordance with clauses (i) and (ii) shall not include any shares (a) sold by such stockholder or any of its affiliates in any transaction that has not been settled or closed, (b) borrowed by such stockholder or any of its affiliates for any purposes or purchased by such stockholder or any of its affiliates pursuant to an agreement to resell or (c) subject to any option, warrant, forward contract, swap, contract of sale, other derivative or similar agreement entered into by such stockholder or any of its affiliates, whether any such instrument or agreement is to be settled with shares or with cash based on the notional amount or value of outstanding shares of the corporation's Common Stock, in any such case which instrument or agreement has, or is intended to have, the purpose or effect of (1) reducing in any manner, to any extent or at any time in the future, such stockholder's or affiliate's full right to vote or direct the voting of any such shares, and/or (2) hedging, offsetting or altering to

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any degree gain or loss arising from the full economic ownership of such shares by such stockholder or affiliate. A stockholder shall "own" shares held in the name of a nominee or other intermediary so long as the stockholder retains the right to instruct how the shares are voted with respect to the election of directors and possesses the full economic interest in the shares. A stockholder's ownership of shares that otherwise satisfies the requirements under this Section 1(e) shall be deemed to continue during any period in which the stockholder has (i) delegated any voting power by means of a proxy, power of attorney or other instrument or arrangement that is revocable at any time by the stockholder, (ii) loaned such shares, provided that such stockholder has the power to recall such loaned shares on three business days' notice; or (iii) delegated any voting power by means of a proxy, power of attorney or other instrument or arrangement that is revocable at any time by such stockholder. Whether outstanding shares of the corporation's Common Stock are "owned" for these purposes shall be determined by the Board of Directors, which determination shall be conclusive and binding on the corporation and its stockholders. For purposes of this Section 1(e), the term "affiliate" shall have the meaning ascribed thereto in the regulations promulgated under the Exchange Act.

(5) The Eligible Stockholder may provide to the Secretary, within the notice period specified above, a written statement for inclusion in the corporation's proxy statement for the meeting, not to exceed 500 words, in support of the Stockholder Nominee's candidacy (the "Statement"). Notwithstanding anything to the contrary contained in this Section 1(e), the corporation may omit from its proxy materials any information or Statement that it believes would violate any applicable law, rule, regulation or listing standard.

(6) The corporation shall not be required to include, pursuant to this Section 1(e), a Stockholder Nominee in its proxy materials (i) for any meeting for which the Secretary receives a notice that the Eligible Stockholder does not expressly elect at the time of providing the notice to have its nominee included in the corporation's proxy materials pursuant to this Section 1(e), (ii) if the Eligible Stockholder who has nominated such Stockholder Nominee has engaged in or is currently engaged in, or has been or is a "participant" in another person's, "solicitation" within the meaning of Rule 14a-1(l) under the Exchange Act in support of the election of any individual as a director at the meeting other than its Stockholder Nominee(s) or a nominee nominated by the Board, (iii) who is not independent under the independence standards for directors adopted by the Board, (iv) whose election as a member of the Board of Directors would cause the corporation to be in violation of these By-Laws, the corporation's certificate of incorporation, the listing standards of the principal exchange upon which the corporation's Common Stock is traded, or any applicable state or federal law, rule or regulation, (v) who is or has been, within the past three years, an officer or director of a competitor, as defined in Section 8 of the Clayton Antitrust Act of 1914, (vi) who is a named subject of a pending criminal proceeding (excluding traffic violations and other minor offenses) or has been convicted in such a criminal proceeding within the past ten years, (vii) who is subject to any order of the type specified in Rule 506(d) of Regulation D promulgated under the Securities Act of 1933, as amended, (viii) if such Stockholder Nominee or the applicable Eligible Stockholder shall have provided information to the corporation in respect to such nomination that was untrue in any

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material respect or omitted to state a material fact necessary in order to make the statement made, in light of the circumstances under which they were made, not misleading, as determined by the Board of Directors, or (ix) if the Eligible Stockholder or applicable Stockholder Nominee otherwise contravenes any of the agreements or representations made by such Eligible Stockholder or Stockholder Nominee or fails to comply with its obligations pursuant to this Section 1(e).

(7) Notwithstanding anything to the contrary set forth herein, the Board of Directors or the person presiding at the meeting shall declare a nomination by an Eligible Stockholder to be invalid, and such nomination shall be disregarded notwithstanding that proxies in respect of such vote may have been received by the corporation, if (i) the Stockholder Nominee(s) and/or the applicable Eligible Stockholder shall have breached its or their obligations, agreements or representations under this Section 1(e), as determined by the Board of Directors or the person presiding at the meeting, or (ii) the Eligible Stockholder (or a qualified representative thereof) does not appear at the meeting to present any nomination pursuant to this Section 1(e).

(8) The Eligible Stockholder (including any person who owns shares that constitute part of the Eligible Stockholder's ownership for purposes of satisfying the requirements of this Section 1(e)) shall file with the SEC any solicitation or other communication with the corporation's stockholders relating to the meeting at which the Stockholder Nominee will be nominated, regardless of whether any such filing is required under Regulation 14A of the Exchange Act or whether any exemption from filing is available for such solicitation or other communication under Regulation 14A of the Exchange Act.

(9) No person may be a member of more than one group of persons constituting an Eligible Stockholder under this Section 1(e).

SECTION 2. The Board of Directors, by the affirmative vote of a majority of directors in office and irrespective of any personal interest of any of them, may establish reasonable compensation of directors for services to the corporation as directors, officers, or otherwise.

SECTION 3. Except as provided in Section 1 of Article I of these By-Laws and in this paragraph, each director shall be elected by the vote of the majority of the votes cast with respect to the director at any meeting for the election of directors at which a quorum is present; provided that if the number of nominees exceeds the number of directors to be elected, the directors shall be elected by the vote of a plurality of the shares represented in person or by proxy at any such meeting and entitled to vote on the election of directors. A majority of votes cast means that the number of shares cast "for" a director's election exceeds the number of votes cast "against" that director. The following shall not be votes cast: (i) a share which is marked as withheld; (ii) a share otherwise present at the meeting but for which there is an abstention; and (iii) a share otherwise present at the meeting as to which a shareholder gives no authority or direction.

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ARTICLE II.

OFFICERS.

SECTION 1. The elective officers of the corporation shall include a President, one or more Vice Presidents, a Secretary, one or more Assistant Secretaries, a Treasurer, and one or more Assistant Treasurers, and may also include a Chairman of the Board, one or more Senior Executive Vice Presidents, one or more Executive Vice Presidents, and one or more Senior Vice Presidents. The Chairman of the Board and the President shall be members of the Board of Directors. All elective officers of the corporation shall be elected by the Board of Directors at the first meeting thereof after the annual election of directors. The Board of Directors shall also have power, at any time, to elect additional Senior Executive Vice Presidents, Executive Vice Presidents, Senior Vice Presidents, Vice Presidents, Assistant Secretaries, and Assistant Treasurers. The Board of Directors may appoint such other officers as it shall from time to time deem necessary, who shall have such powers and perform such duties as may be assigned to them by the Board of Directors, the Executive Committee, or the person exercising the authority of the chief executive officer of the corporation. Any two or more offices may be held by the same person.

The Board of Directors shall have the power to fill any vacancy in any existing office or to fill any newly created office, at any time.

The Chairman of the Board, the President, each Senior Executive Vice President, each Executive Vice President, each Senior Vice President, and each Vice President, severally, shall have the power to sign deeds, contracts, and other instruments. Each elective officer shall have such powers and perform such duties as may be assigned to him by the Board of Directors, the Executive Committee, or the chief executive officer, in addition to any powers and duties that are assigned to him specifically by these By-Laws.

The term of office of each officer shall be from the time of his or her election or appointment and qualification until the first meeting of the Board of Directors after the last annual election of Directors, or such other term of office as shall be provided in the resolution of election or appointment, and until the election or appointment and qualification of his or her successor, subject to earlier termination by removal or resignation.

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ARTICLE III.

CHAIRMAN OF THE BOARD; PRESIDENT;
SENIOR EXECUTIVE VICE PRESIDENTS;
EXECUTIVE VICE PRESIDENTS; SENIOR VICE PRESIDENTS.

SECTION 1. If there be a Chairman of the Board, he shall preside at all meetings of the stockholders and of the Board of Directors, and shall have such other powers and perform such other duties as may be assigned to him by the Board of Directors or the Executive Committee.

SECTION 2. If there be a Chairman of the Board, the Board of Directors shall designate either the Chairman of the Board or the President as the chief executive officer of the corporation with plenary powers of supervision and direction of the business and affairs of the corporation, unless such offices are occupied by the same person. If there be no Chairman of the Board, the President shall be the chief executive officer.

SECTION 3. If there be a Chairman of the Board and if he be designated as the chief executive officer of the corporation, the President shall have charge of the coordination and supervision of all matters of operation of the corporation. In the absence of the Chairman of the Board, the President shall have the powers and perform the duties of the Chairman of the Board.

SECTION 4. The Senior Executive Vice Presidents, severally, in the order designated by the Chief Executive Officer, shall, in the absence of the President, have the powers and perform the duties of the President, and if there be a Chairman of the Board, they shall, in the absence of the Chairman of the Board and the President, have the powers and perform the duties of the Chairman of the Board.

SECTION 5. The Executive Vice Presidents, severally, in the order designated by the chief executive officer, shall, in the absence of the President and the Senior Executive Vice Presidents, have the powers and perform the duties of the President, and if there be a Chairman of the Board, they shall, in the absence of the Chairman of the Board and the President, have the powers and perform the duties of the Chairman of the Board.

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SECTION 6. The Senior Vice Presidents, severally, in the order designated by the chief executive officer, shall, in the absence of the President, the Senior Executive Vice Presidents and the Executive Vice Presidents, have the powers and perform the duties of the President, and if there be a Chairman of the Board, they shall, in the absence of the Chairman of the Board, the President, the Senior Executive Vice Presidents and the Executive Vice Presidents, have the powers and perform the duties of the Chairman of the Board.

ARTICLE IV.

VICE PRESIDENTS.

SECTION 1. The Vice Presidents, severally, in the order designated by the chief executive officer, shall, in the absence of the President, the Senior Executive Vice Presidents, the Executive Vice Presidents and the Senior Vice Presidents, have the powers and perform the duties of the President, and if there be a Chairman of the Board, they shall, in the absence of the Chairman of the Board, the President, the Senior Executive Vice Presidents, the Executive Vice Presidents and the Senior Vice Presidents, have the powers and perform the duties of the Chairman of the Board.

ARTICLE V.

SECRETARY.

SECTION 1. The Secretary shall keep minutes of all meetings of the stockholders of the Board of Directors and of the Executive Committee, and shall give all notices of meetings of the stockholders, of the Board of Directors, and of the Executive Committee. He shall have custody of all deeds, contracts, and other instruments, documents, and records, except as otherwise provided in these By-Laws, or by the Board of Directors, and shall attend to such correspondence of the corporation as the Board of Directors or the chief executive officer shall direct. He shall be the custodian of the seal of the corporation and shall affix it to any instrument requiring the same, except as otherwise provided herein or by the Board of Directors.

ARTICLE VI.

ASSISTANT SECRETARIES.

SECTION 1. Each Assistant Secretary shall have such powers and shall perform such duties as may be assigned to him by the Secretary. In the absence of the Secretary, the Assistant Secretaries, in the order designated by the Secretary, shall have the powers and perform the duties of the Secretary.

ARTICLE VII.

TREASURER.

SECTION 1. The Treasurer shall have charge of all receipts and disbursements of the corporation and shall be the custodian of the corporation's funds. He shall have full authority to receive and give receipts for all moneys due and payable to the corporation from any source whatever, and to endorse or cause to be endorsed checks, drafts, warrants, and other instruments for the payment of money in its name and on its behalf, and full discharge for the

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same to give. The funds of the corporation shall be deposited in its name in such depositaries as may be designated from time to time by the Board of Directors or by the Treasurer if the Board of Directors shall authorize him to do so. All checks, drafts, and other instruments for the payment of money, and all notes and other evidences of indebtedness, issued in the name of the corporation, shall be signed by such officer or officers, employee or employees, agent or agents, of the corporation, and in such manner, including the use of facsimile signatures, as shall be determined from time to time by the Board of Directors, or by the Treasurer if the Board of Directors shall authorize him to make such determination. A report of the financial condition of the corporation shall be made by the Treasurer whenever requested by the chief executive officer. If required by the Board of Directors, he shall give bond for the faithful performance of his duties, in such sum and with such surety or sureties as the Board of Directors may determine.

ARTICLE VIII.

ASSISTANT TREASURERS.

SECTION 1. Each Assistant Treasurer shall have such powers and shall perform such duties as may be assigned to him by the Treasurer. In the absence of the Treasurer, the Assistant Treasurers, in the order designated by the Treasurer, shall have the powers and perform the duties of the Treasurer.

ARTICLE IX.

MEETINGS.

SECTION 1. The meetings of the Stockholders shall, unless otherwise provided by law, be held at such place, within or without the State of New Jersey, as may be fixed by the Board of Directors and stated in the notice of the meeting.

Each annual meeting of the stockholders for the election of the class of directors for the ensuing year, and for the transaction of such other business as may be brought before the meeting, shall be held at such time, not more than 13 months after the last annual meeting, as may be fixed by the Board of Directors.

SECTION 2. Except as herein or in the Certificate of Incorporation expressly provided to the contrary or as otherwise required by law or except as otherwise fixed by or pursuant to the provisions of Article 3 of the Certificate of Incorporation relating to the rights of the holders of any class or series of stock having a preference over the Common Stock as to dividends or upon liquidation to elect additional directors under specified circumstances, all voting rights in the corporation shall be vested exclusively in the holders of Common Stock.

Except as herein or in the Certificate of Incorporation expressly provided to the contrary or as otherwise required by law or except as otherwise fixed by or pursuant to the provisions of Article 3 of the Certificate of Incorporation relating to the rights of the holders of any class or series of stock having a preference over the Common Stock as to dividends or upon liquidation to elect additional directors under specified circumstances, at all meetings of stockholders the holders of Common Stock shall be entitled to cast one vote for each share of Common Stock held.

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The information contained herein may not be copied, adapted or distributed and is not warranted to be accurate, complete or timely. The user assumes all risks for any damages or losses arising from any use of this information, except to the extent such damages or losses cannot be limited or excluded by applicable law. Past financial performance is no guarantee of future results.

SECTION 3. Every stockholder entitled to vote at a meeting of stockholders or to express consent or dissent without a meeting may authorize another person or persons to act for him by proxy. No proxy shall be valid after 11 months from the date of its execution, unless a longer time is expressly provided therein, but in no event shall a proxy be valid after three years from the date of execution. A proxy shall not be revoked by the death or incapacity of the stockholder but shall continue in force until revoked by the personal representative or guardian of the stockholder. The presence at any meeting of any stockholder who has given a proxy shall not revoke such proxy unless the stockholder shall file written notice of such revocation with the secretary of the meeting prior to the voting of such proxy.

A person named in a proxy as the attorney or agent of a stockholder may, if the proxy so provides, substitute another person to act in his place, including any other person named as an attorney or agent in the same proxy. The substitution shall not be effective until an instrument effecting it is filed with the Secretary.

SECTION 4. All elections for directors shall be by ballot, and the polls at every such election shall remain open so long as may be reasonably necessary to permit all stockholders entitled to vote at such meeting, present in person or by proxy, to cast their votes.

SECTION 5. Special meetings of the stockholders may be called at any time by the Board of Directors or by the chief executive officer or upon the written request of the holders of the capital stock entitled to cast a majority of votes thereat.

Except as otherwise provided by law, and unless waived, written notice of the time, place and purposes of every meeting of stockholders shall be given not less than 10 nor more than 60 days before the date of the meeting, to each stockholder of record entitled to vote at the meeting, either personally or by mailing a notice to him at his last post office address appearing on the books of the corporation.

SECTION 6. At any meeting of the stockholders the holders of stock entitled to cast a majority of the votes at the meeting, present in person or represented by proxy, shall constitute a quorum of the stockholders for all purposes unless the representation of a larger number shall be required by law, and in that case the representation of the number so required shall constitute a quorum.

If the holders of the amount of stock necessary to constitute a quorum shall fail to attend in person or by proxy at the time and place and fixed for any meeting of stockholders, the meeting may be adjourned from time to time by the vote of a majority of the votes cast by the holders of stock present in person or represented by proxy at such meeting, without notice other than by announcement at the meeting, and at any such adjourned meeting held more than one week after such time the holders of stock entitled to cast 40% of the votes at such meeting, present in person or represented by proxy, shall constitute a quorum of the stockholders for all purposes unless the representation of a larger number shall be required by law, and in that case the representation of the number so required shall constitute a quorum. At any such adjourned meeting, whenever held, at which a quorum shall be present, any business may be transacted which might have been transacted at the meeting as originally called.

SECTION 7. Regular meetings of the Board of Directors shall be held monthly unless otherwise determined by resolution of the Board.

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Special meetings of the Board of Directors may be called at any time by the Chairman of the Board, or by the President if he be the chief executive officer. The Secretary shall also call such meetings on the written request of a majority of the directors.

No notice shall be required for regular meetings of the Board of Directors. The meeting for organization may be held on the day of and after the annual meeting of stockholders. At least two days' notice of a special meeting of the Board of Directors shall be given, but this notice may be waived in writing or by telegraph, either before or after the meeting. A meeting may be held without notice at any time when all the directors are present.

At all meetings of the Board of Directors a majority of the directors in office, or one-third of the entire Board, whichever is greater, shall constitute a quorum for the transaction of business. A less number than a quorum, however, may meet and adjourn to any day.

SECTION 8. The Board of Directors may, in advance of any meeting of stockholders, appoint one or more inspectors to act at the meeting or any adjournment thereof. If inspectors are not so appointed by the Board of Directors or shall fail to qualify, the person presiding at a meeting of stockholders may, and on the request of any stockholder entitled to vote thereat, shall make such appointment. In case any person appointed as inspector fails to appear or act, the vacancy may be filled by appointment made by the Board of Directors in advance of the meeting of stockholders or at the meeting by the person presiding at the meeting. Each inspector, before entering upon the discharge of his duties, shall take and sign an oath faithfully to execute the duties of inspector at such meeting with strict impartiality and according to the best of his ability. No person shall be elected a director at a meeting at which he has served as an inspector.

SECTION 9. Subject to the rights of holders of any class or series of stock having a preference over the Common Stock as to dividends or upon liquidation, nominations for the election of directors may be made by the Board of Directors or a committee appointed by the Board of Directors or by any stockholder entitled to vote in the election of directors generally. However any stockholder entitled to vote in the election of directors generally may nominate one or more persons for election as directors at a meeting only if written notice of such stockholder's intent to make such nomination or nominations has been given, either by personal delivery or by United States mail, postage prepaid, to the Secretary not later than (i) with respect to an election to be held at an annual meeting of stockholders, 90 days in advance of such meeting, and (ii) with respect to an election to be held at a special meeting of stockholders for the election of directors, the close of business on the seventh day following the date on which notice of such meeting is first given to stockholders. Each such notice shall set forth: (a) the name and address of the stockholder who intends to make the nomination and of the person or persons to be nominated; (b) a representation that the stockholder is a holder of record of stock of the corporation entitled to vote at such meeting and intends to appear in person or by proxy at the meeting to nominate the person or persons specified in the notice; (c) a description of all arrangements or understandings between the stockholder and each nominee and any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by the stockholder; (d) such other information regarding each nominee proposed by such stockholder as would be required to be included in a proxy statement filed pursuant to the proxy rules of the Securities and Exchange Commission, had the nominee been nominated, or intended to be nominated, by the Board of Directors; and (e) the consent of each nominee to serve as a director of the corporation if so elected. The Chairman of the meeting may refuse to acknowledge the nomination of

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any person not made in compliance with the foregoing procedure. Nothing in this Section 9 shall be construed to require any such stockholder nomination to be included in any Proxy Statement issued on behalf of the Board of Directors or to require the Board to endorse any such nomination.

ARTICLE X.

RECORD DATE FOR DETERMINATION OF
RIGHTS OF STOCKHOLDERS.

SECTION 1. For the purpose of determining the stockholders entitled to notice of or to vote at any meeting of stockholders or any adjournment thereof, or to express consent to or dissent from any proposal without a meeting, or for the purpose of determining stockholders entitled to receive payment of any dividend or allotment of any right, or for the purpose of any other action, the Board of Directors may fix, in advance, a date as the record date for any such determination of stockholders. Such date shall not be more than 60 nor less than 10 days before the date of such meeting, nor more than 60 days prior to any other action. When a determination of stockholders entitled to notice of or to vote at any meeting of stockholders has been so made, such determination shall apply to any adjournment thereof, unless the Board of Directors fixes a new record date for the adjourned meeting.

ARTICLE XI.

COMMITTEES.

SECTION 1. The Board of Directors, by resolution adopted by a majority of the entire Board, may appoint from among its members an Executive Committee and one or more other committees. Except as otherwise provided by law, the Executive Committee shall have and may exercise all the authority of the Board of Directors when the Board is not in session, and each such other committee of the Board shall have and may exercise the authority of the Board to the extent provided in the resolution of appointment.

The Board of Directors, by resolution adopted by a majority of the entire Board, may (a) fill any vacancy in any committee of the Board, (b) appoint one or more directors to serve as alternate members of any such committee, to act in the absence or disability of members of any such committee with all the powers of such absent or disabled members (c) abolish any such committee at its pleasure and (d) remove any director from membership on such committee at any time, with or without cause.

Actions taken at a meeting of any committee of the Board of Directors shall be reported to the Board at its next meeting following such committee meeting; except that, when the meeting of the Board is held within two days after the committee meeting, such report shall, if not made at the first meeting, be made to the Board at its second meeting following such committee meeting.

SECTION 2. The Board of Directors may appoint and prescribe the powers and duties of other committees, the members of which may but need not be directors and shall serve at the pleasure of the Board.

SECTION 3. One-third of the entire committee, or two members, whichever is greater, shall constitute a quorum for the transaction of business.

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SECTION 4. Each committee shall fix its own rules of procedure, shall meet where and as provided by such rules of procedure or by resolution of the Board of Directors, shall keep full records of its proceedings, and shall report from time to time to the Board as called upon by the Board.

ARTICLE XII.

VOTING UPON STOCKS OWNED BY THE CORPORATION.

SECTION 1. Unless otherwise ordered by the Board of Directors, the Chairman of the Board, the President, the Senior Executive Vice Presidents, the Executive Vice Presidents, the Senior Vice Presidents and the Vice Presidents, severally, shall each have full power and authority on behalf of the corporation to attend, act, and vote at any meeting of the stockholders of any corporation in which this corporation may hold stock, and to appoint one or more other persons as proxy or proxies to attend, act, and vote at any such meeting and such officer or such proxy or proxies shall possess and may exercise on behalf of this corporation any and all rights and powers incident to its ownership of such stock. The Board of Directors or the Executive Committee from time to time by resolution may confer like powers upon any other person or persons.

ARTICLE XIII.

STOCK.

SECTION 1. The shares of stock in this corporation may be represented by certificates or may be uncertificated shares. To the extent that certificates shall be issued for shares of stock in this corporation, such certificates shall be signed by the Chairman of the Board, the President, or a Vice President, and either the Treasurer or an Assistant Treasurer, or the Secretary or an Assistant Secretary. If the certificate is countersigned by a transfer agent or registrar, who is not an officer or employee of the corporation, any and all other signatures may be facsimiles.

SECTION 2. The shares of stock issued by this corporation shall be transferable only on the books of the corporation by the holder or owner thereof in person or by power of attorney, and if such shares are represented by a certificate, on surrender of the certificate therefor.

SECTION 3. The Treasurer shall make and certify a complete list of the stockholders entitled to vote at a meeting of stockholders or any adjournment thereof. Such list shall be arranged alphabetically within each class and series, with the addresses of, and the number of shares held by, each stockholder, shall be produced at the time and place of the meeting, and shall be subject to the inspection of any stockholder during the whole time of the meeting.

ARTICLE XIV.

FISCAL YEAR.

SECTION 1. The fiscal year of the corporation shall begin on January first of each year.

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ARTICLE XV.

SEAL.

SECTION 1. The seal of the corporation shall be circular in form, and shall have inscribed thereon the following words and figures: "PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED Incorporated 1985".

ARTICLE XVI.

AMENDMENTS.

SECTION 1. Subject to the provisions of the Certificate of Incorporation, these By-Laws may be altered, amended or repealed at any regular meeting of the stockholders (or at any special meeting thereof duly called for that purpose) by a majority vote of the shares represented and entitled to vote at such meeting. Subject to the laws of the State of New Jersey, the Certificate of Incorporation and these By-Laws, the Board of Directors may by majority vote of those present at any meeting at which a quorum is present amend these By-Laws or enact such other By-Laws as in their judgment may be advisable for the regulation of the conduct of the affairs of the corporation.

ARTICLE XVII.

ADVANCEMENT OF EXPENSES.

SECTION 1. Expenses incurred by any person made, or threatened to be made, a party to any pending, threatened or completed civil, criminal, administrative or arbitrative action, suit or proceeding and any appeal therein (and any inquiry or investigation which could lead to such action, suit or proceeding) by reason of the fact that he is or was a director, officer or employee of the corporation or serves or served any other enterprise as a director, officer or employee at the request of the corporation, shall be paid by the corporation in advance of the final disposition of the action, suit or proceeding promptly upon receipt of an undertaking by or on behalf of such person to repay such amount if it shall ultimately be determined that such person is not entitled to be indemnified by the corporation.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported)
December 19, 2017

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)

973-430-7000
(Registrant's telephone number, including area code)

http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers.

On December 19, 2017, upon the recommendation of the Corporate Governance Committee, the Board of Directors (the "Board") of Public Service Enterprise Group Incorporated (the "Company") increased the size of the Board to twelve directors and elected Barry H. Ostrowsky to serve as a new director, in each case effective February 20, 2018. The Board has determined that Mr. Ostrowsky is an independent director within the meaning of the listing standards of the New York Stock Exchange and the Securities Exchange Act of 1934, as amended. Mr. Ostrowsky has not been named to any committees of the Board at this time, although the Board expects to name him to one or more committees in the future.

As of February 20, 2018, Mr. Ostrowsky will participate in the Company's compensation plans for non-management directors, as described under "Proposal 1: Election of Directors—Director Compensation" in the Company's proxy statement filed with the Securities and Exchange Commission on March 14, 2017.

As part of the Company's philanthropic activities and commitment to invest in the communities in which we do business, the Company, directly or through a subsidiary, and PSEG Foundation, a 501(c)(3) organization that is funded by the Company, have periodically made charitable contributions to facilities operated by RWJ Barnabas Health, Inc., a not-for-profit, tax-exempt corporation incorporated in New Jersey ("RWJBarnabas"). Mr. Ostrowsky is the President and Chief Executive Officer of RWJBarnabas. In 2016, the Company and PSEG Foundation, collectively, donated approximately $363,500 to facilities operated by RWJBarnabas and its predecessor entities. To date in 2017, the Company and PSEG Foundation, collectively, have donated approximately $186,550 to facilities operated by RWJBarnabas. The Board expects that the Company and PSEG Foundation will make future contributions to facilities operated by RWJBarnabas. PSEG Foundation has already pledged a $125,000 contribution to one facility operated by RWJBarnabas, to occur in 2018.

Since 2008, the Company's subsidiary, Public Service Electric and Gas Company ("PSE&G"), has engaged in an ongoing Hospital Energy Efficiency Program (the "HEE Program"), through which PSE&G provides funds for energy efficiency upgrades to hospitals throughout the PSE&G service territory. The HEE Program was approved, and is overseen, by the New Jersey Board of Public Utilities (the "BPU"). As of September 1, 2017, PSE&G has committed to invest approximately $199 million in a variety of hospitals through the HEE Program, including commitments of approximately $30.6 million to RWJBarnabas facilities. These projects are in various stages of completion, with several fully completed and others in progress or in the planning stage. The aggregate portion that RWJBarnabas facilities have committed to repay to PSE&G through utility bills in accordance with the BPU-approved terms of the program is equal to approximately $10.7 million. Because the HEE Program is ongoing, the investment and repayment figures are subject to change in the coming years.

Since 2013, the Company's subsidiary, PSEG Services Corporation, has had a contractual arrangement with an RWJBarnabas affiliate, Robert Wood Johnson University Hospital Hamilton ("RWJ Hamilton"), pursuant to which RWJ Hamilton provides medical care, medical testing and related services to the Company and its subsidiaries. In 2016, the Company paid a total of approximately $267,000 for services provided pursuant to this arrangement. As of October 31, 2017, the Company has paid a total of approximately $197,000 for services provided pursuant to this arrangement.

S1-SSA-0009 - 10605

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No arrangement or understanding exists between Mr. Ostrowsky and any other person pursuant to which Mr. Ostrowsky was selected as a director of the Company.

The Company issued a press release on December 22, 2017 announcing the election of Mr. Ostrowsky. A copy of the press release is attached hereto as Exhibit 99.1 and is incorporated herein by reference.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits

Exhibit Number	Description
99.1	Press Release dated December 22, 2017

S1-SSA-0009 - 10606

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
STUART J. BLACK
Vice President and Controller
(Principal Accounting Officer)

Date: December 22, 2017

S1-SSA-0009 - 10607

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EXHIBIT 99.1

Media Relations

Public Service Enterprise Group
80 Park Plaza, T6
Newark, NJ 07102

FOR IMMEDIATE RELEASE
December 22, 2017

CONTACT: Paul Rosengren
973-430-5911
Paul.Rosengren@pseg.com

PSEG elects Barry Ostrowsky to board of directors

(December 22, 2017 – Newark, N.J.) – Public Service Enterprise Group (PSEG) today announced that Barry H. Ostrowsky, president and chief executive officer, RWJBarnabas Health, has been elected to its board of directors, effective February 20.

Mr. Ostrowsky joined Saint Barnabas Medical Center in 1991 as executive vice president and general counsel and served in the same role when Barnabas Health was created in 1996. At Barnabas Health, he became president and chief operating officer in 2010 and president and chief executive officer in 2012. In April 2016, with the merger of Barnabas Health and Robert Wood Johnson Health System, he assumed his present position. He has 20 years of experience, strong leadership skills and broad knowledge of the health care industry.

"Barry's vast experience in leading one of the largest health care systems in our region through this challenging, dynamic and highly regulated environment, combined with his widely acclaimed prominence as a role model of corporate citizenship makes him an invaluable addition to our board of directors," said Ralph Izzo, PSEG's chairman, president and chief executive officer.

Prior to Mr. Ostrowsky's tenure at RWJBarnabas, he was a senior partner in the law firm of Brach, Eichler, Rosenberg, Silver, Bernstein, Hammer and Gladstone. He currently serves on the board of directors of RWJBarnabas Health, Cerebral Palsy of North Jersey, Public Media NJ, Inc. and the New Jersey Chamber of Commerce. He has played an active role in shaping the evolution of New Jersey's health care delivery system and worked closely with physicians, hospitals and insurers to improve the health and wellness of our state's diverse communities.

# # #

Public Service Enterprise Group (NYSE: PEG) is a publicly traded diversified energy company with annual revenues of approximately $9 billion. Its operating subsidiaries are: Public Service Electric and Gas Company (PSE&G), PSEG Power, and PSEG Long Island.

From time to time, PSEG, PSE&G and PSEG Power release important information via postings on their corporate website at http://investor.pseg.com. Investors and other interested parties are encouraged to visit the corporate website to review new postings. The "Email Alerts" link at http://investor.pseg.com may be used to enroll to receive automatic email alerts and/or Really Simple Syndication (RSS) feeds regarding new postings.

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K/A

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) December 19, 2017

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Exact name of registrant as specified in its charter)

New Jersey	001-09120	22-2625848
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

80 Park Plaza
Newark, New Jersey 07102
(Address of principal executive offices) (Zip Code)
973-430-7000
(Registrant's telephone number, including area code)
http://www.pseg.com

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether any of the registrants is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act ☐

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On December 19, 2017, Public Service Enterprise Group Incorporated ("PSEG" or the "Company") elected Mr. Barry H. Ostrowsky to its Board of Directors, effective February 20, 2018, for a term ending at the 2018 Annual Meeting of Stockholders. The Current Report on Form 8-K filed by the Company with the Securities and Exchange Commission on December 22, 2017 is being amended hereby to report Mr. Ostrowsky's appointment as a member of various committees of the Board of Directors.

Item 5.02. Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers

On February 20, 2018, the PSEG Board of Directors appointed Mr. Barry H. Ostrowsky to the PSEG Organization and Compensation Committee and PSEG Finance Committee, effective immediately.

S1-SSA-0009 - 10610

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /s/ Stuart J. Black
STUART J. BLACK
Vice President and Controller
(Principal Accounting Officer)

Date: February 22, 2018

S1-SSA-0009 - 10611

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10-Ks

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
100 F ST., N.E.
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2012,

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange On Which Registered
Public Service Enterprise Group Incorporated	Common Stock without par value	New York Stock Exchange
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange
	First and Refunding Mortgage Bonds	
Public Service Electric and Gas Company	9 1/4% Series CC, due 2021 6 3/4% Series VV, due 2016 8%, due 2037 5%, due 2037	New York Stock Exchange

(Cover continued on next page)

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(Cover continued from previous page)

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
PSEG Power LLC	Limited Liability Company Membership Interest
Public Service Electric and Gas Company	Medium-Term Notes

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Public Service Enterprise Group Incorporated	Yes ☒	No ☐
PSEG Power LLC	Yes ☐	No ☒
Public Service Electric and Gas Company	Yes ☒	No ☐

Indicate by check mark if each of the registrants is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☒

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2012 was $16,420,936,616 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Public Service Enterprise Group Incorporated's sole class of Common Stock as of January 31, 2013 was 505,959,216.

As of January 31, 2013, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K. Each is filing its Annual Report on Form 10-K with the reduced disclosure format authorized by General Instruction I.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K of Public Service Enterprise Group Incorporated	Documents Incorporated by Reference
III	Portions of the definitive Proxy Statement for the 2013 Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 8, 2013, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), Item 8. Financial Statements and Supplementary Data —Note 13. Commitments and Contingent Liabilities, and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC). These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission in the future, and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to balance our energy obligations, available supply and risks,
- any deterioration in our credit quality or the credit quality of our counterparties, including in our leveraged leases,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers,
- increase in competition in energy supply markets as well as competition for certain rate-based transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements, and
- changes in technology and customer usage patterns.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or, even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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FILING FORMAT AND GLOSSARY

This combined Annual Report on Form 10-K is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information relating to any individual company is filed by such company on its own behalf. Power and PSE&G are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, Power, PSE&G and PSEG Energy Holdings L.L.C. (Energy Holdings). Depending on the context of each section, references to "we," "us," and "our" relate to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 191.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and special reports, proxy statements and other information with the SEC. You may read and copy any document that we file at the Public Reference Room of the SEC at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. You may also obtain our filed documents from commercial document retrieval services, the SEC's internet website at www.sec.gov or our website at www.pseg.com. Information on our website should not be deemed incorporated into or as a part of this report. Our Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

PART I

ITEM 1. BUSINESS

We were incorporated under the laws of the State of New Jersey in 1985 and our principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07102. We conduct our business through three direct wholly owned subsidiaries, Power, PSE&G and Energy Holdings, each of which also has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. PSEG Services Corporation (Services), our other wholly owned subsidiary, provides us and these operating subsidiaries with certain management, administrative and general services at cost.

We are an energy company with a diversified business mix. Our operations are located primarily in the Northeastern and Mid- Atlantic United States. Our business approach focuses on operational excellence, financial strength and disciplined investment. As a holding company, our profitability depends on our subsidiaries' operating results. Below are descriptions of our direct operating subsidiaries.

Power	PSE&G	Energy Holdings
A Delaware limited liability company formed in 1999 that integrates its generating asset operations with its wholesale energy sales, fuel supply and energy trading functions. Earns revenues from selling under contract or on the spot market a range of diverse products such as electricity, natural gas, capacity, emissions credits and a series of energy-related products used to optimize the operation of the energy grid.	A New Jersey corporation, incorporated in 1924, which is a franchised public utility in New Jersey. It is also the provider of last resort for gas and electric commodity service for end users in its service territory. Earns revenues from its regulated rate tariffs under which it provides electric transmission and electric and gas distribution to residential, commercial and industrial customers in its service territory. It also offers appliance services and repairs to customers throughout its service territory. Has also implemented demand response and energy efficiency programs and invested in solar generation within New Jersey.	A New Jersey limited liability company (successor to a corporation which was formed in 1989) that invests and operates through its two primary subsidiaries. Earns revenues primarily from its portfolio of lease investments and its solar generation projects.

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The following is a more detailed description of our business, including a discussion of our:

- Business Operations and Strategy
- Competitive Environment
- Employee Relations
- Regulatory Issues
- Environmental Matters

BUSINESS OPERATIONS AND STRATEGY

Power

Through Power, we seek to produce low-cost energy by efficiently operating our nuclear, coal, gas and oil-fired generation facilities, while balancing generation production, fuel requirements and supply obligations through energy portfolio management. We use commodity contracts and financial instruments, combined with our owned generation, to cover our commitments for Basic Generation Service (BGS) in New Jersey and other bilateral supply contract agreements.

Products and Services

As a merchant generator, our profit is derived from selling a range of products and services under contract to power marketers and to others, such as investor-owned and municipal utilities, and to aggregators who resell energy to retail consumers, or in the spot market. These products and services include:

- **Energy**—the electrical output produced by generation plants that is ultimately delivered to customers for use in lighting, heating, air conditioning and operation of other electrical equipment. Energy is our principal product and is priced on a usage basis, typically in cents per kilowatt hour (kWh) or dollars per megawatt hour (MWh).
- **Capacity**—a product distinct from energy, is a market commitment that a given generation unit will be available to an Independent System Operator (ISO) for dispatch if it is needed to meet system demand. Capacity is typically priced in dollars per megawatt (MW) for a given sale period.
- **Ancillary Services**—related activities supplied by generation unit owners to the wholesale market, required by the ISO to ensure the safe and reliable operation of the bulk power system. Owners of generation units may bid units into the ancillary services market in return for compensatory payments. Costs to pay generators for ancillary services are recovered through charges imposed on market participants.
- **Emissions Allowances and Congestion Credits**—Emissions allowances (or credits) represent the right to emit a specific amount of certain pollutants. Allowance trading is used to control air pollution by providing economic incentives for achieving reductions in the emissions of pollutants. Congestion credits (or Financial Transmission Rights) are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path.

Power also sells wholesale natural gas, primarily through a full requirements Basic Gas Supply Service (BGSS) contract with PSE&G to meet the gas supply requirements of PSE&G's customers. This long-term contract was for an initial period which extended through March 31, 2012 and continues on a year-to-year basis thereafter, unless terminated by either party with a one year notice.

Approximately 46% of PSE&G’s peak daily gas requirements is provided from Power’s firm transportation capacity, which is available every day of the year. Power satisfies the remainder of PSE&G’s requirements from storage contracts, liquefied natural gas, seasonal purchases, contract peaking supply, propane and refinery gas. Based upon availability, Power also sells gas to others.

How Power Operates

We own approximately 13,226 MW of generation capacity located in the Northeast and Mid-Atlantic regions of the United States in some of the country’s largest and most developed electricity markets.

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The map below shows the locations of our Northeast and Mid-Atlantic generation facilities

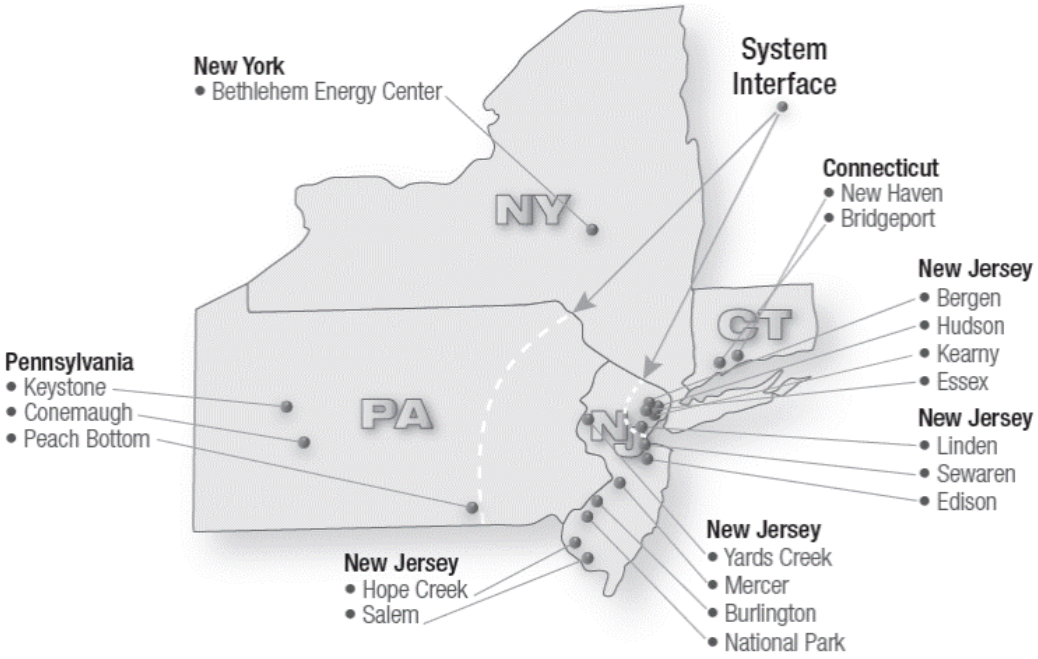

- **Generation Capacity**

Power has approved the expenditure of approximately $192 million for a steam path retrofit and related upgrades at its co-owned Peach Bottom Units 2 and 3. Unit 3 upgrades were completed in October 2011. Unit 2 upgrades were completed in October 2012. The balance of work to ensure efficient operation is expected to be completed by 2014. Total expenditures through December 31, 2012 were $154 million.

Power has also approved the expenditure of $419 million for an extended power uprate of the Peach Bottom nuclear units. The uprate is expected to result in an increase in Power's share of nominal capacity by approximately 130 MW. The uprate is expected to be in service in 2015 for Unit 2 and 2016 for Unit 3. Total expenditures through December 31, 2012 were $73 million.

In 2011, we sold 2,000 MW of generation facilities we owned and operated in Texas. See Item 8. Financial Statements and Supplementary Data —Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies and Note 4. Discontinued Operations and Dispositions, for additional information.

For additional information on each of our generation facilities, see Item 2. Properties.

Our installed capacity utilizes a diverse mix of fuels: 45% gas, 28% nuclear, 18% coal, 8% oil and 1% pumped storage. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2012 was approximately 53,000 gigawatt hours (GWh). The generation mix by fuel type has changed slightly in recent years due to the relatively favorable price of natural gas as compared to coal, making it more economical to run certain of our gas units than our coal units. The following table indicates the proportionate share of generating output by fuel type.

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Generation by Fuel Type	Actual 2012	
Nuclear:		
New Jersey facilities	39%	
Pennsylvania facilities	18%	
Fossil:		
Coal:		
Pennsylvania facilities	9%	
Connecticut facilities	—%	(A)
Coal and Natural Gas:		
New Jersey facilities	2%	
Oil and Natural Gas:		
New Jersey facilities	23%	
New York facilities	9%	
Connecticut facilities	—%	(A)
Total	**100%**	

(A) Less than one percent.

- **Generation Dispatch**

Our generation units are typically characterized as serving one or more of three general energy market segments: base load; load following; and peaking, based on their operating capability and performance. On a capacity basis, our portfolio of generation assets consists of 33% base load, 43% load following and 24% peaking. This diversity helps to reduce the risk associated with market demand cycles and allows us to participate in the market at each segment of the dispatch curve.

- **Base Load Units** run the most and typically operate whenever they are available. These units generally derive revenues from energy and capacity sales. Variable operating costs are low due to the combination of highly efficient operations and the use of relatively lower-cost fuels. Performance is generally measured by the unit's "capacity factor," or the ratio of the actual output to the theoretical maximum output. In 2012, our base load capacity factors were as follows:

Unit	2012 Capacity Factor
Nuclear	
Salem Unit 1	95.2%
Salem Unit 2	87.3%
Hope Creek	89.8%
Peach Bottom Unit 2	85.9%
Peach Bottom Unit 3	99.0%
Coal	
Keystone	63.8%
Conemaugh	71.3%

No assurances can be given that these capacity factors will be achieved in the future.

- **Load Following Units** typically operate between 20% and 80% of the time. The operating costs are higher per unit of output due to lower efficiency and/or the use of higher-cost fuels such as oil, natural gas and, in some cases, coal. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.
- **Peaking Units** run the least amount of time and utilize higher-priced fuels. These units typically operate less than 20% of the time. Costs per unit of output tend to be much higher than for base load units. The majority of

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revenues are from capacity and ancillary service sales. The characteristics of these units enable them to capture energy revenues during periods of high energy prices.

In the energy markets in which we operate, owners of power plants specify to the ISO prices at which they are prepared to generate and sell energy based on the marginal cost of generating energy from each individual unit. The ISOs will dispatch in merit order, calling on the lowest variable cost units first and dispatching progressively higher-cost units until the point that the entire system demand for power (known as the system "load") is satisfied. Base load units are dispatched first, with load following units next, followed by peaking units.

During periods when one or more parts of the transmission grid are operating at full capability, thereby resulting in a constraint on the transmission system, it may not be possible to dispatch units in merit order without violating transmission reliability standards. Under such circumstances, the ISO will dispatch higher-cost generation out of merit order within the congested area and power suppliers will be paid an increased Locational Marginal Price (LMP) in congested areas, reflecting the bid prices of those higher-cost generation units.

The following chart depicts the merit order of dispatch of our units in PJM Interconnection L.L.C. (PJM), where most of our generation units are located, based on illustrative historical dispatch cost. It should be noted that market price fluctuations have resulted in changes from historical norms, with lower gas prices allowing some gas generation to displace some coal generation.

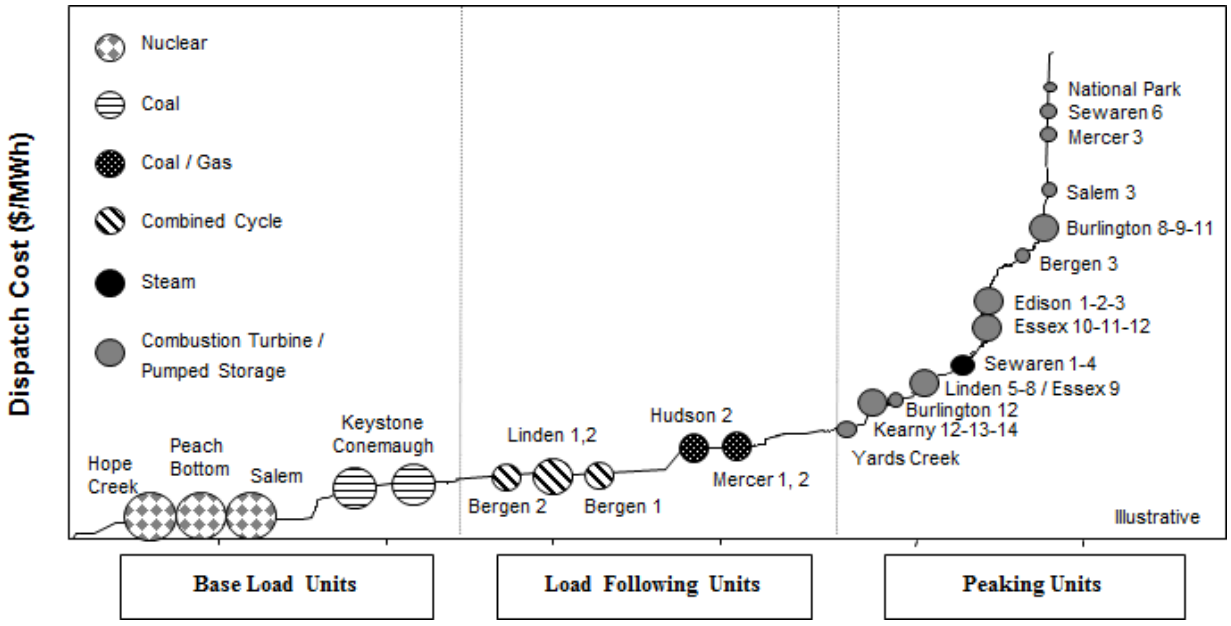

The size of each facility's fuel circle in the above chart illustrates the relative MW capacity of the generating capacity of that facility. For additional information on each of our generation facilities, see Item 2. Properties.

The bid price of the last unit dispatched by an ISO establishes the energy market-clearing price. After considering the market-clearing price and the effect of transmission congestion and other factors, the ISO calculates the LMP for every location in the system. The ISO pays all units that are dispatched their respective LMP for each MWh of energy produced, regardless of their specific bid prices. Since bids generally approximate the marginal cost of production, units with lower marginal costs typically generate higher operating profits than units with comparatively higher marginal costs.

This method of determining supply and pricing creates an environment in the markets such that natural gas prices often have a major impact on the price that generators will receive for their output, especially in periods of relatively strong demand. Therefore, significant changes in the price of natural gas will often translate into significant changes in the wholesale price of electricity. This can be seen in the following graphs which present historical annual spot prices and forward calendar prices as averaged over each year.

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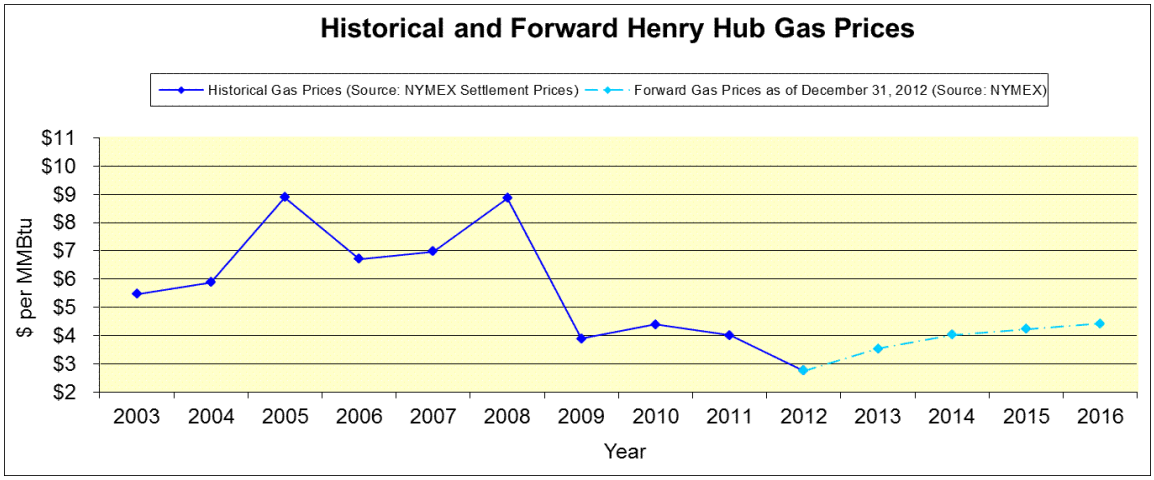

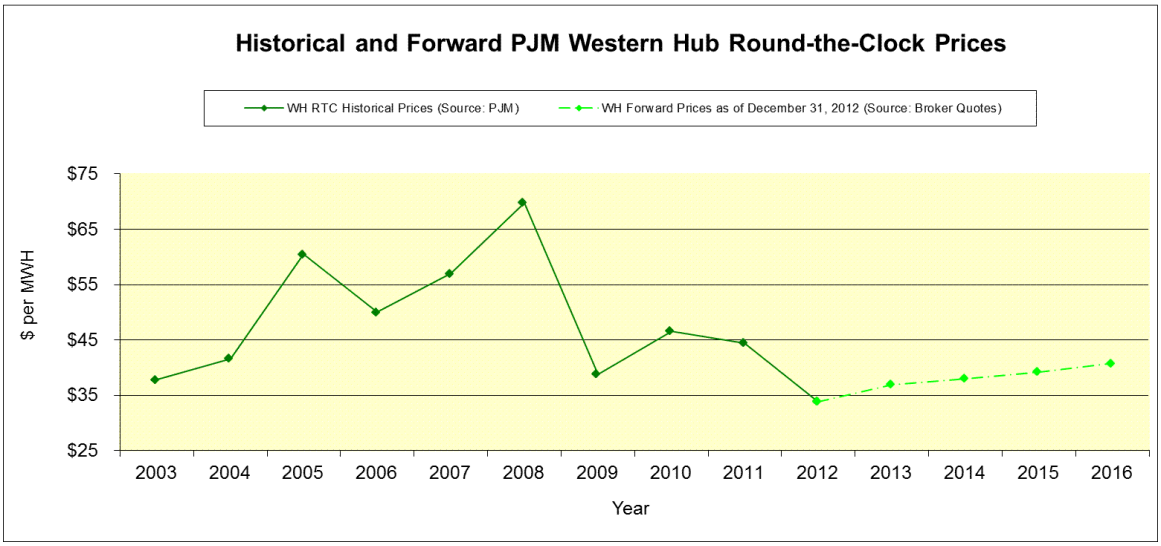

Historical data and forward prices would imply that the price of natural gas will continue to have a strong influence on the price of electricity in the primary markets in which we operate.

The prices reflected in the tables above do not necessarily illustrate our contract prices, but they are representative of market prices at relatively liquid hubs, with nearer-term forward pricing generally resulting from more liquid markets than pricing for later years. In addition, the prices do not reflect locational differences resulting from congestion or other factors, which can be considerable. While these prices provide some perspective on past and future prices, the forward prices are highly volatile and there can be no assurance that such prices will remain in effect or that we will be able to contract output at these forward prices.

Fuel Supply

- ***Nuclear Fuel Supply***—To run our nuclear units we have long-term contracts for nuclear fuel. These contracts provide for:
  - purchase of uranium (concentrates and uranium hexafluoride),
  - conversion of uranium concentrates to uranium hexafluoride,
  - enrichment of uranium hexafluoride, and
  - fabrication of nuclear fuel assemblies.

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- ***Coal Supply***—Coal is the primary fuel for our Keystone, Conemaugh and Bridgeport stations. Coal is also used by Hudson and Mercer which operate on both coal and natural gas. We have coal contracts with numerous suppliers. Coal is delivered to our units through a combination of rail, truck, barge or ocean shipments.

  In order to minimize emissions levels, our Bridgeport 3 unit uses a specific type of coal obtained from Indonesia. If the supply from Indonesia or equivalent coal from other sources was not available for this facility, its long-term operations would be adversely impacted since additional material capital expenditures would be required to modify our Bridgeport 3 station to enable it to operate using a broader mix of coal sources.
- ***Gas Supply***—Natural gas is the primary fuel for the bulk of our load following and peaking fleet. We purchase gas directly from natural gas producers and marketers. These supplies are transported to New Jersey by four interstate pipelines with whom we have contracted. In addition, we have firm gas transportation contracts to serve our Bethlehem Energy Center (BEC) in New York.

  We have 1.3 billion cubic feet-per-day of firm transportation capacity under contract to meet our obligations under the BGSS contract. On an as available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet. We supplement that supply with a total storage capacity of 76 billion cubic feet.
- ***Oil***—Oil is used as the primary fuel for one load following steam unit and nine combustion turbine peaking units and can be used as an alternate fuel by several load following and peaking units that have dual-fuel capability. Oil for operations is drawn from on-site storage and is generally purchased on the spot market and delivered by truck, barge or pipeline.

We expect to be able to meet the fuel supply demands of our customers and our own operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather and other factors. For additional information, see Item 7. Management's Discussion and Analysis (MD&A)—Overview of 2012 and Future Outlook and Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities.

Markets and Market Pricing

Power's generation assets are located in three centralized, competitive electricity markets operated by ISO organizations all of which are subject to the regulatory oversight of the Federal Energy Regulatory Commission (FERC):

- **PJM Regional Transmission Organization**—PJM conducts the largest centrally dispatched energy market in North America. It serves over 60 million people, nearly 20% of the total United States population, and has a peak demand of over 163,848 MW. The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The majority of our generating stations operate in PJM.
- **New York**—The NYISO is the market coordinator for New York State and is responsible for managing the New York Power Pool and for administering its energy marketplace. This service area has a population of about 19 million and a peak demand of over 33,939 MW. Our BEC station operates in New York.
- **New England**—ISO-NE coordinates the movement of electricity in a region covering Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. This service area has a population of about 14 million and a peak demand of over 28,130 MW. Our Bridgeport and New Haven stations operate in Connecticut.

The price of electricity varies by location in each of these markets. Depending upon our production and our obligations, these price differentials can serve to increase or decrease our profitability.

Commodity prices, such as electricity, gas, coal, oil and emissions, as well as the availability of our diverse fleet of generation units to produce these products, also have a considerable effect on our profitability. These commodity prices have been, and continue to be, subject to significant market volatility. Over the long-term, the higher the forward prices are, the more attractive an environment exists for us to contract for the sale of our anticipated output. However, higher prices also increase the cost of replacement power; thereby placing us at greater risk should our generating units fail to function effectively or otherwise become unavailable.

Over the past few years, a decline in wholesale natural gas prices has resulted in lower electricity prices. One of the reasons for the decline in natural gas prices is greater supply from shale production. This trend has reduced margin on forward sales as we re-contract our expected generation output.

In addition to energy sales, we also earn revenue from capacity payments for our generating assets. These payments are compensation for committing a portion of our capacity to the ISO for dispatch at its discretion. Capacity payments reflect the

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value to the ISO of assurance that there is sufficient generating capacity available at all times to meet system reliability and energy requirements. Currently, there is sufficient capacity in the markets in which we operate. However, in certain areas of these markets there are transmission system constraints, raising concerns about reliability and creating a more acute need for capacity.

In PJM and ISO-NE, where we operate most of our generation, the market design for capacity payments provides for a structured, forward-looking, transparent capacity pricing mechanism. This is through the Reliability Pricing Model (RPM) in PJM and the Forward Capacity Market (FCM) in ISO-NE. These mechanisms provide greater transparency regarding the value of capacity, resulting in an improved pricing signal to prospective investors in new generating facilities so as to encourage expansion of capacity to meet future market demands.

The prices to be received by generating units in PJM for capacity have been set through RPM base residual auctions and depend upon the zone in which the generating unit is located. The majority of our PJM generating units are located in zones where the following prices have been set:

Delivery Year	MW-day	kW-yr
June 2012 to May 2013	$ 139.73	$ 51.70
June 2013 to May 2014	$ 245.00	$ 89.43
June 2014 to May 2015	$ 136.50	$ 49.82
June 2015 to May 2016	$ 167.46	$ 61.12

For each delivery year, the prices differ in the various areas of PJM, depending on the constraints in each area of the transmission system. Keystone and Conemaugh receive lower prices than the majority of our PJM generating units since there are fewer constraints in that region and our generating units in northern New Jersey usually receive higher pricing.

The price that must be paid by an entity serving load in the various zones is also set through these auctions. These prices can be higher or lower than the prices noted in the table above due to import and export capability to and from lower-priced areas.

Like PJM and ISO-NE, the NYISO provides capacity payments to its generating units, but unlike the other two markets, the New York market does not provide a forward price signal beyond a six month auction period.

On a prospective basis, many factors may affect the capacity pricing, including but not limited to:

- changes in load and demand,
- changes in the available amounts of demand response resources,
- changes in available generating capacity (including retirements, additions, derates, forced outages, etc.),
- increases in transmission capability between zones,
- changes to the pricing mechanism, including potentially increasing the number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM and the other ISOs may propose over time, and
- changes driven by legislative and/or regulatory action, that permit states to subsidize local electric power generation.

For additional information on the RPM and FCM markets, as well as on state subsidization through various mechanisms, see Regulatory Issues—Federal Regulation.

Hedging Strategy

In an attempt to mitigate volatility in our results, we seek to contract in advance for a significant portion of our anticipated electric output, capacity and fuel needs. We seek to sell a portion of our anticipated lower-cost generation over a multi-year forward horizon, normally over a period of two to three years. We believe this hedging strategy increases stability of earnings.

Among the ways in which we hedge our output are: (1) sales at PJM West and (2) BGS contracts. Sales at PJM West reflect block energy sales at the liquid PJM Western Hub and other transactions that seek to secure price certainty for our generation related products. In addition, the BGS-Fixed Price contract, a full requirements contract that includes energy and capacity, ancillary and other services, is awarded for three-year periods through an auction process managed by the New Jersey Board of Public Utilities (BPU). The volume of BGS contracts and the electric utilities that our generation operations serve will vary from year to year. Pricing for the BGS contracts, including a capacity component, for recent and future periods by purchasing utility is as follows:

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Load Zone ($/MWh)	2009-2012	2010-2013	2011-2014	2012-2015	2013-2016
PSE&G	$103.72	$95.77	$94.30	$83.88	$92.18
Jersey Central Power & Light	$103.51	$95.17	$92.56	$81.76	$83.70
Atlantic City Electric	$105.36	$98.56	$100.95	$85.10	$87.27
Rockland Electric Company	$112.70	$103.32	$106.84	$92.51	$92.58

We have obtained price certainty for all of our PJM and New England capacity through May 2016 through the RPM and FCM pricing mechanisms.

Although we enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation, there is variability in both our actual output as well as in our hedges. Our actual output will vary based upon total market demand, the relative cost position of our units compared to all units in the market and the operational flexibility of our units. Our hedge volume can also vary, depending on the type of hedge into which we have entered. The BGS auction, for example, results in a contract that provides for the supplier to serve a percentage of the default load of a New Jersey electric distribution company (EDC), that is, the load that remains after some customers have chosen to be served directly by third party suppliers. The amount of power supplied through the BGS auction varies based on the level of the EDC's default load, which is affected by the number of customers who choose a third party supplier, as well as by other factors such as weather and the economy.

Historically, the number of customers that have switched to third party suppliers was relatively constant, but in recent years, as market prices declined from past years' historic highs, there was additional incentive for more of the smaller commercial and industrial electric customers to switch. In a falling price environment, this has a negative impact on our margins, as the anticipated BGS pricing is replaced by lower spot market pricing. While this impact has been reduced as average BGS rates have declined to a level more closely resembling current market prices, customers may still see an incentive to switch to third party suppliers. We are unable to determine the degree to which this switching, or “migration,” will continue, but the impact on our results could be material.

As of February 6, 2013, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2015.

Base Load Generation	2013	2014	2015
Generation Sales	100%	80%-85%	40%-45%

Our strategy is to maintain certain levels of uranium in inventory and to make periodic purchases to support such levels. Our nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements for the three years. We also have various long-term fuel purchase commitments for coal to support our fossil generation stations. These purchase obligations are consistent with our strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

We take a more opportunistic approach in hedging our anticipated natural gas-fired generation. The generation from these units is less predictable, as a significant portion of these units will only dispatch when aggregate market demand has exceeded the supply provided by lower-cost units.

In a changing market environment, this hedging strategy may cause our realized prices to differ materially from current market prices. In a rising price environment, this strategy normally results in lower margins than would have been the case if little or no hedging activity had been conducted. Alternatively, in a falling price environment, this hedging strategy will tend to create margins higher than those implied by the then current market.

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PSE&G

Our public utility, PSE&G, distributes electric energy and gas to customers within a designated service territory running diagonally across New Jersey where approximately 6.2 million people, or about 70% of New Jersey's population resides.

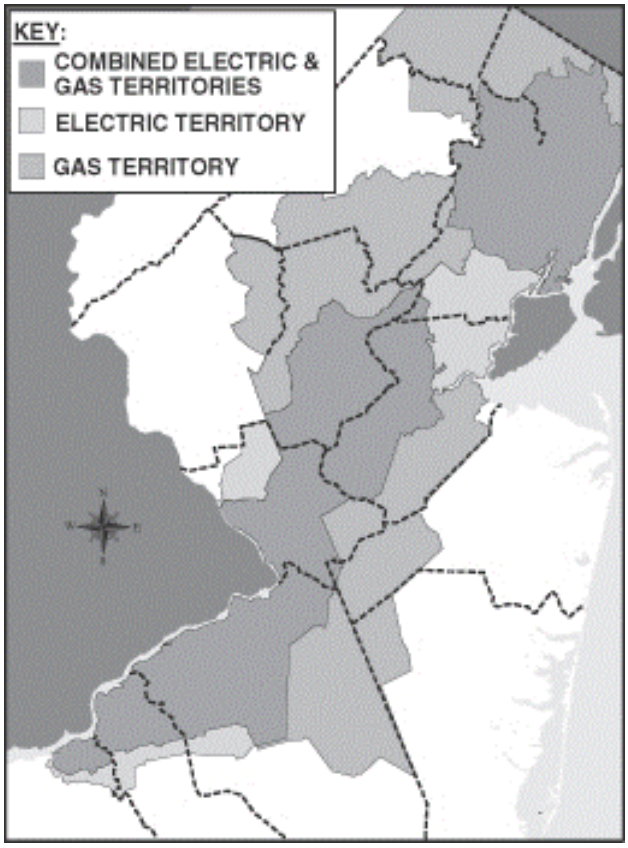

Products and Services

Our utility operations primarily earn margins through the transmission and distribution of electricity and the distribution of gas.

- **Transmission**—the movement of electricity at high voltage from generating plants to substations and transformers, where it is then reduced to a lower voltage for distribution to homes, businesses and industrial customers. Our revenues for these services are based upon tariffs approved by the FERC.
- **Distribution**—the delivery of electricity and gas to the retail customer's home, business or industrial facility. Our revenues for these services are based upon tariffs approved by the BPU.

We also earn margins through competitive services, such as appliance repair. The commodity portion of our utility business' electric and gas sales is managed by BGS and BGSS suppliers. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for our utility operations.

In addition to our current utility products and services, we have implemented several programs to increase the level of solar generation including:

- a program to help finance the installation of solar power systems throughout our electric service area, and
- a program to develop, own and operate solar power systems.

We have also implemented a set of energy efficiency and demand response programs to encourage conservation and energy efficiency by providing energy and cost saving measures directly to businesses and families. For additional information concerning these programs and the components of our tariffs, see Regulatory Issues.

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How PSE&G Operates

We provide network transmission and point-to-point transmission services, which are coordinated with PJM, and provide distribution service to 2.2 million electric customers and 1.8 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately three hundred suburban and rural communities.

Transmission

We use formula rates for our transmission investments. Formula-type rates provide a method of rate recovery where the transmission owner annually determines its revenue requirements through a fixed formula which considers Operations and Maintenance expenditures, Rate Base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. Our approved rates provide for a base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn an additional incentive rate. For more information on current transmission construction activities, see Regulatory Issues, Federal Regulation—Transmission Regulation.

Transmission Statistics

December 31, 2012

Network Circuit Miles	Billing Peak (MW)	Historical Annual Load Growth 2008-2012
1,461	10,470	0.4%

Distribution

The primary business of our utility is the distribution of gas and electricity to end users in our service territory. Our load requirements were split among residential, commercial and industrial customers, as described below for 2012. We believe that we have all the franchise rights (including consents) necessary for our electric and gas distribution operations in the territory we serve.

	% of 2012 Sales	
Customer Type	**Electric**	**Gas**
Commercial	57%	36%
Residential	33%	60%
Industrial	10%	4%
Total	**100%**	**100%**

While our customer base has remained steady, gas and electric load have declined as illustrated:

Electric and Gas Distribution Statistics

December 31, 2012

	Number of Customers	Electric Sales and Gas Sold and Transported	Historical Annual Load Decline 2008-2012
Electric	2.2 Million	41,641 GWh	(1.4)%
Gas	1.8 Million	3,397 Million Therms	(0.6)%

The decline in both electric and gas sales were impacted by the unfavorable winter weather experienced in 2012 and customer conservation as a result of the economy. The first six months of 2012 were the warmest first half of a year on record in the United States. Electric sales were also impacted by a decline in the Industrial sector.

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Solar Generation

We have undertaken major initiatives in order to spur investment in solar power in New Jersey. For additional details, please refer to our discussion under Energy Policy.

Supply

Although commodity revenues make up almost 48% of our revenues, we make no margin on the supply of energy since the actual costs are passed through to our customers.

All electric and gas customers in New Jersey have the ability to choose their own electric energy and/or gas supplier. Pursuant to the BPU requirements, we serve as the supplier of last resort for electric and gas customers within our service territory that are not served by another supplier. As a practical matter, this means we are obligated to provide supply to a vast majority of residential customers and a smaller portion of commercial and industrial customers.

We procure the supply to meet our BGS obligations through auctions authorized by the BPU for New Jersey's total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers are authorized to supply BGS to New Jersey's EDCs. Once validated by the BPU, electricity prices for BGS service are set.

PSE&G procures the supply requirements of our default service BGSS gas customers through a full requirements contract with Power. The BPU has approved a mechanism designed to recover all gas commodity costs related to BGSS for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. Any difference between rates charged under the BGSS contract and rates charged to our residential customers is deferred and collected or refunded through adjustments in future rates. Commercial and industrial customers that do not have third party suppliers are also supplied under the BGSS arrangement. These customers are charged a market-based price largely determined by prices for commodity futures contracts.

Markets and Market Pricing

Historically, there has been significant volatility in commodity prices. Such volatility can have a considerable impact on us since a rising commodity price environment results in higher delivered electric and gas rates for customers. This could result in decreased demand for electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs from our customers may be deferred under our regulated rate structure. A declining commodity price on the other hand, would be expected to have the opposite effect. For additional information, including the impact of natural gas commodity prices on electricity prices such as BGS, see Item 7. MD&A—Overview of 2012 and Future Outlook.

Energy Holdings

Energy Holdings primarily owns and manages a portfolio of lease investments and solar generation projects and is exploring opportunities for additional investment in renewable generation.

Over the past several years, we have terminated all of our international leveraged leases in order to reduce the cash tax exposure related to these leases. We have also reduced our risk by opportunistically monetizing all of our previous international investments. In February, 2012, the California Public Utilities Commission approved the shutdown of GWF Power and we anticipate recovering the remaining book value of our investment. For additional information on these generation facilities, see Item 2. Properties.

Products and Services

The majority of our remaining $840 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2012, 67% of our total leveraged lease investments were rated as below investment grade by Standard & Poor's.

Our leveraged leasing portfolio is designed to provide a fixed rate of return. Leveraged lease investments involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease financing, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and, with respect to our lease investments, is not presented on our Consolidated Balance Sheets.

The lessor acquires economic and tax ownership of the asset and then leases it to the lessee for a period of time no greater than 80% of its remaining useful life. As the owner, the lessor is entitled to depreciate the asset under applicable federal and state tax guidelines. The lessor receives income from lease payments made by the lessee during the term of the lease and from tax benefits associated with interest and depreciation deductions with respect to the leased property. Our ability to realize these tax

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benefits is dependent on operating gains generated by our other operating subsidiaries and allocated pursuant to the consolidated tax sharing agreement between us and our operating subsidiaries.

Lease rental payments are unconditional obligations of the lessee and are set at levels at least sufficient to service the non-recourse lease debt. The lessor is also entitled to any residual value associated with the leased asset at the end of the lease term. An evaluation of the after-tax cash flows to the lessor determines the return on the investment. Under accounting principles generally accepted in the United States (GAAP), the leveraged lease investment is recorded net of non-recourse debt and income is recognized as a constant return on the net unrecovered investment.

For additional information on leases, including the credit, tax and accounting risks, see Item 1A. Risk Factors, Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Credit Risk, Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables and Note 13. Commitments and Contingent Liabilities.

Through Energy Holdings, we own and operate solar projects in New Jersey, Delaware, Florida, Ohio and Arizona totaling 69 MW. See Item 2. Properties for additional information.

In January 2012, we acquired a 25 MW solar project in Arizona. This project is currently in service. All of the energy, capacity and environmental attributes generated by the project in the first 20 years are expected to be sold under a long-term power purchase agreement. The total investment for the project was approximately $75 million.

In September 2012, we acquired a 15 MW solar project in Delaware. This project is currently in service. The project has a 20-year power purchase agreement for energy and the majority of renewable energy credits with a wholesale electric utility servicing municipal EDCs in Delaware. Energy Holdings has issued guarantees of up to $37 million for payment of obligations related to the construction of the project, of which $4 million was outstanding as of December 31, 2012. The total investment for the project was approximately $47 million.

In December 2012, we acquired an additional 19 MW solar project currently under construction in Arizona. The project is expected to begin commercial operation in the latter half of 2013. Energy Holdings has issued guarantees of up to $48 million for payment of obligations related to the construction of the project, all of which were outstanding as of December 31, 2012. The total investment for the project is expected to be approximately $51 million.

Also, in December 2011, the Long Island Power Authority (LIPA) selected PSEG Long Island LLC (PSEG LI), a newly formed wholly owned subsidiary of Energy Holdings, to manage its electric transmission and distribution system in Long Island, New York. LIPA issued a press release that it had selected us for a variety of reasons, including our proven track record of first quartile customer service and reliability, commitment to cost control, corporate culture of transparency and local decision making, technical expertise and proven environmental track record. The ten-year contract, Operations Services Agreement (OSA), is scheduled to commence on January 1, 2014, following completion of the Transition Services Agreement (TSA). As part of the OSA, PSEG LI will be expected to develop and manage the implementation of a number of operational improvements to provide safe and reliable service for LIPA's customers, increase customer satisfaction and manage the operational and maintenance costs of LIPA. In November, 2012, the Governor of New York initiated an inquiry into the current structure of LIPA as a political subdivision of the State Of New York. The privatization of LIPA's transmission and distribution system is among the restructuring options under consideration. LIPA has the right under the OSA and the TSA to terminate each agreement, in the event that LIPA elects to either transfer its transmission and distribution system to a third party (privatization) or operate and maintain its transmission and distribution system with its own employees (municipalization). If LIPA elects to implement either of these options, LIPA is required to pay PSEG LI its service fees, milestone payments and wind-down expenses, in each case up to the effective date of such termination.

COMPETITIVE ENVIRONMENT

Power

Various market participants compete with us and one another in buying and selling in the wholesale energy markets, entering into bilateral contracts and selling to aggregated retail customers. Our competitors include:

- merchant generators,
- domestic and multi-national utility generators,
- energy marketers,
- banks, funds and other financial entities,
- fuel supply companies, and
- affiliates of other industrial companies.

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New additions of lower-cost or more efficient generation capacity could make our plants less economical in the future. Although it is not clear if this capacity will be built or, if so, what the economic impact will be, such additions could impact market prices and our competitiveness.

Our business is also under competitive pressure due to demand side management (DSM) and other efficiency efforts aimed at changing the quantity and patterns of usage by consumers which could result in a reduction in load requirements. A reduction in load requirements can also be caused by economic cycles, weather, customer migration and other factors. It is also possible that advances in technology, such as distributed generation, will reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, our revenues could be adversely affected. Changes in the rules governing what types of transmission will be built, who is permitted to build transmission and who will pay the costs of future transmission could also impact our revenues.

We are also at risk if the states in which we operate take actions that interfere with competitive wholesale markets. For example, on January 28, 2011, New Jersey enacted a law establishing a long-term capacity agreement pilot program (LCAPP) which provides for up to 2,000 MW of subsidized base load or mid-merit electric power generation. This action may have the effect of artificially depressing prices in the competitive wholesale market and thus has the potential to harm competitive markets, on both a short-term and a long-term basis.

Environmental issues, such as restrictions on emissions of carbon dioxide (CO_2) and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant, thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states. If any new legislation were to require our competitors to meet the environmental standards currently imposed upon us, we would likely have an economic advantage since we have already installed significant pollution-control technology at most of our fossil stations.

In addition, pressures from renewable resources could increase over time. For example, many parts of the country, including the mid-western region within the footprint of the Midwest Independent System Operator, the California ISO and the PJM region, have either implemented or proposed implementing changes to their respective regional transmission planning processes that may enable the construction of large amounts of "public policy" transmission to move renewable generation to load centers. For additional information, see the discussion in Regulatory Issues—Federal Regulation, below.

PSE&G

Our transmission and distribution business is minimally impacted when customers choose alternate electric or gas suppliers since we earn our return by providing transmission and distribution service, not by supplying the commodity. The demand for electric energy and gas by customers is affected by customer conservation, economic conditions, weather and other factors not within our control.

Changes in the current policies for building new transmission lines, such as those ordered by the FERC and being implemented by PJM and other ISOs to eliminate contractual provisions that provide us a "right of first refusal" to construct projects in our service territory, could result in additional competition to build transmission lines in our area in the future and would allow us to seek opportunities to build in other service territories.

Construction of new local generation, such as the proposed subsidized generation in New Jersey and Maryland, also has the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints.

EMPLOYEE RELATIONS

As of December 31, 2012, we had 9,798 employees within our subsidiaries, including 6,248 covered under collective bargaining agreements. During the fourth quarter of 2012, we reached agreements with four labor unions to extend their collective bargaining agreements for four years. Three of these agreements expire in April 2017 and one expires in October 2017. Collectively, these four unions represent approximately 80% of union employees of PSE&G, Power and Services. Our collective bargaining agreements with our other two unions are set to expire in April and May 2014, respectively. We believe we maintain satisfactory relationships with our employees.

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Employees as of December 31, 2012

	Power	PSE&G	Energy Holdings	Services
Non-Union	1,172	1,398	15	965
Union	1,442	4,797	—	9
Total Employees	**2,614**	**6,195**	**15**	**974**
Number of Union Groups	3	5	—	1

REGULATORY ISSUES

Federal Regulation

FERC

The FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act. PSE&G and the generation and energy trading subsidiaries of Power are public utilities as defined by the FPA. The FERC has extensive oversight over such "public utilities." FERC approval is usually required when a public utility seeks to: sell or acquire an asset that is regulated by the FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations.

The FERC also regulates generating facilities known as qualifying facilities (QFs). QFs are cogeneration facilities that produce electricity and another form of useful thermal energy, or small power production facilities where the primary energy source is renewable, biomass, waste or geothermal resources. QFs must meet certain criteria established by the FERC. We own various QFs through Energy Holdings. QFs are subject to some, but not all, of the same FERC requirements as public utilities.

The FERC also regulates Regional Transmission Operators/ISOs, such as PJM, and their energy and capacity markets.

For us, the major effects of the FERC regulation fall into five general categories:

- Regulation of Wholesale Sales—Generation/Market Issues
- Energy Clearing Prices
- Capacity Market Issues
- Transmission Regulation
- Compliance

Regulation of Wholesale Sales—Generation/Market Issues

Market Power

Under FERC regulations, public utilities must receive FERC authorization to sell power in interstate commerce. They can sell power at cost-based rates or apply to the FERC for authority to make market based rate (MBR) sales. For a requesting company to receive MBR authority, the FERC must first make a determination that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. The FERC requires that holders of MBR tariffs file an update every three years demonstrating that they continue to lack market power and/or that market power has been sufficiently mitigated and report in the interim to FERC any material change in facts from those the FERC relied on in granting MBR authority.

PSE&G, PSEG Energy Resources & Trade LLC, PSEG Power Connecticut, PSEG Fossil LLC and PSEG Nuclear LLC were each granted continued MBR authority from the FERC in June 2011. PSEG New Haven LLC was also granted initial MBR authority in May 2012. Retention of MBR authority is important to the maintenance of our current generation business' revenues.

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Energy Clearing Prices

Energy clearing prices in the markets in which we operate are generally based on bids submitted by generating units. Under FERC-approved market rules, bids are subject to price caps and mitigation rules applicable to certain generation units. The FERC rules also govern the overall design of these markets. At present, all units receive a single clearing price based on the bid of the marginal unit (i.e. the last unit that must be dispatched to serve the needs of load). These FERC rules have a direct impact on the energy prices received by our units.

Capacity Market Issues

PJM, NYISO, and ISO-NE each have capacity markets that have been approved by FERC.

PJM—RPM is a locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of RPM in PJM continue to evolve and be refined in stakeholder proceedings in which we are active, and there is currently significant discussion about the future role of demand response in the RPM market, including examining how demand response resources should be paid and how these resources and programs should be measured and verified to ensure their availability.

ISO-NE—ISO-NE's market for installed capacity with all generators in New England provides fixed capacity payments. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of generators on the system and contains incentive mechanisms to encourage generator availability during generation shortages. As in PJM, capacity market rules in ISO-NE continue to develop. We challenged in court the results of ISO-NE's first forward capacity auction, arguing that our units received inadequate compensation notwithstanding the location of our resources in a constrained area. The D.C. Circuit Court of Appeals ruled in our favor and remanded the proceeding to the FERC where it remains pending. We and other generators also filed a complaint at the FERC regarding ISO-NE's capacity market design, alleging that it insufficiently reflects locational capacity values. The FERC acted on the complaint, largely accepting the ISO-NE's capacity market design; however, an appeal of this rule is pending.

NYISO—NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. The NYISO capacity model recognizes only two separate zones that potentially may separate in price: New York City and Long Island. NYISO is creating a third locality encompassing the lower Hudson Valley to take effect May 1, 2014. The exact configuration of this new zone has not yet been determined. The triennial process for updating demand curves used for establishing capacity prices is also underway. The NYISO is required to file with the FERC by the end of 2013 revised demand curves covering the May 1, 2014 through April 30, 2017 period. Discussions concerning other potential changes to NYISO capacity markets, including rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons, are also ongoing.

Long-Term Capacity Agreement Pilot Program Act (LCAPP)—In 2011, the State of New Jersey concluded that new natural gas-fired generation was needed and enacted the LCAPP Act to subsidize approximately 2,000 MW of new generation. The LCAPP Act provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey Electric Distribution Companies (EDCs). The SOCA required each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers. Each of the New Jersey EDCs, including PSE&G, entered into the SOCAs as directed by the State, but did so under protest reserving their rights. In May 2012, two of the three generators, CPV Shore, LLC (CPV), a subsidiary of Competitive Power Ventures, Inc. and Hess Newark, LLC (Hess), a subsidiary of Hess Corporation, that received SOCA contracts cleared the RPM auction for the 2015/2016 delivery year in the aggregate notional amount of approximately 1,300 MW of installed capacity.

Legal challenges to the BPU's implementation of the LCAPP Act were filed in New Jersey appellate court and the appeal remains pending. In addition, the LCAPP Act has been challenged on constitutional grounds in federal court. The hearing for this matter is scheduled to begin in March 2013.

Maryland is also taking action to subsidize above-market new generation. In April 2012, the Maryland Public Service Commission (PSC) issued an order requiring the Maryland utility companies to enter into a contract with CPV Shore, LLC (CPV) to build a new 661 MW natural gas-fired, combined cycle station in Maryland with an in-service date of June 2015. This contract has not yet been finalized, as the Maryland PSC continues to evaluate its terms. In the May 2012 RPM auction, the CPV generator cleared the auction. We have joined other generators in challenging this order on constitutional grounds in federal court and that case is set for hearing in March 2013. The Maryland EDCs have also appealed the April 2012 order in state court.

These efforts to artificially depress prices in the wholesale capacity auction were intended to be mitigated by the Minimum Offer Price Rule (MOPR) approved by the FERC. The MOPR was intended to restrict new generation from bidding in RPM at less than an established minimum level established by Tariff, or a cost-based bid to the extent that the generator can demonstrate that its costs are lower than the MOPR. The MOPR was in place for the May 2012 auction, but we believe it did

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not operate to protect the market against these suppression efforts given that two of the three SOCA generators cleared the auction. As a result, discussions among a diverse group of PJM stakeholders to improve the MOPR ensued and a settlement was reached among those stakeholders. That proposal was then subject to a PJM stakeholder review and vote. The proposal was modified and received almost a 90% supporting vote. In December 2012, PJM filed Tariff changes with the FERC to implement the revised MOPR. In February 2013, the FERC issued a deficiency letter to PJM seeking additional information regarding the proposed MOPR changes. PJM must respond to those changes within 30 days and then the FERC has 60 days to act on the proposal. If FERC approves the proposal, we believe these modifications should significantly improve the MOPR rules and appropriately reduce the ability for subsidized generation assets to artificially suppress wholesale market prices. We cannot predict the outcome of this matter.

Transmission Regulation

The FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are then trued up the following year to reflect actual annual expenses/capital expenditures. Our allowed ROE is 11.68% for both existing and new transmission investments and we have received incentive rates, affording a higher ROE, for certain large scale transmission investments. Our 2012 Annual Formula Rate Update with the FERC provided for approximately $94 million in increased annual transmission revenues effective January 1, 2012. We filed our 2013 Annual Formula Rate Update with the FERC in October 2012, which provides for approximately $174 million in increased annual transmission revenues effective January 1, 2013.

- ***Transmission Policy Developments***—In 2010, the FERC initiated a proceeding to evaluate whether reforms to current transmission planning and cost allocation rules were necessary to stimulate additional transmission development. The rulemaking also addressed the issue of whether construction of transmission should be opened up to competition by eliminating the "right of first refusal" (ROFR) under which incumbent transmission companies such as PSE&G have a ROFR to build transmission located within their respective service territories. The FERC ultimately concluded in Order No. 1000 that the ROFR should be eliminated, subject to certain exceptions, and left it to Regional Transmission Organizations/Independent System Operators such as PJM to establish the implementation details. We, along with many other companies, have challenged the FERC's orders in federal court. In addition, we have joined other PJM transmission owners in filing for the FERC approval of new rules that will determine who pays for future transmission projects in PJM.

  We cannot predict the final outcome or impact on us; however, specific implementation of Order 1000 in the various regions, including within our service territory, may expose us to competition for certain types of transmission projects, while at the same time providing opportunities to build transmission outside of our service territory.

- ***Transmission Expansion***—In June 2007, PJM identified the need for the construction of the Susquehanna-Roseland line, a new 500 kiloVolt (kV) transmission line intended to maintain the reliability of the electrical grid serving New Jersey customers. PJM assigned construction responsibility for the new line to us and PPL Corporation (PPL) for the New Jersey and Pennsylvania portions of the project, respectively. The estimated cost of our portion of this construction project is up to $790 million, and PJM had originally directed that the line be placed into service by June 2012. As of December 31, 2012, total capital expenditures were $324 million. Construction of the Susquehanna-Roseland line is contingent upon obtaining all necessary federal, state, municipal and landowner permits and approvals. We have obtained environmental permits for the project from the New Jersey Department of Environmental Protection (NJDEP). On October 1, 2012, the National Park Service (NPS) issued a final Environmental Impact Statement (EIS) for the Susquehanna-Roseland line, selecting our and PPL's choice of route in certain federal park lands subject to the NPS' jurisdiction that follows the existing right of way. On October 15, 2012, several environmental groups filed a complaint in federal court, which, as amended, challenges the NPS' issuance of the final EIS, seeking to set aside the EIS and asking the court for an injunction that would generally prohibit construction of the project within the federal park lands at issue. If this request for injunctive relief is granted, the construction schedule for the project could be impacted. We have begun construction in those areas where necessary permits have been obtained. Currently, the expected in-service date for the Eastern segment of the project is June 2014 and for the Western segment is June 2015, although further delays are possible. Delays in the construction schedule could impact the cost of construction and the timing of expected transmission revenues.

Also, in 2010, certain environmental groups had appealed the BPU's approval of the Susquehanna-Roseland line, although no stay was sought. On February 11, 2013, the Appellate Division of the New Jersey Superior Court issued an order rejecting the appeal and affirming the BPU's approval of the project.

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We had previously been directed by PJM to build a 500 kV reliability project from Branchburg to Roseland to Hudson. The scope of this project has since changed; it is now a 230 kV project referred to as the Northeast Grid project, for which we are currently seeking to obtain municipal siting approvals. The Northeast Grid project has an expected in-service date of June 2015 and an estimated cost of construction of $895 million. As of December 31, 2012, total capital expenditures were $88 million.

In 2012, both the BPU and the NJDEP approved siting of the North Central Reliability project. This project, which involves upgrading certain circuits and switching stations from 138 kV to 230 kV in the northern and central portions of New Jersey, is estimated to cost up to $390 million and has an in-service date of June 2014. The project is currently under construction and, as of December 31, 2012, total capital expenditures for this project were $163 million.

In 2012, we received both municipal siting and the NJDEP approval for the Burlington-Camden project. The project, which also involves upgrading certain circuits and switching stations from 138 kV to 230 kV in the southern portion of New Jersey, is estimated to cost up to $399 million and has an in-service date of June 2014. The project is currently under construction. As of December 31, 2012, total capital expenditures for the project were $169 million.

We are still in the process of obtaining necessary municipal and environmental approvals for the Mickleton-Gloucester-Camden project. This is another project that involves converting both circuits and switching stations from 138 kV to 230 kV in southern New Jersey and is estimated to cost up to $435 million. The project has an in-service date of June 2015. This project is still in the engineering/design phase and, as of December 31, 2012, total capital expenditures were $24 million.

- ***Transmission Rate Proceedings***—In September 2011, the Massachusetts Attorney General, along with several state utility commissions, consumer advocates and consumer groups from six New England states, filed a complaint at the FERC against a group of New England transmission owners seeking to reduce the base return on equity used in calculating these transmission owners' formula transmission rates. The matter has been set for hearing, and the proceeding is pending. In addition, there have been FERC complaints filed by municipal utilities in New York against a New York transmission-owning utility seeking to lower that utility's transmission ROE. While we are not the subject of any of these complaints. The results of these proceedings could set a precedent for the FERC-regulated transmission owners with formula rates in place, such as ours.

Compliance

- ***FERC Audit***—Each of the PSEG companies that have MBR authority from the FERC is being audited by the FERC for compliance with its rules for (i) receiving and retaining MBR authority (ii) the filing of electric quarterly reports and (iii) our units' receipt of payments from the RTO/ISO when they are required to run for reliability reasons when it is not economic for them to do so. The FERC will issue a report at the conclusion of the audit.
- ***Reliability Standards—***Congress has required the FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the United States electric transmission and generation system and to prevent major system blackouts. Many reliability standards have been developed and approved. These standards apply both to reliability of physical assets interconnected to the bulk power system and to the protection of critical cyber assets. Our generation assets were audited in 2011 and our utility assets were audited in 2012. NERC compliance represents a significant and challenging area of compliance responsibility for us. As new standards are developed and approved, existing standards are revised and registration requirements are modified which could increase our compliance responsibilities.

Commodity Futures Trading Commission (CFTC)

In accordance with the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), the SEC and the CFTC are in the process of implementing a new regulatory framework for swaps and security-based swaps. The legislation was enacted to reduce systemic risk, increase transparency and promote market integrity within the financial system by providing for the registration and comprehensive regulation of swap dealers and by imposing recordkeeping, data reporting, margin and clearing requirements with respect to swaps. To implement the Dodd-Frank Act, the CFTC has engaged in a comprehensive rulemaking process and has issued a number of proposed and final rules addressing many of the key issues. For example, the CFTC has issued rules defining the term “swap dealer” and “commercial end user” (We fall in the latter category). The CFTC also issued rules establishing position limits for trading in certain commodities, such as natural gas but a federal court vacated these rules. The CFTC has appealed this decision to vacate the position limits rules. We are currently preparing to comply with the new record keeping and data reporting requirements of the Dodd-Frank Act applicable to commercial end users, for compliance in April 2013. We are continuing to analyze the potential impact of these rules and preparing to comply with the requirements that apply to entities that are considered commercial end-users under the Dodd-Frank Act.

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Nuclear Regulatory Commission (NRC)

Our operation of nuclear generating facilities is subject to comprehensive regulation by the NRC, a federal agency established to regulate nuclear activities to ensure protection of public health and safety, as well as the security and protection of the environment. Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstration to the NRC that plant operations meet requirements is also necessary. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate. The current operating licenses of our nuclear facilities expire in the years shown below:

Unit	Year
Salem Unit 1	2036
Salem Unit 2	2040
Hope Creek	2046
Peach Bottom Unit 2	2033
Peach Bottom Unit 3	2034

In 2010, we also filed an application for an Early Site Permit (ESP) for a new nuclear generating station to be located at the current site of the Salem and Hope Creek generating stations. The NRC acceptance review is complete and agency evaluation is underway. There were no petitions filed for permission to intervene. The current NRC schedule would likely result in a decision with respect to the issuance of the ESP in 2015. While the ESP qualifies the site as an approved location for a new reactor for a period of 20 years, it imposes no obligation to do so.

As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in March 2011, the NRC began performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events in Japan have resulted in additional regulation for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants currently meet the stringent applicable design and safety specifications of the NRC.

In 2011, the NRC task force submitted a report containing various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. The NRC staff also issued a document which provided for a prioritization of the task force recommendations. The NRC approved the staff's prioritization and implementation recommendations subject to a number of conditions. Among other things, the NRC advised the staff to give the highest priority to those activities that can achieve the greatest safety benefit and/or have the broadest applicability (Tier 1), to review filtration of boiling water reactor (BWR) primary containment vents and encouraged the staff to create requirements based on a performance-based system which allows for flexible approaches and the ability to address a diverse range of site-specific circumstances and conditions and strive to implement the requirements by 2016. The NRC issued letters and orders to licensees implementing the Tier 1 recommendations in March 2012. Additional regulations are expected.

Separately, a petition was filed with the NRC in April 2011 seeking suspension of the operating licenses of all General Electric BWRs utilizing the Mark I containment design in the United States, including our Hope Creek and Peach Bottom units, pending completion of the NRC review. Fukushima Daiichi Units 1-4 are BWRs equipped with Mark I containments. The petition names 23 of the total 104 active commercial nuclear reactors in the United States. While we do not believe the petition will be successful, we are unable to predict the outcome of any action that the NRC may take in connection with the petition

State Regulation

Since our operations are primarily located within New Jersey, our principal state regulator is the BPU, which oversees electric and natural gas distribution companies in New Jersey. Our utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. PSE&G's participation in solar, demand response and energy efficiency programs is also regulated by the BPU, as the terms and conditions of these programs are approved by the BPU. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey.

We are also subject to various other states' regulations due to our operations in those states.

Rates

- ***Electric and Gas Base Rates***—We must file electric and gas rate cases with the BPU in order to change our utility base distribution rates. Our last base rate adjustment was in 2010.

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- ***Rate Adjustment Clauses and Other Regulatory Filings***—In addition to base rates, we recover certain costs or earn on certain investments, from customers pursuant to mechanisms known as adjustment clauses. These clauses permit, at set intervals, the flow-through of costs to, or the recovery of investments from, customers related to specific programs, outside the context of base rate case proceedings. Recovery of these costs or investments is subject to BPU approval for which we make periodic filings. Delays in the pass-through of costs or recovery of investments under these mechanisms could result in significant changes in cash flow. For additional information on our specific filings, see Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

Some of our more significant recovery mechanisms and filings are as follows:

- ***Storm Damage Deferral***—In December 2012, the BPU granted our request to defer on our books actually incurred, uninsured, incremental storm restoration costs to our gas and electric distribution systems associated with extraordinary storms, including Hurricane Irene and Superstorm Sandy. In February 2013, the BPU announced that it would initiate a generic proceeding to evaluate the prudency of extraordinary, storm-related costs incurred by all of the regulated utilities as a result of the natural disasters experienced in New Jersey in 2011 and 2012 and in this proceeding will consider the manner in which such prudent costs shall be recovered.
- ***Capital Infrastructure Programs (CIP I and CIP II)***—We have received approval from the BPU for programs that provide for accelerated investment in utility infrastructure. The goal of these accelerated capital investments is to improve the reliability of our utility's infrastructure and New Jersey's economy through job creation. The programs allow us to receive a full return of and on our investments. In December 2012, the BPU approved stipulations regarding our CIP I and CIP II filings effective January 1, 2013. These Orders resulted in a combined increase of $40 million and $23 million for electric and gas customers, respectively.
- ***Weather Normalization Clause (WNC)***—Our WNC is an annual rate mechanism that allows us to increase our rates to compensate for lower revenues we receive from customers as a result of warmer-than-normal winters and to decrease our rates to make up for higher revenues we receive as a result of colder-than-normal winters. The payments and refunds are subject to certain limitations and rate caps. Unrecovered balances associated with application of the rate cap are deferred until the next recovery period. This rate mechanism requires us to calculate, at the end of each October-to-May period, the level by which margin revenues differed from what would have resulted if normal weather had occurred. In June 2012, we filed a petition and testimony with the BPU including eight months of actual and four months of forecasted data, which sought BPU approval to recover $41 million in deficiency revenues from our customers during the 2012-2013 Winter Period (October 1 to May 31) and a carryover deficiency of $16 million to the 2013-2014 Winter Period. In September 2012, an Order approving the stipulation for provisional rates was signed. In December 2012, we made a supplemental filing incorporating twelve months of actual financial data, which would, if approved by the BPU, result in no change to customer rates during the 2012-2013 Winter Period. The supplemental filing would, however, result in an increase of the carryover deficiency to the 2013-2014 Winter Period from $16 million to $24 million. We are awaiting a final Order.
- ***Solar and Energy Efficiency Recovery Charges (RRC)*** —are comprised of: Carbon Abatement, Energy Efficiency Economic Stimulus Program (EEE), EEE Extension, Demand Response, Solar 4 All, and Solar Loan II. These programs are aimed at reducing the New Jersey's Greenhouse Gas (GHG) Emissions. We file for annual recovery for our investments under these programs which includes a return on our investment and recovery of expenses. In July 2012, we filed a petition with the BPU requesting an increase in RRC seeking to recover approximately $62 million in electric revenue and $8 million in gas revenue, on an annual basis consistent with the terms of the approved program. The discovery phase of this proceeding is underway.

Other material rate filings pending before the BPU include:

Energy Strong (ES) Program—In February 2013, we filed a petition with the BPU describing the improvements we recommend making to our BPU jurisdictional electric and gas system to harden and improve resiliency for the future. The changes that were described would be made over a ten year period. In this petition, we are seeking approval to invest $0.9 billion in our gas distribution system and $1.7 billion in our electric distribution system over an initial five year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. The current estimated cost of the entire program, including the first five years of investments for which we sought approval in this petition, is $3.9 billion. We anticipate seeking BPU approval to complete our investment under the program at a later date. For additional information, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements.

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Solar 4 All Extension—In July 2012, we filed for an extension of our Solar 4 All program. In this filing, we are seeking BPU approval to invest up to $690 million to develop 136 MW of utility-owned solar photovoltaic systems over a five year period starting in 2013. Consistent with the existing Solar 4 All program, we propose to sell the energy and capacity from the solar systems in the PJM wholesale energy and capacity markets which will offset the cost of the program.

We also filed for an additional extension of our Solar Loan program (Solar Loan III) in July 2012. In the filing, we are seeking BPU approval to provide financing support for the installation of 97.5 MW of solar systems by providing loans to qualified customers. The total investment of the proposed Solar Loan III program is anticipated to be up to $193 million once the program is fully subscribed, the projects are built and the loans are closed.

Energy Supply

BGS—New Jersey's EDCs provide two types of BGS, the default electric supply service for customers who do not have a third party supplier. The first type, which represents about 80% of PSE&G's load requirements, provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Fixed Price). These rates change annually on June 1 and are based on the average price obtained at auctions in the current year and two prior years. The second type provides default supply for larger customers, with energy priced at hourly PJM real-time market prices for a contract term of 12 months (BGS-CIEP).

All of New Jersey's EDCs jointly procure the supply to meet their BGS obligations through two concurrent auctions authorized each year by the BPU for New Jersey's total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers provide BGS to New Jersey's EDCs.

Approximately one-third of PSE&G's total BGS-Fixed Price eligible load is auctioned each year for a three-year term. Current pricing is as follows:

	2010	2011	2012	2013	
36 Month Terms Ending	May 2013	May 2014	May 2015	May 2016	(A)
Eligible Load (MW)	2,800	2,800	2,900	2,800	
$ per kWh	0.09577	0.09430	0.08388	0.09218	

(A) Prices set in the February 2013 BGS Auction will be effective on June 1, 2013 when the 2010 BGS agreements expire.

The BPU approved the auction process for 2013 with no significant changes to the process.

For additional information, see Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities.

BGSS—BGSS is the mechanism approved by the BPU designed to recover all gas costs related to the supply for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. PSE&G's revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each year. In addition, we have the ability to put in place two self-implementing BGSS increases on December 1 and February 1 of up to 5% and also may reduce the BGSS rate at any time.

PSE&G had a full requirements contract with Power for an initial period which extended through March 2012 to meet the supply requirements of default service gas customers. This long-term contract continues on a year-to-year basis thereafter, unless terminated by either party with a one year notice. Power charges PSE&G for gas commodity costs which PSE&G recovers from customers. Any difference between rates charged by Power under the BGSS contract and rates charged to PSE&G's residential customers are deferred and collected or refunded through adjustments in future rates. PSE&G earns no margin on the provision of BGSS.

In June 2012, we made our annual BGSS filing with the BPU. The filing requested a decrease in annual BGSS revenue of $71 million, excluding sales and use tax, to be effective October 1, 2012. This represented a reduction of approximately 5.2% for a typical residential gas heating customer. This BGSS reduction was the ninth consecutive reduction since January 2009. We entered into a Stipulation with the parties which put the requested lower BGSS rate into effect as filed on October 1, 2012 on a provisional basis. A final decision is expected in early 2013.

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Energy Policy

New Jersey Energy Master Plan (EMP)—New Jersey law requires that an EMP be developed every three years, the purpose of which is to ensure safe, secure and reasonably-priced energy supply, foster economic growth and development and protect the environment. The most recent EMP was finalized in December 2011.

The 2011 EMP places an emphasis on expanding in-state electricity resources and reducing energy costs. The plan also recognizes the impact of climate change and accepts the previously set goal of a 22.5% target for the renewable portfolio standard (RPS) in 2021. It also references a goal that 70% of New Jersey's energy supplies should be from clean energy sources by 2050. To meet this goal, the plan redefined clean energy to include nuclear, natural gas and hydro power along with defined renewable sources and proposes a number of changes aimed at reducing the cost of achieving the 22.5% goal.

Specific program initiatives in the EMP include:

- construction of new combined cycle natural gas plants through the implementation of LCAPP, with the continued State challenge to FERC and PJM policies on market pricing rules in the capacity market,
- support for construction of new nuclear generation,
- changes to the solar program to reduce cost, expand opportunities, expand transparency and ensure economic and environmental benefits,
- expanded natural gas use to meet energy needs,
- development of decentralized combined heat and power,
- redesign of the delivery of state energy efficiency programs, and
- continued support for implementation of off-shore wind, without setting a specific capacity goal.

Solar Initiatives—In order to spur investment in solar power in New Jersey and meet renewable energy goals, we have undertaken two major initiatives at PSE&G.

- **Solar Loans:** The first solar initiative helps finance the installation of 81 MW of solar systems throughout our electric service area by providing loans to customers. The borrowers can repay the loans over a period of either 10 years (for residential customer loans) or 15 years (for non-residential customers), by providing us with solar renewable energy certificates (SRECs) or cash. The value of the SRECs towards the repayment of the loan is guaranteed to be not less than a floor price. SRECs received by us in repayment of the loan are sold through a periodic auction. Proceeds are used to offset program costs.

  The total investment of both phases of the Solar Loan Program is expected to be between $210 million and $250 million once the program is fully subscribed, projects are built and loans are closed. As of December 31, 2012, we have provided a total of $209 million in loans for 878 projects representing 67 MW.

- **Solar 4 All:** The second solar initiative is the Solar 4 All Program under which we are investing approximately $456 million to develop 80 MW of utility-owned solar photovoltaic (PV) systems over four years. The program consists of centralized solar systems 500 kW or greater installed on PSE&G-owned property and third-party sites in our electric service territory (40 MW) and solar panels installed on distribution system poles (40 MW). We sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition, we sell any SRECs received from the projects through the same auction used in the loan program. Proceeds from these sales are used to offset program costs.

  As of December 31, 2012, we have installed and placed in service 35 MW on approximately 160,000 distribution poles with an investment of approximately $245 million, and 39 MW of centralized solar systems representing 23 projects with an investment of approximately $192 million.

BPU Storm Report — In 2011, the BPU commenced an investigation of all four New Jersey electric utilities, including PSE&G, to examine their preparations, performance and restoration efforts during Hurricane Irene and the October 2011 snow storm. Following the completion of a report by its consultant, the BPU issued an order in January 2013, ordering the utilities to take specific action to improve their preparedness and responses to major storms. There are 103 separate measures contained in the Order, with most of the measures requiring utility implementation by September 2013. We are evaluating the implications of this report.

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BPU Audits

Management/Affiliate Audit—In 2009, the BPU, in accordance with New Jersey statutes, initiated audits of PSE&G with respect to the effectiveness of its management and its compliance with rules governing PSE&G's interactions with its affiliated companies. In 2012, the BPU issued a report making a number of findings and recommendations, including the finding that no violations of either the state or federal affiliate rules were found. The BPU is expected to issue an order addressing the audit report's findings and recommendations, although timing is uncertain.

BPU Investigations

RRC/CIP—In January 2012, New Jersey's Rate Counsel requested that the BPU investigate certain allegations of wrong doing in PSE&G's solar, EEE, and CIP programs raised by three former employees in a lawsuit. The BPU initiated an inquiry into these allegations and requested documentation from PSE&G. PSE&G has cooperated with the BPU and provided all requested information and documentation.

ENVIRONMENTAL MATTERS

Changing environmental laws and regulations significantly impact the manner in which our operations are currently conducted and impose costs on us to reduce the health and environmental impacts of our operations. To the extent that environmental requirements are more stringent and compliance more costly in certain states where we operate compared to other states that are part of the same market, such rules may impact our ability to compete within that market. Due to evolving environmental regulations, it is difficult to project future costs of compliance and their impact on competition. Capital costs of complying with known pollution control requirements are included in our estimate of construction expenditures in Item 7. MD&A—Capital Requirements. The costs of compliance associated with any new requirements that may be imposed by future regulations are not known, but may be material.

Areas of environmental regulation may include, but are not limited to:

- air pollution control,
- climate change,
- water pollution control,
- hazardous substance liability, and
- fuel and waste disposal.

For additional information related to environmental matters, including proceedings not discussed below, as well as anticipated expenditures for installation of pollution control equipment, hazardous substance liabilities and fuel and waste disposal costs, see Item 1A. Risk Factors, Item 3. Legal Proceedings and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Air Pollution Control

Our facilities are subject to federal regulation under the Clean Air Act (CAA) which requires controls of emissions from sources of air pollution and imposes record keeping, reporting and permit requirements. Our facilities are also subject to requirements established under state and local air pollution laws.

The CAA requires all major sources, such as our generation facilities, to obtain and keep current an operating permit. The costs of compliance associated with any new requirements that may be imposed and included in these permits in the future could be material and are not included in our estimates of capital expenditures.

- ***New Jersey Nitrogen Oxide (NO_x) Regulation: High Electric Demand Day***—In April 2009, the New Jersey Department of Environmental Protection (NJDEP) finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on our generation fleet, as it imposes NO_x emissions limits that require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) and four older New Jersey steam electric generation units (approximately 400 MW) by May 2015. Retirement notifications for the combustion turbines, except for Salem Unit 3, have been filed with PJM. The Salem Unit 3 combustion turbine (38 MW) will be transitioning to an emergency generator. Evaluations are ongoing for the steam electric generation units.
- ***Connecticut NO_x Regulation***—Under current Connecticut regulations, our Bridgeport and New Haven facilities have been utilizing Discrete Emission Reduction Credits (DERCs) to comply with certain NOx emission limitations that

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were incorporated into the facilities' operating permits. In 2010, we negotiated new agreements with the State of Connecticut extending the continued use of DERCs for certain emission units and equipment until May 31, 2014.

- ***Hazardous Air Pollutants Regulation***—In accordance with a ruling of the United States Court of Appeals of the District of Columbia (Court of Appeals), the EPA published a Maximum Achievable Control Technology (MACT) regulation on February 16, 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the Court of Appeals in support of the EPA's implementation of MATS. The Court of Appeals has split the litigation related to these matters into three cases, addressing separately the existing source NESHAP, new source NESHAP and the NSPS. These cases remain pending. The EPA has stayed implementation of the new source NESHAP rule pending its reconsideration. The EPA published the proposed reconsideration for the new source NESHAP and the NSPS in the Federal Register on November 30, 2012. The EPA expects to finalize the reconsideration of the new source NESHAP and the NSPS in March 2013.

  The impact to our fossil generation fleet in New Jersey and Connecticut and our jointly-owned coal fired generating facilities in Pennsylvania is currently being determined. We believe the back-end technology environmental controls installed at our Hudson and Mercer coal facilities should meet the MACT's requirements. Some additional controls could be necessary at our Connecticut facility, pending engineering evaluation. In December 2011, a decision was reached to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction (SCR) systems at our jointly-owned coal fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be completed in the fourth quarter of 2014. Our share of this investment is approximately $147 million.

- ***Cross-State Air Pollution Rule (CSAPR)***—On July 6, 2011, the EPA issued the final CSAPR. CSAPR limits power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season NO_x in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards (NAAQS).

  On August 21, 2012, the Court of Appeals vacated CSAPR and ordered that the existing Clean Air Interstate Rule (CAIR) requirements remain in effect until an appropriate substitute rule has been promulgated. On October 5, 2012, the EPA filed a request for rehearing which the Court denied on January 24, 2013. What future actions the EPA will take regarding the Court's decision or the timing of those actions are unknown at this time. The purpose of CAIR is to improve ozone and fine particulate air quality within states that have not demonstrated achievement of the NAAQS. CAIR was implemented through a cap-and-trade program and, to date, the impact has not been material to us as the allowances allocated to our stations were sufficient. If 2013 operations are similar to those in the past three years, it is expected that the impact to operations in New Jersey, New York and Connecticut from the temporary implementation of CAIR in 2013 will not be significant.

  We currently anticipate that this rule will not have a material adverse impact to our capital investment program or our units' operations.

Climate Change

- ***CO_2 Regulation Under the* CAA**—In April 2010, the EPA and the National Highway Transportation Safety Board (NHTSB) jointly issued a final rule to regulate GHGs emissions from certain motor vehicles (Motor Vehicle Rule). Under the CAA, the adoption of the Motor Vehicle Rule would have automatically subjected many emission sources, including ours, to CAA permitting for new facilities and major facility modifications that increase the emission of GHGs, including CO_2. However, guidance issued by the EPA in March 2010 interpreted the CAA to require permitting for GHGs at other facilities, such as ours, only when the Motor Vehicle Rule was scheduled to take effect in January 2011. In May 2010, the EPA finalized a "Tailoring Rule" that would have phased in beginning in 2011, the application of this permitting requirement to facilities such as ours. The significance of the permitting requirement is that, in cases where a new source is constructed or an existing source undergoes a major modification, the owner of the facility would need to evaluate and perhaps install best available control technology (BACT) for GHG emissions.

  In November 2010, the EPA published guidance to state and local permitting authorities to undertake BACT determinations for new and modified emission sources. The guidance does not define the specific technology or technologies that should be considered BACT. The guidance does emphasize the use of energy efficiency, and specifically states that the technology of storing CO_2 under the earth, also known as carbon capture and storage, is not yet mature enough to be considered a viable alternative at this stage. On April 13, 2012, the EPA published the

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proposed New Source Performance Standards (NSPS) for GHG for new power plants and refineries. New or modified sources must employ BACT which is defined on a case-by-case basis and can be no less stringent than the applicable NSPS. Thus, for new power plants where the proposed NSPS identifies the applicable standard, if adopted as proposed, all permit decisions regarding BACT and application completeness should be made to reflect at least the level of stringency contained in those standards. The EPA is expected to move to regulation of existing electric generating units under the CAA. However, implementation of such regulations for existing sources is anticipated to be several years away.

- ***Climate-Related Legislation***—The federal government may consider legislative proposals to define a national energy policy and address climate change. Proposals under consideration include, but are not limited to, provisions to establish a national clean energy portfolio standard and to establish an energy efficiency resource standard. Provisions of any new proposal may present material risks and opportunities to our businesses. The final design of any legislation will determine the impact on us, which we are not now able to reasonably estimate.
- ***Regional Greenhouse Gas Initiative (RGGI)***—In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. Ten northeastern states, including New Jersey, New York and Connecticut, originally established RGGI to cap and reduce CO_2 emissions in the region. In general, these states adopted state-specific rules to enable the RGGI regulatory mandate in each state.

  Applicable rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three year period (e.g. 2009, 2010, and 2011). Allowances are available through the auction or through secondary markets and were required to be submitted to states by March 2012 for the first compliance period.

  The Governor of New Jersey withdrew New Jersey from RGGI beginning in 2012. Therefore, our New Jersey facilities are no longer obligated to acquire CO_2 emission allowances, but our generation facilities in New York and Connecticut remain subject to RGGI. The Governor's action to withdraw has been challenged by environmental groups in the New Jersey state court.

  New Jersey also adopted the Global Warming Response Act in 2007, which calls for stabilizing its GHGs emissions to 1990 levels by 2020, followed by a further reduction of greenhouse emissions to 80% below 2006 levels by 2050. To reach this goal, the NJDEP, the BPU, other state agencies and stakeholders are required to evaluate methods to meet and exceed the emission reduction targets, taking into account their economic benefits and costs.

Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to U.S. waters from point sources, except pursuant to a National Pollutant Discharge Elimination System (NPDES) permit issued by the EPA or by a state under a federally authorized state program. The FWPCA authorizes the imposition of technology-based and water quality-based effluent limits to regulate the discharge of pollutants into surface waters and ground waters. The EPA has delegated authority to a number of state agencies, including those in New Jersey, New York and Connecticut, to administer the NPDES program through state acts. We also have ownership interests in facilities in other jurisdictions that have their own laws and implement regulations to control discharges to their surface waters and ground waters that directly govern our facilities in those jurisdictions.

In addition to regulating the discharge of pollutants, the FWPCA regulates the intake of surface waters for cooling. The use of cooling water is a significant part of the generation of electricity at steam-electric generating stations. Section 316(b) of the FWPCA requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The impact of regulations under Section 316(b) can be significant, particularly at steam-electric generating stations which do not have closed cycle cooling through the use of cooling towers to recycle water for cooling purposes. The installation of cooling towers at an existing generating station can impose significant engineering challenges and significant costs, which can affect the economic viability of a particular plant. In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule by July 27, 2012.

In April 2011, the EPA published a new proposed rule which did not establish any particular technology as the BTA (e.g. closed-cycle cooling). Instead, the proposed rule established marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. We reviewed the proposed rule, assessed the potential impact on our generating facilities and used this information to develop our comments to the EPA which were filed in August 2011. On June 11, 2012, the EPA posted a Notice of Data Availability (NODA) requesting comment on a series of technical issues related to the impingement mortality proposed standards. On June 12, 2012, the EPA posted a second NODA outlining its plans to finalize a “Willingness to Pay” survey it initiated to develop non-use benefits data in support of the April 2011 rule proposal. PSEG and industry trade associations submitted comments on both NODAs in July 2012. In July 2012, the EPA and

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environmental groups agreed to delay the deadline for finalization of the Rule to June 27, 2013 to allow for more time to address public comments and analyze data submitted in response to the NODAs.

If the rule were to be adopted as proposed, the impact on us would be material since the majority of our electric generating stations would be affected. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Note 13. Commitments and Contingent Liabilities for additional information.

Hazardous Substance Liability

The production and delivery of electricity, the distribution of gas and, formerly, the manufacture of gas, results in various by-products and substances classified by federal and state regulations as hazardous. These regulations may impose liability for damages to the environment from hazardous substances, including obligations to conduct environmental remediation of discharged hazardous substances as well as monetary payments, regardless of the absence of fault and the absence of any prohibitions against the activity when it occurred, as compensation for injuries to natural resources. Our historic operations and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by federal and state agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex. For additional information, see Item 8. Financial Statements and Supplementary Data —Note 13. Commitments and Contingent Liabilities.

- ***Site Remediation***—The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and the New Jersey Spill Compensation and Control Act (Spill Act) require the remediation of discharged hazardous substances and authorize the EPA, the NJDEP and private parties to commence lawsuits to compel clean-ups or reimbursement for such remediation. The clean-ups can be more complicated and costly when the hazardous substances are in a body of water.
- ***Natural Resource Damages***—CERCLA and the Spill Act authorize the assessment of damages against persons who have discharged a hazardous substance, causing an injury to natural resources. Pursuant to the Spill Act, the NJDEP requires persons conducting remediation to characterize injuries to natural resources and to address those injuries through restoration or damages. The NJDEP adopted regulations concerning site investigation and remediation that require an ecological evaluation of potential damages to natural resources in connection with an environmental investigation of contaminated sites. The NJDEP also issued guidance to assist parties in calculating their natural resource damage liability for settlement purposes, but has stated that those calculations are applicable only for those parties that volunteer to settle a claim for natural resource damages before a claim is asserted by the NJDEP. We are currently unable to assess the magnitude of the potential financial impact of this regulatory change, although such impacts could be material.

Fuel and Waste Disposal

- ***Nuclear Fuel Disposal***—The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. Under the contracts, the U.S. Department of Energy (DOE) was required to begin taking possession of the spent nuclear fuel by no later than 1998 but has not yet done so. The Nuclear Waste Policy Act of 1982 requires the DOE to perform an annual review of the Nuclear Waste Fee to determine whether that fee is set appropriately to fund the national nuclear waste disposal program. In October 2009, the DOE stated that the current fee of 1/10 cent per kWh was adequate to recover program costs. In March 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit seeking suspension of the Nuclear Waste Fee. On June 1, 2012, The U.S. Court of Appeals for the District of Columbia ruled that the DOE failed to justify continued payments by electricity consumers into the Nuclear Waste Fund. The court ordered the DOE to conduct a complete reassessment of this fee within six months. The DOE's assessment was completed in January 2013, and concluded that fee collection should be maintained. On January 31, 2013, motions were filed with the Court seeking to reopen the case and set a schedule for expedited review of the DOE fee adequacy report.

  Spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites. We have on-site storage facilities that are expected to satisfy the storage needs of Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 through the end of their operating licenses.
- ***Low Level Radioactive Waste***—As a by-product of their operations, nuclear generation units produce low level radioactive waste. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. These waste materials are accumulated on site and disposed of at licensed permanent disposal facilities. New Jersey, Connecticut and South Carolina have formed the Atlantic Compact, which gives New Jersey nuclear

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generators continued access to the Barnwell waste disposal facility which is owned by South Carolina. We believe that the Atlantic Compact will provide for adequate low level radioactive waste disposal for Salem and Hope Creek through the end of their current licenses including full decommissioning, although no assurances can be given. Low Level Radioactive Waste is periodically being shipped to the Barnwell site from Salem and Hope Creek. Additionally, there are on-site storage facilities for Salem, Hope Creek and Peach Bottom, which we believe have the capacity for at least five years of temporary storage for each facility.

- ***Coal Combustion Residuals (CCRs)***—In June 2010, the EPA formally published a proposed rule offering three main options for the management of CCRs under the Resource Conservation and Recovery Act. One of these options regulates CCRs as a hazardous waste and the other two options are variations of a non-hazardous designation. All options communicate the EPA's intent of ceasing wet ash transfer and instituting engineering controls on ash ponds and landfills to limit impact on human health and the environment. The outcome of the EPA rulemaking cannot be predicted. The EPA has not established a date for release of a final rule.

  On April 5, 2012, several environmental organizations and CCR marketers brought a citizens' suit against the EPA in federal court arguing that the EPA has a non-discretionary duty to issue the CCR rules by a certain date. On May 15, 2012, the Utility Solid Waste Activities Group Policy Committee filed a Motion to Intervene in order to be in alignment with the EPA in defending against the environmental organizations' action. After May 2012, all parties agreed to a schedule for submitting briefs in this case. Motions for summary judgment remain pending.

SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Item 8. Financial Statements and Supplementary Data—Note 22. Financial Information by Business Segment.

ITEM 1A. RISK FACTORS

The following factors should be considered when reviewing our business. These factors could have a material adverse impact on our financial position, results of operations or net cash flows and could cause results to differ materially from those expressed elsewhere in this document.

The factors discussed in Item 7. MD&A may also have a material adverse effect on our results of operations and cash flows and affect the market prices for our publicly-traded securities. While we believe that we have identified and discussed the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant.

We are subject to comprehensive and evolving regulation by federal, state and local regulatory agencies that affects, or may affect, our businesses.

We are subject to regulation by federal, state and local authorities. Changes in regulation can cause significant delays in or materially affect business planning and transactions and can materially increase our costs. Regulation affects almost every aspect of our businesses, such as our ability to:

- ***Obtain fair and timely rate relief***—Our utility's retail rates are regulated by the BPU and its wholesale transmission rates are regulated by the FERC. The retail rates for electric and gas distribution services are established in a base rate case and remain in effect until a new base rate case is filed and concluded. In addition, our utility has received approval for several clause recovery mechanisms, some of which provide for recovery of and on the authorized investments. These clause mechanisms require periodic updates to be reviewed and approved by the BPU. Our utility's transmission rates are recovered through a FERC approved formula rate. The revenue requirements are reset each year through this formula. Transmission ROEs have recently become the target of certain state utility commissions, municipal utilities, consumer advocates and consumer groups seeking to lower customer rates in New England and New York. These agencies and groups have filed complaints at the FERC asking the FERC to reduce the base ROE of various transmission owners. They point to changes in the capital markets as justification for lowering the ROE of these companies. While we are not the subject of any of these complaints, the matter could set a precedent for FERC-regulated transmission owners, such as PSE&G. Inability to obtain fair or timely recovery of all our costs, including a return of or on our investments in rates, could have a material impact on our business.
- ***Obtain required regulatory approvals***—The majority of our businesses operate under MBR authority granted by the FERC, which has determined that our subsidiaries do not have unmitigated market power and that MBR rules have

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been satisfied. Failure to maintain MBR eligibility, or the effects of any severe mitigation measures that may be required if market power was evaluated differently in the future, could have a material adverse effect on us.

We may also require various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals on a timely basis could materially adversely affect our results of operations and cash flows.

- ***Comply with regulatory requirements***—There are Federal standards, including mandatory NERC and cybersecurity standards, in place to ensure the reliability of the U. S. electric transmission and generation system and to prevent major system black-outs. We have been, and will continue to be, periodically audited by the NERC for compliance.

  Further, the FERC requires compliance with all of its rules and orders, including rules concerning Standards of Conduct, market behavior and anti-manipulation rules, reporting, interlocking directorate rules and cross-subsidization. Our companies with MBR authority are currently being audited by the FERC for compliance with FERC's rules regarding MBR authority, the filing of Electric Quarterly Reports (EQRs) and the receipt of payments in organized markets by our generating units that are required to run for reliability reasons when it is not economical for them to do so.

  We will soon be subject to the reporting and record-keeping requirements of the Dodd-Frank Act, as implemented by the CFTC, and may in the future be subject to CFTC requirements regarding position limits for trading of certain commodities. As part of the Dodd-Frank Act compliance, we will need to be vigilant in monitoring and reporting our swap transactions.

  The BPU conducts periodic combined management/competitive service audits of New Jersey utilities related to affiliate standard requirements, competitive services, cross-subsidization, cost allocation and other issues. The BPU is near completion of a management audit and an affiliate transactions audit of PSE&G.

We are exposed to commodity price volatility as a result of our participation in the wholesale energy markets.

The material risks associated with the wholesale energy markets known or currently anticipated that could adversely affect our operations include:

- ***Price fluctuations and collateral requirements***—We expect to meet our supply obligations through a combination of generation and energy purchases. We also enter into derivative and other positions related to our generation assets and supply obligations. As a result, we are subject to the risk of price fluctuations that could affect our future results and impact our liquidity needs. These include:
  - variability in costs, such as changes in the expected price of energy and capacity that we sell into the market,
  - increases in the price of energy purchased to meet supply obligations or the amount of excess energy sold into the market,
  - the cost of fuel to generate electricity, and
  - the cost of emission credits and congestion credits that we use to transmit electricity.

In the markets where we operate, natural gas prices typically have a major impact on the price that generators will receive for their output, especially in periods of relatively strong demand. Therefore, significant changes in the price of natural gas will usually translate into significant changes in the wholesale price of electricity.

Over the past few years, wholesale prices for natural gas have declined from the peak levels experienced in 2008. One of the reasons for this decline is increased shale gas production as extraction technology has improved. Lower gas prices have resulted in lower electricity prices, which has reduced our margins as nuclear and coal generation costs have not declined similarly. Over that time, generation by our coal units was also adversely affected by the relatively lower price of natural gas as compared to coal, making it sometimes more economical to run certain of our gas units than our coal units.

Natural gas prices may remain at low levels for an extended period and continue to decline if further advances in technology result in greater volumes of shale gas production.

Many factors may affect capacity pricing in PJM, including but not limited to:

- changes in load and demand,
- changes in the available amounts of demand response resources,
- changes in available generating capacity (including retirements, additions, derates, forced outage rates, etc.),

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- increases in transmission capability between zones, and
- changes to the pricing mechanism, including increasing the potential number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM may propose over time, including issues currently pending at the FERC.

Potential changes to the rules governing energy markets in which the output of our plants is sold also poses risk to our business.

Also, as market prices for energy and fuel fluctuate, our forward energy sale and forward fuel purchase contracts could require us to post substantial additional collateral, thus requiring us to obtain additional sources of liquidity during periods when our ability to do so may be limited. If Power were to lose its investment grade credit rating, it would be required under certain agreements to provide a significant amount of additional collateral in the form of letters of credit or cash, which would have a material adverse effect on our liquidity and cash flows. If Power had lost its investment grade credit rating as of December 31, 2012, it may have had to provide approximately $654 million in additional collateral. We may also be subject to additional collateral requirements which could be required under new rules being developed by the CFTC which are expected to be implemented in 2013.

- ***Our cost of coal and nuclear fuel may substantially increase*** —Our coal and nuclear units have a diversified portfolio of contracts and inventory that will provide a substantial portion of our fuel needs over the next several years. However, it will be necessary to enter into additional arrangements to acquire coal and nuclear fuel in the future. Market prices for coal and nuclear fuel have recently been volatile. Although our fuel contract portfolio provides a degree of hedging against these market risks, future increases in our fuel costs cannot be predicted with certainty and could materially and adversely affect liquidity, financial condition and results of operations.

  While our generation runs on diverse fuels, allowing for flexibility, the mix of fuels ultimately used can impact earnings.
- ***Third party credit risk***—We sell generation output and buy fuel through the execution of bilateral contracts. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure to perform by these counterparties could have a material adverse impact on our results of operations, cash flows and financial position. In the spot markets, we are exposed to the risks of whatever default mechanisms exist in those markets, some of which attempt to spread the risk across all participants, which may not be an effective way of lessening the severity of the risk and the amounts at stake. The impact of economic conditions may also increase such risk.

We are subject to numerous Federal and state environmental laws and regulations that may significantly limit or affect our businesses, adversely impact our business plans or expose us to significant environmental fines and liabilities.

We are subject to extensive environmental regulation by Federal, state and local authorities regarding air quality, water quality, site remediation, land use, waste disposal, aesthetics, impact on global climate, natural resources damages and other matters. These laws and regulations affect the manner in which we conduct our operations and make capital expenditures. Future changes may result in significant increases in compliance costs.

Delay in obtaining, or failure to obtain and maintain, any environmental permits or approvals, or delay in or failure to satisfy any applicable environmental regulatory requirements, could:

- prevent construction of new facilities,
- prevent continued operation of existing facilities,
- prevent the sale of energy from these facilities, or
- result in significant additional costs, each of which could materially affect our business, results of operations and cash flows.

In obtaining required approvals and maintaining compliance with laws and regulations, we focus on several key environmental issues, including:

- ***Concerns over global climate change could result in laws and regulations to limit CO_2 emissions or other GHG produced by our fossil generation facilities***—Federal and state legislation and regulation designed to address global climate change through the reduction of GHG emissions could materially impact our fossil generation facilities. Legislation enacted in the states where our generation facilities are located establishes aggressive goals for the reduction of CO_2 emissions over a 40-year period. There could be significant costs incurred to continue operation of our fossil generation facilities, including the potential need to purchase CO_2 emission allowances. Such expenditures could materially affect the continued economic viability of one or more such facilities. Multiple states are developing

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or have developed state-specific or regional initiatives to obtain CO_2 emissions reductions in the electric power industry. The RGGI is such a program in the northeast.

- ***CO_2 Litigation***—In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings regarding alleged impacts of global climate change not involving us could be material to the future liability of energy companies.

  In June 2012, the United States Court of Appeals for the D.C. Circuit upheld the EPA finding that GHGs could reasonably be expected to endanger public health and welfare. However, the Court dismissed the action brought by individuals, local governments and interest groups alleging that various industries, including various energy companies, emitted GHGs, causing global climate change resulting in a variety of damages. Plaintiffs are expected to appeal to the United States Supreme Court.

  In November 2012, the Ninth Circuit Court of Appeals refused to reconsider its decision not to rehear an Alaskan village's public nuisance lawsuit alleging that GHGs emissions from ExxonMobil Corporation and many other energy companies had made the village uninhabitable. The appellate court denied the petition for rehearing which accused these companies of causing GHGs emissions that contributed to global warming and alleged injury to the village. If relevant federal or state common law were to develop that imposed liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to us could be material.

- ***Potential closed-cycle cooling requirements***—Our Salem nuclear generating facility has a permit from the NJDEP allowing for its continued operation with its existing cooling water system. That permit expired in July 2006. Our application to renew the permit, filed in February 2006, estimated the costs associated with cooling towers for Salem to be approximately $1 billion, of which our share was approximately $575 million. These amounts have not been updated since our 2006 filing.

  If the NJDEP and the Connecticut Department of Environmental Protection were to require installation of closed-cycle cooling or its equivalent at our Salem, Mercer, Hudson, Bridgeport, Sewaren or New Haven generating stations, the related increased costs and impacts would be material to our financial position, results of operations and net cash flows and would require further economic review to determine whether to continue operations or decommission the stations.

  The EPA issued a proposed rule in 2011 regarding regulation of cooling water intake structures. If adopted as proposed, the impact of this rulemaking could significantly impact states' permitting decisions on whether to require closed cycle cooling and could materially increase our cost of compliance. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

- ***Remediation of environmental contamination at current or formerly owned facilities***—We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. Also, we are currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, the related costs of which could have a material adverse effect on our financial condition, results of operations and cash flows. Recent amendments to New Jersey law now place affirmative obligations on us to investigate and, if necessary, remediate contaminated property upon which we were in any way responsible for a discharge of hazardous substances. While those amendments do not change our liability, they do impact the speed by which we will need to investigate contaminated properties, which could adversely impact cash flow.

  The State of New Jersey has filed multiple lawsuits against parties, including us, who were alleged to be responsible for injuries to natural resources in New Jersey, including a site being remediated under our MGP program. We cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to these or other natural resource damages claims. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

- ***More stringent air pollution control requirements in New Jersey***—Most of our generating facilities are located in New Jersey where restrictions are generally considered to be more stringent in comparison to other states. Therefore, there may be instances where the facilities located in New Jersey are subject to more restrictive and, therefore, more costly pollution control requirements and liability for damage to natural resources, than competing facilities in other states. Most of New Jersey has been classified as "nonattainment" with NAAQS for one or more air pollutants. This requires New Jersey to develop programs to reduce air emissions. Such programs can impose additional costs on us by requiring that we offset any emissions increases from new electric generators we may want to build and by setting more stringent emission limits on our facilities that run during the hottest days of the year.

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- ***Coal Ash Management***—Coal ash is a CCR produced as a byproduct of generation at our coal-fired facilities. We currently have a program to beneficially reuse coal ash as presently allowed by federal and state regulations. In June 2010, the EPA formally published a proposed rule offering three main options for the management of CCRs under the Resource Conservation and Recovery Act. One of these options regulates CCRs as a hazardous waste and the other two options are variations of a non-hazardous designation. All options communicate the EPA's intent of ceasing wet ash transfer and instituting engineering controls on ash ponds and landfills to limit impact on human health and the environment. The outcome of the EPA rulemaking cannot be predicted. Proposed regulations which more stringently regulate coal ash, including regulating coal ash as hazardous waste, could materially increase costs at our coal-fired generation facilities. The EPA has not established a date for release of a final rule.

Our ownership and operation of nuclear power plants involve regulatory, financial, environmental, health and safety risks.

Approximately half of our total generation output each year is provided by our nuclear fleet, which comprises approximately one-fourth of our total owned generation capacity. For this reason, we are exposed to risks related to the continued successful operation of our nuclear facilities and issues that may adversely affect the nuclear generation industry. These include:

- ***Storage and Disposal of Spent Nuclear Fuel***—We currently use on-site storage for spent nuclear fuel. Disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel, could impact future operations of these stations. In addition, the availability of an off-site repository for spent nuclear fuel may affect our ability to fully decommission our nuclear units in the future.
- ***Regulatory and Legal Risk***—The NRC may modify, suspend or revoke licenses, or shut down a nuclear facility and impose substantial civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms and conditions of the licenses for nuclear generating facilities. As with all of our generation facilities, as discussed above, our nuclear facilities are also subject to comprehensive, evolving environmental regulation. Our nuclear generating facilities are currently operating under NRC licenses that expire in 2033 through 2046.
- ***Operational Risk***—Operations at any of our nuclear generating units could degrade to the point where the affected unit needs to be shut down or operated at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Since our nuclear fleet provides the majority of our generation output, any significant outage could result in reduced earnings as we would need to purchase or generate higher-priced energy to meet our contractual obligations.
- ***Nuclear Incident or Accident Risk***—Accidents and other unforeseen problems have occurred at nuclear stations, both in the United States and elsewhere. The consequences of an accident can be severe and may include loss of life, significant property damage and/or a change in the regulatory climate. We have nuclear units at two sites. It is possible that an accident or other incident at a nuclear generating unit could adversely affect our ability to continue to operate unaffected units located at the same site, which would further affect our financial condition, operating results and cash flows. An accident or incident at a nuclear unit not owned by us could also affect our ability to continue to operate our units. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages.

We may be adversely affected by changes in energy regulatory policies, including energy and capacity market design rules and developments affecting transmission.

The energy industry continues to be regulated and the rules to which our businesses are subject are always at risk of being changed. Our business has been impacted by established rules that create locational capacity markets in each of PJM, ISO-NE and NYISO. Under these rules, generators located in constrained areas are paid more for their capacity so there is an incentive to locate in those areas where generation capacity is most needed. Because much of our generation is located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM's locational capacity market design rules and New England forward capacity market rules have been challenged in court and continue to evolve. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

In addition, legislative developments in the State of New Jersey have the potential to adversely impact RPM prices. In January 2011, New Jersey enacted a law establishing a LCAPP which provides for the construction of subsidized base load or mid-merit electric power generation. The LCAPP may have the effect of artificially depressing prices in the competitive wholesale market on both a short-term and long-term basis. PJM's Independent Market Monitor has released a report estimating that the impact of bidding 2,000 MW of capacity in New Jersey as a price taker could be a reduction in capacity market revenues to PJM suppliers of more than $2 billion in the first year.

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We could also be impacted by a number of other events, including regulatory or legislative actions favoring non-competitive markets and energy efficiency and demand response initiatives. Further, some of the market-based mechanisms in which we participate, including BGS auctions, are at times the subject of review or discussion by some of the participants in the New Jersey and Federal regulatory and political arenas. We can provide no assurance that these mechanisms will continue to exist in their current form, nor otherwise be modified.

To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, Power's revenues could be adversely affected. Moreover, the FERC has issued a rule, currently being challenged in court, that requires changes to transmission planning processes which may result in more transmission being built to facilitate renewable generation. This rule has also opened up the construction of certain types of transmission to competition through elimination of the ROFR.

Changes in the current policies for building new transmission lines could result in additional competition to build transmission lines in our service territory in the future and would allow us to seek opportunities to build in other service territories.

We face significant competition in the merchant energy markets.

Our wholesale power and marketing businesses are subject to significant competition that may adversely affect our ability to make investments or sales on favorable terms and achieve our annual objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower earnings. Decreased competition could negatively impact results through a decline in market liquidity. Some of our competitors include:

- merchant generators,
- domestic and multi-national utility rate-based generators,
- energy marketers,
- utilities,
- banks, funds and other financial entities,
- fuel supply companies, and
- affiliates of other industrial companies.

Regulatory, environmental, industry and other operational developments will have a significant impact on our ability to compete in energy markets, potentially resulting in erosion of our market share and impairment in the value of our power plants. Our ability to compete will also be impacted by:

- ***DSM and other efficiency efforts***—DSM and other efficiency efforts aimed at changing the quantity and patterns of consumers' usage could result in a reduction in load requirements.
- ***Changes in technology and/or customer conservation*** —It is possible that advances in technology will reduce the cost of alternative methods of producing electricity, such as fuel cells, micro turbines, windmills and PV (solar) cells, to a level that is competitive with that of most central station electric production. It is also possible that electric customers may significantly decrease their electric consumption due to demand-side energy conservation programs. Changes in technology could also alter the channels through which retail electric customers buy electricity, which could adversely affect our financial results.

Our inability to balance energy obligations with available supply could negatively impact results.

The revenues generated by the operation of our generating stations are subject to market risks that are beyond our control. Generation output will either be used to satisfy wholesale contract requirements, other bilateral contracts or be sold into competitive power markets. Participants in the competitive power markets are not guaranteed any specified rate of return on their capital investments. Generation revenues and results of operations are dependent upon prevailing market prices for energy, capacity, ancillary services and fuel supply in the markets served.

Our generation business frequently involves the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that we have produced or purchased energy in excess of our contracted obligations, a reduction in market prices could reduce profitability. Conversely, to the extent that we have contracted obligations in excess of energy we have produced or purchased, an increase in market prices could reduce profitability. If the strategy we utilize to hedge our exposure to these various risks is not effective, we could incur significant losses. Our market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors,

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including weather in various geographical areas, short-term supply and demand imbalances, customer migration and pricing differentials at various geographic locations. These cannot be predicted with certainty.

Increases in market prices also affect our ability to hedge generation output and fuel requirements as the obligation to post margin increases with increasing prices and could require the maintenance of liquidity resources that would be prohibitively expensive.

Any inability to recover the carrying amount of our assets could result in future impairment charges which could have a material adverse impact on our financial condition, results of operations and cash flows.

In accordance with accounting guidance, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset's or group of assets' carrying amount may not be recoverable. Significant reductions in our expected revenues or cash flows for an extended period of time resulting from such events could result in future asset impairment charges, which could have a material adverse impact on our financial condition and results of operations.

Inability to access sufficient capital at reasonable rates or commercially reasonable terms or maintain sufficient liquidity in the amounts and at the times needed could adversely impact our business.

Capital for projects and investments has been provided primarily by internally-generated cash flow and external financings. We have significant capital requirements and will need continued access to debt capital from outside sources in order to efficiently fund the construction and other cash flow needs of our businesses. The ability to arrange financing and the costs of capital depend on numerous factors including, among other things, general economic and market conditions, the availability of credit from banks and other financial institutions, investor confidence, the success of current projects and the quality of new projects.

The ability to have continued access to the credit and capital markets at a reasonable economic cost is dependent upon our current and future capital structure, financial performance, our credit ratings and the availability of capital under reasonable terms and conditions. As a result, no assurance can be given that we will be successful in obtaining re-financing for maturing debt, financing for projects and investments or funding the equity commitments required for such projects and investments in the future.

Financial market performance directly affects the asset values of our nuclear decommissioning trust funds and defined benefit plan trust funds. Sustained decreases in asset value of trust assets could result in the need for significant additional funding.

The performance of the financial markets will affect the value of the assets that are held in trust to satisfy our future obligations under our pension and postretirement benefit plans and to decommission our nuclear generating plants. A decline in the market value of our pension assets similar to the one experienced in 2008 could result in the need for us to make significant contributions in the future to maintain our funding at sufficient levels.

An extended economic recession would likely have a material adverse effect on our businesses.

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices of commodities. Adverse conditions in the economy affect the markets in which we operate and can negatively impact our results. Declines in demand for energy will reduce overall sales and lessen cash flows, especially as customers reduce their consumption of electricity and gas. Although our utility business is subject to regulated allowable rates of return, overall declines in electricity and gas sold and/or increases in non-payment of customer bills would materially adversely affect our liquidity, financial condition and results of operations.

We may be adversely affected by equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers and remain competitive.

The success of our businesses is dependent on our ability to continue providing safe and reliable service to our customers while minimizing service disruptions. We are also exposed to the risk of accidents, severe weather events such as we experienced from Hurricane Irene and Superstorm Sandy, or other incidents which could result in damage to or destruction of our facilities or damage to persons or property. The physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns and other related phenomena have exacerbated these risks. Such issues experienced at our facilities, or by others in our industry, could adversely impact our revenues, increase costs to repair and maintain our systems, subject us to potential litigation and/or damage claims and increase the level of oversight of our utility and generation operations and infrastructure through investigations or through the imposition of additional regulatory or legislative requirements. Such actions could affect our costs, competitiveness and future investments, which could be material to our financial position, results of operations and cash flow.

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Acts of war, terrorism or cybersecurity breaches could adversely affect our operations.

Our businesses and industry may be impacted by acts and threats of war or terrorism. These actions could result in increased political, economic and financial market instability and volatility in fuel prices which could materially adversely affect our operations. In addition, our infrastructure facilities, such as our generating stations, transmission and distribution facilities and information management systems for customer-related operations, could be direct or indirect targets or be affected by terrorist or other criminal activity.

Our businesses could also be impacted by cybersecurity breaches. Cybersecurity threats include:

- operational interference, such as attacks on our generation facilities, transmission lines or the power grid,
- information theft as to employees, shareholders, vendors and/or customers, such as personal financial and health records, and
- business system interruption or compromise.

Such events could severely disrupt business operations and prevent us from servicing our customers or collecting revenues. These events could also result in significant expenses to repair security breaches or system damage as well as increased capital, insurance and operating costs, including increased security costs for our facilities. A breach of certain business systems could affect our ability to record, process and/or report financial information correctly. In addition, new or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.

Inability to successfully develop or construct generation, transmission and distribution projects within budget could adversely impact our businesses.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of required environmental upgrades and retrofits, construction and/or acquisition of additional generation units and transmission facilities and modernizing existing infrastructure. Currently, we have several significant projects underway or being contemplated.

Our success will depend, in part, on our ability to complete these projects within budgets, on commercially reasonable terms and conditions and, in our regulated businesses, our ability to recover the related costs through rates. Any delays, cost escalations or otherwise unsuccessful construction and development could materially affect our financial position, results of operations and cash flows.

We may be unable to achieve, or continue to sustain, our expected levels of operating performance.

One of the key elements to achieving the results in our business plan is the ability to sustain generating operating performance and capacity factors at expected levels since our forward sales of energy and capacity assume acceptable levels of operating performance. This is especially important at our lower-cost facilities. Operations at any of our plants could degrade to the point where the plant has to shut down or operate at less than full capacity. Some issues that could impact the operation of our facilities are:

- breakdown or failure of equipment, processes or management effectiveness,
- disruptions in the transmission of electricity,
- labor disputes,
- fuel supply interruptions,
- transportation constraints,
- limitations which may be imposed by environmental or other regulatory requirements,
- permit limitations, and
- operator error or catastrophic events such as fires, earthquakes, explosions, floods, severe storms, acts of terrorism or other similar occurrences.

Identifying and correcting any of these issues may require significant time and expense. Depending on the materiality of the issue, we may choose to close a plant rather than incur the expense of restarting it or returning it to full capacity. In either event, to the extent that our operational targets are not met, we could have to operate higher-cost generation facilities or meet our obligations through higher-cost open market purchases.

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Challenges associated with retention of a qualified workforce could adversely impact our businesses.

Our operations depend on the retention of a skilled workforce. The loss or retirement of key executives or other employees, including those with the specialized knowledge required to support our generation, transmission and distribution operations, could result in various operational challenges. These challenges may include the lack of appropriate replacements, the loss of institutional and industry knowledge and the increased costs to hire and train new personnel. This has the potential to become more critical over the next several years as a growing number of employees become eligible to retire.

In addition, because a significant portion of our employees are covered under collective bargaining agreements, our success will depend on our ability to successfully renegotiate these agreements as they expire. Inability to do so may result in employee strikes or work stoppages which would disrupt our operations and could also result in increased costs.

Our receipt of payment of receivables related to our domestic leveraged leases is dependent upon the credit quality and the ability of lessees to meet their obligations.

Our receipt of payments of equity rent, debt service and other fees related to our leveraged lease portfolio in accordance with the lease contracts can be impacted by various factors. The factors which may impact future lease cash flow include, but are not limited to, new environmental legislation regarding air quality and other discharges in the process of generating electricity, market prices for fuel and electricity, including the impact of low gas prices on our coal generation investments, overall financial condition of lease counterparties and the quality and condition of assets under lease. If a lessee were to default, we could potentially be required to impair our current investment balances. For additional information relating to these leases, see Item 7. MD&A—Critical Accounting Estimates and Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, Power and PSE&G

None.

ITEM 2. PROPERTIES

Our subsidiaries own all of our physical property. We believe that we and our subsidiaries maintain adequate insurance coverage against loss or damage to plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

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Generation Facilities

Power

As of December 31, 2012, Power's share of summer installed generating capacity is shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used	Mission
Steam:						
Hudson	NJ	620	100%	620	Coal/Gas	Load Following
Mercer	NJ	632	100%	632	Coal/Gas	Load Following
Sewaren	NJ	453	100%	453	Gas	Load Following
Keystone (A)	PA	1,711	23%	391	Coal	Base Load
Conemaugh (A)	PA	1,711	23%	385	Coal	Base Load
Bridgeport Harbor	CT	383	100%	383	Coal	Load Following
New Haven Harbor	CT	448	100%	448	Oil	Load Following
Total Steam		**5,958**		**3,312**		
Nuclear:						
Hope Creek	NJ	1,174	100%	1,174	Nuclear	Base Load
Salem 1 & 2	NJ	2,326	57%	1,335	Nuclear	Base Load
Peach Bottom 2 & 3 (B)	PA	2,245	50%	1,123	Nuclear	Base Load
Total Nuclear		**5,745**		**3,632**		
Combined Cycle:						
Bergen	NJ	1,183	100%	1,183	Gas	Load Following
Linden	NJ	1,236	100%	1,236	Gas	Load Following
Bethlehem	NY	757	100%	757	Gas	Load Following
Total Combined Cycle		**3,176**		**3,176**		
Combustion Turbine:						
Essex	NJ	617	100%	617	Gas	Peaking
Edison	NJ	504	100%	504	Gas	Peaking
Kearny	NJ	463	100%	463	Gas	Peaking
Burlington	NJ	557	100%	557	Oil/Gas	Peaking
Linden	NJ	340	100%	340	Gas	Peaking
Mercer	NJ	115	100%	115	Oil	Peaking
Sewaren	NJ	105	100%	105	Oil	Peaking
Bergen	NJ	21	100%	21	Gas	Peaking
National Park	NJ	21	100%	21	Oil	Peaking
Salem	NJ	38	57%	22	Oil	Peaking
New Haven Harbor	CT	129	100%	129	Gas/Oil	Peaking
Bridgeport Harbor	CT	12	100%	12	Oil	Peaking
Total Combustion Turbine		**2,922**		**2,906**		
Pumped Storage:						
Yards Creek (C)	NJ	400	50%	200		Peaking
Total Power Plants		**18,201**		**13,226**		

(A) Operated by GenOn Northeast Management Company

(B) Operated by Exelon Generation

(C) Operated by Jersey Central Power & Light Company

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PSE&G

As of December 31, 2012, PSE&G had 73 MW of installed solar capacity throughout New Jersey.

Energy Holdings

Energy Holdings had investments in the following generation facilities as of December 31, 2012:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used
Kalaeloa	HI	209	50%	105	Oil
Hackettstown	NJ	2	100%	2	Solar
Wyandot	OH	12	100%	12	Solar
Jacksonville	FL	15	100%	15	Solar
Queen Creek	AZ	25	100%	25	Solar
Milford	DE	15	100%	15	Solar
Total Operating Power Plants		**278**		**174**	

Transmission and Distribution Facilities

As of December 31, 2012, PSE&G's electric transmission and distribution system included 23,856 circuit miles, of which 8,357 circuit miles were underground, and 838,236 poles, of which 546,614 poles were jointly-owned. Approximately 99% of this property is located in New Jersey.

In addition, as of December 31, 2012, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2012, the daily gas capacity of PSE&G's 100%-owned peaking facilities (the maximum daily gas delivery available during the three peak winter months) consisted of liquid petroleum air gas (LPG) and liquefied natural gas (LNG) and aggregated 2,790,500 therms (270,932,330 cubic feet on an equivalent basis of 100,000 Btu/therm and 1,030 Btu/cubic foot) as shown in the following table:

Plant	Location	Daily Capacity (Therms)
Burlington LNG	Burlington, NJ	670,500
Camden LPG	Camden, NJ	320,000
Central LPG	Edison, NJ	900,000
Harrison LPG	Harrison, NJ	900,000
Total		**2,790,500**

As of December 31, 2012, PSE&G owned and operated 17,713 miles of gas mains, owned 12 gas distribution headquarters and two subheadquarters, all in four operating regions located in New Jersey and owned one meter shop in New Jersey serving all such areas. In addition, PSE&G operated 62 natural gas metering and regulating stations, all located in New Jersey, of which 26 were located on land owned by customers or natural gas pipeline suppliers and were operated under lease, easement or other similar arrangement. In some instances, the pipeline companies owned portions of the metering and regulating facilities.

PSE&G's First and Refunding Mortgage, securing the bonds issued thereunder, constitutes a direct first mortgage lien on substantially all of PSE&G's property.

PSE&G's electric lines and gas mains are located over or under public highways, streets, alleys or lands, except where they are located over or under property owned by PSE&G or occupied by it under easements or other rights. PSE&G deems these easements and other rights to be adequate for the purposes for which they are being used.

In addition, as of December 31, 2012, PSE&G owned 42 switching stations in New Jersey with an aggregate installed capacity of 25,103 megavolt-amperes (MVA) and 246 substations with an aggregate installed capacity of 8,179 MVA. In addition, four of our substations in New Jersey having an aggregate installed capacity of 109 MVA were operated on leased property.

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ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, other than those discussed below, see Item 1. Business—Regulatory Issues and Environmental Matters and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Con Edison (Con Ed)

In 2001, Con Ed filed a complaint with the FERC against PSE&G, PJM and NYISO asserting a failure to comply with agreements between PSE&G and Con Ed covering 1,000 MW of transmission. On September 16, 2010, the FERC approved a settlement agreement entered into by PSE&G, Con Ed, PJM, NYISO and others. This settlement provides the basis for moving forward with Con Ed after the current contracts expire in 2012 and settles all issues associated with the existing contracts, including cases pending in the D.C. Circuit Court of Appeals. However, dismissal of these court cases is contingent upon receipt of a final, non-appealable order from the FERC. One party to the proceeding sought rehearing of the FERC approval order, which the FERC denied in an order issued on April 8, 2011. The party then appealed this decision to the D.C. Circuit Court of Appeals. This appeal is pending.

Electric Discount and Energy Competition Act (Competition Act)

In 2007, PSE&G and Transition Funding were served with a purported class action complaint (Complaint) in New Jersey Superior Court challenging the constitutional validity of certain stranded cost recovery provisions of the Competition Act, seeking injunctive relief against continued collection from PSE&G's electric customers of the Transition Bond Charge (TBC) of Transition Funding, as well as recovery of TBC amounts previously collected. The Superior Court subsequently granted PSE&G's motion to dismiss the Complaint, which dismissal was upheld by the Appellate Division.

In July 2007, the same plaintiff also filed a petition with the BPU requesting review and adjustment to PSE&G's recovery of the same stranded cost charges. In June 2010, the BPU granted PSE&G's motion to dismiss, and the plaintiff/petitioner subsequently appealed this dismissal to the Appellate Division. In June 2012, the Appellate Division affirmed the BPU's decision, concluding that the BPU had correctly found that the plaintiff's claims failed as a matter of law. The petitioner subsequently filed a Notice of Petition for Certification with the New Jersey Supreme Court. By order dated November 16, 2012, the New Jersey Supreme Court denied this Notice. On February 11, 2013, the Court denied the plaintiff's subsequent motion for reconsideration.

Environmental Matters

The following items are environmental matters involving governmental authorities not discussed elsewhere in this Form 10-K. We do not expect expenditures for any such site relating to the items listed below, individually or for all such current sites in the aggregate, to have a material effect on our financial condition, results of operations and net cash flows.

(1) Claim made in 1985 by the U.S. Department of the Interior under CERCLA with respect to the Pennsylvania Avenue and Fountain Avenue municipal landfills in Brooklyn, New York, for damages to natural resources. The United States Government alleges damages of approximately $200 million. To PSE&G's knowledge there has been no action on this matter since 1988.

(2) Various Spill Act directives were issued by the NJDEP to PRPs, including PSE&G with respect to the PJP Landfill in Jersey City, Hudson County, New Jersey, ordering payment of costs associated with operation and maintenance, interim remedial measures and a Remedial Investigation and Feasibility Study (RI/FS) in excess of $25 million. The directives also sought reimbursement of the NJDEP's past and future oversight costs and the costs of any future remedial action.

(3) Claim by the EPA, Region III, under CERCLA with respect to a Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and other companies are alleged to be liable for contamination at the site and PSE&G has been named as a PRP. A Final Remedial Design Report was submitted to the EPA in September of 2002. This document presented the design details of the EPA's selected remediation remedy. PSE&G and other utility companies as members of a PRP group entered into a Consent Decree and agreed to implement a negotiated EPA selected remediation remedy. The PRP group implementation of the remedy was completed in 2010. Although subject to EPA approval and oversight, long term monitoring activities designed to demonstrate the effectiveness of the implemented remedy are planned through 2018 at an estimated cost of $2.8 million.

(4) The Klockner Road site is located in Hamilton Township, Mercer County, New Jersey, and occupies approximately two acres on PSE&G's Trenton Switching Station property. In 1996, PSE&G entered into a memorandum of

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agreement with the NJDEP for the Klockner Road site pursuant to which PSE&G conducted an RI/FS and remedial action at the site to address the presence of soil and groundwater contamination. Anticipated future activities at the site include the filing of certification(s) with the NJDEP once every two years regarding the effectiveness of engineering and institutional controls, quarterly groundwater monitoring for several years and the installation of additional off-site groundwater monitoring wells as directed by the NJDEP.

(5) In 1996, Morton International, Inc., a subsidiary of The Dow Chemical Company, filed a lawsuit against the former customers of a former mercury refining operation located on the banks of Berry's Creek in Wood-Ridge, New Jersey. The lawsuit seeks to recover cleanup costs incurred and to be incurred in remediating the site. PSE&G was among the former customers sued based on allegations that mercury originating at its Kearny Generating Station was sent to the site for refining.

(6) The EPA sent Power, PSE&G and approximately 157 other entities a notice that the EPA considered each of the entities to be a PRP with respect to contamination in Berry's Creek in Bergen County, New Jersey and requesting that the PRPs perform a RI/FS on Berry's Creek and the connected tributaries and wetlands. Berry's Creek flows through approximately 6.5 miles of areas that have been used for a variety of industrial purposes and landfills. The EPA estimates that the study could be completed in approximately five years at a total cost of approximately $18 million. As members of a PRP Group, Power and certain of the other entities named in the EPA Notice entered into an Administrative Settlement Agreement and Order on Consent to conduct the RI/FS.

(7) In January 2010, we received a letter from the NJDEP asserting that we are the current owner of the Gates Construction Corporation Landfill and that the subject landfill has not been properly closed in accordance with NJDEP Solid Waste Regulations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange, Inc. As of December 31, 2012, there were 78,842 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2007 in our common stock and the subsequent reinvestment of quarterly dividends, the S&P Composite Stock Price Index, the Dow Jones Utilities Index and the S&P Electric Utilities Index.

	2007	2008	2009	2010	2011	2012
PSEG	$ 100.00	$ 61.55	$ 73.15	$ 73.09	$ 79.08	$ 76.68
S&P 500	$ 100.00	$ 63.06	$ 79.70	$ 91.68	$ 93.63	$ 108.55
DJ Utilities	$ 100.00	$ 72.22	$ 81.18	$ 86.41	$ 103.34	$ 104.70
S&P Electrics	$ 100.00	$ 74.20	$ 76.68	$ 76.68	$ 95.92	$ 95.37

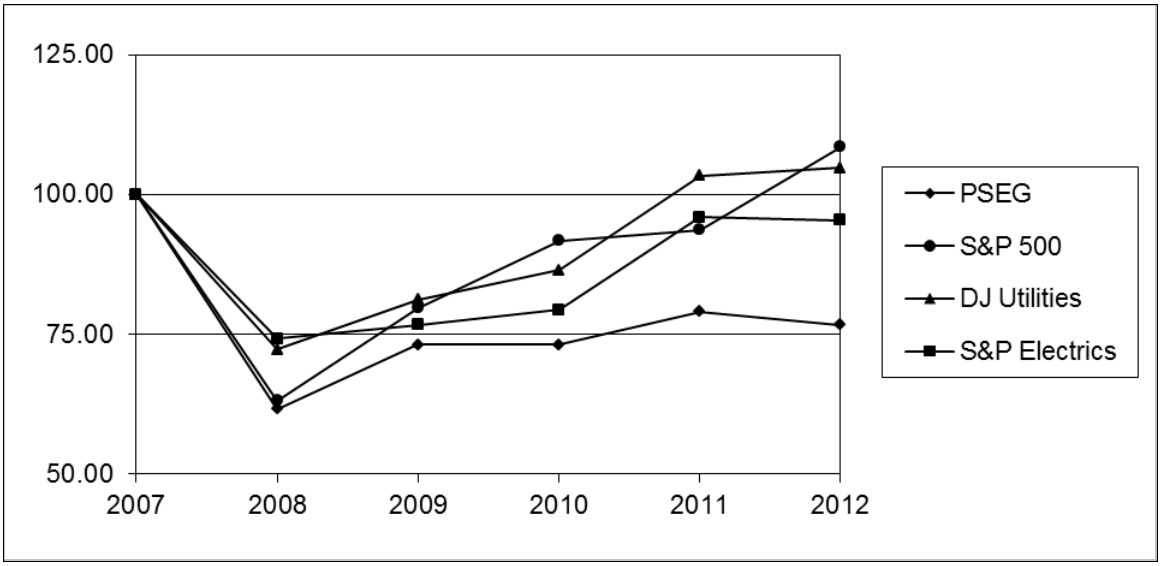

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The following table indicates the high and low sale prices for our common stock and dividends paid for the periods indicated:

Common Stock	High	Low	Dividend per Share
2012			
First Quarter	$ 33.25	$ 29.59	$ 0.3550
Second Quarter	$ 32.51	$ 28.92	$ 0.3550
Third Quarter	$ 34.07	$ 31.19	$ 0.3550
Fourth Quarter	$ 33.36	$ 29.05	$ 0.3550
2011			
First Quarter	$ 33.12	$ 30.15	$ 0.3425
Second Quarter	$ 34.22	$ 30.30	$ 0.3425
Third Quarter	$ 35.48	$ 27.97	$ 0.3425
Fourth Quarter	$ 34.96	$ 30.60	$ 0.3425

On February 19, 2013, our Board of Directors approved $0.36 per share of common stock dividend for the first quarter of 2013. This reflects an indicated annual dividend rate of $1.44 per share.

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation award grants during the fourth quarter of 2012:

Three Months Ended December 31, 2012	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$ —
November 1-November 30	50,000	$ 30.36
December 1-December 31	31,000	$ 30.01

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2012:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans	
Equity compensation plans approved by security holders	2,945,400	$ 34.19	17,013,520	(A)
Equity compensation plans not approved by security holders	—	$ —	3,589,032	(B)
Total	**2,945,400**	**$ 34.19**	**20,602,552**	

(A) Shares issuable under our Long-Term Incentive Plan.
(B) Shares issuable under our Employee Stock Purchase Plan.

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data—Note 18. Stock Based Compensation.

Power

We own all of Power's outstanding limited liability company membership interests. For additional information regarding Power's ability to pay dividends, see Item 7. MD&A—Overview of 2012 and Future Outlook.

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PSE&G

We own all of the common stock of PSE&G. For additional information regarding PSE&G's ability to continue to pay dividends, see Item 7. MD&A —Overview of 2012 and Future Outlook.

ITEM 6. SELECTED FINANCIAL DATA

PSEG

The information presented below should be read in conjunction with the MD&A and the Consolidated Financial Statements and Notes to Consolidated Financial Statements (Notes).

PSEG

Years Ended December 31,	2012	2011	2010	2009	2008
	Millions, except Earnings per Share				
Operating Revenues	$ 9,781	$ 11,079	$ 11,793	$ 12,035	$ 12,609
Income from Continuing Operations (A)	$ 1,275	$ 1,407	$ 1,557	$ 1,594	$ 918
Net Income	$ 1,275	$ 1,503	$ 1,564	$ 1,592	$ 1,188
Earnings per Share:					
Income from Continuing Operations					
Basic (A)	$ 2.52	$ 2.78	$ 3.08	$ 3.15	$ 1.81
Diluted (A)	$ 2.51	$ 2.77	$ 3.07	$ 3.14	$ 1.81
Net Income					
Basic	$ 2.52	$ 2.97	$ 3.09	$ 3.15	$ 2.34
Diluted	$ 2.51	$ 2.96	$ 3.08	$ 3.14	$ 2.34
Dividends Declared per Share	$ 1.42	$ 1.37	$ 1.37	$ 1.33	$ 1.29
As of December 31:					
Total Assets	$ 31,725	$ 29,821	$ 29,909	$ 28,678	$ 29,049
Long-Term Obligations (B)	$ 6,701	$ 7,482	$ 7,847	$ 7,679	$ 8,044

(A) Income from Continuing Operations for 2011 and 2008 includes after-tax charges of $ 170 million and $490 million, respectively, related to certain leveraged leases.

(B) Includes capital lease obligations.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of three reportable segments, which are:

- **Power,** our wholesale energy supply company that integrates its generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States,
- **PSE&G,** our public utility company which provides transmission and distribution of electric energy and gas in New Jersey; implements demand response and energy efficiency programs and invests in solar generation, and
- **Energy Holdings,** which principally owns and manages a portfolio of lease investments and solar generation projects.

Our business discussion in Part I, Item 1. Business provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I Item 1A provides information about factors that could have a material adverse impact on our businesses. The following discussion provides an overview of the significant events and business developments that have occurred during 2012 and key factors that we expect will drive our future performance. This discussion refers to the Consolidated Financial Statements (Statements) and the Related Notes to Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements and Notes.

OVERVIEW OF 2012 AND FUTURE OUTLOOK

2012 Overview

During 2012, our financial results continued to be adversely impacted by lower prices for electricity and natural gas in the markets we serve. Electricity prices remained low due to a combination of a slow recovery in demand growth and sustained low natural gas prices. The slow economic recovery negatively impacts utility sales, and the wholesale energy and capacity markets in which we operate. The continued decline in wholesale natural gas prices resulting from greater supply from shale production has further contributed to the steady decline in the wholesale price of electricity.

In the face of reduced pricing and lower demand for electricity, we continued to pursue our three-pronged strategy of operational excellence, financial strength and disciplined investment. Our focus has been to change the business mix of our operations with increased investments in our regulated utility. Through our regulated utility operations, we secured higher and more stable transmission revenues in 2012 resulting from our annual transmission formula rate update filing with the Federal Energy Regulatory Commission (FERC) and made additional solar and energy efficiency investments in New Jersey, on which we receive contemporaneous returns. Through allocating capital to transmission and distribution infrastructure projects, we were able to take advantage of a low interest rate environment and tap into an available labor pool in the region, while enhancing the reliability of our service to our customers. Additionally, these sources of revenue allowed us to partially offset the impact of lower prices for electricity and natural gas, while the reduction in supply costs allows us to continue to invest in infrastructure improvements without raising our utility customers' rates.

While we have been successfully increasing our regulated utility earnings, we have not fully compensated for the reduction in generation earnings. Over the past few years, we experienced a decline in wholesale energy prices. Basic Generation Service (BGS) rates also declined, resulting in lower revenues for our generation business. As BGS rates reached a level closer to current spot market prices, customer migration away from BGS supply contracts continued in 2012, but at a slower pace as there was less incentive to switch to third party suppliers.

In addition, at year-end we were severely impacted by Superstorm Sandy, which resulted in the highest level of customer outages in our history. We sustained significant damage to some of our generation, transmission and distribution facilities. We received an order from the New Jersey Board of Public Utilities (BPU) allowing us to defer incurred, uninsured, incremental storm restoration costs associated with our gas and electric distribution systems.

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As of December 31, 2012, Power had incurred approximately $85 million in costs related to Superstorm Sandy, primarily comprised of repairs at certain generating stations and damage to materials and supplies, both at our fossil fleet. All the costs were recognized in Operation and Maintenance Expense, offset by $19 million of a pending future recovery of insurance proceeds. Power estimates that it will incur additional future costs primarily relating to repairs to, and replacement of, equipment and property up to approximately $215 million.

As of December 31, 2012, PSE&G had incurred approximately $295 million of costs to restore service to PSE&G's distribution and transmission systems and $5 million to repair its infrastructure and return it to pre-storm conditions. Of the costs incurred, approximately $40 million was recognized in Operation and Maintenance Expense, $75 million was recorded as Property, Plant and Equipment and $180 million was recorded as a Regulatory Asset because such costs were deferred as approved by the BPU under an Order received in December 2012. PSE&G recognized $6 million of insurance proceeds.

We are working with our insurance carriers with regard to other losses and expenses due to the storm but no assurances can be given relative to the timing or amount of insurance recovery. For additional information on the impacts of Superstorm Sandy, see Item 8. Financial Statements and Supplementary Data-Note 13. Commitments and Contingent Liabilities.

There have also been significant regulatory and legislative developments during the year which may affect our operations and financial results in the future as new rules and regulations are developed. Competitive wholesale power market design is of particular importance to our results. Through litigation and the regulatory processes, we advocated for policies and rules in response to subsidized generation and procurement activities in New Jersey in connection with the Long-Term Capacity Agreement Pilot Program (LCAPP), and in Maryland through the Maryland Public Service Commission's Request for Proposal. After a favorable stakeholder vote, PJM filed proposed modifications to the Minimum Offer Price Rule (MOPR) with the FERC. In February 2013, the FERC issued a deficiency letter to PJM seeking additional information regarding the proposed MOPR changes. If the FERC approves the proposal, these modifications should significantly improve the MOPR rules and appropriately reduce the ability for subsidized generation assets to artificially suppress wholesale market prices. Litigation with respect to the New Jersey LCAPP and Maryland's efforts to subsidize new generation and challenges to the BPU's implementation of LCAPP continues. See Item 1. Business, Federal Regulation, FERC - Capacity Market Issues for further information.

We continued to monitor and advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA). The EPA is proceeding to implement its regulatory initiatives but the outcome of judicial review remains uncertain. The EPA's 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. However, we believe our generation business remains well-positioned for Clean Air Act regulations, if and when they are implemented. For additional information on the potential impacts of the 316(b) rule, see Item 8. Financial Statements and Supplementary Data-Note 13. Commitments and Contingent Liabilities.

Another regulatory development in 2012 that could have a material impact on our business are FERC rules under Order 1000, which altered the right of first refusal previously held by incumbent utilities to build all transmission within their respective service territories. We are opposing these rules in litigation and have worked with PJM to develop implementing rules that mitigate the impact of Order 1000. We cannot predict the final outcome or impact on us; however, specific implementation of Order 1000 within our service territory may expose us to competition for certain types of transmission projects, while at the same time affording us opportunities to construct transmission outside of our service territory. See Item 1. Business, Federal Regulation, FERC -Transmission Regulation.

We are making progress in addressing these challenges, but regulatory uncertainty remains a concern.

In 2012, our continued focus on operational excellence provided the foundation for our financial strength, in turn enabling us to invest in a disciplined way for growth, providing value for our customers, employees and shareholders and allowing us to best succeed in a sustained low electricity price environment. Some specific highlights in the areas of operational excellence, financial strength and disciplined investment in 2012 are discussed in more detail below.

Operational Excellence

We seek to emphasize operational performance while developing opportunities in our competitive and regulated businesses. Low commodity prices continue to stress margins, but the flexibility of our generating fleet has allowed us to take advantage of market opportunities as we remain diligent in managing costs. In 2012, we

- constructed approximately $656M million of gross plant additions to our transmission assets currently in service,
- continued to achieve high nuclear capacity factors, which averaged 91.1% for our nuclear fleet in 2012,
- improved fossil plant summer output,
- realized high combined cycle gas turbine fleet capacity utilization factors,

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- optimized fleet-switching from coal to gas to improve dispatch economics,
- extended collective bargaining agreements with four of our labor unions for four years,
- implemented more efficient plant staffing,
- were awarded the 2011 National Reliability Excellence Award for “demonstrating sustained leadership, innovation and achievement in the area of electric reliability," representing the fifth time in eight years we received this recognition, and eleven straight years that we garnered the ReliabilityOne Award for the Mid-Atlantic region, and
- received other award recognition for reliability and outage response.

Financial Strength

Our financial metrics remained strong in 2012. We maintained

- a strong balance sheet and operating cash flow,
- substantial liquidity resources, including total credit capacity of $4.3 billion and $379 million of cash on hand as of December 31, 2012, with a portion of available credit facilities extending until 2017,
- stable credit ratings,
- dividend payments of $1.42 per share for 2012, representing a change in our dividend policy moving from a strict earnings payout based approach to one that takes into consideration the growing contribution to earnings and cash from our regulated operations and continued cash flow from our generation business, and
- a well-funded position for our pension obligation, having made a $224 million contribution to our pension plan in 2012.

We also funded our capital program with internally generated cash and external debt financing.

In addition, we entered into a closing agreement settling our dispute with the Internal Revenue Service (IRS) over certain international leveraged lease transactions with finality for all tax periods in which we realized tax deductions from these transactions. Also, we executed settlement agreements covering all audit issues for tax years 1997 through 2006, concluding ten years of open audits for us. For additional information on the IRS audit settlements, see Item 8. Financial Statements and Supplementary Data-Note 20. Income Taxes.

Disciplined Investment

We seek to invest in areas that complement our existing businesses and provide attractive risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. We also have several projects where we are investing to continue to improve our operational performance. As noted above, over the past few years, we have shifted our focus to investing at the utility. Our capital expenditure forecast includes approximately $6.1 billion in spending over the next three years, 80% of which is at PSE&G. In addition, in 2012 we:

- invested approximately $1.1 billion in transmission infrastructure projects,
- completed the Peach Bottom steam path retrofit,
- added 400 MW of additional capacity with new peaking plants in New Jersey and Connecticut,
- completed solar projects in Arizona and Delaware, with the expectation to complete an additional Arizona solar project in 2013,
- made additional investments in our Capital Infrastructure Program (CIP II) and our Energy Efficiency and Demand Response Programs, and
- obtained BPU and NJDEP approvals of the North Central Reliability transmission project.

On February 20, 2013, we filed a petition with the BPU describing $3.9 billion of improvements we recommend making to our electric and gas distribution systems over a ten year period to harden and improve resiliency for the future. In addition, we anticipate investing an additional $1.5 billion in improvements to our transmission system for the same reason. See Capital Requirements for additional information.

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There is no guarantee that our projects currently underway or any future initiatives will be achieved since many issues need to be favorably resolved, such as regulatory approvals. Delays in the construction schedules of our projects could impact their costs as well as the timing of expected revenues.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a difficult economy and cost-constrained environment and to respond to the issues and challenges described below and take advantage of these and other regulatory and legislative initiatives. In order to do this, we must continue to:

- focus on controlling costs while maintaining our safety, reliability and compliance standards,
- successfully re-contract our open supply positions,
- execute our capital investment program, including investments for growth that yield contemporaneous and attractive risk-adjusted returns while enhancing the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and FERC of market design rules that continue to protect competition and achieve appropriate RPM and BGS pricing, and
- reach out to and engage multiple stakeholders, including regulators, government officials, customers and investors.

For 2013 and beyond, the key issues and challenges we expect our business to confront include

- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate,
- challenges to competitive markets, including support for subsidized generation in many states, particularly in New Jersey,
- customer migration away from our BGS supply contracts,
- uncertainty in the national and regional economic recovery and continuing customer conservation efforts, which impact customer demand,
- regulatory and political uncertainty, particularly with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation,
- the aftermath of Hurricane Irene and Superstorm Sandy, including addressing the BPU's review of performance and communications, as well as cost recovery and opportunities for investment in system strengthening and improvements,
- compressed margins and reduced utilization at coal plants,
- uncertain pension expenses and funding requirements given market volatility,
- liquidating the remaining portfolio of non-core assets where possible, while managing risk,
- monitoring financially stressed power plant leveraged lease investments, and
- successfully managing the transition to our operation of Long Island Power Authority's (LIPA) transmission and distribution system.

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RESULTS OF OPERATIONS

	Years Ended December 31,		
	2012	2011	2010
Earnings (Losses)	Millions		
Power (A)	$ 647	$ 1,002	$ 1,136
PSE&G (A) (B)	528	521	359
Energy Holdings (C)	86	(134)	49
Other (D)	14	18	13
PSEG Income from Continuing Operations	**1,275**	**1,407**	**1,557**
Income (Loss) from Discontinued Operations, Including Gain on Disposal (E)	—	96	7
PSEG Net Income	**$ 1,275**	**$ 1,503**	**$ 1,564**

	Years Ended December 31,		
Earnings Per Share (Diluted)	2012	2011	2010
PSEG Income from Continuing Operations	**$ 2.51**	**$ 2.77**	**$ 3.07**
Income from Discontinued Operations, Including Gain on Disposal (E)	—	0.19	0.01
PSEG Net Income	**$ 2.51**	**$ 2.96**	**$ 3.08**

(A) Power's and PSE&G's results in 2012 include after-tax expenses of $39 million and $24 million, respectively, for Operation and Maintenance (O&M) costs due to severe damage caused by Superstorm Sandy. See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingencies.

(B) PSE&G's results in 2010 include an after-tax charge of $72 million related to an agreement to refund previous Market Transition Charge (MTC) collections in the succeeding two years.

(C) Energy Holdings' results include an after-tax charge of $170 million taken in 2011 related to the reserve for assets underlying a leveraged lease receivable. See Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables.

(D) Other includes parent company interest and financing costs, donations, certain administrative and general expenses.

(E) See Item 8. Financial Statements and Supplementary Data—Note 4. Discontinued Operations and Dispositions.

The 2012 year-over-year decrease in our Income from Continuing Operations was driven by the following:

- lower average pricing and volumes for electricity sold under our BGS contracts,
- lower average prices realized on generation sold into various power pools,
- unfavorable amounts related to the MTM activity, discussed below,
- higher Operation and Maintenance costs due to severe damage caused by Superstorm Sandy to our transmission and distribution system throughout our service territory as well as to some of our generation infrastructure in the northern part of New Jersey.

The decreases were partially offset by:

- the absence of the $170 million after-tax charge taken in 2011 on leveraged leases related to Dynegy and the settlement proceeds received in 2012 (see Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables), and
- higher transmission revenues at PSE&G.

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The 2011 year-over-year decrease in our Income from Continuing Operations was driven by the following:

- the $170 million after-tax charge on leveraged leases related to Dynegy,
- the absence of an after-tax charge of $72 million related to an agreement to refund previous MTC collections in the succeeding two years,
- lower average pricing and volumes for electricity sold under our BGS contracts,
- lower realized prices and/or lower sales volumes in the various power pools,
- higher interest costs and depreciation expense related to the completion of installation of back-end technology at two of our fossil plants, and
- the absence of realized gains recognized in 2010 due to restructuring of the investments in our Rabbi Trust.

The decreases were partially offset by:

- favorable amounts related to the MTM activity reported below,
- an increase in revenues from new wholesale contracts entered into in the first half of 2011, and
- lower Operation and Maintenance costs primarily due to lower pension and OPEB costs.

Our results include the realized gains, losses and earnings on Power's Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity. Net realized gains, interest and dividend income and other costs related to the NDT Fund are recorded in Other Income and Deductions, and impairments on certain NDT securities are recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance Expense, as well as the depreciation related to the ARO asset. In September 2012, we restructured a portion of our NDT Fund and realized gains of $59 million. The investments were transitioned to new investment managers.

Our results also include the after-tax impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The combined after-tax impact on Income from Continuing Operations for the years ended December 31, 2012, 2011 and 2010 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2012	2011	2010
	Millions, after tax		
NDT Fund and Related Activity	$ 52	$ 50	$ 46
Non-Trading MTM Gains (Losses)	$ (10)	$ 107	$ (1)

PSEG

Our results of operations are primarily comprised of the results of operations of our operating subsidiaries, Power, PSE&G and Energy Holdings, excluding charges related to intercompany transactions, which are eliminated in consolidation. We also include certain financing costs, charitable contributions and general and administrative costs at the parent company. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data—Note 23. Related-Party Transactions.

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	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2012	2011	2010	2012 vs. 2011		2011 vs. 2010	
	Millions			Millions	%	Millions	%
Operating Revenues	$ 9,781	$ 11,079	$ 11,793	$ (1,298)	(12)	$ (714)	(6)
Energy Costs	3,719	4,747	5,261	(1,028)	(22)	(514)	(10)
Operation and Maintenance	2,632	2,481	2,504	151	6	(23)	(1)
Depreciation and Amortization	1,054	976	955	78	8	21	2
Income from Equity Method Investments	12	4	4	8	N/A	—	—
Other Income and (Deductions)	162	135	158	27	20	(23)	(15)
Other-Than-Temporary Impairments	18	22	11	(4)	(18)	11	100
Interest Expense	423	475	472	(52)	(11)	3	1
Income Tax Expense	736	977	1,059	(241)	(25)	(82)	(8)
Income from Discontinued Operations, including Gain on Disposal, net of tax	—	96	7	(96)	(100)	89	N/A

For a detailed explanation of the variances, see the discussions for Power, PSE&G and Energy Holdings below.

Power

	Years Ended December 31,			Increase/ (Decrease)	Increase/ (Decrease)
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	Millions				
Income from Continuing Operations	$ 647	$ 1,002	$ 1,136	$ (355)	$ (134)
Income (Loss) from Discontinued Operations, net of tax	—	96	7	(96)	89
Net Income	$ 647	$ 1,098	$ 1,143	$ (451)	$ (45)

The 2012 year-over-year decrease in Income from Continuing Operations was driven by the following:

- lower average prices realized on generation sold into the PJM and New York (NY) power pools and MTM losses due from the realization of prior year unrealized gains and adverse changes in unrealized prices in 2012 for forward positions,
- lower average pricing and lower volumes of electricity sold under our BGS contracts, net of lower cost to serve,
- lower volumes on wholesale load contracts in PJM, lower operating reserve, ancillary and Reliability Must Run (RMR) revenues primarily in PJM and New England,
- lower average pricing and volumes of gas sold under our BGSS contracts, net of lower cost to serve, and
- higher Operation and Maintenance Expense due to damage to our generation infrastructure, primarily our fossil fleet, from Superstorm Sandy and higher refueling and maintenance costs at our nuclear plants.

These decreases were partially offset by

- lower planned outages and maintenance costs in 2012 at certain of our fossil plants, and

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- lower interest expense due to the maturity of Senior Notes in April 2011 and the early redemption of Senior Notes in December 2011.

For the year ended December 31, 2011, the primary reasons for the decrease in Income from Continuing Operations were

- lower average pricing and lower volumes of electricity sold under our BGS contracts, as a result of customer migration,
- higher Operation and Maintenance expense related to planned outage work at certain of our fossil plants, and
- higher depreciation expense related to the completion of installation of back-end technology at two of our fossil plants.

The decreases were partially offset by

- favorable amounts related to the MTM activity,
- favorable results from our coal optimization efforts, and
- an increase from new wholesale contracts entered into in the first half of 2011.

The year-over-year detail for these variances for these periods is discussed below:

Power	Years Ended December 31, 2012	2011	2010	Increase / (Decrease) 2012 vs. 2011		Increase / (Decrease) 2011 vs. 2010	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 4,865	$ 6,143	$ 6,558	$ (1,278)	(21)	$ (415)	(6)
Energy Costs	2,383	3,046	3,374	(663)	(22)	(328)	(10)
Operation and Maintenance	1,122	1,102	1,046	20	2	56	5
Depreciation and Amortization	237	224	175	13	6	49	28
Other Income (Deductions)	109	111	117	(2)	(2)	(6)	(5)
Other-Than-Temporary Impairments	18	20	9	(2)	(10)	11	N/A
Interest Expense	134	175	157	(41)	(23)	18	11
Income Tax Expense	433	685	778	(252)	(37)	(93)	(12)
Income (Loss) from Discontinued Operations	—	96	7	(96)	(100)	89	N/A

Year ended December 31, 2012 as compared to 2011

Operating Revenues decreased $1,278 million due to

Generation Revenues decreased $975 million due primarily to

- lower net revenues of $564 million due primarily to lower average realized prices for our generation sold into the PJM and NY power pools and MTM losses due from the realization of prior year unrealized gains and adverse changes in unrealized prices in 2012 for forward positions,
- a decrease of $264 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts, primarily as a result of warmer winter weather in 2012 as well as customer migration, and
- a net decrease of $154 million due to lower volumes on wholesale load contracts in the PJM and New England (NE) regions,
- partially offset by a net increase of $7 million in other revenues consisting of higher net capacity revenues, partially offset by lower operating reserve, ancillary and RMR revenues.

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Gas Supply Revenues decreased $336 million due primarily to

- a decrease of $306 million in sales under the BGSS contract, substantially comprised of lower average gas prices on lower volumes of sales in 2012 due to warmer average temperatures during the first quarter of 2012, and
- a net decrease of $31 million due primarily to lower average prices, partially offset by higher sales volumes to third party customers.

Trading Revenues increased $33 million in 2012 due to the discontinuation of trading activities in the second quarter of 2011. As a result, the increase is due primarily to the absence of losses on electric energy supply contracts recognized in 2011.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $663 million due to

- ***Gas costs*** decreased $312 million, principally related to obligations under the BGSS contract, reflecting lower average gas inventory costs coupled with lower sales volumes in 2012 due primarily to warmer average temperatures during the first quarter of 2012.
- ***Generation costs*** decreased $351 million due primarily to $227 million of lower fuel costs, reflecting the utilization of lower volumes of coal and lower average natural gas prices, partially offset by the utilization of higher volumes of natural gas and higher nuclear fuel prices in 2012. The decrease was also attributable to $152 million of lower energy purchases, primarily in the PJM region as a result of lower load contract volumes in 2012, and $31 million of lower emission charges due to lower coal generation in the PJM and NE regions and impairment charges recorded in 2011 related to excess SO_2 emission allowances. These decreases were partially offset by an increase of $59 million due primarily to higher congestion costs in the PJM region.

Operation and Maintenance increased $20 million due primarily to

- an increase of $85 million due to damage from Superstorm Sandy for repairs to certain of our generation plants, primarily those in our fossil fleet, and to recognize the estimated loss of use of fossil materials and supplies, partially offset by a $19 million insurance recovery, and
- a net increase of $64 million due to higher refueling costs in 2012 for refueling outages at our 100%-owned Hope Creek nuclear unit and our 57%-owned Salem Unit 2 as compared to refueling outages for both of our 57%-owned Salem nuclear units in 2011,
- partially offset by a net decrease of $109 million largely due to lower fossil planned outages in 2012 and lower maintenance costs, principally at our gas-fired Bethlehem Energy Center (BEC) in New York, gas-fired Bergen and Linden facilities, coal/gas-fired Hudson and Mercer coal/gas-fired plants in New Jersey, and 23%-owned coal-fired Conemaugh plant in Pennsylvania, as well as to the absence of costs incurred for the cancellation and renegotiation of a major contractual agreement for parts and services in 2011.

Depreciation and Amortization increased $13 million due primarily to higher depreciable asset bases at Fossil and Nuclear, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut on June 1, 2012 and completion of the steam path retrofit upgrades at our co-owned Peach Bottom Units 2 and 3 in October 2012 and October 2011, respectively.

Other Income (Deductions) experienced no material change.

Other-Than-Temporary Impairments decreased $2 million due to lower impairments in 2012 on the NDT and Rabbi Trust Funds.

Interest Expense decreased $41 million due primarily to a decrease of $55 million resulting primarily from the maturity of $606 million of 7.75% Senior Notes in early April 2011 and the early redemption of $600 million of 6.95% Senior Notes in December 2011, partially offset by increases of $12 million due to two $250 million Senior Notes issuances in September 2011 and $3 million in higher interest costs since interest capitalization ceased for our Kearny and New Haven projects on their June 1, 2012 in-service date.

Income Tax Expense decreased $252 million in 2012 due primarily to lower pre-tax income.

Income (Loss) from Discontinued Operations

In 2011, we sold our two 1,000 MW combined-cycle generating facilities in Texas in separate transactions. In March 2011, we completed the sale of one plant for proceeds of $352 million at an after-tax gain of $54 million. In July 2011, we completed the sale of the second plant for proceeds of $335 million at an after-tax gain of $25 million. The results of operations for both

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plants for 2011 and 2010, including the gains in 2011 on the sales of the plants, are included in this category. See Item 8. Financial Statements and Supplementary Data—Note 4. Discontinued Operations and Dispositions for additional information.

Year ended December 31, 2011 as compared to 2010

Operating Revenues decreased $415 million due to

Gas Supply Revenues decreased $290 million due primarily to

- a net decrease of $283 million in sales under the BGSS contract, substantially comprised of lower average gas prices on lower volumes of sales in 2011 due to warmer average temperatures during the fourth quarter of 2011,
- a net decrease of $7 million due primarily to lower average gas prices partially offset by higher sales volumes to third party customers.

Generation Revenues decreased $143 million due primarily to

- a net decrease of $305 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts as a result of customer migration,
- a decrease of $70 million due primarily to lower capacity payments from the various power pools resulting from lower market prices, and
- a decrease of $8 million due to lower operating reserve revenue in 2011.

These were partially offset by

- an increase of $136 million from new wholesale load contracts in the PJM and NE regions commencing in January 2011 and April 2011, respectively, net of lower average realized prices in the NE region, and
- higher net revenues of $108 million due primarily to MTM gains on economic hedging activity of $228 million, partially offset by lower realized prices in the PJM and NY power pools and lower volumes of generation sold in the PJM and NE power pools of $120 million.

Trading Revenues increased $18 million due primarily to lower net losses in 2011 on certain electric energy supply contracts as well as the discontinuation of trading activities in the second quarter of 2011.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel purchases for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $328 million due to

- Gas costs decreased $282 million, principally related to obligations under the BGSS contract, reflecting lower average gas inventory costs coupled with lower sales volumes in 2011 due to warmer average temperatures during the fourth quarter of 2011.
- Generation costs decreased by $46 million due primarily to $211 million of lower fuel costs, including $251 million of lower fossil fuel costs primarily reflecting the utilization of lower volumes of both coal and oil, favorable results from our coal optimization efforts, and lower natural gas prices, partially offset by higher MTM losses and higher nuclear fuel costs in 2011. The decrease was also attributable to $16 million of lower emission charges, including $10 million of lower impairment charges related to excess SO_2 emission allowances. These decreases were partially offset by an increase of $153 million in higher energy purchases in 2011 in the PJM and NE power pools as the result of lower generation and the need to meet higher load contract demand in 2011 and $23 million of higher operating reserve obligations in the PJM region.

Operation and Maintenance increased $56 million due primarily to

- a net increase of $47 million due largely to planned outage costs, including hot gas path inspection outage costs at our BEC and Linden facilities as well as higher outage costs at our Bergen, and Keystone facilities, partially offset by higher outage and repair costs at certain of our other fossil plants in 2010,
- $20 million of costs incurred for the cancellation and renegotiation of a major contractual agreement for parts and services for our combined cycle Bethlehem Energy (BEC) facility in New York and Linden and Bergen facilities in New Jersey, and

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- a net increase of $3 million due to refurbishment projects at our Salem nuclear facilities,
- partially offset by a decrease of $13 million due to a decrease in pension and OPEB costs tempered by higher labor costs and incentive awards.

Depreciation and Amortization increased $49 million due primarily to

- a $37 million increase due to completion of installation of back-end technology at the end of 2010 at our Mercer and Hudson generating facilities, and
- a $12 million increase due to higher depreciable asset bases at Nuclear and Fossil.

Other Income and (Deductions) The net decrease of $6 million was due primarily to

- a $17 million premium paid on the early extinguishment of 6.95% Senior Notes due in June 2012, and
- the absence of $7 million of gains realized in 2010 from restructuring the Rabbi Trust,
- partially offset by higher net realized gains of $19 million on our NDT Fund.

Other-Than-Temporary Impairments increased $11 million due primarily to higher impairments on the NDT Fund in 2011.

Interest Expense increased $18 million due primarily to

- Higher interest expense of $49 million resulting primarily from the installation by year-end 2010 of back-end technology at our Mercer and Hudson stations for which we had been allowed to capitalize interest costs in 2010 while such projects were under construction,
- partially offset by lower interest expense of $30 million due primarily to the redemption of $606 million of 7.75% Senior Notes in early April 2011 and lower debt issuance costs of $3 million.

Income Tax Expense decreased $93 million in 2011 due primarily to lower pre-tax income.

Income (Loss) from Discontinued Operations

See explanation above for year ended December 31, 2012 as compared to 2011.

PSE&G

	Years Ended December 31,			Increase	Increase
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	Millions				
Income from Continuing Operations	$ 528	$ 521	$ 359	$ 7	$ 162
Net Income	$ 528	$ 521	$ 359	$ 7	$ 162

For the year ended December 31, 2012, the primary reasons for the increase in Income from Continuing Operations were

- higher transmission revenues due to increased investments in transmission projects, and
- tax benefits related to settlement of IRS audits,
- partially offset by higher Operation and Maintenance expense, including higher storm costs and higher pension and OPEB expenses.

For the year ended December 31, 2011, the primary reasons for the increase in Income from Continuing Operations were

- the absence of a $72 million after-tax charge recorded in June 2010 related to the refund of previous MTC collections,
- higher annualized base rates for electric and gas delivery as well as transmission, and
- lower Operation and Maintenance expense, largely due to lower pension and OPEB expenses.

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The year-over-year details for these variances for these periods are discussed below:

PSE&G	Years Ended December 31, 2012	2011	2010	Increase / (Decrease) 2012 vs. 2011		Increase / (Decrease) 2011 vs. 2010	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 6,626	$ 7,326	$ 7,869	$ (700)	(10)	$ (543)	(7)
Energy Costs	3,159	3,951	4,655	(792)	(20)	(704)	(15)
Operation and Maintenance	1,508	1,372	1,442	136	10	(70)	(5)
Depreciation and Amortization	778	719	750	59	8	(31)	(4)
Taxes Other Than Income Taxes	98	133	136	(35)	(26)	(3)	(2)
Other Income (Deductions)	47	21	23	26	N/A	(2)	(9)
Other-Than-Temporary Impairments	—	1	—	(1)	(100)	1	100
Interest Expense	295	310	318	(15)	(5)	(8)	(3)
Income Tax Expense	307	340	232	(33)	(10)	108	47

Year ended December 31, 2012 as compared to 2011

Operating Revenues decreased $700 million due primarily to

Commodity Revenue decreased $792 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $488 million due primarily to $431 million in lower BGS revenues and $57 million in lower revenues from the sale of Non-Utility Generation (NUG) energy and collections of Non-Utility Generation Charges (NGC) due primarily to lower prices. BGS sales decreased 12% due primarily to customer migration to third party suppliers (TPS); in contrast, delivery sales decreased only 1%.
- Gas revenues decreased $304 million due to lower BGSS volumes of $115 million and lower BGSS prices of $189 million. The average price of natural gas was 15% lower in 2012 than in 2011.

Delivery Revenues increased $81 million due primarily to an increase in transmission revenues.

- Transmission revenues were $83 million higher due to increased investments in transmission projects.
- Electric distribution revenues decreased $6 million due primarily to lower Transitional Energy Facilities Assessment (TEFA) revenue of $22 million due to a lower TEFA rate and lower sales volumes of $13 million, partially offset by higher Solar, Energy Efficiency and Conservation Program (Solar/EE) revenue of $20 million and higher Capital Infrastructure Program (CIP) revenue of $9 million.
- Gas distribution revenues increased $4 million due primarily to higher Weather Normalization Clause (WNC) revenue of $52 million and higher CIP revenue of $8 million, partially offset by lower sales volumes of $43 million, and lower TEFA revenue of $13 million due to a lower TEFA rate.

Clause Revenues increased $12 million due primarily to higher Securitization Transition Charge (STC) revenues of $19 million, partially offset by lower Societal Benefit Charges (SBC) of $6 million and a lower Margin Adjustment Clause (MAC) of $2 million. The changes in STC and SBC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, MAC or STC collections.

Energy Costs decreased $792 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $488 million or 18% due to $258 million in lower BGS and NUG volumes, $202 million of lower BGS prices, and $28 million for decreased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.
- Gas costs decreased $304 million or 24% due to $115 million or 9% in lower sales volumes due primarily to weather and $189 million or 15% in lower prices.

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Operation and Maintenance increased $136 million, of which the most significant components were

- a $32 million increase in costs recognized related to SBC, Solar/EE and CIP,
- a $27 million increase in pension and other postretirement benefits (OPEB) expenses,
- a $17 million increase in storm damages,
- a $10 million increase in transmission related costs, and
- a $7 million increase in payroll costs.

Depreciation and Amortization increased $59 million due primarily to

- a $39 million increase in amortization of Regulatory Assets, and
- a $21 million increase in additional plant in service.

Taxes Other Than Income Taxes decreased $35 million due to a lower TEFA rate and lower sales volumes for electric and gas.

Other Income and (Deductions) net increase of $26 million was due primarily to

- a $14 million increase in capitalized allowance for equity funds used during construction,
- an $8 million increase in solar loan interest income, and
- a $4 million increase in Rabbi Trust interest and gains.

Other-Than-Temporary Impairments experienced no material change.

Interest Expense decreased $15 million due primarily to the partial redemption of securitization debt and higher interest capitalization related to higher construction work in progress, partially offset by interest relating to the new debt issued in 2012. See Note 9. Changes in Capitalization for details.

Income Tax Expense decreased $33 million due primarily to changes in tax reserves related to settlement of IRS tax audits.

Year ended December 31, 2011 as compared to 2010

Operating Revenues decreased $543 million due primarily to

Commodity Revenue decreased $704 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS.

- Electric revenues decreased $397 million due primarily to $466 million in lower BGS revenues, partially offset by $69 million in higher revenues from the sale of NUG energy and collections of NGC due primarily to higher prices. BGS sales decreased 16% due primarily to customer migration to TPS; in contrast, delivery sales decreased only 2%.
- Gas revenues decreased $307 million due to lower BGSS prices of $259 million and lower BGSS volumes of $48 million. The average price of gas was 3% lower in 2011 than in 2010.

Delivery Revenues increased $74 million due primarily to an increase in prices for electric and gas distribution and transmission.

- Transmission revenues were $42 million higher due primarily to increased investments in transmission projects.
- Gas distribution revenues increased $32 million due primarily to higher WNC revenue of $19 million and the impact of base rate increases of $17 million, partially offset by lower CIP revenue of $5 million.
- Electric distribution revenues were flat due primarily to the impact of base rate increases of $17 million and higher CIP revenue of $1 million, offset by lower sales volumes of $18 million.

Clause Revenues increased $73 million due primarily to the absence of $122 million charge recorded in June 2010 related to our agreement to refund previous MTC collections over two years and higher SBC and MAC of $49 million, partially offset by lower STC revenues of $98 million. The changes in STC, SBC and MAC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G earns no margins on SBC, STC or MAC collections.

Other Operating Revenues increased $14 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

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Energy Costs decreased $704 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $397 million due to $405 million in lower BGS and NUG volumes and $75 million of lower BGS and NUG prices, partially offset by $83 million for increased deferred cost recovery. BGS and NUG volumes decreased 14% due primarily to customer migration to TPS.
- Gas costs decreased $307 million or 19% due to $259 million or 16% in lower prices and $48 million or 3% in lower sales volumes due primarily to weather.

Operation and Maintenance decreased $70 million due primarily to

- a $71 million decrease in pension and OPEB expenses,
- $20 million of lower net deferred expenses associated with SBC, Regional Greenhouse Gas Initiative and Stimulus clauses, and
- the absence of $15 million in expenses relating to 2010 rate case disallowances.

These were partially offset by

- a $9 million increase in storm restoration work,
- a $6 million increase in costs relating to tree trimming,
- a $3 million increase in bad debt expense, and
- a $3 million increase in incentive payments.

Depreciation and Amortization decreased $31 million due primarily to

- a decrease of $63 million for amortization of Regulatory Assets,
- partially offset by an increase of $28 million for additional plant in service, and an increase of $3 million in net other charges.

Other Income and (Deductions) experienced no material change.

Other-Than-Temporary Impairments experienced no material change.

Interest Expense decreased $8 million due primarily to lower average debt balances.

Income Tax Expense increased $108 million due primarily to higher pre-tax income.

Energy Holdings

	Years Ended December 31,			Increase/ (Decrease)	Increase/ (Decrease)
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	Millions				
Income from Continuing Operations	$ 86	$ (134)	$ 49	$ 220	$ (183)
Net Income	$ 86	$ (134)	$ 49	$ 220	$ (183)

For the year ended December 31, 2012, the primary reasons for the increase in Income from Continuing Operations were

- the absence of the $170 million after-tax charge on leveraged leases related to Dynegy in 2011 and the settlement proceeds received in 2012 (see Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables), and
- the tax benefits related to the settlement of IRS tax audits in the first quarter of 2012.

For the year ended December 31, 2011, the primary reason for the decrease in Income from Continuing Operations was

- the $170 million after-tax charge on leveraged leases related to Dynegy.

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LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our three direct operating subsidiaries.

Financing Methodology

We expect our capital requirements to be met through internally generated cash flows and external financings, consisting of short-term debt for working capital needs and long-term debt for capital investments.

PSE&G's sources of external liquidity include a $600 million multi-year syndicated credit facility. PSE&G's commercial paper program is the primary vehicle for meeting seasonal, intra-month and temporary working capital needs. PSE&G does not engage in any intercompany borrowing or lending. PSE&G maintains back-up facilities in an amount sufficient to cover 100% of commercial paper outstanding. PSE&G's dividend payments to PSEG are consistent with its capital structure objectives which have been established to maintain investment grade credit ratings. PSE&G's long-term financing plan is designed to replace maturities, fund a portion of its capital program and manage short-term debt balances. Generally, PSE&G uses either secured medium-term notes or first mortgage bonds to raise long-term capital.

PSEG, Power, Energy Holdings and PSEG Services Corporation participate in a corporate money pool, an aggregation of daily cash balances designed to efficiently manage their respective short-term liquidity needs. PSEG's sources of external liquidity include multi-year syndicated credit facilities totaling $1 billion. These facilities are available to back-stop PSEG's commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to PSEG's subsidiaries. PSEG's credit facilities and the commercial paper program are available to support PSEG working capital needs or to temporarily fund growth opportunities in advance of obtaining permanent financing. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power's sources of external liquidity include $2.7 billion of syndicated multi-year credit facilities. Additionally, from time to time, Power maintains bilateral credit agreements designed to enhance its liquidity position. Credit capacity is primarily used to provide collateral in support of hedging activities and to meet potential collateral postings in the event of a credit rating downgrade below investment grade. Power's dividend payments to PSEG are also designed to be consistent with its capital structure objectives which have been established to maintain investment grade credit ratings and provide sufficient financial flexibility. Generally, Power issues senior unsecured debt to raise long-term capital.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the year ended December 31, 2012, our operating cash flow decreased by $770 million. For the year ended December 31, 2011, our operating cash flow increased by $1,393 million. The net changes were due to net changes from our subsidiaries as discussed below.

Power

Power's operating cash flow decreased $433 million from $1,812 million to $1,379 million for the year ended December 31, 2012, as compared to 2011, primarily resulting from lower earnings and a $173 million decrease from lower net collections of counterparty receivables, partially offset by

- a decrease of $57 million in benefit plan funding,
- a $73 million decrease in spending for fuel, materials and supplies, and
- a $246 million decrease in net payment of counterparty payables.

Power's operating cash flow increased $246 million from $1,566 million to $1,812 million for the year ended December 31, 2011, as compared to 2010, primarily resulting from

- an increase of $368 million due to lower tax payments, primarily related to the benefits of accelerated tax depreciation under new tax provisions enacted in 2010 (see Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes for additional information), and
- a $302 million increase from net collection of counterparty receivables.

These were partially offset by

- a $171 million increase in net payment of counterparty payables,

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- a $161 million net increase in spending on fuel inventories, and
- lower earnings.

PSE&G

PSE&G's operating cash flow decreased $520 million from $1,776 million to $1,256 million for the year ended December 31, 2012, as compared to 2011, due primarily to

- a lower tax receipt of $484 million due to lower benefit of accelerated tax depreciation, and
- a decrease of $306 million due to lower collections from customer billings,
- partially offset by a decrease of $117 million in benefit plan funding, and
- a decrease of $88 million in net prepayments due primarily to the application of prior year prepayment carryforwards towards current year state tax liabilities.

PSE&G's operating cash flow increased $765 million from $1,011 million to $1,776 million for the year ended December 31, 2011, as compared to 2010, due primarily to higher earnings combined with

- an increase of $587 million due to lower tax payments, primarily related to the benefits of accelerated tax depreciation under new tax provisions enacted in 2010 (see Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes for additional information), and
- an increase of $273 million due to higher collections of customer billings,
- partially offset by a decrease of $108 million in net other working capital.

Energy Holdings

Energy Holdings' operating cash flow increased $149 million for the year ended December 31, 2012, as compared to 2011, primarily due to lower tax payments in 2012 related to the absence of lease sale activity in 2012 and tax benefits related to settlement of IRS audits.

Energy Holdings' operating cash flow increased $341 million for the year ended December 31, 2011, as compared to 2010, primarily due to lower tax payments in 2011 related to less lease sale activity in 2011.

Short-Term Liquidity

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of December 31, 2012 were as follows:

	As of December 31, 2012		
Company/Facility	**Total Facility**	**Usage**	**Available Liquidity**
	Millions		
PSEG	$ 1,000	$ 4	$ 996
Power	2,700	165	2,535
PSE&G	600	276	324
Total	**$ 4,300**	**$ 445**	**$ 3,855**

As of December 31, 2012, our credit facility capacity is in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating. PSE&G's credit facility primary use is to support its Commercial Paper Program under which as of December 31, 2012, $263 million was outstanding. For

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additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities and Note 14. Schedule of Consolidated Debt.

Long-Term Debt Financing

PSE&G had $150 million of 5.00% Medium Term Notes mature in January 2013 and issued $400 million of 3.80% Secured Medium-Term Notes, Series H, due January, 2043. PSE&G also has $300 million of 5.38% Medium Term Notes maturing in September 2013 and $275 million of 6.33% Medium Term Notes maturing in November 2013. Power has $300 million of 2.50% Senior Notes maturing in April 2013.

For a discussion of our long-term debt transactions during 2012 and into 2013, see Item 8. Financial Statements and Supplementary Data—Note 14. Schedule of Consolidated Debt.

Debt Covenants

Our credit agreements contain maximum debt to equity ratios and other restrictive covenants and conditions to borrowing. We are currently in compliance with all of our debt covenants. Continued compliance with applicable financial covenants will depend upon our future financial position, level of earnings and cash flows, as to which no assurances can be given.

In addition, under its First and Refunding Mortgage (Mortgage), PSE&G may issue new First and Refunding Mortgage Bonds against previous additions and improvements, provided that its ratio of earnings to fixed charges calculated in accordance with its Mortgage is at least 2 to 1, and/or against retired Mortgage Bonds. As of December 31, 2012, PSE&G's Mortgage coverage ratio was 3.6 to 1 and the Mortgage would permit up to approximately $2.6 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.

Default Provisions

Our bank credit agreements and indentures contain various default provisions that could result in the potential acceleration of payment under the defaulting company's agreement. We have not defaulted under these agreements.

PSEG's bank credit agreements contain cross default provisions under which events at Power or PSE&G, including payment defaults, bankruptcy events, the failure to satisfy certain final judgments or other events of default under their financing agreements, would each constitute an event of default. Under the bank credit agreements, it would be an event of default if both Power and PSE&G cease to be wholly owned by PSEG.

There are no cross default provisions to affiliates in Power's or PSE&G's credit agreements or indentures.

Ratings Triggers

Our debt indentures and credit agreements do not contain any material 'ratings triggers' that would cause an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, any one or more of the affected companies may be subject to increased interest costs on certain bank debt and certain collateral requirements. In the event that we are not able to affirm representations and warranties on credit agreements, lenders would not be required to make loans.

Fluctuations in commodity prices or a deterioration of Power's credit rating to below investment grade could increase Power's required margin postings under various agreements entered into in the normal course of business. Power believes it has sufficient liquidity to meet the required posting of collateral which would likely result from a credit rating downgrade at today's market prices.

In accordance with BPU requirements under the BGS contracts, PSE&G is required to maintain an investment grade credit rating. If PSE&G were to lose its investment grade rating, it would be required to file a plan to assure continued payment for the BGS requirements of its customers.

PSE&G is the servicer for the bonds issued by PSE&G Transition Funding LLC and PSE&G Transition Funding II LLC. Cash collected by PSE&G to service these bonds is commingled with PSE&G's other cash until it is remitted to the bond trustee each month. If PSE&G were to lose its investment grade rating, PSE&G would be required to remit collected cash daily to the bond trustee. PSE&G is prohibited from advancing its own funds to make payments related to such bonds.

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Common Stock Dividends

Dividend Payments on Common Stock	Years Ended December 31, 2012	2011	2010
Per Share	$ 1.42	$ 1.37	$ 1.37
in Millions	$ 718	$ 693	$ 693

In 2012, dividend payments increased from $1.37 per share to $1.42 per share, representing a change in our dividend policy, moving from a strict earnings payout based approach to one that takes into consideration the growing contribution to earnings and cash from our regulated operations and continued cash flow from our generation business.

On February 19, 2013, our Board of Directors approved a $0.36 per share common stock dividend for the first quarter of 2013. This reflects an indicated annual dividend rate of $1.44 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In May 2012, Moody's published updated credit opinions on PSEG, Power and PSE&G. Moody's upgraded PSE&G's Mortgage Bond Rating to A1 from A2 and revised the outlook to stable from positive. PSEG's and Power's ratings and outlooks remained unchanged. In October 2012, S&P published updated credit opinions that left the ratings and outlooks for Power and PSE&G unchanged. In November 2012, S&P published an updated credit opinion for PSEG that left its ratings and outlook unchanged. In July 2012, Fitch upgraded PSE&G's Mortgage Bond Rating to A+ from A and its stable outlook remained unchanged. In January 2013, Fitch published updated credit opinions on PSEG, Power and PSE&G. PSEG's, Power's and PSE&G's ratings and outlooks remained unchanged.

	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	**Stable**	**Positive**	**Stable**
Commercial Paper	P2	A2	F2
Power			
Outlook	**Stable**	**Positive**	**Stable**
Senior Notes	Baa1	BBB	BBB+
PSE&G			
Outlook	**Stable**	**Positive**	**Stable**
Mortgage Bonds	A1	A-	A+
Commercial Paper	P2	A2	F2

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.
(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.
(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1 (highest) to D (lowest) for short-term securities.

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Other Comprehensive Loss

For the year ended December 31, 2012, we had Other Comprehensive Loss of $51 million on a consolidated basis. Other Comprehensive Loss was due primarily to a $46 million increase in our consolidated liability for pension and postretirement benefits and $24 million of unrealized losses on derivative contracts accounted for as hedges and was partially offset by $19 million of net unrealized gains related to Available-for-Sale Securities.

CAPITAL REQUIREMENTS

It is expected that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. Projected capital construction and investment expenditures, excluding nuclear fuel purchases, for the next three years are presented in the table below. These amounts are subject to change, based on various factors. We will continue to approach non-regulated solar and other renewables investments opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2013	2014	2015
Power:		Millions	
Baseline Maintenance	$ 215	$ 170	$ 200
Environmental/Regulatory	70	70	15
Nuclear Expansion	115	125	90
Total Power	**$ 400**	**$ 365**	**$ 305**
PSE&G:			
Transmission			
Reliability Enhancements	$ 1,230	$ 1,040	$ 550
Facility Replacement	265	145	160
Support Facilities	10	15	10
Environmental/Regulatory	5	—	—
Distribution			
Reliability Enhancements	85	75	75
Facility Replacement	140	150	175
Support Facilities	45	50	45
New Business	125	130	135
Environmental/Regulatory	35	35	30
Renewables	100	40	—
Total PSE&G	**$ 2,040**	**$ 1,680**	**$ 1,180**
Non-Utility Renewables	50	—	—
Other	45	40	30
Total PSEG	**$ 2,535**	**$ 2,085**	**$ 1,515**

Power

Power's projected expenditures for the various items listed above are primarily comprised of the following:

- Baseline Maintenance—investments to replace major parts and enhance operational performance.
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Nuclear Expansion—investments associated with various capital projects at existing facilities to either extend plants' useful lives or increase operating output.

In 2012, Power made $438 million of capital expenditures, including interest capitalized during construction (IDC) but excluding $208 million for nuclear fuel, primarily related to various projects at Fossil and Nuclear.

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PSE&G

PSE&G's projections for future capital expenditures include material additions and replacements to its transmission and distribution systems to meet expected growth and to manage reliability. As project scope and cost estimates develop, PSE&G will modify its current projections to include these required investments. PSE&G's projected expenditures for the various items reported above are primarily comprised of the following:

- Reliability Enhancements—investments made to improve the reliability and efficiency of the system or function.
- Facility Replacement—investments made to replace systems or equipment in kind.
- Support Facilities—ancillary equipment needed to support the business lines, such as computers, office furniture and buildings and structures housing support personnel or equipment/inventory.
- New Business—investments made in support of new business (e.g. to add new customers).
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Renewables—investments made in response to regulatory or legal mandates relating to renewable energy.

In 2012, PSE&G made $1,852 million of capital expenditures, including $1,770 million of investment in plant, primarily for transmission and distribution system reliability and $82 million in solar loan investments. This does not include expenditures for certain energy efficiency and renewable programs of $8 million or cost of removal, net of salvage, of $116 million, which are included in operating cash flows.

Additional Projects

The estimated project expenditures related to the following filings or transmission infrastructure investments are not included in our $6.1 billion three-year capital forecast table.

In February 2013, we filed a petition with the BPU describing the improvements we recommend making to our electric and gas distribution systems over a ten year period to harden and improve resiliency for the future. In this petition, we sought approval to invest $0.9 billion in our gas distribution system and $1.7 billion in our electric distribution over an initial five year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. This matter is pending. The current estimated cost of the entire program, including the first five years of investments for which we sought approval in this petition, is $3.9 billion. We anticipate seeking BPU approval to complete our investment under the program at a later date. We also intend to invest $1.5 billion in FERC jurisdictional investments in transmission infrastructure over the next ten years.

In July 2012, we filed for an extension of our Solar 4 All program. In this filing, we are seeking BPU approval for up to $690 million to develop 136 MW of utility-owned solar photovoltaic systems over a five year period starting in 2013. Consistent with the existing Solar 4 All program, we propose to sell the energy and capacity from the solar systems in the PJM wholesale energy and capacity markets which will offset the cost of the program.

We also filed for an additional extension of our Solar Loan program (Solar Loan III) in July 2012. In the filing, we are seeking BPU approval to provide financing support for the installation of 97.5 MW of solar systems by providing loans to qualified customers. The total investment of the proposed Solar Loan III program is anticipated to be up to $193 million once the program is fully subscribed, projects are built and loans are closed.

Disclosures about Long-Term Maturities, Contractual and Commercial Obligations and Certain Investments

The following table reflects our contractual cash obligations and other commercial commitments in the respective periods in which they are due. See Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities for a discussion of contractual commitments related to the construction activity, discussed above, and for a variety of services for which annual amounts are not quantifiable. In addition, the table summarizes anticipated recourse and non-recourse debt maturities for the years shown. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 14. Schedule of Consolidated Debt. The table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities for uncertain tax positions since we are unable to reasonably estimate the timing of liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes for additional information.

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	Total Amount Committed	Less Than 1 Year	2 - 3 Years	4- 5 Years	Over 5 Years
			Millions		
Contractual Cash Obligations					
Long-Term Recourse Debt Maturities					
Power	$ 2,353	$ 300	$ 344	$ 553	$ 1,156
PSE&G	4,804	725	800	171	3,108
Transition Funding (PSE&G)	690	214	476	—	—
Transition Funding II (PSE&G)	32	12	20	—	—
Long-Term Non-Recourse Project Financing					
Energy Holdings	44	1	18	8	17
Interest on Recourse Debt					
Power	1,194	118	228	172	676
PSE&G	3,370	224	356	314	2,476
Transition Funding (PSE&G)	80	42	38	—	—
Transition Funding II (PSE&G)	2	1	1	—	—
Interest on Non-Recourse Project Financing					
Energy Holdings	12	2	4	3	3
Capital Lease Obligations					
PSEG	20	7	13	—	—
Power	5	2	3	—	—
Operating Leases					
PSEG	214	—	3	25	186
Power	8	—	2	2	4
PSE&G	54	7	9	6	32
Energy Holdings	21	2	4	3	12
Energy-Related Purchase Commitments					
Power	2,796	667	1,133	811	185
Total Contractual Cash Obligations	**$ 15,699**	**$ 2,324**	**$ 3,452**	**$ 2,068**	**$ 7,855**
Commercial Commitments					
Standby Letters of Credit					
Power	$ 214	$ 169	$ 45	$ —	$ —
PSE&G	13	13	—	—	—
Guarantees and Equity Commitments					
Energy Holdings	53	53	—	—	—
Total Commercial Commitments	**$ 280**	**$ 235**	**$ 45**	**$ —**	**$ —**
Liability Payments for Uncertain Tax Positions					
PSEG	$ —	$ —	$ —	$ —	$ —
Power	5	5	—	—	—
PSE&G	—	—	—	—	—
Energy Holdings	70	70	—	—	—

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OFF-BALANCE SHEET ARRANGEMENTS

Power

Power issues guarantees in conjunction with certain of its energy contracts. See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities for further discussion.

Energy Holdings

We have certain investments that are accounted for under the equity method in accordance with GAAP. Accordingly, amounts recorded on the Consolidated Balance Sheets for such investments represent our equity investment, which is increased for our pro-rata share of earnings less any dividend distribution from such investments. One of the companies in which we invest that is accounted for under the equity method has an aggregate $28 million of long-term debt on its Consolidated Balance Sheet. Our pro-rata share of such debt is $14 million. This debt is non-recourse to us. We are generally not required to support the debt service obligations of this company. However, default with respect to this non-recourse debt could result in a loss of invested equity.

Through Energy Holdings, we have investments in leveraged leases that are accounted for in accordance with GAAP Accounting for Leases. Leveraged lease investments generally involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease arrangement, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and is not presented on our Consolidated Balance Sheets. In the event of default, the leased asset, and in some cases the lessee, secures the loan. As a lessor, Energy Holdings has ownership rights to the property and rents the property to the lessees for use in their business operations. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 7. Long-Term Investments.

In the event that collectability of the minimum lease payments to be received by Energy Holdings is no longer reasonably assured, the accounting treatment for some of the leases may change. In such cases, Energy Holdings may deem that a lessee has a high probability of defaulting on the lease obligation, and would reclassify the lease from a leveraged lease to an operating lease and would consider the need to record an impairment of its investment. Should this event occur, the fair value of the underlying asset and the associated debt would be recorded on the Consolidated Balance Sheets instead of the net equity investment in the lease.

CRITICAL ACCOUNTING ESTIMATES

Under GAAP, many accounting standards require the use of estimates, variable inputs and assumptions (collectively referred to as estimates) that are subjective in nature. Because of this, differences between the actual measure realized versus the estimate can have a material impact on results of operations, financial position and cash flows. We have determined that the following estimates are considered critical to the application of rules that relate to the respective businesses.

Accounting for Pensions

We calculate pension costs using various economic and demographic assumptions.

***Assumptions and Approach Used*:** Economic assumptions include the discount rate and the long-term rate of return on trust assets. Demographic assumptions include projections of future mortality rates, pay increases and retirement patterns.

Assumption	2012	2011	2010
Discount Rate	4.20%	5.00%	5.51%
Rate of Return on Plan Assets	8.00%	8.50%	8.50%

Our discount rate assumption, which is determined annually, is based on the rates of return on high-quality fixed-income investments currently available and expected to be available during the period to maturity of the pension benefits. The discount rate used to calculate pension obligations is determined as of December 31 each year, our measurement date. The discount rate used to determine year-end obligations is also used to develop the following year's net periodic pension cost.

Our expected rate of return on plan assets reflects current asset allocations, historical long-term investment performance and an estimate of future long-term returns by asset class and long-term inflation assumptions.

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Based on the above assumptions, we have estimated net periodic pension expense of approximately $110 million, net of amounts capitalized, and contributions of up to $145 million in 2013.

***Effect if Different Assumptions Used*:** As part of the business planning process, we have modeled future costs assuming an 8.00% rate of return and a 4.20% discount rate for 2013, a 4.50% discount rate for 2014, increasing annually by 25 basis points to 5.25% in 2017. Actual future pension expense and funding levels will depend on future investment performance, changes in discount rates, market conditions, funding levels relative to our projected benefit obligation and accumulated benefit obligation and various other factors related to the populations participating in the pension plans.

The following chart reflects the sensitivities associated with a change in certain assumptions. The effects of the assumption changes shown below solely reflect the impact of that specific assumption.

Assumption	% Change	Impact on Pension Benefit Obligation As of December 31, 2012	Increase to Pension Expense in 2013
		Millions	
Discount Rate	(1)%	$ 751	$ 72
Rate of Return on Plan Assets	(1)%	$ —	$ 44

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Hedge and MTM Accounting

Current guidance requires us to recognize the fair value of derivative instruments, not designated as normal purchases or normal sales, at their fair value on the balance sheet. Many non-trading contracts qualify for normal purchases and normal sales exemption and are accounted for upon settlement.

***Assumptions and Approach Used*:** In general, the fair value of our derivative instruments is determined by reference to quoted market prices from contracts listed on exchanges or from brokers. Some of these derivative contracts are long-term and rely on forward price quotations over the entire duration of the derivative contracts.

For a small number of contracts where quoted market prices are not available, we utilize mathematical models that rely on historical data to develop forward pricing information in the determination of fair value. Because the determination of fair value using such models is subject to significant assumptions and estimates, we developed reserve policies that are consistently applied to model-generated results to determine reasonable estimates of the fair value to record in the financial statements.

We have entered into various derivative instruments to manage risk from changes in commodity prices and interest rates. In accordance with our hedging strategy, derivatives that are hedging these risks and qualify are designated as either cash flow hedges or fair value hedges. For derivatives designated as hedges, the change in the value of a derivative instrument is measured against the offsetting change in the value of the underlying contract, anticipated transaction or other business condition that the derivative instrument is intended to hedge. This is known as the measure of hedge effectiveness. Changes in the fair value of the effective portion of a derivative instrument designated as a fair value hedge, along with changes in the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in current period earnings. Changes in the fair value of the effective portion of derivative instruments designated as cash flow hedges, are reported in Accumulated Other Comprehensive Income (Loss), net of tax, until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings. During periods of extreme price volatility, there will be significant changes in the value recorded in Accumulated Other Comprehensive Income (Loss).

For our wholesale energy business, many of the forward sale, forward purchase, option and other contracts are derivative instruments that hedge commodity price risk, but do not meet the requirements for either cash flow or fair value hedge accounting. The changes in value of such derivative contracts are marked to market through earnings as the related commodity prices fluctuate. As a result, our earnings may experience significant fluctuations depending on the volatility of commodity prices.

***Effect if Different Assumptions Used*:** Any significant changes to the fair market values of our derivatives instruments could result in a material change in the value of the assets or liabilities recorded on our Consolidated Balance Sheets and could result in a material change to the unrealized gains or losses recorded in our Consolidated Statements of Operations.

For additional information regarding Derivative Financial Instruments, see Item 8. Financial Statements and Supplementary Data—Note 16. Financial Risk Management Activities.

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Lease Investments

Our Investments in Leases, included in Long-Term Investments on our Consolidated Balance Sheets, are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. A significant portion of the estimated residual value of leased assets is related to merchant power plants leased to other energy companies. See Item 8. Financial Statements and Supplementary Data – Note 7. Long-Term Investments, and Note 8. Financing Receivables.

Assumptions and Approach Used: Residual values are the estimated values of the leased assets at the end of the respective lease terms. The estimated values are calculated by discounting the cash flows related to the leased assets after the lease term. For the merchant power plants, the estimated discounted cash flows are dependent upon various assumptions, including:

- estimated forward power and capacity prices in the years after the lease,
- related prices of fuel for the plants,
- dispatch rates for the plants,
- future capital expenditures required to maintain the plants,
- future operation and maintenance expenses, and
- discount rates.

Residual valuations are performed annually for each plant subject to lease using specific assumptions tailored to each plant. Those annual valuations are compared to the recorded residual values to determine if an impairment is warranted.

Effect if Different Assumptions Used: A significant change to the assumptions, such as a large decrease in near-term power prices that affects the market's view of long-term power prices, or a change in the credit rating or bankruptcy of a counterparty, could result in an impairment of one or more of the residual values, but not necessarily to all of the residual values. However, if, because of changes in assumptions, all the residual values related to the merchant energy plants were deemed to be zero, we would recognize an after-tax charge to income of approximately $177 million.

NDT Fund

Our NDT Fund is comprised of both debt and equity securities. The assets in the NDT Fund are classified as available-for-sale securities and are marked to market with unrealized gains and losses recorded in Accumulated Other Comprehensive Income (Loss) unless securities with such unrealized losses are deemed to be other-than-temporarily-impaired. Realized gains, losses and dividend and interest income are recorded in our Consolidated Statements of Operations as Other Income and Other Deductions. Unrealized losses that are deemed to be other-than-temporarily impaired are charged against earnings rather than Accumulated Other Comprehensive Income (Loss) and reflected as a separate line in the Consolidated Statement of Operations.

***Assumptions and Approach Used*:** The NDT Fund investments are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. See Item 8. Financial Statements and Supplementary Data—Note 17. Fair Value Measurements for additional information.

***Effect if Different Assumptions Used*:** Any significant changes to the fair market values of the fund securities could result in a material change in the value of our NDT Fund with a corresponding impact to earnings, which could potentially result in additional funding requirements to satisfy our decommissioning obligations. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Asset Retirement Obligations (ARO)

Power, PSE&G and Services recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists. These AROs are recorded at fair value in the period in which they are incurred and are capitalized as part of the carrying amount of the related long-lived assets. PSE&G, as a rate-regulated entity, recognizes regulatory assets or liabilities as a result of timing differences between the recording of costs and costs recovered through the ratemaking process. We accrete the ARO liability to reflect the passage of time.

Assumptions and Approach Used: Because quoted market prices are not available for AROs, we estimate the initial fair value of an ARO by calculating discounted cash flows that are dependent upon various assumptions, including:

- estimation of dates for retirement,
- amounts and timing of future cash expenditures associated with retirement, settlement or remediation activities,

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- discount rates,
- cost escalation rates,
- market risk premium,
- inflation rates, and
- if applicable, past experience with government regulators regarding similar obligations.

We obtain updated cost studies every three years unless new information necessitates more frequent updates. The most recent cost study was done in 2012. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset which impacts the amount of accretion and depreciation expense recognized in future periods.

Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power's nuclear facilities comprised 94% of Power's total AROs as of December 31, 2012. Power determines its AROs for its nuclear units by assigning probability weighting to various discounted cash flow outcomes for each of its nuclear units that incorporate the assumptions above as well as:

- license renewals,
- early shutdown,
- safe storage for a period of time after retirement, and
- recovery from the federal government of costs incurred for spent nuclear fuel.

Effect if Different Assumptions Used: Changes in the assumptions could result in a material change in the ARO balance sheet obligation and the period over which we accrete to the ultimate liability. For example, a 1% decrease in the discount rate used at December 31, 2012 would result in a $134 million increase in the Nuclear ARO as of December 31, 2012. A 1% increase in the inflation rate used at December 31, 2012 would result in a $335 million increase in the Nuclear ARO as of December 31, 2012. Also, if we did not assume that we would recover from the federal government the costs incurred for spent nuclear fuel, the Nuclear ARO would increase by $273 million at December 31, 2012.

Accounting for Regulated Businesses

PSE&G prepares its financial statements to comply with GAAP for rate-regulated enterprises, which differs in some respects from accounting for non-regulated businesses. In general, accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (Regulatory Asset) or recognize obligations (Regulatory Liability) if the rates established are designed to recover the costs and if the competitive environment makes it probable that such rates can be charged or collected. This accounting results in the recognition of revenues and expenses in different time periods than that of enterprises that are not regulated.

Assumptions and Approach Used: PSE&G recognizes Regulatory Assets where it is probable that such costs will be recoverable in future rates from customers and Regulatory Liabilities where it is probable that refunds will be made to customers in future billings. The highest degree of probability is an order from the BPU either approving recovery of the deferred costs over a future period or requiring the refund of a liability over a future period.

Virtually all of PSE&G's regulatory assets and liabilities are supported by BPU orders. In the absence of an order, PSE&G will consider the following when determining whether to record a Regulatory Asset or Liability:

- past experience regarding similar items with the BPU,
- treatment of a similar item in an order by the BPU for another utility,
- passage of new legislation, and
- recent discussions with the BPU.

All deferred costs are subject to prudence reviews by the BPU. When the recovery of a Regulatory asset or payment of a Regulatory Liability is no longer probable, PSE&G charges or credits earnings, as appropriate.

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***Effect if Different Assumptions Used*:** A change in the above assumptions may result in a material impact on our results of operations or our cash flows. See Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities for a description of the amounts and nature of regulatory balance sheet amounts.

Accounting for Insurance Proceeds

In late October 2012, Superstorm Sandy caused severe damage to our transmission and distribution system as well as to some of our generation infrastructure in the northern part of New Jersey. Strong winds resulted in a storm surge that caused damage to switching stations, substations and generating infrastructure. We are in the early stages of gathering information needed in preparing an insurance claim relating to that damage. As of December 31, 2012, we recorded estimated insurance proceeds of $25 million ($19 million for Power and $6 million for PSE&G). See Item 8. Financial Statements and Supplementary Data —Note 13. Commitments and Contingencies for additional information.

Assumptions and Approach Used: In December 2012, we received correspondence from representatives of the various insurance carriers acknowledging that damages were sustained and authorizing $25 million in advance payments to be made to us. Based on that authorization, we recorded the estimated insurance proceeds of $25 million. We believe that any further proceeds to be received under our policies are not estimable at December 31, 2012. We are at the early stages of documenting our insurance claim which then needs to be submitted to, and reviewed by, the insurers. We believe we have no basis for developing an estimate for any further insurance recoveries at this time.

Effect if Different Assumptions Used: If we were to use different assumptions regarding additional insurance proceeds, there would be a dollar for dollar effect on Operation and Maintenance Expense and Operating Income for Power. If we were to recognize any additional insurance proceeds for PSE&G, we would allocate those proceeds between Operation and Maintenance Expense and costs that have been deferred for regulatory recovery or capitalized. In either case, we would not recognize insurance proceeds in excess of actual costs incurred.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The market risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

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Year Ended December 31, 2012	MTM VaR (A)	
		Millions
95% Confidence Level,		
Loss could exceed VaR one day in 20 days		
Period End	$	18
Average for the Period	$	16
High	$	29
Low	$	7
99.5% Confidence Level,		
Loss could exceed VaR one day in 200 days		
Period End	$	28
Average for the Period	$	25
High	$	46
Low	$	11

(A) As of December 31, 2012 and December 31, 2011, there was no trading VaR since we discontinued trading activities in the second quarter of 2011.

See Item 8. Financial Statements and Supplementary Data—Note 16. Financial Risk Management Activities for a discussion of credit risk.

Interest Rates

We are subject to the risk of fluctuating interest rates in the normal course of business. We manage interest rate risk by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, we use a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

As of December 31, 2012, a hypothetical 10% increase in market interest rates would result in

- less than $1 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and
- a $223 million decrease in the fair value of debt, including a $56 million decrease at Power and a $166 million decrease at PSE&G.

Debt and Equity Securities

We have $4.6 billion of assets in our pension plan trusts. Although fluctuations in market prices of securities within this portfolio do not directly affect our earnings in the current period, changes in the value of these investments could affect

- our future contributions to these plans,
- our financial position if our accumulated benefit obligation under our pension plans exceeds the fair value of the pension trust funds, and
- future earnings, as we could be required to adjust pension expense and the assumed rate of return.

The NDT Fund is comprised of both fixed income and equity securities totaling $1.5 billion as of December 31, 2012. As of December 31, 2012, the portfolio includes $789 million of equity securities and $627 million in fixed income securities. The fair market value of the assets in the NDT Fund will fluctuate primarily depending upon the performance of equity markets. As of December 31, 2012, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $79 million.

We use duration to measure the interest rate sensitivity of the fixed income portfolio. Duration is a summary statistic of the effective average maturity of the fixed income portfolio. The benchmark for the fixed income component of the NDT Fund currently has duration of 4.31 years and a yield of 1.24%. The portfolio's value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2012, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $27 million.

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Credit Risk

See Item 8. Financial Statements and Supplementary Data—Note 16. Financial Risk Management Activities for a discussion of credit risk and a discussion about Power's credit risk.

BGS suppliers expose PSE&G to credit losses in the event of non-performance or non-payment upon a default of the BGS supplier. Credit requirements are governed under BPU approved BGS contracts.

Energy Holdings has credit risk with respect to its counterparties to power purchase agreements and other parties.

Energy Holdings also has credit risk related to its investments in leases, which totaled $117 million, net of deferred taxes of $723 million, as of December 31, 2012. These leveraged leases are concentrated in the United States energy industry. See Item 8. Financial Statements and Supplementary Data -Note 8. Financing Receivables for counterparties' credit ratings and other information. The credit exposure to the lessees is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverages are not met and similar cash flow restrictions if ratings are not maintained at stated levels. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a temporary market downturn or degradation in operating performance of the leased assets.

In any lease transaction, in the event of a default, Energy Holdings would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. Under a worst-case scenario, if a foreclosure were to occur, Energy Holdings would record a pre-tax write-off up to its outstanding gross investment, including deferred taxes, in these facilities. Also, in the event of a potential foreclosure, the net tax benefits generated by Energy Holdings' portfolio of investments could be materially reduced in the period in which gains associated with the potential forgiveness of debt at these projects occurs. The amount and timing of any potential reduction in net tax benefits is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, the amount of lease debt outstanding, any cash trapped at the projects and negotiations during such potential foreclosure process. The potential loss of earnings, impairment and/or tax payments could have a material impact to our financial position, results of operations and net cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined Form 10-K is separately filed by PSEG, Power and PSE&G. Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations as to any other company.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of
Public Service Enterprise Group Incorporated:

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(a). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Sole Member and Board of Directors of
PSEG Power LLC:

We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, member's equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(b). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Sole Stockholder and Board of Directors of
Public Service Electric and Gas Company:

We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(c). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2013

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2012	2011	2010
OPERATING REVENUES	$ 9,781	$ 11,079	$ 11,793
OPERATING EXPENSES			
Energy Costs	3,719	4,747	5,261
Operation and Maintenance	2,632	2,481	2,504
Depreciation and Amortization	1,054	976	955
Taxes Other Than Income Taxes	98	133	136
Total Operating Expenses	7,503	8,337	8,856
OPERATING INCOME	2,278	2,742	2,937
Income from Equity Method Investments	12	4	4
Other Income	260	220	221
Other Deductions	(98)	(85)	(63)
Other-Than-Temporary Impairments	(18)	(22)	(11)
Interest Expense	(423)	(475)	(472)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,011	2,384	2,616
Income Tax (Expense) Benefit	(736)	(977)	(1,059)
INCOME FROM CONTINUING OPERATIONS	1,275	1,407	1,557
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $0, $(51) and $(8) for the years ended 2012, 2011 and 2010, respectively	—	96	7
NET INCOME	$ 1,275	$ 1,503	$ 1,564
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):			
BASIC	505,933	505,949	505,985
DILUTED	507,086	506,982	507,045
EARNINGS PER SHARE:			
BASIC			
INCOME FROM CONTINUING OPERATIONS	$ 2.52	$ 2.78	$ 3.08
NET INCOME	$ 2.52	$ 2.97	$ 3.09
DILUTED			
INCOME FROM CONTINUING OPERATIONS	$ 2.51	$ 2.77	$ 3.07
NET INCOME	$ 2.51	$ 2.96	$ 3.08
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 1.42	$ 1.37	$ 1.37

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2012	**2011**	**2010**
NET INCOME	$ 1,275	$ 1,503	$ 1,564
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(24), $43 and $(12) for the years ended 2012, 2011 and 2010, respectively	19	(39)	6
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $(11), $(33) and $(42) for the years ended 2012, 2011 and 2010, respectively	17	47	60
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $29, $87 and $90 for the years ended 2012, 2011 and 2010, respectively	(41)	(127)	(129)
Pension/OPEB adjustment, net of tax (expense) benefit of $32, $44 and $(18) for the years ended 2012, 2011 and 2010, respectively	(46)	(62)	23
Other Comprehensive Income (Loss), net of tax	(51)	(181)	(40)
COMPREHENSIVE INCOME	$ 1,224	$ 1,322	$ 1,524

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10694

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2012	2011
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 379	$ 834
Accounts Receivable, net of allowances of $56 and $56 in 2012 and 2011, respectively	1,069	967
Tax Receivable	227	16
Unbilled Revenues	314	289
Fuel	583	685
Materials and Supplies, net	422	367
Prepayments	283	308
Derivative Contracts	138	156
Deferred Income Taxes	49	—
Regulatory Assets	349	167
Other	56	122
Total Current Assets	3,869	3,911
PROPERTY, PLANT AND EQUIPMENT	27,402	25,080
Less: Accumulated Depreciation and Amortization	(7,666)	(7,231)
Net Property, Plant and Equipment	19,736	17,849
NONCURRENT ASSETS		
Regulatory Assets	3,830	3,805
Regulatory Assets of Variable Interest Entities (VIEs)	713	925
Long-Term Investments	1,324	1,303
Nuclear Decommissioning Trust (NDT) Fund	1,540	1,349
Other Special Funds	191	172
Goodwill	16	16
Other Intangibles	34	131
Derivative Contracts	153	106
Restricted Cash of VIEs	23	22
Other	296	232
Total Noncurrent Assets	8,120	8,061
TOTAL ASSETS	$ 31,725	$ 29,821

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10695

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2012	December 31, 2011
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year (includes $50 at fair value in 2011)	$ 1,026	$ 417
Securitization Debt of VIEs Due Within One Year	226	216
Commercial Paper and Loans	263	—
Accounts Payable	1,304	1,184
Derivative Contracts	46	131
Accrued Interest	91	97
Accrued Taxes	17	30
Deferred Income Taxes	72	170
Clean Energy Program	153	214
Obligation to Return Cash Collateral	122	107
Regulatory Liabilities	67	100
Other	390	291
Total Current Liabilities	3,777	2,957
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	6,542	5,458
Regulatory Liabilities	209	228
Regulatory Liabilities of VIEs	10	9
Asset Retirement Obligations	627	489
Other Postretirement Benefit (OPEB) Costs	1,285	1,127
Accrued Pension Costs	876	734
Clean Energy Program	—	39
Environmental Costs	537	643
Derivative Contracts	122	26
Long-Term Accrued Taxes	164	292
Other	108	86
Total Noncurrent Liabilities	10,480	9,131
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	6,148	6,694
Securitization Debt of VIEs	496	723
Project Level, Non-Recourse Debt	43	44
Total Long-Term Debt	6,687	7,461
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2012 and 2011—533,556,660 shares	4,833	4,823
Treasury Stock, at cost, 2012—27,664,188 shares; 2011—27,611,374 shares	(607)	(601)
Retained Earnings	6,942	6,385
Accumulated Other Comprehensive Loss	(388)	(337)
Total Common Stockholders' Equity	10,780	10,270
Noncontrolling Interest	1	2
Total Stockholders' Equity	10,781	10,272
Total Capitalization	17,468	17,733
TOTAL LIABILITIES AND CAPITALIZATION	$ 31,725	$ 29,821

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10696

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2012	**2011**	**2010**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,275	$ 1,503	$ 1,564
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Gain on Disposal of Discontinued Operations	—	(122)	—
Depreciation and Amortization	1,054	982	974
Amortization of Nuclear Fuel	173	153	136
Provision for Deferred Income Taxes (Other than Leases) and ITC	721	811	1,106
Non-Cash Employee Benefit Plan Costs	271	175	315
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	93	(55)	(336)
Loss on Leases, net of tax	—	170	—
Net (Gain) Loss on Lease Investments	(49)	(55)	(56)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	63	(165)	50
Deferred Storm Costs	(90)	(60)	(8)
Net Change in Regulatory Assets and Liabilities	(132)	(130)	(58)
Cost of Removal	(116)	(62)	(58)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(118)	(117)	(106)
Net Change in Tax Receivable	(211)	673	(689)
Net Change in Certain Current Assets and Liabilities	97	247	(221)
Employee Benefit Plan Funding and Related Payments	(314)	(508)	(508)
Other	70	117	59
Net Cash Provided By (Used In) Operating Activities	2,787	3,557	2,164
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,574)	(2,083)	(2,160)
Proceeds from Sale of Discontinued Operations	—	687	—
Proceeds from Sale of Capital Leases and Investments	58	179	496
Proceeds from Sales of Available-for-Sale Securities	1,666	1,355	1,116
Investments in Available-for-Sale Securities	(1,700)	(1,386)	(1,140)
Other	(75)	(21)	19
Net Cash Provided By (Used In) Investing Activities	(2,625)	(1,269)	(1,669)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	263	(64)	(466)
Issuance of Long-Term Debt	900	794	1,728
Redemption of Long-Term Debt, including Securitization Debt	(1,003)	(1,720)	(972)
Repayment of Non-Recourse Debt	(1)	(1)	(32)
Cash Dividend Paid on Common Stock	(718)	(693)	(693)
Redemption of Preferred Securities	—	—	(80)
Other	(58)	(50)	(50)
Net Cash Provided By (Used In) Financing Activities	(617)	(1,734)	(565)
Net Increase (Decrease) in Cash and Cash Equivalents	(455)	554	(70)
Cash and Cash Equivalents at Beginning of Period	834	280	350
Cash and Cash Equivalents at End of Period	$ 379	$ 834	$ 280
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 121	$ (219)	$ 1,070
Interest Paid, Net of Amounts Capitalized	$ 402	$ 479	$ 444
Accrued Property, Plant and Equipment Expenditures	$ 370	$ 336	$ 235

See the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10698

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Millions

	Common Stock		Treasury Stock					
	Shs.	Amount	Shs.	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance as of January 1, 2010	534	$ 4,788	(28)	$ (588)	$ 4,704	$ (116)	$ 10	$ 8,798
Net Income	—	—	—	—	1,564	—	—	1,564
Other Comprehensive Income (Loss), net of tax (expense) benefit of $18	—	—	—	—	—	(40)	—	(40)
Comprehensive Income								1,524
Cash Dividends on Common Stock	—	—	—	—	(693)	—	—	(693)
Noncontrolling Interest in Losses of Consolidated Entity	—	—	—	—	—	—	(2)	(2)
Other	—	19	—	(5)	—	—	—	14
Balance as of December 31, 2010	534	$ 4,807	(28)	$ (593)	$ 5,575	$ (156)	$ 8	$ 9,641
Net Income	—	—	—	—	1,503	—	—	1,503
Other Comprehensive Income (Loss), net of tax (expense) benefit of $141	—	—	—	—	—	(181)	—	(181)
Comprehensive Income								1,322
Cash Dividends on Common Stock	—	—	—	—	(693)	—	—	(693)
Noncontrolling Interest in Losses of Consolidated Entity	—	—	—	—	—	—	(6)	(6)
Other	—	16	—	(8)	—	—	—	8
Balance as of December 31, 2011	534	$ 4,823	(28)	$ (601)	$ 6,385	$ (337)	$ 2	$ 10,272
Net Income	—	—	—	—	1,275	—	—	1,275
Other Comprehensive Income (Loss), net of tax (expense) benefit of $26	—	—	—	—	—	(51)	—	(51)
Comprehensive Income								1,224
Cash Dividends on Common Stock	—	—	—	—	(718)	—	—	(718)
Noncontrolling Interest in Losses of Consolidated Entity	—	—	—	—	—	—	(1)	(1)
Other	—	10	—	(6)	—	—	—	4
Balance as of December 31, 2012	534	$ 4,833	(28)	$ (607)	$ 6,942	$ (388)	$ 1	$ 10,781

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10699

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2012	2011	2010
OPERATING REVENUES	$ 4,865	$ 6,143	$ 6,558
OPERATING EXPENSES			
Energy Costs	2,383	3,046	3,374
Operation and Maintenance	1,122	1,102	1,046
Depreciation and Amortization	237	224	175
Total Operating Expenses	3,742	4,372	4,595
OPERATING INCOME	1,123	1,771	1,963
Other Income	199	190	170
Other Deductions	(90)	(79)	(53)
Other-Than-Temporary Impairments	(18)	(20)	(9)
Interest Expense	(134)	(175)	(157)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	1,080	1,687	1,914
Income Tax (Expense) Benefit	(433)	(685)	(778)
INCOME FROM CONTINUING OPERATIONS	647	1,002	1,136
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $0, $(51) and $(8) for the years ended 2012, 2011 and 2010, respectively	—	96	7
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 647	$ 1,098	$ 1,143

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10700

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2012	**2011**	**2010**
NET INCOME	$ 647	$ 1,098	$ 1,143
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(24), $45 and $(17) for the years ended 2012, 2011 and 2010, respectively	18	(42)	15
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $(11), $(33) and $(42) for the years ended 2012, 2011 and 2010, respectively	17	47	60
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $29, $87, and $90 for the years ended 2012, 2011 and 2010, respectively	(41)	(127)	(129)
Pension/OPEB adjustment, net of tax (expense) benefit of $32, $40, and $(15) for the years ended 2012, 2011 and 2010, respectively	(46)	(59)	21
Other, net of tax (expense) benefit of $0 for the year ended 2010	—	—	(1)
Other Comprehensive Income (Loss), net of tax	(52)	(181)	(34)
COMPREHENSIVE INCOME	$ 595	$ 917	$ 1,109

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10701

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2012	2011
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 7	$ 12
Accounts Receivable	269	267
Accounts Receivable—Affiliated Companies, net	340	381
Short-Term Loan to Affiliate	574	907
Fuel	583	685
Materials and Supplies, net	307	272
Derivative Contracts	118	139
Prepayments	17	24
Other	19	—
Total Current Assets	2,234	2,687
PROPERTY, PLANT AND EQUIPMENT	9,697	9,191
Less: Accumulated Depreciation and Amortization	(2,679)	(2,460)
Net Property, Plant and Equipment	7,018	6,731
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,540	1,349
Goodwill	16	16
Other Intangibles	34	131
Other Special Funds	36	33
Derivative Contracts	49	55
Other	105	85
Total Noncurrent Assets	1,780	1,669
TOTAL ASSETS	$ 11,032	$ 11,087

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10702

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2012	December 31, 2011
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 300	$ 66
Accounts Payable	498	541
Derivative Contracts	46	124
Deferred Income Taxes	16	53
Accrued Interest	26	32
Other	81	86
Total Current Liabilities	967	902
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	1,575	1,266
Asset Retirement Obligations	369	259
Other Postretirement Benefit (OPEB) Costs	221	180
Derivative Contracts	15	24
Accrued Pension Costs	272	236
Long-Term Accrued Taxes	50	8
Other	84	83
Total Noncurrent Liabilities	2,586	2,056
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
LONG-TERM DEBT		
Total Long-Term Debt	2,040	2,685
MEMBER'S EQUITY		
Contributed Capital	2,028	2,028
Basis Adjustment	(986)	(986)
Retained Earnings	4,725	4,678
Accumulated Other Comprehensive Loss	(328)	(276)
Total Member's Equity	5,439	5,444
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 11,032	$ 11,087

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10703

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 647	$ 1,098	$ 1,143
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Gain on Disposal of Discontinued Operations	—	(122)	—
Depreciation and Amortization	237	231	194
Amortization of Nuclear Fuel	173	153	136
Provision for Deferred Income Taxes and ITC	342	231	650
Interest Accretion on Asset Retirement Obligation	21	18	18
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	63	(165)	50
Non-Cash Employee Benefit Plan Costs	70	41	71
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(118)	(117)	(106)
Net Change in Certain Current Assets and Liabilities:			
Fuel, Materials and Supplies	47	(26)	135
Margin Deposit	(116)	49	(91)
Accounts Receivable	24	197	(105)
Accounts Payable	92	(154)	17
Accounts Receivable/Payable-Affiliated Companies, net	(40)	459	(386)
Accrued Interest Payable	(6)	(8)	(3)
Other Current Assets and Liabilities	(16)	38	(63)
Employee Benefit Plan Funding and Related Payments	(72)	(129)	(132)
Other	31	18	38
Net Cash Provided By (Used In) Operating Activities	1,379	1,812	1,566
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(646)	(757)	(825)
Proceeds from Sale of Discontinued Operations	—	687	—
Proceeds from Sales of Available-for-Sale Securities	1,478	1,355	989
Investments in Available-for-Sale Securities	(1,506)	(1,380)	(1,013)
Short-Term Loan—Affiliated Company, net	333	(509)	(398)
Other	(7)	26	42
Net Cash Provided By (Used In) Investing Activities	(348)	(578)	(1,205)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Recourse Long-Term Debt	—	544	594
Cash Dividend Paid	(600)	(500)	(549)
Redemption of Long-Term Debt	(414)	(1,250)	(248)
Short-Term Loan—Affiliated Company, net	—	—	(194)
Cash Payment on Debt Redemption/Exchange	(15)	(17)	(13)
Other	(7)	(10)	(4)
Net Cash Provided By (Used In) Financing Activities	(1,036)	(1,233)	(414)
Net Increase (Decrease) in Cash and Cash Equivalents	(5)	1	(53)
Cash and Cash Equivalents at Beginning of Period	12	11	64
Cash and Cash Equivalents at End of Period	$ 7	$ 12	$ 11
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 136	$ 171	$ 539
Interest Paid, Net of Amounts Capitalized	$ 119	$ 176	$ 151
Accrued Property, Plant and Equipment Expenditures	$ 95	$ 132	$ 111

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10704

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY
Millions

	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2010	$ 2,028	$ (986)	$ 3,486	$ (61)	$ 4,467
Net Income	—	—	1,143	—	1,143
Other Comprehensive Income (Loss), net of tax (expense) benefit of $16	—	—	—	(34)	(34)
Comprehensive Income					1,109
Cash Dividends Paid	—	—	(549)	—	(549)
Balance as of December 31, 2010	$ 2,028	$ (986)	$ 4,080	$ (95)	$ 5,027
Net Income	—	—	1,098	—	1,098
Other Comprehensive Income (Loss), net of tax (expense) benefit of $139	—	—	—	(181)	(181)
Comprehensive Income					917
Cash Dividends Paid	—	—	(500)	—	(500)
Balance as of December 31, 2011	$ 2,028	$ (986)	$ 4,678	$ (276)	$ 5,444
Net Income	—	—	647	—	647
Other Comprehensive Income (Loss), net of tax (expense) benefit of $26	—	—	—	(52)	(52)
Comprehensive Income					595
Cash Dividends Paid	—	—	(600)	—	(600)
Balance as of December 31, 2012	$ 2,028	$ (986)	$ 4,725	$ (328)	$ 5,439

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10705

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2012	2011	2010
OPERATING REVENUES	$ 6,626	$ 7,326	$ 7,869
OPERATING EXPENSES			
Energy Costs	3,159	3,951	4,655
Operation and Maintenance	1,508	1,372	1,442
Depreciation and Amortization	778	719	750
Taxes Other Than Income Taxes	98	133	136
Total Operating Expenses	5,543	6,175	6,983
OPERATING INCOME	1,083	1,151	886
Other Income	52	25	26
Other Deductions	(5)	(4)	(3)
Other-Than-Temporary Impairments	—	(1)	—
Interest Expense	(295)	(310)	(318)
INCOME BEFORE INCOME TAXES	835	861	591
Income Tax (Expense) Benefit	(307)	(340)	(232)
NET INCOME	528	521	359
Preferred Stock Dividends	—	—	(1)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 528	$ 521	$ 358

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 10706

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2012	**2011**	**2010**
NET INCOME	$ 528	$ 521	$ 359
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $(1) and $3 for the years ended 2012, 2011 and 2010, respectively	—	2	(5)
COMPREHENSIVE INCOME	$ 528	$ 523	$ 354

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2012	2011
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 116	$ 143
Accounts Receivable, net of allowances of $56 and $56 in 2012 and 2011, respectively	783	691
Tax Receivable	—	16
Unbilled Revenues	314	289
Materials and Supplies	114	94
Prepayments	29	117
Regulatory Assets	349	167
Derivative Contracts	5	—
Deferred Income Taxes	49	—
Other	24	21
Total Current Assets	1,783	1,538
PROPERTY, PLANT AND EQUIPMENT	17,006	15,306
Less: Accumulated Depreciation and Amortization	(4,726)	(4,539)
Net Property, Plant and Equipment	12,280	10,767
NONCURRENT ASSETS		
Regulatory Assets	3,830	3,805
Regulatory Assets of VIEs	713	925
Long-Term Investments	348	280
Other Special Funds	61	57
Derivative Contracts	62	4
Restricted Cash of VIEs	23	22
Other	123	89
Total Noncurrent Assets	5,160	5,182
TOTAL ASSETS	$ 19,223	$ 17,487

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2012	December 31, 2011
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 725	$ 300
Securitization Debt of VIEs Due Within One Year	226	216
Commercial Paper and Loans	263	—
Accounts Payable	630	498
Accounts Payable—Affiliated Companies, net	73	280
Accrued Interest	65	65
Clean Energy Program	153	214
Derivative Contracts	—	7
Deferred Income Taxes	60	32
Obligation to Return Cash Collateral	122	107
Regulatory Liabilities	67	100
Other	269	186
Total Current Liabilities	2,653	2,005
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,223	3,675
Other Postretirement Benefit (OPEB) Costs	1,011	900
Accrued Pension Costs	463	355
Regulatory Liabilities	209	228
Regulatory Liabilities of VIEs	10	9
Clean Energy Program	—	39
Environmental Costs	486	592
Asset Retirement Obligations	250	226
Derivative Contracts	107	—
Long-Term Accrued Taxes	32	83
Other	38	35
Total Noncurrent Liabilities	6,829	6,142
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	4,070	3,970
Securitization Debt of VIEs	496	723
Total Long-Term Debt	4,566	4,693
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2012 and 2011 —132,450,344 shares	892	892
Contributed Capital	420	420
Basis Adjustment	986	986
Retained Earnings	2,875	2,347
Accumulated Other Comprehensive Income	2	2
Total Stockholder's Equity	5,175	4,647
Total Capitalization	9,741	9,340
TOTAL LIABILITIES AND CAPITALIZATION	$ 19,223	$ 17,487

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 528	$ 521	$ 359
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	778	719	750
Provision for Deferred Income Taxes and ITC	442	571	444
Non-Cash Employee Benefit Plan Costs	179	118	217
Cost of Removal	(116)	(62)	(58)
Deferred Storm Costs	(90)	(60)	(8)
Net Change in Regulatory Assets and Liabilities	(132)	(130)	(58)
Net Change in Certain Current Assets and Liabilities:			
Accounts Receivable and Unbilled Revenues	(54)	252	(21)
Materials and Supplies	(20)	(4)	(20)
Prepayments	88	—	(31)
Net Change in Tax Receivable	16	(16)	—
Accounts Receivable/Payable-Affiliated Companies, net	(132)	197	(286)
Other Current Assets and Liabilities	12	(40)	68
Employee Benefit Plan Funding and Related Payments	(213)	(330)	(327)
Other	(30)	40	(18)
Net Cash Provided By (Used In) Operating Activities	1,256	1,776	1,011
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(1,770)	(1,302)	(1,257)
Proceeds from Sales of Available-for-Sale Securities	77	—	54
Investments in Available-for-Sale Securities	(77)	—	(54)
Solar Loan Investments	(74)	(51)	(27)
Other	(1)	(1)	4
Net Cash Provided By (Used In) Investing Activities	(1,845)	(1,354)	(1,280)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	263	—	—
Issuance of Long-Term Debt	900	250	1,114
Redemption of Long-Term Debt	(373)	(264)	(400)
Redemption of Securitization Debt	(216)	(206)	(197)
Redemption of Preferred Securities	—	—	(80)
Cash Dividend Paid	—	(300)	(150)
Other	(12)	(4)	(13)
Net Cash Provided By (Used In) Financing Activities	562	(524)	274
Net Increase (Decrease) in Cash and Cash Equivalents	(27)	(102)	5
Cash and Cash Equivalents at Beginning of Period	143	245	240
Cash and Cash Equivalents at End of Period	$ 116	$ 143	$ 245
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ (30)	$ (514)	$ 73
Interest Paid, Net of Amounts Capitalized	$ 280	$ 297	$ 294
Accrued Property, Plant and Equipment Expenditures	$ 275	$ 204	$ 124

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
Millions

	Common Stock	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2010	$ 892	$ 420	$ 986	$ 1,918	$ 5	$ 4,221
Net Income	—	—	—	359	—	359
Other Comprehensive Income, net of tax (expense) benefit of $3	—	—	—	—	(5)	(5)
Comprehensive Income						354
Cash Dividends on Preferred Stock	—	—	—	(1)	—	(1)
Cash Dividends on Common Stock	—	—	—	(150)	—	(150)
Balance as of December 31, 2010	$ 892	$ 420	$ 986	$ 2,126	$ —	$ 4,424
Net Income	—	—	—	521	—	521
Other Comprehensive Income, net of tax (expense) benefit of $(1)	—	—	—	—	2	2
Comprehensive Income						523
Cash Dividends on Common Stock	—	—	—	(300)	—	(300)
Balance as of December 31, 2011	$ 892	$ 420	$ 986	$ 2,347	$ 2	$ 4,647
Net Income	—	—	—	528	—	528
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	—	—
Comprehensive Income						528
Cash Dividends on Common Stock	—	—	—	—	—	—
Balance as of December 31, 2012	$ 892	$ 420	$ 986	$ 2,875	$ 2	$ 5,175

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

Public Service Enterprise Group Incorporated, (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **PSEG Power LLC (Power)**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through three principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and the states in which they operate.
- **Public Service Electric and Gas Company (PSE&G)**—which is an operating public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the FERC. PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs, which are regulated by the BPU.
- **PSEG Energy Holdings L.L.C. (Energy Holdings)**—which primarily has investments in leveraged leases and solar generation projects through its direct wholly owned subsidiaries. Certain Energy Holdings' subsidiaries are subject to regulation by the FERC and the states in which they operate. Energy Holdings has also been awarded a contract to manage the transmission and distribution assets of the Long Island Power Authority (LIPA) starting in 2014.
- **PSEG Services Corporation (Services)**—which provides management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Annual Reports on Form 10-K and in accordance with accounting guidance generally accepted in the United States (GAAP).

Significant Accounting Policies

Principles of Consolidation

Each company consolidates those entities in which it has a controlling interest or is the primary beneficiary. See Note 3. Variable Interest Entities. Entities over which the companies exhibit significant influence, but do not have a controlling interest and/or are not the primary beneficiary, are accounted for under the equity method of accounting. For investments in which significant influence does not exist and the investor is not the primary beneficiary, the cost method of accounting is applied. All significant intercompany accounts and transactions are eliminated in consolidation, except as discussed in Note 23. Related-Party Transactions.

Power and PSE&G also have undivided interests in certain jointly-owned facilities, with each responsible for paying its respective ownership share of construction costs, fuel purchases and operating expenses. Power and PSE&G consolidated their portion of any revenues and expenses related to these facilities in the appropriate revenue and expense categories.

Accounting for the Effects of Regulation

In accordance with accounting guidance for rate-regulated entities, PSE&G's financial statements must reflect the economic effects of regulation. PSE&G is required to defer the recognition of costs (a Regulatory Asset) or record the recognition of obligations (a Regulatory Liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs and recoveries, which are being amortized over various future periods. To the extent that collection of any such costs or payment of liabilities is no longer probable as a result of changes in regulation and/or competitive position, the associated Regulatory Asset or Liability is charged or credited to income. Management believes that PSE&G's transmission and distribution businesses continue to meet the accounting requirements for rate-regulated entities. For additional information, see Note 6. Regulatory Assets and Liabilities.

Derivative Financial Instruments

Each company uses derivative financial instruments to manage risk from changes in interest rates, commodity prices, congestion costs and emission credit prices, pursuant to its business plans and prudent practices.

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Derivative instruments, not designated as normal purchases or sales, are recognized on the balance sheet at their fair value. Changes in the fair value of a derivative that is highly effective as, and that is designated and qualifies as, a fair value hedge, along with changes of the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in current period earnings. Changes in the fair value of a derivative that is highly effective as, and that is designated and qualifies as, a cash flow hedge are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings. For derivative contracts that do not qualify as cash flow or fair value hedges or are not designated as normal purchases or sales, changes in fair value are recorded in current period earnings.

Many non-trading contracts qualify for the normal purchases and normal sales exemption and are accounted for upon settlement.

For additional information regarding derivative financial instruments, see Note 16. Financial Risk Management Activities.

Revenue Recognition

The majority of Power's revenues relate to bilateral contracts, which are accounted for on the accrual basis as the energy is delivered. Power's revenue also includes changes in the value of non-trading energy derivative contracts that are not designated as normal purchases or sales or as cash flow or fair value hedges of other positions. Power records margins from energy trading on a net basis. See Note 16. Financial Risk Management Activities for further discussion.

PSE&G's revenues are recorded based on services rendered to customers. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. The unbilled revenue is estimated each month based on usage per day, the number of unbilled days in the period, estimated seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms.

Energy Holdings' revenues are earned primarily from income relating to its investments in leveraged leases, which is recognized by a method which produces a constant after-tax rate of return on the outstanding investment in the lease, net of the related deferred tax liability, in the years in which the net investment is positive. Any gains or losses incurred as a result of a lease termination are recorded in Operating Revenues as these events occur in the ordinary course of business of managing the investment portfolio. See Note 7. Long-Term Investments for further discussion.

Depreciation and Amortization

Power calculates depreciation on generation-related assets under the straight-line method based on the assets' estimated useful lives. The estimated useful lives are:

- general plant assets—3 years to 20 years
- fossil production assets—10 years to 79 years
- nuclear generation assets—approximately 60 years
- pumped storage facilities—76 years

PSE&G calculates depreciation under the straight-line method based on estimated average remaining lives of the several classes of depreciable property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU or the FERC. The depreciation rate stated as a percentage of original cost of depreciable property was as follows:

	2012 Avg Rate	2011 Avg Rate	2010 Avg Rate
PSE&G Depreciation Rate	2.48%	2.46%	2.46%

Taxes Other Than Income Taxes

Excise taxes and transitional energy facilities assessment (TEFA) collected from PSE&G's customers are presented in the financial statements on a gross basis. For the years ended December 31, 2012, 2011 and 2010, TEFA is included in the following captions in the Consolidated Statements of Operations:

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Years Ended December 31,		
	2012	2011	2010
	Millions		
TEFA included in:			
Operating Revenues	$ 108	$ 146	$ 149
Taxes Other Than Income Taxes	$ 98	$ 133	$ 136

Interest Capitalized During Construction (IDC) and Allowance for Funds Used During Construction (AFUDC)

IDC represents the cost of debt used to finance construction at Power and Energy Holdings. AFUDC represents the cost of debt and equity funds used to finance the construction of new utility assets at PSE&G. The amount of IDC or AFUDC capitalized as Property, Plant and Equipment is included as a reduction of interest charges or other income for the equity portion. The amounts and average rates used to calculate IDC or AFUDC for the years ended December 31, 2012, 2011 and 2010 were as follows:

	IDC/AFUDC Capitalized					
	2012		2011		2010	
	Millions	Avg Rate	Millions	Avg Rate	Millions	Avg Rate
Power	$ 27	5.16%	$ 30	5.91%	$ 78	6.57%
PSE&G	$ 33	8.43%	$ 13	6.56%	$ 7	6.22%

Income Taxes

PSEG and its subsidiaries file a consolidated federal income tax return and income taxes are allocated to PSEG's subsidiaries based on the taxable income or loss of each subsidiary. Investment tax credits deferred in prior years are being amortized over the useful lives of the related property.

Uncertain income tax positions are accounted for using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. See Note 20. Income Taxes for further discussion.

Impairment of Long-Lived Assets

In accordance with accounting guidance, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset's or asset group's carrying amount may not be recoverable. In such an event, an undiscounted cash flow analysis is performed to determine if an impairment exists. When a long-lived asset's carrying amount exceeds the undiscounted estimated future cash flows associated with the asset, the asset is considered impaired to the extent that the asset's fair value is less than its carrying amount. An impairment would result in a reduction of the long-lived asset value through a non-cash charge to earnings.

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Accounts Receivable—Allowance for Doubtful Accounts

PSE&G's accounts receivable are reported in the balance sheet as gross outstanding amounts adjusted for doubtful accounts. The allowance for doubtful accounts reflects PSE&G's best estimates of losses on the accounts receivable balances. The allowance is based on accounts receivable aging, historical experience, write-off forecasts and other currently available evidence.

Accounts receivable are charged off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable are recorded when it is known they will be received.

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Materials and Supplies and Fuel

Materials and supplies for Power and Energy Holdings are valued at the lower of average cost or market. Fuel inventory at Power includes the weighted average costs of stored natural gas, coal, fuel oil and propane used to generate power and to satisfy obligations under Power's gas supply contracts with PSE&G. The costs of fuel, including transportation costs, are included in inventory when purchased and charged at average cost to Energy Costs when used or sold. PSE&G's materials and supplies are carried at average cost consistent with the rate-making process.

Restricted Funds

PSE&G's restricted funds represent revenues collected from its retail electric customers that must be used to pay the principal, interest and other expenses associated with the securitization bonds of PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II).

Property, Plant and Equipment

Power capitalizes costs which increase the capacity or extend the life of an existing asset, represent a newly acquired or constructed asset or represent the replacement of a retired asset. The cost of maintenance, repair and replacement of minor items of property is charged to appropriate expense accounts as incurred. Environmental costs are capitalized if the costs mitigate or prevent future environmental contamination or if the costs improve existing assets' environmental safety or efficiency. All other environmental expenditures are expensed as incurred.

PSE&G's additions to and replacements of existing property, plant and equipment are capitalized at original cost. The cost of maintenance, repair and replacement of minor items of property is charged to expense as incurred. At the time units of depreciable property are retired or otherwise disposed of, the original cost, adjusted for net salvage value, is charged to accumulated depreciation.

Available-for-Sale Securities

These securities are comprised of the Nuclear Decommissioning Trust (NDT) Fund, a master independent external trust account maintained to provide for the costs of decommissioning upon termination of operations of Power's nuclear facilities and amounts comprising Other Special Funds that are deposited to fund a Rabbi Trust which was established to meet the obligations related to non-qualified pension plans and deferred compensation plans.

Realized gains and losses on available-for-sale securities are recorded in earnings and unrealized gains and losses on such securities are recorded as a component of Accumulated Other Comprehensive Income (Loss) (except credit loss on debt securities which is recorded in earnings). Securities with unrealized losses that are deemed to be other-than-temporarily impaired are recorded in earnings. See Note 9. Available-for-Sale Securities for further discussion.

Pension and Other Postretirement Benefits (OPEB) Plan Assets

The market-related value of plan assets held for the qualified pension and OPEB plans is equal to the fair value of those assets as of year-end. Fair value is determined using quoted market prices and independent pricing services based upon the security type as reported by the trustee at the measurement dates (December 31) for all plan assets. See Note 12. Pension, OPEB and Savings Plans for further discussion.

Basis Adjustment

Power and PSE&G have recorded a Basis Adjustment in their respective Consolidated Balance Sheets related to the generation assets that were transferred from PSE&G to Power in August 2000 at the price specified by the BPU. Because the transfer was between affiliates, the transaction was recorded at the net book value of the assets and liabilities rather than the transfer price. The difference between the total transfer price and the net book value of the generation-related assets and liabilities, $986 million, net of tax, was recorded as a Basis Adjustment on Power's and PSE&G's Consolidated Balance Sheets. The $986 million is a reduction of Power's Member's Equity and an addition to PSE&G's Common Stockholder's Equity. These amounts are eliminated on PSEG's consolidated financial statements.

Use of Estimates

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements.

Reclassifications

During 2011, Power sold its two natural gas combined cycle power plants in Texas that were owned and operated by its subsidiary, PSEG Texas. As a result, amounts related to these plants were reclassified as Discontinued Operations in the financial statements of PSEG and Power for the years ended December 31, 2011 and 2010. See Note 4. Discontinued Operations and Dispositions.

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Note 2. Recent Accounting Standards

New Standards Adopted during 2012

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in GAAP and International Financial Reporting Standards (IFRS)

This accounting standard updates guidance related to fair value measurements and disclosures as a step towards achieving convergence between GAAP and IFRS. The updated guidance

- clarifies intent about application of existing fair value measurements and disclosures,
- changes some requirements for fair value measurements, and
- requires expanded disclosures.

We adopted this standard prospectively effective January 1, 2012. Upon adoption there was no material impact on our consolidated financial position, results of operations or cash flows; however, it has resulted in expanded disclosures. For additional information, see Note 17. Fair Value Measurements.

Presentation of Comprehensive Income

This accounting standard addresses the presentation of comprehensive income as a step towards achieving convergence between GAAP and IFRS. The updated guidance

- allows an entity to present components of net income and other comprehensive income in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive statements, and
- eliminates the current option to report other comprehensive income and its components in the statement of changes in equity.

We adopted this standard retrospectively effective January 1, 2012. Upon adoption of the new amended guidance, there was no impact on our consolidated financial position, results of operations or cash flows, but there was a change in the presentation of the components of other comprehensive income.

New Accounting Standards Issued But Not Yet Adopted

Disclosures about Offsetting Assets and Liabilities

This accounting standard requires balance sheet offsetting disclosures to facilitate comparability between financial statements prepared on the basis of GAAP and IFRS. This standard requires entities

- to disclose information about offsetting and related arrangements to enable users of financial statements to understand the effect of those arrangements on an entity's financial position, and
- to present both net (offset amounts) and gross information in the notes to the financial statements for relevant assets and liabilities that are offset.

The guidance is applicable to certain financial instruments (i.e. derivatives, repurchase agreements and reverse repurchase agreements) and securities borrowing and lending transactions. It is effective for fiscal years and interim periods beginning on or after January 1, 2013. As this standard requires disclosures only, it will not have any impact on our consolidated financial position, results of operations or cash flows.

Reclassification Adjustments out of Accumulated Other Comprehensive Income (AOCI)

This accounting standard requires entities to disclose the following information about reclassification adjustments related to AOCI:

- changes in AOCI balances by components; and
- significant amounts reclassified out of AOCI by respective line items of net income (for amounts that are required by GAAP to be reclassified to net income in their entirety in the same reporting period). For other types of reclassifications, reference to other note disclosures would be required.

The guidance is effective for fiscal years and interim periods beginning on or after January 1, 2013. As this standard requires disclosures only, it will not have any impact on our consolidated financial position, results of operations or cash flows.

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Note 3. Variable Interest Entities (VIEs)

VIEs for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary of and consolidates two marginally capitalized VIEs, Transition Funding and Transition Funding II, which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to the trustee for these bonds. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of these VIEs are presented separately on the face of the Consolidated Balance Sheets of PSEG and PSE&G because the Transition Funding and Transition Funding II assets are restricted and can only be used to settle their respective obligations. The Transition Funding and Transition Funding II creditors do not have any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding and Transition Funding II, respectively.

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of December 31, 2012 and 2011. PSE&G considers the risk of actual loss to be remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II in 2012 or 2011. Further, PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding and Transition Funding II.

Note 4. Discontinued Operations and Dispositions

Discontinued Operations

Power

In March 2011, Power completed the sale of its 1,000 MW gas-fired Guadalupe generating facility for a total sale price of $ 352 million, resulting in an after-tax gain of $54 million.

In July 2011, Power completed the sale of its 1,000 MW gas-fired Odessa generating facility for a total sale price of $ 335 million, resulting in an after-tax gain of $25 million.

PSEG Texas' operating results for years ended December 31, 2011 and 2010, which were reclassified to Discontinued Operations, are summarized below:

	Years Ended December 31,	
	2011	2010
	Millions	
Operating Revenues	$ 112	$ 402
Income Before Income Taxes	$ 26	$ 15
Net Income (Loss)	$ 17	$ 7

Dispositions

Leveraged Leases

For the year ended December 31, 2011, Energy Holdings sold its leveraged lease investment in an office building in Denver, Colorado for gross proceeds of $215 million. Proceeds net of sales costs were $175 million.

For the year ended December 31, 2010, Energy Holdings sold its interest in six leveraged leases, including five international leases.

	Years Ended December 31,	
	2011	2010
	Millions	
Net Proceeds from Sales	$ 175	$ 433
Gain (Loss) on Sales, after-tax	$ 34	$ 30

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Note 5. Property, Plant and Equipment and Jointly-Owned Facilities

Information related to Property, Plant and Equipment as of December 31, 2012 and 2011 is detailed below:

	Power	PSE&G	Other	PSEG Consolidated
		Millions		
2012				
Generation:				
Fossil Production	$ 6,886	$ —	$ —	$ 6,886
Nuclear Production	1,415	—	—	1,415
Nuclear Fuel in Service	853	—	—	853
Other Production-Solar	—	434	217	651
Construction Work in Progress	450	7	—	457
Total Generation	9,604	441	217	10,262
Transmission and Distribution:				
Electric Transmission	—	3,053	—	3,053
Electric Distribution	—	6,807	—	6,807
Gas Transmission	—	89	—	89
Gas Distribution	—	5,065	—	5,065
Construction Work in Progress	—	1,048	—	1,048
Plant Held for Future Use	—	6	—	6
Other	—	380	—	380
Total Transmission and Distribution	—	16,448	—	16,448
Other	93	117	482	692
Total	**$ 9,697**	**$ 17,006**	**$ 699**	**$ 27,402**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2011	Power	PSE&G	Other	PSEG Consolidated
		Millions		
Generation:				
Fossil Production	$ 6,415	$ —	$ —	$ 6,415
Nuclear Production	1,138	—	—	1,138
Nuclear Fuel in Service	774	—	—	774
Other Production-Solar	—	345	89	434
Construction Work in Progress	784	19	—	803
Total Generation	9,111	364	89	9,564
Transmission and Distribution:				
Electric Transmission	—	2,441	—	2,441
Electric Distribution	—	6,522	—	6,522
Gas Transmission	—	91	—	91
Gas Distribution	—	4,858	—	4,858
Construction Work in Progress	—	546	—	546
Plant Held for Future Use	—	9	—	9
Other	—	386	—	386
Total Transmission and Distribution	—	14,853	—	14,853
Other	80	89	494	663
Total	**$ 9,191**	**$ 15,306**	**$ 583**	**$ 25,080**

Power and PSE&G have ownership interests in and are responsible for providing their respective shares of the necessary financing for the following jointly-owned facilities. All amounts reflect the share of Power's and PSE&G's jointly-owned projects and the corresponding direct expenses are included in the Consolidated Statements of Operations as operating expenses.

December 31, 2012	Ownership Interest	Plant	Accumulated Depreciation
		Millions	
Power:			
Coal Generating			
Conemaugh	23%	$ 321	$ 132
Keystone	23%	$ 387	$ 128
Nuclear Generating			
Peach Bottom	50%	$ 730	$ 193
Salem	57%	$ 865	$ 209
Nuclear Support Facilities	Various	$ 191	$ 29
Pumped Storage Facilities			
Yards Creek	50%	$ 35	$ 23
Merrill Creek Reservoir	14%	$ 1	$ —
PSE&G:			
Transmission Facilities	Various	$ 156	$ 63

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December 31, 2011	Ownership Interest	Plant	Accumulated Depreciation
		Millions	
Power:			
Coal Generating			
Conemaugh	23%	$ 289	$ 126
Keystone	23%	$ 381	$ 117
Nuclear Generating			
Peach Bottom	50%	$ 559	$ 171
Salem	57%	$ 807	$ 211
Nuclear Support Facilities	Various	$ 171	$ 27
Pumped Storage Facilities			
Yards Creek	50%	$ 34	$ 23
Merrill Creek Reservoir	14%	$ 1	$ —
PSE&G:			
Transmission Facilities	Various	$ 152	$ 61

Power holds undivided ownership interests in the jointly-owned facilities above, excluding related nuclear fuel and inventories. Power is entitled to shares of the generating capability and output of each unit equal to its respective ownership interests. Power also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. Power's share of expenses for the jointly-owned facilities is included in the appropriate expense category. Each owner is responsible for any financing with respect to its pro rata share of capital expenditures.

Power co-owns Salem and Peach Bottom with Exelon Generation. Power is the operator of Salem and Exelon Generation is the operator of Peach Bottom. A committee appointed by the co-owners provides oversight. Proposed Operation and Maintenance (O&M) budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

GenOn Northeast Management Company is a co-owner and the operator for Keystone Generating Station and Conemaugh Generating Station. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

Power is a co-owner in the Yards Creek Pumped Storage Generation Facility. Jersey Central Power & Light Company (JCP&L) is also a co-owner and the operator of this facility. JCP&L submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Power is a minority owner in the Merrill Creek Reservoir and Environmental Preserve in Warren County, New Jersey. Merrill Creek Owners Group is the owner-operator of this facility. The operator submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Note 6. Regulatory Assets and Liabilities

PSE&G prepares its financial statements in accordance with GAAP accounting for regulated utilities. A regulated utility is required to defer the recognition of costs (a Regulatory Asset) or the recognition of obligations (a Regulatory Liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs, which will be amortized over various future periods. These costs are deferred based on rate orders issued by the BPU or the FERC or PSE&G's experience with prior rate cases. Most of PSE&G's Regulatory Assets and Liabilities as of December 31, 2012 are supported by written orders, either explicitly or implicitly through the BPU's treatment of various cost items.

Regulatory Assets are subject to prudence reviews and can be disallowed in the future by regulatory authorities. PSE&G believes that all of its Regulatory Assets are probable of recovery. To the extent that collection of any Regulatory Assets or payments of Regulatory Liabilities is no longer probable, the amounts would be charged or credited to income.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G had the following Regulatory Assets and Liabilities:

	As of December 31, 2012	As of December 31, 2011	Recovery/Refund Period
	Millions		
Regulatory Assets			
Current:			
Underrecovered Electric Energy Costs—Basic Generation Service (BGS)	$ —	$ 28	Various (1) (2)
Societal Benefits Charges (SBC)	74	87	Annual filing for recovery (1) (2)
Solar and Energy Efficiency Recovery Charges (RRC)	33	6	Annual filing for recovery (1) (2)
Solar Pilot Recovery Charge (SPRC)	14	4	Annual filing for recovery (1) (2)
Capital Stimulus Undercollection	34	21	Annual filing for recovery (1) (2)
Weather Normalization Clause (WNC)	30	2	Annual filing for recovery (2)
New Jersey Clean Energy Program	154	—	Annual filing for recovery (1) (2)
Other	10	19	Various
Total Current Regulatory Assets	**$ 349**	**$ 167**	
Noncurrent			
Stranded Costs To Be Recovered	$ 1,112	$ 1,460	Through December 2016 (1) (2)
Manufactured Gas Plant (MGP) Remediation Costs	588	635	Various (2)
Pension and Other Postretirement	1,550	1,280	Various
Deferred Income Taxes	405	393	Various
Remediation Adjustment Charge (RAC) (Other SBC)	88	92	Through 2019 (1) (2)
New Jersey Clean Energy Program	—	253	Through February 2013 (1) (2)
Mark-to-Market (MTM) Contracts	107	110	Various
Unamortized Loss on Reacquired Debt and Debt Expense	89	96	Over remaining debt life (1)
Conditional Asset Retirement Obligation	110	84	Various
Gas Margin Adjustment Clause	7	29	Through July 2015 (2)
RRC	142	140	Various (2)
WNC Deferral	27	—	Annual filing for recovery (2)
Storm Damage Deferral	244	68	To be determined
Other	74	90	Various
Total Noncurrent Regulatory Assets	**$ 4,543**	**$ 4,730**	
Total Regulatory Assets	**$ 4,892**	**$ 4,897**	

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31, 2012	As of December 31, 2011	Recovery/Refund Period
	Millions		
Regulatory Liabilities			
Current:			
Market Transition Charge (MTC) Refund, net	$ —	$ 23	Through June 2012 (2)
Deferred Income Taxes	32	39	Various
Overrecovered Gas and Electric Costs—Basic Gas Supply Service (BGSS) and Basic Generation Service (BGS)	21	30	Annual filing for recovery (1) (2)
FERC Formula Rate True-up	5	1	Annual filing for recovery (1) (2)
Non-Utility Generation Charge (NGC)	9	5	Annual filing for recovery (1) (2)
Other	—	2	Various
Total Current Regulatory Liabilities	**$ 67**	**$ 100**	
Noncurrent:			
Electric Cost of Removal	$ 166	$ 222	Reduced as cost is incurred
MTM Contracts	40	—	Various
Other	13	15	Various
Total Noncurrent Regulatory Liabilities	**$ 219**	**$ 237**	
Total Regulatory Liabilities	**$ 286**	**$ 337**	

(1) Recovered/Refunded with interest.

(2) Recoverable/Refundable per specific rate order.

All Regulatory Assets and Liabilities are excluded from PSE&G's rate base unless otherwise noted. The Regulatory Assets and Liabilities in the table above are defined as follows:

- **Underrecovered Electric Energy Costs:** These costs represent the underrecovered amounts associated with BGS, as approved by the BPU.
- **SBC:** The SBC, as authorized by the BPU and the New Jersey Electric Discount and Energy Competition Act (Competition Act), includes costs related to PSE&G's electric and gas business as follows: 1) the USF; 2) Energy Efficiency and Renewable Energy Programs; 3) Social Programs (electric only) which include electric bad debt expense; and 4) the RAC for incurred MGP remediation expenditures. All components accrue interest on both over and underrecoveries.
- **RRC:** These costs are amounts associated with various renewable energy and energy efficiency programs. Components of the RRC include: Carbon Abatement, Energy Efficiency Economic Stimulus Program, Energy Efficiency Economic Extension Program, the Demand Response Program, Solar Generation Investment Program (Solar 4 All) and Solar Loan II Program.
- **SPRC:** This charge is designed to recover the revenue requirements associated with the PSE&G Solar Pilot Program (Solar Loan I) per the BPU Order, less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. The net recovery is subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances.
- **Capital Stimulus Undercollection:** PSE&G has received approval from the BPU for programs that provide for accelerated investment in utility infrastructure. The goal of these accelerated capital investments is to improve the reliability of PSE&G's infrastructure and New Jersey's economy through job creation.
- **WNC Deferral:** This represents the over or under collection of gas margin refundable or recoverable under the BPU's weather normalization clause. The WNC requires PSE&G to calculate, at the end of each October-to-May period, the level by which margin revenues differed from what would have resulted if normal weather had occurred.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

- **New Jersey Clean Energy Program:** The BPU approved future funding requirements for Energy Efficiency and Renewable Energy Programs through the first half of 2013. Once the rates are measured, they are recovered through the SBC.
- **Stranded Costs To Be Recovered:** This reflects deferred costs, which are being recovered through the securitization transition charges authorized by the BPU in irrevocable financing orders and being collected by PSE&G, as servicer on behalf of Transition Funding and Transition Funding II, respectively. Collected funds collected are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs and taxes.

  Transition Funding and Transition Funding II are wholly owned, bankruptcy-remote subsidiaries of PSE&G that purchased certain transition property from PSE&G and issued transition bonds secured by such property. The transition property consists principally of the rights to receive electricity consumption-based per kilowatt-hour (kWh) charges from PSE&G electric distribution customers, which represent irrevocable rights to receive amounts sufficient to recover certain of PSE&G's transition costs related to deregulation, as approved by the BPU.
- **MGP Remediation Costs:** Represents the low end of the range for the remaining environmental investigation and remediation program cleanup costs for manufactured gas plants that are probable of recovery in future rates. Once these costs are incurred, they are recovered through the RAC in the SBC.
- **Pension and Other Postretirement:** Pursuant to the adoption of accounting guidance for employers' defined benefit pension and OPEB plans, PSE&G recorded the unrecognized costs for defined benefit pension and other OPEB plans on the balance sheet as a Regulatory Asset. These costs represent actuarial gains or losses, prior service costs and transition obligations as a result of adoption, which have not been expensed. These costs are amortized and recovered in future rates.
- **Deferred Income Taxes:** These amounts represent the portion of deferred income taxes that will be recovered or refunded through future rates, based upon established regulatory practices.
- **RAC (Other SBC):** Costs incurred to clean up manufactured gas plants which are recovered over seven years.
- **MTM Contracts:** The estimated fair value of long-term standard offer capacity agreements (SOCAs), gas hedge contracts and gas cogeneration supply contracts. The regulatory asset/liability is offset by a derivative asset/liability and, with respect to the gas hedge contracts only, an intercompany receivable/payable on the Consolidated Balance Sheets.
- **Unamortized Loss on Reacquired Debt and Debt Expense:** Represents losses on reacquired long-term debt, which are recovered through rates over the remaining life of the debt.
- **Conditional Asset Retirement Obligation:** These costs represent the differences between rate regulated cost of removal accounting and asset retirement accounting under GAAP. These costs will be recovered in future rates.
- **Gas Margin Adjustment Clause:** PSE&G defers the margin differential received from Transportation Gas Service Non-Firm Customers versus bill credits provided to BGSS-Firm customers.
- **Storm Damage Deferral:** Costs incurred in the cleanup of 2012, 2011 and 2010 storms, as approved by the BPU under an Order received in December 2012 authorizing the deferral of incremental costs.
- **MTC Refund, net:** These costs represent the overrecovered amounts associated with MTC.
- **Overrecovered Gas and Electric Costs:** These costs represent the overrecovered amounts associated with BGSS and BGS, as approved by the BPU. Interest is accrued on overrecovered balances.
- **FERC Formula Rate True-up:** Overcollection or undercollection of transmission earnings calculated using a FERC approved formula.
- **NGC:** Represents the difference between the cost of non-utility generation and the amounts realized from selling that energy at market rates through PJM and ratepayer collections.
- **Electric Cost of Removal:** PSE&G accrues and collects for cost of removal in rates. The liability for non-legally required cost of removal is classified as a Regulatory Liability. This liability is reduced as removal costs are incurred. Accumulated cost of removal is a reduction to the rate base.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Significant 2012 orders and pending rate filings are as follows:

- ***Storm Damage Deferral***—In December 2012, the BPU granted PSE&G's request to defer on its books actually incurred, uninsured, incremental storm restoration costs to its gas and electric distribution systems associated with extraordinary storms, including Hurricane Irene and Superstorm Sandy. In February 2013, the BPU announced that it would initiate a generic proceeding to evaluate the prudency of extraordinary, storm-related costs incurred by all of the regulated utilities as a result of the natural disasters experienced in New Jersey in 2011 and 2012 and in this proceeding will consider the manner in which such prudent costs shall be recovered.
- ***Transmission Formula Rates***—PSE&G's 2012 Annual Formula Rate Update with the FERC provided for approximately $94 million in increased annual transmission revenues effective January 1, 2012. PSE&G filed its 2013 Annual Formula Rate Update with FERC in October 2012, which provides for approximately $174 million in increased annual transmission revenues effective January 1, 2013.
- ***SBC/NGC***—In March 2012, PSE&G made an annual SBC/NGC filing requesting a $5 million electric increase and a $29 million gas increase. PSE&G updated the filing with actual data through August 31, 2012, resulting in a decrease of $77 million for electric customers while the gas increase remained unchanged. A Stipulation signed by the Parties was approved by the BPU effective February 1, 2013.
- ***Universal Service Fund (USF)/Lifeline***—The USF is an energy assistance program mandated by the BPU to provide payment assistance to low income customers. The Lifeline program is a separate mandated energy assistance program to provide payment assistance to elderly and disabled customers. In June 2012, New Jersey's electric and gas utilities, including PSE&G, filed requests to reset the statewide rates for the USF and the Lifeline program. The filed USF rates were set to recover approximately $230 million on a statewide basis. Of this amount, the statewide electric rates are set to recover $173 million with the remaining $57 million recovered through gas rates. The rates for the Lifeline program were set to recover $66 million, $46 million for electric and $20 million for gas. The filed rates were subsequently updated and approved effective October 1, 2012. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on Net Income.
- ***Capital Infrastructure Programs (CIP I and CIP II)***—In December 2012, the BPU approved stipulations regarding our CIP I and CIP II filings resulting in a combined increase of $40 million and $23 million for electric and gas customers, respectively effective January 1, 2013.
- ***WNC***— In June 2012, PSE&G filed a petition and testimony with the BPU, including eight months of actual and four months of forecasted data, which sought BPU approval to recover $41 million in deficiency revenues from its customers during the 2012-2013 Winter Period (October 1 to May 31) and a carryover deficiency of $16 million to the 2013-2014 Winter Period. In September 2012, an Order approving the stipulation for provisional rates was signed. In December 2012, PSE&G made a supplemental filing incorporating twelve months of actual financial data, which would, if approved by the BPU, result in no change to customer rates during the 2012-2013 Winter Period. The supplemental filing would, however, result in an increase of the carryover deficiency to the 2013-2014 Winter Period from $16 million to $24 million. PSE&G is awaiting a final Order.
- ***RAC***—In November 2011, PSE&G filed a RAC 19 petition with the BPU requesting a decrease in electric and gas RAC revenues on an annual basis of $9 million and $10 million, respectively. In October 2012, PSE&G received the Administrative Law Judge's (ALJ) Initial Decision allowing full recovery of RAC 19 costs including costs of the Passaic River and Newark Bay Superfund (CERCLA) matters and the Occidental litigation that were allocated to PSE&G and included in this request. In October 2012, the BPU issued a final Order approving the ALJ's Initial Decision.
- ***RRC***—In July 2012, PSE&G filed a petition with the BPU requesting an increase in the RRC seeking to recover approximately $62 million in electric revenue and $8 million in gas revenue on an annual basis. The discovery phase of this proceeding is underway.
- ***SPRC***—In July 2012, the BPU approved a Stipulation regarding our March 2010 SPRC (Solar Loan I) filing authorizing an increase in rates of $3 million for PSE&G's electric customers effective August 1, 2012. In July 2012, PSE&G filed a petition with the BPU for an annual increase in the electric SPRC of $17 million. The discovery phase of this proceeding is underway.

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Note 7. Long-Term Investments

Long-Term Investments as of December 31, 2012 and 2011 included the following:

	As of December 31, 2012	2011
	Millions	
Power		
Partnerships and Corporate Joint Ventures (Equity Method Investments)	$ 40	$ 32
PSE&G		
Life Insurance and Supplemental Benefits	161	162
Solar Loan Investments	180	111
Other Investments	7	7
Energy Holdings		
Leveraged Leases	840	881
Partnerships and Corporate Joint Ventures:		
Equity Method Investments (A)	94	106
Cost Method Investments (B)	2	4
Total Long-Term Investments	**$ 1,324**	**$ 1,303**

(A) During the three years ended December 31, 2012, 2011 and 2010, the amount of dividends from these investments was $17 million, $3 million and $5 million, respectively. Energy Holdings' share of income and cash flow distribution percentages were at 50% as of December 31, 2012.

(B) Reflects Energy Holdings' investments in certain companies in which it does not have the ability to exercise significant influence. Such investments are accounted for under the cost method.

Leases

Energy Holdings has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Consolidated Balance Sheets. The following table shows Energy Holdings' gross and net lease investment as of December 31, 2012 and 2011, respectively.

	As of December 31, 2012	2011
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 721	$ 763
Estimated Residual Value of Leased Assets	535	553
	1,256	1,316
Unearned and Deferred Income	(416)	(435)
Gross Investments in Leases	840	881
Deferred Tax Liabilities	(723)	(716)
Net Investments in Leases	**$ 117**	**$ 165**

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The pre-tax income and income tax effects, excluding gains and losses on sales, related to investments in leases were as follows:

	Years Ended December 31,		
	2012	2011	2010
	Millions		
Pre-Tax Income (Loss) from Leases	$ 78	$ (228)	$ 45
Income Tax Expense (Benefit) on Pre-Tax Income from Leases	$ 34	$ (77)	$ 14

Equity Method Investments

Power and Energy Holdings had the following equity method investments as of December 31, 2012:

Name	Location	% Owned
Power		
Keystone Fuels, LLC	PA	23%
Conemaugh Fuels, LLC	PA	23%
Energy Holdings		
Kalaeloa	HI	50%
GWF	CA	50%
Hanford L. P. (Hanford)	CA	50%

Note 8. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with SRECS generated from the installed solar electric system. The following table reflects the outstanding short and long-term loans by class of customer, none of which would be considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of December 31, 2012	2011
	Millions	
Commercial/Industrial	$ 174	$ 106
Residential	15	10
	$ 189	**$ 116**

Energy Holdings

Energy Holdings had a net investment in domestic energy and real estate assets subject primarily to leveraged lease accounting of $117 million and $165 million as of December 31, 2012 and 2011, respectively (See Note 7. Long-Term Investments).

The corresponding receivables associated with the lease portfolio are reflected below, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. "Not Rated" counterparties relate to investments in leases of commercial real estate properties.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Counterparties' Credit Rating (S&P) as of December 31, 2012	Lease Receivables, Net of Non-Recourse Debt As of December 31, 2012	2011
	Millions	
AA	$ 21	$ 21
AA-	73	110
BBB+ - BBB-	316	316
B	166	299
D	134	—
Not Rated	11	17
	$ 721	**$ 763**

The "B" and "D" ratings above represent lease receivables related to coal-fired assets in Illinois and Pennsylvania. As of December 31, 2012, the gross investment in the leases of such assets, net of non-recourse debt, was $559 million ($19 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions		MW			
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	D	Edison Mission Energy
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	D	Edison Mission Energy
Keystone Station Units 1 and 2	PA	$ 116	17%	1,711	Coal	B	GenOn REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 116	17%	1,711	Coal	B	GenOn REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 109	100%	603	Coal	B	GenOn REMA, LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities.

Of facilities under lease by indirect subsidiary companies of Energy Holdings to GenOn REMA, LLC (GenOn REMA), a subsidiary of GenOn Energy Inc. (GenOn), which was acquired by NRG Energy, Inc. in December 2012. Keystone has installed flue gas desulfurization control for sulfur dioxide (SO_2), selective catalytic reduction (SCR) equipment for nitrogen oxide (NOx) and mercury control to meet current environmental requirements. Conemaugh has flue gas desulfurization control, while SCR and mercury control are scheduled to be installed and operational in the first quarter of 2015. GenOn's plan for the coal-fired units at the Shawville facility is to place them in a "long-term protective layup" by April 2015 while continuing to pay the required rent and maintaining the facility in accordance with the lease terms or terminating the lease for obsolescence in which case the lessee would be required, among other things, to pay the contractual termination value structured to recover Energy Holdings' indirect subsidiaries' lease investment as specified in the lease agreement.

Although all lease payments from the GenOn REMA leases are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited

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to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel and electricity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

With respect to Edison Mission Energy's (EME) Midwest Generation (MWG) leases on the Powerton and Joliet coal units in Illinois, the lessee, MWG, substantially completed investments in mercury removal (Activated Carbon Injection) and NOx emission controls (low NOx burners and Selective Non-Catalytic Reduction systems), and plans to invest in SO_2 emission controls (Dry Sorbent Injection (Trona) systems). EME does not anticipate a material change in this current approach in order to comply with existing federal and Illinois environmental rules. On November 30, 2012, MWG filed a variance request with the Illinois Pollution Control Board seeking two additional years to meet upcoming air emission compliance deadlines under Illinois law. EME and MWG remain in litigation with the U.S. Environmental Protection Agency (EPA) and the State of Illinois regarding certain air emissions. On March 16, 2011, the federal district court dismissed new source review claims in reference to Powerton and Joliet, but certain opacity claims remain pending against MWG. The EPA and the State of Illinois have appealed the dismissal of the new source review claims. On November 11, 2011, the federal district court stayed proceedings in connection with the opacity claims until the appeal by the EPA and the State of Illinois is resolved.

On December 17, 2012, EME and MWG filed for relief under Chapter 11 of the U.S. Bankruptcy Code. Immediately prior to that filing, EME, MWG, Nesbitt Asset Recovery, LLC (which is an indirect, wholly owned subsidiary of Energy Holdings), and Associates Capital Investments, L.L.P., as well as certain affiliated owner lessors and owner participants, entered into a forbearance agreement with holders of a majority of the lease debt that financed the original sale-leaseback transaction. The forbearance agreement, which was approved by the bankruptcy court and limited the ability of the lease indenture trustee to accelerate or exercise other remedies with respect to that nonrecourse debt, expired on February 15, 2013. A new forbearance agreement is currently being negotiated by the parties. MWG has not determined whether to assume or reject those leases. MWG did not make its scheduled rent payments (which related to the prior six month period) totaling approximately $48 million on the Powerton and Joliet leases due on January 2, 2013, most of which is a pre-petition bankruptcy claim. Rental for the utilization of the facilities by MWG during pendency of the bankruptcy will likely be treated as an administrative expense in bankruptcy. In mid-February, pursuant to the terms of the forbearance agreement, a rental payment of approximately $5 million was received covering the period from the date of the petition filing through January 2, 2013.

On December 13, 2011, indirect subsidiary companies of Energy Holdings and Dynegy Incorporated (Dynegy) reached a settlement agreement resolving disputes that had arisen between them with regard to Dynegy Holding’s (DH) rejection of the Dynegy leases. The settlement agreement resolved certain disputes regarding Energy Holdings' Dynegy leases, including claims under Tax Indemnity Agreements that indirect subsidiaries of Energy Holdings have with DH. The original terms of the settlement agreement included a cash payment to Energy Holdings of $7.5 million, which was received on January 4, 2012, and an allowed claim in Bankruptcy Court of $110 million against DH. On December 30, 2011, the effective date of the court order authorizing the Dynegy lease rejections, the leases no longer qualified for leveraged lease accounting treatment under GAAP. As a result, Energy Holdings wrote off the $264 million gross lease investment against the previously recorded reserve. The Energy Holdings' indirect subsidiary companies that are owners/lessors of the two plants ceased leveraged lease accounting and recorded the generation assets and related nonrecourse project debt on their balance sheets at their respective fair values (See Note 17. Fair Value Measurements).

On June 1, 2012, an amended and restated settlement agreement entered into by DH, Dynegy and their creditors (including indirect subsidiary companies of Energy Holdings) was approved by the Bankruptcy Court. The agreement allocated proceeds from the sale of the facilities to pay DH’s creditors, including the lease bondholders, and grants the lease bondholders claims in agreed upon amounts against DH in its bankruptcy proceedings. The settlement agreement also included an exchange of releases by various settling claimants, including parties to the leases with respect to claims arising out of the leases. On October 1, 2012, Dynegy emerged from bankruptcy and distributed cash and stock settlements to the claimants. The total recovery of Energy Holdings' indirect subsidiary companies from the Dynegy leases was approximately $63 million, of which $50 million was recorded in Operating Revenues in the fourth quarter of 2012.

Note 9. Available-for-Sale Securities

NDT Fund

In accordance with NRC regulations, entities owning an interest in nuclear generating facilities are required to determine the costs and funding methods necessary to decommission such facilities upon termination of operation. As a general practice, each nuclear owner places funds in independent external trust accounts it maintains to provide for decommissioning. Power is required to file periodic reports with the NRC demonstrating that the NDT Fund meets the formula-based minimum NRC funding requirements.

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon their respective termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. Power's share of decommissioning costs related to its five nuclear units was estimated to be between $2.2 billion and $2.4 billion, including contingencies. The liability for decommissioning recorded on a discounted basis as of December 31, 2012 was approximately $348 million and is included in the Asset Retirement Obligation. The trust funds are managed by third-party investment advisors who operate under investment guidelines developed by Power. In September 2012, Power revised the asset structure for a portion of its NDT Fund and realized gains of $59 million. The investments were transitioned to new investment managers to remove under-performing managers.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund:

	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 648	$ 147	$ (6)	$ 789
Debt Securities				
Government Obligations	274	11	—	285
Other Debt Securities	320	22	—	342
Total Debt Securities	594	33	—	627
Other Securities	124	—	—	124
Total NDT Available-for-Sale Securities	**$ 1,366**	**$ 180**	**$ (6)**	**$ 1,540**

	As of December 31, 2011			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 582	$ 126	$ (23)	$ 685
Debt Securities				
Government Obligations	343	16	—	359
Other Debt Securities	268	15	(2)	281
Total Debt Securities	611	31	(2)	640
Other Securities	24	—	—	24
Total NDT Available-for-Sale Securities	**$ 1,217**	**$ 157**	**$ (25)**	**$ 1,349**

These amounts do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as shown in the following table.

	As of December 31, 2012	As of December 31, 2011
	Millions	
Accounts Receivable	$ 18	$ 27
Accounts Payable	$ 53	$ 22

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2012				As of December 31, 2011			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 139	$ (6)	$ —	$ —	$ 183	$ (23)	$ —	$ —
Debt Securities								
Government Obligations (B)	34	—	1	—	20	—	3	—
Other Debt Securities (C)	31	—	6	—	56	(1)	4	(1)
Total Debt Securities	65	—	7	—	76	(1)	7	(1)
NDT Available-for-Sale Securities	**$ 204**	**$ (6)**	**$ 7**	**$ —**	**$ 259**	**$ (24)**	**$ 7**	**$ (1)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over hundreds of companies with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2012.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2012.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2012.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Years Ended December 31,		
	2012	2011	2010
	Millions		
Proceeds from Sales	**$ 1,433**	**$ 1,355**	**$ 958**
Net Realized Gains:			
Gross Realized Gains	$ 153	$ 144	$ 119
Gross Realized Losses	(52)	(45)	(39)
Net Realized Gains (Losses) on NDT Fund	**$ 101**	**$ 99**	**$ 80**

Net realized gains disclosed in the above table were recognized in Other Income and Other Deductions in PSEG's and Power's Consolidated Statements of Operations. Net unrealized gains of $84 million (after-tax) are included in Accumulated Other Comprehensive Loss on Power's Consolidated Balance Sheet as of December 31, 2012.

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The available-for-sale debt securities held as of December 31, 2012 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 18
1 - 5 years	136
6 - 10 years	176
11 - 15 years	42
16 - 20 years	10
Over 20 years	245
Total NDT Available-for-Sale Debt Securities	**$ 627**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2012, other-than-temporary impairments of $18 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

In March 2012, PSEG restructured the fixed income component of its Rabbi Trust and realized a gain of $5 million. In August 2010, PSEG revised the asset structure of the Rabbi Trust and realized gains of approximately $31 million as the investments were transitioned to a new asset allocation and investment manager.

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost bases for the securities held in the Rabbi Trust.

	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 13	$ 5	$ —	$ 18
Debt Securities				
Government Obligations	114	3	—	117
Other Debt Securities	45	2	—	47
Total Debt Securities	159	5	—	164
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 175**	**$ 10**	**$ —**	**$ 185**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31, 2011			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 16	$ 3	$ —	$ 19
Debt Securities	148	5	—	153
Total Rabbi Trust Available-for-Sale Securities	**$ 164**	**$ 8**	**$ —**	**$ 172**

As of December 31, 2012, amounts in the above table do not include Accounts Receivable of $4 million and Accounts Payable of $5 million for Rabbi Trust Fund transactions which had not yet settled. These amounts are included on the Consolidated Balance Sheets.

	Years Ended December 31,		
	2012	2011	2010
	Millions		
Proceeds from Rabbi Trust Sales	**$ 233**	**$ —**	**$ 158**
Net Realized Gains (Losses):			
Gross Realized Gains	$ 6	$ —	$ 31
Gross Realized Losses	—	—	—
Net Realized Gains (Losses) on Rabbi Trust	**$ 6**	**$ —**	**$ 31**

Gross realized gains disclosed in the above table were recognized in Other Income in the Consolidated Statements of Operations. Net unrealized gains of $6 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets as of December 31, 2012. The Rabbi Trust available-for-sale debt securities held as of December 31, 2012 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ —
1 - 5 years	60
6 - 10 years	31
11 - 15 years	9
16 - 20 years	5
Over 20 years	59
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 164**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities. In 2012, there were no other-than-temporary impairments recognized on investments of the Rabbi Trust.

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The fair value of the Rabbi Trust related to PSEG, Power and PSE&G are detailed as follows:

	As of December 31, 2012	As of December 31, 2011
	Millions	
Power	$ 36	$ 33
PSE&G	61	57
Other	88	82
Total Rabbi Trust Available-for-Sale Securities	**$ 185**	**$ 172**

Note 10. Goodwill and Other Intangibles

As of each of December 31, 2012 and 2011, Power had goodwill of $16 million related to the Bethlehem Energy Center. Power conducted an annual review for goodwill impairment as of October 31, 2012 and concluded that goodwill was not impaired. No events occurred subsequent to that date which would require a further review of goodwill for impairment.

In addition to goodwill, as of December 31, 2012 and 2011, Power had intangible assets of $34 million and $131 million, respectively, related to emissions allowances and renewable energy credits. Emissions expense includes impairments of emissions allowances and costs for emissions, which is recorded as emissions occur. As load is served under contracts requiring energy from renewable sources, the related expense is recorded. Such expenses for the years ended December 31, 2012, 2011 and 2010 were as follows:

	Years Ended December 31,		
	2012	2011	2010
	Millions		
Emissions Expense	$ 5	$ 35	$ 52
Renewable Energy Expense	$ 34	$ 43	$ 50

Note 11. Asset Retirement Obligations (AROs)

PSEG, Power and PSE&G have recorded various AROs which represent legal obligations to remove or dispose of an asset or some component of an asset at retirement.

Power's ARO liability primarily relates to the decommissioning of its nuclear power plants in accordance with NRC requirements. To estimate this decommissioning obligation related to its nuclear power plants, Power uses a probability weighted, discounted cash flow model which, on a unit by unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning studies, cost escalation rates, inflation rates and discount rates. Power has an independent external trust that is intended to fund decommissioning of its nuclear facilities upon termination of operation. For additional information, see Note 9. Available-for-Sale Securities. Power also identified conditional AROs primarily related to Power's fossil generation units, including liabilities for

- removal of asbestos, stored hazardous liquid material and underground storage tanks from industrial power sites,
- restoration of leased office space to rentable condition upon lease termination,
- permits and authorizations,
- restoration of an area occupied by a reservoir when the reservoir is no longer needed, and
- demolition of certain plants, and the restoration of the sites at which they reside, when the plants are no longer in service.

PSE&G has a conditional ARO for legal obligations related to the removal of asbestos and underground storage tanks at certain industrial establishments, removal of wood poles, leases and licenses, removal of solar panels from leased property and the requirement to seal natural gas pipelines at all sources of gas when the pipelines are no longer in service. PSE&G did not record an ARO for its protected steel and poly-based natural gas transmission lines, as management believes that these categories of transmission lines have an indeterminable life.

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The changes to the ARO liabilities for PSEG, Power and PSE&G during 2011 and 2012 are presented in the following table:

	PSEG	Power	PSE&G	Other
	Millions			
ARO Liability as of January 1, 2011	$ 461	$ 242	$ 216	$ 3
Liabilities Settled	(6)	(1)	(5)	—
Liabilities Incurred	2	—	2	—
Accretion Expense	19	18	—	1
Accretion Expense Deferred and Recovered in Rate Base (A)	13	—	13	—
ARO Liability as of December 21, 2011	**$ 489**	**$ 259**	**$ 226**	**$ 4**
Liabilities Settled	(5)	(1)	(5)	1
Liabilities Incurred	11	1	7	3
Accretion Expense	21	21	—	—
Accretion Expense Deferred and Recovered in Rate Base (A)	14	—	14	—
Revisions to Present Values of Estimated Cash Flows	97	89	8	—
ARO Liability as of December 31, 2012	**$ 627**	**$ 369**	**$ 250**	**$ 8**

(A) Not reflected as expense in Consolidated Statements of Operations

During 2012, Power recorded an increase in its ARO liabilities, primarily due to an increase in the estimated cost to decommission its nuclear power plants and increased accretion. The increase in the estimated costs to decommission Power's nuclear plants resulted primarily from the receipt of updated decommissioning cost studies in 2012 and the impact of lower discount rates. This change in the ARO did not result in any material impact in Power's Consolidated Statement of Operations.

Note 12. Pension, OPEB and Savings Plans

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. Eligible employees of Power, PSE&G, Energy Holdings and Services participate in non-contributory pension and OPEB plans sponsored by PSEG and administered by Services. In addition, represented and nonrepresented employees are eligible for participation in PSEG's two defined contribution plans described below.

PSEG, Power and PSE&G are required to record the under or over funded positions of their defined benefit pension and OPEB plans on their respective balance sheets. Such funding positions of each PSEG company are required to be measured as of the date of its respective year-end Consolidated Balance Sheets. For under funded plans, the liability is equal to the difference between the plan's benefit obligation and the fair value of plan assets. For defined benefit pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. In addition, accounting guidance requires that the total unrecognized costs for defined benefit pension and OPEB plans be recorded as an after-tax charge to Accumulated Other Comprehensive Income (Loss), a separate component of Stockholders' Equity. However, for PSE&G, because the amortization of the unrecognized costs is being collected from customers, the accumulated unrecognized costs are recorded as a Regulatory Asset. The unrecognized costs represent actuarial gains or losses, prior service costs and transition obligations arising from the adoption of the revised accounting guidance for pensions and OPEB, which had not been expensed.

For Power, the charge to Accumulated Other Comprehensive Income (Loss) is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations. For PSE&G, the Regulatory Asset is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations.

The following table provides a roll-forward of the changes in the benefit obligation and the fair value of plan assets during each of the two years in the periods ended December 31, 2012 and 2011. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

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	Pension Benefits		Other Benefits	
	2012	2011	2012	2011
	Millions			
Change in Benefit Obligation:				
Benefit Obligation at Beginning of Year	$ 4,572	$ 4,353	$ 1,338	$ 1,162
Service Cost	101	92	17	14
Interest Cost	223	228	65	61
Actuarial (Gain) Loss	586	300	182	179
Gross Benefits Paid	(248)	(236)	(69)	(67)
Medicare Subsidy Receipts	—	—	5	6
Plan Amendments	—	(165)	—	(17)
Special Termination Benefits	1	—	—	—
Benefit Obligation at End of Year	**$ 5,235**	**$ 4,572**	**$ 1,538**	**$ 1,338**
Change in Plan Assets:				
Fair Value of Assets at Beginning of Year	$ 3,831	$ 3,555	$ 211	$ 195
Actual Return on Plan Assets	541	87	31	5
Employer Contributions	233	425	75	72
Gross Benefits Paid	(248)	(236)	(69)	(67)
Medicare Subsidy Receipts	—	—	5	6
Fair Value of Assets at End of Year	**$ 4,357**	**$ 3,831**	**$ 253**	**$ 211**
Funded Status:				
Funded Status (Plan Assets less Benefit Obligation)	**$ (878)**	**$ (741)**	**$ (1,285)**	**$ (1,127)**
Additional Amounts Recognized in the Consolidated Balance Sheets:				
Noncurrent Assets	$ 6	$ —	$ — —	$ —
Current Accrued Benefit Cost	(8)	(7)	—	—
Noncurrent Accrued Benefit Cost	(876)	(734)	(1,285)	(1,127)
Amounts Recognized	**$ (878)**	**$ (741)**	**$ (1,285)**	**$ (1,127)**
Additional Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulated Assets and Deferred Assets (A):				
Net Transition Obligation	$ —	$ —	$ —	$ 2
Prior Service Cost	(139)	(158)	(67)	(81)
Net Actuarial Loss	2,174	1,991	527	390
Total	**$ 2,035**	**$ 1,833**	**$ 460**	**$ 311**

(A) Includes $827 million ($485 million, after-tax) and $745 million ($438 million, after-tax) in Accumulated Other Comprehensive Loss related to Pension and OPEB as of December 31, 2012 and 2011, respectively.

The pension benefits table above provides information relating to the funded status of all qualified and nonqualified pension plans and OPEB plans on an aggregate basis. As of December 31, 2012, PSEG had funded approximately 83% of its projected benefit obligation. This percentage does not include $ 185 million of assets in the Rabbi Trust as of December 31, 2012, which are used to partially fund the nonqualified pension plans. The fair values of the Rabbi Trust assets are included in the Consolidated Balance Sheets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Accumulated Benefit Obligation

The accumulated benefit obligation for all PSEG's defined benefit pension plans was $ 4.9 billion as of December 31, 2012 and $4.3 billion as of December 31, 2011.

The following table provides the components of net periodic benefit cost for the years ended December 31, 2012, 2011 and 2010.

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2012	2011	2010	2012	2011	2010
	Millions					
Components of Net Periodic Benefit Cost:						
Service Cost	$ 101	$ 92	$ 87	$ 17	$ 14	$ 16
Interest Cost	223	228	231	65	61	72
Expected Return on Plan Assets	(306)	(334)	(266)	(17)	(18)	(14)
Amortization of Net						
Transition Obligation	—	—	—	2	4	27
Prior Service Cost	(18)	(11)	—	(14)	(13)	13
Actuarial Loss	167	119	122	31	14	8
Net Periodic Benefit Cost	**$ 167**	**$ 94**	**$ 174**	**$ 84**	**$ 62**	**$ 122**
Special Termination Benefits	1	—	—	—	—	—
Effect of Regulatory Asset	—	—	—	19	19	19
Total Benefit Costs, Including Effect of Regulatory Asset	**$ 168**	**$ 94**	**$ 174**	**$ 103**	**$ 81**	**$ 141**

Pension costs and OPEB costs for PSEG, Power and PSE&G are detailed as follows:

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2012	2011	2010	2012	2011	2010
	Millions					
Power	$ 52	$ 29	$ 54	$ 18	$ 12	$ 17
PSE&G	97	51	97	82	67	120
Other	19	14	23	3	2	4
Total Benefit Costs	**$ 168**	**$ 94**	**$ 174**	**$ 103**	**$ 81**	**$ 141**

The following table provides the pre-tax changes recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Deferred Assets:

	Pension		OPEB	
	2012	2011	2012	2011
	Millions			
Net Actuarial (Gain) Loss in Current Period	$ 350	$ 547	$ 169	$ 192
Amortization of Net Actuarial Gain (Loss)	(167)	(119)	(32)	(14)
Prior Service Credit in Current Period	—	(165)	—	(17)
Amortization of Prior Service Credit	19	11	14	13
Amortization of Transition Asset	—	—	(2)	(4)
Total	**$ 202**	**$ 274**	**$ 149**	**$ 170**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Amounts that are expected to be amortized from Accumulated Other Comprehensive Loss, Regulatory Assets and Deferred Assets into Net Periodic Benefit Cost in 2013 are as follows:

	Pension Benefits 2013	Other Benefits 2013
	Millions	
Actuarial (Gain) Loss	$ 188	$ 43
Prior Service Cost	$ (19)	$ (14)

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

	Pension Benefits			Other Benefits		
	2012	2011	2010	2012	2011	2010
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31:						
Discount Rate	4.20%	5.00%	5.51%	4.20%	5.00%	5.50%
Rate of Compensation Increase	4.61%	4.61%	4.61%	4.61%	4.61%	4.61%
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31:						
Discount Rate	5.00%	5.40%	5.91%	5.00%	5.38%	5.90%
Expected Return on Plan Assets	8.00%	8.50%	8.50%	8.00%	8.50%	8.50%
Rate of Compensation Increase	4.61%	4.61%	4.61%	4.61%	4.61%	4.61%
Assumed Health Care Cost Trend Rates as of December 31:						
Administrative Expense				3.00%	5.00%	5.00%
Dental Costs				6.00%	6.00%	6.00%
Pre-65 Medical Costs						
Immediate Rate				8.88%	8.00%	7.75%
Ultimate Rate				5.00%	5.00%	5.00%
Year Ultimate Rate Reached				2023	2016	2015
Post-65 Medical Costs						
Immediate Rate				7.98%	8.25%	8.75%
Ultimate Rate				5.00%	5.00%	5.00%
Year Ultimate Rate Reached				2019	2017	2016
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs:						
				Millions		
Total of Service Cost and Interest Cost				$ 12	$ 11	$ 10
Postretirement Benefit Obligation				$ 180	$ 155	$ 122
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs:						
Total of Service Cost and Interest Cost				$ (9)	$ (9)	$ (8)
Postretirement Benefit Obligation				$ (149)	$ (128)	$ (102)

Plan Assets

All the investments of pension plans and OPEB plans are held in a trust account by the trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension and OPEB plans are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 17. Fair Value Measurements for more information on fair value guidance. Use of the Master Trust permits the commingling of pension plan assets and OPEB plan assets for investment and administrative purposes. Although assets of both plans are commingled in the Master Trust, the Trustee maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Trustee to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating

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plans. As of December 31, 2012, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 94% and 6%, respectively.

The following tables present information about the investments measured at fair value on a recurring basis as of December 31, 2012 and 2011, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2012			
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Temporary Investment Funds (A)	$ 67	$ —	$ 67	$ —
Common Stocks (B)				
Commingled—United States	1,928	1,928	—	—
Commingled—International	839	839	—	—
Other	431	431	—	—
Bonds (C)				
Government (United States & Foreign)	623	—	623	—
Other	691	—	691	—
Private Equity (E)	31	—	—	31
Total	**$ 4,610**	**$ 3,198**	**$ 1,381**	**$ 31**

	Recurring Fair Value Measurements as of December 31, 2011			
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Temporary Investment Funds (A)	$ 32	$ —	$ 32	$ —
Common Stocks (B)				
Commingled—United States	1,653	1,653	—	—
Commingled—International	603	603	—	—
Other	356	356	—	—
Bonds (C)				
Government (United States & Foreign)	662	—	662	—
Other	663	—	663	—
Pooled Real Estate (D)	36	—	—	36
Private Equity (E)	37	—	—	37
Total	**$ 4,042**	**$ 2,612**	**$ 1,357**	**$ 73**

(A) Certain temporary investment funds are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (primarily Level 2).

(B) Wherever possible, fair values of equity investments in stocks and in commingled funds are derived from quoted market prices as substantially all of these instruments have active markets (primarily Level 1). Most investments in stocks are priced utilizing the principal market close price or in some cases midpoint, bid or ask price.

(C) Investments in fixed income securities including bond funds are priced using an evaluated pricing approach or the most recent exchange or quoted bid (primarily Level 2).

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(D) The fair value of real estate investments is based on annual independent appraisals. The investments are also valued internally every quarter by the investment managers based on significant changes in property operations and market conditions (primarily Level 3).

(E) Limited partnership interests in private equity funds are valued using significant unobservable inputs as there is little, if any, market activity. In addition, there may be transfer restrictions on private equity securities. The process for determining the fair value of such securities relied on commonly accepted valuation techniques, including the use of earnings multiples based on comparable public securities, industry-specific non-earnings-based multiples and discounted cash flow models. These inputs require significant management judgment or estimation (primarily Level 3).

Reconciliations of the beginning and ending balances of the Pension and OPEB Plans' Level 3 assets for the years ended December 31, 2012 and 2011 follow:

	Balance as of January 1, 2012	Purchases/ (Sales)	Transfer In/ (Out)	Actual Return on Asset Sales	Actual Return on Assets Still Held	Balance as of December 31, 2012
			Millions			
Pooled Real Estate	$ 36	$ (38)	$ —	$ 2	$ —	$ —
Private Equity	$ 37	$ (6)	$ —	$ 5	$ (5)	$ 31

	Balance as of January 1, 2011	Purchases/ (Sales)	Transfer In/ (Out) (A)	Actual Return on Asset Sales	Actual Return on Assets Still Held	Balance as of December 31, 2011
			Millions			
Temporary Investment Funds	$ 23	$ —	$ (23)	$ —	$ —	$ —
Commingled Bonds —United States	$ 8	$ (8)	$ —	$ —	$ —	$ —
Pooled Real Estate	$ 48	$ (18)	$ —	$ 1	$ 5	$ 36
Private Equity	$ 38	$ (5)	$ —	$ 7	$ (3)	$ 37

(A) During the year ended December 31, 2011, $23 million of the temporary investment funds in the Pension and OPEB Fund were transferred from Level 3 to Level 2, due to more observable pricing for the underlying securities. As per PSEG's policy, this transfer was recognized as of the beginning of the first quarter (i.e. the quarter in which the transfer occurred).

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans as of the measurement date, December 31:

	As of December 31,	
Investments	**2012**	**2011**
Equity Securities	69%	64%
Fixed Income Securities	29	33
Real Estate Assets	—	1
Other Investments	2	2
Total Percentage	**100%**	**100%**

PSEG utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. In 2011, PSEG completed its latest asset/liability study. The results from the study indicated that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. Derivative financial instruments are used by the plans' investment managers primarily to rebalance the fixed

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income/equity allocation of the portfolio and hedge the currency risk component of foreign investments. The expected long-term rate of return on plan assets was 8.00% as of December 31, 2012 and will remain unchanged for 2013. This expected return was determined based on the study discussed above and considered the plans' historical annualized rate of return since inception, which was an annualized return of 9.3%.

Plan Contributions

PSEG may contribute up to $145 million into its pension plans and $14 million into its OPEB plan for calendar year 2013.

Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to plan participants.

Year	Pension Benefits	Other Benefits
	Millions	
2013	$ 254	$ 79
2014	260	80
2015	267	82
2016	274	84
2017	284	85
2018-2022	1,592	459
Total	**$ 2,931**	**$ 869**

401(k) Plans

PSEG sponsors two 401(k) plans, which are Employee Retirement Income Security Act defined contribution retirement plans. Eligible represented employees of PSEG's subsidiaries participate in the PSEG Employee Savings Plan (Savings Plan), while eligible non-represented employees of PSEG's subsidiaries participate in the PSEG Thrift and Tax-Deferred Savings Plan (Thrift Plan). Eligible employees may contribute up to 50% of their compensation to these plans. PSEG matches 50% of such employee contributions up to 7% of pay for Savings Plan participants and up to 8% of pay for Thrift Plan participants.

The amount paid for employer matching contributions to the plans for PSEG, Power and PSE&G are detailed as follows:

	Thrift Plan and Savings Plan		
	Years Ended December 31,		
	2012	2011	2010
	Millions		
Power	$ 10	$ 8	$ 5
PSE&G	18	14	9
Other	4	2	3
Total Employer Matching Contributions	**$ 32**	**$ 24**	**$ 17**

Note 13. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

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Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

The face value of outstanding guarantees, current exposure and margin positions as of December 31, 2012 and 2011 are shown below:

	As of December 31, 2012	As of December 31, 2011
	Millions	
Face Value of Outstanding Guarantees	$ 1,508	$ 1,756
Exposure under Current Guarantees	$ 226	$ 315
Letters of Credit Margin Posted	$ 124	$ 135
Letters of Credit Margin Received	$ 69	$ 91
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$ 15	$ 20
Counterparty Cash Margin Received	$ (4)	$ (7)
Net Broker Balance Deposited (Received)	$ 26	$ (92)
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that could be Required	$ 654	$ 812
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,531	$ 3,415
Additional Amounts Posted		
Other Letters of Credit	$ 45	$ 52

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 16. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a two level downgrade from its current S&P ratings or a three level downgrade from its current Moody's and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

During 2012, the SEC and the Commodity Futures Trading Commission (CFTC) continued efforts to implement new rules to enact stricter regulation over swaps and derivatives. The CFTC has issued Final Rules regarding the definition of a swap dealer

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and the definition of a swap. However, in September 2012, a federal court vacated the CFTC's rule on monitoring of position limits for several commodities, including natural gas, thereby indefinitely delaying the effectiveness of these position limits rules. The CFTC has appealed the court's decision to vacate the position limits rules. PSEG is carefully monitoring all of these new rules as they are issued to analyze the potential impact on its swap and derivatives transactions, including any potential increase in its collateral requirements.

In addition to amounts for outstanding guarantees, current exposure and margin positions, Power had posted letters of credit to support various other non-energy contractual and environmental obligations. See table above.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The EPA has determined that an eight-mile stretch of the Passaic River in the area of Newark, New Jersey is a "facility" within the meaning of that term under CERCLA. The EPA has determined the need to perform a study of the entire 17-mile tidal reach of the lower Passaic River.

PSE&G and certain of its predecessors conducted operations at properties in this area on or adjacent to the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites. When the Essex Site was transferred from PSE&G to Power, PSE&G obtained releases and indemnities for liabilities arising out of the former Essex generating station and Power assumed any environmental liabilities.

The EPA believes that certain hazardous substances were released from the Essex Site and one of PSE&G's former MGP locations (Harrison Site). In 2006, the EPA notified the potentially responsible parties (PRPs) that the cost of its Remedial Investigation and Feasibility Study (RI/FS) would greatly exceed the original estimated cost of $20 million. The total cost of the RI/FS is now estimated at approximately $110 million. Seventy-three PRPs, including Power and PSE&G, agreed to assume responsibility for the RI/FS and formed the Cooperating Parties Group (CPG) to divide the associated costs according to a mutually agreed upon formula. The CPG group, currently 70 members, is presently executing the RI/FS. Approximately five percent of the RI/FS costs are attributable to PSE&G's former MGP sites and approximately one percent to Power's generating stations. Power has provided notice to insurers concerning this potential claim.

In 2007, the EPA released a draft "Focused Feasibility Study" (FFS) that proposed six options to address the contamination cleanup of the lower eight miles of the Passaic River. The EPA estimated costs for the proposed remedy range from $1.3 billion to $3.7 billion. The work contemplated by the FFS is not subject to the cost sharing agreement discussed above. The EPA's revised proposed FFS may be released for public comment as early as April 2013.

In June 2008, an agreement was announced between the EPA and Tierra Solutions, Inc. and Maxus Energy Corporation (Tierra/Maxus) for removal of a portion of the contaminated sediment in the Passaic River at an estimated cost of $80 million. Phase I of the removal work has been completed. Phase II is contingent on the approval of an appropriate sediment disposal facility. Tierra/Maxus have reserved their rights to seek contribution for the removal costs from the other PRPs, including Power and PSE&G.

The EPA has advised that the levels of contaminants at Passaic River mile 10.9 will require removal in advance of the completion of the RI/FS. The CPG members, with the exception of Tierra/Maxus, which are no longer members, have agreed to fund the removal, currently estimated at approximately $30 million. PSEG's share of that effort is approximately three percent.

Except for the Passaic River 10.9 mile removal, Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to the Passaic River matters.

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New Jersey Spill Compensation and Control Act (Spill Act)

In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit against a PRP and its related companies in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of the PRP's discharge of hazardous substances into both the Passaic River and the balance of the Newark Bay Complex. Power and PSE&G are alleged to have owned, operated or contributed hazardous substances to a total of 11 sites or facilities that impacted these water bodies. In February 2009, third party complaints were filed against some 320 third party defendants, including Power and PSE&G, claiming that each of the third party defendants is responsible for its proportionate share of the clean-up costs for the hazardous substances it allegedly discharged into the Passaic River and the Newark Bay Complex. The third party complaints seek statutory contribution and contribution under the Spill Act to recover past and future removal costs and damages. Power and PSE&G filed answers to the complaints in June 2010. A special master for discovery has been appointed by the court and document production has commenced. In October 2012, the Court issued a 90 day stay of discovery for the third party defendants to explore a possible settlement of this matter with the State of New Jersey. The original stay has been extended, most recently until March 23, 2013, and is likely to be extended again, to permit the parties to continue forward with a settlement process. Power and PSE&G believe they have good and valid defenses to the allegations contained in the third party complaints and will vigorously assert those defenses. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

Natural Resource Damage Claims

In 2003, the NJDEP directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the Spill Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G is unable to estimate its portion of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area and encouraged the PRPs to contact Occidental Chemical Corporation (OCC) to discuss participating in the Remedial Investigation/Feasibility Study that OCC was conducting. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but it is uncertain at this time whether the PSEG companies will consent to fund the third phase. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $588 million and $675 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $588 million as of December 31, 2012. Of this amount, $113 million was recorded in Other Current Liabilities and $475 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $588 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

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In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Hazardous Air Pollutants Regulation

In accordance with a ruling of the U.S. Court of Appeals of the District of Columbia (Court of Appeals), the EPA published a Maximum Achievable Control Technology (MACT) regulation on February 16, 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the Court of Appeals in support of the EPA's implementation of MATS. Litigation of these matters remains pending and the impact on the implementation schedule is unknown at this time.

Power believes that it will not be necessary to install any material controls at its other New Jersey facilities. Additional controls may be necessary at Power's Bridgeport Harbor coal-fired unit at an immaterial cost. In December 2011, to comply with the MACT regulators, a decision was reached to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction (SCR) systems at Power's jointly owned coal-fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be completed in the first quarter of 2015. Power's share of this investment is approximately $147 million.

NOx Regulation

In April 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on Power's generation fleet, as it imposes NO_x emissions limits that will require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) and four older New Jersey steam electric generation units (approximately 400 MW) by May 30, 2015. Retirement notifications for the combustion turbines, except for Salem Unit 3, have been filed with PJM. The Salem Unit 3 combustion turbine (38 MW) will be transitioning to an emergency generator. Evaluations are ongoing for the steam electric generation units.

Under current Connecticut regulations, Power's Bridgeport and New Haven facilities have been utilizing Discrete Emission Reduction Credits (DERCs) to comply with certain NO_x emission limitations that were incorporated into the facilities' operating permits. In 2010, Power negotiated new agreements with the State of Connecticut extending the continued use of DERCs for certain emission units and equipment until May 31, 2014.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System (NPDES) permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The New Jersey Department of Environmental Protection manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

One of the most significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. Power prepared its renewal application in accordance with the FWPCA Section 316(b) and the 316(b) rules published in 2004.

As a result of several legal challenges to the 2004 316(b) rule by certain northeast states, environmentalists and industry groups, the rule has been suspended and has been returned to the EPA to be consistent with a 2009 United States Supreme Court decision which concluded that the EPA could rely upon cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II regulations.

In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule by July 27, 2012. In April 2011, the EPA published a new proposed rule which did not establish any particular technology as the best technology available (e.g. closed cycle cooling). Instead, the proposed rule established marine life

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mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. In June 2012, the EPA posted two Notices of Data Availability (NODA) requesting comment on aspects of the April 2011 proposed rule. In July 2012, PSEG and industry trade associations submitted comments on both NODAs and the EPA and environmental groups agreed to delay the deadline for finalization of the Rule to June 27, 2013 to allow for more time to address public comments and analyze data submitted in response to the NODAs.

Power is unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on its future capital requirements, financial condition, results of operations or cash flows. The results of further proceedings on this matter could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would have been approximately $575 million. These cost estimates have not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

Capital Expenditures

The construction programs of PSEG and its subsidiaries are currently estimated to include a base level total investment of approximately $6.1 billion for the three years ended 2015. The three year capital expenditures for PSEG, Power and PSE&G are as follows:

	2013	2014	2015
		Millions	
Power	$ 400	$ 365	$ 305
PSE&G	2,040	1,680	1,180
Other	95	40	30
Total PSEG	**$ 2,535**	**$ 2,085**	**$ 1,515**

Power's projected capital expenditures include baseline maintenance, investments in response to environmental or legal mandates and nuclear expansion. PSE&G's projections include material additions and replacements in its transmission and distribution systems to meet expected growth and manage reliability.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements for customers who do not purchase electric supply from third party suppliers through the annual New Jersey BGS auctions. Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with Power, as well as with other winning BGS suppliers, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has contracted for its anticipated BGS-Fixed Price eligible load, as follows:

	Auction Year				
	2010	2011	2012	2013	
36-Month Terms Ending	May 2013	May 2014	May 2015	May 2016	(A)
Load (MW)	2,800	2,800	2,900	2,800	
$ per kWh	0.09577	0.09430	0.08388	0.09218	

(A) Prices set in the 2013 BGS auction will become effective on June 1, 2013 when the 2010 BGS auction agreements expire.

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PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 23. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power has various long-term fuel purchase commitments for coal through 2017 to support its fossil generation stations and for supply of nuclear fuel for the Salem, Hope Creek and Peach Bottom nuclear generating stations and for firm transportation and storage capacity for natural gas.

Power's strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2015 and a portion through 2017 at Salem, Hope Creek and Peach Bottom.

Power's various multi-year contracts for firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

As of December 31, 2012, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2017
	Millions
Nuclear Fuel	
Uranium	$ 518
Enrichment	$ 453
Fabrication	$ 146
Natural Gas	$ 939
Coal	$ 555

Regulatory Proceedings

New Jersey Clean Energy Program

In 2008, the BPU approved funding requirements for each New Jersey EDC applicable to its Renewable Energy and Energy Efficiency programs for the years 2009 to 2012. In late 2012, the BPU approved additional funding requirements for these programs for the first half of 2013. The aggregate funding for the first half of 2013 is $195 million. PSE&G's share is $153 million which it recorded as a current liability as of December 31, 2012. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the SBC.

The BPU has started a new Comprehensive Resource Analysis proceeding to determine SBC funding for the years 2013-2016. The proceeding has no impact on current SBC assessments.

Long-Term Capacity Agreement Pilot Program (LCAPP)

In 2011, New Jersey enacted the LCAPP Act that resulted in the selection of three generators to build a total of approximately 2,000 MW of new combined-cycle generating facilities located in New Jersey. Each of the New Jersey EDCs, including PSE&G, was directed to execute a standard offer capacity agreement (SOCA) with the three selected generators, but did so under protest preserving their legal rights. The SOCA provides for the EDCs to guarantee specified annual capacity payments to the generators subject to the terms and conditions of the agreement. Legal challenges to the BPU's implementation of the LCAPP Act were filed in New Jersey appellate court and this appeal is pending. In addition, the LCAPP Act itself has been challenged on constitutional grounds in federal court.

In May 2012, two of the three generators cleared the Reliability Pricing Model auction for the 2015/2016 delivery year in the aggregate notional amount of approximately 1,300 MW of installed capacity. SOCA payments are for a 15 year term, which are scheduled to commence for one of the generators in the 2015/2016 delivery year and for the other generator in the 2016/2017

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delivery year. Based upon the expected percentage of state load that PSE&G will be serving during the term of these contracts, PSE&G would be responsible for approximately 52% or 676 MW of this amount.

Under current accounting guidance, the current estimated fair value of the SOCAs is recorded as a Derivative Asset or Liability with an offsetting Regulatory Asset or Liability on PSE&G's Consolidated Balance Sheets. See Note 17. Fair Value Measurements for additional information.

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's transmission and distribution system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds resulted in a storm surge that caused damage to switching stations, substations and generating infrastructure.

As of December 31, 2012, Power had incurred approximately $85 million in costs related to Superstorm Sandy, primarily comprised of repairs at certain generating stations and damage to materials and supplies, both at our fossil fleet. All the costs were recognized in Operation and Maintenance Expense, offset by $19 million of a pending future recovery of insurance proceeds. Power expects that it will incur additional future costs, primarily relating to repairs to, and replacement of, equipment and property, which could be material.

As of December 31, 2012, PSE&G had incurred approximately $295 million of costs to restore service to PSE&G's distribution and transmission systems and $5 million to repair its infrastructure and return it to pre-storm conditions. Of the costs incurred, approximately $40 million was recognized in Operation and Maintenance Expense, $75 million was recorded as Property, Plant and Equipment and $180 million was recorded as a Regulatory Asset because such costs were deferred as approved by the BPU under an Order received in December 2012. PSE&G recognized $6 million of insurance proceeds.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. PSEG is seeking recovery from its insurers for the property damage, above its self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. PSEG received an authorization for $25 million from its insurance carriers as an advance payment which was recorded in 2012. PSEG believes that additional insurance recoveries are not estimable as of December 31, 2012. PSEG is at the early stages of documenting its insurance claim which then will need to be submitted to and reviewed by its insurers. PSEG does not believe that it has a basis for estimating additional probable insurance recoveries at this time.

Leveraged Lease Investments

On January 31, 2012, PSEG entered into a specific matter closing agreement with the Internal Revenue Service (IRS) settling all matters related to cross border lease transactions. This agreement settles the leasing dispute with finality for all tax periods in which PSEG realized tax deductions from these transactions. On January 31, 2012, PSEG also signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. On March 26, 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These two agreements conclude ten years of audits for PSEG and the leasing issue for all tax years. For PSEG, the impact of these agreements is an increase in financial statement Income Tax Expense of approximately $175 million. In prior periods, PSEG had established financial statement tax liabilities for uncertain tax positions in the amount of $246 million with respect to these tax years. Accordingly, the settlement resulted in a net $71 million decrease in the Income Tax Expense of PSEG.

Cash Impact

For tax years 1997 through 2003, the tax and interest PSEG owes the IRS as a result of this settlement will be reduced by the $320 million PSEG has on deposit with the IRS for this matter. PSEG paid a net deficiency for these years of approximately $4 million during the second quarter of 2012. Based upon the closing agreement and the Form 870-AD for tax years 2004 through 2006, PSEG owes the IRS approximately $620 million in tax and interest for tax years from 2004 through 2006. Based on the settlement of the leasing dispute, for tax years 2007 through 2010, the IRS owes PSEG approximately $676 million. PSEG has filed amended returns for tax years 2007-2010 reflecting the impact of the settlement. These returns have been audited by the IRS and accepted as filed. As required by statute, the IRS presented the refund claim to the Joint Committee on Taxation for approval. On October 16, 2012, PSEG was notified that the Joint Committee took no exception to the refund claim. The IRS is now processing those claims and preparing interest computations. In spite of the progress noted above, it is still possible that PSEG would have to pay $620 million over the next year to the IRS and wait while the IRS processes the $676 million refund claim in the normal course; it could take several years for the IRS to process these claims. In addition to the above, PSEG will claim a tax deduction for the accrued deficiency interest associated with this settlement in 2012, which will give rise to a cash tax savings of approximately $100 million.

Nuclear Insurance Coverages and Assessments

Power is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides the primary property and decontamination liability insurance at Salem, Hope Creek and Peach Bottom. NEIL also provides excess

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property insurance through its decontamination liability, decommissioning liability and excess property policy and replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in case of adverse loss experience. Power's maximum potential liabilities under these assessments are included in the table and notes below. Certain provisions in the NEIL policies provide that the insurer may suspend coverage with respect to all nuclear units on a site without notice if the NRC suspends or revokes the operating license for any unit on that site, issues a shutdown order with respect to such unit or issues a confirmatory order keeping such unit down.

The American Nuclear Insurers (ANI) and NEIL policies both include coverage for claims arising out of acts of terrorism. NEIL makes a distinction between certified and non-certified acts of terrorism, as defined under the Terrorism Risk Insurance Act (TRIA), and thus its policies respond accordingly. For non-certified acts of terrorism, NEIL policies are subject to an industry aggregate limit of $3.2 billion plus any amounts available through reinsurance or indemnity for non-certified acts of terrorism. For any act of terrorism, Power's nuclear liability policies will respond similarly to other covered events. For certified acts, Power's nuclear property NEIL policies will respond similarly to other covered events.

The Price-Anderson Act sets the "limit of liability" for claims that could arise from an incident involving any licensed nuclear facility in the United States The "limit of liability" is based on the number of licensed nuclear reactors and is adjusted at least every five years based on the Consumer Price Index. The current "limit of liability" is $12.6 billion. All owners of nuclear reactors, including Power, have provided for this exposure through a combination of private insurance and mandatory participation in a financial protection pool as established by the Price-Anderson Act. Under the Price-Anderson Act, each party with an ownership interest in a nuclear reactor can be assessed its share of $118 million per reactor per incident, payable at $18 million per reactor per incident per year. If the damages exceed the "limit of liability," the President is to submit to Congress a plan for providing additional compensation to the injured parties. Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Power's maximum aggregate assessment per incident is $370 million (based on Power's ownership interests in Hope Creek, Peach Bottom and Salem) and its maximum aggregate annual assessment per incident is $55 million. Further, a decision by the U.S. Supreme Court, not involving Power, has held that the Price-Anderson Act did not preclude awards based on state law claims for punitive damages.

Power's insurance coverages and maximum retrospective assessments for its nuclear operations are as follows:

Type and Source of Coverages	Total Site Coverage		Retrospective Assessments
	Millions		
Public and Nuclear Worker Liability (Primary Layer):			
ANI	$ 375	(A)	$ —
Nuclear Liability (Excess Layer):			
Price-Anderson Act	12,219	(B)	370
Nuclear Liability Total	**$ 12,594**	(C)	**$ 370**
Property Damage (Primary Layer):			
NEIL Primary (Salem/Hope Creek/Peach Bottom)	$ 500		$ 22
Property Damage (Excess Layers):			
NEIL II (Salem/Hope Creek/Peach Bottom)	750		8
NEIL Blanket Excess (Salem/Hope Creek/Peach Bottom)	850	(D)	5
Property Damage Total (Per Site)	**$ 2,100**		**$ 35**
Accidental Outage:			
NEIL I (Peach Bottom)	$ 245	(E)	$ 6
NEIL I (Salem)	281	(E)	7
NEIL I (Hope Creek)	490	(E)	6
Replacement Power Total	**$ 1,016**		**$ 19**

(A) The primary limit for Public Liability is a per site aggregate limit with no potential for assessment. The Nuclear Worker Liability represents the potential liability from workers claiming exposure to the hazard of nuclear radiation. This coverage is subject to an industry aggregate limit that is subject to reinstatement at ANI discretion.

(B) Retrospective premium program under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. Power is subject to retrospective assessment with respect to loss from an incident at any licensed nuclear reactor in the United States that produces greater than 100 MW of electrical power. This retrospective assessment can be adjusted for inflation every five years. The last adjustment was effective as of October 29, 2008. The next

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adjustment is due on or before October 29, 2013. This retrospective program is in excess of the Public and Nuclear Worker Liability primary layers.

(C) Limit of liability under the Price-Anderson Act for each nuclear incident.

(D) For property limits in excess of $1.25 billion, Power participates in a Blanket Limit policy where the $850 million limit is shared by Power with Exelon Generation among the Braidwood, Byron, Clinton, Dresden, La Salle, Limerick, Oyster Creek, Quad Cities, TMI-1 facilities owned by Exelon Generation and the Peach Bottom, Salem and Hope Creek facilities. This limit is not subject to reinstatement in the event of a loss. Participation in this program materially reduces Power's premium and the associated potential assessment.

(E) Peach Bottom has an aggregate indemnity limit based on a weekly indemnity of $2.3 million for 52 weeks followed by 80% of the weekly indemnity for 68 weeks. Salem has an aggregate indemnity limit based on a weekly indemnity of $2.5 million for 52 weeks followed by 80% of the weekly indemnity for 75 weeks. Hope Creek has an aggregate indemnity limit based on a weekly indemnity of $4.5 million for 52 weeks followed by 80% of the weekly indemnity for 71 weeks.

Minimum Lease Payments

Power, PSE&G and Energy Holdings have entered into various operating leases. The total future minimum payments of these operating leases as of December 31, 2012 are:

	PSEG	Power	PSE&G	Energy Holdings
		Millions		
2013	$ —	$ —	$ 7	$ 2
2014	—	1	6	2
2015	3	1	3	2
2016	12	1	3	2
2017	13	1	3	1
Thereafter	186	4	32	12
Total Minimum Lease Payments	**$ 214**	**$ 8**	**$ 54**	**$ 21**

Note 14. Schedule of Consolidated Debt

Long-Term Debt

	As of December 31, 2012	2011
	Millions	
PSEG (Parent)		
Fair Value of Swaps (A)	$ 57	$ 62
Unamortized Discount Related to Debt Exchange (B)	(19)	(23)
Total Long-Term Debt of PSEG (Parent)	**$ 38**	**$ 39**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2012	2011
		Millions	
Power			
Senior Notes:			
2.50%	2013	$ 300	$ 300
5.00%	2014	—	250
5.50%	2015	300	300
5.32%	2016	303	303
2.75%	2016	250	250
5.13%	2020	406	406
4.15%	2021	250	250
8.63%	2031	500	500
Total Senior Notes		2,309	2,559
Pollution Control Notes:			
Floating Rate (C)	2014	44	44
5.00%	2012	—	66
5.50%	2020	—	14
5.85%	2027	—	19
5.75%	2031	—	25
5.75%	2037	—	40
Total Pollution Control Notes		44	208
Principal Amount Outstanding		2,353	2,767
Amounts Due Within One Year		(300)	(66)
Net Unamortized Discount		(13)	(16)
Total Long-Term Debt of Power		**$ 2,040**	**$ 2,685**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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	Maturity	As of December 31, 2012	2011
		Millions	
PSE&G			
First and Refunding Mortgage Bonds (D):			
6.75%	2016	$ 171	$ 171
9.25%	2021	134	134
8.00%	2037	7	7
5.00%	2037	8	8
Total First and Refunding Mortgage Bonds		320	320
Pollution Control Bonds (D):			
5.20%	2025	—	23
5.45%	2032	—	50
Floating rate (C)	2033	50	—
Floating rate (C)	2046	50	—
Total Pollution Control Bonds		100	73
Medium-Term Notes (MTNs) (D):			
5.13%	2012	—	300
5.00%	2013	150	150
5.38%	2013	300	300
6.33%	2013	275	275
0.85%	2014	250	250
5.00%	2014	250	250
2.70%	2015	300	300
5.30%	2018	400	400
7.04%	2020	9	9
3.50%	2020	250	250
5.25%	2035	250	250
5.70%	2036	250	250
5.80%	2037	350	350
5.38%	2039	250	250
5.50%	2040	300	300
3.95%	2042	450	—
3.65%	2042	350	—
Total MTNs		4,384	3,884
Principal Amount Outstanding		4,804	4,277
Amounts Due Within One Year		(725)	(300)
Net Unamortized Discount		(9)	(7)
Total Long-Term Debt of PSE&G (excluding Transition Funding and Transition Funding II)		**$ 4,070**	**$ 3,970**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2012	2011
		Millions	
Transition Funding (PSE&G)			
Securitization Bonds:			
6.61%	2011-2013	$ 100	$ 305
6.75%	2013-2014	220	220
6.89%	2014-2015	370	370
Principal Amount Outstanding		690	895
Amounts Due Within One Year		(214)	(205)
Total Securitization Debt of Transition Funding		**476**	**690**
Transition Funding II (PSE&G)			
Securitization Bonds:			
4.34%	2011-2012	—	1
4.49%	2012-2013	9	20
4.57%	2013-2015	23	23
Principal Amount Outstanding		32	44
Amounts Due Within One Year		(12)	(11)
Total Securitization Debt of Transition Funding II		**20**	**33**
Total Long-Term Debt of PSE&G		**$ 4,566**	**$ 4,693**

Energy Holdings	Maturity	As of December 31, 2012	2011
		Millions	
Non-Recourse Project Debt (E):			
Resources - 5.00% to 8.75%	2011-2020	$ 44	$ 45
Resources - Other (F)	2012	—	50
Principal Amount Outstanding		44	95
Amounts Due Within One Year		(1)	(51)
Total Non-Recourse Project Debt		43	44
Total Long-Term Debt of Energy Holdings		**$ 43**	**$ 44**

(A) PSEG entered into various interest rate swaps to hedge the fair value of certain debt at Power. The fair value adjustments from these hedges are reflected as offsets to long-term debt on the Consolidated Balance Sheet. For additional information, see Note 16. Financial Risk Management Activities.

(B) In September 2009, Power completed an exchange offer with eligible holders of Energy Holdings' 8.50% Senior Notes due 2011 in order to manage long-term debt maturities. Since the debt exchange was between two subsidiaries of the same parent company, PSEG, and treated as a debt modification for accounting purposes, the resulting premium was deferred and is being amortized over the term of the newly issued debt. The deferred amount is reflected as an offset to Long-Term Debt on PSEG's Consolidated Balance Sheet.

(C) The Pennsylvania Economic Development Authority (PEDFA) bond and The Pollution Control Financing Authority of Salem County bonds for Power and PSE&G, respectively, are variable rate bonds that are in weekly reset mode.

(D) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.

(E) Non-recourse financing transactions consist of loans from banks and other lenders that are typically secured by project assets and cash flows and generally impose no material obligation on the parent-level investor to repay any debt incurred by the project borrower. The consequences of permitting a project-level default include the potential for loss of any invested equity by the parent.

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(F) As a result of the Dynegy bankruptcy proceedings, Energy Holdings ceased leveraged lease accounting and recorded the related nonrecourse project debt on its balance sheet at its fair value of $50 million. Upon settlement of the claims against Dynegy in 2012, Energy Holdings was released from this debt.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2012 are as follows:

		PSE&G			Energy Holdings	
Year	Power	PSE&G	Transition Funding	Transition Funding II	Non-Recourse Debt	Total
				Millions		
2013	$ 300	$ 725	$ 214	$ 12	$ 1	$ 1,252
2014	44	500	225	12	1	782
2015	300	300	251	8	17	876
2016	553	171	—	—	7	731
2017	—	—	—	—	1	1
Thereafter	1,156	3,108	—	—	17	4,281
Total	**$ 2,353**	**$ 4,804**	**$ 690**	**$ 32**	**$ 44**	**$ 7,923**

Long-Term Debt Financing Transactions

During 2012, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions:

Power

- redeemed $250 million of 5.00% Senior Notes due April 1, 2014,
- redeemed and retired Pollution Control Notes servicing and securing $98 million of tax-exempt financings, including $14 million of 5.50% York County Industrial Development Authority Pollution Control Revenue Refunding Bonds due September 1, 2020; $19 million of 5.85% Indiana County Industrial Development Authority Pollution Control Revenue Refunding Bonds due June 1, 2027; $25 million of 5.75% Pollution Control Financing Authority of Salem County Pollution Control Revenue Refunding Bonds due April 1, 2031; and $40 million of 5.75% Connecticut Development Authority Solid Waste Disposal Facility Revenue Bonds due November 1, 2037,
- paid $66 million of 5.00% Pollution Control Revenue Refunding Notes at maturity, and
- paid cash dividends of $600 million to PSEG.

PSE&G

- remarketed $50 million of weekly-reset variable rate demand bonds of the Pollution Control Financing Authority of Salem County due November 1, 2033, which are serviced and secured by PSE&G's First and Refunding Mortgage Bonds of like tenor,
- paid $300 million of 5.13% Secured Medium-Term Notes at maturity,
- issued $350 million of 3.65% Secured Medium-Term Notes, Series H due September 2042,
- refinanced at par $50 million of 5.45% fixed rate Pollution Control Financing Authority of Salem County Authority Bonds due February 1, 2032, which were serviced and secured by PSE&G's First and Refunding Mortgage Bonds of like tenor, with $50 million of weekly-reset variable rate demand bonds due April 1, 2046, which are serviced and secured by PSE&G's First and Refunding Mortgage Bonds of like tenor,
- redeemed and retired at par $23 million of 5.20% fixed rate Pollution Control Financing Authority of Salem County Authority Bonds due March 1, 2025, which were serviced and secured by PSE&G's First and Refunding Mortgage Bonds of like tenor,
- issued $450 million of 3.95% Secured Medium-Term Notes, Series H due May 2042,
- paid $205 million of Transition Funding's securitization debt, and

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- paid $11 million of Transition Funding II's securitization debt.

Energy Holdings

- was released from $50 million of nonrecourse project debt related to the Dynegy Leases, and
- paid cash dividends of $500 million to PSEG.

PSE&G

In January 2013, PSE&G issued $400 million of 3.80% Secured Medium-Term Notes, Series H, due January 2043, and paid $150 million of 5.00% Secured Medium-Term Notes, at maturity.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements primarily through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Both commercial paper programs are fully back-stopped by their own separate credit facilities.

The commitments under our credit facilities are provided by a diverse bank group. As of December 31, 2012, no single institution represented more than 8% of the total commitments in our credit facilities.

As of December 31, 2012, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of December 31, 2012 were as follows:

	As of December 31, 2012			
Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facility	$ 500	$ 4 (A)	$ 496	Mar 2017	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility	500	—	500	Apr 2016	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 4**	**$ 996**		
Power					
5-year Credit Facility	$ 1,600	$ 65 (A)	$ 1,535	Mar 2017	Funding/Letters of Credit
5-year Credit Facility	1,000	—	1,000	Apr 2016	Funding/Letters of Credit
Bilateral Credit Facility	100	100 (A)	—	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 165**	**$ 2,535**		
PSE&G					
5-year Credit Facility	$ 600	$ 276 (B)	$ 324	Apr 2016	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 276**	**$ 324**		
Total	**$ 4,300**	**$ 445**	**$ 3,855**		

(A) Includes amounts related to letters of credit outstanding.
(B) Includes amounts related to CP and letters of credit outstanding

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of December 31, 2012 and 2011. See Note 17. Fair Value Measurements for more information on fair value guidance and the hierarchy that prioritizes the inputs to fair value measurements into three levels.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	December 31, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 38	$ 57	$ 39	$ 62
Power -Recourse Debt (B)	2,340	2,818	2,751	3,158
PSE&G (B)	4,795	5,606	4,270	4,905
Transition Funding (PSE&G) (B)	690	765	895	1,016
Transition Funding II (PSE&G) (B)	32	34	44	47
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	44	44	95	95
	$ 7,939	**$ 9,324**	**$ 8,094**	**$ 9,283**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Fair value amounts as of December 31, 2011 include $50 million of non-recourse project debt related to Dynegy which is classified as a Level 3 measurement. As of the June 5, 2012, the effective date of the amended settlement agreement, the $50 million of Notes Payable was written off. See the Fair Value Option Section of Note 17. Fair Value Measurements for additional information. Non-recourse project debt of $44 million is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

Note 15. Schedule of Consolidated Capital Stock

	As of December 31,			
	Outstanding Shares		Book Value	
	2012	2011	2012	2011
			Millions	
PSEG Common Stock (no par value) (A)				
Authorized 1,000,000,000 shares	505,892,472	505,945,286	$ 4,226	$ 4,222

(A) PSEG did not issue any new shares under the Dividend Reinvestment and Stock Purchase Plan (DRASPP) and the Employee Stock Purchase Plan (ESPP) in 2012 or 2011. Total authorized and unissued shares of common stock available for issuance through PSEG's DRASPP, ESPP and various employee benefit plans amounted to 7 million shares as of December 31, 2012.

As of December 31, 2012, there was an aggregate of 7.5 million shares of $100 par value and 10 million shares of $25 par value Cumulative Preferred Stock, which were authorized and unissued and which, upon issuance, may or may not provide for mandatory sinking fund redemption.

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Note 16. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Commodity Prices

The availability and price of energy commodities are subject to fluctuations due to weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions, transmission availability and other events. Power uses physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. Derivative contracts that do not qualify for hedge accounting or normal purchases/normal sales treatment are MTM with changes in fair value recorded in the income statement. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps and futures contracts to hedge

- forecasted energy sales from its generation stations and the related load obligations,
- the price of fuel to meet its fuel purchase requirements, and
- certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

These derivative transactions are designated and effective as cash flow hedges. During the second quarter of 2012, Power de-designated certain of its commodity derivative transactions that had previously qualified as cash flow hedges as they were deemed to no longer be highly effective as required by the relevant accounting guidance. As a result, since June 1, 2012, Power recognizes all gains and losses from changes in the fair value of these derivatives immediately in earnings rather than deferring any such amounts in Accumulated Other Comprehensive Income (Loss). The fair values of Power's de-designated hedges were frozen in Accumulated Other Comprehensive Income (Loss) as the original forecasted transactions are still expected to occur and are reclassified into earnings as the original derivative transactions settle.

As of December 31, 2012 and 2011, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity was as follows:

	As of December 31,	
	2012	2011
	Millions	
Fair Value of Cash Flow Hedges	$ 3	$ 57
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 9	$ 33

The expiration date of the longest-dated cash flow hedge at Power is in 2014. Power's after-tax unrealized gains on these derivatives that are expected to be reclassified to earnings during the next 12 months are $ 8 million. There was no ineffectiveness associated with qualifying hedges as of December 31, 2012.

Trading Derivatives

The primary purpose of Power's wholesale marketing operation is to optimize the value of the output of the generating facilities via various products and services available in the markets it serves. Historically, Power engaged in trading of electricity and energy-related products where such transactions were not associated with the output or fuel purchase requirements of its facilities. This trading consisted mostly of energy supply contracts where Power secured sales commitments with the intent to supply the energy services from purchases in the market rather than from its owned generation. Such trading activities were marked to market through the income statement and represented less than one percent of gross margin (revenues less energy costs) on an annual basis. Effective July 2011, Power has not entered into any trading derivative contracts and anticipates that it will not do so in the future.

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Other Derivatives

Power enters into additional contracts that are derivatives, but do not qualify for or are not designated as cash flow hedges. These transactions are intended to mitigate exposure to fluctuations in commodity prices and optimize the value of its expected generation. Trade types include financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. Changes in fair market value of these contracts are recorded in earnings.

PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization. In addition, as further described in Note 13. Commitments and Contingent Liabilities, PSE&G was directed to execute long-term SOCAs with certain generators to support the LCAPP Act. Two of the three generators cleared the Reliability Pricing Model auction for the 2015/2016 delivery year. These two SOCA contracts qualify as derivatives and are marked to fair value with the offset recorded to Regulatory Assets and Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. In order to redeem Power's $250 million of 5% Senior Notes due April 2014 in December 2012, PSEG terminated its $250 million interest rate swap that had converted this debt into variable-rate. As of December 31, 2012, PSEG had seven interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of December 31, 2012 and 2011, the fair value of all the underlying hedges was $57 million and $62 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was $(2) million as of December 31, 2012 and 2011.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Consolidated Balance Sheets:

	As of December 31, 2012						
	Power				PSE&G	PSEG	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (A)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 3	$ 332	$ (217)	$ 118	$ 5	$ 15	$ 138
Noncurrent Assets	—	75	(26)	49	62	42	153
Total Mark-to-Market Derivative Assets	**$ 3**	**$ 407**	**$ (243)**	**$ 167**	**$ 67**	**$ 57**	**$ 291**
Derivative Contracts							
Current Liabilities	$ —	$ (265)	$ 219	$ (46)	$ —	$ —	$ (46)
Noncurrent Liabilities	—	(41)	26	(15)	(107)	—	(122)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (306)**	**$ 245**	**$ (61)**	**$ (107)**	**$ —**	**$ (168)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 3**	**$ 101**	**$ 2**	**$ 106**	**$ (40)**	**$ 57**	**$ 123**

	As of December 31, 2011						
	Power				PSE&G	PSEG	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (A)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 55	$ 532	$ (448)	$ 139	$ —	$ 17	$ 156
Noncurrent Assets	8	121	(74)	55	4	47	106
Total Mark-to-Market Derivative Assets	**$ 63**	**$ 653**	**$ (522)**	**$ 194**	**$ 4**	**$ 64**	**$ 262**
Derivative Contracts							
Current Liabilities	$ (5)	$ (506)	$ 387	$ (124)	$ (7)	$ —	$ (131)
Noncurrent Liabilities	(1)	(76)	53	(24)	—	(2)	(26)
Total Mark-to-Market Derivative (Liabilities)	**$ (6)**	**$ (582)**	**$ 440**	**$ (148)**	**$ (7)**	**$ (2)**	**$ (157)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 57**	**$ 71**	**$ (82)**	**$ 46**	**$ (3)**	**$ 62**	**$ 105**

(A) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. As of December 31, 2012 and December 31, 2011, net cash collateral paid of $2 million and net cash collateral received of $82 million, respectively, was netted against the corresponding net derivative contract positions. Of the $2 million as of December 31, 2012, cash collateral of $(3) million was netted against current assets and cash collateral of $5 million was netted against current liabilities. Of the $82 million as of December 31, 2011, cash collateral of $(77) million and $(23) million were netted against current assets and noncurrent assets,

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respectively, and cash collateral of $16 million and $2 million were netted against current liabilities and noncurrent liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded or lose its investment grade credit rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $98 million and $285 million as of December 31, 2012 and 2011, respectively. As of December 31, 2012 and 2011, Power had the contractual right of offset of $61 million and $149 million, respectively, related to derivative instruments that are assets with the same counterparty under master agreements and net of margin posted. If Power had been downgraded or lost its investment grade rating, it would have had additional collateral obligations of $37 million and $136 million as of December 31, 2012 and 2011, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $654 million and $812 million as of December 31, 2012 and 2011, respectively, discussed in Note 13. Commitments and Contingent Liabilities.

The following shows the effect on the Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the years ended December 31, 2012, 2011 and 2010:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Years Ended December 31,			Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Years Ended December 31,			Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Years Ended December 31,		
	2012	2011	2010		2012	2011	2010	2012	2011	2010
					Millions					
PSEG (A)										
Energy-Related Contracts	$ 32	$ 84	$ 101	Operating Revenues	$ 79	$ 213	$ 222	$ 1	$ (2)	$ 1
Energy-Related Contracts	(4)	(4)	1	Energy Costs	(9)	2	(2)	—	—	—
Interest Rate Swaps	—	—	—	Interest Expense	—	(1)	(1)	—	—	—
Total PSEG	**$ 28**	**$ 80**	**$ 102**		**$ 70**	**$ 214**	**$ 219**	**$ 1**	**$ (2)**	**$ 1**
Power										
Energy-Related Contracts	$ 32	$ 84	$ 101	Operating Revenues	$ 79	$ 213	$ 222	$ 1	$ (2)	$ 1
Energy-Related Contracts	(4)	(4)	1	Energy Costs	(9)	2	(2)	—	—	—
Total Power	**$ 28**	**$ 80**	**$ 102**		**$ 70**	**$ 215**	**$ 220**	**$ 1**	**$ (2)**	**$ 1**

(A) Includes amounts for PSEG parent.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following reconciles the AOCI for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis:

AOCI	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2010	**$ 188**	**$ 111**
Gain Recognized in AOCI	80	47
Less: Gain Reclassified into Income	(214)	(127)
Balance as of December 31, 2011	**$ 54**	**$ 31**
Gain Recognized in AOCI	28	17
Less: Gain Reclassified into Income	(70)	(41)
Balance as of December 31, 2012	**$ 12**	**$ 7**

The following shows the effect on the Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the years ended December 31, 2012, 2011 and 2010:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2012	2011	2010
		Millions		
PSEG and Power				
Energy-Related Contracts	Operating Revenues	$ 232	$ 205	$ (53)
Energy-Related Contracts	Energy Costs	(19)	(42)	(9)
Total PSEG and Power		**$ 213**	**$ 163**	**$ (62)**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $22 million, $25 million and $24 million for the years ended December 31, 2012, 2011 and 2010, respectively.

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The following reflects the gross volume, on an absolute value basis, of derivatives as of December 31, 2012 and 2011:

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of December 31, 2012					
Natural Gas	Dth	596	—	404	192
Electricity	MWh	208	—	208	—
Capacity	MW days	4	—	—	4
FTRs	MWh	19	—	19	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
Coal	Tons	1	—	1	—
As of December 31, 2011					
Natural Gas	Dth	612	—	377	235
Electricity	MWh	137	—	137	—
FTRs	MWh	12	—	12	—
Interest Rate Swaps	U.S. Dollars	1,100	1,100	—	—
Coal	Tons	1	—	1	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of December 31, 2012, 94% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of December 31, 2012. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 317	$ 61	$ 313	2	$ 165	(A)
Non-Investment Grade—External Rating	22	—	22	—	—	
Investment Grade—No External Rating	10	—	10	—	—	
Non-Investment Grade—No External Rating	—	—	—	—	—	
Total	**$ 349**	**$ 61**	**$ 345**	**2**	**$ 165**	

(A) Includes net exposure of $119 million with PSE&G. The remaining net exposure of $46 million is with a nonaffiliated power purchaser which is a regulated investment grade counterparty.

The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure.

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When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of December 31, 2012, Power had 174 active counterparties.

Note 17. Fair Value Measurements

PSEG, Power and PSE&G adopted accounting standard update "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in GAAP and International Financial Reporting Standards (IFRS)" effective January 1, 2012. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of December 31, 2012, these consisted primarily of electric swaps whose basis is deemed significant to the fair value measurement, electric load deals, long-term electric capacity contracts and long-term gas supply contracts.

The following tables present information about PSEG's, Power's and PSE&G's respective assets and (liabilities) measured at fair value on a recurring basis as of December 31, 2012 and December 31, 2011, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Description	Recurring Fair Value Measurements as of December 31, 2012			
	Total	Cash Collateral Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 234	$ (3)	$ —	$ 157	$ 80
Interest Rate Swaps (B)	$ 57	$ —	$ —	$ 57	$ —
NDT Fund (C)					
Equity Securities	$ 789	$ —	$ 789	$ —	$ —
Debt Securities—Govt Obligations	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Other	$ 342	$ —	$ —	$ 342	$ —
Other Securities	$ 124	$ —	$ —	$ 124	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 18	$ —	$ 18	$ —	$ —
Debt Securities—Govt Obligations	$ 117	$ —	$ —	$ 117	$ —
Debt Securities—Other	$ 47	$ —	$ —	$ 47	$ —
Other Securities	$ 3	$ —	$ —	$ 3	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (168)	$ 5	$ —	$ (62)	$ (111)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 167	$ (3)	$ —	$ 157	$ 13
NDT Fund (C)					
Equity Securities	$ 789	$ —	$ 789	$ —	$ —
Debt Securities—Govt Obligations	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Other	$ 342	$ —	$ —	$ 342	$ —
Other Securities	$ 124	$ —	$ —	$ 124	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 3	$ —	$ 3	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 9	$ —	$ —	$ 9	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (61)	$ 5	$ —	$ (62)	$ (4)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (A)	$ 67	$ —	$ —	$ —	$ 67
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—Govt Obligations	$ 39	$ —	$ —	$ 39	$ —
Debt Securities—Other	$ 15	$ —	$ —	$ 15	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy Related Contracts (A)	$ (107)	$ —	$ —	$ —	$ (107)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Description	Recurring Fair Value Measurements as of December 31, 2011			
	Total	Cash Collateral Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 198	$ (100)	$ —	$ 257	$ 41
Interest Rate Swaps (B)	$ 64	$ —	$ —	$ 64	$ —
NDT Fund (C)					
Equity Securities	$ 685	$ —	$ 685	$ —	$ —
Debt Securities—Govt Obligations	$ 359	$ —	$ —	$ 359	$ —
Debt Securities—Other	$ 281	$ —	$ —	$ 281	$ —
Other Securities	$ 24	$ —	$ —	$ 24	$ —
Rabbi Trust—Mutual Funds (C)	$ 172	$ —	$ 19	$ 153	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (155)	$ 18	$ —	$ (153)	$ (20)
Interest Rate Swaps (B)	$ (2)	$ —	$ —	$ (2)	$ —
Non-Recourse Debt (D)	$ (50)	$ —	$ —	$ —	$ (50)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 194	$ (100)	$ —	$ 257	$ 37
NDT Fund (C)					
Equity Securities	$ 685	$ —	$ 685	$ —	$ —
Debt Securities—Govt Obligations	$ 359	$ —	$ —	$ 359	$ —
Debt Securities—Other	$ 281	$ —	$ —	$ 281	$ —
Other Securities	$ 24	$ —	$ —	$ 24	$ —
Rabbi Trust—Mutual Funds (C)	$ 33	$ —	$ 4	$ 29	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (148)	$ 18	$ —	$ (153)	$ (13)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (A)	$ 4	$ —	$ —	$ —	$ 4
Rabbi Trust—Mutual Funds (C)	$ 57	$ —	$ 6	$ 51	$ —
Liabilities:					
Derivative Contracts:					
Energy Related Contracts (A)	$ (7)	$ —	$ —	$ —	$ (7)

(A) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual

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terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(B) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(C) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price (primarily Level 1). The Rabbi Trust equity index fund is valued based on quoted prices in an active market (Level 1).

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds and United States Treasury obligations or Federal Agency mortgage-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes, and issuer spreads (primarily Level 2). Short-term investments and certain commingled temporary investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield (primarily Level 2).

(D) For Non-Recourse Debt, see Fair Value Option discussion.

(E) Cash collateral netting represents collateral amounts netted against derivative assets and liabilities as permitted under the accounting guidance for Offsetting of Amounts Related to Certain Contracts.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

The following table provides detail surrounding significant Level 3 valuations, of which the most significant positions are electric swaps and electric load deals for Power and long-term electric capacity contracts and long-term natural gas supply contracts for PSE&G. For Power, in general, electric swaps are valued based on at least two pricing inputs, basis and underlying. To the extent the basis component is based on a single broker quote and is significant to the fair value of the electric swap, it is categorized as Level 3. The remaining balance of Power's Level 3 positions consist primarily of certain long-term electric capacity contracts, electric load deals in which load consumption may change hourly and certain long-term natural gas supply contracts. Long-term electric capacity contracts are measured at fair value using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. Electric load deals are fair valued using certain unobservable inputs, such as historic load variability. For Power and PSE&G, long-term gas supply contracts are measured at fair value using both actively traded pricing points as well as unobservable inputs such as gas prices beyond observable periods and long-term basis quotes and accordingly, the fair value measurements are classified in Level 3. For PSE&G, long-term electric capacity contracts are measured at fair value using both observable capacity prices and unobservable inputs consisting of forecasts of future long-term electric capacity prices and include adjustments for contingencies, such as litigation risk and plant construction risk. Accordingly, the fair value measurements are classified as Level 3.

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The table below discloses the significant unobservable inputs used in developing the fair value of these Level 3 positions:

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2012 Assets	Fair Value as of December 31, 2012 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ 7	$ (1)	Discounted cash flow	Power Basis	$0 - $10/MWh
Electricity	Electric Load Deals	1	(2)	Discounted cash flow	Historic Load Variability	-5% - +10%
Other	Various (A)	5	(1)			
Total Power		**$ 13**	**$ (4)**			
PSE&G						
Gas and Capacity	Forward Contracts (B)	$ 67	$ (107)	Discounted cash flow	Long-Term Gas Basis and Capacity Prices	(B)
Total PSE&G		**$ 67**	**$ (107)**			
Total PSEG		**$ 80**	**$ (111)**			

(A) Includes long-term electric capacity and long-term gas supply positions which are immaterial.

(B) Includes long-term gas supply and long-term electric capacity positions with various unobservable inputs. Significant unobservable inputs for the gas supply contracts include long-term basis prices in the range of $0 to $2/MMBTU of natural gas. Unobservable inputs for the long-term electric capacity contracts include forecasted capacity prices in the range of $100 to $400/MW day.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power and PSE&G are sellers, an increase in either the power basis or the load variability or the longer-term basis amounts would decrease the fair value. For long-term electric capacity contracts where Power or PSE&G are buyers, an increase in the capacity price would increase the fair value.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the years ended December 31, 2012 and 2011 follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2012

Description	Balance as of January 1, 2012	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales) (C)	Issuances (Settlements) (D)	Transfers In (Out) (E)	Balance as of December 31, 2012
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 21	$ 42	$ (37)	$ —	$ (57)	$ —	$ (31)
Non-Recourse Debt	$ (50)	$ 50	$ —	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 24	$ 42	$ —	$ —	$ (57)	$ —	$ 9
PSE&G							
Net Derivative Assets (Liabilities)	$ (3)	$ —	$ (37)	$ —	$ —	$ —	$ (40)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2011

Description	Balance as of January 1, 2011	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales) (C)	Issuances (Settlements) (D)	Transfers In (Out) (E)	Balance as of December 31, 2011
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 47	$ 22	$ (8)	$ 30	$ (37)	$ (33)	$ 21
NDT Fund	$ 8	$ —	$ —	$ —	$ —	$ (8)	$ —
Non-Recourse Debt	$ —	$ —	$ —	$ —	$ (50)	$ —	$ (50)
Power							
Net Derivative Assets (Liabilities)	$ 42	$ 22	$ —	$ 30	$ (37)	$ (33)	$ 24
NDT Fund	$ 8	$ —	$ —	$ —	$ —	$ (8)	$ —
PSE&G							
Net Derivative Assets (Liabilities)	$ 5	$ —	$ (8)	$ —	$ —	$ —	$ (3)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $42 million and $17 million in Operating Income in 2012 and 2011, $0 million and $2 million in OCI in 2012 and 2011, and $3 million in Income from Discontinued Operations in 2011. Of the $42 million in Operating Income in 2012, $(15) million is unrealized. Of the $17 million in Operating Income in 2011, $9 million is unrealized. Energy Holding's release from its obligations under the non-recourse debt is included in PSEG's Operating Income and is offset by the write-off of the related assets.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or OCI, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Includes $66 million in purchases and $(36) million in sales in 2011.

(D) Represents $(57) million in settlements for derivative contracts in 2012. Includes $(25) million in issuances and $(12) million in settlements for derivative contracts and includes $(50) million of issuances due to initial recognition of lessor notes resulting from rejection of the Dynegy leveraged leases in 2011. See Fair Value Option discussion.

(E) During the year ended December 31, 2012, there were no transfers among levels. During the year ended December 31, 2011, $ 8 million of assets in the NDT Fund were transferred from Level 3 to Level 2, due to more observable pricing for the underlying securities and $33 million of net derivative assets were transferred from Level 3 to Level 2 due to more available observable market data. The transfers were recognized as of the beginning of the first quarter and fourth quarter, respectively, (i.e. the quarters in which the transfers occurred), as per PSEG's policy.

As of December 31, 2012, PSEG carried $1.8 billion of net assets that are measured at fair value on a recurring basis, of which $ 31 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of December 31, 2011, PSEG carried $1.6 billion of net assets that are measured at fair value on a recurring basis, of which $ 29 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

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Fair Value Option

As of December 31, 2011, the effective date of the Dynegy lease rejections, the leases of the Roseton and Danskammer generation facilities were effectively terminated and no longer qualified for leveraged lease accounting under the guidance for leases. As the owner of the facilities, Energy Holdings was required to recognize the underlying assets and nonrecourse notes payable (Notes Payable) associated with these leases at their respective fair values on the effective date of the rejection. Energy Holdings elected to record the Notes Payable at fair value each reporting period under the fair value option in accordance with guidance for Financial Instruments. The fair value option permits the irrevocable fair value election for selected eligible financial assets or liabilities. Any changes in the fair value of the Notes Payable are included in earnings each period. The $ 550 million of contractual principal outstanding on the Notes Payable was valued at $ 50 million as of December 31, 2011. Energy Holdings elected this option to eliminate certain complexities in applying the effective interest method of amortization given the uncertain payment streams between the election date and the expected foreclosure date. There were no other debt instruments of this type eligible for the fair value option as of December 31, 2011. The $ 50 million fair value of these Notes Payable is included on PSEG's Consolidated Balance Sheet as of December 31, 2011. The fair values of the Notes Payable include significant internal assumptions based on expected cash flows and the fair values of the underlying collateral. Changes to projected capacity factors, capacity and energy prices, fuel costs and other required cash outflows could significantly impact the fair value of the collateral which would increase or decrease the fair value of the Notes. These Notes Payable are classified as Level 3 in the fair value hierarchy as a result of mainly unobservable inputs. As of the June 5, 2012 effective date of the amended settlement agreement, the Notes Payable and related assets were written off.

The table of fair value of debt is included in Note 14. Schedule of Consolidated Debt.

Non-recurring Fair Value Measurements

2011

During the fourth quarter of 2011, DH filed for protection under Chapter 11 of the U.S. Bankruptcy Code. As a result of the settlement agreement that was reached relating to the lease of electric generation facilities to subsidiaries of DH (See Note 8. Financing Receivables), Energy Holdings ceased leveraged lease accounting for the leased assets and recorded those generation facilities at their respective fair values totaling $50 million, which were carried as nonrecurring fair values as of December 31, 2011. The fair values of those generation facilities were determined based on a third party appraisal using significant assumptions including expectations of cash flows which are considered mainly unobservable inputs (Level 3).

Note 18. Stock Based Compensation

PSEG's 2004 Long-Term Incentive Plan (2004 LTIP) is a broad-based equity compensation program that provides for grants of various long-term incentive compensation awards, such as stock options, stock appreciation rights, performance units, restricted stock, restricted stock units, cash awards or any combination thereof. The types of long-term incentive awards that have been granted and remain outstanding under the 2004 LTIP are non-qualified options to purchase shares of PSEG's common stock, restricted stock awards, restricted stock unit awards and performance unit awards. The type of equity award that is granted and the details of that award may vary from time to time and is subject to the approval of the Organization and Compensation Committee of PSEG's Board of Directors (OCC), the plan's administrative committee.

The 2004 LTIP currently provides for the issuance of equity awards with respect to approximately 26 million shares of common stock. As of December 31, 2012, there were approximately 17 million shares available for future awards under the 2004 LTIP.

Stock Options

Under the 2004 LTIP, non-qualified options to acquire shares of PSEG common stock may be granted to officers and other key employees selected by the OCC. Option awards are granted with an exercise price equal to the market price of PSEG's common stock at the grant date. The options generally vest over four years of continuous service. Vesting schedules may be accelerated upon the occurrence of certain events, such as a change-in-control (unless substituted with an equity award of equal value), retirement, death or disability. Options are exercisable over a period of time designated by the OCC (but not prior to one year or longer than 10 years from the date of grant) and are subject to such other terms and conditions as the OCC determines. Payment by option holders upon exercise of an option may be made in cash or, with the consent of the OCC, by delivering previously acquired shares of PSEG common stock.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Restricted Stock

Under the 2004 LTIP, PSEG has granted restricted stock awards to officers and other key employees. These shares are subject to risk of forfeiture until vested by continued employment. Restricted stock generally vests annually over three or four years, but is considered outstanding at the time of grant, as the recipients are entitled to dividends and voting rights. Vesting may be accelerated upon certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

Restricted Stock Units

Under the 2004 LTIP, PSEG has granted restricted stock unit awards to officers and other key employees. These awards, which are bookkeeping entries only, are subject to risk of forfeiture until vested by continued employment. Until vested, the units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. The restricted stock unit grants for 2012 and 2011 generally vest at the end of three years. Vesting may be accelerated upon certain events such as change-in-control or death. Prior to 2011, restricted stock unit grants generally vested over four years.

Performance Units

Under the 2004 LTIP, performance units were granted to officers and other key employees, which provide for payment in shares of PSEG common stock based on achievement of certain financial goals over a three-year performance period. The payout varies from 0% to 200% of the number of performance units granted depending on PSEG's performance with respect to certain financial targets, including targets related to comparative performance against other companies in a peer group of energy companies. The performance units are credited with dividend equivalents in an amount equal to dividends paid on PSEG common stock up until the shares are distributed. Vesting may be pro-rated for the employee's service during the performance period as a result of certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

Stock-Based Compensation

All outstanding unvested stock options are being expensed based on their grant date fair values, which were determined using the Black-Scholes option-pricing model. Stock option awards are expensed on a tranche-specific basis over the requisite service period of the award. Ultimately, compensation expense for stock options is recognized for awards that vest.

PSEG recognizes compensation expense for restricted stock and restricted stock units over the vesting period based on the grant date fair market value of the shares, which is equal to the market price of PSEG's common stock on the date of the grant.

PSEG recognizes compensation expense for performance units based on the grant date fair values of the award, which were determined using the Monte Carlo model. The accrual of compensation cost was based on the probable achievement of the performance conditions, which result in a payout from 0% to 200% of the initial grant. The accrual during the year of grant is estimated at 100% of the original grant. The accrual may be adjusted for subsequent changes in the estimated or actual outcome.

	2012	2011	2010
		Millions	
Compensation Cost included in Operation and Maintenance Expense	$ 25	$ 23	$ 29
Income Tax Benefit Recognized in Consolidated Statement of Operations	$ 10	$ 10	$ 12

There was less than $1 million of excess tax benefits for 2012. The was $1 million of excess tax benefits included as financing cash flows on the Consolidated Statements of Cash Flow for each of the years ended December 31, 2011 and 2010, respectively.

PSEG recognizes compensation cost of awards issued over the shorter of the original vesting period or the period beginning on the date of grant and ending on the date an individual is eligible for retirement and the award vests.

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Stock Options

Changes in stock options for 2012 are summarized as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding as of January 1, 2012	3,272,300	$ 32.78		
Exercised	326,900	$ 20.10		
Outstanding as of December 31, 2012	**2,945,400**	**$ 34.19**	**5.3**	**$ 1,509,670**
Exercisable at December 31, 2012	2,750,325	$ 34.24	5.2	$ 1,506,268

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. There were no option grants in 2012, 2011 and 2010.

Activity for options exercised for the years ended December 31, 2012, 2011 and 2010 is shown below:

	2012	2011	2010
		Millions	
Total Intrinsic Value of Options Exercised	$ 4	$ 2	$ 1
Cash Received from Options Exercised	$ 7	$ 6	$ 3
Tax Benefit Realized from Options Exercised	$ 1	$ 1	$ 1

Less than one million options vested during each of the years ended December 31, 2012, 2011 and 2010. The total fair value of the stock options vested during the years ended December 31, 2012, 2011 and 2010 was $3 million, $5 million and $7 million, respectively.

As of December 31, 2012, there was approximately $1 million of unrecognized compensation cost related to stock options, which is to be recognized over a weighted average period of 0.5 years.

Restricted Stock

Changes in restricted stock for the year ended December 31, 2012 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2012	70,300	$ 32.83		
Vested	1,500	$ 44.44		
Non-vested as of December 31, 2012	**68,800**	**$ 32.57**	**0.2**	**$ 2,105,280**

There were no restricted stock awards granted in 2012, 2011 and 2010.

The total intrinsic value of restricted stock vested during the years ended December 31, 2012, 2011 and 2010 was less than $1 million, $1 million and $3 million, respectively.

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Restricted Stock Units

Changes in restricted stock units for the year ended December 31, 2012 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2012	648,551	$ 31.17		
Granted	345,440	$ 30.95		
Vested	125,838	$ 30.87		
Canceled/Forfeited	33,626	$ 31.24		
Non-vested as of December 31, 2012	**834,527**	**$ 31.12**	**1.2**	**$ 25,536,532**

The weighted average grant date fair value per share for restricted stock during the years ended December 31, 2012, 2011 and 2010 was $30.95, $32.03 and $31.13 per share, respectively.

The total intrinsic value of restricted stock units vested during the years ended December 31, 2012, 2011 and 2010 was $5 million, $7 million and $6 million, respectively.

As of December 31, 2012, there was approximately $9 million of unrecognized compensation cost related to the restricted stock units, which is expected to be recognized over a weighted average period of 1.0 year. Dividend equivalents units of 40,044 accrued on the restricted stock units during the year.

Performance Share Units

Changes in Performance Share Units for the year ended December 31, 2012 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2012	641,986	$ 35.13		
Granted	404,460	$ 31.25		
Vested	258,501	$ 36.35		
Canceled/Forfeited	37,952	$ 33.51		
Non-vested as of December 31, 2012	**749,993**	**$ 32.70**	**1.5**	**$ 22,949,786**

The weighted average grant date fair value per share for performance share units during the years ended December 31, 2012, 2011 and 2010 was $31.25, $35.33 and $34.29 per share, respectively.

The total intrinsic value of performance share units vested during the year ended December 31, 2012, 2011 and 2010 was $4 million, $9 million and $15 million, respectively.

As of December 31, 2012, there was approximately $13 million of unrecognized compensation cost related to the performance share units, which is expected to be recognized over a weighted average period of 1.0 year. Dividend equivalents units of 49,170 accrued on the performance share units during the year.

Outside Directors

Under the Directors Equity Plan, annually, on the first business day of May, each non-employee member of the Board of Directors is awarded stock units based on amount of annual compensation to be paid at the closing price of PSEG common stock on that date. Dividend equivalents are credited quarterly and distributions will commence upon the director leaving the Board.

The fair value of these awards is recorded as compensation expense in the Consolidated Statements of Operations. Compensation expense for the plan for each of the years ended December 31, 2012, 2011 and 2010 was approximately $1 million.

Employee Stock Purchase Plan (ESPP)

PSEG maintains an ESPP for all eligible employees of PSEG and its subsidiaries. Under the ESPP, shares of PSEG common stock may be purchased at 95% of the fair market value through payroll deductions. In any year, employees may purchase shares having a value not exceeding 10% of their base pay. During the years ended December 31, 2012, 2011 and 2010,

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employees purchased 191,572, 183,338 and 178,684 shares at an average price of $31.32, $30.69 and $30.32 per share, respectively. As of December 31, 2012, 3.6 million shares were available for future issuance under this plan.

Note 19. Other Income and Deductions

Other Income	Power	PSE&G	Other (A)	Consolidated Total
			Millions	
Year Ended December 31, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$ 194	$ —	$ —	$ 194
Allowance of Funds Used During Construction	—	23	—	23
Rabbi Trust Realized Gains, Interest and Dividends	2	4	5	11
Solar Loan Interest	—	18	—	18
Other	3	7	4	14
Total Other Income	**$ 199**	**$ 52**	**$ 9**	**$ 260**
Year Ended December 31, 2011				
NDT Fund Gains, Interest, Dividend and Other Income	$ 186	$ —	$ —	$ 186
Allowance of Funds Used During Construction	—	9	—	9
Solar Loan Interest	—	10	—	10
Other	4	6	5	15
Total Other Income	**$ 190**	**$ 25**	**$ 5**	**$ 220**
Year Ended December 31, 2010				
NDT Fund Gains, Interest, Dividend and Other Income	$ 159	$ —	$ —	$ 159
Allowance of Funds Used During Construction	—	5	—	5
Rabbi Trust Realized Gains	7	11	13	31
Solar Loan Interest	—	6	—	6
Other	4	4	12	20
Total Other Income	**$ 170**	**$ 26**	**$ 25**	**$ 221**

Other Deductions	Power	PSE&G	Other (A)	Consolidated Total
			Millions	
Year Ended December 31, 2012				
NDT Fund Realized Losses and Expense	$ 58	$ —	$ —	$ 58
Loss on Early Extinguishment of Debt	15	—	—	15
Other	17	5	3	25
Total Other Deductions	**$ 90**	**$ 5**	**$ 3**	**$ 98**
Year Ended December 31, 2011				
NDT Fund Realized Losses and Expense	$ 50	$ —	$ —	$ 50
Loss on Early Extinguishment of Debt	17	—	—	17
Other	12	4	2	18
Total Other Deductions	**$ 79**	**$ 4**	**$ 2**	**$ 85**
Year Ended December 31, 2010				
NDT Fund Realized Losses and Expense	$ 45	$ —	$ —	$ 45
Other	8	3	7	18
Total Other Deductions	**$ 53**	**$ 3**	**$ 7**	**$ 63**

(A) Other primarily consists of activity at PSEG (parent company), Energy Holdings and Services and intercompany eliminations.

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Note 20. Income Taxes

A reconciliation of reported income tax expense for PSEG with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

	Years Ended December 31,		
	2012	2011	2010
	Millions		
Net Income	$ 1,275	$ 1,503	$ 1,564
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax benefit	—	96	7
Income from Continuing Operations	1,275	1,407	1,557
Preferred Dividends	—	—	(1)
Income from Continuing Operations, excluding Preferred Dividends	$ 1,275	$ 1,407	$ 1,558
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ (204)	$ 258	$ (166)
State	(2)	32	157
Total Current	(206)	290	(9)
Deferred Expense:			
Federal	758	501	992
State	125	191	79
Total Deferred	883	692	1,071
Investment Tax Credit	59	(5)	(3)
Total Income Taxes	**$ 736**	**$ 977**	**$ 1,059**
Pre-Tax Income	$ 2,011	$ 2,384	$ 2,617
Tax Computed at Statutory Rate @ 35%	$ 704	$ 834	$ 916
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	115	146	154
Uncertain Tax Positions	4	19	30
Manufacturing Deduction	—	(15)	(24)
Nuclear Decommissioning Trust	10	14	10
Plant-Related Items	(5)	(6)	(3)
Tax Credits	(10)	(5)	(2)
Audit Settlement	(71)	—	—
Other	(11)	(10)	(22)
Sub-Total	32	143	143
Total Income Tax Provision	**$ 736**	**$ 977**	**$ 1,059**
Effective Income Tax Rate	36.6%	41.0%	40.5%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for PSEG:

	As of December 31,	
	2012	2011
	Millions	
Deferred Income Taxes		
Assets:		
Current (net)	$ 49	$ —
Noncurrent:		
Unrecovered Investment Tax Credit	$ 30	$ 15
Accumulated Other Comprehensive Income (Loss)	40	39
Cumulative Effect of a Change in Accounting Principle	11	11
OPEB	200	208
Cost of Removal	51	51
Contractual Liabilities & Environmental Costs	35	35
MTC	18	26
Related to Uncertain Tax Positions	75	104
Capital Loss	35	—
Other	82	44
Total Non-Current Assets	$ 577	$ 533
Total Assets	$ 626	$ 533
Liabilities:		
Current (net)	$ 72	$ 170
Noncurrent:		
Plant-Related Items	$ 4,685	$ 3,894
Nuclear Decommissioning	209	155
New Jersey Corporate Business Tax	343	180
Securitization	371	495
Leasing Activities	656	527
Partnership Activity	17	18
Conservation Costs	101	97
Pension Costs	180	129
AROs	297	302
Taxes Recoverable Through Future Rate (net)	165	158
Total Noncurrent Liabilities	$ 7,024	$ 5,955
Total Liabilities	$ 7,096	$ 6,125
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	**$ 49**	**$ —**
Net Current Deferred Income Tax Liability	**$ 72**	**$ 170**
Net Noncurrent Deferred Income Tax Liabilities	$ 6,447	$ 5,422
Investment Tax Credit (ITC)	95	36
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 6,542**	**$ 5,458**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for Power with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

	Years Ended December 31,		
	2012	2011	2010
	Millions		
Net Income	$ 647	$ 1,098	$ 1,143
Income (Loss) from Discontinued Operations, net of tax	—	96	7
Income from Continuing Operations	$ 647	$ 1,002	$ 1,136
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 83	$ 400	$ 12
State	53	40	127
Total Current	136	440	139
Deferred Expense:			
Federal	262	151	598
State	35	94	41
Total Deferred	297	245	639
Total Income Taxes	**$ 433**	**$ 685**	**$ 778**
Pre-Tax Income	$ 1,080	$ 1,687	$ 1,914
Tax Computed at Statutory Rate @ 35%	$ 378	$ 591	$ 670
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	55	87	109
Manufacturing Deduction	—	(15)	(24)
Nuclear Decommissioning Trust	10	14	10
Uncertain Tax Positions	(6)	11	10
Audit Settlement	(1)	—	—
Other	(3)	(3)	3
Sub-Total	55	94	108
Total Income Tax Provision	**$ 433**	**$ 685**	**$ 778**
Effective Income Tax Rate	40.1%	40.6%	40.6%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for Power:

	As of December 31,	
	2012	2011
	Millions	
Deferred Income Taxes		
Assets:		
Noncurrent:		
Cumulative Effect of a Change in Accounting Principle	$ 11	$ 11
Pension Costs	38	53
Accumulated Other Comprehensive Income (Loss)	40	39
Cost of Removal	51	51
Contractual Liabilities & Environmental Costs	35	35
Related to Uncertain Tax Positions	27	4
Capital Loss	12	—
Other	2	22
Total Noncurrent Assets	$ 216	$ 215
Total Assets	$ 216	$ 215
Liabilities:		
Current (net)	$ 16	$ 53
Noncurrent:		
Plant-Related Items	$ 1,253	$ 1,013
New Jersey Corporate Business Tax	28	7
Nuclear Decommissioning	209	155
AROs	297	302
Total Noncurrent Liabilities	$ 1,787	$ 1,477
Total Liabilities	$ 1,803	$ 1,530
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Liabilities	**$ 16**	**$ 53**
Net Noncurrent Deferred Income Tax Liabilities	$ 1,571	$ 1,262
Investment Tax Credit (ITC)	4	4
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 1,575**	**$ 1,266**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for PSE&G with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

	Years Ended December 31,		
	2012	**2011**	**2010**
	Millions		
Net Income	$ 528	$ 521	$ 358
Preferred Dividends	—	—	(1)
Income from Continuing Operations, excluding Preferred Dividends	$ 528	$ 521	$ 359
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ (217)	$ (225)	$ (211)
State	9	(6)	(1)
Total Current	(208)	(231)	(212)
Deferred Expense:			
Federal	409	483	384
State	83	92	63
Total Deferred	492	575	447
Investment Tax Credit	23	(4)	(3)
Total Income Taxes	**$ 307**	**$ 340**	**$ 232**
Pre-Tax Income	$ 835	$ 861	$ 591
Tax Computed at Statutory Rate @ 35%	$ 292	$ 301	$ 207
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	52	56	40
Uncertain Tax Positions	7	(1)	(1)
Plant-Related Items	(4)	(6)	(3)
Tax Credits	(3)	(4)	(2)
Audit Settlement	(31)	—	—
Other	(6)	(6)	(9)
Sub-Total	15	39	25
Total Income Tax Provision	**$ 307**	**$ 340**	**$ 232**
Effective Income Tax Rate	36.8%	39.5%	39.2%

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The following is an analysis of deferred income taxes for PSE&G:

	As of December 31,	
	2012	2011
	Millions	
Deferred Income Taxes		
Assets:		
Current (net)	$ 49	$ —
Noncurrent:		
Unrecovered ITC	$ 18	$ 10
OPEB	189	197
MTC	18	26
Related to Uncertain Tax Positions	15	30
Other	42	13
Total Noncurrent Assets	$ 282	$ 276
Total Assets	$ 331	$ 276
Liabilities:		
Current (net)	$ 60	$ 32
Noncurrent:		
Plant-Related Items	$ 3,374	$ 2,875
New Jersey Corporate Business Tax	253	146
Securitization	371	495
Conservation Costs	101	97
Pension Costs	189	151
Taxes Recoverable Through Future Rate (net)	165	158
Total Noncurrent Liabilities	$ 4,453	$ 3,922
Total Liabilities	$ 4,513	$ 3,954
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	**$ 49**	**$ —**
Net Current Deferred Income Tax Liability	**$ 60**	**$ 32**
Net Noncurrent Deferred Income Tax Liability	$ 4,171	$ 3,646
Investment Tax Credit (ITC)	52	29
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 4,223**	**$ 3,675**

As of December 31, 2012, PSE&G had New Jersey State income tax net operating loss (NOL) carryforwards of $1.5 billion, on which a deferred tax asset of $87 million was recorded, which will expire between 2031 and 2033. We believe that it is more-likely-than-not that the benefit from the state NOL carryforwards will be realized.

Each of PSEG, Power and PSE&G provide deferred taxes at the enacted statutory tax rate for all temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities irrespective of the treatment for rate-making purposes. Management believes that it is probable that the accumulated tax benefits that previously have been treated as a flow-through item to PSE&G customers will be recovered from or refunded to PSE&G's customers in the future. These amounts were determined using the enacted federal income tax rate of 35% and state income tax rate of 9%. For additional information, see Note 6. Regulatory Assets and Liabilities.

The Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 include various health care-related provisions which will go into effect over the next several years. One of the provisions eliminates the tax deductibility of retiree health care costs, to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage. Although this change does not take effect immediately, the accounting impact was required to be recognized when the legislation was signed. As a result, in the first quarter of 2010, PSEG recorded non-cash after tax charges of $9 million for income tax expense to establish the related deferred tax liabilities,

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primarily related to Power. There was no immediate impact on PSE&G's income tax expense or effective tax rate since the related amount of $78 million was deferred as a Regulatory Asset to be collected and amortized over future periods.

Two other tax provisions were enacted during 2010 that had a significant impact on PSEG's cash position. The Small Business Jobs Act of 2010 extended the tax deduction for 50% bonus depreciation through 2010 for qualified property. The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 is eligible for 50% bonus depreciation for tax purposes. On January 2, 2013, the President signed into law the American Taxpayer Relief Act of 2012 that further extends 50% bonus depreciation for property placed in service before January 1, 2014. These provisions contain rules which afford certain projects which have a long production period, the benefit of bonus depreciation. These provisions will also generate cash for PSEG through tax benefits related to accelerated depreciation, most of which was realized in 2011. These tax benefits would have otherwise been received over an estimated average 20 year period.

With respect to ITC, for financial statement periods including 2010 and 2011, the law provided an option to claim either a grant or the ITC. Accordingly, in those periods, the ITC was accounted for as a reduction of the book basis of the related assets as opposed to being recorded in tax expense. In 2012 the law changed and the grant option is no longer available; as such, the accumulated deferred ITC generated in 2012 was recorded as a noncurrent deferred tax liability, which was included in Deferred Income Taxes and ITC on PSEG's and PSE&G's Consolidated Balance Sheets as of December 31, 2012.

PSEG recorded the following amounts related to its unrecognized tax benefits, which was primarily comprised of amounts recorded for Power, PSE&G and Energy Holdings:

2012	PSEG	Power	PSE&G	Energy Holdings
			Millions	
Total Amount of Unrecognized Tax Benefits as of January 1, 2012	$ 825	$ 121	$ 113	$ 555
Increases as a Result of Positions Taken in a Prior Period	92	27	55	9
Decreases as a Result of Positions Taken in a Prior Period	(173)	(7)	(47)	(119)
Increases as a Result of Positions Taken during the Current Period	47	3	42	—
Decreases as a Result of Positions Taken during the Current Period	—	—	—	—
Decreases as a Result of Settlements with Taxing Authorities	(389)	(10)	—	(344)
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2012	$ 402	$ 134	$ 163	$ 101
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(264)	(93)	(133)	(35)
Regulatory Asset—Unrecognized Tax Benefits	(30)	—	(30)	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 108**	**$ 41**	**$ —**	**$ 66**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2011	PSEG	Power	PSE&G	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2011	$ 756	$ 101	$ 82	$ 539
Increases as a Result of Positions Taken in a Prior Period	58	24	14	17
Decreases as a Result of Positions Taken in a Prior Period	(22)	(9)	—	(12)
Increases as a Result of Positions Taken during the Current Period	37	8	18	11
Decreases as a Result of Positions Taken during the Current Period	(4)	(3)	(1)	—
Decreases as a Result of Settlements with Taxing Authorities	—	—	—	—
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2011	$ 825	$ 121	$ 113	$ 555
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(379)	(77)	(65)	(213)
Regulatory Asset—Unrecognized Tax Benefits	(20)	—	(20)	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 426**	**$ 44**	**$ 28**	**$ 342**

2010	PSEG	Power	PSE&G	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2010	$ 836	$ (42)	$ 35	$ 820
Increases as a Result of Positions Taken in a Prior Period	290	111	79	90
Decreases as a Result of Positions Taken in a Prior Period	(450)	(29)	(38)	(383)
Increases as a Result of Positions Taken during the Current Period	82	63	6	12
Decreases as a Result of Positions Taken during the Current Period	(2)	(2)	—	—
Decreases as a Result of Settlements with Taxing Authorities	—	—	—	—
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2010	$ 756	$ 101	$ 82	$ 539
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(332)	(67)	(38)	(204)
Regulatory Asset—Unrecognized Tax Benefits	(16)	—	(16)	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 408**	**$ 34**	**$ 28**	**$ 335**

On June 26, 2009, September 15, 2008 and December 17, 2007, PSEG made tax deposits with the IRS in the amount of $140 million, $80 million and $100 million, respectively, to defray potential interest costs associated with disputed tax assessments associated with certain lease investments (see Note 13. Commitments and Contingent Liabilities). The $320 million of deposits were fully refundable and were recorded in Current Accrued Taxes on PSEG's Consolidated Balance Sheets in the years in which the deposits were made, but are not reflected in the amounts shown above. On January 31, 2012, PSEG signed a specific matter closing agreement with the IRS regarding this matter. Based on this agreement, these deposits have been applied against tax and interest due pursuant to the closing agreement.

PSEG and its subsidiaries include all accrued interest and penalties related to uncertain tax positions required to be recorded, as income tax expense. Interest and penalties on uncertain tax positions were as follows:

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Interest and Penalties on Uncertain Tax Positions Years Ended December 31,		
	2012	2011	2010
	Millions		
Power	$ (2)	$ (11)	$ (17)
PSE&G	1	(24)	(20)
Energy Holdings	39	420	407
Other	—	10	9
Total	**$ 38**	**$ 395**	**$ 379**

It is reasonably possible that total unrecognized tax benefits will decrease within the next twelve months due to either agreements with various taxing authorities upon audit or the expiration of the Statute of Limitations. These potential decreases are as follows:

Possible Decrease in Total Unrecognized Tax Benefits including Interest	Over the next 12 Months
	Millions
PSEG	$ 75
Power	$ 5
PSE&G	$ —

As a result of a change in accounting method for the capitalization of indirect costs, PSEG reduced the net amount of its uncertain tax positions (including interest) by $97 million, approximately $43 million of which related to PSE&G. Pursuant to an agreement signed with the IRS on January 31, 2012, this matter is settled and there will be a resulting increase in uncertain tax positions within the next twelve months. These amounts are not included in the table above.

A description of income tax years that remain subject to examination by material jurisdictions, where an examination has not already concluded are:

	PSEG	Power	PSE&G
United States			
Federal	2007-2011	N/A	N/A
New Jersey	2006-2011	N/A	2006-2011
Pennsylvania	2001-2011	N/A	2000-2011
Connecticut	2002-2011	N/A	N/A
Texas	2007-2011	N/A	N/A
California	2003-2011	N/A	N/A
New York	2009-2011	2009-2011	N/A

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Note 21. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under our stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Years Ended December 31,					
	2012		2011		2010	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator:						
(Millions)						
Continuing Operations	$ 1,275	$ 1,275	$ 1,407	$ 1,407	$ 1,557	$ 1,557
Discontinued Operations	—	—	96	96	7	7
Net Income	**$ 1,275**	**$ 1,275**	**$ 1,503**	**$ 1,503**	**$ 1,564**	**$ 1,564**
EPS Denominator:						
(Thousands)						
Weighted Average Common Shares Outstanding	505,933	505,933	505,949	505,949	505,985	505,985
Effect of Stock Based Compensation Awards	—	1,153	—	1,033	—	1,060
Total Shares	**505,933**	**507,086**	**505,949**	**506,982**	**505,985**	**507,045**
EPS:						
Continuing Operations	$ 2.52	$ 2.51	$ 2.78	$ 2.77	$ 3.08	$ 3.07
Discontinued Operations	—	—	0.19	0.19	0.01	0.01
Net Income	**$ 2.52**	**$ 2.51**	**$ 2.97**	**$ 2.96**	**$ 3.09**	**$ 3.08**

There were approximately 1.8 million, 1.8 million and 1.9 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the years ended December 31, 2012, 2011 and 2010, respectively. No other stock options had an antidilutive effect for the years ended December 31, 2012, 2011 or 2010.

Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	**2012**	**2011**	**2010**
Per Share	$ 1.42	$ 1.37	$ 1.37
in Millions	$ 718	$ 693	$ 693

On February 19, 2013, PSEG's Board of Directors approved a $ 0.36 per share common stock dividend for the first quarter of 2013.

Note 22. Financial Information by Business Segment

Basis of Organization

PSEG's operating segments are Power, PSE&G and Energy Holdings. The operating segments were determined by management in accordance with GAAP —Disclosures about Segments of an Enterprise and Related Information. These segments were determined based on how management measures performance based on segment Net Income, as illustrated in the following table, and how it allocates resources to each business.

See Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies for additional information.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power

Power earns revenues by selling energy, capacity and ancillary services on a wholesale basis under contract to power marketers and to load serving entities and by bidding energy, capacity and ancillary services into the markets for these products. Power also enters into contracts for energy, capacity, FTRs, gas, emission allowances and other energy-related contracts to optimize the value of its portfolio of generating assets and its electric and gas supply obligations.

PSE&G

PSE&G earns revenues from its tariffs, under which it provides electric transmission and electric and gas distribution services to residential, commercial and industrial customers in New Jersey. The rates charged for electric transmission are regulated by the FERC while the rates charged for electric and gas distribution are regulated by the BPU. Revenues are also earned from several other activities such as sundry sales, the appliance service business, wholesale transmission services and other miscellaneous services.

Energy Holdings

Energy Holdings earns revenues from its solar generation projects and its portfolio of passive investments primarily consisting of domestic leveraged leases. Gains and losses on sales of the lease investments are typically recognized in revenues. Energy Holdings also has equity method generation projects. Earnings from these projects are presented below Operating Income.

Other

Other activities include amounts applicable to PSEG (parent corporation), Services and intercompany eliminations, primarily relating to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 23. Related-Party Transactions. The net losses primarily relate to financing and certain administrative and general costs.

	Power	PSE&G	Energy Holdings	Other	Consolidated Total
			Millions		
Year Ended December 31, 2012					
Operating Revenues	$ 4,865	$ 6,626	$ 113	$ (1,823)	$ 9,781
Depreciation and Amortization	237	778	19	20	1,054
Operating Income (Loss)	1,123	1,083	62	10	2,278
Income from Equity Method Investments	—	—	12	—	12
Interest Income	3	20	2	2	27
Interest Expense	134	295	1	(7)	423
Income (Loss) before Income Taxes	1,080	835	78	18	2,011
Income Tax Expense (Benefit)	433	307	(8)	4	736
Income (Loss) from Continuing Operations	647	528	86	14	1,275
Net Income (Loss)	647	528	86	14	1,275
Segment Earnings (Loss)	647	528	86	14	1,275
Gross Additions to Long-Lived Assets	$ 646	$ 1,770	$ 127	$ 31	$ 2,574
As of December 31, 2012					
Total Assets	$ 11,032	$ 19,223	$ 1,454	$ 16	$ 31,725
Investments in Equity Method Subsidiaries	$ 40	$ —	$ 94	$ —	$ 134

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	PSE&G	Energy Holdings	Other	Consolidated Total
			Millions		
Year Ended December 31, 2011					
Operating Revenues	$ 6,143	$ 7,326	$ (140)	$ (2,250)	$ 11,079
Depreciation and Amortization	224	719	15	18	976
Operating Income (Loss)	1,771	1,151	(197)	17	2,742
Income from Equity Method Investments	—	—	4	—	4
Interest Income	4	12	2	1	19
Interest Expense	175	310	3	(13)	475
Income (Loss) before Income Taxes	1,687	861	(193)	29	2,384
Income Tax Expense (Benefit)	685	340	(59)	11	977
Income (Loss) from Continuing Operations	1,002	521	(134)	18	1,407
Income from Discontinued Operations, net of tax	96	—	—	—	96
Net Income (Loss)	1,098	521	(134)	18	1,503
Segment Earnings (Loss)	1,098	521	(134)	18	1,503
Gross Additions to Long-Lived Assets	$ 757	$ 1,302	$ 4	$ 20	$ 2,083
As of December 31, 2011					
Total Assets	$ 11,087	$ 17,487	$ 1,888	$ (641)	$ 29,821
Investments in Equity Method Subsidiaries	$ 31	$ —	$ 106	$ —	$ 137

	Power	PSE&G	Energy Holdings	Other	Consolidated Total
			Millions		
Year Ended December 31, 2010					
Operating Revenues	$ 6,558	$ 7,869	$ 137	$ (2,771)	$ 11,793
Depreciation and Amortization	175	750	14	16	955
Operating Income (Loss)	1,963	886	81	7	2,937
Income from Equity Method Investments	—	—	4	—	4
Interest Income	3	7	2	8	20
Interest Expense	157	318	11	(14)	472
Income (Loss) before Income Taxes	1,914	591	86	25	2,616
Income Tax Expense (Benefit)	778	232	37	12	1,059
Income (Loss) from Continuing Operations	1,136	359	49	13	1,557
Income from Discontinued Operations, net of tax	7	—	—	—	7
Net Income (Loss)	1,143	359	49	13	1,564
Segment Earnings (Loss)	1,143	358	49	14	1,564
Gross Additions to Long-Lived Assets	$ 825	$ 1,257	$ 63	$ 15	$ 2,160
As of December 31, 2010					
Total Assets	$ 11,452	$ 16,873	$ 2,234	$ (650)	$ 29,909
Investments in Equity Method Subsidiaries	$ 25	$ —	$ 105	$ —	$ 130

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Note 23. Related-Party Transactions

The majority of the following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

Power

The financial statements for Power include transactions with related parties presented as follows:

Related Party Transactions	Years Ended December 31, 2012	2011	2010
		Millions	
Revenue from Affiliates:			
Billings to PSE&G through BGSS (A)	$ 987	$ 1,294	$ 1,591
Billings to PSE&G through BGS (A)	815	921	1,139
Total Revenue from Affiliates	**$ 1,802**	**$ 2,215**	**$ 2,730**
Expense Billings from Affiliates:			
Administrative Billings from Services (B)	$ (154)	$ (147)	$ (145)
Total Expense Billings from Affiliates	**$ (154)**	**$ (147)**	**$ (145)**

Related Party Transactions	Years Ended December 31, 2012	2011
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$ 238	$ 247
Receivables from PSE&G Related to Gas Supply Hedges for BGSS (A)	27	109
Receivable from (Payable to) Services (B)	(31)	(26)
Tax Receivable from (Payable to) PSEG (C)	111	58
Receivable from (Payable to) PSEG	(5)	(7)
Accounts Receivable (Payable)—Affiliated Companies, net	**$ 340**	**$ 381**
Short-Term Loan to (from) Affiliate (demand Note to (from) PSEG) (D)	**$ 574**	**$ 907**
Working Capital Advances to Services (E)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable (Payable) (C)	**$ (50)**	**$ (8)**

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related Party Transactions	Years Ended December 31, 2012	2011	2010
		Millions	
Expense Billings from Affiliates:			
Billings from Power through BGSS (A)	$ (987)	$ (1,294)	$ (1,591)
Billings from Power through BGS (A)	(815)	(921)	(1,139)
Administrative Billings from Services (B)	(230)	(210)	(206)
Total Expense Billings from Affiliates	**$ (2,032)**	**$ (2,425)**	**$ (2,936)**

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Related Party Transactions	Years Ended December 31, 2012	2011
	Millions	
Payable to Power through BGS and BGSS Contracts (A)	$ (238)	$ (247)
Payable to Power Related to Gas Supply Hedges for BGSS (A)	(27)	(109)
Payable to Power from SREC Liability (F)	(7)	(7)
Receivable from (Payable to) Services (B)	(65)	(56)
Tax Receivable from (Payable to) PSEG (C)	256	131
Receivable from (Payable to) PSEG	6	8
Receivable from Energy Holdings	2	—
Accounts Receivable (Payable)—Affiliated Companies, net	**$ (73)**	**$ (280)**
Working Capital Advances to Services (E)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Receivable (Payable) (C)	**$ (32)**	**$ (83)**

(A) PSE&G has a full requirements contract with Power to meet the supply requirements of default service gas customers. This long-term contract was for an initial period which extended through March 31, 2012 and continues on a year-to-year basis thereafter, unless terminated by either party with a one year notice. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to Power and PSE&G at cost. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

(E) Power and PSE&G have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on Power's and PSE&G's Consolidated Balance Sheets.

(F) In 2008, the BPU issued a decision that certain BGS suppliers will be reimbursed for the cost they incurred above $300 per Solar Renewable Energy Certificate (SREC) during the period June 1, 2008 through May 31, 2010. The BPU order further provided that the excess cost may be passed on to ratepayers. Following an appeal, on March 10, 2011, the New Jersey Supreme Court reversed and remanded the BPU's 2008 order. On May 1, 2012, the BPU reaffirmed its earlier decision and on December 19, 2012, approved a settlement that defines requirements for review and reimbursement of incremental SREC costs to certain BGS suppliers. PSE&G has estimated and accrued a total liability for the excess SREC cost of $17 million as of December 31, 2012 and 2011, including approximately $7 million for Power's share which is included in PSE&G's Accounts Payable—Affiliated Companies as of December 31, 2012 and 2011. Under current guidance, Power is unable to record the related intercompany receivable on its Consolidated Balance Sheet. As a result, PSE&G's liability to Power is not eliminated in consolidation and is included in Other Current Liabilities on PSEG's Consolidated Balance Sheet as of December 31, 2012 and 2011.

Note 24. Selected Quarterly Data (Unaudited)

The information shown in the following tables, in the opinion of PSEG, Power and PSE&G includes all adjustments, consisting only of normal recurring accruals, necessary to fairly present such amounts.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2012	2011	2012	2011	2012	2011	2012	2011
PSEG Consolidated:	Millions							
Operating Revenues	$ 2,875	$ 3,354	$ 2,098	$ 2,469	$ 2,402	$ 2,620	$ 2,406	$ 2,636
Operating Income	$ 783	$ 856	$ 433	$ 621	$ 594	$ 556	$ 468	$ 709
Income (Loss) from Continuing Operations	$ 493	$ 462	$ 211	$ 320	$ 347	$ 265	$ 224	$ 360
Income (Loss) from Discontinued Operations, including Gain (Loss) on Disposal, net of tax	$ —	$ 64	$ —	$ 3	$ —	$ 29	$ —	$ —
Net Income (Loss)	$ 493	$ 526	$ 211	$ 323	$ 347	$ 294	$ 224	$ 360
Earnings Per Share:								
Basic:								
Income (Loss) from Continuing Operations	$ 0.97	$ 0.91	$ 0.42	$ 0.63	$ 0.69	$ 0.52	$ 0.44	$ 0.71
Net Income (Loss)	$ 0.97	$ 1.04	$ 0.42	$ 0.63	$ 0.69	$ 0.58	$ 0.44	$ 0.71
Diluted:								
Income (Loss) from Continuing Operations	$ 0.97	$ 0.91	$ 0.42	$ 0.63	$ 0.68	$ 0.52	$ 0.44	$ 0.71
Net Income (Loss)	$ 0.97	$ 1.04	$ 0.42	$ 0.63	$ 0.68	$ 0.58	$ 0.44	$ 0.71
Weighted Average Common Shares Outstanding:								
Basic	506	506	506	506	506	506	506	506
Diluted	507	507	507	507	507	507	507	507

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2012	2011	2012	2011	2012	2011	2012	2011
Power:	Millions							
Operating Revenues	$ 1,561	$ 1,967	$ 985	$ 1,285	$ 1,038	$ 1,398	$ 1,281	$ 1,493
Operating Income	$ 441	$ 501	$ 196	$ 355	$ 267	$ 483	$ 219	$ 432
Income (Loss) from Continuing Operations	$ 253	$ 298	$ 104	$ 205	$ 181	$ 273	$ 109	$ 226
Income (Loss) from Discontinued Operations, including Gain (Loss) on Disposal, net of tax	$ —	$ 64	$ —	$ 3	$ —	$ 29	$ —	$ —
Net Income (Loss)	$ 253	$ 362	$ 104	$ 208	$ 181	$ 302	$ 109	$ 226

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2012	2011	2012	2011	2012	2011	2012	2011
PSE&G:	Millions							
Operating Revenues	$ 1,939	$ 2,306	$ 1,407	$ 1,571	$ 1,683	$ 1,841	$ 1,597	$ 1,608
Operating Income	$ 342	$ 350	$ 227	$ 252	$ 321	$ 328	$ 193	$ 221
Net Income (Loss)	$ 197	$ 163	$ 101	$ 105	$ 155	$ 154	$ 75	$ 99

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Note 25. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following table presents financial information for the guarantor subsidiaries as well as Power's non-guarantor subsidiaries as of December 31, 2012 and 2011 and for the years ended December 31, 2012, 2011 and 2010.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2012					
Operating Revenues	$ —	$ 6,238	$ 125	$ (1,498)	$ 4,865
Operating Expenses	7	5,118	115	(1,498)	3,742
Operating Income (Loss)	(7)	1,120	10	—	1,123
Equity Earnings (Losses) of Subsidiaries	688	(10)	—	(678)	—
Other Income	45	206	—	(52)	199
Other Deductions	(31)	(59)	—	—	(90)
Other-Than-Temporary Impairments	—	(18)	—	—	(18)
Interest Expense	(118)	(51)	(18)	53	(134)
Income Tax Benefit (Expense)	70	(501)	(2)	—	(433)
Net Income (Loss)	**$ 647**	**$ 687**	**$ (10)**	**$ (677)**	**$ 647**
Comprehensive Income (Loss)	**$ 595**	**$ 681**	**$ (10)**	**$ (671)**	**$ 595**
As of December 31, 2012					
Current Assets	$ 3,922	$ 8,084	$ 940	$ (10,712)	$ 2,234
Property, Plant and Equipment, net	80	5,988	950	—	7,018
Investment in Subsidiaries	4,317	733	—	(5,050)	—
Noncurrent Assets	201	1,660	60	(141)	1,780
Total Assets	**$ 8,520**	**$ 16,465**	**$ 1,950**	**$ (15,903)**	**$ 11,032**
Current Liabilities	$ 482	$ 10,187	$ 1,010	$ (10,712)	$ 967
Noncurrent Liabilities	559	1,960	207	(140)	2,586
Long-Term Debt	2,040	—	—	—	2,040
Member's Equity	5,439	4,318	733	(5,051)	5,439
Total Liabilities and Member's Equity	**$ 8,520**	**$ 16,465**	**$ 1,950**	**$ (15,903)**	**$ 11,032**
Year Ended December 31, 2012					
Net Cash Provided By (Used In) Operating Activities	$ 298	$ 1,562	$ (7)	$ (474)	$ 1,379
Net Cash Provided By (Used In) Investing Activities	$ 715	$ (1,206)	$ (27)	$ 170	$ (348)
Net Cash Provided By (Used In) Financing Activities	$ (1,013)	$ (361)	$ 33	$ 305	$ (1,036)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2011					
Operating Revenues	$ —	$ 7,452	$ 146	$ (1,455)	$ 6,143
Operating Expenses	5	5,673	150	(1,456)	4,372
Operating Income (Loss)	(5)	1,779	(4)	1	1,771
Equity Earnings (Losses) of Subsidiaries	1,175	92	—	(1,267)	—
Other Income	40	195	—	(45)	190
Other Deductions	(28)	(51)	—	—	(79)
Other-Than-Temporary Impairments	(1)	(19)	—	—	(20)
Interest Expense	(146)	(56)	(18)	45	(175)
Income Tax Benefit (Expense)	63	(762)	14	—	(685)
Income (Loss) on Discontinued Operations, net of Tax Benefit	—	—	97	(1)	96
Net Income (Loss)	**$ 1,098**	**$ 1,178**	**$ 89**	**$ (1,267)**	**$ 1,098**
Comprehensive Income (Loss)	**$ 917**	**$ 1,055**	**$ 89**	**$ (1,144)**	**$ 917**
As of December 31, 2011					
Current Assets	$ 4,311	$ 7,248	$ 951	$ (9,823)	$ 2,687
Property, Plant and Equipment, net	66	5,715	950	—	6,731
Investment in Subsidiaries	4,185	804	—	(4,989)	—
Noncurrent Assets	179	1,557	51	(118)	1,669
Total Assets	**$ 8,741**	**$ 15,324**	**$ 1,952**	**$ (14,930)**	**$ 11,087**
Current Liabilities	$ 172	$ 9,549	$ 1,003	$ (9,822)	$ 902
Noncurrent Liabilities	440	1,589	145	(118)	2,056
Long-Term Debt	2,685	—	—	—	2,685
Member's Equity	5,444	4,186	804	(4,990)	5,444
Total Liabilities and Member's Equity	**$ 8,741**	**$ 15,324**	**$ 1,952**	**$ (14,930)**	**$ 11,087**
Year Ended December 31, 2011					
Net Cash Provided By (Used In) Operating Activities	$ 609	$ 2,427	$ (284)	$ (940)	$ 1,812
Net Cash Provided By (Used In) Investing Activities	$ 596	$ (1,171)	$ 594	$ (597)	$ (578)
Net Cash Provided By (Used In) Financing Activities	$ (1,205)	$ (1,256)	$ (309)	$ 1,537	$ (1,233)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2010					
Operating Revenues	$ —	$ 7,746	$ 125	$ (1,313)	$ 6,558
Operating Expenses	9	5,760	139	(1,313)	4,595
Operating Income (Loss)	(9)	1,986	(14)	—	1,963
Equity Earnings (Losses) of Subsidiaries	1,182	(15)	—	(1,167)	—
Other Income	45	170	—	(45)	170
Other Deductions	(4)	(49)	—	—	(53)
Other-Than-Temporary Impairments	—	(9)	—	—	(9)
Interest Expense	(113)	(67)	(22)	45	(157)
Income Tax Benefit (Expense)	42	(834)	14	—	(778)
Income (Loss) on Discontinued Operations, net of Tax Benefit	—	—	7	—	7
Net Income (Loss)	**$ 1,143**	**$ 1,182**	**$ (15)**	**$ (1,167)**	**$ 1,143**
Comprehensive Income (Loss)	**$ 1,109**	**$ 1,130**	**$ (15)**	**$ (1,115)**	**$ 1,109**
Year Ended December 31, 2010					
Net Cash Provided By (Used In) Operating Activities	$ 467	$ 2,249	$ 28	$ (1,178)	$ 1,566
Net Cash Provided By (Used In) Investing Activities	$ (252)	$ (1,567)	$ (34)	$ 648	$ (1,205)
Net Cash Provided By (Used In) Financing Activities	$ (216)	$ (687)	$ (40)	$ 529	$ (414)

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, Power and PSE&G

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (Exchange Act) that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer and Chief Financial Officer of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the Chief Financial Officer and Chief Executive Officer of each respective company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The Chief Financial Officer and Chief Executive Officer of each company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, Power and PSE&G

We have conducted assessments of our internal control over financial reporting as of December 31, 2012, as required by Section 404 of the Sarbanes-Oxley Act, using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". Management's reports on PSEG's, Power's and PSE&G's internal control over financial reporting are included on pages 173, 174 and 175, respectively. The Independent Registered Public Accounting Firm's report with respect to the effectiveness of PSEG's internal control over financial reporting is included on page 176. Management has concluded that internal control over financial reporting is effective as of December 31, 2012.

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of their financial reporting. There have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2012 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSEG

Management of Public Service Enterprise Group (PSEG) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSEG's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSEG's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSEG are being made only in accordance with authorizations of PSEG's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSEG's assets that could have a material effect on the financial statements.

In connection with the preparation of PSEG's annual financial statements, management of PSEG has undertaken an assessment, which includes the design and operational effectiveness of PSEG's internal control over financial reporting using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSEG's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSEG's financial reporting and the preparation of its financial statements as of December 31, 2012 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2012.

PSEG's external auditors, Deloitte & Touche LLP, have audited PSEG's financial statements for the year ended December 31, 2012 included in this annual report on Form 10-K and, as part of that audit, have issued a report on the effectiveness of PSEG's internal control over financial reporting, a copy of which is included in this annual report on Form 10-K.

/S/ RALPH IZZO

Chief Executive Officer

/s/ CAROLINE DORSA

Chief Financial Officer
February 25, 2013

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—Power

Management of PSEG Power LLC (Power) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

Power's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of Power's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of Power are being made only in accordance with authorizations of Power's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Power's assets that could have a material effect on the financial statements.

In connection with the preparation of Power's annual financial statements, management of Power has undertaken an assessment, which includes the design and operational effectiveness of Power's internal control over financial reporting using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that Power's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of Power's financial reporting and the preparation of its financial statements as of December 31, 2012 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2012.

/s/ RALPH IZZO
Chief Executive Officer

/s/ CAROLINE DORSA
Chief Financial Officer

February 25, 2013

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSE&G

Management of Public Service Electric and Gas Company (PSE&G) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSE&G's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSE&G's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSE&G are being made only in accordance with authorizations of PSE&G's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSE&G's assets that could have a material effect on the financial statements.

In connection with the preparation of PSE&G's annual financial statements, management of PSE&G has undertaken an assessment, which includes the design and operational effectiveness of PSE&G's internal control over financial reporting using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSE&G's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSE&G's financial reporting and the preparation of its financial statements as of December 31, 2012 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2012.

/s/ RALPH IZZO

Chief Executive Officer

/s/ CAROLINE DORSA

Chief Financial Officer

February 25, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of

Public Service Enterprise Group Incorporated:

We have audited the internal control over financial reporting of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2012, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting-PSEG. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and consolidated financial statement schedule listed in the Index at Item 15(B)(a) as of and for the year ended December 31, 2012 of the Company and our report dated February 25, 2013 expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2013

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

PSEG

Name	Age as of December 31, 2012	Office	Effective Date First Elected to Present Position
Ralph Izzo	5 5	Chairman of the Board, President and Chief Executive Officer (PSEG)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Power)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (PSE&G)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Energy Holdings)	April 2007 to present
		Chairman of the Board, President and Chief Executive Officer (Services)	January 2010 to present
		Chairman of the Board and Chief Executive Officer (Services)	April 2007 to January 2010
		President and Chief Operating Officer (PSEG)	October 2006 to March 2007
Caroline Dorsa	53	Executive Vice President and Chief Financial Officer (PSEG)	April 2009 to present
		Executive Vice President and Chief Financial Officer (Power)	April 2009 to present
		Executive Vice President and Chief Financial Officer (PSE&G)	April 2009 to present
		Chief Financial Officer (Energy Holdings)	April 2009 to present
		Executive Vice President and Chief Financial Officer (Services)	April 2009 to present
		Senior Vice President, Global Human Health Strategy and Integration (Merck and Co., Inc.)	January 2008 to April 2009
		Senior Vice President and Chief Financial Officer (Gilead Sciences, Inc.)	November 2007 to January 2008
		Senior Vice President and Chief Financial Officer (Avaya, Inc.)	February 2007 to November 2007
William Levis	5 6	President and Chief Operating Officer (Power)	June 2007 to present
		President and Chief Nuclear Officer (Nuclear)	January 2007 to October 2008
Ralph LaRossa	49	President and Chief Operating Officer (PSE&G)	October 2006 to present

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Name	Age as of December 31, 2012	Office	Effective Date First Elected to Present Position
Derek M. DiRisio	48	Vice President and Controller (PSEG)	January 2007 to present
		Vice President and Controller (PSE&G)	January 2007 to present
		Vice President and Controller (Power)	January 2007 to present
		Vice President and Controller (Energy Holdings)	January 2007 to present
		Vice President and Controller (Services)	January 2007 to present
		Assistant Controller Enterprise (Services)	July 2004 to January 2007
Randall E. Mehrberg	57	President and Chief Operating Officer (Energy Holdings)	June 2009 to present
		Executive Vice President—Strategy and Development (Services)	April 2009 to present
		Executive Vice President—Planning and Strategy (Services)	September 2008 to April 2009
		Various positions, last being Executive Vice President, Chief Administrative Officer and Chief Legal Officer (Exelon Corporation)	2000 to June 2008
J.A. Bouknight, Jr.	68	Executive Vice President and General Counsel (PSEG)	January 2010 to present
		Executive Vice President and General Counsel (Power)	January 2010 to present
		Executive Vice President and General Counsel (PSE&G)	January 2010 to present
		Executive Vice President and General Counsel (Services)	January 2010 to present
		Partner, Steptoe & Johnson LLP	July 2008 to November 2009
		Executive Vice President and General Counsel (Edison International)	July 2005 to July 2008

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Directors

PSEG

The information required by Item 10 of Form 10-K with respect to (i) present directors of PSEG who are nominees for election as directors at PSEG's 2013 Annual Meeting of Stockholders, and (ii) compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth under the headings 'Election of Directors' and "Section 16(a) Beneficial Ownership Reporting Compliance" in PSEG's definitive Proxy Statement for such Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 8, 2013 and which information set forth under said heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Code of Ethics

Our Standards of Integrity (Standards) is a code of ethics applicable to us and our subsidiaries. The Standards are an integral part of our business conduct compliance program and embody our commitment to conduct operations in accordance with the highest legal and ethical standards. The Standards apply to all of our directors and employees (including Power's, PSE&G's,

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Energy Holdings' and Services' respective principal executive officer, principal financial officer, principal accounting officer or Controller and persons performing similar functions). Each such person is responsible for understanding and complying with the Standards. The Standards are posted on our website, www.pseg.com/info/investors/governance/document.jsp. We will send you a copy on request.

The Standards establish a set of common expectations for behavior to which each employee must adhere in dealings with investors, customers, fellow employees, competitors, vendors, government officials, the media and all others who may associate their words and actions with us. The Standards have been developed to provide reasonable assurance that, in conducting our business, employees behave ethically and in accordance with the law and do not take advantage of investors, regulators or customers through manipulation, abuse of confidential information or misrepresentation of material facts.

We will post on our website, www.pseg.com/info/investors/governance/document.jsp:

- Any amendment (other than one that is technical, administrative or non-substantive) that we adopt to our Standards; and
- Any grant by us of a waiver from the Standards that applies to any director, principal executive officer, principal financial officer, principal accounting officer or Controller, or persons performing similar functions, for us or our direct subsidiaries noted above, and that relates to any element enumerated by the SEC.

In 2012, we did not grant any waivers to the Standards.

ITEM 11. EXECUTIVE COMPENSATION

PSEG

The information required by Item 11 of Form 10-K is set forth in PSEG's definitive Proxy Statement for the 2013 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 8, 2013 and such information set forth under such heading is incorporated herein by this reference thereto.

Section 16 Beneficial Ownership Reporting Compliance

During 2012, none of our directors or executive officers was late in filing a Form 3, 4 or 5 in accordance with the requirements of Section 16(a) of the Securities Exchange Act of 1934, as amended, with regard to transactions involving our Common Stock, with the exception of Susan Tomasky, one of our Directors. Ms. Tomasky filed one late report on Form 3 to report any ownership by her of our Common Stock at the time of her election to the Board. At that time, Ms. Tomasky did not own any of our Common Stock.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDERS MATTERS

PSEG

The information required by Item 12 of Form 10-K with respect to directors, executive officers and certain beneficial owners is set forth under the heading "Security Ownership of Directors, Management and Certain Beneficial Owners" in PSEG's definitive Proxy Statement for the 2013 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 8, 2013, and such information set forth under such heading is incorporated herein by this reference thereto.

For information relating to securities authorized for issuance under equity compensation plans, see Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

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ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

PSEG

The information required by Item 13 of Form 10-K is set forth under the heading "Transactions with Related Persons" in PSEG's definitive Proxy Statement for the 2013 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 8, 2013 and such information set forth under such heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10K.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 of Form 10-K is set forth under the heading "Fees Billed to PSEG by Deloitte & Touche LLP for 2012 and 2011" in PSEG's definitive Proxy Statement for the 2013 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 8, 2013. Such information set forth under such heading is incorporated herein by this reference hereto.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(A) The following Financial Statements are filed as a part of this report:

a. Public Service Enterprise Group Incorporated's Consolidated Balance Sheets as of December 31, 2012 and 2011 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Stockholders' Equity for the three years ended December 31, 2012 on pages 74 through 79.

b. PSEG Power LLC's Consolidated Balance Sheets as of December 31, 2012 and 2011 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Capitalization and Member's Equity for the three years ended December 31, 2012 on pages 80 through 85.

c. Public Service Electric and Gas Company's Consolidated Balance Sheets as of December 31, 2012 and 2011 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Common Stockholders' Equity for the three years ended December 31, 2012 on pages 86 through 91.

(B) The following documents are filed as a part of this report:

a. PSEG's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2012 (page 189).

b. Power's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2012 (page 189).

c. PSE&G's Financial Statement Schedules:

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Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2012 (page 190).

Schedules other than those listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(C) The following documents are filed as part of this report:

LIST OF EXHIBITS:

a.	**PSEG:**
3a	Certificate of Incorporation Public Service Enterprise Group Incorporated [1]
3b	By-Laws of Public Service Enterprise Group Incorporated effective November 17, 2009 [2]
3c	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 23, 1987 [3]
3d	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 20, 2007 [4]
4a(1)	Indenture between Public Service Enterprise Group Incorporated and First Union National Bank (U.S. Bank National Association, successor), as Trustee, dated January 1, 1998 providing for Deferrable Interest Subordinated Debentures in Series (relating to Quarterly Preferred Securities)[5]
9	Inapplicable
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011 [6]
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees as amended May 31, 2011 [7]
10a(3)	Employment Agreement with William Levis dated December 8, 2006 [8]
10a(4)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011 [9]
10a(5)	Employee Stock Purchase Plan[10]
10a(6)	Deferred Compensation Plan for Directors, amended July 19, 2011 [11]
10a(7)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011 [75]
10a(8)	1989 Long-Term Incentive Plan, as amended[13]
10a(9)	2001 Long-Term Incentive Plan[14]
10a(10)	Senior Management Incentive Compensation Plan [15]
10a(11)	Amended and Restated Key Executive Severance Plan, amended effective December 17, 2012
10a(12)	Severance Agreement with Ralph Izzo dated December 16, 2008 [16]
10a(13)	Employment Agreement with Randall Mehrberg dated June 30, 2008 [17]
10a(14)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009 [18]
10a(15)	Stock Plan for Outside Directors, as amended [19]
10a(16)	Compensation Plan for Outside Directors [20]
10a(17)	2004 Long-Term Incentive Plan, amended effective December 1, 2009 [21]
10a(18)	Form of Advancement of Expenses Agreement with Outside Directors [22]
10a(19)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011 [76]
10a(20)	Employment Agreement with J.A. Bouknight dated August 26, 2009 [77]
10a(21)	Amendment to Employment Agreement with Randall Mehrberg, dated May 3, 2011 [72]
10a(22)	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011 [73]
10a(23)	Amendment to Employment Agreement with Randall Mehrberg, dated June 8, 2011 [74]
10a(24)	Amendment to Employment Agreement with William Levis, dated September 19, 2011 [12]

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LIST OF EXHIBITS:

10a(25)	Amendment to Employment Agreement with J.A. Bouknight dated November 19, 2012 (78)
11	Inapplicable
12	Computation of Ratios of Earnings to Fixed Charges
13	Inapplicable
16	Inapplicable
18	Inapplicable
21	Subsidiaries of the Registrant
22	Inapplicable
23	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934 (1934 Act)
31a	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32a	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
b.	**Power:**
3a	Certificate of Formation of PSEG Power LLC (23)
3b	PSEG Power LLC Limited Liability Company Agreement (24)
3c	Trust Agreement for PSEG Power Capital Trust I (25)
3d	Trust Agreement for PSEG Power Capital Trust II (26)
3e	Trust Agreement for PSEG Power Capital Trust III (27)
3f	Trust Agreement for PSEG Power Capital Trust IV (28)
3g	Trust Agreement for PSEG Power Capital Trust V (29)
4a	Indenture dated April 16, 2001 between and among PSEG Power, PSEG Fossil, PSEG Nuclear, PSEG Energy Resources & Trade and The Bank of New York Mellon and form of Subsidiary Guaranty included therein (30)
4b	First Supplemental Indenture, supplemental to Exhibit 4a, dated as of March 13, 2002 (31)
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011 (6)
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees, as amended May 31, 2011 (7)
10a(3)	Employment Agreement with William Levis dated December 8, 2006 (8)
10a(4)	Employee Stock Purchase Plan (10)
10a(5)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011 (75)
10a(6)	1989 Long-Term Incentive Plan, as amended (13)
10a(7)	2001 Long-Term Incentive Plan (14)
10a(8)	Senior Management Incentive Compensation Plan (15)

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LIST OF EXHIBITS:

10a(9)	Amended and Restated Key Executive Severance Plan, amended effective December 17, 2012
10a(10)	Severance Agreement with Ralph Izzo dated December 16, 2008 (16)
10a(11)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009 (18)
10a(12)	2004 Long-Term Incentive Plan, amended effective December 1, 2009 (21)
10a(19)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011 (76)
10a(20)	Employment Agreement with J.A. Bouknight dated August 26, 2009 (77)
10a(21)	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011 (73)
10a(22)	Amendment to Employment Agreement with William Levis, dated September 19, 2011 (12)
10a(23)	Amendment to Employment Agreement with J.A. Bouknight dated November 19, 2012 (78)
11	Inapplicable
12a	Computation of Ratio of Earnings to Fixed Charges
13	Inapplicable
16	Inapplicable
18	Inapplicable
19	Inapplicable
23a	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31b	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31c	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32b	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32c	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
c.	**PSE&G**
3a(1)	Restated Certificate of Incorporation of PSE&G (32)
3a(2)	Certificate of Amendment of Certificate of Restated Certificate of Incorporation of PSE&G filed February 18, 1987 with the State of New Jersey adopting limitations of liability provisions in accordance with an amendment to New Jersey Business Corporation Act (33)
3a(3)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed June 17, 1992 with the State of New Jersey, establishing the 7.44% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock (34)
3a(4)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed March 11, 1993 with the State of New Jersey, establishing the 5.97% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock (35)
3a(5)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed January 27, 1994 with the State of New Jersey, establishing the 6.92% Cumulative Preferred Stock ($100 Par) and the 6.75% Cumulative Preferred Stock ($25 Par) as a series of Preferred Stock (36)
3b(1)	By-Laws of PSE&G as in effect April 17, 2007 (37)

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LIST OF EXHIBITS:

4a(1)	Indenture between PSE&G and Fidelity Union Trust Company (now, Wachovia Bank, National Association), as Trustee, dated August 1, 1924[38], securing First and Refunding Mortgage Bond and Supplemental Indentures between PSE&G and U.S. Bank National Association, successor, as Trustee, supplemental to Exhibit 4a(1), dated as follows:
4a(2)	April 1, 1927[39]
4a(3)	June 1, 1937[40]
4a(4)	July 1, 1937[41]
4a(5)	December 19, 1939[42]
4a(6)	March 1, 1942[43]
4a(7)	June 1, 1991 (No. 1)[44]
4a(8)	July 1, 1993[45]
4a(9)	September 1, 1993[46]
4a(10)	February 1, 1994[47]
4a(11)	March 1, 1994 (No. 2)[48]
4a(12)	May 1, 1994[49]
4a(13)	October 1, 1994 (No. 2)[50]
4a(14)	January 1, 1996 (No. 1)[51]
4a(15)	January 1, 1996 (No. 2)[52]
4a(16)	May 1, 1998[53]
4a(17)	September 1, 2002[54]
4a(18)	August 1, 2003[55]
4a(19)	December 1, 2003 (No. 1)[56]
4a(20)	December 1, 2003 (No. 2)[57]
4a(21)	December 1, 2003 (No. 3)[58]
4a(22)	December 1, 2003 (No. 4)[59]
4a(23)	June 1, 2004[60]
4a(24)	August 1, 2004 (No. 1)[61]
4a(25)	August 1, 2004 (No. 2)[62]
4a(26)	August 1, 2004 (No. 3)[63]
4a(27)	August 1, 2004 (No. 4)[64]
4a(28)	April 1, 2007[65]
4a(29)	November 1, 2008[66]
4a(30)	November 1, 2009[67]
4a(31)	October 1, 2010[68]
4a(32)	May 1, 2012
4a(33)	June 1, 2012
4b	Indenture of Trust between PSE&G and Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor), as Trustee, providing for Secured medium-Term Notes dated July 1, 1993 [69]
4c	Indenture dated as of December 1, 2000 between Public Service Electric and Gas Company and First Union National Bank (U.S. Bank National Association, successor), as Trustee, providing for Senior Debt Securities [70]
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011 [6]
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees as amended May 31, 2011 [7]

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LIST OF EXHIBITS:

10a(3)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011 (9)
10a(4)	Employee Stock Purchase Plan (10)
10a(5)	Deferred Compensation Plan for Directors, amended July 19, 2011 (11)
10a(6)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011
10a(7)	1989 Long-Term Incentive Plan, as amended (13)
10a(8)	2001 Long-Term Incentive Plan (14)
10a(9)	Senior Management Incentive Compensation Plan (15)
10a(10)	Amended and Restated Key Executive Severance Plan, amended effective December 17, 2012
10a(11)	Severance Agreement with Ralph Izzo dated December 16, 2008 (16)
10a(12)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009 (18)
10a(13)	Stock Plan for Outside Directors, as amended (19)
10a(14)	Compensation Plan for Outside Directors (20)
10a(15)	2004 Long-Term Incentive Plan, amended effective December 1, 2009 (21)
10a(16)	Form of Advancement of Expenses Agreement with Outside Directors (71)
10a(19)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011
10a(20)	Employment Agreement with J.A. Bouknight dated August 26, 2009
10a(21)	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011 (73)
10a(22)	Amendment to Employment Agreement with J.A. Bouknight dated November 19, 2012 (78)
11	Inapplicable
12b	Computation of Ratios of Earnings to Fixed Charges
12c	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
13	Inapplicable
16	Inapplicable
18	Inapplicable
19	Inapplicable
23b	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31d	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31e	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32d	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32e	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document

(1) Filed as Exhibit 3.1a with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.

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(2) Filed as Exhibit 3.1 with Current Report on Form 8-K, File No. 001-09120 on November 18, 2009 and incorporated herein by this reference.
(3) Filed as Exhibit 3.1b with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.
(4) Filed as Exhibit 3.1c with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.
(5) Filed as Exhibit 4(f) with Quarterly Report on Form 10-Q for the quarter ended March 31, 1998, File No. 001-09120 on May 13, 1998 and incorporated herein by this reference.
(6) Filed as Exhibit 10.1 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(7) Filed as Exhibit 10.2 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(8) Filed as Exhibit 10a(4) with Annual Report on Form 10-K for the year ended December 31, 2007, File Nos. 001-09120 on February 28, 2008 and 000-49614, and incorporated herein by reference.
(9) Filed as Exhibit 10.5 with Quarterly Report on Form 10-Q for the quarter ended September 20, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(10) Filed with Registration Statement on Form S-8, File No. 333-106330 filed on June 20, 2003 and incorporated herein by this reference.
(11) Filed as Exhibit 10.6 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(12) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(13) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 001-09120, on November 4, 2002 and incorporated herein by this reference.
(14) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2000, File No. 001-09120, on March 6, 2001 and incorporated herein by this reference.
(15) Filed as Exhibit 10a(11) with Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-09120, on February 26, 2009 and incorporated herein by this reference.
(16) Filed as Exhibit 99 with Current Report on Form 8-K, File Nos. 001-09120, 000-49614 and 001-00973 on December 22, 2008 and incorporated herein by this reference.
(17) Filed as Exhibit 10a(14) with Annual Report on Form 10-K, for the year ended December 31, 2009, File No. 001-09120 on February 25, 2010 and incorporated herein by reference.
(18) Filed as Exhibit 10 with Quarterly Report on Form 10-Q, File No. 001-00973 on May 6, 2009 and incorporated herein by reference.
(19) Filed as Exhibit 10a(17) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(20) Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(21) Filed as Exhibit 10.1 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, File No. 001-09120 on May 5, 2011 and incorporated herein by this reference.
(22) Filed as Exhibit 10.1 with Current Report on Form 8-K, File No. 001-09120 on February 19, 2009 and incorporated herein by reference.
(23) Filed as Exhibit 3.1 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.
(24) Filed as Exhibit 3.2 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.
(25) Filed as Exhibit 3.6 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.
(26) Filed as Exhibit 3.7 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.
(27) Filed as Exhibit 3.8 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.
(28) Filed as Exhibit 3.9 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.
(29) Filed as Exhibit 3.10 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.
(30) Filed as Exhibit 4.1 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.

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(31) Filed as Exhibit 4.7 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, File No. 000-49614, on May 15, 2002 and incorporated herein by this reference.
(32) Filed as Exhibit 3(a) with Quarterly Report on Form 10-Q for the quarter ended June 30, 1986, File No. 001-00973, on August 28, 1986 and incorporated herein by this reference.
(33) Filed as Exhibit 3a(2) with Annual Report on Form 10-K for the year ended December 31, 1987, File No. 001-00973, on March 28, 1988 and incorporated herein by this reference.
(34) Filed as Exhibit 3a(3) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(35) Filed as Exhibit 3a(4) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(36) Filed as Exhibit 3a(5) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(37) Filed as Exhibit 3.3 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-00973 on May 4, 2007 and incorporated herein by this reference.
(38) Filed as Exhibit 4b(1) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(39) Filed as Exhibit 4b(2) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(40) Filed as Exhibit 4b(3) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(41) Filed as Exhibit 4b(4) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(42) Filed as Exhibit 4b(5) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(43) Filed as Exhibit 4b(6) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(44) Filed as Exhibit 4 on Form 8-A, File No. 001-00973 on June 1, 1991 and incorporated herein by this reference.
(45) Filed as Exhibit 4(i) on Form 8-A, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.
(46) Filed as Exhibit 4 on Form 8-A, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.
(47) Filed as Exhibit 4(i) on Form 8-A, File No. 001-00973 on February 4, 1994 and incorporated herein by this reference.
(48) Filed as Exhibit 4 on Form 8-A, File No. 001-00973 on March 15, 1994 and incorporated herein by this reference.
(49) Filed as Exhibit 4a(87) with Quarterly Report on Form 10-Q for the quarter ended September 30, 1994, File No. 001-00973 on November 8, 1994 and incorporated herein by this reference.
(50) Filed as Exhibit 4a(91) with Quarterly Report on Form 10-Q for the quarter ended September 30, 1994, File No. 001-00973, on November 8, 1994 and incorporated herein by this reference.
(51) Filed as Exhibit 4a(2) on Form 8-A, File No. 001-00973 on January 26, 1996 and incorporated herein by this reference.
(52) Filed as Exhibit 4a(3) on Form 8-A, File No. 001-00973 on January 26, 1996 and incorporated herein by this reference.
(53) Filed as Exhibit 4 on Form 8-A, File No. 001-00973 on May 15, 1998 and incorporated herein by this reference.
(54) Filed as Exhibit 4a(97) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-00973 on February 25, 2003 and incorporated herein by this reference.
(55) Filed as Exhibit 4a(98) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(56) Filed as Exhibit 4a(99) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(57) Filed as Exhibit 4a(100) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(58) Filed as Exhibit 4a(101) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(59) Filed as Exhibit 4a(102) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(60) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File No. 001-00973 on August 3, 2004 and incorporated herein by this reference.
(61) Filed as Exhibit 4a(25) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(62) Filed as Exhibit 4a(26) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(63) Filed as Exhibit 4a(27) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(64) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.

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(65) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-00973, on February 28, 2008 and incorporated herein by this reference.
(66) Filed as Exhibit 4a(29) with Annual Report on Form 10-K, for the year ended December 31, 2009, File No. 001-00973 on February 25, 2010 and incorporated herein by reference.
(67) Filed as Exhibit 4a(30) with Annual Report on Form 10-K, for the year ended December 31, 2009, File No. 001-00973 on February 25, 2010 and incorporated herein by reference.
(68) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2010, File No. 001-00973 on October 29, 2010 and incorporated herein by reference.
(69) Filed as Exhibit 4 with Current Report on Form 8-K, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.
(70) Filed as Exhibit 4.6 to Registration Statement on Form S-3, No. 333-76020 filed on December 27, 2001 and incorporated herein by this reference.
(71) Filed as Exhibit 10.2 with Current Report on Form 8-K, File No. 001-00973 on February 19, 2009 and incorporated herein by reference.
(72) Filed as Exhibit 10.2 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, File No. 001-09120 on May 5, 2011 and incorporated herein by this reference.
(73) Filed as Exhibit 10.1 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, File No. 001-09120 on August 3, 2011 and incorporated herein by this reference.
(74) Filed as Exhibit 10.2 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, File No. 001-09120 on August 3, 2011 and incorporated herein by this reference.
(75) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120 on February 27, 2012.
(76) Filed as Exhibit 10a(19) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120 on February 27, 2012.
(77) Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120 on February 27, 2012.
(78) Filed as Exhibit 10 with Current Report on Form 8-K, File No. 001-09120 on November 26, 2012 and incorporated herein by reference.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2012—December 31, 2010

Column A	Column B	Column C		Column D		Column E
		Additions				
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2012						
Allowance for Doubtful Accounts	$ 56	$ 96	$ —	$ 96	(A)	$ 56
Materials and Supplies Valuation Reserve	3	21	—	2	(B)	22
2011						
Allowance for Doubtful Accounts	$ 68	$ 102	$ —	$ 114	(A)	$ 56
Materials and Supplies Valuation Reserve	4	2	—	3	(B)	3
2010						
Allowance for Doubtful Accounts	$ 79	$ 99	$ —	$ 110	(A)	$ 68
Materials and Supplies Valuation Reserve	5	—	—	1	(B)	4
Other Valuation Allowances	8	—	—	8	(C)	—

(A) Accounts Receivable written off.

(B) Reduced reserve to appropriate level and to remove obsolete inventory.

(C) Valuation Allowance written off.

PSEG POWER LLC

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2012—December 31, 2010

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2012						
Materials and Supplies Valuation Reserve	$ 3	$ 21	$ —	$ 2	(A)	$ 22
2011						
Materials and Supplies Valuation Reserve	$ 4	$ 2	$ —	$ 3	(A)	$ 3
2010						
Materials and Supplies Valuation Reserve	$ 5	$ —	$ —	$ 1	(A)	$ 4

(A) Reduced reserve to appropriate level and to remove obsolete inventory.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2012—December 31, 2010

	Column A	Column B	Column C Additions		Column D		Column E
	Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
				Millions			
2012							
	Allowance for Doubtful Accounts	$ 56	$ 96	$ —	$ 96	(A)	$ 56
2011							
	Allowance for Doubtful Accounts	$ 67	$ 102	$ —	$ 113	(A)	$ 56
2010							
	Allowance for Doubtful Accounts	$ 78	$ 99	$ —	$ 110	(A)	$ 67

(A) Accounts Receivable written off.

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Term	Phrase/Description
Base load	Minimum amount of electric power delivered or required over a given period of time at a constant rate, this is the level of demand that is seen as a minimum during a 24-hour day
BGS	Basic Generation Service
	PSE&G is required to provide BGS for all customers in New Jersey who are not supplied by a TPS.
BGS-Fixed Price	Basic Generation Service-Fixed Price
	Seasonally adjusted fixed prices charged for a three-year term for electric supply service to smaller industrial and commercial customers and residential customers who are not supplied by a TPS
BGSS	Basic Gas Supply Service
	Mechanism approved by the BPU for NJ utilities to recover all commodity costs related to supplying gas to residential customers
BPU	New Jersey Board of Public Utilities
	Agency responsible for regulating public utilities doing business in New Jersey
Capacity	Amount of electricity that can be produced by a specific generating facility
CAA	Clean Air Act
Combined Cycle	A method of generation whereby electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity
Competition Act	Electric Discount and Energy Competition Act
	New Jersey's 1999 Electric Utility Restructuring Legislation
Congestion	Condition when the available capacity of a transmission line is being closely approached (or exceeded) by the electric power trying to go through it; at such times, alternative power line pathways (or local generators near the load) must be used instead
Distribution	The delivery of electricity to the retail customer's home, business or industrial facility through low voltage distribution lines
EDC	Electric Distribution Company
	A company that owns the power lines and equipment necessary to deliver purchased electricity to the end user.
Energy Holdings	PSEG Energy Holdings L.L.C.
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
	A private, not-for-profit organization whose primary purpose, as designated by the SEC, is to develop accounting standards for public companies in the U.S.
FERC	U.S. Federal Energy Regulatory Commission
Forward contracts	A customized, non-exchange traded contract in which the buyer is obligated to deliver a specified amount of a commodity with a predetermined price formula on a specified future date, at which time payment is due in full
GAAP	Generally Accepted Accounting Principles
	Standard framework of guidelines issued by the FASB for financial accounting used in the U.S.
GHG	Greenhouse gas emissions (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon) that trap the heat of the sun in the earth's atmosphere, increasing the mean global surface temperature of the earth

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Term	Phrase/Description
Grid	A system of interconnected power lines and generators that is managed so that the generators are dispatched as needed to meet the electricity requirements of the customers connected to the grid at various points
Hedging	Entering into a contract or transaction designed to reduce exposure to various risks, such as changes in market prices
Hope Creek	Hope Creek Nuclear Generating Station
ISO	Independent System Operator
	An independent, regulated entity established to manage a regional electric transmission system in a non-discriminatory manner and to help ensure the safety and reliability of the bulk of the power system
ITC	Investment Tax Credit
	A credit against income taxes, usually computed as a percent of the cost of investment in certain types of assets
LCAPP	Long-Term Capacity Agreement Pilot Program
	A program established in January 2011 which provides for up to 2,000 MW of subsidized base load or mid-merit electric power generation in New Jersey.
Lifeline Program	A New Jersey social program for utility assistance that offers $225 per year to persons who meet the eligibility requirements
Load	Amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of consumers.
MBR	Market Based Rates
	Electric service prices determined in an open market system of supply and demand under which the price is set solely by agreement as to what a buyer will pay and a seller will accept
MGP	Manufactured Gas Plant
NDT	Nuclear Decommissioning Trust
ISO-NE	New England Power Pool
	An ISO comprised of an alliance of approximately 100 utility companies who manage and direct all major energy production and transmission in the New England states
NJDEP	New Jersey Department of Environmental Protection
NRC	U.S. Nuclear Regulatory Commission
NUG	Non-Utility Generation
	Power produced by independent power producers, exempt wholesale generators and other companies that have been exempted from traditional utility regulation
OPEB	Other Postretirement Benefits
	Benefits other than pensions payable to former employees
Outage	The period during which a generating unit, transmission line, or other facility is out of service due to scheduled (planned) or unscheduled maintenance
Peach Bottom	Peach Bottom Atomic Power Station

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Term	Phrase/Description
PJM	PJM Interconnection, L.L.C.
	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 northeastern states and the District of Columbia
Power	PSEG Power LLC
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies
PRP	Potentially Responsible Parties
PSE&G	Public Service Electric and Gas Company
PSEG	Public Service Enterprise Group Incorporated
Renewable Energy	Energy derived from resources that are regenerative or that cannot be depleted (i.e. moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy)
Regulatory Asset	Costs deferred by a regulated utility company in accordance with SFAS 71
Regulatory Liability	Costs recognized by a regulated utility company in accordance with SFAS 71
RGGI	Regional Greenhouse Gas Initiative
	The first mandatory, market-based effort in the U. S. to reduce greenhouse gas emissions; states will sell emission allowances through auctions and invest proceeds in consumer benefits: energy efficiency, renewable energy, and other clean energy technologies
RMR	Reliability-Must-Run
	Designation of a power plant whose output is needed to maintain local reliability regardless of its operating cost or market price
RPM	Reliability Pricing Model
	A process for pricing generation capacity based on overall system reliability requirements; using multi-year forward auctions, participants could bid capacity in the form of generation, demand response, or transmission to meet reliability needs by location and/or an ISO market
Salem	Salem Nuclear Generating Station
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
Services	PSEG Services Corporation
Spill Act	New Jersey Spill Compensation and Control Act
TPS	Third Party Supplier
Transmission	The high-voltage wires and networks that move electricity through states and regions in large quantities -- from power plants where it is produced, to the distribution networks that deliver it to homes and businesses.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

By: /s/ RALPH IZZO
Ralph Izzo
Chairman of the Board, President and Chief Executive Officer

Date: February 25, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2013
/s/ CAROLINE DORSA **Caroline Dorsa**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2013
/s/ DEREK M. DIRISIO **Derek M. DiRisio**	Vice President and Controller (Principal Accounting Officer)	February 25, 2013
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper, Jr.**	Director	February 25, 2013
/s/ WILLIAM V. HICKEY **William V. Hickey**	Director	February 25, 2013
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 25, 2013
/s/ DAVID LILLEY **David Lilley**	Director	February 25, 2013
/s/ THOMAS A. RENYI **Thomas A. Renyi**	Director	February 25, 2013
/s/ HAK CHEOL SHIN **Hak Cheol Shin**	Director	February 25, 2013
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 25, 2013
/s/ SUSAN TOMASKY **Susan Tomasky**	Director	February 25, 2013
/s/ ALFRED W. ZOLLAR **Alfred W. Zollar**	Director	February 25, 2013

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PSEG POWER LLC

By: /s/ WILLIAM LEVIS
William Levis
President and
Chief Operating Officer

Date: February 25, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2013
/s/ CAROLINE DORSA **Caroline Dorsa**	Executive Vice President and Chief Financial Officer and Director (Principal Financial Officer)	February 25, 2013
/s/ DEREK M. DIRISIO **Derek M. DiRisio**	Vice President and Controller (Principal Accounting Officer)	February 25, 2013
/s/ J.A. BOUKNIGHT, JR. **J.A. Bouknight, Jr.**	Director	February 25, 2013
/s/ WILLIAM LEVIS **William Levis**	Director	February 25, 2013
/s/ RANDALL E. MEHRBERG **Randall E. Mehrberg**	Director	February 25, 2013
/s/ MARGARET M. PEGO **Margaret M. Pego**	Director	February 25, 2013

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By: /s/ RALPH LAROSSA

Ralph LaRossa
President and Chief Operating Officer

Date: February 25, 2013

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2013
/s/ CAROLINE DORSA **Caroline Dorsa**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2013
/s/ DEREK M. DIRISIO **Derek M. DiRisio**	Vice President and Controller (Principal Accounting Officer)	February 25, 2013
/s/ ALBERT R. GAMPER, JR. Albert R. Gamper Jr.	Director	February 25, 2013
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 25, 2013
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 25, 2013

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EXHIBIT INDEX

The following documents are filed as a part of this report:

a. PSEG:	
Exhibit 10a(11):	Amended and Restated Key Executive Severance Plan, amended effective December 17, 2012
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 21:	Subsidiaries of the Registrant
Exhibit 23:	Consent of Independent Registered Public Accounting Firm
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31a:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32a:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document
b. Power:	
Exhibit 10a(9):	Amended and Restated Key Executive Severance Plan, amended effective December 17, 2012
Exhibit 12a:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 23a:	Consent of Independent Registered Public Accounting Firm
Exhibit 31b:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31c:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32b:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32c:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document
c. PSE&G:	
Exhibit 4a(32):	Supplemental Indenture to Mortgage Indenture, dated May 1, 2012

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Exhibit 4a(33):	Supplemental Indenture to Mortgage Indenture, dated June 1, 2012
Exhibit 10a(10):	Amended and Restated Key Executive Severance Plan, amended effective December 17, 2012
Exhibit 12b:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12c:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
Exhibit 23b:	Consent of Independent Registered Public Accounting Firm
Exhibit 31d:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31e:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32d:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32e:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
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SUPPLEMENTAL MORTGAGE

Supplemental Indenture

Dated May 1, 2012

_____

SUPPLEMENTAL TO
FIRST AND REFUNDING MORTGAGE
DATED AUGUST 1, 1924

_____

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
TO
U.S. BANK NATIONAL ASSOCIATION
Trustee
21 South Street
Morristown, New Jersey 07960

_____

PROVIDING FOR THE ISSUE OF
$1,500,000,000 FIRST AND REFUNDING MORTGAGE BONDS,
MEDIUM-TERM NOTES SERIES H

RECORD IN MORTGAGE BOOK AND RETURN TO:
M. COURTNEY McCORMICK, ESQ.
80 PARK PLAZA, T5B
NEWARK, N.J. 07102-4194

Prepared by

(DONALD S. LEIBOWITZ, ESQ.)

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SUPPLEMENTAL INDENTURE, dated the 1st day of May 2012 for convenience of reference and effective from the time of execution and delivery hereof, between PUBLIC SERVICE ELECTRIC AND GAS COMPANY, a corporation organized under the laws of the State of New Jersey, hereinafter called the "Company", party of the first part, and U.S. Bank National Association, a national banking association organized under the laws of the United States of America, as successor Trustee to Wachovia Bank, National Association (previously known as Fidelity Union Trust Company) under the indenture dated August 1, 1924, below mentioned, hereinafter called the "Trustee", party of the second part.

WHEREAS, on July 25, 1924, the Company executed and delivered to FIDELITY UNION TRUST COMPANY, a certain indenture dated August 1, 1924 (hereinafter called the "Indenture") to secure and to provide for the issue of First and Refunding Mortgage Gold Bonds of the Company; and

WHEREAS, the Indenture has been recorded in the following counties of the State of New Jersey, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Atlantic	Clerk's	1955 of Mortgages	160
Bergen	Clerk's	94 of Chattel Mortgages	123 etc.
		693 of Mortgages	88 etc.
Burlington	Clerk's	52 of Chattel Mortgages	Folio 8 etc.
		177 of Mortgages	Folio 354 etc.
Camden	Register's	45 of Chattel Mortgages	184 etc.
		239 of Mortgages	1 etc.
Cumberland	Clerk's	786 of Mortgages	638 & c.
Essex	Register's	437 of Chattel Mortgages	1-48
		T-51 of Mortgages	341-392
Gloucester	Clerk's	34 of Chattel Mortgages	123 etc.
		142 of Mortgages	7 etc.
Hudson	Register's	453 of Chattel Mortgages	9 etc.
		1245 of Mortgages	484, etc.
Hunterdon	Clerk's	151 of Mortgages	344
Mercer	Clerk's	67 of Chattel Mortgages	1 etc.
		384 of Mortgages	1 etc.
Middlesex	Clerk's	113 of Chattel Mortgages	3 etc.
		437 of Mortgages	294 etc.
Monmouth	Clerk's	951 of Mortgages	291 & c.
Morris	Clerk's	N-3 of Chattel Mortgages	446 etc.
		F-10 of Mortgages	269 etc.
Ocean	Clerk's	1809 of Mortgages	40
Passaic	Register's	M-6 of Chattel Mortgages	178, etc.
		R-13 of Mortgages	268 etc.
Salem	Clerk's	267 of Mortgages	249 etc.
Somerset	Clerk's	46 of Chattel Mortgages	207 etc.
		N-10 of Mortgages	1 etc.
Sussex	Clerk's	123 of Mortgages	10 & c.
Union	Register's	9584 of Mortgages	259 etc.
Warren	Clerk's	124 of Mortgages	141 etc.

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and

WHEREAS, the Indenture has also been recorded in the following counties of the Commonwealth of Pennsylvania, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Adams	Recorder's	22 of Mortgages	105
Armstrong	Recorder's	208 of Mortgages	381
Bedford	Recorder's	90 of Mortgages	917
Blair	Recorder's	671 of Mortgages	430
Cambria	Recorder's	407 of Mortgages	352
Cumberland	Recorder's	500 of Mortgages	136
Franklin	Recorder's	285 of Mortgages	373
Huntington	Recorder's	128 of Mortgages	47
Indiana	Recorder's	197 of Mortgages	281
Lancaster	Recorder's	984 of Mortgages	1
Montgomery	Recorder's	5053 of Mortgages	1,221
Westmoreland	Recorder's	1281 of Mortgages	198
York	Recorder's	31-V of Mortgages	446

and

WHEREAS, the Indenture granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company, more fully set forth and described in the Indenture, then owned or which might thereafter be acquired by the Company; and

WHEREAS, the Company, by various supplemental indentures, supplemental to the Indenture, the last of which was dated October 1, 2010, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company acquired by it after the execution and delivery of the Indenture; and

WHEREAS, since the execution and delivery of said supplemental indenture dated October 1, 2010, the Company has acquired property which, in accordance with the provisions of the Indenture, is subject to the lien thereof and the Company desires to confirm such lien; and

WHEREAS, the Indenture has been amended or supplemented from time to time; and

WHEREAS, it is provided in the Indenture that no bonds other than those of the 5-1/2% Series due 1959 therein authorized may be issued thereunder unless a supplemental indenture providing for the issue of such additional bonds shall have been executed and delivered by the Company to the Trustee; and

WHEREAS, the Company is making provisions for the issuance and sale of its Secured Medium-Term Notes, Series H (the “Series H Notes”), to be issued under an Indenture of Trust (the “Note Indenture”) dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as Trustee (the “Note Trustee”); and

WHEREAS, such Note Indenture provides, among other things, for the pledge and delivery by the Company of a series of First and Refunding Mortgage Bonds of the Company to evidence the Company’s obligation to pay the principal and interest with respect to outstanding Series H Notes; and for such purpose and in order to service and secure payment of the principal and interest in respect of the Series H Notes, the Company desires to provide for the issue of $1,500,000,000 aggregate principal amount of bonds under the Indenture of a series to be designated as “First and Refunding Mortgage Bonds, Medium-Term Notes Series H” (hereinafter sometimes called “Bonds of the Medium-Term Notes Series H”); and

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WHEREAS, the text of the Bonds of the Medium-Term Notes Series H and of the certificate of authentication to be borne by the Bonds of the Medium-Term Notes Series H shall be substantially of the following tenor:

(FORM OF BOND)

This Bond is not transferable except as provided in the Indenture and in the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor trustee) as Trustee.

REGISTERED NUMBER R REGISTERED AMOUNT $1,500,000,000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
FIRST AND REFUNDING MORTGAGE BOND,
MEDIUM-TERM NOTES SERIES H

Public Service Electric and Gas Company (hereinafter called the "Company"), a corporation of the State of New Jersey, for value received, hereby promises to pay to The Bank of New York Mellon as successor trustee to The Chase Manhattan Bank (National Association)), under the Indenture of Trust dated as of July 1, 1993 between the Company and such trustee, or registered assigns, on the surrender hereof, the principal sum of One Billion Five Hundred Million Dollars, on May 1, 2047, and to pay interest thereon from the date hereof, at the rate of 10% per annum, and until payment of said principal sum, such interest to be payable May 1 and November 1 in each year; provided, however, that the Company shall receive certain credits against such obligations as set forth in the Supplemental Indenture dated May 1, 2012 referred to below.

Both the principal hereof and interest hereon shall be paid at the principal corporate trust office of U.S. Bank National Association in the City of Morristown, State of New Jersey, or (at the option of the registered owner) at the corporate trust office of any paying agent appointed by the Company, in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts; provided, however, that any such payments of principal and interest shall be subject to receipt of certain credits against such payment obligations as set forth in the Supplemental Indenture dated May 1, 2012 referred to below.

This Bond is one of the First and Refunding Mortgage Bonds of the Company issued and to be issued under and pursuant to, and all equally secured by, an indenture of mortgage or deed of trust dated August 1, 1924, as supplemented and amended by supplemental indentures thereto, including the Supplemental Indenture dated May 1, 2012, duly executed by the Company and U.S. Bank National Association as Trustee. This Bond is one of the Bonds of the Medium-Term Notes Series H, which series is limited to the aggregate principal amount of $1,500,000,000 and is issued pursuant to said Supplemental Indenture dated May 1, 2012. Reference is hereby made to said indenture and all supplements thereto for a specification of the principal amount of Bonds from time to time issuable thereunder, and for a description of the properties mortgaged and conveyed or assigned to said Trustee or its successors, the nature and extent of the security, and the rights of the holders of said Bonds and any coupons appurtenant thereto, and of the Trustee in respect of such security.

In and by said indenture, as amended and supplemented, it is provided that with the written approval of the Company and the Trustee, any of the provisions of said indenture may from time to time be eliminated or modified and other provisions may be added thereto provided the change does not alter the annual interest rate, redemption price or date, date of maturity or amount payable on maturity of any then outstanding Bond or conflict with the Trust Indenture Act of 1939 as then in effect, and provided the holders of 85% in principal amount of the Bonds secured by said indenture and then outstanding (including, if such change affects the Bonds of one or more series but less than all series then outstanding, a like percentage of the then outstanding Bonds of each series affected by such change, and excluding Bonds owned or controlled by the Company or by the parties owning at least 10% of the outstanding voting stock of the Company, as more fully specified in said indenture) consent in writing thereto, all as more fully set forth in said indenture, as amended and supplemented.

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First and Refunding Mortgage Bonds issuable under said indenture are issuable in series, and the Bonds of any series may be for varying principal amounts and in the form of coupon bonds and of registered bonds without coupons, and the Bonds of any one series may differ from the Bonds of any other series as to date, maturity, interest rate and otherwise, all as in said indenture provided and set forth. The Bonds of the Medium-Term Notes Series H, in which this Bond is included, are designated "First and Refunding Mortgage Bonds, Medium-Term Notes Series H".

In case of the happening of an event of default as specified in said indenture and said supplemental indenture dated March 1, 1942, the principal sum of the Bonds of this series may be declared or may become due and payable forthwith, in the manner and with the effect in said indenture provided.

The Bonds of this series are subject to redemption as provided in the Supplemental Indenture dated May 1, 2012.

This Bond is transferable, but only as provided in said indenture and the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as trustee, upon surrender hereof, by the registered owner in person or by attorney duly authorized in writing, at either of said offices where the principal hereof and interest hereon are payable; upon any such transfer a new fully registered Bond similar hereto will be issued to the transferee. This Bond may in like manner be exchanged for one or more new fully registered Bonds of the same series of other authorized denominations but of the same aggregate principal amount. No service charge shall be made for any such transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto. The Company and the Trustee hereunder and any paying agent may deem and treat the person in whose name this Bond is registered as the absolute owner hereof for the purpose of receiving payment of or on account of the principal hereof and the interest hereon and for all other purposes; and neither the Company nor the Trustee hereunder nor any paying agent shall be affected by any notice to the contrary.

The Bonds of this series are issuable only in fully registered form, in any denomination authorized by the Company.

No recourse under or upon any obligation, covenant or agreement contained in said indenture or in any indenture supplemental thereto, or in any Bond issued thereunder, or because of any indebtedness arising thereunder, shall be had against any incorporator, or against any past, present or future stockholder, officer, or director, as such, of the Company or of any successor corporation, either directly or through the Company or any successor corporation, under any rule of law, statute or constitutional provision or by the enforcement of any assessment or by any legal or equitable proceeding or otherwise, it being expressly agreed and understood that said indenture, any indenture supplemental thereto and the obligations issued thereunder, are solely corporate obligations, and that no personal liability whatever shall attach to, or be incurred by, such incorporators, stockholders, officers or directors, as such, of the Company, or of any successor corporation, or any of them, because of the incurring of the indebtedness thereby authorized, or under or by reason of any of the obligations, covenants or agreements contained in the indenture or in any indenture supplemental thereto or in any of the Bonds issued thereunder, or implied therefrom.

This Bond shall not be entitled to any security or benefit under said indenture, as amended and supplemented, and shall not become valid or obligatory for any purpose, until the certificate of authentication, hereon endorsed, shall have been signed by U.S. Bank National Association as Trustee, or by its successor in trust under said indenture.

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IN WITNESS WHEREOF, the Company has caused this Bond to be duly executed by its proper officers under its corporate seal.

Dated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY,

By. . . . . .
(Vice) President

(Seal)

Attest:

. . . . . .
(Assistant) Secretary

(FORM OF CERTIFICATE OF AUTHENTICATION)
CERTIFICATE OF AUTHENTICATION

This Bond is one of the Bonds of the series designated therein which is described in the within-mentioned indenture and supplemental indenture dated May 1, 2012, as secured thereby.

U.S. BANK NATIONAL ASSOCIATION, TRUSTEE,

By. . . . .

. . . . . .

Authorized Signatory

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WHEREAS, the execution and delivery of this supplemental indenture have been duly authorized by the Board of Directors of the Company; and

WHEREAS, the Company represents that all things necessary to make the bond of the series hereinafter described, when duly authenticated by the Trustee and issued by the Company, a valid, and legal obligation of the Company, and to make this supplemental indenture a valid and binding agreement supplemental to the Indenture, have been done and performed:

NOW, THEREFORE, THIS SUPPLEMENTAL INDENTURE WITNESSETH that the Company, in consideration of the premises and the execution and delivery by the Trustee of this supplemental indenture, and in pursuance of the covenants and agreements contained in the Indenture and for other good and valuable consideration, the receipt of which is hereby acknowledged, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over, and by these presents does grant, bargain, sell, alien, remise, release, convey, confirm, assign, transfer and set over unto the Trustee, its successors and assigns, forever, all the right, title and interest of the Company in and to all property of every kind and description (except cash, accounts and bills receivable and all merchandise bought, sold or manufactured for sale in the ordinary course of the Company's business, stocks, bonds or other corporate obligations or securities, other than such as are described in Part V of the Granting Clauses of the Indenture, not acquired with the proceeds of bonds secured by the Indenture, and except as in the Indenture and herein otherwise expressly excluded) acquired by the Company since the execution and delivery of the supplemental indenture dated October 1, 2010, subsequent to the Indenture (except any such property duly released from, or disposed of, free from the lien of the Indenture, in accordance with the provisions thereof) and all such property which at any time hereafter may be acquired by the Company;

All of which property it is intended shall be included in and granted by this supplemental indenture and covered by the lien of the Indenture as heretofore and hereby amended and supplemented;

UNDER AND SUBJECT to any encumbrances or mortgages existing on property acquired by the Company at the time of such acquisition and not heretofore discharged of record; and

SUBJECT also, to the exceptions, reservations and provisions in the Indenture and in this supplemental indenture recited, and to the liens, reservations, exceptions, limitations, conditions and restrictions imposed by or contained in the several deeds, grants, franchises and contracts or other instruments through which the Company acquired or claims title to the aforesaid property; and Subject, also, to the existing leases, to liens on easements or rights of way, to liens for taxes, assessments and governmental charges not in default or the payment of which is deferred, pending appeal or other contest by legal proceedings, pursuant to Section 4 of Article Five of the indenture, or the payment of which is deferred pending billing, transfer of title or final determination of amount, to easements for alleys, streets, highways, rights of way and railroads that may run across or encroach upon the said property, to joint pole and similar agreements, to undetermined liens and charges, if any, incidental to construction, and other encumbrances permitted by the indenture as heretofore and hereby amended and supplemented;

TO HAVE AND TO HOLD the property hereby conveyed or assigned, or intended to be conveyed or assigned, unto the Trustee, its successor or successors and assigns, forever;

IN TRUST, NEVERTHELESS, upon the terms, conditions and trusts set forth in the Indenture as heretofore and hereby amended and supplemented, to the end that the said property shall be subject to the lien of the Indenture as heretofore and hereby amended and supplemented, with the same force and effect as though said property had been included in the Granting Clauses of the Indenture at the time of the execution and delivery thereof;

AND THIS SUPPLEMENTAL INDENTURE FURTHER WITNESSETH that for the considerations aforesaid, it is hereby covenanted between the Company and the Trustee as follows:

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ARTICLE I.

BONDS OF THE MEDIUM-TERM NOTES SERIES H.

The series of bonds authorized by this supplemental indenture to be issued under and secured by the Indenture shall be designated "First and Refunding Mortgage Bonds, Medium-Term Notes Series H"; shall be limited to the aggregate principal amount of $1,500,000,000; shall be issued initially to the Note Trustee and shall mature and bear interest as set forth in the form of bond set forth herein; provided, however, that the Company shall receive certain credits against principal and interest as set forth in Section 3.01 hereof. The date of each Bond of the Medium-Term Notes Series H shall be the interest payment date next preceding the date of authentication, unless such date of authentication be an interest payment date, in which case the date shall be the date of authentication, or unless such date of authentication be prior to the first semi-annual interest payment date, in which case the date shall be May 1, 2012.

Bonds of the Medium-Term Notes Series H shall be issuable only in the form of fully registered bonds in any denomination authorized by the Company. Interest on the Bonds of the Medium-Term Notes Series H shall be payable semi-annually in arrears on May 1 and November 1 of each year, payable initially on November 1, 2012, subject to receipt of certain credits against principal and interest as set forth in Section 3.01 hereof and shall be payable as to both principal and interest in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts, at the principal corporate trust office of the Trustee, or at the corporate trust office of any paying agent appointed.

Bonds of the Medium-Term Notes Series H shall be transferable and exchangeable, but only as provided in the Indenture and the Note Indenture, upon surrender thereof for cancellation by the registered owner in person or by attorney duly authorized in writing at either of said offices. The Company hereby waives any right to make a charge for any transfer or exchange of Bonds of the Medium-Term Notes Series H, but the Company may require payment of a sum sufficient to cover any tax or any other governmental charge that may be imposed in relation thereto.

ARTICLE II.

REDEMPTION OF BONDS OF MEDIUM-TERM NOTES SERIES H.

SECTION 2.01. *Redemption—Redemption Price*. Bonds of the Medium-Term Notes Series H shall be subject to redemption prior to maturity under the conditions, and upon payment of the amounts as may be specified in the following conditions:

(a) at any time in whole or in part at the option of the Company upon receipt by the Trustee of written certification of the Company and of the Note Trustee that the principal amount of the Series H Notes then outstanding under the Note Indenture is not in excess of such principal amount of the Bonds of the Medium-Term Notes Series H as shall remain pledged to the Note Trustee after giving effect to such redemption; (b) at any time by the application of any proceeds of released property or other money held by the Trustee and which, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, are applied to the redemption of Bonds of the Medium-Term Notes Series H, upon payment of 100% of the principal amount thereof, together with interest accrued to the redemption date, provided that any such payment shall be subject to receipt by the Company of certain credits against such obligations as set forth in Section 3.01 hereof or (c) automatically upon failure to pay the principal of any Series H Notes then outstanding under the Note Indenture when due, on their stated maturity date or earlier redemption or repayment date, in a principal amount of Bonds of the Medium-Term Notes Series H equal to the principal amount of such Series H Notes, in each case, at a price equal to 100% of the principal amount thereof, together with accrued interest, if applicable.

SECTION 2.02. *Redemptions Pursuant to Section 4C of Article Eight of the Indenture*. If, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, any proceeds of released property or other money then held by the Trustee shall be applied to the redemption of the Bonds of the Medium-Term Notes Series H, the Trustee shall give at least 45 days prior written notice of such redemption to the Note Trustee whereupon on the date fixed for redemption such principal amount thereof

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as is equal to such proceeds shall be redeemed; provided that no such redemption shall be made unless the Trustee shall be in receipt of a written certification of the Company and the Note Trustee that a like principal amount of Series H Notes shall have been theretofore redeemed in accordance with the provisions of the Note Indenture. For purposes of determining which of the Company's First and Refunding Mortgage Bonds are subject to such mandatory redemption, the Mortgage Trustee shall consider the 10% stated annual interest rate of the Bonds of the Medium-Term Notes Series H, not the weighted average interest rate of outstanding Series H Notes. Bonds of said series so redeemed shall be cancelled.

SECTION 2.03. *Interest on Called Bonds to Cease.* Each Bond of the Medium-Term Notes Series H or portion thereof called for redemption under Section 2.02 hereof shall be due and payable at the office of the Note Trustee, as paying agent hereunder, at its redemption price and on the specified redemption date, anything herein or in such Bond to the contrary notwithstanding. From and after the date when each Bond of the Medium-Term Notes Series H or portion thereof shall be due and payable as aforesaid (unless upon said date the full amount due thereon shall not be held by the Note Trustee, as paying agent hereunder, and be immediately available for payment), all further interest shall cease to accrue on such bond or on such portion thereof, as the case may be.

SECTION 2.04. *Bonds Called in Part.* If only a portion of any Bond of the Medium-Term Notes Series H shall be called for redemption pursuant to Section 2.02 hereof, upon payment of the portion so called for redemption, the Note Trustee shall make an appropriate notation upon the Bond of the principal amount so redeemed.

SECTION 2.05. *Provisions of Indenture Not Applicable*. The provisions of Article Four of the Indenture, as amended and supplemented, shall not apply to the procedure for the exercise of any right of redemption reserved by the Company, or to any mandatory redemption provided, in this Article in respect of the Bonds of the Medium-Term Notes Series H. There shall be no sinking fund for the Bonds of the Medium-Term Notes Series H.

ARTICLE III.

CREDITS WITH RESPECT TO BONDS OF THE MEDIUM-TERM NOTES SERIES H.

SECTION 3.01. *Credits.* In addition to any other credit, payment or satisfaction to which the Company is entitled with respect to the Bonds of the Medium-Term Notes Series H, the Company shall be entitled to credits against amounts otherwise payable in respect of the Bonds of the Medium-Term Notes Series H in an amount corresponding to (i) the principal amount of any of the Company's Series H Notes issued under the Note Indenture surrendered to the Note Trustee by the Company, or purchased by the Note Trustee, for cancellation, (ii) the amount of money held by the Note Trustee and available and designated for the payment of principal or redemption price (exclusive of any premium) of, and/or interest on, the Series H Notes, regardless of the source of payment to the Note Trustee of such moneys and (iii) the amount by which principal of and interest due on the Bonds of the Medium-Term Notes Series H exceeds principal of and interest due on the Series H Notes. The Note Trustee shall make notation on such Bonds authorized hereby of any such credit.

SECTION 3.02. *Certificate of the Company.* A certificate of the Company signed by the President or any Vice President, and attested to by the Secretary or any Assistant Secretary, and consented to by the Note Trustee, stating that the Company is entitled to a credit under Section 3.01 hereof or that Bonds of the Medium-Term Notes Series H have been cancelled, and setting forth the basis therefor in reasonable detail, shall be conclusive evidence of such entitlement, and the Trustee shall accept such certificate as such evidence without further investigation or verification of the matters stated therein.

ARTICLE IV.

MISCELLANEOUS.

SECTION 4.01. *Authentication of Bonds of Medium-Term Notes Series H.* None of the Bonds of the Medium-Term Notes Series H, the issue of which is provided for by this supplemental indenture, shall be authenticated by or on behalf of the Trustee except in accordance with the provisions of the Indenture, as amended and supplemented, and this supplemental indenture, and upon compliance with the conditions in that behalf therein contained.

SECTION 4.02. *Additional Restrictions on Authentication of Additional Bonds Under Indenture.* The Company covenants that from and after the date of execution of this supplemental indenture no additional bonds (as defined in Section 1 of Article Two of the Indenture) shall be authenticated and delivered by the

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Trustee under Subdivision A of Section 4 of said Article Two on account of additions or improvements to the mortgaged property;

(1) unless the net earnings of the Company for the period required by Subdivision C of Section 6 of said Article Two shall have been at least twice the fixed charges (in lieu of 1-3/4 times such fixed charges, as required by said Subdivision C); and for the purpose of this condition (a) such fixed charges shall in each case include interest on the bonds applied for, notwithstanding the parenthetical provision contained in clause (4) of said Subdivision C, and (b) in computing such net earnings there shall be included in expenses of operation (under paragraph (c) of said Subdivision C) all charges against earnings for depreciation, renewals or replacements, and all certificates with respect to net earnings delivered to the Trustee in connection with any authentication of additional bonds under said Article Two shall so state; and (2) except to the extent of 60% (in lieu of 75% as permitted by Subdivision A of Section 7 of said Article Two) of the cost or fair value to the Company of the additions or improvements forming the basis for such authentication of additional bonds.

SECTION 4.03. *Restriction on Dividends.* The Company will not declare or pay any dividend on any shares of its common stock (other than dividends payable in shares of its common stock) or make any other distribution on any such shares, or purchase or otherwise acquire any such shares (except shares acquired without cost to the Company) whenever such action would reduce the earned surplus of the Company to an amount less than $10,000,000 or such lesser amount as may remain after deducting from said $10,000,000 all amounts appearing in the books of account of the Company on December 31, 1948, which shall thereafter, pursuant to any order or rule of any regulatory body entered after said date, be required to be removed, in whole or in part, from the books of account of the Company by charges to earned surplus.

SECTION 4.04. *Use of Facsimile Seal and Signatures.* The seal of the Company and any or all signatures of the officers of the Company upon any of the Bonds of the Medium-Term Notes Series H may be facsimiles.

SECTION 4.05. *Time for Making of Payment.* All payments of principal or redemption price of, and interest on, the Bonds of the Medium-Term Notes Series H shall be made either prior to the due date thereof or on the due date thereof in immediately available funds. In any case where the date of any such payment shall be a Saturday or Sunday or a legal holiday or a day on which banking institutions in the city of payment are authorized by law to close, then such payment need not be made on such date but may be made on the next succeeding business day with the same force and effect as if made on the due date, and no interest on such payment shall accrue for the period after such date.

SECTION 4.06. *Effective Period of Supplemental Indenture.* The preceding provisions of Articles I, II and III of this supplemental indenture shall remain in effect only so long as any of the Bonds of the Medium-Term Notes Series H shall remain outstanding.

SECTION 4.07. *Effect of Approval of Board of Public Utilities of the State of New Jersey.* The approval of the Board of Public Utilities of the State of New Jersey of the execution and delivery of these presents and of the issue of any Bond of the Medium-Term Notes Series H shall not be construed as approval of said Board of any other act, matter or thing which requires approval of said Board under the laws of the State of New Jersey.

SECTION 4.08. *Execution in Counterparts.* For the purpose of facilitating the recording hereof, this supplemental indenture has been executed in several counterparts, each of which shall be and shall be taken to be an original, and all collectively but one instrument.

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IN WITNESS WHEREOF, Public Service Electric and Gas Company, party hereto of the first part, after due corporate and other proceedings, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents and its corporate seal hereunto to be affixed and to be attested by the signature of its Secretary or an Assistant Secretary; and U.S. Bank National Association, as Trustee, party hereto of the second part, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents, and its corporate seal to be hereunto affixed and to be attested by the signature of its Secretary, Assistant Secretary, Vice President, or an Assistant Vice President. Executed and delivered this 4th day of May 2012.

Attest:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By /s/ B.D. Huntington
. . . . . .
B.D. Huntington
Vice President

Attest:
/s/ M.C. McCormick
. . . . . .
M.C. McCormick
Secretary

U.S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes
. . . . . .
N. Barnes
Vice President

Attest:
/s/ T.J. Brett
. . . . . .
T.J. Brett
Vice President

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STATE OF NEW JERSEY)

SS:)
COUNTY OF ESSEX)

Be it Remembered, that on this 4th day of May, 2012, before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared B.D. Huntington, who, I am satisfied, is a Vice President of Public Service Electric and Gas Company, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors, and that said corporation, the mortgagor, has received a true copy of said instrument.

/s/ Susan M. Costello
. . . . . .
Susan M. Costello
Notary Public of New Jersey
My Commission Expires March 26, 2017

STATE OF NEW JERSEY)

SS:)
COUNTY OF ESSEX)

Be it Remembered, that on this 4th day of May 2012 before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared N. Barnes, who, I am satisfied, is a Vice President of U.S. Bank National Association, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, and that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors.

/s/ Melody A. Simpson
.....
Melody A. Simpson
Notary Public of New Jersey
My Commission Expires March 1, 2016

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CERTIFICATE OF RESIDENCE

U.S. Bank National Association, Mortgagee and Trustee within named, hereby certifies that its precise residence is 21 South Street, Morristown, New Jersey 07960.

U.S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes

. . . . . .

N. Barnes
Vice President

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SUPPLEMENTAL MORTGAGE

Supplemental Indenture

Dated June 1, 2012

SUPPLEMENTAL TO
FIRST AND REFUNDING MORTGAGE
DATED AUGUST 1, 1924

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
TO
U.S. BANK NATIONAL ASSOCIATION
Trustee
21 South Street
Morristown, New Jersey 07960

PROVIDING FOR THE ISSUE OF
FIRST AND REFUNDING MORTGAGE BONDS,
POLLUTION CONTROL SERIES AG

RECORD IN MORTGAGE BOOK AND RETURN TO:
M. COURTNEY McCORMICK, ESQ.
80 PARK PLAZA, T5B
P.O. BOX 570
NEWARK, N.J. 07101

This instrument prepared by
(EDWARD C. FEDAK, ESQ.)

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SUPPLEMENTAL INDENTURE, dated the 1st day of June, 2012, for convenience of reference and effective from the time of execution and delivery hereof, between PUBLIC SERVICE ELECTRIC AND GAS COMPANY, a corporation organized under the laws of the State of New Jersey, hereinafter called the "Company", party of the first part, and U.S. BANK NATIONAL ASSOCIATION, a national banking association organized under the laws of the United States of America, as successor Trustee under the indenture dated August 1, 1924, below mentioned, hereinafter called the "Trustee", party of the second part.

WHEREAS, on July 25, 1924, the Company executed and delivered to Fidelity Union Trust Company (U S. Bank National Association, successor trustee), a certain indenture dated August 1, 1924 (hereinafter called the "Indenture"), to secure and to provide for the issue of First and Refunding Mortgage Gold Bonds of the Company; and

WHEREAS, the Indenture has been recorded in the following counties of the State of New Jersey, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Atlantic	Clerk's	1955 of Mortgages	160
Bergen	Clerk's	94 of Chattel Mortgages	123 etc.
		693 of Mortgages	88 etc.
Burlington	Clerk's	52 of Chattel Mortgages	Folio 8 etc.
		177 of Mortgages	Folio 354 etc.
Camden	Register's	45 of Chattel Mortgages	184 etc.
		239 of Mortgages	1 etc.
Cumberland	Clerk's	786 of Mortgages	638 & c.
Essex	Register's	437 of Chattel Mortgages	1-48
		T-51 of Mortgages	341-392
Gloucester	Clerk's	34 of Chattel Mortgages	123 etc.
		142 of Mortgages	7 etc.
Hudson	Register's	453 of Chattel Mortgages	9 etc.
		1245 of Mortgages	484, etc.
Hunterdon	Clerk's	151 of Mortgages	344
Mercer	Clerk's	67 of Chattel Mortgages	1 etc.
		384 of Mortgages	1 etc.
Middlesex	Clerk's	113 of Chattel Mortgages	3 etc.
		437 of Mortgages	294 etc.
Monmouth	Clerk's	951 of Mortgages	291 & c.
Morris	Clerk's	N-3 of Chattel Mortgages	446 etc.
		F-10 of Mortgages	269 etc.
Ocean	Clerk's	1809 of Mortgages	40
Passaic	Register's	M-6 of Chattel Mortgages	178, etc.
		R-13 of Mortgages	268 etc.
Salem	Clerk's	267 of Mortgages	249 etc.
Somerset	Clerk's	46 of Chattel Mortgages	207 etc.
		N-10 of Mortgages	1 etc.
Sussex	Clerk's	123 of Mortgages	10 & c.
Union	Register's	9584 of Mortgages	259 etc.
Warren	Clerk's	124 of Mortgages	141 etc.

and

WHEREAS, the Indenture has also been recorded in the following counties of the Commonwealth of Pennsylvania, in the offices, and therein in the books and at the pages, as follows:

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County	Office	Book Number	Page Number
Adams	Recorder's	22 of Mortgages	105
Armstrong	Recorder's	208 of Mortgages	381
Bedford	Recorder's	90 of Mortgages	917
Blair	Recorder's	671 of Mortgages	430
Cambria	Recorder's	407 of Mortgages	352
Cumberland	Recorder's	500 of Mortgages	136
Franklin	Recorder's	285 of Mortgages	373
Huntington	Recorder's	128 of Mortgages	47
Indiana	Recorder's	197 of Mortgages	281
Lancaster	Recorder's	984 of Mortgages	1
Montgomery	Recorder's	5053 of Mortgages	1,221
Westmoreland	Recorder's	1281 of Mortgages	198
York	Recorder's	31-V of Mortgages	446

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and

WHEREAS, the Indenture granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company, more fully set forth and described in the Indenture, then owned or which might thereafter be acquired by the Company; and

WHEREAS, the Company, by various supplemental indentures, supplemental to the Indenture, the last of which was dated May 1, 2012, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company acquired by it after the execution and delivery of the Indenture; and

WHEREAS, since the execution and delivery of said supplemental indenture dated May 1, 2012, the Company has acquired property which, in accordance with the provisions of the Indenture, is subject to the lien thereof and the Company desires to confirm such lien; and

WHEREAS, the Indenture has been amended or supplemented from time to time; and

WHEREAS, it is provided in the Indenture that no bonds other than those of the 5 1/2% Series due 1959 therein authorized may be issued thereunder unless a supplemental indenture providing for the issue of such additional bonds shall have been executed and delivered by the Company to the Trustee; and

WHEREAS, The Pollution Control Financing Authority of Salem County (the "Authority") has previously issued and sold $50,000,000 aggregate principal amount of its Pollution Control Revenue Bonds, 1994 Series A (Public Service Electric and Gas Company Project) (the "1994 Authority Bonds") to finance the acquisition and construction by the Company of certain pollution control facilities at the Hope Creek Generating Station located in Lower Alloways Creek Township, Salem County, New Jersey (such generating station being sometimes referred to herein as the "Plant" and the pollution control facilities being sometimes referred to herein as the "Project"); and

WHEREAS, the ownership and operation of the Plant and the Project has been transferred by the Company to its affiliate, PSEG Nuclear LLC ("PSEG Nuclear"); and

WHEREAS, the Authority is making provision for the issuance and sale of its Pollution Control Revenue Refunding Bonds, 2012 Series A (Public Service Electric and Gas Company Project) (the "2012 Authority Bonds") to provide a portion of the funds for the refunding and redemption of the 1994 Authority Bonds; and

WHEREAS, the 2012 Authority Bonds are to be issued under a Trust Indenture to be dated as of June 1, 2012 (the "Authority Indenture") between the Authority and U.S. Bank National Association, as trustee (the "Authority Trustee"); and

WHEREAS, the Company will enter into a Pollution Control Facilities Loan Agreement dated as of June 1, 2012 (the "Agreement") with the Authority providing, among other things, for the loan by the Authority to the Company of funds to provide a portion of the funds for the refunding and redemption of the 1994 Authority Bonds, and for the issuance by the Company to the Authority Trustee, as assignee of the Authority, of First and Refunding Mortgage Bonds of the Company to evidence the Company's obligation to repay said loan, and for such purposes the Company desires to provide for the issue of $50,000,000 aggregate principal amount of bonds secured by the Indenture of a series to be designated as "First and Refunding Mortgage Bonds, Pollution Control Series AG" (hereinafter sometimes called "Pollution Control Series AG"); and

WHEREAS, the text of the bonds of the Pollution Control Series AG and of the certificate of authentication to be borne by the bonds of the Pollution Control Series AG shall be substantially of the following tenor:

[FORM OF BOND]

This Bond is not transferable except as provided in the Trust Indenture dated as of June 1, 2012 between The Pollution Control Financing Authority of Salem County and U.S. Bank National Association, as Trustee (the "Authority Indenture"). Capitalized terms used herein, not otherwise expressly defined herein, shall have the meanings ascribed to them in the Authority Indenture.

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REGISTERED REGISTERED
NUMBER AMOUNT
R- $50,000,000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
FIRST AND REFUNDING MORTGAGE BOND,
POLLUTION CONTROL SERIES AG

Public Service Electric and Gas Company (hereinafter called the "Company"), a corporation of the State of New Jersey, for value received, hereby promises to pay to U.S. Bank National Association, as trustee under the Authority Indenture, or registered assigns, the principal sum of Fifty Million Dollars, on April 1, 2046, and to pay interest thereon from the date hereof, at the rate of 15.0% per annum, and until payment of said principal sum, provided, however, that the Company shall receive certain credits against such obligations to the extent that interest payable by the Authority from time to time for the Authority's Pollution Control Revenue Refunding Bonds, 2012 Series A (Public Service Electric and Gas Company Project) (the "2012 Authority Bonds") issued pursuant to the Authority Indenture is less than interest calculated pursuant to the foregoing rate. Such interest to be payable at such times and in such manner as interest is payable on the 2012 Authority Bonds.

Both the principal hereof and interest hereon shall be paid at the corporate trust office of U.S. Bank National Association in the City of Morristown, State of New Jersey, or at the corporate trust office of any paying agent appointed by the Company, in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts.

This Bond is one of the First and Refunding Mortgage Bonds of the Company issued and to be issued under and pursuant to, and all equally secured by, an indenture of mortgage or deed of trust dated August 1, 1924, between the Company and U.S. Bank National Association, a national banking association, as successor Trustee, as supplemented and amended by the supplemental indentures thereto, including the supplemental indenture dated June 1, 2012. This Bond is one of the Bonds of the Pollution Control Series AG, which series is limited to the aggregate principal amount of $50,000,000 and is issued pursuant to said supplemental indenture dated June 1, 2012. Reference is hereby made to said indenture and all supplements thereto for a specification of the principal amount of Bonds from time to time issuable thereunder, and for a description of the properties mortgaged and conveyed or assigned to said Trustee or its successors, the nature and extent of the security, and the rights of the holders of said Bonds and any coupons appurtenant thereto, and of the Trustee in respect of such security.

In and by said indenture, as amended and supplemented, it is provided that with the written approval of the Company and the Trustee, any of the provisions of said indenture may from time to time be eliminated or modified and other provisions may be added thereto provided the change does not alter the annual interest rate, interest payment dates, redemption price or date, date of maturity or amount payable on maturity of any then outstanding Bond or conflict with the Trust Indenture Act of 1939 as then in effect, and provided the holders of 85% in principal amount of the Bonds secured by said indenture and then outstanding (including, if such change affects the Bonds of one or more series but less than all series then outstanding, a like percentage of the then outstanding Bonds of each series affected by such change, and excluding Bonds owned or controlled by the Company or by the parties owning at least 10% of the outstanding voting stock of the Company, as more fully specified in said indenture) consent in writing thereto, all as more fully set forth in said indenture, as amended and supplemented.

First and Refunding Mortgage Bonds issuable under said indenture are issuable in series, and the Bonds of any series may be for varying principal amounts and in the form of coupon Bonds and of registered Bonds without coupons, and the Bonds of any one series may differ from the Bonds of any other series as to date, maturity, interest rate and otherwise, all as in said indenture provided and set forth. The Bonds of the Pollution Control Series AG, in which this Bond is included, are designated "First and Refunding Mortgage Bonds, Pollution Control Series AG".

In case of the happening of an event of default as specified in said indenture and in the supplemental indenture dated March 1, 1942 supplemental thereto, the principal sum of the Bonds of this issue may be declared or may become due and payable forthwith, in the manner and with the effect in said indenture provided.

The Bonds of this series are subject to redemption as provided in said supplemental indenture dated June 1, 2012.

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This Bond is transferable, but only as provided in the Authority Indenture upon surrender hereof, by the registered owner in person or by attorney duly authorized in writing, at the office of the Trustee; upon any such transfer a new Bond similar hereto will be issued to the transferee. No service charge shall be made for any such transfer, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto. The Company and the Trustee and any paying agent may deem and treat the person in whose name this Bond is registered as the absolute owner hereof for the purpose of receiving payment of or on account of the principal hereof and the interest hereon and for all other purposes; and neither the Company nor the Trustee nor any paying agent shall be affected by any notice to the contrary.

The Bonds of this series are issuable only in fully registered form, in any denomination authorized by the Company.

No recourse under or upon any obligation, covenant or agreement contained in said indenture or in any indenture supplemental thereto, or in any Bond or coupon issued thereunder, or because of any indebtedness arising thereunder, shall be had against any incorporator, or against any past, present or future stockholder, officer or director, as such, of the Company or of any successor corporation, either directly or through the Company or any successor corporation, under any rule of law, statute or constitutional provision or by the enforcement of any assessment or by any legal or equitable proceeding or otherwise; it being expressly agreed and understood that said indenture, any indenture supplemental thereto and the obligations issued thereunder, are solely corporate obligations, and that no personal liability whatever shall attach to, or be incurred by, such incorporators, stockholders, officers or directors, as such, of the Company, or of any successor corporation, or any of them, because of the incurring of the indebtedness thereby authorized, or under or by reason of any of the obligations, covenants or agreements contained in the indenture or in any indenture supplemental thereto or in any of the Bonds or coupons issued thereunder, or implied therefrom.

This Bond shall not be entitled to any security or benefit under said indenture, as amended and supplemented, and shall not become valid or obligatory for any purpose, until the certificate of authentication, hereon endorsed, shall have been signed by U.S. Bank National Association, as Trustee, or by its successor in trust under said indenture.

IN WITNESS WHEREOF, the Company has caused this Bond to be duly executed by its proper officers under its corporate seal.

Dated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY,

By. . . . . .
(Vice) President

(Seal)

Attest:

. . . . . .
(Assistant) Secretary

[FORM OF CERTIFICATE OF AUTHENTICATION]
CERTIFICATE OF AUTHENTICATION

This Bond is one of the Bonds of the series designated therein which are described in the within-mentioned indenture and supplemental indenture dated June 1, 2012, as secured thereby.

U.S. BANK NATIONAL ASSOCIATION, TRUSTEE,

By. . . . . Authorized Signatory

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WHEREAS, the execution and delivery of this supplemental indenture have been duly authorized by the Board of Directors of the Company; and

WHEREAS, the Company represents that all things necessary to make the bonds of the Pollution Control Series AG hereinafter described, when duly authenticated by the Trustee and issued by the Company, valid, binding and legal obligations of the Company, and to make this supplemental indenture a valid and binding agreement supplemental to the Indenture, have been done and performed:

NOW, THEREFORE, THIS SUPPLEMENTAL INDENTURE WITNESSETH that the Company, in consideration of the premises and the execution and delivery by the Trustee of this supplemental indenture, and in pursuance of the covenants and agreements contained in the Indenture and for other good and valuable consideration, the receipt of which is hereby acknowledged, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over, and by these presents does grant, bargain, sell, alien, remise, release, convey, confirm, assign, transfer and set over unto the Trustee, its successors and assigns, forever, all the right, title and interest of the Company in and to all property of every kind and description (except cash, accounts and bills receivable and all merchandise bought, sold or manufactured for sale in the ordinary course of the Company's business, stocks, bonds or other corporate obligations or securities, other than such as are described in Part V of the Granting Clauses of the Indenture, not acquired with the proceeds of bonds secured by the Indenture, and except as in the Indenture and herein otherwise expressly excluded) acquired by the Company since the execution and delivery of the supplemental indenture dated May 1, 2012, supplemental to the Indenture (except any such property duly released from, or disposed of free from, the lien of the Indenture, in accordance with the provisions thereof) and all such property which at any time hereafter may be acquired by the Company;

All of which property it is intended shall be included in and granted by this supplemental indenture and covered by the lien of the Indenture as heretofore and hereby amended and supplemented;

UNDER AND SUBJECT to any encumbrances or mortgages existing on property acquired by the Company at the time of such acquisition and not heretofore discharged of record; and

SUBJECT, also, to the exceptions, reservations and provisions in the Indenture and in this supplemental indenture recited, and to the liens, reservations, exceptions, limitations, conditions and restrictions imposed by or contained in the several deeds, grants, franchises and contracts or other instruments through which the Company acquired or claims title to the aforesaid property; and subject, also, to existing leases, to liens on easements or rights of way, to liens for taxes, assessments and governmental charges not in default or the payment of which is deferred, pending appeal or other contest by legal proceedings, pursuant to Section 4 of Article Five of the Indenture, or the payment of which is deferred pending billing, transfer of title or final determination of amount, to easements for alleys, streets, highways, rights of way and railroads that may run across or encroach upon the said property, to joint pole and similar agreements, to undetermined liens and charges, if any, incidental to construction, and other encumbrances permitted by the Indenture as heretofore and hereby amended and supplemented;

TO HAVE AND TO HOLD the property hereby conveyed or assigned, or intended to be conveyed or assigned, unto the Trustee, its successor or successors and assigns, forever;

IN TRUST, NEVERTHELESS, upon the terms, conditions and trusts set forth in the Indenture as heretofore and hereby amended and supplemented, to the end that the said property shall be subject to the lien of the Indenture as heretofore and hereby amended and supplemented, with the same force and effect as though said property had been included in the Granting Clauses of the Indenture at the time of the execution and delivery thereof;

AND THIS SUPPLEMENTAL INDENTURE FURTHER WITNESSETH that for the considerations aforesaid, it is hereby

covenanted between the Company and the Trustee as follows: ARTICLE I.

BONDS OF THE POLLUTION CONTROL SERIES AG.

The series of bonds authorized by this supplemental indenture to be issued under and secured by the Indenture shall be designated "First and Refunding Mortgage Bonds, Pollution Control Series AG"; shall be limited to the aggregate principal amount of $50,000,000; shall be issued initially to the Authority Trustee, as assignee of the

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Authority, to evidence the Company's obligation to repay the loan to refinance a portion of the costs of the Project made pursuant to the Pollution Control Facilities Loan Agreement; and shall mature and bear interest as set forth in the form of bond hereinbefore described; provided, however, that the Company shall receive certain credits against principal and interest obligations as set forth in Section 3.01 hereof. The date of each bond of the Pollution Control Series AG shall be the interest payment date next preceding the date of authentication, unless such date of authentication be an interest payment date, in which case the date shall be the date of authentication, or unless such date of authentication be prior to the first interest payment date, in which case the date shall be June 1, 2012.

Bonds of the Pollution Control Series AG shall be issued as fully registered bonds in any denomination authorized by the Company. Interest on bonds of the Pollution Control Series AG shall be payable at such time and in such manner as interest is payable on the 2012 Authority Bonds, subject to certain credits against principal and interest as set forth in Section 3.01 hereof and shall be payable as to both principal and interest in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts, at the principal office of the Trustee, or at the corporate trust office of any paying agent appointed by the Company.

Bonds of the Pollution Control Series AG shall be transferable (but only as provided in the Authority Indenture) upon surrender thereof for cancellation by the registered owner in person or by attorney duly authorized in writing at said office of the Trustee.

The Company hereby waives any right to make a charge for any transfer of bonds of the Pollution Control Series AG, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto.

ARTICLE II.

REDEMPTION OF BONDS—POLLUTION CONTROL SERIES AG.

SECTION 2.01. *Redemption—Redemption Prices.* Bonds of the Pollution Control Series AG shall be subject to redemption prior to maturity, under the conditions and upon the payment of the amounts specified in the following subsections, together, in each case, with interest accrued to the redemption date:

(a) At the option of the Company:

(i) whenever the Interest Rate Mode for the 2012 Authority Bonds is the Daily Rate, the Weekly Rate, or the Semi-Annual Rate ,in whole or in part on any date, at a redemption price of 100% of the principal amount thereof;

(ii) whenever the Interest Rate Mode for the 2012 Authority Bonds is the Commercial Paper Rate, in whole or in part, at a redemption price of 100% of the principal amount thereof on the Interest Payment Date for each Commercial Paper Rate Period for a 2012 Authority Bond or Bonds, such redemption to be in the same principal amount of such 2012 Authority Bond or Bonds;

(iii) whenever the Interest Rate Mode for the 2012 Authority Bonds is the Auction Rate, in whole or in part, at a redemption price of 100% of the principal amount thereof on the final Interest Payment Date for each Auction Period;

(iv) whenever the Interest Rate Mode for the 2012 Authority Bonds is the Term Rate, in whole or in part, on the final Interest Payment Date for the then current Term Rate Period at a redemption price of 100% of the principal amount thereof plus accrued interest, if any, to the redemption date, and, prior to the end of the then current Term Rate Period, at any time during the redemption periods and at the redemption prices set forth below, plus accrued interest, if any, to the redemption date:

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Original Length of Current Term Rate Period (Years)	Commencement of Redemption Period	Redemption Price as Percentage of Principal
More than 15 years	Tenth anniversary of commencement of Term Rate Period	100%
Greater than 10 years but equal to or less than 15 years	Fifth anniversary of commencement of Term Rate Period	100%
Equal to or less than 10 years	Non-callable	Non-callable

If, at the time of the Company's notice of a change in the Term Rate Period pursuant to Section 2.02(d) of the Authority Indenture, or its notice of Conversion of the Interest Rate Mode for the 2012 Authority Bonds to the Term Rate pursuant to Section 2.02(e) of the Authority Indenture, or, when the Interest Rate Mode for the 2012 Authority Bonds is the Term Rate, at least 35 days prior to the Purchase Date for the 2012 Authority Bonds pursuant to Section 3.01 (b)(i) of the Authority Indenture, the Company provides a certification of the Remarketing Agent to the Authority Trustee and the Authority that the foregoing schedule is not consistent with Prevailing Market Conditions and an opinion of Bond Counsel that a change in the redemption provisions of the 2012 Authority Bonds will not adversely affect the exclusion from gross income of interest on the 2012 Authority Bonds for federal income tax purposes, the foregoing redemption periods and redemption prices may be revised effective as of the date of such change in the Term Rate Period, the Conversion Date, or that Purchase Date, as determined by the Remarketing Agent in its judgment, taking into account the then Prevailing Market Conditions, as stipulated in such certification, which shall be appended by the Trustee to its counterpart of this supplemental indenture. Any such revision of the redemption periods and redemption prices shall not be considered an amendment of or a supplement to this supplemental indenture and shall not require the consent of any other person or entity.

(v) whenever the Interest Rate Mode for 2012 Authority Bonds is the Annual Rate, in whole or in part, at a redemption price equal to 100% of the principal amount thereof on the final Interest Payment Date for such Annual Rate Period.

(b) Special Mandatory Redemption: in whole (or in part, if in the opinion of Bond Counsel such partial redemption will preserve the exclusion from gross income for federal income tax purposes of interest on the 2012 Authority Bonds remaining outstanding after such redemption) at any time at a redemption price of 100% of the principal amount thereof, plus interest accrued to the redemption date, if a "final determination" (as defined in the Authority Indenture) is made that the interest paid or payable on any 2012 Authority Bond to other than a "substantial user" of the Project or a "related person" (within the meaning of Section 147(a) of the Code) is or was includable in the gross income of the owner thereof for federal income tax purposes under the Code as a result of the failure by the Company to observe or perform any covenant, condition or warranty on its part to be observed or performed under the Agreement or the inaccuracy of any representation or warranty by the Company under the Agreement and under the Use of Proceeds Certificate of the Company dated the Closing Date. Any special mandatory redemption shall be made as soon as practicable but in any event not more than 180 days from the date of such "final determination" and shall be on the date specified by the Company pursuant to Section 8.01(b) of the Authority Indenture or, if no date is so specified, the date established by the Authority Trustee in accordance with Section 8.01(b) of the Authority Indenture.

(c) in whole at 100% of the principal amount thereof whenever the Company receives from the Authority Trustee a copy of a written demand sent to the Trustee stating that the principal of all outstanding 2012 Authority Bonds has been declared to be immediately due and payable because of an Event of Default under the Authority Indenture. In such case, redemption of the bonds of the Pollution Control Series AG shall be any date selected by the Company, not more than 180 days after receipt by the Company of such written demand for redemption.

SECTION 2.02. *Notice of Redemption.* (a) The election of the Company under subsection (a) of Section 2.01 hereof to redeem any of the bonds of the Pollution Control Series AG shall be evidenced by a resolution of the Board of

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Directors of the Company calling for redemption on a stated date of all or a stated principal amount thereof. To exercise its option to redeem the bonds of the Pollution Control Series AG under subsection (a) of Section 2.01 hereof, the Company shall deliver to the Trustee, the Authority and the Authority Trustee a certified copy of said resolution calling all or a stated principal amount of the bonds of the Pollution Control Series AG for redemption on a date not less than 20 days (35 days if the Interest Rate Mode is the Term Rate) nor more than 65 days from the date said resolution is delivered. The delivery to the Authority Trustee of a certified copy of such resolution shall constitute notice to the Authority Trustee of the redemption referred to therein, on the terms specified therein. The Company shall on or before such redemption date deposit with the Trustee, as paying agent hereunder, the total applicable redemption price of all the bonds so called, with interest accrued thereon to the redemption date, less any credits to which the Company may be entitled pursuant to Section 3.01 hereof, and the Trustee, as such paying agent, shall apply such funds on the redemption date to the redemption of the bonds so called.

(b) The Company shall, within 10 days after the occurrence of a "final determination" under subsection (b) of Section 2.01 hereof, deliver to the Trustee written notice of such "final determination". The Company shall, by resolution of its Board of Directors, fix a redemption date for such redemption and shall deliver to the Trustee, the Authority and the Authority Trustee a certified copy of said resolution not later than 60 days after a "final determination" is made and at least 40 days prior to the date so selected for redemption. Such redemption date may be any day not more than 180 days after the occurrence of such "final determination". If the Trustee does not receive written notice of such selection by the Company within 60 days after the date of the occurrence of such "final determination," then the redemption date shall be the redemption date established by the Authority Trustee in accordance with Section 8.01(b) of the Authority Indenture. On or before such redemption date, the Company shall deposit with the Trustee, as paying agent hereunder, the total redemption price of the bonds so called, with interest accrued thereon to the redemption date, less any credits to which the Company may be entitled pursuant to Section 3.01 hereof, and the Trustee, as such paying agent, shall apply such funds, on the redemption date, to the redemption of the bonds so called. The delivery to the Authority Trustee of a certified copy of such resolution shall constitute notice to the Authority Trustee of the redemption referred to therein on the terms specified therein.

SECTION 2.03. *Interest on Called Bonds to Cease.* Each bond or portion thereof of the Pollution Control Series AG called for redemption under Section 2.02 hereof shall be due and payable at the office of the Trustee, as paying agent hereunder, at the applicable redemption price and on the specified redemption date, anything herein or in such bond to the contrary notwithstanding. From and after the date when each bond or portion thereof of the Pollution Control Series AG shall be due and payable as aforesaid (unless upon said date the full amount due thereon shall not be held by or provided to the Trustee, as paying agent hereunder, and be immediately available for payment), all further interest shall cease to accrue on such bond or on such portion thereof, as the case may be.

SECTION 2.04. *Bonds Called in Part.* If only a portion of any bond of the Pollution Control Series AG shall be called for redemption pursuant to Section 2.02 hereof, the notice of redemption hereinbefore provided for shall specify the portion of the principal amount thereof to be redeemed. Upon payment of the portion so called for redemption, the Trustee, as paying agent hereunder, shall give prompt written notice thereof to the Company.

SECTION 2.05. *Provisions of Indenture Not Applicable.* The provisions of Article Four of the Indenture, as amended and supplemented, shall not apply to the procedure for the exercise of any right of redemption reserved by the Company, or to any mandatory redemption provided in this Article in respect of the bonds of the Pollution Control Series AG. There shall be no sinking fund for the bonds of the Pollution Control Series AG.

ARTICLE III.

CREDITS WITH RESPECT TO THE BONDS OF THE POLLUTION CONTROL SERIES AG.

SECTION 3.01. *Credits.* (a) In addition to any other credit, payment or satisfaction to which the Company is entitled with respect to the bonds of the Pollution Control Series AG, the Company shall be entitled to credits against amounts otherwise payable in respect of the bonds of the Pollution Control Series AG in an amount corresponding to the amount by which interest due on the bonds of the Pollution Control Series AG exceeds the interest due on the 2012 Authority Bonds.

(b) The Company shall be entitled to credits against amounts otherwise payable in respect of the bonds of the Pollution Control Series AG in an amount corresponding to (i) the principal amount of any 2012 Authority Bond surrendered to the Authority Trustee by the Company or the Authority, or purchased by the Authority Trustee, for cancellation and (ii) the amount of money held by the Authority Trustee and available and designated for or applied toward the payment of principal or redemption price of and interest on the 2012 Authority Bonds, as the case may

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be, regardless of the source of payment to the Authority Trustee of such moneys. The Trustee, as paying agent hereunder, shall give prompt written notice to the Company of any such credit with respect to the payment of interest.

(c) The Trustee, as paying agent hereunder, shall (i) promptly notify the Company of each deposit in the Debt Service Fund under the Authority Indenture, (ii) provide evidence to the Company that such deposit has been credited to such Fund and (iii) give prompt written notice to the Company of any credits with respect to payment of principal or redemption price of and interest on the bonds of the Pollution Control Series AG.

SECTION 3.02. *Certificate of the Company.* A certificate of the Company signed by the President, any Vice President or any Assistant Treasurer, and attested to by the Secretary or any Assistant Secretary, and consented to by the Authority Trustee, stating that the Company is entitled to a credit under Section 3.01 hereof and setting forth the basis therefor in reasonable detail, shall be conclusive evidence of such entitlement, and the Trustee shall accept such certificate as such evidence without further investigation or verification of the matters stated therein.

ARTICLE IV.

MISCELLANEOUS.

SECTION 4.01. *Authentication of Bonds of Pollution Control Series AG.* None of the bonds of the Pollution Control Series AG, the issue of which is provided for by this supplemental indenture, shall be authenticated by the Trustee except in accordance with the provisions of the Indenture, as amended and supplemented, and this supplemental indenture, and upon compliance with the conditions in that behalf therein contained.

SECTION 4.02. *Additional Restrictions on Authentication of Additional Bonds Under Indenture.* The Company covenants that from and after the date of execution of this supplemental indenture, no additional bonds (as defined in Section I of Article Two of the Indenture) shall be authenticated and delivered by the Trustee under Subdivision A of Section 4 of said Article Two on account of additions or improvements to the mortgaged property:

(1) unless the net earnings of the Company for the period required by Subdivision C of Section 6 of said Article Two shall have been at least twice the fixed charges (in lieu of 1 3/4 times such fixed charges, as required by said Subdivision C); and for the purpose of this condition (a) such fixed charges shall in each case include interest on the bonds applied for, notwithstanding the parenthetical provision contained in clause (4) of said Subdivision C, and (b) in computing such net earnings there shall be included in expenses of operation (under paragraph (c) of said Subdivision C) all charges against earnings for depreciation, renewals or replacements, and all certificates with respect to net earnings delivered to the Trustee in connection with any authentication of additional bonds under said Article Two shall so state; and

(2) except to the extent of 60% (in lieu of 75% as permitted by Subdivision A of Section 7 of said Article Two) of the cost or fair value to the Company of the additions or improvements forming the basis for such authentication of additional bonds.

SECTION 4.03. *Restriction on Dividends.* The Company will not declare or pay any dividend on any shares of its common stock (other than dividends payable in shares of its common stock) or make any other distribution on any such shares, or purchase or otherwise acquire any such shares (except shares acquired without cost to the Company) whenever such action would reduce the earned surplus of the Company to an amount less than $10,000,000 or such lesser amount as may remain after deducting from said $10,000,000 all amounts appearing in the books of account of the Company on December 31, 1948, which shall thereafter, pursuant to any order or rule of any regulatory body entered after said date, be required to be removed, in whole or in part, from the books of account of the Company by charges to earned surplus.

SECTION 4.04. *Use of Facsimile Seal and Signatures.* The seal of the Company and any or all signatures of the officers of the Company upon any of the bonds of the Pollution Control Series AG may be facsimiles.

SECTION 4.05. *Effective Period of Supplemental Indenture.* The preceding provisions of Articles I, II and III of this supplemental indenture shall remain in effect only so long as any of the bonds of the Pollution Control Series AG shall remain outstanding.

SECTION 4.06. *Time for Making of Payment.* All payments of principal or redemption price of and interest on the bonds of the Pollution Control Series AG shall be made to the Authority Trustee in such funds as shall constitute immediately available funds when payment is due. In any case where the date of payment of the principal or redemption price of or interest on the bonds of the Pollution Control Series AG or the date fixed for redemption of any such bonds shall be in the city of payment a Saturday, Sunday or a legal holiday or a day on which banking institutions are authorized

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by law to close, then such payment need not be made on such date but may be made on the next succeeding business day with the same force and effect as if made on the date of maturity or the date fixed for redemption, and no interest on such payment shall accrue for the period after such date.

SECTION 4.07. *Effect of Approval of Board of Public Utilities of the State of New Jersey.* The approval of the Board of Public Utilities of the State of New Jersey of the execution and delivery of these presents and of the issue of any bonds of the Pollution Control Series AG shall not be construed as approval of said Board of any other act, matter or thing which requires approval of said Board under the laws of the State of New Jersey.

SECTION 4.08. *Execution in Counterparts.* For the purpose of facilitating the recording hereof, this supplemental indenture has been executed in several counterparts, each of which shall be and shall be taken to be an original, and all collectively but one instrument.

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IN WITNESS WHEREOF, Public Service Electric and Gas Company, party hereto of the first part, after due corporate and other proceedings, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents and its corporate seal hereunto to be affixed and to be attested by the signature of its Secretary or an Assistant Secretary; and U.S. Bank National Association, as Trustee, party hereto of the second part, has caused this supplemental indenture to be signed and acknowledged or proved by its President, one of its Vice Presidents or one of its Assistant Vice Presidents and its corporate seal to be hereunto affixed and to be attested by the signature of one of its Vice Presidents, Assistant Vice Presidents, its Cashier, one of its Assistant Cashiers, or one of its Corporate Trust Officers. Executed and delivered this 11 th day of June, 2012.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By /s/ B.D. Huntington
. . . . . .
B. D. Huntington
Vice President

Attest:
/s/ M. Courtney McCormick
. . . . . .
M. Courtney McCormick
Secretary

U.S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes
. . . . . .
N. Barnes
Vice President

Attest:
/s/ P. O'Brien
. . . . . .
P. O’Brien
Vice President

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STATE OF NEW JERSEY)

SS:)

COUNTY OF ESSEX)

BE IT REMEMBERED, that on this 11th day of June, 2012, before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared B. D. Huntington who, I am satisfied, is a Vice President of PUBLIC SERVICE ELECTRIC AND GAS COMPANY, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors, and that said corporation, the mortgagor, has received a true copy of said instrument.

/s/ Susan Costello

. . . . . .

Susan Costello
Notary Public of New Jersey
My Commission Expires March 26, 2017

STATE OF NEW JERSEY)

SS:)

COUNTY OF ESSEX)

BE IT REMEMBERED, that on this 11th day of June, 2012, before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared N. Barnes who, I am satisfied, is a Vice President of U.S. BANK NATIONAL ASSOCIATION, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal; and that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors.

/s/ Melody A. Simpson

. . . . . .

Melody A. Simpson
Notary Public of New Jersey
My Commission Expires March 1, 2016

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CERTIFICATE OF RESIDENCE

U.S. Bank National Association, Mortgagee and Trustee within named, hereby certifies that its precise residence is 21 South Street, Morristown, New Jersey 07960

U. S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes
. . . . . .
N. Barnes
Vice President

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Exhibit 10a(11) (PSEG)
Exhibit 10a(9) (Power)
Exhibit 10a(10) (PSE&G)

KEY EXECUTIVE SEVERANCE PLAN OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Amended effective December 17, 2012

S1-SSA-0009 - 10853

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ARTICLE I

PURPOSE OF THE PLAN

1.1 Purpose The Key Executive Severance Plan of Public Service Enterprise Group Incorporated ("Plan") is maintained by the Company to provide severance benefits to certain key executive-level employees of the Company and its affiliates whose employment is terminated under the circumstances described herein. The Plan is being amended and restated effective December 17, 2012.

The Plan is intended to comply in operation and form with Section 409A to the Internal Revenue Code of 1986, as amended ("Code"). The timing and form of payment of benefits provided under the Plan will be deemed to be automatically modified, and a Participant's rights under the Plan will be limited so as to conform to any requirements under Section 409A of the Code.

ARTICLE II

DEFINITIONS

2.1 "Accrued Obligation" shall have the meaning set forth in Section 4.1 or 5.1 of the Plan.

2.2 "Affiliate" means any corporation, trade or business if it or the Company are members of a controlled group of corporations, are under common control or are members of an affiliated service group, within the meanings of Sections 414(b), 414(c) and 414(m), respectively, of the Code. The term "Affiliate" shall also include any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code.

2.3 "Annual Base Salary" means the annual rate of base salary payable to a Participant for services performed for an Employer, as in effect immediately prior to the Participant's Date of Termination.

2.4 "Board" means the board of directors of the Company.

2.5 "Cause" means:

(a) For purposes of Article IV:

(i) Misconduct, gross negligence, theft, or fraud against the Company;

(ii) For "Performance Reasons," as defined in Section 2.21 of the Plan;

(iii) Violation of the Standards of Integrity or other Company policy;

(iv) Insubordination;

(v) One or more significant acts of dishonesty;

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(vi) Any act that is likely to have the effect of injuring the reputation, business, or business relationship of, the Company, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries;

(vii) Violation of any fiduciary duty;

(viii) Breach of any duty of loyalty;

(ix) Any breach of the restrictive covenants contained in Exhibit I below;

(x) One or more acts of moral turpitude that constitute a violation of applicable law (included but not limited to a felony); or

(xi) Conviction of a felony or plea of *nolo contendere* to a felony charge.

(b) For purposes of Article V:

(i) The willful and continued failure to substantially perform his employment duties;

(ii) The willful engaging in gross misconduct that is materially and demonstrably injurious to the Employer;

(iii) The willful violation of the Company's Standards of Integrity or other applicable corporate code of conduct, or

(iv) The conviction of a felony or a plea of *nolo contetendere* to a felony charge.

No act or failure to act on the part of the Participant shall be considered "willful" unless it is done, or omitted to be done, by the Participant in bad faith or without reasonable belief that the Participant's action or omission was in the best interests of the Employer. Any act or failure to act that is based upon authority given pursuant to a resolution duly adopted by the Board, or the advice of counsel for the Employer, shall be conclusively presumed to be done, or omitted to be done, by the Participant in good faith and in the best interests of the Employer.

Notwithstanding the forgoing, for purposes of the Plan, the termination of a Participant's employment with an Employer shall not be deemed to be for Cause unless such termination is effected in accordance with the following procedures. The Employer shall give the Participant written notice ("Notice of Termination for Cause") of its intention to terminate the Participant's employment for Cause, setting forth in reasonable detail the specific conduct of the Participant that it considers to constitute Cause. Such notice shall be given no later than 60 days after the act or failure (or the last in a series of acts or failures) that the Employer alleges to constitute Cause. The Participant shall have 30 days after receiving the Notice of Termination for Cause in which to cure such act or failure, to the extent such cure is possible. In the case of a termination under clause (a), (b) or (c) above, if the Participant fails to cure such act or failure to the reasonable satisfaction of the Employer, the Employer shall give the Participant a second written notice stating that in the good faith opinion of the Employer, the Participant is guilty of the conduct described in the Notice of Termination for Cause and that such conduct constitutes Cause under the Plan.

2.6 "Change in Control" means the occurrence of any of the following events:

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(a) Any "person" (within the meaning of Section 13(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") is or becomes the beneficial owner within the meaning of Rule 13d-3 under the Exchange Act (a "Beneficial Owner"), directly or indirectly, of securities of the Company (not including in the securities beneficially owned by such person any securities acquired directly from the Company or its Affiliates) representing 25% or more of the combined voting power of the Company's then outstanding securities, excluding any person who becomes such a Beneficial Owner in connection with a transaction described in clause (i) of paragraph (c) below; or

(b) The following individuals cease for any reason to constitute a majority of the number of directors of the Company then serving: individuals who, on the Effective Date, constitute the Board and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's stockholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on the Effective Date or whose appointment, election or nomination for election was previously so approved or recommended; or

(c) There is consummated a merger or consolidation of the Company or any direct or indirect wholly-owned subsidiary of the Company with any other corporation, other than (i) a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of the Company or of its Affiliates, at least 75% of the combined voting power of the securities of the Company or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (ii) a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the Beneficial Owner, directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company's then outstanding securities; or

(d) The shareholders of the Company approve a plan of complete liquidation or dissolution of the Company or there is consummated an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 75% of the combined voting power of the voting securities of which are owned by stockholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale.

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Notwithstanding the foregoing, a "Change in Control" shall not be deemed to have occurred by virtue of the consummation of any transaction or series of integrated transactions immediately following which the record holders of the common stock of the Company immediately prior to such transaction or series of transactions continue to have substantially the same proportionate ownership in an entity which owns all or substantially all of the assets of the Company immediately following such transaction or series of transactions.

2.7 "Code" means the Internal Revenue Code of 1986, as amended, and the regulations promulgated thereunder.

2.8 "Committee" means the Organization and Compensation Committee of the Board or any successor of such Committee.

2.9 "Company" means Public Service Enterprise Group Incorporated and any successors thereto.

2.10 "Confidential Information" means all trade secrets, proprietary and confidential business information belonging to, used by, or in the possession of the Company or any of its Affiliates, including but not limited to information, knowledge or data related to business strategies, plans and financial information, mergers, acquisitions or consolidations, purchase or sale of property, leasing, pricing, sales programs or tactics, actual or past sellers, purchasers, lessees, lessors or customers, those with whom the Company or its Affiliates has begun negotiations for new business, costs, employee compensation, marketing and development plans, inventions and technology, whether such confidential information, knowledge or data is oral, written or electronically recorded or stored, except information in the public domain, information known by the Participant prior to employment with an Employer, and information received by the Participant from sources other than the Company or its Affiliates, without obligation of confidentiality.

2.11 "Date of Termination" means the date of a Participant's death, Disability Effective Date, or the date on which the termination of the Participant's employment by an Employer for Cause or without Cause or by the Participant for Good Reason or without Good Reason, including Retirement, is effective, as the case may be, provided that the termination constitutes a Separation from Service.

2.12 "Disability" means that the Participant (a) is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, or (b) is, by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, receiving income replacement benefits for a period of not less than three months under an accident or health plan covering employees of an Employer.

2.13 "Disability Effective Date" means the 30th day after the Participant's receipt of written notice of the Employer's intention to terminate the Participant's employment on account of Disability, provided that, within the 30 days after the Participant's receipt of such notice, the Participant shall not have returned to full-time performance of his employment duties.

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2.14 "Eligible Employee" means an individual who is designated as such in accordance with Section 3.1.

2.15 "Effective Date" of the amendment and restatement is December 17, 2012.

2.16 "Employer" means the Company and each Affiliate, and any successors thereto.

2.17 "Good Reason" means:

(a) Any material reduction in the Participant's Annual Base Salary, Target Bonus or Target Long-Term Incentive, other than reductions pursuant to a broad-based compensation reduction program or policy affecting the Participant and all similarly situated employees of the Employer;

(b) Any material adverse change in the Participant's title, authority, duties, or responsibilities or the assignment to the Participant of any duties or responsibilities inconsistent in any respect with those customarily associated with the position of the Participant immediately prior to the Change in Control;

(c) The failure of any successor to the Company to assume this Plan in accordance with Section 11.5(b);

(d) Where the only comparable position offered to the Participant within the Employer following a Change in Control would otherwise meet the requirements of subsections (a) and (b) of this Section 2.17 of the Plan, but would require the Participant to increase his or her one-way commuting distance from his or her principal residence by more than 50 miles; or

(e) Any other material breach of the terms of the Plan by the Company that either is not taken in good faith or, even if taken in good faith, is not remedied by the Company promptly after receipt of notice thereof from the Participant.

Notwithstanding the forgoing, for purposes of the Plan, the termination of a Participant's employment with an Employer shall not be deemed to be for Good Reason unless such termination is effected in accordance with the following procedures. The Participant shall give his Employer a written notice ("Notice of Termination for Good Reason") of the termination, setting forth in reasonable detail the specific acts or omissions of the Employer that constitute Good Reason and the specific provision(s) of the Plan on which the Participant relies. Unless the Committee determines otherwise, a Notice of Termination for Good Reason by the Participant must be made within 60 days after the Participant first has actual knowledge of the act or omission (or the last in a series of acts or omissions) that the Participant alleges to constitute Good Reason, and the Employer shall have 30 days from the receipt of such Notice of Termination for Good Reason to cure the conduct cited therein. A termination of employment by the Participant for Good Reason shall be effective on the final day of such 30-day cure period unless prior to such time the Employer has cured the specific conduct asserted by the Participant to constitute Good Reason to the reasonable satisfaction of the Participant.

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For purposes of the Plan, a Participant's determination that an act or failure to act constitutes Good Reason shall be presumed to be valid unless such determination is decided to be unreasonable by the Committee or its delegate pursuant to Article IX.

2.18 "Nonqualified Plan" the Retirement Income Reinstatement Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated.

2.19 "Other Benefits" shall have the meaning set forth in Articles IV and V, as applicable.

2.20 "Participant" means an Eligible Employee who has satisfied the conditions for participation in the Plan, as set out in Section 3.2, and is listed on either Schedule A or Schedule B hereto, as the same may be amended from time to time.

2.21 "Performance Reasons" means the Participant's failure meet the expectations established for his function in the Company as: (a) communicated to him by his manager during any performance review, or (b) may be communicated to him otherwise by his manager from time to time either orally or in writing.

2.22 "Plan" means this Key Executive Severance Plan of Public Service Enterprise Group Incorporated, as set forth herein and as may be amended, modified or supplemented from time to time.

2.23 "Prior Equity Awards" shall mean outstanding stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares and performance shares units.

2.24 "Retirement" means a Separation from Service after the Participant has satisfied the eligibility requirements for early or normal retirement under the terms of the Retirement Plan in which the Participant participates. Notwithstanding the foregoing, for the purposes of determining benefit entitlements under Article V of the Plan, Retirement shall not include forced retirements or any termination by an Employer without Cause or voluntary termination by the Participant for Good Reason that occurs on a date on which the Participant is Retirement eligible.

2.25 "Retirement Plan" the retirement plan in which the Participant participates either the Pension Plan of Public Service Enterprise Group Incorporated or the Cash Balance Pension Plan of Public Service Enterprise Group Incorporated.

2.26 "Schedule A Participant" shall mean a Participant listed on Schedule A hereto.

2.27 "Schedule B Participant" shall mean a Participant listed on Schedule B hereto.

2.28 "Separation from Service" shall be deemed to have occurred if a Participant and the Company or any Affiliate reasonably anticipates, based on the facts and circumstances, that either:

(a) The Participant will not provide any additional services for the Company or an Affiliate after a certain date; or

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(b) The level of bona fide services performed by the Participant after a certain date will permanently decrease to no more than 50 percent of the average level of bona fide services performed by the Participant over the immediately preceding 36 months.

(c) If a Participant is absent from employment due to military leave, sick leave or any other bona fide leave of absence authorized by the Company or an Affiliate and there is a reasonable expectation that the Participant will return to perform services for the Company or an Affiliate, a Separation from Service will not occur until the later of: (i) the first date immediately following the date that is six months after the date that the Participant was first absent from employment; or (ii) the date the Participant no longer retains a right to reemployment, to the extent the Participant retains a right to reemployment with the Company or any Affiliates under applicable law or by contract. If a Participant fails to return to work upon the expiration of any military leave, sick leave or other bona fide leave of absence where such leave is for less than six months, the Separation from Service shall occur as of the date of the expiration of such leave, unless a greater period is provided for under applicable law.

2.29 "Specified Employee" shall mean any individual who is a key employee (as defined in Section 416(i) of the Code without regard to Section 416(i)(5)) of the Company at any time during the 12-month period ending on each December 31 (the "identification date"). If an individual is a key employee as of an identification date, the individual shall be treated as a Specified Employee for the 12-month period beginning on the April 1 following the identification date. Notwithstanding the foregoing, an individual shall not be treated as a Specified Employee unless any stock of the Company or an Affiliate is publicly traded on an established securities market or otherwise.

2.30 "Target Bonus" means the Participant's target annual bonus, if any, under the applicable annual incentive compensation plan of the Company for the fiscal year in which the Date of Termination occurs.

2.31 "Target Long-Term Incentive" means the Participant's target long-term incentive award, if any, under the applicable long-term incentive compensation plan of the Company.

ARTICLE III

ELIGIBILITY AND PARTICIPATION

3.1 Eligible Employees. Eligibility to participate in the Plan shall be limited to certain key executives of an Employer who (a) are not parties to individual employment or change in control agreements that provide for severance benefits, and (b) are designated, by duly adopted resolution of the Committee, as Eligible Employees.

3.2 Participation. As a condition to becoming a Participant and being entitled to the benefits and protections provided under the Plan, each Eligible Employee must execute and deliver to the Company, within 30 days after the later of the Effective Date and the date such individual is designated by the Committee as an Eligible Employee, a written agreement in the

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form attached hereto as Exhibit I (or in such other form as may be satisfactory to the Company) to be bound by the restrictive covenants set forth in Article VII. Schedules A and B hereto list the Eligible Employees who have satisfied the conditions for Plan participation and the date as of which each such Eligible Employee became a Participant. The Committee shall cause Schedules A and B to be updated from time to time to reflect the Participants who are currently participating in the Plan.

3.3 Release of Claims. Notwithstanding anything in the Plan to the contrary, payment of any benefits under the Plan is expressly contingent upon the Participant's execution and delivery to the Company, within 30 days after the Participant's Date of Termination, of a written agreement provided by the Company, wherein the Participant releases and discharges the Company and each of its Affiliates of any and all claims against the Company and its Affiliates related in any way to the Participant's employment with an Employer and the termination of such employment.

3.4 Committee Discretion. The Committee shall have the sole discretion to determine eligibility for benefits under the Plan.

ARTICLE IV

SEVERANCE BENEFITS IN GENERAL

4.1 Termination by Employer Other than for Cause or by the Participant for Good Reason. Subject to Section 3.3 and Article VI of the Plan, if a Participant's employment is involuntarily terminated by an Employer for reasons other than Cause or a Participant terminates employment for Good Reason, the Participant shall be entitled to the benefits described in Sections 4.2 through 4.9 of the Plan. For purposes of clarity, subject to Section 3.3 and Article VI of the Plan, Participant shall be entitled to the benefits described in Sections 4.2 through 4.9 of the Plan if a Participant's employment is involuntarily terminated by an Employer due to a reduction in force or a reorganization of the Employer (as determined by the Committee), or a Participant experiences a cessation of employment in connection with a reduction in force or Employer reorganization (as determined by the Committee) where the only position offered to the Participant within the Company and Affiliates would require the Participant to accept a reduction in his or her annual rate of base salary of more than 20% below the annual rate of base salary of the Participant's position immediately prior to such action.

For the avoidance of any doubt, a Participant shall not be entitled to benefits under the Plan if (i) his employment terminates as a result of death, Disability, the Participant voluntarily terminates employment, except for Good Reason, or (ii) the Participant's cessation of employment is in connection with the sale of the Participant's Employer, line or unit of business of the Employer within which the Participant's position is located, business function of the Employer within which the Participant's position is located, or the assets related to the Employer, line or unit or business, or business function within which the Participant's position is located, and the Participant accepts employment with the purchaser within 90 days of the closing of the transaction in a position that has an annual rate of base salary that is at least 80 percent of the Participant's annual rate of base salary immediately prior to the closing of the sale).

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4.2 Cash payment. The Company shall pay to the Participant a lump sum, in cash, the sum of (a) and (b):

(a) The Participant's base salary and accrued vacation pay through the Date of Termination to the extent not theretofore paid (hereinafter referred to as the "Accrued Obligations"); and

(b) An amount equal to the product of 1.0 times (0.5 times if the Participant were employed less than one year) the sum of the Participant's Annual Base Salary and Target Bonus.

4.3 Long-Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

4.4 Annual Incentive Awards. The Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of calendar days of employment in the calendar year in which the Participant's termination occurs through the Participant's Date of Termination. For purposes of this Section 4.4, calendar year shall mean 365 days.

Annual incentive awards with respect to the calendar year in which a Participant's Date of Termination occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

4.5 Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the Participant's Date of Termination or such earlier date designated by the Participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

4.6 Educational Assistance. Educational assistance shall be provided in accordance with the Employer's tuition program.

4.7 Health Care Benefits.

(a) Retiree Health Care Coverage. A Participant who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(i) The Participant has attained age 50 and completed ten or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80; or

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(ii) The Participant has attained age 49 and completed 20 or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Participant's Termination Date. The Participant shall be charged the full cost of retiree coverage under these plans.

(b) COBRA Continuation Coverage. Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this Section 4.7 of the Plan shall be entitled, pursuant to any continuation coverage rights under the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended ("COBRA"), to continue individual and dependent coverage under the Company's group health care plans following the Participant's Date of Termination. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the one-year period following the Participant's Date of Termination, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of the cost of coverage) during the remainder of the COBRA coverage period, if any, and the full expense of dental and (if applicable) vision and hearing coverage (102 percent of the cost of coverage) during the entire COBRA coverage period.

4.8 Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled, for the one-year period following the Participant's Date of Termination to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination.

4.9 Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided hereunder or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time. (The amounts and benefits payable to the Participant pursuant to Sections 4.3 through 4.9 of the Plan shall be hereinafter referred to as the "Other Benefits").

4.10 Termination where a Participant experiences a cessation of employment in connection with a reduction in force or Employer reorganization where the only position offered to the Participant within the Company and Affiliates would require the Participant to increase his or her one-way commuting distance by more than 50 miles. Subject to Section 3.3 and Article V, if a Participant experiences a cessation of employment in connection with a reduction in force or an Employer reorganization (as determined by the Committee) where the only position offered to the Participant within the Company and Affiliates would require the Participant to increase his or her one-way commuting distance by more than 50 miles:

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(a) Severance Pay. The Participant shall receive a lump sum cash payment in accordance with Section 6.1 of the Plan, based upon the amount of the Participant's base salary, the number of Years of Service completed as of the Participant's Termination Date, as follows:

(i) **Less than Thirteen Years of Service:** If, as of the Participant's Date of Termination, he has completed fewer than thirteen Years of Service, the amount of severance pay shall equal 26 weeks of base salary.

(ii) **Thirteen or More Years of Service:** If, as of the Participant's Date of Termination, he has completed thirteen or more Years of Service, the amount of severance pay shall equal two weeks of base salary for each Year of Service, up to a maximum of 52 weeks of base salary.

(b) Annual Incentive Awards. A Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of days of employment in the calendar year in which the participant's Termination of Employment occurs through the employee's Termination Date. Annual incentive awards with respect to the calendar year in which a Participant's Termination Date occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

(c) Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the participant's Termination Date or such earlier date designated by the participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

(d) Educational Assistance. Education assistance shall be provided in accordance with the Employer's tuition program.

(e) Health Care Benefits.

(i) Retiree Health Care Coverage**.** An Eligible Employee who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(A) The Participant has attained age 50 and completed ten or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80; or

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(B) The Participant has attained age 49 and completed 20 or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Participant's Date of Date. The Participant shall be charged the full cost of retiree coverage under these plans.

(ii) COBRA Continuation Coverage. Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this subsection (i) shall be entitled, pursuant to any continuation coverage rights under COBRA to continue individual and dependent coverage under the Company's group health care plans following the Participant's Termination Date. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of the cost of coverage) during the remainder of the COBRA coverage period, if any, and the full expense of dental and (if applicable) vision and hearing coverage (102 percent of the cost of coverage) during the entire COBRA coverage period.

(f) Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination Date.

(g) Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided under the Plan or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time.

ARTICLE V
SEVERANCE BENEFITS AFTER A CHANGE IN CONTROL

5.1 Termination By Employer Other Than For Cause or By Participant For Good Reason (other than Good Reason as described in Subsection 2.17(d)) Within Two Years After a Change in Control. Subject to Section 3.3 and Article VI of the Plan, if, within two years

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following the occurrence of a Change in Control, either (a) an Employer shall terminate a Participant's employment other than for Cause or Disability, or (b) a Participant shall voluntarily terminate his employment for Good Reason pursuant to Subsections 2.17 (a), (b), (c) or (e), the Participant shall be entitled to benefits in Sections 5.2 through 5.8 of the Plan. For the avoidance of any doubt, a Participant shall not be entitled to benefits under the Plan if his employment terminates as a result of death, Disability or the Participant voluntarily terminates employment, except for Good Reason, except as otherwise provided under the Plan.

5.2 Cash Payment. The Company shall pay to the Participant, in a lump sum in cash, the aggregate of the amounts in (a) and (b) below:

(a) the sum of:

(i) The Participant's base salary and accrued through the Date of Termination; and

(ii) The product of (x) the Participant's Target Bonus and (y) a fraction, the numerator of which is the number of days in the current calendar year through the Date of Termination, and the denominator of which is 365;

in each case to the extent not theretofore paid (the sum of the amounts described in clauses (i) and (ii) shall be hereinafter referred to as the "Accrued Obligations"); and

(b) Either (i) or (ii):

(i) In the case of a Schedule A Participant, the amount equal to the product of two times the sum of the Schedule A Participant's Annual Base Salary and Target Bonus; or

(ii) In the case of a Schedule B Participant, the amount equal to the product of three times the sum of the Schedule B Participant's Annual Base Salary and Target Bonus.

5.3 Long Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.4 Health Care and Other Welfare Benefits. The Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for 18 months after the Date of Termination provided that the Participant makes an election to continue such coverage in the Company's medical and dental employee benefit plans under COBRA, subject to the requirements and limitations thereof. Unless otherwise limited by applicable law, thereafter, the Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for an additional period of six months, in the case of a Schedule A Participant, or 18 months, in the case of a Schedule B Participant; provided however, that if the Participant becomes re-employed with another employer and is eligible to receive medical or dental benefits under another employer provided plan, the medical and dental benefits

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provided by the Company under this Plan shall be secondary to those provided under such other plan during the applicable period of eligibility.

Unless otherwise limited by applicable law, for two years after the Date of Termination in the case of a Schedule A Participant or three years after the Date of Termination in the case of a Schedule B Participant (or such longer period as may be provided by the terms of the appropriate plan, program, practice or policy), the Company shall continue benefits (other than medical and dental benefits) to the Participant and/or the Participant's family at least equal to those which would have been provided to them in accordance with the welfare plans, programs, practices and policies maintained by the Company if the Participant's employment had not been terminated or, if more favorable to the Participant, as in effect generally at any time thereafter with respect to other peer executives of the Employer and their families.

Unless otherwise limited by applicable law, the Participant's eligibility (but not the time of commencement of such benefits) for retiree benefits pursuant to the welfare plans, programs, practices and policies maintained by the Company shall be determined as if the Participant had (A) remained employed until two years (in the case of a Schedule A Participant) or three years (in the case of a Schedule B Participant) after the Date of Termination and (B) retired on the last day of such period.

5.5 Nonqualified Pension Benefit. The Participant shall be paid, in a lump sum payment in cash, an amount equal to the excess of:

(a) The actuarial equivalent of the benefit under the Company's applicable Retirement Plan (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the Effective Date), any benefit under the Nonqualified Plan and, to the extent applicable, any other defined benefit retirement arrangement between the Participant and the Company ("Other Pension Benefits") which the Participant would receive if the Participant's employment continued for two or three additional years (for Schedule A Participants and Schedule B Participants, respectively) beyond the Date of Termination and, assuming that the Participant's compensation for such deemed additional period was the Participant's Annual Base Salary as in effect immediately prior to the Date of Termination and assuming a bonus in each year during such deemed additional period equal to the Target Bonus, over

(b) The actuarial equivalent of the Participant's actual benefit (paid or payable), if any, under the Retirement Plan, the Nonqualified Plan and Other Pension Benefits as of the Date of Termination (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the effective date of the Change in Control).

5.6 Deferred Compensation. Any compensation previously deferred (other than pursuant to a tax-qualified plan) by or on behalf of the Participant (together with any accrued interest or earnings thereon), whether or not then vested, shall become vested on the Date of

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Termination and shall be paid in accordance with the terms of the applicable deferred compensation plan, policy or practice under which it was deferred to the extent permitted by Section 409A of the Code.

5.7 Outplacement Services. The Company shall, at its sole expense as incurred, provide the Participant with outplacement services suitable to the Participant's position for a period not to exceed one year following the Date of Termination with a nationally recognized outplacement firm.

5.8 Other Benefits. To the extent not theretofore paid or provided, the Company shall pay or provide to the Participant any other amounts or benefits required to be paid or provided or which the Participant is entitled to receive under any plan, program, policy, practice, contract or agreement of the Company (or other Employer), including earned but unpaid stock and similar compensation, but excluding medical or dental benefits if the Participant is eligible for such benefits to be provided by a subsequent employer, and benefits payable under any severance plan or policy (such other amounts and benefits that are payable to the Participant shall be hereinafter referred to as the "Other Benefits").

5.9 Termination By Participant For Good Reason as described in Subsection 2.17(d) Within Two Years After a Change in Control. Subject to Section 3.3 and Article V of the Plan, if, within two years following the occurrence of a Change in Control, a Participant shall voluntarily terminate his or her employment for Good Reason as described in Subsection 2.17(d):

(a) Severance Pay. The Participant shall receive a lump sum payment in accordance with Section 6.1 of the Plan based upon the amount of the Participant's base salary, the number of Years of Service completed as of the Participant's Termination Date, as indicated below:

(i) **Less than Thirteen Years of Service:** If, as of the Participant's Termination Date he or she has completed fewer than thirteen Years of Service, the amount of severance pay shall equal 26 weeks of base salary.

(ii) **Thirteen or More Years of Service:** If, as of the Participant's Termination Date, he or she has completed thirteen or more Years of Service, the amount of severance pay shall equal two weeks of base salary for each Year of Service, up to a maximum of 52 weeks of base salary.

(b) Annual Incentive Awards. A Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of days of employment in the calendar year in which the participant's Termination of Employment occurs through the employee's Termination Date. Annual incentive awards with respect to the calendar year in which a Participant's Termination Date occurs will be paid at the

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same time as awards for such calendar year are paid to active employees of the Employer.

(c) Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the Participant's Date of Termination or such earlier date designated by the participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

(d) Educational Assistance. Education assistance shall be provided in accordance with the Employer's tuition program.

(e) Health Care Benefits.

(i) Retiree Health Care Coverage. An Eligible Employee who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination Date, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(A) The Participant has attained age 50 and completed ten or more Years of Service as of his or her Termination Date but the sum of the Participant's age and Years of Service is less than 80; or

(B) The Participant has attained age 49 and completed 20 or more Years of Service as of his or her Termination Date but the sum of the Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Participant's Termination Date. The Participant shall be charged the full cost of retiree coverage under these plans.

(ii) COBRA Continuation Coverage. Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this subsection (e) shall be entitled, pursuant to any continuation coverage rights under COBRA to continue individual and dependent coverage under the Company's group health care plans following the Participant's Termination Date. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of the cost of coverage) during the remainder of the COBRA coverage period, if any, and the full expense of dental and (if applicable) vision and hearing coverage (102

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percent of the cost of coverage) during the entire COBRA coverage period.

(f) Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled, during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination.

(g) Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided under the Plan or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time.

5.10 Termination By Employer For Cause or By Participant Other Than For Good Reason. If, at any time after a Change in Control, either (a) an Employer shall terminate a Participant's employment for Cause or (b) the Participant shall voluntarily terminate his employment other than for Good Reason, the Employer shall have no further payment obligations to the Participant other than for the Participant's base salary through the Date of Termination and any accrued but unpaid vacation pay. In such case, all such amounts shall be paid to the Participant in a lump sum in accordance with Section 6.1 of the Plan.

5.1 Death. If a Participant's employment terminates by reason of the Participant's death after a Change in Control, all Accrued Obligations as of the time of death shall be paid to the Participant's estate or beneficiary, as applicable, in a lump sum in cash in accordance with Section 6.1 of the Plan. The Participant's estate or beneficiary shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.2 Disability. If a Participant's employment is terminated by reason of Disability after a Change in Control, all Accrued Obligations shall be paid to the Participant in a lump sum in cash in accordance with Section 6.1 of the Plan. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.3 Retirement. If a Participant's employment terminates as a result of Retirement after a Change in Control, the Participant shall be paid the Accrued Obligations in a lump sum in cash in accordance with Section 6.1 of the Plan and the Participant shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

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ARTICLE VI

TIMING OF, LIMITATIONS ON AND ADJUSTMENTS TO PLAN PAYMENTS

6.1 Time of Payments. Payments under the Plan shall be made to the Participant as follows:

(a) With respect to benefits under Sections 4.2, 4.10(a), 5.2, 5.5, 5.9(a), 5.12 and 5.13 of the Plan, payment to a Participant who is not a Specified Employee shall be made within the 60-day period following the Participant's Date of Termination. With respect to benefits under Section 5.11 of the Plan, payment shall be made within the 60-day period following the Participant's date of the Participant's death. However, if the period to consider and revoke the written agreement required to receive the benefits described in Articles IV and V of the Plan (i.e., the waiver and release) spans two taxable years, in all events the payments will be made in second taxable year within 30 days following the later of the end of the first taxable year or the date the executed release is received by the Company.

(b) With respect to benefits under Sections 4.4, 4.10(b) and 5.9(b) of the Plan, payments shall be made to the Participants at the same time the payments are made to active employees.

(c) Notwithstanding anything to the contrary in the Plan, to the extent necessary to comply with Section 409A of the Code, payments to a Participant who is a Specified Employee shall be made within the 60-day period following the six-month anniversary of the Participant's Date of Termination (other than by reason of death).

(d) All payments under the Plan that are reimbursements of covered expenses incurred by the Participant shall be made within the taxable year in which the expense is incurred.

6.2 Payment Offsets. Notwithstanding anything in the Plan to the contrary, in the event a Participant is entitled to receive severance payments both under this Plan and under the terms of either (a) an individual change of control or employment agreement, (b) another severance pay plan or policy of an Employer or (c) any existing or future law or regulation, the benefits payable under this Plan shall be reduced by the amount of any severance benefits such Participant is entitled to receive under such individual agreement, plan, policy, law or regulation.

6.3 Cap on Excess Parachute Payments; Gross-Up Payments . Notwithstanding anything in the Plan to the contrary, if (a) a Participant is a "disqualified individual" (as defined in Section 280G(c) of the Code) and (b) the severance benefits provided under Articles IV or V, as applicable, together with any other payments the Participant has the right to receive from an Employer, would constitute a "parachute payment" (as defined in Section 280G(b) of the Code) ("Parachute Payments"), the following provisions shall apply:

(a) The severance benefits under Articles IV or V shall not exceed an amount which, together with any other Parachute Payments the Participant has a right to receive from the Employer, would be 2.99 times the Participant's "base amount" (as

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defined in Section 280G of the Code) so that no portion of the amounts received by the Participant shall be subject to the excise tax imposed under Section 4999 of the Code.

(b) The determination of whether any limitation on the severance benefits payable under Articles IV or V is necessary shall be made by the Company's independent auditor or such other certified public accounting firm as may be jointly designated by the Participant and the Company (the "Accounting Firm"), which shall provide detailed supporting calculations to the Participant and the Company. The determinations of the Accounting Firm shall be conclusive and binding on the Company and the Participant. All fees and expenses of the Accounting Firm shall be borne solely by the Company.

(c) If through error or otherwise, a Participant shall receive payments under the Plan, together with other Parachute Payments the Participant has the right to receive from an Employer, in excess of 2.99 times his base amount, the Participant shall immediately repay the excess to the Employer upon notification from the Employer that an overpayment has been made. If the Participant fails to repay the excess to the Employer within 10 business days of the date of the Employer's notification, the Participant will become liable to the Employer for an amount equal to two (2) times the excess amount.

6.4 Compliance with Section 409A of the Code. Notwithstanding anything in the Plan to the contrary, all Plan benefit obligations and payments are subject to Section 409A of the Code. To the extent required, the Company may modify the severance benefits payable hereunder to comply with Section 409A of the Code; provided, however, that the present value of the aggregate Plan benefits payable to a Participant after such modification shall not be less than the present value of the Plan benefits payable to the Participant prior to the modification.

6.5 Tax Withholding. Notwithstanding any other provision of this Plan, the Company may withhold from any amounts payable under this Plan such Federal, state, local, employment or foreign taxes as shall be required to be withheld pursuant to any applicable law or regulation.

ARTICLE VII
RESTRICTIVE COVENANTS

7.1 Confidentiality. As a condition to participation in the Plan, each Participant agrees to hold in a fiduciary capacity for the benefit of the Company and its Affiliates all Confidential Information which shall have been obtained by the Participant during the Participant's employment by the Employer; except, however, that this Section 7.1 shall not apply to Confidential Information that is or becomes public knowledge, unless such Confidential Information became or becomes public knowledge due to acts of the Participant or representatives of the Participant in violation of this Section 7.1. Upon termination of the Participant's employment, he shall return to the Company all Confidential Information in his possession. After termination of the Participant's employment with the Employer, the Participant shall not, without the prior written consent of the Company or as may otherwise be required by law or legal process, communicate or divulge any such Confidential Information to

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anyone other than the Company and those designated by it, except (a) otherwise publicly available information, (b) as may be necessary to enforce his rights under the Plan or as necessary to defend himself against a claim asserted directly or indirectly by the Company or its Affiliates or (c) as may be compelled by service of a valid subpoena or other legal process. If the Participant is served with a valid subpoena or other legal process, he must so notify the Company within three business days. Unless and until a determination has been made in accordance with Section 7.4 that the Participant has violated this Section 7.1, an asserted violation of the provisions of this Section 7.1 shall not constitute a basis for deferring or withholding any amounts otherwise payable to the Participant under the Plan.

7.2 Non-Compete. As a condition to participation in the Plan, each Participant agrees, that, in the event the Participant voluntarily terminates his employment other than for Good Reason, for the period of one year from Date of Termination he will not, without the written consent of the Company, directly or indirectly own, manage, operate, join, control, become employed by, consult to or participate in the ownership, management, or control of any business which is in direct competition with the Company or its Affiliates.

7.3 Non-Solicitation. As a condition to participation in the Plan, each Participant agrees that, in the event the Participant voluntarily terminates his employment other than for Good Reason, for the period of one year following the Date of Termination, he will not, directly or indirectly, solicit or hire, or encourage the solicitation or hiring by any employer other than the Company or its Affiliates, for any position as an employee, independent contractor, consultant or otherwise, any person who was a managerial or higher level employee of an Employer at any time during the term of the Participant's employment by the Employer; provided, however, that this provision shall not apply with respect to the solicitation of any person after six months from the date on which such person's employment by an Employer has terminated.

7.4 Enforcement. In the event of a breach by the Participant of any of the covenants set forth in this Article VII, it is agreed that the Company shall suffer irreparable harm for which money damages are not an adequate remedy, and that, in the event of such breach, the Company shall be entitled to obtain an order of a court of competent jurisdiction for equitable relief from such breach, including, but not limited to, temporary restraining orders and preliminary and/or permanent injunctions against the breach of such covenants by the Participant. In the event that the Company should initiate any legal action for the breach or enforcement of any of the provisions contained in this Article VII and the Company does not prevail in such action, the Company shall promptly reimburse the Participant the full amount of any court costs, filing fees, attorney's fees which the Participant incurs in defending such action, and any loss of income during the period of such litigation.

ARTICLE VIII
AMENDMENT AND TERMINATION

8.1 Amendment. The Company may amend this Plan at any time, and from time to time, by action of the Committee; provided, however, that no amendment adopted after the effective date of a Change in Control shall have the effect of either (a) removing an individual from the list of Participants, (b) adding conditions for participation or the entitlement to receive

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benefits hereunder, (c) reducing the amount of benefits payable to a Participant or (d) otherwise restricting a Participant's right to receive benefits under the Plan, except as may otherwise be required to conform such payments to the requirements of Section 409A of the Code, as provided in Section 1.1.

8.2 Termination. The Committee may terminate the Plan at any time prior to a Change in Control. The Plan may not be terminated after the effective date of a Change in Control.

ARTICLE IX

ADMINISTRATION

9.1 Plan Administrator. The Plan shall be administered by the Committee, which shall have the duties and responsibilities for administering the Plan as are specifically set forth in this Article IX.

9.2 Responsibilities of Committee.

(a) The Committee shall have responsibility for the day to day administration of the Plan. In addition, the Committee shall have the specific powers, duties, responsibilities and obligations specifically provided for herein.

(b) Subject to the express provisions of the Plan, the Committee shall have full and exclusive authority to interpret the Plan and to make all other factual determinations deemed necessary or advisable in the implementation and administration of the Plan, including but not limited to determinations with respect to the eligibility of Participants to receive benefits under the Plan and the status and rights of such Participants and all other persons affected hereunder. The Committee's interpretation and construction of the Plan shall be conclusive and binding on all persons.

(c) The Committee shall have sole authority to adopt rules and regulations, which shall be administered by the Committee. In addition, the Committee shall have the discretionary authority to issue rulings and interpretations concerning the Plan and all matters arising thereunder, on a uniform and nondiscriminatory basis, provided the same shall not be contrary to or inconsistent with any provision of the Plan.

(d) As a condition of distributing any benefit under the Plan, the Committee may prescribe the use of such forms and require the furnishing of such information as the Committee may deem appropriate for administering the Plan.

9.3 Allocation or Delegation of Duties and Responsibilities. In furtherance of its duties and responsibilities under the Plan, the Committee may:

(a) Employ agents to carry out non-fiduciary responsibilities;

(b) Employ agents to carry out fiduciary responsibilities;

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(c) Consult with counsel, who may be counsel to the Company; and

(d) Delegate any of its duties and responsibilities hereunder to such officer or officers of the Company as the Committee shall designate; except, however, that the Committee may not delegate to any other person the designation of Eligible Employees under Section 3.1 or the authority to consider and determine appeals of alleged adverse benefit determinations.

9.4 Expenses. Unless otherwise agreed to by the Company, no person acting as a fiduciary hereunder (who is an employee of an Employer) shall receive any compensation for services as such. Expenses incurred by fiduciaries in connection with the administration of the Plan shall be paid by the Company.

9.5 Indemnification of Plan Administrator. The Company shall indemnify, to the fullest extent permitted by law, each person made or threatened to be made a party to any civil or criminal action or proceeding by reason of the fact that he, or his testator or intestate, was a member of the Committee, or a delegate of the Committee, acting in the capacity of Plan administrator.

9.6 Reliance Upon Others. The Committee, any person to whom it may delegate such of its duties and powers as provided herein, and the officers and directors of the Company shall be entitled to rely conclusively upon and shall be fully protected in any action taken by them in good faith in reliance upon any tables, valuations, certificates, opinions, reports or other advice furnished to them by any duly appointed actuary, accountant, legal counsel (who may be counsel for the Company) or other specialist.

9.7 Notification. All notices, reports and statements in connection with the Plan that are given, made, delivered or transmitted to a Participant shall be deemed duly given, made, delivered, or transmitted when mailed, by such class as the sender may deem appropriate, with postage prepaid and addressed to the Participant at the address last appearing on the records of the Employer with respect to this Plan. All notices, direct actions or other communications given, made, delivered or transmitted by a Participant to an Employer or Committee shall not be deemed to have been duly given, made, delivered, transmitted or received unless and until actually received by the Employer or Committee.

9.8 Multiple Capacities. A person may serve in more than one fiduciary capacity with respect to the Plan.

ARTICLE X
CLAIMS PROCEDURE

10.1 Submission of Claims. The initial claim by any Participant for benefits under this Plan shall be submitted in writing to the Committee (or its delegate) within 60 days after the occurrence of the termination of employment that the Participant claims to have triggered entitlement to Plan benefits.

10.2 Computation and Review of Claims. All benefits shall be computed by the Committee or its delegate. All claims shall be approved or denied by the Committee (or its delegate) as soon as practicable, but in no event later than 90 days after application by the

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Participant. The Committee may take an additional 90 days to review the claim, provided that the Participant is notified in writing within the initial 90-day period.

(a) Initial Denial of Claim - Any denial of a claim shall include:

(i) Reason or reasons for the denial;

(ii) Reference to pertinent Plan provisions on which the denial is based;

(iii) Description of any additional material or information necessary for the Participant to perfect the claim together with an explanation of why the material or information is necessary; and

(iv) Explanation of the Plan's claim review procedure, described below.

(b) Review of a Denied Claim - A Participant shall have a reasonable opportunity to appeal a denied claim to the Committee (or its delegate) for a full and fair review. The Participant or a duly authorized representative:

(i) Shall have 60 days, after receipt of written notification of the denial of claim in which to request a review.

(ii) May request a review upon written application to the Committee.

(iii) Shall submit written comments, documents, records and other information relating to the claim.

(iv) May review, free of charge, pertinent Plan documents, records and other information relevant to the claim.

(c) Committee Review - The Committee's (or its delegate's) review shall take into account all comments, documents, records and other information submitted by the Participant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

(d) Written Decision - The Committee (or its delegate) shall issue a decision on the reviewed claim promptly but no later than 60 days after receipt of the review. The Committee may take an additional 60 days to review the claim, provided that the Participant is notified in writing within the initial 60-day period. The Committee's decision shall be in writing and shall include:

(i) Reasons for the decision;

(ii) References to the Plan provisions on which the decision is based;

(iii) Statement that the Participant is entitled to receive, upon request, reasonable access to, and copies of, all documents, records and other information relevant to the claim; and

(iv) Statement that the Participant is entitled to bring a civil suit under Section 502(a) of ERISA.

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(e) Binding Effect - The Committee's (or its delegate's) decision shall be final and binding on the Participant and the Employer.

ARTICLE XI
GENERAL PROVISIONS

11.1 Construction. This Plan shall be construed and enforced in accordance with and governed by the internal substantive laws (and not the laws relating to conflict of laws or choice of laws) of the State of New Jersey, except to the extent that such laws are preempted by Federal law.

11.2 Unfunded Plan. The obligations of the Company under this Plan are not required to be funded in advance. Nothing contained in this Plan shall give an Eligible Employee or Participant any right, title or interest in any property of the Company or any of its Affiliates.

11.3 No Right to Continued Employment. Nothing contained herein shall be deemed to give any Eligible Employee or Participant the right to be retained in the employment of an Employer or to limit the rights of any Employer to discharge any Eligible Employee or Participant at any time, with or without notice and with or without Cause.

11.4 Partial Invalidity. The invalidity or unenforceability of any term or provision, or any clause, or portion thereof, of this Plan shall in no way impair or affect the validity or enforceability of any other provision of this Plan, which shall remain in full force and effect.

11.5 Successors and Assigns.

(a) This Plan shall inure to the benefit of and be binding upon the Company and its successors and assigns.

(b) The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform the Company's obligations under the Plan in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place.

(c) In no event shall a Participant assign his interests under the Plan to any other person without the prior written consent of the Committee.

11.6 Waivers. Failure to strictly comply with any term, condition or requirement set forth in the Plan shall not be deemed a waiver of such term, condition or requirement, nor shall any waiver of any such term, condition or requirement at any one time or times be deemed to result in a waiver of such term, condition or requirement at any other time or times.

11.7 Gender and Number. Masculine pronouns include the feminine as well as the neuter genders, and the singular shall include the plural, unless indicated otherwise by the context.

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11.8 Headings. The headings of the Plan are for purposes of reference only and shall not limit or otherwise affect the meaning hereof.

* * *

_____ _____

Signature Date

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SCHEDULE A
As Amended as of December 17, 2012
PARTICIPANTS

NAME	TITLE	PARTICPATION DATE
Stuart J. Black	VP and Assistant Controller (Power)	03/01/10
Robert C. Braun	SVP & Chief Operating Officer, PSEG Nuclear	12/4/09
Jorge L. Cardenas	VP – Asset Management and Centralized Services, PSE&G	1/23/07
Rose M. Chernick	VP – Finance (PSE&G)	8/09/10
John Paul Cowan	SVP – Operations, PSEG Fossil	09/15/09
Lathrop B. Craig	VP – Risk Management & Chief Risk Officer	09/05/11
David M. Daly	VP – LIPA Transition	1/28/08
Raymond V. DePillo	VP – Power Operations and Asset Mgmt, PSEG ER&T	03/20/07
Derek DiRisio	VP & Controller	12/20/04
Diana L. Drysdale	VP – Renewables, PSEG Energy Holdings	02/15/10
Kathleen Fitzgerald	VP – Corporate Communications	01/03/12
Joseph A. Forline	VP – Customer Solutions, PSE&G	12/19/06
Carl J. Fricker	VP – Salem, PSEG Nuclear	12/14/09
Robert F. Friend	VP – Procurement	04/20/10
Kim C. Hanemann	VP – Delivery Projects and Construction	12/21/10
Anne E. Hoskins	SVP – Public Affairs and Sustainability	04/05/07
Bradford D. Huntington	VP & Treasurer	04/16/11
Scott Jennings	President – PSEG Global and VP – Mergers & Acquisitions	10/18/05
Thomas P. Joyce	President & CNO, PSEG Nuclear	01/01/07
Robert C. Krueger, Jr	VP & Assistant Controller – Tax	12/19/06
Kathleen A. Lally	VP – Investor Relations	01/16/07
John R. Latka	VP – Electric Operations, PSE&G	10/23/06
Shawn P. Leyden	VP – Commercial	12/20/04
Tamara L. Linde	VP – Regulatory	12/19/06
Richard P. Lopriore	President, PSEG Fossil	06/19/07
Kristen M. Ludecke	VP – Federal Affairs	02/22/10
Shahid Malik	President – Energy Resources & Trade (ER&T0	12/5/11
NAME	**TITLE**	**PARTICPATION DATE**
Patricia R. McLaughlin	VP – Internal Auditing Services	03/01/10
Michael S. Paszynsky	VP – Business Assurance and Resilience	03/01/10
Margaret M. Pego	SVP – Human Resources & CHRO	12/20/04
John F. Perry	VP – Hope Creek, PSEG Nuclear	09/15/09

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Kevin J. Quinn	VP – Finance (Energy Holdings) and Corp. Planning & Analysis	03/01/10
Sheila J. Rostiac	VP – Talent, Development and Diversity	08/20/12
Joseph Santamaria	VP – Information Technology & CIO	10/29/12
John P. Scarlata	– Gas Supply, PSEG ER&T	4/20/10
Richard T. Thigpen	VP - – State Governmental Affairs	3/26/07
John F. Tiberi	VP – Employee Benefits, Health & Safety	07/09/12

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SCHEDULE B
As Amended as of December 17, 2012
PARTICIPANTS

NAME	TITLE	PARTICPATION DATE
Ralph Izzo	Chairman of the Board, President and CEO	12/15/08
J. A. Bouknight, Jr.	EVP and General Counsel	11/02/09
Caroline Dorsa	EVP and CFO	04/09/09
Ralph A. LaRossa	President – Public Service Electric and Gas Company	10/17/06
William Levis	President – PSEG Power LLC	01/01/07
Randall E. Mehrberg	EVP Strategy & Development, & President, PSEG Energy Holdings L.L.C.	09/22/08

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EXHIBIT I

Form of Restrictive Covenant Agreement

AGREEMENT, by and between Public Service Enterprise Group Incorporated, a New Jersey Corporation (the "Company") and [_____] ("Executive"), dated as of [_____].

WHEREAS, the Company maintains the Key Executive Severance Plan of Public Service Enterprise Group Incorporated (the "Plan"), effective December 17, 2012, and as thereafter amended, modified or supplemented;

WHEREAS, Executive was designated as an Eligible Employee under the Plan by the Organization and Compensation Committee of the Company's Board of Directors;

WHEREAS, pursuant to Section 3.2 of the Plan, in order to be a Participant in and be entitled to benefits and protections under the Plan, Executive must execute and delivery to the Company within 30 days after Executive was designated as an Eligible Employee a written agreement to be bound by the terms and conditions of certain covenants set out in Article VII of the Plan, which is hereby incorporated herein;

NOW THEREFORE, the parties agree as follows:

1. Executive has received a copy of the Plan and has read and understands the terms of conditions of Section 7.1, Confidentiality, Section 7.2, Non-Compete, and Section 7.3, Non-Solicitation, therein, as applied to Executive (the "Covenants").

2. Executive agrees to be bound by and comply with the terms of the Covenants in consideration for becoming a Participant in the Plan.

3. Executive acknowledges that the Covenants are reasonable in the scope of the activities restricted, the geographic area covered by the restrictions, the duration of the restrictions, and that such Covenants are reasonably necessary to protect the Company's legitimate interests in its Confidential Information and its relationships with its employees, customers and suppliers.

4. Executive acknowledges that the Covenants will not deprive Executive of the ability to earn a livelihood or to support Executive's dependents.

5. Executive shall be a Participant in the Plan and be entitled to all of the rights and benefits provided thereunder as of the date of this Agreement.

6. This Agreement shall be construed and enforced in accordance with and governed by the internal substantive laws (and not the laws relating to conflict of laws or choice of laws) of the State of New Jersey, except to the extent that such laws are preempted by Federal law.

S1-SSA-0009 - 10882

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IN WITNESS WHEREOF, the parties have executed this Agreement as of the date and year first above written.

[This Agreement may be executed in counterparts.]

EXECUTIVE

PUBLIC SERVICE ENTERPRISE
GROUP INCORPORATED

By:_____

Title:_____

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2012	2011	2010	2009	2008
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 2,011	$ 2,384	$ 2,616	$ 2,636	$ 1,806
(Income) Loss from Equity Investees, net of Distributions	9	(4)	(19)	(25)	(5)
Fixed Charges	479	522	571	600	633
Capitalized Interest	(19)	(14)	(67)	(45)	(37)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	(2)	(6)	(6)
Total Earnings	$ 2,480	$ 2,888	$ 3,099	$ 3,160	$ 2,391
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 465	$ 509	$ 555	$ 581	$ 615
Interest Factor in Rentals	14	13	14	13	12
Preferred Securities Dividend Requirements of Subsidiaries	—	—	2	6	6
Total Fixed Charges	$ 479	$ 522	$ 571	$ 600	$ 633
Ratio of Earnings to Fixed Charges	5.18	5.53	5.43	5.27	3.78

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12a

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2012	2011	2010	2009	2008
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 1,080	$ 1,687	$ 1,914	$ 1,958	$ 1,711
Fixed Charges	163	208	238	221	210
Capitalized Interest	(4)	(10)	(62)	(43)	(31)
Total Earnings	$ 1,239	$ 1,885	$ 2,090	$ 2,136	$ 1,890
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 161	$ 205	$ 235	$ 219	$ 208
Interest Factor in Rentals	2	3	3	2	2
Total Fixed Charges	$ 163	$ 208	$ 238	$ 221	$ 210
Ratio of Earnings to Fixed Charges	7.60	9.06	8.78	9.67	9.00

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12b

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2012	2011	2010	2009	2008
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 835	$ 861	$ 591	$ 551	$ 592
Fixed Charges	314	319	325	317	325
Capitalized Interest	(13)	(4)	(2)	(1)	—
Total Earnings	$ 1,136	$ 1,176	$ 914	$ 867	$ 917
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 308	$ 314	$ 320	$ 313	$ 325
Interest Factor in Rentals	6	5	5	4	—
Total Fixed Charges	$ 314	$ 319	$ 325	$ 317	$ 325
Ratio of Earnings to Fixed Charges	3.62	3.69	2.81	2.74	2.82

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12c

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Years Ended December 31,				
	2012	2011	2010	2009	2008
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 835	$ 861	$ 591	$ 551	$ 592
Fixed Charges	314	319	327	323	332
Capitalized Interest	(13)	(4)	(2)	(1)	—
Preferred Securities Dividend Requirements	—	—	(2)	(6)	(6)
Total Earnings	$ 1,136	$ 1,176	$ 914	$ 867	$ 918
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 308	$ 314	$ 320	$ 313	$ 325
Interest Factor in Rentals	6	5	5	4	—
Preferred Securities Dividend	—	—	1	4	4
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	1	2	2
Total Fixed Charges	$ 314	$ 319	$ 327	$ 323	$ 331
Ratio of Earnings to Fixed Charges	3.62	3.69	2.80	2.68	2.77

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 21

PUBLIC SERVICES ENTERPRISE GROUP INCORPORATED
SIGNIFICANT SUBSIDIARIES

Name	Ownership %	State of Incorporation
Public Service Electric and Gas Company	100	New Jersey
PSEG Power LLC	100	Delaware
PSEG Fossil LLC	100	Delaware
PSEG Nuclear LLC	100	Delaware
PSEG Energy Resources & Trade LLC	100	Delaware

The remaining subsidiaries of Public Service Enterprise Group Incorporated are not significant as defined in Regulation S-X.

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Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-120100, 333-106330, 033-44581 and 033-44582 on Form S-8 and Registration Statement No. 333-178143 on Form S-3 of our report dated February 25, 2013, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of and for the year ended December 31, 2012, and our report dated February 25, 2013 relating to the effectiveness of the Company's internal control over financial reporting as of December 31, 2012, appearing in this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated for the year ended December 31, 2012.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 25, 2013

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Exhibit 23a

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-175397 on Form S-3 of our report dated February 25, 2013, relating to the consolidated financial statements and consolidated financial statement schedule of PSEG Power LLC and subsidiaries, appearing in this Annual Report on Form 10-K of PSEG Power LLC for the year ended December 31, 2012.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 25, 2013

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Exhibit 23b

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-178133 on Form S-3 of our report dated February 25, 2013, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Electric and Gas Company and subsidiaries, appearing in this Annual Report on Form 10-K of Public Service Electric and Gas Company for the year ended December 31, 2012.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 25, 2013

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2013

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31a

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2013

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31b

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2013

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31c

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2013

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 31d

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2013

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31e

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2013

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2012 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
February 25, 2013

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EXHIBIT 32a

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2012 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Carolina Dorsa

Carolina Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer
February 25, 2013

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EXHIBIT 32b

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2012 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
February 25, 2013

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EXHIBIT 32c

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2012 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Carolina Dorsa

Carolina Dorsa

PSEG Power LLC
Chief Financial Officer
February 25, 2013

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EXHIBIT 32d

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2012 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
February 25, 2013

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EXHIBIT 32e

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2012 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Carolina Dorsa

Carolina Dorsa

Public Service Electric and Gas Company
Chief Financial Officer
February 25, 2013

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2013,

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange On Which Registered
Public Service Enterprise Group Incorporated	Common Stock without par value	New York Stock Exchange
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange
	First and Refunding Mortgage Bonds	
Public Service Electric and Gas Company	9 1/4% Series CC, due 2021 6 3/4% Series VV, due 2016 8%, due 2037 5%, due 2037	New York Stock Exchange

(Cover continued on next page)

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(Cover continued from previous page)

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
PSEG Power LLC	Limited Liability Company Membership Interest
Public Service Electric and Gas Company	Medium-Term Notes

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Public Service Enterprise Group Incorporated	Yes ☒	No ☐
PSEG Power LLC	Yes ☐	No ☒
Public Service Electric and Gas Company	Yes ☒	No ☐

Indicate by check mark if each of the registrants is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☒

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2013 was $16,421,163,580 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Public Service Enterprise Group Incorporated's sole class of Common Stock as of January 31, 2014 was 506,164,959.

As of January 31, 2014, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K. Each is filing its Annual Report on Form 10-K with the reduced disclosure format authorized by General Instruction I.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K of Public Service Enterprise Group Incorporated	Documents Incorporated by Reference
III	Portions of the definitive Proxy Statement for the 2014 Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 10, 2014, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), Item 8. Financial Statements and Supplementary Data — Note 13. Commitments and Contingent Liabilities, and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC) including our subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission in the future, and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to balance our energy obligations, available supply and risks,
- any deterioration in our credit quality or the credit quality of our counterparties, including in our leveraged leases,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient coverage or recover proceeds of insurance with respect to such events,
- cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as competition for certain transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements, and
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies and changes in customer behaviors, including energy efficiency, net-metering and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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FILING FORMAT AND GLOSSARY

This combined Annual Report on Form 10-K is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information relating to any individual company is filed by such company on its own behalf. Power and PSE&G are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, Power and PSE&G. Depending on the context of each section, references to "we," "us," and "our" relate to PSEG or to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 186.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document that we file at the Public Reference Room of the SEC at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. You may also obtain our filed documents from commercial document retrieval services, the SEC's internet website at www.sec.gov or our website at www.pseg.com. Information on our website should not be deemed incorporated into or as a part of this report. Our Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

PART I

ITEM 1. BUSINESS

We were incorporated under the laws of the State of New Jersey in 1985 and our principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07102. We conduct our business through two direct wholly owned subsidiaries, Power and PSE&G, each of which also has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102.

We are an energy company with a diversified business mix. Our operations are located primarily in the Northeastern and Mid- Atlantic United States. Our business approach focuses on operational excellence, financial strength and disciplined investment. As a holding company, our profitability depends on our subsidiaries' operating results. Below are descriptions of our two principal direct operating subsidiaries.

Power	PSE&G
A Delaware limited liability company formed in 1999 that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy sales, fuel supply and energy trading functions. Earns revenues from selling under contract or on the spot market a range of diverse products such as electricity, natural gas, capacity, emissions credits and a series of energy-related products used to optimize the operation of the energy grid.	A New Jersey corporation, incorporated in 1924, which is a franchised public utility in New Jersey. It is also the provider of last resort for gas and electric commodity service for end users in its service territory. Earns revenues from its regulated rate tariffs under which it provides electric transmission and electric and gas distribution to residential, commercial and industrial customers in its service territory. It also offers appliance services and repairs to customers throughout its service territory. Has also implemented demand response and energy efficiency programs and invested in solar generation within New Jersey.

Our other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's transmission and distribution system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and our operating subsidiaries with certain management, administrative and general services at cost.

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The following is a more detailed description of our business, including a discussion of our:

- Business Operations and Strategy
- Competitive Environment
- Employee Relations
- Regulatory Issues
- Environmental Matters

BUSINESS OPERATIONS AND STRATEGY

Power

Through Power, we seek to produce low-cost energy by efficiently operating our nuclear, coal, gas, oil-fired and renewable generation assets, while balancing generation output, fuel requirements and supply obligations through energy portfolio management. We use our owned generation combined with commodity contracts and financial instruments to cover our commitments for Basic Generation Service (BGS) in New Jersey and other bilateral supply contract agreements.

Products and Services

As a merchant generator, our profit is derived from selling a range of products and services under contract to power marketers and to others, such as investor-owned and municipal utilities, and to aggregators who resell energy to retail consumers, or in the open market. These products and services include:

- **Energy**—the electrical output produced by generation plants that is ultimately delivered to customers for use in lighting, heating, air conditioning and operation of other electrical equipment. Energy is our principal product and is priced on a usage basis, typically in cents per kilowatt hour (kWh) or dollars per megawatt hour (MWh).
- **Capacity**—a product distinct from energy, is a market commitment that a given generation unit will be available to an Independent System Operator (ISO) for dispatch when it is needed to meet system demand. Capacity is typically priced in dollars per megawatt (MW) for a given sale period.
- **Ancillary Services**—related activities supplied by generation unit owners to the wholesale market that are required by the ISO to ensure the safe and reliable operation of the bulk power system. Owners of generation units may bid units into the ancillary services market in return for compensatory payments. Costs to pay generators for ancillary services are recovered through charges imposed on market participants.
- **Emissions Allowances and Congestion Credits**—Emissions allowances (or credits) represent the right to emit a specific amount of certain pollutants. Allowance trading is used to control air pollution by providing economic incentives for achieving reductions in the emissions of pollutants. Congestion credits (or Financial Transmission Rights) are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path.

Power also sells wholesale natural gas, primarily through a full requirements Basic Gas Supply Service (BGSS) contract with PSE&G to meet the gas supply requirements of PSE&G's customers. This long-term arrangement was for an initial period which extended through March 31, 2012 and continues on a year-to-year basis unless terminated by either party with a one year notice.

Approximately 46% of PSE&G's peak daily gas requirements is provided from Power's firm gas transportation capacity, which is available every day of the year. Power satisfies the remainder of PSE&G's requirements from storage contracts, liquefied natural gas, seasonal purchases, contract peaking supply, propane and refinery gas. Based upon the availability of natural gas beyond PSE&G's daily needs, Power also sells gas to others.

In addition to its nuclear and fossil generation fleet, Power owns and operates 88 MW of photovoltaic (PV) solar generation facilities and has a 50% ownership interest in an oil-fired generation facility in Hawaii.

The remainder of this section about Power covers our nuclear and fossil fleet in the Mid-Atlantic and Northeast regions which comprise the vast majority of Power's operations and financial performance.

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How Power Operates

We own approximately 13,466 MW of generation capacity, of which 13,274 MW of nuclear and fossil generation capacity is located in the Northeast and Mid-Atlantic regions of the United States in some of the country's largest and most developed electricity markets.

The map below shows the locations of our Northeast and Mid-Atlantic nuclear and fossil generation facilities:

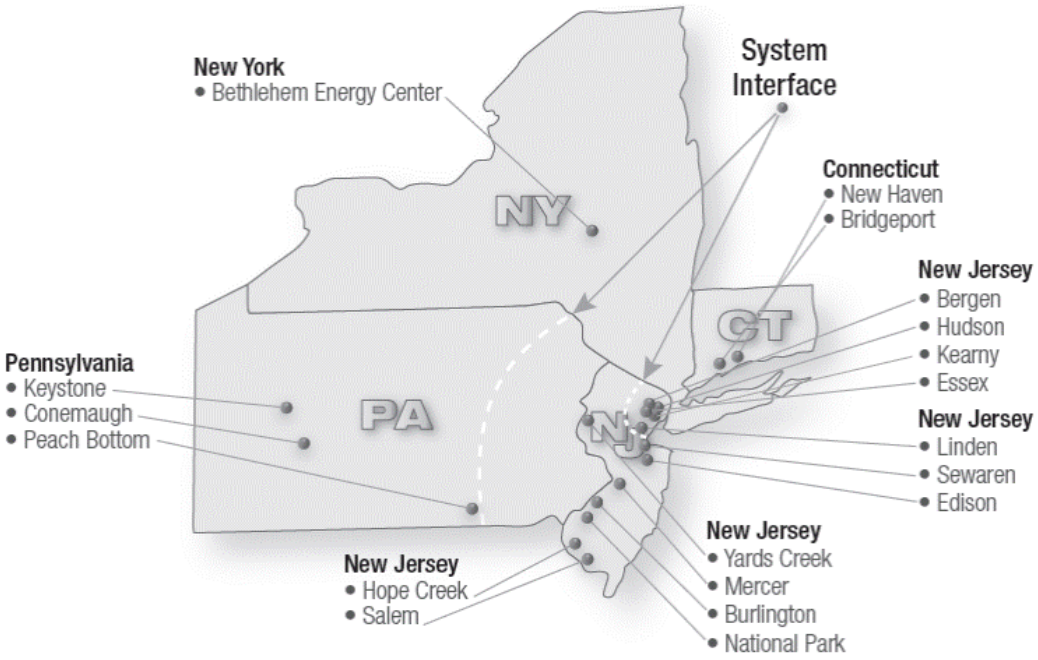

- **Generation Capacity**

  Power has approved the expenditure of $419 million for an extended power uprate of the Peach Bottom nuclear units. The uprate is expected to result in an increase in Power's share of nominal capacity of approximately 130 MW. The uprate is expected to be in service in 2015 for Unit 2 and 2016 for Unit 3. Total expenditures through December 31, 2013 were $154 million.

  Power has also approved the expenditure of $191 million for the upgrading of its natural gas-fired combined cycle units located at Bergen and Linden in New Jersey and at the Bethlehem Energy Center (BEC) unit located in New York. When completed in 2018, these upgrades will add approximately 152 MW of capacity and improve the heat rates of these units. Total expenditures through December 31, 2013 were $13 million.

  For additional information on each of our generation facilities, see Item 2. Properties.

  Our nuclear and fossil installed capacity utilizes a diverse mix of fuels: 44% gas, 28% nuclear, 18% coal, 9% oil and 1% pumped storage. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2013 was approximately 53,000 gigawatt hours (GWh). The generation mix by fuel type has changed slightly in recent years due to the relatively favorable price of natural gas as compared to coal, making it more economical to run certain of our gas units than our coal units. The following table indicates the proportionate share of generating output by fuel type in 2013.

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Generation by Fuel Type (A)	Actual 2013	
Nuclear:		
New Jersey facilities	38%	
Pennsylvania facilities	17%	
Fossil:		
Coal:		
Pennsylvania facilities	11%	
Connecticut facilities	1%	
Coal and Natural Gas:		
New Jersey facilities	2%	
Oil and Natural Gas:		
New Jersey facilities	24%	
New York facilities	7%	
Connecticut facilities	—%	(B)
Total	**100%**	

(A) Excludes pumped storage, solar facilities and fossil generation in Hawaii
(B) Less than one percent

- **Generation Dispatch**

Our generation units are typically characterized as serving one or more of three general energy market segments: base load; load following; and peaking, based on their operating capability and performance. On a capacity basis, our portfolio of generation assets consists of 33% base load, 43% load following and 24% peaking. This diversity helps to reduce the risk associated with market demand cycles and allows us to participate in the market at each segment of the dispatch curve.

- **Base Load Units** run the most and typically operate whenever they are available. These units generally derive revenues from energy and capacity sales. Variable operating costs are low due to the combination of highly efficient operations and the use of relatively lower-cost fuels. Performance is generally measured by the unit's "capacity factor," or the ratio of the actual output to the theoretical maximum output. In 2013, our base load capacity factors were as follows:

Unit	2013 Capacity Factor
Nuclear	
Salem Unit 1	87.0%
Salem Unit 2	99.5%
Hope Creek	85.6%
Peach Bottom Unit 2	98.4%
Peach Bottom Unit 3	85.3%
Coal	
Keystone	83.7%
Conemaugh	79.1%

No assurances can be given that these capacity factors will be achieved in the future.

- **Load Following Units** typically operate between 20% and 80% of the time. The operating costs are higher per unit of output due to the use of higher-cost fuels such as oil, natural gas and, in some cases, coal or lower overall unit efficiency. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.

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- **Peaking Units** run the least amount of time and utilize higher-priced fuels. These units typically operate less than 20% of the time. Costs per unit of output tend to be much higher than for base load units given the combination of higher heat rates and fuel costs. The majority of revenues are from capacity and ancillary service sales. The characteristics of these units enable them to capture energy revenues during periods of high energy prices.

In the energy markets in which we operate, owners of power plants specify to the ISO prices at which they are prepared to generate and sell energy based on the marginal cost of generating energy from each individual unit. The ISOs will generally dispatch in merit order, calling on the lowest variable cost units first and dispatching progressively higher-cost units until the point that the entire system demand for power (known as the system "load") is satisfied reliably. Base load units are dispatched first, with load following units next, followed by peaking units.

During periods when one or more parts of the transmission grid are operating at full capability, thereby resulting in a constraint on the transmission system, it may not be possible to dispatch units in merit order without violating transmission reliability standards. Under such circumstances, the ISO will dispatch higher-cost generation out of merit order within the congested area and power suppliers will be paid an increased Locational Marginal Price (LMP) in congested areas, reflecting the bid prices of those higher-cost generation units.

The following chart depicts the unconstrained merit order of dispatch of our units in PJM Interconnection L.L.C. (PJM), the ISO in the region where most of our generation units are located, based on illustrative historical dispatch cost. It should be noted that market price fluctuations have resulted in changes from historical norms, with lower gas prices allowing some gas-fired generation to displace some coal-fired generation in the load-following portion of the curve.

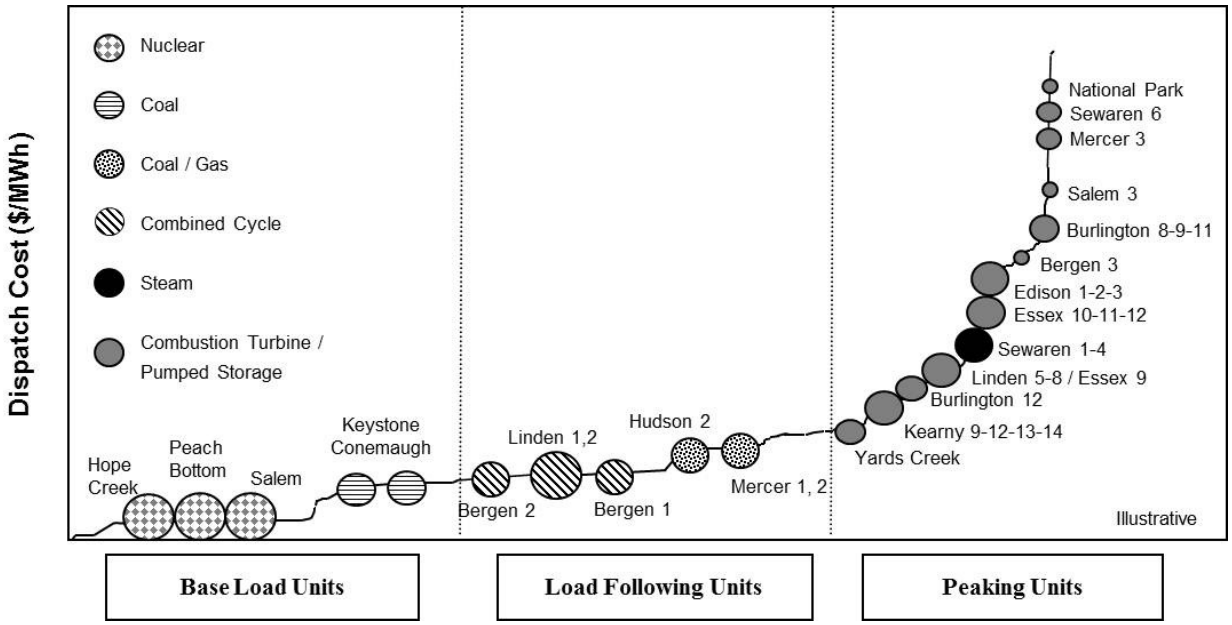

The size of each facility's circle in the above chart illustrates the relative MW generating capacity of that facility. For additional information on each of our generation facilities, see Item 2. Properties.

The bid price of the last unit dispatched by an ISO establishes the energy market-clearing price. After considering the market-clearing price and the effect of transmission congestion and other factors, the ISO calculates the LMP for every location in the system. The ISO pays all units that are dispatched their respective LMP for each MWh of energy produced, regardless of their specific bid prices. Since bids generally approximate the marginal cost of production, units with lower marginal costs typically generate higher operating profits than units with comparatively higher marginal costs.

This method of determining supply and pricing creates a situation where natural gas prices often have a major influence on the price that generators will receive for their output, especially in periods of relatively strong demand. Therefore, significant changes in the price of natural gas will often translate into significant changes in the wholesale price of electricity. This can be seen in the following graphs which present historical annual spot prices and forward calendar prices as averaged over each year at two liquid trading hubs.

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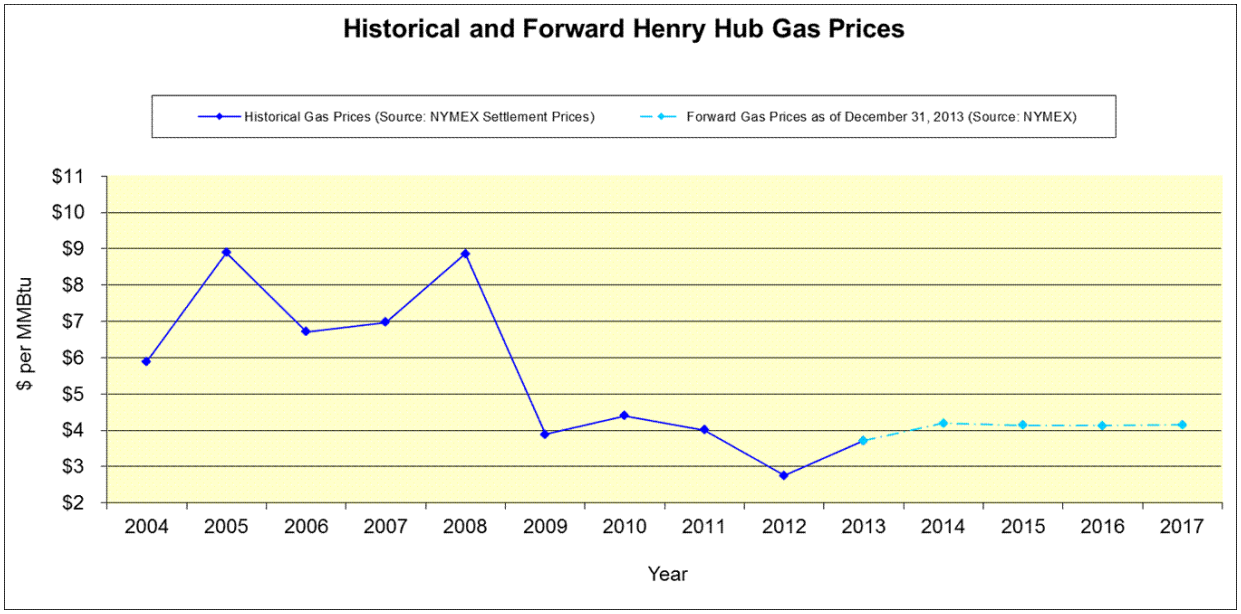

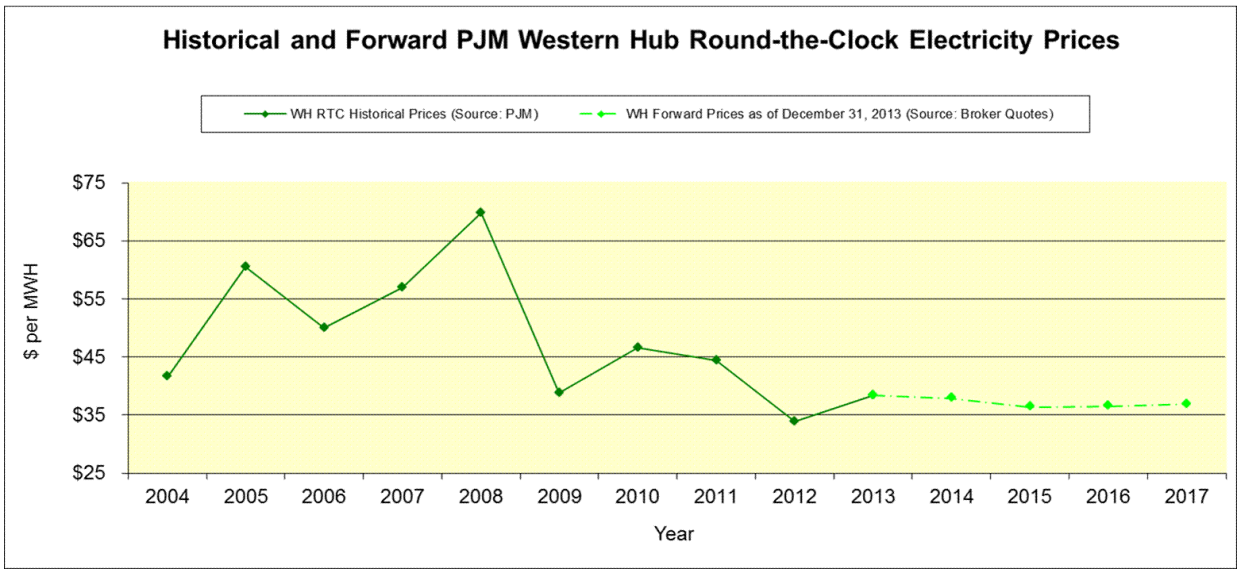

Historical data and forward prices imply that the price of natural gas will continue to have a strong influence on the price of electricity in the primary markets in which we operate.

The prices reflected in the preceding graphs above do not necessarily illustrate our contract prices, but they are representative of market prices at relatively liquid hubs, with nearer-term forward pricing generally resulting from more liquid markets than pricing for later years. In addition, the prices do not reflect locational differences resulting from congestion or other factors, such as the availability of natural gas from the Marcellus and other shale-gas regions, which can be considerable. While these prices provide some perspective on past and future prices, the forward prices are highly volatile and there can be no assurance that such prices will remain in effect or that we will be able to contract output at these forward prices.

Fuel Supply

- ***Nuclear Fuel Supply***—We have long-term contracts for nuclear fuel. These contracts provide for:
  - purchase of uranium (concentrates and uranium hexafluoride),
  - conversion of uranium concentrates to uranium hexafluoride,

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- enrichment of uranium hexafluoride, and
- fabrication of nuclear fuel assemblies.

- ***Coal Supply***—Our Keystone, Conemaugh and Bridgeport stations operate on coal. Our Hudson and Mercer stations have the ability to operate on both coal and natural gas. We have coal contracts with numerous suppliers. Coal is delivered to our units through a combination of rail, truck, barge or ocean shipments.

  In order to control emissions levels, our Bridgeport 3 unit uses a specific type of coal obtained from Indonesia. If the supply from Indonesia or equivalent coal from other sources was not available for this facility, its long-term operations would be adversely impacted since additional material capital expenditures would be required to modify this station to enable it to operate using a broader mix of coal sources.

- ***Gas Supply***—Natural gas is the primary fuel for the bulk of our load following and peaking fleet. We purchase gas directly from natural gas producers and marketers. These supplies are transported to New Jersey by three interstate pipelines with which we have contracted. In addition, we have firm gas transportation contracts to serve our BEC station in New York.

  We have 1.3 billion cubic feet-per-day of firm transportation capacity under contract to meet our obligations under the BGSS contract. This transportation capacity includes approximately 0.6 billion cubic feet-per-day of access to the northeast Pennsylvania Marcellus shale gas region. We supplement that supply with a total storage capacity of 76 billion cubic feet. On an as-available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet.

- ***Oil***—Oil is used as the primary fuel for one load following steam unit and nine combustion turbine peaking units and can be used as an alternate fuel by several load following and peaking units that have dual-fuel capability. Oil for operations is drawn from on-site storage and is generally purchased on the spot market and delivered by truck, barge or pipeline.

We expect to be able to meet the fuel supply demands of our customers and our own operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather and other factors. For additional information, see Item 7. Management's Discussion and Analysis (MD&A)—Overview of 2013 and Future Outlook and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities .

Markets and Market Pricing

The vast majority of Power's generation assets are located in three centralized, competitive electricity markets operated by ISO organizations all of which are subject to the regulatory oversight of the Federal Energy Regulatory Commission (FERC):

- **PJM Regional Transmission Organization**—PJM conducts the largest centrally dispatched energy market in North America. It serves over 61 million people, nearly 20% of the total United States population, and has a peak demand of 165,492 MW. The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The majority of our generating stations operate in PJM.

- **New York**—The New York ISO (NYISO) is the market coordinator for New York State and is responsible for managing the New York Power Pool and for administering its energy marketplace. This service area has a population of about 20 million and a peak demand of 33,939 MW. Our BEC station operates in New York.

- **New England**—The ISO-New England (ISO-NE) is the market coordinator for the New England Power Pool and for administering its energy marketplace which covers Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. This service area has a population of about 14 million and a peak demand of 28,130 MW. Our Bridgeport and New Haven stations operate in Connecticut.

The price of electricity varies by location in each of these markets. Depending upon our production and our obligations, these price differentials can serve to increase or decrease our profitability.

Commodity prices, such as electricity, gas, coal, oil and emissions, as well as the availability of our diverse fleet of generation units to operate, also have a considerable effect on our profitability. These commodity prices have been, and continue to be, subject to significant market volatility. Over the long-term, the higher the forward prices are, the more attractive an environment exists for us to contract for the sale of our anticipated output. However, higher prices also increase the cost of

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replacement power; thereby placing us at greater risk should our generating units fail to function effectively or otherwise become unavailable.

Over the past few years, a decline in wholesale natural gas prices has resulted in lower electric energy prices. One of the reasons for the decline in natural gas prices is greater supply from more recently developed sources, such as shale gas. This trend has reduced margin on forward sales as we re-contract our expected generation output.

In addition to energy sales, we earn revenue from capacity payments for our generating assets. These payments are compensation for committing our generating capacity to the ISO for dispatch at its discretion. Capacity payments reflect the value to the ISO of assurance that there will be sufficient generating capacity available at all times to meet system reliability and energy requirements. Currently, there is sufficient capacity in the markets in which we operate. However, in certain areas of these markets there are transmission system constraints which raise concerns about reliability and create a more acute need for capacity.

In PJM and ISO-NE, where we operate most of our generation, the market design for capacity payments provides for a structured, forward-looking, transparent capacity pricing mechanism. This is through the Reliability Pricing Model (RPM) in PJM and the Forward Capacity Market (FCM) in ISO-NE. These mechanisms provide greater transparency regarding the value of capacity and provide a pricing signal to prospective investors in new generating facilities so as to encourage expansion of capacity to meet future market demands.

The prices to be received by generating units in PJM for capacity have been set through RPM base residual auctions and depend upon the zone in which the generating unit is located. For each delivery year, the prices differ in the various areas of PJM, depending on the constraints in each area of the transmission system. Keystone and Conemaugh receive lower prices than the majority of our PJM generating units since there are fewer constraints in that region and our generating units in northern New Jersey usually receive higher pricing.

Our PJM generating units are located in several zones and Power expects to realize the following average capacity prices from the base auctions which have been completed:

Delivery Year	MW-day
June 2013 to May 2014	$244
June 2014 to May 2015	$162
June 2015 to May 2016	$167
June 2016 to May 2017	$166

The price that must be paid by an entity serving load in the various zones is also set through these auctions. These prices can be higher or lower than the prices noted in the table above due to import and export capability to and from lower-priced areas.

Like PJM and ISO-NE, the NYISO provides capacity payments to its generating units, but unlike the other two markets, the New York market does not provide a forward price signal beyond a six month auction period.

We have obtained price certainty for our PJM and New England capacity through May 2017 through the RPM and FCM pricing mechanisms.

On a prospective basis, many factors may affect the capacity pricing, including but not limited to:

- load and demand,
- available amounts of demand response resources,
- capacity imports from external regions,
- available generating capacity (including retirements, additions, derates, forced outages, etc.),
- transmission capability between zones,
- pricing mechanisms, including potentially increasing the number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM and the other ISOs may propose over time, and
- legislative and/or regulatory actions that permit states to subsidize local electric power generation.

For additional information on the RPM and FCM markets, as well as on state subsidization through various mechanisms, see Regulatory Issues—Federal Regulation.

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Hedging Strategy

To mitigate volatility in our results, we seek to contract in advance for a significant portion of our anticipated electric output, capacity and fuel needs. We seek to sell a portion of our anticipated lower-cost generation over a multi-year forward horizon, normally over a period of two to three years. We believe this hedging strategy increases stability of earnings.

Among the ways in which we hedge our output are: (1) sales at PJM West and (2) BGS contracts. Sales at PJM West reflect block energy sales at the liquid PJM Western Hub and other transactions that seek to secure price certainty for our generation related products. In addition, the BGS-Fixed Price contract, a full requirements contract that includes energy and capacity, ancillary and other services, is awarded for three-year periods through an auction process managed by the New Jersey Board of Public Utilities (BPU). The volume of BGS contracts and the electric utilities that our generation operations serve will vary from year to year. Pricing for the BGS contracts, including a capacity component, for recent and future periods by purchasing utility is as follows:

Load Zone ($/MWh)	2010-2013	2011-2014	2012-2015	2013-2016	2014-2017
PSE&G	$95.77	$94.30	$83.88	$92.18	$97.39
Jersey Central Power & Light	$95.17	$92.56	$81.76	$83.70	$84.44
Atlantic City Electric	$98.56	$100.95	$85.10	$87.27	$87.80
Rockland Electric Company	$103.32	$106.84	$92.51	$92.58	$95.61

Although we enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation, there is variability in both our actual output as well as in our hedges. Our actual output will vary based upon total market demand, the relative cost position of our units compared to other units in the market and the operational flexibility of our units. Our hedge volume can also vary, depending on the type of hedge into which we have entered. The BGS auction, for example, results in a contract that provides for the supplier to serve a percentage of the default load of a New Jersey electric distribution company (EDC), that is, the load that remains after some customers have chosen to be served directly either by third party suppliers or through municipal aggregation. The amount of power supplied through the BGS auction varies based on the level of the EDC's default load, which is affected by the number of customers who choose a third party supplier, as well as by other factors such as weather and the economy.

In recent years, as market prices declined from previous levels, there was an incentive for more of the smaller commercial and industrial electric customers to switch to third party suppliers. In a falling price environment, this has a negative impact on our margins, as the anticipated BGS pricing is replaced by lower spot market pricing. As average BGS rates have declined to a level that more closely resembles current market prices, customers may see less of an incentive to switch to third party suppliers. We are unable to determine the degree to which this switching, or “migration,” will continue, but the impact on our results could be material should market prices fall significantly.

As of February 11, 2014, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2016.

Base Load Generation	2014	2015	2016
Generation Sales	100%	75%-80%	30%-35%

In a changing market environment, this hedging strategy may cause our realized prices to differ materially from current market prices. In a rising price environment, this strategy normally results in lower margins than would have been the case if little or no hedging activity had been conducted. Alternatively, in a falling price environment, this hedging strategy will tend to create margins higher than those implied by the then current market.

Our fuel strategy is to maintain certain levels of uranium in inventory and to make periodic purchases to support such levels. Our nuclear fuel commitments cover approximately 100% of our estimated uranium, enrichment and fabrication requirements through 2015 and a portion of 2016. We also have various long-term fuel purchase commitments for coal to support our fossil generation stations. These purchase obligations are consistent with our strategy to enter into contracts for its fuel supply in comparable volumes to our sales contracts.

We take a more opportunistic approach in hedging our anticipated natural gas-fired generation. The generation from these units is less predictable, as a significant portion of these units will only dispatch when aggregate market demand has exceeded the supply provided by lower-cost units. Additionally, the recent development of low-cost gas supplies in the Marcellus region presents opportunities during certain portions of the year to procure gas for our generating units at attractive prices.

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PSE&G

Our regulated transmission and distribution public utility, PSE&G, distributes electric energy and gas to customers within a designated service territory running diagonally across New Jersey where approximately 6.2 million people, or about 70% of New Jersey's population resides.

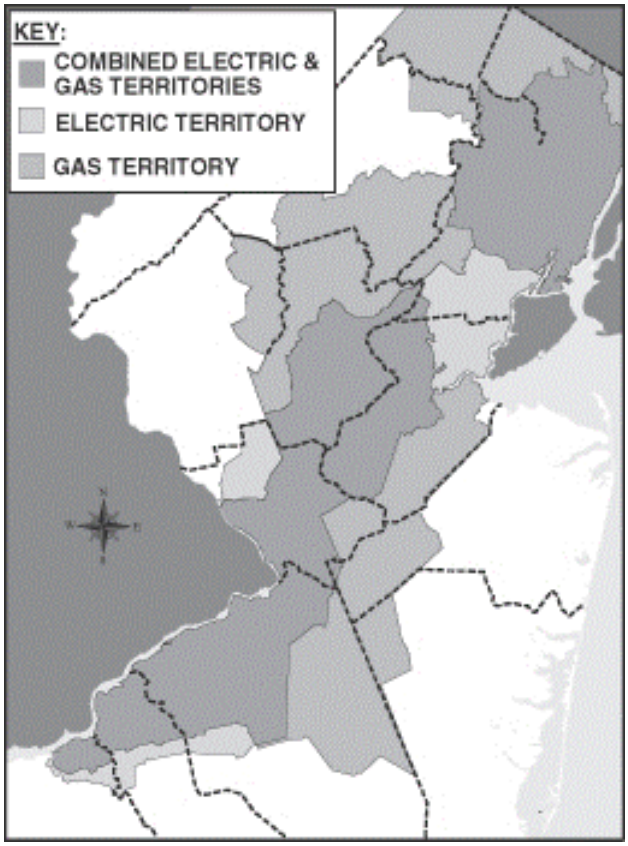

Products and Services

Our utility operations primarily earn margins through the transmission and distribution of electricity and the distribution of gas.

- **Transmission**—the movement of electricity at high voltage from generating plants to substations and transformers, where it is then reduced to a lower voltage for distribution to homes, businesses and industrial customers. Our revenues for these services are based upon tariffs approved by the FERC.
- **Distribution**—the delivery of electricity and gas to the retail customer's home, business or industrial facility. Our revenues for these services are based upon tariffs approved by the BPU.

The commodity portion of our utility business' electric and gas sales is managed by BGS and BGSS suppliers. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for our utility operations.

We also earn margins through competitive services, such as appliance repair.

In addition to our current utility products and services, we have implemented several programs to increase the level of regulated solar generation within New Jersey, including:

- programs to help finance the installation of solar power systems throughout our electric service area, and
- programs to develop, own and operate solar power systems.

We have also implemented a set of energy efficiency and demand response programs to encourage conservation and energy efficiency by providing energy and cost saving measures directly to businesses and families. For additional information

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concerning these programs and the components of our tariffs, see Regulatory Issues—State Regulation and Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

How PSE&G Operates

We are a transmission owner in PJM and we provide distribution service to 2.2 million electric customers and 1.8 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately three hundred suburban and rural communities.

Transmission

We use formula rates for our transmission cost of service and investments. Formula-type rates provide a method of rate recovery where the transmission owner annually determines its revenue requirements through a fixed formula which considers Operations and Maintenance expenditures, Rate Base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. Our approved rates provide for a base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn an additional incentive rate. For more information, see Regulatory Issues—Federal Regulation—Transmission Regulation.

Transmission Statistics

December 31, 2013		
Network Circuit Miles	**Billing Peak (MW)**	**Historical Annual Load Growth 2009-2013**
1,499	10,414	(0.5)%

During 2013, we continued to execute our five major regional transmission projects for which we were assigned construction responsibility by PJM:

Major Transmission Projects
As of December 31, 2013

Project	Total Estimated Project Costs	Total Project Spend	Expected In-Service Date
	Millions		
Susquehanna-Roseland	$790	$661	June 2014/June 2015
Northeast Grid Reliability	$907	$228	June 2015
North Central Reliability	$390	$349	June 2014
Burlington-Camden 230kV	$399	$301	June 2014
Mickleton-Gloucester-Camden 230kV	$435	$122	June 2015

In December 2013, we were assigned construction by PJM of a new transmission project that will provide a double-circuit 345kV line in the Bergen-Linden Corridor to maintain reliability. This project has an expected in-service date of June 2018, and an estimated construction cost of up to $1.2 billion. The net increase in PSE&G's capital expenditures is expected to be less than the estimated cost of the 345 kV project, as it will eliminate the need for certain other projects that had been previously assigned by PJM.

Distribution

PSE&G distributes gas and electricity to end users in our service territory. Our load requirements were split among residential, commercial and industrial customers, as described in the following table for 2013. We believe that we have all the franchise rights (including consents) necessary for our electric and gas distribution operations in the territory we serve.

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Customer Type	% of 2013 Sales Electric	Gas
Commercial	57%	36%
Residential	33%	60%
Industrial	10%	4%
Total	**100%**	**100%**

While our customer base has remained steady, gas load has increased and electric load has declined as illustrated:

Electric and Gas Distribution Statistics

December 31, 2013

	Number of Customers	Electric Sales and Gas Sold and Transported	Historical Annual Load Growth 2009-2013
Electric	2.2 Million	41,277 GWh	(1.1)%
Gas	1.8 Million	3,813 Million Therms	2.1%

The decline in electric sales is the result of changes in customer usage patterns, including conservation, and the slowdown in economic activity that occurred during the recent recession. Gas sales increased as a result of increased usage by non-firm customers as a result of lower gas prices and more favorable winter weather.

Solar Generation

In order to support New Jersey's Energy Master Plan and the state's renewable energy goals, we have undertaken two major solar initiatives at PSE&G, the Solar Loan Program and the Solar 4 All Program. Our Solar Loan Program provides solar system financing to our residential and commercial customers. The loans are repaid with cash or solar renewable energy certificates (SRECs). We sell the SRECs used to repay the loans through a periodic auction, the proceeds of which are used to offset program costs. Our Solar 4 All Program invests in utility-owned solar PV centralized solar systems installed on PSE&G property and third party sites, and solar panels installed on distribution system poles in our electric service territory. We sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition, we sell SRECs generated by the projects through the same periodic auction used in the loan program, the proceeds of which are used to offset program costs. As of December 31, 2013, we have invested an aggregate of approximately $700 million in both solar programs.

Supply

Although commodity revenues make up almost 43% of our revenues, we make no margin on the supply of electricity and gas since the actual costs are passed through to our customers.

All electric and gas customers in New Jersey have the ability to choose their own electric energy and/or gas supplier. Pursuant to the BPU requirements, we serve as the supplier of last resort for two types of electric and gas customers within our service territory that are not served by another supplier. The first type, which represents about 80% of PSE&G's load requirements, provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Fixed Price). These rates change annually on June 1 and are based on the average price obtained at auctions in the current year and two prior years. The second type provides default supply for larger customers, with energy priced at hourly PJM real-time market prices for a contract term of 12 months (BGS-CIEP).

We procure the supply to meet our BGS obligations through auctions authorized by the BPU for New Jersey's total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers are authorized to supply BGS to New Jersey's EDCs. Once validated by the BPU, electricity prices for BGS service are set. Approximately one-third of PSE&G's total BGS-Fixed Price eligible load is auctioned each year for a three-year term. For information on current prices, see Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities.

PSE&G procures the supply requirements of its default service BGSS gas customers through a full requirements contract with Power. The BPU has approved a mechanism designed to recover all gas commodity costs related to BGSS for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. PSE&G's revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each

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year. In addition, we have the ability to put in place two self-implementing BGSS increases on December 1 and February 1 of up to 5% and also may reduce the BGSS rate at any time. See Item 8. Financial Statements and Supplementary Data— Note 6. Regulatory Assets and Liabilities for information on recent self-implementing credits. Any difference between rates charged under the BGSS contract and rates charged to our residential customers is deferred and collected or refunded through adjustments in future rates. Commercial and industrial customers that do not have third party suppliers are also supplied under the BGSS arrangement. These customers are charged a market-based price largely determined by prices for commodity futures contracts.

Markets and Market Pricing

Historically, there has been significant volatility in commodity prices. Such volatility can have a considerable impact on us since a rising commodity price environment results in higher delivered electric and gas rates for customers. This could result in decreased demand for electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs from our customers may be deferred under our regulated rate structure. A declining commodity price on the other hand, would be expected to have the opposite effect. For additional information, including the impact of natural gas commodity prices on electricity prices such as BGS, see Item 7. MD&A—Overview of 2013 and Future Outlook.

Other

Energy Holdings primarily owns and manages a portfolio of lease investments. Over the past several years, we have terminated all of our international leveraged leases in order to reduce the cash tax exposure related to these leases. We have also reduced our risk by opportunistically monetizing all of our previous international investments.

The majority of Energy Holdings' remaining $825 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2013, 70% of our total leveraged lease investments were rated as below investment grade by Standard & Poor's.

Energy Holdings' leveraged leasing portfolio is designed to provide a fixed rate of return. Leveraged lease investments involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease financing, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and, with respect to our lease investments, is not presented on our Consolidated Balance Sheets.

The lessor acquires economic and tax ownership of the asset and then leases it to the lessee for a period of time no greater than 80% of its remaining useful life. As the owner, the lessor is entitled to depreciate the asset under applicable federal and state tax guidelines. The lessor receives income from lease payments made by the lessee during the term of the lease and from tax benefits associated with interest and depreciation deductions with respect to the leased property. Our ability to realize these tax benefits is dependent on operating gains generated by our other operating subsidiaries and allocated pursuant to the consolidated tax sharing agreement between us and our operating subsidiaries.

Lease rental payments are unconditional obligations of the lessee and are set at levels at least sufficient to service the non-recourse lease debt. The lessor is also entitled to any residual value associated with the leased asset at the end of the lease term. An evaluation of the after-tax cash flows to the lessor determines the return on the investment. Under accounting principles generally accepted in the United States (GAAP), the leveraged lease investment is recorded net of non-recourse debt and income is recognized as a constant return on the net unrecovered investment.

For additional information on leases, including the credit, tax and accounting risks, see Item 1A. Risk Factors, Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Credit Risk, Item 8. Financial Statements and Supplementary Data— Note 8. Financing Receivables and Note 13. Commitments and Contingent Liabilities.

On December 31, 2013, PSEG Long Island LLC (PSEG LI) and the Long Island Power Authority (LIPA) entered into a twelve year Amended and Restated Operations Services Agreement (OSA) effective January 1, 2014 to operate LIPA’s electric transmission and distribution (T&D) system in Long Island, New York. As required by the OSA, PSEG LI also provides administrative support functions to LIPA. PSEG LI uses its brand in the Long Island T&D service area. Pursuant to the OSA, PSEG LI acts as LIPA's agent in performing many of its obligations and in return (a) receives reimbursement for pass-through operating expenditures, (b) receives a fixed management fee, and (c) is eligible to receive an incentive fee contingent on meeting established performance metrics. In addition, there is the opportunity for the parties to extend the contract for an additional eight years subject to the achievement by PSEG LI of certain performance levels during the initial term of the OSA. Also, beginning in 2015, Power will provide fuel procurement and power management services to LIPA under separate agreements.

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COMPETITIVE ENVIRONMENT

Power

Various market participants compete with us and one another in buying and selling in the wholesale energy markets, entering into bilateral contracts and selling to aggregated retail customers. Our competitors include:

- merchant generators,
- domestic and multi-national utility generators,
- energy marketers,
- banks, funds and other financial entities,
- fuel supply companies, and
- affiliates of other industrial companies.

New additions of lower-cost or more efficient generation capacity could make our plants less economical in the future. Although it is not clear if this capacity will be built or, if so, what the economic impact will be, such additions could impact market prices and our competitiveness.

Our business is also under competitive pressure due to demand side management (DSM) and other efficiency efforts aimed at changing the quantity and patterns of usage by consumers which could result in a reduction in load requirements. A reduction in load requirements can also be caused by economic cycles, weather, municipal aggregation and other customer migration and other factors. In addition, how resources such as demand response and capacity imports are permitted to bid into the capacity markets also affects the prices paid to generators such as Power in these markets. It is also possible that advances in technology, such as distributed generation and micro grids, will reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. To the extent that additions to the electric transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, our revenues could be adversely affected. Changes in the rules governing what types of transmission will be built, who is permitted to build transmission and who will pay the costs of future transmission could also impact our revenues.

Adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, would have the effect of artificially depressing prices in the competitive wholesale market and thus have the potential to harm competitive markets, on both a short-term and a long-term basis.

Environmental issues, such as restrictions on emissions of carbon dioxide (CO_2) and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant, thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states. If any new legislation were to require our competitors to meet the environmental standards currently imposed upon us, we would likely have an economic advantage since we have already installed significant pollution-control technology at most of our fossil stations.

In addition, pressures from renewable resources could increase over time. For example, many parts of the country, including the mid-western region within the footprint of the Midwest Independent System Operator (MISO), the California ISO and the PJM region, have either implemented or proposed implementing changes to their respective regional transmission planning processes that may enable the construction of large amounts of "public policy" transmission to move renewable generation to load centers. For additional information, see the discussion in Regulatory Issues—Federal Regulation, below.

PSE&G

Our transmission and distribution business is minimally impacted when customers choose alternate electric or gas suppliers since we earn our return by providing transmission and distribution service, not by supplying the commodity. Increased reliance by customers on net-metered generation, including solar, and changes in customer behaviors can result in decreased reliance on our system and impact our revenues and investment opportunities. The demand for electric energy and gas by customers is affected by customer conservation, economic conditions, weather and other factors not within our control.

Changes in the current policies for building new transmission lines, such as those ordered by the FERC and being implemented by PJM and other ISOs to eliminate contractual provisions that provide us a "right of first refusal" to construct projects in our service territory, could result in third party construction of transmission lines in our area in the future and also allow us to seek

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opportunities to build in other service territories. For additional information, see the discussion in Regulatory Issues—Federal Regulation—Transmission Regulation, below.

Construction of new local generation also has the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints.

EMPLOYEE RELATIONS

As of December 31, 2013, we had 9,887 employees within our subsidiaries, including 6,125 covered under collective bargaining agreements. In December 2013, we reached agreement with one of our six labor unions to extend its collective bargaining agreement for three years through April, 2017. Our other collective bargaining agreements expire in April 2017 with three labor unions, in October 2017 with one labor union and in May 2018 with one labor union. We believe we maintain satisfactory relationships with our employees.

Employees as of December 31, 2013

	Power	PSE&G	Other
Non-Union	1,224	1,548	990
Union	1,409	4,707	9
Total Employees	**2,633**	**6,255**	**999**

Effective January 1, 2014, in connection with our new management contract with LIPA we assumed the collective bargaining agreement between National Grid, LIPA's previous management contractor, and a labor union. This union contract expires in February, 2015. We commenced operations in Long Island with approximately 1,400 union employees and 700 non-union employees.

REGULATORY ISSUES

Federal Regulation

FERC

The FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act. PSE&G and the generation and energy trading subsidiaries of Power are public utilities as defined by the FPA. The FERC has extensive oversight over such public utilities. FERC approval is usually required when a public utility seeks to: sell or acquire an asset that is regulated by the FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations.

The FERC also regulates generating facilities known as qualifying facilities (QFs). QFs are cogeneration facilities that produce electricity and another form of useful thermal energy, or small power production facilities where the primary energy source is renewable, biomass, waste or geothermal resources. QFs must meet certain criteria established by the FERC. We own various QFs through Power. QFs are subject to some, but not all, of the same FERC requirements as public utilities.

The FERC also regulates Regional Transmission Operators/ISOs, such as PJM, and their energy and capacity markets.

For us, the major effects of FERC regulation fall into five general categories:

- Regulation of Wholesale Sales—Generation/Market Issues
- Energy Clearing Prices
- Capacity Market Issues
- Transmission Regulation
- Compliance

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Regulation of Wholesale Sales—Generation/Market Issues

Market Power

Under FERC regulations, public utilities must receive FERC authorization to sell power in interstate commerce. They can sell power at cost-based rates or apply to the FERC for authority to make market-based rate (MBR) sales. For a requesting company to receive MBR authority, the FERC must first make a determination that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. The FERC requires that holders of MBR tariffs file an update every three years demonstrating that they continue to lack market power and/or that market power has been sufficiently mitigated and report in the interim to the FERC any material change in facts from those the FERC relied on in granting MBR authority.

PSE&G, PSEG Energy Resources & Trade LLC, PSEG Power Connecticut, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG New Haven LLC all have been granted MBR authority from the FERC. Each of these companies, except PSEG New Haven LLC (which received MBR authority in May 2012), filed a market power update with the FERC at the end of 2013, which the FERC must accept in order for these companies to retain MBR authority. Retention of MBR authority is important to the maintenance of our current generation business' revenues. The matter is pending.

Energy Clearing Prices

Energy clearing prices in the markets in which we operate are generally based on bids submitted by generating units. Under FERC-approved market rules, bids are subject to price caps and mitigation rules applicable to certain generation units. The FERC rules also govern the overall design of these markets. At present, all units receive a single clearing price based on the bid of the marginal unit (i.e. the last unit that must be dispatched to serve the needs of load). These FERC rules have a direct impact on the energy prices received by our units.

Capacity Market Issues

PJM, the NYISO, and the ISO-NE each have capacity markets that have been approved by the FERC. The FERC regulates these markets and held a technical conference in September 2013 to examine whether the market design for these three capacity markets is working optimally. One of the specific issues being considered by the FERC is whether capacity market rules are properly responding to, and fostering the development of, state public policies, demand response and emerging technologies. We cannot predict what action, if any, the FERC might take with regard to capacity market design.

PJM—RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of RPM in PJM continue to evolve and be refined in stakeholder proceedings in which we are active. There is currently significant discussion about (i) the future role of demand response in the RPM market, including examining how demand response resources should be paid and how these resources and programs - both existing and planned - should be measured, verified and bid in RPM to ensure their availability, (ii) the setting of the Cost of New Entry (CONE) value for the RPM demand curve for the next three years, which is a major input in establishing the price generators will be paid in RPM, (iii) the future process for submitting below Minimum Offer Price Rule (MOPR) bids by subsidized generation into the capacity market, as further discussed below and (iv) the impact of "seams" issues on the PJM capacity market, such as the extent to which the rules governing generation located within PJM are being equally applied to generation imported into PJM from the MISO, as further discussed below.

The FERC has recently issued an order capping the amount of "limited" demand response resources (i.e. resources which can only be called on by PJM a limited number of times during the summer months) that can clear in PJM's capacity auctions. PJM expects that capping "limited" demand response participation will have an upward effect on capacity prices in the next auction.

MISO—MISO does not have a mandatory capacity market in place, as load serving entities may submit Fixed Resource Adequacy Plans in lieu of participating in the capacity auction. In the May 2013 RPM auction, the difference between the MISO and PJM capacity markets was highlighted, as significant amounts of MISO generation were bid as imports into PJM and cleared in RPM. MISO is seeking to facilitate additional exports. The FERC is currently examining this "capacity portability" issue. To the extent that MISO generation is not subject to the same types of rules and requirements as generation located within PJM, Power could be adversely impacted.

ISO-NE—ISO-NE's market for installed capacity in New England provides fixed capacity payments for generators, imports and demand response. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. The FERC has recently issued an order requiring the implementation of a downward sloping demand curve, similar to the design in place in PJM, for use in ISO-NE's ninth capacity market auction to be held in February 2015 and effective in the 2018-2019 power year. This action is expected to result in greater stability of capacity prices in New

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England. As in PJM, capacity market rules in the ISO-NE continue to develop, with significant issues still under consideration, including the number and location of capacity zones to be utilized and how the ISO-NE addresses the impact of state-funded programs such as renewable resources.

NYISO—NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. The NYISO capacity model currently recognizes only two separate zones that potentially may separate in price: New York City and Long Island. On August 13, 2013, the FERC issued an order approving NYISO's April 30, 2013 filing establishing the boundaries of a third capacity zone that will encompass the super zone that includes the lower Hudson Valley and New York City to take effect May 1, 2014. The FERC is also currently considering what type of generation unit should be used as the reference unit for the purposes of establishing the CONE in the "rest of State" zone (excluding the lower Hudson Valley, New York City and Long Island). This issue is significant since it will set the demand curve on which future capacity prices paid to generators will be based for the period May 1, 2014 through April 30, 2017. In January 2014, the FERC issued an order accepting the NYISO's proposed reference unit (a unit with no environmental controls), which may have the effect of depressing capacity prices. This order is subject to rehearing.

Discussions at the FERC concerning other potential changes to NYISO capacity markets, including rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons, are also ongoing.

Long-Term Capacity Agreement Pilot Program Act (LCAPP)—In 2011, the State of New Jersey enacted the LCAPP to subsidize approximately 2,000 MW of new natural gas-fired generation. The LCAPP provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey EDCs. The SOCA required each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers. Each of the New Jersey EDCs, including PSE&G, entered into three SOCAs as directed by the State, but did so under protest reserving their rights.

In 2013, the U.S. District Court in New Jersey found that the LCAPP was unconstitutional and declared the LCAPP null and void. This federal court decision is currently being challenged on appeal in the Third Circuit Court of Appeals. The State of Maryland also took action to subsidize above-market new generation. This action was also determined to be unconstitutional in 2013 in the U.S. District Court in Maryland. The federal court decision is currently being challenged in the Fourth Circuit Court of Appeals.

As a result of the New Jersey U.S. District Court's final decision, PSE&G terminated the SOCA contracts in November 2013 with CPV Shore, LLC (CPV), a subsidiary of Competitive Power Ventures, Inc. and Hess Newark, LLC (Hess), a subsidiary of Hess Corporation, the counterparties to two of the SOCA contracts, by providing written notice in accordance with the terms of the SOCA contracts. The third SOCA contract had been terminated earlier in 2013 due to a default by the generator.

Transmission Regulation

The FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are then trued up the following year to reflect actual annual expenses and capital expenditures. Our allowed ROE is 11.68% for both existing and new transmission investments and we have received incentive rates, affording a higher ROE, for certain large scale transmission investments. For information about our transmission formula rate, including our 2014 Annual Formula Rate update filing with the FERC, see Item 8. Financial Statements and Supplementary Data— Note 6. Regulatory Assets and Liabilities .

Our 2013 Annual Formula Rate Update with the FERC provided for approximately $174 million in increased annual transmission revenues effective January 1, 2013. Our 2014 Annual Formula Rate Update with the FERC provides for approximately $171 million in increased annual transmission revenues effective January 1, 2014.

- ***Transmission Policy Developments***—The FERC concluded in Order No. 1000 that the incumbent transmission owner should not always have a "right of first refusal" (ROFR) to construct and own transmission projects in its service territory. We have challenged the FERC's elimination of the ROFR in federal court, which challenge remains pending. PJM is currently implementing new rules under which the construction of certain types of transmission projects is no longer subject to a ROFR for incumbents. The FERC has also approved the "state agreement approach" to cost allocation under which transmission projects being built to address public policy concerns may be placed into PJM's planning process if the state sponsoring the project agrees to pay the costs of the project. To date, no such projects have been placed into the planning process but this mechanism could potentially facilitate transmission projects that are not needed for reliability or market efficiency under PJM standards for transmission, including potential offshore wind projects proposed by third parties, should a state or states agree to fund the costs of such projects.

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We cannot predict the final outcome or impact on us; however, specific implementation of Order 1000 in the various regions, including within our service territory, may expose us to competition from third party construction of certain transmission projects within our service territory while at the same time providing opportunities to build transmission outside of our service territory.

- ***Transmission Rate Proceedings***—In September 2011, a complaint was filed by several state utility commissions and consumer advocates against transmission owners in New England challenging their base ROE. In August 2013, a FERC Administrative Law Judge (ALJ) issued a decision finding the utilities' base ROE to no longer be just and reasonable. In February 2013, several state utility commissions and consumer advocates, including the BPU and the New Jersey Division of Rate Counsel, also filed a complaint at the FERC challenging the base ROE and formula transmission rate implementation protocols of transmission owners in Maryland, Pennsylvania, Delaware and New Jersey. This complaint remains pending. In addition, on November 12, 2013, a group of industrial customers in MISO filed a complaint against the MISO transmission owners, requesting that the FERC reduce the transmission owners' base ROE and eliminate the ROE adders for among other things, participation in an RTO. Alternatively, the customers requested that the FERC find the base ROE to be unjust and unreasonable and expeditiously establish settlement procedures. Further, on February 6, 2014, a public power association in New York filed a complaint against one of the New York transmission owners asking the FERC to reduce the ROE used to calculate the transmission owner's rates. The results of these proceedings could set a precedent for the FERC-regulated transmission owners with formula rates in place, such as ours.

The FERC has issued an order setting for hearing and settlement procedures certain rate challenges raised by a municipal electric cooperative against a transmission owner in PJM. Specifically, the electric cooperative challenged the prudency of categories of costs included by the transmission owner in its formula rate. The FERC found that the challenges raised issues of fact that warranted examination at hearing. While we are not the subject of the challenge, the result of this proceeding could set a precedent for other transmission owners with formula rates in place, including PSE&G.

Compliance

- ***FERC Audit***—Each of the PSEG companies that have MBR authority from the FERC is being audited by the FERC for compliance with its rules for (i) receiving and retaining MBR authority (ii) the filing of electric quarterly reports and (iii) our units' receipt of payments from the RTO/ISO when they are required to run for reliability reasons when it is not economical for them to do so. The FERC will issue a report at the conclusion of the audit.
- ***Reliability Standards***—Congress has required the FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the United States electric transmission and generation system and to prevent major system blackouts. Many reliability standards have been developed and approved. These standards apply both to reliability of physical assets interconnected to the bulk power system and to the protection of critical cyber assets. In 2013, the FERC enacted new rules that will bring our generating units within the scope of the standards applicable to critical cyber assets and increase our compliance responsibilities.

Commodity Futures Trading Commission (CFTC)

In accordance with the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), the SEC and the CFTC are in the process of implementing a new regulatory framework for swaps and security-based swaps. The legislation was enacted to reduce systemic risk, increase transparency and promote market integrity within the financial system by providing for the registration and comprehensive regulation of swap dealers and by imposing recordkeeping, data reporting, margin and clearing requirements with respect to swaps. To implement the Dodd-Frank Act, the CFTC has engaged in a comprehensive rulemaking process and has issued a number of proposed and final rules addressing many of the key issues. We are currently subject to record keeping and data reporting requirements applicable to commercial end users. The CFTC has also proposed rules establishing position limits for trading in certain commodities, such as natural gas, and we are currently analyzing the potential impact of these rules on our business.

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Nuclear Regulatory Commission (NRC)

Our operation of nuclear generating facilities is subject to comprehensive regulation by the NRC, a federal agency established to regulate nuclear activities to ensure protection of public health and safety, as well as the security and protection of the environment. Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstration to the NRC that plant operations meet requirements is also necessary. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate. The current operating licenses of our nuclear facilities expire in the years shown in the following table:

Unit	Year
Salem Unit 1	2036
Salem Unit 2	2040
Hope Creek	2046
Peach Bottom Unit 2	2033
Peach Bottom Unit 3	2034

As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in 2011, the NRC began performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events in Japan have resulted in additional regulation for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants currently meet the stringent applicable design and safety specifications of the NRC.

In 2011, the NRC task force submitted a report containing various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. The NRC staff also issued a document which provided for a prioritization of the task force recommendations. The NRC approved the staff's prioritization and implementation recommendations subject to a number of conditions. Among other things, the NRC advised the staff to give the highest priority to those activities that can achieve the greatest safety benefit and/or have the broadest applicability (Tier 1), to review filtration of boiling water reactor (BWR) primary containment vents and encouraged the staff to create requirements based on a performance-based system which allows for flexible approaches and the ability to address a diverse range of site-specific circumstances and conditions and strive to implement the requirements by 2016. The NRC issued letters and orders to licensees implementing the Tier 1 recommendations in March 2012.

Separately, a petition was filed with the NRC in April 2011 seeking suspension of the operating licenses of all General Electric BWRs utilizing the Mark I containment design in the United States, including our Hope Creek and Peach Bottom units, pending completion of the NRC review. Fukushima Daiichi Units 1-4 are BWRs equipped with Mark I containments. The petition names 23 of the total 104 active commercial nuclear reactors in the United States. While we do not believe the petition will be successful, we are unable to predict the outcome of any action that the NRC may take in connection with the petition.

On March 19, 2013, the NRC initiated a rulemaking process for improvements to venting systems at 31 U.S. BWRs with “Mark I” and “Mark II” containments (similar to those at Fukushima), which include our Hope Creek Unit and Peach Bottom Units 2 and 3. On June 6, 2013, the NRC issued orders requiring Mark I and Mark II licensees to upgrade or replace their reliable hardened vents with containment venting systems designed and installed to remain functional during severe accident conditions. For our Hope Creek and Peach Bottom units, final installation of the required modifications is expected to occur during the planned refueling outages in 2016-2018.

The NRC is currently developing the regulatory basis for the filtering strategies rulemaking. That evaluation is expected to be completed in December 2014. The NRC continues to evaluate potential revisions to its requirements in connection with its operational and safety reviews of nuclear facilities in the United States as a result of the Fukushima Daiichi incident.

We are unable to predict the final outcome of these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to our Salem, Hope Creek and Peach Bottom facilities, but such cost could be material.

State Regulation

Since our operations are primarily located within New Jersey, our principal state regulator is the BPU, which oversees electric and natural gas distribution companies in New Jersey. We are also subject to various other states’ regulations due to our operations in those states.

Our New Jersey utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. PSE&G's participation in solar, demand response and energy efficiency programs is also regulated by the

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BPU, as the terms and conditions of these programs are approved by the BPU. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey.

We must file electric and gas rate cases with the BPU in order to change our utility base distribution rates. Our last base rate case was settled in 2010. In addition to base rates, we recover certain costs or earn on certain investments pursuant to mechanisms known as adjustment clauses. These clauses permit the flow-through of costs to, or the recovery of investments from, customers related to specific programs, outside the context of base rate case proceedings. Recovery of these costs or investments is subject to BPU approval for which we make periodic filings. Delays in the pass-through of costs or recovery of investments under these mechanisms could result in significant changes in cash flow. For additional information on our specific filings, see Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

Significant state regulatory matters that may have an impact on our business are as follows:

Energy Strong Program—In February 2013, we filed a petition with the BPU describing the improvements we recommend making to our BPU jurisdictional electric and gas system to improve resiliency for the future. The changes that were described would be made over a ten-year period. In this petition, we are seeking approval to invest $0.9 billion in our gas distribution system and $1.7 billion in our electric distribution system over an initial five-year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. The current estimated cost of the entire program, including the first five years of investments for which we sought approval in this petition, is $3.9 billion. We anticipate seeking BPU approval to complete our investment under the program at a later date. We have continued to respond to data requests from the BPU, the New Jersey Division of Rate Counsel and intervenors. All required public hearings were completed in October 2013, and the review of PSE&G's proposal is ongoing at the BPU. We cannot predict the outcome of this matter. For additional information, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations —Capital Requirements.

Storm Proceedings—In the fourth quarter of 2012, we were severely impacted by Superstorm Sandy, which resulted in the highest level of customer outages in our history. We sustained significant damage to some of our generation, transmission and distribution facilities. In December 2012, the BPU issued an order allowing PSE&G to defer on its books actually incurred, prudent, incremental storm restoration costs associated with extraordinary storms, including Superstorm Sandy and Hurricane Irene, and not otherwise recoverable through base rates or insurance. In March 2013, the BPU initiated two generic proceedings with the New Jersey utilities, including PSE&G. The first was a proceeding to evaluate the prudency of storm costs incurred in 2011 and 2012 and the second was to evaluate major storm event mitigation proposals. In June 2013, PSE&G made its compliance filing in the storm cost prudency proceeding, providing certain details of our storm restoration costs for Superstorm Sandy as well as other major storms, including outage information, capital expenditures, operation and maintenance (O&M) expenses and incremental O&M expenses. We requested that the BPU issue an Order approving the compliance filing and specifically finding that the storm costs incurred were reasonable and prudent, and should be recovered from ratepayers. The review of the prudency of these expenses is now pending before the BPU. We cannot predict the outcome of this review. As of December 31, 2013, we had deferred $245 million in storm costs as a Regulatory Asset.

New Jersey Energy Master Plan (EMP)—New Jersey law requires that an EMP be developed every three years, the purpose of which is to ensure safe, secure and reasonably-priced energy supply, foster economic growth and development and protect the environment. While not having the force of law, the EMP provides an overview of energy policy in New Jersey and may provide both opportunities and challenges for PSEG. The most recent EMP was finalized in December 2011 and placed an emphasis on expanding in-state electricity resources, reducing energy costs, recognizing the impact of climate change and setting new targets for a renewable portfolio standard and goals for energy supplies from clean energy sources.

ENVIRONMENTAL MATTERS

Changing environmental laws and regulations significantly impact the manner in which our operations are currently conducted and impose costs on us to reduce the health and environmental impacts of our operations. To the extent that environmental requirements are more stringent and compliance more costly in certain states where we operate compared to other states that are part of the same market, such rules may impact our ability to compete within that market. Due to evolving environmental regulations, it is difficult to project future costs of compliance and their impact on competition. Capital costs of complying with known pollution control requirements are included in our estimate of construction expenditures in Item 7. MD&A—Capital Requirements. The costs of compliance associated with any new requirements that may be imposed by future regulations are not known, but may be material.

Areas of environmental regulation may include, but are not limited to:

- air pollution control,
- climate change,

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- water pollution control,
- hazardous substance liability, and
- fuel and waste disposal.

For additional information related to environmental matters, including proceedings not discussed below, as well as anticipated expenditures for installation of pollution control equipment, hazardous substance liabilities and fuel and waste disposal costs, see Item 1A. Risk Factors, Item 3. Legal Proceedings and Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities.

Air Pollution Control

Our facilities are subject to federal regulation under the Clean Air Act (CAA) which requires controls of emissions from sources of air pollution and imposes record keeping, reporting and permit requirements. Our facilities are also subject to requirements established under state and local air pollution laws. The CAA requires all major sources, such as our generation facilities, to obtain and keep current an operating permit. The costs of compliance associated with any new requirements that may be imposed and included in these permits in the future could be material and are not included in our estimates of capital expenditures.

- ***Nitrogen Oxide (NO_x) Regulation: New Jersey High Electric Demand Day***—In April 2009, the New Jersey Department of Environmental Protection (NJDEP) finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on our generation fleet, as it imposes NO_x emissions limits that require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) and four older New Jersey steam electric generation units (approximately 400 MW) by May 2015. See Item 8. Financial and Supplementary Data— Note 13. Commitments and Contingent Liabilities for further discussion of this issue.
- ***Hazardous Air Pollutants Regulation***—In February 2012, the EPA published under the National Emission Standard for Hazardous Air Pollutants provisions of the CAA, Mercury Air Toxics Standards (MATS) for both newly-built and existing electric generating sources. The impact to our fossil generation fleet in New Jersey and Connecticut and our jointly-owned coal-fired generating facilities in Pennsylvania is further discussed in Item 8. Financial and Supplementary Data— Note 13. Commitments and Contingent Liabilities.
- ***Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation***—In March and April 2013, we filed petitions at the EPA and in federal court, respectively, challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued on January 30, 2013. Among other things, the final EPA rule allows owners and operators of stationary emergency RICE to operate their engines as part of an emergency DR program without the installation and operation of emission controls or compliance with emission limits otherwise applicable to non-emergency counterparts. This waiver of NESHAP standards results in disparate treatment of different generation technology types. In our appeal, we are seeking more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. On June 28, 2013, the EPA announced that it would reconsider certain other items included in the final rule that are also subject to the appeal. We cannot predict the final outcome of the EPA's action regarding NESHAP.
- ***Cross-State Air Pollution Rule (CSAPR)***—In July 2011, the EPA issued the final CSAPR, which limits power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season NO_x in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards (NAAQS). In August 2012, the U.S. Court of Appeals for the D.C. Circuit (D.C. Court) vacated CSAPR and ordered that the existing Clean Air Interstate Rule (CAIR) requirements remain in effect until an appropriate substitute rule has been promulgated. The purpose of CAIR is to improve ozone and fine particulate air quality within states that have not demonstrated achievement of the NAAQS. CAIR was implemented through a cap-and-trade program and, to date, the impact has not been material to us as the allowances allocated to our stations were sufficient. If 2014 operations are similar to those in the past four years, it is expected that the impact to our operations from CAIR in New Jersey, New York and Connecticut in 2014 will not be significant.

  In June 2013, the Supreme Court announced that it would review the D.C. Court's decision. Oral arguments were held in December 2013. If the Supreme Court were to overturn the D.C. Court's ruling and reinstate CSAPR, we do not anticipate that there will be any material adverse impact on our earnings and financial condition. The EPA has announced its plan to propose a new rule in late 2014 to replace the vacated CSAPR that will solely address ozone NAAQS for NO_x. We cannot determine the impact that this new rule might have on us.

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Climate Change

- ***CO_2 Regulation Under the* CAA**—In April 2013, several industrial groups petitioned the Supreme Court to review various EPA rules issued under the CAA, including the Tailoring Rule, to regulate greenhouse gas (GHG) emissions, including CO_2. The Tailoring Rule requires a new source or an existing source which undergoes a major modification, to evaluate and perhaps install best available control technology (BACT) for GHG emissions. On October 15, 2013, the Supreme Court agreed to add the case to the docket for its current term to consider whether the EPA has authority to regulate CO_2 emissions of stationary sources, including power plants.

  In April 2012, the EPA published the proposed New Source Performance Standards (NSPS) for GHG for new power plants only. On June 25, 2013, the President directed the EPA to propose revised NSPS for new power plants by September 20, 2013, propose GHG regulations for existing power plants by June 1, 2014, finalize such regulations by June 1, 2015 and require states to submit GHG implementation regulations by June 30, 2016.

  On January 8, 2014, the EPA proposed revised NSPS for new power plants. The revised NSPS establish three emission standards for CO_2 emissions for the following categories: (i) fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units, (ii) large natural gas combustion turbines, and (iii) small natural gas combustion turbines. The EPA is requesting comment on use of an electric output sales threshold to determine applicability to the NSPS. This electric output sales threshold would eliminate the outright exclusion of simple cycle combustion turbines which was proposed in the initial April 2012 NSPS. We cannot predict the final outcome of these proposed standards.

  If relevant federal or state common law were to impose liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to our fossil generation operations could be material. However, approximately 60% of our generation output comes from nuclear facilities which are GHG-free and would not be impacted.

- ***Climate-Related Legislation***—The federal government may consider legislative proposals to define a national energy policy and address climate change. Proposals under consideration include, but are not limited to, provisions to establish a national clean energy portfolio standard and to establish an energy efficiency resource standard. Provisions of any new proposal may present material risks and opportunities to our businesses. The final design of any legislation will determine the impact on us, which we are not now able to reasonably estimate.

- ***Regional Greenhouse Gas Initiative (RGGI)***—In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. Certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions.

  These rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three-year period. Allowances are available through the auction or through secondary markets.

  On February 7, 2013, the RGGI States released an updated Model Rule that, among other things, reduces the amount of available regional CO_2 allowances beginning in 2014. Each RGGI State must implement the changes through state-specific regulations. We do not expect these changes, or any future changes, to the RGGI rules will have a material impact on us.

  New Jersey withdrew from RGGI beginning in 2012. As a result, our New Jersey facilities are no longer obligated to acquire CO_2 emission allowances. This action has been challenged by environmental groups in the New Jersey state court. We cannot predict the outcome of this matter.

  New Jersey also adopted the Global Warming Response Act in 2007, which calls for stabilizing its GHG emissions to 1990 levels by 2020, followed by a further reduction of greenhouse emissions to 80% below 2006 levels by 2050. To reach this goal, the NJDEP, the BPU, other state agencies and stakeholders are required to evaluate methods to meet and exceed the emission reduction targets, taking into account their economic benefits and costs.

Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to U.S. waters from point sources, except pursuant to a National Pollutant Discharge Elimination System (NPDES) permit issued by the EPA or by a state under a federally authorized state program. The FWPCA authorizes the imposition of technology-based and water quality-based effluent limits to regulate the discharge of pollutants into surface waters and ground waters. The EPA has delegated authority to a number of state agencies, including those in New Jersey, New York and Connecticut, to administer the NPDES program

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through state action. We also have ownership interests in facilities in other jurisdictions that have their own laws and implement regulations to control discharges to their surface waters and ground waters that directly govern our facilities in those jurisdictions.

- ***Steam Electric Effluent Guidelines***—In April 2013, the EPA issued notice of a proposed rule that would further limit the discharge of pollutants in wastewater from the operation of coal-fired generating facilities. Our co-owned Keystone and Conemaugh facilities continue to use technologies that generate these wastewater discharges. However, our other coal-fired facilities no longer discharge many of these types of wastewater pollutants. We are unable to predict the impact on Keystone and Conemaugh but do not believe there would be any material impact on our other coal-fired facilities.

In addition to regulating the discharge of pollutants, the FWPCA regulates the intake of surface waters for cooling. The use of cooling water is a significant part of the generation of electricity at steam-electric generating stations. Section 316(b) of the FWPCA requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The impact of regulations under Section 316(b) can be significant, particularly at steam-electric generating stations which do not have closed cycle cooling through the use of cooling towers to recycle water for cooling purposes. The installation of cooling towers at an existing generating station can impose significant engineering challenges and significant costs, which can affect the economic viability of a particular plant.

- ***Cooling Water Intake Structure Regulation***—In 2011, the EPA published a new proposed rule which did not establish any particular technology as the BTA (e.g. closed-cycle cooling). Instead, the proposed rule established marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. We reviewed the proposed rule, assessed the potential impact on our generating facilities and used this information to develop our comments to the EPA which were filed in August 2011. In June 2012, the EPA posted a Notice of Data Availability (NODA) requesting comment on a series of technical issues related to the impingement mortality proposed standards. The EPA also posted a second NODA outlining its plans to finalize a "Willingness to Pay" survey it initiated to develop non-use benefits data in support of the initial rule proposal. We and industry trade associations submitted comments on both NODAs in July 2012. The EPA has rescheduled the date for adoption of a final rule several times. The EPA is currently scheduled to issue a final rule on April 17, 2014.

  If the rule were to be adopted as originally proposed, the impact on us would be material since the majority of our electric generating stations would be affected. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities for additional information.

  On October 1, 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court of New Jersey seeking to force the NJDEP to take action on our pending application for permit renewal at Salem either by denying the application or issuing a draft for public comment. The permit is currently pending the EPA's finalization of the Clean Water Act 316(b) regulations. We were not named in the lawsuit nor do we know how this legal action will proceed but it could have a material impact on us.

Hazardous Substance Liability

The production and delivery of electricity, the distribution of gas and, formerly, the manufacture of gas, results in various by-products and substances classified by federal and state regulations as hazardous. These regulations may impose liability for damages to the environment from hazardous substances, including obligations to conduct environmental remediation of discharged hazardous substances as well as monetary payments, regardless of the absence of fault and the absence of any prohibitions against the activity when it occurred, as compensation for injuries to natural resources. Our historic operations and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by federal and state agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex. For additional information, see Item 8. Financial Statements and Supplementary Data —Note 13. Commitments and Contingent Liabilities .

- ***Site Remediation***—The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and the New Jersey Spill Compensation and Control Act (Spill Act) require the remediation of discharged hazardous substances and authorize the EPA, the NJDEP and private parties to commence lawsuits to compel clean-ups or reimbursement for such remediation. The clean-ups can be more complicated and costly when the hazardous substances are in a body of water.
- ***Natural Resource Damages***—CERCLA and the Spill Act authorize the assessment of damages against persons who have discharged a hazardous substance, causing an injury to natural resources. Pursuant to the Spill Act, the NJDEP

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requires persons conducting remediation to characterize injuries to natural resources and to address those injuries through restoration or damages. The NJDEP adopted regulations concerning site investigation and remediation that require an ecological evaluation of potential damages to natural resources in connection with an environmental investigation of contaminated sites. The NJDEP also issued guidance to assist parties in calculating their natural resource damage liability for settlement purposes, but has stated that those calculations are applicable only for those parties that volunteer to settle a claim for natural resource damages before a claim is asserted by the NJDEP. We are currently unable to assess the magnitude of the potential financial impact of this regulatory change, although such impacts could be material.

Fuel and Waste Disposal

- ***Nuclear Fuel Disposal***—The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In accordance with the Nuclear Waste Policy Act of 1982, in 2009 the U.S. Department of Energy (DOE) conducted its annual review of the adequacy of the Nuclear Waste Fee and concluded that the current fee of 1/10 cent per kWh was adequate to recover program costs. In 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit in federal court seeking suspension of the Nuclear Waste Fee. In June 2012, the court ruled that the DOE failed to justify continued payments by electricity consumers into the Nuclear Waste Fund and ordered the DOE to conduct a complete reassessment of this fee.

  Spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites. We have on-site storage facilities that are expected to satisfy the storage needs of Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 through the end of their operating licenses. In November 2013, the court ordered the DOE Secretary to submit a proposal to Congress to adjust the fee to zero. In January 2014, the DOE Secretary comported with the court order and submitted the zero fee adjustment change letter to Congress, subject to DOE appeal rights. Absent Congressional and/or further Court action, the fee will revert to zero after ninety days of continuous legislative session. The earliest this is anticipated to occur is in the third quarter of 2014. If the fee were to be eliminated, Power would see an annualized pre-tax benefit of approximately $30 million.
- ***Low Level Radioactive Waste***—As a by-product of their operations, nuclear generation units produce low level radioactive waste. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. These waste materials are accumulated on site and disposed of at licensed permanent disposal facilities. New Jersey, Connecticut and South Carolina have formed the Atlantic Compact, which gives New Jersey nuclear generators continued access to the Barnwell waste disposal facility which is owned by South Carolina. We believe that the Atlantic Compact will provide for adequate low level radioactive waste disposal for Salem and Hope Creek through the end of their current licenses including full decommissioning, although no assurances can be given. Low Level Radioactive Waste is periodically being shipped to the Barnwell site from Salem and Hope Creek. Additionally, **t**here are on-site storage facilities for Salem, Hope Creek and Peach Bottom, which we believe have the capacity for at least five years of temporary storage for each facility.
- ***Coal Combustion Residuals (CCRs)***—In June 2010, the EPA published a proposed rule offering three main options for the management of CCRs under the Resource Conservation and Recovery Act. One of these options regulates CCRs as a hazardous waste. The final outcome of the EPA's proposed rulemaking cannot be predicted.

  In April 2012, several environmental organizations and CCR marketers brought a citizens' suit against the EPA in federal court arguing that the EPA has a non-discretionary duty to issue the CCR rules by a certain date. In May 2012, the Utility Solid Waste Activities Group, of which PSEG is a member, filed a Motion to Intervene in order to be in alignment with the EPA in defending against the environmental organizations' action. On October 29, 2013, the Court issued a decision requiring the EPA to establish a regulatory deadline to issue the CCR Final Rule.

SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Item 8. Financial Statements and Supplementary Data— Note 23. Financial Information by Business Segment.

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ITEM 1A. RISK FACTORS

The following factors should be considered when reviewing our business. These factors could have a material adverse impact on our financial position, results of operations or net cash flows and could cause results to differ materially from those expressed elsewhere in this report.

The factors discussed in Item 7. MD&A may also have a material adverse effect on our results of operations and cash flows and affect the market prices for our publicly-traded securities. While we believe that we have identified and discussed the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant.

We are subject to comprehensive and evolving regulation by federal, state and local regulatory agencies that affects, or may affect, our businesses.

We are subject to regulation by federal, state and local authorities. Changes in regulation can cause significant delays in or materially affect business planning and transactions and can materially increase our costs. Regulation affects almost every aspect of our businesses, such as our ability to:

- ***Obtain fair and timely rate relief***—PSE&G's retail rates are regulated by the BPU and its wholesale transmission rates are regulated by the FERC. The retail rates for electric and gas distribution services are established in a base rate case and remain in effect until a new base rate case is filed and concluded. In addition, our utility has received approval for several clause recovery mechanisms, some of which provide for recovery of and on the authorized investments. These clause mechanisms require periodic updates to be reviewed and approved by the BPU. Our utility's transmission rates are recovered through a FERC-approved formula rate. The revenue requirements are reset each year through this formula. Transmission ROEs have recently become the target of certain state utility commissions, municipal utilities, consumer advocates and consumer groups seeking to lower customer rates in New England and New York. These agencies and groups have filed complaints at the FERC asking the FERC to reduce the base ROE of various transmission owners. They point to changes in the capital markets as justification for lowering the ROE of these companies. While we are not the subject of any of these complaints, they could set a precedent for FERC-regulated transmission owners, such as PSE&G. Inability to obtain fair or timely recovery of all our costs, including a return of or on our investments in rates, could have a material adverse impact on our business.
- ***Obtain required regulatory approvals***—The majority of our businesses operate under MBR authority granted by the FERC, which has determined that our subsidiaries do not have unmitigated market power and that MBR rules have been satisfied. Failure to maintain MBR eligibility, or the effects of any severe mitigation measures that may be required if market power was evaluated differently in the future, could have a material adverse effect on us.

  We may also require various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals on a timely basis could materially adversely affect our results of operations and cash flows.
- ***Comply with regulatory requirements***—There are federal standards, including mandatory NERC and Critical Infrastructure Protection standards, in place to ensure the reliability of the U. S. electric transmission and generation system and to prevent major system black-outs. We have been, and will continue to be, periodically audited by the NERC for compliance.

  Further, the FERC requires compliance with all of its rules and orders, including rules concerning Standards of Conduct, market behavior and anti-manipulation rules, reporting, interlocking directorate rules and cross-subsidization. Our companies with MBR authority are currently being audited by the FERC for compliance with FERC's rules regarding MBR authority, the filing of Electric Quarterly Reports (EQRs) and the receipt of payments in organized markets by our generating units that are required to run for reliability reasons when it is not economical for them to do so.

  We are subject to the reporting and record-keeping requirements of the Dodd-Frank Act, as implemented by the CFTC, and may in the future be subject to CFTC requirements regarding position limits for trading of certain commodities. As part of the Dodd-Frank Act compliance, we will need to be vigilant in monitoring and reporting our swap transactions.

  The BPU conducts periodic combined management/competitive service audits of New Jersey utilities related to affiliate standard requirements, competitive services, cross-subsidization, cost allocation and other issues. The BPU is near completion of a combined management audit and affiliate transactions audit of PSE&G.

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We are exposed to commodity price volatility as a result of our participation in the wholesale energy markets.

The material risks associated with the wholesale energy markets known or currently anticipated that could adversely affect our operations include:

- ***Price fluctuations and collateral requirements*** —We expect to meet our supply obligations through a combination of generation and energy purchases. We also enter into derivative and other positions related to our generation assets and supply obligations. As a result, we are subject to the risk of price fluctuations that could affect our future results and impact our liquidity needs. These include:
  - variability in costs, such as changes in the expected price of energy and capacity that we sell into the market,
  - increases in the price of energy purchased to meet supply obligations or the amount of excess energy sold into the market,
  - the cost of fuel to generate electricity, and
  - the cost of emission credits and congestion credits that we use to transmit electricity.

In the markets where we operate, natural gas prices typically have a major impact on the price that generators receive for their output, especially in periods of relatively strong demand. Therefore, significant changes in the price of natural gas usually translate into significant changes in the wholesale price of electricity.

Over the past few years, wholesale prices for natural gas have declined from the peak levels experienced in 2008. One reason for this decline is increased shale gas production as extraction technology has improved. Lower gas prices have resulted in lower electricity prices, which has reduced our margins as nuclear and coal generation costs have not declined similarly. Over that time, generation by our coal units was also adversely affected by the relatively lower price of natural gas as compared to coal, making it sometimes more economical to run certain of our gas units than our coal units.

Natural gas prices may remain at low levels for an extended period and continue to decline if further advances in technology result in greater volumes of shale gas production.

Many factors may affect capacity pricing in PJM, including but not limited to:

- changes in load and demand,
- changes in the available amounts of demand response resources,
- changes in available generating capacity (including retirements, additions, derates, forced outage rates, etc.),
- increases in transmission capability between zones, and
- changes to the pricing mechanism, including increasing the potential number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM may propose over time, including issues currently pending at the FERC.

Potential changes to the rules governing energy markets in which the output of our plants is sold also poses risk to our business, as discussed further below.

As market prices for energy and fuel fluctuate, our forward energy sale and forward fuel purchase contracts could require us to post substantial additional collateral, thus requiring us to obtain additional sources of liquidity during periods when our ability to do so may be limited. If Power were to lose its investment grade credit rating, it would be required under certain agreements to provide a significant amount of additional collateral in the form of letters of credit or cash, which would have a material adverse effect on our liquidity and cash flows. If Power had lost its investment grade credit rating as of December 31, 2013, it may have had to provide approximately $691 million in additional collateral. We may also be subject to additional collateral requirements which could be required under new rules being developed by the CFTC which are expected to be implemented in 2014.

- ***Our cost of coal and nuclear fuel may substantially increase*** —Our coal and nuclear units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel needs over the next several years. However, it will be necessary to enter into additional arrangements to acquire coal and nuclear fuel in the future. Market prices for coal and nuclear fuel have recently been volatile. Although our fuel contract portfolio provides a degree of hedging against these market risks, future increases in our fuel costs cannot be predicted with certainty and could materially and adversely affect liquidity, financial condition and results of operations. While our generation runs on diverse fuels, allowing for flexibility, the mix of fuels ultimately used can impact earnings.

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- ***Third party credit risk***—We sell generation output and buy fuel through the execution of bilateral contracts. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure to perform by these counterparties could have a material adverse impact on our results of operations, cash flows and financial position. In the spot markets, we are exposed to the risks of whatever default mechanisms exist in those markets, some of which attempt to spread the risk across all participants, which may not be an effective way of lessening the severity of the risk of the amounts at stake. The impact of economic conditions may also increase such risk.

We are subject to numerous federal and state environmental laws and regulations that may significantly limit or affect our businesses, adversely impact our business plans or expose us to significant environmental fines and liabilities.

We are subject to extensive environmental regulation by federal, state and local authorities regarding air quality, water quality, site remediation, land use, waste disposal, aesthetics, impact on global climate, natural resources damages and other matters. These laws and regulations affect the manner in which we conduct our operations and make capital expenditures. Future changes may result in significant increases in compliance costs.

Delay in obtaining, or failure to obtain and maintain, any environmental permits or approvals, or delay in or failure to satisfy any applicable environmental regulatory requirements, could:

- prevent construction of new facilities,
- prevent continued operation of existing facilities,
- prevent the sale of energy from these facilities, or
- result in significant additional costs, each of which could materially affect our business, results of operations and cash flows.

In obtaining required approvals and maintaining compliance with laws and regulations, we focus on several key environmental issues, including:

- ***Concerns over global climate change could result in laws and regulations to limit CO_2 emissions or other GHG produced by our fossil generation facilities***—Federal and state legislation and regulation designed to address global climate change through the reduction of GHG emissions could materially impact our fossil generation facilities. Legislation enacted in the states where our generation facilities are located establishes aggressive goals for the reduction of CO_2 emissions over a 40-year period. Multiple states are developing or have developed state-specific or regional initiatives to obtain CO_2 emissions reductions in the electric power industry. The RGGI is such a program in the Northeast. There could be significant costs incurred to continue operation of our fossil generation facilities, including the potential need to purchase CO_2 emission allowances. Such expenditures could materially affect the continued economic viability of one or more such facilities.
- ***CO_2 Litigation***—In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings regarding alleged impacts of global climate change not involving us could be material to the future liability of energy companies. If relevant federal or state common law were to develop that imposed liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to our fossil generation operations could be material.
- ***Potential closed-cycle cooling requirements***—Our Salem nuclear generating facility has a permit from the NJDEP allowing for its continued operation with its existing cooling water system. That permit expired in July 2006. Our application to renew the permit, filed in February 2006, estimated the costs associated with cooling towers for Salem to be approximately $1 billion, of which our share was approximately $575 million. The renewal filing has not been updated since the 2006 filing.

  If the NJDEP and the Connecticut Department of Environmental Protection were to require installation of closed-cycle cooling or its equivalent at our Salem, Mercer, Hudson, Bridgeport, Sewaren or New Haven generating stations, the related increased costs and impacts would be material to our financial position, results of operations and net cash flows and would require further economic review to determine whether to continue operations or decommission the stations.

  The EPA issued a proposed rule in 2011 regarding regulation of cooling water intake structures. If adopted as proposed, the impact of this rulemaking could significantly impact states' permitting decisions on whether to require closed cycle cooling and could materially increase our cost of compliance. The EPA is expected to issue a final rule in 2014.

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- ***Remediation of environmental contamination at current or formerly-owned facilities*** —We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. Also, we are currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, the related costs of which could have a material adverse effect on our financial condition, results of operations and cash flows. New Jersey law places affirmative obligations on us to investigate and, if necessary, remediate contaminated property upon which we were in any way responsible for a discharge of hazardous substances, impacting the speed by which we will need to investigate contaminated properties, which could adversely impact cash flow. We cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to these or other natural resource damages claims. However, exposure to natural resource damages could subject us to additional potentially material liability.
- ***More stringent air pollution control requirements in New Jersey*** —Most of our generating facilities are located in New Jersey where restrictions are generally considered to be more stringent in comparison to other states. Therefore, there may be instances where the facilities located in New Jersey are subject to more restrictive and, therefore, more costly pollution control requirements and liability for damage to natural resources, than competing facilities in other states. Most of New Jersey has been classified as "nonattainment" with NAAQS for one or more air pollutants. This requires New Jersey to develop programs to reduce air emissions. Such programs can impose additional costs on us by requiring that we offset any emissions increases from new electric generators we may want to build and by setting more stringent emission limits on our facilities that run during the hottest days of the year.
- ***Coal Ash Management***—Coal ash is a CCR produced as a byproduct of generation at our coal-fired facilities. We currently have a program to beneficially reuse coal ash as presently allowed by federal and state regulations. In 2010, the EPA formally published a proposed rule offering three main options for the management of CCRs under the Resource Conservation and Recovery Act. One of these options regulates CCRs as a hazardous waste. The outcome of the EPA rulemaking cannot be predicted. Proposed regulations which more stringently regulate coal ash, including regulating coal ash as hazardous waste, could materially increase costs at our coal-fired generation facilities. The EPA has not established a date for release of a final rule.

Our ownership and operation of nuclear power plants involve regulatory, financial, environmental, health and safety risks.

Approximately half of our total generation output each year is provided by our nuclear fleet, which comprises approximately one-fourth of our total owned generation capacity. For this reason, we are exposed to risks related to the continued successful operation of our nuclear facilities and issues that may adversely affect the nuclear generation industry. These include:

- ***Storage and Disposal of Spent Nuclear Fuel***—We currently use on-site storage for spent nuclear fuel. Disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel, could impact future operations of these stations. In addition, the availability of an off-site repository for spent nuclear fuel may affect our ability to fully decommission our nuclear units in the future.
- ***Regulatory and Legal Risk***—The NRC may modify, suspend or revoke licenses, or shut down a nuclear facility and impose substantial civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms and conditions of the licenses for nuclear generating facilities. As with all of our generation facilities, as discussed above, our nuclear facilities are also subject to comprehensive, evolving environmental regulation. Our nuclear generating facilities are currently operating under NRC licenses that expire in 2033 through 2046.
- ***Operational Risk***—Operations at any of our nuclear generating units could degrade to the point where the affected unit needs to be shut down or operated at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Since our nuclear fleet provides the majority of our generation output, any significant outage could result in reduced earnings as we would need to purchase or generate higher-priced energy to meet our contractual obligations.
- ***Nuclear Incident or Accident Risk***—Accidents and other unforeseen problems have occurred at nuclear stations, both in the United States and elsewhere. The consequences of an accident can be severe and may include loss of life, significant property damage and/or a change in the regulatory climate. We have nuclear units at two sites. It is possible that an accident or other incident at a nuclear generating unit could adversely affect our ability to continue to operate unaffected units located at the same site, which would further affect our financial condition, operating results and cash flows. An accident or incident at a nuclear unit not owned by us could also affect our ability to continue to

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operate our units. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages.

We may be adversely affected by changes in energy regulatory policies, including energy and capacity market design rules and developments affecting transmission.

The energy industry continues to be regulated and the rules to which our businesses are subject are always at risk of being changed. Our business has been impacted by established rules that create locational capacity markets in each of PJM, ISO-NE and NYISO. Under these rules, generators located in constrained areas are paid more for their capacity so there is an incentive to locate in those areas where generation capacity is most needed. Because much of our generation is located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM's locational capacity market design rules and New England forward capacity market rules have been challenged in court and continue to evolve. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

In January 2011, New Jersey enacted a law establishing a LCAPP which provided for the construction of subsidized base load or mid-merit electric power generation. The LCAPP legislation was invalidated on constitutional grounds by a federal court order issued in October 2013. However, future state actions to subsidize the construction of new generation could have the effect of artificially depressing prices in the competitive wholesale market on both a short-term and long-term basis.

We could also be impacted by a number of other events, including regulatory or legislative actions favoring non-competitive markets and energy efficiency and demand response initiatives. Further, some of the market-based mechanisms in which we participate, including BGS auctions, are at times the subject of review or discussion by some of the participants in the New Jersey and federal regulatory and political arenas. We can provide no assurance that these mechanisms will continue to exist in their current form, nor otherwise be modified.

To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, Power's capacity and energy revenues could be adversely affected. Moreover, the FERC has issued a rule, currently being challenged in court, that requires changes to transmission planning processes which may result in more transmission being built to facilitate renewable generation.

In this rule, the FERC has also acted to eliminate the ROFR, which will have the effect of allowing third parties to build certain types of transmission projects in the service territories of incumbent utilities such as PSE&G. As a result, we could face competitive pressures for our transmission business in New Jersey, as well as in in other utilities' service territories where we will be able to seek opportunities to build.

We face significant competition in the merchant energy markets.

Our wholesale power and marketing businesses are subject to significant competition that may adversely affect our ability to make investments or sales on favorable terms and achieve our annual objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower earnings. Decreased competition could negatively impact results through a decline in market liquidity. Some of our competitors include:

- merchant generators,
- domestic and multi-national utility rate-based generators,
- energy marketers,
- utilities,
- banks, funds and other financial entities,
- fuel supply companies,
- affiliates of other industrial companies, and
- distributed generation.

Regulatory, environmental, industry and other operational developments will have a significant impact on our ability to compete in energy markets, potentially resulting in erosion of our market share and impairment in the value of our power plants.

Changes in customer usage patterns and technology could adversely impact us.

- ***DSM and other efficiency efforts***—DSM and other efficiency efforts aimed at changing the quantity and patterns of consumers' usage could result in a reduction in load requirements.

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- ***Changes in technology and/or customer behaviors*** —It is possible that advances in technology will reduce the cost of alternative methods of producing electricity, including distributed generation, such as fuel cells, micro turbines, micro grids, windmills and net-metered PV (solar) cells, to a level that is competitive with that of most central station electric production. Large customers, such as universities and hospitals, continue to explore potential micro grid installation. Substantial micro grid penetration can impact energy costs, system performance, and demand growth. It is also possible that electric customers may significantly decrease their electric consumption due to demand-side energy conservation programs. Changes in technology and usage, such as municipal aggregation, could also alter the channels through which retail electric customers buy electricity, which could adversely affect our financial results. Increased reliance by customers on on-site generation, including solar, and changes in customer behaviors can result in decreased reliance on our system and impact our revenues and investment opportunities.

Our inability to balance energy obligations with available supply could negatively impact results.

The revenues generated by the operation of our generating stations are subject to market risks that are beyond our control. Generation output will either be used to satisfy wholesale contract requirements, other bilateral contracts or be sold into competitive power markets. Participants in the competitive power markets are not guaranteed any specified rate of return on their capital investments. Generation revenues and results of operations are dependent upon prevailing market prices for energy, capacity, ancillary services and fuel supply in the markets served.

Our generation business frequently involves the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that we have produced or purchased energy in excess of our contracted obligations, a reduction in market prices could reduce profitability. Conversely, to the extent that we have contracted obligations in excess of energy we have produced or purchased, an increase in market prices could reduce profitability. If the strategy we utilize to hedge our exposure to these various risks is not effective, we could incur significant losses. Our market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors, including weather in various geographical areas, short-term supply and demand imbalances, customer migration and pricing differentials at various geographic locations. These cannot be predicted with certainty.

Increases in market prices also affect our ability to hedge generation output and fuel requirements as the obligation to post margin increases with increasing prices and could require maintaining liquidity resources that would be prohibitively expensive.

Any inability to recover the carrying amount of our assets could result in future impairment charges which could have a material adverse impact on our financial condition, results of operations and cash flows.

In accordance with accounting guidance, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset's or group of assets' carrying amount may not be recoverable. Significant reductions in our expected revenues or cash flows for an extended period of time resulting from such events could result in future asset impairment charges, which could have a material adverse impact on our financial condition and results of operations.

Inability to access sufficient capital at reasonable rates or commercially reasonable terms or maintain sufficient liquidity in the amounts and at the times needed could adversely impact our business.

Capital for projects and investments has been provided primarily by internally-generated cash flow and external financings. We have significant capital requirements and will need continued access to debt capital from outside sources in order to efficiently fund the construction and other cash flow needs of our businesses. The ability to arrange financing and the costs of capital depend on numerous factors including, among other things, general economic and market conditions, the availability of credit from banks and other financial institutions, investor confidence, the success of current projects and the quality of new projects.

The ability to have continued access to the credit and capital markets at a reasonable economic cost is dependent upon our current and future capital structure, financial performance, our credit ratings and the availability of capital under reasonable terms and conditions. As a result, no assurance can be given that we will be successful in obtaining re-financing for maturing debt or financing for projects and investments.

Financial market performance directly affects the asset values of our nuclear decommissioning trust funds and defined benefit plan trust funds. Sustained decreases in asset value of trust assets could result in the need for significant additional funding.

The performance of the financial markets will affect the value of the assets that are held in trust to satisfy our future obligations under our pension and postretirement benefit plans and to decommission our nuclear generating plants. A decline in the market

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value of our pension assets could result in the need for us to make significant contributions in the future to maintain our funding at sufficient levels.

An extended economic recession would likely have a material adverse effect on our businesses.

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices of commodities. Adverse conditions in the economy affect the markets in which we operate and can negatively impact our results. Declines in demand for energy will reduce overall sales and cash flows, especially as customers reduce their consumption of electricity and gas. Although our utility business is subject to regulated allowable rates of return, overall declines in electricity and gas sold and/or increases in non-payment of customer bills would materially adversely affect our liquidity, financial condition and results of operations.

We may be adversely affected by equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers and remain competitive.

The success of our businesses is dependent on our ability to continue providing safe and reliable service to our customers while minimizing service disruptions. We are also exposed to the risk of accidents, severe weather events such as we experienced from Hurricane Irene and Superstorm Sandy, or other incidents which could result in damage to or destruction of our facilities or damage to persons or property. The physical risks of climate change, such as more frequent or more extreme weather events, changes in sea level, temperature and precipitation patterns and other related phenomena have exacerbated these risks. Such issues experienced at our facilities, or by others in our industry, could adversely impact our revenues, increase costs to repair and maintain our systems, subject us to potential litigation and/or damage claims and increase the level of oversight of our utility and generation operations and infrastructure through investigations or through the imposition of additional regulatory or legislative requirements. Such actions could adversely affect our costs, competitiveness and future investments, which could be material to our financial position, results of operations and cash flow.

Acts of war or terrorism could adversely affect our operations.

Our businesses and industry may be impacted by acts and threats of war or terrorism. These actions could result in increased political, economic and financial market instability and volatility in fuel prices which could materially adversely affect our operations. In addition, our infrastructure facilities, such as our generating stations, transmission and distribution facilities, could be direct or indirect targets or be affected by terrorist or other criminal activity. Such events could severely disrupt business operations and prevent us from servicing our customers. In addition, new or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.

Cybersecurity attacks or intrusions could adversely impact our businesses.

We own and/or operate generating stations, transmission and distribution facilities, which are dependent on the operation of our computing systems. Our ability to market our generation output and acquire and hedge fuel and power are also dependent on our computing systems. Our computing systems may be impacted by cybersecurity attacks, hostile technological intrusions, or inadvertent disclosure of company and/or customer information. Cybersecurity threats to our operations include:

- Disruption of the operation of our assets and the power grid,
- Information theft of confidential company, employee, shareholder, vendor or customer information, and
- General business system and process interruption or compromise, including preventing us from servicing our customers, collecting revenues, or the ability to record, process and/or report financial information correctly.

If a significant cybersecurity event or breach should occur, it could result in material costs for repair and remediation, breach notification, operations, insurance and increased capital costs. Such a cyber incident could also cause us to be non-compliant with applicable laws, regulations or contracts that require us to securely maintain confidential data, causing us to incur costs related to legal claims or proceedings, regulatory fines and increased scrutiny, and possible damage to our reputation and brand. We devote resources to network and application security, encryption and other measures to protect our computing systems and infrastructure from unauthorized access or misuse and interface with numerous external entities to improve our cybersecurity situational awareness. However, given the ever changing nature of cybersecurity threats, there can be no assurance the steps we take can protect us against all possible occurrences.

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Inability to successfully develop or construct generation, transmission and distribution projects within budget could adversely impact our businesses.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of required environmental upgrades and retrofits, construction and/or acquisition of additional generation units and transmission facilities and modernizing existing infrastructure. Currently, we have several significant projects underway or being contemplated.

Our success will depend, in part, on our ability to obtain necessary regulatory approvals, complete these projects within budgets, on commercially reasonable terms and conditions and, in our regulated businesses, our ability to recover the related costs through rates. Any delays, cost escalations or otherwise unsuccessful construction and development could materially affect our financial position, results of operations and cash flows.

We may be unable to achieve, or continue to sustain, our expected levels of operating performance.

One of the key elements to achieving the results in our business plan is the ability to sustain generating operating performance and capacity factors at expected levels since our forward sales of energy and capacity assume acceptable levels of operating performance. This is especially important at our lower-cost facilities. Operations at any of our plants could degrade to the point where the plant has to shut down or operate at less than full capacity. Some issues that could impact the operation of our facilities are:

- breakdown or failure of equipment, processes or management effectiveness,
- disruptions in the transmission of electricity,
- labor disputes,
- fuel supply interruptions,
- transportation constraints,
- limitations which may be imposed by environmental or other regulatory requirements,
- permit limitations, and
- operator error or catastrophic events such as fires, earthquakes, explosions, floods, severe storms, acts of terrorism or other similar occurrences.

Identifying and correcting any of these issues may require significant time and expense. Depending on the materiality of the issue, we may choose to close a plant rather than incur the expense of restarting it or returning it to full capacity. In either event, to the extent that our operational targets are not met, we could have to operate higher-cost generation facilities or meet our obligations through higher-cost open market purchases.

Challenges associated with retention of a qualified workforce could adversely impact our businesses.

Our operations depend on the retention of a skilled workforce. The loss or retirement of key executives or other employees, including those with the specialized knowledge required to support our generation, transmission and distribution operations, could result in various operational challenges. These challenges may include the lack of appropriate replacements, the loss of institutional and industry knowledge and the increased costs to hire and train new personnel. This has the potential to become more critical over the next several years as a growing number of employees become eligible to retire.

In addition, because a significant portion of our employees are covered under collective bargaining agreements, our success will depend on our ability to successfully renegotiate these agreements as they expire. Inability to do so may result in employee strikes or work stoppages which would disrupt our operations and could also result in increased costs.

Our receipt of payment of receivables related to our domestic leveraged leases is dependent upon the credit quality and the ability of lessees to meet their obligations.

Our receipt of payments of equity rent, debt service and other fees related to our leveraged lease portfolio in accordance with the lease contracts can be impacted by various factors. The factors which may impact future lease cash flow include, but are not limited to, new environmental legislation regarding air quality and other discharges in the process of generating electricity, market prices for fuel and electricity, including the impact of low gas prices on our coal generation investments, overall financial condition of lease counterparties and the quality and condition of assets under lease. If a lessee were to default, we could potentially be required to impair our current investment balances.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, Power and PSE&G

None.

ITEM 2. PROPERTIES

Our subsidiaries own all of our physical property. We believe that we and our subsidiaries maintain adequate insurance coverage against loss or damage to plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities .

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Generation Facilities

Power

As of December 31, 2013, Power's share of summer installed fossil and nuclear generating capacity is shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used	Mission
Steam:						
Hudson	NJ	620	100%	620	Coal/Gas	Load Following
Mercer	NJ	632	100%	632	Coal/Gas	Load Following
Sewaren	NJ	453	100%	453	Gas	Load Following
Keystone (A)	PA	1,711	23%	391	Coal	Base Load
Conemaugh (A)	PA	1,711	23%	385	Coal	Base Load
Bridgeport Harbor	CT	383	100%	383	Coal	Load Following
New Haven Harbor	CT	448	100%	448	Oil	Load Following
Total Steam		**5,958**		**3,312**		
Nuclear:						
Hope Creek	NJ	1,178	100%	1,178	Nuclear	Base Load
Salem 1 & 2	NJ	2,365	57%	1,358	Nuclear	Base Load
Peach Bottom 2 & 3 (B)	PA	2,251	50%	1,125	Nuclear	Base Load
Total Nuclear		**5,794**		**3,661**		
Combined Cycle:						
Bergen	NJ	1,188	100%	1,188	Gas	Load Following
Linden	NJ	1,230	100%	1,230	Gas	Load Following
Bethlehem	NY	756	100%	756	Gas	Load Following
Kalaeloa	HI	208	50%	104	Oil	(C)
Total Combined Cycle		**3,382**		**3,278**		
Combustion Turbine:						
Essex	NJ	617	100%	617	Gas	Peaking
Edison	NJ	516	100%	516	Gas	Peaking
Kearny	NJ	463	100%	463	Gas	Peaking
Burlington	NJ	560	100%	560	Oil/Gas	Peaking
Linden	NJ	340	100%	340	Gas	Peaking
Mercer	NJ	115	100%	115	Oil	Peaking
Sewaren	NJ	105	100%	105	Oil	Peaking
Bergen	NJ	21	100%	21	Gas	Peaking
National Park	NJ	21	100%	21	Oil	Peaking
Salem 3	NJ	38	57%	22	Oil	Peaking
New Haven Harbor	CT	130	100%	130	Gas/Oil	Peaking
Bridgeport Harbor	CT	17	100%	17	Oil	Peaking
Total Combustion Turbine		**2,943**		**2,927**		
Pumped Storage:						
Yards Creek (D)	NJ	400	50%	200		Peaking
Total Power Plants		**18,477**		**13,378**		

(A) Operated by GenOn Northeast Management Company

(B) Operated by Exelon Generation

(C) Contracted under a power purchase agreement

(D) Operated by Jersey Central Power & Light Company

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As of December 31, 2013, Power also owned and operated 88 MW of photovoltaic solar generation facilities in various states. In December 2013, Power agreed to acquire a 4 MW solar project in Shasta, California. The project is expected to be placed into service by mid-2014.

PSE&G

As of December 31, 2013, PSE&G had 79 MW of installed solar capacity throughout New Jersey.

Transmission and Distribution Facilities

PSE&G

As of December 31, 2013, PSE&G's electric transmission and distribution system included 23,810 circuit miles, of which 8,235 circuit miles were underground, and 842,992 poles, of which 547,998 poles were jointly-owned. Approximately 100% of this property is located in New Jersey.

In addition, as of December 31, 2013, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2013, the daily gas capacity of PSE&G's 100%-owned peaking facilities (the maximum daily gas delivery available during the three peak winter months) consisted of liquid petroleum air gas (LPG) and liquefied natural gas (LNG) and aggregated 2,790,420 therms (270,914,563 cubic feet on an equivalent basis of 100,000 Btu/therm and 1,030 Btu/cubic foot) as shown in the following table:

Plant	Location	Daily Capacity (Therms)
Burlington LNG	Burlington, NJ	772,500
Camden LPG	Camden, NJ	384,000
Central LPG	Edison, NJ	839,040
Harrison LPG	Harrison, NJ	794,880
Total		**2,790,420**

As of December 31, 2013, PSE&G owned and operated 17,758 miles of gas mains, owned 12 gas distribution headquarters and two sub-headquarters, all in four operating regions located in New Jersey and owned one meter shop in New Jersey serving all such areas. In addition, PSE&G operated 62 natural gas metering and regulating stations, all located in New Jersey, of which 26 were located on land owned by customers or natural gas pipeline suppliers and were operated under lease, easement or other similar arrangement. In some instances, the pipeline companies owned portions of the metering and regulating facilities.

PSE&G's First and Refunding Mortgage, securing the bonds issued thereunder, constitutes a direct first mortgage lien on substantially all of PSE&G's property.

PSE&G's electric lines and gas mains are located over or under public highways, streets, alleys or lands, except where they are located over or under property owned by PSE&G or occupied by it under easements or other rights. PSE&G deems these easements and other rights to be adequate for the purposes for which they are being used.

In addition, as of December 31, 2013, PSE&G owned 42 switching stations in New Jersey with an aggregate installed capacity of 25,103 megavolt-amperes (MVA) and 246 substations with an aggregate installed capacity of 8,179 MVA. In addition, four of our substations in New Jersey having an aggregate installed capacity of 109 MVA were operated on leased property.

ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, other than those discussed below, see Item 1. Business—Regulatory Issues and Environmental Matters and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Superstorm Sandy

For a discussion of the lawsuit in New Jersey state court related to recoveries for property damage under PSEG's insurance policies, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

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Environmental Matters

The following items are environmental matters involving governmental authorities not discussed elsewhere in this Form 10-K. We do not expect expenditures for any such site relating to the items listed below, individually or for all such current sites in the aggregate, to have a material effect on our financial condition, results of operations and net cash flows.

(1) Various Spill Act directives were issued by the NJDEP to potentially responsible parties (PRPs), including PSE&G with respect to the PJP Landfill in Jersey City, Hudson County, New Jersey, ordering payment of costs associated with operation and maintenance, interim remedial measures and a Remedial Investigation and Feasibility Study (RI/FS) in excess of $25 million. The directives also sought reimbursement of the NJDEP's past and future oversight costs and the costs of any future remedial action.

(2) Claim by the EPA, Region III, under CERCLA with respect to a Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and other companies are alleged to be liable for contamination at the site and PSE&G has been named as a PRP. A Final Remedial Design Report was submitted to the EPA in September of 2002. This document presented the design details of the EPA's selected remediation remedy. PSE&G and other utility companies as members of a PRP group entered into a Consent Decree and agreed to implement a negotiated EPA selected remediation remedy. The PRP group implementation of the remedy was completed in 2010. Although subject to EPA approval and oversight, long term monitoring activities designed to demonstrate the effectiveness of the implemented remedy are planned through 2018 at an estimated cost of $2.8 million.

(3) The Klockner Road site is located in Hamilton Township, Mercer County, New Jersey, and occupies approximately two acres on PSE&G's Trenton Switching Station property. In 1996, PSE&G entered into a memorandum of agreement with the NJDEP for the Klockner Road site pursuant to which PSE&G conducted an RI/FS and remedial action at the site to address the presence of soil and groundwater contamination. Anticipated future activities at the site include the filing of certification(s) with the NJDEP once every two years regarding the effectiveness of engineering and institutional controls, quarterly groundwater monitoring for several years and the installation of additional off-site groundwater monitoring wells as directed by the NJDEP.

(4) The EPA sent Power, PSE&G and approximately 157 other entities a notice that the EPA considered each of the entities to be a PRP with respect to contamination in Berry's Creek in Bergen County, New Jersey and requesting that the PRPs perform a RI/FS on Berry's Creek and the connected tributaries and wetlands. Berry's Creek flows through approximately 6.5 miles of areas that have been used for a variety of industrial purposes and landfills. The EPA estimates that the study could cost approximately $18 million. As members of a PRP Group, Power and certain of the other entities named in the EPA Notice entered into an Administrative Settlement Agreement and Order on Consent in 2008 to conduct the RI/FS, which is estimated to be completed in 2017/2018.

(5) In January 2010, we received a letter from the NJDEP asserting that we are the current owner of the Gates Construction Corporation Landfill and that the subject landfill has not been properly closed in accordance with the NJDEP Solid Waste Regulations. Power has retained an environmental consultant to prepare a closure plan acceptable to the NJDEP.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange, Inc. As of December 31, 2013, there were 72,713 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2008 in our common stock and the subsequent reinvestment of quarterly dividends, the S&P Composite Stock Price Index, the Dow Jones Utilities Index and the S&P Electric Utilities Index.

	2008	2009	2010	2011	2012	2013
PSEG	$ 100.00	$ 118.86	$ 118.75	$ 128.49	$ 124.58	$ 136.24
S&P 500	$ 100.00	$ 126.37	$ 145.36	$ 148.44	$ 172.08	$ 227.69
DJ Utilities	$ 100.00	$ 112.42	$ 119.66	$ 143.10	$ 145.38	$ 163.80
S&P Electrics	$ 100.00	$ 103.34	$ 106.88	$ 129.16	$ 128.39	$ 138.44

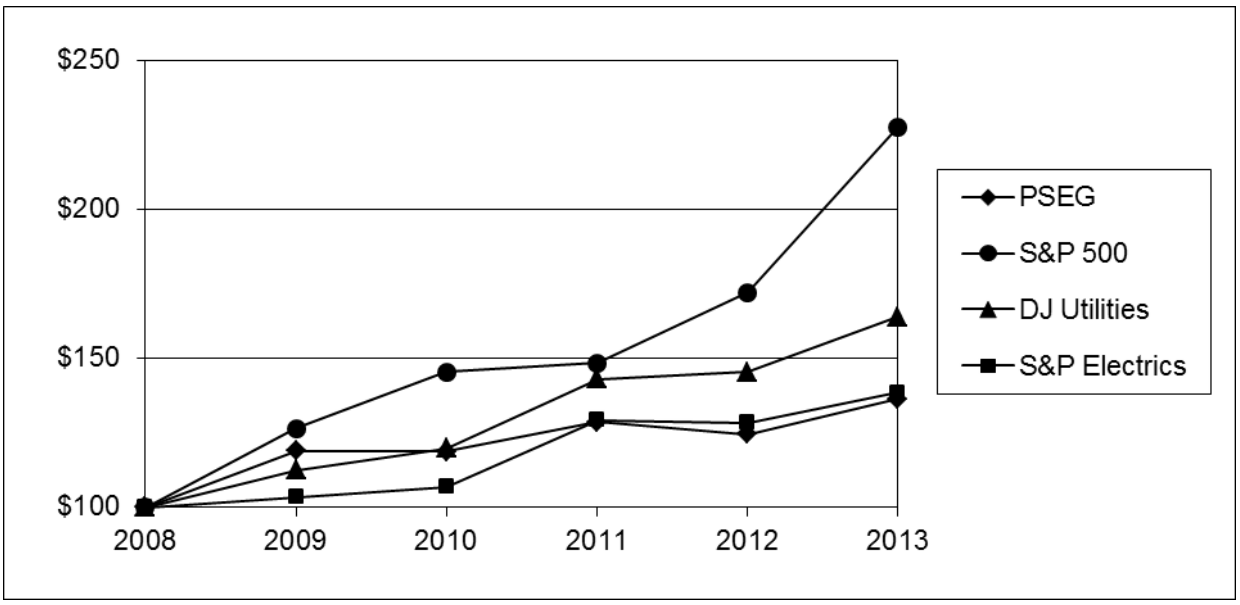

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The following table indicates the high and low sale prices for our common stock and dividends paid for the periods indicated:

Common Stock		High	Low	Dividend per Share
	2013			
First Quarter		$ 34.34	$ 29.78	$ 0.360
Second Quarter		$ 36.61	$ 31.21	$ 0.360
Third Quarter		$ 34.53	$ 31.66	$ 0.360
Fourth Quarter		$ 34.32	$ 31.65	$ 0.360
	2012			
First Quarter		$ 33.25	$ 29.59	$ 0.355
Second Quarter		$ 32.51	$ 28.92	$ 0.355
Third Quarter		$ 34.07	$ 31.19	$ 0.355
Fourth Quarter		$ 33.36	$ 29.05	$ 0.355

On February 18, 2014, our Board of Directors approved a $0.370 per share common stock dividend for the first quarter of 2014. This reflects an indicated annual dividend rate of $1.48 per share.

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation award grants during the fourth quarter of 2013:

Three Months Ended December 31, 2013	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$ —
November 1-November 30	4,000	$ 33.01
December 1-December 31	—	$ —

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2013:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Long-Term Incentive Plan	2,615,166	$ 34.43	16,508,170
Employee Stock Purchase Plan	—	$ —	3,589,032
Total	**2,615,166**	**$ 34.43**	**20,097,202**

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data— Note 18. Stock Based Compensation.

Power

We own all of Power's outstanding limited liability company membership interests. For additional information regarding Power's ability to pay dividends, see Item 7. MD&A—Overview of 2013 and Future Outlook.

PSE&G

We own all of the common stock of PSE&G. For additional information regarding PSE&G's ability to continue to pay dividends, see Item 7. MD&A —Overview of 2013 and Future Outlook.

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ITEM 6. SELECTED FINANCIAL DATA

PSEG

The information presented below should be read in conjunction with the MD&A and the Consolidated Financial Statements and Notes to Consolidated Financial Statements (Notes).

PSEG Years Ended December 31,	2013	2012	2011	2010	2009
	Millions, except Earnings per Share				
Operating Revenues	$ 9,968	$ 9,781	$ 11,079	$ 11,793	$ 12,035
Income from Continuing Operations (A)	$ 1,243	$ 1,275	$ 1,407	$ 1,557	$ 1,594
Net Income	$ 1,243	$ 1,275	$ 1,503	$ 1,564	$ 1,592
Earnings per Share:					
Income from Continuing Operations					
Basic (A)	$ 2.46	$ 2.52	$ 2.78	$ 3.08	$ 3.15
Diluted (A)	$ 2.45	$ 2.51	$ 2.77	$ 3.07	$ 3.14
Net Income					
Basic	$ 2.46	$ 2.52	$ 2.97	$ 3.09	$ 3.15
Diluted	$ 2.45	$ 2.51	$ 2.96	$ 3.08	$ 3.14
Dividends Declared per Share	$ 1.44	$ 1.42	$ 1.37	$ 1.37	$ 1.33
As of December 31,					
Total Assets	$ 32,522	$ 31,725	$ 29,821	$ 29,909	$ 28,678
Long-Term Obligations (B)	$ 7,872	$ 6,701	$ 7,482	$ 7,847	$ 7,679

(A) Income from Continuing Operations for 2011 includes an after-tax charge of $ 170 million related to certain leveraged leases.

(B) Includes capital lease obligations.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, its principal direct wholly owned subsidiaries, which are:

- **Power,** our wholesale energy supply company that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States, and
- **PSE&G,** our public utility company which provides electric transmission services and distribution of electric energy and natural gas, implements demand response and energy efficiency programs and invests in solar generation in New Jersey.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which effective January 1, 2014 operates the Long Island Power Authority's transmission and distribution system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors provides information about factors that could have a material adverse impact on our businesses. The following discussion provides an overview of the significant events and business developments that have occurred during 2013 and key factors that we expect will drive our future performance. This discussion refers to the Consolidated Financial Statements (Statements) and the Related Notes to Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements and Notes.

OVERVIEW OF 2013 AND FUTURE OUTLOOK

2013 Overview

Our business plan is designed to manage the risks associated with fluctuating commodity prices and changes in customer demand as we invest to achieve growth in light of market, regulatory and economic trends. In 2013, we continued our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- Growing our utility operations through continued investment in transmission and distribution infrastructure projects with a consequent rebalancing of our business mix and greater diversification of regulatory oversight, and
- Maintaining a reliable generation fleet with the flexibility to utilize a diverse mix of fuels to allow us to capitalize on market opportunities as they arise in the locations in which we operate.

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Financial Results

The results for PSEG, Power and PSE&G for the years ended December 31, 2013 and 2012 are presented below:

	Years Ended December 31, 2013	2012
Earnings (Losses)	Millions, except per share data	
Power	$ 644	$ 666
PSE&G	612	528
Other	(13)	81
PSEG Net Income	**$ 1,243**	**$ 1,275**
Earnings Per Share (Diluted)		
PSEG Net Income	**$ 2.45**	**$ 2.51**

Our $32 million 2013 over 2012 decrease in Net Income was due primarily to higher Operations and Maintenance (O&M) costs in 2013 related to planned outage work and higher mark-to-market losses at Power. In addition, 2012 Net Income included recoveries from one of Energy Holdings' leverage lease investments, and a one-time benefit from the settlement of the 1997-2006 Internal Revenue Service audits in 2012. These factors were partially offset by higher market prices, fuel supply cost savings and increased capacity pricing at Power, and higher transmission revenues at PSE&G. For a more detailed discussion of our financial results, see Results of Operations.

Power's results also benefited from access to low-cost natural gas from the Marcellus region during the latter half of 2013 through its existing firm pipeline transportation and storage contracts. Power manages these contracts for the benefit of PSE&G's customers through the basic gas supply service (BGSS) arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When the customers' demand for gas is lower, which frequently occurs outside of the winter usage period, Power can use the remaining available pipeline transportation to make third party sales and supply the Marcellus gas to its generating units in New Jersey.

At PSE&G, our regulated utility, we continued to invest capital in transmission and distribution infrastructure projects aimed at maintaining the reliability of our service to our customers. PSE&G's results for 2013 reflect the favorable impacts from these investments. In January 2014, we filed a Modified 2014 Annual Formula Rate Update with the Federal Energy Regulatory Commission (FERC) in December 2013 which provides for approximately $171 million in increased annual transmission revenues effective January 1, 2014. Over the past few years, these types of investments have altered the business mix of PSEG's overall results of operations to reflect a higher percentage contribution by PSE&G.

Regulatory, Legislative and Other Developments

In developing and implementing our strategy of operational excellence, financial strength and disciplined investment, we monitor significant regulatory and legislative developments. Competitive wholesale power market design is of particular importance to our results and we continue to advocate for policies and rules that promote competitive electricity markets. This includes opposing efforts by states to subsidize generation and supporting rule changes which we believe are necessary to avoid artificial price suppression and other distortions in the energy and capacity markets. Federal court decisions in New Jersey and Maryland invalidated legislation in those states which sought to subsidize generation. For a more detailed discussion of the status of these efforts, refer to Item 1. Business—Regulatory Issues—Federal Regulation.

We continue to advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. In particular, the EPA's 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. Clean Air Act (CAA) regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology (MACT) rules are also of significance; however, we believe our generation business remains well-positioned for such air pollution control regulations if and when they are implemented. These matters are discussed in Item 1. Business—Environmental Matters.

As discussed in further detail under Item 1. Business—Regulatory Issues—Federal Regulation, the FERC's rules under Order 1000 altered the right of first refusal previously held by incumbent utilities to build all transmission within their respective service territories. We are challenging the FERC's determination in court as we do not believe that the FERC sufficiently justified its decision to alter this right embedded in the FERC-approved contracts and tariffs. At the same time, the FERC's action presents opportunities for us to construct transmission outside of our service territory.

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In the fourth quarter of 2012, we were severely impacted by Superstorm Sandy, which resulted in the highest level of customer outages in our history. We sustained significant damage to some of our generation, transmission and distribution facilities. The New Jersey Board of Public Utilities (BPU) issued an order allowing PSE&G to defer actually incurred prudent, incremental storm restoration costs not otherwise recoverable through base rates or insurance. Proceedings at the BPU on the prudency and recovery of storm-related costs are pending. Power also incurred significant storm-related expenses, primarily for repairs at certain of its coal and gas-fired generating stations in 2013. We are seeking recovery from our insurers for the property damage, above our self-insured retentions; however, no assurances can be given relative to the timing or amount of any such recovery. In June 2013, we filed suit against the insurance carriers seeking legal interpretation of certain terms in the insurance policies regarding losses resulting from damage caused by Superstorm Sandy's storm surge. For more detailed information, refer to Item 1. Business—Regulatory and Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities for additional information.

In February 2013, we filed a petition with the BPU describing our Energy Strong program, consisting of $3.9 billion of proposed improvements we recommend making to our gas and electric distribution systems over a ten-year period to improve resiliency. In the petition, we sought approval for $2.6 billion of the $3.9 billion of investments over an initial five- year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. We cannot predict the outcome of this pending proceeding. As proposed, we believe that the rate impacts of the Energy Strong program will be significantly muted as a result of scheduled reductions to customer bills that will be taking place over the next few years and assuming continued low gas prices. See Item 1. Business—State Regulation for additional details.

During 2013, we continued to execute our five major regional transmission projects for which we were assigned construction responsibility by PJM. In December 2013, we were assigned construction by PJM of a new transmission project that will provide a double-circuit 345kV line in the Bergen-Linden Corridor to maintain reliability. See Item 1. Business—Business Operations and Strategy—PSE&G for additional information.

On January 1, 2014, we commenced operation of the Long Island Power Authority (LIPA) transmission and distribution (T&D) system under a twelve-year contract with opportunity to extend for an additional eight years. Also, beginning in 2015, Power will provide fuel procurement and power management services to LIPA under separate agreements. See Item 1. Business—Business Operations and Strategy—Other for additional details.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. In 2013, our

- total nuclear fleet achieved an average capacity factor in excess of 90% for the ninth consecutive year,
- outstanding performance allowed us to increase generation to meet loads,
- construction of transmission and solar projects proceeded on schedule and within budget, and
- utility ranked nationally in the top quartile for safety and reliability.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during 2013 as we:

- had cash on hand of $493 million as of December 31, 2013,
- extended the expiration date of approximately half of our credit facilities, and maintained substantial liquidity and solid investment grade credit ratings, as evidenced by the recent credit rating upgrades by Standard & Poor's (S&P) of PSEG, Power and PSE&G and upgrade by Moody's of PSE&G as disclosed below in Liquidity and Capital Resources—Credit Ratings,
- completed pension funding for 2013, which when combined with strong market results and a higher discount rate, resulted in a year-end ratio of the value of our pension plan assets to our projected pension benefit obligation of 106 percent,
- issued bonds at historically low rates at PSE&G to refinance its maturing debt and fund its capital program, and
- paid an annual dividend of $1.44 and increased our indicated annual dividend for 2014 to $1.48.

We expect to be able to fund our proposed Energy Strong program with internally generated cash and external debt financing .

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Disciplined Investment

We utilize rigorous investment criteria when deploying capital, and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In 2013 we:

- made additional investments in transmission infrastructure projects of $1.7 billion,
- continued to execute our existing BPU-approved utility programs,
- obtained approval from the BPU to increase our spending up to $247 million and $199 million under our Solar 4 All Extension and Solar Loan III investment programs, respectively,
- approved additional investments in our existing generation facilities to increase output and improve efficiency, and
- commenced operation of a newly constructed 19 MW solar project in Arizona.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a difficult economy and cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully re-contract our open supply positions,
- execute our capital investment program, including investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and the FERC of market design rules that continue to protect competition and achieve appropriate Reliability Pricing Model (RPM) and basic generation service (BGS) pricing,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system.

For 2014 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, particularly with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation,
- uncertainty in the national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer demand,
- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate,
- the aftermath of Hurricane Irene and Superstorm Sandy, including addressing the BPU's review of performance and communications, as well as cost recovery and opportunities for investment in system strengthening, including our proposed Energy Strong program, and
- delays and other obstacles that might arise in connection with the construction of our transmission and distribution projects, including in connection with permitting and regulatory approvals.

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RESULTS OF OPERATIONS

	Years Ended December 31,		
	2013	2012	2011
Earnings (Losses)	Millions		
Power (A)	$ 644	$ 666	$ 1,013
PSE&G (A)	612	528	521
Other (B)	(13)	81	(127)
PSEG Income from Continuing Operations	**1,243**	**1,275**	**1,407**
Income (Loss) from Discontinued Operations, Including Gain on Disposal (C)	—	—	96
PSEG Net Income	**$ 1,243**	**$ 1,275**	**$ 1,503**

	Years Ended December 31,		
Earnings Per Share (Diluted)	2013	2012	2011
PSEG Income from Continuing Operations	**$ 2.45**	**$ 2.51**	**$ 2.77**
Income from Discontinued Operations, Including Gain on Disposal (C)	—	—	0.19
PSEG Net Income	**$ 2.45**	**$ 2.51**	**$ 2.96**

(A) Power's results in 2013 and 2012 include after-tax expenses, net of insurance recoveries, of $32 million and $39 million, respectively, and PSE&G's results in 2012 include after-tax expenses of $24 million for O&M costs due to severe damage caused by Superstorm Sandy. See Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities.

(B) Other includes an after-tax charge of $170 million taken in 2011 at Energy Holdings related to the reserve for assets underlying a leveraged lease receivable. See Item 8. Financial Statements and Supplementary Data— Note 8. Financing Receivables.

(C) See Item 8. Financial Statements and Supplementary Data— Note 4. Discontinued Operations and Dispositions.

The 2013 year-over-year decrease in our Income from Continuing Operations/Net Income was driven primarily by:

- lower volumes of electricity sold under Power's basic generation service (BGS) contracts at lower average prices,
- lower volumes of wholesale load contracts in the PJM and New England (NE) regions,
- unfavorable amounts related to the mark-to-market (MTM) activity, discussed below,
- higher generation costs due to higher fuel costs,
- higher planned outage and maintenance costs at certain of our fossil and nuclear plants, partially offset by cost control measures,
- the absence of the gain on the Dynegy settlement in 2012 (see Item 8. Financial Statements and Supplementary Data— Note 8. Financing Receivables), and
- higher Income Tax Expense due to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012 (see Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes).

These decreases were largely offset by

- higher capacity revenues in the PJM region resulting from higher average prices as well as higher generation sold primarily in the PJM region,
- higher average gas prices on increased sales to third party customers, and
- higher revenues due to increased investments in transmission projects.

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The 2012 year-over-year decrease in our Income from Continuing Operations was driven by:

- lower average pricing and volumes for electricity sold under our BGS contracts,
- lower average prices realized on generation sold into various power pools,
- unfavorable amounts related to the MTM activity, discussed below,
- higher O&M costs due to severe damage caused by Superstorm Sandy to our transmission and distribution system throughout our service territory as well as to some of our generation infrastructure in the northern part of New Jersey.

The decreases were partially offset by:

- the absence of the $170 million after-tax charge taken in 2011 on leveraged leases related to Dynegy and the settlement proceeds received in 2012 (see Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables), and
- higher transmission revenues at PSE&G.

Our results include the realized gains, losses and earnings on Power's Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity. Net realized gains, interest and dividend income and other costs related to the NDT Fund are recorded in Other Income and Deductions, and impairments on certain NDT securities are recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance Expense, as well as the depreciation related to the ARO asset. In September 2012, we restructured a portion of our NDT Fund and realized gains of $59 million. The investments were transitioned to new investment managers.

Our results also include the after-tax impacts of non-trading MTM activity, which consist of the financial impact from positions with forward delivery dates.

The combined after-tax impact on Income from Continuing Operations for the years ended December 31, 2013, 2012 and 2011 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2013	2012	2011
	Millions, after tax		
NDT Fund and Related Activity	$ 40	$ 52	$ 50
Non-Trading MTM Gains (Losses)	$ (74)	$ (10)	$ 107

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, Power and PSE&G, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data—Note 24. Related-Party Transactions.

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	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2013	2012	2011	2013 vs. 2012		2012 vs. 2011	
	Millions			Millions	%	Millions	%
Operating Revenues	$ 9,968	$ 9,781	$ 11,079	$ 187	2	$ (1,298)	(12)
Energy Costs	3,536	3,719	4,747	(183)	(5)	(1,028)	(22)
Operation and Maintenance	2,887	2,632	2,481	255	10	151	6
Depreciation and Amortization	1,178	1,054	976	124	12	78	8
Income from Equity Method Investments	11	12	4	(1)	(8)	8	N/A
Other Income and (Deductions)	159	162	135	(3)	(2)	27	20
Other-Than-Temporary Impairments	12	18	22	(6)	(33)	(4)	(18)
Interest Expense	402	423	475	(21)	(5)	(52)	(11)
Income Tax Expense	812	736	977	76	10	(241)	(25)
Income from Discontinued Operations, including Gain on Disposal, net of tax	—	—	96	—	—	(96)	(100)

For a detailed explanation of the variances, see the following discussions for Power and PSE&G.

Power

Power	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2013	2012	2011	2013 vs. 2012		2012 vs. 2011	
	Millions			Millions	%	Millions	%
Operating Revenues	$ 5,063	$ 4,873	$ 6,150	$ 190	4	$ (1,277)	(21)
Energy Costs	2,496	2,381	3,044	115	5	(663)	(22)
Operation and Maintenance	1,224	1,127	1,105	97	9	22	2
Depreciation and Amortization	273	242	228	31	13	14	6
Income from Equity Method Investments	16	15	14	1	7	1	7
Other Income (Deductions)	105	111	111	(6)	(5)	—	—
Other-Than-Temporary Impairments	12	18	20	(6)	(33)	(2)	(10)
Interest Expense	116	132	175	(16)	(12)	(43)	(25)
Income Tax Expense	419	433	690	(14)	(3)	(257)	(37)
Income (Loss) from Discontinued Operations, Including Gain on Disposal	—	—	96	—	—	(96)	(100)

Year Ended December 31, 2013 as compared to 2012

Operating Revenues increased $190 million due to changes in generation and supply revenues.

Generation Revenues increased $102 million due primarily to

- an increase of $341 million due to higher capacity revenues resulting from higher average auction prices and an increase in operating reserve revenues in PJM, and
- higher net revenues of $36 million due primarily to higher generation sold in the PJM and NE regions partly offset by higher MTM losses in 2013 resulting from an increase in prices on forward positions in the PJM and NE regions,

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- partially offset by a decrease of $155 million due primarily to lower volumes of electricity sold under our BGS contracts and lower average pricing, and
- a net decrease of $120 million due to lower volumes on wholesale load contracts in the PJM and NE regions.

Gas Supply Revenues increased $88 million due primarily to

- a net increase of $40 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during the 2013 winter heating season, partially offset by lower average gas prices, and
- a net increase of $48 million due primarily to higher average gas prices and higher sales volumes to third party customers.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $115 million due to

- ***Gas costs*** increased $40 million, principally related to obligations under the BGSS contract, reflecting higher sales volumes in 2013 due to colder average temperatures during the 2013 winter heating season and higher volumes on third party sales, partially offset by lower average gas inventory costs.
- ***Generation costs*** increased $75 million due primarily to $84 million of higher fuel costs, reflecting higher average realized natural gas prices, higher nuclear fuel costs and the utilization of higher volumes of coal and oil, partially offset by lower average coal prices and lower average unrealized natural gas prices on forward positions.

Operation and Maintenance increased $97 million due primarily to

- higher planned outage and maintenance costs in 2013, mainly at our gas-fired Bethlehem Energy Center (BEC) plant in New York, Bergen gas-fired plant in New Jersey, Linden gas-fired plant in New Jersey and 23%-owned Conemaugh coal-fired plant in Pennsylvania, partially offset by lower storm costs in 2013, and
- higher outage costs at our nuclear generating facilities, primarily at our 100%-owned Hope Creek station.

Depreciation and Amortization increased $31 million due primarily to a higher depreciable asset base at Fossil and Nuclear, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut in June 2012, completion of the steam path retrofit upgrade at our co-owned Peach Bottom Unit 2 in October 2012, and placing two solar facilities into service in the fourth quarter of 2012. In addition, an update to the nuclear asset retirement obligation became effective in November 2012, causing higher depreciation in 2013.

Income from Equity Method Investments experienced no material change.

Other Income (Deductions) decreased $6 million due primarily to lower NDT Fund realized gains in 2013, partially offset by lower NDT Fund realized losses in 2013. In addition, we recognized a loss on the extinguishment of debt in 2012.

Other-Than-Temporary Impairments decreased $6 million due to lower impairments on the NDT Fund in 2013.

Interest Expense decreased $16 million due primarily to a decrease of $23 million resulting from the maturity of $300 million of 2.50% of Senior Notes in April 2013, and the early redemptions of $250 million of 5.00% medium term notes and various tax-exempt bonds in December 2012, partially offset by higher interest costs of $6 million in 2013 since interest capitalization ceased for our Kearny and New Haven gas-fired peaking projects on their June 2012 in-service date.

Income Tax Expense decreased $14 million in 2013 due primarily to lower pre-tax income.

Year ended December 31, 2012 as compared to 2011

Operating Revenues decreased $1,277 million due to changes in generation and supply revenues.

Generation Revenues decreased $974 million due primarily to

- lower net revenues of $564 million due primarily to lower average realized prices for our generation sold into the PJM and NY power pools and MTM losses due from the realization of prior year unrealized gains and adverse changes in unrealized prices in 2012 for forward positions,
- a decrease of $264 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts, primarily as a result of warmer winter weather in 2012 as well as customer migration, and
- a net decrease of $154 million due to lower volumes on wholesale load contracts in the PJM and NE regions,

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- partially offset by a net increase of $7 million in other revenues consisting of higher net capacity revenues, partially offset by lower operating reserve, ancillary and RMR revenues.

Gas Supply Revenues decreased $336 million due primarily to

- a decrease of $306 million in sales under the BGSS contract, substantially comprised of lower average gas prices on lower volumes of sales in 2012 due to warmer average temperatures during the first quarter of 2012, and
- a net decrease of $31 million due primarily to lower average prices, partially offset by higher sales volumes to third party customers.

Trading Revenues increased $33 million in 2012 due to the discontinuation of trading activities in the second quarter of 2011. As a result, the increase is due primarily to the absence of losses on electric energy supply contracts recognized in 2011.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $663 million due to

- ***Gas costs*** decreased $312 million, principally related to obligations under the BGSS contract, reflecting lower average gas inventory costs coupled with lower sales volumes in 2012 due primarily to warmer average temperatures during the first quarter of 2012.
- ***Generation costs*** decreased $351 million due primarily to $227 million of lower fuel costs, reflecting the utilization of lower volumes of coal and lower average natural gas prices, partially offset by the utilization of higher volumes of natural gas and higher nuclear fuel prices in 2012. The decrease was also attributable to $152 million of lower energy purchases, primarily in the PJM region as a result of lower load contract volumes in 2012, and $31 million of lower emission charges due to lower coal generation in the PJM and NE regions and impairment charges recorded in 2011 related to excess SO_2 emission allowances. These decreases were partially offset by an increase of $59 million due primarily to higher congestion costs in the PJM region.

Operation and Maintenance increased $22 million due primarily to

- an increase of $85 million due to damage from Superstorm Sandy for repairs to certain of our generation plants, primarily those in our fossil fleet, and to recognize the estimated loss of use of fossil materials and supplies, partially offset by a $19 million insurance recovery, and
- a net increase of $64 million due to higher refueling costs in 2012 for refueling outages at our 100%-owned Hope Creek nuclear unit and our 57%-owned Salem Unit 2 as compared to refueling outages for both of our 57%-owned Salem nuclear units in 2011,
- partially offset by a net decrease of $109 million largely due to lower fossil planned outages in 2012 and lower maintenance costs, principally at our BEC station, our gas-fired Bergen and Linden facilities and coal/gas-fired Hudson and Mercer plants in New Jersey, and 23%-owned Conemaugh plant, as well as to the absence of costs incurred for the cancellation and renegotiation of a major contractual agreement for parts and services in 2011.

Depreciation and Amortization increased $14 million due primarily to higher depreciable asset bases at Fossil and Nuclear, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut in June 2012 and completion of the steam path retrofit upgrades at our co-owned Peach Bottom Units 2 and 3 in October 2012 and October 2011, respectively.

Income from Equity Method Investments experienced no material change.

Other Income (Deductions) experienced no material change.

Other-Than-Temporary Impairments decreased $2 million due to lower impairments in 2012 on the NDT and Rabbi Trust Funds.

Interest Expense decreased $43 million due primarily to a decrease of $55 million resulting primarily from the maturity of $606 million of 7.75% Senior Notes in early April 2011 and the early redemption of $600 million of 6.95% Senior Notes in December 2011, partially offset by increases of $12 million due to two $250 million Senior Notes issuances in September 2011 and $3 million in higher interest costs since interest capitalization ceased for our Kearny and New Haven projects in their June 2012 in-service date.

Income Tax Expense decreased $257 million in 2012 due primarily to lower pre-tax income.

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Income (Loss) from Discontinued Operations

In 2011, we sold our two 1,000 MW combined-cycle generating facilities in Texas in separate transactions. In March 2011, we completed the sale of one plant for proceeds of $352 million at an after-tax gain of $54 million. In July 2011, we completed the sale of the second plant for proceeds of $335 million at an after-tax gain of $25 million. The results of operations for both plants for 2011, including the gain on the sales of the plants, are included in this category. See Item 8. Financial Statements and Supplementary Data— Note 4. Discontinued Operations and Dispositions for additional information.

PSE&G

PSE&G	Years Ended December 31, 2013	2012	2011	Increase / (Decrease) 2013 vs. 2012		Increase / (Decrease) 2012 vs. 2011	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 6,655	$ 6,626	$ 7,326	$ 29	—	$ (700)	(10)
Energy Costs	2,841	3,159	3,951	(318)	(10)	(792)	(20)
Operation and Maintenance	1,639	1,508	1,372	131	9	136	10
Depreciation and Amortization	872	778	719	94	12	59	8
Taxes Other Than Income Taxes	68	98	133	(30)	(31)	(35)	(26)
Other Income (Deductions)	51	47	21	4	9	26	N/A
Other-Than-Temporary Impairments	—	—	1	—	—	(1)	(100)
Interest Expense	293	295	310	(2)	(1)	(15)	(5)
Income Tax Expense	381	307	340	74	24	(33)	(10)

Year Ended December 31, 2013 as compared to 2012

Operating Revenues increased $29 million due primarily to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $223 million due primarily to an increase in transmission revenues.

- Transmission revenues were $184 million higher due to increased investments in transmission projects.
- Gas distribution revenues increased $24 million due primarily to higher sales volumes of $70 million, higher Capital Infrastructure Program (CIP) related revenue of $23 million and higher revenue from Solar and Energy Efficiency Recovery Charges (formerly RRC and currently Green Program Recovery Charges (GPRC)) of $5 million, partially offset by lower Weather Normalization Clause (WNC) revenue of $67 million due to more normal weather compared to the prior year and lower Transitional Energy Facilities Assessment (TEFA) revenue of $7 million due to a lower TEFA rate.
- Electric distribution revenues increased $15 million due primarily to higher GPRC of $37 million and higher CIP related revenue of $11 million, partially offset by lower TEFA revenue of $23 million due to a lower TEFA rate and lower sales volumes of $10 million.

Clause Revenues increased $110 million due primarily to higher Securitization Transition Charge (STC) revenues of $51 million, higher Societal Benefit Charges (SBC) of $47 million and a higher Solar Pilot Recovery Charge (SPRC) of $11 million. The changes in STC, SBC and SPRC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC or SPRC collections.

Commodity Revenue decreased $318 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $308 million due primarily to $169 million in lower BGS revenues and $139 million in lower revenues from the sale of Non-Utility Generation (NUG) energy and collections of Non-Utility Generation Charges (NGC) due primarily to lower prices. BGS sales decreased 4% due primarily to customer migration to third party suppliers (TPS) and weather.
- Gas revenues decreased $10 million due to lower BGSS prices of $121 million, partially offset by higher BGSS volumes of $111 million. The average price of natural gas was 12% lower in 2013 than in 2012.

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Other Operating Revenues increased $14 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Operating Expenses

Energy Costs decreased $318 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $308 million or 14% due to $214 million in lower BGS and NUG volumes, $35 million of lower BGS prices, and $59 million for decreased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.
- Gas costs decreased $10 million or 1% due to $121 million or 12% in lower prices, partially offset by $111 million or 11% in higher sales volumes due primarily to weather.

Operation and Maintenance increased $131 million, of which the most significant components were

- a $131 million increase in costs related to SBC, GPRC and CIP,
- a $24 million increase in transmission related costs, and
- a $10 million increase in appliance service costs,
- partially offset by the absence of $40 million in transmission and distribution storm damages in 2012,
- a $10 million decrease in pension and other postretirement benefits (OPEB) expenses, and
- an $11 million decrease in gas bad debt expense.

Depreciation and Amortization increased $94 million due primarily to

- a $59 million increase in amortization of Regulatory Assets, and
- a $33 million increase in additional plant in service.

Taxes Other Than Income Taxes decreased $30 million due to a lower TEFA rate, partially offset by higher sales volumes for gas.

Other Income and (Deductions) net increase of $4 million was due primarily to

- a $5 million increase in solar loan interest income,
- partially offset by a $1 million decrease in Rabbi Trust interest and gains.

Interest Expense experienced no material change.

Income Tax Expense increased $74 million due primarily to higher pre-tax income and the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012.

Year ended December 31, 2012 as compared to 2011

Operating Revenues decreased $700 million due to changes in delivery, clause, commodity and other operating revenues.

Commodity Revenue decreased $792 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $488 million due primarily to $431 million in lower BGS revenues and $57 million in lower revenues from the sale of NUG energy and collections of NGC due primarily to lower prices. BGS sales decreased 12% due primarily to customer migration to TPS; in contrast, delivery sales decreased only 1%.
- Gas revenues decreased $304 million due to lower BGSS volumes of $115 million and lower BGSS prices of $189 million. The average price of natural gas was 15% lower in 2012 than in 2011.

Delivery Revenues increased $83 million due primarily to an increase in transmission revenues.

- Transmission revenues were $83 million higher due to increased investments in transmission projects.
- Electric distribution revenues decreased $6 million due primarily to lower TEFA revenue of $22 million due to a lower TEFA rate and lower sales volumes of $13 million, partially offset by higher GPRC revenue of $20 million and higher CIP revenue of $9 million.

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- Gas distribution revenues increased $4 million due primarily to higher WNC revenue of $52 million and higher CIP revenue of $8 million, partially offset by lower sales volumes of $43 million, and lower TEFA revenue of $13 million due to a lower TEFA rate.

Clause Revenues increased $12 million due primarily to higher STC revenues of $19 million, partially offset by lower SBC of $6 million and a Margin Adjustment Clause (MAC) of $2 million. The changes in STC, SBC and MAC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, STC or MAC collections.

Operating Expenses

Energy Costs decreased $792 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $488 million or 18% due to $258 million in lower BGS and NUG volumes, $202 million of lower BGS prices, and $28 million for decreased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.
- Gas costs decreased $304 million or 24% due to $115 million or 9% in lower sales volumes due primarily to weather and $189 million or 15% in lower prices.

Operation and Maintenance increased $136 million, of which the most significant components were

- a $32 million increase in costs recognized related to SBC, GPRC and CIP,
- a $27 million increase in pension and OPEB expenses,
- a $17 million increase in storm damages,
- a $10 million increase in transmission related costs, and
- a $7 million increase in payroll costs.

Depreciation and Amortization increased $59 million due primarily to

- a $39 million increase in amortization of Regulatory Assets, and
- a $21 million increase in additional plant in service.

Taxes Other Than Income Taxes decreased $35 million due to a lower TEFA rate and lower sales volumes for electric and gas.

Other Income and (Deductions) net increase of $26 million was due primarily to

- a $14 million increase in capitalized allowance for equity funds used during construction,
- an $8 million increase in solar loan interest income, and
- a $4 million increase in Rabbi Trust interest and gains.

Other-Than-Temporary Impairments experienced no material change.

Interest Expense decreased $15 million due primarily to the partial redemption of securitization debt and higher interest capitalization related to higher construction work in progress, partially offset by interest relating to the new debt issued in 2012.

Income Tax Expense decreased $33 million due primarily to changes in tax reserves related to settlement of IRS tax audits.

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LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Financing Methodology

We expect our capital requirements to be met through internally generated cash flows and external financings, consisting of short-term debt for working capital needs and long-term debt for capital investments.

PSE&G's sources of external liquidity include a $600 million multi-year syndicated credit facility. PSE&G's commercial paper program is the primary vehicle for meeting seasonal, intra-month and temporary working capital needs. PSE&G does not engage in any intercompany borrowing or lending. PSE&G maintains back-up facilities in an amount sufficient to cover the commercial paper and letters of credit outstanding. PSE&G's dividend payments to PSEG are consistent with its capital structure objectives which have been established to maintain investment grade credit ratings. PSE&G's long-term financing plan is designed to replace maturities, fund a portion of its capital program and manage short-term debt balances. Generally, PSE&G uses either secured medium-term notes or first mortgage bonds to raise long-term capital.

PSEG, Power, Energy Holdings, PSEG LI and PSEG Services Corporation participate in a corporate money pool, an aggregation of daily cash balances designed to efficiently manage their respective short-term liquidity needs. Long Island Electric Utility Servco LLC (ServCo), a wholly owned subsidiary of PSEG LI, does not participate in the corporate money pool. ServCo's short-term liquidity needs are met through an account funded and owned by LIPA.

PSEG's sources of external liquidity include multi-year syndicated credit facilities totaling $1 billion. These facilities are available to back-stop PSEG's commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to PSEG's subsidiaries. PSEG's credit facilities and the commercial paper program are available to support PSEG working capital needs or to temporarily fund growth opportunities in advance of obtaining permanent financing. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power's sources of external liquidity include $2.7 billion of syndicated multi-year credit facilities. Additionally, from time to time, Power maintains bilateral credit agreements designed to enhance its liquidity position. Credit capacity is primarily used to provide collateral in support of Power's forward energy sale and forward fuel purchase contracts as the market prices for energy and fuel fluctuate, and to meet potential collateral postings in the event of a credit rating downgrade below investment grade. Power's dividend payments to PSEG are also designed to be consistent with its capital structure objectives which have been established to maintain investment grade credit ratings and provide sufficient financial flexibility. Generally, Power issues senior unsecured debt to raise long-term capital.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the year ended December 31, 2013, our operating cash flow increased by $371 million. For the year ended December 31, 2012, our operating cash flow decreased by $770 million. The net changes were due to net changes from our subsidiaries as discussed below.

Power

Power's operating cash flow decreased $106 million from $1,453 million to $1,347 million for the year ended December 31, 2013, as compared to 2012, primarily resulting from

- lower earnings, and
- higher tax payments,
- partially offset by a decrease of $73 million related to margin deposits, and
- a decrease of $26 million in employee benefit plan funding.

Power's operating cash flow decreased $364 million from $1,817 million to $1,453 million for the year ended December 31, 2012, as compared to 2011, primarily resulting from lower earnings and a $172 million decrease from lower net collections of counterparty receivables, partially offset by

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- a decrease of $57 million in benefit plan funding,
- a $73 million decrease in spending for fuel, materials and supplies, and
- a $249 million decrease in net payment of counterparty payables.

PSE&G

PSE&G's operating cash flow increased $389 million from $1,256 million to $1,645 million for the year ended December 31, 2013, as compared to 2012, due primarily to

- higher earnings,
- an increase of $134 million due to an increase from a net change in regulatory deferrals primarily related to BGSS gas costs and the collection of Gas Weather Normalization Charges, and
- a decrease of $47 million in benefit plan funding,
- partially offset by $114 million related to higher tax payments

PSE&G's operating cash flow decreased $520 million from $1,776 million to $1,256 million for the year ended December 31, 2012, as compared to 2011, due primarily to

- a lower tax receipt of $484 million due to lower benefit of accelerated tax depreciation, and
- a decrease of $306 million due to lower collections from customer billings,
- partially offset by a decrease of $117 million in benefit plan funding, and
- a decrease of $88 million in net prepayments due primarily to the application of prior year prepayment carryforwards towards current year state tax liabilities.

Short-Term Liquidity

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of December 31, 2013 were as follows:

	As of December 31, 2013		
Company/Facility	**Total Facility**	**Usage**	**Available Liquidity**
	Millions		
PSEG	$ 1,000	$ 8	$ 992
Power	2,700	170	2,530
PSE&G	600	73	527
Total	**$ 4,300**	**$ 251**	**$ 4,049**

As of December 31, 2013, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating. PSE&G's credit facility primary use is to support its Commercial Paper Program under which as of December 31, 2013, $60 million was outstanding. Most of our credit facilities expire in 2017 and 2018. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities and Note 14. Schedule of Consolidated Debt.

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Long-Term Debt Financing

PSE&G has $250 million of 5.00%, Series D, Medium Term Notes and $250 million of 0.85%, Series G, Medium Term Notes both maturing in August 2014.

Power has a $44 million pollution control facilities loan servicing and securing a Pennsylvania Economic Development Financing Authority (PEDFA) bond due November 2042. The bond is backed by a three-year letter of credit that expires in November 2014. The PEDFA bond has been reclassified as debt due within the year.

For a discussion of our long-term debt transactions during 2013 and into 2014, see Item 8. Financial Statements and Supplementary Data— Note 14. Schedule of Consolidated Debt.

Debt Covenants

Our credit agreements contain maximum debt to equity ratios and other restrictive covenants and conditions to borrowing. We are currently in compliance with all of our debt covenants. Continued compliance with applicable financial covenants will depend upon our future financial position, level of earnings and cash flows, as to which no assurances can be given.

In addition, under its First and Refunding Mortgage (Mortgage), PSE&G may issue new First and Refunding Mortgage Bonds against previous additions and improvements, provided that its ratio of earnings to fixed charges calculated in accordance with its Mortgage is at least 2 to1, and/or against retired Mortgage Bonds. As of December 31, 2013, PSE&G's Mortgage coverage ratio was 4.2 to1 and the Mortgage would permit up to approximately $2.7 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.

Default Provisions

Our bank credit agreements and indentures contain various default provisions that could result in the potential acceleration of payment under the defaulting company's agreement. We have not defaulted under these agreements.

PSEG's bank credit agreements contain cross default provisions under which events at Power or PSE&G, including payment defaults, bankruptcy events, the failure to satisfy certain final judgments or other events of default under their financing agreements, would each constitute an event of default. Under the bank credit agreements, it would be an event of default if both Power and PSE&G cease to be wholly owned by PSEG.

There are no cross default provisions to affiliates in Power's or PSE&G's credit agreements or indentures.

Ratings Triggers

Our debt indentures and credit agreements do not contain any material 'ratings triggers' that would cause an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, any one or more of the affected companies may be subject to increased interest costs on certain bank debt and certain collateral requirements. In the event that we are not able to affirm representations and warranties on credit agreements, lenders would not be required to make loans.

Fluctuations in commodity prices or a deterioration of Power's credit rating to below investment grade could increase Power's required margin postings under various agreements entered into in the normal course of business. Power believes it has sufficient liquidity to meet the required posting of collateral which would likely result from a credit rating downgrade at today's market prices.

In accordance with BPU requirements under the BGS contracts, PSE&G is required to maintain an investment grade credit rating. If PSE&G were to lose its investment grade rating, it would be required to file a plan to assure continued payment for the BGS requirements of its customers.

PSE&G is the servicer for the bonds issued by PSE&G Transition Funding LLC and PSE&G Transition Funding II LLC. Cash collected by PSE&G to service these bonds is commingled with PSE&G's other cash until it is remitted to the bond trustee each month. If PSE&G were to lose its investment grade rating, PSE&G would be required to remit collected cash daily to the bond trustee. PSE&G is prohibited from advancing its own funds to make payments related to such bonds.

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Common Stock Dividends

Dividend Payments on Common Stock	Years Ended December 31, 2013	2012	2011
Per Share	$ 1.44	$ 1.42	$ 1.37
in Millions	$ 728	$ 718	$ 693

On February 18, 2014, our Board of Directors approved a $0.370 per share common stock dividend for the first quarter of 2014. This reflects an indicated annual dividend rate of $1.48 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In April 2013, S&P upgraded the corporate credit ratings on PSEG, Power and PSE&G to BBB+ from BBB and PSE&G's Mortgage Bond rating to A from A-. PSEG's, Power's and PSE&G's outlooks were changed to stable from positive. In May 2013, Moody's published updated credit opinions on PSEG, Power and PSE&G. PSEG's, Power's and PSE&G's ratings and outlooks remained unchanged. In July 2013, Fitch published updated research on PSEG, Power and PSE&G which kept their ratings and outlooks unchanged. In January 2014, Moody's upgraded PSE&G's Mortgage Bond Rating from A1 to Aa3 and its commercial paper rating from P2 to P1. PSE&G's outlook is stable.

	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	**Stable**	**Stable**	**Stable**
Commercial Paper	P2	A2	F2
Power			
Outlook	**Stable**	**Stable**	**Stable**
Senior Notes	Baa1	BBB+	BBB+
PSE&G			
Outlook	**Stable**	**Stable**	**Stable**
Mortgage Bonds	Aa3	A	A+
Commercial Paper	P1	A2	F2

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1 (highest) to D (lowest) for short-term securities.

Other Comprehensive Income

For the year ended December 31, 2013, we had Other Comprehensive Income of $293 million on a consolidated basis. Other Comprehensive Income was due primarily to a $55 million increase in net unrealized gains related to Available-for-Sale Securities, and a $247 million decrease in our consolidated liability for pension and postretirement benefits and was partially

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offset by $9 million of unrealized losses on derivative contracts accounted for as hedges. See Item 8. Financial Statements and Supplementary Data— Note 21. Accumulated Other Comprehensive Income (Loss), Net of Tax for additional information.

CAPITAL REQUIREMENTS

It is expected that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. Projected capital construction and investment expenditures, excluding nuclear fuel purchases, for the next three years are presented in the table below. These amounts are subject to change, based on various factors. We will continue to approach non-regulated solar and other renewables investments opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2014	2015	2016
Power:		Millions	
Baseline	$ 210	$ 210	$ 210
Environmental/Regulatory	85	55	35
Fossil Growth Opportunities	40	15	—
Nuclear Expansion	140	85	25
Solar Expansion	5	—	—
Total Power	**$ 480**	**$ 365**	**$ 270**
PSE&G:			
Transmission			
Reliability Enhancements	$ 1,435	$ 1,290	$ 975
Facility Replacement	110	125	135
Support Facilities	10	15	15
Distribution			
Reliability Enhancements	90	85	95
Facility Replacement	145	160	160
Support Facilities	45	45	45
New Business	155	155	160
Environmental/Regulatory	40	40	40
Renewables	125	125	55
Total PSE&G	**$ 2,155**	**$ 2,040**	**$ 1,680**
Services	45	35	25
Total PSEG	**$ 2,680**	**$ 2,440**	**$ 1,975**

Power

Power's projected expenditures for the various items listed above are primarily comprised of the following:

- Baseline—investments to replace major parts and enhance operational performance.
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Fossil Growth Opportunities—investments associated with upgrades to increase efficiency and output at combined cycle plants.
- Nuclear Expansion—investments associated with certain Nuclear capital projects, primarily at existing facilities designed to increase operating output.

In 2013, Power made $415 million of capital expenditures, excluding $194 million for nuclear fuel, primarily related to various projects at Fossil and Nuclear.

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PSE&G

PSE&G's projections for future capital expenditures include material additions and replacements to its transmission and distribution systems to meet expected growth and to manage reliability. As project scope and cost estimates develop, PSE&G will modify its current projections to include these required investments. PSE&G's projected expenditures for the various items reported above are primarily comprised of the following:

- Reliability Enhancements—investments made to maintain the reliability and efficiency of the system or function.
- Facility Replacement—investments made to replace systems or equipment in kind.
- Support Facilities—ancillary equipment needed to support the business lines, such as computers, office furniture and buildings and structures housing support personnel or equipment/inventory.
- New Business—investments made in support of new business (e.g. to add new customers).
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Renewables—investments made in response to regulatory or legal mandates relating to renewable energy.

In 2013, PSE&G made $2,207 million of capital expenditures, including $2,175 million of investment in plant, primarily for transmission and distribution system reliability and $32 million in solar loan investments. This does not include expenditures for certain energy efficiency and renewable programs of $8 million or cost of removal, net of salvage, of $93 million, which are included in operating cash flows.

Additional Projects

In February 2013, we filed a petition with the BPU describing the improvements we recommend making to our electric and gas distribution systems over a ten year period to improve resiliency for the future. In this petition, we sought approval to invest $0.9 billion in our gas distribution system and $1.7 billion in our electric distribution over an initial five year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. This matter is pending. The current estimated cost of the entire program, including the first five years of investments for which we sought approval in this petition, is $3.9 billion. We anticipate seeking BPU approval to complete our investment under the program at a later date.

The estimated project expenditures related to this filing are not included above in our $7.1 billion three-year capital forecast table.

Disclosures about Long-Term Maturities, Contractual and Commercial Obligations and Certain Investments

The following table reflects our contractual cash obligations and other commercial commitments in the respective periods in which they are due. In addition, the table summarizes anticipated recourse and non-recourse debt maturities for the years shown. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 14. Schedule of Consolidated Debt. The table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities for uncertain tax positions since we are unable to reasonably estimate the timing of liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes for additional information.

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	Total Amount Committed	Less Than 1 Year	2 - 3 Years	4- 5 Years	Over 5 Years
			Millions		
Contractual Cash Obligations					
Long-Term Recourse Debt Maturities					
Power	$ 2,553	$ 44	$ 853	$ 250	$ 1,406
PSE&G	5,579	500	471	750	3,858
Transition Funding (PSE&G)	476	225	251	—	—
Transition Funding II (PSE&G)	20	12	8	—	—
Long-Term Non-Recourse Project Financing					
Other	16	—	16	—	—
Interest on Recourse Debt					
Power	1,214	132	245	182	655
PSE&G	3,850	232	417	387	2,814
Transition Funding (PSE&G)	38	27	11	—	—
Transition Funding II (PSE&G)	1	1	—	—	—
Interest on Non-Recourse Project Financing					
Other	2	1	1	—	—
Capital Lease Obligations					
Power	7	2	2	1	2
Services	13	7	6	—	—
Operating Leases					
Power	22	1	2	3	16
PSE&G	64	9	13	9	33
Services	214	—	15	26	173
Other	6	2	3	1	—
Energy-Related Purchase Commitments					
Power	3,364	661	1,227	701	775
Total Contractual Cash Obligations	**$ 17,439**	**$ 1,856**	**$ 3,541**	**$ 2,310**	**$ 9,732**
Commercial Commitments					
Standby Letters of Credit					
PSEG	$ 8	$ 8	$ —	$ —	$ —
Power	$ 215	$ 215	$ —	$ —	$ —
PSE&G	$ 13	$ 13	$ —	$ —	$ —
Guarantees and Equity Commitments					
Power	10	9	—	—	1
Total Commercial Commitments	**$ 246**	**$ 245**	**$ —**	**$ —**	**$ 1**
Liability Payments for Uncertain Tax Positions					
PSEG	$ 2	$ 2	$ —	$ —	$ —
Power	71	71	—	—	—
PSE&G	11	11	—	—	—
Other	73	73	—	—	—

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OFF-BALANCE SHEET ARRANGEMENTS

Power

Power issues guarantees in conjunction with certain of its energy contracts. See Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities for further discussion.

Other

Through Energy Holdings, we have investments in leveraged leases that are accounted for in accordance with GAAP Accounting for Leases. Leveraged lease investments generally involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease arrangement, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and is not presented on our Consolidated Balance Sheets. In the event of default, the leased asset, and in some cases the lessee, secures the loan. As a lessor, Energy Holdings has ownership rights to the property and rents the property to the lessees for use in their business operations. For additional information, see Item 8. Financial Statements and Supplementary Data— Note 7. Long-Term Investments.

In the event that collection of the minimum lease payments to be received by Energy Holdings is no longer reasonably assured, the accounting treatment for some of the leases may change. In such cases, Energy Holdings may deem that a lessee has a high probability of defaulting on the lease obligation, and would reclassify the lease from a leveraged lease to an operating lease and would consider the need to record an impairment of its investment. Should this event occur, the fair value of the underlying asset and the associated debt would be recorded on the Consolidated Balance Sheets instead of the net equity investment in the lease.

CRITICAL ACCOUNTING ESTIMATES

Under GAAP, many accounting standards require the use of estimates, variable inputs and assumptions (collectively referred to as estimates) that are subjective in nature. Because of this, differences between the actual measure realized versus the estimate can have a material impact on results of operations, financial position and cash flows. We have determined that the following estimates are considered critical to the application of rules that relate to the respective businesses.

Accounting for Pensions

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The market-related value of plan assets held
for the qualified pension and OPEB plans is equal to the fair value of these assets as of year-end. The plan assets are comprised of investments in both debt and equity securities which are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. We calculate pension costs using various economic and demographic assumptions.

***Assumptions and Approach Used*:** Economic assumptions include the discount rate and the long-term rate of return on trust assets. Demographic assumptions include projections of future mortality rates, pay increases and retirement patterns.

Assumption	2013	2012	2011
Discount Rate	5.00%	4.20%	5.00%
Rate of Return on Plan Assets	8.00%	8.00%	8.50%

The discount rate used to calculate pension obligations is determined as of December 31 each year, our measurement date. The discount rate used to determine year-end obligations is also used to develop the following year's net periodic pension cost.
In selecting the annual discount rate to calculate benefit obligations, we utilize a hypothetical portfolio of high quality corporate bonds with cash flows that match the benefit plan liability. The composite yield on the hypothetical bond portfolio reflects the rate at which the obligations could effectively be settled.

Our expected rate of return on plan assets reflects current asset allocations, historical long-term investment performance and an estimate of future long-term returns by asset class and long-term inflation assumptions.

Based on the above assumptions, we have estimated net periodic pension income of approximately $13 million, net of amounts capitalized, and no contributions in 2014.

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We utilize a corridor approach that reduces the volatility of reported pension expense /income. The corridor requires differences between actuarial assumptions and plan results be deferred and amortized as part of expense/income. This occurs only when the accumulated differences exceed 10% of the greater of the pension benefit obligation or the fair value of plan assets as of each year-end. The excess would be amortized over the average remaining service period of the active employees, which is approximately eight years.

***Effect if Different Assumptions Used*:** As part of the business planning process, we have modeled future costs assuming an 8.00% rate of return and a 5.00% discount rate for 2014, increasing annually by 25 basis points to 5.75% in 2017 and beyond. Actual future pension expense/income and funding levels will depend on future investment performance, changes in discount rates, market conditions, funding levels relative to our projected benefit obligation and accumulated benefit obligation and various other factors related to the populations participating in the pension plans.

The following chart reflects the sensitivities associated with a change in certain assumptions. The effects of the assumption changes shown below solely reflect the impact of that specific assumption.

Assumption	% Change	Impact on Pension Benefit Obligation as of December 31, 2013	Increase to Pension Expense in 2014
		Millions	
Discount Rate	(1)%	$ 644	$ 69
Rate of Return on Plan Assets	(1)%	$ —	$ 50

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Hedge and MTM Accounting

Current guidance requires us to recognize the fair value of derivative instruments, not designated as normal purchases or normal sales, at their fair value on the balance sheet. Many non-trading contracts qualify for normal purchases and normal sales exemption and are accounted for upon settlement.

***Assumptions and Approach Used*:** In general, the fair value of our derivative instruments is determined by reference to quoted market prices from contracts listed on exchanges or from brokers. Some of these derivative contracts are long-term and rely on forward price quotations over the entire duration of the derivative contracts.

For a small number of contracts where quoted market prices are not available, we utilize mathematical models that rely on historical data to develop forward pricing information in the determination of fair value. Because the determination of fair value using such models is subject to significant assumptions and estimates, we developed reserve policies that are consistently applied to model-generated results to determine reasonable estimates of the fair value to record in the financial statements.

We have entered into various derivative instruments to manage risk from changes in commodity prices and interest rates. In accordance with our hedging strategy, derivatives that are hedging these risks and qualify are designated as either cash flow hedges or fair value hedges. For derivatives designated as hedges, the change in the value of a derivative instrument is measured against the offsetting change in the value of the underlying contract, anticipated transaction or other business condition that the derivative instrument is intended to hedge. This is known as the measure of hedge effectiveness. Changes in the fair value of the effective portion of a derivative instrument designated as a fair value hedge, along with changes in the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in current period earnings. Changes in the fair value of the effective portion of derivative instruments designated as cash flow hedges, are reported in Accumulated Other Comprehensive Income (Loss), net of tax, until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings. During periods of extreme price volatility, there will be significant changes in the value recorded in Accumulated Other Comprehensive Income (Loss).

For our wholesale energy business, many of the forward sale, forward purchase, option and other contracts are derivative instruments that hedge commodity price risk, but do not meet the requirements for either cash flow or fair value hedge accounting. The changes in value of such derivative contracts are marked to market through earnings as the related commodity prices fluctuate. As a result, our earnings may experience significant fluctuations depending on the volatility of commodity prices.

***Effect if Different Assumptions Used*:** Any significant changes to the fair market values of our derivatives instruments could result in a material change in the value of the assets or liabilities recorded on our Consolidated Balance Sheets and could result in a material change to the unrealized gains or losses recorded in our Consolidated Statements of Operations.

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For additional information regarding Derivative Financial Instruments, see Item 8. Financial Statements and Supplementary Data— Note 16. Financial Risk Management Activities.

Lease Investments

Our Investments in Leases, included in Long-Term Investments on our Consolidated Balance Sheets, are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. A significant portion of the estimated residual value of leased assets is related to merchant power plants leased to other energy companies. See Item 8. Financial Statements and Supplementary Data – Note 7. Long-Term Investments, and Note 8. Financing Receivables.

***Assumptions and Approach Used*:** Residual values are the estimated values of the leased assets at the end of the respective lease terms. The estimated values are calculated by discounting the cash flows related to the leased assets after the lease term. For the merchant power plants, the estimated discounted cash flows are dependent upon various assumptions, including:

- estimated forward power and capacity prices in the years after the lease,
- related prices of fuel for the plants,
- dispatch rates for the plants,
- future capital expenditures required to maintain the plants,
- future operation and maintenance expenses, and
- discount rates.

Residual valuations are performed annually for each plant subject to lease using specific assumptions tailored to each plant. Those annual valuations are compared to the recorded residual values to determine if an impairment is warranted.

***Effect if Different Assumptions Used*:** A significant change to the assumptions, such as a large decrease in near-term power prices that affects the market's view of long-term power prices, or a change in the credit rating or bankruptcy of a counterparty, could result in an impairment of one or more of the residual values, but not necessarily to all of the residual values. However, if, because of changes in assumptions, all the residual values related to the merchant energy plants were deemed to be zero, we would recognize an after-tax charge to income of approximately $179 million.

NDT Fund

Our NDT Fund is comprised of both debt and equity securities. The assets in the NDT Fund are classified as available-for-sale securities and are marked to market with unrealized gains and losses recorded in Accumulated Other Comprehensive Income (Loss) unless securities with such unrealized losses are deemed to be other-than-temporarily impaired. Realized gains, losses and dividend and interest income are recorded in our Consolidated Statements of Operations as Other Income and Other Deductions. Unrealized losses that are deemed to be other-than-temporarily impaired are charged against earnings rather than Accumulated Other Comprehensive Income (Loss) and reflected as a separate line in the Consolidated Statement of Operations.

***Assumptions and Approach Used*:** The NDT Fund investments are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. See Item 8. Financial Statements and Supplementary Data— Note 17. Fair Value Measurements for additional information.

***Effect if Different Assumptions Used*:** Any significant changes to the fair market values of the fund securities could result in a material change in the value of our NDT Fund with a corresponding impact to earnings, which could potentially result in additional funding requirements to satisfy our decommissioning obligations. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Asset Retirement Obligations (ARO)

Power, PSE&G and Services recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists. These AROs are recorded at fair value in the period in which they are incurred and are capitalized as part of the carrying amount of the related long-lived assets. PSE&G, as a rate-regulated entity, recognizes regulatory assets or liabilities as a result of timing differences between the recording of costs and costs recovered through the ratemaking process. We accrete the ARO liability to reflect the passage of time.

***Assumptions and Approach Used*:** Because quoted market prices are not available for AROs, we estimate the initial fair value of an ARO by calculating discounted cash flows that are dependent upon various assumptions, including:

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- estimation of dates for retirement,
- amounts and timing of future cash expenditures associated with retirement, settlement or remediation activities,
- discount rates,
- cost escalation rates,
- market risk premium,
- inflation rates, and
- if applicable, past experience with government regulators regarding similar obligations.

We obtain updated cost studies every three years unless new information necessitates more frequent updates. The most recent cost study was done in 2012. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset which impacts the amount of accretion and depreciation expense recognized in future periods.

Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power's nuclear facilities comprised 92% of Power's total AROs as of December 31, 2013. Power determines its AROs for its nuclear units by assigning probability weighting to various discounted cash flow outcomes for each of its nuclear units that incorporate the assumptions above as well as:

- license renewals,
- early shutdown,
- safe storage for a period of time after retirement, and
- recovery from the federal government of costs incurred for spent nuclear fuel.

***Effect if Different Assumptions Used*:** Changes in the assumptions could result in a material change in the ARO balance sheet obligation and the period over which we accrete to the ultimate liability. For example, a 1% decrease in the discount rate would result in a $137 million increase in the Nuclear ARO as of December 31, 2013. A 1% increase in the inflation rate would result in a $353 million increase in the Nuclear ARO as of December 31, 2013. Also, if we did not assume that we would recover from the federal government the costs incurred for spent nuclear fuel, the Nuclear ARO would increase by $289 million at December 31, 2013.

Accounting for Regulated Businesses

PSE&G prepares its financial statements to comply with GAAP for rate-regulated enterprises, which differs in some respects from accounting for non-regulated businesses. In general, accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (Regulatory Asset) or recognize obligations (Regulatory Liability) if the rates established are designed to recover the costs and if the competitive environment makes it probable that such rates can be charged or collected. This accounting results in the recognition of revenues and expenses in different time periods than that of enterprises that are not regulated.

***Assumptions and Approach Used*:** PSE&G recognizes Regulatory Assets where it is probable that such costs will be recoverable in future rates from customers and Regulatory Liabilities where it is probable that refunds will be made to customers in future billings. The highest degree of probability is an order from the BPU either approving recovery of the deferred costs over a future period or requiring the refund of a liability over a future period.

Virtually all of PSE&G's regulatory assets and liabilities are supported by BPU orders. In the absence of an order, PSE&G will consider the following when determining whether to record a Regulatory Asset or Liability:

- past experience regarding similar items with the BPU,
- treatment of a similar item in an order by the BPU for another utility,
- passage of new legislation, and
- recent discussions with the BPU.

All deferred costs are subject to prudence reviews by the BPU. When the recovery of a Regulatory Asset or payment of a Regulatory Liability is no longer probable, PSE&G charges or credits earnings, as appropriate.

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***Effect if Different Assumptions Used*:** A change in the above assumptions may result in a material impact on our results of operations or our cash flows. See Item 8. Financial Statements and Supplementary Data— Note 6. Regulatory Assets and Liabilities for a description of the amounts and nature of regulatory balance sheet amounts.

Accounting for Insurance Proceeds

In late October 2012, strong winds and the resulting storm surge from Superstorm Sandy caused severe damage to our transmission and distribution system throughout our service territory as well as to some of our generation infrastructure. PSE&G has recognized $6 million in insurance proceeds. Power received total insurance proceeds of $44 million related to their expenses. See Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities for additional information.

***Assumptions and Approach Used*:** As of December 31, 2013, we recovered approximately $50 million in total from our insurance carriers. In June 2013, PSEG, Power and PSE&G filed suit in New Jersey state court against the insurance carriers seeking legal interpretation of certain terms in the insurance policies regarding losses from damage caused by Superstorm Sandy's storm surge. In August 2013, the insurance carriers filed an answer in which they denied most of the allegations made in the complaint. Discovery is ongoing. We believe that any further proceeds to be received under our policies are not estimable at December 31, 2013.

***Effect if Different Assumptions Used*:** If we were to use different assumptions regarding additional insurance proceeds, there would be a dollar for dollar effect on Operation and Maintenance Expense and Operating Income for Power. If we were to recognize any additional insurance proceeds for PSE&G, we would allocate those proceeds between Operation and Maintenance Expense and costs that have been deferred for regulatory recovery or capitalized. In either case, we would not recognize insurance proceeds in excess of actual costs incurred.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The market risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

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Years Ended December 31,	MTM VaR Millions 2013	2012
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 12	$ 18
Average for the Period	$ 15	$ 16
High	$ 29	$ 29
Low	$ 8	$ 7
99.5% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 18	$ 28
Average for the Period	$ 23	$ 25
High	$ 46	$ 46
Low	$ 13	$ 11

See Item 8. Financial Statements and Supplementary Data— Note 16. Financial Risk Management Activities for a discussion of credit risk.

Interest Rates

We are subject to the risk of fluctuating interest rates in the normal course of business. We manage interest rate risk by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, we use a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

As of December 31, 2013, a hypothetical 10% increase in market interest rates would result in

- less than $1 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and
- a $288 million decrease in the fair value of debt, including a $68 million decrease at Power and a $220 million decrease at PSE&G.

Debt and Equity Securities

We have $5.4 billion of assets in our pension plan trusts. Although fluctuations in market prices of securities within this portfolio do not directly affect our earnings in the current period, changes in the value of these investments could affect

- our future contributions to these plans,
- our financial position if our accumulated benefit obligation under our pension plans exceeds the fair value of the pension trust funds, and
- future earnings, as we could be required to adjust pension expense and the assumed rate of return.

The NDT Fund is comprised of both fixed income and equity securities totaling $1.7 billion as of December 31, 2013. As of December 31, 2013, the portfolio includes $897 million of equity securities and $720 million in fixed income securities. The fair market value of the assets in the NDT Fund will fluctuate primarily depending upon the performance of equity markets. As of December 31, 2013, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $90 million.

We use duration to measure the interest rate sensitivity of the fixed income portfolio. Duration is a summary statistic of the effective average maturity of the fixed income portfolio. The benchmark for the fixed income component of the NDT Fund currently has duration of 5.55 years and a yield of 2.48%. The portfolio's value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2013, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $40 million.

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Credit Risk

See Item 8. Financial Statements and Supplementary Data— Note 16. Financial Risk Management Activities for a discussion of credit risk and a discussion about Power's credit risk.

BGS suppliers expose PSE&G to credit losses in the event of non-performance or non-payment upon a default of the BGS supplier. Credit requirements are governed under BPU-approved BGS contracts.

Energy Holdings has credit risk related to its investments in leases, which totaled $98 million, net of deferred taxes of $727 million, as of December 31, 2013. These leveraged leases are concentrated in the United States energy industry. See Item 8. Financial Statements and Supplementary Data – Note 8. Financing Receivables for counterparties' credit ratings and other information. The credit exposure to the lessees is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverages are not met and similar cash flow restrictions if ratings are not maintained at stated levels. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a temporary market downturn or degradation in operating performance of the leased assets.

In any lease transaction, in the event of a default, Energy Holdings would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. Under a worst-case scenario, if a foreclosure were to occur, Energy Holdings would record a pre-tax write-off up to its outstanding gross investment, including deferred taxes, in these facilities. Also, in the event of a potential foreclosure, the net tax benefits generated by Energy Holdings' portfolio of investments could be materially reduced in the period in which gains associated with the potential forgiveness of debt at these projects occurs. The amount and timing of any potential reduction in net tax benefits is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, the amount of lease debt outstanding, any cash trapped at the projects and negotiations during such potential foreclosure process. The potential loss of earnings, impairment and/or tax payments could have a material impact to our financial position, results of operations and net cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined Form 10-K is separately filed by PSEG, Power and PSE&G. Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations as to any other company.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of
Public Service Enterprise Group Incorporated:

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(a). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Sole Member and Board of Directors of
PSEG Power LLC:

We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, member's equity, and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(b). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Sole Stockholder and Board of Directors of
Public Service Electric and Gas Company:

We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(c). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2014

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data

	Years Ended December 31,		
	2013	2012	2011
OPERATING REVENUES	$ 9,968	$ 9,781	$ 11,079
OPERATING EXPENSES			
Energy Costs	3,536	3,719	4,747
Operation and Maintenance	2,887	2,632	2,481
Depreciation and Amortization	1,178	1,054	976
Taxes Other Than Income Taxes	68	98	133
Total Operating Expenses	7,669	7,503	8,337
OPERATING INCOME	2,299	2,278	2,742
Income from Equity Method Investments	11	12	4
Other Income	213	260	220
Other Deductions	(54)	(98)	(85)
Other-Than-Temporary Impairments	(12)	(18)	(22)
Interest Expense	(402)	(423)	(475)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,055	2,011	2,384
Income Tax (Expense) Benefit	(812)	(736)	(977)
INCOME FROM CONTINUING OPERATIONS	1,243	1,275	1,407
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $0, $0 and $(51) for the years ended 2013, 2012 and 2011, respectively	—	—	96
NET INCOME	$ 1,243	$ 1,275	$ 1,503
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):			
BASIC	505,889	505,933	505,949
DILUTED	507,525	507,086	506,982
EARNINGS PER SHARE:			
BASIC			
INCOME FROM CONTINUING OPERATIONS	$ 2.46	$ 2.52	$ 2.78
NET INCOME	$ 2.46	$ 2.52	$ 2.97
DILUTED			
INCOME FROM CONTINUING OPERATIONS	$ 2.45	$ 2.51	$ 2.77
NET INCOME	$ 2.45	$ 2.51	$ 2.96

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2013	**2012**	**2011**
NET INCOME	$ 1,243	$ 1,275	$ 1,503
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(54), $(24) and $43 for the years ended 2013, 2012 and 2011, respectively	55	19	(39)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $7, $18 and $54 for the years ended 2013, 2012 and 2011, respectively	(9)	(24)	(80)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(172), $32 and $44 for the years ended 2013, 2012 and 2011, respectively	247	(46)	(62)
Other Comprehensive Income (Loss), net of tax	293	(51)	(181)
COMPREHENSIVE INCOME	$ 1,536	$ 1,224	$ 1,322

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

ASSETS	December 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 493	$ 379
Accounts Receivable, net of allowances of $56 and $56 in 2013 and 2012, respectively	1,203	1,069
Tax Receivable	109	227
Unbilled Revenues	300	314
Fuel	545	583
Materials and Supplies, net	479	422
Prepayments	89	283
Derivative Contracts	98	138
Deferred Income Taxes	24	49
Regulatory Assets	243	349
Other	31	56
Total Current Assets	3,614	3,869
PROPERTY, PLANT AND EQUIPMENT	29,713	27,402
Less: Accumulated Depreciation and Amortization	(8,068)	(7,666)
Net Property, Plant and Equipment	21,645	19,736
NONCURRENT ASSETS		
Regulatory Assets	2,612	3,830
Regulatory Assets of Variable Interest Entities (VIEs)	476	713
Long-Term Investments	1,313	1,324
Nuclear Decommissioning Trust (NDT) Fund	1,701	1,540
Other Special Funds	613	191
Goodwill	16	16
Other Intangibles	33	34
Derivative Contracts	163	153
Restricted Cash of VIEs	24	23
Other	312	296
Total Noncurrent Assets	7,263	8,120
TOTAL ASSETS	$ 32,522	$ 31,725

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2013	December 31, 2012
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 544	$ 1,026
Securitization Debt of VIEs Due Within One Year	237	226
Commercial Paper and Loans	60	263
Accounts Payable	1,222	1,304
Derivative Contracts	76	46
Accrued Interest	95	91
Accrued Taxes	37	17
Deferred Income Taxes	—	72
Clean Energy Program	142	153
Obligation to Return Cash Collateral	119	122
Regulatory Liabilities	43	67
Other	488	390
Total Current Liabilities	3,063	3,777
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	7,107	6,542
Regulatory Liabilities	233	209
Regulatory Liabilities of VIEs	11	10
Asset Retirement Obligations	677	627
Other Postretirement Benefit (OPEB) Costs	1,095	1,285
Accrued Pension Costs	121	876
Environmental Costs	414	537
Derivative Contracts	31	122
Long-Term Accrued Taxes	180	164
Other	119	108
Total Noncurrent Liabilities	9,988	10,480
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	7,587	6,148
Securitization Debt of VIEs	259	496
Project Level, Non-Recourse Debt	16	43
Total Long-Term Debt	7,862	6,687
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2013 and 2012— 533,556,660 shares	4,861	4,833
Treasury Stock, at cost, 2013— 27,699,398 shares; 2012— 27,664,188 shares	(615)	(607)
Retained Earnings	7,457	6,942
Accumulated Other Comprehensive Loss	(95)	(388)
Total Common Stockholders' Equity	11,608	10,780
Noncontrolling Interest	1	1
Total Stockholders' Equity	11,609	10,781
Total Capitalization	19,471	17,468
TOTAL LIABILITIES AND CAPITALIZATION	$ 32,522	$ 31,725

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,243	$ 1,275	$ 1,503
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Gain on Disposal of Discontinued Operations	—	—	(122)
Depreciation and Amortization	1,178	1,054	982
Amortization of Nuclear Fuel	192	173	153
Provision for Deferred Income Taxes (Other than Leases) and ITC	270	721	811
Non-Cash Employee Benefit Plan Costs	243	271	175
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	31	93	(55)
Loss on Leases, net of tax	—	—	170
Net (Gain) Loss on Lease Investments	2	(49)	(55)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	79	63	(165)
Change in Accrued Storm Costs	(90)	(90)	(60)
Net Change in Regulatory Assets and Liabilities	2	(132)	(130)
Cost of Removal	(93)	(116)	(62)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(104)	(118)	(117)
Net Change in Tax Receivable	19	(211)	673
Net Change in Certain Current Assets and Liabilities	299	97	247
Employee Benefit Plan Funding and Related Payments	(231)	(314)	(508)
Other	118	70	117
Net Cash Provided By (Used In) Operating Activities	3,158	2,787	3,557
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,811)	(2,574)	(2,083)
Proceeds from Sale of Discontinued Operations	—	—	687
Proceeds from Sale of Capital Leases and Investments	50	58	179
Proceeds from Sales of Available-for-Sale Securities	1,159	1,666	1,355
Investments in Available-for-Sale Securities	(1,170)	(1,700)	(1,386)
Other	(29)	(75)	(21)
Net Cash Provided By (Used In) Investing Activities	(2,801)	(2,625)	(1,269)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	(203)	263	(64)
Issuance of Long-Term Debt	2,000	900	794
Redemption of Long-Term Debt	(1,025)	(787)	(1,514)
Redemption of Securitization Debt	(226)	(216)	(206)
Repayment of Non-Recourse Debt	—	(1)	(1)
Cash Dividend Paid on Common Stock	(728)	(718)	(693)
Other	(61)	(58)	(50)
Net Cash Provided By (Used In) Financing Activities	(243)	(617)	(1,734)
Net Increase (Decrease) in Cash and Cash Equivalents	114	(455)	554
Cash and Cash Equivalents at Beginning of Period	379	834	280
Cash and Cash Equivalents at End of Period	$ 493	$ 379	$ 834
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 241	$ 121	$ (219)
Interest Paid, Net of Amounts Capitalized	$ 385	$ 402	$ 479
Accrued Property, Plant and Equipment Expenditures	$ 336	$ 370	$ 336

See the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Millions

	Common Stock		Treasury Stock					
	Shs.	Amount	Shs.	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance as of January 1, 2011	534	$ 4,807	(28)	$ (593)	$ 5,575	$ (156)	$ 8	$ 9,641
Net Income	—	—	—	—	1,503	—	—	1,503
Other Comprehensive Income (Loss), net of tax (expense) benefit of $141	—	—	—	—	—	(181)	—	(181)
Comprehensive Income								1,322
Cash Dividends on Common Stock	—	—	—	—	(693)	—	—	(693)
Noncontrolling Interest in Losses of Consolidated Entity	—	—	—	—	—	—	(6)	(6)
Other	—	16	—	(8)	—	—	—	8
Balance as of December 31, 2011	534	$ 4,823	(28)	$ (601)	$ 6,385	$ (337)	$ 2	$ 10,272
Net Income	—	—	—	—	1,275	—	—	1,275
Other Comprehensive Income (Loss), net of tax (expense) benefit of $26	—	—	—	—	—	(51)	—	(51)
Comprehensive Income								1,224
Cash Dividends on Common Stock	—	—	—	—	(718)	—	—	(718)
Noncontrolling Interest in Losses of Consolidated Entity	—	—	—	—	—	—	(1)	(1)
Other	—	10	—	(6)	—	—	—	4
Balance as of December 31, 2012	534	$ 4,833	(28)	$ (607)	$ 6,942	$ (388)	$ 1	$ 10,781
Net Income	—	—	—	—	1,243	—	—	1,243
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(219)	—	—	—	—	—	293	—	293
Comprehensive Income								1,536
Cash Dividends on Common Stock	—	—	—	—	(728)	—	—	(728)
Other	—	28	—	(8)	—	—	—	20
Balance as of December 31, 2013	534	$ 4,861	(28)	$ (615)	$ 7,457	$ (95)	$ 1	$ 11,609

See Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2013	**2012**	**2011**
OPERATING REVENUES	$ 5,063	$ 4,873	$ 6,150
OPERATING EXPENSES			
Energy Costs	2,496	2,381	3,044
Operation and Maintenance	1,224	1,127	1,105
Depreciation and Amortization	273	242	228
Total Operating Expenses	3,993	3,750	4,377
OPERATING INCOME	1,070	1,123	1,773
Income from Equity Method Investments	16	15	14
Other Income	154	201	190
Other Deductions	(49)	(90)	(79)
Other-Than-Temporary Impairments	(12)	(18)	(20)
Interest Expense	(116)	(132)	(175)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	1,063	1,099	1,703
Income Tax (Expense) Benefit	(419)	(433)	(690)
INCOME FROM CONTINUING OPERATIONS	644	666	1,013
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $0, $0 and $(51) for the years ended 2013, 2012 and 2011, respectively	—	—	96
NET INCOME	$ 644	$ 666	$ 1,109

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2013	**2012**	**2011**
NET INCOME	$ 644	$ 666	$ 1,109
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(55), $(24) and $45 for the years ended 2013, 2012 and 2011, respectively	57	18	(42)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $7, $18 and $54 for the years ended 2013, 2012 and 2011, respectively	(10)	(24)	(80)
Pension/OPEB adjustment, net of tax (expense) benefit of $(151), $32 and $40 for the years ended 2013, 2012 and 2011, respectively	218	(46)	(59)
Other Comprehensive Income (Loss), net of tax	265	(52)	(181)
COMPREHENSIVE INCOME	$ 909	$ 614	$ 928

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2013	2012
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 6	$ 7
Accounts Receivable	338	270
Accounts Receivable—Affiliated Companies, net	333	340
Short-Term Loan to Affiliate	790	574
Fuel	545	583
Materials and Supplies, net	362	307
Derivative Contracts	57	118
Prepayments	13	17
Deferred Taxes	30	—
Other	2	20
Total Current Assets	2,476	2,236
PROPERTY, PLANT AND EQUIPMENT	10,278	9,914
Less: Accumulated Depreciation and Amortization	(2,911)	(2,692)
Net Property, Plant and Equipment	7,367	7,222
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,701	1,540
Long-Term Investments	123	125
Goodwill	16	16
Other Intangibles	33	34
Other Special Funds	139	36
Derivative Contracts	72	49
Other	75	65
Total Noncurrent Assets	2,159	1,865
TOTAL ASSETS	$ 12,002	$ 11,323

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2013	December 31, 2012
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 44	$ 300
Accounts Payable	516	499
Derivative Contracts	76	46
Deferred Income Taxes	—	16
Accrued Interest	28	26
Other	136	81
Total Current Liabilities	800	968
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	2,031	1,669
Asset Retirement Obligations	400	374
Other Postretirement Benefit (OPEB) Costs	206	221
Derivative Contracts	31	15
Accrued Pension Costs	35	272
Long-Term Accrued Taxes	53	50
Other	91	84
Total Noncurrent Liabilities	2,847	2,685
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
LONG-TERM DEBT		
Total Long-Term Debt	2,497	2,040
MEMBER'S EQUITY		
Contributed Capital	2,214	2,190
Basis Adjustment	(986)	(986)
Retained Earnings	4,693	4,754
Accumulated Other Comprehensive Loss	(63)	(328)
Total Member's Equity	5,858	5,630
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,002	$ 11,323

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2013	**2012**	**2011**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 644	$ 666	$ 1,109
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Gain on Disposal of Discontinued Operations	—	—	(122)
Depreciation and Amortization	273	242	235
Amortization of Nuclear Fuel	192	173	153
Provision for Deferred Income Taxes and ITC	122	397	237
Interest Accretion on Asset Retirement Obligation	23	21	18
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	79	63	(165)
Non-Cash Employee Benefit Plan Costs	66	70	41
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(104)	(118)	(117)
Net Change in Certain Current Assets and Liabilities:			
Fuel, Materials and Supplies	(8)	47	(26)
Margin Deposit	(43)	(116)	49
Accounts Receivable	(4)	24	196
Accounts Payable	28	93	(156)
Accounts Receivable/Payable-Affiliated Companies, net	—	(40)	459
Accrued Interest Payable	2	(6)	(8)
Other Current Assets and Liabilities	70	(17)	34
Employee Benefit Plan Funding and Related Payments	(46)	(72)	(129)
Other	53	26	9
Net Cash Provided By (Used In) Operating Activities	1,347	1,453	1,817
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(609)	(770)	(757)
Proceeds from Sale of Discontinued Operations	—	—	687
Proceeds from Sales of Available-for-Sale Securities	1,084	1,478	1,355
Investments in Available-for-Sale Securities	(1,102)	(1,506)	(1,380)
Short-Term Loan—Affiliated Company, net	(216)	333	(509)
Other	(18)	(7)	26
Net Cash Provided By (Used In) Investing Activities	(861)	(472)	(578)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Recourse Long-Term Debt	500	—	544
Cash Dividend Paid	(705)	(619)	(511)
Redemption of Long-Term Debt	(300)	(414)	(1,250)
Contributed Capital	24	69	6
Cash Payment on Debt Redemption/Exchange	—	(15)	(17)
Other	(6)	(7)	(10)
Net Cash Provided By (Used In) Financing Activities	(487)	(986)	(1,238)
Net Increase (Decrease) in Cash and Cash Equivalents	(1)	(5)	1
Cash and Cash Equivalents at Beginning of Period	7	12	11
Cash and Cash Equivalents at End of Period	$ 6	$ 7	$ 12
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 291	$ 81	$ 172
Interest Paid, Net of Amounts Capitalized	$ 106	$ 119	$ 176
Accrued Property, Plant and Equipment Expenditures	$ 90	$ 95	$ 132

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY
Millions

	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2011	$ 2,115	$ (986)	$ 4,109	$ (95)	$ 5,143
Net Income	—	—	1,109	—	1,109
Other Comprehensive Income (Loss), net of tax (expense) benefit of $139	—	—	—	(181)	(181)
Comprehensive Income					928
Contributed Capital	6	—	—		6
Cash Dividends Paid	—	—	(511)		(511)
Balance as of December 31, 2011	$ 2,121	$ (986)	$ 4,707	$ (276)	$ 5,566
Net Income	—	—	666	—	666
Other Comprehensive Income (Loss), net of tax (expense) benefit of $26	—	—	—	(52)	(52)
Comprehensive Income					614
Contributed Capital	69	—	—		69
Cash Dividends Paid	—	—	(619)		(619)
Balance as of December 31, 2012	$ 2,190	$ (986)	$ 4,754	$ (328)	$ 5,630
Net Income	—	—	644	—	644
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(199)	—	—	—	265	265
Comprehensive Income					909
Contributed Capital	24	—	—		24
Cash Dividends Paid	—	—	(705)		(705)
Balance as of December 31, 2013	$ 2,214	$ (986)	$ 4,693	$ (63)	$ 5,858

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2013	**2012**	**2011**
OPERATING REVENUES	$ 6,655	$ 6,626	$ 7,326
OPERATING EXPENSES			
Energy Costs	2,841	3,159	3,951
Operation and Maintenance	1,639	1,508	1,372
Depreciation and Amortization	872	778	719
Taxes Other Than Income Taxes	68	98	133
Total Operating Expenses	5,420	5,543	6,175
OPERATING INCOME	1,235	1,083	1,151
Other Income	54	52	25
Other Deductions	(3)	(5)	(4)
Other-Than-Temporary Impairments	—	—	(1)
Interest Expense	(293)	(295)	(310)
INCOME BEFORE INCOME TAXES	993	835	861
Income Tax (Expense) Benefit	(381)	(307)	(340)
NET INCOME	$ 612	$ 528	$ 521

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2013	**2012**	**2011**
NET INCOME	$ 612	$ 528	$ 521
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $1, $0 and $(1) for the years ended 2013, 2012 and 2011, respectively	(1)	—	2
COMPREHENSIVE INCOME	$ 611	$ 528	$ 523

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 18	$ 116
Accounts Receivable, net of allowances of $56 and $56 in 2013 and 2012, respectively	832	783
Unbilled Revenues	300	314
Materials and Supplies	115	114
Prepayments	24	29
Regulatory Assets	243	349
Derivative Contracts	25	5
Deferred Income Taxes	16	49
Other	12	24
Total Current Assets	1,585	1,783
PROPERTY, PLANT AND EQUIPMENT	19,071	17,006
Less: Accumulated Depreciation and Amortization	(4,964)	(4,726)
Net Property, Plant and Equipment	14,107	12,280
NONCURRENT ASSETS		
Regulatory Assets	2,612	3,830
Regulatory Assets of VIEs	476	713
Long-Term Investments	361	348
Other Special Funds	354	61
Derivative Contracts	69	62
Restricted Cash of VIEs	24	23
Other	132	123
Total Noncurrent Assets	4,028	5,160
TOTAL ASSETS	$ 19,720	$ 19,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2013	December 31, 2012
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 500	$ 725
Securitization Debt of VIEs Due Within One Year	237	226
Commercial Paper and Loans	60	263
Accounts Payable	535	630
Accounts Payable—Affiliated Companies, net	190	73
Accrued Interest	67	65
Clean Energy Program	142	153
Deferred Income Taxes	30	60
Obligation to Return Cash Collateral	119	122
Regulatory Liabilities	43	67
Other	314	269
Total Current Liabilities	2,237	2,653
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,406	4,223
Other Postretirement Benefit (OPEB) Costs	839	1,011
Accrued Pension Costs	27	463
Regulatory Liabilities	233	209
Regulatory Liabilities of VIEs	11	10
Environmental Costs	363	486
Asset Retirement Obligations	274	250
Derivative Contracts	—	107
Long-Term Accrued Taxes	72	32
Other	47	38
Total Noncurrent Liabilities	6,272	6,829
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	5,066	4,070
Securitization Debt of VIEs	259	496
Total Long-Term Debt	5,325	4,566
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2013 and 2012 —132,450,344 shares	892	892
Contributed Capital	520	420
Basis Adjustment	986	986
Retained Earnings	3,487	2,875
Accumulated Other Comprehensive Income	1	2
Total Stockholder's Equity	5,886	5,175
Total Capitalization	11,211	9,741
TOTAL LIABILITIES AND CAPITALIZATION	$ 19,720	$ 19,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

Millions

	Years Ended December 31,		
	2013	**2012**	**2011**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 612	$ 528	$ 521
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	872	778	719
Provision for Deferred Income Taxes and ITC	198	442	571
Non-Cash Employee Benefit Plan Costs	156	179	118
Cost of Removal	(93)	(116)	(62)
Change in Accrued Storm Costs	(90)	(90)	(60)
Net Change in Regulatory Assets and Liabilities	2	(132)	(130)
Net Change in Certain Current Assets and Liabilities:			
Accounts Receivable and Unbilled Revenues	(5)	(54)	252
Materials and Supplies	(1)	(20)	(4)
Prepayments	5	88	—
Net Change in Tax Receivable	—	16	(16)
Accounts Payable	19	(25)	9
Accounts Receivable/Payable-Affiliated Companies, net	100	(132)	197
Other Current Assets and Liabilities	40	37	(49)
Employee Benefit Plan Funding and Related Payments	(166)	(213)	(330)
Other	(4)	(30)	40
Net Cash Provided By (Used In) Operating Activities	1,645	1,256	1,776
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,175)	(1,770)	(1,302)
Proceeds from Sales of Available-for-Sale Securities	38	77	—
Investments in Available-for-Sale Securities	(20)	(77)	—
Solar Loan Investments	(15)	(74)	(51)
Other	—	(1)	(1)
Net Cash Provided By (Used In) Investing Activities	(2,172)	(1,845)	(1,354)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	(203)	263	—
Issuance of Long-Term Debt	1,500	900	250
Redemption of Long-Term Debt	(725)	(373)	(264)
Redemption of Securitization Debt	(226)	(216)	(206)
Cash Dividend Paid	—	—	(300)
Contributed Capital	100	—	—
Other	(17)	(12)	(4)
Net Cash Provided By (Used In) Financing Activities	429	562	(524)
Net Increase (Decrease) in Cash and Cash Equivalents	(98)	(27)	(102)
Cash and Cash Equivalents at Beginning of Period	116	143	245
Cash and Cash Equivalents at End of Period	$ 18	$ 116	$ 143
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 84	$ (30)	$ (514)
Interest Paid, Net of Amounts Capitalized	$ 275	$ 280	$ 297
Accrued Property, Plant and Equipment Expenditures	$ 246	$ 275	$ 204

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
Millions

	Common Stock	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2011	$ 892	$ 420	$ 986	$ 2,126	$ —	$ 4,424
Net Income	—	—	—	521	—	521
Other Comprehensive Income, net of tax (expense) benefit of $(1)	—	—	—	—	2	2
Comprehensive Income						523
Cash Dividends on Common Stock	—	—	—	(300)	—	(300)
Balance as of December 31, 2011	$ 892	$ 420	$ 986	$ 2,347	$ 2	$ 4,647
Net Income	—	—	—	528	—	528
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	—	—
Comprehensive Income						528
Balance as of December 31, 2012	$ 892	$ 420	$ 986	$ 2,875	$ 2	$ 5,175
Net Income	—	—	—	612	—	612
Other Comprehensive Income, net of tax (expense) benefit of $1	—	—	—	—	(1)	(1)
Comprehensive Income						611
Contributed Capital	—	100	—	—	—	100
Balance as of December 31, 2013	$ 892	$ 520	$ 986	$ 3,487	$ 1	$ 5,886

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

Public Service Enterprise Group Incorporated, (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **PSEG Power LLC (Power)**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through three principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and the states in which they operate.
- **Public Service Electric and Gas Company (PSE&G)**—which is an operating public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the FERC. PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which, effective January 1, 2014, operates the Long Island Power Authority's transmission and distribution system under a contractual agreement; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Annual Reports on Form 10-K and in accordance with accounting guidance generally accepted in the United States (GAAP).

On December 31, 2013, Energy Holdings distributed the outstanding equity of its 50% interest in a partnership that owns and operates a generation facility in Hawaii and its wholly owned interest in PSEG Solar Source LLC to PSEG. PSEG in turn contributed this distribution to Power as an additional equity investment. This transaction was accounted for as a noncash transfer of equity interest between entities under common control. Power recognized the related assets and liabilities at their carrying amounts (historical cost) at the date of transfer. In addition, as required under current guidance, Power accounted for the transaction to include the earnings and assets and liabilities related to the transfer as if the transfer had occurred at the beginning of the year, and prior years have been retrospectively adjusted to furnish comparative information. This resulted in an increase to Power's Operating Revenues of $15 million, $8 million and $7 million for the years ended December 31, 2013, 2012 and 2011, respectively, with an increase to Power's Net Income of $16 million, $19 million and $11 million for those years. The adjustments also resulted in an increase of $351 million and $291 million to Power's Total Assets as of December 31, 2013 and 2012, respectively, primarily comprised of Property, Plant and Equipment of the transferred solar facilities and the partnership investment in the generation facility in Hawaii.

Significant Accounting Policies

Principles of Consolidation

Each company consolidates those entities in which it has a controlling interest or is the primary beneficiary. See Note 3. Variable Interest Entities. Entities over which the companies exhibit significant influence, but do not have a controlling interest and/or are not the primary beneficiary, are accounted for under the equity method of accounting. For investments in which significant influence does not exist and the investor is not the primary beneficiary, the cost method of accounting is applied. All significant intercompany accounts and transactions are eliminated in consolidation, except as discussed in Note 24. Related-Party Transactions.

Power and PSE&G also have undivided interests in certain jointly-owned facilities, with each responsible for paying its respective ownership share of construction costs, fuel purchases and operating expenses. Power and PSE&G consolidated their portion of any revenues and expenses related to their respective jointly-owned facilities in the appropriate revenue and expense categories.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Accounting for the Effects of Regulation

In accordance with accounting guidance for rate-regulated entities, PSE&G's financial statements must reflect the economic effects of regulation. PSE&G is required to defer the recognition of costs (a Regulatory Asset) or record the recognition of obligations (a Regulatory Liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs and recoveries, which are being amortized over various future periods. To the extent that collection of any such costs or payment of liabilities is no longer probable as a result of changes in regulation and/or competitive position, the associated Regulatory Asset or Liability is charged or credited to income. Management believes that PSE&G's transmission and distribution businesses continue to meet the accounting requirements for rate-regulated entities. For additional information, see Note 6. Regulatory Assets and Liabilities .

Derivative Financial Instruments

Each company uses derivative financial instruments to manage risk from changes in interest rates, commodity prices, congestion costs and emission credit prices, pursuant to its business plans and prudent practices.

Derivative instruments, not designated as normal purchases or sales, are recognized on the balance sheet at their fair value. Changes in the fair value of a derivative that is highly effective as and that is designated and qualifies as a fair value hedge, along with changes of the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in current period earnings. Changes in the fair value of a derivative that is highly effective as and that is designated and qualifies as a cash flow hedge are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings. For derivative contracts that do not qualify nor are designated as cash flow or fair value hedges or as normal purchases or sales, changes in fair value are recorded in current period earnings.

Many non-trading contracts qualify for the normal purchases and normal sales exemption and are accounted for upon settlement.

For additional information regarding derivative financial instruments, see Note 16. Financial Risk Management Activities .

Revenue Recognition

The majority of Power's revenues relate to bilateral contracts, which are accounted for on the accrual basis as the energy is delivered. Power's revenue also includes changes in the value of non-trading energy derivative contracts that are not designated as normal purchases or sales or as cash flow or fair value hedges of other positions. Power records margins from energy trading on a net basis. See Note 16. Financial Risk Management Activities for further discussion.

PSE&G's revenues are recorded primarily based on services rendered to customers. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. The unbilled revenue is estimated each month based on usage per day, the number of unbilled days in the period, estimated seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms.

Depreciation and Amortization

Power calculates depreciation on generation-related assets under the straight-line method based on the assets' estimated useful lives. The estimated useful lives are:

- general plant assets—3 years to 20 years
- fossil production assets—19 years to 79 years
- nuclear generation assets—approximately 60 years
- pumped storage facilities—76 years
- solar assets—25 years

PSE&G calculates depreciation under the straight-line method based on estimated average remaining lives of the several classes of depreciable property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU or the FERC. The depreciation rate stated as a percentage of original cost of depreciable property was as follows:

	2013 Avg Rate	2012 Avg Rate	2011 Avg Rate
PSE&G Depreciation Rate	2.48%	2.48%	2.46%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Taxes Other Than Income Taxes

Excise taxes and transitional energy facilities assessment (TEFA) collected from PSE&G's customers are presented in the financial statements on a gross basis. For the years ended December 31, 2013, 2012 and 2011, TEFA is included in the following captions in the Consolidated Statements of Operations:

	Years Ended December 31,		
	2013	2012	2011
	Millions		
TEFA included in:			
Operating Revenues	$ 74	$ 108	$ 146
Taxes Other Than Income Taxes	$ 68	$ 98	$ 133

Interest Capitalized During Construction (IDC) and Allowance for Funds Used During Construction (AFUDC)

IDC represents the cost of debt used to finance construction at Power. AFUDC represents the cost of debt and equity funds used to finance the construction of new utility assets at PSE&G. The amount of IDC or AFUDC capitalized as Property, Plant and Equipment is included as a reduction of interest charges or other income for the equity portion. The amounts and average rates used to calculate IDC or AFUDC for the years ended December 31, 2013, 2012 and 2011 were as follows:

	IDC/AFUDC Capitalized					
	2013		2012		2011	
	Millions	Avg Rate	Millions	Avg Rate	Millions	Avg Rate
Power	$ 23	5.36%	$ 29	5.16%	$ 30	5.91%
PSE&G	$ 34	8.11%	$ 33	8.43%	$ 13	6.56%

Income Taxes

PSEG and its subsidiaries file a consolidated federal income tax return and income taxes are allocated to PSEG's subsidiaries based on the taxable income or loss of each subsidiary. Investment tax credits deferred in prior years are being amortized over the useful lives of the related property.

Uncertain income tax positions are accounted for using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. See Note 20. Income Taxes for further discussion.

Impairment of Long-Lived Assets

In accordance with accounting guidance, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset's or asset group's carrying amount may not be recoverable. In such an event, an undiscounted cash flow analysis is performed to determine if an impairment exists. When a long-lived asset's carrying amount exceeds the undiscounted estimated future cash flows associated with the asset, the asset is considered impaired to the extent that the asset's fair value is less than its carrying amount. An impairment would result in a reduction of the long-lived asset value through a non-cash charge to earnings.

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Accounts Receivable—Allowance for Doubtful Accounts

PSE&G's accounts receivable are reported in the balance sheet as gross outstanding amounts adjusted for doubtful accounts. The allowance for doubtful accounts reflects PSE&G's best estimates of losses on the accounts receivable balances. The allowance is based on accounts receivable aging, historical experience, write-off forecasts and other currently available evidence.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Accounts receivable are charged off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable are recorded when it is known they will be received.

Materials and Supplies and Fuel

Materials and supplies for Power are valued at the lower of average cost or market. Fuel inventory at Power includes the weighted average costs of stored natural gas, coal, fuel oil and propane used to generate power and to satisfy obligations under Power's gas supply contracts with PSE&G. The costs of fuel, including transportation costs, are included in inventory when purchased and charged at average cost to Energy Costs when used or sold. PSE&G's materials and supplies are carried at average cost consistent with the rate-making process.

Restricted Funds

PSE&G's restricted funds represent revenues collected from its retail electric customers that must be used to pay the principal, interest and other expenses associated with the securitization bonds of PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II).

Property, Plant and Equipment

Power capitalizes costs which increase the capacity or extend the life of an existing asset, represent a newly acquired or constructed asset or represent the replacement of a retired asset. The cost of maintenance, repair and replacement of minor items of property is charged to appropriate expense accounts as incurred. Environmental costs are capitalized if the costs mitigate or prevent future environmental contamination or if the costs improve existing assets' environmental safety or efficiency. All other environmental expenditures are expensed as incurred.

PSE&G's additions to and replacements of existing property, plant and equipment are capitalized at original cost. The cost of maintenance, repair and replacement of minor items of property is charged to expense as incurred. At the time units of depreciable property are retired or otherwise disposed of, the original cost, adjusted for net salvage value, is charged to accumulated depreciation.

Available-for-Sale Securities

These securities are comprised of the Nuclear Decommissioning Trust (NDT) Fund, a master independent external trust account maintained to provide for the costs of decommissioning upon termination of operations of Power's nuclear facilities and amounts comprising Other Special Funds that are deposited to fund a Rabbi Trust which was established to meet the obligations related to non-qualified pension plans and deferred compensation plans.

Realized gains and losses on available-for-sale securities are recorded in earnings and unrealized gains and losses on such securities are recorded as a component of Accumulated Other Comprehensive Income (Loss) (except credit losses on debt securities which are recorded in earnings). Securities with unrealized losses that are deemed to be other-than-temporarily impaired are recorded in earnings. See Note 9. Available-for-Sale Securities for further discussion.

Pension and Other Postretirement Benefits (OPEB) Plan Assets

The market-related value of plan assets held for the qualified pension and OPEB plans is equal to the fair value of those assets as of year-end. Fair value is determined using quoted market prices and independent pricing services based upon the security type as reported by the trustee at the measurement dates (December 31) for all plan assets. See Note 12. Pension, Other Postretirement Benefits (OPEB) and Savings Plans for further discussion.

Basis Adjustment

Power and PSE&G have recorded a Basis Adjustment in their respective Consolidated Balance Sheets related to the generation assets that were transferred from PSE&G to Power in August 2000 at the price specified by the BPU. Because the transfer was between affiliates, the transaction was recorded at the net book value of the assets and liabilities rather than the transfer price. The difference between the total transfer price and the net book value of the generation-related assets and liabilities, $986 million, net of tax, was recorded as a Basis Adjustment on Power's and PSE&G's Consolidated Balance Sheets. The $986 million is a reduction of Power's Member's Equity and an addition to PSE&G's Common Stockholder's Equity. These amounts are eliminated on PSEG's consolidated financial statements.

Use of Estimates

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements.

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Note 2. Recent Accounting Standards

New Standards Adopted during 2013

Disclosures about Offsetting Assets and Liabilities

This accounting standard requires enhanced disclosures regarding assets and liabilities that are either offset in the financial statements, or are subject to an enforceable master netting arrangement or similar agreement. The guidance is applicable to certain financial instruments (e.g. derivatives) and securities borrowing and lending transactions. This standard requires entities:

- to disclose information about offsetting and related arrangements to enable users of financial statements to understand the effect of those arrangements on an entity's financial position, and
- to present both net (offset amounts) and gross information in the notes to the financial statements for relevant assets and liabilities.

We adopted this standard retrospectively effective January 1, 2013. As this standard requires disclosures only, it did not have any impact on our consolidated financial position, results of operations or cash flows. For additional information, see Note 16. Financial Risk Management Activities .

Reclassification Adjustments out of Accumulated Other Comprehensive Income

This accounting standard requires entities to disclose the following information about reclassification adjustments related to Accumulated Other Comprehensive Income:

- changes in Accumulated Other Comprehensive Income balances by component, and
- significant amounts reclassified out of Accumulated Other Comprehensive Income by respective line items of net income (for amounts that are required by GAAP to be reclassified to net income in their entirety in the same reporting period).

We adopted this standard prospectively effective January 1, 2013. As this standard requires disclosures only, it did not have any impact on our consolidated financial position, results of operations or cash flows. For additional information, see Note 21. Accumulated Other Comprehensive Income (Loss), Net of Tax .

New Accounting Standards Issued But Not Yet Adopted

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

This accounting standard was issued to address diversity in practice related to the presentation of an unrecognized tax benefit in certain cases. This standard requires entities to present an unrecognized tax benefit or a portion thereof on the Balance Sheet as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward.

However, the unrecognized tax benefit will be presented on the Balance Sheet as a liability and will not be combined with deferred tax assets in cases where that tax benefit cannot or will not, if permissible, be used to settle any additional income taxes that would result from the disallowance of a tax position.

The standard is effective for fiscal years and interim periods beginning after December 15, 2013. We believe the impact of adopting this standard will be immaterial.

Note 3. Variable Interest Entities (VIEs)

VIEs for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary of and consolidates two marginally capitalized VIEs, Transition Funding and Transition Funding II, which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to the trustee for these bonds. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to the trustee for Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of these VIEs are presented separately on the face of the Consolidated Balance Sheets of PSEG and PSE&G because the Transition Funding and Transition Funding II assets are restricted and can only be used to settle their respective obligations. The Transition Funding and Transition Funding II creditors do not have any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding and Transition Funding II, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of December 31, 2013 and 2012. PSE&G considers the risk of actual loss to be remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II in 2013 or 2012. Further, PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding and Transition Funding II.

Note 4. Discontinued Operations and Dispositions

Discontinued Operations

Power

In March 2011, Power completed the sale of its 1,000 MW gas-fired Guadalupe generating facility for a total sale price of $ 352 million, resulting in an after-tax gain of $54 million.

In July 2011, Power completed the sale of its 1,000 MW gas-fired Odessa generating facility for a total sale price of $ 335 million, resulting in an after-tax gain of $25 million.

PSEG Texas' operating results for the year ended December 31, 2011, which were reclassified to Discontinued Operations, are summarized below:

	Year Ended December 31, 2011	
	Millions	
Operating Revenues	$	112
Income Before Income Taxes	$	26
Net Income (Loss)	$	17

Dispositions

Leveraged Leases

For the year ended December 31, 2011, Energy Holdings sold its leveraged lease investment in an office building in Denver, Colorado for gross proceeds of $215 million. Proceeds net of sales costs were $175 million with an after-tax gain of $34 million.

Other Leases

In June 2013, Energy Holdings closed on the sale of its investments in a commercial office complex for proceeds of $41 million, resulting in an after-tax gain of $6 million.

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Note 5. Property, Plant and Equipment and Jointly-Owned Facilities

Information related to Property, Plant and Equipment as of December 31, 2013 and 2012 is detailed below:

	Power	PSE&G	Other	PSEG Consolidated
			Millions	
2013				
Generation:				
Fossil Production	$ 6,924	$ —	$ —	$ 6,924
Nuclear Production	1,636	—	—	1,636
Nuclear Fuel in Service	857	—	—	857
Other Production-Solar	273	469	—	742
Construction Work in Progress	489	—	—	489
Total Generation	10,179	469	—	10,648
Transmission and Distribution:				
Electric Transmission	—	4,037	—	4,037
Electric Distribution	—	7,109	—	7,109
Gas Transmission	—	89	—	89
Gas Distribution	—	5,230	—	5,230
Construction Work in Progress	—	1,605	—	1,605
Plant Held for Future Use	—	3	—	3
Other	—	372	—	372
Total Transmission and Distribution	—	18,445	—	18,445
Other	99	157	364	620
Total	**$ 10,278**	**$ 19,071**	**$ 364**	**$ 29,713**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	PSE&G	Other	PSEG Consolidated
			Millions	
2012				
Generation:				
Fossil Production	$ 6,886	$ —	$ —	$ 6,886
Nuclear Production	1,415	—	—	1,415
Nuclear Fuel in Service	853	—	—	853
Other Production-Solar	217	434	—	651
Construction Work in Progress	450	7	—	457
Total Generation	9,821	441	—	10,262
Transmission and Distribution:				
Electric Transmission	—	3,053	—	3,053
Electric Distribution	—	6,807	—	6,807
Gas Transmission	—	89	—	89
Gas Distribution	—	5,065	—	5,065
Construction Work in Progress	—	1,048	—	1,048
Plant Held for Future Use	—	6	—	6
Other	—	380	—	380
Total Transmission and Distribution	—	16,448	—	16,448
Other	93	117	482	692
Total	**$ 9,914**	**$ 17,006**	**$ 482**	**$ 27,402**

Power and PSE&G have ownership interests in and are responsible for providing their respective shares of the necessary financing for the following jointly-owned facilities. All amounts reflect the share of Power's and PSE&G's jointly-owned projects and the corresponding direct expenses are included in the Consolidated Statements of Operations as operating expenses.

		As of December 31,			
		2013		2012	
	Ownership Interest	Plant	Accumulated Depreciation	Plant	Accumulated Depreciation
			Millions		
Power:					
Coal Generating					
Conemaugh	23%	$ 374	$ 139	$ 321	$ 132
Keystone	23%	$ 388	$ 140	$ 387	$ 128
Nuclear Generating					
Peach Bottom	50%	$ 886	$ 215	$ 730	$ 193
Salem	57%	$ 897	$ 254	$ 865	$ 209
Nuclear Support Facilities	Various	$ 205	$ 37	$ 191	$ 29
Pumped Storage Facilities					
Yards Creek	50%	$ 36	$ 23	$ 35	$ 23
Merrill Creek Reservoir	14%	$ 1	$ —	$ 1	$ —
PSE&G:					
Transmission Facilities	Various	$ 161	$ 66	$ 156	$ 63

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Power holds undivided ownership interests in the jointly-owned facilities above. Power is entitled to shares of the generating capability and output of each unit equal to its respective ownership interests. Power also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. Power's share of expenses for the jointly-owned facilities is included in the appropriate expense category. Each owner is responsible for any financing with respect to its pro rata share of capital expenditures.

Power co-owns Salem and Peach Bottom with Exelon Generation. Power is the operator of Salem and Exelon Generation is the operator of Peach Bottom. A committee appointed by the co-owners provides oversight. Proposed Operation and Maintenance (O&M) budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

GenOn Northeast Management Company is a co-owner and the operator for Keystone Generating Station and Conemaugh Generating Station. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

Power is a co-owner in the Yards Creek Pumped Storage Generation Facility. Jersey Central Power & Light Company (JCP&L) is also a co-owner and the operator of this facility. JCP&L submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Power is a minority owner in the Merrill Creek Reservoir and Environmental Preserve in Warren County, New Jersey. Merrill Creek Owners Group is the owner-operator of this facility. The operator submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Note 6. Regulatory Assets and Liabilities

PSE&G prepares its financial statements in accordance with GAAP accounting for regulated utilities as described in Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies. PSE&G has deferred certain costs based on rate orders issued by the BPU or the FERC or based on PSE&G's experience with prior rate cases. Most of PSE&G's Regulatory Assets and Liabilities as of December 31, 2013 are supported by written orders, either explicitly or implicitly through the BPU's treatment of various cost items. These costs will be recovered and amortized over various future periods.

Regulatory Assets are subject to prudence reviews and can be disallowed in the future by regulatory authorities. PSE&G believes that all of its Regulatory Assets are probable of recovery. To the extent that collection of any Regulatory Assets or payments of Regulatory Liabilities is no longer probable, the amounts would be charged or credited to income.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G had the following Regulatory Assets and Liabilities:

	As of December 31, 2013	2012	Recovery/Refund Period
	Millions		
Regulatory Assets			
Current			
Non-Utility Generation Charge (NGC)	$ 6	$ —	Annual filing for recovery (1) (2)
Societal Benefits Charges (SBC)	16	74	Annual filing for recovery (1) (2)
Solar and Energy Efficiency Recovery Charges (formerly RRC and currently Green Program Recovery Charges (GPRC))	41	33	Annual filing for recovery (1) (2)
Solar Pilot Recovery Charge (SPRC)	12	14	Annual filing for recovery (1) (2)
Capital Stimulus Undercollection	3	34	Annual filing for recovery (1) (2)
Weather Normalization Clause (WNC)	20	30	Annual filing for recovery (2)
New Jersey Clean Energy Program	142	154	Annual filing for recovery (1) (2)
Other	3	10	Various
Total Current Regulatory Assets	**$ 243**	**$ 349**	
Noncurrent			
Stranded Costs To Be Recovered	$ 701	$ 1,112	Through December 2016 (1) (2)
Manufactured Gas Plant (MGP) Remediation Costs	445	588	Various (2)
Pension and Other Postretirement Benefit Costs	637	1,550	Various
Deferred Income Taxes	444	405	Various
Remediation Adjustment Charge (RAC) (Other SBC)	144	88	Through 2019 (1) (2)
Mark-to-Market (MTM) Contracts	—	107	See MTM Contracts below
Unamortized Loss on Reacquired Debt and Debt Expense	81	89	Over remaining debt life (1)
Conditional Asset Retirement Obligation	123	110	Various
Gas Margin Adjustment Clause	—	7	Through July 2015 (2)
GPRC	151	142	Various (2)
WNC	—	27	Annual filing for recovery (2)
Storm Damage Deferral	245	244	To be determined
Other	117	74	Various
Total Noncurrent Regulatory Assets	**$ 3,088**	**$ 4,543**	
Total Regulatory Assets	**$ 3,331**	**$ 4,892**	

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31, 2013	As of December 31, 2012	Recovery/Refund Period
	Millions		
Regulatory Liabilities			
Current			
Deferred Income Taxes	$ 31	$ 32	Various
Overrecovered Gas and Electric Costs—Basic Gas Supply Service (BGSS) and Basic Generation Service (BGS)	9	21	Annual filing for recovery (1) (2)
FERC Formula Rate True-up	—	5	Annual filing for recovery (1) (2)
NGC	—	9	Annual filing for recovery (1) (2)
Other	3	—	Various
Total Current Regulatory Liabilities	**$ 43**	**$ 67**	
Noncurrent			
Electric Cost of Removal	$ 137	$ 166	Reduced as cost is incurred
MTM Contracts	74	40	Various
Other	33	13	Various
Total Noncurrent Regulatory Liabilities	**$ 244**	**$ 219**	
Total Regulatory Liabilities	**$ 287**	**$ 286**	

(1) Recovered/Refunded with interest.

(2) Recoverable/Refundable per specific rate order.

All Regulatory Assets and Liabilities are excluded from PSE&G's rate base unless otherwise noted. The Regulatory Assets and Liabilities in the table above are defined as follows:

- **NGC:** Represents the difference between the cost of non-utility generation and the amounts realized from selling that energy at market rates through PJM and ratepayer collections.
- **SBC:** The SBC, as authorized by the BPU and the New Jersey Electric Discount and Energy Competition Act, includes costs related to PSE&G's electric and gas business as follows: (1) the USF; (2) Energy Efficiency and Renewable Energy Programs; (3) Electric bad debt expense; and (4) the RAC for incurred MGP remediation expenditures. All components accrue interest on both over and underrecoveries.
- **GPRC:** These costs are amounts associated with various renewable energy and energy efficiency programs. Components of the GPRC include: Carbon Abatement, Energy Efficiency Economic Stimulus Program, Energy Efficiency Economic Extension Program, the Demand Response Program, Solar Generation Investment Program (Solar 4 All), Solar 4 All Extension, Solar Loan II Program and Solar Loan III Program.
- **SPRC:** This charge is designed to recover the revenue requirements associated with the PSE&G Solar Pilot Program (Solar Loan I) per a BPU Order, less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. The net recovery is subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances.
- **Capital Stimulus Undercollection:** PSE&G has received approval from the BPU for programs that provide for accelerated investment in utility infrastructure. The goal of these accelerated capital investments is to improve the reliability of PSE&G's infrastructure and New Jersey's economy through job creation.
- **WNC Deferral:** This represents the over- or under- collection of gas margin refundable or recoverable under the BPU's weather normalization clause. The WNC requires PSE&G to calculate, at the end of each October-to-May period, the level by which margin revenues differed from what would have resulted if normal weather had occurred.
- **New Jersey Clean Energy Program:** The BPU approved future funding requirements for Energy Efficiency and Renewable Energy Programs through the first half of 2013. Once the rates are measured, they are recovered through the SBC.
- **Stranded Costs To Be Recovered:** This reflects deferred costs, which are being recovered through the securitization transition charges authorized by the BPU in irrevocable financing orders and being collected by PSE&G, as servicer

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on behalf of Transition Funding and Transition Funding II, respectively. Collected funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs and taxes.

Transition Funding and Transition Funding II are wholly owned, bankruptcy-remote subsidiaries of PSE&G that purchased certain transition property from PSE&G and issued transition bonds secured by such property. The transition property consists principally of the rights to receive electricity consumption-based per kilowatt-hour (kWh) charges from PSE&G's electric distribution customers, which represent irrevocable rights to receive amounts sufficient to recover certain of PSE&G's transition costs related to deregulation, as approved by the BPU.

- **MGP Remediation Costs:** Represents the low end of the range for the remaining environmental investigation and remediation program cleanup costs for manufactured gas plants that are probable of recovery in future rates. Once these costs are incurred, they are recovered through the RAC in the SBC.
- **Pension and Other Postretirement Benefit Costs:** Pursuant to the adoption of accounting guidance for employers' defined benefit pension and OPEB plans, PSE&G recorded the unrecognized costs for defined benefit pension and other OPEB plans on the balance sheet as a Regulatory Asset. These costs represent actuarial gains or losses, prior service costs and transition obligations as a result of adoption, which have not been expensed. These costs are amortized and recovered in future rates.
- **Deferred Income Taxes:** These amounts represent the portion of deferred income taxes that will be recovered or refunded through future rates, based upon established regulatory practices.
- **RAC (Other SBC):** Costs incurred to clean up manufactured gas plants which are recovered over seven years.
- **MTM Contracts:** The estimated fair value of gas hedge contracts, gas cogeneration supply contracts and long-term standard offer capacity agreements (SOCAs) as provided in New Jersey's Long-Term Capacity Agreement Pilot Program (LCAPP). The regulatory asset/liability is offset by a derivative asset/liability and, with respect to the gas hedge contracts only, an intercompany receivable/payable on the Consolidated Balance Sheets. As a result of a federal court ruling that held the LCAPP to be unconstitutional, the SOCAs were terminated and the related derivative liability and regulatory asset reversed in the fourth quarter of 2013.
- **Unamortized Loss on Reacquired Debt and Debt Expense:** Represents losses on reacquired long-term debt and expenses associated with issuances of new debt, which are recovered through rates over the remaining life of the debt.
- **Conditional Asset Retirement Obligation:** These costs represent the differences between rate regulated cost of removal accounting and asset retirement accounting under GAAP. These costs will be recovered in future rates.
- **Gas Margin Adjustment Clause:** PSE&G defers the margin differential received from Transportation Gas Service Non-Firm Customers versus bill credits provided to BGSS-Firm customers.
- **Storm Damage Deferral:** Costs incurred in the cleanup of major storms in 2012, 2011 and 2010, including Hurricane Irene and Superstorm Sandy under a BPU Order received in December 2012 authorizing the deferral of incremental and otherwise unreimbursed costs.
- **Overrecovered Gas and Electric Costs:** These costs represent the net overrecovered amounts associated with BGSS and BGS, as approved by the BPU. For BGS, interest is accrued on both overrecovered and underrecovered balances. For BGSS, interest is accrued only on overrecovered balances from residential customers.
- **FERC Formula Rate True-up:** Overcollection or undercollection of transmission earnings calculated using a FERC approved formula.
- **Electric Cost of Removal:** PSE&G accrues and collects for cost of removal in rates. The liability for non-legally required cost of removal is classified as a Regulatory Liability. This liability is reduced as removal costs are incurred. Accumulated cost of removal is a reduction to the rate base.

Significant 2013 regulatory orders received from and currently pending rate filings with the FERC and the BPU are as follows:

- ***Transmission Formula Rates***—PSE&G's 2013 Annual Formula Rate Update with the FERC provided for approximately $174 million in increased annual transmission revenues effective January 1, 2013. In October 2013, PSE&G filed its 2014 Annual Formula Rate Update with the FERC, which provided for approximately $176 million in increased annual transmission revenues effective January 1, 2014. PSE&G subsequently reached an agreement with certain customers providing for a downward adjustment of postretirement benefits other than pension included in its Formula Rate, and in December 2013 submitted to the FERC a Modified Annual Update for 2014 and a request

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that the FERC authorize the agreed-upon revenue decrease. Under this modified proposal, annual transmission revenues would increase by $171 million rather than $176 million, effective January 1, 2014. In mid-January 2014, the FERC issued an order authorizing the proposed tariff.

- ***BGSS***—In October 2013, PSE&G filed a self-implementing two-month BGSS residential customer bill credit with the BPU. This bill credit was 35 cents per therm for the months of November and December 2013 and provided approximately $115 million in total credits to residential customers over the two months, reducing the BGSS deferred balance. The BGSS rate reverted back to the current rate on January 1, 2014. In January 2014, PSE&G filed a self-implementing one-month BGSS residential customer bill credit with the BPU. This bill credit is 25 cents per therm for the month of February 2014 and is expected to provide approximately $50 million in total credits to residential customers over the month, reducing the BGSS deferred balance. In February 2014, PSE&G filed an additional self-implementing one-month BGSS residential customer bill credit with the BPU which will continue the 25 cents per therm credit through the month of March 2014. This additional credit is expected to provide approximately $43 million in total credits to residential customers, reducing the deferred BGSS balance. On April 1, 2014, the BGSS rate will revert back to the current rate.
- ***RAC***—On February 19, 2014, the BPU approved PSE&G's filing with respect to its RAC 20 petition allowing recovery of net MGP expenditures through July 31, 2012.
- ***GPRC***—In May 2013, PSE&G received BPU approval for recovery of GPRC program costs incurred through November 30, 2012. In July 2013, PSE&G filed a petition with the BPU to recover GPRC program costs incurred after November 2012. On February 19, 2014, the BPU approved that request which allowed recovery of GPRC program costs incurred through September 30, 2013.
- ***WNC***—In April 2013, the BPU approved PSE&G's filing with respect to deficiency revenues from the 2011-2012 Winter Period. As a result, final rates were approved to recover $41 million from customers during the 2012-2013 Winter Period, with a carryover deficiency of $24 million to the 2013-2014 Winter Period. In September 2013, the BPU provisionally approved PSE&G's filing with respect to deficiency revenues from the 2012-2013 Winter Period, inclusive of the $24 million carryover deficiency from the 2011-2012 Winter Period. As a result, a total of $26 million of deficiency revenues will be recovered from customers during the 2013-2014 Winter Period (October 1 through May 31).
- ***Universal Service Fund (USF)/Lifeline***—The USF is an energy assistance program mandated by the BPU and funded through the SBC clause mechanism to provide payment assistance to low income customers. The Lifeline program is a separate mandated energy assistance program to provide payment assistance to elderly and disabled customers. In September 2013, the BPU approved rates set to recover costs incurred under the Program. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on Net Income.
- ***Capital Stimulus Infrastructure Programs (CIP II)***—In November 2013, PSE&G filed a petition with the BPU to recover program costs incurred for its CIP II investments through September 30, 2013. The discovery phase of this proceeding is underway.
- ***SBC***—In November 2013, PSE&G filed a petition with the BPU to recover NGC and SBC costs incurred through September 30, 2013 under its Energy Efficiency & Renewable Energy Programs, Social Programs and NGC. The discovery phase of this proceeding is underway.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 7. Long-Term Investments

Long-Term Investments as of December 31, 2013 and 2012 included the following:

	As of December 31, 2013	2012
	Millions	
Power		
Partnerships and Corporate Joint Ventures (Equity Method Investments) (A)	$ 123	$ 125
PSE&G		
Life Insurance and Supplemental Benefits	158	161
Solar Loan Investments	196	180
Other Investments	7	7
Energy Holdings		
Lease Investments	825	840
Partnerships and Corporate Joint Ventures:		
Equity Method Investments (A)	3	9
Cost Method Investments (B)	1	2
Total Long-Term Investments	**$ 1,313**	**$ 1,324**

(A) During the three years ended December 31, 2013, 2012 and 2011, the amount of dividends from these investments was $11 million, $17 million and $3 million, respectively.

(B) Reflects Energy Holdings' investments in certain companies in which it does not have the ability to exercise significant influence. Such investments are accounted for under the cost method.

Leases

Energy Holdings has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Consolidated Balance Sheets. The following table shows Energy Holdings' gross and net lease investment as of December 31, 2013 and 2012, respectively.

	As of December 31, 2013	2012
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 701	$ 721
Estimated Residual Value of Leased Assets	529	535
Total Investment in Rental Receivables	1,230	1,256
Unearned and Deferred Income	(405)	(416)
Gross Investments in Leases	825	840
Deferred Tax Liabilities	(727)	(723)
Net Investments in Leases	**$ 98**	**$ 117**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The pre-tax income and income tax effects, excluding gains and losses on sales, related to investments in leases were as follows:

	Years Ended December 31,		
	2013	2012	2011
	Millions		
Pre-Tax Income (Loss) from Leases	$ 11	$ 78	$ (228)
Income Tax Expense (Benefit) on Pre-Tax Income from Leases	$ 6	$ 34	$ (77)

Equity Method Investments

Power and Energy Holdings had the following equity method investments as of December 31, 2013:

Name	Location	% Owned
Power		
Keystone Fuels, LLC	PA	23%
Conemaugh Fuels, LLC	PA	23%
Kalaeloa	HI	50%
Energy Holdings		
GWF	CA	50%
Hanford L. P. (Hanford)	CA	50%

Note 8. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with SRECs generated from the installed solar electric system. The following table reflects the outstanding loans by class of customer, none of which would be considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of December 31, 2013	2012
	Millions	
Commercial/Industrial	$ 192	$ 174
Residential	15	15
	$ 207	**$ 189**

Energy Holdings

Energy Holdings had a net investment in domestic energy and real estate assets subject to leveraged lease accounting of $98 million and $117 million as of December 31, 2013 and 2012, respectively (See Note 7. Long-Term Investments).

The corresponding receivables associated with the lease portfolio are reflected below, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. "Not Rated" counterparties represent investments in lease receivables related to coal-fired assets and commercial real estate properties.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Counterparties' Credit Rating (S&P) as of December 31, 2013	Lease Receivables, Net of Non-Recourse Debt As of December 31, 2013	2012
	Millions	
AA	$ 19	$ 21
AA-	56	73
BBB+ - BB+	316	316
B	166	166
Not Rated	144	145
	$ 701	**$ 721**

The "B" rating and the "Not Rated" above include lease receivables related to coal-fired assets in Pennsylvania and Illinois, respectively. As of December 31, 2013, the gross investment in the leases of such assets, net of non-recourse debt, was $561 million ($7 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	Not Rated	Edison Mission Energy
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	Not Rated	Edison Mission Energy
Keystone Station Units 1 and 2	PA	$ 116	17%	1,711	Coal	B	GenOn REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 117	17%	1,711	Coal	B	GenOn REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 110	100%	603	Coal	B	GenOn REMA, LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Indirect subsidiary companies of Energy Holdings lease three coal-fired generation facilities in Pennsylvania (Keystone, Conemaugh and Shawville) to GenOn REMA, LLC (GenOn REMA), a subsidiary of GenOn Energy Inc. (GenOn), which was acquired by NRG Energy, Inc. (NRG) in December 2012. With respect to addressing various environmental controls: Keystone has installed a flue gas desulfurization (FGD) system for sulfur dioxide (SO_2), selective catalytic reduction (SCR) equipment for nitrogen oxide (NO_X) and mercury control; Conemaugh has a FGD system, while SCR and mercury control equipment are scheduled to be installed and operational by the first quarter of 2015; and GenOn has disclosed its plan to place Shawville in a "long-term protective layup" by April 2015. GenOn has stated that it is evaluating whether to continue to pay the required rent and maintain the facility in accordance with the lease terms or terminate the lease for obsolescence in which case the lessee would be required, among other things, to pay the contractual termination value structured to recover Energy Holdings' indirect subsidiaries' lease investment as specified in the lease agreement.

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Although all lease payments from the GenOn REMA leases are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

Nesbitt Asset Recovery, LLC (Nesbitt), (an indirect, wholly owned subsidiary of Energy Holdings), owns approximately 64% of the lease interest in the Powerton and Joliet coal units in Illinois, with the balance held by Associates Capital Investments, L.L.P. (Associates) (an affiliate of Citigroup, and, together with Nesbitt, the "Equity Investors"). These facilities are leased to Midwest Generation (MWG), an indirect subsidiary of Edison Mission Energy (EME).

MWG has substantially completed investments in mercury removal (Activated Carbon Injection) and NO_X emission controls (low NO_X burners and Selective Non-Catalytic Reduction systems). In April 2013, MWG obtained approval from the Illinois Pollution Control Board to defer capital investments for up to two additional years to meet upcoming air emission compliance deadlines under Illinois law. Also, in July 2013, the U.S. Court of Appeals affirmed the judgment of the lower court dismissing claims brought by the U.S. Environmental Protection Agency (EPA) and the State of Illinois against EME and MWG for alleged violations of the Clean Air Act.

In December 2012, EME and MWG filed for relief under Chapter 11 of the U.S. Bankruptcy Code. Immediately prior to that filing, EME, MWG and the Equity Investors, as well as certain affiliated owner lessors, entered into a forbearance agreement with holders of a majority of the lease debt that financed the original sale-leaseback transaction. As part of this agreement, (i) MWG will make partial lease payments of $4 million each month during the extension period starting in July 2013, (ii) MWG will continue to make certain environmental capital expenditures at the units, and (iii) the parties reserve their rights, claims, and defenses with respect to whether the leases are secured financings, rent amounts due under the leases, and the classification of claims under the leases, among other things.

In October 2013, NRG, EME, MWG, the Equity Investors and other creditor parties involved in the bankruptcy executed a new agreement, which was approved by the Bankruptcy Court. The new agreement contains the terms and conditions under which NRG would acquire substantially all of EME's assets, including the Powerton and Joliet leased assets. As part of the proposed transaction, (i) the leases for the Powerton and Joliet coal units would be assumed on their existing terms, (ii) all past due rent under the leases would be paid in full, (iii) NRG would assume EME's tax indemnity and guarantee obligations, and (iv) NRG would invest up to $350 million in the Powerton and Joliet coal units so they could be operated in compliance with all environmental regulations. The proposed transaction also requires approval by the FERC and other regulatory bodies, and there can be no assurances that the above transaction will be consummated. NRG and EME have stated that they expect the transaction to close in March 2014. The terms of the aforementioned forbearance agreement remain in effect until such time as the NRG acquisition is consummated or terminated.

In December 2011, indirect subsidiary companies of Energy Holdings and Dynegy Incorporated (Dynegy) reached a settlement agreement resolving disputes that had arisen between them with regard to Dynegy Holding's (DH) rejection of the Dynegy leases. The original terms of the settlement agreement included an allowed claim in Bankruptcy Court of $110 million against DH. In December 2011, upon the effective date of the court order authorizing the Dynegy lease rejections, the leases no longer qualified for leveraged lease accounting treatment under GAAP. As a result, Energy Holdings wrote off the $264 million gross lease investment against the previously recorded reserve. The Energy Holdings' indirect subsidiary companies that are owners/lessors of the two plants ceased leveraged lease accounting and recorded the generation assets and related nonrecourse project debt on their balance sheets at their respective fair values (See Note 17. Fair Value Measurements).

In June 2012, an amended and restated settlement agreement entered into by DH, Dynegy and their creditors (including indirect subsidiary companies of Energy Holdings) was approved by the Bankruptcy Court. In October 2012, Dynegy emerged from bankruptcy and distributed cash and stock settlements to the claimants. The total recovery of Energy Holdings' indirect subsidiary companies from the Dynegy leases was approximately $63 million, which was recorded in Operating Revenues in 2012.

In December 2013, Energy Holdings executed a lease extension for its share of the Grand Gulf nuclear unit in Mississippi with the lessee, System Energy Resources, Inc., an affiliate of Entergy Corporation. The lease terms are for $14 million of annual rent commencing at the end of the current lease in July 2015 and extending through July 2036.

Note 9. Available-for-Sale Securities

NDT Fund

In accordance with NRC regulations, entities owning an interest in nuclear generating facilities are required to determine the costs and funding methods necessary to decommission such facilities upon termination of operation. As a general practice, each nuclear owner places funds in independent external trust accounts it maintains to provide for decommissioning. Power is

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required to file periodic reports with the NRC demonstrating that the NDT Fund meets the formula-based minimum NRC funding requirements.

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon their respective termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. Power's share of decommissioning costs related to its five nuclear units was estimated to be between $2.2 billion and $2.4 billion, including contingencies. The liability for decommissioning recorded on a discounted basis as of December 31, 2013 was approximately $369 million and is included in the Asset Retirement Obligation. The trust funds are managed by third-party investment advisors who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund:

	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 609	$ 290	$ (2)	$ 897
Debt Securities				
Government Obligations	438	3	(12)	429
Other Debt Securities	285	10	(4)	291
Total Debt Securities	723	13	(16)	720
Other Securities	84	—	—	84
Total NDT Available-for-Sale Securities	**$ 1,416**	**$ 303**	**$ (18)**	**$ 1,701**

	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 648	$ 147	$ (6)	$ 789
Debt Securities				
Government Obligations	274	11	—	285
Other Debt Securities	320	22	—	342
Total Debt Securities	594	33	—	627
Other Securities	124	—	—	124
Total NDT Available-for-Sale Securities	**$ 1,366**	**$ 180**	**$ (6)**	**$ 1,540**

These amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as shown in the following table.

	As of December 31, 2013	As of December 31, 2012
	Millions	
Accounts Receivable	$ 39	$ 18
Accounts Payable	$ 36	$ 53

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The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2013				As of December 31, 2012			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 30	$ (2)	$ 2	$ —	$ 139	$ (6)	$ —	$ —
Debt Securities								
Government Obligations (B)	300	(11)	1	(1)	34	—	1	—
Other Debt Securities (C)	107	(4)	3	—	31	—	6	—
Total Debt Securities	407	(15)	4	(1)	65	—	7	—
NDT Available-for-Sale Securities	**$ 437**	**$ (17)**	**$ 6**	**$ (1)**	**$ 204**	**$ (6)**	**$ 7**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over companies with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2013.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2013.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2013.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Years Ended December 31,		
	2013	2012	2011
	Millions		
Proceeds from Sales	**$ 1,070**	**$ 1,433**	**$ 1,355**
Net Realized Gains			
Gross Realized Gains	$ 112	$ 153	$ 144
Gross Realized Losses	(26)	(52)	(45)
Net Realized Gains (Losses) on NDT Fund	**$ 86**	**$ 101**	**$ 99**

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Consolidated Statements of Operations. Net unrealized gains of $141 million (after-tax) are included in Accumulated Other Comprehensive Loss on PSEG's and Power's Consolidated Balance Sheets as of December 31, 2013.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The available-for-sale debt securities held as of December 31, 2013 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 44
1 - 5 years	180
6 - 10 years	180
11 - 15 years	45
16 - 20 years	26
Over 20 years	245
Total NDT Available-for-Sale Debt Securities	**$ 720**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2013, other-than-temporary impairments of $12 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost bases for the securities held in the Rabbi Trust.

	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 14	$ 9	$ —	$ 23
Debt Securities				
Government Obligations	109	—	(2)	107
Other Debt Securities	46	1	(1)	46
Total Debt Securities	155	1	(3)	153
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 172**	**$ 10**	**$ (3)**	**$ 179**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 13	$ 5	$ —	$ 18
Debt Securities				
Government Obligations	114	3	—	117
Other Debt Securities	45	2	—	47
Total Debt Securities	159	5	—	164
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 175**	**$ 10**	**$ —**	**$ 185**

These amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as show in the following table.

	As of December 31, 2013	As of December 31, 2012
	Millions	
Accounts Receivable	$ 1	$ 4
Accounts Payable	$ 2	$ 5

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2013				As of December 31, 2012			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	47	(2)	2	—	—	—	—	—
Other Debt Securities (C)	18	(1)	1	—	—	—	—	—
Total Debt Securities	65	(3)	3	—	—	—	—	—
Rabbi Trust Available-for-Sale Securities	**$ 65**	**$ (3)**	**$ 3**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund is through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors. PSEG does not consider these securities to be other-than-temporarily impaired as of December 31, 2013.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of December 31, 2013.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2013.

The proceeds from the sales of and the net realized gains on securities in the Rabbi Trust Fund were:

	Years Ended December 31,		
	2013	2012	2011
	Millions		
Proceeds from Rabbi Trust Sales	**$ 89**	**$ 233**	**$ —**
Net Realized Gains (Losses):			
Gross Realized Gains	$ 4	$ 6	$ —
Gross Realized Losses	(3)	—	—
Net Realized Gains (Losses) on Rabbi Trust	**$ 1**	**$ 6**	**$ —**

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in the Consolidated Statements of Operations. Net unrealized gains of $4 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets as of December 31, 2013. The Rabbi Trust available-for-sale debt securities held as of December 31, 2013 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ —
1 - 5 years	58
6 - 10 years	30
11 - 15 years	7
16 - 20 years	4
Over 20 years	54
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 153**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities. In 2013, there were no other-than-temporary impairments recognized on investments of the Rabbi Trust.

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The fair value of the Rabbi Trust related to PSEG, Power and PSE&G are detailed as follows:

	As of December 31, 2013	As of December 31, 2012
	Millions	
Power	$ 39	$ 36
PSE&G	42	61
Other	98	88
Total Rabbi Trust Available-for-Sale Securities	**$ 179**	**$ 185**

Note 10. Goodwill and Other Intangibles

As of each of December 31, 2013 and 2012, Power had goodwill of $16 million related to the Bethlehem Energy Center facility. Power conducted an annual review for goodwill impairment as of October 31, 2013 and concluded that goodwill was not impaired. No events occurred subsequent to that date which would require a further review of goodwill for impairment.

In addition to goodwill, as of December 31, 2013 and 2012, Power had intangible assets of $33 million and $34 million, respectively, related to emissions allowances and renewable energy credits. Emissions expense includes impairments of emissions allowances and costs for emissions, which is recorded as emissions occur. As load is served under contracts requiring energy from renewable sources, the related expense is recorded. Such expenses for the years ended December 31, 2013, 2012 and 2011 were as follows:

	Years Ended December 31,		
	2013	2012	2011
	Millions		
Emissions Expense	$ 6	$ 5	$ 35
Renewable Energy Expense	$ 26	$ 34	$ 43

Note 11. Asset Retirement Obligations (AROs)

PSEG, Power and PSE&G have recorded various AROs which represent legal obligations to remove or dispose of an asset or some component of an asset at retirement.

Power's ARO liability primarily relates to the decommissioning of its nuclear power plants in accordance with NRC requirements. To estimate this decommissioning obligation related to its nuclear power plants, Power uses a probability weighted, discounted cash flow model which, on a unit by unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on third party decommissioning cost estimates, cost escalation rates, inflation rates and discount rates. Power has an independent external trust that is intended to fund decommissioning of its nuclear facilities upon termination of operation. For additional information, see Note 9. Available-for-Sale Securities. Power also identified conditional AROs primarily related to Power's fossil generation units, including liabilities for

- removal of asbestos, stored hazardous liquid material and underground storage tanks from industrial power sites,
- restoration of leased office space to rentable condition upon lease termination,
- permits and authorizations,
- restoration of an area occupied by a reservoir when the reservoir is no longer needed, and
- demolition of certain plants, and the restoration of the sites at which they reside, when the plants are no longer in service.

PSE&G has conditional AROs primarily for legal obligations related to the removal of treated wood poles and the requirement to seal natural gas pipelines at all sources of gas when the pipelines are no longer in service. PSE&G did not record an ARO for its protected steel and poly-based natural gas transmission lines, as management believes that these categories of transmission lines have an indeterminable life.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The changes to the ARO liabilities for PSEG, Power and PSE&G during 2012 and 2013 are presented in the following table:

	PSEG	Power	PSE&G	Other
	Millions			
ARO Liability as of January 1, 2012	$ 489	$ 261	$ 226	$ 2
Liabilities Settled	(5)	(1)	(5)	1
Liabilities Incurred	11	4	7	—
Accretion Expense	21	21	—	—
Accretion Expense Deferred and Recovered in Rate Base (A)	14	—	14	—
Revisions to Present Values of Estimated Cash Flows	97	89	8	—
ARO Liability as of December 31, 2012	**$ 627**	**$ 374**	**$ 250**	**$ 3**
Liabilities Settled	(5)	(1)	(4)	—
Liabilities Incurred	17	4	13	—
Accretion Expense	23	23	—	—
Accretion Expense Deferred and Recovered in Rate Base (A)	15	—	15	—
ARO Liability as of December 31, 2013	**$ 677**	**$ 400**	**$ 274**	**$ 3**

(A) Not reflected as expense in Consolidated Statements of Operations

During 2012, Power recorded an increase in its ARO liabilities, primarily due to an increase in the estimated cost to decommission its nuclear power plants and increased accretion. The increase in the estimated costs to decommission Power's nuclear plants resulted primarily from the receipt of updated decommissioning cost studies in 2012 and the impact of lower discount rates. This change in the ARO did not result in any material impact in Power's Consolidated Statements of Operations.

Note 12. Pension, Other Postretirement Benefits (OPEB) and Savings Plans

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. Eligible employees participate in non-contributory pension and OPEB plans sponsored by PSEG and administered by Services. In addition, represented and nonrepresented employees are eligible for participation in PSEG's two defined contribution plans described below.

PSEG, Power and PSE&G are required to record the under or over funded positions of their defined benefit pension and OPEB plans on their respective balance sheets. Such funding positions of each PSEG company are required to be measured as of the date of its respective year-end Consolidated Balance Sheets. For under funded plans, the liability is equal to the difference between the plan's benefit obligation and the fair value of plan assets. For defined benefit pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. In addition, accounting guidance requires that the total unrecognized costs for defined benefit pension and OPEB plans be recorded as an after-tax charge to Accumulated Other Comprehensive Income (Loss), a separate component of Stockholders' Equity. However, for PSE&G, because the amortization of the unrecognized costs is being collected from customers, the accumulated unrecognized costs are recorded as a Regulatory Asset. The unrecognized costs represent actuarial gains or losses, prior service costs and transition obligations arising from the adoption of the revised accounting guidance for pensions and OPEB, which had not been expensed.

For Power, the charge to Accumulated Other Comprehensive Income (Loss) is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations. For PSE&G, the Regulatory Asset is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations.

The following table provides a roll-forward of the changes in the benefit obligation and the fair value of plan assets during each of the two years in the periods ended December 31, 2013 and 2012. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Pension Benefits		Other Benefits	
	2013	2012	2013	2012
	Millions			
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year (A)	$ 5,235	$ 4,572	$ 1,538	$ 1,338
Service Cost	116	101	21	17
Interest Cost	215	223	63	65
Actuarial (Gain) Loss	(501)	586	(144)	182
Gross Benefits Paid	(253)	(248)	(64)	(69)
Medicare Subsidy Receipts	—	—	—	5
Special Termination Benefits	—	1	—	—
Benefit Obligation at End of Year (A)	**$ 4,812**	**$ 5,235**	**$ 1,414**	**$ 1,538**
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$ 4,357	$ 3,831	$ 253	$ 211
Actual Return on Plan Assets	857	541	52	31
Employer Contributions	155	233	78	75
Gross Benefits Paid	(253)	(248)	(64)	(69)
Medicare Subsidy Receipts	—	—	—	5
Fair Value of Assets at End of Year	**$ 5,116**	**$ 4,357**	**$ 319**	**$ 253**
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	**$ 304**	**$ (878)**	**$ (1,095)**	**$ (1,285)**
Additional Amounts Recognized in the Consolidated Balance Sheets				
Noncurrent Assets	$ 434	$ 6	$ —	$ —
Current Accrued Benefit Cost	(9)	(8)	—	—
Noncurrent Accrued Benefit Cost	(121)	(876)	(1,095)	(1,285)
Amounts Recognized	**$ 304**	**$ (878)**	**$ (1,095)**	**$ (1,285)**
Additional Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulated Assets and Deferred Assets (B)				
Prior Service Cost	$ (120)	$ (139)	$ (53)	$ (67)
Net Actuarial Loss	977	2,174	310	527
Total	**$ 857**	**$ 2,035**	**$ 257**	**$ 460**

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for Other benefits.

(B) Includes $408 million ($238 million, after-tax) and $827 million ($485 million, after-tax) in Accumulated Other Comprehensive Loss related to Pension and OPEB as of December 31, 2013 and 2012, respectively.

The pension benefits table above provides information relating to the funded status of all qualified and nonqualified pension plans and OPEB plans on an aggregate basis. As of December 31, 2013, PSEG had funded approximately 106% of its projected benefit obligation. This percentage does not include $179 million of assets in the Rabbi Trust as of December 31, 2013 which were used partially to fund the nonqualified pension plans. As of December 31, 2013, the nonqualified pension plans included in the benefit obligation in the above table and in the projected benefit obligation were $130 million. The fair values of the Rabbi Trust assets are included in Other Special Funds on the Consolidated Balance Sheets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Accumulated Benefit Obligation

The accumulated benefit obligation for all PSEG's defined benefit pension plans was $ 4.5 billion as of December 31, 2013 and $4.9 billion as of December 31, 2012.

The following table provides the components of net periodic benefit cost for the years ended December 31, 2013, 2012 and 2011.

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2013	2012	2011	2013	2012	2011
	Millions					
Components of Net Periodic Benefit Cost						
Service Cost	$ 116	$ 101	$ 92	$ 21	$ 17	$ 14
Interest Cost	215	223	228	63	65	61
Expected Return on Plan Assets	(348)	(306)	(334)	(21)	(17)	(18)
Amortization of Net						
Transition Obligation	—	—	—	—	2	4
Prior Service Cost	(19)	(18)	(11)	(14)	(14)	(13)
Actuarial Loss	188	167	119	42	31	14
Net Periodic Benefit Cost	**$ 152**	**$ 167**	**$ 94**	**$ 91**	**$ 84**	**$ 62**
Special Termination Benefits	—	1	—	—	—	—
Effect of Regulatory Asset	—	—	—	—	19	19
Total Benefit Costs, Including Effect of Regulatory Asset	**$ 152**	**$ 168**	**$ 94**	**$ 91**	**$ 103**	**$ 81**

Pension costs and OPEB costs for PSEG, Power and PSE&G are detailed as follows:

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2013	2012	2011	2013	2012	2011
	Millions					
Power	$ 43	$ 52	$ 29	$ 23	$ 18	$ 12
PSE&G	91	97	51	65	82	67
Other	18	19	14	3	3	2
Total Benefit Costs	**$ 152**	**$ 168**	**$ 94**	**$ 91**	**$ 103**	**$ 81**

The following table provides the pre-tax changes recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Deferred Assets:

	Pension		OPEB	
	2013	2012	2013	2012
	Millions			
Net Actuarial (Gain) Loss in Current Period	$ (1,009)	$ 350	$ (175)	$ 169
Amortization of Net Actuarial Gain (Loss)	(188)	(167)	(42)	(32)
Amortization of Prior Service Credit	19	19	14	14
Amortization of Transition Asset	—	—	—	(2)
Total	**$ (1,178)**	**$ 202**	**$ (203)**	**$ 149**

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Amounts that are expected to be amortized from Accumulated Other Comprehensive Loss, Regulatory Assets and Deferred Assets into Net Periodic Benefit Cost in 2014 are as follows:

	Pension Benefits 2014	Other Benefits 2014
	Millions	
Actuarial (Gain) Loss	$ 56	$ 23
Prior Service Cost	$ (19)	$ (14)

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

	Pension Benefits			Other Benefits		
	2013	2012	2011	2013	2012	2011
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	5.00%	4.20%	5.00%	5.01%	4.20%	5.00%
Rate of Compensation Increase	4.61%	4.61%	4.61%	4.61%	4.61%	4.61%
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount Rate	4.20%	5.00%	5.40%	4.20%	5.00%	5.38%
Expected Return on Plan Assets	8.00%	8.00%	8.50%	8.00%	8.00%	8.50%
Rate of Compensation Increase	4.61%	4.61%	4.61%	4.61%	4.61%	4.61%
Assumed Health Care Cost Trend Rates as of December 31						
Administrative Expense				3.00%	3.00%	5.00%
Dental Costs				5.00%	6.00%	6.00%
Pre-65 Medical Costs						
Immediate Rate				8.00%	8.88%	8.00%
Ultimate Rate				5.00%	5.00%	5.00%
Year Ultimate Rate Reached				2021	2023	2016
Post-65 Medical Costs						
Immediate Rate				7.88%	7.98%	8.25%
Ultimate Rate				5.00%	5.00%	5.00%
Year Ultimate Rate Reached				2021	2019	2017
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs						
				Millions		
Total of Service Cost and Interest Cost				$ 12	$ 12	$ 11
Postretirement Benefit Obligation				$ 161	$ 180	$ 155
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$ (9)	$ (9)	$ (9)
Postretirement Benefit Obligation				$ (134)	$ (149)	$ (128)

Plan Assets

All the investments of pension plans and OPEB plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension and OPEB plans are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 17. Fair Value Measurements for more information on fair value guidance. Use of the Master Trust permits the commingling of pension plan assets and OPEB plan assets for investment and administrative purposes. Although assets of both plans are commingled in the Master Trust, the Trustee maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Trustee to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating

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plans. As of December 31, 2013, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 94% and 6%, respectively.

The following tables present information about the investments measured at fair value on a recurring basis as of December 31, 2013 and 2012, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2013			
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Temporary Investment Funds (A)	$ 93	$ 52	$ 41	$ —
Common Stocks (B)				
Commingled—United States	2,264	2,264	—	—
Commingled—International	1,016	1,016	—	—
Other	704	704	—	—
Bonds (C)				
Government (United States & Foreign)	596	—	596	—
Other	737	—	737	—
Private Equity (D)	25	—	—	25
Total	**$ 5,435**	**$ 4,036**	**$ 1,374**	**$ 25**

	Recurring Fair Value Measurements as of December 31, 2012			
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Temporary Investment Funds (A)	$ 67	$ —	$ 67	$ —
Common Stocks (B)				
Commingled—United States	1,928	1,928	—	—
Commingled—International	839	839	—	—
Other	431	431	—	—
Bonds (C)				
Government (United States & Foreign)	623	—	623	—
Other	691	—	691	—
Private Equity (D)	31	—	—	31
Total	**$ 4,610**	**$ 3,198**	**$ 1,381**	**$ 31**

(A) Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active market (Level 1). Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

(B) Wherever possible, fair values of equity investments in stocks and in commingled funds are derived from quoted market prices as substantially all of these instruments have active markets (primarily Level 1). Most investments in stocks are priced utilizing the principal market close price or in some cases midpoint, bid or ask price.

(C) Investments in fixed income securities including bond funds are priced using an evaluated pricing approach or the most recent exchange or quoted bid (primarily Level 2).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(D) Limited partnership interests in private equity funds are valued using significant unobservable inputs as there is little, if any, market activity. In addition, there may be transfer restrictions on private equity securities. The process for determining the fair value of such securities relied on commonly accepted valuation techniques, including the use of earnings multiples based on comparable public securities, industry-specific non-earnings-based multiples and discounted cash flow models. These inputs require significant management judgment or estimation (primarily Level 3).

Reconciliations of the beginning and ending balances of the Pension and OPEB Plans' Level 3 assets for the years ended December 31, 2013 and 2012 are as follows:

	Balance as of January 1, 2013	Purchases/ (Sales)	Transfer In/ (Out)	Actual Return on Asset Sales	Actual Return on Assets Still Held	Balance as of December 31, 2013
			Millions			
Private Equity	$ 31	$ (11)	$ —	$ 11	$ (6)	$ 25

	Balance as of January 1, 2012	Purchases/ (Sales)	Transfer In/ (Out)	Actual Return on Asset Sales	Actual Return on Assets Still Held	Balance as of December 31, 2012
			Millions			
Pooled Real Estate	$ 36	$ (38)	$ —	$ 2	$ —	$ —
Private Equity	$ 37	$ (6)	$ —	$ 5	$ (5)	$ 31

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans as of the measurement date, December 31:

	As of December 31,	
Investments	**2013**	**2012**
Equity Securities	73%	69%
Fixed Income Securities	25	29
Other Investments	2	2
Total Percentage	**100%**	**100%**

PSEG utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. In 2011, PSEG completed its latest asset/liability study. The results from the study indicated that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. Derivative financial instruments are used by the plans' investment managers primarily to adjust the fixed income duration of the portfolio and hedge the currency risk component of foreign investments. The expected long-term rate of return on plan assets was 8.00% as of December 31, 2013 and will remain unchanged for 2014. This expected return was determined based on the study discussed above, including a premium for active management and considered the plans' historical annualized rate of return since inception, which was 9.5%.

Plan Contributions

PSEG does not anticipate making additional contributions into its pension plans during 2014. PSEG may contribute up to $14 million into its OPEB plan during 2014.

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Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to plan participants.

Year	Pension Benefits	Other Benefits
	Millions	
2014	$ 256	$ 77
2015	263	78
2016	272	80
2017	282	82
2018	293	84
2019-2023	1,647	458
Total	**$ 3,013**	**$ 859**

Long Island Electric Utility Servco LLC (ServCo) Pension and OPEB

PSEG Long Island (PSEG LI) and the Long Island Power Authority (LIPA) entered into a twelve year Amended and Restated Operations Services Agreement (OSA) effective January 1, 2014 to operate LIPA's electric transmission and distribution (T&D) system in Long Island, New York. ServCo, a wholly owned subsidiary of PSEG LI, has created benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D manager for LIPA. Such benefits include defined benefit and cash balance pension plans and health and welfare plans for union, nonunion and management employees. Since the vast majority of ServCo's employees had worked under NGES' T&D operations services arrangement with LIPA, ServCo's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The OSA provides for all of these employee benefit costs to be funded by LIPA. ServCo amounts are not included in any of the preceding pension and OPEB disclosures.

401(k) Plans

PSEG sponsors two 401(k) plans, which are Employee Retirement Income Security Act defined contribution retirement plans. Eligible represented employees of PSEG's subsidiaries participate in the PSEG Employee Savings Plan (Savings Plan), while eligible non-represented employees of PSEG's subsidiaries participate in the PSEG Thrift and Tax-Deferred Savings Plan (Thrift Plan). Eligible employees may contribute up to 50% of their compensation to these plans. PSEG matches 50% of such employee contributions up to 7% of pay for Savings Plan participants and up to 8% of pay for Thrift Plan participants.

The amount paid for employer matching contributions to the plans for PSEG, Power and PSE&G are detailed as follows:

	Thrift Plan and Savings Plan Years Ended December 31,		
	2013	2012	2011
	Millions		
Power	$ 10	$ 10	$ 8
PSE&G	19	18	14
Other	4	4	2
Total Employer Matching Contributions	**$ 33**	**$ 32**	**$ 24**

Note 13. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

The face value of outstanding guarantees, current exposure and margin positions as of December 31, 2013 and 2012 are shown below:

	As of December 31, 2013	As of December 31, 2012
	Millions	
Face Value of Outstanding Guarantees	$ 1,639	$ 1,508
Exposure under Current Guarantees	$ 246	$ 226
Letters of Credit Margin Posted	$ 132	$ 124
Letters of Credit Margin Received	$ 25	$ 69
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$ —	$ 15
Counterparty Cash Margin Received	$ —	$ (4)
Net Broker Balance Deposited (Received)	$ 80	$ 26
In the Event Power were to Lose its Investment Grade Rating		
Additional Collateral that could be Required	$ 691	$ 654
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,522	$ 3,531
Additional Amounts Posted		
Other Letters of Credit	$ 45	$ 45

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As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 16. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P, Moody's and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

The SEC and the Commodity Futures Trading Commission (CFTC) continue efforts to implement new rules to effect stricter regulation over swaps and derivatives, including imposing reporting and record-keeping requirements. In August 2013, PSEG began reporting its swap transactions to a CFTC-approved swap data repository. PSEG continues to monitor developments in this area, as the CFTC considers additional requirements such as a new position limits rule for energy commodity swaps.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See table above.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed below.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The EPA has determined that a 17-mile stretch of the Passaic River from Newark to Clifton, New Jersey is a "Super Fund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA has determined the need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

Seventy-three Potentially Responsible Parties (PRPs), including Power and PSE&G, agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) and formed the Cooperating Parties Group (CPG) to divide the associated costs according to a mutually agreed upon formula. The CPG group, currently 67 members, is presently conducting the RI/FS. Approximately seven percent of the RI/FS costs are currently attributable to PSE&G's former MGP sites and approximately one percent to Power's generating stations. Power has provided notice to insurers concerning this potential claim. The RI/FS is expected to be completed by the end of 2014 at an estimated cost of approximately $125 million.

In 2007, the EPA released a draft "Focused Feasibility Study" (FFS) that proposed six options to address the contamination cleanup of the lower eight miles of the Passaic River. The EPA estimated costs for the proposed remedy ranged from $1.3 billion to $3.7 billion. The work contemplated by the draft FFS is not subject to the cost sharing agreement discussed above. The EPA's revised proposed FFS is scheduled to be released for public comment in the first quarter of 2014.

In June 2008, an agreement was announced between the EPA and Tierra Solutions, Inc. and Maxus Energy Corporation (Tierra/Maxus) for removal of a portion of the contaminated sediment in the Passaic River at an estimated cost of $80 million. Phase I of the removal work has been completed. Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G.

At the EPA's direction, the CPG, with the exception of Tierra and Maxus, which are no longer members, has commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSEG's share of the cost of that effort is approximately three percent.

Except for the Passaic River 10.9 mile removal, Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to the Passaic River matters.

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New Jersey Spill Compensation and Control Act (Spill Act)

In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of a certain PRP's discharge of hazardous substances into both the Passaic River and the balance of the Newark Bay Complex. In 2009, third party complaints were filed against some 320 third party defendants, including Power and PSE&G, claiming that each of the third party defendants is responsible for its proportionate share of the clean-up costs for the hazardous substances it allegedly discharged into the Passaic River and the Newark Bay Complex. Power and PSE&G are alleged to have owned, operated or contributed to a total of 11 sites or facilities that impacted these water bodies. The third party complaints sought statutory contribution and contribution under the Spill Act to recover past and future removal costs and damages. In December 2013, the Court approved a settlement of the entire third party action. Power and PSE&G's contributions to the settlement, either individually or in the aggregate, were immaterial.

Natural Resource Damage Claims

In 2003, the NJDEP directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the Spill Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G is unable to estimate its portion of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $445 million and $521 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $445 million as of December 31, 2013. Of this amount, $92 million was recorded in Other Current Liabilities and $353 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $445 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

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Hazardous Air Pollutants Regulation

In accordance with a ruling of the U.S. Court of Appeals of the District of Columbia (D.C. Court), the EPA published a Maximum Achievable Control Technology (MACT) regulation on February 16, 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the D.C. Court in support of the EPA's implementation of MATS. Oral arguments were held in December 2013. A final decision remains pending and the impact on the implementation schedule is unknown at this time.

Power believes that it will not be necessary to install any material controls at its New Jersey facilities. Additional controls may be necessary at Power's Bridgeport Harbor coal-fired unit at an immaterial cost. In December 2011, to comply with the MACT regulations, the co-owners group, including Power, agreed to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction (SCR) systems at Power's jointly owned coal-fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be completed in the first quarter of 2015. Power's share of this investment is approximately $110 million.

NO_x Regulation

In 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on Power's generation fleet, as it imposes NO_x emissions limits that will require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) and four older New Jersey steam electric generation units (approximately 400 MW) by May 30, 2015. Retirement notifications for the combustion turbines have been submitted to PJM. PJM was notified that the Salem Unit 3 combustion turbine will no longer be available as a capacity resource and will be transitioned to an emergency generator for site use only. Based upon Power's recently-completed evaluations of its steam electric generation units, a minimal investment will be required to consistently reduce NO_x emissions below required limits beginning on May 1, 2015.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System (NPDES) permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The New Jersey Department of Environmental Protection manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

One of the most significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued.

In April 2011, the EPA published a proposed rule to establish marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. The EPA is currently scheduled to issue a final rule on April 17, 2014.

Power is unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on its future capital requirements, financial condition, results of operations or cash flows. The results of further proceedings on this matter could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would have been approximately $575 million. The filing has not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

On October 1, 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court in New Jersey seeking to compel the NJDEP to take action on Power's pending application for permit renewal at Salem either by denying the application or issuing a draft for public comments. At the NJDEP's request, the case was transferred to the Appellate Division on December 16, 2013. Power is unable to predict the outcome of this proceeding.

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Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements for customers who do not purchase electric supply from third party suppliers through the annual New Jersey BGS auctions. Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with Power, as well as with other winning BGS suppliers, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has contracted for its anticipated BGS-Fixed Price eligible load, as follows:

	Auction Year				
	2011	2012	2013	2014	
36-Month Terms Ending	May 2014	May 2015	May 2016	May 2017	(A)
Load (MW)	2,800	2,900	2,800	2,800	
$ per kWh	0.09430	0.08388	0.09218	0.09739	

(A) Prices set in the 2014 BGS auction will become effective on June 1, 2014 when the 2011 BGS auction agreements expire.

PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 24. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations and for supply of nuclear fuel for the Salem, Hope Creek and Peach Bottom nuclear generating stations and for firm transportation and storage capacity for natural gas.

Power's fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2015 and a portion through 2018 at Salem, Hope Creek and Peach Bottom.

Power's various multi-year contracts for firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

As of December 31, 2013, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type		Power's Share of Commitments through 2018
		Millions
Nuclear Fuel		
Uranium	$	532
Enrichment	$	454
Fabrication	$	137
Natural Gas	$	1,061
Coal	$	405

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Regulatory Proceedings

New Jersey Clean Energy Program

In June 2013, the BPU established the funding level for fiscal 2014 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2014 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a remaining current liability of $142 million as of December 31, 2013 for its outstanding share of the fiscal 2014 and remaining fiscal 2013 funding. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

Long-Term Capacity Agreement Pilot Program (LCAPP)

In 2011, New Jersey enacted the LCAPP Act that resulted in the selection of three generators to build a total of approximately 2,000 MW of new combined-cycle generating facilities located in New Jersey. Each of the New Jersey EDCs, including PSE&G, was directed to execute a standard offer capacity agreement (SOCA) with the selected generators, providing for the EDCs to guarantee specified annual capacity payments to the generators subject to the terms and conditions of the agreement, but did so under protest preserving their legal rights. The SOCA contracts, which had a 15-year term, were for the aggregate notional amount of approximately 1,300 MW of installed capacity. PSE&G was to have been responsible for the positive difference of the contract price and the annual RPM clearing price for approximately 52% or 676 MW of this amount, assuming generator satisfaction of its contractual obligations.

In July 2013, one of the SOCA contracts was terminated early as a result of a default by the generator. In November 2013, as a result of a federal court decision finding (i) the LCAPP Act to be unconstitutional and (ii) the SOCA contracts to be void, invalid and unenforceable, and a subsequent decision denying a request to stay this decision pending appeal, PSE&G terminated the other two SOCA contracts by providing written notice to both counterparties. The SOCA generators have appealed the federal court decision and this appeal remains pending.

As a result of the federal court's decision and PSE&G's subsequent termination of the contracts, the estimated fair value of the SOCAs that had been recorded as a Derivative Asset or Liability with an offsetting Regulatory Asset or Liability on PSE&G's Consolidated Balance Sheets were removed in the fourth quarter of 2013. See Note 17. Fair Value Measurements for additional information.

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's transmission and distribution system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure.

As of December 31, 2012, PSE&G had incurred approximately $295 million of costs to restore service to PSE&G's distribution and transmission systems and $5 million to repair its infrastructure and return it to pre-storm conditions. Of the costs incurred, approximately $40 million was recognized in Operation and Maintenance (O&M) Expense, $75 million was recorded as Property, Plant and Equipment and $180 million was recorded as a Regulatory Asset because such costs were deferred as approved by the BPU under an Order received in December 2012. PSE&G recognized $6 million of insurance proceeds. There were no significant changes to these amounts in 2013. PSE&G made a filing with the BPU to review the prudency of unreimbursed incremental storm restoration costs, including O&M and capital expenditures associated with certain extreme weather events, for recovery in our next base rate case or sooner through a BPU-approved cost recovery mechanism. The BPU is currently conducting a review regarding the amount, prudency, cost effectiveness and cost efficiency of PSE&G's unreimbursed incremental storm restoration costs for extreme weather events from 2010-2012.

Power incurred $79 million of storm-related expense for the year ended December 31, 2013 primarily for repairs at certain generating stations in Power's fossil fleet. Power had incurred $85 million of costs in 2012. These costs were recognized in O&M Expense, offset by $25 million and $19 million of insurance recoveries in the second quarter of 2013 and the fourth quarter of 2012, respectively.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. PSEG is seeking recovery from its insurers for the property damage, above its self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. PSEG has recorded proceeds of $50 million from its insurance carriers as advance payments, $25 million of which was recognized in 2013 and $25 million was recognized in 2012. PSEG does not believe that it has a basis for estimating additional probable insurance recoveries at this time. In June 2013, PSEG, Power and PSE&G filed suit in New Jersey state court against the insurance carriers seeking legal interpretation of certain terms in the insurance policies regarding losses resulting from damage caused by Superstorm Sandy's storm surge. The dispute concerns whether certain sub-limits in the policies apply to damage to property caused by Superstorm Sandy's storm surge. In that lawsuit, PSEG stated that its estimate of the total costs required to restore damaged facilities to their pre-Superstorm Sandy

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condition was approximately $426 million. Of these costs, $364 million and $62 million related to Power and PSE&G, respectively. In August 2013, the insurance carriers filed an answer in which they denied most of the allegations made in the Complaint. Discovery is ongoing.

Nuclear Insurance Coverages and Assessments

Power is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides the primary property and decontamination liability insurance at Salem, Hope Creek and Peach Bottom. NEIL also provides excess property insurance through its decontamination liability, decommissioning liability and excess property policy and replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in case of adverse loss experience. Power's maximum potential liabilities under these assessments are included in the table and notes below. Certain provisions in the NEIL policies provide that the insurer may suspend coverage with respect to all nuclear units on a site without notice if the NRC suspends or revokes the operating license for any unit on that site, issues a shutdown order with respect to such unit or issues a confirmatory order keeping such unit down.

The American Nuclear Insurers (ANI) and NEIL policies both include coverage for claims arising out of acts of terrorism. NEIL makes a distinction between certified and non-certified acts of terrorism, as defined under the Terrorism Risk Insurance Act, and thus its policies respond accordingly. For non-certified acts of terrorism, NEIL policies are subject to an industry aggregate limit of $3.2 billion plus any amounts available through reinsurance or indemnity for non-certified acts of terrorism. For any act of terrorism, Power's nuclear liability policies will respond similarly to other covered events. For certified acts, Power's nuclear property NEIL policies will respond similarly to other covered events.

The Price-Anderson Act sets the "limit of liability" for claims that could arise from an incident involving any licensed nuclear facility in the United States. The "limit of liability" is based on the number of licensed nuclear reactors and is adjusted at least every five years based on the Consumer Price Index. The current "limit of liability" is $13.6 billion. All owners of nuclear reactors, including Power, have provided for this exposure through a combination of private insurance and mandatory participation in a financial protection pool as established by the Price-Anderson Act. Under the Price-Anderson Act, each party with an ownership interest in a nuclear reactor can be assessed its share of $127 million per reactor per incident, payable at $19 million per reactor per incident per year. If the damages exceed the "limit of liability," the President is to submit to Congress a plan for providing additional compensation to the injured parties. Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Power's maximum aggregate assessment per incident is $401 million (based on Power's ownership interests in Hope Creek, Peach Bottom and Salem) and its maximum aggregate annual assessment per incident is $60 million. Further, a decision by the U.S. Supreme Court, not involving Power, has held that the Price-Anderson Act did not preclude awards based on state law claims for punitive damages.

Power's insurance coverages and maximum retrospective assessments for its nuclear operations are as follows:

Type and Source of Coverages	Total Site Coverage		Retrospective Assessments
	Millions		
Public and Nuclear Worker Liability (Primary Layer):			
ANI	$ 375	(A)	$ —
Nuclear Liability (Excess Layer):			
Price-Anderson Act	13,241	(B)	401
Nuclear Liability Total	**$ 13,616**	(C)	**$ 401**
Property Damage (Primary Layer):			
NEIL Primary (Salem/Hope Creek/Peach Bottom)	$ 500		$ 24
Property Damage (Excess Layers)			
NEIL II (Salem/Hope Creek/Peach Bottom)	750		8
NEIL Blanket Excess (Salem/Hope Creek/Peach Bottom)	850	(D)	5
Property Damage Total (Per Site)	**$ 2,100**	(E)	**$ 37**
Accidental Outage:			
NEIL I (Peach Bottom)	$ 245	(F)	$ 6
NEIL I (Salem)	281	(F)	7
NEIL I (Hope Creek)	490	(F)	6
Replacement Power Total	**$ 1,016**		**$ 19**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(A) The primary limit for Public Liability is a per site aggregate limit with no potential for assessment. The Nuclear Worker Liability represents the potential liability from workers claiming exposure to the hazard of nuclear radiation. This coverage is subject to an industry aggregate limit that is subject to reinstatement at ANI discretion.

(B) Retrospective premium program under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. Power is subject to retrospective assessment with respect to loss from an incident at any licensed nuclear reactor in the United States that produces greater than 100 MW of electrical power. This retrospective assessment can be adjusted for inflation every five years. The last adjustment was effective as of September 10, 2013. The next adjustment is due on or before September 10, 2018. This retrospective program is in excess of the Public and Nuclear Worker Liability primary layers.

(C) Limit of liability under the Price-Anderson Act for each nuclear incident.

(D) For property limits in excess of $1.25 billion, Power participates in a Blanket Limit policy where the $850 million limit is shared by Power with Exelon Generation among the Braidwood, Byron, Clinton, Dresden, La Salle, Limerick, Oyster Creek, Quad Cities, TMI-1 facilities owned by Exelon Generation and the Peach Bottom, Salem and Hope Creek facilities. This limit is not subject to reinstatement in the event of a loss. Participation in this program materially reduces Power's premium and the associated potential assessment.

(E) Power's property limits provide a $2.1 billion limit for a nuclear event, but provide a sublimit of $1.5 billion for conventional property losses that do not involve a nuclear event.

(F) Peach Bottom has an aggregate indemnity limit based on a weekly indemnity of $2.3 million for 52 weeks followed by 80% of the weekly indemnity for 68 weeks. Salem has an aggregate indemnity limit based on a weekly indemnity of $2.5 million for 52 weeks followed by 80% of the weekly indemnity for 72 weeks. Hope Creek has an aggregate indemnity limit based on a weekly indemnity of $4.5 million for 52 weeks followed by 80% of the weekly indemnity for 71 weeks.

Minimum Lease Payments

The total future minimum payments under various operating leases as of December 31, 2013 are:

	Power	PSE&G	Services	Other
		Millions		
2014	$ 1	$ 9	$ 1	$ 2
2015	1	7	4	2
2016	1	6	12	1
2017	1	5	13	1
2018	2	4	13	—
Thereafter	16	33	173	—
Total Minimum Lease Payments	**$ 22**	**$ 64**	**$ 216**	**$ 6**

Note 14. Schedule of Consolidated Debt

Long-Term Debt

	As of December 31, 2013	2012
	Millions	
PSEG (Parent)		
Fair Value of Swaps (A)	$ 38	$ 57
Unamortized Discount Related to Debt Exchange (B)	(14)	(19)
Total Long-Term Debt of PSEG (Parent)	**$ 24**	**$ 38**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2013	2012
		Millions	
Power			
Senior Notes:			
2.50%	2013	$ —	$ 300
5.50%	2015	300	300
5.32%	2016	303	303
2.75%	2016	250	250
2.45%	2018	250	—
5.13%	2020	406	406
4.15%	2021	250	250
4.30%	2023	250	—
8.63%	2031	500	500
Total Senior Notes		2,509	2,309
Pollution Control Notes:			
Floating Rate (C)	2014	44	44
Total Pollution Control Notes		44	44
Principal Amount Outstanding		2,553	2,353
Amounts Due Within One Year		(44)	(300)
Net Unamortized Discount		(12)	(13)
Total Long-Term Debt of Power		**$ 2,497**	**$ 2,040**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2013	2012
		Millions	
PSE&G			
First and Refunding Mortgage Bonds (D):			
6.75%	2016	$ 171	$ 171
9.25%	2021	134	134
8.00%	2037	7	7
5.00%	2037	8	8
Total First and Refunding Mortgage Bonds		320	320
Pollution Control Bonds (D):			
Floating rate (C)	2033	50	50
Floating rate (C)	2046	50	50
Total Pollution Control Bonds		100	100
Medium-Term Notes (MTNs) (D):			
5.00%	2013	—	150
5.38%	2013	—	300
6.33%	2013	—	275
0.85%	2014	250	250
5.00%	2014	250	250
2.70%	2015	300	300
5.30%	2018	400	400
2.30%	2018	350	—
7.04%	2020	9	9
3.50%	2020	250	250
2.38%	2023	500	—
3.75%	2024	250	—
5.25%	2035	250	250
5.70%	2036	250	250
5.80%	2037	350	350
5.38%	2039	250	250
5.50%	2040	300	300
3.95%	2042	450	450
3.65%	2042	350	350
3.80%	2043	400	—
Total MTNs		5,159	4,384
Principal Amount Outstanding		5,579	4,804
Amounts Due Within One Year		(500)	(725)
Net Unamortized Discount		(13)	(9)
Total Long-Term Debt of PSE&G (excluding Transition Funding and Transition Funding II)		**$ 5,066**	**$ 4,070**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2013	2012
		Millions	
Transition Funding (PSE&G)			
Securitization Bonds:			
6.61%	2013	$ —	$ 100
6.75%	2013-2014	106	220
6.89%	2014-2015	370	370
Principal Amount Outstanding		476	690
Amounts Due Within One Year		(225)	(214)
Total Securitization Debt of Transition Funding		**251**	**476**
Transition Funding II (PSE&G)			
Securitization Bonds:			
4.49%	2013	—	9
4.57%	2013-2015	20	23
Principal Amount Outstanding		20	32
Amounts Due Within One Year		(12)	(12)
Total Securitization Debt of Transition Funding II		**8**	**20**
Total Long-Term Debt of PSE&G		**$ 5,325**	**$ 4,566**

	Maturity	As of December 31, 2013	2012
		Millions	
Energy Holdings			
Non-Recourse Project Debt (E):			
Resources - 5.00% to 5.275%	2013-2015	$ 16	$ 44
Principal Amount Outstanding		16	44
Amounts Due Within One Year		—	(1)
Total Non-Recourse Project Debt		16	43
Total Long-Term Debt of Energy Holdings		**$ 16**	**$ 43**

(A) PSEG entered into various interest rate swaps to hedge the fair value of certain debt at Power. The fair value adjustments from these hedges are reflected as offsets to long-term debt on the Consolidated Balance Sheet. For additional information, see Note 16. Financial Risk Management Activities.

(B) In September 2009, Power completed an exchange offer with eligible holders of Energy Holdings' 8.50% Senior Notes due 2011 in order to manage long-term debt maturities. Since the debt exchange was between two subsidiaries of the same parent company, PSEG, and treated as a debt modification for accounting purposes, the resulting premium was deferred and is being amortized over the term of the newly issued debt. The deferred amount is reflected as an offset to Long-Term Debt on PSEG's Consolidated Balance Sheets.

(C) The Pennsylvania Economic Development Authority (PEDFA) bond and The Pollution Control Financing Authority of Salem County bonds that are serviced and secured by Power Pollution Control Notes and PSE&G Pollution Control Bonds, respectively, are variable rate bonds that are in weekly reset mode. The PEDFA bond is backed by a three-year letter of credit that expires in November 2014. The Power Pollution Control Note backing the PEDFA bond has been reclassified as debt due within the year.

(D) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.

(E) Non-recourse financing transactions consist of loans from banks and other lenders that are typically secured by project assets and cash flows and generally impose no material obligation on the parent-level investor to repay any debt incurred by the project borrower. The consequences of permitting a project-level default include the potential for loss of any invested equity by the parent.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2013 are as follows:

		PSE&G			Energy Holdings	
Year	Power	PSE&G	Transition Funding	Transition Funding II	Non-Recourse Debt	Total
			Millions			
2014	$ 44	$ 500	$ 225	$ 12	$ —	$ 781
2015	300	300	251	8	16	875
2016	553	171	—	—	—	724
2017	—	—	—	—	—	—
2018	250	750	—	—	—	1,000
Thereafter	1,406	3,858	—	—	—	5,264
Total	**$ 2,553**	**$ 5,579**	**$ 476**	**$ 20**	**$ 16**	**$ 8,644**

Long-Term Debt Financing Transactions

During 2013, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions:

Power

- issued $250 million of 4.30% Senior Notes, due November 2023,
- issued $250 million of 2.45% Senior Notes, due November 2018, and
- paid $300 million of 2.50% Senior Notes at maturity.

PSE&G

- paid $275 million of 6.33% Secured Medium-Term Notes at maturity,
- issued $350 million of 2.30% Secured Medium-Term Notes, Series I due September 2018,
- issued $250 million of 3.75% Secured Medium-Term Notes, Series I due March 2024,
- paid $300 million of 5.375% Secured Medium-Term Notes at maturity,
- issued $500 million of 2.375% Secured Medium-Term Notes, Series I due May 2023,
- paid $150 million of 5.00% Secured Medium-Term Notes at maturity,
- issued $400 million of 3.80% Secured Medium-Term Notes, Series H due January 2043,
- paid $214 million of Transition Funding's securitization debt, and
- paid $12 million of Transition Funding II's securitization debt.

Energy Holdings

- reclassified $9 million of non-recourse long-term debt associated with a commercial real estate property held for sale to Other Current Liabilities, and
- defeased approximately $19 million of non-recourse long-term debt in order to sell a commercial real estate property.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our credit facilities are provided by a diverse bank group. In March 2013, Power, PSEG and PSE&G amended their respective 5-year credit agreements, extending the expiration dates from April 2016 to March 2018. Of the total commitments of $2.1 billion under these agreements, $2.0 billion has been extended until 2018. The commitments for the $100 million balance will terminate in 2016. As of December 31, 2013, the total credit capacity was $4.3 billion.

As of December 31, 2013, no single institution represented more than 8% of the total commitments in our credit facilities.

As of December 31, 2013, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of December 31, 2013 were as follows:

	As of December 31, 2013				
Company/Facility	**Total Facility**	**Usage**	**Available Liquidity**	**Expiration Date**	**Primary Purpose**
		Millions			
PSEG					
5-year Credit Facility	$ 500	$ 8 (D)	$ 492	Mar 2017	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—	500	Mar 2018	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 8**	**$ 992**		
Power					
5-year Credit Facility	$ 1,600	$ 70 (D)	$ 1,530	Mar 2017	Funding/Letters of Credit
5-year Credit Facility (B)	1,000	—	1,000	Mar 2018	Funding/Letters of Credit
Bilateral Credit Facility	100	100 (D)	—	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 170**	**$ 2,530**		
PSE&G					
5-year Credit Facility (C)	$ 600	$ 73 (D)	$ 527	Mar 2018	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 73**	**$ 527**		
Total	**$ 4,300**	**$ 251**	**$ 4,049**		

(A) In April 2016, this facility will be reduced by $23 million.

(B) In April 2016, this facility will be reduced by $48 million.

(C) In April 2016, this facility will be reduced by $29 million.

(D) Includes amounts related to letters of credit outstanding.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of December 31, 2013 and 2012. See Note 17. Fair Value Measurements for more information on fair value guidance and the hierarchy that prioritizes the inputs to fair value measurements into three levels.

	December 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 24	$ 38	$ 38	$ 57
Power - Recourse Debt (B)	2,541	2,846	2,340	2,818
PSE&G (B)	5,566	5,629	4,795	5,606
Transition Funding (PSE&G) (B)	476	511	690	765
Transition Funding II (PSE&G) (B)	20	21	32	34
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	16	16	44	44
	$ 8,643	**$ 9,061**	**$ 7,939**	**$ 9,324**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

Note 15. Schedule of Consolidated Capital Stock

	As of December 31,			
	Outstanding Shares		Book Value	
	2013	2012	2013	2012
			Millions	
PSEG Common Stock (no par value) (A)				
Authorized 1,000,000,000 shares	505,857,262	505,892,472	$ 4,246	$ 4,226

(A) PSEG did not issue any new shares under the Dividend Reinvestment and Stock Purchase Plan (DRASPP) or the Employee Stock Purchase Plan (ESPP) in 2013 or 2012. Total authorized and unissued shares of common stock available for issuance through PSEG's DRASPP, ESPP and various employee benefit plans amounted to approximately 7 million shares as of December 31, 2013.

As of December 31, 2013, there was an aggregate of 7.5 million shares of $100 par value and 10 million shares of $25 par value Cumulative Preferred Stock, which were authorized and unissued and which, upon issuance, may or may not provide for mandatory sinking fund redemption.

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Note 16. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Commodity Prices

The availability and price of energy commodities are subject to fluctuations due to weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions, transmission availability and other events. Power uses physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. Derivative contracts that do not qualify for hedge accounting or normal purchases/normal sales treatment are MTM with changes in fair value recorded in the Consolidated Statements of Operations. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps and futures contracts to hedge

- forecasted energy sales from its generation stations and the related load obligations,
- the price of fuel to meet its fuel purchase requirements, and
- certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

These derivative transactions are designated and effective as cash flow hedges. During the second quarter of 2012, Power de-designated certain of its commodity derivative transactions that had previously qualified as cash flow hedges as they were deemed to no longer be highly effective as required by the relevant accounting guidance. As a result, since June 1, 2012, Power recognizes all gains and losses from changes in the fair value of these derivatives immediately in earnings rather than deferring any such amounts in Accumulated Other Comprehensive Income (Loss). The fair values of Power's de-designated hedges were frozen in Accumulated Other Comprehensive Income (Loss) as the original forecasted transactions are still expected to occur and are reclassified into earnings as the original derivative transactions settle.

As of December 31, 2013 and 2012, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity was as follows:

	As of December 31,	
	2013	2012
	Millions	
Fair Value of Cash Flow Hedges	$ (4)	$ 3
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ (1)	$ 9

The expiration date of the longest-dated cash flow hedge at Power is in 2014. Power's after-tax unrealized losses on these derivatives that are expected to be reclassified to earnings during the next 12 months are $ 1 million. There was no ineffectiveness associated with qualifying hedges as of December 31, 2013.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Trading Derivatives

The primary purpose of Power's wholesale marketing operation is to optimize the value of the output of the generating facilities via various products and services available in the markets it serves. Historically, Power engaged in trading of electricity and energy-related products where such transactions were not associated with the output or fuel purchase requirements of its facilities. This trading consisted mostly of energy supply contracts where Power secured sales commitments with the intent to supply the energy services from purchases in the market rather than from its owned generation. Such trading activities were marked to market through the Consolidated Statement of Operations and represented less than one percent of gross margin (revenues less energy costs) on an annual basis. Power has not entered into any trading derivative contracts since June 2011 and anticipates that it will not do so in the future.

Other Derivatives

Power enters into additional contracts that are derivatives, but do not qualify for or are not designated as cash flow hedges. These transactions are intended to mitigate exposure to fluctuations in commodity prices and optimize the value of its expected generation. Trade types include financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. Changes in fair market value of these contracts are recorded in earnings. PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of December 31, 2013, PSEG had seven interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of December 31, 2013 and 2012, the fair value of all the underlying hedges was $38 million and $57 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was $(1) million and $(2) million as of December 31, 2013 and 2012, respectively.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. See Note 2. Recent Accounting Standards. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset on the Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31, 2013						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ —	$ 323	$ (266)	$ 57	$ 25	$ 16	$ 98
Noncurrent Assets	—	155	(83)	72	69	22	163
Total Mark-to-Market Derivative Assets	**$ —**	**$ 478**	**$ (349)**	**$ 129**	**$ 94**	**$ 38**	**$ 261**
Derivative Contracts							
Current Liabilities	$ (4)	$ (343)	$ 271	$ (76)	$ —	$ —	$ (76)
Noncurrent Liabilities	—	(111)	80	(31)	—	—	(31)
Total Mark-to-Market Derivative (Liabilities)	**$ (4)**	**$ (454)**	**$ 351**	**$ (107)**	**$ —**	**$ —**	**$ (107)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ (4)**	**$ 24**	**$ 2**	**$ 22**	**$ 94**	**$ 38**	**$ 154**

	As of December 31, 2012						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 3	$ 332	$ (217)	$ 118	$ 5	$ 15	$ 138
Noncurrent Assets	—	75	(26)	49	62	42	153
Total Mark-to-Market Derivative Assets	**$ 3**	**$ 407**	**$ (243)**	**$ 167**	**$ 67**	**$ 57**	**$ 291**
Derivative Contracts							
Current Liabilities	$ —	$ (265)	$ 219	$ (46)	$ —	$ —	$ (46)
Noncurrent Liabilities	—	(41)	26	(15)	(107)	—	(122)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (306)**	**$ 245**	**$ (61)**	**$ (107)**	**$ —**	**$ (168)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 3**	**$ 101**	**$ 2**	**$ 106**	**$ (40)**	**$ 57**	**$ 123**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of December 31, 2013 and 2012. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Consolidated Balance Sheet. As of December 31, 2013 and 2012, net cash collateral paid of $2 million was netted against the corresponding net derivative contract positions. Of the $2

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million as of December 31, 2013, $(3) million and $5 million were netted against noncurrent assets and current liabilities, respectively. Of the $2 million as of December 31, 2012, cash collateral of $(3) million and $5 million were netted against current assets and current liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded or lose its investment grade credit rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $91 million and $98 million as of December 31, 2013 and 2012, respectively. As of December 31, 2013 and 2012, Power had the contractual right of offset of $39 million and $61 million, respectively, related to derivative instruments that are assets with the same counterparty under master agreements and net of margin posted. If Power had been downgraded or lost its investment grade rating, it would have had additional collateral obligations of $52 million and $37 million as of December 31, 2013 and 2012, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $691 million and $654 million as of December 31, 2013 and 2012, respectively, discussed in Note 13. Commitments and Contingent Liabilities.

The following shows the effect on the Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the years ended December 31, 2013, 2012 and 2011:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Years Ended December 31,			Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Years Ended December 31,			Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Years Ended December 31,		
	2013	2012	2011		2013	2012	2011	2013	2012	2011
	Millions				Millions					
PSEG										
Energy-Related Contracts	$ (4)	$ 32	$ 84	Operating Revenues	$ 13	$ 79	$ 213	$ (1)	$ 1	$ (2)
Energy-Related Contracts	—	(4)	(4)	Energy Costs	—	(9)	2	—	—	—
Interest Rate Swaps (A)	—	—	—	Interest Expense	(1)	—	(1)	—	—	—
Total PSEG	**$ (4)**	**$ 28**	**$ 80**		**$ 12**	**$ 70**	**$ 214**	**$ (1)**	**$ 1**	**$ (2)**
Power										
Energy-Related Contracts	$ (4)	$ 32	$ 84	Operating Revenues	$ 13	$ 79	$ 213	$ (1)	$ 1	$ (2)
Energy-Related Contracts	—	(4)	(4)	Energy Costs	—	(9)	2	—	—	—
Total Power	**$ (4)**	**$ 28**	**$ 80**		**$ 13**	**$ 70**	**$ 215**	**$ (1)**	**$ 1**	**$ (2)**

(A) Includes amounts for PSEG parent.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following reconciles the AOCI for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis:

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2011	**$ 54**	**$ 31**
Gain Recognized in AOCI	28	17
Less: Gain Reclassified into Income	(70)	(41)
Balance as of December 31, 2012	**$ 12**	**$ 7**
Loss Recognized in AOCI	(4)	(2)
Less: Gain Reclassified into Income	(12)	(7)
Balance as of December 31, 2013	**$ (4)**	**$ (2)**

The following shows the effect on the Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the years ended December 31, 2013, 2012 and 2011:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2013	2012	2011
		Millions		
PSEG and Power				
Energy-Related Contracts	Operating Revenues	$ (128)	$ 232	$ 205
Energy-Related Contracts	Energy Costs	106	(19)	(42)
Total PSEG and Power		**$ (22)**	**$ 213**	**$ 163**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $19 million, $22 million and $25 million for the years ended December 31, 2013, 2012 and 2011, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following reflects the gross volume, on an absolute value basis, of derivatives as of December 31, 2013 and 2012:

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of December 31, 2013					
Natural Gas	Dth	614	—	466	148
Electricity	MWh	243	—	243	—
FTRs	MWh	16	—	16	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2012					
Natural Gas	Dth	596	—	404	192
Electricity	MWh	208	—	208	—
Capacity	MW days	4	—	—	4
FTRs	MWh	19	—	19	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
Coal	Tons	1	—	1	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of December 31, 2013, 97% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of December 31, 2013. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 331	$ 14	$ 331	1	$ 251	(A)
Non-Investment Grade—External Rating	1	—	1	—	—	
Investment Grade—No External Rating	6	—	6	—	—	
Non-Investment Grade—No External Rating	7	—	7	—	—	
Total	**$ 345**	**$ 14**	**$ 345**	**1**	**$ 251**	

(A) Represents net exposure with PSE&G.

The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of December 31, 2013, Power had 154 active counterparties.

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Note 17. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of December 31, 2013, these consisted primarily of electric swaps whose basis is deemed significant to the fair value measurement, electric load deals and long-term gas supply contracts.

The following tables present information about PSEG's, Power's and PSE&G's respective assets and (liabilities) measured at fair value on a recurring basis as of December 31, 2013 and December 31, 2012, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Description	Recurring Fair Value Measurements as of December 31, 2013				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 439	$ —	$ 439	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 223	$ (349)	$ —	$ 474	$ 98
Interest Rate Swaps (C)	$ 38	$ —	$ —	$ 38	$ —
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 892	$ 5	$ —
Debt Securities—Govt Obligations	$ 429	$ —	$ —	$ 429	$ —
Debt Securities—Other	$ 291	$ —	$ —	$ 291	$ —
Other Securities	$ 84	$ —	$ 57	$ 27	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—Govt Obligations	$ 107	$ —	$ —	$ 107	$ —
Debt Securities—Other	$ 46	$ —	$ —	$ 46	$ —
Other Securities	$ 3	$ —	$ —	$ 3	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (107)	$ 351	$ —	$ (448)	$ (10)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 129	$ (349)	$ —	$ 474	$ 4
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 892	$ 5	$ —
Debt Securities—Govt Obligations	$ 429	$ —	$ —	$ 429	$ —
Debt Securities—Other	$ 291	$ —	$ —	$ 291	$ —
Other Securities	$ 84	$ —	$ 57	$ 27	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 10	$ —	$ —	$ 10	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (107)	$ 351	$ —	$ (448)	$ (10)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (B)	$ 94	$ —	$ —	$ —	$ 94
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 25	$ —	$ —	$ 25	$ —
Debt Securities—Other	$ 11	$ —	$ —	$ 11	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Description	Recurring Fair Value Measurements as of December 31, 2012				
	Total	Netting (F)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 287	$ —	$ 287	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 234	$ (3)	$ —	$ 157	$ 80
Interest Rate Swaps (C)	$ 57	$ —	$ —	$ 57	$ —
NDT Fund (D)					
Equity Securities	$ 789	$ —	$ 789	$ —	$ —
Debt Securities—Govt Obligations	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Other	$ 342	$ —	$ —	$ 342	$ —
Other Securities	$ 124	$ —	$ —	$ 124	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 18	$ —	$ 18	$ —	$ —
Debt Securities—Govt Obligations	$ 117	$ —	$ —	$ 117	$ —
Debt Securities—Other	$ 47	$ —	$ —	$ 47	$ —
Other Securities	$ 3	$ —	$ —	$ 3	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (168)	$ 5	$ —	$ (62)	$ (111)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 167	$ (3)	$ —	$ 157	$ 13
NDT Fund (D)					
Equity Securities	$ 789	$ —	$ 789	$ —	$ —
Debt Securities—Govt Obligations	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Other	$ 342	$ —	$ —	$ 342	$ —
Other Securities	$ 124	$ —	$ —	$ 124	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 3	$ —	$ 3	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 9	$ —	$ —	$ 9	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (61)	$ 5	$ —	$ (62)	$ (4)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 65	$ —	$ 65	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ 67	$ —	$ —	$ —	$ 67
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—Govt Obligations	$ 39	$ —	$ —	$ 39	$ —
Debt Securities—Other	$ 15	$ —	$ —	$ 15	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy Related Contracts (B)	$ (107)	$ —	$ —	$ —	$ (107)

(A) Represents money market mutual funds

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds and United States Treasury obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Consolidated Balance Sheet. As of December 31, 2013, net cash collateral (received) paid of $2 million, was netted against the corresponding net derivative contract positions. Of the $2 million as of December 31, 2013, $(3) million of cash collateral was netted against assets, and $5 million was netted against liabilities.

(F) Cash collateral netting represents collateral amounts netted against derivative assets and liabilities as permitted under the accounting guidance for Offsetting of Amounts Related to Certain Contracts.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group, and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For Power, in general, electric swaps are measured at fair value based on at least two pricing inputs, the underlying price of electricity at a liquid reference point and the basis difference between electricity prices at the liquid reference point and electricity prices at the respective delivery locations. To the extent the basis component is based on a single broker quote and is significant to the fair value of the electric swap, it is categorized as Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. For Power and PSE&G, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. For PSE&G, long-term electric capacity contracts are measured at fair value using both observable capacity auction prices and unobservable future long-term capacity prices as of December 31, 2012. The measurement of these contracts includes adjustments for contingencies, such as the potential outcome of litigation specifically related to the contract and the risk related to the construction of the specified capacity facilities. Accordingly, the fair value measurements are classified as Level 3. There is no liability associated with these contracts as of December 31, 2013 as these contracts were terminated. For additional information see Note 13. Commitments and Contingent Liabilities. The following table provides detail surrounding significant Level 3 valuations as of December 31, 2013 and 2012.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2013 Assets	Fair Value as of December 31, 2013 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ 3	$ (1)	Discounted Cash Flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	—	(8)	Discounted cash flow	Historic Load Variability	-5% to +10%
Other	Various (A)	1	(1)			
Total Power		**$ 4**	**$ (10)**			
PSE&G						
Gas	Forward Contracts	$ 94	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 94**	**$ —**			
Total PSEG		**$ 98**	**$ (10)**			

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2012 Assets	Fair Value as of December 31, 2012 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ 7	$ (1)	Discounted Cash Flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	1	(2)	Discounted Cash Flow	Historic Load Variability	-5% to +10%
Other	Various (A)	5	(1)			
Total Power		**$ 13**	**$ (4)**			
PSE&G						
Gas and Capacity	Forward Contracts (B)	$ 67	$ (107)	Discounted Cash Flow	Long-Term Gas Basis and Capacity Prices	(B)
Total PSE&G		**$ 67**	**$ (107)**			
Total PSEG		**$ 80**	**$ (111)**			

(A) Includes gas supply positions which are immaterial as of December 31, 2013 and 2012. Also includes long-term electric capacity positions which are immaterial as of December 31, 2012.

(B) Includes long-term electric capacity and long-term gas supply positions with various unobservable inputs. Unobservable inputs for the long-term electric capacity contracts include forecasted capacity prices in the range of $100 to $400/MW day. Significant unobservable inputs for the gas supply contracts include long-term basis prices in the range of $0 to $4/MMBTU of natural gas.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value. For long-term electric capacity contracts where PSE&G is a buyer, an increase in the capacity price would increase the fair value. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the years ended December 31, 2013 and 2012, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2013

Description	Balance as of January 1, 2013	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances (Settlements) (C)	Transfers In (Out) (D)	Balance as of December 31, 2013
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (31)	$ (27)	$ 134	$ —	$ 8	$ 4	$ 88
Power							
Net Derivative Assets (Liabilities)	$ 9	$ (27)	$ —	$ —	$ 8	$ 4	$ (6)
PSE&G							
Net Derivative Assets (Liabilities)	$ (40)	$ —	$ 134	$ —	$ —	$ —	$ 94

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2012

Description	Balance as of January 1, 2012	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances (Settlements) (C)	Transfers In (Out) (D)	Balance as of December 31, 2012
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 21	$ 42	$ (37)	$ —	$ (57)	$ —	$ (31)
Non-Recourse Debt	$ (50)	$ 50	$ —	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 24	$ 42	$ —	$ —	$ (57)	$ —	$ 9
PSE&G							
Net Derivative Assets (Liabilities)	$ (3)	$ —	$ (37)	$ —	$ —	$ —	$ (40)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $(27) million and $42 million in Operating Income in 2013 and 2012, respectively. Of the $(27) million in Operating Income in 2013, $(19) million is unrealized. Of the $42 million in Operating Income in 2012, $(15) million is unrealized. Energy Holdings' release from its obligations under the non-recourse debt is included in PSEG's Operating Income and is offset by the write-off of the related assets.

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(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or OCI, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers. As discussed in Note 13. Commitments and Contingent Liabilities, PSE&G's long-term electric capacity positions represented by the SOCA contracts have been terminated and the related derivative asset or liability and regulatory asset and liability reversed in the fourth quarter of 2013.

(C) Represents $8 million and $(57) million in settlements for derivative contracts in 2013 and 2012, respectively.

(D) During the year ended December 31, 2013, $4 million of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. The transfers were recognized as of the beginning of the quarters (i.e. the quarter in which the transfers occurred), as per PSEG's policy. During the year ended December 31, 2012, there were no transfers among levels.

As of December 31, 2013, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $88 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of December 31, 2012, PSEG carried $2.1 billion of net assets that are measured at fair value on a recurring basis, of which $31 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Note 18. Stock Based Compensation

PSEG's Amended and Restated 2004 Long-Term Incentive Plan (LTIP) is a broad-based equity compensation program that provides for grants of various long-term incentive compensation awards, such as stock options, stock appreciation rights, performance units, restricted stock, restricted stock units, cash awards or any combination thereof. The types of long-term incentive awards that have been granted and remain outstanding under the LTIP are non-qualified options to purchase shares of PSEG's common stock, restricted stock awards, restricted stock unit awards and performance unit awards. The type of equity award that is granted and the details of that award may vary from time to time and is subject to the approval of the Organization and Compensation Committee of PSEG's Board of Directors (OCC), the plan's administrative committee.

The LTIP currently provides for the issuance of equity awards with respect to approximately 26 million shares of common stock. As of December 31, 2013, there were approximately 17 million shares available for future awards under the LTIP.

Stock Options

Under the LTIP, non-qualified options to acquire shares of PSEG common stock may be granted to officers and other key employees selected by the OCC. Option awards are granted with an exercise price equal to the market price of PSEG's common stock at the grant date. The options generally vest over four years of continuous service. Vesting schedules may be accelerated upon the occurrence of certain events, such as a change-in-control (unless substituted with an equity award of equal value), retirement, death or disability. Options are exercisable over a period of time designated by the OCC (but not prior to one year or longer than ten years from the date of grant) and are subject to such other terms and conditions as the OCC determines. Payment by option holders upon exercise of an option may be made in cash or, with the consent of the OCC, by delivering previously acquired shares of PSEG common stock.

Restricted Stock

Under the LTIP, PSEG has granted restricted stock awards to officers and other key employees. These shares are subject to risk of forfeiture until vested by continued employment. Restricted stock generally vests annually over three or four years, but is considered outstanding at the time of grant, as the recipients are entitled to dividends and voting rights. Vesting may be accelerated upon certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

Restricted Stock Units

Under the LTIP, PSEG has granted restricted stock unit awards to officers and other key employees. These awards, which are bookkeeping entries only, are subject to risk of forfeiture until vested by continued employment. Until vested, the units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. The restricted stock unit grants for 2013 and 2012 generally vest at the end of three years. Vesting may be accelerated upon certain events such as change-in-control or death. Prior to 2011, restricted stock unit grants generally vested over four years.

Performance Share Units

Under the LTIP, PSEG has granted performance share units to officers and other key employees. These provide for payment in shares of PSEG common stock based on achievement of certain financial goals over a three-year performance period. The payout varies from 0% to 200% of the number of performance units granted depending on PSEG's performance with respect to certain financial targets, including targets related to comparative performance against other companies in a peer group of energy

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companies. The performance share units are credited with dividend equivalents in an amount equal to dividends paid on PSEG common stock up until the shares are distributed. Vesting may be pro-rated for the employee's service during the performance period as a result of certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

Stock-Based Compensation

All outstanding unvested stock options are being expensed based on their grant date fair values, which were determined using the Black-Scholes option-pricing model. Stock option awards are expensed on a tranche-specific basis over the requisite service period of the award. Ultimately, compensation expense for stock options is recognized for awards that vest.

PSEG recognizes compensation expense for restricted stock and restricted stock units over the vesting period based on the grant date fair market value of the shares, which is equal to the market price of PSEG's common stock on the date of the grant.
PSEG recognizes compensation expense for performance share units based on the grant date fair values of the award, which were determined using the Monte Carlo model. The accrual of compensation cost was based on the probable achievement of the performance conditions, which result in a payout from 0% to 200% of the initial grant. The accrual during the year of grant is estimated at 100% of the original grant. The accrual may be adjusted for subsequent changes in the estimated or actual outcome.

	2013	2012	2011
		Millions	
Compensation Cost included in Operation and Maintenance Expense	$ 32	$ 25	$ 23
Income Tax Benefit Recognized in Consolidated Statement of Operations	$ 13	$ 10	$ 10

There was no excess tax benefit for 2013. There was less than $1 million of excess tax benefits for 2012. There was $1 million of excess tax benefits included as financing cash flows on the Consolidated Statements of Cash Flow for the year ended December 31, 2011.

PSEG recognizes compensation cost of awards issued over the shorter of the original vesting period or the period beginning on the date of grant and ending on the date an individual is eligible for retirement and the award vests.

Stock Options

Changes in stock options for 2013 are summarized as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding as of January 1, 2013	2,945,400	$ 34.19		
Exercised	229,700	$ 28.30		
Canceled/Forfeited	100,534	$ 41.44		
Outstanding as of December 31, 2013	**2,615,166**	**$ 34.43**	**4.7**	**$ 2,311,503**
Exercisable at December 31, 2013	2,615,166	$ 34.43	4.7	$ 2,311,503

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. There were no option grants in 2013, 2012 and 2011.

Activity for options exercised for the years ended December 31, 2013, 2012 and 2011 is shown below:

	2013	2012	2011
		Millions	
Total Intrinsic Value of Options Exercised	$ 1	$ 4	$ 2
Cash Received from Options Exercised	$ 7	$ 7	$ 6
Tax Benefit Realized from Options Exercised	$ —	$ 1	$ 1

Less than one million options vested during each of the years ended December 31, 2013, 2012 and 2011. The total fair value of the stock options vested during the years ended December 31, 2013, 2012 and 2011 was $1 million, $3 million and $5 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Restricted Stock

Changes in restricted stock for the year ended December 31, 2013 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2013	68,800	$ 32.57		
Vested	60,000	$ 32.93		
Non-vested as of December 31, 2013	**8,800**	**$ 30.18**	**0.3**	**$ 281,952**

There were no restricted stock awards granted in 2013, 2012 and 2011.

The total intrinsic value of restricted stock vested during the years ended December 31, 2013, 2012 and 2011 was $2 million, $1 million and $1 million, respectively.

Restricted Stock Units

Changes in restricted stock units for the year ended December 31, 2013 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2013	834,527	$ 31.12		
Granted	325,035	$ 31.41		
Vested	109,691	$ 30.25		
Canceled/Forfeited	2,302	$ 31.49		
Non-vested as of December 31, 2013	**1,047,569**	**$ 31.30**	**1.1**	**$ 33,564,117**

The weighted average grant date fair value per share for restricted stock during the years ended December 31, 2013, 2012 and 2011 was $31.41, $30.95 and $32.03 per share, respectively.

The total intrinsic value of restricted stock units vested during the years ended December 31, 2013, 2012 and 2011 was $4 million, $5 million and $7 million, respectively.

As of December 31, 2013, there was approximately $7 million of unrecognized compensation cost related to the restricted stock units, which is expected to be recognized over a weighted average period of 1.0 year. Dividend equivalents units of 48,861 accrued on the restricted stock units during the year.

Performance Share Units

Changes in Performance Share Units for the year ended December 31, 2013 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2013	749,993	$ 32.70		
Granted	420,385	$ 35.07		
Vested	270,140	$ 34.26		
Canceled/Forfeited	98,120	$ 34.10		
Non-vested as of December 31, 2013	**802,118**	**$ 33.25**	**1.5**	**$ 25,699,861**

The weighted average grant date fair value per share for performance share units during the years ended December 31, 2013, 2012 and 2011 was $35.07, $31.25 and $35.33 per share, respectively.

The total intrinsic value of performance share units vested during the year ended December 31, 2013, 2012 and 2011 was $5 million, $4 million and $9 million, respectively.

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As of December 31, 2013, there was approximately $13 million of unrecognized compensation cost related to the performance share units, which is expected to be recognized over a weighted average period of 1.0 year. Dividend equivalents units of 54,124 accrued on the performance share units during the year.

Outside Directors

Under the Directors Equity Plan, annually, on the first business day of May, each non-employee member of the Board of Directors is awarded stock units based on amount of annual compensation to be paid at the closing price of PSEG common stock on that date. Dividend equivalents are credited quarterly and distributions will commence upon the director leaving the Board as specified by him/her in accordance with the provisions of the plan.

The fair value of these awards is recorded as compensation expense in the Consolidated Statements of Operations. Compensation expense for the plan for each of the years ended December 31, 2013, 2012 and 2011 was approximately $1 million.

Employee Stock Purchase Plan (ESPP)

PSEG maintains an ESPP for all eligible employees of PSEG and its subsidiaries. Under the ESPP, shares of PSEG common stock may be purchased at 95% of the fair market value for Represented Employees and 90% for Non-Represented Employees through payroll deductions. Dividends will be reinvested for all employees at 95% of the fair market price unless the participant elects to receive a cash dividend. All employees are required to hold the shares purchased under the ESPP for at least three months from the purchase date. In any year, employees may purchase shares having a value not exceeding 10% of their base pay.

During the years ended December 31, 2013, 2012 and 2011, employees purchased 257,513 shares, 191,572 shares and 183,338 shares at an average price of $30.57, $31.32 and $30.69 per share, respectively. As of December 31, 2013, 3.6 million shares were available for future issuance under this plan.

Note 19. Other Income and Deductions

Other Income	Power	PSE&G	Other (A)	Consolidated Total
		Millions		
Year Ended December 31, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ 152	$ —	$ —	$ 152
Allowance of Funds Used During Construction	—	24	—	24
Solar Loan Interest	—	23	—	23
Other	2	7	5	14
Total Other Income	**$ 154**	**$ 54**	**$ 5**	**$ 213**
Year Ended December 31, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$ 194	$ —	$ —	$ 194
Allowance of Funds Used During Construction	—	23	—	23
Solar Loan Interest	—	18	—	18
Other	7	11	7	25
Total Other Income	**$ 201**	**$ 52**	**$ 7**	**$ 260**
Year Ended December 31, 2011				
NDT Fund Gains, Interest, Dividend and Other Income	$ 186	$ —	$ —	$ 186
Allowance of Funds Used During Construction	—	9	—	9
Solar Loan Interest	—	10	—	10
Other	4	6	5	15
Total Other Income	**$ 190**	**$ 25**	**$ 5**	**$ 220**

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Other Deductions	Power	PSE&G	Other (A)	Consolidated Total
			Millions	
Year Ended December 31, 2013				
NDT Fund Realized Losses and Expense	$ 34	$ —	$ —	$ 34
Other	15	3	2	20
Total Other Deductions	**$ 49**	**$ 3**	**$ 2**	**$ 54**
Year Ended December 31, 2012				
NDT Fund Realized Losses and Expense	$ 58	$ —	$ —	$ 58
Loss on Early Extinguishment of Debt	15	—	—	15
Other	17	5	3	25
Total Other Deductions	**$ 90**	**$ 5**	**$ 3**	**$ 98**
Year Ended December 31, 2011				
NDT Fund Realized Losses and Expense	$ 50	$ —	$ —	$ 50
Loss on Early Extinguishment of Debt	17	—	—	17
Other	12	4	2	18
Total Other Deductions	**$ 79**	**$ 4**	**$ 2**	**$ 85**

(A) Other primarily consists of activity at PSEG (parent company), Energy Holdings, Services and intercompany eliminations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 20. Income Taxes

A reconciliation of reported income tax expense for PSEG with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSEG	Years Ended December 31, 2013	2012	2011
		Millions	
Net Income	$ 1,243	$ 1,275	$ 1,503
Income (Loss) from Discontinued Operations, net of tax	—	—	96
Income from Continuing Operations	$ 1,243	$ 1,275	$ 1,407
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 487	$ (204)	$ 258
State	42	(2)	32
Total Current	529	(206)	290
Deferred Expense:			
Federal	147	758	501
State	118	125	191
Total Deferred	265	883	692
Investment Tax Credit	18	59	(5)
Total Income Taxes	**$ 812**	**$ 736**	**$ 977**
Pre-Tax Income	$ 2,055	$ 2,011	$ 2,384
Tax Computed at Statutory Rate @ 35%	$ 719	$ 704	$ 834
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	108	115	146
Uncertain Tax Positions	10	4	19
Manufacturing Deduction	(9)	—	(15)
Nuclear Decommissioning Trust	12	10	14
Plant-Related Items	(14)	(5)	(6)
Tax Credits	(9)	(10)	(5)
Audit Settlement	—	(71)	—
Other	(5)	(11)	(10)
Sub-Total	93	32	143
Total Income Tax Provision	**$ 812**	**$ 736**	**$ 977**
Effective Income Tax Rate	39.5%	36.6%	41.0%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for PSEG:

PSEG	As of December 31, 2013	2012
	Millions	
Deferred Income Taxes		
Assets:		
Current (net)	$ 24	$ 49
Noncurrent		
OPEB	$ 280	$ 200
Related to Uncertain Tax Position	201	75
Accumulated Other Comprehensive Income (Loss)	3	40
Other	124	262
Total Noncurrent Assets	$ 608	$ 577
Total Assets	$ 632	$ 626
Liabilities:		
Current (net)	$ —	$ 72
Noncurrent:		
Plant-Related Items	$ 4,865	$ 4,685
Nuclear Decommissioning	282	209
New Jersey Corporate Business Tax	534	343
Securitization	279	371
Leasing Activities	639	656
Pension Costs	288	180
AROs	241	297
Taxes Recoverable Through Future Rate (net)	181	165
Other	293	$ 118
Total Noncurrent Liabilities	$ 7,602	$ 7,024
Total Liabilities	$ 7,602	$ 7,096
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	**$ 24**	**$ 49**
Net Current Deferred Income Tax Liability	**$ —**	**$ 72**
Net Noncurrent Deferred Income Tax Liabilities	$ 6,994	$ 6,447
Investment Tax Credit (ITC)	113	95
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 7,107**	**$ 6,542**

The deferred tax effect of certain assets and liabilities are presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for Power with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

Power	Years Ended December 31, 2013	2012	2011
		Millions	
Net Income	$ 644	$ 666	$ 1,109
Income (Loss) from Discontinued Operations, net of tax	—	—	96
Income from Continuing Operations	$ 644	$ 666	$ 1,013
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 262	$ 30	$ 400
State	40	51	39
Total Current	302	81	439
Deferred Expense:			
Federal	69	279	156
State	35	37	95
Total Deferred	104	316	251
Investment Tax Credit	13	36	—
Total Income Taxes	**$ 419**	**$ 433**	**$ 690**
Pre-Tax Income	$ 1,063	$ 1,099	$ 1,703
Tax Computed at Statutory Rate @ 35%	$ 372	$ 385	$ 596
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	51	55	90
Manufacturing Deduction	(10)	—	(15)
Nuclear Decommissioning Trust	12	10	14
Tax Credits	(2)	(7)	(1)
Uncertain Tax Positions	3	(6)	11
Audit Settlement	—	(1)	—
Other	(7)	(3)	(5)
Sub-Total	47	48	94
Total Income Tax Provision	**$ 419**	**$ 433**	**$ 690**
Effective Income Tax Rate	39.4%	39.4%	40.5%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for Power:

Power	As of December 31, 2013	2012
	Millions	
Deferred Income Taxes		
Assets:		
Current	$ 30	$ —
Noncurrent:		
Pension Costs	$ —	$ 38
Accumulated Other Comprehensive Income (Loss)	—	40
Contractual Liabilities & Environmental Costs	35	35
Related to Uncertain Tax Positions	32	27
Other	91	61
Total Noncurrent Assets	$ 158	$ 201
Total Assets	$ 188	$ 201
Liabilities:		
Current (net)	$ —	$ 16
Noncurrent:		
Plant-Related Items	$ 1,416	$ 1,291
New Jersey Corporate Business Tax	81	32
Nuclear Decommissioning	282	209
Pension Costs	77	—
AROs	241	297
Accumulated Other Comprehensive Income (Loss)	2	—
Other	36	—
Total Noncurrent Liabilities	2,135	$ 1,829
Total Liabilities	$ 2,135	$ 1,845
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	**$ 30**	**$ —**
Net Current Deferred Income Tax Liabilities	**$ —**	**$ 16**
Net Noncurrent Deferred Income Tax Liabilities	$ 1,977	$ 1,628
Investment Tax Credit (ITC)	54	41
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 2,031**	**$ 1,669**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for PSE&G with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSE&G	Years Ended December 31, 2013	2012	2011
		Millions	
Net Income	$ 612	$ 528	$ 521
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 183	$ (217)	$ (225)
State	—	9	(6)
Total Current	183	(208)	(231)
Deferred Expense:			
Federal	101	409	483
State	92	83	92
Total Deferred	193	492	575
Investment Tax Credit	5	23	(4)
Total Income Taxes	**$ 381**	**$ 307**	**$ 340**
Pre-Tax Income	$ 993	$ 835	$ 861
Tax Computed at Statutory Rate @ 35%	$ 348	$ 292	$ 301
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	59	52	56
Uncertain Tax Positions	—	7	(1)
Plant-Related Items	(14)	(4)	(6)
Tax Credits	(6)	(3)	(4)
Audit Settlement	—	(31)	—
Other	(6)	(6)	(6)
Sub-Total	33	15	39
Total Income Tax Provision	**$ 381**	**$ 307**	**$ 340**
Effective Income Tax Rate	38.4%	36.8%	39.5%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for PSE&G:

PSE&G	As of December 31, 2013	2012
	Millions	
Deferred Income Taxes		
Assets:		
Current (net)	$ 16	$ 49
Noncurrent:		
OPEB	$ 182	$ 189
Other	—	93
Total Noncurrent Assets	$ 182	$ 282
Total Assets	$ 198	$ 331
Liabilities:		
Current (net)	$ 30	$ 60
Noncurrent:		
Plant-Related Items	$ 3,439	$ 3,374
New Jersey Corporate Business Tax	340	253
Securitization	279	371
Conservation Costs	52	101
Pension Costs	171	189
Taxes Recoverable Through Future Rate (net)	181	165
Other	68	—
Total Noncurrent Liabilities	$ 4,530	$ 4,453
Total Liabilities	$ 4,560	$ 4,513
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	**$ 16**	**$ 49**
Net Current Deferred Income Tax Liability	**$ 30**	**$ 60**
Net Noncurrent Deferred Income Tax Liability	$ 4,348	$ 4,171
Investment Tax Credit (ITC)	58	52
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 4,406**	**$ 4,223**

The deferred tax effect of certain assets and liabilities are presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals.

As of December 31, 2013, PSEG had a federal net operating loss (NOL) of $243 million and PSE&G had a New Jersey State NOL carryforward of $731 million. The federal loss will expire in 2033, while the New Jersey loss will expire between 2031 and 2033. PSEG and PSE&G believe that it is more-likely-than-not that the federal and the state benefits from the NOL will be realized.

Each of PSEG, Power and PSE&G provide deferred taxes at the enacted statutory tax rate for all temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities irrespective of the treatment for rate-making purposes. Management believes that it is probable that the accumulated tax benefits that previously have been treated as a flow-through item to PSE&G customers will be recovered from or refunded to PSE&G's customers in the future. These amounts were determined using the enacted federal income tax rate of 35% and state income tax rate of 9%. For additional information, see Note 6. Regulatory Assets and Liabilities.

In September 2013, the U.S. Department of the Treasury and the IRS released final regulations that provide guidance on applying Section 263(a) of the Internal Revenue Code to amounts paid to acquire, produce, or improve tangible property, as well as rules for materials and supplies. These regulations become effective in 2014 and their implementation is not expected to have a material impact on PSEG's and its subsidiaries' results of operations, financial condition or cash flows.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 was eligible for 50% bonus depreciation for tax purposes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On January 2, 2013, the President signed into law the American Taxpayer Relief Act of 2012 that further extended the 50% bonus depreciation for qualified property placed into service before January 1, 2014. These provisions have generated cash for PSEG through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period.

With respect to ITC, for financial statement periods including 2010 and 2011, the law provided an option to claim either a grant or the ITC. Accordingly, in those periods, the ITC was accounted for as a reduction of the book basis of the related assets as opposed to being recorded in tax expense. In 2012 the law changed and the grant option is no longer available; as such, the accumulated deferred ITC generated in 2012 and thereafter has been recorded as a noncurrent deferred tax liability, which was included in Deferred Income Taxes and ITC on PSEG's and PSE&G's Consolidated Balance Sheets as of December 31, 2013.

PSEG recorded the following amounts related to its unrecognized tax benefits, which was primarily comprised of amounts recorded for Power, PSE&G and Energy Holdings:

2013	PSEG	Power	PSE&G	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2013	$ 402	$ 134	$ 163	$ 101
Increases as a Result of Positions Taken in a Prior Period	83	33	39	11
Decreases as a Result of Positions Taken in a Prior Period	(30)	(19)	(9)	(2)
Increases as a Result of Positions Taken during the Current Period	23	8	15	—
Decreases as a Result of Positions Taken during the Current Period	—	—	—	—
Decreases as a Result of Settlements with Taxing Authorities	—	—	—	—
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2013	$ 478	$ 156	$ 208	$ 110
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(320)	(105)	(177)	(37)
Regulatory Asset—Unrecognized Tax Benefits	(30)	—	(30)	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 128**	**$ 51**	**$ 1**	**$ 73**

2012	PSEG	Power	PSE&G	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2012	$ 825	$ 121	$ 113	$ 555
Increases as a Result of Positions Taken in a Prior Period	92	27	55	9
Decreases as a Result of Positions Taken in a Prior Period	(173)	(7)	(47)	(119)
Increases as a Result of Positions Taken during the Current Period	47	3	42	—
Decreases as a Result of Positions Taken during the Current Period	—	—	—	—
Decreases as a Result of Settlements with Taxing Authorities	(389)	(10)	—	(344)
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2012	$ 402	$ 134	$ 163	$ 101
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(264)	(93)	(133)	(35)
Regulatory Asset—Unrecognized Tax Benefits	(30)	—	(30)	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 108**	**$ 41**	**$ —**	**$ 66**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2011	PSEG	Power	PSE&G	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2011	$ 756	$ 101	$ 82	$ 539
Increases as a Result of Positions Taken in a Prior Period	58	24	14	17
Decreases as a Result of Positions Taken in a Prior Period	(22)	(9)	—	(12)
Increases as a Result of Positions Taken during the Current Period	37	8	18	11
Decreases as a Result of Positions Taken during the Current Period	(4)	(3)	(1)	—
Decreases as a Result of Settlements with Taxing Authorities	—	—	—	—
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2011	$ 825	$ 121	$ 113	$ 555
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(379)	(77)	(65)	(213)
Regulatory Asset—Unrecognized Tax Benefits	(20)	—	(20)	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 426**	**$ 44**	**$ 28**	**$ 342**

On January 31, 2012, PSEG signed a specific matter closing agreement with the IRS regarding disputed tax assessments associated with certain lease investments. On the same date, PSEG signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. In March 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These agreements concluded the audits for these years for PSEG and the leasing issue for all tax years. The financial statement impacts of these agreements, net of existing financial statement reserves, was a net decrease in tax expense in the first quarter of 2012 of $71 million for PSEG, including $30 million and $1 million for PSE&G and Power, respectively.

PSEG and its subsidiaries include all accrued interest and penalties related to uncertain tax positions required to be recorded, as income tax expense. Interest and penalties on uncertain tax positions were as follows:

	Interest and Penalties on Uncertain Tax Positions Years Ended December 31,		
	2013	2012	2011
		Millions	
Power	$ (2)	$ (2)	$ (11)
PSE&G	6	1	(24)
Energy Holdings	44	39	420
Other	—	—	10
Total	**$ 48**	**$ 38**	**$ 395**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

It is reasonably possible that total unrecognized tax benefits will decrease within the next twelve months due to either agreements with various taxing authorities upon audit or the expiration of the Statute of Limitations. These potential decreases are as follows:

Possible Decrease in Total Unrecognized Tax Benefits including Interest	Over the next 12 Months
	Millions
PSEG	$ 157
Power	$ 71
PSE&G	$ 11

As a result of a change in accounting method for the capitalization of indirect costs, PSEG reduced the net amount of its uncertain tax positions (including interest) by $97 million, approximately $43 million of which related to PSE&G. Pursuant to an agreement signed with the IRS on January 31, 2012, this matter is settled and there is a resulting increase in uncertain tax positions. These amounts are not included in the table above.

A description of income tax years that remain subject to examination by material jurisdictions, where an examination has not already concluded are:

	PSEG	Power	PSE&G
United States			
Federal	2007-2012	N/A	N/A
New Jersey	2006-2012	N/A	2006-2012
Pennsylvania	2001-2012	N/A	2000-2012
Connecticut	2002-2012	N/A	N/A
Texas	2007-2012	N/A	N/A
California	2003-2012	N/A	N/A
New York	2009-2012	2009-2012	N/A

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 21. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Year Ended December 31, 2013			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 7	$ (485)	$ 90	$ (388)
Other Comprehensive Income before Reclassifications	(2)	210	91	299
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(7)	37	(36)	(6)
Net Current Period Other Comprehensive Income (Loss)	(9)	247	55	293
Balance as of December 31, 2013	**$ (2)**	**$ (238)**	**$ 145**	**$ (95)**

Power	Other Comprehensive Income (Loss) Year Ended December 31, 2013			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 9	$ (422)	$ 85	$ (328)
Other Comprehensive Income before Reclassifications	(2)	185	93	276
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(8)	33	(36)	(11)
Net Current Period Other Comprehensive Income (Loss)	(10)	218	57	265
Balance as of December 31, 2013	**$ (1)**	**$ (204)**	**$ 142**	**$ (63)**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 13	$ (5)	$ 8
Interest Rate Swaps	Interest Expense	(1)	—	$ (1)
Total Cash Flow Hedges		12	(5)	7
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	Operation and Maintenance Expense	11	(4)	7
Amortization of Actuarial Loss	Operation and Maintenance Expense	(75)	31	(44)
Total Pension and OPEB Plans		(64)	27	(37)
Available-for-Sale Securities				
Realized Gains	Other Income	116	(59)	57
Realized Losses	Other Deductions	(29)	14	(15)
Other-Than-Temporary Impairments	Other-Than-Temporary Impairments	(12)	6	(6)
Total Available-for-Sale Securities		75	(39)	36
Total		**$ 23**	**$ (17)**	**$ 6**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 13	$ (5)	$ 8
Total Cash Flow Hedges		13	(5)	8
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	Operation and Maintenance Expense	9	(4)	5
Amortization of Actuarial Loss	Operation and Maintenance Expense	(64)	26	(38)
Total Pension and OPEB Plans		(55)	22	(33)
Available-for-Sale Securities				
Realized Gains	Other Income	112	(57)	55
Realized Losses	Other Deductions	(26)	13	(13)
Other-Than-Temporary Impairments	Other-Than-Temporary Impairments	(12)	6	(6)
Total Available-for-Sale Securities		74	(38)	36
Total		**$ 32**	**$ (21)**	**$ 11**

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Note 22. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under our stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Years Ended December 31,					
	2013		2012		2011	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator:						
(Millions)						
Continuing Operations	$ 1,243	$ 1,243	$ 1,275	$ 1,275	$ 1,407	$ 1,407
Discontinued Operations	—	—	—	—	96	96
Net Income	**$ 1,243**	**$ 1,243**	**$ 1,275**	**$ 1,275**	**$ 1,503**	**$ 1,503**
EPS Denominator:						
(Thousands)						
Weighted Average Common Shares Outstanding	505,889	505,889	505,933	505,933	505,949	505,949
Effect of Stock Based Compensation Awards	—	1,636	—	1,153	—	1,033
Total Shares	**505,889**	**507,525**	**505,933**	**507,086**	**505,949**	**506,982**
EPS:						
Continuing Operations	$ 2.46	$ 2.45	$ 2.52	$ 2.51	$ 2.78	$ 2.77
Discontinued Operations	—	—	—	—	0.19	0.19
Net Income	**$ 2.46**	**$ 2.45**	**$ 2.52**	**$ 2.51**	**$ 2.97**	**$ 2.96**

There were approximately 1.6 million, 1.8 million and 1.8 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the years ended December 31, 2013, 2012 and 2011, respectively. No other stock options had an antidilutive effect for the years ended December 31, 2013, 2012 or 2011.

Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	**2013**	**2012**	**2011**
Per Share	$ 1.44	$ 1.42	$ 1.37
in Millions	$ 728	$ 718	$ 693

On February 18, 2014, PSEG's Board of Directors approved a $0.37 per share common stock dividend for the first quarter of 2014.

Note 23. Financial Information by Business Segment

Basis of Organization

PSEG's operating segments are Power and PSE&G. The operating segments were determined by management in accordance with GAAP—Disclosures about Segments of an Enterprise and Related Information. These segments were determined based on how management measures performance based on segment Net Income, as illustrated in the following table, and how it allocates resources to each business.

On December 31, 2013, Energy Holdings' solar generation facilities and its interest in a generation facility in Hawaii were transferred to Power. As a result, the earnings, assets and liabilities related to this transfer are presented as if the transfer

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occurred at the beginning of the year and prior years have been retrospectively adjusted to furnish comparative information. See Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies for additional information.

Power

Power earns revenues by selling energy, capacity and ancillary services on a wholesale basis under contract to power marketers and to load serving entities and by bidding energy, capacity and ancillary services into the markets for these products. Power also enters into contracts for energy, capacity, FTRs, gas, emission allowances and other energy-related contracts to optimize the value of its portfolio of generating assets and its electric and gas supply obligations.

PSE&G

PSE&G earns revenues from its tariffs, under which it provides electric transmission and electric and gas distribution services to residential, commercial and industrial customers in New Jersey. The rates charged for electric transmission are regulated by the FERC while the rates charged for electric and gas distribution are regulated by the BPU. Revenues are also earned from several other activities such as solar investments, sundry sales, the appliance service business, wholesale transmission services and other miscellaneous services.

Other

This category includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

	Power	PSE&G	Other	Eliminations (A)	Consolidated Total
			Millions		
Year Ended December 31, 2013					
Operating Revenues	$ 5,063	$ 6,655	$ 52	$ (1,802)	$ 9,968
Depreciation and Amortization	273	872	33	—	1,178
Operating Income (Loss)	1,070	1,235	(6)	—	2,299
Income from Equity Method Investments	16	—	(5)	—	11
Interest Income	1	25	25	(22)	29
Interest Expense	116	293	15	(22)	402
Income (Loss) before Income Taxes	1,063	993	(1)	—	2,055
Income Tax Expense (Benefit)	419	381	12	—	812
Income (Loss) from Continuing Operations	644	612	(13)	—	1,243
Net Income (Loss)	644	612	(13)	—	1,243
Gross Additions to Long-Lived Assets	$ 609	$ 2,175	$ 27	—	$ 2,811
As of December 31, 2013					
Total Assets	$ 12,002	$ 19,720	$ 4,025	$ (3,225)	$ 32,522
Investments in Equity Method Subsidiaries	$ 123	$ —	$ 3	$ —	$ 126

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	PSE&G	Other	Eliminations (A)	Consolidated Total
			Millions		
Year Ended December 31, 2012					
Operating Revenues	$ 4,873	$ 6,626	$ 103	$ (1,821)	$ 9,781
Depreciation and Amortization	242	778	34	—	1,054
Operating Income (Loss)	1,123	1,083	72	—	2,278
Income from Equity Method Investments	15	—	(3)	—	12
Interest Income	3	20	25	(21)	27
Interest Expense	132	295	17	(21)	423
Income (Loss) before Income Taxes	1,099	835	77	—	2,011
Income Tax Expense (Benefit)	433	307	(4)	—	736
Income (Loss) from Continuing Operations	666	528	81	—	1,275
Net Income (Loss)	666	528	81	—	1,275
Gross Additions to Long-Lived Assets	$ 770	$ 1,770	$ 34	$ —	$ 2,574
As of December 31, 2012					
Total Assets	$ 11,323	$ 19,223	$ 4,161	$ (2,982)	$ 31,725
Investments in Equity Method Subsidiaries	$ 125	$ —	$ 9	$ —	$ 134

	Power	PSE&G	Other	Eliminations (A)	Consolidated Total
			Millions		
Year Ended December 31, 2011					
Operating Revenues	$ 6,150	$ 7,326	$ (149)	$ (2,248)	$ 11,079
Depreciation and Amortization	228	719	29	—	976
Operating Income (Loss)	1,773	1,151	(182)	—	2,742
Income from Equity Method Investments	14	—	(10)	—	4
Interest Income	4	12	20	(17)	19
Interest Expense	175	310	7	(17)	475
Income (Loss) before Income Taxes	1,703	861	(180)	—	2,384
Income Tax Expense (Benefit)	690	340	(53)	—	977
Income (Loss) from Continuing Operations	1,013	521	(127)	—	1,407
Income from Discontinued Operations, net of tax	96	—	—	—	96
Net Income (Loss)	1,109	521	(127)	—	1,503
Gross Additions to Long-Lived Assets	$ 757	$ 1,302	$ 24	$ —	$ 2,083

(A) Intercompany eliminations, primarily relate to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 24. Related-Party Transactions.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 24. Related-Party Transactions

The majority of the following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

Power

The financial statements for Power include transactions with related parties presented as follows:

Related Party Transactions	Years Ended December 31, 2013	2012	2011
		Millions	
Revenue from Affiliates:			
Billings to PSE&G through BGSS and BGS (A)	**$ 1,797**	**$ 1,802**	**$ 2,215**
Expense Billings from Affiliates:			
Administrative Billings from Services (B)	$ (178)	$ (154)	$ (147)
Total Expense Billings from Affiliates	**$ (178)**	**$ (154)**	**$ (147)**

Related Party Transactions	Years Ended December 31, 2013	2012
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$ 267	$ 265
Receivable from (Payable to) Services (B)	(31)	(31)
Receivable from (Payable to) PSEG (C)	97	106
Accounts Receivable (Payable)—Affiliated Companies, net	**$ 333**	**$ 340**
Short-Term Loan to (from) Affiliate (demand Note to (from) PSEG) (D)	**$ 790**	**$ 574**
Working Capital Advances to Services (E)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable (Payable)	**$ (53)**	**$ (50)**

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related Party Transactions	Years Ended December 31, 2013	2012	2011
		Millions	
Expense Billings from Affiliates:			
Billings from Power through BGSS and BGS (A)	$ (1,797)	$ (1,802)	$ (2,215)
Administrative Billings from Services (B)	(255)	(230)	(210)
Total Expense Billings from Affiliates	**$ (2,052)**	**$ (2,032)**	**$ (2,425)**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Related Party Transactions	Years Ended December 31, 2013	2012
	Millions	
Payable to Power through BGS and BGSS Contracts (A)	$ (267)	$ (265)
Payable to Power from SREC Liability (F)	—	(7)
Receivable from (Payable to) Services (B)	(73)	(65)
Receivable from (Payable to) PSEG (C)	150	262
Receivable from Energy Holdings	—	2
Accounts Receivable (Payable)—Affiliated Companies, net	**$ (190)**	**$ (73)**
Working Capital Advances to Services (E)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Receivable (Payable)	**$ (72)**	**$ (32)**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to Power and PSE&G at cost. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) Receivable primarily relates to tax amounts due to PSEG from its affiliates as PSEG files a consolidated federal income tax return together with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

(E) Power and PSE&G have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on Power's and PSE&G's Consolidated Balance Sheets.

(F) Pursuant to a 2008 BPU Order, certain BGS suppliers, including Power, would be reimbursed for the cost they incurred above $300 per Solar Renewable Energy Certificate (SREC) or per Solar Alternative Compliance Payment during the period June 1, 2008 through May 31, 2010 and such excess cost would be passed onto ratepayers. In accordance with a Stipulation of Settlement approved by the BPU in a December 2012 Order describing the mechanism for BGS suppliers to recover these costs, PSE&G, as a New Jersey EDC, estimated and accrued a total liability for the excess SREC cost expected to be recovered from ratepayers of $17 million, including approximately $7 million for Power's share which was included in PSE&G's Accounts Receivable (Payable)—Affiliated Companies, as of December 31, 2012. Under current accounting guidance, Power was unable to record the related intercompany receivable on its Consolidated Balance Sheet until the BPU issued an Order approving such payments. As a result, PSE&G's liability to Power was not eliminated in consolidation and was included in Other Current Liabilities on PSEG's Consolidated Balance Sheet as of December 31, 2012. In May 2013, the BPU issued an Order approving the BGS payments for these SRECs. This Order was not appealed and went into effect in July 2013. As a result, Power recorded its $9 million then outstanding receivable from PSE&G. In August 2013, PSE&G reimbursed Power and its other BGS suppliers for the excess SREC costs.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 25. Selected Quarterly Data (Unaudited)

The information shown in the following tables, in the opinion of PSEG, Power and PSE&G includes all adjustments, consisting only of normal recurring accruals, necessary to fairly present such amounts.

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2013	2012	2013	2012	2013	2012	2013	2012
PSEG Consolidated:	Millions, except per share data							
Operating Revenues	$ 2,786	$ 2,875	$ 2,310	$ 2,098	$ 2,554	$ 2,402	$ 2,318	$ 2,406
Operating Income	$ 610	$ 783	$ 612	$ 433	$ 712	$ 594	$ 365	$ 468
Net Income (Loss)	$ 320	$ 493	$ 333	$ 211	$ 390	$ 347	$ 200	$ 224
Earnings Per Share:								
Basic:								
Net Income (Loss)	$ 0.63	$ 0.97	$ 0.66	$ 0.42	$ 0.77	$ 0.69	$ 0.40	$ 0.44
Diluted:								
Net Income (Loss)	$ 0.63	$ 0.97	$ 0.66	$ 0.42	$ 0.77	$ 0.68	$ 0.39	$ 0.44
Weighted Average Common Shares Outstanding:								
Basic	506	506	506	506	506	506	506	506
Diluted	507	507	507	507	508	507	508	507

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2013	2012	2013	2012	2013	2012	2013	2012
Power: (A)	Millions							
Operating Revenues	$ 1,451	$ 1,563	$ 1,193	$ 987	$ 1,174	$ 1,041	$ 1,245	$ 1,282
Operating Income	$ 242	$ 441	$ 351	$ 198	$ 370	$ 268	$ 107	$ 216
Net Income (Loss)	$ 141	$ 257	$ 210	$ 109	$ 226	$ 187	$ 67	$ 113

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2013	2012	2013	2012	2013	2012	2013	2012
PSE&G:	Millions							
Operating Revenues	$ 1,995	$ 1,939	$ 1,423	$ 1,407	$ 1,666	$ 1,683	$ 1,571	$ 1,597
Operating Income	$ 365	$ 342	$ 253	$ 227	$ 346	$ 321	$ 271	$ 193
Net Income (Loss)	$ 179	$ 197	$ 121	$ 101	$ 168	$ 155	$ 144	$ 75

(A) Power's information has been restated for all periods presented to reflect the transfer of certain of Energy Holdings' equity investments to Power on December 31, 2013. For additional information see Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies .

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 26. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following table presents financial information for the guarantor subsidiaries as well as Power's non-guarantor subsidiaries as of December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2013					
Operating Revenues	$ —	$ 6,490	$ 190	$ (1,617)	$ 5,063
Operating Expenses	23	5,413	174	(1,617)	3,993
Operating Income (Loss)	(23)	1,077	16	—	1,070
Equity Earnings (Losses) of Subsidiaries	684	(5)	16	(679)	16
Other Income	35	157	—	(38)	154
Other Deductions	(14)	(35)	—	—	(49)
Other-Than-Temporary Impairments	—	(12)	—	—	(12)
Interest Expense	(93)	(42)	(19)	38	(116)
Income Tax Benefit (Expense)	55	(474)	—	—	(419)
Net Income (Loss)	**$ 644**	**$ 666**	**$ 13**	**$ (679)**	**$ 644**
Comprehensive Income (Loss)	**$ 909**	**$ 713**	**$ 11**	**$ (724)**	**$ 909**
As of December 31, 2013					
Current Assets	$ 4,160	$ 8,916	$ 944	$ (11,544)	$ 2,476
Property, Plant and Equipment, net	81	6,108	1,178	—	7,367
Investment in Subsidiaries	4,645	729	—	(5,374)	—
Noncurrent Assets	222	1,847	138	(48)	2,159
Total Assets	**$ 9,108**	**$ 17,600**	**$ 2,260**	**$ (16,966)**	**$ 12,002**
Current Liabilities	$ 444	$ 10,919	$ 982	$ (11,545)	$ 800
Noncurrent Liabilities	309	2,247	338	(47)	2,847
Long-Term Debt	2,497	—	—	—	2,497
Member's Equity	5,858	4,434	940	(5,374)	5,858
Total Liabilities and Member's Equity	**$ 9,108**	**$ 17,600**	**$ 2,260**	**$ (16,966)**	**$ 12,002**
Year Ended December 31, 2013					
Net Cash Provided By (Used In) Operating Activities	$ 288	$ 1,503	$ 82	$ (526)	$ 1,347
Net Cash Provided By (Used In) Investing Activities	$ 193	$ (1,092)	$ (71)	$ 109	$ (861)
Net Cash Provided By (Used In) Financing Activities	$ (481)	$ (412)	$ (11)	$ 417	$ (487)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2012					
Operating Revenues	$ —	$ 6,238	$ 135	$ (1,500)	$ 4,873
Operating Expenses	7	5,118	125	(1,500)	3,750
Operating Income (Loss)	(7)	1,120	10	—	1,123
Equity Earnings (Losses) of Subsidiaries	707	(10)	15	(697)	15
Other Income	45	206	2	(52)	201
Other Deductions	(31)	(59)	—	—	(90)
Other-Than-Temporary Impairments	—	(18)	—	—	(18)
Interest Expense	(118)	(51)	(16)	53	(132)
Income Tax Benefit (Expense)	70	(501)	(2)	—	(433)
Net Income (Loss)	**$ 666**	**$ 687**	**$ 9**	**$ (696)**	**$ 666**
Comprehensive Income (Loss)	**$ 614**	**$ 681**	**$ 9**	**$ (690)**	**$ 614**
As of December 31, 2012					
Current Assets	$ 3,922	$ 8,084	$ 942	$ (10,712)	$ 2,236
Property, Plant and Equipment, net	80	5,988	1,154	—	7,222
Investment in Subsidiaries	4,508	733	—	(5,241)	—
Noncurrent Assets	201	1,660	145	(141)	1,865
Total Assets	**$ 8,711**	**$ 16,465**	**$ 2,241**	**$ (16,094)**	**$ 11,323**
Current Liabilities	$ 482	$ 10,187	$ 1,011	$ (10,712)	$ 968
Noncurrent Liabilities	559	1,960	306	(140)	2,685
Long-Term Debt	2,040	—	—	—	2,040
Member's Equity	5,630	4,318	924	(5,242)	5,630
Total Liabilities and Member's Equity	**$ 8,711**	**$ 16,465**	**$ 2,241**	**$ (16,094)**	**$ 11,323**
Year Ended December 31, 2012					
Net Cash Provided By (Used In) Operating Activities	$ 298	$ 1,562	$ 67	$ (474)	$ 1,453
Net Cash Provided By (Used In) Investing Activities	$ 715	$ (1,206)	$ (151)	$ 170	$ (472)
Net Cash Provided By (Used In) Financing Activities	$ (963)	$ (361)	$ 83	$ 255	$ (986)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2011					
Operating Revenues	$ —	$ 7,452	$ 155	$ (1,457)	$ 6,150
Operating Expenses	5	5,673	157	(1,458)	4,377
Operating Income (Loss)	(5)	1,779	(2)	1	1,773
Equity Earnings (Losses) of Subsidiaries	1,186	92	14	(1,278)	14
Other Income	40	195	—	(45)	190
Other Deductions	(28)	(51)	—	—	(79)
Other-Than-Temporary Impairments	(1)	(19)	—	—	(20)
Interest Expense	(146)	(56)	(18)	45	(175)
Income Tax Benefit (Expense)	63	(762)	9	—	(690)
Income (Loss) on Discontinued Operations, net of Tax Benefit	—	—	97	(1)	96
Net Income (Loss)	**$ 1,109**	**$ 1,178**	**$ 100**	**$ (1,278)**	**$ 1,109**
Comprehensive Income (Loss)	**$ 928**	**$ 1,055**	**$ 100**	**$ (1,155)**	**$ 928**
Year Ended December 31, 2011					
Net Cash Provided By (Used In) Operating Activities	$ 609	$ 2,427	$ (279)	$ (940)	$ 1,817
Net Cash Provided By (Used In) Investing Activities	$ 596	$ (1,171)	$ 594	$ (597)	$ (578)
Net Cash Provided By (Used In) Financing Activities	$ (1,210)	$ (1,256)	$ (314)	$ 1,542	$ (1,238)

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, Power and PSE&G

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, Power and PSE&G

We have conducted assessments of our internal control over financial reporting as of December 31, 2013, as required by Section 404 of the Sarbanes-Oxley Act, using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". Management's reports on PSEG's, Power's and PSE&G's internal control over financial reporting are included on pages 170, 171 and 172, respectively. The Independent Registered Public Accounting Firm's report with respect to the effectiveness of PSEG's internal control over financial reporting is included on page 173. Management has concluded that internal control over financial reporting is effective as of December 31, 2013.

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of their financial reporting. There have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSEG

Management of Public Service Enterprise Group Incorporated (PSEG) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSEG's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSEG's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSEG are being made only in accordance with authorizations of PSEG's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSEG's assets that could have a material effect on the financial statements.

In connection with the preparation of PSEG's annual financial statements, management of PSEG has undertaken an assessment, which includes the design and operational effectiveness of PSEG's internal control over financial reporting based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSEG's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSEG's financial reporting and the preparation of its financial statements as of December 31, 2013 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2013.

PSEG's external auditors, Deloitte & Touche LLP, have audited PSEG's financial statements for the year ended December 31, 2013 included in this annual report on Form 10-K and, as part of that audit, have issued a report on the effectiveness of PSEG's internal control over financial reporting, a copy of which is included in this annual report on Form 10-K.

/s/ RALPH IZZO

Chief Executive Officer

/s/ CAROLINE DORSA

Chief Financial Officer

February 26, 2014

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—Power

Management of PSEG Power LLC (Power) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

Power's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of Power's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of Power are being made only in accordance with authorizations of Power's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Power's assets that could have a material effect on the financial statements.

In connection with the preparation of Power's annual financial statements, management of Power has undertaken an assessment, which includes the design and operational effectiveness of Power's internal control over financial reporting based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that Power's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of Power's financial reporting and the preparation of its financial statements as of December 31, 2013 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2013.

/s/ RALPH IZZO
Chief Executive Officer

/s/ CAROLINE DORSA
Chief Financial Officer
February 26, 2014

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSE&G

Management of Public Service Electric and Gas Company (PSE&G) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSE&G's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSE&G's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSE&G are being made only in accordance with authorizations of PSE&G's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSE&G's assets that could have a material effect on the financial statements.

In connection with the preparation of PSE&G's annual financial statements, management of PSE&G has undertaken an assessment, which includes the design and operational effectiveness of PSE&G's internal control over financial reporting based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSE&G's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSE&G's financial reporting and the preparation of its financial statements as of December 31, 2013 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2013.

/s/ RALPH IZZO
Chief Executive Officer

/s/ CAROLINE DORSA
Chief Financial Officer
February 26, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of
Public Service Enterprise Group Incorporated:

We have audited the internal control over financial reporting of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting - PSEG. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control - Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and consolidated financial statement schedule listed in the Index at Item 15(B)(a) as of and for the year ended December 31, 2013 of the Company and our report dated February 26, 2014 expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2014

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

PSEG

Name	Age as of December 31, 2013	Office	Effective Date First Elected to Present Position
Ralph Izzo	56	Chairman of the Board, President and Chief Executive Officer (PSEG)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Power)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (PSE&G)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Energy Holdings)	April 2007 to present
		Chairman of the Board, President and Chief Executive Officer (Services)	January 2010 to present
		Chairman of the Board and Chief Executive Officer (Services)	April 2007 to January 2010
Caroline Dorsa	54	Executive Vice President and Chief Financial Officer (PSEG)	April 2009 to present
		Executive Vice President and Chief Financial Officer (Power)	April 2009 to present
		Executive Vice President and Chief Financial Officer (PSE&G)	April 2009 to present
		Chief Financial Officer (Energy Holdings)	April 2009 to present
		Executive Vice President and Chief Financial Officer (Services)	April 2009 to present
		Senior Vice President, Global Human Health Strategy and Integration (Merck and Co., Inc.)	January 2008 to April 2009
William Levis	57	President and Chief Operating Officer (Power)	June 2007 to present
Ralph LaRossa	50	President and Chief Operating Officer (PSE&G)	October 2006 to present
		Chairman of the Board of PSEG Long Island LLC	October 2013 to present
Derek M. DiRisio	49	Vice President and Controller (PSEG)	January 2007 to present
		Vice President and Controller (PSE&G)	January 2007 to present
		Vice President and Controller (Power)	January 2007 to present
		Vice President and Controller (Energy Holdings)	January 2007 to present
		Vice President and Controller (Services)	January 2007 to present
J.A. Bouknight, Jr.	69	Executive Vice President and General Counsel (PSEG)	January 2010 to present
		Executive Vice President and General Counsel (Power)	January 2010 to present
		Executive Vice President and General Counsel (PSE&G)	January 2010 to present
		Executive Vice President and General Counsel (Services)	January 2010 to present
		Partner, Steptoe & Johnson LLP	July 2008 to November 2009
		Executive Vice President and General Counsel (Edison International)	July 2005 to July 2008

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Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Directors

PSEG

The information required by Item 10 of Form 10-K with respect to (i) present directors of PSEG who are nominees for election as directors at PSEG's 2014 Annual Meeting of Stockholders, and (ii) compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth under the headings 'Election of Directors' and "Section 16(a) Beneficial Ownership Reporting Compliance" in PSEG's definitive Proxy Statement for such Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 10, 2014 and which information set forth under said heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Code of Ethics

Our Standards of Integrity (Standards) is a code of ethics applicable to us and our subsidiaries. The Standards are an integral part of our business conduct compliance program and embody our commitment to conduct operations in accordance with the highest legal and ethical standards. The Standards apply to all of our directors and employees (including Power's, PSE&G's, Energy Holdings' and Services' respective principal executive officer, principal financial officer, principal accounting officer or Controller and persons performing similar functions). Each such person is responsible for understanding and complying with the Standards. The Standards are posted on our website, www.pseg.com/info/investors/governance/document.jsp. We will send you a copy on request.

The Standards establish a set of common expectations for behavior to which each employee must adhere in dealings with investors, customers, fellow employees, competitors, vendors, government officials, the media and all others who may associate their words and actions with us. The Standards have been developed to provide reasonable assurance that, in conducting our business, employees behave ethically and in accordance with the law and do not take advantage of investors, regulators or customers through manipulation, abuse of confidential information or misrepresentation of material facts.

We will post on our website, www.pseg.com/info/investors/governance/document.jsp:

- Any amendment (other than one that is technical, administrative or non-substantive) that we adopt to our Standards; and
- Any grant by us of a waiver from the Standards that applies to any director, principal executive officer, principal financial officer, principal accounting officer or Controller, or persons performing similar functions, for us or our direct subsidiaries noted above, and that relates to any element enumerated by the SEC.

In 2013, we did not grant any waivers to the Standards.

ITEM 11. EXECUTIVE COMPENSATION

PSEG

The information required by Item 11 of Form 10-K is set forth in PSEG's definitive Proxy Statement for the 2014 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 10, 2014 and such information set forth under such heading is incorporated herein by this reference thereto.

Section 16 Beneficial Ownership Reporting Compliance

During 2013, none of our directors or executive officers was late in filing a Form 3, 4 or 5 in accordance with the requirements of Section 16(a) of the Securities Exchange Act of 1934, as amended, with regard to transactions involving our Common Stock.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDERS MATTERS

PSEG

The information required by Item 12 of Form 10-K with respect to directors, executive officers and certain beneficial owners is set forth under the heading "Security Ownership of Directors, Management and Certain Beneficial Owners" in PSEG's definitive Proxy Statement for the 2014 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 10, 2014 and such information set forth under such heading is incorporated herein by this reference thereto.

For information relating to securities authorized for issuance under equity compensation plans, see Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

PSEG

The information required by Item 13 of Form 10-K is set forth under the heading "Transactions with Related Persons" in PSEG's definitive Proxy Statement for the 2014 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 10, 2014 and such information set forth under such heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10K.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 of Form 10-K is set forth under the heading "Fees Billed to PSEG by Deloitte & Touche LLP for 2013 and 2012" in PSEG's definitive Proxy Statement for the 2014 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 10, 2014. Such information set forth under such heading is incorporated herein by this reference hereto.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(A) The following Financial Statements are filed as a part of this report:

a. Public Service Enterprise Group Incorporated's Consolidated Balance Sheets as of December 31, 2013 and 2012 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Stockholders' Equity for the three years ended December 31, 2013 on pages 69 through 74.

b. PSEG Power LLC's Consolidated Balance Sheets as of December 31, 2013 and 2012 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Capitalization and Member's Equity for the three years ended December 31, 2013 on pages 75 through 80.

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c. Public Service Electric and Gas Company's Consolidated Balance Sheets as of December 31, 2013 and 2012 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Common Stockholders' Equity for the three years ended December 31, 2013 on pages 81 through 86.

(B) The following documents are filed as a part of this report:

a. PSEG's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2013 (page 184).

b. Power's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2013 (page 184).

c. PSE&G's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2013 (page 185).

Schedules other than those listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(C) The following documents are filed as part of this report:

LIST OF EXHIBITS:

a.	**PSEG:**
3a	Certificate of Incorporation Public Service Enterprise Group Incorporated [1]
3b	By-Laws of Public Service Enterprise Group Incorporated effective November 17, 2009 [2]
3c	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 23, 1987 [3]
3d	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 20, 2007 [4]
4a(1)	Indenture between Public Service Enterprise Group Incorporated and First Union National Bank (U.S. Bank National Association, successor), as Trustee, dated January 1, 1998 providing for Deferrable Interest Subordinated Debentures in Series (relating to Quarterly Preferred Securities)[5]
9	Inapplicable
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011 [6]
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees as amended May 31, 2011 [7]
10a(3)	Employment Agreement with William Levis dated December 8, 2006 [8]
10a(4)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011 [9]
10a(5)	Deferred Compensation Plan for Directors, amended July 19, 2011 [10]
10a(6)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011 [64]
10a(7)	1989 Long-Term Incentive Plan, as amended[12]
10a(8)	2001 Long-Term Incentive Plan[13]
10a(9)	Senior Management Incentive Compensation Plan [14]
10a(10)	Amended and Restated Key Executive Severance Plan, amended effective December 17, 2012 [68]
10a(11)	Severance Agreement with Ralph Izzo dated December 16, 2008 [15]
10a(12)	Employment Agreement with Randall Mehrberg dated June 30, 2008 [16]
10a(13)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009 [17]
10a(14)	Stock Plan for Outside Directors, as amended [18]
10a(15)	Compensation Plan for Outside Directors [19]
10a(16)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013 [20]

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LIST OF EXHIBITS:

10a(17)	Form of Advancement of Expenses Agreement with Outside Directors (21)
10a(18)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011 (65)
10a(19)	Employment Agreement with J.A. Bouknight dated August 26, 2009 (66)
10a(20)	Amendment to Employment Agreement with Randall Mehrberg, dated May 3, 2011 (61)
10a(21)	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011 (62)
10a(22)	Amendment to Employment Agreement with Randall Mehrberg, dated June 8, 2011 (63)
10a(23)	Amendment to Employment Agreement with William Levis, dated September 19, 2011 (11)
10a(24)	Amendment to Employment Agreement with J.A. Bouknight dated November 20, 2012 (67)
10a(25)	Amendment to Employment Agreement with J.A. Bouknight dated February 18, 2014 (69)
11	Inapplicable
12	Computation of Ratios of Earnings to Fixed Charges
13	Inapplicable
16	Inapplicable
18	Inapplicable
21	Subsidiaries of the Registrant
22	Inapplicable
23	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934 (1934 Act)
31a	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32a	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
b.	**Power:**
3a	Certificate of Formation of PSEG Power LLC (22)
3b	PSEG Power LLC Limited Liability Company Agreement (23)
3c	Trust Agreement for PSEG Power Capital Trust I (24)
3d	Trust Agreement for PSEG Power Capital Trust II (25)
3e	Trust Agreement for PSEG Power Capital Trust III (26)
3f	Trust Agreement for PSEG Power Capital Trust IV (27)
3g	Trust Agreement for PSEG Power Capital Trust V (28)
4a	Indenture dated April 16, 2001 between and among PSEG Power, PSEG Fossil, PSEG Nuclear, PSEG Energy Resources & Trade and The Bank of New York Mellon and form of Subsidiary Guaranty included therein (29)
4b	First Supplemental Indenture, supplemental to Exhibit 4a, dated as of March 13, 2002 (30)
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011 (6)
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees, as amended May 31, 2011 (7)
10a(3)	Employment Agreement with William Levis dated December 8, 2006 (8)
10a(4)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011 (64)
10a(5)	1989 Long-Term Incentive Plan, as amended (12)

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LIST OF EXHIBITS:

10a(6)	2001 Long-Term Incentive Plan[13]
10a(7)	Senior Management Incentive Compensation Plan [14]
10a(8)	Amended and Restated Key Executive Severance Plan, amended effective December 17, 2012 [68]
10a(9)	Severance Agreement with Ralph Izzo dated December 16, 2008 [15]
10a(10)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009 [17]
10a(11)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013 [20]
10a(12)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011 [65]
10a(13)	Employment Agreement with J.A. Bouknight dated August 26, 2009 [66]
10a(14)	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011 [62]
10a(15)	Amendment to Employment Agreement with William Levis, dated September 19, 2011 [11]
10a(16)	Amendment to Employment Agreement with J.A. Bouknight dated November 20, 2012 [67]
10a(17)	Amendment to Employment Agreement with J.A. Bouknight dated February 18, 2014 [69]
11	Inapplicable
12a	Computation of Ratio of Earnings to Fixed Charges
13	Inapplicable
16	Inapplicable
18	Inapplicable
19	Inapplicable
23a	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31b	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31c	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32b	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
c.	**PSE&G**
3a(1)	Restated Certificate of Incorporation of PSE&G [31]
3a(2)	Certificate of Amendment of Certificate of Restated Certificate of Incorporation of PSE&G filed February 18, 1987 with the State of New Jersey adopting limitations of liability provisions in accordance with an amendment to New Jersey Business Corporation Act [32]
3a(3)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed June 17, 1992 with the State of New Jersey, establishing the 7.44% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock [33]
3a(4)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed March 11, 1993 with the State of New Jersey, establishing the 5.97% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock [34]
3a(5)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed January 27, 1994 with the State of New Jersey, establishing the 6.92% Cumulative Preferred Stock ($100 Par) and the 6.75% Cumulative Preferred Stock ($25 Par) as a series of Preferred Stock[35]
3b(1)	By-Laws of PSE&G as in effect April 17, 2007 [36]

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LIST OF EXHIBITS:

4a(1)	Indenture between PSE&G and Fidelity Union Trust Company (now, Wachovia Bank, National Association), as Trustee, dated August 1, 1924[37], securing First and Refunding Mortgage Bond and Supplemental Indentures between PSE&G and U.S. Bank National Association, successor, as Trustee, supplemental to Exhibit 4a(1), dated as follows:
4a(2)	June 1, 1937[38]
4a(3)	July 1, 1937[39]
4a(4)	March 1, 1942[40]
4a(5)	June 1, 1991 (No. 1)[41]
4a(6)	July 1, 1993[42]
4a(7)	January 1, 1996 (No. 1)[43]
4a(8)	December 1, 2003 (No. 1)[44]
4a(9)	December 1, 2003 (No. 2)[45]
4a(10)	December 1, 2003 (No. 3)[46]
4a(11)	December 1, 2003 (No. 4)[47]
4a(12)	August 1, 2004 (No. 1)[48]
4a(13)	August 1, 2004 (No. 2)[49]
4a(14)	August 1, 2004 (No. 3)[50]
4a(15)	August 1, 2004 (No. 4)[51]
4a(16)	April 1, 2007[52]
4a(17)	November 1, 2008[53]
4a(18)	October 1, 2010[54]
4a(19)	May 1, 2012[57]
4a(20)	June 1, 2012[58]
4a(21)	May 1, 2013[59]
4b	Indenture of Trust between PSE&G and Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor), as Trustee, providing for Secured medium-Term Notes dated July 1, 1993[55]
4c	Indenture dated as of December 1, 2000 between Public Service Electric and Gas Company and First Union National Bank (U.S. Bank National Association, successor), as Trustee, providing for Senior Debt Securities[56]
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011[6]
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees as amended May 31, 2011[7]
10a(3)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011[9]
10a(4)	Deferred Compensation Plan for Directors, amended July 19, 2011[10]
10a(5)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011[64]
10a(6)	1989 Long-Term Incentive Plan, as amended[12]
10a(7)	2001 Long-Term Incentive Plan[13]
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10a(10)	Severance Agreement with Ralph Izzo dated December 16, 2008[15]
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10a(12)	Stock Plan for Outside Directors, as amended[18]
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10a(18)	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011[62]

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LIST OF EXHIBITS:

10a(19)	Amendment to Employment Agreement with J.A. Bouknight dated November 20, 2012 (67)
10a(20)	Amendment to Employment Agreement with J.A. Bouknight dated February 18, 2014 (69)
11	Inapplicable
12b	Computation of Ratios of Earnings to Fixed Charges
12c	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
13	Inapplicable
16	Inapplicable
18	Inapplicable
19	Inapplicable
23b	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31d	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31e	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32d	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32e	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document

(1) Filed as Exhibit 3.1a with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.
(2) Filed as Exhibit 3.1 with Current Report on Form 8-K, File No. 001-09120 on November 18, 2009 and incorporated herein by this reference.
(3) Filed as Exhibit 3.1b with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.
(4) Filed as Exhibit 3.1c with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.
(5) Filed as Exhibit 4(f) with Quarterly Report on Form 10-Q for the quarter ended March 31, 1998, File No. 001-09120 on May 13, 1998 and incorporated herein by this reference.
(6) Filed as Exhibit 10.1 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(7) Filed as Exhibit 10.2 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(8) Filed as Exhibit 10a(4) with Annual Report on Form 10-K for the year ended December 31, 2007, File Nos. 001-09120 on February 28, 2008 and 000-49614, and incorporated herein by reference.
(9) Filed as Exhibit 10.5 with Quarterly Report on Form 10-Q for the quarter ended September 20, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(10) Filed as Exhibit 10.6 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(11) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(12) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 001-09120, on November 4, 2002 and incorporated herein by this reference.
(13) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2000, File No. 001-09120, on March 6, 2001 and incorporated herein by this reference.
(14) Filed as Exhibit 10a(11) with Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-09120, on February 26, 2009 and incorporated herein by this reference.

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(15) Filed as Exhibit 99 with Current Report on Form 8-K, File Nos. 001-09120, 000-49614 and 001-00973 on December 22, 2008 and incorporated herein by this reference.
(16) Filed as Exhibit 10a(14) with Annual Report on Form 10-K, for the year ended December 31, 2009, File No. 001-09120 on February 25, 2010 and incorporated herein by reference.
(17) Filed as Exhibit 10 with Quarterly Report on Form 10-Q, File No. 001-00973 on May 6, 2009 and incorporated herein by reference.
(18) Filed as Exhibit 10a(17) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(19) Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(20) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, File No. 001-09120 on April 30, 2013 and incorporated herein by reference.
(21) Filed as Exhibit 10.1 with Current Report on Form 8-K, File No. 001-09120 on February 19, 2009 and incorporated herein by this reference.
(22) Filed as Exhibit 3.1 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.
(23) Filed as Exhibit 3.2 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.
(24) Filed as Exhibit 3.6 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.
(25) Filed as Exhibit 3.7 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.
(26) Filed as Exhibit 3.8 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.
(27) Filed as Exhibit 3.9 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.
(28) Filed as Exhibit 3.10 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.
(29) Filed as Exhibit 4.1 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.
(30) Filed as Exhibit 4.7 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, File No. 000-49614, on May 15, 2002 and incorporated herein by this reference.
(31) Filed as Exhibit 3(a) with Quarterly Report on Form 10-Q for the quarter ended June 30, 1986, File No. 001-00973, on August 28, 1986 and incorporated herein by this reference.
(32) Filed as Exhibit 3a(2) with Annual Report on Form 10-K for the year ended December 31, 1987, File No. 001-00973, on March 28, 1988 and incorporated herein by this reference.
(33) Filed as Exhibit 3a(3) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(34) Filed as Exhibit 3a(4) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(35) Filed as Exhibit 3a(5) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(36) Filed as Exhibit 3.3 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-00973 on May 4, 2007 and incorporated herein by this reference.
(37) Filed as Exhibit 4b(1) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(38) Filed as Exhibit 4b(3) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(39) Filed as Exhibit 4b(4) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(40) Filed as Exhibit 4b(6) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(41) Filed as Exhibit 4 on Form 8-A, File No. 001-00973 on June 1, 1991 and incorporated herein by this reference.
(42) Filed as Exhibit 4(i) on Form 8-A, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.
(43) Filed as Exhibit 4a(2) on Form 8-A, File No. 001-00973 on January 26, 1996 and incorporated herein by this reference.
(44) Filed as Exhibit 4a(99) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(45) Filed as Exhibit 4a(100) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(46) Filed as Exhibit 4a(101) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.

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(47) Filed as Exhibit 4a(102) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(48) Filed as Exhibit 4a(25) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(49) Filed as Exhibit 4a(26) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(50) Filed as Exhibit 4a(27) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(51) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(52) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-00973, on February 28, 2008 and incorporated herein by this reference.
(53) Filed as Exhibit 4a(29) with Annual Report on Form 10-K, for the year ended December 31, 2009, File No. 001-00973 on February 25, 2010 and incorporated herein by reference.
(54) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2010, File No. 001-00973 on October 29, 2010 and incorporated herein by reference.
(55) Filed as Exhibit 4 with Current Report on Form 8-K, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.
(56) Filed as Exhibit 4.6 to Registration Statement on Form S-3, No. 333-76020 filed on December 27, 2001 and incorporated herein by this reference.
(57) Filed as Exhibit 4a(32) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-00973 on February 25, 2013.
(58) Filed as Exhibit 4a(33) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-00973 on February 25, 2013.
(59) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, File No. 001-00973 on July 30, 2013.
(60) Filed as Exhibit 10.2 with Current Report on Form 8-K, File No. 001-00973 on February 19, 2009 and incorporated herein by reference.
(61) Filed as Exhibit 10.2 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, File No. 001-09120 on May 5, 2011 and incorporated herein by this reference.
(62) Filed as Exhibit 10.1 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, File No. 001-09120 on August 3, 2011 and incorporated herein by this reference.
(63) Filed as Exhibit 10.2 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, File No. 001-09120 on August 3, 2011 and incorporated herein by this reference.
(64) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120 on February 27, 2012.
(65) Filed as Exhibit 10a(19) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120 on February 27, 2012.
(66) Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120 on February 27, 2012.
(67) Filed as Exhibit 10 with Current Report on Form 8-K, File No. 001-09120 on November 26, 2012 and incorporated herein by reference.
(68) Filed as Exhibit 10a(11) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-09120 on February 25, 2013.
(69) Filed as Exhibit 10 with Current Report on Form 8-K, File No. 001-09120 on February 21, 2014 and incorporated herein by reference.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2013—December 31, 2011

Column A	Column B	Column C		Column D		Column E
		Additions				
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2013						
Allowance for Doubtful Accounts	$ 56	$ 90	$ —	$ 90	(A)	$ 56
Materials and Supplies Valuation Reserve	22	2	—	16	(B)	8
2012						
Allowance for Doubtful Accounts	$ 56	$ 96	$ —	$ 96	(A)	$ 56
Materials and Supplies Valuation Reserve	3	21	—	2	(B)	22
2011						
Allowance for Doubtful Accounts	$ 68	$ 102	$ —	$ 114	(A)	$ 56
Materials and Supplies Valuation Reserve	4	2	—	3	(B)	3

(A) Accounts Receivable written off.

(B) Reduced reserve to appropriate level and to remove obsolete inventory.

PSEG POWER LLC

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2013—December 31, 2011

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2013						
Materials and Supplies Valuation Reserve	$ 22	$ 2	$ —	$ 16	(A)	$ 8
2012						
Materials and Supplies Valuation Reserve	$ 3	$ 21	$ —	$ 2	(A)	$ 22
2011						
Materials and Supplies Valuation Reserve	$ 4	$ 2	$ —	$ 3	(A)	$ 3

(A) Reduced reserve to appropriate level and to remove obsolete inventory.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2013—December 31, 2011

	Column A	Column B	Column C Additions		Column D		Column E
	Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
				Millions			
2013							
	Allowance for Doubtful Accounts	$ 56	$ 90	$ —	$ 90	(A)	$ 56
2012							
	Allowance for Doubtful Accounts	$ 56	$ 96	$ —	$ 96	(A)	$ 56
2011							
	Allowance for Doubtful Accounts	$ 67	$ 102	$ —	$ 113	(A)	$ 56

(A) Accounts Receivable written off.

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Term	Phrase/Description
ASC	Accounting Standards Codification FASB's official source of authoritative, nongovernmental U.S. GAAP
Base load	Minimum amount of electric power delivered or required over a given period of time at a constant rate, this is the level of demand that is seen as a minimum during a 24-hour day
BGS	Basic Generation Service PSE&G is required to provide BGS for all customers in New Jersey who are not supplied by a TPS.
BGS-Fixed Price	Basic Generation Service-Fixed Price Seasonally adjusted fixed prices charged for a three-year term for electric supply service to smaller industrial and commercial customers and residential customers who are not supplied by a TPS
BGSS	Basic Gas Supply Service Mechanism approved by the BPU for NJ utilities to recover all commodity costs related to supplying gas to residential customers
BPU	New Jersey Board of Public Utilities Agency responsible for regulating public utilities doing business in New Jersey
Capacity	Amount of electricity that can be produced by a specific generating facility
CAA	Clean Air Act
Combined Cycle	A method of generation whereby electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity
Congestion	Condition when the available capacity of a transmission line is being closely approached (or exceeded) by the electric power trying to go through it; at such times, alternative power line pathways (or local generators near the load) must be used instead
Distribution	The delivery of electricity to the retail customer's home, business or industrial facility through low voltage distribution lines
EDC	Electric Distribution Company A company that owns the power lines and equipment necessary to deliver purchased electricity to the end user
Energy Holdings	PSEG Energy Holdings L.L.C.
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board A private, not-for-profit organization whose primary purpose, as designated by the SEC, is to develop accounting standards for public companies in the U.S.
FERC	U.S. Federal Energy Regulatory Commission
Forward contracts	A customized, non-exchange traded contract in which the buyer is obligated to deliver a specified amount of a commodity with a predetermined price formula on a specified future date, at which time payment is due in full
GAAP	Generally Accepted Accounting Principles Standard framework of guidelines issued by the FASB for financial accounting used in the U.S.
GHG	Greenhouse gas emissions (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon) that trap the heat of the sun in the earth's atmosphere, increasing the mean global surface temperature of the earth

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Term	Phrase/Description
Hedging	Entering into a contract or transaction designed to reduce exposure to various risks, such as changes in market prices
Hope Creek	Hope Creek Nuclear Generating Station
ISO	Independent System Operator An independent, regulated entity established to manage a regional electric transmission system in a non-discriminatory manner and to help ensure the safety and reliability of the bulk of the power system
ITC	Investment Tax Credit A credit against income taxes, usually computed as a percent of the cost of investment in certain types of assets
Lifeline Program	A New Jersey social program for utility assistance that offers $225 per year to persons who meet the eligibility requirements
Load	Amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of consumers.
MBR	Market Based Rates Electric service prices determined in an open market system of supply and demand under which the price is set solely by agreement as to what a buyer will pay and a seller will accept
MGP	Manufactured Gas Plant
NDT	Nuclear Decommissioning Trust
ISO-NE	New England Power Pool An ISO comprised of an alliance of approximately 100 utility companies who manage and direct all major energy production and transmission in the New England states
NJDEP	New Jersey Department of Environmental Protection
NRC	U.S. Nuclear Regulatory Commission
NUG	Non-Utility Generation Power produced by independent power producers, exempt wholesale generators and other companies that have been exempted from traditional utility regulation
OPEB	Other Postretirement Benefits Benefits other than pensions payable to former employees
Outage	The period during which a generating unit, transmission line, or other facility is out of service due to scheduled (planned) or unscheduled maintenance
Peach Bottom	Peach Bottom Atomic Power Station
PJM	PJM Interconnection, L.L.C. A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 northeastern states and the District of Columbia
Power	PSEG Power LLC
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies

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Term	Phrase/Description
PRP	Potentially Responsible Parties
PSE&G	Public Service Electric and Gas Company
PSEG	Public Service Enterprise Group Incorporated
Renewable Energy	Energy derived from resources that are regenerative or that cannot be depleted (i.e. moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy)
Regulatory Asset	Costs deferred by a regulated utility company in accordance with Accounting Standard Codification Topic 980: Regulated operations (ASC 980)
Regulatory Liability	Costs recognized by a regulated utility company in accordance with ASC 980
RGGI	Regional Greenhouse Gas Initiative The first mandatory, market-based effort in the U. S. to reduce greenhouse gas emissions; states will sell emission allowances through auctions and invest proceeds in consumer benefits: energy efficiency, renewable energy, and other clean energy technologies
RPM	Reliability Pricing Model A process for pricing generation capacity based on overall system reliability requirements; using multi-year forward auctions, participants could bid capacity in the form of generation, demand response, or transmission to meet reliability needs by location and/or an ISO market
Salem	Salem Nuclear Generating Station
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
Services	PSEG Services Corporation
Spill Act	New Jersey Spill Compensation and Control Act
TPS	Third Party Supplier
Transmission	The high-voltage wires and networks that move electricity through states and regions in large quantities - from power plants where it is produced, to the distribution networks that deliver it to homes and businesses

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

By: /s/ RALPH IZZO
Ralph Izzo
Chairman of the Board, President and Chief Executive Officer

Date: February 26, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2014
/s/ CAROLINE DORSA **Caroline Dorsa**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2014
/s/ DEREK M. DIRISIO **Derek M. DiRisio**	Vice President and Controller (Principal Accounting Officer)	February 26, 2014
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper, Jr.**	Director	February 26, 2014
/s/ WILLIAM V. HICKEY **William V. Hickey**	Director	February 26, 2014
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 26, 2014
/s/ DAVID LILLEY **David Lilley**	Director	February 26, 2014
/s/ THOMAS A. RENYI **Thomas A. Renyi**	Director	February 26, 2014
/s/ HAK CHEOL SHIN **Hak Cheol Shin**	Director	February 26, 2014
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 26, 2014
/s/ SUSAN TOMASKY **Susan Tomasky**	Director	February 26, 2014
/s/ ALFRED W. ZOLLAR **Alfred W. Zollar**	Director	February 26, 2014

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC

By: /s/ WILLIAM LEVIS
William Levis
President and
Chief Operating Officer

Date: February 26, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2014
/s/ CAROLINE DORSA **Caroline Dorsa**	Executive Vice President and Chief Financial Officer and Director (Principal Financial Officer)	February 26, 2014
/s/ DEREK M. DIRISIO **Derek M. DiRisio**	Vice President and Controller (Principal Accounting Officer)	February 26, 2014
/s/ J.A. BOUKNIGHT, JR. **J.A. Bouknight, Jr.**	Director	February 26, 2014
/s/ WILLIAM LEVIS **William Levis**	Director	February 26, 2014
/s/ MARGARET M. PEGO **Margaret M. Pego**	Director	February 26, 2014

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By: /s/ RALPH LAROSSA
Ralph LaRossa
President and Chief Operating Officer

Date: February 26, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2014
/s/ CAROLINE DORSA **Caroline Dorsa**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2014
/s/ DEREK M. DIRISIO **Derek M. DiRisio**	Vice President and Controller (Principal Accounting Officer)	February 26, 2014
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper Jr.**	Director	February 26, 2014
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 26, 2014
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 26, 2014

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EXHIBIT INDEX

The following documents are filed as a part of this report:

a. PSEG:	
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 21:	Subsidiaries of the Registrant
Exhibit 23:	Consent of Independent Registered Public Accounting Firm
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31a:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32a:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document
b. Power:	
Exhibit 12a:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 23a:	Consent of Independent Registered Public Accounting Firm
Exhibit 31b:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31c:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32b:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32c:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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c. PSE&G:	
Exhibit 12b:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12c:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
Exhibit 23b:	Consent of Independent Registered Public Accounting Firm

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Exhibit 31d:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31e:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32d:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32e:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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S1-SSA-0009 - 11104

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 2,055	$ 2,011	$ 2,384	$ 2,616	$ 2,636
(Income) Loss from Equity Investees, net of Distributions	(7)	9	(4)	(19)	(25)
Fixed Charges	458	479	522	571	600
Capitalized Interest	(16)	(19)	(14)	(67)	(45)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	(2)	(6)
Total Earnings	$ 2,490	$ 2,480	$ 2,888	$ 3,099	$ 3,160
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 442	$ 465	$ 509	$ 555	$ 581
Interest Factor in Rentals	16	14	13	14	13
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	2	6
Total Fixed Charges	$ 458	$ 479	$ 522	$ 571	$ 600
Ratio of Earnings to Fixed Charges	5.44	5.18	5.53	5.43	5.27

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12.a

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 1,063	$ 1,099	$ 1,703	$ 1,932	$ 1,969
(Income) Loss from Equity Investees, net of Distributions	(10)	(6)	(12)	(8)	(7)
Fixed Charges	143	164	208	238	221
Capitalized Interest	1	(6)	(10)	(63)	(43)
Total Earnings	$ 1,197	$ 1,251	$ 1,889	$ 2,099	$ 2,140
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 139	$ 161	$ 205	$ 235	$ 219
Interest Factor in Rentals	4	3	3	3	2
Total Fixed Charges	$ 143	$ 164	$ 208	$ 238	$ 221
Ratio of Earnings to Fixed Charges	8.37	7.63	9.08	8.82	9.68

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.b

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 993	$ 835	$ 861	$ 591	$ 551
Fixed Charges	316	314	319	325	317
Capitalized Interest	(16)	(13)	(4)	(2)	(1)
Total Earnings	$ 1,293	$ 1,136	$ 1,176	$ 914	$ 867
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 309	$ 308	$ 314	$ 320	$ 313
Interest Factor in Rentals	7	6	5	5	4
Total Fixed Charges	$ 316	$ 314	$ 319	$ 325	$ 317
Ratio of Earnings to Fixed Charges	4.09	3.62	3.69	2.81	2.74

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.c

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 993	$ 835	$ 861	$ 591	$ 551
Fixed Charges	316	314	319	327	323
Capitalized Interest	(16)	(13)	(4)	(2)	(1)
Preferred Securities Dividend Requirements	—	—	—	(2)	(6)
Total Earnings	$ 1,293	$ 1,136	$ 1,176	$ 914	$ 867
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 309	$ 308	$ 314	$ 320	$ 313
Interest Factor in Rentals	7	6	5	5	4
Preferred Securities Dividend	—	—	—	1	4
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	—	1	2
Total Fixed Charges	$ 316	$ 314	$ 319	$ 327	$ 323
Ratio of Earnings to Fixed Charges	4.09	3.62	3.69	2.80	2.68

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 21

PUBLIC SERVICES ENTERPRISE GROUP INCORPORATED
SIGNIFICANT SUBSIDIARIES

Name	Ownership %	State of Incorporation
Public Service Electric and Gas Company	100	New Jersey
PSEG Power LLC	100	Delaware
PSEG Fossil LLC	100	Delaware
PSEG Nuclear LLC	100	Delaware
PSEG Energy Resources & Trade LLC	100	Delaware

The remaining subsidiaries of Public Service Enterprise Group Incorporated are not significant as defined in Regulation S-X.

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Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-120100, 333-106330, 033-44581, 033-44582, 333-193126 and 333-193127 on Form S-8 and Registration Statement No. 333-178143 on Form S-3 of our reports dated February 26, 2014, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Enterprise Group Incorporated and subsidiaries (the "Company,") and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated for the year ended December 31, 2013.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 26, 2014

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Exhibit 23a

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-175397 on Form S-3 of our report dated February 26, 2014, relating to the consolidated financial statements and consolidated financial statement schedule of PSEG Power LLC and subsidiaries, appearing in this Annual Report on Form 10-K of PSEG Power LLC for the year ended December 31, 2013.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 26, 2014

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Exhibit 23b

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-178133 on Form S-3 of our report dated February 26, 2014, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Electric and Gas Company and subsidiaries, appearing in this Annual Report on Form 10-K of Public Service Electric and Gas Company for the year ended December 31, 2013.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 26, 2014

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2014

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31a

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2014

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31b

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2014

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31c

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2014

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 31d

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2014

/s/ Ralph Izzo

Ralph Izzo
Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31e

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2014

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
February 26, 2014

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EXHIBIT 32a

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Carolina Dorsa

Carolina Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer
February 26, 2014

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EXHIBIT 32b

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer
February 26, 2014

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EXHIBIT 32c

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Carolina Dorsa

Carolina Dorsa
PSEG Power LLC
Chief Financial Officer
February 26, 2014

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EXHIBIT 32d

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo
Public Service Electric and Gas Company
Chief Executive Officer
February 26, 2014

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EXHIBIT 32e

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Carolina Dorsa

Carolina Dorsa
Public Service Electric and Gas Company
Chief Financial Officer
February 26, 2014

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2014

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange On Which Registered
Public Service Enterprise Group Incorporated	Common Stock without par value	New York Stock Exchange
	First and Refunding Mortgage Bonds	
Public Service Electric and Gas Company	9 1/4% Series CC, due 2021	New York Stock Exchange
	6 3/4% Series VV, due 2016	
	8%, due 2037	
	5%, due 2037	
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange

(Cover continued on next page)

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(Cover continued from previous page)

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
Public Service Electric and Gas Company	Medium-Term Notes
PSEG Power LLC	Limited Liability Company Membership Interest

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Public Service Enterprise Group Incorporated	Yes ☒	No ☐
Public Service Electric and Gas Company	Yes ☒	No ☐
PSEG Power LLC	Yes ☒	No ☐

Indicate by check mark if each of the registrants is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☒

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2014 was $20,598,517,672 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Public Service Enterprise Group Incorporated's sole class of Common Stock as of January 30, 2015 was 506,179,029.

As of January 30, 2015, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K. Each is filing its Annual Report on Form 10-K with the reduced disclosure format authorized by General Instruction I.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K of Public Service Enterprise Group Incorporated	Documents Incorporated by Reference
III	Portions of the definitive Proxy Statement for the 2015 Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 9, 2015, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words “anticipate,” “intend,” “estimate,” “believe,” “expect,” “plan,” “should,” “hypothetical,” “potential,” “forecast,” “project,” variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1A. Risk Factors, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations (MD&A), Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities, and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC) including our subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulations, including market structures and transmission planning,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- any deterioration in our credit quality or the credit quality of our counterparties,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as for transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies, and
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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FILING FORMAT AND GLOSSARY

This combined Annual Report on Form 10-K is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to "we," "us," and "our" relate to PSEG or to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 190.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document that we file at the Public Reference Room of the SEC at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. You may also obtain our filed documents from commercial document retrieval services, the SEC's internet website at www.sec.gov or our website at www.pseg.com. Information on our website should not be deemed incorporated into or as a part of this report. Our Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

PART I

ITEM 1. BUSINESS

We were incorporated under the laws of the State of New Jersey in 1985 and our principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07102. We conduct our business through two direct wholly owned subsidiaries, Power and PSE&G, each of which also has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102.

We are an energy company with a diversified business mix. Our operations are located primarily in the Northeastern and Mid- Atlantic United States. Our business approach focuses on operational excellence, financial strength and disciplined investment. As a holding company, our profitability depends on our subsidiaries' operating results. Below are descriptions of our two principal direct operating subsidiaries.

PSE&G	Power
A New Jersey corporation, incorporated in 1924, which is a franchised public utility in New Jersey. It is also the provider of last resort for gas and electric commodity service for end users in its service territory.	A Delaware limited liability company formed in 1999 that integrates its merchant nuclear, fossil and renewable generating asset operations with its wholesale energy sales, fuel supply and energy trading functions.
Earns revenues from its regulated rate tariffs under which it provides electric transmission and electric and gas distribution to residential, commercial and industrial customers in its service territory. It also offers appliance services and repairs to customers throughout its service territory.	Earns revenues from selling under contract or on the spot market a range of diverse products such as electricity, natural gas, emissions credits and a series of energy-related products used to optimize the operation of the energy grid.
Has also implemented regulated demand response and energy efficiency programs and invested in solar generation within New Jersey.	

Our other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and our operating subsidiaries with certain management, administrative and general services at cost.

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The following is a more detailed description of our business, including a discussion of our:

- Business Operations and Strategy
- Competitive Environment
- Employee Relations
- Regulatory Issues
- Environmental Matters

BUSINESS OPERATIONS AND STRATEGY

PSE&G

Our regulated transmission and distribution public utility, PSE&G, distributes electric energy and gas to customers within a designated service territory running diagonally across New Jersey where approximately 6.2 million people, or about 70% of New Jersey's population resides.

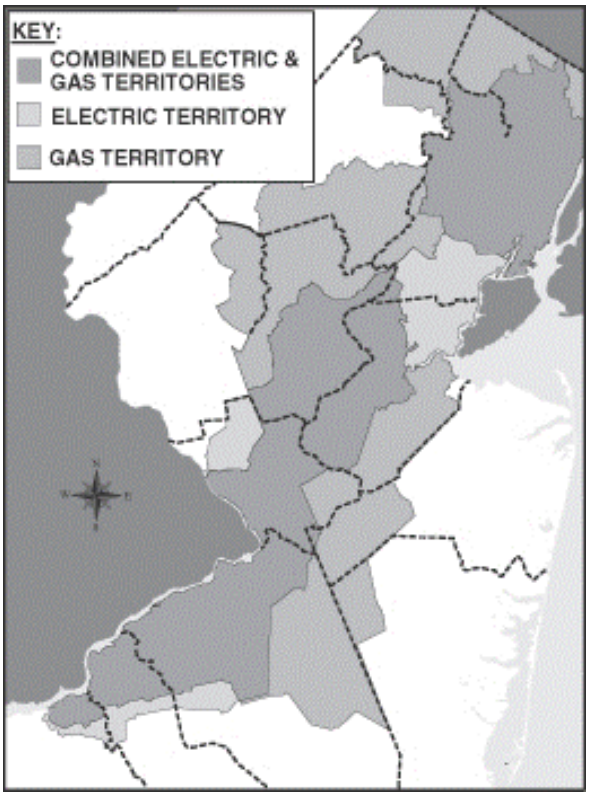

Products and Services

Our utility operations primarily earn margins through the transmission and distribution of electricity and the distribution of gas.

- **Transmission**—the movement of electricity at high voltage from generating plants to substations and transformers, where it is then reduced to a lower voltage for distribution to homes, businesses and industrial customers. Our revenues for these services are based upon tariffs approved by the Federal Energy Regulatory Commission (FERC).
- **Distribution**—the delivery of electricity and gas to the retail customer's home, business or industrial facility. Our revenues for these services are based upon tariffs approved by the New Jersey Board of Public Utilities (BPU).

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The commodity portion of our utility business' electric and gas sales is managed by basic generation service (BGS) and basic gas supply service (BGSS) suppliers. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for our utility operations.

We also earn margins through competitive services, such as appliance repair.

In addition to our current utility products and services, we have implemented several programs to increase the level of regulated solar generation within New Jersey, including:

- programs to help finance the installation of solar power systems throughout our electric service area, and
- programs to develop, own and operate solar power systems.

We have also implemented a set of energy efficiency and demand response programs to encourage conservation and energy efficiency by providing energy and cost saving measures directly to businesses and families. For additional information concerning these programs and the components of our tariffs, see Regulatory Issues—State Regulation and Part II, Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

How PSE&G Operates

We are a transmission owner in PJM Interconnection, L.L.C. (PJM) and we provide distribution service to 2.2 million electric customers and 1.8 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately three hundred suburban and rural communities.

Transmission

We use formula rates for our transmission cost of service and investments. Formula-type rates provide a method of rate recovery where the transmission owner annually determines its revenue requirements through a fixed formula which considers Operations and Maintenance expenditures, Rate Base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. Our current approved rates provide for a base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn an additional incentive rate. For more information, see Regulatory Issues—Federal Regulation—Transmission Regulation.

Transmission Statistics

December 31, 2014		
Network Circuit Miles	Billing Peak Megawatt (MW)	Historical Annual Load Growth 2010-2014
1,659	9,515	(0.4)%

In April 2014, we completed our North Central Reliability project, an upgrade of 55 circuit miles of 138 kilovolts (kV) transmission line to 230 kV and conversion of six existing stations to 230 kV operation and our Burlington-Camden project, an upgrade of 37 circuit miles of 138 kV transmission line to 230 kV.

During 2014, we continued to execute four major regional transmission projects for which we were assigned construction responsibility by PJM:

Major Transmission Projects
As of December 31, 2014

Project	Total Estimated Project Costs Up To	Total Project Spend	Expected In-Service Date
	Millions		
Susquehanna-Roseland 500 kV (A)	$790	$775	June 2015
Northeast Grid Reliability 230 kV	$907	$569	June-December 2015
Mickleton-Gloucester-Camden 230 kV	$435	$278	June 2015
Bergen-Linden Corridor 345 kV	$1,200	$40	June 2018

(A) On April 1, 2014, Phase One was completed on schedule, placing into service the eastern part of the transmission line from Hopatcong to Roseland, New Jersey. Construction of the transmission line from New Jersey to the Pennsylvania border was completed in 2014.

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Distribution

PSE&G distributes gas and electricity to end users in our respective franchised service territories. Our approved rates, established in our most recent gas and electric base rate proceeding completed in mid-2010, provide for an allowed ROE of 10.3% on distribution rate base. The BPU has also approved a series of PSE&G infrastructure, energy efficiency and renewable energy investment programs with cost recovery through various clause mechanisms, with allowed ROEs ranging from 9.75% to 10.3%. Our load requirements are split among residential, commercial and industrial customers, as described in the following table for 2014.

	% of 2014 Sales	
Customer Type	**Electric**	**Gas**
Commercial	58%	36%
Residential	32%	60%
Industrial	10%	4%
Total	**100%**	**100%**

While our customer base has remained steady, electric load has declined and gas load has increased as illustrated below:

Electric and Gas Distribution Statistics

December 31, 2014

	Number of Customers	Electric Sales and Gas Firm Sales (A)	Historical Annual Load Growth 2010-2014
Electric	2.2 Million	40,737 Gigawatt hours (GWh)	(0.6)%
Gas	1.8 Million	2,628 Million Therms	2.0%

(A) Excludes Contract Service Gas (CSG) rate class sales, which do not impact margin.

The decline in electric sales is the result of changes in customer usage patterns, including conservation and more energy efficient appliances. Gas firm sales increased to all customer classes as a result of lower gas prices and more favorable weather. Only gas firm sales impact margin.

Solar Generation

In order to support New Jersey's Energy Master Plan and the state's renewable energy goals, we have undertaken two major solar initiatives at PSE&G, the Solar Loan Program and the Solar 4 All and Solar 4 All Extension Programs. Our Solar Loan Program provides solar system financing to our residential and commercial customers. The loans are repaid with cash or solar renewable energy certificates (SRECs). We sell the SRECs used to repay the loans through a periodic auction, the proceeds of which are used to offset program costs. Our Solar 4 All Programs invest in utility-owned solar photovoltaic (PV) centralized solar systems installed on PSE&G property and third party sites, including landfill facilities, and solar panels installed on distribution system poles in our electric service territory. We sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition, we sell SRECs generated by the projects through the same periodic auction used in the loan program, the proceeds of which are used to offset program costs. As of December 31, 2014, we have invested an aggregate of approximately $765 million in both solar programs.

Supply

Although commodity revenues make up almost 43% of our revenues, we make no margin on the default supply of electricity and gas since the actual costs are passed through to our customers.

All electric and gas customers in New Jersey have the ability to choose their own electric energy and/or gas supplier. Pursuant to BPU requirements, we serve as the supplier of last resort for two types of electric and gas customers within our service territory that are not served by another supplier. The first type, which represents about 80% of PSE&G's load requirements, provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Residential Small Commercial Pricing (RSCP)). These rates change annually on June 1 and are based on the average price obtained at auctions in the current year and two prior years. The second type provides default supply for larger customers, with energy priced at hourly PJM real-time market prices for a contract term of 12 months (BGS-CIEP).

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We procure the supply to meet our BGS obligations through auctions authorized by the BPU for New Jersey's total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers are authorized to supply BGS to New Jersey's electric distribution companies (EDCs). Once validated by the BPU, electricity prices for BGS service are set. Approximately one-third of PSE&G's total BGS-RSCP eligible load is auctioned each year for a three-year term. For information on current prices, see Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

PSE&G procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with Power. The BPU has approved a mechanism designed to recover all gas commodity costs related to BGSS for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. PSE&G's revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each year. In addition, we have the ability to put in place two self-implementing BGSS increases on December 1 and February 1 of 5% and also may reduce the BGSS rate at any time. See Part II, Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities for information on recent self-implementing credits. Any difference between rates charged under the BGSS contract and rates charged to our residential customers is deferred and collected or refunded through adjustments in future rates. Commercial and industrial customers that do not select third party suppliers are also supplied under the BGSS arrangement. These customers are charged a market-based price largely determined by prices for commodity futures contracts.

Markets and Market Pricing

Historically, there has been significant volatility in commodity prices. Such volatility can have a considerable impact on us since a rising commodity price environment results in higher delivered electric and gas rates for customers. This could result in decreased demand for electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs from our customers may be deferred under our regulated rate structure. A declining commodity price on the other hand, would be expected to have the opposite effect. For additional information, including the impact of natural gas commodity prices on electricity prices such as BGS, see Part II, Item 7. MD&A—Executive Overview of 2014 and Future Outlook.

Power

Through Power, we seek to produce low-cost electricity by efficiently operating our nuclear, coal, gas, oil-fired and renewable generation assets, while balancing generation output, fuel requirements and supply obligations through energy portfolio management. We use the generation we own combined with commodity contracts and financial instruments to cover our commitments for BGS in New Jersey and other bilateral supply contract agreements.

Products and Services

As a merchant generator, our profit is derived from selling a range of products and services under contract to power marketers and to others, such as investor-owned and municipal utilities, and to aggregators who resell energy to retail consumers, or in the open market. These products and services include:

- **Energy**—the electrical output produced by generation plants that is ultimately delivered to customers for use in lighting, heating, air conditioning and operation of other electrical equipment. Energy is our principal product and is priced on a usage basis, typically in cents per kilowatt hour (kWh) or dollars per megawatt hour (MWh).
- **Capacity**—distinct from energy, capacity is a market commitment that a given generation unit will be available to an Independent System Operator (ISO) for dispatch when it is needed to meet system demand. Capacity is typically priced in dollars per MW for a given sale period (e.g. day or month).
- **Ancillary Services**—related activities supplied by generation unit owners to the wholesale market that are required by the ISO to ensure the safe and reliable operation of the bulk power system. Owners of generation units may bid units into the ancillary services market in return for compensatory payments. Costs to pay generators for ancillary services are recovered through charges collected from market participants.
- **Emissions Allowances and Congestion Credits**—Emissions allowances (or credits) represent the right to emit a specific amount of certain pollutants. Allowance trading is used to control air pollution by providing economic incentives for achieving reductions in the emissions of pollutants. Congestion credits (or Financial Transmission Rights) are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path.

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Power also sells wholesale natural gas, primarily through a full-requirements BGSS contract with PSE&G to meet the gas supply requirements of PSE&G's customers. This long-term arrangement had been for an initial period which extended through March 31, 2012 and continued on a year-to-year basis unless terminated by either party with a one year notice. On March 19, 2014, the BPU approved an extension of the BGSS contract to March 31, 2019 and then year to year thereafter unless terminated by either party with a two year notice.

Approximately 46% of PSE&G's peak daily gas requirements is provided from Power's firm gas transportation capacity, which is available every day of the year. Power satisfies the remainder of PSE&G's requirements from storage contracts, liquefied natural gas, seasonal purchases, contract peaking supply, propane and refinery gas. Based upon the availability of natural gas beyond PSE&G's daily needs, Power also sells gas to others and uses it in its generation fleet.

In addition to its nuclear and fossil generation fleet, Power owns and operates 109 MW direct current (dc) of PV solar generation facilities and has a 50% ownership interest in a 208 MW oil-fired generation facility in Hawaii.

The remainder of this section about Power covers our nuclear and fossil fleet in the Mid-Atlantic and Northeast regions which comprise the vast majority of Power's operations and financial performance.

How Power Operates

Nearly all of our generation capacity consists of nuclear and fossil generation (13,146 MW) that is located in the Northeast and Mid-Atlantic regions of the United States in some of the country's largest and most developed electricity markets. For additional information see Item 2. Properties.

The map below shows the locations of our Northeast and Mid-Atlantic nuclear and fossil generation facilities:

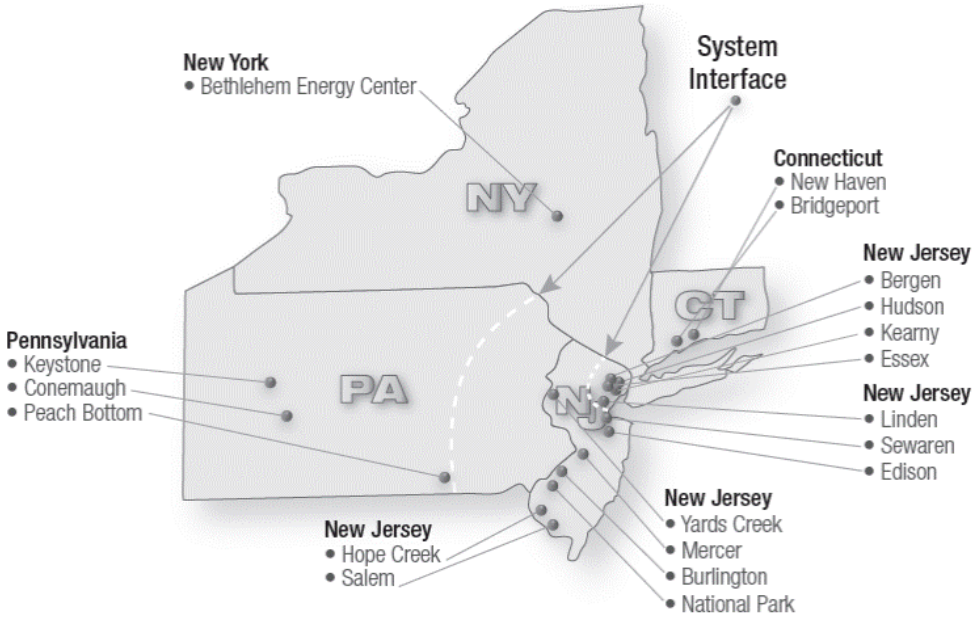

- **Generation Capacity**

  Our nuclear and fossil installed capacity utilizes a diverse mix of fuels: 46% gas, 28% nuclear, 18% coal, 7% oil and 1% pumped storage. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2014 was approximately 54,000 GWh. The generation mix by fuel type has changed slightly in recent years due to the relatively favorable price of natural gas as compared to coal, making it more economical to run certain of our gas units in place of our coal units. The following table indicates the proportionate share of generating output by fuel type in 2014.

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Generation by Fuel Type (A)	Actual 2014	
Nuclear:		
New Jersey facilities	37%	
Pennsylvania facilities	17%	
Fossil:		
Coal:		
Pennsylvania facilities	9%	
Connecticut facilities	2%	
Coal and Natural Gas:		
New Jersey facilities	3%	
Natural Gas and Oil:		
New Jersey facilities	24%	
New York facilities	8%	
Connecticut facilities	—%	(B)
Total	**100%**	

(A) Excludes pumped storage, solar facilities and fossil generation in Hawaii
(B) Less than one percent

- **Generation Dispatch**

Our generation units are typically characterized as serving one or more of three general energy market segments: base load; load following; and peaking, based on their operating capability and performance. On a capacity basis, our portfolio of generation assets consists of 34% base load, 44% load following and 22% peaking. This diversity helps to reduce the risk associated with market demand cycles and allows us to participate in the market at each segment of the dispatch curve.

- **Base Load Units** run the most and typically are called to operate whenever they are available. These units generally derive revenues from energy and capacity sales. Variable operating costs are low due to the combination of highly efficient operations and the use of relatively lower-cost fuels. Performance is generally measured by the unit's "capacity factor," or the ratio of the actual output to the theoretical maximum output. In 2014, our base load capacity factors were as follows:

Unit	2014 Capacity Factor
Nuclear	
Salem Unit 1	85.8%
Salem Unit 2 (A)	72.6%
Hope Creek	97.9%
Peach Bottom Unit 2	84.7%
Peach Bottom Unit 3	99.2%
Coal	
Keystone	77.4%
Conemaugh	73.9%

(A) Salem Unit 2's capacity factor in 2014 was negatively affected by an extended outage to make repairs to the unit's reactor coolant pumps.

- **Load Following Units** typically operate between 20% and 70% of the time. The operating costs are higher per unit of output than for base load units due to the use of higher-cost fuels such as oil, natural gas and, in some cases, coal or lower overall unit efficiency. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.

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- **Peaking Units** run the least amount of time and may utilize higher-priced fuels. These units typically operate less than 20% of the time. Costs per unit of output tend to be much higher than for base load units given the combination of higher heat rates and fuel costs. The majority of revenues are from capacity and ancillary service sales. The characteristics of these units enable them to capture energy revenues during periods of high energy prices.

In the energy markets in which we operate, owners of power plants specify to the ISO prices at which they are prepared to generate and sell energy based on the marginal cost of generating energy from each individual unit. The ISOs will generally dispatch in merit order, calling on the lowest variable cost units first and dispatching progressively higher-cost units until the point that the entire system demand for power (known as the system "load") is satisfied reliably. Base load units are dispatched first, with load following units next, followed by peaking units.

During periods when one or more parts of the transmission grid are operating at full capability, thereby resulting in a constraint on the transmission system, it may not be possible to dispatch units in merit order without violating transmission reliability standards. Under such circumstances, the ISO may dispatch higher-cost generation out of merit order within the congested area and power suppliers will be paid an increased Locational Marginal Price (LMP) in congested areas, reflecting the bid prices of those higher-cost generation units.

The following chart depicts the unconstrained merit order of dispatch of our units in PJM, the ISO in the region where most of our generation units are located, based on illustrative historical dispatch cost. It should be noted that market price fluctuations have resulted in changes from historical norms, with lower gas prices allowing some gas-fired generation to displace some coal-fired generation in the load-following portion of the curve.

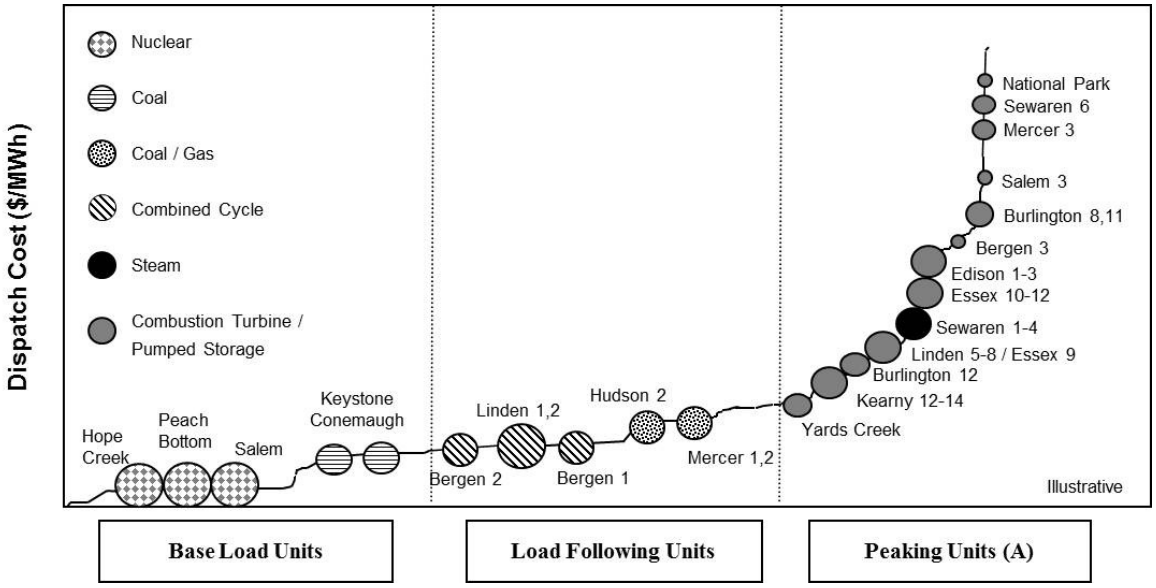

(A)The National Park, Sewaren 6, Mercer 3, Salem 3, Burlington 8 and 11, Bergen 3, Edison 1, 2 and 3 and Essex 10, 11 and 12 peaking units are scheduled to be retired in June 2015. Salem 3 is expected to continue to be used as an emergency backup generator for the Salem nuclear site.

The size of each facility's circle in the above chart illustrates the relative MW generating capacity of that facility. For additional information on each of our generation facilities, see Item 2. Properties.

Typically, the bid price of the last unit dispatched by an ISO establishes the energy market-clearing price. After considering the market-clearing price and the effect of transmission congestion and other factors, the ISO calculates the LMP for every location in the system. The ISO pays all units that are dispatched their respective LMP for each MWh of energy produced, regardless of their specific bid prices. Since bids generally approximate the marginal cost of production, units with lower marginal costs typically generate higher operating profits than units with comparatively higher marginal costs.

This method of determining supply and pricing creates a situation where natural gas prices often have a major influence on the price that generators will receive for their output, especially in periods of relatively strong demand. Therefore, changes in the price of natural gas will often translate into changes in the wholesale price of electricity. This can be seen in the following

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graphs which present historical annual spot prices and forward calendar prices as averaged over each year at two liquid trading hubs.

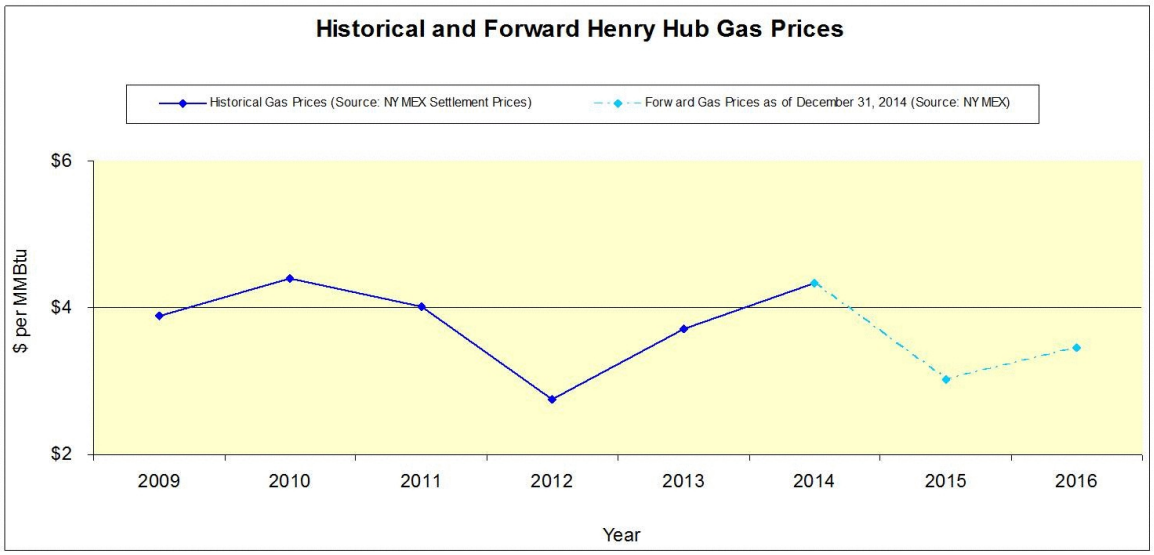

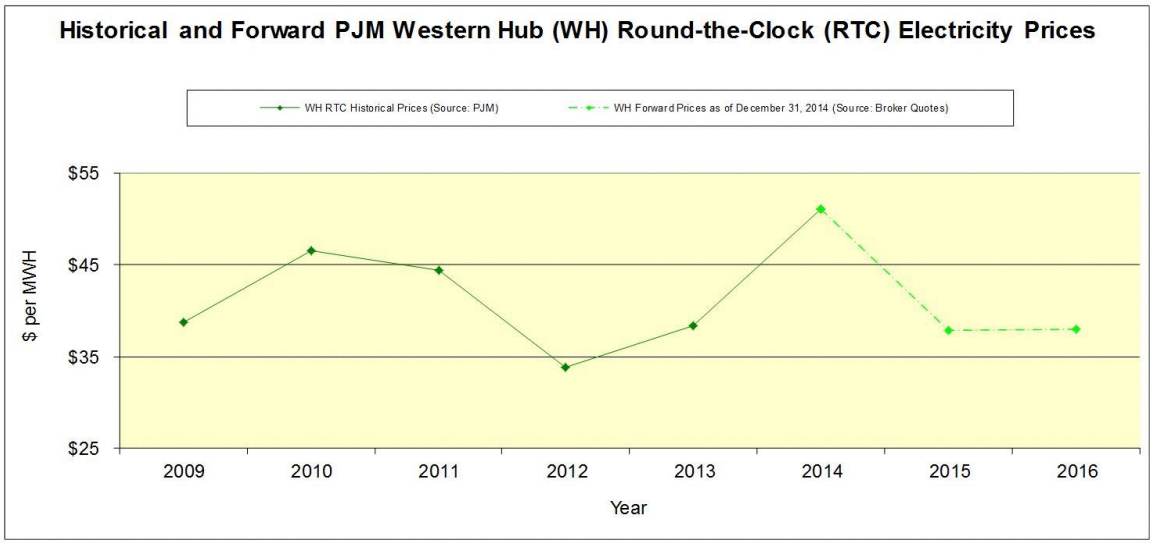

Historical data implies that the price of natural gas will continue to have a strong influence on the price of electricity in the primary markets in which we operate.

The prices reflected in the preceding graphs above do not necessarily illustrate our contract prices, but they are representative of market prices at relatively liquid hubs, with nearer-term forward pricing generally resulting from more liquid markets than pricing for later years. In addition, the prices do not reflect locational differences resulting from congestion or other factors, such as the availability of natural gas from the Marcellus and other shale-gas regions, which can be considerable. While these prices provide some perspective on past and future prices, the forward prices are volatile and there can be no assurance that such prices will remain in effect or that we will be able to contract output at these forward prices.

Fuel Supply

- ***Nuclear Fuel Supply***—We have long-term contracts for nuclear fuel. These contracts provide for:
  - purchase of uranium (concentrates and uranium hexafluoride),

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- conversion of uranium concentrates to uranium hexafluoride,
- enrichment of uranium hexafluoride, and
- fabrication of nuclear fuel assemblies.

- ***Coal Supply***—Our Keystone, Conemaugh and Bridgeport stations operate on coal. Our Hudson and Mercer stations have the ability to operate on both coal and natural gas. We have coal contracts with numerous suppliers. Coal is delivered to our units through a combination of rail, truck, barge and ocean shipments.

  In order to control emissions levels, our Bridgeport 3 unit uses a specific type of coal obtained from Indonesia. If the supply from Indonesia or equivalent coal from other sources were not available for this facility, its long-term operations would be adversely impacted since additional material capital expenditures would be required to modify this station to enable it to operate using a broader mix of coal sources.

- ***Gas Supply***—Natural gas is the primary fuel for the bulk of our load following and peaking fleet. We purchase gas directly from natural gas producers and marketers. These supplies are transported to New Jersey by four interstate pipelines with which we have contracted. In addition, we have firm gas transportation contracts to serve a portion of the gas requirements for our Bethlehem Energy Center (BEC) station in New York.

  We have 1.3 billion cubic feet-per-day of firm transportation capacity and 0.9 billion cubic feet-per-day of firm storage delivery under contract to meet our obligations under the BGSS contract. This capacity includes approximately 0.6 billion cubic feet-per-day of access to the northeast Pennsylvania Marcellus shale gas region. On an as-available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet.

  In September 2014, Power obtained an equity interest with an expected investment of $100 million-$120 million in the approximately 110 mile PennEast Pipeline to transport natural gas from eastern Pennsylvania to New Jersey with a targeted in-service date of November 2017. Power has contracted for approximately 125 million cubic feet-per-day of delivery capability on the PennEast Pipeline.

- ***Oil***—Oil is used as the primary fuel for one load following steam unit and six combustion turbine peaking units and can be used as an alternate fuel by several load following and peaking units that have dual-fuel capability. Oil for operations is drawn from on-site storage and is generally purchased on the spot market and delivered by truck, barge or pipeline.

We expect to be able to meet the fuel supply demands of our customers and our own operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather and other factors. For additional information, see Part II, Item 7. MD&A—Executive Overview of 2014 and Future Outlook and Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Markets and Market Pricing

The vast majority of Power's generation assets are located in three centralized, competitive electricity markets operated by ISO organizations all of which are subject to the regulatory oversight of the FERC:

- **PJM Regional Transmission Organization**—PJM conducts the largest centrally dispatched energy market in North America. It serves over 61 million people, nearly 20% of the total United States population, and has a peak demand of 165,492 MW. The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The majority of our generating stations operate in PJM.

- **New York**—The New York ISO (NYISO) is the market coordinator for New York State and is responsible for managing the New York Power Pool and for administering its energy marketplace. This service area has a population of about 20 million and a peak demand of 33,956 MW. Our BEC station operates in New York.

- **New England**—The ISO-New England (ISO-NE) is the market coordinator for the New England Power Pool and for administering its energy marketplace which covers Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. This service area has a population of about 14 million and a peak demand of 28,130 MW. Our Bridgeport and New Haven stations operate in Connecticut.

The price of electricity varies by location in each of these markets. Depending upon our production and our obligations, these price differentials may increase or decrease our profitability.

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Commodity prices, such as electricity, gas, coal, oil and emissions, as well as the availability of our diverse fleet of generation units to operate, also have a considerable effect on our profitability. These commodity prices have been, and continue to be, subject to significant market volatility. Over the long-term, the higher the forward prices are, the more attractive an environment exists for us to contract for the sale of our anticipated output. However, higher prices also increase the cost of replacement power, thereby placing us at greater risk should our generating units fail to function effectively or otherwise become unavailable.

Over the past few years, lower wholesale natural gas prices have resulted in lower electric energy prices. One of the reasons for the lower natural gas prices is greater supply from more recently-developed sources, such as shale gas. This trend has reduced margin on forward sales as we re-contract our expected generation output.

In addition to energy sales, we earn revenue from capacity payments for our generating assets. These payments are compensation for committing our generating capacity to the ISO for dispatch at its discretion. Capacity payments reflect the value to the ISO of assurance that there will be sufficient generating capacity available at all times to meet system reliability and energy requirements. Currently, there is sufficient capacity in the markets in which we operate. However, in certain areas of these markets there are transmission system constraints which raise concerns about reliability and create a more acute need for capacity.

In PJM and ISO-NE, where we operate most of our generation, the market design for capacity payments provides for a structured, forward-looking, transparent capacity pricing mechanism. This is through the Reliability Pricing Model (RPM) in PJM and the Forward Capacity Market (FCM) in ISO-NE. These mechanisms provide greater transparency regarding the value of capacity and provide a pricing signal to prospective investors in new generating facilities so as to encourage expansion of capacity to meet future market demands.

The prices to be received by generating units in PJM for capacity have been set through RPM base residual auctions and depend upon the zone in which the generating unit is located. For each delivery year, the prices differ in the various areas of PJM, depending on the constraints in each area of the transmission system. Keystone and Conemaugh receive lower prices than the majority of our PJM generating units since there are fewer constraints in that region and our generating units in northern New Jersey usually receive higher pricing.

Our PJM generating units are located in several zones and Power expects to realize the following average capacity prices from the base auctions which have been completed:

Delivery Year	MW-day
June 2014 to May 2015	$166
June 2015 to May 2016	$167
June 2016 to May 2017	$169
June 2017 to May 2018	$165

The price that must be paid by an entity serving load in the various zones is also set through these auctions. These prices can be higher or lower than the prices noted in the table above due to import and export capability to and from lower-priced areas.

Like PJM and ISO-NE, the NYISO provides capacity payments to its generating units, but unlike the other two markets, the New York market does not provide a forward price signal beyond a six month auction period.

We have obtained price certainty for our PJM capacity through May 2018 and New England capacity through May 2019 through the RPM and FCM pricing mechanisms, respectively.

On a prospective basis, many factors may affect the capacity pricing, including but not limited to:

- load and demand,
- available amounts of demand response resources,
- capacity imports from external regions,
- availability of generating capacity (including retirements, additions, derates, forced outage rates, etc.),
- transmission capability between zones,
- pricing mechanisms, including potentially increasing the number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM and the other ISOs may propose over time, including PJM's recent proposal that provides the opportunity for additional energy and capacity market compensation to generators like Power that certify their availability during emergency system conditions, and

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- legislative and/or regulatory actions that permit states to subsidize local electric power generation.

For additional information on the RPM and FCM markets, as well as on state subsidization through various mechanisms, see Regulatory Issues—Federal Regulation.

Hedging Strategy

To mitigate volatility in our results, we seek to contract in advance for a significant portion of our anticipated electric output, capacity and fuel needs. We seek to sell a portion of our anticipated lower-cost generation over a multi-year forward horizon, normally over a period of two to three years. We believe this hedging strategy increases stability of earnings.

Among the ways in which we hedge our output are: (1) sales at PJM West and (2) BGS and similar full-requirements contracts. Sales at PJM West reflect block energy sales at the liquid PJM Western Hub and other transactions that seek to secure price certainty for our generation related products. In addition, the BGS-RSCP contract, a full-requirements contract that includes energy and capacity, ancillary and other services, is awarded for three-year periods through an auction process managed by the BPU. The volume of BGS contracts and the mix of electric utilities that our generation operations serve will vary from year to year. Pricing for the BGS contracts, including a capacity component, for recent and future periods by purchasing utility is as follows:

Load Zone ($/MWh)	2012-2015	2013-2016	2014-2017	2015-2018
PSE&G	$83.88	$92.18	$97.39	$99.54
Jersey Central Power & Light Company (JCP&L)	$81.76	$83.70	$84.44	$80.42
Atlantic City Electric Company	$85.10	$87.27	$87.80	$86.06
Rockland Electric Company	$92.51	$92.58	$95.61	$90.66

Although we enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation, there is variability in both our actual output as well as in our hedges. Our actual output will vary based upon total market demand, the relative cost position of our units compared to other units in the market and the operational flexibility of our units. Our hedge volume can also vary, depending on the type of hedge into which we have entered. The BGS auction, for example, results in a contract that provides for the supplier to serve a percentage of the default load of a New Jersey EDC, that is, the load that remains after some customers have chosen to be served directly either by third party suppliers or through municipal aggregation. The amount of power supplied through the BGS auction varies based on the level of the EDC's default load, which is affected by the number of customers who are served by a third party supplier, as well as by other factors such as weather and the economy.

In recent years, as market prices declined from previous levels, there was an incentive for more of the smaller commercial and industrial electric customers to switch to third party suppliers. In a falling price environment, this has a negative impact on our margins, as the anticipated BGS pricing is replaced by lower spot market pricing. As average BGS rates have declined to a level that more closely resembles current market prices, customers may see less of an incentive to switch to third party suppliers. We are unable to determine the degree to which this switching, or "migration," will continue, but the impact on our results could be material should market prices fall or rise significantly.

As of February 12, 2015, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2017.

Base Load Generation	2015	2016	2017
Generation Sales	100%	80%-85%	40%-45%

In a changing market environment, this hedging strategy may cause our realized prices to differ materially from current market prices. In a rising price environment, this strategy normally results in lower margins than would have been the case had no hedging activity been conducted. Alternatively, in a falling price environment, this hedging strategy will tend to create margins higher than those implied by the then-current market.

We take a more opportunistic approach in hedging our anticipated natural gas-fired generation. The generation from these units is less predictable, as a significant portion of these units will only dispatch when aggregate market demand has exceeded the supply provided by lower-cost units. Additionally, the recent development of low-cost gas supplies in the Marcellus region presents opportunities during certain portions of the year to procure gas for our generating units at attractive prices.

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Our fuel strategy is to maintain certain levels of uranium in inventory and to make periodic purchases to support such levels. Our nuclear fuel commitments cover approximately 100% of our estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2019. We also have various long-term fuel purchase commitments for coal to support our fossil generation stations. These purchase obligations are consistent with our strategy in general to enter into contracts for our fuel supply in comparable volumes to our sales contracts.

Other

Energy Holdings primarily owns and manages a portfolio of lease investments. Over the past several years, we have terminated all of our international leveraged leases in order to reduce the cash tax exposure related to these leases. We have also reduced our risk by opportunistically monetizing all of our previous international investments.

The majority of Energy Holdings' remaining $836 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2014, 69% of our total leveraged lease investments were rated as below investment grade by Standard & Poor's.

Energy Holdings' leveraged leasing portfolio is designed to provide a fixed rate of return. Leveraged lease investments involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease financing, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and, with respect to our lease investments, is not presented on our Consolidated Balance Sheets.

The lessor acquires economic and tax ownership of the asset and then leases it to the lessee for a period of time no greater than 80% of its remaining useful life. As the owner, the lessor is entitled to depreciate the asset under applicable federal and state tax guidelines. The lessor receives income from lease payments made by the lessee during the term of the lease and from tax benefits associated with interest and depreciation deductions with respect to the leased property. Our ability to realize these tax benefits is dependent on operating gains generated by our other operating subsidiaries and allocated pursuant to the consolidated tax sharing agreement between us and our operating subsidiaries.

Lease rental payments are unconditional obligations of the lessee and are set at levels at least sufficient to service the non-recourse lease debt. The lessor is also entitled to any residual value associated with the leased asset at the end of the lease term. An evaluation of the after-tax cash flows to the lessor determines the return on the investment. Under accounting principles generally accepted in the United States (GAAP), the leveraged lease investment is recorded net of non-recourse debt and income is recognized as a constant return on the net unrecovered investment.

For additional information on leases, including the credit, tax and accounting risks, see Item 1A. Risk Factors, Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Credit Risk, and Item 8. Financial Statements and Supplementary Data—Note 7. Financing Receivables.

In accordance with a twelve year Amended and Restated Operations Services Agreement (OSA) entered into by PSEG LI and the LIPA, PSEG LI commenced operating LIPA’s electric T&D system in Long Island, New York on January 1, 2014. As required by the OSA, PSEG LI also provides certain administrative support functions to LIPA. PSEG LI uses its brand in the Long Island T&D service area. Pursuant to the OSA, PSEG LI acts as LIPA's agent in performing many of its obligations and in return (a) receives reimbursement for pass-through operating expenditures, (b) receives a fixed management fee and (c) is eligible to receive an incentive fee contingent on meeting established performance metrics. In addition, there is the opportunity for the parties to extend the contract for an additional eight years subject to the achievement by PSEG LI of certain performance levels during the initial term of the OSA. Also, as of January 2015, Power began providing fuel procurement and power management services to LIPA under separate agreements.

On July 1, 2014, PSEG LI submitted a proposal to LIPA to invest up to $200 million of capital in equipment at customer facilities that would improve energy efficiency and reduce peak load. PSEG LI proposed to make the investments from 2015 through 2018 and recover its investment and earn a return over approximately ten years. On October 6, 2014, PSEG LI filed an interim update which increased the size of the proposed program to approximately $345 million, reaffirmed its original investment proposal to fund up to $200 million of the program and also offered an alternate economic structure which included a performance incentive mechanism rather than utilizing PSEG LI’s capital. The New York State Department of Public Service will review the proposal and make a recommendation to LIPA which is expected to take action on the proposal in 2015.

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COMPETITIVE ENVIRONMENT

PSE&G

Our transmission and distribution business is minimally impacted when customers choose alternate electric or gas suppliers since we earn our return by providing transmission and distribution service, not by supplying the commodity. Increased reliance by customers on net-metered generation, including solar, and changes in customer behaviors can result in decreased reliance on our system and impact our revenues and investment opportunities. The demand for electric energy and gas by customers is affected by customer conservation, economic conditions, weather and other factors not within our control.

Changes in the current policies for building new transmission lines, such as those ordered by the FERC and being implemented by PJM and other ISOs to eliminate contractual provisions that previously provided us a "right of first refusal" (ROFR) to construct projects in our service territory, could result in third party construction of transmission lines in our area in the future and also allow us to seek opportunities to build in other service territories. These implementing rules within the regions are still in flux so both the extent of the risk within our service territory and the opportunities for our transmission business elsewhere remain difficult to assess. For additional information, see the discussion in Regulatory Issues—Federal Regulation—Transmission Regulation, below.

Construction of new local generation also has the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints.

Power

Various market participants compete with us and one another in buying and selling in the wholesale energy markets, entering into bilateral contracts and selling to aggregated retail customers. Our competitors include:

- merchant generators,
- domestic and multi-national utility generators,
- energy marketers,
- banks, funds and other financial entities,
- fuel supply companies, and
- affiliates of other industrial companies.

New additions of lower-cost or more efficient generation capacity could make our plants less economic in the future. Although it is not clear if this capacity will be built or, if so, what the economic impact will be, such additions could impact market prices and our competitiveness.

Our business is also under competitive pressure due to demand side management (DSM) and other efficiency efforts aimed at changing the quantity and patterns of usage by consumers which could result in a reduction in load requirements. A reduction in load requirements can also be caused by economic cycles, weather, municipal aggregation and other customer migration and other factors. In addition, how resources such as demand response and capacity imports are permitted to bid into the capacity markets also affects the prices paid to generators such as Power in these markets. It is also possible that advances in technology, such as distributed generation and micro grids, will reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. To the extent that additions to the electric transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, our revenues could be adversely affected. Changes in the rules governing what types of transmission will be built, who is selected to build transmission and who will pay the costs of future transmission could also impact our revenues.

Adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, would have the effect of artificially depressing prices in the competitive wholesale market and thus have the potential to harm competitive markets, on both a short-term and a long-term basis. At the same time, changes such as that proposed by PJM and discussed more fully in Regulatory Issues—Federal Regulation provide the opportunity for additional compensation in both the energy and capacity markets for being available (and making the necessary investments to ensure availability) during emergency conditions.

Environmental issues, such as restrictions on emissions of carbon dioxide (CO_2) and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant, thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states. If any new legislation or regulations were to require our competitors to meet the

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environmental standards currently imposed upon us, we would likely have an economic advantage since we have already installed significant pollution-control technology at most of our fossil stations.

In addition, pressures from renewable resources could increase over time. For example, many parts of the country, including the mid-western region within the footprint of the Midwest Independent System Operator (MISO), the PJM region and the California ISO, have either implemented or proposed implementing changes to their respective regional transmission planning processes that may enable the construction of large amounts of "public policy" transmission to move renewable generation to load centers. For additional information, see the discussion in Regulatory Issues—Federal Regulation.

EMPLOYEE RELATIONS

As of December 31, 2014, we had 12,689 employees within our subsidiaries, including 7,958 covered under collective bargaining agreements. Four of our collective bargaining union agreements will expire in April 2017, two in October 2017 and one in May 2018. Effective January 1, 2014, in connection with our management contract with LIPA, we assumed the collective bargaining agreement between National Grid Electric Services LLC, LIPA's previous management contractor, and a labor union. That union contract will expire in November, 2016. We believe we maintain satisfactory relationships with our employees.

Employees as of December 31, 2014

	PSE&G	Power	PSEG LI	Other
Non-Union	1,693	1,282	725	1,031
Union	4,832	1,691	1,427	8
Total Employees	**6,525**	**2,973**	**2,152**	**1,039**

REGULATORY ISSUES

Federal Regulation

FERC

The FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act. PSE&G and the generation and energy trading subsidiaries of Power are public utilities as defined by the FPA. The FERC has extensive oversight over such public utilities. FERC approval is usually required when a public utility seeks to: sell or acquire an asset that is regulated by the FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations.

The FERC also regulates generating facilities known as qualifying facilities (QFs). QFs are cogeneration facilities that produce electricity and another form of useful thermal energy, or small power production facilities where the primary energy source is renewable, biomass, waste or geothermal resources. QFs must meet certain criteria established by the FERC. We own various QFs through Power. QFs are subject to some, but not all, of the same FERC requirements as public utilities.

The FERC also regulates Regional Transmission Operators/ISOs, such as PJM, and their energy and capacity markets.

For us, the major effects of FERC regulation fall into five general categories:

- Regulation of Wholesale Sales—Generation/Market Issues
- Energy Clearing Prices
- Capacity Market Issues
- Transmission Regulation
- Compliance

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Regulation of Wholesale Sales—Generation/Market Issues

Market Power

Under FERC regulations, public utilities must receive FERC authorization to sell power in interstate commerce. They can sell power at cost-based rates or apply to the FERC for authority to make market-based rate (MBR) sales. For a requesting company to receive MBR authority, the FERC must first make a determination that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. The FERC requires that holders of MBR tariffs file an update every three years demonstrating that they continue to lack market power and/or that their market power has been sufficiently mitigated and report in the interim to the FERC any material change in facts from those the FERC relied on in granting MBR authority.

PSE&G, PSEG Energy Resources & Trade LLC, PSEG Power Connecticut, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG New Haven LLC all have been granted MBR authority from the FERC. Each of these companies, except PSEG New Haven LLC (which received MBR authority in May 2012), filed a market power update with the FERC at the end of 2013. In an order issued in October 2014, the FERC accepted these filings as having satisfied the requirements for retention of MBR authority.

Energy Clearing Prices

Energy clearing prices in the markets in which we operate are generally based on bids submitted by generating units. Under FERC-approved market rules, bids are subject to price caps and mitigation rules applicable to certain generation units. The FERC rules also govern the overall design of these markets. At present, all units receive a single clearing price based on the bid of the marginal unit (i.e. the last unit that must be dispatched to serve the needs of load). These FERC rules have a direct impact on the energy prices received by our units.

As a result of the polar vortex and related cold weather events in January 2014, there were both gas and electric price spikes in the Northeast markets, including in PJM. The FERC has examined the facts surrounding these price spikes, as well as “lessons learned” from the various Regional Transmission Operators/Independent System Operators (RTO/ISO) and potential changes in market rules intended to encourage dual fuel capability of generating units, the purchase of firm fuel to operate these units and the construction of additional natural gas pipeline capacity. As discussed below, PJM has proposed changes to its capacity market construct to develop a new capacity product that would be compensated in both the energy and capacity markets for availability during emergency conditions on the system. The FERC is also examining price formation issues, focusing on levels of compensation to generators in the energy and ancillary services markets, and we are advocating in this context for changes in market rules that would provide more transparency about energy market prices. We cannot predict what action the FERC might ultimately take, but such an examination could lead to future rule changes.

Capacity Market Issues

PJM, the NYISO and the ISO-NE each have capacity markets that have been approved by the FERC. The FERC regulates these markets and continues to examine whether the market design for each of these three capacity markets is working optimally. Specific issues being considered by the FERC are whether capacity market rules properly address and foster the development of state public policies, demand response (DR) and emerging technologies and whether generators are being sufficiently compensated in the capacity market. We cannot predict what action, if any, the FERC might take with regard to capacity market design.

PJM—The RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under the RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of the RPM in PJM continue to evolve and be refined in stakeholder proceedings and FERC proceedings in which we are active. There is currently significant activity concerning three topics: (i) the future role of DR in the RPM market in light of a decision by the D.C. Circuit Court of Appeals (D.C. Court) holding that DR is not a FERC-jurisdictional product, (ii) PJM’s development of a new capacity product called a Capacity Performance (CP) product, and (iii) the setting of the Cost of New Entry (CONE) value for the RPM demand curve for the auctions to be conducted in the next four years.

In May 2014, in a case involving the proper level of compensation for DR resources in the energy markets, the D.C. Court held that DR is not a FERC-jurisdictional product, thereby calling into question DR resources’ ability to participate in either the energy or capacity markets in the future. In January 2015, the FERC filed a petition to the U.S. Supreme Court to review the D.C. Court's ruling. The D.C. Court's decision has been stayed until the U.S. Supreme Court acts on this petition, which is not expected to occur until the end of April. In the meantime, FirstEnergy Corp. has filed a complaint at the FERC which argues that DR resources should no longer participate in the PJM capacity market and seeks to invalidate the results of the last RPM Base Residual Auction that was conducted in May 2014. In addition, PJM has recently submitted a filing at the FERC, conditioned on denial by the U.S. Supreme Court of the FERC's petition for review, that if accepted by the FERC, would only

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allow DR to participate in the capacity market through adjustment of the demand curve rather than as a capacity resource that receives a revenue stream. Should the FERC accept PJM's filing, this new model would be in effect for the upcoming May 2015 Base Residual Auction and could have an upward effect on the auction's clearing prices.

In September 2014, PJM filed at the FERC to re-set the Variable Resource Requirement (VRR) curve for the RPM, as going forward will be done every four years. Establishment of the VRR curve is a critical component in determining how generators are paid in the capacity auction. In November 2014, the FERC accepted PJM's filing, which we believe represents an improvement over the status quo in terms of appropriately setting the demand curve. However, we and other generators have challenged the FERC's approval order on rehearing, taking exception with the FERC's approval of the manner in which PJM calculated the cost of capital and labor costs that form the basis for the CONE component of the demand curve, which we believe have been set too low and do not accurately reflect the costs of building a new generating unit in PJM. The rehearing request remains pending at the FERC.

On December 12, 2014, PJM filed a proposal at the FERC to implement a CP mechanism. Under this mechanism, PJM has created a more robust capacity product definition with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. While there is no specific eligibility requirement, the CP resource must represent that it has made, or will make, the necessary investments to ensure that the resource has the capability to provide energy when emergency conditions on the system exist. CP resources will be able to offer into the capacity market up to Net CONE (the CONE value including offsets for expected energy and ancillary services revenues), but risk remains that bids up to Net CONE may be challenged by regulatory authorities from the standpoint of bidding behavior even when supported by a commercially reasonable assessment of costs. This new product, if accepted by the FERC, will be phased in over the next few years, with full implementation for the 2020-2021 delivery year. PJM's approach may provide the opportunity for enhanced capacity market revenue streams for Power. However, there may be requirements for additional investment and there are additional performance risks, as well as risks associated with our ability to bid in a manner that would ensure recovery of any capital investment.

MISO—MISO does not have a mandatory capacity market in place, as load serving entities may submit Fixed Resource Adequacy Plans in lieu of participating in the capacity auction. In the May 2013 RPM auction, the difference between the MISO and PJM capacity markets was highlighted, as significant amounts of MISO generation were bid as imports into PJM and cleared in RPM. MISO is seeking to facilitate additional exports. The FERC tightened the rules in 2014 and permitted PJM to establish annual capacity import limits, which were then incorporated into the 2017/2018 planning parameters for the May 2014 base residual auction. We believe that this action had a resultant upward effect on prices in PJM. The FERC continues to examine this "capacity portability" issue and, in response to a complaint filed by a utility company in Indiana, the FERC is also examining whether current PJM/MISO rules regarding capacity imports and exports entered into under the Joint Operating Agreement between the regions are appropriate.

ISO-NE—ISO-NE's market for installed capacity in New England provides fixed capacity payments for generators, imports and DR. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. In May 2014, the FERC issued an order requiring the implementation of a downward sloping demand curve, similar to the design in place in PJM, for use in ISO-NE's ninth capacity market auction, which was recently held and effective in the 2018-2019 delivery year. This action decreased volatility in capacity prices and, in conjunction with an ISO-established seven-year locked-in clearing price for new resources (other than certain subsidized renewable resources) incented the clearing of new generation in the auction. One aspect of this May 2014 FERC order that we did not support was the exemption from the Minimum Offer Price Rule afforded annually up to 600 MW of renewable resources. We challenged this portion of the order on rehearing on the grounds that we believe that it is unduly discriminatory and will suppress capacity prices. In an order issued in January 2015, the FERC denied our rehearing request.

In addition, in the FERC order referenced above, the FERC directed the ISO-NE to develop demand curves for each capacity zone in the market. The ISO-NE is currently conducting a stakeholder proceeding and expects to make a filing with the FERC in the next few months. The shape of the demand curve in the zones will have a significant impact upon the revenues our generation can expect to receive in the capacity market in New England.

NYISO—NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. Prior to 2013, the NYISO capacity model had recognized only two separate zones that potentially may separate in price: New York City and Long Island. In August 2013, the FERC issued an order approving a third capacity zone that would encompass the super zone that includes the lower Hudson Valley and New York City which took effect on May 1, 2014.

In January 2014, the FERC issued an order accepting the NYISO's proposed reference unit (a generation unit with no environmental controls) that should be used for the purposes of establishing the CONE in the "rest of State" zone (excluding the lower Hudson Valley, New York City and Long Island), which may have the effect of depressing capacity prices. This order will set the demand curve on which future capacity prices paid to generators will be based for the period May 1, 2014 through April 30, 2017. That order was upheld by the FERC on rehearing in May 2014 and the federal appellate court subsequently denied motions for a stay of the effect of the order.

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Discussions at the FERC concerning other potential changes to NYISO capacity markets, including rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons, are also ongoing.

Long-Term Capacity Agreement Pilot Program Act (LCAPP)—In 2011, the State of New Jersey enacted the LCAPP to subsidize approximately 2,000 MW of new natural gas-fired generation. The LCAPP provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey EDCs. The SOCA required each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers. Each of the New Jersey EDCs, including PSE&G, entered into three SOCAs as directed by the State, but did so under protest reserving their rights.

In 2013, the U.S. District Court in New Jersey found that the LCAPP was unconstitutional and declared the LCAPP null and void. As a result of that decision, PSE&G terminated its SOCA contracts. This federal court decision was subsequently challenged on appeal in the U.S. Third Circuit Court of Appeals. The State of Maryland also took similar action to subsidize above-market new generation. This action was also determined to be unconstitutional in 2013 in the U.S. District Court in Maryland and such decision was challenged in the U.S. Fourth Circuit Court of Appeals. Both appeals were denied, with the U.S. Fourth Circuit Court of Appeals denying the appeal regarding the State of Maryland's action in June 2014 and the U.S. Third Circuit Court of Appeals denying the LCAPP appeal in September 2014. These denials have now been challenged on appeal to the U.S. Supreme Court, which action remains pending.

Transmission Regulation

The FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures. Our allowed ROE is 11.68% for both existing and new transmission investments and we have received incentive rates, affording a higher ROE, for certain large scale transmission investments.

Our 2015 Formula Rate Update with the FERC for approximately $182 million in increased annual transmission revenues went into effect on January 1, 2015. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. The adjustment for 2015 will include the impact of the extension of bonus depreciation, which was enacted after the filing was made, and is estimated to reduce our 2015 revenue increase as filed by approximately $21 million. For additional information about our transmission formula rate, see Part II, Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

- ***Transmission Policy Developments***—The FERC concluded in Order 1000 that the incumbent transmission owner should not always have a ROFR to construct and own transmission projects in its service territory. We had challenged the FERC's elimination of the ROFR in federal court. In August 2014, our challenge was rejected by the D.C. Court. PJM is currently implementing its rules under which the construction of certain types of transmission projects will no longer be subject to a ROFR for incumbents. In May 2014, the FERC approved PJM's rules, which retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including projects being built on existing right-of-way and whose construction would interfere with incumbents' use of their right-of-way. Several companies, including PSE&G, have appealed various aspects of this approval order.

  The FERC has also approved the "state agreement approach" to cost allocation under which transmission projects being built to address public policy concerns may be placed into PJM's planning process if the state sponsoring the project agrees to pay the costs of the project. To date, no such projects have been placed into the planning process but this mechanism could potentially facilitate transmission projects that are not needed for reliability or market efficiency under PJM standards for transmission, including potential offshore wind projects proposed by third parties, should a state or states agree to fund the costs of such projects.

  In addition, in September 2014, PJM filed at the FERC to add another category of project - the "multi-driver" project - to its planning process. This type of project would contain reliability, economic and/or public policy elements. Projects falling within this category would be required to independently satisfy all of the different drivers in order to be approved. However, this category could also serve as a vehicle for the development of large, public policy-driven projects. In October 2014, the FERC issued a deficiency letter regarding PJM's "multi-driver" filing seeking additional information and clarification with respect to the filing, to which PJM responded in December 2014. We have protested the filing on the grounds that this new project category is not needed for reliability and that the rules to allocate costs for these projects are unclear. The FERC has recently issued an order accepting PJM's filing. We are currently considering whether to seek rehearing.

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PJM's first action toward complying with Order 1000 began in April 2013, when it initiated its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues at Artificial Island. PJM has not yet concluded this process. On January 30, 2015, PSE&G filed a complaint against PJM at the FERC, asserting that PJM had failed to follow its tariff rules governing the process and requesting that the FERC direct PJM to do so. If the FERC grants the complaint, one outcome could be that PJM will be required to re-start the entire selection process for this project. The FERC could also require PJM to make changes to the rules governing future competitive solicitations.

In addition, the FERC is currently considering two significant transmission cost allocation matters. The first involves a November 2014 complaint brought by Con Edison against PJM at the FERC challenging PJM's allocation of costs for two PSE&G projects in northern New Jersey, including the Bergen-Linden Corridor Project (BLC Project) discussed below. We have opposed Con Edison's complaint. The other proceeding is a matter remanded from a federal appellate court concerning the appropriate cost allocation for certain 500 kV projects in PJM that either have been built or are in the process of being built, including the Susquehanna-Roseland project. This matter is currently in settlement discussions at the FERC. Resolution of these two proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey.

- ***Transmission Rate Proceedings***—In December 2013, PSE&G was assigned construction responsibility by PJM of a new transmission project that will provide a double-circuit 345 kV line in the BLC Project to maintain reliability. Phases One through Three of the BLC Project are scheduled to be in service in 2016, 2017 and 2018, respectively, with certain components of Phase One required to be in service as early as June 2015. The estimated construction costs of the BLC Project are $1.2 billion. On March 28, 2014, we filed a petition with the FERC seeking incentives for the BLC Project, specifically recovery of Construction Work in Progress in rate base and authorization to recover 100% of all prudently incurred development and construction costs if the BLC Project is abandoned or canceled, in whole or in part, for reasons beyond the control of PSE&G. In May 2014, the FERC issued an order granting our petition requesting incentives. A merchant transmission company has challenged its allocated cost responsibility for the BLC Project and the order granting PSE&G's request for incentives related to that project.

  There are several complaints pending at the FERC against transmission owners around the country, challenging those transmission owners' base ROEs. While we are not the subject of a challenge to the ROE employed in PSE&G's transmission formula rate, the results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Compliance

- ***FERC Audit***—In November 2012, the FERC commenced an audit of each of the PSEG companies that have MBR authority from the FERC. The companies were audited by the FERC for compliance with its rules for (i) receiving and retaining MBR authority, (ii) the filing of electric quarterly reports (EQRs), and (iii) our generating units' receipt of payments from the RTO/ISO when they are required to run for reliability reasons when it is not economical for them to do so. On October 16, 2014, the FERC issued a final, public audit report that contained two findings and recommendations for enhanced review and reporting of our EQRs. In November 2014, we submitted a compliance plan to the FERC explaining how we intend to implement the FERC's recommendations and we are providing quarterly updates to the FERC until we have implemented all such recommendations.
- ***FERC***—In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, we retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. On September 2, 2014, the FERC staff initiated a preliminary, non-public staff investigation into the matter. This investigation, which is ongoing, could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with this matter, or the applicability of mitigating factors. See Part II, Item 8. Financial Statements and Supplementary Data. Note 12. Commitments and Contingent Liabilities—FERC Compliance for further discussion of this matter.

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- ***Reliability Standards***—Congress has required the FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the United States electric transmission and generation system (grid) and to prevent major system blackouts. There has been considerable focus recently on physical security in light of, among other things, a substation attack in California that occurred in 2013. As a result, the FERC directed the NERC to draft a physical security standard intended to further protect assets deemed "critical" to reliability of the grid. In November 2014, the FERC issued an order approving the NERC's proposed physical security standard. Under the standard, utilities will be required to identify critical substations as well as develop threat assessment plans to be reviewed by independent third parties. In our case, the third party is PJM. As part of these plans, utilities could decide or be required to build additional redundancy into their systems. This standard will supplement the Critical Infrastructure Protection standards that are already in place and that establish physical and cybersecurity protections for critical systems.

Commodity Futures Trading Commission (CFTC)

In accordance with the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), the SEC and the CFTC are in the process of implementing a new regulatory framework for swaps and security-based swaps. The legislation was enacted to reduce systemic risk, increase transparency and promote market integrity within the financial system by providing for the registration and comprehensive regulation of swap dealers and by imposing recordkeeping, data reporting, margin and clearing requirements with respect to swaps. To implement the Dodd-Frank Act, the CFTC has engaged in a comprehensive rulemaking process and has issued a number of proposed and final rules addressing many of the key issues. We are currently subject to record keeping and data reporting requirements applicable to commercial end users. The CFTC has also proposed rules establishing position limits for trading in certain commodities, such as natural gas, and we are currently analyzing the potential impact of these rules on our business.

Nuclear Regulatory Commission (NRC)

Our operation of nuclear generating facilities is subject to comprehensive regulation by the NRC, a federal agency established to regulate nuclear activities to ensure protection of public health and safety, as well as the security and protection of the environment. Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstration to the NRC that plant operations meet requirements is also necessary. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate. The current operating licenses of our nuclear facilities expire in the years shown in the following table:

Unit	Year
Salem Unit 1	2036
Salem Unit 2	2040
Hope Creek	2046
Peach Bottom Unit 2	2033
Peach Bottom Unit 3	2034

As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in 2011, the NRC began performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events in Japan have resulted in additional regulation for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants currently meet the stringent applicable design and safety specifications of the NRC.

In 2011, a NRC task force submitted a report containing various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. The NRC staff also issued a document which provided for a prioritization of the task force recommendations. The NRC approved the staff's prioritization and implementation recommendations subject to a number of conditions. Among other things, the NRC advised the staff to give the highest priority to those activities that can achieve the greatest safety benefit and/or have the broadest applicability (Tier 1), to review filtration of boiling water reactor (BWR) primary containment vents and encouraged the staff to create requirements based on a performance-based system which allows for flexible approaches and the ability to address a diverse range of site-specific circumstances and conditions and strive to implement the requirements by 2016.

Separately, a petition was filed with the NRC in April 2011 seeking suspension of the operating licenses of all General Electric BWRs utilizing the Mark I containment design in the United States, including our Hope Creek and Peach Bottom units, pending completion of the NRC review. Fukushima Daiichi Units 1-4 are BWRs equipped with Mark I containments. The petition

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named 23 of the then total 104 active commercial nuclear reactors in the United States. In March 2014, the NRC formally closed the petition without opting to conduct further proceedings.

The NRC issued letters and orders to licensees implementing the Tier 1 recommendations in March 2012. In March 2013, the NRC initiated a rulemaking process for improvements to venting systems at 31 U.S. BWRs with "Mark I" and "Mark II" containments (similar to those at Fukushima), which include our Hope Creek and Peach Bottom units. In June 2013, the NRC issued orders requiring Mark I and Mark II licensees to upgrade or replace their reliable hardened vents with containment venting systems designed and installed to remain functional during severe accident conditions. We are implementing the diverse and flexible strategies and spent fuel pool level indication modifications in accordance with the regulatory requirements at the Salem, Hope Creek and Peach Bottom nuclear units. For our Hope Creek and Peach Bottom units, final installation of the required modifications is expected to occur during the planned refueling outages in 2016-2018.

The NRC is currently developing the regulatory basis for drywell filtration strategies rulemaking. The NRC expects to complete its evaluation and vote on a final rule in 2017. The NRC continues to evaluate potential revisions to its requirements in connection with its operational and safety reviews of nuclear facilities in the United States as a result of the Fukushima Daiichi incident.

We are unable to predict the final outcome of these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to our Salem, Hope Creek and Peach Bottom facilities, but such cost could be material.

State Regulation

Since our operations are primarily located within New Jersey, our principal state regulator is the BPU, which oversees electric and natural gas distribution companies in New Jersey. We are also subject to various other states' regulations due to our operations in those states.

Our New Jersey utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. PSE&G's participation in solar, demand response and energy efficiency programs is also regulated by the BPU, as the terms and conditions of these programs are approved by the BPU. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey.

We must file electric and gas rate cases with the BPU in order to change our utility base distribution rates. Our last base rate case was settled in 2010. As a result of our Energy Strong order discussed below, we are required to file our next base rate case proceeding no later than November 1, 2017. In addition to base rates, we recover certain costs or earn on certain investments pursuant to mechanisms known as adjustment clauses. These clauses permit the flow-through of costs to, or the recovery of investments from, customers related to specific programs, outside the context of base rate case proceedings. Recovery of these costs or investments is subject to BPU approval for which we make periodic filings. Delays in the pass-through of costs or recovery of investments under these mechanisms could result in significant changes in cash flow. For additional information on our specific filings, see Part II, Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

Energy Strong Program—In February 2013, we filed a petition with the BPU describing the improvements we recommend making to our BPU jurisdictional electric and gas system to improve resiliency for the future. The changes that were described, designated as the "Energy Strong Program," would be made over a ten-year period. In this petition, we sought approval to invest $0.9 billion in our gas distribution system and $1.7 billion in our electric distribution system over an initial five-year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. In May 2014, the BPU issued an Order approving the settlement of our Energy Strong program. Under the settlement, PSE&G will invest $1.22 billion to (1) upgrade all of its electric substations that were damaged by water in recent storms; make investments that will create redundancy in the electric distribution system, reducing outages when damage occurs; and deploy technologies to better monitor system operations, enabling PSE&G to restore customers more quickly in the event of an electric outage, and (2) with respect to PSE&G's gas system, replace and modernize 250 miles of low-pressure cast iron gas mains in or near flood areas; and upgrade five natural gas metering stations and a liquefied natural gas station recently affected by severe weather or located in flood zones. The settlement provides for cost recovery at a 9.75% rate of ROE on the first $1.0 billion of the investment, plus associated Allowance for Funds Used Under Construction, and will occur for completed projects on a semi-annual (for electric investments) or annual (for gas investments) basis. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, which as noted above, is to be filed no later than November 1, 2017.

In September 2014, PSE&G filed its initial Energy Strong cost recovery petition, seeking BPU approval to recover in base rates capitalized Energy Strong electric investment costs expected to be in service through November 30, 2014. This request was updated in December 2014 for actual costs and recovery of an estimated annual revenue increase of $1.1 million effective March 1, 2015.

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Energy Efficiency Economic Stimulus Extension II (EEE Ext II)—In August 2014, we filed for approval from the BPU of an EEE Ext II Program to extend three EEE subprograms (multi-family, direct install and hospital efficiency). We proposed to extend the subprograms' offerings under the same clause recovery process as currently approved while seeking additional capital expenditures of approximately $96 million and additional administrative costs of $14 million. The matter is pending.

Consolidated Tax Adjustments (CTA)—New Jersey is one of only a few states that make CTA in setting rates for regulated utilities. These adjustments to rate base are made during the rate setting process and are intended to allocate to utility customers a portion of the tax benefits realized from the filing of a consolidated federal tax return by the utility's parent corporation. The BPU has been considering the appropriateness of the adjustment and the methodology and mechanics of the calculation for some time. On October 22, 2014, the BPU approved a proposal by its Staff that limits the tax benefit period to be considered in the calculation to five years, sets the rate base adjustment at 25% of any such tax benefit and eliminates from the process any tax benefits tied to transmission earnings. In accordance with this October action, this CTA policy will be applied only with respect to future rate cases. The adoption of these modifications by the BPU is not expected to have a material impact on PSE&G's current earnings nor in its next rate case filing. On November 5, 2014, the New Jersey Division of Rate Counsel appealed the BPU's decision. The appeal remains pending.

New Jersey Energy Master Plan (EMP)—New Jersey law requires that an EMP be developed every three years, the purpose of which is to ensure safe, secure and reasonably-priced energy supply, foster economic growth and development and protect the environment. While not having the force of law, the EMP provides an overview of energy policy in New Jersey and may provide both opportunities and challenges for PSEG. The most recent EMP was finalized in December 2011 and placed an emphasis on expanding in-state electricity resources, reducing energy costs, recognizing the impact of climate change and setting new targets for a renewable portfolio standard and goals for energy supplies from clean energy sources.

Additional matters are discussed in Part II, Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

ENVIRONMENTAL MATTERS

Changing environmental laws and regulations significantly impact the manner in which our operations are currently conducted and impose costs on us to reduce the health and environmental impacts of our operations. To the extent that environmental requirements are more stringent and compliance more costly in certain states where we operate compared to other states that are part of the same market, such rules may impact our ability to compete within that market. Due to evolving environmental regulations, it is difficult to project future costs of compliance and their impact on competition. Capital costs of complying with known pollution control requirements are included in our estimate of construction expenditures in Item 7. MD&A—Capital Requirements. The costs of compliance associated with any new requirements that may be imposed by future regulations are not known, but may be material.

Areas of environmental regulation may include, but are not limited to:

- air pollution control,
- climate change,
- water pollution control,
- hazardous substance liability, and
- fuel and waste disposal.

For additional information related to environmental matters, including proceedings not discussed below, as well as anticipated expenditures for installation of pollution control equipment, hazardous substance liabilities and fuel and waste disposal costs, see Item 1A. Risk Factors, Item 3. Legal Proceedings and Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Air Pollution Control

Our facilities are subject to federal regulation under the Clean Air Act (CAA) which requires controls of emissions from sources of air pollution and imposes record keeping, reporting and permit requirements. Our facilities are also subject to requirements established under state and local air pollution laws. The CAA requires all major sources, such as our generation facilities, to obtain and keep current an operating permit. The costs of compliance associated with any new requirements that may be imposed and included in these permits in the future could be material and are not included in our estimates of capital expenditures.

- ***Hazardous Air Pollutants Regulation***—In February 2012**,** the Environmental Protection Agency **(**EPA) published under the National Emission Standard for Hazardous Air Pollutants provisions of the Clean Air Act, Mercury Air

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Toxics Standards (MATS) for both newly-built and existing electric generating sources. The impact to our fossil generation fleet in New Jersey and Connecticut and our jointly-owned coal-fired generating facilities in Pennsylvania is further discussed in Part II, Item 8. Financial and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

- ***Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation***—In March 2013, Power filed a petition at the EPA challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued in January 2013. In April 2013, Power, along with several other energy companies, filed a petition for review at the D.C. Court which remains pending. Among other things, the final EPA rule allows owners and operators of stationary emergency RICE to operate their engines as part of an emergency DR program without the installation and operation of emission controls or compliance with emission limits otherwise applicable to non-emergency counterparts. This waiver of NESHAP standards results in disparate treatment of different generation technology types. In its appeal, Power sought more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. In August 2014, the EPA denied the March 2013 petition and in October 2014, Power appealed the EPA's denial to the D.C. Court.

- ***Cross-State Air Pollution Rule (CSAPR)***—In July 2011, the EPA issued the final CSAPR, which limits power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season NO_x in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards (NAAQS). In August 2012, the D.C. Court vacated CSAPR and ordered that the existing Clean Air Interstate Rule (CAIR) requirements remain in effect until an appropriate substitute rule has been promulgated. The purpose of CAIR is to improve ozone and fine particulate air quality within states that have not demonstrated achievement of the NAAQS. CAIR was implemented through a cap-and-trade program and, to date, the impact has not been material to us as the allowances allocated to our stations were sufficient. In April 2014, the Supreme Court overturned the D.C. Court's ruling. In October 2014, the D.C. Court lifted the stay on CSAPR. On November 21, 2014, the EPA issued a notice to implement CSAPR effective January 1, 2015. We do not anticipate any material impact on our earnings or financial condition due to the CSAPR.

Climate Change

- ***CO_2 Regulation Under the* CAA**—In April 2012, the EPA published the proposed New Source Performance Standards (NSPS) under the CAA for greenhouse gas (GHG) emissions for new power plants only. In June 2013, the President directed the EPA to propose revised NSPS for new power plants by September 20, 2013, propose GHG regulations for existing power plants by June 1, 2014, finalize such regulations by June 1, 2015 and require states to submit GHG implementation regulations by June 30, 2016.

  In January 2014, the EPA proposed revised NSPS for new power plants. The revised NSPS establish three emission standards for CO_2 for the following categories: (i) fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units, (ii) large natural gas combustion turbines, and (iii) small natural gas combustion turbines. The EPA is requesting comment on use of an electric output sales threshold to determine applicability to the NSPS. This electric output sales threshold would eliminate the outright exclusion of simple cycle combustion turbines which was proposed in the initial April 2012 NSPS. We cannot predict the final outcome of these proposed standards.

  In June 2014, the EPA issued a proposed GHG emissions regulation for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction (BSER). The BSER consists of four components: (i) heat rate improvements at existing coal-fired power plants, (ii) increased use of existing natural gas combined cycle capacity, (iii) operation of zero-emitting generation (renewables and nuclear), and (iv) increased use of demand-side energy efficiency. States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions.

  Since the EPA has requested comments on many aspects of the proposal, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact. A final rule is expected in mid-summer 2015.

  The FERC will hold a series of technical conferences early in 2015 to discuss the implications of compliance approaches to the EPA’s proposed GHG regulation for existing power plants. The conferences will focus on issues related to electric reliability, wholesale electric markets and operations and energy infrastructure.

  In August 2014, an Ohio-based energy company and several states filed petitions for review with the D.C. Circuit Court. The parties are challenging the EPA's authority to regulate existing electric generating units under the existing source performance standards section of the CAA. The matter is pending.

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- ***Climate-Related Legislation or Regulation***—The federal government may consider legislative and/or regulatory proposals to define a national energy policy and address climate change. Proposals under consideration include, but are not limited to, provisions to establish a national clean energy portfolio standard and to establish an energy efficiency resource standard. Provisions of any new proposal may present material risks and opportunities to our businesses. The final design of any legislation or regulation will determine the impact on us, which we are not now able to reasonably estimate.
- ***Regional Greenhouse Gas Initiative (RGGI)***—In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. Certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions.

  These rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three-year period. Allowances are available through the auction or through secondary markets.

  In February 2013, the RGGI States released an updated Model Rule that, among other things, reduced the amount of available regional CO_2 allowances beginning in 2014. Each RGGI State must implement the changes through state-specific regulations. We do not expect these changes, or any future changes, to the RGGI rules will have a material impact on us.

  New Jersey withdrew from RGGI beginning in 2012. As a result, our New Jersey facilities are no longer obligated to acquire CO_2 emission allowances. This action has been challenged by environmental groups in the New Jersey state court. In March 2014, the Appellate Division of the New Jersey Superior Court ruled that the New Jersey Department of Environmental Protection (NJDEP) improperly withdrew its regulation under which RGGI had been implemented. The Court gave the NJDEP 60 days to initiate a public process to either repeal or amend that regulation to provide that it is applicable only when New Jersey is a participant in a regional or other established greenhouse gas program. In July 2014, the NJDEP published its intent to formally repeal the rules implementing RGGI in New Jersey. We cannot predict the outcome of this matter.

  New Jersey also adopted the Global Warming Response Act in 2007, which calls for stabilizing its GHG emissions to 1990 levels by 2020, followed by a further reduction of greenhouse emissions to 80% below 2006 levels by 2050. To reach this goal, the NJDEP, the BPU, other state agencies and stakeholders are required to evaluate methods to meet and exceed the emission reduction targets, taking into account their economic benefits and costs.

Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to U.S. waters from point sources, except pursuant to a National Pollutant Discharge Elimination System (NPDES) permit issued by the EPA or by a state under a federally authorized state program. The FWPCA authorizes the imposition of technology-based and water quality-based effluent limits to regulate the discharge of pollutants into surface waters and ground waters. The EPA has delegated authority to a number of state agencies, including those in New Jersey, New York and Connecticut, to administer the NPDES program through state action. We also have ownership interests in facilities in other jurisdictions that have their own laws and implement regulations to control discharges to their surface waters and ground waters that directly govern our facilities in those jurisdictions.

- ***Steam Electric Effluent Guidelines***—In April 2013, the EPA issued notice of a proposed rule that would further limit the discharge of pollutants in wastewater from the operation of coal-fired generating facilities. Our co-owned Keystone and Conemaugh facilities continue to use technologies that generate these wastewater discharges. However, our other coal-fired facilities no longer discharge many of these types of wastewater pollutants. We are unable to predict the impact on Keystone and Conemaugh but do not believe there would be any material impact on our other coal-fired facilities. The EPA is expected to finalize the rule in September 2015.

In addition to regulating the discharge of pollutants, the FWPCA regulates the intake of surface waters for cooling. The use of cooling water is a significant part of the generation of electricity at steam-electric generating stations. Section 316(b) of the FWPCA requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The impact of regulations under Section 316(b) can be significant, particularly at steam-electric generating stations which do not have closed cycle cooling and do not use cooling towers to recycle water for cooling purposes. The installation of cooling towers at an existing generating station can impose significant engineering challenges and significant costs, which can affect the economic viability of a particular plant.

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- ***Cooling Water Intake Structure Regulation***—In 2011, the EPA published a new proposed rule under Section 316(b) which did not establish any particular technology as the best technology available (e.g. closed-cycle cooling). Instead, the proposed rule established marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. We reviewed the proposed rule, assessed the potential impact on our generating facilities and used this information to develop our comments to the EPA which were filed in August 2011. In June 2012, the EPA posted a Notice of Data Availability (NODA) requesting comment on a series of technical issues related to the impingement mortality proposed standards. The EPA also posted a second NODA outlining its plans to finalize a "Willingness to Pay" survey it initiated to develop non-use benefits data in support of the initial rule proposal. We and industry trade associations submitted comments on both NODAs in July 2012. In May 2014, the EPA issued a final cooling water intake rule under Section 316(b) of the Clean Water Act that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

  The EPA did not mandate closed cycle cooling as "Best Technology Available." Instead, the EPA set a fish impingement mortality standard that relies on a technology-based approach. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. The rule also requires that entrainment BTA decisions rely on site-specific analysis that includes an assessment of social costs-social benefits.

  The EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the BTA of each facility that seeks permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. In August 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. In September 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Second Circuit Court of Appeals. In two related actions on October 17, 2014 and November 20, 2014, several environmental non-governmental groups initiated challenges to the Endangered Species Act provisions of the 316 (b) rule.

  We are assessing the potential impact of the rule on each of our affected facilities and are unable to predict the outcome of permitting decisions and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Part II, Item 8. Financial Statements and Supplementary Data— Note 12. Commitments and Contingent Liabilities for additional information.

  In October 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court of New Jersey seeking to force the NJDEP to take action on our pending application for permit renewal at Salem either by denying the application or issuing a draft for public comment. An application for renewal of the permit was submitted in January 2006 and the NJDEP had delayed action pending the EPA's finalization of the Clean Water Act 316(b) regulations. In November 2014, the environmental groups announced settlement of the lawsuit filed with the NJDEP and that the NJDEP has committed to issue a draft permit by June 30, 2015.

- ***Waters of the United States***—In April 2014, the EPA Administrator and the Assistant Secretary of the Army (Civil Works) jointly published a proposed rule to clarify the definition of waters of the U.S. under the Clean Water Act (CWA) programs in order to protect the streams and wetlands that form the foundation of the nation's water resources. This definition will have broad application to all areas of compliance under the CWA, including permitted discharges and construction activities. On November 14, 2014, we participated with other energy companies in submitting comments on the proposed rule. Given the broad nature of the proposed rule, we are unable to determine the materiality of the impacts that might result from the final rule.

Hazardous Substance Liability

The production and delivery of electricity, the distribution of gas and, formerly, the manufacture of gas, results in various by-products and substances classified by federal and state regulations as hazardous. These regulations may impose liability for damages to the environment from hazardous substances, including obligations to conduct environmental remediation of discharged hazardous substances as well as monetary payments, regardless of the absence of fault and the absence of any prohibitions against the activity when it occurred, as compensation for injuries to natural resources. See Item 3. Legal Proceedings. Our historic operations and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by federal and state agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex. For additional information, see Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

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- ***Site Remediation***—The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and the New Jersey Spill Compensation and Control Act (Spill Act) require the remediation of discharged hazardous substances and authorize the EPA, the NJDEP and private parties to commence lawsuits to compel clean-ups or reimbursement for such remediation. The clean-ups can be more complicated and costly when the hazardous substances are in a body of water.
- ***Natural Resource Damages***—CERCLA and the Spill Act authorize the assessment of damages against persons who have discharged a hazardous substance, causing an injury to natural resources. Pursuant to the Spill Act, the NJDEP requires persons conducting remediation to characterize injuries to natural resources and to address those injuries through restoration or damages. The NJDEP adopted regulations concerning site investigation and remediation that require an ecological evaluation of potential damages to natural resources in connection with an environmental investigation of contaminated sites. The NJDEP also issued guidance to assist parties in calculating their natural resource damage liability for settlement purposes, but has stated that those calculations are applicable only for those parties that volunteer to settle a claim for natural resource damages before a claim is asserted by the NJDEP. We are currently unable to assess the magnitude of the potential financial impact of this regulatory change, although such impacts could be material.

Fuel and Waste Disposal

- ***Nuclear Fuel Disposal***—The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In accordance with the Nuclear Waste Policy Act of 1982, in 2009 the U.S. Department of Energy (DOE) conducted its annual review of the adequacy of the Nuclear Waste Fee and concluded that the current fee of 1/10 cent per kWh was adequate to recover program costs. In 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit in federal court seeking suspension of the Nuclear Waste Fee. In June 2012, the court ruled that the DOE failed to justify continued payments by electricity consumers into the Nuclear Waste Fund and ordered the DOE to conduct a complete reassessment of this fee. Spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites. In May 2014, the DOE advised us that as of May 16, 2014, the nuclear waste fee was being suspended/reduced to zero. The elimination of this fee is expected to result in an annualized pre-tax benefit of approximately $30 million.

  We have on-site storage facilities that are expected to satisfy the storage needs of Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 through the end of their operating licenses.
- ***Low Level Radioactive Waste***—As a by-product of their operations, nuclear generation units produce low level radioactive waste. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. These waste materials are accumulated on site and disposed of at licensed permanent disposal facilities. New Jersey, Connecticut and South Carolina have formed the Atlantic Compact, which gives New Jersey nuclear generators continued access to the Barnwell waste disposal facility which is owned by South Carolina. We believe that the Atlantic Compact will provide for adequate low level radioactive waste disposal for Salem and Hope Creek through the end of their current licenses including full decommissioning, although no assurances can be given. Low Level Radioactive Waste is periodically being shipped to the Barnwell site from Salem and Hope Creek. Additionally, there are on-site storage facilities for Salem, Hope Creek and Peach Bottom, which we believe have the capacity for at least five years of temporary storage for each facility.
- ***Coal Combustion Residuals (CCRs)***—In 2010, the EPA published a proposed rule offering three main options for the management of CCRs under the Resource Conservation and Recovery Act (RCRA). One of these options regulates CCRs as a hazardous waste while the other two options would continue to regulate the disposal of CCRs as a non-hazardous waste. In 2012, several environmental organizations and CCR marketers brought a citizens' suit against the EPA in federal court arguing that the EPA failed to perform its mandatory duty under RCRA to review and revise, if necessary, the RCRA rule applicable to CCRs. The EPA issued a final rule on December 19, 2014 which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Our Hudson and Mercer generating stations, along with our co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. The scope of the work entailed to comply has not yet been finalized but we expect that the impacts of this rule will not be material to our results of operations, financial condition or cash flows.

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SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Part II, Item 8. Financial Statements and Supplementary Data—Note 22. Financial Information by Business Segments.

ITEM 1A. RISK FACTORS

The following factors should be considered when reviewing our business. These factors could have a material adverse impact on our financial position, results of operations or net cash flows and could cause results to differ materially from those expressed elsewhere in this report.

The factors discussed in Item 7. MD&A may also have a material adverse effect on our results of operations and cash flows and affect the market prices for our publicly-traded securities. While we believe that we have identified and discussed the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant.

We are subject to comprehensive and evolving regulation by federal, state and local regulatory agencies that affects, or may affect, our businesses.

We are subject to regulation by federal, state and local authorities. Changes in regulation can cause significant delays in or materially affect business planning and transactions and can materially increase our costs. Regulation affects almost every aspect of our businesses, such as our ability to:

- ***Obtain fair and timely rate relief***—PSE&G's retail rates are regulated by the BPU and its wholesale transmission rates are regulated by the FERC. The retail rates for electric and gas distribution services are established in a base rate case and remain in effect until a new base rate case is filed and concluded. In addition, our utility has received approval for several clause recovery mechanisms, some of which provide for recovery of and on the authorized investments. These clause mechanisms require periodic updates to be reviewed and approved by the BPU. Our utility's transmission rates are recovered through a FERC-approved formula rate. The revenue requirements are reset each year through this formula. Transmission ROEs have recently become the target of certain state utility commissions, municipal utilities, consumer advocates and consumer groups seeking to lower customer rates in New England and New York. These agencies and groups have filed complaints at the FERC asking the FERC to reduce the base ROE of various transmission owners. They point to changes in the capital markets as justification for lowering the ROE of these companies. While we are not the subject of any of these complaints, they could set a precedent for FERC-regulated transmission owners, such as PSE&G. Inability to obtain fair or timely recovery of all our costs, including a return of or on our investments in rates, could have a material adverse impact on our business.
- ***Obtain required regulatory approvals***—The majority of our businesses operate under MBR authority granted by the FERC, which has determined that our subsidiaries do not have unmitigated market power and that MBR rules have been satisfied. Failure to maintain MBR eligibility, or the effects of any severe mitigation measures that may be required if market power was evaluated differently in the future, could have a material adverse effect on us.

  We may also require various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals on a timely basis could materially adversely affect our results of operations and cash flows.
- ***Comply with regulatory requirements***—There are federal standards, including mandatory NERC and Critical Infrastructure Protection standards, in place to ensure the reliability of the U. S. electric transmission and generation system and to prevent major system black-outs. We have been, and will continue to be, periodically audited by the NERC for compliance and are subject to penalties for non-compliance with applicable NERC standards.

  Further, the FERC requires compliance with all of its rules and orders, including rules concerning Standards of Conduct, market behavior and anti-manipulation rules, reporting, interlocking directorate rules and cross-subsidization.

  In addition, Power is currently being investigated by the FERC Staff with respect to errors in certain of its bids submitted for its fossil-generating units into the PJM market. See Item 1. Federal Regulation—Compliance—FERC for further information on this matter.

  We are subject to the reporting and record-keeping requirements of the Dodd-Frank Act, as implemented by the CFTC, and may in the future be subject to CFTC requirements regarding position limits for trading of certain

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commodities. As part of the Dodd-Frank Act compliance, we will need to be vigilant in monitoring and reporting our swap transactions.

The BPU conducts periodic combined management/competitive service audits of New Jersey utilities related to affiliate standard requirements, competitive services, cross-subsidization, cost allocation and other issues. The BPU is near completion of a combined management audit and affiliate transactions audit of PSE&G.

We are exposed to commodity price volatility as a result of our participation in the wholesale energy markets.

The material risks associated with the wholesale energy markets known or currently anticipated that could adversely affect our operations include:

- ***Price fluctuations and collateral requirements***—We expect to meet our supply obligations through a combination of generation and energy purchases. We also enter into derivative and other positions related to our generation assets and supply obligations. As a result, we are subject to the risk of price fluctuations that could affect our future results and impact our liquidity needs. These include:
  - variability in costs, such as changes in the expected price of energy and capacity that we sell into the market,
  - increases in the price of energy purchased to meet supply obligations or the amount of excess energy sold into the market,
  - variation in the relative prices of electricity and gas at the hubs within the markets,
  - the cost of fuel to generate electricity, and
  - the cost of emission credits and congestion credits that we use to transmit electricity.

In the markets where we operate, natural gas prices typically have a major impact on the price that generators receive for their output, especially in periods of relatively strong demand. Therefore, significant changes in the price of natural gas usually translate into significant changes in the wholesale price of electricity.

Over the past few years, wholesale prices for natural gas have declined from the peak levels experienced in 2008. One reason for this decline is increased shale gas production as extraction technology has improved. Lower gas prices have resulted in lower electricity prices, which has reduced our margins as nuclear and coal generation costs have not declined similarly. Over that time, generation by our coal units was also adversely affected by the relatively lower price of natural gas as compared to coal, making it sometimes more economic to run certain of our gas units than our coal units.

Natural gas prices may remain at low levels for an extended period and continue to decline if further advances in technology result in greater volumes of shale gas production.

Many factors may affect capacity pricing in PJM, including but not limited to:

- changes in load and demand,
- changes in the available amounts of demand response resources,
- changes in available generating capacity (including retirements, additions, derates, forced outage rates, etc.),
- increases in transmission capability between zones, and
- changes to the pricing mechanism, including increasing the potential number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM may propose over time, including issues currently pending at the FERC regarding compensation for generators that certify their availability during emergency conditions.

Potential changes to the rules governing energy markets in which the output of our plants is sold also poses risk to our business, as discussed further below.

As market prices for energy and fuel fluctuate, our forward energy sale and forward fuel purchase contracts could require us to post substantial additional collateral, thus requiring us to obtain additional sources of liquidity during periods when our ability to do so may be limited. If Power were to lose its investment grade credit rating, it would be required under certain agreements to provide a significant amount of additional collateral in the form of letters of credit or cash, which would have a material adverse effect on our liquidity and cash flows. If Power had lost its investment grade credit rating as of December 31, 2014, it may have had to provide approximately $945 million in additional collateral.

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- ***Our cost of coal and nuclear fuel may substantially increase***—Our coal and nuclear units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel needs over the next several years. However, it will be necessary to enter into additional arrangements to acquire coal and nuclear fuel in the future. Although our fuel contract portfolio provides a degree of hedging against these market risks, future increases in our fuel costs cannot be predicted with certainty and could materially and adversely affect liquidity, financial condition and results of operations. While our generation runs on diverse fuels, allowing for flexibility, the mix of fuels ultimately used can impact earnings.
- ***Third party credit risk***—We sell generation output and buy fuel through the execution of bilateral contracts. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure to perform by these counterparties could have a material adverse impact on our results of operations, cash flows and financial position. In the spot markets, we are exposed to the risks of whatever default mechanisms exist in those markets, some of which attempt to spread the risk across all participants, which may not be an effective way of lessening the severity of the risk of the amounts at stake. The impact of economic conditions may also increase such risk.

We are subject to numerous federal and state environmental laws and regulations that may significantly limit or affect our businesses, adversely impact our business plans or expose us to significant environmental fines and liabilities.

We are subject to extensive environmental regulation by federal, state and local authorities regarding air quality, water quality, site remediation, land use, waste disposal, aesthetics, impact on global climate, natural resources damages and other matters. These laws and regulations affect the manner in which we conduct our operations and make capital expenditures. Future changes may result in significant increases in compliance costs.

Delay in obtaining, or failure to obtain and maintain, any environmental permits or approvals, or delay in or failure to satisfy any applicable environmental regulatory requirements, could:

- prevent construction of new facilities,
- prevent continued operation of existing facilities,
- prevent the sale of energy from these facilities, or
- result in significant additional costs, each of which could materially affect our business, results of operations and cash flows.

In obtaining required approvals and maintaining compliance with laws and regulations, we focus on several key environmental issues, including:

- ***Concerns over global climate change could result in laws and regulations to limit CO_2 emissions or other GHG produced by our fossil generation facilities***—Federal and state legislation and regulation designed to address global climate change through the reduction of GHG emissions could materially impact our fossil generation facilities. The current direction in this area is the EPA's proposed regulation of existing fossil-fueled generating facilities under the existing source performance standards section of the CAA. Legislation enacted in the states where our generation facilities are located establishes aggressive goals for the reduction of CO_2 emissions over a 40-year period. Multiple states are developing or have developed state-specific or regional initiatives to obtain CO_2 emissions reductions in the electric power industry. The RGGI is such a program in the Northeast. There could be significant costs incurred to continue operation of our fossil generation facilities, including the potential need to purchase CO_2 emission allowances. Such expenditures could materially affect the continued economic viability of one or more such facilities.
- ***CO_2 Litigation***—In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings regarding alleged impacts of global climate change not involving us could be material to the future liability of energy companies. If relevant federal or state common law were to develop that imposed liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to our fossil generation operations could be material.
- ***Potential closed-cycle cooling requirements***—Our Salem nuclear generating facility has a permit from the NJDEP allowing for its continued operation with its existing cooling water system. That permit expired in July 2006. Our application to renew the permit, filed in February 2006, estimated the costs associated with cooling towers for Salem to be approximately $1 billion, of which our share was approximately $575 million. The renewal filing has not been updated since the 2006 filing.

  The EPA issued a proposed rule in 2011 regarding regulation of cooling water intake structures. Following the receipt of extensive comments on its proposed rule, the EPA finalized this rule on May 19, 2014 with an effective date of October 14, 2014. The EPA did not mandate closed cycle cooling as the BTA. Instead, the EPA set a fish

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impingement mortality standard that relies on a technology-based approach. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. The rule also requires that entrainment BTA decisions rely on site-specific analysis that includes an assessment of social costs-social benefits.

The EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the BTA of each facility that seeks permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. State actions to renew permits under the provisions of this rule are ongoing at this time.

If the NJDEP or the Connecticut Department of Environmental Protection were to require installation of closed-cycle cooling or its equivalent at our Salem, Mercer, Hudson, Bridgeport, Sewaren or New Haven generating stations, the related increased costs and impacts would be material to our financial position, results of operations and net cash flows and would require further economic review to determine whether to continue operations or decommission the stations.

- ***Remediation of environmental contamination at current or formerly-owned facilities***—We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. Also, we are currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, the related costs of which could have a material adverse effect on our financial condition, results of operations and cash flows. New Jersey law places affirmative obligations on us to investigate and, if necessary, remediate contaminated property upon which we were in any way responsible for a discharge of hazardous substances, impacting the speed by which we will need to investigate contaminated properties, which could adversely impact cash flow. We cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to these or other natural resource damages claims. However, exposure to natural resource damages could subject us to additional potentially material liability.

Our ownership and operation of nuclear power plants involve regulatory, financial, environmental, health and safety risks.

Approximately half of our total generation output each year is provided by our nuclear fleet, which comprises approximately one-fourth of our total owned generation capacity. For this reason, we are exposed to risks related to the continued successful operation of our nuclear facilities and issues that may adversely affect the nuclear generation industry. These include:

- ***Storage and Disposal of Spent Nuclear Fuel***—We currently use on-site storage for spent nuclear fuel. Disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel, could impact future operations of these stations. In addition, the availability of an off-site repository for spent nuclear fuel may affect our ability to fully decommission our nuclear units in the future.
- ***Regulatory and Legal Risk***—The NRC may modify, suspend or revoke licenses, or shut down a nuclear facility and impose substantial civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms and conditions of the licenses for nuclear generating facilities. As with all of our generation facilities, as discussed above, our nuclear facilities are also subject to comprehensive, evolving environmental regulation. Our nuclear generating facilities are currently operating under NRC licenses that expire in 2033 through 2046.
- ***Operational Risk***—Operations at any of our nuclear generating units could degrade to the point where the affected unit needs to be shut down or operated at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Since our nuclear fleet provides approximately half of our generation output, any significant outage could result in reduced earnings as we would need to purchase or generate higher-priced energy to meet our contractual obligations.
- ***Nuclear Incident or Accident Risk***—Accidents and other unforeseen problems have occurred at nuclear stations, both in the United States and elsewhere. The consequences of an accident can be severe and may include loss of life, significant property damage and/or a change in the regulatory climate. We have nuclear units at two sites. It is possible that an accident or other incident at a nuclear generating unit could adversely affect our ability to continue to operate unaffected units located at the same site, which would further affect our financial condition, operating results and cash flows. An accident or incident at a nuclear unit not owned by us could also affect our ability to continue to operate our units. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages. Further, as a licensed nuclear operator subject to the Price-Anderson Act and a member of a

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nuclear industry mutual insurance company, Power is subject to potential retroactive assessments as a result of a nuclear incident or retroactive adverse loss experience.

We may be adversely affected by changes in energy regulatory policies, including energy and capacity market design rules and developments affecting transmission.

The energy industry continues to be regulated and the rules to which our businesses are subject are always at risk of being changed. Our business has been impacted by established rules that create locational capacity markets in each of PJM, ISO-NE and NYISO. Under these rules, generators located in constrained areas are paid more for their capacity so there is an incentive to locate in those areas where generation capacity is most needed. Because much of our generation is located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM's locational capacity market design rules and New England forward capacity market rules have been challenged in court and continue to evolve. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

In January 2011, New Jersey enacted a law establishing a LCAPP which provided for the construction of subsidized base load or mid-merit electric power generation. The LCAPP legislation was invalidated on constitutional grounds by a federal court order issued in October 2013 and a subsequent challenge in the U.S. Court of Appeals for the Third Circuit upheld that decision. that decision has now been filed with the U.S. Supreme Court for consideration on appeal. However, future state actions in New Jersey and elsewhere to subsidize the construction of new generation could have the effect of artificially depressing prices in the competitive wholesale market on both a short-term and long-term basis.

We could also be impacted by a number of other events, including regulatory or legislative actions, including, among other things, direct and indirect subsidies, favoring non-competitive markets and/or technologies and energy efficiency and demand response initiatives. Further, some of the market-based mechanisms in which we participate, including BGS auctions, are at times the subject of review or discussion by some of the participants in the New Jersey and federal regulatory and political arenas. We can provide no assurance that these mechanisms will continue to exist in their current form, nor otherwise be modified.

To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, Power's capacity and energy revenues could be adversely affected. Moreover, through changes encouraged by the FERC to transmission planning processes, or through RTO/ISO initiatives to change their planning processes, such as the recently accepted multi-driver project category in PJM, more transmission may ultimately be built to facilitate renewable generation or support other public policy initiatives.

The FERC has also eliminated the ROFR, which will have the effect of allowing third parties to build certain types of transmission projects in the service territories of incumbent utilities such as PSE&G. As a result, we could face competitive pressures for our transmission business in New Jersey, as well as in in other utilities' service territories where we will be able to seek opportunities to build. Changes to FERC policies regarding transmission planning and rate treatment for transmission investment, including ROEs and incentive rates, could also have an impact on our transmission business. In addition, certain PJM cost allocation determinations have been recently challenged at the FERC, the resolution of which could impact costs borne by New Jersey ratepayers and increase customer bills.

We face significant competition in the merchant energy markets.

Our wholesale power and marketing businesses are subject to significant competition that may adversely affect our ability to make investments or sales on favorable terms and achieve our annual objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower earnings. Decreased competition could negatively impact results through a decline in market liquidity. Some of our competitors include:

- merchant generators,
- domestic and multi-national utility rate-based generators,
- energy marketers,
- utilities,
- banks, funds and other financial entities,
- fuel supply companies,
- affiliates of other industrial companies, and
- distributed generation.

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Regulatory, environmental, industry and other operational developments will have a significant impact on our ability to compete in energy markets, potentially resulting in erosion of our market share and impairment in the value of our power plants.

Changes in customer usage patterns and technology could adversely impact us.

- ***DSM and other efficiency efforts***—DSM and other efficiency efforts aimed at changing the quantity and patterns of consumers' usage could result in a reduction in load requirements.
- ***Changes in technology and/or customer behaviors***—It is possible that advances in technology will reduce the cost of alternative methods of producing electricity, including distributed generation, such as fuel cells, micro turbines, micro grids, windmills and net-metered PV (solar) cells, to a level that is competitive with that of most central station electric production. Large customers, such as universities and hospitals, continue to explore potential micro grid installation. Substantial micro grid penetration can impact energy costs, system performance and demand growth. It is also possible that electric customers may significantly decrease their electric consumption due to demand-side energy conservation programs. Changes in technology and usage, such as municipal aggregation, could also alter the channels through which retail electric customers buy electricity, which could adversely affect our financial results. Increased reliance by customers on on-site generation, including solar, and changes in customer behaviors can result in decreased reliance on our system and impact our revenues and investment opportunities.

Our inability to balance energy obligations with available supply could negatively impact results.

The revenues provided by the operation of our generating stations are subject to market risks that are beyond our control. Generation output will either be used to satisfy wholesale contract requirements, other bilateral contracts or be sold into competitive power markets. Participants in the competitive power markets are not guaranteed any specified rate of return on their capital investments. Generation revenues and results of operations are dependent upon prevailing market prices for energy, capacity, ancillary services and fuel supply in the markets served.

Our generation business frequently involves the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that we have produced or purchased energy in excess of our contracted obligations, a reduction in market prices could reduce profitability. Conversely, to the extent that we have contracted obligations in excess of energy we have produced or purchased, an increase in market prices could reduce profitability. If the strategy we utilize to hedge our exposure to these various risks is not effective, we could incur significant losses. Our market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors, including weather in various geographical areas, short-term supply and demand imbalances, customer migration and pricing differentials at various geographic locations. These risks cannot be predicted with certainty.

Increases in market prices also affect our ability to hedge generation output and fuel requirements as the obligation to post margin increases with increasing prices.

Any inability to recover the carrying amount of our assets could result in future impairment charges which could have a material adverse impact on our financial condition and results of operations.

In accordance with accounting guidance, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset's or group of assets' carrying amount may not be recoverable. Significant reductions in our expected revenues or cash flows for an extended period of time resulting from such events could result in future asset impairment charges, which could have a material adverse impact on our financial condition and results of operations.

Inability to access sufficient capital at reasonable rates or commercially reasonable terms or maintain sufficient liquidity in the amounts and at the times needed could adversely impact our business.

Capital for projects and investments has been provided primarily by internally-generated cash flow and external financings. We have significant capital requirements and will need continued access to debt capital from outside sources in order to efficiently fund the construction and other cash flow needs of our businesses. The ability to arrange financing and the costs of capital depend on numerous factors including, among other things, general economic and market conditions, the availability of credit from banks and other financial institutions, investor confidence, the success of current projects and the quality of new projects.

The ability to have continued access to the credit and capital markets at a reasonable economic cost is dependent upon our current and future capital structure, financial performance, our credit ratings and the availability of capital under reasonable terms and conditions. As a result, no assurance can be given that we will be successful in obtaining re-financing for maturing debt or financing for projects and investments.

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Financial market performance directly affects the asset values of our nuclear decommissioning trust funds and defined benefit plan trust funds. Sustained decreases in asset value of trust assets could result in the need for significant additional funding.

The performance of the financial markets will affect the value of the assets that are held in trust to satisfy our future obligations under our pension and postretirement benefit plans and to decommission our nuclear generating plants. A decline in the market value of our pension assets could result in the need for us to make significant contributions in the future to maintain our funding at sufficient levels.

An extended economic recession would likely have a material adverse effect on our businesses.

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices of commodities. Adverse conditions in the economy affect the markets in which we operate and can negatively impact our results. Declines in demand for energy will reduce overall sales and cash flows, especially as customers reduce their consumption of electricity and gas. Although our utility business is subject to regulated allowable rates of return, overall declines in electricity and gas sold and/or increases in non-payment of customer bills would materially adversely affect our liquidity, financial condition and results of operations.

We may be adversely affected by equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers and remain competitive and could result in substantial financial losses.

The success of our businesses is dependent on our ability to continue providing safe and reliable service to our customers while minimizing service disruptions. We are also exposed to the risk of equipment failures, accidents, severe weather events, or other incidents which could result in damage to or destruction of our facilities or damage to persons or property. For instance, equipment failures in our natural gas distribution could give rise to a variety of hazards and operating risks, such as leaks, accidental explosions and mechanical problems, which could cause substantial financial losses. PSE&G operates and maintains more than 17,700 miles of distribution mains that transport gas to 1.8 million customers. PSE&G also operates and maintains the largest cast iron infrastructure in any one state in the country at approximately 4,000 miles.

In addition, the physical risks of severe weather events, such as experienced from Hurricane Irene and Superstorm Sandy, and of climate change, changes in sea level, temperature and precipitation patterns and other related phenomena have further exacerbated these risks. Such issues experienced at our facilities, or by others in our industry, could adversely impact our revenues, increase costs to repair and maintain our systems, subject us to potential litigation and/or damage claims and increase the level of oversight of our utility and generation operations and infrastructure through investigations or through the imposition of additional regulatory or legislative requirements. Such actions could adversely affect our costs, competitiveness and future investments, which could be material to our financial position, results of operations and cash flow.

Acts of war or terrorism could adversely affect our operations.

Our businesses and industry may be impacted by acts and threats of war or terrorism. These actions could result in increased political, economic and financial market instability and volatility in fuel prices which could materially adversely affect our operations. In addition, our infrastructure facilities, such as our generating stations, transmission and distribution facilities, could be direct or indirect targets or be affected by terrorist or other criminal activity. Such events could severely disrupt business operations and prevent us from servicing our customers. In addition, new or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.

Cybersecurity attacks or intrusions could adversely impact our businesses.

We own and/or operate generating stations, transmission and distribution facilities, which are dependent on the operation of our computing systems. Our ability to market our generation output and acquire and hedge fuel and power are also dependent on our computing systems. Our computing systems may be impacted by cybersecurity attacks, hostile technological intrusions or inadvertent disclosure of company and/or customer information or a cybersecurity attack may leverage our information technology to cause disruptions at another company. Cybersecurity threats to our operations include:

- Disruption of the operation of our assets and the power grid,
- Theft of confidential company, employee, shareholder, vendor or customer information,
- General business system and process interruption or compromise, including preventing us from servicing our customers, collecting revenues or the ability to record, process and/or report financial information correctly, and
- Breaches of vendors' infrastructures where our confidential information is stored.

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If a significant cybersecurity event or breach should occur, it could result in material costs for repair and remediation, breach notification, operations and increased capital costs. Such a cybersecurity incident could also cause us to be non-compliant with applicable laws, regulations or contracts that require us to securely maintain confidential data, causing us to incur costs related to legal claims or proceedings, regulatory fines and increased scrutiny and possible damage to our reputation and brand, resulting in a reduction in customer confidence. We devote resources to network and application security, encryption and other measures to protect our computing systems and infrastructure from unauthorized access or misuse and interface with numerous external entities to improve our cybersecurity situational awareness. However, given the ever changing nature of cybersecurity threats, there can be no assurance the steps we take can protect us against all possible occurrences.

Inability to successfully develop or construct generation, transmission and distribution projects within budget could adversely impact our businesses.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of required environmental upgrades and retrofits, construction and/or acquisition of additional generation units and transmission facilities and modernizing existing infrastructure. Currently, we have several significant projects underway or being contemplated.

Our success will depend, in part, on our ability to obtain necessary regulatory approvals, complete these projects within budgets, on commercially reasonable terms and conditions and, in our regulated businesses, our ability to recover the related costs through rates. Any delays, cost escalations or otherwise unsuccessful construction and development could materially affect our financial position, results of operations and cash flows.

We may be unable to achieve, or continue to sustain, our expected levels of operating performance.

One of the key elements to achieving the results in our business plan is the ability to sustain generating operating performance and capacity factors at expected levels since our forward sales of energy and capacity assume acceptable levels of operating performance. This is especially important at our lower-cost facilities. Operations at any of our plants could degrade to the point where the plant has to shut down or operate at less than full capacity. Some issues that could impact the operation of our facilities are:

- breakdown or failure of equipment, information technology, processes or management effectiveness,
- disruptions in the transmission of electricity,
- labor disputes,
- fuel supply interruptions,
- transportation constraints,
- limitations which may be imposed by environmental or other regulatory requirements,
- permit limitations, and
- operator error or catastrophic events such as fires, earthquakes, explosions, floods, severe storms, acts of terrorism or other similar occurrences.

Identifying and correcting any of these issues may require significant time and expense. Depending on the materiality of the issue, we may choose to close a plant rather than incur the expense of restarting it or returning it to full capacity. In either event, to the extent that our operational targets are not met, we could have to operate higher-cost generation facilities or meet our obligations through higher-cost open market purchases.

Challenges associated with retention of a qualified workforce could adversely impact our businesses.

Our operations depend on the retention of a skilled workforce. The loss or retirement of key executives or other employees, including those with the specialized knowledge required to support our generation, transmission and distribution operations, could result in various operational challenges. These challenges may include the lack of appropriate replacements, the loss of institutional and industry knowledge and the increased costs to hire and train new personnel. This has the potential to become more critical over the next several years as a growing number of employees become eligible to retire.

In addition, because a significant portion of our employees are covered under collective bargaining agreements, our success will depend on our ability to successfully renegotiate these agreements as they expire. Inability to do so may result in employee strikes or work stoppages which would disrupt our operations and could also result in increased costs.

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Our receipt of payment of receivables related to our domestic leveraged leases is dependent upon the credit quality and the ability of lessees to meet their obligations.

Our receipt of payments of equity rent, debt service and other fees related to our leveraged lease portfolio in accordance with the lease contracts can be impacted by various factors. The factors which may impact future lease cash flow include, but are not limited to, new environmental legislation regarding air quality and other discharges in the process of generating electricity, market prices for fuel and electricity, including the impact of low gas prices on our coal generation investments, overall financial condition of lease counterparties and the quality and condition of assets under lease. If a lessee were to default, we could potentially be required to impair our current investment balances.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, PSE&G and Power

None.

ITEM 2. PROPERTIES

Our subsidiaries own all of our physical property. We believe that we and our subsidiaries maintain adequate insurance coverage against loss or damage to plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

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Generation Facilities

Power

As of December 31, 2014, Power's share of summer installed fossil and nuclear generating capacity is shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used	Mission
Steam:						
Hudson	NJ	620	100%	620	Coal/Gas	Load Following
Mercer	NJ	632	100%	632	Coal/Gas	Load Following
Sewaren	NJ	453	100%	453	Gas	Load Following
Keystone (A)	PA	1,711	23%	391	Coal	Base Load
Conemaugh (A)	PA	1,711	23%	385	Coal	Base Load
Bridgeport Harbor	CT	383	100%	383	Coal	Load Following
New Haven Harbor	CT	443	100%	443	Oil	Load Following
Total Steam		**5,953**		**3,307**		
Nuclear:						
Hope Creek	NJ	1,178	100%	1,178	Nuclear	Base Load
Salem 1 & 2	NJ	2,307	57%	1,324	Nuclear	Base Load
Peach Bottom 2 & 3 (B)	PA	2,242	50%	1,121	Nuclear	Base Load
Total Nuclear		**5,727**		**3,623**		
Combined Cycle:						
Bergen	NJ	1,198	100%	1,198	Gas	Load Following
Linden	NJ	1,300	100%	1,300	Gas	Load Following
Bethlehem	NY	774	100%	774	Gas	Load Following
Kalaeloa	HI	208	50%	104	Oil	Load Following
Total Combined Cycle		**3,480**		**3,376**		
Combustion Turbine (C):						
Essex	NJ	623	100%	623	Gas	Peaking
Edison	NJ	516	100%	516	Gas	Peaking
Kearny	NJ	452	100%	452	Gas	Peaking
Burlington	NJ	376	100%	376	Oil/Gas	Peaking
Linden	NJ	347	100%	347	Gas	Peaking
Mercer	NJ	115	100%	115	Oil	Peaking
Sewaren	NJ	105	100%	105	Oil	Peaking
Bergen	NJ	21	100%	21	Gas	Peaking
National Park	NJ	21	100%	21	Oil	Peaking
Salem 3	NJ	38	57%	22	Oil	Peaking
New Haven Harbor	CT	129	100%	129	Gas/Oil	Peaking
Bridgeport Harbor	CT	17	100%	17	Oil	Peaking
Total Combustion Turbine		**2,760**		**2,744**		
Pumped Storage:						
Yards Creek (D)	NJ	400	50%	200		Peaking
Total Power Plants		**18,320**		**13,250**		

(A) Operated by GenOn Northeast Management Company

(B) Operated by Exelon Generation. In March 2015, our share of Peach Bottom 2's installed generation capacity is expected to increase by 65 MW as a result of an extended power uprate completed in 2014. A similar increase is expected to occur in the first quarter of 2016 at Peach Bottom 3 after work is completed in late 2015.

(C) 1,545 MW of owned installed combustion turbine capacity will be retired in 2015.

(D) Operated by JCP&L Company

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As of December 31, 2014, Power also owned and operated 109 MW direct current (dc) of photovoltaic solar generation facilities in various states.

PSE&G

As of December 31, 2014, PSE&G had 99 MWdc of installed solar capacity throughout New Jersey.

Transmission and Distribution Facilities

PSE&G

As of December 31, 2014, PSE&G's electric transmission and distribution system included 23,872 circuit miles, of which 8,191 circuit miles were underground, and 846,058 poles, of which 548,854 poles were jointly-owned. Approximately 100% of this property is located in New Jersey.

In addition, as of December 31, 2014, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2014, the daily gas capacity of PSE&G's 100%-owned peaking facilities (the maximum daily gas delivery available during the three peak winter months) consisted of liquid petroleum air gas (LPG) and liquefied natural gas (LNG) and aggregated 2,790,420 therms (270,914,563 cubic feet on an equivalent basis of 100,000 Btu/therm and 1,030 Btu/cubic foot) as shown in the following table:

Plant	Location	Daily Capacity (Therms)
Burlington LNG	Burlington, NJ	772,500
Camden LPG	Camden, NJ	384,000
Central LPG	Edison, NJ	839,040
Harrison LPG	Harrison, NJ	794,880
Total		**2,790,420**

As of December 31, 2014, PSE&G owned and operated 17,792 miles of gas mains, owned 12 gas distribution headquarters and two sub-headquarters, all in four operating regions located in New Jersey and owned one meter shop in New Jersey serving all such areas. In addition, PSE&G operated 62 natural gas metering and regulating stations, all located in New Jersey, of which 26 were located on land owned by customers or natural gas pipeline suppliers and were operated under lease, easement or other similar arrangement. In some instances, the pipeline companies owned portions of the metering and regulating facilities.

PSE&G's First and Refunding Mortgage, securing the bonds issued thereunder, constitutes a direct first mortgage lien on substantially all of PSE&G's property.

PSE&G's electric lines and gas mains are located over or under public highways, streets, alleys or lands, except where they are located over or under property owned by PSE&G or occupied by it under easements or other rights. PSE&G deems these easements and other rights to be adequate for the purposes for which they are being used.

In addition, as of December 31, 2014, PSE&G owned 43 switching stations in New Jersey with an aggregate installed capacity of 28,777 megavolt-amperes (MVA) and 246 substations with an aggregate installed capacity of 8,179 MVA. In addition, four of our substations in New Jersey having an aggregate installed capacity of 109 MVA were operated on leased property.

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ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, other than those discussed below, see Item 1. Business—Regulatory Issues and Environmental Matters and Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Superstorm Sandy

For a discussion of the lawsuit in New Jersey state court related to recoveries for property damage under PSEG's insurance policies, see Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Environmental Matters

The following items are environmental matters involving governmental authorities not discussed elsewhere in this Form 10-K. We do not expect expenditures for any such site relating to the items listed below, individually or for all such current sites in the aggregate, to have a material effect on our financial condition, results of operations and net cash flows.

(1) Claim by the EPA, Region III, under CERCLA with respect to a Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and other companies are alleged to be liable for contamination at the site and PSE&G has been named as a PRP. A Final Remedial Design Report was submitted to the EPA in September of 2002. This document presented the design details of the EPA's selected remediation remedy. PSE&G and other utility companies as members of a PRP group entered into a Consent Decree and agreed to implement a negotiated EPA selected remediation remedy. The PRP group implementation of the remedy was completed in 2010. Although subject to EPA approval and oversight, long-term monitoring activities designed to demonstrate the effectiveness of the implemented remedy are planned through 2018 at an estimated cost of $2.8 million.

(2) The EPA sent PSE&G, Power and approximately 157 other entities a notice that the EPA considered each of the entities to be a PRP with respect to contamination in Berry's Creek in Bergen County, New Jersey and requesting that the PRPs perform a RI/FS on Berry's Creek and the connected tributaries and wetlands. Berry's Creek flows through approximately 6.5 miles of areas that have been used for a variety of industrial purposes and landfills. The EPA estimates that the study could cost approximately $18 million. As members of a PRP Group, Power and certain of the other entities named in the EPA Notice entered into an Administrative Settlement Agreement and Order on Consent in 2008 to conduct the RI/FS, which is estimated to be completed in 2017/2018.

(3) In January 2010, we received a letter from the NJDEP asserting that we are the current owner of the Gates Construction Corporation Landfill and that the subject landfill has not been properly closed in accordance with the NJDEP Solid Waste Regulations. Power has retained an environmental consultant to prepare a closure plan acceptable to the NJDEP.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange, Inc. As of December 31, 2014, there were 69,735 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2009 in our common stock and the subsequent reinvestment of quarterly dividends, the S&P Composite Stock Price Index, the Dow Jones Utilities Index and the S&P Electric Utilities Index.

	2009	2010	2011	2012	2013	2014
PSEG	$ 100.00	$ 99.91	$ 108.11	$ 104.82	$ 114.62	$ 153.80
S&P 500	$ 100.00	$ 115.03	$ 117.47	$ 136.18	$ 180.18	$ 204.75
DJ Utilities	$ 100.00	$ 106.44	$ 127.30	$ 129.32	$ 145.70	$ 190.13
S&P Electrics	$ 100.00	$ 103.42	$ 124.99	$ 124.24	$ 133.97	$ 175.52

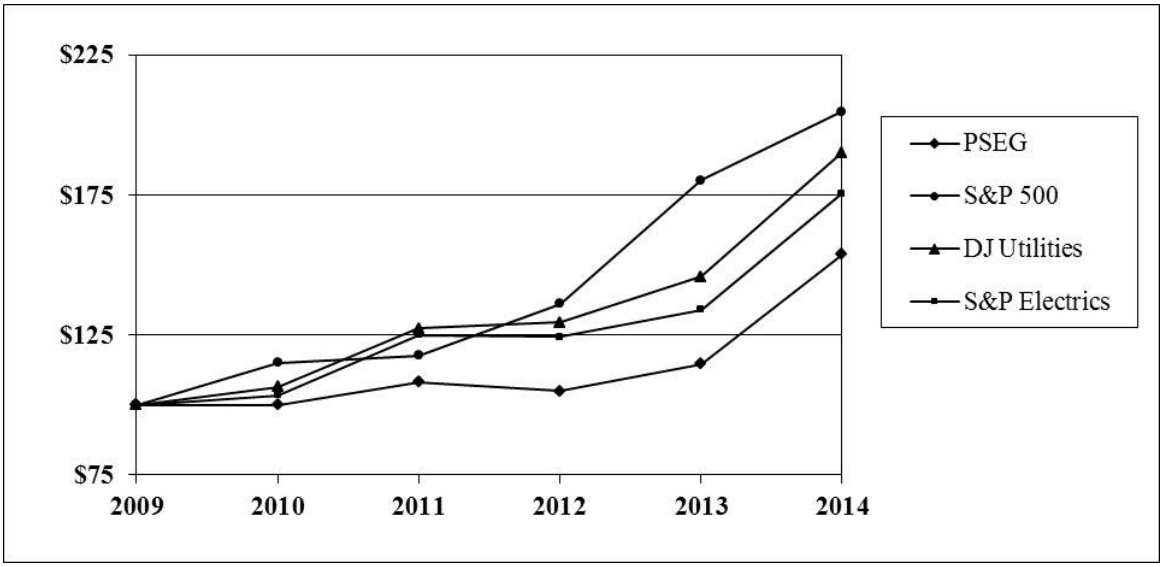

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The following table indicates the high and low sale prices for our common stock and dividends paid for the periods indicated:

Common Stock	High	Low	Dividend per Share
2014			
First Quarter	$ 38.44	$ 31.25	$ 0.37
Second Quarter	$ 41.38	$ 36.91	$ 0.37
Third Quarter	$ 40.68	$ 34.05	$ 0.37
Fourth Quarter	$ 43.77	$ 36.37	$ 0.37
2013			
First Quarter	$ 34.34	$ 29.78	$ 0.36
Second Quarter	$ 36.61	$ 31.21	$ 0.36
Third Quarter	$ 34.53	$ 31.66	$ 0.36
Fourth Quarter	$ 34.32	$ 31.65	$ 0.36

On February 17, 2015, our Board of Directors approved a $0.39 per share common stock dividend for the first quarter of 2015. This reflects an indicated annual dividend rate of $1.56 per share.

The following table indicates our common share repurchases in the open market during the fourth quarter of 2014 to satisfy obligations under various equity compensation award grants:

Three Months Ended December 31, 2014	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$ —
November 1-November 30	245,942	$ 41.35
December 1-December 31	11,050	$ 41.77

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2014:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Long-Term Incentive Plan	2,075,850	**$ 35.35**	15,925,279
Employee Stock Purchase Plan	—	$ —	3,589,032
Total	**2,075,850**	**$ 35.35**	**19,514,311**

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data—Note 17. Stock Based Compensation.

PSE&G

We own all of the common stock of PSE&G. For additional information regarding PSE&G's ability to continue to pay dividends, see Item 7. MD&A—Executive Overview of 2014 and Future Outlook.

Power

We own all of Power's outstanding limited liability company membership interests. For additional information regarding Power's ability to pay dividends, see Item 7. MD&A—Executive Overview of 2014 and Future Outlook.

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ITEM 6. SELECTED FINANCIAL DATA

PSEG

The information presented below should be read in conjunction with the MD&A and the Consolidated Financial Statements and Notes to Consolidated Financial Statements (Notes).

PSEG Years Ended December 31,	2014	2013	2012	2011	2010
	Millions, except Earnings per Share				
Operating Revenues (A)	$ 10,886	$ 9,968	$ 9,781	$ 11,079	$ 11,793
Income from Continuing Operations (B)	$ 1,518	$ 1,243	$ 1,275	$ 1,407	$ 1,557
Net Income	$ 1,518	$ 1,243	$ 1,275	$ 1,503	$ 1,564
Earnings per Share:					
Income from Continuing Operations					
Basic (A)	$ 3.00	$ 2.46	$ 2.52	$ 2.78	$ 3.08
Diluted (A)	$ 2.99	$ 2.45	$ 2.51	$ 2.77	$ 3.07
Net Income					
Basic	$ 3.00	$ 2.46	$ 2.52	$ 2.97	$ 3.09
Diluted	$ 2.99	$ 2.45	$ 2.51	$ 2.96	$ 3.08
Dividends Declared per Share	$ 1.48	$ 1.44	$ 1.42	$ 1.37	$ 1.37
As of December 31,					
Total Assets	$ 35,333	$ 32,522	$ 31,725	$ 29,821	$ 29,909
Long-Term Obligations (C)	$ 8,264	$ 7,872	$ 6,701	$ 7,482	$ 7,847

(A) Operating Revenues for 2014 includes $389 million for Long Island Electric Utility Servco, LLC (Servco), a wholly owned subsidiary of PSEG LI. See Item 8. Financial Statements and Supplementary Data—Note 3. Variable Interest Entities for additional information.

(B) Income from Continuing Operations for 2011 includes an after-tax charge of $170 million related to certain leveraged leases.

(C) Includes capital lease obligations.

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G,** our public utility company which primarily provides electric transmission services and distribution of electric energy and natural gas, implements demand response and energy efficiency programs and invests in solar generation in New Jersey, and
- **Power,** our wholesale energy supply company that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which effective January 1, 2014, operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors provides information about factors that could have a material adverse impact on our businesses. The following discussion provides an overview of the significant events and business developments that have occurred during 2014 and key factors that we expect will drive our future performance. This discussion refers to the Consolidated Financial Statements (Statements) and the related Notes to Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements and Notes.

EXECUTIVE OVERVIEW OF 2014 AND FUTURE OUTLOOK

2014 Overview

Our business plan seeks to achieve growth while managing risks. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- Growing our utility operations through continued investment in T&D infrastructure projects with greater diversity of regulatory oversight, and
- Maintaining a reliable generation fleet with the flexibility to utilize a diverse mix of fuels to allow us to respond to market volatility and capitalize on opportunities as they arise in the locations in which we operate.

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Financial Results

The results for PSEG, PSE&G and Power for the years ended December 31, 2014 and 2013 are presented below:

	Years Ended December 31,	
	2014	2013
Earnings (Losses)	Millions, except per share data	
PSE&G	$ 725	$ 612
Power	760	644
Other	33	(13)
PSEG Net Income	**$ 1,518**	**$ 1,243**
PSEG Net Income Per Share (Diluted)	**$ 2.99**	**$ 2.45**

Our $275 million 2014 over 2013 increase in Net Income was due primarily to higher transmission revenues at PSE&G and mark-to-market gains in 2014 as compared to losses in 2013 and higher volumes of gas sales under the BGSS contract and to third party customers at Power. In addition, the increase was also due to lower Operations and Maintenance (O&M) costs at PSE&G and Power, principally related to a reduction in pension and other postretirement employee benefit (OPEB) costs. These factors were partially offset by lower volumes of electricity sold under the BGS contract and higher fuel costs incurred to generate electricity at Power. For a more detailed discussion of our financial results, see Results of Operations.

At PSE&G, our regulated utility, we continued to invest capital in T&D infrastructure projects aimed at maintaining the reliability of our service to our customers. PSE&G's results for 2014 reflect the favorable impacts from these investments as well as a slowly improving economy. Effective January 1, 2014, PSE&G's formula rate increased our annual transmission revenues by approximately $171 million. In October 2014, we filed our 2015 Formula Rate Update with the Federal Energy Regulatory Commission (FERC) for approximately $182 million in increased annual transmission revenues which went into effect on January 1, 2015. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. The adjustment for 2015 will include the impact of the extension of bonus depreciation, which was enacted after the filing was made, and is estimated to reduce our 2015 revenue increase as filed by approximately $21 million. Over the past few years, these types of investments have altered the business mix of our overall results of operations to reflect a higher percentage contribution by PSE&G.

Power's results benefited from access to natural gas supplies through its existing firm pipeline transportation contracts during the cold weather experienced in the first quarter of 2014. Power manages these contracts for the benefit of PSE&G's customers through the BGSS arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to make third party sales and supply gas to its generating units in New Jersey.

Power's 2014 results were unfavorably impacted by an extended refueling outage at Salem Unit 2. A planned refueling outage began on April 12, 2014 but was extended due to repairs to the reactor coolant pump turning vanes. Salem Unit 2 returned to service on July 14, 2014.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission Planning

The FERC's rule under Order 1000 altered the right of first refusal (ROFR) previously held by incumbent utilities to build all transmission within their respective service territories. Our challenge to the rule itself was rejected by the federal court. However, the FERC's action presents opportunities for us to construct transmission outside of our service territory as long as the applicable rules are clear to all participating transmission developers. In April 2013, PJM Interconnection, L.L.C. (PJM) initiated a solicitation process pursuant to Order 1000 to review technical solutions to improve the operational performance in the Artificial Island area, consisting of our Salem and Hope Creek nuclear generation facilities. PJM has not yet made a decision in this process. On January 30, 2015, PSE&G filed a complaint against PJM at the FERC, arguing that PJM had failed to follow its rules during this process and requesting that the FERC order PJM to do so. If the FERC grants this complaint, the FERC could order PJM to re-start the entire process or make changes to the rules governing future competitive solicitations.

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PJM filed with the FERC, and the FERC has recently accepted, a new "multi-driver" category of transmission projects, which projects may include a combination of reliability, economic and public policy elements. Changes to the factors used in making determinations in the PJM project planning and cost-allocation processes could have significant implications for the types of projects selected and the utility customers ultimately charged for the costs of such new transmission facilities. See Part I, Item 1. Business—Federal Regulation—Transmission Regulation—Transmission Policy Developments.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM), remains an important focus for us. In May 2014, a federal court issued a rule that vacated a FERC Order in which the FERC had determined that demand response (DR) providers should receive full market compensation for power and held that the FERC has no jurisdiction over DR. A subsequent challenge to the participation of DR as a resource in the PJM capacity market is pending at the FERC as is a filing made by PJM at the FERC that would remove DR as a supply resource in upcoming auctions. In addition, PJM has filed at the FERC to reset the demand curve for the RPM, which FERC subsequently accepted. We generally supported PJM's approach in the filing but sought rehearing on certain issues, including the proper level of labor costs required to build new generation in New Jersey, which is pending. Further, in December 2014, PJM filed at the FERC its proposal for a capacity performance product to include generators, DR and energy efficiency providers who would certify as to availability during emergency conditions, as a supplement to base capacity and with enhanced performance-based incentives and penalties. The implications of these developments could be significant for the capacity market. See Part I, Item 1. Business—Regulatory Issues—Federal Regulation—Capacity Market Issues—PJM for additional information.

Under the PJM capacity auction conducted in May 2014, Power cleared 8,693 MW of its generating capacity at an average price of $164.61 MW-day for the 2017-2018 delivery period, a price consistent with what has been realized in the past three auctions. For a more detailed discussion on the RPM capacity auction, refer to Part I, Item 1. Business—Federal Regulation—Capacity Market Issues—PJM.

In 2014, appeals to challenge the federal court rulings that the New Jersey Long-Term Capacity Agreement Pilot Program Act to subsidize above-market new generation and a similar action taken by Maryland were unconstitutional and null and void were each denied. The appellants subsequently sought review at the U.S. Supreme Court and the U.S. Supreme Court has not yet acted. For additional information, refer to Part I, Item 1. Business—Regulatory Issues—Federal Regulation—Capacity Market Issues—Long-Term Capacity Agreement Pilot Program Act.

A critical aspect of our wholesale energy marketing business is the continued retention of market-based rate (MBR) authority from the FERC for our operating subsidiaries that engage in such activities. On October 14, 2014, the FERC issued an Order that accepted our triennial market power update, concluding that our submission satisfied its requirements for retention of MBR authority.

Environmental Regulation

We also advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. On May 19, 2014, the EPA released the final Clean Water Act Section 316(b) rule on cooling water intake that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. Eight of Power's generating facilities and three of its jointly-owned generating facilities are subject to the rule. As adopted by the EPA, the rule requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts, primarily by reducing the amount of fish and shellfish that are impinged or entrained at a cooling water intake structure. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. However, the EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis, and will require facilities to conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. A federal court challenge to the EPA rule is pending. We are unable to predict the outcome that these permitting decisions may take and the effect, if any, that they may have on us although such impacts could be material. See Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities and Part I, Item 1. Business—Environmental Matters—Water Pollution Control for additional information.

In June 2014, the EPA issued a proposed greenhouse gas emissions regulation for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction. States may choose these or other methodologies to achieve the necessary reductions of carbon dioxide emissions. The EPA had requested comment on many aspects of the proposal and therefore, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact of the regulation. See Part I, Item 1. Business—Environmental Matters—Climate Change for additional information.

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In addition, Clean Air Act (CAA) regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology rules are also of significance; however, we believe our generation business remains well-positioned for such air pollution control regulations if and when they are implemented.

Other Developments

In recent years we have been impacted by severe weather conditions, including Hurricane Irene in 2011 and Superstorm Sandy in 2012, the latter storm resulting in the highest level of customer outages in our history. For more detailed information, refer to Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities—Superstorm Sandy. We have begun work in our gas and electric distribution systems to improve resiliency. The New Jersey Board of Public Utilities (BPU) approved the settlement of our Energy Strong Proposal in a total amount of $1.22 billion. The settlement provides for cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated allowance for funds used during construction, through an accelerated recovery mechanism. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, which is to be filed no later than November 1, 2017. We filed our initial Energy Strong cost recovery petition, seeking BPU approval to recover in base rates an estimated annual revenue increase of $1.1 million effective March 1, 2015. This increase represents capitalized Energy Strong electric investment costs in service through November 30, 2014. For additional information, refer to Part I, Item 1. Business—Regulatory Issues—State Regulation—Energy Strong Program.

In September 2014, the BPU approved substantially our entire request for a determination that our storm related costs, in the total amount of $366 million, were prudently incurred and recoverable in a future base rate proceeding, subject to offset for the amount of insurance proceeds received. For additional information, refer to Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

On January 1, 2014, we commenced operation of the LIPA T&D system under a twelve-year contract with opportunity to extend for an additional eight years. In addition, in January 2015, Power assumed responsibility for fuel procurement and power management services to LIPA under separate agreements.

In the first and second quarters of 2014, Power discovered and further investigated (i) incorrect calculations for certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market and (ii) differences in the quantity of energy that Power offered into the energy market for its fossil peaking units from the amount for which Power was compensated in the capacity market for those units. We informed the FERC, PJM and the PJM Independent Market Monitor of these issues, and have corrected these errors. Power has an ongoing process of implementing improved procedures to help mitigate the risk of similar issues occurring in the future. In the third quarter of 2014, the FERC Staff initiated a preliminary, non-public staff investigation into the matter. This investigation could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with this matter, or the applicability of mitigating factors. For more detailed information regarding this matter, refer to Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities—FERC Compliance.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. In 2014, our

- diverse fuel mix and dispatch flexibility allowed us to generate approximately 54,000 GWh, while addressing unit outages and balancing fuel availability and price volatility,
- Bergen 1 and 2 and Linden 1 Units and our combined cycle gas turbine fleet overall achieved record generation,
- Hope Creek Unit achieved its second best generation ever,
- construction of transmission and solar projects proceeded on schedule and within budget, and
- utility ranked highest in electric and gas service business customer satisfaction among large utilities in the eastern United States.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during 2014 as we:

- had cash on hand of $402 million as of December 31, 2014,

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- extended the expiration dates of PSEG's $500 million and Power's $1.6 billion five-year credit facilities from 2017 to 2019, and maintained substantial liquidity,
- maintained solid investment grade credit ratings, and
- paid an annual dividend of $1.48 and increased our indicated annual dividend for 2015 to $1.56 per share.

We expect to be able to fund our transmission projects required under PJM's reliability program, our Energy Strong program and other projects with internally generated cash and external debt financing.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In 2014 we:

- placed into service our 230 kV Burlington-Camden and 230 kV North Central Reliability transmission projects,
- made additional investments in transmission infrastructure projects,
- continued to execute our existing BPU-approved utility programs,
- completed installation of equipment to increase output and improve efficiency at our Linden combined cycle gas generating plant and continue to plan for the installation of such equipment at our Bergen 2 and Bethlehem Energy Center (BEC) combined cycle gas units,
- completed the physical upgrades for the extended power uprate at Peach Bottom Unit 2,
- acquired an equity interest with an expected investment of $100 million-$120 million in the approximately 110 mile PennEast Pipeline to transport natural gas from eastern Pennsylvania to New Jersey, and
- acquired rights to solar energy facilities located near El Paso, Texas and Burlington, Vermont, totaling 16.6 MWdc which became operational in late 2014 and a 12.9 MWdc solar energy facility located near Waldorf, Maryland which we expect to be operational before June 2015.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-moving economy and a cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions,
- execute our capital investment program, including our Energy Strong program and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and the FERC of market design rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system.

For 2015 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,

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- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate, and
- delays and other obstacles that might arise in connection with the construction of our T&D projects, including in connection with permitting and regulatory approvals.

RESULTS OF OPERATIONS

	Years Ended December 31,		
	2014	2013	2012
Earnings (Losses)	Millions		
PSE&G (A)	$ 725	$ 612	$ 528
Power (A)	760	644	666
Other (B)	33	(13)	81
PSEG Net Income	**$ 1,518**	**$ 1,243**	**$ 1,275**
PSEG Net Income Per Share (Diluted)	**$ 2.99**	**$ 2.45**	**$ 2.51**

(A) PSE&G's results in 2012 include after-tax expenses of $24 million for O&M costs and Power's results in 2014, 2013 and 2012 include after-tax expenses of $17 million, $32 million and $39 million, respectively, for O&M costs net of insurance recoveries in 2013 and 2012, due to severe damage caused by Superstorm Sandy. See Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

(B) Other includes after-tax activities at the parent company, PSEG LI and Energy Holdings as well as intercompany eliminations.

The 2014 year-over-year increase in our Net Income was driven primarily by:

- mark-to-market (MTM) gains in 2014 resulting from a decrease in prices on forward positions, as compared to MTM losses in 2013,
- higher sales volumes under the basic gas supply service (BGSS) contract due to colder average temperatures in the 2014 winter heating season,
- higher volumes of gas sold to third party customers,
- higher revenues due to increased investments in transmission projects, and
- lower O&M expense at PSE&G and Power, largely due to a reduction in pension and OPEB costs.

These increases were partially offset by

- lower volumes of electricity sold under Power's basic generation service (BGS) contracts resulting from serving fewer tranches in 2014, and
- higher generation costs due to higher fuel costs.

The 2013 year-over-year decrease in our Net Income was driven by:

- lower volumes of electricity sold under Power's BGS contracts at lower average prices,
- lower volumes of wholesale load contracts in the PJM and New England (NE) regions,
- unfavorable amounts related to the MTM activity, discussed below,
- higher generation costs due to higher fuel costs,
- higher planned outage and maintenance costs at certain of our fossil and nuclear plants, partially offset by cost control measures,
- the absence of the gain on the Dynegy leveraged lease settlement in 2012, and

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- higher Income Tax Expense due to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012 (see Item 8. Financial Statements and Supplementary Data—Note 19. Income Taxes).

These decreases were largely offset by

- higher capacity revenues in the PJM region resulting from higher average prices as well as higher generation sold primarily in the PJM region,
- higher average gas prices on increased sales to third party customers, and
- higher revenues due to increased investments in transmission projects.

Our results include the realized gains, losses and earnings on Power's Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity. Net realized gains, interest and dividend income and other costs related to the NDT Fund are recorded in Other Income and Deductions, and impairments on certain NDT securities are recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense. In 2014 and 2012, we restructured portions of our NDT Fund and realized gains of $65 million and $59 million, respectively.

Our results also include the after-tax impacts of non-trading MTM activity, which consist of the financial impact from positions with forward delivery dates.

The combined after-tax impact on Net Income for the years ended December 31, 2014, 2013 and 2012 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2014	2013	2012
	Millions, after tax		
NDT Fund and Related Activity	$ 68	$ 40	$ 52
Non-Trading MTM Gains (Losses)	$ 66	$ (74)	$ (10)

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, Power and PSE&G, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data—Note 23. Related-Party Transactions.

	Years Ended December 31,			Increase / (Decrease) 2014 vs. 2013		Increase / (Decrease) 2013 vs. 2012	
	2014	2013	2012				
	Millions			Millions	%	Millions	%
Operating Revenues	$ 10,886	$ 9,968	$ 9,781	$ 918	9	$ 187	2
Energy Costs	3,886	3,536	3,719	350	10	(183)	(5)
Operation and Maintenance	3,150	2,887	2,632	263	9	255	10
Depreciation and Amortization	1,227	1,178	1,054	49	4	124	12
Income from Equity Method Investments	13	11	12	2	18	(1)	(8)
Other Income and (Deductions)	229	159	162	70	44	(3)	(2)
Other-Than-Temporary Impairments	20	12	18	8	67	(6)	(33)
Interest Expense	389	402	423	(13)	(3)	(21)	(5)
Income Tax Expense	938	812	736	126	16	76	10

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The 2014 amounts in the preceding table for Operating Revenues and O&M Costs each include $389 million for Servco. These amounts represent the O&M pass-through costs for the Long Island operations, the full reimbursement of which is reflected in Operating Revenues. See Item 8. Financial Statements and Supplementary Data—Note 3. Variable Interest Entities for further explanation. The following discussions for Power and PSE&G provide a detailed explanation of their respective variances.

PSE&G

PSE&G	Years Ended December 31, 2014	2013	2012	Increase / (Decrease) 2014 vs. 2013		Increase / (Decrease) 2013 vs. 2012	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 6,766	$ 6,655	$ 6,626	$ 111	2	$ 29	—
Energy Costs	2,909	2,841	3,159	68	2	(318)	(10)
Operation and Maintenance	1,558	1,639	1,508	(81)	(5)	131	9
Depreciation and Amortization	906	872	778	34	4	94	12
Taxes Other Than Income Taxes	—	68	98	(68)	(100)	(30)	(31)
Other Income (Deductions)	58	51	47	7	14	4	9
Interest Expense	277	293	295	(16)	(5)	(2)	(1)
Income Tax Expense	449	381	307	68	18	74	24

Year Ended December 31, 2014 as compared to 2013

Operating Revenues increased $111 million due primarily to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $88 million due primarily to an increase in transmission revenues.

- Transmission revenues were $138 million higher due to increased investments in transmission projects.
- Gas distribution revenues decreased $5 million due primarily to lower Weather Normalization Clause (WNC) revenue of $32 million due to more normal weather compared to the prior year, lower Transitional Energy Facilities Assessment (TEFA) revenue of $22 million due to elimination of the TEFA tax effective January 1, 2014, lower Capital Infrastructure Program (CIP) related revenue of $11 million, partially offset by higher sales volumes of $54 million, and higher revenue from Solar and Energy Efficiency Recovery Charges (formerly RRC and currently Green Program Recovery Charges (GPRC)) of $6 million.
- Electric distribution revenues decreased $45 million due primarily to a $45 million decrease due to elimination of the TEFA tax in 2014, lower sales volumes of $17 million and lower CIP related revenue of $5 million, partially offset by higher GPRC of $22 million.

Clause Revenues decreased $51 million due primarily to lower Societal Benefit Charges (SBC) of $32 million, lower Securitization Transition Charge (STC) revenues of $18 million, and lower Margin Adjustment Clause (MAC) of $7 million, partially offset by higher Solar Pilot Recovery Charge (SPRC) of $6 million. The changes in SBC, STC, MAC and SPRC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, STC, MAC or SPRC collections.

Commodity Revenue increased $68 million due to higher Electric and Gas revenues. This is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues increased $22 million due primarily to $64 million in higher BGS revenues, partially offset by $42 million in lower revenues from the sale of Non-Utility Generation (NUG) energy and collections of Non-Utility Generation Charges (NGC) due primarily to lower prices. BGS sales increased 2% due primarily to weather.
- Gas revenues increased $46 million due to higher BGSS volumes of $93 million, partially offset by lower BGSS prices of $47 million. The average price of natural gas was 5% lower in 2014 than in 2013.

Other Operating Revenues increased $6 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

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Operating Expenses

Energy Costs increased $68 million. This is entirely offset by Commodity Revenue.

- Electric costs increased $22 million or 1% due to $75 million of increased deferred cost recovery, $30 million in higher BGS volumes and a $2 million increase in NUG prices, partially offset by $78 million in lower NUG volumes and $7 million from lower BGS prices. BGS volume increased 2% due to customer migration from third party suppliers (TPS).
- Gas costs increased $46 million or 5% due to $93 million or 10% in higher sales volumes due primarily to weather, partially offset by $47 million or 5% in lower prices.

Operation and Maintenance decreased $81 million, of which the most significant components were decreases of

- $73 million in pension and other postretirement benefits (OPEB) expenses, and
- $21 million in costs related to SBC, GPRC and CIP,
- partially offset by a $12 million net increase in operational expenses due primarily to increases in storm related costs of $8 million, wages of $6 million and transmission related costs of $2 million, partially offset by a $4 million decrease in general operating expenses, and
- a $1 million increase in gas bad debt expense.

Depreciation and Amortization increased $34 million due primarily to increases of

- $47 million in additional plant in service, and
- $2 million in software amortization,
- partially offset by a $15 million decrease in amortization of Regulatory Assets.

Taxes Other Than Income Taxes decreased $68 million due to the elimination of the TEFA tax in 2014.

Other Income and (Deductions) net increase of $7 million was due primarily to increases of

- $7 million in Allowance for Funds Used During Construction, and
- $1 million in solar loan interest income,
- partially offset by a $1 million decrease in Rabbi Trust interest and gains.

Interest Expense decreased $16 million primarily due to decreases of

- $16 million due to partial redemption of securitization debt in 2014,
- $25 million due to maturities of $725 million in 2013, and
- $5 million due to maturities of $500 million in 2014,
- partially offset by an increase of $14 million due to the issuance of $1,250 million of debt in 2014, and
- an increase of $17 million due to the issuance of $1,500 million of debt in 2013.

Income Tax Expense increased $68 million due primarily to higher pre-tax income.

Year ended December 31, 2013 as compared to 2012

Operating Revenues increased $29 million due primarily to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $223 million due primarily to an increase in transmission revenues.

- Transmission revenues were $184 million higher due to increased investments in transmission projects.
- Gas distribution revenues increased $24 million due primarily to higher sales volumes of $70 million, higher CIP related revenue of $23 million and higher revenue from Solar and Energy Efficiency Recovery Charges of $5 million, partially offset by lower WNC revenue of $67 million due to more normal weather compared to the prior year and lower TEFA revenue of $7 million due to a lower TEFA rate.

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- Electric distribution revenues increased $15 million due primarily to higher GPRC of $37 million and higher CIP related revenue of $11 million, partially offset by lower TEFA revenue of $23 million due to a lower TEFA rate and lower sales volumes of $10 million.

Clause Revenues increased $110 million due primarily to STC revenues of $51 million, higher SBC of $47 million and a higher SPRC of $11 million. The changes in STC, SBC and SPRC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC or SPRC collections.

Commodity Revenue decreased $318 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $308 million due primarily to $169 million in lower BGS revenues and $139 million in lower revenues from the sale of NUG energy and collections of NGC due primarily to lower prices. BGS sales decreased 4% due primarily to customer migration to TPS and weather.
- Gas revenues decreased $10 million due to lower BGSS prices of $121 million, partially offset by higher BGSS volumes of $111 million. The average price of natural gas was 12% lower in 2013 than in 2012.

Other Operating Revenues increased $14 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Operating Expenses

Energy Costs decreased $318 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $308 million or 14% due to $214 million in lower BGS and NUG volumes, $35 million of lower BGS prices, and $59 million for decreased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.
- Gas costs decreased $10 million or 1% due to $121 million or 12% in lower prices, partially offset by $111 million or 11% in higher sales volumes due primarily to weather.

Operation and Maintenance increased $131 million, of which the most significant components were increases of

- $131 million in costs related to SBC, GPRC and CIP,
- $24 million in transmission related costs, and
- $10 million in appliance service costs,
- partially offset by the absence of $40 million in transmission and distribution storm damages in 2012,
- a $10 million decrease in pension and OPEB expenses, and
- an $11 million decrease in gas bad debt expense.

Depreciation and Amortization increased $94 million due primarily to increases of

- $59 million in amortization of Regulatory Assets, and
- $33 million in additional plant in service.

Taxes Other Than Income Taxes decreased $30 million due to a lower TEFA rate, partially offset by higher sales volumes for gas.

Other Income and (Deductions) net increase of $4 million was due primarily to

- a $5 million increase in solar loan interest income,
- partially offset by a $1 million decrease in Rabbi Trust interest and gains.

Interest Expense experienced no material change.

Income Tax Expense increased $74 million due primarily to higher pre-tax income and the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012.

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Power

Power	Years Ended December 31, 2014	2013	2012	Increase / (Decrease) 2014 vs. 2013		Increase / (Decrease) 2013 vs. 2012	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 5,434	$ 5,063	$ 4,873	$ 371	7	$ 190	4
Energy Costs	2,747	2,496	2,381	251	10	115	5
Operation and Maintenance	1,186	1,224	1,127	(38)	(3)	97	9
Depreciation and Amortization	292	273	242	19	7	31	13
Income from Equity Method Investments	14	16	15	(2)	(13)	1	7
Other Income (Deductions)	170	105	111	65	62	(6)	(5)
Other-Than-Temporary Impairments	20	12	18	8	67	(6)	(33)
Interest Expense	122	116	132	6	5	(16)	(12)
Income Tax Expense	491	419	433	72	17	(14)	(3)

Year Ended December 31, 2014 as compared to 2013

Operating Revenues increased $371 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues increased $263 million due primarily to

- higher revenues of $366 million due primarily to MTM gains in 2014 resulting from a decrease in prices on forward positions and higher energy volumes sold in the New York and New England (NE) regions, and
- a net increase of $27 million due primarily to higher volumes on wholesale load contracts in the PJM region, offset in part by lower wholesale load volumes in the NE region,
- partially offset by a decrease of $89 million due to lower volumes of electricity sold as a result of serving fewer tranches in 2014 under our BGS contracts and lower average pricing, and
- a net decrease of $41 million due primarily to a decrease in operating reserve revenue, partially offset by higher ancillary revenue in the PJM region.

Gas Supply Revenues increased $93 million due primarily to

- a net increase of $44 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during the 2014 winter heating season, partially offset by lower average gas prices, and
- a net increase of $49 million due to higher sales volumes to third party customers.

Other Operating Revenues increased $15 million due to transition fees related to fuel management and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $251 million due to

- ***Generation costs*** increased $252 million due primarily to higher fuel costs, reflecting higher average realized natural gas prices, the unfavorable MTM impact from lower average natural gas prices on forward positions and the utilization of higher volumes of gas and oil. These increased costs were partially offset by lower congestion costs in the PJM region.
- ***Gas costs*** decreased $1 million related to a decrease of $137 million in average gas inventory costs, substantially offset by $136 million of higher volumes sold under the BGSS contract and to third party customers due to colder average temperatures during the 2014 winter heating season.

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Operation and Maintenance decreased $38 million due primarily to

- lower pension and OPEB costs of $42 million,
- a decrease of $15 million due primarily to the outage of our 100%-owned Hope Creek nuclear facility in the fall of 2013, which was partially offset by the extension of our 57%-owned nuclear Salem Unit 2 refueling outage in 2014, and
- a decrease of $27 million due to lower storm costs related to Superstorm Sandy,
- partially offset by an increase of $40 million related primarily to higher planned outage and maintenance costs at our fossil plants, including maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant and outages at our Keystone and Hudson facilities.

Depreciation and Amortization increased $19 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income (Deductions) increased $65 million due primarily to higher realized gains from the NDT Fund due to the restructuring of the portfolio in 2014.

Other-Than-Temporary Impairments increased $8 million due to an increase in impairments of the NDT Fund.

Interest Expense increased $6 million due primarily to the issuance of a $250 million 2.45% Senior Note and a $250 million 4.30% Senior Note in November 2013, partially offset by the maturity of $300 million of 2.50% Senior Notes in April 2013.

Income Tax Expense increased $72 million in 2014 due primarily to higher pre-tax income.

Year ended December 31, 2013 as compared to 2012

Operating Revenues increased $190 million due to changes in generation and supply revenues.

Generation Revenues increased $102 million due primarily to

- an increase of $341 million due to higher capacity revenues resulting from higher average auction prices and an increase in operating reserve revenues in PJM, and
- higher net revenues of $36 million due primarily to higher generation sold in the PJM and NE regions partly offset by higher MTM losses in 2013 resulting from an increase in prices on forward positions in the PJM and NE regions,
- partially offset by a decrease of $155 million due primarily to lower volumes of electricity sold under our BGS contracts and lower average pricing, and
- a net decrease of $120 million due to lower volumes on wholesale load contracts in the PJM and NE regions.

Gas Supply Revenues increased $88 million due primarily to

- a net increase of $40 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during the 2013 winter heating season, partially offset by lower average gas prices, and
- a net increase of $48 million due primarily to higher average gas prices and higher sales volumes to third party customers.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $115 million due to

- ***Generation costs*** increased $75 million due primarily to $84 million of higher fuel costs, reflecting higher average realized natural gas prices, higher nuclear fuel costs and the utilization of higher volumes of coal and oil, partially offset by lower average coal prices and lower average unrealized natural gas prices on forward positions.
- ***Gas costs*** increased $40 million, principally related to obligations under the BGSS contract, reflecting higher sales volumes in 2013 due to colder average temperatures during the 2013 winter heating season and higher volumes on third party sales, partially offset by lower average gas inventory costs.

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Operation and Maintenance increased $97 million due primarily to

- higher planned outage and maintenance costs in 2013, mainly at our gas-fired BEC plant in New York, Bergen gas-fired plant in New Jersey, Linden gas-fired plant in New Jersey and 23%-owned Conemaugh coal-fired plant in Pennsylvania, partially offset by lower storm costs in 2013, and
- higher outage costs at our nuclear generating facilities, primarily at our 100%-owned Hope Creek station.

Depreciation and Amortization increased $31 million due primarily to a higher depreciable asset base at Fossil and Nuclear, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut in June 2012, completion of the steam path retrofit upgrade at our co-owned Peach Bottom Unit 2 in October 2012, and placing two solar facilities into service in the fourth quarter of 2012. In addition, an update to the nuclear asset retirement obligation became effective in November 2012, causing higher depreciation in 2013.

Income from Equity Method Investments experienced no material change.

Other Income (Deductions) decreased $6 million due primarily to lower NDT Fund realized gains in 2013, partially offset by lower NDT Fund realized losses in 2013. In addition, we recognized a loss on the extinguishment of debt in 2012.

Other-Than-Temporary Impairments decreased $6 million due to lower impairments on the NDT Fund in 2013.

Interest Expense decreased $16 million due primarily to a decrease of $23 million resulting from the maturity of $300 million of 2.50% of Senior Notes in April 2013, and the early redemptions of $250 million of 5.00% medium term notes and various tax-exempt bonds in December 2012, partially offset by higher interest costs of $6 million in 2013 since interest capitalization ceased for our Kearny and New Haven gas-fired peaking projects on their June 2012 in-service date.

Income Tax Expense decreased $14 million in 2013 due primarily to lower pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Financing Methodology

We expect our capital requirements to be met through internally generated cash flows and external financings, consisting of short-term debt for working capital needs and long-term debt for capital investments.

PSE&G's sources of external liquidity include a $600 million multi-year syndicated credit facility. PSE&G's commercial paper program is the primary vehicle for meeting seasonal, intra-month and temporary working capital needs. PSE&G does not engage in any intercompany borrowing or lending. PSE&G maintains back-up facilities in an amount sufficient to cover the commercial paper and letters of credit outstanding. PSE&G's dividend payments to PSEG are consistent with its capital structure objectives which have been established to maintain investment grade credit ratings. PSE&G's long-term financing plan is designed to replace maturities, fund a portion of its capital program and manage short-term debt balances. Generally, PSE&G uses either secured medium-term notes or first mortgage bonds to raise long-term capital.

PSEG, Power, Energy Holdings, PSEG LI and Services participate in a corporate money pool, an aggregation of daily cash balances designed to efficiently manage their respective short-term liquidity needs. Servco does not participate in the corporate money pool. Servco's short-term liquidity needs are met through an account funded and owned by LIPA.

PSEG's sources of external liquidity include multi-year syndicated credit facilities totaling $1 billion. These facilities are available to back-stop PSEG's commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to PSEG's subsidiaries. PSEG's credit facilities and the commercial paper program are available to support PSEG working capital needs or to temporarily fund growth opportunities in advance of obtaining permanent financing. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power's sources of external liquidity include $2.6 billion of syndicated multi-year credit facilities. Additionally, from time to time, Power maintains bilateral credit agreements designed to enhance its liquidity position. Power has $100 million of bilateral credit agreements that are scheduled to expire in September 2015. Credit capacity is primarily used to provide collateral in support of Power's forward energy sale and forward fuel purchase contracts as the market prices for energy and fuel fluctuate, and to meet potential collateral postings in the event of a credit rating downgrade below investment grade. Power's dividend payments to PSEG are also designed to be consistent with its capital structure objectives which have been established to maintain investment grade credit ratings and provide sufficient financial flexibility. Generally, Power issues senior unsecured debt to raise long-term capital.

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Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the year ended December 31, 2014, our operating cash flow increased by $2 million. For the year ended December 31, 2013, our operating cash flow increased by $371 million. The net changes were primarily due to net changes from our subsidiaries as discussed below and tax payments at the parent company and Energy Holdings.

PSE&G

PSE&G's operating cash flow increased $188 million from $1,645 million to $1,833 million for the year ended December 31, 2014, as compared to 2013, due primarily to

- higher earnings,
- an increase of $188 million due to an increase from a net change in regulatory deferrals, primarily related to over collections of BGSS gas costs, the over collection of gas revenues due to the Gas Weather Normalization clause and GPRC rate recoveries,
- an increase of $83 million due to decrease in employee benefit plan funding,
- partially offset by $199 million related to higher tax payments.

PSE&G's operating cash flow increased $389 million from $1,256 million to $1,645 million for the year ended December 31, 2013, as compared to 2012, due primarily to

- higher earnings,
- an increase of $134 million due to an increase from a net change in regulatory deferrals, primarily related to over collections of BGSS gas costs and the collection of prior year deficiency revenues under the Gas Weather Normalization clause mechanism, and
- a decrease of $47 million in benefit plan funding,
- partially offset by $114 million related to higher tax payments.

Power

Power's operating cash flow increased $78 million from $1,347 million to $1,425 million for the year ended December 31, 2014, as compared to 2013, primarily resulting from

- lower tax payments,
- partially offset by increase of $87 million in payments to counterparties, and
- a decrease of $11 million due to collection of counterparty receivables.

Power's operating cash flow decreased $106 million from $1,453 million to $1,347 million for the year ended December 31, 2013, as compared to 2012, primarily resulting from

- lower earnings, and
- higher tax payments,
- partially offset by a decrease of $73 million related to margin deposits, and
- a decrease of $26 million in employee benefit plan funding.

Short-Term Liquidity

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of December 31, 2014 were as follows:

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Company/Facility	As of December 31, 2014 Total Facility	Usage	Available Liquidity
		Millions	
PSEG	$ 1,000	$ 8	$ 992
PSE&G	600	14	586
Power	2,700	197	2,503
Total	**$ 4,300**	**$ 219**	**$ 4,081**

As of December 31, 2014, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating. PSE&G's credit facility primary use is to support its Commercial Paper Program under which as of December 31, 2014, no amounts were outstanding. Most of our credit facilities expire in 2018 and 2019. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities and Note 13. Schedule of Consolidated Debt.

Long-Term Debt Financing

PSE&G has $300 million of 2.70%, Series G Medium Term Notes maturing in May 2015.

Power has a $300 million of 5.50% Senior Notes maturing in December 2015.

For a discussion of our long-term debt transactions during 2014 and into 2015, see Item 8. Financial Statements and Supplementary Data—Note 13. Schedule of Consolidated Debt.

Debt Covenants

Our credit agreements contain maximum debt to equity ratios and other restrictive covenants and conditions to borrowing. We are currently in compliance with all of our debt covenants. Continued compliance with applicable financial covenants will depend upon our future financial position, level of earnings and cash flows, as to which no assurances can be given.

In addition, under its First and Refunding Mortgage (Mortgage), PSE&G may issue new First and Refunding Mortgage Bonds against previous additions and improvements, provided that its ratio of earnings to fixed charges calculated in accordance with its Mortgage is at least 2 to 1, and/or against retired Mortgage Bonds. As of December 31, 2014, PSE&G's Mortgage coverage ratio was 5.6 to 1 and the Mortgage would permit up to approximately $3.8 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.

Default Provisions

Our bank credit agreements and indentures contain various default provisions that could result in the potential acceleration of payment under the defaulting company's agreement. We have not defaulted under these agreements.

PSEG's bank credit agreements contain cross default provisions under which events at Power or PSE&G, including payment defaults, bankruptcy events, the failure to satisfy certain final judgments or other events of default under their financing agreements, would each constitute an event of default. Under the bank credit agreements, it would be an event of default if both PSE&G and Power cease to be wholly owned by PSEG.

There are no cross default provisions to affiliates in PSE&G's or Power's credit agreements or indentures.

Ratings Triggers

Our debt indentures and credit agreements do not contain any material 'ratings triggers' that would cause an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, any one or more of the affected companies may be subject to increased interest costs on certain bank debt and certain collateral requirements. In the event that we are not able to affirm representations and warranties on credit agreements, lenders would not be required to make loans.

In accordance with BPU requirements under the BGS contracts, PSE&G is required to maintain an investment grade credit rating. If PSE&G were to lose its investment grade rating, it would be required to file a plan to assure continued payment for the BGS requirements of its customers.

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PSE&G is the servicer for the bonds issued by PSE&G Transition Funding LLC and PSE&G Transition Funding II LLC. Cash collected by PSE&G to service these bonds is commingled with PSE&G's other cash until it is remitted to the bond trustee each month. If PSE&G were to lose its investment grade rating, PSE&G would be required to remit collected cash daily to the bond trustee. PSE&G is prohibited from advancing its own funds to make payments related to such bonds.

Fluctuations in commodity prices or a deterioration of Power's credit rating to below investment grade could increase Power's required margin postings under various agreements entered into in the normal course of business. Power believes it has sufficient liquidity to meet the required posting of collateral which would likely result from a credit rating downgrade at today's market prices.

Common Stock Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	**2014**	**2013**	**2012**
Per Share	$ 1.48	$ 1.44	$ 1.42
in Millions	$ 748	$ 728	$ 718

On February 17, 2015, our Board of Directors approved a $0.39 per share common stock dividend for the first quarter of 2015. This reflects an indicated annual dividend rate of $1.56 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's and Fitch) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In May 2014, Moody's published updated research reports on PSEG, PSE&G and Power and the existing ratings and outlooks were unchanged. In May 2014, S&P published updated research reports and revised the outlook to positive from stable for PSEG's Corporate Credit Rating. S&P also affirmed the senior unsecured rating of BBB+ at Power and mortgage bond rating of A at PSE&G. In October 2014, Fitch affirmed the ratings and outlooks for PSEG, PSE&G and Power.

	Moody's (A)	**S&P (B)**	**Fitch (C)**
PSEG			
Outlook	**Stable**	**Positive**	**Stable**
Commercial Paper	P2	A2	F2
PSE&G			
Outlook	**Stable**	**Positive**	**Stable**
Mortgage Bonds	Aa3	A	A+
Commercial Paper	P1	A2	F2
Power			
Outlook	**Stable**	**Positive**	**Stable**
Senior Notes	Baa1	BBB+	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

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(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities. The Corporate Credit Rating outlook does not apply to PSEG's or PSE&G's Commercial Paper Rating or PSE&G's Mortgage Bond rating.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1 (highest) to D (lowest) for short-term securities.

Other Comprehensive Income

For the year ended December 31, 2014, we had Other Comprehensive Loss of $188 million on a consolidated basis. Other Comprehensive Loss was due primarily to a $173 million increase in our consolidated liability for pension and postretirement benefits and a $27 million decrease in net unrealized gains related to Available-for-Sale Securities, and was partially offset by $12 million of unrealized gains on derivative contracts accounted for as hedges. See Item 8. Financial Statements and Supplementary Data—Note 20. Accumulated Other Comprehensive Income (Loss), Net of Tax for additional information.

CAPITAL REQUIREMENTS

It is expected that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. Projected capital construction and investment expenditures, excluding nuclear fuel purchases, for the next three years are presented in the table below. These amounts are subject to change, based on various factors. We will continue to approach non-regulated solar and other renewables investments opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2015	2016	2017
		Millions	
PSE&G:			
Transmission			
Reliability Enhancements	$ 1,420	$ 1,230	$ 1,185
Facility Replacement	165	185	200
Support Facilities	5	35	15
Environmental/Regulatory	5	5	5
Distribution			
Reliability Enhancements	285	435	295
Facility Replacement	385	235	225
Support Facilities	55	50	55
New Business	155	160	160
Environmental/Regulatory	40	50	55
Renewables	100	80	80
Total PSE&G	**$ 2,615**	**$ 2,465**	**$ 2,275**
Power:			
Baseline	$ 225	$ 220	$ 190
Environmental/Regulatory	60	50	45
Fossil Growth Opportunities	20	—	20
Nuclear Expansion	95	20	10
Solar Expansion	155	105	—
Total Power	**$ 555**	**$ 395**	**$ 265**
Services	$ 50	$ 35	$ 35
Total PSEG	**$ 3,220**	**$ 2,895**	**$ 2,575**

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PSE&G

PSE&G's projections for future capital expenditures include material additions and replacements to its transmission and distribution systems to meet expected growth and to manage reliability. As project scope and cost estimates develop, PSE&G will modify its current projections to include these required investments. PSE&G's projected expenditures for the various items reported above are primarily comprised of the following:

- Reliability Enhancements—investments made to maintain the reliability and efficiency of the system or function.
- Facility Replacement—investments made to replace systems or equipment in kind.
- Support Facilities—ancillary equipment needed to support the business lines, such as computers, office furniture and buildings and structures housing support personnel or equipment/inventory.
- New Business—investments made in support of new business (e.g. to add new customers).
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Renewables—investments made in response to regulatory or legal mandates relating to renewable energy.

In 2014, PSE&G made $2,170 million of capital expenditures, including $2,164 million of investment in plant, primarily for transmission and distribution system reliability and $6 million in solar loan investments. This does not include expenditures for cost of removal, net of salvage, of $98 million, which are included in operating cash flows.

Power

Power's projected expenditures for the various items listed above are primarily comprised of the following:

- Baseline—investments to replace major parts and enhance operational performance.
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Fossil Growth Opportunities—investments associated with upgrades to increase efficiency and output at combined cycle plants.
- Nuclear Expansion—investments associated with certain Nuclear capital projects, primarily at existing facilities designed to increase operating output.
- Solar Expansion—investments associated with the construction of utility-scale photovoltaic facilities.

In 2014, Power made $460 million of capital expenditures, excluding $166 million for nuclear fuel, primarily related to various projects at Fossil and Nuclear.

Disclosures about Long-Term Maturities, Contractual and Commercial Obligations and Certain Investments

The following table reflects our contractual cash obligations and other commercial commitments in the respective periods in which they are due. In addition, the table summarizes anticipated recourse and non-recourse debt maturities for the years shown. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Schedule of Consolidated Debt.

The table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities for uncertain tax positions since we are unable to reasonably estimate the timing of liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Item 8. Financial Statements and Supplementary Data—Note 19. Income Taxes for additional information.

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	Total Amount Committed	Less Than 1 Year	2 - 3 Years	4- 5 Years	Over 5 Years
			Millions		
Contractual Cash Obligations					
Long-Term Recourse Debt Maturities					
PSE&G	$ 6,329	$ 300	$ 171	$ 1,250	$ 4,608
Transition Funding (PSE&G)	251	251	—	—	—
Transition Funding II (PSE&G)	8	8	—	—	—
Power	2,553	300	553	294	1,406
Long-Term Non-Recourse Project Financing					
Other	16	16	—	—	—
Interest on Recourse Debt					
PSE&G	4,113	248	473	427	2,965
Transition Funding (PSE&G)	11	11	—	—	—
Transition Funding II (PSE&G)	—	—	—	—	—
Power	1,142	131	207	179	625
Interest on Non-Recourse Project Financing					
Other	1	1	—	—	—
Capital Lease Obligations					
Power	5	2	1	1	1
Services	5	5	—	—	—
Operating Leases					
PSE&G	95	12	16	12	55
Power	32	2	3	4	23
Services	215	5	25	26	159
Other	4	2	2	—	—
Energy-Related Purchase Commitments					
Power	3,222	892	1,119	559	652
Total Contractual Cash Obligations	**$ 18,002**	**$ 2,186**	**$ 2,570**	**$ 2,752**	**$ 10,494**
Commercial Commitments					
Standby Letters of Credit					
PSEG	$ 8	$ 8	$ —	$ —	$ —
PSE&G	14	14	—	—	—
Power	242	242	—	—	—
Guarantees and Equity Commitments					
Power	80	79	—	—	1
Total Commercial Commitments	**$ 344**	**$ 343**	**$ —**	**$ —**	**$ 1**
Liability Payments for Uncertain Tax Positions					
PSEG	$ 59	$ 59	$ —	$ —	$ —
PSE&G	2	2	—	—	—
Power	23	23	—	—	—

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OFF-BALANCE SHEET ARRANGEMENTS

Power

Power issues guarantees in conjunction with certain of its energy contracts. See Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities for further discussion.

Other

Through Energy Holdings, we have investments in leveraged leases that are accounted for in accordance with GAAP Accounting for Leases. Leveraged lease investments generally involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease arrangement, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and is not presented on our Consolidated Balance Sheets. In the event of default, the leased asset, and in some cases the lessee, secures the loan. As a lessor, Energy Holdings has ownership rights to the property and rents the property to the lessees for use in their business operations. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 6. Long-Term Investments.

In the event that collection of the minimum lease payments to be received by Energy Holdings is no longer reasonably assured, the accounting treatment for some of the leases may change. In such cases, Energy Holdings may deem that a lessee has a high probability of defaulting on the lease obligation, and would reclassify the lease from a leveraged lease to an operating lease and would consider the need to record an impairment of its investment. Should this event occur, the fair value of the underlying asset and the associated debt would be recorded on the Consolidated Balance Sheets instead of the net equity investment in the lease.

CRITICAL ACCOUNTING ESTIMATES

Under GAAP, many accounting standards require the use of estimates, variable inputs and assumptions (collectively referred to as estimates) that are subjective in nature. Because of this, differences between the actual measure realized versus the estimate can have a material impact on results of operations, financial position and cash flows. We have determined that the following estimates are considered critical to the application of rules that relate to the respective businesses.

Accounting for Pensions

PSEG sponsors several qualified and nonqualified pension plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The market-related value of plan assets held for the qualified pension plan is equal to the fair value of these assets as of year-end. The plan assets are comprised of investments in both debt and equity securities which are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. We calculate pension costs using various economic and demographic assumptions.

***Assumptions and Approach Used*:** Economic assumptions include the discount rate and the long-term rate of return on trust assets. Demographic assumptions include projections of future mortality rates, pay increases and retirement patterns.

Assumption	2014	2013	2012
Discount Rate	4.20%	5.00%	4.20%
Rate of Return on Plan Assets	8.00%	8.00%	8.00%

The discount rate used to calculate pension obligations is determined as of December 31 each year, our measurement date. The discount rate used to determine year-end obligations is also used to develop the following year's net periodic pension cost.
In selecting the annual discount rate to calculate benefit obligations, we utilize a hypothetical portfolio of high quality corporate bonds with cash flows that match the benefit plan liability. The composite yield on the hypothetical bond portfolio reflects the rate at which the obligations could effectively be settled.

Our expected rate of return on plan assets reflects current asset allocations, historical long-term investment performance and an estimate of future long-term returns by asset class and long-term inflation assumptions.

Based on the above assumptions, we have estimated net periodic pension expense of approximately $55 million, net of amounts capitalized.

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We utilize a corridor approach that reduces the volatility of reported pension expense /income. The corridor requires differences between actuarial assumptions and plan results be deferred and amortized as part of expense/income. This occurs only when the accumulated differences exceed 10% of the greater of the pension benefit obligation or the fair value of plan assets as of each year-end. The excess would be amortized over the average remaining service period of the active employees, which is approximately eight years.

***Effect if Different Assumptions Used*:** As part of the business planning process, we have modeled future costs assuming an 8.00% rate of return and a 4.20% discount rate for 2015. Actual future pension expense/income and funding levels will depend on future investment performance, changes in discount rates, market conditions, funding levels relative to our projected benefit obligation and accumulated benefit obligation and various other factors related to the populations participating in the pension plans.

The following chart reflects the sensitivities associated with a change in certain assumptions. The effects of the assumption changes shown below solely reflect the impact of that specific assumption.

Assumption	% Change	Impact on Pension Benefit Obligation as of December 31, 2014	Increase to Pension Expense in 2015
		Millions	
Discount Rate	(1)%	$ 888	$ 100
Rate of Return on Plan Assets	(1)%	$ —	$ 52

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Hedge and MTM Accounting

Current guidance requires us to recognize the fair value of derivative instruments, not designated as normal purchases or normal sales, at their fair value on the balance sheet. Many non-trading contracts qualify for normal purchases and normal sales exemption and are accounted for upon settlement.

***Assumptions and Approach Used*:** In general, the fair value of our derivative instruments is determined by reference to quoted market prices from contracts listed on exchanges or from brokers. Some of these derivative contracts are long-term and rely on forward price quotations over the entire duration of the derivative contracts.

For a small number of contracts where quoted market prices are not available, we utilize mathematical models that rely on historical data to develop forward pricing information in the determination of fair value.

We have entered into various derivative instruments to manage risk from changes in commodity prices and interest rates. In accordance with our hedging strategy, derivatives that are hedging these risks and qualify are designated as either cash flow hedges or fair value hedges. For derivatives designated as hedges, the change in the value of a derivative instrument is measured against the offsetting change in the value of the underlying contract, anticipated transaction or other business condition that the derivative instrument is intended to hedge. This is known as the measure of hedge effectiveness. Changes in the fair value of the effective portion of a derivative instrument designated as a fair value hedge, along with changes in the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in current period earnings. Changes in the fair value of the effective portion of derivative instruments designated as cash flow hedges, are reported in Accumulated Other Comprehensive Income (Loss), net of tax, until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings. During periods of extreme price volatility, there will be significant changes in the value recorded in Accumulated Other Comprehensive Income (Loss).

For our wholesale energy business, many of the forward sale, forward purchase, option and other contracts are derivative instruments that hedge commodity price risk, but do not meet the requirements for either cash flow or fair value hedge accounting. The changes in value of such derivative contracts are marked to market through earnings as the related commodity prices fluctuate. As a result, our earnings may experience significant fluctuations depending on the volatility of commodity prices.

***Effect if Different Assumptions Used*:** Any significant changes to the fair market values of our derivatives instruments could result in a material change in the value of the assets or liabilities recorded on our Consolidated Balance Sheets and could result in a material change to the unrealized gains or losses recorded in our Consolidated Statements of Operations.

For additional information regarding Derivative Financial Instruments, see Item 8. Financial Statements and Supplementary Data—Note 15. Financial Risk Management Activities.

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Lease Investments

Our Investments in Leases, included in Long-Term Investments on our Consolidated Balance Sheets, are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. A significant portion of the estimated residual value of leased assets is related to merchant power plants leased to other energy companies. See Item 8. Financial Statements and Supplementary Data – Note 6. Long-Term Investments and Note 7. Financing Receivables.

***Assumptions and Approach Used*:** Residual values are the estimated values of the leased assets at the end of the respective lease terms. The estimated values are calculated by discounting the cash flows related to the leased assets after the lease term. For the merchant power plants, the estimated discounted cash flows are dependent upon various assumptions, including:

- estimated forward power and capacity prices in the years after the lease,
- related prices of fuel for the plants,
- dispatch rates for the plants,
- future capital expenditures required to maintain the plants,
- future operation and maintenance expenses, and
- discount rates.

Residual valuations are performed annually for each plant subject to lease using specific assumptions tailored to each plant. Those annual valuations are compared to the recorded residual values to determine if an impairment is warranted.

***Effect if Different Assumptions Used*:** A significant change to the assumptions, such as a large decrease in near-term power prices that affects the market's view of long-term power prices, or a change in the credit rating or bankruptcy of a counterparty, could result in an impairment of one or more of the residual values, but not necessarily to all of the residual values. However, if, because of changes in assumptions, all the residual values related to the merchant energy plants were deemed to be zero, we would recognize an after-tax charge to income of approximately $177 million.

NDT Fund

Our NDT Fund comprises both debt and equity securities. The assets in the NDT Fund are classified as available-for-sale securities and are marked to market with unrealized gains and losses recorded in Accumulated Other Comprehensive Income (Loss) unless securities with such unrealized losses are deemed to be other-than-temporarily impaired. Unrealized losses that are deemed to be other-than-temporarily impaired are charged against earnings rather than Accumulated Other Comprehensive Income (Loss) and reflected as a separate line in the Consolidated Statement of Operations. Realized gains, losses and dividend and interest income are recorded in our Consolidated Statements of Operations as Other Income and Other Deductions.

***Assumptions and Approach Used*:** The NDT Fund investments are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. See Item 8. Financial Statements and Supplementary Data—Note 16. Fair Value Measurements for additional information.

***Effect if Different Assumptions Used*:** Any significant changes to the fair market values of the fund securities could result in a material change in the value of our NDT Fund with a corresponding impact to earnings, which could potentially result in additional funding requirements to satisfy our decommissioning obligations. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Asset Retirement Obligations (ARO)

PSE&G, Power and Services recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists. These AROs are recorded at fair value in the period in which they are incurred and are capitalized as part of the carrying amount of the related long-lived assets. PSE&G, as a rate-regulated entity, recognizes regulatory assets or liabilities as a result of timing differences between the recording of costs and costs recovered through the rate-making process. We accrete the ARO liability to reflect the passage of time.

***Assumptions and Approach Used*:** Because quoted market prices are not available for AROs, we estimate the initial fair value of an ARO by calculating discounted cash flows that are dependent upon various assumptions, including:

- estimation of dates for retirement,
- amounts and timing of future cash expenditures associated with retirement, settlement or remediation activities,

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- discount rates,
- cost escalation rates,
- market risk premium,
- inflation rates, and
- if applicable, past experience with government regulators regarding similar obligations.

We obtain updated cost studies triennially unless new information necessitates more frequent updates. The most recent cost study was done in 2012. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset which impacts the amount of accretion and depreciation expense recognized in future periods.

Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power's nuclear facilities comprised 93% of Power's total AROs as of December 31, 2014. Power determines its AROs for its nuclear units by assigning probability weighting to various discounted cash flow outcomes for each of its nuclear units that incorporate the assumptions above as well as:

- license renewals,
- early shutdown,
- safe storage for a period of time after retirement, and
- recovery from the federal government of costs incurred for spent nuclear fuel.

***Effect if Different Assumptions Used*:** Changes in the assumptions could result in a material change in the ARO balance sheet obligation and the period over which we accrete to the ultimate liability. For example, a decrease of 1% in the discount rate would result in a $141 million increase in the Nuclear ARO as of December 31, 2014. An increase of 1% in the inflation rate would result in a $372 million increase in the Nuclear ARO as of December 31, 2014. Also, if we did not assume that we would recover from the federal government the costs incurred for spent nuclear fuel, the Nuclear ARO would increase by $302 million at December 31, 2014.

Accounting for Regulated Businesses

PSE&G prepares its financial statements to comply with GAAP for rate-regulated enterprises, which differs in some respects from accounting for non-regulated businesses. In general, accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (Regulatory Asset) or recognize obligations (Regulatory Liability) if the rates established are designed to recover the costs and if the competitive environment makes it probable that such rates can be charged or collected. This accounting results in the recognition of revenues and expenses in different time periods than that of enterprises that are not regulated.

***Assumptions and Approach Used*:** PSE&G recognizes Regulatory Assets where it is probable that such costs will be recoverable in future rates from customers and Regulatory Liabilities where it is probable that refunds will be made to customers in future billings. The highest degree of probability is an order from the BPU either approving recovery of the deferred costs over a future period or requiring the refund of a liability over a future period.

Virtually all of PSE&G's regulatory assets and liabilities are supported by BPU orders. In the absence of an order, PSE&G will consider the following when determining whether to record a Regulatory Asset or Liability:

- past experience regarding similar items with the BPU,
- treatment of a similar item in an order by the BPU for another utility,
- passage of new legislation, and
- recent discussions with the BPU.

All deferred costs are subject to prudence reviews by the BPU. When the recovery of a Regulatory Asset or payment of a Regulatory Liability is no longer probable, PSE&G charges or credits earnings, as appropriate.

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***Effect if Different Assumptions Used*:** A change in the above assumptions may result in a material impact on our results of operations or our cash flows. See Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities for a description of the amounts and nature of regulatory balance sheet amounts.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

	MTM VaR	
	Millions	
Years Ended December 31,	**2014**	**2013**
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 36	$ 12
Average for the Period	$ 30	$ 15
High	$ 195	$ 29
Low	$ 14	$ 8
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 56	$ 18
Average for the Period	$ 46	$ 23
High	$ 306	$ 46
Low	$ 22	$ 13

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See Item 8. Financial Statements and Supplementary Data—Note 15. Financial Risk Management Activities for a discussion of credit risk.

Interest Rates

We are subject to the risk of fluctuating interest rates in the normal course of business. We manage interest rate risk by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, we use a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

As of December 31, 2014, a hypothetical 10% increase in market interest rates would result in

- less than $1 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and
- a $288 million decrease in the fair value of debt, including a $233 million decrease at PSE&G and a $55 million decrease at Power.

Debt and Equity Securities

We have $5.7 billion of assets in our pension plan trusts. Although fluctuations in market prices of securities within this portfolio do not directly affect our earnings in the current period, changes in the value of these investments could affect

- our future contributions to these plans,
- our financial position if our accumulated benefit obligation under our pension plans exceeds the fair value of the pension trust funds, and
- future earnings, as we could be required to adjust pension expense and the assumed rate of return.

The NDT Fund is comprised of both fixed income and equity securities totaling $1,780 million as of December 31, 2014. As of December 31, 2014, the portfolio includes $897 million of equity securities and $777 million in fixed income securities. The fair market value of the assets in the NDT Fund will fluctuate primarily depending upon the performance of equity markets. As of December 31, 2014, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $90 million.

We use duration to measure the interest rate sensitivity of the fixed income portfolio. Duration is a summary statistic of the effective average maturity of the fixed income portfolio. The benchmark for the fixed income component of the NDT Fund currently has a duration of 5.56 years and a yield of 2.25%. The portfolio's value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2014, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $43 million.

Credit Risk

See Item 8. Financial Statements and Supplementary Data—Note 15. Financial Risk Management Activities for a discussion of credit risk and a discussion about Power's and PSE&G's credit risk.

Energy Holdings has credit risk related to its investments in leases, which totaled $98 million, net of deferred taxes of $738 million, as of December 31, 2014. These leveraged leases are concentrated in the United States energy industry. See Item 8. Financial Statements and Supplementary Data—Note 7. Financing Receivables for counterparties' credit ratings and other information. The credit exposure to the lessees is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverages are not met and similar cash flow restrictions if ratings are not maintained at stated levels. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a temporary market downturn or degradation in operating performance of the leased assets.

In any lease transaction, in the event of a default, Energy Holdings would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. Under a worst-case scenario, if a foreclosure were to occur, Energy Holdings would record a pre-tax write-off up to its outstanding gross investment, including deferred taxes, in these facilities. Also, in the event of a potential foreclosure, the net tax benefits generated by Energy Holdings' portfolio of investments could be materially reduced in the period in which gains associated with the potential forgiveness of debt at these projects occurs. The

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amount and timing of any potential reduction in net tax benefits is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, the amount of lease debt outstanding, any cash trapped at the projects and negotiations during such potential foreclosure process. The potential loss of earnings, impairment and/or tax payments could have a material impact to our financial position, results of operations and net cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined Form 10-K is separately filed by PSEG, PSE&G and Power. Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations as to any other company.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of
Public Service Enterprise Group Incorporated:

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B) (a). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Sole Stockholder and Board of Directors of
Public Service Electric and Gas Company:

We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(b). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2015

S1-SSA-0009 - 11198

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Sole Member and Board of Directors of
PSEG Power LLC:

We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, member's equity, and cash flows for each of the three years in the period ended December 31, 2014. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(c). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2014 and 2013, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2015

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data

	Years Ended December 31,		
	2014	2013	2012
OPERATING REVENUES	$ 10,886	$ 9,968	$ 9,781
OPERATING EXPENSES			
Energy Costs	3,886	3,536	3,719
Operation and Maintenance	3,150	2,887	2,632
Depreciation and Amortization	1,227	1,178	1,054
Taxes Other Than Income Taxes	—	68	98
Total Operating Expenses	8,263	7,669	7,503
OPERATING INCOME	2,623	2,299	2,278
Income from Equity Method Investments	13	11	12
Other Income	290	213	260
Other Deductions	(61)	(54)	(98)
Other-Than-Temporary Impairments	(20)	(12)	(18)
Interest Expense	(389)	(402)	(423)
INCOME BEFORE INCOME TAXES	2,456	2,055	2,011
Income Tax (Expense) Benefit	(938)	(812)	(736)
NET INCOME	$ 1,518	$ 1,243	$ 1,275
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
BASIC	506	506	506
DILUTED	508	508	507
NET INCOME PER SHARE:			
BASIC	$ 3.00	$ 2.46	$ 2.52
DILUTED	$ 2.99	$ 2.45	$ 2.51

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11200

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2014	**2013**	**2012**
NET INCOME	$ 1,518	$ 1,243	$ 1,275
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $26, $(54) and $(24) for the years ended 2014, 2013 and 2012, respectively	(27)	55	19
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(8), $7 and $18 for the years ended 2014, 2013 and 2012, respectively	12	(9)	(24)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $120, $(172) and $32 for years ended 2014, 2013 and 2012, respectively	(173)	247	(46)
Other Comprehensive Income (Loss), net of tax	(188)	293	(51)
COMPREHENSIVE INCOME	$ 1,330	$ 1,536	$ 1,224

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11201

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2014	**2013**
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 402	$ 493
Accounts Receivable, net of allowances of $52 and $56 in 2014 and 2013, respectively	1,254	1,203
Tax Receivable	211	109
Unbilled Revenues	284	300
Fuel	538	545
Materials and Supplies, net	484	479
Prepayments	108	89
Derivative Contracts	240	98
Deferred Income Taxes	11	24
Regulatory Assets	323	243
Regulatory Assets of Variable Interest Entities (VIEs)	249	—
Other	15	31
Total Current Assets	4,119	3,614
PROPERTY, PLANT AND EQUIPMENT	32,196	29,713
Less: Accumulated Depreciation and Amortization	(8,607)	(8,068)
Net Property, Plant and Equipment	23,589	21,645
NONCURRENT ASSETS		
Regulatory Assets	3,192	2,612
Regulatory Assets of VIEs	—	476
Long-Term Investments	1,307	1,313
Nuclear Decommissioning Trust (NDT) Fund	1,780	1,701
Long-Term Receivable of VIEs	580	—
Other Special Funds	212	613
Goodwill	16	16
Other Intangibles	84	33
Derivative Contracts	77	163
Restricted Cash of VIEs	24	24
Other	353	312
Total Noncurrent Assets	7,625	7,263
TOTAL ASSETS	$ 35,333	$ 32,522

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11202

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2014	2013
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 624	$ 544
Securitization Debt of VIEs Due Within One Year	259	237
Commercial Paper and Loans	—	60
Accounts Payable	1,178	1,222
Derivative Contracts	132	76
Accrued Interest	95	95
Accrued Taxes	21	37
Deferred Income Taxes	173	—
Clean Energy Program	142	142
Obligation to Return Cash Collateral	121	119
Regulatory Liabilities	186	43
Other	547	488
Total Current Liabilities	3,478	3,063
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	7,303	7,107
Regulatory Liabilities	258	233
Regulatory Liabilities of VIEs	39	11
Asset Retirement Obligations	743	677
Other Postretirement Benefit (OPEB) Costs	1,277	1,095
OPEB Costs of Servco	452	—
Accrued Pension Costs	440	121
Accrued Pension Costs of Servco	126	—
Environmental Costs	417	414
Derivative Contracts	33	31
Long-Term Accrued Taxes	208	180
Other	112	119
Total Noncurrent Liabilities	11,408	9,988
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	8,261	7,587
Securitization Debt of VIEs	—	259
Project Level, Non-Recourse Debt	—	16
Total Long-Term Debt	8,261	7,862
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2014 and 2013— 533,556,660 shares	4,876	4,861
Treasury Stock, at cost, 2014— 27,720,068 shares; 2013— 27,699,398 shares	(635)	(615)
Retained Earnings	8,227	7,457
Accumulated Other Comprehensive Loss	(283)	(95)
Total Common Stockholders' Equity	12,185	11,608
Noncontrolling Interest	1	1
Total Stockholders' Equity	12,186	11,609
Total Capitalization	20,447	19,471
TOTAL LIABILITIES AND CAPITALIZATION	$ 35,333	$ 32,522

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2014	**2013**	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,518	$ 1,243	$ 1,275
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,227	1,178	1,054
Amortization of Nuclear Fuel	200	192	173
Provision for Deferred Income Taxes (Other than Leases) and ITC	515	270	721
Non-Cash Employee Benefit Plan Costs	47	243	271
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(4)	31	93
Net (Gain) Loss on Lease Investments	(3)	2	(49)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(93)	79	63
Change in Accrued Storm Costs	(3)	(90)	(90)
Net Change in Regulatory Assets and Liabilities	190	2	(132)
Cost of Removal	(98)	(93)	(116)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(166)	(104)	(118)
Net Change in Tax Receivable	30	19	(211)
Net Change in Certain Current Assets and Liabilities	(209)	299	97
Employee Benefit Plan Funding and Related Payments	(95)	(231)	(314)
Other	104	118	70
Net Cash Provided By (Used In) Operating Activities	3,160	3,158	2,787
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,820)	(2,811)	(2,574)
Proceeds from Sale of Capital Leases and Investments	25	50	58
Proceeds from Sales of Available-for-Sale Securities	1,915	1,159	1,666
Investments in Available-for-Sale Securities	(1,934)	(1,170)	(1,700)
Other	(78)	(29)	(75)
Net Cash Provided By (Used In) Investing Activities	(2,892)	(2,801)	(2,625)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	(60)	(203)	263
Issuance of Long-Term Debt	1,250	2,000	900
Redemption of Long-Term Debt	(500)	(1,025)	(787)
Redemption of Securitization Debt	(237)	(226)	(216)
Repayment of Non-Recourse Debt	—	—	(1)
Cash Dividend Paid on Common Stock	(748)	(728)	(718)
Other	(64)	(61)	(58)
Net Cash Provided By (Used In) Financing Activities	(359)	(243)	(617)
Net Increase (Decrease) in Cash and Cash Equivalents	(91)	114	(455)
Cash and Cash Equivalents at Beginning of Period	493	379	834
Cash and Cash Equivalents at End of Period	$ 402	$ 493	$ 379
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 538	$ 241	$ 121
Interest Paid, Net of Amounts Capitalized	$ 382	$ 385	$ 402
Accrued Property, Plant and Equipment Expenditures	$ 382	$ 336	$ 370

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11205

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Millions

	Common Stock		Treasury Stock					
	Shs.	Amount	Shs.	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance as of January 1, 2012	534	$ 4,823	(28)	$ (601)	$ 6,385	$ (337)	$ 2	$ 10,272
Net Income	—	—	—	—	1,275	—	—	1,275
Other Comprehensive Income (Loss), net of tax (expense) benefit of $26	—	—	—	—	—	(51)	—	(51)
Comprehensive Income								1,224
Cash Dividends on Common Stock	—	—	—	—	(718)	—	—	(718)
Noncontrolling Interest in Losses of Consolidated Entity	—	—	—	—	—	—	(1)	(1)
Other	—	10	—	(6)	—	—	—	4
Balance as of December 31, 2012	534	$ 4,833	(28)	$ (607)	$ 6,942	$ (388)	$ 1	$ 10,781
Net Income	—	—	—	—	1,243	—	—	1,243
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(219)	—	—	—	—	—	293	—	293
Comprehensive Income								1,536
Cash Dividends on Common Stock	—	—	—	—	(728)	—	—	(728)
Other	—	28	—	(8)	—	—	—	20
Balance as of December 31, 2013	534	$ 4,861	(28)	$ (615)	$ 7,457	$ (95)	$ 1	$ 11,609
Net Income	—	—	—	—	1,518	—	—	1,518
Other Comprehensive Income (Loss), net of tax (expense) benefit of $138	—	—	—	—	—	(188)	—	(188)
Comprehensive Income								1,330
Cash Dividends on Common Stock	—	—	—	—	(748)	—	—	(748)
Other	—	15	—	(20)	—	—	—	(5)
Balance as of December 31, 2014	534	$ 4,876	(28)	$ (635)	$ 8,227	$ (283)	$ 1	$ 12,186

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11206

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2014	2013	2012
OPERATING REVENUES	$ 6,766	$ 6,655	$ 6,626
OPERATING EXPENSES			
Energy Costs	2,909	2,841	3,159
Operation and Maintenance	1,558	1,639	1,508
Depreciation and Amortization	906	872	778
Taxes Other Than Income Taxes	—	68	98
Total Operating Expenses	5,373	5,420	5,543
OPERATING INCOME	1,393	1,235	1,083
Other Income	61	54	52
Other Deductions	(3)	(3)	(5)
Interest Expense	(277)	(293)	(295)
INCOME BEFORE INCOME TAXES	1,174	993	835
Income Tax (Expense) Benefit	(449)	(381)	(307)
NET INCOME	$ 725	$ 612	$ 528

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2014	**2013**	**2012**
NET INCOME	$ 725	$ 612	$ 528
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $1 and $0 for the years ended 2014, 2013 and 2012, respectively	1	(1)	—
COMPREHENSIVE INCOME	$ 726	$ 611	$ 528

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11208

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2014	2013
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 310	$ 18
Accounts Receivable, net of allowances of $52 and $56 in 2014 and 2013, respectively	864	832
Accounts Receivable-Affiliated Companies	274	—
Unbilled Revenues	284	300
Materials and Supplies	133	115
Prepayments	42	24
Regulatory Assets	323	243
Regulatory Assets of VIEs	249	—
Derivative Contracts	18	25
Deferred Income Taxes	24	16
Other	7	12
Total Current Assets	2,528	1,585
PROPERTY, PLANT AND EQUIPMENT	21,103	19,071
Less: Accumulated Depreciation and Amortization	(5,183)	(4,964)
Net Property, Plant and Equipment	15,920	14,107
NONCURRENT ASSETS		
Regulatory Assets	3,192	2,612
Regulatory Assets of VIEs	—	476
Long-Term Investments	348	361
Other Special Funds	53	354
Derivative Contracts	8	69
Restricted Cash of VIEs	24	24
Other	150	132
Total Noncurrent Assets	3,775	4,028
TOTAL ASSETS	$ 22,223	$ 19,720

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2014	2013
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 300	$ 500
Securitization Debt of VIEs Due Within One Year	259	237
Commercial Paper and Loans	—	60
Accounts Payable	574	535
Accounts Payable—Affiliated Companies	379	190
Accrued Interest	68	67
Clean Energy Program	142	142
Deferred Income Taxes	165	30
Obligation to Return Cash Collateral	121	119
Regulatory Liabilities	186	43
Other	381	314
Total Current Liabilities	2,575	2,237
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,575	4,406
Other Postretirement Benefit (OPEB) Costs	967	839
Accrued Pension Costs	173	27
Regulatory Liabilities	258	233
Regulatory Liabilities of VIEs	39	11
Environmental Costs	364	363
Asset Retirement Obligations	290	274
Long-Term Accrued Taxes	116	72
Other	67	47
Total Noncurrent Liabilities	6,849	6,272
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	6,012	5,066
Securitization Debt of VIEs	—	259
Total Long-Term Debt	6,012	5,325
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2014 and 2013—132,450,344 shares	892	892
Contributed Capital	695	520
Basis Adjustment	986	986
Retained Earnings	4,212	3,487
Accumulated Other Comprehensive Income	2	1
Total Stockholder's Equity	6,787	5,886
Total Capitalization	12,799	11,211
TOTAL LIABILITIES AND CAPITALIZATION	$ 22,223	$ 19,720

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11210

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 725	$ 612	$ 528
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	906	872	778
Provision for Deferred Income Taxes and ITC	310	198	442
Non-Cash Employee Benefit Plan Costs	27	156	179
Cost of Removal	(98)	(93)	(116)
Change in Accrued Storm Costs	(3)	(90)	(90)
Net Change in Regulatory Assets and Liabilities	190	2	(132)
Net Change in Certain Current Assets and Liabilities:			
Accounts Receivable and Unbilled Revenues	63	(5)	(54)
Materials and Supplies	(18)	(1)	(20)
Prepayments	(18)	5	88
Net Change in Tax Receivable	—	—	16
Accounts Payable	(3)	19	(25)
Accounts Receivable/Payable-Affiliated Companies, net	(167)	100	(132)
Other Current Assets and Liabilities	6	40	37
Employee Benefit Plan Funding and Related Payments	(83)	(166)	(213)
Other	(4)	(4)	(30)
Net Cash Provided By (Used In) Operating Activities	1,833	1,645	1,256
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,164)	(2,175)	(1,770)
Proceeds from Sales of Available-for-Sale Securities	103	38	77
Investments in Available-for-Sale Securities	(101)	(20)	(77)
Solar Loan Investments	7	(15)	(74)
Other	—	—	(1)
Net Cash Provided By (Used In) Investing Activities	(2,155)	(2,172)	(1,845)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	(60)	(203)	263
Issuance of Long-Term Debt	1,250	1,500	900
Redemption of Long-Term Debt	(500)	(725)	(373)
Redemption of Securitization Debt	(237)	(226)	(216)
Contributed Capital	175	100	—
Other	(14)	(17)	(12)
Net Cash Provided By (Used In) Financing Activities	614	429	562
Net Increase (Decrease) in Cash and Cash Equivalents	292	(98)	(27)
Cash and Cash Equivalents at Beginning of Period	18	116	143
Cash and Cash Equivalents at End of Period	$ 310	$ 18	$ 116
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 283	$ 84	$ (30)
Interest Paid, Net of Amounts Capitalized	$ 259	$ 275	$ 280
Accrued Property, Plant and Equipment Expenditures	$ 292	$ 246	$ 275

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
Millions

	Common Stock	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2012	$ 892	$ 420	$ 986	$ 2,347	$ 2	$ 4,647
Net Income	—	—	—	528	—	528
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	—	—
Comprehensive Income						528
Balance as of December 31, 2012	$ 892	$ 420	$ 986	$ 2,875	$ 2	$ 5,175
Net Income	—	—	—	612	—	612
Other Comprehensive Income, net of tax (expense) benefit of $1	—	—	—	—	(1)	(1)
Comprehensive Income						611
Contributed Capital	—	100	—	—	—	100
Balance as of December 31, 2013	$ 892	$ 520	$ 986	$ 3,487	$ 1	$ 5,886
Net Income	—	—	—	725	—	725
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	1	1
Comprehensive Income						726
Contributed Capital	—	175	—	—	—	175
Balance as of December 31, 2014	$ 892	$ 695	$ 986	$ 4,212	$ 2	$ 6,787

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2014	**2013**	**2012**
OPERATING REVENUES	$ 5,434	$ 5,063	$ 4,873
OPERATING EXPENSES			
Energy Costs	2,747	2,496	2,381
Operation and Maintenance	1,186	1,224	1,127
Depreciation and Amortization	292	273	242
Total Operating Expenses	4,225	3,993	3,750
OPERATING INCOME	1,209	1,070	1,123
Income from Equity Method Investments	14	16	15
Other Income	222	154	201
Other Deductions	(52)	(49)	(90)
Other-Than-Temporary Impairments	(20)	(12)	(18)
Interest Expense	(122)	(116)	(132)
INCOME BEFORE INCOME TAXES	1,251	1,063	1,099
Income Tax (Expense) Benefit	(491)	(419)	(433)
NET INCOME	$ 760	$ 644	$ 666

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2014	**2013**	**2012**
NET INCOME	$ 760	$ 644	$ 666
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $28, $(55) and $(24) for the years ended 2014, 2013 and 2012, respectively	(30)	57	18
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(8), $7 and $18 for the years ended 2014, 2013 and 2012, respectively	12	(10)	(24)
Pension/OPEB adjustment, net of tax (expense) benefit of $101, $(151) and $32 for the years ended 2014, 2013 and 2012, respectively	(147)	218	(46)
Other Comprehensive Income (Loss), net of tax	(165)	265	(52)
COMPREHENSIVE INCOME	$ 595	$ 909	$ 614

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11214

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2014	2013
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 9	$ 6
Accounts Receivable	334	338
Tax Receivable	3	—
Accounts Receivable—Affiliated Companies	313	333
Short-Term Loan to Affiliate	584	790
Fuel	538	545
Materials and Supplies, net	350	362
Derivative Contracts	207	57
Prepayments	17	13
Deferred Taxes	—	30
Other	4	2
Total Current Assets	2,359	2,476
PROPERTY, PLANT AND EQUIPMENT	10,732	10,278
Less: Accumulated Depreciation and Amortization	(3,217)	(2,911)
Net Property, Plant and Equipment	7,515	7,367
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,780	1,701
Long-Term Investments	121	123
Goodwill	16	16
Other Intangibles	84	33
Other Special Funds	49	139
Derivative Contracts	62	72
Other	60	75
Total Noncurrent Assets	2,172	2,159
TOTAL ASSETS	$ 12,046	$ 12,002

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2014	December 31, 2013
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 300	$ 44
Accounts Payable	424	516
Accounts Payable—Affiliated Companies	118	—
Derivative Contracts	132	76
Deferred Income Taxes	43	—
Accrued Interest	27	28
Other	140	136
Total Current Liabilities	1,184	800
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	2,065	2,031
Asset Retirement Obligations	450	400
Other Postretirement Benefit (OPEB) Costs	248	206
Derivative Contracts	33	31
Accrued Pension Costs	153	35
Long-Term Accrued Taxes	41	53
Other	71	91
Total Noncurrent Liabilities	3,061	2,847
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
LONG-TERM DEBT		
Total Long-Term Debt	2,243	2,497
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,558	4,693
Accumulated Other Comprehensive Loss	(228)	(63)
Total Member's Equity	5,558	5,858
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,046	$ 12,002

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 760	$ 644	$ 666
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	292	273	242
Amortization of Nuclear Fuel	200	192	173
Provision for Deferred Income Taxes and ITC	221	122	397
Interest Accretion on Asset Retirement Obligation	30	23	21
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(93)	79	63
Non-Cash Employee Benefit Plan Costs	13	66	70
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(166)	(104)	(118)
Net Change in Certain Current Assets and Liabilities:			
Fuel, Materials and Supplies	19	(8)	47
Margin Deposit	(22)	(43)	(116)
Accounts Receivable	(15)	(4)	24
Accounts Payable	(59)	28	93
Accounts Receivable/Payable-Affiliated Companies, net	220	—	(40)
Accrued Interest Payable	—	2	(6)
Other Current Assets and Liabilities	(6)	70	(17)
Employee Benefit Plan Funding and Related Payments	(7)	(46)	(72)
Other	38	53	26
Net Cash Provided By (Used In) Operating Activities	1,425	1,347	1,453
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(626)	(609)	(770)
Proceeds from Sales of Available-for-Sale Securities	1,557	1,084	1,478
Investments in Available-for-Sale Securities	(1,573)	(1,102)	(1,506)
Short-Term Loan—Affiliated Company, net	206	(216)	333
Other	(88)	(18)	(7)
Net Cash Provided By (Used In) Investing Activities	(524)	(861)	(472)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Recourse Long-Term Debt	—	500	—
Cash Dividend Paid	(895)	(705)	(619)
Redemption of Long-Term Debt	—	(300)	(414)
Contributed Capital	—	24	69
Cash Payment on Debt Redemption/Exchange	—	—	(15)
Other	(3)	(6)	(7)
Net Cash Provided By (Used In) Financing Activities	(898)	(487)	(986)
Net Increase (Decrease) in Cash and Cash Equivalents	3	(1)	(5)
Cash and Cash Equivalents at Beginning of Period	6	7	12
Cash and Cash Equivalents at End of Period	$ 9	$ 6	$ 7
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 68	$ 291	$ 81
Interest Paid, Net of Amounts Capitalized	$ 119	$ 106	$ 119
Accrued Property, Plant and Equipment Expenditures	$ 91	$ 90	$ 95

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY
Millions

	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2012	$ 2,121	$ (986)	$ 4,707	$ (276)	$ 5,566
Net Income	—	—	666	—	666
Other Comprehensive Income (Loss), net of tax (expense) benefit of $26	—	—	—	(52)	(52)
Comprehensive Income					614
Contributed Capital	69	—	—	—	69
Cash Dividends Paid	—	—	(619)		(619)
Balance as of December 31, 2012	$ 2,190	$ (986)	$ 4,754	$ (328)	$ 5,630
Net Income	—	—	644	—	644
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(199)	—	—	—	265	265
Comprehensive Income					909
Contributed Capital	24	—	—	—	24
Cash Dividends Paid	—	—	(705)	—	(705)
Balance as of December 31, 2013	$ 2,214	$ (986)	$ 4,693	$ (63)	$ 5,858
Net Income	—	—	760	—	760
Other Comprehensive Income (Loss), net of tax (expense) benefit of $121	—	—	—	(165)	(165)
Comprehensive Income					595
Cash Dividends Paid	—	—	(895)	—	(895)
Balance as of December 31, 2014	$ 2,214	$ (986)	$ 4,558	$ (228)	$ 5,558

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

Public Service Enterprise Group Incorporated, (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Public Service Electric and Gas Company (PSE&G)**—which is an operating public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- **PSEG Power LLC (Power)**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the FERC, the Nuclear Regulatory Commission (NRC) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which, effective January 1, 2014, operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a twelve-year Amended and Restated Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Annual Reports on Form 10-K and in accordance with accounting guidance generally accepted in the United States (GAAP).

Significant Accounting Policies

Principles of Consolidation

Each company consolidates those entities in which it has a controlling interest or is the primary beneficiary. See Note 3. Variable Interest Entities. Entities over which the companies exhibit significant influence, but do not have a controlling interest and/or are not the primary beneficiary, are accounted for under the equity method of accounting. For investments in which significant influence does not exist and the investor is not the primary beneficiary, the cost method of accounting is applied. All intercompany accounts and transactions are eliminated in consolidation, except as discussed in Note 23. Related-Party Transactions.

PSE&G and Power also have undivided interests in certain jointly-owned facilities, with each responsible for paying its respective ownership share of construction costs, fuel purchases and operating expenses. PSE&G and Power consolidated their portion of any revenues and expenses related to their respective jointly-owned facilities in the appropriate revenue and expense categories.

Accounting for the Effects of Regulation

In accordance with accounting guidance for rate-regulated entities, PSE&G's financial statements reflect the economic effects of regulation. PSE&G defers the recognition of costs (a Regulatory Asset) or records the recognition of obligations (a Regulatory Liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs and recoveries, which are being amortized over various future periods. To the extent that collection of any such costs or payment of liabilities becomes no longer probable as a result of changes in regulation and/or competitive position, the associated Regulatory Asset or Liability is charged or credited to income. Management believes that PSE&G's transmission and distribution businesses continue to meet the accounting requirements for rate-regulated entities. For additional information, see Note 5. Regulatory Assets and Liabilities.

Derivative Financial Instruments

Each company uses derivative financial instruments to manage risk pursuant to its business plans and prudent practices.

Derivative instruments, not designated as normal purchases or sales, are recognized on the balance sheet at their fair value. Changes in the fair value of a derivative that is highly effective as and that is designated and qualifies as a fair value hedge,

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along with changes of the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in current period earnings. Changes in the fair value of a derivative that is highly effective as and that is designated and qualifies as a cash flow hedge are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings. For derivative contracts that do not qualify or are not designated as cash flow or fair value hedges or as normal purchases or sales, changes in fair value are recorded in current period earnings.

Many non-trading contracts qualify for the normal purchases and normal sales exemption and are accounted for upon settlement.

For additional information regarding derivative financial instruments, see Note 15. Financial Risk Management Activities.

Revenue Recognition

PSE&G's revenues are recorded primarily based on services rendered to customers. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. The unbilled revenue is estimated each month based on usage per day, the number of unbilled days in the period, estimated seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms.

The majority of Power's revenues relate to bilateral contracts, which are accounted for on the accrual basis as the energy is delivered. Power's revenue also includes changes in the value of non-trading energy derivative contracts that are not designated as normal purchases or sales or as cash flow or fair value hedges of other positions. See Note 15. Financial Risk Management Activities for further discussion.

PSEG LI is the primary beneficiary of Long Island Electric Utility Servco, LLC (Servco). For transactions in which Servco acts as principal, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operations and Maintenance (O&M) Expense, respectively. See Note 3. Variable Interest Entities for further information.

Depreciation and Amortization

PSE&G calculates depreciation under the straight-line method based on estimated average remaining lives of the several classes of depreciable property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU or the FERC. The depreciation rate stated as a percentage of original cost of depreciable property was as follows:

	2014 Avg Rate	2013 Avg Rate	2012 Avg Rate
PSE&G Depreciation Rate	2.47%	2.48%	2.48%

Power calculates depreciation on generation-related assets under the straight-line method based on the assets' estimated useful lives. The estimated useful lives are:

- general plant assets—3 years to 20 years
- fossil production assets—19 years to 79 years
- nuclear generation assets—approximately 60 years
- pumped storage facilities—76 years
- solar assets—25 years

Taxes Other Than Income Taxes

Excise taxes and the transitional energy facilities assessment (TEFA) collected from PSE&G's customers are presented in the financial statements on a gross basis. Effective January 1, 2014, the TEFA was eliminated. For the years ended December 31, 2013 and 2012, the TEFA is included in the following captions in the Consolidated Statements of Operations:

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Years Ended December 31, 2013	2012
	Millions	
TEFA included in:		
Operating Revenues	$ 74	$ 108
Taxes Other Than Income Taxes	$ 68	$ 98

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized During Construction (IDC)

AFUDC represents the cost of debt and equity funds used to finance the construction of new utility assets at PSE&G. IDC represents the cost of debt used to finance construction at Power. The amount of AFUDC or IDC capitalized as Property, Plant and Equipment is included as a reduction of interest charges or other income for the equity portion. The amounts and average rates used to calculate AFUDC or IDC for the years ended December 31, 2014, 2013 and 2012 were as follows:

	AFUDC/IDC Capitalized					
	2014		2013		2012	
	Millions	Avg Rate	Millions	Avg Rate	Millions	Avg Rate
PSE&G	$ 44	8.09%	$ 34	8.11%	$ 33	8.43%
Power	$ 24	5.14%	$ 23	5.36%	$ 29	5.16%

Income Taxes

PSEG and its subsidiaries file a consolidated federal income tax return and income taxes are allocated to PSEG's subsidiaries based on the taxable income or loss of each subsidiary. Investment tax credits deferred in prior years are being amortized over the useful lives of the related property.

Uncertain income tax positions are accounted for using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. See Note 19. Income Taxes for further discussion.

Impairment of Long-Lived Assets

In accordance with GAAP, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset's or asset group's carrying amount may not be recoverable. In such an event, an undiscounted cash flow analysis is performed to determine if an impairment exists. When a long-lived asset's carrying amount exceeds the undiscounted estimated future cash flows associated with the asset, the asset is considered impaired to the extent that the asset's fair value is less than its carrying amount. An impairment would result in a reduction of the long-lived asset value through a non-cash charge to earnings.

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Accounts Receivable—Allowance for Doubtful Accounts

PSE&G's accounts receivable are reported in the balance sheet as gross outstanding amounts adjusted for doubtful accounts. The allowance for doubtful accounts reflects PSE&G's best estimates of losses on the accounts receivable balances. The allowance is based on accounts receivable aging, historical experience, write-off forecasts and other currently available evidence.

Accounts receivable are charged off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable are recorded when it is known they will be received.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Materials and Supplies and Fuel

PSE&G's materials and supplies are carried at average cost consistent with the rate-making process. Materials and supplies for Power are valued at cost and charged to inventory when purchased and expensed or capitalized to Property, Plant and Equipment, as appropriate, when installed or used. Fuel inventory at Power is valued at the lower of average cost or market and includes stored natural gas, coal, fuel oil and propane used to generate power and to satisfy obligations under Power's gas supply contracts with PSE&G. The costs of fuel, including transportation costs, are included in inventory when purchased and charged to Energy Costs when used or sold. The cost of nuclear fuel is capitalized within Property, Plant and Equipment and amortized to fuel expense using the unit-of-production method.

Restricted Funds

PSE&G's restricted funds represent revenues collected from its retail electric customers that must be used to pay the principal, interest and other expenses associated with the securitization bonds of PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II).

Property, Plant and Equipment

PSE&G's additions to and replacements of existing property, plant and equipment are capitalized at cost. The cost of maintenance, repair and replacement of minor items of property is charged to expense as incurred. At the time units of depreciable property are retired or otherwise disposed of, the original cost, adjusted for net salvage value, is charged to accumulated depreciation.

Power capitalizes costs, including those related to its jointly-owned facilities, which increase the capacity or extend the life of an existing asset, represent a newly acquired or constructed asset or represent the replacement of a retired asset. The cost of maintenance, repair and replacement of minor items of property is charged to appropriate expense accounts as incurred. Environmental costs are capitalized if the costs mitigate or prevent future environmental contamination or if the costs improve existing assets' environmental safety or efficiency. All other environmental expenditures are expensed as incurred.

Available-for-Sale Securities

These securities comprise the Nuclear Decommissioning Trust (NDT) Fund, a master independent external trust account maintained to provide for the costs of decommissioning upon termination of operations of Power's nuclear facilities and amounts that are deposited to fund a Rabbi Trust which was established to meet the obligations related to non-qualified pension plans and deferred compensation plans.

Realized gains and losses on available-for-sale securities are recorded in earnings and unrealized gains and losses on such securities are recorded as a component of Accumulated Other Comprehensive Income (Loss) (except credit losses on debt securities which are recorded in earnings). Securities with unrealized losses that are deemed to be other-than-temporarily impaired are recorded in earnings. See Note 8. Available-for-Sale Securities for further discussion.

Pension and Other Postretirement Benefits (OPEB) Plans

The market-related value of plan assets held for the qualified pension and OPEB plans is equal to the fair value of those assets as of year-end. Fair value is determined using quoted market prices and independent pricing services based upon the security type as reported by the trustee at the measurement date (December 31) for all plan assets.

PSEG recognizes a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and OPEB liabilities. This receivable is presented separately on the Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted.

Pursuant to the OSA, Servco records expense only to the extent of its contributions to its pension plan trusts and for OPEB payments made to retirees.

See Note 11. Pension and Other Postretirement Benefits for further discussion.

Basis Adjustment

PSE&G and Power have recorded a Basis Adjustment in their respective Consolidated Balance Sheets related to the generation assets that were transferred from PSE&G to Power in August 2000 at the price specified by the BPU. Because the transfer was between affiliates, the transaction was recorded at the net book value of the assets and liabilities rather than the transfer price. The difference between the total transfer price and the net book value of the generation-related assets and liabilities, $986 million, net of tax, was recorded as a Basis Adjustment on PSE&G's and Power's Consolidated Balance Sheets. The $986 million is an addition to PSE&G's Common Stockholder's Equity and a reduction of Power's Member's Equity. These amounts are eliminated on PSEG's consolidated financial statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Use of Estimates

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements.

Note 2. Recent Accounting Standards

New Standards Adopted during 2014

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

This accounting standard was issued to address diversity in practice related to the presentation of an unrecognized tax benefit in certain cases. This standard requires entities to present an unrecognized tax benefit or a portion thereof on the Balance Sheet as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward.

However, the unrecognized tax benefit will be presented on the Balance Sheet as a liability and will not be combined with deferred tax assets in cases where that tax benefit cannot or will not, if permissible, be used to settle any additional income taxes that would result from the disallowance of a tax position.

The standard was effective for fiscal years and interim periods beginning after December 15, 2013. The impact of adopting this standard was immaterial.

Business Combinations: Pushdown Accounting

The amendments in this standard provide an acquired entity with an option to apply pushdown accounting in its separate financial statements when an acquirer obtains control of the acquired entity. Pushdown accounting provides for the use of the acquirer's basis, including fair value adjustments and goodwill as applicable, in the preparation of the acquiree's separate financial statements. An acquired entity may elect the option to apply pushdown accounting in the reporting period in which the change-in-control event occurs. An acquired entity can elect whether to apply pushdown accounting for each individual change-in-control event in which an acquirer obtains control of the acquired entity. An election to apply pushdown accounting in a reporting period after the reporting period in which the change-in-control event occurred should be considered a change in accounting principle. If an acquired entity elects the option to apply pushdown accounting in its separate financial statements, it should disclose information in the current reporting period.

The update became effective on November 18, 2014. We will evaluate all future acquisitions under the new guidance.

New Standards Issued but Not Yet Required to be Adopted

Revenue from Contracts with Customers

This accounting standard was issued to clarify the principles for recognizing revenue and to develop a common standard that would remove inconsistencies in revenue requirements; improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provide improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The update is effective for annual and interim reporting periods beginning after December 15, 2016. Early application is not permitted. We are currently analyzing the impact of this standard on our financial statements.

Presentation of Financial Statements and Property, Plant and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

This accounting standard was issued to change the criteria for reporting discontinued operations. The standard requires that a component of an entity be reported in discontinued operations if the disposal represents a strategic shift that has, or will have, a major effect on the entity's operations and financial results, including a disposal of a major geographical area, a major line of business, a major equity method investment or other major parts of an entity.

The amendment should be applied prospectively for all disposals of an entity that occur within interim and annual periods beginning on or after December 15, 2014; and all businesses that, on acquisition, are classified as held for sale that occur within interim and annual periods beginning on or after December 15, 2014. We will evaluate all future disposals under the new guidance beginning on January 1, 2015.

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Transfers and Servicing - Repurchase-to-Maturity Transactions, Repurchase-Financings and Disclosures

This standard changes the accounting for repurchase-to-maturity transactions and linked repurchase-financings to secured borrowing accounting, which is consistent with the accounting for other repurchase agreements. It also requires disclosures for repurchase agreements, securities lending transactions and repurchase-to-maturity transactions that are accounted for as secured borrowings.

This standard is effective for the first interim or annual period beginning after December 15, 2014.

We are currently analyzing this standard but do not expect its impact to be material to our financial statements.

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern

The amendments in this standard provide guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. Substantial doubt about an entity's ability to continue as a going concern exists when relevant conditions and events, considered in the aggregate, indicate that it is probable that the entity will be unable to meet its obligations as they become due within one year after the date that its financial statements are issued.

The update is effective for annual and interim reporting periods beginning after December 15, 2016.

The update requires that we identify, assess and evaluate uncertainties and their impact, if any, on our ability to meet financial obligations. However, we do not expect this standard to impact our financial statements.

Note 3. Variable Interest Entities (VIEs)

VIEs for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, Transition Funding and Transition Funding II, which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of Transition Funding and Transition Funding II are presented separately on the face of the Consolidated Balance Sheets of PSEG and PSE&G because the assets of these VIEs are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II.

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of December 31, 2014 and 2013. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II in 2014 or 2013. PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding and Transition Funding II.

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Servco, a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and O&M Expense, respectively. In 2014, Servco recorded $389 million of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Consolidated Statement of Operations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 4. Property, Plant and Equipment and Jointly-Owned Facilities

Information related to Property, Plant and Equipment as of December 31, 2014 and 2013 is detailed below:

	PSE&G	Power	Other	PSEG Consolidated
			Millions	
2014				
Transmission and Distribution:				
Electric Transmission	$ 5,845	$ —	$ —	$ 5,845
Electric Distribution	7,295	—	—	7,295
Gas Transmission	89	—	—	89
Gas Distribution	5,479	—	—	5,479
Construction Work in Progress	1,304	—	—	1,304
Plant Held for Future Use	15	—	—	15
Other	401	—	—	401
Total Transmission and Distribution	20,428	—	—	20,428
Generation:				
Fossil Production	—	6,964	—	6,964
Nuclear Production	—	1,751	—	1,751
Nuclear Fuel in Service	—	889	—	889
Other Production-Solar	521	314	—	835
Construction Work in Progress	—	714	—	714
Total Generation	521	10,632	—	11,153
Other	154	100	361	615
Total	**$ 21,103**	**$ 10,732**	**$ 361**	**$ 32,196**

	PSE&G	Power	Other	PSEG Consolidated
			Millions	
2013				
Transmission and Distribution:				
Electric Transmission	$ 4,037	$ —	$ —	$ 4,037
Electric Distribution	7,109	—	—	7,109
Gas Transmission	89	—	—	89
Gas Distribution	5,230	—	—	5,230
Construction Work in Progress	1,605	—	—	1,605
Plant Held for Future Use	3	—	—	3
Other	372	—	—	372
Total Transmission and Distribution	18,445	—	—	18,445
Generation:				
Fossil Production	—	6,924	—	6,924
Nuclear Production	—	1,636	—	1,636
Nuclear Fuel in Service	—	857	—	857
Other Production-Solar	469	273	—	742
Construction Work in Progress	—	489	—	489
Total Generation	469	10,179	—	10,648
Other	157	99	364	620
Total	**$ 19,071**	**$ 10,278**	**$ 364**	**$ 29,713**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G and Power have ownership interests in and are responsible for providing their respective shares of the necessary financing for the following jointly-owned facilities. All amounts reflect the share of PSE&G's and Power's jointly-owned projects and the corresponding direct expenses are included in the Consolidated Statements of Operations as operating expenses.

		As of December 31,			
		2014		2013	
	Ownership Interest	Plant	Accumulated Depreciation	Plant	Accumulated Depreciation
		Millions			
PSE&G:					
Transmission Facilities	Various	$ 162	$ 69	$ 161	$ 66
Power:					
Coal Generating					
Conemaugh	23%	$ 397	$ 142	$ 374	$ 139
Keystone	23%	$ 396	$ 151	$ 388	$ 140
Nuclear Generating					
Peach Bottom	50%	$ 1,087	$ 236	$ 886	$ 215
Salem	57%	$ 916	$ 236	$ 897	$ 254
Nuclear Support Facilities	Various	$ 218	$ 49	$ 205	$ 37
Pumped Storage Facilities					
Yards Creek	50%	$ 41	$ 24	$ 36	$ 23
Merrill Creek Reservoir	14%	$ 1	$ —	$ 1	$ —

Power holds undivided ownership interests in the jointly-owned facilities above. Power is entitled to shares of the generating capability and output of each unit equal to its respective ownership interests. Power also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. Power's share of expenses for the jointly-owned facilities is included in the appropriate expense category. Each owner is responsible for any financing with respect to its pro rata share of capital expenditures.

Power co-owns Salem and Peach Bottom with Exelon Generation. Power is the operator of Salem and Exelon Generation is the operator of Peach Bottom. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

GenOn Northeast Management Company is a co-owner and the operator for Keystone Generating Station and Conemaugh Generating Station. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

Power is a co-owner in the Yards Creek Pumped Storage Generation Facility. Jersey Central Power & Light Company (JCP&L) is also a co-owner and the operator of this facility. JCP&L submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Power is a minority owner in the Merrill Creek Reservoir and Environmental Preserve in Warren County, New Jersey. Merrill Creek Owners Group is the owner-operator of this facility. The operator submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Note 5. Regulatory Assets and Liabilities

PSE&G prepares its financial statements in accordance with GAAP for regulated utilities as described in Note 1. Organization and Basis of Presentation and Summary of Significant Accounting Policies. PSE&G has deferred certain costs based on rate orders issued by the BPU or the FERC or based on PSE&G's experience with prior rate cases. Most of PSE&G's Regulatory Assets and Liabilities as of December 31, 2014 are supported by written orders, either explicitly or implicitly through the BPU's treatment of various cost items. These costs will be recovered and amortized over various future periods.

Regulatory Assets are subject to prudence reviews and can be disallowed in the future by regulatory authorities. PSE&G believes that all of its Regulatory Assets are probable of recovery. To the extent that collection of any Regulatory Assets or payments of Regulatory Liabilities is no longer probable, the amounts would be charged or credited to income.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G had the following Regulatory Assets and Liabilities:

	As of December 31, 2014	As of December 31, 2013	Recovery/Refund Period
	Millions		
Regulatory Assets			
Current			
Non-Utility Generation Charge (NGC)	$ —	$ 6	Annual filing for recovery (1) (2)
Societal Benefits Charges (SBC)	—	16	Annual filing for recovery (1) (2)
Solar and Energy Efficiency Recovery Charges (formerly RRC and currently Green Program Recovery Charges (GPRC))	13	41	Annual filing for recovery (1) (2)
Solar Pilot Recovery Charge (SPRC)	—	12	Annual filing for recovery (1) (2)
Capital Stimulus Undercollection	—	3	Annual filing for recovery (1) (2)
Weather Normalization Clause (WNC)	—	20	Annual filing for recovery (2)
New Jersey Clean Energy Program	142	142	Annual filing for recovery (1) (2)
Stranded Costs (including $249 in 2014 related to VIEs)	412	—	Through December 2015 (2)
Other	5	3	Various
Total Current Regulatory Assets	**$ 572**	**$ 243**	
Noncurrent			
Stranded Costs (including $476 in 2013 related to VIEs)	$ —	$ 701	Through December 2016 (1) (2)
Manufactured Gas Plant (MGP) Remediation Costs	434	445	Various (2)
Pension and OPEB Costs	1,265	637	Various
Deferred Income Taxes	473	444	Various
Remediation Adjustment Charge (RAC) (Other SBC)	164	144	Through 2021 (1) (2)
Mark-to-Market (MTM) Contracts	75	—	Through 2017
Unamortized Loss on Reacquired Debt and Debt Expense	74	81	Over remaining debt life (1)
Conditional Asset Retirement Obligation	138	123	Various
GPRC	134	151	Various (2)
Electric Cost of Removal	91	23	Reduced as cost is incurred
Storm Damage Deferrals	245	245	To be determined
Other	99	94	Various
Total Noncurrent Regulatory Assets	**$ 3,192**	**$ 3,088**	
Total Regulatory Assets	**$ 3,764**	**$ 3,331**	

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31, 2014	As of December 31, 2013	Recovery/Refund Period
	Millions		
Regulatory Liabilities			
Current			
Deferred Income Taxes	$ 28	$ 31	Various
Overrecovered Gas and Electric Costs—Basic Gas Supply Service (BGSS) and Basic Generation Service (BGS)	80	9	Annual filing for recovery (1) (2)
WNC	31	—	Annual filing for recovery (2)
Gas Margin Adjustment Clause	28	—	Annual filing for recovery (1) (2)
Other	19	3	Various
Total Current Regulatory Liabilities	**$ 186**	**$ 43**	
Noncurrent			
Electric Cost of Removal	$ 133	$ 137	Reduced as cost is incurred
MTM Contracts	—	74	Various
Stranded Costs (including $39 and $11 in 2014 and 2013, respectively, related to VIEs)	134	11	Through December 2016 (1) (2)
FERC Formula Rate True-up	26	—	Through December 2016 (1) (2)
Other	4	22	Various
Total Noncurrent Regulatory Liabilities	**$ 297**	**$ 244**	
Total Regulatory Liabilities	**$ 483**	**$ 287**	

(1) Recovered/Refunded with interest.
(2) Recoverable/Refundable per specific rate order.

All Regulatory Assets and Liabilities are excluded from PSE&G's rate base unless otherwise noted. The Regulatory Assets and Liabilities in the table above are defined as follows:

- **NGC:** Represents the difference between the cost of non-utility generation and the amounts realized from selling that energy at market rates through PJM Interconnection, L.L.C. (PJM) and ratepayer collections.
- **SBC:** The SBC, as authorized by the BPU and the New Jersey Electric Discount and Energy Competition Act, includes costs related to PSE&G's electric and gas business as follows: (1) the Universal Service Fund (USF); (2) Energy Efficiency and Renewable Energy Programs; (3) Electric bad debt expense; and (4) the RAC for incurred MGP remediation expenditures. All components accrue interest on both over and underrecoveries.
- **GPRC:** These costs are amounts associated with various renewable energy and energy efficiency programs. Components of the GPRC include: Carbon Abatement, Energy Efficiency Economic Stimulus Program, Energy Efficiency Economic Extension Program, the Demand Response Program, Solar Generation Investment Program (Solar 4 All), Solar 4 All Extension, Solar Loan II Program and Solar Loan III Program.
- **SPRC:** This charge is designed to recover the revenue requirements associated with the PSE&G Solar Pilot Program (Solar Loan I) per a BPU Order, less the net proceeds from the sale of associated Solar Renewable Energy Certificates (SRECs) or cash received in lieu of SRECs. The net recovery is subject to deferred accounting. Interest at the two-year constant maturity treasury rate plus 60 basis points will be accrued monthly on any under- or over-recovered balances.
- **Capital Stimulus Undercollection:** PSE&G has received approval from the BPU for programs that provide for accelerated investment in utility infrastructure. The goal of these accelerated capital investments is to improve the reliability of PSE&G's infrastructure and New Jersey's economy through job creation.
- **WNC Deferral:** This represents the over- or under- collection of gas margin refundable or recoverable under the BPU's weather normalization clause. The WNC requires PSE&G to calculate, at the end of each October-to-May period, the level by which margin revenues differed from what would have resulted if normal weather had occurred.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

- **New Jersey Clean Energy Program:** The BPU approved future funding requirements for Energy Efficiency and Renewable Energy Programs through the first half of 2013. Once the rates are measured, they are recovered through the SBC.
- **Stranded Costs:** This reflects deferred costs, which are being recovered through the securitization transition charges authorized by the BPU in irrevocable financing orders and being collected by PSE&G, as servicer on behalf of Transition Funding and Transition Funding II, respectively. Collected funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs and taxes.

  Transition Funding and Transition Funding II are wholly owned, bankruptcy-remote subsidiaries of PSE&G that purchased certain transition property from PSE&G and issued transition bonds secured by such property. The transition property consists principally of the rights to receive electricity consumption-based per kilowatt-hour (kWh) charges from PSE&G's electric distribution customers, which represent irrevocable rights to receive amounts sufficient to recover certain of PSE&G's transition costs related to deregulation, as approved by the BPU.
- **MGP Remediation Costs:** Represents the low end of the range for the remaining environmental investigation and remediation program cleanup costs for manufactured gas plants that are probable of recovery in future rates. Once these costs are incurred, they are recovered through the RAC in the SBC.
- **Pension and OPEB Costs:** Pursuant to the adoption of accounting guidance for employers' defined benefit pension and OPEB plans, PSE&G recorded the unrecognized costs for defined benefit pension and other OPEB plans on the balance sheet as a Regulatory Asset. These costs represent actuarial gains or losses, prior service costs and transition obligations as a result of adoption, which have not been expensed. These costs are amortized and recovered in future rates.
- **Deferred Income Taxes:** These amounts represent the portion of deferred income taxes that will be recovered or refunded through future rates, based upon established regulatory practices.
- **Remediation Adjustment Charge (RAC) (Other SBC):** Costs incurred to clean up manufactured gas plants which are recovered over seven years.
- **MTM Contracts:** The estimated fair value of gas hedge contracts and gas cogeneration supply contracts.The regulatory asset/liability is offset by a derivative asset/liability and, with respect to the gas hedge contracts only, an intercompany receivable/payable on the Consolidated Balance Sheets.
- **Unamortized Loss on Reacquired Debt and Debt Expense:** Represents losses on reacquired long-term debt and expenses associated with issuances of new debt, which are recovered through rates over the remaining life of the debt.
- **Conditional Asset Retirement Obligation:** These costs represent the differences between rate regulated cost of removal accounting and asset retirement accounting under GAAP. These costs will be recovered in future rates.
- **Storm Damage Deferrals:** Costs incurred in the cleanup of major storms in 2010 through 2014. This includes $240 million of storm costs, primarily as a result of Hurricane Irene and Superstorm Sandy, approved for future recovery under a BPU Order received in September 2014.
- **Overrecovered Gas and Electric Costs:** These costs represent the net overrecovered amounts associated with BGSS and BGS, as approved by the BPU. For BGS, interest is accrued on both overrecovered and underrecovered balances. For BGSS, interest is accrued only on overrecovered balances from residential customers.
- **Gas Margin Adjustment Clause:** This mechanism credits Firm delivery customers for net distribution margin revenue collected from Transportation Gas Service Non-Firm (TSG-NF) delivery customers. The balance represents the difference between the net margin collected from the TSG-NF Customers versus bill credits provided to Firm delivery customers.
- **Electric Cost of Removal:** PSE&G accrues and collects for cost of removal in rates. The liability for non-legally required cost of removal is classified as a Regulatory Liability. This liability is reduced as removal costs are incurred. Accumulated cost of removal is a reduction to the rate base.
- **FERC Formula Rate True-up:** Overcollection or undercollection of transmission earnings calculated using a FERC approved formula.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Significant 2014 regulatory orders received and currently pending rate filings with the FERC and the BPU by PSE&G are as follows:

- ***RAC***—On February 11, 2015, the BPU approved PSE&G's filing with respect to its RAC 21 petition allowing recovery of $66 million related to net MGP expenditures from August 1, 2012 through July 31, 2013.
- ***BGSS***—In January and February 2014, PSE&G filed self-implementing one-month BGSS residential customer bill credits with the BPU for 25 cents per therm for the months of February and March 2014. These credits provided approximately $93 million in total credits to residential customers, reducing the BGSS deferred balance. On April 1, 2014, the BGSS rate reverted back to the current rate.

  In May 2014, PSE&G made its annual BGSS filing with the BPU requesting a reduction of $112 million in annual BGSS revenues. In September 2014, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was reduced from approximately 54 cents to 45 cents per therm effective October 1, 2014.
  In October 2014, PSE&G filed a self-implementing three-month bill credit for residential customers to be effective during November and December 2014 and January 2015. This credit is 28 cents per therm for the three-month period and is estimated to provide approximately $160 million to customers. In January 2015, PSE&G filed a letter with the BPU to extend the three-month bill credit for two additional months through February and March 2015 which is estimated to provide an additional approximate $100 million to customers. The specific amount returned will depend on actual usage over that period.
- ***Storm Damage Deferrals***—In September 2014, the BPU approved a Stipulation finding that PSE&G's 2010 through 2012 major storm incremental O&M costs of $240 million (deferred as Regulatory Assets) and capital expenditures of $126 million were prudent and recoverable in a future base rate proceeding, subject to offset for the amount of insurance proceeds received.
- ***WNC***—In April 2014, the BPU approved PSE&G's filing with respect to deficiency revenues from the 2012-2013 Winter Period. The BPU's approval of a final WNC resulted in no change to the provisional rate previously approved by the BPU and implemented effective October 1, 2013, which was set to recover $26 million from customers during the 2013-2014 Winter Period (October 1, 2013 through May 31, 2014).

  In September 2014, the BPU provisionally approved PSE&G's filing with respect to excess revenues collected during the colder than normal 2013-2014 Winter Period. Effective October 1, 2014, PSE&G is returning $45 million in revenues to its customers during the 2014-2015 Winter Period as a result of excess revenues collected during the colder than normal 2013-2014 Winter Period (October 1, 2014 through May 31, 2015).
- ***USF/Lifeline***—The USF is an energy assistance program mandated by the BPU and funded through the SBC clause mechanism to provide payment assistance to low income customers. The Lifeline program is a separate mandated energy assistance program to provide payment assistance to elderly and disabled customers. In September 2014, the BPU approved rates set to recover costs incurred under the USF/Lifeline energy assistance programs effective October 1, 2014. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on Net Income.
- ***Capital Stimulus Infrastructure Programs (CIP II)***—In June 2014, the BPU approved PSE&G's petition to recover annual revenue requirements of approximately $28 million for program costs incurred for its CIP II investments through September 30, 2013, which represents the final phase of the program. Base rates were adjusted effective July 1, 2014 to reflect the recovery.
- ***SBC and NGC***—In May 2014, the BPU approved PSE&G's petition to recover actual SBC and NGC costs incurred through December 31, 2013 under its Energy Efficiency & Renewable Energy Programs, Social Programs and NGC. New rates were implemented on June 1, 2014 to recover approximately $400 million over the succeeding 12 months.
- ***Transmission Formula Rate Filings***—In May 2014, PSE&G filed its 2014 True-Up Adjustment pertaining to its formula rates in effect for 2013, which resulted in an adjustment of $5 million above the 2013 filed revenues. In accordance with PSE&G's formula rate protocols, this Rate Year 2013 True-Up Adjustment has been incorporated into its Annual Formula Rate Update for the 2015 Rate Year. The 2015 Formula Rate Update filed with the FERC in October 2014 for approximately $182 million in increased annual transmission revenues went into effect on January 1, 2015.
- ***Energy Strong Recovery Filing***—In December 2014, PSE&G updated its initial Energy Strong cost recovery petition, seeking BPU approval to recover in base rates an estimated annual revenue increase of $1.1 million effective March 1, 2015. This increase represents capitalized Energy Strong electric investment costs in service through November 30, 2014. Pursuant to a Stipulation, the BPU approved PSE&G's request on February 11, 2015.

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- ***GPRC***—In June 2014, PSE&G filed a petition with the BPU requesting recovery of costs and investments in the combined eight components of the electric and gas GPRC for the period October 1, 2014 through September 30, 2015. The rates proposed in our filing are designed to recover $111 million and $18 million in electric and gas revenues, respectively, on an annual basis. This matter is currently pending.
- ***RAC***—In December 2014, PSE&G filed a petition with the BPU requesting recovery of $86 million related to RAC 22 net MGP expenditures from August 1, 2013 through July 31, 2014. This matter is currently pending.

Note 6. Long-Term Investments

Long-Term Investments as of December 31, 2014 and 2013 included the following:

	As of December 31,	
	2014	2013
	Millions	
PSE&G		
Life Insurance and Supplemental Benefits	$ 156	$ 158
Solar Loans	187	196
Other Investments	5	7
Power		
Partnerships and Corporate Joint Ventures (Equity Method Investments) (A)	121	123
Energy Holdings		
Lease Investments	836	825
Partnerships and Corporate Joint Ventures:		
Equity Method Investments (A)	2	3
Cost Method Investments (B)	—	1
Total Long-Term Investments	**$ 1,307**	**$ 1,313**

(A) During the three years ended December 31, 2014, 2013 and 2012, the amount of dividends from these investments was $17 million, $11 million and $17 million, respectively.

(B) Reflects Energy Holdings' investments in certain companies in which it does not have the ability to exercise significant influence. Such investments are accounted for under the cost method.

Leases

Energy Holdings has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Consolidated Balance Sheets. The following table shows Energy Holdings' gross and net lease investment as of December 31, 2014 and 2013, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31,	
	2014	2013
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 691	$ 701
Estimated Residual Value of Leased Assets	525	529
Total Investment in Rental Receivables	1,216	1,230
Unearned and Deferred Income	(380)	(405)
Gross Investments in Leases	836	825
Deferred Tax Liabilities	(738)	(727)
Net Investments in Leases	**$ 98**	**$ 98**

The pre-tax income and income tax effects, excluding gains and losses on sales, related to investments in leases were as follows:

	Years Ended December 31,		
	2014	2013	2012
	Millions		
Pre-Tax Income (Loss) from Leases	$ 24	$ 11	$ 78
Income Tax Expense (Benefit) on Pre-Tax Income from Leases	$ 32	$ 6	$ 34

Equity Method Investments

Power and Energy Holdings had the following equity method investments as of December 31, 2014:

Name	Location	% Owned
Power		
Keystone Fuels, LLC	PA	23%
Conemaugh Fuels, LLC	PA	23%
Kalaeloa	HI	50%
Energy Holdings		
GWF	CA	50%
Hanford L. P. (Hanford)	CA	50%

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Note 7. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with SRECs generated from the installed solar electric system. The following table reflects the outstanding loans, including the noncurrent portion reported in Note 6. Long-Term Investments, by class of customer, none of which would be considered "non-performing."

Credit Risk Profile Based on Payment Activity

	As of December 31,	
Consumer Loans	**2014**	**2013**
	Millions	
Commercial/Industrial	$ 188	$ 192
Residential	13	15
	$ 201	**$ 207**

Energy Holdings

Energy Holdings had a net investment in domestic energy and real estate assets subject to leveraged lease accounting of $98 million as of December 31, 2014 and 2013 (See Note 6. Long-Term Investments).

The corresponding receivables associated with the lease portfolio are reflected below, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. The "Not Rated" counterparty represents an investment in lease receivable related to a commercial real estate property.

	Lease Receivables, Net of Non-Recourse Debt
Counterparties' Credit Rating (S&P) as of December 31, 2014	**As of December 31, 2014**
	Millions
AA	$ 18
AA-	56
BBB+ - BBB-	317
BB-	134
B-	164
Not Rated	2
	$ 691

The "BB-" and the "B-" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of December 31, 2014, the gross investment in the leases of such assets, net of non-recourse debt, was $572 million, ($(20) million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

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Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	B-	NRG REMA LLC
Conemaugh Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	B-	NRG REMA LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 112	100%	603	Coal	B-	NRG REMA LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

NRG REMA LLC, an indirect subsidiary of NRG Energy, Inc. (NRG) notified PJM that it no longer intends to place the coal-fired units at the Shawville generating facility in long-term protective layup. Instead, those units will be shut down temporarily beginning in April 2015, with an expected return to service no later than June 2016 using an alternative fuel.

Nesbitt Asset Recovery, LLC (Nesbitt), (an indirect, wholly owned subsidiary of Energy Holdings), owns approximately 64% of the lease interest in the Powerton and Joliet coal units in Illinois. These facilities are leased to Midwest Generation (MWG), which was an indirect subsidiary of Edison Mission Energy (EME). In December 2012, EME and MWG filed for relief under Chapter 11 of the U.S. Bankruptcy Code. In October 2013, NRG, EME, MWG, Nesbitt and other creditor parties involved in the bankruptcy executed a new agreement under which NRG acquired substantially all of EME's assets, including the Powerton and Joliet leased assets. In March 2014, the Bankruptcy Court approved the transaction. As part of the transaction, (i) the leases for the Powerton and Joliet coal units were assumed on their existing terms, (ii) all past due rent under the leases was paid in full, (iii) NRG assumed EME's tax indemnity and guarantee obligations, and (iv) NRG agreed to invest up to $350 million in the Powerton and Joliet coal units so they can be operated in compliance with environmental regulations. On April 1, 2014, NRG and EME closed on the transaction in accordance with these terms, bringing the lease payments current.

Note 8. Available-for-Sale Securities

NDT Fund

In accordance with NRC regulations, entities owning an interest in nuclear generating facilities are required to determine the costs and funding methods necessary to decommission such facilities upon termination of operation. As a general practice, each nuclear owner places funds in independent external trust accounts it maintains to provide for decommissioning. Power is required to file periodic reports with the NRC demonstrating that its NDT Fund meets the formula-based minimum NRC funding requirements.

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon their respective termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. Power's

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share of decommissioning costs related to its five nuclear units was estimated to be between $2.2 billion and $2.4 billion, including contingencies. The liability for decommissioning recorded on a discounted basis as of December 31, 2014 was approximately $419 million and is included in the Asset Retirement Obligation. The trust funds are managed by third-party investment advisors who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund:

	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 685	$ 220	$ (8)	$ 897
Debt Securities				
Government Obligations	430	9	(1)	438
Other Debt Securities	333	9	(3)	339
Total Debt Securities	763	18	(4)	777
Other Securities	106	—	—	106
Total NDT Available-for-Sale Securities	**$ 1,554**	**$ 238**	**$ (12)**	**$ 1,780**

	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 609	$ 290	$ (2)	$ 897
Debt Securities				
Government Obligations	438	3	(12)	429
Other Debt Securities	285	10	(4)	291
Total Debt Securities	723	13	(16)	720
Other Securities	84	—	—	84
Total NDT Available-for-Sale Securities	**$ 1,416**	**$ 303**	**$ (18)**	**$ 1,701**

These amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as shown in the following table.

	As of December 31, 2014	As of December 31, 2013
	Millions	
Accounts Receivable	$ 10	$ 39
Accounts Payable	$ 2	$ 36

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2014				As of December 31, 2013			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 162	$ (8)	$ 1	$ —	$ 30	$ (2)	$ 2	$ —
Debt Securities								
Government Obligations (B)	95	—	28	(1)	300	(11)	1	(1)
Other Debt Securities (C)	99	(1)	30	(2)	107	(4)	3	—
Total Debt Securities	194	(1)	58	(3)	407	(15)	4	(1)
NDT Available-for-Sale Securities	**$ 356**	**$ (9)**	**$ 59**	**$ (3)**	**$ 437**	**$ (17)**	**$ 6**	**$ (1)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over companies with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2014.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2014.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2014.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Years Ended December 31,		
	2014	2013	2012
	Millions		
Proceeds from Sales (A)	**$ 1,448**	**$ 1,070**	**$ 1,433**
Net Realized Gains			
Gross Realized Gains	$ 177	$ 112	$ 153
Gross Realized Losses	(23)	(26)	(52)
Net Realized Gains (Losses) on NDT Fund	**$ 154**	**$ 86**	**$ 101**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Consolidated Statements of Operations. Net unrealized gains of $110 million (after-tax) are included in Accumulated Other Comprehensive Loss on PSEG's and Power's Consolidated Balance Sheets as of December 31, 2014.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The available-for-sale debt securities held as of December 31, 2014 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 10
1 - 5 years	271
6 - 10 years	179
11 - 15 years	54
16 - 20 years	49
Over 20 years	214
Total NDT Available-for-Sale Debt Securities	**$ 777**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2014, other-than-temporary impairments of $20 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost bases for the securities held in the Rabbi Trust.

	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 11	$ —	$ 23
Debt Securities				
Government Obligations	89	2	—	91
Other Debt Securities	74	1	—	75
Total Debt Securities	163	3	—	166
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 177**	**$ 14**	**$ —**	**$ 191**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 14	$ 9	$ —	$ 23
Debt Securities				
Government Obligations	109	—	(2)	107
Other Debt Securities	46	1	(1)	46
Total Debt Securities	155	1	(3)	153
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 172**	**$ 10**	**$ (3)**	**$ 179**

These amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as show in the following table.

	As of December 31, 2014	As of December 31, 2013
	Millions	
Accounts Receivable	$ 1	$ 1
Accounts Payable	$ —	$ 2

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2014				As of December 31, 2013			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	2	—	—	—	47	(2)	2	—
Other Debt Securities (C)	24	—	—	—	18	(1)	1	—
Total Debt Securities	26	—	—	—	65	(3)	3	—
Rabbi Trust Available-for-Sale Securities	**$ 26**	**$ —**	**$ —**	**$ —**	**$ 65**	**$ (3)**	**$ 3**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund is through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors. PSEG does not consider these securities to be other-than-temporarily impaired as of December 31, 2014.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of December 31, 2014.

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(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2014.

The proceeds from the sales of and the net realized gains on securities in the Rabbi Trust Fund were:

	Years Ended December 31,		
	2014	2013	2012
	Millions		
Proceeds from Rabbi Trust Sales (A)	**$ 467**	**$ 89**	**$ 233**
Net Realized Gains (Losses):			
Gross Realized Gains	$ 4	$ 4	$ 6
Gross Realized Losses	(3)	(3)	—
Net Realized Gains (Losses) on Rabbi Trust	**$ 1**	**$ 1**	**$ 6**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in the Consolidated Statements of Operations. Net unrealized gains of $8 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets as of December 31, 2014. The Rabbi Trust available-for-sale debt securities held as of December 31, 2014 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ —
1 - 5 years	49
6 - 10 years	31
11 - 15 years	9
16 - 20 years	7
Over 20 years	70
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 166**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities. In 2014, there were no other-than-temporary impairments recognized on investments of the Rabbi Trust.

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The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of December 31, 2014	As of December 31, 2013
	Millions	
PSE&G	$ 41	$ 42
Power	45	39
Other	105	98
Total Rabbi Trust Available-for-Sale Securities	**$ 191**	**$ 179**

Note 9. Goodwill and Other Intangibles

As of December 31, 2014 and 2013, Power had goodwill of $16 million related to the Bethlehem Energy Center facility. Power conducted an annual review for goodwill impairment as of October 31, 2014 and concluded that goodwill was not impaired. No events occurred subsequent to that date which would require a further review of goodwill for impairment.

In addition to goodwill, as of December 31, 2014 and 2013, Power had intangible assets of $84 million and $33 million, respectively, related to emissions allowances and renewable energy credits. Emissions expense includes impairments of emissions allowances and costs for emissions, which is recorded as emissions occur. As load is served under contracts requiring energy from renewable sources, the related expense is recorded. Such expenses for the years ended December 31, 2014, 2013 and 2012 were as follows:

	Years Ended December 31,		
	2014	2013	2012
	Millions		
Emissions Expense	$ 10	$ 6	$ 5
Renewable Energy Expense	$ 59	$ 26	$ 34

Note 10. Asset Retirement Obligations (AROs)

PSEG, PSE&G and Power have recorded various AROs which represent legal obligations to remove or dispose of an asset or some component of an asset at retirement.

PSE&G has conditional AROs primarily for legal obligations related to the removal of treated wood poles and the requirement to seal natural gas pipelines at all sources of gas when the pipelines are no longer in service. PSE&G does not record an ARO for its protected steel and poly-based natural gas lines, as management believes that these categories of gas lines have an indeterminable life.

Power's ARO liability primarily relates to the decommissioning of its nuclear power plants in accordance with NRC requirements. Power has an independent external trust that is intended to fund decommissioning of its nuclear facilities upon termination of operation. For additional information, see Note 8. Available-for-Sale Securities. Power also identified conditional AROs primarily related to Power's fossil generation units and solar facilities, including liabilities for removal of asbestos, stored hazardous liquid material and underground storage tanks from industrial power sites, and demolition of certain plants, and the restoration of the sites at which they reside, when the plants are no longer in service. To estimate the fair value of its AROs, Power uses a probability weighted, discounted cash flow model which, on a unit by unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on third party decommissioning cost estimates, cost escalation rates, inflation rates and discount rates.

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The changes to the ARO liabilities for PSEG, PSE&G and Power during 2013 and 2014 are presented in the following table:

	PSEG	PSE&G	Power	Other
	Millions			
ARO Liability as of January 1, 2013	$ 627	$ 250	$ 374	$ 3
Liabilities Settled	(5)	(4)	(1)	—
Liabilities Incurred	17	13	4	—
Accretion Expense	23	—	23	—
Accretion Expense Deferred and Recovered in Rate Base (A)	15	15	—	—
ARO Liability as of December 31, 2013	**$ 677**	**$ 274**	**$ 400**	**$ 3**
Liabilities Settled	(2)	(2)	—	—
Liabilities Incurred	23	3	20	—
Accretion Expense	30	—	30	—
Accretion Expense Deferred and Recovered in Rate Base (A)	15	15	—	—
ARO Liability as of December 31, 2014	**$ 743**	**$ 290**	**$ 450**	**$ 3**

(A) Not reflected as expense in Consolidated Statements of Operations

Note 11. Pension, Other Postretirement Benefits (OPEB) and Savings Plans

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. Eligible employees participate in non-contributory pension and OPEB plans sponsored by PSEG and administered by Services. In addition, represented and nonrepresented employees are eligible for participation in PSEG's two defined contribution plans described below.

PSEG, PSE&G and Power are required to record the under or over funded positions of their defined benefit pension and OPEB plans on their respective balance sheets. Such funding positions of each PSEG company are required to be measured as of the date of its respective year-end Consolidated Balance Sheets. For under funded plans, the liability is equal to the difference between the plan's benefit obligation and the fair value of plan assets. For defined benefit pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. In addition, GAAP requires that the total unrecognized costs for defined benefit pension and OPEB plans be recorded as an after-tax charge to Accumulated Other Comprehensive Income (Loss), a separate component of Stockholders' Equity. However, for PSE&G, because the amortization of the unrecognized costs is being collected from customers, the accumulated unrecognized costs are recorded as a Regulatory Asset. The unrecognized costs represent actuarial gains or losses, prior service costs and transition obligations arising from the adoption of the revised accounting guidance for pensions and OPEB, which had not been expensed.

For PSE&G, the Regulatory Asset is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations. For Power, the charge to Accumulated Other Comprehensive Income (Loss) is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations.

Amounts for Servco are not included in any of the following pension and OPEB benefit information for PSEG and its affiliates but rather are separately disclosed later in this note.

The following table provides a roll-forward of the changes in the benefit obligation and the fair value of plan assets during each of the two years in the periods ended December 31, 2014 and 2013. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Pension Benefits		Other Benefits	
	2014	2013	2014	2013
	Millions			
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year (A)	$ 4,812	$ 5,235	$ 1,414	$ 1,538
Service Cost	104	116	18	21
Interest Cost	234	215	69	63
Actuarial (Gain) Loss (B)	838	(501)	210	(144)
Gross Benefits Paid	(266)	(253)	(73)	(64)
Benefit Obligation at End of Year (A) (B)	**$ 5,722**	**$ 4,812**	**$ 1,638**	**$ 1,414**
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$ 5,116	$ 4,357	$ 319	$ 253
Actual Return on Plan Assets	433	857	28	52
Employer Contributions	10	155	87	78
Gross Benefits Paid	(266)	(253)	(73)	(64)
Fair Value of Assets at End of Year	**$ 5,293**	**$ 5,116**	**$ 361**	**$ 319**
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	**$ (429)**	**$ 304**	**$ (1,277)**	**$ (1,095)**
Additional Amounts Recognized in the Consolidated Balance Sheets				
Noncurrent Assets (included in Other Special Funds)	$ 21	$ 434	$ —	$ —
Current Accrued Benefit Cost	(10)	(9)	—	—
Noncurrent Accrued Benefit Cost	(440)	(121)	(1,277)	(1,095)
Amounts Recognized	**$ (429)**	**$ 304**	**$ (1,277)**	**$ (1,095)**
Additional Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulated Assets and Deferred Assets (C)				
Prior Service Cost	$ (102)	$ (120)	$ (39)	$ (53)
Net Actuarial Loss	1,724	977	495	310
Total	**$ 1,622**	**$ 857**	**$ 456**	**$ 257**

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits.

(B) In October 2014, the Society of Actuaries' Retirement Plans Experience Committee issued its final report on mortality tables (RP-2014 Mortality Tables Report). As of December 31, 2014, PSEG updated its mortality assumptions based on the information contained in this report. The impact of this change is reflected in Actuarial (Gain) Loss in 2014 and added $314 million and $79 million to the Benefit Obligations for Pension and OPEB, respectively, since December 31, 2013.

(C) Includes $702 million ($411 million, after-tax) and $408 million ($238 million, after-tax) in Accumulated Other Comprehensive Loss related to Pension and OPEB as of December 31, 2014 and 2013, respectively.

The pension benefits table above provides information relating to the funded status of all qualified and nonqualified pension plans and OPEB plans on an aggregate basis. As of December 31, 2014, PSEG had funded approximately 93% of its projected benefit obligation. This percentage does not include $191 million of assets in the Rabbi Trust as of December 31, 2014 which were used partially to fund the nonqualified pension plans. As of December 31, 2014, the nonqualified pension plans included in the benefit obligation in the above table and in the projected benefit obligation were $161 million. The fair values of the Rabbi Trust assets are included in Other Special Funds on the Consolidated Balance Sheets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Accumulated Benefit Obligation

The accumulated benefit obligation for all PSEG's defined benefit pension plans was $5.5 billion as of December 31, 2014 and $4.5 billion as of December 31, 2013.

The following table provides the components of net periodic benefit cost for the years ended December 31, 2014, 2013 and 2012.

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2014	2013	2012	2014	2013	2012
	Millions					
Components of Net Periodic Benefit Cost (Credit)						
Service Cost	$ 104	$ 116	$ 101	$ 18	$ 21	$ 17
Interest Cost	234	215	223	69	63	65
Expected Return on Plan Assets	(399)	(348)	(306)	(26)	(21)	(17)
Amortization of Net						
Transition Obligation	—	—	—	—	—	2
Prior Service Cost	(18)	(19)	(18)	(14)	(14)	(14)
Actuarial Loss	56	188	167	23	42	31
Net Periodic Benefit Cost (Credit)	**$ (23)**	**$ 152**	**$ 167**	**$ 70**	**$ 91**	**$ 84**
Special Termination Benefits	—	—	1	—	—	—
Effect of Regulatory Asset	—	—	—	—	—	19
Total Benefit Costs (Credit), Including Effect of Regulatory Asset	**$ (23)**	**$ 152**	**$ 168**	**$ 70**	**$ 91**	**$ 103**

Pension costs and OPEB costs for PSEG, PSE&G and Power are detailed as follows:

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2014	2013	2012	2014	2013	2012
	Millions					
PSE&G	$ (19)	$ 91	$ 97	$ 46	$ 65	$ 82
Power	(7)	43	52	20	23	18
Other	3	18	19	4	3	3
Total Benefit Costs (Credit)	**$ (23)**	**$ 152**	**$ 168**	**$ 70**	**$ 91**	**$ 103**

The following table provides the pre-tax changes recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Deferred Assets:

	Pension		OPEB	
	2014	2013	2014	2013
	Millions			
Net Actuarial (Gain) Loss in Current Period	$ 803	$ (1,009)	$ 208	$ (175)
Amortization of Net Actuarial Gain (Loss)	(56)	(188)	(23)	(42)
Amortization of Prior Service Credit	18	19	14	14
Total	**$ 765**	**$ (1,178)**	**$ 199**	**$ (203)**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Amounts that are expected to be amortized from Accumulated Other Comprehensive Loss, Regulatory Assets and Deferred Assets into Net Periodic Benefit Cost in 2015 are as follows:

	Pension Benefits 2015	Other Benefits 2015
	Millions	
Actuarial (Gain) Loss	$ 150	$ 43
Prior Service Cost	$ (19)	$ (14)

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

	Pension Benefits			Other Benefits		
	2014	2013	2012	2014	2013	2012
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	4.20%	5.00%	4.20%	4.21%	5.01%	4.20%
Rate of Compensation Increase	3.61%	4.61%	4.61%	3.61%	4.61%	4.61%
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount Rate	5.00%	4.20%	5.00%	5.01%	4.20%	5.00%
Expected Return on Plan Assets	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Rate of Compensation Increase	4.61%	4.61%	4.61%	4.61%	4.61%	4.61%
Assumed Health Care Cost Trend Rates as of December 31						
Administrative Expense				3.00%	3.00%	3.00%
Dental Costs						
Immediate Rate				5.25%	5.50%	6.00%
Ultimate Rate				5.00%	5.00%	6.00%
Year Ultimate Rate Reached				2016	2016	2013
Pre-65 Medical Costs						
Immediate Rate				7.50%	8.00%	8.88%
Ultimate Rate				5.00%	5.00%	5.00%
Year Ultimate Rate Reached				2022	2021	2023
Post-65 Medical Costs						
Immediate Rate				7.25%	7.88%	7.98%
Ultimate Rate				5.00%	5.00%	5.00%
Year Ultimate Rate Reached				2022	2021	2019
					Millions	
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$ 13	$ 12	$ 12
Postretirement Benefit Obligation				$ 201	$ 161	$ 180
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$ (10)	$ (9)	$ (9)
Postretirement Benefit Obligation				$ (165)	$ (134)	$ (149)

Plan Assets

All the investments of pension plans and OPEB plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension and OPEB plans are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 16. Fair Value Measurements for more information on fair value guidance. Use of the Master Trust permits the commingling of pension plan assets and OPEB plan assets for investment and administrative purposes. Although assets of the plans are commingled in the Master Trust, the Trustee maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Trustee to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

plans. As of December 31, 2014, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 94% and 6%, respectively.

The following tables present information about the investments measured at fair value on a recurring basis as of December 31, 2014 and 2013, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2014			
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Temporary Investment Funds (A)	$ 153	$ 92	$ 61	$ —
Common Stocks (B)				
Commingled—United States	2,292	2,292	—	—
Commingled—International	1,005	1,005	—	—
Other	727	727	—	—
Bonds (C)				
Government (United States & Foreign)	509	—	509	—
Other	943	—	943	—
Private Equity (D)	25	—	—	25
Total	**$ 5,654**	**$ 4,116**	**$ 1,513**	**$ 25**

	Recurring Fair Value Measurements as of December 31, 2013			
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Temporary Investment Funds (A)	$ 93	$ 52	$ 41	$ —
Common Stocks (B)				
Commingled—United States	2,264	2,264	—	—
Commingled—International	1,016	1,016	—	—
Other	704	704	—	—
Bonds (C)				
Government (United States & Foreign)	596	—	596	—
Other	737	—	737	—
Private Equity (D)	25	—	—	25
Total	**$ 5,435**	**$ 4,036**	**$ 1,374**	**$ 25**

(A) Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active market (Level 1). Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

(B) Wherever possible, fair values of equity investments in stocks and in commingled funds are derived from quoted market prices as substantially all of these instruments have active markets (primarily Level 1). Most investments in stocks are priced utilizing the principal market close price or in some cases midpoint, bid or ask price.

(C) Investments in fixed income securities including bond funds are priced using an evaluated pricing approach or the most recent exchange or quoted bid (primarily Level 2).

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(D) Limited partnership interests in private equity funds are valued using significant unobservable inputs as there is little, if any, market activity. In addition, there may be transfer restrictions on private equity securities. The process for determining the fair value of such securities relied on commonly accepted valuation techniques, including the use of earnings multiples based on comparable public securities, industry-specific non-earnings-based multiples and discounted cash flow models. These inputs require significant management judgment or estimation (primarily Level 3).

Reconciliations of the beginning and ending balances of the Pension and OPEB Plans' Level 3 assets for the years ended December 31, 2014 and 2013 are as follows:

	Balance as of January 1, 2014	Purchases/ (Sales)	Transfer In/ (Out)	Actual Return on Asset Sales	Actual Return on Assets Still Held	Balance as of December 31, 2014
			Millions			
Private Equity	$ 25	$ (5)	$ —	$ 3	$ 2	$ 25

	Balance as of January 1, 2013	Purchases/ (Sales)	Transfer In/ (Out)	Actual Return on Asset Sales	Actual Return on Assets Still Held	Balance as of December 31, 2013
			Millions			
Private Equity	$ 31	$ (11)	$ —	$ 11	$ (6)	$ 25

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans as of the measurement date, December 31:

	As of December 31,	
Investments	**2014**	**2013**
Equity Securities	71%	73%
Fixed Income Securities	26	25
Other Investments	3	2
Total Percentage	**100%**	**100%**

PSEG utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. PSEG's latest asset/liability study indicates that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. Derivative financial instruments are used by the plans' investment managers primarily to adjust the fixed income duration of the portfolio and hedge the currency risk component of foreign investments. The expected long-term rate of return on plan assets was 8.00% as of December 31, 2014 and will remain unchanged for 2015. This expected return was determined based on the study discussed above, including a premium for active management and considered the plans' historical annualized rate of return since inception, which was 9.5%.

Plan Contributions

PSEG may contribute up to $25 million into its pension plans and up to $14 million into its OPEB plan, respectively, during 2015.

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Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to plan participants.

Year	Pension Benefits	Other Benefits
	Millions	
2015	$ 282	$ 79
2016	283	82
2017	294	84
2018	305	87
2019	318	90
2020-2024	1,770	495
Total	**$ 3,252**	**$ 917**

401(k) Plans

PSEG sponsors two 401(k) plans, which are Employee Retirement Income Security Act (ERISA) defined contribution retirement plans. Eligible represented employees of PSEG's subsidiaries participate in the PSEG Employee Savings Plan (Savings Plan), while eligible non-represented employees of PSEG's subsidiaries participate in the PSEG Thrift and Tax-Deferred Savings Plan (Thrift Plan). Eligible employees may contribute up to 50% of their compensation to these plans. PSEG matches 50% of such employee contributions up to 7% of pay for Savings Plan participants and up to 8% of pay for Thrift Plan participants.

The amount paid for employer matching contributions to the plans for PSEG, PSE&G and Power are detailed as follows:

	Thrift Plan and Savings Plan Years Ended December 31,		
	2014	2013	2012
	Millions		
PSE&G	$ 20	$ 19	$ 18
Power	11	$ 10	10
Other	5	4	4
Total Employer Matching Contributions	**$ 36**	**$ 33**	**$ 32**

Servco Pension and OPEB

At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities. These obligations, as well as the offsetting long-term receivable, are separately presented on the Consolidated Balance Sheet of PSEG.

The following table provides a roll-forward of the changes in Servco's benefit obligation and the fair value of its plan assets during the year ended December 31, 2014. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of 2014.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Pension Benefits 2014	Other Benefits 2014
	Millions	
Change in Benefit Obligation		
Benefit Obligation at Beginning of Year	$ —	$ —
Service	20	13
Interest	7	17
Differences in Actuarial Assumptions versus Actual Experience	42	107
Plan Amendments	126	315
Benefit Obligation at End of Year (A)	**$ 195**	**$ 452**
Change in Plan Assets		
Fair Value of Assets at Beginning of Year	$ —	$ —
Actual Return on Plan Assets	2	—
Employer Contributions	67	—
Fair Value of Assets at End of Year	**$ 69**	**$ —**
Funded Status		
Funded Status (Plan Assets less Benefit Obligation)	**$ (126)**	**$ (452)**
Additional Amounts Recognized in the Consolidated Balance Sheets		
Accrued Pension Costs of Servco	$ (126)	$ —
OPEB Costs of Servco	—	(452)
Amounts Recognized (B)	**$ (126)**	**$ (452)**

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits.

(B) Amounts equal to the accrued pension and OPEB costs of Servco are offset in Long-Term Receivable of VIE on PSEG's Consolidated Balance Sheet.

Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. The pension-related revenues and costs for 2014 were $67 million. Servco has contributed its entire planned contribution amount to its pension plan trusts during 2014. The OPEB-related revenues earned or costs incurred in 2014 were immaterial.

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The following assumptions were used to determine the benefit obligations of Servco:

	Pension Benefits	Other Benefits
	December 31, 2014	
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31, 2014		
Discount Rate	4.50%	4.60%
Rate of Compensation Increase	3.25%	3.25%
Assumed Health Care Cost Trend Rates as of December 31, 2014		
Administrative Expense		5.00%
Dental Costs		
Immediate Rate		8.00%
Ultimate Rate		5.00%
Year Ultimate Rate Reached		2018
Pre-65 Medical Costs		
Immediate Rate		7.50%
Ultimate Rate		5.00%
Year Ultimate Rate Reached		2022
Post-65 Medical Costs		
Immediate Rate		7.44%
Ultimate Rate		5.00%
Year Ultimate Rate Reached		2022
		Millions
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs		
Postretirement Benefit Obligation		$ 160
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs		
Postretirement Benefit Obligation		$ (106)

Plan Assets

All the investments of Servco's pension plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 16. Fair Value Measurements for more information on fair value guidance. The Actuary maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Actuary to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans.

The following table presents information about Servco's investments measured at fair value on a recurring basis as of December 31, 2014, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2014			
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Temporary Investment Funds (A)	$ 1	$ —	$ 1	$ —
Common Stocks (B)				
Commingled—United States	48	48	—	—
Bonds (C)				
Other	20	—	20	—
Total	**$ 69**	**$ 48**	**$ 21**	**$ —**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(A) Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

(B) Wherever possible, fair values of equity investments in commingled stock funds are derived from quoted market prices as substantially all of these instruments have active markets (primarily Level 1). Most investments in stocks are priced utilizing the principal market close price or in some cases midpoint, bid or ask price.

(C) Investments in fixed income securities including bond funds are priced using an evaluated pricing approach or the most recent exchange or quoted bid (primarily Level 2).

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans of Servco as of the measurement date, December 31:

Investments	As of December 31, 2014
Equity Securities	70%
Fixed Income Securities	29
Other Investments	1
Total Percentage	**100%**

Servco utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. The results from Servco's latest asset/liability study indicated that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. The expected long-term rate of return on plan assets was 7.70% as of December 31, 2014 and will remain unchanged for 2015. This expected return was determined based on the study discussed above, including a premium for active management and considered the plans' 2014 rate of return, which was 6.3%.

Plan Contributions

Servco may contribute up to $30 million into its pension plan during 2015.

Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to Servco's plan participants:

Year	Pension Benefits	Other Benefits
	Millions	
2015	$ —	$ 2
2016	1	4
2017	2	6
2018	3	7
2019	4	9
2020-2024	49	74
Total	**$ 59**	**$ 102**

Servco 401(k) Plans

Servco sponsors two 401(k) plans, which are defined contribution retirement plans subject to the ERISA. Eligible non-represented employees of Servco participate in the Servco Incentive Thrift Plan I (Thrift Plan I), and eligible represented employees of Servco participate in the Servco Incentive Thrift Plan II. Eligible employees may contribute up to 50% of their compensation to these plans. For employees in Thrift Plan I, Servco matches 50% of such employee contributions up to 8% and provides core contributions (based on years of service and age) to employees who do not participate in Servco's pension plan.

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Note 12. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The face value of outstanding guarantees, current exposure and margin positions as of December 31, 2014 and 2013 are shown below:

	As of December 31, 2014	As of December 31, 2013
	Millions	
Face Value of Outstanding Guarantees	$ 1,814	$ 1,639
Exposure under Current Guarantees	$ 273	$ 246
Letters of Credit Margin Posted	$ 159	$ 132
Letters of Credit Margin Received	$ 40	$ 25
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (13)	$ —
Net Broker Balance Deposited (Received)	$ 115	$ 80
In the Event Power were to Lose its Investment Grade Rating		
Additional Collateral that could be Required	$ 945	$ 691
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,495	$ 3,522
Additional Amounts Posted		
Other Letters of Credit	$ 45	$ 45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 15. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P, Moody's and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

The SEC and the Commodity Futures Trading Commission (CFTC) continue efforts to implement new rules to effect stricter regulation over swaps and derivatives, including imposing reporting and record-keeping requirements. In August 2013, PSEG began reporting its swap transactions to a CFTC-approved swap data repository. PSEG continues to monitor developments in this area, as the CFTC considers additional requirements such as a new position limits rule for physical commodity futures contracts and swaps that are economically equivalent to those contracts.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG had also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, this guarantee would have to be replaced by a letter of credit.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Super Fund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA further determined that there was a need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this allocation, approximately seven percent of the RI/FS costs were deemed attributable to PSE&G's former MGP sites and approximately one percent was attributed to Power's generating stations. These allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. Power has provided notice to insurers concerning this potential claim.

The CPG, which consisted of 61 members as of December 31, 2014, continues to conduct the RI/FS which is expected to be completed during the first quarter of 2015 at an estimated cost of approximately $136 million. Of the estimated $136 million, as of December 31, 2014, the CPG Group had spent approximately $130 million, of which PSEG's total share had been approximately $9 million.

In June 2008, the EPA, Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra and Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement among the EPA, Tierra and Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including PSE&G and Power. This agreement and the work undertaken pursuant to the early action agreement has no impact on the ultimate remedy that the EPA will select for the remediation of the 17-mile stretch of the lower Passaic River.

In 2012, Tierra and Maxus withdrew from the CPG and refused to participate as members going forward, other than in respect of their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSEG's share of the cost of that effort is approximately three percent. The remaining CPG members have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River that had originally been designated as a Super Fund site. The FFS sets forth various alternatives for remediating this portion of the Passaic River. The EPA's estimated costs to remediate the lower eight miles of the Passaic River range from $365 million for a targeted remedy to $3.25 billion for a deep dredge of this portion of the Passaic River. The EPA also identified in the FFS its preferred alternative, which would involve dredging the river bank to bank and installing an engineered cap. The estimated cost in the FFS for its preferred alternative is $1.7 billion. No provisional cost allocation has been made by the CPG for the work contemplated by the draft FFS, and the work contemplated by the FFS is not subject to the CPG's cost sharing allocation agreed to in connection with the removal work for River Mile 10.9 or in connection with the conduct of the RI/FS.

The draft FFS was subject to a public comment period, and remains subject to the EPA's response to comments submitted, a design phase and at least an estimated five years for completion of the work. The public comment period on the draft FFS closed on August 21, 2014. Over 300 comments were submitted by a variety of entities potentially impacted by the FFS, including the CPG, individual companies, municipalities, public officials, citizens groups, Amtrak, NJ Transit and others. The EPA will consider the comments received prior to issuing a Record of Decision (ROD) of a selected remedy for the lower eight miles. The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability.

Based on the facts and circumstance known at this time, and calculated in reference to the EPA estimate set forth in the FFS for its preferred remedy, PSE&G and Power believe that their respective shares of the costs to clean up the Passaic River will be immaterial. However, until (i) the RI/FS is completed, (ii) a final remedy is determined by the EPA or through litigation, (iii) PSE&G's and Power's respective share of the costs, both in the aggregate as well as individually, are determined, and (iv)

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PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on our financial statements.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G is unable to estimate its portion of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their portion of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $434 million and $505 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $434 million as of December 31, 2014. Of this amount, $79 million was recorded in Other Current Liabilities and $355 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $434 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Hazardous Air Pollutants Regulation

In accordance with a ruling of the U.S. Court of Appeals of the District of Columbia (D.C. Court), the EPA published a Maximum Achievable Control Technology (MACT) regulation in February 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the D.C. Court in support of the EPA's implementation of MATS. In April 2014, the D.C. Court denied all petitions for review of the existing source NESHAP.

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Several parties, including 21 states, have filed petitions for review with the U.S. Supreme Court. On November 25, 2014, the U.S. Supreme Court issued an order granting review solely of the issue as to whether the EPA was unreasonable in its refusal to consider the materiality of costs in determining whether it is appropriate to regulate the emission of hazardous air pollutants by electric utilities.

Power believes that it will not be necessary to install any material new controls at its New Jersey facilities. Dry sorbent injection to control acid gases was installed at Power's Bridgeport Harbor coal-fired unit in the fourth quarter of 2014 at an immaterial cost. This system is currently undergoing operational verification testing. In December 2011, to comply with the MACT regulations, the co-owners group, including Power, agreed to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction (SCR) systems at Power's jointly owned coal-fired generating facility at Conemaugh in Pennsylvania. This installation was completed in November 2014. Power's share of this investment is approximately $110 million.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

One of the more significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued.

In October 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court of New Jersey seeking to force the NJDEP to take action on Power's pending application for permit renewal at Salem either by denying the application or issuing a draft for public comment. An application for renewal of the permit was submitted in January 2006 and the NJDEP had delayed action pending the EPA's finalization of the Clean Water Act 316 (b) regulations. In November 2014, the environmental groups announced settlement of the lawsuit filed with the NJDEP and that the NJDEP had committed to issue a draft permit by June 30, 2015.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. On August 15, 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. On September 5, 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Second Circuit Court of Appeals. In two related actions on October 17, 2014 and November 20, 2014, several environmental non-governmental groups initiated challenges to the endangered species act provisions of the 316 (b) rule. Power is unable to determine the ultimate impact of these actions on the implementation of the rule.

State permitting decisions could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would have been approximately $575 million. The filing has not been updated. Action on the issuance of a draft permit for Salem is anticipated by June 30, 2015. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, are residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category are larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2015 is $272.78 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2015 of $282.04 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2012	2013	2014	2015	
36-Month Terms Ending	May 2015	May 2016	May 2017	May 2018	(A)
Load (MW)	2,900	2,800	2,800	2,900	
$ per MWh	$83.88	$92.18	$97.39	$99.54	

(A) Prices set in the 2015 BGS auction will become effective on June 1, 2015 when the 2012 BGS auction agreements expire.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 23. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2019 at Salem, Hope Creek and Peach Bottom.

Power has various long-term fuel purchase commitments for coal through 2017 to support its fossil generation stations and for firm transportation and storage capacity for natural gas.

Power's various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

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As of December 31, 2014, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type		Power's Share of Commitments through 2019
		Millions
Nuclear Fuel		
Uranium	$	439
Enrichment	$	431
Fabrication	$	208
Natural Gas	$	1,186
Coal	$	306

Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. PSEG notified the FERC, PJM and the PJM Independent Market Monitor (IMM) of this issue. During the three months ended March 31, 2014, Power recorded a charge to income in the amount of $25 million related to these findings for these past errors based upon its best estimate available at the time. PSEG cannot provide any assurances that the total liability associated with this matter will not increase or decrease over the amount recorded.

Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed the FERC, PJM and the IMM of these additional issues, and has corrected these errors. Power has an ongoing process of implementing improved procedures to help mitigate the risk of similar issues occurring in the future.

On September 2, 2014, the FERC Staff initiated a preliminary, non-public staff investigation into the matter, which is ongoing. This investigation could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with this matter, or the applicability of mitigating factors. It is possible that Power will incur additional losses, and that such losses may be material, but PSEG cannot at the current time estimate the amount or range of any additional losses.

New Jersey Clean Energy Program

In June 2014, the BPU established the funding level for fiscal 2015 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2015 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a remaining current liability of $142 million as of December 31, 2014 for its outstanding share of the fiscal 2015 and remaining fiscal 2014 funding. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the SBC.

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's T&D system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure.

As of December 31, 2012, PSE&G had incurred approximately $295 million of costs to restore service to PSE&G's distribution and transmission systems and $5 million to repair its infrastructure and return it to pre-storm conditions. Of the costs incurred, approximately $40 million was recognized in O&M Expense, $75 million was recorded as Property, Plant and Equipment and $180 million was recorded as a Regulatory Asset because such costs were deferred as approved by the BPU under an Order received in December 2012. PSE&G recognized $6 million of insurance proceeds. There were no significant changes to these amounts since 2012. PSE&G made a filing with the BPU to review the prudency of unreimbursed incremental storm restoration costs, including O&M and capital expenditures associated with Superstorm Sandy and certain other extreme weather events, for

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recovery in our next base rate case or sooner through a BPU-approved cost recovery mechanism. In September 2014, the BPU approved our filing. See Note 5. Regulatory Assets and Liabilities for additional information.

Power had incurred $79 million and $85 million of storm-related expense in 2013 and 2012, respectively, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized in O&M Expense, offset by $25 million and $19 million of insurance recoveries in 2013 and 2012, respectively. Power incurred an additional $27 million of O&M costs in 2014 primarily for repairs at certain generating stations in Power's fossil fleet.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. As previously reported, PSEG continues to seek recovery from its insurers for the property damage resulting from Superstorm Sandy, above its self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. In June 2013, PSEG, PSE&G and Power filed suit in New Jersey state court against its insurance carriers seeking an interpretation that the insurance policies cover their losses resulting from damage caused by Superstorm Sandy's storm surge. In August 2013, the insurance carriers filed an answer in which they denied most of the allegations made in the Complaint. In December 2014, PSEG notified the insurance carriers of an estimate of $564 million for total costs related to damaged facilities, of which $88 million and $476 million related to PSE&G and Power, respectively. Discovery in the case has been completed. On October 7, 2014, both parties filed cross-motions for summary judgment and those motions are scheduled to be argued on March 20, 2015. We cannot predict the outcome of this proceeding.

Nuclear Insurance Coverages and Assessments

Power is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides the property, decontamination and decommissioning liability insurance at the Salem/Hope Creek and Peach Bottom sites. NEIL also provides replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in case of adverse loss experience. Power’s maximum potential liabilities under these assessments are included in the table and notes below. Certain provisions in the NEIL policies provide that the insurer may suspend coverage with respect to all nuclear units on a site without notice if the NRC suspends or revokes the operating license for any unit on that site, issues a shutdown order with respect to such unit or issues a confirmatory order keeping such unit down.

The American Nuclear Insurers (ANI) and NEIL policies all include coverage for claims arising out of acts of terrorism, however, NEIL policies are subject to an industry aggregate limit of $3.2 billion plus such additional amounts as NEIL recovers for such losses from reinsurance, indemnity and any other source applicable to such losses.

The Price-Anderson Act sets the “limit of liability” for claims that could arise from an incident involving any licensed nuclear facility in the United States. The “limit of liability” is based on the number of licensed nuclear reactors and is adjusted at least every five years based on the Consumer Price Index. The current “limit of liability” is $13.6 billion. All owners of nuclear reactors, including Power, have provided for this exposure through a combination of private insurance and mandatory participation in a financial protection pool as established by the Price-Anderson Act. Under the Price-Anderson Act, each licensee can be assessed $127 million per reactor per incident, payable at not more than $19 million per reactor per incident per year. If the damages exceed the “limit of liability,” the Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Power’s maximum aggregate assessment per incident is $401 million (based on Power’s ownership interests in Hope Creek, Peach Bottom and Salem) and its maximum aggregate annual assessment per incident is $60 million. Further, a decision by the U.S. Supreme Court, not involving Power, has held that the Price-Anderson Act did not preclude awards based on state law claims for punitive damages.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power's insurance coverages and maximum retrospective assessments for its nuclear operations are as follows:

Type and Source of Coverages	Total Site Coverage		Retrospective Assessments
	Millions		
Public and Nuclear Worker Liability (Primary Layer):			
ANI	$ 375	(A)	$ —
Nuclear Liability (Excess Layer):			
Price-Anderson Act	13,241	(B)	401
Nuclear Liability Total	**$ 13,616**	(C)	**$ 401**
Property Damage (Primary Layer):			
NEIL Primary (Salem/Hope Creek and Peach Bottom)	$ 1,500		$ 38
Property Damage (Excess Layers)			
NEIL Excess (Salem/Hope Creek and Peach Bottom)	600	(D)	5
Property Damage Total (Per Site)	**$ 2,100**		**$ 43**
Accidental Outage:			
NEIL I (Peach Bottom)	$ 245	(E)	$ 7
NEIL I (Salem)	281	(E)	7
NEIL I (Hope Creek)	490	(E)	6
Replacement Power Total	**$ 1,016**		**$ 20**

(A) The primary limit for Public Liability is a per site aggregate limit with no potential for assessment. The Nuclear Worker Liability represents the potential liability from third party workers claiming exposure to the nuclear energy hazard. This coverage is subject to an industry aggregate limit that is subject to reinstatement at ANI discretion.

(B) Retrospective premium program under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. Power is subject to retrospective assessment with respect to loss from an incident at any licensed nuclear reactor in the United States that produces greater than 100 MW of electrical power. This retrospective assessment can be adjusted for inflation every five years. The last adjustment was effective as of September 10, 2013. The next adjustment is due on or before September 10, 2018. This retrospective program is in excess of the Public and Nuclear Worker Liability primary layers.

(C) Limit of liability under the Price-Anderson Act for each nuclear incident.

(D) For nuclear event property limits in excess of $1.5 billion, Power participates in a $600 million nuclear event Blanket Limit Policy. The blanket limit policy is shared with Exelon Generation and covers the following facilities: Braidwood, Byron, Clinton, Dresden, La Salle, Limerick, Oyster Creek, Quad Cities, TMI-1 Peach Bottom, Salem and Hope Creek. This limit is not subject to reinstatement in the event of a loss. Participation in this program reduces Power's premium and the associated potential assessment. In addition, for non-nuclear event limits in excess of $1.5 billion, Power maintains a $600 million limit shared by the Salem and Hope Creek facilities. Exelon maintains a $600 million non-nuclear event limit shared by Peach Bottom, Braidwood, Byron, Clinton, Dresden, LaSalle, Limerick, Oyster Creek, Quad Cities, and the TMI-1 facilities.

(E) Peach Bottom 2 and 3 have an aggregate indemnity limit based on a weekly indemnity of $2.3 million for 52 weeks followed by 80% of the weekly indemnity for 68 weeks. Salem 1 and 2 have an aggregate indemnity limit based on a weekly indemnity of $2.5 million for 52 weeks followed by 80% of the weekly indemnity for 76 weeks. Hope Creek has an aggregate indemnity limit based on a weekly indemnity of $4.5 million for 52 weeks followed by 80% of the weekly indemnity for 71 weeks.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Minimum Lease Payments

The total future minimum payments under various operating leases as of December 31, 2014 are:

	PSE&G	Power	Services	Other
	Millions			
2015	$ 12	$ 2	$ 5	$ 2
2016	9	2	12	1
2017	7	1	13	1
2018	6	2	13	—
2019	6	2	13	—
Thereafter	55	23	159	—
Total Minimum Lease Payments	**$ 95**	**$ 32**	**$ 215**	**$ 4**

Note 13. Schedule of Consolidated Debt

Long-Term Debt

	As of December 31,	
	2014	2013
	Millions	
PSEG (Parent)		
Fair Value of Swaps (A)	$ 22	$ 38
Amounts Due Within One Year	(8)	—
Unamortized Discount Related to Debt Exchange (B)	(8)	(14)
Total Long-Term Debt of PSEG (Parent)	**$ 6**	**$ 24**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2014	2013
		Millions	
PSE&G			
First and Refunding Mortgage Bonds (C):			
6.75%	2016	$ 171	$ 171
9.25%	2021	134	134
8.00%	2037	7	7
5.00%	2037	8	8
Total First and Refunding Mortgage Bonds		320	320
Pollution Control Bonds (C):			
Floating rate (D)	2033	50	50
Floating rate (D)	2046	50	50
Total Pollution Control Bonds		100	100
Medium-Term Notes (MTNs) (C):			
0.85%	2014	—	250
5.00%	2014	—	250
2.70%	2015	300	300
5.30%	2018	400	400
2.30%	2018	350	350
1.80%	2019	250	—
2.00%	2019	250	—
7.04%	2020	9	9
3.50%	2020	250	250
2.38%	2023	500	500
3.75%	2024	250	250
3.15%	2024	250	—
3.05%	2024	250	—
5.25%	2035	250	250
5.70%	2036	250	250
5.80%	2037	350	350
5.38%	2039	250	250
5.50%	2040	300	300
3.95%	2042	450	450
3.65%	2042	350	350
3.80%	2043	400	400
4.00%	2044	250	—
Total MTNs		5,909	5,159
Principal Amount Outstanding		6,329	5,579
Amounts Due Within One Year		(300)	(500)
Net Unamortized Discount		(17)	(13)
Total Long-Term Debt of PSE&G (excluding Transition Funding and Transition Funding II)		**$ 6,012**	**$ 5,066**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2014	2013
		Millions	
Transition Funding (PSE&G)			
Securitization Bonds:			
6.75%	2014	$ —	$ 106
6.89%	2014-2015	251	370
Principal Amount Outstanding		251	476
Amounts Due Within One Year		(251)	(225)
Total Securitization Debt of Transition Funding		—	**251**
Transition Funding II (PSE&G)			
Securitization Bonds:			
4.57%	2014-2015	8	20
Principal Amount Outstanding		8	20
Amounts Due Within One Year		(8)	(12)
Total Securitization Debt of Transition Funding II		—	**8**
Total Long-Term Debt of PSE&G		**$ 6,012**	**$ 5,325**

	Maturity	As of December 31, 2014	2013
		Millions	
Power			
Senior Notes:			
5.50%	2015	$ 300	$ 300
5.32%	2016	303	303
2.75%	2016	250	250
2.45%	2018	250	250
5.13%	2020	406	406
4.15%	2021	250	250
4.30%	2023	250	250
8.63%	2031	500	500
Total Senior Notes		2,509	2,509
Pollution Control Notes:			
Floating Rate (D)	2019	44	44
Total Pollution Control Notes		44	44
Principal Amount Outstanding		2,553	2,553
Amounts Due Within One Year		(300)	(44)
Net Unamortized Discount		(10)	(12)
Total Long-Term Debt of Power		**$ 2,243**	**$ 2,497**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2014	2013
		Millions	
Energy Holdings			
Non-Recourse Project Debt (E):			
Resources - 5.00% to 5.275%	2014-2015	$ 16	$ 16
Principal Amount Outstanding		16	16
Amounts Due Within One Year		(16)	—
Total Non-Recourse Project Debt		—	16
Total Long-Term Debt of Energy Holdings		**$ —**	**$ 16**

(A) PSEG entered into various interest rate swaps to hedge the fair value of certain debt at Power. The fair value adjustments from these hedges are reflected as offsets to long-term debt on the Consolidated Balance Sheets. For additional information, see Note 15. Financial Risk Management Activities.

(B) In September 2009, Power completed an exchange offer with eligible holders of Energy Holdings' 8.50% Senior Notes due 2011 in order to manage long-term debt maturities. Since the debt exchange was between two subsidiaries of the same parent company, PSEG, and treated as a debt modification for accounting purposes, the resulting premium was deferred and is being amortized over the term of the newly issued debt. The deferred amount is reflected as an offset to Long-Term Debt on PSEG's Consolidated Balance Sheets.

(C) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.

(D) The Pollution Control Financing Authority of Salem County bonds and the Pennsylvania Economic Development Authority (PEDFA) bond that are serviced and secured by PSE&G Pollution Control Bonds and Power Pollution Control Notes, respectively, are variable rate bonds that are in weekly reset mode. In October 2014, Power executed an extension of the letter of credit backing PEDFA bond. The existing letter of credit, which was scheduled to expire on November 30, 2014, has been extended through November 30, 2019.

(E) Non-recourse financing transactions consist of loans from banks and other lenders that are typically secured by project assets and cash flows and generally impose no material obligation on the parent-level investor to repay any debt incurred by the project borrower. The consequences of permitting a project-level default include the potential for loss of any invested equity by the parent.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2014 are as follows:

	PSE&G				Energy Holdings	
Year	PSE&G	Transition Funding	Transition Funding II	Power	Non-Recourse Debt	Total
			Millions			
2015	$ 300	$ 251	$ 8	$ 300	$ 16	$ 875
2016	171	—	—	553	—	724
2017	—	—	—	—	—	—
2018	750	—	—	250	—	1,000
2019	500	—	—	44	—	544
Thereafter	4,608	—	—	1,406	—	6,014
Total	**$ 6,329**	**$ 251**	**$ 8**	**$ 2,553**	**$ 16**	**$ 9,157**

Long-Term Debt Financing Transactions

During 2014, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions:

PSE&G

- issued $250 million of 1.80% Secured Medium-Term Notes, Series I due June 2019,

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- issued $250 million of 4.00% Secured Medium-Term Notes, Series I due June 2044,
- issued $250 million of 2.00% Secured Medium-Term Notes, Series J due August 2019,
- issued $250 million of 3.15% Secured Medium-Term Notes, Series J due August 2024,
- issued $250 million of 3.05% Secured Medium-Term Notes, Series J due November 2024,
- paid $250 million of 0.85% Secured Medium-Term Notes at maturity,
- paid $250 million of 5.00% Secured Medium-Term Notes at maturity,
- paid $225 million of Transition Funding's securitization debt,
- paid $12 million of Transition Funding II's securitization debt, and
- received $175 million capital contribution from PSEG.

Power

- paid cash dividends of $895 million to PSEG.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our $4.3 billion credit facilities are provided by a diverse bank group. As of December 31, 2014, our total available credit capacity was $4.1 billion.

As of December 31, 2014, no single institution represented more than 8% of the total commitments in our credit facilities.

As of December 31, 2014, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. In April 2014, PSEG and Power amended their 2012 credit agreements ending in 2017, extending the expiration date from March 2017 to April 2019. PSEG's $500 million and Power's $1.6 billion facility amendments, resulting in total commitments of $2.1 billion, will mature in 2019.

Our total credit facilities and available liquidity as of December 31, 2014 were as follows:

	As of December 31, 2014				
Company/Facility	**Total Facility**	**Usage**	**Available Liquidity**	**Expiration Date**	**Primary Purpose**
	Millions				
PSEG					
5-year Credit Facility	$ 500	$ 8	$ 492	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—	500	Mar 2018	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 8**	**$ 992**		
PSE&G					
5-year Credit Facility (B)	$ 600	$ 14	$ 586	Mar 2018	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 14**	**$ 586**		
Power					
5-year Credit Facility	$ 1,600	$ 97	$ 1,503	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (C)	1,000	—	1,000	Mar 2018	Funding/Letters of Credit
Bilateral Credit Facility	100	100	—	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 197**	**$ 2,503**		
Total	**$ 4,300**	**$ 219**	**$ 4,081**		

(A) In April 2016, this facility will be reduced by $23 million.

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(B) In April 2016, this facility will be reduced by $29 million.

(C) In April 2016, this facility will be reduced by $48 million.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of December 31, 2014 and 2013. See Note 16. Fair Value Measurements for more information on fair value guidance and the hierarchy that prioritizes the inputs to fair value measurements into three levels.

	December 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 14	$ 22	$ 24	$ 38
PSE&G (B)	6,312	6,912	5,566	5,629
Transition Funding (PSE&G) (B)	251	261	476	511
Transition Funding II (PSE&G) (B)	8	8	20	21
Power - Recourse Debt (B)	2,543	2,930	2,541	2,846
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	16	16	16	16
	$ 9,144	**$ 10,149**	**$ 8,643**	**$ 9,061**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

Note 14. Schedule of Consolidated Capital Stock

	As of December 31,			
	Outstanding Shares		Book Value	
	2014	2013	2014	2013
			Millions	
PSEG Common Stock (no par value) (A)				
Authorized 1,000,000,000 shares	505,836,592	505,857,262	$ 4,241	$ 4,246

(A) PSEG did not issue any new shares under the Dividend Reinvestment and Stock Purchase Plan (DRASPP) or the Employee Stock Purchase Plan (ESPP) in 2014 or 2013. Total authorized and unissued shares of common stock available for issuance through PSEG's DRASPP, ESPP and various employee benefit plans amounted to approximately 7 million shares as of December 31, 2014.

As of December 31, 2014, PSE&G had an aggregate of 7.5 million shares of $100 par value and 10 million shares of $25 par value Cumulative Preferred Stock, which were authorized and unissued and which, upon issuance, may or may not provide for mandatory sinking fund redemption.

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Note 15. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. Transactions receiving NPNS treatment are accounted for upon settlement. For a derivative instrument that qualifies and is designated as a cash flow hedge, the changes in the fair value of such a derivative that are highly effective are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. For a derivative instrument that qualifies and is designated as a fair value hedge, the gains or losses on the derivative as well as the offsetting losses or gains on the hedged item attributable to the hedged risk are recognized in earnings each period. Power and PSE&G enter into additional contracts that are derivatives, but do not qualify for or are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and changes in the fair value of these contracts are recorded in earnings each period.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

PSEG and Power use forward sale and purchase contracts, swaps and futures contracts to hedge certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

These derivative transactions qualify and are designated as cash flow hedges. During the second quarter of 2012, Power de-designated commodity derivative transactions related to the hedging of forecasted energy sales from its generation stations that had previously qualified as cash flow hedges as they were deemed to no longer be highly effective as required by the relevant accounting guidance. As a result, since June 1, 2012, Power recognizes all gains and losses from changes in the fair value of these derivatives immediately in earnings rather than deferring any such amounts in Accumulated Other Comprehensive Income (Loss). The fair values of Power's de-designated hedges were frozen in Accumulated Other Comprehensive Income (Loss) as the original forecasted transactions are still expected to occur and are reclassified into earnings as the original derivative transactions settle.

As of December 31, 2014 and 2013, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity was as follows:

	As of December 31,	
	2014	2013
	Millions	
Fair Value of Cash Flow Hedges	$ 18	$ (4)
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 10	$ (1)

The expiration date of the longest-dated cash flow hedge at Power is in December 2015. Power's after-tax unrealized gains on these derivatives that are expected to be reclassified to earnings during the next 12 months are $10 million. There was no ineffectiveness associated with qualifying hedges as of December 31, 2014.

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Economic Hedges

PSEG and Power enter into derivative contracts that do not qualify or are not designated as either cash flow or fair value hedges. Power enters into financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. These transactions are economic hedges, intended to mitigate exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization. Changes in the fair market value of these contracts are recorded in earnings.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of December 31, 2014, PSEG had interest rate swaps outstanding totaling $850 million. These swaps convert Power’s $300 million of 5.5% Senior Notes due December 2015, $300 million of Power’s $303 million of 5.32% Senior Notes due September 2016 and Power’s $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of December 31, 2014 and 2013, the fair value of all the underlying hedges was $22 million and $38 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was immaterial as of December 31, 2014 and 2013.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset on the Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31, 2014						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 18	$ 597	$ (408)	$ 207	$ 18	$ 15	$ 240
Noncurrent Assets	—	171	(109)	62	8	7	77
Total Mark-to-Market Derivative Assets	**$ 18**	**$ 768**	**$ (517)**	**$ 269**	**$ 26**	**$ 22**	**$ 317**
Derivative Contracts							
Current Liabilities	$ —	$ (568)	$ 436	$ (132)	$ —	$ —	$ (132)
Noncurrent Liabilities	—	(138)	105	(33)	—	—	(33)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (706)**	**$ 541**	**$ (165)**	**$ —**	**$ —**	**$ (165)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 18**	**$ 62**	**$ 24**	**$ 104**	**$ 26**	**$ 22**	**$ 152**

	As of December 31, 2013						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ —	$ 323	$ (266)	$ 57	$ 25	$ 16	$ 98
Noncurrent Assets	—	155	(83)	72	69	22	163
Total Mark-to-Market Derivative Assets	**$ —**	**$ 478**	**$ (349)**	**$ 129**	**$ 94**	**$ 38**	**$ 261**
Derivative Contracts							
Current Liabilities	$ (4)	$ (343)	$ 271	$ (76)	$ —	$ —	$ (76)
Noncurrent Liabilities	—	(111)	80	(31)	—	—	(31)
Total Mark-to-Market Derivative (Liabilities)	**$ (4)**	**$ (454)**	**$ 351**	**$ (107)**	**$ —**	**$ —**	**$ (107)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ (4)**	**$ 24**	**$ 2**	**$ 22**	**$ 94**	**$ 38**	**$ 154**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of December 31, 2014 and 2013. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Consolidated Balance Sheets. As of December 31, 2014 and 2013, net cash collateral paid of $24 million and $2 million, respectively, were netted against the corresponding net derivative

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contract positions. Of the $24 million as of December 31, 2014, $(4) million and $(8) million were netted against current assets and noncurrent assets, respectively, and $32 million and $4 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $2 million as of December 31, 2013, cash collateral of $(3) million and $5 million were netted against noncurrent assets and current liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $127 million and $91 million as of December 31, 2014 and 2013, respectively. As of December 31, 2014 and 2013, Power had the contractual right of offset of $18 million and $39 million, respectively, related to derivative instruments that are assets with the same counterparty under master agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $109 million and $52 million as of December 31, 2014 and 2013, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $945 million and $691 million as of December 31, 2014 and 2013, respectively, discussed in Note 12. Commitments and Contingent Liabilities.

The following shows the effect on the Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the years ended December 31, 2014, 2013 and 2012:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Years Ended December 31,			Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Years Ended December 31,			Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Years Ended December 31,		
	2014	2013	2012		2014	2013	2012	2014	2013	2012
	Millions				Millions					
PSEG										
Energy-Related Contracts	$ 12	$ (4)	$ 32	Operating Revenues	$ (9)	$ 13	$ 79	$ —	$ (1)	$ 1
Energy-Related Contracts	—	—	(4)	Energy Costs	—	—	(9)	—	—	—
Interest Rate Swaps (A)	—	—	—	Interest Expense	—	(1)	—	—	—	—
Total PSEG	**$ 12**	**$ (4)**	**$ 28**		**$ (9)**	**$ 12**	**$ 70**	**$ —**	**$ (1)**	**$ 1**
Power										
Energy-Related Contracts	$ 12	$ (4)	$ 32	Operating Revenues	$ (9)	$ 13	$ 79	$ —	$ (1)	$ 1
Energy-Related Contracts	—	—	(4)	Energy Costs	—	—	(9)	—	—	—
Total Power	**$ 12**	**$ (4)**	**$ 28**		**$ (9)**	**$ 13**	**$ 70**	**$ —**	**$ (1)**	**$ 1**

(A) Includes amounts for PSEG parent.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following reconciles the AOCI for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis:

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2012	**$ 12**	**$ 7**
Loss Recognized in AOCI	(4)	(2)
Less: Gain Reclassified into Income	(12)	(7)
Balance as of December 31, 2013	**$ (4)**	**$ (2)**
Gain Recognized in AOCI	12	7
Plus: Loss Reclassified into Income	9	5
Balance as of December 31, 2014	**$ 17**	**$ 10**

The following shows the effect on the Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the years ended December 31, 2014, 2013 and 2012:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2014	2013	2012
		Millions		
PSEG and Power				
Energy-Related Contracts	Operating Revenues	$ (348)	$ (128)	$ 232
Energy-Related Contracts	Energy Costs	32	106	(19)
Total PSEG and Power		**$ (316)**	**$ (22)**	**$ 213**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $20 million, $19 million and $22 million for the years ended December 31, 2014, 2013 and 2012, respectively.

The following reflects the gross volume, on an absolute value basis, of derivatives as of December 31, 2014 and 2013:

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of December 31, 2014					
Natural Gas	Dth	274	—	216	58
Electricity	MWh	310	—	310	—
Financial Transmission Rights (FTRs)	MWh	15	—	15	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2013					
Natural Gas	Dth	614	—	466	148
Electricity	MWh	243	—	243	—
FTRs	MWh	16	—	16	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of December 31, 2014, 99.7% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of December 31, 2014. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 436	$ 51	$ 425	2	$ 259	(A)
Non-Investment Grade—External Rating	2	—	1	—	—	
Investment Grade—No External Rating	6	—	6	—	—	
Non-Investment Grade—No External Rating	—	—	—	—	—	
Total	**$ 444**	**$ 51**	**$ 432**	**2**	**$ 259**	

(A) Includes net exposure of $206 million with PSE&G. The remaining net exposure of $53 million is with a nonaffiliated power purchaser which is a regulated investment grade counterparty.

The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of December 31, 2014, Power had 148 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2014, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's suppliers' credit exposure is calculated each business day. As of December 31, 2014, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 16. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of December 31, 2014, these consisted primarily of electric load contracts whose basis is deemed significant to the fair value measurement and long-term gas supply contracts.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of December 31, 2014 and December 31, 2013, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Description	Recurring Fair Value Measurements as of December 31, 2014				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 295	$ (517)	$ —	$ 774	$ 38
Interest Rate Swaps (C)	$ 22	$ —	$ —	$ 22	$ —
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 896	$ 1	$ —
Debt Securities—Govt Obligations	$ 438	$ —	$ —	$ 438	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 106	$ —	$ 106	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—Govt Obligations	$ 91	$ —	$ —	$ 91	$ —
Debt Securities—Other	$ 75	$ —	$ —	$ 75	$ —
Other Securities	$ 2	$ —	$ —	$ 2	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (165)	$ 541	$ —	$ (705)	$ (1)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 294	$ —	$ 294	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ 26	$ —	$ —	$ —	$ 26
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 20	$ —	$ —	$ 20	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 269	$ (517)	$ —	$ 774	$ 12
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 896	$ 1	$ —
Debt Securities—Govt Obligations	$ 438	$ —	$ —	$ 438	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 106	$ —	$ 106	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (165)	$ 541	$ —	$ (705)	$ (1)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Description	Recurring Fair Value Measurements as of December 31, 2013				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 439	$ —	$ 439	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 223	$ (349)	$ —	$ 474	$ 98
Interest Rate Swaps (C)	$ 38	$ —	$ —	$ 38	$ —
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 892	$ 5	$ —
Debt Securities—Govt Obligations	$ 429	$ —	$ —	$ 429	$ —
Debt Securities—Other	$ 291	$ —	$ —	$ 291	$ —
Other Securities	$ 84	$ —	$ 57	$ 27	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—Govt Obligations	$ 107	$ —	$ —	$ 107	$ —
Debt Securities—Other	$ 46	$ —	$ —	$ 46	$ —
Other Securities	$ 3	$ —	$ —	$ 3	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (107)	$ 351	$ —	$ (448)	$ (10)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (B)	$ 94	$ —	$ —	$ —	$ 94
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 25	$ —	$ —	$ 25	$ —
Debt Securities—Other	$ 11	$ —	$ —	$ 11	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 129	$ (349)	$ —	$ 474	$ 4
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 892	$ 5	$ —
Debt Securities—Govt Obligations	$ 429	$ —	$ —	$ 429	$ —
Debt Securities—Other	$ 291	$ —	$ —	$ 291	$ —
Other Securities	$ 84	$ —	$ 57	$ 27	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 10	$ —	$ —	$ 10	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (107)	$ 351	$ —	$ (448)	$ (10)

(A) Represents money market mutual funds

(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also

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corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds and United States Treasury obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Consolidated Balance Sheet. As of December 31, 2014, net cash collateral (received) paid of $24 million was netted against the corresponding net derivative contract positions. Of the $24 million of cash collateral as of December 31, 2014, $(12) million was netted against assets, and $36 million was netted against liabilities. As of December 31, 2013, net cash collateral (received) paid of $2 million was netted against the corresponding net derivative contract positions. Of the $2 million of cash collateral as of December 31, 2013, $(3) million was netted against assets and $5 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G and Power, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. For Power, in general, electric swaps are measured at fair value based on at least two pricing inputs, the underlying price of electricity at a liquid reference point and the basis difference between electricity prices at the liquid reference point and electricity prices at the respective delivery locations. To

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the extent the basis component is based on a single broker quote and is significant to the fair value of the electric swap, it is categorized as Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. For additional information see Note 12. Commitments and Contingent Liabilities. The following tables provide detail surrounding significant Level 3 valuations as of December 31, 2014 and 2013.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2014		Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)			
		Millions				
PSE&G						
Gas	Forward Contracts	$ 26	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 26**	**$ —**			
Power						
Electricity	Electric Load Contracts	$ 12	$ (1)	Discounted Cash flow	Historic Load Variability	0% to +10%
Other	Various (A)	—	—			
Total Power		**$ 12**	**$ (1)**			
Total PSEG		**$ 38**	**$ (1)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2013		Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)			
		Millions				
PSE&G						
Gas	Forward Contracts	$ 94	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 94**	**$ —**			
Power						
Electricity	Electric Swaps	$ 3	$ (1)	Discounted Cash Flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	—	(8)	Discounted Cash Flow	Historic Load Variability	-5% to +10%
Other	Various (B)	1	(1)			
Total Power		**$ 4**	**$ (10)**			
Total PSEG		**$ 98**	**$ (10)**			

(A) Includes gas supply positions and long-term electric capacity positions which were immaterial as of December 31, 2014.

(B) Includes gas supply positions which were immaterial as of December 31, 2013.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value. For energy-related contracts in cases where Power is a seller, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the years ended December 31, 2014 and 2013, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2014

Description	Balance as of January 1, 2014	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances (Settlements) (C)	Transfers In (Out) (D)	Balance as of December 31, 2014
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 88	$ (31)	$ (68)	$ —	$ 51	$ (3)	$ 37
PSE&G							
Net Derivative Assets (Liabilities)	$ 94	$ —	$ (68)	$ —	$ —	$ —	$ 26
Power							
Net Derivative Assets (Liabilities)	$ (6)	$ (31)	$ —	$ —	$ 51	$ (3)	$ 11

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2013

Description	Balance as of January 1, 2013	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances (Settlements) (C)	Transfers In (Out) (D)	Balance as of December 31, 2013
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (31)	$ (27)	$ 134	$ —	$ 8	$ 4	$ 88
PSE&G							
Net Derivative Assets (Liabilities)	$ (40)	$ —	$ 134	$ —	$ —	$ —	$ 94
Power							
Net Derivative Assets (Liabilities)	$ 9	$ (27)	$ —	$ —	$ 8	$ 4	$ (6)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $(31) million and $(27) million in Operating Income in 2014 and 2013, respectively. Of the $(31) million in Operating Income in 2014, $22 million is unrealized. Of the $(27) million in Operating Income in 2013, $(19) million is unrealized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income (Loss), as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

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(C) Represents $51 million and $8 million in settlements for derivative contracts in 2014 and 2013, respectively.

(D) During the years ended December 31, 2014 and 2013, $(3) million and $4 million, respectively, of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. The transfers were recognized as of the beginning of the quarters (i.e. the quarter in which the transfers occurred), as per PSEG's policy.

As of December 31, 2014, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $37 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of December 31, 2013, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $88 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Non-recurring Fair Value Measurements

During the fourth quarter of 2014, an assessment of recoverability was triggered for two commercial real estate properties located in Ohio and Michigan. As a result of the evaluation, Energy Holdings recorded a pre-tax impairment of $14 million which is included in Operating Revenues in PSEG's Consolidated Statement of Operations for the year ended December 31, 2014. The remaining investment in these properties of $9 million is carried as a nonrecurring fair value measurement determined using an income approach valuation technique (cash flow analyses) along with bids received as part of a marketing initiative. This technique relied on significant unobservable inputs and is considered a Level 3 measurement within the fair value hierarchy.

Note 17. Stock Based Compensation

PSEG's Amended and Restated 2004 Long-Term Incentive Plan (LTIP) is a broad-based equity compensation program that provides for grants of various long-term incentive compensation awards, such as stock options, stock appreciation rights, performance share units, restricted stock, restricted stock units, cash awards or any combination thereof. The types of long-term incentive awards that have been granted and remain outstanding under the LTIP are non-qualified options to purchase shares of PSEG's common stock, restricted stock awards, restricted stock unit awards and performance share unit awards. The type of equity award that is granted and the details of that award may vary from time to time and is subject to the approval of the Organization and Compensation Committee of PSEG's Board of Directors (OCC), the plan's administrative committee.

The LTIP currently provides for the issuance of equity awards with respect to approximately 16 million shares of common stock. As of December 31, 2014, there were approximately 16 million shares available for future awards under the LTIP.

Stock Options

Under the LTIP, non-qualified options to acquire shares of PSEG common stock may be granted to officers and other key employees selected by the OCC. Option awards are granted with an exercise price equal to the market price of PSEG's common stock at the grant date. The options generally vest over four years of continuous service. Vesting schedules may be accelerated upon the occurrence of certain events, such as a change-in-control (unless substituted with an equity award of equal value), retirement, death or disability. Options are exercisable over a period of time designated by the OCC (but not prior to one year or longer than ten years from the date of grant) and are subject to such other terms and conditions as the OCC determines. Payment by option holders upon exercise of an option may be made in cash or, with the consent of the OCC, by delivering previously acquired shares of PSEG common stock.

Restricted Stock

Under the LTIP, PSEG has granted restricted stock awards to officers and other key employees. These shares are subject to risk of forfeiture until vested by continued employment. Restricted stock generally vests annually over three or four years, but is considered outstanding at the time of grant, as the recipients are entitled to dividends and voting rights. Vesting may be accelerated upon certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

Restricted Stock Units

Under the LTIP, PSEG has granted restricted stock unit awards to officers and other key employees. These awards, which are bookkeeping entries only, are subject to risk of forfeiture until vested by continued employment. Until vested, the units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. The restricted stock unit grants for 2014 and 2013 generally vest at the end of three years. Vesting may be accelerated upon certain events such as change-in-control or death. Prior to 2011, restricted stock unit grants generally vested over four years.

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Performance Share Units

Under the LTIP, PSEG has granted performance share units to officers and other key employees. These provide for payment in shares of PSEG common stock based on achievement of certain financial goals over a three-year performance period. The payout varies from 0% to 200% of the number of performance units granted depending on PSEG's performance with respect to certain financial targets, including targets related to comparative performance against other companies in a peer group of energy companies. The performance share units are credited with dividend equivalents in an amount equal to dividends paid on PSEG common stock up until the shares are distributed. Vesting may be pro-rated for the employee's service during the performance period as a result of certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

Stock-Based Compensation

All outstanding unvested stock options are being expensed based on their grant date fair values, which were determined using the Black-Scholes option-pricing model. Stock option awards are expensed on a tranche-specific basis over the requisite service period of the award. Ultimately, compensation expense for stock options is recognized for awards that vest.

PSEG recognizes compensation expense for restricted stock and restricted stock units over the vesting period based on the grant date fair value of the shares, which is equal to the market price of PSEG's common stock on the date of the grant.
PSEG recognizes compensation expense for the total shareholder return target for its performance share unit awards based on the grant date fair values of the award, which are determined using the Monte Carlo model. The accrual of compensation cost is based on the probable achievement of the performance conditions, which result in a payout from 0% to 200% of the initial grant. PSEG recognizes compensation expense for the return on invested capital target for its performance share units based on the grant date fair value of the awards, which is equal to the market price of PSEG's common stock on the date of the grant. The accrual during the year of grant is estimated at 100% of the original grant. Such accrual may be adjusted to reflect the actual outcome.

	2014	2013	2012
		Millions	
Compensation Cost included in Operation and Maintenance Expense	$ 32	$ 32	$ 25
Income Tax Benefit Recognized in Consolidated Statement of Operations	$ 13	$ 13	$ 10

There was no excess tax benefit for 2014 and 2013. There was less than $1 million of excess tax benefits for 2012.

PSEG recognizes compensation cost of awards issued over the shorter of the original vesting period or the period beginning on the date of grant and ending on the date an individual is eligible for retirement and the award vests.

Stock Options

Changes in stock options for 2014 are summarized as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding as of January 1, 2014	2,615,166	$ 34.43		
Exercised	519,250	$ 30.51		
Canceled/Forfeited	20,066	$ 39.88		
Outstanding as of December 31, 2014	**2,075,850**	**$ 35.35**	**3.8**	**$ 15,016,886**
Exercisable at December 31, 2014	2,075,850	$ 35.35	3.8	$ 15,016,886

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. There were no option grants in 2014, 2013 and 2012.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Activity for options exercised for the years ended December 31, 2014, 2013 and 2012 is shown below:

	2014	2013	2012
		Millions	
Total Intrinsic Value of Options Exercised	$ 4	$ 1	$ 4
Cash Received from Options Exercised	$ 16	$ 7	$ 7
Tax Benefit Realized from Options Exercised	$ —	$ —	$ 1

No options were vested during the year ended December 31, 2014. Less than one million options vested during each of the years ended December 31, 2013 and 2012. The total fair value of the stock options vested during the years ended December 31, 2013 and 2012 was $1 million and $3 million, respectively.

Restricted Stock

Changes in restricted stock for the year ended December 31, 2014 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2014	8,800	$ 30.18		
Vested	8,800	$ 30.18		
Non-vested as of December 31, 2014	**—**	**$ —**	**0**	**$ —**

There were no restricted stock awards granted in 2014, 2013 and 2012.

The total intrinsic value of restricted stock vested during the years ended December 31, 2014, 2013 and 2012 was $2 million, $2 million and $1 million, respectively.

Restricted Stock Units

Changes in restricted stock units for the year ended December 31, 2014 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2014	1,047,569	$ 31.30		
Granted	356,240	$ 35.16		
Vested	325,504	$ 31.57		
Canceled/Forfeited	9,276	$ 33.95		
Non-vested as of December 31, 2014	**1,069,029**	**$ 32.49**	**1.1**	**$ 44,268,491**

The weighted average grant date fair value per share for restricted stock during the years ended December 31, 2014, 2013 and 2012 was $35.16, $31.41 and $30.95 per share, respectively.

The total intrinsic value of restricted stock units vested during the years ended December 31, 2014, 2013 and 2012 was $12 million, $4 million and $5 million, respectively.

As of December 31, 2014, there was approximately $5 million of unrecognized compensation cost related to the restricted stock units, which is expected to be recognized over a weighted average period of one year. Dividend equivalents units of 42,648 accrued on the restricted stock units during the year.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Performance Share Units

Changes in performance share units for the year ended December 31, 2014 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2014	802,118	$ 33.25		
Granted	358,265	$ 38.94		
Vested	382,504	$ 31.25		
Canceled/Forfeited	12,246	$ 36.45		
Non-vested as of December 31, 2014	**765,633**	**$ 36.86**	**1.5**	**$ 31,704,863**

The weighted average grant date fair value per share for performance share units during the years ended December 31, 2014, 2013 and 2012 was $38.94, $35.07 and $31.25 per share, respectively.

The total intrinsic value of performance share units vested during the year ended December 31, 2014, 2013 and 2012 was $6 million, $5 million and $4 million, respectively.

As of December 31, 2014, there was approximately $14 million of unrecognized compensation cost related to the performance share units, which is expected to be recognized over a weighted average period of one year. Dividend equivalents units of 45,779 accrued on the performance share units during the year.

Outside Directors

Under the Directors Equity Plan, annually, on the first business day of May, each non-employee member of the Board of Directors is awarded stock units based on amount of annual compensation to be paid at the closing price of PSEG common stock on that date. Dividend equivalents are credited quarterly and distributions will commence upon the director leaving the Board as specified by him/her in accordance with the provisions of the plan.

The fair value of these awards is recorded as compensation expense in the Consolidated Statements of Operations. Compensation expense for the plan for each of the years ended December 31, 2014, 2013 and 2012 was approximately $1 million.

Employee Stock Purchase Plan (ESPP)

PSEG maintains an ESPP for all eligible employees of PSEG and its subsidiaries. Under the ESPP, shares of PSEG common stock may be purchased at 95% of the fair market value for represented employees and 90% for non-represented employees through payroll deductions. Dividends will be reinvested for all employees at 95% of the fair market price unless the participant elects to receive a cash dividend. All employees are required to hold the shares purchased under the ESPP for at least three months from the purchase date. In any year, employees may purchase shares having a value not exceeding 10% of their base pay.

During the years ended December 31, 2014, 2013 and 2012, employees purchased 207,248 shares, 257,513 shares and 191,572 shares at an average price of $36.07, $30.57 and $31.32 per share, respectively. As of December 31, 2014, 3.6 million shares were available for future issuance under this plan.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 18. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated Total
Year Ended December 31, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 219	$ —	$ 219
Allowance for Funds Used During Construction	31	—	—	31
Solar Loan Interest	24	—	—	24
Other	6	3	7	16
Total Other Income	**$ 61**	**$ 222**	**$ 7**	**$ 290**
Year Ended December 31, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 152	$ —	$ 152
Allowance for Funds Used During Construction	24	—	—	24
Solar Loan Interest	23	—	—	23
Other	7	2	5	14
Total Other Income	**$ 54**	**$ 154**	**$ 5**	**$ 213**
Year Ended December 31, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 194	$ —	$ 194
Allowance for Funds Used During Construction	23	—	—	23
Solar Loan Interest	18	—	—	18
Other	11	7	7	25
Total Other Income	**$ 52**	**$ 201**	**$ 7**	**$ 260**

Other Deductions	PSE&G	Power	Other (A)	Consolidated Total
Year Ended December 31, 2014				
NDT Fund Realized Losses and Expense	$ —	$ 31	$ —	$ 31
Other	3	21	6	30
Total Other Deductions	**$ 3**	**$ 52**	**$ 6**	**$ 61**
Year Ended December 31, 2013				
NDT Fund Realized Losses and Expense	$ —	$ 34	$ —	$ 34
Other	3	15	2	20
Total Other Deductions	**$ 3**	**$ 49**	**$ 2**	**$ 54**
Year Ended December 31, 2012				
NDT Fund Realized Losses and Expense	$ —	$ 58	$ —	$ 58
Loss on Early Extinguishment of Debt	—	15	—	15
Other	5	17	3	25
Total Other Deductions	**$ 5**	**$ 90**	**$ 3**	**$ 98**

(A) Other primarily consists of activity at PSEG (as parent company), Energy Holdings, Services and intercompany eliminations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 19. Income Taxes

A reconciliation of reported income tax expense for PSEG with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSEG	Years Ended December 31, 2014	2013	2012
		Millions	
Net Income	$ 1,518	$ 1,243	$ 1,275
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 335	$ 487	$ (204)
State	58	42	(2)
Total Current	393	529	(206)
Deferred Expense:			
Federal	262	147	758
State	260	118	125
Total Deferred	522	265	883
Investment Tax Credit (ITC)	23	18	59
Total Income Taxes	**$ 938**	**$ 812**	**$ 736**
Pre-Tax Income	$ 2,456	$ 2,055	$ 2,011
Tax Computed at Statutory Rate @ 35%	$ 860	$ 719	$ 704
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	145	108	115
Uncertain Tax Positions	(9)	10	4
Manufacturing Deduction	(16)	(9)	—
NDT Fund	14	12	10
Plant-Related Items	(13)	(14)	(5)
Tax Credits	(14)	(9)	(10)
Audit Settlement	(12)	—	(71)
Other	(17)	(5)	(11)
Sub-Total	78	93	32
Total Income Tax Provision	**$ 938**	**$ 812**	**$ 736**
Effective Income Tax Rate	38.2%	39.5%	36.6%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for PSEG:

PSEG	As of December 31, 2014	2013
	Millions	
Deferred Income Taxes		
Assets:		
Current (net)	$ 11	$ 24
Noncurrent		
OPEB	$ 269	$ 280
Related to Uncertain Tax Position	160	201
Securitization-Overcollection	55	—
Accumulated Other Comprehensive Income (Loss)	—	3
Other	—	124
Total Noncurrent Assets	$ 484	$ 608
Total Assets	$ 495	$ 632
Liabilities:		
Current (net)		
Securitization	$ 163	$ —
Other	$ 10	$ —
Total Current Liabilities (net)	$ 173	$ —
Noncurrent:		
Plant-Related Items	$ 5,422	$ 4,865
New Jersey Corporate Business Tax	535	534
Securitization	—	279
Leasing Activities	623	639
Pension Costs	219	288
AROs and NDT Fund	419	523
Taxes Recoverable Through Future Rate (net)	196	181
Other	240	293
Total Noncurrent Liabilities	$ 7,654	$ 7,602
Total Liabilities	$ 7,827	$ 7,602
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	**$ 11**	**$ 24**
Net Current Deferred Income Tax Liabilities	**$ 173**	**$ —**
Net Noncurrent Deferred Income Tax Liabilities	$ 7,170	$ 6,994
ITC	133	113
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 7,303**	**$ 7,107**

The deferred tax effect of certain assets and liabilities are presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals. Also, the deferred tax effect of AROs are presented net of the deferred tax effect of the associated funding of those obligations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for PSE&G with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSE&G	Years Ended December 31, 2014	2013	2012
		Millions	
Net Income	$ 725	$ 612	$ 528
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 124	$ 183	$ (217)
State	16	—	9
Total Current	140	183	(208)
Deferred Expense:			
Federal	214	101	409
State	84	92	83
Total Deferred	298	193	492
ITC	11	5	23
Total Income Taxes	**$ 449**	**$ 381**	**$ 307**
Pre-Tax Income	$ 1,174	$ 993	$ 835
Tax Computed at Statutory Rate @ 35%	$ 411	$ 348	$ 292
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	65	59	52
Uncertain Tax Positions	—	—	7
Plant-Related Items	(13)	(14)	(4)
Tax Credits	(7)	(6)	(3)
Audit Settlement	1	—	(31)
Other	(8)	(6)	(6)
Sub-Total	38	33	15
Total Income Tax Provision	**$ 449**	**$ 381**	**$ 307**
Effective Income Tax Rate	38.2%	38.4%	36.8%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for PSE&G:

PSE&G	As of December 31, 2014	2013
	Millions	
Deferred Income Taxes		
Assets:		
Current (net)	$ 24	$ 16
Noncurrent:		
OPEB	$ 173	$ 182
Securitization-Overcollection	55	—
Total Noncurrent Assets	$ 228	$ 182
Total Assets	$ 252	$ 198
Liabilities:		
Current (net)		
Securitization	$ 163	$ —
Other	2	30
Total Current Liabilities (net)	$ 165	$ 30
Noncurrent:		
Plant-Related Items	$ 3,869	$ 3,439
New Jersey Corporate Business Tax	268	340
Securitization	—	279
Conservation Costs	48	52
Pension Costs	269	171
Taxes Recoverable Through Future Rate (net)	196	181
Other	84	68
Total Noncurrent Liabilities	$ 4,734	$ 4,530
Total Liabilities	$ 4,899	$ 4,560
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	**$ 24**	**$ 16**
Net Current Deferred Income Tax Liabilities	**$ 165**	**$ 30**
Net Noncurrent Deferred Income Tax Liabilities	$ 4,506	$ 4,348
ITC	69	58
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 4,575**	**$ 4,406**

The deferred tax effect of certain assets and liabilities are presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for Power with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

Power	Years Ended December 31, 2014	2013	2012
		Millions	
Net Income	$ 760	$ 644	$ 666
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 231	$ 262	$ 30
State	39	40	51
Total Current	270	302	81
Deferred Expense:			
Federal	163	69	279
State	48	35	37
Total Deferred	211	104	316
ITC	10	13	36
Total Income Taxes	**$ 491**	**$ 419**	**$ 433**
Pre-Tax Income	$ 1,251	$ 1,063	$ 1,099
Tax Computed at Statutory Rate @ 35%	$ 438	$ 372	$ 385
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	58	51	55
Manufacturing Deduction	(16)	(10)	—
NDT Fund	15	12	10
Tax Credits	(6)	(2)	(7)
Uncertain Tax Positions	(8)	3	(6)
Audit Settlement	(4)	—	(1)
Other	14	(7)	(3)
Sub-Total	53	47	48
Total Income Tax Provision	**$ 491**	**$ 419**	**$ 433**
Effective Income Tax Rate	39.2%	39.4%	39.4%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for Power:

Power	As of December 31, 2014	2013
	Millions	
Deferred Income Taxes		
Assets:		
Current	$ —	$ 30
Noncurrent:		
Pension Costs	$ 52	$ —
Contractual Liabilities & Environmental Costs	18	35
Related to Uncertain Tax Positions	23	32
Other	70	91
Total Noncurrent Assets	$ 163	$ 158
Total Assets	$ 163	$ 188
Liabilities:		
Current (net)	$ 43	$ —
Noncurrent:		
Plant-Related Items	$ 1,552	$ 1,416
New Jersey Corporate Business Tax	192	81
Pension Costs	—	77
AROs and NDT Fund	420	523
Accumulated Other Comprehensive Income (Loss)	—	2
Other	—	36
Total Noncurrent Liabilities	$ 2,164	$ 2,135
Total Liabilities	$ 2,207	$ 2,135
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	**$ —**	**$ 30**
Net Current Deferred Income Tax Liabilities	**$ 43**	**$ —**
Net Noncurrent Deferred Income Tax Liabilities	$ 2,001	$ 1,977
ITC	64	54
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 2,065**	**$ 2,031**

In the above table, the deferred tax effect of asset retirement obligations are presented net of the deferred tax effect of the associated funding of those obligations.

As of December 31, 2014, PSEG had a federal net operating loss (NOL) carryforward of $243 million. The loss was generated in 2012 and will expire in 2033. PSEG believes that it is more-likely-than-not that the federal benefit from the NOL will be realized.

PSEG, PSE&G and Power each provide deferred taxes at the enacted statutory tax rate for all temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities irrespective of the treatment for rate-making purposes. Management believes that it is probable that the accumulated tax benefits that previously have been treated as a flow-through item to PSE&G customers will be recovered from or refunded to PSE&G's customers in the future. These amounts were determined using the enacted federal income tax rate of 35% and state income tax rate of 9%. For additional information, see Note 5. Regulatory Assets and Liabilities.

On August 11, 2014, PSEG received notice from the IRS that the audit settlement covering tax years 2007 through 2010 had been approved by the Joint Committee on Taxation. This effectively settles all issues with the IRS through 2010. On September 9, 2014, PSEG received refunds from the IRS totaling $121 million, representing the net settlement of all disputed amounts, including interest, through the tax year 2010. As a result of the settlement of this audit, PSEG recorded a $12 million reduction of tax expense in the quarter ended September 30, 2014.

In September 2013, the U.S. Department of the Treasury and the IRS released final regulations effective in 2014 that provide guidance on applying Section 263(a) of the Internal Revenue Code to amounts paid to acquire, produce or improve tangible

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property, as well as rules for materials and supplies. Implementation of these regulations did not have any material impact on PSEG's and its subsidiaries' results of operations, financial condition or cash flows.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 was eligible for 50% bonus depreciation for tax purposes. The American Taxpayer Relief Act of 2012 extended the 50% bonus depreciation rules for qualified property placed into service before January 1, 2014. In addition, long production property placed into service in 2014 is eligible for 50% bonus depreciation for tax purposes. On December 19, 2014, the Tax Increase Prevention Act of 2014 was enacted. This act further extended the 50% bonus depreciation rules for qualified property that was placed into service before January 1, 2015 and for long production property that is to be placed into service in 2015. These provisions have generated cash for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period.

PSEG recorded the following amounts related to its unrecognized tax benefits, which were primarily comprised of amounts recorded for PSE&G, Power and Energy Holdings:

2014	PSEG	PSE&G	Power	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2014	$ 478	$ 208	$ 156	$ 110
Increases as a Result of Positions Taken in a Prior Period	82	65	17	—
Decreases as a Result of Positions Taken in a Prior Period	(190)	(92)	(80)	(18)
Increases as a Result of Positions Taken during the Current Period	30	16	9	5
Decreases as a Result of Positions Taken during the Current Period	(8)	—	(8)	—
Decreases as a Result of Settlements with Taxing Authorities	(60)	(32)	(24)	(2)
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2014	$ 332	$ 165	$ 70	$ 95
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(225)	(138)	(52)	(35)
Regulatory Asset—Unrecognized Tax Benefits	(27)	(27)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 80**	**$ —**	**$ 18**	**$ 60**

2013	PSEG	PSE&G	Power	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2013	$ 402	$ 163	$ 134	$ 101
Increases as a Result of Positions Taken in a Prior Period	83	39	33	11
Decreases as a Result of Positions Taken in a Prior Period	(30)	(9)	(19)	(2)
Increases as a Result of Positions Taken during the Current Period	23	15	8	—
Decreases as a Result of Positions Taken during the Current Period	—	—	—	—
Decreases as a Result of Settlements with Taxing Authorities	—	—	—	—
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2013	$ 478	$ 208	$ 156	$ 110
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(320)	(177)	(105)	(37)
Regulatory Asset—Unrecognized Tax Benefits	(30)	(30)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 128**	**$ 1**	**$ 51**	**$ 73**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2012	PSEG	PSE&G	Power	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2012	$ 825	$ 113	$ 121	$ 555
Increases as a Result of Positions Taken in a Prior Period	92	55	27	9
Decreases as a Result of Positions Taken in a Prior Period	(173)	(47)	(7)	(119)
Increases as a Result of Positions Taken during the Current Period	47	42	3	—
Decreases as a Result of Positions Taken during the Current Period	—	—	—	—
Decreases as a Result of Settlements with Taxing Authorities	(389)	—	(10)	(344)
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2012	$ 402	$ 163	$ 134	$ 101
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(264)	(133)	(93)	(35)
Regulatory Asset—Unrecognized Tax Benefits	(30)	(30)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 108**	**$ —**	**$ 41**	**$ 66**

PSEG and its subsidiaries include accrued interest and penalties related to uncertain tax positions required to be recorded, as Income Tax Expense in the Consolidated Statements of Operations. Accumulated interest and penalties that are recorded on the Consolidated Balance Sheets on uncertain tax positions were as follows:

	Interest and Penalties on Uncertain Tax Positions Years Ended December 31,		
	2014	2013	2012
		Millions	
PSE&G	$ 15	$ 6	$ 1
Power	9	(2)	(2)
Energy Holdings	45	44	39
Total	**$ 69**	**$ 48**	**$ 38**

It is reasonably possible that total unrecognized tax benefits will decrease within the next twelve months due to either agreements with various taxing authorities upon audit or the expiration of the Statute of Limitations. These potential decreases are as follows:

Possible Decrease in Total Unrecognized Tax Benefits including Interest	Over the next 12 Months
	Millions
PSEG	$ 59
PSE&G	$ 2
Power	$ 23

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A description of income tax years that remain subject to examination by material jurisdictions, where an examination has not already concluded are:

	PSEG	PSE&G	Power
United States			
Federal	2011-2013	N/A	N/A
New Jersey	2006-2013	2006-2013	N/A
Pennsylvania	2001-2013	2000-2013	N/A
Connecticut	2002-2013	N/A	N/A
Texas	2007-2013	N/A	N/A
California	2003-2013	N/A	N/A
New York	2009-2013	N/A	2009-2013

Note 20. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss)			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 7	$ (485)	$ 90	$ (388)
Other Comprehensive Income before Reclassifications	(2)	210	91	299
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(7)	37	(36)	(6)
Net Current Period Other Comprehensive Income (Loss)	(9)	247	55	293
Balance as of December 31, 2013	**$ (2)**	**$ (238)**	**$ 145**	**$ (95)**
Other Comprehensive Income before Reclassifications	7	(184)	42	(135)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	5	11	(69)	(53)
Net Current Period Other Comprehensive Income (Loss)	12	(173)	(27)	(188)
Balance as of December 31, 2014	**$ 10**	**$ (411)**	**$ 118**	**$ (283)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss)			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 9	$ (422)	$ 85	$ (328)
Other Comprehensive Income before Reclassifications	(2)	185	93	276
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(8)	33	(36)	(11)
Net Current Period Other Comprehensive Income (Loss)	(10)	218	57	265
Balance as of December 31, 2013	**$ (1)**	**$ (204)**	**$ 142**	**$ (63)**
Other Comprehensive Income before Reclassifications	7	(156)	39	(110)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	5	9	(69)	(55)
Net Current Period Other Comprehensive Income (Loss)	12	(147)	(30)	(165)
Balance as of December 31, 2014	**$ 11**	**$ (351)**	**$ 112**	**$ (228)**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 13	$ (5)	$ 8
Interest Rate Swaps	Interest Expense	(1)	—	(1)
Total Cash Flow Hedges		12	(5)	7
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	11	(4)	7
Amortization of Actuarial Loss	O&M Expense	(75)	31	(44)
Total Pension and OPEB Plans		(64)	27	(37)
Available-for-Sale Securities				
Realized Gains	Other Income	116	(59)	57
Realized Losses	Other Deductions	(29)	14	(15)
Other-Than-Temporary Impairments (OTTI)	OTTI	(12)	6	(6)
Total Available-for-Sale Securities		75	(39)	36
Total		**$ 23**	**$ (17)**	**$ 6**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ (9)	$ 4	$ (5)
Total Cash Flow Hedges		(9)	4	(5)
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	10	(4)	6
Amortization of Actuarial Loss	O&M Expense	(28)	11	(17)
Total Pension and OPEB Plans		(18)	7	(11)
Available-for-Sale Securities				
Realized Gains	Other Income	181	(89)	92
Realized Losses	Other Deductions	(26)	13	(13)
OTTI	OTTI	(20)	10	(10)
Total Available-for-Sale Securities		135	(66)	69
Total		**$ 108**	**$ (55)**	**$ 53**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 13	$ (5)	$ 8
Total Cash Flow Hedges		13	(5)	8
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	9	(4)	5
Amortization of Actuarial Loss	O&M Expense	(64)	26	(38)
Total Pension and OPEB Plans		(55)	22	(33)
Available-for-Sale Securities				
Realized Gains	Other Income	112	(57)	55
Realized Losses	Other Deductions	(26)	13	(13)
OTTI	OTTI	(12)	6	(6)
Total Available-for-Sale Securities		74	(38)	36
Total		**$ 32**	**$ (21)**	**$ 11**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ (9)	$ 4	$ (5)
Total Cash Flow Hedges		(9)	4	(5)
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	9	(4)	5
Amortization of Actuarial Loss	O&M Expense	(25)	11	(14)
Total Pension and OPEB Plans		(16)	7	(9)
Available-for-Sale Securities				
Realized Gains	Other Income	178	(87)	91
Realized Losses	Other Deductions	(24)	12	(12)
OTTI	OTTI	(20)	10	(10)
Total Available-for-Sale Securities		134	(65)	69
Total		**$ 109**	**$ (54)**	**$ 55**

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Note 21. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Years Ended December 31,					
	2014		2013		2012	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator:						
(Millions)						
Net Income	**$ 1,518**	**$ 1,518**	**$ 1,243**	**$ 1,243**	**$ 1,275**	**$ 1,275**
EPS Denominator:						
(Millions)						
Weighted Average Common Shares Outstanding	506	506	506	506	506	506
Effect of Stock Based Compensation Awards	—	2	—	2	—	1
Total Shares	**506**	**508**	**506**	**508**	**506**	**507**
EPS:						
Net Income	**$ 3.00**	**$ 2.99**	**$ 2.46**	**$ 2.45**	**$ 2.52**	**$ 2.51**

There were approximately 0.4 million, 1.6 million and 1.8 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the years ended December 31, 2014, 2013 and 2012, respectively. No other stock options had an antidilutive effect for the years ended December 31, 2014, 2013 or 2012.

Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	**2014**	**2013**	**2012**
Per Share	$ 1.48	$ 1.44	$ 1.42
in Millions	$ 748	$ 728	$ 718

On February 17, 2015, PSEG's Board of Directors approved a $0.39 per share common stock dividend for the first quarter of 2015.

Note 22. Financial Information by Business Segment

Basis of Organization

PSEG's operating segments are PSE&G and Power. The operating segments were determined by management in accordance with GAAP. These segments were determined based on how management measures performance based on segment Net Income, as illustrated in the following table, and how it allocates resources to each business.

PSE&G

PSE&G earns revenues from its tariffs, under which it provides electric transmission and electric and gas distribution services to residential, commercial and industrial customers in New Jersey. The rates charged for electric transmission are regulated by the FERC while the rates charged for electric and gas distribution are regulated by the BPU. Revenues are also earned from several other activities such as solar investments, sundry sales, the appliance service business, wholesale transmission services and other miscellaneous services.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power

Power earns revenues by selling energy, capacity and ancillary services on a wholesale basis under contract to power marketers and to load serving entities and by bidding energy, capacity and ancillary services into the markets for these products. Power also enters into contracts for energy, capacity, FTRs, gas, emission allowances and other energy-related contracts to optimize the value of its portfolio of generating assets and its electric and gas supply obligations.

Other

This category includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

	PSE&G	Power	Other	Eliminations (A)	Consolidated Total
Year Ended December 31, 2014					
Operating Revenues	$ 6,766	$ 5,434	$ 455	$ (1,769)	$ 10,886
Depreciation and Amortization	906	292	29	—	1,227
Operating Income (Loss)	1,393	1,209	21	—	2,623
Income from Equity Method Investments	—	14	(1)	—	13
Interest Income	26	1	25	(22)	30
Interest Expense	277	122	12	(22)	389
Income (Loss) before Income Taxes	1,174	1,251	31	—	2,456
Income Tax Expense (Benefit)	449	491	(2)	—	938
Net Income (Loss)	725	760	33	—	1,518
Gross Additions to Long-Lived Assets	$ 2,164	$ 626	$ 30	$ —	$ 2,820
As of December 31, 2014					
Total Assets	$ 22,223	$ 12,046	$ 2,799	$ (1,735)	$ 35,333
Investments in Equity Method Subsidiaries	$ —	$ 121	$ 2	$ —	$ 123

	PSE&G	Power	Other	Eliminations (A)	Consolidated Total
Year Ended December 31, 2013					
Operating Revenues	$ 6,655	$ 5,063	$ 52	$ (1,802)	$ 9,968
Depreciation and Amortization	872	273	33	—	1,178
Operating Income (Loss)	1,235	1,070	(6)	—	2,299
Income from Equity Method Investments	—	16	(5)	—	11
Interest Income	25	1	25	(22)	29
Interest Expense	293	116	15	(22)	402
Income (Loss) before Income Taxes	993	1,063	(1)	—	2,055
Income Tax Expense (Benefit)	381	419	12	—	812
Net Income (Loss)	612	644	(13)	—	1,243
Gross Additions to Long-Lived Assets	$ 2,175	$ 609	$ 27	$ —	$ 2,811
As of December 31, 2013					
Total Assets	$ 19,720	$ 12,002	$ 4,025	$ (3,225)	$ 32,522
Investments in Equity Method Subsidiaries	$ —	$ 123	$ 3	$ —	$ 126

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	PSE&G	Power	Other	Eliminations (A)	Consolidated Total
Year Ended December 31, 2012					
Operating Revenues	$ 6,626	$ 4,873	$ 103	$ (1,821)	$ 9,781
Depreciation and Amortization	778	242	34	—	1,054
Operating Income (Loss)	1,083	1,123	72	—	2,278
Income from Equity Method Investments	—	15	(3)	—	12
Interest Income	20	3	25	(21)	27
Interest Expense	295	132	17	(21)	423
Income (Loss) before Income Taxes	835	1,099	77	—	2,011
Income Tax Expense (Benefit)	307	433	(4)	—	736
Net Income (Loss)	528	666	81	—	1,275
Gross Additions to Long-Lived Assets	$ 1,770	$ 770	$ 34	$ —	$ 2,574
As of December 31, 2012					
Total Assets	$ 19,223	$ 11,323	$ 4,161	$ (2,982)	$ 31,725
Investments in Equity Method Subsidiaries	$ —	$ 125	$ 9	$ —	$ 134

(A) Intercompany eliminations, primarily relate to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 23. Related-Party Transactions.

Note 23. Related-Party Transactions

The majority of the following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

	Years Ended December 31,		
Related Party Transactions	**2014**	**2013**	**2012**
	Millions		
Expense Billings from Affiliates:			
Billings from Power primarily through BGSS and BGS (A)	$ 1,771	$ 1,797	$ 1,802
Administrative Billings from Services (B)	248	255	230
Total Expense Billings from Affiliates	**$ 2,019**	**$ 2,052**	**$ 2,032**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Related Party Transactions	Years Ended December 31, 2014	2013
	Millions	
Payable to Power (A)	$ (313)	$ (267)
Receivable from (Payable to) Services (B)	(66)	(73)
Receivable from (Payable to) PSEG (C)	274	150
Accounts Receivable (Payable)—Affiliated Companies, net	**$ (105)**	**$ (190)**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Receivable (Payable)	**$ (116)**	**$ (72)**

Power

The financial statements for Power include transactions with related parties presented as follows:

Related Party Transactions	Years Ended December 31, 2014	2013	2012
		Millions	
Revenue from Affiliates:			
Billings to PSE&G primarily through BGSS and BGS (A)	**$ 1,771**	**$ 1,797**	**$ 1,802**
Expense Billings from Affiliates:			
Administrative Billings from Services (B)	**$ 165**	**$ 178**	**$ 154**

Related Party Transactions	Years Ended December 31, 2014	2013
	Millions	
Receivables from PSE&G (A)	$ 313	$ 267
Receivable from (Payable to) Services (B)	(23)	(31)
Receivable from (Payable to) PSEG (C)	(95)	97
Accounts Receivable (Payable)—Affiliated Companies, net	**$ 195**	**$ 333**
Short-Term Loan (to) from Affiliate (Demand Note (to) from PSEG) (E)	**$ 584**	**$ 790**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable (Payable)	**$ (41)**	**$ (53)**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

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Note 24. Selected Quarterly Data (Unaudited)

The information shown in the following tables, in the opinion of PSEG, PSE&G and Power includes all adjustments, consisting only of normal recurring accruals, necessary to fairly present such amounts.

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2014	2013	2014	2013	2014	2013	2014	2013
PSEG Consolidated:	Millions, except per share data							
Operating Revenues	$ 3,223	$ 2,786	$ 2,249	$ 2,310	$ 2,641	$ 2,554	$ 2,773	$ 2,318
Operating Income	$ 705	$ 610	$ 365	$ 612	$ 746	$ 712	$ 807	$ 365
Net Income (Loss)	$ 386	$ 320	$ 212	$ 333	$ 444	$ 390	$ 476	$ 200
Earnings Per Share:								
Basic:								
Net Income (Loss)	$ 0.76	$ 0.63	$ 0.42	$ 0.66	$ 0.88	$ 0.77	$ 0.94	$ 0.40
Diluted:								
Net Income (Loss)	$ 0.76	$ 0.63	$ 0.42	$ 0.66	$ 0.87	$ 0.77	$ 0.94	$ 0.39
Weighted Average Common Shares Outstanding:								
Basic	506	507	506	506	506	506	506	506
Diluted	508	507	508	508	507	508	508	508

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2014	2013	2014	2013	2014	2013	2014	2013
PSE&G:	Millions							
Operating Revenues	$ 2,145	$ 1,995	$ 1,435	$ 1,423	$ 1,655	$ 1,666	$ 1,531	$ 1,571
Operating Income	$ 411	$ 365	$ 291	$ 253	$ 383	$ 346	$ 308	$ 271
Net Income (Loss)	$ 214	$ 179	$ 151	$ 121	$ 200	$ 168	$ 160	$ 144

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2014	2013	2014	2013	2014	2013	2014	2013
Power:	Millions							
Operating Revenues	$ 1,700	$ 1,451	$ 986	$ 1,193	$ 1,138	$ 1,174	$ 1,610	$ 1,245
Operating Income	$ 282	$ 242	$ 67	$ 351	$ 353	$ 370	$ 507	$ 107
Net Income (Loss)	$ 164	$ 141	$ 54	$ 210	$ 222	$ 226	$ 320	$ 67

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Note 25. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following table presents financial information for the guarantor subsidiaries as well as Power's non-guarantor subsidiaries as of December 31, 2014 and 2013 and for the years ended December 31, 2014, 2013 and 2012.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2014					
Operating Revenues	$ —	$ 5,390	$ 153	$ (109)	$ 5,434
Operating Expenses	16	4,175	143	(109)	4,225
Operating Income (Loss)	(16)	1,215	10	—	1,209
Equity Earnings (Losses) of Subsidiaries	799	(5)	14	(794)	14
Other Income	34	222	—	(34)	222
Other Deductions	(20)	(32)	—	—	(52)
Other-Than-Temporary Impairments	—	(20)	—	—	(20)
Interest Expense	(102)	(35)	(19)	34	(122)
Income Tax Benefit (Expense)	65	(558)	2	—	(491)
Net Income (Loss)	**$ 760**	**$ 787**	**$ 7**	**$ (794)**	**$ 760**
Comprehensive Income (Loss)	**$ 595**	**$ 768**	**$ 7**	**$ (775)**	**$ 595**
As of December 31, 2014					
Current Assets	$ 4,263	$ 2,037	$ 150	$ (4,091)	$ 2,359
Property, Plant and Equipment, net	81	6,265	1,169	—	7,515
Investment in Subsidiaries	4,516	120	—	(4,636)	—
Noncurrent Assets	278	1,952	137	(195)	2,172
Total Assets	**$ 9,138**	**$ 10,374**	**$ 1,456**	**$ (8,922)**	**$ 12,046**
Current Liabilities	$ 883	$ 3,606	$ 786	$ (4,091)	$ 1,184
Noncurrent Liabilities	454	2,442	360	(195)	3,061
Long-Term Debt	2,243	—	—	—	2,243
Member's Equity	5,558	4,326	310	(4,636)	5,558
Total Liabilities and Member's Equity	**$ 9,138**	**$ 10,374**	**$ 1,456**	**$ (8,922)**	**$ 12,046**
Year Ended December 31, 2014					
Net Cash Provided By (Used In) Operating Activities	$ 577	$ 1,674	$ 76	$ (902)	$ 1,425
Net Cash Provided By (Used In) Investing Activities	$ 148	$ (856)	$ (42)	$ 226	$ (524)
Net Cash Provided By (Used In) Financing Activities	$ (724)	$ (818)	$ (32)	$ 676	$ (898)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2013					
Operating Revenues	$ —	$ 5,022	$ 190	$ (149)	$ 5,063
Operating Expenses	23	3,945	174	(149)	3,993
Operating Income (Loss)	(23)	1,077	16	—	1,070
Equity Earnings (Losses) of Subsidiaries	684	(5)	16	(679)	16
Other Income	35	157	—	(38)	154
Other Deductions	(14)	(35)	—	—	(49)
Other-Than-Temporary Impairments	—	(12)	—	—	(12)
Interest Expense	(93)	(42)	(19)	38	(116)
Income Tax Benefit (Expense)	55	(474)	—	—	(419)
Net Income (Loss)	**$ 644**	**$ 666**	**$ 13**	**$ (679)**	**$ 644**
Comprehensive Income (Loss)	**$ 909**	**$ 713**	**$ 11**	**$ (724)**	**$ 909**
As of December 31, 2013					
Current Assets	$ 4,413	$ 2,076	$ 102	$ (4,115)	$ 2,476
Property, Plant and Equipment, net	81	6,108	1,178	—	7,367
Investment in Subsidiaries	4,645	124	—	(4,769)	—
Noncurrent Assets	222	1,847	138	(48)	2,159
Total Assets	**$ 9,361**	**$ 10,155**	**$ 1,418**	**$ (8,932)**	**$ 12,002**
Current Liabilities	$ 697	$ 3,474	$ 745	$ (4,116)	$ 800
Noncurrent Liabilities	309	2,247	338	(47)	2,847
Long-Term Debt	2,497	—	—	—	2,497
Member's Equity	5,858	4,434	335	(4,769)	5,858
Total Liabilities and Member's Equity	**$ 9,361**	**$ 10,155**	**$ 1,418**	**$ (8,932)**	**$ 12,002**
Year Ended December 31, 2013					
Net Cash Provided By (Used In) Operating Activities	$ 288	$ 1,503	$ 82	$ (526)	$ 1,347
Net Cash Provided By (Used In) Investing Activities	$ (395)	$ (1,092)	$ (71)	$ 697	$ (861)
Net Cash Provided By (Used In) Financing Activities	$ 107	$ (412)	$ (11)	$ (171)	$ (487)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2012					
Operating Revenues	$ —	$ 4,850	$ 135	$ (112)	$ 4,873
Operating Expenses	7	3,730	125	(112)	3,750
Operating Income (Loss)	(7)	1,120	10	—	1,123
Equity Earnings (Losses) of Subsidiaries	707	(10)	15	(697)	15
Other Income	45	206	2	(52)	201
Other Deductions	(31)	(59)	—	—	(90)
Other-Than-Temporary Impairments	—	(18)	—	—	(18)
Interest Expense	(118)	(51)	(16)	53	(132)
Income Tax Benefit (Expense)	70	(501)	(2)	—	(433)
Net Income (Loss)	**$ 666**	**$ 687**	**$ 9**	**$ (696)**	**$ 666**
Comprehensive Income (Loss)	**$ 614**	**$ 681**	**$ 9**	**$ (690)**	**$ 614**
Year Ended December 31, 2012					
Net Cash Provided By (Used In) Operating Activities	$ 298	$ 1,562	$ 67	$ (474)	$ 1,453
Net Cash Provided By (Used In) Investing Activities	$ (14)	$ (1,206)	$ (151)	$ 899	$ (472)
Net Cash Provided By (Used In) Financing Activities	$ (284)	$ (361)	$ 83	$ (424)	$ (986)

Immaterial Correction of Prior Financial Information

The financial information included in the tables above has been corrected from the disclosure provided in Power's Form 10-K filed on February 26, 2014 (2013 10-K) to conform to the requirements of Section 210.3-10 of SEC Regulation S-X.

In the prior disclosure, Operating Revenues and Operating Expenses among the Guarantor Subsidiaries were eliminated in the Consolidating Adjustments column. The revised presentation eliminates this activity in the Guarantor Subsidiaries column and removes such activity from the Consolidating Adjustments column. This revised presentation decreased both Operating Revenues and Operating Expenses in both the Guarantor Subsidiaries and Consolidating Adjustments columns. This correction had no impact on Power’s consolidated Operating Revenues and Operating Expenses.

In the prior disclosure, loans payable by Power parent company to one of its guarantor subsidiaries were netted against loans receivable in net cash flows used in investing activities. The revised presentation reclassifies the increase in loans payable by the parent company to the guarantor subsidiary from net cash flows used in investing activities to net cash flows provided by financing activities. This revised presentation decreased net cash flows used in investing activities and increased net cash flows provided by financing activities in the Power column with corresponding offsets to the amounts in the Consolidating Adjustments Column.

In addition, the revised information was corrected to present the intercompany balances on a net basis when the right of offset exists in either Current Assets or Current Liabilities. This revised presentation resulted in increases/(decreases) to certain categories of the Consolidated Balance Sheet.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes the adjustments for all prior periods that have been revised in this Note.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Increase (Decrease)		
			Millions		
Year Ended December 31, 2013					
Operating Revenues	$ —	$ (1,468)	$ —	$ 1,468	$ —
Operating Expenses	$ —	$ (1,468)	$ —	$ 1,468	$ —
Net Cash Provided By (Used In) Investing Activities	$ (588)	$ —	$ —	$ 588	$ —
Net Cash Provided By (Used In) Financing Activities	$ 588	$ —	$ —	$ (588)	$ —
As of December 31, 2013					
Current Assets	$ 253	$ (6,840)	$ (842)	$ 7,429	$ —
Investment in Subsidiaries	—	(605)	—	605	—
Total Assets	**$ 253**	**$ (7,445)**	**$ (842)**	**$ 8,034**	**$ —**
Current Liabilities	$ 253	$ (7,445)	$ (237)	$ 7,429	$ —
Member's Equity	—	—	(605)	605	—
Total Liabilities and Member's Equity	**$ 253**	**$ (7,445)**	**$ (842)**	**$ 8,034**	**$ —**
Year Ended December 31, 2012					
Operating Revenues	$ —	$ (1,388)	$ —	$ 1,388	$ —
Operating Expenses	$ —	$ (1,388)	$ —	$ 1,388	$ —
Net Cash Provided By (Used In) Investing Activities	$ (729)	$ —	$ —	$ 729	$ —
Net Cash Provided By (Used In) Financing Activities	$ 679	$ —	$ —	$ (679)	$ —

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, PSE&G and Power

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Public Service Electric and Gas Company, and PSEG Power LLC. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company, and PSEG Power LLC have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, PSE&G and Power

We have conducted assessments of our internal control over financial reporting as of December 31, 2014, as required by Section 404 of the Sarbanes-Oxley Act, using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO." Management's reports on PSEG's, PSE&G's and Power's internal control over financial reporting are included on pages 174, 175 and 176, respectively. The Independent Registered Public Accounting Firm's report with respect to the effectiveness of PSEG's internal control over financial reporting is included on page 177. Management has concluded that internal control over financial reporting is effective as of December 31, 2014.

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of their financial reporting. There have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2014 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSEG

Management of Public Service Enterprise Group Incorporated (PSEG) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSEG's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSEG's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSEG are being made only in accordance with authorizations of PSEG's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSEG's assets that could have a material effect on the financial statements.

In connection with the preparation of PSEG's annual financial statements, management of PSEG has undertaken an assessment, which includes the design and operational effectiveness of PSEG's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSEG's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSEG's financial reporting and the preparation of its financial statements as of December 31, 2014 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2014.

PSEG's external auditors, Deloitte & Touche LLP, have audited PSEG's financial statements for the year ended December 31, 2014 included in this annual report on Form 10-K and, as part of that audit, have issued a report on the effectiveness of PSEG's internal control over financial reporting, a copy of which is included in this annual report on Form 10-K.

/s/ RALPH IZZO

Chief Executive Officer

/s/ CAROLINE DORSA

Chief Financial Officer

February 25, 2015

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSE&G

Management of Public Service Electric and Gas Company (PSE&G) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSE&G's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSE&G's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSE&G are being made only in accordance with authorizations of PSE&G's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSE&G's assets that could have a material effect on the financial statements.

In connection with the preparation of PSE&G's annual financial statements, management of PSE&G has undertaken an assessment, which includes the design and operational effectiveness of PSE&G's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSE&G's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSE&G's financial reporting and the preparation of its financial statements as of December 31, 2014 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2014.

/s/ RALPH IZZO

Chief Executive Officer

/s/ CAROLINE DORSA

Chief Financial Officer

February 25, 2015

S1-SSA-0009 - 11306

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—Power

Management of PSEG Power LLC (Power) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

Power's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of Power's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of Power are being made only in accordance with authorizations of Power's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Power's assets that could have a material effect on the financial statements.

In connection with the preparation of Power's annual financial statements, management of Power has undertaken an assessment, which includes the design and operational effectiveness of Power's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that Power's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of Power's financial reporting and the preparation of its financial statements as of December 31, 2014 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2014.

/s/ RALPH IZZO
Chief Executive Officer

/s/ CAROLINE DORSA
Chief Financial Officer
February 25, 2015

S1-SSA-0009 - 11307

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of
Public Service Enterprise Group Incorporated:

We have audited the internal control over financial reporting of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2014 based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting - PSEG. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and consolidated financial statement schedule listed in the Index 15 (B)(a) as of and for the year ended December 31, 2014 of the Company and our report dated February 25, 2015 expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2015

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

PSEG

Name	Age as of December 31, 2014	Office	Effective Date First Elected to Present Position
Ralph Izzo	57	Chairman of the Board, President and Chief Executive Officer (PSEG)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Power)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (PSE&G)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Energy Holdings)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Services)	January 2010 to present
Caroline Dorsa	55	Executive Vice President and Chief Financial Officer (PSEG)	April 2009 to present
		Executive Vice President and Chief Financial Officer (PSE&G)	April 2009 to present
		Executive Vice President and Chief Financial Officer (Power)	April 2009 to present
		Chief Financial Officer (Energy Holdings)	April 2009 to present
		Executive Vice President and Chief Financial Officer (Services)	April 2009 to present
William Levis	58	President and Chief Operating Officer (Power)	June 2007 to present
Ralph LaRossa	51	President and Chief Operating Officer (PSE&G)	October 2006 to present
		Chairman of the Board of PSEG Long Island LLC	October 2013 to present
Derek M. DiRisio	50	President (Services)	August 2014 to present
		Vice President and Controller (PSEG)	January 2007 to August 2014
		Vice President and Controller (PSE&G)	January 2007 to August 2014
		Vice President and Controller (Power)	January 2007 to August 2014
		Vice President and Controller (Energy Holdings)	January 2007 to August 2014
		Vice President and Controller (Services)	January 2007 to August 2014
Stuart J. Black	52	Vice President and Controller (PSEG)	August 2014 to present
		Vice President and Controller (PSE&G)	August 2014 to present
		Vice President and Controller (Power)	August 2014 to present
		Vice President (Services) and Assistant Controller (Power)	March 2010 to August 2014
		Vice President of Internal Auditing Services (Services)	January 2005 to March 2010
Tamara L. Linde	50	Executive Vice President and General Counsel (PSEG)	July 2014 to present
		Executive Vice President and General Counsel (PSE&G)	July 2014 to present
		Executive Vice President and General Counsel (Power)	July 2014 to present
		Vice President - Regulatory (Services)	December 2006 to July 2014

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PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Directors

PSEG

The information required by Item 10 of Form 10-K with respect to (i) present directors of PSEG who are nominees for election as directors at PSEG's 2015 Annual Meeting of Stockholders, and (ii) compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth under the headings 'Election of Directors' and "Section 16(a) Beneficial Ownership Reporting Compliance" in PSEG's definitive Proxy Statement for such Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 9, 2015 and which information set forth under said heading is incorporated herein by this reference thereto.

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Code of Ethics

Our Standards of Integrity (Standards) is a code of ethics applicable to us and our subsidiaries. The Standards are an integral part of our business conduct compliance program and embody our commitment to conduct operations in accordance with the highest legal and ethical standards. The Standards apply to all of our directors and employees (including PSE&G's, Power's, Energy Holdings' and Services' respective principal executive officer, principal financial officer, principal accounting officer or Controller and persons performing similar functions). Each such person is responsible for understanding and complying with the Standards. The Standards are posted on our website, www.pseg.com/info/investors/governance/document.jsp. We will send you a copy on request.

The Standards establish a set of common expectations for behavior to which each employee must adhere in dealings with investors, customers, fellow employees, competitors, vendors, government officials, the media and all others who may associate their words and actions with us. The Standards have been developed to provide reasonable assurance that, in conducting our business, employees behave ethically and in accordance with the law and do not take advantage of investors, regulators or customers through manipulation, abuse of confidential information or misrepresentation of material facts.

We will post on our website, www.pseg.com/info/investors/governance/document.jsp:

- Any amendment (other than one that is technical, administrative or non-substantive) that we adopt to our Standards; and
- Any grant by us of a waiver from the Standards that applies to any director, principal executive officer, principal financial officer, principal accounting officer or Controller, or persons performing similar functions, for us or our direct subsidiaries noted above, and that relates to any element enumerated by the SEC.

In 2014, we did not grant any waivers to the Standards.

ITEM 11. EXECUTIVE COMPENSATION

PSEG

The information required by Item 11 of Form 10-K is set forth in PSEG's definitive Proxy Statement for the 2015 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 9, 2015 and such information set forth under such heading is incorporated herein by this reference thereto.

Section 16 Beneficial Ownership Reporting Compliance

During 2014, none of our directors or executive officers was late in filing a Form 3, 4 or 5 in accordance with the requirements of Section 16(a) of the Securities Exchange Act of 1934, as amended, with regard to transactions involving our Common Stock.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDERS MATTERS

PSEG

The information required by Item 12 of Form 10-K with respect to directors, executive officers and certain beneficial owners is set forth under the heading "Security Ownership of Directors, Management and Certain Beneficial Owners" in PSEG's definitive Proxy Statement for the 2015 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 9, 2015 and such information set forth under such heading is incorporated herein by this reference thereto.

For information relating to securities authorized for issuance under equity compensation plans, see Part II, Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

PSEG

The information required by Item 13 of Form 10-K is set forth under the heading "Transactions with Related Persons" in PSEG's definitive Proxy Statement for the 2015 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 9, 2015 and such information set forth under such heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10K.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 of Form 10-K is set forth under the heading "Fees Billed by Deloitte & Touche LLP for 2014 and 2013" in PSEG's definitive Proxy Statement for the 2015 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 9, 2015. Such information set forth under such heading is incorporated herein by this reference hereto.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(A) The following Financial Statements are filed as a part of this report:

a. Public Service Enterprise Group Incorporated's Consolidated Balance Sheets as of December 31, 2014 and 2013 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Stockholders' Equity for the three years ended December 31, 2014 on pages 71 through 76.

b. Public Service Electric and Gas Company's Consolidated Balance Sheets as of December 31, 2014 and 2013 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Common Stockholders' Equity for the three years ended December 31, 2014 on pages 77 through 82.

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c. PSEG Power LLC's Consolidated Balance Sheets as of December 31, 2014 and 2013 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Capitalization and Member's Equity for the three years ended December 31, 2014 on pages 83 through 88.

(B) The following documents are filed as a part of this report:

a. PSEG's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2014 (page 188).

b. PSE&G's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2014 (page 188).

c. Power's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2014 (page 189).

Schedules other than those listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(C) The following documents are filed as part of this report:

LIST OF EXHIBITS:

a.	**PSEG:**
3a	Certificate of Incorporation Public Service Enterprise Group Incorporated[1]
3b	By-Laws of Public Service Enterprise Group Incorporated effective November 17, 2009[2]
3c	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 23, 1987[3]
3d	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 20, 2007[4]
4a(1)	Indenture between Public Service Enterprise Group Incorporated and First Union National Bank (U.S. Bank National Association, successor), as Trustee, dated January 1, 1998 providing for Deferrable Interest Subordinated Debentures in Series (relating to Quarterly Preferred Securities)[5]
9	Inapplicable
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011[6]
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees as amended May 31, 2011[7]
10a(3)	Employment Agreement with William Levis dated December 8, 2006[8]
10a(4)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011[9]
10a(5)	Deferred Compensation Plan for Directors, amended July 19, 2011[10]
10a(6)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011[57]
10a(7)	1989 Long-Term Incentive Plan, as amended[12]
10a(8)	2001 Long-Term Incentive Plan[13]
10a(9)	Senior Management Incentive Compensation Plan[14]
10a(10)	Amended and Restated Key Executive Severance Plan, amended effective December 17, 2012[61]
10a(11)	Severance Agreement with Ralph Izzo dated December 16, 2008[15]
10a(12)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009[16]
10a(13)	Stock Plan for Outside Directors, as amended[17]
10a(14)	Compensation Plan for Outside Directors[18]
10a(15)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013[19]

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LIST OF EXHIBITS:

10a(16)	Form of Advancement of Expenses Agreement with Outside Directors(20)
10a(17)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011(58)
10a(18)	Employment Agreement with J.A. Bouknight dated August 26, 2009(59)
10a(19)	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011(56)
10a(20)	Amendment to Employment Agreement with William Levis, dated September 19, 2011(11)
10a(21)	Amendment to Employment Agreement with J.A. Bouknight dated November 20, 2012(60)
10a(22)	Amendment to Employment Agreement with J.A. Bouknight dated February 18, 2014(62)
10a(23)	Agreement with Tamara L. Linde dated June 18, 2014
11	Inapplicable
12	Computation of Ratios of Earnings to Fixed Charges
13	Inapplicable
16	Inapplicable
18	Inapplicable
21	Subsidiaries of the Registrant
22	Inapplicable
23	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934 (1934 Act)
31a	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32a	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
b.	**Power:**
3a	Certificate of Formation of PSEG Power LLC(21)
3b	PSEG Power LLC Limited Liability Company Agreement(22)
4a	Indenture dated April 16, 2001 between and among PSEG Power, PSEG Fossil, PSEG Nuclear, PSEG Energy Resources & Trade and The Bank of New York Mellon and form of Subsidiary Guaranty included therein(23)
4b	First Supplemental Indenture, supplemental to Exhibit 4a, dated as of March 13, 2002(24)
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011(6)
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees, as amended May 31, 2011(7)
10a(3)	Employment Agreement with William Levis dated December 8, 2006(8)
10a(4)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011(57)
10a(5)	1989 Long-Term Incentive Plan, as amended(12)
10a(6)	2001 Long-Term Incentive Plan(13)
10a(7)	Senior Management Incentive Compensation Plan(14)
10a(8)	Amended and Restated Key Executive Severance Plan, amended effective December 17, 2012 (61)
10a(9)	Severance Agreement with Ralph Izzo dated December 16, 2008(15)
10a(10)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009(16)
10a(11)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013(19)

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LIST OF EXHIBITS:

10a(12)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011[58]
10a(13)	Employment Agreement with J.A. Bouknight dated August 26, 2009[59]
10a(14)	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011[56]
10a(15)	Amendment to Employment Agreement with William Levis, dated September 19, 2011[11]
10a(16)	Amendment to Employment Agreement with J.A. Bouknight dated November 20, 2012[60]
10a(17)	Amendment to Employment Agreement with J.A. Bouknight dated February 18, 2014[62]
10a(18)	Agreement with Tamara L. Linde dated June 18, 2014
11	Inapplicable
12a	Computation of Ratio of Earnings to Fixed Charges
13	Inapplicable
16	Inapplicable
18	Inapplicable
19	Inapplicable
23a	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31b	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31c	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32b	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32c	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
c.	**PSE&G**
3a(1)	Restated Certificate of Incorporation of PSE&G[25]
3a(2)	Certificate of Amendment of Certificate of Restated Certificate of Incorporation of PSE&G filed February 18, 1987 with the State of New Jersey adopting limitations of liability provisions in accordance with an amendment to New Jersey Business Corporation Act[26]
3a(3)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed June 17, 1992 with the State of New Jersey, establishing the 7.44% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock[27]
3a(4)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed March 11, 1993 with the State of New Jersey, establishing the 5.97% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock[28]
3a(5)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed January 27, 1994 with the State of New Jersey, establishing the 6.92% Cumulative Preferred Stock ($100 Par) and the 6.75% Cumulative Preferred Stock ($25 Par) as a series of Preferred Stock[29]
3b(1)	By-Laws of PSE&G as in effect April 17, 2007[30]
4a(1)	Indenture between PSE&G and Fidelity Union Trust Company (now, Wachovia Bank, National Association), as Trustee, dated August 1, 1924[31], securing First and Refunding Mortgage Bond and Supplemental Indentures between PSE&G and U.S. Bank National Association, successor, as Trustee, supplemental to Exhibit 4a(1), dated as follows:
4a(2)	June 1, 1937[32]
4a(3)	July 1, 1937[33]
4a(4)	March 1, 1942[34]
4a(5)	June 1, 1991 (No. 1)[35]

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LIST OF EXHIBITS:

4a(6)	July 1, 1993[36]
4a(7)	January 1, 1996 (No. 1)[37]
4a(8)	December 1, 2003 (No. 1)[38]
4a(9)	December 1, 2003 (No. 2)[39]
4a(10)	December 1, 2003 (No. 3)[40]
4a(11)	December 1, 2003 (No. 4)[41]
4a(12)	August 1, 2004 (No. 1)[42]
4a(13)	August 1, 2004 (No. 2)[43]
4a(14)	August 1, 2004 (No. 3)[44]
4a(15)	August 1, 2004 (No. 4)[45]
4a(16)	April 1, 2007[46]
4a(17)	November 1, 2008[47]
4a(18)	October 1, 2010[48]
4a(19)	May 1, 2012[51]
4a(20)	June 1, 2012[52]
4a(21)	May 1, 2013[53]
4a(22)	August 1, 2014[54]
4b	Indenture of Trust between PSE&G and Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor), as Trustee, providing for Secured medium-Term Notes dated July 1, 1993[49]
4c	Indenture dated as of December 1, 2000 between Public Service Electric and Gas Company and First Union National Bank (U.S. Bank National Association, successor), as Trustee, providing for Senior Debt Securities[50]
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011[6]
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees as amended May 31, 2011[7]
10a(3)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011[9]
10a(4)	Deferred Compensation Plan for Directors, amended July 19, 2011[10]
10a(5)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011[57]
10a(6)	1989 Long-Term Incentive Plan, as amended[12]
10a(7)	2001 Long-Term Incentive Plan[13]
10a(8)	Senior Management Incentive Compensation Plan[14]
10a(9)	Amended and Restated Key Executive Severance Plan, amended effective December 17, 2012[61]
10a(10)	Severance Agreement with Ralph Izzo dated December 16, 2008[15]
10a(11)	Employment Agreement with Caroline Dorsa dated March 11, 2009, as amended April 24, 2009[16]
10a(12)	Stock Plan for Outside Directors, as amended[17]
10a(13)	Compensation Plan for Outside Directors[18]
10a(14)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013[19]
10a(15)	Form of Advancement of Expenses Agreement with Outside Directors[55]
10a(16)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011[58]
10a(17)	Employment Agreement with J.A. Bouknight dated August 26, 2009[59]
10a(18)	Amendment to Employment Agreement with Caroline Dorsa, dated July 12, 2011[56]
10a(19)	Amendment to Employment Agreement with J.A. Bouknight dated November 20, 2012[60]
10a(20)	Amendment to Employment Agreement with J.A. Bouknight dated February 18, 2014[62]
10a(21)	Agreement with Tamara L. Linde dated June 18, 2014
11	Inapplicable
12b	Computation of Ratios of Earnings to Fixed Charges

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LIST OF EXHIBITS:

12c	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
13	Inapplicable
16	Inapplicable
18	Inapplicable
19	Inapplicable
23b	Consent of Independent Registered Public Accounting Firm
24	Inapplicable
31d	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31e	Certification by Caroline Dorsa, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32d	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32e	Certification by Caroline Dorsa, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document

(1) Filed as Exhibit 3.1a with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.
(2) Filed as Exhibit 3.1 with Current Report on Form 8-K, File No. 001-09120 on November 18, 2009 and incorporated herein by this reference.
(3) Filed as Exhibit 3.1b with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.
(4) Filed as Exhibit 3.1c with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.
(5) Filed as Exhibit 4(f) with Quarterly Report on Form 10-Q for the quarter ended March 31, 1998, File No. 001-09120 on May 13, 1998 and incorporated herein by this reference.
(6) Filed as Exhibit 10.1 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(7) Filed as Exhibit 10.2 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(8) Filed as Exhibit 10a(4) with Annual Report on Form 10-K for the year ended December 31, 2007, File Nos. 001-09120 on February 28, 2008 and 000-49614, and incorporated herein by reference.
(9) Filed as Exhibit 10.5 with Quarterly Report on Form 10-Q for the quarter ended September 20, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(10) Filed as Exhibit 10.6 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(11) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(12) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 001-09120, on November 4, 2002 and incorporated herein by this reference.
(13) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2000, File No. 001-09120, on March 6, 2001 and incorporated herein by this reference.
(14) Filed as Exhibit 10a(11) with Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-09120, on February 26, 2009 and incorporated herein by this reference.
(15) Filed as Exhibit 99 with Current Report on Form 8-K, File Nos. 001-09120, 000-49614 and 001-00973 on December 22, 2008 and incorporated herein by this reference.
(16) Filed as Exhibit 10 with Quarterly Report on Form 10-Q, File No. 001-00973 on May 6, 2009 and incorporated herein by reference.

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(17) Filed as Exhibit 10a(17) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(18) Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(19) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, File No. 001-09120 on April 30, 2013 and incorporated herein by reference.
(20) Filed as Exhibit 10.1 with Current Report on Form 8-K, File No. 001-09120 on February 19, 2009 and incorporated herein by this reference.
(21) Filed as Exhibit 3.1 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.
(22) Filed as Exhibit 3.2 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.
(23) Filed as Exhibit 4.1 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.
(24) Filed as Exhibit 4.7 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, File No. 000-49614, on May 15, 2002 and incorporated herein by this reference.
(25) Filed as Exhibit 3(a) with Quarterly Report on Form 10-Q for the quarter ended June 30, 1986, File No. 001-00973, on August 28, 1986 and incorporated herein by this reference.
(26) Filed as Exhibit 3a(2) with Annual Report on Form 10-K for the year ended December 31, 1987, File No. 001-00973, on March 28, 1988 and incorporated herein by this reference.
(27) Filed as Exhibit 3a(3) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(28) Filed as Exhibit 3a(4) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(29) Filed as Exhibit 3a(5) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(30) Filed as Exhibit 3.3 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-00973 on May 4, 2007 and incorporated herein by this reference.
(31) Filed as Exhibit 4b(1) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(32) Filed as Exhibit 4b(3) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(33) Filed as Exhibit 4b(4) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(34) Filed as Exhibit 4b(6) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(35) Filed as Exhibit 4 on Form 8-A, File No. 001-00973 on June 1, 1991 and incorporated herein by this reference.
(36) Filed as Exhibit 4(i) on Form 8-A, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.
(37) Filed as Exhibit 4a(2) on Form 8-A, File No. 001-00973 on January 26, 1996 and incorporated herein by this reference.
(38) Filed as Exhibit 4a(99) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(39) Filed as Exhibit 4a(100) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(40) Filed as Exhibit 4a(101) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(41) Filed as Exhibit 4a(102) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(42) Filed as Exhibit 4a(25) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(43) Filed as Exhibit 4a(26) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(44) Filed as Exhibit 4a(27) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(45) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.

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(46) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-00973, on February 28, 2008 and incorporated herein by this reference.
(47) Filed as Exhibit 4a(29) with Annual Report on Form 10-K, for the year ended December 31, 2009, File No. 001-00973 on February 25, 2010 and incorporated herein by reference.
(48) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2010, File No. 001-00973 on October 29, 2010 and incorporated herein by reference.
(49) Filed as Exhibit 4 with Current Report on Form 8-K, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.
(50) Filed as Exhibit 4.6 to Registration Statement on Form S-3, No. 333-76020 filed on December 27, 2001 and incorporated herein by this reference.
(51) Filed as Exhibit 4a(32) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-00973 on February 25, 2013.
(52) Filed as Exhibit 4a(33) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-00973 on February 25, 2013.
(53) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, File No. 001-00973 on July 30, 2013.
(54) Filed as Exhibit 4a(22) with Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, File No. 001-09120 on October 30, 2014 and incorporated herein by reference.
(55) Filed as Exhibit 10.2 with Current Report on Form 8-K, File No. 001-00973 on February 19, 2009 and incorporated herein by reference.
(56) Filed as Exhibit 10.1 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, File No. 001-09120 on August 3, 2011 and incorporated herein by this reference.
(57) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120 on February 27, 2012.
(58) Filed as Exhibit 10a(19) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120 on February 27, 2012.
(59) Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120 on February 27, 2012.
(60) Filed as Exhibit 10 with Current Report on Form 8-K, File No. 001-09120 on November 26, 2012 and incorporated herein by reference.
(61) Filed as Exhibit 10a(11) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-09120 on February 25, 2013.
(62) Filed as Exhibit 10 with Current Report on Form 8-K, File No. 001-09120 on February 21, 2014 and incorporated herein by reference.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2014—December 31, 2012

Column A	Column B	Column C		Column D		Column E
		Additions				
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2014						
Allowance for Doubtful Accounts	$ 56	$ 86	$ —	$ 90	(A)	$ 52
Materials and Supplies Valuation Reserve	8	9	—	2		15
2013						
Allowance for Doubtful Accounts	$ 56	$ 90	$ —	$ 90	(A)	$ 56
Materials and Supplies Valuation Reserve	22	2	—	16	(B)	8
2012						
Allowance for Doubtful Accounts	$ 56	$ 96	$ —	$ 96	(A)	$ 56
Materials and Supplies Valuation Reserve	3	21	—	2	(B)	22

(A) Accounts Receivable written off.

(B) Reduced reserve to appropriate level and to remove obsolete inventory.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2014—December 31, 2012

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2014						
Allowance for Doubtful Accounts	$ 56	$ 86	$ —	$ 90	(A)	$ 52
Materials and Supplies Valuation Reserve	—	2	—	—		2
2013						
Allowance for Doubtful Accounts	$ 56	$ 90	$ —	$ 90	(A)	$ 56
2012						
Allowance for Doubtful Accounts	$ 56	$ 96	$ —	$ 96	(A)	$ 56

(A) Accounts Receivable written off.

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PSEG POWER LLC

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2014—December 31, 2012

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2014						
Materials and Supplies Valuation Reserve	$ 8	$ 7	$ —	$ 2		$ 13
2013						
Materials and Supplies Valuation Reserve	$ 22	$ 2	$ —	$ 16	(A)	$ 8
2012						
Materials and Supplies Valuation Reserve	$ 3	$ 21	$ —	$ 2	(A)	$ 22

(A) Reduced reserve to appropriate level and to remove obsolete inventory.

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Term	Phrase/Description
ASC	Accounting Standards Codification FASB's official source of authoritative, nongovernmental U.S. GAAP
Base load	Minimum amount of electric power delivered or required over a given period of time at a constant rate, this is the level of demand that is seen as a minimum during a 24-hour day
BGS	Basic Generation Service PSE&G is required to provide BGS for all customers in New Jersey who are not supplied by a TPS.
BGS-RSCP	Basic Generation Service-Residential Small Commercial Product Seasonally adjusted fixed prices charged for a three-year term for electric supply service to smaller industrial and commercial customers and residential customers who are not supplied by a TPS
BGSS	Basic Gas Supply Service Mechanism approved by the BPU for NJ utilities to recover all commodity costs related to supplying gas to residential customers
BPU	New Jersey Board of Public Utilities Agency responsible for regulating public utilities doing business in New Jersey
Capacity	Amount of electricity that can be produced by a specific generating facility
CAA	Clean Air Act
Combined Cycle	A method of generation whereby electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity
Congestion	Condition when the available capacity of a transmission line is being closely approached (or exceeded) by the electric power trying to go through it; at such times, alternative power line pathways (or local generators near the load) must be used instead
Distribution	The delivery of electricity to the retail customer's home, business or industrial facility through low voltage distribution lines
EDC	Electric Distribution Company A company that owns the power lines and equipment necessary to deliver purchased electricity to the end user
Energy Holdings	PSEG Energy Holdings L.L.C.
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board A private, not-for-profit organization whose primary purpose, as designated by the SEC, is to develop accounting standards for public companies in the U.S.
FERC	U.S. Federal Energy Regulatory Commission
Forward contracts	A customized, non-exchange traded contract in which the buyer is obligated to deliver a specified amount of a commodity with a predetermined price formula on a specified future date, at which time payment is due in full
GAAP	Generally Accepted Accounting Principles Standard framework of guidelines issued by the FASB for financial accounting used in the U.S.
GHG	Greenhouse gas emissions (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon) that trap the heat of the sun in the Earth's atmosphere, increasing the mean global surface temperature of the earth

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Term	Phrase/Description
Hedging	Entering into a contract or transaction designed to reduce exposure to various risks, such as changes in market prices
Hope Creek	Hope Creek Nuclear Generating Station
ISO	Independent System Operator An independent, regulated entity established to manage a regional electric transmission system in a non-discriminatory manner and to help ensure the safety and reliability of the bulk of the power system
ITC	Investment Tax Credit A credit against income taxes, usually computed as a percent of the cost of investment in certain types of assets
Lifeline Program	A New Jersey social program for utility assistance that offers up to $225 per year to persons who meet the eligibility requirements
Load	Amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of consumers.
MBR	Market Based Rates Electric service prices determined in an open market system of supply and demand under which the price is set solely by agreement as to what a buyer will pay and a seller will accept
MGP	Manufactured Gas Plant
NDT	Nuclear Decommissioning Trust
ISO-NE	New England Power Pool An ISO comprised of an alliance of approximately 100 utility companies who manage and direct all major energy production and transmission in the New England states
NJDEP	New Jersey Department of Environmental Protection
NRC	U.S. Nuclear Regulatory Commission
NUG	Non-Utility Generation Power produced by independent power producers, exempt wholesale generators and other companies that have been exempted from traditional utility regulation
OPEB	Other Postretirement Benefits Benefits other than pensions payable to former employees
Outage	The period during which a generating unit, transmission line, or other facility is out of service due to scheduled (planned) or unscheduled maintenance
Peach Bottom	Peach Bottom Atomic Power Station
PJM	PJM Interconnection, L.L.C. A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 northeastern states and the District of Columbia
Power	PSEG Power LLC
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies
PRP	Potentially Responsible Parties
PSE&G	Public Service Electric and Gas Company
PSEG	Public Service Enterprise Group Incorporated

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Term	Phrase/Description
Renewable Energy	Energy derived from resources that are regenerative or that cannot be depleted (i.e. moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy)
Regulatory Asset	Costs deferred by a regulated utility company in accordance with Accounting Standard Codification Topic 980: Regulated operations (ASC 980)
Regulatory Liability	Costs recognized by a regulated utility company in accordance with ASC 980
RGGI	Regional Greenhouse Gas Initiative The first mandatory, market-based effort in the U. S. to reduce greenhouse gas emissions; states will sell emission allowances through auctions and invest proceeds in consumer benefits: energy efficiency, renewable energy, and other clean energy technologies
RPM	Reliability Pricing Model (PJM market) A process for pricing generation capacity based on overall system reliability requirements; using multi-year forward auctions, participants could bid capacity in the form of generation, demand response, or transmission to meet reliability needs by location and/or an ISO market
Salem	Salem Nuclear Generating Station
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
Services	PSEG Services Corporation
Spill Act	New Jersey Spill Compensation and Control Act
TPS	Third Party Supplier
Transmission	The high-voltage wires and networks that move electricity through states and regions in large quantities - from power plants where it is produced, to the distribution networks that deliver it to homes and businesses

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

By: /s/ RALPH IZZO
Ralph Izzo
Chairman of the Board, President and
Chief Executive Officer

Date: February 25, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2015
/s/ CAROLINE DORSA **Caroline Dorsa**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2015
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 25, 2015
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper, Jr.**	Director	February 25, 2015
/s/ WILLIAM V. HICKEY **William V. Hickey**	Director	February 25, 2015
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 25, 2015
/s/ DAVID LILLEY **David Lilley**	Director	February 25, 2015
/s/ THOMAS A. RENYI **Thomas A. Renyi**	Director	February 25, 2015
/s/ HAK CHEOL SHIN **Hak Cheol Shin**	Director	February 25, 2015
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 25, 2015
/s/ SUSAN TOMASKY **Susan Tomasky**	Director	February 25, 2015
/s/ ALFRED W. ZOLLAR **Alfred W. Zollar**	Director	February 25, 2015

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By: /s/ RALPH LAROSSA
Ralph LaRossa
President and Chief Operating Officer

Date: February 25, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2015
/s/ CAROLINE DORSA **Caroline Dorsa**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2015
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 25, 2015
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper Jr.**	Director	February 25, 2015
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 25, 2015
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 25, 2015

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC

By: /s/ WILLIAM LEVIS
William Levis
President and
Chief Operating Officer

Date: February 25, 2015

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2015
/s/ CAROLINE DORSA **Caroline Dorsa**	Executive Vice President and Chief Financial Officer and Director (Principal Financial Officer)	February 25, 2015
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 25, 2015
/s/ DEREK M. DIRISIO **Derek M. DiRisio**	Director	February 25, 2015
/s/ WILLIAM LEVIS **William Levis**	Director	February 25, 2015
/s/ TAMARA L. LINDE **Tamara L. Linde**	Director	February 25, 2015
/s/ MARGARET M. PEGO **Margaret M. Pego**	Director	February 25, 2015

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EXHIBIT INDEX

The following documents are filed as a part of this report:

a. PSEG:	
Exhibit 10a(23)	Agreement with Tamara L. Linde dated June 18, 2014
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 21:	Subsidiaries of the Registrant
Exhibit 23:	Consent of Independent Registered Public Accounting Firm
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31a:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32a:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document
b. Power:	
Exhibit 10a(18)	Agreement with Tamara L. Linde dated June 18, 2014
Exhibit 12a:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 23a:	Consent of Independent Registered Public Accounting Firm
Exhibit 31b:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31c:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32b:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32c:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document
c. PSE&G:	
Exhibit 10a(21)	Agreement with Tamara L. Linde dated June 18, 2014

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Exhibit 12b:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12c:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
Exhibit 23b:	Consent of Independent Registered Public Accounting Firm
Exhibit 31d:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31e:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32d:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32e:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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Margaret M. Pego **Human Resources**
Senior Vice President-Human Resources 80 Park Plaza, T4, Newark, NJ 07102
and Chief Human Resources Officer tel: 973-430-7243 fax: 973-643-6063
email: Margaret.Pego@pseg.com

June 18, 2014

Tamara L. Linde
954 West Front Street
Red Bank, NJ 07701

Dear Tamara:

I am pleased to offer you the position of Executive Vice President and General Counsel in PSEG Services Corporation, effective July 2, 2014. In this position, you will be paid a base annual salary of $470,000. You shall be eligible for your next salary review in January 2015. Salary reviews will be conducted annually thereafter.

You will be eligible to participate in PSEG's Senior Management Incentive Compensation Plan ("SMICP") under the terms and conditions of the SMICP. Your target incentive award for 2014 will be 65% of your base salary, however, you may be eligible to receive up to 97.5% of your base salary dependent upon business results. Targets and awards may be adjusted from time to time in accordance with established plan procedures. There is no guarantee of payment under the SMICP, and any such payment will be contingent upon your establishment and successful completion of goals and objectives. Your first award under the SMICP, if earned, will be based upon the successful completion of goals and objectives for 2014 and payable in 2015. Any SMICP award for 2014 will be prorated based on your promotion date of July 2, 2014. You will be eligible for a prorated Management Incentive Compensation Plan ("MICP") award for the period January 1 to July 1, 2014.

You will continue to be a participant in the PSEG 2004 Long-Term Incentive Plan as amended ("LTIP"). It will be recommended to the Organization and Compensation Committee ("O&CC") that you be granted a total 2014 LTIP award of $437,500. This award total will be reduced by your recent 2014 LTIP award of $200,000 resulting in an additional LTIP award of $237,500. As a Senior Officer, this and future grants will be in the form of 40% as Restricted Stock Units ("RSUs") and 60% as Performance Share Units ("PSUs"). In the future, the number and form of LTIP grants recommended in any given year will appropriately reflect your responsibilities and ability to contribute to the long-term success of PSEG and is subject to the approval of the O&CC of the Board. All grants under the LTIP for 2014 and any future years will be subject to the terms of the LTIP and the related grant award agreements.

You will continue to be eligible to participate in the PSEG Deferred Compensation Plan For Certain Employees ("Deferred Compensation Plan"), which will allow you to defer all or a portion of your base pay and/or any cash incentive you may receive in any given year. In November, you will receive information regarding participation in the Deferred Compensation Plan for 2015.

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For 2015, you will continue to be eligible to participate in the PSEG Equity Deferral Plan ("Deferred Equity Plan"), which will allow you to defer all or a portion of the receipt of shares under the LTIP. In November 2014, you will receive information regarding participation in the Deferred Equity Plan for 2015.

If, at the time you terminate from employment, you are determined to be a "specified employee" as defined in Section 409A of the Internal Revenue Code of 1986, as amended ("Section 409A"), your nonqualified deferred compensation payments will be delayed for six months following your termination of employment to the extent necessary to satisfy Section 409A.

You will continue to be a Schedule A participant in the Key Executive Severance Plan of Public Service Enterprise Group Incorporated, as amended from time to time.

You will be eligible for an annual physical examination through the University of Pennsylvania.

You will continue to be provided a parking space in the Company parking garage in Newark, NJ. Aditionally, you will be eligible for a monthly vehicle stipend of $1,000.

You will be required to own and retain a level of company stock commensurate with your new position as outlined in the attached Officer Stock Ownership and Retention Policy.

At all times, your employment with PSEG Services Corporation is and will be considered at-will, which means that either you or the Company is free to terminate the employment relationship at any time, for any reason, with or without cause.

This letter shall not be construed, nor is it intended to be construed, as a binding contract of employment.

Additionally, enclosed is a booklet referencing the Responsibilities of Corporate Officers and Directors.

Finally, you will be required to sign the enclosed Confidentiality, Non-Competition, and Non-Solicitation Agreement, and the enclosed Arbitration Agreement.

If the foregoing is in accordance with your understanding, please sign this letter and the enclosed Agreements, and return them to me.

Sincerely,

/s/ Margaret M. Pego

Margaret M. Pego
Senior Vice President - Human Resources
and Chief Human Resources Officer

Agreed to this 2nd day of July, 2014.

/s/ Tamara L. Linde
Tamara L. Linde

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Attachments:

1. Officer Stock Ownership & Retention Policy
2. Responsibilities of Corporate Officers and Directors
3. Confidentiality, Non-Competition and Non-Solicitation Agreement
4. Arbitration Agreement

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PSEG OFFICER STOCK OWNERSHIP AND RETENTION POLICY

Revised July 15, 2013

Purpose

The purpose of the PSEG Officer Stock Ownership and Retention Policy (the "Policy) is to strengthen the alignment of the interests of management with the interests of shareholders.

Covered Officers

This Policy applies to all officers at the level of Vice President and above of Public Service Enterprise Group Incorporated (the "Company") , Public Service Electric and Gas Company, PSEG Power LLC, PSEG Energy Holdings L.L.C., PSEG Services Corporation, PSEG Fossil LLC ("Fossil"), PSEG Nuclear LLC ("Nuclear"), PSEG Global L.L.C. and PSEG Resources L.L.C. This Policy also applies to the President of PSEG Energy Resources & Trade LLC ("ER&T"). In addition, officers at the Vice President and above levels of newly-formed subsidiaries may be subject to this Policy as determined in writing by the Company's Chief Executive Officer ("CEO"). Each such officer to which this Policy applies shall be hereinafter referred to as a "Covered Officer."

Retention Requirement

Multiple of Salary Requirement

As set forth below, each Covered Officer shall, during the Covered Officer's employment, maintain ownership of a sufficient number of shares of the Company's Common Stock ("Shares") having a market value equal to the following multiples of such covered officer's annual base salary, as in effect from time to time (the "Multiple of Salary Requirement"):

Position	Multiple
Chief Executive Officer	6
President/Chief Operating Officer	3
Executive Vice President	3
President (Fossil, Nuclear and ER&T)	2
Senior Vice President	2
Vice President	1

Compliance with the above shall be determined annually as of January 1st by multiplying the number of the Covered Officer's Qualifying Shares (as defined below) by the average of the daily closing price of the Shares on the New York Stock Exchange for the preceding 12 months (the "Annual Value").

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Equity Compensation Awards

In addition to the Multiple of Salary Requirement described above, Covered Officers shall retain not less than 100%, after tax and costs of issuance, of all Shares acquired by the Covered Officer through equity grants made by the Company, including the vesting of restricted stock or restricted stock units, the payout of performance awards and the exercise of option grants ("Equity Compensation Awards"), until it is determined that the Covered Officer satisfies the Multiple of Salary Requirement (the "Actual Compliance Date").

Upon satisfaction of the Multiple of Salary Requirement, Covered Officers shall retain 25%, after tax and costs of issuance, of all Shares acquired as a result of the vesting, exercise or payout of any Equity Compensation Award, until the Covered Officer retires or his or her employment otherwise ends. A Covered Officer's Multiple of Salary Requirement and the requirements with respect to retention of Equity Compensation Awards described herein comprise a Covered Officer's "Retention Requirement" under this Policy.

For the avoidance of doubt, the calculation of the Retention Requirement following the Actual Compliance Date will include only those Shares acquired as a result of the vesting, exercise or payout of any Equity Compensation Award granted to the Covered Officer at any time following such Covered Officer's Actual Compliance Date.

Time Period to Achieve Compliance

Each Covered Officer who was serving as of the date this Policy was initially adopted (November 20, 2007) shall acquire the applicable amount of Qualifying Shares to satisfy the Retention Requirement by January 1, 2013. Each Covered Officer newly elected or promoted after November 20, 2007 shall acquire the applicable amount of Qualifying Shares and satisfy the Retention Requirement for such position no later than January 1st following the fifth anniversary of the date of each such election or promotion (the "Required Compliance Date").

A change in a Covered Officer's Retention Requirement that results from an adjustment to a Covered Officer's base salary will become effective as of January 1st in the year immediately following such change and will be assessed as part of the annual review for such subsequent calendar year.

Qualifying Shares

In fulfilling the Retention Requirement, all Shares owned by the Covered Officer shall be counted, including (i) Shares held in trusts for the benefit of immediate family members where the covered officer is the trustee, (ii) Shares granted to the Covered Officer in the form of restricted stock or restricted stock units, whether or not vested, and (iii) Shares credited to the covered officer's account in the Company's Thrift and Profit-Sharing Plan. In addition, for the purposes of compliance with this Policy, all restricted stock units, and all dividend equivalent units related thereto, held by the covered officer shall be considered as qualifying Shares ("Qualifying Shares").

Stock options and performance units (as distinct from Shares which are actually issued as a result of exercise or vesting) shall not be counted as Qualifying Shares. As provided in Practice 615-6, the PSEG Insider Trading Practice "short sales" of Shares, including the purchase "puts"

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or “collars,” or otherwise hedging or pledging Shares is prohibited, and as such could are not counted as Qualifying Shares.

Administration

The Organization and Compensation Committee of the Company’s Board of Directors (“Committee”) shall have authority to vary the application of the provisions of this Policy for good cause or exceptional circumstances. The Senior Vice President - Human Resources shall report annually to the Committee on the status of each Covered Officer’s compliance with this Policy. In the event a covered officer is not in compliance with any provision of this Policy, the Committee may take such action as it deems appropriate, consistent with the provisions of the Company’s compensation plans and applicable law and regulations, to enable the covered officer to achieve compliance at the earliest practicable time or otherwise enforce this Policy. Such action may include establishing conditions with respect to all or part of any award granted under the terms of any of the Company’s incentive compensation programs.

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CONFIDENTIALITY, NON-COMPETITION AND NON-SOLICITATION AGREEMENT

In consideration of employment with PSEG Services Corporation, or any and all of its past, present or future predecessors, successors, parents, affiliated or subsidiary companies, divisions, or assigns thereof (the "Company"), I hereby agree to the following terms of this Confidentiality, Non-Competition and Non-Solicitation Agreement (the "Agreement"):

1. Confidentiality

a. I acknowledge that, during the course of my employment, I will come into possession of confidential Company information. I further acknowledge that this "Confidential Information" is a valuable, special, and unique business asset to the Company. I further acknowledge that it is the Company's policy to maintain as secret and confidential all Confidential Information, and that the disclosure of Confidential Information could cause irreparable damage to the Company. In recognition of the foregoing, I agree, at all times during the term of my employment with the Company and thereafter, to hold in strict confidence, and not to participate in the "Unauthorized" use of or to disclose to any person or entity any Confidential Information which I encounter, discover, obtain, conceive, create or develop.

b. As used in this Agreement, the term "Confidential Information" means any Company proprietary information, technical, business and financial data, knowledge, or trade secrets, including, but not limited to, research, products, services, vendor lists, identity of vendors, supplier lists, identity of suppliers, customer lists, identity of customers, contracts, agreements, identities of purchasers/sellers, leases, identities of lessors/lessess, licenses, account numbers, pricing information and costs, markets, software, computer programs, ideas, concepts, developments, inventions, discoveries, protocols, scripts, procedures and modes of operation, interfaces, works of authorship, databases or database criteria, methodologies, processes, formulas, computer codes, technology, designs, models, drawings, measures, internal documentation, engineering materials, hardware information, marketing data, finances, budgets, projections, forecasts, strategies, plans, organizational information/structure, employee and personnel information (including but not limited to salaries and other terms of compensation), other business information disclosed to me by the Company either directly or indirectly in writing, orally or by drawings or observation during the period of my employment with the Company, and any other information relating to matters within the scope of Company business or concerning any Company dealings or affairs.

c. As used in the Agreement, the term "Unauthorized" shall mean any use or disclosure, whether intentional or not: (i) in violation or contravention of the Company's policies or procedures; (ii) inconsistent with the Company's measures to protect its interests in the Confidential Information; (iii) in violation or contravention of any lawful instruction or directive, either written or oral, of a Company employee empowered to issue such instruction or directive; and/or (iv) in contravention of any duty existing under law or contract.

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d. During my employment with the Company and thereafter, I agree to take any and all reasonable and lawful measures to prevent the Unauthorized use and disclosure of Confidential Information by me, persons under my direction and/or supervision, or other persons about whom I have knowledge of having engaged in the Unauthorized use or disclosure of Confidential Information.

e. I agree to promptly disclose to the Company, as appropriate, all Confidential Information developed in whole or in part by me during my employment with the Company and which relates to the Company's business. Such Confidential Information is, and shall remain, the exclusive property of the Company. All writings created during my employment with the Company (excluding writings unrelated to the Company's business) are considered to be "works for hire" for the benefit of the Company, and, as such, the Company shall own all rights in such writings.

f. I understand that Confidential Information includes, but is not limited to, information pertaining to any aspect of the Company's business which is either information not known by actual or potential competitors of the Company or is confidential or proprietary information of the Company or its customers or suppliers, whether of a technical nature or otherwise. Notwithstanding the foregoing, I understand that Confidential Information shall not include: (i) any of the foregoing items which have become publicly known through no wrongful act of mine or of others who were under confidentiality obligations as to the item or items involved; or (ii) any information that I am required to disclose to, or by, any governmental or judicial authority; provided, however, that I give the Company prompt written notice thereof so that the Company may seek an appropriate protective order and/or waive in writing compliance with the confidentiality provisions of this Agreement.

g. I represent that my performance of all terms of this Agreement as an employee of the Company has not breached and will not breach any agreement to keep in confidence proprietary information, knowledge or data acquired by me in confidence or trust prior or subsequent to the commencement of my employment with the Company, and I will not disclose to the Company, or induce the Company to use, any inventions, confidential or proprietary information or material I may have obtained in connection with employment with any prior employer in violation of a confidentiality agreement, nondisclosure agreement or similar agreement with such prior employer. I further represent that my employment by the Company and the performance of my duties for the Company will not violate any agreement to which I am bound, including, but not limited to, confidentiality, non-competition and non-solicitation agreements.

h. I recognize that the Company has received and in the future will receive confidential or proprietary information from third parties subject to a Company duty to maintain the confidentiality of such information and to use it only for certain limited purposes. I agree to hold all such confidential or proprietary information in the strictest confidence and not to disclose it to any person, firm or corporation or to use it except as necessary in carrying out my work for the Company consistent with the Company's agreement with any such third party.

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2. Non-Competition

a. During my employment with the Company, I agree not to compete in any manner, either directly or indirectly, whether for compensation or otherwise, with the Company, or to assist any other person or entity, business or otherwise, to compete with the Company. Further, during my employment with the Company, I agree not to engage in other conduct, employment or business enterprise that is in conflict with, may present an actual conflict with, or may appear to be in conflict with or to present a conflict with, the Company without the prior written consent of the Company. Such consent shall not be effective unless it is provided in writing by the Vice President (or his/her superior(s)) of the business unit in which I am employed. I further acknowledge that the scope of the Company's business may change from time to time without notice to me and without formal amendment of this Agreement.

3. Non-Solicitation

a. I recognize and acknowledge that during my employment with the Company, I will have access to, learn, be provided with and, in some cases, prepare and create certain Confidential Information, all of which is of substantial value to the Company's business. I further recognize that I will have substantial contacts with customers, clients, investors, consultants, contractors and strategic partners of the Company and hereby acknowledge a fiduciary relationship will exist between me and the Company by reason of my having received and been privy to client, customer and other proprietary information which would give me an unfair advantage in attracting the Company's clients and customers or otherwise competing against the Company.

b. In light of the foregoing, during my employment with the Company and for a period of 12 months following the termination of my employment with the Company for any reason, I shall not either on my own behalf or on behalf of any other person or entity, business or otherwise (other than the Company), directly or indirectly:

(i) hire, solicit, or induce, or in any manner attempt to hire, solicit, or induce, any person who either at the time of such hiring, solicitation, or inducement or within the prior 12 months is employed by, an agent of, or a service provider to the Company, to terminate such person's employment, agency or service, as the case may be, with the Company;

(ii) call on, solicit or service any person or entity who was or is then a customer, vendor, supplier, licensee, licensor, purchaser, seller, lessee, lessor, or any other person or entity sharing a business relationship with the Company, in order to induce or attempt to induce the same to cease doing business with the Company, or in any way interfere with the relationship between any such customer, vendor, supplier, licensee, licensor, purchaser, seller, lessee, lessor, or any other person or entity sharing a business relationship with the Company (including, without limitation, making any negative statements or communications about the Company); or

(iii) call on, solicit or service any person or entity who was identified as a potential customer, vendor, supplier, licensee, licensor, purchaser, seller, lessee, lessor, or any other person or entity sharing a business relationship with the Company at the time

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I was an employee of the Company and with respect to which I participated, directly or actively, in conducting business on behalf of the Company, in order to induce or attempt to induce the same to cease doing business with the Company, or in any way interfere with the relationship between any such customer, vendor, supplier, licensee, licensor, purchaser, seller, lessee, lessor, or any other person or entity sharing a business relationship with the Company (including, without limitation, making any negative statements or communications about the Company).

4. Inventions

a. I have attached hereto, as Exhibit A, a list describing with particularity all intellectual property, including, but not limited to, property inventions, copyrights, copyright applications or registrations, original works of authorship, developments, improvements, patents, patent applications, trademarks, trademark applications, trade names or trade secrets which were created or owned by me prior to the commencement of my employment and which belong solely to me or belong to me jointly with another, which relate in any way to any of the Company's proposed businesses, products or research and development (collectively referred to as "Prior Inventions"), and which are not assigned to the Company. If disclosure of any such Prior Inventions would cause me to violate any prior confidentiality agreement, I understand that I am not to list such Prior Inventions in Exhibit A but am only to disclose a cursory name for each such invention, a listing of the parties to whom it belongs and the fact that full disclosure as to such inventions has not been made for that reason (to the extent these disclosures would not violate the confidentiality agreement). A space is provided on Exhibit A for such purpose. If I have no Prior Inventions to list, I will return Exhibit A with the appropriate box marked. If, in the course of the Employment Period, I agree to incorporate into a Company product, process or machine a Prior Invention owned by me or in which I have an interest, absent a prior written agreement or license between myself and the Company for such incorporation of the Prior Invention into a Company product, process or machine, then the Company is hereby granted and shall have a non-exclusive, royalty-free, irrevocable, perpetual, worldwide license (with the right to sublicense) to make, have made, copy, modify, make derivative works of, use, sell and otherwise distribute such Prior Invention as part of or in connection with such product, process or machine.

b. I agree that I will, without additional compensation, promptly make full written disclosure to the Company, will hold in trust for the sole right and benefit of the Company, and hereby assign to the Company and its successors and assigns my entire right, title, and interest throughout the world in any and all inventions, ideas, developments, concepts, know-how, improvements, trade secrets, or original works of authorship, regardless of whether or not any such inventions, ideas developments, concepts, know-how, improvements, trade secrets, or original works of authorship are in whole or in part capable of being patented, copyrighted or trademarked, which I may solely or jointly conceive, develop or reduce to practice, or cause to be conceived, developed or reduced to practice, while employed by the Company (whether or not during regular working hours) and which relate in any manner to the actual or reasonably anticipated business, research and/or other activities of the Company or which is suggested by or results from any task assigned to or performed by me on behalf of the Company. This assignment set forth in this Section (4)(b) will

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continue in full force and effect for a period of 12 months following the termination of my employment with the Company for any reason, provided the inventions, ideas, developments, concepts, know-how, improvements, trade secrets, or original works of authorship either: (i) relate at the time of conception or development to the actual or demonstrably proposed business or research and development activities of the Company; (ii) result from or relate to any work performed for the Company; or (iii) are developed through the use of Confidential Information and/or Company owned resources or in consultation with Company personnel (collectively referred to as "Inventions"). I further acknowledge that all Inventions which are made by me (solely or jointly with others) within the scope of and during my employment with the Company are "works made for hire" (to the greatest extent permitted by applicable law) for which I am, in part, compensated by my salary, unless regulated otherwise by law; but that, in the event any such Invention is deemed not to be a work made for hire, I hereby assign all rights in such Invention to the Company. I further represent and agree that to the best of my knowledge and belief, the practice by the Company of any of the Inventions will not violate or infringe upon any right, patent, copyright, trademark or right of privacy, or constitute libel or slander against or violate any other rights of any person, firm or corporation, and that I will use my best efforts to prevent any such violation.

c. I agree to keep and maintain reasonable and current written records of all Inventions made by me (solely or jointly with others) during my period of employment with the Company. The records may be in the form of notes, sketches, drawings, flow charts, electronic data or recordings, laboratory notebooks, and any other format. The records will be available to and remain the sole property of the Company at all times. I agree not to remove such records from the Company's place of business except as expressly permitted by Company policy which may, from time to time, be revised at the sole discretion of the Company for the purpose of furthering the Company's business.

a. I agree to assist the Company, or its designee, at the Company's expense, in every reasonable way to secure the Company's rights in the Inventions and any copyrights, copyright applications or registrations, patents, patent applications, trademarks, trademark applications, trade names, service marks, logos, database rights, algorithms, know-how, domain names, or other intellectual property rights relating thereto in any and all countries, including the disclosure to the Company of all pertinent information and data with respect thereto, the execution of all applications, specifications, oaths, assignments, recordations, and all other instruments which the Company shall deem necessary in order to apply for, obtain, maintain and transfer such rights and in order to assign and convey to the Company, its successors, assigns and nominees the sole and exclusive right, title and interest in and to such Inventions, and any intellectual property or other proprietary rights relating thereto. I further agree that my obligation to execute or cause to be executed, when it is in my power to do so, any such instrument or papers shall continue after the termination of this Agreement until the expiration of the last such intellectual property right to expire in any country of the world. If the Company is unable because of my mental or physical incapacity or unavailability for any other reason to secure my signature to apply for or to pursue any application for any United States or foreign patents or copyright registrations covering Inventions or original works of authorship assigned to the

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Company as above, then I hereby irrevocably designate and appoint the Company and its duly authorized officers and agents as my agent and attorney in fact, to act for and in my behalf and stead to execute and file any such applications or records and to do all other lawfully permitted acts to further the application for, prosecution, issuance, maintenance or transfer of letters patent or registrations thereon with the same legal force and effect as if originally executed by me. I hereby waive and irrevocably quitclaim to the Company any and all claims, of any nature whatsoever, which I now or hereafter have for past, present or future infringement of any and all proprietary rights assigned to the Company.

5. Representations, Warranties and Acknowledgments

a. I represent and warrant that my employment with the Company does not conflict with nor appear to conflict with and will not be constrained by any prior business relationship.

b. I understand and acknowledge: (i) that the Confidential Information is commercially and competitively valuable to the Company and is vital to the success of the Company's business at all locations at which the Company does business; (ii) that the Unauthorized use or disclosure of said Confidential Information would cause irreparable harm to the Company; (iii) that, by this Agreement, the Company is taking reasonable steps to protect its legitimate interests in its Confidential Information; (iv) that the restrictions on the activities in which I may engage set forth in this Agreement, and the locations and periods of time for which such restrictions apply, are reasonably necessary in order to protect the Company's legitimate interests in its Confidential Information; (v) that nothing herein shall prohibit the Company from pursuing any remedies, whether in law or equity, available to the Company for breach or threatened breach of this Agreement, including without limitation the recovery of damages by the Company from me and the enjoinment of such activities by temporary and permanent injunction; and (vi) by reason of the foregoing, I consent and agree that if I violate any of the provisions of this Agreement, the Company shall be entitled, in addition to any remedies the Company may have, including money damages, to an injunction to be issued by a court of competent jurisdiction, restraining me from committing or continuing any violations of the provision of this Agreement without the necessity of posting a bond or proving actual damages.

c. This Agreement is not applicable to the disclosure of "Confidential Information" in order to comply with an Order of any court or agency of competent jurisdiction. However, I agree to notify the Company immediately upon learning that such an Order has been requested or issued and I agree to advise the issuing court or agency of the existence of this Agreement.

6. Returning Company Property

I agree that, at the time of termination of my employment with the Company for any reason, or at any time at the request of the Company, I will deliver to the Company (and will not keep in my possession, recreate or deliver to anyone else) any and all Confidential Information and all other documents, materials, information or property pertaining to my employment with or otherwise belonging to the Company. This representation applies

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to information in any form, including, but not limited to, originals, photocopies, hard copies, and electronic versions. I further agree that any property situated on the Company's premises and owned by the Company, including disks and other storage media, filing cabinets or other work areas, is subject to inspection by Company personnel at any time with or without notice.

7. Investing or Trading in Securities

I agree not to solicit, use or disclose any information not generally available to the public, including, without limitation, Confidential Information, in any manner, directly or indirectly, so that I or any third party would obtain an advantage, benefit or gain, whether real or potential, over the general public, whether in connection with investing or trading in securities or for any other purpose.

8. Disclosure of Agreement

For a period of 12 months following the termination of my employment with the Company for any reason, I will disclose the existence of this Agreement to any prospective employer, partner, co-venturer, investor or lender prior to entering into an employment, partnership or other business relationship with such person or entity; provided, however, the foregoing shall not obligate me to disclose the existence of this Agreement when I am engaging in activities unrelated to the business of the Company.

9. Reasonableness of Restrictions

I recognize and acknowledge that the restrictions and limitations set forth in this Agreement are legitimate and reasonable. I further acknowledge that the restrictions and limitations set forth in this Agreement will in no way interfere with my ability to earn a living following the termination of my employment with the Company and that my ability to earn a livelihood without violating such restrictions is a material condition to my employment with the Company.

10. Injunctive Relief

I expressly acknowledge that any breach or threatened breach of any of the terms and/or conditions set forth in this Agreement will result in substantial, continuing and irreparable injury to the Company for which the Company would have no adequate remedy at law. Therefore, I hereby agree that, in addition to any other remedy that may be available to the Company, the Company shall be entitled to injunctive relief, specific performance or other equitable relief by a court of appropriate jurisdiction in the event of any breach or threatened breach of the terms of this Agreement. The Company may seek the foregoing relief without the necessity of posting a bond. Notwithstanding any other provision to the contrary, I acknowledge and agree that the Non-Competition Period (Section 2) or the Non-Solicitation Period (Section 3), as applicable, shall be tolled during any period of violation of any of the covenants in Section 2 or Section 3 hereof and during any other period required for litigation during which the Company seeks to enforce such covenants against me if it is ultimately determined that I was in breach of such covenants. The terms of this paragraph shall not prevent the Company from pursuing any other available remedies for any breach or threatened breach hereof, including, but not limited to, remedies available under this Agreement and the recovery of damages.

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11. General

a. I hereby acknowledge, and I agree not to claim any additional or special payment for my assignment of property contemplated in Section 4(b) above, and/or for my compliance with the other covenants and agreements herein contained.

b. This Agreement shall be governed by and in accordance with the laws of the State of New Jersey and is being executed in the State of New Jersey. The laws of New Jersey (including the choice of law rule of New Jersey) shall govern the validity and interpretation of this Agreement as well as the performance by me and the Company of our respective duties and obligations. Any dispute or claim relating to this Agreement shall be brought in a court of competent jurisdiction in New Jersey, and I hereby agree and consent to personal jurisdiction in New Jersey.

c. This Agreement shall not in any way be construed as to change, alter or modify the employment-at-will relationship between the Company and me.

d. If any provision or clause of this Agreement, or portion thereof, shall be held by any court or other tribunal of competent jurisdiction to be illegal, void or unenforceable in such jurisdiction, the remainder of such provisions shall not thereby be affected and shall be given full effect, without regard to the invalid portion. It is agreed that it is the intention of the parties to this Agreement that if any court construes any provision or clause of this Agreement, or any portion thereof, to be illegal, void or unenforceable because of the duration of such provision or the area or matter covered thereby, such court shall reduce the duration, area, or matter of such provision and, in its reduced form, such provision shall then be enforceable and shall be enforced.

e. This Agreement sets forth the entire agreement and understanding between the Company and me relating to the subject matter herein and merges all prior discussions between us. No modification or amendment to this Agreement, nor any waiver of any rights under this Agreement, will be effective unless in writing signed by the party to be charged. Any subsequent change or changes in my duties, obligations, rights or compensation will not affect the validity or scope of this Agreement.

f. I agree that if subsequent to execution of this Agreement I am transferred to or accept another position with any company affiliated with the Company, this Agreement shall continue in effect and shall be deemed as having been automatically assigned to such entity. Further, no change in assignment, position, department, division, unit or location to which I am assigned shall in any way affect the obligations under this Agreement. This Agreement shall not be affected by any change in name of the Company, or any consolidation, merger, acquisition or addition or deletion, and shall be automatically assigned to any successor company of the Company, and continue in full force and effect thereafter in accordance with its terms.

g. This Agreement shall inure to the benefit of the Company's successors or assigns and, as far as legally possible, shall be binding upon my heirs, legal representations and assigns.

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h. This Agreement shall survive termination of my employment with the Company irrespective of the reasons therefor.

i. The Company's waiver or failure to enforce the terms of this Agreement or any similar agreement in any one instance shall not constitute a waiver of its rights hereunder with respect to other violations of this Agreement.

j. I acknowledge that: (i) I have read and understand this Agreement; (ii) I fully understand the limitations which it imposes on me; (iii) I have had the opportunity to review this Agreement with the counsel of my choice; and (iv) I have signed and entered into this Agreement voluntarily and of my own free will.

Acknowledged, accepted and agreed this 2nd day of July, 2014
(Date) (Month) (Year)

Signature of Employee: /s/ Tamara L. Linde

Printed name of Employee: Tamara L. Linde

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EXHIBIT A

LIST OF PRIOR INVENTIONS
AND ORIGINAL WORKS OF AUTHORSHIP
EXCLUDED FROM SECTION 4 OF THE AGREEMENT

Title	Date	Identifying Number or Brief Description

_√___ No inventions or improvements

_____ Additional Sheets Attached

_____ Due to a prior confidentiality agreement, I cannot complete the disclosure above with respect to inventions or improvements generally listed below. Disclosing such information listed below will not violate the confidentiality agreement by which I am bound.

Invention or Improvement	Parties	Relationship

Signature of Employee: /s/ Tamara L. Linde

Printed Name of Employee: Tamara L. Linde

S1-SSA-0009 - 11345

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MANDATORY ARBITRATION AGREEMENT FOR OFFICERS ("Agreement")

As a condition of and in consideration for your employment with Public Service Enterprise Group, its subsidiaries or affiliates ("PSEG"), you agree that any and all disputes arising out of or relating to your employment with PSEG, the termination of your employment, or this Agreement will, at the demand of either party, be resolved through binding arbitration. Specifically:

- You agree to waive your right to a jury trial and a judicial forum in any action or proceeding related to your employment with PSEG, the termination of your employment, or this Agreement whether the claim is based upon statute, regulation, contract, tort or other common law principles. Such claims include but are not limited to claims of workplace discrimination, harassment, or retaliation. This waiver applies to claims against PSEG, its past, present or future, parents, affiliated or subsidiary companies, divisions, assigns, successors, insurers, and each of its/their past, present or future officers, directors, agents, consultants, employees, attorneys, boards of directors, and representatives.
- You understand that all substantive rights will be preserved in the arbitral forum, including any remedies that may be available.
- You acknowledge that the statute of limitations provided for by law will apply to any claim you may have, and any claim will be barred by the statute of limitations if a demand for arbitration is not made within that statute of limitations period.
- To the extent permitted by law, you agree that you will not participate in and are precluded from participating in any class or collective action, whether in a judicial or arbitral forum, related to your employment with PSEG or the termination thereof.
- You understand that claims for workers' compensation benefits or unemployment benefits are not subject to this Agreement as well as any claims where a judicial forum may not be waived by law.

Any arbitration under this Agreement will be administered by the American Arbitration Association ("AAA") in accordance with the Employment Dispute Resolution Rules of the AAA and in accordance with the Federal Arbitration Act. Arbitration will be conducted before one arbitrator at the AAA offices in Somerset, New Jersey or, by mutual consent, at another location agreed to by both parties. Following the demand for arbitration, either party may propose an arbitrator, and the parties will attempt to mutually agree upon an arbitrator. If the parties cannot mutually agree to an arbitrator within 30 days from the date the demand for arbitration is filed, the parties will notify AAA, and the parties will select an arbitrator utilizing AAA's regular process for the selection of arbitrators. Based on your position as an officer of the Company, each party will pay one-half of the filing fee, the arbitrator's fees, and administrative expenses related to the arbitration. Each party, if they choose to be represented, will be responsible for their own attorneys' fees and related costs. The arbitrator may award either party reasonable attorneys' fees and costs in accordance with and to the extent provided for by applicable laws.

Each party agrees to keep all such disputes and arbitration proceedings, and the facts underlying or related to any claims, strictly confidential except for disclosure of information required by law. The foregoing is not intended to preclude communications with previously identified fact and expert witnesses for the purpose of arbitrating the matter(s) in dispute. Each party further agrees to abide by and perform any award rendered by the arbitrator, and that a judgment of a court of competent jurisdiction may be entered on the award.

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If any clause of this Agreement should ever be determined to be illegal, void, or unenforceable, it is agreed that such determination will not affect the enforceability of any other clause or the remainder of the Agreement, which shall be enforced to the maximum extent possible. Further, if any provision of this Agreement is held to be overbroad or unreasonable, such provision shall be given effect to the maximum extent possible under law.

This Agreement will remain in full force and effect if you assume a new position within PSEG, including any transfer to a subsidiary or affiliate.

This Agreement does not alter your employment relationship with the Company which is employment at-will as explained in the accompanying offer letter.

You have a right to carefully review this Agreement and to consult with a person of your choosing, including an attorney (at your own expense), before signing this document.

If you have any questions regarding this Agreement, please contact the individual in Compensation & Benefits you are working with in connection with your offer of employment.

By signing this document, you represent that you are entering into this Agreement knowingly and voluntarily and free from any duress or coercion.

Acknowledged, accepted and agreed this 2nd day of July, 2014
(Date) (Month) (Year)

Signature of Employee: /s/ Tamara L. Linde

Printed name of Employee: Tamara L. Linde

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 2,456	$ 2,055	$ 2,011	$ 2,384	$ 2,616
(Income) Loss from Equity Investees, net of Distributions	4	(7)	9	(4)	(19)
Fixed Charges	450	458	479	522	571
Capitalized Interest	(16)	(16)	(19)	(14)	(67)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	(2)
Total Earnings	$ 2,894	$ 2,490	$ 2,480	$ 2,888	$ 3,099
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 430	$ 442	$ 465	$ 509	$ 555
Interest Factor in Rentals	20	16	14	13	14
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	2
Total Fixed Charges	$ 450	$ 458	$ 479	$ 522	$ 571
Ratio of Earnings to Fixed Charges	**6.43**	**5.44**	**5.18**	**5.53**	**5.43**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12a

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$1,251	$1,063	$1,099	$1,703	$1,932
(Income) Loss from Equity Investees, net of Distributions	3	(10)	(6)	(12)	(8)
Fixed Charges	150	143	164	208	238
Capitalized Interest	1	1	(6)	(10)	(63)
Total Earnings	$1,405	$1,197	$1,251	$1,889	$2,099
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 146	$ 139	$ 161	$ 205	$ 235
Interest Factor in Rentals	4	4	3	3	3
Total Fixed Charges	$ 150	$ 143	$ 164	$ 208	$ 238
Ratio of Earnings to Fixed Charges	**9.37**	**8.37**	**7.63**	**9.08**	**8.82**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12b

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$1,174	$ 993	$ 835	$ 861	$ 591
Fixed Charges	303	316	314	319	325
Capitalized Interest	(16)	(16)	(13)	(4)	(2)
Total Earnings	$1,461	$1,293	$1,136	$ 1,176	$ 914
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 293	$ 309	$ 308	$ 314	$ 320
Interest Factor in Rentals	10	7	6	5	5
Total Fixed Charges	$ 303	$ 316	$ 314	$ 319	$ 325
Ratio of Earnings to Fixed Charges	**4.82**	**4.09**	**3.62**	**3.69**	**2.81**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12c

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Years Ended December 31,				
	2014	**2013**	**2012**	**2011**	**2010**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$1,174	$ 993	$ 835	$ 861	$ 591
Fixed Charges	303	316	314	319	327
Capitalized Interest	(16)	(16)	(13)	(4)	(2)
Preferred Securities Dividend Requirements	—	—	—	—	(2)
Total Earnings	$1,461	$1,293	$1,136	$1,176	$ 914
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 293	$ 309	$ 308	$ 314	$ 320
Interest Factor in Rentals	10	7	6	5	5
Preferred Securities Dividend	—	—	—	—	1
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	—	—	1
Total Fixed Charges	$ 303	$ 316	$ 314	$ 319	$ 327
Ratio of Earnings to Fixed Charges	**4.82**	**4.09**	**3.62**	**3.69**	**2.80**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period, (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries, and (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 21

PUBLIC SERVICES ENTERPRISE GROUP INCORPORATED
SIGNIFICANT SUBSIDIARIES

Name	Ownership %	State of Incorporation
Public Service Electric and Gas Company	100	New Jersey
PSEG Power LLC	100	Delaware
PSEG Fossil LLC	100	Delaware
PSEG Nuclear LLC	100	Delaware
PSEG Energy Resources & Trade LLC	100	Delaware

The remaining subsidiaries of Public Service Enterprise Group Incorporated are not significant as defined in Regulation S-X.

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Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-120100, 333-106330, 333-193126, and 333-193127 on Forms S-8 and Registration No. 333-200352 on Form S-3 of our reports dated February 25, 2015, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Enterprise Group Incorporated and subsidiaries (the "Company,") and the effectiveness of the Company's internal control over financial reporting, appearing in the Annual Report on Form 10-K of Public Service Enterprise Group Incorporated for the year ended December 31, 2014.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 25, 2015

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Exhibit 23a

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-200354 on Form S-3 of our report dated February 25, 2015, relating to the consolidated financial statements and consolidated financial statement schedule of PSEG Power LLC and subsidiaries, appearing in this Annual Report on Form 10-K of PSEG Power LLC for the year ended December 31, 2014.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 25, 2015

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Exhibit 23b

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-200353 on Form S-3 of our report dated February 25, 2015, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Electric and Gas Company and subsidiaries, appearing in this Annual Report on Form 10-K of Public Service Electric and Gas Company for the year ended December 31, 2014.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 25, 2015

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2015

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31a

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2015

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31b

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2015

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31c

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2015

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 31d

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2015

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31e

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2015

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer

S1-SSA-0009 - 11361

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
February 25, 2015

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EXHIBIT 32a

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Carolina Dorsa

Carolina Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer
February 25, 2015

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EXHIBIT 32b

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
February 25, 2015

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EXHIBIT 32c

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Carolina Dorsa

Carolina Dorsa

PSEG Power LLC
Chief Financial Officer
February 25, 2015

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EXHIBIT 32d

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
February 25, 2015

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EXHIBIT 32e

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Carolina Dorsa

Carolina Dorsa

Public Service Electric and Gas Company
Chief Financial Officer
February 25, 2015

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2015

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange On Which Registered
Public Service Enterprise Group Incorporated	Common Stock without par value	New York Stock Exchange
	First and Refunding Mortgage Bonds	
Public Service Electric and Gas Company	9 1/4% Series CC, due 2021	New York Stock Exchange
	8%, due 2037	
	5%, due 2037	
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange

(Cover continued on next page)

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(Cover continued from previous page)

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
Public Service Electric and Gas Company	Medium-Term Notes
PSEG Power LLC	Limited Liability Company Membership Interest

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Public Service Enterprise Group Incorporated	Yes ☒	No ☐
Public Service Electric and Gas Company	Yes ☒	No ☐
PSEG Power LLC	Yes ☒	No ☐

Indicate by check mark if each of the registrants is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☒

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2015 was $19,819,621,677 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Public Service Enterprise Group Incorporated's sole class of Common Stock as of February 19, 2016 was 506,435,137.

As of February 19, 2016, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K. Each is filing its Annual Report on Form 10-K with the reduced disclosure format authorized by General Instruction I.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K of Public Service Enterprise Group Incorporated	Documents Incorporated by Reference
III	Portions of the definitive Proxy Statement for the 2016 Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 9, 2016, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities, and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC) including our subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or ongoing low pricing of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulations, including market structures and transmission planning,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators, including prudency reviews and disallowances,
- any deterioration in our credit quality or the credit quality of our counterparties,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations or increase the cost of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- delays or unforeseen cost escalations in our construction and development activities, or the inability to recover the carrying amount of our assets,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- increases in competition in energy supply markets as well as for transmission projects,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies,
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- an extended economic recession,
- an inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce, and
- changes in the credit quality and the ability of lessees to meet their obligations under our domestic leveraged leases.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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FILING FORMAT AND GLOSSARY

This combined Annual Report on Form 10-K is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to "we," "us," and "our" relate to PSEG or to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 191.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document that we file at the Public Reference Room of the SEC at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. You may also obtain our filed documents from commercial document retrieval services, the SEC's internet website at www.sec.gov or our website at www.pseg.com. Information on our website should not be deemed incorporated into or as a part of this report. Our Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

PART I

ITEM 1. BUSINESS

We were incorporated under the laws of the State of New Jersey in 1985 and our principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07102. We conduct our business through two direct wholly owned subsidiaries, PSE&G and Power, each of which also has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102.

We are an energy company with a diversified business mix. Our operations are located primarily in the Northeastern and Mid- Atlantic United States. Our business approach focuses on operational excellence, financial strength and disciplined investment. As a holding company, our profitability depends on our subsidiaries' operating results. Below are descriptions of our two principal direct operating subsidiaries.

PSE&G	Power
A New Jersey corporation, incorporated in 1924, which is a franchised public utility in New Jersey. It is also the provider of last resort for gas and electric commodity service for end users in its service territory. Earns revenues from its regulated rate tariffs under which it provides electric transmission and electric and gas distribution to residential, commercial and industrial customers in its service territory. It also offers appliance services and repairs to customers throughout its service territory. Has also implemented regulated demand response and energy efficiency programs and invested in solar generation within New Jersey.	A Delaware limited liability company formed in 1999 as a result of the deregulation and restructuring of the electric power industry in New Jersey. It integrates the operations of its merchant nuclear, fossil and renewable generating assets with its wholesale energy sales, fuel supply and energy transacting functions. Earns revenues from selling under contract or on the spot market a range of diverse products such as electricity, natural gas, emissions credits and other energy-related products used to optimize the operation of the energy grid.

Our other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and our operating subsidiaries with certain management, administrative and general services at cost.

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The following is a more detailed description of our business, including a discussion of our:

- Business Operations and Strategy
- Competitive Environment
- Employee Relations
- Regulatory Issues
- Environmental Matters

BUSINESS OPERATIONS AND STRATEGY

PSE&G

Our regulated transmission and distribution public utility, PSE&G, distributes electric energy and gas to customers within a designated service territory running diagonally across New Jersey where approximately 6.2 million people, or about 70% of New Jersey's population resides.

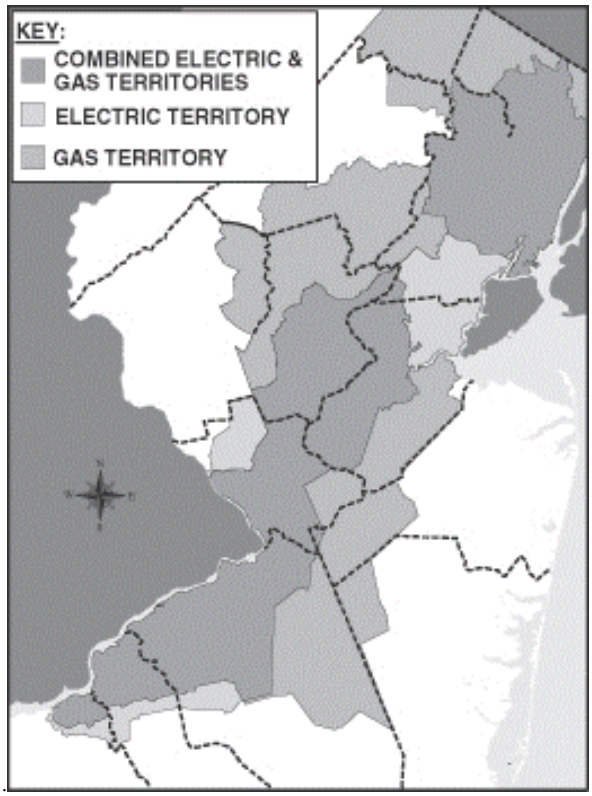

Products and Services

Our utility operations primarily earn margins through the transmission and distribution of electricity and the distribution of gas.

- **Transmission**—the movement of electricity at high voltage from generating plants to substations and transformers, where it is then reduced to a lower voltage for distribution to homes, businesses and industrial customers. Our revenues for these services are based upon tariffs approved by the Federal Energy Regulatory Commission (FERC).
- **Distribution**—the delivery of electricity and gas to the retail customer's home, business or industrial facility. Our revenues for these services are based upon tariffs approved by the New Jersey Board of Public Utilities (BPU).

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The commodity portion of our utility business' electric and gas sales is managed by basic generation service (BGS) and basic gas supply service (BGSS) suppliers. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for our utility operations.

We also earn margins through competitive services, such as appliance repair.

In addition to our current utility products and services, we have implemented several programs to increase the level of regulated solar generation within New Jersey, including:

- programs to help finance the installation of solar power systems throughout our electric service area, and
- programs to develop, own and operate solar power systems.

We have also implemented a set of energy efficiency and demand response programs to encourage conservation and energy efficiency by providing energy and cost saving measures directly to businesses and families. For additional information concerning these programs and the components of our tariffs, see Regulatory Issues—State Regulation and Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

How PSE&G Operates

We are a transmission owner in PJM Interconnection, L.L.C. (PJM) and we provide distribution service to 2.2 million electric customers and 1.8 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately 300 suburban and rural communities.

Transmission

We use formula rates for our transmission cost of service and investments. Formula-type rates provide a method of rate recovery where the transmission owner annually determines its revenue requirements through a fixed formula that considers Operations and Maintenance expenditures, Rate Base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. Our current approved rates provide for a base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn an additional incentive rate. For more information, see Regulatory Issues—Federal Regulation—Transmission Regulation.

Transmission Statistics

December 31, 2015		
Network Circuit Miles	**Billing Peak Megawatt (MW)**	**Historical Annual Load Growth 2011-2015**
1,769	9,595	(2.3)%

In 2015, we completed:

- the final phase of our portion of the 500 kV Susquehanna-Roseland project, bolstering electric reliability by partnering with PPL Electric Utilities (PPL) to construct a 150 mile power line between PPL's nuclear switchyard in Susquehanna, Pennsylvania and our switchyard in Roseland, New Jersey, and
- our Mickleton-Gloucester-Camden project which consisted of upgrading 10 circuit miles of overhead transmission, installing approximately 16 underground circuit miles and 10 overhead circuit miles of new 230 kilovolt (kV) and modifications/upgrades at five existing stations.

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We are also continuing to execute the following projects that focus on reliability improvements and replacement of aging infrastructure which are included in the 2016-2018 capital spend of $4.7 billion for Transmission disclosed in Item 7. MD&A—Capital Requirements.

Major Transmission Projects
As of December 31, 2015

Project	Expected In-Service Date
Northeast Grid Reliability (230 kV)	June 2015-June 2016
Bergen-Linden Corridor (345 kV)	June 2018
PJM Regional Transmission Expansion Plan - multiple projects	Various
69 kV Upgrade - multiple projects	Various
Transmission Life Cycle - multiple projects to replace aging infrastructure	Various
Transmission Hardening - multiple reliability projects	Various

Distribution

PSE&G distributes gas and electricity to end users in our respective franchised service territories. Our approved rates, established in our most recent gas and electric base rate proceeding completed in mid-2010, provide for a ROE of 10.3% on distribution rate base. The BPU has also approved a series of PSE&G infrastructure, energy efficiency and renewable energy investment programs with cost recovery through various clause mechanisms, with approved ROEs ranging from 9.75% to 10.3%. Our load requirements are split among residential, commercial and industrial customers, as described in the following table for 2015:

	% of 2015 Sales	
Customer Type	**Electric**	**Gas**
Commercial	57%	37%
Residential	33%	59%
Industrial	10%	4%
Total	**100%**	**100%**

While our customer base has modestly increased, electric load has declined and gas load has increased as illustrated below:

Electric and Gas Distribution Statistics
December 31, 2015

	Number of Customers	Electric Sales and Gas Firm Sales (A)	Historical Annual Load Growth 2011-2015
Electric	2.2 Million	41,715 Gigawatt hours (GWh)	(0.9)%
Gas	1.8 Million	2,523 Million Therms	2.1%

(A) Excludes Contract Service Gas (CSG) rate class sales, which do not impact margin.

The decline in electric sales is the result of changes in customer usage patterns, including conservation and more energy efficient appliances. Gas firm sales increased as a result of lower gas prices. Only gas firm sales impact margin.

During 2015, PSE&G continued to execute its BPU-approved $1.2 billion Energy Strong Program to (1) upgrade all of its electric substations that were damaged by water in recent storms; make investments that will create redundancy in the electric distribution system, reducing outages when damage occurs; and deploy technologies to better monitor system operations, enabling PSE&G to restore customers more quickly in the event of an electric outage, and (2) with respect to PSE&G's gas system, replace and modernize 250 miles of low-pressure cast iron gas mains in or near flood areas and upgrade five natural gas metering stations and a liquefied natural gas station recently affected by severe weather or located in flood zones.

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In addition, in November 2015, the BPU approved our settlement with the BPU Staff and the New Jersey Division of Rate Counsel regarding our Gas System Modernization Program (GSMP) through which we will invest $905 million over three years to modernize PSE&G's gas systems. The GSMP will replace approximately 510 miles of cast iron and unprotected steel gas mains and about 38,000 unprotected steel service lines to homes and businesses, including the uprating of the mains to higher pressure. The mains and service lines will be replaced with stronger, more durable plastic piping, reducing the potential for leaks and release of methane gas. The new elevated pressure systems also enable the installation of excess flow valves that automatically shut off gas flow if a service line is damaged, and better support the use of high-efficiency appliances.

Solar Generation

In order to support New Jersey's Energy Master Plan and the state's renewable energy goals, we have undertaken two major solar initiatives at PSE&G, the Solar Loan Program and the Solar 4 All and Solar 4 All Extension Programs. Our Solar Loan Program provides solar system financing to our residential and commercial customers. The loans are repaid with cash or solar renewable energy certificates (SRECs). We sell the SRECs used to repay the loans through a periodic auction, the proceeds of which are used to offset program costs. Our Solar 4 All Programs invest in utility-owned solar photovoltaic (PV) centralized solar systems installed on PSE&G property and third party sites, including landfill facilities, and solar panels installed on distribution system poles in our electric service territory. We sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition, we sell SRECs generated by the projects through the same periodic auction used in the loan program, the proceeds of which are used to offset program costs. As of December 31, 2015, we have invested an aggregate of approximately $818 million in both solar programs.

Supply

Although commodity revenues make up almost 41% of our revenues, we make no margin on the default supply of electricity and gas since the actual costs are passed through to our customers.

All electric and gas customers in New Jersey have the ability to choose their own electric energy and/or gas supplier. Pursuant to BPU requirements, we serve as the supplier of last resort for two types of electric and gas customers within our service territory that are not served by another supplier. The first type, which represents about 80% of PSE&G's load requirements, provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Residential Small Commercial Pricing (RSCP)). These rates change annually on June 1 and are based on the average price obtained at auctions in the current year and two prior years. The second type provides default supply for larger customers, with energy priced at hourly PJM real-time market prices for a contract term of 12 months (BGS-Commercial Industrial Energy Pricing (CIEP)).

We procure the supply to meet our BGS obligations through auctions authorized by the BPU for New Jersey's total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers are authorized to supply BGS to New Jersey's electric distribution companies (EDCs). Once validated by the BPU, electricity prices for BGS service are set. Approximately one-third of PSE&G's total BGS-RSCP eligible load is auctioned each year for a three-year term. For information on current prices, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

PSE&G procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with Power. The BPU has approved a mechanism designed to recover all gas commodity costs related to BGSS for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. PSE&G's revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each year. In addition, we have the ability to put in place two self-implementing BGSS increases on December 1 and February 1 of up to 5% and also may reduce the BGSS rate at any time and/or provide bill credits. See Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities for information on recent self-implementing credits. Any difference between rates charged under the BGSS contract and rates charged to our residential customers is deferred and collected or refunded through adjustments in future rates. Commercial and industrial customers that do not select third party suppliers are also supplied under the BGSS arrangement. These customers are charged a market-based price largely determined by prices for commodity futures contracts.

Markets and Market Pricing

Historically, there has been significant volatility in commodity prices. Such volatility can have a considerable impact on us since a rising commodity price environment results in higher delivered electric and gas rates for customers. This could result in decreased demand for electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs from our customers may be deferred under our regulated rate structure. A declining commodity price on the other hand, would be expected to have the opposite effect. For additional information, including the

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impact of natural gas commodity prices on electricity prices such as BGS, see Item 7. MD&A—Executive Overview of 2015 and Future Outlook.

Power

Through Power, we seek to produce low-cost electricity by efficiently operating our nuclear, coal, gas, oil-fired and renewable generation assets while balancing generation output, fuel requirements and supply obligations through energy portfolio management. We use the generation we own combined with commodity contracts and financial instruments to cover our commitments for BGS in New Jersey and other bilateral supply contract agreements.

Products and Services

As a merchant generator, our profit is derived from selling a range of products and services under contract to power marketers and to others, such as investor-owned and municipal utilities, and to aggregators who resell energy to retail consumers, or in the open market. These products and services include:

- **Energy**—the electrical output produced by generation plants that is ultimately delivered to customers for use in lighting, heating, air conditioning and operation of other electrical equipment. Energy is our principal product and is priced on a usage basis, typically in cents per kilowatt hour (kWh) or dollars per megawatt hour (MWh).
- **Capacity**—distinct from energy, capacity is a market commitment that a given generation unit will be available to an Independent System Operator (ISO) for dispatch to produce energy when it is needed to meet system demand. Capacity is typically priced in dollars per MW for a given sale period (e.g. day or month).
- **Ancillary Services**—related activities supplied by generation unit owners to the wholesale market that are required by the ISO to ensure the safe and reliable operation of the bulk power system. Owners of generation units may bid units into the ancillary services market in return for compensatory payments. Costs to pay generators for ancillary services are recovered through charges collected from market participants.
- **Emissions Allowances and Congestion Credits**—Emissions allowances (or credits) represent the right to emit a specific amount of certain pollutants. Allowance trading is used to control air pollution by providing economic incentives for achieving reductions in the emissions of pollutants. Congestion credits (or Financial Transmission Rights) are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path.

Power also sells wholesale natural gas, primarily through a full-requirements BGSS contract with PSE&G to meet the gas supply requirements of PSE&G's customers. On March 19, 2014, the BPU approved an extension of the long-term BGSS contract to March 31, 2019 and then year-to-year thereafter unless terminated by either party with a two year notice.

Approximately 45% of PSE&G's peak daily gas requirements is provided from Power's firm gas transportation capacity, which is available every day of the year. Power satisfies the remainder of PSE&G's requirements from storage contracts, liquefied natural gas, seasonal purchases, contract peaking supply and propane. Based upon the availability of natural gas beyond PSE&G's daily needs, Power sells gas to others and uses it for its generation fleet.

In addition to its nuclear and fossil generation fleet, Power owns and operates 148 MW direct current (dc) of PV solar generation facilities and has a 50% ownership interest in a 208 MW oil-fired generation facility in Hawaii.

The remainder of this section about Power covers our nuclear and fossil fleet in the Mid-Atlantic and Northeast regions which comprises the vast majority of Power's operations and financial performance.

How Power Operates

Nearly all of our generation capacity consists of nuclear and fossil generation (11,678 MW) that is located in the Northeast and Mid-Atlantic regions of the United States in some of the country's largest and most developed electricity markets. For additional information see Item 2. Properties.

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The map below shows the locations of our Northeast and Mid-Atlantic nuclear and fossil generation facilities:

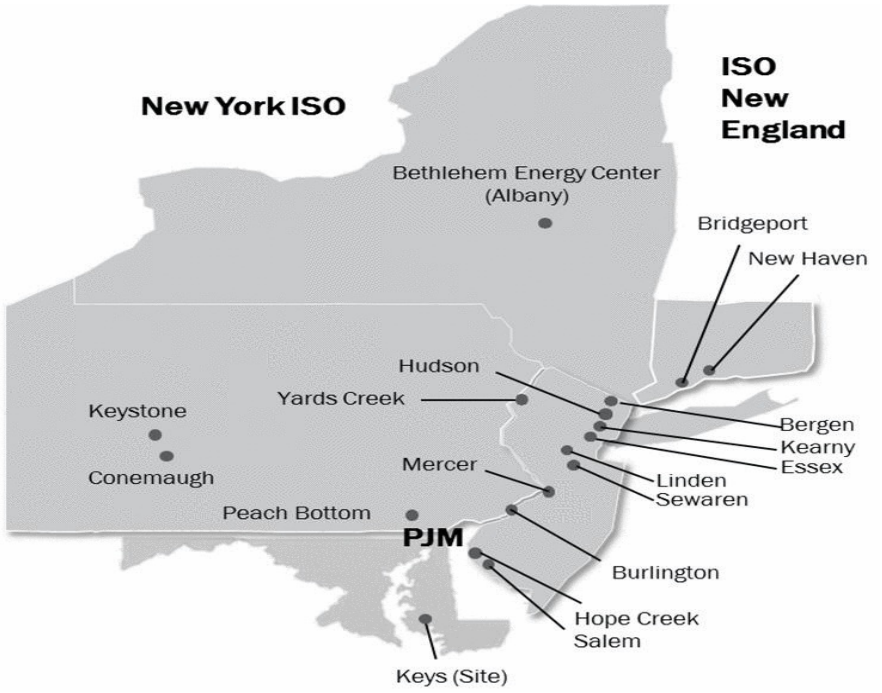

- **Generation Capacity**

Our nuclear and fossil installed capacity utilizes a diverse mix of fuels: 42% gas, 32% nuclear, 21% coal, 4% oil and 1% pumped storage. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2015 was approximately 55,000 GWh. The generation mix by fuel type in recent years has reflected the relatively more favorable price of natural gas compared to coal, making it more economical to run certain of our gas units in place of our coal units. The following table indicates the proportionate share of generating output by fuel type in 2015.

Generation by Fuel Type (A)	Actual 2015	
Nuclear:		
New Jersey facilities	36%	
Pennsylvania facilities	18%	
Fossil:		
Coal:		
Pennsylvania facilities	9%	
Connecticut facilities	1%	
Coal and Natural Gas:		
New Jersey facilities	1%	
Natural Gas and Oil:		
New Jersey facilities	26%	
New York facilities	9%	
Connecticut facilities	—%	(B)
Total	**100%**	

(A) Excludes pumped storage, solar facilities and fossil generation in Hawaii which account for less than 1.5 percent of total generation.

(B) Less than one percent.

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During 2015, we completed the extended power uprate of 130 MW at our co-owned Peach Bottom 2 and 3 nuclear units and installation of an advanced gas path uprate of 31 MW at our Bergen generation station. We are also executing the following growth projects which are included in the 2016-2018 capital spend of $1.9 billion for Fossil Growth Opportunities disclosed in Item 7. MD&A—Capital Requirements.

Major Growth Projects
As of December 31, 2015

Project	Location	Expected In-Service Date
Keys Energy Center gas-fired combined cycle generating station (755 MW)	Maryland	2018
Sewaren 7 dual-fueled combined cycle generating station (540 MW)	New Jersey	2018
Bridgeport Harbor 5 gas-fired combined cycle generating station (485 MW)	Connecticut	2019
Bethlehem Energy Center (BEC) combined cycle uprate (58 MW)	New York	2017/2018

- **Generation Dispatch**

  Our generation units are typically characterized as serving one or more of three general energy market segments: base load; load following; and peaking, based on their operating capability and performance. On a capacity basis, our portfolio of generation assets consists of 39% base load, 49% load following and 12% peaking. This diversity helps to reduce the risk associated with market demand cycles and allows us to participate in the market at each segment of the dispatch curve.

  - **Base Load Units** run the most and typically are called to operate whenever they are available. These units generally derive revenues from both energy and capacity sales. Variable operating costs are low due to the combination of highly efficient operations and the use of relatively lower-cost fuels. Performance is generally measured by the unit's "capacity factor," or the ratio of the actual output to the theoretical maximum output. In 2015, our base load capacity factors were as follows:

Unit	2015 Capacity Factor
Nuclear	
Salem Unit 1	93.9%
Salem Unit 2	85.9%
Hope Creek	88.6%
Peach Bottom Unit 2	95.7%
Peach Bottom Unit 3	89.6%
Coal	
Keystone	63.9%
Conemaugh	74.9%

  - **Load Following Units** typically operate between 20% and 70% of the time. The operating costs are generally higher per unit of output than for base load units due to the use of higher-cost fuels such as oil, natural gas and, in some cases, coal or lower overall unit efficiency. These units usually have more flexible operating characteristics than base load units which enable them to more easily follow fluctuations in load. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.
  - **Peaking Units** run the least amount of time and in some cases may utilize higher-priced fuels. These units typically operate less than 20% of the time but can typically start very quickly in response to system needs. Costs per unit of output tend to be higher than for base load units given the combination of higher heat rates and fuel costs. The majority of revenues are from capacity and ancillary service sales. The characteristics of these units enable them to capture energy revenues during periods of high energy prices.

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In the energy markets in which we operate, owners of power plants specify to the ISO prices at which they are prepared to generate and sell energy based on the marginal cost of generating energy from each individual unit. The ISOs will generally dispatch in merit order, calling on the lowest variable cost units first and dispatching progressively higher-cost units until the point that the entire system demand for power (known as the system "load") is satisfied reliably. Base load units are dispatched first, with load following units next, followed by peaking units.

During periods when one or more parts of the transmission grid are operating at full capability, thereby resulting in a constraint on the transmission system, it may not be possible to dispatch units in merit order without violating transmission reliability standards. Under such circumstances, the ISO may dispatch higher-cost generation out of merit order within the congested area and power suppliers will be paid an increased Locational Marginal Price (LMP) in congested areas, reflecting the bid prices of those higher-cost generation units.

The following chart depicts the unconstrained merit order of dispatch of our units in PJM, the ISO in the region where most of our generation units are located, based on illustrative historical dispatch cost. It should be noted that the low price of natural gas has resulted in changes in market price fluctuations from historical norms, wherein some gas-fired generation is now able to displace some coal-fired generation in the load-following portion of the curve.

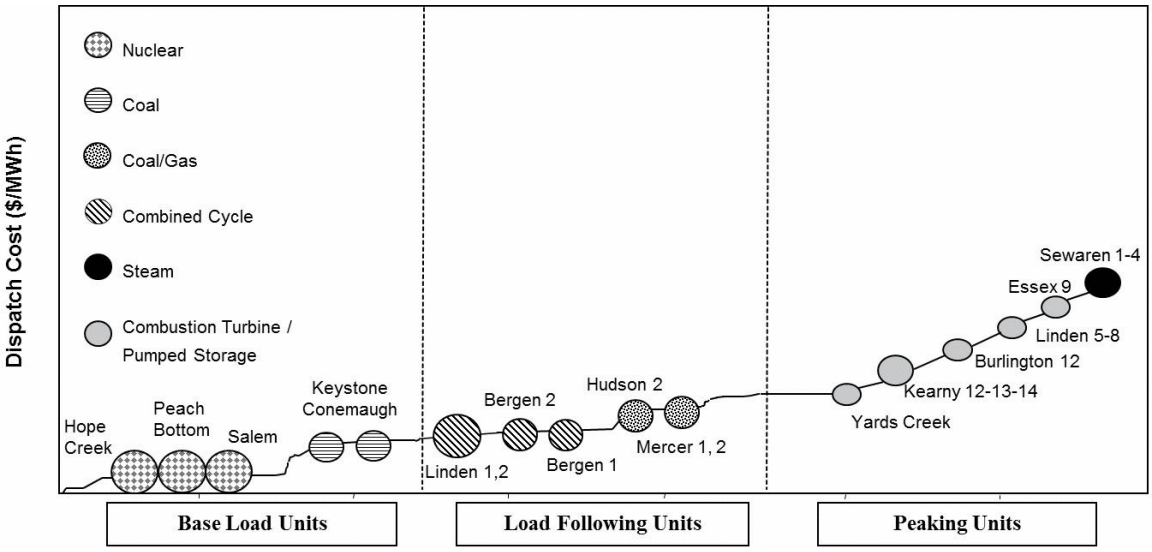

(A) The National Park, Sewaren 6, Mercer 3, Salem 3, Burlington 8 and 11, Bergen 3, Edison 1, 2 and 3 and Essex 10, 11 and 12 peaking units were retired in June 2015. Salem 3 continues to be used as an emergency backup generator for the Salem nuclear site.

(B) Keys Energy Center and Sewaren 7, which will replace Sewaren Units 1, 2, 3 and 4, are expected to be added to dispatch in 2018. Bridgeport Harbor Station 5 is scheduled to be added to dispatch in 2019. See Major Growth Projects above.

The size of each facility's circle in the above chart illustrates the relative MW generating capacity of that facility. For additional information on each of our generation facilities, see Item 2. Properties.

Typically, the bid price of the last unit dispatched by an ISO establishes the energy market-clearing price. After considering the market-clearing price and the effect of transmission congestion and other factors, the ISO calculates the LMP for every location in the system. The ISO pays all units that are dispatched their respective LMP for each MWh of energy produced, regardless of their specific bid prices. Since bids generally approximate the marginal cost of production, units with lower marginal costs typically generate higher operating profits than units with comparatively higher marginal costs.

This method of determining supply and pricing creates a situation where natural gas prices often have a major influence on the price that generators will receive for their output, especially in periods of relatively strong or weak demand. Therefore, changes in the price of natural gas will often translate into changes in the wholesale price of electricity. This can be seen in the following graphs which present historical annual spot prices and forward calendar prices as averaged over each year at two liquid trading hubs.

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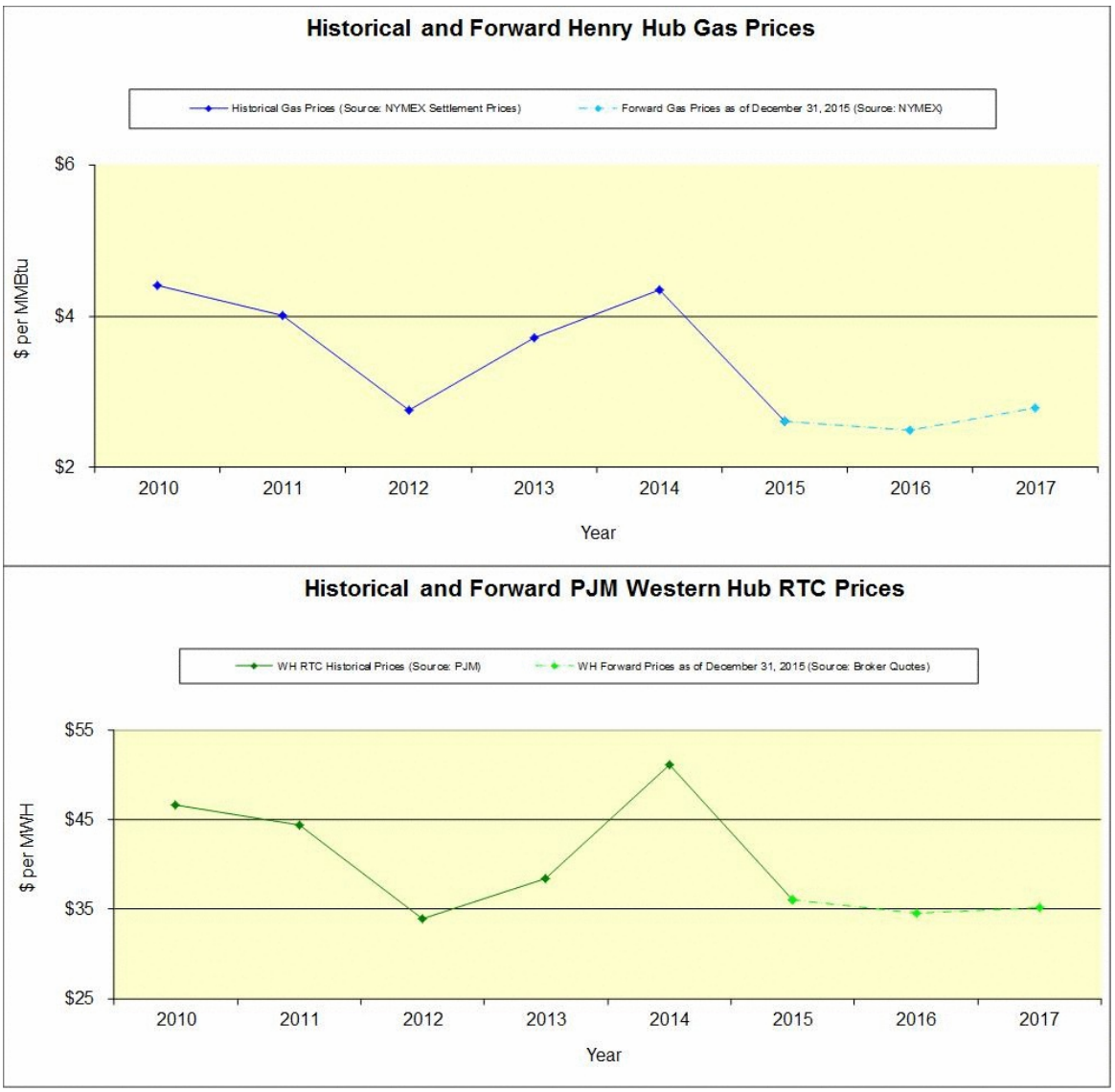

Historical data implies that the price of natural gas will continue to have a strong influence on the price of electricity in the primary markets in which we operate.

The prices reflected in the preceding graphs above do not necessarily illustrate our contract prices, but they are representative of market prices at relatively liquid hubs, with nearer-term forward pricing generally resulting from more liquid markets than pricing for later years. In addition, the prices do not reflect locational differences resulting from congestion or other factors, such as the availability of natural gas from the Marcellus and other shale-gas regions, which can be considerable. While these prices provide some perspective on past and future prices, the forward prices are volatile and there can be no assurance that such prices will remain in effect or that we will be able to contract output at these forward prices.

Fuel Supply

- ***Nuclear Fuel Supply***—We have long-term contracts for nuclear fuel. These contracts provide for:
  - purchase of uranium (concentrates and uranium hexafluoride),
  - conversion of uranium concentrates to uranium hexafluoride,

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- enrichment of uranium hexafluoride, and
- fabrication of nuclear fuel assemblies.

- ***Coal Supply***—Our Keystone, Conemaugh and Bridgeport stations operate on coal. Our Hudson and Mercer stations have the ability to operate on both coal and natural gas. Coal is delivered to our units through a combination of rail, truck, barge and ocean shipments.

  In order to control emissions levels, our Bridgeport 3 unit uses a specific type of coal obtained from Indonesia. We currently have a coal supply contract from Indonesia under contract through 2017 for the Bridgeport facility and believe that additional coal would be available after 2017 as required.

- ***Gas Supply***—Natural gas is the primary fuel for the bulk of our load following and peaking fleet. We purchase gas directly from natural gas producers and marketers. These supplies are transported to New Jersey by four interstate pipelines with which we have contracted. In addition, we have firm gas transportation contracts to serve a portion of the gas requirements for our BEC station in New York.

  We have 1.3 billion cubic feet-per-day of firm transportation capacity and 0.9 billion cubic feet-per-day of firm storage delivery under contract to meet our obligations under the BGSS contract. This capacity includes approximately 0.6 billion cubic feet-per-day of access to the northeast Pennsylvania Marcellus shale gas region. On an as-available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet.

  Power has contracted for approximately 125 million cubic feet-per-day of delivery capability on the PennEast Pipeline from eastern Pennsylvania to New Jersey with a targeted in-service date of November 2017. This additional delivery capability will be used to supplement the BGSS contract.

- ***Oil***—Oil is used as the primary fuel for one load following steam unit and four combustion turbine peaking units and can be used as an alternate fuel by several load following and peaking units that have dual-fuel capability. Oil for operations is drawn from on-site storage and is generally purchased on the spot market and delivered by truck or barge.

We expect to be able to meet the fuel supply demands of our customers and our own operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather, environmental regulations, and other factors. For additional information, see Item 7. MD&A—Executive Overview of 2015 and Future Outlook and Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Markets and Market Pricing

The vast majority of Power's generation assets are located in three centralized, competitive electricity markets operated by ISO organizations all of which are subject to the regulatory oversight of FERC:

- **PJM Regional Transmission Organization**—PJM conducts the largest centrally dispatched energy market in North America. It serves over 61 million people, nearly 19% of the total United States population, and has a record peak demand of 165,492 MW. The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The majority of our generating stations operate in PJM.

- **New York**—The New York ISO (NYISO) is the market coordinator for New York State and is responsible for managing the New York Power Pool and for administering its energy marketplace. This service area has a population of about 19 million and a record peak demand of 33,956 MW. Our BEC station operates in New York.

- **New England**—The ISO-New England (ISO-NE) is the market coordinator for the New England Power Pool and for administering its energy marketplace which covers Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. This service area has a population of about 14 million and a record peak demand of 28,130 MW. Our Bridgeport and New Haven stations operate in Connecticut.

The price of electricity varies by location in each of these markets. Depending upon our production and our obligations, these price differentials may increase or decrease our profitability.

Commodity prices, such as electricity, gas, coal, oil and emissions, as well as the availability of our diverse fleet of generation units to operate, also have a considerable effect on our profitability. These commodity prices have been, and continue to be, subject to significant market volatility. Over the long-term, the higher the forward prices are, the more attractive an

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environment exists for us to contract for the sale of our anticipated output. However, higher prices also increase the cost of replacement power; thereby placing us at greater risk should our generating units fail to operate effectively or otherwise become unavailable.

Over the past few years, lower wholesale natural gas prices have resulted in lower electric energy prices. One of the reasons for the lower natural gas prices is greater supply from more recently-developed sources, such as shale gas, much of which is produced in adjacent states (e.g. Pennsylvania). This trend has reduced margin on forward sales as we re-contract our expected generation output.

In addition to energy sales, we earn revenue from capacity payments for our generating assets. These payments are compensation for committing our generating units to the ISO for dispatch at its discretion. Capacity payments reflect the value to the ISO of assurance that there will be sufficient generating capacity available at all times to meet system reliability and energy requirements. Currently, there is sufficient capacity in the markets in which we operate. However, in certain areas of these markets there are transmission system transfer limitations which raise concerns about reliability and create a more acute need for capacity.

In PJM and ISO-NE, where we operate most of our generation, the market design for capacity payments provides for a structured, forward-looking, transparent capacity pricing mechanism. This is through the Reliability Pricing Model (RPM) in PJM and the Forward Capacity Market (FCM) in ISO-NE. These mechanisms provide greater transparency regarding the value of capacity and provide a pricing signal to prospective investors in new generating facilities so as to encourage expansion of capacity to meet future market demands.

The prices to be received by generating units in PJM for capacity have been set through RPM base residual and incremental auctions and depend upon the zone in which the generating unit is located. For each delivery year, the prices differ in the various areas of PJM, depending on the transfer limitations of the transmission system in each area. Keystone and Conemaugh receive lower capacity prices than the majority of our PJM generating units since there are fewer constraints in that region and our generating units in New Jersey usually receive higher pricing.

Our PJM generating units are located in several zones and Power expects to realize the following average capacity prices from the base and incremental auctions which have been completed:

Delivery Year	MW-day
June 2015 to May 2016	$168
June 2016 to May 2017	$172
June 2017 to May 2018	$177
June 2018 to May 2019	$215

The price that must be paid by an entity serving load in the various zones is also set through these auctions. These prices can be higher or lower than the prices noted in the table above due to import and export capability to and from lower-priced areas.

We have obtained price certainty for our PJM capacity through May 2019 and New England capacity through May 2020 through the RPM and FCM pricing mechanisms, respectively.

Like PJM and ISO-NE, the NYISO provides capacity payments to its generating units, but unlike the other two markets, the New York market does not provide a forward price signal beyond a six month auction period.

On a prospective basis, many factors may affect the capacity pricing, including but not limited to:

- load and demand,
- availability of generating capacity (including retirements, additions, derates and forced outage rates),
- capacity imports from external regions,
- transmission capability between zones,
- available amounts of demand response resources,
- pricing mechanisms, including potentially increasing the number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM and the other ISOs may propose over time, and
- legislative and/or regulatory actions that permit subsidized local electric power generation.

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For additional information on the RPM and FCM markets, as well as on state subsidization through various mechanisms, see Regulatory Issues—Federal Regulation.

Hedging Strategy

To mitigate volatility in our results, we seek to contract in advance for a significant portion of our anticipated electric output, capacity and fuel needs. We seek to sell a portion of our anticipated lower-cost generation over a multi-year forward horizon, normally over a period of two to three years. We believe this hedging strategy increases stability of earnings.

Among the ways in which we hedge our output are: (1) sales at PJM West and (2) BGS and similar full-requirements contracts. Sales at PJM West reflect block energy sales at the liquid PJM Western Hub and other transactions that seek to secure price certainty for our generation related products. The BGS-RSCP contract, a full-requirements contract that includes energy and capacity, ancillary and other services, is awarded for three-year periods through an auction process managed by the BPU. The volume of BGS contracts and the mix of electric utilities that our generation operations serve will vary from year to year. Pricing for the BGS contracts, including a capacity component, for recent and future periods by purchasing utility is as follows:

Load Zone ($/MWh)	2013-2016	2014-2017	2015-2018	2016-2019
PSE&G	$92.18	$97.39	$99.54	$96.38
Jersey Central Power & Light Company (JCP&L)	$83.70	$84.44	$80.42	$74.85
Atlantic City Electric Company	$87.27	$87.80	$86.06	$82.14
Rockland Electric Company	$92.58	$95.61	$90.66	$85.02

Although we enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation, there is variability in both our actual output as well as in the effectiveness of our hedges. Actual output will vary based upon total market demand, the relative cost position of our units compared to other units in the market and the operational flexibility of our units. Hedge volume can also vary, depending on the type of hedge into which we have entered. The BGS auction, for example, results in a contract that provides for the supplier to serve a percentage of the default load of a New Jersey EDC, that is, the load that remains after some customers have chosen to be served directly either by third party suppliers or through municipal aggregation. The amount of power supplied through the BGS auction varies based on the level of the EDC's default load, which is affected by the number of customers who are served by third party suppliers, as well as by other factors such as weather and the economy.

In recent years, as market prices declined from previous levels, there was an incentive for more of the smaller commercial and industrial electric customers to switch to third party suppliers. In a falling price environment, this has a negative impact on our margins, as the anticipated BGS pricing is replaced by lower spot market pricing. As average BGS rates have declined to a level that more closely resembles current market prices, customers may see less of an incentive to switch to third party suppliers. We are unable to determine the degree to which this switching, or “migration,” will continue, but the impact on our results could be material should market prices fall or rise significantly.

As of February 11, 2016, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2018.

Base Load Generation	2016	2017	2018
Generation Sales	100%	70%-75%	25%-30%

In a changing market environment, this hedging strategy may cause our realized prices to differ materially from current market prices. In a rising price environment, this strategy normally results in lower margins than would have been the case had no hedging activity been conducted. Alternatively, in a falling price environment, this hedging strategy will tend to create margins higher than those implied by the then-current market.

Our fuel strategy is to maintain certain levels of uranium in inventory and to make periodic purchases to support such levels. Our nuclear fuel commitments cover approximately 100% of our estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2020. We also have various long-term fuel purchase commitments for coal to support our fossil generation stations. These purchase obligations are consistent with our strategy in general to enter into contracts for our fuel supply in comparable volumes to our sales contracts.

We take a more opportunistic approach in hedging both the fuel for and the anticipated output of our natural gas-fired generation. The generation from these units is less predictable, as a significant portion of these units will only dispatch when aggregate market demand has exceeded the supply provided by lower-cost units. Additionally, the recent development of low-

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cost gas supplies in the Marcellus region presents opportunities during certain portions of the year to procure gas for our generating units at attractive prices.

Taking into account the hedging strategy, our expected capacity revenues from the capacity market mechanisms described above and certain ancillary service payments such as reactive power, more than half of Power's gross margin in the upcoming year is relatively certain.

Other

Energy Holdings primarily owns and manages a portfolio of lease investments. Over the past several years, we have terminated all of our international leveraged leases in order to reduce the cash tax exposure related to these leases. We have also reduced our risk by opportunistically monetizing all of our previous international investments.

The majority of Energy Holdings' remaining $784 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2015, 73% of our total leveraged lease investments were rated as below investment grade by Standard & Poor's.

Energy Holdings' leveraged leasing portfolio is designed to provide a fixed rate of return. Leveraged lease investments involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease financing, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and, with respect to our lease investments, is not presented on our Consolidated Balance Sheets.

The lessor acquires economic and tax ownership of the asset and then leases it to the lessee for a period of time no greater than 80% of its remaining useful life. As the owner, the lessor is entitled to depreciate the asset under applicable federal and state tax guidelines. The lessor receives income from lease payments made by the lessee during the term of the lease and from tax benefits associated with interest and depreciation deductions with respect to the leased property. Our ability to realize these tax benefits is dependent on operating gains generated by our other operating subsidiaries and allocated pursuant to the consolidated tax sharing agreement between us and our operating subsidiaries.

Lease rental payments are unconditional obligations of the lessee and are set at levels at least sufficient to service the non-recourse lease debt. The lessor is also entitled to any residual value associated with the leased asset at the end of the lease term. An evaluation of the after-tax cash flows to the lessor determines the return on the investment. Under accounting principles generally accepted in the United States (GAAP), the leveraged lease investment is recorded net of non-recourse debt and income is recognized as a constant return on the net unrecovered investment.

For additional information on leases, including the credit, tax and accounting risks, see Item 1A. Risk Factors, Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Credit Risk, and Item 8. Financial Statements and Supplementary Data—Note 7. Financing Receivables.

In accordance with a twelve year Amended and Restated Operations Services Agreement (OSA) entered into by PSEG LI and the LIPA, PSEG LI commenced operating LIPA's electric T&D system in Long Island, New York on January 1, 2014. As required by the OSA, PSEG LI also provides certain administrative support functions to LIPA. PSEG LI uses its brand in the Long Island T&D service area. Pursuant to the OSA, PSEG LI acts as LIPA's agent in performing many of its obligations and in return (a) receives reimbursement for pass-through operating expenditures, (b) receives a fixed management fee and (c) is eligible to receive an incentive fee contingent on meeting established performance metrics. In addition, there is the opportunity for the parties to extend the contract for an additional eight years subject to the achievement by PSEG LI of certain performance levels during the initial term of the OSA. Also, as of January 2015, Power began providing fuel procurement and power management services to LIPA under separate agreements.

COMPETITIVE ENVIRONMENT

PSE&G

Our transmission and distribution business is minimally impacted when customers choose alternate electric or gas suppliers since we earn our return by providing transmission and distribution service, not by supplying the commodity. Increased reliance by customers on net-metered generation, including solar, and changes in customer behaviors can result in decreased reliance on our system and impact our revenues and investment opportunities. The demand for electric energy and gas by customers is affected by customer conservation, economic conditions, weather and other factors not within our control.

Changes in the current policies for building new transmission lines, such as those ordered by FERC and being implemented by PJM and other ISOs to eliminate contractual provisions that previously provided us a "right of first refusal" (ROFR) to

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construct projects in our service territory, could result in third party construction of transmission lines in our area in the future and also allow us to seek opportunities to build in other service territories. These implementing rules within the regions are still in flux so both the extent of the risk within our service territory and the opportunities for our transmission business elsewhere remain difficult to assess. For additional information, see the discussion in Regulatory Issues—Federal Regulation—Transmission Regulation, below.

Construction of new local generation also has the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints.

Power

Various market participants compete with us and one another in buying and selling in the wholesale energy markets, entering into bilateral contracts and selling to aggregated retail customers. Our competitors include:

- merchant generators,
- domestic and multi-national utility generators,
- energy marketers,
- banks, funds and other financial entities,
- fuel supply companies, and
- affiliates of other industrial companies.

New additions of lower-cost or more efficient generation capacity could make our plants less economic in the future. Although it is not clear if this capacity will be built or, if so, what the economic impact will be, such additions would impact market prices and our competitiveness.

Our business is also under competitive pressure due to demand side management (DSM) and other efficiency efforts aimed at changing the quantity and patterns of usage by consumers which could result in a reduction in load requirements. A reduction in load requirements can also be caused by economic cycles, weather, municipal aggregation and other customer migration and other factors. In addition, how resources such as demand response and capacity imports are permitted to bid into the capacity markets also affects the prices paid to generators such as Power in these markets. It is also possible that advances in technology, such as distributed generation and micro grids, will reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. To the extent that additions to the electric transmission system relieve or reduce limitations and constraints in eastern PJM where most of our plants are located, our revenues could be adversely affected. Changes in the rules governing what types of transmission will be built, who is selected to build transmission and who will pay the costs of future transmission could also impact our revenues.

Adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, would have the effect of artificially depressing prices in the competitive wholesale market and thus have the potential to harm competitive markets, on both a short-term and a long-term basis. At the same time, changes implemented in the PJM and New England capacity markets and other proposed market changes discussed more fully in Regulatory Issues—Federal Regulation provide the opportunity for additional compensation in both the energy and capacity markets.

Environmental issues, such as restrictions on emissions of carbon dioxide (CO_2) and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant, thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states. If any new legislation or regulations were to require our competitors to meet the environmental standards currently imposed upon us, we would likely have an economic advantage since we have already installed significant pollution-control technology at most of our fossil-fueled stations.

In addition, pressures from renewable resources could increase over time. For example, many parts of the country, including the mid-western region served by the Midwest Independent System Operator (MISO), the PJM region and the California ISO, have either implemented or proposed implementing changes to their respective regional transmission planning processes that may enable the construction of large amounts of "public policy" transmission to move renewable generation to load centers. For additional information, see the discussion in Regulatory Issues—Federal Regulations—Transmission Regulation.

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EMPLOYEE RELATIONS

As of December 31, 2015, we had 13,025 employees within our subsidiaries, including 8,111 covered under collective bargaining agreements. Two of our collective bargaining union agreements will expire in November 2016, five in April 2017, two in October 2017, and one in May 2018. We believe we maintain satisfactory relationships with our employees.

Employees as of December 31, 2015	PSE&G	Power	PSEG LI	Other
Non-Union	1,812	1,280	755	1,067
Union	4,968	1,659	1,476	8
Total Employees	**6,780**	**2,939**	**2,231**	**1,075**

REGULATORY ISSUES

Federal Regulation

FERC

FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act. PSE&G and the generation and energy trading subsidiaries of Power are public utilities as defined by the FPA. FERC has extensive oversight over such public utilities. FERC approval is usually required when a public utility seeks to: sell or acquire an asset that is regulated by FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations.

FERC also regulates generating facilities known as qualifying facilities (QFs). QFs are cogeneration facilities that produce electricity and another form of useful thermal energy, or small power production facilities where the primary energy source is renewable, biomass, waste or geothermal resources. QFs must meet certain criteria established by FERC. We own various QFs through Power. QFs are subject to some, but not all, of the same FERC requirements as public utilities.

FERC also regulates Regional Transmission Operators (RTOs)/ISOs, such as PJM, and their energy and capacity markets.

For us, the major effects of FERC regulation fall into five general categories:

- Regulation of Wholesale Sales—Generation/Market Issues/Market Power
- Energy Clearing Prices
- Capacity Market Issues
- Transmission Regulation
- Compliance

Regulation of Wholesale Sales—Generation/Market Issues/Market Power

Under FERC regulations, public utilities must receive FERC authorization to sell power in interstate commerce. They can sell power at cost-based rates or apply to FERC for authority to make market-based rate (MBR) sales. For a requesting company to receive MBR authority, FERC must first make a determination that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. FERC requires that holders of MBR tariffs file an update every three years demonstrating that they continue to lack market power and/or that their market power has been sufficiently mitigated and report in the interim to FERC any material change in facts from those FERC relied on in granting MBR authority.

PSE&G, PSEG Energy Resources & Trade LLC, PSEG Power Connecticut, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG New Haven LLC all were granted MBR authority from FERC in October 2014. In order to retain its MBR authority, each of these entities will be required to submit its power uprate compliance filing to FERC by the end of December 2016.

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Energy Clearing Prices

Energy clearing prices in the markets in which we operate are generally based on bids submitted by generating units. Under FERC-approved market rules, bids are subject to price caps and mitigation rules applicable to certain generation units. FERC rules also govern the overall design of these markets. At present, all units within a delivery zone receive a clearing price based on the bid of the marginal unit (i.e. the last unit that must be dispatched to serve the needs of load) which can vary by location. In addition, recent rule changes in the energy markets administered by PJM and ISO-NE (see Capacity Market Issues below) impose rigorous performance obligations and nonperformance penalties on resources during times of system stress. These FERC rules have a direct impact on the prices received by our units.

FERC has also recently ordered certain favorable changes to energy market price formation rules improving shortage pricing and enhancing bidding flexibility for units. We continue to advocate in this context for additional changes in market rules that would provide more transparency about energy market prices. We cannot predict what action FERC might ultimately take, but such an examination could lead to future rule changes.

Capacity Market Issues

PJM, the NYISO and the ISO-NE each have capacity markets that have been approved by FERC. FERC regulates these markets and continues to examine whether the market design for each of these three capacity markets is working optimally. Issues presented in various forums include consideration of whether capacity market rules properly address and foster the development of state public policies, demand response (DR) and emerging technologies, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market outcomes. We cannot predict what action, if any, FERC might take with regard to capacity market design.

PJM—The RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under the RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of the RPM in PJM continue to evolve and be refined in stakeholder proceedings and FERC proceedings in which we are active.

During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product definition with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. However, aspects of FERC's order are currently pending on rehearing before the FERC Commission and, ultimately, appeals of FERC's rehearing order are likely. The CP mechanism was implemented for the 2015 base residual auction (covering the 2018-2019 Delivery Year) which concluded on August 21, 2015. The CP product will be implemented fully for the 2020-2021 Delivery Year. Based upon the August 2015 base residual auction results, the CP mechanism appears to have provided the opportunity for enhanced capacity market revenue streams for Power but future impacts cannot be assured. Further compliance with the CP mechanism may entail additional performance risks and require additional investments.

In May 2014, in a case involving the proper level of compensation for DR resources in the energy markets, the D.C. Circuit Court of Appeals (D.C. Court) held that DR is not a FERC-jurisdictional product, thereby calling into question DR resources' ability to participate in either the energy or capacity markets in the future. In January 2015, FERC filed a petition to the U.S. Supreme Court to review the D.C. Court's ruling. In January 2016, the U.S. Supreme Court overturned the D.C. Court's ruling and determined that FERC has the authority to regulate wholesale DR and market operators' compensation of DR bids at full market value. This ruling removes any risk to DR's participation in the energy and capacity markets. As a result, we expect activity to continue at the PJM stakeholder process regarding eligibility criteria for DR, including as a CP resource.

In September 2014, PJM filed at FERC to re-set the Variable Resource Requirement (VRR) curve for the RPM. PJM expects to reset the VRR every four years. Establishment of the VRR curve is a critical component in determining how generators are paid in the capacity auction. In November 2014, FERC accepted PJM's filing, which we believe represents an improvement over the status quo in terms of appropriately setting the demand curve. However, we and other generators have challenged FERC's approval order on rehearing, taking exception to FERC's approval of the manner in which PJM calculated the cost of capital and labor costs that form the basis for the Cost of New Entry component of the demand curve, which we believe have been set too low and do not accurately reflect the costs of building a new generating unit in PJM. Rehearing was denied in December 2015 and the PSEG Companies, and a trade association, have sought review of FERC's order at the D.C. Court.

An emerging issue in PJM involves the impact of subsidized generation on RPM market outcomes. This issue is most directly presented in connection with proposals pending before the Ohio Public Utility Commission whereby First Energy Corp. and American Electric Power are proposing to enter into power purchase agreements (PPAs) with their non-utility generation affiliates providing for above-market purchases from certain coal plants and a nuclear plant. The subsidies under these contracts would likely enable the affected generators to submit reduced bids into PJM capacity markets that are not reflective of their actual costs of operation and may prevent uneconomic generating facilities from retiring. Either of these conditions could artificially suppress capacity market prices, especially given that PJM's currently effective "minimum offer price rule" (MOPR) would not apply to these plants as the MOPR only applies to new gas-fired units.

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We are unable to predict the results of these pending proceedings or any future related proceedings or to calculate the potential impacts on our business.

MISO—MISO does not have a mandatory capacity market in place, as load serving entities may submit Fixed Resource Adequacy Plans in lieu of participating in the capacity auction. Significant quantities of capacity from MISO are imported into PJM which tends to have a downward effect on PJM capacity prices. However, recent enhancements to PJM market rules have tightened eligibility requirements for PJM imports and reduced these impacts. The issue of "capacity portability" from MISO continues to be examined in the stakeholder process.

ISO-NE—ISO-NE's market for installed capacity in New England provides fixed capacity payments for generators, imports and DR. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. ISO-NE also employs a mechanism, similar to PJM's CP mechanism, that provides incentives for performance and that imposes penalties for non-performance during times of system stress. We view this mechanism as generally positive for generating resources as providing more robust income streams. However, it also imposes additional penalty risk for non-performance. One aspect of the current market design that we do not support is the exemption from the MOPR in the capacity market afforded for up to 200 MW annually (600 MW cumulatively) of renewable resources. We believe that the exemption is unduly discriminatory and will artificially suppress capacity prices. In March 2015, in conjunction with other companies, we filed a petition for review with the D.C. Court of FERC's ruling accepting the exemption. On December 1, 2015, following a request by FERC for a voluntary remand of the order, the D.C. Court remanded the case to FERC for additional consideration. Also in December 2015, ISO-NE filed a proposal that would allow resource owners to submit bids in the capacity auction reflecting their desire to retire a resource. However, this proposal also includes elements which we believe would have an unwarranted disruptive effect on efficient price formation in the capacity market. We have filed in opposition to this proposal. Finally, demand curves for ISO-NE capacity zones, including potential changes to the system-wide demand curves, are under consideration in an ISO-NE stakeholder process. These curves could have a significant impact upon the revenues our generation can expect to receive in the capacity market in New England.

NYISO—NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. Various matters pending before FERC could affect the competitiveness of this market and the outcome of these proceedings could result in artificial price suppression unless sufficient market protections are adopted.

One capacity market matter pending before FERC involves rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons. On March 19, 2015, FERC issued an order which held that units receiving special reliability payments could properly take those payments into account in formulating capacity market bids. We believe that this ruling could impact efficient price formation in the capacity market and could artificially suppress capacity market outcomes. On April 20, 2015, a trade association, Independent Power Producers of New York, Inc. (IPPNY) of which Power is a member filed for rehearing by FERC of this ruling. This rehearing is still pending. Also, in connection with this same proceeding, FERC required NYISO to submit a report addressing whether buyer-side mitigation measures are needed for new entry occurring in the "Rest of State" region and for uneconomic retention and repowering anywhere in the state. NYISO filed a report with FERC in December 2015 contending that these measures are not needed. The IPPNY has opposed NYISO's contentions. In addition, on May 8, 2015, the New York Public Service Commission and other New York agencies filed a complaint at FERC requesting certain exemptions from the NYISO rules that prevent capacity suppliers from submitting bids that are not market competitive. On October 9, 2015, FERC granted in part, certain of the requested exemptions for renewable resources and for resources being used by the owner for self-supply. The IPPNY has sought rehearing of this order. This rehearing is still pending.

Price Formation Initiatives

Power has been actively involved both through stakeholder processes and through filings at FERC in seeking improvements to the rules for setting prices for energy in the day-ahead and real-time markets administered by PJM and other system operators. A recent development which is designed to increase market transparency involves a November 20, 2015 order in which FERC directed each RTO/ISO to publicly provide information related to certain price formation issues. If FERC's initiative leads to reforms in the identified price formation issue areas, it could result in energy market prices that more accurately reflect prevailing system conditions and the costs of operating the marginal generating units. Specifically, each RTO/ISO was required to submit information regarding: (1) the ability of inflexible resources to set price; (2) how simultaneously occurring system outages are reflected in the market model; (3) the tools to anticipate near-term system conditions; (4) the allocation of costs associated with units dispatched for reliability out-of-merit; and (5) transparency. Each RTO/ISO was also directed to file a report that provides an update on its current practices in the identified topic areas, that provides the status of its efforts (if any) to address each of the five issues, and that fully responds to the questions contained in the FERC order by March 4, 2016. Following the submission of the RTOs'/ISOs' reports, FERC will allow for public comment. FERC will use the reports and comments to determine what further action is appropriate.

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Reactive Power Rates

In June 2015, Power submitted a tariff filing with FERC to increase Power's rates for reactive supply and voltage control service from approximately $27 million per year to about $39 million per year. The rates were last adjusted in 2008 and since that time various generating units have been de-activated, activated or improved with the net impact supportive of an upward rate adjustment. FERC accepted Power's rate filing increase to become effective in January 2016, subject to refund, hearing and settlement procedures. FERC also referred the filing to the FERC Office of Enforcement for its evaluation. Power has participated in two settlement conferences to date with the FERC Trial Staff. Following settlement discussion with FERC Trial Staff, Power agreed to accept an overall rate of $34 million per year. Approval of this rate increase is currently pending before FERC.

Long-Term Capacity Agreement Pilot Program Act (LCAPP)

In 2011, the State of New Jersey enacted the LCAPP to subsidize approximately 2,000 MW of new natural gas-fired generation. The LCAPP provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey EDCs.

In 2013, the U.S. District Court in New Jersey found that the LCAPP was unconstitutional and declared the LCAPP null and void. This federal court decision was subsequently challenged on appeal in the U.S. Third Circuit Court of Appeals (Third Circuit). The State of Maryland also took similar action to subsidize above-market new generation. This action was also determined to be unconstitutional in 2013 in the U.S. District Court in Maryland and such decision was challenged in the U.S. Fourth Circuit Court of Appeals (Fourth Circuit). Both appeals were denied, with the Fourth Circuit denying the appeal regarding the State of Maryland's action in June 2014 and the Third Circuit denying the LCAPP appeal in September 2014. These denials have been challenged on appeal to the U.S. Supreme Court. In October 2015, the U.S. Supreme Court announced that it would consider the appeal of the Fourth Circuit's decision involving Maryland. The U.S. Supreme Court will hear the case and is expected to issue a decision in 2016. We cannot predict the outcome of this appeal.

Transmission Regulation

FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures. Our allowed ROE is 11.68% for both existing and new transmission investments and we have received incentive rates, affording a higher ROE, for certain large scale transmission investments.

Our 2016 Formula Rate Update with FERC for approximately $146 million in increased annual transmission revenues went into effect on January 1, 2016. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. The adjustment for 2016 will include the impact of the extension of bonus depreciation, which was enacted after our 2016 filing was made, and is estimated to reduce our 2016 revenue increase as filed by approximately $27 million. For additional information about our transmission formula rate, see Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

Transmission Policy Developments—FERC concluded in Order 1000 that the incumbent transmission owner should not always have a ROFR to construct and own transmission projects in its service territory. We and other companies appealed Order 1000 but this appeal was denied in 2014 by the D.C. Court. The current PJM rules retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including immediately needed reliability projects, upgrades to existing transmission facilities, projects cost-allocated to a single transmission zone, and projects being built on existing rights-of-way and whose construction would interfere with incumbents' use of their rights-of-way. While these carve-outs ameliorate the impacts of the Order 1000 ruling, we and several other companies appealed various aspects of the FERC order approving PJM's implementation of Order 1000 on the grounds that FERC had not met the requisite legal burden in eliminating the ROFR from the PJM Tariff. This appeal remains pending in federal court.

In April 2013, PJM initiated its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues at Artificial Island in New Jersey. On July 29, 2015, the PJM Board approved the PJM staff's recommendation for a transmission project consisting of various components to be constructed by LS Power, PSE&G and Potomac Holding Company. In August 2015, PJM sent PSE&G a Construction Responsibility Letter (to which PSE&G responded on November 9 and again on February 16, 2016) awarding PSE&G three components of the project, estimated by PJM to cost approximately $126 million. PSE&G has accepted construction responsibility, subject to reaching agreement with PJM on a reasonable cost estimate. Discussions are ongoing with PJM regarding the cost estimate for PSE&G's portion of the work. On February 18, 2016, FERC issued an order granting PSE&G's request that it be permitted to seek recovery of 100% of its portion of the Artificial Island projects costs if the project

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is cancelled for reasons beyond PSE&G's control. PSE&G continues to work with both PJM and its stakeholders to improve the rules governing open window processes in PJM.

In a September 2015 order, FERC directed that a technical conference be held to address "concerns regarding how PJM plans for local transmission projects." Parties in the case raised concerns that too many projects are being approved outside of the Regional Transmission Expansion Plan (RTEP) mechanism to address "local" reliability requirements without going through the Order 1000 open window process. Intervenors also complained that there is inadequate transparency regarding the PJM transmission owners' consideration and selection of Supplemental Projects (which are not approved by the PJM Board). PSE&G is participating in the process before FERC in support of the current PJM processes. In addition, certain PJM stakeholders have proposed an examination of the current planning rules, including changes with regard to criteria to be used for replacement of facilities that have reached their "end of life." PSE&G intends to actively participate in this process. However, we are unable to predict the outcome of these efforts.

In a February 2016 order, FERC reversed a previous order and accepted a filing by the PJM transmission owners seeking authority to assign costs for RTEP projects (subject to PJM Board approval requirements) solely addressing localized needs to customers within the local transmission owner's zone. FERC's action in this order provides an exemption from the Order 1000 open window procedures for projects constructed by transmission owners to meet local transmission planning criteria.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G. In addition, in a separate proceeding, a merchant transmission operator has sought rehearing of the May 2014 order granting PSE&G's request for incentives related to the Bergen-Linden Corridor Project (BLC), solely with respect to the cost allocation for that project. That rehearing request remains pending. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey and may cause increased scrutiny regarding PSE&G's future capital investments. In addition, Power, as a BGS supplier, submits bids into the auction and obtains an obligation to provide services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these transmission costs, BGS suppliers may be entitled to an adjustment. However, suppliers may not be able to recoup these adjustments immediately as they are subject to BPU approval.

In one proceeding, Con Edison filed a complaint against PJM at FERC in November 2014 challenging PJM's allocation of costs for two PSE&G projects in northern New Jersey, including the BLC. In June 2015, FERC issued an order dismissing the complaint. Con Edison and a merchant generator have sought judicial review of certain aspects of FERC's order and Con Edison has filed a rehearing request with FERC.

Another proceeding is a matter remanded from a federal appellate court concerning the appropriate cost allocation for certain 500 kV projects in PJM that either have been built or are in the process of being built, including the Susquehanna-Roseland project. This matter is currently in advanced settlement discussions at FERC. Under possible settlement outcomes under consideration, Power, as a BGS supplier could become obligated to pay amounts previously paid by other PJM transmission customers. However, Power does not believe that the anticipated level of any such potential payments would have a material effect on Power's financial statements.

In another complaint proceeding against PJM, in May 2015 and as amended in July 2015, a merchant transmission operator challenged PJM's allocation of costs for four PSE&G projects, including BLC. PSE&G filed an opposition to the complaint and the matter is currently pending at FERC. In August 2015, the Delaware Public Service Commission and the Maryland Public Service Commission also filed a complaint against PJM and certain transmission owners that have voting rights over cost allocation and rate design, including PSE&G, alleging that PJM tariff provisions allocate an excessive share of the Artificial Island project costs to them relative to the actual benefits of the project to residents of Delaware and Maryland. PSE&G participated in a group filing of transmission owners that opposed the complaint. PJM also answered the Delaware/Maryland complaint but stated that the Artificial Island cost allocation appeared "disproportionate" and raised "equity concerns." On January 12, 2016, we participated in a technical conference at FERC related to PJM cost allocation with the stated purpose of determining whether special allocation rules are needed for reliability projects based upon the reliability needs other than insufficient flow capability over the affected transmission facilities. We are unable to predict the outcome of these proceedings.

In June 2015, a transmission developer filed a complaint against PJM claiming that PJM wrongfully refused to provide data and a transparent process for evaluating transmission network upgrade requests that the transmission developer had submitted to PJM. According to the complaint, PJM and certain transmission owners wrongfully inflated the scope and associated costs of mitigation work needed to accommodate the developer's proposal in order to prevent it from pursuing its projects. Although not named as a respondent in the complaint, PSE&G is identified as one of the companies claimed to have been involved. In July 2015, PJM filed a response, which included a supporting affidavit from PSE&G, contesting the allegations. Settlement conferences in this matter are currently on-going.

Transmission Rate Proceedings—Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base ROEs. Certain of those complaints have

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resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. While we are not the subject of a challenge to the ROE employed in PSE&G's transmission formula rate, the results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Compliance

FERC Audit—In November 2012, FERC commenced an audit of each of the PSEG companies that have MBR authority from FERC. The companies were audited by FERC for compliance with its rules for (i) receiving and retaining MBR authority, (ii) the filing of electric quarterly reports (EQRs), and (iii) our generating units' receipt of payments from the RTO/ISO when they are required to run for reliability reasons when it is not economical for them to do so. On October 16, 2014, FERC issued a final, public audit report that contained two findings and recommendations for enhanced review and reporting of our EQRs. In November 2014, we submitted a compliance plan to FERC explaining how we intend to implement FERC's recommendations and we thereafter provided quarterly updates to FERC reporting on our progress in implementing the recommendations. At this time, we have satisfied all of FERC's requirements.

FERC—For information about the preliminary non-public investigation initiated by the FERC Staff regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Reliability Standards—Congress has required FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the U.S. electric transmission and generation system (grid) and to prevent major system blackouts. There has been considerable focus recently on physical security in light of, among other things, a substation attack in California that occurred in 2013. As a result, FERC directed the NERC to draft a physical security standard intended to further protect assets deemed "critical" to reliability of the grid. In November 2014, FERC issued an order approving the NERC's proposed physical security standard. Under the standard, utilities will be required to identify critical substations as well as develop threat assessment plans to be reviewed by independent third parties. In our case, the third party is PJM. As part of these plans, utilities could decide or be required to build additional redundancy into their systems. This standard will supplement the Critical Infrastructure Protection standards that are already in place and that establish physical and cybersecurity protections for critical systems. We are on schedule to meet all NERC requirements.

Commodity Futures Trading Commission (CFTC)

In accordance with the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), the SEC and the CFTC are in the process of implementing a new regulatory framework for swaps and security-based swaps. The legislation was enacted to reduce systemic risk, increase transparency and promote market integrity within the
financial system by providing for the registration and comprehensive regulation of swap dealers and by imposing recordkeeping, data reporting, margin and clearing requirements with respect to swaps. To implement the Dodd-Frank Act, the CFTC has engaged in a comprehensive rulemaking process and has issued a number of proposed and final rules addressing many of the key issues. We are currently subject to record keeping and data reporting requirements applicable to commercial end users. The CFTC has also proposed rules establishing position limits for trading in certain commodities, such as natural gas, and we are currently analyzing the potential impact of these rules on our business.

Nuclear Regulatory Commission (NRC)

Our operation of nuclear generating facilities is subject to comprehensive regulation by the NRC, a federal agency established to regulate nuclear activities to ensure protection of public health and safety, as well as the security and protection of the environment. Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstration to the NRC that plant operations meet requirements is also necessary. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate. The current operating licenses of our nuclear facilities expire in the years shown in the following table:

Unit	Year
Salem Unit 1	2036
Salem Unit 2	2040
Hope Creek	2046
Peach Bottom Unit 2	2033
Peach Bottom Unit 3	2034

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As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in 2011, the NRC began performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events in Japan have resulted in additional regulation for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants currently meet the stringent applicable design and safety specifications of the NRC.

In 2011, a NRC task force submitted a report containing various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. The NRC staff also issued a document which provided for a prioritization of the task force recommendations. The NRC approved the staff's prioritization and implementation recommendations subject to a number of conditions. Among other things, the NRC advised the staff to give the highest priority to those activities that can achieve the greatest safety benefit and/or have the broadest applicability (Tier 1), to review filtration of boiling water reactor (BWR) primary containment vents and encouraged the staff to create requirements based on a performance-based system which allows for flexible approaches and the ability to address a diverse range of site-specific circumstances and conditions and strive to implement the requirements in 2016.

The NRC issued letters and orders to licensees implementing the Tier 1 recommendations in March 2012. In March 2013, the NRC initiated a rulemaking process for improvements to venting systems at 31 U.S. BWRs with “Mark I” and “Mark II” containments (similar to those at Fukushima), which include our Hope Creek and Peach Bottom units. In June 2013, the NRC issued orders requiring Mark I and Mark II licensees to upgrade or replace their reliable hardened vents with containment venting systems designed and installed to remain functional during severe accident conditions. We are implementing the diverse and flexible strategies and spent fuel pool level indication modifications in accordance with the regulatory requirements at the Salem, Hope Creek and Peach Bottom nuclear units. For our Hope Creek and Peach Bottom units, final installation of the required modifications is expected to occur during the planned refueling outages in 2016-2018.

The NRC is currently developing the regulatory basis for drywell filtration strategies rulemaking. The NRC expects to complete its evaluation and vote on a final rule in 2017. The NRC continues to evaluate potential revisions to its requirements in connection with its operational and safety reviews of nuclear facilities in the United States as a result of the Fukushima Daiichi incident.

We are unable to predict the final outcome of these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to our Salem, Hope Creek and Peach Bottom facilities, but such cost could be material.

State Regulation

Since our operations are primarily located within New Jersey, our principal state regulator is the BPU, which oversees electric and natural gas distribution companies in New Jersey. We are also subject to various other states’ regulations due to our operations in those states.

Our New Jersey utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. PSE&G's participation in solar, demand response and energy efficiency programs is also regulated by the BPU, as the terms and conditions of these programs are approved by the BPU. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey.

We must file electric and gas rate cases with the BPU in order to change our utility base distribution rates. Our last base rate case was settled in 2010. As a result of our Energy Strong order discussed below, we are required to file our next base rate case proceeding no later than November 1, 2017. In addition to base rates, we recover certain costs or earn on certain investments pursuant to mechanisms known as adjustment clauses. These clauses permit the flow-through of costs to, or the recovery of investments from, customers related to specific programs, outside the context of base rate case proceedings. Recovery of these costs or investments is subject to BPU approval for which we make periodic filings. Delays in the pass-through of costs or recovery of investments under these mechanisms could result in significant changes in cash flow. For additional information on our specific filings, see Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

Energy Strong Program—In May 2014, the BPU issued an Order approving our Energy Strong program which provides for investment in our BPU jurisdictional electric and gas system to improve resiliency for the future. Under the settlement, PSE&G will invest up to $1.2 billion over an initial five-year period. The Order provides for cost recovery at a 9.75% rate of ROE on the first $1.0 billion of the investment, plus associated Allowance for Funds Used Under Construction, and will occur for completed projects on a semi-annual (for electric investments) or annual (for gas investments) basis. We will seek recovery of the remaining investment in PSE&G's next base rate case. See Business—PSE&G—Distribution for additional information about Energy Strong.

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During 2015, the BPU approved two Energy Strong petitions which allow us to recover in base rates capitalized Energy Strong investment costs for projects placed in service through May 31, 2015. The BPU Orders provide for a total $24 million annual revenue increase.

Gas System Modernization Program (GSMP)—In November 2015, the BPU issued an Order approving the settlement of our GSMP through which PSE&G will invest $905 million over the next three years to modernize its gas system. The settlement enables the utility to replace up to 510 miles of gas mains and 38,000 service lines over a three-year period, with cost recovery at a 9.75% rate of return on equity on $650 million of the investment through an accelerated recovery mechanism. Under the settlement, PSE&G will seek recovery of the remaining $255 million of investment in its next base rate case. We expect to file our first investment recovery petition in 2016.

Connecticut Rate Filing—In June 2015, Power's subsidiary, PSEG New Haven LLC, filed a mandatory annual rate case with the Connecticut Public Utilities Regulatory Authority (PURA) for recovery of its costs and investment in its Connecticut-based PSEG New Haven LCC peaking units. Power requested 2016 revenues of $21 million. On November 18, 2015, PURA issued a Final Decision to approve the entirety of Power's request. The newly approved rates are effective as of January 1, 2016.

Consolidated Tax Adjustments (CTA)—New Jersey is one of only a few states that make CTA in setting rates for regulated utilities. These adjustments to rate base are made during the rate setting process and are intended to allocate to utility customers a portion of the tax benefits realized from the filing of a consolidated federal tax return by the utility's parent corporation. The BPU has been considering the appropriateness of the adjustment and the methodology and mechanics of the calculation for some time. On October 22, 2014, the BPU approved a proposal by its Staff that limits the tax benefit period to be considered in the calculation to five years, sets the rate base adjustment at 25% of any such tax benefit and eliminates from the process any tax benefits tied to transmission earnings. In accordance with this October action, this CTA policy will be applied only with respect to future rate cases. The adoption of these modifications by the BPU is not expected to have a material impact on PSE&G's current earnings nor in its next rate case filing. On November 5, 2014, the New Jersey Division of Rate Counsel appealed the BPU's decision. All briefs have been filed and the appeal remains pending.

New Jersey Energy Master Plan (EMP)—New Jersey law requires that an EMP be developed every three years, the purpose of which is to ensure safe, secure and reasonably-priced energy supply, foster economic growth and development and protect the environment. While not having the force of law, the EMP provides an overview of energy policy in New Jersey and may provide both opportunities and challenges for PSEG. The most recent EMP was finalized in December 2011 and placed an emphasis on expanding in-state electricity resources, reducing energy costs, recognizing the impact of climate change and setting new targets for a renewable portfolio standard and goals for energy supplies from clean energy sources. An update to the December 2011 EMP was released on December 31, 2015 which continued to emphasize the policies set forth in the December 2011 EMP while also addressing certain issues that have emerged since that time, placing an emphasis on improved system resiliency, critical energy infrastructure, emergency preparedness and cybersecurity.

Additional matters are discussed in Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

ENVIRONMENTAL MATTERS

We are subject to federal, state and local laws and regulations with regard to environmental matters including, but not limited to:

- air pollution control,
- climate change,
- water pollution control,
- hazardous substance liability, and
- fuel and waste disposal.

Changing environmental laws and regulations significantly impact the manner in which our operations are currently conducted and impose costs on us to reduce the health and environmental impacts of our operations. Such laws and regulations may also affect the timing, cost, location, design, construction and operation of new facilities. To the extent that environmental requirements are more stringent and compliance more costly in certain states where we operate compared to other states that are part of the same market, such rules may impact our ability to compete within that market. Due to evolving environmental regulations, it is difficult to project future costs of compliance and their impact on competition. Capital costs of complying with known pollution control requirements are included in our estimate of construction expenditures in Item 7. MD&A—Capital Requirements. The costs of compliance associated with any new requirements that may be imposed by future regulations are not known, but may be material.

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For additional information related to environmental matters, including proceedings not discussed below, as well as anticipated expenditures for installation of pollution control equipment, hazardous substance liabilities and fuel and waste disposal costs, see Item 1A. Risk Factors, Item 3. Legal Proceedings and Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Air Pollution Control

Our facilities are subject to federal regulation under the Clean Air Act (CAA) which requires controls of emissions from sources of air pollution and imposes record keeping, reporting and permit requirements. Our facilities are also subject to requirements established under state and local air pollution laws. The CAA requires all major sources, such as our generation facilities, to obtain and keep current an operating permit. The costs of compliance associated with any new requirements that may be imposed and included in these permits in the future could be material and are not included in our estimates of capital expenditures.

- ***Hazardous Air Pollutants Regulation***—In February 2012**,** the Environmental Protection Agency (EPA) published Mercury Air Toxics Standards (MATS) for both newly-built and existing electric generating sources under the National Emission Standard for Hazardous Air Pollutants (NESHAP) provisions of the CAA. The MATS established allowable levels for mercury as well as other hazardous air pollutants and went into effect in April 2015. On June 29, 2015, the U.S. Supreme Court held that it was unreasonable for the EPA to refuse to consider the materiality of costs in determining whether to regulate hazardous air pollutants from power plants and remanded the matter back to the D.C. Court. On December 15, 2015, the D.C. Court remanded the MATS to the EPA without vacating the rule. On December 1, 2015, the EPA proposed a Supplemental Finding that considers the materiality of costs in determining whether to regulate hazardous air pollutants from power plants in response to the U.S. Supreme Court's June ruling.
- ***Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation***—In March 2013, Power filed a petition at the EPA challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued in January 2013. Among other things, the NESHAP include two exemptions that allow owners and operators of stationery emergency RICE to operate their engines without the installation and operation of emission controls (1) as part of an emergency DR program for 100 hours per year (100 hour exemption) or (2) as part of a financial arrangement with another entity per specified restrictions in non-emergency situations for 50 hours per year (50 hour exemption). This waiver of NESHAP standards results in disparate treatment of different generation technology types. In its appeal, Power sought more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. In August 2014, the EPA denied the March 2013 petition and in October 2014, Power appealed the EPA's denial to the D.C. Court. On May 1, 2015, the D.C. Court vacated the 100 hour exemption but thereafter granted a stay until May 1, 2016. On September 23, 2015, the D.C. Court granted the EPA's motion for voluntary remand of the 50 hour exemption provision to the EPA. While both provisions remain in place, the EPA will undergo proceedings to address the D.C. Court's orders. We believe that the impact of the D.C. Court's rulings would likely benefit Power's and its competitors' operations of their power generation peaking units.
- ***Cross-State Air Pollution Rule (CSAPR)***—On January 1, 2015, the final CSAPR became effective which limits power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season nitrogen oxide ($NO_)$ in 28 states that contribute to the ability of downwind states to attain and/or maintain the 1997 and 2006 particulate matter and the 1997 ozone National Ambient Air Quality Standards (NAAQS). On April 6, 2015, the EPA revoked the 1997 ozone NAAQS of 80 parts per billion (ppb) and began implementation of the more stringent 2008 ozone NAAQS of 75 ppb. On December 3, 2015, the EPA published the proposed CSAPR Updating Rule to address the 2008 ozone NAAQS. The proposal establishes more stringent annual ozone season (May 1 through September 30) caps beginning May 1, 2017. We do not anticipate any material impact on our earnings or financial condition due to the CSAPR.
- ***Ozone Standard***—In December 2014, the EPA proposed a rule to lower the ambient air quality standard for the level of ozone in the atmosphere from 75 ppb to a level in the range of 65-70 ppb. On October 1, 2015, the EPA finalized a standard of 70 ppb. To meet the new standard, the EPA and the states have to implement additional emission reduction strategies for NO and volatile organic compounds. Some portions of the Mid-Atlantic and New England states are not expected to be able to meet the new standard. Although the majority of our fossil generating units employ state-of-the-art NO emission controls, we cannot predict the outcome of this matter since new requirements of the EPA and the states are unknown at this time. Numerous parties have filed petitions for review with the D.C. Court to challenge the rule.

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Climate Change

- ***CO_2 Regulation under the* CAA**—On October 23, 2015, the EPA published the New Source Performance Standards (NSPS) for new power plants. The NSPS establishes two emission standards for CO_2 for the following categories: (i) fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units, and (ii) natural gas combustion turbines. Simple cycle combustion turbines are exempt from the rule.

  On October 23, 2015, the EPA published the Clean Power Plan (CPP), a greenhouse gas (GHG) emissions regulation under the CAA for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction (BSER). The BSER consists of three components: (i) heat rate improvements at existing coal-fired power plants, (ii) increased use of existing natural gas combined cycle capacity, and (iii) operation of incremental zero-emitting generation (renewables and nuclear). States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions.

  Each state must submit a compliance plan to the EPA by September 6, 2016 or seek a two-year extension to September 6, 2018. States can comply using an emission rate-based plan (pounds CO_2/MWh) or a mass-based plan (tons). Compliance with the final rule is effective January 1, 2022.

  The EPA, FERC and the U.S. Department of Energy (DOE) announced that they plan to meet at least quarterly to evaluate states' plans and identify reliability concerns so adjustments can be made before the final plans are submitted. The agencies are engaging various stakeholders, including the Regional Transmission Operators/Independent System Operators. The agencies will continue to meet after the states' plans are in effect to assess if revisions are required.

  On October 23, 2015, the EPA also published proposed federal implementation requirements for states that do not submit an EPA-approved compliance plan. Comments were due by January 21, 2016.

  Numerous states, including New Jersey, and several industry groups filed petitions for review with the D.C. Court to challenge the CPP. In addition, the petitioners sought a stay of the rule. On January 21, 2016, the D.C. Court declined to stay the CPP. However, on February 9, 2016, the U.S. Supreme Court stayed the rule pending further review of the case.

  The U.S. Supreme Court's decision to stay the implementation of the CPP will delay deadlines for submission of state requests for extensions and final plans. If the CPP is upheld, new deadlines will need to be established and the effective date of the compliance period may be impacted.

- ***Regional Greenhouse Gas Initiative (RGGI)***—In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. Certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions.

  These rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three-year period. Allowances are available through the auction or through secondary markets.

  In February 2013, the RGGI States released an updated Model Rule that, among other things, reduced the amount of available regional CO_2 allowances beginning in 2014. Each RGGI State must implement the changes through state-specific regulations. We do not expect these changes, or any future changes, to the RGGI rules will have a material impact on us.

  On November 17, 2015 the RGGI States initiated a 2016 Program Review stakeholder process. The focus of the 2016 Program Review is the post-2020 caps on GHG emissions and the incorporation of the EPA's CPP requirements.

  New Jersey withdrew from RGGI beginning in 2012. As a result, our New Jersey facilities are no longer obligated to acquire CO_2 emission allowances. This action has been challenged by environmental groups in the New Jersey state court. In March 2014, the Appellate Division of the New Jersey Superior Court ruled that the New Jersey Department of Environmental Protection (NJDEP) improperly withdrew its regulation under which RGGI had been implemented. The Court gave the NJDEP 60 days to initiate a public process to either repeal or amend that regulation to provide that it is applicable only when New Jersey is a participant in a regional or other established greenhouse gas program. On August 3, 2015, the NJDEP published its formal repeal of the rules implementing RGGI in New Jersey.

  New Jersey also adopted the Global Warming Response Act in 2007, which calls for stabilizing its GHG emissions to 1990 levels by 2020, followed by a further reduction of greenhouse emissions to 80% below 2006 levels by 2050. To reach this goal, the NJDEP, the BPU, other state agencies and stakeholders are required to evaluate methods to meet and exceed the emission reduction targets, taking into account their economic benefits and costs.

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Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to U.S. waters from point sources, except pursuant to a National Pollutant Discharge Elimination System (NPDES) permit issued by the EPA or by a state under a federally authorized state program. The FWPCA authorizes the imposition of technology-based and water quality-based effluent limits to regulate the discharge of pollutants into surface waters and ground waters. The EPA has delegated authority to a number of state agencies, including those in New Jersey, New York and Connecticut, to administer the NPDES program through state action. We also have ownership interests in facilities in other jurisdictions that have their own laws and implement regulations to control discharges to their surface waters and ground waters that directly govern our facilities in those jurisdictions.

- ***Steam Electric Effluent Guidelines***—On September 30, 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Mercer and Bridgeport Harbor stations and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under this rule. We are unable to predict if this rule will have a material impact on our future capital requirements, financial condition and results of operations.

In addition to regulating the discharge of pollutants, the FWPCA regulates the intake of surface waters for cooling. The use of cooling water is a significant part of the generation of electricity at steam-electric generating stations. Section 316(b) of the FWPCA requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The impact of regulations under Section 316(b) can be significant, particularly at steam-electric generating stations which do not have closed cycle cooling and do not use cooling towers to recycle water for cooling purposes. The installation of cooling towers at an existing generating station can impose significant engineering challenges and significant costs, which can affect the economic viability of a particular plant.

- ***Cooling Water Intake Structure Regulation***—In May 2014, the EPA issued a final cooling water intake rule under Section 316(b) of the Clean Water Act (CWA) that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

  The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the BTA of each facility that seeks a permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. In August 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis.

  In September 2014, several environmental non-governmental groups and certain energy industry groups filed petitions for review of the rule and the case has been assigned to the U.S. Second Circuit Court of Appeals (Second Circuit). Environmental organizations, including but not limited to the environmental petitioners in the Second Circuit, have also filed suit under the Endangered Species Act (ESA) challenging the Biological Opinion issued by U.S. Fish & Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS) on the 316(b) rule in the U.S. District Court for the Northern District of California. Parties to these cases filed motions seeking to consolidate this secondary action with the primary case residing with the Second Circuit. The Second Circuit has agreed to consolidate the case and to allow industry petitioners to amend their petition to include review of the Biological Opinion issued by the FWS and NMFS and to add both parties as Respondents. This means that the FWS and NMFS will be parties to the 316(b) litigation, and the ESA claims against them will not be proceeding in the U.S. District Court. Briefings before the court are scheduled to begin in 2016 but the schedule has not yet been established.

  We are assessing the potential impact of the rule on each of our affected facilities and are unable to predict the outcome of permitting decisions and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Item 8. Financial Statements and Supplementary Data— Note 12. Commitments and Contingent Liabilities for additional information.

  On June 30, 2015, the NJDEP issued a draft New Jersey Pollutant Discharge Elimination System (NJPDES) permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The draft permit was subject to a public notice and comment period. We participated in the NJDEP's August 5, 2015 public hearing and submitted comments on the draft permit on September 18, 2015. The NJDEP may make revisions before issuing the

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final permit which is expected in the first half of 2016. For additional information, see Item 8. Note 12. Commitments and Contingent Liabilities.

We are actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA's CWA Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, we would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire the BH3 within five years of the effective date of the final permit. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in the summer of 2016 indicating a potential retirement date for BH3 by summer 2021, which is four years earlier than the current estimated useful life ending in 2025. If the permit is not issued and the conditions below are not met, we will seek to operate BH3 through the current estimated useful life.

Separately, we have also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that we would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates, which could occur in 2017. Absent those conditions being met, and the permit renewal referred to above not being issued, we will seek to operate BH3 through the current estimated useful life. In February 2016, the proposed generating facility was awarded a capacity obligation. Construction is expected to commence in 2017, with operations expected to begin in mid-2019.

- ***Waters of the United States***—In April 2014, the EPA Administrator and the Assistant Secretary of the Army (Civil Works) jointly published a proposed rule to clarify the definition of waters of the U.S. under the CWA programs in order to protect the streams and wetlands that form the foundation of the nation's water resources. This definition will have broad application to all areas of compliance under the CWA, including permitted discharges and construction activities. The final rule was published on June 29, 2015 and we are reviewing it to determine the materiality of the impacts that might result from the final rule. Some states, including New Jersey, are subject to state requirements beyond those imposed under federal law. While we do not anticipate material impacts to projects in New Jersey, the new definition could impose requirements in other states and regions that could impact the development of renewables.

Various states, industry coalitions and environmental organizations have initiated legal action related to the provisions of the final rule. On October 9, 2015, the Sixth Circuit Court of Appeals issued a stay of the rule pending further court action.

- ***Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance***—In April 2015, we determined that monitoring and reporting practices related to certain permitted wastewater discharges at our Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject us to fines and penalties. We have notified the CTDEEP of the issues and have taken actions to investigate and resolve the potential non-compliance. We cannot predict the impact of this matter.
- ***Endangered Species Act***—On June 16, 2015, the Sierra Club and another environmental group submitted to the NJDEP a sixty-day notice of intent to sue alleging the agency has caused violations of the Endangered Species Act by allowing our Mercer generation station to operate in a manner which has caused the mortality of certain species of sturgeon. Among other things, the notice requested the NJDEP to prioritize completion of a permit renewal action for Mercer which addresses the alleged Endangered Species Act violations. We cannot predict the outcome of this action.

Hazardous Substance Liability

The production and delivery of electricity and the distribution and manufacture of gas, results in various by-products and substances classified by federal and state regulations as hazardous. These regulations may impose liability for damages to the environment from hazardous substances, including obligations to conduct environmental remediation of discharged hazardous substances as well as monetary payments, regardless of the absence of fault and the absence of any prohibitions against the activity when it occurred, as compensation for injuries to natural resources. See Item 3. Legal Proceedings. Our historic operations and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by federal and state agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex. The EPA is also evaluating the Hackensack River, a tributary to Newark Bay, for inclusion in the Superfund program. We no longer manufacture gas. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

- ***Site Remediation***—The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and the New Jersey Spill Compensation and Control Act (Spill Act) require the remediation of discharged hazardous substances and authorize the EPA, the NJDEP and private parties to commence lawsuits to compel clean-

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ups or reimbursement for such remediation. The clean-ups can be more complicated and costly when the hazardous substances are in a body of water.

- ***Natural Resource Damages***—CERCLA and the Spill Act authorize the assessment of damages against persons who have discharged a hazardous substance, causing an injury to natural resources. Pursuant to the Spill Act, the NJDEP requires persons conducting remediation to characterize injuries to natural resources and to address those injuries through restoration or damages. The NJDEP adopted regulations concerning site investigation and remediation that require an ecological evaluation of potential damages to natural resources in connection with an environmental investigation of contaminated sites. The NJDEP also issued guidance to assist parties in calculating their natural resource damage liability for settlement purposes, but has stated that those calculations are applicable only for those parties that volunteer to settle a claim for natural resource damages before a claim is asserted by the NJDEP. We are currently unable to assess the magnitude of the potential financial impact of this regulatory change, although such impacts could be material.

Fuel and Waste Disposal

- ***Nuclear Fuel Disposal***—The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In accordance with the Nuclear Waste Policy Act of 1982, in 2009 the DOE conducted its annual review of the adequacy of the Nuclear Waste Fee and concluded that the current fee of 1/10 cent per kWh was adequate to recover program costs. In 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit in federal court seeking suspension of the Nuclear Waste Fee. In June 2012, the court ruled that the DOE failed to justify continued payments by electricity consumers into the Nuclear Waste Fund and ordered the DOE to conduct a complete reassessment of this fee. Spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites. Since May 2014, the DOE reduced the nuclear waste fee to zero. Prior to the elimination of this fee, the annualized pre-tax cost was approximately $30 million.

  We have on-site storage facilities that are expected to satisfy the storage needs of Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 through the end of their operating licenses.
- ***Low Level Radioactive Waste***—As a by-product of their operations, nuclear generation units produce low level radioactive waste. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. These waste materials are accumulated on site and disposed of at licensed permanent disposal facilities. New Jersey, Connecticut and South Carolina have formed the Atlantic Compact, which gives New Jersey nuclear generators continued access to the Barnwell waste disposal facility which is owned by South Carolina. We believe that the Atlantic Compact will provide for adequate low level radioactive waste disposal for Salem and Hope Creek through the end of their current licenses including full decommissioning, although no assurances can be given. Low Level Radioactive Waste is periodically being shipped to the Barnwell site from Salem and Hope Creek. Additionally, there are on-site storage facilities for Salem, Hope Creek and Peach Bottom, which we believe have the capacity for at least five years of temporary storage for each facility.
- ***Coal Combustion Residuals (CCRs)***—On December 19, 2014, the EPA issued a final rule which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Our Hudson and Mercer generating stations, along with our co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 19, 2015. The impact of this final rule was not material to our results of operations, financial condition or cash flows. See Item 8. Note 12. Commitments and Contingent Liabilities for additional information.

SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Item 8. Financial Statements and Supplementary Data—Note 22. Financial Information by Business Segments.

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EXECUTIVE OFFICERS OF THE REGISTRANT (PSEG)

Name	Age as of December 31, 2015	Office	Effective Date First Elected to Present Position
Ralph Izzo	58	Chairman of the Board, President and Chief Executive Officer (PSEG)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (PSE&G)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Power)	
		Chairman of the Board and Chief Executive Officer (Energy Holdings)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Services)	January 2010 to present
Daniel J. Cregg	52	Executive Vice President and CFO (PSEG)	October 2015 to present
		Executive Vice President and CFO (PSE&G)	October 2015 to present
		Executive Vice President and CFO (Power)	October 2015 to present
		Vice President-Finance (PSE&G)	June 2013 to October 2015
		Vice President-Finance (Power)	December 2011 to June 2013
		President (Energy Resources & Trade LLC)	May 2011 to December 2011
		Vice President-Finance (Power)	December 2006 to May 2011
William Levis	59	President and Chief Operating Officer (Power)	June 2007 to present
Ralph LaRossa	52	President and Chief Operating Officer (PSE&G)	October 2006 to present
		Chairman of the Board of PSEG Long Island LLC	October 2013 to present
Derek M. DiRisio	51	President (Services)	August 2014 to present
		Vice President and Controller (PSEG)	January 2007 to August 2014
		Vice President and Controller (PSE&G)	January 2007 to August 2014
		Vice President and Controller (Power)	January 2007 to August 2014
		Vice President and Controller (Energy Holdings)	January 2007 to August 2014
		Vice President and Controller (Services)	January 2007 to August 2014
Stuart J. Black	53	Vice President and Controller (PSEG)	August 2014 to present
		Vice President and Controller (PSE&G)	August 2014 to present
		Vice President and Controller (Power)	August 2014 to present
		Vice President (Services) and Assistant Controller (Power)	March 2010 to August 2014
		Vice President of Internal Auditing Services (Services)	January 2005 to March 2010
Tamara L. Linde	51	Executive Vice President and General Counsel (PSEG)	July 2014 to present
		Executive Vice President and General Counsel (PSE&G)	July 2014 to present
		Executive Vice President and General Counsel (Power)	July 2014 to present
		Vice President - Regulatory (Services)	December 2006 to July 2014

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ITEM 1A. RISK FACTORS

The following factors should be considered when reviewing our business. These factors could have a material adverse impact on our financial position, results of operations or net cash flows and could cause results to differ materially from those expressed elsewhere in this report.

The factors discussed in Item 7. MD&A may also have a material adverse effect on our results of operations and cash flows and affect the market prices for our publicly-traded securities. While we believe that we have identified and discussed the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant.

We are exposed to commodity price volatility as a result of our participation in the wholesale energy markets.

The material risks associated with the wholesale energy markets known or currently anticipated that could adversely affect our operations include:

- ***Price fluctuations and collateral requirements***—We expect to meet our supply obligations through a combination of generation and energy purchases. We also enter into derivative and other positions related to our generation assets and supply obligations. As a result, we are subject to the risk of price fluctuations that could affect our future results and impact our liquidity needs. These include:
  - variability in costs, such as changes in the expected price of energy and capacity that we sell into the market,
  - increases in the price of energy purchased to meet supply obligations or the amount of excess energy sold into the market,
  - variation in the relative prices of electricity and gas at the hubs within the markets,
  - the cost of fuel to generate electricity, and
  - the cost of emission credits and congestion credits that we use to transmit electricity.

  In the markets where we operate, natural gas prices have a major impact on the price that generators receive for their output, especially in periods of relatively weak or strong demand. Therefore, significant changes in the price of natural gas usually translate into significant changes in the wholesale price of electricity.

  Over the past few years, wholesale prices for natural gas have declined from the peak levels experienced in 2008. One reason for this decline is increased shale gas production as extraction technology has improved. Lower gas prices have resulted in lower electricity prices, which has reduced our margins as nuclear and coal generation costs have not declined similarly. Over that time, generation by our coal units was also adversely affected by the relatively lower price of natural gas as compared to coal, making it sometimes more economic to run certain of our gas units than our coal units.

  Natural gas prices may remain at low levels for an extended period and continue to decline if further advances in technology result in greater volumes of shale gas production. Consequently, our margin may continue to be reduced as a result of sustained lower electricity prices.

  Many factors may affect capacity pricing in PJM, including but not limited to:
  - changes in load and demand,
  - changes in the available amounts of demand response resources,
  - changes in available generating capacity (including retirements, additions, derates, forced outage rates, etc.),
  - increases in transmission capability between zones,
  - changes to the pricing mechanism, including increasing the potential number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM may propose over time,
  - environmental regulation and legislation,
  - weather conditions,
  - electric supply disruptions, including plant outages and transmission disruptions, and
  - development of new fuels and new technologies for the production of power.

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Potential changes to the rules governing energy markets in which the output of our plants is sold also poses risk to our business, as discussed further below.

As market prices for energy and fuel fluctuate, our forward energy sale and forward fuel purchase contracts could require us to post substantial additional collateral, thus requiring us to obtain additional sources of liquidity during periods when our ability to do so may be limited. If Power were to lose its investment grade credit rating, it would be required under certain agreements to provide a significant amount of additional collateral in the form of letters of credit or cash, which would have a material adverse effect on our liquidity and cash flows. If Power had lost its investment grade credit rating as of December 31, 2015, it may have had to provide approximately $864 million in additional collateral.

- ***Our cost of coal and nuclear fuel may substantially increase***—Our coal and nuclear units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel needs over the next several years. However, it will be necessary to enter into additional arrangements to acquire coal and nuclear fuel in the future. Although our fuel contract portfolio provides a degree of hedging against these market risks, future increases in our fuel costs cannot be predicted with certainty and could materially and adversely affect our liquidity, financial condition and results of operations. While our generation runs on diverse fuels, allowing for flexibility, the mix of fuels ultimately used can impact earnings.
- ***Third party credit risk***—We sell generation output and buy fuel through the execution of bilateral contracts. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure to perform by these counterparties could have a material adverse impact on our results of operations, cash flows and financial position. In the spot markets, we are exposed to the risks of the default mechanisms that exist in those markets, some of which attempt to spread the risk across all participants, which may not be an effective way of lessening the severity of the risk of the amounts at stake. The impact of economic conditions may also increase such risk.

We are subject to comprehensive and evolving regulation by federal, state and local regulatory agencies that affects, or may affect, our businesses.

We are subject to regulation by federal, state and local authorities. Changes in regulation can cause significant delays in or materially affect business planning and transactions and can materially increase our costs. Regulation affects almost every aspect of our businesses, including business management, the terms and rates of transmission and distribution services, investment strategies, the financing of our operations and the payment of dividends, as well as our ability to:

- ***Obtain fair and timely rate relief***—PSE&G's retail rates are regulated by the BPU and its wholesale transmission rates are regulated by FERC. The retail rates for electric and gas distribution services are established in a base rate case and remain in effect until a new base rate case is filed and concluded. As a result of our Energy Strong order, we are required to file our next base rate case proceeding no later than November 1, 2017. In addition, our utility has received approval for several clause recovery mechanisms, some of which provide for recovery of costs and earn returns on authorized investments. These clause mechanisms require periodic updates to be reviewed and approved by the BPU and are subject to prudency reviews. Our utility's transmission rates are recovered through a FERC-approved formula rate. The revenue requirements are reset each year through this formula. The formula rate is also subject to prudency review. In addition, transmission ROEs have recently become the target of certain state utility commissions, municipal utilities, consumer advocates and consumer groups seeking to lower customer rates. These agencies and groups have filed complaints at FERC asking FERC to reduce the base ROE of various transmission owners. They point to changes in the capital markets as justification for lowering the ROE of these companies. While we are not the subject of any of these complaints, they could set a precedent for FERC-regulated transmission owners, such as PSE&G. Inability to obtain fair or timely recovery of all our costs, including a return of or on our investments in rates, could have a material adverse impact on our business.
- ***Obtain required regulatory approvals***—The majority of our businesses operate under MBR authority granted by FERC, which has determined that our subsidiaries do not have unmitigated market power and that MBR rules have been satisfied. Failure to maintain MBR eligibility, or the effects of any severe mitigation measures that may be required if market power was evaluated differently in the future, could have a material adverse effect on us.

  We may also be required to obtain various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals on a timely basis could materially adversely affect our results of operations and cash flows.

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- ***Comply with regulatory requirements***—There are federal standards, including mandatory NERC and Critical Infrastructure Protection standards, in place to ensure the reliability of the U. S. electric transmission and generation system and to prevent major system black-outs. We have been, and will continue to be, periodically audited by the NERC for compliance and are subject to penalties for non-compliance with applicable NERC standards.

  Further, FERC requires compliance with all of its rules and orders, including rules concerning Standards of Conduct, market behavior and anti-manipulation rules, reporting, interlocking directorate rules and cross-subsidization.

  In connection with an ongoing investigation by the FERC Staff regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units, we may incur potential disgorgement and other penalties which span a wide range depending on the success of our legal arguments. If our legal arguments do not prevail in whole or in part with FERC or in a judicial challenge that we may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to PSEG's and Power's results of operations in the quarterly and annual periods in which they are recorded. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

  We are subject to the reporting and record-keeping requirements of the Dodd-Frank Act, as implemented by the CFTC, and may in the future be subject to CFTC requirements regarding position limits for trading of certain commodities. As part of the Dodd-Frank Act compliance, we will need to be vigilant in monitoring and reporting our swap transactions.

  The BPU conducts periodic combined management/competitive service audits of New Jersey utilities related to affiliate standard requirements, competitive services, cross-subsidization, cost allocation and other issues.

We may be adversely affected by changes in energy regulatory policies, including energy and capacity market design rules and developments affecting transmission.

The energy industry continues to be regulated and the rules to which our businesses are subject are always at risk of being changed. Our business has been impacted by established rules that create locational capacity markets in each of PJM, ISO-NE and NYISO. Under these rules, generators located in constrained areas are paid more for their capacity so there is an incentive to locate in those areas where generation capacity is most needed. Because much of our generation is located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM's locational capacity market design rules and New England forward capacity market rules have been challenged in court and continue to evolve. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

In January 2011, New Jersey enacted a law establishing a LCAPP which provided for the construction of subsidized base load or mid-merit electric power generation. The LCAPP legislation was invalidated on constitutional grounds by a federal court order issued in October 2013 and a subsequent challenge in the Third Circuit upheld that decision. That decision has now been filed with the U.S. Supreme Court for consideration on appeal. However, future state actions in New Jersey and elsewhere to subsidize the construction of new generation could have the effect of artificially depressing prices in the competitive wholesale market on both a short-term and long-term basis.

We could also be impacted by a number of other events, including regulatory or legislative actions, including, among other things, direct and indirect subsidies, favoring non-competitive markets and/or technologies and energy efficiency and demand response initiatives. Further, some of the market-based mechanisms in which we participate, including BGS auctions, are at times the subject of review or discussion by some of the participants in the New Jersey and federal regulatory and political arenas. We can provide no assurance that these mechanisms will continue to exist in their current form, nor otherwise be modified.

To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, Power's capacity and energy revenues could be adversely affected. Moreover, through changes encouraged by FERC to transmission planning processes, or through RTO/ISO initiatives to change their planning processes, such as the recently accepted multi-driver project category in PJM, more transmission may ultimately be built to facilitate renewable generation or support other public policy initiatives. Any such addition to the transmission system could have a material adverse impact on our financial condition and results of operations.

FERC has also eliminated the ROFR, which will have the effect of allowing third parties to build certain types of transmission projects in the service territories of incumbent utilities such as PSE&G. As a result, we could face competitive pressures for our transmission business in New Jersey, as well as in in other utilities' service territories where we will be able to seek opportunities to build. Changes to FERC policies regarding transmission planning and rate treatment for transmission investment, including ROEs and incentive rates, could also have an impact on our transmission business. In addition, certain

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PJM cost allocation determinations have been recently challenged at FERC, the resolution of which could impact costs borne by New Jersey ratepayers and increase customer bills.

We are subject to numerous federal and state environmental laws and regulations that may significantly limit or affect our businesses, adversely impact our business plans or expose us to significant environmental fines and liabilities.

We are subject to extensive environmental regulation by federal, state and local authorities regarding air quality, water quality, site remediation, land use, waste disposal, the impact on global climate, natural resources damages and other matters. These laws and regulations affect the manner in which we conduct our operations and make capital expenditures. Changes in these laws, or violations of existing laws, could result in significant increases in our compliance costs, capital expenditures to bring existing facilities into compliance, operating costs for remediation and clean-up actions, civil penalties or damages from actions brought by third parties for alleged health or property damages. Any such increase in our costs could have a material impact on our financial condition, results of operations and cash flows. We may also be unable to successfully recover certain of these cost increases through existing regulatory rate structures or our contracts with our customers.

Delay in obtaining, or failure to obtain and maintain, any environmental permits or approvals, or delay in or failure to satisfy any applicable environmental regulatory requirements, could:

- prevent construction of new facilities,
- limit or prevent continued operation of existing facilities,
- limit or prevent the sale of energy from these facilities, or
- result in significant additional costs, each of which could materially affect our business, financial condition, results of operations and cash flows.

In obtaining required approvals and maintaining compliance with laws and regulations, we focus on several key environmental issues, including:

- ***Concerns over global climate change could result in laws and regulations to limit CO_2 emissions or other GHG emissions produced by our fossil generation facilities***—Federal and state legislation and regulation designed to address global climate change through the reduction of GHG emissions could materially impact our fossil generation facilities. For example, in 2015 the EPA published new rules for both new and existing power plants. We may be required to incur significant costs to comply with these regulations and to continue operation of our fossil generation facilities, which could include the potential need to purchase CO_2 emission allowances. Such expenditures could materially affect the continued economic viability of one or more such facilities.
- ***CO_2 Litigation***—In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings regarding alleged impacts of global climate change not involving us could be material to the future liability of energy companies. If relevant federal or state common law were to develop that imposed liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to our fossil generation operations could be material.
- ***Potential closed-cycle cooling requirements***—The EPA issued a proposed rule in 2011 regarding regulation of cooling water intake structures. Following the receipt of extensive comments on its proposed rule, the EPA finalized this rule on May 19, 2014 with an effective date of October 14, 2014. The EPA did not mandate closed cycle cooling as the BTA. Instead, the EPA set a fish impingement mortality standard that relies on a technology-based approach. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. The rule also requires that entrainment BTA decisions rely on site-specific analysis that includes an assessment of social costs-social benefits.

  The EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the BTA of each facility that seeks permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. State actions to renew permits under the provisions of this rule are ongoing at this time.

  If the NJDEP or the CTEEP were to require installation of closed-cycle cooling or its equivalent at any of our Salem, Mercer, Hudson, Bridgeport, Sewaren or New Haven generating stations, the related increased costs and impacts would be material to our financial position, results of operations and cash flows and would require further economic review to determine whether to continue operations or decommission any such station.
- ***Remediation of environmental contamination at current or formerly-owned facilities***—We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities

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associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. In addition, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. The EPA is also evaluating the Hackensack River, a tributary to Newark Bay, for inclusion in the Superfund program. We are also involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, the related costs of which could have a material adverse effect on our financial condition, results of operations and cash flows. New Jersey law places affirmative obligations on us to investigate and, if necessary, remediate contaminated property upon which we were in any way responsible for a discharge of hazardous substances, impacting the speed by which we will need to investigate contaminated properties, which could adversely impact cash flow. We cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to these or other natural resource damages claims. However, exposure to natural resource damages could subject us to additional potentially material liability. For a discussion of these and other environmental matters, see Item 8. Note 12. Commitments and Contingent Liabilities.

Our ownership and operation of nuclear power plants involve regulatory, financial, environmental, health and safety risks.

More than half of our total generation output each year is provided by our nuclear fleet, which comprises approximately one-third of our total owned generation capacity. For this reason, we are exposed to risks related to the continued successful operation of our nuclear facilities and issues that may adversely affect the nuclear generation industry. These include:

- ***Storage and Disposal of Spent Nuclear Fuel***—We currently use on-site storage for spent nuclear fuel. Disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel, could impact future operations of these stations. In addition, the availability of an off-site repository for spent nuclear fuel may affect our ability to fully decommission our nuclear units in the future.
- ***Regulatory and Legal Risk***—The NRC may modify, suspend or revoke licenses, or shut down a nuclear facility and impose substantial civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms and conditions of the licenses for nuclear generating facilities. As with all of our generation facilities, as discussed above, our nuclear facilities are also subject to comprehensive, evolving environmental regulation. Our nuclear generating facilities are currently operating under NRC licenses that expire in 2033 through 2046.
- ***Operational Risk***—Operations at any of our nuclear generating units could degrade to the point where the affected unit needs to be shut down or operated at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Since our nuclear fleet provides approximately half of our generation output, any significant outage could result in reduced earnings as we would need to purchase or generate higher-priced energy to meet our contractual obligations.
- ***Nuclear Incident or Accident Risk***—Accidents and other unforeseen problems have occurred at nuclear stations, both in the United States and elsewhere. The consequences of an accident can be severe and may include loss of life, significant property damage and/or a change in the regulatory climate. We have nuclear units at two sites. It is possible that an accident or other incident at a nuclear generating unit could adversely affect our ability to continue to operate unaffected units located at the same site, which would further affect our financial condition, operating results and cash flows. An accident or incident at a nuclear unit not owned by us could also affect our ability to continue to operate our units. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages. Further, as a licensed nuclear operator subject to the Price-Anderson Act and a member of a nuclear industry mutual insurance company, Power is subject to potential retroactive assessments as a result of a nuclear incident or retroactive adverse loss experience.

In the event of non-compliance with applicable legislation, regulation and licenses, the NRC may increase regulatory oversight, impose fines, and/or shut down a unit, depending on its assessment of the severity of the non-compliance. If a serious nuclear incident were to occur, our business, reputation, financial condition and results of operations could be materially adversely affected. In each case, the amount and types of insurance commercially available to cover losses that might arise in connection with the operation of our nuclear fleet are limited and may be insufficient to cover any costs we may incur.

Our inability to balance energy obligations with available supply could negatively impact results.

The revenues provided by the operation of our generating stations are subject to market risks that are beyond our control. Generation output will either be used to satisfy wholesale contract requirements or other bilateral contracts or be sold into competitive power markets. Participants in the competitive power markets are not guaranteed any specified rate of return on their capital investments. Generation revenues and results of operations are dependent upon prevailing market prices for energy,

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capacity, ancillary services and fuel supply in the markets served. A decrease in prevailing market prices could have a material adverse effect on our financial condition and results of operations.

Our generation business frequently involves the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that we have produced or purchased energy in excess of our contracted obligations, a reduction in market prices could reduce profitability. Conversely, to the extent that we have contracted obligations in excess of energy we have produced or purchased, an increase in market prices could reduce profitability. If the strategy we utilize to hedge our exposure to these various risks is not effective, we could incur significant losses. Our market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors, including weather in various geographical areas, short-term supply and demand imbalances, customer migration and pricing differentials at various geographic locations. These risks cannot be predicted with certainty.

Increases in market prices also affect our ability to hedge generation output and fuel requirements as the obligation to post margin increases with increasing prices.

Inability to successfully develop or construct generation, transmission and distribution projects within budget could adversely impact our businesses.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of required environmental upgrades and retrofits, construction and/or acquisition of additional generation units and transmission facilities and modernizing existing infrastructure. Currently, we have several significant projects underway or being contemplated.

Our success will depend, in part, on our ability to obtain necessary regulatory approvals, complete these projects within budgets, on commercially reasonable terms and conditions and, in our regulated businesses, our ability to recover the related costs through rates. Any delays, cost escalations or otherwise unsuccessful construction and development could materially affect our financial position, results of operations and cash flows.

Any inability to recover the carrying amount of our assets could result in future impairment charges which could have a material adverse impact on our financial condition and results of operations.

In accordance with accounting guidance, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, including prolonged periods of adverse commodity and capacity prices, could potentially indicate an asset's or group of assets' carrying amount may not be recoverable. Significant reductions in our expected revenues or cash flows for an extended period of time resulting from such events could result in future asset impairment charges, which could have a material adverse impact on our financial condition and results of operations.

Inability to access sufficient capital at reasonable rates or commercially reasonable terms or maintain sufficient liquidity in the amounts and at the times needed could adversely impact our business.

Capital for projects and investments has been provided primarily by internally-generated cash flow and external financings. We have significant capital requirements and will need continued access to debt capital from outside sources in order to efficiently fund the construction and other cash flow needs of our businesses. The ability to arrange financing and the costs of capital depend on numerous factors including, among other things, general economic and market conditions, the availability of credit from banks and other financial institutions, investor confidence, the success of current projects and the quality of new projects.

The ability to have continued access to the credit and capital markets at a reasonable economic cost is dependent upon our current and future capital structure, financial performance, our credit ratings and the availability of capital under reasonable terms and conditions. As a result, no assurance can be given that we will be successful in obtaining re-financing for maturing debt or financing for projects and investments on acceptable terms or at all.

We face significant competition in the merchant energy markets.

Our wholesale power and marketing businesses are subject to significant competition that may adversely affect our ability to make investments or sales on favorable terms and achieve our annual objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower earnings. Decreased competition could negatively impact results through a decline in market liquidity. Some of our competitors include:

- merchant generators,
- domestic and multi-national utility rate-based generators,
- energy marketers,

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- utilities,
- banks, funds and other financial entities,
- fuel supply companies,
- affiliates of other industrial companies, and
- distributed generation.

Regulatory, environmental, industry and other operational developments will have a significant impact on our ability to compete in energy markets, potentially resulting in erosion of our market share and impairment in the value of our power plants.

Changes in customer usage patterns and technology could adversely impact us.

- ***DSM and other efficiency efforts***—DSM and other efficiency efforts aimed at changing the quantity and patterns of consumers' usage could result in a reduction in load requirements which could adversely affect our financial condition and results of operations.
- ***Changes in technology and/or customer behaviors***—It is possible that advances in technology will reduce the cost of alternative methods of producing electricity, including distributed generation, such as fuel cells, micro turbines, micro grids, windmills and net-metered solar installations, to a level that is competitive with that of most central station electric production. Large customers, such as universities and hospitals, continue to explore potential micro grid installation. Substantial micro grid penetration can impact energy costs, system performance and demand growth. It is also possible that electric customers may significantly decrease their electric consumption due to demand-side energy conservation programs. Changes in technology and usage, such as municipal aggregation, could also alter the channels through which retail electric customers buy electricity, which could adversely affect our financial results. Advances in these or other technologies could reduce the cost of power production, increase reliance by customers on on-site generation, including solar, and changes in customer behaviors could result in decreased reliance on our system, each of which could adversely impact our cash flows, financial condition, results of operations, competitive position and investment opportunities.

Financial market performance directly affects the asset values of our nuclear decommissioning trust funds and defined benefit plan trust funds. Sustained decreases in asset value of trust assets could result in the need for significant additional funding.

The performance of the financial markets will affect the value of the assets that are held in trust to satisfy our future obligations under our pension and postretirement benefit plans and to decommission our nuclear generating plants. A decline in the market value of our pension assets could result in the need for us to make significant contributions in the future to maintain our funding at sufficient levels.

We may be adversely affected by equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers and remain competitive and could result in substantial financial losses.

The success of our businesses is dependent on our ability to continue providing safe and reliable service to our customers while minimizing service disruptions. We are also exposed to the risk of equipment failures, accidents, severe weather events, or other incidents which could result in damage to or destruction of our facilities or damage to persons or property. For instance, equipment failures in our natural gas distribution could give rise to a variety of hazards and operating risks, such as leaks, accidental explosions and mechanical problems, which could cause substantial financial losses and harm our reputation. PSE&G operates and maintains more than 17,700 miles of distribution mains that transport gas to 1.8 million customers. PSE&G also operates and maintains the largest cast iron infrastructure in any one state in the country at approximately 4,000 miles.

In addition, the physical risks of severe weather events, such as experienced from Hurricane Irene and Superstorm Sandy, and of climate change, changes in sea level, temperature and precipitation patterns and other related phenomena have further exacerbated these risks. Such issues experienced at our facilities, or by others in our industry, could adversely impact our revenues, increase costs to repair and maintain our systems, subject us to potential litigation and/or damage claims, fines/penalties, and increase the level of oversight of our utility and generation operations and infrastructure through investigations or through the imposition of additional regulatory or legislative requirements. Such actions could adversely affect our costs, competitiveness and future investments, which could be material to our financial position, results of operations and cash flow.

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Acts of war or terrorism could adversely affect our operations.

Our businesses and industry may be impacted by acts and threats of war or terrorism. These actions could result in increased political, economic and financial market instability and volatility in fuel prices which could materially adversely affect our business and results of operations. In addition, our infrastructure facilities, such as our generating stations, transmission and distribution facilities, could be direct or indirect targets or be affected by terrorist or other criminal activity. Such events could severely disrupt our business operations and prevent us from servicing our customers. In addition, new or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.

Cybersecurity attacks or intrusions could adversely impact our businesses.

We own and/or operate generating stations and transmission and distribution facilities, all of which are dependent on the operation of our information technology systems. Our ability to market our generation output and acquire and hedge fuel and power are also dependent on our information technology systems. Our information technology systems may be impacted by cybersecurity attacks, hostile technological intrusions or inadvertent disclosure of company and/or customer information or a cybersecurity attack may leverage our information technology to cause disruptions at another company. Cybersecurity threats to our operations include:

- Disruption of the operation of our assets and the power grid,
- Theft of confidential company, employee, shareholder, vendor or customer information,
- General business system and process interruption or compromise, including preventing us from servicing our customers, collecting revenues or the ability to record, process and/or report financial information correctly, and
- Breaches of vendors' infrastructures where our confidential information is stored.

If a significant cybersecurity event or breach should occur, it could result in material costs for repair and remediation, breach notification, operations and increased capital costs. Such a cybersecurity incident could also cause us to be non-compliant with applicable laws, regulations or contracts that require us to securely maintain confidential data, causing us to incur costs related to legal claims or proceedings, regulatory fines and increased scrutiny and possible damage to our reputation and brand, resulting in a reduction in customer confidence. We devote resources to network and application security, encryption and other measures to protect our computing systems and infrastructure from unauthorized access or misuse and interface with numerous external entities to improve our cybersecurity situational awareness. However, given the ever changing nature of cybersecurity threats, there can be no assurance the security measures we have taken and will take in the future can protect us against all possible occurrences.

We may be unable to achieve, or continue to sustain, our expected levels of operating performance.

One of the key elements to achieving the results in our business plan is the ability to sustain generating operating performance and capacity factors at expected levels since our forward sales of energy and capacity assume acceptable levels of operating performance. This is especially important at our lower-cost facilities. Operations at any of our plants could degrade to the point where the plant has to shut down or operate at less than full capacity. Some issues that could impact the operation of our facilities are:

- breakdown or failure of equipment, information technology, processes or management effectiveness,
- disruptions in the transmission of electricity,
- labor disputes,
- fuel supply interruptions,
- transportation constraints,
- limitations which may be imposed by environmental or other regulatory requirements, and,
- operator error or catastrophic events such as fires, earthquakes, explosions, floods, severe storms, acts of terrorism or other similar occurrences.

Identifying and correcting any of these issues may require significant time and expense. Depending on the materiality of the issue, we may choose to close a plant rather than incur the expense of restarting it or returning it to full capacity. In either event, to the extent that our operational targets are not met, we could have to operate higher-cost generation facilities or meet our obligations through higher-cost open market purchases. This could have a material adverse effect on our financial condition, results of operations and cash flows.

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An extended economic recession would likely have a material adverse effect on our businesses.

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices of commodities. Adverse conditions in the economy affect the markets in which we operate and can negatively impact our results. Declines in demand for energy will reduce overall sales and cash flows, especially as customers reduce their consumption of electricity and gas. Although our utility business is subject to regulated allowable rates of return, overall declines in electricity and gas sold and/or increases in non-payment of customer bills would materially adversely affect our liquidity, financial condition and results of operations.

We may be unable to realize anticipated tax benefits or retain existing tax credits.

The deferred tax assets and tax credits of PSEG, PSE&G or Power are evaluated for ultimate realizability. While presently not the case, a valuation allowance may be recorded against the deferred tax assets if we estimate that such assets are more likely than not to be unrealizable. A valuation allowance related to deferred tax assets or the monetization of tax credits can be affected by changes to tax laws, statutory tax rates and future taxable income levels. In the event that we determine that we would not be able to realize all or a portion of our deferred tax assets in the future or the benefit of tax credits, we would reduce such amounts through a charge to income tax expense in the period in which that determination was made, which could have a material adverse impact on our financial condition and results of operations.

Because PSEG is a holding company, its ability to meet its corporate funding needs, service debt and pay dividends could be limited.

PSEG is a holding company with no material assets other than the stock or membership interests of its subsidiaries and project affiliates. Accordingly, all of the operations of PSEG are conducted by its subsidiaries and project affiliates which are separate and distinct legal entities that have no obligation, contingent or otherwise, to pay any amounts when due on the debt of, or to make any funds available to PSEG to pay such amounts and satisfy its other corporate funding needs. These corporate funding needs include PSEG's operating expenses, the payment of interest on and principal of its outstanding indebtedness and the payment of dividends on its capital stock. As a result, PSEG can give no assurances that its subsidiaries and project affiliates will be able to transfer funds to PSEG to meet all of these obligations.

Challenges associated with retention of a qualified workforce could adversely impact our businesses.

Our operations depend on the retention of a skilled workforce. The loss or retirement of key executives or other employees, including those with the specialized knowledge required to support our generation, transmission and distribution operations, could result in various operational challenges. These challenges may include the lack of appropriate replacements, the loss of institutional and industry knowledge and the increased costs to hire and train new personnel. This has the potential to become more critical over the next several years as a growing number of employees become eligible to retire.

In addition, because a significant portion of our employees are covered under collective bargaining agreements, our success will depend on our ability to successfully renegotiate these agreements as they expire. Inability to do so may result in employee strikes or work stoppages which would disrupt our operations and could also result in increased costs.

Our receipt of payment of receivables related to our domestic leveraged leases is dependent upon the credit quality and the ability of lessees to meet their obligations.

Our receipt of payments of equity rent, debt service and other fees related to our leveraged lease portfolio in accordance with the lease contracts can be impacted by various factors. The factors which may impact future lease cash flow include, but are not limited to, new environmental legislation regarding air quality and other discharges in the process of generating electricity, market prices for fuel and electricity, including the impact of low gas prices on our coal generation investments, overall financial condition of lease counterparties and the quality and condition of assets under lease. If a lessee were to default, we could potentially be required to impair our current investment balances.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, PSE&G and Power

None.

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ITEM 2. PROPERTIES

Our subsidiaries own all of our physical property. We believe that we and our subsidiaries maintain adequate insurance coverage against loss or damage to plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Generation Facilities

Power

As of December 31, 2015, Power's share of installed fossil and nuclear generating capacity is shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used	Mission
Steam:						
Hudson	NJ	620	100%	620	Coal/Gas	Load Following
Mercer	NJ	632	100%	632	Coal/Gas	Load Following
Sewaren	NJ	451	100%	451	Gas	Load Following
Keystone (A)	PA	1,711	23%	391	Coal	Base Load
Conemaugh (A)	PA	1,711	23%	385	Coal	Base Load
Bridgeport Harbor	CT	383	100%	383	Coal	Load Following
New Haven Harbor	CT	447	100%	447	Oil/Gas	Load Following
Total Steam		**5,955**		**3,309**		
Nuclear:						
Hope Creek	NJ	1,176	100%	1,176	Nuclear	Base Load
Salem 1 & 2	NJ	2,294	57%	1,317	Nuclear	Base Load
Peach Bottom 2 & 3 (B)	PA	2,502	50%	1,251	Nuclear	Base Load
Total Nuclear		**5,972**		**3,744**		
Combined Cycle:						
Bergen	NJ	1,229	100%	1,229	Gas/Oil	Load Following
Linden	NJ	1,242	100%	1,242	Gas/Oil	Load Following
Bethlehem	NY	757	100%	757	Gas	Load Following
Kalaeloa	HI	208	50%	104	Oil	Load Following
Total Combined Cycle		**3,436**		**3,332**		
Combustion Turbine:						
Essex	NJ	81	100%	81	Gas/Oil	Peaking
Kearny	NJ	456	100%	456	Gas/Oil	Peaking
Burlington	NJ	168	100%	168	Gas/Oil	Peaking
Linden	NJ	336	100%	336	Gas/oil	Peaking
New Haven Harbor	CT	129	100%	129	Gas/Oil	Peaking
Bridgeport Harbor	CT	17	100%	17	Oil	Peaking
Total Combustion Turbine		**1,187**		**1,187**		
Pumped Storage:						
Yards Creek (C)	NJ	420	50%	210		Peaking
Total Power Plants		**16,970**		**11,782**		

(A) Operated by GenOn Northeast Management Company

(B) Operated by Exelon Generation.

(C) Operated by Jersey Central Power & Light Company.

As of December 31, 2015, Power also owned and operated 148 MW direct current (dc) of photovoltaic solar generation facilities in various states.

PSE&G

As of December 31, 2015, PSE&G had 114 MW-dc of installed solar capacity throughout New Jersey.

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Transmission and Distribution Facilities

PSE&G

As of December 31, 2015, PSE&G's electric transmission and distribution system included 24,022 circuit miles, of which 8,226 circuit miles were underground, and 848,496 poles, of which 549,636 poles were jointly-owned. Primarily all of this property is located in New Jersey.

In addition, as of December 31, 2015, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2015, the daily gas capacity of PSE&G's 100%-owned peaking facilities (the maximum daily gas delivery available during the three peak winter months) consisted of liquid petroleum air gas (LPG) and liquefied natural gas (LNG) and aggregated 2,790,420 therms (270,914,563 cubic feet on an equivalent basis of 100,000 Btu/therm and 1,030 Btu/cubic foot) as shown in the following table:

Plant	Location	Daily Capacity (Therms)
Burlington LNG	Burlington, NJ	772,500
Camden LPG	Camden, NJ	384,000
Central LPG	Edison, NJ	839,040
Harrison LPG	Harrison, NJ	794,880
Total		**2,790,420**

As of December 31, 2015, PSE&G owned and operated 18,112 miles of gas mains, owned 12 gas distribution headquarters and two sub-headquarters, all in four operating regions located in New Jersey and owned one meter shop in New Jersey serving all such areas. In addition, PSE&G operated 60 natural gas metering and regulating stations, all located in New Jersey, of which 24 were located on land owned by customers or natural gas pipeline suppliers and were operated under lease, easement or other similar arrangement. In some instances, the pipeline companies owned portions of the metering and regulating facilities.

PSE&G's First and Refunding Mortgage, securing the bonds issued thereunder, constitutes a direct first mortgage lien on substantially all of PSE&G's property.

PSE&G's electric lines and gas mains are located over or under public highways, streets, alleys or lands, except where they are located over or under property owned by PSE&G or occupied by it under easements or other rights. PSE&G deems these easements and other rights to be adequate for the purposes for which they are being used.

In addition, as of December 31, 2015, PSE&G owned 43 switching stations in New Jersey with an aggregate installed capacity of 29,090 megavolt-amperes (MVA) and 246 substations with an aggregate installed capacity of 8,179 MVA. In addition, four of our substations in New Jersey having an aggregate installed capacity of 109 MVA were operated on leased property.

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ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, other than those discussed below, see Item 1. Business—Regulatory Issues and Environmental Matters and Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Environmental Matters

The following items are environmental matters involving governmental authorities not discussed elsewhere in this Form 10-K. We do not expect expenditures for any such site relating to the items listed below, individually or for all such current sites in the aggregate, to have a material effect on our financial condition, results of operations and net cash flows.

(1) Claim by the EPA, Region III, under CERCLA with respect to a Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and other companies are alleged to be liable for contamination at the site and PSE&G has been named as a Potential Responsible Party (PRP). A Final Remedial Design Report was submitted to the EPA in September of 2002. This document presented the design details of the EPA's selected remediation remedy. PSE&G and other utility companies as members of a PRP group entered into a Consent Decree and agreed to implement a negotiated EPA selected remediation remedy. The PRP group implementation of the remedy was completed in 2010. Although subject to EPA approval and oversight, long-term monitoring activities designed to demonstrate the effectiveness of the implemented remedy are planned through 2018 at an estimated cost of $2.8 million.

(2) The EPA sent PSE&G, Power and approximately 157 other entities a notice that the EPA considered each of the entities to be a PRP with respect to contamination in Berry's Creek in Bergen County, New Jersey and requesting that the PRPs perform a Remedial Investigation and Feasibility Study (RI/FS) on Berry's Creek and the connected tributaries and wetlands. Berry's Creek flows through approximately 6.5 miles of areas that have been used for a variety of industrial purposes and landfills. The EPA estimates that the study could cost approximately $18 million. As members of a PRP Group, Power and certain of the other entities named in the EPA Notice entered into an Administrative Settlement Agreement and Order on Consent in 2008 to conduct the RI/FS, which is estimated to be completed in 2017/2018.

(3) In January 2010, we, as the current owner of the Gates Construction Corporation Landfill, received a letter from the NJDEP asserting that the subject landfill has not been properly closed in accordance with the NJDEP Solid Waste Regulations. Power has retained an environmental consultant to prepare a closure plan acceptable to the NJDEP.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange, Inc. As of February 19, 2016, there were 66,445 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2010 in our common stock and the subsequent reinvestment of quarterly dividends, the S&P Composite Stock Price Index, the Dow Jones Utilities Index and the S&P Electric Utilities Index.

	2010	2011	2012	2013	2014	2015
PSEG	$ 100.00	$ 108.20	$ 104.91	$ 114.72	$ 153.93	$ 149.45
S&P 500	$ 100.00	$ 102.12	$ 118.38	$ 156.64	$ 177.99	$ 180.50
DJ Utilities	$ 100.00	$ 119.59	$ 121.49	$ 136.89	$ 178.61	$ 173.21
S&P Electrics	$ 100.00	$ 119.81	$ 121.30	$ 137.31	$ 176.88	$ 168.37

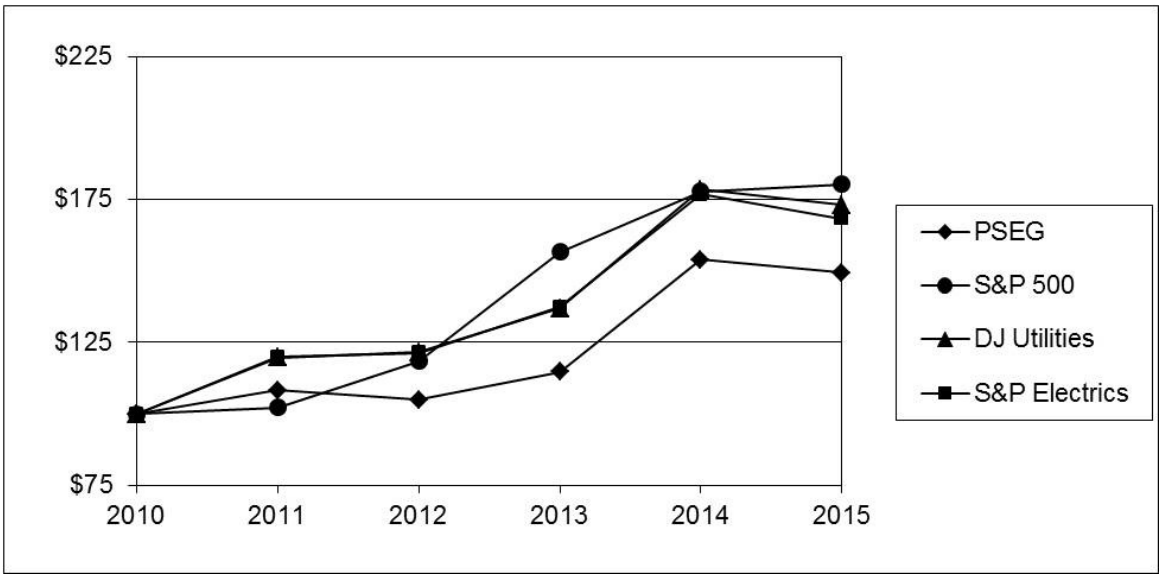

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The following table indicates the high and low sale prices for our common stock and dividends paid for the periods indicated:

Common Stock	High	Low	Dividend per Share
2015			
First Quarter	$ 44.45	$ 39.00	$ 0.39
Second Quarter	$ 43.97	$ 38.93	$ 0.39
Third Quarter	$ 43.91	$ 38.16	$ 0.39
Fourth Quarter	$ 44.18	$ 36.80	$ 0.39
2014			
First Quarter	$ 38.44	$ 31.25	$ 0.37
Second Quarter	$ 41.38	$ 36.91	$ 0.37
Third Quarter	$ 40.68	$ 34.05	$ 0.37
Fourth Quarter	$ 43.77	$ 36.37	$ 0.37

On February 16, 2016, our Board of Directors approved a $0.41 per share common stock dividend for the first quarter of 2016. This reflects an indicative annual dividend rate of $1.64 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

The following table indicates our common share repurchases in the open market during the fourth quarter of 2015 to satisfy obligations under various equity compensation award grants:

Three Months Ended December 31, 2015	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$ —
November 1-November 30	199,102	$ 40.47
December 1-December 31	20,000	$ 38.28

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2015:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Long-Term Incentive Plan	1,707,250	**$ 36.00**	15,248,540
Employee Stock Purchase Plan	—	—	3,589,032
Total	**1,707,250**	**$ 36.00**	**18,837,572**

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data—Note 17. Stock Based Compensation.

PSE&G

We own all of the common stock of PSE&G. For additional information regarding PSE&G's ability to continue to pay dividends, see Item 7. MD&A—Executive Overview of 2015 and Future Outlook.

Power

We own all of Power's outstanding limited liability company membership interests. For additional information regarding Power's ability to pay dividends, see Item 7. MD&A—Executive Overview of 2015 and Future Outlook.

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ITEM 6. SELECTED FINANCIAL DATA

PSEG

The information presented below should be read in conjunction with the MD&A and the Consolidated Financial Statements and Notes to Consolidated Financial Statements (Notes).

PSEG Years Ended December 31,	2015	2014	2013	2012	2011
	Millions, except Earnings per Share				
Operating Revenues (A)	$ 10,415	$ 10,886	$ 9,968	$ 9,781	$ 11,079
Income from Continuing Operations (B)	$ 1,679	$ 1,518	$ 1,243	$ 1,275	$ 1,407
Net Income	$ 1,679	$ 1,518	$ 1,243	$ 1,275	$ 1,503
Earnings per Share:					
Income from Continuing Operations					
Basic (A)	$ 3.32	$ 3.00	$ 2.46	$ 2.52	$ 2.78
Diluted (A)	$ 3.30	$ 2.99	$ 2.45	$ 2.51	$ 2.77
Net Income					
Basic	$ 3.32	$ 3.00	$ 2.46	$ 2.52	$ 2.97
Diluted	$ 3.30	$ 2.99	$ 2.45	$ 2.51	$ 2.96
Dividends Declared per Share	$ 1.56	$ 1.48	$ 1.44	$ 1.42	$ 1.37
As of December 31,					
Total Assets (C)	$ 37,535	$ 35,287	$ 32,480	$ 31,694	$ 29,791
Long-Term Obligations (C) (D)	$ 8,837	$ 8,218	$ 7,830	$ 6,670	$ 7,452

(A) Operating Revenues for 2015 and 2014 includes $375 million and $389 million, respectively, for Long Island Electric Utility Servco, LLC (Servco), a wholly owned subsidiary of PSEG Long Island LLC (PSEG LI). See Item 8. Financial Statements and Supplementary Data—Note 3. Variable Interest Entities for additional information.

(B) Income from Continuing Operations includes an after-tax insurance recovery for Superstorm Sandy of $102 million for 2015 and an after-tax charge of $170 million for 2011 related to certain leveraged leases.

(C) Total Assets and Long-Term Obligations for the years ended December 31, 2014, 2013, 2012 and 2011 include reclassified debt issuance costs from Noncurrent Assets to Long-Term Debt of $46 million, $42 million, $31 million and $30 million, respectively. See Item 8. Financial Statements and Supplementary Data—Note 2. Recent Accounting Standards for additional information.

(D) Includes capital lease obligations.

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G,** our public utility company which is engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU, and
- **Power,** our multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy transacting functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA), and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Item 1. Business provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Item 1A. Risk Factors provides information about factors that could have a material adverse impact on our businesses. The following discussion provides an overview of the significant events and business developments that have occurred during 2015 and key factors that we expect may drive our future performance. This discussion refers to the Consolidated Financial Statements (Statements) and the related Notes to Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements and Notes.

EXECUTIVE OVERVIEW OF 2015 AND FUTURE OUTLOOK

2015 Overview

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- growing our utility operations through continued investment in T&D and other infrastructure projects, and
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the years ended December 31, 2015 and 2014 are presented below:

	Years Ended December 31,	
	2015	2014
Earnings (Losses)	Millions, except per share data	
PSE&G	$ 787	$ 725
Power	856	760
Other	36	33
PSEG Net Income	**$ 1,679**	**$ 1,518**
PSEG Net Income Per Share (Diluted)	**$ 3.30**	**$ 2.99**

Our $161 million 2015 over 2014 increase in Net Income was due primarily to higher transmission revenues at PSE&G, higher mark-to-market (MTM) gains and lower generation costs driven by lower natural gas and coal prices at Power and insurance recoveries of Superstorm Sandy costs, primarily at Power. These increases were partially offset by higher pension and other postretirement benefit (OPEB) costs and lower capacity revenues and Nuclear Decommissioning Trust (NDT) activity at Power. For a more detailed discussion of our financial results, see Results of Operations.

During 2015, we grew earnings, maintained cash flows and sustained a strong balance sheet. We effectively deployed capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results and allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our multi-year, long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, our merchant generator, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, in 2015 we continued to make investments and seek recovery on such investments made to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the BPU in 2014. As approved, the Energy Strong program provides for up to $1.2 billion of investment, with cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated allowance for funds used during construction, through an accelerated recovery mechanism. We will seek recovery of up to $220 million of investment in PSE&G's next base rate case, which is to be filed no later than November 1, 2017.

In November 2015, the BPU approved our settlement with the BPU Staff and the New Jersey Division of Rate Counsel regarding PSE&G's Gas System Modernization Program (GSMP) through which we will invest $905 million over three years to modernize PSE&G's gas systems. The order provides for cost recovery at a 9.75% rate of return on equity on the first $650 million of the investment through an accelerated recovery mechanism. PSE&G will seek recovery of the remaining $255 million of investment in its next base rate case. For additional information, see Item 1. Business—Regulatory Issues—State Regulation.

Effective January 1, 2015, PSE&G's formula rate increased our annual transmission revenues by approximately $182 million. Each year, we file estimated transmission revenues subject to true up with actual current year data. The true-up adjustment for 2015, which will be filed in the Spring of 2016, will primarily include the impact on rate base of the extension of bonus depreciation, which was enacted after the filing was made, and is estimated to reduce our 2015 annual revenue increase by approximately $21 million. In October 2015, we filed our 2016 Annual Formula Rate Update with FERC, which will provide $146 million in increased annual transmission revenues effective January 1, 2016. Our 2016 transmission revenues will be adjusted for the impact of the continued extension of bonus depreciation, which was enacted after our 2016 filing was made, and is estimated to reduce our 2016 revenues as filed by approximately $27 million.

Over the past few years, these types of investments have altered our business mix to reflect a higher percentage contribution by PSE&G.

During 2015, Power successfully improved its performance for both nuclear and fossil operations, with continued upgrades in efficiency and output, while mitigating environmental impacts. Power's results benefited from access to natural gas supplies through its existing firm pipeline transportation contracts. Power manages these contracts for the benefit of PSE&G's customers through the basic gas supply service (BGSS) arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to

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make third party sales and supply gas to its generating units in New Jersey. Power's strategic hedging practices and ability to use market conditions to its advantage help it to balance some of the volatility of the merchant power business.

Three recent investments reflect our recognition of the value of opportunistic growth in the Power business. In June 2015, we acquired a development project to construct a 755 MW gas-fired combined cycle generating station (Keys Energy Center) in Maryland with completion expected in 2018 at an estimated investment of $825 million - $875 million. In August 2015, we announced our plan to construct Sewaren 7, a new 540 MW dual-fueled combined cycle generating plant in Woodbridge, New Jersey, scheduled to be in-service for the summer of 2018 at an estimated investment of $625 million - $675 million. The Sewaren 7 plant will replace Sewaren Units 1, 2, 3 and 4. In February 2016, we announced our plan to build Bridgeport Harbor Station 5 (BH5), a 485 MW gas-fired combined cycle generating plant on our existing Bridgeport Harbor station site in Bridgeport, Connecticut scheduled to be in-service for the summer of 2019 at an estimated investment of more than $550 million. These additions to our fleet expand our geographic diversity and are expected to contribute to the overall efficiency of operations.

In the PJM capacity auction held in August 2015 for the 2018-2019 delivery year, Power cleared 8,634 MW of its generating capacity at an average price of $215 MW-day. The capacity that Power cleared for the 2018-2019 delivery year included Sewaren 7 and Keys Energy Center generation plants. In the two prior PJM capacity auctions covering the 2016-2017 and 2017-2018 delivery years, Power cleared approximately 8,700 MW at average prices of $172 MW-day and $177 MW-day, respectively. In The ISO-NE auction held in February 2016, Power cleared BH5 at an average price of $232 MW-day for the 2019-2020 delivery year.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission Planning

FERC's rule under Order 1000 altered the right of first refusal (ROFR) previously held by incumbent utilities to build transmission within their respective service territories, creating the potential that new transmission projects in our service territory could be assigned to third parties rather than PSE&G. Order 1000 also presents opportunities for us to construct transmission outside of our service territory. In April 2013, PJM Interconnection, L.L.C. (PJM) initiated a solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues at Artificial Island in New Jersey. In August 2015, PJM awarded PSE&G three components of the transmission project, estimated by PJM to cost approximately $126 million. PSE&G has accepted construction responsibility, subject to reaching agreement with PJM on a reasonable cost estimate. Discussions are ongoing with PJM regarding the cost estimate for PSE&G's portion of the work. See Item 1. Business—Regulatory Issues—Federal Regulation—Transmission Regulation for additional information.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey and may cause increased scrutiny regarding PSE&G's future capital investments. In addition, Power, as a basic generation service (BGS) supplier, submits bids into the auction and obtains an obligation to provide services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these transmission costs, BGS suppliers may be entitled to an adjustment. However, suppliers may not be able to recoup these adjustments immediately as they are subject to BPU approval. We do not believe that these matters will have a material effect on Power's financial statements.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. In May 2014, a federal court issued a rule that vacated a FERC Order in which FERC had determined that demand response (DR) providers should receive full market compensation for power and held that FERC has no jurisdiction over DR. In January 2016, the U.S. Supreme Court overturned the federal court's decision which removed any risk to DR's participation in the energy and capacity markets.

In a separate development of significance to the wholesale capacity market, in December 2014 PJM filed at FERC its proposal for a capacity performance (CP) product to include generators, DR and energy efficiency providers, which will be required to perform during emergency conditions, as a supplement to the base capacity product. The proposal included enhanced performance-based incentives and penalties. In June 2015, FERC conditionally accepted the proposal and the CP mechanism was implemented for the 2015 capacity auction noted above. We believe that the auction pricing adequately reflects the

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increased costs that could result from operating under more stringent rules for generation availability. Based on the auction results, the CP mechanism appears to have provided the opportunity for enhanced capacity market revenue streams for Power, but future impacts cannot be assured. Further, there may be requirements for additional investment and there are additional performance risks.

Applications for rehearing of FERC's capacity performance order are pending. See Item 1. Business—Regulatory Issues—Federal Regulation—Capacity Market Issues for additional information.

We have also been actively involved both through stakeholder processes and through filings at FERC in seeking improvements to the rules for setting prices for energy in the day-ahead and real-time markets administered by PJM and other system operators. A November 2015 development which we view as positive involves both a notice of proposed rulemaking on dispatch intervals and scarcity pricing and a separate order directing the system operators to submit reports on five other price formation issues. We believe that, if implemented, these changes will improve energy price formation in the future.

See Item 1. Business—Regulatory Issues—Federal Regulation—Price Formation Initiatives for additional information.

An emerging issue in PJM involves the impact of subsidized existing generation on RPM market outcomes. These subsidies would likely enable the affected generators to submit reduced bids into PJM capacity markets that are not reflective of their actual costs of operation and may prevent uneconomic generating facilities from retiring. Either of these conditions could artificially suppress capacity market prices, especially given that PJM's currently effective "minimum offer price rule" (MOPR) would not apply to these plants because it only applies to new gas-fired units. See Item 1. Business—Regulatory Issues—Federal Regulation—Capacity Market Issues for additional information.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act (FWPCA) requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) could adversely impact future nuclear and fossil operations and costs. In June 2015, the New Jersey Department of Environmental Protection (NJDEP) issued a draft New Jersey Pollutant Discharge Elimination System (NJPDES) permit governing cooling water intake structures for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The NJDEP may make revisions before issuing the final permit which is expected during the first half of 2016. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

In October 2015, the EPA published the Clean Power Plan (CPP), a greenhouse gas (GHG) emissions regulation under the Clean Air Act (CAA) for existing power plants. The regulation establishes state-specific emission targets based on implementation of the best systems of emission reduction. Each state must submit a compliance plan to the EPA by September 6, 2016 or seek a two-year extension to September 6, 2018. We continue to work with FERC and other federal and state regulators, as well as industry partners, to determine the potential impact of these regulations. Numerous states, including New Jersey and several industry groups, filed petitions for review with the D.C. Court to challenge the CPP. In addition, the petitioners sought a stay of the rule. On January 21, 2016, the D.C. Court declined to stay the CPP. However, on February 9, 2016, the U.S. Supreme Court stayed the rule pending further review of the case.

The U.S. Supreme Court's decision to stay the implementation of the CPP will delay deadlines for submission of state requests for extensions and final plans. If the CPP is upheld, new deadlines will need to be established and the effective date of the compliance period may be impacted. See Item 1. Business—Environmental Matters—Climate Change for additional information.

CAA regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology rules are also of significance; however, we believe our generation business remains well-positioned for such regulations if and when they are implemented. In addition, state environmental regulations governing emissions from power plants also have a significant impact on our operations. In the second quarter of 2015, we retired 1,545 MW of fully depreciated combustion turbine capacity that would not be able to comply with the more stringent emission standards for high electric demand day units (HEDD) under the New Jersey HEDD regulations for nitrous oxide, which reduces our capacity revenues.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

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For further information regarding the matters described above as well as other matters that may impact our financial condition and results of operations, see Item 1. Business—Environmental Matters, Item 3. Legal Proceedings, and Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

FERC Compliance

The FERC Staff has initiated a preliminary non-public investigation regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units. This investigation is ongoing. The amounts of potential disgorgement and other potential penalties that we may incur span a wide range depending on the success of our legal arguments. If our legal arguments do not prevail, in whole or in part with FERC or in a judicial challenge that we may choose to pursue, it is likely that Power would record losses that would be material to PSEG's and Power's results of operations in the quarterly and annual periods in which they are recorded. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Bonus Depreciation

In December 2015, Congress passed the Protecting Americans from Tax Hikes Act of 2015 (Tax Act). The Tax Act includes an extension of the bonus depreciation rules. For federal tax purposes, bonus depreciation allows a tax deduction equal to the applicable percentage of qualifying assets that are placed in service during the applicable year. The extension of bonus depreciation associated with changes under the Tax Act is expected to reduce the rate of growth in PSE&G's rate base given an anticipated increase in deferred taxes; it is also expected to have a significant cash benefit over the next several years. For more detailed information, refer to Item 8. Financial Statements and Supplementary Data—Note 19. Income Taxes.

Change in Accounting Estimate

At the end of 2015, we changed the approach used to measure future service and interest costs for pension and other post-retirement benefits. For 2015 and prior, we calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, we have elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows. We believe the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations. As a change in accounting estimate, this change will be reflected prospectively. We estimate this will reduce 2016 pension and OPEB expense by approximately $34 million and $13 million, respectively, net of amounts capitalized.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. In 2015, our

- total nuclear fleet achieved an average capacity factor of 90%,
- nuclear output increased by 3.1% and combined cycle output by 11.4%, (including record performance at the Linden Units 1 and 2 and the Bethlehem Energy Center (BEC) combined cycle units) as compared to the same period in 2014,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 55 TWh while addressing unit outages and balancing fuel availability and price volatility, and
- utility ranked highest in electric and gas service business customer satisfaction among large utilities in the eastern United States and was recognized as the most reliable utility in the Mid-Atlantic region.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during 2015 as we:

- had cash on hand of $394 million as of December 31, 2015,
- maintained solid investment grade credit ratings,
- extended the expiration dates for approximately $2.0 billion of five-year credit facilities for PSEG, PSE&G and Power from 2018 to 2020,
- received cash federal tax benefits from the extension of bonus depreciation, and

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- increased our indicative annual dividend for 2015 to $1.56 per share.

We expect to be able to fund our transmission projects required under PJM's reliability program, Energy Strong distribution program, GSMP, Keys Energy Center, Sewaren 7, BH5 and other planned projects, without the issuance of new equity.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In 2015, we commenced construction of the Keys Energy Center in Maryland and Sewaren 7 in New Jersey, each of which generating station cleared in the 2018/2019 capacity auction. In addition, we:

- placed into service the final phase of our 500 kV Susquehanna-Roseland and 230 kV Mickleton-Gloucester-Camden transmission projects,
- made additional investments in transmission infrastructure projects,
- secured approval to extend three Energy Efficiency Economic Stimulus subprograms to allow for additional capital expenditures and administrative expenses to provide energy efficiency assistance to hospitals, healthcare facilities and residential multi-family housing units,
- received approval for our GSMP and continued to execute our Energy Strong and other existing BPU-approved utility programs,
- completed the power ascension for the extended power uprate at our co-owned Peach Bottom 2 and 3 nuclear stations,
- completed installation of equipment to increase output and improve efficiency at our Bergen 2 combined cycle gas unit similar to our 2014 installation at our Linden plant, and
- placed into service a 13 MW-direct current (dc) solar energy facility near Waldorf, Maryland, acquired and placed into service a 25 MW-dc solar energy facility near San Francisco, California and acquired a 63 MW-dc solar energy project near Salt Lake City, Utah which is expected to be in-service by the end of 2016.

In January 2016, we acquired a 26 MW-dc solar energy project in Martin County, North Carolina and expect commercial operation by July 2016. In February 2016, we acquired a 36 MW-dc solar energy project in Larimer County, Colorado and expect commercial operation by the fourth quarter of 2016.

In February 2016, we announced our plan to commence construction of BH5 in 2017, with operations expected to begin in mid-2019. See Financial Results above for additional information.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-moving economy and a cost-constrained environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions,
- execute our utility capital investment program, including our Energy Strong program, GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction of our Keys Energy Center, Sewaren 7 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

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For 2016 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- FERC Staff's continuing investigation of certain of Power's New Jersey fossil generating unit bids in the PJM energy market,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate, and
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development projects, including in connection with permitting and regulatory approvals.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of transmission and distribution facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition of new businesses,
- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency and modernizing existing infrastructure.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

RESULTS OF OPERATIONS

	Years Ended December 31,		
	2015	2014	2013
Earnings (Losses)	Millions		
PSE&G	$ 787	$ 725	$ 612
Power (A)	856	760	644
Other (B)	36	33	(13)
PSEG Net Income	**$ 1,679**	**$ 1,518**	**$ 1,243**
PSEG Net Income Per Share (Diluted)	**$ 3.30**	**$ 2.99**	**$ 2.45**

(A) Power's results in 2015 include an after-tax insurance recovery for Superstorm Sandy of $102 million. Power's 2014 and 2013 results include after-tax expenses of $17 million and $32 million, respectively, for Operation and Maintenance (O&M) costs net of insurance recoveries in 2013, due to severe damage caused by Superstorm Sandy. See Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

(B) Other includes after-tax activities at the parent company, PSEG LI and Energy Holdings as well as intercompany eliminations.

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The 2015 year-over-year increase in our Net Income was driven primarily by:

- higher revenues due to increased investments in transmission projects,
- lower generation costs due to lower fuel costs, primarily reflecting lower natural gas and coal prices,
- higher MTM gains in 2015, and
- insurance recoveries of Superstorm Sandy costs, primarily at Power.

These increases were partially offset by:

- lower capacity revenues resulting from lower average auction prices coupled with lower ancillary and operating reserve revenues in the PJM region,
- lower realized gains and higher other-than-temporary impairments related to the NDT Fund, and
- higher pension and OPEB costs, net of amounts capitalized.

The 2014 year-over-year increase in our Net Income was driven by:

- MTM gains in 2014 resulting from a decrease in prices on forward positions, as compared to MTM losses in 2013,
- higher sales volumes under the BGSS contract due to colder average temperatures in the 2014 winter heating season,
- higher volumes of gas sold to third party customers,
- higher revenues due to increased investments in transmission projects, and
- lower O&M expense at PSE&G and Power, largely due to a reduction in pension and OPEB costs, net of amounts capitalized.

These increases were partially offset by:

- lower volumes of electricity sold under Power's BGS contracts resulting from serving fewer tranches in 2014, and
- higher generation costs due to higher fuel costs.

Our results include the realized gains, losses and earnings on Power's NDT Fund and other related NDT activity. Realized gains and losses, interest and dividend income and other costs related to the NDT Fund are recorded in Other Income (Deductions), and impairments on certain NDT securities are recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in O&M Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense. In 2014, we restructured portions of our NDT Fund and realized a pre-tax gain of $65 million.

Our results also include the after-tax impacts of non-trading MTM activity, which consist of the financial impact from positions with forward delivery dates.

The combined after-tax impact on Net Income for the years ended December 31, 2015, 2014 and 2013 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2015	2014	2013
		Millions, after tax	
NDT Fund and Related Activity	$ 8	$ 68	$ 40
Non-Trading MTM Gains (Losses)	$ 93	$ 66	$ (74)

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PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data—Note 23. Related-Party Transactions.

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
	Millions			Millions	%	Millions	%
Operating Revenues	$ 10,415	$ 10,886	$ 9,968	$ (471)	(4)	$ 918	9
Energy Costs	3,261	3,886	3,536	(625)	(16)	350	10
Operation and Maintenance	2,978	3,150	2,887	(172)	(5)	263	9
Depreciation and Amortization	1,214	1,227	1,178	(13)	(1)	49	4
Income from Equity Method Investments	12	13	11	(1)	(8)	2	18
Other Income (Deductions)	152	229	159	(77)	(34)	70	44
Other-Than-Temporary Impairments	53	20	12	33	N/A	8	67
Interest Expense	393	389	402	4	1	(13)	(3)
Income Tax Expense	1,001	938	812	63	7	126	16

The 2015 and 2014 amounts in the preceding table for Operating Revenues and O&M costs each include $375 million and $389 million, respectively, for Servco. These amounts represent the O&M pass-through costs for the Long Island operations, the full reimbursement of which is reflected in Operating Revenues. See Item 8. Financial Statements and Supplementary Data—Note 3. Variable Interest Entities for further explanation. The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
	Millions			Millions	%	Millions	%
Operating Revenues	$ 6,636	$ 6,766	$ 6,655	$ (130)	(2)	$ 111	2
Energy Costs	2,722	2,909	2,841	(187)	(6)	68	2
Operation and Maintenance	1,560	1,558	1,639	2	—	(81)	(5)
Depreciation and Amortization	892	906	872	(14)	(2)	34	4
Taxes Other Than Income Taxes	—	—	68	—	N/A	(68)	(100)
Other Income (Deductions)	75	58	51	17	29	7	14
Interest Expense	280	277	293	3	1	(16)	(5)
Income Tax Expense	470	449	381	21	5	68	18

Year Ended December 31, 2015 as compared to 2014

Operating Revenues decreased $130 million due primarily to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $212 million due primarily to an increase in transmission revenues.

- Transmission revenues were $164 million higher due to increased investments in transmission projects.

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- Electric distribution revenues increased $31 million due primarily to higher sales volumes due to weather.
- Gas distribution revenues increased $17 million due primarily to higher Weather Normalization Clause (WNC) revenue of $35 million due to warmer weather in 2015 compared to 2014, partially offset by $18 million due to lower sales volumes.

Clause Revenues decreased $154 million due primarily to lower Securitization Transition Charge (STC) revenues of $86 million, lower Societal Benefit Charges (SBC) of $31 million, lower Margin Adjustment Clause (MAC) of $29 million, and lower Solar Pilot Recovery Charges (SPRC) of $8 million. The changes in STC, SBC, MAC and SPRC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC, MAC or SPRC collections.

Commodity Revenue decreased $187 million due to lower Gas revenues, partially offset by higher Electric revenues. This is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Gas revenues decreased $266 million due primarily to lower BGSS prices of $295 million, partially offset by $29 million from higher sales volumes. The average price of natural gas was 29% lower to the customer in 2015 than in 2014.
- Electric revenues increased $79 million due primarily to $120 million in higher net BGS revenues, comprised of $166 million from higher sales volumes, partially offset by lower prices of $46 million. BGS sales volume increased due primarily to weather. The BGS net revenue increase was partially offset by $41 million in lower revenues from the sale of Non-Utility Generation (NUG) energy and collections of Non-Utility Generation Charges (NGC) due primarily to lower prices.

Operating Expenses

Energy Costs decreased $187 million. This is entirely offset by Commodity Revenue.

Operation and Maintenance increased $2 million, primarily due to increases of

- $33 million in pension and OPEB expenses, net of amounts capitalized,
- $13 million in transmission operating expenses,
- $7 million in gas bad debt expense, and
- a $49 million net increase due primarily to various increases, including information technology expenditures, wages, appliance service costs and preventative maintenance,
- almost entirely offset by a $90 million net reduction in costs related to various clause mechanisms, GPRC and the Capital Infrastructure Program (CIP), and
- $10 million of insurance recovery proceeds.

Depreciation and Amortization decreased $14 million due primarily to a $69 million decrease in amortization of Regulatory Assets, partially offset by an increase in depreciation of $55 million due to additional plant in service.

Other Income (Deductions) net increase of $17 million in Allowance for Funds Used During Construction.

Interest Expense increased $3 million primarily due to increases of

- $12 million due to net issuances in the latter half of 2014, and
- $9 million due to net issuances in 2015,
- partially offset by a decrease of $17 million due to the redemption of securitization debt in 2015.

Income Tax Expense increased $21 million due primarily to higher pre-tax income.

Year Ended December 31, 2014 as compared to 2013

Operating Revenues increased $111 million due primarily to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $88 million due primarily to an increase in transmission revenues.

- Transmission revenues were $138 million higher due to increased investments in transmission projects.

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- Gas distribution revenues decreased $5 million due primarily to lower WNC revenue of $32 million due to more normal weather compared to the prior year, lower Transitional Energy Facilities Assessment (TEFA) revenue of $22 million due to elimination of TEFA tax effective January 1, 2014, lower CIP related revenue of $11 million, partially offset by higher sales volumes of $54 million, and higher revenue from GPRC of $6 million.
- Electric distribution revenues decreased $45 million due primarily to a $45 million decrease due to the elimination of the TEFA tax in 2014, lower sales volumes of $17 million and lower CIP related revenue of $5 million, partially offset by higher GPRC of $22 million.

Clause Revenues decreased $51 million due primarily to lower SBC of $32 million and lower STC revenues of $18 million. The changes in clause revenue amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on clause revenue collections.

Commodity Revenues increased $68 million due to lower Electric and Gas revenues. This is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues increased $22 million due primarily to $64 million in higher BGS revenues, partially offset by $42 million in lower revenues from the sale of NUG energy and collections of NGC due primarily to lower prices. BGS sales increased 2% due primarily to weather.
- Gas revenues increased $46 million due to higher BGSS volumes of $93 million, partially offset by lower BGSS prices of $47 million. The average price of natural gas was 5% lower in 2014 than in 2013.

Other Operating Revenues increased $6 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Operating Expenses

Energy Costs increased $68 million. This is entirely offset by Commodity Revenues.

Operation and Maintenance decreased $81 million, of which the most significant components were decreases of

- $73 million in pension and OPEB expenses, net of amounts capitalized, and
- $21 million in costs related to clause mechanisms, GPRC and CIP,
- partially offset by a $13 million net increase in operational expenses due primarily to an increase in storm related costs of $8 million.

Depreciation and Amortization increased $34 million due primarily to increases of $47 million in additional plant in service partially offset by a $15 million decrease in amortization of Regulatory Assets.

Taxes Other Than Income Taxes decreased $68 million due to the elimination of the TEFA tax in 2014.

Interest Expense decreased $16 million primarily due to decreases of

- $16 million due to partial redemption of securitization debt of in 2014,
- $25 million due to maturities of $725 million in 2013, and
- $5 million due to maturities of $500 million in 2014,
- partially offset by an increase of $14 million due to the issuance of $1,250 million of debt in 2014, and
- an increase of $17 million due to the issuance of $1,500 million of debt in 2013.

Income Tax Expense increased $68 million due primarily to higher pre-tax income.

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Power

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 4,928	$ 5,434	$ 5,063	$ (506)	(9)	$ 371	7
Energy Costs	2,150	2,747	2,496	(597)	(22)	251	10
Operation and Maintenance	1,057	1,186	1,224	(129)	(11)	(38)	(3)
Depreciation and Amortization	291	292	273	(1)	—	19	7
Income from Equity Method Investments	14	14	16	—	—	(2)	(13)
Other Income (Deductions)	97	170	105	(73)	(43)	65	62
Other-Than-Temporary Impairments	53	20	12	33	N/A	8	67
Interest Expense	121	122	116	(1)	(1)	6	5
Income Tax Expense	511	491	419	20	4	72	17

Year Ended December 31, 2015 as compared to 2014

Operating Revenues decreased $506 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $172 million due primarily to

- a decrease of $192 million due primarily to lower capacity revenues resulting from lower average auction prices and the retirement of older peaking units in June 2015, coupled with lower ancillary and operating reserve revenues in the PJM region, and
- lower net revenues of $73 million due primarily to lower energy volumes sold in the New England (NE) region and lower average realized prices in the NE and New York (NY) regions, partially offset by higher energy volumes sold in the NY and PJM regions. Also included in the net decrease is $22 million due to lower MTM gains in 2015.
- partially offset by an increase of $56 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions coupled with higher average prices in the NE region, and
- an increase of $37 million due primarily to higher volumes of electricity sold under the BGS contract at higher average prices.

Gas Supply Revenues decreased $336 million due primarily to

- a net decrease of $214 million in sales under the BGSS contract, substantially comprised of lower average sales prices, and
- a decrease of $122 million on sales to third party customers, of which $93 million was due to lower average sales prices and $29 million to lower volumes sold.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $597 million due to

- ***Generation costs*** decreased $254 million due primarily to lower fuel costs of $330 million reflecting lower average realized natural gas and coal prices and the utilization of lower volumes of oil and coal. MTM gains in 2015 as compared to MTM losses in 2014 resulted in a $66 million decrease. These decreased costs were partially offset by higher congestion costs in the PJM region of $140 million.
- ***Gas costs*** decreased $343 million mainly related to a decrease in average gas costs on both obligations under the BGSS contract and sales to third parties.

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Operation and Maintenance decreased $129 million due primarily to

- a decrease of $145 million due to insurance recoveries received in 2015 related to Superstorm Sandy, and
- a net decrease of $61 million related to our fossil plants, largely due to higher costs incurred in 2014 for planned outage costs, including maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant, partially offset by planned outage costs in 2015 at our BEC generating plant and installation of upgraded technology at our combined cycle Bergen plant,
- partially offset by an increase of $51 million at our nuclear facilities, primarily due to higher planned outage costs at our 100%-owned Hope Creek and 50%-owned Peach Bottom 3 nuclear plants in 2015 as compared to our 57%-owned Salem nuclear unit 2 in 2014, and
- a $30 million increase due to higher pension and OPEB costs, net of amounts capitalized.

Other Income (Deductions) decreased $73 million due primarily to lower net realized gains from the NDT Fund, partially offset by a $28 million insurance recovery related to Superstorm Sandy.

Other-Than-Temporary Impairments increased $33 million due primarily to an increase in impairments of equity securities in the NDT Fund.

Income Tax Expense increased $20 million in 2015 due primarily to higher pre-tax income.

Year Ended December 31, 2014 as compared to 2013

Operating Revenues increased $371 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues increased $263 million due primarily to

- higher revenues of $366 million due primarily to MTM gains in 2014 resulting from a decrease in prices on forward positions and higher energy volumes sold in the NY and NE regions, and
- a net increase of $27 million due primarily to higher volumes on wholesale load contracts in the PJM region, offset in part by lower wholesale load volumes in the NE region,
- partially offset by a decrease of $89 million due to lower volumes of electricity sold as a result of serving fewer tranches in 2014 under our BGS contracts and lower average pricing, and
- a net decrease of $41 million due primarily to a decrease in operating reserve revenue, partially offset by higher ancillary revenue in the PJM region.

Gas Supply Revenues increased $93 million due primarily to

- a net increase of $44 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during the 2014 winter heating season, partially offset by lower average gas prices, and
- a net increase of $49 million due to higher sales volumes to third party customers.

Other Operating Revenues increased $15 million due to transition fees related to fuel management and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $251 million due to

- ***Generation costs*** increased $252 million due primarily to higher fuel costs, reflecting higher average realized natural gas prices, the unfavorable MTM impact from lower average natural gas prices on forward positions and the utilization of higher volumes of gas and oil. These increased costs were partially offset by lower congestion costs in the PJM region.
- ***Gas costs*** decreased $1 million related to a decrease of $137 million in average gas inventory costs, substantially offset by $136 million of higher volumes sold under the BGSS contract and to third party customers due to colder average temperatures during the 2014 winter heating season.

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Operation and Maintenance decreased $38 million due primarily to

- lower pension and OPEB costs, net of amounts capitalized of $42 million,
- a decrease of $15 million due primarily to the outage of our 100%-owned Hope Creek nuclear facility in the fall of 2013, which was partially offset by the extension of our 57%-owned nuclear Salem Unit 2 refueling outage in 2014, and
- a decrease of $27 million due to lower storm costs related to Superstorm Sandy,
- partially offset by an increase of $40 million related primarily to higher planned outage and maintenance costs at our fossil plants, including maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant and outages at our Keystone and Hudson facilities.

Depreciation and Amortization increased $19 million due primarily to a higher depreciable fossil and nuclear asset base.

Other Income (Deductions) increased $65 million due primarily to higher realized gains from the NDT Fund due to the restructuring of the portfolio in 2014.

Other-Than-Temporary Impairments increased $8 million due to an increase in impairments of the NDT Fund.

Interest Expense increased $6 million due primarily to the issuance of a $250 million 2.45% Senior Note and a $250 million 4.30% Senior Note in November 2013, partially offset by the maturity of $300 million of 2.50% Senior Notes in April 2013.

Income Tax Expense increased $72 million in 2014 due primarily to higher pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Financing Methodology

We expect our capital requirements to be met through internally generated cash flows and external financings, consisting of short-term debt for working capital needs and long-term debt for capital investments.

PSE&G's sources of external liquidity include a $600 million multi-year syndicated credit facility. PSE&G's commercial paper program is the primary vehicle for meeting seasonal, intra-month and temporary working capital needs. PSE&G does not engage in any intercompany borrowing or lending arrangements. PSE&G maintains back-up facilities in an amount sufficient to cover the commercial paper and letters of credit outstanding. PSE&G's dividend payments to PSEG are consistent with its capital structure objectives which have been established to maintain investment grade credit ratings. PSE&G's long-term financing plan is designed to replace maturities, fund a portion of its capital program and manage short-term debt balances. Generally, PSE&G uses either secured medium-term notes or first mortgage bonds to raise long-term capital.

PSEG, Power, Energy Holdings, PSEG LI and Services participate in a corporate money pool, an aggregation of daily cash balances designed to efficiently manage their respective short-term liquidity needs. Servco does not participate in the corporate money pool. Servco's short-term liquidity needs are met through an account funded and owned by LIPA.

PSEG's sources of external liquidity may include the issuance of long-term debt securities and the incurrence of additional indebtedness under credit facilities. Our current sources of external liquidity include multi-year syndicated credit facilities totaling $1 billion. These facilities are available to back-stop PSEG's commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to PSEG's subsidiaries. PSEG's credit facilities and the commercial paper program are available to support PSEG working capital needs or to temporarily fund growth opportunities in advance of obtaining permanent financing. PSEG also has a $500 million term loan credit agreement that is scheduled to expire in November 2017. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power's sources of external liquidity include $2.6 billion of syndicated multi-year credit facilities. Additionally, from time to time, Power maintains bilateral credit agreements designed to enhance its liquidity position. Credit capacity is primarily used to provide collateral in support of Power's forward energy sale and forward fuel purchase contracts as the market prices for energy and fuel fluctuate, and to meet potential collateral postings in the event of a credit rating downgrade below investment grade. Power's dividend payments to PSEG are also designed to be consistent with its capital structure objectives which have been established to maintain investment grade credit ratings and provide sufficient financial flexibility. Generally, Power issues senior unsecured debt to raise long-term capital.

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Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the year ended December 31, 2015, our operating cash flow increased by $759 million. For the year ended December 31, 2014, our operating cash flow increased by $2 million. The net changes were primarily due to net changes from our subsidiaries as discussed below and higher tax payments in 2014 at the parent company and Energy Holdings.

PSE&G

PSE&G's operating cash flow increased $292 million from $1,833 million to $2,125 million for the year ended December 31, 2015, as compared to 2014, due primarily to

- higher earnings,
- a $311 million reduction in tax payments, and
- an increase of $102 million due to higher customer billings in the fourth quarter of 2014 primarily as a result of increased usage due to weather,
- partially offset by a decrease of $250 million related to a change in regulatory deferrals, primarily driven by the return of prior year overcollections to customers for BGSS gas costs, Gas WNC charges and BGS costs.

PSE&G's operating cash flow increased $188 million from $1,645 million to $1,833 million for the year ended December 31, 2014, as compared to 2013, due primarily to

- higher earnings,
- an increase of $188 million due to an increase from a net change in regulatory deferrals, primarily related to over collections of BGSS gas costs, the over collection of gas revenues due to the Gas WNC and GPRC rate recoveries, and
- an increase of $83 million due to decrease in employee benefit plan funding,
- partially offset by $199 million related to higher tax payments.

Power

Power's operating cash flow increased $281 million from $1,425 million to $1,706 million for the year ended December 31, 2015, as compared to 2014, primarily resulting from

- higher earnings,
- a decrease in margin deposit requirements of $144 million, and
- a $78 million increase from net collection of counterparty receivables,
- partially offset by an increase of $325 million in tax payments.

Power's operating cash flow increased $78 million from $1,347 million to $1,425 million for the year ended December 31, 2014, as compared to 2013, primarily resulting from

- lower tax payments,
- partially offset by increase of $87 million in payments to counterparties, and
- a decrease of $11 million due to collection of counterparty receivables.

Short-Term Liquidity

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of December 31, 2015 were as follows:

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Company/Facility	As of December 31, 2015 Total Facility	Usage	Available Liquidity
		Millions	
PSEG	$ 1,000	$ 221	$ 779
PSE&G	600	167	433
Power	2,600	164	2,436
Total	**$ 4,200**	**$ 552**	**$ 3,648**

As of December 31, 2015, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating. PSEG's credit facilities are available to back-stop its Commercial Paper Program and issue letters of credit under which as of December 31, 2015, $211 million of Commercial Paper was outstanding. PSE&G's credit facility primary use is to support its Commercial Paper Program under which as of December 31, 2015, $153 million was outstanding. Most of our credit facilities expire in 2019 and 2020. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities and Note 13. Schedule of Consolidated Debt.

Long-Term Debt Financing

PSE&G had $171 million of 6.75% Mortgage Bonds mature in January 2016.

Power has $303 million of 5.32% Senior Notes and $250 million of 2.75% maturing in September 2016.

For a discussion of our long-term debt transactions during 2015 and into 2016, see Item 8. Financial Statements and Supplementary Data—Note 13. Schedule of Consolidated Debt.

Debt Covenants

Our credit agreements contain maximum debt to equity ratios and other restrictive covenants and conditions to borrowing. We are currently in compliance with all of our debt covenants. Continued compliance with applicable financial covenants will depend upon our future financial position, level of earnings and cash flows, as to which no assurances can be given.

In addition, under its First and Refunding Mortgage (Mortgage), PSE&G may issue new First and Refunding Mortgage Bonds against previous additions and improvements, provided that its ratio of earnings to fixed charges calculated in accordance with its Mortgage is at least 2 to 1, and/or against retired Mortgage Bonds. As of December 31, 2015, PSE&G's Mortgage coverage ratio was 3.87 to 1 and the Mortgage would permit up to approximately $4.0 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.

Default Provisions

Our bank credit agreements and indentures contain various, customary default provisions that could result in the potential acceleration of indebtedness under the defaulting company's agreement. We have not defaulted under these agreements.
In particular, PSEG's bank credit agreements contain provisions under which certain events, including an acceleration of material indebtedness under PSE&G's and Power's respective financing agreements, a failure by PSE&G or Power to satisfy certain final judgments and certain bankruptcy events by PSE&G or Power, that would constitute an event of default under the PSEG bank credit agreements. Under the PSEG bank credit agreements, it would also be an event of default if either PSE&G or Power ceases to be wholly owned by PSEG. The PSE&G and Power bank credit agreements include similar default provisions; however such provisions only relate to the respective borrower under such agreement and its subsidiaries and do not contain cross default provisions to each other. The PSE&G and Power bank credit agreements do not include cross default provisions relating to PSEG.

There are no cross default provisions in PSEG's or PSE&G's indentures. Power's indenture includes cross default provisions similar to those described above for PSEG; however, such provisions only relate to Power's subsidiaries and do not cross default to PSEG or PSE&G.

Ratings Triggers

Our debt indentures and credit agreements do not contain any material 'ratings triggers' that would cause an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, any one or more of the affected companies may be subject to increased interest costs on certain bank debt and certain collateral

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requirements. In the event that we are not able to affirm representations and warranties on credit agreements, lenders would not be required to make loans.

In accordance with BPU requirements under the BGS contracts, PSE&G is required to maintain an investment grade credit rating. If PSE&G were to lose its investment grade rating, it would be required to file a plan to assure continued payment for the BGS requirements of its customers.

Fluctuations in commodity prices or a deterioration of Power's credit rating to below investment grade could increase Power's required margin postings under various agreements entered into in the normal course of business. Power believes it has sufficient liquidity to meet the required posting of collateral which would likely result from a credit rating downgrade at today's market prices.

Common Stock Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	**2015**	**2014**	**2013**
Per Share	$ 1.56	$ 1.48	$ 1.44
in Millions	$ 789	$ 748	$ 728

On February 16, 2016, our Board of Directors approved a $0.41 per share common stock dividend for the first quarter of 2016. This reflects an indicative annual dividend rate of $1.64 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In May 2015, Moody's published research reports on PSEG, PSE&G and Power and the existing ratings and outlooks were unchanged. In May 2015, S&P published updated research reports and revised the outlook to stable from positive for PSEG's Corporate Credit Rating and Power's Senior Notes. S&P also affirmed the senior unsecured rating of BBB+ at Power and the mortgage bond rating of A at PSE&G. In September 2015, Moody's published an updated research report on PSEG and revised the outlook to positive from stable. In September and October 2015, Fitch published full rating reports on PSEG and Power leaving ratings and outlooks unchanged. In October 2015, PSEG ended a contractual agreement with Fitch to provide credit rating services for PSEG, PSE&G and Power. In January 2016, S&P published updated research reports on PSEG and PSE&G and the existing ratings and outlooks were unchanged.

	Moody's (A)	**S&P (B)**
PSEG		
Outlook	**Positive**	**Stable**
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP

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(lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities. The Corporate Credit Rating outlook does not apply to PSEG's or PSE&G's Commercial Paper Rating or PSE&G's Mortgage Bond rating.

Other Comprehensive Income

For the year ended December 31, 2015, we had Other Comprehensive Loss of $12 million on a consolidated basis. Other Comprehensive Loss was due primarily to a $27 million decrease in net unrealized gains related to Available-for-Sale Securities and $10 million of unrealized losses on derivative contracts accounted for as hedges, partially offset by a $25 million decrease in our consolidated liability for pension and postretirement benefits. See Item 8. Financial Statements and Supplementary Data—Note 20. Accumulated Other Comprehensive Income (Loss), Net of Tax for additional information.

CAPITAL REQUIREMENTS

It is expected that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. Projected capital construction and investment expenditures, excluding nuclear fuel purchases, for the next three years are presented in the table below. These projections include Allowance for Funds Used During Construction and Interest Capitalized During Construction for PSE&G and Power, respectively. These amounts are subject to change, based on various factors. We will continue to approach non-regulated solar and other renewable investments opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2016	2017	2018
		Millions	
PSE&G:			
Transmission	$ 1,765	$ 1,740	$ 1,210
Distribution			
Baseline	655	645	580
Clause Recovery			
Energy Strong	340	250	55
Gas System Modernization Program	240	305	315
Solar/Energy Efficiency	85	80	50
Total PSE&G	**$ 3,085**	**$ 3,020**	**$ 2,210**
Power:			
Baseline	$ 270	$ 205	$ 260
Environmental/Regulatory	40	45	60
Fossil Growth Opportunities	740	745	390
Nuclear Expansion	15	10	5
Solar Growth Opportunities	230	20	—
Total Power	**$ 1,295**	**$ 1,025**	**$ 715**
Other	$ 55	$ 40	$ 35
Total PSEG	**$ 4,435**	**$ 4,085**	**$ 2,960**

PSE&G

PSE&G's projections for future capital expenditures include material additions and replacements to its transmission and distribution systems to meet expected growth and to manage reliability. As project scope and cost estimates develop, PSE&G will modify its current projections to include these required investments. PSE&G's projected expenditures for the various items reported above are primarily comprised of the following:

- Transmission—investments focused on reliability improvements and replacement of aging infrastructure.
- Baseline—investments for new business, reliability improvements, and replacement of defective equipment.
- Energy Strong—Electric and Gas Distribution reliability investment program focused on system hardening and resiliency.

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- Gas System Modernization Program—Gas Distribution investment program to replace aging infrastructure.
- Solar/Energy Efficiency—investments associated with grid-connected solar, solar loan programs, and customer energy efficiency programs.

In 2015, PSE&G made $2,692 million of capital expenditures, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $120 million, which are included in operating cash flows.

Power

Power's projected expenditures for the various items listed above are primarily comprised of the following:

- Baseline—investments to replace major parts and enhance operational performance.
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Fossil Growth Opportunities—investments associated with new construction, including Keys Energy Center, Sewaren 7 and BH5, and with upgrades to increase efficiency and output at combined cycle plants.
- Nuclear Expansion—investments associated with certain Nuclear capital projects, primarily at existing facilities designed to increase operating output.
- Solar Growth Opportunities—investments associated with the construction of utility-scale photovoltaic facilities.

In 2015, Power made $881 million of capital expenditures, excluding $236 million for nuclear fuel, primarily related to various projects at Fossil and Nuclear.

Disclosures about Long-Term Maturities, Contractual and Commercial Obligations and Certain Investments

The following table reflects our contractual cash obligations and other commercial commitments in the respective periods in which they are due. In addition, the table summarizes anticipated recourse and non-recourse debt maturities for the years shown. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Schedule of Consolidated Debt.

The table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities for uncertain tax positions since we are unable to reasonably estimate the timing of liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Item 8. Financial Statements and Supplementary Data—Note 19. Income Taxes for additional information.

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	Total Amount Committed	Less Than 1 Year	2 - 3 Years	4- 5 Years	Over 5 Years
			Millions		
Contractual Cash Obligations					
Long-Term Recourse Debt Maturities					
PSEG (Parent)	$ 500	$ —	$ 500	$ —	$ —
PSE&G	6,879	171	750	759	5,199
Power	2,253	553	250	450	1,000
Long-Term Non-Recourse Project Financing					
Other	7	7	—	—	—
Interest on Recourse Debt					
PSEG (Parent)	18	8	10	—	—
PSE&G	4,572	269	517	460	3,326
Power	1,004	114	184	163	543
Interest on Non-Recourse Project Financing					
Other	—	—	—	—	—
Capital Lease Obligations					
Power	3	1	1	—	1
Operating Leases					
PSE&G	108	12	17	13	66
Power	44	2	4	5	33
Services	211	13	26	26	146
Other	4	2	2	—	—
Energy-Related Purchase Commitments					
Power	2,903	786	1,048	562	507
Total Contractual Cash Obligations	**$ 18,506**	**$ 1,938**	**$ 3,309**	**$ 2,438**	**$ 10,821**
Commercial Commitments					
Standby Letters of Credit					
PSEG (Parent)	$ 10	$ 10	$ —	$ —	$ —
PSE&G	14	14	—	—	—
Power	209	209	—	—	—
Guarantees and Equity Commitments					
Power	56	52	—	—	4
Total Commercial Commitments	**$ 289**	**$ 285**	**$ —**	**$ —**	**$ 4**
Liability Payments for Uncertain Tax Positions					
PSEG	$ 158	$ 158	$ —	$ —	$ —
PSE&G	102	102	—	—	—
Power	42	42	—	—	—

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OFF-BALANCE SHEET ARRANGEMENTS

Power

Power issues guarantees in conjunction with certain of its energy contracts. See Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities for further discussion.

Other

Through Energy Holdings, we have investments in leveraged leases that are accounted for in accordance with GAAP Accounting for Leases. Leveraged lease investments generally involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease arrangement, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and is not presented on our Consolidated Balance Sheets. In the event of default, the leased asset, and in some cases the lessee, secures the loan. As a lessor, Energy Holdings has ownership rights to the property and rents the property to the lessees for use in their business operations. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 6. Long-Term Investments and Note 7. Financing Receivables.

In the event that collection of the minimum lease payments to be received by Energy Holdings is no longer reasonably assured, Energy Holdings may deem that a lessee has a high probability of defaulting on the lease obligation, and would consider the need to record an impairment of its investment. In the event the lease is ultimately rejected by a Bankruptcy Court, the fair value of the underlying asset and the associated debt would be recorded on the Consolidated Balance Sheets instead of the net equity investment in the lease.

CRITICAL ACCOUNTING ESTIMATES

Under GAAP, many accounting standards require the use of estimates, variable inputs and assumptions (collectively referred to as estimates) that are subjective in nature. Because of this, differences between the actual measure realized versus the estimate can have a material impact on results of operations, financial position and cash flows. We have determined that the following estimates are considered critical to the application of rules that relate to the respective businesses.

Accounting for Pensions

PSEG sponsors several qualified and nonqualified pension plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The market-related value of plan assets held for the qualified pension plan is equal to the fair value of these assets as of year-end. The plan assets are comprised of investments in both debt and equity securities which are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. We calculate pension costs using various economic and demographic assumptions.

***Assumptions and Approach Used*:** Economic assumptions include the discount rate and the long-term rate of return on trust assets. Demographic assumptions include projections of future mortality rates, pay increases and retirement patterns.

Assumption	2015	2014	2013
Discount Rate	4.54%	4.20%	5.00%
Rate of Return on Plan Assets	8.00%	8.00%	8.00%

The discount rate used to calculate pension obligations is determined as of December 31 each year, our measurement date. The discount rate is determined by developing a spot rate curve based on the yield to maturity of a universe of high quality corporate bonds with similar maturities to the plan obligations. The spot rates are used to discount the estimated plan distributions. The discount rate is the single equivalent rate that produces the same result as the full spot rate curve.

At the end of 2015, we changed the approach used to measure future service and interest costs for pension benefits. For 2015 and prior, we calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, we have elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows. We believe the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations. As a change in accounting estimate, this change will be reflected prospectively. We estimate this will reduce 2016 pension expense by approximately $47

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million or $34 million, net of amounts capitalized, as compared to the 2016 amount that would have been derived from applying our 2015 and prior years' methodology.

Our expected rate of return on plan assets reflects current asset allocations, historical long-term investment performance and an estimate of future long-term returns by asset class and long-term inflation assumptions.

Based on the above assumptions, we have estimated net periodic pension expense in 2016 of approximately $56 million or $40 million, net of amounts capitalized.

We utilize a corridor approach that reduces the volatility of reported pension expense/income. The corridor requires differences between actuarial assumptions and plan results be deferred and amortized as part of expense/income. This occurs only when the accumulated differences exceed 10% of the greater of the pension benefit obligation or the fair value of plan assets as of each year-end. The excess would be amortized over the average remaining service period of the active employees, which is approximately eight years.

***Effect if Different Assumptions Used*:** As part of the business planning process, we have modeled future costs assuming an 8.00% rate of return and a 4.54% discount rate for 2016. Actual future pension expense/income and funding levels will depend on future investment performance, changes in discount rates, market conditions, funding levels relative to our projected benefit obligation and accumulated benefit obligation and various other factors related to the populations participating in the pension plans.

The following chart reflects the sensitivities associated with a change in certain assumptions. The effects of the assumption changes shown below solely reflect the impact of that specific assumption.

Assumption	% Change	Impact on Pension Benefit Obligation as of December 31, 2015	Increase to Pension Expense in 2016	Increase to Pension Expense, net of Amounts Capitalized in 2016
		Millions		
Discount Rate	(1)%	$ 706	$ 75	$ 54
Expected Rate of Return on Plan Assets	(1)%	N/A	$ 49	$ 35

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Hedge and MTM Accounting

Current guidance requires us to recognize the fair value of derivative instruments, not designated as normal purchases or normal sales, at their fair value on the balance sheet. Many contracts qualify for normal purchases and normal sales exemption and are accounted for upon settlement.

***Assumptions and Approach Used*:** In general, the fair value of our derivative instruments is determined by reference to quoted market prices from contracts listed on exchanges or from brokers. Some of these derivative contracts are long-term and rely on forward price quotations over the entire duration of the derivative contracts.

For a small number of contracts where quoted market prices are not available, we utilize mathematical models that rely on historical data to develop forward pricing information in the determination of fair value.

We have entered into various derivative instruments to manage risk from changes in commodity prices and interest rates. In accordance with our hedging strategy, derivatives that are hedging these risks and qualify are designated as either cash flow hedges or fair value hedges. For derivatives designated as hedges, the change in the value of a derivative instrument is measured against the offsetting change in the value of the underlying contract, anticipated transaction or other business condition that the derivative instrument is intended to hedge. This is known as the measure of hedge effectiveness. Changes in the fair value of the effective portion of a derivative instrument designated as a fair value hedge, along with changes in the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in current period earnings. Changes in the fair value of the effective portion of derivative instruments designated as cash flow hedges are reported in Accumulated Other Comprehensive Income (Loss), net of tax, until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings. During periods of extreme price volatility, there will be significant changes in the value recorded in Accumulated Other Comprehensive Income (Loss). As of December 31, 2015, we had no commodity contracts designated as cash flow hedges.

For our wholesale energy business, many of the forward sale, forward purchase, option and other contracts are derivative instruments that hedge commodity price risk, but do not meet the requirements for either cash flow or fair value hedge

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accounting. The changes in value of such derivative contracts are marked to market through earnings as the related commodity prices fluctuate. As a result, our earnings may experience significant fluctuations depending on the volatility of commodity prices.

***Effect if Different Assumptions Used*:** Any significant changes to the fair market values of our derivatives instruments could result in a material change in the value of the assets or liabilities recorded on our Consolidated Balance Sheets and could result in a material change to the unrealized gains or losses recorded in our Consolidated Statements of Operations.

For additional information regarding Derivative Financial Instruments, see Item 8. Financial Statements and Supplementary Data—Note 15. Financial Risk Management Activities.

Long-Lived Assets

In accordance with GAAP, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset's or asset group's carrying amount may not be recoverable.

Assumptions and Approach Used: In the event certain triggers exist indicating an asset/asset group may not be recoverable, an undiscounted cash flow test is performed to determine if an impairment exists. When the carrying value of a long-lived asset/asset group exceeds the undiscounted estimate of future cash flows associated with the asset/asset group, an impairment may exist to the extent that the fair value of the asset/asset group is less than its carrying amount. These tests require significant estimates and judgment when developing expected future cash flows; however, generating units are typically evaluated at a regional portfolio level.

Effect if Different Assumptions Used: The above cash flow tests and fair value estimates may be impacted by changes in forecasted power prices, fuel costs, dispatch rates, other operating and capital expenditures and the cost of borrowing which if different, could significantly impact the outcome, triggering additional impairment tests or write-offs.

Lease Investments

Our Investments in Leases, included in Long-Term Investments on our Consolidated Balance Sheets, are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. A significant portion of the estimated residual value of leased assets is related to merchant power plants leased to other energy companies. See Item 8. Financial Statements and Supplementary Data – Note 6. Long-Term Investments and Note 7. Financing Receivables.

***Assumptions and Approach Used*:** Residual values are the estimated values of the leased assets at the end of the respective lease terms. The estimated values are calculated by discounting the cash flows related to the leased assets after the lease term. For the merchant power plants, the estimated discounted cash flows are dependent upon various assumptions, including:

- estimated forward power and capacity prices in the years after the lease,
- related prices of fuel for the plants,
- dispatch rates for the plants,
- future capital expenditures required to maintain the plants,
- future operation and maintenance expenses, and
- discount rates.

Residual valuations are performed annually for each plant subject to lease using specific assumptions tailored to each plant. Those annual valuations are compared to the recorded residual values to determine if an impairment is warranted.

***Effect if Different Assumptions Used*:** A significant change to the assumptions, such as a large decrease in near-term power prices that affects the market's view of long-term power prices, or a change in the credit rating or bankruptcy of a counterparty, could result in an impairment of one or more of the residual values, but not necessarily to all of the residual values. However, if, because of changes in assumptions, all the residual values related to the merchant energy plants were deemed to be zero, we would recognize an after-tax charge to income of approximately $177 million.

Asset Retirement Obligations (ARO)

PSE&G, Power and Services recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists. These AROs are recorded at fair value in the period in which they are incurred and are capitalized as part of the carrying amount of the related long-lived assets. PSE&G, as a rate-regulated entity, recognizes regulatory assets or liabilities as a result

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of timing differences between the recording of costs and costs recovered through the rate-making process. We accrete the ARO liability to reflect the passage of time.

***Assumptions and Approach Used*:** Because quoted market prices are not available for AROs, we estimate the initial fair value of an ARO by calculating discounted cash flows that are dependent upon various assumptions, including:

- estimation of dates for retirement, which can be dependent on environmental and other legislation,
- amounts and timing of future cash expenditures associated with retirement, settlement or remediation activities,
- discount rates,
- cost escalation rates,
- market risk premium,
- inflation rates, and
- if applicable, past experience with government regulators regarding similar obligations.

We obtain updated cost studies triennially unless new information necessitates more frequent updates. The most recent cost study was done in 2015. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset which impacts the amount of accretion and depreciation expense recognized in future periods.

Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power's nuclear facilities comprised 94% of Power's total AROs as of December 31, 2015. Power determines its AROs for its nuclear units by assigning probability weighting to various discounted cash flow outcomes for each of its nuclear units that incorporate the assumptions above as well as:

- license renewals,
- early shutdown,
- safe storage for a period of time after retirement, and
- recovery from the federal government of costs incurred for spent nuclear fuel.

***Effect if Different Assumptions Used*:** Changes in the assumptions could result in a material change in the ARO balance sheet obligation and the period over which we accrete to the ultimate liability. For example, a decrease of 1% in the discount rate would result in a $37 million increase in the Nuclear ARO as of December 31, 2015. An increase of 1% in the inflation rate would result in a $191 million increase in the Nuclear ARO as of December 31, 2015. Also, if we did not assume that we would recover from the federal government the costs incurred for spent nuclear fuel, the Nuclear ARO would increase by $267 million at December 31, 2015.

Accounting for Regulated Businesses

PSE&G prepares its financial statements to comply with GAAP for rate-regulated enterprises, which differs in some respects from accounting for non-regulated businesses. In general, accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (Regulatory Asset) or recognize obligations (Regulatory Liability) if the rates established are designed to recover the costs and if the competitive environment makes it probable that such rates can be charged or collected. This accounting results in the recognition of revenues and expenses in different time periods than that of enterprises that are not regulated.

***Assumptions and Approach Used*:** PSE&G recognizes Regulatory Assets where it is probable that such costs will be recoverable in future rates from customers and Regulatory Liabilities where it is probable that refunds will be made to customers in future billings. The highest degree of probability is an order from the BPU either approving recovery of the deferred costs over a future period or requiring the refund of a liability over a future period.

Virtually all of PSE&G's regulatory assets and liabilities are supported by BPU orders. In the absence of an order, PSE&G will consider the following when determining whether to record a Regulatory Asset or Liability:

- past experience regarding similar items with the BPU,
- treatment of a similar item in an order by the BPU for another utility,
- passage of new legislation, and

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- recent discussions with the BPU.

All deferred costs are subject to prudence reviews by the BPU. When the recovery of a Regulatory Asset or payment of a Regulatory Liability is no longer probable, PSE&G charges or credits earnings, as appropriate.

***Effect if Different Assumptions Used*:** A change in the above assumptions may result in a material impact on our results of operations or our cash flows. See Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities for a description of the amounts and nature of regulatory balance sheet amounts.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

	MTM VaR	
	Millions	
Years Ended December 31,	**2015**	**2014**
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 24	$ 36
Average for the Period	$ 17	$ 30
High	$ 40	$ 195
Low	$ 8	$ 14
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 38	$ 56
Average for the Period	$ 26	$ 46
High	$ 63	$ 306
Low	$ 12	$ 22

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See Item 8. Financial Statements and Supplementary Data—Note 15. Financial Risk Management Activities for a discussion of credit risk.

Interest Rates

We are subject to the risk of fluctuating interest rates in the normal course of business. We manage interest rate risk by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, we use a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

As of December 31, 2015, a hypothetical 10% increase in market interest rates would result in

- less than $1 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and
- a $323 million decrease in the fair value of debt, including a $270 million decrease at PSE&G and a $53 million decrease at Power.

Debt and Equity Securities

We have $5.4 billion of assets in our pension plan trusts. Although fluctuations in market prices of securities within this portfolio do not directly affect our earnings in the current period, changes in the value of these investments could affect

- our future contributions to these plans,
- our financial position if our accumulated benefit obligation under our pension plans exceeds the fair value of the pension trust funds, and
- future earnings, as we could be required to adjust pension expense and the assumed rate of return.

The NDT Fund is comprised primarily of fixed income and equity securities and has a balance $1,754 million as of December 31, 2015. As of December 31, 2015, the portfolio includes $865 million of equity securities and $847 million in fixed income securities. The fair market value of the assets in the NDT Fund will fluctuate primarily depending upon the performance of equity markets. As of December 31, 2015, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $87 million.

We use duration to measure the interest rate sensitivity of the fixed income portfolio. Duration is a summary statistic of the effective average maturity of the fixed income portfolio. The benchmark for the fixed income component of the NDT Fund currently has a duration of 5.68 years and a yield of 2.59%. The portfolio's value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2015, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $48 million.

Credit Risk

See Item 8. Financial Statements and Supplementary Data—Note 15. Financial Risk Management Activities for a discussion of credit risk and a discussion about Power's and PSE&G's credit risk.

Energy Holdings has credit risk related to its investments in leases, which totaled $60 million, net of deferred taxes of $724 million, as of December 31, 2015. These leveraged leases are concentrated in the U.S. energy industry. See Item 8. Financial Statements and Supplementary Data—Note 7. Financing Receivables for counterparties' credit ratings and other information. The credit exposure to the lessees is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverages are not met and similar cash flow restrictions if ratings are not maintained at stated levels. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a temporary market downturn or degradation in operating performance of the leased assets.

In any lease transaction, in the event of a default, Energy Holdings would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. Under a worst-case scenario, if a foreclosure were to occur, Energy Holdings would record a pre-tax write-off up to its outstanding gross investment in these facilities. Also, in the event of a potential foreclosure, the net tax benefits generated by Energy Holdings' portfolio of investments could be materially reduced in the period in which gains associated with the potential forgiveness of debt at these projects occurs. The amount and timing of

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any potential reduction in net tax benefits is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, the amount of lease debt outstanding, any cash trapped at the projects and negotiations during such potential foreclosure process. The potential loss of earnings, impairment and/or tax payments could have a material impact to our financial position, results of operations and net cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined Form 10-K is separately filed by PSEG, PSE&G and Power. Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations as to any other company.

S1-SSA-0009 - 11443

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Public Service Enterprise Group Incorporated
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(a). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2016, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2016

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Sole Stockholder of
Public Service Electric and Gas Company
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(b). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2016

S1-SSA-0009 - 11445

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Sole Member of
PSEG Power LLC
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, member's equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(c). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2016

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data

	Years Ended December 31,		
	2015	2014	2013
OPERATING REVENUES	$ 10,415	$ 10,886	$ 9,968
OPERATING EXPENSES			
Energy Costs	3,261	3,886	3,536
Operation and Maintenance	2,978	3,150	2,887
Depreciation and Amortization	1,214	1,227	1,178
Taxes Other Than Income Taxes	—	—	68
Total Operating Expenses	7,453	8,263	7,669
OPERATING INCOME	2,962	2,623	2,299
Income from Equity Method Investments	12	13	11
Other Income	254	290	213
Other Deductions	(102)	(61)	(54)
Other-Than-Temporary Impairments	(53)	(20)	(12)
Interest Expense	(393)	(389)	(402)
INCOME BEFORE INCOME TAXES	2,680	2,456	2,055
Income Tax (Expense) Benefit	(1,001)	(938)	(812)
NET INCOME	$ 1,679	$ 1,518	$ 1,243
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
BASIC	505	506	506
DILUTED	508	508	508
NET INCOME PER SHARE:			
BASIC	$ 3.32	$ 3.00	$ 2.46
DILUTED	$ 3.30	$ 2.99	$ 2.45

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11447

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2015	**2014**	**2013**
NET INCOME	$ 1,679	$ 1,518	$ 1,243
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $34, $26 and $(54) for the years ended 2015, 2014 and 2013, respectively	(27)	(27)	55
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $7, $(8) and $7 for the years ended 2015, 2014 and 2013, respectively	(10)	12	(9)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(18), $120 and $(172) for the years ended 2015, 2014 and 2013, respectively	25	(173)	247
Other Comprehensive Income (Loss), net of tax	(12)	(188)	293
COMPREHENSIVE INCOME	$ 1,667	$ 1,330	$ 1,536

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 394	$ 402
Accounts Receivable, net of allowances of $67 and $52 in 2015 and 2014, respectively	1,068	1,254
Tax Receivable	305	211
Unbilled Revenues	197	284
Fuel	463	538
Materials and Supplies, net	513	484
Prepayments	135	108
Derivative Contracts	242	240
Deferred Income Taxes	—	11
Regulatory Assets	164	323
Regulatory Assets of Variable Interest Entities (VIEs)	—	249
Other	13	15
Total Current Assets	3,494	4,119
PROPERTY, PLANT AND EQUIPMENT	35,494	32,196
Less: Accumulated Depreciation and Amortization	(8,955)	(8,607)
Net Property, Plant and Equipment	26,539	23,589
NONCURRENT ASSETS		
Regulatory Assets	3,196	3,192
Long-Term Investments	1,233	1,307
Nuclear Decommissioning Trust (NDT) Fund	1,754	1,780
Long-Term Tax Receivable	171	64
Long-Term Receivable of VIEs	495	580
Other Special Funds	227	212
Goodwill	16	16
Other Intangibles	102	84
Derivative Contracts	77	77
Restricted Cash of VIEs	—	24
Other	231	243
Total Noncurrent Assets	7,502	7,579
TOTAL ASSETS	$ 37,535	$ 35,287

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11449

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2015	December 31, 2014
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 734	$ 624
Securitization Debt of VIEs Due Within One Year	—	259
Commercial Paper and Loans	364	—
Accounts Payable	1,369	1,178
Derivative Contracts	76	132
Accrued Interest	96	95
Accrued Taxes	42	21
Deferred Income Taxes	—	173
Clean Energy Program	142	142
Obligation to Return Cash Collateral	128	121
Regulatory Liabilities	123	186
Regulatory Liabilities of VIEs	42	—
Other	459	547
Total Current Liabilities	3,575	3,478
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	8,166	7,303
Regulatory Liabilities	175	258
Regulatory Liabilities of VIEs	—	39
Asset Retirement Obligations	679	743
Other Postretirement Benefit (OPEB) Costs	1,228	1,277
OPEB Costs of Servco	375	452
Accrued Pension Costs	487	440
Accrued Pension Costs of Servco	114	126
Environmental Costs	415	417
Derivative Contracts	27	33
Long-Term Accrued Taxes	212	208
Other	181	112
Total Noncurrent Liabilities	12,059	11,408
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
CAPITALIZATION		
LONG-TERM DEBT	8,834	8,215
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2015 and 2014— 534 shares	4,915	4,876
Treasury Stock, at cost, 2015 and 2014— 28 shares	(671)	(635)
Retained Earnings	9,117	8,227
Accumulated Other Comprehensive Loss	(295)	(283)
Total Common Stockholders' Equity	13,066	12,185
Noncontrolling Interest	1	1
Total Stockholders' Equity	13,067	12,186
Total Capitalization	21,901	20,401
TOTAL LIABILITIES AND CAPITALIZATION	$ 37,535	$ 35,287

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,679	$ 1,518	$ 1,243
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,214	1,227	1,178
Amortization of Nuclear Fuel	213	200	192
Provision for Deferred Income Taxes (Other than Leases) and ITC	685	515	270
Non-Cash Employee Benefit Plan Costs	161	47	243
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	26	(4)	31
Net (Gain) Loss on Lease Investments	—	(3)	2
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(143)	(93)	79
Change in Accrued Storm Costs	12	(3)	(90)
Net Change in Regulatory Assets and Liabilities	(60)	190	2
Cost of Removal	(120)	(98)	(93)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(38)	(166)	(104)
Net Change in Certain Current Assets and Liabilities			
Tax Receivable	(94)	30	19
Accrued Taxes	(91)	(156)	81
Margin Deposit	122	(22)	(43)
Other Current Assets and Liabilities	288	(31)	261
Employee Benefit Plan Funding and Related Payments	(109)	(95)	(231)
Other	174	104	118
Net Cash Provided By (Used In) Operating Activities	3,919	3,160	3,158
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(3,863)	(2,820)	(2,811)
Proceeds from Sale of Capital Leases and Investments	14	25	50
Proceeds from Sales of Available-for-Sale Securities	1,501	1,915	1,159
Investments in Available-for-Sale Securities	(1,552)	(1,934)	(1,170)
Other	(42)	(78)	(29)
Net Cash Provided By (Used In) Investing Activities	(3,942)	(2,892)	(2,801)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	364	(60)	(203)
Issuance of Long-Term Debt	1,350	1,250	2,000
Redemption of Long-Term Debt	(600)	(500)	(1,025)
Redemption of Securitization Debt	(259)	(237)	(226)
Cash Dividend Paid on Common Stock	(789)	(748)	(728)
Other	(51)	(64)	(61)
Net Cash Provided By (Used In) Financing Activities	15	(359)	(243)
Net Increase (Decrease) in Cash and Cash Equivalents	(8)	(91)	114
Cash and Cash Equivalents at Beginning of Period	402	493	379
Cash and Cash Equivalents at End of Period	$ 394	$ 402	$ 493
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 447	$ 538	$ 241
Interest Paid, Net of Amounts Capitalized	$ 381	$ 382	$ 385
Accrued Property, Plant and Equipment Expenditures	$ 510	$ 382	$ 336

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Millions

	Common Stock		Treasury Stock					
	Shs.	Amount	Shs.	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance as of January 1, 2013	534	$ 4,833	(28)	$ (607)	$ 6,942	$ (388)	$ 1	$ 10,781
Net Income	—	—	—	—	1,243	—	—	1,243
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(219)	—	—	—	—	—	293	—	293
Comprehensive Income								1,536
Cash Dividends on Common Stock	—	—	—	—	(728)	—	—	(728)
Other	—	28	—	(8)	—	—	—	20
Balance as of December 31, 2013	534	$ 4,861	(28)	$ (615)	$ 7,457	$ (95)	$ 1	$ 11,609
Net Income	—	—	—	—	1,518	—	—	1,518
Other Comprehensive Income (Loss), net of tax (expense) benefit of $138	—	—	—	—	—	(188)	—	(188)
Comprehensive Income								1,330
Cash Dividends on Common Stock	—	—	—	—	(748)	—	—	(748)
Other	—	15	—	(20)	—	—	—	(5)
Balance as of December 31, 2014	534	$ 4,876	(28)	$ (635)	$ 8,227	$ (283)	$ 1	$ 12,186
Net Income	—	—	—	—	1,679	—	—	1,679
Other Comprehensive Income (Loss), net of tax (expense) benefit of $23	—	—	—	—	—	(12)	—	(12)
Comprehensive Income								1,667
Cash Dividends on Common Stock	—	—	—	—	(789)	—	—	(789)
Other	—	39	—	(36)	—	—	—	3
Balance as of December 31, 2015	534	$ 4,915	(28)	$ (671)	$ 9,117	$ (295)	$ 1	$ 13,067

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11452

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2015	2014	2013
OPERATING REVENUES	$ 6,636	$ 6,766	$ 6,655
OPERATING EXPENSES			
Energy Costs	2,722	2,909	2,841
Operation and Maintenance	1,560	1,558	1,639
Depreciation and Amortization	892	906	872
Taxes Other Than Income Taxes	—	—	68
Total Operating Expenses	5,174	5,373	5,420
OPERATING INCOME	1,462	1,393	1,235
Other Income	79	61	54
Other Deductions	(4)	(3)	(3)
Interest Expense	(280)	(277)	(293)
INCOME BEFORE INCOME TAXES	1,257	1,174	993
Income Tax (Expense) Benefit	(470)	(449)	(381)
NET INCOME	$ 787	$ 725	$ 612

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11453

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2015	2014	2013
NET INCOME	$ 787	$ 725	$ 612
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0 and $1 for the years ended 2015, 2014 and 2013, respectively	(1)	1	(1)
COMPREHENSIVE INCOME	$ 786	$ 726	$ 611

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2015	2014
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 198	$ 310
Accounts Receivable, net of allowances of $67 and $52 in 2015 and 2014, respectively	787	864
Accounts Receivable-Affiliated Companies	222	274
Unbilled Revenues	197	284
Materials and Supplies	148	133
Prepayments	31	42
Regulatory Assets	164	323
Regulatory Assets of VIEs	—	249
Derivative Contracts	13	18
Deferred Income Taxes	—	24
Other	9	7
Total Current Assets	1,769	2,528
PROPERTY, PLANT AND EQUIPMENT	23,732	21,103
Less: Accumulated Depreciation and Amortization	(5,504)	(5,183)
Net Property, Plant and Equipment	18,228	15,920
NONCURRENT ASSETS		
Regulatory Assets	3,196	3,192
Long-Term Investments	330	348
Other Special Funds	49	53
Derivative Contracts	—	8
Restricted Cash of VIEs	—	24
Other	105	113
Total Noncurrent Assets	3,680	3,738
TOTAL ASSETS	$ 23,677	$ 22,186

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2015	2014
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 171	$ 300
Securitization Debt of VIEs Due Within One Year	—	259
Commercial Paper and Loans	153	—
Accounts Payable	724	574
Accounts Payable—Affiliated Companies	292	379
Accrued Interest	70	68
Clean Energy Program	142	142
Deferred Income Taxes	—	165
Obligation to Return Cash Collateral	128	121
Regulatory Liabilities	123	186
Regulatory Liabilities of VIEs	42	—
Other	297	381
Total Current Liabilities	2,142	2,575
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	5,181	4,575
OPEB Costs	937	967
Accrued Pension Costs	202	173
Regulatory Liabilities	175	258
Regulatory Liabilities of VIEs	—	39
Environmental Costs	365	364
Asset Retirement Obligations	218	290
Derivative Contracts	11	—
Long-Term Accrued Taxes	109	116
Other	114	67
Total Noncurrent Liabilities	7,312	6,849
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
CAPITALIZATION		
LONG-TERM DEBT	6,650	5,975
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2015 and 2014—132 shares	892	892
Contributed Capital	695	695
Basis Adjustment	986	986
Retained Earnings	4,999	4,212
Accumulated Other Comprehensive Income	1	2
Total Stockholder's Equity	7,573	6,787
Total Capitalization	14,223	12,762
TOTAL LIABILITIES AND CAPITALIZATION	$ 23,677	$ 22,186

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 787	$ 725	$ 612
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	892	906	872
Provision for Deferred Income Taxes and ITC	386	310	198
Non-Cash Employee Benefit Plan Costs	95	27	156
Cost of Removal	(120)	(98)	(93)
Change in Accrued Storm Costs	12	(3)	(90)
Net Change in Other Regulatory Assets and Liabilities	(60)	190	2
Net Change in Certain Current Assets and Liabilities:			
Accounts Receivable and Unbilled Revenues	165	63	(5)
Materials and Supplies	(15)	(18)	(1)
Prepayments	11	(18)	5
Accounts Payable	45	(3)	19
Accounts Receivable/Payable-Affiliated Companies, net	—	(167)	100
Other Current Assets and Liabilities	(29)	6	40
Employee Benefit Plan Funding and Related Payments	(91)	(83)	(166)
Other	47	(4)	(4)
Net Cash Provided By (Used In) Operating Activities	2,125	1,833	1,645
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,692)	(2,164)	(2,175)
Proceeds from Sales of Available-for-Sale Securities	21	103	38
Investments in Available-for-Sale Securities	(22)	(101)	(20)
Solar Loan Investments	11	7	(15)
Other	11	—	—
Net Cash Provided By (Used In) Investing Activities	(2,671)	(2,155)	(2,172)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	153	(60)	(203)
Issuance of Long-Term Debt	850	1,250	1,500
Redemption of Long-Term Debt	(300)	(500)	(725)
Redemption of Securitization Debt	(259)	(237)	(226)
Contributed Capital	—	175	100
Other	(10)	(14)	(17)
Net Cash Provided By (Used In) Financing Activities	434	614	429
Net Increase (Decrease) in Cash and Cash Equivalents	(112)	292	(98)
Cash and Cash Equivalents at Beginning of Period	310	18	116
Cash and Cash Equivalents at End of Period	$ 198	$ 310	$ 18
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ (28)	$ 283	$ 84
Interest Paid, Net of Amounts Capitalized	$ 261	$ 259	$ 275
Accrued Property, Plant and Equipment Expenditures	$ 396	$ 292	$ 246

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
Millions

	Common Stock	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2013	$ 892	$ 420	$ 986	$ 2,875	$ 2	$ 5,175
Net Income	—	—	—	612	—	612
Other Comprehensive Income, net of tax (expense) benefit of $1	—	—	—	—	(1)	(1)
Comprehensive Income						611
Contributed Capital		100				100
Balance as of December 31, 2013	$ 892	$ 520	$ 986	$ 3,487	$ 1	$ 5,886
Net Income	—	—	—	725	—	725
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	1	1
Comprehensive Income						726
Contributed Capital	—	175	—	—	—	175
Balance as of December 31, 2014	$ 892	$ 695	$ 986	$ 4,212	$ 2	$ 6,787
Net Income	—	—	—	787	—	787
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	(1)	(1)
Comprehensive Income						786
Balance as of December 31, 2015	$ 892	$ 695	$ 986	$ 4,999	$ 1	$ 7,573

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2015	2014	2013
OPERATING REVENUES	$ 4,928	$ 5,434	$ 5,063
OPERATING EXPENSES			
Energy Costs	2,150	2,747	2,496
Operation and Maintenance	1,057	1,186	1,224
Depreciation and Amortization	291	292	273
Total Operating Expenses	3,498	4,225	3,993
OPERATING INCOME	1,430	1,209	1,070
Income from Equity Method Investments	14	14	16
Other Income	169	222	154
Other Deductions	(72)	(52)	(49)
Other-Than-Temporary Impairments	(53)	(20)	(12)
Interest Expense	(121)	(122)	(116)
INCOME BEFORE INCOME TAXES	1,367	1,251	1,063
Income Tax (Expense) Benefit	(511)	(491)	(419)
NET INCOME	$ 856	$ 760	$ 644

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2015	**2014**	**2013**
NET INCOME	$ 856	$ 760	$ 644
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $32, $28 and $(55) for the years ended 2015, 2014 and 2013, respectively	(25)	(30)	57
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $7, $(8) and $7 for the years ended 2015, 2014 and 2013, respectively	(11)	12	(10)
Pension/OPEB adjustment, net of tax (expense) benefit of $(16), $101, and $(151) for the years ended 2015, 2014 and 2013 respectively	24	(147)	218
Other Comprehensive Income (Loss), net of tax	(12)	(165)	265
COMPREHENSIVE INCOME	$ 844	$ 595	$ 909

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 12	$ 9
Accounts Receivable	217	334
Accounts Receivable—Affiliated Companies	276	313
Short-Term Loan to Affiliate	363	584
Fuel	463	538
Materials and Supplies, net	363	350
Derivative Contracts	223	207
Prepayments	25	17
Other	7	7
Total Current Assets	1,949	2,359
PROPERTY, PLANT AND EQUIPMENT	11,354	10,732
Less: Accumulated Depreciation and Amortization	(3,227)	(3,217)
Net Property, Plant and Equipment	8,127	7,515
NONCURRENT ASSETS		
NDT Fund	1,754	1,780
Long-Term Investments	119	121
Goodwill	16	16
Other Intangibles	102	84
Other Special Funds	55	49
Derivative Contracts	77	62
Other	51	51
Total Noncurrent Assets	2,174	2,163
TOTAL ASSETS	$ 12,250	$ 12,037

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2015	December 31, 2014
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 553	$ 300
Accounts Payable	432	424
Accounts Payable—Affiliated Companies	33	118
Derivative Contracts	76	132
Deferred Income Taxes	—	43
Accrued Interest	25	27
Other	107	140
Total Current Liabilities	1,226	1,184
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	2,347	2,065
Asset Retirement Obligations	457	450
OPEB Costs	230	248
Derivative Contracts	16	33
Accrued Pension Costs	166	153
Long-Term Accrued Taxes	35	41
Other	87	71
Total Noncurrent Liabilities	3,338	3,061
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
LONG-TERM DEBT	1,684	2,234
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	5,014	4,558
Accumulated Other Comprehensive Loss	(240)	(228)
Total Member's Equity	6,002	5,558
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,250	$ 12,037

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 856	$ 760	$ 644
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	291	292	273
Amortization of Nuclear Fuel	213	200	192
Provision for Deferred Income Taxes and ITC	261	221	122
Interest Accretion on Asset Retirement Obligation	26	30	23
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(143)	(93)	79
Non-Cash Employee Benefit Plan Costs	48	13	66
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(38)	(166)	(104)
Net Change in Certain Current Assets and Liabilities:			
Fuel, Materials and Supplies	62	19	(8)
Margin Deposit	122	(22)	(43)
Accounts Receivable	63	(15)	(4)
Accounts Payable	(46)	(59)	28
Accounts Receivable/Payable-Affiliated Companies, net	(84)	220	—
Other Current Assets and Liabilities	(36)	(6)	72
Employee Benefit Plan Funding and Related Payments	(11)	(7)	(46)
Other	122	38	53
Net Cash Provided By (Used In) Operating Activities	1,706	1,425	1,347
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(1,117)	(626)	(609)
Proceeds from Sales of Available-for-Sale Securities	1,422	1,557	1,084
Investments in Available-for-Sale Securities	(1,455)	(1,573)	(1,102)
Short-Term Loan—Affiliated Company, net	221	206	(216)
Other	(72)	(88)	(18)
Net Cash Provided By (Used In) Investing Activities	(1,001)	(524)	(861)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Long-Term Debt	—	—	500
Cash Dividend Paid	(400)	(895)	(705)
Redemption of Long-Term Debt	(300)	—	(300)
Contributed Capital	—	—	24
Other	(2)	(3)	(6)
Net Cash Provided By (Used In) Financing Activities	(702)	(898)	(487)
Net Increase (Decrease) in Cash and Cash Equivalents	3	3	(1)
Cash and Cash Equivalents at Beginning of Period	9	6	7
Cash and Cash Equivalents at End of Period	$ 12	$ 9	$ 6
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 393	$ 68	$ 291
Interest Paid, Net of Amounts Capitalized	$ 116	$ 119	$ 106
Accrued Property, Plant and Equipment Expenditures	$ 114	$ 91	$ 90

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY
Millions

	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2013	$ 2,190	$ (986)	$ 4,754	$ (328)	$ 5,630
Net Income	—	—	644	—	644
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(199)	—	—	—	265	265
Comprehensive Income					909
Contributed Capital	24	—	—	—	24
Cash Dividends Paid	—	—	(705)		(705)
Balance as of December 31, 2013	$ 2,214	$ (986)	$ 4,693	$ (63)	$ 5,858
Net Income	—	—	760	—	760
Other Comprehensive Income (Loss), net of tax (expense) benefit of $121	—	—	—	(165)	(165)
Comprehensive Income					595
Cash Dividends Paid	—	—	(895)	—	(895)
Balance as of December 31, 2014	$ 2,214	$ (986)	$ 4,558	$ (228)	$ 5,558
Net Income	—	—	856	—	856
Other Comprehensive Income (Loss), net of tax (expense) benefit of $23	—	—	—	(12)	(12)
Comprehensive Income					844
Cash Dividends Paid	—	—	(400)	—	(400)
Balance as of December 31, 2015	$ 2,214	$ (986)	$ 5,014	$ (240)	$ 6,002

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

Public Service Enterprise Group Incorporated (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Public Service Electric and Gas Company (PSE&G)**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- **PSEG Power LLC (Power)**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy transacting functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Annual Reports on Form 10-K and in accordance with accounting guidance generally accepted in the United States (GAAP).

Significant Accounting Policies

Principles of Consolidation

Each company consolidates those entities in which it has a controlling interest or is the primary beneficiary. See Note 3. Variable Interest Entities. Entities over which the companies exhibit significant influence, but do not have a controlling interest and/or are not the primary beneficiary, are accounted for under the equity method of accounting. For investments in which significant influence does not exist and the investor is not the primary beneficiary, the cost method of accounting is applied. All intercompany accounts and transactions are eliminated in consolidation.

PSE&G and Power also have undivided interests in certain jointly-owned facilities, with each responsible for paying its respective ownership share of construction costs, fuel purchases and operating expenses. PSE&G and Power consolidate their portion of any revenues and expenses related to their respective jointly-owned facilities in the appropriate revenue and expense categories.

Accounting for the Effects of Regulation

In accordance with accounting guidance for rate-regulated entities, PSE&G's financial statements reflect the economic effects of regulation. PSE&G defers the recognition of costs (a Regulatory Asset) or records the recognition of obligations (a Regulatory Liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs and recoveries, which are being amortized over various future periods. To the extent that collection of any such costs or payment of liabilities becomes no longer probable as a result of changes in regulation and/or competitive position, the associated Regulatory Asset or Liability is charged or credited to income. Management believes that PSE&G's transmission and distribution businesses continue to meet the accounting requirements for rate-regulated entities. For additional information, see Note 5. Regulatory Assets and Liabilities.

Derivative Financial Instruments

Each company uses derivative financial instruments to manage risk pursuant to its business plans and prudent practices.

Derivative instruments, not designated as normal purchases or sales, are recognized on the balance sheet at their fair value. Changes in the fair value of a derivative that is highly effective as and that is designated and qualifies as a fair value hedge, along with changes of the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in

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current period earnings. Changes in the fair value of a derivative that is highly effective as and that is designated and qualifies as a cash flow hedge are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings. For derivative contracts that do not qualify or are not designated as cash flow or fair value hedges or as normal purchases or sales, changes in fair value are recorded in current period earnings.

Many contracts qualify for the normal purchases and normal sales exemption and are accounted for upon settlement.

For additional information regarding derivative financial instruments, see Note 15. Financial Risk Management Activities.

Revenue Recognition

PSE&G's regulated electric and gas revenues are recorded primarily based on services rendered to customers. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. The unbilled revenue is estimated each month based on usage per day, the number of unbilled days in the period, estimated seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms.

Regulated revenues from the transmission of electricity are recognized as services are provided based on a FERC-approved annual formula rate mechanism. This mechanism provides for an annual filing of estimated revenue requirement with rates effective January 1 of each year. After completion of the annual period ending December 31, PSE&G files a true-up whereby it compares its actual revenue requirement to the original estimate to determine any over or under collection of revenue. PSE&G records the estimated financial statement impact of the difference between the actual and the filed revenue requirement as a refund or deferral for future recovery when such amounts are probable and can be reasonably estimated in accordance with accounting guidance for rate-regulated entities.

The majority of Power's revenues relate to bilateral contracts, which are accounted for on the accrual basis as the energy is delivered. Power's revenue also includes changes in the value of energy derivative contracts that are not designated as normal purchases or sales or as cash flow or fair value hedges of other positions. See Note 15. Financial Risk Management Activities for further discussion.

PJM Interconnection, L.L.C. (PJM), the Independent System Operator-New England (ISO-NE) and the New York Independent System Operator (NYISO) facilitate the dispatch of energy and energy-related products. Power generally reports sales and purchases conducted with those individual ISOs on a net hourly basis in either Revenues or Energy Costs in its Consolidated Statement of Operations, the classification of which depends on the net hourly activity. Capacity revenue and expense is also reported net based on Power's net sale or purchase position in the individual ISOs.

PSEG LI is the primary beneficiary of Long Island Electric Utility Servco, LLC (Servco). For transactions in which Servco acts as principal, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operations and Maintenance (O&M) Expense, respectively. See Note 3. Variable Interest Entities for further information.

Depreciation and Amortization

PSE&G calculates depreciation under the straight-line method based on estimated average remaining lives of the several classes of depreciable property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU or FERC. The depreciation rate stated as a percentage of original cost of depreciable property was as follows:

	2015 Avg Rate	2014 Avg Rate	2013 Avg Rate
PSE&G Depreciation Rate	2.46%	2.47%	2.48%

Power calculates depreciation on generation-related assets under the straight-line method based on the assets' estimated useful lives. The estimated useful lives are:

- general plant assets—3 years to 20 years
- fossil production assets—19 years to 79 years
- nuclear generation assets—approximately 60 years
- pumped storage facilities—76 years
- solar assets—25 years

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Taxes Other Than Income Taxes

Excise taxes and the transitional energy facilities assessment (TEFA) collected from PSE&G's customers are presented in the financial statements on a gross basis. Effective January 1, 2014, the TEFA was eliminated. For the year ended December 31, 2013, $74 million and $68 million of the TEFA were included in Operating Revenues and Taxes Other Than Income Taxes, respectively, in the Consolidated Statements of Operations.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized During Construction (IDC)

AFUDC represents the cost of debt and equity funds used to finance the construction of new utility assets at PSE&G. IDC represents the cost of debt used to finance construction at Power. The amount of AFUDC or IDC capitalized as Property, Plant and Equipment is included as a reduction of interest charges or other income for the equity portion. The amounts and average rates used to calculate AFUDC or IDC for the years ended December 31, 2015, 2014 and 2013 were as follows:

	AFUDC/IDC Capitalized					
	2015		2014		2013	
	Millions	Avg Rate	Millions	Avg Rate	Millions	Avg Rate
PSE&G	$ 65	8.01%	$ 44	8.09%	$ 34	8.11%
Power	$ 27	5.14%	$ 24	5.14%	$ 23	5.36%

Income Taxes

PSEG and its subsidiaries file a consolidated federal income tax return and income taxes are allocated to PSEG's subsidiaries based on the taxable income or loss of each subsidiary in accordance with a tax sharing agreement between PSEG and each of its affiliated subsidiaries. Allocations between PSEG and its subsidiaries are recorded through intercompany accounts. Investment tax credits deferred in prior years are being amortized over the useful lives of the related property.

Uncertain income tax positions are accounted for using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. See Note 19. Income Taxes for further discussion.

Impairment of Long-Lived Assets

In accordance with GAAP, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, including prolonged periods of adverse commodity and capacity prices, could potentially indicate an asset's or asset group's carrying amount may not be recoverable. In such an event, an undiscounted cash flow analysis is performed to determine if an impairment exists. When a long-lived asset's or asset group's carrying amount exceeds the associated undiscounted estimated future cash flows, the asset/asset group is considered impaired to the extent that its fair value is less than its carrying amount. An impairment would result in a reduction of the value of the long-lived asset/asset group through a non-cash charge to earnings.

For Power, cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generation units are generally evaluated at a regional portfolio level (PJM, NYISO, ISO-NE) along with cash flows generated from the customer supply and risk management activities, inclusive of cash flows from contracts, including those that are accounted for as derivatives or that meet the normal purchases and normal sales exemption. In certain cases, generation assets are evaluated on an individual basis where those assets are individually contracted on a long-term basis with a third party and operations are independent of other generation assets (typically Power's solar plants and Kalaeloa).

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Accounts Receivable—Allowance for Doubtful Accounts

PSE&G's accounts receivable are reported in the balance sheet as gross outstanding amounts adjusted for doubtful accounts. The allowance for doubtful accounts reflects PSE&G's best estimates of losses on the accounts receivable balances. The allowance is based on accounts receivable aging, historical experience, write-off forecasts and other currently available evidence.

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Accounts receivable are charged off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable are recorded when it is known they will be received.

Materials and Supplies and Fuel

PSE&G's and Power's materials and supplies are carried at average cost and charged to inventory when purchased and expensed or capitalized to Property, Plant and Equipment, as appropriate, when installed or used. Fuel inventory at Power is valued at the lower of average cost or market and includes stored natural gas, coal, fuel oil and propane used to generate power and to satisfy obligations under Power's gas supply contracts with PSE&G. The costs of fuel, including transportation costs, are included in inventory when purchased and charged to Energy Costs when used or sold. The cost of nuclear fuel is capitalized within Property, Plant and Equipment and amortized to fuel expense using the units-of-production method.

Property, Plant and Equipment

PSE&G's additions to and replacements of existing property, plant and equipment are capitalized at cost. The cost of maintenance, repair and replacement of minor items of property is charged to expense as incurred. At the time units of depreciable property are retired or otherwise disposed of, the original cost, adjusted for net salvage value, is charged to accumulated depreciation.

Power capitalizes costs, including those related to its jointly-owned facilities, which increase the capacity or extend the life of an existing asset, represent a newly acquired or constructed asset or represent the replacement of a retired asset. The cost of maintenance, repair and replacement of minor items of property is charged to appropriate expense accounts as incurred. Environmental costs are capitalized if the costs mitigate or prevent future environmental contamination or if the costs improve existing assets' environmental safety or efficiency. All other environmental expenditures are expensed as incurred.

Available-for-Sale Securities

These securities comprise the Nuclear Decommissioning Trust (NDT) Fund, a master independent external trust account maintained to provide for the costs of decommissioning upon termination of operations of Power's nuclear facilities and amounts that are deposited to fund a Rabbi Trust which was established to meet the obligations related to non-qualified pension plans and deferred compensation plans.

Realized gains and losses on available-for-sale securities are recorded in earnings and unrealized gains and losses on such securities are recorded as a component of Accumulated Other Comprehensive Income (Loss) (except credit losses on debt securities which are recorded in earnings). Securities with unrealized losses that are deemed to be other-than-temporarily impaired are recorded in earnings. See Note 8. Available-for-Sale Securities for further discussion.

Pension and Other Postretirement Benefits (OPEB) Plans

The market-related value of plan assets held for the qualified pension and OPEB plans is equal to the fair value of those assets as of year-end. Fair value is determined using quoted market prices and independent pricing services based upon the security type as reported by the trustee at the measurement date (December 31) for all plan assets.

PSEG recognizes a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and OPEB liabilities. This receivable is presented separately on the Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted.

Pursuant to the OSA, Servco records expense only to the extent of its contributions to its pension plan trusts and for OPEB payments made to retirees.

See Note 11. Pension and Other Postretirement Benefits (OPEB) and Savings Plans for further discussion.

Basis Adjustment

PSE&G and Power have recorded a Basis Adjustment in their respective Consolidated Balance Sheets related to the generation assets that were transferred from PSE&G to Power in August 2000 at the price specified by the BPU. Because the transfer was between affiliates, the transaction was recorded at the net book value of the assets and liabilities rather than the transfer price. The difference between the total transfer price and the net book value of the generation-related assets and liabilities, $986 million, net of tax, was recorded as a Basis Adjustment on PSE&G's and Power's Consolidated Balance Sheets. The $986 million is an addition to PSE&G's Common Stockholder's Equity and a reduction of Power's Member's Equity. These amounts are eliminated on PSEG's consolidated financial statements.

Use of Estimates

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements.

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Note 2. Recent Accounting Standards

New Standards Adopted in 2015

Simplifying the Presentation of Debt Issuance Costs

This standard was issued to simplify presentation of debt issuance costs. The standard requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by this standard.

The update is effective for annual and interim reporting periods beginning after December 15, 2015. Early adoption is permitted for financial statements that have not been previously issued; therefore, PSEG has elected to early adopt these amendments in the fourth quarter of 2015 on a retrospective basis and therefore reclassified debt issuance costs in the 2014 Consolidated Balance Sheets. Unamortized debt issuance costs for PSE&G and Power were $41 million and $8 million, respectively, as of December 31, 2015 and $37 million and $9 million, respectively, as of December 31, 2014.

Balance Sheet Classification of Deferred Taxes

This standard was issued to reduce complexity in the presentation of deferred taxes. The new guidance requires that all deferred tax assets and liabilities be classified as noncurrent on the balance sheet. The guidance is effective for annual and interim periods beginning after December 15, 2016. Early application is permitted as of the beginning of an interim or annual reporting period and the guidance may be applied either prospectively to all deferred tax assets and liabilities or retrospectively to all periods presented. PSEG has elected to early adopt the guidance as of the fourth quarter of 2015 and to apply it prospectively. Prior periods were not retrospectively adjusted.

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard was issued to clarify the principles for recognizing revenue and to develop a common standard that would remove inconsistencies in revenue requirements; improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provide improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The update was originally to be effective for annual and interim reporting periods beginning after December 15, 2016; however, the Financial Accounting Standards Board issued new guidance deferring the effective date by one year to periods beginning after December 31, 2017. Early application will be permitted as of the original effective date. PSEG is currently analyzing the impact of this standard on its financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

This accounting standard will change how entities measure equity investments that are not consolidated or accounted for under the equity method and how they will present changes in the fair value of financial liabilities measured under the fair value option that are attributable to their own credit. Under the new guidance, equity investments (other than those accounted for using the equity method) will now have to be measured at fair value through Net Income instead of Other Comprehensive Income (Loss). For equity investments which do not have readily determinable fair values, the impairment assessment will be simplified by requiring a qualitative assessment to identify impairments. The new standard also changes certain disclosures.

The accounting standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early application is permitted for fiscal years or interim periods for which financial statements have not been issued. PSEG is currently analyzing the impact of this standard on our financial statements; however, PSEG expects increased volatility in net income due to changes in fair value of our equity securities within the NDT and Rabbi Trust Funds.

Leases

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee would recognize a lease asset and corresponding lease obligation. A lessee would classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor would classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard

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requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements.

The accounting standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Note 3. Variable Interest Entities (VIEs)

VIEs for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs. During 2015, Transition Funding and Transition Funding II paid their final securitization bond payments and as of December 31, 2015, no further debt or related costs remain with these VIEs.

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Servco, a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco’s operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI’s annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and O&M Expense, respectively. In 2015 and 2014, Servco recorded $375 million and $389 million, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Consolidated Statement of Operations.

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Note 4. Property, Plant and Equipment and Jointly-Owned Facilities

Information related to Property, Plant and Equipment as of December 31, 2015 and 2014 is detailed below:

	PSE&G	Power	Other	PSEG Consolidated
			Millions	
2015				
Transmission and Distribution:				
Electric Transmission	$ 7,554	$ —	$ —	$ 7,554
Electric Distribution	7,553	—	—	7,553
Gas Transmission	89	—	—	89
Gas Distribution	5,875	—	—	5,875
Construction Work in Progress	1,459	—	—	1,459
Plant Held for Future Use	26	—	—	26
Other	411	—	—	411
Total Transmission and Distribution	22,967	—	—	22,967
Generation:				
Fossil Production	—	7,005	—	7,005
Nuclear Production	—	2,202	—	2,202
Nuclear Fuel in Service	—	785	—	785
Other Production-Solar	569	389	—	958
Construction Work in Progress	—	892	—	892
Total Generation	569	11,273	—	11,842
Other	196	81	408	685
Total	**$ 23,732**	**$ 11,354**	**$ 408**	**$ 35,494**

	PSE&G	Power	Other	PSEG Consolidated
			Millions	
2014				
Transmission and Distribution:				
Electric Transmission	$ 5,845	$ —	$ —	$ 5,845
Electric Distribution	7,295	—	—	7,295
Gas Transmission	89	—	—	89
Gas Distribution	5,479	—	—	5,479
Construction Work in Progress	1,304	—	—	1,304
Plant Held for Future Use	15	—	—	15
Other	401	—	—	401
Total Transmission and Distribution	20,428	—	—	20,428
Generation:				
Fossil Production	—	6,964	—	6,964
Nuclear Production	—	1,751	—	1,751
Nuclear Fuel in Service	—	889	—	889
Other Production-Solar	521	314	—	835
Construction Work in Progress	—	714	—	714
Total Generation	521	10,632	—	11,153
Other	154	100	361	615
Total	**$ 21,103**	**$ 10,732**	**$ 361**	**$ 32,196**

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PSE&G and Power have ownership interests in and are responsible for providing their respective shares of the necessary financing for the following jointly-owned facilities. All amounts reflect the share of PSE&G's and Power's jointly-owned projects and the corresponding direct expenses are included in the Consolidated Statements of Operations as operating expenses.

		As of December 31,			
		2015		2014	
	Ownership Interest	Plant	Accumulated Depreciation	Plant	Accumulated Depreciation
		Millions			
PSE&G:					
Transmission Facilities	Various	$ 166	$ 72	$ 162	$ 69
Power:					
Coal Generating:					
Conemaugh	23%	$ 404	$ 154	$ 397	$ 142
Keystone	23%	$ 408	$ 163	$ 396	$ 151
Nuclear Generating:					
Peach Bottom	50%	$ 1,219	$ 262	$ 1,087	$ 236
Salem	57%	$ 990	$ 276	$ 916	$ 236
Nuclear Support Facilities	Various	$ 226	$ 60	$ 218	$ 49
Pumped Storage Facilities:					
Yards Creek	50%	$ 42	$ 24	$ 41	$ 24
Merrill Creek Reservoir	14%	$ 1	$ —	$ 1	$ —

Power holds undivided ownership interests in the jointly-owned facilities above. Power is entitled to shares of the generating capability and output of each unit equal to its respective ownership interests. Power also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. Power's share of expenses for the jointly-owned facilities is included in the appropriate expense category. Each owner is responsible for any financing with respect to its pro rata share of capital expenditures.

Power co-owns Salem and Peach Bottom with Exelon Generation. Power is the operator of Salem and Exelon Generation is the operator of Peach Bottom. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

GenOn Northeast Management Company is a co-owner and the operator for Keystone Generating Station and Conemaugh Generating Station. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

Power is a co-owner in the Yards Creek Pumped Storage Generation Facility. Jersey Central Power & Light Company (JCP&L) is also a co-owner and the operator of this facility. JCP&L submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Power is a minority owner in the Merrill Creek Reservoir and Environmental Preserve in Warren County, New Jersey. Merrill Creek Owners Group is the owner-operator of this facility. The operator submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Note 5. Regulatory Assets and Liabilities

PSE&G prepares its financial statements in accordance with GAAP for regulated utilities as described in Note 1. Organization and Basis of Presentation and Summary of Significant Accounting Policies. PSE&G has deferred certain costs based on rate orders issued by the BPU or FERC or based on PSE&G's experience with prior rate cases. Most of PSE&G's Regulatory Assets and Liabilities as of December 31, 2015 are supported by written orders, either explicitly or implicitly through the BPU's treatment of various cost items. These costs will be recovered and amortized over various future periods.

Regulatory Assets and other investments and costs incurred under our various infrastructure filings and clause mechanisms are subject to prudence reviews and can be disallowed in the future by regulatory authorities. To the extent that collection of any

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infrastructure or clause mechanism revenue, Regulatory Assets or payments of Regulatory Liabilities is no longer probable, the amounts would be charged or credited to income.

PSE&G had the following Regulatory Assets and Liabilities:

	As of December 31,		
	2015	2014	Recovery/Refund Period
	Millions		
Regulatory Assets			
Current			
New Jersey Clean Energy Program	$ 142	$ 142	Annual filing for recovery (2)
Stranded Costs (including $249 in 2014 related to VIEs)	—	412	Through December 2015 (2)
Underrecovered Electric Energy Costs—Basic Generation Service	11	—	Annual filing for recovery (1) (2)
Weather Normalization Clause (WNC)	10	—	Annual filing for recovery (2)
Solar and Energy Efficiency Recovery Charges (Green Program Recovery Charges (GPRC))	1	13	Annual filing for recovery (1) (2)
Other	—	5	Various
Total Current Regulatory Assets	**$ 164**	**$ 572**	
Noncurrent			
Pension and OPEB Costs	$ 1,270	$ 1,265	Various
Deferred Income Taxes	467	473	Various
Manufactured Gas Plant (MGP) Remediation Costs	431	434	Various (2)
Storm Damage Deferrals	233	245	To be determined
Remediation Adjustment Charge (RAC) (Other SBC)	174	164	Through 2022 (1) (2)
Conditional Asset Retirement Obligation	152	138	Various
Electric Transmission Cost of Removal	133	91	Through depreciation rates
GPRC	104	134	Various (1) (2)
Unamortized Loss on Reacquired Debt and Debt Expense	67	74	Over remaining debt life
Mark-to-Market (MTM) Contracts	63	75	Through 2017
Other	102	99	Various
Total Noncurrent Regulatory Assets	**$ 3,196**	**$ 3,192**	
Total Regulatory Assets	**$ 3,360**	**$ 3,764**	

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	As of December 31, 2015	2014	Recovery/Refund Period
	Millions		
Regulatory Liabilities			
Current			
Stranded Costs (including $42 in 2015 related to VIEs)	$ 64	$ —	Through December 2016 (2)
GPRC	36	6	Annual filing for recovery (1) (2)
Societal Benefit Clause (SBC)	31	13	Various (1) (2)
FERC Formula Rate True-up	19	—	Annual filing for recovery (1) (2)
Gas Margin Adjustment Clause	13	28	Annual filing for recovery (1) (2)
Overrecovered Gas Costs —Basic Gas Supply Service	1	46	Annual filing for recovery (1) (2)
WNC	—	31	Annual filing for recovery (2)
Deferred Income Taxes	—	28	Various
Overrecovered Electric Energy Costs— Basic Generation Service	—	21	Annual filing for recovery (1) (2)
Overrecovered Non-Utility Generation Charge (NGC)	1	13	Annual filing for recovery (1) (2)
Total Current Regulatory Liabilities	**$ 165**	**$ 186**	
Noncurrent			
Electric Distribution Cost of Removal	$ 122	$ 133	Through depreciation rates
FERC Formula Rate True-up	49	26	Annual filing for recovery (1) (2)
Stranded Costs (including $39 in 2014 related to VIEs)	—	134	Through December 2016 (2)
Other	4	4	Various
Total Noncurrent Regulatory Liabilities	**$ 175**	**$ 297**	
Total Regulatory Liabilities	**$ 340**	**$ 483**	

(1) Recovered/Refunded with interest.
(2) Recoverable/Refundable per specific rate order.

All Regulatory Assets and Liabilities are excluded from PSE&G's rate base unless otherwise noted. The Regulatory Assets and Liabilities in the table above are defined as follows:

- **Conditional Asset Retirement Obligation:** These costs represent the differences between rate regulated cost of removal accounting and asset retirement accounting under GAAP. These costs will be recovered in future rates.
- **Deferred Income Taxes:** These amounts represent the portion of deferred income taxes that will be recovered or refunded through future rates, based upon established regulatory practices.
- **Electric and Gas Cost of Removal:** PSE&G accrues and collects in rates for the cost of removing, dismantling and disposing of its transmission and distribution assets upon retirement. The regulatory asset or liability for non-legally required cost of removal represents the difference between amounts collected in rates and costs actually incurred.
- **FERC Formula Rate True-up:** Overcollection or undercollection of transmission earnings calculated using a FERC approved formula.
- **Gas Margin Adjustment Clause:** This mechanism credits Firm delivery customers for net distribution margin revenue collected from Transportation Gas Service Non-Firm (TSG-NF) delivery customers. The balance represents the difference between the net margin collected from the TSG-NF Customers versus bill credits provided to Firm delivery customers.
- **GPRC:** These costs are amounts associated with various renewable energy and energy efficiency programs. Components of the GPRC include: Carbon Abatement, Energy Efficiency Economic Stimulus Program, Energy Efficiency Economic (EEE) Extension Program, EEE Extension II Program, the Demand Response Program, Solar

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Generation Investment Program (Solar 4 All), Solar 4 All Extension, Solar Loan II Program and Solar Loan III Program.

- **MGP Remediation Costs:** Represents the low end of the range for the remaining environmental investigation and remediation program cleanup costs for manufactured gas plants that are probable of recovery in future rates. Once these costs are incurred, they are recovered through the RAC in the SBC.
- **MTM Contracts:** The estimated fair value of gas hedge contracts and gas cogeneration supply contracts. The regulatory asset/liability is offset by a derivative asset/liability and, with respect to the gas hedge contracts only, an intercompany receivable/payable on the Consolidated Balance Sheets.
- **New Jersey Clean Energy Program:** The BPU approved future funding requirements for Energy Efficiency and Renewable Energy Programs through the first half of 2016. Once the rates are measured, they are recovered through the SBC.
- **NGC:** These costs represent the difference between rate payer collections and the cost of non-utility generation netted against amounts realized from selling that energy at market rates through PJM.
- **Overrecovered Electric Energy Costs:** These costs represent the overrecovered amounts associated with Basic Generation Service (BGS), as approved by the BPU. Pursuant to BPU requirements, PSE&G serves as the supplier of last resort for electric customers within its service territory that are not served by another supplier. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for PSE&G's operations. For BGS, interest is accrued on both overrecovered and underrecovered balances.
- **Overrecovered Gas Costs:** These costs represent the overrecovered amounts associated with Basic Gas Supply Service (BGSS), as approved by the BPU. Pursuant to BPU requirements, PSE&G serves as the supplier of last resort for gas customers within its service territory that are not served by another supplier. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for PSE&G's operations. For BGSS, interest is accrued only on overrecovered balances.
- **Pension and OPEB Costs:** Pursuant to the adoption of accounting guidance for employers' defined benefit pension and OPEB plans, PSE&G recorded the unrecognized costs for defined benefit pension and other OPEB plans on the balance sheet as a Regulatory Asset. These costs represent actuarial gains or losses, prior service costs and transition obligations as a result of adoption, which have not been expensed. These costs are amortized and recovered in future rates.
- **RAC (Other SBC):** Costs incurred to clean up manufactured gas plants which are recovered over seven years.
- **SBC:** The SBC, as authorized by the BPU and the New Jersey Electric Discount and Energy Competition Act, includes costs related to PSE&G's electric and gas business as follows: (1) the Universal Service Fund (USF); (2) Energy Efficiency and Renewable Energy Programs; (3) Electric bad debt expense; and (4) the RAC for incurred MGP remediation expenditures. All components accrue interest on both over and underrecoveries.
- **Storm Damage Deferrals:** Costs incurred in the cleanup of major storms in 2010 through 2015. As of December 31, 2015, this includes the $220 million of storm costs, net of insurance recoveries, primarily as a result of Hurricane Irene and Superstorm Sandy, approved for future recovery under a BPU Order received in September 2014.
- **Stranded Costs:** This reflects the overrecovered balance of costs, which were recovered through the securitization transition charges authorized by the BPU in irrevocable financing orders and collected by PSE&G, as servicer on behalf of Transition Funding and Transition Funding II, respectively. Collected funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs and taxes. During 2015, Transition Funding and Transition Funding II paid their final securitization bond payments and as of December 31, 2015, no further debt or related costs remain.

  Transition Funding and Transition Funding II are wholly owned, bankruptcy-remote subsidiaries of PSE&G that purchased certain transition property from PSE&G and issued transition bonds secured by such property. The transition property consists principally of the rights to receive electricity consumption-based per kilowatt-hour (kWh) charges from PSE&G's electric distribution customers, which represent irrevocable rights to receive amounts sufficient to recover certain of PSE&G's transition costs related to deregulation, as approved by the BPU.

  Effective January 1, 2016, PSE&G commenced refunding the overcollections from customers associated with Stranded Costs and expects to fully refund these liabilities in 2016.

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- **Unamortized Loss on Reacquired Debt and Debt Expense:** Represents losses on reacquired long-term debt and expenses associated with issuances of new debt, which are recovered through rates over the remaining life of the debt.
- **Underrecovered Electric Energy Costs:** These costs represent the underrecovered amounts associated with BGS, as approved by the BPU. For BGS, interest is accrued on both overrecovered and underrecovered balances.
- **WNC:** This represents the over- or under- collection of gas margin refundable or recoverable under the BPU's weather normalization clause. The WNC requires PSE&G to calculate, at the end of each October-to-May period, the level by which margin revenues differed from what would have resulted if normal weather had occurred. Over recoveries are refunded to customers in the next winter season while under recoveries (subject to an earnings cap) are collected from customers in the next winter season.

Significant 2015 regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

- ***Energy Strong Recovery Filing***—In February 2015, the BPU approved PSE&G's initial Energy Strong filing to recover in base rates an estimated annual electric revenue increase of $1 million effective March 1, 2015. This increase represents capitalized Energy Strong electric investment costs in service through November 30, 2014. In August 2015, the BPU approved PSE&G's second Energy Strong petition to recover in base rates an estimated annual revenue increases in electric revenues of $6 million and gas revenues of $17 million effective September 1, 2015. These increases represent a return on investment and recovery of Energy Strong capitalized investment costs placed in service from December 1, 2014 through May 31, 2015 for electric and from June 1, 2014 through May 31, 2015 for gas.

  In September 2015, PSE&G filed an Energy Strong electric cost recovery petition seeking BPU approval to recover the revenue requirements associated with Energy Strong capitalized investment costs placed in service from June 1, 2015 through November 30, 2015. In February 2016, the BPU approved PSE&G's request for an annualized increase in electric revenue requirements of $10 million with rates effective March 1, 2016.
- ***BGSS***—In January 2015 and March 2015, PSE&G filed letters with the BPU to provide self-implementing bill credits for February, March and April 2015. When combined with the January 2015 bill credit filed with the BPU in 2014, a total of $243 million was returned to customers for the period January 1 to April 30, 2015. In April 2015, the BPU issued an Order approving PSE&G's BGSS rate of 45 cents per therm which had been implemented on October 1, 2014 as final.

  In June 2015, PSE&G made its Annual BGSS Filing with the BPU requesting a reduction of $70 million in annual BGSS revenues. In September 2015, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was reduced from approximately 45 cents to 40 cents per therm effective October 1, 2015. In February 2016, the BPU issued an Order approving PSE&G's BGSS rate of 40 cents per therm as final.

  In November, 2015, PSE&G filed with the BPU for a self-implementing three-month bill credit of 25 cents per therm for the months of December 2015 and January and February 2016. The bill credits are estimated to provide approximately $155 million to customers. The specific amount returned will depend on actual usage over that period.
- ***WNC***—On April 15, 2015, the BPU approved PSE&G's final filing with respect to excess revenues collected during the colder than normal 2013-2014 Winter Period (October 1, 2013 through May 31, 2014). Effective October 1, 2014, PSEG commenced returning $45 million in revenues to its customers during the 2014-2015 Winter Period (October 1, 2014 through May 31, 2015).

  In September 2015, the BPU approved PSE&G's filing on a provisional basis with respect to excess revenues collected during the colder than normal 2014-2015 Winter Period. Effective October 1, 2015, PSE&G commenced returning $40 million in revenues to its customers during the 2015-2016 Winter Period (October 1, 2015 through May 31, 2016). In January 2016, the BPU gave final approval to the provisional rates.
- ***Solar and Energy Efficiency - GPRC and Solar Pilot Recovery Charges (SPRC)***—In April 2015, the BPU approved PSE&G's petition for an EEE Extension II Program to extend three EEE subprograms (multi-family, direct install and hospital efficiency). The Order allows PSE&G to extend the subprogram offerings under the same clause recovery process as its existing EEE Program and allows for $95 million of additional capital expenditures over the next three years and an allowance for $12 million of additional administrative expenses over the next 15 years. The EEE Extension II Program was added as a ninth component of the GPRC rate effective May 1, 2015.

  In July of each year, PSE&G files for annual recovery for its Green Program investments which include a return on its investment and recovery of expenses. In May 2015, the BPU approved PSE&G's July 2014 filing requesting recovery

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of costs and investments in the first eight combined components of the electric and gas GPRC for the period October 1, 2014 through September 30, 2015. In July 2015, PSE&G filed its annual GPRC and SPRC cost recovery petitions with the BPU, requesting recovery of costs and investments for the first eight combined components of the electric and gas GPRC, as well as the electric SPRC. The filings proposed rates for the period October 1, 2015 through September 30, 2016 designed to recover approximately $66 million and $10 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved programs. In September 2015, the BPU approved the July 2015 filings on a provisional basis, with new rates effective October 1, 2015. In November 2015, PSE&G filed updated costs with the BPU. In January 2016, the BPU gave final approval for rates set to recover adjusted amounts based on this update of approximately $57 million and $8 million in electric and gas revenues, respectively, on an annual basis with rates effective February 1, 2016.

- ***Transmission Formula Rate Filings***—In June 2015, PSE&G filed its 2014 true-up adjustment pertaining to its formula rates in effect for 2014, which resulted in an adjustment of $19 million less than the 2014 originally filed revenues. The adjustment was primarily due to the impact of bonus depreciation and lower interest rates which PSE&G had recognized in its Consolidated Statement of Operations for the year ended December 31, 2014. In accordance with PSE&G's formula rate protocols this Rate Year 2014 true-up adjustment has been incorporated into PSE&G's Annual Formula Rate Update for the 2016 Rate Year.

  The 2016 Annual Formula Rate Update was filed with FERC in October 2015 and provides for $146 million in increased annual transmission revenues effective January 1, 2016. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. The adjustment for 2016 will include the impact of the extension of bonus depreciation, which was enacted after our 2016 filing was made. This adjustment will be incorporated with the 2016 true-up adjustments filed in 2017 and will be incorporated into PSE&G's Annual Formula Rate Update for the 2017 Rate Year.
- ***RAC***—In August 2015, the BPU approved PSE&G's filing with respect to its RAC 22 petition allowing recovery of $85 million effective September 1, 2015 related to net Manufactured Gas Plant expenditures from August 1, 2013 through July 31, 2014.
- ***USF/Lifeline***—In September 2015, the BPU approved rates set to recover costs incurred under the USF/Lifeline energy assistance programs effective October 1, 2015.
- ***SBC and NGC***—In May 2015, PSE&G filed a petition to recover approximately $311 million in actual SBC and NGC costs incurred through December 31, 2014 under its Energy Efficiency & Renewable Energy Programs, Social Programs and NGC. In January 2016, the BPU approved PSE&G's petition with rates effective February 1, 2016.

Note 6. Long-Term Investments

Long-Term Investments as of December 31, 2015 and 2014 included the following:

	As of December 31,	
	2015	2014
	Millions	
PSE&G		
Life Insurance and Supplemental Benefits	$ 150	$ 156
Solar Loans	175	187
Other Investments	5	5
Power		
Partnerships and Corporate Joint Ventures (Equity Method Investments) (A)	119	121
Energy Holdings		
Lease Investments	784	836
Partnerships and Corporate Joint Ventures (Equity Method Investments) (A)	—	2
Total Long-Term Investments	**$ 1,233**	**$ 1,307**

(A) During the three years ended December 31, 2015, 2014 and 2013, the amount of dividends from these investments was $16 million, $17 million and $11 million, respectively.

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Leases

Energy Holdings has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Consolidated Balance Sheets. The following table shows Energy Holdings' gross and net lease investment as of December 31, 2015 and 2014, respectively.

	As of December 31,	
	2015	2014
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 631	$ 691
Estimated Residual Value of Leased Assets	519	525
Total Investment in Rental Receivables	1,150	1,216
Unearned and Deferred Income	(366)	(380)
Gross Investments in Leases	784	836
Deferred Tax Liabilities	(724)	(738)
Net Investments in Leases	**$ 60**	**$ 98**

The pre-tax income and income tax effects, excluding gains and losses on sales, related to investments in leases were as follows:

	Years Ended December 31,		
	2015	2014	2013
	Millions		
Pre-Tax Income (Loss) from Leases	$ 12	$ 24	$ 11
Income Tax Expense (Benefit) on Pre-Tax Income from Leases	$ 5	$ 32	$ 6

Equity Method Investments

Power had the following equity method investments as of December 31, 2015:

Name	As of December 31, 2015	Location	% Owned
	Millions		
Power			
Keystone Fuels, LLC	$ 16	PA	23%
Conemaugh Fuels, LLC	$ 14	PA	23%
PennEast Pipeline	$ 5	PA	12%
Kalaeloa	$ 84	HI	50%

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Note 7. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with solar renewable energy certificates (SRECs) generated from the installed solar electric system. The following table reflects the outstanding loans, including the noncurrent portion reported in Note 6. Long-Term Investments, by class of customer, none of which would be considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of December 31, 2015	2014
	Millions	
Commercial/Industrial	$ 177	$ 188
Residential	12	13
	$ 189	**$ 201**

Energy Holdings

Energy Holdings had a net investment in domestic energy and real estate assets subject to leveraged lease accounting of $60 million as of December 31, 2015 and $98 million as of December 31, 2014 (See Note 6. Long-Term Investments).

The corresponding receivables associated with the lease portfolio are reflected below, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

Counterparties' Credit Rating Standard and Poor's (S&P) as of December 31, 2015	Lease Receivables, Net of Non-Recourse Debt As of December 31, 2015
	Millions
AA	$ 17
BBB+ - BBB-	316
BB-	134
CCC+	164
	$ 631

The "BB-" and the "CCC+" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of December 31, 2015, the gross investment in the leases of such assets, net of non-recourse debt, was $573 million, ($(30) million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	CCC+	NRG REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	CCC+	NRG REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 113	100%	603	Coal	CCC+	NRG REMA, LLC

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The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

NRG REMA, LLC (NRG) notified PJM that it deactivated the coal-fired units at the Shawville generating facility in June 2015 and has disclosed that it expects to return the Shawville units to service in the summer of 2016 with the ability to use natural gas.

Note 8. Available-for-Sale Securities

NDT Fund

In accordance with NRC regulations, entities owning an interest in nuclear generating facilities are required to determine the costs and funding methods necessary to decommission such facilities upon termination of operation. As a general practice, each nuclear owner places funds in independent external trust accounts it maintains to provide for decommissioning. Power is required to file periodic reports with the NRC demonstrating that its NDT Fund meets the formula-based minimum NRC funding requirements.

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon their respective termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. Power's share of decommissioning costs related to its five nuclear units was estimated to be between $2.8 billion and $3.0 billion, including contingencies. The liability for decommissioning recorded on a discounted basis as of December 31, 2015 was approximately $429 million and is included in the Asset Retirement Obligation. The trust funds are managed by third-party investment advisors who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund:

	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 693	$ 185	$ (13)	$ 865
Debt Securities				
Government Obligations	483	8	(3)	488
Other Debt Securities	366	3	(10)	359
Total Debt Securities	849	11	(13)	847
Other Securities	42	—	—	42
Total NDT Available-for-Sale Securities	**$ 1,584**	**$ 196**	**$ (26)**	**$ 1,754**

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	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 685	$ 220	$ (8)	$ 897
Debt Securities				
Government Obligations	430	9	(1)	438
Other Debt Securities	333	9	(3)	339
Total Debt Securities	763	18	(4)	777
Other Securities	106	—	—	106
Total NDT Available-for-Sale Securities	**$ 1,554**	**$ 238**	**$ (12)**	**$ 1,780**

These amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as shown in the following table.

	As of December 31, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$ 17	$ 10
Accounts Payable	$ 10	$ 2

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2015				As of December 31, 2014			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 151	$ (13)	$ 1	$ —	$ 162	$ (8)	$ 1	$ —
Debt Securities								
Government Obligations (B)	245	(2)	19	(1)	95	—	28	(1)
Other Debt Securities (C)	222	(7)	36	(3)	99	(1)	30	(2)
Total Debt Securities	467	(9)	55	(4)	194	(1)	58	(3)
NDT Available-for-Sale Securities	**$ 618**	**$ (22)**	**$ 56**	**$ (4)**	**$ 356**	**$ (9)**	**$ 59**	**$ (3)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over companies with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2015.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the U.S. government or an agency of the U.S. government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2015.

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(C) Debt Securities (Corporate)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2015.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Years Ended December 31,		
	2015	2014	2013
	Millions		
Proceeds from Sales (A)	**$ 1,397**	**$ 1,448**	**$ 1,070**
Net Realized Gains (Losses):			
Gross Realized Gains	$ 97	$ 177	$ 112
Gross Realized Losses	(37)	(23)	(26)
Net Realized Gains (Losses) on NDT Fund	**$ 60**	**$ 154**	**$ 86**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Consolidated Statements of Operations. Net unrealized gains of $86 million (after-tax) are included in Accumulated Other Comprehensive Loss on PSEG's and Power's Consolidated Balance Sheets as of December 31, 2015.

The available-for-sale debt securities held as of December 31, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 16
1 - 5 years	209
6 - 10 years	200
11 - 15 years	57
16 - 20 years	49
Over 20 years	316
Total NDT Available-for-Sale Debt Securities	**$ 847**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2015, other-than-temporary impairments of $53 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

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PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost bases for the securities held in the Rabbi Trust.

	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 10	$ —	$ 22
Debt Securities				
Government Obligations	108	1	(1)	108
Other Debt Securities	82	—	(1)	81
Total Debt Securities	190	1	(2)	189
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 204**	**$ 11**	**$ (2)**	**$ 213**

	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 11	$ —	$ 23
Debt Securities				
Government Obligations	89	2	—	91
Other Debt Securities	74	1	—	75
Total Debt Securities	163	3	—	166
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 177**	**$ 14**	**$ —**	**$ 191**

These amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as show in the following table.

	As of December 31, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$ 1	$ 1
Accounts Payable	$ —	$ —

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The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2015				As of December 31, 2014			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	53	(1)	2	—	2	—	—	—
Other Debt Securities (C)	46	(1)	9	—	24	—	—	—
Total Debt Securities	99	(2)	11	—	26	—	—	—
Rabbi Trust Available-for-Sale Securities	**$ 99**	**$ (2)**	**$ 11**	**$ —**	**$ 26**	**$ —**	**$ —**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund is through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the U.S. government or an agency of the U.S. government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of December 31, 2015.

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2015.

The proceeds from the sales of and the net realized gains on securities in the Rabbi Trust Fund were:

	Years Ended December 31,		
	2015	2014	2013
	Millions		
Proceeds from Rabbi Trust Sales (A)	**$ 104**	**$ 467**	**$ 89**
Net Realized Gains (Losses):			
Gross Realized Gains	$ 3	$ 4	$ 4
Gross Realized Losses	(2)	(3)	(3)
Net Realized Gains (Losses) on Rabbi Trust	**$ 1**	**$ 1**	**$ 1**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers

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Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in the Consolidated Statements of Operations. Net unrealized gains of $5 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets as of December 31, 2015. The Rabbi Trust available-for-sale debt securities held as of December 31, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 3
1 - 5 years	49
6 - 10 years	44
11 - 15 years	5
16 - 20 years	8
Over 20 years	80
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 189**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities. In 2015, there were no other-than-temporary impairments recognized on investments of the Rabbi Trust.

The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of December 31, 2015	As of December 31, 2014
	Millions	
PSE&G	$ 42	$ 41
Power	52	45
Other	119	105
Total Rabbi Trust Available-for-Sale Securities	**$ 213**	**$ 191**

Note 9. Goodwill and Other Intangibles

As of December 31, 2015 and 2014, Power had goodwill of $16 million related to the Bethlehem Energy Center facility. Power conducted an annual review for goodwill impairment as of October 31, 2015 and concluded that goodwill was not impaired. No events occurred subsequent to that date which would require a further review of goodwill for impairment.

In addition to goodwill, as of December 31, 2015 and 2014, Power had intangible assets of $102 million and $84 million, respectively, related to emissions allowances and renewable energy credits. Emissions expense includes impairments of emissions allowances and costs for emissions, which is recorded as emissions occur. As load is served under contracts requiring energy from renewable sources, the related expense is recorded. Such expenses for the years ended December 31, 2015, 2014 and 2013 were as follows:

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	Years Ended December 31,		
	2015	2014	2013
	Millions		
Emissions Expense	$ 13	$ 10	$ 6
Renewable Energy Expense	$ 91	$ 59	$ 26

Note 10. Asset Retirement Obligations (AROs)

PSEG, PSE&G and Power have recorded various AROs which represent legal obligations to remove or dispose of an asset or some component of an asset at retirement.

PSE&G has conditional AROs primarily for legal obligations related to the removal of treated wood poles and the requirement to seal natural gas pipelines at all sources of gas when the pipelines are no longer in service. PSE&G does not record an ARO for its protected steel and poly-based natural gas lines, as management believes that these categories of gas lines have an indeterminable life.

Power's ARO liability primarily relates to the decommissioning of its nuclear power plants in accordance with NRC requirements. Power has an independent external trust that is intended to fund decommissioning of its nuclear facilities upon termination of operation. For additional information, see Note 8. Available-for-Sale Securities. Power also identified conditional AROs primarily related to Power's fossil generation units and solar facilities, including liabilities for removal of asbestos, stored hazardous liquid material and underground storage tanks from industrial power sites, and demolition of certain plants, and the restoration of the sites at which they reside, when the plants are no longer in service. To estimate the fair value of its AROs, Power uses a probability weighted, discounted cash flow model which, on a unit by unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on third party decommissioning cost estimates, cost escalation rates, inflation rates and discount rates.

Updated cost studies are obtained triennially unless new information necessitates more frequent updates. The most recent cost study was done in 2015. When assumptions are revised to calculate fair values of existing AROs, the ARO balance and corresponding long-lived asset are adjusted which impact the amount of accretion and depreciation expense recognized in future periods. For PSE&G, Regulatory Assets and Regulatory Liabilities result when accretion and amortization are adjusted to match rates established by regulators resulting in the regulatory deferral of any gain or loss.

The changes to the ARO liabilities for PSEG, PSE&G and Power during 2014 and 2015 are presented in the following table:

	PSEG	PSE&G	Power	Other
	Millions			
ARO Liability as of January 1, 2014	$ 677	$ 274	$ 400	$ 3
Liabilities Settled	(2)	(2)	—	—
Liabilities Incurred	23	3	20	—
Accretion Expense	30	—	30	—
Accretion Expense Deferred and Recovered in Rate Base (A)	15	15	—	—
ARO Liability as of December 31, 2014	**$ 743**	**$ 290**	**$ 450**	**$ 3**
Liabilities Settled	(5)	(4)	(1)	—
Liabilities Incurred	14	1	12	1
Accretion Expense	26	—	26	—
Accretion Expense Deferred and Recovered in Rate Base (A)	16	16	—	—
Revision to Present Values of Estimated Cash Flows	(115)	(85)	(30)	—
ARO Liability as of December 31, 2015	**$ 679**	**$ 218**	**$ 457**	**$ 4**

(A) Not reflected as expense in Consolidated Statements of Operations

During 2015, PSE&G recorded a reduction to its ARO liabilities primarily due to the impact of lower inflation rates. These changes had no impact in PSE&G's Consolidated Statement of Operations.

During 2015, Power recorded a reduction to its ARO liabilities, primarily due to changes in the inflation and discount rates and changes in assumptions related to the weighted probabilities for nuclear AROs partially offset by increases in estimated costs to

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decommission our nuclear units pursuant to our most recent cost study. These changes did not result in any material impact in Power's Consolidated Statement of Operations.

Note 11. Pension, Other Postretirement Benefits (OPEB) and Savings Plans

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. Eligible employees participate in non-contributory pension and OPEB plans sponsored by PSEG and administered by Services. In addition, represented and nonrepresented employees are eligible for participation in PSEG's two defined contribution plans described below.

PSEG, PSE&G and Power are required to record the under or over funded positions of their defined benefit pension and OPEB plans on their respective balance sheets. Such funding positions of each PSEG company are required to be measured as of the date of its respective year-end Consolidated Balance Sheets. For underfunded plans, the liability is equal to the difference between the plan's benefit obligation and the fair value of plan assets. For defined benefit pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. In addition, GAAP requires that the total unrecognized costs for defined benefit pension and OPEB plans be recorded as an after-tax charge to Accumulated Other Comprehensive Income (Loss), a separate component of Stockholders' Equity. However, for PSE&G, because the amortization of the unrecognized costs is being collected from customers, the accumulated unrecognized costs are recorded as a Regulatory Asset. The unrecognized costs represent actuarial gains or losses and prior service costs which had not been expensed.

For PSE&G, the Regulatory Asset is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations. For Power, the charge to Accumulated Other Comprehensive Income (Loss) is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations.

At the end of 2015, PSEG changed the approach used to measure future service and interest costs for pension benefits. For 2015 and prior, PSEG calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, PSEG has elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows. PSEG believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations. As a change in accounting estimate, this change will be reflected prospectively.

Amounts for Servco are not included in any of the following pension and OPEB benefit information for PSEG and its affiliates but rather are separately disclosed later in this note.

The following table provides a roll-forward of the changes in the benefit obligation and the fair value of plan assets during each of the two years in the periods ended December 31, 2015 and 2014. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

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	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
	Millions			
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year (A)	$ 5,722	$ 4,812	$ 1,638	$ 1,414
Service Cost	123	104	22	18
Interest Cost	234	234	67	69
Actuarial (Gain) Loss (B)	(289)	838	(45)	210
Gross Benefits Paid	(268)	(266)	(70)	(73)
Benefit Obligation at End of Year (A) (B)	**$ 5,522**	**$ 5,722**	**$ 1,612**	**$ 1,638**
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$ 5,293	$ 5,116	$ 361	$ 319
Actual Return on Plan Assets	(11)	433	(1)	28
Employer Contributions	25	10	84	87
Gross Benefits Paid	(268)	(266)	(70)	(73)
Fair Value of Assets at End of Year	**$ 5,039**	**$ 5,293**	**$ 374**	**$ 361**
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	**$ (483)**	**$ (429)**	**$ (1,238)**	**$ (1,277)**
Additional Amounts Recognized in the Consolidated Balance Sheets				
Noncurrent Assets (included in Other Special Funds)	$ 14	$ 21	$ —	$ —
Current Accrued Benefit Cost	(10)	(10)	(10)	—
Noncurrent Accrued Benefit Cost	(487)	(440)	(1,228)	(1,277)
Amounts Recognized	**$ (483)**	**$ (429)**	**$ (1,238)**	**$ (1,277)**
Additional Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulated Assets and Deferred Assets (C)				
Prior Service Cost	$ (83)	$ (102)	$ (25)	$ (39)
Net Actuarial Loss	1,710	1,724	438	495
Total	**$ 1,627**	**$ 1,622**	**$ 413**	**$ 456**

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits.

(B) In October 2014, the Society of Actuaries' Retirement Plans Experience Committee issued its final report on mortality tables (RP-2014 Mortality Tables Report). As of December 31, 2014, PSEG updated its mortality assumptions based on the information contained in this report. The impact of this change is reflected in Actuarial (Gain) Loss in 2014 and added $314 million and $79 million to the Benefit Obligations for Pension and OPEB, respectively, since December 31, 2013.

(C) Includes $658 million ($386 million, after-tax) and $702 million ($411 million, after-tax) in Accumulated Other Comprehensive Loss related to Pension and OPEB as of December 31, 2015 and 2014, respectively.

The pension benefits table above provides information relating to the funded status of all qualified and nonqualified pension plans and OPEB plans on an aggregate basis. As of December 31, 2015, PSEG had funded approximately 91% of its projected benefit obligation. This percentage does not include $213 million of assets in the Rabbi Trust as of December 31, 2015 which were used partially to fund the nonqualified pension plans. As of December 31, 2015, the nonqualified pension plans included in the projected benefit obligation in the above table were $159 million. The fair values of the Rabbi Trust assets are included in Other Special Funds on the Consolidated Balance Sheets.

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Accumulated Benefit Obligation

The accumulated benefit obligation for all PSEG's defined benefit pension plans was $5.4 billion as of December 31, 2015 and $5.5 billion as of December 31, 2014.

The following table provides the components of net periodic benefit cost for the years ended December 31, 2015, 2014 and 2013.

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2015	2014	2013	2015	2014	2013
	Millions					
Components of Net Periodic Benefit Cost (Credit)						
Service Cost	$ 123	$ 104	$ 116	$ 22	$ 18	21
Interest Cost	234	234	215	67	69	63
Expected Return on Plan Assets	(414)	(399)	(348)	(31)	(26)	(21)
Amortization of Net						
Prior Service Cost	(19)	(18)	(19)	(14)	(14)	(14)
Actuarial Loss	150	56	188	43	23	42
Net Periodic Benefit Cost (Credit)	**$ 74**	**$ (23)**	**$ 152**	**$ 87**	**$ 70**	**$ 91**

Pension costs and OPEB costs for PSEG, PSE&G and Power are detailed as follows:

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2015	2014	2013	2015	2014	2013
	Millions					
PSE&G	$ 40	$ (19)	$ 91	$ 55	$ 46	$ 65
Power	21	(7)	43	27	20	23
Other	13	3	18	5	4	3
Total Benefit Cost (Credit)	**$ 74**	**$ (23)**	**$ 152**	**$ 87**	**$ 70**	**$ 91**

The following table provides the pre-tax changes recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Deferred Assets:

	Pension		OPEB	
	2015	2014	2015	2014
	Millions			
Net Actuarial (Gain) Loss in Current Period	$ 136	$ 803	$ (14)	$ 208
Amortization of Net Actuarial Gain (Loss)	(150)	(56)	(43)	(23)
Amortization of Prior Service Credit	19	18	14	14
Total	**$ 5**	**$ 765**	**$ (43)**	**$ 199**

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Amounts that are expected to be amortized from Accumulated Other Comprehensive Loss, Regulatory Assets and Deferred Assets into Net Periodic Benefit Cost in 2016 are as follows:

	Pension Benefits 2016	Other Benefits 2016
	Millions	
Actuarial (Gain) Loss	$ 158	$ 40
Prior Service Cost	$ (18)	$ (14)

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

	Pension Benefits			Other Benefits		
	2015	2014	2013	2015	2014	2013
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	4.54%	4.20%	5.00%	4.58%	4.21%	5.01%
Rate of Compensation Increase	3.61%	3.61%	4.61%	3.61%	3.61%	4.61%
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount Rate	4.20%	5.00%	4.20%	4.21%	5.01%	4.20%
Expected Return on Plan Assets	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Rate of Compensation Increase	3.61%	4.61%	4.61%	3.61%	4.61%	4.61%
Assumed Health Care Cost Trend Rates as of December 31						
Administrative Expense				3.00%	3.00%	3.00%
Health Care Costs						
Immediate Rate				7.75%	7.40%	7.83%
Ultimate Rate				4.75%	5.00%	5.00%
Year Ultimate Rate Reached				2025	2022	2021
					Millions	
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$ 12	$ 13	$ 12
Postretirement Benefit Obligation				$ 194	$ 201	$ 161
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$ (10)	$ (10)	$ (9)
Postretirement Benefit Obligation				$ (160)	$ (165)	$ (134)

Plan Assets

All the investments of pension plans and OPEB plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension and OPEB plans are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 16. Fair Value Measurements for more information on fair value guidance. Use of the Master Trust permits the commingling of pension plan assets and OPEB plan assets for investment and administrative purposes. Although assets of the plans are commingled in the Master Trust, the Trustee maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Trustee to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans. As of December 31, 2015, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 93% and 7%, respectively.

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The following tables present information about the investments measured at fair value on a recurring basis as of December 31, 2015 and 2014, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2015			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		Millions		
Cash Equivalents (A)	$ 103	$ 102	$ 1	$ —
Common Stocks (B)				
Commingled-United States	1,980	1,980	—	—
Commingled-International	987	987	—	—
Other	816	816	—	—
Bonds (C)				
Government (United States & Foreign)	602	—	602	—
Other	906	—	906	—
Private Equity (D)	19	—	—	19
Total	**$ 5,413**	**$ 3,885**	**$ 1,509**	**$ 19**

	Recurring Fair Value Measurements as of December 31, 2014			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		Millions		
Cash Equivalents (A)	$ 153	$ 92	$ 61	$ —
Common Stocks (B)				
Commingled-United States	2,292	2,292	—	—
Commingled-International	1,005	1,005	—	—
Other	727	727	—	—
Bonds (C)				
Government (United States & Foreign)	509	—	509	—
Other	943	—	943	—
Private Equity (D)	25	—	—	25
Total	**$ 5,654**	**$ 4,116**	**$ 1,513**	**$ 25**

(A) Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active market (Level 1). Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

(B) Wherever possible, fair values of equity investments in stocks and in commingled funds are derived from quoted market prices as substantially all of these instruments have active markets (primarily Level 1). Most investments in stocks are priced utilizing the principal market close price or in some cases midpoint, bid or ask price.

(C) Investments in fixed income securities including bond funds are priced using an evaluated pricing approach or the most recent exchange or quoted bid (primarily Level 2).

(D) Limited partnership interests in private equity funds are valued using significant unobservable inputs as there is little, if any, market activity. In addition, there may be transfer restrictions on private equity securities. The process for determining the fair value of such securities relied on commonly accepted valuation techniques, including the use of earnings multiples based on comparable public securities, industry-specific non-earnings-based multiples and

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discounted cash flow models. These inputs require significant management judgment or estimation (primarily Level 3).

Reconciliations of the beginning and ending balances of the Pension and OPEB Plans' Level 3 assets for the years ended December 31, 2015 and 2014 are as follows:

	Balance as of January 1, 2015	Purchases/ (Sales)	Transfer In/ (Out)	Actual Return on Asset Sales	Actual Return on Assets Still Held	Balance as of December 31, 2015
			Millions			
Private Equity	$ 25	$ (10)	$ —	$ 1	$ 3	$ 19

	Balance as of January 1, 2014	Purchases/ (Sales)	Transfer In/ (Out)	Actual Return on Asset Sales	Actual Return on Assets Still Held	Balance as of December 31, 2014
			Millions			
Private Equity	$ 25	$ (5)	$ —	$ 3	$ 2	$ 25

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans as of the measurement date, December 31:

	As of December 31,	
Investments	**2015**	**2014**
Equity Securities	70%	71%
Fixed Income Securities	28	26
Other Investments	2	3
Total Percentage	**100%**	**100%**

PSEG utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. PSEG's latest asset/liability study indicates that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. Derivative financial instruments are used by the plans' investment managers primarily to adjust the fixed income duration of the portfolio and hedge the currency risk component of foreign investments. The expected long-term rate of return on plan assets was 8.00% as of December 31, 2015 and will remain unchanged for 2016. This expected return was determined based on the study discussed above, including a premium for active management and considered the plans' historical annualized rate of return since inception, which was 9.3%.

Plan Contributions

PSEG plans to contribute $21 million into its qualified pension plans and $14 million into its OPEB plan, respectively, during 2016.

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Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to plan participants.

Year	Pension Benefits	Other Benefits
	Millions	
2016	$ 285	$ 81
2017	295	84
2018	305	87
2019	317	91
2020	329	95
2021-2025	1,818	518
Total	**$ 3,349**	**$ 956**

401(k) Plans

PSEG sponsors two 401(k) plans, which are Employee Retirement Income Security Act (ERISA) defined contribution retirement plans. Eligible represented employees of PSEG's subsidiaries participate in the PSEG Employee Savings Plan (Savings Plan), while eligible non-represented employees of PSEG's subsidiaries participate in the PSEG Thrift and Tax-Deferred Savings Plan (Thrift Plan). Eligible employees may contribute up to 50% of their compensation to these plans. PSEG matches 50% of such employee contributions up to 7% of pay for Savings Plan participants and up to 8% of pay for Thrift Plan participants.

The amount paid for employer matching contributions to the plans for PSEG, PSE&G and Power are detailed as follows:

	Thrift Plan and Savings Plan Years Ended December 31,		
	2015	2014	2013
	Millions		
PSE&G	$ 22	$ 20	$ 19
Power	12	11	10
Other	5	5	4
Total Employer Matching Contributions	**$ 39**	**$ 36**	**$ 33**

Servco Pension and OPEB

At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities. These obligations, as well as the offsetting long-term receivable, are separately presented on the Consolidated Balance Sheet of PSEG.

The following table provides a roll-forward of the changes in Servco's benefit obligation and the fair value of its plan assets during the years ended December 31, 2015 and 2014. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

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	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
			Millions	
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year	$ 195	$ —	$ 452	$ —
Service Cost	26	20	17	13
Interest Cost	9	7	21	17
Actuarial (Gain) Loss	(20)	42	(114)	107
Gross Benefits Paid	—	—	(1)	—
Plan Amendments	1	126	—	315
Benefit Obligation at End of Year (A)	**$ 211**	**$ 195**	**$ 375**	**$ 452**
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$ 69	$ —	$ —	$ —
Actual Return on Plan Assets	(2)	2	—	—
Employer Contributions	30	67	1	—
Gross Benefits Paid	—	—	(1)	—
Fair Value of Assets at End of Year	**$ 97**	**$ 69**	**$ —**	**$ —**
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	**$ (114)**	**$ (126)**	**$ (375)**	**$ (452)**
Additional Amounts Recognized in the Consolidated Balance Sheets				
Accrued Pension Costs of Servco	$ (114)	$ (126)	N/A	N/A
OPEB Costs of Servco	N/A	N/A	(375)	(452)
Amounts Recognized (B)	**$ (114)**	**$ (126)**	**$ (375)**	**$ (452)**

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits.

(B) Amounts equal to the accrued pension and OPEB costs of Servco are offset in Long-Term Receivable of VIE on PSEG's Consolidated Balance Sheet.

Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. The pension-related revenues and costs for 2015 and 2014 were $30 million and $67 million, respectively. Servco has contributed its entire planned contribution amount to its pension plan trusts during 2015. The OPEB-related revenues earned and costs incurred in 2015 and 2014 were immaterial.

The following assumptions were used to determine the benefit obligations of Servco:

	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31				
Discount Rate	4.92%	4.50%	4.97%	4.60%
Rate of Compensation Increase	3.25%	3.25%	3.25%	3.25%
Assumed Health Care Cost Trend Rates as of December 31				
Administrative Expense			5.00%	5.00%
Health Care Costs				
Immediate Rate			7.55%	7.33%
Ultimate Rate			4.75%	5.00%
Year Ultimate Rate Reached			2025	2021
			Millions	
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs				
Postretirement Benefit Obligation			$ 75	$ 160
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs				
Postretirement Benefit Obligation			$ (60)	$ (106)

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Plan Assets

All the investments of Servco's pension plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 16. Fair Value Measurements for more information on fair value guidance. The Actuary maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Actuary to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans.

The following tables present information about Servco's investments measured at fair value on a recurring basis as of December 31, 2015 and 2014, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2015			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		Millions		
Cash Equivalents (A)	$ —	$ —	$ —	$ —
Common Stocks (B)				
Commingled-United States	68	68	—	—
Bonds (C)				
Other	29	—	29	—
Total	**$ 97**	**$ 68**	**$ 29**	**$ —**

	Recurring Fair Value Measurements as of December 31, 2014			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		Millions		
Cash Equivalents (A)	$ 1	$ —	$ 1	$ —
Common Stocks (B)				
Commingled-United States	48	48	—	—
Bonds (C)				
Other	20	—	20	—
Total	**$ 69**	**$ 48**	**$ 21**	**$ —**

(A) Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

(B) Wherever possible, fair values of equity investments in commingled stock funds are derived from quoted market prices as substantially all of these instruments have active markets (primarily Level 1). Most investments in stocks are priced utilizing the principal market close price or in some cases midpoint, bid or ask price.

(C) Investments in fixed income securities including bond funds are priced using an evaluated pricing approach or the most recent exchange or quoted bid (primarily Level 2).

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The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans of Servco as of the measurement date, December 31:

	As of December 31,	
Investments	**2015**	**2014**
Equity Securities	71%	70%
Fixed Income Securities	29	29
Other Investments	—	1
Total Percentage	**100%**	**100%**

Servco utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. The results from Servco's latest asset/liability study indicated that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. The expected long-term rate of return on plan assets was 7.7% as of December 31, 2015 and will remain unchanged for 2016. This expected return was determined based on the study discussed above, including a premium for active management.

Plan Contributions

Servco plans to contribute $28 million into its pension plan during 2016.

Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to Servco's plan participants:

Year	**Pension Benefits**	**Other Benefits**
	Millions	
2016	$ 1	$ 3
2017	2	5
2018	3	7
2019	4	8
2020	6	10
2021-2025	60	80
Total	**$ 76**	**$ 113**

Servco 401(k) Plans

Servco sponsors two 401(k) plans, which are defined contribution retirement plans subject to ERISA. Eligible non-represented employees of Servco participate in the Long Island Electric Utility Servco LLC Incentive Thrift Plan I (Thrift Plan I), and eligible represented employees of Servco participate in the Long Island Electric Utility Servco LLC Incentive Thrift Plan II (Thrift Plan II). Participants in the Plans may contribute up to 50% of their eligible compensation to these plans, not to exceed the IRS maximums, including any Catch-Up Contributions for those employees age 50 and above. Servco does not provide an employer match or core contribution for employees in Thrift Plan II. For employees in Thrift Plan I, Servco matches 50% of such employee contributions up to 8% of eligible compensation and provides core contributions (based on years of service and age) to employees who do not participate in Servco's Retirement Income Plan. The amounts expensed by Servco for employer matching contributions for the years ended December 31, 2015, 2014 and 2013 were immaterial and pursuant to the OSA, Servco recognizes Operating Revenues for the reimbursement of these costs.

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Note 12. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The face value of outstanding guarantees, current exposure and margin positions as of December 31, 2015 and 2014 are shown below:

	As of December 31, 2015	As of December 31, 2014
	Millions	
Face Value of Outstanding Guarantees	$ 1,734	$ 1,814
Exposure under Current Guarantees	$ 172	$ 273
Letters of Credit Margin Posted	$ 122	$ 159
Letters of Credit Margin Received	$ 192	$ 40
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (15)	$ (13)
Net Broker Balance Deposited (Received)	$ (5)	$ 115
In the Event Power were to Lose its Investment Grade Rating		
Additional Collateral that could be Required	$ 864	$ 945
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,215	$ 3,495
Additional Amounts Posted		
Other Letters of Credit	$ 51	$ 45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 15. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P and Moody's ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power have posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline and a $21 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA further determined that there was a need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties

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included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G. This agreement and the work undertaken pursuant to the action agreement will not affect the ultimate remedy that the EPA will select for the remediation of the 17-mile stretch of the lower Passaic River.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than with respect to their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSEG's share of the cost of that effort is approximately three percent. The remaining CPG members have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS sets forth various alternatives for remediating this portion of the Passaic River. The EPA's estimated costs to remediate the lower eight miles of the Passaic River range from $365 million for a targeted remedy to $3.3 billion for a deep dredge of this portion of the Passaic River. The EPA also identified in the revised draft FFS its preferred alternative, which would involve dredging the lower eight miles of the river bank-to-bank and installing an engineered cap. The estimated cost in the revised draft FFS for the EPA's preferred alternative is $1.7 billion on a discounted basis. No provisional cost allocation has been made by the CPG for the work contemplated by the revised draft FFS, and the work contemplated by the revised draft FFS is not subject to the CPG's cost sharing allocation agreed to in connection with the removal work for River Mile 10.9 or in connection with the conduct of the RI/FS.

The revised draft FFS was subject to a public comment period, and remains subject to the EPA's response to comments submitted, a design phase and at least an estimated five years for completion of the work. The public comment period for the revised draft FFS closed on August 21, 2014. Over 300 comments were submitted by a variety of entities potentially impacted by the revised draft FFS, including the CPG, individual companies, municipalities, public officials, citizens groups, Amtrak, NJ Transit and others.

The CPG, which consisted of 54 members as of December 31, 2015, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost of the RI/FS is approximately $163 million, which the CPG continues to incur. Of the estimated $163 million, as of December 31, 2015, the CPG had spent approximately $147 million, of which PSEG's total share was approximately $10 million.

The draft FS sets forth various alternatives for remediating the lower Passaic River. The draft FS sets forth the CPG's estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranges from approximately $518 million to $772 million. No provisional cost allocation has been made by the CPG for the work contemplated by the draft FS. However, based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimates of their share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

The EPA will consider the comments received on its revised draft FFS and is expected to consider the CPG's RI/FS prior to issuing a Record of Decision (ROD) of a selected remedy for the lower Passaic River. The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD

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might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS is finalized, (ii) a final remedy is determined by the EPA or through litigation, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on our financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $431 million and $499 million through 2021, including its $10 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $431 million as of December 31, 2015. Of this amount, $76 million was recorded in Other Current Liabilities and $355 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $431 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

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Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. On June 30, 2015, the NJDEP issued a draft permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The draft permit was subject to a public notice and comment period. The NJDEP may make revisions before issuing the final permit expected during the first half of 2016. Power participated in the NJDEP's August 5, 2015 public hearing and submitted comments on the draft permit on September 18, 2015.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. On August 15, 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. On September 5, 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Second Circuit Court of Appeals. In two related actions on October 17, 2014 and November 20, 2014, several environmental non-governmental groups initiated challenges to the endangered species act provisions of the 316 (b) rule. Power is unable to determine the ultimate impact of these actions on the implementation of the rule.

State permitting decisions could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities, and could result in acceleration of decommissioning activities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would have been approximately $575 million. The filing has not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA's Clean Water Act Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, Power would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire the BH3 within five years of the effective date of the final permit. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in the summer of 2016 indicating a potential retirement date for BH3 by summer 2021, which is four years earlier than the current estimated useful life ending in 2025. If the permit is not issued and the conditions below are not met, Power will seek to operate BH3 through the current estimated useful life.

Separately, Power has also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that Power would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates, which could occur in 2017. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power will seek to operate BH3 through the current estimated useful life.

If either the permit renewal is received, or all the conditions precedent in the CEBA occur, a triggering event will be deemed to have occurred and Power will test its New England generating fleet for impairment at that time. The New England generation fleet currently has a net book value of approximately $210 million.

In February 2016, the proposed generating facility was awarded a capacity obligation. Construction is expected to commence in 2017, with operations expected to begin in mid-2019.

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Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.

Steam Electric Effluent Guidelines

On September 30, 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Mercer and Bridgeport Harbor stations and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under this rule. Power is unable to predict if this rule will have a material impact on its future capital requirements, financial condition and results of operations.

Coal Combustion Residuals (CCRs)

On December 19, 2014, the EPA issued a final rule which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Power's Hudson and Mercer generating stations, along with its co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 19, 2015. Accordingly in June 2015, Power recorded an additional asset retirement obligation to comply with the final CCR rule which was not material to Power's results of operations, financial condition or cash flows.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, are residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category are larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2016 is $335.33 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2016 of $272.78 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2013	2014	2015	2016	
36-Month Terms Ending	May 2016	May 2017	May 2018	May 2019	(A)
Load (MW)	2,800	2,800	2,900	2,800	
$ per MWh	$92.18	$97.39	$99.54	$96.38	

(A) Prices set in the 2016 BGS auction will become effective on June 1, 2016 when the 2013 BGS auction agreements expire.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

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PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 23. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2020 at Salem, Hope Creek and Peach Bottom.

Power has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations.

Power also has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available, Power can use the gas to supply its fossil generating stations.

As of December 31, 2015, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type		Power's Share of Commitments through 2020
		Millions
Nuclear Fuel		
Uranium	$	475
Enrichment	$	394
Fabrication	$	204
Natural Gas	$	1,023
Coal	$	300

Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future.

During the three month period ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. No additional charges to income have been recorded for this matter since that time.

In September 2014, FERC Staff initiated a preliminary, non-public staff investigation into the matter and issued data requests covering a period from 2002 through the date of the self-report. This investigation is ongoing. Since that time, Power has and is continuing to respond to data requests from FERC Staff, including recent data requests in which Power has recalculated certain of its energy bids in PJM for a five year period, and may receive additional data requests or other fact finding. The FERC Staff investigation is still in the fact finding stage and there is considerable uncertainty around FERC's response to PSEG's legal arguments and the amount of disgorgement or other remedies FERC may ultimately seek.

PSEG is unable to reasonably estimate the range of possible loss for this matter; however, the amounts of potential disgorgement and other potential penalties that Power may incur span a wide range depending on the success of PSEG's legal arguments. These arguments include that Power's energy market bids in a substantial majority of the hours were below the allowed rate under the Tariff and therefore any errors in those hours were immaterial and that it is unclear whether the quantity of the bids violated any legal requirement. If PSEG's legal arguments do not prevail in whole or in part with FERC or in a

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judicial challenge that PSEG may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to PSEG's and Power's Consolidated Statements of Operations in the quarterly and annual periods in which they are recorded.

New Jersey Clean Energy Program

In June 2015, the BPU established the funding level for fiscal year 2016 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2016 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a remaining current liability of $142 million as of December 31, 2015 for its outstanding share of the fiscal year 2016 and remaining fiscal year 2015 funding, respectively. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the SBC.

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's T&D system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. In June 2013, PSEG, PSE&G and Power filed suit in New Jersey state court (NJ Court) against its insurance carriers seeking an interpretation that the insurance policies cover their losses resulting from damage caused by Superstorm Sandy's storm surge.

As of December 31, 2012, PSE&G had incurred approximately $295 million of costs to restore service to PSE&G's distribution and transmission systems and $5 million to repair its infrastructure and return it to pre-storm conditions. Of the costs incurred, approximately $40 million was recognized in O&M Expense, $75 million was recorded as Property, Plant and Equipment and $180 million was recorded as a Regulatory Asset because such costs were deferred as approved by the BPU under an Order received in December 2012. Of the $295 million, $36 million related to insured property. PSE&G recognized $6 million of insurance proceeds. There were no significant additional costs incurred since 2012.

PSE&G made a filing with the BPU to review the prudency of unreimbursed incremental storm restoration costs, including O&M and capital expenditures associated with Superstorm Sandy and certain other extreme weather events, for recovery in its next base rate case or sooner through a BPU-approved cost recovery mechanism. In September 2014, the BPU approved its filing.

Power had incurred $193 million of storm-related costs from 2012 through 2014, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized primarily in O&M Expense, offset by $44 million of insurance recoveries in 2013 and 2012. Power incurred an additional $2 million of O&M costs in 2015 which were recognized primarily in O&M Expense.

In the first half of 2015, PSEG reached settlements with its insurers with respect to claims for coverage of its Superstorm Sandy-related losses. PSEG received an additional $214 million under these settlements (consisting of $159 million and $55 million recognized in the three months ended March 31, 2015 and June 30, 2015, respectively), bringing cumulative insurance proceeds to $264 million. Of the $214 million recognized in 2015, PSE&G and Power recorded $35 million and $179 million, respectively. In addition to the $35 million recognized in 2015, PSE&G recognized the aforementioned $6 million of previously deferred insurance recoveries, resulting in reductions in Regulatory Assets of $20 million, O&M Expense of $10 million and Property, Plant and Equipment of $11 million. Power recorded reductions in both O&M Expense of $145 million and Property, Plant and Equipment of $6 million and an increase in Other Income of $28 million.

The claim filed by PSEG, PSE&G and Power related to Superstorm Sandy insurance coverage is now fully resolved.

Nuclear Insurance Coverages and Assessments

Power is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides the property, decontamination and decommissioning liability insurance at the Salem/Hope Creek and Peach Bottom sites. NEIL also provides replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in case of adverse loss experience. Power's maximum potential liabilities under these assessments are included in the table and notes below. Certain provisions in the NEIL policies provide that the insurer may suspend coverage with respect to all nuclear units on a site without notice if the NRC suspends or revokes the operating license for any unit on that site, issues a shutdown order with respect to such unit or issues a confirmatory order keeping such unit down.

Power is also a member of the joint underwriting association, American Nuclear Insurers (ANI), which provides nuclear liability insurance coverage at the Salem/Hope Creek and Peach Bottom sites. The ANI policies are designed to satisfy the financial protection requirements outlined in the Price-Anderson Act.

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The ANI and NEIL policies all include coverage for claims arising out of acts of terrorism, however, NEIL policies are subject to an industry aggregate limit of $3.2 billion plus such additional amounts as NEIL recovers for such losses from reinsurance, indemnity and any other source applicable to such losses.

The Price-Anderson Act sets the "limit of liability" for claims that could arise from an incident involving any licensed nuclear facility in the United States. The "limit of liability" is based on the number of licensed nuclear reactors and is adjusted at least every five years based on the Consumer Price Index. The current "limit of liability" is $13.5 billion. All owners of nuclear reactors, including Power, have provided for this exposure through a combination of private insurance and mandatory participation in a financial protection pool as established by the Price-Anderson Act. Under the Price-Anderson Act, each licensee can be assessed $127 million per reactor per incident, payable at not more than $19 million per reactor per incident per year. If the damages exceed the "limit of liability," the Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Power's maximum aggregate assessment per incident is $401 million (based on Power's ownership interests in Hope Creek, Peach Bottom and Salem) and its maximum aggregate annual assessment per incident is $60 million. Further, a decision by the U.S. Supreme Court, not involving Power, has held that the Price-Anderson Act did not preclude awards based on state law claims for punitive damages.

Power's insurance coverages and maximum retrospective assessments for its nuclear operations are as follows:

Type and Source of Coverages	Total Site Coverage		Retrospective Assessments
	Millions		
Public and Nuclear Worker Liability (Primary Layer):			
ANI	$ 375	(A)	$ —
Nuclear Liability (Excess Layer):			
Price-Anderson Act	13,113	(B)	401
Nuclear Liability Total	**$ 13,488**	(C)	**$ 401**
Property Damage (Primary Layer):			
NEIL Primary (Salem/Hope Creek and Peach Bottom)	$ 1,500		$ 46
Property Damage (Excess Layers)			
NEIL Excess (Salem/Hope Creek and Peach Bottom)	600	(D)	6
Property Damage Total (Per Site)	**$ 2,100**		**$ 52**
Accidental Outage:			
NEIL I (Peach Bottom)	$ 245	(E)	$ 8
NEIL I (Salem)	281	(E)	9
NEIL I (Hope Creek)	490	(E)	7
Replacement Power Total	**$ 1,016**		**$ 24**

(A) The primary limit for Public Liability is a per site aggregate limit with no potential for assessment. The Nuclear Worker Liability represents the potential liability from third party workers claiming exposure to the nuclear energy hazard. This coverage is subject to an industry aggregate limit that is subject to reinstatement at ANI discretion.

(B) Retrospective premium program under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. Power is subject to retrospective assessment with respect to loss from an incident at any licensed nuclear reactor in the United States that produces greater than 100 MW of electrical power. This retrospective assessment can be adjusted for inflation every five years. The last adjustment was effective as of September 10, 2013. The next adjustment is due on or before September 10, 2018. This retrospective program is in excess of the Public and Nuclear Worker Liability primary layers.

(C) Limit of liability under the Price-Anderson Act for each nuclear incident.

(D) For nuclear event property limits in excess of $1.5 billion, Power participates in a $600 million nuclear event Blanket Limit Policy. The blanket limit policy is shared with Exelon Generation and covers the following facilities: Braidwood, Byron, Clinton, Dresden, La Salle, Limerick, Oyster Creek, Quad Cities, TMI-1 Peach Bottom, Salem and Hope Creek. This limit is not subject to reinstatement in the event of a loss. Participation in this program reduces Power's premium and the associated potential assessment. In addition, for non-nuclear event limits in excess of $1.5 billion, Power maintains a $600 million limit shared by the Salem and Hope Creek facilities. Exelon maintains a $600 million non-nuclear event limit shared by Peach Bottom, Braidwood, Byron, Clinton, Dresden, LaSalle, Limerick, Oyster Creek, Quad Cities, and the TMI-1 facilities.

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(E) Peach Bottom 2 and 3 have an aggregate indemnity limit based on a weekly indemnity of $2.3 million for 52 weeks followed by 80% of the weekly indemnity for 68 weeks. Salem 1 and 2 have an aggregate indemnity limit based on a weekly indemnity of $2.5 million for 52 weeks followed by 80% of the weekly indemnity for 76 weeks. Hope Creek has an aggregate indemnity limit based on a weekly indemnity of $4.5 million for 52 weeks followed by 80% of the weekly indemnity for 71 weeks.

Minimum Lease Payments

The total future minimum payments under various operating leases as of December 31, 2015 are:

	PSE&G	Power	Services	Other	Total
	Millions				
2016	$ 12	$ 2	$ 13	$ 2	$ 29
2017	9	2	13	1	25
2018	8	2	13	1	24
2019	7	2	13	—	22
2020	6	3	13	—	22
Thereafter	66	33	146	—	245
Total Minimum Lease Payments	**$ 108**	**$ 44**	**$ 211**	**$ 4**	**$ 367**

Note 13. Schedule of Consolidated Debt

Long-Term Debt

	Maturity	As of December 31, 2015	2014
		Millions	
PSEG (Parent)			
Term Loan:			
Variable	2017	$ 500	$ —
Total Term Loan		**500**	**—**
Fair Value of Swaps (A)		6	22
Amounts Due Within One Year		(6)	(8)
Unamortized Discount Related to Debt Exchange (B)		—	(8)
Total Long-Term Debt of PSEG (Parent)		**$ 500**	**$ 6**

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	Maturity	As of December 31, 2015	2014
		Millions	
PSE&G			
First and Refunding Mortgage Bonds (C):			
6.75%	2016	$ 171	$ 171
9.25%	2021	134	134
8.00%	2037	7	7
5.00%	2037	8	8
Total First and Refunding Mortgage Bonds		320	320
Pollution Control Bonds (C):			
Floating Rate (D)	2033	50	50
Floating Rate (D)	2046	50	50
Total Pollution Control Bonds		100	100
Medium-Term Notes (MTNs) (C):			
2.70%	2015	—	300
5.30%	2018	400	400
2.30%	2018	350	350
1.80%	2019	250	250
2.00%	2019	250	250
7.04%	2020	9	9
3.50%	2020	250	250
2.38%	2023	500	500
3.75%	2024	250	250
3.15%	2024	250	250
3.05%	2024	250	250
3.00%	2025	350	—
5.25%	2035	250	250
5.70%	2036	250	250
5.80%	2037	350	350
5.38%	2039	250	250
5.50%	2040	300	300
3.95%	2042	450	450
3.65%	2042	350	350
3.80%	2043	400	400
4.00%	2044	250	250
4.05%	2045	250	—
4.15%	2045	250	—
Total MTNs		6,459	5,909
Principal Amount Outstanding		6,879	6,329
Amounts Due Within One Year		(171)	(300)
Net Unamortized Discount and Debt Issuance Costs		(58)	(54)
Total Long-Term Debt of PSE&G (excluding Transition Funding and Transition Funding II)		**$ 6,650**	**$ 5,975**

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	Maturity	As of December 31, 2015	2014
		Millions	
Transition Funding (PSE&G)			
Securitization Bonds:			
6.89%	2014-2015	$ —	$ 251
Principal Amount Outstanding		—	251
Amounts Due Within One Year		—	(251)
Total Securitization Debt of Transition Funding		—	—
Transition Funding II (PSE&G)			
Securitization Bonds:			
4.57%	2014-2015	—	8
Principal Amount Outstanding		—	8
Amounts Due Within One Year		—	(8)
Total Securitization Debt of Transition Funding II		—	—
Total Long-Term Debt of PSE&G		**$ 6,650**	**$ 5,975**

	Maturity	As of December 31, 2015	2014
		Millions	
Power			
Senior Notes:			
5.50%	2015	$ —	$ 300
5.32%	2016	303	303
2.75%	2016	250	250
2.45%	2018	250	250
5.13%	2020	406	406
4.15%	2021	250	250
4.30%	2023	250	250
8.63%	2031	500	500
Total Senior Notes		2,209	2,509
Pollution Control Notes:			
Floating Rate (D)	2019	44	44
Total Pollution Control Notes		44	44
Principal Amount Outstanding		2,253	2,553
Amounts Due Within One Year		(553)	(300)
Net Unamortized Discount and Debt Issuance Costs		(16)	(19)
Total Long-Term Debt of Power		**$ 1,684**	**$ 2,234**

(A) PSEG entered into various interest rate swaps to hedge the fair value of certain debt at Power. The fair value adjustments from these hedges are reflected as offsets to long-term debt on the Consolidated Balance Sheets. For additional information, see Note 15. Financial Risk Management Activities.

(B) In September 2009, Power completed an exchange offer with eligible holders of Energy Holdings' 8.50% Senior Notes due 2011 in order to manage long-term debt maturities. Since the debt exchange was between two subsidiaries of the same parent company, PSEG, and treated as a debt modification for accounting purposes, the resulting premium was deferred and is being amortized over the term of the newly issued debt. The remaining deferred amount of $3 million as of December 31, 2015 is reflected as an offset to Long-Term Debt due within one year on PSEG's Consolidated Balance Sheets.

(C) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.

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(D) The Pollution Control Financing Authority of Salem County bonds and the Pennsylvania Economic Development Authority (PEDFA) bond that are serviced and secured by PSE&G Pollution Control Bonds and Power Pollution Control Notes, respectively, are variable rate bonds that are in weekly reset mode. In October 2014, Power executed an extension of the letter of credit backing the PEDFA bond which expires on November 30, 2019.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2015 are as follows:

				Energy Holdings	
Year	PSEG (Parent)	PSE&G	Power	Non-Recourse Debt	Total
			Millions		
2016	$ —	$ 171	$ 553	$ 7	$ 731
2017	500	—	—	—	500
2018	—	750	250	—	1,000
2019	—	500	44	—	544
2020	—	259	406	—	665
Thereafter	—	5,199	1,000	—	6,199
Total	**$ 500**	**$ 6,879**	**$ 2,253**	**$ 7**	**$ 9,639**

Long-Term Debt Financing Transactions

During 2015, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions:

PSEG (Parent)

- entered into an agreement for a new term loan maturing November 2017. The term loan has a balance of $500 million at an interest rate of 1 month LIBOR + 0.875% and can be terminated at any time without penalty.

PSE&G

- issued $350 million of 3.00% Secured Medium-Term Notes, Series K due May 2025,
- issued $250 million of 4.05% Secured Medium-Term Notes, Series K due May 2045,
- issued $250 million of 4.15% Secured Medium-Term Notes, Series K due November 2045,
- paid $300 million of 2.70% Secured Medium-Term Notes at maturity,
- paid $251 million of Transition Funding's securitization debt, and
- paid $8 million of Transition Funding II's securitization debt.

Power

- paid $300 million of 5.50% Senior Notes at maturity.

PSE&G

PSE&G had $171 million of 6.75% Mortgage Bonds mature in January 2016.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our $4.2 billion credit facilities are provided by a diverse bank group. As of December 31, 2015, our total available credit capacity was $3.6 billion.

As of December 31, 2015, no single institution represented more than 7% of the total commitments in our credit facilities.

As of December 31, 2015, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

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Each of our credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs.

Our total credit facilities and available liquidity as of December 31, 2015 were as follows:

	As of December 31, 2015				
Company/Facility	Total Facility	Usage (D)	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facility	$ 500	$ 10	$ 490	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	211	289	Apr 2020	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 221**	**$ 779**		
PSE&G					
5-year Credit Facility (B)	$ 600	$ 167	$ 433	Apr 2020	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 167**	**$ 433**		
Power					
5-year Credit Facility	$ 1,600	$ 161	$ 1,439	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (C)	1,000	3	997	Apr 2020	Funding/Letters of Credit
Total Power	**$ 2,600**	**$ 164**	**$ 2,436**		
Total	**$ 4,200**	**$ 552**	**$ 3,648**		

(A) PSEG facility will be reduced by $23 million in April 2016 and $12 million in March 2018.

(B) PSE&G facility will be reduced by $29 million in April 2016 and $14 million in March 2018.

(C) Power facility will be reduced by $48 million in April 2016 and $24 million in March 2018.

(D) The primary use of PSEG's and PSE&G's credit facilities is to support their respective Commercial Paper Programs under which as of December 31, 2015, $211 million and $153 million, respectively, were outstanding. The weighted average interest rates on PSEG's and PSE&G's Commercial Paper Programs were 0.96% and 0.91%, respectively, at December 31, 2015.

Fair Value of Debt

The estimated fair values, carrying amounts and methods used to determine fair value of long-term debt as of December 31, 2015 and 2014 are included in the following table and accompanying notes as of December 31, 2015 and 2014. See Note 16. Fair Value Measurements for more information on fair value guidance and the hierarchy that prioritizes the inputs to fair value measurements into three levels.

	December 31, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 503	$ 506	$ 14	$ 22
PSE&G (B)	6,821	7,235	6,275	6,912
Transition Funding (PSE&G) (B)	—	—	251	261
Transition Funding II (PSE&G) (B)	—	—	8	8
Power - Recourse Debt (B)	2,237	2,508	2,534	2,930
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	7	7	16	16
	$ 9,568	**$ 10,256**	**$ 9,098**	**$ 10,149**

(A) Fair value includes a $500 million floating rate term loan in 2015 and net offsets in 2015 and 2014 to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. The fair value of the term loan debt (Level 2 measurement) was considered to be equal to the carrying value because the interest payments are based on LIBOR rates that are reset monthly. Carrying amount includes such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

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(B) Given that most bonds do not trade, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

Note 14. Schedule of Consolidated Capital Stock

	As of December 31,			
	Outstanding Shares		Book Value	
	2015	2014	2015	2014
			Millions	
PSEG Common Stock (no par value) (A)				
Authorized 1,000,000,000 shares	505,282,421	505,836,592	$ 4,244	$ 4,241

(A) PSEG did not issue any new shares under the Dividend Reinvestment and Stock Purchase Plan (DRASPP) or the Employee Stock Purchase Plan (ESPP) in 2015 or 2014. Total authorized and unissued shares of common stock available for issuance through PSEG's DRASPP, ESPP and various employee benefit plans amounted to approximately 7 million shares as of December 31, 2015.

As of December 31, 2015, PSE&G had an aggregate of 7.5 million shares of $100 par value and 10 million shares of $25 par value Cumulative Preferred Stock, which were authorized and unissued and which, upon issuance, may or may not provide for mandatory sinking fund redemption.

Note 15. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. Transactions receiving NPNS treatment are accounted for upon settlement. For a derivative instrument that qualifies and is designated as a cash flow hedge, the changes in the fair value of such a derivative that are highly effective are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. For a derivative instrument that qualifies and is designated as a fair value hedge, the gains or losses on the derivative as well as the offsetting losses or gains on the hedged item attributable to the hedged risk are recognized in earnings each period. Power and PSE&G enter into additional contracts that are derivatives, but do not qualify for or are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and

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electricity prices. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

PSEG and Power use forward sale contracts, swaps and futures contracts to hedge certain forecasted natural gas sales made to support the BGSS contract with PSE&G. Historically, these derivative transactions qualified and were designated as cash flow hedges. PSEG and Power had no contracts designated as cash flow hedges as of December 31, 2015.

As of December 31, 2015 and 2014, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity was as follows:

	As of December 31,	
	2015	2014
	Millions	
Fair Value of Cash Flow Hedges	$ —	$ 18
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ —	$ 10

Economic Hedges

Power enters into derivative contracts that do not qualify or are not designated as either cash flow or fair value hedges. Power enters into financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. These transactions are economic hedges, intended to mitigate exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of these contracts are recorded in earnings. PSE&G is a party to a long-term natural gas sales derivative contract to optimize its pipeline capacity utilization. Changes in the fair market value of the contract are recorded in Regulatory Assets and Regulatory Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of December 31, 2015, PSEG had interest rate swaps outstanding totaling $550 million. These swaps convert $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of December 31, 2015 and 2014, the fair value of all the underlying hedges was $6 million and $22 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was immaterial as of December 31, 2015 and 2014.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset on the Consolidated Balance Sheets of Power, PSE&G and PSEG.

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The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of December 31, 2015						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ —	$ 700	$ (477)	$ 223	$ 13	$ 6	$ 242
Noncurrent Assets	—	208	(131)	77	—	—	77
Total Mark-to-Market Derivative Assets	**$ —**	**$ 908**	**$ (608)**	**$ 300**	**$ 13**	**$ 6**	**$ 319**
Derivative Contracts							
Current Liabilities	$ —	$ (513)	$ 437	$ (76)	$ —	$ —	$ (76)
Noncurrent Liabilities	—	(132)	116	(16)	(11)	—	(27)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (645)**	**$ 553**	**$ (92)**	**$ (11)**	**$ —**	**$ (103)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ —**	**$ 263**	**$ (55)**	**$ 208**	**$ 2**	**$ 6**	**$ 216**

	As of December 31, 2014						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 18	$ 597	$ (408)	$ 207	$ 18	$ 15	$ 240
Noncurrent Assets	—	171	(109)	62	8	7	77
Total Mark-to-Market Derivative Assets	**$ 18**	**$ 768**	**$ (517)**	**$ 269**	**$ 26**	**$ 22**	**$ 317**
Derivative Contracts							
Current Liabilities	$ —	$ (568)	$ 436	$ (132)	$ —	$ —	$ (132)
Noncurrent Liabilities	—	(138)	105	(33)	—	—	(33)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (706)**	**$ 541**	**$ (165)**	**$ —**	**$ —**	**$ (165)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 18**	**$ 62**	**$ 24**	**$ 104**	**$ 26**	**$ 22**	**$ 152**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of December 31, 2015 and 2014. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Consolidated Balance Sheets. As of December 31, 2015 and 2014, net

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cash collateral (received) paid of $(55) million and $24 million, respectively, were netted against the corresponding net derivative contract positions. Of the $(55) million as of December 31, 2015, $(53) million and $(16) million were netted against current assets and noncurrent assets, respectively, and $12 million and $2 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $24 million as of December 31, 2014, cash collateral of $(4) million and $(8) million were netted against current assets and noncurrent assets, respectively, and $32 million and $4 million were netted against current liabilities and noncurrent liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $78 million and $127 million as of December 31, 2015 and 2014, respectively. As of December 31, 2015 and 2014, Power had the contractual right of offset of $12 million and $18 million, respectively, related to derivative instruments that are assets with the same counterparty under master agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $66 million and $109 million as of December 31, 2015 and 2014, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $864 million and $945 million as of December 31, 2015 and 2014, respectively, discussed in Note 12. Commitments and Contingent Liabilities.

The following shows the effect on the Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the years ended December 31, 2015, 2014 and 2013:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)			Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion)			Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)		
	Years Ended December 31,				Years Ended December 31,			Years Ended December 31,		
	2015	2014	2013		2015	2014	2013	2015	2014	2013
	Millions				Millions					
PSEG										
Energy-Related Contracts	$ 3	$ 12	$ (4)	Operating Revenues	$ 20	$ (9)	$ 13	$ —	$ —	$ (1)
Interest Rate Swaps (A)	—	—	—	Interest Expense	—	—	(1)	—	—	—
Total PSEG	**$ 3**	**$ 12**	**$ (4)**		**$ 20**	**$ (9)**	**$ 12**	**$ —**	**$ —**	**$ (1)**
Power										
Energy-Related Contracts	$ 3	$ 12	$ (4)	Operating Revenues	$ 20	$ (9)	$ 13	$ —	$ —	$ (1)
Total Power	**$ 3**	**$ 12**	**$ (4)**		**$ 20**	**$ (9)**	**$ 13**	**$ —**	**$ —**	**$ (1)**

(A) Includes amounts for PSEG parent.

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The following reconciles the AOCI for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis:

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2013	**$ (4)**	**$ (2)**
Gain Recognized in AOCI	12	7
Plus: Loss Reclassified into Income	9	5
Balance as of December 31, 2014	**$ 17**	**$ 10**
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	(20)	(12)
Balance as of December 31, 2015	**$ —**	**$ —**

The following shows the effect on the Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the years ended December 31, 2015, 2014 and 2013:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2015	2014	2013
		Millions		
PSEG and Power				
Energy-Related Contracts	Operating Revenues	$ 412	$ (348)	$ (128)
Energy-Related Contracts	Energy Costs	(8)	32	106
Total PSEG and Power		**$ 404**	**$ (316)**	**$ (22)**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $19 million, $20 million and $19 million for the years ended December 31, 2015, 2014 and 2013, respectively.

The following reflects the gross volume, on an absolute value basis, of derivatives as of December 31, 2015 and 2014:

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of December 31, 2015					
Natural Gas	Dth	201	—	168	33
Electricity	MWh	299	—	299	—
Financial Transmission Rights (FTRs)	MWh	23	—	23	—
Interest Rate Swaps	U.S. Dollars	550	550	—	—
As of December 31, 2014					
Natural Gas	Dth	274	—	216	58
Electricity	MWh	310	—	310	—
FTRs	MWh	15	—	15	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—

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Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of December 31, 2015, 92% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of December 31, 2015. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 451	$ 175	$ 276	1	$ 160	(A)
Non-Investment Grade—External Rating	24	—	24	—	—	
Investment Grade—No External Rating	12	1	11	—	—	
Non-Investment Grade—No External Rating	1	—	1	—	—	
Total	**$ 488**	**$ 176**	**$ 312**	**1**	**$ 160**	

(A) Represents net exposure with PSE&G.

As of December 31, 2015, collateral held from counterparties where Power had credit exposure included $14 million in cash collateral and $162 million in letters of credit.

As of December 31, 2015, Power had 133 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2015, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's suppliers' credit exposure is calculated each business day. As of December 31, 2015, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 16. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of December 31, 2015, these consisted primarily of long-term gas supply and certain electric load contracts.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of December 31, 2015 and December 31, 2014, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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Description	Recurring Fair Value Measurements as of December 31, 2015				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 326	$ —	$ 326	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 313	$ (608)	$ —	$ 896	$ 25
Interest Rate Swaps (C)	$ 6	$ —	$ —	$ 6	$ —
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—Govt Obligations	$ 488	$ —	$ —	$ 488	$ —
Debt Securities—Other	$ 359	$ —	$ —	$ 359	$ —
Other Securities	$ 42	$ —	$ 42	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—Govt Obligations	$ 108	$ —	$ —	$ 108	$ —
Debt Securities—Other	$ 81	$ —	$ —	$ 81	$ —
Other Securities	$ 2	$ —	$ 2	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (103)	$ 553	$ —	$ (644)	$ (12)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 160	$ —	$ 160	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ 13	$ —	$ —	$ —	$ 13
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (11)	$ —	$ —	$ —	$ (11)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 300	$ (608)	$ —	$ 896	$ 12
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—Govt Obligations	$ 488	$ —	$ —	$ 488	$ —
Debt Securities—Other	$ 359	$ —	$ —	$ 359	$ —
Other Securities	$ 42	$ —	$ 42	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 26	$ —	$ —	$ 26	$ —
Debt Securities—Other	$ 20	$ —	$ —	$ 20	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (92)	$ 553	$ —	$ (644)	$ (1)

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Description	Recurring Fair Value Measurements as of December 31, 2014				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 295	$ (517)	$ —	$ 774	$ 38
Interest Rate Swaps (C)	$ 22	$ —	$ —	$ 22	$ —
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 896	$ 1	$ —
Debt Securities—Govt Obligations	$ 438	$ —	$ —	$ 438	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 106	$ —	$ 106	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—Govt Obligations	$ 91	$ —	$ —	$ 91	$ —
Debt Securities—Other	$ 75	$ —	$ —	$ 75	$ —
Other Securities	$ 2	$ —	$ —	$ 2	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (165)	$ 541	$ —	$ (705)	$ (1)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 294	$ —	$ 294	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ 26	$ —	$ —	$ —	$ 26
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 20	$ —	$ —	$ 20	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 269	$ (517)	$ —	$ 774	$ 12
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 896	$ 1	$ —
Debt Securities—Govt Obligations	$ 438	$ —	$ —	$ 438	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 106	$ —	$ 106	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (165)	$ 541	$ —	$ (705)	$ (1)

(A) Represents money market mutual funds.

(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also

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corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds, collateralized mortgage obligations, asset backed securities and government obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Consolidated Balance Sheets. As of December 31, 2015, net cash collateral (received) paid of $(55) million was netted against the corresponding net derivative contract positions. Of the $(55) million of cash collateral as of December 31, 2015, $(69) million was netted against assets, and $14 million was netted against liabilities. As of December 31, 2014, net cash collateral (received) paid of $24 million was netted against the corresponding net derivative contract positions. Of the $24 million of cash collateral as of December 31, 2014, $(12) million was netted against assets and $36 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G and Power, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. For Power, in general, electric swaps are measured at fair value based on at least two pricing inputs, the underlying price of electricity at a liquid reference point and the basis difference between electricity prices at the liquid reference point and electricity prices at the respective delivery locations. To

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the extent the basis component is based on a single broker quote and is significant to the fair value of the electric swap, it is categorized as Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. For additional information see Note 12. Commitments and Contingent Liabilities. The following tables provide detail surrounding significant Level 3 valuations as of December 31, 2015 and 2014.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2015		Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)			
		Millions				
PSE&G						
Gas	Natural Gas Supply Contract	$ 13	$ (11)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/dekatherm
Total PSE&G		**$ 13**	**$ (11)**			
Power						
Electricity	Electric Load Contracts	$ 11	$ (1)	Discounted Cash flow	Historic Load Variability	0% to +10%
Other	Various (A)	1	—			
Total Power		**$ 12**	**$ (1)**			
Total PSEG		**$ 25**	**$ (12)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2014		Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)			
		Millions				
PSE&G						
Gas	Natural Gas Supply Contract	$ 26	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 26**	**$ —**			
Power						
Electricity	Electric Load Contracts	12	(1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Other	Various (B)	—	—			
Total Power		**$ 12**	**$ (1)**			
Total PSEG		**$ 38**	**$ (1)**			

(A) Includes long-term electric capacity positions which were immaterial as of December 31, 2015.

(B) Includes gas supply positions and long-term electric capacity positions which were immaterial as of December 31, 2014.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For gas supply contract where PSE&G is a seller, an increase in gas transportation cost would increase the fair value. For energy-related contracts in cases where Power is a seller, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the years ended December 31, 2015 and 2014, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2015

Description	Balance as of January 1, 2015	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances (Settlements) (C)	Transfers In (Out)	Balance as of December 31, 2015
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 37	$ 20	$ (24)	$ —	$ (20)	$ —	$ 13
PSE&G							
Net Derivative Assets (Liabilities)	$ 26	$ —	$ (24)	$ —	$ —	$ —	$ 2
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 20	$ —	$ —	$ (20)	$ —	$ 11

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2014

Description	Balance as of January 1, 2014	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances (Settlements) (C)	Transfers In (Out) (D)	Balance as of December 31, 2014
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 88	$ (31)	$ (68)	$ —	$ 51	$ (3)	$ 37
PSE&G							
Net Derivative Assets (Liabilities)	$ 94	$ —	$ (68)	$ —	$ —	$ —	$ 26
Power							
Net Derivative Assets (Liabilities)	$ (6)	$ (31)	$ —	$ —	$ 51	$ (3)	$ 11

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $20 million and $(31) million in Operating Income in 2015 and 2014, respectively. The $20 million in Operating Income in 2015 is realized. Of the $(31) million in Operating Income in 2014, $22 million is unrealized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income (Loss), as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

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(C) Represents $(20) million and $51 million in settlements for derivative contracts in 2015 and 2014, respectively.

(D) During the year ended December 31, 2014, $(3) million of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. The transfers were recognized as of the beginning of the quarters (i.e. the quarter in which the transfers occurred), as per PSEG's policy.

As of December 31, 2015, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $13 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of December 31, 2014, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $37 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Non-recurring Fair Value Measurements

During the fourth quarter of 2014, an assessment of recoverability was triggered for two commercial real estate properties located in Ohio and Michigan. As a result of the evaluation, Energy Holdings recorded a pre-tax impairment of $14 million which is included in Operating Revenues in PSEG's Consolidated Statement of Operations for the year ended December 31, 2014. On September 30, 2015 the property located in Michigan was sold. The real estate investment of $5 million is carried as a nonrecurring fair value measurement determined using an income approach valuation technique (cash flow analyses) along with bids received as part of a marketing initiative. This technique relied on significant unobservable inputs and is considered a Level 3 measurement within the fair value hierarchy.

Note 17. Stock Based Compensation

PSEG's Amended and Restated 2004 Long-Term Incentive Plan (LTIP) is a broad-based equity compensation program that provides for grants of various long-term incentive compensation awards, such as stock options, stock appreciation rights, performance share units, restricted stock, restricted stock units, cash awards or any combination thereof. The types of long-term incentive awards that have been granted and remain outstanding under the LTIP are non-qualified options to purchase shares of PSEG's common stock, restricted stock unit awards and performance share unit awards. The type of equity award that is granted and the details of that award may vary from time to time and is subject to the approval of the Organization and Compensation Committee of PSEG's Board of Directors (OCC), the plan's administrative committee.

The LTIP currently provides for the issuance of equity awards with respect to approximately 16 million shares of common stock. As of December 31, 2015, there were approximately 15 million shares available for future awards under the LTIP.

Stock Options

Under the LTIP, non-qualified options to acquire shares of PSEG common stock may be granted to officers and other key employees selected by the OCC. Option awards are granted with an exercise price equal to the market price of PSEG's common stock at the grant date. The options generally vest over four years of continuous service. Vesting schedules may be accelerated upon the occurrence of certain events, such as a change-in-control (unless substituted with an equity award of equal value), retirement, death or disability. Options are exercisable over a period of time designated by the OCC (but not prior to one year or longer than ten years from the date of grant) and are subject to such other terms and conditions as the OCC determines. Payment by option holders upon exercise of an option may be made in cash or, with the consent of the OCC, by delivering previously acquired shares of PSEG common stock.

Restricted Stock Units

Under the LTIP, PSEG has granted restricted stock unit awards to officers and other key employees. These awards, which are bookkeeping entries only, are subject to risk of forfeiture until vested by continued employment. Until vested, the units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. The restricted stock unit grants for 2015 and 2014 generally vest at the end of three years. Vesting may be accelerated upon certain events such as retirement, disability, change-in-control or death.

Performance Share Units

Under the LTIP, PSEG has granted performance share units to officers and other key employees. These provide for payment in shares of PSEG common stock based on achievement of certain financial goals over a three-year performance period. Following the end of the performance period, the payout varies from 0% to 200% of the number of performance units granted depending on PSEG's performance with respect to certain financial targets, including targets related to comparative performance against other companies in a peer group of energy companies. The performance share units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. Vesting may be pro-rated for the employee's service during the performance period as a result of certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

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Stock-Based Compensation

All outstanding unvested stock options are being expensed based on their grant date fair values, which were determined using the Black-Scholes option-pricing model. Stock option awards are expensed on a tranche-specific basis over the requisite service period of the award. Ultimately, compensation expense for stock options is recognized for awards that vest.

PSEG recognizes compensation expense for restricted stock units over the vesting period based on the grant date fair value of the shares, which is equal to the market price of PSEG's common stock on the date of the grant.

PSEG recognizes compensation expense for the total shareholder return target for its performance share unit awards based on the grant date fair values of the award, which are determined using the Monte Carlo model. The accrual of compensation cost is based on the probable achievement of the performance conditions, which result in a payout from 0% to 200% of the initial grant. PSEG recognizes compensation expense for the return on invested capital target for its performance share units based on the grant date fair value of the awards, which is equal to the market price of PSEG's common stock on the date of the grant. The accrual during the year of grant is estimated at 100% of the original grant. Such accrual may be adjusted to reflect the actual outcome.

	2015	2014	2013
		Millions	
Compensation Cost included in Operation and Maintenance Expense	$ 34	$ 32	$ 32
Income Tax Benefit Recognized in Consolidated Statement of Operations	$ 14	$ 13	$ 13

For 2015 the excess tax benefit was $3 million. There was no excess tax benefit for 2014 and 2013.

PSEG recognizes compensation cost of awards issued over the shorter of the original vesting period or the period beginning on the date of grant and ending on the date an individual is eligible for retirement and the award vests.

Stock Options

Changes in stock options for 2015 are summarized as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding as of January 1, 2015	2,075,850	$ 35.35		
Exercised	368,600	$ 32.37		
Canceled/Forfeited	—	$ —		
Outstanding as of December 31, 2015	**1,707,250**	**$ 36.00**	**2.8**	**$ 8,120,788**
Exercisable at December 31, 2015	1,707,250	$ 36.00	2.8	$ 8,120,788

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. There were no option grants in 2015, 2014 and 2013.

Activity for options exercised for the years ended December 31, 2015, 2014 and 2013 is shown below:

	2015	2014	2013
		Millions	
Total Intrinsic Value of Options Exercised	$ 3	$ 4	$ 1
Cash Received from Options Exercised	$ 12	$ 16	$ 7
Tax Benefit Realized from Options Exercised	$ —	$ —	$ —

No options were vested during the years ended December 31, 2015 and 2014. Less than one million options vested during the year ended December 31, 2013. The total fair value of the stock options vested during the year ended December 31, 2013 was $1 million.

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Restricted Stock Units

Changes in restricted stock units for the year ended December 31, 2015 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2015	1,069,029	$ 32.49		
Granted	318,805	$ 39.65		
Vested	963,387	$ 33.73		
Canceled/Forfeited	15,940	$ 37.28		
Non-vested as of December 31, 2015	**408,507**	**$ 34.95**	**1.1**	**$ 15,805,175**

The weighted average grant date fair value per share for restricted stock during the years ended December 31, 2015, 2014 and 2013 was $39.65, $35.16 and $31.41 per share, respectively.

The total intrinsic value of restricted stock units vested during the years ended December 31, 2015, 2014 and 2013 was $11 million, $12 million and $4 million, respectively.

As of December 31, 2015, there was approximately $5 million of unrecognized compensation cost related to the restricted stock units, which is expected to be recognized over a weighted average period of one year. Dividend equivalents units of 43,081 accrued on the restricted stock units during the year.

Performance Share Units

Changes in performance share units for the year ended December 31, 2015 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2015	765,633	$ 36.86		
Granted	337,585	$ 41.32		
Vested	655,201	$ 36.82		
Canceled/Forfeited	44,056	$ 38.97		
Non-vested as of December 31, 2015	**403,961**	**$ 40.42**	**1.6**	**$ 15,629,251**

The weighted average grant date fair value per share for performance share units during the years ended December 31, 2015, 2014 and 2013 was $41.32, $38.94 and $35.07 per share, respectively.

The total intrinsic value of performance share units vested during the year ended December 31, 2015, 2014 and 2013 was $13 million, $6 million and $5 million, respectively.

As of December 31, 2015, there was approximately $15 million of unrecognized compensation cost related to the performance share units, which is expected to be recognized over a weighted average period of one year. Dividend equivalents units of 44,559 accrued on the performance share units during the year.

Outside Directors

Under the Directors Equity Plan, annually, on the first business day of May, each non-employee member of the Board of Directors is awarded stock units based on amount of annual compensation to be paid at the closing price of PSEG common stock on that date. Dividend equivalents are credited quarterly and distributions will commence upon the director leaving the Board as specified by him/her in accordance with the provisions of the plan.

The fair value of these awards is recorded as compensation expense in the Consolidated Statements of Operations. Compensation expense for the plan for each of the years ended December 31, 2015, 2014 and 2013 was approximately $1 million.

Employee Stock Purchase Plan (ESPP)

PSEG maintains an ESPP for all eligible employees of PSEG and its subsidiaries. Under the ESPP, shares of PSEG common stock may be purchased at 95% of the fair market value for represented employees and 90% for non-represented employees through payroll deductions. Dividends will be reinvested for all employees at 95% of the fair market price unless the participant

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elects to receive a cash dividend. All employees are required to hold the shares purchased under the ESPP for at least three months from the purchase date. In any year, employees may purchase shares having a value not exceeding 10% of their base pay. Compensation expense recognized under this program was immaterial for the years ended December 31, 2015, 2014 and 2013.

During the years ended December 31, 2015, 2014 and 2013, employees purchased 250,499 shares, 207,248 shares and 257,513 shares at an average price of $36.66, $36.07 and $30.57 per share, respectively. As of December 31, 2015, 3.7 million shares were available for future issuance under this plan.

Note 18. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated Total
		Millions		
Year Ended December 31, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 138	$ —	$ 138
Allowance for Funds Used During Construction	48	—	—	48
Solar Loan Interest	23	—	—	23
Gain on Insurance Recovery	—	28	—	28
Other	8	3	6	17
Total Other Income	**$ 79**	**$ 169**	**$ 6**	**$ 254**
Year Ended December 31, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 219	$ —	$ 219
Allowance for Funds Used During Construction	31	—	—	31
Solar Loan Interest	24	—	—	24
Other	6	3	7	16
Total Other Income	**$ 61**	**$ 222**	**$ 7**	**$ 290**
Year Ended December 31, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 152	$ —	$ 152
Allowance for Funds Used During Construction	24	—	—	24
Solar Loan Interest	23	—	—	23
Other	7	2	5	14
Total Other Income	**$ 54**	**$ 154**	**$ 5**	**$ 213**

Other Deductions	PSE&G	Power	Other (A)	Consolidated Total
		Millions		
Year Ended December 31, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 45	$ —	$ 45
Other	4	27	26	57
Total Other Deductions	**$ 4**	**$ 72**	**$ 26**	**$ 102**
Year Ended December 31, 2014				
NDT Fund Realized Losses and Expenses	$ —	$ 31	$ —	$ 31
Other	3	21	6	30
Total Other Deductions	**$ 3**	**$ 52**	**$ 6**	**$ 61**
Year Ended December 31, 2013				
NDT Fund Realized Losses and Expenses	$ —	$ 34	$ —	$ 34
Other	3	15	2	20
Total Other Deductions	**$ 3**	**$ 49**	**$ 2**	**$ 54**

(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

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Note 19. Income Taxes

A reconciliation of reported income tax expense for PSEG with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSEG	Years Ended December 31, 2015	2014	2013
		Millions	
Net Income	$ 1,679	$ 1,518	$ 1,243
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 243	$ 335	$ 487
State	85	58	42
Total Current	328	393	529
Deferred Expense:			
Federal	540	262	147
State	104	260	118
Total Deferred	644	522	265
Investment Tax Credit (ITC)	29	23	18
Total Income Taxes	**$ 1,001**	**$ 938**	**$ 812**
Pre-Tax Income	$ 2,680	$ 2,456	$ 2,055
Tax Computed at Statutory Rate @ 35%	$ 938	$ 860	$ 719
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	129	145	108
Uncertain Tax Positions	7	(9)	10
Manufacturing Deduction	(10)	(16)	(9)
NDT Fund	7	14	12
Plant-Related Items	(20)	(13)	(14)
Tax Credits	(13)	(14)	(9)
Audit Settlement	—	(12)	—
Nuclear Decommissioning Tax Carryback	(33)	—	—
Other	(4)	(17)	(5)
Sub-Total	63	78	93
Total Income Tax Provision	**$ 1,001**	**$ 938**	**$ 812**
Effective Income Tax Rate	37.4%	38.2%	39.5%

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The following is an analysis of deferred income taxes for PSEG:

PSEG	As of December 31, 2015	2014
	Millions	
Deferred Income Taxes		
Assets:		
Current (net)	$ —	$ 11
Noncurrent		
OPEB	$ 256	$ 269
Related to Uncertain Tax Position	160	160
Securitization-Overcollection	27	55
Total Noncurrent Assets	$ 443	$ 484
Total Assets	$ 443	$ 495
Liabilities:		
Current (net)		
Securitization	$ —	$ 163
Other	—	10
Total Current Liabilities (net)	$ —	$ 173
Noncurrent:		
Plant-Related Items	$ 6,174	$ 5,422
New Jersey Corporate Business Tax	615	535
Leasing Activities	612	623
Pension Costs	218	219
AROs and NDT Fund	393	419
Taxes Recoverable Through Future Rate (net)	191	196
Other	244	240
Total Noncurrent Liabilities	$ 8,447	$ 7,654
Total Liabilities	$ 8,447	$ 7,827
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	**$ —**	**$ 11**
Net Current Deferred Income Tax Liabilities	**$ —**	**$ 173**
Net Noncurrent Deferred Income Tax Liabilities	$ 8,004	$ 7,170
ITC	162	133
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 8,166**	**$ 7,303**

The deferred tax effect of certain assets and liabilities is presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals. Also, the deferred tax effect of AROs is presented net of the deferred tax effect of the associated funding of those obligations.

PSEG has early adopted the accounting standards update Balance Sheet Classification of Deferred Taxes as of December 31, 2015. This standard requires noncurrent classification of all deferred tax assets and liabilities. For further details refer to Note 2. Recent Accounting Standards.

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A reconciliation of reported income tax expense for PSE&G with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSE&G	Years Ended December 31, 2015	2014	2013
		Millions	
Net Income	$ 787	$ 725	$ 612
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 32	$ 124	$ 183
State	52	16	—
Total Current	84	140	183
Deferred Expense:			
Federal	325	214	101
State	52	84	92
Total Deferred	377	298	193
ITC	9	11	5
Total Income Taxes	**$ 470**	**$ 449**	**$ 381**
Pre-Tax Income	$ 1,257	$ 1,174	$ 993
Tax Computed at Statutory Rate @ 35%	$ 440	$ 411	$ 348
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	67	65	59
Uncertain Tax Positions	(14)	—	—
Plant-Related Items	(20)	(13)	(14)
Tax Credits	(6)	(7)	(6)
Audit Settlement	—	1	—
Other	3	(8)	(6)
Sub-Total	30	38	33
Total Income Tax Provision	**$ 470**	**$ 449**	**$ 381**
Effective Income Tax Rate	37.4%	38.2%	38.4%

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The following is an analysis of deferred income taxes for PSE&G:

PSE&G	As of December 31, 2015	2014
	Millions	
Deferred Income Taxes		
Assets:		
Current (net)	$ —	$ 24
Noncurrent:		
OPEB	$ 164	$ 173
Securitization-Overcollection	27	55
Total Noncurrent Assets	$ 191	$ 228
Total Assets	$ 191	$ 252
Liabilities:		
Current (net)		
Securitization	$ —	$ 163
Other	—	2
Total Current Liabilities (net)	$ —	$ 165
Noncurrent:		
Plant-Related Items	$ 4,435	$ 3,869
New Jersey Corporate Business Tax	312	268
Conservation Costs	40	48
Pension Costs	262	269
Taxes Recoverable Through Future Rate (net)	191	196
Other	54	84
Total Noncurrent Liabilities	$ 5,294	$ 4,734
Total Liabilities	$ 5,294	$ 4,899
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	**$ —**	**$ 24**
Net Current Deferred Income Tax Liabilities	**$ —**	**$ 165**
Net Noncurrent Deferred Income Tax Liabilities	$ 5,103	$ 4,506
ITC	78	69
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 5,181**	**$ 4,575**

The deferred tax effect of certain assets and liabilities is presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals.

PSEG has early adopted the accounting standards update Balance Sheet Classification of Deferred Taxes as of December 31, 2015. This standard requires noncurrent classification of all deferred tax assets and liabilities. For further details refer to Note 2. Recent Accounting Standards.

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A reconciliation of reported income tax expense for Power with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

Power	Years Ended December 31, 2015	2014	2013
		Millions	
Net Income	$ 856	$ 760	$ 644
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 220	$ 231	$ 262
State	30	39	40
Total Current	250	270	302
Deferred Expense:			
Federal	189	163	69
State	52	48	35
Total Deferred	241	211	104
ITC	20	10	13
Total Income Taxes	**$ 511**	**$ 491**	**$ 419**
Pre-Tax Income	$ 1,367	$ 1,251	$ 1,063
Tax Computed at Statutory Rate @ 35%	$ 478	$ 438	$ 372
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	59	58	51
Manufacturing Deduction	(10)	(16)	(10)
NDT Fund	7	15	12
Tax Credits	(7)	(6)	(2)
Uncertain Tax Positions	22	(8)	3
Audit Settlement	—	(4)	—
Nuclear Decommissioning Tax Carryback	(33)	—	—
Other	(5)	14	(7)
Sub-Total	33	53	47
Total Income Tax Provision	**$ 511**	**$ 491**	**$ 419**
Effective Income Tax Rate	37.4%	39.2%	39.4%

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The following is an analysis of deferred income taxes for Power:

Power	As of December 31, 2015	2014
	Millions	
Deferred Income Taxes		
Assets:		
Current	$ —	$ —
Noncurrent:		
Pension Costs	$ 56	$ 52
Contractual Liabilities & Environmental Costs	18	18
Related to Uncertain Tax Positions	47	23
Other	—	70
Total Noncurrent Assets	$ 121	$ 163
Total Assets	$ 121	$ 163
Liabilities:		
Current (net)	$ —	$ 43
Noncurrent:		
Plant-Related Items	$ 1,736	$ 1,552
New Jersey Corporate Business Tax	243	192
AROs and NDT Fund	395	420
Other	10	—
Total Noncurrent Liabilities	$ 2,384	$ 2,164
Total Liabilities	$ 2,384	$ 2,207
Summary of Accumulated Deferred Income Taxes:		
Net Current Deferred Income Tax Assets	**$ —**	**$ —**
Net Current Deferred Income Tax Liabilities	**$ —**	**$ 43**
Net Noncurrent Deferred Income Tax Liabilities	$ 2,263	$ 2,001
ITC	84	64
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 2,347**	**$ 2,065**

In the above table, the deferred tax effect of asset retirement obligations is presented net of the deferred tax effect of the associated funding of those obligations.

PSEG has early adopted the accounting standards update Balance Sheet Classification of Deferred Taxes as of December 31, 2015. This standard requires noncurrent classification of all deferred tax assets and liabilities. For further details refer to Note 2. Recent Accounting Standards.

PSEG, PSE&G and Power each provide deferred taxes at the enacted statutory tax rate for all temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities irrespective of the treatment for rate-making purposes. Management believes that it is probable that the accumulated tax benefits that previously have been treated as a flow-through item to PSE&G customers will be recovered from or refunded to PSE&G's customers in the future. These amounts were determined using the enacted federal income tax rate of 35% and state income tax rate of 9%. For additional information, see Note 5. Regulatory Assets and Liabilities.

In August 2014, PSEG received notice from the IRS that the audit settlement covering tax years 2007 through 2010 had been approved by the Joint Committee on Taxation. This effectively settled all issues with the IRS through 2010. In September 2014, PSEG received refunds from the IRS totaling $121 million, representing the net settlement of all disputed amounts, including interest, through the tax year 2010. As a result of the settlement of this audit, PSEG recorded a $12 million reduction of tax expense in the quarter ended September 30, 2014.

In September 2013, the U.S. Department of the Treasury and the IRS released final regulations effective in 2014 that provide guidance on applying Section 263(a) of the Internal Revenue Code to amounts paid to acquire, produce or improve tangible property, as well as rules for materials and supplies. Implementation of these regulations did not have any material impact on PSEG's and its subsidiaries' results of operations, financial condition or cash flows.

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The American Taxpayer Relief Act of 2012 extended the 50% bonus depreciation rules enacted in 2010 for qualified property placed into service before January 1, 2014. In addition, long production property placed into service in 2014 was eligible for 50% bonus depreciation for federal tax purposes. On December 19, 2014, the Tax Increase Prevention Act of 2014 was enacted. This act further extended the 50% bonus depreciation rules for qualified property that was placed into service before January 1, 2015 and for long production property that was placed into service in 2015.

In December 2015, Congress passed the Protecting Americans from Tax Hikes Act of 2015 (Tax Act). Among other provisions, the Tax Act includes an extension of the bonus depreciation rules and the 30% ITC for qualified property placed into service after 2016. Qualified property that is placed in service from January 1, 2015 through December 31, 2017 is eligible for 50% bonus depreciation. The rate is reduced to 40% and 30% for eligible property placed in service in 2018 and 2019, respectively. In addition, long production property placed in service in 2020 will also qualify for 30% bonus depreciation. The ITC rate has been extended through December 31, 2019 but is reduced to 26% and 22% for projects commenced in 2020 and 2021, respectively. The financial impact of the extensions of the ITC rate will depend upon future transactions.

These provisions have generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period. However, these tax benefits will have a negative impact on the rate base of several of PSE&G's programs.

PSEG recorded the following amounts related to its unrecognized tax benefits, which were primarily comprised of amounts recorded for PSE&G, Power and Energy Holdings:

2015	PSEG	PSE&G	Power	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2015	$ 332	$ 165	$ 70	$ 95
Increases as a Result of Positions Taken in a Prior Period	87	55	28	4
Decreases as a Result of Positions Taken in a Prior Period	(50)	(43)	(6)	(1)
Increases as a Result of Positions Taken during the Current Period	28	5	23	—
Decreases as a Result of Positions Taken during the Current Period	(1)	(1)	—	—
Decreases as a Result of Settlements with Taxing Authorities	(10)	—	(4)	(5)
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2015	$ 386	$ 181	$ 111	$ 93
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(264)	(162)	(68)	(34)
Regulatory Asset—Unrecognized Tax Benefits	(27)	(27)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 95**	**$ (8)**	**$ 43**	**$ 59**

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2014	PSEG	PSE&G	Power	Energy Holdings
	Millions			
Total Amount of Unrecognized Tax Benefits as of January 1, 2014	$ 478	$ 208	$ 156	$ 110
Increases as a Result of Positions Taken in a Prior Period	82	65	17	—
Decreases as a Result of Positions Taken in a Prior Period	(190)	(92)	(80)	(18)
Increases as a Result of Positions Taken during the Current Period	30	16	9	5
Decreases as a Result of Positions Taken during the Current Period	(8)	—	(8)	—
Decreases as a Result of Settlements with Taxing Authorities	(60)	(32)	(24)	(2)
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2014	$ 332	$ 165	$ 70	$ 95
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(225)	(138)	(52)	(35)
Regulatory Asset—Unrecognized Tax Benefits	(27)	(27)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 80**	**$ —**	**$ 18**	**$ 60**

2013	PSEG	PSE&G	Power	Energy Holdings
	Millions			
Total Amount of Unrecognized Tax Benefits as of January 1, 2013	$ 402	$ 163	$ 134	$ 101
Increases as a Result of Positions Taken in a Prior Period	83	39	33	11
Decreases as a Result of Positions Taken in a Prior Period	(30)	(9)	(19)	(2)
Increases as a Result of Positions Taken during the Current Period	23	15	8	—
Decreases as a Result of Positions Taken during the Current Period	—	—	—	—
Decreases as a Result of Settlements with Taxing Authorities	—	—	—	—
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2013	$ 478	$ 208	$ 156	$ 110
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(320)	(177)	(105)	(37)
Regulatory Asset—Unrecognized Tax Benefits	(30)	(30)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 128**	**$ 1**	**$ 51**	**$ 73**

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PSEG and its subsidiaries include accrued interest and penalties related to uncertain tax positions required to be recorded, as Income Tax Expense in the Consolidated Statements of Operations. Accumulated interest and penalties that are recorded on the Consolidated Balance Sheets on uncertain tax positions were as follows:

	Accumulated Interest and Penalties on Uncertain Tax Positions as of December 31,		
	2015	2014	2013
	Millions		
PSE&G	$ 20	$ 15	$ 6
Power	6	9	(2)
Energy Holdings	40	45	44
Total	**$ 66**	**$ 69**	**$ 48**

It is reasonably possible that total unrecognized tax benefits will decrease within the next twelve months due to either agreements with various taxing authorities upon audit or the expiration of the Statute of Limitations. These potential decreases are as follows:

Possible Decrease in Total Unrecognized Tax Benefits	Over the next 12 Months
	Millions
PSEG	$ 158
PSE&G	$ 102
Power	$ 42

A description of income tax years that remain subject to examination by material jurisdictions, where an examination has not already concluded are:

	PSEG	PSE&G	Power
United States			
Federal	2011-2014	N/A	N/A
New Jersey	2006-2014	2006-2014	N/A
Pennsylvania	2006-2014	2006-2014	N/A
Connecticut	2002-2014	N/A	N/A
Texas	2007-2014	N/A	N/A
California	2003-2014	N/A	N/A
New York	2011-2014	N/A	2011-2014

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Note 20. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss)			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 7	$ (485)	$ 90	$ (388)
Other Comprehensive Income before Reclassifications	(2)	210	91	299
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(7)	37	(36)	(6)
Net Current Period Other Comprehensive Income (Loss)	(9)	247	55	293
Balance as of December 31, 2013	**$ (2)**	**$ (238)**	**$ 145**	**$ (95)**
Other Comprehensive Income before Reclassifications	7	(184)	42	(135)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	5	11	(69)	(53)
Net Current Period Other Comprehensive Income (Loss)	12	(173)	(27)	(188)
Balance as of December 31, 2014	**$ 10**	**$ (411)**	**$ 118**	**$ (283)**
Other Comprehensive Income before Reclassifications	2	(7)	(25)	(30)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(12)	32	(2)	18
Net Current Period Other Comprehensive Income (Loss)	(10)	25	(27)	(12)
Balance as of December 31, 2015	**$ —**	**$ (386)**	**$ 91**	**$ (295)**

Power	Other Comprehensive Income (Loss)			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 9	$ (422)	$ 85	$ (328)
Other Comprehensive Income before Reclassifications	(2)	185	93	276
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(8)	33	(36)	(11)
Net Current Period Other Comprehensive Income (Loss)	(10)	218	57	265
Balance as of December 31, 2013	**$ (1)**	**$ (204)**	**$ 142**	**$ (63)**
Other Comprehensive Income before Reclassifications	7	(156)	39	(110)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	5	9	(69)	(55)
Net Current Period Other Comprehensive Income (Loss)	12	(147)	(30)	(165)
Balance as of December 31, 2014	**$ 11**	**$ (351)**	**$ 112**	**$ (228)**
Other Comprehensive Income before Reclassifications	1	(4)	(24)	(27)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(12)	28	(1)	15
Net Current Period Other Comprehensive Income (Loss)	(11)	24	(25)	(12)
Balance as of December 31, 2015	**$ —**	**$ (327)**	**$ 87**	**$ (240)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 13	$ (5)	$ 8
Interest Rate Swaps	Interest Expense	(1)	—	(1)
Total Cash Flow Hedges		12	(5)	7
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	11	(4)	7
Amortization of Actuarial Loss	O&M Expense	(75)	31	(44)
Total Pension and OPEB Plans		(64)	27	(37)
Available-for-Sale Securities				
Realized Gains	Other Income	116	(59)	57
Realized Losses	Other Deductions	(29)	14	(15)
Other-Than-Temporary Impairments (OTTI)	OTTI	(12)	6	(6)
Total Available-for-Sale Securities		75	(39)	36
Total		**$ 23**	**$ (17)**	**$ 6**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 13	$ (5)	$ 8
Total Cash Flow Hedges		13	(5)	8
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	9	(4)	5
Amortization of Actuarial Loss	O&M Expense	(64)	26	(38)
Total Pension and OPEB Plans		(55)	22	(33)
Available-for-Sale Securities				
Realized Gains	Other Income	112	(57)	55
Realized Losses	Other Deductions	(26)	13	(13)
OTTI	OTTI	(12)	6	(6)
Total Available-for-Sale Securities		74	(38)	36
Total		**$ 32**	**$ (21)**	**$ 11**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ (9)	$ 4	$ (5)
Total Cash Flow Hedges		(9)	4	(5)
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	10	(4)	6
Amortization of Actuarial Loss	O&M Expense	(28)	11	(17)
Total Pension and OPEB Plans		(18)	7	(11)
Available-for-Sale Securities				
Realized Gains	Other Income	181	(89)	92
Realized Losses	Other Deductions	(26)	13	(13)
OTTI	OTTI	(20)	10	(10)
Total Available-for-Sale Securities		135	(66)	69
Total		**$ 108**	**$ (55)**	**$ 53**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ (9)	$ 4	$ (5)
Total Cash Flow Hedges		(9)	4	(5)
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	9	(4)	5
Amortization of Actuarial Loss	O&M Expense	(25)	11	(14)
Total Pension and OPEB Plans		(16)	7	(9)
Available-for-Sale Securities				
Realized Gains	Other Income	178	(87)	91
Realized Losses	Other Deductions	(24)	12	(12)
OTTI	OTTI	(20)	10	(10)
Total Available-for-Sale Securities		134	(65)	69
Total		**$ 109**	**$ (54)**	**$ 55**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 20	$ (8)	$ 12
Total Cash Flow Hedges		20	(8)	12
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	12	(3)	9
Amortization of Actuarial Loss	O&M Expense	(68)	27	(41)
Total Pension and OPEB Plans		(56)	24	(32)
Available-for-Sale Securities				
Realized Gains	Other Income	100	(52)	48
Realized Losses	Other Deductions	(39)	20	(19)
OTTI	OTTI	(53)	26	(27)
Total Available-for-Sale Securities		8	(6)	2
Total		**$ (28)**	**$ 10**	**$ (18)**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 20	$ (8)	$ 12
Total Cash Flow Hedges		20	(8)	12
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	11	(3)	8
Amortization of Actuarial Loss	O&M Expense	(60)	24	(36)
Total Pension and OPEB Plans		(49)	21	(28)
Available-for-Sale Securities				
Realized Gains	Other Income	98	(51)	47
Realized Losses	Other Deductions	(38)	19	(19)
OTTI	OTTI	(53)	26	(27)
Total Available-for-Sale Securities		7	(6)	1
Total		**$ (22)**	**$ 7**	**$ (15)**

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Note 21. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Years Ended December 31,					
	2015		2014		2013	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator:						
(Millions)						
Net Income	**$ 1,679**	**$ 1,679**	**$ 1,518**	**$ 1,518**	**$ 1,243**	**$ 1,243**
EPS Denominator:						
(Millions)						
Weighted Average Common Shares Outstanding	505	505	506	506	506	506
Effect of Stock Based Compensation Awards	—	3	—	2	—	2
Total Shares	**505**	**508**	**506**	**508**	**506**	**508**
EPS:						
Net Income	**$ 3.32**	**$ 3.30**	**$ 3.00**	**$ 2.99**	**$ 2.46**	**$ 2.45**

There were approximately 0.5 million, 0.4 million and 1.6 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the years ended December 31, 2015, 2014 and 2013, respectively. No other stock options had an antidilutive effect for the years ended December 31, 2015, 2014 or 2013.

Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	**2015**	**2014**	**2013**
Per Share	$ 1.56	$ 1.48	$ 1.44
in Millions	$ 789	$ 748	$ 728

On February 16, 2016, PSEG's Board of Directors approved a $0.41 per share common stock dividend for the first quarter of 2016.

Note 22. Financial Information by Business Segment

Basis of Organization

PSEG's, PSE&G's and Power's operating segments were determined by management in accordance with GAAP. These segments were determined based on how management measures performance based on segment Net Income, as illustrated in the following table, and how resources are allocated to each business. PSEG's reportable segments are PSE&G and Power. PSE&G and Power each represent a single reportable segment and therefore no separate segment information is provided for these Registrants.

PSE&G

PSE&G earns revenues from its tariffs, under which it provides electric transmission and electric and gas distribution services to residential, commercial and industrial customers in New Jersey. The rates charged for electric transmission are regulated by FERC while the rates charged for electric and gas distribution are regulated by the BPU. Revenues are also earned from several

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other activities such as solar investments, sundry sales, the appliance service business, wholesale transmission services and other miscellaneous services.

Power

Power earns revenues by selling energy, capacity and ancillary services on a wholesale basis under contract to power marketers and to load serving entities and by bidding energy, capacity and ancillary services into the markets for these products. Power also enters into contracts for energy, capacity, FTRs, gas, emission allowances and other energy-related contracts to optimize the value of its portfolio of generating assets and its electric and gas supply obligations.

Other

This category includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Year Ended December 31, 2015					
Operating Revenues	$ 6,636	$ 4,928	$ 462	$ (1,611)	$ 10,415
Depreciation and Amortization	892	291	31	—	1,214
Operating Income (Loss)	1,462	1,430	70	—	2,962
Income from Equity Method Investments	—	14	(2)	—	12
Interest Income	25	2	33	(29)	31
Interest Expense	280	121	21	(29)	393
Income (Loss) before Income Taxes	1,257	1,367	56	—	2,680
Income Tax Expense (Benefit)	470	511	20	—	1,001
Net Income (Loss)	787	856	36	—	1,679
Gross Additions to Long-Lived Assets	$ 2,692	$ 1,117	$ 54	$ —	$ 3,863
As of December 31, 2015					
Total Assets	$ 23,677	$ 12,250	$ 2,810	$ (1,202)	$ 37,535
Investments in Equity Method Subsidiaries	$ —	$ 119	$ —	$ —	$ 119

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Year Ended December 31, 2014					
Operating Revenues	$ 6,766	$ 5,434	$ 455	$ (1,769)	$ 10,886
Depreciation and Amortization	906	292	29	—	1,227
Operating Income (Loss)	1,393	1,209	21	—	2,623
Income from Equity Method Investments	—	14	(1)	—	13
Interest Income	26	1	25	(22)	30
Interest Expense	277	122	12	(22)	389
Income (Loss) before Income Taxes	1,174	1,251	31	—	2,456
Income Tax Expense (Benefit)	449	491	(2)	—	938
Net Income (Loss)	725	760	33	—	1,518
Gross Additions to Long-Lived Assets	$ 2,164	$ 626	$ 30	$ —	$ 2,820
As of December 31, 2014					
Total Assets	$ 22,186	$ 12,037	$ 2,799	$ (1,735)	$ 35,287
Investments in Equity Method Subsidiaries	$ —	$ 121	$ 2	$ —	$ 123

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	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Year Ended December 31, 2013					
Operating Revenues	$ 6,655	$ 5,063	$ 52	$ (1,802)	$ 9,968
Depreciation and Amortization	872	273	33	—	1,178
Operating Income (Loss)	1,235	1,070	(6)	—	2,299
Income from Equity Method Investments	—	16	(5)	—	11
Interest Income	25	1	25	(22)	29
Interest Expense	293	116	15	(22)	402
Income (Loss) before Income Taxes	993	1,063	(1)	—	2,055
Income Tax Expense (Benefit)	381	419	12	—	812
Net Income (Loss)	612	644	(13)	—	1,243
Gross Additions to Long-Lived Assets	$ 2,175	$ 609	$ 27	$ —	$ 2,811
As of December 31, 2013					
Total Assets	$ 19,689	$ 11,991	$ 4,025	$ (3,225)	$ 32,480
Investments in Equity Method Subsidiaries	$ —	$ 123	$ 3	$ —	$ 126

(A) Includes amounts applicable to Energy Holdings and PSEG LI (for 2015 and 2014), which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations primarily relate to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 23. Related-Party Transactions.

Note 23. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related Party Transactions	Years Ended December 31, 2015	2014	2013
		Millions	
Billings from Affiliates:			
Billings from Power primarily through BGS and BGSS (A)	$ 1,630	$ 1,771	$ 1,797
Administrative Billings from Services (B)	274	248	255
Total Billings from Affiliates	**$ 1,904**	**$ 2,019**	**$ 2,052**

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Related Party Transactions	Years Ended December 31, 2015	2014
	Millions	
Receivables from PSEG (C)	**$ 222**	**$ 274**
Payable to Power (A)	$ 212	$ 313
Payable to Services (B)	80	66
Accounts Payable—Affiliated Companies	**$ 292**	**$ 379**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 109**	**$ 116**

Power

The financial statements for Power include transactions with related parties presented as follows:

Related Party Transactions	Years Ended December 31, 2015	2014	2013
		Millions	
Billings to Affiliates:			
Billings to PSE&G primarily through BGS and BGSS (A)	**$ 1,630**	**$ 1,771**	**$ 1,797**
Billings from Affiliates:			
Administrative Billings from Services (B)	**$ 187**	**$ 165**	**$ 178**

Related Party Transactions	Years Ended December 31, 2015	2014
	Millions	
Receivable from PSE&G (A)	$ 212	$ 313
Receivable from PSEG (C)	64	—
Accounts Receivable—Affiliated Companies	**$ 276**	**$ 313**
Payable to Services (B)	$ 33	$ 23
Payable to PSEG (C)	—	95
Accounts Payable—Affiliated Companies	**$ 33**	**$ 118**
Short-Term Loan due (to) from Affiliate (E)	**$ 363**	**$ 584**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 35**	**$ 41**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Consolidated Balance Sheets.

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(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

Note 24. Selected Quarterly Data (Unaudited)

The information shown in the following tables, in the opinion of PSEG, PSE&G and Power includes all adjustments, consisting only of normal recurring accruals, necessary to fairly present such amounts.

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2015	2014	2015	2014	2015	2014	2015	2014
PSEG Consolidated:	Millions, except per share data							
Operating Revenues	$ 3,135	$ 3,223	$ 2,314	$ 2,249	$ 2,688	$ 2,641	$ 2,278	$ 2,773
Operating Income	$ 1,048	$ 705	$ 568	$ 365	$ 814	$ 746	$ 532	$ 807
Net Income (Loss)	$ 586	$ 386	$ 345	$ 212	$ 439	$ 444	$ 309	$ 476
Earnings Per Share:								
Basic:								
Net Income (Loss)	$ 1.16	$ 0.76	$ 0.68	$ 0.42	$ 0.87	$ 0.88	$ 0.61	$ 0.94
Diluted:								
Net Income (Loss)	$ 1.15	$ 0.76	$ 0.68	$ 0.42	$ 0.87	$ 0.87	$ 0.60	$ 0.94
Weighted Average Common Shares Outstanding:								
Basic	506	506	506	506	505	506	505	506
Diluted	508	508	508	508	508	507	508	508

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2015	2014	2015	2014	2015	2014	2015	2014
PSE&G:	Millions							
Operating Revenues	$ 2,002	$ 2,145	$ 1,466	$ 1,435	$ 1,766	$ 1,655	$ 1,402	$ 1,531
Operating Income	$ 451	$ 411	$ 320	$ 291	$ 404	$ 383	$ 287	$ 308
Net Income (Loss)	$ 242	$ 214	$ 167	$ 151	$ 222	$ 200	$ 156	$ 160

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2015	2014	2015	2014	2015	2014	2015	2014
Power:	Millions							
Operating Revenues	$ 1,725	$ 1,700	$ 1,025	$ 986	$ 1,096	$ 1,138	$ 1,082	$ 1,610
Operating Income	$ 584	$ 282	$ 228	$ 67	$ 391	$ 353	$ 227	$ 507
Net Income (Loss)	$ 335	$ 164	$ 166	$ 54	$ 206	$ 222	$ 149	$ 320

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Note 25. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following table presents financial information for the guarantor subsidiaries as well as Power's non-guarantor subsidiaries as of December 31, 2015 and 2014 and for the years ended December 31, 2015, 2014 and 2013.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2015					
Operating Revenues	$ —	$ 4,883	$ 179	$ (134)	$ 4,928
Operating Expenses	12	3,451	169	(134)	3,498
Operating Income (Loss)	(12)	1,432	10	—	1,430
Equity Earnings (Losses) of Subsidiaries	906	(4)	14	(902)	14
Other Income	48	174	—	(53)	169
Other Deductions	(27)	(45)	—	—	(72)
Other-Than-Temporary Impairments	—	(53)	—	—	(53)
Interest Expense	(116)	(39)	(19)	53	(121)
Income Tax Benefit (Expense)	57	(574)	6	—	(511)
Net Income (Loss)	**$ 856**	**$ 891**	**$ 11**	**$ (902)**	**$ 856**
Comprehensive Income (Loss)	**$ 844**	**$ 855**	**$ 11**	**$ (866)**	**$ 844**
As of December 31, 2015					
Current Assets	$ 4,501	$ 1,912	$ 364	$ (4,828)	$ 1,949
Property, Plant and Equipment, net	83	6,502	1,542	—	8,127
Investment in Subsidiaries	4,501	346	—	(4,847)	—
Noncurrent Assets	155	1,959	136	(76)	2,174
Total Assets	**$ 9,240**	**$ 10,719**	**$ 2,042**	**$ (9,751)**	**$ 12,250**
Current Liabilities	$ 1,112	$ 3,866	$ 1,076	$ (4,828)	$ 1,226
Noncurrent Liabilities	442	2,597	375	(76)	3,338
Long-Term Debt	1,684	—	—	—	1,684
Member's Equity	6,002	4,256	591	(4,847)	6,002
Total Liabilities and Member's Equity	**$ 9,240**	**$ 10,719**	**$ 2,042**	**$ (9,751)**	**$ 12,250**
Year Ended December 31, 2015					
Net Cash Provided By (Used In) Operating Activities	$ 571	$ 2,089	$ 80	$ (1,034)	$ 1,706
Net Cash Provided By (Used In) Investing Activities	$ (366)	$ (1,519)	$ (430)	$ 1,314	$ (1,001)
Net Cash Provided By (Used In) Financing Activities	$ (205)	$ (571)	$ 354	$ (280)	$ (702)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2014					
Operating Revenues	$ —	$ 5,390	$ 153	$ (109)	$ 5,434
Operating Expenses	16	4,175	143	(109)	4,225
Operating Income (Loss)	(16)	1,215	10	—	1,209
Equity Earnings (Losses) of Subsidiaries	799	(5)	14	(794)	14
Other Income	34	222	—	(34)	222
Other Deductions	(20)	(32)	—	—	(52)
Other-Than-Temporary Impairments	—	(20)	—	—	(20)
Interest Expense	(102)	(35)	(19)	34	(122)
Income Tax Benefit (Expense)	65	(558)	2	—	(491)
Net Income (Loss)	**$ 760**	**$ 787**	**$ 7**	**$ (794)**	**$ 760**
Comprehensive Income (Loss)	**$ 595**	**$ 768**	**$ 7**	**$ (775)**	**$ 595**
As of December 31, 2014					
Current Assets	$ 4,263	$ 2,037	$ 150	$ (4,091)	$ 2,359
Property, Plant and Equipment, net	81	6,265	1,169	—	7,515
Investment in Subsidiaries	4,516	120	—	(4,636)	—
Noncurrent Assets	269	1,952	137	(195)	2,163
Total Assets	**$ 9,129**	**$ 10,374**	**$ 1,456**	**$ (8,922)**	**$ 12,037**
Current Liabilities	$ 883	$ 3,606	$ 786	$ (4,091)	$ 1,184
Noncurrent Liabilities	454	2,442	360	(195)	3,061
Long-Term Debt	2,234	—	—	—	2,234
Member's Equity	5,558	4,326	310	(4,636)	5,558
Total Liabilities and Member's Equity	**$ 9,129**	**$ 10,374**	**$ 1,456**	**$ (8,922)**	**$ 12,037**
Year Ended December 31, 2014					
Net Cash Provided By (Used In) Operating Activities	$ 577	$ 1,674	$ 76	$ (902)	$ 1,425
Net Cash Provided By (Used In) Investing Activities	$ 148	$ (856)	$ (42)	$ 226	$ (524)
Net Cash Provided By (Used In) Financing Activities	$ (724)	$ (818)	$ (32)	$ 676	$ (898)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2013					
Operating Revenues	$ —	$ 5,022	$ 190	$ (149)	$ 5,063
Operating Expenses	23	3,945	174	(149)	3,993
Operating Income (Loss)	(23)	1,077	16	—	1,070
Equity Earnings (Losses) of Subsidiaries	684	(5)	16	(679)	16
Other Income	35	157	—	(38)	154
Other Deductions	(14)	(35)	—	—	(49)
Other-Than-Temporary Impairments	—	(12)	—	—	(12)
Interest Expense	(93)	(42)	(19)	38	(116)
Income Tax Benefit (Expense)	55	(474)	—	—	(419)
Net Income (Loss)	**$ 644**	**$ 666**	**$ 13**	**$ (679)**	**$ 644**
Comprehensive Income (Loss)	**$ 909**	**$ 713**	**$ 11**	**$ (724)**	**$ 909**
Year Ended December 31, 2013					
Net Cash Provided By (Used In) Operating Activities	$ 288	$ 1,503	$ 82	$ (526)	$ 1,347
Net Cash Provided By (Used In) Investing Activities	$ (395)	$ (1,092)	$ (71)	$ 697	$ (861)
Net Cash Provided By (Used In) Financing Activities	$ 107	$ (412)	$ (11)	$ (171)	$ (487)

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, PSE&G and Power

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of PSEG, PSE&G and Power. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of PSEG, PSE&G and Power have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, PSE&G and Power

We have conducted assessments of our internal control over financial reporting as of December 31, 2015, as required by Section 404 of the Sarbanes-Oxley Act, using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO." Management's reports on PSEG's, PSE&G's and Power's internal control over financial reporting are included on pages 177, 178 and 179, respectively. The Independent Registered Public Accounting Firm's report with respect to the effectiveness of PSEG's internal control over financial reporting is included on page 180. Management has concluded that internal control over financial reporting is effective as of December 31, 2015.

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2015 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSEG

Management of Public Service Enterprise Group Incorporated (PSEG) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSEG's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSEG's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSEG are being made only in accordance with authorizations of PSEG's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSEG's assets that could have a material effect on the financial statements.

In connection with the preparation of PSEG's annual financial statements, management of PSEG has undertaken an assessment, which includes the design and operational effectiveness of PSEG's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSEG's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSEG's financial reporting and the preparation of its financial statements as of December 31, 2015 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2015.

PSEG's external auditors, Deloitte & Touche LLP, have audited PSEG's financial statements for the year ended December 31, 2015 included in this annual report on Form 10-K and, as part of that audit, have issued a report on the effectiveness of PSEG's internal control over financial reporting, a copy of which is included in this annual report on Form 10-K.

/s/ RALPH IZZO

Chief Executive Officer

/s/ DANIEL J. CREGG

Chief Financial Officer

February 25, 2016

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSE&G

Management of Public Service Electric and Gas Company (PSE&G) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSE&G's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSE&G's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSE&G are being made only in accordance with authorizations of PSE&G's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSE&G's assets that could have a material effect on the financial statements.

In connection with the preparation of PSE&G's annual financial statements, management of PSE&G has undertaken an assessment, which includes the design and operational effectiveness of PSE&G's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSE&G's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSE&G's financial reporting and the preparation of its financial statements as of December 31, 2015 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2015.

/s/ RALPH IZZO

Chief Executive Officer

/s/ DANIEL J. CREGG

Chief Financial Officer

February 25, 2016

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—Power

Management of PSEG Power LLC (Power) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

Power's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of Power's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of Power are being made only in accordance with authorizations of Power's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Power's assets that could have a material effect on the financial statements.

In connection with the preparation of Power's annual financial statements, management of Power has undertaken an assessment, which includes the design and operational effectiveness of Power's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that Power's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of Power's financial reporting and the preparation of its financial statements as of December 31, 2015 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2015.

/s/ RALPH IZZO
Chief Executive Officer

/s/ DANIEL J. CREGG
Chief Financial Officer
February 25, 2016

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Public Service Enterprise Group Incorporated
Newark, New Jersey

We have audited the internal control over financial reporting of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting - PSEG. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and consolidated financial statement schedule listed in the Index at Item 15 (B)(a) as of and for the year ended December 31, 2015 of the Company and our report dated February 25, 2016 expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2016

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

PSEG

The information required by Item 10 of Form 10-K with respect to executive officers is set forth in Part I. Executive Officers of the Registrant (PSEG).

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Directors

PSEG

The information required by Item 10 of Form 10-K with respect to (i) present directors of PSEG who are nominees for election as directors at PSEG's 2016 Annual Meeting of Stockholders, (ii) the director nomination process, and (iii) the composition of the Audit Committee of the Board, is set forth under the headings "Nominees and Election-Board Composition and Individual Qualifications," "Nominees and Election-Nomination Process," and "Corporate Governance-Board Committee Responsibilities-Audit Committee," respectively, in PSEG's definitive Proxy Statement for such Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 9, 2016 and which information set forth under said heading is incorporated herein by this reference thereto.

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Code of Ethics

Our Standards of Integrity (Standards) is a code of ethics applicable to us and our subsidiaries. The Standards are an integral part of our business conduct compliance program and embody our commitment to conduct operations in accordance with the highest legal and ethical standards. The Standards apply to all of our directors and employees (including PSE&G's, Power's, Energy Holdings' and Services' respective principal executive officer, principal financial officer, principal accounting officer or Controller and persons performing similar functions). Each such person is responsible for understanding and complying with the Standards. The Standards are posted on our website, www.pseg.com/info/investors/governance/document.jsp. We will send you a copy on request.

The Standards establish a set of common expectations for behavior to which each employee must adhere in dealings with investors, customers, fellow employees, competitors, vendors, government officials, the media and all others who may associate their words and actions with us. The Standards have been developed to provide reasonable assurance that, in conducting our business, employees behave ethically and in accordance with the law and do not take advantage of investors, regulators or customers through manipulation, abuse of confidential information or misrepresentation of material facts.

We will post on our website, www.pseg.com/info/investors/governance/document.jsp:

- Any amendment (other than one that is technical, administrative or non-substantive) that we adopt to our Standards; and
- Any grant by us of a waiver from the Standards that applies to any director, principal executive officer, principal financial officer, principal accounting officer or Controller, or persons performing similar functions, for us or our direct subsidiaries noted above, and that relates to any element enumerated by the SEC.

In 2015, we did not grant any waivers to the Standards.

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Section 16(a) Beneficial Ownership Reporting Compliance

PSEG

The information required by Item 10 of Form 10-K with respect to compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth under the heading "Section 16(a) Beneficial Ownership Reporting Compliance," in PSEG's definitive Proxy Statement for the 2016 Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the SEC on or about March 9, 2016 and which information set forth under said heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

PSEG

The information required by Item 11 of Form 10-K is set forth in PSEG's definitive Proxy Statement for the 2016 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 9, 2016 and such information set forth under such heading is incorporated herein by this reference thereto.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDERS MATTERS

PSEG

The information required by Item 12 of Form 10-K with respect to directors, executive officers and certain beneficial owners is set forth under the heading "Security Ownership of Directors, Management and Certain Beneficial Owners" in PSEG's definitive Proxy Statement for the 2016 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 9, 2016 and such information set forth under such heading is incorporated herein by this reference thereto.

For information relating to securities authorized for issuance under equity compensation plans, see Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

PSEG

The information required by Item 13 of Form 10-K is set forth under the heading "Corporate Governance—Transactions with Related Persons" in PSEG's definitive Proxy Statement for the 2016 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 9, 2016 and such information set forth under such heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10K.

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ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 of Form 10-K is set forth under the heading "Fees Billed by Deloitte & Touche LLP for 2015 and 2014" in PSEG's definitive Proxy Statement for the 2016 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 9, 2016. Such information set forth under such heading is incorporated herein by this reference hereto.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(A) The following Financial Statements are filed as a part of this report:

a. Public Service Enterprise Group Incorporated's Consolidated Balance Sheets as of December 31, 2015 and 2014 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Stockholders' Equity for the three years ended December 31, 2015 on pages 75 through 80.

b. Public Service Electric and Gas Company's Consolidated Balance Sheets as of December 31, 2015 and 2014 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Common Stockholder's Equity for the three years ended December 31, 2015 on pages 81 through 86.

c. PSEG Power LLC's Consolidated Balance Sheets as of December 31, 2015 and 2014 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Capitalization and Member's Equity for the three years ended December 31, 2015 on pages 87 through 92.

(B) The following documents are filed as a part of this report:

a. PSEG's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2015 (page 189).

b. PSE&G's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2015 (page 189).

c. Power's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2015 (page 190).

Schedules other than those listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(C) The following documents are filed as part of this report:

LIST OF EXHIBITS:

a.	**PSEG:**
3a	Certificate of Incorporation Public Service Enterprise Group Incorporated[(1)]
3b	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 23, 1987[(2)]
3c	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 20, 2007[(3)]
3d	By-Laws of Public Service Enterprise Group Incorporated effective December 15, 2015[(4)]

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LIST OF EXHIBITS:

4a	Indenture between Public Service Enterprise Group Incorporated and First Union National Bank (U.S. Bank National Association, successor), as Trustee, dated January 1, 1998 providing for Deferrable Interest Subordinated Debentures in Series (relating to Quarterly Preferred Securities)(5)
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011(6)
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees as amended May 31, 2011(7)
10a(3)	Employment Agreement with William Levis dated December 8, 2006(8)
10a(4)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011(9)
10a(5)	Deferred Compensation Plan for Directors, amended July 19, 2011(10)
10a(6)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011(11)
10a(7)	1989 Long-Term Incentive Plan, as amended(12)
10a(8)	2001 Long-Term Incentive Plan(13)
10a(9)	Senior Management Incentive Compensation Plan(14)
10a(10)	Amended Key Executive Severance Plan, effective December 15, 2015
10a(11)	Severance Agreement with Ralph Izzo dated December 16, 2008(15)
10a(12)	Stock Plan for Outside Directors, as amended(16)
10a(13)	Compensation Plan for Outside Directors(17)
10a(14)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013(18)
10a(15)	Form of Advancement of Expenses Agreement with Outside Directors(19)
10a(16)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011(20)
10a(17)	Amendment to Employment Agreement with William Levis, dated September 19, 2011(21)
10a(18)	Agreement with Tamara L. Linde dated June 18, 2014(22)
10a(19)	Agreement with Daniel J. Cregg dated September 22, 2015(23)
10a(20)	Clawback Practice, effective December 15, 2015
12	Computation of Ratios of Earnings to Fixed Charges
21	Subsidiaries of the Registrant
23	Consent of Independent Registered Public Accounting Firm
31	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934 (1934 Act)
31a	Certification by Daniel J. Cregg, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32a	Certification by Daniel J. Cregg, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
b.	**Power:**
3a	Certificate of Formation of PSEG Power LLC(24)
3b	PSEG Power LLC Limited Liability Company Agreement(25)
4a	Indenture dated April 16, 2001 between and among PSEG Power, PSEG Fossil, PSEG Nuclear, PSEG Energy Resources & Trade and The Bank of New York Mellon and form of Subsidiary Guaranty included therein(26)
4b	First Supplemental Indenture, supplemental to Exhibit 4a, dated as of March 13, 2002(27)
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011(6)
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees, as amended May 31, 2011(7)
10a(3)	Employment Agreement with William Levis dated December 8, 2006(8)
10a(4)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011(11)

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LIST OF EXHIBITS:

10a(5)	1989 Long-Term Incentive Plan, as amended[12]
10a(6)	2001 Long-Term Incentive Plan[13]
10a(7)	Senior Management Incentive Compensation Plan[14]
10a(8)	Amended Key Executive Severance Plan, effective December 15, 2015
10a(9)	Severance Agreement with Ralph Izzo dated December 16, 2008[15]
10a(10)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013[18]
10a(11)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011[20]
10a(12)	Amendment to Employment Agreement with William Levis, dated September 19, 2011[21]
10a(13)	Agreement with Tamara L. Linde dated June 18, 2014[22]
10a(14)	Agreement with Daniel J. Cregg dated September 22, 2015[23]
10a(15)	Clawback Practice, effective December 15, 2015
12a	Computation of Ratio of Earnings to Fixed Charges
23a	Consent of Independent Registered Public Accounting Firm
31b	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31c	Certification by Daniel J. Cregg, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32b	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32c	Certification by Daniel J. Cregg, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
c.	**PSE&G**
3a(1)	Restated Certificate of Incorporation of PSE&G[28]
3a(2)	Certificate of Amendment of Certificate of Restated Certificate of Incorporation of PSE&G filed February 18, 1987 with the State of New Jersey adopting limitations of liability provisions in accordance with an amendment to New Jersey Business Corporation Act[29]
3a(3)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed June 17, 1992 with the State of New Jersey, establishing the 7.44% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock[30]
3a(4)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed March 11, 1993 with the State of New Jersey, establishing the 5.97% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock[31]
3a(5)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed January 27, 1994 with the State of New Jersey, establishing the 6.92% Cumulative Preferred Stock ($100 Par) and the 6.75% Cumulative Preferred Stock ($25 Par) as a series of Preferred Stock[32]
3b(1)	By-Laws of PSE&G as in effect April 17, 2007[33]
4a(1)	Indenture between PSE&G and Fidelity Union Trust Company (now, Wachovia Bank, National Association), as Trustee, dated August 1, 1924[34], securing First and Refunding Mortgage Bond and Supplemental Indentures between PSE&G and U.S. Bank National Association, successor, as Trustee, supplemental to Exhibit 4a(1), dated as follows:
4a(2)	June 1, 1937[35]
4a(3)	July 1, 1937[36]
4a(4)	March 1, 1942[37]
4a(5)	June 1, 1991 (No. 1)[38]
4a(6)	July 1, 1993[39]
4a(7)	December 1, 2003 (No. 1)[40]
4a(8)	December 1, 2003 (No. 2)[41]
4a(9)	December 1, 2003 (No. 3)[42]

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LIST OF EXHIBITS:

4a(10)	December 1, 2003 (No. 4)[43]
4a(11)	August 1, 2004 (No. 1)[44]
4a(12)	August 1, 2004 (No. 2)[45]
4a(13)	August 1, 2004 (No. 3)[46]
4a(14)	August 1, 2004 (No. 4)[47]
4a(15)	April 1, 2007[48]
4a(16)	October 1, 2010[49]
4a(17)	May 1, 2012[50]
4a(18)	June 1, 2012[51]
4a(19)	May 1, 2013[52]
4a(20)	August 1, 2014[53]
4a(21)	May 1, 2015[54]
4b	Indenture of Trust between PSE&G and Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor), as Trustee, providing for Secured medium-Term Notes dated July 1, 1993[55]
4c	Indenture dated as of December 1, 2000 between Public Service Electric and Gas Company and First Union National Bank (U.S. Bank National Association, successor), as Trustee, providing for Senior Debt Securities[56]
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011[6]
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees as amended May 31, 2011[7]
10a(3)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011[9]
10a(4)	Deferred Compensation Plan for Directors, amended July 19, 2011[10]
10a(5)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011[11]
10a(6)	1989 Long-Term Incentive Plan, as amended[12]
10a(7)	2001 Long-Term Incentive Plan[13]
10a(8)	Senior Management Incentive Compensation Plan[14]
10a(9)	Amended Key Executive Severance Plan, effective December 15, 2015
10a(10)	Severance Agreement with Ralph Izzo dated December 16, 2008[15]
10a(11)	Stock Plan for Outside Directors, as amended[16]
10a(12)	Compensation Plan for Outside Directors[17]
10a(13)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013[18]
10a(14)	Form of Advancement of Expenses Agreement with Outside Directors[57]
10a(15)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011[20]
10a(16)	Agreement with Tamara L. Linde dated June 18, 2014[22]
10a(17)	Agreement with Daniel J. Cregg dated September 22, 2015[23]
10a(18)	Clawback Practice, effective December 15, 2015
12b	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
23b	Consent of Independent Registered Public Accounting Firm
31d	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31e	Certification by Daniel J. Cregg, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32d	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32e	Certification by Daniel J. Cregg, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document

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(1) Filed as Exhibit 3.1a with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.
(2) Filed as Exhibit 3.1b with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.
(3) Filed as Exhibit 3.1c with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.
(4) Filed as Exhibit 99.1 with Current Report on Form 8-K, File No. 001-09120 on December 16, 2015 and incorporated herein by this reference.
(5) Filed as Exhibit 4(f) with Quarterly Report on Form 10-Q for the quarter ended March 31, 1998, File No. 001-09120 on May 13, 1998 and incorporated herein by this reference.
(6) Filed as Exhibit 10.1 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(7) Filed as Exhibit 10.2 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(8) Filed as Exhibit 10a(4) with Annual Report on Form 10-K for the year ended December 31, 2007, File Nos. 001-09120 on February 28, 2008 and 000-49614, and incorporated herein by reference.
(9) Filed as Exhibit 10.5 with Quarterly Report on Form 10-Q for the quarter ended September 20, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(10) Filed as Exhibit 10.6 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by this reference.
(11) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the quarter ended December 31, 2011, File No. 001-09120 on February 27, 2012 and incorporated herein by this reference.
(12) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 001-09120, on November 4, 2002 and incorporated herein by this reference.
(13) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2000, File No. 001-09120, on March 6, 2001 and incorporated herein by this reference.
(14) Filed as Exhibit 10a(11) with Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-09120, on February 26, 2009 and incorporated herein by this reference.
(15) Filed as Exhibit 99 with Current Report on Form 8-K, File Nos. 001-09120, 000-49614 and 001-00973 on December 22, 2008 and incorporated herein by this reference.
(16) Filed as Exhibit 10a(17) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(17) Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(18) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, File No. 001-09120 on April 30, 2013 and incorporated herein by reference.
(19) Filed as Exhibit 10.1 with Current Report on Form 8-K, File No. 001-09120 on February 19, 2009 and incorporated herein by this reference.
(20) Filed as Exhibit 10a(19) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120 on February 27, 2012.
(21) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120 on November 1, 2011 and incorporated herein by reference.
(22) Filed as Exhibit 10a with Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-09120 on February 26, 2015.
(23) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, File No. 001-09120 on October 30, 2015.
(24) Filed as Exhibit 3.1 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.
(25) Filed as Exhibit 3.2 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.
(26) Filed as Exhibit 4.1 to Registration Statement on Form S-4, No. 333-69228 filed on September 10, 2001 and incorporated herein by this reference.
(27) Filed as Exhibit 4.7 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, File No. 000-49614, on May 15, 2002 and incorporated herein by this reference.
(28) Filed as Exhibit 3(a) with Quarterly Report on Form 10-Q for the quarter ended June 30, 1986, File No. 001-00973, on August 28, 1986 and incorporated herein by this reference.

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(29) Filed as Exhibit 3a(2) with Annual Report on Form 10-K for the year ended December 31, 1987, File No. 001-00973, on March 28, 1988 and incorporated herein by this reference.
(30) Filed as Exhibit 3a(3) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(31) Filed as Exhibit 3a(4) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(32) Filed as Exhibit 3a(5) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(33) Filed as Exhibit 3.3 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-00973 on May 4, 2007 and incorporated herein by this reference.
(34) Filed as Exhibit 4b(1) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(35) Filed as Exhibit 4b(3) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(36) Filed as Exhibit 4b(4) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(37) Filed as Exhibit 4b(6) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.
(38) Filed as Exhibit 4 on Form 8-A, File No. 001-00973 on June 1, 1991 and incorporated herein by this reference.
(39) Filed as Exhibit 4(i) on Form 8-A, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.
(40) Filed as Exhibit 4a(99) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(41) Filed as Exhibit 4a(100) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(42) Filed as Exhibit 4a(101) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(43) Filed as Exhibit 4a(102) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.
(44) Filed as Exhibit 4a(25) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(45) Filed as Exhibit 4a(26) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(46) Filed as Exhibit 4a(27) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(47) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.
(48) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-00973, on February 28, 2008 and incorporated herein by this reference.
(49) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2010, File No. 001-00973 on October 29, 2010 and incorporated herein by reference.
(50) Filed as Exhibit 4a(32) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-00973 on February 25, 2013.
(51) Filed as Exhibit 4a(33) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-00973 on February 25, 2013.
(52) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, File No. 001-00973 on July 30, 2013.
(53) Filed as Exhibit 4a(22) with Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, File No. 001-09120 on October 30, 2014 and incorporated herein by reference.
(54) Filed as Exhibit 4a(23) with Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 001-09120 on July 31, 2015 and incorporated herein by reference.
(55) Filed as Exhibit 4 with Current Report on Form 8-K, File No. 001-00973 on December 1, 1993 and incorporated herein by reference.
(56) Filed as Exhibit 4.6 to Registration Statement on Form S-3, File No. 333-76020 filed on December 27, 2001 and incorporated herein by reference.
(57) Filed as Exhibit 10.2 with Current Report on Form 8-K, File No. 001-00973 on February 19, 2009 and incorporated herein by reference.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2015—December 31, 2013

Column A	Column B	Column C		Column D		Column E
		Additions				
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2015						
Allowance for Doubtful Accounts	$ 52	$ 101	$ —	$ 86	(A)	$ 67
Materials and Supplies Valuation Reserve	15	2	—	6	(B)	11
2014						
Allowance for Doubtful Accounts	$ 56	$ 86	$ —	$ 90	(A)	$ 52
Materials and Supplies Valuation Reserve	8	9	—	2	(B)	15
2013						
Allowance for Doubtful Accounts	$ 56	$ 90	$ —	$ 90	(A)	$ 56
Materials and Supplies Valuation Reserve	22	2	—	16	(B)	8

(A) Accounts Receivable written off.

(B) Reduced reserve to appropriate level and to remove obsolete inventory.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2015—December 31, 2013

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2015						
Allowance for Doubtful Accounts	$ 52	$ 101	$ —	$ 86	(A)	$ 67
Materials and Supplies Valuation Reserve	2	—	—	1	(B)	1
2014						
Allowance for Doubtful Accounts	$ 56	$ 86	$ —	$ 90	(A)	$ 52
Materials and Supplies Valuation Reserve	—	2	—	—		2
2013						
Allowance for Doubtful Accounts	$ 56	$ 90	$ —	$ 90	(A)	$ 56

(A) Accounts Receivable written off.

(B) Reduced reserve to appropriate level and to remove obsolete inventory.

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PSEG POWER LLC

Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2015—December 31, 2013

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2015						
Materials and Supplies Valuation Reserve	$ 13	$ 2	$ —	$ 5	(A)	$ 10
2014						
Materials and Supplies Valuation Reserve	$ 8	$ 7	$ —	$ 2	(A)	$ 13
2013						
Materials and Supplies Valuation Reserve	$ 22	$ 2	$ —	$ 16	(A)	$ 8

(A) Reduced reserve to appropriate level and to remove obsolete inventory.

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Term	Phrase/Description
ASC	Accounting Standards Codification FASB's official source of authoritative, nongovernmental U.S. GAAP
Base load	Minimum amount of electric power delivered or required over a given period of time at a constant rate, this is the level of demand that is seen as a minimum during a 24-hour day
BGS	Basic Generation Service PSE&G is required to provide BGS for all customers in New Jersey who are not supplied by a third party supplier.
BGS-RSCP	Basic Generation Service-Residential Small Commercial Product Seasonally adjusted fixed prices charged for a three-year term for electric supply service to smaller industrial and commercial customers and residential customers who are not supplied by a TPS
BGSS	Basic Gas Supply Service Mechanism approved by the BPU for NJ utilities to recover all commodity costs related to supplying gas to residential customers
BPU	New Jersey Board of Public Utilities Agency responsible for regulating public utilities doing business in New Jersey
Capacity	Amount of electricity that can be produced by a specific generating facility
CAA	Clean Air Act
Combined Cycle	A method of generation whereby electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity
Congestion	Condition when the available capacity of a transmission line is being closely approached (or exceeded) by the electric power trying to go through it; at such times, alternative power line pathways (or local generators near the load) must be used instead
Distribution	The delivery of electricity to the retail customer's home, business or industrial facility through low voltage distribution lines
EDC	Electric Distribution Company A company that owns the power lines and equipment necessary to deliver purchased electricity to the end user
Energy Holdings	PSEG Energy Holdings L.L.C.
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board A private, not-for-profit organization whose primary purpose, as designated by the SEC, is to develop accounting standards for public companies in the U.S.
FERC	U.S. Federal Energy Regulatory Commission
Forward contracts	A customized, non-exchange traded contract in which the buyer is obligated to deliver a specified amount of a commodity with a predetermined price formula on a specified future date, at which time payment is due in full
GAAP	Generally Accepted Accounting Principles Standard framework of guidelines issued by the FASB for financial accounting used in the U.S.
GHG	Greenhouse gas emissions (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon) that trap the heat of the sun in the Earth's atmosphere, increasing the mean global surface temperature of the earth

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Term	Phrase/Description
Hedging	Entering into a contract or transaction designed to reduce exposure to various risks, such as changes in market prices
Hope Creek	Hope Creek Nuclear Generating Station
ISO	Independent System Operator An independent, regulated entity established to manage a regional electric transmission system in a non-discriminatory manner and to help ensure the safety and reliability of the bulk of the power system
ITC	Investment Tax Credit A credit against income taxes, usually computed as a percent of the cost of investment in certain types of assets
Lifeline Program	A New Jersey social program for utility assistance that offers up to $225 per year to persons who meet the eligibility requirements
Load	Amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of consumers.
MBR	Market Based Rates Electric service prices determined in an open market system of supply and demand under which the price is set solely by agreement as to what a buyer will pay and a seller will accept
MGP	Manufactured Gas Plant
NDT	Nuclear Decommissioning Trust
ISO-NE	New England Power Pool An ISO comprised of an alliance of approximately 100 utility companies who manage and direct all major energy production and transmission in the New England states
NJDEP	New Jersey Department of Environmental Protection
NRC	U.S. Nuclear Regulatory Commission
NUG	Non-Utility Generation Power produced by independent power producers, exempt wholesale generators and other companies that have been exempted from traditional utility regulation
OPEB	Other Postretirement Benefits Benefits other than pensions payable to former employees
Outage	The period during which a generating unit, transmission line, or other facility is out of service due to scheduled (planned) or unscheduled maintenance
Peach Bottom	Peach Bottom Atomic Power Station
PJM	PJM Interconnection, L.L.C. A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 northeastern states and the District of Columbia
Power	PSEG Power LLC
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies
PRP	Potentially Responsible Parties
PSE&G	Public Service Electric and Gas Company
PSEG	Public Service Enterprise Group Incorporated

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Term	Phrase/Description
Renewable Energy	Energy derived from resources that are regenerative or that cannot be depleted (i.e. moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy)
Regulatory Asset	Costs deferred by a regulated utility company in accordance with Accounting Standard Codification Topic 980: Regulated operations (ASC 980)
Regulatory Liability	Costs recognized by a regulated utility company in accordance with ASC 980
RGGI	Regional Greenhouse Gas Initiative The first mandatory, market-based effort in the U. S. to reduce greenhouse gas emissions; states will sell emission allowances through auctions and invest proceeds in consumer benefits: energy efficiency, renewable energy, and other clean energy technologies
RPM	Reliability Pricing Model (PJM market) A process for pricing generation capacity based on overall system reliability requirements; using multi-year forward auctions, participants could bid capacity in the form of generation, demand response, or transmission to meet reliability needs by location and/or an ISO market
Salem	Salem Nuclear Generating Station
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
Services	PSEG Services Corporation
Spill Act	New Jersey Spill Compensation and Control Act
Transmission	The high-voltage wires and networks that move electricity through states and regions in large quantities - from power plants where it is produced, to the distribution networks that deliver it to homes and businesses

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

By: /s/ RALPH IZZO
Ralph Izzo
Chairman of the Board, President and Chief Executive Officer

Date: February 25, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2016
/s/ DANIEL J. CREGG **Daniel J. Cregg**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2016
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 25, 2016
/s/ WILLIE A. DEESE **Willie A. Deese**	Director	February 25, 2016
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper, Jr.**	Director	February 25, 2016
/s/ WILLIAM V. HICKEY **William V. Hickey**	Director	February 25, 2016
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 25, 2016
/s/ DAVID LILLEY **David Lilley**	Director	February 25, 2016
/s/ THOMAS A. RENYI **Thomas A. Renyi**	Director	February 25, 2016
/s/ HAK CHEOL SHIN **Hak Cheol Shin**	Director	February 25, 2016
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 25, 2016
/s/ SUSAN TOMASKY **Susan Tomasky**	Director	February 25, 2016
/s/ ALFRED W. ZOLLAR	Director	February 25, 2016

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By: /s/ RALPH LAROSSA
Ralph LaRossa
President and Chief Operating Officer

Date: February 25, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2016
/s/ DANIEL J. CREGG **Daniel J. Cregg**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2016
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 25, 2016
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper Jr.**	Director	February 25, 2016
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 25, 2016
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 25, 2016

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC

By: /s/ WILLIAM LEVIS
William Levis
President and
Chief Operating Officer

Date: February 25, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2016
/s/ DANIEL J. CREGG **Daniel J. Cregg**	Executive Vice President and Chief Financial Officer and Director (Principal Financial Officer)	February 25, 2016
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 25, 2016
/s/ DEREK M. DIRISIO **Derek M. DiRisio**	Director	February 25, 2016
/s/ WILLIAM LEVIS **William Levis**	Director	February 25, 2016
/s/ TAMARA L. LINDE **Tamara L. Linde**	Director	February 25, 2016
/s/ MARGARET M. PEGO **Margaret M. Pego**	Director	February 25, 2016

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EXHIBIT INDEX

The following documents are filed as a part of this report:

a. PSEG:	
Exhibit 10a(10)	Amended Key Executive Severance Plan, effective December 15, 2015
Exhibit 10a(20)	Clawback Practice, effective December 15, 2015
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 21:	Subsidiaries of the Registrant
Exhibit 23:	Consent of Independent Registered Public Accounting Firm
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31a:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32a:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document
b. Power:	
Exhibit 10a(8)	Amended Key Executive Severance Plan, effective December 15, 2015
Exhibit 10a(15)	Clawback Practice, effective December 15, 2015
Exhibit 12a:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 23a:	Consent of Independent Registered Public Accounting Firm
Exhibit 31b:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31c:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32b:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document
c. PSE&G:	
Exhibit 10a(9)	Amended Key Executive Severance Plan, effective December 15, 2015
Exhibit 10a(18)	Clawback Practice, effective December 15, 2015
Exhibit 12b:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
Exhibit 23b:	Consent of Independent Registered Public Accounting Firm
Exhibit 31d:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31e:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32d:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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Exhibit 10a(10)

KEY EXECUTIVE SEVERANCE PLAN OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Amended effective December 15, 2015

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ARTICLE I

PURPOSE OF THE PLAN

1.1 Purpose. The Key Executive Severance Plan of Public Service Enterprise Group Incorporated ("Plan") is maintained by the Company to provide severance benefits to certain key executive-level employees of the Company and its affiliates whose employment is terminated under the circumstances described herein. The Plan was amended and restated effective December 17, 2012.

The Plan was amended effective January 1, 2014 to provide that (i) for Eligible Employees who become Schedule B Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to two times Annual Base Salary and Target Bonus, and (ii) for Eligible Employees who become Schedule A Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to 1.5 times Annual Base Salary and Target Bonus. The Plan was further amended to provide that the for purposes of determining the nonqualified plan change in control benefit under Section 5.5(a) of the Plan, with respect to Eligible Employees who become Schedule A or Schedule B Participants after December 31, 2013, their employment shall be assumed to have continued for 1.5 or two additional years (for Schedule A Participants and Schedule B Participants, respectively). Finally, the Plan was amended to update the Schedule A Participant list.

The Plan was amended effective June 16, 2014 to (i) add a new class of eligible Participants, Schedule C Participants, (ii) to provide that there will be no additions to Schedule B Participants, (iii) to provide that other than a current Schedule B Participant, an Eligible Employee newly hired or promoted into a position reflected on Schedule B as of June 16, 2014, shall become a Schedule A Participant, and (iv) to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

The Plan was amended effective July 14, 2014 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan was amended effective February 17, 2015 to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

The Plan was amended effective November 18, 2015 to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list, and to include the language to comply with the Securities and Exchange Commission's whistleblower protections.

The Plan is being amended effective December 15, 2015 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan is intended to comply in operation and form with Section 409A to the Internal Revenue Code of 1986, as amended ("Code"). The timing and form of payment of benefits provided under the Plan will be deemed to be automatically modified, and a Participant's rights

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under the Plan will be limited so as to conform to any requirements under Section 409A of the Code.

ARTICLE II

DEFINITIONS

2.1 "Accrued Obligation" shall have the meaning set forth in Section 4.1 or 5.1 of the Plan.

2.2 "Affiliate" means any corporation, trade or business if it or the Company are members of a controlled group of corporations, are under common control or are members of an affiliated service group, within the meanings of Sections 414(b), 414(c) and 414(m), respectively, of the Code. The term "Affiliate" shall also include any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code.

2.3 "Annual Base Salary" means the annual rate of base salary payable to a Participant for services performed for an Employer, as in effect immediately prior to the Participant's Date of Termination.

2.4 "Board" means the board of directors of the Company.

2.5 "Cause" means:

(a) For purposes of Article IV:

(i) Misconduct, gross negligence, theft, or fraud against the Company;

(ii) For "Performance Reasons," as defined in Section 2.21 of the Plan;

(iii) Violation of the Standards of Integrity or other Company policy;

(iv) Insubordination;

(v) One or more significant acts of dishonesty;

(vi) Any act that is likely to have the effect of injuring the reputation, business, or business relationship of, the Company, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries;

(vii) Violation of any fiduciary duty;

(viii) Breach of any duty of loyalty;

(ix) Any breach of the restrictive covenants contained in Exhibit I below;

(x) One or more acts of moral turpitude that constitute a violation of applicable law (included but not limited to a felony); or

(xi) Conviction of a felony or plea of *nolo contendere* to a felony charge.

(b) For purposes of Article V:

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(i) The willful and continued failure to substantially perform his employment duties;

(ii) The willful engaging in gross misconduct that is materially and demonstrably injurious to the Employer;

(iii) The willful violation of the Company's Standards of Integrity or other applicable corporate code of conduct, or

(iv) The conviction of a felony or a plea of *nolo contetendere* to a felony charge.

No act or failure to act on the part of the Participant shall be considered "willful" unless it is done, or omitted to be done, by the Participant in bad faith or without reasonable belief that the Participant's action or omission was in the best interests of the Employer. Any act or failure to act that is based upon authority given pursuant to a resolution duly adopted by the Board, or the advice of counsel for the Employer, shall be conclusively presumed to be done, or omitted to be done, by the Participant in good faith and in the best interests of the Employer.

Notwithstanding the forgoing, for purposes of the Plan, the termination of a Participant's employment with an Employer shall not be deemed to be for Cause unless such termination is effected in accordance with the following procedures. The Employer shall give the Participant written notice ("Notice of Termination for Cause") of its intention to terminate the Participant's employment for Cause, setting forth in reasonable detail the specific conduct of the Participant that it considers to constitute Cause. Such notice shall be given no later than 60 days after the act or failure (or the last in a series of acts or failures) that the Employer alleges to constitute Cause. The Participant shall have 30 days after receiving the Notice of Termination for Cause in which to cure such act or failure, to the extent such cure is possible. In the case of a termination under clause (a), (b) or (c) above, if the Participant fails to cure such act or failure to the reasonable satisfaction of the Employer, the Employer shall give the Participant a second written notice stating that in the good faith opinion of the Employer, the Participant is guilty of the conduct described in the Notice of Termination for Cause and that such conduct constitutes Cause under the Plan.

2.6 "Change in Control" means the occurrence of any of the following events:

(a) Any "person" (within the meaning of Section 13(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") is or becomes the beneficial owner within the meaning of Rule 13d-3 under the Exchange Act (a "Beneficial Owner"), directly or indirectly, of securities of the Company (not including in the securities beneficially owned by such person any securities acquired directly from the Company or its Affiliates) representing 25% or more of the combined voting power of the Company's then outstanding securities, excluding any person who becomes such a Beneficial Owner in connection with a transaction described in clause (i) of paragraph (c) below; or

(b) The following individuals cease for any reason to constitute a majority of the number of directors of the Company then serving: individuals who, on the Effective Date, constitute the Board and any new director (other than a director

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whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's stockholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on the Effective Date or whose appointment, election or nomination for election was previously so approved or recommended; or

(c) There is consummated a merger or consolidation of the Company or any direct or indirect wholly-owned subsidiary of the Company with any other corporation, other than (i) a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of the Company or of its Affiliates, at least 75% of the combined voting power of the securities of the Company or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (ii) a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the Beneficial Owner, directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company's then outstanding securities; or

(d) The shareholders of the Company approve a plan of complete liquidation or dissolution of the Company or there is consummated an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 75% of the combined voting power of the voting securities of which are owned by stockholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale.

Notwithstanding the foregoing, a "Change in Control" shall not be deemed to have occurred by virtue of the consummation of any transaction or series of integrated transactions immediately following which the record holders of the common stock of the Company immediately prior to such transaction or series of transactions continue to have substantially the same proportionate ownership in an entity which owns all or substantially all of the assets of the Company immediately following such transaction or series of transactions.

2.7 "Code" means the Internal Revenue Code of 1986, as amended, and the regulations promulgated thereunder.

2.8 "Committee" means the Organization and Compensation Committee of the Board or any successor of such Committee.

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2.9 "Company" means Public Service Enterprise Group Incorporated and any successors thereto.

2.10 "Confidential Information" means all trade secrets, proprietary and confidential business information belonging to, used by, or in the possession of the Company or any of its Affiliates, including but not limited to information, knowledge or data related to business strategies, plans and financial information, mergers, acquisitions or consolidations, purchase or sale of property, leasing, pricing, sales programs or tactics, actual or past sellers, purchasers, lessees, lessors or customers, those with whom the Company or its Affiliates has begun negotiations for new business, costs, employee compensation, marketing and development plans, inventions and technology, whether such confidential information, knowledge or data is oral, written or electronically recorded or stored, except information in the public domain, information known by the Participant prior to employment with an Employer, and information received by the Participant from sources other than the Company or its Affiliates, without obligation of confidentiality.

2.11 "Date of Termination" means the date of a Participant's death, Disability Effective Date, or the date on which the termination of the Participant's employment by an Employer for Cause or without Cause or by the Participant for Good Reason or without Good Reason, including Retirement, is effective, as the case may be, provided that the termination constitutes a Separation from Service.

2.12 "Disability" means that the Participant (a) is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, or (b) is, by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, receiving income replacement benefits for a period of not less than three months under an accident or health plan covering employees of an Employer.

2.13 "Disability Effective Date" means the 30th day after the Participant's receipt of written notice of the Employer's intention to terminate the Participant's employment on account of Disability, provided that, within the 30 days after the Participant's receipt of such notice, the Participant shall not have returned to full-time performance of his employment duties.

2.14 "Eligible Employee" means an individual who is designated as such in accordance with Section 3.1.

2.15 "Effective Date" of the amendment and restatement is December 15, 2015.

2.16 "Employer" means the Company and each Affiliate, and any successors thereto.

2.17 "Good Reason" means:

(a) Any material reduction in the Participant's Annual Base Salary, Target Bonus or Target Long-Term Incentive, other than reductions pursuant to a broad-based compensation reduction program or policy affecting the Participant and all similarly situated employees of the Employer;

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(b) Any material adverse change in the Participant's title, authority, duties, or responsibilities or the assignment to the Participant of any duties or responsibilities inconsistent in any respect with those customarily associated with the position of the Participant immediately prior to the Change in Control;

(c) The failure of any successor to the Company to assume this Plan in accordance with Section 11.5(b);

(d) Where the only comparable position offered to the Participant within the Employer following a Change in Control would otherwise meet the requirements of subsections (a) and (b) of this Section 2.17 of the Plan, but would require the Participant to increase his or her one-way commuting distance from his or her principal residence by more than 50 miles; or

(e) Any other material breach of the terms of the Plan by the Company that either is not taken in good faith or, even if taken in good faith, is not remedied by the Company promptly after receipt of notice thereof from the Participant.

Notwithstanding the forgoing, for purposes of the Plan, the termination of a Participant's employment with an Employer shall not be deemed to be for Good Reason unless such termination is effected in accordance with the following procedures. The Participant shall give his Employer a written notice ("Notice of Termination for Good Reason") of the termination, setting forth in reasonable detail the specific acts or omissions of the Employer that constitute Good Reason and the specific provision(s) of the Plan on which the Participant relies. Unless the Committee determines otherwise, a Notice of Termination for Good Reason by the Participant must be made within 60 days after the Participant first has actual knowledge of the act or omission (or the last in a series of acts or omissions) that the Participant alleges to constitute Good Reason, and the Employer shall have 30 days from the receipt of such Notice of Termination for Good Reason to cure the conduct cited therein. A termination of employment by the Participant for Good Reason shall be effective on the final day of such 30-day cure period unless prior to such time the Employer has cured the specific conduct asserted by the Participant to constitute Good Reason to the reasonable satisfaction of the Participant.

For purposes of the Plan, a Participant's determination that an act or failure to act constitutes Good Reason shall be presumed to be valid unless such determination is decided to be unreasonable by the Committee or its delegate pursuant to Article IX.

2.18 "Nonqualified Plan" the Retirement Income Reinstatement Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated.

2.19 "Other Benefits" shall have the meaning set forth in Articles IV and V, as applicable.

2.20 "Participant" means an Eligible Employee who has satisfied the conditions for participation in the Plan, as set out in Section 3.2, and is listed on either Schedule A, Schedule B or Schedule C hereto, as the same may be amended from time to time.

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2.21 "Performance Reasons" means the Participant's failure meet the expectations established for his function in the Company as: (a) communicated to him by his manager during any performance review, or (b) may be communicated to him otherwise by his manager from time to time either orally or in writing.

2.22 "Plan" means this Key Executive Severance Plan of Public Service Enterprise Group Incorporated, as set forth herein and as may be amended, modified or supplemented from time to time.

2.23 "Prior Equity Awards" shall mean outstanding stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares and performance shares units.

2.24 "Retirement" means a Separation from Service after the Participant has satisfied the eligibility requirements for early or normal retirement under the terms of the Retirement Plan in which the Participant participates. Notwithstanding the foregoing, for the purposes of determining benefit entitlements under Article V of the Plan, Retirement shall not include forced retirements or any termination by an Employer without Cause or voluntary termination by the Participant for Good Reason that occurs on a date on which the Participant is Retirement eligible.

2.25 "Retirement Plan" the retirement plan in which the Participant participates either the Pension Plan of Public Service Enterprise Group Incorporated or the Cash Balance Pension Plan of Public Service Enterprise Group Incorporated.

2.26 "Schedule A Participant" shall mean a Participant listed on Schedule A hereto.

2.27 "Schedule B Participant" shall mean a Participant listed on Schedule B hereto.

2.28 "Schedule C Participant" shall mean a Participant listed on Schedule C hereto.

2.29 "Separation from Service" shall be deemed to have occurred if a Participant and the Company or any Affiliate reasonably anticipates, based on the facts and circumstances, that either:

(a) The Participant will not provide any additional services for the Company or an Affiliate after a certain date; or

(b) The level of bona fide services performed by the Participant after a certain date will permanently decrease to no more than 50 percent of the average level of bona fide services performed by the Participant over the immediately preceding 36 months.

(c) If a Participant is absent from employment due to military leave, sick leave or any other bona fide leave of absence authorized by the Company or an Affiliate and there is a reasonable expectation that the Participant will return to perform services for the Company or an Affiliate, a Separation from Service will not occur until the later of: (i) the first date immediately following the date that is six months after the date that the Participant was first absent from employment; or (ii) the date the Participant no longer retains a right to reemployment, to the extent the

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Participant retains a right to reemployment with the Company or any Affiliates under applicable law or by contract. If a Participant fails to return to work upon the expiration of any military leave, sick leave or other bona fide leave of absence where such leave is for less than six months, the Separation from Service shall occur as of the date of the expiration of such leave, unless a greater period is provided for under applicable law.

2.30 "Specified Employee" shall mean any individual who is a key employee (as defined in Section 416(i) of the Code without regard to Section 416(i)(5)) of the Code) of the Company at any time during the 12-month period ending on each December 31 (the "identification date"). If an individual is a key employee as of an identification date, the individual shall be treated as a Specified Employee for the 12-month period beginning on the April 1 following the identification date. Notwithstanding the foregoing, an individual shall not be treated as a Specified Employee unless any stock of the Company or an Affiliate is publicly traded on an established securities market or otherwise.

2.31 "Target Bonus" means the Participant's target annual bonus, if any, under the applicable annual incentive compensation plan of the Company for the fiscal year in which the Date of Termination occurs.

2.32 "Target Long-Term Incentive" means the Participant's target long-term incentive award, if any, under the applicable long-term incentive compensation plan of the Company.

ARTICLE III

ELIGIBILITY AND PARTICIPATION

3.1 Eligible Employees. Eligibility to participate in the Plan shall be limited to certain key executives of an Employer who (a) are not parties to individual employment or change in control agreements that provide for severance benefits, and (b) are designated, by duly adopted resolution of the Committee, as Eligible Employees.

3.2 Participation. As a condition to becoming a Participant and being entitled to the benefits and protections provided under the Plan, each Eligible Employee must execute and deliver to the Company, within 30 days after the later of the Effective Date and the date such individual is designated by the Committee as an Eligible Employee, a written agreement in the form attached hereto as Exhibit I (or in such other form as may be satisfactory to the Company) to be bound by the restrictive covenants set forth in Article VII. Schedules A, B and C hereto list the Eligible Employees who have satisfied the conditions for Plan participation and the date as of which each such Eligible Employee became a Participant. The Committee shall cause Schedules A, B and C to be updated from time to time to reflect the Participants who are currently participating in the Plan. An employee who becomes an Eligible Employee on or after January 1, 2014 shall become a Schedule C Participant, provided, however, that an employee who is hired or promoted to a position reflected on Schedule B as of the Effective Date and who is otherwise an Eligible Employee shall become a Schedule A Participant.

3.3 Release of Claims. Notwithstanding anything in the Plan to the contrary, payment of any benefits under the Plan is expressly contingent upon the Participant's execution and

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delivery to the Company, within 30 days after the Participant's Date of Termination, of a written agreement provided by the Company, wherein the Participant releases and discharges the Company and each of its Affiliates of any and all claims against the Company and its Affiliates related in any way to the Participant's employment with an Employer and the termination of such employment.

3.4 Committee Discretion. The Committee shall have the sole discretion to determine eligibility for benefits under the Plan.

ARTICLE IV

SEVERANCE BENEFITS IN GENERAL

4.1 Termination by Employer Other than for Cause or by the Participant for Good Reason. Subject to Section 3.3 and Article VI of the Plan, if a Participant's employment is involuntarily terminated by an Employer for reasons other than Cause or a Participant terminates employment for Good Reason, the Participant shall be entitled to the benefits described in Sections 4.2 through 4.9 of the Plan. For purposes of clarity, subject to Section 3.3 and Article VI of the Plan, Participant shall be entitled to the benefits described in Sections 4.2 through 4.9 of the Plan if a Participant's employment is involuntarily terminated by an Employer due to a reduction in force or a reorganization of the Employer (as determined by the Committee), or a Participant experiences a cessation of employment in connection with a reduction in force or Employer reorganization (as determined by the Committee) where the only position offered to the Participant within the Company and Affiliates would require the Participant to accept a reduction in his or her annual rate of base salary of more than 20% below the annual rate of base salary of the Participant's position immediately prior to such action.

For the avoidance of any doubt, a Participant shall not be entitled to benefits under the Plan if (i) his employment terminates as a result of death, Disability, the Participant voluntarily terminates employment, except for Good Reason, or (ii) the Participant's cessation of employment is in connection with the sale of the Participant's Employer, line or unit of business of the Employer within which the Participant's position is located, business function of the Employer within which the Participant's position is located, or the assets related to the Employer, line or unit or business, or business function within which the Participant's position is located, and the Participant accepts employment with the purchaser within 90 days of the closing of the transaction in a position that has an annual rate of base salary that is at least 80 percent of the Participant's annual rate of base salary immediately prior to the closing of the sale).

4.2 Cash payment. The Company shall pay to the Participant a lump sum, in cash, the sum of (a) and (b):

(a) The Participant's base salary and accrued vacation pay through the Date of Termination to the extent not theretofore paid (hereinafter referred to as the "Accrued Obligations"); and

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(b) An amount equal to the product of 1.0 times (0.5 times if the Participant were employed less than one year) the sum of the Participant's Annual Base Salary and Target Bonus.

4.3 Long-Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

4.4 Annual Incentive Awards. The Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of calendar days of employment in the calendar year in which the Participant's termination occurs through the Participant's Date of Termination. For purposes of this Section 4.4, calendar year shall mean 365 days.

Annual incentive awards with respect to the calendar year in which a Participant's Date of Termination occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

4.5 Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the Participant's Date of Termination or such earlier date designated by the Participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

4.6 Educational Assistance. Educational assistance shall be provided in accordance with the Employer's tuition program.

4.7 Health Care Benefits.

(a) Retiree Health Care Coverage**.** A Participant who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(i) The Participant has attained age 50 and completed ten or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80; or

(ii) The Participant has attained age 49 and completed 20 or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Participant's Termination Date. The Participant shall be charged the full cost of retiree coverage under these plans.

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(b) COBRA Continuation Coverage**.** Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this Section 4.7 of the Plan shall be entitled, pursuant to any continuation coverage rights under the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended ("COBRA"), to continue individual and dependent coverage under the Company's group health care plans following the Participant's Date of Termination. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the one-year period following the Participant's Date of Termination, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of the cost of coverage) during the remainder of the COBRA coverage period, if any, and the full expense of dental and (if applicable) vision and hearing coverage (102 percent of the cost of coverage) during the entire COBRA coverage period.

4.8 Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled, for the one-year period following the Participant's Date of Termination to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination.

4.9 Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided hereunder or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time. (The amounts and benefits payable to the Participant pursuant to Sections 4.3 through 4.9 of the Plan shall be hereinafter referred to as the "Other Benefits").

4.10 Termination where a Participant experiences a cessation of employment in connection with a reduction in force or Employer reorganization where the only position offered to the Participant within the Company and Affiliates would require the Participant to increase his or her one-way commuting distance by more than 50 miles. Subject to Section 3.3 and Article V, if a Participant experiences a cessation of employment in connection with a reduction in force or an Employer reorganization (as determined by the Committee) where the only position offered to the Participant within the Company and Affiliates would require the Participant to increase his or her one-way commuting distance by more than 50 miles:

(a) Severance Pay. The Participant shall receive a lump sum cash payment in accordance with Section 6.1 of the Plan, based upon the amount of the Participant's base salary, the number of Years of Service completed as of the Participant's Termination Date, as follows:

(i) **Less than Thirteen Years of Service:** If, as of the Participant's Date of Termination, he has completed fewer than thirteen Years of Service, the amount of severance pay shall equal 26 weeks of base salary.

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(ii) **Thirteen or More Years of Service:** If, as of the Participant's Date of Termination, he has completed thirteen or more Years of Service, the amount of severance pay shall equal two weeks of base salary for each Year of Service, up to a maximum of 52 weeks of base salary.

(b) Annual Incentive Awards. A Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of days of employment in the calendar year in which the participant's Termination of Employment occurs through the employee's Termination Date. Annual incentive awards with respect to the calendar year in which a Participant's Termination Date occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

(c) Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the participant's Termination Date or such earlier date designated by the participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

(d) Educational Assistance. Education assistance shall be provided in accordance with the Employer's tuition program.

(e) Health Care Benefits.

(i) Retiree Health Care Coverage**.** An Eligible Employee who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(A) The Participant has attained age 50 and completed ten or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80; or

(B) The Participant has attained age 49 and completed 20 or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Participant's Date of Date. The Participant shall be charged the full cost of retiree coverage under these plans.

(ii) COBRA Continuation Coverage. Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this subsection (i) shall be entitled, pursuant to any continuation coverage

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rights under COBRA to continue individual and dependent coverage under the Company's group health care plans following the Participant's Termination Date. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of the cost of coverage) during the remainder of the COBRA coverage period, if any, and the full expense of dental and (if applicable) vision and hearing coverage (102 percent of the cost of coverage) during the entire COBRA coverage period.

(f) Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination Date.

(g) Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided under the Plan or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time.

ARTICLE V

SEVERANCE BENEFITS AFTER A CHANGE IN CONTROL

5 . 1 Termination By Employer Other Than For Cause or By Participant For Good Reason (other than Good Reason as described in Subsection 2.17(d)) Within Two Years After a Change in Control . Subject to Section 3.3 and Article VI of the Plan, if, within two years following the occurrence of a Change in Control, either (a) an Employer shall terminate a Participant's employment other than for Cause or Disability, or (b) a Participant shall voluntarily terminate his employment for Good Reason pursuant to Subsections 2.17 (a), (b), (c) or (e), the Participant shall be entitled to benefits in Sections 5.2 through 5.8 of the Plan. For the avoidance of any doubt, a Participant shall not be entitled to benefits under the Plan if his employment terminates as a result of death, Disability or the Participant voluntarily terminates employment, except for Good Reason, except as otherwise provided under the Plan.

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5.2 Cash Payment. The Company shall pay to the Participant, in a lump sum in cash, the aggregate of the amounts in (a) and (b) below:

(a) the sum of:

(i) The Participant's base salary and accrued through the Date of Termination; and

(ii) The product of (x) the Participant's Target Bonus and (y) a fraction, the numerator of which is the number of days in the current calendar year through the Date of Termination, and the denominator of which is 365;

in each case to the extent not theretofore paid (the sum of the amounts described in clauses (i) and (ii) shall be hereinafter referred to as the "Accrued Obligations"); and

(b) Either (i), (ii) or (iii):

(i) In the case of a Schedule A Participant, the amount equal to the product of two times the sum of the Schedule A Participant's Annual Base Salary and Target Bonus;

(ii) In the case of a Schedule B Participant, the amount equal to the product of three times the sum of the Schedule B Participant's Annual Base Salary and Target Bonus; or

(iii) In the case of a Schedule C Participant, the amount equal to the product of one and half times the sum of the Schedule C Participant's Annual Base Salary and Target Bonus.

5.3 Long Term Incentive Awards . The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.4 Health Care and Other Welfare Benefits. The Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for 18 months after the Date of Termination provided that the Participant makes an election to continue such coverage in the Company's medical and dental employee benefit plans under COBRA, subject to the requirements and limitations thereof. Unless otherwise limited by applicable law, thereafter, the Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for an additional period of six months, in the case of a Schedule A Participant, or 18 months, in the case of a Schedule B Participant (for a Schedule C Participant, no additional period beyond the initial 18 months); provided however, that if the Participant becomes re-employed with another employer and is eligible to receive medical or dental benefits under another employer provided plan, the medical and dental benefits provided by the Company under this Plan shall be secondary to those provided under such other plan during the applicable period of eligibility.

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Unless otherwise limited by applicable law, for two years after the Date of Termination in the case of a Schedule A Participant, three years after the Date of Termination in the case of a Schedule B Participant, or in the case of a Schedule C Participant, eighteen months after the Date of Termination (or for any Participant such longer period as may be provided by the terms of the appropriate plan, program, practice or policy), the Company shall continue benefits (other than medical and dental benefits) to the Participant and/or the Participant's family at least equal to those which would have been provided to them in accordance with the welfare plans, programs, practices and policies maintained by the Company if the Participant's employment had not been terminated or, if more favorable to the Participant, as in effect generally at any time thereafter with respect to other peer executives of the Employer and their families.

Unless otherwise limited by applicable law, the Participant's eligibility (but not the time of commencement of such benefits) for retiree benefits pursuant to the welfare plans, programs, practices and policies maintained by the Company shall be determined as if the Participant had (A) remained employed until two years (in the case of a Schedule A Participant), three years (in the case of a Schedule B Participant), or eighteen months (in the case of a Schedule C Participant) after the Date of Termination and (B) retired on the last day of such period.

5.5 Nonqualified Pension Benefit. The Participant shall be paid, in a lump sum payment in cash, an amount equal to the excess of:

(a) The actuarial equivalent of the benefit under the Company's applicable Retirement Plan (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the Effective Date), any benefit under the Nonqualified Plan and, to the extent applicable, any other defined benefit retirement arrangement between the Participant and the Company ("Other Pension Benefits") which the Participant would receive if the Participant's employment continued for two, three or one and half additional years (for Schedule A Participants, Schedule B and Schedule C Participants, respectively) beyond the Date of Termination and, assuming that the Participant's compensation for such deemed additional period was the Participant's Annual Base Salary as in effect immediately prior to the Date of Termination and assuming a bonus in each year during such deemed additional period equal to the Target Bonus, over

(b) The actuarial equivalent of the Participant's actual benefit (paid or payable), if any, under the Retirement Plan, the Nonqualified Plan and Other Pension Benefits as of the Date of Termination (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the effective date of the Change in Control).

5.6 Deferred Compensation. Any compensation previously deferred (other than pursuant to a tax-qualified plan) by or on behalf of the Participant (together with any accrued interest or earnings thereon), whether or not then vested, shall become vested on the Date of Termination and shall be paid in accordance with the terms of the applicable deferred

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compensation plan, policy or practice under which it was deferred to the extent permitted by Section 409A of the Code.

5.7 Outplacement Services. The Company shall, at its sole expense as incurred, provide the Participant with outplacement services suitable to the Participant's position for a period not to exceed one year following the Date of Termination with a nationally recognized outplacement firm.

5.8 Other Benefits. To the extent not theretofore paid or provided, the Company shall pay or provide to the Participant any other amounts or benefits required to be paid or provided or which the Participant is entitled to receive under any plan, program, policy, practice, contract or agreement of the Company (or other Employer), including earned but unpaid stock and similar compensation, but excluding medical or dental benefits if the Participant is eligible for such benefits to be provided by a subsequent employer, and benefits payable under any severance plan or policy (such other amounts and benefits that are payable to the Participant shall be hereinafter referred to as the "Other Benefits").

5.9 Termination By Participant For Good Reason as described in Subsection 2.17(d) Within Two Years After a Change in Control. Subject to Section 3.3 and Article V of the Plan, if, within two years following the occurrence of a Change in Control, a Participant shall voluntarily terminate his or her employment for Good Reason as described in Subsection 2.17(d):

(a) Severance Pay. The Participant shall receive a lump sum payment in accordance with Section 6.1 of the Plan based upon the amount of the Participant's base salary, the number of Years of Service completed as of the Participant's Termination Date, as indicated below:

(i) Less than Thirteen Years of Service: If, as of the Participant's Termination Date he or she has completed fewer than thirteen Years of Service, the amount of severance pay shall equal 26 weeks of base salary.

(ii) Thirteen or More Years of Service: If, as of the Participant's Termination Date, he or she has completed thirteen or more Years of Service, the amount of severance pay shall equal two weeks of base salary for each Year of Service, up to a maximum of 52 weeks of base salary.

(b) Annual Incentive Awards. A Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of days of employment in the calendar year in which the participant's Termination of Employment occurs through the employee's Termination Date. Annual incentive awards with respect to the calendar year in which a Participant's Termination Date occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

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(c) Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the Participant's Date of Termination or such earlier date designated by the participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

(d) Educational Assistance. Education assistance shall be provided in accordance with the Employer's tuition program.

(e) Health Care Benefits.

(i) Retiree Health Care Coverage**.** An Eligible Employee who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination Date, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(A) The Participant has attained age 50 and completed ten or more Years of Service as of his or her Termination Date but the sum of the Participant's age and Years of Service is less than 80; or

(B) The Participant has attained age 49 and completed 20 or more Years of Service as of his or her Termination Date but the sum of the Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Participant's Termination Date. The Participant shall be charged the full cost of retiree coverage under these plans.

(ii) COBRA Continuation Coverage. Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this subsection (e) shall be entitled, pursuant to any continuation coverage rights under COBRA to continue individual and dependent coverage under the Company's group health care plans following the Participant's Termination Date. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of the cost of coverage) during the remainder of the COBRA coverage period, if any, and the full expense of dental and (if applicable) vision and hearing coverage (102 percent of the cost of coverage) during the entire COBRA coverage period.

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(f) Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled, during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination.

(g) Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided under the Plan or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time.

5.10 Termination By Employer For Cause or By Participant Other Than For Good Reason. If, at any time after a Change in Control, either (a) an Employer shall terminate a Participant's employment for Cause or (b) the Participant shall voluntarily terminate his employment other than for Good Reason, the Employer shall have no further payment obligations to the Participant other than for the Participant's base salary through the Date of Termination and any accrued but unpaid vacation pay. In such case, all such amounts shall be paid to the Participant in a lump sum in accordance with Section 6.1 of the Plan.

5.11 Death. If a Participant's employment terminates by reason of the Participant's death after a Change in Control, all Accrued Obligations as of the time of death shall be paid to the Participant's estate or beneficiary, as applicable, in a lump sum in cash in accordance with Section 6.1 of the Plan. The Participant's estate or beneficiary shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.12 Disability. If a Participant's employment is terminated by reason of Disability after a Change in Control, all Accrued Obligations shall be paid to the Participant in a lump sum in cash in accordance with Section 6.1 of the Plan. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.13 Retirement. If a Participant's employment terminates as a result of Retirement after a Change in Control, the Participant shall be paid the Accrued Obligations in a lump sum in cash in accordance with Section 6.1 of the Plan and the Participant shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

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ARTICLE VI

TIMING OF, LIMITATIONS ON AND ADJUSTMENTS TO PLAN PAYMENTS

6.1 Time of Payments. Payments under the Plan shall be made to the Participant as follows:

(a) With respect to benefits under Sections 4.2, 4.10(a), 5.2, 5.5, 5.9(a), 5.12 and 5.13 of the Plan, payment to a Participant who is not a Specified Employee shall be made within the 60-day period following the Participant's Date of Termination. With respect to benefits under Section 5.11 of the Plan, payment shall be made within the 60-day period following the Participant's date of the Participant's death. However, if the period to consider and revoke the written agreement required to receive the benefits described in Articles IV and V of the Plan (i.e., the waiver and release) spans two taxable years, in all events the payments will be made in second taxable year within 30 days following the later of the end of the first taxable year or the date the executed release is received by the Company.

(b) With respect to benefits under Sections 4.4, 4.10(b) and 5.9(b) of the Plan, payments shall be made to the Participants at the same time the payments are made to active employees.

(c) Notwithstanding anything to the contrary in the Plan, to the extent necessary to comply with Section 409A of the Code, payments to a Participant who is a Specified Employee shall be made within the 60-day period following the six-month anniversary of the Participant's Date of Termination (other than by reason of death).

(d) All payments under the Plan that are reimbursements of covered expenses incurred by the Participant shall be made within the taxable year in which the expense is incurred.

6.2 Payment Offsets. Notwithstanding anything in the Plan to the contrary, in the event a Participant is entitled to receive severance payments both under this Plan and under the terms of either (a) an individual change of control or employment agreement, (b) another severance pay plan or policy of an Employer or (c) any existing or future law or regulation, the benefits payable under this Plan shall be reduced by the amount of any severance benefits such Participant is entitled to receive under such individual agreement, plan, policy, law or regulation.

6.3 Cap on Excess Parachute Payments; Gross-Up Payments. Notwithstanding anything in the Plan to the contrary, if (a) a Participant is a "disqualified individual" (as defined in Section 280G(c) of the Code) and (b) the severance benefits provided under Articles IV or V, as applicable, together with any other payments the Participant has the right to receive from an Employer, would constitute a "parachute payment" (as defined in Section 280G(b) of the Code) ("Parachute Payments"), the following provisions shall apply:

(a) The severance benefits under Articles IV or V shall not exceed an amount which, together with any other Parachute Payments the Participant has a right to receive from the Employer, would be 2.99 times the Participant's "base amount" (as

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defined in Section 280G of the Code) so that no portion of the amounts received by the Participant shall be subject to the excise tax imposed under Section 4999 of the Code.

(b) The determination of whether any limitation on the severance benefits payable under Articles IV or V is necessary shall be made by the Company's independent auditor or such other certified public accounting firm as may be jointly designated by the Participant and the Company (the "Accounting Firm"), which shall provide detailed supporting calculations to the Participant and the Company. The determinations of the Accounting Firm shall be conclusive and binding on the Company and the Participant. All fees and expenses of the Accounting Firm shall be borne solely by the Company.

(c) If through error or otherwise, a Participant shall receive payments under the Plan, together with other Parachute Payments the Participant has the right to receive from an Employer, in excess of 2.99 times his base amount, the Participant shall immediately repay the excess to the Employer upon notification from the Employer that an overpayment has been made. If the Participant fails to repay the excess to the Employer within 10 business days of the date of the Employer's notification, the Participant will become liable to the Employer for an amount equal to two (2) times the excess amount.

6.4 Compliance with Section 409A of the Code. Notwithstanding anything in the Plan to the contrary, all Plan benefit obligations and payments are subject to Section 409A of the Code. To the extent required, the Company may modify the severance benefits payable hereunder to comply with Section 409A of the Code; provided, however, that the present value of the aggregate Plan benefits payable to a Participant after such modification shall not be less than the present value of the Plan benefits payable to the Participant prior to the modification.

6.5 Tax Withholding. Notwithstanding any other provision of this Plan, the Company may withhold from any amounts payable under this Plan such Federal, state, local, employment or foreign taxes as shall be required to be withheld pursuant to any applicable law or regulation.

ARTICLE VII

RESTRICTIVE COVENANTS

7.1 Confidentiality. As a condition to participation in the Plan, each Participant agrees to hold in a fiduciary capacity for the benefit of the Company and its Affiliates all Confidential Information which shall have been obtained by the Participant during the Participant's employment by the Employer; except, however, that this Section 7.1 shall not apply to Confidential Information that is or becomes public knowledge, unless such Confidential Information became or becomes public knowledge due to acts of the Participant or representatives of the Participant in violation of this Section 7.1. Upon termination of the Participant's employment, he shall return to the Company all Confidential Information in his possession. After termination of the Participant's employment with the Employer, the Participant shall not, without the prior written consent of the Company or as may otherwise be required by law or legal process, communicate or divulge any such Confidential Information to

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anyone other than the Company and those designated by it, except (a) otherwise publicly available information, (b) as may be necessary to enforce his rights under the Plan or as necessary to defend himself against a claim asserted directly or indirectly by the Company or its Affiliates or (c) as may be compelled by service of a valid subpoena or other legal process. If the Participant is served with a valid subpoena or other legal process, he must so notify the Company within three business days. Unless and until a determination has been made in accordance with Section 7.4 that the Participant has violated this Section 7.1, an asserted violation of the provisions of this Section 7.1 shall not constitute a basis for deferring or withholding any amounts otherwise payable to the Participant under the Plan.

7.2 Non-Compete. As a condition to participation in the Plan, each Participant agrees, that, in the event the Participant voluntarily terminates his employment other than for Good Reason, for the period of one year from Date of Termination he will not, without the written consent of the Company, directly or indirectly own, manage, operate, join, control, become employed by, consult to or participate in the ownership, management, or control of any business which is in direct competition with the Company or its Affiliates.

7.3 Non-Solicitation. As a condition to participation in the Plan, each Participant agrees that, in the event the Participant voluntarily terminates his employment other than for Good Reason, for the period of one year following the Date of Termination, he will not, directly or indirectly, solicit or hire, or encourage the solicitation or hiring by any employer other than the Company or its Affiliates, for any position as an employee, independent contractor, consultant or otherwise, any person who was a managerial or higher level employee of an Employer at any time during the term of the Participant's employment by the Employer; provided, however, that this provision shall not apply with respect to the solicitation of any person after six months from the date on which such person's employment by an Employer has terminated.

7.4 Enforcement. In the event of a breach by the Participant of any of the covenants set forth in this Article VII, it is agreed that the Company shall suffer irreparable harm for which money damages are not an adequate remedy, and that, in the event of such breach, the Company shall be entitled to obtain an order of a court of competent jurisdiction for equitable relief from such breach, including, but not limited to, temporary restraining orders and preliminary and/or permanent injunctions against the breach of such covenants by the Participant. In the event that the Company should initiate any legal action for the breach or enforcement of any of the provisions contained in this Article VII and the Company does not prevail in such action, the Company shall promptly reimburse the Participant the full amount of any court costs, filing fees, attorney's fees which the Participant incurs in defending such action, and any loss of income during the period of such litigation.

Nothing in this Plan prohibits the Participant from reporting possible violations of Federal law or regulation to any governmental agency or entity, including but not limited to the Department of Justice, the Securities and Exchange Commission, the Congress, and any agency Inspector General, or making other disclosures that are protected under the whistleblower provisions of federal law or regulation. The Participant does not need the prior authorization of the Law Department to make any such reports or disclosures, and is not required to notify the Company that such reports or disclosures have been made.

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ARTICLE VIII

AMENDMENT AND TERMINATION

8 . 1 Amendment. The Company may amend this Plan at any time, and from time to time, by action of the Committee; provided, however, that no amendment adopted after the effective date of a Change in Control shall have the effect of either (a) removing an individual from the list of Participants, (b) adding conditions for participation or the entitlement to receive benefits hereunder, (c) reducing the amount of benefits payable to a Participant or (d) otherwise restricting a Participant's right to receive benefits under the Plan, except as may otherwise be required to conform such payments to the requirements of Section 409A of the Code, as provided in Section 1.1.

8 . 2 Termination. The Committee may terminate the Plan at any time prior to a Change in Control. The Plan may not be terminated after the effective date of a Change in Control.

ARTICLE IX

ADMINISTRATION

9.1 Plan Administrator. The Plan shall be administered by the Committee, which shall have the duties and responsibilities for administering the Plan as are specifically set forth in this Article IX.

9.2 Responsibilities of Committee.

(a) The Committee shall have responsibility for the day to day administration of the Plan. In addition, the Committee shall have the specific powers, duties, responsibilities and obligations specifically provided for herein.

(b) Subject to the express provisions of the Plan, the Committee shall have full and exclusive authority to interpret the Plan and to make all other factual determinations deemed necessary or advisable in the implementation and administration of the Plan, including but not limited to determinations with respect to the eligibility of Participants to receive benefits under the Plan and the status and rights of such Participants and all other persons affected hereunder. The Committee's interpretation and construction of the Plan shall be conclusive and binding on all persons.

(c) The Committee shall have sole authority to adopt rules and regulations, which shall be administered by the Committee. In addition, the Committee shall have the discretionary authority to issue rulings and interpretations concerning the Plan and all matters arising thereunder, on a uniform and nondiscriminatory basis, provided the same shall not be contrary to or inconsistent with any provision of the Plan.

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(d) As a condition of distributing any benefit under the Plan, the Committee may prescribe the use of such forms and require the furnishing of such information as the Committee may deem appropriate for administering the Plan.

9.3 Allocation or Delegation of Duties and Responsibilities. In furtherance of its duties and responsibilities under the Plan, the Committee may:

(a) Employ agents to carry out non-fiduciary responsibilities;

(b) Employ agents to carry out fiduciary responsibilities;

(c) Consult with counsel, who may be counsel to the Company; and

(d) Delegate any of its duties and responsibilities hereunder to such officer or officers of the Company as the Committee shall designate; except, however, that the Committee may not delegate to any other person the designation of Eligible Employees under Section 3.1 or the authority to consider and determine appeals of alleged adverse benefit determinations.

9.4 Expenses. Unless otherwise agreed to by the Company, no person acting as a fiduciary hereunder (who is an employee of an Employer) shall receive any compensation for services as such. Expenses incurred by fiduciaries in connection with the administration of the Plan shall be paid by the Company.

9.5 Indemnification of Plan Administrator. The Company shall indemnify, to the fullest extent permitted by law, each person made or threatened to be made a party to any civil or criminal action or proceeding by reason of the fact that he, or his testator or intestate, was a member of the Committee, or a delegate of the Committee, acting in the capacity of Plan administrator.

9.6 Reliance Upon Others. The Committee, any person to whom it may delegate such of its duties and powers as provided herein, and the officers and directors of the Company shall be entitled to rely conclusively upon and shall be fully protected in any action taken by them in good faith in reliance upon any tables, valuations, certificates, opinions, reports or other advice furnished to them by any duly appointed actuary, accountant, legal counsel (who may be counsel for the Company) or other specialist.

9.7 Notification. All notices, reports and statements in connection with the Plan that are given, made, delivered or transmitted to a Participant shall be deemed duly given, made, delivered, or transmitted when mailed, by such class as the sender may deem appropriate, with postage prepaid and addressed to the Participant at the address last appearing on the records of the Employer with respect to this Plan. All notices, direct actions or other communications given, made, delivered or transmitted by a Participant to an Employer or Committee shall not be deemed to have been duly given, made, delivered, transmitted or received unless and until actually received by the Employer or Committee.

9.8 Multiple Capacities. A person may serve in more than one fiduciary capacity with respect to the Plan.

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ARTICLE X

CLAIMS PROCEDURE

10.1 Submission of Claims. The initial claim by any Participant for benefits under this Plan shall be submitted in writing to the Committee (or its delegate) within 60 days after the occurrence of the termination of employment that the Participant claims to have triggered entitlement to Plan benefits.

10.2 Computation and Review of Claims. All benefits shall be computed by the Committee or its delegate. All claims shall be approved or denied by the Committee (or its delegate) as soon as practicable, but in no event later than 90 days after application by the Participant. The Committee may take an additional 90 days to review the claim, provided that the Participant is notified in writing within the initial 90-day period.

(a) Initial Denial of Claim - Any denial of a claim shall include:

(i) Reason or reasons for the denial;

(ii) Reference to pertinent Plan provisions on which the denial is based;

(iii) Description of any additional material or information necessary for the Participant to perfect the claim together with an explanation of why the material or information is necessary; and

(iv) Explanation of the Plan's claim review procedure, described below.

(b) Review of a Denied Claim - A Participant shall have a reasonable opportunity to appeal a denied claim to the Committee (or its delegate) for a full and fair review. The Participant or a duly authorized representative:

(i) Shall have 60 days, after receipt of written notification of the denial of claim in which to request a review.

(ii) May request a review upon written application to the Committee.

(iii) Shall submit written comments, documents, records and other information relating to the claim.

(iv) May review, free of charge, pertinent Plan documents, records and other information relevant to the claim.

(c) Committee Review - The Committee's (or its delegate's) review shall take into account all comments, documents, records and other information submitted by the Participant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

(d) Written Decision - The Committee (or its delegate) shall issue a decision on the reviewed claim promptly but no later than 60 days after receipt of the review. The Committee may take an additional 60 days to review the claim, provided that the Participant is notified in writing within the initial 60-day period. The Committee's decision shall be in writing and shall include:

(i) Reasons for the decision;

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(ii) References to the Plan provisions on which the decision is based;

(iii) Statement that the Participant is entitled to receive, upon request, reasonable access to, and copies of, all documents, records and other information relevant to the claim; and

(iv) Statement that the Participant is entitled to bring a civil suit under Section 502(a) of ERISA.

(e) Binding Effect - The Committee's (or its delegate's) decision shall be final and binding on the Participant and the Employer.

ARTICLE XI

GENERAL PROVISIONS

11.1 Construction. This Plan shall be construed and enforced in accordance with and governed by the internal substantive laws (and not the laws relating to conflict of laws or choice of laws) of the State of New Jersey, except to the extent that such laws are preempted by Federal law.

11.2 Unfunded Plan. The obligations of the Company under this Plan are not required to be funded in advance. Nothing contained in this Plan shall give an Eligible Employee or Participant any right, title or interest in any property of the Company or any of its Affiliates.

11.3 No Right to Continued Employment. Nothing contained herein shall be deemed to give any Eligible Employee or Participant the right to be retained in the employment of an Employer or to limit the rights of any Employer to discharge any Eligible Employee or Participant at any time, with or without notice and with or without Cause.

11.4 Partial Invalidity. The invalidity or unenforceability of any term or provision, or any clause, or portion thereof, of this Plan shall in no way impair or affect the validity or enforceability of any other provision of this Plan, which shall remain in full force and effect.

11.5 Successors and Assigns.

(a) This Plan shall inure to the benefit of and be binding upon the Company and its successors and assigns.

(b) The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform the Company's obligations under the Plan in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place.

(c) In no event shall a Participant assign his interests under the Plan to any other person without the prior written consent of the Committee.

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11.6 Waivers. Failure to strictly comply with any term, condition or requirement set forth in the Plan shall not be deemed a waiver of such term, condition or requirement, nor shall any waiver of any such term, condition or requirement at any one time or times be deemed to result in a waiver of such term, condition or requirement at any other time or times.

11.7 Gender and Number. Masculine pronouns include the feminine as well as the neuter genders, and the singular shall include the plural, unless indicated otherwise by the context.

11.8 Headings. The headings of the Plan are for purposes of reference only and shall not limit or otherwise affect the meaning hereof.

* * *

/s/ Margaret M. Pego 12/21/15
Signature Date

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SCHEDULE A

As Amended as of December 15, 2015
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Stuart J. Black	VP and Controller	03/01/10
Robert C. Braun	President & CNO, PSEG Nuclear	12/4/09
Jorge L. Cardenas	VP - Asset Management and Centralized Services, PSE&G	1/23/07
Rose M. Chernick	VP - Finance Holdings & Corporate Strategy & Planning	8/09/10
John Paul Cowan	SVP - Operations, PSEG Fossil	09/15/09
Lathrop B. Craig	VP - ISO Operations (ER&T)	09/05/11
Daniel J. Cregg	EVP & CFO	12/09/06
David M. Daly	President and COO - PSEG Long Island	1/28/08
Paul J. Davison	VP - Hope Creek, PSEG Nuclear	12/14/09
Derek DiRisio	President - PSEG Services Corporation	12/20/04
Diana L. Drysdale	VP - Renewables, PSEG Energy Holdings	02/15/10
Kathleen Fitzgerald	VP - Corporate Communications	01/03/12
Joseph A. Forline	VP - Gas Operations (effective 12/21/15)	12/19/06
Carl J. Fricker	VP - Trading Support & Operations (ER&T)	12/14/09
Robert F. Friend	VP - Procurement	04/20/10
Kim C. Hanemann	SVP - Delivery Projects and Construction	12/21/10
Bradford D. Huntington	VP & Treasurer	04/16/11
Scott Jennings	VP - Finance PSE&G	10/18/05
Robert C. Krueger, Jr	VP & Assistant Controller - Tax	12/19/06
Kathleen A. Lally	VP - Investor Relations	01/16/07
John R. Latka	SVP - Electric & Gas Operations, PSE&G	10/23/06
Shawn P. Leyden	VP and Deputy General Counsel	12/20/04
Tamara L. Linde	EVP and General Counsel	12/19/06

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NAME	TITLE	PARTICIPATION DATE
Richard P. Lopriore	President, PSEG Fossil	06/19/07
Kristen M. Ludecke	VP - Federal Affairs	02/22/10
Shahid Malik	President - Energy Resources & Trade (ER&T)	12/5/11
Christine T. Neely	VP - Internal Auditing Services	9/30/13
Margaret M. Pego	SVP - Human Resources & CHRO	12/20/04
John F. Perry	VP - Salem, PSEG Nuclear	09/15/09
Kevin J. Quinn	VP - Finance Power	03/01/10
Sheila J. Rostiac	VP - Total Rewards & Talent Management (effective 1/1/16)	08/20/12
Joseph Santamaria	VP - Information Technology & CIO	10/29/12
John P. Scarlata	VP - Gas Supply, PSEG ER&T	4/20/10
Richard T. Thigpen	VP - State Governmental Affairs	3/26/07
John F. Tiberi	VP - Employee Benefits, Health & Safety	07/09/12

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SCHEDULE B

As Amended as of December 15, 2015
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Ralph Izzo	Chairman of the Board, President and CEO	12/15/08
Ralph A. LaRossa	President & COO - Public Service Electric and Gas Company, and COB, PSEG Long Island	10/17/06
William Levis	President & COO, PSEG Power LLC	01/01/07

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SCHEDULE C

As Amended as of December 15, 2015
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
John A. Bridges	VP Electric Operations (effective 12/21/15)	12/21/15
Kevin B. Cellars	VP Construction	2/17/15
Gregory Dunlap	VP Customer Operations - PSE&G	7/14/14
Aaron Ford	VP Business Assurance and Resilience	11/18/15
M. Courtney McCormick	VP Renewables and Energy Solutions (effective 12/21/15)	3/31/14
Laurent Pommier	VP Risk Management and Chief Risk Officer	7/14/14

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EXHIBIT I

Form of Restrictive Covenant Agreement

AGREEMENT, by and between Public Service Enterprise Group Incorporated, a New Jersey Corporation (the "Company") and [_____] ("Executive"), dated as of [_____].

WHEREAS, the Company maintains the Key Executive Severance Plan of Public Service Enterprise Group Incorporated (the "Plan"), effective December 17, 2012, and as thereafter amended, modified or supplemented;

WHEREAS, Executive was designated as an Eligible Employee under the Plan by the Organization and Compensation Committee of the Company's Board of Directors;

WHEREAS, pursuant to Section 3.2 of the Plan, in order to be a Participant in and be entitled to benefits and protections under the Plan, Executive must execute and delivery to the Company within 30 days after Executive was designated as an Eligible Employee a written agreement to be bound by the terms and conditions of certain covenants set out in Article VII of the Plan, which is hereby incorporated herein;

NOW THEREFORE, the parties agree as follows:

1. Executive has received a copy of the Plan and has read and understands the terms of conditions of Section 7.1, Confidentiality, Section 7.2, Non-Compete, and Section 7.3, Non-Solicitation, therein, as applied to Executive (the "Covenants").

2. Executive agrees to be bound by and comply with the terms of the Covenants in consideration for becoming a Participant in the Plan.

3. Executive acknowledges that the Covenants are reasonable in the scope of the activities restricted, the geographic area covered by the restrictions, the duration of the restrictions, and that such Covenants are reasonably necessary to protect the Company's legitimate interests in its Confidential Information and its relationships with its employees, customers and suppliers.

4. Executive acknowledges that the Covenants will not deprive Executive of the ability to earn a livelihood or to support Executive's dependents.

5. Executive shall be a Participant in the Plan and be entitled to all of the rights and benefits provided thereunder as of the date of this Agreement.

6. This Agreement shall be construed and enforced in accordance with and governed by the internal substantive laws (and not the laws relating to conflict of laws or choice of laws) of the State of New Jersey, except to the extent that such laws are preempted by Federal law.

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IN WITNESS WHEREOF, the parties have executed this Agreement as of the date and year first above written.

[This Agreement may be executed in counterparts.]

EXECUTIVE

PUBLIC SERVICE ENTERPRISE
GROUP INCORPORATED

By:_____

Title:_____

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CLAWBACK PRACTICE

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Effective as of December 15, 2015

Section 1. Purpose.

The Public Service Enterprise Group Incorporated Clawback Practice ("Clawback Practice") is effective December 15, 2015. The Clawback Practice has been adopted by the Board of Directors.

The purpose of the Clawback Practice is for the Company to recover or cause to be forfeited Incentive Compensation of Covered Employees upon the occurrence of a Covered Event. The Clawback Practice is intended to underscore and be aligned with the Company's Standards of Integrity.

The Clawback Practice supersedes all clawback and forfeiture provisions in the Covered Plans and is incorporated into those Covered Plans; however, particular grants and awards under the Covered Plans may include additional clawback provisions not otherwise specifically stated in this Clawback Practice. The Clawback Practice is in addition to any clawback and forfeiture provisions that are in Company's compensation plans or programs which are not Covered Plans.

Section 2. Definitions.

"**Administrator**" shall mean with respect to Key Executives, the Committee, and with respect to all other Covered Employees, the Senior Vice President of Human Resources & Chief Human Resources Officer.

"**Clawback**" shall mean the recoupment or forfeiture of a Covered Employee's Incentive Compensation whether paid, vested, granted or accrued, upon the occurrence of a Covered Event.

"**Clawback Amount**" shall have the meaning set forth in Section 4(a) of this Clawback Practice.

"**Company**" shall mean the Public Service Enterprise Group Incorporated.

"**Committee**" shall mean the Organization and Compensation Committee of the Board of Directors.

"**Covered Employees**" shall mean any non-represented Employee or former Employee, including an Executive Officer, who receives or is entitled to receive Incentive Compensation.

"**Covered Event**" shall mean one or more of the below events that the Administrator, in its sole discretion, determines to be appropriate:

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(a) If as a result of misconduct, the Company or any of its subsidiaries is required by the Securities and Exchange Commission ("SEC") to file an accounting restatement for any fiscal year due to its material noncompliance with accounting requirements under the federal securities laws, and the Covered Employee (i) knowingly engaged in the misconduct, or (ii) recklessly failed to prevent the misconduct, or (iii) is a person who is one of the individuals subject to automatic forfeiture under Section 304 of the Sarbanes-Oxley Act of 2002.

(b) If as a result of misconduct, the Company or any of its subsidiaries has determined that it is necessary to recalculate any Incentive Compensation for any year, and the Covered Employee (i) knowingly engaged in the misconduct, or (ii) recklessly failed to prevent the misconduct.

(c) A Covered Employee's act or omission constitutes a material violation of the Company's Standards of Integrity, in effect from time to time, that results in the Covered Employee's termination from employment.

"**Covered Plan**" shall mean the following:

(a) Performance Incentive Plan for Certain Employees of Public Service Electric and Gas Company and Subsidiaries, Performance Incentive Plan for Certain Employees of PSEG Services Corporation and Subsidiaries, Performance Incentive Plan for Certain Employees of PSEG Power LLC and Subsidiaries, Performance Incentive Plan for Certain Employees of PSEG Long Island LLC, and Performance Incentive Plan for Certain Employees of Long Island Electric Utility ServCo LLC (collectively, "PIP");

(b) PSEG Power LLC Incentive Compensation Program for PSEG Energy Resources & Trade LLC Employees ("ER&T Plan");

(c) Deferred Compensation Plan for Certain Employees of Public Service Enterprise Group Incorporated and Its Affiliates ("Deferred Compensation Plan");

(d) Public Service Enterprise Group Incorporated 2004 Long-Term Incentive Plan, as amended and restated ("LTIP");

(e) Public Service Enterprise Group Incorporated Equity Deferral Plan ("Equity Deferral Plan");

(f) Public Service Enterprise Group Incorporated Management Incentive Compensation Plan ("MICP");

(g) Public Service Enterprise Group Incorporated Senior Management Incentive Compensation Plan ("SMICP").

"**Effective Date**" shall mean the date this Clawback Practice is adopted by the Board of Directors.

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"**Incentive Compensation**" shall mean compensation or awards paid to, granted to, or accrued for a Covered Employee under a Covered Plan.

"**Key Executive**" shall mean any current or former employee of the Company that is, or was during employment, on Schedule A, B or C of the Key Executive Severance Plan of Public Service Enterprise Group Incorporated.

Section 3. Clawback Authority.

The Administrator, in its sole discretion, shall determine whether a Covered Employee shall be subject to Clawback upon the occurrence of a Covered Event and shall determine the amount of Clawback. The Administrator shall exercise the Clawback authority pursuant to this Clawback Practice.

Section 4. Clawback Amount and Method of Clawback.

(a) Amount. The Clawback Amount shall be determined by the Administrator, in its sole discretion. The amount of Incentive Compensation that may be subject to Clawback is the Incentive Compensation that the Covered Employee received or is determined to be entitled to receive within the three completed fiscal years immediately preceding the Covered Event.

(b) Method. The Administrator, in its sole discretion, shall determine the method that will be used to recoup the Clawback Amount, including but not limited to, (i) not paying or distributing the Incentive Compensation that has not yet been paid or distributed to the Covered Employee (including amounts deferred under the Deferred Compensation Plan or Equity Deferral Plan, (ii) making demand upon the Covered Employee to repay such Clawback Amount as has been paid or distributed, and (iii) causing the Clawback Amount to be withheld from other compensation, including but not limited to, future Incentive Compensation, to the extent permitted under applicable law.

Section 5. Applicability of Clawback Practice.

All award agreements with a Covered Employee shall include language that the award is subject to the Clawback Practice and that the Covered Employee agrees that the award is subject thereto. Notwithstanding the immediately preceding sentence, the Clawback Practice applies to each Covered Plan and all awards issued thereunder regardless of whether the Covered Plan or award issued thereunder specifically includes such language, and each Covered Employee is deemed to have agreed that an award under a Covered Plan is subject to this Clawback Practice.

Any award granted on or after the date of adoption of this Clawback Practice shall be deemed to be subject to the provisions of such clawback rules and regulations adopted by the SEC and in effect from time to time, as if such rules and regulations had been in effect at the time of the grant of the award, and each Covered Employee shall be deemed to have so agreed to the applicability of such provisions.

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Section 6. Notice of Covered Employees.

The Administrator shall cause to have notice of this Clawback Practice given to the Covered Employees, in such manner as determined by the Administrator from time to time.

Section 7. Administration.

The Clawback Practice shall be administered by the Administrator. The Committee will make determinations and interpretations and to take such actions in connection with the Clawback Practice as it deems necessary or advisable. All determinations and interpretations made by the Committee shall be final and binding.

The Senior Vice President of Human Resources & Chief Human Resources Officer shall report to the Committee during a Committee meeting if any Covered Employee, other than a Key Executive, was subject to Clawback since the last Committee meeting.

The rights and remedies provided in this Clawback Practice are not exclusive. Nothing in this Clawback Practice shall preclude the Company's right to take legal action against a Covered Employee or otherwise to enforce the provisions of this Clawback Practice.

Section 8. Indemnification.

The Company shall not indemnify any Covered Employee for the amount subject to Clawback.

Section 9. Applicable Law.

All provisions of this Clawback Practice, including the applicability, interpretation, administration and enforcement thereof, shall comply with and be subject to applicable law and regulation.

Section 10. Amendment and Termination.

The Committee shall have the authority to amend the Clawback Practice at any time and for any reason. The Board shall have the authority to terminate the Clawback Practice at any time and for any reason.

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 2,680	$ 2,456	$ 2,055	$ 2,011	$ 2,384
(Income) Loss from Equity Investees, net of Distributions	3	4	(7)	9	(4)
Fixed Charges	457	450	458	479	522
Capitalized Interest	(18)	(16)	(16)	(19)	(14)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—
Total Earnings	$ 3,122	$ 2,894	$ 2,490	$ 2,480	$ 2,888
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 437	$ 430	$ 442	$ 465	$ 509
Interest Factor in Rentals	20	20	16	14	13
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—
Total Fixed Charges	$ 457	$ 450	$ 458	$ 479	$ 522
Ratio of Earnings to Fixed Charges	**6.83**	**6.43**	**5.44**	**5.18**	**5.53**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12a

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$1,367	$1,251	$1,063	$1,099	$1,703
(Income) Loss from Equity Investees, net of Distributions	1	3	(10)	(6)	(12)
Fixed Charges	152	150	143	164	208
Capitalized Interest	(1)	1	1	(6)	(10)
Total Earnings	$1,519	$1,405	$1,197	$1,251	$1,889
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 148	$ 146	$ 139	$ 161	$ 205
Interest Factor in Rentals	4	4	4	3	3
Total Fixed Charges	$ 152	$ 150	$ 143	$ 164	$ 208
Ratio of Earnings to Fixed Charges	**9.99**	**9.37**	**8.37**	**7.63**	**9.08**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12b

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Years Ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$1,257	$1,174	$ 993	$ 835	$ 861
Fixed Charges	306	303	316	314	319
Capitalized Interest	(17)	(16)	(16)	(13)	(4)
Total Earnings	$1,546	$1,461	$1,293	$ 1,136	$1,176
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 297	$ 293	$ 309	$ 308	$ 314
Interest Factor in Rentals	9	10	7	6	5
Total Fixed Charges	$ 306	$ 303	$ 316	$ 314	$ 319
Ratio of Earnings to Fixed Charges	**5.05**	**4.82**	**4.09**	**3.62**	**3.69**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G. There were no preferred stock dividend requirements for any period presented.

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Exhibit 21

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

SIGNIFICANT SUBSIDIARIES

Name	Ownership %	State of Incorporation
Public Service Electric and Gas Company	100	New Jersey
PSEG Power LLC	100	Delaware
PSEG Fossil LLC	100	Delaware
PSEG Nuclear LLC	100	Delaware
PSEG Energy Resources & Trade LLC	100	Delaware

The remaining subsidiaries of Public Service Enterprise Group Incorporated are not significant subsidiaries as defined in Regulation S-X.

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Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-202594, 333-202591, 333-120100, 333-106330, 333-193126, and 333-193127 on Form S-8 and Registration No. 333-200352 on Form S-3 of our reports dated February 25, 2016, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") and the effectiveness of the Company's internal control over financial reporting, appearing in the Annual Report on Form 10-K of Public Service Enterprise Group Incorporated for the year ended December 31, 2015.

/s/ Deloitte & Touche LLP

Parsippany, New Jersey
February 25, 2016

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Exhibit 23a

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-200354 on Form S-3 of our report dated February 25, 2016, relating to the consolidated financial statements and consolidated financial statement schedule of PSEG Power LLC and subsidiaries appearing in the Annual Report on Form 10-K of PSEG Power LLC for the year ended December 31, 2015.

/s/ Deloitte & Touche LLP

Parsippany, New Jersey
February 25, 2016

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Exhibit 23b

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-200353 on Form S-3 of our report dated February 25, 2016, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Electric and Gas Company and subsidiaries, appearing in the Annual Report on Form 10-K of Public Service Electric and Gas Company for the year ended December 31, 2015.

/s/ Deloitte & Touche LLP

Parsippany, New Jersey
February 25, 2016

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2016

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31a

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31b

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2016

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31c

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 31d

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2016

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31e

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

S1-SSA-0009 - 11622

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
February 25, 2016

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EXHIBIT 32a

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
February 25, 2016

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EXHIBIT 32b

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
February 25, 2016

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EXHIBIT 32c

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
February 25, 2016

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EXHIBIT 32d

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
February 25, 2016

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EXHIBIT 32e

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
February 25, 2016

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2016

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-3663480

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange On Which Registered
Public Service Enterprise Group Incorporated	Common Stock without par value	New York Stock Exchange
	First and Refunding Mortgage Bonds	
Public Service Electric and Gas Company	9 1/4% Series CC, due 2021	New York Stock Exchange
	8%, due 2037	
	5%, due 2037	
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange

(Cover continued on next page)

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(Cover continued from previous page)

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
Public Service Electric and Gas Company	Medium-Term Notes
PSEG Power LLC	Limited Liability Company Membership Interest

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Public Service Enterprise Group Incorporated	Yes ☒	No ☐
Public Service Electric and Gas Company	Yes ☒	No ☐
PSEG Power LLC	Yes ☒	No ☐

Indicate by check mark if each of the registrants is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☒

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2016 was $23,504,828,537 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Public Service Enterprise Group Incorporated's sole class of Common Stock as of February 17, 2017 was 506,217,300.

As of February 17, 2017, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record, by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K. Each is filing its Annual Report on Form 10-K with the reduced disclosure format authorized by General Instruction I.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K of Public Service Enterprise Group Incorporated	Documents Incorporated by Reference
III	Portions of the definitive Proxy Statement for the 2017 Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 14, 2017, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities, and other filings we make with the United States Securities and Exchange Commission (SEC), including our subsequent reports on Form 10-Q and Form 8-K. These factors include, but are not limited to:

- fluctuations in wholesale power and natural gas markets, including the potential impacts on the economic viability of our generation units;
- our ability to obtain adequate fuel supply;
- any inability to manage our energy obligations with available supply;
- increases in competition in wholesale energy and capacity markets;
- changes in technology related to energy generation, distribution and consumption and customer usage patterns;
- economic downturns;
- third-party credit risk relating to our sale of generation output and purchase of fuel;
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements;
- changes in state and federal legislation and regulations;
- the impact of pending rate case proceedings;
- regulatory, financial, environmental, health and safety risks associated with our ownership and operation of nuclear facilities;
- adverse changes in energy industry laws, policies and regulations, including market structures and transmission planning;
- changes in federal and state environmental regulations and enforcement;
- delays in receipt of, or an inability to receive, necessary licenses and permits;
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry;
- changes in tax laws and regulations;
- the impact of our holding company structure on our ability to meet our corporate funding needs, service debt and pay dividends;
- lack of growth or slower growth in the number of customers or changes in customer demand;
- any inability of Power to meet its commitments under forward sale obligations;
- reliance on transmission facilities that we do not own or control and the impact on our ability to maintain adequate transmission capacity;
- any inability to successfully develop or construct generation, transmission and distribution projects;
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers;

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- our inability to exercise control over the operations of generation facilities in which we do not maintain a controlling interest;
- any inability to maintain sufficient liquidity;
- any inability to realize anticipated tax benefits or retain tax credits;
- challenges associated with recruitment and/or retention of key executives and a qualified workforce;
- the impact of our covenants in our debt instruments on our operations; and
- the impact of acts of terrorism, cybersecurity attacks or intrusions.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business, prospects, financial condition, results of operations or cash flows. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even in light of new information or future events, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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FILING FORMAT AND GLOSSARY

This combined Annual Report on Form 10-K is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to "we," "us," and "our" relate to PSEG or to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 193.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document that we file at the Public Reference Room of the SEC at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. You may also obtain our filed documents from commercial document retrieval services, the SEC's internet website at www.sec.gov or our website at www.pseg.com. Information on our website should not be deemed incorporated into or as a part of this report. Our Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

PART I

ITEM 1. BUSINESS

We were incorporated under the laws of the State of New Jersey in 1985 and our principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07102. We conduct our business through two direct wholly owned subsidiaries, PSE&G and Power, each of which also has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102.

We are an energy company with a diversified business mix. Our operations are located primarily in the Northeastern and Mid- Atlantic United States. Our business approach focuses on operational excellence, financial strength and disciplined investment. As a holding company, our profitability depends on our subsidiaries' operating results. Below are descriptions of our two principal direct operating subsidiaries.

PSE&G	Power
A New Jersey corporation, incorporated in 1924, which is a franchised public utility in New Jersey. It is also the provider of last resort for gas and electric commodity service for end users in its service territory. Earns revenues from its regulated rate tariffs under which it provides electric transmission and electric and gas distribution to residential, commercial and industrial customers in its service territory. It also offers appliance services and repairs to customers throughout its service territory. Has also implemented regulated demand response and energy efficiency programs and invested in solar generation within New Jersey.	A Delaware limited liability company formed in 1999 as a result of the deregulation and restructuring of the electric power industry in New Jersey. It integrates the operations of its merchant nuclear and fossil generating assets with its wholesale power marketing businesses through competitive energy sales in well-developed energy markets and fuel supply functions. Earns revenues from the generation and marketing of power and natural gas to hedge business risks and optimize the value of its portfolio of power plants, other contractual arrangements and oil and gas storage facilities. This is achieved primarily by selling power and transacting in natural gas and other energy-related products, on the spot market or using short-term or long-term contracts for physical and financial products. Also earns revenues from solar generation under long-term sales contracts for power and environmental products.

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Our other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and our operating subsidiaries with certain management, administrative and general services at cost.

The following is a more detailed description of our business, including a discussion of our:

- Business Operations and Strategy
- Competitive Environment
- Employee Relations
- Regulatory Issues
- Environmental Matters

BUSINESS OPERATIONS AND STRATEGY

PSE&G

Our regulated transmission and distribution public utility, PSE&G, distributes electric energy and gas to customers within a designated service territory running diagonally across New Jersey where approximately 6.2 million people, or about 70% of New Jersey's population resides.

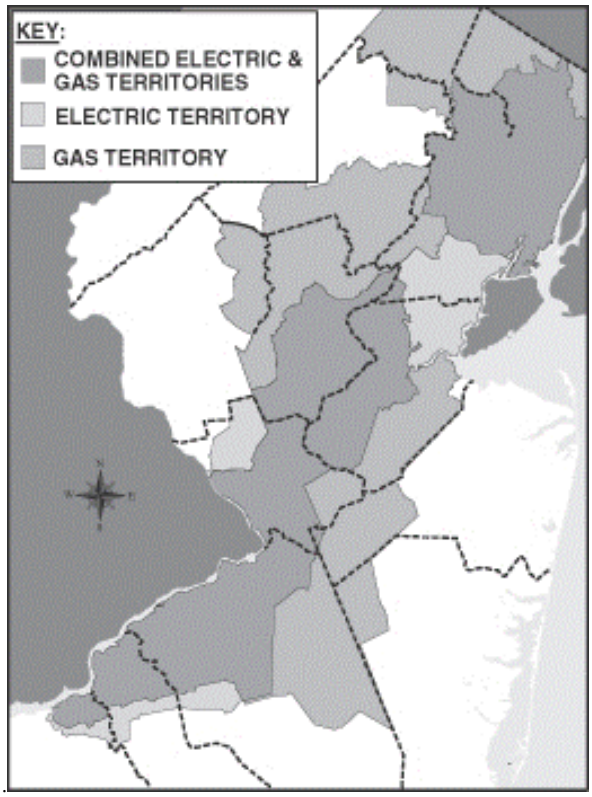

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Products and Services

Our utility operations primarily earn margins through the transmission and distribution of electricity and the distribution of gas.

- **Transmission**—the movement of electricity at high voltage from generating plants to substations and transformers, where it is then reduced to a lower voltage for distribution to homes, businesses and industrial customers. Our revenues for these services are based upon tariffs approved by the Federal Energy Regulatory Commission (FERC).
- **Distribution**—the delivery of electricity and gas to the retail customer's home, business or industrial facility. Our revenues for these services are based upon tariffs approved by the New Jersey Board of Public Utilities (BPU).

The commodity portion of our utility business' electric and gas sales is managed by basic generation service (BGS) and basic gas supply service (BGSS) suppliers. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for our utility operations.

We also earn margins through competitive services, such as appliance repair.

In addition to our current utility products and services, we have implemented several programs to invest in regulated solar generation within New Jersey, including:

- programs to help finance the installation of solar power systems throughout our electric service area, and
- programs to develop, own and operate solar power systems.

We have also implemented a set of energy efficiency and demand response programs to encourage conservation and energy efficiency by providing energy and cost saving measures directly to businesses and families. For additional information concerning these programs and the components of our tariffs, see Regulatory Issues—State Regulation and Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

How PSE&G Operates

We are a transmission owner in PJM Interconnection, L.L.C. (PJM) and we provide distribution service to 2.2 million electric customers and 1.8 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately 300 suburban and rural communities.

Transmission

We use formula rates for our transmission cost of service and investments. Formula-type rates provide a method of rate recovery where the transmission owner annually determines its revenue requirements through a fixed formula that considers Operation and Maintenance expenditures, rate base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures. Our current approved rates provide for a base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn an additional incentive rate. For more information, see Regulatory Issues—Federal Regulation.

We continue to invest in transmission projects that are included for review in the FERC-approved PJM transmission expansion process. These projects focus on reliability improvements and replacement of aging infrastructure with anticipated capital spend of $4.1 billion for transmission in 2017-2019 as disclosed in Item 7. MD&A—Capital Requirements.

Distribution

PSE&G distributes gas and electricity to end users in our respective franchised service territories. Our approved rates, established in our most recent gas and electric base rate proceeding completed in mid-2010, provide for a ROE of 10.3% on distribution rate base. We are required to file our next distribution base rate case proceeding no later than November 1, 2017. The BPU has also approved a series of PSE&G infrastructure, energy efficiency and renewable energy investment programs with cost recovery through various clause mechanisms, with approved ROEs ranging from 9.75% to 10.3%. Our load requirements are split among residential, commercial and industrial customers, as described in the following table for 2016:

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Customer Type	% of 2016 Sales Electric	Gas
Commercial	58%	37%
Residential	33%	59%
Industrial	9%	4%
Total	**100%**	**100%**

While our customer base has modestly increased since 2012, electric load has declined and gas load has increased as illustrated below:

Electric and Gas Distribution Statistics

December 31, 2016

	Number of Customers	Electric Sales and Gas Firm Sales (A)	Historical Annual Load Growth 2012-2016
Electric	2.2 Million	41,580 Gigawatt hours (GWh)	(0.4)%
Gas	1.8 Million	2,360 Million Therms	0.7%

(A) Excludes sales from Gas rate classes that do not impact margin, specifically Contract, Non-Firm Transportation, Cogeneration Interruptible and Interruptible Services.

The decline in electric sales is the result of changes in customer usage patterns, including conservation and more energy efficient appliances. Gas firm sales increased as a result of lower gas prices. Only gas firm sales impact margin.

During 2016, PSE&G, as part of its BPU-approved $1.2 billion Energy Strong Program, completed the replacement and modernization of 240 miles of low-pressure cast iron gas mains in or near flood areas. PSE&G continues to execute the Energy Strong Program to (1) upgrade all of its electric substations that were damaged by water in recent storms; make investments that will create redundancy in the electric distribution system, reducing outages when damage occurs; and deploy technologies to better monitor system operations, enabling PSE&G to restore customers more quickly in the event of an electric outage, and (2) with respect to PSE&G's gas system, upgrade five natural gas metering stations and a liquefied natural gas station recently affected by severe weather or located in flood zones.

PSE&G also commenced modernizing its gas distribution system as part of our Gas System Modernization Program (GSMP) which was approved by the BPU in late 2015. The GSMP, through which we will invest $905 million over three years, will replace approximately 510 miles of cast iron and unprotected steel gas mains and about 38,000 unprotected steel service lines to homes and businesses, including the uprating of the mains to higher pressure. The mains and service lines will be replaced with stronger, more durable plastic piping, reducing the potential for leaks and release of methane gas. The new elevated pressure systems also enable the installation of excess flow valves that automatically shut off gas flow if a service line is damaged, and better support the use of high-efficiency appliances.

Solar Generation

In order to support New Jersey's Energy Master Plan and the state's renewable energy goals, we have undertaken two major solar initiatives at PSE&G, the Solar Loan Program and the Solar 4 All and Solar 4 All Extension Programs. Our Solar Loan Program provides solar system financing to our residential and commercial customers. The loans are repaid with cash or solar renewable energy certificates (SRECs). We sell the SRECs received through periodic auctions and use the proceeds to offset program costs. Our Solar 4 All Programs invest in utility-owned solar photovoltaic (PV) centralized solar systems installed on PSE&G property and third-party sites, including landfill facilities, and solar panels installed on distribution system poles in our electric service territory. We sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition, we sell SRECs generated by the projects through the same periodic auction used in the loan program, the proceeds of which are used to offset program costs.

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Supply

Although commodity revenues make up almost 41% of our revenues, we make no margin on the default supply of electricity and gas since the actual costs are passed through to our customers.

All electric and gas customers in New Jersey have the ability to choose their own electric energy and/or gas supplier. Pursuant to BPU requirements, we serve as the supplier of last resort for two types of electric and gas customers within our service territory that are not served by another supplier. The first type, which represents about 80% of PSE&G's load requirements, provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Residential Small Commercial Pricing (RSCP)). These rates change annually on June 1 and are based on the average price obtained at auctions in the current year and two prior years. The second type provides default supply for larger customers, with energy priced at hourly PJM real-time market prices for a contract term of 12 months (BGS-Commercial Industrial Energy Pricing (CIEP)).

We procure the supply to meet our BGS obligations through auctions authorized by the BPU for New Jersey's total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers are authorized to supply BGS to New Jersey's electric distribution companies (EDCs). Once validated by the BPU, electricity prices for BGS service are set. Approximately one-third of PSE&G's total BGS-RSCP eligible load is auctioned each year for a three-year term. For information on current prices, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

PSE&G procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with Power. The BPU has approved a mechanism designed to recover all gas commodity costs related to BGSS for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. PSE&G's revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each year. In addition, we have the ability to put in place two self-implementing BGSS increases on December 1 and February 1 of up to 5% and also may reduce the BGSS rate at any time and/or provide bill credits. See Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities for information on recent self-implementing credits. Any difference between rates charged under the BGSS contract and rates charged to our residential customers is deferred and collected or refunded through adjustments in future rates. Commercial and industrial customers that do not select third-party suppliers are also supplied under the BGSS arrangement. These customers are charged a market-based price largely determined by prices for commodity futures contracts.

Markets and Market Pricing

Historically, there has been significant volatility in commodity prices. Such volatility can have a considerable impact on us since a rising commodity price environment results in higher delivered electric and gas rates for customers. This could result in decreased demand for electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs from our customers may be deferred under our regulated rate structure. A declining commodity price on the other hand, would be expected to have the opposite effect. For additional information, including the impact of natural gas commodity prices on electricity prices such as BGS, see Item 7. MD&A—Executive Overview of 2016 and Future Outlook.

Power

Through Power, we seek to produce low-cost electricity by efficiently operating our nuclear, coal, gas, oil-fired and renewable generation assets while balancing generation output, fuel requirements and supply obligations through energy portfolio management. Our commitments for load, such as BGS in New Jersey and other bilateral supply contracts, are backed by the generation we own and may be combined with the use of physical commodity purchases and financial instruments from the market to optimize the economic efficiency of serving the load. Power is a public utility within the meaning of the Federal Power Act and the payments it receives and how it operates are subject to FERC regulation. Power is also subject to certain regulatory requirements imposed by state utility commissions such as those in New York and Connecticut.

Products and Services

As a merchant generator and power marketer, our profit is derived from selling a range of products and services under contract to an array of customers including utilities, other power marketers, such as retail energy providers, or counterparties in the open market. These products and services may be transacted bilaterally or through exchange markets and include but are not limited to:

- **Energy**—the electrical output produced by generation plants that is ultimately delivered to customers for use in lighting, heating, air conditioning and operation of other electrical equipment. Energy is our principal product and is priced on a usage basis, typically in cents per kilowatt hour (kWh) or dollars per megawatt hour (MWh).

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- **Capacity**—distinct from energy, capacity is a market commitment that a given generation unit will be available to an Independent System Operator (ISO) for dispatch to produce energy when it is needed to meet system demand. Capacity is typically priced in dollars per MW for a given sale period (e.g. day or month).
- **Ancillary Services**—related activities supplied by generation unit owners to the wholesale market that are required by the ISO to ensure the safe and reliable operation of the bulk power system. Owners of generation units may bid units into the ancillary services market in return for compensatory payments. Costs to pay generators for ancillary services are recovered through charges collected from market participants.
- **Congestion and Renewable Energy Credits**—Congestion credits (or Financial Transmission Rights) are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path. Renewable Energy Credits (RECs) are obtained through Power's owned renewable generation or purchased in the open market. Electric suppliers of load are required to deliver a certain amount or percentage of their delivered power from renewable resources as mandated by applicable regulatory requirements.

Power also sells wholesale natural gas, primarily through a full-requirements BGSS contract with PSE&G to meet the gas supply requirements of PSE&G's customers. On March 19, 2014, the BPU approved an extension of the long-term BGSS contract to March 31, 2019 and then year-to-year thereafter unless terminated by either party with a two year notice.

Approximately 45% of PSE&G's peak daily gas requirements is provided from Power's firm gas transportation capacity, which is available every day of the year. Power satisfies the remainder of PSE&G's requirements from storage contracts, liquefied natural gas, seasonal purchases, contract peaking supply and propane. Based upon the availability of natural gas beyond PSE&G's daily needs, Power sells gas to others and uses it for its generation fleet.

In addition to its nuclear and fossil generation fleet, Power owns and operates 326 MW direct current (dc) of PV solar generation facilities and has an additional 70 MW dc of PV solar generation in construction. Power has a 50% ownership interest in a 208 MW oil-fired generation facility in Hawaii.

The remainder of this section about Power covers our nuclear and fossil fleet in the Mid-Atlantic and Northeast regions which comprises the vast majority of Power's operations and financial performance.

How Power's Generation Operates

Nearly all of our generation capacity consists of nuclear and fossil generation (11,681 MW) that is located in the Northeast and Mid-Atlantic regions of the United States in some of the country's largest and most developed electricity markets. For additional information see Item 2. Properties.

The map below shows the locations of our Northeast and Mid-Atlantic nuclear and fossil generation facilities and projects under construction:

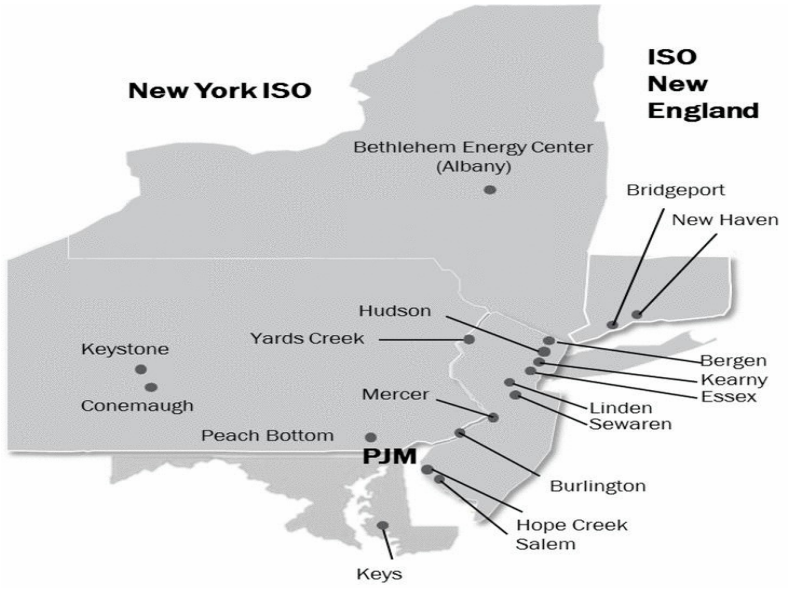

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- **Generation Capacity**

Our nuclear and fossil installed capacity utilizes a diverse mix of fuels. As of December 31, 2016, our fuel mix was comprised of 41% gas, 32% nuclear, 20% coal, 5% oil and 2% pumped storage. This fuel mix does not give effect to our previously announced decision to cease generation operations of the existing coal/gas units at our Hudson and Mercer generating stations on June 1, 2017. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2016 was approximately 52,000 GWh. The generation mix by fuel type in recent years has reflected the relatively more favorable price of natural gas compared to coal, making it more economical to run certain of our gas units in place of our coal units. The following table indicates the proportionate share of generating output by fuel type in 2016.

Generation by Fuel Type (A)	Actual 2016	
Nuclear:		
New Jersey facilities	36%	
Pennsylvania facilities	21%	
Fossil:		
Coal:		
Pennsylvania facilities	9%	
Connecticut facilities	—%	(B)
Coal and Natural Gas:		
New Jersey facilities	—%	(B)
Natural Gas and Oil:		
New Jersey facilities	24%	
New York facilities	10%	
Connecticut facilities	—%	(B)
Total	**100%**	

(A) Excludes pumped storage, solar facilities and fossil generation in Hawaii which account for less than two percent of total generation.

(B) Less than one percent.

We are also executing the following growth projects which are included in the 2017-2019 capital spend of $1.3 billion for Fossil Growth Opportunities disclosed in Item 7. MD&A—Capital Requirements.

Major Growth Projects
As of December 31, 2016

Project	Location	Expected In-Service Date
Keys Energy Center gas-fired combined cycle generating station (755 MW)	Maryland	2018
Sewaren 7 dual-fueled combined cycle generating station (540 MW)	New Jersey	2018
Bridgeport Harbor 5 gas-fired combined cycle generating station (485 MW)	Connecticut	2019
Bethlehem Energy Center (BEC) combined cycle uprate (58 MW)	New York	2017/2018

- **Generation Dispatch**

Our generation units have historically been characterized as serving one or more of three general energy market segments: base load; load following; and peaking, based on their operating capability and performance.

- **Base Load Units** run the most and typically are called to operate whenever they are available. These units generally derive revenues from both energy and capacity sales. Variable operating costs are low due to the combination of highly efficient operations and the use of relatively lower-cost fuels. Performance is generally measured by the unit's "capacity factor," or the ratio of the actual output to the theoretical maximum output. In 2016, our base load capacity factors were as follows:

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Unit	2016 Capacity Factor
Nuclear	
Salem Unit 1	67.0%
Salem Unit 2	84.3%
Hope Creek	89.8%
Peach Bottom Unit 2	91.7%
Peach Bottom Unit 3	100.0%
Coal	
Keystone	68.4%
Conemaugh	61.7%

- **Load Following Units'** operating costs are generally higher per unit of output than for base load units due to the use of higher-cost fuels such as oil, natural gas and, in some cases, coal or lower overall unit efficiency. These units usually have more flexible operating characteristics than base load units which enable them to more easily follow fluctuations in load. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.
- **Peaking Units** run the least amount of time and in some cases may utilize higher-priced fuels. These units typically start very quickly in response to system needs. Costs per unit of output tend to be higher than for base load units given the combination of higher heat rates and fuel costs. The majority of revenues are from capacity and ancillary service sales. The characteristics of these units enable them to capture energy revenues during periods of high energy prices.

In the energy markets in which we operate, owners of power plants specify to the ISO prices at which they are prepared to generate and sell energy based on the marginal cost of generating energy from each individual unit. The ISOs will generally dispatch in merit order, calling on the lowest variable cost units first and dispatching progressively higher-cost units until the point that the entire system demand for power (known as the system "load") is satisfied reliably. Base load units are dispatched first, with load following units next, followed by peaking units. It should be noted that the sustained lower pricing of natural gas over the past several years has resulted in changes in relative operating costs compared to historical norms, wherein some gas-fired generation is now able to displace some coal-fired generation. This change, combined with the addition of new, more efficient generation capacity, has altered the historical dispatch order of certain plants in the markets where we operate.

During periods when one or more parts of the transmission grid are operating at full capability, thereby resulting in a constraint on the transmission system, it may not be possible to dispatch units in merit order without violating transmission reliability standards. Under such circumstances, the ISO may dispatch higher-cost generation out of merit order within the congested area and power suppliers will be paid an increased Locational Marginal Price (LMP) in congested areas, reflecting the bid prices of those higher-cost generation units.

Typically, the bid price of the last unit dispatched by an ISO establishes the energy market-clearing price. After considering the market-clearing price and the effect of transmission congestion and other factors, the ISO calculates the LMP for every location in the system. The ISO pays all units that are dispatched their respective LMP for each MWh of energy produced, regardless of their specific bid prices. Since bids generally approximate the marginal cost of production, units with lower marginal costs typically generate higher operating profits than units with comparatively higher marginal costs.

This method of determining supply and pricing creates a situation where natural gas prices often have a major influence on the price that generators will receive for their output, especially in periods of relatively strong or weak demand. Therefore, changes in the price of natural gas will often translate into changes in the wholesale price of electricity. This can be seen in the following graphs which present historical annual spot prices and forward calendar prices as averaged over each year at two liquid trading hubs.

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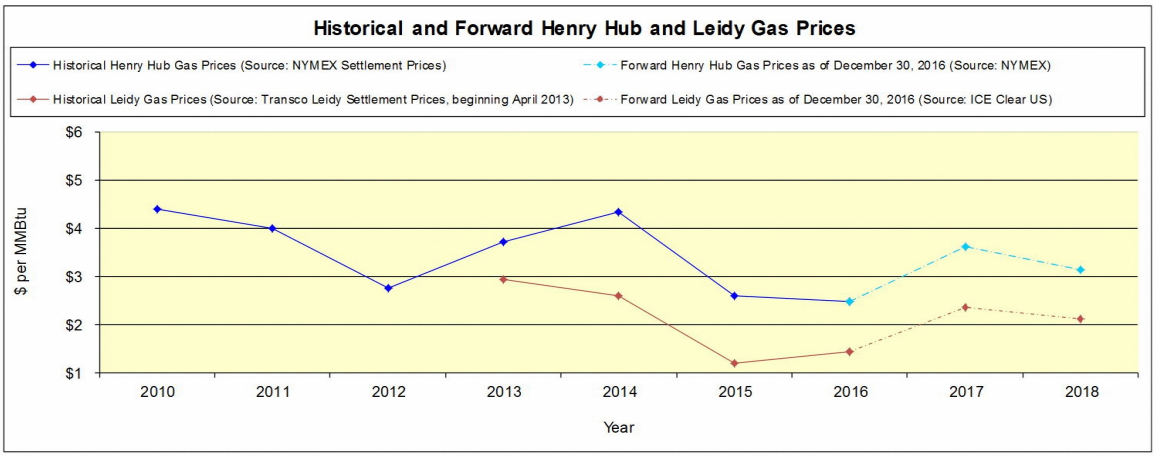

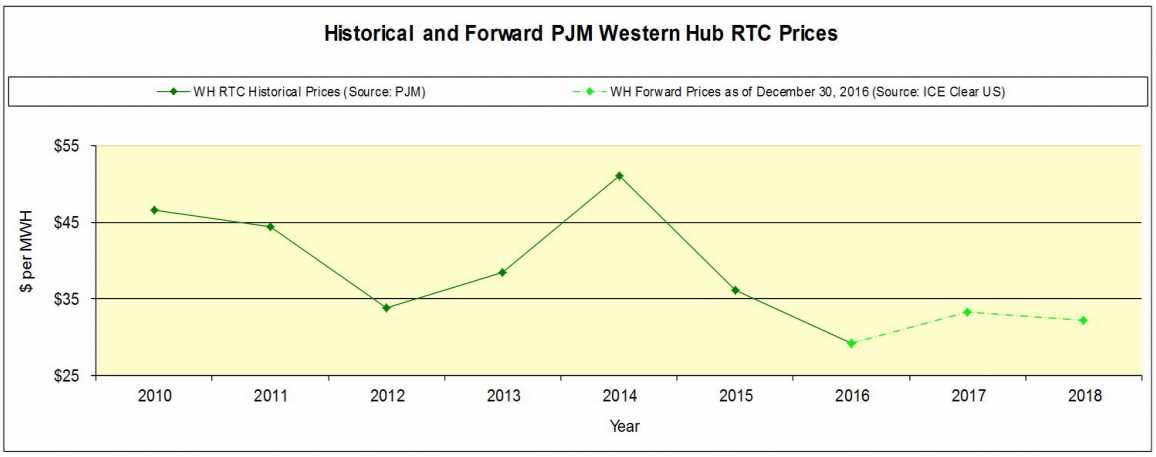

Historical data implies that the price of natural gas will continue to have a strong influence on the price of electricity in the primary markets in which we operate.

The prices reflected in the preceding graphs above do not necessarily illustrate our contract prices, but they are representative of market prices at relatively liquid hubs, with nearer-term forward pricing generally resulting from more liquid markets than pricing for later years. As shown above, prices may vary by location resulting from congestion or other factors, such as the availability of natural gas from the Marcellus (Leidy) and other shale-gas regions These variations can be considerable. Concurrent with the development of regional shale gas, we have been increasing our purchases from the Marcellus/Utica shale gas regions and in 2016 they accounted for approximately 90% of the gas we procured. While these prices provide some perspective on past and future prices, the forward prices are volatile and there can be no assurance that such prices will remain in effect or that we will be able to contract output at these forward prices.

Fuel Supply

- ***Nuclear Fuel Supply***—We have long-term contracts for nuclear fuel. These contracts provide for:
  - purchase of uranium (concentrates and uranium hexafluoride),
  - conversion of uranium concentrates to uranium hexafluoride,
  - enrichment of uranium hexafluoride, and
  - fabrication of nuclear fuel assemblies.

  Our nuclear fuel contracts cover approximately 100% of our estimated uranium, enrichment and fabrication requirements through 2018 and a significant portion through 2021.

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- ***Coal Supply***—Our Keystone, Conemaugh and Bridgeport stations operate on coal. Coal is delivered to our units through a combination of rail, truck, barge and ocean shipments.

  In order to control emissions levels, our Bridgeport 3 unit uses a specific type of coal obtained from Indonesia. We currently have a coal supply contract from Indonesia under contract through 2017 for the Bridgeport facility and believe that additional coal would be available after 2017 as required.
- ***Gas Supply***—Natural gas is the primary fuel for the bulk of our load following and peaking fleet. We purchase gas directly from natural gas producers and marketers. These supplies are transported to New Jersey by four interstate pipelines with which we have contracted. In addition, we have firm gas transportation contracted for this winter season to serve a portion of the gas requirements for our BEC station in New York.

  We have 1.3 billion cubic feet-per-day of firm transportation capacity and 0.9 billion cubic feet-per-day of firm storage delivery under contract to meet our obligations under the BGSS contract. This volume includes capacity from the Pennsylvania and Ohio shale gas regions where we purchase the majority of our natural gas. On an as-available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet.

  Power has contracted for approximately 125 million cubic feet-per-day of delivery capability on the PennEast Pipeline from eastern Pennsylvania to New Jersey with a targeted in-service date in the latter half of 2018. This additional delivery capability will be used to supplement the BGSS contract.
- ***Oil***—Oil is used as the primary fuel for one load following steam unit and four combustion turbine peaking units and can be used as an alternate fuel by several load following and peaking units that have dual-fuel capability. Oil for operations is drawn from on-site storage and is generally purchased on the spot market and delivered by truck or barge.

We expect to be able to meet the fuel supply demands of our customers and our own operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather, environmental regulations, and other factors. For additional information, see Item 7. MD&A—Executive Overview of 2016 and Future Outlook and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Markets and Market Pricing

The vast majority of Power's generation assets are located in three centralized, competitive electricity markets operated by ISO organizations all of which are subject to the regulatory oversight of FERC:

- **PJM Regional Transmission Organization**—PJM conducts the largest centrally dispatched energy market in North America. It serves over 61 million people, nearly 19% of the total United States population, and has a record peak demand of 165,492 MW. The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The majority of our generating stations operate in PJM.
- **New York**—The New York ISO (NYISO) is the market coordinator for New York State and is responsible for managing the New York Power Pool and for administering its energy marketplace. This service area has a population of about 19 million and a record peak demand of 33,956 MW. Our BEC station operates in New York.
- **New England**—The ISO-New England (ISO-NE) is the market coordinator for the New England Power Pool and for administering its energy marketplace which covers Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. This service area has a population of about 15 million and a record peak demand of 28,130 MW. Our Bridgeport and New Haven stations operate in Connecticut.

The price of electricity varies by location in each of these markets. Depending upon our production and our obligations, these price differentials may increase or decrease our profitability.

Commodity prices, such as electricity, gas, coal, oil and environmental products, as well as the availability of our diverse fleet of generation units to operate, also have a considerable effect on our profitability. Over the long-term, the higher the forward prices are, the more attractive an environment exists for us to contract for the sale of our anticipated output. However, higher prices also increase the cost of replacement power; thereby placing us at greater risk should our generating units fail to operate effectively or otherwise become unavailable.

Over the past few years, lower wholesale natural gas prices have resulted in lower electric energy prices. One of the reasons for the lower natural gas prices is greater supply from more recently-developed sources, such as shale gas, much of which is

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produced in adjacent states (e.g. Pennsylvania). This trend has reduced margin on forward sales as we re-contract our expected generation output.

In addition to energy sales, we earn revenue from capacity payments for our generating assets. These payments are compensation for committing our generating units to the ISO for dispatch at its discretion. Capacity payments reflect the value to the ISO of assurance that there will be sufficient generating capacity available at all times to meet system reliability and energy requirements. Currently, there is sufficient capacity in the markets in which we operate. However, in certain areas of these markets there are transmission system transfer limitations which raise concerns about reliability and create a more acute need for capacity.

In PJM and ISO-NE, where we operate most of our generation, the market design for capacity payments provides for a structured, forward-looking, transparent capacity pricing mechanism. This is through the Reliability Pricing Model (RPM) in PJM and the Forward Capacity Market (FCM) in ISO-NE. These mechanisms provide greater transparency regarding the value of capacity and provide a pricing signal to prospective investors in new generating facilities so as to encourage expansion of capacity to meet future market demands.

The prices to be received by generating units in PJM for capacity have been set through RPM base residual and incremental auctions and depend upon the zone in which the generating unit is located. For each delivery year, the prices differ in the various areas of PJM, depending on the transfer limitations of the transmission system in each area. Keystone and Conemaugh receive lower capacity prices than the majority of our PJM generating units since there are fewer constraints in that region and our generating units in New Jersey usually receive higher pricing.

Our PJM generating units are located in several zones and Power expects to realize the following average capacity prices from the base and incremental auctions which have been completed:

Delivery Year	MW-day
June 2016 to May 2017	$172
June 2017 to May 2018	$177
June 2018 to May 2019	$215
June 2019 to May 2020	$116

The price that must be paid by an entity serving load in the various zones is also set through these auctions. These prices can be higher or lower than the prices noted in the table above due to import and export capability to and from lower-priced areas. Prices in the most recent auction reflect PJM's downwardly-revised demand forecast, changes in the emergency transfer limits due to transmission expansion and the effects of both the new generation and uncleared generation from the prior year's auction.

We have obtained price certainty for our PJM capacity through May 2020 and New England capacity through May 2021 through the RPM and FCM pricing mechanisms, respectively.

Like PJM and ISO-NE, the NYISO provides capacity payments to its generating units, but unlike the other two markets, the New York market does not provide a forward price signal beyond a six month auction period.

On a prospective basis, many factors may affect the capacity pricing, including but not limited to:

- load and demand,
- availability of generating capacity (including retirements, additions, derates and forced outage rates),
- capacity imports from external regions,
- transmission capability between zones,
- available amounts of demand response resources,
- pricing mechanisms, including potentially increasing the number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM and the other ISOs may propose over time, and
- legislative and/or regulatory actions that permit subsidized local electric power generation.

For additional information on the RPM and FCM markets, as well as on state subsidization through various mechanisms, see Regulatory Issues—Federal Regulation.

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Hedging Strategy

To mitigate volatility in our results, we seek to contract in advance for a significant portion of our anticipated electric output, capacity and fuel needs. We seek to sell a portion of our anticipated lower-cost generation over a multi-year forward horizon, normally over a period of two to three years. We believe this hedging strategy increases stability of earnings.

Among the ways in which we hedge our output are: (1) sales at PJM West and (2) BGS and similar full-requirements contracts. Sales at PJM West reflect block energy sales at the liquid PJM Western Hub and other transactions that seek to secure price certainty for our generation related products. The BGS-RSCP contract, a full-requirements contract that includes energy and capacity, ancillary and other services, is awarded for three-year periods through an auction process managed by the BPU. The volume of BGS contracts and the mix of electric utilities that our generation operations serve will vary from year to year. Pricing for the BGS contracts, including a capacity component, for recent and future periods by purchasing utility is as follows:

Load Zone ($/MWh)	2014-2017	2015-2018	2016-2019	2017-2020
PSE&G	$97.39	$99.54	$96.38	$90.78
Jersey Central Power & Light Company (JCP&L)	$84.44	$80.42	$74.85	$69.08
Atlantic City Electric Company	$87.80	$86.06	$82.14	$75.49
Rockland Electric Company	$95.61	$90.66	$85.02	$80.50

Although we enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation, there is variability in both our actual output as well as in the effectiveness of our hedges. Actual output will vary based upon total market demand, the relative cost position of our units compared to other units in the market and the operational flexibility of our units. Hedge volume can also vary, depending on the type of hedge into which we have entered. The BGS auction, for example, results in a contract that provides for the supplier to serve a percentage of the default load of a New Jersey EDC, that is, the load that remains after some customers have chosen to be served directly either by third-party suppliers or through municipal aggregation. The amount of power supplied through the BGS auction varies based on the level of the EDC's default load, which is affected by the number of customers who are served by third-party suppliers, as well as by other factors such as weather and the economy.

In recent years, as market prices declined from previous levels, there was an incentive for more of the smaller commercial and industrial electric customers to switch to third-party suppliers. In a falling price environment, this has a negative impact on our margins, as the anticipated BGS pricing is replaced by lower spot market pricing. As average BGS rates have declined to a level that more closely resembles current market prices, customers may see less of an incentive to switch to third-party suppliers. We are unable to determine the degree to which this switching, or "migration," will continue, but the impact on our results could be material should market prices fall or rise significantly.

In 2016, Power announced its intention to develop a retail energy platform to sell physical electricity and natural gas directly to commercial and industrial customers. We believe a retail energy platform would complement our existing wholesale generation-to-load marketing business and is intended to hedge our generation at improved margins in the geographic areas where we have generation facilities. Power was granted licenses in 2016 to sell both electricity and gas in the states of New Jersey and Pennsylvania and expects to begin its marketing efforts in 2017.

As of February 9, 2017, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2019.

Base Load Generation	2017	2018	2019
Generation Sales	100%	80%-85%	35%-40%

In a changing market environment, this hedging strategy may cause our realized prices to differ materially from current market prices. In a rising price environment, this strategy normally results in lower margins than would have been the case had no hedging activity been conducted. Alternatively, in a falling price environment, this hedging strategy will tend to create margins higher than those implied by the then-current market.

Our fuel strategy is to maintain certain levels of uranium in inventory and to make periodic purchases to support such levels. Our nuclear fuel commitments cover approximately 100% of our estimated uranium, enrichment and fabrication requirements through 2018 and a significant portion through 2021. We also have various long-term fuel purchase commitments for coal to support our Keystone, Conemaugh and Bridgeport Harbor stations. These purchase obligations are consistent with our strategy in general to enter into contracts for our fuel supply in comparable volumes to our sales contracts.

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We take a more opportunistic approach in hedging both the fuel for and the anticipated output of our natural gas-fired generation. The generation from these units is less predictable, as a significant portion of these units will only dispatch when aggregate market demand has exceeded the supply provided by lower-cost units. Additionally, the recent development of low-cost gas supplies in the Marcellus region presents opportunities during certain portions of the year to procure gas for our generating units at attractive prices.

More than half of Power's expected gross margin in the upcoming year relates to our hedging strategy, our expected revenues from the capacity market mechanisms described above and certain ancillary service payments such as reactive power.

Other

Energy Holdings primarily owns and manages a portfolio of domestic lease investments. The majority of Energy Holdings' $649 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2016, the counterparties for 66% of our total leveraged lease investments were rated below investment grade by Standard & Poor's (S&P). See Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables for additional information.

Energy Holdings' leveraged leasing portfolio is designed to provide a fixed rate of return. Leveraged lease investments involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease financing, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and, with respect to our lease investments, is not presented on our Consolidated Balance Sheets.

The lessor acquires economic and tax ownership of the asset and then leases it to the lessee for a period of time no greater than 80% of its remaining useful life. As the owner, the lessor is entitled to depreciate the asset under applicable federal and state tax guidelines. The lessor receives income from lease payments made by the lessee during the term of the lease and from tax benefits associated with interest and depreciation deductions with respect to the leased property. Our ability to realize these tax benefits is dependent on operating gains generated by our other operating subsidiaries and allocated pursuant to the consolidated tax sharing agreement between us and our operating subsidiaries.

Lease rental payments are unconditional obligations of the lessee and are set at levels at least sufficient to service the non-recourse lease debt. The lessor is also entitled to any residual value associated with the leased asset at the end of the lease term. An evaluation of the after-tax cash flows to the lessor determines the return on the investment. Under accounting principles generally accepted in the United States (GAAP), the leveraged lease investment is recorded net of non-recourse debt and income is recognized as a constant return on the net unrecovered investment.

For additional information on leases, including the credit, tax and accounting risks, see Item 1A. Risk Factors, Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Credit Risk, and Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables.

In accordance with a twelve year Amended and Restated Operations Services Agreement (OSA) entered into by PSEG LI and the LIPA, PSEG LI commenced operating LIPA's electric T&D system in Long Island, New York on January 1, 2014. As required by the OSA, PSEG LI also provides certain administrative support functions to LIPA. PSEG LI uses its brand in the Long Island T&D service area. Pursuant to the OSA, PSEG LI acts as LIPA's agent in performing many of its obligations and in return (a) receives reimbursement for pass-through operating expenditures, (b) receives a fixed management fee and (c) is eligible to receive an incentive fee contingent on meeting established performance metrics. In addition, there is the opportunity for the parties to extend the contract for an additional eight years subject to the achievement by PSEG LI of certain performance levels during the initial term of the OSA. Also, as of January 2015, Power began providing fuel procurement and power management services to LIPA under separate agreements.

COMPETITIVE ENVIRONMENT

PSE&G

Our transmission and distribution business is minimally impacted when customers choose alternate electric or gas suppliers since we earn our return by providing transmission and distribution service, not by supplying the commodity. Increased reliance by customers on net-metered generation, including solar, and changes in customer behaviors can result in decreased reliance on our system and impact our revenues and investment opportunities. The demand for electric energy and gas by customers is affected by customer conservation, economic conditions, weather and other factors not within our control.

Changes in the current policies for building new transmission lines, such as those ordered by FERC and being implemented by PJM and other ISOs to eliminate contractual provisions that previously provided us a "right of first refusal" (ROFR) to construct projects in our service territory, could result in third-party construction of transmission lines in our area in the future

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and also allow us to seek opportunities to build in other service territories. These implementing rules within the regions are still in flux so both the extent of the risk within our service territory and the opportunities for our transmission business elsewhere remain difficult to assess. For additional information, see the discussion in Regulatory Issues—Federal Regulation—Transmission Regulation, below.

Construction of new local generation and changing customer usage patterns also have the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints.

Power

Various market participants compete with us and one another in buying and selling in the wholesale energy markets, entering into bilateral contracts and selling to aggregated retail customers. Our competitors include:

- merchant generators,
- domestic and multi-national utility generators,
- energy marketers,
- banks, funds and other financial entities,
- fuel supply companies, and
- affiliates of other industrial companies.

New additions of lower-cost or more efficient generation capacity could make our plants less economic in the future. Although it is not clear if this capacity will be built or, if so, what the economic impact will be, such additions would impact market prices and our competitiveness.

Our business is also under competitive pressure due to demand side management (DSM) and other efficiency efforts aimed at changing the quantity and patterns of usage by consumers which could result in a reduction in load requirements. A reduction in load requirements can also be caused by economic cycles, weather, municipal aggregation and other customer migration and other factors. In addition, how resources such as demand response and capacity imports are permitted to bid into the capacity markets also affects the prices paid to generators such as Power in these markets. It is also possible that advances in technology, such as distributed generation and micro grids, will reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. To the extent that additions to the electric transmission system relieve or reduce limitations and constraints in eastern PJM where most of our plants are located, our revenues could be adversely affected. Changes in the rules governing what types of transmission will be built, who is selected to build transmission and who will pay the costs of future transmission could also impact our generation revenues.

Adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, would have the effect of artificially depressing prices in the competitive wholesale market and thus have the potential to harm competitive markets, on both a short-term and a long-term basis. At the same time, changes implemented in the PJM and New England capacity markets and other proposed market changes discussed more fully in Regulatory Issues—Federal Regulation provide the opportunity for additional compensation in both the energy and capacity markets.

Environmental issues, such as restrictions on emissions of carbon dioxide (CO_2) and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant, thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states.

While it is our expectation that efforts may be undertaken by the new administration, following the 2016 U.S. presidential election, to preserve the existing base of fossil generating plants, we still believe that pressures from renewable resources will continue to increase. For example, many parts of the country, including the mid-western region served by the Midwest Independent System Operator (MISO), the PJM region and the California ISO, have either implemented or proposed implementing changes to their respective regional transmission planning processes that may enable the construction of large amounts of “public policy” transmission to move renewable generation to load centers. For additional information, see the discussion in Regulatory Issues—Federal Regulation.

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EMPLOYEE RELATIONS

As of December 31, 2016, we had 13,065 employees within our subsidiaries, including 8,161 covered under collective bargaining agreements. Since the beginning of 2016, six of our eight labor unions ratified extensions of their collective bargaining agreements with us, with expiration dates from 2019 to 2021. The collective bargaining agreements for the remaining two unions expire in June 2017 and May 2018. We believe we maintain satisfactory relationships with our employees.

	Employees as of December 31, 2016			
	PSE&G	Power	PSEG LI	Other
Non-Union	1,898	1,165	811	1,030
Union	5,108	1,549	1,496	8
Total Employees	**7,006**	**2,714**	**2,307**	**1,038**

REGULATORY ISSUES

In the ordinary course of our business, we are subject to regulation by, and are party to various claims and regulatory proceedings with, FERC, the BPU, the Commodity Futures Trading Commission and various state and federal environmental regulators, among others. For information regarding material matters, other than those discussed below, see Item 3. Legal Proceedings and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Federal Regulation

FERC

FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act. PSE&G and the generation and energy trading subsidiaries of Power are public utilities as defined by the FPA. FERC has extensive oversight over such public utilities. FERC approval is usually required when a public utility seeks to: sell or acquire an asset that is regulated by FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations. As a result of the change in administration following the U.S. presidential election, FERC does not currently have the quorum required to issue certain substantive orders. Until quorum is obtained, FERC Staff has been delegated authority, which allows FERC to continue carrying out its regulatory obligations in the absence of a quorum of Commissioners. The FERC order delegated to FERC Staff the ability to take certain actions to avoid filings going into effect by operation of law until FERC again has a quorum and moves to lift the delegation order.

FERC also regulates generating facilities known as qualifying facilities (QFs). QFs are cogeneration facilities that produce electricity and another form of useful thermal energy, or small power production facilities where the primary energy source is renewable, biomass, waste or geothermal resources. QFs must meet certain criteria established by FERC. We own various QFs through Power. QFs are subject to some, but not all, of the same FERC requirements as public utilities.

FERC also regulates Regional Transmission Operators (RTOs)/ISOs, such as PJM, and their energy and capacity markets.

For us, the major effects of FERC regulation fall into five general categories:

- Regulation of Wholesale Sales—Generation/Market Issues/Market Power
- Energy Clearing Prices
- Capacity Market Issues
- Transmission Regulation
- Compliance

Regulation of Wholesale Sales—Generation/Market Issues/Market Power

Under FERC regulations, public utilities that wish to sell power at market rates must receive FERC authorization ("MBR Authority") to sell power in interstate commerce before making power sales. They can sell power at cost-based rates or apply to FERC for authority to make market-based rate (MBR) sales. For a requesting company to receive MBR Authority, FERC must

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first make a determination that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. The following PSEG companies are public utilities and currently have MBR Authority: PSE&G, PSEG ER&T, PSEG Fossil, PSEG Nuclear, PSEG Power Connecticut, PSEG New Haven, PSEG Energy Solutions, Pavant Solar II LLC, San Isabel Solar LLC and Bison Solar LLC. FERC requires that holders of MBR Authority file an update every three years demonstrating that they continue to lack market power and/or that their market power has been sufficiently mitigated and report in the interim to FERC any material change in facts from those FERC relied on in granting MBR Authority.

In December 2016, the PSEG companies with MBR Authority filed their triennial market power analysis as required by FERC regulations. A FERC order on the PSEG companies' triennial filing is expected in the third quarter 2017.

Energy Clearing Prices

Energy clearing prices in the markets in which we operate are generally based on bids submitted by generating units. Under FERC-approved market rules, bids are subject to price caps and mitigation rules applicable to certain generation units. FERC rules also govern the overall design of these markets. At present, all units within a delivery zone receive a clearing price based on the bid of the marginal unit (i.e. the last unit that must be dispatched to serve the needs of load) which can vary by location. In addition, recent rule changes in the energy markets administered by PJM and ISO-NE (see Capacity Market Issues below) impose rigorous performance obligations and nonperformance penalties on resources during times of system stress. These FERC rules have a direct impact on the prices received by our units.

FERC has also recently ordered certain favorable changes to energy market price formation rules improving shortage pricing and enhancing bidding flexibility for units. We continue to advocate in this context for additional changes in market rules that would provide more transparency about energy market prices. We cannot predict what action FERC might ultimately take, but such an examination could lead to future rule changes.

Capacity Market Issues

PJM, NYISO and ISO-NE each have capacity markets that have been approved by FERC. FERC regulates these markets and continues to examine whether the market design for each of these three capacity markets is working optimally. Issues presented in various forums include consideration of whether capacity market rules properly address and foster the development of state public policies, demand response (DR) and emerging technologies, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market outcomes. We cannot predict what action, if any, FERC might take with regard to capacity market design.

PJM—The RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under the RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of the RPM in PJM continue to evolve and be refined in stakeholder proceedings and FERC proceedings in which we are active.

During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product definition with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. However, aspects of FERC's order are currently pending appeal in the Court of Appeals for the D.C. Circuit (D.C. Circuit). The CP product will be implemented fully for the 2020-2021 Delivery Year. Based upon the August 2015 base residual auction results, the CP mechanism appears to have provided the opportunity for enhanced capacity market revenue streams for Power but future impacts cannot be assured. Efforts to modify the CP construct to enhance the participation of intermittent and DR resources ("seasonal resources") are currently pending before FERC. PJM has proposed modifications to the aggregation rules to improve the ability of seasonal resources to participate and two complaints have been filed requesting that FERC investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions. We expect either FERC action on PJM's proposal or inaction in the event that it goes into effect by operation of law before the upcoming base residual auction in May 2017. If PJM's proposal goes into effect by operation of law, there could be an increase in the participation of seasonal resources in the auction.

In September 2014, PJM filed at FERC to re-set the Variable Resource Requirement (VRR) curve for the RPM. PJM expects to reset the VRR every four years. Establishment of the VRR curve is a critical component in determining how generators are paid in the capacity auction. In November 2014, FERC accepted PJM's filing, which we believe represents an improvement over the status quo in terms of appropriately setting the demand curve. However, we and a trade association composed of other generators have challenged FERC's approval order on appeal at the D.C. Circuit, taking exception to FERC's approval of the manner in which PJM calculated the cost of capital and labor costs that form the basis for the Cost of New Entry component of the demand curve, which we believe have been set too low and do not accurately reflect the costs of building a new generating unit in PJM.

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Over the past several years, certain entities in PJM, namely, FirstEnergy Corp. (FE) and American Electric Power (AEP) sought financial support arrangements from the Ohio Public Utility Commission (PUCO) for certain coal plants and, for FE, a nuclear plant. FE and AEP originally proposed to enter into power purchase agreements (PPAs) with their non-utility generation affiliates providing for above-market purchases from these plants. The PUCO Staff proposed a payment to support modernization of the distribution system (distribution modernization rider) in the FE case which was ultimately accepted by the PUCO. The Dayton Power and Light Company also recently filed for a distribution modernization rider for the generating plants that it owns.

The PUCO proceedings created a concern that subsidized units within the PJM footprint would submit bids in the capacity market that are not reflective of their actual operating costs and would, in turn, artificially suppress capacity prices. As a result, certain parties requested that FERC should direct PJM to expand the "minimum offer price rule" to apply to existing units.

We are unable to predict the results of these pending proceedings or any future related proceedings or to calculate the potential impacts on our business.

MISO—MISO does not have a mandatory capacity market in place, as load serving entities may submit Fixed Resource Adequacy Plans in lieu of participating in the capacity auction. Significant quantities of capacity from MISO are imported into PJM which tends to have a downward effect on PJM capacity prices. However, recent enhancements to PJM market rules have tightened eligibility requirements for PJM imports and reduced these impacts. The issue of "capacity portability" from MISO continues to be examined in the stakeholder process.

ISO-NE—ISO-NE's market for installed capacity in New England provides fixed capacity payments for generators, imports and DR. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. ISO-NE also employs a mechanism, similar to PJM's CP mechanism, that provides incentives for performance and that imposes charges for non-performance during times of system stress. We view this mechanism as generally positive for generating resources as providing more robust income streams. However, it also imposes additional financial risk for non-performance. One aspect of the current market design that we do not support is the exemption from the MOPR in the capacity market afforded for up to 200 MW annually (600 MW cumulatively) of renewable resources. FERC has approved downward sloping demand curves and zonal curves for the three designated capacity zones for Forward Capacity Auction (FCA) 11. In addition, ISO-NE's review of the Net Cost of New Entry (Net CONE) was recently submitted at FERC which would be implemented for FCA 12. If approved by FERC, the value of Net CONE will be reduced which could impact the revenues we expect to receive for our generation in the New England capacity market.

NYISO—NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. Various matters pending before FERC could affect the competitiveness of this market and the outcome of these proceedings could result in artificial price suppression unless sufficient market protections are adopted.

One capacity market matter pending before FERC involves rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons. In March 2015, FERC issued an order which held that units receiving special reliability payments could properly take those payments into account in formulating capacity market bids. We believe that this ruling could impact efficient price formation in the capacity market and could artificially suppress capacity market outcomes. In April 2015, a trade association, Independent Power Producers of New York, Inc. (IPPNY) of which Power is a member, filed for rehearing by FERC of this ruling. This rehearing is still pending. Also, in connection with this same proceeding, FERC required NYISO to submit a report addressing whether buyer-side mitigation measures are needed for new entry occurring in the "Rest of State" (ROS) region and for uneconomic retention and repowering anywhere in the state. NYISO filed a report with FERC in December 2015 contending that these measures are not needed. The IPPNY has opposed NYISO's contentions. The matter remains pending before FERC. In addition, in May 2015, the New York Public Service Commission and other New York agencies filed a complaint at FERC requesting certain exemptions from the NYISO rules that prevent capacity suppliers from submitting bids that are not market competitive. On October 9, 2015, FERC granted in part, certain of the requested exemptions for renewable resources and for resources being used by the owner for self-supply. The IPPNY has challenged NYISO's proposed implementation of the newly required exemptions. This challenge is still pending.

NYISO's capacity market incorporates demand curves that are determined periodically by NYISO and approved by FERC. In November 2016, NYISO submitted to FERC for approval proposed demand curves that updated key parameters. The updated demand curves reflect the expected cost of new entry of peaking plants in New York and in each of the three capacity localities. If approved, this could impact the revenues we expect to receive for our generation in the New York capacity market. FERC issued an order substantially accepting NYISO's proposed demand curves, but did not accept the proposal that the ROS proxy peaking unit design include selective catalytic reduction (SCR) emissions control technology.

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Price Formation Initiatives

Power has been actively involved both through stakeholder processes and through filings at FERC in seeking improvements to the rules for setting prices for energy in the day-ahead and real-time markets administered by PJM and other system operators. FERC recently issued a notice of proposed rulemaking (NOPR) proposing that RTOs/ISOs modify their rules governing fast-start resources. Fast-start resources typically are committed in real-time, very close to the interval when needed and can respond quickly to unforeseen system needs. However, without fast-start pricing, some fast-start resources are ineligible to set prices due to inflexible operating limits. As a result, prices may not reflect the marginal cost of serving load. In a separate proceeding, PJM has submitted a proposal at FERC's request to modify its rules to allow market sellers to submit day-ahead offers that vary by hour and to allow market sellers to update their offers in real time on an hourly basis under certain circumstances. These rule changes are currently pending before FERC. If both changes are approved, we believe that they would improve price formation in the energy and ancillary services markets.

Transmission Regulation

FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures. Our allowed ROE is 11.68% for both existing and new transmission investments and we have received incentive rates, affording a higher ROE, for certain large scale transmission investments.

In October 2016, PSE&G filed its 2017 Annual Formula Rate Update with FERC which requests approximately $121 million in increased annual transmission revenues effective January 1, 2017, subject to true-up. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. For additional information about our transmission formula rate, see Item 8. Financial Statements and Supplementary Data —Note 6. Regulatory Assets and Liabilities.

Transmission Policy Developments—FERC concluded in Order 1000 that the incumbent transmission owner should not always have a ROFR to construct and own transmission projects in its service territory. We and other companies appealed Order 1000 but this appeal was denied in 2014 by the D.C. Court. The current PJM rules retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including immediately needed reliability projects, upgrades to existing transmission facilities, projects cost-allocated to a single transmission zone, and projects being built on existing rights-of-way and whose construction would interfere with incumbents' use of their rights-of-way.

In a September 2015 order, FERC directed that a technical conference be held to address "concerns regarding how PJM plans for local transmission projects." Parties in the case raised concerns that too many projects are being approved outside of the Regional Transmission Expansion Plan (RTEP) mechanism to address "local" reliability requirements without going through the Order 1000 open window process. Intervenors also complained that there is inadequate transparency regarding the PJM transmission owners' consideration and selection of Supplemental Projects (which are not approved by the PJM Board). PSE&G is participating in the process before FERC in support of the current PJM processes. In addition, certain PJM stakeholders have proposed an examination of the current planning rules, including changes with regard to criteria to be used for replacement of facilities that have reached their "end of life." PSE&G has been actively participating in this process. However, we are unable to predict the outcome of these efforts.

In a February 2016 order, FERC reversed a previous order and accepted a filing by the PJM transmission owners seeking authority to assign costs for RTEP projects (subject to PJM Board approval requirements) solely addressing localized needs to customers within the local transmission owner's zone. FERC's action in this order provides an exemption from the Order 1000 open window procedures for projects constructed by transmission owners to meet local transmission planning criteria. In April 2016, PJM filed at FERC to incorporate a voltage threshold into PJM's RTEP process to exempt, except under certain circumstances, reliability violations on facilities below 200 kV from PJM's proposal window process. We generally support this reform as a measure to improve the efficiency of the open window procedure that will permit transmission developers to focus on the projects most likely to benefit from a competitive process.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G contending that insufficient levels of costs are being allocated to customers in the PSE&G transmission zone. Projects involved include the Artificial Island project, the Bergen-Linden project in New Jersey and a smaller project in Sewaren, New Jersey. In April 2016, FERC issued orders denying the complaints and leaving the current cost allocation in effect as to the Artificial Island and Bergen-Linden projects. Due to an intervening FERC order concerning the allocation of costs for projects constructed to meet local reliability requirements, FERC directed that all of the Sewaren costs be allocated to customers in the PSE&G transmission zone. It is anticipated that additional proceedings are likely to occur.

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In February 2016, FERC issued an order granting PSE&G's request that it be permitted to seek recovery of 100% of its portion of the project's costs to address identified high voltage issues at Artificial Island in New Jersey if the project is canceled for reasons beyond PSE&G's control. In April 2016, PSE&G accepted construction responsibility for the three components of the project that PJM assigned to it, based on having reached agreement with PJM regarding an estimate for the project base cost of $273 million, plus risk and contingency for a total project cost of up to $340 million. In August 2016, PJM announced that it had suspended the Artificial Island transmission project and would be performing a comprehensive analysis to support a future course of action. PJM is expected to submit its final recommendation to the PJM Board at the April 2017 Board meeting.

In June 2015, a transmission developer filed a complaint against PJM claiming that PJM wrongfully refused to provide data and a transparent process for evaluating transmission network upgrade requests that the transmission developer had submitted to PJM. According to the complaint, PJM and certain transmission owners wrongfully inflated the scope and associated costs of mitigation work needed to accommodate the developer's proposal in order to prevent it from pursuing its projects. Although not named as a respondent in the complaint, PSE&G is identified as one of the companies claimed to have been involved. FERC set the complaint for hearing and settlement procedures and the parties are currently engaged in discovery. We are unable to predict the outcome of these proceedings.

Another proceeding is a matter remanded from a federal appellate court concerning the appropriate cost allocation for certain 500 kV projects in PJM that either have been built or are in the process of being built, including the Susquehanna-Roseland project. A proposed settlement was filed with FERC in June 2016. The settlement, if adopted by FERC, would result in increased annual cost allocations to customers in the PSE&G transmission zone. Under this settlement, Power, as a BGS supplier could become obligated to pay amounts previously paid by other PJM transmission customers. However, we do not believe that the anticipated level of any such potential payments would have a material effect on Power's financial statements. We believe that there is a mechanism in place under the BGS contract for the pass-through of increases in transmission charges.

Transmission Rate Proceedings—Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base ROEs. Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. While we are not the subject of a challenge to the ROE employed in PSE&G's transmission formula rate, the results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Con Edison Wheeling Agreement—In April 2016, Con Edison informed PJM that it would allow its Wheeling Agreement to expire effective as of May 1, 2017. The Wheeling Agreement enables Con Edison to move 1,000 MW of power from southeastern New York across the PSE&G system for delivery into New York City. NYISO and PJM submitted proposed tariff provisions in January 2017. The proposal concerns future operational procedures and transmission planning assumptions associated with the affected transmission lines. The manner in which PJM has calculated the import assumptions for the upcoming base residual auction has decreased the potential for locational splits in the zones where PSEG has its assets. However, PJM has indicated that it is still reviewing these import assumptions and may publish revised values before the auction. We cannot predict the impact of the proposal on energy prices or transmission planning at this time. Also, PSE&G will continue to recover the costs associated with the new arrangement through its formula rate. However, we continue to review the proposal and may protest certain of its elements.

Compliance

FERC—For information about the preliminary non-public investigation initiated by the FERC Staff regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Reliability Standards—Congress has required FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the U.S. electric transmission and generation system (grid) and to prevent major system blackouts. There has been considerable focus recently on physical security in light of, among other things, a substation attack in California that occurred in 2013. As a result, FERC directed the NERC to draft a physical security standard intended to further protect assets deemed "critical" to reliability of the grid. In November 2014, FERC issued an order approving the NERC's proposed physical security standard. Under the standard, utilities will be required to identify critical substations as well as develop threat assessment plans to be reviewed by independent third parties. In our case, the third-party is PJM. As part of these plans, utilities could decide or be required to build additional redundancy into their systems. This standard will supplement the Critical Infrastructure Protection standards that are already in place and that establish physical and cybersecurity protections for critical systems. We are taking steps to meet the new obligations. FERC directed the NERC to develop a new reliability standard to provide security controls for supply chain management associated with the procurement of industrial control system hardware, software, and services related to bulk electric system operations. When adopted, compliance with these new standards would be expected to impose additional obligations and costs.

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Commodity Futures Trading Commission (CFTC)

In accordance with the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), the SEC and the CFTC are in the process of implementing a new regulatory framework for swaps and security-based swaps. The legislation was enacted to reduce systemic risk, increase transparency and promote market integrity within the financial system by providing for the registration and comprehensive regulation of swap dealers and by imposing recordkeeping, data reporting, margin and clearing requirements with respect to swaps. To implement the Dodd-Frank Act, the CFTC has engaged in a comprehensive rulemaking process and has issued a number of proposed and final rules addressing many of the key issues. We are currently subject to recordkeeping and data reporting requirements applicable to commercial end users. The CFTC has also re-proposed rules establishing position limits for trading in certain commodities, such as natural gas, and we will begin complying with these rules once they become final.

Nuclear Regulatory Commission (NRC)

Our operation of nuclear generating facilities is subject to comprehensive regulation by the NRC, a federal agency established to regulate nuclear activities to ensure protection of public health and safety, as well as the security and protection of the environment. Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstration to the NRC that plant operations meet requirements is also necessary. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate. The current operating licenses of our nuclear facilities expire in the years shown in the following table:

Unit	Year
Salem Unit 1	2036
Salem Unit 2	2040
Hope Creek	2046
Peach Bottom Unit 2	2033
Peach Bottom Unit 3	2034

As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in 2011, the NRC began performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events in Japan have resulted in additional regulation and implementation guidance for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants currently meet the stringent applicable design and safety specifications of the NRC.

We have implemented the diverse and flexible mitigating strategies and spent fuel pool level indication modifications in accordance with the regulatory requirements at the Salem, Hope Creek and Peach Bottom nuclear units. For our Hope Creek and Peach Bottom units, implementation of the required venting system modifications is expected to be completed by 2018.

The NRC continues to evaluate potential revisions to its requirements in connection with its operational and safety reviews of nuclear facilities in the United States as a result of the Fukushima Daiichi incident.

We are unable to predict the final outcome of these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to our Salem, Hope Creek and Peach Bottom facilities, but such cost could be material.

State Regulation

Since our operations are primarily located within New Jersey, our principal state regulator is the BPU, which oversees electric and natural gas distribution companies in New Jersey. We are also subject to various other states' regulations due to our operations in those states.

Our New Jersey utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. PSE&G's participation in solar, demand response and energy efficiency programs is also regulated by the BPU, as the terms and conditions of these programs are approved by the BPU. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey.

We must file electric and gas rate cases with the BPU in order to change our utility base distribution rates. Our last base rate case was settled in 2010. As a result of our 2014 Energy Strong Order, we are required to file our next distribution base rate case proceeding no later than November 1, 2017. In addition to base rates, we recover certain costs or earn on certain investments pursuant to mechanisms known as adjustment clauses. These clauses permit the flow-through of costs to, or the

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recovery of investments from, customers related to specific programs, outside the context of base rate case proceedings. Recovery of these costs or investments is subject to BPU approval for which we make periodic filings. Delays in the pass-through of costs or recovery of investments under these mechanisms could result in significant changes in cash flow. For additional information on our specific filings, see Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

Gas System Modernization Program (GSMP)—In November 2015, the BPU issued an order approving the settlement of our GSMP through which PSE&G will invest $905 million over the next three years to modernize its gas system. The settlement enables the utility to replace up to 510 miles of gas mains and 38,000 service lines over a three-year period, with cost recovery at a 9.75% rate of return on equity on $650 million of the investment through an accelerated recovery mechanism. Under the settlement, PSE&G will seek recovery of the remaining $255 million of investment in its next base rate case. In December 2016, the BPU approved PSE&G's initial GSMP cost recovery petition which allows PSE&G to recover in base rates capitalized GSMP investment costs for infrastructure placed in service through September 30, 2016. The BPU order provides for a total $10 million annual revenue increase effective January 1, 2017.

BPU Cybersecurity Requirements for Regulated Entities—In March 2016, the BPU issued an order for the regulated electric, natural gas, and water/wastewater utilities to further reduce the potential for cyber threats to the reliability and resiliency of utility service and to protect customers' information. The order requires these regulated utilities, including PSE&G, to, among other conditions, implement a cybersecurity program that defines and implements organization accountabilities and responsibilities for cyber risk management activities, and establishes policies, plans, processes and procedures for identifying and mitigating cyber risk to critical systems.

In December 2016, PSE&G submitted a required letter to the BPU outlining its compliance efforts to date and noting that it currently has not identified any potential barriers to compliance with the order's requirements. New Jersey utilities, including PSE&G, are required to be compliant with these requirements by October 1, 2017, taking various measures aimed to meet this compliance deadline. For a discussion of the risks associated with cyber threats, see Item 1A. Risk Factors.

Solar 4 All Program Extension II—In November 2016, the BPU approved a settlement providing for an extension of PSE&G's existing landfill/brownfield solar program to construct up to 33 MW of grid connected facilities with projected capital expenditures of approximately $80 million through May 2020.

Consolidated Tax Adjustments (CTA)—New Jersey is one of only a few states that make CTA in setting rates for regulated utilities. These adjustments to rate base are made during the rate setting process and are intended to allocate to utility customers a portion of the tax benefits realized from the filing of a consolidated federal tax return by the utility's parent corporation. The BPU has been considering the appropriateness of the adjustment and the methodology and mechanics of the calculation for some time. In October 2014, the BPU approved a proposal by its Staff that limits the tax benefit period to be considered in the calculation to five years, sets the rate base adjustment at 25% of any such tax benefit and eliminates from the process any tax benefits tied to transmission earnings. In accordance with this October action, this CTA policy will be applied only with respect to future rate cases. The adoption of these modifications by the BPU is not expected to have a material impact on PSE&G's current earnings nor in its next rate case filing. In November 2014, the New Jersey Division of Rate Counsel appealed the BPU's decision which remains pending.

Connecticut Rate Filing—In June 2016, Power's subsidiary, PSEG New Haven LLC, filed a mandatory annual rate case with the Connecticut Public Utilities Regulatory Authority for recovery of its costs and investment in its Connecticut-based peaking unit. Power requested 2017 revenues of $20 million, which was approved in its entirety.

Additional matters are discussed in Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

ENVIRONMENTAL MATTERS

We are subject to federal, state and local laws and regulations with regard to environmental matters including, but not limited to:

- air pollution control,
- climate change,
- water pollution control,
- hazardous substance liability, and
- fuel and waste disposal.

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We expect there will be changes to existing environmental laws and regulations, particularly in light of the change in administration following the 2016 U.S. presidential election, which could significantly impact the manner in which our operations are currently conducted. Such laws and regulations may also affect the timing, cost, location, design, construction and operation of new facilities. Due to evolving environmental regulations, it is difficult to project future costs of compliance and their impact on competition. Capital costs of complying with known pollution control requirements are included in our estimate of construction expenditures in Item 7. MD&A—Capital Requirements. The costs of compliance associated with any new requirements that may be imposed by future regulations are not known, but may be material.

For additional information related to environmental matters, including proceedings not discussed below, as well as anticipated expenditures for installation of pollution control equipment, hazardous substance liabilities and fuel and waste disposal costs, see Item 1A. Risk Factors, Item 3. Legal Proceedings and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Air Pollution Control

Our facilities are subject to federal regulation under the Clean Air Act (CAA) which requires controls of emissions from sources of air pollution and imposes recordkeeping, reporting and permit requirements. Our facilities are also subject to requirements established under state and local air pollution laws. The CAA requires all major sources, such as our generation facilities, to obtain and keep current an operating permit. The costs of compliance associated with any new requirements that may be imposed and included in these permits in the future could be material and are not included in our estimates of capital expenditures.

Hazardous Air Pollutants Regulation—In February 2012**,** the Environmental Protection Agency (EPA) published Mercury Air Toxics Standards (MATS) for both newly-built and existing electric generating sources under the National Emission Standard for Hazardous Air Pollutants (NESHAP) provisions of the CAA. The MATS established allowable levels for mercury as well as other hazardous air pollutants and went into effect in April 2015. In June 2015, the U.S. Supreme Court held that it was unreasonable for the EPA to refuse to consider the materiality of costs in determining whether to regulate hazardous air pollutants from power plants. In April 2016, the EPA released the final Supplemental Finding that considers the materiality of costs in determining whether to regulate hazardous air pollutants from power plants in response to the U.S. Supreme Court's ruling. Industry participants and various state authorities have filed petitions with the D.C. Court challenging the EPA's Supplemental Finding. We do not expect this Supplemental Finding to impact operation of our facilities.

Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation—In March 2013, Power filed a petition at the EPA challenging the NESHAP for RICE issued in January 2013. Among other things, the NESHAP include two exemptions that allow owners and operators of stationery emergency RICE to operate their engines without the installation and operation of emission controls (1) as part of an emergency DR program for 100 hours per year (100 hour exemption) or (2) as part of a financial arrangement with another entity per specified restrictions in non-emergency situations for 50 hours per year (50 hour exemption). In its petition, Power sought more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. In August 2014, the EPA denied the March 2013 petition and in October 2014, Power appealed the EPA's denial to the D.C. Court. In September 2015, the D.C. Court granted the EPA's motion for voluntary remand of the 50 hour exemption provision to the EPA. In May 2016, the D.C. Court vacated the 100 hour exemption which removes that provision from the rule.

Cross-State Air Pollution Rule (CSAPR)—In January 2015, the final CSAPR became effective which limits power plant emissions of sulfur dioxide (SO_2) and annual and ozone season nitrogen oxide (NO_x) in 28 states that contribute to the ability of downwind states to attain and/or maintain the 1997 and 2006 particulate matter and the 1997 ozone National Ambient Air Quality Standards (NAAQS). In April 2015, the EPA revoked the 1997 ozone NAAQS of 80 parts per billion (ppb) and began implementation of the more stringent 2008 ozone NAAQS of 75 ppb. In September 2016, the EPA published the final CSAPR Updating Rule to address the 2008 National Ambient Air Quality Standards for ground-level ozone. The rule establishes more stringent annual ozone season (May 1 through September 30) caps beginning in May 2017. We do not anticipate any material impact on our business or financial condition due to the CSAPR. Numerous parties have filed petitions for review with the D.C. Court to challenge the CSAPR Updating Rule.

Ozone Standard—In December 2014, the EPA proposed a rule to lower the ambient air quality standard for the level of ozone in the atmosphere from 75 ppb to a level in the range of 65-70 ppb. On October 1, 2015, the EPA finalized a standard of 70 ppb. To meet the new standard, the EPA and the states have to implement additional emission reduction strategies for NO_x and volatile organic compounds. Some portions of the Mid-Atlantic and New England states are not expected to be able to meet the new standard. Although the majority of our fossil generating units employ state-of-the-art NO_x emission controls, we cannot predict the outcome of this matter since new requirements of the EPA and the states are unknown at this time. Numerous parties have filed petitions for review with the D.C. Court to challenge the rule.

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Climate Change

***CO_2 Regulation under the* CAA**—In October 2015, the EPA published the New Source Performance Standards (NSPS) for new power plants. The NSPS establishes two emission standards for CO_2 for the following categories: (i) fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units, and (ii) natural gas combustion turbines. Simple cycle combustion turbines are exempt from the rule.

In October 2015, the EPA published the Clean Power Plan (CPP), a greenhouse gas (GHG) emissions regulation under the CAA for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction (BSER). The BSER consists of three components: (i) heat rate improvements at existing coal-fired power plants, (ii) increased use of existing natural gas combined cycle capacity, and (iii) operation of incremental zero-emitting generation (renewables and nuclear). States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions.

Numerous states, including New Jersey, and several industry groups filed petitions for review with the D.C. Court to challenge the CPP. In addition, the petitioners sought a stay of the rule. The U.S. Supreme Court stayed the rule pending further review of the case.

The U.S. Supreme Court's decision to stay the implementation of the CPP will delay deadlines for submission of state requests for extensions and final plans. If the CPP is upheld, new deadlines will need to be established and the effective date of the compliance period may be impacted.

Regional Greenhouse Gas Initiative (RGGI)—In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. New Jersey withdrew from RGGI in 2012. However, certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions.

These rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three-year period. Allowances are available through the auction or through secondary markets.

In November 2015 the RGGI States initiated a 2016 Program Review stakeholder process. The focus of the 2016 Program Review is the post-2020 caps on GHG emissions and the incorporation of the EPA's CPP requirements.

New Jersey adopted the Global Warming Response Act in 2007, which calls for stabilizing its GHG emissions to 1990 levels by 2020, followed by a further reduction of greenhouse emissions to 80% below 2006 levels by 2050. To reach this goal, the NJDEP, the BPU, other state agencies and stakeholders are required to evaluate methods to meet and exceed the emission reduction targets, taking into account their economic benefits and costs.

Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to U.S. waters from point sources, except pursuant to a National Pollutant Discharge Elimination System (NPDES) permit issued by the EPA or by a state under a federally authorized state program. The FWPCA authorizes the imposition of technology-based and water quality-based effluent limits to regulate the discharge of pollutants into surface waters and ground waters. The EPA has delegated authority to a number of state agencies, including those in New Jersey, New York and Connecticut, to administer the NPDES program through state action. We also have ownership interests in facilities in other jurisdictions that have their own laws and implement regulations to control discharges to their surface waters and ground waters that directly govern our facilities in those jurisdictions.

Steam Electric Effluent Guidelines—In September 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Bridgeport Harbor stations and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under this rule. We are unable to predict if this rule will have a material impact on our future capital requirements, financial condition and results of operations.

In addition to regulating the discharge of pollutants, the FWPCA regulates the intake of surface waters for cooling. The use of cooling water is a significant part of the generation of electricity at steam-electric generating stations. Section 316(b) of the FWPCA requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The impact of regulations under Section 316(b) can be significant, particularly at steam-electric generating stations which do not have closed cycle cooling and do not use cooling towers to recycle water for cooling purposes.

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The installation of cooling towers at an existing generating station can impose significant engineering challenges and significant costs, which can affect the economic viability of a particular plant.

Cooling Water Intake Structure Regulation—In May 2014, the EPA issued a final cooling water intake rule under Section 316(b) of the Clean Water Act (CWA) that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with assessment of the best technology available for minimizing adverse environmental impacts of each facility that seeks a permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications.

In September 2014, several environmental non-governmental groups and certain energy industry groups filed petitions for review of the rule and the case has been assigned to the U.S. Second Circuit Court of Appeals (Second Circuit). Environmental organizations, including but not limited to the environmental petitioners in the Second Circuit, have also filed suit under the Endangered Species Act. The cases were subsequently consolidated at the Second Circuit and a decision is expected by mid-2017.

We are assessing the potential impact of the rule on each of our affected facilities and are unable to predict the outcome of permitting decisions and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities for additional information.

In June 2016, the New Jersey Department of Environmental Protection (NJDEP) issued the final New Jersey Pollutant Discharge Elimination System (NJPDES) permit for Salem, with an effective date of August 1, 2016. The final permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the Clean Water Act, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of a final NJPDES renewal permit for Salem. The Riverkeeper's filing does not change the effective date of the permit. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

We are actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA's CWA Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, we would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire the BH3 within five years of the effective date of the final permit. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in 2017 with a retirement date for BH3 by summer 2021, which is four years earlier than the previously estimated useful life ending in 2025. If the permit is not issued and the conditions below are not met, we may seek to operate BH3 through the previously estimated useful life.

Separately, we have also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that we would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates, which could occur in 2017. Absent those conditions being met, and the permit renewal referred to above not being issued, we may seek to operate BH3 through the previously estimated useful life. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements.

In February 2016, the proposed generating facility, Bridgeport Harbor Station Unit 5 (BH5), was awarded a capacity obligation. Construction is expected to commence in 2017, with operations expected to begin in mid-2019. The Connecticut Siting Council issued an order to approve siting BH5. All major environmental permits have been obtained except for the New Source air permit that is currently in draft form for public comment.

Waters of the United States—In April 2014, the EPA Administrator and the Assistant Secretary of the Army (Civil Works) jointly published a proposed rule to clarify the definition of waters of the U.S. under the CWA programs in order to protect the streams and wetlands that form the foundation of the nation's water resources. This definition will have broad application to all areas of compliance under the CWA, including permitted discharges and construction activities. The final rule was published in June 2015 and various states, industry coalitions and environmental organizations have initiated legal action related to the provisions of the final rule as well as which court has jurisdiction over the rule. The U.S. Supreme Court is expected to rule on the question of jurisdiction by June 2017. Some states, including New Jersey, are subject to state requirements beyond those imposed under federal law. While we do not anticipate material impacts to projects in New Jersey, the new definition could impose requirements in other states and regions that could impact the development of renewables.

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Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance—In April 2015, we determined that monitoring and reporting practices related to certain permitted wastewater discharges at our Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject us to fines and penalties. We have notified the CTDEEP of the issues and have taken actions to investigate and resolve the potential non-compliance. We cannot predict the impact of this matter.

Endangered Species Act—In June 2015, the Sierra Club and another environmental group submitted to the NJDEP a sixty-day notice of intent to sue alleging the agency has caused violations of the Endangered Species Act by allowing our Mercer generation station to operate in a manner which has caused the mortality of certain species of sturgeon. Among other things, the notice requested the NJDEP to prioritize completion of a permit renewal action for Mercer which addresses the alleged Endangered Species Act violations. We are currently working with the National Marine Fisheries Service regarding an Incidental Take Permit that will outline operation and monitoring requirements through retirement of the Mercer generation station in May 2017 and subsequent decommissioning.

Hazardous Substance Liability

The production and delivery of electricity and the distribution and manufacture of gas result in various by-products and substances classified by federal and state regulations as hazardous. These regulations may impose liability for damages to the environment from hazardous substances, including obligations to conduct environmental remediation of discharged hazardous substances as well as monetary payments, regardless of the absence of fault and the absence of any prohibitions against the activity when it occurred, as compensation for injuries to natural resources. See Item 3. Legal Proceedings. Our historic operations and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by federal and state agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex. The EPA is also evaluating the Hackensack River, a tributary to Newark Bay, for inclusion in the Superfund program. We no longer manufacture gas. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Site Remediation—The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and the New Jersey Spill Compensation and Control Act (Spill Act) require the remediation of discharged hazardous substances and authorize the EPA, the NJDEP and private parties to commence lawsuits to compel clean-ups or reimbursement for such remediation. The clean-ups can be more complicated and costly when the hazardous substances are in a body of water.

Natural Resource Damages—CERCLA and the Spill Act authorize the assessment of damages against persons who have discharged a hazardous substance, causing an injury to natural resources. Pursuant to the Spill Act, the NJDEP requires persons conducting remediation to characterize injuries to natural resources and to address those injuries through restoration or damages. The NJDEP adopted regulations concerning site investigation and remediation that require an ecological evaluation of potential damages to natural resources in connection with an environmental investigation of contaminated sites. The NJDEP also issued guidance to assist parties in calculating their natural resource damage liability for settlement purposes, but has stated that those calculations are applicable only for those parties that volunteer to settle a claim for natural resource damages before a claim is asserted by the NJDEP. We are currently unable to assess the magnitude of the potential financial impact of this regulatory change, although such impacts could be material.

Fuel and Waste Disposal

Nuclear Fuel Disposal—The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In accordance with the Nuclear Waste Policy Act of 1982, in 2009 the DOE conducted its annual review of the adequacy of the Nuclear Waste Fee and concluded that the current fee of 1/10 cent per kWh was adequate to recover program costs. In 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit in federal court seeking suspension of the Nuclear Waste Fee. In June 2012, the court ruled that the DOE failed to justify continued payments by electricity consumers into the Nuclear Waste Fund and ordered the DOE to conduct a complete reassessment of this fee. Spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites. Since May 2014, the DOE reduced the nuclear waste fee to zero. Prior to the elimination of this fee, the annualized pre-tax cost was approximately $30 million.

We have on-site storage facilities that are expected to satisfy the storage needs of Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 through the end of their operating licenses.

Low Level Radioactive Waste—As a by-product of their operations, nuclear generation units produce low level radioactive waste. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. These waste materials are accumulated on site and disposed of at licensed permanent disposal facilities. New Jersey, Connecticut and South Carolina have formed the Atlantic Compact, which gives New Jersey nuclear generators continued access to the Barnwell waste disposal facility which is owned by South Carolina. We believe that the Atlantic Compact will provide for adequate low level

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radioactive waste disposal for Salem and Hope Creek through the end of their current licenses including full decommissioning, although no assurances can be given. Low Level Radioactive Waste is periodically being shipped to the Barnwell site from Salem and Hope Creek. Additionally, there are on-site storage facilities for Salem, Hope Creek and Peach Bottom, which we believe have the capacity for at least five years of temporary storage for each facility.

Coal Combustion Residuals (CCRs)—In December 2014, the EPA issued a final rule that regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities for additional information.

In December 2016, the Water Infrastructure Improvements for the Nation Act was enacted, which includes provisions regarding CCRs which allow for implementation of the EPA CCR rule through a state or EPA-based permit program. We believe this will have minimal impact to our operations.

SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Item 8. Financial Statements and Supplementary Data—Note 23. Financial Information by Business Segment.

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EXECUTIVE OFFICERS OF THE REGISTRANT (PSEG)

Name	Age as of December 31, 2016	Office	Effective Date First Elected to Present Position
Ralph Izzo	59	Chairman of the Board, President and Chief Executive Officer (PSEG)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (PSE&G)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Power)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Energy Holdings)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Services)	January 2010 to present
Daniel J. Cregg	53	Executive Vice President and CFO (PSEG)	October 2015 to present
		Executive Vice President and CFO (PSE&G)	October 2015 to present
		Executive Vice President and CFO (Power)	October 2015 to present
		Vice President-Finance (PSE&G)	June 2013 to October 2015
		Vice President-Finance (Power)	December 2011 to June 2013
William Levis	60	President and Chief Operating Officer (Power)	June 2007 to present
Ralph LaRossa	53	President and Chief Operating Officer (PSE&G)	October 2006 to present
		Chairman of the Board of PSEG Long Island LLC	October 2013 to present
Derek M. DiRisio	52	President (Services)	August 2014 to present
		Vice President and Controller (PSEG)	January 2007 to August 2014
		Vice President and Controller (PSE&G)	January 2007 to August 2014
		Vice President and Controller (Power)	January 2007 to August 2014
		Vice President and Controller (Energy Holdings)	January 2007 to August 2014
		Vice President and Controller (Services)	January 2007 to August 2014
Tamara L. Linde	52	Executive Vice President and General Counsel (PSEG)	July 2014 to present
		Executive Vice President and General Counsel (PSE&G)	July 2014 to present
		Executive Vice President and General Counsel (Power)	July 2014 to present
		Vice President - Regulatory (Services)	December 2006 to July 2014
Stuart J. Black	54	Vice President and Controller (PSEG)	August 2014 to present
		Vice President and Controller (PSE&G)	August 2014 to present
		Vice President and Controller (Power)	August 2014 to present
		Vice President (Services) and Assistant Controller (Power)	March 2010 to August 2014

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ITEM 1A. RISK FACTORS

The following factors should be considered when reviewing our business. These factors could have a material adverse impact on our business, prospects, financial position, results of operations or cash flows and could cause results to differ materially from those expressed elsewhere in this report.

MARKET AND COMPETITION RISKS

Fluctuations in the wholesale power and natural gas markets could negatively affect our financial condition, results of operations and cash flows.

In the markets where we operate, natural gas prices have a major impact on the price that generators receive for their output. Over the past several years, wholesale prices for natural gas have remained well below the peak levels experienced in 2008, in part due to increased shale gas production as extraction technology has improved. Lower gas prices have resulted in lower electricity prices, which has reduced our margins as nuclear and coal generation costs have not declined similarly.

In October 2016, Power determined that it will cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. The primary factors considered during this process that contributed to the decision to retire these units early include significant declines in revenues and margin caused by the sustained period of depressed wholesale power prices and reduced capacity factors caused by lower natural gas prices making coal generation less economically competitive than natural gas-fired generation. Despite experiencing recent warmer than normal weather in PJM this summer, Power did not experience the usual increase in electricity prices in PJM as it had in past hot summers. This trend has a further adverse economic impact to these units because they generally dispatch and earn energy margin on peak hot and cold days. In addition, the upcoming PJM capacity auction in May 2017 for the capacity period from June 2020 to May 2021 will be the first to require all generating units to meet the increased operating performance standards of PJM's new capacity performance regulations. During the current annual five-year strategic planning process, Power determined, on October 3, 2016, that the costs to upgrade the existing units at the Hudson and Mercer stations to comply with these higher reliability standards to be too significant and not economic given current market conditions, including anticipated future capacity prices, current forward energy prices and past operational performance results of the units. The decision to retire the Hudson and Mercer units early had and will continue to have a material effect on PSEG's and Power's results of operations through the retirement date.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to ensure their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact our ability to operate or maintain these assets in the future. These generating stations may be impacted by factors such as continued depressed wholesale power prices or capacity factors, among other things. Any early retirement of these coal units before the end of their current estimated useful lives or change in the classification as held for use may have a material adverse impact on PSEG's and Power's future financial results.

Low natural gas prices, as well as continuing costs for regulatory compliance and federal and state-level policies that provide credits to renewable energy such as wind and solar, but do not apply to nuclear generating stations, have been a contributing factor to the significantly reduced revenues from nuclear generating stations while simultaneously raising the unit cost of production. If these trends continue or worsen, our nuclear generating units could cease being economically competitive which may cause us to retire such units prior to the end of their useful lives. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs and environmental remediation costs, could be material.

We may be unable to obtain an adequate fuel supply in the future.

We obtain substantially all of our physical natural gas, coal and nuclear fuel supply from third parties pursuant to arrangements that vary in term, pricing structure, firmness and delivery flexibility. Our fuel supply arrangements must be coordinated with transportation agreements, balancing agreements, storage services, financial hedging transactions and other contracts to ensure that the natural gas, coal and nuclear fuel is delivered to our power plants at the times, in the quantities and otherwise in a manner that meets the needs of our generation portfolio and our customers. We must also comply with laws and regulations governing the transportation of such fuels.

Additionally, the PJM power market has recently experienced an increase in natural gas-fired generation assets that supply electricity to the region. As a result, there has been a corresponding increase in the need for natural gas transportation assets to serve power generation assets. When extreme cold temperatures rapidly increase the demand for natural gas used for residential heating, it can also create constraints on natural gas pipelines that serve power generation assets. When these conditions exist, it could interrupt the fuel supply to our natural gas-fired power plants in the PJM power market.

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We are exposed to increases in the price of natural gas, coal and nuclear fuel, and it is possible that sufficient supplies to operate our generating facilities profitably may not continue to be available to us. Significant changes in the price of natural gas and nuclear fuel could affect our future results and impact our liquidity needs. In addition, we face risks with regard to the delivery to, and the use of natural gas, coal and nuclear fuel by, our power plants including the following:

- transportation may be unavailable if pipeline infrastructure is damaged or disabled;
- pipeline tariff changes may adversely affect our ability to, or cost to, deliver such fuels;
- creditworthiness of third-party suppliers, defaults by third-party suppliers on supply obligations and our ability to replace supplies currently under contract may delay or prevent timely delivery;
- market liquidity for physical supplies of such fuels or availability of related services (e.g. storage) may be insufficient or available only at prices that are not acceptable to us;
- variation in the quality of such fuels may adversely affect our power plant operations;
- legislative or regulatory actions or requirements, including those related to integrity inspections, may increase the cost of such fuels;
- fuel supplies diverted to residential heating may limit the availability of such fuels for our power plants; and
- the loss of critical infrastructure, terrorist attacks (including cybersecurity breaches) or catastrophic events such as fires, earthquakes, explosions, floods, severe storms or other similar occurrences could impede the delivery of such fuels.

Our nuclear facilities and certain of our other generation facilities require fuel that may only be available from one or a limited number of suppliers. The availability and price of this fuel may vary due to supplier financial or operational disruptions, transportation disruptions and force majeure. At times, such fuel may not be available at any price, or we may not be able to transport it to our facilities on a timely basis. In this case, we may not be able to run those facilities even if it would be profitable. If we had sold forward the power from such a facility, we could be required to supply or purchase power from alternate sources, perhaps at a loss. This could have a material adverse impact on the financial results of specific plants and on our results of operations.

Our nuclear units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel needs over the next several years. However, it will be necessary to enter into additional arrangements to acquire nuclear fuel in the future. Although our fuel contract portfolio provides a degree of hedging against these market risks, such hedging may not be effective and future increases in our fuel costs could materially and adversely affect our liquidity, financial condition and results of operations. While our generation runs on a mix of fuels, primarily natural gas and nuclear fuel, an increase in the cost of any particular fuel ultimately used could impact our results of operations.

Our inability to balance energy obligations with available supply could negatively impact results.

The revenues provided by the operation of our generating stations are subject to market risks that are beyond our control. Generation output will either be used to satisfy wholesale contract requirements or other bilateral contracts or be sold into competitive power markets. Participants in the competitive power markets are not guaranteed any specified rate of return on their capital investments. Generation revenues and results of operations are dependent upon prevailing market prices for energy, capacity, ancillary services and fuel supply in the markets served. Changes in prevailing market prices could have a material adverse effect on our financial condition and results of operations.

Factors that may cause market price fluctuations include:

- increases and decreases in generation capacity, including the addition of new supplies of power as a result of the development of new power plants, expansion of existing power plants or additional transmission capacity;
- power transmission or fuel transportation capacity constraints or inefficiencies;
- power supply disruptions, including power plant outages and transmission disruptions;
- weather conditions, particularly unusually mild summers or warm winters in our market areas;
- quarterly and seasonal fluctuations;
- economic and political conditions that could negatively impact demand for power;
- changes in the supply of, and demand for, energy commodities;
- development of new fuels or new technologies for the production or storage of power;
- federal and state regulations and actions of the ISOs; and

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- federal and state power, market and environmental regulation and legislation, including financial incentives for new renewable energy generation capacity that could lead to oversupply.

Our generation business frequently involves the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that we have produced or purchased energy in excess of our contracted obligations, a reduction in market prices could reduce profitability. Conversely, to the extent that we have contracted obligations in excess of energy we have produced or purchased, an increase in market prices could reduce profitability. If the strategy we utilize to hedge our exposure to these various risks is not effective, we could incur material losses. Our market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors, including weather in various geographical areas, short-term supply and demand imbalances, customer migration and pricing differentials at various geographic locations. These risks cannot be predicted with certainty.

Increases in market prices also affect our ability to hedge generation output and fuel requirements as the obligation to post margin increases with increasing prices.

We face significant competition in the wholesale energy and capacity markets.

Our wholesale power and marketing businesses are subject to significant competition that may adversely affect our ability to make investments or sales on favorable terms and achieve our business objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower earnings. Decreased competition could negatively impact results through a decline in market liquidity. Regulatory, environmental, industry and other operational developments will have a significant impact on our ability to compete in energy and capacity markets, potentially resulting in erosion of our market share and impairment in the value of our power plants. Recently, certain states have taken, or are considering taking, actions to subsidize or otherwise provide economic support to renewables, energy efficiency initiatives and existing, uneconomic generation facilities that could adversely affect capacity and energy prices. Increased generation supply and lower energy prices due to these subsidies could have an adverse impact on our results of operations.

The introduction or expansion of technologies related to energy generation, distribution and consumption and changes in customer usage patterns and could adversely impact us.

The power generation business has seen a substantial change in the technologies used to produce power. Newer generation facilities are often more efficient than aging facilities, which may put some of these older facilities at a competitive disadvantage to the extent newer facilities are able to consume the same or less fuel to achieve a higher level of generation output. Federal and state incentives for the development and production of renewable sources of power has allowed for the penetration of competing technologies, such as wind, solar, and commercial-sized power storage. Additionally, the development of DSM tools and practices can impact peak demand requirements for some of our markets at certain times during the year. The continued development of subsidized, competing power generation technologies and significant development of DSM tools and practices could alter the market and price structure for power generation and could result in a reduction in load requirements, negatively impacting our financial condition, results of operations and cash flows. Additionally, technological advances driven by federal laws mandating new levels of energy efficiency in end-use electric devices or other improvements in, or applications of, technology could lead to declines in per capita energy consumption.

Advances in distributed generation technologies, such as fuel cells, micro turbines, micro grids, windmills and net-metered solar installations, may reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. Large customers, such as universities and hospitals, continue to explore potential micro grid installation. Such developments could (i) affect the price of energy, (ii) reduce energy deliveries as customer-owned generation becomes more cost-effective, (iii) require further improvements to our distribution systems to address changing load demands and (iv) make portions of our transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy.

Some or all of these factors, could result in a lack of growth or decline in customer demand for electricity or number of customers, and may cause us to fail to fully realize anticipated benefits from significant capital investments and expenditures, which could have a material adverse effect on our financial position, results of operations and cash flows. These factors could also materially affect our results of operations, cash flows or financial positions through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Economic downturns would likely have a material adverse effect on our businesses.

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices for power, generation capacity and natural gas, which can fluctuate substantially. Increased unemployment of residential customers and decreased demand for products and services provided by commercial and industrial customers resulting from an economic downturn could lead to declines in the demand for energy and an increase in the number of uncollectible customer balances, which would negatively impact our overall sales and cash flows. Although our utility

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business is subject to regulated allowable rates of return, overall declines in electricity and gas sold could materially adversely affect our financial condition, results of operations and cash flows. Additionally, prolonged economic downturns that negatively impact our financial condition, results of operations and cash flows could result in future material impairment charges to write down the carrying value of certain assets to their respective fair values.

We are subject to third-party credit risk relating to our sale of generation output and purchase of fuel.

We sell generation output and buy fuel through the execution of bilateral contracts. We also seek to contract in advance for a significant proportion of our anticipated output capacity and fuel needs. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure to perform by these counterparties could require Power to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, which could have a material adverse impact on our results of operations, cash flows and financial position. In the spot markets, we are exposed to the risks of the default sharing mechanisms that exist in those markets, some of which attempt to spread the risk across all participants. Therefore, a default by a third party could increase our costs, which could negatively impact our results of operations and cash flows.

Financial market performance directly affects the asset values of our nuclear decommissioning trust funds and defined benefit plan trust funds. Market performance and other factors could decrease the value of trust assets and could result in the need for significant additional funding.

The performance of the financial markets will affect the value of the assets that are held in trust to satisfy our future obligations under our defined benefit plans and to decommission our nuclear generating plants. A decline in the market value of our nuclear decommissioning trust funds could increase Power's funding requirements to decommission its nuclear plants. A decline in the market value of the defined benefit plan trust funds could increase our pension and other postretirement benefit (OPEB) plan funding requirements. The market value of our trusts could be negatively impacted by decreases in the rate of return on trust assets, decreased interest rates used to measure the required minimum funding levels and future government regulation. Additional funding requirements for our defined benefit plans could be caused by changes in required or voluntary contributions, an increase in the number of employees becoming eligible to retire and changes in life expectancy assumptions. Increased costs could also lead to additional funding requirements for our decommissioning trust. Failure to adequately manage our investments in our nuclear decommissioning trust and defined benefit plan trusts could result in the need for us to make significant cash contributions in the future to maintain our funding at sufficient levels, which would negatively impact our results of operations, cash flows and financial position.

REGULATORY, LEGISLATIVE AND LEGAL RISKS

PSE&G's revenues, earnings and results of operations are dependent upon state laws and regulations that affect distribution and related activities.

PSE&G is subject to regulation by the BPU. Such regulation affects almost every aspect of its businesses, including its retail rates, and failure to comply with these regulations could have a material adverse impact on PSE&G's ability to operate its business and could result in fines, penalties or sanctions. The retail rates for electric and gas distribution services are established in a base rate case and remain in effect until a new base rate case is filed and concluded. As a result of our Energy Strong Order, we are required to file our next distribution base rate case proceeding no later than November 1, 2017. In addition, our utility has received approval for several clause recovery mechanisms, some of which provide for recovery of costs and earn returns on authorized investments. These clause mechanisms require periodic updates to be reviewed and approved by the BPU and are subject to prudency reviews. Inability to obtain fair or timely recovery of all our costs, including a return of, or on, our investments in rates, could have a material adverse impact on our results of operations and cash flows. In addition, if legislative and regulatory structures were to evolve in such a way that PSE&G's exclusive rights to serve its regulated customers were eroded, its future earnings could be negatively impacted.

Efforts designed to promote and expand the use of energy efficiency measures and distributed generation technologies, such as rooftop solar and battery storage, in PSE&G's service territories could result in customers leaving the electric distribution system and an increase in customer net energy metering. Over time, customer adoption of these and other technologies and increased energy efficiency could adversely impact PSE&G's revenue and ability to fully recover the costs, which could require PSE&G to pursue a rate case to adjust revenue requirements or seek recovery though other mechanisms.

The BPU also conducts periodic combined management/competitive service audits of New Jersey utilities related to affiliate standard requirements, competitive services, cross-subsidization, cost allocation and other issues. A finding by the BPU of non-compliance with these requirements could result in fines, a reduction in PSE&G's authorized base rate or the disallowance of the recovery of certain costs, which could have a materially adverse impact on our business, results of operations and cash flows.

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In addition, PSE&G procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with Power. Government officials, legislators and advocacy groups are aware of the affiliation between PSE&G and Power. In periods of rising utility rates, those officials and advocacy groups may question or challenge costs and transactions incurred by PSE&G with Power, irrespective of any previous regulatory processes or approvals underlying those transactions. The occurrence of such challenges may subject Power to a level of scrutiny not faced by other unaffiliated competitors in those markets and could adversely affect retail rates received by PSE&G in an effort to offset any perceived benefit to Power from the affiliation.

PSE&G periodically files base rate case proceedings. Such proceedings are at times contentious, lengthy and subject to appeal, which could lead to uncertainty as to the ultimate results and which could introduce time delays in effectuating rate changes.

PSE&G periodically files base rate case proceedings with the BPU. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for PSE&G to recover its costs by the time the rates become effective. Established rates are also subject to subsequent reviews by state regulators, whereby various portions of rates could be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, bad debt, MGP remediation, smart grid infrastructure and energy efficiency, demand response and renewable energy programs. If the base rate case proceeding is protracted or results in approved rates that do not allow PSE&G to fully recover its costs or result in ROEs that are below historical levels, our financial condition, results of operations and cash flows would be materially adversely impacted. Our next distribution base rate case proceeding is required to be filed no later than November 1, 2017.

We are subject to comprehensive federal regulation that affects, or may affect, our businesses.

We are subject to regulation by federal authorities. Such regulation affects almost every aspect of our businesses, including management and operations; the terms and rates of transmission services; investment strategies; the financing of our operations and the payment of dividends. Failure to comply with these regulations could have a material adverse impact on our ability to operate our business and could result in fines, penalties or sanctions.

Recovery of wholesale transmission rates—PSE&G's wholesale transmission rates are regulated by FERC and are recovered through a FERC-approved formula rate. The revenue requirements are reset each year through this formula. In addition, transmission ROEs have recently become the target of certain state utility commissions, municipal utilities, consumer advocates and consumer groups seeking to lower customer rates. These agencies and groups have filed complaints with FERC asking to reduce the base ROE of various transmission owners. They point to changes in the capital markets as justification for lowering the ROE of these companies. While we are not the subject of any of these complaints, they could set a precedent for FERC-regulated transmission owners, such as PSE&G. Inability to obtain fair or timely recovery of all our costs, including a return of or on our investments in rates, could have a material adverse impact on our business.

NERC Compliance—Mandatory NERC and Critical Infrastructure Protection standards have been established to ensure the reliability of the U.S. electric transmission and generation system and to prevent major system black-outs. We have been, and will continue to be, periodically audited by NERC for compliance and are subject to penalties for non-compliance with applicable NERC standards. Failure to comply with such standards could result in penalties or increased costs to bring such facilities into compliance. Such penalties and costs, as well as lost revenue from prolonged outages required to bring facilities into compliance with these standards, could materially adversely impact our business, results of operations and cash flows.

Market-Based Rate (MBR) Authority and Other Regulatory Approvals—Under FERC regulations, public utilities that wish to sell power at market rates must receive MBR Authority before making power sales, and the majority of our businesses operate with such authority. Failure to maintain MBR authorization, or the effects of any severe mitigation measures that may be required if market power was evaluated differently in the future, could have a material adverse effect on our business, financial condition and results of operations.

In December 2016, the PSEG companies with MBR Authority filed their triennial market power analysis as required by FERC regulations. A FERC order on the PSEG companies' triennial filing is expected in the third quarter 2017.

Oversight by the Commodity Futures Trading Commission (CFTC) relating to derivative transactions—The CFTC has regulatory oversight of the swap and futures markets, including energy trading, and licensed futures professionals such as brokers, clearing members and large traders. Changes to regulations or adoption of additional regulations by the CFTC, including any regulations relating to position limits on futures and other derivatives or margin for derivatives and increased investigations by the CFTC, could negatively impact Power's ability to hedge its portfolio in an efficient, cost-effective manner by, among other things, potentially decreasing liquidity in the forward commodity and derivatives markets or limiting Power's ability to utilize non-cash collateral for derivatives transactions.

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We may also be required to obtain various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals on a timely basis could materially adversely affect our results of operations and cash flows.

Our ownership and operation of nuclear power plants involve regulatory, financial, environmental, health and safety risks.

Approximately half of our total generation output each year is provided by our nuclear fleet. For this reason, we are exposed to risks related to the continued successful operation of our nuclear facilities and issues that may adversely affect the nuclear generation industry. These include:

Storage and Disposal of Spent Nuclear Fuel—Federal law requires the DOE to provide for the permanent storage of spent nuclear fuel but the DOE has not yet begun accepting spent nuclear fuel. Until a federal site is available, we use on-site storage for spent nuclear fuel, which is reimbursed by the DOE. However, future capital expenditures may be required to increase spent fuel storage capacity at our nuclear facilities. Once a federal site is available, the DOE may impose fees to support a permanent repository. In addition, the on-site storage for spent nuclear fuel may significantly increase the decommissioning costs of our nuclear units.

Regulatory and Legal Risk—We may be required to substantially increase capital expenditures or operating or decommissioning costs at our nuclear facilities to the extent there is a change in the Atomic Energy Act or the applicable regulations or the environmental rules and regulations applicable to nuclear facilities; a modification, suspension or revocation of licenses issued by the NRC; the imposition of civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms and conditions of the licenses for nuclear generating facilities or the shutdown of one of our nuclear facilities. Any such event could have a material adverse effect on our financial position or results of operations.

Operational Risk—Operations at any of our nuclear generating units could degrade to the point where the affected unit needs to be shut down or operated at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. In April 2016, during a scheduled refueling outage at Salem Unit 1, a visual inspection revealed degradation to a number of bolts inside the reactor vessel. The required bolt replacement significantly extended the duration of the outage. We expect to continue to inspect and replace degraded bolts at both Salem units over the next several refueling outage cycles and are developing a strategy to maintain the long-term health of both reactor vessel internals. Any significant outages could result in reduced earnings as we would need to purchase or generate higher-priced energy to meet our contractual obligations.

In addition, if a station cannot be operated through the end of its current estimated useful life, our results of operations could be adversely affected by increased depreciation rates, impairment charges and accelerated future decommissioning costs.

Nuclear Incident or Accident Risk—Accidents and other unforeseen problems have occurred at nuclear stations, both in the U.S. and elsewhere. The consequences of an accident can be severe and may include loss of life, significant property damage and/or a change in the regulatory climate. We have nuclear units at two sites. It is possible that an accident or other incident at a nuclear generating unit could adversely affect our ability to continue to operate unaffected units located at the same site, which would further affect our financial condition, results of operations and cash flows. An accident or incident at a nuclear unit not owned by us could also affect our ability to continue to operate our units. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages. Further, as a licensed nuclear operator subject to the Price-Anderson Act and a member of a nuclear industry mutual insurance company, Power is subject to potential retroactive assessments as a result of a nuclear incident or retroactive adverse loss experience.

In the event of non-compliance with applicable legislation, regulation and licenses, the NRC may increase regulatory oversight, impose fines, and/or shut down a unit, depending on its assessment of the severity of the non-compliance. If a serious nuclear incident were to occur, our business, reputation, financial condition and results of operations could be materially adversely affected. In each case, the amount and types of insurance commercially available to cover losses that might arise in connection with the operation of our nuclear fleet are limited and may be insufficient to cover any costs we may incur.

We may be adversely affected by changes in energy regulatory policies, including energy and capacity market design rules and developments affecting transmission.

The energy industry continues to be regulated and the rules to which our businesses are subject are always at risk of being changed, particularly in light of the change in administration following the 2016 U.S. presidential election. Our business has been impacted by established rules that create locational capacity markets in each of PJM, ISO-NE and NYISO. Under these rules, generators located in constrained areas are paid more for their capacity so there is an incentive to locate in those areas where generation capacity is most needed. Because much of our generation has historically been located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM's locational capacity market

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design rules and ISO-NE's forward capacity market rules have been challenged in court and continue to evolve. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

In 2011, New Jersey enacted a law that provided for the construction of subsidized electric power generation. While this legislation was subsequently invalidated as unconstitutional, future state actions in New Jersey and elsewhere to subsidize the construction of new generation could have the effect of artificially depressing prices in the competitive wholesale market on both a short-term and long-term basis.

We could also be impacted by a number of other events, including regulatory or legislative actions such as direct and indirect subsidies, favoring non-competitive markets and/or technologies and energy efficiency and demand response initiatives. Further, some of the market-based mechanisms in which we participate, including BGS auctions, are at times the subject of review or discussion by some of the participants in the New Jersey and federal regulatory and political arenas. We can provide no assurance that these mechanisms will continue to exist in their current form, nor otherwise be modified.

To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, Power's capacity and energy revenues could be adversely affected. Moreover, through changes encouraged by FERC to transmission planning processes, or through RTO/ISO initiatives to change their planning processes, such as the recently accepted multi-driver project category in PJM, more transmission may ultimately be built to facilitate renewable generation or support other public policy initiatives. Any such addition to the transmission system could have a material adverse impact on our financial condition and results of operations.

We are subject to numerous federal, state and local environmental laws and regulations that may significantly limit or affect our businesses, adversely impact our business plans or expose us to significant environmental fines and liabilities.

We are subject to extensive federal, state and local environmental laws and regulations regarding air quality, water quality, site remediation, land use, waste disposal, the impact on global climate, natural resources damages and other matters. These laws and regulations affect the manner in which we conduct our operations and make capital expenditures. We expect there will be changes to existing environmental laws and regulations, particularly in light of the change in administration following the 2016 U.S. presidential election. Changes in these laws, or violations of laws, could result in significant increases in our compliance costs, capital expenditures to bring our facilities into compliance, operating costs for remediation and clean-up actions, civil penalties or damages from actions brought by third parties for alleged health or property damages. Any such increase in our costs could have a material impact on our financial condition, results of operations and cash flows and could require further economic review to determine whether to continue operations or decommission an affected facility. We may also be unable to successfully recover certain of these cost increases through our existing regulatory rate structures, in the case of PSE&G, or our contracts with our customers, in the case of Power.

Environmental laws and regulations have generally become more stringent over time, and this trend is likely to continue. In particular:

Concerns over global climate change could result in laws and regulations to limit CO_2 emissions or other GHG emissions produced by our fossil generation facilities—Federal and state legislation and regulation designed to address global climate change through the reduction of GHG emissions could materially impact our fossil generation facilities. For example, in 2015 the EPA published new rules for both new and existing power plants. We may be required to incur significant costs to comply with these regulations and to continue operation of our fossil generation facilities, which could include the potential need to purchase CO_2 emission allowances. Such expenditures could materially affect the continued economic viability of one or more such facilities.

In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings regarding alleged impacts of global climate change not involving us could be material to the future liability of energy companies. If relevant federal or state common law were to develop that imposed liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to our fossil generation operations could be material.

Potential closed-cycle cooling requirements—In 2014, the EPA finalized rules regarding the regulation of cooling water intake structures. The EPA did not mandate closed cycle cooling as the BTA. Instead, the EPA set a fish impingement mortality standard that relies on a technology-based approach. The EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the BTA of each facility that seeks permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. State actions to renew permits under the provisions of this rule are ongoing at this time. If the NJDEP or the CTEEP were to require installation of closed-cycle cooling or its equivalent at any of our Salem, Bridgeport, Sewaren or New Haven generating stations, the related increased costs and impacts would be material to our financial position, results of operations and cash flows and would require further economic review to determine whether to continue operations or decommission any such station.

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Remediation of environmental contamination at current or formerly-owned facilities—We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. In addition, the historic operations of our companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. The EPA is also evaluating the Hackensack River, a tributary to Newark Bay, for inclusion in the Superfund program. We are also involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, the related costs of which could have a material adverse effect on our financial condition, results of operations and cash flows. New Jersey law places affirmative obligations on us to investigate and, if necessary, remediate contaminated property upon which we were in any way responsible for a discharge of hazardous substances, impacting the speed by which we will need to investigate contaminated properties, which could adversely impact cash flows. We cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to these or other natural resource damages claims. However, exposure to natural resource damages could subject us to additional potentially material liability. For a discussion of these and other environmental matters, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

We may not receive necessary licenses and permits in a timely manner or at all, which could adversely impact our business and results of operations.

We must periodically apply for licenses and permits from various regulatory authorities, including environmental regulatory authorities, and abide by their respective orders. Delay in obtaining, or failure to obtain and maintain, any permits or approvals, including environmental permits or approvals, or delay in or failure to satisfy any applicable regulatory requirements, could:

- prevent construction of new facilities,
- limit or prevent continued operation of existing facilities,
- limit or prevent the sale of energy from these facilities, or
- result in significant additional costs,

each of which could materially affect our business, financial condition, results of operations and cash flows. In addition, the process of obtaining licenses and permits from regulatory authorities may be delayed or defeated by concerted community opposition and such delay or defeat could have a material effect on our business.

We cannot predict the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim relating to our business activities. An adverse determination could negatively impact our financial condition, results of operations and cash flows.

From time to time we are involved in legal, regulatory and other proceedings or claims arising out of our business operations, the most significant of which are summarized in Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities. Adverse outcomes in any of these proceedings could require significant expenditures that could have a material adverse effect on our financial condition, results of operations and cash flows.

In particular, as previously disclosed, Power has discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors to FERC, PJM and the PJM Independent Market Monitor (IMM). FERC Staff initiated a preliminary, non-public staff investigation into the matter, which is ongoing. We are unable to reasonably estimate the range of possible loss for this matter; however, the amounts of potential disgorgement and other potential penalties that Power may incur span a wide range depending on the success of PSEG's legal arguments. If we do not prevail in whole or in part with FERC or in a judicial challenge that we may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to our results of operations.

Changes in tax law and regulation and the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact our results of operations and cash flows.

There exists the potential for comprehensive tax reform in the U.S. that may significantly change the tax rules applicable to domestic businesses, including changes that may impact investment incentives, deductions for depreciation, interest or otherwise, and dividends. We cannot assess what the overall effect of such potential legislation could be on our results of operations or cash flows. In addition, we are required to make judgments in order to estimate our obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes. These judgments can include reserves for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities. If our actual tax obligations materially differ from our estimated obligations, our results of operations and cash flows could be materially adversely affected.

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OPERATIONAL RISKS

Because PSEG is a holding company, its ability to meet its corporate funding needs, service debt and pay dividends could be limited.

PSEG is a holding company with no material assets other than the stock or membership interests of its subsidiaries. Accordingly, all of the operations of PSEG are conducted by its subsidiaries, which are separate and distinct legal entities that have no obligation, contingent or otherwise, to pay the debt of PSEG or to make any funds available to PSEG to pay such debt or satisfy its other corporate funding needs. These corporate funding needs include PSEG's operating expenses, the payment of interest on and principal of its outstanding indebtedness and the payment of dividends on its capital stock. As a result, PSEG can give no assurances that its subsidiaries will be able to transfer funds to PSEG to meet all of these obligations.

Lack of growth or slower growth in the number of customers, or a decline in customer demand, could adversely impact our financial condition, results of operations and cash flows.

Growth in customer accounts and growth of customer usage each directly influence demand for electricity and the need for additional generation, transmission and distribution facilities. Customer growth and customer usage may be affected by a number of factors, including:

- regulatory incentives to reduce energy consumption;
- mandated energy efficiency measures;
- demand-side management tools;
- technological advances; and
- a shift in the composition of our customer base from commercial and industrial customers to residential customers.

Some or all of these factors could result in a lack of growth or decline in customer demand for electricity and may prevent us from fully realizing the benefits from significant capital investments and expenditures, which could have a material adverse effect on our financial position, results of operations and cash flows.

There may be periods when Power may not be able to meet its commitments under forward sale obligations at a reasonable cost or at all.

A substantial portion of Power's generation output has been sold forward under fixed price power sales contracts and Power also sells forward the output from its intermediate and peaking facilities when it deems it commercially advantageous to do so. Our forward sales of energy and capacity assume sustained, acceptable levels of operating performance. This is especially important at our lower-cost facilities. Operations at any of our plants could degrade to the point where the plant has to shut down or operate at less than full capacity. Some issues that could impact the operation of our facilities are:

- breakdown or failure of equipment, information technology, processes or management effectiveness;
- disruptions in the transmission of electricity;
- labor disputes or work stoppages;
- fuel supply interruptions;
- transportation constraints;
- limitations which may be imposed by environmental or other regulatory requirements; and
- operator error, terrorist attacks (including cybersecurity breaches) or catastrophic events such as fires, earthquakes, explosions, floods, severe storms or other similar occurrences.

Identifying and correcting any of these issues may require significant time and expense. Depending on the materiality of the issue, we may choose to close a plant rather than incur the expense of restarting it or returning it to full capacity.

Because the obligations under most of these agreements are not contingent on a unit being available to generate power, Power is generally required to deliver power to the buyer, even in the event of a plant outage, fuel supply disruption or a reduction in the available capacity of the unit. To the extent that Power does not have sufficient lower cost capacity to meet its commitments under its forward sale obligations, Power would be required to supply replacement power either by running its other higher cost power plants or by obtaining power from third-party sources at market prices that could substantially exceed the contract price. This could have a material adverse effect on our financial condition, results of operations and cash flows. If Power fails to deliver the contracted power, it would be required to pay the difference between the market price at the delivery point and the contract price, and the amount of such payments could be substantial.

In addition, as market prices for energy and fuel fluctuate, our forward energy sale and forward fuel purchase contracts could require us to post substantial additional collateral, thus requiring us to obtain additional sources of liquidity during periods when our ability to do so may be limited.

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Certain of our generation facilities rely on transmission facilities that we do not own or control and that may be subject to transmission constraints. Our inability to maintain adequate transmission capacity could restrict our ability to deliver wholesale electric power to our customers and we may either incur additional costs or forego revenues. Conversely, improvements to certain transmission systems could also reduce revenues.

We depend on transmission facilities owned and operated by others to deliver the wholesale power we sell from our generation facilities. If transmission is disrupted or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be adversely impacted. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

In addition, in certain of the markets in which we operate, energy transmission congestion may occur and we may be deemed responsible for congestion costs if we schedule delivery of power between congestion zones during times when congestion occurs between the zones. If we were liable for such congestion costs, our financial results could be adversely affected.

A portion of our generation is located in load pockets. Expansion of transmission systems to reduce or eliminate these load pockets could negatively impact the value or profitability of our existing generation facilities in these areas.

Inability to successfully develop or construct generation, transmission and distribution projects could adversely impact our businesses.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of required environmental upgrades and retrofits; construction and/or acquisition of additional generation units and transmission and distribution facilities; and modernizing existing infrastructure pursuant to investment programs entitled to current recovery. Currently, we have several significant projects underway or being contemplated.

The successful construction and development of these projects will depend, in part, on our ability to:

- obtain necessary governmental and regulatory approvals;
- obtain environmental permits and approvals;
- obtain community support for such projects to avoid delays in the receipt of permits and approvals from regulatory authorities;
- complete such projects within budgets and on commercially reasonable terms and conditions;
- obtain any necessary debt financing on acceptable terms and/or necessary governmental financial incentives;
- ensure that contracting parties, including suppliers, perform under their contracts in a timely and cost effective manner; and
- at PSE&G, recover the related costs through rates.

Any delays, cost escalations or otherwise unsuccessful construction and development could materially affect our financial position, results of operations and cash flows. Further, any unexpected failure of our existing facilities, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures could result in reduced profitability. Modifications to existing facilities may require us to install the best available control technology or to achieve the lowest achievable emission rates required by then-current regulations, which would likely result in substantial additional capital expenditures.

In addition, the successful operation of new or upgraded generation facilities or transmission or distribution projects is subject to risks relating to supply interruptions; work stoppages and labor disputes; weather interferences; unforeseen engineering and environmental problems, including those related to climate change; and the other risks described herein. Any of these risks could cause our return on these investments to be lower than expected or they could cause these facilities to operate below expected capacity or availability levels, which would adversely impact our financial condition and results of operations through lost revenue, increased expenses, higher maintenance costs and penalties.

FERC Order 1000 has generally opened transmission development to competition from independent developers, allowing such developers to compete with incumbent utilities for the construction and operation of transmission facilities in its service territory. While Order 1000 retains limited carve-outs for certain projects that will continue to default to incumbents for construction responsibility, including immediately needed reliability projects, upgrades to existing transmission facilities, projects cost-allocated to a single transmission zone, and projects being built on existing rights-of-way and whose construction would interfere with incumbents' use of their rights-of-way, increased competition for transmission projects could decrease the value of new investments that would be subject to recovery by PSE&G under its rate base, which could have a material adverse impact on our financial condition and results of operations. In addition, certain PJM cost allocation determinations have been

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recently challenged at FERC, the resolution of which could impact costs borne by New Jersey ratepayers and increase customer bills.

We may be adversely affected by equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers and remain competitive and could result in substantial financial losses.

The success of our businesses is dependent on our ability to continue providing safe and reliable service to our customers while minimizing service disruptions. We are exposed to the risk of equipment failures, accidents, severe weather events, or other incidents which could result in damage to or destruction of our facilities or damage to persons or property. For instance, equipment failures in our natural gas distribution could give rise to a variety of hazards and operating risks, such as leaks, accidental explosions and mechanical problems, which could cause substantial financial losses and harm our reputation.

In addition, the physical risks of severe weather events, such as experienced from Hurricane Irene and Superstorm Sandy, and of climate change, changes in sea level, temperature and precipitation patterns and other related phenomena have further exacerbated these risks. Such issues experienced at our facilities, or by others in our industry, could adversely impact our revenues; increase costs to repair and maintain our systems; subject us to potential litigation and/or damage claims, fines/penalties; and increase the level of oversight of our utility and generation operations and infrastructure through investigations or through the imposition of additional regulatory or legislative requirements. Such actions could adversely affect our costs, competitiveness and future investments, which could be material to our financial position, results of operations and cash flow. For our transmission and distribution business, the cost of storm restoration efforts may not be fully recoverable through the regulatory process.

We own less than a controlling interest in some of our generating facilities.

We have limited control over the operation of some of our generating facilities, including the Keystone, Conemaugh and Peach Bottom facilities, because our investments represent less than a controlling interest. We seek to exert a degree of influence with respect to the management and operation of projects in which we own less than a controlling interest by negotiating to obtain positions on management committees or to receive certain limited governance rights. However, we may not always succeed in such negotiations. As a result, we may be dependent on our partners to operate such facilities. The approval of our partners also may be required for us to transfer our interest in such projects. Reliance on our partners for the management and operation of these facilities could result in a lower return on these facilities than what we believe we could have otherwise achieved.

Any inability to recover the carrying amount of our assets and leveraged leases could result in future impairment charges which could have a material adverse impact on our financial condition and results of operations.

Long-lived assets represent approximately 74%, 79% and 70% of the total assets of PSEG, PSE&G and Power, respectively, as of December 31, 2016. Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation business climate or market conditions, including prolonged periods of adverse commodity and capacity prices, could potentially indicate an asset's or group of assets' carrying amount may not be recoverable. Significant reductions in our expected revenues or cash flows for an extended period of time resulting from such events could result in future asset impairment charges, which could have a material adverse impact on our financial condition and results of operations.

Energy Holdings has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third-party debt investor. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. Our receipt of payments related to our leveraged lease portfolio in accordance with the lease contracts can be impacted by various factors, including new environmental legislation regarding air quality and other discharges in the process of generating electricity; market prices for fuel and electricity, including the impact of low gas prices on our coal generation investments; overall financial condition of lease counterparties; and the quality and condition of assets under lease.

During the third quarter of 2016, in connection with Energy Holdings' annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases, it was determined that the revised residual value estimates for such leases were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016. During the fourth quarter of 2016, Energy Holdings recorded a $10 million pre-tax charge reflecting its best estimate of loss as a result of the current liquidity issues facing REMA.

In addition, REMA's parent company, GenOn Energy, Inc. (GenOn), reported in August 2016 that it did not expect to have sufficient liquidity to repay their senior unsecured notes due in June 2017. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's efforts to restructure its portfolio and improve its liquidity and the possible related

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impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments, which could include further write-downs of the values of Energy Holdings' leveraged leases.

There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.

Inability to maintain sufficient liquidity in the amounts and at the times needed or access sufficient capital at reasonable rates or on commercially reasonable terms could adversely impact our business.

Funding for our investments in capital improvement and additions, scheduled payments of principal and interest on our existing indebtedness and the extension and refinancing of such indebtedness has been provided primarily by internally-generated cash flow and external financings. We have significant capital requirements and depend on our ability to generate cash in the future from our operations and continued access to capital and credit markets to efficiently fund our cash flow needs. Our ability to generate cash flow is dependent upon, among other things, industry conditions and general economic, financial, competitive, legislative, regulatory and other factors. The ability to arrange financing and the costs of such financing depend on numerous factors including, among other things.

- general economic and capital market conditions;
- the availability of credit from banks and other financial institutions;
- tax, regulatory and securities law developments;
- for PSE&G, our ability to obtain necessary regulatory approvals for the incurrence of additional indebtedness;
- investor confidence in us and our industry;
- our current level of indebtedness and compliance with covenants in our debt agreements;
- the success of current projects and the quality of new projects;
- our current and future capital structure;
- our financial performance and the continued reliable operation of our business; and
- maintenance of our investment grade credit ratings.

Market disruptions, such as economic downturns experienced in the U.S. and abroad in recent years, the bankruptcy of an unrelated energy company, changes in market prices for electricity and gas, and actual or threatened terrorist attacks, may increase our cost of borrowing or adversely affect our ability to access capital. As a result, no assurance can be given that we will be successful in obtaining financing for projects and investments, to extend or refinance maturing debt or for our other cash flow needs on acceptable terms or at all, which could materially adversely impact our financial position, results of operations and future growth.

In addition, if Power were to lose its investment grade credit rating from S&P or Moody's, it would be required under certain agreements to provide a significant amount of additional collateral in the form of letters of credit or cash, which would have a material adverse effect on our liquidity and cash flows.

We may be unable to realize anticipated tax benefits or retain existing tax credits.

The deferred tax assets and tax credits of PSEG, PSE&G or Power are evaluated for ultimate ability to realize these assets. A valuation allowance may be recorded against the deferred tax assets if we estimate that such assets are more likely than not to be unrealizable based on available evidence including cumulative and forecasted pretax book earnings at the time the estimate is made. A valuation allowance related to deferred tax assets or the monetization of tax credits can be affected by changes to tax laws, statutory tax rates and future taxable income levels. In the event that we determine that we would not be able to realize all or a portion of our deferred tax assets in the future or the benefit of tax credits, we would reduce such amounts through a charge to income tax expense in the period in which that determination was made, which could have a material adverse impact on our financial condition and results of operations.

Challenges associated with retention of key executives and a skilled workforce could adversely impact our businesses.

Our operations depend on the retention of key executives and a skilled workforce. The loss or retirement of key executives or other employees, including those with the specialized knowledge required to support our generation, transmission and distribution operations, could result in various operational challenges. We may incur increased costs for contractors to replace employees, and the loss of institutional and industry knowledge and the increased costs to hire and lengthy time to train new personnel could result in lower productivity, resulting in increased costs, which would negatively impact our results of operations. This has the potential to become more critical as a growing number of employees become eligible to retire.

As of December 31, 2016, approximately 62% of our employees were covered by collective bargaining agreements. As a result, our success will depend on our ability to successfully renegotiate these agreements as they expire. Inability to do so may result

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in employee strikes or work stoppages which would disrupt our operations and could also result in increased costs, all of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Covenants in our debt instruments may adversely affect our operations.

PSEG's, PSE&G's and Power's debt instruments contain events of default customary for financings of their type, including cross accelerations to other debt of that entity and, in the case of PSEG's and Power's bank credit agreements, certain change of control events. Power's bank credit agreements and outstanding notes also contain limitations on the incurrence of subsidiary debt and liens and Power's outstanding notes require Power to repurchase such notes upon certain change of control events. Our ability to comply with these covenants may be affected by events beyond our control. If we fail to comply with the covenants and are unable to obtain a waiver or amendment, or a default exists and is continuing under such debt, the lenders or the holders or trustee of such debt, as applicable, could give notice and declare outstanding borrowings and other obligations under such debt immediately due and payable. We may not be able to obtain waivers, amendments or alternative financing, or if obtainable, it could be on terms that are not acceptable to us. Any of these events could adversely impact our financial condition, results of operations and cash flows.

Cybersecurity attacks or intrusions could adversely impact our businesses.

We own and/or operate generating stations and transmission and distribution facilities, all of which are dependent on the operation of our information technology systems. Our ability to market our generation output and acquire and hedge fuel and power are also dependent on our information technology systems as well as information technology systems owned and operated by third parties, such as ISOs and RTOs. Our and third-party information technology systems may be impacted by cybersecurity attacks or hostile technological intrusions involving domestic or foreign sources (including nation states and special interest groups) or inadvertent disclosure of company and/or customer information. A cybersecurity attack may also leverage such information technology to cause disruptions at a third party. Cybersecurity threats to our operations include:

- disruption of the operation of our assets and the power grid,
- theft of confidential company, employee, shareholder, vendor or customer information,
- general business system and process interruption or compromise, including preventing us from servicing our customers, collecting revenues or the ability to record, process and/or report financial information correctly, and
- breaches of vendors' infrastructures where our confidential information is stored.

We have experienced and expect to continue to experience actual or attempted cyber-attacks on our information technology systems. However, none of these actual or attempted cyber-attacks has had a material impact on our operations or financial condition. If a significant cybersecurity event or breach should occur, we could (i) experience disruptions to our business, property damage, theft of unauthorized access to customer or other information; (ii) experience significant loss of revenue or incur material costs for repair, remediation and breach notification and increased capital and operating costs to implement increased security measures; and (iii) be subject to increased regulation, litigation and reputational damage. Similarly, a significant cybersecurity event or breach experienced by a competitor, regulatory authority, RTO or ISO could also materially impact our business and results of operations. Experiencing a cybersecurity incident could also cause us to be non-compliant with applicable laws and regulations, including those promulgated by the NRC and NERG, or contracts that require us to securely maintain confidential data, causing us to incur costs related to legal claims or proceedings, regulatory fines and increased scrutiny and possible damage to our reputation and brand, resulting in a reduction in customer confidence.

The market for cybersecurity insurance is relatively new and coverage available for cybersecurity events may evolve as the industry matures. While we maintain insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damage we experience.

Acts of war or terrorism could adversely affect our operations.

Our businesses and industry may be impacted by acts and threats of war or terrorism. These actions could result in increased political, economic and financial and insurance market instability and volatility in power and fuel markets, which could materially adversely affect our business and results of operations, including our ability to access capital on terms and conditions acceptable to us. In addition, our infrastructure facilities, such as our generating stations, transmission and distribution facilities and information technology systems, could be direct or indirect targets or be affected by terrorist or other criminal activity. Such events could severely disrupt our business operations and prevent us from servicing our customers. New or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, PSE&G and Power

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None.

ITEM 2. PROPERTIES

Our subsidiaries own all of our physical property. We believe that we and our subsidiaries maintain adequate insurance coverage against loss or damage to plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Generation Facilities

Power

As of December 31, 2016, Power's share of installed fossil and nuclear generating capacity is shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used
Steam:					
Hudson (A)	NJ	565	100%	565	Coal/Gas
Mercer (A)	NJ	632	100%	632	Coal/Gas
Sewaren	NJ	445	100%	445	Gas
Keystone (B)	PA	1,711	23%	391	Coal
Conemaugh (B)	PA	1,711	23%	385	Coal
Bridgeport Harbor	CT	383	100%	383	Coal
New Haven Harbor	CT	448	100%	448	Oil/Gas
Total Steam		**5,895**		**3,249**	
Nuclear:					
Hope Creek	NJ	1,172	100%	1,172	Nuclear
Salem 1 & 2	NJ	2,296	57%	1,318	Nuclear
Peach Bottom 2 & 3 (C)	PA	2,450	50%	1,225	Nuclear
Total Nuclear		**5,918**		**3,715**	
Combined Cycle:					
Bergen	NJ	1,229	100%	1,229	Gas/Oil
Linden	NJ	1,230	100%	1,230	Gas/Oil
Bethlehem	NY	757	100%	757	Gas
Kalaeloa	HI	208	50%	104	Oil
Total Combined Cycle		**3,424**		**3,320**	
Combustion Turbine:					
Essex	NJ	81	100%	81	Gas/Oil
Kearny	NJ	456	100%	456	Gas/Oil
Burlington	NJ	168	100%	168	Gas/Oil
Linden	NJ	336	100%	336	Gas/Oil
New Haven Harbor	CT	129	100%	129	Gas/Oil
Bridgeport Harbor	CT	17	100%	17	Oil
Total Combustion Turbine		**1,187**		**1,187**	
Pumped Storage:					
Yards Creek (D)	NJ	420	50%	210	
Total Power Plants		**16,844**		**11,681**	

(A) In October 2016, Power determined that it would cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements for additional information.

(B) Operated by GenOn Northeast Management Company.

(C) Operated by Exelon Generation.

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(D) Operated by Jersey Central Power & Light Company.

As of December 31, 2016, Power also owned and operated 326 MW dc of photovoltaic solar generation facilities in various states.

PSE&G

Primarily all of PSE&G's property is located in New Jersey and PSE&G's First and Refunding Mortgage, which secures the bonds issued thereunder, constitutes a direct first mortgage lien on substantially all of PSE&G's property. PSE&G's electric lines and gas mains are located over or under public highways, streets, alleys or lands, except where they are located over or under property owned by PSE&G or occupied by it under easements or other rights. PSE&G deems these easements and other rights to be adequate for the purposes for which they are being used.

Electric Property and Facilities

As of December 31, 2016, PSE&G's electric transmission and distribution system included approximately 24,000 circuit miles, and 851,000 poles, of which 65% are jointly-owned. In addition, PSE&G owns and operates 47 switching stations with an aggregate installed capacity of 30,037 megavolt-amperes (MVA) and 246 substations with an aggregate installed capacity of 8,179 MVA. Four of those substations, having an aggregate installed capacity of 109 MVA are operated on leased property. In addition, PSE&G owns four electric distribution headquarters and five electric sub-headquarters.

Gas Property and Facilities

As of December 31, 2016, PSE&G's gas system included approximately 18,000 miles of gas mains, 12 gas distribution headquarters, two sub-headquarters, and one meter shop serving all of its gas territory in New Jersey. In addition, PSE&G operates 61 natural gas metering and regulating stations, of which 25 are located on land owned by customers or natural gas pipeline suppliers and are operated under lease, easement or other similar arrangement. In some instances, the pipeline companies own portions of the metering and regulating facilities. PSE&G also owns one liquefied natural gas (LNG) and three liquid petroleum air gas (LPG) peaking facilities. The daily gas capacity of these peaking facilities (the maximum daily gas delivery available during the three peak winter months) is approximately 2.8 million therms in the aggregate.

Solar

As of December 31, 2016, PSE&G had 123 MW dc of installed solar capacity throughout New Jersey.

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ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, other than those discussed below, see Item 1. Business—Regulatory Issues and Environmental Matters and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Ewing Explosion

In 2014, pursuant to an existing contract, PSE&G assigned Henkels and McCoy (Henkels) to replace the electrical service at a home in the South Fork Townhouse Community in Ewing Township, Mercer County, New Jersey. As Henkels began work to install new electric service, a gas explosion occurred in the townhouse community resulting in damage to numerous properties, personal injuries and one fatality.

Twenty-two lawsuits have been filed to date relating to the gas explosion, of which PSE&G was named as a defendant in nineteen cases. To date, six of these cases have resolved through private negotiations and/or mediation. In one of the remaining pending matters, plaintiffs representing the estate of the decedent are seeking damages under the New Jersey Wrongful Death Act and the New Jersey Survivors Act as well as punitive damages. PSE&G has denied all allegations of liability. We intend to continue to vigorously defend these lawsuits. At this stage of the litigation, we are unable to determine or predict the ultimate outcome of any of the remaining lawsuits. Henkels has agreed to indemnify PSE&G for all compensatory damages awarded as a result of this incident unless it is proven that PSE&G is solely responsible. Any award for punitive damages against PSE&G would not be covered by such indemnity.

Environmental Matters

The following items are environmental matters involving governmental authorities not discussed elsewhere in this Form 10-K. We do not expect expenditures for any such site relating to the items listed below, individually or for all such current sites in the aggregate, to have a material effect on our financial condition, results of operations or net cash flows.

(1) Claim by the EPA, Region III, under CERCLA with respect to the Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and the former and current site owners are alleged to be liable for contamination at the site and PSE&G has been named as a Potentially Responsible Party (PRP). The EPA approved the Final Revised Remedial Design for the Site in early 2008. This document presented the design details of the EPA's selected remedy. PSE&G and other utility companies as members of a PRP group entered into a Consent Decree and agreed to implement the negotiated EPA selected remedy. The EPA settled its claims against the site owners who did not join the Consent Decree to implement the remedy. The PRP group's implementation of the remedy was completed in 2010; however, an additional estimated cost of $200,000 was incurred by PSE&G in 2016 to repair part of the remedy. Although the PRP Group has not received a formal Certification of Completion of the Remedy from the EPA, the PRP Group does not anticipate further significant costs at this time. Although subject to EPA approval and oversight, long-term monitoring, operations, and maintenance activities are anticipated through 2018 at a total estimated cost to PSE&G of $200,000.

(2) The EPA sent PSE&G, Power and approximately 157 other entities a notice that the EPA considered each of the entities to be a PRP with respect to contamination in Berry's Creek in Bergen County, New Jersey and requesting that the PRPs perform a Remedial Investigation and Feasibility Study (RI/FS) on Berry's Creek and the connected tributaries and wetlands. Berry's Creek flows through approximately 6.5 miles of areas that have been used for a variety of industrial purposes and landfills. The EPA estimates that the study could cost approximately $18 million. As members of a PRP Group, Power and certain of the other entities named in the EPA Notice entered into an Administrative Settlement Agreement and Order on Consent in 2008 to conduct the RI/FS, which is estimated to be completed in 2017/2018.

(3) In January 2010, we, as the current owner of the Gates Construction Corporation Landfill, received a letter from the NJDEP asserting that the subject landfill has not been properly closed in accordance with the NJDEP Solid Waste Regulations. Power has retained an environmental consultant to prepare a closure plan acceptable to the NJDEP.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange, Inc. As of February 17, 2017, there were 63,718 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2011 in our common stock and the subsequent reinvestment of quarterly dividends, the S&P Composite Stock Price Index, the Dow Jones Utilities Index and the S&P Electric Utilities Index.

	2011	2012	2013	2014	2015	2016
PSEG	$ 100.00	$ 96.96	$ 106.03	$ 142.26	$ 138.12	$ 162.47
S&P 500	$ 100.00	$ 115.93	$ 153.39	$ 174.30	$ 176.76	$ 197.77
DJ Utilities	$ 100.00	$ 101.59	$ 114.46	$ 149.35	$ 144.84	$ 170.94
S&P Electrics	$ 100.00	$ 101.24	$ 114.61	$ 147.63	$ 140.53	$ 163.20

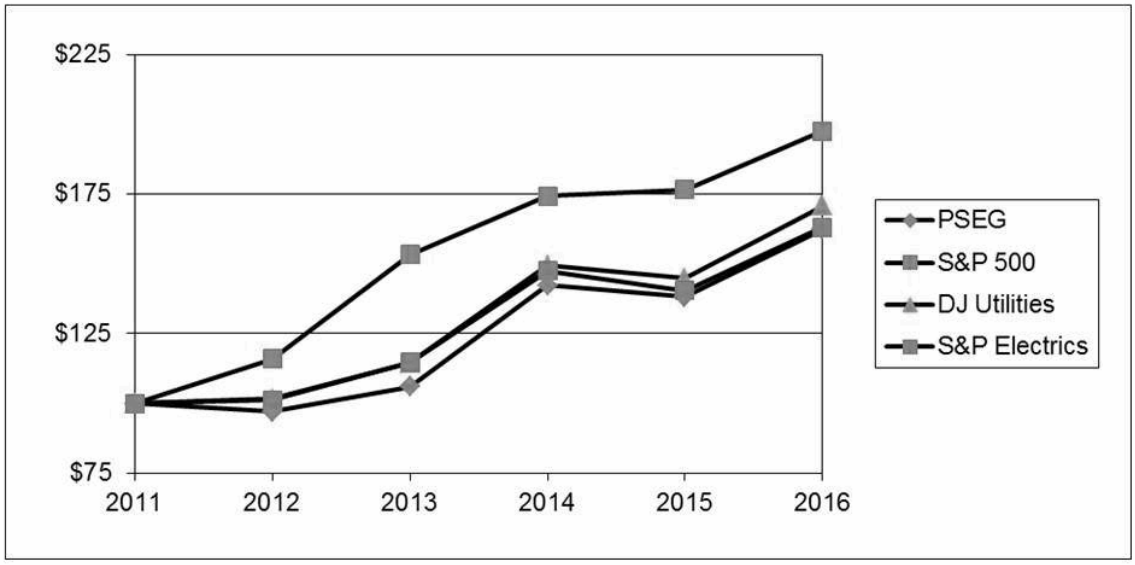

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The following table indicates the high and low sale prices for our common stock and dividends paid for the periods indicated:

Common Stock	High	Low	Dividend per Share
2016			
First Quarter	$ 47.22	$ 37.85	$ 0.41
Second Quarter	$ 47.41	$ 42.77	$ 0.41
Third Quarter	$ 46.81	$ 41.07	$ 0.41
Fourth Quarter	$ 44.29	$ 39.28	$ 0.41
2015			
First Quarter	$ 44.45	$ 39.00	$ 0.39
Second Quarter	$ 43.97	$ 38.93	$ 0.39
Third Quarter	$ 43.91	$ 38.16	$ 0.39
Fourth Quarter	$ 44.18	$ 36.80	$ 0.39

On February 21, 2017, our Board of Directors approved a $0.43 per share common stock dividend for the first quarter of 2017. This reflects an indicative annual dividend rate of $1.72 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

The following table indicates our common share repurchases in the open market during the fourth quarter of 2016 to satisfy obligations under various equity compensation award grants:

Three Months Ended December 31, 2016	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$ —
November 1-November 30	127,128	$ 40.97
December 1-December 31	30,000	$ 41.42

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2016:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Long-Term Incentive Plan	1,029,900	**$ 37.93**	14,517,886
Employee Stock Purchase Plan	—	—	3,463,447
Total	**1,029,900**	**$ 37.93**	**17,981,333**

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data—Note 18. Stock Based Compensation.

PSE&G

We own all of the common stock of PSE&G. For additional information regarding PSE&G's ability to continue to pay dividends, see Item 7. MD&A—Liquidity and Capital Resources.

Power

We own all of Power's outstanding limited liability company membership interests. For additional information regarding Power's ability to pay dividends, see Item 7. MD&A—Liquidity and Capital Resources.

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ITEM 6. SELECTED FINANCIAL DATA

PSEG

The information presented below should be read in conjunction with the MD&A and the Consolidated Financial Statements and Notes to Consolidated Financial Statements (Notes).

PSEG Years Ended December 31,	2016	2015	2014	2013	2012
	Millions, except Earnings per Share				
Operating Revenues (A)	$ 9,061	$ 10,415	$ 10,886	$ 9,968	$ 9,781
Income from Continuing Operations (B)	$ 887	$ 1,679	$ 1,518	$ 1,243	$ 1,275
Net Income	$ 887	$ 1,679	$ 1,518	$ 1,243	$ 1,275
Earnings per Share:					
Income from Continuing Operations					
Basic (A)	$ 1.76	$ 3.32	$ 3.00	$ 2.46	$ 2.52
Diluted (A)	$ 1.75	$ 3.30	$ 2.99	$ 2.45	$ 2.51
Net Income					
Basic	$ 1.76	$ 3.32	$ 3.00	$ 2.46	$ 2.52
Diluted	$ 1.75	$ 3.30	$ 2.99	$ 2.45	$ 2.51
Dividends Declared per Share	$ 1.64	$ 1.56	$ 1.48	$ 1.44	$ 1.42
As of December 31,					
Total Assets	$ 40,070	$ 37,535	$ 35,287	$ 32,480	$ 31,694
Long-Term Obligations (C)	$ 10,897	$ 8,837	$ 8,218	$ 7,830	$ 6,670

(A) Operating Revenues for 2016, 2015 and 2014 includes $410 million, $375 million and $389 million, respectively, for Long Island Electric Utility Servco, LLC (Servco), a wholly owned subsidiary of PSEG Long Island LLC (PSEG LI). See Item 8. Financial Statements and Supplementary Data—Note 4. Variable Interest Entities for additional information.

(B) Income from Continuing Operations includes after-tax expenses of $396 million related to the early retirement of Power's Hudson and Mercer coal/gas generation plants and after-tax charges totaling $92 million related to investments in NRG REMA, LLC's leveraged leases for 2016 and an after-tax insurance recovery for Superstorm Sandy of $102 million for 2015. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements, Note 7. Long-Term Investments and Note 8. Financing Receivables for additional information for 2016.

(C) Includes capital lease obligations.

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU, and
- **Power**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses through competitive energy sales in well-developed energy markets and fuel supply functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Our business discussion in Item 1. Business provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Item 1A. Risk Factors provides information about factors that could have a material adverse impact on our businesses. The following discussion provides an overview of the significant events and business developments that have occurred during 2016 and key factors that we expect may drive our future performance. This discussion refers to the Consolidated Financial Statements (Statements) and the related Notes to the Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements and Notes.

EXECUTIVE OVERVIEW OF 2016 AND FUTURE OUTLOOK

2016 Overview

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- improving utility operations through growth in investment in T&D and other infrastructure projects designed to enhance system reliability and resiliency and to meet customer expectations and public policy objectives,
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the years ended December 31, 2016 and 2015 are presented below:

	Years Ended December 31,	
	2016	2015
Earnings (Losses)	Millions, except per share data	
PSE&G	$ 889	$ 787
Power	18	856
Other	(20)	36
PSEG Net Income	**$ 887**	**$ 1,679**
PSEG Net Income Per Share (Diluted)	**$ 1.75**	**$ 3.30**

Our 2016 over 2015 decrease in Net Income was due primarily to charges related to the early retirement of our Hudson and Mercer units, mark-to-market (MTM) losses in 2016 as compared to gains in 2015, lower volumes of electricity and gas sold at lower average realized sales prices, lower capacity and operating reserve revenues, storm insurance recoveries received primarily by Power in 2015 related to Superstorm Sandy, and charges in 2016 related to investments in certain leveraged leases at Energy Holdings. These decreases were partially offset by higher transmission revenues, lower generation costs and higher costs incurred at Power for planned outages in 2015, and higher management fee revenues at PSEG LI pursuant to the OSA. For a more detailed discussion of our financial results, see Results of Operations.

During 2016, we maintained a strong balance sheet. We continued to effectively deploy capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results, which when combined with the cash flow generated by Power, our merchant generator and power marketer, has allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our multi-year, long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, we continue to invest in transmission projects that focus on reliability improvements and replacement of aging infrastructure. We also continue to make investments to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the BPU in 2014 and to seek recovery on such investments. We also commenced modernizing PSE&G's gas distribution systems as part of our Gas System Modernization Program (GSMP) that was approved by the BPU in late 2015. Over the past few years, these types of investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G. In 2017, as a result of our Energy Strong Order from the BPU, we will be required to file a distribution base rate case proceeding. We cannot predict the impact such proceeding will have on our distribution business.

Despite the unseasonable warm winter weather patterns in 2016, Power's results benefited from access to natural gas supplies through existing firm pipeline transportation contracts. Power manages these contracts for the benefit of PSE&G's customers through the BGSS arrangement. The contracts are sized to provide for delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to make third-party sales and supply gas to its generating units in New Jersey. Alternatively, gas supply and pipeline capacity constraints could adversely impact our ability to meet the needs of our utility customers and generating units. Power's hedging practices and ability to capitalize on market opportunities help it to balance some of the volatility of the merchant power business. More than half of Power's expected gross margin in the upcoming year relates to our hedging strategy, our expected revenues from the capacity market mechanisms and certain ancillary service payments such as reactive power.

Our investments in the latter half of 2015 and early 2016 in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. See Item 1. Business—Power for additional information on major growth projects. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to contribute to the overall efficiency of operations.

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced as being at risk for early retirement. This situation is generally due to low natural gas prices resulting from the growth of shale gas production since 2007, the continuing cost of regulatory compliance for nuclear facilities and both federal and state-level policies that provide credits to renewable energy such as wind and solar, but do not apply to

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nuclear generating stations. These trends have significantly reduced the revenues to nuclear generating stations while simultaneously raising the unit cost of production. This may result in the electric generation industry experiencing a shift from nuclear generation to natural gas-fired generation, creating greater reliance on natural gas pipelines for delivery and less diversity of the generation fleet.

If trends noted above continue or worsen, our nuclear generating units could cease being economically competitive which may cause us to retire such units prior to the end of their useful lives. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs and environmental remediation costs, could be material. We continue to advocate for sound policies that recognize nuclear power as a source of clean energy and an important part of a diverse and reliable energy portfolio.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission Planning

In April 2013, PJM initiated its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues in New Jersey. In February 2016, FERC issued an order granting PSE&G's request that it be permitted to seek recovery of 100% of its portion of the project's costs to address identified high voltage issues at Artificial Island in New Jersey if the project is canceled for reasons beyond PSE&G's control. In April 2016, PSE&G accepted construction responsibility for the three components of the project that PJM assigned to it, based on having reached agreement with PJM regarding an estimate for the project base cost of $273 million, plus risk and contingency for a total project cost of up to $340 million. In August 2016, PJM announced that it had suspended the Artificial Island transmission project and would be performing a comprehensive analysis to support a future course of action. PJM will submit its final recommendation to the PJM Board at the April 2017 Board meeting.

In April 2016, PJM filed at FERC to incorporate a voltage threshold into PJM's Regional Transmission Expansion Plan (RTEP) process to exempt, except under certain circumstances, reliability violations on facilities below 200 kV from PJM's proposal window process. We generally support this reform as a measure to improve the efficiency of the open window procedure that will permit transmission developers to focus on the projects most likely to benefit from a competitive process.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey and may cause increased scrutiny regarding PSE&G's future capital investments. In addition, as a basic generation service (BGS) supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers may be entitled to an adjustment, subject to BPU approval. We do not believe that these matters will have a material effect on Power's business or results of operations.

Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base return on equity (ROE). Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. While we are not the subject of a challenge to the ROE employed in PSE&G's transmission formula rate, the results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. In June 2015, FERC conditionally accepted a proposal from PJM for a capacity performance product to include generators, Demand Response and energy efficiency providers, which will be required to perform during emergency conditions, as a supplement to the base capacity product. The proposal included enhanced performance-based incentives and penalties. We believe that the auction pricing adequately reflects the increased costs that could result from operating under more stringent rules for generation availability. Based on the auction results, the capacity performance mechanism appears to have provided the opportunity for enhanced capacity market revenue streams for Power, but future impacts cannot be assured. Further, there may be requirements for additional investment and there are additional performance and financial risks. Appeals of FERC's capacity performance orders are pending.

In May 2016, PJM announced the results of the RPM capacity auction for the 2019-2020 delivery year. Power cleared 8,895 MW of its generating capacity at an average price of $116 per MW-day for the 2019-2020 delivery period. Of the cleared

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capacity, Power believes that nearly all is compliant with PJM's capacity performance requirements. In the two prior capacity auctions covering the 2017-2018 and 2018-2019 delivery years, Power cleared approximately 8,700 MW at average prices of $177 per MW-day and $215 per MW-day, respectively. Prices in the most recent auction reflect PJM's downwardly-revised demand forecast, changes in the capacity emergency transfer limits due to transmission expansion and the effects of both the new generation and uncleared generation from the prior year's auction.

As a result of the efforts of certain entities in PJM to obtain financial support arrangements from their state commission, a group of suppliers requested that FERC direct PJM to expand the currently effective "minimum offer price rule" to apply to certain existing units seeking subsidies. The suppliers' request was intended to avoid a scenario where the subsidized generators would submit bids into the PJM capacity market that did not reflect their actual costs of operation and could artificially suppress capacity market prices. We are currently awaiting FERC action on the suppliers' request and cannot predict the outcome of the proceeding.

See Item 1. Business—Federal Regulation for additional information.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act (FWPCA) requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs.

The U.S. Supreme Court's February 2016 decision to stay the implementation of the Clean Power Plan (CPP), a greenhouse gas emissions regulation under the Clean Air Act (CAA) for existing power plants, will delay deadlines for submission of state requests for extensions and final plans. If the CPP is upheld, new deadlines will need to be established and the effective date of the compliance period may be impacted.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above as well as other matters that may impact our financial condition and results of operations, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

FERC Compliance

Since September 2014, FERC Staff has been conducting a preliminary non-public investigation regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units. This investigation is ongoing. The amounts of potential disgorgement and other potential penalties that we may incur span a wide range depending on the success of our legal arguments. If our legal arguments do not prevail, in whole or in part with FERC or in a judicial challenge that we may choose to pursue, it is likely that Power would record losses that would be material to PSEG's and Power's results of operations in the quarterly and annual periods in which they are recorded. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Early Retirement of Hudson and Mercer Units

In October 2016, Power determined it will cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. The exact timing of the early retirement of these units may be impacted by operational and other conditions that could subsequently arise. The decision to retire the Hudson and Mercer units will have a material effect on PSEG's and Power's results of operations. In 2016, PSEG and Power recognized pre-tax charges in Energy Costs and Operation and Maintenance (O&M) of $62 million and $53 million, respectively, related to coal inventory adjustments, capacity penalties, materials and supplies inventory reserve adjustments for parts that cannot be used at other generating units, employee-related severance benefits costs and construction work in progress impairments, among other shut down items. In addition to these charges, Power recognized incremental Depreciation and Amortization during 2016 of $555 million ($571 million in total) and expects to recognize an additional $931 million ($958 million in total) in 2017 due to the significant shortening of the expected economic useful lives of Hudson and Mercer. Additional employee-related salary continuance and severance costs and various miscellaneous costs may also be incurred during the period prior to retirement. Finally, Power currently anticipates using the

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sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such remediation are neither currently probable nor estimable but may be material. For additional information, including our estimated costs through 2017, see Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements.

The primary factors considered during our annual five-year strategic planning process that contributed to the decision to retire these units early include significant declines in revenues and margin caused by a sustained period of depressed wholesale power prices and reduced capacity factors caused by lower natural gas prices making coal generation less economically competitive than natural gas-fired generation. Despite experiencing recent warmer than normal weather in PJM this summer, Power did not experience the usual increase in electricity prices in PJM as it had in past hot summers. This trend has a further adverse economic impact to these units because they generally dispatch and earn energy margin on peak hot and cold days. In addition, the upcoming PJM capacity auction in May 2017 will be the first to require all generating units to meet the increased operating performance standards of PJM's new capacity performance construct. Power determined that the costs to upgrade the existing units at the Hudson and Mercer stations to be able to comply with these higher reliability standards are too significant and not economic given current market conditions.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to ensure their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact our ability to operate or maintain these assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Leveraged Lease Impairments

During the third quarter of 2016, Energy Holdings completed its annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases. The outcome indicated that the revised residual value estimates were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM, as discussed in Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements, negatively impacting the economic outlook of the leased assets. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016, calculated by comparing the gross investment in the leases before and after the revised residual estimates. During the fourth quarter of 2016, Energy Holdings recorded a $10 million pre-tax charge in Operating Revenues reflecting its best estimate of loss as a result of the current liquidity issues facing REMA. There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.

Additional facilities in our leveraged lease portfolio include the Joliet and Shawville generating facilities, which were converted to use natural gas. However, these units may have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units. As a result, these facilities may not be as economically competitive as newer combined cycle gas units and could continue to be adversely impacted by the same economic conditions experienced by coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged leases associated with these facilities.

Further, REMA's parent company, GenOn Energy, Inc. (GenOn), reported in August 2016 that it did not expect to have sufficient liquidity to repay their senior unsecured notes due in June 2017. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's efforts to restructure its portfolio and improve its liquidity and the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments, which could include further write-downs of the values of Energy Holdings' leveraged leases. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables.

Salem Operations

The previously announced bolt replacement at Salem Unit 1 was completed and the unit returned to service on July 30, 2016. We expect to continue to inspect and replace degraded bolts at both Salem units over the next several refueling outage cycles. We are participating with the Electric Power Research Institute, the Nuclear Energy Institute and other operators of similarly-designed pressurized water reactors in developing a strategy to maintain the long-term health of the reactor vessel internals.

Extension of the Salem Unit 1 outage into July and an unplanned outage at Salem Unit 2 due to a transformer failure currently under investigation reduced output from the Salem units in the third quarter. This was partially offset by increased production at our Hope Creek and Peach Bottom units. As a result, our nuclear capacity factor for the year ended December 31, 2016 was 86.9%.

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Pension Plan Merger

As of December 31, 2016, PSEG merged its three qualified defined benefit pension plans (excluding Servco plans) into one plan, thereby also merging all of the pension plans' assets. As a result, we estimate that in 2017, the total net periodic benefit costs are expected to decrease by approximately $72 million or $48 million, net of amounts capitalized, as compared to the 2017 amounts that would have been recognized had the plans not been merged. This is due to the amortization period for gains and losses for the merged plan resulting in lower amortization than that of the individual plans. No changes were made to the benefit formulas, vesting provisions, or to the employees covered by the plans.

Pension and Other Postretirement Benefits—Change in Accounting Estimate

At the end of 2015, we changed the approach used to measure future service and interest costs for pension and other post-retirement benefits. For 2015 and prior, we calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, we have elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows. We believe the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change did not affect the measurement of the plan obligations. As a change in accounting estimate, this change was reflected prospectively. We reduced 2016 pension and OPEB expense by approximately $34 million and $13 million, respectively, net of amounts capitalized.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of opportunities in a rapidly evolving market as we remain diligent in managing costs. In 2016, our

- diverse fuel mix and dispatch flexibility allowed us to generate approximately 52 terra-watt hours while addressing fuel availability and price volatility and compensating for the extended outages at our Salem units,
- combined cycle fleet produced 16 terawatt hours at an average capacity factor of 57%, and
- utility was recognized for the fifteenth consecutive year as the most reliable utility in the Mid-Atlantic region.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during 2016 as we:

- maintained sufficient liquidity,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2016 to $1.64 per share.

We expect to be able to fund our planned capital requirements, as described in Liquidity and Capital Resources, without the issuance of new equity.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In 2016, we

- made additional investments in transmission infrastructure projects,
- began executing our GSMP and continued executing Energy Strong and other existing BPU-approved utility programs,
- commenced construction of our Keys and Sewaren 7 generation projects for targeted commercial operation in 2018 and announced our plan to construct BH5 and commence operations in mid-2019, and
- acquired solar energy projects totaling 248 MW-direct current (dc), of which 177 MW dc are already in-service, primarily in North Carolina, Colorado and Utah. The remaining MW dc are scheduled to be in-service by the fourth quarter of 2017.

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Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-growing economy and a cost-constrained environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions in response to changes in demand,
- execute our utility capital investment program, including our Energy Strong program, GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction of our Keys, Sewaren 7, BH5 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

For 2017 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- fair and timely rate relief from the BPU and FERC for recovery of costs and return on investments, including with respect to our distribution base rate case which must be filed with the BPU no later than November 1, 2017,
- the potential for comprehensive tax reform, particularly in light of public statements by the current U.S. administration and key members of Congress,
- uncertainty in the national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate,
- the impact of lower natural gas prices and increasing environmental compliance costs on the competitiveness of our nuclear and remaining coal-fired generation plants, and the potential for retirement of such plants earlier than their current useful lives,
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development projects, including in connection with permitting and regulatory approvals,
- maintaining a diverse mix of fuels to mitigate risks associated with fuel price volatility and market demand cycles, and
- FERC Staff's continuing investigation of certain of Power's New Jersey fossil generating unit bids in the PJM energy market.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of transmission and distribution facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses,

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- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency, modernizing existing infrastructure and participation in transmission projects through FERC's "open window" solicitation process.

In 2016, Power announced its intention to develop a retail platform to sell physical electricity and natural gas, which we believe would complement our existing wholesale marketing business. Power was granted licenses in 2016 to sell both electricity and gas in the states of New Jersey and Pennsylvania.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

RESULTS OF OPERATIONS

	Years Ended December 31,		
	2016	2015	2014
Earnings (Losses)	Millions		
PSE&G	$ 889	$ 787	$ 725
Power (A)	18	856	760
Other (B)	(20)	36	33
PSEG Net Income	**$ 887**	**$ 1,679**	**$ 1,518**
PSEG Net Income Per Share (Diluted)	**$ 1.75**	**$ 3.30**	**$ 2.99**

(A) Power's results in 2016 includes after-tax expenses of $396 million related to the early retirement of its Hudson and Mercer coal/gas generation plants. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements for additional information. Power's results in 2015 include an after-tax insurance recovery for Superstorm Sandy of $102 million.

(B) Other includes after-tax activities at the parent company, PSEG LI and Energy Holdings as well as intercompany eliminations. Energy Holdings recorded after-tax charges totaling $92 million related to its investments in NRG REMA, LLC's leveraged leases in 2016. See Item 8. Financial Statements and Supplementary Data—Note 7. Long-Term Investments and Note 8. Financing Receivables for further information.

Our results include the realized gains, losses and earnings on Power's NDT Fund and other related NDT activity. Realized gains and losses, interest and dividend income and other costs related to the NDT Fund are recorded in Other Income (Deductions), and impairments on certain NDT securities are recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear ARO is recorded in O&M Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense. In 2014, we restructured portions of our NDT Fund and realized a pre-tax gain of $65 million.

Our results also include the after-tax impacts of non-trading MTM activity, which consist of the financial impact from positions with forward delivery dates.

The combined after-tax impact on Net Income for the years ended December 31, 2016, 2015 and 2014 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2016	2015	2014
	Millions, after tax		
NDT Fund and Related Activity (A)	$ —	$ 8	$ 68
Non-Trading MTM Gains (Losses) (B)	$ (100)	$ 93	$ 66

(A) Net of tax (expense) benefit of $(5) million, $(16) million and $(70) million for the years ended December 31, 2016, 2015 and 2014, respectively.

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(B) Net of tax (expense) benefit of $68 million, $(65) million and $(45) million for the years ended December 31, 2016, 2015 and 2014, respectively.

The 2016 year-over-year decrease in our Net Income was driven primarily by:

- charges related to the early retirement of two coal/gas generation units at Power (See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements),
- MTM losses in 2016 as compared to MTM gains in 2015,
- lower volumes of energy sold at lower average realized sales prices,
- lower capacity and operating reserve revenues in PJM,
- higher 2016 congestion costs in PJM due primarily to realized gains on financial transmission rights (FTR) in PJM in the prior year due to extremely cold weather,
- lower volumes of gas sold at lower average prices under the Basic Gas Supply Service (BGSS) contract,
- insurance recoveries received primarily by Power in 2015 related to Superstorm Sandy, and
- an impairment related to investments in certain leveraged leases at Energy Holdings (See Item 8. Financial Statements and Supplementary Data —Note 8. Financing Receivables).

These decreases were partially offset by:

- lower generation costs driven by lower fuel costs, particularly for natural gas, and reduced generation output at Power,
- higher costs incurred at Power for planned outages in 2015,
- higher transmission revenues, and
- higher management fee revenues at PSEG LI pursuant to the OSA.

The 2015 year-over-year increase in our Net Income was driven by:

- higher transmission revenues,
- lower generation costs due to lower fuel costs, primarily reflecting lower natural gas and coal prices,
- higher MTM gains in 2015, and
- insurance recoveries of Superstorm Sandy costs, primarily at Power.

These increases were partially offset by:

- lower capacity revenues resulting from lower average auction prices coupled with lower ancillary and operating reserve revenues in the PJM region,
- lower realized gains and higher other-than-temporary impairments related to the NDT Fund, and
- higher pension and OPEB costs, net of amounts capitalized.

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PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data—Note 24. Related-Party Transactions.

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2016	2015	2014	2016 vs. 2015		2015 vs. 2014	
	Millions			Millions	%	Millions	%
Operating Revenues	$ 9,061	$ 10,415	$ 10,886	$ (1,354)	(13)	$ (471)	(4)
Energy Costs	3,001	3,261	3,886	(260)	(8)	(625)	(16)
Operation and Maintenance	3,008	2,978	3,150	30	1	(172)	(5)
Depreciation and Amortization	1,476	1,214	1,227	262	22	(13)	(1)
Income from Equity Method Investments	11	12	13	(1)	(8)	(1)	(8)
Other Income (Deductions)	124	152	229	(28)	(18)	(77)	(34)
Other-Than-Temporary Impairments	28	53	20	(25)	(47)	33	N/A
Interest Expense	385	393	389	(8)	(2)	4	1
Income Tax Expense	411	1,001	938	(590)	(59)	63	7

The 2016, 2015 and 2014 amounts in the preceding table for Operating Revenues and O&M costs each include $410 million, $375 million and $389 million, respectively, for Servco. These amounts represent the O&M pass-through costs for the Long Island operations, the full reimbursement of which is reflected in Operating Revenues. See Item 8. Financial Statements and Supplementary Data—Note 4. Variable Interest Entities for further explanation. The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2016	2015	2014	2016 vs. 2015		2015 vs. 2014	
	Millions			Millions	%	Millions	%
Operating Revenues	$ 6,221	$ 6,636	$ 6,766	$ (415)	(6)	$ (130)	(2)
Energy Costs	2,567	2,722	2,909	(155)	(6)	(187)	(6)
Operation and Maintenance	1,475	1,560	1,558	(85)	(5)	2	—
Depreciation and Amortization	565	892	906	(327)	(37)	(14)	(2)
Other Income (Deductions)	79	75	58	4	5	17	29
Interest Expense	289	280	277	9	3	3	1
Income Tax Expense	515	470	449	45	10	21	5

Year Ended December 31, 2016 as compared to 2015

Operating Revenues decreased $415 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $191 million due primarily to an increase in transmission revenues.

- Transmission revenues were $223 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.

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- Electric distribution revenues decreased $27 million due primarily to $47 million in lower collections of Green Program Recovery Charges (GPRC), partially offset by an $18 million increase in Energy Strong revenues.
- Gas distribution revenues decreased $5 million due to a decrease of $43 million due to lower sales volumes and $7 million in lower collections of GPRC. These decreases were partially offset by higher Weather Normalization Clause (WNC) revenues of $25 million due to warmer weather in 2016 compared to 2015 and $20 million due to the inclusion of Energy Strong in base rates.

Clause Revenues decreased $445 million due to lower Securitization Transition Charge (STC) revenues of $419 million, lower Societal Benefit Charges (SBC) of $33 million, and lower Solar Pilot Recovery Charges (SPRC) of $8 million. These decreases were partially offset by higher Margin Adjustment Clause (MAC) revenues of $15 million. The changes in STC, SBC, SPRC and MAC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC, SPRC or MAC collections.

Commodity Revenues decreased $155 million due to lower Electric and Gas revenues. This is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $136 million due to $73 million in lower collections of Non-Utility Generation Charges (NGC) due primarily to lower prices, $42 million in lower revenues from the sale of Non-Utility Generation (NUG) energy and $21 million in lower BGS revenues primarily due to lower sales volumes.
- Gas revenues decreased $19 million due to $80 million from lower sales volumes, partially offset by higher BGSS prices of $61 million.

Operating Expenses

Energy Costs decreased $155 million. This is entirely offset by Commodity Revenues.

Operation and Maintenance decreased $85 million due to

- a $98 million net reduction related to various clause mechanisms and GPRC, and
- a $13 million decrease in pension and OPEB expenses, net of amounts capitalized,
- partially offset by $10 million of insurance recovery proceeds in 2015,
- a $10 million increase in vegetation management costs, and
- a $6 million net increase due primarily to transmission and distribution corrective maintenance and appliance service costs.

Depreciation and Amortization decreased $327 million due primarily to a $396 million net decrease in amortization of Regulatory Assets, partially offset by an increase in depreciation of $65 million due additional plant placed into service in 2016.

Interest Expense increased $9 million due to increases of

- $14 million due to net debt issuances in 2015, and
- $13 million due to net debt issuances in 2016,
- partially offset by a decreases of $11 million due to the redemption of securitization debt in 2015 and
- $7 million of higher interest related to BGSS in 2015.

Income Tax Expense increased $45 million due primarily to higher pre-tax income partially offset by changes in the reserve for uncertain tax positions and flow through items.

Year Ended December 31, 2015 as compared to 2014

Operating Revenues decreased $130 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $212 million due primarily to an increase in transmission revenues.

- Transmission revenues were $164 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.

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- Electric distribution revenues increased $31 million due primarily to higher sales volumes due to weather.
- Gas distribution revenues increased $17 million due to higher WNC revenues of $35 million due to warmer weather in 2015 compared to 2014, partially offset by $18 million due to lower sales volumes.

Clause Revenues decreased $154 million due to lower STC revenues of $86 million, lower SBC of $31 million, lower MAC of $29 million, and lower SPRC of $8 million. The changes in STC, SBC, MAC and SPRC amounts were entirely offset by decreases in the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC, MAC or SPRC collections.

Commodity Revenues decreased $187 million due to lower Gas revenues, partially offset by higher Electric revenues. This is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Gas revenues decreased $266 million due to lower BGSS prices of $295 million, partially offset by $29 million from higher sales volumes. The average price of natural gas was 29% lower to the customer in 2015 than in 2014.
- Electric revenues increased $79 million due to $120 million in higher net BGS revenues, comprised of $166 million from higher sales volumes, partially offset by lower prices of $46 million. BGS sales volume increased due primarily to weather. The BGS net revenue increase was partially offset by $41 million in lower revenues from the sale of NUG energy and the collections of NGC due primarily to lower prices.

Operating Expenses

Energy Costs decreased $187 million. This is entirely offset by Commodity Revenues.

Operation and Maintenance increased $2 million, of which the most significant components were increases of

- $33 million in pension and OPEB expenses, net of amounts capitalized,
- $13 million in transmission operating expenses,
- $7 million in gas bad debt expense, and
- a $49 million net increase due to various increases, including information technology expenditures, wages, appliance service costs and preventative maintenance,
- almost entirely offset by a $90 million net reduction related to various clause mechanisms, GPRC and the Capital Infrastructure Program, and
- $10 million of insurance recovery proceeds.

Depreciation and Amortization decreased $14 million due to a $69 million decrease in amortization of Regulatory Assets, partially offset by an increase in depreciation of $55 million due to additional plant in service.

Other Income (Deductions) net increase of $17 million in AFUDC.

Interest Expense increased $3 million due primarily to increases of

- $12 million due to net debt issuances in the latter half of 2014, and
- $9 million due to net debt issuances in 2015,
- partially offset by a decrease of $17 million due to the redemption of securitization debt in 2015.

Income Tax Expense increased $21 million due primarily to higher pre-tax income.

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Power

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2016	2015	2014	2016 vs. 2015		2015 vs. 2014	
	Millions			Millions	%	Millions	%
Operating Revenues	$ 4,023	$ 4,928	$ 5,434	$ (905)	(18)	$ (506)	(9)
Energy Costs	1,986	2,150	2,747	(164)	(8)	(597)	(22)
Operation and Maintenance	1,143	1,057	1,186	86	8	(129)	(11)
Depreciation and Amortization	881	291	292	590	N/A	(1)	—
Income from Equity Method Investments	11	14	14	(3)	(21)	—	—
Other Income (Deductions)	45	97	170	(52)	(54)	(73)	(43)
Other-Than-Temporary Impairments	28	53	20	(25)	(47)	33	N/A
Interest Expense	84	121	122	(37)	(31)	(1)	(1)
Income Tax Expense (Benefit)	(61)	511	491	(572)	N/A	20	4

Year Ended December 31, 2016 as compared to 2015

Operating Revenues decreased $905 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $714 million due primarily to

- a decrease of $317 million due to MTM losses in 2016 as compared to MTM gains in 2015. Of this amount, $199 million was due to changes in forward power prices resulting in lower MTM gains this year compared to last year. Also contributing to the decrease was $118 million of higher gains on positions reclassified to realized upon settlement this year compared to last year,
- a decrease of $298 million in energy sales volumes in the PJM, NE and NY regions due primarily to milder weather in 2016 and lower average realized prices,
- a decrease of $80 million in capacity revenue primarily in the PJM region due to the retirement of older peaking units in June 2015, and
- a decrease of $49 million due to lower operating reserve revenues in the PJM region due to less congestion and lower prices,
- partially offset by a net increase of $19 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions, partially offset by lower average prices, and
- a net increase of $8 million due to new solar projects beginning commercial operations.

Gas Supply Revenues decreased $191 million due primarily to

- a decrease of $183 million in sales under the BGSS contract due primarily to lower average sales prices and a decrease in sales volumes due to warmer average temperatures in the 2016 heating season, and
- a decrease of $9 million due to MTM losses in 2016 due to changes in forward prices.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $164 million due to

Generation costs decreased $95 million due primarily to

- lower fuel costs of $288 million reflecting lower average realized prices for natural gas and the utilization of lower volumes of fuel,
- partially offset by a net increase of $143 million primarily due to realized gains on FTRs in PJM in the prior year due to extremely cold weather, and

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- a $62 million charge associated with the announced early retirement of the Mercer and Hudson units, primarily related to a coal inventory write-down.

Gas costs decreased $69 million due to

- a decrease of $101 million related to sales under the BGSS contract due primarily to lower average gas costs and a decrease in volumes sold due to warmer average temperatures during the 2016 winter heating season,
- partially offset by an increase of $32 million related to sales to third parties due primarily to higher average gas costs and an increase in volumes sold.

Operation and Maintenance increased $86 million due to

- $145 million of insurance recoveries received in 2015 related to Superstorm Sandy, and
- $53 million of charges related to the early retirement of the Hudson and Mercer units,
- partially offset by a net decrease of $73 million related to our fossil plants, largely due to higher costs incurred in 2015 for our planned major outages at the Bethlehem Energy Center and Bergen generating plants,
- a net decrease of $31 million related to our nuclear plants due primarily to lower planned outage costs at our 100%-owned Hope Creek plant and our 57%-owned Salem Unit 1 plant, and
- an $8 million decrease due to lower pension and OPEB costs.

Depreciation and Amortization increased $590 million due primarily to

- $555 million of accelerated depreciation due to the early retirement of the Hudson and Mercer units,
- a $24 million increase due primarily to a higher nuclear asset base, and
- $5 million of higher depreciation due to new solar projects.

Other Income (Deductions) decreased $52 million due primarily to $28 million of insurance recoveries received in 2015 related to Superstorm Sandy and $38 million of lower net realized gains from the NDT Fund in 2016, partially offset by $10 million of lower purchased tax credits in 2016.

Other-Than-Temporary Impairments decreased $25 million due to lower impairments of equity securities in the NDT Fund in 2016.

Interest Expense decreased $37 million due to

- $27 million of interest capitalized for the construction of three new fossil stations: Bridgeport Harbor 5, Sewaren 7 and Keys Energy Center, and
- a $15 million decrease due to the maturity of 5.50% of Senior Notes in December 2015,
- partially offset by an increase of $5 million due to net debt issuances in 2016.

Income Tax Expense decreased $572 million in 2016 due primarily to a pre-tax loss in 2016 as compared to pre-tax income in 2015.

Year Ended December 31, 2015 as compared to 2014

Operating Revenues decreased $506 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $172 million due to

- a decrease of $192 million due primarily to lower capacity revenues resulting from lower average auction prices and the retirement of older peaking units in June 2015, coupled with lower ancillary and operating reserve revenues in the PJM region, and

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- lower net revenues of $73 million due primarily to lower energy volumes sold in the NE region and lower average realized prices in the NE and NY regions, partially offset by higher energy volumes sold in the NY and PJM regions. Also included in the net decrease is $22 million due to lower MTM gains in 2015.
- partially offset by an increase of $56 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions coupled with higher average prices in the NE region, and
- an increase of $37 million due primarily to higher volumes of electricity sold under the BGS contract at higher average prices.

Gas Supply Revenues decreased $336 million due to

- a net decrease of $214 million in sales under the BGSS contract, substantially comprised of lower average sales prices, and
- a decrease of $122 million on sales to third-party customers, of which $93 million was due to lower average sales prices and $29 million to lower volumes sold.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $597 million due to

- ***Generation costs*** decreased $254 million due primarily to lower fuel costs of $330 million reflecting lower average realized natural gas and coal prices and the utilization of lower volumes of oil and coal. MTM gains in 2015 as compared to MTM losses in 2014 resulted in a $66 million decrease. These decreased costs were partially offset by higher congestion costs in the PJM region of $140 million.
- ***Gas costs*** decreased $343 million mainly related to a decrease in average gas costs on both obligations under the BGSS contract and sales to third parties.

Operation and Maintenance decreased $129 million due primarily to

- a decrease of $145 million due to insurance recoveries received in 2015 related to Superstorm Sandy, and
- a net decrease of $61 million related to our fossil plants, largely due to higher costs incurred in 2014 for planned outage costs, including maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant, partially offset by planned outage costs in 2015 at our BEC generating plant and installation of upgraded technology at our combined cycle Bergen plant,
- partially offset by an increase of $51 million at our nuclear facilities, primarily due to higher planned outage costs at our 100%-owned Hope Creek and 50%-owned Peach Bottom 3 nuclear plants in 2015 as compared to our 57%-owned Salem nuclear unit 2 in 2014, and
- a $30 million increase due to higher pension and OPEB costs, net of amounts capitalized.

Other Income (Deductions) decreased $73 million due primarily to lower net realized gains from the NDT Fund, partially offset by a $28 million insurance recovery related to Superstorm Sandy.

Other-Than-Temporary Impairments increased $33 million due primarily to an increase in impairments of equity securities in the NDT Fund.

Income Tax Expense increased $20 million in 2015 due primarily to higher pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Financing Methodology

We expect our capital requirements to be met through internally generated cash flows and external financings, consisting of short-term debt for working capital needs and long-term debt for capital investments.

PSE&G's sources of external liquidity include a $600 million multi-year syndicated credit facility. PSE&G uses internally generated cash flow and its commercial paper program to meet seasonal, intra-month and temporary working capital needs.

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PSE&G does not engage in any intercompany borrowing or lending arrangements. PSE&G maintains back-up facilities in an amount sufficient to cover the commercial paper and letters of credit outstanding. PSE&G's dividend payments to/capital contributions from PSEG are consistent with its capital structure objectives which have been established to maintain investment grade credit ratings. PSE&G's long-term financing plan is designed to replace maturities, fund a portion of its capital program and manage short-term debt balances. Generally, PSE&G uses either secured medium-term notes or first mortgage bonds to raise long-term capital.

PSEG, Power, Energy Holdings, PSEG LI and Services participate in a corporate money pool, an aggregation of daily cash balances designed to efficiently manage their respective short-term liquidity needs. Servco does not participate in the corporate money pool. Servco's short-term liquidity needs are met through an account funded and owned by LIPA.

PSEG's sources of external liquidity may include the issuance of long-term debt securities and the incurrence of additional indebtedness under credit facilities. Our current sources of external liquidity include multi-year syndicated credit facilities totaling $1 billion. These facilities are available to back-stop PSEG's commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to PSEG's subsidiaries. PSEG's credit facilities and the commercial paper program are available to support PSEG working capital needs or to temporarily fund growth opportunities in advance of obtaining permanent financing. PSEG also has a $500 million term loan credit agreement that is scheduled to expire in November 2017. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power's sources of external liquidity include $2.6 billion of syndicated multi-year credit facilities. Additionally, from time to time, Power maintains bilateral credit agreements designed to enhance its liquidity position. Credit capacity is primarily used to provide collateral in support of Power's forward energy sale and forward fuel purchase contracts as the market prices for energy and fuel fluctuate, and to meet potential collateral postings in the event that Power is downgraded to below investment grade by S&P or Moody's. Power's dividend payments to PSEG are also designed to be consistent with its capital structure objectives which have been established to maintain investment grade credit ratings and provide sufficient financial flexibility. Generally, Power issues senior unsecured debt to raise long-term capital.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the year ended December 31, 2016, our operating cash flow decreased by $608 million. For the year ended December 31, 2015, our operating cash flow increased by $759 million. The net changes were primarily due to net changes from our subsidiaries as discussed below.

PSE&G

PSE&G's operating cash flow decreased $231 million from $2,125 million to $1,894 million for the year ended December 31, 2016, as compared to 2015, due primarily to a decrease from lower collections for securitization debt principal repayments which were $259 million in 2015, a decrease of $249 million in cash receipts from customers due to lower sales driven by warmer winter weather in 2016 compared to 2015, a decrease of $90 million related to a change in regulatory deferrals, primarily driven by net returns to customers in 2016 related to 2015 overcollections, partially offset by higher bill credits and $74 million in increased vendor payments. These amounts were partially offset by higher earnings and higher tax refunds in 2016.

PSE&G's operating cash flow increased $292 million from $1,833 million to $2,125 million for the year ended December 31, 2015, as compared to 2014, due primarily to higher earnings, a $311 million reduction in tax payments, and an increase of $102 million due to higher customer billings in the fourth quarter of 2014 primarily as a result of increased usage due to weather. These increases were partially offset by a decrease of $250 million related to a change in regulatory deferrals, primarily driven by the return of prior year overcollections to customers for BGSS gas costs, Gas WNC charges and BGS costs.

Power

Power's operating cash flow decreased $451 million from $1,706 million to $1,255 million for the year ended December 31, 2016, as compared to 2015, primarily resulting from lower earnings, an increase in margin deposit requirements of $198 million, and a $134 million decrease from net collection of counterparty receivables, partially offset by a reduction in tax payments.

Power's operating cash flow increased $281 million from $1,425 million to $1,706 million for the year ended December 31, 2015, as compared to 2014, primarily resulting from higher earnings, a decrease in margin deposit requirements of $144 million, and a $78 million increase from net collection of counterparty receivables. These amounts were partially offset by an increase of $325 million in tax payments.

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Short-Term Liquidity

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of December 31, 2016 were as follows:

Company/Facility	As of December 31, 2016		
	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$ 1,000	$ 398	$ 602
PSE&G	600	14	586
Power	2,553	198	2,355
Total	**$ 4,153**	**$ 610**	**$ 3,543**

As of December 31, 2016, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating from S&P or Moody's, which would represent a three level downgrade from its current S&P or Moody's ratings. In the event of a deterioration of Power's credit rating certain of Power's agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $783 million and $864 million as of December 31, 2016 and 2015, respectively. The early retirement of Power's Hudson and Mercer coal/gas generation units is not expected to have a material impact on Power's debt covenant ratios or its ability to obtain credit facilities. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements.

For additional information, see Item 8.Financial Statements and Supplementary Data—Note 14. Debt and Credit Facilities.

Long-Term Debt Financing

PSEG has a floating rate $500 million term loan maturing in November 2017.

For a discussion of our long-term debt transactions during 2016 and into 2017, see Item 8. Financial Statements and Supplementary Data—Note 14. Debt and Credit Facilities.

Debt Covenants

Our credit agreements contain maximum debt to equity ratios and other restrictive covenants and conditions to borrowing. We are currently in compliance with all of our debt covenants. Continued compliance with applicable financial covenants will depend upon our future financial position, level of earnings and cash flows, as to which no assurances can be given.

In addition, under its First and Refunding Mortgage (Mortgage), PSE&G may issue new First and Refunding Mortgage Bonds against previous additions and improvements, provided that its ratio of earnings to fixed charges calculated in accordance with its Mortgage is at least 2 to 1, and/or against retired Mortgage Bonds. As of December 31, 2016, PSE&G's Mortgage coverage ratio was 4.2 to 1 and the Mortgage would permit up to approximately $5.7 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.

Default Provisions

Our bank credit agreements and indentures contain various, customary default provisions that could result in the potential acceleration of indebtedness under the defaulting company's agreement.

In particular, PSEG's bank credit agreements contain provisions under which certain events, including an acceleration of material indebtedness under PSE&G's and Power's respective financing agreements, a failure by PSE&G or Power to satisfy certain final judgments and certain bankruptcy events by PSE&G or Power, that would constitute an event of default under the PSEG bank credit agreements. Under the PSEG bank credit agreements, it would also be an event of default if either PSE&G or Power ceases to be wholly owned by PSEG. The PSE&G and Power bank credit agreements include similar default provisions; however such provisions only relate to the respective borrower under such agreement and its subsidiaries and do not contain cross default provisions to each other. The PSE&G and Power bank credit agreements do not include cross default provisions relating to PSEG.

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There are no cross acceleration provisions in PSEG's or PSE&G's indentures. However, PSEG's existing notes include a cross acceleration provision that may be triggered upon the acceleration of more than $75 million of indebtedness incurred by PSEG. Such provision does not extend to an acceleration of indebtedness by any of PSEG's subsidiaries. Power's indenture includes a cross acceleration provision similar to that described above for PSEG's existing notes except that such provision may be triggered upon the acceleration of more than $50 million of indebtedness incurred by Power or any of its subsidiaries. Such provision does not cross accelerate to PSEG, any of PSEG's subsidiaries (other than Power and its subsidiaries), PSE&G or any of PSE&G's subsidiaries.

Ratings Triggers

Our debt indentures and credit agreements do not contain any material 'ratings triggers' that would cause an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, any one or more of the affected companies may be subject to increased interest costs on certain bank debt and certain collateral requirements. In the event that we are not able to affirm representations and warranties on credit agreements, lenders would not be required to make loans.

In accordance with BPU requirements under the BGS contracts, PSE&G is required to maintain an investment grade credit rating. If PSE&G were to lose its investment grade rating, it would be required to file a plan to assure continued payment for the BGS requirements of its customers.

Fluctuations in commodity prices or a deterioration of Power's credit rating to below investment grade could increase Power's required margin postings under various agreements entered into in the normal course of business. Power believes it has sufficient liquidity to meet the required posting of collateral which would likely result from a credit rating downgrade to below investment grade by S&P or Moody's at today's market prices.

Common Stock Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	2016	2015	2014
Per Share	$ 1.64	$ 1.56	$ 1.48
in Millions	$ 830	$ 789	$ 748

On February 21, 2017, our Board of Directors approved a $0.43 per share common stock dividend for the first quarter of 2017. This reflects an indicative annual dividend rate of $1.72 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 8. Financial Statements and Supplementary Data—Note 22. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In January 2016, S&P published updated research reports on PSEG and PSE&G and the existing ratings and outlooks were unchanged. In June 2016, Moody's published credit opinions on Power and PSE&G and the existing ratings and outlooks were unchanged. In June 2016, S&P published an updated research report on Power and the existing rating and outlook were unchanged. In September 2016, Moody's published an updated research report on PSEG and the existing rating and outlook were unchanged.

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	Moody's (A)	S&P (B)
PSEG		
Outlook	**Positive**	**Stable**
Senior Notes	Baa2	BBB
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

Other Comprehensive Income

For the year ended December 31, 2016, we had Other Comprehensive Income of $32 million on a consolidated basis. Other Comprehensive Income was due primarily to a $42 million increase in net unrealized gains related to Available-for-Sale Securities and $2 million of unrealized gains on derivative contracts accounted for as hedges, partially offset by a decrease of $12 million in our consolidated liability for pension and postretirement benefits. See Item 8. Financial Statements and Supplementary Data—Note 21. Accumulated Other Comprehensive Income (Loss), Net of Tax for additional information.

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CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. Projected capital construction and investment expenditures, excluding nuclear fuel purchases, for the next three years are presented in the table below. These projections include Allowance for Funds Used During Construction and Interest Capitalized During Construction for PSE&G and Power, respectively. These amounts are subject to change, based on various factors. Amounts shown below for Energy Strong, GSMP and Solar/Energy Efficiency programs are for currently approved programs. We intend to continue to invest in infrastructure modernization and will seek to extend these and related programs as appropriate. We will also continue to approach potential growth investments for Power opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2017	2018	2019
		Millions	
PSE&G:			
Transmission	$ 1,630	$ 1,375	$ 1,110
Distribution	1,180	775	615
Energy Strong	205	75	15
Gas System Modernization Program	305	315	50
Solar/Energy Efficiency	90	75	60
Total PSE&G	**$ 3,410**	**$ 2,615**	**$ 1,850**
Power:			
Baseline	$ 190	$ 210	$ 170
Environmental/Regulatory	35	35	35
Fossil Growth Opportunities	825	405	90
Nuclear Expansion	20	20	10
Solar Growth Opportunities	130	—	—
Total Power	**$ 1,200**	**$ 670**	**$ 305**
Other	$ 50	$ 35	$ 35
Total PSEG	**$ 4,660**	**$ 3,320**	**$ 2,190**

PSE&G

PSE&G's projections for future capital expenditures include material additions and replacements to its transmission and distribution systems to meet expected growth and to manage reliability. As project scope and cost estimates develop, PSE&G will modify its current projections to include these required investments. PSE&G's projected expenditures for the various items reported above are primarily comprised of the following:

- Transmission—investments focused on reliability improvements and replacement of aging infrastructure.
- Distribution—investments for new business, reliability improvements, and replacement of equipment that has reached the end of its useful life.
- Energy Strong—Electric and Gas Distribution reliability investment program focused on system hardening and resiliency.
- Gas System Modernization Program—Gas Distribution investment program to replace aging infrastructure.
- Solar/Energy Efficiency—investments associated with grid-connected solar, solar loan programs, and customer energy efficiency programs.

In August 2016, PSE&G filed a petition with the BPU requesting approval of the $268 million investment and an associated cost recovery mechanism to develop a project where PSE&G would rebuild New Jersey Transit's Mason substation and related facilities in Kearny, NJ. This is not included in PSE&G's projected capital expenditures.

In 2016, PSE&G made $2,816 million of capital expenditures, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $131 million, which are included in operating cash flows.

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Power

Power's projected expenditures for the various items listed above are primarily comprised of the following:

- Baseline—investments to replace major parts and enhance operational performance.
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Fossil Growth Opportunities—investments associated with new construction, including Keys Energy Center, Sewaren 7 and BH5, and with upgrades to increase efficiency and output at combined cycle plants.
- Nuclear Expansion—investments associated with certain nuclear capital projects, primarily at existing facilities designed to increase operating output.
- Solar Growth Opportunities—investments associated with the construction of utility-scale photovoltaic facilities.

In 2016, Power made $1,136 million of capital expenditures, excluding $207 million for nuclear fuel, primarily related to various projects at Fossil, Solar and Nuclear.

Disclosures about Contractual Obligations

The following table reflects our contractual cash obligations in the respective periods in which they are due. In addition, the table summarizes anticipated debt maturities for the years shown. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 14. Debt and Credit Facilities.

The table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities for uncertain tax positions since we are unable to reasonably estimate the timing of liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes for additional information.

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	Total Amount Committed	Less Than 1 Year	2 - 3 Years	4 - 5 Years	Over 5 Years
			Millions		
Contractual Cash Obligations					
Long-Term Recourse Debt Maturities					
PSEG	$ 1,200	$ 500	$ 400	$ 300	$ —
PSE&G	7,883	—	1,250	693	5,940
Power	2,400	—	294	1,356	750
Interest on Recourse Debt					
PSEG	57	20	25	12	—
PSE&G	4,986	299	555	502	3,630
Power	935	113	221	170	431
Capital Lease Obligations					
Power	3	1	1	1	—
Operating Leases					
PSE&G	100	12	15	12	61
Power	52	3	6	4	39
Services	198	13	26	27	132
Other	5	1	2	2	—
Energy-Related Purchase Commitments					
Power	2,625	745	898	450	532
Total Contractual Cash Obligations	**$ 20,444**	**$ 1,707**	**$ 3,693**	**$ 3,529**	**$ 11,515**
Liability Payments for Uncertain Tax Positions					
PSEG	$ 14	$ 14	$ —	$ —	$ —
PSE&G	3	3	—	—	—
Power	7	7	—	—	—

OFF-BALANCE SHEET ARRANGEMENTS

PSEG and Power issue guarantees, primarily in conjunction with certain of Power's energy contracts. See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities for further discussion.

Through Energy Holdings, we have investments in leveraged leases that are accounted for in accordance with GAAP Accounting for Leases. Leveraged lease investments generally involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease arrangement, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and is not presented on our Consolidated Balance Sheets. In the event of default, the leased asset, and in some cases the lessee, secures the loan. As a lessor, Energy Holdings has ownership rights to the property and rents the property to the lessees for use in their business operations. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 7. Long-Term Investments and Note 8. Financing Receivables.

In the event that collection of the minimum lease payments to be received by Energy Holdings is no longer reasonably assured, Energy Holdings may deem that a lessee has a high probability of defaulting on the lease obligation, and would consider the need to record an impairment of its investment. In the event the lease is ultimately rejected by the lessee in a Bankruptcy Court proceeding, the fair value of the underlying asset and the associated debt would be recorded on the Consolidated Balance Sheets instead of the net equity investment in the lease.

CRITICAL ACCOUNTING ESTIMATES

Under GAAP, many accounting standards require the use of estimates, variable inputs and assumptions (collectively referred to as estimates) that are subjective in nature. Because of this, differences between the actual measure realized versus the estimate

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can have a material impact on results of operations, financial position and cash flows. We have determined that the following estimates are considered critical to the application of rules that relate to the respective businesses.

Accounting for Pensions

PSEG sponsors qualified and nonqualified pension plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The market-related value of plan assets held for the qualified pension plan is equal to the fair value of these assets as of year-end. The plan assets are comprised of investments in both debt and equity securities which are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. We calculate pension costs using various economic and demographic assumptions.

***Assumptions and Approach Used*:** Economic assumptions include the discount rate and the long-term rate of return on trust assets. Demographic assumptions include projections of future mortality rates, pay increases and retirement patterns.

Assumption	2016	2015	2014
Discount Rate	4.29%	4.54%	4.20%
Expected Rate of Return on Plan Assets	8.00%	8.00%	8.00%

The discount rate used to calculate pension obligations is determined as of December 31 each year, our measurement date. The discount rate is determined by developing a spot rate curve based on the yield to maturity of a universe of high quality corporate bonds with similar maturities to the plan obligations. The spot rates are used to discount the estimated plan distributions. The discount rate is the single equivalent rate that produces the same result as the full spot rate curve.

At the end of 2015, we changed the approach used to measure future service and interest costs for pension benefits. See Item 8. Financial Statements and Supplementary Data—Note 12. Pension and Other Postretirement Benefits (OPEB) and Savings Plans for additional information.

Our expected rate of return on plan assets reflects current asset allocations, historical long-term investment performance and an estimate of future long-term returns by asset class, long-term inflation assumptions and a premium for active management.

Based on the above assumptions, we have estimated net periodic pension expense in 2017 of approximately $3 million or $6 million, net of amounts capitalized.

We utilize a corridor approach that reduces the volatility of reported pension expense/income. The corridor requires differences between actuarial assumptions and plan results be deferred and amortized as part of expense/income. This occurs only when the accumulated differences exceed 10% of the greater of the pension benefit obligation or the fair value of plan assets as of each year-end. The excess would be amortized over the average remaining service period of the active employees, which is approximately thirteen years.

As of December 31, 2016, PSEG merged its three qualified defined benefit pension plans (excluding Servco plans) into one plan, thereby also merging all of the pension plans' assets. As a result, we estimate that in 2017, the total net periodic benefit costs are expected to decrease by approximately $72 million or $48 million, net of amounts capitalized, as compared to the 2017 amounts that would have been recognized had the plans not been merged. This is due to the amortization period for gains and losses for the merged plan resulting in lower amortization than that of the individual plans. No changes were made to the benefit formulas, vesting provisions, or to the employees covered by the plans.

***Effect if Different Assumptions Used*:** As part of the business planning process, we have modeled future costs assuming a 7.80% expected rate of return and a 4.29% discount rate for 2017. Actual future pension expense/income and funding levels will depend on future investment performance, changes in discount rates, market conditions, funding levels relative to our projected benefit obligation and accumulated benefit obligation and various other factors related to the populations participating in the pension plans.

The following chart reflects the sensitivities associated with a change in certain assumptions. The effects of the assumption changes shown below solely reflect the impact of that specific assumption.

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Assumption	% Change	Impact on Pension Benefit Obligation as of December 31, 2016	Increase to Pension Expense in 2017	Increase to Pension Expense, net of Amounts Capitalized in 2017
		Millions		
Discount Rate	(1)%	$ 737	$ 40	$ 27
Expected Rate of Return on Plan Assets	(1)%	N/A	$ 50	$ 33

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Derivative Instruments

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through executing derivative transactions. Derivative instruments are used to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Current accounting guidance requires us to recognize all derivatives on the balance sheet at their fair value, except for derivatives that qualify for and are designated as normal purchases and normal sales contracts.

***Assumptions and Approach Used*:** In general, the fair value of our derivative instruments is determined primarily by end of day clearing market prices from an exchange, such as NYMEX, Intercontinental Exchange and Nodal Exchange, or auction prices. Fair values of other energy contracts may be based on broker quotes.

For a small number of contracts where limited observable inputs or pricing information are available, modeling techniques are employed in determination of their fair value using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable.

For our wholesale energy business, many of the forward sale, forward purchase, option and other contracts are derivative instruments that hedge commodity price risk, but do not meet the requirements for, or are not designated as, either cash flow or fair value hedge accounting. The changes in value of such derivative contracts are marked to market through earnings as the related commodity prices fluctuate. As a result, our earnings may experience significant fluctuations depending on the volatility of commodity prices.

***Effect if Different Assumptions Used*:** Any significant changes to the fair market values of our derivatives instruments could result in a material change in the value of the assets or liabilities recorded on our Consolidated Balance Sheets and could result in a material change to the unrealized gains or losses recorded in our Consolidated Statements of Operations.

For additional information regarding Derivative Financial Instruments, see Item 8. Financial Statements and Supplementary Data – Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies, Note 16. Financial Risk Management Activities and Note 17. Fair Value Measurements.

Long-Lived Assets

Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset's or asset group's carrying amount may not be recoverable.

Assumptions and Approach Used: In the event certain triggers exist indicating an asset/asset group may not be recoverable, an undiscounted cash flow test is performed to determine if an impairment exists. When the carrying value of a long-lived asset/asset group exceeds the undiscounted estimate of future cash flows associated with the asset/asset group, an impairment may exist to the extent that the fair value of the asset/asset group is less than its carrying amount. These tests require significant estimates and judgment when developing expected future cash flows. Significant inputs include forward power prices, fuel costs, dispatch rates, other operating and capital expenditures and the cost of borrowing.

Effect if Different Assumptions Used: The above cash flow tests and fair value estimates may be impacted by a change in the assumptions noted above and could significantly impact the outcome, triggering additional impairment tests or write-offs.

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Lease Investments

Our Investments in Leases, included in Long-Term Investments on our Consolidated Balance Sheets, are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. A significant portion of the estimated residual value of leased assets is related to merchant power plants leased to other energy companies. See Item 8. Financial Statements and Supplementary Data – Note 7. Long-Term Investments and Note 8. Financing Receivables.

***Assumptions and Approach Used*:** Residual values are the estimated values of the leased assets at the end of the respective lease terms. The estimated values are calculated by discounting the cash flows related to the leased assets after the lease term. For the merchant power plants, the estimated discounted cash flows are dependent upon various assumptions, including:

- estimated forward power and capacity prices in the years after the lease,
- related prices of fuel for the plants,
- dispatch rates for the plants,
- future capital expenditures required to maintain the plants,
- future operation and maintenance expenses,
- discount rates, and
- the current estimated economic viability of the plants after the end of the base lease term.

Residual valuations are performed at least annually for each plant subject to lease using specific assumptions tailored to each plant. Those valuations are compared to the recorded residual values to determine if an impairment is warranted.

***Effect if Different Assumptions Used*:** A significant change to the assumptions, such as a large decrease in near-term power prices that affects the market's view of long-term power prices, could result in an impairment of one or more of the residual values, but not necessarily to all of the residual values. However, if, because of changes in assumptions, all the residual values related to the merchant energy plants were deemed to be zero, we would recognize an after-tax charge to income of approximately $91 million.

Asset Retirement Obligations (ARO)

PSE&G, Power and Services recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists. These AROs are recorded at fair value in the period in which they are incurred and are capitalized as part of the carrying amount of the related long-lived assets. PSE&G, as a rate-regulated entity, recognizes regulatory assets or liabilities as a result of timing differences between the recording of costs and costs recovered through the rate-making process. We accrete the ARO liability to reflect the passage of time.

***Assumptions and Approach Used*:** Because quoted market prices are not available for AROs, we estimate the initial fair value of an ARO by calculating discounted cash flows that are dependent upon various assumptions, including:

- estimation of dates for retirement, which can be dependent on environmental and other legislation,
- amounts and timing of future cash expenditures associated with retirement, settlement or remediation activities,
- discount rates,
- cost escalation rates,
- market risk premium,
- inflation rates, and
- if applicable, past experience with government regulators regarding similar obligations.

We obtain updated cost studies triennially unless new information necessitates more frequent updates. The most recent cost study was done in 2015. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset which impacts the amount of accretion and depreciation expense recognized in future periods.

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Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power's nuclear facilities comprised 89% of Power's total AROs as of December 31, 2016. Power determines its AROs for its nuclear units by assigning probability weighting to various discounted cash flow outcomes for each of its nuclear units that incorporate the assumptions above as well as:

- license renewals,
- early shutdown,
- safe storage for a period of time after retirement, and
- recovery from the federal government of costs incurred for spent nuclear fuel.

***Effect if Different Assumptions Used*:** Changes in the assumptions could result in a material change in the ARO balance sheet obligation and the period over which we accrete to the ultimate liability. For example, a decrease of 1% in the discount rate would result in a $39 million increase in the Nuclear ARO as of December 31, 2016. An increase of 1% in the inflation rate would result in a $203 million increase in the Nuclear ARO as of December 31, 2016. Also, if we did not assume that we would recover from the federal government the costs incurred for spent nuclear fuel, the Nuclear ARO would increase by $283 million at December 31, 2016.

Accounting for Regulated Businesses

PSE&G prepares its financial statements to comply with GAAP for rate-regulated enterprises, which differs in some respects from accounting for non-regulated businesses. In general, accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (Regulatory Asset) or recognize obligations (Regulatory Liability) if the rates established are designed to recover the costs and if the competitive environment makes it probable that such rates can be charged or collected. This accounting results in the recognition of revenues and expenses in different time periods than that of enterprises that are not regulated.

***Assumptions and Approach Used*:** PSE&G recognizes Regulatory Assets where it is probable that such costs will be recoverable in future rates from customers and Regulatory Liabilities where it is probable that refunds will be made to customers in future billings. The highest degree of probability is an order from the BPU either approving recovery of the deferred costs over a future period or requiring the refund of a liability over a future period.

Virtually all of PSE&G's regulatory assets and liabilities are supported by BPU orders. In the absence of an order, PSE&G will consider the following when determining whether to record a Regulatory Asset or Liability:

- past experience regarding similar items with the BPU,
- treatment of a similar item in an order by the BPU for another utility,
- passage of new legislation, and
- recent discussions with the BPU.

All deferred costs are subject to prudence reviews by the BPU. When the recovery of a Regulatory Asset or payment of a Regulatory Liability is no longer probable, PSE&G charges or credits earnings, as appropriate.

***Effect if Different Assumptions Used*:** A change in the above assumptions may result in a material impact on our results of operations or our cash flows. See Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities for a description of the amounts and nature of regulatory balance sheet amounts.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

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Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

	MTM VaR	
	Millions	
Years Ended December 31,	**2016**	**2015**
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 26	$ 24
Average for the Period	$ 16	$ 17
High	$ 32	$ 40
Low	$ 10	$ 8
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 40	$ 38
Average for the Period	$ 25	$ 26
High	$ 51	$ 63
Low	$ 16	$ 12

See Item 8. Financial Statements and Supplementary Data—Note 16. Financial Risk Management Activities for a discussion of credit risk.

Interest Rates

We are subject to the risk of fluctuating interest rates in the normal course of business. We manage interest rate risk by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, we use a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

As of December 31, 2016, a hypothetical 10% increase in market interest rates would result in

- less than $1 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and
- a $366 million decrease in the fair value of debt, including a $303 million decrease at PSE&G and a $57 million decrease at Power.

Debt and Equity Securities

We have $5.6 billion of assets in our pension plan trusts. Although fluctuations in market prices of securities within this portfolio do not directly affect our earnings in the current period, changes in the value of these investments could affect

- our future contributions to these plans,

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- our financial position if our accumulated benefit obligation under our pension plans exceeds the fair value of the pension trust funds, and
- future earnings, as we could be required to adjust pension expense and the assumed rate of return.

The NDT Fund is comprised primarily of fixed income and equity securities. As of December 31, 2016, the portfolio included $957 million of equity securities and $857 million in fixed income securities. The fair market value of the assets in the NDT Fund will fluctuate primarily depending upon the performance of equity markets. As of December 31, 2016, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $96 million.

We use duration to measure the interest rate sensitivity of the fixed income portfolio. Duration is a summary statistic of the effective average maturity of the fixed income portfolio. The benchmark for the fixed income component of the NDT Fund currently has a duration of 5.89 years and a yield of 2.61%. The portfolio's value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2016, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $50 million.

Credit Risk

See Item 8. Financial Statements and Supplementary Data—Note 16. Financial Risk Management Activities for a discussion of credit risk and a discussion about Power's and PSE&G's credit risk.

Energy Holdings has credit risk related to its investments in leases, which totaled $(25) million, net of deferred taxes of $674 million, as of December 31, 2016. These leveraged leases are concentrated in the U.S. energy industry. See Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables for counterparties' credit ratings and other information. The credit exposure to the lessees is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverages are not met and similar cash flow restrictions if ratings are not maintained at stated levels. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a temporary market downturn or degradation in operating performance of the leased assets.

In any lease transaction, in the event of a default, Energy Holdings would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. Under a worst-case scenario, if a foreclosure were to occur, Energy Holdings would record a pre-tax write-off up to its outstanding gross investment in these facilities. Also, in the event of a potential foreclosure, the net tax benefits generated by Energy Holdings' portfolio of investments could be materially reduced in the period in which gains associated with the potential forgiveness of debt at these projects occurs. The amount and timing of any potential reduction in net tax benefits is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, the amount of lease debt outstanding, any cash trapped at the projects and negotiations during such potential foreclosure process. The potential loss of earnings, impairment and/or tax payments could have a material impact to our financial position, results of operations and net cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined Form 10-K is separately filed by PSEG, PSE&G and Power. Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations as to any other company.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Public Service Enterprise Group Incorporated
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(a). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2017

S1-SSA-0009 - 11709

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Sole Stockholder of
Public Service Electric and Gas Company
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(b). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2017

S1-SSA-0009 - 11710

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Sole Member of
PSEG Power LLC
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, member's equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(c). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2017

S1-SSA-0009 - 11711

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data

	Years Ended December 31,		
	2016	2015	2014
OPERATING REVENUES	$ 9,061	$ 10,415	$ 10,886
OPERATING EXPENSES			
Energy Costs	3,001	3,261	3,886
Operation and Maintenance	3,008	2,978	3,150
Depreciation and Amortization	1,476	1,214	1,227
Total Operating Expenses	7,485	7,453	8,263
OPERATING INCOME	1,576	2,962	2,623
Income from Equity Method Investments	11	12	13
Other Income	191	254	290
Other Deductions	(67)	(102)	(61)
Other-Than-Temporary Impairments	(28)	(53)	(20)
Interest Expense	(385)	(393)	(389)
INCOME BEFORE INCOME TAXES	1,298	2,680	2,456
Income Tax Expense	(411)	(1,001)	(938)
NET INCOME	$ 887	$ 1,679	$ 1,518
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
BASIC	505	505	506
DILUTED	508	508	508
NET INCOME PER SHARE:			
BASIC	$ 1.76	$ 3.32	$ 3.00
DILUTED	$ 1.75	$ 3.30	$ 2.99

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11712

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2016	**2015**	**2014**
NET INCOME	$ 887	$ 1,679	$ 1,518
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(41), $34, and $26 for the years ended 2016, 2015 and 2014, respectively	42	(27)	(27)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(1), $7 and $(8) for the years ended 2016, 2015 and 2014, respectively	2	(10)	12
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $8, $(18) and $120 for the years ended 2016, 2015 and 2014, respectively	(12)	25	(173)
Other Comprehensive Income (Loss), net of tax	32	(12)	(188)
COMPREHENSIVE INCOME	$ 919	$ 1,667	$ 1,330

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11713

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 423	$ 394
Accounts Receivable, net of allowances of $68 in 2016 and $67 in 2015	1,161	1,068
Tax Receivable	78	305
Unbilled Revenues	260	197
Fuel	326	463
Materials and Supplies, net	561	513
Prepayments	76	135
Derivative Contracts	163	242
Regulatory Assets	199	164
Other	7	13
Total Current Assets	3,254	3,494
PROPERTY, PLANT AND EQUIPMENT	39,337	35,494
Less: Accumulated Depreciation and Amortization	(10,051)	(8,955)
Net Property, Plant and Equipment	29,286	26,539
NONCURRENT ASSETS		
Regulatory Assets	3,319	3,196
Long-Term Investments	1,050	1,233
Nuclear Decommissioning Trust (NDT) Fund	1,859	1,754
Long-Term Tax Receivable	104	171
Long-Term Receivable of VIEs	589	495
Other Special Funds	217	227
Goodwill	16	16
Other Intangibles	98	102
Derivative Contracts	24	77
Other	254	231
Total Noncurrent Assets	7,530	7,502
TOTAL ASSETS	$ 40,070	$ 37,535

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11714

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2016	December 31, 2015
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 500	$ 734
Commercial Paper and Loans	388	364
Accounts Payable	1,459	1,369
Derivative Contracts	13	76
Accrued Interest	97	96
Accrued Taxes	31	42
Clean Energy Program	142	142
Obligation to Return Cash Collateral	132	128
Regulatory Liabilities	88	123
Regulatory Liabilities of VIEs	—	42
Other	426	459
Total Current Liabilities	3,276	3,575
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	8,658	8,166
Regulatory Liabilities	118	175
Asset Retirement Obligations	726	679
Other Postretirement Benefit (OPEB) Costs	1,324	1,228
OPEB Costs of Servco	452	375
Accrued Pension Costs	568	487
Accrued Pension Costs of Servco	128	114
Environmental Costs	401	415
Derivative Contracts	3	27
Long-Term Accrued Taxes	180	212
Other	211	181
Total Noncurrent Liabilities	12,769	12,059
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT	10,895	8,834
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2016 and 2015— 534 shares	4,936	4,915
Treasury Stock, at cost, 2016—29 shares; 2015—28 shares	(717)	(671)
Retained Earnings	9,174	9,117
Accumulated Other Comprehensive Loss	(263)	(295)
Total Common Stockholders' Equity	13,130	13,066
Noncontrolling Interest	—	1
Total Stockholders' Equity	13,130	13,067
Total Capitalization	24,025	21,901
TOTAL LIABILITIES AND CAPITALIZATION	$ 40,070	$ 37,535

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11715

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 887	$ 1,679	$ 1,518
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,476	1,214	1,227
Amortization of Nuclear Fuel	203	213	200
Renewable Energy Credit (REC) Compliance Accrual	109	104	69
Impairment Costs for Early Plant Retirements	102	—	—
Provision for Deferred Income Taxes (Other than Leases) and ITC	474	685	515
Non-Cash Employee Benefit Plan Costs	127	161	47
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(6)	26	(4)
Net (Gain) Loss on Lease Investments	92	—	(3)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	183	(143)	(93)
Net Change in Regulatory Assets and Liabilities	(138)	(48)	187
Cost of Removal	(131)	(120)	(98)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(26)	(38)	(166)
Net Change in Certain Current Assets and Liabilities			
Tax Receivable	303	(94)	30
Accrued Taxes	3	(91)	(156)
Margin Deposit	(76)	122	(22)
Other Current Assets and Liabilities	(180)	288	(31)
Employee Benefit Plan Funding and Related Payments	(103)	(109)	(95)
Other	12	70	35
Net Cash Provided By (Used In) Operating Activities	3,311	3,919	3,160
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(4,199)	(3,863)	(2,820)
Purchase of Emissions Allowances and RECs	(99)	(106)	(101)
Proceeds from Sale of Capital Leases and Investments	—	14	25
Proceeds from Sales of Available-for-Sale Securities	824	1,501	1,915
Investments in Available-for-Sale Securities	(856)	(1,552)	(1,934)
Other	82	64	23
Net Cash Provided By (Used In) Investing Activities	(4,248)	(3,942)	(2,892)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	24	364	(60)
Issuance of Long-Term Debt	2,675	1,350	1,250
Redemption of Long-Term Debt	(824)	(600)	(500)
Redemption of Securitization Debt	—	(259)	(237)
Cash Dividend Paid on Common Stock	(830)	(789)	(748)
Other	(79)	(51)	(64)
Net Cash Provided By (Used In) Financing Activities	966	15	(359)
Net Increase (Decrease) in Cash and Cash Equivalents	29	(8)	(91)
Cash and Cash Equivalents at Beginning of Period	394	402	493
Cash and Cash Equivalents at End of Period	$ 423	$ 394	$ 402
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ (245)	$ 447	$ 538
Interest Paid, Net of Amounts Capitalized	$ 365	$ 381	$ 382
Accrued Property, Plant and Equipment Expenditures	$ 664	$ 510	$ 382

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11716

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Millions

	Common Stock		Treasury Stock					
	Shs.	Amount	Shs.	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance as of January 1, 2014	534	$ 4,861	(28)	$ (615)	$ 7,457	$ (95)	$ 1	$ 11,609
Net Income	—	—	—	—	1,518	—	—	1,518
Other Comprehensive Income (Loss), net of tax (expense) benefit of $138	—	—	—	—	—	(188)	—	(188)
Comprehensive Income								1,330
Cash Dividends on Common Stock	—	—	—	—	(748)	—	—	(748)
Other	—	15	—	(20)	—	—	—	(5)
Balance as of December 31, 2014	534	$ 4,876	(28)	$ (635)	$ 8,227	$ (283)	$ 1	$ 12,186
Net Income	—	—	—	—	1,679	—	—	1,679
Other Comprehensive Income (Loss), net of tax (expense) benefit of $23	—	—	—	—	—	(12)	—	(12)
Comprehensive Income								1,667
Cash Dividends on Common Stock	—	—	—	—	(789)	—	—	(789)
Other	—	39	—	(36)	—	—	—	3
Balance as of December 31, 2015	534	$ 4,915	(28)	$ (671)	$ 9,117	$ (295)	$ 1	$ 13,067
Net Income	—	—	—	—	887	—	—	887
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(34)	—	—	—	—	—	32	—	32
Comprehensive Income								919
Cash Dividends on Common Stock	—	—	—	—	(830)	—	—	(830)
Other	—	21	(1)	(46)	—	—	(1)	(26)
Balance as of December 31, 2016	534	$ 4,936	(29)	$ (717)	$ 9,174	$ (263)	$ —	$ 13,130

See Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11717

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2016	2015	2014
OPERATING REVENUES	$ 6,221	$ 6,636	$ 6,766
OPERATING EXPENSES			
Energy Costs	2,567	2,722	2,909
Operation and Maintenance	1,475	1,560	1,558
Depreciation and Amortization	565	892	906
Total Operating Expenses	4,607	5,174	5,373
OPERATING INCOME	1,614	1,462	1,393
Other Income	83	79	61
Other Deductions	(4)	(4)	(3)
Interest Expense	(289)	(280)	(277)
INCOME BEFORE INCOME TAXES	1,404	1,257	1,174
Income Tax Expense	(515)	(470)	(449)
NET INCOME	$ 889	$ 787	$ 725

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2016	2015	2014
NET INCOME	$ 889	$ 787	$ 725
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0 and $0 for the years ended 2016, 2015 and 2014, respectively	—	(1)	1
COMPREHENSIVE INCOME	$ 889	$ 786	$ 726

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11719

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

ASSETS	December 31, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 390	$ 198
Accounts Receivable, net of allowances of $68 in 2016 and $67 in 2015	810	787
Accounts Receivable-Affiliated Companies	76	222
Unbilled Revenues	260	197
Materials and Supplies	180	148
Prepayments	9	31
Regulatory Assets	199	164
Derivative Contracts	—	13
Other	6	9
Total Current Assets	1,930	1,769
PROPERTY, PLANT AND EQUIPMENT	26,347	23,732
Less: Accumulated Depreciation and Amortization	(5,760)	(5,504)
Net Property, Plant and Equipment	20,587	18,228
NONCURRENT ASSETS		
Regulatory Assets	3,319	3,196
Long-Term Investments	299	330
Other Special Funds	43	49
Other	110	105
Total Noncurrent Assets	3,771	3,680
TOTAL ASSETS	$ 26,288	$ 23,677

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11720

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2016	2015
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ —	$ 171
Commercial Paper and Loans	—	153
Accounts Payable	718	724
Accounts Payable—Affiliated Companies	260	292
Accrued Interest	76	70
Clean Energy Program	142	142
Derivative Contracts	5	—
Obligation to Return Cash Collateral	132	128
Regulatory Liabilities	88	123
Regulatory Liabilities of VIEs	—	42
Other	296	297
Total Current Liabilities	1,717	2,142
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	5,873	5,181
OPEB Costs	1,009	937
Accrued Pension Costs	250	202
Regulatory Liabilities	118	175
Environmental Costs	332	365
Asset Retirement Obligations	213	218
Derivative Contracts	—	11
Long-Term Accrued Taxes	130	109
Other	116	114
Total Noncurrent Liabilities	8,041	7,312
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT	7,818	6,650
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2016 and 2015—132 shares	892	892
Contributed Capital	945	695
Basis Adjustment	986	986
Retained Earnings	5,888	4,999
Accumulated Other Comprehensive Income	1	1
Total Stockholder's Equity	8,712	7,573
Total Capitalization	16,530	14,223
TOTAL LIABILITIES AND CAPITALIZATION	$ 26,288	$ 23,677

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11721

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

Millions

	Years Ended December 31,		
	2016	**2015**	**2014**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 889	$ 787	$ 725
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	565	892	906
Provision for Deferred Income Taxes and ITC	658	386	310
Non-Cash Employee Benefit Plan Costs	72	95	27
Cost of Removal	(131)	(120)	(98)
Net Change in Other Regulatory Assets and Liabilities	(138)	(48)	187
Net Change in Certain Current Assets and Liabilities:			
Accounts Receivable and Unbilled Revenues	(84)	165	63
Materials and Supplies	(7)	(15)	(18)
Prepayments	22	11	(18)
Accounts Payable	(29)	45	(3)
Accounts Receivable/Payable-Affiliated Companies, net	199	—	(167)
Other Current Assets and Liabilities	8	(29)	6
Employee Benefit Plan Funding and Related Payments	(82)	(91)	(83)
Other	(48)	47	(4)
Net Cash Provided By (Used In) Operating Activities	1,894	2,125	1,833
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,816)	(2,692)	(2,164)
Proceeds from Sales of Available-for-Sale Securities	22	21	103
Investments in Available-for-Sale Securities	(24)	(22)	(101)
Solar Loan Investments	14	11	7
Other	15	11	—
Net Cash Provided By (Used In) Investing Activities	(2,789)	(2,671)	(2,155)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	(153)	153	(60)
Issuance of Long-Term Debt	1,275	850	1,250
Redemption of Long-Term Debt	(271)	(300)	(500)
Redemption of Securitization Debt	—	(259)	(237)
Contributed Capital	250	—	175
Other	(14)	(10)	(14)
Net Cash Provided By (Used In) Financing Activities	1,087	434	614
Net Increase (Decrease) in Cash and Cash Equivalents	192	(112)	292
Cash and Cash Equivalents at Beginning of Period	198	310	18
Cash and Cash Equivalents at End of Period	$ 390	$ 198	$ 310
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ (295)	$ (28)	$ 283
Interest Paid, Net of Amounts Capitalized	$ 273	$ 261	$ 259
Accrued Property, Plant and Equipment Expenditures	$ 420	$ 396	$ 292

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
Millions

	Common Stock	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2014	$ 892	$ 520	$ 986	$ 3,487	$ 1	$ 5,886
Net Income	—	—	—	725	—	725
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	1	1
Comprehensive Income						726
Contributed Capital		175	—	—	—	175
Balance as of December 31, 2014	$ 892	$ 695	$ 986	$ 4,212	$ 2	$ 6,787
Net Income	—	—	—	787	—	787
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	(1)	(1)
Comprehensive Income						786
Balance as of December 31, 2015	$ 892	$ 695	$ 986	$ 4,999	$ 1	$ 7,573
Net Income	—	—	—	889	—	889
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	—	—
Comprehensive Income						889
Contributed Capital	—	250	—	—	—	250
Balance as of December 31, 2016	$ 892	$ 945	$ 986	$ 5,888	$ 1	$ 8,712

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2016	**2015**	**2014**
OPERATING REVENUES	$ 4,023	$ 4,928	$ 5,434
OPERATING EXPENSES			
Energy Costs	1,986	2,150	2,747
Operation and Maintenance	1,143	1,057	1,186
Depreciation and Amortization	881	291	292
Total Operating Expenses	4,010	3,498	4,225
OPERATING INCOME	13	1,430	1,209
Income from Equity Method Investments	11	14	14
Other Income	102	169	222
Other Deductions	(57)	(72)	(52)
Other-Than-Temporary Impairments	(28)	(53)	(20)
Interest Expense	(84)	(121)	(122)
INCOME (LOSS) BEFORE INCOME TAXES	(43)	1,367	1,251
Income Tax Benefit (Expense)	61	(511)	(491)
NET INCOME	$ 18	$ 856	$ 760

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2016	**2015**	**2014**
NET INCOME	$ 18	$ 856	$ 760
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(41), $32, and $28 for the years ended 2016, 2015 and 2014, respectively	42	(25)	(30)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $7 and $(8) for the years ended 2016, 2015 and 2014, respectively	—	(11)	12
Pension/OPEB adjustment, net of tax (expense) benefit of $9, $(16), and $101 for the years ended 2016, 2015 and 2014, respectively	(13)	24	(147)
Other Comprehensive Income (Loss), net of tax	29	(12)	(165)
COMPREHENSIVE INCOME	$ 47	$ 844	$ 595

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

ASSETS	December 31, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 11	$ 12
Accounts Receivable	276	217
Accounts Receivable—Affiliated Companies	205	276
Short-Term Loan to Affiliate	87	363
Fuel	326	463
Materials and Supplies, net	381	363
Derivative Contracts	162	223
Prepayments	10	25
Other	2	7
Total Current Assets	1,460	1,949
PROPERTY, PLANT AND EQUIPMENT	12,655	11,354
Less: Accumulated Depreciation and Amortization	(4,135)	(3,227)
Net Property, Plant and Equipment	8,520	8,127
NONCURRENT ASSETS		
NDT Fund	1,859	1,754
Long-Term Investments	102	119
Goodwill	16	16
Other Intangibles	98	102
Other Special Funds	53	55
Derivative Contracts	24	77
Other	61	51
Total Noncurrent Assets	2,213	2,174
TOTAL ASSETS	$ 12,193	$ 12,250

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2016	2015
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ —	$ 553
Accounts Payable	539	432
Accounts Payable—Affiliated Companies	25	33
Derivative Contracts	8	76
Accrued Interest	20	25
Other	88	107
Total Current Liabilities	680	1,226
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	2,170	2,347
Asset Retirement Obligations	511	457
OPEB Costs	251	230
Derivative Contracts	3	16
Accrued Pension Costs	191	166
Long-Term Accrued Taxes	77	35
Other	129	87
Total Noncurrent Liabilities	3,332	3,338
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
LONG-TERM DEBT	2,382	1,684
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,782	5,014
Accumulated Other Comprehensive Loss	(211)	(240)
Total Member's Equity	5,799	6,002
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,193	$ 12,250

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2016	**2015**	**2014**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 18	$ 856	$ 760
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	881	291	292
Amortization of Nuclear Fuel	203	213	200
Provision for Deferred Income Taxes and ITC	(208)	261	221
Interest Accretion on Asset Retirement Obligation	26	26	30
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	183	(143)	(93)
Renewable Energy Credit (REC) Compliance Accrual	109	104	69
Impairment Costs for Early Plant Retirements	102	—	—
Non-Cash Employee Benefit Plan Costs	39	48	13
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(26)	(38)	(166)
Net Change in Certain Current Assets and Liabilities:			
Fuel, Materials and Supplies	31	62	19
Margin Deposit	(76)	122	(22)
Accounts Receivable	(71)	63	(15)
Accounts Payable	(22)	(46)	(59)
Accounts Receivable/Payable-Affiliated Companies, net	6	(84)	220
Other Current Assets and Liabilities	10	(36)	(6)
Employee Benefit Plan Funding and Related Payments	(13)	(11)	(7)
Other	63	18	(31)
Net Cash Provided By (Used In) Operating Activities	1,255	1,706	1,425
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(1,343)	(1,117)	(626)
Purchase of Emissions Allowances and RECs	(99)	(106)	(101)
Proceeds from Sales of Available-for-Sale Securities	739	1,422	1,557
Investments in Available-for-Sale Securities	(766)	(1,455)	(1,573)
Short-Term Loan—Affiliated Company, net	276	221	206
Other	46	34	13
Net Cash Provided By (Used In) Investing Activities	(1,147)	(1,001)	(524)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Long-Term Debt	700	—	—
Cash Dividend Paid	(250)	(400)	(895)
Redemption of Long-Term Debt	(553)	(300)	—
Other	(6)	(2)	(3)
Net Cash Provided By (Used In) Financing Activities	(109)	(702)	(898)
Net Increase (Decrease) in Cash and Cash Equivalents	(1)	3	3
Cash and Cash Equivalents at Beginning of Period	12	9	6
Cash and Cash Equivalents at End of Period	$ 11	$ 12	$ 9
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 50	$ 393	$ 68
Interest Paid, Net of Amounts Capitalized	$ 81	$ 116	$ 119
Accrued Property, Plant and Equipment Expenditures	$ 244	$ 114	$ 91

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY
Millions

	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2014	$ 2,214	$ (986)	$ 4,693	$ (63)	$ 5,858
Net Income	—	—	760	—	760
Other Comprehensive Income (Loss), net of tax (expense) benefit of $121	—	—	—	(165)	(165)
Comprehensive Income					595
Cash Dividends Paid	—	—	(895)		(895)
Balance as of December 31, 2014	$ 2,214	$ (986)	$ 4,558	$ (228)	$ 5,558
Net Income	—	—	856	—	856
Other Comprehensive Income (Loss), net of tax (expense) benefit of $23	—	—	—	(12)	(12)
Comprehensive Income					844
Cash Dividends Paid	—	—	(400)	—	(400)
Balance as of December 31, 2015	$ 2,214	$ (986)	$ 5,014	$ (240)	$ 6,002
Net Income	—	—	18	—	18
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(32)	—	—	—	29	29
Comprehensive Income					47
Cash Dividends Paid	—	—	(250)	—	(250)
Balance as of December 31, 2016	$ 2,214	$ (986)	$ 4,782	$ (211)	$ 5,799

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

Public Service Enterprise Group Incorporated (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Public Service Electric and Gas Company (PSE&G)**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- **PSEG Power LLC (Power)**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses through competitive energy sales in well-developed energy markets and fuel supply functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Annual Reports on Form 10-K and in accordance with accounting guidance generally accepted in the United States (GAAP).

Significant Accounting Policies

Principles of Consolidation

Each company consolidates those entities in which it has a controlling interest or is the primary beneficiary. See Note 4. Variable Interest Entities. Entities over which the companies exhibit significant influence, but do not have a controlling interest and/or are not the primary beneficiary, are accounted for under the equity method of accounting. For investments in which significant influence does not exist and the investor is not the primary beneficiary, the cost method of accounting is applied. All intercompany accounts and transactions are eliminated in consolidation.

PSE&G and Power also have undivided interests in certain jointly-owned facilities, with each responsible for paying its respective ownership share of construction costs, fuel purchases and operating expenses. PSE&G and Power consolidate their portion of any revenues and expenses related to their respective jointly-owned facilities in the appropriate revenue and expense categories.

Accounting for the Effects of Regulation

In accordance with accounting guidance for rate-regulated entities, PSE&G's financial statements reflect the economic effects of regulation. PSE&G defers the recognition of costs (a Regulatory Asset) or records the recognition of obligations (a Regulatory Liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs and recoveries, which are being amortized over various future periods. To the extent that collection of any such costs or payment of liabilities becomes no longer probable as a result of changes in regulation and/or competitive position, the associated Regulatory Asset or Liability is charged or credited to income. Management believes that PSE&G's transmission and distribution businesses continue to meet the accounting requirements for rate-regulated entities. For additional information, see Note 6. Regulatory Assets and Liabilities.

Derivative Instruments

Each company uses derivative instruments to manage risk pursuant to its business plans and prudent practices.

Determining whether a contract qualifies as a derivative requires that management exercise significant judgment, including assessing the contract's market liquidity. PSEG has determined that contracts to purchase and sell certain products do not meet

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the definition of a derivative under the current authoritative guidance since they do not provide for net settlement, or the markets are not sufficiently liquid to conclude that physical forward contracts are readily convertible to cash.

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for derivatives that are designated as normal purchases and normal sales (NPNS). Further, derivatives that qualify for hedge accounting can be designated as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings.

For derivative contracts that do not qualify or are not designated as cash flow or fair value hedges or as NPNS, changes in fair value are recorded in current period earnings. PSEG does not currently elect fair value or cash flow hedge accounting on its commodity derivative positions.

Contracts that qualify for, and are designated, as NPNS are accounted for upon settlement. Contracts which qualify for NPNS are contracts for which physical delivery is probable, they will not be financially settled, and the quantities under contract are expected to be used or sold in the normal course of business over a reasonable period of time.

For additional information regarding derivative financial instruments, see Note 16. Financial Risk Management Activities.

Revenue Recognition

PSE&G's regulated electric and gas revenues are recorded primarily based on services rendered to customers. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. The unbilled revenue is estimated each month based on usage per day, the number of unbilled days in the period, estimated seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms.

Regulated revenues from the transmission of electricity are recognized as services are provided based on a FERC-approved annual formula rate mechanism. This mechanism provides for an annual filing of estimated revenue requirement with rates effective January 1 of each year. After completion of the annual period ending December 31, PSE&G files a true-up whereby it compares its actual revenue requirement to the original estimate to determine any over or under collection of revenue. PSE&G records the estimated financial statement impact of the difference between the actual and the filed revenue requirement as a refund or deferral for future recovery when such amounts are probable and can be reasonably estimated in accordance with accounting guidance for rate-regulated entities.

The majority of Power's revenues relate to bilateral contracts, which are accounted for on the accrual basis as the energy is delivered. Power's revenue also includes changes in the value of energy derivative contracts that are not designated as NPNS. See Note 16. Financial Risk Management Activities for further discussion.

PJM Interconnection, L.L.C. (PJM), the Independent System Operator-New England (ISO-NE) and the New York Independent System Operator (NYISO) facilitate the dispatch of energy and energy-related products. Power generally reports electricity sales and purchases conducted with those individual ISOs on a net hourly basis in either Revenues or Energy Costs in its Consolidated Statement of Operations, the classification of which depends on the net hourly activity. Capacity revenue and expense is also reported net based on Power's monthly net sale or purchase position in the individual ISOs.

PSEG LI is the primary beneficiary of Long Island Electric Utility Servco, LLC (Servco). For transactions in which Servco acts as principal, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operations and Maintenance (O&M) Expense, respectively. See Note 4. Variable Interest Entities for further information.

Depreciation and Amortization

PSE&G calculates depreciation under the straight-line method based on estimated average remaining lives of the several classes of depreciable property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU or FERC. The depreciation rate stated as a percentage of original cost of depreciable property was as follows:

	2016 Avg Rate	2015 Avg Rate	2014 Avg Rate
PSE&G Depreciation Rate	2.45%	2.46%	2.47%

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Power calculates depreciation on generation-related assets under the straight-line method based on the assets' estimated useful lives. The estimated useful lives are:

- general plant assets—3 years to 20 years
- fossil production assets—30 years to 70 years
- nuclear generation assets—approximately 60 years
- pumped storage facilities—76 years
- solar assets—25 years

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized During Construction (IDC)

AFUDC represents the cost of debt and equity funds used to finance the construction of new utility assets at PSE&G. IDC represents the cost of debt used to finance construction at Power. The amount of AFUDC or IDC capitalized as Property, Plant and Equipment is included as a reduction of interest charges or other income for the equity portion. The amounts and average rates used to calculate AFUDC or IDC for the years ended December 31, 2016, 2015 and 2014 were as follows:

	AFUDC/IDC Capitalized					
	2016		2015		2014	
	Millions	Avg Rate	Millions	Avg Rate	Millions	Avg Rate
PSE&G	$ 66	7.81%	$ 65	8.01%	$ 44	8.09%
Power	$ 54	4.87%	$ 27	5.14%	$ 24	5.14%

Income Taxes

PSEG and its subsidiaries file a consolidated federal income tax return and income taxes are allocated to PSEG's subsidiaries based on the taxable income or loss of each subsidiary in accordance with a tax sharing agreement between PSEG and each of its affiliated subsidiaries. Allocations between PSEG and its subsidiaries are recorded through intercompany accounts. Investment tax credits deferred in prior years are being amortized over the useful lives of the related property.

Uncertain income tax positions are accounted for using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. See Note 20. Income Taxes for further discussion.

Impairment of Long-Lived Assets

Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, including prolonged periods of adverse commodity and capacity prices or a current expectation that a long-lived asset will be sold or disposed of significantly before the end of its previously estimated useful life, could potentially indicate an asset's or asset group's carrying amount may not be recoverable. In such an event, an undiscounted cash flow analysis is performed to determine if an impairment exists. When a long-lived asset's or asset group's carrying amount exceeds the associated undiscounted estimated future cash flows, the asset/asset group is considered impaired to the extent that its fair value is less than its carrying amount. An impairment would result in a reduction of the value of the long-lived asset/asset group through a non-cash charge to earnings. See Note 3. Early Plant Retirements for more information.

For Power, cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generation units are generally evaluated at a regional portfolio level (PJM, NYISO, ISO-NE) along with cash flows generated from the customer supply and risk management activities, inclusive of cash flows from contracts, including those that are accounted for as derivatives and meet the NPNS scope exception. In certain cases, generation assets are evaluated on an individual basis where those assets are individually contracted on a long-term basis with a third party and operations are independent of other generation assets (typically Power's solar plants and Kalaeloa).

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

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Accounts Receivable—Allowance for Doubtful Accounts

PSE&G's accounts receivable are reported in the balance sheet as gross outstanding amounts adjusted for doubtful accounts. The allowance for doubtful accounts reflects PSE&G's best estimates of losses on the accounts receivable balances. The allowance is based on accounts receivable aging, historical experience, write-off forecasts and other currently available evidence.

Accounts receivable are charged off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable are recorded when it is known they will be received.

Materials and Supplies and Fuel

PSE&G's and Power's materials and supplies are carried at average cost and charged to inventory when purchased and expensed or capitalized to Property, Plant and Equipment, as appropriate, when installed or used. Fuel inventory at Power is valued at the lower of average cost or market and includes stored natural gas, coal, fuel oil and propane used to generate power and to satisfy obligations under Power's gas supply contracts with PSE&G. The costs of fuel, including transportation costs, are included in inventory when purchased and charged to Energy Costs when used or sold. The cost of nuclear fuel is capitalized within Property, Plant and Equipment and amortized to fuel expense using the units-of-production method.

Property, Plant and Equipment

PSE&G's additions to and replacements of existing property, plant and equipment are capitalized at cost. The cost of maintenance, repair and replacement of minor items of property is charged to expense as incurred. At the time units of depreciable property are retired or otherwise disposed of, the original cost, adjusted for net salvage value, is charged to accumulated depreciation.

Power capitalizes costs, including those related to its jointly-owned facilities, which increase the capacity or extend the life of an existing asset, represent a newly acquired or constructed asset or represent the replacement of a retired asset. The cost of maintenance, repair and replacement of minor items of property is charged to appropriate expense accounts as incurred. Environmental costs are capitalized if the costs mitigate or prevent future environmental contamination or if the costs improve existing assets' environmental safety or efficiency. All other environmental expenditures are expensed as incurred. Power also capitalizes spare parts that meet specific criteria. Capitalized spares are depreciated over the remaining lives of their associated assets.

Available-for-Sale Securities

These securities comprise the Nuclear Decommissioning Trust (NDT) Fund, a master independent external trust account maintained to provide for the costs of decommissioning upon termination of operations of Power's nuclear facilities and amounts that are deposited to fund a Rabbi Trust which was established to meet the obligations related to non-qualified pension plans and deferred compensation plans.

Realized gains and losses on available-for-sale securities are recorded in earnings and unrealized gains and losses on such securities are recorded as a component of Accumulated Other Comprehensive Income (Loss). Securities with unrealized losses that are deemed to be other-than-temporarily impaired are recorded in earnings. See Note 9. Available-for-Sale Securities for further discussion.

Pension and Other Postretirement Benefits (OPEB) Plans

The market-related value of plan assets held for the qualified pension and OPEB plans is equal to the fair value of those assets as of year-end. Fair value is determined using quoted market prices and independent pricing services based upon the security type as reported by the trustee at the measurement date (December 31) for all plan assets.

PSEG recognizes a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and OPEB liabilities. This receivable is presented separately on the Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted.

Pursuant to the OSA, Servco records expense only to the extent of its contributions to its pension plan trusts and for OPEB payments made to retirees.

See Note 12. Pension and Other Postretirement Benefits (OPEB) and Savings Plans for further discussion.

Basis Adjustment

PSE&G and Power have recorded a Basis Adjustment in their respective Consolidated Balance Sheets related to the generation assets that were transferred from PSE&G to Power in August 2000 at the price specified by the BPU. Because the transfer was between affiliates, the transaction was recorded at the net book value of the assets and liabilities rather than the transfer price. The difference between the total transfer price and the net book value of the generation-related assets and liabilities, $986 million, net of tax, was recorded as a Basis Adjustment on PSE&G's and Power's Consolidated Balance Sheets. The $986

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million is an addition to PSE&G's Common Stockholder's Equity and a reduction of Power's Member's Equity. These amounts are eliminated on PSEG's consolidated financial statements.

Use of Estimates

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements.

Note 2. Recent Accounting Standards

New Standards Issued and Adopted

Stock Compensation-Improvements to Employee Share-Based Payment Accounting

This accounting standard was issued to simplify aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the Statement of Cash Flows.

Under the new guidance, all excess tax benefits and tax deficiencies related to employee share-based payments will be recognized in income tax expense rather than recognized in additional paid in capital. In the Statement of Cash Flows, excess tax benefits and deficiencies will be classified with other income tax cash flows as an operating activity rather than a financing activity as currently classified. In addition, the minimum statutory tax withholding requirements were simplified in order to facilitate equity classification of the award.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early adoption is permitted for an entity in any interim or annual period. An entity that elects early adoption must adopt all of the amendments in the same period; however, the amendments within this update require different adoption methods. PSEG adopted this standard in the fourth quarter of 2016. The impact to the financial statements was immaterial.

Disclosure for Investments in Certain Entities that Calculate Net Asset Value (NAV) per Share

This accounting standard eliminates the requirement to categorize, in the fair value hierarchy, investments whose fair values are measured at NAV using the practical expedient provided in the fair value guidance. The practical expedient applies to investments in mutual funds or structures similar to a mutual fund for which there is not a readily determinable fair value. Although not required in the fair value hierarchy, sufficient information must be provided to allow for reconciliation between the fair value of assets categorized in the hierarchy and the balance sheet.

The standard is effective for annual and interim periods beginning after December 15, 2015 with early adoption permitted. PSEG adopted this standard in the fourth quarter 2016 on a retrospective basis and has reflected the effect of the new disclosure requirements in Note 12. Pension, Other Postretirement Benefits (OPEB) and Savings Plan.

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern

This accounting standard requires management to assess an entity's ability to continue as a going concern and provide related disclosures in certain circumstances. These disclosures are only required when conditions give rise to substantial doubt about an entity's ability to continue as a going concern within one year from the financial statement issuance date. The standard is effective for annual and interim periods beginning after December 15, 2016. PSEG adopted this standard in the fourth quarter of 2016; however, no disclosures were required this period based on the above criteria.

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard clarifies the principles for recognizing revenue and removes inconsistencies in revenue recognition requirements; improves comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provides improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early application is permitted. PSEG expects the new guidance to result in more detailed disclosures of revenue compared to current guidance, and possibly changes in presentation. PSEG continues to evaluate all of its revenue streams and its contracts. Certain implementation issues continue to be debated and are currently being addressed by the AICPA's Revenue Recognition Working Group and the FASB's Transition Resource Group, including the ability to recognize revenue for certain contracts where there

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is uncertainty regarding collection from customers and accounting for contributions in aid of construction. As the ultimate impact of the new standard has not yet been determined, PSEG has not elected its transition method.

Recognition and Measurement of Financial Assets and Financial Liabilities

This accounting standard will change how entities measure equity investments that are not consolidated or accounted for under the equity method. Under the new guidance, equity investments (other than those accounted for using the equity method) will be measured at fair value through Net Income instead of Other Comprehensive Income (Loss). Entities that have elected the fair value option for financial liabilities will present changes in fair value due to a change in their own credit risk through Other Comprehensive Income (Loss). For equity investments which do not have readily determinable fair values, the impairment assessment will be simplified by requiring a qualitative assessment to identify impairments. The new standard also changes certain disclosures.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG is currently analyzing the impact of this standard on our financial statements; however, PSEG expects increased volatility in Net Income due to changes in fair value of our equity securities within the NDT and Rabbi Trust Funds.

Leases

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor will classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. However, existing guidance related to leveraged leases will not change.

The standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Measurement of Credit Losses on Financial Instruments

This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however, this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments

This accounting standard reduces the diversity in practice in how certain cash receipts and cash payments are presented and classified in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt early including in an interim period. PSEG is currently analyzing the impact of this standard on its financial statements.

Statement of Cash Flows: Restricted Cash

This accounting standard requires entities to explain the change during the period in the total of cash and cash equivalents and include amounts described as restricted cash or restricted cash equivalents in its reconciliation of beginning of period and end-of-period amounts in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt early including in an interim period. PSEG will include those amounts that are deemed to be restricted cash and restricted cash equivalents in its cash and cash equivalents balances in the statement of cash flows as well as disclosure regarding the nature of restricted amounts.

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Business Combinations: Clarifying the Definition of a Business

This accounting standard was issued mainly to provide more consistency in how the definition of a business is applied to acquisitions or dispositions. The new guidance will generally reduce the number of transactions that will require treatment as a business combination. The definition of a business now includes a filter that would consider whether substantially all the fair value of the gross assets acquired or disposed of is concentrated in a single identifiable asset or a group of similar identifiable assets. If this condition is met, the transaction would not qualify as a business.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt it for transactions that have closed before the effective date but have not been reported in financial statements that have been issued or made available for issuance. PSEG is currently evaluating the impact of this standard on its financial statements; however, PSEG does not expect this guidance to materially impact its financial statements upon adoption.

Simplifying the Test for Goodwill Impairment

This accounting standard requires an entity to perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

An entity should apply this standard on a prospective basis and will be required to disclose the nature of and reason for the change in accounting principle upon transition. The new standard is effective for impairment tests for periods beginning January 1, 2020. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. PSEG is currently assessing the impact of this guidance upon its financial statements.

Note 3. Early Plant Retirements

On October 3, 2016, Power determined that it would cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. Power has filed deactivation notices with PJM for these existing units at both stations and final must-offer exception requests for the 2020-2021 PJM capacity auction to the PJM Independent Market Monitor. Power expects the units to continue to be available to generate electricity and receive previously cleared capacity payments through the date the units cease operations. The exact timing of the early retirement of these units may be impacted by operational and other conditions that could subsequently arise.

PSEG and Power undertake their annual five-year strategic planning process primarily during the third and fourth quarters of each year. The primary factors considered during this process that contributed to the decision to retire these units early include significant declines in revenues and margin caused by a sustained period of depressed wholesale power prices and reduced capacity factors caused by lower natural gas prices making coal generation less economically competitive than natural gas-fired generation. Despite experiencing recent warmer than normal weather in PJM this summer, Power did not experience the usual increase in electricity prices in PJM as it had in past hot summers. This trend has a further adverse economic impact to these units because they generally dispatch and earn energy margin on peak hot and cold days. In addition, the upcoming PJM capacity auction in May 2017 for the capacity period from June 2020 to May 2021 will be the first to require all generating units to meet the increased operating performance standards of PJM's new capacity performance regulations. During the current annual five-year strategic planning process, Power determined, on October 3, 2016, that the costs to upgrade the existing units at the Hudson and Mercer stations to comply with these higher reliability standards to be too significant and not economic given current market conditions, including anticipated future capacity prices, current forward energy prices and past operational performance results of the units. While these units have the capability to run on both coal and natural gas, they have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units.

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The decision to retire the Hudson and Mercer units early had and will continue to have a material effect on PSEG's and Power's results of operations. In 2016, PSEG and Power recognized the following pre-tax charges in Energy Costs, Operation and Maintenance and Depreciation expense during the period following the announcement of the early retirement of the plants:

	Year Ended December 31, 2016
	Millions
Statement of Operations Expense (pre-tax)	
Energy Costs	
Coal Inventory Lower of Cost or Market Adjustments and Capacity Penalties	$ 62
Operation and Maintenance	
Materials and Supplies Obsolescence	31
Write-down of Construction Work in Progress	14
Other (A)	8
Depreciation and Amortization	
Depreciation including Asset Retirement Costs	571
Total Pre-Tax Expense	**$ 686**

(A) Includes severance and miscellaneous costs. Power recorded $7 million of severance expense which it expects to pay in 2017.

In addition to these charges, Power expects to recognize the remaining Depreciation and Amortization of $958 million in 2017 due to the significant shortening of the expected economic useful lives of Hudson and Mercer. Additional employee-related salary continuance and severance costs and various miscellaneous costs may also be incurred during the period prior to retirement. Finally, Power currently anticipates using the sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such environmental remediation are neither currently probable nor estimable but may be material.

Because the Hudson and Mercer generating units will cease operations significantly before the end of their previously estimated useful lives, Power performed a recoverability test for its portfolio of generating assets in the PJM region to determine if an impairment exists. As of September 30, 2016, the estimated undiscounted future cash flows of the PJM asset group exceeded the carrying amount and no impairment was identified. For additional information on impairment of long-lived assets, see Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies.

In addition, Power has reduced the estimated useful life of Bridgeport Harbor Station unit 3 from 2025 to the summer of 2021 as it is more likely than not it will retire the unit by this time. The change in the estimated useful life is not expected to have a material impact on Power's future financial results. PSEG and Power continue to monitor their Keystone and Conemaugh generating stations to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain these assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Note 4. Variable Interest Entities (VIEs)

VIEs for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which was pledged as collateral to a trustee. PSE&G acted as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds were remitted to Transition Funding and Transition Funding II and were used for interest and principal payments on the transition bonds and related costs. During 2015, Transition Funding and Transition Funding II paid their final securitization bond payments and as of December 31, 2015, no further debt or related costs remained with these VIEs. During 2016,

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Transition Funding and Transition Funding II refunded final over-collected transition charges to ratepayers and as of December 31, 2016 the securitization program was completed.

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Servco, a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and O&M Expense, respectively. In 2016, 2015 and 2014, Servco recorded $410 million, $375 million and $389 million, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Consolidated Statement of Operations.

Note 5. Property, Plant and Equipment and Jointly-Owned Facilities

Information related to Property, Plant and Equipment as of December 31, 2016 and 2015 is detailed below:

	PSE&G	Power	Other	PSEG Consolidated
			Millions	
2016				
Transmission and Distribution:				
Electric Transmission	$ 9,132	$ —	$ —	$ 9,132
Electric Distribution	7,974	—	—	7,974
Gas Transmission	89	—	—	89
Gas Distribution	6,369	—	—	6,369
Construction Work in Progress	1,501	—	—	1,501
Plant Held for Future Use	19	—	—	19
Other	439	—	—	439
Total Transmission and Distribution	25,523	—	—	25,523
Generation:				
Fossil Production	—	7,096	—	7,096
Nuclear Production	—	2,516	—	2,516
Nuclear Fuel in Service	—	783	—	783
Other Production-Solar	591	687	—	1,278
Construction Work in Progress	—	1,483	—	1,483
Total Generation	591	12,565	—	13,156
Other	233	90	335	658
Total	**$ 26,347**	**$ 12,655**	**$ 335**	**$ 39,337**

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	PSE&G	Power	Other	PSEG Consolidated
		Millions		
2015				
Transmission and Distribution:				
Electric Transmission	$ 7,554	$ —	$ —	$ 7,554
Electric Distribution	7,553	—	—	7,553
Gas Transmission	89	—	—	89
Gas Distribution	5,875	—	—	5,875
Construction Work in Progress	1,459	—	—	1,459
Plant Held for Future Use	26	—	—	26
Other	411	—	—	411
Total Transmission and Distribution	22,967	—	—	22,967
Generation:				
Fossil Production	—	7,005	—	7,005
Nuclear Production	—	2,202	—	2,202
Nuclear Fuel in Service	—	785	—	785
Other Production-Solar	569	389	—	958
Construction Work in Progress	—	892	—	892
Total Generation	569	11,273	—	11,842
Other	196	81	408	685
Total	**$ 23,732**	**$ 11,354**	**$ 408**	**$ 35,494**

PSE&G and Power have ownership interests in and are responsible for providing their respective shares of the necessary financing for the following jointly-owned facilities to which they are a party. All amounts reflect PSE&G's or Power's share of the jointly-owned projects and the corresponding direct expenses are included in the Consolidated Statements of Operations as operating expenses.

		As of December 31,			
		2016		2015	
	Ownership Interest	Plant	Accumulated Depreciation	Plant	Accumulated Depreciation
		Millions			
PSE&G:					
Transmission Facilities	Various	$ 169	$ 65	$ 166	$ 72
Power:					
Coal Generating:					
Conemaugh	23%	$ 408	$ 166	$ 404	$ 154
Keystone	23%	$ 409	$ 176	$ 408	$ 163
Nuclear Generating:					
Peach Bottom	50%	$ 1,272	$ 306	$ 1,219	$ 262
Salem	57%	$ 1,077	$ 304	$ 990	$ 276
Nuclear Support Facilities	Various	$ 238	$ 71	$ 226	$ 60
Pumped Storage Facilities:					
Yards Creek	50%	$ 42	$ 25	$ 42	$ 24
Merrill Creek Reservoir	14%	$ 1	$ —	$ 1	$ —

Power holds undivided ownership interests in the jointly-owned facilities above. Power is entitled to shares of the generating capability and output of each unit equal to its respective ownership interests. Power also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. Power's share of expenses for the jointly-owned facilities

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is included in the appropriate expense category. Each owner is responsible for any financing with respect to its pro rata share of capital expenditures.

Power co-owns Salem and Peach Bottom with Exelon Generation. Power is the operator of Salem and Exelon Generation is the operator of Peach Bottom. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

GenOn Northeast Management Company is a co-owner and the operator for Keystone Generating Station and Conemaugh Generating Station. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

Power is a co-owner in the Yards Creek Pumped Storage Generation Facility. Jersey Central Power & Light Company (JCP&L) is also a co-owner and the operator of this facility. JCP&L submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Power is a minority owner in the Merrill Creek Reservoir and Environmental Preserve in Warren County, New Jersey. Merrill Creek Owners Group is the owner-operator of this facility. The operator submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Note 6. Regulatory Assets and Liabilities

PSE&G prepares its financial statements in accordance with GAAP for regulated utilities as described in Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies. PSE&G has deferred certain costs based on rate orders issued by the BPU or FERC or based on PSE&G's experience with prior rate cases. Most of PSE&G's Regulatory Assets and Liabilities as of December 31, 2016 are supported by written orders, either explicitly or implicitly through the BPU's treatment of various cost items. These costs will be recovered and amortized over various future periods.

Regulatory Assets and other investments and costs incurred under our various infrastructure filings and clause mechanisms are subject to prudence reviews and can be disallowed in the future by regulatory authorities. To the extent that collection of any infrastructure or clause mechanism revenue, Regulatory Assets or payments of Regulatory Liabilities is no longer probable, the amounts would be charged or credited to income.

PSE&G had the following Regulatory Assets and Liabilities:

	As of December 31,		
	2016	2015	Recovery/Refund Period
	Millions		
Regulatory Assets			
Current			
New Jersey Clean Energy Program	$ 142	$ 142	Annual filing for recovery (2)
Weather Normalization Clause (WNC)	49	10	Annual filing for recovery (2)
Underrecovered Electric Energy Costs—Basic Generation Service	2	11	Annual filing for recovery (1) (2)
Other	6	1	Various
Total Current Regulatory Assets	**$ 199**	**$ 164**	
Noncurrent			
Pension and OPEB Costs	$ 1,403	$ 1,270	Various
Deferred Income Taxes	507	467	Various
Manufactured Gas Plant (MGP) Remediation Costs	403	431	Various (2)
Storm Damage Deferrals	239	233	To be determined
Electric Transmission and Gas Cost of Removal	189	160	Through depreciation rates
Remediation Adjustment Charge (RAC) (Other SBC)	180	174	Through 2022 (1) (2)
Conditional Asset Retirement Obligation	157	152	Various
Green Program Recovery Charges (GPRC)	91	104	Various (1) (2)
Unamortized Loss on Reacquired Debt and Debt Expense	61	67	Over remaining debt life
Mark-to-Market (MTM) Contracts	—	63	Through 2017
Other	89	75	Various
Total Noncurrent Regulatory Assets	**$ 3,319**	**$ 3,196**	
Total Regulatory Assets	**$ 3,518**	**$ 3,360**	

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31, 2016	As of December 31, 2015	Recovery/Refund Period
	Millions		
Regulatory Liabilities			
Current			
FERC Formula Rate True-up	$ 34	$ 19	Annual filing for recovery (1) (2)
GPRC	28	36	Annual filing for recovery (1) (2)
Gas Margin Adjustment Clause	11	13	Annual filing for recovery (1) (2)
Overrecovered Gas Costs —Basic Gas Supply Service	6	1	Annual filing for recovery (1) (2)
Overrecovered Non-Utility Generation Charge (NGC)	5	1	Annual filing for recovery (1) (2)
Societal Benefit Clause (SBC)	4	31	Various (1) (2)
Stranded Costs (including $42 in 2015 related to VIEs)	—	64	Through December 2016 (2)
Total Current Regulatory Liabilities	**$ 88**	**$ 165**	
Noncurrent			
Electric Distribution Cost of Removal	$ 94	$ 122	Through depreciation rates
MTM Contracts	20	—	Various
FERC Formula Rate True-up	1	49	Annual filing for recovery (1) (2)
Other	3	4	Various
Total Noncurrent Regulatory Liabilities	**$ 118**	**$ 175**	
Total Regulatory Liabilities	**$ 206**	**$ 340**	

(1) Recovered/Refunded with interest.
(2) Recoverable/Refundable per specific rate order.

All Regulatory Assets and Liabilities are excluded from PSE&G's rate base unless otherwise noted. The Regulatory Assets and Liabilities in the table above are defined as follows:

- **Conditional Asset Retirement Obligation:** These costs represent the differences between rate regulated cost of removal accounting and asset retirement accounting under GAAP. These costs will be recovered in future rates.
- **Deferred Income Taxes:** These amounts represent the portion of deferred income taxes that will be recovered or refunded through future rates, based upon established regulatory practices.
- **Electric and Gas Cost of Removal:** PSE&G accrues and collects in rates for the cost of removing, dismantling and disposing of its transmission and distribution assets upon retirement. The regulatory asset or liability for non-legally required cost of removal represents the difference between amounts collected in rates and costs actually incurred.
- **FERC Formula Rate True-up:** Overcollection or undercollection of transmission earnings calculated using a FERC approved formula.
- **Gas Margin Adjustment Clause:** This mechanism credits Firm delivery customers for net distribution margin revenue collected from Transportation Gas Service Non-Firm (TSG-NF) delivery customers. The balance represents the difference between the net margin collected from the TSG-NF Customers versus bill credits provided to Firm delivery customers.
- **GPRC:** These costs are amounts associated with various renewable energy and energy efficiency programs. Components of the GPRC include: Carbon Abatement, Energy Efficiency Economic Stimulus Program, Energy Efficiency Economic (EEE) Extension Program, EEE Extension II Program, the Demand Response Program, Solar Generation Investment Program (Solar 4 All), Solar 4 All Extension, Solar 4 All Extension II, Solar Loan II Program and Solar Loan III Program.
- **MGP Remediation Costs:** Represents the low end of the range for the remaining environmental investigation and remediation program cleanup costs for manufactured gas plants that are probable of recovery in future rates. Once these costs are incurred, they are recovered through the RAC in the SBC.
- **MTM Contracts:** The estimated fair value of gas hedge contracts and gas cogeneration supply contract. The regulatory asset/liability is offset by a derivative asset/liability and, with respect to the gas hedge contracts only, an intercompany receivable/payable on the Consolidated Balance Sheets.

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- **New Jersey Clean Energy Program:** The BPU approved future funding requirements for Energy Efficiency and Renewable Energy Programs through the first half of 2017. The BPU funding requirements are recovered through the SBC.
- **NGC:** These costs represent the difference between the cost of non-utility generation and the benefit realized from the energy received at market rates.
- **Overrecovered Gas Costs:** These costs represent the overrecovered amounts associated with Basic Gas Supply Service (BGSS), as approved by the BPU. Pursuant to BPU requirements, PSE&G serves as the supplier of last resort for gas customers within its service territory that are not served by another supplier. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for PSE&G's operations. For BGSS, interest is accrued only on overrecovered balances.
- **Pension and OPEB Costs:** Pursuant to the adoption of accounting guidance for employers' defined benefit pension and OPEB plans, PSE&G recorded the unrecognized costs for defined benefit pension and other OPEB plans on the balance sheet as a Regulatory Asset. These costs represent actuarial gains or losses, prior service costs and transition obligations as a result of adoption, which have not been expensed. These costs are amortized and recovered in future rates.
- **RAC (Other SBC):** Costs incurred to clean up manufactured gas plants which are recovered over seven years.
- **SBC:** The SBC, as authorized by the BPU and the New Jersey Electric Discount and Energy Competition Act, includes costs related to PSE&G's electric and gas business as follows: (1) the Universal Service Fund (USF); (2) Energy Efficiency and Renewable Energy Programs; (3) Electric bad debt expense; and (4) the RAC for incurred MGP remediation expenditures. All components accrue interest on both over and underrecoveries.
- **Storm Damage Deferrals:** Costs incurred in the cleanup of major storms in 2010 through 2016. As of December 31, 2016, this includes the $220 million of storm costs, net of insurance recoveries, primarily as a result of Hurricane Irene and Superstorm Sandy, approved for recovery in a future base rate case proceeding under a BPU order received in September 2014.
- **Stranded Costs:** As of December 31, 2015, the balance represented overrecovered costs, which were collected by PSE&G as servicer on behalf of Transition Funding and Transition Funding II, respectively through the securitization transition charges authorized by the BPU in irrevocable financing. Collected funds were remitted to Transition Funding and Transition Funding II and used for interest and principal payments on the transition bonds and related costs and taxes. During 2015, Transition Funding and Transition Funding II paid their final securitization bond payments and as of December 31, 2015, no further debt or related costs remained. In 2016, PSE&G refunded over-collections from customers associated with Stranded Costs and as of December 31, 2016, there were no remaining Regulatory Assets or Liabilities associated with this program.
- **Unamortized Loss on Reacquired Debt and Debt Expense:** Represents losses on reacquired long-term debt and expenses associated with issuances of new debt, which are recovered through rates over the remaining life of the debt.
- **Underrecovered Electric Energy Costs:** These costs represent the underrecovered amounts associated with BGS, as approved by the BPU. For BGS, interest is accrued on both overrecovered and underrecovered balances.
- **WNC:** This represents the over- or under- collection of gas margin refundable or recoverable under the BPU's weather normalization clause. The WNC requires PSE&G to calculate, at the end of each October-to-May period, the level by which margin revenues differed from what would have resulted if normal weather had occurred. Over recoveries are refunded to customers in the next winter season while under recoveries (subject to an earnings cap) are collected from customers in the next winter season.

Significant 2016 regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

- ***Transmission Formula Rate Filings***—In June 2016, PSE&G filed its 2015 true-up adjustment pertaining to its transmission formula rates in effect for 2015. This resulted in an adjustment of $34 million less than the 2015 originally filed revenues primarily due to the impact of bonus depreciation legislation enacted after PSE&G filed its 2015 formula rate requirement in October 2014. PSE&G had recognized the majority of this adjustment in its Consolidated Statement of Operations for the year ended December 31, 2015. For the year ended December 31, 2016, PSE&G does not anticipate a significant true-up adjustment to its 2016 Annual Formula rate. That true-up will be filed

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by no later than June 15, 2017. In October 2016, the 2017 Annual Formula Rate Update was filed with FERC and requests approximately $121 million in increased annual transmission revenues effective January 1, 2017, subject to true-up.

- ***Energy Strong Recovery Filing***—In March and September of each year, PSE&G files with the BPU for base rate recovery of Energy Strong investments which include a return of and on its investment. In June 2016, PSE&G updated its March cost recovery petition to include Energy Strong investments in service as of May 31, 2016 which represents estimated annual increases in electric and gas revenues of $16 million and $23 million, respectively. In August 2016, the BPU approved these rate increases effective September 1, 2016.

  In September 2016, PSE&G filed its Energy Strong electric cost recovery petition seeking BPU approval to recover the revenue requirements associated with Energy Strong capitalized investment costs placed in service from June 1, 2016 through November 30, 2016. In February 2017, the BPU approved PSE&G's request for an annualized increase in electric revenue requirements of $12 million with rates effective March 1, 2017.
- ***Gas System Modernization Program (GSMP)***—In December 2016, the BPU approved PSE&G's initial annual GSMP cost recovery petition which results in an annual revenue increase of $10 million effective January 1, 2017. This increase represents the return of and on investment for GSMP infrastructure in service through September 30, 2016.
- ***Green Program Recovery Charges (GPRC)***—Each year PSE&G files with the BPU for annual recovery of its Green Program investments which include a return on its investment and recovery of expenses. In July 2016, PSE&G filed its 2016 GPRC cost recovery petition requesting recovery for the nine combined components of the electric and gas GPRC. In September 2016, the BPU approved rates on a provisional basis effective October 1, 2016 designed to recover approximately $44 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved programs.

  In November 2016, the BPU approved PSE&G's petition for a Solar 4 All Extension II Program for an additional 33 MWs of solar development on brownfields and closed landfills. The order allows PSE&G to extend the program under the same clause recovery process as its existing Solar 4 All Programs, with an estimated initial capital investment (excluding AFUDC) of approximately $80 million with a 9.75% ROE. The Solar 4 All Extension II Program is the tenth component of the GPRC.
- ***BGSS***—In June 2016, PSE&G made its annual BGSS filing with the BPU requesting a reduction of $87 million in annual BGSS revenues. In September 2016, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was reduced from approximately 40 cents to 34 cents per therm effective October 1, 2016. The rate is subject to final settlement. In December 2016, PSE&G filed with the BPU for a self-implementing two-month bill credit of 7.5 cents per therm for the months of January and February 2017. In February 2017, PSE&G filed with the BPU to extend the self-implementing bill credit of 7.5 cents per therm to customers through March 2017. The 3-month bill credits are estimated to provide approximately $47 million in customer credits. The specific amount returned will depend on actual usage over that period.
- ***Weather Normalization Clause***—In July 2016, PSE&G filed a petition requesting approval to collect $54 million in net deficiency gas revenues as a result of the warmer than normal 2015-2016 Winter Period. The deficiency gas revenues would be collected from customers over the 2016-2017 and 2017-2018 Winter Periods (October 1 through May 31). In September 2016, the BPU approved PSE&G's filing on a provisional basis with respect to the $54 million in deficiency revenues to be collected from customers effective October 1, 2016. This matter is pending.
- ***Remediation Adjustment Charge (RAC)***—In April 2016, the BPU approved PSE&G's filing with respect to its RAC 23 petition allowing recovery of $54 million effective May 7, 2016 related to net Manufactured Gas Plant expenditures from August 1, 2014 through July 31, 2015. In November 2016, PSE&G filed a RAC 24 Petition with the BPU requesting recovery of $41 million of net Manufactured Gas Plant expenditures from August 1, 2015 through July 31, 2016. This matter is pending.
- ***Universal Service Fund (USF)/Lifeline***—In September 2016, the BPU approved rates set to recover state-wide costs incurred by New Jersey electric and gas distribution companies under the State's USF/Lifeline energy assistance programs effective October 1, 2016. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on its Consolidated Statement of Operations.

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Note 7. Long-Term Investments

Long-Term Investments as of December 31, 2016 and 2015 included the following:

	As of December 31, 2016	2015
	Millions	
PSE&G		
Life Insurance and Supplemental Benefits	$ 140	$ 150
Solar Loans	159	175
Other Investments	—	5
Power		
Partnerships and Corporate Joint Ventures (Equity Method Investments) (A)	102	119
Energy Holdings		
Lease Investments	649	784
Total Long-Term Investments	**$ 1,050**	**$ 1,233**

(A) During the three years ended December 31, 2016, 2015 and 2014, dividends from these investments were $18 million, $16 million and $17 million, respectively.

Leases

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third-party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Consolidated Balance Sheets.

During the third quarter of 2016, Energy Holdings completed its annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases. The outcome indicated that the revised residual value estimates were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM, as discussed in Note 3. Early Plant Retirements, negatively impacting the economic outlook of the leased assets. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016, calculated by comparing the gross investment in the leases before and after the revised residual estimates. During the fourth quarter of 2016, Energy Holdings recorded a $10 million charge for its best estimate of loss as a result of the current liquidity issues facing REMA, which was reflected in Operating Revenues and is included in Gross Investments in Leases as of December 31, 2016. For additional information, see Note 8. Financing Receivables.

The following table shows Energy Holdings' gross and net lease investment as of December 31, 2016 and 2015, respectively.

	As of December 31, 2016	2015
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 629	$ 631
Estimated Residual Value of Leased Assets	346	519
Total Investment in Rental Receivables	975	1,150
Unearned and Deferred Income	(326)	(366)
Gross Investments in Leases	649	784
Deferred Tax Liabilities	(674)	(724)
Net Investments in Leases	**$ (25)**	**$ 60**

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The pre-tax income (loss) and income tax effects, excluding gains and losses on sales, related to investments in leases were as follows:

	Years Ended December 31,		
	2016	2015	2014
	Millions		
Pre-Tax Income (Loss) from Leases	$ (135)	$ 12	$ 24
Income Tax Expense (Benefit) on Income from Leases	$ (51)	$ 5	$ 32

Equity Method Investments

Power had the following equity method investments as of December 31, 2016 and 2015:

	As of December 31,			
Name	2016	2015	Location	% Owned
	Millions			
Power				
Keystone Fuels, LLC	$ 7	$ 16	PA	23%
Conemaugh Fuels, LLC	$ 8	$ 14	PA	23%
PennEast Pipeline	$ 11	$ 5	PA	10%
Kalaeloa	$ 76	$ 84	HI	50%

Note 8. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with solar renewable energy certificates (SRECs) generated from the installed solar electric system. The following table reflects the outstanding loans, including the noncurrent portion reported in Note 7. Long-Term Investments, by class of customer, none of which would be considered "non-performing."

Outstanding Loans by Class of Customer

	As of December 31,	
Consumer Loans	2016	2015
	Millions	
Commercial/Industrial	$ 164	$ 177
Residential	11	12
Total	**$ 175**	**$ 189**

Energy Holdings

Energy Holdings had a net investment in domestic energy and real estate assets subject to leveraged lease accounting of $(25) million as of December 31, 2016 and $60 million as of December 31, 2015 (See Note 7. Long-Term Investments).

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The corresponding receivables associated with the lease portfolio are reflected as follows, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

Counterparties' Credit Rating Standard & Poor's (S&P) as of December 31, 2016	Lease Receivables, Net of Non-Recourse Debt As of December 31, 2016
	Millions
AA	$ 16
BBB+ — BBB-	316
BB-	133
CCC	164
Total	**$ 629**

The "BB-" and the "CCC" ratings in the preceding table represent lease receivables related to coal and gas-fired assets in Illinois and Pennsylvania, respectively. As of December 31, 2016, the gross investment in the leases of such assets, net of non-recourse debt, was $426 million, ($(131) million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 83	64%	1,036	Gas	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 55	17%	1,711	Coal	CCC (A)	REMA
Conemaugh Station Units 1 and 2	PA	$ 55	17%	1,711	Coal	CCC (A)	REMA
Shawville Station Units 1, 2, 3 and 4	PA	$ 99	100%	596	Gas	CCC (A)	REMA

(A) REMA's parent company, GenOn Energy Inc. (GenOn), reported in August 2016 that GenOn did not expect to have sufficient liquidity to repay its senior unsecured notes due in June 2017. In January 2017, S&P further lowered its corporate credit rating on GenOn and its affiliates (including REMA) to "CCC - " from "CCC" reflecting the primary credit concern of the near-term maturity of GenOn's senior unsecured notes in June 2017 and expressed a negative outlook reflecting the continuing pressure on financial measures. In October 2016, Moody's downgraded the GenOn Corporate Family Rating to "Caa3" to reflect its high debt burden relative to cash flow.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease structures. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital and trigger certain material tax obligations which could wholly or partially be mitigated by tax indemnification claims against the counterparty. A bankruptcy of a lessee would likely delay and potentially limit any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's efforts to restructure its portfolio and improve its liquidity and the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments. If lease rejections or foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service.

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Additional factors that may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and their affiliates and the quality and condition of assets under lease.

Note 9. Available-for-Sale Securities

NDT Fund

In accordance with NRC regulations, entities owning an interest in nuclear generating facilities are required to determine the costs and funding methods necessary to decommission such facilities upon termination of operation. As a general practice, each nuclear owner places funds in independent external trust accounts it maintains to provide for decommissioning. Power is required to file periodic reports with the NRC demonstrating that its NDT Fund meets the formula-based minimum NRC funding requirements.

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon their respective termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. Power's share of decommissioning costs related to its five nuclear units was estimated to be between $2.8 billion and $3.0 billion, including contingencies. The liability for decommissioning recorded on a discounted basis as of December 31, 2016 was approximately $454 million and is included in the Asset Retirement Obligation. The funds are managed by third-party investment managers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 705	$ 263	$ (11)	$ 957
Debt Securities				
Government	518	8	(6)	520
Corporate	337	4	(4)	337
Total Debt Securities	855	12	(10)	857
Other Securities	44	—	—	44
Total NDT Available-for-Sale Securities (A)	**$ 1,604**	**$ 275**	**$ (21)**	**$ 1,858**

(A) The NDT available-for-sale securities table excludes cash of $1 million which is part of the NDT Fund.

	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 693	$ 185	$ (13)	$ 865
Debt Securities				
Government	483	8	(3)	488
Corporate	366	3	(10)	359
Total Debt Securities	849	11	(13)	847
Other Securities	42	—	—	42
Total NDT Available-for-Sale Securities	**$ 1,584**	**$ 196**	**$ (26)**	**$ 1,754**

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The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as shown in the following table.

	As of December 31, 2016	As of December 31, 2015
	Millions	
Accounts Receivable	$ 8	$ 17
Accounts Payable	$ 5	$ 10

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months.

	As of December 31, 2016				As of December 31, 2015			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 120	$ (10)	$ 8	$ (1)	$ 151	$ (13)	$ 1	$ —
Debt Securities								
Government (B)	276	(6)	4	—	245	(2)	19	(1)
Corporate (C)	139	(3)	15	(1)	222	(7)	36	(3)
Total Debt Securities	415	(9)	19	(1)	467	(9)	55	(4)
NDT Available-for-Sale Securities	**$ 535**	**$ (19)**	**$ 27**	**$ (2)**	**$ 618**	**$ (22)**	**$ 56**	**$ (4)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2016.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. Power also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2016.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2016.

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The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Years Ended December 31,		
	2016	2015	2014
	Millions		
Proceeds from Sales (A)	**$ 711**	**$ 1,397**	**$ 1,448**
Net Realized Gains (Losses):			
Gross Realized Gains	$ 53	$ 97	$ 177
Gross Realized Losses	(32)	(37)	(23)
Net Realized Gains (Losses) on NDT Fund	**$ 21**	**$ 60**	**$ 154**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Consolidated Statements of Operations. Net unrealized gains of $128 million (after-tax) are included in Accumulated Other Comprehensive Loss on PSEG's and Power's Consolidated Balance Sheets as of December 31, 2016.

The available-for-sale debt securities held as of December 31, 2016 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 15
1 - 5 years	257
6 - 10 years	193
11 - 15 years	50
16 - 20 years	60
Over 20 years	282
Total NDT Available-for-Sale Debt Securities	**$ 857**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2016, other-than-temporary impairments of $28 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

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PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost bases for the securities held in the Rabbi Trust.

	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 11	$ 11	$ —	$ 22
Debt Securities				
Government	105	—	(2)	103
Corporate	92	1	(2)	91
Total Debt Securities	197	1	(4)	194
Other Securities	1	—	—	1
Total Rabbi Trust Available-for-Sale Securities	**$ 209**	**$ 12**	**$ (4)**	**$ 217**

	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 10	$ —	$ 22
Debt Securities				
Government	108	1	(1)	108
Corporate	82	—	(1)	81
Total Debt Securities	190	1	(2)	189
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 204**	**$ 11**	**$ (2)**	**$ 213**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as shown in the following table.

	As of December 31, 2016	As of December 31, 2015
	Millions	
Accounts Receivable	$ 5	$ 1
Accounts Payable	$ 3	$ —

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2016				As of December 31, 2015			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government (B)	60	(2)	1	—	53	(1)	2	—
Corporate (C)	46	(2)	3	—	46	(1)	9	—
Total Debt Securities	106	(4)	4	—	99	(2)	11	—
Rabbi Trust Available-for-Sale Securities	**$ 106**	**$ (4)**	**$ 4**	**$ —**	**$ 99**	**$ (2)**	**$ 11**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. PSEG also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2016.

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2016.

The proceeds from the sales of and the net realized gains on securities in the Rabbi Trust Fund were:

	Years Ended December 31,		
	2016	2015	2014
	Millions		
Proceeds from Rabbi Trust Sales (A)	**$ 113**	**$ 104**	**$ 467**
Net Realized Gains (Losses):			
Gross Realized Gains	$ 6	$ 3	$ 4
Gross Realized Losses	(5)	(2)	(3)
Net Realized Gains (Losses) on Rabbi Trust	**$ 1**	**$ 1**	**$ 1**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

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Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in the Consolidated Statements of Operations. Net unrealized gains of $5 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets as of December 31, 2016. The Rabbi Trust available-for-sale debt securities held as of December 31, 2016 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 8
1 - 5 years	44
6 - 10 years	44
11 - 15 years	9
16 - 20 years	8
Over 20 years	81
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 194**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities. In 2016, there were no other-than-temporary impairments recognized on investments of the Rabbi Trust.

The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of December 31, 2016	As of December 31, 2015
	Millions	
PSE&G	$ 43	$ 42
Power	53	52
Other	121	119
Total Rabbi Trust Available-for-Sale Securities	**$ 217**	**$ 213**

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Note 10. Goodwill and Other Intangibles

As of December 31, 2016 and 2015, Power had goodwill of $16 million related to the Bethlehem Energy Center facility. Power conducted an annual review for goodwill impairment in the fourth quarter of 2016 and concluded that goodwill was not impaired. In addition to goodwill, as of December 31, 2016 and 2015, Power had intangible assets of $98 million and $102 million, respectively, related to emissions allowances and renewable energy credits. Emissions expense includes impairments of emissions allowances and costs for emissions, which is recorded as emissions occur. As load is served under contracts requiring energy from renewable sources, the related expense is recorded. Such expenses for the years ended December 31, 2016, 2015 and 2014 were as follows:

	Years Ended December 31,		
	2016	2015	2014
	Millions		
Emissions Expense	$ 14	$ 13	$ 10
Renewable Energy Expense	$ 95	$ 91	$ 59

Note 11. Asset Retirement Obligations (AROs)

PSEG, PSE&G and Power have recorded various AROs which represent legal obligations to remove or dispose of an asset or some component of an asset at retirement.

PSE&G has conditional AROs primarily for legal obligations related to the removal of treated wood poles and the requirement to seal natural gas pipelines at all sources of gas when the pipelines are no longer in service. PSE&G does not record an ARO for its protected steel and poly-based natural gas lines, as management believes that these categories of gas lines have an indeterminable life.

Power's ARO liability primarily relates to the decommissioning of its nuclear power plants in accordance with NRC requirements. Power has an independent external trust that is intended to fund decommissioning of its nuclear facilities upon termination of operation. For additional information, see Note 9. Available-for-Sale Securities. Power also identified conditional AROs primarily related to Power's fossil generation units and solar facilities, including liabilities for removal of asbestos, stored hazardous liquid material and underground storage tanks from industrial power sites, and demolition of certain plants, and the restoration of the sites at which they reside, when the plants are no longer in service. To estimate the fair value of its AROs, Power uses a probability weighted, discounted cash flow model which, on a unit by unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on third-party decommissioning cost estimates, cost escalation rates, inflation rates and discount rates.

Updated cost studies are obtained triennially unless new information necessitates more frequent updates. The most recent cost study was done in 2015. When assumptions are revised to calculate fair values of existing AROs, the ARO balance and corresponding long-lived asset are adjusted which impact the amount of accretion and depreciation expense recognized in future periods. For PSE&G, Regulatory Assets and Regulatory Liabilities result when accretion and amortization are adjusted to match rates established by regulators resulting in the regulatory deferral of any gain or loss.

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The changes to the ARO liabilities for PSEG, PSE&G and Power during 2015 and 2016 are presented in the following table:

	PSEG	PSE&G	Power	Other
	Millions			
ARO Liability as of January 1, 2015	$ 743	$ 290	$ 450	$ 3
Liabilities Settled	(5)	(4)	(1)	—
Liabilities Incurred	14	1	12	1
Accretion Expense	26	—	26	—
Accretion Expense Deferred and Recovered in Rate Base (A)	16	16	—	—
Revision to Present Values of Estimated Cash Flows	(115)	(85)	(30)	—
ARO Liability as of December 31, 2015	**$ 679**	**$ 218**	**$ 457**	**$ 4**
Liabilities Settled	(13)	(9)	(4)	—
Liabilities Incurred	25	2	23	—
Accretion Expense	26	—	26	—
Accretion Expense Deferred and Recovered in Rate Base (A)	12	12	—	—
Revision to Present Values of Estimated Cash Flows	(3)	(10)	9	(2)
ARO Liability as of December 31, 2016	**$ 726**	**$ 213**	**$ 511**	**$ 2**

(A) Not reflected as expense in Consolidated Statements of Operations

During 2016, PSE&G recorded a reduction in its ARO liabilities primarily due to the impact of settlements and changes to cash flow estimates. These changes had no impact in PSE&G's Consolidated Statement of Operations.

During 2016, Power recorded $23 million primarily related to new ARO liabilities at its fossil units coupled with new solar generation ARO liabilities.

Note 12. Pension, Other Postretirement Benefits (OPEB) and Savings Plans

PSEG sponsors qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. Eligible employees participate in non-contributory pension and OPEB plans sponsored by PSEG and administered by Services. In addition, represented and nonrepresented employees are eligible for participation in PSEG's two defined contribution plans described below.

PSEG, PSE&G and Power are required to record the under or over funded positions of their defined benefit pension and OPEB plans on their respective balance sheets. Such funding positions of each PSEG company are required to be measured as of the date of its respective year-end Consolidated Balance Sheets. For underfunded plans, the liability is equal to the difference between the plan's benefit obligation and the fair value of plan assets. For defined benefit pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. In addition, GAAP requires that the total unrecognized costs for defined benefit pension and OPEB plans be recorded as an after-tax charge to Accumulated Other Comprehensive Income (Loss), a separate component of Stockholders' Equity. However, for PSE&G, because the amortization of the unrecognized costs is being collected from customers, the accumulated unrecognized costs are recorded as a Regulatory Asset. The unrecognized costs represent actuarial gains or losses and prior service costs which had not been expensed.

For PSE&G, the Regulatory Asset is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations. For Power, the charge to Accumulated Other Comprehensive Income (Loss) is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations.

Effective January 1, 2016, PSEG changed the approach used to measure future service and interest costs for pension benefits. For 2015 and prior, PSEG calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, PSEG has elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows. PSEG believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations. As a change in accounting estimate, this change was reflected prospectively. Pension and OPEB costs, net of amounts capitalized, were reduced by $34 million and $13 million, respectively, as compared to the 2016 amounts that would have been derived from applying PSEG's 2015 and prior years' methodology.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2016, PSEG merged its three qualified defined benefit pension plans (excluding Servco plans) into one plan, thereby also merging all of the pension plans' assets. No changes were made to the benefit formulas, the vesting provisions, or to the employees covered by the plans.

Amounts for Servco are not included in any of the following pension and OPEB benefit information for PSEG and its affiliates but rather are separately disclosed later in this note.

The following table provides a roll-forward of the changes in the benefit obligation and the fair value of plan assets during each of the two years in the periods ended December 31, 2016 and 2015. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
	Millions			
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year (A)	$ 5,522	$ 5,722	$ 1,612	$ 1,638
Service Cost	109	123	17	22
Interest Cost	202	234	59	67
Actuarial (Gain) Loss (B)	219	(289)	127	(45)
Gross Benefits Paid	(282)	(268)	(57)	(70)
Plan Amendments	2	—	(4)	—
Benefit Obligation at End of Year (A)	**$ 5,772**	**$ 5,522**	**$ 1,754**	**$ 1,612**
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$ 5,039	$ 5,293	$ 374	$ 361
Actual Return on Plan Assets	403	(11)	32	(1)
Employer Contributions	33	25	71	84
Gross Benefits Paid	(282)	(268)	(57)	(70)
Fair Value of Assets at End of Year	**$ 5,193**	**$ 5,039**	**$ 420**	**$ 374**
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	**$ (579)**	**$ (483)**	**$ (1,334)**	**$ (1,238)**
Additional Amounts Recognized in the Consolidated Balance Sheets				
Noncurrent Assets (included in Other Special Funds)	$ —	$ 14	$ —	$ —
Current Accrued Benefit Cost	(11)	(10)	(10)	(10)
Noncurrent Accrued Benefit Cost	(568)	(487)	(1,324)	(1,228)
Amounts Recognized	**$ (579)**	**$ (483)**	**$ (1,334)**	**$ (1,238)**
Additional Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulated Assets and Deferred Assets (B)				
Prior Service Cost	$ (63)	$ (83)	$ (14)	$ (25)
Net Actuarial Loss	1,763	1,710	523	438
Total	**$ 1,700**	**$ 1,627**	**$ 509**	**$ 413**

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits.

(B) Includes $679 million ($398 million, after-tax) and $658 million ($386 million, after-tax) in Accumulated Other Comprehensive Loss related to Pension and OPEB as of December 31, 2016 and 2015, respectively.

The pension benefits table above provides information relating to the funded status of the qualified, nonqualified pension and OPEB plans on an aggregate basis. As of December 31, 2016, PSEG had funded approximately 90% of its projected benefit obligation. This percentage does not include $217 million of assets in the Rabbi Trust as of December 31, 2016 which were used partially to fund the nonqualified pension plans. As of December 31, 2016, the nonqualified pension plans included in the projected benefit obligation in the above table were $161 million. The fair values of the Rabbi Trust assets are included in Other Special Funds on the Consolidated Balance Sheets.

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Accumulated Benefit Obligation

The accumulated benefit obligation for all PSEG's defined benefit pension plans was $5.6 billion as of December 31, 2016 and $5.4 billion as of December 31, 2015.

The following table provides the components of net periodic benefit cost for the years ended December 31, 2016, 2015 and 2014.

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2016	2015	2014	2016	2015	2014
	Millions					
Components of Net Periodic Benefit Cost (Credit)						
Service Cost	$ 109	$ 123	$ 104	$ 17	$ 22	18
Interest Cost	202	234	234	59	67	69
Expected Return on Plan Assets	(394)	(414)	(399)	(31)	(31)	(26)
Amortization of Net						
Prior Service Credit	(19)	(19)	(18)	(14)	(14)	(14)
Actuarial Loss	158	150	56	40	43	23
Net Periodic Benefit Cost (Credit)	**$ 56**	**$ 74**	**$ (23)**	**$ 71**	**$ 87**	**$ 70**

Pension costs and OPEB costs for PSEG, PSE&G and Power are detailed as follows:

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2016	2015	2014	2016	2015	2014
	Millions					
PSE&G	$ 29	$ 40	$ (19)	$ 43	$ 55	$ 46
Power	16	21	(7)	23	27	20
Other	11	13	3	5	5	4
Total Benefit Cost (Credit)	**$ 56**	**$ 74**	**$ (23)**	**$ 71**	**$ 87**	**$ 70**

The following table provides the pre-tax changes recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Deferred Assets:

	Pension		OPEB	
	2016	2015	2016	2015
	Millions			
Net Actuarial (Gain) Loss in Current Period	$ 211	$ 136	$ 125	$ (14)
Amortization of Net Actuarial Gain (Loss)	(158)	(150)	(40)	(43)
Prior Service Cost (Credit) in current period	1	—	(3)	—
Amortization of Prior Service Credit	19	19	14	14
Total	**$ 73**	**$ 5**	**$ 96**	**$ (43)**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Amounts that are expected to be amortized from Accumulated Other Comprehensive Loss, Regulatory Assets and Deferred Assets into Net Periodic Benefit Cost in 2017 are as follows:

	Pension Benefits 2017	Other Benefits 2017
	Millions	
Actuarial (Gain) Loss	$ 97	$ 51
Prior Service Cost	$ (18)	$ (11)

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

	Pension Benefits			Other Benefits		
	2016	2015	2014	2016	2015	2014
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	4.29%	4.54%	4.20%	4.37%	4.58%	4.21%
Rate of Compensation Increase	3.61%	3.61%	3.61%	3.61%	3.61%	3.61%
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount Rate	4.54%	4.20%	5.00%	4.58%	4.21%	5.01%
Service Cost Interest Rate	4.81%	4.20%	5.00%	4.87%	4.21%	5.01%
Interest Cost Interest Rate	3.75%	4.20%	5.00%	3.76%	4.21%	5.01%
Expected Return on Plan Assets	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Rate of Compensation Increase	3.61%	3.61%	4.61%	3.61%	3.61%	4.61%
Assumed Health Care Cost Trend Rates as of December 31						
Administrative Expense				3.00%	3.00%	3.00%
Health Care Costs						
Immediate Rate				7.55%	7.75%	7.40%
Ultimate Rate				4.75%	4.75%	5.00%
Year Ultimate Rate Reached				2025	2025	2022
					Millions	
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$ 11	$ 12	$ 13
Postretirement Benefit Obligation				$ 191	$ 194	$ 201
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$ (9)	$ (10)	$ (10)
Postretirement Benefit Obligation				$ (160)	$ (160)	$ (165)

Plan Assets

The investments of pension and OPEB plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension and OPEB plans are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 17. Fair Value Measurements for more information on fair value guidance. Use of the Master Trust permits the commingling of pension plan assets and OPEB plan assets for investment and administrative purposes. Although assets of the plans are commingled in the Master Trust, the Trustee maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Trustee to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans. As of December 31, 2016, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 93% and 7%, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tables present information about the investments measured at fair value on a recurring basis as of December 31, 2016 and 2015, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2016			
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Cash Equivalents (A)	$ 107	$ 105	$ 2	$ —
Equities (B)				
Common Stock	944	944	—	—
Commingled (C)	1,387	1,247	140	—
Preferred Stock	1	1	—	—
Bonds (D)				
US Treasury	441	—	441	—
Government—Other	263	—	263	—
Corporate	836	—	836	—
Subtotal Fair Value	**$ 3,979**	**$ 2,297**	**$ 1,682**	**$ —**
Measured at net asset value practical expedient (C)				
Commingled—Equities	1,604			
Private Equity (E)	16			
Total Fair Value (F)	**$ 5,599**			

	Recurring Fair Value Measurements as of December 31, 2015			
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Cash Equivalents (A)	$ 96	$ 95	$ 1	$ —
Equities (B)				
Common Stock	816	816	—	—
Commingled (C)	1,463	1,269	194	—
Bonds (D)				
US Treasury	322	—	322	—
Government—Other	279	—	279	—
Corporate	906	—	906	—
Subtotal Fair Value	**$ 3,882**	**$ 2,180**	**$ 1,702**	**$ —**
Measured at net asset value practical expedient (C)				
Commingled—Equities	1,504			
Private Equity (E)	19			
Total Fair Value (F)	**$ 5,405**			

(A) Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active market (Level 1). Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

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(B) Common stocks and preferred stocks are measured using observable data in active markets and considered Level 1. Investments in certain commingled equity funds are measured at their published daily net asset value (NAV) available to investors; if they are redeemable daily without restrictions, they are classified as Level 1 or, if they have restrictions which prevent daily redemptions, they are classified as Level 2.

(C) In 2016, PSEG re-evaluated the classification, within the fair value hierarchy, of its commingled equity funds. As a result, PSEG determined that certain commingled funds in the amount of $1,698 million at December 31, 2015 should have been classified as Level 2 instead of Level 1, as previously presented for 2015, due to the funds having certain redemption restrictions which prevent daily redemptions at their published price. PSEG has determined that this error is immaterial to its previously filed financial reports and, accordingly, has corrected the error by revising the amounts disclosed for 2015 to report such investments as Level 2. In addition, as part of our implementation of the new accounting guidance on investments measured at fair value using NAV as a practical expedient in 2016, the majority of these same commingled equity funds have been removed from the fair value hierarchy as they are measured at fair value using the NAV per share (or its equivalent) practical expedient. See Note 2. Recent Accounting Standards. These funds do not meet the definition of readily determinable fair value due to limitations in published NAV (last business day of the month) and include certain redemption restrictions ranging from one to fifteen days advance notice prior to redemption days and limitations on withdrawals over 25% of the total fund. The objectives of these funds are mainly tracking the S&P Index or achieving long-term growth through investment in foreign equity securities and the MSCI Emerging Markets Index. As a result of the error correction for the $1,698 million that should have been classified as Level 2 for 2015 and $1,504 million that was removed from the fair value hierarchy as part of the new guidance on NAV practical expedient implementation, $194 million has been reclassified to Level 2 as of December 31, 2015.

(D) Fixed income securities include mainly investment grade corporate and municipal bonds, US Treasury obligations and Federal Agency asset-backed securities with a wide range of maturities. These investments are valued using an evaluated pricing approach that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads or the most recent quoted for similar securities which are a Level 2 measure.

(E) Private equity investments include various limited partnerships that invest in operating companies through acquisitions or developing a portfolio of non-US distressed investments. These investments are valued at NAV on an annual basis and have significant redemption restrictions preventing redemption until fund liquidation and limited ability to sell these investments. These investments have been removed from the fair value hierarchy in accordance with the new guidance on NAV practical expedient.

(F) Excludes net receivable of $14 million and $8 million at December 31, 2016 and 2015, respectively, which consists of interest and dividend, receivables and payables related to pending securities sales and purchases.

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans as of the measurement date, December 31:

	As of December 31,	
Investments	**2016**	**2015**
Equity Securities	70%	70%
Fixed Income Securities	28	28
Other Investments	2	2
Total Percentage	**100%**	**100%**

PSEG utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. PSEG's latest asset/liability study indicates that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. Derivative financial instruments are used by the plans' investment managers primarily to adjust the fixed income duration of the portfolio and hedge the currency risk component of foreign investments. The expected long-term rate of return on plan assets was 8.0% for 2016 and will be 7.8% for 2017. This expected return was determined based on the study discussed above, including a premium for active management and considered the plans' historical annualized rate of return since inception, which was 9.3%.

Plan Contributions

PSEG plans to contribute $14 million into its OPEB plan during 2017.

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Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to plan participants.

Year	Pension Benefits	Other Benefits
	Millions	
2017	$ 310	$ 82
2018	307	86
2019	319	90
2020	331	94
2021	343	99
2022-2026	1,887	534
Total	**$ 3,497**	**$ 985**

401(k) Plans

PSEG sponsors two 401(k) plans, which are Employee Retirement Income Security Act (ERISA) defined contribution retirement plans. Eligible represented employees of PSEG's subsidiaries participate in the PSEG Employee Savings Plan (Savings Plan), while eligible non-represented employees of PSEG's subsidiaries participate in the PSEG Thrift and Tax-Deferred Savings Plan (Thrift Plan). Eligible employees may contribute up to 50% of their compensation to these plans, not to exceed the IRS maximums, including any catch-up contributions for those employees age 50 and above. PSEG matches 50% of such employee contributions up to 7% of pay for Savings Plan participants and up to 8% of pay for Thrift Plan participants.

The amount paid for employer matching contributions to the plans for PSEG, PSE&G and Power are detailed as follows:

	Thrift Plan and Savings Plan Years Ended December 31,		
	2016	2015	2014
	Millions		
PSE&G	$ 24	$ 22	$ 20
Power	12	12	11
Other	5	5	5
Total Employer Matching Contributions	**$ 41**	**$ 39**	**$ 36**

Servco Pension and OPEB

At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 4. Variable Interest Entities. These obligations, as well as the offsetting long-term receivable, are separately presented on the Consolidated Balance Sheet of PSEG.

The following table provides a roll-forward of the changes in Servco's benefit obligation and the fair value of its plan assets during the years ended December 31, 2016 and 2015. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
			Millions	
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year	$ 211	$ 195	$ 375	$ 452
Service Cost	24	26	12	17
Interest Cost	9	9	17	21
Actuarial (Gain) Loss	14	(20)	50	(114)
Gross Benefits Paid	(1)	—	(2)	(1)
Plan Amendments	5	1	—	—
Benefit Obligation at End of Year (A)	**$ 262**	**$ 211**	**$ 452**	**$ 375**
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$ 97	$ 69	$ —	$ —
Actual Return on Plan Assets	10	(2)	—	—
Employer Contributions	28	30	2	1
Gross Benefits Paid	(1)	—	(2)	(1)
Fair Value of Assets at End of Year	**$ 134**	**$ 97**	**$ —**	**$ —**
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	**$ (128)**	**$ (114)**	**$ (452)**	**$ (375)**
Additional Amounts Recognized in the Consolidated Balance Sheets				
Accrued Pension Costs of Servco	$ (128)	$ (114)	N/A	N/A
OPEB Costs of Servco	N/A	N/A	(452)	(375)
Amounts Recognized (B)	**$ (128)**	**$ (114)**	**$ (452)**	**$ (375)**

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits.

(B) Amounts equal to the accrued pension and OPEB costs of Servco are offset in Long-Term Receivable of VIE on PSEG's Consolidated Balance Sheets.

Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. The pension-related revenues and costs for 2016, 2015 and 2014 were $28 million, $30 million and $67 million, respectively. Servco has contributed its entire planned contribution amount to its pension plan trusts during 2016. The OPEB-related revenues earned and costs incurred in 2016 was $2 million, and were immaterial 2015 and 2014.

The following assumptions were used to determine the benefit obligations of Servco:

	Pension Benefits			Other Benefits		
	2016	2015	2014	2016	2015	2014
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	4.61%	4.92%	4.50%	4.71%	4.97%	4.60%
Rate of Compensation Increase	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
Assumed Health Care Cost Trend Rates as of December 31						
Administrative Expense				5.00%	5.00%	5.00%
Health Care Costs						
Immediate Rate				7.55%	7.55%	7.33%
Ultimate Rate				4.75%	4.75%	5.00%
Year Ultimate Rate Reached				2025	2025	2021
					Millions	
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs						
Postretirement Benefit Obligation				$ 97	$ 75	$ 160
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs						
Postretirement Benefit Obligation				$ (75)	$ (60)	$ (106)

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Plan Assets

All the investments of Servco's pension plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 17. Fair Value Measurements for more information on fair value guidance. The Actuary maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Actuary to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans.

The following tables present information about Servco's investments measured at fair value on a recurring basis as of December 31, 2016 and 2015, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2016			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		Millions		
Commingled Equities (A)	$ 96	$ —	$ 96	$ —
Commingled Bonds (A)	38	—	38	—
Total	**$ 134**	**$ —**	**$ 134**	**$ —**

	Recurring Fair Value Measurements as of December 31, 2015			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		Millions		
Commingled Equities (A)	$ 68	$ —	$ 68	$ —
Commingled Bonds (A)	29	—	29	—
Total	**$ 97**	**$ —**	**$ 97**	**$ —**

(A) Investments in commingled equity and bond funds have a readily determinable fair value as they publish a daily NAV available to investors which is the basis for current transactions and contain certain redemption restrictions requiring advance notice of one to two days for withdrawals (Level 2). In 2016, PSEG re-evaluated the classification, within the fair value hierarchy, of its commingled funds. As a result, PSEG determined that the commingled equity funds should have been classified as Level 2 instead of Level 1, as previously presented for 2015, due to the funds having certain redemption restrictions which prevent daily redemptions at the published price. In addition to the advance notice of one or two days, redemption days may be limited to twice per month for certain funds. PSEG has determined that this error is immaterial to its previously filed financial reports and, accordingly, has corrected the error by revising the amounts disclosed for 2015 to report the commingled equity fund balance of $68 million as of December 31, 2015 as Level 2.

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans of Servco as of the measurement date, December 31:

	As of December 31,	
Investments	2016	2015
Equity Securities	71%	71%
Fixed Income Securities	29	29
Total Percentage	**100%**	**100%**

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Servco utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. The results from Servco's latest asset/liability study indicated that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. The expected long-term rate of return on plan assets was 7.7% for 2016 and will be 7.6% for 2017. This expected return was determined based on the study discussed above, including a premium for active management.

Plan Contributions

Servco plans to contribute $35 million into its pension plan during 2017.

Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to Servco's plan participants:

Year	Pension Benefits	Other Benefits
	Millions	
2017	$ 2	$ 4
2018	3	6
2019	5	9
2020	7	11
2021	8	13
2022-2026	76	96
Total	**$ 101**	**$ 139**

Servco 401(k) Plans

Servco sponsors two 401(k) plans, which are defined contribution retirement plans subject to ERISA. Eligible non-represented employees of Servco participate in the Long Island Electric Utility Servco LLC Incentive Thrift Plan I (Thrift Plan I), and eligible represented employees of Servco participate in the Long Island Electric Utility Servco LLC Incentive Thrift Plan II (Thrift Plan II). Participants in the Plans may contribute up to 50% of their eligible compensation to these plans, not to exceed the IRS maximums, including any Catch-Up Contributions for those employees age 50 and above. Servco does not provide an employer match or core contribution for employees in Thrift Plan II. For employees in Thrift Plan I, Servco matches 50% of such employee contributions up to 8% of eligible compensation and provides core contributions (based on years of service and age) to employees who do not participate in Servco's Retirement Income Plan. The amounts expensed by Servco for employer matching contributions for the years ended December 31, 2016, 2015 and 2014 were $5 million, $4 million and $3 million, respectively, and pursuant to the OSA, Servco recognizes Operating Revenues for the reimbursement of these costs.

Note 13. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees as a form of collateral.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

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- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- the net position of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. Current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of December 31, 2016 and 2015.

	As of December 31, 2016	As of December 31, 2015
	Millions	
Face Value of Outstanding Guarantees	$ 1,806	$ 1,734
Exposure under Current Guarantees	$ 139	$ 172
Letters of Credit Margin Posted	$ 157	$ 122
Letters of Credit Margin Received	$ 99	$ 192
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (1)	$ (15)
Net Broker Balance Deposited (Received)	$ 57	$ (5)
Additional Amounts Posted		
Other Letters of Credit	$ 51	$ 51

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 16. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline and a $21 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

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Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA determined that there was a need to perform a comprehensive study of the entire 17 miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than with respect to their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. Construction is complete. The CPG is awaiting EPA approval of the construction report, long-term monitoring plan and confirmatory sampling plan. PSE&G's and Power's combined share of the cost of that effort is approximately three percent. The remaining CPG members, PSE&G and Power included, have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS sets forth various alternatives for remediating this portion of the Passaic River.

The CPG, which consisted of 52 members as of December 31, 2016, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost of the RI/FS is approximately $190 million, which the CPG continues to incur. Of the estimated $190 million, as of December 31, 2016, the CPG had spent approximately $158 million, of which PSEG's total share was approximately $11 million.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River. It set forth the CPG's estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion on an undiscounted basis. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranged from approximately $518 million to $772 million. Based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimated share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

In March 2016, the EPA released its Record of Decision (ROD) for the FFS which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The ROD Remedy requires a bank-to-bank dredge ranging from approximately 5 to 30 feet deep in the federal navigation channel from River Mile 0 to River Mile 1.7 and an approximately 2.5 foot deep dredge everywhere else in the lower 8.3 miles of the river. An engineered cap approximately two feet thick will be placed over the dredged areas. Dredged sediments will be transported to facilities and landfills out-of-state. The EPA estimates the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation.

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Based upon the estimated cost of the ROD Remedy, PSEG's estimate of PSE&G's and Power's shares of that cost, and the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued an additional $36 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued an additional $8 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2016. As of December 31, 2016, these accruals bring the total liability to approximately $57 million, $46 million applicable to PSE&G and $11 million applicable to Power.

Also in March 2016, the EPA sent a notice letter to 105 PRPs, including PSE&G, all other past and present members of the CPG, including Occidental Chemical Corporation (OCC), and the towns of Newark, Kearny and Harrison and the Passaic Valley Sewerage Commission stating that the EPA wants to determine whether OCC, a successor company to Diamond Shamrock, would voluntarily perform the remedial design for the ROD Remedy. On September 30, 2016, OCC and the EPA executed an Administrative Settlement Agreement and Order on Consent for Remedial Design under which OCC agreed to conduct the remedial design for the ROD. With OCC's commitment to perform the remedial design, it is anticipated that the EPA will begin negotiation of a remedial action consent decree, under which OCC and the other "major PRPs" will implement and/or pay for the EPA's ROD Remedy for the lower 8.3 miles. The EPA has not defined "major PRPs."

On June 16, 2016, Tierra and Maxus, successors to Diamond Shamrock, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Although PSEG does not currently anticipate that the filing for bankruptcy by Tierra and Maxus will affect its allocable share or total liability for the Passaic River matter, PSEG, through the CPG and independently, will monitor the bankruptcy proceedings to identify any potential impact on PSEG's share of the costs.

The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on PSEG's financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

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MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $403 million and $460 million through 2021, including its $46 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $403 million as of December 31, 2016. Of this amount, $81 million was recorded in Other Current Liabilities and $322 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $403 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly. NJDEP, PSEG and EPA representatives have had discussions regarding whether sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In May 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the best technology available for minimizing adverse environmental impacts of each facility that seeks a permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications.

In September 2014, several environmental non-governmental groups and certain energy industry groups filed petitions for review of the rule and the case has been assigned to the U.S. Second Circuit Court of Appeals (Second Circuit). Environmental organizations, including but not limited to the environmental petitioners in the Second Circuit, have also filed suit under the Endangered Species Act. The cases were subsequently consolidated at the Second Circuit and a decision is expected by mid-2017.

In June 2016, the NJDEP issued a final NJPDES permit for Salem with an effective date of August 1, 2016. The final permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the Clean Water Act, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final permit for Salem. The Riverkeeper's filing does not change the effective date of the permit. If the Riverkeeper's challenge were successful, Power may be required to incur additional costs to comply with the Clean Water Act. Such service water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

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State permitting decisions at Bridgeport and possibly New Haven could also have a material impact on Power's ability to renew permits at its existing larger once-through cooled plants without making significant upgrades to existing intake structures and cooling systems.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA's Clean Water Act Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, Power would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the previously estimated useful life ending in 2025. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in 2017. See Note 3. Early Plant Retirements.

Separately, Power has also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that Power would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. The receipt of permits to allow construction and operation of the new facility could occur in 2017. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power may seek to operate BH3 through the previously estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. The Connecticut Siting Council issued an order to approve siting BH5. All major environmental permits have been obtained except for the New Source air permit that is currently in draft form for public comment. Operations are expected to begin in mid-2019.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.

Jersey City, New Jersey Subsurface Feeder Cable Matter

In early October 2016, a discharge of mineral oil dielectric fluid from subsurface feeder cables located in the Hudson River near Jersey City, New Jersey, was identified and reported to the NJDEP. The feeder cables are located within a subsurface easement granted to PSE&G by the property owners, Newport Associates Development Company (NADC) and Newport Associates Phase I Developer Limited Partnership. The feeder cables are subject to agreements between PSE&G and Consolidated Edison Company of New York, Inc. (Con Edison) and are jointly owned by PSE&G and Con Edison, with PSE&G owning the portion of the cables located in New Jersey and Con Edison owning the portion of the cables located in New York. The NJDEP has declared an emergency and an emergency response action has been undertaken to investigate, contain, remediate and stop the fluid discharge; to assess, repair and restore the cables to good working order; and to restore the property. The regulatory agencies overseeing the emergency response, including the U.S. Coast Guard, the NJDEP and the Army Corps of Engineers, have issued multiple notices, orders and directives to the various parties related to this matter. The investigation and response actions related to the fluid discharge are ongoing. The investigation of the discharge and its potential cause is in the preliminary stages, making it difficult to determine the timing and potential costs to resolve this matter, as well as responsibility for such costs between PSE&G, Con Edison and NADC. Based on currently available information and the potential scope of the necessary repair and remediation work, the costs will likely be material. In addition, the timeline for completing the repairs has been extended due to the presence of debris within PSE&G's easement. In November 2016, PSE&G filed an action in New Jersey Federal Court seeking an order requiring NADC to remove its debris from PSE&G's easement so that PSE&G and Con Edison may comply with NJDEP and U.S. Coast Guard directives and complete the necessary repairs. NADC subsequently informed PSE&G that it would comply with the U.S. Coast Guard's order and undertake debris removal activities so that PSE&G and Con Edison can complete the necessary repairs. NADC's debris removal activities are ongoing.

Steam Electric Effluent Guidelines

In September 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have

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bottom ash transport water discharges that are regulated under this rule. Power is unable to predict if this rule will have a material impact on its future capital requirements, financial condition and results of operations.

Coal Combustion Residuals (CCRs)

On December 19, 2014, the EPA issued a final rule that regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Power's Hudson and Mercer generating stations, along with its co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 19, 2015. Accordingly in June 2015, Power recorded an additional asset retirement obligation to comply with the final CCR rule which was not material to Power's results of operations, financial condition or cash flows.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third-party suppliers. The first category, which represents about 80% of PSE&G's load requirement, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2017 is $276.83 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2017 of $335.33 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2014	2015	2016	2017	
36-Month Terms Ending	May 2017	May 2018	May 2019	May 2020	(A)
Load (MW)	2,800	2,900	2,800	2,800	
$ per MWh	$97.39	$99.54	$96.38	$90.78	

(A) Prices set in the 2017 BGS auction will become effective on June 1, 2017 when the 2014 BGS auction agreements expire.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 24. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2018 and a significant portion through 2021 at Salem, Hope Creek and Peach Bottom.

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Power has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available beyond the needs of PSE&G's customers, Power can use the gas to supply its fossil generating stations.

Power also has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations.

As of December 31, 2016, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2021
	Millions
Nuclear Fuel	
Uranium	$ 301
Enrichment	$ 356
Fabrication	$ 192
Natural Gas	$ 1,029
Coal	$ 215

Regulatory Proceedings

FERC Compliance

PJM Bidding Matter

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future.

During the three month period ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. No additional charges to income have been recorded for this matter since that time.

Since September 2014, FERC Staff has been conducting a preliminary, non-public staff investigation into the matter and issued data requests covering a period from 2002 through the date of the self-report. This investigation is ongoing. Since that time, Power has responded to data requests from FERC Staff, including recent data requests in which Power has recalculated certain of its energy bids in PJM for a five year period, and may receive additional data requests or other fact finding. The FERC Staff investigation is still in the fact finding stage and there is considerable uncertainty around FERC's response to PSEG's legal arguments and the amount of disgorgement or other remedies FERC may ultimately seek.

PSEG is unable to reasonably estimate the range of possible loss for this matter; however, the amounts of potential disgorgement and other potential penalties that Power may incur span a wide range depending on the success of PSEG's legal arguments. These arguments include that Power's energy market bids in a substantial majority of the hours were below the allowed rate under the Tariff and therefore any errors in those hours were immaterial and that it is unclear whether the quantity of the bids violated any legal requirement. If PSEG's legal arguments do not prevail in whole or in part with FERC or in a judicial challenge that PSEG may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to PSEG's and Power's Consolidated Statements of Operations in the quarterly and annual periods in which they are recorded.

Financial Transmission Rights (FTR) Auction Matter

In January 2017, ER&T received requests from the FERC Office of Enforcement relating to the planning and implementation of ER&T's participation in the annual FTR auction in PJM for the 2016-2017 planning year and the monthly FTR auctions in PJM for February, March and April 2016. PSEG is cooperating with FERC in this matter. PSEG cannot predict the outcome of this matter at this time.

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Nuclear Insurance Coverages and Assessments

Power is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides the property, decontamination and decommissioning liability insurance at the Salem/Hope Creek and Peach Bottom sites. NEIL also provides replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in case of adverse loss experience. Power's maximum potential liabilities under these assessments are included in the table and notes below. Certain provisions in the NEIL policies provide that the insurer may suspend coverage with respect to all nuclear units on a site without notice if the NRC suspends or revokes the operating license for any unit on that site, issues a shutdown order with respect to such unit or issues a confirmatory order keeping such unit down.

Power is also a member of the joint underwriting association, American Nuclear Insurers (ANI), which provides nuclear liability insurance coverage at the Salem/Hope Creek and Peach Bottom sites. The ANI policies are designed to satisfy the financial protection requirements outlined in the Price-Anderson Act.

The ANI and NEIL policies all include coverage for claims arising out of acts of terrorism, however, NEIL policies are subject to an industry aggregate limit of $3.2 billion plus such additional amounts as NEIL recovers for such losses from reinsurance, indemnity and any other source applicable to such losses.

The Price-Anderson Act sets the "limit of liability" for claims that could arise from an incident involving any licensed nuclear facility in the United States. The "limit of liability" is based on the number of licensed nuclear reactors and is adjusted at least every five years based on the Consumer Price Index. The "limit of liability" per incident per site is comprised of a primary and excess layer. As of December 31, 2016, nuclear sites were required to purchase $375 million of primary liability coverage for each site (through ANI). This limit was increased to $450 million effective January 1, 2017.The primary layer is supplemented by an excess layer, which is an industry self-insurance pool. In the event a nuclear site has a claim that exceeds the primary layer, each licensee would be assessed a prorated share of the excess, up to $127 million per reactor, payable at not more than $19 million per reactor per incident per year. With 102 reactors currently in the insurance pool, the excess layer limit is $13.0 billion. If the damages exceed the "limit of liability," Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Power's maximum aggregate assessment per incident is $401 million (based on Power's ownership interests in Hope Creek, Peach Bottom and Salem) and its maximum aggregate annual assessment per incident is $60 million. Further, a decision by the U.S. Supreme Court, not involving Power, has held that the Price-Anderson Act did not preclude awards based on state law claims for punitive damages.

Power's insurance coverages and maximum retrospective assessments for its nuclear operations as of December 31, 2016 were as follows:

Type and Source of Coverages	Site Coverage		Retrospective Assessments
	Millions		
Public and Nuclear Worker Liability (Primary Layer):			
ANI	$ 375	(A)	$ —
Nuclear Liability (Excess Layer):			
Price-Anderson Act	12,986	(B)	401
Nuclear Liability Total	**$ 13,361**	(C)	**$ 401**
Property Damage (Primary Layer):			
NEIL Primary (Salem/Hope Creek)	$ 1,500		$ 35
NEIL Primary (Peach Bottom)	$ 1,500		14
Property Damage (Excess Layers):			
NEIL Excess (Salem/Hope Creek - Nuclear)	$ 300	(D)	2
NEIL Excess (Peach Bottom - Nuclear)	$ 300	(D)	1
NEIL Excess (Salem/Hope Creek - Non - Nuclear)	$ 300	(D)	1
NEIL Excess (Peach Bottom - Non - Nuclear)	$ 600	(D)	1
Accidental Outage - PSEG Share:(Nuclear / Non-Nuclear)			
NEIL I (Peach Bottom)	$245 / $164	(E)	8
NEIL I (Salem)	$281 / $188	(E)	9
NEIL I (Hope Creek)	$490 / $328	(E)	7
Nuclear Property Total			**$ 78**

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(A) The primary limit for Public Liability is a per site aggregate limit with no potential for retrospective assessment. The Nuclear Worker Liability represents the potential liability from third-party workers claiming exposure to the nuclear energy hazard. This coverage is subject to an industry aggregate limit that is subject to reinstatement at ANI discretion.

(B) Retrospective premium program under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. Power is subject to retrospective assessment with respect to loss from an incident at any licensed nuclear reactor in the United States that produces greater than 100 MW of electrical power. This retrospective assessment can be adjusted for inflation every five years. The last adjustment was effective as of September 10, 2013. The next adjustment is due on or before September 10, 2018. This retrospective program is in excess of the Public and Nuclear Worker Liability primary layers.

(C) Maximum limit of liability under the Price-Anderson Act for each nuclear incident per site.

(D) For nuclear event property limits in excess of $1.5 billion, Power purchases a $300 million Excess Policy for the Salem/Hope Creek site, and a $300 million Excess Policy only for Power's 50% interest in Peach Bottom. This limit is not subject to reinstatement in the event of a loss. In addition, for non-nuclear event limits in excess of $1.5 billion, Power maintains a $300 million limit for the combined Salem/Hope Creek sites. Exelon maintains a $600 million non-nuclear event limit for Peach Bottom.

(E) Peach Bottom 2 and 3 have an aggregate nuclear indemnity limit based on a weekly indemnity of $2.3 million for 52 weeks followed by 80% of the weekly indemnity for 68 weeks. Peach Bottom 2 and 3 have an aggregate non-nuclear indemnity limit based on a weekly indemnity of $2.3 million for 52 weeks followed by 80% of the weekly indemnity for 24 weeks. Salem 1 and 2 have an aggregate nuclear indemnity limit based on a weekly indemnity of $2.5 million for 52 weeks followed by 80% of the weekly indemnity for 76 weeks. Salem 1 and 2 have an aggregate non-nuclear indemnity limit based on a weekly indemnity of $2.5 million for 52 weeks followed by 80% of the weekly indemnity for 29 weeks. Hope Creek has an aggregate nuclear indemnity limit based on a weekly indemnity of $4.5 million for 52 weeks followed by 80% of the weekly indemnity for 71 weeks. Hope Creek has an aggregate non-nuclear indemnity limit based on a weekly indemnity of $4.5 million for 52 weeks followed by 80% of the weekly indemnity for 26 weeks.

Minimum Lease Payments

The total future minimum payments under various operating leases as of December 31, 2016 are:

	PSE&G	Power	Services	Other	Total
	Millions				
2017	$ 12	$ 3	$ 13	$ 1	$ 29
2018	8	3	13	1	25
2019	7	3	13	1	24
2020	6	2	13	1	22
2021	6	2	14	1	23
Thereafter	61	39	132	—	232
Total Minimum Lease Payments	**$ 100**	**$ 52**	**$ 198**	**$ 5**	**$ 355**

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Note 14. Debt and Credit Facilities

Long-Term Debt

	Maturity	As of December 31, 2016	2015
		Millions	
PSEG			
Term Loan:			
Variable	2017	$ 500	$ 500
Total Term Loan		500	500
Senior Notes:			
1.60%	2019	400	—
2.00%	2021	300	—
Total Senior Notes		700	—
Principal Amount Outstanding		1,200	500
Fair Value of Swaps (A)		—	6
Amounts Due Within One Year		(500)	(6)
Net Unamortized Discount and Debt Issuance Costs		(5)	—
Total Long-Term Debt of PSEG		**$ 695**	**$ 500**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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	Maturity	As of December 31, 2016	2015
		Millions	
PSE&G			
First and Refunding Mortgage Bonds (B):			
6.75%	2016	$ —	$ 171
9.25%	2021	134	134
8.00%	2037	7	7
5.00%	2037	8	8
Total First and Refunding Mortgage Bonds		149	320
Pollution Control Bonds (B):			
Floating Rate (C)	2033	—	50
Floating Rate (C)	2046	—	50
Total Pollution Control Bonds		—	100
Medium-Term Notes (MTNs) (B):			
5.30%	2018	400	400
2.30%	2018	350	350
1.80%	2019	250	250
2.00%	2019	250	250
7.04%	2020	9	9
3.50%	2020	250	250
1.90%	2021	300	—
2.38%	2023	500	500
3.75%	2024	250	250
3.15%	2024	250	250
3.05%	2024	250	250
3.00%	2025	350	350
2.25%	2026	425	—
5.25%	2035	250	250
5.70%	2036	250	250
5.80%	2037	350	350
5.38%	2039	250	250
5.50%	2040	300	300
3.95%	2042	450	450
3.65%	2042	350	350
3.80%	2043	400	400
4.00%	2044	250	250
4.05%	2045	250	250
4.15%	2045	250	250
3.80%	2046	550	—
Total MTNs		7,734	6,459
Principal Amount Outstanding		7,883	6,879
Amounts Due Within One Year		—	(171)
Net Unamortized Discount and Debt Issuance Costs		(65)	(58)
Total Long-Term Debt of PSE&G		**$ 7,818**	**$ 6,650**

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	Maturity	As of December 31, 2016	2015
		Millions	
Power			
Senior Notes:			
5.32%	2016	$ —	$ 303
2.75%	2016	—	250
2.45%	2018	250	250
5.13%	2020	406	406
4.15%	2021	250	250
3.00%	2021	700	—
4.30%	2023	250	250
8.63%	2031	500	500
Total Senior Notes		2,356	2,209
Pollution Control Notes:			
Floating Rate (C)	2019	44	44
Total Pollution Control Notes		44	44
Principal Amount Outstanding		2,400	2,253
Amounts Due Within One Year		—	(553)
Net Unamortized Discount and Debt Issuance Costs		(18)	(16)
Total Long-Term Debt of Power		**$ 2,382**	**$ 1,684**

(A) PSEG entered into various interest rate swaps to hedge the fair value of certain debt at Power. The fair value adjustments from these hedges are reflected as offsets to long-term debt on the Consolidated Balance Sheets. For additional information, see Note 16. Financial Risk Management Activities.

(B) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.

(C) The Pollution Control Financing Authority of Salem County bonds (Salem Bonds), which were repurchased and retired in 2016, and the Pennsylvania Economic Development Authority (PEDFA) bond that are serviced and secured by PSE&G Pollution Control Bonds and Power Pollution Control Notes, respectively, were variable rate bonds that were in weekly reset mode.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2016 are as

Year	PSEG	PSE&G	Power	Total
2017	$ 500	$ —	$ —	$ 500
2018	—	750	250	1,000
2019	400	500	44	944
2020	—	259	406	665
2021	300	434	950	1,684
Thereafter	—	5,940	750	6,690
Total	**$ 1,200**	**$ 7,883**	**$ 2,400**	**$ 11,483**

Long-Term Debt Financing Transactions

During 2016, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions:

PSEG

- issued $400 million of 1.60% Senior Notes due November 2019, and

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- issued $300 million of 2.00% Senior Notes due November 2021

PSE&G

- issued $300 million of 1.90% Secured Medium-Term Notes, Series K due March 2021,
- issued $550 million of 3.80% Secured Medium-Term Notes, Series K due March 2046,
- issued $425 million of 2.25% Secured Medium-Term Notes, Series L due September 2026,
- retired $171 million of 6.75% Secured First and Refunding Mortgage Bonds Series VV at maturity, and
- repurchased at par $100 million of Salem Bonds and retired a like aggregate principal amount of its First and Refunding Mortgage Bonds which serviced and secured the Salem Bonds.

Power

- issued $700 million of 3.00% Senior Notes due June 2021,
- retired $303 million of 5.32% Senior Notes due September 2016, and
- retired $250 million of 2.75% Senior Notes due September 2016.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under the $4.2 billion credit facilities are provided by a diverse bank group. As of December 31, 2016, the total available credit capacity was $3.5 billion.

As of December 31, 2016, no single institution represented more than 7% of the total commitments in the credit facilities.

As of December 31, 2016, the total credit capacity was in excess of the anticipated maximum liquidity requirements.

Each of the credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs.

The total credit facilities and available liquidity as of December 31, 2016 were as follows:

	As of December 31, 2016				
Company/Facility	Total Facility	Usage (D)	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facility	$ 500	$ 10	$ 490	Mar 2019	Commercial Paper Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	388	112	Apr 2020	Commercial Paper Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 398**	**$ 602**		
PSE&G					
5-year Credit Facility (B)	$ 600	$ 14	$ 586	Apr 2020	Commercial Paper Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 14**	**$ 586**		
Power					
5-year Credit Facility	$ 1,600	$ 195	$ 1,405	Mar 2019	Funding/Letters of Credit
5-year Credit Facility (C)	953	3	950	Apr 2020	Funding/Letters of Credit
Total Power	**$ 2,553**	**$ 198**	**$ 2,355**		
Total	**$ 4,153**	**$ 610**	**$ 3,543**		

(A) PSEG facility will be reduced by $12 million in March 2018.

(B) PSE&G facility will be reduced by $14 million in March 2018.

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(C) Power facility will be reduced by $24 million in March 2018.

(D) The primary use of PSEG's and PSE&G's credit facilities is to support their respective Commercial Paper Programs under which as of December 31, 2016, PSEG had $388 million outstanding at a weighted average interest rate of 1.03%. PSE&G had no amounts outstanding under its Commercial Paper Program as of December 31, 2016.

Fair Value of Debt

The estimated fair values, carrying amounts and methods used to determine fair value of long-term debt as of December 31, 2016 and 2015 are included in the following table and accompanying notes as of December 31, 2016 and 2015. See Note 17. Fair Value Measurements for more information on fair value guidance and the hierarchy that prioritizes the inputs to fair value measurements into three levels.

	December 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (A) (B)	$ 1,195	$ 1,185	$ 503	$ 506
PSE&G (B)	7,818	8,240	6,821	7,235
Power - Recourse Debt (B)	2,382	2,578	2,237	2,508
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	—	—	7	7
	$ 11,395	**$ 12,003**	**$ 9,568**	**$ 10,256**

(A) Fair value includes a $500 million floating rate term loan and net offsets. The fair value of the term loan debt (Level 2 measurement) was considered to be equal to the carrying value because the interest payments are based on LIBOR rates that are reset monthly. As of December 31, 2015, carrying amount includes such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) Given that most bonds do not trade, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

(C) Non-recourse project debt was valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

Note 15. Schedule of Consolidated Capital Stock

	As of December 31,			
	Outstanding Shares		Book Value	
	2016	2015	2016	2015
			Millions	
PSEG Common Stock (no par value) (A)				
Authorized 1,000,000,000 shares	504,866,212	505,282,421	$ 4,219	$ 4,244

(A) PSEG did not issue any new shares under the Dividend Reinvestment and Stock Purchase Plan (DRASPP) or the Employee Stock Purchase Plan (ESPP) in 2016 or 2015. Total authorized and unissued shares of common stock available for issuance through PSEG's DRASPP, ESPP and various employee benefit plans amounted to approximately 7 million shares as of December 31, 2016.

As of December 31, 2016, PSE&G had an aggregate of 7.5 million shares of $100 par value and 10 million shares of $25 par value Cumulative Preferred Stock, which were authorized and unissued and which, upon issuance, may or may not provide for mandatory sinking fund redemption.

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Note 16. Financial Risk Management Activities

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include NPNS, cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow or fair value hedges. Power and PSE&G enter into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of the derivative contracts are recorded in earnings.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. The changes in fair value of the interest rate swaps are fully offset by changes in the fair value of the underlying forecasted interest payments of the debt. Interest rate swaps totaling $550 million that converted Power's Senior Notes due September 2016 into variable-rate debt matured in the third quarter of 2016. There were no outstanding interest rate swaps as of December 31, 2016. As of December 31, 2015, the fair value of all the underlying hedges was $6 million. The fair value hedges reduced interest expense by $6 million, $19 million and $20 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. As of December 31, 2016, PSEG had interest rate hedges outstanding totaling $500 million. These hedges were executed during the first quarter of 2016 and convert PSEG's $500 million variable rate term loan due November 2017 into a fixed rate loan. The fair value of these hedges was $1 million and there was no ineffectiveness as of December 31, 2016. There were no outstanding interest rate hedges as of December 31, 2015.

PSEG executed forward starting swaps totaling $400 million during the first quarter of 2016 which were terminated upon the issuance of Power's $700 million of 3.00% Senior Notes due June 2021. In the fourth quarter of 2016, PSEG executed $500 million of forward starting swaps which were terminated upon the issuance of PSEG's $400 million of 1.6% Senior Notes due November 2019 and $300 million of 2.0% Senior Notes due November 2021. For additional information see Note 14. Debt and Credit Facilities.

The Accumulated Other Comprehensive Income (Loss) (after tax) related to existing and terminated interest rate derivatives designated as cash flow hedges was $2 million as of December 31, 2016 and immaterial as of December 31, 2015. The after-tax unrealized gains on these hedges expected to be reclassified to earnings during the next 12 months is $1 million.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with PSEG's accounting policy, these positions are offset on the Consolidated Balance Sheets of Power and PSEG.

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The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of December 31, 2016					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Cash Flow Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 435	$ (273)	$ 162	$ —	$ 1	$ 163
Noncurrent Assets	122	(98)	24	—	—	24
Total Mark-to-Market Derivative Assets	**$ 557**	**$ (371)**	**$ 186**	**$ —**	**$ 1**	**$ 187**
Derivative Contracts						
Current Liabilities	$ (285)	$ 277	$ (8)	$ (5)	$ —	$ (13)
Noncurrent Liabilities	(98)	95	(3)	—	—	(3)
Total Mark-to-Market Derivative (Liabilities)	**$ (383)**	**$ 372**	**$ (11)**	**$ (5)**	**$ —**	**$ (16)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 174**	**$ 1**	**$ 175**	**$ (5)**	**$ 1**	**$ 171**

	As of December 31, 2015					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 700	$ (477)	$ 223	$ 13	$ 6	$ 242
Noncurrent Assets	208	(131)	77	—	—	77
Total Mark-to-Market Derivative Assets	**$ 908**	**$ (608)**	**$ 300**	**$ 13**	**$ 6**	**$ 319**
Derivative Contracts						
Current Liabilities	$ (513)	$ 437	$ (76)	$ —	$ —	$ (76)
Noncurrent Liabilities	(132)	116	(16)	(11)	—	(27)
Total Mark-to-Market Derivative (Liabilities)	**$ (645)**	**$ 553**	**$ (92)**	**$ (11)**	**$ —**	**$ (103)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 263**	**$ (55)**	**$ 208**	**$ 2**	**$ 6**	**$ 216**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of December 31, 2016 and 2015. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Consolidated Balance Sheets. As of December 31, 2016 and 2015, net cash collateral (received) paid of $1 million and $(55) million, respectively, were netted against the corresponding net

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derivative contract positions. Of the $1 million as of December 31, 2016, $(3) million was netted against noncurrent assets and $4 million was netted against current liabilities. Of the $(55) million as of December 31, 2015, cash collateral of $(53) million and $(16) million were netted against current assets and noncurrent assets, respectively, and $12 million and $2 million were netted against current liabilities and noncurrent liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating by S&P or Moody's, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P or Moody's ratings. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $19 million and $78 million as of December 31, 2016 and 2015, respectively. As of December 31, 2016 and 2015, Power had the contractual right of offset of $9 million and $12 million, respectively, related to derivative instruments that are assets with the same counterparty under master agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $10 million and $66 million as of December 31, 2016 and 2015, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.

The following shows the effect on the Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the years ended December 31, 2016, 2015 and 2014.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Years Ended December 31,			Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Years Ended December 31,		
	2016	2015	2014		2016	2015	2014
	Millions				Millions		
PSEG							
Energy-Related Contracts	$ —	$ 3	$ 12	Operating Revenues	$ —	$ 20	$ (9)
Interest Rate Swaps	3	—	—	Interest Expense	—	—	—
Total PSEG	**$ 3**	**$ 3**	**$ 12**		**$ —**	**$ 20**	**$ (9)**
Power							
Energy-Related Contracts	$ —	$ 3	$ 12	Operating Revenues	$ —	$ 20	$ (9)
Total Power	**$ —**	**$ 3**	**$ 12**		**$ —**	**$ 20**	**$ (9)**

There were no pre-tax gain (loss) recognized in income on derivatives (ineffective portion) as of December 31, 2016, 2015 and 2014.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following reconciles the AOCI for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2014	**$ 17**	**$ 10**
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	(20)	(12)
Balance as of December 31, 2015	**$ —**	**$ —**
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	—	—
Balance as of December 31, 2016	**$ 3**	**$ 2**

The following shows the effect on the Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS for the years ended December 31, 2016, 2015 and 2014.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2016	2015	2014
		Millions		
PSEG and Power				
Energy-Related Contracts	Operating Revenues	$ 230	$ 412	$ (348)
Energy-Related Contracts	Energy Costs	(8)	(8)	32
Total PSEG and Power		**$ 222**	**$ 404**	**$ (316)**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. The tables above do not include contracts for which Power has designated as NPNS, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load.

The following reflects the gross volume, on an absolute value basis, of derivatives as of December 31, 2016 and 2015.

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of December 31, 2016					
Natural Gas	Dth	357	—	348	9
Electricity	MWh	323	—	323	—
Financial Transmission Rights (FTRs)	MWh	9	—	9	—
Interest Rate Swaps	U.S. Dollars	500	500	—	—
As of December 31, 2015					
Natural Gas	Dth	201	—	168	33
Electricity	MWh	299	—	299	—
FTRs	MWh	23	—	23	—
Interest Rate Swaps	U.S. Dollars	550	550	—	—

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Credit Risk

Credit risk relates to the risk of loss that Power would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG has established credit policies that it believes significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of December 31, 2016, 93% of the net credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives, NPNS and non-derivatives).

The following table provides information on Power's credit risk from others, net of collateral, as of December 31, 2016. It further delineates that exposure by the credit rating of the counterparties, which is determined by the lowest rating from S&P, Moody's or an internal scoring model. In addition, it provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade	$ 423	$ 94	$ 329	1	$ 219	(A)
Non-Investment Grade	26	1	25	—	—	
Total	**$ 449**	**$ 95**	**$ 354**	**1**	**$ 219**	

(A) Represents net exposure with PSE&G.

As of December 31, 2016, collateral held from counterparties where Power had credit exposure included $1 million in cash collateral and $94 million in letters of credit.

As of December 31, 2016, Power had 149 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2016, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's BGS suppliers' credit exposure is calculated each business day. As of December 31, 2016, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 17. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds, as well as natural gas futures contracts executed on NYMEX.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of December 31, 2016, these consisted primarily of gas supply contracts and certain electric load contracts.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of December 31, 2016 and December 31, 2015, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Description	Recurring Fair Value Measurements as of December 31, 2016			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 186	$ (371)	$ 17	$ 533	$ 7
Interest Rate Swaps (C)	$ 1	$ —	$ —	$ 1	$ —
NDT Fund (D)					
Equity Securities	$ 957	$ —	$ 954	$ 3	$ —
Debt Securities—US Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 293	$ —	$ —	$ 293	$ —
Debt Securities—Corporate	$ 337	$ —	$ —	$ 337	$ —
Other Securities	$ 44	$ —	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—US Treasury	$ 37	$ —	$ —	$ 37	$ —
Debt Securities—Govt Other	$ 66	$ —	$ —	$ 66	$ —
Debt Securities—Corporate	$ 91	$ —	$ —	$ 91	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (16)	$ 372	$ (18)	$ (364)	$ (6)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ —	$ —	$ —	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—US Treasury	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Govt Other	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Corporate	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (5)	$ —	$ —	$ —	$ (5)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 186	$ (371)	$ 17	$ 533	$ 7
NDT Fund (D)					
Equity Securities	$ 957	$ —	$ 954	$ 3	$ —
Debt Securities—US Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 293	$ —	$ —	$ 293	$ —
Debt Securities—Corporate	$ 337	$ —	$ —	$ 337	$ —
Other Securities	$ 44	$ —	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—US Treasury	$ 9	$ —	$ —	$ 9	$ —
Debt Securities—Govt Other	$ 16	$ —	$ —	$ 16	$ —
Debt Securities—Corporate	$ 23	$ —	$ —	$ 23	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —

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Liabilities:										
Derivative Contracts:										
Energy-Related Contracts (B)	$	(11)	$	372	$	(18)	$	(364)	$	(1)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Description	Recurring Fair Value Measurements as of December 31, 2015				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 326	$ —	$ 326	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 313	$ (608)	$ —	$ 896	$ 25
Interest Rate Swaps (C)	$ 6	$ —	$ —	$ 6	$ —
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—US Treasury	$ 177	$ —	$ —	$ 177	$ —
Debt Securities—Govt Other	$ 311	$ —	$ —	$ 311	$ —
Debt Securities—Corporate	$ 359	$ —	$ —	$ 359	$ —
Other Securities	$ 42	$ —	$ 42	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—US Treasury	$ 48	$ —	$ —	$ 48	$ —
Debt Securities—Govt Other	$ 60	$ —	$ —	$ 60	$ —
Debt Securities—Corporate	$ 81	$ —	$ —	$ 81	$ —
Other Securities	$ 2	$ —	$ 2	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (103)	$ 553	$ —	$ (644)	$ (12)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 160	$ —	$ 160	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ 13	$ —	$ —	$ —	$ 13
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—US Treasury	$ 9	$ —	$ —	$ 9	$ —
Debt Securities—Govt Other	$ 12	$ —	$ —	$ 12	$ —
Debt Securities—Corporate	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (11)	$ —	$ —	$ —	$ (11)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 300	$ (608)	$ —	$ 896	$ 12
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—US Treasury	$ 177	$ —	$ —	$ 177	$ —
Debt Securities—Govt Other	$ 311	$ —	$ —	$ 311	$ —
Debt Securities—Corporate	$ 359	$ —	$ —	$ 359	$ —
Other Securities	$ 42	$ —	$ 42	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—US Treasury	$ 12	$ —	$ —	$ 12	$ —
Debt Securities—Govt Other	$ 14	$ —	$ —	$ 14	$ —
Debt Securities—Corporate	$ 20	$ —	$ —	$ 20	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —

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Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (92)	$ 553	$ —	$ (644)	$ (1)

(A) Represents money market mutual funds.

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(B) Level 1—During 2016 a net fair value of $1 million relating to energy-related contracts was transferred from Level 2 into Level 1. These contracts represent natural gas futures contracts executed on NYMEX, and are being valued solely on settled pricing inputs which come directly from the exchange.

Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using settled prices from an exchange, such as NYMEX, Intercontinental Exchange and Nodal Exchange, or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The fair value measurement table excludes cash of $1 million which is part of the NDT Fund, The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities include investment grade corporate bonds, collateralized mortgage obligations, asset-backed securities and certain government and US Treasury obligations or Federal Agency asset-backed securities and municipal bonds with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. The preferred stocks are not actively traded on a daily basis and therefore, are also priced using an evaluated pricing methodology. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of December 31, 2016, net cash collateral (received) paid of $1 million was netted against the corresponding net derivative contract positions. Of the $1 million of cash collateral as of December 31, 2016, $(3) million was netted against assets, and $4 million was netted against liabilities. As of December 31, 2015, net cash collateral (received) paid of $(55) million was netted against the corresponding net derivative contract positions. Of the $(55) million of cash collateral as of December 31, 2015, $(69) million was netted against assets and $14 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG.

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Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G, the natural gas supply contract is measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The following tables provide details surrounding significant Level 3 valuations as of December 31, 2016 and 2015.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2016		Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)			
		Millions				
PSE&G						
Gas	Natural Gas Supply Contract	$ —	$ (5)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ —**	**$ (5)**			
Power						
Electricity	Electric Load Contracts	$ 7	$ (1)	Discounted Cash flow	Historic Load Variability	0% to +10%
Gas (A)	Other	—	—			
Total Power		**$ 7**	**$ (1)**			
Total PSEG		**$ 7**	**$ (6)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2015		Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)			
		Millions				
PSE&G						
Gas	Natural Gas Supply Contract	$ 13	$ (11)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ 13**	**$ (11)**			
Power						
Electricity	Electric Load Contracts	$ 11	$ (1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Electricity	Other	1	—			
Total Power		**$ 12**	**$ (1)**			
Total PSEG		**$ 25**	**$ (12)**			

(A) Includes gas supply positions which were immaterial as of December 31, 2016.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value. For energy-related contracts in cases where Power is a seller, an increase in the load variability would decrease the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the years ended December 31, 2016 and 2015, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2016

Description	Balance as of January 1, 2016	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of December 31, 2016
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ 13	$ 13	$ (7)	$ 3	$ (21)	$ —	$ 1
PSE&G							
Net Derivative Assets (Liabilities)	$ 2	$ —	$ (7)	$ —	$ —	$ —	$ (5)
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 13	$ —	$ 3	$ (21)	$ —	$ 6

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2015

Description	Balance as of January 1, 2015	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of December 31, 2015
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ 37	$ 20	$ (24)	$ —	$ (20)	$ —	$ 13
PSE&G							
Net Derivative Assets (Liabilities)	$ 26	$ —	$ (24)	$ —	$ —	$ —	$ 2
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 20	$ —	$ —	$ (20)	$ —	$ 11

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $13 million and $20 million in Operating Income in 2016 and 2015, respectively. Of the $13 million in Operating Income in 2016 $(5) million is unrealized. The $20 million in Operating Income in 2015 is realized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

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(C) Represents $(21) million and $(20) million in settlements for derivative contracts in 2016 and 2015, respectively.

As of December 31, 2016, PSEG carried $2.6 billion of net assets that are measured at fair value on a recurring basis, of which $1 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of December 31, 2015, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $13 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Note 18. Stock Based Compensation

PSEG's Amended and Restated 2004 Long-Term Incentive Plan (LTIP) is a broad-based equity compensation program that provides for grants of various long-term incentive compensation awards, such as stock options, stock appreciation rights, performance share units, restricted stock, restricted stock units, cash awards or any combination thereof. The types of long-term incentive awards that have been granted and remain outstanding under the LTIP are non-qualified options to purchase shares of PSEG's common stock, restricted stock unit awards and performance share unit awards. The type of equity award that is granted and the details of that award may vary from time to time and is subject to the approval of the Organization and Compensation Committee of PSEG's Board of Directors (O&CC), the LTIP's administrative committee.

The LTIP currently provides for the issuance of equity awards with respect to approximately 16 million shares of common stock. As of December 31, 2016, there were approximately 15 million shares available for future awards under the LTIP.

Stock Options

Under the LTIP, non-qualified options to acquire shares of PSEG common stock may be granted to officers and other key employees selected by the O&CC. Option awards are granted with an exercise price equal to the market price of PSEG's common stock at the grant date. The options generally vest over four years of continuous service. Vesting schedules may be accelerated upon the occurrence of certain events, such as a change-in-control (unless substituted with an equity award of equal value), retirement, death or disability. Options are exercisable over a period of time designated by the O&CC (but not prior to one year or longer than ten years from the date of grant) and are subject to such other terms and conditions as the O&CC determines. Payment by option holders upon exercise of an option may be made in cash or, with the consent of the O&CC, by delivering previously acquired shares of PSEG common stock. No options have been issued since 2009.

Restricted Stock Units

Under the LTIP, PSEG has granted restricted stock unit awards to officers and other key employees. These awards, which are bookkeeping entries only, are subject to risk of forfeiture until vested by continued employment. Until distributed, the units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. The restricted stock unit grants for 2016 and 2015 generally vest at the end of three years. Vesting may be accelerated (pro-rated basis or full vesting) upon certain events such as retirement, disability, change-in-control or death.

Performance Share Units

Under the LTIP, PSEG has granted performance share units to officers and other key employees. These provide for payment in shares of PSEG common stock based on achievement of certain financial goals over a three-year performance period. Following the end of the performance period, the payout varies from 0% to 200% of the number of performance units granted depending on PSEG's performance with respect to certain financial targets, including targets related to comparative performance against other companies in a peer group of energy companies. The performance share units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. Vesting may be accelerated on a pro-rated basis for the period of the employee's service during the performance period as a result of certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

Stock-Based Compensation

PSEG recognizes compensation expense for stock options based on their grant date fair values, which are determined using the Black-Scholes option-pricing model. Stock option awards are expensed on a tranche-specific basis over the requisite service period of the award. Ultimately, compensation expense for stock options is recognized for awards that vest.

PSEG recognizes compensation expense for restricted stock units over the vesting period based on the grant date fair value of the shares, which is equal to the market price of PSEG's common stock on the date of the grant.

PSEG recognizes compensation expense for the total shareholder return target for its performance share unit awards based on the grant date fair values of the award, which are determined using the Monte Carlo model. The accrual of compensation cost is based on the probable achievement of the performance conditions, which result in a payout from 0% to 200% of the initial grant. PSEG recognizes compensation expense for the return on invested capital target for its performance share units based on the grant date fair value of the awards, which is equal to the market price of PSEG's common stock on the date of the grant. The

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accrual during the year of grant is estimated at 100% of the original grant. Such accrual may be adjusted to reflect the actual outcome.

	2016	2015	2014
		Millions	
Compensation Cost included in Operation and Maintenance Expense	$ 29	$ 34	$ 32
Income Tax Benefit Recognized in Consolidated Statement of Operations	$ 12	$ 14	$ 13

For 2016 and 2015 the excess tax benefit was $4 million and $3 million, respectively. There was no excess tax benefit for 2014.

PSEG recognizes compensation cost of awards issued over the shorter of the original vesting period or the period beginning on the date of grant and ending on the date an individual is eligible for retirement and the award vests.

Stock Options

Changes in stock options for 2016 are summarized as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding as of January 1, 2016	1,707,250	$ 36.00		
Exercised	677,350	$ 33.06		
Canceled/Forfeited	—	$ —		
Outstanding as of December 31, 2016	**1,029,900**	**$ 37.93**	**2.0**	**$ 7,640,178**
Exercisable at December 31, 2016	1,029,900	$ 37.93	2.0	$ 7,640,178

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. There were no option grants in 2016, 2015 and 2014.

Activity for options exercised for the years ended December 31, 2016, 2015 and 2014 is shown below:

	2016	2015	2014
		Millions	
Total Intrinsic Value of Options Exercised	$ 7	$ 3	$ 4
Cash Received from Options Exercised	$ 22	$ 12	$ 16
Tax Benefit Realized from Options Exercised	$ 1	$ —	$ —

No options were vested during the years ended December 31, 2016, 2015 and 2014.

Restricted Stock Units

Changes in restricted stock units for the year ended December 31, 2016 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2016	408,507	$ 34.95		
Granted	285,258	$ 42.28		
Vested	362,098	$ 37.23		
Canceled/Forfeited	9,471	$ 39.67		
Non-vested as of December 31, 2016	**322,196**	**$ 38.75**	**1.0**	**$ 14,137,960**

The weighted average grant date fair value per share for restricted stock during the years ended December 31, 2016, 2015 and 2014 was $42.28, $39.65 and $35.16 per share, respectively.

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The total intrinsic value of restricted stock units vested during the years ended December 31, 2016, 2015 and 2014 was $17 million, $11 million and $12 million, respectively.

As of December 31, 2016, there was approximately $4 million of unrecognized compensation cost related to the restricted stock units, which is expected to be recognized over a weighted average period of ten months. Dividend equivalents units of 35,537 accrued on the restricted stock units during the year.

Performance Share Units

Changes in performance share units for the year ended December 31, 2016 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2016	403,961	$ 40.42		
Granted	319,718	$ 45.97		
Vested	301,554	$ 41.22		
Canceled/Forfeited	28,313	$ 42.04		
Non-vested as of December 31, 2016	**393,812**	**$ 44.20**	**1.6**	**$ 17,280,471**

The weighted average grant date fair value per share for performance share units during the years ended December 31, 2016, 2015 and 2014 was $45.97, $41.32 and $38.94 per share, respectively.

The total intrinsic value of performance share units vested during the years ended December 31, 2016, 2015 and 2014 was $17 million, $13 million and $6 million, respectively.

As of December 31, 2016, there was approximately $13 million of unrecognized compensation cost related to the performance share units, which is expected to be recognized over a weighted average period of one year. Dividend equivalents units of 36,856 accrued on the performance share units during the year.

Outside Directors

Under the Directors Equity Plan, annually, on the first business day of May, each non-employee member of the Board of Directors is awarded stock units based on the amount of annual compensation to be paid at the closing price of PSEG common stock on that date. Dividend equivalents are credited quarterly and distributions will commence upon the director leaving the Board as specified by him/her in accordance with the provisions of the Directors Equity Plan.

The fair value of these awards is recorded as compensation expense in the Consolidated Statements of Operations. Compensation expense for the plan for each of the years ended December 31, 2016, 2015 and 2014 was approximately $1 million.

Employee Stock Purchase Plan (ESPP)

PSEG maintains an ESPP for all eligible employees of PSEG and its subsidiaries. Under the ESPP, shares of PSEG common stock may be purchased at 95% of the fair market value for represented employees and 90% for non-represented employees through payroll deductions. Dividends will be reinvested for all employees at 95% of the fair market price unless the participant elects to receive a cash dividend. All employees are required to hold the shares purchased under the ESPP for at least three months from the purchase date. In any year, employees may purchase shares having a value not exceeding 10% of their base pay. Compensation expense recognized under this program was immaterial for the years ended December 31, 2016, 2015 and 2014.

During the years ended December 31, 2016, 2015 and 2014, employees purchased 262,763 shares, 250,499 shares and 207,248 shares at an average price of $40.70, $36.66 and $36.07 per share, respectively. As of December 31, 2016, 3.5 million shares were available for future issuance under this plan.

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Note 19. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated Total
		Millions		
Year Ended December 31, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 96	$ —	$ 96
Allowance for Funds Used During Construction	49	—	—	49
Solar Loan Interest	22	—	—	22
Other	12	6	6	24
Total Other Income	**$ 83**	**$ 102**	**$ 6**	**$ 191**
Year Ended December 31, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 138	$ —	$ 138
Allowance for Funds Used During Construction	48	—	—	48
Solar Loan Interest	23	—	—	23
Gain on Insurance Recovery	—	28	—	28
Other	8	3	6	17
Total Other Income	**$ 79**	**$ 169**	**$ 6**	**$ 254**
Year Ended December 31, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 219	$ —	$ 219
Allowance for Funds Used During Construction	31	—	—	31
Solar Loan Interest	24	—	—	24
Other	6	3	7	16
Total Other Income	**$ 61**	**$ 222**	**$ 7**	**$ 290**

Other Deductions	PSE&G	Power	Other (A)	Consolidated Total
		Millions		
Year Ended December 31, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 40	$ —	$ 40
Other	4	17	6	27
Total Other Deductions	**$ 4**	**$ 57**	**$ 6**	**$ 67**
Year Ended December 31, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 45	$ —	$ 45
Other	4	27	26	57
Total Other Deductions	**$ 4**	**$ 72**	**$ 26**	**$ 102**
Year Ended December 31, 2014				
NDT Fund Realized Losses and Expenses	$ —	$ 31	$ —	$ 31
Other	3	21	6	30
Total Other Deductions	**$ 3**	**$ 52**	**$ 6**	**$ 61**

(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

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Note 20. Income Taxes

A reconciliation of reported income tax expense for PSEG with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSEG	Years Ended December 31, 2016	2015	2014
		Millions	
Net Income	$ 887	$ 1,679	$ 1,518
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ (74)	$ 243	$ 335
State	61	85	58
Total Current	(13)	328	393
Deferred Expense:			
Federal	311	540	262
State	28	104	260
Total Deferred	339	644	522
Investment Tax Credit (ITC)	85	29	23
Total Income Taxes	**$ 411**	**$ 1,001**	**$ 938**
Pre-Tax Income	$ 1,298	$ 2,680	$ 2,456
Tax Computed at Statutory Rate @ 35%	$ 454	$ 938	$ 860
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	56	129	145
Uncertain Tax Positions	(31)	7	(9)
Manufacturing Deduction	(17)	(10)	(16)
NDT Fund	3	7	14
Plant-Related Items	(20)	(20)	(13)
Tax Credits	(25)	(13)	(14)
Audit Settlement	—	—	(12)
Nuclear Decommissioning Tax Carryback	—	(33)	—
Other	(9)	(4)	(17)
Sub-Total	(43)	63	78
Total Income Tax Provision	**$ 411**	**$ 1,001**	**$ 938**
Effective Income Tax Rate	31.7%	37.4%	38.2%

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The following is an analysis of deferred income taxes for PSEG:

PSEG	As of December 31, 2016	2015
	Millions	
Deferred Income Taxes		
Assets:		
Noncurrent		
OPEB	$ 283	$ 256
Related to Uncertain Tax Position	155	160
Securitization-Overcollection	—	27
Total Noncurrent Assets	$ 438	$ 443
Liabilities:		
Noncurrent:		
Plant-Related Items	$ 6,593	$ 6,174
New Jersey Corporate Business Tax	674	615
Leasing Activities	565	612
Pension Costs	197	218
AROs and NDT Fund	398	393
Taxes Recoverable Through Future Rate (net)	208	191
Other	212	244
Total Noncurrent Liabilities	$ 8,847	$ 8,447
Summary of Accumulated Deferred Income Taxes:		
Net Noncurrent Deferred Income Tax Liabilities	$ 8,409	$ 8,004
ITC	249	162
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 8,658**	**$ 8,166**

The deferred tax effect of certain assets and liabilities is presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals. Also, the deferred tax effect of AROs is presented net of the deferred tax effect of the associated funding of those obligations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for PSE&G with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSE&G	Years Ended December 31, 2016	2015	2014
		Millions	
Net Income	$ 889	$ 787	$ 725
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ (153)	$ 32	$ 124
State	10	52	16
Total Current	(143)	84	140
Deferred Expense:			
Federal	551	325	214
State	102	52	84
Total Deferred	653	377	298
ITC	5	9	11
Total Income Taxes	**$ 515**	**$ 470**	**$ 449**
Pre-Tax Income	$ 1,404	$ 1,257	$ 1,174
Tax Computed at Statutory Rate @ 35%	$ 491	$ 440	$ 411
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	72	67	65
Uncertain Tax Positions	(18)	(14)	—
Plant-Related Items	(20)	(20)	(13)
Tax Credits	(7)	(6)	(7)
Audit Settlement	—	—	1
Other	(3)	3	(8)
Sub-Total	24	30	38
Total Income Tax Provision	**$ 515**	**$ 470**	**$ 449**
Effective Income Tax Rate	36.7%	37.4%	38.2%

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The following is an analysis of deferred income taxes for PSE&G:

PSE&G	As of December 31, 2016	2015
	Millions	
Deferred Income Taxes		
Assets:		
Noncurrent:		
OPEB	$ 189	$ 164
Securitization-Overcollection	—	27
Total Noncurrent Assets	$ 189	$ 191
Liabilities:		
Noncurrent:		
Plant-Related Items	$ 4,983	$ 4,435
New Jersey Corporate Business Tax	385	312
Conservation Costs	33	40
Pension Costs	252	262
Taxes Recoverable Through Future Rate (net)	208	191
Other	118	54
Total Noncurrent Liabilities	$ 5,979	$ 5,294
Summary of Accumulated Deferred Income Taxes:		
Net Noncurrent Deferred Income Tax Liabilities	$ 5,790	$ 5,103
ITC	83	78
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 5,873**	**$ 5,181**

The deferred tax effect of certain assets and liabilities is presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for Power with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

Power	Years Ended December 31, 2016	2015	2014
		Millions	
Net Income	$ 18	$ 856	$ 760
Income Taxes:			
Operating Income:			
Current Expense:			
Federal	$ 107	$ 220	$ 231
State	40	30	39
Total Current	147	250	270
Deferred Expense:			
Federal	(222)	189	163
State	(68)	52	48
Total Deferred	(290)	241	211
ITC	82	20	10
Total Income Taxes	**$ (61)**	**$ 511**	**$ 491**
Pre-Tax Income	$ (43)	$ 1,367	$ 1,251
Tax Computed at Statutory Rate @ 35%	$ (15)	$ 478	$ 438
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	(18)	59	58
Manufacturing Deduction	(17)	(10)	(16)
NDT Fund	3	7	15
Tax Credits	(18)	(7)	(6)
Uncertain Tax Positions	9	22	(8)
Audit Settlement	—	—	(4)
Nuclear Decommissioning Tax Carryback	—	(33)	—
Other	(5)	(5)	14
Sub-Total	(46)	33	53
Total Income Tax Provision	**$ (61)**	**$ 511**	**$ 491**
Effective Income Tax Rate	141.9%	37.4%	39.2%

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The following is an analysis of deferred income taxes for Power:

Power	As of December 31, 2016	2015
	Millions	
Deferred Income Taxes		
Assets:		
Noncurrent:		
Pension Costs	$ 68	$ 56
Contractual Liabilities & Environmental Costs	18	18
Related to Uncertain Tax Positions	53	47
Other	76	—
Total Noncurrent Assets	$ 215	$ 121
Liabilities:		
Noncurrent:		
Plant-Related Items	$ 1,605	$ 1,736
New Jersey Corporate Business Tax	214	243
AROs and NDT Fund	400	395
Other	—	10
Total Noncurrent Liabilities	$ 2,219	$ 2,384
Summary of Accumulated Deferred Income Taxes:		
Net Noncurrent Deferred Income Tax Liabilities	$ 2,004	$ 2,263
ITC	166	84
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 2,170**	**$ 2,347**

In the above table, the deferred tax effect of asset retirement obligations is presented net of the deferred tax effect of the associated funding of those obligations.

PSEG, PSE&G and Power each provide deferred taxes at the enacted statutory tax rate for all temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities irrespective of the treatment for rate-making purposes. Management believes that it is probable that the accumulated tax benefits that previously have been treated as a flow-through item to PSE&G customers will be recovered from or refunded to PSE&G's customers in the future. These amounts were determined using the enacted federal income tax rate of 35% and state income tax rate of 9%. For additional information, see Note 6. Regulatory Assets and Liabilities.

In December 2014, the Tax Increase Prevention Act of 2014 was enacted, which extended the 50% bonus depreciation rules for qualified property that was placed into service before January 1, 2015 and for long production property that was placed into service in 2015.

In December 2015, Congress passed the Protecting Americans from Tax Hikes Act of 2015 (Tax Act). Among other provisions, the Tax Act includes an extension of the bonus depreciation rules and the 30% ITC for qualified property placed into service after 2016. Qualified property that is placed in service from January 1, 2015 through December 31, 2017 is eligible for 50% bonus depreciation. The rate is reduced to 40% and 30% for eligible property placed in service in 2018 and 2019, respectively. In addition, long production property placed in service in 2020 will also qualify for 30% bonus depreciation. The ITC rate has been extended through December 31, 2019 but is reduced to 26% and 22% for projects commenced in 2020 and 2021, respectively. The financial impact of the extensions of the ITC rate will depend upon future transactions.

These provisions have generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period. However, these tax benefits will have a negative impact on the rate base of several of PSE&G's programs.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSEG recorded the following amounts related to its unrecognized tax benefits, which were primarily comprised of amounts recorded for PSE&G, Power and Energy Holdings:

2016	PSEG	PSE&G	Power	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2016	$ 386	$ 181	$ 111	$ 93
Increases as a Result of Positions Taken in a Prior Period	12	3	6	2
Decreases as a Result of Positions Taken in a Prior Period	(62)	(23)	(1)	(38)
Increases as a Result of Positions Taken during the Current Period	19	6	12	—
Decreases as a Result of Positions Taken during the Current Period	—	—	—	—
Decreases as a Result of Settlements with Taxing Authorities	—	—	—	—
Decreases due to Lapses of Applicable Statute of Limitations	(27)	(27)	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2016	$ 328	$ 140	$ 128	$ 57
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(200)	(106)	(74)	(20)
Regulatory Asset—Unrecognized Tax Benefits	(31)	(31)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 97**	**$ 3**	**$ 54**	**$ 37**

2015	PSEG	PSE&G	Power	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2015	$ 332	$ 165	$ 70	$ 95
Increases as a Result of Positions Taken in a Prior Period	87	55	28	4
Decreases as a Result of Positions Taken in a Prior Period	(50)	(43)	(6)	(1)
Increases as a Result of Positions Taken during the Current Period	28	5	23	—
Decreases as a Result of Positions Taken during the Current Period	(1)	(1)	—	—
Decreases as a Result of Settlements with Taxing Authorities	(10)	—	(4)	(5)
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2015	$ 386	$ 181	$ 111	$ 93
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(264)	(162)	(68)	(34)
Regulatory Asset—Unrecognized Tax Benefits	(27)	(27)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 95**	**$ (8)**	**$ 43**	**$ 59**

2014	PSEG	PSE&G	Power	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2014	$ 478	$ 208	$ 156	$ 110
Increases as a Result of Positions Taken in a Prior Period	82	65	17	—
Decreases as a Result of Positions Taken in a Prior Period	(190)	(92)	(80)	(18)
Increases as a Result of Positions Taken during the Current Period	30	16	9	5
Decreases as a Result of Positions Taken during the Current Period	(8)	—	(8)	—
Decreases as a Result of Settlements with Taxing Authorities	(60)	(32)	(24)	(2)
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2014	$ 332	$ 165	$ 70	$ 95
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(225)	(138)	(52)	(35)
Regulatory Asset—Unrecognized Tax Benefits	(27)	(27)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 80**	**$ —**	**$ 18**	**$ 60**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSEG and its subsidiaries include accrued interest and penalties related to uncertain tax positions required to be recorded, as Income Tax Expense in the Consolidated Statements of Operations. Accumulated interest and penalties that are recorded on the Consolidated Balance Sheets on uncertain tax positions were as follows:

	Accumulated Interest and Penalties on Uncertain Tax Positions as of December 31,		
	2016	2015	2014
	Millions		
PSE&G	$ 22	$ 20	$ 15
Power	17	6	9
Energy Holdings	20	40	45
Total	**$ 59**	**$ 66**	**$ 69**

It is reasonably possible that total unrecognized tax benefits will significantly increase or decrease within the next twelve months due to either agreements with various taxing authorities upon audit, the expiration of the Statute of Limitations, or other pending tax matters. These potential increases or decreases are as follows:

Possible (Increase)/Decrease in Total Unrecognized Tax Benefits	Over the next 12 Months
	Millions
PSEG	$ 14
PSE&G	$ 3
Power	$ 7

A description of income tax years that remain subject to examination by material jurisdictions, where an examination has not already concluded are:

	PSEG	PSE&G	Power
United States			
Federal	2011-2015	N/A	N/A
New Jersey	2006-2015	2011-2015	N/A
Pennsylvania	2006-2015	2007-2015	N/A
Connecticut	2007-2015	N/A	N/A
Texas	2008-2015	N/A	N/A
California	2006-2015	N/A	N/A
New York	2014-2015	N/A	2014-2015

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Note 21. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss)			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2013	$ (2)	$ (238)	$ 145	$ (95)
Other Comprehensive Income before Reclassifications	7	(184)	42	(135)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	5	11	(69)	(53)
Net Current Period Other Comprehensive Income (Loss)	12	(173)	(27)	(188)
Balance as of December 31, 2014	**$ 10**	**$ (411)**	**$ 118**	**$ (283)**
Other Comprehensive Income before Reclassifications	2	(7)	(25)	(30)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(12)	32	(2)	18
Net Current Period Other Comprehensive Income (Loss)	(10)	25	(27)	(12)
Balance as of December 31, 2015	**$ —**	**$ (386)**	**$ 91**	**$ (295)**
Other Comprehensive Income before Reclassifications	2	(45)	40	(3)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	33	2	35
Net Current Period Other Comprehensive Income (Loss)	2	(12)	42	32
Balance as of December 31, 2016	**$ 2**	**$ (398)**	**$ 133**	**$ (263)**

Power	Other Comprehensive Income (Loss)			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2013	$ (1)	$ (204)	$ 142	$ (63)
Other Comprehensive Income before Reclassifications	7	(156)	39	(110)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	5	9	(69)	(55)
Net Current Period Other Comprehensive Income (Loss)	12	(147)	(30)	(165)
Balance as of December 31, 2014	**$ 11**	**$ (351)**	**$ 112**	**$ (228)**
Other Comprehensive Income before Reclassifications	1	(4)	(24)	(27)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(12)	28	(1)	15
Net Current Period Other Comprehensive Income (Loss)	(11)	24	(25)	(12)
Balance as of December 31, 2015	**$ —**	**$ (327)**	**$ 87**	**$ (240)**
Other Comprehensive Income before Reclassifications	—	(42)	39	(3)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	29	3	32
Net Current Period Other Comprehensive Income (Loss)	—	(13)	42	29
Balance as of December 31, 2016	**$ —**	**$ (340)**	**$ 129**	**$ (211)**

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PSEG

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement Year Ended December 31, 2014 Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ (9)	$ 4	$ (5)
Total Cash Flow Hedges		(9)	4	(5)
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	10	(4)	6
Amortization of Actuarial Loss	O&M Expense	(28)	11	(17)
Total Pension and OPEB Plans		(18)	7	(11)
Available-for-Sale Securities				
Realized Gains	Other Income	181	(89)	92
Realized Losses	Other Deductions	(26)	13	(13)
Other-Than-Temporary Impairments (OTTI)	OTTI	(20)	10	(10)
Total Available-for-Sale Securities		135	(66)	69
Total		**$ 108**	**$ (55)**	**$ 53**

Power

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement Year Ended December 31, 2014 Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ (9)	$ 4	$ (5)
Total Cash Flow Hedges		(9)	4	(5)
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	9	(4)	5
Amortization of Actuarial Loss	O&M Expense	(25)	11	(14)
Total Pension and OPEB Plans		(16)	7	(9)
Available-for-Sale Securities				
Realized Gains	Other Income	178	(87)	91
Realized Losses	Other Deductions	(24)	12	(12)
OTTI	OTTI	(20)	10	(10)
Total Available-for-Sale Securities		134	(65)	69
Total		**$ 109**	**$ (54)**	**$ 55**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 20	$ (8)	$ 12
Total Cash Flow Hedges		20	(8)	12
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	12	(3)	9
Amortization of Actuarial Loss	O&M Expense	(68)	27	(41)
Total Pension and OPEB Plans		(56)	24	(32)
Available-for-Sale Securities				
Realized Gains	Other Income	100	(52)	48
Realized Losses	Other Deductions	(39)	20	(19)
OTTI	OTTI	(53)	26	(27)
Total Available-for-Sale Securities		8	(6)	2
Total		**$ (28)**	**$ 10**	**$ (18)**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 20	$ (8)	$ 12
Total Cash Flow Hedges		20	(8)	12
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	11	(3)	8
Amortization of Actuarial Loss	O&M Expense	(60)	24	(36)
Total Pension and OPEB Plans		(49)	21	(28)
Available-for-Sale Securities				
Realized Gains	Other Income	98	(51)	47
Realized Losses	Other Deductions	(38)	19	(19)
OTTI	OTTI	(53)	26	(27)
Total Available-for-Sale Securities		7	(6)	1
Total		**$ (22)**	**$ 7**	**$ (15)**

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PSEG

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement — Year Ended December 31, 2016		
		Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 12	$ (5)	$ 7
Amortization of Actuarial Loss	O&M Expense	(68)	28	(40)
Total Pension and OPEB Plans		(56)	23	(33)
Available-for-Sale Securities				
Realized Gains	Other Income	59	(29)	30
Realized Losses	Other Deductions	(37)	19	(18)
OTTI	OTTI	(28)	14	(14)
Total Available-for-Sale Securities		(6)	4	(2)
Total		**$ (62)**	**$ 27**	**$ (35)**

Power

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement — Year Ended December 31, 2016		
		Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 11	$ (5)	$ 6
Amortization of Actuarial Loss	O&M Expense	(59)	24	(35)
Total Pension and OPEB Plans		(48)	19	(29)
Available-for-Sale Securities				
Realized Gains	Other Income	55	(28)	27
Realized Losses	Other Deductions	(33)	17	(16)
OTTI	OTTI	(28)	14	(14)
Total Available-for-Sale Securities		(6)	3	(3)
Total		**$ (54)**	**$ 22**	**$ (32)**

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Note 22. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Years Ended December 31,					
	2016		2015		2014	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator:						
(Millions)						
Net Income	**$ 887**	**$ 887**	**1,679**	**1,679**	**$ 1,518**	**$ 1,518**
EPS Denominator:						
(Millions)						
Weighted Average Common Shares Outstanding	505	505	505	505	506	506
Effect of Stock Based Compensation Awards	—	3	—	3	—	2
Total Shares	**505**	**508**	**505**	**508**	**506**	**508**
EPS:						
Net Income	**$ 1.76**	**$ 1.75**	**3.32**	**3.30**	**$ 3.00**	**$ 2.99**

There were approximately 0.4 million, 0.5 million and 0.4 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the years ended December 31, 2016, 2015 and 2014, respectively. No other stock options had an antidilutive effect for the years ended December 31, 2016, 2015 or 2014.

Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	**2016**	**2015**	**2014**
Per Share	$ 1.64	$ 1.56	$ 1.48
in Millions	$ 830	$ 789	$ 748

On February 21, 2017, PSEG's Board of Directors approved a $0.43 per share common stock dividend for the first quarter of 2017.

Note 23. Financial Information by Business Segment

Basis of Organization

PSEG's, PSE&G's and Power's operating segments were determined by management in accordance with GAAP. These segments were determined based on how management measures performance based on segment Net Income, as illustrated in the following table, and how resources are allocated to each business. PSEG's reportable segments are PSE&G and Power. PSE&G and Power each represent a single reportable segment and therefore no separate segment information is provided for these Registrants.

PSE&G

PSE&G earns revenues from its tariffs, under which it provides electric transmission and electric and gas distribution services to residential, commercial and industrial customers in New Jersey. The rates charged for electric transmission are regulated by FERC while the rates charged for electric and gas distribution are regulated by the BPU. Revenues are also earned from several

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other activities such as solar investments, sundry sales, the appliance service business, wholesale transmission services and other miscellaneous services.

Power

Power earns revenues by selling energy, capacity and ancillary services on a wholesale basis under contract to power marketers and to load serving entities and by bidding energy, capacity and ancillary services into the markets for these products. Power also enters into contracts for energy, capacity, FTRs, gas, emission allowances and other energy-related contracts to optimize the value of its portfolio of generating assets and its electric and gas supply obligations.

Other

This category includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Year Ended December 31, 2016					
Operating Revenues	$ 6,221	$ 4,023	$ 370	$ (1,553)	$ 9,061
Depreciation and Amortization	565	881	30	—	1,476
Operating Income (Loss)	1,614	13	(51)	—	1,576
Income from Equity Method Investments	—	11	—	—	11
Interest Income	24	4	4	(2)	30
Interest Expense	289	84	14	(2)	385
Income (Loss) before Income Taxes	1,404	(43)	(63)	—	1,298
Income Tax Expense (Benefit)	515	(61)	(43)	—	411
Net Income (Loss)	889	18	(20)	—	887
Gross Additions to Long-Lived Assets	$ 2,816	$ 1,343	$ 40	$ —	$ 4,199
As of December 31, 2016					
Total Assets	$ 26,288	$ 12,193	$ 2,373	$ (784)	$ 40,070
Investments in Equity Method Subsidiaries	$ —	$ 102	$ —	$ —	$ 102

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Year Ended December 31, 2015					
Operating Revenues	$ 6,636	$ 4,928	$ 462	$ (1,611)	$ 10,415
Depreciation and Amortization	892	291	31	—	1,214
Operating Income (Loss)	1,462	1,430	70	—	2,962
Income from Equity Method Investments	—	14	(2)	—	12
Interest Income	25	2	33	(29)	31
Interest Expense	280	121	21	(29)	393
Income (Loss) before Income Taxes	1,257	1,367	56	—	2,680
Income Tax Expense (Benefit)	470	511	20	—	1,001
Net Income (Loss)	787	856	36	—	1,679
Gross Additions to Long-Lived Assets	$ 2,692	$ 1,117	$ 54	$ —	$ 3,863
As of December 31, 2015					
Total Assets	$ 23,677	$ 12,250	$ 2,810	$ (1,202)	$ 37,535
Investments in Equity Method Subsidiaries	$ —	$ 119	$ —	$ —	$ 119

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	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Year Ended December 31, 2014					
Operating Revenues	$ 6,766	$ 5,434	$ 455	$ (1,769)	$ 10,886
Depreciation and Amortization	906	292	29	—	1,227
Operating Income (Loss)	1,393	1,209	21	—	2,623
Income from Equity Method Investments	—	14	(1)	—	13
Interest Income	26	1	25	(22)	30
Interest Expense	277	122	12	(22)	389
Income (Loss) before Income Taxes	1,174	1,251	31	—	2,456
Income Tax Expense (Benefit)	449	491	(2)	—	938
Net Income (Loss)	725	760	33	—	1,518
Gross Additions to Long-Lived Assets	$ 2,164	$ 626	$ 30	$ —	$ 2,820
As of December 31, 2014					
Total Assets	$ 22,186	$ 12,037	$ 2,799	$ (1,735)	$ 35,287
Investments in Equity Method Subsidiaries	$ —	$ 121	$ 2	$ —	$ 123

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations primarily relate to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 24. Related-Party Transactions.

Note 24. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

	Years Ended December 31,		
Related Party Transactions	**2016**	**2015**	**2014**
		Millions	
Billings from Affiliates:			
Net Billings from Power primarily through BGS and BGSS (A)	$ 1,587	$ 1,630	$ 1,771
Administrative Billings from Services (B)	312	274	248
Total Billings from Affiliates	**$ 1,899**	**$ 1,904**	**$ 2,019**

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Related Party Transactions	Years Ended December 31, 2016	2015
	Millions	
Receivables from PSEG (C)	**$ 76**	**$ 222**
Payable to Power (A)	$ 193	$ 212
Payable to Services (B)	67	80
Accounts Payable—Affiliated Companies	**$ 260**	**$ 292**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 130**	**$ 109**

Power

The financial statements for Power include transactions with related parties presented as follows:

Related Party Transactions	Years Ended December 31, 2016	2015	2014
		Millions	
Billings to Affiliates:			
Net Billings to PSE&G primarily through BGS and BGSS (A)	**$ 1,587**	**$ 1,630**	**$ 1,771**
Billings from Affiliates:			
Administrative Billings from Services (B)	**$ 179**	**$ 187**	**$ 165**

Related Party Transactions	Years Ended December 31, 2016	2015
	Millions	
Receivable from PSE&G (A)	$ 193	$ 212
Receivable from PSEG (C)	12	64
Accounts Receivable—Affiliated Companies	**$ 205**	**$ 276**
Payable to Services (B)	$ 25	$ 33
Accounts Payable—Affiliated Companies	**$ 25**	**$ 33**
Short-Term Loan due (to) from Affiliate (E)	**$ 87**	**$ 363**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 77**	**$ 35**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. In addition, Power and PSE&G provide certain technical services for each other generally at cost in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Consolidated Balance Sheets.

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(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

Note 25. Selected Quarterly Data (Unaudited)

The information shown in the following tables, in the opinion of PSEG, PSE&G and Power includes all adjustments, consisting only of normal recurring accruals, necessary to fairly present such amounts.

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31, (A)	
	2016	2015	2016	2015	2016	2015	2016	2015
PSEG Consolidated:	Millions, except per share data							
Operating Revenues	$ 2,616	$ 3,135	$ 1,905	$ 2,314	$ 2,450	$ 2,688	$ 2,090	$ 2,278
Operating Income	$ 827	$ 1,048	$ 347	$ 568	$ 577	$ 814	$ (175)	$ 532
Net Income (Loss)	$ 471	$ 586	$ 187	$ 345	$ 327	$ 439	$ (98)	$ 309
Earnings Per Share:								
Basic:								
Net Income (Loss)	$ 0.93	$ 1.16	$ 0.37	$ 0.68	$ 0.65	$ 0.87	$ (0.19)	$ 0.61
Diluted:								
Net Income (Loss)	$ 0.93	$ 1.15	$ 0.37	$ 0.68	$ 0.64	$ 0.87	$ (0.19)	$ 0.60
Weighted Average Common Shares Outstanding:								
Basic	505	506	505	506	505	505	505	505
Diluted	508	508	508	508	508	508	508	508

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2016	2015	2016	2015	2016	2015	2016	2015
PSE&G:	Millions							
Operating Revenues	$ 1,712	$ 2,002	$ 1,350	$ 1,466	$ 1,684	$ 1,766	$ 1,475	$ 1,402
Operating Income	$ 462	$ 451	$ 333	$ 320	$ 450	$ 404	$ 369	$ 287
Net Income	$ 262	$ 242	$ 179	$ 167	$ 255	$ 222	$ 193	$ 156

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31, (A)	
	2016	2015	2016	2015	2016	2015	2016	2015
Power:	Millions							
Operating Revenues	$ 1,313	$ 1,725	$ 714	$ 1,025	$ 1,075	$ 1,096	$ 921	$ 1,082
Operating Income (Loss)	$ 343	$ 584	$ (12)	$ 228	$ 238	$ 391	$ (556)	$ 227
Net Income (Loss)	$ 192	$ 335	$ (11)	$ 166	$ 139	$ 206	$ (302)	$ 149

(A) The decreases in Operating Income at PSEG consolidated and Power in the fourth quarter 2016 as compared to the same quarter in 2015 were primarily due to costs related to closing the coal/gas Hudson and Mercer units and higher MTM losses in 2016.

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Note 26. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries, as of December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2016					
Operating Revenues	$ —	$ 3,971	$ 173	$ (121)	$ 4,023
Operating Expenses	8	3,962	161	(121)	4,010
Operating Income (Loss)	(8)	9	12	—	13
Equity Earnings (Losses) of Subsidiaries	36	(3)	11	(33)	11
Other Income	71	120	—	(89)	102
Other Deductions	(18)	(39)	—	—	(57)
Other-Than-Temporary Impairments	—	(28)	—	—	(28)
Interest Expense	(115)	(40)	(18)	89	(84)
Income Tax Benefit (Expense)	52	(11)	20	—	61
Net Income (Loss)	**$ 18**	**$ 8**	**$ 25**	**$ (33)**	**$ 18**
Comprehensive Income (Loss)	**$ 47**	**$ 50**	**$ 25**	**$ (75)**	**$ 47**
As of December 31, 2016					
Current Assets	$ 4,412	$ 1,593	$ 152	$ (4,697)	$ 1,460
Property, Plant and Equipment, net	55	6,145	2,320	—	8,520
Investment in Subsidiaries	4,249	344	—	(4,593)	—
Noncurrent Assets	168	2,016	129	(100)	2,213
Total Assets	**$ 8,884**	**$ 10,098**	**$ 2,601**	**$ (9,390)**	**$ 12,193**
Current Liabilities	$ 171	$ 3,752	$ 1,454	$ (4,697)	$ 680
Noncurrent Liabilities	532	2,398	502	(100)	3,332
Long-Term Debt	2,382	—	—	—	2,382
Member's Equity	5,799	3,948	645	(4,593)	5,799
Total Liabilities and Member's Equity	**$ 8,884**	**$ 10,098**	**$ 2,601**	**$ (9,390)**	**$ 12,193**
Year Ended December 31, 2016					
Net Cash Provided By (Used In) Operating Activities	$ 97	$ 1,442	$ 323	$ (607)	$ 1,255
Net Cash Provided By (Used In) Investing Activities	$ 60	$ (707)	$ (789)	$ 289	$ (1,147)
Net Cash Provided By (Used In) Financing Activities	$ (157)	$ (736)	$ 466	$ 318	$ (109)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2015					
Operating Revenues	$ —	$ 4,883	$ 179	$ (134)	$ 4,928
Operating Expenses	12	3,451	169	(134)	3,498
Operating Income (Loss)	(12)	1,432	10	—	1,430
Equity Earnings (Losses) of Subsidiaries	906	(4)	14	(902)	14
Other Income	48	174	—	(53)	169
Other Deductions	(27)	(45)	—	—	(72)
Other-Than-Temporary Impairments	—	(53)	—	—	(53)
Interest Expense	(116)	(39)	(19)	53	(121)
Income Tax Benefit (Expense)	57	(574)	6	—	(511)
Net Income (Loss)	**$ 856**	**$ 891**	**$ 11**	**$ (902)**	**$ 856**
Comprehensive Income (Loss)	**$ 844**	**$ 855**	**$ 11**	**$ (866)**	**$ 844**
As of December 31, 2015					
Current Assets	$ 4,501	$ 1,912	$ 364	$ (4,828)	$ 1,949
Property, Plant and Equipment, net	83	6,502	1,542	—	8,127
Investment in Subsidiaries	4,501	346	—	(4,847)	—
Noncurrent Assets	155	1,959	136	(76)	2,174
Total Assets	**$ 9,240**	**$ 10,719**	**$ 2,042**	**$ (9,751)**	**$ 12,250**
Current Liabilities	$ 1,112	$ 3,866	$ 1,076	$ (4,828)	$ 1,226
Noncurrent Liabilities	442	2,597	375	(76)	3,338
Long-Term Debt	1,684	—	—	—	1,684
Member's Equity	6,002	4,256	591	(4,847)	6,002
Total Liabilities and Member's Equity	**$ 9,240**	**$ 10,719**	**$ 2,042**	**$ (9,751)**	**$ 12,250**
Year Ended December 31, 2015					
Net Cash Provided By (Used In) Operating Activities	$ 571	$ 2,089	$ 80	$ (1,034)	$ 1,706
Net Cash Provided By (Used In) Investing Activities	$ (366)	$ (1,519)	$ (430)	$ 1,314	$ (1,001)
Net Cash Provided By (Used In) Financing Activities	$ (205)	$ (571)	$ 354	$ (280)	$ (702)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2014					
Operating Revenues	$ —	$ 5,390	$ 153	$ (109)	$ 5,434
Operating Expenses	16	4,175	143	(109)	4,225
Operating Income (Loss)	(16)	1,215	10	—	1,209
Equity Earnings (Losses) of Subsidiaries	799	(5)	14	(794)	14
Other Income	34	222	—	(34)	222
Other Deductions	(20)	(32)	—	—	(52)
Other-Than-Temporary Impairments	—	(20)	—	—	(20)
Interest Expense	(102)	(35)	(19)	34	(122)
Income Tax Benefit (Expense)	65	(558)	2	—	(491)
Net Income (Loss)	**$ 760**	**$ 787**	**$ 7**	**$ (794)**	**$ 760**
Comprehensive Income (Loss)	**$ 595**	**$ 768**	**$ 7**	**$ (775)**	**$ 595**
Year Ended December 31, 2014					
Net Cash Provided By (Used In) Operating Activities	$ 577	$ 1,674	$ 76	$ (902)	$ 1,425
Net Cash Provided By (Used In) Investing Activities	$ 148	$ (856)	$ (42)	$ 226	$ (524)
Net Cash Provided By (Used In) Financing Activities	$ (724)	$ (818)	$ (32)	$ 676	$ (898)

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, PSE&G and Power

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of PSEG, PSE&G and Power. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of PSEG, PSE&G and Power have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, PSE&G and Power

We have conducted assessments of our internal control over financial reporting as of December 31, 2016, as required by Section 404 of the Sarbanes-Oxley Act, using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO." Managements' reports on PSEG's, PSE&G's and Power's internal control over financial reporting are included on pages 180, 181 and 182, respectively. The Independent Registered Public Accounting Firm's report with respect to the effectiveness of PSEG's internal control over financial reporting is included on page 183. Management has concluded that internal control over financial reporting is effective as of December 31, 2016.

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2016 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSEG

Management of Public Service Enterprise Group Incorporated (PSEG) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSEG's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSEG's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSEG are being made only in accordance with authorizations of PSEG's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSEG's assets that could have a material effect on the financial statements.

In connection with the preparation of PSEG's annual financial statements, management of PSEG has undertaken an assessment, which includes the design and operational effectiveness of PSEG's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSEG's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSEG's financial reporting and the preparation of its financial statements as of December 31, 2016 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2016.

PSEG's external auditors, Deloitte & Touche LLP, have audited PSEG's financial statements for the year ended December 31, 2016 included in this annual report on Form 10-K and, as part of that audit, have issued a report on the effectiveness of PSEG's internal control over financial reporting, a copy of which is included in this annual report on Form 10-K.

/s/ RALPH IZZO

Chief Executive Officer

/s/ DANIEL J. CREGG

Chief Financial Officer

February 27, 2017

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSE&G

Management of Public Service Electric and Gas Company (PSE&G) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSE&G's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSE&G's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSE&G are being made only in accordance with authorizations of PSE&G's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSE&G's assets that could have a material effect on the financial statements.

In connection with the preparation of PSE&G's annual financial statements, management of PSE&G has undertaken an assessment, which includes the design and operational effectiveness of PSE&G's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSE&G's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSE&G's financial reporting and the preparation of its financial statements as of December 31, 2016 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2016.

/s/ RALPH IZZO

Chief Executive Officer

/s/ DANIEL J. CREGG

Chief Financial Officer

February 27, 2017

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—Power

Management of PSEG Power LLC (Power) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

Power's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of Power's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of Power are being made only in accordance with authorizations of Power's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Power's assets that could have a material effect on the financial statements.

In connection with the preparation of Power's annual financial statements, management of Power has undertaken an assessment, which includes the design and operational effectiveness of Power's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that Power's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of Power's financial reporting and the preparation of its financial statements as of December 31, 2016 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2016.

/s/ RALPH IZZO

Chief Executive Officer

/s/ DANIEL J. CREGG

Chief Financial Officer

February 27, 2017

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Public Service Enterprise Group Incorporated
Newark, New Jersey

We have audited the internal control over financial reporting of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2016, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting - PSEG. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and consolidated financial statement schedule listed in the Index at Item 15 (B)(a) as of and for the year ended December 31, 2016 of the Company and our report dated February 27, 2017 expressed an unqualified opinion on those consolidated financial statements and the consolidated financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2017

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

PSEG

The information required by Item 10 of Form 10-K with respect to executive officers is set forth in Part I. Executive Officers of the Registrant (PSEG).

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Directors

PSEG

The information required by Item 10 of Form 10-K with respect to (i) present directors of PSEG who are nominees for election as directors at PSEG's 2017 Annual Meeting of Stockholders, (ii) the director nomination process, and (iii) the composition of the Audit Committee of the Board, is set forth under the headings "Nominees and Election-Board Composition and Individual Qualifications," "Nominees and Election-Nomination Process," and "Corporate Governance-Board Committee Responsibilities-Audit Committee," respectively, in PSEG's definitive Proxy Statement for such Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 14, 2017 and which information set forth under said heading is incorporated herein by this reference thereto.

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Code of Ethics

Our Standards of Integrity (Standards) is a code of ethics applicable to us and our subsidiaries. The Standards are an integral part of our business conduct compliance program and embody our commitment to conduct operations in accordance with the highest legal and ethical standards. The Standards apply to all of our directors and employees (including PSE&G's, Power's, Energy Holdings' and Services' respective principal executive officer, principal financial officer, principal accounting officer or Controller and persons performing similar functions). Each such person is responsible for understanding and complying with the Standards. The Standards are posted on our website, www.pseg.com/info/investors/governance/document.jsp. We will send you a copy on request.

The Standards establish a set of common expectations for behavior to which each employee must adhere in dealings with investors, customers, fellow employees, competitors, vendors, government officials, the media and all others who may associate their words and actions with us. The Standards have been developed to provide reasonable assurance that, in conducting our business, employees behave ethically and in accordance with the law and do not take advantage of investors, regulators or customers through manipulation, abuse of confidential information or misrepresentation of material facts.

We will post on our website, www.pseg.com/info/investors/governance/document.jsp:

- Any amendment (other than one that is technical, administrative or non-substantive) that we adopt to our Standards; and
- Any grant by us of a waiver from the Standards that applies to any director, principal executive officer, principal financial officer, principal accounting officer or Controller, or persons performing similar functions, for us or our direct subsidiaries noted above, and that relates to any element enumerated by the SEC.

In 2016, we did not grant any waivers to the Standards.

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Section 16(a) Beneficial Ownership Reporting Compliance

PSEG

The information required by Item 10 of Form 10-K with respect to compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth under the heading "Section 16(a) Beneficial Ownership Reporting Compliance," in PSEG's definitive Proxy Statement for the 2017 Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the SEC on or about March 14, 2017 and which information set forth under said heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

PSEG

The information required by Item 11 of Form 10-K is set forth in PSEG's definitive Proxy Statement for the 2017 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 14, 2017 and such information set forth under such heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDERS MATTERS

PSEG

The information required by Item 12 of Form 10-K with respect to directors, executive officers and certain beneficial owners is set forth under the heading "Security Ownership of Directors, Management and Certain Beneficial Owners" in PSEG's definitive Proxy Statement for the 2017 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 14, 2017 and such information set forth under such heading is incorporated herein by this reference thereto.

For information relating to securities authorized for issuance under equity compensation plans, see Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

PSEG

The information required by Item 13 of Form 10-K is set forth under the heading "Corporate Governance—Transactions with Related Persons" in PSEG's definitive Proxy Statement for the 2017 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 14, 2017 and such information set forth under such heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10K.

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ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 of Form 10-K is set forth under the heading "Fees Billed by Deloitte & Touche LLP for 2016 and 2015" in PSEG's definitive Proxy Statement for the 2017 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 14, 2017. Such information set forth under such heading is incorporated herein by this reference hereto.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(A) The following Financial Statements are filed as a part of this report:

a. Public Service Enterprise Group Incorporated's Consolidated Balance Sheets as of December 31, 2016 and 2015 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Stockholders' Equity for the three years ended December 31, 2016 on pages 78 through 83.

b. Public Service Electric and Gas Company's Consolidated Balance Sheets as of December 31, 2016 and 2015 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Common Stockholder's Equity for the three years ended December 31, 2016 on pages 84 through 89.

c. PSEG Power LLC's Consolidated Balance Sheets as of December 31, 2016 and 2015 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Capitalization and Member's Equity for the three years ended December 31, 2016 on pages 90 through 95.

(B) The following documents are filed as a part of this report:

a. PSEG's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2016 (page 192).

b. PSE&G's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2016 (page 192).

c. Power's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2016 (page 192).

Schedules other than those listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(C) The following documents are filed as part of this report:

LIST OF EXHIBITS:

a.	**PSEG:**
3a	Certificate of Incorporation Public Service Enterprise Group Incorporated[1]
3b	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 23, 1987[2]
3c	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 20, 2007[3]
3d	By-Laws of Public Service Enterprise Group Incorporated effective December 15, 2015[4]

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LIST OF EXHIBITS:

4a	Indenture between Public Service Enterprise Group Incorporated and First Union National Bank (U.S. Bank National Association, successor), as Trustee, dated January 1, 1998 providing for Deferrable Interest Subordinated Debentures in Series (relating to Quarterly Preferred Securities)(5)
4b	Indenture between Public Service Enterprise Group Incorporated and U.S. Bank National Association (as successor to First Union National Bank), as Trustee, dated November 1, 1998 providing for Senior Debt Securities(6)
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011(7)
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees as amended May 31, 2011(8)
10a(3)	Employment Agreement with William Levis dated December 8, 2006(9)
10a(4)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011(10)
10a(5)	Deferred Compensation Plan for Directors, amended July 19, 2011(11)
10a(6)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011(12)
10a(7)	1989 Long-Term Incentive Plan, as amended(13)
10a(8)	2001 Long-Term Incentive Plan(14)
10a(9)	Senior Management Incentive Compensation Plan(15)
10a(10)	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective February 20, 2017
10a(11)	Severance Agreement with Ralph Izzo dated December 16, 2008(16)
10a(12)	Stock Plan for Outside Directors, as amended(17)
10a(13)	Compensation Plan for Outside Directors(18)
10a(14)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013(19)
10a(15)	Form of Agreement for Advancement of Expenses with Outside Directors(20)
10a(16)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011(21)
10a(17)	Amendment to Employment Agreement with William Levis, dated September 19, 2011(22)
10a(18)	Agreement with Tamara L. Linde dated June 18, 2014(23)
10a(19)	Agreement with Daniel J. Cregg dated September 22, 2015(24)
10a(20)	Clawback Practice, effective December 15, 2015(25)
12	Computation of Ratios of Earnings to Fixed Charges
21	Subsidiaries of the Registrant
23	Consent of Independent Registered Public Accounting Firm
31	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934 (1934 Act)
31a	Certification by Daniel J. Cregg, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32a	Certification by Daniel J. Cregg, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
b.	**Power:**
3a	Certificate of Formation of PSEG Power LLC(26)
3b	PSEG Power LLC Limited Liability Company Agreement(27)
4a	Indenture dated April 16, 2001 between and among PSEG Power, PSEG Fossil, PSEG Nuclear, PSEG Energy Resources & Trade and The Bank of New York Mellon and form of Subsidiary Guaranty included therein(28)
4b	First Supplemental Indenture, supplemental to Exhibit 4a, dated as of March 13, 2002(29)
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011(7)

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LIST OF EXHIBITS:

10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees, as amended May 31, 2011[8]
10a(3)	Employment Agreement with William Levis dated December 8, 2006[9]
10a(4)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011[12]
10a(5)	1989 Long-Term Incentive Plan, as amended[13]
10a(6)	2001 Long-Term Incentive Plan[14]
10a(7)	Senior Management Incentive Compensation Plan[15]
10a(8)	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective February 20, 2017
10a(9)	Severance Agreement with Ralph Izzo dated December 16, 2008[16]
10a(10)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013[19]
10a(11)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011[21]
10a(12)	Amendment to Employment Agreement with William Levis, dated September 19, 2011[22]
10a(13)	Agreement with Tamara L. Linde dated June 18, 2014[23]
10a(14)	Agreement with Daniel J. Cregg dated September 22, 2015[24]
10a(15)	Clawback Practice, effective December 15, 2015[26]
12a	Computation of Ratio of Earnings to Fixed Charges
23a	Consent of Independent Registered Public Accounting Firm
31b	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31c	Certification by Daniel J. Cregg, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32b	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32c	Certification by Daniel J. Cregg, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
c.	**PSE&G**
3a(1)	Restated Certificate of Incorporation of PSE&G[30]
3a(2)	Certificate of Amendment of Certificate of Restated Certificate of Incorporation of PSE&G filed February 18, 1987 with the State of New Jersey adopting limitations of liability provisions in accordance with an amendment to New Jersey Business Corporation Act[31]
3a(3)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed June 17, 1992 with the State of New Jersey, establishing the 7.44% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock[32]
3a(4)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed March 11, 1993 with the State of New Jersey, establishing the 5.97% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock[33]
3a(5)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed January 27, 1994 with the State of New Jersey, establishing the 6.92% Cumulative Preferred Stock ($100 Par) and the 6.75% Cumulative Preferred Stock ($25 Par) as a series of Preferred Stock[34]
3b(1)	By-Laws of PSE&G as in effect April 17, 2007[35]
4a(1)	Indenture between PSE&G and Fidelity Union Trust Company (now, Wachovia Bank, National Association), as Trustee, dated August 1, 1924[36], securing First and Refunding Mortgage Bond and Supplemental Indentures between PSE&G and U.S. Bank National Association, successor, as Trustee, supplemental to Exhibit 4a(1), dated as follows:
4a(2)	June 1, 1937[37]
4a(3)	July 1, 1937[38]
4a(4)	March 1, 1942[39]
4a(5)	June 1, 1991 (No. 1)[40]

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LIST OF EXHIBITS:

4a(6)	July 1, 1993[41]
4a(7)	August 1, 2004 (No. 4)[42]
4a(8)	April 1, 2007[43]
4a(9)	May 1, 2012[44]
4a(10)	June 1, 2012[45]
4a(11)	May 1, 2013[46]
4a(12)	August 1, 2014[47]
4a(13)	May 1, 2015[48]
4a(14)	September 1, 2016
4b	Indenture of Trust between PSE&G and Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor), as Trustee, providing for Secured Medium-Term Notes dated July 1, 1993[49]
4c	Indenture dated as of December 1, 2000 between Public Service Electric and Gas Company and First Union National Bank (U.S. Bank National Association, successor), as Trustee, providing for Senior Debt Securities[50]
10a(1)	Supplemental Executive Retirement Income Plan, effective as of May 31, 2011[7]
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees as amended May 31, 2011[8]
10a(3)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011[10]
10a(4)	Deferred Compensation Plan for Directors, amended July 19, 2011[11]
10a(5)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011[12]
10a(6)	1989 Long-Term Incentive Plan, as amended[13]
10a(7)	2001 Long-Term Incentive Plan[14]
10a(8)	Senior Management Incentive Compensation Plan[15]
10a(9)	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective February 20, 2017
10a(10)	Severance Agreement with Ralph Izzo dated December 16, 2008[16]
10a(11)	Stock Plan for Outside Directors, as amended[17]
10a(12)	Compensation Plan for Outside Directors[18]
10a(13)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013[19]
10a(14)	Form of Agreement for Advancement of Expenses with Outside Directors[51]
10a(15)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011[21]
10a(16)	Agreement with Tamara L. Linde dated June 18, 2014[23]
10a(17)	Agreement with Daniel J. Cregg dated September 22, 2015[24]
10a(18)	Clawback Practice, effective December 15, 2015[25]
12b	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
23b	Consent of Independent Registered Public Accounting Firm
31d	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31e	Certification by Daniel J. Cregg, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32d	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32e	Certification by Daniel J. Cregg, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document

(1) Filed as Exhibit 3.1a with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120, on May 4, 2007 and incorporated herein by this reference.

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(2) Filed as Exhibit 3.1b with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120, on May 4, 2007 and incorporated herein by this reference.
(3) Filed as Exhibit 3.1c with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120, on May 4, 2007 and incorporated herein by this reference.
(4) Filed as Exhibit 99.1 with Current Report on Form 8-K, File No. 001-09120, on December 16, 2015 and incorporated herein by this reference.
(5) Filed as Exhibit 4(f) with Quarterly Report on Form 10-Q for the quarter ended March 31, 1998, File No. 001-09120, on May 13, 1998 and incorporated herein by this reference.
(6) Filed as Exhibit 4(f) to the Annual Report on Form 10-K for the year ended December 31, 1998, File No. 001-09120, on February 23, 1999 and incorporated herein by this reference
(7) Filed as Exhibit 10.1 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120, on November 1, 2011 and incorporated herein by this reference.
(8) Filed as Exhibit 10.2 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120, on November 1, 2011 and incorporated herein by this reference.
(9) Filed as Exhibit 10a (4) with Annual Report on Form 10-K for the year ended December 31, 2007, File Nos. 001-09120 on February 28, 2008 and 000-49614, and incorporated herein by reference.
(10) Filed as Exhibit 10.5 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120, on November 1, 2011 and incorporated herein by this reference.
(11) Filed as Exhibit 10.6 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120, on November 1, 2011 and incorporated herein by this reference.
(12) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the quarter ended December 31, 2011, File No. 001-09120, on February 27, 2012 and incorporated herein by this reference.
(13) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 001-09120, on November 4, 2002 and incorporated herein by this reference.
(14) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2000, File No. 001-09120, on March 6, 2001 and incorporated herein by this reference.
(15) Filed as Exhibit 10a(11) with Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-09120, on February 26, 2009 and incorporated herein by this reference.
(16) Filed as Exhibit 99 with Current Report on Form 8-K, File Nos. 001-09120, 000-49614 and 001-00973, on December 22, 2008 and incorporated herein by this reference.
(17) Filed as Exhibit 10a(17) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(18) Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(19) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, File No. 001-09120, on May 1, 2013 and incorporated herein by reference.
(20) Filed as Exhibit 10.1 with Current Report on Form 8-K, File No. 001-09120, on February 19, 2009 and incorporated herein by this reference.
(21) Filed as Exhibit 10a(19) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120, on February 27, 2012.
(22) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120, on November 1, 2011 and incorporated herein by reference.
(23) Filed as Exhibit 10a with Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-09120, on February 26, 2015.
(24) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, File No. 001-09120, on October 30, 2015.
(25) Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2015, File No. 001-09120, on February 26, 2016 and incorporated herein by this reference.
(26) Filed as Exhibit 3.1 to Registration Statement on Form S-4, No. 333-69228, filed on September 10, 2001 and incorporated herein by this reference.
(27) Filed as Exhibit 3.2 to Registration Statement on Form S-4, No. 333-69228, filed on September 10, 2001 and incorporated herein by this reference.
(28) Filed as Exhibit 4.1 to Registration Statement on Form S-4, No. 333-69228, filed on September 10, 2001 and incorporated herein by this reference.
(29) Filed as Exhibit 4.7 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, File No. 000-49614, on May 15, 2002 and incorporated herein by this reference.
(30) Filed as Exhibit 3(a) with Quarterly Report on Form 10-Q for the quarter ended June 30, 1986, File No. 001-00973, on August 28, 1986 and incorporated herein by this reference.

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(31) Filed as Exhibit 3a(2) with Annual Report on Form 10-K for the year ended December 31, 1987, File No. 001-00973, on March 28, 1988 and incorporated herein by this reference.
(32) Filed as Exhibit 3a(3) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(33) Filed as Exhibit 3a(4) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(34) Filed as Exhibit 3a(5) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(35) Filed as Exhibit 3.3 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-00973, on May 4, 2007 and incorporated herein by this reference.
(36) Filed as Exhibit 4b(1) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973, on February 18, 1981 and incorporated herein by this reference.
(37) Filed as Exhibit 4b(3) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973, on February 18, 1981 and incorporated herein by this reference.
(38) Filed as Exhibit 4b(4) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973, on February 18, 1981 and incorporated herein by this reference.
(39) Filed as Exhibit 4b(6) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973, on February 18, 1981 and incorporated herein by this reference.
(40) Filed as Exhibit 4 on Form 8-A, File No. 001-00973, on June 1, 1991 and incorporated herein by this reference.
(41) Filed as Exhibit 4(i) on Form 8-A, File No. 001-00973, on December 1, 1993 and incorporated herein by this reference.
(42) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973, on March 1, 2005 and incorporated herein by this reference.
(43) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-00973, on February 28, 2008 and incorporated herein by this reference.
(44) Filed as Exhibit 4a(32) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-00973, on February 26, 2013.
(45) Filed as Exhibit 4a(33) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-00973, on February 26, 2013.
(46) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, File No. 001-00973, on July 30, 2013.
(47) Filed as Exhibit 4a(22) with Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, File No. 001-09120, on October 30, 2014 and incorporated herein by reference.
(48) Filed as Exhibit 4a(23) with Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 001-09120, on July 31, 2015 and incorporated herein by reference.
(49) Filed as Exhibit 4 with Current Report on Form 8-K, File No. 001-00973, on December 1, 1993 and incorporated herein by reference.
(50) Filed as Exhibit 4.6 to Registration Statement on Form S-3, File No. 333-76020, filed on December 27, 2001 and incorporated herein by reference.
(51) Filed as Exhibit 10.2 with Current Report on Form 8-K, File No. 001-00973, on February 19, 2009 and incorporated herein by reference.

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Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2016—December 31, 2014

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2016						
Allowance for Doubtful Accounts	$ 67	$ 85	$ —	$ 84	(A)	$ 68
Materials and Supplies Valuation Reserve	11	32	—	6	(B)	37
2015						
Allowance for Doubtful Accounts	$ 52	$ 101	$ —	$ 86	(A)	$ 67
Materials and Supplies Valuation Reserve	15	2	—	6	(B)	11
2014						
Allowance for Doubtful Accounts	$ 56	$ 86	$ —	$ 90	(A)	$ 52
Materials and Supplies Valuation Reserve	8	9	—	2	(B)	15

(A) Accounts Receivable written off.
(B) Reduced reserve to appropriate level and to remove obsolete inventory.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2016						
Allowance for Doubtful Accounts	$ 67	$ 85	$ —	$ 84	(A)	$ 68
Materials and Supplies Valuation Reserve	1	—	—	1	(B)	—
2015						
Allowance for Doubtful Accounts	$ 52	$ 101	$ —	$ 86	(A)	$ 67
Materials and Supplies Valuation Reserve	2	—	—	1	(B)	1
2014						
Allowance for Doubtful Accounts	$ 56	$ 86	$ —	$ 90	(A)	$ 52
Materials and Supplies Valuation Reserve	—	2	—	—		2

(A) Accounts Receivable written off.
(B) Reduced reserve to appropriate level and to remove obsolete inventory.

PSEG POWER LLC

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2016						
Materials and Supplies Valuation Reserve	$ 10	$ 32	$ —	$ 5	(A)	$ 37
2015						
Materials and Supplies Valuation Reserve	$ 13	$ 2	$ —	$ 5	(A)	$ 10
2014						
Materials and Supplies Valuation Reserve	$ 8	$ 7	$ —	$ 2	(A)	$ 13

(A) Reduced reserve to appropriate level and to remove obsolete inventory.

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Term	Phrase/Description
Base load	Minimum amount of electric power delivered or required over a given period of time at a constant rate, this is the level of demand that is seen as a minimum during a 24-hour day
BGS	Basic Generation Service PSE&G is required to provide BGS for all customers in New Jersey who are not supplied by a third-party supplier.
BGS-RSCP	Basic Generation Service-Residential Small Commercial Product Seasonally adjusted fixed prices charged for a three-year term for electric supply service to smaller industrial and commercial customers and residential customers who are not supplied by a TPS
BGSS	Basic Gas Supply Service Mechanism approved by the BPU for NJ utilities to recover all commodity costs related to supplying gas to residential customers
BPU	New Jersey Board of Public Utilities Agency responsible for regulating public utilities doing business in New Jersey
Capacity	Amount of electricity that can be produced by a specific generating facility
Combined Cycle	A method of generation whereby electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity
Congestion	Condition when the available capacity of a transmission line is being closely approached (or exceeded) by the electric power trying to go through it; at such times, alternative power line pathways (or local generators near the load) must be used instead
Distribution	The delivery of electricity to the retail customer's home, business or industrial facility through low voltage distribution lines
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board A private, not-for-profit organization whose primary purpose, as designated by the SEC, is to develop accounting standards for public companies in the U.S.
FERC	U.S. Federal Energy Regulatory Commission
Forward contracts	A customized, non-exchange traded contract in which the buyer is obligated to deliver a specified amount of a commodity with a predetermined price formula on a specified future date, at which time payment is due in full
GAAP	Generally Accepted Accounting Principles Standard framework of guidelines issued by the FASB for financial accounting used in the U.S.
GHG	Greenhouse gas emissions (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon) that trap the heat of the sun in the Earth's atmosphere, increasing the mean global surface temperature of the earth
Hedging	Entering into a contract or transaction designed to reduce exposure to various risks, such as changes in market prices
ISO	Independent System Operator An independent, regulated entity established to manage a regional electric transmission system in a non-discriminatory manner and to help ensure the safety and reliability of the bulk of the power system
ITC	Investment Tax Credit A credit against income taxes, usually computed as a percent of the cost of investment in certain types of assets

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Term	Phrase/Description
Load	Amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of consumers.
MBR	Market Based Rates Electric service prices determined in an open market system of supply and demand under which the price is set solely by agreement as to what a buyer will pay and a seller will accept
MGP	Manufactured Gas Plant
ISO-NE	New England Power Pool An ISO comprised of an alliance of approximately 100 utility companies who manage and direct all major energy production and transmission in the New England states
NJDEP	New Jersey Department of Environmental Protection
NRC	U.S. Nuclear Regulatory Commission
NUG	Non-Utility Generation Power produced by independent power producers, exempt wholesale generators and other companies that have been exempted from traditional utility regulation
OPEB	Other Postretirement Benefits Benefits other than pensions payable to former employees
Outage	The period during which a generating unit, transmission line, or other facility is out of service due to scheduled (planned) or unscheduled maintenance
PJM	PJM Interconnection, L.L.C. A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 northeastern states and the District of Columbia
Power	PSEG Power LLC
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies
PSE&G	Public Service Electric and Gas Company
PSEG	Public Service Enterprise Group Incorporated
Renewable Energy	Energy derived from resources that are regenerative or that cannot be depleted (i.e. moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy)
Regulatory Asset	Costs deferred by a regulated utility company in accordance with Accounting Standard Codification Topic 980: Regulated operations (ASC 980)
Regulatory Liability	Costs recognized by a regulated utility company in accordance with ASC 980
RPM	Reliability Pricing Model (PJM market) A process for pricing generation capacity based on overall system reliability requirements; using multi-year forward auctions, participants could bid capacity in the form of generation, demand response, or transmission to meet reliability needs by location and/or an ISO market
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
Transmission	The high-voltage wires and networks that move electricity through states and regions in large quantities - from power plants where it is produced, to the distribution networks that deliver it to homes and businesses

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

By: /s/ RALPH IZZO

Ralph Izzo
Chairman of the Board, President and
Chief Executive Officer

Date: February 27, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	February 27, 2017
/s/ DANIEL J. CREGG **Daniel J. Cregg**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2017
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 27, 2017
/s/ WILLIE A. DEESE **Willie A. Deese**	Director	February 27, 2017
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper, Jr.**	Director	February 27, 2017
/s/ WILLIAM V. HICKEY **William V. Hickey**	Director	February 27, 2017
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 27, 2017
/s/ DAVID LILLEY **David Lilley**	Director	February 27, 2017
/s/ THOMAS A. RENYI **Thomas A. Renyi**	Director	February 27, 2017
/s/ HAK CHEOL SHIN **Hak Cheol Shin**	Director	February 27, 2017
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 27, 2017
/s/ SUSAN TOMASKY **Susan Tomasky**	Director	February 27, 2017
/s/ ALFRED W. ZOLLAR	Director	February 27, 2017

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By: /s/ RALPH LAROSSA
Ralph LaRossa
President and Chief Operating Officer

Date: February 27, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 27, 2017
/s/ DANIEL J. CREGG **Daniel J. Cregg**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2017
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 27, 2017
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper Jr.**	Director	February 27, 2017
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 27, 2017
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 27, 2017

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC

By: /s/ WILLIAM LEVIS
William Levis
President and
Chief Operating Officer

Date: February 27, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 27, 2017
/s/ DANIEL J. CREGG **Daniel J. Cregg**	Executive Vice President and Chief Financial Officer and Director (Principal Financial Officer)	February 27, 2017
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 27, 2017
/s/ DEREK M. DIRISIO **Derek M. DiRisio**	Director	February 27, 2017
/s/ WILLIAM LEVIS **William Levis**	Director	February 27, 2017
/s/ TAMARA L. LINDE **Tamara L. Linde**	Director	February 27, 2017
/s/ MARGARET M. PEGO **Margaret M. Pego**	Director	February 27, 2017

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EXHIBIT INDEX

The following documents are filed as a part of this report:

a. PSEG:	
Exhibit 10a(10)	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective February 20, 2017
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 21:	Subsidiaries of the Registrant
Exhibit 23:	Consent of Independent Registered Public Accounting Firm
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31a:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32a:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document
b. Power:	
Exhibit 10a(8)	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective February 20, 2017
Exhibit 12a:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 23a:	Consent of Independent Registered Public Accounting Firm
Exhibit 31b:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31c:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32b:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32c:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document
c. PSE&G:	
Exhibit 4a(14)	Supplemental Indenture dated September 1, 2016
Exhibit 10(a)9	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective February 20, 2017
Exhibit 12b:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
Exhibit 23b:	Consent of Independent Registered Public Accounting Firm
Exhibit 31d:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31e:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32d:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32e:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
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Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

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Exhibit 4a(14)

SUPPLEMENTAL MORTGAGE

Supplemental Indenture

Dated September 1, 2016

_____

SUPPLEMENTAL TO
FIRST AND REFUNDING MORTGAGE
DATED AUGUST 1, 1924

_____

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
TO
U.S. BANK NATIONAL ASSOCIATION
Trustee
21 South Street
Morristown, New Jersey 07960

_____

PROVIDING FOR THE ISSUE OF
$1,450,000,000 FIRST AND REFUNDING MORTGAGE BONDS,
MEDIUM-TERM NOTES SERIES L

RECORD IN MORTGAGE BOOK AND RETURN TO:
ANDREW J. WOODWORTH, ESQ.
80 PARK PLAZA, T5B
NEWARK, N.J. 07102-4194

Prepared by

/s/ Andrew J. Woodworth

(Andrew J. Woodworth, ESQ.)

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SUPPLEMENTAL INDENTURE, dated the 1st day of September 2016 for convenience of reference and effective from the time of execution and delivery hereof, between Public Service Electric and Gas Company, a corporation organized under the laws of the State of New Jersey, hereinafter called the "Company", party of the first part, and U.S. Bank National Association, a national banking association organized under the laws of the United States of America, as successor Trustee to Wachovia Bank, National Association (previously known as Fidelity Union Trust Company) under the indenture dated August 1, 1924, below mentioned, hereinafter called the "Trustee", party of the second part.

WHEREAS, on July 25, 1924, the Company executed and delivered to Fidelity Union Trust Company, a certain indenture dated August 1, 1924 (hereinafter called the "Indenture") to secure and to provide for the issue of First and Refunding Mortgage Gold Bonds of the Company; and

Whereas, the Indenture has been recorded in the following counties of the State of New Jersey, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Atlantic	Clerk's	1955 of Mortgages	160
Bergen	Clerk's	94 of Chattel Mortgages	123 etc.
		693 of Mortgages	88 etc.
Burlington	Clerk's	52 of Chattel Mortgages	Folio 8 etc.
		177 of Mortgages	Folio 354 etc.
Camden	Register's	45 of Chattel Mortgages	184 etc.
		239 of Mortgages	1 etc.
Cumberland	Clerk's	786 of Mortgages	638 & c.
Essex	Register's	437 of Chattel Mortgages	1-48
		T-51 of Mortgages	341-392
Gloucester	Clerk's	34 of Chattel Mortgages	123 etc.
		142 of Mortgages	7 etc.
Hudson	Register's	453 of Chattel Mortgages	9 etc.
		1245 of Mortgages	484, etc.
Hunterdon	Clerk's	151 of Mortgages	344
Mercer	Clerk's	67 of Chattel Mortgages	1 etc.
		384 of Mortgages	1 etc.
Middlesex	Clerk's	113 of Chattel Mortgages	3 etc.
		437 of Mortgages	294 etc.
Monmouth	Clerk's	951 of Mortgages	291 & c.
Morris	Clerk's	N-3 of Chattel Mortgages	446 etc.
		F-10 of Mortgages	269 etc.
Ocean	Clerk's	1809 of Mortgages	40
Passaic	Register's	M-6 of Chattel Mortgages	178, etc.
		R-13 of Mortgages	268 etc.
Salem	Clerk's	267 of Mortgages	249 etc.
Somerset	Clerk's	46 of Chattel Mortgages	207 etc.
		N-10 of Mortgages	1 etc.
Sussex	Clerk's	123 of Mortgages	10 & c.
Union	Register's	9584 of Mortgages	259 etc.
Warren	Clerk's	124 of Mortgages	141 etc.

and

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Whereas, the Indenture has also been recorded in the following counties of the Commonwealth of Pennsylvania, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Adams	Recorder's	22 of Mortgages	105
Armstrong	Recorder's	208 of Mortgages	381
Bedford	Recorder's	90 of Mortgages	917
Blair	Recorder's	671 of Mortgages	430
Cambria	Recorder's	407 of Mortgages	352
Cumberland	Recorder's	500 of Mortgages	136
Franklin	Recorder's	285 of Mortgages	373
Huntingdon	Recorder's	128 of Mortgages	47
Indiana	Recorder's	197 of Mortgages	281
Lancaster	Recorder's	984 of Mortgages	1
Montgomery	Recorder's	5053 of Mortgages	1221
Westmoreland	Recorder's	1281 of Mortgages	198
York	Recorder's	31-V of Mortgages	446

and

Whereas, the Indenture granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company, more fully set forth and described in the Indenture, then owned or which might thereafter be acquired by the Company; and

Whereas, the Company, by various supplemental indentures, supplemental to the Indenture, the last of which was dated May 1, 2015, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company acquired by it after the execution and delivery of the Indenture; and

Whereas, since the execution and delivery of said supplemental indenture dated May 1, 2015, the Company has acquired property which, in accordance with the provisions of the Indenture, is subject to the lien thereof and the Company desires to confirm such lien; and

Whereas, the Indenture has been amended or supplemented from time to time; and

Whereas, it is provided in the Indenture that no bonds other than those of the 5-1/2% Series due 1959 therein authorized may be issued thereunder unless a supplemental indenture providing for the issue of such additional bonds shall have been executed and delivered by the Company to the Trustee; and

Whereas, the Company is making provisions for the issuance and sale of its Secured Medium-Term Notes, Series L (the "Series L Notes"), to be issued under an Indenture of Trust (the "Note Indenture") dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as Trustee (the "Note Trustee"); and

Whereas, such Note Indenture provides, among other things, for the pledge and delivery by the Company of a series of First and Refunding Mortgage Bonds of the Company to evidence the Company's obligation to pay the principal and interest with respect to outstanding Series L Notes; and for such purpose and in order to service and secure payment of the principal and interest in respect of the Series L Notes, the Company desires to provide for the issue of $1,450,000,000 aggregate principal amount of bonds under the Indenture of a series to be designated as "First and Refunding Mortgage Bonds, Medium-Term Notes Series L" (hereinafter sometimes called "Bonds of the Medium-Term Notes Series L"); and

Whereas, the text of the Bonds of the Medium-Term Notes Series L and of the certificate of authentication to be borne by the Bonds of the Medium-Term Notes Series L shall be substantially of the following tenor:

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(Form of Bond)

This Bond is not transferable except as provided in the Indenture and in the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor trustee) as Trustee.

REGISTERED NUMBER	REGISTERED AMOUNT
R	$1,450,000,000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
First and Refunding Mortgage Bond,

Medium-Term Notes Series L

Public Service Electric and Gas Company (hereinafter called the "Company"), a corporation of the State of New Jersey, for value received, hereby promises to pay to The Bank of New York Mellon (as successor trustee to The Chase Manhattan Bank (National Association)), under the Indenture of Trust dated as of July 1, 1993 between the Company and such trustee, or registered assigns, on the surrender hereof, the principal sum of One Billion Four Hundred and Fifty Million Dollars, on September 1, 2051, and to pay interest thereon from the date hereof, at the rate of 10% per annum, and until payment of said principal sum, such interest to be payable March 1 and September 1 in each year; provided, however, that the Company shall receive certain credits against such obligations as set forth in the Supplemental Indenture dated September 1, 2016 referred to below.

Both the principal hereof and interest hereon shall be paid at the principal corporate trust office of U.S. Bank National Association in the City of Morristown, State of New Jersey, or (at the option of the registered owner) at the corporate trust office of any paying agent appointed by the Company, in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts; provided, however, that any such payments of principal and interest shall be subject to receipt of certain credits against such payment obligations as set forth in the Supplemental Indenture dated September 1, 2016 referred to below.

This Bond is one of the First and Refunding Mortgage Bonds of the Company issued and to be issued under and pursuant to, and all equally secured by, an indenture of mortgage or deed of trust dated August 1, 1924, as supplemented and amended by supplemental indentures thereto, including the Supplemental Indenture dated September 1, 2016, duly executed by the Company and U.S. Bank National Association as Trustee. This Bond is one of the Bonds of the Medium-Term Notes Series L, which series is limited to the aggregate principal amount of $1,450,000,000 and is issued pursuant to said Supplemental Indenture dated September 1, 2016. Reference is hereby made to said indenture and all supplements thereto for a specification of the principal amount of Bonds from time to time issuable thereunder, and for a description of the properties mortgaged and conveyed or assigned to said Trustee or its successors, the nature and extent of the security, and the rights of the holders of said Bonds and any coupons appurtenant thereto, and of the Trustee in respect of such security.

In and by said indenture, as amended and supplemented, it is provided that with the written approval of the Company and the Trustee, any of the provisions of said indenture may from time to time be eliminated or modified and other provisions may be added thereto provided the change does not alter the annual interest rate, redemption price or date, date of maturity or amount payable on maturity of any then outstanding Bond or conflict with the Trust Indenture Act of 1939 as then in effect, and provided the holders of 85% in principal amount of the Bonds secured by said indenture and then outstanding (including, if such change affects the Bonds of one or more series but less than all series then outstanding, a like percentage of the then outstanding Bonds of each series affected by such change, and excluding Bonds owned or controlled by the Company or by the parties owning at least 10% of the outstanding voting stock of the Company, as more fully specified in said indenture) consent in writing thereto, all as more fully set forth in said indenture, as amended and supplemented.

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First and Refunding Mortgage Bonds issuable under said indenture are issuable in series, and the Bonds of any series may be for varying principal amounts and in the form of coupon bonds and of registered bonds without coupons, and the Bonds of any one series may differ from the Bonds of any other series as to date, maturity, interest rate and otherwise, all as in said indenture provided and set forth. The Bonds of the Medium-Term Notes Series L, in which this Bond is included, are designated "First and Refunding Mortgage Bonds, Medium-Term Notes Series L".

In case of the happening of an event of default as specified in said indenture and said supplemental indenture dated March 1, 1942, the principal sum of the Bonds of this series may be declared or may become due and payable forthwith, in the manner and with the effect in said indenture provided.

The Bonds of this series are subject to redemption as provided in Article II of the Supplemental Indenture dated September 1, 2016.

This Bond is transferable, but only as provided in said indenture and the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as trustee, upon surrender hereof, by the registered owner in person or by attorney duly authorized in writing, at either of said offices where the principal hereof and interest hereon are payable; upon any such transfer a new fully registered Bond similar hereto will be issued to the transferee. This Bond may in like manner be exchanged for one or more new fully registered Bonds of the same series of other authorized denominations but of the same aggregate principal amount. No service charge shall be made for any such transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto. The Company and the Trustee hereunder and any paying agent may deem and treat the person in whose name this Bond is registered as the absolute owner hereof for the purpose of receiving payment of or on account of the principal hereof and the interest hereon and for all other purposes; and neither the Company nor the Trustee hereunder nor any paying agent shall be affected by any notice to the contrary.

The Bonds of this series are issuable only in fully registered form, in any denomination authorized by the Company.

No recourse under or upon any obligation, covenant or agreement contained in said indenture or in any indenture supplemental thereto, or in any Bond issued thereunder, or because of any indebtedness arising thereunder, shall be had against any incorporator, or against any past, present or future stockholder, officer, or director, as such, of the Company or of any successor corporation, either directly or through the Company or any successor corporation, under any rule of law, statute or constitutional provision or by the enforcement of any assessment or by any legal or equitable proceeding or otherwise, it being expressly agreed and understood that said indenture, any indenture supplemental thereto and the obligations issued thereunder, are solely corporate obligations, and that no personal liability whatever shall attach to, or be incurred by, such incorporators, stockholders, officers or directors, as such, of the Company, or of any successor corporation, or any of them, because of the incurring of the indebtedness thereby authorized, or under or by reason of any of the obligations, covenants or agreements contained in the indenture or in any indenture supplemental thereto or in any of the Bonds issued thereunder, or implied therefrom.

This Bond shall not be entitled to any security or benefit under said indenture, as amended and supplemented, and shall not become valid or obligatory for any purpose, until the certificate of authentication, hereon endorsed, shall have been signed by U.S. Bank National Association as Trustee, or by its successor in trust under said indenture.

[To be executed and attested under seal in accordance with the provisions of the Indenture.]

(Form of Certificate of Authentication)

Certificate of Authentication

[To be authenticated in accordance with the provisions of the Indenture.]

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Whereas, the execution and delivery of this supplemental indenture have been duly authorized by the Board of Directors of the Company; and

Whereas, the Company represents that all things necessary to make the bond of the series hereinafter described, when duly authenticated by the Trustee and issued by the Company, a valid and legal obligation of the Company, and to make this supplemental indenture a valid and binding agreement supplemental to the Indenture, have been done and performed:

Now, therefore, this supplemental indenture witnesseth that the Company, in consideration of the premises and the execution and delivery by the Trustee of this supplemental indenture, and in pursuance of the covenants and agreements contained in the Indenture and for other good and valuable consideration, the receipt of which is hereby acknowledged, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over, and by these presents does grant, bargain, sell, alien, remise, release, convey, confirm, assign, transfer and set over unto the Trustee, its successors and assigns, forever, all the right, title and interest of the Company in and to all property of every kind and description (except cash, accounts and bills receivable and all merchandise bought, sold or manufactured for sale in the ordinary course of the Company's business, stocks, bonds or other corporate obligations or securities, other than such as are described in Part V of the Granting Clauses of the Indenture, not acquired with the proceeds of bonds secured by the Indenture, and except as in the Indenture and herein otherwise expressly excluded) acquired by the Company since the execution and delivery of the supplemental indenture dated May 1, 2015, subsequent to the Indenture (except any such property duly released from, or disposed of, free from the lien of the Indenture, in accordance with the provisions thereof) and all such property which at any time hereafter may be acquired by the Company;

All of which property it is intended shall be included in and granted by this supplemental indenture and covered by the lien of the Indenture as heretofore and hereby amended and supplemented;

Under and subject to any encumbrances or mortgages existing on property acquired by the Company at the time of such acquisition and not heretofore discharged of record; and

Subject also, to the exceptions, reservations and provisions in the Indenture and in this supplemental indenture recited, and to the liens, reservations, exceptions, limitations, conditions and restrictions imposed by or contained in the several deeds, grants, franchises and contracts or other instruments through which the Company acquired or claims title to the aforesaid property; and Subject, also, to the existing leases, to liens on easements or rights of way, to liens for taxes, assessments and governmental charges not in default or the payment of which is deferred, pending appeal or other contest by legal proceedings, pursuant to Section 4 of Article Five of the Indenture, or the payment of which is deferred pending billing, transfer of title or final determination of amount, to easements for alleys, streets, highways, rights of way and railroads that may run across or encroach upon the said property, to joint pole and similar agreements, to undetermined liens and charges, if any, incidental to construction, and other encumbrances permitted by the Indenture as heretofore and hereby amended and supplemented;

To have and to hold the property hereby conveyed or assigned, or intended to be conveyed or assigned, unto the Trustee, its successor or successors and assigns, forever;

In trust, nevertheless, upon the terms, conditions and trusts set forth in the Indenture as heretofore and hereby amended and supplemented, to the end that the said property shall be subject to the lien of the Indenture as heretofore and hereby amended and supplemented, with the same force and effect as though said property had been included in the Granting Clauses of the Indenture at the time of the execution and delivery thereof;

And this supplemental indenture further witnesseth that for the considerations aforesaid, it is hereby covenanted between the Company and the Trustee as follows:

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ARTICLE I.

Bonds of the Medium-Term Notes Series L.

The series of bonds authorized by this supplemental indenture to be issued under and secured by the Indenture shall be designated "First and Refunding Mortgage Bonds, Medium-Term Notes Series L"; shall be limited to the aggregate principal amount of $1,450,000,000; shall be issued initially to the Note Trustee and shall mature and bear interest as set forth in the form of bond set forth herein; provided, however, that the Company shall receive certain credits against principal and interest as set forth in Section 3.01 hereof. The date of each Bond of the Medium-Term Notes Series L shall be the interest payment date next preceding the date of authentication, unless such date of authentication be an interest payment date, in which case the date shall be the date of authentication, or unless such date of authentication be prior to the first semi-annual interest payment date, in which case the date shall be September 1, 2016.

Bonds of the Medium-Term Notes Series L shall be issuable only in the form of fully registered bonds in any denomination authorized by the Company. Interest on the Bonds of the Medium-Term Notes Series L shall be payable semi-annually in arrears on March 1 and September 1 of each year, payable initially on March 1, 2017, subject to receipt of certain credits against principal and interest as set forth in Section 3.01 hereof and shall be payable as to both principal and interest in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts, at the principal corporate trust office of the Trustee, or at the corporate trust office of any paying agent appointed.

Bonds of the Medium-Term Notes Series L shall be transferable and exchangeable, but only as provided in the Indenture and the Note Indenture, upon surrender thereof for cancellation by the registered owner in person or by attorney duly authorized in writing at either of said offices. The Company hereby waives any right to make a charge for any transfer or exchange of Bonds of the Medium-Term Notes Series L, but the Company may require payment of a sum sufficient to cover any tax or any other governmental charge that may be imposed in relation thereto.

ARTICLE II.

Redemption of Bonds of Medium-Term Notes Series L.

Section 2.01. *Redemption-Redemption Price*. Bonds of the Medium-Term Notes Series L shall be subject to redemption prior to maturity under the conditions, and upon payment of the amounts as may be specified in the following conditions:

(a) at any time in whole or in part at the option of the Company upon receipt by the Trustee of written certification of the Company and of the Note Trustee that the principal amount of the Series L Notes then outstanding under the Note Indenture is not in excess of such principal amount of the Bonds of the Medium-Term Notes Series L as shall remain pledged to the Note Trustee after giving effect to such redemption; (b) at any time by the application of any proceeds of released property or other money held by the Trustee and which, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, are applied to the redemption of Bonds of the Medium-Term Notes Series L, upon payment of 100% of the principal amount thereof, together with interest accrued to the redemption date, provided that any such payment shall be subject to receipt by the Company of certain credits against such obligations as set forth in Section 3.01 hereof or (c) automatically upon failure to pay the principal of any Series L Notes then outstanding under the Note Indenture when due, on their stated maturity date or earlier redemption or repayment date, in a principal amount of Bonds of the Medium-Term Notes Series L equal to the principal amount of such Series L Notes, in each case, at a price equal to 100% of the principal amount thereof, together with accrued interest, if applicable.

Section 2.02. *Redemptions Pursuant to Section 4C of Article Eight of the Indenture*. If, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, any proceeds of released property or other money then held by the Trustee shall be applied to the redemption of the Bonds of the Medium-Term Notes Series L, the Trustee shall give at least 45 days prior written

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notice of such redemption to the Note Trustee whereupon on the date fixed for redemption such principal amount thereof as is equal to such proceeds shall be redeemed; provided that no such redemption shall be made unless the Trustee shall be in receipt of a written certification of the Company and the Note Trustee that a like principal amount of Series L Notes shall have been theretofore redeemed in accordance with the provisions of the Note Indenture. For purposes of determining which of the Company's First and Refunding Mortgage Bonds are subject to such mandatory redemption, the Mortgage Trustee shall consider the 10% stated annual interest rate of the Bonds of the Medium-Term Notes Series L, not the weighted average interest rate of outstanding Series L Notes. Bonds of said series so redeemed shall be cancelled.

Section 2.03. *Interest on Called Bonds to Cease.* Each Bond of the Medium-Term Notes Series L or portion thereof called for redemption under Section 2.02 hereof shall be due and payable at the office of the Note Trustee, as paying agent hereunder, at its redemption price and on the specified redemption date, anything herein or in such Bond to the contrary notwithstanding. From and after the date when each Bond of the Medium-Term Notes Series L or portion thereof shall be due and payable as aforesaid (unless upon said date the full amount due thereon shall not be held by the Note Trustee, as paying agent hereunder, and be immediately available for payment), all further interest shall cease to accrue on such bond or on such portion thereof, as the case may be.

Section 2.04. *Bonds Called in Part.* If only a portion of any Bond of the Medium-Term Notes Series L shall be called for redemption pursuant to Section 2.02 hereof, upon payment of the portion so called for redemption, the Note Trustee shall make an appropriate notation upon the Bond of the principal amount so redeemed.

Section 2.05. *Provisions of Indenture Not Applicable*. The provisions of Article Four of the Indenture, as amended and supplemented, shall not apply to the procedure for the exercise of any right of redemption reserved by the Company, or to any mandatory redemption provided, in this Article in respect of the Bonds of the Medium-Term Notes Series L. There shall be no sinking fund for the Bonds of the Medium-Term Notes Series L.

ARTICLE III.

Credits with Respect to Bonds of the Medium-Term Notes Series L.

Section 3.01. *Credits.* In addition to any other credit, payment or satisfaction to which the Company is entitled with respect to the Bonds of the Medium-Term Notes Series L, the Company shall be entitled to credits against amounts otherwise payable in respect of the Bonds of the Medium-Term Notes Series L in an amount corresponding to (i) the principal amount of any of the Company's Series L Notes issued under the Note Indenture surrendered to the Note Trustee by the Company, or purchased by the Note Trustee, for cancellation, (ii) the amount of money held by the Note Trustee and available and designated for the payment of principal or redemption price (exclusive of any premium) of, and/or interest on, the Series L Notes, regardless of the source of payment to the Note Trustee of such moneys and (iii) the amount by which principal of and interest due on the Bonds of the Medium-Term Notes Series L exceeds principal of and interest due on the Series L Notes. The Note Trustee shall make notation on such Bonds authorized hereby of any such credit.

Section 3.02. *Certificate of the Company*. A certificate of the Company signed by the President or any Vice President, and attested to by the Secretary or any Assistant Secretary, and consented to by the Note Trustee, stating that the Company is entitled to a credit under Section 3.01 hereof or that Bonds of the Medium-Term Notes Series L have been cancelled, and setting forth the basis therefor in reasonable detail, shall be conclusive evidence of such entitlement, and the Trustee shall accept such certificate as such evidence without further investigation or verification of the matters stated therein.

ARTICLE IV.

Miscellaneous.

Section 4.01. *Authentication of Bonds of Medium-Term Notes Series L.* None of the Bonds of the Medium-Term Notes Series L, the issue of which is provided for by this supplemental indenture, shall be authenticated by or on behalf of the Trustee except in accordance with the provisions of the Indenture, as amended and supplemented, and this supplemental indenture, and upon compliance with the conditions in that behalf therein contained.

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Section 4.02. *Additional Restrictions on Authentication of Additional Bonds Under Indenture.* The Company covenants that from and after the date of execution of this supplemental indenture no additional bonds (as defined in Section 1 of Article Two of the Indenture) shall be authenticated and delivered by the Trustee under Subdivision A of Section 4 of said Article Two on account of additions or improvements to the mortgaged property;

(1) unless the net earnings of the Company for the period required by Subdivision C of Section 6 of said Article Two shall have been at least twice the fixed charges (in lieu of 1-3/4 times such fixed charges, as required by said Subdivision C); and for the purpose of this condition (a) such fixed charges shall in each case include interest on the bonds applied for, notwithstanding the parenthetical provision contained in clause (4) of said Subdivision C, and (b) in computing such net earnings there shall be included in expenses of operation (under paragraph (c) of said Subdivision C) all charges against earnings for depreciation, renewals or replacements, and all certificates with respect to net earnings delivered to the Trustee in connection with any authentication of additional bonds under said Article Two shall so state; and (2) except to the extent of 60% (in lieu of 75% as permitted by Subdivision A of Section 7 of said Article Two) of the cost or fair value to the Company of the additions or improvements forming the basis for such authentication of additional bonds.

Section 4.03. *Restriction on Dividends.* The Company will not declare or pay any dividend on any shares of its common stock (other than dividends payable in shares of its common stock) or make any other distribution on any such shares, or purchase or otherwise acquire any such shares (except shares acquired without cost to the Company) whenever such action would reduce the earned surplus of the Company to an amount less than $10,000,000 or such lesser amount as may remain after deducting from said $10,000,000 all amounts appearing in the books of account of the Company on December 31, 1948, which shall thereafter, pursuant to any order or rule of any regulatory body entered after said date, be required to be removed, in whole or in part, from the books of account of the Company by charges to earned surplus.

Section 4.04. *Use of Facsimile Seal and Signatures.* The seal of the Company and any or all signatures of the officers of the Company upon any of the Bonds of the Medium-Term Notes Series L may be facsimiles.

Section 4.05. *Time for Making of Payment.* All payments of principal or redemption price of, and interest on, the Bonds of the Medium-Term Notes Series L shall be made either prior to the due date thereof or on the due date thereof in immediately available funds. In any case where the date of any such payment shall be a Saturday or Sunday or a legal holiday or a day on which banking institutions in the city of payment are authorized by law to close, then such payment need not be made on such date but may be made on the next succeeding business day with the same force and effect as if made on the due date, and no interest on such payment shall accrue for the period after such date.

Section 4.06. *Effective Period of Supplemental Indenture.* The preceding provisions of Articles I, II and III of this supplemental indenture shall remain in effect only so long as any of the Bonds of the Medium-Term Notes Series L shall remain outstanding.

Section 4.07. *Effect of Approval of Board of Public Utilities of the State of New Jersey.* The approval of the Board of Public Utilities of the State of New Jersey of the execution and delivery of these presents and of the issue of any Bond of the Medium-Term Notes Series L shall not be construed as approval of said Board of any other act, matter or thing which requires approval of said Board under the laws of the State of New Jersey.

Section 4.08. *Execution in Counterparts.* For the purpose of facilitating the recording hereof, this supplemental indenture has been executed in several counterparts, each of which shall be and shall be taken to be an original, and all collectively but one instrument.

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In witness whereof, Public Service Electric and Gas Company, party hereto of the first part, after due corporate and other proceedings, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents and its corporate seal hereunto to be affixed and to be attested by the signature of its Secretary or an Assistant Secretary; and U.S. Bank National Association, as Trustee, party hereto of the second part, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents, and its corporate seal to be hereunto affixed and to be attested by the signature of its Secretary, Assistant Secretary, Vice President, or an Assistant Vice President. Executed and delivered this 1st day of September 2016.

Attest:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By /s/ Bradford D. Huntington
. . . . . .
B.D. Huntington
Vice President

Attest:
/s/ Michael K. Hyun
. . . . . .
Michael K. Hyun
Secretary

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U.S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes
. . . . . .
N. Barnes
Vice President

Attest:
/s/ A. Harris
. . . . . .
A. Harris
Vice President

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STATE OF NEW JERSEY)
SS:)
COUNTY OF ESSEX)

Be it Remembered, that on this 1st day of September, 2016, before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared B.D. Huntington, who, I am satisfied, is a Vice President of Public Service Electric and Gas Company, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors, and that said corporation, the mortgagor, has received a true copy of said instrument.

/s/ Jeanette M. Scott
. . . . . .
Jeanette M. Scott
Notary Public of New Jersey
My Commission Expires December 17, 2017

STATE OF NEW JERSEY)
SS:)
COUNTY OF ESSEX)

Be it Remembered, that on this 1st day of September 2016 before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared N. Barnes, who, I am satisfied, is a Vice President of U.S. Bank National Association, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, and that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors.

/s/ Mary Ryan
.....
Mary Ryan
Notary Public of New Jersey
My Commission Expires July 14, 2021

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CERTIFICATE OF RESIDENCE

U.S. Bank National Association, Mortgagee and Trustee within named, hereby certifies that its precise residence is 21 South Street, Morristown, New Jersey 07960.

U.S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes
. . . . . .
N. Barnes
Vice President

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PSEG Exhibit 10a(10)
PSE&G Exhibit 10a(9)
Power Exhibit 10a(8)

KEY EXECUTIVE SEVERANCE PLAN OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Amended effective February 20, 2017

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ARTICLE I

PURPOSE OF THE PLAN

1.1 Purpose. The Key Executive Severance Plan of Public Service Enterprise Group Incorporated ("Plan") is maintained by the Company to provide severance benefits to certain key executive-level employees of the Company and its affiliates whose employment is terminated under the circumstances described herein. The Plan was amended and restated effective December 17, 2012.

The Plan was amended effective January 1, 2014 to provide that (i) for Eligible Employees who become Schedule B Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to two times Annual Base Salary and Target Bonus, and (ii) for Eligible Employees who become Schedule A Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to 1.5 times Annual Base Salary and Target Bonus. The Plan was further amended to provide that the for purposes of determining the nonqualified plan change in control benefit under Section 5.5(a) of the Plan, with respect to Eligible Employees who become Schedule A or Schedule B Participants after December 31, 2013, their employment shall be assumed to have continued for 1.5 or 2 additional years (for Schedule A Participants and Schedule B Participants, respectively). Finally, the Plan was amended to update the Schedule A Participant list.

The Plan was amended effective June 16, 2014 to (i) add a new class of eligible Participants, Schedule C Participants, (ii) to provide that there will be no additions to Schedule B Participants, (iii) to provide that other than a current Schedule B Participant, an Eligible Employee newly hired or promoted into a position reflected on Schedule B as of June 16, 2014, shall become a Schedule A Participant, and (iv) to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

The Plan was amended effective July 14, 2014 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan was amended effective February 17, 2015 to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

The Plan was amended effective November 18, 2015 to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list, and to include the language to comply with the Securities and Exchange Commission's whistleblower protections.

The Plan was amended effective December 15, 2015 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan was amended effective July 19, 2016 to update the Schedule A Participant list and the Schedule C Participant list. The Plan was amended to comply with the Defense of Trade Secrets Act regarding the confidentiality provision. Finally, the Plan was amended

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to clarify that if an Eligible Employee is newly hired or promoted into a position reflected on Schedule B as of June 6, 2014, such Eligible Employee shall become a Schedule A Participant.

The Plan was amended effective November 14, 2016 to (i) revise the definition of Cause, (ii) align the severance benefits in Article IV, (iii) align the Change in Control benefits in Article V, (iv) update the Schedule A Participant list and the Schedule C Participant list, and (v) to make administrative clarifications. The Plan is intended to comply in operation and form with Section 409A of the Internal Revenue Code of 1986, as amended ("Code"). The timing and form of payment of benefits provided under the Plan will be deemed to be automatically modified, and a Participant's rights under the Plan will be limited so as to conform to any requirements under Section 409A of the Code.

The Plan is being amended effective February 20, 2017 to update the Schedule A Participant list.

ARTICLE II

DEFINITIONS

2.1 "Accrued Obligation" shall have the meaning set forth in Sections 4.2 and 5.2 of the Plan.

2.2 "Affiliate" means any corporation, trade or business if it or the Company are members of a controlled group of corporations, are under common control or are members of an affiliated service group within the meanings of Sections 414(b), 414(c) and 414(m), respectively, of the Code. The term "Affiliate" shall also include any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code.

2.3 "Annual Base Salary" means the annual rate of base salary payable to a Participant for services performed for an Employer, as in effect immediately prior to the Participant's Date of Termination.

2.4 "Benefits 2000 Participant" means a Participant who is a participant in the Public Service Enterprise Group Incorporated Benefits 2000 Health and Welfare Benefits Plan.

2.5 "Board" means the board of directors of the Company.

2.6 "Cause" means:

(a) For purposes of Article IV and Article V:

(i) Misconduct, gross negligence, theft, or fraud against the Company, including an isolated incident that is determined by the Committee's delegate to be material misconduct or material gross negligence;

(ii) For "Performance Reasons," as defined in Section 2.20 of the Plan;

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(iii) Material violation of the Standards of Integrity or other Company policy;

(iv) Insubordination, including an isolated incident that is determined by the Committee's delegate to be material insubordination;

(v) One or more significant acts of dishonesty;

(vi) Any act that is likely to have the effect of injuring the reputation, business, or business relationship of, the Company, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries;

(vii) Violation of any fiduciary duty, including an isolated incident that is determined by the Committee's delegate to be a material violation;

(viii) Breach of any duty of loyalty including an isolated incident that is determined by the Committee's delegate to be a material breach;

(ix) Any breach of the restrictive covenants contained in Exhibit I below;

(x) One or more acts of moral turpitude that constitute a violation of applicable law (included but not limited to a felony);

(xi) Conviction of a felony or plea of *nolo contendere* to a felony charge;

(xii) Pattern of behaviors that fail to meet the Company's expectations described in "PSEG Values, Behaviors, and Leadership Competencies." or

(xiii) Any other reason determined to be Cause by the Chief Executive Officer of the Company.

2.7 "Change in Control" means the occurrence of any of the following events:

(a) Any "person" (within the meaning of Section 13(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) is or becomes the beneficial owner within the meaning of Rule 13d-3 under the Exchange Act (a "Beneficial Owner"), directly or indirectly, of securities of the Company (not including in the securities beneficially owned by such person any securities acquired directly from the Company or its Affiliates) representing 25% or more of the combined voting power of the Company's then outstanding securities, excluding any person who becomes such a Beneficial Owner in connection with a transaction described in clause (i) of paragraph (c) below; or

(b) The following individuals cease for any reason to constitute a majority of the number of directors of the Company then serving: individuals who, on the Effective Date, constitute the Board and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's stockholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on the Effective Date or whose appointment, election or nomination for election was previously so approved or recommended; or

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(c) There is consummated a merger or consolidation of the Company or any direct or indirect wholly-owned subsidiary of the Company with any other corporation, other than (i) a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of the Company or of its Affiliates, at least 75% of the combined voting power of the securities of the Company or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (ii) a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the Beneficial Owner, directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company's then outstanding securities; or

(d) The shareholders of the Company approve a plan of complete liquidation or dissolution of the Company or there is consummated an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 75% of the combined voting power of the voting securities of which are owned by stockholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale.

Notwithstanding the foregoing, a "Change in Control" shall not be deemed to have occurred by virtue of the consummation of any transaction or series of integrated transactions immediately following which the record holders of the common stock of the Company immediately prior to such transaction or series of transactions continue to have substantially the same proportionate ownership in an entity which owns all or substantially all of the assets of the Company immediately following such transaction or series of transactions.

2.8 "Code" means the Internal Revenue Code of 1986, as amended, and the regulations promulgated thereunder.

2.9 "Committee" means the Organization and Compensation Committee of the Board or any successor of such Committee.

2.10 "Company" means Public Service Enterprise Group Incorporated and any successors thereto.

2.11 "Confidential Information" means all trade secrets, proprietary and confidential business information belonging to, used by, or in the possession of the Company or any of its Affiliates, including but not limited to information, knowledge or data related to business strategies, plans and financial information, mergers, acquisitions or consolidations, purchase or sale of property, leasing, pricing, sales programs or tactics, actual or past sellers, purchasers, lessees, lessors or customers, those with whom the Company or its

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Affiliates has begun negotiations for new business, costs, employee compensation, marketing and development plans, inventions and technology, whether such confidential information, knowledge or data is oral, written or electronically recorded or stored, except information in the public domain, information known by the Participant prior to employment with an Employer, and information received by the Participant from sources other than the Company or its Affiliates, without obligation of confidentiality.

2.12 "Date of Termination" means, provided that the termination constitutes a Separation from Service, (i) the date of a Participant's death, (ii) the date on which the termination of the Participant's employment by an Employer for Cause or without Cause, or (iii) the date on which the Participant terminates employment for Good Reason or without Good Reason, including Retirement and Disability.

2.13 "Disability" means (a) if the Participant is a participant in the Pension Plan, the Participant is determined to be totally and permanently disabled by the Company's medical director; or (ii) if the Participant is a participant in the Cash Balance Plan, the Participant is receiving benefits from the Company's long-term disability plan.

2.14 "Eligible Employee" means an individual who is designated as such in accordance with Section 3.1. An Eligible Employee shall not include a "project employee."

2.15 "Effective Date" of the amendment and restatement is February 20, 2017.

2.16 "Employer" means the Company and each Affiliate, and any successors thereto.

2.17 "Good Reason" means:

(a) Any material reduction in the Participant's Annual Base Salary, Target Bonus or Target Long-Term Incentive, other than reductions pursuant to a broad-based compensation reduction program or policy affecting the Participant and all similarly situated employees of the Employer. Notwithstanding the foregoing, this Subsection (a) shall not apply if the Participant moves into a position with ER&T;

(b) Any material adverse change in the Participant's title, authority, duties, or responsibilities or the assignment to the Participant of any duties or responsibilities inconsistent in any respect with those customarily associated with the position of the Participant immediately prior to the Change in Control. Notwithstanding the foregoing, this Subsection (b) shall not apply if the Participant moves into a position with ER&T;

(c) The failure of any successor to the Company to assume this Plan in accordance with Section 11.5(b);

(d) Where the only comparable position offered to the Participant within the Employer following a Change in Control would otherwise meet the requirements of Subsections (a) and (b) of this Section 2.17 of the Plan, but would require the Participant to increase their one-way commuting distance from their principal residence by more than 50 miles; or

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(e) Any other material breach of the terms of the Plan by the Company that either is not taken in good faith or, even if taken in good faith, is not remedied by the Company promptly after receipt of notice thereof from the Participant.

Notwithstanding the forgoing, for purposes of the Plan, the termination of a Participant's employment with an Employer shall not be deemed to be for Good Reason unless such termination is effected in accordance with the following procedures. The Participant shall give the Employer a written notice ("Notice of Termination for Good Reason") of the termination, setting forth in reasonable detail the specific acts or omissions of the Employer that constitute Good Reason and the specific provision(s) of the Plan on which the Participant relies. Unless the Committee determines otherwise, a Notice of Termination for Good Reason by the Participant must be made within 60 days after the Participant first has actual knowledge of the act or omission (or the last in a series of acts or omissions) that the Participant alleges to constitute Good Reason, and the Employer shall have 30 days from the receipt of such Notice of Termination for Good Reason to cure the conduct cited therein. A termination of employment by the Participant for Good Reason shall be effective on the final day of such 30-day cure period unless prior to such time the Employer has cured the specific conduct asserted by the Participant to constitute Good Reason to the reasonable satisfaction of the Participant.

For purposes of the Plan, a Participant's determination that an act or failure to act constitutes Good Reason shall be presumed to be valid unless such determination is decided to be unreasonable by the Committee or its delegate pursuant to Article IX.

2.18 "Nonqualified Plan" means the Retirement Income Reinstatement Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated.

2.19 "Participant" means an Eligible Employee who is listed on either Schedule A, Schedule B or Schedule C hereto, as the same may be amended from time to time.

2.20 "Performance Reasons" means the Participant's failure meet the expectations established for such Participant's function in the Company as: (i) communicated to the Participant by their manager during any performance review, or (ii) may be communicated to the Participant otherwise by their manager from time to time either orally or in writing.

2.21 "Plan" means this Key Executive Severance Plan of Public Service Enterprise Group Incorporated, as set forth herein and as may be amended, modified or supplemented from time to time.

2.22 "Prior Equity Awards" means outstanding stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares and performance shares units.

2.23 "Retiree Medical Plan" means the Public Service Enterprise Group Incorporated Medical Benefits Plan for Retired Employees.

2.24 "Retirement" means a Separation from Service after the Participant has satisfied the eligibility requirements for early or normal retirement under the terms of the Retirement Plan in which the Participant participates. Notwithstanding the foregoing, for the purposes

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of determining benefit entitlements under Article V of the Plan, Retirement shall not include forced retirements or any termination by an Employer without Cause or voluntary termination by the Participant for Good Reason that occurs on a date on which the Participant is Retirement eligible.

2.25 "Retirement Plan" means the retirement plan in which the Participant participates in either the Pension Plan of Public Service Enterprise Group Incorporated or the Cash Balance Pension Plan of Public Service Enterprise Group Incorporated.

2.26 "Schedule A Participant" means a Participant listed on Schedule A hereto.

2.27 "Schedule B Participant" means a Participant listed on Schedule B hereto.

2.28 "Schedule C Participant" means a Participant listed on Schedule C hereto.

2.29 "Selectline Participant" means a Participant who is a participant in the Public Service Enterprise Group Incorporated Selectline Benefits Plan.

2.30 "Separation from Service" shall be deemed to have occurred if a Participant and the Company or any Affiliate reasonably anticipates, based on the facts and circumstances, that either:

(a) The Participant will not provide any additional services for the Company or an Affiliate after a certain date; or
(b) The level of bona fide services performed by the Participant after a certain date will permanently decrease to no more than 50 percent of the average level of bona fide services performed by the Participant over the immediately preceding 36 months.

If a Participant is absent from employment due to military leave, sick leave or any other bona fide leave of absence authorized by the Company or an Affiliate and there is a reasonable expectation that the Participant will return to perform services for the Company or an Affiliate, a Separation from Service will not occur until the later of: (i) the first date immediately following the date that is six months after the date that the Participant was first absent from employment; or (ii) the date the Participant no longer retains a right to reemployment, to the extent the Participant retains a right to reemployment with the Company or any Affiliates under applicable law or by contract. If a Participant fails to return to work upon the expiration of any military leave, sick leave or other bona fide leave of absence where such leave is for less than six months, the Separation from Service shall occur as of the date of the expiration of such leave, unless a greater period is provided for under applicable law.

2.31 "Specified Employee" means any individual who is a key employee (as defined in Section 416(i) of the Code without regard to Section 416(i)(5) of the Code) of the Company at any time during the 12-month period ending on each December 31 (the "identification date"). If an individual is a key employee as of an identification date, the individual shall be treated as a Specified Employee for the 12-month period beginning on the April 1 following the identification date. Notwithstanding the foregoing, an individual shall not

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be treated as a Specified Employee unless any stock of the Company or an Affiliate is publicly traded on an established securities market or otherwise.

2.32 "Target Bonus" means the Participant's target annual bonus, if any, under the applicable annual incentive compensation plan of the Company for the fiscal year in which the Date of Termination occurs.

2.33 "Target Long-Term Incentive" means the Participant's target long-term incentive award, if any, under the applicable long-term incentive compensation plan of the Company.

ARTICLE III

ELIGIBILITY AND PARTICIPATION

3.1 Eligible Employees. Eligibility to participate in the Plan shall be limited to certain key executives of an Employer who (a) are not parties to individual employment or change in control agreements that provide for severance benefits, and (b) are designated, by duly adopted resolution of the Committee, as Eligible Employees.

3.2 Participation. Schedules A, B and C hereto list the Eligible Employees who have satisfied the conditions for Plan participation and the date as of which each such Eligible Employee became a Participant. The Committee shall cause Schedules A, B and C to be updated from time to time to reflect the Participants who are currently participating in the Plan. An employee who becomes an Eligible Employee on or after January 1, 2014 shall become a Schedule C Participant. However, if an Eligible Employee is newly hired or promoted into a position reflected on Schedule B as of June 6, 2014, the Eligible Employee shall become a Schedule A Participant.

3.3 Release of Claims. Notwithstanding anything in the Plan to the contrary, payment of any benefits under the Plan is expressly contingent upon the Participant's execution and delivery to the Company, within 30 days after the Participant's Date of Termination, of a written agreement provided by the Company, wherein the Participant releases and discharges the Company and each of its Affiliates of any and all claims against the Company and its Affiliates related in any way to the Participant's employment with an Employer and the termination of such employment.

3.4 Committee Discretion. The Committee shall have the sole discretion to determine eligibility for benefits under the Plan.

ARTICLE IV

SEVERANCE BENEFITS IN GENERAL

1. Eligible Terminations. If a Participant's employment is involuntarily terminated by an Employer for any reason other than Cause, the Participant shall be eligible for the benefits described in this Article IV.

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If a Participant terminates employment for Good Reason, other than in connection with a change in employment on account of Performance Reasons, the Participant shall be eligible for the benefits described in this Article IV.

If a Participant experiences a cessation of employment in connection with a reduction in force or an Employer reorganization (as determined by the Committee) where the only position offered to the Participant within the Company and Affiliates would require the Participant to increase their one-way commuting distance by more than 50 miles, the Participant shall be eligible for benefits described in this Article IV.

For the avoidance of any doubt, a Participant shall not be entitled to benefits under the Plan if termination from employment is the result of death, Disability, the Participant voluntarily terminates employment, except for Good Reason other than in connection with a change in employment on account of Performance Reasons. Also, the Participant shall not be entitled to benefits under the Plan if the Participant's cessation of employment is in connection with the sale of the Participant's Employer, line or unit of business of the Employer within which the Participant's position is located, business function of the Employer within which the Participant's position is located, or the assets related to the Employer, line or unit or business, or business function within which the Participant's position is located, and the Participant accepts employment with the purchaser within 90 days of the closing of the transaction in a position that has an annual rate of base salary that is at least 80 percent of the Participant's annual rate of base salary immediately prior to the closing of the sale.

If a Participant enters into a Voluntary Separation Agreement ("VSA") with an Employer, such Participant shall not be eligible for benefits under the Plan.

4.2 Cash payment. The Company shall pay to the Participant a lump sum, in cash, the sum of (a) and (b):

(a) The Participant's base salary and accrued vacation pay through the Date of Termination to the extent not theretofore paid (hereinafter referred to as the "Accrued Obligations"); and

(b) An amount equal to the product of 1.0 times (0.5 times if the Participant were employed less than one year) the sum of the Participant's Annual Base Salary and Target Bonus.

4.3 Long-Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

4.4 Annual Incentive Awards. The Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of calendar days of employment in the calendar year in which the Participant's

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termination occurs through the Participant's Date of Termination. For purposes of this Section 4.4, calendar year shall mean 365 days.

Annual incentive awards with respect to the calendar year in which a Participant's Date of Termination occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

4.5 Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the Participant's Date of Termination or such earlier date designated by the Participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

4.6 Educational Assistance. Educational assistance shall be provided in accordance with the Employer's tuition program.

4.7 Health Care Benefits.

(a) Medical Coverage for Selectline Participants.

(i) A Selectline Participant who has satisfied the eligibility requirements for medical coverage under the Retiree Medical Plan on the Date of Termination shall be eligible to elect coverage thereunder in accordance with the terms of the Retiree Medical Plan.

(ii) A Selectline Participant who has not otherwise satisfied the eligibility criteria for participation in the Retiree Medical Plan prior to the Date of Termination, shall be eligible to elect coverage under the Retiree Medical Plan as though such Selectline Participant has otherwise satisfied the eligibility requirements if:

(A) The Selectline Participant has attained age 50 and completed ten or more Years of Service as of the Date of Termination but the sum of the Selectline Participant's age and Years of Service is less than 80; or

(B) The Selectline Participant has attained age 49 and completed 20 or more Years of Service as of the Date of Termination but the sum of the Selectline Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Selectline Participant's Date of Termination. The Selectline Participant shall be charged the full cost of coverage under the Retiree Medical Plan.

(iii) If a Selectline Participant who is not eligible for, or does not elect, coverage under the Retiree Medical Plan, timely elects continuation coverage under the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended ("COBRA"), the Employer shall pay the same portion of the cost of medical and/or dental coverage that it paid immediately prior to

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the Selectline Participant's Date of Termination for active employees during the one-year period following the Selectline Participant's Date of Termination. During the one-year period, the Participant shall pay the difference between the total cost of medical and/or dental coverage and the Employer's portion of the cost. After the expiration of the one-year period, the Selectline Participant shall be charged the COBRA rate for medical and/or dental coverage for the remainder of the COBRA period. If the Participant does not timely elect COBRA medical and/or dental coverage, the Participant shall not be entitled to the benefit under this Subsection (iii). Following the one-year period, the Selectline Participant shall not be permitted to elect coverage, or be covered, under the Retiree Medical Plan. During the entire COBRA period, the Selectline Participant shall be responsible for the full cost of COBRA vision and hearing coverage, as applicable.

(b) Medical Coverage for Benefits 2000 Participants. If a Benefits 2000 Participant who is not eligible for, or does not elect, coverage under the Retiree Plan, timely elects COBRA continuation medical and/or dental coverage, the Employer shall pay the same portion of the cost of medical and/or dental coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the one-year period following the Participant's Date of Termination. During the one-year period, the Participant shall pay the difference between the total cost of medical and/or dental coverage and the Employer's portion of the cost. After the expiration of the one-year period, the Benefits 2000 Participant shall be charged the COBRA rate for medical and/or dental coverage for the remainder of the COBRA period. If the Participant does not timely elect COBRA medical and/or dental coverage, the Participant shall not be entitled to the benefit under this Subsection (b). Following the one-year period, the Benefits 2000 Participant shall not be permitted to elect coverage, or be covered, under the Retiree Medical Plan. During the entire COBRA period, the Benefits 2000 Participant shall be responsible for the full cost of COBRA vision.

4.8 Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided hereunder or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time.

ARTICLE V

SEVERANCE BENEFITS AFTER A CHANGE IN CONTROL

5.1 Eligible Terminations After a Change Control. If, within two years following the occurrence of a Change in Control, either (a) an Employer shall terminate a Participant's employment for any reason other than for Cause, or (b) a Participant shall voluntarily

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terminate employment for Good Reason, the Participant shall be eligible for benefits described in this Article V of the Plan. Notwithstanding anything in the Plan to the contrary, a Participant shall not be entitled to benefits under the Plan if termination from employment is the result of death, Disability or the Participant voluntarily terminates employment, except for Good Reason and except as otherwise provided under the Plan.

If a Participant enters into a VSA with an Employer, such Participant shall not be eligible for benefits under the Plan.

5.2 Cash Payment. The Company shall pay to the Participant, in a lump sum in cash, the aggregate of the amounts in (a) and (b) below:

(a) The sum of:

(i) The Participant's base salary and accrued vacation through the Date of Termination; and

(ii) The product of (x) the Participant's Target Bonus and (y) a fraction, the numerator of which is the number of days in the current calendar year through the Date of Termination, and the denominator of which is 365;

in each case to the extent not theretofore paid (the sum of the amounts described in clauses (i) and (ii) shall be hereinafter referred to as the "Accrued Obligations"); and

(b) Either (i), (ii) or (iii):

(i) In the case of a Schedule A Participant, the amount equal to the product of two times the sum of the Schedule A Participant's Annual Base Salary and Target Bonus;

(ii) In the case of a Schedule B Participant, the amount equal to the product of three times the sum of the Schedule B Participant's Annual Base Salary and Target Bonus; or

(iii) In the case of a Schedule C Participant, the amount equal to the product of one and one-half times the sum of the Schedule C Participant's Annual Base Salary and Target Bonus.

5.3 Long Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.4 Health Care and Other Welfare Benefits. The Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for 18 months after the Date of Termination provided that the Participant timely makes an election to continue such coverage in the Company's medical and dental employee benefit plans under COBRA, subject to the requirements and limitations thereof. Unless otherwise limited by applicable law, thereafter, the Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for

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an additional period of six months, in the case of a Schedule A Participant, or 18 months, in the case of a Schedule B Participant (for a Schedule C Participant, no additional period beyond the initial 18 months); provided however, that if the Participant becomes re-employed with another employer and is eligible to receive medical or dental benefits under another employer provided plan, the medical and dental benefits provided by the Company under this Plan shall be secondary to those provided under such other plan during the applicable period of eligibility. If the Participant does not timely elect COBRA coverage, the Participant shall not be entitled to the COBRA continuation benefit under this Section 5.4 of the Plan.

Unless otherwise limited by applicable law or by a third-party vendor contract, for two years after the Date of Termination in the case of a Schedule A Participant, three years after the Date of Termination in the case of a Schedule B Participant, or in the case of a Schedule C Participant, eighteen months after the Date of Termination (or for any Participant such longer period as may be provided by the terms of the appropriate plan, program, practice or policy), the Company shall continue benefits (other than medical and dental benefits) to the Participant and/or the Participant's family at least equal to those which would have been provided to them in accordance with the welfare plans, programs, practices and policies maintained by the Company if the Participant's employment had not been terminated or, if more favorable to the Participant, as in effect generally at any time thereafter with respect to other peer executives of the Employer and their families.

Unless otherwise limited by applicable law or by a third-party vendor contract, the Participant's eligibility (but not the time of commencement of such benefits) for retiree benefits pursuant to the welfare plans, programs, practices and policies maintained by the Company shall be determined as if the Participant had (A) remained employed until two years (in the case of a Schedule A Participant), three years (in the case of a Schedule B Participant), or eighteen months (in the case of a Schedule C Participant) after the Date of Termination and (B) retired on the last day of such period.

5.5 Nonqualified Pension Benefit. The Participant shall be paid, in a lump sum payment in cash, an amount equal to the excess of (a) - (b):

(a) The actuarial equivalent of the benefit under the Company's applicable Retirement Plan (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the Effective Date), any benefit under the Nonqualified Plan and, to the extent applicable, any other defined benefit retirement arrangement between the Participant and the Company ("Other Pension Benefits") which the Participant would receive if the Participant's employment continued for two, three or one and one-half additional years (for Schedule A Participants, Schedule B and Schedule C Participants, respectively) beyond the Date of Termination and, assuming that the Participant's compensation for such deemed additional period was the Participant's Annual Base Salary as in effect immediately prior to the Date of Termination and assuming a bonus in

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each year during such deemed additional period equal to the Target Bonus,

(b) The actuarial equivalent of the Participant's actual benefit (paid or payable), if any, under the Retirement Plan, the Nonqualified Plan and Other Pension Benefits as of the Date of Termination (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the effective date of the Change in Control).

5.6 Deferred Compensation. Any compensation previously deferred (other than pursuant to a tax-qualified plan) by or on behalf of the Participant (together with any accrued interest or earnings thereon), whether or not then vested, shall become vested on the Date of Termination and shall be paid in accordance with the terms of the applicable deferred compensation plan, policy or practice under which it was deferred to the extent permitted by Section 409A of the Code.

5.7 Outplacement Services. The Company shall, at its sole expense as incurred, provide the Participant with outplacement services suitable to the Participant's position for a period not to exceed one year following the Date of Termination with a nationally recognized outplacement firm.

5.8 Other Benefits. To the extent not theretofore paid or provided, the Company shall pay or provide to the Participant any other amounts or benefits required to be paid or provided or which the Participant is entitled to receive under any plan, program, policy, practice, contract or agreement of the Company (or other Employer), including earned but unpaid stock and similar compensation, but excluding medical or dental benefits if the Participant is eligible for such benefits to be provided by a subsequent employer, and benefits payable under any severance plan or policy.

5.9 Termination By Employer For Cause or By Participant Other Than For Good Reason. If, at any time after a Change in Control, either (a) an Employer shall terminate a participant's employment for Cause or (b) the Participant shall voluntarily terminate employment other than for Good Reason, the Employer shall have no further payment obligations to the Participant other than for the Participant's base salary through the Date of Termination and any accrued but unpaid vacation pay. In such case, all such amounts shall be paid to the Participant in a lump sum in accordance with Section 6.1 of the Plan.

5.10 Death. If a Participant's employment terminates by reason of the Participant's death after a Change in Control, all Accrued Obligations as of the time of death shall be paid to the Participant's estate or beneficiary, as applicable, in a lump sum in cash in accordance with Section 6.1 of the Plan. The Participant's estate or beneficiary shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

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5.11 Disability. If a Participant's employment is terminated by reason of Disability after a Change in Control, all Accrued Obligations shall be paid to the Participant in a lump sum in cash in accordance with Section 6.1 of the Plan. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.12 Retirement. If a Participant's employment terminates as a result of Retirement after a Change in Control, the Participant shall be paid the Accrued Obligations in a lump sum in cash in accordance with Section 6.1 of the Plan and the Participant shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

ARTICLE VI

TIMING OF, LIMITATIONS ON AND ADJUSTMENTS TO PLAN PAYMENTS

6.1 Time of Payments. Payments under the Plan shall be made to the Participant as follows:

(a) With respect to benefits, except those under Sections 4.4 and 5.10 of the Plan, payment to a Participant who is not a Specified Employee shall be made within the 60-day period following the Participant's Date of Termination. However, if the period to consider and revoke the written agreement required to receive the benefits described in Articles IV and V of the Plan (i.e., the waiver and release) spans two taxable years, in all events the payments will be made in the second taxable year within 30 days following the later of the end of the first taxable year or the date the executed release is received by the Company.

(b) With respect to benefits under Section 5.10 of the Plan, payment shall be made within the 60-day period following the Participant's date of the Participant's death.

(c) With respect to benefits under Section 4.4 of the Plan, payments shall be made to the Participant at the same time the payments are made to active employees.

(d) Notwithstanding anything to the contrary in the Plan, to the extent necessary to comply with Section 409A of the Code, payments to a Participant who is a Specified Employee shall be made within the 60-day period following the six-month anniversary of the Participant's Date of Termination (other than by reason of death).

(e) All payments under the Plan that are reimbursements of covered expenses incurred by the Participant shall be made within the taxable year in which the expense is incurred.

6.2 Payment Offsets. Notwithstanding anything in the Plan to the contrary, in the event a Participant is entitled to receive severance payments both under this Plan and under the terms of either (a) an individual change of control or employment agreement, (b) another

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severance pay plan or policy of an Employer or (c) any existing or future law or regulation, the benefits payable under this Plan shall be reduced by the amount of any severance benefits such Participant is entitled to receive under such individual agreement, plan, policy, law or regulation.

6.3 Cap on Excess Parachute Payments; Gross-Up Payments. Notwithstanding anything in the Plan to the contrary, if (a) a Participant is a "disqualified individual" (as defined in Section 280G(c) of the Code) and (b) the severance benefits provided under Articles IV or V, as applicable, together with any other payments the Participant has the right to receive from an Employer, would constitute a "parachute payment" (as defined in Section 280G(b) of the Code) ("Parachute Payments"), the following provisions shall apply:

(a) The severance benefits under Articles IV or V shall not exceed an amount which, together with any other Parachute Payments, the Participant has a right to receive from the Employer, would be 2.99 times the Participant's "base amount" (as defined in Section 280G of the Code) so that no portion of the amounts received by the Participant shall be subject to the excise tax imposed under Section 4999 of the Code.

(b) The determination of whether any limitation on the severance benefits payable under Articles IV or V is necessary shall be made by the Company's independent auditor or such other certified public accounting firm as may be jointly designated by the Participant and the Company (the "Accounting Firm"), which shall provide detailed supporting calculations to the Participant and the Company. The determinations of the Accounting Firm shall be conclusive and binding on the Company and the Participant. All fees and expenses of the Accounting Firm shall be borne solely by the Company.

(c) If through error or otherwise, a Participant shall receive payments under the Plan, together with other Parachute Payments the Participant has the right to receive from an Employer, in excess of 2.99 times the Participant's base amount, the Participant shall immediately repay the excess to the Employer upon notification from the Employer that an overpayment has been made. If the Participant fails to repay the excess to the Employer within 10 business days of the date of the Employer's notification, the Participant will become liable to the Employer for an amount equal to two (2) times the excess amount.

6.4 Compliance with Section 409A of the Code. Notwithstanding anything in the Plan to the contrary, all Plan benefit obligations and payments are subject to Section 409A of the Code. To the extent required, the Company may modify the severance benefits payable hereunder to comply with Section 409A of the Code; provided, however, that the present value of the aggregate Plan benefits payable to a Participant after such modification shall not be less than the present value of the Plan benefits payable to the Participant prior to the modification.

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6.5 Tax Withholding. Notwithstanding any other provision of this Plan, the Company may withhold from any amounts payable under this Plan such Federal, state, local, employment or foreign taxes as shall be required to be withheld pursuant to any applicable law or regulation.

ARTICLE VII
RESTRICTIVE COVENANTS

7.1 Confidentiality. As a condition to participation in the Plan, each Participant agrees to hold in a fiduciary capacity for the benefit of the Company and its Affiliates all Confidential Information which shall have been obtained by the Participant during the Participant's employment by the Employer; except, however, that this Section 7.1 shall not apply to Confidential Information that is or becomes public knowledge, unless such Confidential Information became or becomes public knowledge due to acts of the Participant or representatives of the Participant in violation of this Section 7.1. Upon termination of the Participant's employment, the Participant shall return to the Company all Confidential Information in their possession. After termination of the Participant's employment with the Employer, the Participant shall not, without the prior written consent of the Company or as may otherwise be required by law or legal process, communicate or divulge any such Confidential Information to anyone other than the Company and those designated by it, except (a) otherwise publicly available information, (b) as may be necessary to enforce the Participant's rights under the Plan or as necessary for the Participant to defend against a claim asserted directly or indirectly by the Company or its Affiliates, or (c) as may be compelled by service of a valid subpoena or other legal process (if the Participant is served with a valid subpoena or other legal process, the Participant must so notify the Company within three business days). Furthermore, nothing contained in this Plan prevents a Participant from disclosing without notice to the Company any perceived violation of law to any Federal, state, or local governmental agency or entity including, but not limited to, the Securities and Exchange Commission, or making other disclosures that are protected under the whistleblower provisions of any law. Finally, nothing in this Plan prevents a Participant - nor should a Participant be held civilly or criminally liable under any law - if the Participant discloses a trade secret: (a) in confidence to a Federal, State or local government official, either directly or indirectly, or to an attorney solely for the purpose of reporting or investigating a suspected violation of law; (b) in a complaint or other document filed in a lawsuit or other proceeding, if such filing is made under seal; (c) to the Participant's attorney in connection with a lawsuit alleging retaliation by an employer for reporting a suspected violation of law; or (d) in connection with a lawsuit described in the immediately preceding subparagraph (c), provided the Participant: (i) files any document containing the trade secret under seal; and (ii) does not disclose the trade secret, except pursuant to a court order. Unless and until a determination has been made in accordance with Section 7.4 that the Participant has violated this Section 7.1, an asserted violation of the provisions of this Section 7.1 shall not constitute a basis for deferring or withholding any amounts otherwise payable to the Participant under the Plan.

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7.2 Non-Compete. As a condition to participation in the Plan, each Participant agrees that in the event the Participant voluntarily terminates employment other than for Good Reason, for the period of one year from Date of Termination, the Participant will not, without the written consent of the Company, directly or indirectly own, manage, operate, join, control, become employed by, consult to or participate in the ownership, management, or control of any business which is in direct competition with the Company or its Affiliates.

7.3 Non-Solicitation. As a condition to participation in the Plan, each Participant agrees that, in the event the Participant voluntarily terminates employment other than for Good Reason, for the period of one year following the Date of Termination, the Participant will not, directly or indirectly, solicit or hire, or encourage the solicitation or hiring by any employer other than the Company or its Affiliates, for any position as an employee, independent contractor, consultant or otherwise, any person who was a managerial or higher level employee of an Employer at any time during the term of the Participant's employment by the Employer; provided, however, that this provision shall not apply with respect to the solicitation of any person after six months from the date on which such person's employment by an Employer has terminated.

7.4 Enforcement. In the event of a breach by the Participant of any of the covenants set forth in this Article VII, it is agreed that the Company shall suffer irreparable harm for which money damages are not an adequate remedy, and that, in the event of such breach, the Company shall be entitled to obtain an order of a court of competent jurisdiction for equitable relief from such breach, including, but not limited to, temporary restraining orders and preliminary and/or permanent injunctions against the breach of such covenants by the Participant. In the event that the Company should initiate any legal action for the breach or enforcement of any of the provisions contained in this Article VII and the Company does not prevail in such action, the Company shall promptly reimburse the Participant the full amount of any court costs, filing fees, attorney's fees which the Participant incurs in defending such action, and any loss of income during the period of such litigation.

Nothing in this Plan prohibits the Participant from reporting possible violations of Federal law or regulation to any governmental agency or entity, including but not limited to the Department of Justice, the Securities and Exchange Commission, the Congress, and any agency Inspector General, or making other disclosures that are protected under the whistleblower provisions of Federal law or regulation. The Participant does not need the prior authorization of the Law Department to make any such reports or disclosures, and is not required to notify the Company that such reports or disclosures have been made.

ARTICLE VIII

AMENDMENT AND TERMINATION

8.1 Amendment. The Company may amend this Plan at any time, and from time to time, by action of the Committee; provided, however, that no amendment adopted after the effective date of a Change in Control shall have the effect of either (a) removing an

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individual from the list of Participants, (b) adding conditions for participation or the entitlement to receive benefits hereunder, (c) reducing the amount of benefits payable to a Participant, or (d) otherwise restricting a Participant's right to receive benefits under the Plan, except as may otherwise be required to conform such payments to the requirements of Section 409A of the Code.

8.2 Termination. The Committee may terminate the Plan at any time prior to a Change in Control. The Plan may not be terminated after the effective date of a Change in Control.

ARTICLE IX

ADMINISTRATION

9.1 Plan Administrator. The Plan shall be administered by the Committee, which shall have the duties and responsibilities for administering the Plan as are specifically set forth in this Article IX.

9.2 Responsibilities of Committee.

(a) The Committee shall have responsibility for the day to day administration of the Plan. In addition, the Committee shall have the specific powers, duties, responsibilities and obligations specifically provided for herein.

(b) Subject to the express provisions of the Plan, the Committee shall have full and exclusive authority to interpret the Plan and to make all other factual determinations deemed necessary or advisable in the implementation and administration of the Plan, including but not limited to determinations with respect to the eligibility of Participants to receive benefits under the Plan and the status and rights of such Participants and all other persons affected hereunder. The Committee's interpretation and construction of the Plan shall be conclusive and binding on all persons.

(c) The Committee shall have sole authority to adopt rules and regulations, which shall be administered by the Committee. In addition, the Committee shall have the discretionary authority to issue rulings and interpretations concerning the Plan and all matters arising thereunder, on a uniform and nondiscriminatory basis, provided the same shall not be contrary to or inconsistent with any provision of the Plan.

(d) As a condition of distributing any benefit under the Plan, the Committee may prescribe the use of such forms and require the furnishing of such information as the Committee may deem appropriate for administering the Plan.

9.3 Allocation or Delegation of Duties and Responsibilities. In furtherance of its duties and responsibilities under the Plan, the Committee may:

(a) Employ agents to carry out non-fiduciary responsibilities;

(b) Employ agents to carry out fiduciary responsibilities;
(c) Consult with counsel, who may be counsel to the Company; and
(d) Delegate any of its duties and responsibilities hereunder to such officer or officers

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of the Company as the Committee shall designate; except, however, that the Committee may not delegate to any other person the designation of Eligible Employees under Section 3.1 or the authority to consider and determine appeals of alleged adverse benefit determinations.

The Committee delegates to the Chief Executive Officer of the Company the responsibility and authority to interpret the terms of the Plan, including the benefits payable thereunder. Furthermore, the Committee delegates to the Senior Vice President of Human Resources, Chief Human Resources Officer of the Company the authority to enter into a VSA with a Participant in lieu of providing benefits under the Plan.

9.4 Expenses. Unless otherwise agreed to by the Company, no person acting as a fiduciary hereunder (who is an employee of an Employer) shall receive any compensation for services as such. Expenses incurred by fiduciaries in connection with the administration of the Plan shall be paid by the Company.

9.5 Indemnification of Plan Administrator. The Company shall indemnify, to the fullest extent permitted by law, each person made or threatened to be made a party to any civil or criminal action or proceeding by reason of the fact that such person, or such person's testator or intestate, was a member of the Committee, or a delegate of the Committee, acting in the capacity of Plan administrator.

9.6 Reliance Upon Others. The Committee, any person to whom it may delegate such of its duties and powers as provided herein, and the officers and directors of the Company shall be entitled to rely conclusively upon and shall be fully protected in any action taken by them in good faith in reliance upon any tables, valuations, certificates, opinions, reports or other advice furnished to them by any duly appointed actuary, accountant, legal counsel (who may be counsel for the Company) or other specialist.

9.7 Notification. All notices, reports and statements in connection with the Plan that are given, made, delivered or transmitted to a Participant shall be deemed duly given, made, delivered, or transmitted when mailed, by such class as the sender may deem appropriate, with postage prepaid and addressed to the Participant at the address last appearing on the records of the Employer with respect to this Plan. All notices, direct actions or other communications given, made, delivered or transmitted by a Participant to an Employer or Committee shall not be deemed to have been duly given, made, delivered, transmitted or received unless and until actually received by the Employer or Committee.

9.8 Multiple Capacities. A person may serve in more than one fiduciary capacity with respect to the Plan.

ARTICLE X

CLAIMS PROCEDURE

10.1 Submission of Claims. The initial claim by any Participant for benefits under this Plan shall be submitted in writing to the Committee (or its delegate) within 60 days after the occurrence of the termination of employment that the Participant claims to have triggered entitlement to Plan benefits.

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10.2 Computation and Review of Claims. All benefits shall be computed by the Committee or its delegate. All claims shall be approved or denied by the Committee (or its delegate) as soon as practicable, but in no event later than 90 days after application by the Participant. The Committee may take an additional 90 days to review the claim, provided that the Participant is notified in writing within the initial 90-day period.

(a) Initial Denial of Claim - Any denial of a claim shall include:

(i) Reason or reasons for the denial;

(ii) Reference to pertinent Plan provisions on which the denial is based;

(iii) Description of any additional material or information necessary for the Participant to perfect the claim together with an explanation of why the material or information is necessary; and

(iv) Explanation of the Plan's claim review procedure, described below.

(b) Review of a Denied Claim - A Participant shall have a reasonable opportunity to appeal a denied claim to the Committee (or its delegate) for a full and fair review. The Participant or a duly authorized representative shall have 60 days after receipt of written notification of the denial of claim in which to file an appeal with the Committee. The request for review shall be in writing and the Participant or a duly authorized representative shall submit written comments, documents, records and other information relating to the appeal. The Participant or a duly authorized representative may review, free of charge, pertinent Plan documents, records and other information relevant to the appeal.

(c) Committee Review - The Committee's (or its delegate's) review shall take into account all comments, documents, records and other information submitted by the Participant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

(d) Written Decision - The Committee (or its delegate) shall issue a decision on the reviewed claim promptly but no later than 60 days after receipt of the review. The Committee may take an additional 60 days to review the claim, provided that the Participant is notified in writing within the initial 60-day period. The Committee's decision shall be in writing and shall include:

(i) Reasons for the decision;

(ii) References to the Plan provisions on which the decision is based;

(iii) Statement that the Participant is entitled to receive, upon request, reasonable access to, and copies of, all documents, records and other information relevant to the claim; and

(iv) Statement that the Participant is entitled to bring a civil suit under Section 502(a) of ERISA.

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(e) Binding Effect - The Committee's (or its delegate's) decision shall be final and binding on the Participant and the Employer.

ARTICLE XI

GENERAL PROVISIONS

11.1 Construction. This Plan shall be construed and enforced in accordance with and governed by the internal substantive laws (and not the laws relating to conflict of laws or choice of laws) of the State of New Jersey, except to the extent that such laws are preempted by Federal law.

11.2 Unfunded Plan. The obligations of the Company under this Plan are not required to be funded in advance. Nothing contained in this Plan shall give an Eligible Employee or Participant any right, title or interest in any property of the Company or any of its Affiliates.

11.3 No Right to Continued Employment. Nothing contained herein shall be deemed to give any Eligible Employee or Participant the right to be retained in the employment of an Employer or to limit the rights of any Employer to discharge any Eligible Employee or Participant at any time, with or without notice and with or without Cause.

11.4 Partial Invalidity. The invalidity or unenforceability of any term or provision, or any clause, or portion thereof, of this Plan shall in no way impair or affect the validity or enforceability of any other provision of this Plan, which shall remain in full force and effect.

11.5 Successors and Assigns.

(a) This Plan shall inure to the benefit of and be binding upon the Company and its successors and assigns.

(b) The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform the Company's obligations under the Plan in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place.

(c) In no event shall a Participant assign their interests under the Plan to any other person without the prior written consent of the Committee.

11.6 Waivers. Failure to strictly comply with any term, condition or requirement set forth in the Plan shall not be deemed a waiver of such term, condition or requirement, nor shall any waiver of any such term, condition or requirement at any one time or times be deemed to result in a waiver of such term, condition or requirement at any other time or times.

11.7 Gender and Number. The singular shall include the plural, unless indicated otherwise by the context.

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11.8 Headings. The headings of the Plan are for purposes of reference only and shall not limit or otherwise affect the meaning hereof.

* * *

_/s/ Margaret M. Pego

_Margaret M. Pego Date 2/20/2017

Signature

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SCHEDULE A

As Amended as of February 20, 2017
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Stuart J. Black	**VP and Controller**	**03/01/10**
Jorge L. Cardenas	VP - Asset Management and Centralized Services, PSE&G	1/23/07
Rose M. Chernick	VP - Finance Holdings & Corporate Strategy & Planning	8/09/10
John Paul Cowan	SVP - Operations, PSEG Fossil	09/15/09
Lathrop B. Craig	VP - ISO Operations (ER&T)	09/05/11
Daniel J. Cregg	EVP & CFO, PSEG	12/19/06
David M. Daly	President and COO - PSEG Long Island	1/28/08
Paul J. Davison	VP - Nuclear Engineering, PSEG Nuclear	12/14/09
Derek DiRisio	President - PSEG Services Corporation	12/20/04
Diana L. Drysdale	VP - Renewables	02/15/10
Joseph A. Forline	VP - Gas Operations	12/19/06
Carl J. Fricker	VP - Trading Support & Operations (ER&T)	12/14/09
Kim C. Hanemann	SVP - Delivery Projects and Construction	12/21/10
Bradford D. Huntington	VP & Treasurer	04/16/11
Scott Jennings	VP - Finance PSE&G	10/18/05
Robert C. Krueger, Jr	VP & Assistant Controller - Tax	12/19/06
Kathleen A. Lally	VP - Investor Relations	01/16/07
John R. Latka	SVP - Electric & Gas Operations, PSE&G	10/23/06
Shawn P. Leyden	VP and Deputy General Counsel	12/20/04
Tamara L. Linde	EVP and General Counsel	12/19/06
Kristen M. Ludecke	VP - Federal Affairs	02/22/10
Shahid Malik	President - Energy Resources & Trade (ER&T)	12/5/11
Christine T. Neely	VP - Internal Auditing Services	9/30/13
Margaret M. Pego	SVP - Human Resources & CHRO	12/20/04
Kevin J. Quinn	VP - Finance Power	03/01/10
Sheila J. Rostiac	VP - Total Rewards & Talent Management	08/20/12
Joseph Santamaria	VP - Information Technology & CIO	10/29/12
John P. Scarlata	VP - Gas Supply, PSEG ER&T	4/20/10
Richard T. Thigpen	VP - State Governmental Affairs	3/26/07

SCHEDULE B

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As Amended as of February 20, 2017
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Ralph Izzo	**Chairman of the Board, President and CEO**	**12/15/08**
Ralph A. LaRossa	President & COO - Public Service Electric and Gas Company, and COB, PSEG Long Island	10/17/06
William Levis	President & COO, PSEG Power LLC	01/01/07

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SCHEDULE C

As Amended as of February 20, 2017
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
John A. Bridges	VP Electric Operations	12/21/15
Eric Carr	VP Hope Creek - PSEG Nuclear	10/3/16
Kevin B. Cellars	VP Construction	2/17/15
Brian J. Clark	VP Procurement	8/29/16
Gregory C. Dunlap	VP Customer Operations - PSE&G	7/14/14
Aaron T. Ford	VP Business Assurance and Resilience	11/18/15
M. Courtney McCormick	**VP Renewables and Energy Solutions**	**3/31/14**
Charles V. McFeaters	VP Salem - PSEG Nuclear	10/3/16
Laurent C. Pommier	VP Risk Management and Chief Risk Officer	7/14/14
Peter P. Sena III	President & CNO, PSEG Nuclear	3/21/16

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 1,298	$ 2,680	$ 2,456	$ 2,055	$ 2,011
(Income) Loss from Equity Investees, net of Distributions	7	3	4	(7)	9
Fixed Charges	477	457	450	458	479
Capitalized Interest	(7)	(18)	(16)	(16)	(19)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—
Total Earnings	$ 1,775	$ 3,122	$ 2,894	$ 2,490	$ 2,480
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 456	$ 437	$ 430	$ 442	$ 465
Interest Factor in Rentals	21	20	20	16	14
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—
Total Fixed Charges	$ 477	$ 457	$ 450	$ 458	$ 479
Ratio of Earnings to Fixed Charges	**3.72**	**6.83**	**6.43**	**5.44**	**5.18**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12a

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ (43)	$1,367	$1,251	$1,063	$1,099
(Income) Loss from Equity Investees, net of Distributions	7	1	3	(10)	(6)
Fixed Charges	142	152	150	143	164
Capitalized Interest	11	(1)	1	1	(6)
Total Earnings	$ 117	$1,519	$1,405	$1,197	$1,251
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 138	$ 148	$ 146	$ 139	$ 161
Interest Factor in Rentals	4	4	4	4	3
Total Fixed Charges	$ 142	$ 152	$ 150	$ 143	$ 164
Ratio of Earnings to Fixed Charges (C)	**0.82**	**9.99**	**9.37**	**8.37**	**7.63**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

(C) The ratio of earnings to fixed charges for the year ended December 31, 2016, was 0.82, as noted above, which represents a deficiency of $25 million.

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EXHIBIT 12b

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Years Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$1,404	$1,257	$1,174	$ 993	$ 835
Fixed Charges	316	306	303	316	314
Capitalized Interest	(17)	(17)	(16)	(16)	(13)
Total Earnings	$1,703	$1,546	$1,461	$ 1,293	$1,136
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 306	$ 297	$ 293	$ 309	$ 308
Interest Factor in Rentals	10	9	10	7	6
Total Fixed Charges	$ 316	$ 306	$ 303	$ 316	$ 314
Ratio of Earnings to Fixed Charges	**5.39**	**5.05**	**4.82**	**4.09**	**3.62**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 21

PUBLIC SERVICES ENTERPRISE GROUP INCORPORATED
SIGNIFICANT SUBSIDIARIES

Name	Ownership %	State of Incorporation
Public Service Electric and Gas Company	100	New Jersey
PSEG Power LLC	100	Delaware
PSEG Fossil LLC	100	Delaware
PSEG Nuclear LLC	100	Delaware

The remaining subsidiaries of Public Service Enterprise Group Incorporated are not significant as defined in Regulation S-X.

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Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-202594, 333-202591, 333-120100, 333-106330, 333-193126, and 333-193127 on Forms S-8 and Registration No. 333-200352 on Form S-3 of our reports dated February 27, 2017, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Enterprise Group Incorporated and subsidiaries (the "Company,") and the effectiveness of the Company's internal control over financial reporting, appearing in the Annual Report on Form 10-K of Public Service Enterprise Group Incorporated for the year ended December 31, 2016.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 27, 2017

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Exhibit 23a

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-200354 on Form S-3 of our report dated February 27, 2017, relating to the consolidated financial statements and consolidated financial statement schedule of PSEG Power LLC and subsidiaries, appearing in this Annual Report on Form 10-K of PSEG Power LLC for the year ended December 31, 2016.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 27, 2017

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Exhibit 23b

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-200353 on Form S-3 of our report dated February 27, 2017, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Electric and Gas Company and subsidiaries, appearing in this Annual Report on Form 10-K of Public Service Electric and Gas Company for the year ended December 31, 2016.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 27, 2017

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2017

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31a

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31b

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2017

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31c

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 31d

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2017

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31e

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
February 27, 2017

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EXHIBIT 32a

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
February 27, 2017

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EXHIBIT 32b

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
February 27, 2017

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EXHIBIT 32c

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
February 27, 2017

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EXHIBIT 32d

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
February 27, 2017

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EXHIBIT 32e

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
February 27, 2017

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2017

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-3663480

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange On Which Registered
Public Service Enterprise Group Incorporated	Common Stock without par value	New York Stock Exchange
	First and Refunding Mortgage Bonds	
Public Service Electric and Gas Company	9 1/4% Series CC, due 2021	New York Stock Exchange
	8%, due 2037	
	5%, due 2037	
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange

(Cover continued on next page)

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(Cover continued from previous page)

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
Public Service Electric and Gas Company	Medium-Term Notes
PSEG Power LLC	Limited Liability Company Membership Interest

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Public Service Enterprise Group Incorporated	Yes ☒	No ☐
Public Service Electric and Gas Company	Yes ☒	No ☐
PSEG Power LLC	Yes ☒	No ☐

Indicate by check mark if each of the registrants is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ☐ No ☒

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐

If any of the registrants is an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2017 was $21,673,743,255 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Public Service Enterprise Group Incorporated's sole class of Common Stock as of February 16, 2018 was 504,764,707.

As of February 16, 2018, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record, by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K. Each is filing its Annual Report on Form 10-K with the reduced disclosure format authorized by General Instruction I.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K of Public Service Enterprise Group Incorporated	Documents Incorporated by Reference
III	Portions of the definitive Proxy Statement for the 2018 Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 12, 2018, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities, and other filings we make with the United States Securities and Exchange Commission (SEC), including our subsequent reports on Form 10-Q and Form 8-K. These factors include, but are not limited to:

- fluctuations in wholesale power and natural gas markets, including the potential impacts on the economic viability of our generation units;
- our ability to obtain adequate fuel supply;
- any inability to manage our energy obligations with available supply;
- increases in competition in wholesale energy and capacity markets;
- changes in technology related to energy generation, distribution and consumption and customer usage patterns;
- economic downturns;
- third-party credit risk relating to our sale of generation output and purchase of fuel;
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements;
- changes in state and federal legislation and regulations;
- the impact of pending rate case proceedings;
- regulatory, financial, environmental, health and safety risks associated with our ownership and operation of nuclear facilities;
- adverse changes in energy industry laws, policies and regulations, including market structures and transmission planning;
- changes in federal and state environmental regulations and enforcement;
- delays in receipt of, or an inability to receive, necessary licenses and permits;
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry;
- changes in tax laws and regulations;
- the impact of our holding company structure on our ability to meet our corporate funding needs, service debt and pay dividends;
- lack of growth or slower growth in the number of customers or changes in customer demand;
- any inability of Power to meet its commitments under forward sale obligations;
- reliance on transmission facilities that we do not own or control and the impact on our ability to maintain adequate transmission capacity;
- any inability to successfully develop or construct generation, transmission and distribution projects;
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers;

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- our inability to exercise control over the operations of generation facilities in which we do not maintain a controlling interest;
- any inability to recover the carrying amount of our long-lived assets and leveraged leases;
- any inability to maintain sufficient liquidity;
- any inability to realize anticipated tax benefits or retain tax credits;
- challenges associated with recruitment and/or retention of key executives and a qualified workforce;
- the impact of our covenants in our debt instruments on our operations; and
- the impact of acts of terrorism, cybersecurity attacks or intrusions.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business, prospects, financial condition, results of operations or cash flows. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even in light of new information or future events, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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FILING FORMAT AND GLOSSARY

This combined Annual Report on Form 10-K is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to "we," "us," and "our" relate to PSEG or to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 194.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document that we file at the Public Reference Room of the SEC at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. You may also obtain our filed documents from commercial document retrieval services, the SEC's internet website at www.sec.gov or our website at www.pseg.com. Information on our website should not be deemed incorporated into or as a part of this report. Our Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

PART I

ITEM 1. BUSINESS

We were incorporated under the laws of the State of New Jersey in 1985 and our principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07102. We conduct our business through two direct wholly owned subsidiaries, PSE&G and Power, each of which also has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102.

We are an energy company with a diversified business mix. Our operations are located primarily in the Northeastern and Mid- Atlantic United States. Our business approach focuses on operational excellence, financial strength and disciplined investment. As a holding company, our profitability depends on our subsidiaries' operating results. Below are descriptions of our two principal direct operating subsidiaries.

PSE&G	Power
A New Jersey corporation, incorporated in 1924, which is a franchised public utility in New Jersey. It is also the provider of last resort for gas and electric commodity service for end users in its service territory. Earns revenues from its regulated rate tariffs under which it provides electric transmission and electric and gas distribution to residential, commercial and industrial customers in its service territory. It also offers appliance services and repairs to customers throughout its service territory. Also invests in solar generation projects and regulated energy efficiency and related programs in New Jersey.	A Delaware limited liability company formed in 1999 as a result of the deregulation and restructuring of the electric power industry in New Jersey. It integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets. Earns revenues from the generation and marketing of power and natural gas to hedge business risks and optimize the value of its portfolio of power plants, other contractual arrangements and oil and gas storage facilities. This is achieved primarily by selling power and transacting in natural gas and other energy-related products, on the spot market or using short-term or long-term contracts for physical and financial products. Also earns revenues from solar generation facilities under long-term sales contracts for power and environmental products.

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Our other direct wholly owned subsidiaries are: PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) electric transmission and distribution (T&D) system under a contractual agreement; PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; and PSEG Services Corporation (Services), which provides us and our operating subsidiaries with certain management, administrative and general services at cost.

The following is a more detailed description of our business, including a discussion of our:

- Business Operations and Strategy
- Competitive Environment
- Employee Relations
- Regulatory Issues
- Environmental Matters

BUSINESS OPERATIONS AND STRATEGY

PSE&G

Our regulated transmission and distribution public utility, PSE&G, distributes electric energy and gas to customers within a designated service territory running diagonally across New Jersey where approximately 6.2 million people, or about 70% of New Jersey's population resides.

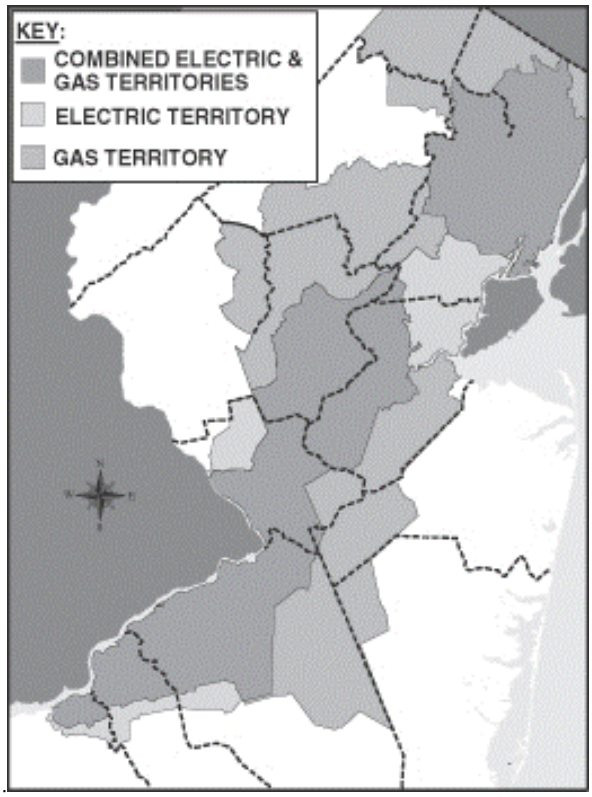

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Products and Services

Our utility operations primarily earn margins through the transmission and distribution of electricity and the distribution of gas.

- **Transmission**—the movement of electricity at high voltage from generating plants to substations and transformers, where it is then reduced to a lower voltage for distribution to homes, businesses and industrial customers. Our revenues for these services are based upon tariffs approved by the Federal Energy Regulatory Commission (FERC).
- **Distribution**—the delivery of electricity and gas to the retail customer's home, business or industrial facility. Our revenues for these services are based upon tariffs approved by the New Jersey Board of Public Utilities (BPU).

The commodity portion of our utility business' electric and gas sales is managed by basic generation service (BGS) and basic gas supply service (BGSS) suppliers. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for our utility operations.

We also earn margins through competitive services, such as appliance repair.

In addition to our current utility products and services, we have implemented several programs to invest in regulated solar generation within New Jersey, including:

- programs to help finance the installation of solar power systems throughout our electric service area, and
- programs to develop, own and operate solar power systems.

We have also implemented a set of energy efficiency and demand response programs to encourage conservation and energy efficiency by providing energy and cost saving measures directly to businesses and families. For additional information concerning these programs and the components of our tariffs, see Regulatory Issues—State Regulation and Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

How PSE&G Operates

We are a transmission owner in PJM Interconnection, L.L.C. (PJM) and we provide distribution service to 2.2 million electric customers and 1.8 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately 300 suburban and rural communities.

Transmission

We use formula rates for our transmission cost of service and investments. Formula-type rates provide a method of rate recovery where the transmission owner annually determines its revenue requirements through a fixed formula that considers Operation and Maintenance expenditures, rate base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures. Our current approved rates provide for a base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn an additional incentive rate. For more information, see Regulatory Issues—Federal Regulation.

We continue to invest in transmission projects that are included for review in the FERC-approved PJM transmission expansion process. These projects focus on reliability improvements and replacement of aging infrastructure with planned capital spend of $3.8 billion for transmission in 2018-2020 as disclosed in Item 7. MD&A—Capital Requirements.

Distribution

PSE&G distributes gas and electricity to end users in our respective franchised service territories. Our approved rates, established in our most recent gas and electric base rate proceeding completed in mid-2010, provide for a ROE of 10.3% on distribution rate base. In January 2018, we filed a distribution base rate case requesting an adjustment in electric and gas base delivery rates that, if approved by the BPU, would increase overall revenues by approximately one percent. PSE&G anticipates that new base rates will take effect in the fourth quarter of 2018. The BPU has also approved a series of PSE&G infrastructure, energy efficiency and renewable energy investment programs with cost recovery through various clause mechanisms, with approved ROEs ranging from 9.75% to 10.3%. Our load requirements are split among residential, commercial and industrial customers, as described in the following table for 2017:

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Customer Type	% of 2017 Sales Electric	Gas
Commercial	58%	37%
Residential	32%	59%
Industrial	10%	4%
Total	**100%**	**100%**

While our customer base has modestly increased since 2013, electric load has declined and gas load has increased as illustrated below:

Electric and Gas Distribution Statistics

December 31, 2017

	Number of Customers	Electric Sales and Gas Firm Sales (A)	Historical Annual Load Growth 2013-2017
Electric	2.2 Million	40,740 Gigawatt hours (GWh)	(0.4)%
Gas	1.8 Million	2,397 Million Therms	2.8%

(A) Excludes sales from Gas rate classes that do not impact margin, specifically Contract, Non-Firm Transportation, Cogeneration Interruptible and Interruptible Services.

The decline in electric sales is the result of changes in customer usage patterns, including conservation and more energy efficient appliances. Gas firm sales increased as a result of customer response to continued low gas prices. Only gas firm sales impact margin.

PSE&G, as part of its BPU-approved Energy Strong Program, completed the replacement and modernization of 240 miles of low-pressure cast iron gas mains in or near flood areas. PSE&G continues to execute the Energy Strong Program to upgrade all of its electric substations that were damaged by water in recent storms; make investments that will create redundancy in the electric distribution system, reducing outages when damage occurs; and deploy technologies to better monitor system operations, enabling PSE&G to restore customers more quickly in the event of an electric outage, and with respect to PSE&G's gas system, upgrade five natural gas metering stations and a liquefied natural gas station recently affected by severe weather or located in flood zones.

PSE&G continues modernizing its gas distribution system as part of our Gas System Modernization Program (GSMP) which was approved by the BPU in late 2015. The GSMP, through which we expect to invest $905 million over three years, will replace approximately 510 miles of cast iron and unprotected steel gas mains and about 38,000 unprotected steel service lines to homes and businesses, including the uprating of the mains to higher pressure. The mains and service lines will be replaced with stronger, more durable plastic piping, reducing the potential for leaks and release of methane gas. The new elevated pressure systems also enable the installation of excess flow valves that automatically shut off gas flow if a service line is damaged, and better support the use of high-efficiency appliances.

In July 2017, we filed a petition with the BPU for a GSMP II program, an extension of our GSMP through which PSE&G has proposed investing $2.7 billion over five years beginning in 2019 to continue to modernize our gas system. For additional information, see Regulatory Issues.

Solar Generation

In order to support New Jersey's Energy Master Plan and the state's renewable energy goals, we have undertaken two major solar initiatives at PSE&G, the Solar Loan Program and the Solar 4 All and Solar 4 All Extension Programs. Our Solar Loan Program provides solar system financing to our residential and commercial customers. The loans are repaid with cash or solar renewable energy certificates (SRECs). We sell the SRECs received through periodic auctions and use the proceeds to offset program costs. Our Solar 4 All Programs invest in utility-owned solar photovoltaic (PV) centralized solar systems installed on PSE&G property and third-party sites, including landfill facilities, and solar panels installed on distribution system poles in our electric service territory. We sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition, we sell SRECs generated by the projects through the same periodic auction used in the loan program, the proceeds of which are used to offset program costs.

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Supply

Although commodity revenues make up almost 38% of our revenues, we make no margin on the default supply of electricity and gas since the actual costs are passed through to our customers.

All electric and gas customers in New Jersey have the ability to choose their own electric energy and/or gas supplier. Pursuant to BPU requirements, we serve as the supplier of last resort for two types of electric and gas customers within our service territory that are not served by another supplier. The first type, which represents about 80% of PSE&G's load requirements, provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Residential Small Commercial Pricing (RSCP)). These rates change annually on June 1 and are based on the average price obtained at auctions in the current year and two prior years. The second type provides default supply for larger customers, with energy priced at hourly PJM real-time market prices for a contract term of 12 months (BGS-Commercial Industrial Energy Pricing (CIEP)).

We procure the supply to meet our BGS obligations through auctions authorized by the BPU for New Jersey's total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers are authorized to supply BGS to New Jersey's electric distribution companies (EDCs). Once validated by the BPU, electricity prices for BGS service are set. Approximately one-third of PSE&G's total BGS-RSCP eligible load is auctioned each year for a three-year term. For information on current prices, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

PSE&G procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with Power. The BPU has approved a mechanism designed to recover all gas commodity costs related to BGSS for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. PSE&G's revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each year. In addition, we have the ability to put in place two self-implementing BGSS increases on December 1 and February 1 of up to 5% and also may reduce the BGSS rate at any time and/or provide bill credits. See Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities for information on recent self-implementing credits. Any difference between rates charged under the BGSS contract and rates charged to our residential customers is deferred and collected or refunded through adjustments in future rates. Commercial and industrial customers that do not select third-party suppliers are also supplied under the BGSS arrangement. These customers are charged a market-based price largely determined by prices for commodity futures contracts.

Markets and Market Pricing

Historically, there has been significant volatility in commodity prices. Such volatility can have a considerable impact on us since a rising commodity price environment results in higher delivered electric and gas rates for customers. This could result in decreased demand for electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs from our customers may be deferred under our regulated rate structure. A declining commodity price on the other hand, would be expected to have the opposite effect. For additional information, including the impact of natural gas commodity prices on electricity prices such as BGS, see Item 7. MD&A—Executive Overview of 2017 and Future Outlook.

Power

Through Power, we seek to produce low-cost electricity by efficiently operating our nuclear, coal, gas, oil-fired and renewable generation assets while balancing generation output, fuel requirements and supply obligations through energy portfolio management. Our commitments for load, such as BGS in New Jersey and other bilateral supply contracts, are backed by the generation we own and may be combined with the use of physical commodity purchases and financial instruments from the market to optimize the economic efficiency of serving the load. Power is a public utility within the meaning of the Federal Power Act and the payments it receives and how it operates are subject to FERC regulation. Power is also subject to certain regulatory requirements imposed by state utility commissions such as those in New York and Connecticut.

Products and Services

As a merchant generator and power marketer, our profit is derived from selling a range of products and services under contract to an array of customers including utilities, other power marketers, such as retail energy providers, or counterparties in the open market. These products and services may be transacted bilaterally or through exchange markets and include but are not limited to:

- **Energy**—the electrical output produced by generation plants that is ultimately delivered to customers for use in lighting, heating, air conditioning and operation of other electrical equipment. Energy is our principal product and is priced on a usage basis, typically in cents per kilowatt hour (kWh) or dollars per megawatt hour (MWh).

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- **Capacity**—distinct from energy, capacity is a market commitment that a given generation unit will be available to an Independent System Operator (ISO) for dispatch to produce energy when it is needed to meet system demand. Capacity is typically priced in dollars per MW for a given sale period (e.g. day or month).
- **Ancillary Services**—related activities supplied by generation unit owners to the wholesale market that are required by the ISO to ensure the safe and reliable operation of the bulk power system. Owners of generation units may bid units into the ancillary services market in return for compensatory payments. Costs to pay generators for ancillary services are recovered through charges collected from market participants.
- **Congestion and Renewable Energy Credits**—Congestion credits (or Financial Transmission Rights) are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path. Renewable Energy Credits (RECs) are obtained through Power's owned renewable generation or purchased in the open market. Electric suppliers of load are required to deliver a certain amount or percentage of their delivered power from renewable resources as mandated by applicable regulatory requirements.

Power also sells wholesale natural gas, primarily through a full-requirements BGSS contract with PSE&G to meet the gas supply requirements of PSE&G's customers. In 2014, the BPU approved an extension of the long-term BGSS contract to March 31, 2019 and then year-to-year thereafter unless terminated by either party with a two year notice.

Approximately 45% of PSE&G's peak daily gas requirements is provided from Power's firm gas transportation capacity, which is available every day of the year. Power satisfies the remainder of PSE&G's requirements from storage contracts, liquefied natural gas, seasonal purchases, contract peaking supply and propane. Based upon the availability of natural gas beyond PSE&G's daily needs, Power sells gas to others and uses it for its generation fleet.

In addition to its nuclear and fossil generation fleet, Power owns and operates 414 MW direct current (dc) of PV solar generation facilities. Power also has a 50% ownership interest in a 208 MW oil-fired generation facility in Hawaii.

The remainder of this section about Power covers our nuclear and fossil fleet in the Mid-Atlantic and Northeast regions which comprises the vast majority of Power's operations and financial performance.

How Power's Generation Operates

Nearly all of our generation capacity consists of nuclear and fossil generation (10,562 MW) that is located in the Northeast and Mid-Atlantic regions of the United States in some of the country's largest and most developed electricity markets. For additional information see Item 2. Properties.

The map below shows the locations of our Northeast and Mid-Atlantic nuclear and fossil generation facilities, including projects currently under construction:

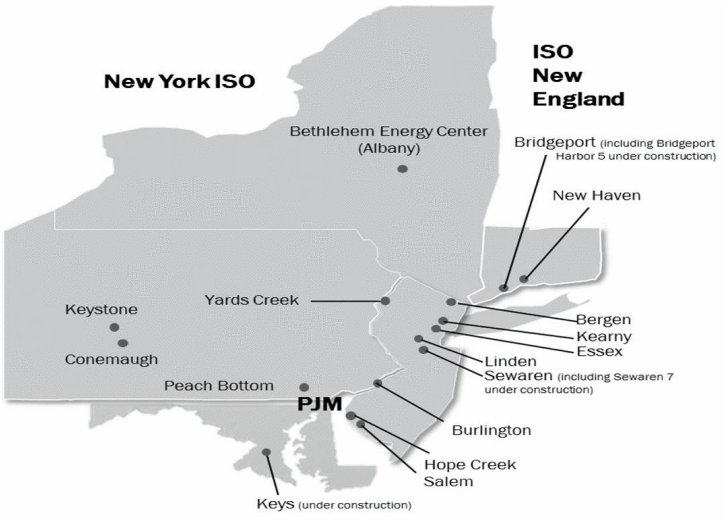

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- **Generation Capacity**

Our nuclear and fossil installed capacity utilizes a diverse mix of fuels. As of December 31, 2017, our fuel mix was comprised of 47% gas, 35% nuclear, 11% coal, 5% oil and 2% pumped storage. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2017 was approximately 51,100 GWh. The generation mix by fuel type in recent years has reflected the relatively more favorable price of natural gas compared to coal, making it more economical to run certain of our gas units in place of our coal units. The following table indicates the proportionate share of generating output by fuel type in 2017.

Generation by Fuel Type (A)	Actual 2017	
Nuclear:		
New Jersey facilities	41%	
Pennsylvania facilities	21%	
Fossil:		
Coal:		
Pennsylvania facilities	11%	
Connecticut facilities	—%	(B)
Natural Gas and Oil:		
New Jersey facilities	17%	
New York facilities	10%	
Connecticut facilities	—%	(B)
Total	**100%**	

(A) Excludes pumped storage, solar facilities and fossil generation in Hawaii which account for less than 2.5 percent of total generation.

(B) Less than one percent.

We are also executing the following growth projects which are included in the 2018-2020 planned capital spend of $520 million for Fossil Growth Opportunities disclosed in Item 7. MD&A—Capital Requirements.

Major Growth Projects
As of December 31, 2017

Project	Location	Expected In-Service Date	
Keys Energy Center gas-fired combined cycle generating station (755 MW)	Maryland	2018	
Sewaren 7 dual-fueled combined cycle generating station (540 MW)	New Jersey	2018	
Bridgeport Harbor 5 gas-fired combined cycle generating station (485 MW)	Connecticut	2019	
Bethlehem Energy Center (BEC) combined cycle uprate (56 MW)	New York	2019	(A)
Bergen dual-fueled combined cycle uprate (32 MW)	New Jersey	2020	

(A) Two-thirds of the project is complete and operational.

- **Generation Dispatch**

Our generation units have historically been characterized as serving one or more of three general energy market segments: base load; load following; and peaking, based on their operating capability and performance.

- **Base Load Units** run the most and typically are called to operate whenever they are available. These units generally derive revenues from both energy and capacity sales. Variable operating costs are low due to the combination of highly efficient operations and the use of relatively lower-cost fuels. Performance is generally measured by the unit's "capacity factor," or the ratio of the actual output to the theoretical maximum output. In 2017, our base load capacity factors were as follows:

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Unit	2017 Capacity Factor
Nuclear	
Salem Unit 1	89.0%
Salem Unit 2	84.9%
Hope Creek	100.0%
Peach Bottom Unit 2	99.2%
Peach Bottom Unit 3	91.4%
Coal	
Keystone	79.4%
Conemaugh	75.7%

- **Load Following Units'** operating costs are generally higher per unit of output than for base load units due to the use of higher-cost fuels such as oil, natural gas and, in some cases, coal or lower overall unit efficiency. These units usually have more flexible operating characteristics than base load units which enable them to more easily follow fluctuations in load. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.
- **Peaking Units** run the least amount of time and in some cases may utilize higher-priced fuels. These units typically start very quickly in response to system needs. Costs per unit of output tend to be higher than for base load units given the combination of higher heat rates and fuel costs. The majority of revenues are from capacity and ancillary service sales. The characteristics of these units enable them to capture energy revenues during periods of high energy prices.

In the energy markets in which we operate, owners of power plants specify to the ISO prices at which they are prepared to generate and sell energy based on the marginal cost of generating energy from each individual unit. The ISOs will generally dispatch in merit order, calling on the lowest variable cost units first and dispatching progressively higher-cost units until the point that the entire system demand for power (known as the system "load") is satisfied reliably. Base load units are dispatched first, with load following units next, followed by peaking units. It should be noted that the sustained lower pricing of natural gas over the past several years has resulted in changes in relative operating costs compared to historical norms, wherein some gas-fired generation is now able to displace some coal-fired generation. This change, combined with the addition of new, more efficient generation capacity, has altered the historical dispatch order of certain plants in the markets where we operate.

During periods when one or more parts of the transmission grid are operating at full capability, thereby resulting in a constraint on the transmission system, it may not be possible to dispatch units in merit order without violating transmission reliability standards. Under such circumstances, the ISO may dispatch higher-cost generation out of merit order within the congested area and power suppliers will be paid an increased Locational Marginal Price (LMP) in congested areas, reflecting the bid prices of those higher-cost generation units.

Typically, the bid price of the last unit dispatched by an ISO establishes the energy market-clearing price. After considering the market-clearing price and the effect of transmission congestion and other factors, the ISO calculates the LMP for every location in the system. The ISO pays all units that are dispatched their respective LMP for each MWh of energy produced, regardless of their specific bid prices. Since bids generally approximate the marginal cost of production, units with lower marginal costs typically generate higher operating profits than units with comparatively higher marginal costs.

This method of determining supply and pricing creates a situation where natural gas prices often have a major influence on the price that generators will receive for their output, especially in periods of relatively strong or weak demand. Therefore, changes in the price of natural gas will often translate into changes in the wholesale price of electricity. This can be seen in the following graphs which present historical annual spot prices and forward calendar prices as averaged over each year at two liquid trading hubs.

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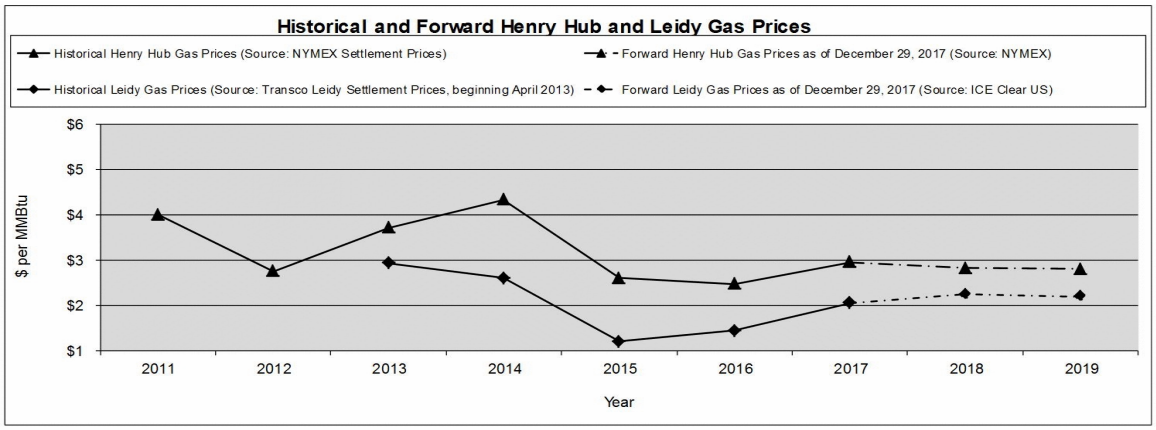

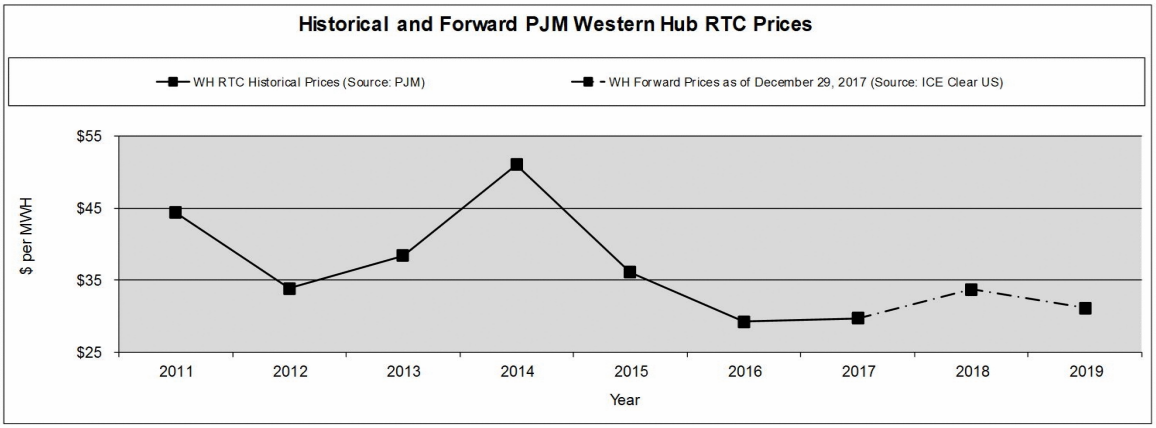

Historical data implies that the price of natural gas will continue to have a strong influence on the price of electricity in the primary markets in which we operate.

The prices reflected in the preceding graphs above do not necessarily illustrate our contract prices, but they are representative of market prices at relatively liquid hubs, with nearer-term forward pricing generally resulting from more liquid markets than pricing for later years. As shown above, prices may vary by location resulting from congestion or other factors, such as the availability of natural gas from the Marcellus (Leidy) and other shale-gas regions. These variations can be considerable. Concurrent with the development of regional shale gas, we have been increasing our purchases from the Marcellus/Utica shale gas regions and in 2017 they accounted for approximately 86% of the gas we procured. While these prices provide some perspective on past and future prices, the forward prices are volatile and there can be no assurance that such prices will remain in effect or that we will be able to contract output at these forward prices.

Fuel Supply

- ***Nuclear Fuel Supply***—We have long-term contracts for nuclear fuel. These contracts provide for:
  - purchase of uranium (concentrates and uranium hexafluoride),
  - conversion of uranium concentrates to uranium hexafluoride,
  - enrichment of uranium hexafluoride, and
  - fabrication of nuclear fuel assemblies.

  Our nuclear fuel contracts cover approximately 100% of our estimated uranium, enrichment and fabrication requirements through 2020 and a significant portion through 2022.

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- ***Coal Supply***—Our Keystone, Conemaugh and Bridgeport stations operate on coal. Coal is delivered to our units through a combination of rail, truck, barge and ocean shipments.

  In order to control emissions levels, our Bridgeport 3 unit uses a specific type of coal obtained from Indonesia. We have coal inventory at the Bridgeport Station as well as off-site storage to meet the plant's projected requirements.

- ***Gas Supply***—Natural gas is the primary fuel for the bulk of our load following and peaking fleet. We purchase gas directly from natural gas producers and marketers. These supplies are transported to New Jersey by four interstate pipelines with which we have contracted. In addition, we have firm gas transportation contracted for this winter season to serve a portion of the gas requirements for our BEC station in New York.

  We have 1.3 billion cubic feet-per-day of firm transportation capacity and 0.9 billion cubic feet-per-day of firm storage delivery under contract to meet our obligations under the BGSS contract. This volume includes capacity from the Pennsylvania and Ohio shale gas regions where we purchase the majority of our natural gas. On an as-available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet.

  Power has contracted for approximately 125 million cubic feet-per-day of delivery capability on the PennEast Pipeline from eastern Pennsylvania to New Jersey with a targeted in-service date in 2019. This additional delivery capability will be used to supplement the BGSS contract.

- ***Oil***—Oil is used as the primary fuel for one load following steam unit and four combustion turbine peaking units and can be used as an alternate fuel by several load following and peaking units that have dual-fuel capability. Oil for operations is drawn from on-site storage and is generally purchased on the spot market and delivered by truck or barge.

We expect to be able to meet the fuel supply demands of our customers and our own operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather, environmental regulations, and other factors. For additional information and a discussion of risks, see Item 1A. Risk Factors, Item 7. MD&A—Executive Overview of 2017 and Future Outlook and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Markets and Market Pricing

The vast majority of Power's generation assets are located in three centralized, competitive electricity markets operated by ISO organizations all of which are subject to the regulatory oversight of FERC:

- **PJM Regional Transmission Organization**—PJM conducts the largest centrally dispatched energy market in North America. It serves over 65 million people, nearly 20% of the total United States population, and has a record peak demand of 165,492 MW. The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The majority of our generating stations operate in PJM.

- **New York**—The New York ISO (NYISO) is the market coordinator for New York State and is responsible for managing the New York Power Pool and for administering its energy marketplace. This service area has a population of about 19 million and a record peak demand of 33,956 MW. Our BEC station operates in New York.

- **New England**—The ISO-New England (ISO-NE) is the market coordinator for the New England Power Pool and for administering its energy marketplace which covers Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. This service area has a population of about 15 million and a record peak demand of 28,130 MW. Our Bridgeport and New Haven stations operate in Connecticut.

The price of electricity varies by location in each of these markets. Depending upon our production and our obligations, these price differentials may increase or decrease our profitability.

Commodity prices, such as electricity, gas, coal, oil and environmental products, as well as the availability of our diverse fleet of generation units to operate, also have a considerable effect on our profitability. Over the long-term, the higher the forward prices are, the more attractive an environment exists for us to contract for the sale of our anticipated output. However, higher prices also increase the cost of replacement power; thereby placing us at greater risk should our generating units fail to operate effectively or otherwise become unavailable.

Over the past few years, lower wholesale natural gas prices have resulted in lower electric energy prices. One of the reasons for the lower natural gas prices is greater supply from more recently-developed sources, such as shale gas, much of which is produced in adjacent states (e.g. Pennsylvania). This trend has reduced margin on forward sales as we re-contract our expected generation output.

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In addition to energy sales, we earn revenue from capacity payments for our generating assets. These payments are compensation for committing our generating units to the ISO for dispatch at its discretion. Capacity payments reflect the value to the ISO of assurance that there will be sufficient generating capacity available at all times to meet system reliability and energy requirements. Currently, there is sufficient capacity in the markets in which we operate. However, in certain areas of these markets there are transmission system transfer limitations which raise concerns about reliability and create a more acute need for capacity.

In PJM and ISO-NE, where we operate most of our generation, the market design for capacity payments provides for a structured, forward-looking, transparent capacity pricing mechanism. This is through the Reliability Pricing Model (RPM) in PJM and the Forward Capacity Market (FCM) in ISO-NE. These mechanisms provide greater transparency regarding the value of capacity and provide a pricing signal to prospective investors in new generating facilities so as to encourage expansion of capacity to meet future market demands.

The prices to be received by generating units in PJM for capacity have been set through RPM base residual and incremental auctions and depend upon the zone in which the generating unit is located. For each delivery year, the prices differ in the various areas of PJM, depending on the transfer limitations of the transmission system in each area. Keystone and Conemaugh receive lower capacity prices than the majority of our PJM generating units since there are fewer constraints in that region and our generating units in New Jersey usually receive higher pricing.

Our PJM generating units are located in several zones and Power expects to realize the following average capacity prices from the base and incremental auctions which have been completed:

Delivery Year	MW-day
June 2017 to May 2018	$177
June 2018 to May 2019	$215
June 2019 to May 2020	$116
June 2020 to May 2021	$174

The price that must be paid by an entity serving load in the various zones is also set through these auctions. These prices can be higher or lower than the prices noted in the table above due to import and export capability to and from lower-priced areas.

We have obtained price certainty for our PJM capacity through May 2021 and New England capacity through May 2022 through the RPM and FCM pricing mechanisms, respectively.

Like PJM and ISO-NE, the NYISO provides capacity payments to its generating units, but unlike the other two markets, the New York market does not provide a forward price signal beyond a six month auction period.

On a prospective basis, many factors may affect the capacity pricing, including but not limited to:

- load and demand,
- availability of generating capacity (including retirements, additions, derates and forced outage rates),
- capacity imports from external regions,
- transmission capability between zones,
- available amounts of demand response resources,
- pricing mechanisms, including potentially increasing the number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM and the other ISOs may propose over time, and
- legislative and/or regulatory actions that permit subsidized local electric power generation.

For additional information on the RPM and FCM markets, as well as on state subsidization through various mechanisms, see Regulatory Issues—Federal Regulation.

Hedging Strategy

To mitigate volatility in our results, we seek to contract in advance for a significant portion of our anticipated electric output, capacity and fuel needs. We seek to sell a portion of our anticipated lower-cost generation over a multi-year forward horizon, normally over a period of two to three years. We believe this hedging strategy increases stability of earnings.

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Among the ways in which we hedge our output are: (1) sales at PJM West and (2) BGS and similar full-requirements contracts. Sales at PJM West reflect block energy sales at the liquid PJM Western Hub and other transactions that seek to secure price certainty for our generation related products. The BGS-RSCP contract, a full-requirements contract that includes energy and capacity, ancillary and other services, is awarded for three-year periods through an auction process managed by the BPU. The volume of BGS contracts and the mix of electric utilities that our generation operations serve will vary from year to year. Pricing for the BGS contracts, including a capacity component, for recent and future periods by purchasing utility is as follows:

Load Zone ($/MWh)	2015-2018	2016-2019	2017-2020	2018-2021
PSE&G	$99.54	$96.38	$90.78	$91.77
Jersey Central Power & Light Company (JCP&L)	$80.42	$74.85	$69.08	$73.11
Atlantic City Electric Company	$86.06	$82.14	$75.49	$81.23
Rockland Electric Company	$90.66	$85.02	$80.50	$85.94

Although we enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation, there is variability in both our actual output as well as in the effectiveness of our hedges. Actual output will vary based upon total market demand, the relative cost position of our units compared to other units in the market and the operational flexibility of our units. Hedge volume can also vary, depending on the type of hedge into which we have entered. The BGS auction, for example, results in a contract that provides for the supplier to serve a percentage of the default load of a New Jersey EDC, that is, the load that remains after some customers have chosen to be served directly either by third-party suppliers or through municipal aggregation. The amount of power supplied through the BGS auction varies based on the level of the EDC's default load, which is affected by the number of customers who are served by third-party suppliers, as well as by other factors such as weather and the economy.

In recent years, as market prices declined from previous levels, there was an incentive for more of the smaller commercial and industrial electric customers to switch to third-party suppliers. In a falling price environment, this has a negative impact on our margins, as the anticipated BGS pricing is replaced by lower spot market pricing. As average BGS rates have declined to a level that more closely resembles current market prices, customers may see less of an incentive to switch to third-party suppliers. We are unable to determine the degree to which this switching, or "migration," will continue, but the impact on our results could be material should market prices fall or rise significantly.

Power is developing a retail energy business to sell energy directly to commercial and industrial customers. We believe a retail energy platform complements our existing wholesale generation-to-load marketing business that is intended to hedge our generation assets. Power began these marketing activities in 2017 and has been granted retail energy supplier licenses in New Jersey, Pennsylvania and Maryland.

As of February 8, 2018, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2020.

Base Load Generation	2018	2019	2020
Generation Sales	100%	95%-100%	50%-55%

In a changing market environment, this hedging strategy may cause our realized prices to differ materially from current market prices. In a rising price environment, this strategy normally results in lower margins than would have been the case had no hedging activity been conducted. Alternatively, in a falling price environment, this hedging strategy will tend to create margins higher than those implied by the then-current market.

Our fuel strategy is to maintain certain levels of uranium in inventory and to make periodic purchases to support such levels. Our nuclear fuel commitments cover approximately 100% of our estimated uranium, enrichment and fabrication requirements through 2020 and a significant portion through 2022. In March 2017, Westinghouse Electric Company (WEC) announced that it had filed for Chapter 11 bankruptcy in New York. WEC provides nuclear fuel fabrication services for Salem Units 1 and 2. In January 2018, Brookfield Business Partners LP announced its intention to acquire WEC. The acquisition is expected to close in 2018 if it receives the required approvals from the regulators and bankruptcy courts. No assurances can be given that the acquisition will be approved. In the event that WEC is unable to continue to provide fabrication services, we can provide no assurance that Power would be able to find alternative providers of such services in a timely manner or on acceptable terms. A failure by WEC to perform its obligations during the pendency of, or following its emergence from, bankruptcy could have a material adverse impact on our business, the financial results of specific plants and on our results of operations.

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We also have various long-term fuel purchase commitments for coal to support our Keystone and Conemaugh stations. These purchase obligations are consistent with our strategy in general to enter into contracts for our fuel supply in comparable volumes to our sales contracts.

We take a more opportunistic approach in hedging both the fuel for and the anticipated output of our natural gas-fired generation. The generation from these units is less predictable, as a significant portion of these units will only dispatch when aggregate market demand has exceeded the supply provided by lower-cost units. Additionally, the recent development of low-cost gas supplies in the Marcellus region presents opportunities during certain portions of the year to procure gas for our generating units at attractive prices.

More than half of Power's expected gross margin in 2018 relates to our hedging strategy, our expected revenues from the capacity market mechanisms described above and certain ancillary service payments such as reactive power.

Other

Energy Holdings primarily owns and manages a portfolio of domestic lease investments. The majority of Energy Holdings' $565 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2017, the counterparties for 59% of our total leveraged lease investments were rated below investment grade by Standard & Poor's (S&P). See Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables for additional information.

Energy Holdings' leveraged leasing portfolio is designed to provide a fixed rate of return. Leveraged lease investments involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease financing, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and, with respect to our lease investments, is not presented on our Consolidated Balance Sheets.

The lessor acquires economic and tax ownership of the asset and then leases it to the lessee for a period of time no greater than 80% of its remaining useful life. As the owner, the lessor is entitled to depreciate the asset under applicable federal and state tax guidelines. The lessor receives income from lease payments made by the lessee during the term of the lease and from tax benefits associated with interest and depreciation deductions with respect to the leased property. Our ability to realize these tax benefits is dependent on operating gains generated by our other operating subsidiaries and allocated pursuant to the consolidated tax sharing agreement between us and our operating subsidiaries.

Lease rental payments are unconditional obligations of the lessee and are set at levels at least sufficient to service the non-recourse lease debt. The lessor is also entitled to any residual value associated with the leased asset at the end of the lease term. An evaluation of the after-tax cash flows to the lessor determines the return on the investment. Under accounting principles generally accepted in the United States (GAAP), the leveraged lease investment is recorded net of non-recourse debt and income is recognized as a constant return on the net unrecovered investment.

For additional information on leases, including the credit, tax and accounting risks, see Item 1A. Risk Factors, Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Credit Risk, and Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables.

In accordance with a twelve year Amended and Restated Operations Services Agreement (OSA) entered into by PSEG LI and LIPA, PSEG LI commenced operating LIPA's electric T&D system in Long Island, New York on January 1, 2014. As required by the OSA, PSEG LI also provides certain administrative support functions to LIPA. PSEG LI uses its brand in the Long Island T&D service area. Pursuant to the OSA, PSEG LI acts as LIPA's agent in performing many of its obligations and in return (a) receives reimbursement for pass-through operating expenditures, (b) receives a fixed management fee and (c) is eligible to receive an incentive fee contingent on meeting established performance metrics. In addition, there is the opportunity for the parties to extend the contract for an additional eight years subject to the achievement by PSEG LI of certain performance levels during the initial term of the OSA. Also, since January 2015, Power provides fuel procurement and power management services to LIPA under separate agreements.

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COMPETITIVE ENVIRONMENT

PSE&G

Our T&D business is minimally impacted when customers choose alternate electric or gas suppliers since we earn our return by providing transmission and distribution service, not by supplying the commodity. Increased reliance by customers on net-metered generation, including solar, and changes in customer behaviors can result in decreased reliance on our system and impact our revenues and investment opportunities. The demand for electric energy and gas by customers is affected by customer conservation, economic conditions, weather and other factors not within our control.

Changes in the current policies for building new transmission lines, such as those ordered by FERC and being implemented by PJM and other ISOs to eliminate contractual provisions that previously provided us a "right of first refusal" (ROFR) to construct projects in our service territory, could result in third-party construction of transmission lines in our area in the future and also allow us to seek opportunities to build in other service territories. These implementing rules within the regions are still in flux so both the extent of the risk within our service territory and the opportunities for our transmission business elsewhere remain difficult to assess. For additional information, see the discussion in Regulatory Issues—Federal Regulation—Transmission Regulation, below.

Construction of new local generation and changing customer usage patterns also have the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints.

Power

Various market participants compete with us and one another in transacting in the wholesale energy markets, entering into bilateral contracts and selling to individual and aggregated retail customers. Our competitors include:

- merchant generators,
- domestic and multi-national utility generators,
- energy marketers and retailers,
- private equity firms, banks and other financial entities,
- fuel supply companies, and
- affiliates of other industrial companies.

New additions of lower-cost or more efficient generation capacity could make our plants less economic in the future. Although it is not clear if this capacity will be built or, if so, what the economic impact will be, such additions would impact market prices and our competitiveness.

Our business is also under competitive pressure due to demand side management (DSM) and other efficiency efforts aimed at changing the quantity and patterns of usage by consumers which could result in a reduction in load requirements. A reduction in load requirements can also be caused by economic cycles, weather, municipal aggregation and other customer migration and other factors. In addition, how resources such as demand response and capacity imports are permitted to bid into the capacity markets also affects the prices paid to generators such as Power in these markets. It is also possible that advances in technology, such as distributed generation and micro grids, will reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. To the extent that additions to the electric transmission system relieve or reduce limitations and constraints in eastern PJM where most of our plants are located, our revenues could be adversely affected. Changes in the rules governing what types of transmission will be built, who is selected to build transmission and who will pay the costs of future transmission could also impact our generation revenues.

Adverse changes in energy industry law, policies and regulation could have significant economic, environmental and reliability consequences. Changes implemented in the PJM and New England capacity markets and other proposed market changes discussed more fully in Regulatory Issues—Federal Regulation provide the opportunity for additional compensation in both the energy and capacity markets.

Environmental issues, such as restrictions on emissions of carbon dioxide (CO_2) and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant, thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states.

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While it is our expectation that continued efforts may be undertaken by the federal and state governments to preserve the existing base of fossil and nuclear generating plants, we still believe that pressures from renewable resources will continue to increase. For example, many parts of the country, including the mid-western region served by the Midwest Independent System Operator (MISO), the PJM region and the California ISO, have either implemented or proposed implementing changes to their respective regional transmission planning processes that may enable the construction of large amounts of "public policy" transmission to move renewable generation to load centers. For additional information, see the discussion in Regulatory Issues—Federal Regulation.

EMPLOYEE RELATIONS

As of December 31, 2017, we had 12,945 employees within our subsidiaries, including 7,999 covered under collective bargaining agreements with eight unions expiring from 2019 through 2022. We believe we maintain satisfactory relationships with our employees.

	Employees as of December 31, 2017			
	PSE&G	Power	PSEG LI	Services
Non-Union	1,959	1,118	881	988
Union	5,209	1,293	1,486	11
Total Employees	**7,168**	**2,411**	**2,367**	**999**

REGULATORY ISSUES

In the ordinary course of our business, we are subject to regulation by, and are party to various claims and regulatory proceedings with, FERC, the BPU, the Commodity Futures Trading Commission and various state and federal environmental regulators, among others. For information regarding material matters, other than those discussed below, see Item 3. Legal Proceedings and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Federal Regulation

FERC

FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act. PSE&G and the generation and energy trading subsidiaries of Power are public utilities as defined by the FPA. FERC has extensive oversight over such public utilities. FERC approval is usually required when a public utility seeks to: sell or acquire an asset that is regulated by FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations.

FERC also regulates generating facilities known as qualifying facilities (QFs). QFs are cogeneration facilities that produce electricity and another form of useful thermal energy, or small power production facilities where the primary energy source is renewable, biomass, waste or geothermal resources. QFs must meet certain criteria established by FERC. We own various QFs through Power. QFs are subject to some, but not all, of the same FERC requirements as public utilities.

FERC also regulates Regional Transmission Operators (RTOs)/ISOs, such as PJM, and their energy and capacity markets.

For us, the major effects of FERC regulation fall into five general categories:

- Regulation of Wholesale Sales—Generation/Market Issues/Market Power
- Energy Clearing Prices
- Capacity Market Issues
- Transmission Regulation
- Compliance

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Regulation of Wholesale Sales—Generation/Market Issues/Market Power

Under FERC regulations, public utilities that wish to sell power at market rates must receive FERC authorization (MBR Authority) to sell power in interstate commerce before making power sales. They can sell power at cost-based rates or apply to FERC for authority to make market-based rate (MBR) sales. For a requesting company to receive MBR Authority, FERC must first make a determination that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. The following PSEG companies are public utilities and currently have MBR Authority: PSE&G, PSEG Energy Resources & Trade (ER&T), PSEG Fossil, PSEG Nuclear, PSEG Power Connecticut, PSEG New Haven, PSEG Energy Solutions, PSEG Keys Energy Center LLC, Pavant Solar II LLC, San Isabel Solar LLC and Bison Solar LLC. FERC requires that holders of MBR Authority file an update every three years demonstrating that they continue to lack market power and/or that their market power has been sufficiently mitigated and report in the interim to FERC any material change in facts from those FERC relied on in granting MBR Authority.

In November 2017, FERC issued an order accepting the triennial filing made by the PSEG companies seeking authority to sell energy, capacity and ancillary services at market-based rates.

Energy Clearing Prices

Energy clearing prices in the markets in which we operate are generally based on bids submitted by generating units. Under FERC-approved market rules, bids are subject to price caps and mitigation rules applicable to certain generation units. FERC rules also govern the overall design of these markets. At present, all units within a delivery zone receive a clearing price based on the bid of the marginal unit (i.e. the last unit that must be dispatched to serve the needs of load) which can vary by location. In addition, recent rule changes in the energy markets administered by PJM and ISO-NE (see Capacity Market Issues below) impose rigorous performance obligations and nonperformance penalties on resources during times of system stress. These FERC rules provide an opportunity for bonus payments or require the payment of penalties depending on whether a unit is available during a performance hour.

FERC has also ordered certain favorable changes to energy market price formation rules improving shortage pricing and enhancing bidding flexibility for units. We continue to advocate in this context for additional changes in market rules that would provide more transparency regarding operator actions affecting energy market prices and would promote better alignment between generation dispatch decisions and energy market price outcomes. We cannot predict what actions FERC might ultimately take, but such an examination could lead to future rule changes.

In June 2017, PJM issued an energy price formation proposal to address a flaw in the energy market in which energy prices during off-peak periods often do not reflect the production costs of generators during these periods even though they are serving load. PJM's proposal would allow large, inflexible units to set price. If placed into effect, this proposal will improve price formation by ensuring that the marginal costs of units serving load will be better reflected in clearing prices. We cannot predict the outcome of this matter.

Capacity Market Issues

PJM, NYISO and ISO-NE each have capacity markets that have been approved by FERC. FERC regulates these markets and continues to examine whether the market design for each of these three capacity markets is working optimally. Various forums are considering how the competitive market framework can incorporate or be reconciled with state public policies that support particular resources, resource attributes or emerging technologies, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market prices. We cannot predict what action, if any, FERC might take with regard to capacity market designs.

PJM—The RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under the RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of the RPM in PJM continue to evolve and be refined in stakeholder proceedings and FERC proceedings in which we are active.

During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product with enhanced incentives for performance during emergency conditions and significant penalties for non-performance, which was implemented fully in the May 2017 RPM auction for the 2020-2021 Delivery Year. The CP mechanism is intended to enhance the participation of intermittent and demand response resources (seasonal resources). Specifically, FERC approved PJM's modifications to the aggregation rules to improve the ability of seasonal resources to participate. However, two complaints remain pending that ask FERC to investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions. We cannot predict the outcome of these matters.

PJM issued a series of white papers in response to public policies that seek to recognize value associated with generation plants beyond their cost effectiveness and reliability attributes. The three proposals are intended to spur stakeholder discussion and include both potential capacity and energy market reforms. The first energy market reform (see Energy Clearing Prices and

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Price Formation Initiatives) would allow inflexible generating units to set prices resulting in reduced uplift payments and improved price signals while the second energy market reform contemplates a voluntary carbon pricing program where states that elect to participate in the program would agree to put a price on carbon emissions. The capacity market proposal contemplates a two-stage capacity auction which, in its current form, would improve prices for unsubsidized resources, but would still continue to provide capacity payments for subsidized resources. The two-stage capacity market auction is now pending before the PJM stakeholders for consideration.

ISO-NE—ISO-NE's market for installed capacity in New England provides fixed capacity payments for generators, imports and demand response. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. ISO-NE also employs a mechanism, similar to PJM's CP mechanism, that provides incentives for performance and that imposes charges for non-performance during times of system stress. We view this mechanism as generally positive for generating resources as providing more robust income streams. However, it also imposes additional financial risk for non-performance. One aspect of the current market design that we do not support due to the capacity market suppression associated with this mechanism is the exemption from the MOPR in the capacity market afforded for up to 200 MW annually (600 MW cumulatively) of renewable resources. Recently, ISO-NE submitted proposed changes to the FCM referred to as the Competitive Auctions and Sponsored Policy Resources (CASPR) proposal to accommodate clean and renewable energy policy resources. The CASPR design creates a second auction that commences immediately following the Forward Capacity Auction and provides the opportunity for certain renewable, clean and alternative energy resources to acquire supply obligations when they cannot clear economically in the Forward Capacity Auction. The CASPR design also proposed to phase out the 200 MW exemption from the minimum offer price rule (MOPR). We cannot predict the outcome of this proceeding.

NYISO—NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. Various matters pending before FERC could affect the competitiveness of this market and the outcome of these proceedings could result in artificial price suppression unless sufficient market protections are adopted.

One capacity market matter pending before FERC involves rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons. In March 2015, FERC issued an order which held that units receiving special reliability payments could properly take those payments into account in formulating capacity market bids. We believe that this ruling could impact efficient price formation in the capacity market and could artificially suppress capacity market outcomes. In April 2015, a trade association, Independent Power Producers of New York, Inc. (IPPNY) of which Power is a member, filed for rehearing by FERC of this ruling. This rehearing is still pending. Also, in connection with this same proceeding, FERC required NYISO to submit a report addressing whether buyer-side mitigation measures are needed for new entry occurring in the "Rest of State" (ROS) region and for uneconomic retention and repowering anywhere in the state. NYISO filed a report with FERC in December 2015 contending that these measures are not needed. The IPPNY has opposed NYISO's contentions. The matter remains pending before FERC. In addition, in May 2015, the New York Public Service Commission and other New York agencies filed a complaint at FERC requesting certain exemptions from the NYISO rules that prevent capacity suppliers from submitting bids that are not market competitive. In October 2015, FERC granted in part, certain of the requested exemptions for renewable resources and for resources being used by the owner for self-supply. The IPPNY has challenged NYISO's proposed implementation of the newly required exemptions. This challenge is still pending.

Price Formation Initiatives

Power has been actively involved both through stakeholder processes and through filings at FERC in seeking improvements to the rules for setting prices for energy in the day-ahead and real-time markets administered by PJM and other system operators. FERC recently issued an order instituting an investigation into the pricing of fast-start resources by three grid operators, PJM, NYISO and Southwest Power Pool. Fast-start resources typically are committed in real-time, very close to the interval when needed and can respond quickly to unforeseen system needs. However, without fast-start pricing, some fast-start resources are ineligible to set prices due to inflexible operating limits. As a result, prices may not reflect the marginal cost of serving load. PJM submitted a response to FERC's order that supported reforms to fast-start pricing with minor modifications. PJM also contended that all fast-start resource scheduled by PJM should be eligible to set locational marginal prices. We cannot predict the impact that these changes may have on our business.

Notice of Proposed Rulemaking (NOPR) on Baseload Generation

In September 2017, the Secretary of the U.S. Department of Energy (DOE) issued a NOPR to allow a full recovery of costs for certain eligible units physically located within the FERC-approved organized markets. In January 2018, FERC issued an order terminating the proceeding and initiating a new proceeding to explore resilience issues with the RTOs and ISOs. In the new proceeding, FERC is requiring each RTO and ISO to respond to a series of questions that appear to be intended to gain an

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understanding of the steps each RTO and ISO is taking to ensure the resilience of their respective grids. We expect to participate in this proceeding, but we are unable to predict the outcome.

Transmission Regulation

FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures. Our allowed ROE is 11.68% for both existing and new transmission investments and we have received incentive rates, affording a higher ROE, for certain large scale transmission investments.

In October 2017, the 2018 Annual Formula Rate Update was filed with FERC and requested approximately $212 million in increased annual transmission revenues effective January 1, 2018, subject to true-up. In January 2018, PSE&G filed with FERC a revised 2018 Annual Transmission Formula Rate Update reducing the 2018 transmission annual revenue requirement to reflect the federal corporate income tax rate reduction from 35% to 21%, effective January 1, 2018, as provided in new comprehensive tax legislation enacted in December 2017 (Tax Act). This change in the federal corporate income tax rate reduces the annual revenue requirement by $148 million. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. For additional information about our transmission formula rate, see Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

Transmission Policy Developments—FERC concluded in Order 1000 that the incumbent transmission owner should not always have a ROFR to construct and own transmission projects in its service territory. The current PJM rules retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including immediately needed reliability projects, upgrades to existing transmission facilities, projects cost-allocated to a single transmission zone, and projects being built on existing rights-of-way and whose construction would interfere with incumbents' use of their rights-of-way.

In a February 2016 order, FERC reversed a previous order and accepted a filing by the PJM transmission owners seeking authority to assign costs for Regional Transmission Expansion Plan projects (subject to PJM Board approval requirements) solely addressing localized needs to customers within the local transmission owner's zone. FERC's action in this order provides an exemption from the Order 1000 open window procedures for projects constructed by transmission owners to meet local transmission planning criteria. FERC's orders have been challenged at the D.C. Circuit and PSE&G has intervened in support of FERC.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G contending that insufficient levels of costs are being allocated to customers in the PSE&G transmission zone. Projects involved include the Artificial Island project, the Bergen-Linden project in New Jersey and a smaller project in Sewaren, New Jersey. In April 2016, FERC issued orders denying the complaints and leaving the current cost allocation in effect as to the Artificial Island and Bergen-Linden projects. Due to an intervening FERC order concerning the allocation of costs for projects constructed to meet local reliability requirements, FERC directed that all of the Sewaren costs be allocated to customers in the PSE&G transmission zone. It is anticipated that additional proceedings are likely to occur.

In February 2016, FERC issued an order granting PSE&G's request that it be permitted to seek recovery of 100% of its portion of the project's costs to address identified high voltage issues at Artificial Island in New Jersey if the project is canceled for reasons beyond PSE&G's control. In April 2016, PSE&G accepted construction responsibility for the three components of the project that PJM assigned to it, based on having reached agreement with PJM regarding an estimate for the project base cost of $273 million, plus risk and contingency for a total project cost of up to $340 million. In March 2017, PJM staff made its final recommendation to the PJM Board with respect to the project. In April 2017, the PJM Board approved a portion of the project to PSE&G of the construction of necessary upgrade work at a cost of approximately $130 million. In October 2017, FERC accepted PJM's filing on the grounds that PJM correctly applied its Tariff. However, FERC deferred a ruling on whether the cost allocation methodology applied to the Artificial Island project is appropriate. FERC will decide this issue in a separate proceeding that is currently pending. We are unable to predict the outcome.

In June 2015, a transmission developer filed a complaint against PJM claiming that PJM wrongfully refused to provide data and a transparent process for evaluating transmission network upgrade requests that the transmission developer had submitted to PJM. Although not named as a respondent, the complaint identifies PSE&G as one of the companies claimed to have been involved. In January 2018, a FERC administrative law judge issued an order generally finding that PJM and transmission owners, including PSE&G, did not engage in wrongful conduct. In addition, the developer's assertion of an entitlement to monetary damages was expressly denied. However, in a determination disputed by PSE&G, the order found that the PJM process lacked transparency. The judge's order will now be briefed by all parties for additional determinations by FERC.We are unable to predict the outcome of these proceedings.

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Another proceeding is a matter remanded from a federal appellate court concerning the appropriate cost allocation for certain 500 kV projects in PJM that either have been built or are in the process of being built. A proposed settlement was filed with FERC in June 2016. The settlement, if adopted by FERC, would result in increased annual cost allocations to customers in the PSE&G transmission zone. Under this settlement, Power, as a BGS supplier could become obligated to pay amounts previously paid by other PJM transmission customers. However, we do not believe that the anticipated level of any such potential payments would have a material effect on Power's financial statements. We believe that there is a mechanism in place under the BGS contract for the pass-through of increases in transmission charges.

In February 2018, FERC issued an order finding that the transmission planning procedures used by the PJM transmission owners, a group that includes PSE&G, for supplemental projects do not adhere to the coordination and transparency principles of FERC's Order No. 890. FERC determined that certain terms and conditions in the PJM governing documents are unjust and unreasonable. FERC directed PJM and the PJM transmission owners to submit certain revisions to the manner in which the stakeholder process for supplemental projects is conducted. PSE&G will be participating in the PJM transmission owners' compliance filing.

Transmission Rate Proceedings—Numerous complaints have been filed at FERC in recent years seeking to reduce the base ROE of transmission owners across the country. Many of those complaints were resolved through agreement and settlement resulted in ROE reductions while others remain pending in the FERC adjudication process or are being litigated in the courts. Recent court decisions, as well as anticipated changes in the makeup at FERC, create some uncertainty as to the timing and outcome of these complaints. The results of these settlement and proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Con Edison Wheeling Agreement—Effective May 1, 2017, a wheeling arrangement which enabled Con Edison to move 1,000 MW of power from southeastern New York across the PSE&G system for delivery into New York City expired. Amounts that would have been recovered from Con Edison had this arrangement continued are now being recovered from other customers. PSE&G believes the current planning assumptions used by PJM are consistent with sound transmission planning principles. However, PSE&G disagrees with the absence of a mechanism to assign PJM transmission upgrade costs to Con Edison that reflect Con Edison's reliance on the PJM transmission grid. PSE&G and the BPU jointly filed a rehearing application at FERC seeking reversal of a determination not to create such a mechanism in connection with a PJM/NYISO joint operating agreement. In addition, in December 2017, the BPU filed a complaint at FERC against Con Edison and others petitioning FERC to create such a cost allocation mechanism that would assign PJM costs to New York.

Compliance

FERC—For information about the preliminary non-public investigation initiated by the FERC Staff regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Reliability Standards—Congress has required FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the U.S. electric transmission and generation system (grid) and to prevent major system blackouts. As a result, FERC directed the NERC to draft a physical security standard intended to further protect assets deemed "critical" to reliability of the grid. In November 2014, FERC issued an order approving the NERC's proposed physical security standard. Under the standard, utilities will be required to identify critical substations as well as develop threat assessment plans to be reviewed by independent third parties. In our case, the third-party is PJM. As part of these plans, utilities could decide or be required to build additional redundancy into their systems. This standard will supplement the Critical Infrastructure Protection standards that are already in place and that establish physical and cybersecurity protections for critical systems. We are taking steps to meet these obligations. FERC directed the NERC to develop a new reliability standard to provide security controls for supply chain management associated with the procurement of industrial control system hardware, software, and services related to bulk electric system operations. When adopted, compliance with these new standards would be expected to impose additional obligations and costs.

Commodity Futures Trading Commission (CFTC)

In accordance with the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), the SEC and the CFTC are in the process of implementing a new regulatory framework for swaps and security-based swaps. The legislation was enacted to reduce systemic risk, increase transparency and promote market integrity within the financial system by providing for the registration and comprehensive regulation of swap dealers and by imposing recordkeeping, data reporting, margin and clearing requirements with respect to swaps. To implement the Dodd-Frank Act, the CFTC has engaged in a comprehensive rulemaking process and has issued a number of proposed and final rules addressing many of the key issues. We are currently subject to recordkeeping and data reporting requirements applicable to commercial end users. The CFTC has also re-proposed

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rules establishing position limits for trading in certain commodities, such as natural gas, and we will begin complying with these rules once they become final.

Nuclear Regulatory Commission (NRC)

Our operation of nuclear generating facilities is subject to comprehensive regulation by the NRC, a federal agency established to regulate nuclear activities to ensure protection of public health and safety, as well as the security and protection of the environment. Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstration to the NRC that plant operations meet requirements is also necessary. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate. The current operating licenses of our nuclear facilities expire in the years shown in the following table:

Unit	Year
Salem Unit 1	2036
Salem Unit 2	2040
Hope Creek	2046
Peach Bottom Unit 2	2033
Peach Bottom Unit 3	2034

The NRC conducts ongoing reviews of nuclear industry operating experience and may issue or revise regulatory requirements as a result of these ongoing reviews. We are unable to predict the final outcome of these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to our Salem, Hope Creek and Peach Bottom facilities, but such costs could be material.

State Regulation

Since our operations are primarily located within New Jersey, our principal state regulator is the BPU, which oversees electric and natural gas distribution companies in New Jersey. We are also subject to various other states' regulations due to our operations in those states.

Our New Jersey utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. PSE&G's participation in solar, demand response and energy efficiency programs is also regulated by the BPU, as the terms and conditions of these programs are approved by the BPU. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey.

We must file electric and gas rate cases with the BPU in order to change our utility base distribution rates. In January 2018, PSE&G filed a distribution base rate case as required by the BPU as a condition of approval of PSE&G's Energy Strong Program. The filing requests $9.6 billion in rate base as of December 31, 2018, a 10.3% return on equity and a capitalization structure with a 54% equity component. The filing also requests an approximate one percent increase in revenues and seeks to recover investments made to strengthen electric and gas distribution systems. In its filing, PSE&G requested that these rates take into account a reduction in the revenue requirement as a result of the federal corporate income tax rate reduction from 35% to 21% provided in the Tax Act including a one-time credit for estimated excess income taxes collected between January 1, 2018 and the time new rates go into effect, and the flow-back to customers of certain additional tax benefits. PSE&G anticipates the new base rates will go into effect in the fourth quarter of 2018.

Separately, in January 2018, the BPU issued an order commencing a proceeding to ensure that the rate revenue resulting from expenses relating to taxes reflected in rates but no longer owed as the result of the Tax Act shall be passed onto the ratepayers. The BPU directed New Jersey utilities (including PSE&G) to make filings by March 2, 2018 setting forth interim rates to be effective April 1, 2018 reflecting the new federal corporate tax rate, and to subsequently file proposed final rates, effective July 1, 2018, incorporating all other effects of the Tax Act. This proceeding is currently pending.

In addition to base rates, we recover certain costs or earn on certain investments pursuant to mechanisms known as adjustment clauses. These clauses permit the flow-through of costs to, or the recovery of investments from, customers related to specific programs, outside the context of base rate case proceedings. Recovery of these costs or investments is subject to BPU approval for which we make periodic filings. Delays in the pass-through of costs or recovery of investments under these mechanisms could result in significant changes in cash flow. For additional information on our specific filings, see Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

Infrastructure Investment Program (IIP)—The BPU has enacted IIP regulations that allow utilities to construct, install or remediate utility plant and facilities related to reliability, resiliency and/or safety to support the provision of safe and adequate

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service. Under these regulations, utilities can seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing infrastructure that enhances reliability, resiliency, and/or safety.

Gas System Modernization Program II (GSMP II)—In July 2017, we filed a petition with the BPU for a GSMP II program, an extension of GSMP to continue to modernize our gas system, through which PSE&G has proposed investing $2.7 billion over five years beginning in 2019. Under this proposed program, we plan to replace up to 1,250 miles of gas mains and associated service lines, with cost recovery at a 9.75% rate of return on equity through an accelerated recovery mechanism. This matter is pending. We believe the petition is consistent with the IIP regulations that the BPU approved in December 2017, as described above.

Energy Efficiency 2017 Program (EE 2017)—In August 2017, the BPU approved PSE&G's petition for EE 2017 to extend three existing energy efficiency subprograms (multi-family, direct install and hospital efficiency) and establish two new residential energy efficiency offerings. The two new offerings include deployment of smart thermostats and a pilot program to provide residential customers with energy usage information enabling them to reduce consumption. EE 2017, as approved, allows PSE&G to extend the subprogram offerings and establish the residential energy efficiency sub-programs under its existing energy efficiency clause recovery process. The EE 2017 allows for $69 million of additional investment and $16 million of additional administrative and information technology costs. The EE 2017 was added as the eleventh component of the Green Program Recovery Charges (GPRC) rate effective September 1, 2017.

BPU Cybersecurity Requirements for Regulated Entities—In March 2016, the BPU issued an order for the regulated electric, natural gas and water/wastewater utilities to further reduce the potential for cyber threats to the reliability and resiliency of utility service and to protect customers' information. The Order requires these regulated utilities, including PSE&G, to, among other conditions, implement a cybersecurity program that defines and implements organization accountabilities and responsibilities for cyber risk management activities, and establishes policies, plans, processes and procedures for identifying and mitigating cyber risk to critical systems. New Jersey utilities, including PSE&G, were required to be compliant with these requirements by October 1, 2017. We have submitted the required certification of compliance to the BPU.

In an effort to reduce the likelihood and severity of cyber incidents, we have a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of our company and our customers' information and our systems. In addition, we are subject to maintaining key cybersecurity controls to meet mandatory cybersecurity regulatory requirements. Our cybersecurity program is built on technical, procedural, and people-focused measures to detect, protect against, respond to, and recover from cyber threats to our systems and information including company, employee and customer data. Features of our program include: identifying critical information and systems; conducting cyber risk assessments of our and third party systems; maintaining awareness of cyber threats and vulnerabilities through partnerships with public and private entities, as well as industry groups; maintaining and testing our cybersecurity incident response plans and systems; training personnel on cybersecurity issues; and raising cybersecurity awareness throughout our company with electronic notices and seminars. We cannot assure that our cybersecurity program will be effective in preventing or mitigating cybersecurity incidents. For a discussion of the risks associated with cybersecurity threats, see Item 1A. Risk Factors.

Consolidated Tax Adjustments (CTA)—New Jersey is one of only a few states that make CTA in setting rates for regulated utilities. These adjustments to rate base are made during the rate-setting process and are intended to allocate to utility customers a portion of the tax benefits realized from the filing of a consolidated federal tax return by the utility's parent corporation. The BPU has been considering the appropriateness of the adjustment and the methodology and mechanics of the calculation for some time. In October 2014, the BPU approved a proposal by its Staff that limits the tax benefit period to be considered in the calculation to five years, sets the distribution rate base adjustment at 25% of any such tax benefit and eliminates from the process any tax benefits tied to transmission earnings. In accordance with this action, this CTA policy will be applied only with respect to future distribution rate base cases, including our distribution base rate case filed in January 2018. In November 2014, the New Jersey Division of Rate Counsel appealed the BPU's decision and in September 2017, the New Jersey Superior Court, Appellate Division granted that appeal on procedural grounds. Upon remand, in January 2018, and updated in February 2018, the BPU issued a draft proposed rule that is pending review by the Office of Administrative Law. The draft proposal includes a 60-day comment period. We do not expect the application of a CTA to have a material impact on PSE&G's current earnings or its distribution base rate case filing.

Federal Tax Legislation —As a result of the enactment of the Tax Act, various state regulatory authorities, including the BPU, have taken action to ensure that excess federal income taxes previously collected in rates are returned to ratepayers. We have made filings to adjust the revenue requirement in certain of our rate matters as a result of the change in federal income tax rate.

We continue to assess whether any further action needs to be taken by the company at this time.

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Additional matters are discussed in Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

ENVIRONMENTAL MATTERS

We are subject to federal, state and local laws and regulations with regard to environmental matters including, but not limited to:

- air pollution control,
- climate change,
- water pollution control,
- hazardous substance liability, and
- fuel and waste disposal.

We expect there will be changes to existing environmental laws and regulations that could significantly impact the manner in which our operations are currently conducted. Such laws and regulations may also affect the timing, cost, location, design, construction and operation of new facilities. Due to evolving environmental regulations, it is difficult to project future costs of compliance and their impact on competition. Capital costs of complying with known pollution control requirements are included in our estimate of construction expenditures in Item 7. MD&A—Capital Requirements. The costs of compliance associated with any new requirements that may be imposed by future regulations are not known, but may be material.

For additional information related to environmental matters, including proceedings not discussed below, as well as anticipated expenditures for installation of pollution control equipment, hazardous substance liabilities and fuel and waste disposal costs, see Item 1A. Risk Factors, Item 3. Legal Proceedings and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Air Pollution Control

Our facilities are subject to federal regulation under the Clean Air Act (CAA) that requires controls of emissions from sources of air pollution and imposes recordkeeping, reporting and permit requirements. Our facilities are also subject to requirements established under state and local air pollution laws. The CAA requires all major sources, such as our generation facilities, to obtain and keep current an operating permit. The costs of compliance associated with any new requirements that may be imposed and included in these permits in the future could be material and are not included in our estimates of capital expenditures.

Hazardous Air Pollutants Regulation—In February 2012**,** the Environmental Protection Agency (EPA) published Mercury Air Toxics Standards (MATS) for both newly-built and existing electric generating sources under the National Emission Standard for Hazardous Air Pollutants (NESHAP) provisions of the CAA. The MATS established allowable levels for mercury as well as other hazardous air pollutants and went into effect in April 2015. In June 2015, the U.S. Supreme Court held that it was unreasonable for the EPA to refuse to consider the materiality of costs in determining whether to regulate hazardous air pollutants from power plants. In April 2016, the EPA released the final Supplemental Finding that considers the materiality of costs in determining whether to regulate hazardous air pollutants from power plants in response to the U.S. Supreme Court's ruling. Industry participants and various state authorities have filed petitions with the D.C. Circuit challenging the EPA's Supplemental Finding. The D.C. Circuit is holding the case in abeyance pending further directions from the EPA. We do not expect this Supplemental Finding to impact operation of our facilities.

Climate Change

***CO_2 Regulation under the* CAA**—In October 2015, the EPA published the New Source Performance Standards (NSPS) for new power plants. The NSPS establishes two emission standards for CO_2 for the following categories: (i) fossil fuel-fired utility boilers and integrated gasification combined cycle units, and (ii) natural gas combustion turbines. Simple cycle combustion turbines are exempt from the rule.

In October 2015, the EPA also published the Clean Power Plan (CPP), a greenhouse gas (GHG) emissions regulation under the CAA for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction (BSER). The BSER consists of three components: (i) heat rate improvements at existing coal-fired power plants, (ii) increased use of existing natural gas combined cycle capacity, and (iii) operation of incremental zero-emitting generation (renewables and nuclear). States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions.

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Numerous states and several industry groups filed petitions for review with the D.C. Court to challenge the CPP. In addition, the petitioners sought a stay of the rule. The U.S. Supreme Court stayed the rule pending further review of the case.

In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the NSPS that establish emissions standards for CO_2 for certain new fossil power plants and the CPP. The D.C. Circuit granted the EPA's motion to hold the case in abeyance while the agency reviewed the rule. Upon completion of the review, the EPA Administrator signed a proposed repeal of the CPP. The EPA Administrator concluded that the CPP exceeds the EPA's statutory authority by considering measures that are beyond the control of the owners of the affected sources (fossil fuel-fired electric generating units). The EPA is considering rulemaking to replace the CPP. PSEG cannot assess the impact of any such rulemaking on our business and future results of operations at this time.

Regional Greenhouse Gas Initiative (RGGI)—In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. Certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions. These rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three-year period. Allowances are available through the auction or through secondary markets.

In September 2017, the RGGI States announced their new post-2020 program for a cap on regional CO_2 emissions, which would require a decline in CO_2 emissions in 2021 and each year thereafter, resulting in a 30% reduction in the CO_2 emissions cap by 2030.

New Jersey adopted the Global Warming Response Act in 2007, which calls for stabilizing its GHG emissions to 1990 levels by 2020, followed by a further reduction of greenhouse emissions to 80% below 2006 levels by 2050. To reach this goal, the New Jersey Department of Environmental Protection (NJDEP), the BPU, other state agencies and stakeholders are required to evaluate methods to meet and exceed the emission reduction targets, taking into account their economic benefits and costs. In January 2018, New Jersey Governor Murphy signed an Executive Order requiring the NJDEP to initiate the rulemaking process for New Jersey to reenter RGGI. We cannot estimate the impact of this action on our business or results of operations at this time.

Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to U.S. waters from point sources, except pursuant to a National Pollutant Discharge Elimination System (NPDES) permit issued by the EPA or by a state under a federally authorized state program. The FWPCA authorizes the imposition of technology-based and water quality-based effluent limits to regulate the discharge of pollutants into surface waters and ground waters. The EPA has delegated authority to a number of state agencies, including those in New Jersey, New York and Connecticut, to administer the NPDES program through state action. We also have ownership interests in facilities in other jurisdictions that have their own laws and implement regulations to control discharges to their surface waters and ground waters that directly govern our facilities in those jurisdictions.

Steam Electric Effluent Guidelines—In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG Rule) for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater, and gasification wastewater. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations have bottom ash transport water discharges that are regulated under the ELG Rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the ELG Rule.

Through various orders, the EPA has stayed the compliance dates in the ELG Rule and has announced plans to further revise the requirements and compliance dates of the ELG Rule. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

Cooling Water Intake Structure Regulation—In May 2014, the EPA issued a final cooling water intake rule under Section 316(b) of the Clean Water Act (CWA) that establishes requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing power facilities on a case by case basis, based on studies related to impingement mortality and entrainment and submit the results with their permit applications to be conducted by the facilities seeking renewal permits.

Several environmental organizations and certain energy industry groups have filed suit under the CWA and the Endangered Species Act. The cases have been consolidated at the Second Circuit and a decision remains pending.

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We are assessing the potential impact of the rule on each of our affected facilities and are unable to predict the outcome of permitting decisions and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities for additional information.

In June 2016, the NJDEP issued the final New Jersey Pollutant Discharge Elimination System (NJPDES) permit for Salem. The final permit does not mandate specific service water system modifications but, consistent with Section 316(b) of the CWA, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final NJPDES renewal permit for Salem. NJDEP has granted the hearing request, but it has not yet been scheduled. The Riverkeeper's filing does not change the effective date of the permit. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

A permit application for renewal of the current NPDES permit for the Bridgeport Harbor Station Unit 3 (BH3) is under review by the Connecticut Department of Energy and Environmental Protection (CTDEEP). To address compliance with the EPA's CWA Section 316(b) final rule, we have proposed to continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire the BH3 within five years of the effective date of the final permit. Based on discussions with the CTDEEP, if the proposal is accepted, a final NPDES permit could be issued with a retirement date for BH3 by summer 2021, which is four years earlier than the previously estimated useful life ending in 2025. If the permit is not issued and the conditions below are not met, we may seek to operate BH3 through the previously estimated useful life.

We have negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that we would retire BH3 early if all of its conditions precedent occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. Absent those conditions being met, and the permit renewal referred to above not being issued, we may seek to operate BH3 through the previously estimated useful life. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements.

In February 2016, the proposed generating facility, Bridgeport Harbor Station Unit 5 (BH5), was awarded a capacity obligation. Construction has commenced and operations are expected to begin in mid-2019. The Connecticut Siting Council issued an order to approve siting BH5. All major environmental permits have been obtained except for the modified Title V air permit.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance—In April 2015, we determined that monitoring and reporting practices related to certain permitted wastewater discharges at our Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject us to fines and penalties. We have notified the CTDEEP of the issues and have taken actions to investigate and resolve the potential non-compliance. We cannot predict the impact of this matter.

Hazardous Substance Liability

The production and delivery of electricity and the distribution and manufacture of gas result in various by-products and substances classified by federal and state regulations as hazardous. These regulations may impose liability for damages to the environment from hazardous substances, including obligations to conduct environmental remediation of discharged hazardous substances as well as monetary payments, regardless of the absence of fault and the absence of any prohibitions against the activity when it occurred, as compensation for injuries to natural resources. See Item 3. Legal Proceedings. Our historic operations and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by federal and state agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex. The EPA is also evaluating the Hackensack River, a tributary to Newark Bay, for inclusion in the Superfund program. We no longer manufacture gas. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Site Remediation—The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and the New Jersey Spill Compensation and Control Act (Spill Act) require the remediation of discharged hazardous substances and authorize the EPA, the NJDEP and private parties to commence lawsuits to compel clean-ups or reimbursement for such remediation. The clean-ups can be more complicated and costly when the hazardous substances are in a body of water.

Natural Resource Damages—CERCLA and the Spill Act authorize the assessment of damages against persons who have discharged a hazardous substance, causing an injury to natural resources. Pursuant to the Spill Act, the NJDEP requires persons conducting remediation to address injuries to natural resources through restoration or damages. The NJDEP adopted regulations concerning site investigation and remediation that require an ecological evaluation of potential damages to natural resources in connection with an environmental investigation of contaminated sites.

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Fuel and Waste Disposal

Nuclear Fuel Disposal—The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. Under the Nuclear Waste Policy Act of 1982 (NWPA), nuclear plant owners are required to contribute to a Nuclear Waste Fund to pay for this service. Since May 2014, the DOE reduced the nuclear waste fee to zero. No assurances can be given that this fee will not be increased in the future. The NWPA allows spent nuclear fuel generated in any reactor to be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites.

We have on-site storage facilities that are expected to satisfy the storage needs of Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 through the end of their operating licenses.

Low Level Radioactive Waste—As a by-product of their operations, nuclear generation units produce low level radioactive waste. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. These waste materials are accumulated on site and disposed of at licensed permanent disposal facilities. New Jersey, Connecticut and South Carolina have formed the Atlantic Compact, which gives New Jersey nuclear generators continued access to the Barnwell waste disposal facility which is owned by South Carolina. We believe that the Atlantic Compact will provide for adequate low level radioactive waste disposal for Salem and Hope Creek through the end of their current licenses including full decommissioning, although no assurances can be given. Low Level Radioactive Waste is periodically being shipped to the Barnwell site from Salem and Hope Creek. Additionally, there are on-site storage facilities for Salem, Hope Creek and Peach Bottom, which we believe have the capacity for at least five years of temporary storage for each facility.

SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Item 8. Financial Statements and Supplementary Data—Note 23. Financial Information by Business Segment.

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EXECUTIVE OFFICERS OF THE REGISTRANT (PSEG)

Name	Age as of December 31, 2017	Office	Effective Date First Elected to Present Position
Ralph Izzo	60	Chairman of the Board, President and Chief Executive Officer (PSEG)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (PSE&G)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Power)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Energy Holdings)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Services)	January 2010 to present
Daniel J. Cregg	54	Executive Vice President and CFO (PSEG)	October 2015 to present
		Executive Vice President and CFO (PSE&G)	October 2015 to present
		Executive Vice President and CFO (Power)	October 2015 to present
		Vice President-Finance (PSE&G)	June 2013 to October 2015
		Vice President-Finance (Power)	December 2011 to June 2013
David M. Daly	56	President and Chief Operating Officer (PSE&G)	October 2017 to present
		Chairman of the Board of PSEG Long Island LLC	October 2017 to present
		President and Chief Operating Officer (PSEG Long Island LLC)	October 2013 to October 2017
Ralph LaRossa	54	President and Chief Operating Officer (Power)	October 2017 to present
		President and Chief Operating Officer (PSE&G)	October 2006 to October 2017
		Chairman of the Board of PSEG Long Island LLC	October 2013 to October 2017
Derek M. DiRisio	53	President (Services)	August 2014 to present
		Vice President and Controller (PSEG)	January 2007 to August 2014
		Vice President and Controller (PSE&G)	January 2007 to August 2014
		Vice President and Controller (Power)	January 2007 to August 2014
		Vice President and Controller (Energy Holdings)	January 2007 to August 2014
		Vice President and Controller (Services)	January 2007 to August 2014
Tamara L. Linde	53	Executive Vice President and General Counsel (PSEG)	July 2014 to present
		Executive Vice President and General Counsel (PSE&G)	July 2014 to present
		Executive Vice President and General Counsel (Power)	July 2014 to present
		Vice President - Regulatory (Services)	December 2006 to July 2014
Stuart J. Black	55	Vice President and Controller (PSEG)	August 2014 to present
		Vice President and Controller (PSE&G)	August 2014 to present
		Vice President and Controller (Power)	August 2014 to present
		Vice President (Services) and Assistant Controller (Power)	March 2010 to August 2014

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ITEM 1A. RISK FACTORS

The following factors should be considered when reviewing our business. These factors could have a material adverse impact on our business, prospects, financial position, results of operations or cash flows and could cause results to differ materially from those expressed elsewhere in this report.

MARKET AND COMPETITION RISKS

Fluctuations in the wholesale power and natural gas markets could negatively affect our financial condition, results of operations and cash flows.

In the markets where we operate, natural gas prices have a major impact on the price that generators receive for their output. Over the past several years, wholesale prices for natural gas have remained well below the peak levels experienced in 2008, in part due to increased shale gas production as extraction technology has improved. Lower gas prices have resulted in lower electricity prices, which have reduced our margins as nuclear and coal generation costs have not declined similarly.

PSEG and Power continue to monitor their remaining coal assets, including the Keystone and Conemaugh generating stations, to ensure their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact our ability to operate or maintain these assets in the future. These generating stations may be impacted by factors such as continued depressed wholesale power prices or capacity factors, among other things. Any early retirement of these coal units before the end of their current estimated useful lives or change in the classification as held for use may have a material adverse impact on PSEG's and Power's future financial results.

The decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production have been contributing factors to the significantly reduced revenues from nuclear generating stations while simultaneously raising the unit cost of production.

In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of our nuclear units beyond the current year, including whether and to what extent these units participate in RPM capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be influenced by the financial outlook of the units, including the progress, timing and continued outlook for enactment of proposed legislation in the state of New Jersey. We cannot predict whether the legislation will be enacted or, if enacted, whether our nuclear generating stations in New Jersey will be selected or whether the legislation will provide a sufficient safety net for the continued operation of nuclear generating stations in New Jersey.

If market prices continue to be depressed and legislation is not enacted that adequately compensates nuclear generating stations for their attributes, Power anticipates it will no longer be covering its costs nor be adequately compensated for its market and operational risks at the Salem and Hope Creek nuclear units and would anticipate retiring these units early. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs and additional funding of the Nuclear Decommissioning Trust Fund (NDT) would be material to both PSEG and Power.

We may be unable to obtain an adequate fuel supply in the future.

We obtain substantially all of our physical natural gas, coal and nuclear fuel supply from third parties pursuant to arrangements that vary in term, pricing structure, firmness and delivery flexibility. Our fuel supply arrangements must be coordinated with transportation agreements, balancing agreements, storage services, financial hedging transactions and other contracts to ensure that the natural gas, coal and nuclear fuel are delivered to our power plants at the times, in the quantities and otherwise in a manner that meets the needs of our generation portfolio and our customers. We must also comply with laws and regulations governing the transportation of such fuels.

Additionally, the PJM power market has recently experienced an increase in natural gas-fired generation assets that supply electricity to the region. As a result, there has been a corresponding increase in the need for natural gas transportation assets to serve power generation assets. When extreme cold temperatures significantly increase the demand for natural gas used for residential heating, it can also create constraints on natural gas pipelines that serve power generation assets. When these conditions exist, it could interrupt the fuel supply to our natural gas-fired power plants in the PJM power market.

We are exposed to increases in the price of natural gas, coal and nuclear fuel, and it is possible that sufficient supplies to operate our generating facilities profitably may not continue to be available to us. Significant changes in the price of natural gas, coal

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and nuclear fuel could affect our future results and impact our liquidity needs. In addition, we face risks with regard to the delivery to, and the use of natural gas, coal and nuclear fuel by, our power plants including the following:

- transportation may be unavailable if pipeline infrastructure is damaged or disabled;
- pipeline tariff changes may adversely affect our ability to, or cost to, deliver such fuels;
- creditworthiness of third-party suppliers, defaults by third-party suppliers on supply obligations and our ability to replace supplies currently under contract may delay or prevent timely delivery;
- market liquidity for physical supplies of such fuels or availability of related services (e.g. storage) may be insufficient or available only at prices that are not acceptable to us;
- variation in the quality of such fuels may adversely affect our power plant operations;
- legislative or regulatory actions or requirements, including those related to pipeline integrity inspections, may increase the cost of such fuels;
- fuel supplies diverted to residential heating may limit the availability of such fuels for our power plants; and
- the loss of critical infrastructure, terrorist attacks (including cybersecurity breaches) or catastrophic events such as fires, earthquakes, explosions, floods, severe storms or other similar occurrences could impede the delivery of such fuels.

Our nuclear units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel raw material needs over the next several years. However, each of our nuclear units has contracted with a single fuel fabrication services provider, and transitioning to an alternative provider could take an extended period of time. Certain of our other generation facilities also require fuel or other services that may only be available from one or a limited number of suppliers. The availability and price of this fuel may vary due to supplier financial or operational disruptions, transportation disruptions and force majeure. At times, such fuel may not be available at any price, or we may not be able to transport it to our facilities on a timely basis. In this case, we may not be able to run those facilities even if it would be profitable. If we had sold forward the power from such a facility, we could be required to supply or purchase power from alternate sources, perhaps at a loss. This could have a material adverse impact on our business, the financial results of specific plants and on our results of operations.

In March 2017, WEC announced that it had filed for Chapter 11 bankruptcy in New York. WEC provides nuclear fuel fabrication services for Salem Units 1 and 2. In January 2018, Brookfield Business Partners LP announced its intention to acquire WEC. The acquisition is expected to close in 2018 if it receives the required approvals from the regulators and bankruptcy courts. No assurances can be given that the acquisition will be approved. In the event that WEC is unable to continue to provide fabrication services, we can provide no assurance that Power would be able to find alternative providers of such services in a timely manner or on acceptable terms. A failure by WEC to perform its obligations during the pendency of, or following its emergence from, bankruptcy could have a material adverse impact on our business, the financial results of specific plants and on our results of operations.

Although our fuel contract portfolio provides a degree of hedging against these market risks, such hedging may not be effective and future increases in our fuel costs could materially and adversely affect our liquidity, financial condition and results of operations. While our generation runs on a mix of fuels, primarily natural gas and nuclear fuel, an increase in the cost of any particular fuel ultimately used could impact our results of operations.

Our inability to balance energy obligations with available supply could negatively impact results.

The revenues provided by the operation of our generating stations are subject to market risks that are beyond our control. Generation output will either be used to satisfy wholesale contract requirements or other bilateral contracts or be sold into competitive power markets. Participants in the competitive power markets are not guaranteed any specified rate of return on their capital investments. Generation revenues and results of operations are dependent upon prevailing market prices for energy, capacity, ancillary services and fuel supply in the markets served. Changes in prevailing market prices could have a material adverse effect on our financial condition and results of operations.

Factors that may cause market price fluctuations include:

- increases and decreases in generation capacity, including the addition of new supplies of power as a result of the development of new power plants, expansion of existing power plants or additional transmission capacity;
- power transmission or fuel transportation capacity constraints or inefficiencies;
- power supply disruptions, including power plant outages and transmission disruptions;
- weather conditions, particularly unusually mild summers or warm winters in our market areas;
- quarterly and seasonal fluctuations;

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- economic and political conditions that could negatively impact demand for power;
- changes in the supply of, and demand for, energy commodities;
- development of new fuels or new technologies for the production or storage of power;
- federal and state regulations and actions of the ISOs; and
- federal and state power, market and environmental regulation and legislation, including financial incentives for new renewable energy generation capacity that could lead to oversupply.

Our generation business frequently involves the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that we have produced or purchased energy in excess of our contracted obligations, a reduction in market prices could reduce profitability. Conversely, to the extent that we have contracted obligations in excess of energy we have produced or purchased, an increase in market prices could reduce profitability. If the strategy we utilize to hedge our exposure to these various risks is not effective, we could incur material losses. Our market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors, including weather in various geographical areas, short-term supply and demand imbalances, customer migration and pricing differentials at various geographic locations. These risks cannot be predicted with certainty.

Increases in market prices also affect our ability to hedge generation output and fuel requirements as the obligation to post margin increases with increasing prices.

We face significant competition in the wholesale energy and capacity markets.

Our wholesale power and marketing businesses are subject to significant competition that may adversely affect our ability to make investments or sales on favorable terms and achieve our business objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower earnings. Decreased competition could negatively impact results through a decline in market liquidity. Regulatory, environmental, industry and other operational developments will have a significant impact on our ability to compete in energy and capacity markets, potentially resulting in erosion of our market share and impairment in the value of our power plants. Recently, certain states have taken, or are considering taking, actions to subsidize or otherwise provide economic support to renewables, energy efficiency initiatives and existing, uneconomic generation facilities that could adversely affect capacity and energy prices. Increased generation supply and lower energy prices due to these subsidies could have an adverse impact on our results of operations.

The introduction or expansion of technologies related to energy generation, distribution and consumption and changes in customer usage patterns and could adversely impact us.

The power generation business has seen a substantial change in the technologies used to produce power. Newer generation facilities are often more efficient than aging facilities, which may put some of these older facilities at a competitive disadvantage to the extent newer facilities are able to consume the same or less fuel to achieve a higher level of generation output. Federal and state incentives for the development and production of renewable sources of power have allowed for the penetration of competing technologies, such as wind, solar, and commercial-sized power storage. Additionally, the development of DSM tools and practices can impact peak demand requirements for some of our markets at certain times during the year. The continued development of subsidized, competing power generation technologies and significant development of DSM tools and practices could alter the market and price structure for power generation and could result in a reduction in load requirements, negatively impacting our financial condition, results of operations and cash flows. Additionally, technological advances driven by federal laws mandating new levels of energy efficiency in end-use electric devices or other improvements in, or applications of, technology could lead to declines in per capita energy consumption.

Advances in distributed generation technologies, such as fuel cells, micro turbines, micro grids, windmills and net-metered solar installations, may reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. Large customers, such as universities and hospitals, continue to explore potential micro grid installation. Certain states, such as Massachusetts and California, are also considering mandating the use of power storage resources to replace uneconomic or retiring generation facilities. Such developments could (i) affect the price of energy, (ii) reduce energy deliveries as customer-owned generation becomes more cost-effective, (iii) require further improvements to our distribution systems to address changing load demands and (iv) make portions of our transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy.

Some or all of these factors, could result in a lack of growth or decline in customer demand for electricity or number of customers, and may cause us to fail to fully realize anticipated benefits from significant capital investments and expenditures, which could have a material adverse effect on our financial position, results of operations and cash flows. These factors could also materially affect our results of operations, cash flows or financial positions through, among other things, reduced operating

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revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Economic downturns would likely have a material adverse effect on our businesses.

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices for power, generation capacity and natural gas, which can fluctuate substantially. Increased unemployment of residential customers and decreased demand for products and services provided by commercial and industrial customers resulting from an economic downturn could lead to declines in the demand for energy and an increase in the number of uncollectible customer balances, which would negatively impact our overall sales and cash flows. Although our utility business is subject to regulated allowable rates of return, overall declines in electricity and gas sold could materially adversely affect our financial condition, results of operations and cash flows. Additionally, prolonged economic downturns that negatively impact our financial condition, results of operations and cash flows could result in future material impairment charges to write down the carrying value of certain assets to their respective fair values.

We are subject to third-party credit risk relating to our sale of generation output and purchase of fuel.

We sell generation output and buy fuel through the execution of bilateral contracts. We also seek to contract in advance for a significant proportion of our anticipated output capacity and fuel needs. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure to perform by these counterparties could require Power to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, which could have a material adverse impact on our results of operations, cash flows and financial position. In the spot markets, we are exposed to the risks of the default sharing mechanisms that exist in those markets, some of which attempt to spread the risk across all participants. Therefore, a default by a third party could increase our costs, which could negatively impact our results of operations and cash flows.

Financial market performance directly affects the asset values of our nuclear decommissioning trust funds and defined benefit plan trust funds. Market performance and other factors could decrease the value of trust assets and could result in the need for significant additional funding.

The performance of the financial markets will affect the value of the assets that are held in trust to satisfy our future obligations under our defined benefit plans and to decommission our nuclear generating plants. A decline in the market value of our nuclear decommissioning trust funds could increase Power's funding requirements to decommission its nuclear plants. A decline in the market value of the defined benefit plan trust funds could increase our pension and other postretirement benefit (OPEB) plan funding requirements. The market value of our trusts could be negatively impacted by decreases in the rate of return on trust assets, decreased interest rates used to measure the required minimum funding levels and future government regulation. Additional funding requirements for our defined benefit plans could be caused by changes in required or voluntary contributions, an increase in the number of employees becoming eligible to retire and changes in life expectancy assumptions. Increased costs could also lead to additional funding requirements for our decommissioning trust. Failure to adequately manage our investments in our nuclear decommissioning trust and defined benefit plan trusts could result in the need for us to make significant cash contributions in the future to maintain our funding at sufficient levels, which would negatively impact our results of operations, cash flows and financial position.

REGULATORY, LEGISLATIVE AND LEGAL RISKS

PSE&G's revenues, earnings and results of operations are dependent upon state laws and regulations that affect distribution and related activities.

PSE&G is subject to regulation by the BPU. Such regulation affects almost every aspect of its businesses, including its retail rates, and failure to comply with these regulations could have a material adverse impact on PSE&G's ability to operate its business and could result in fines, penalties or sanctions. The retail rates for electric and gas distribution services are established in a base rate case and remain in effect until a new base rate case is filed and concluded. In January 2018, PSE&G filed a distribution base rate case proceeding. In addition, our utility has received approval for several clause recovery mechanisms, some of which provide for recovery of costs and earn returns on authorized investments. These clause mechanisms require periodic updates to be reviewed and approved by the BPU and are subject to prudency reviews. Inability to obtain fair or timely recovery of all our costs, including a return of, or on, our investments in rates, could have a material adverse impact on our results of operations and cash flows. In addition, if legislative and regulatory structures were to evolve in such a way that PSE&G's exclusive rights to serve its regulated customers were eroded, its future earnings could be negatively impacted.

Efforts designed to promote and expand the use of energy efficiency measures and distributed generation technologies, such as rooftop solar and battery storage, in PSE&G's service territories could result in customers leaving the electric distribution system and an increase in customer net energy metering. Over time, customer adoption of these and other technologies and

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increased energy efficiency could adversely impact PSE&G's revenue and ability to fully recover its costs, which could require PSE&G to pursue a rate case to adjust revenue requirements or seek recovery though other mechanisms.

The BPU also conducts periodic combined management/competitive service audits of New Jersey utilities related to affiliate standard requirements, competitive services, cross-subsidization, cost allocation and other issues. A finding by the BPU of non-compliance with these requirements could result in fines, a reduction in PSE&G's authorized base rate or the disallowance of the recovery of certain costs, which could have a materially adverse impact on our business, results of operations and cash flows.

In addition, PSE&G procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with Power. Government officials, legislators and advocacy groups are aware of the affiliation between PSE&G and Power. In periods of rising utility rates, those officials and advocacy groups may question or challenge costs and transactions incurred by PSE&G with Power, irrespective of any previous regulatory processes or approvals underlying those transactions. The occurrence of such challenges may subject Power to a level of scrutiny not faced by other unaffiliated competitors in those markets and could adversely affect retail rates received by PSE&G in an effort to offset any perceived benefit to Power from the affiliation.

PSE&G periodically files base rate case proceedings. Such proceedings are at times contentious, lengthy and subject to appeal, which could lead to uncertainty as to the ultimate results and which could introduce time delays in effectuating rate changes.

PSE&G periodically files base rate case proceedings with the BPU. In particular, in January 2018, PSE&G filed a distribution base rate case proceeding. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for PSE&G to recover its costs by the time the rates become effective. Established rates are also subject to subsequent reviews by state regulators, whereby various portions of rates could be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, bad debt, manufactured gas plant (MGP) remediation, smart grid infrastructure and energy efficiency, demand response and renewable energy programs. If the base rate case proceeding is protracted or results in approved rates that do not allow PSE&G to fully recover its costs or result in ROEs that are below historical levels, our financial condition, results of operations and cash flows would be materially adversely impacted.

We are subject to comprehensive federal regulation that affects, or may affect, our businesses.

We are subject to regulation by federal authorities. Such regulation affects almost every aspect of our businesses, including management and operations; the terms and rates of transmission services; investment strategies; the financing of our operations and the payment of dividends. Failure to comply with these regulations could have a material adverse impact on our ability to operate our business and could result in fines, penalties or sanctions.

Recovery of wholesale transmission rates—PSE&G's wholesale transmission rates are regulated by FERC and are recovered through a FERC-approved formula rate. The revenue requirements are reset each year through this formula. In addition, transmission ROEs have recently become the target of certain state utility commissions, municipal utilities, consumer advocates and consumer groups seeking to lower customer rates. These agencies and groups have filed complaints with FERC asking to reduce the base ROE of various transmission owners. They point to changes in the capital markets as justification for lowering the ROE of these companies. While we are not the subject of any of these complaints, they could set a precedent for FERC-regulated transmission owners, such as PSE&G. Inability to obtain fair or timely recovery of all our costs, including a return of or on our investments in rates, could have a material adverse impact on our business.

North American Electric Reliability Council (NERC) Compliance—Mandatory NERC and Critical Infrastructure Protection standards have been established to ensure the reliability of the U.S. electric transmission and generation system and to prevent major system black-outs. We have been, and will continue to be, periodically audited by NERC for compliance and are subject to penalties for non-compliance with applicable NERC standards. Failure to comply with such standards could result in penalties or increased costs to bring such facilities into compliance. Such penalties and costs, as well as lost revenue from prolonged outages required to bring facilities into compliance with these standards, could materially adversely impact our business, results of operations and cash flows.

Market-Based Rate (MBR) Authority and Other Regulatory Approvals—Under FERC regulations, public utilities that wish to sell power at market rates must receive MBR Authority before making power sales, and the majority of our businesses operate with such authority. Failure to maintain MBR authorization, or the effects of any severe mitigation measures that may be required if market power was evaluated differently in the future, could have a material adverse effect on our business, financial condition and results of operations.

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In November 2017, FERC issued an order accepting the triennial filing made by the PSEG companies seeking authority to sell energy, capacity and ancillary services at market-based rates.

Oversight by the Commodity Futures Trading Commission (CFTC) relating to derivative transactions—The CFTC has regulatory oversight of the swap and futures markets and options, including energy trading, and licensed futures professionals such as brokers, clearing members and large traders. Changes to regulations or adoption of additional regulations by the CFTC, including any regulations relating to position limits on futures and other derivatives or margin for derivatives and increased investigations by the CFTC, could negatively impact Power's ability to hedge its portfolio in an efficient, cost-effective manner by, among other things, potentially decreasing liquidity in the forward commodity and derivatives markets or limiting Power's ability to utilize non-cash collateral for derivatives transactions.

We may also be required to obtain various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals on a timely basis could materially adversely affect our results of operations and cash flows.

Our ownership and operation of nuclear power plants involve regulatory, financial, environmental, health and safety risks.

Approximately half of our total generation output each year is provided by our nuclear fleet. For this reason, we are exposed to risks related to the continued successful operation of our nuclear facilities and issues that may adversely affect the nuclear generation industry. These include:

Storage and Disposal of Spent Nuclear Fuel—Federal law requires the DOE to provide for the permanent storage of spent nuclear fuel but the DOE has not yet begun accepting spent nuclear fuel. Until a federal site is available, we use on-site storage for spent nuclear fuel, which is reimbursed by the DOE. However, future capital expenditures may be required to increase spent fuel storage capacity at our nuclear facilities. Once a federal site is available, the DOE may impose fees to support a permanent repository. In addition, the on-site storage for spent nuclear fuel may significantly increase the decommissioning costs of our nuclear units.

Regulatory and Legal Risk—We may be required to substantially increase capital expenditures or operating or decommissioning costs at our nuclear facilities to the extent there is a change in the Atomic Energy Act or the applicable regulations or the environmental rules and regulations applicable to nuclear facilities; a modification, suspension or revocation of licenses issued by the NRC; the imposition of civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms and conditions of the licenses for nuclear generating facilities or the shutdown of one of our nuclear facilities. Any such event could have a material adverse effect on our financial position or results of operations.

Operational Risk—Operations at any of our nuclear generating units could degrade to the point where the affected unit needs to be shut down or operated at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Any significant outages could result in reduced earnings as we would need to purchase or generate higher-priced energy to meet our contractual obligations.

In addition, if a station cannot be operated through the end of its current estimated useful life, our results of operations could be adversely affected by increased depreciation rates, impairment charges and accelerated future decommissioning costs.

Nuclear Incident or Accident Risk—Accidents and other unforeseen problems have occurred at nuclear stations, both in the U.S. and elsewhere. The consequences of an accident can be severe and may include loss of life, significant property damage and/or a change in the regulatory climate. We have nuclear units at two sites. It is possible that an accident or other incident at a nuclear generating unit could adversely affect our ability to continue to operate unaffected units located at the same site, which would further affect our financial condition, results of operations and cash flows. An accident or incident at a nuclear unit not owned by us could also affect our ability to continue to operate our units. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages. Further, as a licensed nuclear operator subject to the Price-Anderson Act and a member of a nuclear industry mutual insurance company, Power is subject to potential retroactive assessments as a result of a nuclear incident or retroactive adverse loss experience.

In the event of non-compliance with applicable legislation, regulation and licenses, the NRC may increase regulatory oversight, impose fines, and/or shut down a unit, depending on its assessment of the severity of the non-compliance. If a serious nuclear incident were to occur, our business, reputation, financial condition and results of operations could be materially adversely affected. In each case, the amount and types of insurance commercially available to cover losses that might arise in connection with the operation of our nuclear fleet are limited and may be insufficient to cover any costs we may incur.

Decommissioning—NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available to decommission the facility at the end of its useful life. PSEG Nuclear has established a Nuclear Decommissioning Trust (NDT) to satisfy these obligations. However, forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from

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current estimates. If we determine that it is necessary to retire one of our nuclear generating stations before the end of its useful life, there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT investments could appreciate in value. A shortfall could require PSEG to post parental guarantees or make additional cash contributions to ensure that the NDT continues to satisfy the NRC minimum funding requirements. As a result, our financial position or cash flows could be significantly adversely affected.

We may be adversely affected by changes in energy regulatory policies, including energy and capacity market design rules and developments affecting transmission.

The energy industry continues to be regulated and the rules to which our businesses are subject are always at risk of being changed. Our business has been impacted by established rules that create locational capacity markets in each of PJM, ISO-NE and NYISO. Under these rules, generators located in constrained areas are paid more for their capacity so there is an incentive to locate in those areas where generation capacity is most needed. Because much of our generation has historically been located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM's capacity market design rules and ISO-NE's forward capacity market rules continue to evolve, most recently in response to efforts to integrate public policy initiatives into the wholesale markets. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

We could also be impacted by a number of other events, including regulatory or legislative actions such as direct and indirect subsidies, favoring certain types of resources and/or technologies. Further, some of the market-based mechanisms in which we participate, including BGS auctions, are at times the subject of review or discussion by some of the participants in the New Jersey and federal arenas. We can provide no assurance that these mechanisms will continue to exist in their current form, nor otherwise be modified.

To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, Power's capacity and energy revenues could be adversely affected. Moreover, through changes encouraged by FERC to transmission planning processes, or through RTO/ISO initiatives to change their planning processes, more transmission may ultimately be built to facilitate renewable generation or support other public policy initiatives. Any such addition to the transmission system could have a material adverse impact on our financial condition and results of operations.

We are subject to numerous federal, state and local environmental laws and regulations that may significantly limit or affect our businesses, adversely impact our business plans or expose us to significant environmental fines and liabilities.

We are subject to extensive federal, state and local environmental laws and regulations regarding air quality, water quality, site remediation, land use, waste disposal, the impact on global climate, natural resources damages and other matters. These laws and regulations affect the manner in which we conduct our operations and make capital expenditures. We expect there will be changes to existing environmental laws and regulations, particularly in light of the change in administration following the 2016 U.S. presidential election. Changes in these laws, or violations of laws, could result in significant increases in our compliance costs, capital expenditures to bring our facilities into compliance, operating costs for remediation and clean-up actions, civil penalties or damages from actions brought by third parties for alleged health or property damages. Any such increase in our costs could have a material impact on our financial condition, results of operations and cash flows and could require further economic review to determine whether to continue operations or decommission an affected facility. We may also be unable to successfully recover certain of these cost increases through our existing regulatory rate structures, in the case of PSE&G, or our contracts with our customers, in the case of Power.

Environmental laws and regulations have generally become more stringent over time, and this trend is likely to continue. In particular:

Concerns over global climate change could result in laws and regulations to limit CO_2 emissions or other GHG emissions produced by our fossil generation facilities—Federal and state legislation and regulation designed to address global climate change through the reduction of GHG emissions could materially impact our fossil generation facilities. For example, in 2015 the EPA published new rules for both new and existing power plants. While the EPA recently repealed these rules for existing power plants, actions by northeastern states, including New Jersey, could have cost implications for our fossil generation facilities. Such expenditures could materially affect the continued economic viability of one or more such facilities.

In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings regarding alleged impacts of global climate change not involving us could be material to the future liability of energy companies. If relevant federal or state common law were to develop that imposed liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to our fossil generation operations could be material.

Potential closed-cycle cooling requirements—In 2014, the EPA finalized rules regarding the regulation of cooling water intake structures. The EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis. The rule requires that facilities seeking permit renewals conduct a wide range of studies

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related to impingement mortality and entrainment and submit the results with their permit applications. State actions to renew permits under the provisions of this rule are ongoing at this time.

If the NJDEP or the CTEEP were to require installation of closed-cycle cooling or its equivalent at any of our Salem, Bridgeport or New Haven generating stations, the related increased costs and impacts would be material to our financial position, results of operations and cash flows and would require further economic review to determine whether to continue operations or decommission any such station.

Remediation of environmental contamination at current or formerly-owned facilities—We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. In addition, the historic operations of our companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. The EPA is also evaluating the Hackensack River, a tributary to Newark Bay, for inclusion in the Superfund program. We are also involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, the related costs of which could have a material adverse effect on our financial condition, results of operations and cash flows. New Jersey law places affirmative obligations on us to investigate and, if necessary, remediate contaminated property upon which we were in any way responsible for a discharge of hazardous substances, impacting the speed by which we will need to investigate contaminated properties, which could adversely impact cash flows. We cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to these or other natural resource damages claims. However, exposure to natural resource damages could subject us to additional potentially material liability. For a discussion of these and other environmental matters, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

We may not receive necessary licenses and permits in a timely manner or at all, which could adversely impact our business and results of operations.

We must periodically apply for licenses and permits from various regulatory authorities, including environmental regulatory authorities, and abide by their respective orders. Delay in obtaining, or failure to obtain and maintain, any permits or approvals, including environmental permits or approvals, or delay in or failure to satisfy any applicable regulatory requirements, could:

- prevent construction of new facilities,
- limit or prevent continued operation of existing facilities,
- limit or prevent the sale of energy from these facilities, or
- result in significant additional costs,

each of which could materially affect our business, financial condition, results of operations and cash flows. In addition, the process of obtaining licenses and permits from regulatory authorities may be delayed or defeated by concerted community opposition and such delay or defeat could have a material effect on our business.

We cannot predict the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim relating to our business activities. An adverse determination could negatively impact our financial condition, results of operations and cash flows.

From time to time we are involved in legal, regulatory and other proceedings or claims arising out of our business operations, the most significant of which are summarized in Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities. Adverse outcomes in any of these proceedings could require significant expenditures that could have a material adverse effect on our financial condition, results of operations and cash flows.

In particular, as previously disclosed, Power has discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors to FERC, PJM and the PJM Independent Market Monitor (IMM). FERC Staff initiated a preliminary, non-public staff investigation into the matter, which is ongoing. We are unable to reasonably estimate the range of possible loss for this matter; however, the amounts of potential disgorgement and other potential penalties that Power may incur span a wide range depending on the success of PSEG's legal arguments. If we do not prevail in whole or in part with FERC or in a judicial challenge that we may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to our results of operations.

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Changes in tax law and regulation and the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact our results of operations and cash flows.

In December 2017, the Tax Act was enacted, which made significant changes to U.S. tax law. Among other things, under the Tax Act, the statutory U.S. corporate income tax rate decreased from a maximum of 35% to 21%, effective January 1, 2018, and certain changes were made to bonus depreciation rules. However, the Tax Act is unclear in certain respects and will require interpretations and implementing regulations by the Internal Revenue Service (IRS), as well as state tax authorities, and the Tax Act could be subject to potential amendments and technical corrections. We cannot assess the impact that any such interpretations, regulations, amendments or corrections could have on our results of operations or financial condition. In addition, the regulatory treatment of certain impacts of the Tax Act will be subject to the discretion of FERC and the state regulators which we are unable to determine at this time.

We are subject to the provisions of the Financial Accounting Standards Board (FASB) Accounting Standards Codification 740, Income Taxes (ASC 740), which requires that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change was enacted. The impact of the rate change in 2017's financial statements is discussed in Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes.

We do not have the necessary information available, prepared, or analyzed (including computations) in reasonable detail to complete the accounting under ASC 740 for certain income tax effects of the Tax Act for the reporting period in which the Tax Act was enacted. Accordingly, the amounts recognized in the current reporting period should be considered provisional, in accordance with SEC Staff Accounting Bulletin No. 118, and any revisions to these amounts could be material.

Further, the Tax Act is unclear in certain respects and will require interpretations and implementing regulations by the Internal Revenue Service (IRS), as well as state tax authorities. The Tax Act could also be subject to potential amendments and technical corrections which could impact PSEG, PSE&G and Power's financial statements.

In addition, we are required to make judgments in order to estimate our obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes. These judgments can include reserves for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities. If our actual tax obligations materially differ from our estimated obligations, our results of operations and cash flows could be materially adversely affected.

OPERATIONAL RISKS

Because PSEG is a holding company, its ability to meet its corporate funding needs, service debt and pay dividends could be limited.

PSEG is a holding company with no material assets other than the stock or membership interests of its subsidiaries. Accordingly, all of the operations of PSEG are conducted by its subsidiaries, which are separate and distinct legal entities that have no obligation, contingent or otherwise, to pay the debt of PSEG or to make any funds available to PSEG to pay such debt or satisfy its other corporate funding needs. These corporate funding needs include PSEG's operating expenses, the payment of interest on and principal of its outstanding indebtedness and the payment of dividends on its capital stock. As a result, PSEG can give no assurances that its subsidiaries will be able to transfer funds to PSEG to meet all of these obligations.

Lack of growth or slower growth in the number of customers, or a decline in customer demand, could adversely impact our financial condition, results of operations and cash flows.

Growth in customer accounts and growth of customer usage each directly influence demand for electricity and the need for additional generation, transmission and distribution facilities. Customer growth and customer usage may be affected by a number of factors, including:

- regulatory incentives to reduce energy consumption;
- mandated energy efficiency measures;
- demand-side management tools;
- technological advances; and
- a shift in the composition of our customer base from commercial and industrial customers to residential customers.

Some or all of these factors could result in a lack of growth or decline in customer demand for electricity and may prevent us from fully realizing the benefits from significant capital investments and expenditures, which could have a material adverse effect on our financial position, results of operations and cash flows.

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There may be periods when Power may not be able to meet its commitments under forward sale obligations at a reasonable cost or at all.

A substantial portion of Power's generation output has been sold forward under fixed price power sales contracts and Power also sells forward the output from its intermediate and peaking facilities when it deems it commercially advantageous to do so. Our forward sales of energy and capacity assume sustained, acceptable levels of operating performance. This is especially important at our lower-cost facilities. Operations at any of our plants could degrade to the point where the plant has to shut down or operate at less than full capacity. Some issues that could impact the operation of our facilities are:

- breakdown or failure of equipment, information technology, processes or management effectiveness;
- disruptions in the transmission of electricity;
- labor disputes or work stoppages;
- fuel supply interruptions;
- transportation constraints;
- limitations which may be imposed by environmental or other regulatory requirements; and
- operator error, terrorist attacks (including cybersecurity breaches) or catastrophic events such as fires, earthquakes, explosions, floods, severe storms or other similar occurrences.

Identifying and correcting any of these issues may require significant time and expense. Depending on the materiality of the issue, we may choose to close a plant rather than incur the expense of restarting it or returning it to full capacity.

Because the obligations under most of these agreements are not contingent on a unit being available to generate power, Power is generally required to deliver power to the buyer, even in the event of a plant outage, fuel supply disruption or a reduction in the available capacity of the unit. To the extent that Power does not have sufficient lower cost capacity to meet its commitments under its forward sale obligations, Power would be required to supply replacement power either by running its other higher cost power plants or by obtaining power from third-party sources at market prices that could substantially exceed the contract price. This could have a material adverse effect on our financial condition, results of operations and cash flows. If Power fails to deliver the contracted power, it would be required to pay the difference between the market price at the delivery point and the contract price, and the amount of such payments could be substantial.

In addition, as market prices for energy and fuel fluctuate, our forward energy sale and forward fuel purchase contracts could require us to post substantial additional collateral, thus requiring us to obtain additional sources of liquidity during periods when our ability to do so may be limited.

Certain of our generation facilities rely on transmission facilities that we do not own or control and that may be subject to transmission constraints. Our inability to maintain adequate transmission capacity could restrict our ability to deliver wholesale electric power to our customers and we may either incur additional costs or forego revenues. Conversely, improvements to certain transmission systems could also reduce revenues.

We depend on transmission facilities owned and operated by others to deliver the wholesale power we sell from our generation facilities. If transmission is disrupted or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be adversely impacted. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

In addition, in certain of the markets in which we operate, energy transmission congestion may occur and we may be deemed responsible for congestion costs if we schedule delivery of power between congestion zones during times when congestion occurs between the zones. If we were liable for such congestion costs, our financial results could be adversely affected.

A portion of our generation is located in load pockets. Expansion of transmission systems to reduce or eliminate these load pockets could negatively impact the value or profitability of our existing generation facilities in these areas.

Inability to successfully develop or construct generation, transmission and distribution projects could adversely impact our businesses.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of required environmental upgrades and retrofits; construction and/or acquisition of additional generation units and transmission and distribution facilities; and modernizing existing infrastructure pursuant to investment programs entitled to current recovery. Currently, we have several significant projects underway or being contemplated.

The successful construction and development of these projects will depend, in part, on our ability to:

- obtain necessary governmental and regulatory approvals;

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- obtain environmental permits and approvals;
- obtain community support for such projects to avoid delays in the receipt of permits and approvals from regulatory authorities;
- complete such projects within budgets and on commercially reasonable terms and conditions;
- obtain any necessary debt financing on acceptable terms and/or necessary governmental financial incentives;
- ensure that contracting parties, including suppliers, perform under their contracts in a timely and cost effective manner; and
- at PSE&G, recover the related costs through rates.

Any delays, cost escalations or otherwise unsuccessful construction and development could materially affect our financial position, results of operations and cash flows. Further, any unexpected failure of our existing facilities, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures could result in reduced profitability. Modifications to existing facilities may require us to install the best available control technology or to achieve the lowest achievable emission rates required by then-current regulations, which would likely result in substantial additional capital expenditures.

In addition, the successful operation of new or upgraded generation facilities or transmission or distribution projects is subject to risks relating to supply interruptions; work stoppages and labor disputes; weather interferences; unforeseen engineering and environmental problems, including those related to climate change; and the other risks described herein. Any of these risks could cause our return on these investments to be lower than expected or they could cause these facilities to operate below expected capacity or availability levels, which would adversely impact our financial condition and results of operations through lost revenue, increased expenses, higher maintenance costs and penalties.

FERC Order 1000 has generally opened transmission development to competition from independent developers, allowing such developers to compete with incumbent utilities for the construction and operation of transmission facilities in its service territory. While Order 1000 retains limited carve-outs for certain projects that will continue to default to incumbents for construction responsibility, including immediately needed reliability projects, upgrades to existing transmission facilities, projects cost-allocated to a single transmission zone, and projects being built on existing rights-of-way and whose construction would interfere with incumbents' use of their rights-of-way, increased competition for transmission projects could decrease the value of new investments that would be subject to recovery by PSE&G under its rate base, which could have a material adverse impact on our financial condition and results of operations. In addition, certain PJM cost allocation determinations have been recently challenged at FERC, the resolution of which could impact costs borne by New Jersey ratepayers and increase customer bills.

We may be adversely affected by equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers and remain competitive and could result in substantial financial losses.

The success of our businesses is dependent on our ability to continue providing safe and reliable service to our customers while minimizing service disruptions. We are exposed to the risk of equipment failures, accidents, severe weather events, or other incidents which could result in damage to or destruction of our facilities or damage to persons or property. For instance, equipment failures in our natural gas distribution could give rise to a variety of hazards and operating risks, such as leaks, accidental explosions and mechanical problems, which could cause substantial financial losses and harm our reputation.

In addition, the physical risks of severe weather events, such as experienced from Hurricane Irene and Superstorm Sandy, and of climate change, changes in sea level, temperature and precipitation patterns and other related phenomena have further exacerbated these risks. Such issues experienced at our facilities, or by others in our industry, could adversely impact our revenues; increase costs to repair and maintain our systems; subject us to potential litigation and/or damage claims, fines/penalties; and increase the level of oversight of our utility and generation operations and infrastructure through investigations or through the imposition of additional regulatory or legislative requirements. Such actions could adversely affect our costs, competitiveness and future investments, which could be material to our financial position, results of operations and cash flow. For our transmission and distribution business, the cost of storm restoration efforts may not be fully recoverable through the regulatory process.

We own less than a controlling interest in some of our generating facilities.

We have limited control over the operation of some of our generating facilities, including the Keystone, Conemaugh and Peach Bottom facilities, because our investments represent less than a controlling interest. We seek to exert a degree of influence with respect to the management and operation of projects in which we own less than a controlling interest by negotiating to obtain positions on management committees or to receive certain limited governance rights. However, we may not always succeed in such negotiations. As a result, we may be dependent on our partners to operate such facilities. The approval of our partners also

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may be required for us to transfer our interest in such projects. Reliance on our partners for the management and operation of these facilities could result in a lower return on these facilities than what we believe we could have otherwise achieved.

Any inability to recover the carrying amount of our long-lived assets and leveraged leases could result in future impairment charges which could have a material adverse impact on our financial condition and results of operations.

Long-lived assets represent approximately 74%, 81% and 69% of the total assets of PSEG, PSE&G and Power, respectively, as of December 31, 2017. Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation business climate or market conditions, including prolonged periods of adverse commodity and capacity prices, could potentially indicate an asset's or group of assets' carrying amount may not be recoverable. Significant reductions in our expected revenues or cash flows for an extended period of time resulting from such events could result in future asset impairment charges, which could have a material adverse impact on our financial condition and results of operations.

Energy Holdings has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third-party debt investor. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. Our receipt of payments related to our leveraged lease portfolio in accordance with the lease contracts can be impacted by various factors, including new environmental legislation regarding air quality and other discharges in the process of generating electricity; market prices for fuel and electricity, including the impact of low gas prices on our coal generation investments; overall financial condition of lease counterparties; and the quality and condition of assets under lease.

During 2016, due to the adverse economic conditions experienced by coal generation in PJM, Energy Holdings recorded pre-tax write-downs relating to the NRG REMA, LLC (REMA) leveraged leases in the aggregate of $147 million. During 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as certain discussions with REMA management, Energy Holdings recorded additional pre-tax charges of $77 million in the aggregate.

In June 2017, GenOn Energy, Inc. (GenOn) and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code. REMA was not included in the GenOn filing. Energy Holdings continues to monitor the restructuring of GenOn and its possible impacts on REMA and continues to discuss the situation with various parties relevant to this matter. PSEG cannot predict the outcome of GenOn's efforts to restructure its portfolio and improve its liquidity and the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments, which could include further write-downs of the values of Energy Holdings' leveraged leases.

There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material

Inability to maintain sufficient liquidity in the amounts and at the times needed or access sufficient capital at reasonable rates or on commercially reasonable terms could adversely impact our business.

Funding for our investments in capital improvement and additions, scheduled payments of principal and interest on our existing indebtedness and the extension and refinancing of such indebtedness has been provided primarily by internally-generated cash flow and external financings. We have significant capital requirements and depend on our ability to generate cash in the future from our operations and continued access to capital and credit markets to efficiently fund our cash flow needs. Our ability to generate cash flow is dependent upon, among other things, industry conditions and general economic, financial, competitive, legislative, regulatory and other factors. The ability to arrange financing and the costs of such financing depend on numerous factors including, among other things.

- general economic and capital market conditions;
- the availability of credit from banks and other financial institutions;
- tax, regulatory and securities law developments;
- for PSE&G, our ability to obtain necessary regulatory approvals for the incurrence of additional indebtedness;
- investor confidence in us and our industry;
- our current level of indebtedness and compliance with covenants in our debt agreements;
- the success of current projects and the quality of new projects;
- our current and future capital structure;
- our financial performance and the continued reliable operation of our business; and

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- maintenance of our investment grade credit ratings.

Market disruptions, such as economic downturns experienced in the U.S. and abroad in recent years, the bankruptcy of an unrelated energy company, changes in market prices for electricity and gas, and actual or threatened terrorist attacks, may increase our cost of borrowing or adversely affect our ability to access capital. As a result, no assurance can be given that we will be successful in obtaining financing for projects and investments, to extend or refinance maturing debt or for our other cash flow needs on acceptable terms or at all, which could materially adversely impact our financial position, results of operations and future growth.

In addition, if Power were to lose its investment grade credit rating from S&P or Moody's, it would be required under certain agreements to provide a significant amount of additional collateral in the form of letters of credit or cash, which would have a material adverse effect on our liquidity and cash flows.

We may be unable to realize anticipated tax benefits or retain existing tax credits.

The deferred tax assets and tax credits of PSEG, PSE&G or Power are evaluated for ultimate ability to realize these assets. A valuation allowance may be recorded against the deferred tax assets if we estimate that such assets are more likely than not to be unrealizable based on available evidence including cumulative and forecasted pretax book earnings at the time the estimate is made. A valuation allowance related to deferred tax assets or the monetization of tax credits can be affected by changes to tax laws, statutory tax rates and future taxable income levels. In the event that we determine that we would not be able to realize all or a portion of our deferred tax assets in the future or the benefit of tax credits, we would reduce such amounts through a charge to income tax expense in the period in which that determination was made, which could have a material adverse impact on our financial condition and results of operations.

Challenges associated with recruitment and/or retention of key executives and a skilled workforce could adversely impact our businesses.

Our operations depend on the recruitment and retention of key executives and a skilled workforce. The loss or retirement of key executives or other employees, including those with the specialized knowledge required to support our generation, transmission and distribution operations, could result in various operational challenges. Certain events, such as the potential for early retirement of our nuclear facilities, can make it more difficult to retain these employees. We may incur increased costs for contractors to replace employees, and the loss of institutional and industry knowledge and the increased costs to hire and lengthy time to train new personnel could result in lower productivity, resulting in increased costs, which would negatively impact our results of operations. This has the potential to become more critical as a growing number of employees become eligible to retire.

As of December 31, 2017, approximately 62% of our employees were covered by collective bargaining agreements. As a result, our success will depend on our ability to successfully renegotiate these agreements as they expire. Inability to do so may result in employee strikes or work stoppages which would disrupt our operations and could also result in increased costs, all of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Covenants in our debt instruments may adversely affect our operations.

PSEG's, PSE&G's and Power's debt instruments contain events of default customary for financings of their type, including cross accelerations to other debt of that entity and, in the case of PSEG's and Power's bank credit agreements, certain change of control events. Power's bank credit agreements and outstanding notes also contain limitations on the incurrence of subsidiary debt and liens and Power's outstanding notes require Power to repurchase such notes upon certain change of control events. Our ability to comply with these covenants may be affected by events beyond our control. If we fail to comply with the covenants and are unable to obtain a waiver or amendment, or a default exists and is continuing under such debt, the lenders or the holders or trustee of such debt, as applicable, could give notice and declare outstanding borrowings and other obligations under such debt immediately due and payable. We may not be able to obtain waivers, amendments or alternative financing, or if obtainable, it could be on terms that are not acceptable to us. Any of these events could adversely impact our financial condition, results of operations and cash flows.

Cybersecurity attacks or intrusions could adversely impact our businesses.

Cybersecurity threats to the U.S. energy market infrastructure are increasing in sophistication, magnitude and frequency. We rely on information technology systems that utilize sophisticated digital systems and network infrastructure to operate our generation, transmission and distribution systems. We also store sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers and vendors on our systems and conduct power marketing and hedging activities. In addition, the operation of our business is dependent upon the information technology systems of third parties, including our vendors, regulators, RTOs and Independent System Operators (ISOs), among others. Our and third-party information technology systems may be vulnerable to cybersecurity attacks involving domestic or foreign sources. A cybersecurity attack may also leverage such information technology to cause disruptions at a third party. Cybersecurity impacts to our operations include:

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- disruption of the operation of our assets and the power grid,
- theft of confidential company, employee, shareholder, vendor or customer information, which may cause us to be in breach of certain covenants and contractual obligations,
- general business system and process interruption or compromise, including preventing us from servicing our customers, collecting revenues or the ability to record, process and/or report financial information correctly, and
- breaches of vendors' infrastructures where our confidential information is stored.

In late 2017, PSE&G learned that its customers may be affected by a potential data breach involving the systems of TIO Networks, a subsidiary of PayPal Holdings. PayPal notified PSE&G that there was unauthorized access to TIO Networks' system that stores customer information. TIO Networks processed payments made at automated kiosks in PSE&G's walk-in customer service centers between 2012 and 2017. TIO Networks also facilitated payments PSE&G customers made at third-party payment centers, such as local convenience stores, that accept utility bill payments. The account numbers and addresses for PSE&G's approximately 2.5 million customers may have been exposed as a result of the suspected breach. Customers paying by check via kiosk at one of PSE&G's Customer Service Centers also may have had their personal checking account number and routing number exposed. We continue to work with TIO Networks and PayPal to analyze the impact of this event. While we have experienced and expect to continue to experience actual or attempted cyber-attacks on our information technology systems, none of these incidents has had a material impact on our operations or financial condition.

If a significant cybersecurity event or breach should occur within our company or with one of our material vendors, we could be exposed to significant loss of revenue, material repair costs to intellectual and physical property, significant fines and penalties for non-compliance with existing laws and regulations, significant litigation costs, increased costs to finance our businesses, reputational damage and loss of confidence from our customers, regulators, investors, vendors and employees. Similarly, a significant cybersecurity event or breach experienced by a competitor, regulatory authority, RTO, ISO, or vendor could also materially impact our business and results of operations via enhanced legal and regulatory requirements. For a discussion of state and federal cybersecurity regulatory requirements and information regarding our cybersecurity program, see Part 1, Item 1. Regulatory Issues.

The market for cybersecurity insurance is relatively new and coverage available for cybersecurity events may evolve as the industry matures. While we maintain insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damage we experience.

Acts of war or terrorism could adversely affect our operations.

Our businesses and industry may be impacted by acts and threats of war or terrorism. These actions could result in increased political, economic and financial and insurance market instability and volatility in power and fuel markets, which could materially adversely affect our business and results of operations, including our ability to access capital on terms and conditions acceptable to us. In addition, our infrastructure facilities, such as our generating stations, transmission and distribution facilities and information technology systems, could be direct or indirect targets or be affected by terrorist or other criminal activity. Such events could severely disrupt our business operations and prevent us from servicing our customers. New or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, PSE&G and Power

None.

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ITEM 2. PROPERTIES

Our subsidiaries own all of our physical property. We believe that we and our subsidiaries maintain adequate insurance coverage against loss or damage to plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Generation Facilities

Power

As of December 31, 2017, Power's share of installed fossil and nuclear generating capacity is shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used
Steam:					
Sewaren	NJ	445	100%	445	Gas
Keystone (A)	PA	1,711	23%	391	Coal
Conemaugh (A)	PA	1,711	23%	385	Coal
Bridgeport Harbor	CT	383	100%	383	Coal
New Haven Harbor	CT	448	100%	448	Oil/Gas
Total Steam		**4,698**		**2,052**	
Nuclear:					
Hope Creek	NJ	1,180	100%	1,180	Nuclear
Salem 1 & 2	NJ	2,282	57%	1,310	Nuclear
Peach Bottom 2 & 3 (B)	PA	2,450	50%	1,225	Nuclear
Total Nuclear		**5,912**		**3,715**	
Combined Cycle:					
Bergen	NJ	1,229	100%	1,229	Gas/Oil
Linden	NJ	1,274	100%	1,274	Gas/Oil
Bethlehem	NY	790	100%	790	Gas
Kalaeloa	HI	208	50%	104	Oil
Total Combined Cycle		**3,501**		**3,397**	
Combustion Turbine:					
Essex	NJ	81	100%	81	Gas/Oil
Kearny	NJ	456	100%	456	Gas/Oil
Burlington	NJ	168	100%	168	Gas/Oil
Linden	NJ	336	100%	336	Gas/Oil
New Haven Harbor	CT	130	100%	130	Gas/Oil
Bridgeport Harbor	CT	17	100%	17	Oil
Total Combustion Turbine		**1,188**		**1,188**	
Pumped Storage:					
Yards Creek (C)	NJ	420	50%	210	
Total Power Plants		**15,719**		**10,562**	

(A) Operated by GenOn Northeast Management Company.

(B) Operated by Exelon Generation.

(C) Operated by Jersey Central Power & Light Company.

As of December 31, 2017, Power also owned and operated 414 MW dc of photovoltaic solar generation facilities in various states.

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PSE&G

Primarily all of PSE&G's property is located in New Jersey and PSE&G's First and Refunding Mortgage, which secures the bonds issued thereunder, constitutes a direct first mortgage lien on substantially all of PSE&G's property. PSE&G's electric lines and gas mains are located over or under public highways, streets, alleys or lands, except where they are located over or under property owned by PSE&G or occupied by it under easements or other rights. PSE&G deems these easements and other rights to be adequate for the purposes for which they are being used.

Electric Property and Facilities

As of December 31, 2017, PSE&G's electric transmission and distribution system included approximately 24,000 circuit miles, and 853,000 poles, of which 65% are jointly-owned. In addition, PSE&G owns and operates 50 switching stations with an aggregate installed capacity of 36,023 megavolt-amperes (MVA) and 244 substations with an aggregate installed capacity of 8,250 MVA. Four of those substations, having an aggregate installed capacity of 109 MVA are operated on leased property. In addition, PSE&G owns four electric distribution headquarters and five electric sub-headquarters.

Gas Property and Facilities

As of December 31, 2017, PSE&G's gas system included approximately 18,000 miles of gas mains, 12 gas distribution headquarters, two sub-headquarters, and one meter shop serving all of its gas territory in New Jersey. In addition, PSE&G operates 58 natural gas metering and regulating stations, of which 22 are located on land owned by customers or natural gas pipeline suppliers and are operated under lease, easement or other similar arrangement. In some instances, the pipeline companies own portions of the metering and regulating facilities. PSE&G also owns one liquefied natural gas (LNG) and three liquid petroleum air gas (LPG) peaking facilities. The daily gas capacity of these peaking facilities (the maximum daily gas delivery available during the three peak winter months) is approximately 2.8 million therms in the aggregate.

Solar

As of December 31, 2017, PSE&G had 123 MW dc of installed solar capacity throughout New Jersey.

ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and environmental and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, see Item 1. Business—Regulatory Issues and Environmental Matters and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange, Inc. As of February 16, 2018, there were 60,868 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2012 in our common stock and the subsequent reinvestment of quarterly dividends, the S&P Composite Stock Price Index, the Dow Jones Utilities Index and the S&P Electric Utilities Index.

	2012	2013	2014	2015	2016	2017
PSEG	$ 100.00	$ 109.35	$ 146.73	$ 142.46	$ 167.57	$ 204.11
S&P 500	$ 100.00	$ 132.31	$ 150.35	$ 152.47	$ 170.59	$ 207.74
DJ Utilities	$ 100.00	$ 112.67	$ 147.01	$ 142.57	$ 168.26	$ 190.76
S&P Electrics	$ 100.00	$ 113.20	$ 145.82	$ 138.80	$ 161.20	$ 180.76

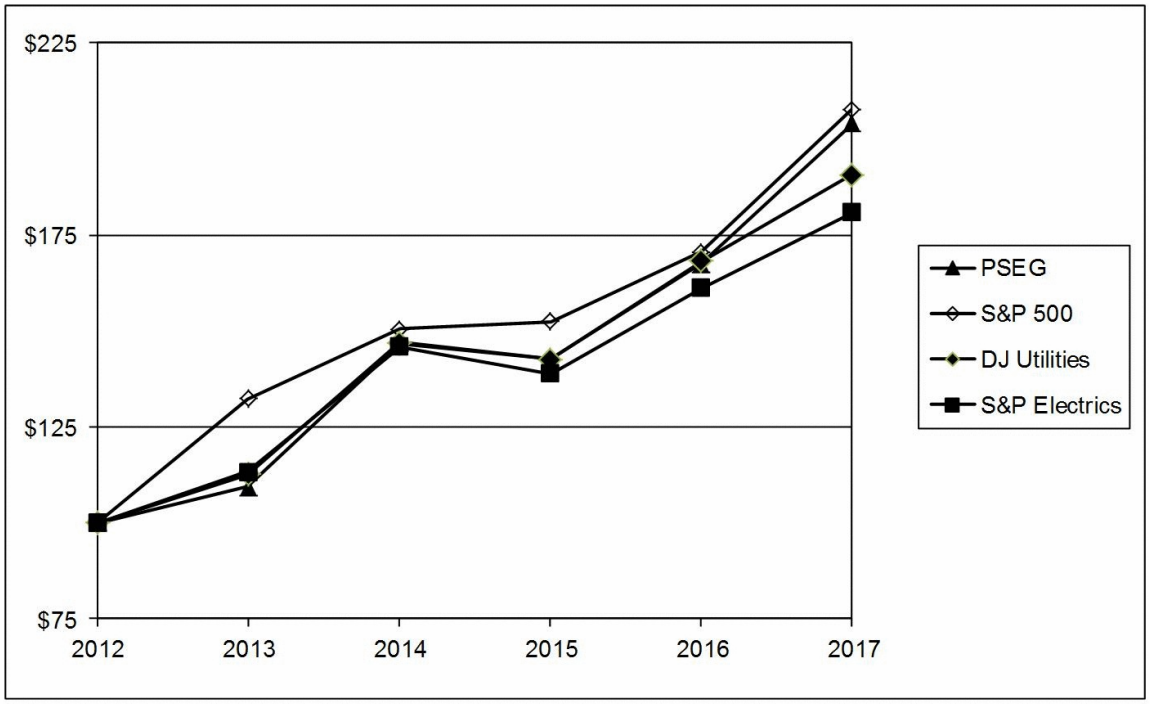

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The following table indicates the high and low sale prices for our common stock and dividends paid for the periods indicated:

Common Stock	High	Low	Dividend per Share
2017			
First Quarter	$ 46.14	$ 42.77	$ 0.43
Second Quarter	$ 45.94	$ 42.47	$ 0.43
Third Quarter	$ 47.47	$ 41.67	$ 0.43
Fourth Quarter	$ 53.28	$ 46.05	$ 0.43
2016			
First Quarter	$ 47.22	$ 37.85	$ 0.41
Second Quarter	$ 47.41	$ 42.77	$ 0.41
Third Quarter	$ 46.81	$ 41.07	$ 0.41
Fourth Quarter	$ 44.29	$ 39.28	$ 0.41

On February 20, 2018, our Board of Directors approved a $0.45 per share common stock dividend for the first quarter of 2018. This reflects an indicative annual dividend rate of $1.80 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

The following table indicates our common share repurchases in the open market during the fourth quarter of 2017 to satisfy obligations under various equity compensation award grants:

Three Months Ended December 31, 2017	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$ —
November 1-November 30	486,635	$ 49.86
December 1-December 31	—	$ —

In December 2017, we entered into a share repurchase plan that complies with Rule 10b5-1 of the Securities Exchange Act of 1934, as amended, solely with respect to the repurchase of shares to satisfy obligations under equity compensation awards that are expected to vest or be exercised in 2018.

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2017:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Long-Term Incentive Plan	347,900	**$ 33.49**	13,771,542
Employee Stock Purchase Plan	—	—	3,174,168
Total	**347,900**	**$ 33.49**	**16,945,710**

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data—Note 18. Stock Based Compensation.

PSE&G

We own all of the common stock of PSE&G. For additional information regarding PSE&G's ability to continue to pay dividends, see Item 7. MD&A—Liquidity and Capital Resources.

Power

We own all of Power's outstanding limited liability company membership interests. For additional information regarding Power's ability to pay dividends, see Item 7. MD&A—Liquidity and Capital Resources.

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ITEM 6. SELECTED FINANCIAL DATA

PSEG

The information presented below should be read in conjunction with the MD&A and the Consolidated Financial Statements and Notes to Consolidated Financial Statements (Notes).

PSEG Years Ended December 31,	2017	2016	2015	2014	2013
	Millions, except Earnings per Share				
Operating Revenues (A)	$ 9,084	$ 9,061	$ 10,415	$ 10,886	$ 9,968
Income from Continuing Operations (B)(C)	$ 1,574	$ 887	$ 1,679	$ 1,518	$ 1,243
Net Income (B)(C)	$ 1,574	$ 887	$ 1,679	$ 1,518	$ 1,243
Earnings per Share:					
Income from Continuing Operations					
Basic	$ 3.12	$ 1.76	$ 3.32	$ 3.00	$ 2.46
Diluted	$ 3.10	$ 1.75	$ 3.30	$ 2.99	$ 2.45
Net Income					
Basic	$ 3.12	$ 1.76	$ 3.32	$ 3.00	$ 2.46
Diluted	$ 3.10	$ 1.75	$ 3.30	$ 2.99	$ 2.45
Dividends Declared per Share	$ 1.72	$ 1.64	$ 1.56	$ 1.48	$ 1.44
As of December 31,					
Total Assets	$ 42,716	$ 40,070	$ 37,535	$ 35,287	$ 32,480
Long-Term Obligations (D)	$ 12,071	$ 10,897	$ 8,837	$ 8,218	$ 7,830

(A) Operating Revenues for 2017, 2016 and 2015 includes $438 million, $410 million and $375 million, respectively, for Long Island Electric Utility Servco, LLC (Servco), a wholly owned subsidiary of PSEG LI. See Item 8. Financial Statements and Supplementary Data—Note 4. Variable Interest Entity for additional information.

(B) Income from Continuing Operations and Net Income for 2017 and 2016 includes after-tax expenses of $577 million and $396 million, respectively, related to the early retirement of Power's Hudson and Mercer coal/gas generation plants and after-tax charges for 2017 and 2016 totaling $45 million and $92 million, respectively, related to investments in REMA's leveraged leases and an after-tax insurance recovery for Superstorm Sandy of $102 million for 2015. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements, Note 7. Long-Term Investments and Note 8. Financing Receivables for additional information for 2017.

(C) Income from Continuing Operations and Net Income for 2017, include the non-cash net income benefit of $745 million, primarily resulting from the remeasurement of deferred tax liabilities required due to the enactment of the Tax Act in December 2017. See Item 8. Financial Statements and Supplementary Data—See Note 20. Income Taxes for additional information for 2017.

(D) Includes capital lease obligations.

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and energy efficiency and related programs in New Jersey, which are regulated by the BPU, and
- **Power**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Our business discussion in Item 1. Business provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Item 1A. Risk Factors provides information about factors that could have a material adverse impact on our businesses. The following discussion provides an overview of the significant events and business developments that have occurred during 2017 and key factors that we expect may drive our future performance. This discussion refers to the Consolidated Financial Statements (Statements) and the related Notes to the Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements and Notes.

EXECUTIVE OVERVIEW OF 2017 AND FUTURE OUTLOOK

2017 Overview

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- improving utility operations through growth in investment in T&D and other infrastructure projects designed to enhance system reliability and resiliency and to meet customer expectations and public policy objectives, and
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the years ended December 31, 2017 and 2016 are presented below:

	Years Ended December 31,	
	2017	2016
Earnings (Losses)	Millions, except per share data	
PSE&G	$ 973	$ 889
Power	479	18
Other	122	(20)
PSEG Net Income	**$ 1,574**	**$ 887**
PSEG Net Income Per Share (Diluted)	**$ 3.10**	**$ 1.75**

Our 2017 over 2016 increase in Net Income was due primarily to the favorable impacts of new tax legislation at Power and Energy Holdings in 2017, discussed below, partially offset by higher charges in 2017 related to the early retirement of our Hudson and Mercer units. Higher transmission revenues in 2017 at PSE&G, lower charges in 2017 related to investments in certain leveraged leases at Energy Holdings and lower plant outage costs at Power, partially offset by lower volumes of electricity sold at lower average prices, also contributed to the increase in Net Income. For a more detailed discussion of our financial results, see Results of Operations.

During 2017, we maintained a strong balance sheet. We continued to effectively deploy capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results, which when combined with the cash flow generated by Power, our merchant generator and power marketer, has allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our multi-year, long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, we continue to invest in transmission projects that focus on reliability improvements and replacement of aging infrastructure. We also continue to make investments to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the BPU in 2014 and to seek recovery on such investments. We are modernizing PSE&G's gas distribution systems as part of our Gas System Modernization Program (GSMP) that was approved by the BPU in late 2015. In July 2017, we filed a petition with the BPU for a GSMP II program, an extension of GSMP to continue to modernize our gas system, through which PSE&G has proposed investing $2.7 billion over five years beginning in 2019. This matter is pending. We believe the petition is consistent with the Infrastructure Investment Program (IIP) regulations that the BPU approved in December 2017. In August 2017, the BPU approved PSE&G's petition for an Energy Efficiency 2017 Program (EE 2017) to extend three existing energy efficiency subprograms (multi-family, direct install and hospital efficiency) and establish two new residential energy efficiency offerings. The EE 2017 allows for $69 million of additional investment and $16 million of additional administrative and information technology costs. The EE 2017 was added as the eleventh component of the Green Program Recovery Charges (GPRC) rate effective September 1, 2017. Over the past few years, these types of investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G.

In January 2018, PSE&G filed a distribution base rate case as required by the BPU as a condition of approval of its Energy Strong Program. The filing requests an approximate one percent increase in revenues and seeks to recover investments made to strengthen electric and gas distribution systems. In its filing, PSE&G requested that these rates take into account a reduction in the revenue requirement as a result of the federal corporate income tax rate reduction from 35% to 21% provided in new tax legislation enacted in December 2017 (Tax Act), including a one-time credit for estimated excess income taxes collected between January 1, 2018 and the time new rates go into effect, and the flow-back to customers of certain additional tax benefits. PSE&G anticipates the new base rates will take effect in the fourth quarter of 2018.

Separately, in January 2018, the BPU issued an order commencing a proceeding to ensure that the rate revenue resulting from expenses relating to taxes reflected in rates but no longer owed as the result of the Tax Act shall be passed onto the ratepayers. The BPU directed New Jersey utilities (including PSE&G) to make filings by March 2, 2018 setting forth interim rates to be effective April 1, 2018, reflecting the new federal corporate tax rate, and to subsequently file proposed final rates, effective July 1, 2018, incorporating all other effects of the Tax Act. This proceeding is currently pending.

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As a result of the enactment of the Tax Act, various state regulatory authorities, including the BPU, have taken action to ensure that excess federal income taxes previously collected in rates are returned to ratepayers. We have made filings to adjust the revenue requirement in certain of our rate matters as a result of the change in federal income tax rate. We continue to assess whether any further action needs to be taken by the company at this time.

For additional information on our specific filings, see Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

Power manages its existing firm pipeline transportation contracts for the benefit of PSE&G's customers through the basic gas supply service (BGSS) arrangement. The contracts are sized to provide for delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power may use it to make third-party sales and supply gas to its generating units in New Jersey. Alternatively, gas supply and pipeline capacity constraints could adversely impact our ability to meet the needs of our utility customers and generating units. Power's hedging practices and ability to capitalize on market opportunities help it to balance some of the volatility of the merchant power business. More than half of Power's expected gross margin in 2018 relates to our hedging strategy, our expected revenues from the capacity market mechanisms and certain ancillary service payments such as reactive power.

Our investments in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. See Item 1. Business—Power for additional information on major growth projects. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to contribute to the overall efficiency of operations.

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. Most recently, in February 2018, Exelon, a co-owner of the Salem units, announced its intention to accelerate the closure of its Oyster Creek nuclear plant located in New Jersey, one year earlier than previously planned for economic reasons. These closures and retirements are generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a further shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

If any or all of the Salem and Hope Creek units were shut down, it would significantly alter New Jersey's energy supply predominately by increasing New Jersey's reliance on natural gas generation. Such a decrease in fuel diversity could also increase the market's vulnerability to price fluctuations and power disruptions in times of high demand. The New Jersey Legislature is assessing legislation that would provide a safety net in order to prevent the loss of environmental attributes from nuclear generating stations. We cannot predict whether the legislation will be enacted or, if enacted, whether our nuclear generating stations in New Jersey will be selected or whether the legislation will provide a sufficient safety net for the continued operation of nuclear generating stations in New Jersey.

In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of our nuclear units beyond the current year, including whether and to what extent these units participate in RPM capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be influenced by the financial outlook of the units, including the progress, timing and continued outlook for enactment of proposed legislation in the state of New Jersey.

If market prices continue to be depressed and legislation is not enacted that adequately compensates nuclear generating stations for their attributes, Power anticipates it will no longer be covering its costs nor be adequately compensated for its market and operational risks at the Salem and Hope Creek nuclear units and would anticipate retiring these units early. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs and additional funding of the Nuclear Decommissioning Trust Fund (NDT) would be material to both PSEG and Power.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

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Transmission Planning

There are several matters pending before FERC and the U. S. Court of Appeals for the District of Columbia Circuit that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey. In addition, as a basic generation service (BGS) supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers may be entitled to recovery, subject to BPU approval. We do not believe that these matters will have a material effect on Power's business or results of operations.

Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base return on equity (ROE). Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. The results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. The CP product was implemented fully in the May 2017 RPM auction for the 2020-2021 Delivery Year. Subsequent to its implementation, FERC approved changes to the CP construct that will enhance the participation of intermittent and demand response resources (seasonal resources). However, two complaints remain pending that ask FERC to investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions.

In May 2017, PJM announced the results of the RPM capacity auction for the 2020-2021 Delivery Year. Power cleared approximately 7,800 MW of its generating capacity at an average price of $174 per MW-day for the 2020-2021 delivery period. In the two prior capacity auctions covering the 2019-2020 and 2018-2019 delivery years, Power cleared approximately 8,900 MW at an average price of $116 per MW-day and approximately 8,700 MW at an average price of $215 per MW-day, respectively. Prices in the most recent auction reflect PJM's downwardly-revised demand forecast, changes in the emergency transfer limits due to transmission expansion and the effects of both the new generation and uncleared generation from the prior year's auction.

As a result of the efforts of certain entities in PJM to obtain financial support arrangements from their state commissions, a group of suppliers requested that FERC direct PJM to expand the currently effective "minimum offer price rule" to apply to certain existing units seeking subsidies. The suppliers' request was intended to avoid a scenario where the subsidized generators would submit bids into the PJM capacity market that did not reflect their actual costs of operation and could artificially suppress capacity market prices. We are currently awaiting FERC action on the suppliers' request and cannot predict the outcome of the proceeding.

In June 2017, PJM issued an energy price formation proposal to address a flaw in the energy market in which energy prices during off-peak periods often do not reflect the production costs of generators during these periods even though they are serving load. PJM's proposal would allow large, inflexible units to set price. If placed into effect, this proposal will improve price formation by ensuring that the marginal costs of units serving load will be better reflected in clearing prices. We cannot predict the outcome of this matter.

See Item 1. Business—Federal Regulation for additional information.

Distribution

The BPU has enacted IIP regulations that allow utilities to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to support the provision of safe and adequate service. Under these regulations, utilities can seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing infrastructure that enhances reliability, resiliency, and/or safety.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the

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best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs.

In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the New Source Performance Standards that establish emissions standards for CO_2 for certain new fossil power plants, and the Clean Power Plan (CPP), a greenhouse gas emissions regulation under the Clean Air Act for existing power plants that establishes state-specific emission rate targets based on implementation of the best system of emission reduction. In October 2017, the EPA Administrator signed a proposed repeal of the CPP. The EPA Administrator concluded that the CPP exceeds the EPA's statutory authority by considering measures that are beyond the control of the owners of the affected sources (fossil fuel-fired electric generating units). The EPA is considering rulemaking to replace the CPP. PSEG cannot assess the impact of any such rulemaking on its business and future results of operations at this time.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above, as well as other matters that may impact our financial condition and results of operations, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

FERC Compliance

Since September 2014, FERC Staff has been conducting a preliminary non-public investigation regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units. While considerable uncertainty remains as to the final resolution of these matters, based upon developments in the investigation in the first quarter of 2017, Power believes the disgorgement and interest costs related to the cost-based bidding matter may range between approximately $35 million and $135 million, depending on the legal interpretation of the principles under the PJM Tariff, plus penalties. Since no point within this range is more likely than any other, Power has accrued the low end of this range of $35 million by recording an additional pre-tax charge to income of $10 million during the three months ended March 31, 2017. PSEG is unable to reasonably estimate the range of possible loss, if any, for the quantity of energy offered matter or the penalties that FERC would impose relating to either the cost-based bidding or quantity of energy matter. However, any of these amounts could be individually material to PSEG and Power. We cannot predict the final outcome of these matters. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Early Retirement of Hudson and Mercer Units

On June 1, 2017, Power completed its previously announced retirement of the generation operations of the existing coal/gas units at the Hudson and Mercer generating stations. The decision to retire the Hudson and Mercer units had a material effect on PSEG's and Power's results of operations in 2016 and continued to adversely impact their results of operations in 2017. As of June 1, 2017, Power completed recognition of the incremental Depreciation and Amortization (D&A) of $938 million ($964 million in total) due to the significant shortening of the expected economic useful lives of Hudson and Mercer. During 2017, Energy Costs of $15 million and Operation and Maintenance (O&M) of $23 million were also incurred. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements for additional information.

Power is exploring various opportunities with these sites, including using the sites for alternative industrial activity or the disposition of one or both of the sites. If Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such remediation are neither currently probable nor estimable but may be material.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

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Leveraged Lease Impairments

GenOn Energy, Inc. (GenOn) and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code on June 14, 2017. NRG REMA, LLC (REMA) was not included in the GenOn bankruptcy filing. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete. PSEG cannot predict the outcome of GenOn's efforts to restructure its balance sheet and improve its liquidity.

During the first quarter of 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as discussions with REMA management, Energy Holdings recorded an additional $55 million pre-tax charge for its current best estimate of loss relating to its REMA leveraged lease receivables, which was reflected in Operating Revenues. During the second quarter of 2017, Energy Holdings recorded an additional $22 million pre-tax charge for its current best estimate of loss related to lease receivables due to collectability of payments ($15 million) and economics impacting the residual value ($7 million) of certain leased assets. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments, which could include further write-downs of the values of Energy Holdings' leveraged lease receivables, and continue to discuss the situation with various parties relevant to this matter. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 7. Long-Term Investments and Note 8. Financing Receivables. There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.

Additional facilities in our leveraged lease portfolio include the Joliet and Powerton generating facilities. Similar to Shawville, Joliet was recently converted to use natural gas. Converted natural gas units such as Shawville and Joliet may have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units. Powerton is a coal-fired generating facility in Illinois. Each of these three facilities may not be as economically competitive as newer combined cycle gas units and could continue to be adversely impacted by the same economic conditions experienced by other less efficient natural gas and coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged lease receivables associated with these facilities.

Tax Legislation

In December 2017, the U.S. government enacted comprehensive tax legislation (Tax Act), which, among other things, decreased the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018, and made certain changes to bonus depreciation rules.

As a result of the enacted reduction in the statutory U.S. corporate income tax rate, as well as other aspects of the Tax Act, we have recorded a one-time, non-cash earnings benefit of $745 million, including $588 million related to Power and $147 million related to Energy Holdings. This benefit is primarily due to the remeasurement of deferred tax balances. In addition, PSE&G had excess deferred taxes of approximately $2.1 billion as of December 31, 2017 and recorded an approximate $2.9 billion revenue impact of these excess deferred taxes as Regulatory Liabilities where it is probable that refunds will be made to customers in future rates. The amount and timing of any such refund cannot be determined at this time.

Beginning in 2018, PSEG, on a consolidated basis, will incur lower income tax expense resulting in a decrease in its projected effective income tax rate. This is also expected to increase PSEG's and Power's net income. To the extent allowed under the Tax Act, Power's operating cash flows will reflect the full expensing of capital investments for income tax purposes. PSEG and Power expect that the interest on their debt will continue to be fully tax deductible albeit at a lower tax rate. For PSE&G, the Tax Act is expected to lead to lower customer rates due to lower income tax expense recoveries and the refund of deferred income tax regulatory liabilities, partially offset by the impacts of higher rate base. The impact of the lower federal income tax rate on PSE&G was reflected in PSE&G's recently filed distribution base rate case and its transmission formula rate filings. The Tax Act is generally expected to result in lower operating cash flows for PSE&G resulting from the elimination of bonus depreciation, partially offset by higher revenues due to the higher rate base. The full impact of these and other provisions of the Tax Act cannot be determined at this time.

The impact of the Tax Act may differ from these estimates, possibly materially, due to, among other things, changes in interpretations and assumptions PSEG has made, guidance that may be issued and actions PSEG may take as a result of the Tax Act. For additional information, see Note 20. Income Taxes.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of opportunities in a rapidly evolving market as we remain diligent in managing costs. In 2017, our

- diverse fuel mix and dispatch flexibility allowed us to generate approximately 51 terra-watt hours while addressing

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fuel availability and price volatility,

- total nuclear fleet achieved an average capacity factor of 94%, and
- utility was recognized for the sixteenth consecutive year as the most reliable utility in the Mid-Atlantic region.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during 2017 as we:

- maintained sufficient liquidity,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2017 to $1.72 per share.

We expect to be able to fund our planned capital requirements, as described in Liquidity and Capital Resources, and manage the impacts of the Tax Act without the issuance of new equity.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In 2017, we

- made additional investments in transmission infrastructure projects,
- continued to execute our GSMP, Energy Strong, Energy Efficiency, solar and other existing BPU-approved utility programs,
- continued construction of our Keys and Sewaren 7 generation projects for targeted commercial operation in 2018 and commenced construction of our BH5 generation project for targeted commercial operation in mid-2019, and
- acquired six solar energy projects in various states totaling 88 MW-direct current (dc), for a total of 414 MW (dc) of installed capacity in 14 states throughout the U.S.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-growing economy and a cost-constrained environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions in response to changes in demand,
- execute our utility capital investment program, including our Energy Strong program, GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers, and obtain approval for extension of these programs,
- effectively manage construction of our Keys, Sewaren 7, BH5 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

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For 2018 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- fair and timely rate relief from the BPU and FERC for recovery of costs and return on investments, including with respect to our distribution base rate case which was filed with the BPU in January 2018,
- continuing discussions regarding the restructuring of GenOn and REMA and its potential impact on the value of our Keystone, Conemaugh and Shawville leveraged leases,
- the continuing impact of the Tax Act,
- uncertainty in the national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate,
- the impact of lower natural gas prices and increasing environmental compliance costs on the competitiveness of our nuclear and remaining coal-fired generation plants, and the potential for retirement of such plants earlier than their current useful lives,
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development projects, including in connection with permitting and regulatory approvals,
- maintaining a diverse mix of fuels to mitigate risks associated with fuel price volatility and market demand cycles, and
- FERC Staff's continuing investigation of certain of Power's New Jersey fossil generating unit bids in the PJM energy market.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of T&D facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses,
- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency, modernizing existing infrastructure and participation in transmission projects through FERC's "open window" solicitation process.

Power is developing a retail energy business to sell energy, which we believe complements our existing wholesale marketing business. Power began these marketing activities in 2017 and has been granted retail energy supplier licenses in New Jersey, Pennsylvania and Maryland.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

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RESULTS OF OPERATIONS

	Years Ended December 31,		
	2017	2016	2015
Earnings (Losses)	Millions		
PSE&G	$ 973	$ 889	$ 787
Power (A)(B)	479	18	856
Other (B)(C)	122	(20)	36
PSEG Net Income	**$ 1,574**	**$ 887**	**$ 1,679**
PSEG Net Income Per Share (Diluted)	**$ 3.10**	**$ 1.75**	**$ 3.30**

(A) Power's results in 2017 and 2016 include after-tax expenses of $577 million and $396 million, respectively, related to the early retirement of its Hudson and Mercer coal/gas generation plants. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements for additional information. Power's results in 2015 include an after-tax insurance recovery for Superstorm Sandy of $102 million.

(B) Results in 2017 include the non-cash net income benefit of $745 million, including $588 million related to Power and $147 million related to Energy Holdings, resulting from the remeasurement of deferred tax liabilities required due to the enactment of the Tax Act in December 2017.

(C) Other includes after-tax activities at the parent company, PSEG LI and Energy Holdings as well as intercompany eliminations. Energy Holdings recorded after-tax charges totaling $45 million and $92 million related to its investments in REMA's leveraged leases in 2017 and 2016. See Item 8. Financial Statements and Supplementary Data—Note 7. Long-Term Investments and Note 8. Financing Receivables for further information.

Our results include the realized gains, losses and earnings on Power's Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity. Realized gains and losses, interest and dividend income and other costs related to the NDT Fund are recorded in Other Income (Deductions), and impairments on certain NDT securities are recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in O&M Expense and the depreciation related to the ARO asset is recorded in D&A Expense.

Our results also include the after-tax impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The combined after-tax impact on Net Income for the years ended December 31, 2017, 2016 and 2015 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2017	2016	2015
	Millions, after tax		
NDT Fund and Related Activity (A)	$ 62	$ —	$ 8
Non-Trading MTM Gains (Losses) (B)	$ (99)	$ (100)	$ 93

(A) Net of tax (expense) benefit of $(72) million, $(5) million and $(16) million for the years ended December 31, 2017, 2016 and 2015, respectively.

(B) Net of tax (expense) benefit of $68 million, $68 million and $(65) million for the years ended December 31, 2017, 2016 and 2015, respectively.

The 2017 year-over-year increase in our Net Income was driven primarily by:

- non-cash net income benefits related to new tax legislation (See Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes) at Power and Energy Holdings,
- higher transmission revenues,
- higher net NDT gains in 2017, and
- lower charges related to investments in certain leveraged leases at Energy Holdings (See Item 8. Financial Statements and Supplementary Data —Note 8. Financing Receivables).

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These increases were partially offset by:

- higher charges related to the early retirement of two coal/gas generation units at Power (See Item 8. Financial Statements and Supplementary Data —Note 3. Early Plant Retirements), and
- lower volumes of energy sold at lower average realized sales prices under the BGS contracts and in the PJM and New England regions.

The 2016 year-over-year decrease in our Net Income was driven primarily by:

- charges related to the early retirement of two coal/gas generation units at Power (See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements),
- MTM losses in 2016 as compared to MTM gains in 2015,
- lower volumes of energy sold at lower average realized sales prices,
- lower capacity and operating reserve revenues in PJM,
- higher 2016 congestion costs in PJM due primarily to realized gains on financial transmission rights (FTR) in PJM in the prior year due to extremely cold weather,
- lower volumes of gas sold at lower average prices under the BGSS contract,
- insurance recoveries received primarily by Power in 2015 related to Superstorm Sandy, and
- an impairment related to investments in certain leveraged leases at Energy Holdings (See Item 8. Financial Statements and Supplementary Data —Note 8. Financing Receivables).

These decreases were partially offset by:

- lower generation costs driven by lower fuel costs, particularly for natural gas, and reduced generation output at Power,
- higher costs incurred at Power for planned outages in 2015,
- higher transmission revenues, and
- higher management fee revenues at PSEG LI pursuant to the OSA.

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PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data—Note 24. Related-Party Transactions.

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2017	2016	2015	2017 vs. 2016		2016 vs. 2015	
	Millions			Millions	%	Millions	%
Operating Revenues	$ 9,084	$ 9,061	$ 10,415	$ 23	—	$ (1,354)	(13)
Energy Costs	2,800	3,001	3,261	(201)	(7)	(260)	(8)
Operation and Maintenance	2,869	3,008	2,978	(139)	(5)	30	1
Depreciation and Amortization	1,986	1,476	1,214	510	35	262	22
Income from Equity Method Investments	14	11	12	3	27	(1)	(8)
Other Income (Deductions)	228	124	152	104	84	(28)	(18)
Other-Than-Temporary Impairments	12	28	53	(16)	(57)	(25)	(47)
Interest Expense	391	385	393	6	2	(8)	(2)
Income Tax (Benefit) Expense	(306)	411	1,001	(717)	(174)	(590)	(59)

The 2017, 2016 and 2015 amounts in the preceding table for Operating Revenues and O&M costs each include $438 million, $410 million and $375 million, respectively, for Servco. These amounts represent the O&M pass-through costs for the Long Island operations, the full reimbursement of which is reflected in Operating Revenues. See Item 8. Financial Statements and Supplementary Data—Note 4. Variable Interest Entity for further explanation. The Income Tax Benefit in 2017 includes the non-cash benefit resulting from the remeasurement of deferred tax liabilities required due to the enactment of the Tax Act in December 2017. The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2017	2016	2015	2017 vs. 2016		2016 vs. 2015	
	Millions			Millions	%	Millions	%
Operating Revenues	$ 6,234	$ 6,221	$ 6,636	$ 13	—	$ (415)	(6)
Energy Costs	2,363	2,567	2,722	(204)	(8)	(155)	(6)
Operation and Maintenance	1,434	1,475	1,560	(41)	(3)	(85)	(5)
Depreciation and Amortization	685	565	892	120	21	(327)	(37)
Other Income (Deductions)	87	79	75	8	10	4	5
Interest Expense	303	289	280	14	5	9	3
Income Tax Expense	563	515	470	48	9	45	10

Year Ended December 31, 2017 as compared to 2016

Operating Revenues increased $13 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $166 million due primarily to an increase in transmission revenues.

- Transmission revenues were $152 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.

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- Gas distribution revenues increased $30 million due to a $16 million increase due to Energy Strong, $10 million from inclusion of the GSMP in base rates, $4 million in higher collections of GPRC and an increase of $2 million due to higher sales volumes. These increases were partially offset by lower Weather Normalization Clause (WNC) revenues of $2 million.
- Electric distribution revenues decreased $16 million due primarily to a $28 million decrease in sales volume and $14 million in lower collections of GPRC, partially offset by a $26 million increase in Energy Strong revenues.

Clause Revenues increased $47 million due to the absence of the return in 2016 to customers of overcollections of Securitization Transition Charge (STC) revenues of $59 million and higher Margin Adjustment Clause (MAC) revenues of $4 million. These increases were partially offset by lower Societal Benefit Charges (SBC) of $17 million. The changes in STC, MAC and SBC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, D&A and Interest Expense. PSE&G does not earn margin on STC, SBC, Solar Pilot Recovery Charges (SPRC) or MAC collections.

Commodity Revenues decreased $204 million due to lower Electric revenues partially offset by higher Gas revenues. This decrease is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $274 million due to $199 million in lower BGS revenues reflecting $109 million from lower sales volumes and $90 million from lower prices, $61 million in lower collections of Non-Utility Generation Charges (NGC) due primarily to lower prices and $14 million in lower revenues from the decreased sales volume of Non-Utility Generation (NUG) energy.
- Gas revenues increased $70 million due to higher BGSS prices of $68 million and $2 million from higher sales volumes.

Operating Expenses

Energy Costs decreased $204 million. This is entirely offset by Commodity Revenues.

Operation and Maintenance decreased $41 million due to

- a $28 million net reduction related to various clause mechanisms and GPRC expenditures,
- a $15 million decrease in appliance service costs, and
- a $7 million net decrease in pension and OPEB expenses, net of amounts capitalized,
- partially offset by a $9 million net increase in other operating expenses.

Depreciation and Amortization increased $120 million due primarily to a $61 million net increase in amortization of Regulatory Assets, including the absence of the STC liability that ended in 2016, and an increase in depreciation of $59 million due to additional plant placed into service in 2017.

Other Income (Deductions) increased $8 million due primarily to a $7 million increase in Allowance for Funds Used During Construction (AFUDC).

Interest Expense increased $14 million primarily due to

- $11 million due to net long-term debt issuances in 2016 and $9 million due to net long-term debt issuances in 2017, partially offset by
- a decrease of $6 million due to clause-related interest for BGSS in 2016.

Income Tax Expense increased $48 million due primarily to higher pre-tax income.

Year Ended December 31, 2016 as compared to 2015

Operating Revenues decreased $415 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $191 million due primarily to an increase in transmission revenues.

- Transmission revenues were $223 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.
- Electric distribution revenues decreased $27 million due primarily to $47 million in lower collections of GPRC, partially offset by an $18 million increase in Energy Strong revenues.

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- Gas distribution revenues decreased $5 million due to a decrease of $43 million due to lower sales volumes and $7 million in lower collections of GPRC. These decreases were partially offset by higher WNC revenues of $25 million due to warmer weather in 2016 compared to 2015 and $20 million due to the inclusion of Energy Strong in base rates.

Clause Revenues decreased $445 million due to lower STC revenues of $419 million, lower SBC of $33 million and lower SPRC of $8 million. These decreases were partially offset by higher MAC revenues of $15 million. The changes in STC, SBC, SPRC and MAC amounts were entirely offset by changes in the amortization of related costs (Regulatory Assets) in O&M, D&A and Interest Expense. PSE&G does not earn margin on STC, SBC, SPRC or MAC collections.

Commodity Revenues decreased $155 million due to lower Electric and Gas revenues. This is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $136 million due to $73 million in lower collections of NGC due primarily to lower prices, $42 million in lower revenues from the sale of NUG energy and $21 million in lower prices BGS revenues primarily due to lower sales volumes.
- Gas revenues decreased $19 million due to $80 million from lower sales volumes, partially offset by higher BGSS prices of $61 million.

Operating Expenses

Energy Costs decreased $155 million. This is entirely offset by Commodity Revenues.

Operation and Maintenance decreased $85 million due to

- a $98 million net reduction related to various clause mechanisms and GPRC, and
- a $13 million decrease in pension and OPEB expenses, net of amounts capitalized,
- partially offset by $10 million of insurance recovery proceeds in 2015,
- a $10 million increase in vegetation management costs, and
- a $6 million net increase due primarily to T&D corrective maintenance and appliance service costs.

Depreciation and Amortization decreased $327 million due primarily to a $396 million net decrease in amortization of Regulatory Assets, partially offset by an increase in depreciation of $65 million due to additional plant in service in 2016.

Interest Expense increased $9 million due to increases of

- $14 million due to net debt issuances in 2015, and
- $13 million due to net debt issuances in 2016,
- partially offset by a decrease of $11 million due to the redemption of securitization debt in 2015, and
- $7 million of higher interest related to BGSS in 2015.

Income Tax Expense increased $45 million due primarily to higher pre-tax income partially offset by changes in the reserve for uncertain tax positions and flow through items.

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Power

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2017	2016	2015	2017 vs. 2016		2016 vs. 2015	
	Millions			Millions	%	Millions	%
Operating Revenues	$ 3,930	$ 4,023	$ 4,928	$ (93)	(2)	$ (905)	(18)
Energy Costs	1,983	1,986	2,150	(3)	N/A	(164)	(8)
Operation and Maintenance	1,038	1,143	1,057	(105)	(9)	86	8
Depreciation and Amortization	1,268	881	291	387	44	590	N/A
Income from Equity Method Investments	14	11	14	3	27	(3)	(21)
Other Income (Deductions)	157	45	97	112	N/A	(52)	(54)
Other-Than-Temporary Impairments	12	28	53	(16)	(57)	(25)	(47)
Interest Expense	50	84	121	(34)	(40)	(37)	(31)
Income Tax Expense (Benefit)	(729)	(61)	511	(668)	N/A	(572)	N/A

Year Ended December 31, 2017 as compared to 2016

Operating Revenues decreased $93 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $204 million due primarily to

- a decrease of $126 million in energy sales in the PJM and New England (NE) regions due primarily to lower average realized prices,
- a decrease of $100 million in electricity sold under our BGS contracts due primarily to lower volumes coupled with lower prices,
- a decrease of $24 million in revenue expected to be returned to ratepayers associated with excess federal income tax previously collected by Power's subsidiary, PSEG New Haven LLC, due to the change in federal tax rates effective January 1, 2018,
- a decrease of $18 million in operating reserves in the PJM region,
- a charge of $10 million due to an increase in the FERC accrual related to the PJM bidding matter,
- a decrease of $7 million due to higher MTM losses in 2017 as compared to 2016. Of this amount, $120 million was due to increased forward prices, partially offset by a decrease of $113 million due to lower gains on positions reclassified to realized upon settlement in 2017 as compared to 2016,
- partially offset by a net increase of $53 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions,
- a net increase of $18 million in capacity revenues in the PJM and NE regions due to increases in cleared capacity and capacity auction prices, and
- an increase of $11 million due to higher sales related to new solar projects.

Gas Supply Revenues increased $110 million due primarily to

- an increase of $67 million in sales under the BGSS contract, of which $40 million was due to higher average sales prices coupled with a $27 million increase in sales volumes due to periods of colder weather in the heating season,
- a net increase of $24 million due to higher MTM gains in 2017 as compared to 2016, and
- an increase of $19 million related to sales to third parties, of which $48 million was due to higher average sales prices, partially offset by $29 million of lower volumes sold.

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Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $3 million due to

Generation costs decreased $69 million due primarily to

- a net decrease of $83 million primarily due to lower congestion costs in PJM due to lower rates coupled with less volumes, partially offset by higher transmission charges due to higher rates,
- a net decrease of $50 million due to charges associated with the announced early retirement of the Mercer and Hudson units in 2016, primarily related to lower coal inventory write-downs in 2017, partially offset by additional retirement costs incurred in 2017,
- partially offset by higher fuel costs of $31 million reflecting higher average realized prices for natural gas coupled with the utilization of higher volumes of coal, partially offset by the utilization of lower volumes of gas,
- an increase of $17 million due to MTM losses in 2017 as compared to MTM gains in 2016, and
- a net increase of $16 million primarily due to an increase in the volume of energy purchases in the NE region to serve load obligations.

Gas costs increased $66 million due to

- an increase of $50 million related to sales under the BGSS contract, of which $31 million was due to higher average gas costs, coupled with a $19 million increase in volumes sold due to periods of colder weather in the heating season, and
- an increase of $16 million related to sales to third parties, of which $44 million was due to higher average gas costs, partially offset by a $28 million decrease in volumes sold.

Operation and Maintenance decreased $105 million due to

- a $72 million decrease at our fossil plants, due primarily to the retirement of the Hudson and Mercer units and higher planned outage costs in 2016,
- a $35 million net decrease related to our nuclear plants due primarily to lower labor-related expenses and outage costs,
- an $8 million net decrease due to lower pension and OPEB costs,
- partially offset by $5 million of costs related to new solar plants placed into service in 2017.

Depreciation and Amortization increased $387 million due primarily to

- $346 million of higher depreciation for Hudson and Mercer, primarily due to the accelerated expense related to the early retirement of those units,
- a $15 million increase due to the accelerated retirement date for the Bridgeport Harbor unit 3,
- an $11 million increase due primarily to a higher nuclear asset base, and
- $11 million of higher depreciation due to new solar projects.

Other Income (Deductions) increased $112 million due primarily to higher net realized gains from the NDT Fund in 2017.

Other-Than-Temporary Impairments decreased $16 million due to lower impairments of equity securities in the NDT Fund in 2017.

Interest Expense decreased $34 million due primarily to

- a $24 million decrease due to higher interest capitalized for the construction of three new fossil stations: BH5, Sewaren 7 and Keys, and
- a net $7 million decrease due to debt maturities in September 2016, partially offset by a debt issuance in June 2016.

Income Tax Expense decreased $668 million due primarily to the one-time benefit recorded as a result of the remeasurement of deferred tax balances required due to the enactment of the Tax Act in December 2017.

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Year Ended December 31, 2016 as compared to 2015

Operating Revenues decreased $905 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $714 million due primarily to

- a decrease of $317 million due to MTM losses in 2016 as compared to MTM gains in 2015. Of this amount, $199 million was due to changes in forward power prices resulting in lower MTM gains in 2016 compared to 2015. Also contributing to the decrease was $118 million of higher gains on positions reclassified to realized upon settlement in 2016 compared to 2015,
- a decrease of $298 million in energy sales volumes in the PJM, NE and NY regions due primarily to milder weather in 2016 and lower average realized prices,
- a decrease of $80 million in capacity revenue primarily in the PJM region due to the retirement of older peaking units in June 2015, and
- a decrease of $49 million due to lower operating reserve revenues in the PJM region due to less congestion and lower prices,
- partially offset by a net increase of $19 million due primarily to higher volumes of electricity sold under wholesale load contract in the PJM and NE regions, partially offset by lower average prices, and
- a net increase of $8 million due to new solar projects beginning commercial operations.

Gas Supply Revenues decreased $191 million due primarily to

- a decrease of $183 million in sales under the BGSS contract due primarily to lower average sales prices and a decrease in sales volumes due to warmer average temperatures in the 2016 heating season, and
- a decrease of $9 million due to MTM losses in 2016 due to changes in forward prices.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $164 million due to

Generation costs decreased $95 million due primarily to

- lower fuel costs of $288 million reflecting lower average realized prices for natural gas and the utilization of lower volumes of fuel,
- partially offset by a net increase of $143 million primarily due to realized gains on FTRs in PJM in 2015 due to extremely cold weather, and
- a $62 million charge associated with the announced early retirement of the Mercer and Hudson units, primarily related to a coal inventory write-down.

Gas costs decreased $69 million due to

- a decrease of $101 million related to sales under the BGSS contract due primarily to lower average gas costs and a decrease in volumes sold due to warmer average temperatures during the 2016 winter heating season,
- partially offset by an increase of $32 million related to sales to third parties due primarily to higher average gas costs and an increase in volumes sold.

Operation and Maintenance increased $86 million due to

- $145 million of insurance recoveries received in 2015 related to Superstorm Sandy, and
- $53 million of charges related to the early retirement of the Hudson and Mercer units,
- partially offset by a net decrease of $73 million related to our fossil plants, largely due to higher costs incurred in 2015 for our planned major outages at the Bethlehem Energy Center and Bergen generating plants,
- a net decrease of $31 million related to our nuclear plants due primarily to lower planned outage costs at our 100%-owned Hope Creek plant and our 57%-owned Salem Unit 1 plant, and
- an $8 million decrease due to lower pension and OPEB costs.

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Depreciation and Amortization increased $590 million due primarily to

- $555 million of accelerated depreciation due to the early retirement of the Hudson and Mercer units,
- a $24 million increase due primarily to a higher nuclear asset base, and
- $5 million of higher depreciation due to new solar projects

Other Income (Deductions) decreased $52 million due primarily to $28 million of insurance recoveries received in 2015 related to Superstorm Sandy and $38 million of lower net realized gains from the NDT Fund in 2016, partially offset by $10 million of lower purchased tax credits in 2016.

Other-Than-Temporary Impairments decreased $25 million due to lower impairments of equity securities in the NDT Fund in 2016.

Interest Expense decreased $37 million due to

- $27 million of interest capitalized for the construction of three new fossil stations: Bridgeport Harbor 5, Sewaren 7 and Keys Energy Center, and
- a $15 million decrease due to the maturity of 5.50% of Senior Notes in December 2015,
- partially offset by an increase of $5 million due to net debt issuances in 2016.

Income Tax Expense decreased $572 million in 2016 due primarily to a pre-tax loss in 2016 as compared to pre-tax income in 2015.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Financing Methodology

We expect our capital requirements to be met through internally generated cash flows and external financings, consisting of short-term debt for working capital needs and long-term debt for capital investments.

PSE&G's sources of external liquidity include a $600 million multi-year revolving credit facility. PSE&G uses internally generated cash flow and its commercial paper program to meet seasonal, intra-month and temporary working capital needs. PSE&G does not engage in any intercompany borrowing or lending arrangements. PSE&G maintains back-up facilities in an amount sufficient to cover the commercial paper and letters of credit outstanding. PSE&G's dividend payments to/capital contributions from PSEG are consistent with its capital structure objectives which have been established to maintain investment grade credit ratings. PSE&G's long-term financing plan is designed to replace maturities, fund a portion of its capital program and manage short-term debt balances. Generally, PSE&G uses either secured medium-term notes or first mortgage bonds to raise long-term capital.

PSEG, Power, Energy Holdings, PSEG LI and Services participate in a corporate money pool, an aggregation of daily cash balances designed to efficiently manage their respective short-term liquidity needs. PSEG LI's subsidiary, Long Island Electric Utility Servco, LLC (Servco), does not participate in the corporate money pool. Servco's short-term liquidity needs are met through an account funded and owned by LIPA.

PSEG's sources of external liquidity may include the issuance of long-term debt securities and the incurrence of additional indebtedness under credit facilities. Our current sources of external liquidity include multi-year revolving credit facilities totaling $1.5 billion. These facilities are available to back-stop PSEG's commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to PSEG's subsidiaries. PSEG's credit facilities and the commercial paper program are available to support PSEG working capital needs or to temporarily fund growth opportunities in advance of obtaining permanent financing. PSEG also has a $700 million term loan credit agreement that is scheduled to expire in June 2019. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power's sources of external liquidity include $2.1 billion of multi-year revolving credit facilities. Additionally, from time to time, Power maintains bilateral credit agreements designed to enhance its liquidity position. Credit capacity is primarily used to provide collateral in support of Power's forward energy sale and forward fuel purchase contracts as the market prices for energy and fuel fluctuate, and to meet potential collateral postings in the event that Power is downgraded to below investment grade by S&P or Moody's. Power's dividend payments to PSEG are also designed to be consistent with its capital structure objectives

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which have been established to maintain investment grade credit ratings and provide sufficient financial flexibility. Generally, Power issues senior unsecured debt to raise long-term capital.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the year ended December 31, 2017, our operating cash flow decreased by $50 million. For the year ended December 31, 2016, our operating cash flow decreased by $608 million. The net changes were primarily due to net tax payments at PSEG and its other subsidiaries in 2017 offset by net changes from our subsidiaries as discussed below.

PSE&G

PSE&G's operating cash flow decreased $55 million from $1,894 million to $1,839 million for the year ended December 31, 2017, as compared to 2016, due primarily to lower tax refunds and a decrease of $50 million related to a change in regulatory deferrals. These amounts were partially offset by higher earnings and $30 million in decreased vendor payments.

PSE&G's operating cash flow decreased $231 million from $2,125 million to $1,894 million for the year ended December 31, 2016, as compared to 2015, due primarily to a decrease from lower collections for securitization debt principal repayments which were $259 million in 2015, a decrease of $249 million in cash receipts from customers due to lower sales driven by warmer winter weather in 2016 compared to 2015, a decrease of $90 million related to a change in regulatory deferrals, primarily driven by net returns to customers in 2016 related to 2015 overcollections, partially offset by higher bill credits and $74 million in increased vendor payments. These amounts were partially offset by higher earnings and higher tax refunds in 2016.

Power

Power's operating cash flow increased $71 million from $1,255 million to $1,326 million for the year ended December 31, 2017, as compared to 2016, primarily resulting from a decrease of $61 million in payments to counterparties, a $26 million increase from higher net collections of counterparty receivables, and higher earnings. These amounts were partially offset by higher tax payments and an increase in margin deposit requirements of $14 million.

Power's operating cash flow decreased $451 million from $1,706 million to $1,255 million for the year ended December 31, 2016, as compared to 2015, primarily resulting from lower earnings, an increase in margin deposit requirements of $198 million, and a $134 million decrease from net collection of counterparty receivables, partially offset by a reduction in tax payments.

Short-Term Liquidity

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of December 31, 2017 were as follows:

	As of December 31, 2017		
Company/Facility	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$ 1,500	$ 556	$ 944
PSE&G	600	15	585
Power	2,100	151	1,949
Total	**$ 4,200**	**$ 722**	**$ 3,478**

As of December 31, 2017, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12-month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating from S&P or Moody's, which would represent a three level downgrade from its current S&P or Moody's ratings. In the event of a deterioration of Power's credit rating certain of Power's agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $848 million and $783 million as of December 31, 2017 and 2016, respectively. The early retirement of Power's Hudson and Mercer coal/gas generation units did not have a material impact on Power's debt covenant ratios or its ability to obtain credit facilities. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements.

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For additional information, see Item 8.Financial Statements and Supplementary Data—Note 14. Debt and Credit Facilities.

Long-Term Debt Financing

PSE&G has $400 million of 5.30% Medium Term Notes maturing in May 2018 and $350 million of 2.30% Medium Term Notes maturing in September 2018.

Power has $250 million of 2.45% Senior Notes maturing in November 2018.

For a discussion of our long-term debt transactions during 2017 and into 2018, see Item 8. Financial Statements and Supplementary Data—Note 14. Debt and Credit Facilities.

Debt Covenants

Our credit agreements contain maximum debt to equity ratios and other restrictive covenants and conditions to borrowing. We are currently in compliance with all of our debt covenants. Continued compliance with applicable financial covenants will depend upon our future financial position, level of earnings and cash flows, as to which no assurances can be given.

In addition, under its First and Refunding Mortgage (Mortgage), PSE&G may issue new First and Refunding Mortgage Bonds against previous additions and improvements, provided that its ratio of earnings to fixed charges calculated in accordance with its Mortgage is at least 2 to 1, and/or against retired Mortgage Bonds. As of December 31, 2017, PSE&G's Mortgage coverage ratio was 5.2 to 1 and the Mortgage would permit up to approximately $6.9 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.

Default Provisions

Our bank credit agreements and indentures contain various, customary default provisions that could result in the potential acceleration of indebtedness under the defaulting company's agreement.

In particular, PSEG's bank credit agreements contain provisions under which certain events, including an acceleration of material indebtedness under PSE&G's and Power's respective financing agreements, a failure by PSE&G or Power to satisfy certain final judgments and certain bankruptcy events by PSE&G or Power, that would constitute an event of default under the PSEG bank credit agreements. Under the PSEG bank credit agreements, it would also be an event of default if either PSE&G or Power ceases to be wholly owned by PSEG. The PSE&G and Power bank credit agreements include similar default provisions; however, such provisions only relate to the respective borrower under such agreement and its subsidiaries and do not contain cross default provisions to each other. The PSE&G and Power bank credit agreements do not include cross default provisions relating to PSEG.

There are no cross acceleration provisions in PSEG's or PSE&G's indentures. However, PSEG's existing notes include a cross acceleration provision that may be triggered upon the acceleration of more than $75 million of indebtedness incurred by PSEG. Such provision does not extend to an acceleration of indebtedness by any of PSEG's subsidiaries. Power's indenture includes a cross acceleration provision similar to that described above for PSEG's existing notes except that such provision may be triggered upon the acceleration of more than $50 million of indebtedness incurred by Power or any of its subsidiaries. Such provision does not cross accelerate to PSEG, any of PSEG's subsidiaries (other than Power and its subsidiaries), PSE&G or any of PSE&G's subsidiaries.

Ratings Triggers

Our debt indentures and credit agreements do not contain any material 'ratings triggers' that would cause an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, any one or more of the affected companies may be subject to increased interest costs on certain bank debt and certain collateral requirements. In the event that we are not able to affirm representations and warranties on credit agreements, lenders would not be required to make loans.

In accordance with BPU requirements under the BGS contracts, PSE&G is required to maintain an investment grade credit rating. If PSE&G were to lose its investment grade rating, it would be required to file a plan to assure continued payment for the BGS requirements of its customers.

Fluctuations in commodity prices or a deterioration of Power's credit rating to below investment grade could increase Power's required margin postings under various agreements entered into in the normal course of business. Power believes it has sufficient liquidity to meet the required posting of collateral which would likely result from a credit rating downgrade to below investment grade by S&P or Moody's at today's market prices.

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Common Stock Dividends

Dividend Payments on Common Stock	Years Ended December 31, 2017	2016	2015
Per Share	$ 1.72	$ 1.64	$ 1.56
in Millions	$ 870	$ 830	$ 789

On February 20, 2018, our Board of Directors approved a $0.45 per share of common stock dividend for the first quarter of 2018. This reflects an indicative annual dividend rate of $1.80 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 8. Financial Statements and Supplementary Data—Note16. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In April 2017, S&P published updated research and affirmed the ratings and outlooks on PSEG and PSE&G. In June 2017, S&P published updated research on Power and the rating and outlook remained unchanged. In July 2017, Moody's upgraded PSEG's senior unsecured rating to Baa1 from Baa2 and revised its outlook to Stable from Positive. Also in July, Moody's affirmed the ratings at PSE&G and Power.

	Moody's (A)	S&P (B)
PSEG		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

Other Comprehensive Income

For the year ended December 31, 2017, we had Other Comprehensive Income of $34 million on a consolidated basis. Other Comprehensive Income was due primarily to a $44 million increase in net unrealized gains related to Available-for-Sale Securities, partially offset by a decrease of $8 million in our consolidated liability for pension and postretirement benefits and $2 million of unrealized losses on derivative contracts accounted for as hedges. See Item 8. Financial Statements and Supplementary Data—Note 21. Accumulated Other Comprehensive Income (Loss), Net of Tax for additional information.

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CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. Projected capital construction and investment expenditures, excluding nuclear fuel purchases, for the next three years are presented in the table below. These projections include Allowance for Funds Used During Construction and Interest Capitalized During Construction for PSE&G and Power, respectively. These amounts are subject to change, based on various factors. Amounts shown below for Energy Strong, GSMP and Solar/Energy Efficiency programs are for currently approved programs. We intend to continue to invest in infrastructure modernization and will seek to extend these and related programs as appropriate. We will also continue to approach potential growth investments for Power opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2018	2019	2020
		Millions	
PSE&G:			
Transmission	$ 1,235	$ 1,290	$ 1,280
Distribution	1,015	715	705
Energy Strong	35	—	—
Gas System Modernization Program	300	40	—
Solar/Energy Efficiency	85	75	55
Total PSE&G	**$ 2,670**	**$ 2,120**	**$ 2,040**
Power:			
Baseline	$ 170	$ 165	$ 165
Fossil Growth Opportunities	445	65	10
Other	30	30	20
Total Power	**$ 645**	**$ 260**	**$ 195**
Other	$ 40	$ 30	$ 20
Total PSEG	**$ 3,355**	**$ 2,410**	**$ 2,255**

PSE&G

PSE&G's projections for future capital expenditures include material additions and replacements to its transmission and distribution systems to meet expected growth and to manage reliability. As project scope and cost estimates develop, PSE&G will modify its current projections to include these required investments. PSE&G's projected expenditures for the various items reported above are primarily comprised of the following:

- Transmission—investments focused on reliability improvements and replacement of aging infrastructure.
- Distribution—investments for new business, reliability improvements, and replacement of equipment that has reached the end of its useful life.
- Energy Strong—Electric and Gas Distribution reliability investment program focused on system hardening and resiliency.
- Gas System Modernization Program—Gas Distribution investment program to replace aging infrastructure.
- Solar/Energy Efficiency—investments associated with grid-connected solar, solar loan programs, and customer energy efficiency programs.

In November 2017, the BPU issued an order approving PSE&G's net investment of $100 million to rebuild New Jersey Transit's Mason electric distribution substation and related facilities in Kearny, New Jersey. This project is expected to be completed in December 2021.

In July 2017, PSE&G filed a petition with the BPU requesting approval of the $2.7 billion next phase of the Gas System Modernization Program (GSMP II) and associated cost recovery mechanism. The GSMP II program will enable PSE&G to continue to accelerate the replacement of its aging cast-iron and unprotected steel gas pipes. This matter is currently pending before the BPU and is not included in the PSE&G's projected capital expenditures above.

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In 2017, PSE&G made $2,919 million of capital expenditures, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $107 million, which are included in operating cash flows.

Power

Power's projected expenditures for the various items listed above are primarily comprised of the following:

- Baseline—investments to replace major parts and enhance operational performance.
- Fossil Growth Opportunities—investments associated with new construction, including Keys, Sewaren 7 and BH5, and with upgrades to increase efficiency and output at combined cycle plants.
- Other—includes investments made in response to environmental, regulatory and legal mandates and other capital projects.

In 2017, Power made $1,040 million of capital expenditures, excluding $191 million for nuclear fuel, primarily related to various projects at Fossil, Solar and Nuclear.

Disclosures about Contractual Obligations

The following table reflects our contractual cash obligations in the respective periods in which they are due. In addition, the table summarizes anticipated debt maturities for the years shown. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 14. Debt and Credit Facilities.

The table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities for uncertain tax positions since we are unable to reasonably estimate the timing of liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes for additional information.

	Total Amount Committed	Less Than 1 Year	2 - 3 Years	4- 5 Years	Over 5 Years
			Millions		
Contractual Cash Obligations					
Long-Term Recourse Debt Maturities					
PSEG	$ 2,100	$ —	$ 1,100	$ 1,000	$ —
PSE&G	8,658	750	759	434	6,715
Power	2,400	250	450	950	750
Interest on Recourse Debt					
PSEG	157	49	65	43	—
PSE&G	5,186	313	578	525	3,770
Power	821	113	202	129	377
Capital Lease Obligations					
Power	2	1	1	—	—
Operating Leases					
PSE&G	113	16	17	15	65
Power	58	5	9	6	38
Services	194	14	30	30	120
Other	6	1	2	2	1
Energy-Related Purchase Commitments					
Power	2,670	730	938	468	534
Total Contractual Cash Obligations	**$ 22,365**	**$ 2,242**	**$ 4,151**	**$ 3,602**	**$ 12,370**
Liability Payments for Uncertain Tax Positions					
PSEG	$ 69	$ 69	$ —	$ —	$ —
PSE&G	35	35	—	—	—
Power	30	30	—	—	—

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OFF-BALANCE SHEET ARRANGEMENTS

PSEG and Power issue guarantees, primarily in conjunction with certain of Power's energy contracts. See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities for further discussion.

Through Energy Holdings, we have investments in leveraged leases that are accounted for in accordance with GAAP Accounting for Leases. Leveraged lease investments generally involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease arrangement, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and is not presented on our Consolidated Balance Sheets. In the event of default, the leased asset, and in some cases the lessee, secures the loan. As a lessor, Energy Holdings has ownership rights to the property and rents the property to the lessees for use in their business operations. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 7. Long-Term Investments and Note 8. Financing Receivables.

In the event that collection of the minimum lease payments to be received by Energy Holdings is no longer reasonably assured, Energy Holdings may deem that a lessee has a high probability of defaulting on the lease obligation, and would consider the need to record an impairment of its investment. In the event the lease is ultimately rejected by the lessee in a Bankruptcy Court proceeding, the fair value of the underlying asset and the associated debt would be recorded on the Consolidated Balance Sheets instead of the net equity investment in the lease.

CRITICAL ACCOUNTING ESTIMATES

Under GAAP, many accounting standards require the use of estimates, variable inputs and assumptions (collectively referred to as estimates) that are subjective in nature. Because of this, differences between the actual measure realized versus the estimate can have a material impact on results of operations, financial position and cash flows. We have determined that the following estimates are considered critical to the application of rules that relate to the respective businesses.

Accounting for Pensions

PSEG sponsors qualified and nonqualified pension plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The market-related value of plan assets held for the qualified pension plan is equal to the fair value of these assets as of year-end. The plan assets are comprised of investments in both debt and equity securities which are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. We calculate pension costs using various economic and demographic assumptions.

***Assumptions and Approach Used*:** Economic assumptions include the discount rate and the long-term rate of return on trust assets. Demographic assumptions include projections of future mortality rates, pay increases and retirement patterns.

Assumption	2017	2016	2015
Discount Rate	3.73%	4.29%	4.54%
Expected Rate of Return on Plan Assets	7.80%	8.00%	8.00%

The discount rate used to calculate pension obligations is determined as of December 31 each year, our measurement date. The discount rate is determined by developing a spot rate curve based on the yield to maturity of a universe of high quality corporate bonds with similar maturities to the plan obligations. The spot rates are used to discount the estimated plan distributions. The discount rate is the single equivalent rate that produces the same result as the full spot rate curve.

Our expected rate of return on plan assets reflects current asset allocations, historical long-term investment performance and an estimate of future long-term returns by asset class, long-term inflation assumptions and a premium for active management.

Based on the above assumptions, we have estimated a net periodic pension credit in 2018 of approximately $(36) million, or $(87) million, net of amounts capitalized.

We utilize a corridor approach that reduces the volatility of reported pension expense/income. The corridor requires differences between actuarial assumptions and plan results be deferred and amortized as part of expense/income. This occurs only when the accumulated differences exceed 10% of the greater of the pension benefit obligation or the fair value of plan assets as of each year-end. The excess would be amortized over the average remaining service period of the active employees, which is approximately thirteen years.

***Effect if Different Assumptions Used*:** As part of the business planning process, we have modeled future costs assuming a 7.80% expected rate of return and a 3.73% discount rate for 2018. Actual future pension expense/income and funding levels

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will depend on future investment performance, changes in discount rates, market conditions, funding levels relative to our projected benefit obligation and accumulated benefit obligation and various other factors related to the populations participating in the pension plans.

The following chart reflects the sensitivities associated with a change in certain assumptions. The effects of the assumption changes shown below solely reflect the impact of that specific assumption.

Assumption	% Change	Impact on Pension Benefit Obligation as of December 31, 2017	Increase to Pension Expense in 2018	Increase to Pension Expense, net of Amounts Capitalized in 2018
		Millions		
Discount Rate	(1)%	$ 866	$ 46	$ 36
Expected Rate of Return on Plan Assets	(1)%	N/A	$ 57	$ 57

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Derivative Instruments

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through executing derivative transactions. Derivative instruments are used to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Current accounting guidance requires us to recognize all derivatives on the balance sheet at their fair value, except for derivatives that qualify for and are designated as normal purchases and normal sales contracts.

***Assumptions and Approach Used*:** In general, the fair value of our derivative instruments is determined primarily by end of day clearing market prices from an exchange, such as NYMEX, Intercontinental Exchange and Nodal Exchange, or auction prices. Fair values of other energy contracts may be based on broker quotes.

For a small number of contracts where limited observable inputs or pricing information are available, modeling techniques are employed in determination of their fair value using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable.

For our wholesale energy business, many of the forward sale, forward purchase, option and other contracts are derivative instruments that hedge commodity price risk, but do not meet the requirements for, or are not designated as, either cash flow or fair value hedge accounting. The changes in value of such derivative contracts are marked to market through earnings as the related commodity prices fluctuate. As a result, our earnings may experience significant fluctuations depending on the volatility of commodity prices.

***Effect if Different Assumptions Used*:** Any significant changes to the fair market values of our derivatives instruments could result in a material change in the value of the assets or liabilities recorded on our Consolidated Balance Sheets and could result in a material change to the unrealized gains or losses recorded in our Consolidated Statements of Operations.

For additional information regarding Derivative Financial Instruments, see Item 8. Financial Statements and Supplementary Data – Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies, Note 16. Financial Risk Management Activities and Note 17. Fair Value Measurements.

Long-Lived Assets

Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset's or asset group's carrying amount may not be recoverable.

Assumptions and Approach Used: In the event certain triggers exist indicating an asset/asset group may not be recoverable, an undiscounted cash flow test is performed to determine if an impairment exists. When the carrying value of a long-lived asset/asset group exceeds the undiscounted estimate of future cash flows associated with the asset/asset group, an impairment may exist to the extent that the fair value of the asset/asset group is less than its carrying amount. These tests require significant estimates and judgment when developing expected future cash flows. Significant inputs include forward power prices, fuel costs, dispatch rates, other operating and capital expenditures and the cost of borrowing.

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Effect if Different Assumptions Used: The above cash flow tests and fair value estimates may be impacted by a change in the assumptions noted above and could significantly impact the outcome, triggering additional impairment tests or write-offs.

Lease Investments

Our Investments in Leases, included in Long-Term Investments on our Consolidated Balance Sheets, are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. A significant portion of the estimated residual value of leased assets is related to merchant power plants leased to other energy companies. See Item 8. Financial Statements and Supplementary Data – Note 7. Long-Term Investments and Note 8. Financing Receivables.

***Assumptions and Approach Used*:** Residual values are the estimated values of the leased assets at the end of the respective lease per the original lease terms, net of any subsequent impairments. The estimated values are calculated by discounting the cash flows related to the leased assets after the lease term. For the merchant power plants, the estimated discounted cash flows are dependent upon various assumptions, including:

- estimated forward power and capacity prices in the years after the lease,
- related prices of fuel for the plants,
- dispatch rates for the plants,
- future capital expenditures required to maintain the plants,
- future operation and maintenance expenses,
- discount rates, and
- the current estimated economic viability of the plants after the end of the base lease term.

A review of the residual valuations is performed at least annually for each plant subject to lease using specific assumptions tailored to each plant. Those valuations are compared to the recorded residual values to determine if an impairment is warranted.

***Effect if Different Assumptions Used*:** A significant change to the assumptions, such as a large decrease in near-term power prices that affects the market's view of long-term power prices, could result in an impairment of one or more of the residual values, but not necessarily to all of the residual values. However, if, because of changes in assumptions, all the residual values related to the merchant energy plants were deemed to be zero, we would recognize an after-tax charge to income of approximately $78 million.

Asset Retirement Obligations (ARO)

PSE&G, Power and Services recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists. These AROs are recorded at fair value in the period in which they are incurred and are capitalized as part of the carrying amount of the related long-lived assets. PSE&G, as a rate-regulated entity, recognizes regulatory assets or liabilities as a result of timing differences between the recording of costs and costs recovered through the rate-making process. We accrete the ARO liability to reflect the passage of time with the corresponding expense recorded in Operation and Maintenance.

***Assumptions and Approach Used*:** Because quoted market prices are not available for AROs, we estimate the initial fair value of an ARO by calculating discounted cash flows that are dependent upon various assumptions, including:

- estimation of dates for retirement, which can be dependent on environmental and other legislation,
- amounts and timing of future cash expenditures associated with retirement, settlement or remediation activities,
- discount rates,
- cost escalation rates,
- market risk premium,
- inflation rates, and
- if applicable, past experience with government regulators regarding similar obligations.

We obtain updated cost studies triennially unless new information necessitates more frequent updates. The most recent cost study was done in 2015. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO

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balance and corresponding long-lived asset which impacts the amount of accretion and depreciation expense recognized in future periods.

Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power's nuclear facilities comprised 93% of Power's total AROs as of December 31, 2017. Power determines its AROs for its nuclear units by assigning probability weighting to various discounted cash flow outcomes for each of its nuclear units that incorporate the assumptions above as well as:

- financial feasibility and impacts on potential early shutdown,
- license renewals,
- safe storage for a period of time after retirement, and
- recovery from the federal government of costs incurred for spent nuclear fuel.

***Effect if Different Assumptions Used*:** Changes in the assumptions could result in a material change in the ARO balance sheet obligation and the period over which we accrete to the ultimate liability. For example, a decrease of 1% in the discount rate would result in a $120 million increase in the Nuclear ARO as of December 31, 2017. An increase of 1% in the inflation rate would result in a $324 million increase in the Nuclear ARO as of December 31, 2017. Also, if we did not assume that we would recover from the federal government the costs incurred for spent nuclear fuel, the Nuclear ARO would increase by $550 million at December 31, 2017. If Power were to increase its early shutdown probability to 100% and retire Salem and Hope Creek in 2021 (when the current capacity obligations for Salem and Hope Creek expire), which is significantly earlier than the end of their current license periods, the Nuclear ARO would increase by $428 million.

Accounting for Regulated Businesses

PSE&G prepares its financial statements to comply with GAAP for rate-regulated enterprises, which differs in some respects from accounting for non-regulated businesses. In general, accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (Regulatory Asset) or recognize obligations (Regulatory Liability) if the rates established are designed to recover the costs and if the competitive environment makes it probable that such rates can be charged or collected. This accounting results in the recognition of revenues and expenses in different time periods than that of enterprises that are not regulated.

***Assumptions and Approach Used*:** PSE&G recognizes Regulatory Assets where it is probable that such costs will be recoverable in future rates from customers and Regulatory Liabilities where it is probable that refunds will be made to customers in future billings. The highest degree of probability is an order from the BPU either approving recovery of the deferred costs over a future period or requiring the refund of a liability over a future period.

Virtually all of PSE&G's regulatory assets and liabilities are supported by BPU orders. In the absence of an order, PSE&G will consider the following when determining whether to record a Regulatory Asset or Liability:

- past experience regarding similar items with the BPU,
- treatment of a similar item in an order by the BPU for another utility,
- passage of new legislation, and
- recent discussions with the BPU.

All deferred costs are subject to prudence reviews by the BPU. When the recovery of a Regulatory Asset or payment of a Regulatory Liability is no longer probable, PSE&G charges or credits earnings, as appropriate.

***Effect if Different Assumptions Used*:** A change in the above assumptions may result in a material impact on our results of operations or our cash flows. See Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities for a description of the amounts and nature of regulatory balance sheet amounts.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management

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Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

	MTM VaR	
	Millions	
Years Ended December 31,	**2017**	**2016**
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 39	$ 26
Average for the Period	$ 10	$ 16
High	$ 39	$ 32
Low	$ 5	$ 10
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 60	$ 40
Average for the Period	$ 15	$ 25
High	$ 60	$ 51
Low	$ 8	$ 16

See Item 8. Financial Statements and Supplementary Data—Note 16. Financial Risk Management Activities for a discussion of credit risk.

Interest Rates

We are subject to the risk of fluctuating interest rates in the normal course of business. We manage interest rate risk by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, we use a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

As of December 31, 2017, a hypothetical 10% increase in market interest rates would result in

- $1 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and
- a $370 million decrease in the fair value of debt, including a $16 million decrease at PSEG, a $309 million decrease at PSE&G and a $45 million decrease at Power.

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Debt and Equity Securities

We have $6.3 billion of assets in a trust for our pension and OPEB plans. Although fluctuations in market prices of securities within this portfolio do not directly affect our earnings in the current period, changes in the value of these investments could affect

- our future contributions to these plans,
- our financial position if our accumulated benefit obligation under our pension plans exceeds the fair value of the pension trust funds, and
- future earnings, as we could be required to adjust pension expense and the assumed rate of return.

The NDT Fund is comprised primarily of fixed income and equity securities. As of December 31, 2017, the portfolio included $1.1 billion of equity securities and $986 million in fixed income securities. The fair market value of the assets in the NDT Fund will fluctuate primarily depending upon the performance of equity markets. As of December 31, 2017, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $106 million.

We use duration to measure the interest rate sensitivity of the fixed income portfolio. Duration is a summary statistic of the effective average maturity of the fixed income portfolio. The benchmark for the fixed income component of the NDT Fund currently has a duration of 5.98 years and a yield of 2.72%. The portfolio's value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2017, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $59 million.

Credit Risk

See Item 8. Financial Statements and Supplementary Data—Note 16. Financial Risk Management Activities for a discussion of credit risk and a discussion about Power's and PSE&G's credit risk.

Energy Holdings has credit risk related to its investments in leases, which totaled $85 million, net of deferred taxes of $480 million, as of December 31, 2017. These leveraged leases are concentrated in the U.S. energy industry. See Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables for counterparties' credit ratings and other information. The credit exposure to the lessees is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, and historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverages are not met. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a temporary market downturn or degradation in operating performance of the leased assets.

In any lease transaction, in the event of a default, Energy Holdings would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. Under a worst-case scenario, if a foreclosure were to occur, Energy Holdings would record a pre-tax write-off up to its outstanding gross investment in these facilities. Also, in the event of a potential foreclosure, the net tax benefits generated by Energy Holdings' portfolio of investments could be materially reduced in the period in which gains associated with the potential forgiveness of debt at these projects occurs. The amount and timing of any potential reduction in net tax benefits is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, the amount of lease debt outstanding, any cash trapped at the projects and negotiations during such potential foreclosure process. The potential loss of earnings, impairment and/or tax payments could have a material impact to our financial position, results of operations and net cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined Form 10-K is separately filed by PSEG, PSE&G and Power. Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations as to any other company.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Public Service Enterprise Group Incorporated
Newark, New Jersey

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, the related notes and the consolidated financial statement schedule listed in the Index at Item 15(B)(a) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2018

We have served as the Company's auditor since 1934.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Sole Stockholder of
Public Service Electric and Gas Company
Newark, New Jersey

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the "Company") as of December 31, 2017 and 2016, and the related consolidated statements of operations, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and the consolidated financial statement schedule listed in the Index at Item 15(B)(b) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2018

We have served as the Company's auditor since 1934.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Sole Member of
PSEG Power LLC
Newark, New Jersey

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income, member's equity, and cash flows for each of the three years in the period ended December 31, 2017, the related notes and the consolidated financial statement schedule listed in the Index at Item 15(B)(c) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2018

We have served as the Company's auditor since 2000.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data

	Years Ended December 31,		
	2017	2016	2015
OPERATING REVENUES	$ 9,084	$ 9,061	$ 10,415
OPERATING EXPENSES			
Energy Costs	2,800	3,001	3,261
Operation and Maintenance	2,869	3,008	2,978
Depreciation and Amortization	1,986	1,476	1,214
Total Operating Expenses	7,655	7,485	7,453
OPERATING INCOME	1,429	1,576	2,962
Income from Equity Method Investments	14	11	12
Other Income	319	191	254
Other Deductions	(91)	(67)	(102)
Other-Than-Temporary Impairments	(12)	(28)	(53)
Interest Expense	(391)	(385)	(393)
INCOME BEFORE INCOME TAXES	1,268	1,298	2,680
Income Tax Benefit (Expense)	306	(411)	(1,001)
NET INCOME	$ 1,574	$ 887	$ 1,679
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
BASIC	505	505	505
DILUTED	507	508	508
NET INCOME PER SHARE:			
BASIC	$ 3.12	$ 1.76	$ 3.32
DILUTED	$ 3.10	$ 1.75	$ 3.30

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2017	**2016**	**2015**
NET INCOME	$ 1,574	$ 887	$ 1,679
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(37), $(41) and $34 for the years ended 2017, 2016 and 2015, respectively	44	42	(27)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $1, $(1), and $7 for the years ended 2017, 2016 and 2015, respectively	(2)	2	(10)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(4), $8 and $(18) for the years ended 2017, 2016 and 2015, respectively	(8)	(12)	25
Other Comprehensive Income (Loss), net of tax	34	32	(12)
COMPREHENSIVE INCOME	$ 1,608	$ 919	$ 1,667

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 313	$ 423
Accounts Receivable, net of allowances of $59 in 2017 and $68 in 2016	1,348	1,161
Tax Receivable	127	78
Unbilled Revenues	296	260
Fuel	289	326
Materials and Supplies, net	577	561
Prepayments	118	76
Derivative Contracts	29	163
Regulatory Assets	211	199
Other	4	7
Total Current Assets	3,312	3,254
PROPERTY, PLANT AND EQUIPMENT	41,231	39,337
Less: Accumulated Depreciation and Amortization	(9,434)	(10,051)
Net Property, Plant and Equipment	31,797	29,286
NONCURRENT ASSETS		
Regulatory Assets	3,222	3,319
Long-Term Investments	932	1,050
Nuclear Decommissioning Trust (NDT) Fund	2,133	1,859
Long-Term Tax Receivable	—	104
Long-Term Receivable of VIEs	686	589
Other Special Funds	231	217
Goodwill	16	16
Other Intangibles	114	98
Derivative Contracts	7	24
Other	266	254
Total Noncurrent Assets	7,607	7,530
TOTAL ASSETS	$ 42,716	$ 40,070

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2017	December 31, 2016
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 1,000	$ 500
Commercial Paper and Loans	542	388
Accounts Payable	1,694	1,459
Derivative Contracts	16	13
Accrued Interest	103	97
Accrued Taxes	48	31
Clean Energy Program	128	142
Obligation to Return Cash Collateral	129	132
Regulatory Liabilities	47	88
Other	461	426
Total Current Liabilities	4,168	3,276
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	5,240	8,658
Regulatory Liabilities	2,948	118
Asset Retirement Obligations	1,024	726
Other Postretirement Benefit (OPEB) Costs	1,455	1,324
OPEB Costs of Servco	542	452
Accrued Pension Costs	537	568
Accrued Pension Costs of Servco	129	128
Environmental Costs	357	401
Derivative Contracts	5	3
Long-Term Accrued Taxes	175	180
Other	221	211
Total Noncurrent Liabilities	12,633	12,769
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT	12,068	10,895
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2017 and 2016— 534 shares	4,961	4,936
Treasury Stock, at cost, 2017 and 2016—29 shares	(763)	(717)
Retained Earnings	9,878	9,174
Accumulated Other Comprehensive Loss	(229)	(263)
Total Stockholders' Equity	13,847	13,130
Total Capitalization	25,915	24,025
TOTAL LIABILITIES AND CAPITALIZATION	$ 42,716	$ 40,070

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 1,574	$ 887	$ 1,679
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,986	1,476	1,214
Amortization of Nuclear Fuel	199	203	213
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	103	109	104
Impairment Costs for Early Plant Retirements	—	102	—
Provision for Deferred Income Taxes (Other than Leases) and ITC	(167)	474	685
Non-Cash Employee Benefit Plan Costs	89	127	161
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(159)	(6)	26
Net (Gain) Loss on Lease Investments	48	92	—
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	188	183	(143)
Net Change in Regulatory Assets and Liabilities	(188)	(138)	(48)
Cost of Removal	(107)	(131)	(120)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(156)	(26)	(38)
Net Change in Certain Current Assets and Liabilities			
Tax Receivable	65	303	(94)
Accrued Taxes	16	3	(91)
Margin Deposit	(90)	(76)	122
Other Current Assets and Liabilities	(70)	(180)	288
Employee Benefit Plan Funding and Related Payments	(81)	(103)	(109)
Other	11	12	70
Net Cash Provided By (Used In) Operating Activities	3,261	3,311	3,919
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(4,190)	(4,199)	(3,863)
Purchase of Emissions Allowances and RECs	(117)	(99)	(106)
Proceeds from Sales of Available-for-Sale Securities	2,319	824	1,501
Investments in Available-for-Sale Securities	(2,340)	(856)	(1,552)
Other	72	82	78
Net Cash Provided By (Used In) Investing Activities	(4,256)	(4,248)	(3,942)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	154	24	364
Issuance of Long-Term Debt	2,175	2,675	1,350
Redemption of Long-Term Debt	(500)	(824)	(600)
Redemption of Securitization Debt	—	—	(259)
Cash Dividends Paid on Common Stock	(870)	(830)	(789)
Other	(74)	(79)	(51)
Net Cash Provided By (Used In) Financing Activities	885	966	15
Net Increase (Decrease) in Cash and Cash Equivalents	(110)	29	(8)
Cash and Cash Equivalents at Beginning of Period	423	394	402
Cash and Cash Equivalents at End of Period	$ 313	$ 423	$ 394
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ (8)	$ (245)	$ 447
Interest Paid, Net of Amounts Capitalized	$ 377	$ 365	$ 381
Accrued Property, Plant and Equipment Expenditures	$ 722	$ 664	$ 510

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Millions

	Common Stock		Treasury Stock					
	Shs.	Amount	Shs.	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance as of January 1, 2015	534	$ 4,876	(28)	$ (635)	$ 8,227	$ (283)	$ 1	$ 12,186
Net Income	—	—	—	—	1,679	—	—	1,679
Other Comprehensive Income (Loss), net of tax (expense) benefit of $23	—	—	—	—	—	(12)	—	(12)
Comprehensive Income								1,667
Cash Dividends on Common Stock	—	—	—	—	(789)	—	—	(789)
Other	—	39	—	(36)	—	—	—	3
Balance as of December 31, 2015	534	$ 4,915	(28)	$ (671)	$ 9,117	$ (295)	$ 1	$ 13,067
Net Income	—	—	—	—	887	—	—	887
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(34)	—	—	—	—	—	32	—	32
Comprehensive Income								919
Cash Dividends on Common Stock	—	—	—	—	(830)	—	—	(830)
Other	—	21	(1)	(46)	—	—	(1)	(26)
Balance as of December 31, 2016	534	$ 4,936	(29)	$ (717)	$ 9,174	$ (263)	$ —	$ 13,130
Net Income	—	—	—	—	1,574	—	—	1,574
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(40)	—	—	—	—	—	34	—	34
Comprehensive Income								1,608
Cash Dividends on Common Stock	—	—	—	—	(870)	—	—	(870)
Other	—	25	—	(46)	—	—	—	(21)
Balance as of December 31, 2017	534	$ 4,961	(29)	$ (763)	$ 9,878	$ (229)	$ —	$ 13,847

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2017	2016	2015
OPERATING REVENUES	$ 6,234	$ 6,221	$ 6,636
OPERATING EXPENSES			
Energy Costs	2,363	2,567	2,722
Operation and Maintenance	1,434	1,475	1,560
Depreciation and Amortization	685	565	892
Total Operating Expenses	4,482	4,607	5,174
OPERATING INCOME	1,752	1,614	1,462
Other Income	92	83	79
Other Deductions	(5)	(4)	(4)
Interest Expense	(303)	(289)	(280)
INCOME BEFORE INCOME TAXES	1,536	1,404	1,257
Income Tax Expense	(563)	(515)	(470)
NET INCOME	$ 973	$ 889	$ 787

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2017	2016	2015
NET INCOME	$ 973	$ 889	$ 787
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0 and $0 for the years ended 2017, 2016 and 2015, respectively	(1)	—	(1)
COMPREHENSIVE INCOME	$ 972	$ 889	$ 786

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11986

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2017	**2016**
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 242	$ 390
Accounts Receivable, net of allowances of $59 in 2017 and $68 in 2016	882	810
Accounts Receivable—Affiliated Companies	—	76
Unbilled Revenues	296	260
Materials and Supplies	197	180
Prepayments	44	9
Regulatory Assets	211	199
Other	4	6
Total Current Assets	1,876	1,930
PROPERTY, PLANT AND EQUIPMENT	29,117	26,347
Less: Accumulated Depreciation and Amortization	(6,101)	(5,760)
Net Property, Plant and Equipment	23,016	20,587
NONCURRENT ASSETS		
Regulatory Assets	3,222	3,319
Long-Term Investments	280	299
Other Special Funds	46	43
Other	114	110
Total Noncurrent Assets	3,662	3,771
TOTAL ASSETS	$ 28,554	$ 26,288

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2017	2016
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 750	$ —
Accounts Payable	728	718
Accounts Payable—Affiliated Companies	340	260
Accrued Interest	78	76
Clean Energy Program	128	142
Derivative Contracts	—	5
Obligation to Return Cash Collateral	129	132
Regulatory Liabilities	47	88
Other	311	296
Total Current Liabilities	2,511	1,717
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	3,391	5,873
OPEB Costs	1,103	1,009
Accrued Pension Costs	226	250
Regulatory Liabilities	2,948	118
Environmental Costs	283	332
Asset Retirement Obligations	212	213
Long-Term Accrued Taxes	91	130
Other	114	116
Total Noncurrent Liabilities	8,368	8,041
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT	7,841	7,818
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2017 and 2016—132 shares	892	892
Contributed Capital	1,095	945
Basis Adjustment	986	986
Retained Earnings	6,861	5,888
Accumulated Other Comprehensive Income	—	1
Total Stockholder's Equity	9,834	8,712
Total Capitalization	17,675	16,530
TOTAL LIABILITIES AND CAPITALIZATION	$ 28,554	$ 26,288

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

Millions

	Years Ended December 31,		
	2017	**2016**	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 973	$ 889	$ 787
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	685	565	892
Provision for Deferred Income Taxes and ITC	616	658	386
Non-Cash Employee Benefit Plan Costs	50	72	95
Cost of Removal	(107)	(131)	(120)
Net Change in Other Regulatory Assets and Liabilities	(188)	(138)	(48)
Net Change in Certain Current Assets and Liabilities			
Accounts Receivable and Unbilled Revenues	(106)	(84)	165
Materials and Supplies	(13)	(7)	(15)
Prepayments	(35)	22	11
Accounts Payable	1	(29)	45
Accounts Receivable/Payable—Affiliated Companies, net	101	199	—
Other Current Assets and Liabilities	17	8	(29)
Employee Benefit Plan Funding and Related Payments	(68)	(82)	(91)
Other	(87)	(48)	47
Net Cash Provided By (Used In) Operating Activities	1,839	1,894	2,125
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,919)	(2,816)	(2,692)
Proceeds from Sales of Available-for-Sale Securities	36	22	21
Investments in Available-for-Sale Securities	(37)	(24)	(22)
Solar Loan Investments	7	14	11
Other	10	15	11
Net Cash Provided By (Used In) Investing Activities	(2,903)	(2,789)	(2,671)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	—	(153)	153
Issuance of Long-Term Debt	775	1,275	850
Redemption of Long-Term Debt	—	(271)	(300)
Redemption of Securitization Debt	—	—	(259)
Contributed Capital	150	250	—
Other	(9)	(14)	(10)
Net Cash Provided By (Used In) Financing Activities	916	1,087	434
Net Increase (Decrease) in Cash and Cash Equivalents	(148)	192	(112)
Cash and Cash Equivalents at Beginning of Period	390	198	310
Cash and Cash Equivalents at End of Period	$ 242	$ 390	$ 198
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ (104)	$ (295)	$ (28)
Interest Paid, Net of Amounts Capitalized	$ 294	$ 273	$ 261
Accrued Property, Plant and Equipment Expenditures	$ 429	$ 420	$ 396

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11989

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
Millions

	Common Stock	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2015	$ 892	$ 695	$ 986	$ 4,212	$ 2	$ 6,787
Net Income	—	—	—	787	—	787
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	(1)	(1)
Comprehensive Income						786
Balance as of December 31, 2015	$ 892	$ 695	$ 986	$ 4,999	$ 1	$ 7,573
Net Income	—	—	—	889	—	889
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	—	—
Comprehensive Income						889
Contributed Capital		250	—	—	—	250
Balance as of December 31, 2016	$ 892	$ 945	$ 986	$ 5,888	$ 1	$ 8,712
Net Income	—	—	—	973	—	973
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	(1)	(1)
Comprehensive Income						972
Contributed Capital	—	150	—	—	—	150
Balance as of December 31, 2017	$ 892	$ 1,095	$ 986	$ 6,861	$ —	$ 9,834

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11990

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2017	2016	2015
OPERATING REVENUES	$ 3,930	$ 4,023	$ 4,928
OPERATING EXPENSES			
Energy Costs	1,983	1,986	2,150
Operation and Maintenance	1,038	1,143	1,057
Depreciation and Amortization	1,268	881	291
Total Operating Expenses	4,289	4,010	3,498
OPERATING INCOME (LOSS)	(359)	13	1,430
Income from Equity Method Investments	14	11	14
Other Income	213	102	169
Other Deductions	(56)	(57)	(72)
Other-Than-Temporary Impairments	(12)	(28)	(53)
Interest Expense	(50)	(84)	(121)
INCOME (LOSS) BEFORE INCOME TAXES	(250)	(43)	1,367
Income Tax Benefit (Expense)	729	61	(511)
NET INCOME	$ 479	$ 18	$ 856

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11991

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2017	**2016**	**2015**
NET INCOME	$ 479	$ 18	$ 856
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(39), $(41) and $32 for the years ended 2017, 2016 and 2015, respectively	46	42	(25)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $0 and $7 for the years ended 2017, 2016 and 2015, respectively	—	—	(11)
Pension/OPEB adjustment, net of tax (expense) benefit of $(3), $9 and $(16) for the years ended 2017, 2016 and 2015, respectively	(7)	(13)	24
Other Comprehensive Income (Loss), net of tax	39	29	(12)
COMPREHENSIVE INCOME	$ 518	$ 47	$ 844

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

S1-SSA-0009 - 11992

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

ASSETS	December 31, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$ 32	$ 11
Accounts Receivable	380	276
Accounts Receivable—Affiliated Companies	221	205
Short-Term Loan to Affiliate	—	87
Fuel	289	326
Materials and Supplies, net	376	381
Derivative Contracts	29	162
Prepayments	11	10
Other	3	2
Total Current Assets	1,341	1,460
PROPERTY, PLANT AND EQUIPMENT	11,755	12,655
Less: Accumulated Depreciation and Amortization	(3,159)	(4,135)
Net Property, Plant and Equipment	8,596	8,520
NONCURRENT ASSETS		
NDT Fund	2,133	1,859
Long-Term Investments	87	102
Goodwill	16	16
Other Intangibles	114	98
Other Special Funds	57	53
Derivative Contracts	7	24
Other	67	61
Total Noncurrent Assets	2,481	2,213
TOTAL ASSETS	$ 12,418	$ 12,193

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31,	
	2017	**2016**
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 250	$ —
Accounts Payable	712	539
Accounts Payable—Affiliated Companies	57	25
Short-Term Loan from Affiliate	281	—
Derivative Contracts	16	8
Accrued Interest	20	20
Other	99	88
Total Current Liabilities	1,435	680
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	1,406	2,170
Asset Retirement Obligations	810	511
OPEB Costs	283	251
Derivative Contracts	5	3
Accrued Pension Costs	184	191
Long-Term Accrued Taxes	52	77
Other	140	129
Total Noncurrent Liabilities	2,880	3,332
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
LONG-TERM DEBT	2,136	2,382
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,911	4,782
Accumulated Other Comprehensive Loss	(172)	(211)
Total Member's Equity	5,967	5,799
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,418	$ 12,193

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 479	$ 18	$ 856
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,268	881	291
Amortization of Nuclear Fuel	199	203	213
Provision for Deferred Income Taxes and ITC	(807)	(208)	261
Interest Accretion on Asset Retirement Obligation	30	26	26
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	188	183	(143)
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	103	109	104
Impairment Costs for Early Plant Retirements	—	102	—
Non-Cash Employee Benefit Plan Costs	28	39	48
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(156)	(26)	(38)
Net Change in Certain Current Assets and Liabilities			
Fuel, Materials and Supplies	42	31	62
Margin Deposit	(90)	(76)	122
Accounts Receivable	(45)	(71)	63
Accounts Payable	39	(22)	(46)
Accounts Receivable/Payable—Affiliated Companies, net	(2)	6	(84)
Other Current Assets and Liabilities	10	10	(36)
Employee Benefit Plan Funding and Related Payments	(7)	(13)	(11)
Other	47	63	18
Net Cash Provided By (Used In) Operating Activities	1,326	1,255	1,706
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(1,231)	(1,343)	(1,117)
Purchase of Emissions Allowances and RECs	(117)	(99)	(106)
Proceeds from Sales of Available-for-Sale Securities	2,182	739	1,422
Investments in Available-for-Sale Securities	(2,199)	(766)	(1,455)
Short-Term Loan—Affiliated Company	87	276	221
Other	46	46	34
Net Cash Provided By (Used In) Investing Activities	(1,232)	(1,147)	(1,001)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Long-Term Debt	—	700	—
Cash Dividend Paid	(350)	(250)	(400)
Redemption of Long-Term Debt	—	(553)	(300)
Short-Term Loan—Affiliated Company	281	—	—
Other	(4)	(6)	(2)
Net Cash Provided By (Used In) Financing Activities	(73)	(109)	(702)
Net Increase (Decrease) in Cash and Cash Equivalents	21	(1)	3
Cash and Cash Equivalents at Beginning of Period	11	12	9
Cash and Cash Equivalents at End of Period	$ 32	$ 11	$ 12
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$ 77	$ 50	$ 393
Interest Paid, Net of Amounts Capitalized	$ 48	$ 81	$ 116
Accrued Property, Plant and Equipment Expenditures	$ 293	$ 244	$ 114

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY
Millions

	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2015	$ 2,214	$ (986)	$ 4,558	$ (228)	$ 5,558
Net Income	—	—	856	—	856
Other Comprehensive Income (Loss), net of tax (expense) benefit of $23	—	—	—	(12)	(12)
Comprehensive Income					844
Cash Dividends Paid	—	—	(400)	—	(400)
Balance as of December 31, 2015	$ 2,214	$ (986)	$ 5,014	$ (240)	$ 6,002
Net Income	—	—	18	—	18
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(32)	—	—	—	29	29
Comprehensive Income					47
Cash Dividends Paid	—	—	(250)	—	(250)
Balance as of December 31, 2016	$ 2,214	$ (986)	$ 4,782	$ (211)	$ 5,799
Net Income	—	—	479	—	479
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(42)	—	—	—	39	39
Comprehensive Income					518
Cash Dividends Paid	—	—	(350)	—	(350)
Balance as of December 31, 2017	$ 2,214	$ (986)	$ 4,911	$ (172)	$ 5,967

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

Public Service Enterprise Group Incorporated (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Public Service Electric and Gas Company (PSE&G)**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and energy efficiency and related programs in New Jersey, which are regulated by the BPU.
- **PSEG Power LLC (Power)**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Annual Reports on Form 10-K and in accordance with accounting guidance generally accepted in the United States (GAAP).

Significant Accounting Policies

Principles of Consolidation

Each company consolidates those entities in which it has a controlling interest or is the primary beneficiary. See Note 4. Variable Interest Entity. Entities over which the companies exhibit significant influence, but do not have a controlling interest and/or are not the primary beneficiary, are accounted for under the equity method of accounting. For investments in which significant influence does not exist and the investor is not the primary beneficiary, the cost method of accounting is applied. All significant intercompany accounts and transactions are eliminated in consolidation.

PSE&G and Power also have undivided interests in certain jointly-owned facilities, with each responsible for paying its respective ownership share of construction costs, fuel purchases and operating expenses. PSE&G and Power consolidate their portion of any revenues and expenses related to their respective jointly-owned facilities in the appropriate revenue and expense categories.

Accounting for the Effects of Regulation

In accordance with accounting guidance for rate-regulated entities, PSE&G's financial statements reflect the economic effects of regulation. PSE&G defers the recognition of costs (a Regulatory Asset) or records the recognition of obligations (a Regulatory Liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs and recoveries, which are being amortized over various future periods. To the extent that collection of any such costs or payment of liabilities becomes no longer probable as a result of changes in regulation and/or competitive position, the associated Regulatory Asset or Liability is charged or credited to income. Management believes that PSE&G's transmission and distribution businesses continue to meet the accounting requirements for rate-regulated entities. For additional information, see Note 6. Regulatory Assets and Liabilities.

Derivative Instruments

Each company uses derivative instruments to manage risk pursuant to its business plans and prudent practices.

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of the derivative contracts are recorded in earnings.

Determining whether a contract qualifies as a derivative requires that management exercise significant judgment, including assessing the contract's market liquidity. PSEG has determined that contracts to purchase and sell certain products do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement, or the markets are not sufficiently liquid to conclude that physical forward contracts are readily convertible to cash.

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for derivatives that are designated as normal purchases and normal sales (NPNS). Further, derivatives that qualify for hedge accounting can be designated as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period.

Certain offsetting derivative assets and liabilities are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, these positions are offset on the Consolidated Balance Sheets of Power and PSEG.

For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings.

For derivative contracts that do not qualify or are not designated as cash flow or fair value hedges or as NPNS, changes in fair value are recorded in current period earnings. PSEG does not currently elect fair value or cash flow hedge accounting on its commodity derivative positions.

Contracts that qualify for, and are designated, as NPNS are accounted for upon settlement. Contracts which qualify for NPNS are contracts for which physical delivery is probable, they will not be financially settled, and the quantities under contract are expected to be used or sold in the normal course of business over a reasonable period of time.

For additional information regarding derivative financial instruments, see Note 16. Financial Risk Management Activities.

Revenue Recognition

PSE&G's regulated electric and gas revenues are recorded primarily based on services rendered to customers. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. The unbilled revenue is estimated each month based on usage per day, the number of unbilled days in the period, estimated seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms.

Regulated revenues from the transmission of electricity are recognized as services are provided based on a FERC-approved annual formula rate mechanism. This mechanism provides for an annual filing of estimated revenue requirement with rates effective January 1 of each year. After completion of the annual period ending December 31, PSE&G files a true-up whereby it compares its actual revenue requirement to the original estimate to determine any over or under collection of revenue. PSE&G records the estimated financial statement impact of the difference between the actual and the filed revenue requirement as a refund or deferral for future recovery when such amounts are probable and can be reasonably estimated in accordance with accounting guidance for rate-regulated entities.

The majority of Power's revenues relate to bilateral contracts, which are accounted for on the accrual basis as the energy is delivered. Power's revenue also includes changes in the value of energy derivative contracts that are not designated as NPNS. See Note 16. Financial Risk Management Activities for further discussion.

PJM Interconnection, L.L.C. (PJM), the Independent System Operator-New England (ISO-NE) and the New York Independent System Operator (NYISO) facilitate the dispatch of energy and energy-related products. Power generally reports electricity sales and purchases conducted with those individual ISOs on a net hourly basis in either Revenues or Energy Costs in its Consolidated Statement of Operations, the classification of which depends on the net hourly activity. Capacity revenue and expense is also reported net based on Power's monthly net sale or purchase position in the individual ISOs.

PSEG LI is the primary beneficiary of Long Island Electric Utility Servco, LLC (Servco). For transactions in which Servco acts as principal, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operations and Maintenance (O&M) Expense, respectively. See Note 4. Variable Interest Entity for further information.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The majority of Energy Holdings' revenues relate to its investments in leveraged leases. Income on leveraged leases is recognized by a method which produces a constant rate of return on the outstanding net investment in the lease, net of the related deferred tax liability, in the years in which the net investment is positive. Any gains or losses incurred as a result of a lease termination are recorded as revenues as these events occur in the ordinary course of business of managing the investment portfolio.

Depreciation and Amortization

PSE&G calculates depreciation under the straight-line method based on estimated average remaining lives of the several classes of depreciable property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU or FERC. The depreciation rate stated as a percentage of original cost of depreciable property was as follows:

	2017 Avg Rate	2016 Avg Rate	2015 Avg Rate
Electric Transmission	2.41%	2.39%	2.42%
Electric Distribution	2.51%	2.49%	2.50%
Gas Distribution	1.63%	1.63%	1.64%

Power calculates depreciation on generation-related assets under the straight-line method based on the assets' estimated useful lives. The estimated useful lives are:

- general plant assets—3 years to 20 years
- fossil production assets—30 years to 70 years
- nuclear generation assets—approximately 60 years
- pumped storage facilities—76 years
- solar assets—25 years

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized During Construction (IDC)

AFUDC represents the cost of debt and equity funds used to finance the construction of new utility assets at PSE&G. IDC represents the cost of debt used to finance construction at Power. The amount of AFUDC or IDC capitalized as Property, Plant and Equipment is included as a reduction of interest charges or other income for the equity portion. The amounts and average rates used to calculate AFUDC or IDC for the years ended December 31, 2017, 2016 and 2015 were as follows:

	AFUDC/IDC Capitalized					
	2017		2016		2015	
	Millions	Avg Rate	Millions	Avg Rate	Millions	Avg Rate
PSE&G	$ 73	7.42%	$ 66	7.81%	$ 65	8.01%
Power	$ 78	4.60%	$ 54	4.87%	$ 27	5.14%

Income Taxes

PSEG and its subsidiaries file a consolidated federal income tax return and income taxes are allocated to PSEG's subsidiaries based on the taxable income or loss of each subsidiary in accordance with a tax sharing agreement between PSEG and each of its affiliated subsidiaries. Allocations between PSEG and its subsidiaries are recorded through intercompany accounts. Investment tax credits deferred in prior years are being amortized over the useful lives of the related property.

Uncertain income tax positions are accounted for using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. See Note 20. Income Taxes for further discussion.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Impairment of Long-Lived Assets and Leveraged Leases

Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, including prolonged periods of adverse commodity and capacity prices or a current expectation that a long-lived asset will be sold or disposed of significantly before the end of its previously estimated useful life, could potentially indicate an asset's or asset group's carrying amount may not be recoverable. In such an event, an undiscounted cash flow analysis is performed to determine if an impairment exists. When a long-lived asset's or asset group's carrying amount exceeds the associated undiscounted estimated future cash flows, the asset/asset group is considered impaired to the extent that its fair value is less than its carrying amount. An impairment would result in a reduction of the value of the long-lived asset/asset group through a non-cash charge to earnings. See Note 3. Early Plant Retirements for more information.

For Power, cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generation units are generally evaluated at a regional portfolio level (PJM, NYISO, ISO-NE) along with cash flows generated from the customer supply and risk management activities, inclusive of cash flows from contracts, including those that are accounted for as derivatives and meet the NPNS scope exception. In certain cases, generation assets are evaluated on an individual basis where those assets are individually contracted on a long-term basis with a third party and operations are independent of other generation assets (typically Power's solar plants and Kalaeloa).

Energy Holdings' leveraged leases are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. Residual values are the estimated values of the leased assets at the end of the respective lease per the original lease terms, net of any subsequent impairments. A review of the residual valuations, which are calculated by discounting the cash flows related to the leased assets after the lease term, is performed at least annually for each plant subject to lease using specific assumptions tailored to each plant. Those valuations are compared to the recorded residual values to determine if an impairment is warranted.

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Accounts Receivable—Allowance for Doubtful Accounts

PSE&G's accounts receivable are reported in the balance sheet as gross outstanding amounts adjusted for doubtful accounts. The allowance for doubtful accounts reflects PSE&G's best estimates of losses on the accounts receivable balances. The allowance is based on accounts receivable aging, historical experience, write-off forecasts and other currently available evidence.

Accounts receivable are charged off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable are recorded when it is known they will be received.

Materials and Supplies and Fuel

PSE&G's and Power's materials and supplies are carried at average cost and charged to inventory when purchased and expensed or capitalized to Property, Plant and Equipment, as appropriate, when installed or used. Fuel inventory at Power is valued at the lower of average cost or market and includes stored natural gas, coal, fuel oil and propane used to generate power and to satisfy obligations under Power's gas supply contracts with PSE&G. The costs of fuel, including initial transportation costs, are included in inventory when purchased and charged to Energy Costs when used or sold. The cost of nuclear fuel is capitalized within Property, Plant and Equipment and amortized to fuel expense using the units-of-production method.

Property, Plant and Equipment

PSE&G's additions to and replacements of existing property, plant and equipment are capitalized at cost. The cost of maintenance, repair and replacement of minor items of property is charged to expense as incurred. At the time units of depreciable property are retired or otherwise disposed of, the original cost, adjusted for net salvage value, is charged to accumulated depreciation.

Power capitalizes costs, including those related to its jointly-owned facilities, which increase the capacity, improve or extend the life of an existing asset, represent a newly acquired or constructed asset or represent the replacement of a retired asset. The cost of maintenance, repair and replacement of minor items of property is charged to appropriate expense accounts as incurred. Environmental costs are capitalized if the costs mitigate or prevent future environmental contamination or if the costs improve existing assets' environmental safety or efficiency. All other environmental expenditures are expensed as incurred. Power also capitalizes spare parts that meet specific criteria. Capitalized spares are depreciated over the remaining lives of their associated assets.

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Available-for-Sale Securities

These securities comprise the Nuclear Decommissioning Trust (NDT) Fund, a master independent external trust account maintained to provide for the costs of decommissioning upon termination of operations of Power's nuclear facilities and amounts that are deposited to fund a Rabbi Trust which was established to meet the obligations related to non-qualified pension plans and deferred compensation plans.

Realized gains and losses on available-for-sale securities are recorded in earnings and unrealized gains and losses on such securities are recorded as a component of Accumulated Other Comprehensive Income (Loss). Securities with unrealized losses that are deemed to be other-than-temporarily impaired are recorded in earnings. See Note 9. Available-for-Sale Securities for further discussion.

Pension and Other Postretirement Benefits (OPEB) Plans

The market-related value of plan assets held for the qualified pension and OPEB plans is equal to the fair value of those assets as of year-end. Fair value is determined using quoted market prices and independent pricing services based upon the security type as reported by the trustee at the measurement date (December 31) for all plan assets.

PSEG recognizes a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and OPEB liabilities. This receivable is presented separately on the Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted.

Pursuant to the OSA, Servco records expense only to the extent of its contributions to its pension plan trusts and for OPEB payments made to retirees.

See Note 12. Pension and Other Postretirement Benefits (OPEB) for further discussion.

Basis Adjustment

PSE&G and Power have recorded a Basis Adjustment in their respective Consolidated Balance Sheets related to the generation assets that were transferred from PSE&G to Power in August 2000 at the price specified by the BPU. Because the transfer was between affiliates, the transaction was recorded at the net book value of the assets and liabilities rather than the transfer price. The difference between the total transfer price and the net book value of the generation-related assets and liabilities, $986 million, net of tax, was recorded as a Basis Adjustment on PSE&G's and Power's Consolidated Balance Sheets. The $986 million is an addition to PSE&G's Common Stockholder's Equity and a reduction of Power's Member's Equity. These amounts are eliminated on PSEG's consolidated financial statements.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Note 2. Recent Accounting Standards

New Standards Issued and Adopted

Business Combinations: Clarifying the Definition of a Business

This accounting standard was issued mainly to provide more consistency in how the definition of a business is applied to acquisitions or dispositions. The new guidance will generally reduce the number of transactions that will require treatment as a business combination. The definition of a business now includes consideration of whether substantially all the fair value of the gross assets acquired or disposed of is concentrated in a single identifiable asset or a group of similar identifiable assets. If this condition is met, the transaction would not qualify as a business.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities were able to adopt it for transactions that closed before the effective date but had not been reported in financial statements that had been issued or made available for issuance. PSEG adopted this standard in the third quarter 2017 with the acquisition of a solar project. This standard upon adoption had no impact on PSEG's financial statements.

Revenue from Contracts with Customers

This accounting standard clarifies the principles for recognizing revenue and removes inconsistencies in revenue recognition requirements; improves comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provides improved disclosures.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG adopted this standard on January 1, 2018. PSEG will elect the full retrospective method of transition. Under this method, PSEG will restate its prior period financial statements to align with the 2018 presentation.

PSEG has evaluated existing contracts and revenue streams for potential changes under the new revenue recognition standard. Included in the scope of the new standard are PSE&G's regulated revenue recorded under tariffs, including the sale of default supply of electric and gas commodity, and the distribution of electricity and gas to retail residential and commercial and industrial customers, and transmission revenues. Tariff revenues comprise substantially all of PSE&G's revenue. PSEG expects no material change in revenue recognition of PSE&G's regulated revenue recorded under tariffs. PSE&G's revenue from contracts with customers will continue to be recorded as electricity or gas is delivered to the customer. Certain reclassifications of PSE&G's revenue streams will affect Operating Revenues and Operating Expenses due to the application of this standard.

Also included in the scope of the new standard are Power's electricity, gas and related product sales. Certain reclassifications of Power's revenue streams will also affect Operating Revenues and Energy Costs due to the application of this standard.

PSEG, PSE&G and Power do not anticipate any material impact to net income as a result of adoption of this new standard.

The new standard will result in more detailed disclosures of revenue compared to current guidance and changes in presentation. PSEG will disaggregate its revenues by operating segment. PSE&G will further disaggregate its revenue by product line (i.e. electric distribution, gas distribution, and transmission). Power will further disaggregate its revenues by product line (i.e. electricity, gas). Electricity revenues will be further disaggregated by region (i.e. PJM, New York ISO and ISO New England). Gas revenues will be further disaggregated by third party sales and sales to affiliates. Other Revenues from Contracts with Customers will also be disclosed including PSE&G appliance service and repair and Power solar power revenues.

PSEG will elect the invoice practical expedient, where applicable, in recording its revenue. Under the practical expedient, PSEG has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of PSEG's performance completed to date. PSEG may recognize revenue in the amount to which it has a right to invoice. As such under this practical expedient, there are no future performance obligations to disclose. Where PSEG has entered into fixed consideration contracts, it will disclose its remaining performance obligations under these agreements.

Recognition and Measurement of Financial Assets and Financial Liabilities

This accounting standard will change how entities measure equity investments that are not consolidated or accounted for under the equity method. Under the new guidance, equity investments (other than those accounted for using the equity method) will be measured at fair value through Net Income instead of Other Comprehensive Income (Loss). Entities that have elected the fair value option for financial liabilities will present changes in fair value due to a change in their own credit risk through Other Comprehensive Income (Loss). For equity investments which do not have readily determinable fair values, the impairment assessment will be simplified by requiring a qualitative assessment to identify impairments. The new standard also changes certain disclosures.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG recorded a cumulative effect adjustment by reclassifying the unrealized gain related to equity investments of $342 million ($176 million, net of tax) from Accumulated Other Comprehensive Income to Retained Earnings on January 1, 2018, and expects increased volatility in Net Income due to changes in fair value of its equity securities within the NDT and Rabbi Trust Funds.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments

This accounting standard reduces the diversity in practice in how certain cash receipts and cash payments are presented and classified in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; early adoption was permitted. PSEG expects no changes in its presentation of its Statement of Cash Flows as a result of adopting this new standard. PSEG adopted this standard on January 1, 2018 using a retrospective transition method to each period presented.

Statement of Cash Flows: Restricted Cash

This accounting standard requires entities to explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents, either in a narrative or a tabular format. Amounts generally described as restricted cash or restricted cash equivalents should be included in entities' reconciliation of beginning-of-period and end-of-period amounts in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; early adoption was permitted. PSEG adopted this standard on January 1, 2018 using a retrospective transition method for each period presented. PSEG will

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continue the current balance sheet classification of restricted cash or restricted cash equivalents. PSEG will provide a reconciliation of cash and cash equivalents and restricted cash or restricted cash equivalents and include a description of these amounts.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (OPEB)

This accounting standard was issued to improve the presentation of net periodic pension cost and net periodic OPEB cost.

Under the new guidance, entities are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by their employees during the period. The other components of net benefit cost are required to be presented in the Statement of Operations separately from the service cost component after Operating Income. Additionally, only the service cost component will be eligible for capitalization, when applicable.

The standard requires the amendments to be applied retrospectively for the presentation of the service cost component and the other cost components of net periodic pension cost and net periodic OPEB cost in the Statement of Operations and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension and OPEB costs.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG adopted this standard as of January 1, 2018. Beginning January 1, 2018, PSEG and each of its subsidiaries began to classify the total net pension and OPEB non-service benefit costs in a separate line item in the Statement of Operations after Operating Income. PSEG will also recast those amounts for prior years in accordance with the new standard by using the practical expedient of using the previously disclosed non-service components of pension and OPEB costs. The service cost component of pension and OPEB costs will continue to be classified in O&M Expense, except for that portion capitalized, as appropriate, within Property, Plant and Equipment. As a result of adopting this new standard, PSE&G expects to reduce its charge to expense by approximately $55 million to $65 million in 2018.

Stock Compensation - Scope of Modification Accounting

This accounting standard provides clarity and reduces both diversity in practice and complexity when applying the stock compensation guidance to a change in the terms or conditions of a stock-based payment award. Specifically, the standard provides guidance as to which changes to the terms or conditions of a stock-based payment award require an entity to apply modification accounting.

The standard is effective for all entities for annual periods, and interim periods within those annual periods, beginning after December 15, 2017, early adoption was permitted. This standard should be applied prospectively to an award modified on or after the adoption date. PSEG adopted this standard effective January 1, 2018.

New Standards Issued But Not Yet Adopted

Leases

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor will classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. However, existing guidance related to leveraged leases will not change.

The standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities

This accounting standard's amendments more closely align hedge accounting with the companies' risk management activities in the financial statements. The amendments expand hedge accounting for both non-financial and financial risk components by permitting contractually specified components to designate as the hedged risk in a cash flow hedge involving the purchase or sale of non-financial assets or variable rate financial instruments. Additionally, the amendments ease the operational burden of applying hedge accounting by allowing more time to prepare hedge documentation, and allow effectiveness assessments to be performed on a qualitative basis after hedge inception.

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The new guidance is effective for annual and interim periods beginning after December 15, 2018. The standard requires using a modified retrospective method upon adoption. Early adoption is permitted. PSEG is currently analyzing the impact of this standard on its consolidated financial statements.

Premium Amortization on Purchased Callable Debt Securities

This accounting standard was issued to shorten the amortization period for certain callable debt securities held at a premium. Specifically, the standard requires the premium to be amortized to the earliest call date. The amendments do not require an accounting change for securities held at a discount; the discount continues to be amortized to maturity.

The standard is effective for annual and interim reporting periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period. If an entity early adopts the standard in an interim period, any
adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity should apply this standard on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. Additionally, in the period of adoption, an entity should provide disclosures about a change in accounting principle. PSEG is currently analyzing the impact of this standard on its financial statements.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

This accounting standard would affect any entity that is required to apply the provisions of the Accounting Standards Codification topic, "Income Statement-Reporting Comprehensive Income," and has items of other comprehensive income for which the related tax effects are presented in other comprehensive income as required by GAAP. Specifically, this standard would allow entities to record a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the newly enacted federal corporate income tax rate. The amount of the reclassification would be the difference between the historical corporate income tax rate and the newly enacted 21% corporate income tax rate.

The standard is effective for all entities for annual periods, and interim periods within those annual periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period for public business entities for reporting periods for which financial statements have not yet been issued or made available for issuance.

An entity would be able to choose to apply this standard retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the new tax legislation enacted in 2017 is recognized or apply the standard in the reporting period adopted. PSEG is currently analyzing the impact this standard, if adopted, could have on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments

This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however, this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

Simplifying the Test for Goodwill Impairment

This accounting standard requires an entity to perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

An entity should apply this standard on a prospective basis and will be required to disclose the nature of and reason for the change in accounting principle upon transition. The new standard is effective for impairment tests for periods beginning January 1, 2020. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. PSEG is currently assessing the impact of this guidance upon its financial statements.

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Note 3. Early Plant Retirements

Fossil

In October 2016, Power determined that it would cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. Both units were available to operate through May 31, 2017 and were subsequently retired from operation on June 1, 2017. As of December 31, 2017, the retirements of both units were substantially complete.

In the latter half of 2016, PSEG and Power recognized pre-tax charges in Energy Costs and O&M of $62 million and $53 million, respectively, related to coal inventory adjustments, capacity penalties, materials and supplies inventory reserve adjustments for parts that cannot be used at other generating units, employee-related severance benefits costs and construction work in progress impairments, among other shut down items. In addition to these charges, Power recognized Depreciation and Amortization (D&A) during 2016 of $571 million due to the significant shortening of the expected economic useful lives of Hudson and Mercer.

As of June 1, 2017, Power recognized total D&A of $964 million for the Hudson and Mercer units to reflect the end of their economic useful lives in 2017. During the year ended December 31, 2017, Power recognized pre-tax charges in Energy Costs of $15 million, primarily for coal inventory lower of cost or market adjustments. During the year ended December 31, 2017, Power also recognized pre-tax charges in O&M of $23 million, including shut down costs and an increase in the Asset Retirement Obligation due to settlements and changes in cash flow estimates, partially offset by changes in employee-related severance costs. Power is exploring various opportunities with these sites, including using the sites for alternative industrial activity or the disposition of one or both of the sites. If Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such environmental remediation are neither currently probable nor estimable but may be material.

As of December 31, 2016, Power had reduced the estimated useful life of Bridgeport Harbor Station unit 3 (BH3) from 2025 to the summer of 2021 as it was more likely than not it will retire the unit by this time.

PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the held for use classification of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Nuclear

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. Most recently, in February 2018, Exelon, a co-owner of the Salem units, announced its intention to accelerate the closure of its Oyster Creek nuclear plant located in New Jersey, one year earlier than previously planned for economic reasons. These closures and retirements are generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a further shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

If any or all of the Salem and Hope Creek units were shut down, it would significantly alter New Jersey's energy supply predominately by increasing New Jersey's reliance on natural gas generation. Such a decrease in fuel diversity could also increase the market's vulnerability to price fluctuations and power disruptions in times of high demand. The New Jersey Legislature is assessing legislation that would provide a safety net in order to prevent the loss of environmental attributes from nuclear generating stations. Power cannot predict whether the legislation will be enacted or, if enacted, whether our nuclear generating stations in New Jersey will be selected or whether the legislation will provide a sufficient safety net for the continued operation of nuclear generating stations in New Jersey.

In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of our nuclear units beyond the current year, including whether and to what extent these units participate in RPM capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be

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influenced by the financial outlook of the units, including the progress, timing and continued outlook for enactment of proposed legislation in the state of New Jersey.

If market prices continue to be depressed and legislation is not enacted that adequately compensates nuclear generating stations for their attributes, Power anticipates it will no longer be covering its costs nor be adequately compensated for its market and operational risks at the Salem and Hope Creek nuclear units and would anticipate retiring these units early. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs and additional funding of the Nuclear Decommissioning Trust Fund (NDT) would be material to both PSEG and Power.

The following table provides the balance sheet amounts by generating station as of December 31, 2017 for significant assets and liabilities associated with Power's owned share of its nuclear assets.

	As of December 31, 2017			
	Hope Creek	Salem	Support Facilities and Other (A)	Peach Bottom
	Millions			
Assets				
Materials and Supplies Inventory	$ 86	$ 78	$ —	$ 41
Nuclear Production, net of Accumulated Depreciation	605	661	211	802
Nuclear Fuel In-Service, net of Accumulated Depreciation	104	124	—	153
Construction Work in Progress (including nuclear fuel)	245	90	1	25
Total Assets	$ 1,040	$ 953	$ 212	$ 1,021
Liabilities				
Asset Retirement Obligation	$ 302	$ 249	$ —	$ 205
Total Liabilities	$ 302	$ 249	$ —	$ 205
Net Assets	$ 738	$ 704	$ 212	$ 816
NRC License Renewal Term	2046	2036/2040	N/A	2033/2034
% Owned	100%	57%	Various	50%

(A) Includes Hope Creek's and Salem's shared support facilities and other nuclear development capital.

The precise timing of any potential early retirement and resulting financial statement impact may be affected by a number of factors, including co-owner considerations, the results of any transmission system reliability study assessments and decommissioning trust fund requirements and other commitments, as well as future energy prices. Power maintains a NDT Fund that funds its decommissioning obligations. See Note 9. Available-for-Sale Securities.

Note 4. Variable Interest Entity (VIE)

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and O&M Expense, respectively. In 2017, 2016 and 2015, Servco recorded $438 million, $410 million

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and $375 million, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Consolidated Statement of Operations.

Note 5. Property, Plant and Equipment and Jointly-Owned Facilities

Information related to Property, Plant and Equipment as of December 31, 2017 and 2016 is detailed below:

	PSE&G	Power	Other	PSEG Consolidated
			Millions	
2017				
Transmission and Distribution:				
Electric Transmission	$ 10,425	$ —	$ —	$ 10,425
Electric Distribution	8,455	—	—	8,455
Gas Distribution and Transmission	7,122	—	—	7,122
Construction Work in Progress	1,735	—	—	1,735
Other	512	—	—	512
Total Transmission and Distribution	28,249	—	—	28,249
Generation:				
Fossil Production	—	4,923	—	4,923
Nuclear Production	—	2,893	—	2,893
Nuclear Fuel in Service	—	745	—	745
Other Production-Solar	593	757	—	1,350
Construction Work in Progress	—	2,339	—	2,339
Total Generation	593	11,657	—	12,250
Other	275	98	359	732
Total	**$ 29,117**	**$ 11,755**	**$ 359**	**$ 41,231**

	PSE&G	Power	Other	PSEG Consolidated
			Millions	
2016				
Transmission and Distribution:				
Electric Transmission	$ 9,149	$ —	$ —	$ 9,149
Electric Distribution	7,976	—	—	7,976
Gas Distribution and Transmission	6,458	—	—	6,458
Construction Work in Progress	1,501	—	—	1,501
Other	439	—	—	439
Total Transmission and Distribution	25,523	—	—	25,523
Generation:				
Fossil Production	—	7,096	—	7,096
Nuclear Production	—	2,516	—	2,516
Nuclear Fuel in Service	—	783	—	783
Other Production-Solar	591	687	—	1,278
Construction Work in Progress	—	1,483	—	1,483
Total Generation	591	12,565	—	13,156
Other	233	90	335	658
Total	**$ 26,347**	**$ 12,655**	**$ 335**	**$ 39,337**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G and Power have ownership interests in and are responsible for providing their respective shares of the necessary financing for the following jointly-owned facilities to which they are a party. All amounts reflect PSE&G's or Power's share of the jointly-owned projects and the corresponding direct expenses are included in the Consolidated Statements of Operations as operating expenses.

		As of December 31,			
		2017		2016	
	Ownership Interest	Plant	Accumulated Depreciation	Plant	Accumulated Depreciation
		Millions			
PSE&G:					
Transmission Facilities	Various	$ 162	$ 58	$ 169	$ 65
Power:					
Coal Generating:					
Conemaugh	23%	$ 408	$ 178	$ 408	$ 166
Keystone	23%	$ 409	$ 187	$ 409	$ 176
Nuclear Generating:					
Peach Bottom	50%	$ 1,328	$ 348	$ 1,272	$ 306
Salem	57%	$ 1,147	$ 277	$ 1,077	$ 304
Nuclear Support Facilities	Various	$ 239	$ 81	$ 238	$ 71
Pumped Storage Facilities:					
Yards Creek	50%	$ 44	$ 26	$ 42	$ 25
Merrill Creek Reservoir	14%	$ 1	$ —	$ 1	$ —

Power holds undivided ownership interests in the jointly-owned facilities above. Power is entitled to shares of the generating capability and output of each unit equal to its respective ownership interests. Power also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. Power's share of expenses for the jointly-owned facilities is included in the appropriate expense category. Each owner is responsible for any financing with respect to its pro rata share of capital expenditures.

Power co-owns Salem and Peach Bottom with Exelon Generation. Power is the operator of Salem and Exelon Generation is the operator of Peach Bottom. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

GenOn Northeast Management Company is a co-owner and the operator for Keystone Generating Station and Conemaugh Generating Station. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

Power is a co-owner in the Yards Creek Pumped Storage Generation Facility. Jersey Central Power & Light Company (JCP&L) is also a co-owner and the operator of this facility. JCP&L submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Power is a minority owner in the Merrill Creek Reservoir and Environmental Preserve in Warren County, New Jersey. Merrill Creek Owners Group is the owner-operator of this facility. The operator submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Note 6. Regulatory Assets and Liabilities

PSE&G prepares its financial statements in accordance with GAAP for regulated utilities as described in Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies. PSE&G has deferred certain costs based on rate orders issued by the BPU or FERC or based on PSE&G's experience with prior rate cases. Most of PSE&G's Regulatory Assets and Liabilities as of December 31, 2017 are supported by written orders, either explicitly or implicitly through the BPU's treatment of various cost items. These costs will be recovered and amortized over various future periods.

Regulatory Assets and other investments and costs incurred under our various infrastructure filings and clause mechanisms are subject to prudence reviews and can be disallowed in the future by regulatory authorities. To the extent that collection of any

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infrastructure or clause mechanism revenue, Regulatory Assets or payments of Regulatory Liabilities is no longer probable, the amounts would be charged or credited to income.

PSE&G had the following Regulatory Assets and Liabilities:

	As of December 31,	
	2017	2016
	Millions	
Regulatory Assets		
Current		
New Jersey Clean Energy Program	$ 128	$ 142
Weather Normalization Clause (WNC)	40	49
Electric Energy Costs—Basic Generation Service	23	2
FERC Formula Rate True-up	12	—
Other	8	6
Total Current Regulatory Assets	**$ 211**	**$ 199**
Noncurrent		
Pension and OPEB Costs	$ 1,488	$ 1,403
Manufactured Gas Plant (MGP) Remediation Costs	358	403
Deferred Income Taxes	282	507
Storm Damage Deferrals	241	239
Electric Transmission and Gas Cost of Removal	199	189
Remediation Adjustment Charge (RAC) (Other SBC)	172	180
Conditional Asset Retirement Obligation	162	157
Green Program Recovery Charges (GPRC)	98	91
Unamortized Loss on Reacquired Debt and Debt Expense	55	61
Gas Costs—Basic Gas Supply Service (BGSS)	30	—
FERC Formula Rate True-up	16	—
Other	121	89
Total Noncurrent Regulatory Assets	**$ 3,222**	**$ 3,319**
Total Regulatory Assets	**$ 3,433**	**$ 3,518**

	As of December 31,	
	2017	2016
	Millions	
Regulatory Liabilities		
Current		
Gas Costs —BGSS	$ 30	$ 6
Gas Margin Adjustment Clause	12	11
GPRC	3	28
FERC Formula Rate True-up	—	34
Other	2	9
Total Current Regulatory Liabilities	**$ 47**	**$ 88**
Noncurrent		
Excess Deferred Income Tax Regulatory Liability	$ 2,868	$ —
Electric Distribution Cost of Removal	80	94
Mark-to-Market (MTM) Contracts	—	20
Other	—	4
Total Noncurrent Regulatory Liabilities	**$ 2,948**	**$ 118**
Total Regulatory Liabilities	**$ 2,995**	**$ 206**

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All Regulatory Assets and Liabilities are excluded from PSE&G's rate base unless otherwise noted. The Regulatory Assets and Liabilities in the table above are defined as follows:

- **Conditional Asset Retirement Obligation:** These costs represent the differences between rate regulated cost of removal accounting and asset retirement accounting under GAAP. These costs will be recovered in future rates as assets are retired.
- **Deferred Income Taxes:** These amounts represent the portion of deferred income taxes that will be recovered or refunded through future rates, based upon established regulatory practices. In December 2017, new tax legislation was enacted (Tax Act) reducing the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018. PSE&G is subject to Financial Accounting Standards Board (FASB) Accounting Standards Codification 740, Income Taxes (ASC 740), which requires that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate was enacted. The impact of reduction in tax rate is the primary reason for the decrease in the Regulatory Asset.
- **Electric and Gas Cost of Removal:** PSE&G accrues and collects in rates for the cost of removing, dismantling and disposing of its transmission and distribution assets upon retirement. The regulatory asset or liability for non-legally required cost of removal represents the difference between amounts collected in rates and costs actually incurred.
- **Electric Energy Costs—Basic Generation Service:** These costs represent the over or under recovered amounts associated with Basic Generation Services (BGS), as approved by the BPU. Pursuant to BPU requirements, PSE&G serves as the supplier of last resort for electric customers within its service territory that are not served by another supplier. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for PSE&G's operations. Over or under recovered balances with interest are returned or recovered through monthly filings.
- **Excess Deferred Income Tax Regulatory Liability:** The $2.9 billion Regulatory Liability represents the future revenue reduction of PSE&G's existing $2.1 billion Accumulated Deferred Income Tax liabilities that are in excess of what is needed to offset future tax liabilities as a result of the Tax Act that reduces the federal corporate income tax rate from a maximum of 35% to 21% effective January 1, 2018. The excess deferred income taxes are primarily related to the difference between book and tax plant depreciation and under the new tax legislation cannot be returned to customers any faster than over the remaining regulatory lives of the related property. For the remaining excess deferred taxes, the mechanism and timing of these refunds will be determined by the BPU and FERC.
- **FERC Formula Rate True-up:** Over or under collection of transmission earnings calculated using a FERC approved formula. Over or under collected balances with interest are returned or recovered through the subsequent annual filing.
- **Gas Costs—Basic Gas Supply Service:** These costs represent the over or under recovered amounts associated with Basic Gas Supply Service (BGSS), as approved by the BPU. Pursuant to BPU requirements, PSE&G serves as the supplier of last resort for gas customers within its service territory that are not served by another supplier. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for PSE&G's operations. Over or under collected balances are returned or recovered through an annual filing. Interest is accrued only on over recovered balances.
- **Gas Margin Adjustment Clause:** This mechanism credits Firm delivery customers for net distribution margin revenue collected from Transportation Gas Service Non-Firm (TSG-NF) delivery customers. The balance represents the difference between the net margin collected from the TSG-NF Customers versus bill credits provided to Firm delivery customers. Over or under recovered balances with interest are returned or recovered through the subsequent annual filing.
- **GPRC:** This amount represents costs of the over or under collected balances associated with various renewable energy and energy efficiency programs. The Company files annually with the BPU for recovery of amounts that include a return on and of its investment over the lives of the underlying investments and capital assets which range from 5 to 10 years. Interest is accrued monthly on any over or under recovered balances. Components of the GPRC include: Carbon Abatement, Energy Efficiency Economic Stimulus Program (EEE), EEE Extension Program, EEE Extension II Program, the Demand Response Program, Solar Generation Investment Program (Solar 4 All), Solar 4 All Extension, Solar 4 All Extension II, Solar Loan II Program, Solar Loan III Program and the Energy Efficiency 2017 Program.
- **MGP Remediation Costs:** Represents the low end of the range for the remaining environmental investigation and remediation program cleanup costs for manufactured gas plants that are probable of recovery in future rates. Once these costs are incurred, they are recovered through the RAC in the SBC over a seven year period with interest.

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- **MTM Contracts:** The estimated fair value of gas hedge contracts and gas cogeneration supply contract. The regulatory asset/liability is offset by a derivative asset/liability and, with respect to the gas hedge contracts only, an intercompany receivable/payable on the Consolidated Balance Sheets.
- **New Jersey Clean Energy Program:** The BPU approved future funding requirements for Energy Efficiency and Renewable Energy Programs through the first half of 2018. The BPU funding requirements are recovered through the SBC.
- **Pension and OPEB Costs:** Pursuant to the adoption of accounting guidance for employers' defined benefit pension and OPEB plans, PSE&G recorded the unrecognized costs for defined benefit pension and other OPEB plans on the balance sheet as a Regulatory Asset. These costs represent actuarial gains or losses, prior service costs and transition obligations as a result of adoption, which have not been expensed. These costs are amortized and recovered in future rates.
- **RAC (Other SBC):** Costs incurred to clean up manufactured gas plants which are recovered over seven years with interest through an annual filing.
- **SBC:** The SBC, as authorized by the BPU and the New Jersey Electric Discount and Energy Competition Act, includes costs related to PSE&G's electric and gas business as follows: (1) the Universal Service Fund (USF); (2) Energy Efficiency and Renewable Energy Programs; (3) Electric bad debt expense; and (4) the RAC for incurred MGP remediation expenditures. Over or under recovered balances with interest are to be returned or recovered through an annual filing.
- **Storm Damage Deferrals:** Costs incurred in the cleanup of major storms in 2010 through 2017. As of December 31, 2017, this includes the $220 million of storm costs, net of insurance recoveries, primarily as a result of Hurricane Irene and Superstorm Sandy, approved for recovery in a future base rate case proceeding under a BPU order received in September 2014.
- **Unamortized Loss on Reacquired Debt and Debt Expense:** Represents losses on reacquired long-term debt and expenses associated with issuances of new debt, which are recovered through rates over the remaining life of the debt.
- **WNC:** This represents the over or under recovery of gas margin under the BPU's weather normalization clause which is filed annually. The WNC requires PSE&G to calculate, at the end of each October-to-May period, the level by which margin revenues differed from what would have resulted if normal weather had occurred. Over recoveries are returned to customers in the next winter season while under recoveries (subject to an earnings cap) are recovered from customers in the next winter season.

Significant 2017 regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

- ***Electric and Gas Distribution Base Rate Filing***—In January 2018, PSE&G filed a distribution base rate case as required as a condition of approval of its Energy Strong Program approved by the BPU in 2014. The filing requests an approximate one percent increase in revenues and seeks to recover investments made to strengthen electric and gas distribution systems. In its filing, PSE&G requested that these rates take into account a reduction in the revenue requirement as a result of the federal corporate income tax rate reduction from 35% to 21% provided in the Tax Act, including a one-time credit for estimated excess income taxes collected between January 1, 2018 and the time new rates go into effect, and the flow back to customers of certain additional tax benefits. PSE&G anticipates the new base rates will go into effect in the fourth quarter of 2018.

  Separately, in January 2018, the BPU issued an order commencing a proceeding to ensure that the rate revenue resulting from expenses relating to taxes reflected in rates but no longer owed as the result of the Tax Act shall be passed onto the ratepayers. The BPU directed New Jersey utilities (including PSE&G) to make filings by March 2, 2018 setting forth interim rates to be effective April 1, 2018 reflecting the new federal corporate tax rate, and to subsequently file proposed final rates, effective July 1, 2018, incorporating all other effects of the Tax Act. This proceeding is currently pending.
- ***Transmission Formula Rate Filings***—In June 2017, PSE&G filed its 2016 true-up adjustment pertaining to its transmission formula rates in effect for 2016. This resulted in an adjustment of $12 million more than the 2016 originally filed revenues.

  For the year ended December 31, 2017, PSE&G recorded an estimated true-up adjustment of $16 million to its 2017 Annual Formula rate. That true-up will be filed by no later than June 15, 2018.

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In October 2017, the 2018 Annual Formula Rate Update was filed with FERC and requested approximately $212 million in increased annual transmission revenues effective January 1, 2018, subject to true-up. In January 2018, PSE&G filed with FERC a revised 2018 Annual Transmission Formula Rate Update reducing the 2018 transmission annual revenue requirement to reflect the federal corporate income tax rate reduction from 35% to 21%, effective January 1, 2018, provided in the Tax Act. This change in the federal corporate tax rate reduces the annual revenue requirement by $148 million. The revised increase in annual transmission revenues effective January 1, 2018 is $64 million.

- ***Energy Strong Recovery Filing***—In March and September of each year, PSE&G files with the BPU for base rate recovery of Energy Strong investments which include a return of and on its investment.

  In June 2017, PSE&G submitted the planned update to its March Energy Strong cost recovery petition, originally filed in March 2017, to include Energy Strong investments in service as of May 31, 2017. This filing requested estimated annual increases in electric and gas revenues of $16 million and $2 million, respectively. In August 2017, the BPU approved these rate increases effective September 1, 2017.

  In September 2017, PSE&G filed its Energy Strong electric cost recovery petition seeking BPU approval to recover the revenue requirements associated with Energy Strong capitalized investment costs placed in service from June 1, 2017 through November 30, 2017. The filing was updated in December 2017 requesting an annual increase in electric revenues of $8 million. This matter is pending.

- ***Gas System Modernization Program (GSMP)***—In July of each year, PSE&G files with the BPU for base rate recovery of GSMP investments which include a return of and on its investment.

  In December 2017, the BPU approved PSE&G's annual GSMP cost recovery petition, originally filed in July 2017, and updated in October 2017, to include GSMP investments in service as of September 30, 2017. The BPU approved an annual increase in gas revenues of $25 million, effective January 1, 2018.

- ***BGSS***—In June 2017, PSE&G made its annual BGSS filing with the BPU requesting an increase in the BGSS rate from approximately 34 cents to 37 cents per therm effective October 1, 2017. In September 2017, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was increased. In December 2017 and February 2018, PSE&G filed with the BPU for self-implementing monthly bill credits of 15 cents per therm for the months of January, February and March 2018. These monthly bill credits are estimated to provide approximately $100 million in customer credits. In November 2017, a filing was made by the Retail Energy Supply Association (RESA) with the BPU requesting that the BPU revisit the BGSS process and establish a gas capacity release program. This filing, which remains pending, is applicable to all New Jersey gas utilities.

- ***Green Program Recovery Charges (GPRC)***—Each year PSE&G files with the BPU for annual recovery for the 11 combined components of its electric and gas Green Program investments which include a return on its investment and recovery of expenses.

  In March 2017, the BPU gave final approval to PSE&G's 2016 GPRC cost recovery petition to recover approximately$37 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved GPRC programs for the period October 1, 2016 through September 30, 2017. The rates were effective May 1, 2017. This Order also included the return of approximately $5 million in remaining overcollections from the completed Securitization Transition Charge.

  In June 2017, PSE&G filed its 2017 GPRC cost recovery petition requesting recovery of approximately $47 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved programs for the period October 1, 2017 through September 30, 2018. This proceeding is ongoing.

  In August 2017, the BPU approved PSE&G's petition for an Energy Efficiency 2017 Program (EE 2017) to extend three existing energy efficiency subprograms (multi-family, direct install and hospital efficiency) and establish two new residential energy efficiency offerings. The two new offerings include deployment of smart thermostats and a pilot program to provide residential customers with energy usage information enabling them to reduce consumption. The Order allows PSE&G to extend the subprogram offerings and establish the residential energy efficiency subprograms under its existing energy efficiency clause recovery process. The EE 2017 allows for $69 million of additional investment and $16 million of additional administrative and information technology costs. The EE 2017 was added as the 11th component of the GPRC rate effective September 1, 2017.

- ***Weather Normalization Clause***—In April 2017, the BPU gave final approval to PSE&G petition to collect $54 million in net deficiency gas revenues as a result of the warmer than normal 2015-2016 Winter Period.

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In September 2017, the BPU approved on a provisional basis, PSE&G's petition to collect $31 million in net deficiency gas revenues as a result of the warmer than normal 2016-2017 Winter Period and a remaining carryover balance of $24 million in net deficiency gas revenues from the 2015-2016 Winter Period for a total recovery of $55 million in net deficiency revenues. The deficiency will be collected from customers over the 2017-2018 and 2018-2019 Winter Periods (October 1 through May 31). Final approval in this matter is pending.

- ***Remediation Adjustment Charge (RAC)***—In June 2017, the BPU approved PSE&G's filing with respect to its RAC 24 petition allowing recovery of $41 million effective July 10, 2017 related to net Manufactured Gas Plant expenditures from August 1, 2015 through July 31, 2016. In February 2018, PSE&G filed a RAC 25 Petition with the BPU requesting recovery of $63 million of net Manufactured Gas Plant expenditures from August 1, 2016 through July 31, 2017. This matter is pending.
- ***Universal Service Fund (USF)/Lifeline***—In September 2017, the BPU approved rates set to recover state-wide costs incurred by New Jersey electric and gas distribution companies under the State's USF/Lifeline energy assistance programs effective October 1, 2017. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on its Consolidated Statement of Operations.

Note 7. Long-Term Investments

Long-Term Investments as of December 31, 2017 and 2016 included the following:

	As of December 31,	
	2017	2016
	Millions	
PSE&G		
Life Insurance and Supplemental Benefits	$ 130	$ 140
Solar Loans	150	159
Power		
Partnerships and Corporate Joint Ventures (Equity Method Investments) (A)	87	102
Energy Holdings		
Lease Investments	565	649
Total Long-Term Investments	**$ 932**	**$ 1,050**

(A) During the three years ended December 31, 2017, 2016 and 2015, dividends from these investments were $18 million, $18 million and $16 million, respectively.

Leases

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third-party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Consolidated Balance Sheets.

During the third quarter of 2016, Energy Holdings completed its annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases. The outcome indicated that the revised residual value estimates were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM, as discussed in Note 3. Early Plant Retirements, negatively impacting the economic outlook of the leased assets. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016, calculated by comparing the gross investment in the leases before and after the revised residual estimates. During the fourth quarter of 2016, Energy Holdings recorded a $10 million charge for its best estimate of loss as a result of the current liquidity issues facing REMA, which was reflected in Operating Revenues and is included in Gross Investments in Leases as of December 31, 2016. For additional information, see Note 8. Financing Receivables.

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During the first quarter of 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as certain recent discussions with REMA management, Energy Holdings recorded an additional $55 million pre-tax charge for its current best estimate of loss related to the lease receivables.

In June 2017, GenOn Energy, Inc. (GenOn) and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code. REMA was not included in the GenOn filing. Energy Holdings continues to monitor the restructuring of GenOn and its possible impacts on REMA and continues to discuss the situation with various parties relevant to this matter. During the second quarter of 2017, Energy Holdings completed its review of estimated residual values embedded in its leveraged lease portfolio of generating assets and the outcome indicated that one of the residual value estimates was lower than the recorded residual value due to a further deterioration of market conditions and changes to operating cost estimates. This decline was determined to be other than temporary. As a result, a pre-tax write-down of $7 million was recorded in the quarter ended June 30, 2017. In addition, based on an ongoing review of (i) the liquidity challenges facing REMA and (ii) available alternatives, Energy Holdings recorded an additional $15 million pre-tax charge in the quarter ended June 30, 2017 for its current best estimate of loss related to lease receivables. Pre-tax write-downs and additional charges are reflected in Operating Revenues and are included in Gross Investment in Leases as of December 31, 2017.

In January 2018, certain subsidiaries of Energy Holdings, REMA, certain holders of the pass-through certificates and other parties entered into a Forbearance Agreement (Forbearance) relating to the Conemaugh facility. Pursuant to the Forbearance, the parties thereto agreed to temporarily forbear from exercising rights and remedies related to certain events of default related to REMA's obligation to procure additional qualifying credit support. The Forbearance will remain effective until the earlier of (i) the later of (a) April 15, 2018 and (b) two weeks following the date on which Energy Holdings subsidiaries, REMA and/or the consenting certificate holders provide written notice to REMA of its intention to terminate the Forbearance, and (ii) the date on which any event of termination as specified in the Forbearance occurs.

PSEG cannot predict the outcome of GenOn's restructuring process or the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments. If lease rejections or foreclosures were to occur, Energy Holdings could potentially record additional pre-tax write-offs up to its gross investment in these facilities and may also be required to accelerate and pay material deferred tax liabilities to the Internal Revenue Service (IRS).

The following table shows Energy Holdings' gross and net lease investment as of December 31, 2017 and 2016.

	As of December 31,	
	2017	2016
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 546	$ 629
Estimated Residual Value of Leased Assets	326	346
Total Investment in Rental Receivables	872	975
Unearned and Deferred Income	(307)	(326)
Gross Investments in Leases	565	649
Deferred Tax Liabilities	(480)	(674)
Net Investments in Leases	**$ 85**	**$ (25)**

In December 2017, new tax legislation was enacted, reducing the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018. PSEG is subject to ASC 740, which requires that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate was enacted. The impact of the reduced tax rate is the primary reason for the decrease in Deferred Tax Liabilities. For additional information, see Note 20. Income Taxes.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The pre-tax income (loss) and income tax effects related to investments in leases, excluding gains and losses on sales and the impacts of the Tax Act, were as follows:

	Years Ended December 31,		
	2017	2016	2015
	Millions		
Pre-Tax Income (Loss) from Leases	$ (69)	$ (135)	$ 12
Income Tax Expense (Benefit) on Income from Leases	$ (26)	$ (51)	$ 5

Equity Method Investments

Power had the following equity method investments as of December 31, 2017 and 2016:

Name	As of December 31, 2017	As of December 31, 2016	Location	% Owned
	Millions			
Power				
Keystone Fuels, LLC	$ 8	$ 7	PA	23%
Conemaugh Fuels, LLC	8	8	PA	23%
PennEast Pipeline	—	11	PA	10%
Kalaeloa	71	76	HI	50%
Total	$ 87	$ 102		

Note 8. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. Interest income on the loans is recorded on an accrual basis. The loans are generally paid back with solar renewable energy certificates (SRECs) generated from the installed solar electric system. In the event of a loan default, the basis of the solar loan would be recovered through a regulatory recovery mechanism. None of the solar loans are impaired; however, in the event a loan becomes impaired, the basis of the loan would be recovered through a regulatory recovery mechanism.

The following table reflects the outstanding loans, including the noncurrent portion reported in Note 7. Long-Term Investments, by class of customer, none of which would be considered “non-performing.”

Outstanding Loans by Class of Customer

Consumer Loans	As of December 31, 2017	As of December 31, 2016
	Millions	
Commercial/Industrial	$ 158	$ 164
Residential	10	11
Total	**$ 168**	**$ 175**

Energy Holdings

Energy Holdings had a net investment in domestic energy and real estate assets subject to leveraged lease accounting of $85 million as of December 31, 2017 and $(25) million as of December 31, 2016 (See Note 7. Long-Term Investments).

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The corresponding receivables associated with the lease portfolio are reflected as follows, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

Counterparties' Credit Rating Standard & Poor's (S&P) as of December 31, 2017	Lease Receivables, Net of Non-Recourse Debt As of December 31, 2017
	Millions
AA	$ 15
BBB+, BBB, BBB-	316
BB-	133
CCC-	82
Total	**$ 546**

The "BB-" and the "CCC-" ratings in the preceding table represent lease receivables related to coal and gas-fired assets in Illinois and Pennsylvania, respectively. As of December 31, 2017, the gross investment in the leases of such assets, net of non-recourse debt, was $335 million, ($(67) million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 132	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 85	64%	1,036	Gas	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 20	17%	1,711	Coal	CCC-	REMA (A)
Conemaugh Station Units 1 and 2	PA	$ 20	17%	1,711	Coal	CCC-	REMA (A)
Shawville Station Units 1, 2, 3 and 4	PA	$ 78	100%	596	Gas	CCC-	REMA (A)

(A) GenOn Energy Inc. (GenOn), and certain of its subsidiaries (which did not include REMA) filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete. Certain subsidiaries of Energy Holdings, REMA, consenting holders of the pass-through certificates and other parties entered into a Forbearance relating to the Conemaugh facility. For additional information, see Note 7. Long-Term Investments.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease structures. These credit enhancement features vary from lease to lease. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital and trigger certain material tax obligations which could wholly or partially be mitigated by tax indemnification claims against the counterparty. A bankruptcy of a lessee would likely delay and potentially limit any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders.

Additional factors that may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and their affiliates and the quality and condition of assets under lease.

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Note 9. Available-for-Sale Securities

NDT Fund

In accordance with NRC regulations, entities owning an interest in nuclear generating facilities are required to determine the costs and funding methods necessary to decommission such facilities upon termination of operation. As a general practice, each nuclear owner places funds in independent external trust accounts it maintains to provide for decommissioning. Power is required to file periodic reports with the NRC demonstrating that its NDT Fund meets the formula-based minimum NRC funding requirements.

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon their respective termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. Power's share of decommissioning costs related to its five nuclear units was estimated to be between $2.8 billion and $3.0 billion, including contingencies. The liability for decommissioning recorded on a discounted basis as of December 31, 2017 was approximately $756 million and is included in the Asset Retirement Obligation. The funds are managed by third-party investment managers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of December 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 405	$ 245	$ (2)	$ 648
International	311	99	(3)	407
Total Equity Securities	716	344	(5)	1,055
Debt Securities				
Government	586	2	(4)	584
Corporate	400	4	(2)	402
Total Debt Securities	986	6	(6)	986
Other Securities	92	—	—	92
Total NDT Available-for-Sale Securities	**$ 1,794**	**$ 350**	**$ (11)**	**$ 2,133**

	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 439	$ 214	$ (3)	$ 650
International	266	49 —	(8)	307
Total Equity Securities	705	263	(11)	957
Debt Securities				
Government	518	8	(6)	520
Corporate	337	4	(4)	337
Total Debt Securities	855	12	(10)	857
Other Securities	44	—	—	44
Total NDT Available-for-Sale Securities (A)	**$ 1,604**	**$ 275**	**$ (21)**	**$ 1,858**

(A) The NDT available-for-sale securities table excludes cash of $1 million as of December 31, 2016, which is part of the NDT Fund.

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The cost of these securities was determined on the basis of specific identification.

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as shown in the following table.

	As of December 31, 2017	As of December 31, 2016
	Millions	
Accounts Receivable	$ 24	$ 8
Accounts Payable	$ 74	$ 5

The following table shows the value of securities in the NDT Fund that have been in a continuous unrealized loss position for less than 12 months and greater than 12 months.

	As of December 31, 2017				As of December 31, 2016			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)								
Domestic	$ 40	$ (2)	$ —	$ —	$ 51	$ (3)	$ 2	$ —
International	29	(3)	2	—	69	(7)	6	(1)
Total Equity Securities	69	(5)	2	—	120	(10)	8	(1)
Debt Securities								
Government (B)	343	(2)	91	(2)	276	(6)	4	—
Corporate (C)	191	(1)	27	(1)	139	(3)	15	(1)
Total Debt Securities	534	(3)	118	(3)	415	(9)	19	(1)
NDT Available-for-Sale Securities	**$ 603**	**$ (8)**	**$ 120**	**$ (3)**	**$ 535**	**$ (19)**	**$ 27**	**$ (2)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2017.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. Power also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since Power does not intend to sell these securities before recovery nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2017.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities before recovery nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2017.

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The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Years Ended December 31,		
	2017	2016	2015
	Millions		
Proceeds from Sales (A)	**$ 2,137**	**$ 711**	**$ 1,397**
Net Realized Gains (Losses):			
Gross Realized Gains	$ 157	$ 53	$ 97
Gross Realized Losses	(23)	(32)	(37)
Net Realized Gains (Losses) on NDT Fund (B)	**$ 134**	**$ 21**	**$ 60**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

(B) The cost of these securities was determined on the basis of specific identification.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Consolidated Statements of Operations. Net unrealized gains of $175 million (after-tax) are included in Accumulated Other Comprehensive Loss on PSEG's and Power's Consolidated Balance Sheets as of December 31, 2017. Under new guidance, equity investments (other than those accounted for using the equity method) will be measured at fair value through Net Income instead of Other Comprehensive Income (Loss), effective January 1, 2018. For additional information, see Note 2. Recent Accounting Standards.

The available-for-sale debt securities held as of December 31, 2017 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 42
1 - 5 years	320
6 - 10 years	207
11 - 15 years	40
16 - 20 years	65
Over 20 years	312
Total NDT Available-for-Sale Debt Securities	**$ 986**

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2017, other-than-temporary impairments of $12 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost bases for the securities held in the Rabbi Trust.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 22	$ 3	$ —	$ 25
International	—	—	—	—
Total Equity Securities	$ 22	$ 3	$ —	$ 25
Debt Securities				
Government	85	1	(1)	85
Corporate	118	2	(1)	119
Total Debt Securities	203	3	(2)	204
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 227**	**$ 6**	**$ (2)**	**$ 231**

	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 11	$ 11	$ —	$ 22
International	—	—	—	—
Total Equity Securities	11	11	—	22
Debt Securities				
Government	105	—	(2)	103
Corporate	92	1	(2)	91
Total Debt Securities	197	1	(4)	194
Other Securities	1	—	—	1
Total Rabbi Trust Available-for-Sale Securities	**$ 209**	**$ 12**	**$ (4)**	**$ 217**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as shown in the following table.

	As of December 31, 2017	As of December 31, 2016
	Millions	
Accounts Receivable	$ 2	$ 5
Accounts Payable	$ 1	$ 3

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the value of securities in the Rabbi Trust Fund that have been in a continuous unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2017				As of December 31, 2016			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)								
Domestic	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
International	—	—	—	—	—	—	—	—
Total Equity Securities	—	—	—	—	—	—	—	—
Debt Securities								
Government (B)	28	—	25	(1)	60	(2)	1	—
Corporate (C)	39	(1)	9	—	46	(2)	3	—
Total Debt Securities	67	(1)	34	(1)	106	(4)	4	—
Rabbi Trust Available-for-Sale Securities	**$ 67**	**$ (1)**	**$ 34**	**$ (1)**	**$ 106**	**$ (4)**	**$ 4**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. PSEG also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since PSEG does not intend to sell these securities before recovery nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2017.

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities before recovery nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2017.

The proceeds from the sales of and the net realized gains on securities in the Rabbi Trust Fund were:

	Years Ended December 31,		
	2017	2016	2015
	Millions		
Proceeds from Rabbi Trust Sales (A)	**$ 182**	**$ 113**	**$ 104**
Net Realized Gains (Losses):			
Gross Realized Gains	$ 17	$ 6	$ 3
Gross Realized Losses	(5)	(5)	(2)
Net Realized Gains (Losses) on Rabbi Trust (B)	**$ 12**	**$ 1**	**$ 1**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

(B) The cost of these securities was determined on the basis of specific identification.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in the Consolidated Statements of Operations. Net unrealized gains of $2 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets as of December 31, 2017. The Rabbi Trust available-for-sale debt securities held as of December 31, 2017 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 1
1 - 5 years	37
6 - 10 years	30
11 - 15 years	5
16 - 20 years	18
Over 20 years	113
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 204**

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities. In 2017, there were no other-than-temporary impairments recognized on investments of the Rabbi Trust. The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of December 31, 2017	As of December 31, 2016
	Millions	
PSE&G	$ 46	$ 43
Power	57	53
Other	128	121
Total Rabbi Trust Available-for-Sale Securities	**$ 231**	**$ 217**

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Note 10. Goodwill and Other Intangibles

As of December 31, 2017 and 2016, Power had goodwill of $16 million related to the Bethlehem Energy Center facility. Power conducted an annual review for goodwill impairment in the fourth quarter of 2017 and concluded that goodwill continues to remain unimpaired. In addition to goodwill, as of December 31, 2017 and 2016, Power had intangible assets of $114 million and $98 million, respectively, related to emissions allowances and renewable energy credits. Emissions allowances and renewable energy credits are recorded at cost and evaluated for impairment at least annually. Emissions expense includes impairments of emissions allowances and costs for emissions, which is recorded as emissions occur. As load is served under contracts requiring energy from renewable sources, the related expense is recorded. The changes to Power's intangible assets during 2016 and 2017 are presented in the following table:

	Emissions Allowances	Renewable Energy Credits	Total Other Intangibles
		Millions	
Balance as of January 1, 2016	$ 62	$ 40	$ 102
Retirements	(6)	(94)	(100)
Purchases	—	99	99
Sales and Transfers, net	(1)	(1)	(2)
Impairments	(1)	—	(1)
Balance as of December 31, 2016	$ 54	$ 44	$ 98
Retirements	(7)	(93)	(100)
Purchases	27	90	117
Sales and Transfers, net	—	(1)	(1)
Balance as of December 31, 2017	$ 74	$ 40	$ 114

Note 11. Asset Retirement Obligations (AROs)

PSEG, PSE&G and Power recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists to remove or dispose of an asset or some component of an asset at retirement. These AROs are recorded at fair value in the period in which they are incurred and are capitalized as part of the carrying amount of the related long-lived assets. PSE&G, as a rate-regulated entity, recognizes regulatory assets or liabilities as a result of timing differences between the recording of costs and costs recovered through the rate-making process. We accrete the ARO liability to reflect the passage of time with the corresponding expense recorded in Operation and Maintenance.

PSE&G has conditional AROs primarily for legal obligations related to the removal of treated wood poles and the requirement to seal natural gas pipelines at all sources of gas when the pipelines are no longer in service. PSE&G does not record an ARO for its protected steel and poly-based natural gas lines, as management believes that these categories of gas lines have an indeterminable life.

Power's ARO liability primarily relates to the decommissioning of its nuclear power plants in accordance with NRC requirements. Power has an independent external trust that is intended to fund decommissioning of its nuclear facilities upon termination of operation. For additional information, see Note 9. Available-for-Sale Securities. Power also identified conditional AROs primarily related to Power's fossil generation units and solar facilities, including liabilities for removal of asbestos, ash ponds, stored hazardous liquid material and underground storage tanks from industrial power sites, and demolition of certain plants, and the restoration of the sites at which they reside, when the plants are no longer in service. To estimate the fair value of its AROs, Power uses a probability weighted, discounted cash flow model which, on a unit by unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on third-party decommissioning cost estimates, cost escalation rates, inflation rates and discount rates.

Updated cost studies are obtained triennially unless new information necessitates more frequent updates. The most recent cost study was done in 2015. When assumptions are revised to calculate fair values of existing AROs, the ARO balance and corresponding long-lived asset are adjusted which impact the amount of accretion and depreciation expense recognized in future periods. For PSE&G, Regulatory Assets and Regulatory Liabilities result when accretion and amortization are adjusted to match rates established by regulators resulting in the regulatory deferral of any gain or loss.

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The changes to the ARO liabilities for PSEG, PSE&G and Power during 2016 and 2017 are presented in the following table:

	PSEG	PSE&G	Power	Other
	Millions			
ARO Liability as of January 1, 2016	$ 679	$ 218	$ 457	$ 4
Liabilities Settled	(13)	(9)	(4)	—
Liabilities Incurred	25	2	23	—
Accretion Expense	26	—	26	—
Accretion Expense Deferred and Recovered in Rate Base (A)	12	12	—	—
Revision to Present Values of Estimated Cash Flows	(3)	(10)	9	(2)
ARO Liability as of December 31, 2016	**$ 726**	**$ 213**	**$ 511**	**$ 2**
Liabilities Settled	(29)	(8)	(21)	—
Liabilities Incurred	1	—	1	—
Accretion Expense	30	—	30	—
Accretion Expense Deferred and Recovered in Rate Base (A)	12	12	—	—
Revision to Present Values of Estimated Cash Flows	284	(5)	289	—
ARO Liability as of December 31, 2017	**$ 1,024**	**$ 212**	**$ 810**	**$ 2**

(A) Not reflected as expense in Consolidated Statements of Operations

During 2017, PSE&G recorded a reduction to its ARO liabilities primarily due to the impact of settlements and changes to cash flow estimates. These changes had no impact in PSE&G's Consolidated Statement of Operations.

During 2017, Power recorded an increase to its ARO liabilities primarily due to a higher assumed probability of early retirement of its nuclear units of $276 million (See Note 3. Early Plant Retirements for additional information).

Note 12. Pension, Other Postretirement Benefits (OPEB) and Savings Plans

PSEG sponsors qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. Eligible employees participate in non-contributory pension and OPEB plans sponsored by PSEG and administered by Services. In addition, represented and nonrepresented employees are eligible for participation in PSEG's two defined contribution plans described below.

PSEG, PSE&G and Power are required to record the under or over funded positions of their defined benefit pension and OPEB plans on their respective balance sheets. Such funding positions of each PSEG company are required to be measured as of the date of its respective year-end Consolidated Balance Sheets. For underfunded plans, the liability is equal to the difference between the plan's benefit obligation and the fair value of plan assets. For defined benefit pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. In addition, GAAP requires that the total unrecognized costs for defined benefit pension and OPEB plans be recorded as an after-tax charge to Accumulated Other Comprehensive Income (Loss), a separate component of Stockholders' Equity. However, for PSE&G, because the amortization of the unrecognized costs is being collected from customers, the accumulated unrecognized costs are recorded as a Regulatory Asset. The unrecognized costs represent actuarial gains or losses and prior service costs which had not been expensed.

For PSE&G, the Regulatory Asset is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations. For Power, the charge to Accumulated Other Comprehensive Income (Loss) is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations.

As of December 31, 2016, PSEG merged its three qualified defined benefit pension plans (excluding Servco plans) into one plan, thereby also merging all of the pension plans' assets. As a result, the total net periodic benefit costs, net of amounts capitalized, decreased by approximately $48 million for the year ended December 31, 2017, as compared to the 2017 amounts that would have been recognized had the plans not been merged. This is due to the amortization period for gains and losses for the merged plan resulting in lower amortization than that of the individual plans. No changes were made to the benefit formulas, vesting provisions, or to the employees covered by the plans.

Amounts for Servco are not included in any of the following pension and OPEB benefit information for PSEG and its affiliates but rather are separately disclosed later in this note.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides a roll-forward of the changes in the benefit obligation and the fair value of plan assets during each of the two years in the periods ended December 31, 2017 and 2016. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

	Pension Benefits		Other Benefits	
	2017	2016	2017	2016
	Millions			
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year (A)	$ 5,772	$ 5,522	$ 1,754	$ 1,612
Service Cost	114	109	17	17
Interest Cost	204	202	63	59
Actuarial (Gain) Loss	564	219	199	127
Gross Benefits Paid	(295)	(282)	(57)	(57)
Plan Amendments	—	2	—	(4)
Benefit Obligation at End of Year (A)	**$ 6,359**	**$ 5,772**	**$ 1,976**	**$ 1,754**
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$ 5,193	$ 5,039	$ 420	$ 374
Actual Return on Plan Assets	903	403	77	32
Employer Contributions	11	33	71	71
Gross Benefits Paid	(295)	(282)	(57)	(57)
Fair Value of Assets at End of Year	**$ 5,812**	**$ 5,193**	**$ 511**	**$ 420**
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	**$ (547)**	**$ (579)**	**$ (1,465)**	**$ (1,334)**
Additional Amounts Recognized in the Consolidated Balance Sheets				
Current Accrued Benefit Cost	(10)	(11)	(10)	(10)
Noncurrent Accrued Benefit Cost	(537)	(568)	(1,455)	(1,324)
Amounts Recognized	**$ (547)**	**$ (579)**	**$ (1,465)**	**$ (1,334)**
Additional Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulated Assets and Deferred Assets (B)				
Prior Service Cost	$ (46)	$ (63)	$ (3)	$ (14)
Net Actuarial Loss	1,721	1,763	629	523
Total	**$ 1,675**	**$ 1,700**	**$ 626**	**$ 509**

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits. The vested benefit obligation is the actuarial present value of the vested benefits to which the employee is currently entitled but based on the employee's expected date of separation of retirement.

(B) Includes $683 million ($406 million, after-tax) and $679 million ($398 million, after-tax) in Accumulated Other Comprehensive Loss related to Pension and OPEB as of December 31, 2017 and 2016, respectively. Also includes Regulatory Assets of $1,485 million and Deferred Assets of $133 million as of December 31, 2017 and Regulatory Assets of $1,396 million and Deferred Assets of $134 million as of December 31, 2016.

The pension benefits table above provides information relating to the funded status of the qualified, nonqualified pension and OPEB plans on an aggregate basis. As of December 31, 2017, PSEG had funded approximately 91% of its projected benefit obligation. This percentage does not include $231 million of assets in the Rabbi Trust as of December 31, 2017 which were used partially to fund the nonqualified pension plans. As of December 31, 2017, the nonqualified pension plans included in the projected benefit obligation in the above table were $167 million. The fair values of the Rabbi Trust assets are included in Other Special Funds on the Consolidated Balance Sheets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Accumulated Benefit Obligation

The accumulated benefit obligation for all PSEG's defined benefit pension plans was $6.1 billion as of December 31, 2017 and $5.6 billion as of December 31, 2016.

The following table provides the components of net periodic benefit cost for the years ended December 31, 2017, 2016 and 2015.

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2017	2016	2015	2017	2016	2015
	Millions					
Components of Net Periodic Benefit Cost						
Service Cost	$ 114	$ 109	$ 123	$ 17	$ 17	22
Interest Cost	204	202	234	63	59	67
Expected Return on Plan Assets	(394)	(394)	(414)	(34)	(31)	(31)
Amortization of Net						
Prior Service Credit	(18)	(19)	(19)	(11)	(14)	(14)
Actuarial Loss	97	158	150	51	40	43
Net Periodic Benefit Cost	**$ 3**	**$ 56**	**$ 74**	**$ 86**	**$ 71**	**$ 87**

Pension costs and OPEB costs for PSEG, PSE&G and Power are detailed as follows:

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2017	2016	2015	2017	2016	2015
	Millions					
PSE&G	$ (4)	$ 29	$ 40	$ 54	$ 43	$ 55
Power	1	16	21	27	23	27
Other	6	11	13	5	5	5
Total Benefit Cost	**$ 3**	**$ 56**	**$ 74**	**$ 86**	**$ 71**	**$ 87**

The following table provides the pre-tax changes recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Deferred Assets:

	Pension		OPEB	
	2017	2016	2017	2016
	Millions			
Net Actuarial (Gain) Loss in Current Period	$ 55	$ 211	$ 156	$ 125
Amortization of Net Actuarial Gain (Loss)	(97)	(158)	(50)	(40)
Prior Service Cost (Credit) in current period	—	1	—	(3)
Amortization of Prior Service Credit	18	19	11	14
Total	**$ (24)**	**$ 73**	**$ 117**	**$ 96**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Amounts that are expected to be amortized from Accumulated Other Comprehensive Loss, Regulatory Assets and Deferred Assets into Net Periodic Benefit Cost in 2018 are as follows:

	Pension Benefits 2018	Other Benefits 2018
	Millions	
Actuarial Loss	$ 85	$ 64
Prior Service Credit	$ (18)	$ (1)

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

	Pension Benefits			Other Benefits		
	2017	2016	2015	2017	2016	2015
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	3.73%	4.29%	4.54%	3.76%	4.37%	4.58%
Rate of Compensation Increase	3.90%	3.61%	3.61%	3.90%	3.61%	3.61%
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount Rate	4.29%	4.54%	4.20%	4.37%	4.58%	4.21%
Service Cost Interest Rate	4.53%	4.81%	4.20%	4.64%	4.87%	4.21%
Interest Cost Interest Rate	3.63%	3.75%	4.20%	3.69%	3.76%	4.21%
Expected Return on Plan Assets	7.80%	8.00%	8.00%	7.80%	8.00%	8.00%
Rate of Compensation Increase	3.61%	3.61%	3.61%	3.61%	3.61%	3.61%
Assumed Health Care Cost Trend Rates as of December 31						
Health Care Costs						
Immediate Rate				7.93%	7.55%	7.75%
Ultimate Rate				4.75%	4.75%	4.75%
Year Ultimate Rate Reached				2026	2025	2025
					Millions	
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$ 13	$ 11	$ 12
Postretirement Benefit Obligation				$ 240	$ 191	$ 194
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$ (10)	$ (9)	$ (10)
Postretirement Benefit Obligation				$ (198)	$ (160)	$ (160)

Plan Assets

The investments of pension and OPEB plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension and OPEB plans are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 17. Fair Value Measurements for more information on fair value guidance. Use of the Master Trust permits the commingling of pension plan assets and OPEB plan assets for investment and administrative purposes. Although assets of the plans are commingled in the Master Trust, the Trustee maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Trustee to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans. As of December 31, 2017, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 92% and 8%, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tables present information about the investments measured at fair value on a recurring basis as of December 31, 2017 and 2016, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2017			
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Cash Equivalents (A)	$ 133	$ 117	$ 16	$ —
Equity Securities				
Common Stock (B)	1,275	1,275	—	—
Commingled (C)	1,401	1,218	183	—
Preferred Stock (B)	6	6	—	—
Debt Securities (D)				
U.S. Treasury	571	—	571	—
Government—Other	272	—	272	—
Corporate	963	—	963	—
Subtotal Fair Value	**$ 4,621**	**$ 2,616**	**$ 2,005**	**$ —**
Measured at net asset value practical expedient				
Commingled—Equities (E)	1,675			
Private Equity (F)	14			
Total Fair Value (G)	**$ 6,310**			

	Recurring Fair Value Measurements as of December 31, 2016			
Description	**Total**	**Quoted Market Prices for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
		Millions		
Cash Equivalents (A)	$ 107	$ 105	$ 2	$ —
Equity Securities				
Common Stock (B)	944	944	—	—
Commingled (C)	1,387	1,247	140	—
Preferred Stock (B)	1	1	—	—
Debt Securities (D)				
U.S. Treasury	441	—	441	—
Government—Other	263	—	263	—
Corporate	836	—	836	—
Subtotal Fair Value	**$ 3,979**	**$ 2,297**	**$ 1,682**	**$ —**
Measured at net asset value practical expedient				
Commingled—Equities (E)	1,604			
Private Equity (F)	16			
Total Fair Value (G)	**$ 5,599**			

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(A) The Collective Investment Fund publishes a daily net asset value (NAV) which participants may use for daily redemptions without restrictions (Level 1). Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

(B) Common stocks and preferred stocks are measured using observable data in active markets and considered Level 1.

(C) Commingled Funds that allow daily redemption at their daily published NAV without restrictions are classified as Level 1. Commingled Funds that publish daily NAV but with certain near term redemption restrictions which prevent redemption at the published daily NAV are classified as Level 2.

(D) Debt securities include mainly investment grade corporate and municipal bonds, US Treasury obligations and Federal Agency asset-backed securities with a wide range of maturities. These investments are valued using an evaluated pricing approach that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads or the most recent quoted for similar securities which are a Level 2 measure.

(E) In 2016, as part of the implementation of the accounting guidance on investments measured at fair value using NAV as a practical expedient, certain commingled equity funds have been removed from the fair value hierarchy as they are measured at fair value using the NAV per share (or its equivalent) practical expedient. These funds do not meet the definition of readily determinable fair value due to limitations in published NAV (last business day of the month) and include certain redemption restrictions ranging from five to fifteen days advance notice prior to redemption days and limitations on withdrawals over 25% of the total fund. The objectives of these funds are mainly tracking the S&P Index or achieving long-term growth through investment in foreign equity securities and the MSCI Emerging Markets Index.

(F) Private equity investments primarily include various limited partnerships that invest in either operating companies through acquisitions or developing a portfolio of non-US distressed investments to maximize total return on capital. These investments are valued at NAV (or its equivalent) on an annual basis and have significant redemption restrictions preventing redemption until fund liquidation and limited ability to sell these investments. Fund liquidation is not expected to occur for several more years. These investments have been removed from the fair value hierarchy in accordance with the guidance on NAV practical expedient.

(G) Excludes net receivable of $13 million and $14 million at December 31, 2017 and 2016, respectively, which consists of interest, dividends and receivables and payables related to pending securities sales and purchases.

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans as of the measurement date, December 31:

	As of December 31,	
Investments	**2017**	**2016**
Equity Securities	69%	70%
Debt Securities	29	28
Other Investments	2	2
Total Percentage	**100%**	**100%**

PSEG utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. PSEG's latest asset/liability study indicates that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. Derivative financial instruments are used by the plans' investment managers primarily to adjust the fixed income duration of the portfolio and hedge the currency risk component of foreign investments. The expected long-term rate of return on plan assets was 7.8% for 2017 and will be 7.8% for 2018. This expected return was determined based on the study discussed above, including a premium for active management and considered the plans' historical annualized rate of return since inception.

Plan Contributions

PSEG has no planned contributions to its pension plans in 2018. PSEG plans to make discretionary contributions of $14 million into its OPEB plan during 2018.

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Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to plan participants.

Year	Pension Benefits	Other Benefits
	Millions	
2018	$ 337	$ 88
2019	331	92
2020	341	96
2021	352	101
2022	364	105
2023-2027	1,954	560
Total	**$ 3,679**	**$ 1,042**

401(k) Plans

PSEG sponsors two 401(k) plans, which are Employee Retirement Income Security Act (ERISA) defined contribution retirement plans. Eligible represented employees of PSEG's subsidiaries participate in the PSEG Employee Savings Plan (Savings Plan), while eligible non-represented employees of PSEG's subsidiaries participate in the PSEG Thrift and Tax-Deferred Savings Plan (Thrift Plan). Eligible employees may contribute up to 50% of their compensation to these plans, not to exceed the IRS maximums, including any catch-up contributions for those employees age 50 and above. PSEG matches 50% of such employee contributions up to 7% of pay for Savings Plan participants and up to 8% of pay for Thrift Plan participants.

The amount paid for employer matching contributions to the plans for PSEG, PSE&G and Power are detailed as follows:

	Thrift Plan and Savings Plan Years Ended December 31,		
	2017	2016	2015
	Millions		
PSE&G	$ 25	$ 24	$ 22
Power	11	12	12
Other	5	5	5
Total Employer Matching Contributions	**$ 41**	**$ 41**	**$ 39**

Servco Pension and OPEB

At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 4. Variable Interest Entity. These obligations, as well as the offsetting long-term receivable, are separately presented on the Consolidated Balance Sheet of PSEG.

The following table provides a roll-forward of the changes in Servco's benefit obligation and the fair value of its plan assets during the years ended December 31, 2017 and 2016. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Pension Benefits		Other Benefits	
	2017	2016	2017	2016
			Millions	
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year	$ 262	$ 211	$ 452	$ 375
Service Cost	27	24	15	12
Interest Cost	11	9	19	17
Actuarial (Gain) Loss	22	14	60	50
Gross Benefits Paid	(2)	(1)	(4)	(2)
Plan Amendments	—	5	—	—
Benefit Obligation at End of Year (A)	**$ 320**	**$ 262**	**$ 542**	**$ 452**
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$ 134	$ 97	$ —	$ —
Actual Return on Plan Assets	24	10	—	—
Employer Contributions	35	28	4	2
Gross Benefits Paid	(2)	(1)	(4)	(2)
Fair Value of Assets at End of Year	**$ 191**	**$ 134**	**$ —**	**$ —**
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	**$ (129)**	**$ (128)**	**$ (542)**	**$ (452)**
Additional Amounts Recognized in the Consolidated Balance Sheets				
Accrued Pension Costs of Servco	$ (129)	$ (128)	N/A	N/A
OPEB Costs of Servco	N/A	N/A	(542)	(452)
Amounts Recognized (B)	**$ (129)**	**$ (128)**	**$ (542)**	**$ (452)**

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits. The vested benefit obligation is the actuarial present value of the vested benefits to which the employee is currently entitled but based on the employee's expected date of separation of retirement.

(B) Amounts equal to the accrued pension and OPEB costs of Servco are offset in Long-Term Receivable of VIE on PSEG's Consolidated Balance Sheets.

Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. The pension-related revenues and costs for 2017, 2016 and 2015 were $35 million, $28 million and $30 million, respectively. Servco has contributed its entire planned contribution amount to its pension plan trusts during 2017. The OPEB-related revenues earned and costs incurred were $4 million and $2 million in 2017 and 2016, respectively, and immaterial for 2015.

The following assumptions were used to determine the benefit obligations of Servco:

	Pension Benefits			Other Benefits		
	2017	2016	2015	2017	2016	2015
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	3.90%	4.61%	4.92%	3.96%	4.71%	4.97%
Rate of Compensation Increase	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
Assumed Health Care Cost Trend Rates as of December 31						
Health Care Costs						
Immediate Rate				7.69%	7.55%	7.55%
Ultimate Rate				4.75%	4.75%	4.75%
Year Ultimate Rate Reached				2026	2025	2025
					Millions	
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs						
Postretirement Benefit Obligation				$ 131	$ 97	$ 75
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs						
Postretirement Benefit Obligation				$ (99)	$ (75)	$ (60)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Plan Assets

All the investments of Servco's pension plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 17. Fair Value Measurements for more information on fair value guidance. The Actuary maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Actuary to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans.

The following tables present information about Servco's investments measured at fair value on a recurring basis as of December 31, 2017 and 2016, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2017			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		Millions		
Commingled Equities (A)	$ 137	$ —	$ 137	$ —
Commingled Bonds (A)	54	—	54	—
Total	**$ 191**	**$ —**	**$ 191**	**$ —**

	Recurring Fair Value Measurements as of December 31, 2016			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		Millions		
Commingled Equities (A)	$ 96	$ —	$ 96	$ —
Commingled Bonds (A)	38	—	38	—
Total	**$ 134**	**$ —**	**$ 134**	**$ —**

(A) Investments in commingled equity and bond funds have a readily determinable fair value as they publish a daily NAV available to investors which is the basis for current transactions and contain certain redemption restrictions requiring advance notice of one to two days for withdrawals (Level 2).

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans of Servco as of the measurement date, December 31:

	As of December 31,	
Investments	2017	2016
Equity Securities	72%	71%
Debt Securities	28	29
Total Percentage	**100%**	**100%**

Servco utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. The results from Servco's latest asset/liability study indicated that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. The expected long-term rate of return on plan assets was 7.6% for 2017 and will be 7.6% for 2018. This expected return was determined based on the study discussed above, including a premium for active management.

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Plan Contributions

Servco plans to contribute $40 million into its pension plan during 2018.

Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to Servco's plan participants:

Year	Pension Benefits	Other Benefits
	Millions	
2018	$ 3	$ 4
2019	4	6
2020	5	8
2021	7	9
2022	9	12
2023-2027	78	87
Total	**$ 106**	**$ 126**

Servco 401(k) Plans

Servco sponsors two 401(k) plans, which are defined contribution retirement plans subject to ERISA. Eligible non-represented employees of Servco participate in the Long Island Electric Utility Servco LLC Incentive Thrift Plan I (Thrift Plan I), and eligible represented employees of Servco participate in the Long Island Electric Utility Servco LLC Incentive Thrift Plan II (Thrift Plan II). Participants in the Plans may contribute up to 50% of their eligible compensation to these plans, not to exceed the IRS maximums, including any Catch-Up Contributions for those employees age 50 and above. Servco does not provide an employer match or core contribution for employees in Thrift Plan II. For employees in Thrift Plan I, Servco matches 50% of such employee contributions up to 8% of eligible compensation and provides core contributions (based on years of service and age) to employees who do not participate in Servco's Retirement Income Plan. The amounts expensed by Servco for employer matching contributions for the years ended December 31, 2017, 2016 and 2015 were $6 million, $5 million and $4 million, respectively, and pursuant to the OSA, Servco recognizes Operating Revenues for the reimbursement of these costs.

Note 13. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees as a form of collateral.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- the net position of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

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Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. Current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of December 31, 2017 and 2016.

	As of December 31, 2017	As of December 31, 2016
	Millions	
Face Value of Outstanding Guarantees	$ 1,701	$ 1,806
Exposure under Current Guarantees	$ 153	$ 139
Letters of Credit Margin Posted	$ 103	$ 157
Letters of Credit Margin Received	$ 32	$ 99
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (1)	$ (1)
Net Broker Balance Deposited (Received)	$ 147	$ 57
Additional Amounts Posted		
Other Letters of Credit	$ 61	$ 51

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 16. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. In June 2017, Power sold its minority interest in PennEast and upon disposition, PSEG's $106 million guarantee that had supported Power's payment obligations related to PennEast was terminated.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The U.S. Environmental Protection Agency (EPA) has determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA and a comprehensive study of the entire 17 miles of the lower Passaic River needed to be performed. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In early 2007, certain Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. The CPG has agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately 7.6 percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately 1.9 percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim. Certain PRPs are currently involved in discussions with the EPA regarding cost allocations and related indemnification matters. We cannot predict the outcome of these discussions, or whether individual PRPs will be able to meet their obligations, either of which could have a material impact on PSE&G's and Power's allocation of costs.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River with an estimated cost to remediate the lower 17 miles of the Passaic River ranging from approximately $518 million to $3.2 billion on an undiscounted basis.

In March 2016, the EPA released its Record of Decision (ROD) for the EPA's own Focused Feasibility Study (FFS) which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The EPA estimates the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation. Occidental Chemical Corporation, one of the PRPs, has committed to perform the remedial design required by the ROD Remedy, reserving its right of cost contribution from all other PRPs.

In September 2017, the EPA concluded that an Agency-commenced allocation process for the Passaic River's lower 8.3 miles should include only certain PRPs. The allocation is intended to lead to a consent decree in which certain of the PRPs agree to perform the remedial action under EPA oversight. Discussions on the matter are ongoing. Conversations between the EPA and the PRPs regarding remediation of the Passaic River's upper 9 miles are ongoing.

Based upon (i) the estimated cost of the ROD Remedy, (ii) PSEG's estimate of PSE&G's and Power's shares of that cost, and (iii) the continued ability of PSE&G to recover such costs in its rates, as of December 31, 2017, PSEG has accrued approximately $57 million. Of this amount $46 million has been accrued by PSE&G as an Environmental Costs Liability and a corresponding Regulatory Asset and $11 million has been accrued by Power as an Other Noncurrent Liability with the corresponding O&M Expense recorded in the periods when the liability was accrued.

The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on PSEG's financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating

S1-SSA-0009 - 12035

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stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $358 million and $403 million on an undiscounted basis through 2021, including its $46 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $358 million as of December 31, 2017. Of this amount, $79 million was recorded in Other Current Liabilities and $279 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $358 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly. NJDEP, PSEG and EPA representatives have had discussions regarding to what extent sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.

Clean Water Act (CWA) Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In May 2014, the EPA issued a final cooling water intake rule that establishes requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing power facilities on a case by case basis, based on studies related to impingement mortality and entrainment and submit the results with their permit applications to be conducted by the facilities seeking renewal permits.

Several environmental organizations and certain energy industry groups have filed suit under the Clean Water Act and the Endangered Species Act. The cases have been consolidated at the Second Circuit and a decision remains pending.

In June 2016, the NJDEP issued a final NJPDES permit for Salem. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the CWA, it requires additional studies and the selection of technology to address impingement for the service water system. The final permit does not mandate specific service water system modifications but, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final NJPDES renewal permit for Salem. NJDEP has granted the hearing request, but it has not yet been scheduled. The Riverkeeper's filing does not change the effective date of the permit. If the Riverkeeper's challenge were successful, Power may be required to incur additional costs to comply with the CWA. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

State permitting decisions at Bridgeport and possibly New Haven could also have a material impact on Power's ability to renew permits at its existing larger once-through cooled plants without making significant upgrades to existing intakes and cooling systems.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA's CWA Section 316(b) final rule, Power has proposed to continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the previously estimated useful life ending in 2025. Power is currently awaiting action by the CTDEEP to issue a draft and then a final permit.

Power has negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut and local community organizations. That CEBA provides that Power would retire BH3 early if all of its conditions precedent occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same

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site that BH3 currently operates. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power may seek to operate BH3 through the previously estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. The Connecticut Siting Council (CSC) issued an order to approve siting Bridgeport Harbor Station unit 5 (BH5). All major environmental permits have been received; however, secondary approvals are still being obtained to allow operations to begin in mid-2019. Power's obligations under the CEBA are being monitored regularly and carried out as needed.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.

Jersey City, New Jersey Subsurface Feeder Cable Matter

In early October 2016, a discharge of dielectric fluid from subsurface feeder cables located in the Hudson River near Jersey City, New Jersey, was identified and reported to the NJDEP. The feeder cables are located within a subsurface easement granted to PSE&G by the property owners, Newport Associates Development Company (NADC) and Newport Associates Phase I Developer Limited Partnership. The feeder cables are subject to agreements between PSE&G and Consolidated Edison Company of New York, Inc. (Con Edison) and are jointly owned by PSE&G and Con Edison, with PSE&G owning the portion of the cables located in New Jersey and Con Edison owning the portion of the cables located in New York. The NJDEP has declared an emergency and an emergency response action has been undertaken to investigate, contain, remediate and stop the fluid discharge; to assess, repair and restore the cables to good working order, if feasible; and to restore the property. The regulatory agencies overseeing the emergency response, including the U.S. Coast Guard, the NJDEP and the Army Corps of Engineers, have issued multiple notices, orders and directives to the various parties related to this matter. The impacted cable was repaired in late-September 2017; however, dielectric fluid continues to appear on the surface and so the investigation and response actions related to the fluid discharge are ongoing. PSE&G may determine that retirement of the affected facilities would be appropriate. Also ongoing is the process to determine ultimate responsibility for the costs to address the leak among PSE&G, Con Edison and NADC, including an action filed by PSE&G in New Jersey federal court seeking damages from NADC. In that action, NADC has also pursued counterclaims against PSE&G and Con Edison seeking damages for its costs to address the leak. In addition, NADC provided notice to the New Jersey Secretary of Transportation of several alleged violations by Con Edison and PSE&G of regulations prescribed under the Hazardous Liquids Pipeline Safety Act (HLPSA), a requirement to preserve NADC's right to pursue injunctive relief under the HLPSA. Based on the information currently available and depending on the outcome of the New Jersey federal action, PSE&G's portion of the costs to address the leak may be material; however, PSE&G anticipates that it will recover these costs through regulatory proceedings.

Steam Electric Effluent Guidelines

In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG Rule) for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under the ELG Rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the ELG Rule.

Through various orders, the EPA has stayed the compliance dates in the ELG Rule and has announced plans to further revise the requirements and compliance dates of the ELG Rule. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third-party suppliers. The first category, which represents about 80% of PSE&G's load requirement, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2018 is $287.76 per MW-

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day, replacing the BGS-CIEP auction year price ending May 31, 2018 of $276.83 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2015	2016	2017	2018	
36-Month Terms Ending	May 2018	May 2019	May 2020	May 2021	(A)
Load (MW)	2,900	2,800	2,800	2,900	
$ per MWh	$99.54	$96.38	$90.78	$91.77	

(A) Prices set in the 2018 BGS auction will become effective on June 1, 2018 when the 2015 BGS auction agreements expire.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 24. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2020 and a significant portion through 2022 at Salem, Hope Creek and Peach Bottom.

Power has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available beyond the needs of PSE&G's customers, Power can use the gas to supply its fossil generating stations.

Power also has various long-term fuel purchase commitments for coal through 2021 to support its fossil generation stations.

As of December 31, 2017, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2022
	Millions
Nuclear Fuel	
Uranium	$ 240
Enrichment	$ 391
Fabrication	$ 170
Natural Gas	$ 1,042
Coal	$ 293

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Regulatory Proceedings

FERC Compliance

PJM Bidding Matter

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power has implemented procedures and continues to review its policies and practices to mitigate the risk of similar issues occurring in the future. During the three month period ended March 31, 2014, based upon its best estimate available at the time, Power recorded a pre-tax charge to income in the amount of $25 million related to this matter.

Since September 2014, FERC Staff has been conducting a preliminary, non-public staff investigation into these matters. While considerable uncertainty remains as to the final resolution of these matters, based upon developments in the investigation in the first quarter of 2017, Power believes the disgorgement and interest costs related to the cost-based bidding matter may range between approximately $35 million and $135 million, depending on the legal interpretation of the principles under the PJM Tariff, plus penalties. Since no point within this range is more likely than any other, Power has accrued the low end of this range of $35 million by recording an additional pre-tax charge to income of $10 million during the three months ended March 31, 2017. Power is unable to reasonably estimate the range of possible loss, if any, for the quantity of energy offered matter or the penalties that FERC would impose relating to either the cost-based bidding or quantity of energy matter. However, any of these amounts could be individually material to PSEG and Power.

Power continues to believe that it has legal defenses that it may assert in a judicial challenge, including the legal defense that its cost-based bidding in a substantial majority of the hours was below the allowed rate under the Tariff and therefore any errors in those hours did not violate the Tariff or were immaterial. Furthermore, it is unclear whether the quantity of energy offered violated any legal requirement. As a result, PSEG and Power cannot predict the final outcome of these matters.

Other Litigation and Legal Proceedings

PSEG and its subsidiaries are party to various lawsuits in the ordinary course of business. In view of the inherent difficulty in predicting the outcome of such matters, PSEG, PSE&G and Power generally cannot predict the eventual outcome of the pending matters, the timing of the ultimate resolution of these matters, or the eventual loss, fines or penalties related to each pending matter.

In accordance with applicable accounting guidance, a liability is accrued when those matters present loss contingencies that are both probable and reasonably estimable. In such cases, there may be an exposure to loss in excess of any amounts accrued. PSEG will continue to monitor the matter for further developments that could affect the amount of the accrued liability that has been previously established.

Based on current knowledge, management does not believe that loss contingencies arising from pending matters, other than the matters described herein, could have a material adverse effect on PSEG's, PSE&G's or Power's consolidated financial position or liquidity. However, in light of the inherent uncertainties involved in these matters, some of which are beyond PSEG's control, and the large or indeterminate damages sought in some of these matters, an adverse outcome in one or more of these matters could be material to PSEG's, PSE&G's or Power's results of operations or liquidity for any particular reporting period.

Nuclear Insurance Coverages and Assessments

Power is a member of the joint underwriting association, American Nuclear Insurers (ANI), which provides nuclear liability insurance coverage at the Salem and Hope Creek site and the Peach Bottom site. The ANI policies are designed to satisfy the financial protection requirements outlined in the Price-Anderson Act, which sets the limit of liability for claims that could arise from an incident involving any licensed nuclear facility in the United States. The limit of liability per incident per site is composed of primary and excess layers. As of December 31, 2017, nuclear sites were required to purchase $450 million of primary liability coverage for each site (through ANI). The primary layer is supplemented by an excess layer, which is an industry self-insurance pool. In the event a nuclear site, which is part of the industry self-insurance pool, has a claim that exceeds the primary layer, each licensee would be assessed a prorated share of the excess layer. The excess layer limit is $13.4 billion. Power's maximum aggregate assessment per incident is $401 million (based on Power's ownership interests in Salem, Hope Creek and Peach Bottom) and its maximum aggregate annual assessment per incident is $60 million. If the damages exceed the limit of liability, Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Further, a decision by the U.S. Supreme Court, not involving Power, held that the Price-Anderson Act did not preclude punitive damage awards based on state law claims.

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Power is also a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides the property, decontamination and decommissioning liability insurance at the Salem and Hope Creek site and the Peach Bottom site. NEIL also provides replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in the case of adverse loss experience. The current maximum aggregate annual retrospective premium obligation for Power is approximately $76 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance. Certain provisions in the NEIL policies provide that the insurer may suspend coverage with respect to all nuclear units on a site without notice if the NRC suspends or revokes the operating license for any unit on that site, issues a shutdown order with respect to such unit or issues a confirmatory order keeping such unit down.

The ANI and NEIL policies all include coverage for claims arising out of acts of terrorism. However, NEIL policies are subject to an industry aggregate limit of $3.2 billion plus such additional amounts as NEIL recovers for such losses from reinsurance, indemnity and any other source applicable to such losses.

Minimum Lease Payments

The total future minimum payments under various operating leases as of December 31, 2017 are:

	PSE&G	Power	Services	Other	Total
			Millions		
2018	$ 16	$ 5	$ 14	$ 1	$ 36
2019	9	6	15	1	31
2020	8	3	15	1	27
2021	8	3	15	1	27
2022	7	3	15	1	26
Thereafter	65	38	120	1	224
Total Minimum Lease Payments	**$ 113**	**$ 58**	**$ 194**	**$ 6**	**$ 371**

Note 14. Debt and Credit Facilities

Long-Term Debt

	Maturity	As of December 31, 2017	2016
		Millions	
PSEG			
Term Loan:			
Variable	2017	$ —	$ 500
Variable	2019	700	—
Total Term Loan		700	500
Senior Notes:			
1.60%	2019	400	400
2.00%	2021	300	300
2.65%	2022	700	—
Total Senior Notes		1,400	700
Principal Amount Outstanding		2,100	1,200
Amounts Due Within One Year		—	(500)
Net Unamortized Discount and Debt Issuance Costs		(9)	(5)
Total Long-Term Debt of PSEG		**$ 2,091**	**$ 695**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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	Maturity	As of December 31, 2017	2016
		Millions	
PSE&G			
First and Refunding Mortgage Bonds (A):			
9.25%	2021	$ 134	$ 134
8.00%	2037	7	7
5.00%	2037	8	8
Total First and Refunding Mortgage Bonds		149	149
Medium-Term Notes (MTNs) (A):			
5.30%	2018	400	400
2.30%	2018	350	350
1.80%	2019	250	250
2.00%	2019	250	250
7.04%	2020	9	9
3.50%	2020	250	250
1.90%	2021	300	300
2.38%	2023	500	500
3.75%	2024	250	250
3.15%	2024	250	250
3.05%	2024	250	250
3.00%	2025	350	350
2.25%	2026	425	425
3.00%	2027	425	—
5.25%	2035	250	250
5.70%	2036	250	250
5.80%	2037	350	350
5.38%	2039	250	250
5.50%	2040	300	300
3.95%	2042	450	450
3.65%	2042	350	350
3.80%	2043	400	400
4.00%	2044	250	250
4.05%	2045	250	250
4.15%	2045	250	250
3.80%	2046	550	550
3.60%	2047	350	—
Total MTNs		8,509	7,734
Principal Amount Outstanding		8,658	7,883
Amounts Due Within One Year		(750)	—
Net Unamortized Discount and Debt Issuance Costs		(67)	(65)
Total Long-Term Debt of PSE&G		**$ 7,841**	**$ 7,818**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2017	2016
		Millions	
Power			
Senior Notes:			
2.45%	2018	$ 250	$ 250
5.13%	2020	406	406
4.15%	2021	250	250
3.00%	2021	700	700
4.30%	2023	250	250
8.63%	2031	500	500
Total Senior Notes		2,356	2,356
Pollution Control Notes:			
Floating Rate (B)	2019	44	44
Total Pollution Control Notes		44	44
Principal Amount Outstanding		2,400	2,400
Amounts Due Within One Year		(250)	—
Net Unamortized Discount and Debt Issuance Costs		(14)	(18)
Total Long-Term Debt of Power		**$ 2,136**	**$ 2,382**

(A) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.

(B) The Pennsylvania Economic Development Authority (PEDFA) bond that is serviced and secured by Power Pollution Control Notes, is a variable rate bond that is in weekly reset mode.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2017 are as follows:

Year	PSEG	PSE&G	Power	Total
2018	$ —	$ 750	$ 250	$ 1,000
2019	1,100	500	44	1,644
2020	—	259	406	665
2021	300	434	950	1,684
2022	700	—	—	700
Thereafter	—	6,715	750	7,465
Total	**$ 2,100**	**$ 8,658**	**$ 2,400**	**$ 13,158**

Long-Term Debt Financing Transactions

During 2017, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions:

PSEG

- entered into an agreement for a new term loan maturing June 2019. The term loan has a balance of $700 million at an interest rate of 1 month LIBOR + 0.80% and can be terminated at any time without penalty,
- issued $700 million of 2.65% Senior Notes due November 2022, and
- redeemed at maturity a $500 million term loan at an interest rate of 1 month LIBOR + 0.875% due November 2017.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G

- issued $425 million of 3.00% Secured Medium-Term Notes, Series L due May 2027, and
- issued $350 million of 3.60% Secured Medium-Term Notes, Series L due December 2047.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under the $4.2 billion credit facilities are provided by a diverse bank group. As of December 31, 2017, the total available credit capacity was $3.5 billion.

As of December 31, 2017, no single institution represented more than 8% of the total commitments in the credit facilities.

As of December 31, 2017, the total credit capacity was in excess of the anticipated maximum liquidity requirements over PSEG's 12-month planning horizon.

Each of the credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs.

The total credit facilities and available liquidity as of December 31, 2017 were as follows:

	As of December 31, 2017				
Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
		Millions			
PSEG					
5-year Credit Facilities (A)	$ 1,500	$ 556	$ 944	Mar 2022	Commercial Paper Support/Funding/Letters of Credit (LC)
Total PSEG	**$ 1,500**	**$ 556**	**$ 944**		
PSE&G					
5-year Credit Facility (A)	$ 600	$ 15	$ 585	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 15**	**$ 585**		
Power					
3-year LC Facilities	$ 200	$ 112	$ 88	Mar 2020	Letters of Credit
5-year Credit Facilities	1,900	39	1,861	Mar 2022	Funding/Letters of Credit
Total Power	**$ 2,100**	**$ 151**	**$ 1,949**		
Total	**$ 4,200**	**$ 722**	**$ 3,478**		

(A) The primary use of PSEG's and PSE&G's credit facilities is to support their respective Commercial Paper Programs under which as of December 31, 2017, PSEG had $542 million outstanding at a weighted average interest rate of 1.89%. PSE&G had no amounts outstanding under its Commercial Paper Program as of December 31, 2017.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fair Value of Debt

The estimated fair values, carrying amounts and methods used to determine fair value of long-term debt as of December 31, 2017 and 2016 are included in the following table and accompanying notes as of December 31, 2017 and 2016. See Note 17. Fair Value Measurements for more information on fair value guidance and the hierarchy that prioritizes the inputs to fair value measurements into three levels.

	December 31, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (A) (B)	$ 2,091	$ 2,081	$ 1,195	$ 1,185
PSE&G (B)	8,591	9,322	7,818	8,240
Power (B)	2,386	2,659	2,382	2,578
	$ 13,068	**$ 14,062**	**$ 11,395**	**$ 12,003**

(A) As of December 31, 2017 and 2016, fair value includes floating rate term loans of $700 million and $500 million, respectively. The fair values of the term loan debt (Level 2 measurement) approximate the carrying values because the interest payments are based on LIBOR rates that are reset monthly and the debt is redeemable at face value by PSEG at any time.

(B) Given that these bonds do not trade actively, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

Note 15. Schedule of Consolidated Capital Stock

	As of December 31,			
	Outstanding Shares		Book Value	
	2017	2016	2017	2016
	Millions			
PSEG Common Stock (no par value) (A)				
Authorized 1,000 shares	505	505	$ 4,198	$ 4,219

(A) PSEG did not issue any new shares under the Dividend Reinvestment and Stock Purchase Plan (DRASPP) or the Employee Stock Purchase Plan (ESPP) in 2017 or 2016.

As of December 31, 2017, PSE&G had an aggregate of 7.5 million shares of $100 par value and 10 million shares of $25 par value Cumulative Preferred Stock, which were authorized and unissued and which, upon issuance, may or may not provide for mandatory sinking fund redemption.

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Note 16. Financial Risk Management Activities

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include NPNS, cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow or fair value hedges. Power and PSE&G enter into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Power also uses derivatives to hedge a portion of its anticipated BGSS obligations with PSE&G. For additional information see Note 13. Commitments and Contingent Liabilities. Changes in the fair market value of these derivative contracts are recorded in earnings.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. The changes in fair value of the interest rate swaps are fully offset by changes in the fair value of the underlying forecasted interest payments of the debt. There were no outstanding interest rate swaps as of December 31, 2017 or 2016. The fair value hedges reduced interest expense by $6 million and $19 million for the years ended December 31, 2016 and 2015, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. There were no outstanding interest rate hedges as of December 31, 2017. As of December 31, 2016, PSEG had interest rate hedges outstanding totaling $500 million. These hedges converted PSEG's $500 million variable rate term loan due November 2017 into a fixed rate loan. As of December 31, 2016, the fair value of these hedges was $1 million and there was no ineffectiveness. The Accumulated Other Comprehensive Income (Loss) (after tax) related to existing and terminated interest rate derivatives designated as cash flow hedges was immaterial as of December 31, 2017 and $2 million as of December 31, 2016. The after-tax unrealized gains on these hedges expected to be reclassified to earnings during the next 12 months is immaterial.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with PSEG's accounting policy, these positions are offset on the Consolidated Balance Sheets of Power and PSEG. For additional information see Note 17. Fair Value Measurements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of December 31, 2017					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Cash Flow Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 391	$ (362)	$ 29	$ —	$ —	$ 29
Noncurrent Assets	78	(71)	7	—	—	7
Total Mark-to-Market Derivative Assets	**$ 469**	**$ (433)**	**$ 36**	**$ —**	**$ —**	**$ 36**
Derivative Contracts						
Current Liabilities	$ (403)	$ 387	$ (16)	$ —	$ —	$ (16)
Noncurrent Liabilities	(95)	90	(5)	—	—	(5)
Total Mark-to-Market Derivative (Liabilities)	**$ (498)**	**$ 477**	**$ (21)**	**$ —**	**$ —**	**$ (21)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ (29)**	**$ 44**	**$ 15**	**$ —**	**$ —**	**$ 15**

	As of December 31, 2016					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 435	$ (273)	$ 162	$ —	$ 1	$ 163
Noncurrent Assets	122	(98)	24	—	—	24
Total Mark-to-Market Derivative Assets	**$ 557**	**$ (371)**	**$ 186**	**$ —**	**$ 1**	**$ 187**
Derivative Contracts						
Current Liabilities	$ (285)	$ 277	$ (8)	$ (5)	$ —	$ (13)
Noncurrent Liabilities	(98)	95	(3)	—	—	(3)
Total Mark-to-Market Derivative (Liabilities)	**$ (383)**	**$ 372**	**$ (11)**	**$ (5)**	**$ —**	**$ (16)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 174**	**$ 1**	**$ 175**	**$ (5)**	**$ 1**	**$ 171**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of December 31, 2017 and 2016. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Consolidated Balance Sheets. As of December 31, 2017, and 2016, Power had net cash collateral/margin payments to counterparties of $146 million and $56 million,

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respectively. Of these net cash collateral/margin payments, $44 million as of December 31, 2017 and $1 million as of December 31, 2016 were netted against the corresponding net derivative contract positions. Of the $44 million as of December 31, 2017, $(3) million was netted against current assets, $28 million was netted against current liabilities and $19 million was netted against noncurrent liabilities. Of the $1 million as of December 31, 2016, $(3) million was netted against noncurrent assets and $4 million was netted against current liabilities.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating by S&P or Moody's, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P or Moody's ratings. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $30 million and $19 million as of December 31, 2017 and 2016, respectively. As of December 31, 2017 and 2016, Power had the contractual right of offset of $13 million and $9 million, respectively, related to derivative instruments that are assets with the same counterparty under master agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $17 million and $10 million as of December 31, 2017 and 2016, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.

The following shows the effect on the Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the years ended December 31, 2017, 2016 and 2015.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Years Ended December 31,			Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Years Ended December 31,		
	2017	2016	2015		2017	2016	2015
	Millions				Millions		
PSEG							
Energy-Related Contracts	$ —	$ —	$ 3	Operating Revenues	$ —	$ —	$ 20
Interest Rate Swaps	—	3	—	Interest Expense	3	—	—
Total PSEG	**$ —**	**$ 3**	**$ 3**		**$ 3**	**$ —**	**$ 20**
Power							
Energy-Related Contracts	$ —	$ —	$ 3	Operating Revenues	$ —	$ —	$ 20
Total Power	**$ —**	**$ —**	**$ 3**		**$ —**	**$ —**	**$ 20**

There were no pre-tax gain (loss) recognized in income on derivatives (ineffective portion) as of December 31, 2017, 2016 and 2015.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following reconciles the AOCI for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2015	**$ —**	**$ —**
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	—	—
Balance as of December 31, 2016	**$ 3**	**$ 2**
Gain Recognized in AOCI	—	—
Less: Gain Reclassified into Income	(3)	(2)
Balance as of December 31, 2017	**$ —**	**$ —**

The following shows the effect on the Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS for the years ended December 31, 2017, 2016 and 2015. Power's derivative contracts reflected in this table include contracts to hedge the purchase and sale of electricity and natural gas, and the purchase of fuel. The table does not include contracts which Power has designated as NPNS, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2017	2016	2015
		Millions		
PSEG and Power				
Energy-Related Contracts	Operating Revenues	$ 72	$ 230	$ 412
Energy-Related Contracts	Energy Costs	(17)	(8)	(8)
Total PSEG and Power		**$ 55**	**$ 222**	**$ 404**

The following table summarizes the net notional volume purchases/(sales) of open derivative transactions by commodity as of December 31, 2017 and 2016.

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of December 31, 2017					
Natural Gas	Dth	154	—	154	—
Electricity	MWh	(63)	—	(63)	—
Financial Transmission Rights (FTRs)	MWh	6	—	6	—
As of December 31, 2016					
Natural Gas	Dth	122	—	113	9
Electricity	MWh	(44)	—	(44)	—
FTRs	MWh	9	—	9	—
Interest Rate Swaps	U.S. Dollars	500	500	—	—

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Credit Risk

Credit risk relates to the risk of loss that Power would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG has established credit policies that it believes significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of December 31, 2017, 99% of the net credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives, NPNS and non-derivatives).

The following table provides information on Power's credit risk from others, net of collateral, as of December 31, 2017. It further delineates that exposure by the credit rating of the counterparties, which is determined by the lowest rating from S&P, Moody's or an internal scoring model. In addition, it provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade	$ 329	$ 25	$ 304	1	$ 204	(A)
Non-Investment Grade	3	1	2	—	—	
Total	**$ 332**	**$ 26**	**$ 306**	**1**	**$ 204**	

(A) Represents net exposure with PSE&G.

As of December 31, 2017, collateral held from counterparties where Power had credit exposure included $1 million in cash collateral and $25 million in letters of credit.

As of December 31, 2017, Power had 152 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2017, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's BGS suppliers' credit exposure is calculated each business day. As of December 31, 2017, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 17. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds, as well as natural gas futures contracts executed on NYMEX.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of December 31, 2017, these consisted primarily of certain electric load contracts and gas contracts.

Certain derivative transactions may transfer from Level 2 to Level 3 if inputs become unobservable and internal modeling techniques are employed to determine fair value. Conversely, measurements may transfer from Level 3 to Level 2 if the inputs become observable.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of December 31, 2017 and December 31, 2016, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Description	Recurring Fair Value Measurements as of December 31, 2017				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 223	$ —	$ 223	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 36	$ (433)	$ 15	$ 442	$ 12
NDT Fund (D)					
Equity Securities	$ 1,055	$ —	$ 1,053	$ 2	$ —
Debt Securities—U.S. Treasury	$ 314	$ —	$ —	$ 314	$ —
Debt Securities—Govt Other	$ 270	$ —	$ —	$ 270	$ —
Debt Securities—Corporate	$ 402	$ —	$ —	$ 402	$ —
Other Securities	$ 92	$ —	$ 92	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 25	$ —	$ 25	$ —	$ —
Debt Securities—U.S. Treasury	$ 51	$ —	$ —	$ 51	$ —
Debt Securities—Govt Other	$ 34	$ —	$ —	$ 34	$ —
Debt Securities—Corporate	$ 119	$ —	$ —	$ 119	$ —
Other Securities	$ 2	$ —	$ 2	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (21)	$ 477	$ (8)	$ (485)	$ (5)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 223	$ —	$ 223	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$ 10	$ —	$ —	$ 10	$ —
Debt Securities—Govt Other	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Corporate	$ 24	$ —	$ —	$ 24	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 36	$ (433)	$ 15	$ 442	$ 12
NDT Fund (D)					
Equity Securities	$ 1,055	$ —	$ 1,053	$ 2	$ —
Debt Securities—U.S. Treasury	$ 314	$ —	$ —	$ 314	$ —
Debt Securities—Govt Other	$ 270	$ —	$ —	$ 270	$ —
Debt Securities—Corporate	$ 402	$ —	$ —	$ 402	$ —
Other Securities	$ 92	$ —	$ 92	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—U.S. Treasury	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Govt Other	$ 8	$ —	$ —	$ 8	$ —
Debt Securities—Corporate	$ 30	$ —	$ —	$ 30	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (21)	$ 477	$ (8)	$ (485)	$ (5)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Description	Recurring Fair Value Measurements as of December 31, 2016			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 186	$ (371)	$ 17	$ 533	$ 7
Interest Rate Swaps (C)	$ 1	$ —	$ —	$ 1	$ —
NDT Fund (D)					
Equity Securities	$ 957	$ —	$ 954	$ 3	$ —
Debt Securities—U.S. Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 293	$ —	$ —	$ 293	$ —
Debt Securities—Corporate	$ 337	$ —	$ —	$ 337	$ —
Other Securities	$ 44	$ —	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—U.S. Treasury	$ 37	$ —	$ —	$ 37	$ —
Debt Securities—Govt Other	$ 66	$ —	$ —	$ 66	$ —
Debt Securities—Corporate	$ 91	$ —	$ —	$ 91	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (16)	$ 372	$ (18)	$ (364)	$ (6)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ —	$ —	$ —	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Govt Other	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Corporate	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (5)	$ —	$ —	$ —	$ (5)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 186	$ (371)	$ 17	$ 533	$ 7
NDT Fund (D)					
Equity Securities	$ 957	$ —	$ 954	$ 3	$ —
Debt Securities—U.S. Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 293	$ —	$ —	$ 293	$ —
Debt Securities—Corporate	$ 337	$ —	$ —	$ 337	$ —
Other Securities	$ 44	$ —	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$ 9	$ —	$ —	$ 9	$ —
Debt Securities—Govt Other	$ 16	$ —	$ —	$ 16	$ —
Debt Securities—Corporate	$ 23	$ —	$ —	$ 23	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —

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Liabilities:												
Derivative Contracts:												
Energy-Related Contracts (B)	$	(11)	$	372	$	(18)	$	(364)	$	(1)		

(A) Represents money market mutual funds.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(B) Level 1—During 2016 a net fair value of $1 million relating to energy-related contracts was transferred from Level 2 into Level 1. These contracts represent natural gas futures contracts executed on NYMEX, and are being valued solely on settled pricing inputs which come directly from the exchange.

Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using settled prices from similar assets and liabilities from an exchange, such as NYMEX, ICE and Nodal Exchange, or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—Unobservable inputs are used for the valuation of certain contracts. See "Additional Information Regarding Level 3 Measurements" below for more information on the utilization of unobservable inputs.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) As of December 31, 2016, the fair value measurement table excludes cash of $1 million, which is part of the NDT Fund. The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in a Russell 3000 index fund and various fixed income securities classified as "available for sale" as of December 31, 2017. The Rabbi Trust maintained investments in an S&P 500 index fund and various securities classified as "available for sale" as of December 31, 2016. These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Other Securities in the NDT and Rabbi Trust Funds consist primarily of investments in Dreyfus money market funds which seek a high level of current income as is consistent with the preservation of capital and the maintenance of liquidity. To pursue its goals, the fund normally invests in a diversified portfolio of high quality, short-term, dollar-denominated debt securities and government securities. The funds' Net Asset Value is priced and published daily. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities include investment grade corporate bonds, collateralized mortgage obligations, asset-backed securities and certain government and U.S. Treasury obligations or Federal Agency asset-backed securities and municipal bonds with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. The preferred stocks are not actively traded on a daily basis and therefore, are also priced using an evaluated pricing methodology. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Consolidated Balance Sheets. As of December 31, 2017 and 2016, Power had net cash collateral/margin payments to counterparties of $146 million and $56 million, respectively. Of these net cash collateral/margin payments $44 million as of December 31, 2017 and $1 million as of December 31, 2016 were netted against the corresponding net derivative contract positions. Of the $44 million of cash collateral as of December 31, 2017, $(3) million was netted against assets, and $47 million was netted against liabilities. Of the $1 million of cash collateral as of December 31, 2016, $(3) million was netted against assets and $4 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in

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Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee (RMC) approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The RMC reports to the Corporate Governance and Audit Committees of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G, the natural gas supply contract is measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The fair value of Power's gas physical contracts at certain illiquid delivery locations are measured using average historical basis and, accordingly, are categorized as Level 3. While these gas physical contracts have an unobservable component in their respective forward price curves, the fluctuations in fair value have been driven primarily by changes in the observable inputs. The following tables provide details surrounding significant Level 3 valuations as of December 31, 2017 and 2016.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2017		Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)			
		Millions				
Power						
Electricity	Electric Load Contracts	$ 1	$ (3)	Discounted Cash flow	Historic Load Variability	0% to +10%
Gas	Gas Physical Contracts	11	(2)	Discounted Cash flow	Average Historical Basis	-40% to -10%
Total Power		**$ 12**	**$ (5)**			
Total PSEG		**$ 12**	**$ (5)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2016		Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)			
		Millions				
PSE&G						
Gas	Natural Gas Supply Contract	$ —	$ (5)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ —**	**$ (5)**			
Power						
Electricity	Electric Load Contracts	$ 7	$ (1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Gas (A)	Other	—	—			
Total Power		**$ 7**	**$ (1)**			
Total PSEG		**$ 7**	**$ (6)**			

(A) Includes gas positions which were immaterial.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in the load variability would

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decrease the fair value. For gas-related contracts in cases where Power is a buyer, an increase in the average historical basis would increase the fair value.

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the years ended December 31, 2017 and 2016, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2017

Description	Balance as of January 1, 2017	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of December 31, 2017
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ 1	$ 26	$ 5	$ —	$ (24)	$ (1)	$ 7
PSE&G							
Net Derivative Assets (Liabilities)	$ (5)	$ —	$ 5	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 6	$ 26	$ —	$ —	$ (24)	$ (1)	$ 7

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Year Ended December 31, 2016

Description	Balance as of January 1, 2016	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of December 31, 2016
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ 13	$ 13	$ (7)	$ 3	$ (21)	$ —	$ 1
PSE&G							
Net Derivative Assets (Liabilities)	$ 2	$ —	$ (7)	$ —	$ —	$ —	$ (5)
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 13	$ —	$ 3	$ (21)	$ —	$ 6

(A) PSEG's and Power's gains(losses) attributable to changes in net derivative assets and liabilities for 2017 include $14 million in Operating Revenues, of which $(9) million is unrealized and $12 million in Energy Costs, all of which is unrealized. For 2016, $25 million is included in Operating Revenues, of which $(5) million is unrealized, and $(12)

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million is in Energy Costs, all of which is realized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $(24) million and $(21) million in settlements for derivative contracts in 2017 and 2016, respectively.

(D) During the year ended December 31, 2017, $(1) million of net derivatives assets/liabilities were transferred from Level 2 to Level 3.

As of December 31, 2017, PSEG carried $2.6 billion of net assets that are measured at fair value on a recurring basis, of which $7 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of December 31, 2016, PSEG carried $2.6 billion of net assets that are measured at fair value on a recurring basis, of which $1 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Note 18. Stock Based Compensation

PSEG's Amended and Restated 2004 Long-Term Incentive Plan (LTIP) is a broad-based equity compensation program that provides for grants of various long-term incentive compensation awards, such as stock options, stock appreciation rights, performance share units, restricted stock, restricted stock units, cash awards or any combination thereof. The types of long-term incentive awards that have been granted and remain outstanding under the LTIP are non-qualified options to purchase shares of PSEG's common stock, restricted stock unit awards and performance share unit awards. The type of equity award that is granted and the details of that award may vary from time to time and is subject to the approval of the Organization and Compensation Committee of PSEG's Board of Directors (O&CC), the LTIP's administrative committee.

The LTIP currently provides for the issuance of equity awards with respect to approximately 16 million shares of common stock. As of December 31, 2017, there were approximately 14 million shares available for future awards under the LTIP.

Stock Options

Under the LTIP, non-qualified options to acquire shares of PSEG common stock may be granted to officers and other key employees selected by the O&CC. Option awards are granted with an exercise price equal to the market price of PSEG's common stock at the grant date. The options generally vest over four years of continuous service. Vesting schedules may be accelerated upon the occurrence of certain events, such as a change-in-control (unless substituted with an equity award of equal value), retirement, death or disability. Options are exercisable over a period of time designated by the O&CC (but not prior to one year or longer than ten years from the date of grant) and are subject to such other terms and conditions as the O&CC determines. Payment by option holders upon exercise of an option may be made in cash or, with the consent of the O&CC, by delivering previously acquired shares of PSEG common stock. No options have been issued since 2009.

Restricted Stock Units

Under the LTIP, PSEG has granted restricted stock unit awards to officers and other key employees. These awards, which are bookkeeping entries only, are subject to risk of forfeiture until vested by continued employment. Until distributed, the units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. The restricted stock unit grants for 2017 and 2016 generally vest at the end of three years. Vesting may be accelerated (pro-rated basis or full vesting) upon certain events such as retirement, disability, change-in-control or death.

Performance Share Units

Under the LTIP, PSEG has granted performance share units to officers and other key employees. These provide for payment in shares of PSEG common stock based on achievement of certain financial goals over a three-year performance period. Following the end of the performance period, the payout varies from 0% to 200% of the number of performance units granted depending on PSEG's performance with respect to certain financial targets, including targets related to comparative performance against other companies in a peer group of energy companies. The performance share units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. Vesting may be accelerated on a pro-rated basis for the period of the employee's service during the performance period as a result of certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

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Stock-Based Compensation

PSEG recognizes compensation expense for stock options based on their grant date fair values, which are determined using the Black-Scholes option-pricing model. Stock option awards are expensed on a tranche-specific basis over the requisite service period of the award. Ultimately, compensation expense for stock options is recognized for awards that vest.

PSEG recognizes compensation expense for restricted stock units over the vesting period based on the grant date fair value of the shares, which is equal to the market price of PSEG's common stock on the date of the grant.

PSEG recognizes compensation expense for the total shareholder return target for its performance share unit awards based on the grant date fair values of the award, which are determined using the Monte Carlo model. The accrual of compensation cost is based on the probable achievement of the performance conditions, which result in a payout from 0% to 200% of the initial grant. PSEG recognizes compensation expense for the return on invested capital target for its performance share units based on the grant date fair value of the awards, which is equal to the market price of PSEG's common stock on the date of the grant. The accrual during the year of grant is estimated at 100% of the original grant. Such accrual may be adjusted to reflect the actual outcome.

	2017	2016	2015
		Millions	
Compensation Cost included in Operation and Maintenance Expense	$ 31	$ 29	$ 34
Income Tax Benefit Recognized in Consolidated Statement of Operations	$ 13	$ 12	$ 14

For 2017, 2016 and 2015 the excess tax benefit of $4 million, $4 million and $3 million, respectively was included as financing cash flows on the Consolidated Statements of Cash Flow.

PSEG recognizes compensation cost of awards issued over the shorter of the original vesting period or the period beginning on the date of grant and ending on the date an individual is eligible for retirement and the award vests.

Stock Options

Changes in stock options for 2017 are summarized as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding as of January 1, 2017	1,029,900	$ 37.93		
Exercised	654,200	$ 40.02		
Canceled/Forfeited	27,800	$ 44.44		
Outstanding as of December 31, 2017	**347,900**	**$ 33.49**	**1.9**	**$ 6,265,679**
Exercisable at December 31, 2017	347,900	$ 33.49	1.9	$ 6,265,679

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. There were no option grants in 2017, 2016 and 2015.

Activity for options exercised for the years ended December 31, 2017, 2016 and 2015 is shown below:

	2017	2016	2015
		Millions	
Total Intrinsic Value of Options Exercised	$ 5	$ 7	$ 3
Cash Received from Options Exercised	$ 26	$ 22	$ 12
Tax Benefit Realized from Options Exercised	$ —	$ 1	$ —

No options were vested during the years ended December 31, 2017, 2016 and 2015.

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Restricted Stock Units

Changes in restricted stock units for the year ended December 31, 2017 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2017	322,196	$ 38.75		
Granted	212,158	$ 44.33		
Vested	303,092	$ 39.96		
Canceled/Forfeited	17,363	$ 41.76		
Non-vested as of December 31, 2017	**213,899**	**$ 42.32**	**1.0**	**$ 11,015,850**

The weighted average grant date fair value per share for restricted stock during the years ended December 31, 2017, 2016 and 2015 was $44.33, $42.28 and $39.65 per share, respectively.

The total intrinsic value of restricted stock units distributed during the years ended December 31, 2017, 2016 and 2015 was $13 million, $17 million and $11 million, respectively.

As of December 31, 2017, there was approximately $3 million of unrecognized compensation cost related to the restricted stock units, which is expected to be recognized over a weighted average period of ten months. Dividend equivalents units of 30,066 accrued on the restricted stock units during the year.

Performance Share Units

Changes in performance share units for the year ended December 31, 2017 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2017	393,812	$ 44.20		
Granted	382,830	$ 45.02		
Vested	402,451	$ 44.03		
Canceled/Forfeited	41,730	$ 44.69		
Non-vested as of December 31, 2017	**332,461**	**$ 45.29**	**1.7**	**$ 17,121,742**

The weighted average grant date fair value per share for performance share units during the years ended December 31, 2017, 2016 and 2015 was $45.02, $45.97 and $41.32 per share, respectively.

The total intrinsic value of performance share units distributed during the years ended December 31, 2017, 2016 and 2015 was $18 million, $17 million and $13 million, respectively.

As of December 31, 2017, there was approximately $16 million of unrecognized compensation cost related to the performance share units, which is expected to be recognized over a weighted average period of one year. Dividend equivalents units of 38,425 accrued on the performance share units during the year.

Outside Directors

Under the Directors Equity Plan, annually, on the first business day of May, each non-employee member of the Board of Directors is awarded stock units based on the amount of annual compensation to be paid at the closing price of PSEG common stock on that date. Dividend equivalents are credited quarterly and distributions will commence upon the director leaving the Board as specified by him/her in accordance with the provisions of the Directors Equity Plan.

The fair value of these awards is recorded as compensation expense in the Consolidated Statements of Operations. Compensation expense for the plan was immaterial for each of the years ended December 31, 2017, 2016 and 2015.

Employee Stock Purchase Plan (ESPP)

PSEG maintains an ESPP for all eligible employees of PSEG and its subsidiaries. Under the ESPP, shares of PSEG common stock may be purchased at 95% of the fair market value for represented employees and 90% for non-represented employees through payroll deductions. Dividends will be reinvested for all employees at 95% of the fair market price unless the participant elects to receive a cash dividend. All employees are required to hold the shares purchased under the ESPP for at least three

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months from the purchase date. In any year, employees may purchase shares having a value not exceeding 10% of their base pay. Compensation expense recognized under this program was immaterial for each of the years ended December 31, 2017, 2016 and 2015.

During the years ended December 31, 2017, 2016 and 2015, employees purchased 288,527 shares, 262,763 shares and 250,499 shares at an average price of $42.07, $40.70 and $36.66 per share, respectively. As of December 31, 2017, 3.2 million shares were available for future issuance under this plan.

Note 19. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated Total
		Millions		
Year Ended December 31, 2017				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 202	$ —	$ 202
Allowance for Funds Used During Construction	56	—	—	56
Rabbi Trust Realized Gains, Interest and Dividends	5	6	13	24
Solar Loan Interest	21	—	—	21
Other	10	5	1	16
Total Other Income	**$ 92**	**$ 213**	**$ 14**	**$ 319**
Year Ended December 31, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 96	$ —	$ 96
Allowance for Funds Used During Construction	49	—	—	49
Rabbi Trust Realized Gains, Interest and Dividends	3	3	6	12
Solar Loan Interest	22	—	—	22
Other	9	3	—	12
Total Other Income	**$ 83**	**$ 102**	**$ 6**	**$ 191**
Year Ended December 31, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 138	$ —	$ 138
Allowance for Funds Used During Construction	48	—	—	48
Rabbi Trust Realized Gains, Interest and Dividends	2	2	6	10
Solar Loan Interest	23	—	—	23
Gain on Insurance Recovery	—	28	—	28
Other	6	1	—	7
Total Other Income	**$ 79**	**$ 169**	**$ 6**	**$ 254**

Other Deductions	PSE&G	Power	Other (A)	Consolidated Total
		Millions		
Year Ended December 31, 2017				
NDT Fund Realized Losses and Expenses	$ —	$ 32	$ —	$ 32
Other	5	24	30	59
Total Other Deductions	**$ 5**	**$ 56**	**$ 30**	**$ 91**
Year Ended December 31, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 40	$ —	$ 40
Other	4	17	6	27
Total Other Deductions	**$ 4**	**$ 57**	**$ 6**	**$ 67**
Year Ended December 31, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 45	$ —	$ 45
Other	4	27	26	57
Total Other Deductions	**$ 4**	**$ 72**	**$ 26**	**$ 102**

(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

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Note 20. Income Taxes

A reconciliation of reported income tax expense for PSEG with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSEG	Years Ended December 31, 2017	2016	2015
		Millions	
Net Income	$ 1,574	$ 887	$ 1,679
Income Taxes:			
Operating Income:			
Current Expense (Benefit):			
Federal	$ 86	$ (74)	$ 243
State	(31)	61	85
Total Current	55	(13)	328
Deferred (Benefit) Expense:			
Federal	(482)	311	540
State	92	28	104
Total Deferred	(390)	339	644
Investment Tax Credit (ITC)	29	85	29
Total Income Tax (Benefit) Expense	**$ (306)**	**$ 411**	**$ 1,001**
Pre-Tax Income	$ 1,268	$ 1,298	$ 2,680
Tax Computed at Statutory Rate @ 35%	$ 444	$ 454	$ 938
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	36	56	129
Uncertain Tax Positions	(3)	(31)	7
Manufacturing Deduction	(13)	(17)	(10)
NDT Fund	19	3	7
Plant-Related Items	(23)	(20)	(20)
Tax Credits	(22)	(25)	(13)
Audit Settlement	6	—	—
Nuclear Decommissioning Tax Carryback	—	—	(33)
Provisional Deferred Tax Benefit - Tax Act	(755)	—	—
Other	5	(9)	(4)
Sub-Total	(750)	(43)	63
Total Income Tax (Benefit) Expense	**$ (306)**	**$ 411**	**$ 1,001**
Effective Income Tax Rate	(24.1)%	31.7%	37.4%

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The following is an analysis of deferred income taxes for PSEG:

PSEG	As of December 31, 2017	2016
	Millions	
Deferred Income Taxes		
Assets:		
Noncurrent		
Regulatory Liability Excess Deferred Tax	$ 602	$ —
OPEB	217	283
Related to Uncertain Tax Position	142	155
Total Noncurrent Assets	$ 961	$ 438
Liabilities:		
Noncurrent:		
Plant-Related Items	$ 4,257	$ 6,593
New Jersey Corporate Business Tax	674	674
Leasing Activities	384	565
AROs and NDT Fund	233	398
Pension Costs	123	197
Taxes Recoverable Through Future Rates (net)	80	208
Other	171	212
Total Noncurrent Liabilities	$ 5,922	$ 8,847
Summary of Accumulated Deferred Income Taxes:		
Net Noncurrent Deferred Income Tax Liabilities	$ 4,961	$ 8,409
ITC	279	249
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 5,240**	**$ 8,658**

The deferred tax effect of certain assets and liabilities is presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals. Also, the deferred tax effect of AROs is presented net of the deferred tax effect of the associated funding of those obligations.

In December 2017, new tax legislation was enacted, reducing the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018. PSEG is subject to ASC 740, which requires that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate was enacted. The impact of the reduced tax rate is the primary reason for the decrease in the deferred tax liabilities.

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A reconciliation of reported income tax expense for PSE&G with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSE&G	Years Ended December 31, 2017	2016	2015
		Millions	
Net Income	$ 973	$ 889	$ 787
Income Taxes:			
Operating Income:			
Current (Benefit) Expense:			
Federal	$ (52)	$ (153)	$ 32
State	(1)	10	52
Total Current	(53)	(143)	84
Deferred Expense:			
Federal	492	551	325
State	129	102	52
Total Deferred	621	653	377
ITC	(5)	5	9
Total Income Tax Expense	**$ 563**	**$ 515**	**$ 470**
Pre-Tax Income	$ 1,536	$ 1,404	$ 1,257
Tax Computed at Statutory Rate @ 35%	$ 538	$ 491	$ 440
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	83	72	67
Uncertain Tax Positions	(9)	(18)	(14)
Plant-Related Items	(23)	(20)	(20)
Tax Credits	(9)	(7)	(6)
Provisional Deferred Tax Benefit - Tax Act	(10)	—	—
Other	(7)	(3)	3
Sub-Total	25	24	30
Total Income Tax Expense	**$ 563**	**$ 515**	**$ 470**
Effective Income Tax Rate	36.7%	36.7%	37.4%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for PSE&G:

PSE&G	As of December 31, 2017	2016
	Millions	
Deferred Income Taxes		
Assets:		
Noncurrent:		
Regulatory Liability Excess Deferred Tax	$ 602	$ —
OPEB	116	189
Total Noncurrent Assets	$ 718	$ 189
Liabilities:		
Noncurrent:		
Plant-Related Items	$ 3,311	$ 4,983
New Jersey Corporate Business Tax	378	385
Pension Costs	152	252
Conservation Costs	24	33
Taxes Recoverable Through Future Rates (net)	80	208
Other	86	118
Total Noncurrent Liabilities	$ 4,031	$ 5,979
Summary of Accumulated Deferred Income Taxes:		
Net Noncurrent Deferred Income Tax Liabilities	$ 3,313	$ 5,790
ITC	78	83
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 3,391**	**$ 5,873**

The deferred tax effect of certain assets and liabilities is presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals.

In December 2017, new tax legislation was enacted, reducing the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018. PSE&G is subject to ASC 740, which requires that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate was enacted. The impact of the reduced tax rate is the primary reason for the decrease in the deferred tax liabilities.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for Power with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

Power	Years Ended December 31, 2017	2016	2015
		Millions	
Net Income	$ 479	$ 18	$ 856
Income Taxes:			
Operating Income:			
Current Expense (Benefit):			
Federal	$ 95	$ 107	$ 220
State	(17)	40	30
Total Current	78	147	250
Deferred (Benefit) Expense:			
Federal	(804)	(222)	189
State	(37)	(68)	52
Total Deferred	(841)	(290)	241
ITC	34	82	20
Total Income Tax (Benefit) Expense	**$ (729)**	**$ (61)**	**$ 511**
Pre-Tax (Loss) Income	$ (250)	$ (43)	$ 1,367
Tax Computed at Statutory Rate @ 35%	$ (88)	$ (15)	$ 478
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	(36)	(18)	59
Manufacturing Deduction	(13)	(17)	(10)
NDT Fund	19	3	7
Tax Credits	(12)	(18)	(7)
Uncertain Tax Positions	7	9	22
Audit Settlement	1	—	—
Nuclear Decommissioning Tax Carryback	—	—	(33)
Provisional Deferred Tax Benefit - Tax Act	(610)	—	—
Other	3	(5)	(5)
Sub-Total	(641)	(46)	33
Total Income Tax (Benefit) Expense	**$ (729)**	**$ (61)**	**$ 511**
Effective Income Tax Rate	291.6%	141.9%	37.4%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for Power:

Power	As of December 31, 2017	2016
	Millions	
Deferred Income Taxes		
Assets:		
Noncurrent:		
Related to Uncertain Tax Positions	$ 45	$ 53
Pension Costs	40	68
Contractual Liabilities & Environmental Costs	12	18
Other	93	76
Total Noncurrent Assets	$ 190	$ 215
Liabilities:		
Noncurrent:		
Plant-Related Items	$ 935	$ 1,605
AROs and NDT Fund	235	400
New Jersey Corporate Business Tax	225	214
Total Noncurrent Liabilities	$ 1,395	$ 2,219
Summary of Accumulated Deferred Income Taxes:		
Net Noncurrent Deferred Income Tax Liabilities	$ 1,205	$ 2,004
ITC	201	166
Net Total Noncurrent Deferred Income Taxes and ITC	**$ 1,406**	**$ 2,170**

In the above table, the deferred tax effect of asset retirement obligations is presented net of the deferred tax effect of the associated funding of those obligations.

PSEG, PSE&G and Power each provide deferred taxes at the enacted statutory tax rate for all temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities irrespective of the treatment for rate-making purposes. Management believes that it is probable that the accumulated tax benefits that previously have been treated as a flow-through item to PSE&G customers will be recovered from or refunded to PSE&G's customers in the future. See Note 6. Regulatory Assets and Liabilities.

In December 2017, the U.S. government enacted comprehensive tax legislation. The Tax Act establishes new tax laws that will take effect in 2018, including, but not limited to (1) reduction of the U.S. federal corporate tax rate from a maximum of 35% to 21%; (2) elimination of the corporate alternative minimum tax (AMT); (3) a new limitation on deductible interest expense; (4) the repeal of the domestic production activity deduction; (5) limitations on the deductibility of certain executive compensation; and (6) limitations on net operating losses (NOLs) generated after December 31, 2017, to 80% of taxable income. In addition, certain changes were made to the bonus depreciation rules that will impact 2017.

The SEC staff issued Staff Accounting Bulletin 118 (SAB 118), which provides guidance on accounting for the tax effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date for companies to complete the accounting under ASC 740. In accordance with SAB 118, a company must reflect the income tax effects of those aspects of the Tax Act for which the accounting under ASC 740 is complete. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete but it is able to determine a reasonable estimate, it must record a provisional estimate in the financial statements. If a company cannot determine a provisional estimate to be included in the financial statements, it should continue to apply ASC 740 on the basis of the provisions of the tax laws that were in effect immediately before the enactment of the Tax Act.

PSEG, PSE&G and Power are subject to ASC 740, which requires that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change is enacted.

The majority of the current period activity was determined using the federal income tax rate of 35% and state income tax rate of 9%. As required under ASC 740, the ending 2017 deferred tax balances were adjusted to reflect the enacted lower tax rate, which resulted in a one-time, provisional deferred tax benefit of $755 million, including $610 million related to Power and $149 million related to Energy Holdings (including other impacts related to the new tax legislation, PSEG's net non-cash provisional earnings benefit was $745 million, including $588 million related to Power and $147 million related to Energy

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Holdings). In addition, PSE&G had excess deferred taxes of approximately $2.1 billion as of December 31, 2017 and recorded a $2.9 billion revenue impact of these excess deferred taxes as Regulatory Liabilities where it is probable that refunds will be made to customers in future rates. The amount and timing of any such refund cannot be determined at this time.

For certain aspects of the Tax Act, which are discussed below, PSEG, PSE&G and Power made reasonable, good faith estimates for which provisional amounts were recorded.

PSEG's accounting for the following elements of the Tax Act is incomplete. However, PSEG was able to make reasonable, good faith estimates of certain effects and, therefore, recorded provisional adjustments for the following: the tax rules regarding the appropriate bonus deprecation rate that should be applied to assets placed in service after September 27, 2017 for Power and PSE&G, including the information required to compute the applicable depreciable tax basis, and the impact on PSEG's, PSE&G's and Power's deferred taxes associated with FIN 48 reserves.

Further, the Tax Act is unclear in certain respects and will require interpretations and implementing regulations by the Internal Revenue Service (IRS), as well as state tax authorities. The Tax Act could also be subject to potential amendments and technical corrections which could impact PSEG, PSE&G and Power's financial statements.

In December 2015, the U.S. government enacted the Protecting Americans from Tax Hikes Act of 2015 (2015 Tax Act). Among other provisions, the 2015 Tax Act included an extension of the bonus depreciation rules and the 30% ITC for qualified property placed into service after 2016. Qualified property that is placed in service from January 1, 2015 through December 31, 2017 is eligible for 50% bonus depreciation. The provisions of the 2015 Tax Act have generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation. Those tax benefits would have otherwise been received over an estimated average 20 year period. However, the tax benefits have a negative impact on the rate base of several of PSE&G's programs.

For the period beginning September 28, 2017, subject to the transition rules, the Tax Act has modified the bonus depreciation rules of the 2015 Tax Act. Subject to further guidance, it is expected that Power will be entitled to 100% expensing and bonus depreciation will no longer apply to PSE&G.

PSEG recorded the following amounts related to its unrecognized tax benefits, which were primarily comprised of amounts recorded for PSE&G, Power and Energy Holdings:

2017	PSEG	PSE&G	Power	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2017	$ 328	$ 140	$ 128	$ 57
Increases as a Result of Positions Taken in a Prior Period	40	15	18	8
Decreases as a Result of Positions Taken in a Prior Period	(32)	(11)	(10)	(13)
Increases as a Result of Positions Taken during the Current Period	12	5	6	1
Decreases as a Result of Positions Taken during the Current Period	(1)	(1)	—	—
Decreases as a Result of Settlements with Taxing Authorities	—	—	—	—
Decreases due to Lapses of Applicable Statute of Limitations	(13)	(13)	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2017	$ 334	$ 135	$ 142	$ 53
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(157)	(73)	(72)	(12)
Regulatory Asset—Unrecognized Tax Benefits	(56)	(56)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 121**	**$ 6**	**$ 70**	**$ 41**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

2016	PSEG	PSE&G	Power	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2016	$ 386	$ 181	$ 111	$ 93
Increases as a Result of Positions Taken in a Prior Period	12	3	6	2
Decreases as a Result of Positions Taken in a Prior Period	(62)	(23)	(1)	(38)
Increases as a Result of Positions Taken during the Current Period	19	6	12	—
Decreases as a Result of Positions Taken during the Current Period	—	—	—	—
Decreases as a Result of Settlements with Taxing Authorities	—	—	—	—
Decreases due to Lapses of Applicable Statute of Limitations	(27)	(27)	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2016	$ 328	$ 140	$ 128	$ 57
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(200)	(106)	(74)	(20)
Regulatory Asset—Unrecognized Tax Benefits	(31)	(31)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 97**	**$ 3**	**$ 54**	**$ 37**

2015	PSEG	PSE&G	Power	Energy Holdings
		Millions		
Total Amount of Unrecognized Tax Benefits as of January 1, 2015	$ 332	$ 165	$ 70	$ 95
Increases as a Result of Positions Taken in a Prior Period	87	55	28	4
Decreases as a Result of Positions Taken in a Prior Period	(50)	(43)	(6)	(1)
Increases as a Result of Positions Taken during the Current Period	28	5	23	—
Decreases as a Result of Positions Taken during the Current Period	(1)	(1)	—	—
Decreases as a Result of Settlements with Taxing Authorities	(10)	—	(4)	(5)
Decreases due to Lapses of Applicable Statute of Limitations	—	—	—	—
Total Amount of Unrecognized Tax Benefits as of December 31, 2015	$ 386	$ 181	$ 111	$ 93
Accumulated Deferred Income Taxes Associated with Unrecognized Tax Benefits	(264)	(162)	(68)	(34)
Regulatory Asset—Unrecognized Tax Benefits	(27)	(27)	—	—
Total Amount of Unrecognized Tax Benefits that if Recognized, would Impact the Effective Tax Rate (including Interest and Penalties)	**$ 95**	**$ (8)**	**$ 43**	**$ 59**

PSEG and its subsidiaries include accrued interest and penalties related to uncertain tax positions required to be recorded, as Income Tax Expense in the Consolidated Statements of Operations. Accumulated interest and penalties that are recorded on the Consolidated Balance Sheets on uncertain tax positions were as follows:

	Accumulated Interest and Penalties on Uncertain Tax Positions as of December 31,		
	2017	2016	2015
		Millions	
PSE&G	$ 25	$ 22	$ 20
Power	24	17	6
Energy Holdings	21	20	40
Total	**$ 70**	**$ 59**	**$ 66**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

It is reasonably possible that total unrecognized tax benefits will significantly increase or decrease within the next twelve months due to either agreements with various taxing authorities upon audit, the expiration of the Statute of Limitations, or other pending tax matters. These potential increases or decreases are as follows:

Possible (Increase)/Decrease in Total Unrecognized Tax Benefits	Over the next 12 Months
	Millions
PSEG	$ 69
PSE&G	$ 35
Power	$ 30

A description of income tax years that remain subject to examination by material jurisdictions, where an examination has not already concluded are:

	PSEG	PSE&G	Power
United States			
Federal	2011-2016	N/A	N/A
New Jersey	2006-2016	2011-2016	N/A
Pennsylvania	2014-2016	2014-2016	N/A
Connecticut	2016	N/A	N/A
Texas	2008-2016	N/A	N/A
California	2006-2016	N/A	N/A
New York	2014-2016	N/A	2014-2016

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Note 21. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss)			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2014	$ 10	$ (411)	$ 118	$ (283)
Other Comprehensive Income before Reclassifications	2	(7)	(25)	(30)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(12)	32	(2)	18
Net Current Period Other Comprehensive Income (Loss)	(10)	25	(27)	(12)
Balance as of December 31, 2015	**$ —**	**$ (386)**	**$ 91**	**$ (295)**
Other Comprehensive Income before Reclassifications	2	(45)	40	(3)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	33	2	35
Net Current Period Other Comprehensive Income (Loss)	2	(12)	42	32
Balance as of December 31, 2016	**$ 2**	**$ (398)**	**$ 133**	**$ (263)**
Other Comprehensive Income before Reclassifications	—	(32)	109	77
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(2)	24	(65)	(43)
Net Current Period Other Comprehensive Income (Loss)	(2)	(8)	44	34
Balance as of December 31, 2017	**$ —**	**$ (406)**	**$ 177**	**$ (229)**

Power	Other Comprehensive Income (Loss)			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2014	$ 11	$ (351)	$ 112	$ (228)
Other Comprehensive Income before Reclassifications	1	(4)	(24)	(27)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(12)	28	(1)	15
Net Current Period Other Comprehensive Income (Loss)	(11)	24	(25)	(12)
Balance as of December 31, 2015	**$ —**	**$ (327)**	**$ 87**	**$ (240)**
Other Comprehensive Income before Reclassifications	—	(42)	39	(3)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	29	3	32
Net Current Period Other Comprehensive Income (Loss)	—	(13)	42	29
Balance as of December 31, 2016	**$ —**	**$ (340)**	**$ 129**	**$ (211)**
Other Comprehensive Income before Reclassifications	—	(28)	106	78
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	21	(60)	(39)
Net Current Period Other Comprehensive Income (Loss)	—	(7)	46	39
Balance as of December 31, 2017	**$ —**	**$ (347)**	**$ 175**	**$ (172)**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 20	$ (8)	$ 12
Total Cash Flow Hedges		20	(8)	12
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	12	(3)	9
Amortization of Actuarial Loss	O&M Expense	(68)	27	(41)
Total Pension and OPEB Plans		(56)	24	(32)
Available-for-Sale Securities				
Realized Gains	Other Income	100	(52)	48
Realized Losses	Other Deductions	(39)	20	(19)
Other-Than-Temporary Impairments (OTTI)	OTTI	(53)	26	(27)
Total Available-for-Sale Securities		8	(6)	2
Total		**$ (28)**	**$ 10**	**$ (18)**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 20	$ (8)	$ 12
Total Cash Flow Hedges		20	(8)	12
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	11	(3)	8
Amortization of Actuarial Loss	O&M Expense	(60)	24	(36)
Total Pension and OPEB Plans		(49)	21	(28)
Available-for-Sale Securities				
Realized Gains	Other Income	98	(51)	47
Realized Losses	Other Deductions	(38)	19	(19)
OTTI	OTTI	(53)	26	(27)
Total Available-for-Sale Securities		7	(6)	1
Total		**$ (22)**	**$ 7**	**$ (15)**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSEG

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement — Year Ended December 31, 2016		
		Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 12	$ (5)	$ 7
Amortization of Actuarial Loss	O&M Expense	(68)	28	(40)
Total Pension and OPEB Plans		(56)	23	(33)
Available-for-Sale Securities				
Realized Gains	Other Income	59	(29)	30
Realized Losses	Other Deductions	(37)	19	(18)
OTTI	OTTI	(28)	14	(14)
Total Available-for-Sale Securities		(6)	4	(2)
Total		**$ (62)**	**$ 27**	**$ (35)**

Power

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement — Year Ended December 31, 2016		
		Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 11	$ (5)	$ 6
Amortization of Actuarial Loss	O&M Expense	(59)	24	(35)
Total Pension and OPEB Plans		(48)	19	(29)
Available-for-Sale Securities				
Realized Gains	Other Income	55	(28)	27
Realized Losses	Other Deductions	(33)	17	(16)
OTTI	OTTI	(28)	14	(14)
Total Available-for-Sale Securities		(6)	3	(3)
Total		**$ (54)**	**$ 22**	**$ (32)**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Interest Rate Swaps	Interest Expense	3	(1)	2
Total Cash Flow Hedges		3	(1)	2
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 10	$ (4)	$ 6
Amortization of Actuarial Loss	O&M Expense	(51)	21	(30)
Total Pension and OPEB Plans		(41)	17	(24)
Available-for-Sale Securities				
Realized Gains	Other Income	174	(89)	85
Realized Losses	Other Deductions	(28)	14	(14)
OTTI	OTTI	(12)	6	(6)
Total Available-for-Sale Securities		134	(69)	65
Total		**$ 96**	**$ (53)**	**$ 43**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Year Ended December 31, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 9	$ (4)	$ 5
Amortization of Actuarial Loss	O&M Expense	(44)	18	(26)
Total Pension and OPEB Plans		(35)	14	(21)
Available-for-Sale Securities				
Realized Gains	Other Income	161	(83)	78
Realized Losses	Other Deductions	(24)	12	(12)
OTTI	OTTI	(12)	6	(6)
Total Available-for-Sale Securities		125	(65)	60
Total		**$ 90**	**$ (51)**	**$ 39**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 22. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. For additional information on PSEG's stock compensation plans see Note 18. Stock Based Compensation. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Years Ended December 31,					
	2017		2016		2015	
	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator:						
(Millions)						
Net Income	**$ 1,574**	**$ 1,574**	**$ 887**	**$ 887**	**$ 1,679**	**$ 1,679**
EPS Denominator:						
(Millions)						
Weighted Average Common Shares Outstanding	505	505	505	505	505	505
Effect of Stock Based Compensation Awards	—	2	—	3	—	3
Total Shares	**505**	**507**	**505**	**508**	**505**	**508**
EPS:						
Net Income	**$ 3.12**	**$ 3.10**	**$ 1.76**	**$ 1.75**	**$ 3.32**	**$ 3.30**

There were approximately 0.4 million and 0.5 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the years ended December 31, 2016 and 2015, respectively.

For additional information on all the types of long-term incentive awards, see Note 18. Stock Based Compensation.

Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	**2017**	**2016**	**2015**
Per Share	$ 1.72	$ 1.64	$ 1.56
in Millions	$ 870	$ 830	$ 789

On February 20, 2018, PSEG's Board of Directors approved a $0.45 per share common stock dividend for the first quarter of 2018.

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Note 23. Financial Information by Business Segment

Basis of Organization

PSEG's, PSE&G's and Power's operating segments were determined by management in accordance with GAAP. These segments were determined based on how management measures performance based on segment Net Income, as illustrated in the following table, and how resources are allocated to each business. PSEG's reportable segments are PSE&G and Power. PSE&G and Power each represent a single reportable segment and therefore no separate segment information is provided for these Registrants.

PSE&G

PSE&G earns revenues from its tariffs, under which it provides electric transmission and electric and gas distribution services to residential, commercial and industrial customers in New Jersey. The rates charged for electric transmission are regulated by FERC while the rates charged for electric and gas distribution are regulated by the BPU. Revenues are also earned from several other activities such as solar investments, sundry sales, the appliance service business, wholesale transmission services and other miscellaneous services.

Power

Power earns revenues by selling energy, capacity and ancillary services on a wholesale basis under contract to power marketers and to load serving entities and by bidding energy, capacity and ancillary services into the markets for these products. A significant portion of Power's revenue is obtained from the various ISOs in which Power operates. The ISOs act similarly to a clearing house for all of its members in that all revenues paid out are collected from market participants based on their consumption of energy and energy-related products. Power also enters into bilateral contracts for energy, capacity, FTRs, gas, emission allowances and other energy-related contracts to optimize the value of its portfolio of generating assets and its electric and gas supply obligations.

Other

This category includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Year Ended December 31, 2017					
Operating Revenues	$ 6,234	$ 3,930	$ 466	$ (1,546)	$ 9,084
Depreciation and Amortization	685	1,268	33	—	1,986
Operating Income (Loss)	1,752	(359)	36	—	1,429
Income from Equity Method Investments	—	14	—	—	14
Interest Income	24	3	5	(2)	30
Interest Expense	303	50	40	(2)	391
Income (Loss) before Income Taxes	1,536	(250)	(18)	—	1,268
Income Tax Expense (Benefit)	563	(729)	(140)	—	(306)
Net Income (Loss)	973	479	122	—	1,574
Gross Additions to Long-Lived Assets	$ 2,919	$ 1,231	$ 40	$ —	$ 4,190
As of December 31, 2017					
Total Assets	$ 28,554	$ 12,418	$ 2,666	$ (922)	$ 42,716
Investments in Equity Method Subsidiaries	$ —	$ 87	$ —	$ —	$ 87

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Year Ended December 31, 2016					
Operating Revenues	$ 6,221	$ 4,023	$ 370	$ (1,553)	$ 9,061
Depreciation and Amortization	565	881	30	—	1,476
Operating Income (Loss)	1,614	13	(51)	—	1,576
Income from Equity Method Investments	—	11	—	—	11
Interest Income	24	4	4	(2)	30
Interest Expense	289	84	14	(2)	385
Income (Loss) before Income Taxes	1,404	(43)	(63)	—	1,298
Income Tax Expense (Benefit)	515	(61)	(43)	—	411
Net Income (Loss)	889	18	(20)	—	887
Gross Additions to Long-Lived Assets	$ 2,816	$ 1,343	$ 40	$ —	$ 4,199
As of December 31, 2016					
Total Assets	$ 26,288	$ 12,193	$ 2,373	$ (784)	$ 40,070
Investments in Equity Method Subsidiaries	$ —	$ 102	$ —	$ —	$ 102

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Year Ended December 31, 2015					
Operating Revenues	$ 6,636	$ 4,928	$ 462	$ (1,611)	$ 10,415
Depreciation and Amortization	892	291	31	—	1,214
Operating Income (Loss)	1,462	1,430	70	—	2,962
Income from Equity Method Investments	—	14	(2)	—	12
Interest Income	25	2	33	(29)	31
Interest Expense	280	121	21	(29)	393
Income (Loss) before Income Taxes	1,257	1,367	56	—	2,680
Income Tax Expense (Benefit)	470	511	20	—	1,001
Net Income (Loss)	787	856	36	—	1,679
Gross Additions to Long-Lived Assets	$ 2,692	$ 1,117	$ 54	$ —	$ 3,863
As of December 31, 2015					
Total Assets	$ 23,677	$ 12,250	$ 2,810	$ (1,202)	$ 37,535
Investments in Equity Method Subsidiaries	$ —	$ 119	$ —	$ —	$ 119

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations primarily relate to intercompany transactions between PSE&G and Power. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 24. Related-Party Transactions.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 24. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related Party Transactions	Years Ended December 31, 2017	2016	2015
		Millions	
Billings from Affiliates:			
Net Billings from Power primarily through BGS and BGSS (A)	$ 1,580	$ 1,587	$ 1,630
Administrative Billings from Services (B)	331	312	274
Total Billings from Affiliates	**$ 1,911**	**$ 1,899**	**$ 1,904**

Related Party Transactions	Years Ended December 31, 2017	2016
	Millions	
Receivables from PSEG (C)	**$ —**	**$ 76**
Payable to Power (A)	$ 221	$ 193
Payable to Services (B)	78	67
Payable to PSEG (C)	$ 41	$ —
Accounts Payable—Affiliated Companies	**$ 340**	**$ 260**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 91**	**$ 130**

Power

The financial statements for Power include transactions with related parties presented as follows:

Related Party Transactions	Years Ended December 31, 2017	2016	2015
		Millions	
Billings to Affiliates:			
Net Billings to PSE&G primarily through BGS and BGSS (A)	**$ 1,580**	**$ 1,587**	**$ 1,630**
Billings from Affiliates:			
Administrative Billings from Services (B)	**$ 168**	**$ 179**	**$ 187**

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Related Party Transactions	Years Ended December 31, 2017	2016
	Millions	
Receivable from PSE&G (A)	$ 221	$ 193
Receivable from PSEG (C)	—	12
Accounts Receivable—Affiliated Companies	**$ 221**	**$ 205**
Payable to Services (B)	$ 28	$ 25
Payable to PSEG (C)	29	—
Accounts Payable—Affiliated Companies	**$ 57**	**$ 25**
Short-Term Loan due (to) from Affiliate (E)	**$ (281)**	**$ 87**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 52**	**$ 77**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. The rates in the BGS and BGSS contracts are prescribed by the BPU. In addition, Power and PSE&G provide certain technical services for each other generally at cost in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 25. Selected Quarterly Data (Unaudited)

The information shown in the following tables, in the opinion of PSEG, PSE&G and Power includes all adjustments, consisting only of normal recurring accruals, necessary to fairly present such amounts.

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31, (A)	
	2017	2016	2017	2016	2017	2016	2017	2016
PSEG Consolidated:	Millions, except per share data							
Operating Revenues	$ 2,592	$ 2,616	$ 2,133	$ 1,905	$ 2,263	$ 2,450	$ 2,096	$ 2,090
Operating Income (Loss)	$ 178	$ 827	$ 196	$ 347	$ 693	$ 577	$ 362	$ (175)
Net Income (Loss)	$ 114	$ 471	$ 109	$ 187	$ 395	$ 327	$ 956	$ (98)
Earnings Per Share:								
Basic:								
Net Income (Loss)	$ 0.23	$ 0.93	$ 0.22	$ 0.37	$ 0.78	$ 0.65	$ 1.89	$ (0.19)
Diluted:								
Net Income (Loss)	$ 0.22	$ 0.93	$ 0.22	$ 0.37	$ 0.78	$ 0.64	$ 1.88	$ (0.19)
Weighted Average Common Shares Outstanding:								
Basic	505	505	505	505	505	505	505	505
Diluted	508	508	507	508	507	508	508	508

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2017	2016	2017	2016	2017	2016	2017	2016
PSE&G:	Millions							
Operating Revenues	$ 1,812	$ 1,712	$ 1,368	$ 1,350	$ 1,509	$ 1,684	$ 1,545	$ 1,475
Operating Income	$ 521	$ 462	$ 379	$ 333	$ 459	$ 450	$ 393	$ 369
Net Income	$ 299	$ 262	$ 208	$ 179	$ 246	$ 255	$ 220	$ 193

	Quarter Ended							
	March 31,		June 30,		September 30,		December 31, (A)	
	2017	2016	2017	2016	2017	2016	2017	2016
Power:	Millions							
Operating Revenues	$ 1,284	$ 1,313	$ 929	$ 714	$ 873	$ 1,075	$ 844	$ 921
Operating Income (Loss)	$ (303)	$ 343	$ (187)	$ (12)	$ 213	$ 238	$ (82)	$ (556)
Net Income (Loss)	$ (170)	$ 192	$ (97)	$ (11)	$ 136	$ 139	$ 610	$ (302)

(A) The increases in Operating Income at PSEG consolidated and Power in the fourth quarter 2017 as compared to the same quarter in 2016 were primarily due to higher costs in 2016 related to closing the coal/gas Hudson and Mercer units, which were fully depreciated as of June 1, 2017. The increases in Net Income at PSEG consolidated and Power in the fourth quarter 2017 as compared to the same quarter in 2016 also includes the impact of the remeasurement of deferred tax balances resulting from the enactment of new tax legislation in December 2017. See Note 20. Income Taxes for additional information.

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Note 26. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries, as of December 31, 2017 and 2016 and for the years ended December 31, 2017, 2016 and 2015.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2017					
Operating Revenues	$ —	$ 3,891	$ 174	$ (135)	$ 3,930
Operating Expenses	8	4,221	195	(135)	4,289
Operating Income (Loss)	(8)	(330)	(21)	—	(359)
Equity Earnings (Losses) of Subsidiaries	567	60	14	(627)	14
Other Income	98	257	2	(144)	213
Other Deductions	(24)	(32)	—	—	(56)
Other-Than-Temporary Impairments	—	(12)	—	—	(12)
Interest Expense	(128)	(49)	(17)	144	(50)
Income Tax Benefit (Expense)	(26)	588	167	—	729
Net Income (Loss)	**$ 479**	**$ 482**	**$ 145**	**$ (627)**	**$ 479**
Comprehensive Income (Loss)	**$ 518**	**$ 529**	**$ 145**	**$ (674)**	**$ 518**
As of December 31, 2017					
Current Assets	$ 4,327	$ 1,500	$ 200	$ (4,686)	$ 1,341
Property, Plant and Equipment, net	54	5,778	2,764	—	8,596
Investment in Subsidiaries	4,844	404	—	(5,248)	—
Noncurrent Assets	100	2,349	110	(78)	2,481
Total Assets	**$ 9,325**	**$ 10,031**	**$ 3,074**	**$ (10,012)**	**$ 12,418**
Current Liabilities	$ 689	$ 3,586	$ 1,846	$ (4,686)	$ 1,435
Noncurrent Liabilities	533	1,966	459	(78)	2,880
Long-Term Debt	2,136	—	—	—	2,136
Member's Equity	5,967	4,479	769	(5,248)	5,967
Total Liabilities and Member's Equity	**$ 9,325**	**$ 10,031**	**$ 3,074**	**$ (10,012)**	**$ 12,418**
Year Ended December 31, 2017					
Net Cash Provided By (Used In) Operating Activities	$ (42)	$ 1,185	$ 238	$ (55)	$ 1,326
Net Cash Provided By (Used In) Investing Activities	$ 506	$ (448)	$ (525)	$ (765)	$ (1,232)
Net Cash Provided By (Used In) Financing Activities	$ (464)	$ (736)	$ 307	$ 820	$ (73)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2016					
Operating Revenues	$ —	$ 3,971	$ 173	$ (121)	$ 4,023
Operating Expenses	8	3,962	161	(121)	4,010
Operating Income (Loss)	(8)	9	12	—	13
Equity Earnings (Losses) of Subsidiaries	36	(3)	11	(33)	11
Other Income	71	120	—	(89)	102
Other Deductions	(18)	(39)	—	—	(57)
Other-Than-Temporary Impairments	—	(28)	—	—	(28)
Interest Expense	(115)	(40)	(18)	89	(84)
Income Tax Benefit (Expense)	52	(11)	20	—	61
Net Income (Loss)	**$ 18**	**$ 8**	**$ 25**	**$ (33)**	**$ 18**
Comprehensive Income (Loss)	**$ 47**	**$ 50**	**$ 25**	**$ (75)**	**$ 47**
As of December 31, 2016					
Current Assets	$ 4,412	$ 1,593	$ 152	$ (4,697)	$ 1,460
Property, Plant and Equipment, net	55	6,145	2,320	—	8,520
Investment in Subsidiaries	4,249	344	—	(4,593)	—
Noncurrent Assets	168	2,016	129	(100)	2,213
Total Assets	**$ 8,884**	**$ 10,098**	**$ 2,601**	**$ (9,390)**	**$ 12,193**
Current Liabilities	$ 171	$ 3,752	$ 1,454	$ (4,697)	$ 680
Noncurrent Liabilities	532	2,398	502	(100)	3,332
Long-Term Debt	2,382	—	—	—	2,382
Member's Equity	5,799	3,948	645	(4,593)	5,799
Total Liabilities and Member's Equity	**$ 8,884**	**$ 10,098**	**$ 2,601**	**$ (9,390)**	**$ 12,193**
Year Ended December 31, 2016					
Net Cash Provided By (Used In) Operating Activities	$ 97	$ 1,442	$ 323	$ (607)	$ 1,255
Net Cash Provided By (Used In) Investing Activities	$ 60	$ (707)	$ (789)	$ 289	$ (1,147)
Net Cash Provided By (Used In) Financing Activities	$ (157)	$ (736)	$ 466	$ 318	$ (109)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2015					
Operating Revenues	$ —	$ 4,883	$ 179	$ (134)	$ 4,928
Operating Expenses	12	3,451	169	(134)	3,498
Operating Income (Loss)	(12)	1,432	10	—	1,430
Equity Earnings (Losses) of Subsidiaries	906	(4)	14	(902)	14
Other Income	48	174	—	(53)	169
Other Deductions	(27)	(45)	—	—	(72)
Other-Than-Temporary Impairments	—	(53)	—	—	(53)
Interest Expense	(116)	(39)	(19)	53	(121)
Income Tax Benefit (Expense)	57	(574)	6	—	(511)
Net Income (Loss)	**$ 856**	**$ 891**	**$ 11**	**$ (902)**	**$ 856**
Comprehensive Income (Loss)	**$ 844**	**$ 855**	**$ 11**	**$ (866)**	**$ 844**
Year Ended December 31, 2015					
Net Cash Provided By (Used In) Operating Activities	$ 571	$ 2,089	$ 80	$ (1,034)	$ 1,706
Net Cash Provided By (Used In) Investing Activities	$ (366)	$ (1,519)	$ (430)	$ 1,314	$ (1,001)
Net Cash Provided By (Used In) Financing Activities	$ (205)	$ (571)	$ 354	$ (280)	$ (702)

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, PSE&G and Power

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of PSEG, PSE&G and Power. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of PSEG, PSE&G and Power have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, PSE&G and Power

We have conducted assessments of our internal control over financial reporting as of December 31, 2017, as required by Section 404 of the Sarbanes-Oxley Act, using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO." Managements' reports on PSEG's, PSE&G's and Power's internal control over financial reporting are included on pages 181, 182 and 183, respectively. The Independent Registered Public Accounting Firm's report with respect to the effectiveness of PSEG's internal control over financial reporting is included on page 184. Management has concluded that internal control over financial reporting is effective as of December 31, 2017.

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2017 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSEG

Management of Public Service Enterprise Group Incorporated (PSEG) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSEG's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSEG's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSEG are being made only in accordance with authorizations of PSEG's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSEG's assets that could have a material effect on the financial statements.

In connection with the preparation of PSEG's annual financial statements, management of PSEG has undertaken an assessment, which includes the design and operational effectiveness of PSEG's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSEG's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSEG's financial reporting and the preparation of its financial statements as of December 31, 2017 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2017.

PSEG's external auditors, Deloitte & Touche LLP, have audited PSEG's financial statements for the year ended December 31, 2017 included in this annual report on Form 10-K and, as part of that audit, have issued a report on the effectiveness of PSEG's internal control over financial reporting, a copy of which is included in this annual report on Form 10-K.

/s/ RALPH IZZO

Chief Executive Officer

/s/ DANIEL J. CREGG

Chief Financial Officer

February 26, 2018

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—PSE&G

Management of Public Service Electric and Gas Company (PSE&G) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSE&G's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSE&G's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSE&G are being made only in accordance with authorizations of PSE&G's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSE&G's assets that could have a material effect on the financial statements.

In connection with the preparation of PSE&G's annual financial statements, management of PSE&G has undertaken an assessment, which includes the design and operational effectiveness of PSE&G's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSE&G's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSE&G's financial reporting and the preparation of its financial statements as of December 31, 2017 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2017.

/s/ RALPH IZZO

Chief Executive Officer

/s/ DANIEL J. CREGG

Chief Financial Officer

February 26, 2018

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING—Power

Management of PSEG Power LLC (Power) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and implemented by the company's management and other personnel, with oversight by the Audit Committee of the Board of Directors of its parent, Public Service Enterprise Group Incorporated, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

Power's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of Power's assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of Power are being made only in accordance with authorizations of Power's management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Power's assets that could have a material effect on the financial statements.

In connection with the preparation of Power's annual financial statements, management of Power has undertaken an assessment, which includes the design and operational effectiveness of Power's internal control over financial reporting based on criteria established in the *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as "COSO". The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that Power's internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of Power's financial reporting and the preparation of its financial statements as of December 31, 2017 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2017.

/s/ RALPH IZZO
Chief Executive Officer

/s/ DANIEL J. CREGG
Chief Financial Officer
February 26, 2018

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Public Service Enterprise Group Incorporated
Newark, New Jersey

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements and the consolidated financial statement schedule listed in the Index at Item 15(B)(a) as of and for the year ended December 31, 2017 of the Company, and our report dated February 26, 2018, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting - PSEG. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
Parsippany, New Jersey
February 26, 2018

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

PSEG

The information required by Item 10 of Form 10-K with respect to executive officers is set forth in Part I. Executive Officers of the Registrant (PSEG).

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Directors

PSEG

The information required by Item 10 of Form 10-K with respect to (i) present directors of PSEG who are nominees for election as directors at PSEG's 2018 Annual Meeting of Stockholders, (ii) the director nomination process, and (iii) the composition of the Audit Committee of the Board, is set forth under the headings "Nominees and Election-Board Composition and Individual Qualifications," "Nominees and Election-Nomination Process," and "Corporate Governance-Board Committee Responsibilities-Audit Committee," respectively, in PSEG's definitive Proxy Statement for such Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 12, 2018 and which information set forth under said heading is incorporated herein by this reference thereto.

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Standards of Conduct

Our Standards of Conduct (Standards) is a code of ethics applicable to us and our subsidiaries. The Standards are an integral part of our business conduct compliance program and embody our commitment to conduct operations in accordance with the highest legal and ethical standards. The Standards apply to all of our directors and employees (including PSE&G's, Power's, Energy Holdings' and Services' respective principal executive officer, principal financial officer, principal accounting officer or Controller and persons performing similar functions). Each such person is responsible for understanding and complying with the Standards. The Standards are posted on our website, www.pseg.com/info/investors/governance/document.jsp. We will send you a copy on request.

The Standards establish a set of common expectations for behavior to which each employee must adhere in dealings with investors, customers, fellow employees, competitors, vendors, government officials, the media and all others who may associate their words and actions with us. The Standards have been developed to provide reasonable assurance that, in conducting our business, employees behave ethically and in accordance with the law and do not take advantage of investors, regulators or customers through manipulation, abuse of confidential information or misrepresentation of material facts.

We will post on our website, www.pseg.com/info/investors/governance/document.jsp:

- Any amendment (other than one that is technical, administrative or non-substantive) that we adopt to our Standards; and
- Any grant by us of a waiver from the Standards that applies to any director or executive officer and that relates to any element enumerated by the SEC.

In 2017, we did not grant any waivers to the Standards.

Section 16(a) Beneficial Ownership Reporting Compliance

PSEG

The information required by Item 10 of Form 10-K with respect to compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth under the heading "Section 16(a) Beneficial Ownership Reporting Compliance," in

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PSEG's definitive Proxy Statement for the 2018 Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the SEC on or about March 12, 2018 and which information set forth under said heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

PSEG

The information required by Item 11 of Form 10-K is set forth in PSEG's definitive Proxy Statement for the 2018 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 12, 2018 and such information set forth under such heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDERS MATTERS

PSEG

The information required by Item 12 of Form 10-K with respect to directors, executive officers and certain beneficial owners is set forth under the heading "Security Ownership of Directors, Management and Certain Beneficial Owners" in PSEG's definitive Proxy Statement for the 2018 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 12, 2018 and such information set forth under such heading is incorporated herein by this reference thereto.

For information relating to securities authorized for issuance under equity compensation plans, see Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

PSEG

The information required by Item 13 of Form 10-K is set forth under the heading "Corporate Governance—Transactions with Related Persons" in PSEG's definitive Proxy Statement for the 2018 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 12, 2018 and such information set forth under such heading is incorporated herein by this reference thereto.

Power and PSE&G

Omitted pursuant to conditions set forth in General Instruction I of Form 10K.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 of Form 10-K is set forth under the heading "Fees Billed by Deloitte & Touche LLP for 2017 and 2016" in PSEG's definitive Proxy Statement for the 2018 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 12, 2018. Such information set forth under such heading is incorporated herein by this reference hereto.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(A) The following Financial Statements are filed as a part of this report:

a. Public Service Enterprise Group Incorporated's Consolidated Balance Sheets as of December 31, 2017 and 2016 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Stockholders' Equity for the three years ended December 31, 2017 on pages 77 through 82.

b. Public Service Electric and Gas Company's Consolidated Balance Sheets as of December 31, 2017 and 2016 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Common Stockholder's Equity for the three years ended December 31, 2017 on pages 83 through 88.

c. PSEG Power LLC's Consolidated Balance Sheets as of December 31, 2017 and 2016 and the related Consolidated Statements of Operations, Comprehensive Income, Cash Flows and Capitalization and Member's Equity for the three years ended December 31, 2017 on pages 89 through 94.

(B) The following documents are filed as a part of this report:

a. PSEG's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2017 (page 193).

b. PSE&G's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2017 (page 193).

c. Power's Financial Statement Schedules:

Schedule II—Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2017 (page 193).

Schedules other than those listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(C) The following documents are filed as part of this report:

LIST OF EXHIBITS:

a.	**PSEG:**
3a	Certificate of Incorporation Public Service Enterprise Group Incorporated(1)
3b	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 23, 1987(2)
3c	Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 20, 2007(3)
3d	By-Laws of Public Service Enterprise Group Incorporated effective December 15, 2015(4)
4a	Indenture between Public Service Enterprise Group Incorporated and First Union National Bank (U.S. Bank National Association, successor), as Trustee, dated January 1, 1998 providing for Deferrable Interest Subordinated Debentures in Series (relating to Quarterly Preferred Securities)(5)
4b	Indenture between Public Service Enterprise Group Incorporated and U.S. Bank National Association (as successor to First Union National Bank), as Trustee, dated November 1, 1998 providing for Senior Debt Securities(6)
10a(1)	Supplemental Executive Retirement Income Plan, dated July 10, 2017(7)
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees, dated July 10, 2017(8)

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LIST OF EXHIBITS:

10a(3)	Employment Agreement with William Levis dated December 8, 2006[9]
10a(4)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011[10]
10a(5)	Deferred Compensation Plan for Directors, amended January 1, 2018
10a(6)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011[11]
10a(7)	1989 Long-Term Incentive Plan, as amended[12]
10a(8)	2001 Long-Term Incentive Plan[13]
10a(9)	Senior Management Incentive Compensation Plan[14]
10a(10)	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective November 20, 2017
10a(11)	Severance Agreement with Ralph Izzo dated December 16, 2008[15]
10a(12)	Stock Plan for Outside Directors, as amended[16]
10a(13)	Compensation Plan for Outside Directors[17]
10a(14)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013[18]
10a(15)	Form of Agreement for Advancement of Expenses with Outside Directors[19]
10a(16)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011[20]
10a(17)	Amendment to Employment Agreement with William Levis, dated September 19, 2011[21]
10a(18)	Agreement with Tamara L. Linde dated June 18, 2014[22]
10a(19)	Agreement with Daniel J. Cregg dated September 22, 2015[23]
10a(20)	Clawback Practice, effective February 20, 2018
10a(21)	Agreement with Ralph LaRossa dated June 21, 2017
10a(22)	Agreement with Derek M. DiRisio dated July 15, 2014
12	Computation of Ratios of Earnings to Fixed Charges
21	Subsidiaries of the Registrant
23	Consent of Independent Registered Public Accounting Firm
31	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934 (1934 Act)
31a	Certification by Daniel J. Cregg, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32a	Certification by Daniel J. Cregg, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
b.	**PSE&G**
3a(1)	Restated Certificate of Incorporation of PSE&G[24]
3a(2)	Certificate of Amendment of Certificate of Restated Certificate of Incorporation of PSE&G filed February 18, 1987 with the State of New Jersey adopting limitations of liability provisions in accordance with an amendment to New Jersey Business Corporation Act[25]
3a(3)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed June 17, 1992 with the State of New Jersey, establishing the 7.44% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock[26]
3a(4)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed March 11, 1993 with the State of New Jersey, establishing the 5.97% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock[27]
3a(5)	Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed January 27, 1994 with the State of New Jersey, establishing the 6.92% Cumulative Preferred Stock ($100 Par) and the 6.75% Cumulative Preferred Stock ($25 Par) as a series of Preferred Stock[28]

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LIST OF EXHIBITS:

3b(1)	By-Laws of PSE&G as in effect April 17, 2007[29]
4a(1)	Indenture between PSE&G and Fidelity Union Trust Company (now, Wachovia Bank, National Association), as Trustee, dated August 1, 1924[30], securing First and Refunding Mortgage Bond and Supplemental Indentures between PSE&G and U.S. Bank National Association, successor, as Trustee, supplemental to Exhibit 4a(1), dated as follows:
4a(2)	June 1, 1937[31]
4a(3)	July 1, 1937[32]
4a(4)	March 1, 1942[33]
4a(5)	June 1, 1991 (No. 1)[34]
4a(6)	July 1, 1993[35]
4a(7)	August 1, 2004 (No. 4)[36]
4a(8)	April 1, 2007[37]
4a(9)	May 1, 2012[38]
4a(10)	June 1, 2012[39]
4a(11)	May 1, 2013[40]
4a(12)	August 1, 2014[41]
4a(13)	May 1, 2015[42]
4a(14)	September 1, 2016[43]
4b	Indenture of Trust between PSE&G and Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor), as Trustee, providing for Secured Medium-Term Notes dated July 1, 1993[44]
4c	Indenture dated as of December 1, 2000 between Public Service Electric and Gas Company and First Union National Bank (U.S. Bank National Association, successor), as Trustee, providing for Senior Debt Securities[45]
10a(1)	Supplemental Executive Retirement Income Plan, dated July 10, 2017[7]
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees, dated July 10, 2017[8]
10a(3)	Amended and Restated 2007 Equity Compensation Plan for Outside Directors, effective July 19, 2011[10]
10a(4)	Deferred Compensation Plan for Directors, amended January 1, 2018
10a(5)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011[11]
10a(6)	1989 Long-Term Incentive Plan, as amended[12]
10a(7)	2001 Long-Term Incentive Plan[13]
10a(8)	Senior Management Incentive Compensation Plan[14]
10a(9)	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective November 20, 2017
10a(10)	Severance Agreement with Ralph Izzo dated December 16, 2008[15]
10a(11)	Stock Plan for Outside Directors, as amended[16]
10a(12)	Compensation Plan for Outside Directors[17]
10a(13)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013[18]
10a(14)	Form of Agreement for Advancement of Expenses with Outside Directors[46]
10a(15)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011[20]
10a(16)	Agreement with Tamara L. Linde dated June 18, 2014[22]
10a(17)	Agreement with Daniel J. Cregg dated September 22, 2015[23]
10a(18)	Clawback Practice, effective February 20, 2018
12a	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements
23a	Consent of Independent Registered Public Accounting Firm
31b	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31c	Certification by Daniel J. Cregg, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32b	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32c	Certification by Daniel J. Cregg, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code

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LIST OF EXHIBITS:

101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document
c.	**Power:**
3a	Certificate of Formation of PSEG Power LLC(47)
3b	PSEG Power LLC Limited Liability Company Agreement(48)
4a	Indenture dated April 16, 2001 between and among PSEG Power, PSEG Fossil, PSEG Nuclear, PSEG Energy Resources & Trade and The Bank of New York Mellon and form of Subsidiary Guaranty included therein(49)
4b	First Supplemental Indenture, supplemental to Exhibit 4a, dated as of March 13, 2002(50)
10a(1)	Supplemental Executive Retirement Income Plan, dated July 10, 2017(7)
10a(2)	Retirement Income Reinstatement Plan for Non-Represented Employees, dated July 10, 2017(8)
10a(3)	Employment Agreement with William Levis dated December 8, 2006(9)
10a(4)	Deferred Compensation Plan for Certain Employees, amended November 1, 2011(11)
10a(5)	1989 Long-Term Incentive Plan, as amended(12)
10a(6)	2001 Long-Term Incentive Plan(13)
10a(7)	Senior Management Incentive Compensation Plan(14)
10a(8)	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective November 20, 2017
10a(9)	Severance Agreement with Ralph Izzo dated December 16, 2008(15)
10a(10)	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013(18)
10a(11)	Equity Deferral Plan, effective November 1, 2011, amended December 9, 2011(20)
10a(12)	Amendment to Employment Agreement with William Levis, dated September 19, 2011(21)
10a(13)	Agreement with Tamara L. Linde dated June 18, 2014(22)
10a(14)	Agreement with Daniel J. Cregg dated September 22, 2015(23)
10a(15)	Clawback Practice, effective February 20, 2018
10a(16)	Agreement with Ralph LaRossa dated June 21, 2017
12b	Computation of Ratio of Earnings to Fixed Charges
23b	Consent of Independent Registered Public Accounting Firm
31d	Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
31e	Certification by Daniel J. Cregg, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
32d	Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
32e	Certification by Daniel J. Cregg, pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation Linkbase
101.LAB	XBRL Taxonomy Extension Labels Linkbase
101.PRE	XBRL Taxonomy Extension Presentation Linkbase
101.DEF	XBRL Taxonomy Extension Definition Document

(1) Filed as Exhibit 3.1a with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120, on May 4, 2007 and incorporated herein by this reference.

(2) Filed as Exhibit 3.1b with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120, on May 4, 2007 and incorporated herein by this reference.

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(3) Filed as Exhibit 3.1c with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120, on May 4, 2007 and incorporated herein by this reference.
(4) Filed as Exhibit 99.1 with Current Report on Form 8-K, File No. 001-09120, on December 16, 2015 and incorporated herein by this reference.
(5) Filed as Exhibit 4(f) with Quarterly Report on Form 10-Q for the quarter ended March 31, 1998, File No. 001-09120, on May 13, 1998 and incorporated herein by this reference.
(6) Filed as Exhibit 4(f) to the Annual Report on Form 10-K for the year ended December 31, 1998, File No. 001-09120, on February 23, 1999 and incorporated herein by this reference
(7) Filed as Exhibit 10.1 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, File No. 001-09120, on July 28, 2017 and incorporated herein by this reference.
(8) Filed as Exhibit 10.2 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, File No. 001-09120, on July 28, 2017 and incorporated herein by this reference.
(9) Filed as Exhibit 10a(4) with Annual Report on Form 10-K for the year ended December 31, 2007, File Nos. 001-09120 on February 28, 2008 and 000-49614, and incorporated herein by reference.
(10) Filed as Exhibit 10.5 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120, on November 1, 2011 and incorporated herein by this reference.
(11) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120, on February 27, 2012 and incorporated herein by this reference.
(12) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 001-09120, on November 4, 2002 and incorporated herein by this reference.
(13) Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2000, File No. 001-09120, on March 6, 2001 and incorporated herein by this reference.
(14) Filed as Exhibit 10a(11) with Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-09120, on February 26, 2009 and incorporated herein by this reference.
(15) Filed as Exhibit 99 with Current Report on Form 8-K, File Nos. 001-09120, 000-49614 and 001-00973, on December 22, 2008 and incorporated herein by this reference.
(16) Filed as Exhibit 10a(17) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(17) Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.
(18) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, File No. 001-09120, on May 1, 2013 and incorporated herein by reference.
(19) Filed as Exhibit 10.1 with Current Report on Form 8-K, File No. 001-09120, on February 19, 2009 and incorporated herein by this reference.
(20) Filed as Exhibit 10a(19) with Annual Report on Form 10-K for the year ended December 31, 2011, File No. 001-09120, on February 27, 2012.
(21) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, File No. 001-09120, on November 1, 2011 and incorporated herein by reference.
(22) Filed as Exhibit 10a with Annual Report on Form 10-K for the year ended December 31, 2014, File No. 001-09120, on February 26, 2015.
(23) Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, File No. 001-09120, on October 30, 2015.
(24) Filed as Exhibit 3(a) with Quarterly Report on Form 10-Q for the quarter ended June 30, 1986, File No. 001-00973, on August 28, 1986 and incorporated herein by this reference.
(25) Filed as Exhibit 3a(2) with Annual Report on Form 10-K for the year ended December 31, 1987, File No. 001-00973, on March 28, 1988 and incorporated herein by this reference.
(26) Filed as Exhibit 3a(3) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(27) Filed as Exhibit 3a(4) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(28) Filed as Exhibit 3a(5) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.
(29) Filed as Exhibit 3.3 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-00973, on May 4, 2007 and incorporated herein by this reference.
(30) Filed as Exhibit 4b(1) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973, on February 18, 1981 and incorporated herein by this reference.
(31) Filed as Exhibit 4b(3) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973, on February 18, 1981 and incorporated herein by this reference.

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(32) Filed as Exhibit 4b(4) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973, on February 18, 1981 and incorporated herein by this reference.
(33) Filed as Exhibit 4b(6) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973, on February 18, 1981 and incorporated herein by this reference.
(34) Filed as Exhibit 4 on Form 8-A, File No. 001-00973, on June 1, 1991 and incorporated herein by this reference.
(35) Filed as Exhibit 4(i) on Form 8-A, File No. 001-00973, on December 1, 1993 and incorporated herein by this reference.
(36) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973, on March 1, 2005 and incorporated herein by this reference.
(37) Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2007, File No. 001-00973, on February 28, 2008 and incorporated herein by this reference.
(38) Filed as Exhibit 4a(32) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-00973, on February 26, 2013.
(39) Filed as Exhibit 4a(33) with Annual Report on Form 10-K for the year ended December 31, 2012, File No. 001-00973, on February 26, 2013.
(40) Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, File No. 001-00973, on July 30, 2013.
(41) Filed as Exhibit 4a(22) with Quarterly Report on Form 10-Q for the quarter ended September 30, 2014, File No. 001-09120, on October 30, 2014 and incorporated herein by reference.
(42) Filed as Exhibit 4a(23) with Quarterly Report on Form 10-Q for the quarter ended June 30, 2015, File No. 001-09120, on July 31, 2015 and incorporated herein by reference.
(43) Filed as Exhibit 4(a)(14) with Annual Report on Form 10-K for the year ended December 31, 2016, File No. 001-00973, on February 27, 2017 and incorporated herein by reference.
(44) Filed as Exhibit 4 with Current Report on Form 8-K, File No. 001-00973, on December 1, 1993 and incorporated herein by reference.
(45) Filed as Exhibit 4.6 to Registration Statement on Form S-3, File No. 333-76020, filed on December 27, 2001 and incorporated herein by reference.
(46) Filed as Exhibit 10.2 with Current Report on Form 8-K, File No. 001-00973, on February 19, 2009 and incorporated herein by reference.
(47) Filed as Exhibit 3.1 to Registration Statement on Form S-4, No. 333-69228, filed on September 10, 2001 and incorporated herein by this reference.
(48) Filed as Exhibit 3.2 to Registration Statement on Form S-4, No. 333-69228, filed on September 10, 2001 and incorporated herein by this reference.
(49) Filed as Exhibit 4.1 to Registration Statement on Form S-4, No. 333-69228, filed on September 10, 2001 and incorporated herein by this reference.
(50) Filed as Exhibit 4.7 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, File No. 000-49614, on May 15, 2002 and incorporated herein by this reference.

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Schedule II—Valuation and Qualifying Accounts Years Ended December 31, 2017—December 31, 2015

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2017						
Allowance for Doubtful Accounts	$ 68	$ 76	$ —	$ 85	(A)	$ 59
Materials and Supplies Valuation Reserve	37	2	—	32	(C)	7
2016						
Allowance for Doubtful Accounts	$ 67	$ 85	$ —	$ 84	(A)	$ 68
Materials and Supplies Valuation Reserve	11	32	—	6	(B)	37
2015						
Allowance for Doubtful Accounts	$ 52	$ 101	$ —	$ 86	(A)	$ 67
Materials and Supplies Valuation Reserve	15	2	—	6	(B)	11

(A) Accounts Receivable written off.
(B) Reduce reserve to appropriate level and to remove obsolete inventory.
(C) Hudson and Mercer inventory written off.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2017						
Allowance for Doubtful Accounts	$ 68	$ 76	$ —	$ 85	(A)	$ 59
Materials and Supplies Valuation Reserve	—	—	—	—		—
2016						
Allowance for Doubtful Accounts	$ 67	$ 85	$ —	$ 84	(A)	$ 68
Materials and Supplies Valuation Reserve	1	—	—	1	(B)	—
2015						
Allowance for Doubtful Accounts	$ 52	$ 101	$ —	$ 86	(A)	$ 67
Materials and Supplies Valuation Reserve	2	—	—	1	(B)	1

(A) Accounts Receivable written off.
(B) Reduce reserve to appropriate level and to remove obsolete inventory.

PSEG POWER LLC

Column A	Column B	Column C Additions		Column D		Column E
Description	Balance at Beginning of Period	Charged to cost and expenses	Charged to other accounts-describe	Deductions-describe		Balance at End of Period
			Millions			
2017						
Materials and Supplies Valuation Reserve	$ 37	$ 2	$ —	$ 32	(A)	$ 7
2016						
Materials and Supplies Valuation Reserve	$ 10	$ 32	$ —	$ 5	(B)	$ 37
2015						
Materials and Supplies Valuation Reserve	$ 13	$ 2	$ —	$ 5	(B)	$ 10

(A) Hudson and Mercer inventory written off.
(B) Reduce reserve to appropriate level and to remove obsolete inventory.

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

Term	Phrase/Description
Base load	Minimum amount of electric power delivered or required over a given period of time at a constant rate, this is the level of demand that is seen as a minimum during a 24-hour day
BGS	Basic Generation Service PSE&G is required to provide BGS for all customers in New Jersey who are not supplied by a third-party supplier.
BGS-RSCP	Basic Generation Service-Residential Small Commercial Product Seasonally adjusted fixed prices charged for a three-year term for electric supply service to smaller industrial and commercial customers and residential customers who are not supplied by a TPS
BGSS	Basic Gas Supply Service Mechanism approved by the BPU for NJ utilities to recover all commodity costs related to supplying gas to residential customers
BPU	New Jersey Board of Public Utilities Agency responsible for regulating public utilities doing business in New Jersey
Capacity	Amount of electricity that can be produced by a specific generating facility
Combined Cycle	A method of generation whereby electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity
Congestion	Condition when the available capacity of a transmission line is being closely approached (or exceeded) by the electric power trying to go through it; at such times, alternative power line pathways (or local generators near the load) must be used instead
Distribution	The delivery of electricity to the retail customer's home, business or industrial facility through low voltage distribution lines
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board A private, not-for-profit organization whose primary purpose, as designated by the SEC, is to develop accounting standards for public companies in the U.S.
FERC	U.S. Federal Energy Regulatory Commission
Forward contracts	A customized, non-exchange traded contract in which the buyer is obligated to deliver a specified amount of a commodity with a predetermined price formula on a specified future date, at which time payment is due in full
GAAP	Generally Accepted Accounting Principles Standard framework of guidelines issued by the FASB for financial accounting used in the U.S.
GHG	Greenhouse gas emissions (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon) that trap the heat of the sun in the Earth's atmosphere, increasing the mean global surface temperature of the earth
Hedging	Entering into a contract or transaction designed to reduce exposure to various risks, such as changes in market prices
ISO	Independent System Operator An independent, regulated entity established to manage a regional electric transmission system in a non-discriminatory manner and to help ensure the safety and reliability of the bulk of the power system
Load	Amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of consumers.

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Term	Phrase/Description
MBR	Market Based Rates Electric service prices determined in an open market system of supply and demand under which the price is set solely by agreement as to what a buyer will pay and a seller will accept
MGP	Manufactured Gas Plant
ISO-NE	New England Power Pool An ISO comprised of an alliance of approximately 100 utility companies who manage and direct all major energy production and transmission in the New England states
NJDEP	New Jersey Department of Environmental Protection
NRC	U.S. Nuclear Regulatory Commission
NUG	Non-Utility Generation Power produced by independent power producers, exempt wholesale generators and other companies that have been exempted from traditional utility regulation
OPEB	Other Postretirement Benefits Benefits other than pensions payable to former employees
Outage	The period during which a generating unit, transmission line, or other facility is out of service due to scheduled (planned) or unscheduled maintenance
PJM	PJM Interconnection, L.L.C. A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 northeastern states and the District of Columbia
Power	PSEG Power LLC
Power Pool	An association of two or more interconnected electric systems having an agreement to coordinate operations and planning for improved reliability and efficiencies
PSE&G	Public Service Electric and Gas Company
PSEG	Public Service Enterprise Group Incorporated
Renewable Energy	Energy derived from resources that are regenerative or that cannot be depleted (i.e. moving water (hydro, tidal and wave power), thermal gradients in ocean water, biomass, geothermal energy, solar energy, and wind energy)
Regulatory Asset	Costs deferred by a regulated utility company in accordance with Accounting Standards Codification Topic 980: Regulated operations (ASC 980)
Regulatory Liability	Costs recognized by a regulated utility company in accordance with ASC 980
RPM	Reliability Pricing Model (PJM market) A process for pricing generation capacity based on overall system reliability requirements; using multi-year forward auctions, participants could bid capacity in the form of generation, demand response, or transmission to meet reliability needs by location and/or an ISO market
SBC	Societal Benefits Charge
SEC	U.S. Securities and Exchange Commission
Tax Act	Comprehensive tax legislation, Public Law 115-97, enacted by the U.S. government in December 2017, which, among other things, decreased the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018, and made certain changes to bonus depreciation rules.
Transmission	The high-voltage wires and networks that move electricity through states and regions in large quantities - from power plants where it is produced, to the distribution networks that deliver it to homes and businesses

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

By: /s/ RALPH IZZO
Ralph Izzo
Chairman of the Board, President and
Chief Executive Officer

Date: February 26, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board, President, Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2018
/s/ DANIEL J. CREGG **Daniel J. Cregg**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2018
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 26, 2018
/s/ WILLIE A. DEESE **Willie A. Deese**	Director	February 26, 2018
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper, Jr.**	Director	February 26, 2018
/s/ WILLIAM V. HICKEY **William V. Hickey**	Director	February 26, 2018
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 26, 2018
/s/ DAVID LILLEY **David Lilley**	Director	February 26, 2018
/s/ BARRY H. OSTROWSKY **Barry H. Ostrowsky**	Director	February 26, 2018
/s/ THOMAS A. RENYI **Thomas A. Renyi**	Director	February 26, 2018
/s/ HAK CHEOL SHIN **Hak Cheol Shin**	Director	February 26, 2018
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 26, 2018
/s/ SUSAN TOMASKY **Susan Tomasky**	Director	February 26, 2018

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/s/ ALFRED W. ZOLLAR	Director	February 26, 2018
Alfred W. Zollar		

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By: /s/ DAVID M. DALY

David M. Daly

President and Chief Operating Officer

Date: February 26, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2018
/s/ DANIEL J. CREGG **Daniel J. Cregg**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2018
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 26, 2018
/s/ ALBERT R. GAMPER, JR. **Albert R. Gamper Jr.**	Director	February 26, 2018
/s/ SHIRLEY ANN JACKSON **Shirley Ann Jackson**	Director	February 26, 2018
/s/ RICHARD J. SWIFT **Richard J. Swift**	Director	February 26, 2018

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC

By: /s/ RALPH LAROSSA
Ralph LaRossa
President and Chief Operating Officer

Date: February 26, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature	Title	Date
/s/ RALPH IZZO **Ralph Izzo**	Chairman of the Board and Chief Executive Officer and Director (Principal Executive Officer)	February 26, 2018
/s/ DANIEL J. CREGG **Daniel J. Cregg**	Executive Vice President and Chief Financial Officer and Director (Principal Financial Officer)	February 26, 2018
/s/ STUART J. BLACK **Stuart J. Black**	Vice President and Controller (Principal Accounting Officer)	February 26, 2018
/s/ DEREK M. DIRISIO **Derek M. DiRisio**	Director	February 26, 2018
/s/ RALPH LAROSSA **Ralph LaRossa**	Director	February 26, 2018
/s/ TAMARA L. LINDE **Tamara L. Linde**	Director	February 26, 2018
/s/ MARGARET M. PEGO **Margaret M. Pego**	Director	February 26, 2018

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Exhibit 10a(5)

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

DEFERRED COMPENSATION PLAN FOR DIRECTORS

Amended Effective January 1, 2018

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
DEFERRED COMPENSATION PLAN FOR DIRECTORS
Amended Effective January 1, 2018

1 PURPOSE. The Plan is designed to provide a method of deferring payment to non-employee Directors of their fees and annual retainers, as fixed from time to time by the Board of Directors, until termination of their services on the Board.

2. PLAN PERIODS. The first Plan Period shall commence upon the election of Directors at the 1987 Annual Stockholders' Meeting and terminate upon the election of Directors at the 1988 Annual Stockholders' Meeting. Subsequent Plan Periods shall relate to successive similar periods between Annual Stockholders Meetings. Effective January 1, 2002, Plan Periods shall be calendar year periods.

3. ADMINISTRATION. The Plan shall be administered by a Committee consisting of the Chief Executive Officer of the Company and two other officers appointed by him. The Committee shall have the power to interpret the Plan and, subject to its provisions, to make all determinations necessary or desirable for the Plan's administration.

4. PARTICIPATION.

(a) An individual who serves as a Director and is not otherwise employed by the Company or any of its subsidiaries shall be eligible to participate in the Plan if he or she elects to have payment of his or her annual retainer, his or her fees or his or her annual retainer and fees in respect of a Plan Period deferred as provided herein.

(b) All elections to defer must be made in the calendar year prior to the year that the services giving rise to the compensation are performed. The election shall be made by written notice to the Plan filed with the Company's Secretary prior to the first day of such Plan Period or, in the case of a Director who first becomes eligible during a Plan Period, not later than 30 days after he or she first becomes eligible. Except as otherwise provided herein, each such election shall be irrevocable.

(c) Special One-Time Election to Rescind 2005 Deferrals - Not later than December 30, 2005, Participants who had elected to defer compensation during 2005 may, by written notice, the form of which shall be designated and published by the Committee, rescind his/her election to defer 2005 compensation and such amounts shall be currently paid to the Participant.

(d) Special One-Time Election to Change Distribution Elections with respect to 2005, 2006, 2007 or 2008 Deferrals - Not later than December 31, 2008, Participants who had elected to defer compensation during 2005, 2006, 2007 or 2008 may, by written notice in a form approved by the Committee, elect to change the distribution elections with respect to any such deferrals.

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5. DEFERRED COMPENSATION ACCOUNTS.

(a) An account shall be established for each eligible electing Director (a "Participant") which shall be designated as his or her Deferred Compensation Account. If a Participant elects to have payment deferred of his or her annual retainer, the amount of the annual retainer payable to him or her with respect to a Plan Period shall be credited, in four equal installments on or about the last day of March , June, September and December in the Plan Period to which such retainer relates, to his or her Deferred Compensation Account, subject to the provisions of Section 5(c). If a Participant elects to have payment deferred of his or her fees, the amount of each fee payable to him or her for attendance at a meeting during a Plan Period shall be credited to his or her Deferred Compensation Account on or about the first business day following such meeting. The Company shall not be required to segregate any amounts credited to the Deferred Compensation Accounts, which shall be established merely as an accounting convenience. Amounts credited to the Deferred Compensation Accounts shall at all times remain solely the property of the Company subject to the claims of its general creditors.

(b) A Director, except a Director not actively serving on the Board on April 1, 2000, may direct investment of his or her Account among the Investment Funds (hereinafter defined) (in the manner established by the Committee) in multiples of one percent; provided, however, that the Committee shall not be obligated to effectuate any such investment direction. The amounts credited to a Deferred Compensation Account shall accrue earnings credits as determined by the Investment Fund(s) selected by the Director. In the case of (i) Director not actively serving on the Board on April 1, 2000 and (ii) a Director who fails to provide a designation of Investment Funds, each such Director shall be deemed to have designated 100 percent of his or her Account to be invested in the Investment Fund that determines income accrual with reference to the prime commercial lending rate of JPMorgan Chase Bank (formerly, the Chase Manhattan Bank). Except with respect to an investment election related to (a) an election made within 30 days of April 1, 2000 and (b) any Investment Fund which is discontinued during a Plan Year, each of which shall be effective immediately. Effective July 1, 2011, the prime commercial lending rate of JPMorgan Chase Bank shall be capped at 120% applicable federal long-term rate.

A Director's investment election may be changed daily.

Each Director's Account shall be valued daily.

(c) 'Investment Fund' - the fund or funds selected by the Committee from time to time and included in Schedule C of the Plan which shall serve as a means of measuring the increase or decrease of each Director's Account. The Committee may, in its discretion, add or discontinue any Investment Fund available under the Plan. The Committee shall provide each affected Director with the opportunity, without

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limiting or otherwise impairing any other right of such Director regarding changes in investment directions, to redirect the allocation of his or her Account invested in any discontinued Investment Fund among the other Investment Funds available under the Plan, including any replacement investment vehicle.

(d) If, prior to the end of a Plan Period, a Participant becomes an employee of the Company or one of its subsidiaries or dies or ceases for any reason to be a Director, or if the effective date of participation by a Participant for any Plan Period shall be other than the first day thereof, he or she will be entitled to be credited with that proportion of the annual retainer for the full Plan Period which the number of days of his or her participation in the Plan during such Plan Period bears to the total number of days in such Plan Period.

6. PAYMENT.

(a) Following termination of a Participant's service on the Board, the Company shall distribute his or her Deferred Compensation Account.

(b) For 2011 and Prior Years Deferrals.

(i) By written notice to the Plan filed with the Company's Secretary, a Participant may elect to have distribution of his or her Deferred Compensation Account commence either (1) on the 30th day following the date of termination of the Participant's service on the Board, (2) on the 15th day of January next following the date of termination of the Participant's service on the Board or (3) on the 15th day of January of any calendar year following termination of the Participant's service on the Board, but not later than the January following the Participant's 71st birthday, unless the Participant is still a Director at such time, in which case distribution shall commence on the 30th day following the date the Participant ceases to be a Director. Any such election, or any change in such election (by such subsequent written notice to the Secretary of the Company), shall apply only to future deferrals. In the event no election is made as to the commencement of distribution, such distribution shall commence on the 30th day following the date the Participant ceases to be a Director of the Company.

(ii) By written notice to the Plan filed with the Company's Secretary, a Participant may elect to receive the distribution of his or her Deferred Compensation Account in the form of (1) one lump-sum payment, or (2) annual distributions over a period selected by the Participant of up to ten years. In the event a lump-sum payment is made under the Plan, the amount then standing to the Participant's credit in his or her Deferred Compensation Account, including earnings credits provided in Section 5(b) to the date of distribution, shall be paid to the Participant on the date determined under Section 6(b)(i). In the case of a distribution over a period

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of years, the Company shall pay to the Participant, commencing on the date determined under Section 6(b)(i), annual installments from the amount then standing to his or her credit in his or her Deferred Compensation Account, including earnings credits on the unpaid balance at the rate provided in Section 5(b) to the date of distribution. The amount of each installment shall be determined by dividing the then unpaid balance, plus earnings credits, in the Participant's Deferred Compensation Account by the number of installments remaining to be paid. If a Participant does not make an election as to the manner of distribution of his or her Deferred Compensation Account, such distribution shall be made in the form of annual installments paid over a five-year period.

(c) For 2012 and Beyond Deferrals. By written notice to the Plan filed with the Company's Secretary, a Participant may elect to have distribution of each year's deferrals and associated earnings occur on the date or event specified in subsections (i) or (ii). A Participant's distribution election shall apply to future years unless the Participant makes a subsequent election.

(i) For each year, a Participant, may elect to have distribution of that year's deferrals, and associated earnings, made or commence within the 30-day period following the Participant's termination of service on the Board. A Participant may elect to receive such distribution in the form of (A) one lump-sum payment, or (B) annual installments over a three to fifteen year period. In the case of a distribution over a period of years, the Company shall pay to the Participant on the date determined under this Section 6(c)(i) and on the yearly anniversaries of such date, annual installments of the unpaid balance of that year's deferrals, including earnings on the unpaid balance at the rate provided in Section 5(b) of this Plan to the date of distribution. The amount of each installment shall be determined by multiplying the then unpaid balance of that year's deferrals, plus accrued earnings, the numerator of which is one and the denominator of which is the number of annual installments remaining to be paid.

(ii) For each year, a Participant, may elect to have distribution of that year's deferrals and associated earnings be paid or commence on a date that is indicated by the Participant as a specified number of years and/or months following termination of service on the Board. Distribution shall be made or commence within the 30 day period following the date that the Participant elects. A Participant may elect to receive such distribution in the form of (A) one lump-sum payment, or (B) annual installments over a three to fifteen year period. In the case of a distribution over a period of years, the Company shall pay to the Participant on the date determined under this Section 6(c)(ii) and on the yearly anniversaries of such date, annual installments of the unpaid balance of that year's deferrals, including earnings on the unpaid balance at the rate provided in Section 5(b) of this Plan to the date of distribution. The amount of each installment

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shall be determined by multiplying the then unpaid balance of that year's deferrals, plus accrued earnings, the numerator of which is one and the denominator of which is the number of annual installments remaining to be paid.

(iii) If, with respect to any election to defer compensation for 2012 or any subsequent year, a Participant fails to make a proper election with respect to the distribution of such deferred compensation, such amount will be distributed in accordance with the prior year's election (but not any election in place for a year prior to 2012). In the event that no valid election is on file, such amount will be distributed in a lump sum on the date specified in Section 6(c)(i).

(d) The payment of all distributions shall be made cash.

(e) Distribution upon Death.

(i) For 2011 and Prior Years Deferrals. In the event of a Participant's death, the balance of the Participant's Deferred Compensation Account shall be distributed to the Participant's Beneficiary(ies) in annual installments over a period of not more than five years, in accordance with the Participant's election on Schedule B to the Plan filed with the Secretary of the Company. Any change in the period over which such payments are made shall only apply to future deferrals. Such distribution shall be made in a manner consistent with Section 6(c) of the Plan and shall commence on the 30th day following the Participant's death. Additional annual payments for distributions made over a period of more than one year shall be made on the yearly anniversaries of such date. In the event of a Participant's death after distribution of this Deferred Compensation Account has commenced, any election under this Section 6(d) shall not extend the time of payment of his or her Deferred Compensation Account beyond the time when distribution would have been completed if the Participant had lived. A Participant may change Beneficiary designations by filing a subsequent Schedule B with the Secretary of the Company. If a Participant does not make an election as to the manner of distribution of his or her Deferred Compensation Account in the event of his or her death, any such distribution shall be made as a lump-sum payment to his or her estate on the 30th day following the Participant's death.

(ii) For 2012 and Beyond Deferrals. In the event of a Participant's death prior to the date that the Participant commences payment of a year's deferrals and associated earnings, such amount shall be distributed to the Participant's Beneficiary(ies) in a lump sum within 90 days following the Participant's death.

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In the event of the Participant's death after he/she commenced distribution of a year's deferrals and associated earnings in the form of installments, the balance of such year's deferrals and associated earnings shall be distributed to the Participant's Beneficiary(ies) in a lump sum within 90 days following the Participant's death.

A Participant's Beneficiary designation shall apply to all 2012 and beyond deferrals. A Participant cannot designate a different Beneficiary for each year's deferrals. A Participant may change Beneficiary designations by filing a subsequent designation with the Secretary of the Company.

(f) Participants may:

(i) By notice filed with the Company prior to December 31st of any year, make changes of distribution elections on a prospective basis;

(ii) By notice filed with the Company, make changes of distribution elections with respect to prior deferred compensation as long (A) any such new distribution election is made at least one year prior to the date that the commencement of the distribution would otherwise have occurred and (B) the revised commencement date is at least five years later than the date that the commencement of the distribution would otherwise have occurred (with respect to 2012 and beyond deferrals, installment payments shall be treated as one payment);

(iii) Special One-Time Election - by notice filed with the Company prior to December 31, 2005, make a one-time election to change any distribution election previously made with respect to compensation deferred on or before December 31, 2005; or

(iv) Special One-Time Election - Participants may, by notice filed with the Company prior to December 31, 2008, make a one-time election to change any distribution election previously made with respect to compensation deferred during 2005, 2006, 2007 or 2008.

(g) Notwithstanding any other provision of the Plan, if the Committee shall determine in its sole discretion that the time of payment of a Participant's Deferred Compensation Account should be advanced because of protracted illness or other undue hardship, then the Committee may advance the time or times of payment (whether before or after the Retirement Date) only if the Committee determines that an emergency beyond the control of the Participant exists and which would cause such Participant severe financial hardship if the payment of such benefits were not approved. Any such distribution for hardship shall be limited to the amount needed to meet such emergency (plus the amount of any tax liability

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resulting from the distribution). A Participant who receives a hardship distribution may not reenter the Plan for twelve months after the date of such distribution. Any distribution for hardship under this Section 6(f) shall commence on the 15th day following the date the Committee determines to make such hardship distribution.

(h) Distribution in Case of Certain Tax Events - If, with respect to any Participant, the Plan fails to meet the requirements of the Internal Revenue Code with respect to the deferral of tax liability, the Company may accelerate distribution from a Participant's Account amounts sufficient to meet such Participant's resulting Federal, State, Local and/or Foreign tax liability (including any interest and penalties).

7. ASSIGNMENT. No benefit under the Plan shall in any manner or to any extent be assigned, alienated, or transferred by any Participant or Beneficiary or subject to attachment, garnishment or other legal process.

8. TERMINATION AND AMENDMENT.

(a) The Board may terminate the Plan at any time so that no further amounts shall be credited to Deferred Compensation Accounts or may, from time to time, amend the Plan, without the consent of Participants or Beneficiaries; provided, however, that no such amendment or termination shall impair any rights, including rights to income credits pursuant to Section 5(b) hereof, which have accrued under the Plan without the consent of the Participant or Beneficiary, or the legal representative of such person, so affected.

(b) Notwithstanding any other provision of this Plan, upon the occurrence of a Change in Control (as defined below), the income credit calculated pursuant to Section 5(b) hereof may not be reduced below the prime commercial lending rate described therein.

For purposes of this Plan, "Change in Control" shall mean the occurrence of any of the following events:

(i) any "person" (within the meaning of Section 13(d) of the Securities Exchange Act of 1934, as amended from time to time (the "Act")) is or becomes the beneficial owner within the meaning of Rule l3d-3 under the Act (a "Beneficial Owner"), directly or indirectly, of securities of the Corporation (not including in the securities beneficially owned by such person any securities acquired directly from the Corporation or its affiliates) representing 25% or more of the combined voting power of the Corporation's then outstanding securities, excluding any person who becomes such a Beneficial Owner in connection with a transaction described in clause (1) of paragraph (iii) below; or

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(ii) the following individuals cease for any reason to constitute a majority of the number of directors then serving: individuals who, on December 15, 1998, constitute the Board of Directors and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Corporation) whose appointment or election by the Board of Directors or nomination for election by the Corporation's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors on December 15, 1998 or whose appointment, election or nomination for election was previously so approved or recommended; or

(iii) there is consummated a merger or consolidation of the Corporation or any direct or indirect wholly owned subsidiary of the Corporation with any other corporation, other than (1) a merger or consolidation which would result in the voting securities of the Corporation outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of the Corporation or any subsidiary of the Corporation, at least 75% of the combined voting power of the securities of the Corporation or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (2) a merger or consolidation effected to implement a recapitalization of the Corporation (or similar transaction) in which no person is or becomes the Beneficial Owner, directly or indirectly, of securities of the Corporation representing 25% or more of the combined voting power of the Corporation's then outstanding securities; or

(iv) the stockholders of the Corporation approve a plan of complete liquidation or dissolution of the Corporation or there is consummated an agreement for the sale or disposition by the Corporation of all or substantially all of the Corporation's assets, other than a sale or disposition by the Corporation of all or substantially all of the Corporation's assets to an entity, at least 75% of the combined voting power of the voting securities of which are owned by stockholders of the Corporation in substantially the same proportions as their ownership of the Corporation immediately prior to such sale.

Notwithstanding the foregoing subparagraphs (i), (ii), (iii) and (iv), a "Change in Control" shall not be deemed to have occurred by virtue of the consummation of any transaction or series of integrated transactions immediately following which the record holders of the common stock of the Corporation immediately prior to such transaction or series of transactions continue to have substantially the same

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proportionate ownership in an entity which owns all or substantially all of the assets of the Corporation immediately following such transaction or series of transactions.

9. WHAT CONSTITUTES NOTICE. Any notice to an Participant, Beneficiary or legal representative hereunder shall be given either by delivering it or by depositing it in the United States mail, postage prepaid, addressed to his/her last known address. Any notice to the Company or the Committee hereunder (including the filing of election and designation forms) shall be given either by delivering it, or depositing it in the United States mail, postage prepaid, to the Secretary of the Employee Benefits Policy Committee, Public Service Enterprise Group Incorporated, 80 Park Plaza, P. 0. Box 1171, Newark, New Jersey 07102.

10. ADVANCE DISCLAIMER OF ANY WAIVER ON THE PART OF THE COMPANY . Failure by the Company to insist upon strict compliance with any of the terms, covenants or conditions hereof shall not be deemed a waiver of any such term, covenant or condition, nor shall any waiver or relinquishment of any right or power hereunder at any one or more times be deemed a waiver or relinquishment of any such right or power at any other time or times.

11. EFFECT ON INVALIDITY OF ANY PART OF THE PLAN. The invalidity or unenforceability of any provision hereof shall in no way affect the validity or enforceability of any other provision.

12. PLAN BINDING ON ANY SUCCESSOR OWNER. Except as otherwise provided herein, this Plan shall inure to the benefit of and be binding upon the Company, its successors and assigns, including but not limited to any corporation which may acquire all or substantially all of the Company's assets and business or with or into which the Company may be consolidated or merged.

13. LAWS GOVERNING THIS PLAN. Except to the extent federal law applies, this Plan shall be governed by the laws of the State of New Jersey. This Plan is specifically intended to comply with the provisions of the American Jobs Creation Act of 2004 (the "AJCA") and Section 409A of the Code and it shall automatically incorporate all applicable restrictions of the AJCA, the Code and its related regulations, and the Company will amend the Plan to the extent necessary to comply with those requirements. The timing under which a Participant will have a right to receive any payment under this Plan will be deemed to be automatically modified, and a Participant's rights under the Plan limited to conform to any requirements under, the AJCA, the Code and its related regulations.

14. MISCELLANEOUS. The masculine pronoun shall mean the feminine wherever appropriate.

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KEY EXECUTIVE SEVERANCE PLAN OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Amended effective November 20, 2017

S1-SSA-0009 - 12114

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ARTICLE I

PURPOSE OF THE PLAN

1.1 Purpose. The Key Executive Severance Plan of Public Service Enterprise Group Incorporated ("Plan") is maintained by the Company to provide severance benefits to certain key executive-level employees of the Company and its affiliates whose employment is terminated under the circumstances described herein. The Plan was amended and restated effective December 17, 2012.

The Plan was amended effective January 1, 2014 to provide that (i) for Eligible Employees who become Schedule B Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to two times Annual Base Salary and Target Bonus, and (ii) for Eligible Employees who become Schedule A Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to 1.5 times Annual Base Salary and Target Bonus. The Plan was further amended to provide that the for purposes of determining the nonqualified plan change in control benefit under Section 5.5(a) of the Plan, with respect to Eligible Employees who become Schedule A or Schedule B Participants after December 31, 2013, their employment shall be assumed to have continued for 1.5 or 2 additional years (for Schedule A Participants and Schedule B Participants, respectively). Finally, the Plan was amended to update the Schedule A Participant list.

The Plan was amended effective June 16, 2014 to (i) add a new class of eligible Participants, Schedule C Participants, (ii) to provide that there will be no additions to Schedule B Participants, (iii) to provide that other than a current Schedule B Participant, an Eligible Employee newly hired or promoted into a position reflected on Schedule B as of June 16, 2014, shall become a Schedule A Participant, and (iv) to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

The Plan was amended effective July 14, 2014 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan was amended effective February 17, 2015 to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

The Plan was amended effective November 18, 2015 to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list, and to include the language to comply with the Securities and Exchange Commission's whistleblower protections.

The Plan was amended effective December 15, 2015 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan was amended effective July 19, 2016 to update the Schedule A Participant list and the Schedule C Participant list. The Plan was amended to comply with the Defense of Trade Secrets Act regarding the confidentiality provision. Finally, the Plan was amended

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to clarify that if an Eligible Employee is newly hired or promoted into a position reflected on Schedule B as of June 6, 2014, such Eligible Employee shall become a Schedule A Participant.

The Plan was amended effective November 14, 2016 to (i) revise the definition of Cause, (ii) align the severance benefits in Article IV, (iii) align the Change in Control benefits in Article V, (iv) update the Schedule A Participant list and the Schedule C Participant list, and (v) to make administrative clarifications. The Plan is intended to comply in operation and form with Section 409A of the Internal Revenue Code of 1986, as amended ("Code"). The timing and form of payment of benefits provided under the Plan will be deemed to be automatically modified, and a Participant's rights under the Plan will be limited so as to conform to any requirements under Section 409A of the Code.

The Plan was amended effective February 20, 2017 to update the Schedule A Participant list.

The Plan was amended effective April 17, 2017 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan was amended effective July18, 2017 (unless otherwise noted) to update the Schedule A Participant list, the Schedule B Participant List and the Schedule C Participant list.

The Plan is being amended effective November 20, 2017 to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

ARTICLE II

DEFINITIONS

2.1 "Accrued Obligation" shall have the meaning set forth in Sections 4.2 and 5.2 of the Plan.

2.2 "Affiliate" means any corporation, trade or business if it or the Company are members of a controlled group of corporations, are under common control or are members of an affiliated service group within the meanings of Sections 414(b), 414(c) and 414(m), respectively, of the Code. The term "Affiliate" shall also include any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code.

2.3 "Annual Base Salary" means the annual rate of base salary payable to a Participant for services performed for an Employer, as in effect immediately prior to the Participant's Date of Termination.

2.4 "Benefits 2000 Participant" means a Participant who is a participant in the Public Service Enterprise Group Incorporated Benefits 2000 Health and Welfare Benefits Plan.

2.5 "Board" means the board of directors of the Company.

2.6 "Cause" means:

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(a) For purposes of Article IV and Article V:

(i) Misconduct, gross negligence, theft, or fraud against the Company, including an isolated incident, that is determined by the Committee's delegate to be material misconduct or material gross negligence;

(ii) For "Performance Reasons," as defined in Section 2.20 of the Plan;

(iii) Material violation of the Standards of Integrity or other Company policy;

(iv) Insubordination, including an isolated incident, that is determined by the Committee's delegate to be material insubordination;

(v) One or more significant acts of dishonesty;

(vi) Any act that is likely to have the effect of injuring the reputation, business, or business relationship of, the Company, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries;

(vii) Violation of any fiduciary duty, including an isolated incident, that is determined by the Committee's delegate to be a material violation;

(viii) Breach of any duty of loyalty including an isolated incident, that is determined by the Committee's delegate to be a material breach;

(ix) Any breach of the restrictive covenants contained in Exhibit I below;

(x) One or more acts of moral turpitude that constitute a violation of applicable law (included but not limited to a felony);

(xi) Conviction of a felony or plea of *nolo contendere* to a felony charge;

(xii) Pattern of behaviors that fail to meet the Company's expectations described in "PSEG Values, Behaviors, and Leadership Competencies." or

(xiii) Any other reason determined to be Cause by the Chief Executive Officer of the Company.

2.7 "Change in Control" means the occurrence of any of the following events:

(a) Any "person" (within the meaning of Section 13(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) is or becomes the beneficial owner within the meaning of Rule 13d-3 under the Exchange Act (a "Beneficial Owner"), directly or indirectly, of securities of the Company (not including in the securities beneficially owned by such person any securities acquired directly from the Company or its Affiliates) representing 25% or more of the combined voting power of the Company's then outstanding securities, excluding any person who becomes such a Beneficial Owner in connection with a transaction described in clause (i) of paragraph (c) below; or

(b) The following individuals cease for any reason to constitute a majority of the number of directors of the Company then serving: individuals who, on the Effective Date, constitute the Board and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened

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election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's stockholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on the Effective Date or whose appointment, election or nomination for election was previously so approved or recommended; or

(c) There is consummated a merger or consolidation of the Company or any direct or indirect wholly-owned subsidiary of the Company with any other corporation, other than (i) a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of the Company or of its Affiliates, at least 75% of the combined voting power of the securities of the Company or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (ii) a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the Beneficial Owner, directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company's then outstanding securities; or

(d) The shareholders of the Company approve a plan of complete liquidation or dissolution of the Company or there is consummated an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 75% of the combined voting power of the voting securities of which are owned by stockholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale.

Notwithstanding the foregoing, a "Change in Control" shall not be deemed to have occurred by virtue of the consummation of any transaction or series of integrated transactions immediately following which the record holders of the common stock of the Company immediately prior to such transaction or series of transactions continue to have substantially the same proportionate ownership in an entity which owns all or substantially all of the assets of the Company immediately following such transaction or series of transactions.

2.8 "Code" means the Internal Revenue Code of 1986, as amended, and the regulations promulgated thereunder.

2.9 "Committee" means the Organization and Compensation Committee of the Board or any successor of such Committee.

2.10 "Company" means Public Service Enterprise Group Incorporated and any successors thereto.

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2.11 "Confidential Information" means all trade secrets, proprietary and confidential business information belonging to, used by, or in the possession of the Company or any of its Affiliates, including but not limited to information, knowledge or data related to business strategies, plans and financial information, mergers, acquisitions or consolidations, purchase or sale of property, leasing, pricing, sales programs or tactics, actual or past sellers, purchasers, lessees, lessors or customers, those with whom the Company or its Affiliates has begun negotiations for new business, costs, employee compensation, marketing and development plans, inventions and technology, whether such confidential information, knowledge or data is oral, written or electronically recorded or stored, except information in the public domain, information known by the Participant prior to employment with an Employer, and information received by the Participant from sources other than the Company or its Affiliates, without obligation of confidentiality.

2.12 "Date of Termination" means, provided that the termination constitutes a Separation from Service, (i) the date of a Participant's death, (ii) the date on which the termination of the Participant's employment by an Employer for Cause or without Cause, or (iii) the date on which the Participant terminates employment for Good Reason or without Good Reason, including Retirement and Disability.

2.13 "Disability" means (a) if the Participant is a participant in the Pension Plan, the Participant is determined to be totally and permanently disabled by the Company's medical director; or (ii) if the Participant is a participant in the Cash Balance Plan, the Participant is receiving benefits from the Company's long-term disability plan.

2.14 "Eligible Employee" means an individual who is designated as such in accordance with Section 3.1. An Eligible Employee shall not include a "project employee."

2.15 "Effective Date" of the amendment and restatement is November 20, 2017.

2.16 "Employer" means the Company and each Affiliate, and any successors thereto.

2.17 "Good Reason" means:

(a) Any material reduction in the Participant's Annual Base Salary, Target Bonus or Target Long-Term Incentive, other than reductions pursuant to a broad-based compensation reduction program or policy affecting the Participant and all similarly situated employees of the Employer. Notwithstanding the foregoing, this Subsection (a) shall not apply if the Participant moves into a position with ER&T;

(b) Any material adverse change in the Participant's title, authority, duties, or responsibilities or the assignment to the Participant of any duties or responsibilities inconsistent in any respect with those customarily associated with the position of the Participant immediately prior to the Change in Control. Notwithstanding the foregoing, this Subsection (b) shall not apply if the Participant moves into a position with ER&T;

(c) The failure of any successor to the Company to assume this Plan in accordance with Section 11.5(b);

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(d) Where the only comparable position offered to the Participant within the Employer following a Change in Control would otherwise meet the requirements of Subsections (a) and (b) of this Section 2.17 of the Plan, but would require the Participant to increase their one-way commuting distance from their principal residence by more than 50 miles; or

(e) Any other material breach of the terms of the Plan by the Company that either is not taken in good faith or, even if taken in good faith, is not remedied by the Company promptly after receipt of notice thereof from the Participant.

Notwithstanding the forgoing, for purposes of the Plan, the termination of a Participant's employment with an Employer shall not be deemed to be for Good Reason unless such termination is effected in accordance with the following procedures. The Participant shall give the Employer a written notice ("Notice of Termination for Good Reason") of the termination, setting forth in reasonable detail the specific acts or omissions of the Employer that constitute Good Reason and the specific provision(s) of the Plan on which the Participant relies. Unless the Committee determines otherwise, a Notice of Termination for Good Reason by the Participant must be made within 60 days after the Participant first has actual knowledge of the act or omission (or the last in a series of acts or omissions) that the Participant alleges to constitute Good Reason, and the Employer shall have 30 days from the receipt of such Notice of Termination for Good Reason to cure the conduct cited therein. A termination of employment by the Participant for Good Reason shall be effective on the final day of such 30-day cure period unless prior to such time the Employer has cured the specific conduct asserted by the Participant to constitute Good Reason to the reasonable satisfaction of the Participant.

For purposes of the Plan, a Participant's determination that an act or failure to act constitutes Good Reason shall be presumed to be valid unless such determination is decided to be unreasonable by the Committee or its delegate pursuant to Article IX.

2.18 "Nonqualified Plan" means the Retirement Income Reinstatement Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated.

2.19 "Participant" means an Eligible Employee who is listed on either Schedule A, Schedule B or Schedule C hereto, as the same may be amended from time to time.

2.20 "Performance Reasons" means the Participant's failure meet the expectations established for such Participant's function in the Company as: (i) communicated to the Participant by their manager during any performance review, or (ii) may be communicated to the Participant otherwise by their manager from time to time either orally or in writing.

2.21 "Plan" means this Key Executive Severance Plan of Public Service Enterprise Group Incorporated, as set forth herein and as may be amended, modified or supplemented from time to time.

2.22 "Prior Equity Awards" means outstanding stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares and performance shares units.

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2.23 "Retiree Medical Plan" means the Public Service Enterprise Group Incorporated Medical Benefits Plan for Retired Employees.

2.24 "Retirement" means a Separation from Service after the Participant has satisfied the eligibility requirements for early or normal retirement under the terms of the Retirement Plan in which the Participant participates. Notwithstanding the foregoing, for the purposes of determining benefit entitlements under Article V of the Plan, Retirement shall not include forced retirements or any termination by an Employer without Cause or voluntary termination by the Participant for Good Reason that occurs on a date on which the Participant is Retirement eligible.

2.25 "Retirement Plan" means the retirement plan in which the Participant participates in either the Pension Plan of Public Service Enterprise Group Incorporated or the Cash Balance Pension Plan of Public Service Enterprise Group Incorporated.

2.26 "Schedule A Participant" means a Participant listed on Schedule A hereto.

2.27 "Schedule B Participant" means a Participant listed on Schedule B hereto.

2.28 "Schedule C Participant" means a Participant listed on Schedule C hereto.

2.29 "Selectline Participant" means a Participant who is a participant in the Public Service Enterprise Group Incorporated Selectline Benefits Plan.

2.30 "Separation from Service" shall be deemed to have occurred if a Participant and the Company or any Affiliate reasonably anticipates, based on the facts and circumstances, that either:

(a) The Participant will not provide any additional services for the Company or an Affiliate after a certain date; or

(b) The level of bona fide services performed by the Participant after a certain date will permanently decrease to no more than 50 percent of the average level of bona fide services performed by the Participant over the immediately preceding 36 months.

If a Participant is absent from employment due to military leave, sick leave or any other bona fide leave of absence authorized by the Company or an Affiliate and there is a reasonable expectation that the Participant will return to perform services for the Company or an Affiliate, a Separation from Service will not occur until the later of: (i) the first date immediately following the date that is six months after the date that the Participant was first absent from employment; or (ii) the date the Participant no longer retains a right to reemployment, to the extent the Participant retains a right to reemployment with the Company or any Affiliates under applicable law or by contract. If a Participant fails to return to work upon the expiration of any military leave, sick leave or other bona fide leave of absence where such leave is for less than six months, the Separation from Service shall occur as of the date of the expiration of such leave, unless a greater period is provided for under applicable law.

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2.31 "Specified Employee" means any individual who is a key employee (as defined in Section 416(i) of the Code without regard to Section 416(i)(5) of the Code) of the Company at any time during the 12-month period ending on each December 31 (the "identification date"). If an individual is a key employee as of an identification date, the individual shall be treated as a Specified Employee for the 12-month period beginning on the April 1 following the identification date. Notwithstanding the foregoing, an individual shall not be treated as a Specified Employee unless any stock of the Company or an Affiliate is publicly traded on an established securities market or otherwise.

2.32 "Target Bonus" means the Participant's target annual bonus, if any, under the applicable annual incentive compensation plan of the Company for the fiscal year in which the Date of Termination occurs.

2.33 "Target Long-Term Incentive" means the Participant's target long-term incentive award, if any, under the applicable long-term incentive compensation plan of the Company.

ARTICLE III

ELIGIBILITY AND PARTICIPATION

3.1 Eligible Employees. Eligibility to participate in the Plan shall be limited to certain key executives of an Employer who (a) are not parties to individual employment or change in control agreements that provide for severance benefits, and (b) are designated, by duly adopted resolution of the Committee, as Eligible Employees.

3.2 Participation. Schedules A, B and C hereto list the Eligible Employees who have satisfied the conditions for Plan participation and the date as of which each such Eligible Employee became a Participant. The Committee shall cause Schedules A, B and C to be updated from time to time to reflect the Participants who are currently participating in the Plan. An employee who becomes an Eligible Employee on or after January 1, 2014 shall become a Schedule C Participant. However, if an Eligible Employee is newly hired or promoted into a position reflected on Schedule B as of June 6, 2014, the Eligible Employee shall become a Schedule A Participant.

3.3 Release of Claims. Notwithstanding anything in the Plan to the contrary, payment of any benefits under the Plan is expressly contingent upon the Participant's execution and delivery to the Company, within 30 days after the Participant's Date of Termination, of a written agreement provided by the Company, wherein the Participant releases and discharges the Company and each of its Affiliates of any and all claims against the Company and its Affiliates related in any way to the Participant's employment with an Employer and the termination of such employment.

3.4 Committee Discretion. The Committee shall have the sole discretion to determine eligibility for benefits under the Plan.

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ARTICLE IV

SEVERANCE BENEFITS IN GENERAL

4.1 Eligible Terminations. If a Participant's employment is involuntarily terminated by an Employer for any reason other than Cause, the Participant shall be eligible for the benefits described in this Article IV.

If a Participant terminates employment for Good Reason, other than in connection with a change in employment on account of Performance Reasons, the Participant shall be eligible for the benefits described in this Article IV.

If a Participant experiences a cessation of employment in connection with a reduction in force or an Employer reorganization (as determined by the Committee) where the only position offered to the Participant within the Company and Affiliates would require the Participant to increase their one-way commuting distance by more than 50 miles, the Participant shall be eligible for benefits described in this Article IV.

For the avoidance of any doubt, a Participant shall not be entitled to benefits under the Plan if termination from employment is the result of death, Disability, the Participant voluntarily terminates employment, except for Good Reason other than in connection with a change in employment on account of Performance Reasons. Also, the Participant shall not be entitled to benefits under the Plan if the Participant's cessation of employment is in connection with the sale of the Participant's Employer, line or unit of business of the Employer within which the Participant's position is located, business function of the Employer within which the Participant's position is located, or the assets related to the Employer, line or unit or business, or business function within which the Participant's position is located, and the Participant accepts employment with the purchaser within 90 days of the closing of the transaction in a position that has an annual rate of base salary that is at least 80 percent of the Participant's annual rate of base salary immediately prior to the closing of the sale.

If a Participant enters into a Voluntary Separation Agreement ("VSA") with an Employer, such Participant shall not be eligible for benefits under the Plan.

4.2 Cash payment. The Company shall pay to the Participant a lump sum, in cash, the sum of (a) and (b):

(a) The Participant's base salary and accrued vacation pay through the Date of Termination to the extent not theretofore paid (hereinafter referred to as the "Accrued Obligations"); and

(b) An amount equal to the product of 1.0 times (0.5 times if the Participant were employed less than one year) the sum of the Participant's Annual Base Salary and Target Bonus.

4.3 Long-Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

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4.4 Annual Incentive Awards. The Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of calendar days of employment in the calendar year in which the Participant's termination occurs through the Participant's Date of Termination. For purposes of this Section 4.4, calendar year shall mean 365 days.

Annual incentive awards with respect to the calendar year in which a Participant's Date of Termination occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

4.5 Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the Participant's Date of Termination or such earlier date designated by the Participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

4.6 Educational Assistance. Educational assistance shall be provided in accordance with the Employer's tuition program.

4.7 Health Care Benefits.

(a) Medical Coverage for Selectline Participants.

(i) A Selectline Participant who has satisfied the eligibility requirements for medical coverage under the Retiree Medical Plan on the Date of Termination shall be eligible to elect coverage thereunder in accordance with the terms of the Retiree Medical Plan.

(ii) A Selectline Participant who has not otherwise satisfied the eligibility criteria for participation in the Retiree Medical Plan prior to the Date of Termination, shall be eligible to elect coverage under the Retiree Medical Plan as though such Selectline Participant has otherwise satisfied the eligibility requirements if:

(A) The Selectline Participant has attained age 50 and completed ten or more Years of Service as of the Date of Termination but the sum of the Selectline Participant's age and Years of Service is less than 80; or

(B) The Selectline Participant has attained age 49 and completed 20 or more Years of Service as of the Date of Termination but the sum of the Selectline Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Selectline Participant's Date of Termination. The Selectline Participant shall be charged the full cost of coverage under the Retiree Medical Plan.

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(iii) If a Selectline Participant who is not eligible for, or does not elect, coverage under the Retiree Medical Plan, timely elects continuation coverage under the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended ("COBRA"), the Employer shall pay the same portion of the cost of medical and/or dental coverage that it paid immediately prior to the Selectline Participant's Date of Termination for active employees during the one-year period following the Selectline Participant's Date of Termination. During the one-year period, the Participant shall pay the difference between the total cost of medical and/or dental coverage and the Employer's portion of the cost. After the expiration of the one-year period, the Selectline Participant shall be charged the COBRA rate for medical and/or dental coverage for the remainder of the COBRA period. If the Participant does not timely elect COBRA medical and/or dental coverage, the Participant shall not be entitled to the benefit under this Subsection (iii). Following the one-year period, the Selectline Participant shall not be permitted to elect coverage, or be covered, under the Retiree Medical Plan. During the entire COBRA period, the Selectline Participant shall be responsible for the full cost of COBRA vision and hearing coverage, as applicable.

(b) Medical Coverage for Benefits 2000 Participants**.** If a Benefits 2000 Participant who is not eligible for, or does not elect, coverage under the Retiree Plan, timely elects COBRA continuation medical and/or dental coverage, the Employer shall pay the same portion of the cost of medical and/or dental coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the one-year period following the Participant's Date of Termination. During the one-year period, the Participant shall pay the difference between the total cost of medical and/or dental coverage and the Employer's portion of the cost. After the expiration of the one-year period, the Benefits 2000 Participant shall be charged the COBRA rate for medical and/or dental coverage for the remainder of the COBRA period. If the Participant does not timely elect COBRA medical and/or dental coverage, the Participant shall not be entitled to the benefit under this Subsection (b). Following the one-year period, the Benefits 2000 Participant shall not be permitted to elect coverage, or be covered, under the Retiree Medical Plan. During the entire COBRA period, the Benefits 2000 Participant shall be responsible for the full cost of COBRA vision.

4.8 Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided hereunder or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time.

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ARTICLE V

SEVERANCE BENEFITS AFTER A CHANGE IN CONTROL

5.1 Eligible Terminations After a Change in Control. If, within two years following the occurrence of a Change in Control, either (a) an Employer shall terminate a Participant's employment for any reason other than for Cause, or (b) a Participant shall voluntarily terminate employment for Good Reason, the Participant shall be eligible for benefits described in this Article V of the Plan. Notwithstanding anything in the Plan to the contrary, a Participant shall not be entitled to benefits under the Plan if termination from employment is the result of death, Disability or the Participant voluntarily terminates employment, except for Good Reason and except as otherwise provided under the Plan.

If a Participant enters into a VSA with an Employer, such Participant shall not be eligible for benefits under the Plan.

5.2 Cash Payment. The Company shall pay to the Participant, in a lump sum in cash, the aggregate of the amounts in (a) and (b) below:

(a) The sum of:

(i) The Participant's base salary and accrued vacation through the Date of Termination; and

(ii) The product of (x) the Participant's Target Bonus and (y) a fraction, the numerator of which is the number of days in the current calendar year through the Date of Termination, and the denominator of which is 365;

in each case to the extent not theretofore paid (the sum of the amounts described in clauses (i) and (ii) shall be hereinafter referred to as the "Accrued Obligations"); and

(b) Either (i), (ii) or (iii):

(i) In the case of a Schedule A Participant, the amount equal to the product of two times the sum of the Schedule A Participant's Annual Base Salary and Target Bonus;

(ii) In the case of a Schedule B Participant, the amount equal to the product of three times the sum of the Schedule B Participant's Annual Base Salary and Target Bonus; or

(iii) In the case of a Schedule C Participant, the amount equal to the product of one and one-half times the sum of the Schedule C Participant's Annual Base Salary and Target Bonus.

5.3 Long Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.4 Health Care and Other Welfare Benefits. The Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the

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Company's medical and dental employee benefit plans for 18 months after the Date of Termination provided that the Participant timely makes an election to continue such coverage in the Company's medical and dental employee benefit plans under COBRA, subject to the requirements and limitations thereof. Unless otherwise limited by applicable law, thereafter, the Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for an additional period of six months, in the case of a Schedule A Participant, or 18 months, in the case of a Schedule B Participant (for a Schedule C Participant, no additional period beyond the initial 18 months); provided however, that if the Participant becomes re-employed with another employer and is eligible to receive medical or dental benefits under another employer provided plan, the medical and dental benefits provided by the Company under this Plan shall be secondary to those provided under such other plan during the applicable period of eligibility. If the Participant does not timely elect COBRA coverage, the Participant shall not be entitled to the COBRA continuation benefit under this Section 5.4 of the Plan.

Unless otherwise limited by applicable law or by a third-party vendor contract, for two years after the Date of Termination in the case of a Schedule A Participant, three years after the Date of Termination in the case of a Schedule B Participant, or in the case of a Schedule C Participant, eighteen months after the Date of Termination (or for any Participant such longer period as may be provided by the terms of the appropriate plan, program, practice or policy), the Company shall continue benefits (other than medical and dental benefits) to the Participant and/or the Participant's family at least equal to those which would have been provided to them in accordance with the welfare plans, programs, practices and policies maintained by the Company if the Participant's employment had not been terminated or, if more favorable to the Participant, as in effect generally at any time thereafter with respect to other peer executives of the Employer and their families.

Unless otherwise limited by applicable law or by a third-party vendor contract, the Participant's eligibility (but not the time of commencement of such benefits) for retiree benefits pursuant to the welfare plans, programs, practices and policies maintained by the Company shall be determined as if the Participant had (A) remained employed until two years (in the case of a Schedule A Participant), three years (in the case of a Schedule B Participant), or eighteen months (in the case of a Schedule C Participant) after the Date of Termination and (B) retired on the last day of such period.

5.5 Nonqualified Pension Benefit. The Participant shall be paid, in a lump sum payment in cash, an amount equal to the excess of (a) - (b):

(a) The actuarial equivalent of the benefit under the Company's applicable Retirement Plan (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the Effective Date), any benefit under the Nonqualified Plan and, to the extent applicable, any other defined benefit retirement arrangement between the Participant and the Company ("Other Pension Benefits") which the Participant would receive if the

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Participant's employment continued for two, three or one and one-half additional years (for Schedule A Participants, Schedule B and Schedule C Participants, respectively) beyond the Date of Termination and, assuming that the Participant's compensation for such deemed additional period was the Participant's Annual Base Salary as in effect immediately prior to the Date of Termination and assuming a bonus in each year during such deemed additional period equal to the Target Bonus,

(b) The actuarial equivalent of the Participant's actual benefit (paid or payable), if any, under the Retirement Plan, the Nonqualified Plan and Other Pension Benefits as of the Date of Termination (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the effective date of the Change in Control).

5.6 Deferred Compensation. Any compensation previously deferred (other than pursuant to a tax-qualified plan) by or on behalf of the Participant (together with any accrued interest or earnings thereon), whether or not then vested, shall become vested on the Date of Termination and shall be paid in accordance with the terms of the applicable deferred compensation plan, policy or practice under which it was deferred to the extent permitted by Section 409A of the Code.

5.7 Outplacement Services. The Company shall, at its sole expense as incurred, provide the Participant with outplacement services suitable to the Participant's position for a period not to exceed one year following the Date of Termination with a nationally recognized outplacement firm.

5.8 Other Benefits. To the extent not theretofore paid or provided, the Company shall pay or provide to the Participant any other amounts or benefits required to be paid or provided or which the Participant is entitled to receive under any plan, program, policy, practice, contract or agreement of the Company (or other Employer), including earned but unpaid stock and similar compensation, but excluding medical or dental benefits if the Participant is eligible for such benefits to be provided by a subsequent employer, and benefits payable under any severance plan or policy.

5.9 Termination By Employer For Cause or By Participant Other Than For Good Reason. If, at any time after a Change in Control, either (a) an Employer shall terminate a participant's employment for Cause or (b) the Participant shall voluntarily terminate employment other than for Good Reason, the Employer shall have no further payment obligations to the Participant other than for the Participant's base salary through the Date of Termination and any accrued but unpaid vacation pay. In such case, all such amounts shall be paid to the Participant in a lump sum in accordance with Section 6.1 of the Plan.

5.10 Death. If a Participant's employment terminates by reason of the Participant's death after a Change in Control, all Accrued Obligations as of the time of death shall be paid to the Participant's estate or beneficiary, as applicable, in a lump sum in cash in accordance with Section 6.1 of the Plan. The Participant's estate or beneficiary shall be entitled to

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any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.11 Disability. If a Participant's employment is terminated by reason of Disability after a Change in Control, all Accrued Obligations shall be paid to the Participant in a lump sum in cash in accordance with Section 6.1 of the Plan. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.12 Retirement. If a Participant's employment terminates as a result of Retirement after a Change in Control, the Participant shall be paid the Accrued Obligations in a lump sum in cash in accordance with Section 6.1 of the Plan and the Participant shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

ARTICLE VI

TIMING OF, LIMITATIONS ON AND ADJUSTMENTS TO PLAN PAYMENTS

6.1 Time of Payments. Payments under the Plan shall be made to the Participant as follows:

(a) With respect to benefits, except those under Sections 4.4 and 5.10 of the Plan, payment to a Participant who is not a Specified Employee shall be made within the 60-day period following the Participant's Date of Termination. However, if the period to consider and revoke the written agreement required to receive the benefits described in Articles IV and V of the Plan (i.e., the waiver and release) spans two taxable years, in all events the payments will be made in the second taxable year within 30 days following the later of the end of the first taxable year or the date the executed release is received by the Company.

(b) With respect to benefits under Section 5.10 of the Plan, payment shall be made within the 60-day period following the Participant's date of the Participant's death.

(c) With respect to benefits under Section 4.4 of the Plan, payments shall be made to the Participant at the same time the payments are made to active employees.

(d) Notwithstanding anything to the contrary in the Plan, to the extent necessary to comply with Section 409A of the Code, payments to a Participant who is a Specified Employee shall be made within the 60-day period following the six- month anniversary of the Participant's Date of Termination (other than by reason of death).

(e) All payments under the Plan that are reimbursements of covered expenses incurred by the Participant shall be made within the taxable year in which the expense is incurred.

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6.2 Payment Offsets. Notwithstanding anything in the Plan to the contrary, in the event a Participant is entitled to receive severance payments both under this Plan and under the terms of either (a) an individual change of control or employment agreement, (b) another severance pay plan or policy of an Employer or (c) any existing or future law or regulation, the benefits payable under this Plan shall be reduced by the amount of any severance benefits such Participant is entitled to receive under such individual agreement, plan, policy, law or regulation.

6.3 Cap on Excess Parachute Payments; Gross-Up Payments. Notwithstanding anything in the Plan to the contrary, if (a) a Participant is a "disqualified individual" (as defined in Section 280G(c) of the Code) and (b) the severance benefits provided under Articles IV or V, as applicable, together with any other payments the Participant has the right to receive from an Employer, would constitute a "parachute payment" (as defined in Section 280G(b) of the Code) ("Parachute Payments"), the following provisions shall apply:

(a) The severance benefits under Articles IV or V shall not exceed an amount which, together with any other Parachute Payments, the Participant has a right to receive from the Employer, would be 2.99 times the Participant's "base amount" (as defined in Section 280G of the Code) so that no portion of the amounts received by the Participant shall be subject to the excise tax imposed under Section 4999 of the Code.

(b) The determination of whether any limitation on the severance benefits payable under Articles IV or V is necessary shall be made by the Company's independent auditor or such other certified public accounting firm as may be jointly designated by the Participant and the Company (the "Accounting Firm"), which shall provide detailed supporting calculations to the Participant and the Company. The determinations of the Accounting Firm shall be conclusive and binding on the Company and the Participant. All fees and expenses of the Accounting Firm shall be borne solely by the Company.

(c) If through error or otherwise, a Participant shall receive payments under the Plan, together with other Parachute Payments the Participant has the right to receive from an Employer, in excess of 2.99 times the Participant's base amount, the Participant shall immediately repay the excess to the Employer upon notification from the Employer that an overpayment has been made. If the Participant fails to repay the excess to the Employer within 10 business days of the date of the Employer's notification, the Participant will become liable to the Employer for an amount equal to two (2) times the excess amount.

6.4 Compliance with Section 409A of the Code. Notwithstanding anything in the Plan to the contrary, all Plan benefit obligations and payments are subject to Section 409A of the Code. To the extent required, the Company may modify the severance benefits payable hereunder to comply with Section 409A of the Code; provided, however, that the present value of the aggregate Plan benefits payable to a Participant after such modification shall not be less than the present value of the Plan benefits payable to the Participant prior to the modification.

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6.5 Tax Withholding. Notwithstanding any other provision of this Plan, the Company may withhold from any amounts payable under this Plan such Federal, state, local, employment or foreign taxes as shall be required to be withheld pursuant to any applicable law or regulation.

ARTICLE VII

RESTRICTIVE COVENANTS

7.1 Confidentiality. As a condition to participation in the Plan, each Participant agrees to hold in a fiduciary capacity for the benefit of the Company and its Affiliates all Confidential Information which shall have been obtained by the Participant during the Participant's employment by the Employer; except, however, that this Section 7.1 shall not apply to Confidential Information that is or becomes public knowledge, unless such Confidential Information became or becomes public knowledge due to acts of the Participant or representatives of the Participant in violation of this Section 7.1. Upon termination of the Participant's employment, the Participant shall return to the Company all Confidential Information in their possession. After termination of the Participant's employment with the Employer, the Participant shall not, without the prior written consent of the Company or as may otherwise be required by law or legal process, communicate or divulge any such Confidential Information to anyone other than the Company and those designated by it, except (a) otherwise publicly available information, (b) as may be necessary to enforce the Participant's rights under the Plan or as necessary for the Participant to defend against a claim asserted directly or indirectly by the Company or its Affiliates, or (c) as may be compelled by service of a valid subpoena or other legal process (if the Participant is served with a valid subpoena or other legal process, the Participant must so notify the Company within three business days). Furthermore, nothing contained in this Plan prevents a Participant from disclosing without notice to the Company any perceived violation of law to any Federal, state, or local governmental agency or entity including, but not limited to, the Securities and Exchange Commission, or making other disclosures that are protected under the whistleblower provisions of any law. Finally, nothing in this Plan prevents a Participant - nor should a Participant be held civilly or criminally liable under any law - if the Participant discloses a trade secret: (a) in confidence to a Federal, State or local government official, either directly or indirectly, or to an attorney solely for the purpose of reporting or investigating a suspected violation of law; (b) in a complaint or other document filed in a lawsuit or other proceeding, if such filing is made under seal; (c) to the Participant's attorney in connection with a lawsuit alleging retaliation by an employer for reporting a suspected violation of law; or (d) in connection with a lawsuit described in the immediately preceding subparagraph (c), provided the Participant: (i) files any document containing the trade secret under seal; and (ii) does not disclose the trade secret, except pursuant to a court order. Unless and until a determination has been made in accordance with Section 7.4 that the Participant has violated this Section 7.1, an asserted violation of the provisions of this Section 7.1 shall not constitute a basis for deferring or withholding any amounts otherwise payable to the Participant under the Plan.

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7.2 Non-Compete. As a condition to participation in the Plan, each Participant agrees that in the event the Participant voluntarily terminates employment other than for Good Reason, for the period of one year from Date of Termination, the Participant will not, without the written consent of the Company, directly or indirectly own, manage, operate, join, control, become employed by, consult to or participate in the ownership, management, or control of any business which is in direct competition with the Company or its Affiliates.

7.3 Non-Solicitation. As a condition to participation in the Plan, each Participant agrees that, in the event the Participant voluntarily terminates employment other than for Good Reason, for the period of one year following the Date of Termination, the Participant will not, directly or indirectly, solicit or hire, or encourage the solicitation or hiring by any employer other than the Company or its Affiliates, for any position as an employee, independent contractor, consultant or otherwise, any person who was a managerial or higher level employee of an Employer at any time during the term of the Participant's employment by the Employer; provided, however, that this provision shall not apply with respect to the solicitation of any person after six months from the date on which such person's employment by an Employer has terminated.

7.4 Enforcement. In the event of a breach by the Participant of any of the covenants set forth in this Article VII, it is agreed that the Company shall suffer irreparable harm for which money damages are not an adequate remedy, and that, in the event of such breach, the Company shall be entitled to obtain an order of a court of competent jurisdiction for equitable relief from such breach, including, but not limited to, temporary restraining orders and preliminary and/or permanent injunctions against the breach of such covenants by the Participant. In the event that the Company should initiate any legal action for the breach or enforcement of any of the provisions contained in this Article VII and the Company does not prevail in such action, the Company shall promptly reimburse the Participant the full amount of any court costs, filing fees, attorney's fees which the Participant incurs in defending such action, and any loss of income during the period of such litigation.

Nothing in this Plan prohibits the Participant from reporting possible violations of Federal law or regulation to any governmental agency or entity, including but not limited to the Department of Justice, the Securities and Exchange Commission, the Congress, and any agency Inspector General, or making other disclosures that are protected under the whistleblower provisions of Federal law or regulation. The Participant does not need the prior authorization of the Law Department to make any such reports or disclosures, and is not required to notify the Company that such reports or disclosures have been made.

ARTICLE VII

AMENDMENT AND TERMINATION

8.1 Amendment. The Company may amend this Plan at any time, and from time to time, by action of the Committee; provided, however, that no amendment adopted after the effective date of a Change in Control shall have the effect of either (a) removing an

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individual from the list of Participants, (b) adding conditions for participation or the entitlement to receive benefits hereunder, (c) reducing the amount of benefits payable to a Participant, or (d) otherwise restricting a Participant's right to receive benefits under the Plan, except as may otherwise be required to conform such payments to the requirements of Section 409A of the Code.

8.2 Termination. The Committee may terminate the Plan at any time prior to a Change in Control. The Plan may not be terminated after the effective date of a Change in Control.

ARTICLE IX

ADMINISTRATION

9.1 Plan Administrator. The Plan shall be administered by the Committee, which shall have the duties and responsibilities for administering the Plan as are specifically set forth in this Article IX.

9.2 Responsibilities of Committee.

(b) The Committee shall have responsibility for the day to day administration of the Plan. In addition, the Committee shall have the specific powers, duties, responsibilities and obligations specifically provided for herein.

(b) Subject to the express provisions of the Plan, the Committee shall have full and exclusive authority to interpret the Plan and to make all other factual determinations deemed necessary or advisable in the implementation and administration of the Plan, including but not limited to determinations with respect to the eligibility of Participants to receive benefits under the Plan and the status and rights of such Participants and all other persons affected hereunder. The Committee's interpretation and construction of the Plan shall be conclusive and binding on all persons.

(c) The Committee shall have sole authority to adopt rules and regulations, which shall be administered by the Committee. In addition, the Committee shall have the discretionary authority to issue rulings and interpretations concerning the Plan and all matters arising thereunder, on a uniform and nondiscriminatory basis, provided the same shall not be contrary to or inconsistent with any provision of the Plan.

(d) As a condition of distributing any benefit under the Plan, the Committee may prescribe the use of such forms and require the furnishing of such information as the Committee may deem appropriate for administering the Plan.

9.3 Allocation or Delegation of Duties and Responsibilities. In furtherance of its duties and responsibilities under the Plan, the Committee may:

(a) Employ agents to carry out non-fiduciary responsibilities;

(b) Employ agents to carry out fiduciary responsibilities;

(c) Consult with counsel, who may be counsel to the Company; and

(d) Delegate any of its duties and responsibilities hereunder to such officer or officers of the Company as the Committee shall designate; except, however, that the

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Committee may not delegate to any other person the designation of Eligible Employees under Section 3.1 or the authority to consider and determine appeals of alleged adverse benefit determinations.

The Committee delegates to the Chief Executive Officer of the Company the responsibility and authority to interpret the terms of the Plan, including the benefits payable thereunder. Furthermore, the Committee delegates to the Senior Vice President of Human Resources, Chief Human Resources Officer of the Company the authority to enter into a VSA with a Participant in lieu of providing benefits under the Plan.

9.4 Expenses. Unless otherwise agreed to by the Company, no person acting as a fiduciary hereunder (who is an employee of an Employer) shall receive any compensation for services as such. Expenses incurred by fiduciaries in connection with the administration of the Plan shall be paid by the Company.

9.5 Indemnification of Plan Administrator. The Company shall indemnify, to the fullest extent permitted by law, each person made or threatened to be made a party to any civil or criminal action or proceeding by reason of the fact that such person, or such person's testator or intestate, was a member of the Committee, or a delegate of the Committee, acting in the capacity of Plan administrator.

9.6 Reliance Upon Others. The Committee, any person to whom it may delegate such of its duties and powers as provided herein, and the officers and directors of the Company shall be entitled to rely conclusively upon and shall be fully protected in any action taken by them in good faith in reliance upon any tables, valuations, certificates, opinions, reports or other advice furnished to them by any duly appointed actuary, accountant, legal counsel (who may be counsel for the Company) or other specialist.

9.7 Notification. All notices, reports and statements in connection with the Plan that are given, made, delivered or transmitted to a Participant shall be deemed duly given, made, delivered, or transmitted when mailed, by such class as the sender may deem appropriate, with postage prepaid and addressed to the Participant at the address last appearing on the records of the Employer with respect to this Plan. All notices, direct actions or other communications given, made, delivered or transmitted by a Participant to an Employer or Committee shall not be deemed to have been duly given, made, delivered, transmitted or received unless and until actually received by the Employer or Committee.

9.8 Multiple Capacities. A person may serve in more than one fiduciary capacity with respect to the Plan.

ARTICLE X

CLAIMS PROCEDURE

10.1 Submission of Claims. The initial claim by any Participant for benefits under this Plan shall be submitted in writing to the Committee (or its delegate) within 60 days after the occurrence of the termination of employment that the Participant claims to have triggered entitlement to Plan benefits.

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10.2 Computation and Review of Claims. All benefits shall be computed by the Committee or its delegate. All claims shall be approved or denied by the Committee (or its delegate) as soon as practicable, but in no event later than 90 days after application by the Participant. The Committee may take an additional 90 days to review the claim, provided that the Participant is notified in writing within the initial 90-day period.

(a) Initial Denial of Claim - Any denial of a claim shall include:

(i) Reason or reasons for the denial;

(ii) Reference to pertinent Plan provisions on which the denial is based;

(iii) Description of any additional material or information necessary for the Participant to perfect the claim together with an explanation of why the material or information is necessary; and

(iv) Explanation of the Plan's claim review procedure, described below.

(b) Review of a Denied Claim - A Participant shall have a reasonable opportunity to appeal a denied claim to the Committee (or its delegate) for a full and fair review. The Participant or a duly authorized representative shall have 60 days after receipt of written notification of the denial of claim in which to file an appeal with the Committee. The request for review shall be in writing and the Participant or a duly authorized representative shall submit written comments, documents, records and other information relating to the appeal. The Participant or a duly authorized representative may review, free of charge, pertinent Plan documents, records and other information relevant to the appeal.

(c) Committee Review - The Committee's (or its delegate's) review shall take into account all comments, documents, records and other information submitted by the Participant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

(d) Written Decision - The Committee (or its delegate) shall issue a decision on the reviewed claim promptly but no later than 60 days after receipt of the review. The Committee may take an additional 60 days to review the claim, provided that the Participant is notified in writing within the initial 60-day period. The Committee's decision shall be in writing and shall include:

(i) Reasons for the decision;

(ii) References to the Plan provisions on which the decision is based;

(iii) Statement that the Participant is entitled to receive, upon request, reasonable access to, and copies of, all documents, records and other information relevant to the claim; and

(iv) Statement that the Participant is entitled to bring a civil suit under Section 502(a) of ERISA.

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(e) Binding Effect - The Committee's (or its delegate's) decision shall be final and binding on the Participant and the Employer.

ARTICLE XI

GENERAL PROVISIONS

11.1 Construction. This Plan shall be construed and enforced in accordance with and governed by the internal substantive laws (and not the laws relating to conflict of laws or choice of laws) of the State of New Jersey, except to the extent that such laws are preempted by Federal law.

11.2 Unfunded Plan. The obligations of the Company under this Plan are not required to be funded in advance. Nothing contained in this Plan shall give an Eligible Employee or Participant any right, title or interest in any property of the Company or any of its Affiliates.

11.3 No Right to Continued Employment. Nothing contained herein shall be deemed to give any Eligible Employee or Participant the right to be retained in the employment of an Employer or to limit the rights of any Employer to discharge any Eligible Employee or Participant at any time, with or without notice and with or without Cause.

11.4 Partial Invalidity. The invalidity or unenforceability of any term or provision, or any clause, or portion thereof, of this Plan shall in no way impair or affect the validity or enforceability of any other provision of this Plan, which shall remain in full force and effect.

11.5 Successors and Assigns.

(a) This Plan shall inure to the benefit of and be binding upon the Company and its successors and assigns.

(b) The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform the Company's obligations under the Plan in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place.

(c) In no event shall a Participant assign their interests under the Plan to any other person without the prior written consent of the Committee.

11.6 Waivers. Failure to strictly comply with any term, condition or requirement set forth in the Plan shall not be deemed a waiver of such term, condition or requirement, nor shall any waiver of any such term, condition or requirement at any one time or times be deemed to result in a waiver of such term, condition or requirement at any other time or times.

11.7 Gender and Number. The singular shall include the plural, unless indicated otherwise by the context.

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11.8 Headings. The headings of the Plan are for purposes of reference only and shall not limit or otherwise affect the meaning hereof.

* * *

/s/ Margaret M. Pego	11/20/2017
Signature	Date

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SCHEDULE A

As Amended as of November 20, 2017
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Stuart J. Black	VP and Controller	03/01/10
Jorge L. Cardenas	VP - Asset Management and Centralized Services, PSE&G	1/23/07
Rose M. Chernick	VP Finance-Corp. Strategy & Planning, Services Corp	8/09/10
John Paul Cowan	SVP - Operations, PSEG Fossil	09/15/09
Lathrop B. Craig	VP - ISO Operations (ER&T)	09/05/11
Daniel J. Cregg	EVP & CFO, PSEG	12/19/06
David M. Daly	President & COO, PSE&G & COB PSEG LI	1/28/08
Paul J. Davison	VP - Nuclear Engineering, PSEG Nuclear	12/14/09
Derek DiRisio	President - PSEG Services Corporation	12/20/04
Diana L. Drysdale	VP - Renewables	02/15/10
Joseph A. Forline	VP - Gas Operations	12/19/06
Carl J. Fricker	VP - Trading Support & Operations (ER&T)	12/14/09
Kim C. Hanemann	SVP - Delivery Projects and Construction	12/21/10
Bradford D. Huntington	VP & Treasurer	04/16/11
Scott Jennings	VP - Finance PSE&G	10/18/05
Robert C. Krueger, Jr	VP Special Projects	12/19/06
Kathleen A. Lally	VP - Investor Relations	01/16/07
John R. Latka	SVP - Electric & Gas Operations, PSE&G	10/23/06
Shawn P. Leyden	VP and Deputy General Counsel	12/20/04
Tamara L. Linde	EVP and General Counsel	12/19/06
Kristen M. Ludecke	VP - Federal Affairs	02/22/10
Shahid Malik	President - Energy Resources & Trade (ER&T)	12/5/11
Christine T. Neely	VP - Internal Auditing Services	9/30/13
Margaret M. Pego	SVP - Human Resources & CHRO	12/20/04
Sheila J. Rostiac	VP - Total Rewards & Talent Management	08/20/12
Joseph Santamaria	VP - Information Technology & CIO	10/29/12
Richard T. Thigpen	VP - State Governmental Affairs	3/26/07

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SCHEDULE B

As Amended as of November 20, 2017
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Ralph Izzo	Chairman of the Board, President and CEO	12/15/08
Ralph A. LaRossa	President & COO, PSEG Power LLC	10/17/06

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SCHEDULE C

As Amended as of November 20, 2017
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
John A. Bridges	VP Electric Operations	12/21/15
David F. Caffery	VP Gas Supply	3/6/17
Eric Carr	VP Hope Creek - PSEG Nuclear	10/3/16
Kevin B. Cellars	VP Construction	2/17/15
Brian J. Clark	VP Procurement	8/29/16
Karen Cleeve	VP Corporate Communications	8/9/17
Gregory C. Dunlap	VP Customer Operations - PSE&G	7/14/14
Daniel Eichhorn	President & COO, PSEG LI	10/2/17
Aaron T. Ford	VP Corporate Security & Claims	11/18/15
M. Courtney McCormick	VP Renewables and Energy Solutions	3/31/14
Charles V. McFeaters	VP Salem - PSEG Nuclear	10/3/16
Clifford Pardo	VP & Assistant Controller - Tax	1/1/18
Timothy P. Pellegrin	VP Finance - Power & Merger & Acquisitions	10/9/17
Laurent C. Pommier	VP Risk Management and Chief Risk Officer	7/14/14
Peter P. Sena III	President & CNO, PSEG Nuclear	3/21/16

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EXHIBIT 10a(20)

CLAWBACK PRACTICE

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Effective as of February 20, 2018

Section 1. Purpose.

The Public Service Enterprise Group Incorporated Clawback Practice ("Clawback Practice") was originally effective December 15, 2015. The Clawback Practice has been adopted by the Board of Directors. The Clawback Practice is amended effective February 20, 2018.

The purpose of the Clawback Practice is for the Company to recover or cause to be forfeited Incentive Compensation of Covered Employees upon the occurrence of a Covered Event. The Clawback Practice is intended to underscore and be aligned with the Company's Standards of Conduct.

The Clawback Practice supersedes all clawback and forfeiture provisions in the Covered Plans and is incorporated into those Covered Plans; however, particular grants and awards under the Covered Plans may include additional clawback provisions not otherwise specifically stated in this Clawback Practice. The Clawback Practice is in addition to any clawback and forfeiture provisions that are in Company's compensation plans or programs which are not Covered Plans.

Section 2. Definitions.

"**Administrator**" shall mean with respect to Key Executives, the Committee, and with respect to all other Covered Employees, the Senior Vice President of Human Resources & Chief Human Resources Officer.

"**Clawback**" shall mean the recoupment or forfeiture of a Covered Employee's Incentive Compensation whether paid, vested, granted or accrued, upon the occurrence of a Covered Event.

"**Clawback Amount**" shall have the meaning set forth in Section 4(a) of this Clawback Practice.

"**Company**" shall mean the Public Service Enterprise Group Incorporated.

"**Committee**" shall mean the Organization and Compensation Committee of the Board of Directors.

"**Covered Employees**" shall mean any non-represented Employee or former Employee, including an Executive Officer, who receives or is entitled to receive Incentive Compensation.

"**Covered Event**" shall mean one or more of the below events that the Administrator, in its sole discretion, determines to be appropriate:

(a) If as a result of misconduct, the Company or any of its subsidiaries is required by the Securities and Exchange Commission ("SEC") to file an accounting restatement

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for any fiscal year due to its material noncompliance with accounting requirements under the federal securities laws, and the Covered Employee (i) knowingly engaged in the misconduct, or (ii) recklessly failed to prevent the misconduct, or (iii) is a person who is one of the individuals subject to automatic forfeiture under Section 304 of the Sarbanes-Oxley Act of 2002.

(b) If as a result of misconduct, the Company or any of its subsidiaries has determined that it is necessary to recalculate any Incentive Compensation for any year, and the Covered Employee (i) knowingly engaged in the misconduct, or (ii) recklessly failed to prevent the misconduct.

(c) If a Covered Employee's act or omission constitutes a material violation of the Company's Standard of Conduct, in effect from time to time, that results in the Covered Employee's termination from employment. A Covered Event includes an act or omission that if it had been known by the Company prior to termination from employment, the act or omission would have resulted in the Covered Employee's termination from employment. The foregoing also includes situations where the Company learns about the act or omission before the employee leaves the Company but did not have time to fully review the act or omission prior to departure. In these situations, if the Company determines the act or omission would have resulted in termination, this shall constitute a Covered Event.

"**Covered Plan**" shall mean the following:

(a) Performance Incentive Plan for Certain Employees of Public Service Electric and Gas Company and Subsidiaries, Performance Incentive Plan for Certain Employees of PSEG Services Corporation and Subsidiaries, Performance Incentive Plan for Certain Employees of PSEG Power LLC and Subsidiaries, Performance Incentive Plan for Certain Employees of PSEG Long Island LLC, and Performance Incentive Plan for Certain Employees of Long Island Electric Utility ServCo LLC (collectively, "PIP");

(b) PSEG Power LLC Incentive Compensation Program for PSEG Energy Resources & Trade LLC Employees ("ER&T Plan");

(c) Deferred Compensation Plan for Certain Employees of Public Service Enterprise Group Incorporated and Its Affiliates ("Deferred Compensation Plan");

(d) Public Service Enterprise Group Incorporated 2004 Long-Term Incentive Plan, as amended and restated ("LTIP");

(e) Public Service Enterprise Group Incorporated Equity Deferral Plan ("Equity Deferral Plan");

(f) Public Service Enterprise Group Incorporated Management Incentive Compensation Plan ("MICP");

S1-SSA-0009 - 12142

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(g) Public Service Enterprise Group Incorporated Senior Management Incentive Compensation Plan ("SMICP"); and

(h) PSEG Power LLC Incentive Compensation Program for Certain Employees of PSEG Energy Solutions LLC.

"**Effective Date**" shall mean the date this Clawback Practice is adopted, or as amended from time to time, by the Board of Directors.

"**Incentive Compensation**" shall mean compensation or awards paid to, granted to, or accrued for a Covered Employee under a Covered Plan.

"**Key Executive**" shall mean any current or former employee of the Company that is, or was during employment, on Schedule A, B or C of the Key Executive Severance Plan of Public Service Enterprise Group Incorporated.

Section 3. Clawback Authority.

The Administrator, in its sole discretion, shall determine whether a Covered Employee shall be subject to Clawback upon the occurrence of a Covered Event and shall determine the amount of Clawback. The Administrator shall exercise the Clawback authority pursuant to this Clawback Practice.

Section 4. Clawback Amount and Method of Clawback.

(a) Amount. The Clawback Amount shall be determined by the Administrator, in its sole discretion. The amount of Incentive Compensation that may be subject to Clawback is the Incentive Compensation that the Covered Employee received or is determined to be entitled to receive within the three completed fiscal years immediately preceding the Covered Event.

(b) Method. The Administrator, in its sole discretion, shall determine the method that will be used to recoup the Clawback Amount, including but not limited to, (i) not paying or distributing the Incentive Compensation that has not yet been paid or distributed to the Covered Employee (including amounts deferred under the Deferred Compensation Plan or Equity Deferral Plan, (ii) making demand upon the Covered Employee to repay such Clawback Amount as has been paid or distributed, and (iii) causing the Clawback Amount to be withheld from other compensation, including but not limited to, future Incentive Compensation, to the extent permitted under applicable law.

Section 5. Applicability of Clawback Practice.

All award agreements with a Covered Employee shall include language that the award is subject to the Clawback Practice and that the Covered Employee agrees that the award is subject thereto. Notwithstanding the immediately preceding sentence, the Clawback Practice applies to each Covered Plan and all awards issued thereunder regardless of whether the Covered Plan or award

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issued thereunder specifically includes such language, and each Covered Employee is deemed to have agreed that an award under a Covered Plan is subject to this Clawback Practice.

Any award granted on or after the date of adoption of this Clawback Practice shall be deemed to be subject to the provisions of such clawback rules and regulations adopted by the SEC and in effect from time to time, as if such rules and regulations had been in effect at the time of the grant of the award, and each Covered Employee shall be deemed to have so agreed to the applicability of such provisions.

Section 6. Notice of Covered Employees.

The Administrator shall cause to have notice of this Clawback Practice given to the Covered Employees, in such manner as determined by the Administrator from time to time.

Section 7. Administration.

The Clawback Practice shall be administered by the Administrator. The Committee will make determinations and interpretations and to take such actions in connection with the Clawback Practice as it deems necessary or advisable. All determinations and interpretations made by the Committee shall be final and binding.

The Senior Vice President of Human Resources & Chief Human Resources Officer shall report to the Committee during a Committee meeting if any Covered Employee, other than a Key Executive, was subject to Clawback since the last Committee meeting.

The rights and remedies provided in this Clawback Practice are not exclusive. Nothing in this Clawback Practice shall preclude the Company's right to take legal action against a Covered Employee or otherwise to enforce the provisions of this Clawback Practice.

Section 8. Indemnification.

The Company shall not indemnify any Covered Employee for the amount subject to Clawback.

Section 9. Applicable Law.

All provisions of this Clawback Practice, including the applicability, interpretation, administration and enforcement thereof, shall comply with and be subject to applicable law and regulation.

Section 10. Amendment and Termination.

The Committee shall have the authority to amend the Clawback Practice at any time and for any reason. The Board shall have the authority to terminate the Clawback Practice at any time and for any reason.

S1-SSA-0009 - 12144

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Margaret M. Pego **Human Resources**
Senior Vice President-Human Resources 80 Park Plaza, T4, Newark, NJ 07102
and Chief Human Resources Officer tel: 973-430-7243 fax: 973-242-5176
email: Margaret.Pego@pseg.com

EXHIBIT 10a(21)

June 21, 2017

Ralph A. La Rossa
366 Paul Avenue
Allendale, NJ 07401

Dear Ralph:

I am pleased to offer you the position of President and Chief Operating Officer ("COO") of PSEG Power LLC ("PSEG Power"), effective October 2, 2017. In this position, you will be an employee of PSEG Power. This role will provide you with the opportunity to broaden and enhance your overall business experience and is consistent with the company's long-term succession plan; however, this opportunity is not a commitment to any particular role beyond what is described herein. The transition from a role in PSE&G to PSEG Power will not constitute any break in services from PSEG. You will continue to be paid a base annual salary of $705,600. You shall be eligible for your next salary review in January 2018. Salary reviews will be conducted annually thereafter.

You will continue to be eligible to participate in PSEG's Senior Management Incentive Compensation Plan ("SMICP") under the terms and conditions of the SMICP. Your target incentive award for 2017 will be 75% of your base salary, however, you may be eligible to receive up to 150% of your base salary dependent upon business results. Targets and awards may be adjusted from time to time in accordance with established plan procedures. There is no guarantee of payment under the SMICP, and any such payment will be contingent upon your establishment and successful completion of 2017 goals and objectives and your award, if earned, for 2017 will be payable in 2018. Any SMICP award for 2017 will be prorated based on your transfer date of October 2, 2017. For the period January 1 to October 1, 2017, the SMICP award will be based on your position as President & COO, PSE&G and Chairman of the Board, PSEG Long Island and for the period of October 2 to December 31, 2017, it will be based on your position as President & COO, PSEG Power.

You will continue to be a participant in the PSEG 2004 Long-Term Incentive Plan as amended ("LTIP"). It has been recommended, and the Organization and Compensation Committee ("O&CC") has approved, a 2018 Retention LTIP award of $3,000,000 for you provided that you are an active employee of PSEG Power at the time of the grant in February 2018. This retention grant will be in the form of 50% Restricted Stock Units ("RSUs") and 50% Performance Share Units ("PSUs") which vests on January 1,2021 and December 31, 2020, respectively. There is no acceleration of vesting for retirement eligibility, retirement, or voluntary termination with respect to this retention grant. This retention award is in addition to your annual LTIP grant and will coincide with the timing of your annual LTIP grant. In the future, the number and form of LTIP grants recommended in any given year will appropriately reflect your responsibilities and ability to contribute to the long-term success of PSEG and are subject to the approval of the O&CC of the Board. All future grants under the LTIP will be subject to the terms of the LTIP and the related grant award agreements.

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You will continue to be eligible for Limited Benefit under the Supplemental Executive Retirement Income Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated and Its Affiliates.

You will continue to be eligible to participate in the PSEG Deferred Compensation Plan For Certain Employees ("Deferred Compensation Plan"), which will allow you to defer all or a portion of your base pay and/or any cash incentive you may receive in any given year. In November, you will receive information regarding participation in the Deferred Compensation Plan for 2018.

You will continue to be eligible to participate in the PSEG Equity Deferral Plan ("Deferred Equity Plan"), which will allow you to defer all or a portion of the receipt of shares under the LTIP. In November, you will receive information regarding participation in the Deferred Equity Plan for 2018.

Please note that the nonqualified plan liability is measured annually and is used to determine the funding for the sub-trusts under the Rabbi Trust. For employees who have transferred between companies, there is a pro-rata allocation of plan liability based on the employees' service with each company. In determining the pro-rata liability, the total benefit stream of payouts is determined and actuarial assumptions are applied. In your case, for the December 31, 2017 valuation, data as of January 1, 2017 will be used and similarly, for the December 31, 2018 valuation, data as of January 1, 2018 will be used. Because you will transfer from PSE&G to Power on October 2, 2017, your plan liability for the December 31, 2017 valuation will be entirely assigned to PSE&G. For the December 31, 2018 valuation, your plan liability will be allocated pro-rata based on your service with PSE&G and Power (two years will be assigned to Power because it is assumed that you were employed by Power for all of 2017 and 2018). The funding of the sub-trusts will be based on the allocation of plan liability.

If, at the time you terminate from employment, you are determined to be a "specified employee" as defined in Section 409A of the Internal Revenue Code of 1986, as amended ("Section 409A"), your nonqualified deferred compensation payments will be delayed for six months following your termination of employment to the extent necessary to satisfy Section 409A.

You will continue to be a Schedule B participant in the Key Executive Severance Plan of Public Service Enterprise Group Incorporated, as amended from time to time.

You will be eligible for an annual physical examination through the University of Pennsylvania.

You will continue to be provided a parking space in the Company parking garage in Newark, NJ. Additionally, you will be eligible for a monthly vehicle stipend of $1,000. Should you elect to decline the monthly stipend, you will be eligible for mileage reimbursement.

You will be required to own and retain a level of company stock commensurate with your new position as outlined in the attached Officer Stock Ownership and Retention Policy.

This position change is conditional upon satisfactory receipt of any necessary regulatory approvals, including but not limited to FERC approvals.

The purpose of this letter is to set forth the terms of your new position with the Company; it is not a contract of employment, nor does it guarantee your employment with the Company for any period of time. Your employment with the Company is at-will, which means that either you or the Company is free to terminate the employment relationship at any time, for any reason, with or

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without cause. This letter shall not be construed, nor is it intended to be construed, as a binding contract of employment.

Additionally, enclosed is an updated booklet referencing the Responsibilities of Corporate Officers and Directors.

Finally, you will be required to sign the enclosed Confidentiality, Non-Competition, and Non-Solicitation Agreement, and the enclosed Arbitration Agreement.

If the foregoing is in accordance with your understanding, please sign this letter and the enclosed Agreements, and return them to me.

Sincerely,

/s/ Margaret M. Pego

Margaret M. Pego
Senior Vice President - Human Resources
and Chief Human Resources Officer

Agreed to this 15 day of July, 2017.

/s/ Ralph A. La Rossa

Ralph A. La Rossa

Attachments:
1. Officer Stock Ownership & Retention Policy
2. Responsibilities of Corporate Officers and Directors
3. Confidentiality, Non-Competition and Non-Solicitation Agreement
4. Arbitration Agreement

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Margaret M. Pego **Human Resources**
Senior Vice President-Human Resources 80 Park Plaza, T4, Newark, NJ 07102
and Chief Human Resources Officer tel: 973-430-7243 fax: 973-242-5176
email: Margaret.Pego@pseg.com

July 15, 2014

Derek DiRisio
60 Elm Avenue
Ramsey, New Jersey 07446

Dear Derek:

I am pleased to offer you the position of President, PSEG Services Corporation in PSEG Services Corporation, effective August 4, 2014. In this position, you will be paid a base annual salary of $360,000. You shall be eligible for your next salary review in January 2015. Salary reviews will be conducted annually thereafter.

Your will be eligible to participate in PSEG's Senior Management Incentive Compensation Plan ("SMICP") under the terms and conditions of the SMICP. Your target inventive award for 2014 will be 60% of your base salary, however, you may be eligible to receive up to 90% of your base salary dependent upon business results. Targets and awards may be adjusted from time to time in accordance with established plan procedures. There is no guarantee of payment under the SMICP, and any such payment will be contingent upon your establishment and successful completion of goals and objectives. Your first award under the SMICP, if earned, will be based upon the successful completion of goals and objectives for 2014 and payable in 2015. Any SMICP award for 2014 will be prorated for the months beginning in August 2014 through December 2014. Your will be eligible for a prorated Management Incentive Compensation Plan ("MICP") award for the period beginning in January 2014 through July 2014.

Your will continue to be a participant in the PSEG 2004 Long-Term Incentive Plan as amended ("LTIP"). The Organization and Compensation Committee ("O&CC") has approved a total 2014 LTIP award of $400,000. This award total will be reduced by our recent 2014 LTOP award of $250,000 resulting in an additional LTIP award of $155,000. As a Senior Officer, this and future grants will be in the form of 40% as Restricted Stock Units ("RSUs") and 60% as Performance Share Units ("PSUs"). In the future, the number and form of LTIP grants recommended in any given year will appropriately reflect your responsibilities and ability to contribute to the long-term success of PSEG and is subject to the approval of the O&CC of the Board. All grants under the LTIP for 2014 and any future years will be subject to the terms of the LTIP and the related grant award agreements.

Your will continue to be eligible to participate in the PSEG Deferred Compensation Plan for Certain Employees ("Deferred Compensation Plan"), which will allow you to defer all or a portion of your base pay and/or any cash incentive you may receive in any given year. In November, you will receive information regarding participation in the Deferred Compensation Plan for 2015.

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For 2015, your will continue to be eligible to participate in the PSEG Equity Deferral Plan ("Deferred Equity Plan"), which will allow you to defer all or a portion of the receipt of shares under the LTIP. In November 2014, you will receive information regarding participation in the Deferred Equity Plan for 2015.

If, at the time your terminate from employment, you are determined to be a "specified employee" as defined in Section 409A of the Internal Revenue Code of 1986, as amended ("Section 409A"), your nonqualified deferred compensation payments will be delayed for six months following your termination of employment to the extent necessary to satisfy Section 409A.

You will continue to be a Schedule A participant in the Key Executive Severance Plan of Public Service Enterprise Group Incorporated, as amended from time to time.

You will be eligible for an annual physical examination through the University of Pennsylvania.

You will continue to be provided a parking space in the Company parking garage in Newark, NJ. Additionally, you will be eligible for a monthly vehicle stipend of $1,000.

You will continue to be required to own and retain a level of company stock commensurate with your new position as outlined in the attached Officer Stock Ownership and Retention Policy.

The purpose of this letter is to set forth the terms of your new position with the Company; it is not a contract of employment, nor does it guarantee your employment with the Company for any period of time. Your employment with the Company is at-will, which means that either you or the Company is free to terminate the employment relationship at any time, for any reason, with or without cause.

Additionally, enclosed is a booklet referencing the Responsibilities of Corporate Officers and Directors.

Finally, you will be required to sign the enclosed Confidentiality, Non-Competition, and Non-Solicitation Agreement, and the enclosed Arbitration Agreement.

If the foregoing is in accordance with your understanding, please sign this letter and the enclosed Agreements, and return them to me.

Sincerely,

/s/ Margaret M. Pego

Margaret M. Pego
Senior Vice-President - Human Resources
and Chief Human Resources Officer

Agreed to this 8th day of August 2014.

/s/ Derek DiRisio

Derek DiRisio

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Attachments:

1. Officer Stock Ownership & Retention Policy
2. Responsibilities of Corporate Officers and Directors
3. Confidentiality, Non-Competition and Non-Solicitation Agreement
4. Arbitration Agreement

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ 1,268	$ 1,298	$ 2,680	$ 2,456	$ 2,055
(Income) Loss from Equity Investees, net of Distributions	4	7	3	4	(7)
Fixed Charges	518	477	457	450	458
Capitalized Interest	(9)	(7)	(18)	(16)	(16)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—
Total Earnings	$ 1,781	$ 1,775	$ 3,122	$ 2,894	$ 2,490
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 487	$ 456	$ 437	$ 430	$ 442
Interest Factor in Rentals	31	21	20	20	16
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—
Total Fixed Charges	$ 518	$ 477	$ 457	$ 450	$ 458
Ratio of Earnings to Fixed Charges	**3.44**	**3.72**	**6.83**	**6.43**	**5.44**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12a

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Years Ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$1,536	$1,404	$1,257	$ 1,174	$ 993
Fixed Charges	331	316	306	303	316
Capitalized Interest	(18)	(17)	(17)	(16)	(16)
Total Earnings	$1,849	$1,703	$1,546	$ 1,461	$1,293
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 321	$ 306	$ 297	$ 293	$ 309
Interest Factor in Rentals	10	10	9	10	7
Total Fixed Charges	$ 331	$ 316	$ 306	$ 303	$ 316
Ratio of Earnings to Fixed Charges	**5.59**	**5.39**	**5.05**	**4.82**	**4.09**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12b

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**
Earnings as Defined in Regulation S-K (A):					
Pre-tax Income from Continuing Operations	$ (250)	$ (43)	$1,367	$1,251	$1,063
(Income) Loss from Equity Investees, net of Distributions	4	7	1	3	(10)
Fixed Charges	139	142	152	150	143
Capitalized Interest	9	11	(1)	1	1
Total Earnings	$ (98)	$ 117	$1,519	$1,405	$1,197
Fixed Charges as Defined in Regulation S-K (B)					
Interest Expense	$ 128	$ 138	$ 148	$ 146	$ 139
Interest Factor in Rentals	11	4	4	4	4
Total Fixed Charges	$ 139	$ 142	$ 152	$ 150	$ 143
Ratio of Earnings to Fixed Charges (C)	**(0.71)**	**0.82**	**9.99**	**9.37**	**8.37**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

(C) The ratio of earnings to fixed charges for the year ended December 31, 2017, was (0.71), as noted above, which represents a deficiency of $237 million. The ratio of earnings to fixed charges for the year ended December 31, 2016, was 0.82, as noted above, which represents a deficiency of $25 million.

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EXHIBIT 21

PUBLIC SERVICES ENTERPRISE GROUP INCORPORATED
SIGNIFICANT SUBSIDIARIES

Name	Ownership %	State of Incorporation
Public Service Electric and Gas Company	100	New Jersey
PSEG Power LLC	100	Delaware
PSEG Fossil LLC	100	Delaware
PSEG Nuclear LLC	100	Delaware
PSEG Energy Resources & Trade LLC	100	Delaware

The remaining subsidiaries of Public Service Enterprise Group Incorporated are not significant as defined in Regulation S-X.

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Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-202594, 333-202591, 333-120100, 333-106330, 333-193126, 333-66426, 333-39738 and 333-193127 on Form S-8 and Registration Statement No. 333-221638 on Form S-3 of our reports dated February 26, 2018, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") and the effectiveness of the Company's internal control over financial reporting, appearing in the Annual Report on Form 10-K of Public Service Enterprise Group Incorporated for the year ended December 31, 2017.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 26, 2018

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Exhibit 23a

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-221639 on Form S-3 of our report dated February 26, 2018, relating to the consolidated financial statements and consolidated financial statement schedule of Public Service Electric and Gas Company and subsidiaries, appearing in the Annual Report on Form 10-K of Public Service Electric and Gas Company for the year ended December 31, 2017.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 26, 2018

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Exhibit 23b

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-221640 on Form S-3 of our report dated February 26, 2018, relating to the consolidated financial statements and consolidated financial statement schedule of PSEG Power LLC and subsidiaries appearing in the Annual Report on Form 10-K of PSEG Power LLC for the year ended December 31, 2017.

/s/Deloitte & Touche LLP
Parsippany, New Jersey
February 26, 2018

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2018

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31a

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31b

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2018

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31c

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Annual Report on Form 10-K of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 31d

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2018

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31e

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Annual Report on Form 10-K of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
February 26, 2018

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EXHIBIT 32a

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Enterprise Group Incorporated on Form 10-K for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
February 26, 2018

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EXHIBIT 32b

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
February 26, 2018

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EXHIBIT 32c

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of Public Service Electric and Gas Company on Form 10-K for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
February 26, 2018

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EXHIBIT 32d

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
February 26, 2018

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EXHIBIT 32e

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Annual Report of PSEG Power LLC on Form 10-K for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
February 26, 2018

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10-Ks - Exelon

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2012

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number	Exact Name of Registrant as Specified in its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
EXELON CORPORATION:	
Common Stock, without par value	New York and Chicago
Series A Junior Subordinated Debentures	New York
PECO ENERGY COMPANY:	
Cumulative Preferred Stock, without par value: $4.68 Series, $4.40 Series, $4.30 Series and $3.80 Series	New York
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York
BALTIMORE GAS AND ELECTRIC COMPANY:	
6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, by Baltimore Gas and Electric Company	New York

Securities registered pursuant to Section 12(g) of the Act:

COMMONWEALTH EDISON COMPANY:
Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes ☒	No ☐
Exelon Generation Company, LLC	Yes ☒	No ☐
Commonwealth Edison Company	Yes ☒	No ☐
PECO Energy Company	Yes ☒	No ☐
Baltimore Gas and Electric Company	Yes ☒	No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

	Large Accelerated	Accelerated	Non-Accelerated	Small Reporting Company
Exelon Corporation	✓			
Exelon Generation Company, LLC			✓	
Commonwealth Edison Company			✓	
PECO Energy Company			✓	
Baltimore Gas and Electric Company			✓	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2012 was as follows:

Exelon Corporation Common Stock, without par value	$ 32,084,086,343
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None
Baltimore Gas and Electric Company, without par value	None

The number of shares outstanding of each registrant's common stock as of January 31, 2013 was as follows:

Exelon Corporation Common Stock, without par value	855,019,272
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,761
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company, without par value	1,000

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Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2013 Annual Meeting of Shareholders and the Commonwealth Edison Company and PECO Energy Company 2013 information statements are incorporated by reference in Part III.

Exelon Generation Company, LLC and Baltimore Gas and Electric Company meet the conditions set forth in General Instruction I (1)(a) and (b) of Form 10-K and are therefore filing this Form in the reduced disclosure format.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon's holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively

Other Terms and Abbreviations

1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended

Other Terms and Abbreviations

Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA
EE&C	Energy Efficiency and Conservation/Demand Response
EGS	Electric Generation Supplier
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste

Other Terms and Abbreviations

LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midwest Independent Transmission System Operator, Inc.
mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal

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Other Terms and Abbreviations

Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SFC	Supplier Forward Contract
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
TEG	Termoelectrica del Golfo
TEP	Termoelectrica Penoles
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by the Registrants. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this Report are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a Registrant include those factors discussed herein, including those factors with respect to such Registrant discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, (c) ITEM 8. Financial Statements and Supplementary Data: Note 19 and (d) other factors discussed herein and in other filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants' websites at www.exeloncorp.com. Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I

ITEM 1. BUSINESS

General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through its principal subsidiary, Generation, in the energy generation business, and through its principal subsidiaries ComEd, PECO and BGE, in the energy delivery businesses discussed below. Exelon's principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603, and its telephone number is 312-394-7398.

Generation

Generation's integrated business consists of its owned and contracted electric generating facilities and investments in generation ventures that are marketed through its leading customer-facing activities. These customer-facing activities include, wholesale energy marketing operations and its competitive retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other regions.

Generation was formed in 2000 as a Pennsylvania limited liability company. Generation began operations as a result of a corporate restructuring, effective January 1, 2001, in which Exelon separated its generation and other competitive businesses from its regulated energy delivery businesses at ComEd and PECO. Generation's principal executive offices are located at 300 Exelon Way, Kennett Square, Pennsylvania 19348, and its telephone number is 610-765-5959.

ComEd

ComEd's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in northern Illinois, including the City of Chicago.

ComEd was organized in the State of Illinois in 1913 as a result of the merger of Cosmopolitan Electric Company into the original corporation named Commonwealth Edison Company, which was incorporated in 1907. ComEd's principal executive offices are located at 440 South LaSalle Street, Chicago, Illinois 60605, and its telephone number is 312-394-4321.

PECO

PECO's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia.

PECO was incorporated in Pennsylvania in 1929. PECO's principal executive offices are located at 2301 Market Street, Philadelphia, Pennsylvania 19103, and its telephone number is 215-841-4000.

BGE

BGE's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in central Maryland,

including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in central Maryland, including the City of Baltimore.

BGE was incorporated in Maryland in 1906. BGE's principal executive offices are located at 110 West Fayette Street, Baltimore, Maryland 21201, and its telephone number is 410-234-5000.

Operating Segments

See Note 21 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's operating segments.

Merger with Constellation Energy Group, Inc.

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation Energy Group, Inc. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information on the Constellation transaction.

Generation

Generation is one of the largest competitive electric generation companies in the United States, as measured by owned and contracted MW. Generation creates incremental strategic value by operating as an integrated business and matching its large generation fleet with a leading customer-facing platform. Generation's presence in well-developed energy markets, its integrated hedging strategy mitigating short-term market volatility, and its low-cost nuclear generating fleet operating consistently at high capacity factors, position it well to succeed in competitive energy markets.

Generation's customer-facing business, now referred to as Constellation, utilizes Generation's energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in spot markets. Generation also sells other energy-related products and other services to meet its customers' requirements. Generation is dependent upon continued deregulation of retail electric and gas markets and its ability to generate and obtain supplies of electricity and gas at competitive prices in the market.

Generation is a public utility under the Federal Power Act, and is subject to FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. FERC's jurisdiction over ratemaking also includes the authority to suspend the market-based rates of utilities (including Generation, which is a public utility as FERC defines that term) and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party

financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities. Additionally, ERCOT is not subject to regulation by FERC but performs a similar function in Texas. Specific operations of Generation are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including the NRC and Federal and state environmental protection agencies. Additionally, Generation is subject to mandatory reliability standards promulgated by the NERC, with the approval of FERC.

RTOs exist in a number of regions to provide transmission service across multiple transmission systems. CAISO, PJM, MISO, ISO-NE, ISO-NY and SPP, have been approved by FERC as RTOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems.

Significant Acquisitions

Antelope Valley Solar Ranch One . On September 30, 2011, Generation acquired Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, which developed and will build, operate, and maintain the project. The first block began operations in December 2012, with three additional blocks coming online in February 2013 and an expectation of full commercial operation by the end of the third quarter of 2013. When fully operational, Antelope Valley will be one of the largest PV solar projects in the world, with approximately 3.8 million solar panels generating enough clean, renewable electricity to power the equivalent of 75,000 average homes per year. The project has a 25-year PPA, approved by the California Public Utilities Commission, with Pacific Gas & Electric Company for the full output of the plant. Exelon expects to invest up to $701 million in equity in the project through 2013. The DOE's Loan Programs Office issued a loan guarantee of up to $646 million to support project financing for Antelope Valley. Exelon expects the total investment of up to $1.3 billion to be accretive to earnings and cash flows beginning in 2013. Once constructed and operating, the project is expected to have stable earnings and cash flow profiles due to the PPA.

Wolf Hollow Generating Station. On August 24, 2011, Generation completed the acquisition of all of the equity interests of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, for a purchase price of $311 million which increased Generation's owned capacity within the ERCOT power market by 720 MWs.

Exelon Wind. In 2010, Generation acquired 735 MWs of installed, operating wind capacity located in eight states for approximately $893 million in cash. In addition, Generation acquired development stage projects which became fully operational in 2012.

See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information on the above acquisitions.

Significant Dispositions

Maryland Clean Coal Stations. Associated with certain of the regulatory approvals required for the merger, Exelon and Constellation agreed to enter into contracts to sell three Constellation generating stations, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland within 150 days (subsequently extended 30 days by the DOJ)

following the merger completion. In accordance with that agreement, on November 30, 2012, a subsidiary of Generation sold these three Maryland generating stations and associated assets to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC for estimated net proceeds from the sale of approximately $371 million, which resulted in a pre-tax loss of $272 million. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Generating Resources

At December 31, 2012, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [a]	
Nuclear	17,202
Fossil	12,050
Renewable (including Hydroelectric) [b]	3,516
Owned generation assets	32,768
Long-term contracts [c]	9,296
Investment in CENG [d]	1,963
Total generating resources	44,027

(a) See "Fuel" for sources of fuels used in electric generation.
(b) Includes equity method investment in certain generating facilities.
(c) Excludes contracts with CENG. See Long-Term Contracts table in this section for additional information.
(d) Generation owns a 50.01% interest in CENG, a joint venture with EDF. See ITEM 2. PROPERTIES—Generation and Note 22—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Generation has six reportable segments, the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions, representing the different geographical areas in which Generation's customer-facing activities are conducted and where Generation's generating resources are located. Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina (approximately 32% of capacity). Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee; and the entire United States footprint of MISO, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, and the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM; and parts of Montana, Missouri and Kentucky (approximately 34% of capacity). New England represents the operations within the ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 8% of capacity). New York represents the operations within ISO-NY, which covers the state of New York in its entirety (approximately 3% of capacity). ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas (approximately 11% of capacity). Other Regions is an aggregate of regions not considered individually significant (approximately 12% of capacity).

Nuclear Facilities

Generation has ownership interests in eleven nuclear generating stations currently in service, consisting of 19 units with an aggregate of 17,202 MW of capacity. Generation wholly owns all of its nuclear generating stations, except for Quad Cities Generating Station (75% ownership), Peach Bottom Generating Station (50% ownership) and Salem Generating Station (Salem) (42.59% ownership). Generation's nuclear generating stations are all operated by Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. In 2012 and 2011, electric supply (in GWh) generated from

the nuclear generating facilities was 53% and 82%, respectively, of Generation's total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation's electric supply sources.

Constellation Energy Nuclear Group, Inc.

Generation also owns a 50.01% interest in CENG, a joint venture with EDF. CENG is governed by a board of ten directors, five of which are appointed by Generation and five by EDF. CENG owns and operates a total of five nuclear generating facilities on three sites, Calvert Cliffs, Ginna and Nine Mile Point. CENG's ownership share in the total capacity of these units is 3,925 MW. See ITEM 2. PROPERTIES for additional information on these sites.

Generation has a unit contingent PPA with CENG under which it purchases 85 to 90% of the output of CENG's nuclear generating facilities that is not sold to third parties under the pre-existing PPAs through 2014. Beginning on January 1, 2015, and continuing to the end of the lives of the respective nuclear facilities, Generation will purchase 50.01% and EDF will purchase 49.99% of the output of the CENG's nuclear facilities. All commitments to purchase subsequent to December 31, 2014 are at market prices. See Note 22—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information regarding CENG.

Nuclear Operations. Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on Generation's results of operations. As the largest generator of nuclear power in the United States, Generation can negotiate favorable terms for the materials and services that its business requires. Generation's operations from its nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

During 2012 and 2011, the nuclear generating facilities operated by Generation achieved capacity factors of 92.7% and 93.3%, respectively. Generation manages its scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for Generation's wholesale and retail marketing and trading activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations.

In addition to the rigorous maintenance and equipment upgrades performed by Generation during scheduled refueling outages, Generation has extensive operating and security procedures in place to ensure the safe operation of the nuclear units. Generation has extensive safety systems in place to protect the plant, personnel and surrounding area in the unlikely event of an accident.

Regulation of Nuclear Power Generation. Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of December 31, 2012, the NRC categorized each unit operated by Generation in the Licensee Response Column, which is the highest of five performance bands. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in

regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. For additional information on the NRC actions related to the Japan Earthquake and Tsunami and the industry's response, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Executive Overview.

Licenses . Generation has 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals for Peach Bottom Units 2 and 3, Dresden Units 2 and 3, Quad Cities Units 1 and 2, Oyster Creek and Three Mile Island Unit 1. Additionally, PSEG has 40-year operating licenses from the NRC and on June 30, 2011, received 20-year operating license renewals for Salem Units 1 and 2. On December 8, 2010, in connection with an Administrative Consent Order (ACO) with the NJDEP, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. The following table summarizes the current operating license expiration dates for Generation's nuclear facilities in service:

Station	Unit	In-Service Date [a]	Current License Expiration
Braidwood	1	1988	2026
	2	1988	2027
Byron	1	1985	2024
	2	1987	2026
Clinton	1	1987	2026
Dresden [b]	2	1970	2029
	3	1971	2031
LaSalle	1	1984	2022
	2	1984	2023
Limerick [c]	1	1986	2024
	2	1990	2029
Oyster Creek [b][d]	1	1969	2029
Peach Bottom [b]	2	1974	2033
	3	1974	2034
Quad Cities [b]	1	1973	2032
	2	1973	2032
Salem [b]	1	1977	2036
	2	1981	2040
Three Mile Island [b]	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) Stations for which the NRC has issued a renewed operating licenses.
(c) On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years.
(d) In December, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

Generation expects to apply for and obtain approval of license renewals for the remaining nuclear units. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC's review. The NRC review process takes approximately two years from the docketing of an application. Each requested license renewal is expected to be for 20 years beyond the original license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual and assumed renewal of operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek.

In August 2012, Generation entered into an operating services agreement with the Omaha Public Power District (OPPD) to provide operational and managerial support services for the Fort Calhoun Station and a licensing agreement for use of the Exelon Nuclear Management Model. The terms for both agreements are 20 years. OPPD will continue to own the plant and remain the NRC licensee.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. Using proven technologies, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the plan in light of changing market conditions. Decisions to implement uprates at particular nuclear plants, the amount of expenditures to implement the plan, and the actual MWs of additional capacity attributable to the uprate program will be determined on a project-by-project basis in accordance with Exelon's normal project evaluation standards and ultimately will depend on market conditions, economic and policy considerations, and other factors.

Based on recent reviews, the nuclear uprate implementation plan was adjusted during 2012, primarily as a result of market conditions, including low natural gas prices and the continued sluggish economy, resulting in the deferral or cancellation of certain projects. In addition, the ability to implement several projects requires the successful resolution of various technical matters. The resolution of these matters may further affect the timing and amount of the power increases associated with the power uprate initiative. Following these reviews, any projects that may be undertaken are expected to be completed by the end of 2021, and may result in between 1,125 and 1,200 MWs of additional capacity at an overnight cost of approximately $3.4 billion in 2013 dollars. Overnight costs do not include financing costs or cost escalation.

Approximately 75% of the planned uprate MWs projects are either complete and in service or in the installation or design and engineering phases across seven nuclear stations including Limerick and Peach Bottom in Pennsylvania and Byron, Braidwood, Dresden, LaSalle and Quad Cities in Illinois. The remaining 25% of uprate MWs, if and when completed, would come from an extended power uprate project at Limerick currently scheduled to begin in 2017. From the program announcement in 2008 through December 31, 2012, Generation has placed in service 310 MWs of nuclear generation through the uprate program at a cost of approximately $810 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's consolidated balance sheets. At December 31, 2012, an additional approximate $310 million has been capitalized to construction work in progress (CWIP) within property, plant and equipment on Exelon's and Generation's consolidated balance sheets, of which approximately $200 million (202 MWs) relates to projects currently in the installation phase. The remaining $110 million (346 MWs) in CWIP relates to projects currently in the design and engineering phase that continue to be evaluated in accordance with Exelon's normal project evaluation standards. The completion of those projects in the design and engineering phase will ultimately depend on market conditions, economic and policy considerations, and other factors. As of December 31, 2012, Generation believes it is more likely than not that all projects in CWIP will ultimately be placed in service. If a project in the design and engineering phase is expected to not be completed as planned, previously capitalized costs would be reversed through earnings as a charge to operating and maintenance expense.

New Nuclear Site Development. On August 28, 2012, Exelon halted efforts to gain initial federal regulatory approvals for new nuclear construction in Victoria County, Texas and notified the Nuclear Regulatory Commission that it has withdrawn its related Early Site Permit application. The action is in response to low natural gas prices and economic and market conditions that have made construction

of new merchant nuclear power plants in competitive markets uneconomical now and for the foreseeable future. The withdrawal of the license application brings an end to all project activity.

Nuclear Waste Disposal. There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by its nuclear generating facilities in on-site storage pools or in dry cask storage facilities. Since Generation's SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, Generation has developed dry cask storage facilities to support operations.

As of December 31, 2012, Generation had approximately 58,100 SNF assemblies (13,900 tons) stored on site in SNF pools or dry cask storage (this includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party; see Note 13 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for Clinton and Three Mile Island. Clinton and Three Mile Island will lose full core reserve, which is when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core, in 2015 and 2023, respectively. Dry cask storage will be in operation at Clinton and Three Mile Island prior to the closing of their respective on-site storage pools. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites through the end of the license renewal periods, and through decommissioning.

For a discussion of matters associated with Generation's contracts with the DOE for the disposal of SNF, see Note 19 of the Combined Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at federally licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into an agreement, although neither state currently has an operational site and none is anticipated to be operational until after 2020.

Generation is currently utilizing on-site storage capacity at its nuclear generation stations for limited amounts of LLRW and has been shipping its Class A LLRW, which represent 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Oyster Creek and Salem), and Connecticut. Generation has received NRC approval for its Peach Bottom and LaSalle stations that will allow storage at these sites of LLRW from its remaining stations with limited capacity. Generation now has enough storage capacity to store all Class B and C LLRW for the life of all stations in Generation's nuclear fleet. During 2012, Generation entered into a six year contract to ship Class B and Class C LLRW to Texas. The terms of the agreement will provide for disposal of all current Class B and Class C LLRW stored at the stations, as well as the waste generated during the term of the agreement. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize cost impacts and on-site storage.

Nuclear Insurance. Generation is subject to liability, property damage and other risks associated with a major accidental outage at any of its nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See "Nuclear Insurance" within Note 19 of the Combined Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. PROPERTIES—Generation. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and results of operations.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview; ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates, Nuclear Decommissioning, Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Notes 3, 9 and 13 of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation's NDT funds and its decommissioning obligations.

Dresden Unit 1 and Peach Bottom Unit 1 have ceased power generation. SNF at Dresden Unit 1 is currently being stored in dry cask storage until a permanent repository under the NWPA is completed. All SNF for Peach Bottom Unit 1, which ceased operation in 1974, has been removed from the site and the SNF pool is drained and decontaminated. Generation's estimated liability to decommission Dresden Unit 1 and Peach Bottom Unit 1 as of December 31, 2012 was $195 million and $121 million, respectively. As of December 31, 2012, NDT funds set aside to pay for these obligations were $390 million.

Zion Station Decommissioning. On December 11, 2007, Generation entered into an Asset Sale Agreement (ASA) with EnergySolutions, Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, LLC (ZionSolutions) under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998.

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities associated with Zion Station. Pursuant to the ASA, ZionSolutions can periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request reimbursement; specifically, if certain milestones as defined in the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. See Note 13 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning and see Note 2 of the Combined Notes to Consolidated Financial Statements for a discussion of variable interest entity considerations related to ZionSolutions.

Fossil and Renewable Facilities (including Hydroelectric)

Generation has ownership interests in 15,566 MW of capacity in fossil and renewable generating facilities currently in service. Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly-owned facilities that include Keystone, Conemaugh, and Wyman; (2) ownership interests through equity method investments in Colver, Malacha, Safe Harbor, and Sunnyside; and (3) certain wind project entities with minority interest owners. Generation's fossil and renewable generating stations are all operated by Generation, with the exception of Colver, Conemaugh, Keystone, LaPorte, Malacha, Safe Harbor, Sunnyside and Wyman, which are operated

by third parties. In 2012 and 2011, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 12% and 7%, respectively, of Generation's total electric supply. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. For additional information regarding Generation's electric generating facilities, see ITEM 2. PROPERTIES—Generation.

Exelon Wind . During 2012, six development projects with a combined capacity of approximately 400 MWs began commercial operations. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview for additional information.

Licenses. Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid. On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Muddy Run Pumped Storage Project and the Conowingo Hydroelectric Project, respectively. The FERC review process is scheduled to be completed by August 31, 2014 and September 1, 2014, when the current Conowingo and Muddy Run licenses expire.

Insurance. Generation maintains business interruption insurance for its renewable projects, and delay in start-up insurance for its renewable projects currently under construction. Generation does not purchase business interruption insurance for its wholly owned fossil and hydroelectric operations. Generation maintains both property damage and liability insurance. For property damage and liability claims for these operations, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. PROPERTIES—Generation.

Long-Term Contracts

In addition to energy produced by owned generation assets, Generation sells electricity purchased under long-term contracts. The following tables summarize Generation's long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2012:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic [(a)]	13	2013 - 2032	973
Midwest	10	2013 - 2026	2,981
New England	6	2015 - 2020	637
New York [(a)]	1	2013	100
ERCOT	3	2013 - 2022	1,088
Other Regions	10	2015 - 2030	3,517
Total	43		9,296

	2013	2014	2015	2016	2017
Capacity Expiring (MW)	1,369	55	1,730	4	2,083

(a) Excludes contracts with CENG.

Fuel

The following table shows sources of electric supply in GWh for 2012 and 2011:

	Source of Electric Supply [a]	
	2012	2011
Nuclear	139,862	139,297
Purchases—non-trading portfolio [b]	91,994	18,908
Fossil	27,760	7,385
Renewable	4,079	4,253
Total supply	263,695	169,843

(a) Represents Generation's proportionate share of the output of its generating plants.
(b) Includes purchases in 2012 pursuant to Generation's PPA with CENG. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

The fuel costs for nuclear generation are less than for fossil-fuel generation. Consequently, nuclear generation is generally the most cost-effective way for Generation to meet its wholesale and retail load servicing requirements.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has uranium concentrate inventory and supply contracts sufficient to meet all of its uranium concentrate requirements through 2016. Generation's contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2020. All of Generation's enrichment requirements have been contracted through 2017. Contracts for fuel fabrication have been obtained through 2018. Generation does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, and spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing. Coal is procured primarily through annual supply contracts, with the remainder supplied through either short-term or spot-market purchases.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures. Generation also hedges forward price risk, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation's integrated business operations include the physical delivery and marketing of power obtained through its generation capacity and through long-term, intermediate-term and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. Generation has also contracted for access to additional generation through bilateral long-term PPAs. PPAs are commitments related to power generation of specific generation plants and/or are dispatchable in nature similar to asset ownership depending on

the type of underlying asset. Generation secures contracted generation as part of its overall strategic plan, with objectives such as obtaining low-cost energy supply sources to meet its physical delivery obligations to both wholesale and retail customers and assisting customers to meet renewable portfolio standards. Generation may buy power to meet the energy demand of its customers, including ComEd, PECO and BGE. Generation sells electricity, natural gas, and related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets. Generation's customer facing operations combine a unified sales force with a customer-centric model that leverages technology to broaden the range of products and solutions offered, which Generation believes promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which provides a platform that is scalable and able to capitalize on opportunities for future growth.

Generation's purchases may be for more than the energy demanded by Generation's customers. Generation then sells this open position, along with capacity not used to meet customer demand, in the wholesale electricity markets. Where necessary, Generation also purchases transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs in markets without an organized RTO. Generation also incorporates contingencies into its planning for extreme weather conditions, including potentially reserving capacity to meet summer loads at levels representative of warmer-than-normal weather conditions. Generation actively manages these physical and contractual assets in order to derive incremental value. Additionally, Generation is involved in the development, exploration, and harvesting of oil, natural gas and natural gas liquids properties.

Price Supply Risk Management

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation also enters into transactions that are outside of this ratable sales plan. Generation is exposed to relatively greater commodity price risk beyond 2013 for which a larger portion of its electricity portfolio may be unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. As of December 31, 2012, the percentage of expected generation hedged for the major reportable segments was 94%-97%, 62%-65% and 27%-30% for 2013, 2014, and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity, including purchased power from CENG. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including sales to ComEd, PECO and BGE to serve their retail load. A portion of Generation's hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation's efforts. The trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop-loss and value-at-risk limits, to manage exposure to market risk. Additionally, the corporate risk management group and Exelon's RMC monitor the financial risks of the wholesale and retail power marketing activities. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

At December 31, 2012, Generation's short and long-term commitments relating to the purchase of energy and capacity from and to unaffiliated utilities and others were as follows:

	Net Capacity Purchases [a]	Power-Related Purchases [b]	Transmission Rights Purchases [c]	Purchased Energy from CENG	Total
2013	$ 374	$ 95	$ 28	$ 777	$1,274
2014	353	69	26	516	964
2015	350	25	13	—	388
2016	266	11	2	—	279
2017	203	3	2	—	208
Thereafter	469	5	34	—	508
Total	$ 2,015	$ 208	$ 105	$ 1,293	$3,621

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2012, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. Expected payments include certain capacity charges which are contingent on plant availability.
(b) Power-Related Purchases include firm REC purchase agreements. The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

As part of reaching a comprehensive agreement with EDF in October 2010, the existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements, CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the available output of CENG's nuclear plants at market prices. Generation discloses in the table above commitments to purchase from CENG at fixed prices. All commitments to purchase from CENG at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 22 of the Combined Notes to Consolidated Financial Statements for more details on this arrangement.

Capital Expenditures

Generation's business is capital intensive and requires significant investments in nuclear fuel and energy generation assets and in other internal infrastructure projects. Generation's estimated capital expenditures for 2013 are as follows:

(in millions)	
Nuclear fuel [a]	$1,000
Production plant	1,000
Renewable energy projects [b]	575
Uprates	225
Other	50
Total	$2,850

(a) Includes Generation's share of the investment in nuclear fuel for the co-owned Salem plant.
(b) Primarily relates to expenditures for the completion of the Antelope Valley development project.

ComEd

ComEd is engaged principally in the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to a diverse base of residential, commercial and industrial customers in northern Illinois. ComEd is a public utility under the Illinois Public Utilities Act subject to regulation by the ICC related to distribution rates and service, the issuance of securities, and certain other aspects of ComEd's business. ComEd is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of ComEd's business. Specific operations of ComEd are also subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, ComEd is subject to NERC mandatory reliability standards.

ComEd's retail service territory has an area of approximately 11,400 square miles and an estimated population of 9 million. The service territory includes the City of Chicago, an area of about 225 square miles with an estimated population of 2.7 million. ComEd has approximately 3.8 million customers.

ComEd's franchises are sufficient to permit it to engage in the business it now conducts. ComEd's franchise rights are generally nonexclusive rights documented in agreements and, in some cases, certificates of public convenience issued by the ICC. With few exceptions, the franchise rights have stated expiration dates ranging from 2013 to 2066. ComEd anticipates working with the appropriate agencies to extend or replace the franchise agreements prior to expiration.

ComEd's kWh deliveries and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. ComEd's highest peak load occurred on July 20, 2011, and was 23,753 MWs; its highest peak load during a winter season occurred on January 15, 2009, and was 16,328 MWs.

Retail Electric Services

Under Illinois law, transmission and distribution services are regulated, while electric customers are allowed to purchase electricity supply from a competitive retail electric supplier.

Electric revenues and purchased power expense are affected by fluctuations in customers' purchases from competitive retail electric suppliers. All ComEd customers have the ability to purchase energy from an alternative retail electric supplier. The customer choice activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense. ComEd's cost of electric supply is passed directly through to default service customers without markup and those rates are subject to adjustment monthly to recover or refund the difference between ComEd's actual cost of electricity delivered and the amount included in rates. For those customers that choose a competitive electric generation supplier, ComEd acts as the billing agent but does not record revenues or expenses related to the electric supply. ComEd remains the distribution service provider for all customers in its service territory and charges a regulated rate for distribution service. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information on customer switching to alternative electric generation suppliers, and Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process and for additional information.

Under Illinois law, ComEd is required to deliver electricity to all customers. ComEd's obligation to provide generation supply service, which is referred to as a POLR obligation, primarily varies by customer size. ComEd's obligation to provide such service to residential customers and other small customers with demands of under 100 kWs continues for all customers who do not or cannot choose a

competitive electric generation supplier or who choose to return to ComEd after taking service from a competitive electric generation supplier. ComEd does not have a fixed-price generation supply service obligation to most of its largest customers with demands of 100 kWs or greater, as this group of customers has previously been declared competitive. Customers with competitive declarations may still purchase power and energy from ComEd, but only at hourly market prices.

Energy Infrastructure Modernization Act (EIMA). Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. In addition, as long as ComEd is subject to EIMA, ComEd will fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

ComEd files an annual reconciliation of the revenue requirement in effect in a given year to reflect the actual costs that the ICC determines are prudently and reasonably incurred for such year. Under the terms of EIMA, ComEd's target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Electric Distribution Rate Cases . The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. On February 23, 2012, the ICC issued an order in the remand proceeding requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation. On March 26, 2012, ComEd filed a notice of appeal. ComEd has recognized for accounting purposes its best estimate of any refund obligation.

On May 24, 2011, the ICC issued an order in ComEd's 2010 electric distribution rate case, which became effective on June 1, 2011. The order approved a $143 million increase to ComEd's annual delivery service revenue requirement and a 10.5% rate of return on common equity. The order has been appealed to the Court by several parties. ComEd cannot predict the results of these appeals. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electric distribution rate cases.

Procurement-Related Proceedings. Since June 2009, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. In order to fulfill a requirement of the Illinois Settlement Legislation, ComEd hedged the price of a significant portion of energy purchased in the spot market with a five-year variable-to-fixed financial swap contract with Generation that expires on May 31, 2013. As required by EIMA, in February 2012 the IPA completed procurement events for energy and REC requirements for the June 2013 through December 2017 period. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's energy commitments.

Continuous Power Interruption. The Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage

due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. See Note 19—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Construction Budget

ComEd's business is capital intensive and requires significant investments primarily in energy transmission and distribution facilities, to ensure the adequate capacity, reliability and efficiency of its system. Based on PJM's RTEP, ComEd has various construction commitments, as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. ComEd's most recent estimate of capital expenditures for electric plant additions and improvements for 2013 is $1,400 million, which includes RTEP projects and infrastructure modernization resulting from EIMA. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

PECO

PECO is engaged principally in the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia. PECO is a public utility under the Pennsylvania Public Utility Code subject to regulation by the PAPUC as to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of PECO's operations. PECO is a public utility under the Federal Power Act subject to regulation by FERC as to transmission rates and certain other aspects of PECO's business and by the U.S. Department of Transportation as to pipeline safety and other areas of gas operations. Specific operations of PECO are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, PECO is also subject to NERC mandatory reliability standards.

PECO's combined electric and natural gas retail service territory has an area of approximately 2,100 square miles and an estimated population of 4.0 million. PECO provides electric distribution service in an area of approximately 1,900 square miles, with a population of approximately 3.9 million, including approximately 1.5 million in the City of Philadelphia. PECO provides natural gas distribution service in an area of approximately 1,900 square miles in southeastern Pennsylvania adjacent to the City of Philadelphia, with a population of approximately 2.4 million. PECO delivers electricity to approximately 1.6 million customers and natural gas to approximately 497,000 customers.

PECO has the necessary authorizations to provide regulated electric and natural gas distribution service in the various municipalities or territories in which it now supplies such services. PECO's authorizations consist of charter rights and certificates of public convenience issued by the PAPUC and/or "grandfathered rights," which are rights generally unlimited as to time and generally exclusive from competition from other electric and natural gas utilities. In a few defined municipalities, PECO's natural gas service territory authorizations overlap with that of another natural gas utility; however, PECO does not consider those situations as posing a material competitive or financial threat.

PECO's kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. PECO's highest peak load occurred on July 22, 2011 and was 8,983 MW; its highest peak load during winter months occurred on December 20, 2004 and was 6,838 MW.

PECO's natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. PECO's highest daily natural gas send out occurred on January 17, 2000 and was 718 mmcf.

Retail Electric Services

PECO's retail electric sales and distribution service revenues are derived pursuant to rates regulated by the PAPUC. Pennsylvania permits competition by EGSs for the supply of retail electricity while retail transmission and distribution service remains regulated under the Competition Act. At December 31, 2012, there were 77 alternative EGSs serving PECO customers. At December 31, 2012, the number of retail customers purchasing energy from an alternative EGS was 496,500 representing approximately 31% of total retail customers. Retail deliveries purchased from EGSs represented approximately 66% of PECO's retail kWh sales for the year ended December 31, 2012. Customers that choose an alternative EGS are not subject to rates for PECO's electric supply procurement costs and retail transmission service charges. PECO presents on customer bills its electric supply Price to Compare, which is updated quarterly, to assist customers with the evaluation of offers from alternative EGSs.

Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense or PECO's financial position. PECO's cost of electric supply is passed directly through to default service customers without markup and those rates are subject to adjustment at least quarterly to recover or refund the difference between PECO's actual cost of electricity delivered and the amount included in rates through the GSA. For those customers that choose an alternative EGS, PECO acts as the billing agent but does not record revenues or purchase power and fuel expense related to this electric supply. PECO remains the distribution service provider for all customers in its service territory and charges a regulated rate for distribution service.

Procurement Proceedings. PECO's electric supply for its customers is procured through contracts executed in accordance with its PAPUC-approved DSP Programs. PECO has entered into contracts with PAPUC-approved bidders, including Generation, as part of its DSP I competitive procurements conducted since June 2009 for its default electric supply beginning January 2011, which include fixed price full requirement contracts for all procurement classes, spot market price full requirements contracts for the commercial and industrial procurement classes, and block energy contracts for the residential procurement class. In September 2012, PECO completed its last competitive procurement for electric supply under its current DSP Program, which expires on May 31, 2013.

On October 12, 2012, the PAPUC approved PECO's second DSP Program, which was filed with the PAPUC in January 2012. The plan outlines how PECO will purchase electric supply for default service customers from June 1, 2013 through May 31, 2015. Pursuant to the second DSP Program, PECO will procure electric supply through five competitive procurements for fixed price full requirements contracts of two years or less for the residential and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes beginning in June 2013.

The second DSP Program also includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs beginning April 1, 2014. PECO expects to file its plan for CAP customers by May 1, 2013.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

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Smart Meter, Smart Grid and Energy Efficiency Programs

Smart Meter and Smart Grid Programs. In April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, which was filed in accordance with the requirements of Act 129. Also, in April 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, PECO has been awarded $200 million, the maximum grant allowable under the program, for its SGIG project—Smart Future Greater Philadelphia. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. On January 18, 2013, PECO filed with the PAPUC its universal deployment plan for approval of its proposal to deploy the remainder of the 1.6 million smart meters on an accelerated basis by the end of 2014. In total, PECO currently expects to spend up to $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, before considering the $200 million SGIG.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Programs. PECO's approved four-year Phase I EE&C plan totals approximately $328 million and sets forth how PECO will meet the required reduction targets established by Act 129's EE&C provisions. PECO's plan includes a CFL program, weatherization programs, an energy efficiency appliance rebate and trade-in program, rebates and energy efficiency programs for non-profit, educational, governmental and business customers, customer incentives for energy management programs and incentives to help customers reduce energy demand during peak periods. Under Act 129's EE&C provisions, PECO was required to reduce peak demand by a minimum of 4.5% of its annual system peak demand in the 100 hours of highest demand by May 31, 2013. The peak demand period ended on September 30, 2012 and PECO will report its compliance with the reduction targets in a preliminary filing with the PAPUC on March 1, 2013. The final compliance report is due to the PAPUC by November 15, 2013. In addition, PECO is required to reduce electric consumption in its service territory by 3% through May 31, 2013.

On August 2, 2012, the PAPUC issued its Phase II EE&C implementation order, under which the PAPUC has established PECO's three year cumulative consumption reduction target at 2.9%. PECO filed its three year EE&C Phase II plan with the PAPUC on November 1, 2012. The plan sets forth how PECO will reduce electric consumption by at least 2.9% in its service territory for the period June 1, 2013 through May 31, 2016.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Natural Gas

PECO's natural gas sales and distribution service revenues are derived through natural gas deliveries at rates regulated by the PAPUC. PECO's purchased natural gas cost rates, which represent a significant portion of total rates, are subject to quarterly adjustments designed to recover or refund the difference between the actual cost of purchased natural gas and the amount included in rates without markup through the PGC.

PECO's natural gas customers have the right to choose their natural gas suppliers or to purchase their gas supply from PECO at cost. At December 31, 2012, the number of retail customers purchasing natural gas from a competitive natural gas supplier was 53,600, representing approximately 11% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 16% of PECO's mmcf sales for the year ended December 31, 2012. PECO provides distribution, billing, metering, installation, maintenance and emergency response services at regulated rates to all its customers in its service territory.

Procurement Proceedings . PECO's natural gas supply is purchased from a number of suppliers primarily under long-term firm transportation contracts for terms of up to two years in accordance with its annual PAPUC PGC settlement. PECO's aggregate annual firm supply under these firm transportation contracts is 35 million dekatherms. Peak natural gas is provided by PECO's liquefied natural gas (LNG) facility and propane-air plant. PECO also has under contract 23 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 30% of PECO's 2012-2013 heating season planned supplies.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Construction Budget

PECO's business is capital intensive and requires significant investments primarily in electric transmission and electric and natural gas distribution facilities to ensure the adequate capacity, reliability and efficiency of its system. PECO, as a transmission facilities owner, has various construction commitments under PJM's RTEP as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. PECO's most recent estimate of capital expenditures for plant additions and improvements for 2013 is $569 million, which includes RTEP projects and capital expenditures related to the smart meter and smart grid project net of expected SGIG DOE reimbursements.

BGE

BGE is engaged principally in the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of distribution services to retail customers in central Maryland, including the City of Baltimore. BGE is a public utility under the Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC as to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of BGE's operations. BGE is a public utility under the Federal Power Act subject to regulation by FERC as to transmission rates and certain other aspects of BGE's business and by the U.S. Department of Transportation as to pipeline safety and other areas of gas operations. Specific operations of BGE are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, BGE is also subject to NERC mandatory reliability standards.

BGE serves an estimated population of 2.8 million in its 2,300 square mile combined electric and gas retail service territory. BGE provides electric distribution service in an area of approximately 2,300 square miles and gas distribution service in an area of approximately 810 miles, both with a population of approximately 2.8 million, including approximately 621,000 in the City of Baltimore. BGE delivers electricity to approximately 1.2 million customers and natural gas to approximately 655,000 customers.

BGE has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities and territories in which it now supplies such services. With respect to electric distribution service, BGE's authorizations consist of charter rights, a state-wide franchise grant and a franchise grant from the City of Baltimore. The franchise grants are not exclusive and are perpetual. With respect to natural gas distribution service, BGE's authorizations consist of charter rights, a perpetual state-wide franchise grant, and franchises granted by all the municipalities and/or governmental bodies in which BGE now supplies services. The franchise grants are not exclusive; some are perpetual and some are for a limited duration, which BGE anticipates being able to extend or replace prior to expiration.

BGE's kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating.

BGE's highest peak load occurred on July 21, 2011 and was 7,236 MW; its highest peak load during winter months occurred on February 6, 2007 and was 6,347 MW.

BGE's natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. BGE's highest daily natural gas send out occurred on February 5, 2007 and was 840 mmcf.

The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This adjustment allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period (referred to as "revenue decoupling"). Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Retail Electric Services

BGE's retail electric sales and distribution service revenues are derived from electricity deliveries at rates regulated by the MDPSC. As a result of the deregulation of electric generation in Maryland effective July 1, 2000, all customers can choose their EGS. While BGE does not sell electric supply to all customers in its service territory, BGE continues to deliver electricity to all customers and provides meter reading, billing, emergency response, and regular maintenance services. Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense or BGE's financial position. At December 31, 2012, there were 53 alternative EGSs serving BGE customers. At December 31, 2012, the number of retail customers purchasing energy from an alternative EGS was 362,117, representing approximately 29% of total retail customers. Retail deliveries purchased from EGSs represented approximately 60% of BGE's retail kWh sales for the year ended December 31, 2012.

BGE is obligated to provide market-based SOS to all of its electric customers. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes a commercial and industrial shareholder return component and an incremental cost component. Bidding to supply BGE's market-based SOS occurs through a competitive bidding process approved by the MDPSC. Successful bidders, which may include Generation, will execute contracts with BGE for terms of three months or two years.

BGE is obligated by the MDPSC to provide several variations of SOS to commercial and industrial customers depending on customer load.

Electric Distribution Rate Cases. In December 2010, the MDPSC issued an abbreviated electric rate order authorizing BGE to increase electric distribution rates for service rendered on or after December 4, 2010 by no more than $31 million. In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated combined electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $19 million of costs as regulatory assets. These costs are being recovered over a 5-year period beginning in December 2010 and include the deferral of $16 million of storm costs incurred in February 2010. The regulatory asset for the storm costs earns the authorized

rate of return. On July 27, 2012, BGE filed a combined application for increases to its electric and gas base rates with the MDPSC. The requested rate of return on equity in the application is 10.5%. On October 22, 2012, BGE filed an updated application to request an increase of $131 million to its electric distribution base revenue requirement. The new electric distribution base rates are expected to take effect in late February 2013. BGE cannot predict how much of the requested increases, if any, the MDPSC will approve.

Smart Meter and Energy Efficiency Programs

Smart Meter Programs. In August 2010, the MDPSC approved BGE's $480 million, SGIP, which includes deployment of a two-way communications network, 2 million smart electric and gas meters and modules, new customer pricing programs, a new customer web portal and numerous enhancements to BGE operations. Also, in April 2010, BGE entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, BGE has been awarded $200 million, the maximum grant allowable under the program, to support its Smart Grid, Peak Rewards and CC&B initiatives. The SGIG funding is being used to significantly reduce the rate impact of those investments on BGE customers. In total, through the ten year life of the Smart Grid program, BGE plans to spend up to $835 million on its smart grid and smart meter infrastructure.

Energy Efficiency Programs. BGE's energy efficiency programs include a CFL program, weatherization programs, an energy efficiency appliance rebate and trade-in program, rebates and energy efficiency programs for non-profit, educational, governmental and business customers, customer incentives for energy management programs and incentives to help customers reduce energy demand during peak periods. The MDPSC initially approved a full portfolio of conservation programs as well as a customer surcharge to recover the associated costs. This customer surcharge is updated annually. In December 2011, the MDPSC approved BGE's conservation programs for implementation in 2012 through 2014.

Natural Gas

BGE's natural gas sales are derived pursuant to a MBR mechanism that applies to customers who buy their gas from BGE. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. Customer choice program activity affects revenue collected from customers related to supplied natural gas; however, that activity has no impact on gas revenue net of purchased power expense or BGE's financial position. At December 31, 2012, there were 27 alternative NGSs serving BGE customers. At December 31, 2012, the number of retail customers purchasing fuel from an alternative NGS was 143,351, representing approximately 22% of total retail customers. Retail deliveries purchased from NGSs represented approximately 56% of BGE's retail mmcf sales for the year ended December 31, 2012.

BGE must secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed price contracts are recovered under the MBR mechanism and are not subject to sharing. BGE meets its natural gas load requirements through firm pipeline transportation and storage entitlements. BGE's current pipeline firm transportation entitlements to serve its firm loads are 362 mmcf per day.

BGE's current maximum storage entitlements are 284 mmcf per day. To supplement its gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, BGE has:

- a liquefied natural gas facility for the liquefaction and storage of natural gas with a total storage capacity of 1,000 mmcf and a daily capacity of 298 mmcf,

- a liquefied natural gas facility for natural gas system pressure support with a total storage capacity of 5.8 mmcf and a daily capacity of 5.8 mmcf, and
- a propane air facility and a mined cavern with a total storage capacity equivalent to 500 mmcf and a daily capacity of 81 mmcf.

BGE has under contract sufficient volumes of propane for the operation of the propane air facility and is capable of liquefying sufficient volumes of natural gas during the summer months for operations of its liquefied natural gas facility during peak winter periods. BGE historically has been able to arrange short-term contracts or exchange agreements with other gas companies in the event of short-term disruptions to gas supplies or to meet additional demand.

BGE also participates in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between shareholders and customers. BGE makes these sales as part of a program to balance its supply of, and cost of, natural gas.

Natural Gas Distribution Rate Cases. In December 2010, the MDPSC issued a rate order authorizing BGE to increase the gas distribution base revenue requirement for service rendered on or after December 4, 2010 by no more than $9.8 million. In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated combined electric and gas distribution rate order issued in December 2010. On July 27, 2012, BGE filed a combined application for increases to its electric and gas base rates with the MDPSC. The requested rate of return on equity in the application is 10.5%. On October 22, 2012, BGE filed an updated application to request an increase of $45 million to its gas distribution base revenue requirement. The new gas distribution base rates are expected to take effect in late February 2013. BGE cannot predict how much of the requested increases, if any, the MDPSC will approve.

Construction Budget

BGE's business is capital intensive and requires significant investments primarily in electric transmission and electric and natural gas distribution facilities to ensure the adequate capacity, reliability and efficiency of its system. BGE, as a transmission facilities owner, has various construction commitments under PJM's RTEP as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. BGE's most recent estimate of capital expenditures for plant additions and improvements for 2013 is $663 million, which includes capital expenditures related to the SGIP net of expected SGIG DOE reimbursements.

ComEd, PECO and BGE

Transmission Services

ComEd, PECO and BGE provide unbundled transmission service under rates approved by FERC. FERC has used its regulation of transmission to encourage competition for wholesale generation services and the development of regional structures to facilitate regional wholesale markets. Under FERC's open access transmission policy promulgated in Order No. 888, ComEd, PECO and BGE, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. ComEd, PECO and BGE are required to comply with FERC's Standards of Conduct regulation governing the communication of non-public information between the transmission owner's employees and wholesale merchant employees.

PJM is the ISO and the FERC-approved RTO for the Mid-Atlantic and Midwest regions. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM

Tariff), operates the PJM energy, capacity and other markets, and, through central dispatch, controls the day-to-day operations of the bulk power system for the PJM region. ComEd, PECO and BGE are members of PJM and provide regional transmission service pursuant to the PJM Tariff. ComEd, PECO, BGE and the other transmission owners in PJM have turned over control of their transmission facilities to PJM, and their transmission systems are currently under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM members at rates based on the costs of transmission service.

ComEd's transmission rates are established based on a formula that was approved by FERC in January 2008. FERC's order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

PECO default service customers are charged for retail transmission services through a rider designed to recover PECO's PJM transmission network service charges and RTEP charges on a full and current basis in accordance with the 2010 electric distribution rate case settlement.

The transmission rate in the PJM Open Access Transmission Tariff under which PECO incurs costs to serve its default service customers and earns revenue as a transmission facility owner is a FERC-approved rate. This is the rate that all load serving entities in the PECO transmission zone pay for wholesale transmission service.

BGE's transmission rates are established based on a formula that was approved by FERC in April 2006. FERC's order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding transmission services.

Employees

As of December 31, 2012, Exelon and its subsidiaries had 26,057 employees in the following companies, of which 8,665 or 33% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 [a]	IBEW Local 614 [b]	Other CBAs [c]	Total Employees Covered by CBAs	Total Employees
Generation	1,701	110	1,889	3,700	12,116
ComEd	3,571	—	—	3,571	5,902
PECO	—	1,286	—	1,286	2,453
BGE	—	—	—	—	3,360
Other [d]	82	—	26	108	2,226
Total	5,354	1,396	1,915	8,665	26,057

(a) A separate CBA between ComEd and IBEW Local 15, ratified on October 10, 2012, covers approximately 24 employees in ComEd's System Services Group. Generation's and ComEd's separate CBAs with IBEW Local 15 will expire in 2013.

(b) 1,286 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614. The CBAs expire on March 31, 2015. Additionally, Exelon Power, an operating unit of Generation, has an agreement with IBEW Local 614, which expires on March 31, 2015 and covers 110 employees.

(c) During 2012, Generation finalized CBAs with the Security Officer unions at Byron, Clinton and TMI, which expire between 2015 and 2016. During 2011, Generation finalized CBAs with the Security Officer unions at Braidwood, Dresden, LaSalle and Quad Cities, which expire between 2014 and 2015. During 2009 and 2010, Generation entered into CBAs with the Security Officer unions at Oyster Creek and Limerick, which expire in 2013 and 2014, respectively. Additionally, during 2009, a 5-year agreement was reached with Oyster Creek Nuclear Local 1289, which will expire in 2015. In 2010, a 3-year agreement was negotiated with New England ENEH, UWUA Local 369, which will expire in 2014 and covers 10 employees.

(d) Other includes shared services employees at BSC.

Environmental Regulation

General

Exelon, Generation, ComEd, PECO and BGE are subject to comprehensive and complex legislation regarding environmental matters by the U.S. Congress and by various state and local jurisdictions in which they operate their facilities. The Registrants are also subject to regulations administered by the U.S. EPA and various state and local environmental protection agencies. Federal, state and local regulation includes the authority to regulate air, water, and solid and hazardous waste disposal.

The Exelon Board of Directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President, Corporate Strategy and Chief Sustainability Officer; the Corporate Environmental Strategy Director and the Environmental Regulatory Strategy Director, as well as senior management of Generation, ComEd, PECO and BGE. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. The Exelon Board has delegated to its corporate governance committee authority to oversee Exelon's compliance with laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including, but not limited to, Exelon's climate change and sustainability policies and programs, and Exelon 2020, Exelon's comprehensive business and environmental plan, as discussed in further detail below. The Exelon Board has also delegated to its generation oversight committee authority to oversee environmental, health and safety issues relating to Generation, and to its energy delivery oversight committee authority to oversee environmental, health and safety issues related to ComEd, PECO and BGE.

Air Quality

Air quality regulations promulgated by the U.S. EPA and the various state and local environmental agencies in Illinois, Maryland, Massachusetts, New York, Pennsylvania and Texas in accordance with the Federal Clean Air Act impose restrictions on emission of particulates, sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury and other pollutants and require permits for operation of emissions sources. Such permits have been obtained by Exelon's subsidiaries and must be renewed periodically. The Clean Air Act establishes a comprehensive and complex national program to substantially reduce air pollution from power plants. Advanced emission controls for SO_2 and NOx have been installed at all of Generation's co-owned bituminous coal-fired units.

See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information regarding clean air regulation and legislation in the forms of the CSAPR and CAIR, the regulation of hazardous air pollutants from coal- and oil-fired electric generating facilities under MATS, and regulation of GHG emissions, in addition to NOVs issued to Generation and ComEd for alleged violations of the Clean Air Act.

During 2012, one of Generation's co-owned facilities began a project to install environmental control equipment. Total costs incurred as of December 31, 2012 was approximately $39 million. The amount to be expended at Exelon and Generation in 2013, 2014 and 2015 is expected to total $70 million, $45 million and $5 million, respectively.

Water Quality

Under the Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the U.S. EPA or from the state environmental agency to which the permit program has been delegated and must be renewed periodically. Certain of Generation's power generation facilities

discharge industrial wastewater into waterways and are therefore subject to these regulations and operate under NPDES permits or pending applications for renewals of such permits after being granted an administrative extension.

See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information regarding the impact to Exelon of state permitting agencies' administration of the Phase II rule implementing Section 316(b) of the Clean Water Act.

Generation is also subject to the jurisdiction of certain other state and regional agencies and compacts, including the Delaware River Basin Commission and the Susquehanna River Basin Commission.

Solid and Hazardous Waste

The CERCLA provides for immediate response and removal actions coordinated by the U.S. EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at sites, most of which are listed by the U.S. EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with a U.S. EPA-directed cleanup, may voluntarily settle with the U.S. EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight prior to listing on the NPL. Various states, including Illinois, Maryland and Pennsylvania, have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, the RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Generation, ComEd, PECO and BGE and their subsidiaries are or are likely to become parties to proceedings initiated by the U.S. EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third party.

See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information regarding solid and hazardous waste regulation and legislation.

Environmental Remediation

ComEd's, PECO's and BGE's environmental liabilities primarily arise from contamination at former MGP sites. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover environmental remediation costs of the MGP sites through a provision within customer rates. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The amount to be expended in 2013 at Exelon for compliance with environmental remediation related to contamination at former MGP sites is expected to total $57 million, consisting of $51 million, $6 million and $0 million at ComEd, PECO and BGE, respectively.

Generation's environmental liabilities primarily arise from contamination at current and former generation and waste storage facilities. As of December 31, 2012, Generation has established an appropriate liability to comply with environmental remediation requirements including contamination

attributable to low level radioactive residues at a storage and reprocessing facility named Latty Avenue, and at a disposal facility named West Lake Landfill, both near St. Louis, Missouri related to operations conducted by Cotter Corporation, a former ComEd subsidiary.

In addition, Generation, ComEd, PECO and BGE may be required to make significant additional expenditures not presently determinable for other environmental remediation costs.

See Notes 3 and 19 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' environmental remediation efforts and related impacts to the Registrants' results of operations, cash flows and financial position.

Global Climate Change

Exelon believes the evidence of global climate change is compelling and that the energy industry, though not alone, is a significant contributor to the human-caused emissions of GHGs that many in the scientific community believe contribute to global climate change, and as reported by the National Academy of Sciences in May 2011. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, hydroelectric, wind and solar photovoltaic), has a relatively small GHG emission profile, or carbon footprint, compared to other domestic generators of electricity. By virtue of its significant investment in low-carbon intensity assets, Generation's emission intensity, or rate of carbon dioxide equivalent (CO_2e) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its fossil fuel-fired generating plants; CO_2, methane and nitrous oxide are all emitted in this process, with CO_2 representing the largest portion of these GHG emissions. GHG emissions from combustion of fossil fuels represent the majority of Exelon's direct GHG emissions in 2012, although only a small portion of Exelon's electric supply is from fossil generating plants. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF_6) leakage in its electric transmission and distribution operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and usage of electricity at its facilities. Despite its focus on low-carbon generation, Exelon believes its operations could be significantly affected by the possible physical risks of climate change and by mandatory programs to reduce GHG emissions. See ITEM 1A. RISK FACTORS for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

Climate Change Regulation. Exelon is, or may become, subject to climate change regulation or legislation at the Federal, regional and state levels.

International Climate Change Regulation. At the international level, the United States has not yet ratified the United Nations Kyoto Protocol, which was extended at the most recent meeting of the United Nations Framework on Climate Change Conference of the Parties (COP 18) in December 2012. The Kyoto Protocol now requires participating developed countries to cap GHG emissions at certain levels until 2020, when the new global agreement on emissions reduction is scheduled to become effective. The new global agreement has been agreed to in concept and further development of its GHG emissions reductions is scheduled to begin in 2015. At this point, there is much debate about the different levels of emission reductions that will be required for developed and developing countries. Another significant outcome of the COP 18 was a re-examination of the long-term temperature goal which could influence international climate policy by the United Nations.

Federal Climate Change Legislation and Regulation. Various stakeholders, including Exelon, legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors are considering ways to address the climate change issue, including the enactment of federal climate change legislation. It is highly uncertain whether Federal

legislation to reduce GHG emissions will be enacted. If such legislation is adopted, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits.

The U.S. EPA is addressing the issue of carbon dioxide (CO_2) emissions regulation for new and existing electric generating units through the Section 111 NSPS under the existing provisions of the Clean Air Act. A proposed Section 111(b) regulation for new units is to be finalized in spring 2013, and may result in material costs of compliance for CO_2 emissions for new fossil-fuel electric generating units. The U.S. EPA is also expected to propose a Section 111(d) rule in 2013 to establish CO_2 emission regulations for existing stationary sources.

Regional and State Climate Change Legislation and Regulation. After a two-year program review, the nine northeast and mid-Atlantic states currently participating in the RGGI released an updated RGGI Model Rule and Program Review Recommendations Summary on February 7, 2013. Under the updated RGGI program, which must be approved pursuant to the applicable legislative and/or regulatory process in each RGGI State, the regional RGGI CO_2 budget would be reduced, starting in 2014, from its current 165 million ton level to 91 million tons, with a 2.5 percent reduction in the cap level each year between 2015-2020. Included in the new program are provisions for cost containment reserve (CCR) allowances, which will become available if the total demand for allowances, above the CCR trigger price, exceeds the number of CO_2 allowances available for purchase at auction. (CCR rigger prices are $4 in 2014, $6 in 2015, $8 in 2016 and $10 in 2017, rising 2.5 percent thereafter to account for inflation). Such an outcome could put modest upward pressure on wholesale power prices; however, the specifics are currently uncertain.

At the state level, on December 18, 2009, Pennsylvania issued the state's final Climate Change Action Plan. The plan sets as a target a 30 percent reduction in GHG emissions by 2020. The Climate Change Advisory Committee continues to meet quarterly to review Climate Action Work Plans for the residential, commercial and industrial sectors. The Climate Change Action Plan does not impose any requirements on Generation or PECO at this time.

The Maryland Commission on Climate Change released its climate action plan on August 27, 2008, recommending that the state begin implementing 42 greenhouse gas reduction strategies. One of the Plan's policy recommendations, to adopt science-based regulatory goals to reduce Maryland's GHG emissions, was realized with the passage of the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA). The law requires Maryland to reduce its GHG emissions by 25 percent below 2006 levels by 2020. It directs the MDE to work with other state agencies to prepare an implementation plan to meet this goal. An interim plan was submitted to the Governor and the General Assembly during the 2012 legislative session, and the final GGRA plan is expected in February of 2013. The final GGRA plan is not expected to impose any additional requirements on BGE. Maryland targeted electricity consumption reduction goals required under the "Empower Maryland" program, and mandatory State participation in the Regional Greenhouse Gas Reduction Initiative (RGGI) Program will be listed as that sector's contribution in the GGRA plan.

The Illinois Climate Change Advisory Group, created by Executive Order 2006-11 on October 5, 2006, made its final recommendations on September 6, 2007 to meet the Governor's GHG reduction goals. At this time, the only requirements imposed by the state are the energy efficiency and renewable portfolio standards in the Illinois Power Act that apply to ComEd.

Exelon's Voluntary Climate Change Efforts . In a world increasingly concerned about global climate change and regulatory action to reduce GHG, Exelon's low-carbon generating fleet is seen by management as a competitive advantage. Exelon remains one of the largest, lowest carbon electric generators in the United States: nuclear for base load, natural gas for marginal and peak demand,

hydro and pumped storage, and supplemental wind and solar renewables. As further legislation and regulation imposing requirements on emissions of GHG and air pollutants are promulgated, Exelon's low carbon, low emission generation fleet will position the company to benefit from its comparative advantage over other generation fleets.

With the announcement in 2008 of Exelon 2020, Exelon set a voluntary goal to reduce, offset or displace more than 15.7 million metric tonnes of GHG emissions per year by 2020. Exelon updated that goal in 2012 following the Constellation merger to account for the integration of former Constellation GHG goals. The updated Exelon 2020 goal is to reduce, offset or displace more than 17.5 million metric tonnes of GHG emissions by 2020. The Exelon 2020 goal encompasses three broad areas of focus: reducing or offsetting Exelon's own carbon footprint (with the year the asset/operations were acquired by Exelon as the baseline), helping customers and communities reduce their GHG emissions, and offering more low-carbon electricity in the marketplace.

Efforts to achieve the Exelon 2020 goal will be supported by the company's current business plans as well as future initiatives that will be integrated into the annual business planning process. This includes a periodic review and refinement of Exelon 2020 initiatives in light of changing market conditions, regulations, technology and other factors that affect the merit of various GHG abatement options. Specific initiatives and the amount of expenditures to implement the plan will depend on economic and policy developments, and will be made on a project-by-project basis in accordance with Exelon's normal project evaluation standards.

Renewable and Alternative Energy Portfolio Standards

Twenty-nine states and the District of Columbia have adopted some form of RPS requirement. As previously described, Illinois, Pennsylvania and Maryland have laws specifically addressing energy efficiency and renewable energy initiatives. In addition to state level activity, RPS legislation has been considered and may be considered again in the future by the United States Congress. Also, states that currently do not have RPS requirements may adopt such legislation in the future.

The Illinois Settlement Legislation required that procurement plans implemented by electric utilities include cost-effective renewable energy resources or approved equivalents such as RECs in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers by June 1, 2008, increasing to 10% by June 1, 2015, with a goal of 25% by June 1, 2025. Utilities are allowed to pass-through any costs from the procurement of these renewable resources or approved equivalents subject to legislated rate impact criteria. As of December 31, 2012, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. See Note 3 and Note 19 of the Combined Notes to Consolidated Financial Statements for additional information.

The AEPS Act was effective for PECO on January 1, 2011, following the expiration of PECO's transition period. During 2012, PECO was required to supply approximately 4.0% and 6.2% of electric energy generated from Tier I (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania) and Tier II (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing wood and by-products of the pulping process and wood, distributed generation systems and integrated combined coal gasification technology) alternative energy resources, respectively, as measured in AECs. The compliance requirements will incrementally escalate to 8.0% for Tier I and 10.0% for Tier II by 2021. In order to comply with these requirements, PECO entered into agreements with varying terms with accepted bidders, including Generation, to purchase non-solar Tier I, solar Tier 1 and Tier II AECs. PECO also purchases AECs through its DSP Program full requirement contracts.

Section 7-703 of the Public Utilities Article in Maryland sets forth the RPS requirement, which applies to all retail electricity sales in Maryland by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, biomass, methane, geothermal, ocean, fuel cell, small hydroelectric, and poultry litter) and Tier 2 sources (hydroelectric, other than pump storage generation, and waste-to-energy). The RPS requirement began in 2006, requiring that suppliers procure 1.0% and 2.5% from Tier 1 and Tier 2 sources, respectively, escalating in 2022 to 22.0% from Tier 1 sources, including at least 2.0% from solar energy, and 0.0% from Tier 2 sources. In 2012, 6.5% were required from Tier 1 renewable sources, including at least 0.1% derived from solar energy, and 2.5% from Tier 2 renewable sources. The wholesale suppliers that supply power to the state's utilities through the SOS procurement auctions have the obligation, by contract with those utilities, to comply with and provide its proportional share of the RPS requirements.

Similar to ComEd, PECO and BGE, Generation's retail electric business must source a portion of the electric load it serves in many of the states in which it does business from renewable resources or approved equivalents such as RECs. Potential regulation and legislation regarding renewable and alternative energy resources could increase the pace of development of wind and other renewable/alternative energy resources, which could put downward pressure on wholesale market prices for electricity in some markets where Exelon operates generation assets. At the same time, such developments may present some opportunities for sales of Generation's renewable power, including from wind, solar, hydroelectric and landfill gas.

See Note 3 and Note 19 of the Combined Notes to Consolidated Financial Statements for additional information.

Executive Officers of the Registrants as of February 21, 2013

Exelon

Name	Age	Position	Period
Crane, Christopher M.	54	Chief Executive Officer, Exelon;	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		President, Exelon; President, Generation	2008 - Present
		Chief Operating Officer, Exelon	2008 - 2012
		Chief Operating Officer, Generation	2007 - 2010
		Executive Vice President, Exelon	2007 - 2008
Shattuck III, Mayo A.	58	Executive Chairman, Exelon	2012 - Present
		Chairman, President and Chief Executive Officer, Constellation	2001 - 2012
Cornew, Kenneth W.	47	Executive Vice President and Chief Commercial Officer, Exelon;	2012 - Present
		President and Chief Executive Officer, Constellation	2012 - Present
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
		Senior Vice President, Trading and Origination, Power Team	2007 - 2008
O'Brien, Denis P.	52	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Chief Executive Officer, PECO; Executive Vice President, Exelon	2007 - 2012
		President and Director, PECO	2003 - 2012

Name	Age	Position	Period
Pramaggiore, Anne R.	54	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 - 2009
Adams, Craig L.	60	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
DeFontes Jr., Kenneth W.	62	President and Chief Executive Officer, BGE	2004 - Present
		Senior Vice President, Constellation Energy	2004 - 2012
Gillis, Ruth Ann M.	58	Executive Vice President, Exelon	2008 - Present
		Chief Administrative Officer, Exelon	2010 - Present
		President, Exelon Business Services Company	2005 - Present
		Chief Diversity Officer, Exelon	2009 - 2012
		Senior Vice President, Exelon	2002 - 2008
Von Hoene Jr., William A.	59	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
		Executive Vice President and General Counsel, Exelon	2008 - 2009
		Senior Vice President, Exelon Business Services Company	2004 - 2009
		Senior Vice President, Exelon	2006 - 2008
Thayer, Jonathan W.	41	Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012
		Vice President, Constellation Energy	2004 - 2008
Glace, Joseph R.	52	Senior Vice President, Exelon	2012 - Present
		Chief Risk Officer, Exelon	2008 - Present
		Vice President, Exelon	2008 - 2012
DesParte, Duane M.	50	Vice President and Corporate Controller, Exelon	2008 - Present
		Vice President, Finance, Exelon Business Services Company	2007 - 2008

Generation

Name	Age	Position	Period
Crane, Christopher M.	54	Chief Executive Officer, Exelon; Chairman, ComEd, PECO & BGE	2012 - Present
		President, Exelon; President, Generation	2008 - Present
		Chief Operating Officer, Exelon	2008 - 2012
		Chief Operating Officer, Generation	2007 - 2010
		Executive Vice President, Exelon	2007 - 2008
Cornew, Kenneth W.	47	Executive Vice President and Chief Commercial Officer, Exelon; President and Chief Executive Officer, Constellation	2012 - Present
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
		Senior Vice President, Trading and Origination, Power Team	2007 - 2008

Name	Age	Position	Period
Pacilio, Michael J.	52	President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - Present
		Chief Operating Officer, Exelon Nuclear	2007 - 2010
DeGregorio, Ronald	50	Senior Vice President, Generation; President, Exelon Power	2012 - Present
		Chief Integration Officer, Exelon	2011 - 2012
		Chief Operating Officer, Exelon Transmission Company	2010 - 2011
		Senior Vice President, Mid-Atlantic Operations, Exelon Nuclear	2007 - 2010
Wright, Bryan P.	46	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
		Chief Accounting Officer, Constellation Energy	2009 - 2012
		Vice President and Controller, Constellation Energy	2008 - 2012
		Vice President and Controller, Constellation Energy Resources	2007 - 2008
Aiken, Robert	46	Vice President and Controller, Generation	2012 - Present
		Executive Director and Assistant Controller, Constellation	2011 - 2012
		Executive Director of Operational Accounting, Constellation Energy Commodities Group	2009 - 2011
		Vice President of International Accounting, Constellation Energy Commodities Group	2007 - 2009

ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	54	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 - 2009
Donnelly, Terence R.	52	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
		Senior Vice President, Transmission and Distribution, ComEd	2007 - 2009
Trpik Jr., Joseph R.	43	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
		Vice President & Assistant Corporate Controller, Exelon Business Services Company	2007 - 2009
		Vice President and Assistant Corporate Controller, Exelon	2004 - 2009
Jensen, Val	57	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
		Senior Vice President, ICF International	2006 - 2008

Name	Age	Position	Period
O'Neill, Thomas S.	50	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2010 - Present
		Senior Vice President, Exelon	2009 - 2010
		Senior Vice President, New Business Development, Generation; Senior Vice President, New Business Development, Exelon	2009 - 2009
		Vice President, New Plant Development, Generation	2007 - 2009
Marquez Jr., Fidel	51	Senior Vice President, Governmental and External Affairs, Exelon	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012
		Vice President of External Affairs and Large Customer Services, ComEd	2007 - 2009
Brookins, Kevin B.	51	Senior Vice President, Strategy & Administration, ComEd	2012 - Present
		Vice President, Operational Strategy and Business Intelligence, ComEd	2010 - 2012
		Vice President, Distribution System Operations, ComEd	2008 - 2010
		Vice President, Work Management and New Business	2007 - 2008
Anthony, J. Tyler	48	Senior Vice President, Distribution Operations, ComEd	2010 - Present
		Vice President, Transmission and Substations, ComEd	2007 - 2010
Waden, Kevin J.	41	Vice President, Comptroller, Accountant and Controller, ComEd	2009 - Present
		Director of Accounting Operations, ComEd	2007 - 2009

PECO

Name	Age	Position	Period
Adams, Craig L.	60	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	49	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	47	Senior Vice President, Operations, PECO	2012 - Present
		Vice President, Distribution System Operations and Smart Grid/Smart Meter, PECO	2010 - 2012
		Vice President, Distribution System Operations	2007 - 2010
Webster Jr., Richard G.	51	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	53	Vice President, Governmental and External Affairs, PECO	2012 - Present
		Director, Governmental & External Affairs, PECO	2007 - 2012
Alden, Mark F.	52	Vice President, Customer Operations, PECO	2009 - Present
		Vice President Gas, PECO	2007 - 2009

Name	Age	Position	Period
Diaz Jr., Romulo L.	66	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
		Associate General Counsel, Exelon	2008 - 2009
		City Solicitor, City of Philadelphia	2005 - 2008
Bailey, Scott A.	36	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012
		Director of Accounting, Power Team	2007 - 2011

BGE

Name	Age	Position	Period
DeFontes Jr., Kenneth W.	62	President and Chief Executive Officer, BGE	2004 - Present
		Senior Vice President, Constellation Energy	2004 - 2012
Woerner, Stephen J.	45	Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - Present
		Vice President and Chief Integration Officer, Constellation Energy	2011 - 2012
		Vice President and Chief Information Officer, Constellation Energy	2010 - 2011
		Vice President, Transformation, Constellation Energy	2009 - 2010
		Senior Vice President, Gas and Electric Operations and Planning, BGE	2007 - 2009
Khouzami, Carim V.	38	Vice President, Chief Financial Officer and Treasurer, BGE	2011 - Present
		Executive Director, Investor Relations, Constellation Energy	2009 - 2011
		Director, Corporate Strategy and Development, Constellation Energy	2008 - 2009
Case, Mark D.	51	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Dempsey, Mary E.	57	Vice President, Governmental Affairs, BGE	2012 - Present
		Executive Director, State Affairs, Constellation Energy	2010 - 2012
		Managing Director, Public Affairs, Constellation Energy	2008 - 2009
Mills, Jeannette M.	46	Vice President, Customer Operations, BGE	2012 - Present
		Chief Customer Officer, BGE	2011 - Present
		Senior Vice President, Customer Relations and Account Services, BGE	2008 - 2012
		Senior Vice President, Gas Operations and Planning, BGE	2007 - 2008
Gahagan, Daniel P.	59	Vice President and General Counsel, BGE	2007 - Present
Vahos, David M.	40	Vice President and Controller, BGE	2012 - Present
		Executive Director, Audit, Constellation	2010 - 2012
		Director, Finance, BGE	2006 - 2010

ITEM 1A. RISK FACTORS

Each of the Registrants operates in a market and regulatory environment that poses significant risks, many of which are beyond the Registrant's control. Management of each Registrant regularly meets with the Chief Risk Officer and the RMC, which comprises officers of the Registrants, to identify and evaluate the most significant risks of the Registrants' businesses, and the appropriate steps to manage and mitigate those risks. The Chief Risk Officer and senior executives of the Registrants discuss those risks with the risk oversight and audit committees of the Exelon Board of directors and the ComEd, PECO and BGE Boards of Directors. In addition, the Exelon Board of directors' generation oversight and energy delivery oversight committees, respectively, evaluate risks related to the generation and energy delivery businesses. The risk factors discussed below may adversely affect one or more of the Registrants' results of operations and cash flows and the market prices of their publicly traded securities. Each of the Registrants has disclosed the known material risks that affect its business at this time. However, there may be further risks and uncertainties that are not presently known or that are not currently believed by a Registrant to be material that may adversely affect its performance or financial condition in the future.

The Registrants' most significant risks arise as a consequence of: (1) Generation's position as a predominantly nuclear generator selling power into competitive energy markets, and (2) the role of ComEd, PECO and BGE as operators of electric transmission and distribution systems in three of the largest metropolitan areas in the United States. The Registrants' major risks fall primarily under the following categories:

- ***Market and Financial Risks.*** Exelon's and Generation's market and financial risks include the risk of price fluctuations in the wholesale and retail power markets. Wholesale power prices are a function of supply and demand, which in turn are driven by factors such as the price of fuels, in particular the price of natural gas and coal, that drive the wholesale market prices that Generation's nuclear power plants receive, the rate of expansion of subsidized low carbon generation such as wind energy in the markets in which Generation's output is sold, and the impacts on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs. In addition, the load serving and retail marketing activities compete for customers in a competitive environment which impacts the margins that Generation can earn and the volumes that it is able to serve.
- ***Regulatory and Legislative Risks.*** The Registrants' regulatory and legislative risks include changes to the laws and regulations that govern competitive markets and utility cost recovery, and that drive environmental policy. In particular, Exelon's and Generation's financial performance may be adversely affected by changes that could affect Generation's ability to sell power into the competitive wholesale power markets at market-based prices. In addition, potential regulation and legislation regarding climate change and renewable portfolio standards could increase the pace of development of wind energy facilities, which could put downward pressure in some markets on wholesale market prices for electricity from Generation's nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation's nuclear assets under a carbon constrained regulatory regime that might exist in the future. Also, regulatory actions in Illinois, Pennsylvania or Maryland could materially lower returns for ComEd, PECO and BGE, respectively.
- ***Operational Risks.*** The Registrants' operational risks include those risks inherent in running the nation's largest fleet of nuclear power reactors and large electric and gas distribution systems. The safe and effective operation of the nuclear facilities and the ability to effectively manage the associated decommissioning obligations as well as the ability to maintain the availability, reliability and safety of its energy delivery systems are fundamental to Exelon's ability to protect and grow shareholder value. Additionally, the operating costs of ComEd, PECO and BGE and the opinions of customers and regulators of ComEd, PECO and BGE are

affected by those companies' ability to maintain the reliability and safety of their energy delivery systems.

- ***Risks Related to the Merger with Constellation.*** As a result of the merger with Constellation that closed on March 12, 2012, Exelon is subject to additional risks.

A discussion of each of these risks and other risk factors is included below.

Market and Financial Risks

Generation is exposed to price fluctuations in the wholesale and retail power markets, which may negatively affect its results of operations. (Exelon and Generation)

Generation hedges the price risk associated with the generation it owns, or controls, through long-term power purchase agreements. Absent any hedging activity through fixed price transactions, Generation would be exposed to the risk of rising and falling spot market prices in the markets in which its assets are located, which would mean that Generation's cash flows would vary accordingly.

The wholesale spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Many times, the next unit of electricity will be supplied from generating stations fueled by fossil fuels, and, therefore, the market price of power will reflect the market price of the marginal fuel. Consequently, changes in the market price of fossil fuels will cause comparable changes to the market price of power. For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing further downward pressure on natural gas prices and has reduced Generation's revenues. In addition, further delay or elimination of EPA air quality regulations could prolong the duration for which the cost of pollution is not factored into market prices which could reduce Generation's revenue. Further, in the event that alternative generation resources, such as wind and solar, are mandated through RPS or otherwise subsidized or encouraged through climate legislation or regulation and added to the available generation supply such resources could displace a higher marginal cost fossil plant, which could reduce the price at which market participants sell their electricity. This occurrence could then reduce the market price at which all generators in that region, including Generation, would be able to sell their output. These events could adversely affect Generation's financial condition, results of operations, and cash flows, and could also result in an impairment of certain long-lived assets.

The market price for electricity is also affected by changes in the demand for electricity. Worse than expected economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs can depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on market prices for electricity. The continued sluggish economy in the United States has in fact led to a slowdown in the growth of demand for electricity. If this continues, it could adversely affect the Registrants' ability to fund other discretionary uses of cash such as growth projects or to pay dividends. In addition, the economic conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Generation's results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs. A slow recovery could result in a prolonged depression of or further decline in commodity prices, including low forward natural gas and power prices and low market volatility, which could also adversely affect Exelon's and Generation's results of operations, cash flows and financial position.

In addition to price fluctuations, Generation is exposed to other risks in the power markets that are beyond its control and may negatively affect its results of operations. (Exelon and Generation)

Credit Risk. In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money, or are obligated to purchase energy or fuel from Generation, will not perform

under their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, Generation might be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. In the spot markets, Generation is exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTO's and ISO's, the purpose of which is to spread such risk across all market participants. Generation is also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, Generation's retail sales subject it to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that may be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Unstable Markets. The wholesale spot markets remain evolving markets that vary from region to region and are still developing practices and procedures. Problems in or the failure of any of these markets could adversely affect Generation's business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

Market performance and other factors may decrease the value of decommissioning trust funds and benefit plan assets and increase the related obligations, which then could require significant additional funding. (Exelon, Generation, ComEd, PECO and BGE)

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy may adversely affect the value of the investments held within Generation's NDTs and Exelon's employee benefit plan trusts. The Registrants have significant obligations in these areas and Exelon and Generation hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which may fall below the Registrants' projected return rates. A decline in the market value of the NDT fund investments may increase the funding requirements to decommission Generation's nuclear plants. A decline in the market value of the pension and other postretirement benefit plan assets will increase the funding requirements associated with Exelon's pension and other postretirement benefit plan obligations. Additionally, Exelon's pension and other postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements may also increase the costs and funding requirements of the obligations related to the pension and other postretirement benefit plans. If future increases in pension and other postretirement costs as a result of reduced plan assets or other factors are not recoverable from ComEd, PECO and BGE customers, the results of operations and financial positions of ComEd, PECO and BGE could be negatively affected. Ultimately, if the Registrants are unable to manage the decommissioning trust funds and benefit plan assets and obligations, their results of operations, cash flows and financial positions could be negatively affected.

Unstable capital and credit markets and increased volatility in commodity markets may adversely affect the Registrants' businesses in several ways, including the availability and cost of short-term funds for liquidity requirements, the Registrants' ability to meet long-term commitments, Generation's ability to hedge effectively its generation portfolio, and the competitiveness and liquidity of energy markets; each could adversely affect the Registrants' financial condition, results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity

needs if internal funds are not available from the Registrants' respective operations. Disruptions in the capital and credit markets in the United States or abroad can adversely affect the Registrants' ability to access the capital markets or draw on their respective bank revolving credit facilities. The Registrants' access to funds under their credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from the Registrants and other borrowers within a short period of time. The inability to access capital markets or credit facilities, and longer term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, changes to Generation's hedging strategy in order to reduce collateral-posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

In addition, the Registrants have exposure to worldwide financial markets, including Europe. The ongoing European debt crisis has contributed to instability in global credit markets. Further disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2012, approximately 31%, or $2.5 billion, of the Registrants' available credit facilities were with European banks. The credit facilities include $8.3 billion in aggregate total commitments of which $6.5 billion was available as of December 31, 2012. There were no borrowings under the Registrants' credit facilities as of December 31, 2012. See Note 11 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in competitive energy markets depend heavily on active participation by multiple trading parties, which could be adversely affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that may affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to the respective businesses of the Registrants. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts such as the financial swap contract between Generation and ComEd as described further in Note 3 of the Combined Notes to Consolidated Financial Statements, which could have a material adverse effect on Exelon's and Generation's results of operations and cash flows.

If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its trading counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs. (Exelon, Generation, ComEd, PECO and BGE)

Generation's business is subject to credit quality standards that may require market participants to post collateral for their obligations. If Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating) or otherwise fail to satisfy the credit standards of trading counterparties, it would be required under its hedging arrangements to provide collateral in the form of letters of credit or cash, which may have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time is dependent on a variety of factors, including (1) the notional amount of the applicable hedge, (2) the nature of counterparty and related agreements, and (3) changes in power or other commodity prices. In addition, if Generation were downgraded, it could experience higher borrowing costs as a result of the downgrade. Generation could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the power generation industry or Generation has deteriorated. Changes in ratings methodologies by the credit rating agencies could also have a negative impact on the ratings of Generation.

ComEd's financial swap contract with Generation and its operating agreement with PJM contain collateral provisions that are affected by its credit rating and market prices. If certain wholesale market conditions exist and ComEd were to lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required under the financial swap contract with Generation to provide collateral in the form of letters of credit or cash, which may have a material adverse effect upon its liquidity. Collateral posting by ComEd under the financial swap will generally increase as forward market prices fall and decrease as forward market prices rise. Conversely, collateral requirements under the PJM operating agreement will generally increase as market prices rise and decrease as market prices fall. Given the relationship to market prices, contract collateral requirements can be volatile. In addition, if ComEd were downgraded, it could experience higher borrowing costs as a result of the downgrade.

PECO's and BGE's operating agreements with PJM and their natural gas procurement contracts contain collateral provisions that are affected by their credit ratings. If certain wholesale market conditions exist and PECO and BGE were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the form of letters of credit or cash, which may have material adverse effects upon their liquidity. PECO's and BGE's collateral requirements relating to their natural gas supply contracts are a function of market prices. Collateral posting requirements for PECO and BGE with respect to these contracts will generally increase as forward market prices fall and decrease as forward market prices rise. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if PECO or BGE were downgraded, they could experience higher borrowing costs as a result of the downgrade.

ComEd, PECO or BGE could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the utility industry in general or ComEd, PECO, or BGE in particular has deteriorated. ComEd, PECO or BGE could experience a downgrade if the current regulatory environments in Illinois, Pennsylvania or Maryland, respectively, become less predictable by materially lowering returns for utilities in the applicable state or adopting other measures to mitigate higher electricity prices. Additionally, the ratings for ComEd, PECO or BGE could be downgraded if their financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage their capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of ComEd, PECO or BGE.

ComEd, PECO and BGE conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that ComEd, PECO and BGE are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate ComEd, PECO and BGE from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as "ringfencing") may help avoid or limit a downgrade in the credit ratings of ComEd, PECO and BGE in the event of a reduction in the credit rating of Exelon. Despite these ringfencing measures, the credit ratings of ComEd, PECO or BGE could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of ComEd, PECO or BGE, or all three. A reduction in the credit rating of ComEd, PECO or BGE could have a material adverse effect on ComEd, PECO or BGE, respectively.

See Liquidity and Capital Resources—Recent Market Conditions and Security Ratings for further information regarding the potential impacts of credit downgrades on the Registrants' cash flows.

Generation's financial performance may be negatively affected by price volatility, availability and other risk factors associated with the procurement of nuclear and fossil fuel. (Exelon and Generation)

Generation depends on nuclear fuel and fossil fuels to operate its generating facilities. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. Coal, natural gas and oil are procured for generating plants through annual, short-term and spot-market purchases. The supply markets for nuclear fuel, coal, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default that may negatively affect the results of operations for Generation.

Generation's risk management policies cannot fully eliminate the risk associated with its commodity trading activities. (Exelon and Generation)

Generation's asset-based power position as well as its power marketing, fuel procurement and other commodity trading activities expose Generation to risks of commodity price movements. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations may be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, Generation cannot predict the impact that its commodity trading activities and risk management decisions may have on its business, operating results, cash flows or financial position.

Generation buys and sells energy and other products in the wholesale markets and enters into financial contracts to manage risk and hedge various positions in Generation's power generation portfolio. The proportion of hedged positions in its power generation portfolio may cause volatility in Generation's future results of operations.

Financial performance and load requirements may be adversely affected if Generation is unable to effectively manage its power portfolio. (Exelon and Generation)

A significant portion of Generation's power portfolio is used to provide power under procurement contracts with ComEd, PECO, BGE and other customers. To the extent portions of the power portfolio are not needed for that purpose, Generation's output is sold in the wholesale market. To the extent its power portfolio is not sufficient to meet the requirements of its customers under the related agreements, Generation must purchase power in the wholesale power markets. Generation's financial results may be negatively affected if it is unable to cost-effectively meet the load requirements of its customers, manage its power portfolio and effectively address the changes in the wholesale power markets.

Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could negatively impact the Registrants' results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Corporate Tax Reform. There exists the potential for comprehensive tax reform in the United States which may significantly change the tax rules that are applicable to U.S. domiciled corporations. Exelon cannot assess what the overall effect of such potential legislation would be on its results of operations and cash flows.

1999 sale of fossil generating assets. The IRS has challenged Exelon's 1999 tax position on an involuntary conversion and like-kind exchange transaction. In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions and for the IRS to withdraw its assertion of a $110 million substantial understatement penalty related to the involuntary conversion position. Definitive documents consistent with the preliminary agreement were finalized in the fourth quarter of 2012. However, Exelon and IRS Appeals failed to reach a settlement on the like-kind exchange position. Exelon expects to initiate litigation on this matter during 2013.

As of March 31, 2013, if the IRS is successful in its challenge to the like-kind exchange position, Exelon's potential cash outflow, including tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $860 million, of which approximately $320 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless. In addition to attempting to impose tax on the like-kind exchange position, the IRS has asserted penalties for a substantial understatement of tax, which could result in an after-tax charge of $86 million to Exelon's and ComEd's results of operations should the IRS prevail in asserting the penalties. The timing effects of the final resolution of the like-kind exchange matter are unknown. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information.

Tax reserves and the recoverability of deferred tax assets. The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeals issues related to these tax matters. These judgments include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by the tax authorities. The Registrants also estimate their ability to utilize tax benefits, including those in the form of carryforwards and tax credits. See Notes 1 and 12 of the Combined Notes to Consolidated Financial Statements for additional information.

Increases in customer rates and the impact of economic downturns may lead to greater expense for uncollectible customer balances. Additionally, increased rates could lead to decreased volumes delivered. Both of these factors may decrease Generation's, ComEd's, PECO's and BGE's results from operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

ComEd's, PECO's and BGE's current procurement plans include purchasing power through contracted suppliers and in the spot market. ComEd's and PECO's costs of purchased power are charged to customers without a return or profit component. BGE's SOS rates charged to customers recover BGE's wholesale power supply costs and include an administrative fee which includes a shareholder return component and an incremental cost component. For PECO, purchased natural gas costs are charged to customers with no return or profit component. For BGE, purchased natural gas costs are charged to customers using a MBR mechanism that compares the actual cost of gas to a market index. The difference between the actual cost and the market index is shared equally between shareholders and customers. Purchased power and natural gas prices fluctuate based on their relevant supply and demand. Significantly higher rates related to purchased power and natural gas can result in declines in customer usage, lower revenues for electric transmission and distribution at ComEd, PECO and BGE, and for gas distribution at PECO, and potentially additional uncollectible accounts expense for ComEd, PECO and BGE. Also, ComEd's, PECO's and BGE's cash flows can be affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

Further, the impacts of economic downturns on ComEd, PECO and BGE customers and purchased natural gas costs for PECO and BGE customers, such as unemployment for residential customers and less demand for products and services provided by commercial and industrial customers, and the related regulatory limitations on residential service terminations may result in an increase in the number of uncollectible customer balances, which would negatively impact ComEd's, PECO's and BGE's results from operations and cash flows. Generation's customer supply activities face economic downturn risks similar to Exelon's utility businesses, such as lower volumes sold and increase expense for uncollectible customer balances. As Generation increases its customer supply footprint, economic downturn impacts could negatively affect Generation's results from operations and cash flows. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants' credit risk.

The effects of weather may impact the Registrants' results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Moderate temperatures adversely affect the usage of energy and resulting revenues at ComEd and PECO. Due to revenue decoupling, BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period, and is not affected by actual weather with the exception of major storms. Extreme weather conditions or damage resulting from storms may stress ComEd's, PECO's and BGE's transmission and distribution systems, communication systems and technology, resulting in increased maintenance and capital costs and limiting each company's ability to meet peak customer demand. These extreme conditions may have detrimental effects on ComEd's, PECO's and BGE's results of operations and cash flows. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and may make period comparisons less relevant.

Generation's operations are also affected by weather, which affects demand for electricity as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation may require greater resources to meet its contractual commitments. Extreme weather conditions or storms may affect the availability of generation and its transmission, limiting Generation's ability to source or send power to where it is sold. In addition, drought-like conditions limiting water usage can impact Generation's ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, may have an adverse effect by causing Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Certain long-lived assets and other assets recorded on the Registrants' statements of financial position may become impaired, which would result in write-offs of the impaired amounts. (Exelon, Generation, ComEd, PECO and BGE)

Long-lived assets represent the single largest asset class on the Registrants' statement of financial position. Specifically, long-lived assets account for 58%, 48%, 60%, 65% and 73% of total assets for Exelon, Generation, ComEd, PECO and BGE, respectively, as of December 31, 2012. In addition, the Registrants have significant balances related to unamortized energy contracts. See Notes 4 and 8 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's unamortized energy contracts. The Registrants evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered when evaluating long-

lived assets for potential impairment. An impairment would require the Registrants to reduce the carrying value of the long-lived asset through a non-cash charge to expense by the amount of the impairment, and such an impairment could have a material adverse impact on the Registrants' results of operations.

Exelon and Generation have investments in certain generating plant projects, including the CENG nuclear joint venture with a carrying value of $1.8 billion as of December 31, 2012. These investments were acquired in the March 2012 Constellation transaction, and were recorded as equity method investments on the balance sheet at fair value on the merger date as part of purchase accounting. Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such issues indicate an other than temporary decline in value. Such impairment could have material adverse impacts on Exelon's and Generation's results of operations.

Exelon holds certain investments in coal-fired plants in Georgia and Texas subject to long-term leases extending through 2028-2032. On an annual basis, Exelon reviews the estimated residual values of these leased assets to determine whether any indications of impairment exist. In determining the estimate of residual value, the expectation of future market conditions, including commodity prices, is considered. An impairment would require Exelon to reduce the value of its investment in the plants through a non-cash charge to expense. Such an impairment could have a material adverse impact on Exelon's results of operations.

Exelon and ComEd had approximately $2.6 billion of goodwill recorded at December 31, 2012 in connection with the merger between PECO and Unicom Corporation, the former parent company of ComEd. Under GAAP, goodwill remains at its recorded amount unless it is determined to be impaired, which is generally based upon an annual analysis that compares the implied fair value of the goodwill to its carrying value. If an impairment occurs, the amount of the impaired goodwill will be written-off and expensed, reducing equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. A successful IRS challenge to Exelon's and ComEd's like-kind exchange income tax position, adverse regulatory actions such as early termination of EIMA, or changes in significant assumptions used in estimating ComEd's fair value (e.g., discount and growth rates, utility sector market performance and transactions, operating and capital expenditure requirements and the fair value of debt) could result in an impairment. Such an impairment would result in a non-cash charge to expense, which could have a material adverse impact on Exelon's and ComEd's results of operations.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Critical Accounting Policies and Estimates and Notes 6 and 8 of the Combined Notes to the Consolidated Financial Statements for additional discussion on long-lived asset and goodwill impairments.

The Registrants' businesses are capital intensive, and their assets may require significant expenditures to maintain and are subject to operational failure, which could result in potential liability. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants' businesses are capital intensive and require significant investments by Generation in energy generation and by ComEd, PECO and BGE in transmission and distribution infrastructure projects. These operational systems and infrastructure have been in service for many years. Older equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Registrants' control, and may require significant expenditures to operate efficiently. The Registrants' results of operations, financial condition, or cash flows could be adversely affected if they were unable to effectively manage their capital

projects or raise the necessary capital. Furthermore, operational failure could result in potential liability if such failure results in damage to property or injury to individuals. See ITEM 1. BUSINESS for further information regarding the Registrants' potential future capital expenditures.

Exelon and its subsidiaries have guaranteed the performance of third parties, which may result in substantial costs in the event of non-performance by third parties. In addition, the Registrants have rights under agreements which obligate third parties to indemnify the Registrants for various obligations, and the Registrants may incur substantial costs in the event that the applicable Registrant is unable to enforce those agreements or the applicable third party is otherwise unable to perform. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have issued guarantees of the performance of third parties, which obligate one or more of the Registrants or their subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, the Registrants could incur substantial cost to fulfill their obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial condition, or cash flows of the Registrants.

The Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are impacted by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected Registrant could be held responsible for the obligations, which could impact that Registrant's results of operations, cash flows and financial position. In connection with Exelon's 2001 corporate restructuring, Generation assumed certain of ComEd's and PECO's rights and obligations with respect to their former generation businesses. Further, ComEd and PECO may have entered into agreements with third parties under which the third party agreed to indemnify ComEd or PECO for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the restructuring. If the third party or Generation experienced events that reduced its creditworthiness or the indemnity arrangement was unenforceable, ComEd or PECO could be liable for any existing or future claims, which could impact ComEd's or PECO's results of operations, cash flows and financial position.

Due to its significant contractual agreements with ComEd, PECO and BGE, Generation will be negatively affected in the event of non-performance or change in the creditworthiness of ComEd, PECO or BGE. (Exelon and Generation)

Generation currently provides power under procurement contracts with ComEd, PECO and BGE for a significant portion of their electricity supply requirements. In addition, Generation entered into a financial swap contract with ComEd, effective August 2007, to hedge a portion of ComEd's electricity supply requirements through May 2013. Consequently, Generation is highly dependent on ComEd's, PECO's, and BGE's continued payments under these contracts and would be adversely affected by negative events impacting these contracts, including the non-performance or a significant change in the creditworthiness of ComEd, PECO or BGE. A default by ComEd, PECO or BGE under these contracts would have an adverse effect on Generation's results of operations and financial position.

Generation's business may be negatively affected by competitive electric generation suppliers. (Exelon and Generation)

Because retail customers where Generation serves load can switch from their respective energy delivery company to a competitive electric generation supplier for their energy needs, planning to meet Generation's obligation to provide the supply needed to serve Generation's share of an electric distribution company's default service obligation is more difficult than planning for retail load before the advent of retail competition. Before retail competition, the primary variables affecting projections of load

were weather and the economy. With retail competition, another major factor is retail customers switching to or from competitive electric generation suppliers. If fewer of such customers switch from its retail load serving counterparties than Generation anticipates, the load that Generation must serve will be greater than anticipated, which could, if market prices have increased, increase Generation's costs (due to its need to go to market to cover its incremental supply obligation) more than the increase in Generation's revenues. If more customers from its retail load serving counterparties switch than Generation anticipates, the load that Generation must serve will be lower than anticipated, which could, if market prices have decreased, cause Generation to lose opportunities in the market.

Regulatory and Legislative Risks

The Registrants' generation and energy delivery businesses are highly regulated and could be subject to adverse regulatory and legislative actions. Fundamental changes in regulation or legislation or violation of tariffs or market rules and anti-manipulation laws, could disrupt the Registrants' business plans and adversely affect their operations and financial results. (Exelon, Generation, ComEd, PECO and BGE)

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation. Further, Exelon's and Generation's operating results and cash flows are heavily dependent upon the ability of Generation to sell power at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon's, ComEd's, PECO's and BGE's operating results and cash flows are heavily dependent on the ability of ComEd, PECO and BGE to recover their costs for the retail purchase and distribution of power to their customers. Similarly, there is risk that financial market regulations could increase the Registrants' compliance costs and limit their ability to engage in certain transactions. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, exchanges, ratemaking agencies and taxing authorities. Additionally, the Registrants should be cognizant of rules changes or Registrant actions that could result in potential violation of tariffs, market rules and anti-manipulation laws. Fundamental changes in regulations or other adverse legislative actions affecting the Registrants' businesses would require changes in their business planning models and operations and could adversely affect their results of operations, cash flows and financial position.

Regulatory and legislative developments related to climate change and RPS may also significantly affect Exelon's and Generation's results of operations, cash flows and financial positions. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, may sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. However, national regulation or legislation addressing climate change through an RPS could also increase the pace of development of wind energy facilities in the Midwest, which could put downward pressure on wholesale market prices for electricity from Generation's Midwest nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation's nuclear assets under a carbon constrained regulatory regime that might exist in the future. Current state level climate change and renewable regulation is already providing incentives for regional wind development. The Registrants cannot predict when or whether any of these various legislative and regulatory proposals may become law or what their effect will be on the Registrants.

Generation may be negatively affected by possible Federal or state legislative or regulatory actions that could affect the scope and functioning of the wholesale markets. (Exelon and Generation)

Federal and state legislative and regulatory bodies are facing pressures to address consumer concerns, or are themselves raising concerns, that energy prices in wholesale markets are too high or insufficient generation is being built because the competitive model is not working, and, therefore, are considering some form of re-regulation or some other means of reducing wholesale market prices or subsidizing new generation. Generation is dependent on robust and competitive wholesale energy markets to achieve its business objectives.

Approximately 60% of Generation's generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Generation's future results of operations will depend on 1) FERC's continued adherence to and support for policies that favor the preservation of competitive wholesale power markets, such as PJM's, and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competitiveness. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize new generation, such as the New Jersey Capacity Legislation and the MDPSC's RFP for new gas-fired generation in Maryland. See Note 3 of the Combined Notes to Consolidated Financial Statements for further details related to the New Jersey Capacity Legislation and the Maryland new electric generation requirements.

In addition, FERC's application of its Order 697 and its subsequent revisions could pose a risk that Generation will have difficulty satisfying FERC's tests for market-based rates. Since Order 697 became final in June 2007, Generation has obtained orders affirming Generation's authority to sell at market-based rates and none denying that authority. Generation's most recent submission seeking reauthorization to sell at market-based rates was accepted by FERC on June 22, 2011 for the PJM region.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank) was enacted into law on July 21, 2010. Its primary objective is to eliminate from the financial system the systemic risk that Congress believed was in part the cause of the financial crisis that unfolded during 2008. Dodd-Frank ushers in a brand new regulatory regime applicable to the over-the-counter (OTC) market for swaps. Generation relies on the OTC swaps markets as part of its program to hedge the price risk associated with its generation portfolio. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Generation has determined that it will conduct its commercial hedging business as an end user in a manner that does not require registration as a swap dealer or major swap participant.

Notwithstanding the foregoing, Generation will still face additional regulatory obligations under Dodd-Frank, including some reporting requirements, clearing some additional transactions that it would otherwise enter into over-the-counter, and having to adhere to position limits. More fundamentally, however, the total burden that the rules could impose on all market participants could cause liquidity in the bilateral OTC swaps market to decrease substantially. Dodd-Frank may require up to $1 billion of additional collateral requirements at Generation, to be met with cash rather than letters of credit in a price stressed environment. Generation continues to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on its results of operations, cash flows or financial position.

Generation's affiliation with ComEd, PECO and BGE, together with the presence of a substantial percentage of Generation's physical asset base within the ComEd, PECO and BGE service territories, could increase Generation's cost of doing business to the extent future complaints or challenges regarding ComEd, PECO and/or BGE retail rates result in settlements or legislative or regulatory requirements funded in part by Generation. (Exelon and Generation)

Generation has significant generating resources within the service areas of ComEd, PECO and BGE and makes significant sales to each of them. Those facts tend to cause Generation to be directly affected by developments in those markets. Government officials, legislators and advocacy groups are aware of Generation's affiliation with ComEd, PECO and BGE and its sales to each of them. In periods of rising utility rates, particularly when driven by increased costs of energy production and supply, those officials and advocacy groups may question or challenge costs incurred by ComEd, PECO or BGE, including transactions between Generation, on the one hand, and ComEd, PECO or BGE, on the other hand, regardless of any previous regulatory processes or approvals underlying those transactions. The prospect of such challenges may increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges may subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators may seek ways to force Generation to contribute to efforts to mitigate potential or actual rate increases, through measures such as generation-based taxes and contributions to rate-relief packages.

The Registrants may incur substantial costs to fulfill their obligations related to environmental and other matters. (Exelon, Generation, ComEd, PECO and BGE)

The businesses which the Registrants operate are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the manner in which the Registrants conduct their operations and make capital expenditures including how they handle air and water emissions and solid waste disposal. Violations of these emission and disposal requirements can subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties' claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generate. The Registrants have incurred and expect to incur significant costs related to environmental compliance, site remediation and clean-up. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

If application of Section 316(b) of the Clean Water Act, which establishes a national requirement for reducing the adverse impacts to aquatic organisms at existing generating stations, requires the retrofitting of cooling water intake structures at Salem or other Exelon power plants, this development could result in material costs of compliance. Pursuant to discussions with the NJDEP regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029.

Additionally, Generation is subject to exposure for asbestos-related personal injury liability alleged at certain current and formerly owned generation facilities. Future legislative action could require Generation to make a material contribution to a fund to settle lawsuits for alleged asbestos-related disease and exposure.

In some cases, a third party who has acquired assets from a Registrant has assumed the liability the Registrant may otherwise have for environmental matters related to the transferred property. If the transferee fails to discharge the assumed liability, a regulatory authority or injured person could attempt to hold the Registrant responsible, and the Registrant's remedies against the transferee may be limited by the financial resources of the transferee. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in ComEd's, PECO's and BGE's respective terms and conditions of service, including their respective rates, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy and subject to appeal, which lead to uncertainty as to the ultimate result and which may introduce time delays in effectuating rate changes. (Exelon, ComEd, PECO and BGE)

ComEd, PECO and BGE are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for ComEd, PECO or BGE to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates can be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs.

In certain instances, ComEd, PECO and BGE may agree to negotiated settlements related to various rate matters, customer initiatives or franchise agreements. These settlements are subject to regulatory approval.

ComEd, PECO and BGE cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania, Maryland or Federal regulators in establishing rates, including the extent, if any, to which certain costs such as significant capital projects will be recovered or what rates of return will be allowed. Nevertheless, the expectation is that ComEd, PECO and BGE will continue to be obligated to deliver electricity to customers in their respective service territories and will also retain significant POLR and default service obligations to provide electricity and natural gas to certain groups of customers in their respective service areas who do not choose an alternative supplier. The ultimate outcome and timing of regulatory rate proceedings have a significant effect on the ability of ComEd, PECO and BGE, as applicable, to recover their costs and could have a material adverse effect on ComEd's, PECO's and BGE's results of operations, cash flows and financial position. See Note 3 of the Combined Notes to the Consolidated Financial Statements for information on the recently enacted EIMA and appeals in connection with ComEd's 2007 and 2010 Illinois electric distribution rate cases.

Federal or additional state RPS and/or energy conservation legislation, along with energy conservation by customers, could negatively affect the results of operations and cash flows of ComEd, PECO and BGE. (Exelon, Generation, ComEd, PECO and BGE)

Changes to current state legislation or the development of Federal legislation that requires the use of renewable and alternate fuel sources, such as wind, solar, biomass and geothermal, could significantly impact Generation, ComEd, PECO and BGE, especially if timely cost recovery is not allowed. The impact could include increased costs for RECs and purchased power and increased rates for customers.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, have increased capital expenditures and could significantly impact ComEd, PECO and BGE, if timely cost recovery is not allowed. Furthermore, regulated energy consumption reduction targets and declines in customer energy consumption resulting from the implementation of new energy conservation technologies could lead to a decline in the revenues of Exelon, ComEd, and PECO. For additional information, see ITEM 1. BUSINESS "Environmental Regulation-Renewable and Alternative Energy Portfolio Standards."

The impact of not meeting the criteria of the FASB guidance for accounting for the effects of certain types of regulation could be material to Exelon, ComEd, PECO and BGE. (Exelon, ComEd, PECO and BGE)

As of December 31, 2012, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria of the authoritative guidance for accounting for the effects of certain types of regulation. If it is concluded in a future period that a separable portion of their businesses no longer meets the criteria, Exelon, ComEd, PECO and BGE are required to eliminate the financial statement effects of regulation for that part of their business. That action would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets and the recognition of a one-time extraordinary item in their Consolidated Statements of Operations. The impact of not meeting the criteria of the authoritative guidance could be material to the financial statements of Exelon, ComEd, PECO and BGE. At December 31, 2012, the extraordinary gain could have been as much as $2.3 billion (before taxes) as a result of the elimination of ComEd's regulatory assets and liabilities. At December 31, 2012, the extraordinary charge could have been as much as $703 million (before taxes) as a result of the elimination of PECO's regulatory assets and liabilities. At December 31, 2012, the extraordinary charge could have been as much as $ 471 million (before taxes) as a result of the elimination of BGE's regulatory assets and liabilities. Exelon would record the same amount of extraordinary gain or charge related to ComEd's, PECO's and BGE's regulatory assets and liabilities. Further, Exelon would record a charge against OCI (before taxes) of up to $3.3 billion, $43 million and $682 million for ComEd, PECO and BGE, respectively, related to Exelon's regulatory assets associated with its defined benefit postretirement plans. The impacts and resolution of the above items could lead to an additional impairment of ComEd's goodwill, which could be significant and at least partially offset the extraordinary gain at ComEd discussed above. A significant decrease in equity as a result of any changes could limit the ability of ComEd, PECO and BGE to pay dividends under Federal and state law and no longer meeting the regulatory accounting criteria could cause significant volatility in future results of operations. See Notes 1, 3 and 8 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd's goodwill, respectively.

Exelon and Generation may incur material costs of compliance if Federal and/or state regulation or legislation is adopted to address climate change. (Exelon and Generation)

Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. In 2009, select Northeast and Mid-Atlantic states implemented a model rule, developed via the RGGI, to regulate CO_2 emissions from fossil-fired generation. RGGI states are working on updated programs to further limit emissions and the EPA has introduced regulation to address greenhouse gases from new fossil plants that could potentially impact existing plants. If carbon reduction regulation or legislation becomes effective, Exelon and Generation may incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. The nature and extent of environmental regulation may also impact the ability of Exelon and its subsidiaries to meet the GHG emission reduction targets of Exelon

2020. For example, more stringent permitting requirements may preclude the construction of lower-carbon nuclear and gas-fired power plants. Similarly, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS "Global Climate Change" and Note 19 of the Combined Notes to Consolidated Financial Statements.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of ComEd, PECO, and BGE to the results of PJM's RTEP and NERC compliance requirements. (Exelon, Generation, ComEd, PECO and BGE)

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation, ComEd, PECO and BGE, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. As operators of natural gas distribution systems, PECO and BGE are also subject to mandatory reliability standards of the U.S. Department of Transportation. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards may subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC and MDPSC impose certain distribution reliability standards on ComEd, PECO and BGE, respectively. If the Registrants were found not to be in compliance with the mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties. Additionally, in 2011, the State of Maryland enacted legislation that imposed reliability and quality of service standards on electric companies and required the MDPSC to enact regulations during 2012 to implement these standards. These regulations could have a material impact on BGE's financial results of operations, cash flows and financial position.

ComEd, PECO and BGE as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments may require ComEd, PECO and BGE to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. Uncertainties exist as to the construction of new transmission facilities, their cost and how those costs will be allocated to transmission system participants and customers. In accordance with a FERC order and related settlement, PJM's RTEP requires the costs of new transmission facilities to be allocated across the entire PJM footprint for new facilities greater than or equal to 500 kV, and requires costs of new facilities less than 500 kV to be allocated to the beneficiaries of the new facilities. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit remanded to FERC its decision related to allocation of new facilities 500 kV and above for further proceedings.

See Notes 3 and 19 of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants cannot predict the outcome of the legal proceedings relating to their business activities. An adverse determination could have a material adverse effect on their results of operations, financial positions and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are involved in legal proceedings, claims and litigation arising out of their business operations, the most significant of which are summarized in Note 19 of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on the Registrants' results of operations.

Generation may be negatively affected by possible Nuclear Regulatory Commission actions that could affect the operations and profitability of its nuclear generating fleet. (Exelon and Generation)

Regulatory risk . A change in the Atomic Energy Act or the applicable regulations or licenses may require a substantial increase in capital expenditures or may result in increased operating or decommissioning costs and significantly affect Generation's results of operations or financial position. Events at nuclear plants owned by others, as well as those owned by Generation, may cause the NRC to initiate such actions.

As an example, prior to the Fukushima Daiichi accident on March 11, 2011, the NRC had been evaluating seismic risk. After the Fukushima Daiichi accident, the NRC's focus on seismic risk intensified. As part of the NRC Near-Term Task Force (Task Force) review and evaluation of the Fukushima Daiichi accident, the Task Force recommended that plant operators conduct seismic reevaluations. In January 2012, the NRC released an updated seismic risk model that plant operators must use in performing the seismic reevaluations recommended by the Task Force. These reevaluations could result in the required implementation of additional mitigation strategies or modifications. Additionally, the Task Force provided recommendations for future regulatory action by the NRC to be taken in the near and longer term. In response, the NRC issued three immediately effective orders (Tier 1) to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. The NRC is currently evaluating the remaining Task Force recommendations and has not taken action with respect to the Tier 2 and Tier 3 recommendations. Actions to comply with the Task Force recommendations may result in increased costs and significantly impact Generation's results of operations or financial position. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview for a more detailed discussion of the Task Force Recommendations.

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF, such as the one previously considered at Yucca Mountain, Nevada, and the timing of such facility opening, will significantly affect the costs associated with storage of SNF, and the ultimate amounts received from the DOE to reimburse Generation for these costs. The NRC's temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants. In June 2012, the United States District Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. In September 2012, the NRC directed NRC Staff to complete a generic environmental impact statement and to revise the temporary storage rule through rulemaking no later than September 6, 2014.

Any regulatory action relating to the timing and availability of a repository for SNF may adversely affect Generation's ability to decommission fully its nuclear units. Furthermore, under its contract with the DOE, Generation would be required to pay the DOE a one-time SNF storage fee including interest of approximately $1 billion as of December 31, 2012, prior to the first delivery of SNF. Generation currently estimates 2025 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information on the spent nuclear fuel obligation.

License renewals. Generation cannot assure that economics will support the continued operation of the facilities for all or any portion of any renewed license period. If the NRC does not renew the operating licenses for Generation's nuclear stations or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased

depreciation rates, impairment charges and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. In addition, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments.

As discussed above, in June 2012, the United States District Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule. Generation does not expect the NRC to issue license renewals until September 2014, at the earliest.

Operational Risks

The Registrants' employees, contractors, customers and the general public may be exposed to a risk of injury due to the nature of the energy industry. (Exelon, Generation, ComEd, PECO and BGE)

Employees and contractors throughout the organization work in, and customers and the general public may be exposed to, potentially dangerous environments near their operations. As a result, employees, contractors, customers and the general public are at risk for serious injury, including loss of life. Significant risks include nuclear accidents, dam failure, gas explosions, pole strikes and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events may adversely affect Exelon's results of operations, its ability to raise capital and its future growth. (Exelon, Generation, ComEd, PECO and BGE)

Generation's fleet of nuclear and fossil-fueled power plants and ComEd's, PECO's and BGE's distribution and transmission infrastructures could be impacted by natural disasters, such as seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Registrants' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. Examples of such events include the June 2012 "Derecho" storm, which interrupted electric service delivery to customers in BGE's service territory, and the October 2012 category 1 hurricane, Hurricane Sandy, which interrupted electric service delivery to customers in PECO's and BGE's service territories and resulted in significant costs to PECO and BGE for restoration efforts. Other events include the 9.0 magnitude earthquake and ensuing tsunami experienced by Japan on March 11, 2011, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co., and the 5.8 magnitude earthquake and flooding associated with Hurricane Irene and Tropical Storm Lee that the Mid-Atlantic region of the United States experienced in 2011. These events increase the risk to Generation that the NRC or other regulatory or legislative bodies may change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological aspects. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for Generation's continued operation, particularly the cooling of generating units. Additionally, natural disasters and other events that have an adverse effect on the economy in general may adversely affect the Registrants' operations and their ability to raise capital.

Exelon does not know the impact that potential terrorist attacks could have on the industry in general and on Exelon in particular. As owner-operators of infrastructure facilities, such as nuclear, fossil and hydroelectric generation facilities and electric and gas transmission and distribution facilities,

the Registrants face a risk that their operations would be direct targets of, or indirect casualties of, an act of terror. Any retaliatory military strikes or sustained military campaign may affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cyber security of Exelon's facilities, which could adversely affect Exelon's ability to manage its business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also may result in a decline in energy consumption, which may adversely affect the Registrants' results of operations and its ability to raise capital. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants would be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate its generating and transmission and distribution assets could be affected, resulting in decreased service levels and increased costs.

In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property and casualty losses subject to unforeseen occurrences or catastrophic events that may damage or destroy assets or interrupt operations.

Generation's financial performance may be negatively affected by matters arising from its ownership and operation of nuclear facilities. (Exelon and Generation)

Nuclear capacity factors. Capacity factors, particularly nuclear capacity factors, significantly affect Generation's results of operations. Nuclear plant operations involve substantial fixed operating costs but produce electricity at low variable costs due to nuclear fuel costs typically being lower than fossil fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear facilities at high capacity factors. Lower capacity factors increase Generation's operating costs by requiring Generation to produce additional energy from primarily its fossil facilities or purchase additional energy in the spot or forward markets in order to satisfy Generation's obligations to committed third-party sales, including ComEd, PECO and BGE. These sources generally have higher costs than Generation incurs to produce energy from its nuclear stations.

Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, can have a significant impact on Generation's results of operations. When refueling outages at wholly and co-owned plants last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales.

Nuclear fuel quality **.** The quality of nuclear fuel utilized by Generation can affect the efficiency and costs of Generation's operations. Certain of Generation's nuclear units have previously had a limited number of fuel performance issues. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

Operational risk **.** Operations at any of Generation's nuclear generation plants could degrade to the point where Generation has to shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Generation may choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation may lose revenue and incur increased fuel and purchased power

expense to meet supply commitments. In addition, Generation may not achieve the anticipated results under its series of planned power uprates across its nuclear fleet. For plants operated but not wholly owned by Generation, Generation may also incur liability to the co-owners. For plants not operated and not wholly owned by Generation, from which Generation receives a portion of the plants' output, Generation's results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by Generation could result in increased regulation and reduced public support for nuclear-fueled energy, which could significantly affect Generation's results of operations or financial position. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident can be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by Generation or owned by others, may exceed Generation's resources, including insurance coverage. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by Generation and could have a material adverse effect on Generation's results of operations or financial position. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, owned by others or Generation, may result in increased regulation and reduced public support for nuclear-fueled energy and significantly affect Generation's results of operations or financial position.

Nuclear insurance. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance. The required amount of nuclear liability insurance is $375 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $12.6 billion limit for a single incident.

Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation's nuclear operations. In previous years, NEIL had made distributions to its members but Generation cannot predict the level of future distributions or if they will occur at all. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Generation is required to provide to the NRC a biennial report by unit (annually for Generation's two units that have been retired) addressing Generation's ability to meet the NRC-estimated funding levels including scheduled contributions to and earnings on the decommissioning trust funds. The NRC funding levels are based upon the assumption that decommissioning will commence after the end of the current licensed life of each unit.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results may differ significantly from current estimates. The performance of capital markets also can significantly affect the value of the trust funds. Currently, Generation is making contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from ComEd customers or from the previous owners of Clinton, TMI Unit No. 1 and Oyster Creek generating stations, if there is a shortfall

of funds necessary for decommissioning. If circumstances changed such that Generation would be unable to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if Generation no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units may be negatively affected and Exelon's and Generation's results of operations and financial position could be significantly affected. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Ultimately, if the investments held by Generation's NDTs are not sufficient to fund the decommissioning of Generation's nuclear plants, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met. As a result, Generation's cash flows and financial position may be significantly adversely affected. See Note 13 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's financial performance may be negatively affected by risks arising from its ownership and operation of hydroelectric facilities. (Exelon and Generation)

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. The license for the Conowingo Hydroelectric Project expires August 31, 2014, and the license for the Muddy Run Pumped Storage Project expires on September 1, 2014. Generation cannot predict whether it will receive all the regulatory approvals for the renewed licenses of its hydroelectric facilities. If FERC does not renew the operating licenses for Generation's hydroelectric facilities or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. Generation may also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions may be imposed as part of the license renewal process that may adversely affect operations, may require a substantial increase in capital expenditures or may result in increased operating costs and significantly affect Generation's results of operations or financial position. Similar effects may result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by Generation.

ComEd's, PECO's and BGE's operating costs, and customers' and regulators' opinions of ComEd, PECO and BGE, respectively, are affected by their ability to maintain the availability and reliability of their delivery and operational systems. (Exelon, ComEd, PECO and BGE)

Failures of the equipment or facilities, including information systems, used in ComEd's, PECO's and BGE's delivery systems can interrupt the electric transmission and electric and natural gas delivery, which could negatively impact related revenues, and increase maintenance and capital expenditures. Equipment or facilities failures can be due to a number of factors, including weather or information systems failure. Specifically, if the implementation of advanced metering infrastructure, smart grid or other technologies in ComEd's, PECO's or BGE's service territory fail to perform as intended or are not successfully integrated with billing and other information systems, ComEd's, PECO's and BGE's financial condition, results of operations, and cash flows could be adversely affected. Furthermore, if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, ComEd's, PECO's or BGE's financial results could be adversely affected. If an employee causes the operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating the operational systems, ComEd's, PECO's or BGE's

financial results could also be adversely affected. In addition, dependence upon automated systems may further increase the risk that operational system flaws or employee tampering or manipulation of those systems will result in losses that are difficult to detect.

The aforementioned failures or those of other utilities, including prolonged or repeated failures, can affect customer satisfaction and the level of regulatory oversight and ComEd's, PECO's and BGE's maintenance and capital expenditures. Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd can be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, and those damages could be material to ComEd's results of operations and cash flows.

ComEd's, PECO's and BGE's respective ability to deliver electricity, their operating costs and their capital expenditures may be negatively affected by transmission congestion. (Exelon, ComEd, PECO and BGE)

Demand for electricity within ComEd's, PECO's and BGE's service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage with consequent effects on operating costs, revenues and results of operations. Also, insufficient availability of electric supply to meet customer demand could jeopardize ComEd's, PECO's and BGE's ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring ComEd, PECO and BGE to upgrade or expand their respective transmission systems through additional capital expenditures.

Failure to attract and retain an appropriately qualified workforce may negatively impact the Registrants' results of operations. (Exelon, Generation, ComEd, PECO and BGE)

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, may lead to operating challenges and increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission and distribution operations. If the Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations could be negatively affected.

The Registrants are subject to physical and information security risks. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants face physical and information security risks as the owner-operators of generation, transmission and distribution facilities. A security breach of the Registrants' physical assets or information systems could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject the Registrants to financial harm associated with theft or inappropriate release of certain types of information, including sensitive customer data. If a significant breach occurred, the reputation of Exelon and its customer supply activities may be adversely affected, customer confidence may be diminished, or Exelon and its subsidiaries may be subject to legal claims, any of which may contribute to the loss of customers and have a negative impact on the business and/or results of operations. ComEd's, PECO's and BGE's deployment of smart meters throughout their service territories may increase the risk of damage from an intentional disruption of the system by third parties. As a requirement of their SGIG grant, the DOE approved PECO's and BGE's cyber security plan related to its smart meter deployment and will review the plan annually through the expiration of the grant. As

with most companies in today's environment, Exelon experiences attempts by hackers to infiltrate its corporate network. To date there have been no infiltrations that have resulted in loss of data or any significant effects on business operations. Exelon utilizes a dedicated team of cyber security professionals to ensure the protection of its information and ability to conduct business operations. Despite the measures taken by the Registrants to prevent a security breach, the Registrants cannot accurately assess the probability that a security breach may occur and are unable to quantify the potential impact of such an event. In addition, new or updated security regulations could require changes in current measures taken by the Registrants or their business operations and could adversely affect their results of operations, cash flows and financial position.

The Registrants may make investments in new business initiatives, including initiatives mandated by regulators, and markets that may not be successful, and acquisitions may not achieve the intended financial results. (Exelon, Generation, ComEd, PECO and BGE)

Generation continuously looks to invest in new business initiatives and actively participate in new markets. These include, but are not limited to, unconventional oil and gas exploration and production, residential power and gas sales, solar and wind generation, and managed load response. Such initiatives may involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market. As these markets mature, there may be new market entrants or expansion by established competitors that increase competition for customers and resources. Additionally, it is possible that FERC, state public utility commissions or others may impose certain other restrictions on such transactions. All of these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment. ComEd, PECO and BGE face risks associated with the Smart Grid mandated regulatory initiative. These risks include, but are not limited to, cost recovery, regulatory concerns, cyber security and obsolescence of technology. Due to these risks, no assurance can be given that such initiatives will be successful and will not have a material adverse effect on ComEd's, PECO's or BGE's financial results.

Risks Related to the Merger

The merger may not achieve its anticipated results, and Exelon may be unable to integrate the operations of Constellation in the manner expected.

Exelon and Constellation entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and Constellation can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Exelon's businesses, processes and systems or inconsistencies in standards, controls, procedures, practices, policies, valuation models, and compensation arrangements, any of which could adversely affect the combined company's ability to achieve the anticipated benefits of the merger as and when expected. Exelon may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect Exelon's future business, financial condition, operating results and prospects.

The merger may not be accretive to earnings and may cause dilution to Exelon's earnings per share, which may negatively affect the market price of Exelon's common stock.

Exelon currently anticipates that the merger will be accretive to earnings per share in 2013, which will be the first full year following completion of the merger. Exelon also could encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect estimates. Any of these factors could cause a decrease in Exelon's adjusted earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Exelon's common stock.

The merger may adversely affect Exelon's ability to attract and retain key employees.

Current and prospective Exelon employees may experience uncertainty about their future roles at Exelon as a result of the merger. In addition, current and prospective Exelon employees may determine that they do not desire to work for the combined company for a variety of possible reasons. These factors may adversely affect Exelon's ability to attract and retain key management and other personnel.

Exelon may incur unexpected transaction fees and merger-related costs in connection with the merger.

Exelon has incurred and expects to further incur a number of non-recurring expenses related to combining the operations of the Exelon and Constellation. Exelon may incur additional unanticipated costs in the integration of the businesses of the two companies. Although Exelon expects that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger-related costs over time, the combined company may not achieve this net benefit in the near term, or at all.

Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the Constellation merger.

As a result of the process to obtain regulatory approvals required for the Constellation merger, Exelon is committed to various programs, contributions, investments and market mitigation measures in several settlement agreements and regulatory approval orders. It is possible that Exelon may encounter delays, unexpected difficulties or costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon's financial position and operating results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 2. PROPERTIES

Generation

The following table describes Generation's interests in net electric generating capacity by station at December 31, 2012:

Station	Region	Location	No. of Units	Percent Owned [a]	Primary Fuel Type	Primary Dispatch Type [b]	Net Generation Capacity (MW) [c]
Limerick	Mid-Atlantic	Limerick Twp., PA	2		Uranium	Base-load	2,314
Peach Bottom	Mid-Atlantic	Peach Bottom Twp., PA	2	50	Uranium	Base-load	1,158[f]
Salem	Mid-Atlantic	Hancock's Bridge, NJ	2	42.59	Uranium	Base-load	1,006[f]
Calvert Cliffs	Mid-Atlantic	Calvert Co., MD	2	50.01	Uranium	Base-load	877[f] [h]
Three Mile Island	Mid-Atlantic	Londonderry Twp, PA	1		Uranium	Base-load	837
Keystone	Mid-Atlantic	Shelocta, PA	2	41.98	Coal	Base-load	714[f]
Oyster Creek	Mid-Atlantic	Forked River, NJ	1		Uranium	Base-load	625[e]
Conowingo	Mid-Atlantic	Harford Co., MD	11		Hydroelectric	Base-load	572
Conemaugh	Mid-Atlantic	New Florence, PA	2	31.28	Coal	Base-load	531[f]
Criterion	Mid-Atlantic	Oakland, MD	28		Wind	Base-load	70
Colver	Mid-Atlantic	Colver Twp., PA	1	25	Waste Coal	Base-load	26[f]
Solar Horizons	Mid-Atlantic	Various	1		Solar	Base-load	16
Solar New Jersey 2	Mid-Atlantic	Various	2		Solar	Base-load	11
Solar New Jersey 1	Mid-Atlantic	Various	3		Solar	Base-load	10
Solar Maryland	Mid-Atlantic	Various	10		Solar	Base-load	8
Solar Federal	Mid-Atlantic	Various	1		Solar	Base-load	5
Solar New Jersey 3	Mid-Atlantic	Various	1		Solar	Base-load	1
Muddy Run	Mid-Atlantic	Lancaster, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Mid-Atlantic	Eddystone, PA	2		Oil/Gas	Intermediate	760
Safe Harbor	Mid-Atlantic	Safe Harbor, PA	12	66.7	Hydroelectric	Intermediate	277[f]
Croydon	Mid-Atlantic	Bristol Twp., PA	8		Oil	Peaking	391
Perryman	Mid-Atlantic	Hartford Co., MD	5		Oil/Gas	Peaking	347
Handsome Lake	Mid-Atlantic	Rockland Twp., PA	5		Gas	Peaking	268
Riverside	Mid-Atlantic	Baltimore Co., MD	4		Oil/Gas	Peaking	228
Westport	Mid-Atlantic	Baltimore Co., MD	1		Gas	Peaking	116
Notch Cliff	Mid-Atlantic	Baltimore, MD	8		Gas	Peaking	101
Richmond	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	98
Gould Street	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	97
Philadelphia Road	Mid-Atlantic	Baltimore Co., MD	4		Oil	Peaking	61
Eddystone	Mid-Atlantic	Eddystone, PA	4		Oil	Peaking	60
Fairless Hills	Mid-Atlantic	Falls Twp, PA	2		Landfill Gas	Peaking	60
Delaware	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	52
Falls	Mid-Atlantic	Falls Twp., PA	3		Oil	Peaking	51
Moser	Mid-Atlantic	Lower Pottsgrove Twp., PA	3		Oil	Peaking	51
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39
Salem	Mid-Atlantic	Hancock's Bridge, NJ	1	42.59	Oil	Peaking	16[f]
Pennsbury	Mid-Atlantic	Falls Twp., PA	2		Landfill Gas	Peaking	6
Keystone	Mid-Atlantic	Shelocta, PA	4	41.98	Oil	Peaking	4[f]
Conemaugh	Mid-Atlantic	New Florence, PA	4	31.28	Oil	Peaking	3[f]
Total Mid-Atlantic							12,993
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,349
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,327
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,326
Dresden	Midwest	Morris, IL	2		Uranium	Base-load	1,790
Quad Cities	Midwest	Cordova, IL	2	75	Uranium	Base-load	1,403[f]

Station	Region	Location	No. of Units	Percent Owned [a]	Primary Fuel Type	Primary Dispatch Type [b]	Net Generation Capacity (MW) [c]
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,067
Michigan Wind 2	Midwest	Bingham Twp., MI	50		Wind	Base-load	90
Beebe	Midwest	Gratiot Co., MI	34		Wind	Base-load	81
Michigan Wind 1	Midwest	Bingham Twp., MI	46		Wind	Base-load	69
Harvest 2	Midwest	Huron Co., MI	33		Wind	Base-load	59
Harvest	Midwest	Huron Co., MI	32		Wind	Base-load	53
Wildcat	Midwest	Lee Co., NM	13		Wind	Base-load	27
Ewington	Midwest	Jackson Co., MN	10	99	Wind	Base-load	21[f]
Marshall	Midwest	Lyon Co., MN	9	98-99	Wind	Base-load	19[f]
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	10
Norgaard	Midwest	Lincoln Co., MN	7	99	Wind	Base-load	9[f]
AgriWind	Midwest	Bureau Co., IL	4	99	Wind	Base-load	8[f]
Cisco	Midwest	Jackson Co., MN	4	99	Wind	Base-load	8[f]
Brewster	Midwest	Jackson Co., MN	6	94-99	Wind	Base-load	6[f]
Wolf	Midwest	Nobles Co., MN	5	99	Wind	Base-load	6[f]
CP Windfarm	Midwest	Faribault Co., MN	2		Wind	Base-load	4
Moore	Midwest	Faribault Co., MN	2		Wind	Base-load	3
Cowell	Midwest	Pipestone Co., MN	1	99	Wind	Base-load	2[f]
Solar Ohio	Midwest	Various	1		Solar	Base-load	1
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296
Total Midwest							12,034
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3		Gas	Intermediate	705
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	565
Colorado Bend	ERCOT	Wharton, TX	1		Gas	Intermediate	498
Quail Run	ERCOT	Odessa, TX	1		Gas	Intermediate	488
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870
Mountain Creek 6, 7	ERCOT	Dallas, TX	2		Gas	Peaking	240
LaPorte	ERCOT	Laporte, TX	4		Gas	Peaking	152
Total ERCOT							3,913
Holyoke Solar	New England	Various	1		Solar	Base-load	5
Solar Massachusetts	New England	Various	5		Solar	Base-load	3
Solar Net Metering	New England	Various	1		Solar	Base-load	3
Solar Connecticut	New England	Various	2		Solar	Base-load	1
Mystic 8, 9	New England	Charlestown, MA	2		Gas	Intermediate	1,382
Fore River	New England	North Weymouth, MA	1		Gas	Intermediate	688
Mystic 7	New England	Charlestown, MA	1		Oil/Gas	Intermediate	560
Wyman	New England	Yarmouth, ME	1	5.89	Oil	Intermediate	36[f]
Medway	New England	West Medway, MA	3		Oil/Gas	Peaking	105
Framingham	New England	Framingham, MA	3		Oil	Peaking	28
New Boston	New England	South Boston, MA	1		Oil	Peaking	12
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9
Total New England							2,832
Nine Mile Point	New York	Scriba, NY	2	50.01	Uranium	Base-load	798[f] [h]
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288[f] [h]
Total New York							1,086
Shooting Star	Other	Kiowa Co., KS	65		Wind	Base-load	104
Whitetail	Other	Webb Co., TX	57		Wind	Base-load	92
Exelon Wind 4	Other	Hansford Co., TX	38		Wind	Base-load	80
Bluegrass Ridge	Other	Gentry Co., MO	27		Wind	Base-load	57

Station	Region	Location	No. of Units	Percent Owned [a]	Primary Fuel Type	Primary Dispatch Type [b]	Net Generation Capacity (MW) [c]
Conception	Other	Nodaway Co., MO	24		Wind	Base-load	50
Cow Branch	Other	Atchinson Co., MO	24		Wind	Base-load	50
Mountain Home	Other	Elmore Co., ID	20		Wind	Base-load	42
High Mesa	Other	Elmore Co., ID	19		Wind	Base-load	40
Echo 1	Other	Umatilla Co., OR	21	99	Wind	Base-load	35[f]
AVSR	Other	Los Angeles County, CA	1		Solar	Base-load	31[g]
Sacramento PV Energy	Other	Various	1		Solar	Base-load	30
Cassia	Other	Twin Falls Co., ID	14		Wind	Base-load	29
Sunnyside	Other	Sunnyside, UT	1	50	Waste Coal	Base-load	26[f]
Echo 2	Other	Morrow Co., OR	10		Wind	Base-load	20
Tuana Springs	Other	Twin Falls Co., ID	8		Wind	Base-load	17
Greensburg	Other	Kiowa Co., KS	10		Wind	Base-load	13
Echo 3	Other	Morrow Co., OR	6	99	Wind	Base-load	10[f]
Exelon Wind 1	Other	Hansford Co., TX	8		Wind	Base-load	10
Exelon Wind 2	Other	Hansford Co., TX	8		Wind	Base-load	10
Exelon Wind 3	Other	Hansford Co., TX	8		Wind	Base-load	10
Exelon Wind 5	Other	Sherman Co., TX	8		Wind	Base-load	10
Exelon Wind 6	Other	Sherman Co., TX	8		Wind	Base-load	10
Exelon Wind 7	Other	Moore Co., TX	8		Wind	Base-load	10
Exelon Wind 8	Other	Moore Co., TX	8		Wind	Base-load	10
Exelon Wind 9	Other	Moore Co., TX	8		Wind	Base-load	10
Exelon Wind 10	Other	Moore Co., TX	8		Wind	Base-load	10
Exelon Wind 11	Other	Moore Co., TX	8		Wind	Base-load	10
High Plains	Other	Moore Co., TX	8	99.5	Wind	Base-load	10[f]
Threemile Canyon	Other	Morrow Co., OR	6		Wind	Base-load	10
Solar Arizona	Other	Various	2		Solar	Base-load	8
Outback Solar	Other	Various	1		Solar	Base-load	6
Loess Hills	Other	Atchinson Co., MO	4		Wind	Base-load	5
Denver Airport Solar	Other	Various	1		Solar	Base-load	4
Solar California	Other	Various	4		Solar	Base-load	3
Hillabee	Other	Alexander City, AL	1		Gas	Intermediate	684
Malacha	Other	Muck Valley, CA	1	50	Hydroelectric	Intermediate	16[f]
West Valley	Other	Salt Lake City, UT	5		Gas	Peaking	200
Grand Prairie	Other	Alberta, Canada	1		Gas	Peaking	93
SEGS 4, 5, 6	Other	Kramer Junction, CA	3	4.2-12.2	Solar	Peaking	8[f]
Total Other							1,873
Total							34,731

(a) 100%, unless otherwise indicated.
(b) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(c) For nuclear stations, capacity reflects the annual mean rating. Fossil stations reflect a summer rating. Wind and solar facilities reflect name plate capacity.
(d) All nuclear stations are boiling water reactors except Braidwood, Byron, Salem and Three Mile Island, which are pressurized water reactors.
(e) Generation has agreed to permanently cease generation operation at Oyster Creek by December 31, 2019.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Expected capacity upon project completion is 230MW. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(h) Reflects Generation's 50.01% interest in CENG, a joint venture with EDF. Generation also has a unit contingent PPA with CENG under which it purchases 85 to 90% of the output of CENG's nuclear generating facilities that is not sold to third parties under the pre-existing PPAs through 2014.

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The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies or generating units being temporarily out of service for inspection, maintenance, refueling, repairs or modifications required by regulatory authorities.

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see ITEM 1. Business—Generation. For its insured losses, Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on Generation's consolidated financial condition or results of operations.

ComEd

ComEd's electric substations and a portion of its transmission rights of way are located on property that ComEd owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ComEd believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements, licenses and franchise rights; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ComEd's higher voltage electric transmission lines owned and in service at December 31, 2012 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,642
138,000	2,237

ComEd's electric distribution system includes 35,563 circuit miles of overhead lines and 30,506 circuit miles of underground lines.

First Mortgage and Insurance

The principal properties of ComEd are subject to the lien of ComEd's Mortgage dated July 1, 1923, as amended and supplemented, under which ComEd's First Mortgage Bonds are issued.

ComEd maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ComEd is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ComEd.

PECO

PECO's electric substations and a significant portion of its transmission lines are located on property that PECO owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. PECO believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

PECO's high voltage electric transmission lines owned and in service at December 31, 2012 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188 [(a)]
230,000	548
138,000	156
69,000	200

(a) In addition, PECO has a 22.00% ownership interest in 127 miles of 500 kV lines located in Pennsylvania and a 42.55% ownership interest in 131 miles of 500 kV lines located in Delaware and New Jersey.

PECO's electric distribution system includes 13,013 circuit miles of overhead lines and 8,901 circuit miles of underground lines.

Gas

The following table sets forth PECO's natural gas pipeline miles at December 31, 2012:

	Pipeline Miles
Transmission	31
Distribution	6,747
Service piping	6,038
Total	12,816

PECO has an LNG facility located in West Conshohocken, Pennsylvania that has a storage capacity of 1,200 mmcf and a send-out capacity of 157 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 1,980,000 gallons and a peaking capability of 25 mmcf/day. In addition, PECO owns 31 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

The principal properties of PECO are subject to the lien of PECO's Mortgage dated May 1, 1923, as amended and supplemented, under which PECO's first and refunding mortgage bonds are issued.

PECO maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, PECO is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of PECO.

BGE

BGE's electric substations and a significant portion of its transmission lines are located on property that BGE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. BGE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

BGE's high voltage electric transmission lines owned and in service at December 31, 2012 were as follows:

Voltage (Volts)	Circuit Miles
500,000	218
230,000	321
138,000	54
115,000	697

BGE's electric distribution system includes 9,411 circuit miles of overhead lines and 15,748 circuit miles of underground lines.

Gas

The following table sets forth BGE's natural gas pipeline miles at December 31, 2012:

	Pipeline Miles
Transmission	164
Distribution	7,015
Service piping	6,146
Total	13,325

BGE has an LNG facility located in Baltimore, Maryland that has a storage capacity of 1,000 mmcf and a send-out capacity of 298 mmcf/day, an LNG facility located in Westminster, Maryland that has a storage capacity of 5.8 mmcf and a send-out capacity of 5.8 mmcf/day, and a propane-air plant located in Baltimore, Maryland, with a storage capacity of 500 mmcf and a send-out capacity of 81 mmcf/day.

Property Insurance

BGE owns its principal headquarters building located in downtown Baltimore. BGE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, BGE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of BGE.

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long-term design changes and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country's energy systems.

ITEM 3. LEGAL PROCEEDINGS

Exelon, Generation, ComEd, PECO and BGE

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Notes 3 and 19 of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

Exelon, Generation, ComEd, PECO and BGE

Not Applicable to the Registrants.

(Dollars in millions except per share data, unless otherwise noted)

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Exelon

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2013, there were 855,019,272 shares of common stock outstanding and approximately 134,194 record holders of common stock.

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2012				2011			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 37.50	$ 39.82	$ 39.37	$ 43.70	$ 45.45	$ 45.27	$ 42.89	$ 43.58
Low price	28.40	34.54	36.27	38.31	39.93	39.51	39.53	39.06
Close	29.74	35.58	37.62	39.21	43.37	42.61	42.84	41.24
Dividends	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index for the period 2008 through 2012.

This performance chart assumes:

- $100 invested on December 31, 2007 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.

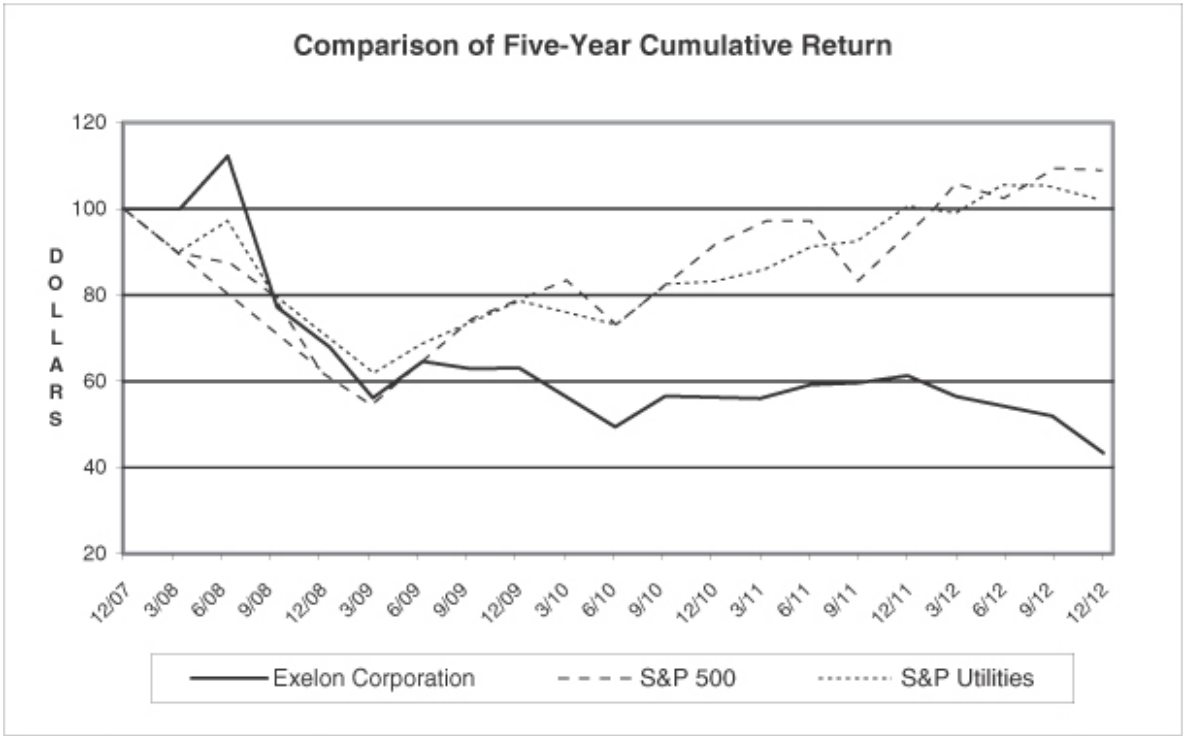

	Value of Investment at December 31,					
	2007	2008	2009	2010	2011	2012
Exelon Corporation	$100.00	$70.14	$64.25	$57.54	$62.96	$45.74
S&P 500	$100.00	$63.00	$79.68	$91.68	$93.61	$108.59
S&P Utilities	$100.00	$71.02	$79.48	$83.82	$100.54	$101.86

Generation

As of January 31, 2013, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2013, there were 127,016,764 outstanding shares of common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. At January 31, 2013, in addition to Exelon, there were 272 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2013, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2013, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

Exelon, Generation, ComEd, PECO and BGE

Dividends

Under applicable Federal law, Generation, ComEd, PECO and BGE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO or BGE may limit the dividends that these companies can distribute to Exelon.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with a financing arranged through ComEd Financing III that ComEd will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO's Amended and Restated Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. At December 31, 2012, such capital was $3 billion and amounted to about 34 times the liquidating value of the outstanding preferred securities of $87 million.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

At December 31, 2012, Exelon had retained earnings of $9,893 million, including Generation's undistributed earnings of $3,168 million, ComEd's retained earnings of $721 million consisting of retained earnings appropriated for future dividends of $2,360 million, partially offset by $1,639 million of unappropriated retained deficits, PECO's retained earnings of $593 million, and BGE's retained earnings of $808 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2012 and 2011:

	2012				2011			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$ 0.525	$ 0.525	$ 0.525	$ 0.525	$ 0.525	$ 0.525	$ 0.525	$ 0.525

The following table sets forth Generation's quarterly distributions and ComEd's, PECO's and BGE's quarterly common dividend payments:

	2012				2011			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 242	$ 493	$ 291	$ 600	$ 111	$ 61	$ —	$ —
ComEd	10	10	10	75	75	75	75	75
PECO	85	86	85	87	80	84	73	111
BGE	—	—	—	—	—	—	—	85[a]

(a) Dividends on common stock for $85 million were paid to Constellation for the year ended December 31, 2011.

First Quarter 2013 Dividend. On February 6, 2013, the Exelon Board of Directors declared a first quarter 2013 regular quarterly dividend of $0.525 per share on Exelon's common stock payable on March 8, 2013, to shareholders of record of Exelon at the end of the day on February 19, 2013.

Revised Dividend Policy. On February 6, 2013, the Exelon Board of Directors approved a revised dividend policy which contemplates a regular $0.31 per share quarterly dividend on Exelon's common stock payable beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis), subject to quarterly declarations by the Board of Directors. The second quarter 2013 quarterly dividend of $0.31 per share on Exelon's common stock is expected to be approved by the Exelon Board of Directors in the second quarter of 2013.

ITEM 6. SELECTED FINANCIAL DATA

Exelon

The selected financial data presented below has been derived from the audited consolidated financial statements of Exelon. This data is qualified in its entirety by reference to and should be read in conjunction with Exelon's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions, except per share data)	2012 [a]	2011	2010	2009	2008
Statement of Operations data:					
Operating revenues	$23,489	$19,063	$18,644	$17,318	$18,859
Operating income	2,380	4,479	4,726	4,750	5,299
Income from continuing operations	1,171	2,499	2,563	2,706	2,717
Income from discontinued operations	—	—	—	1	20
Net income	1,171	2,499	2,563	2,707	2,737
Earnings per average common share (diluted):					
Income from continuing operations	$ 1.42	$ 3.75	$ 3.87	$ 4.09	$ 4.10
Income from discontinued operations	—	—	—	—	0.03
Net income	$ 1.42	$ 3.75	$ 3.87	$ 4.09	$ 4.13
Dividends per common share	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.03
Average shares of common stock outstanding—diluted	819	665	663	662	662

(a) The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012.

	December 31,				
(In millions)	2012	2011	2010	2009	2008
Balance Sheet data:					
Current assets	$10,133	$ 5,713	$ 6,398	$ 5,441	$ 5,130
Property, plant and equipment, net	45,186	32,570	29,941	27,341	25,813
Noncurrent regulatory assets	6,497	4,518	4,140	4,872	5,940
Goodwill	2,625	2,625	2,625	2,625	2,625
Other deferred debits and other assets	14,113	9,569	9,136	8,901	8,038
Total assets	$78,554	$54,995	$52,240	$49,180	$47,546
Current liabilities	$ 7,784	$ 5,134	$ 4,240	$ 4,238	$ 3,811
Long-term debt, including long-term debt to financing trusts	18,346	12,189	12,004	11,385	12,592
Noncurrent regulatory liabilities	3,981	3,627	3,555	3,492	2,520
Other deferred credits and other liabilities	26,626	19,570	18,791	17,338	17,489
Preferred securities of subsidiary	87	87	87	87	87
Noncontrolling interest	106	3	3	—	—
BGE preference stock not subject to mandatory redemption	193	—	—	—	—
Shareholders' equity	21,431	14,385	13,560	12,640	11,047
Total liabilities and shareholders' equity	$78,554	$54,995	$52,240	$49,180	$47,546

Generation

The selected financial data presented below has been derived from the audited consolidated financial statements of Generation. This data is qualified in its entirety by reference to and should be read in conjunction with Generation's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions)	2012 [(a)]	2011	2010	2009	2008
Statement of Operations data:					
Operating revenues	$14,437	$10,447	$10,025	$9,703	$10,754
Operating income	1,120	2,875	3,046	3,295	3,994
Income from continuing operations	558	1,771	1,972	2,122	2,258
Income from discontinued operations	—	—	—	—	20
Net income	558	1,771	1,972	2,122	2,278

(a) The 2012 financial results only include the operations of Constellation from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012.

	December 31,				
(In millions)	2012	2011	2010	2009	2008
Balance Sheet data:					
Current assets	$ 6,211	$ 3,217	$ 3,087	$ 3,360	$ 3,486
Property, plant and equipment, net	19,531	13,475	11,662	9,809	8,907
Other deferred debits and other assets	14,939	10,741	9,785	9,237	7,691
Total assets	$40,681	$27,433	$24,534	$22,406	$20,084
Current liabilities	$ 4,097	$ 2,144	$ 1,843	$ 2,262	$ 2,168
Long-term debt	7,455	3,674	3,676	2,967	2,502
Other deferred credits and other liabilities	16,464	12,907	11,838	10,385	8,848
Noncontrolling interest	108	5	5	2	1
Member's equity	12,557	8,703	7,172	6,790	6,565
Total liabilities and member's equity	$40,681	$27,433	$24,534	$22,406	$20,084

ComEd

The selected financial data presented below has been derived from the audited consolidated financial statements of ComEd. This data is qualified in its entirety by reference to and should be read in conjunction with ComEd's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions)	2012	2011	2010	2009	2008
Statement of Operations data:					
Operating revenues	$5,443	$6,056	$6,204	$5,774	$6,136
Operating income	886	982	1,056	843	667
Net income	379	416	337	374	201

(In millions)	December 31, 2012	2011	2010	2009	2008
Balance Sheet data:					
Current assets	$ 1,775	$ 2,188	$ 2,151	$ 1,579	$ 1,309
Property, plant and equipment, net	13,826	13,121	12,578	12,125	11,655
Goodwill	2,625	2,625	2,625	2,625	2,625
Noncurrent regulatory assets	666	699	947	1,096	858
Other deferred debits and other assets	4,013	4,005	3,351	3,272	2,790
Total assets	$22,905	$22,638	$21,652	$20,697	$19,237
Current liabilities	$ 1,655	$ 2,071	$ 2,134	$ 1,597	$ 1,153
Long-term debt, including long-term debt to financing trusts	5,521	5,421	4,860	4,704	4,915
Noncurrent regulatory liabilities	3,229	3,042	3,137	3,145	2,440
Other deferred credits and other liabilities	5,177	5,067	4,611	4,369	3,994
Shareholders' equity	7,323	7,037	6,910	6,882	6,735
Total liabilities and shareholders' equity	$22,905	$22,638	$21,652	$20,697	$19,237

PECO

The selected financial data presented below has been derived from the audited consolidated financial statements of PECO. This data is qualified in its entirety by reference to and should be read in conjunction with PECO's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

(In millions)	For the Years Ended December 31, 2012	2011	2010	2009	2008
Statement of Operations data:					
Operating revenues	$3,186	$3,720	$5,519	$5,311	$5,567
Operating income	623	655	661	697	699
Net income	381	389	324	353	325
Net income on common stock	377	385	320	349	321

(In millions)	December 31, 2012	2011	2010	2009	2008
Balance Sheet data:					
Current assets	$1,094	$1,243	$1,670	$1,006	$ 819
Property, plant and equipment, net	6,078	5,874	5,620	5,297	5,074
Noncurrent regulatory assets	1,378	1,216	968	1,834	2,597
Other deferred debits and other assets	803	823	727	882	679
Total assets	$9,353	$9,156	$8,985	$9,019	$9,169
Current liabilities	$1,158	$1,145	$1,163	$ 939	$ 981
Long-term debt, including long-term debt to financing trusts	1,831	1,781	2,156	2,405	2,960
Noncurrent regulatory liabilities	538	585	418	317	49
Other deferred credits and other liabilities	2,757	2,620	2,278	2,706	2,910
Preferred securities	87	87	87	87	87
Shareholders' equity	2,982	2,938	2,883	2,565	2,182
Total liabilities and shareholders' equity	$9,353	$9,156	$8,985	$9,019	$9,169

BGE

The selected financial data presented below has been derived from the audited consolidated financial statements of BGE. This data is qualified in its entirety by reference to and should be read in conjunction with BGE's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions)	2012	2011	2010	2009	2008
Statement of Operations data:					
Operating revenues	$2,735	$3,068	$3,541	$3,646	$3,769
Operating income	132	314	350	268	183
Net income	4	136	147	91	52
Net (loss) income on common stock	(9)	123	134	78	39

	December 31,				
(In millions)	2012	2011 (a)	2010 (a)	2009 (a)	2008 (a)
Balance Sheet data:					
Current assets	$ 973	$ 969	$1,012	$1,205	$1,093
Property, plant and equipment, net	5,498	5,132	4,754	4,470	4,290
Noncurrent regulatory assets	522	551	566	602	670
Other deferred debits and other assets	506	551	545	386	231
Total assets	$7,499	$7,203	$6,877	$6,663	$6,284
Current liabilities	$ 973	$ 734	$ 728	$ 753	$1,041
Long-term debt, including long-term debt to financing trusts and variable interest entities	1,969	2,186	2,060	2,141	2,198
Noncurrent regulatory liabilities	214	201	192	188	175
Other deferred credits and other liabilities	1,985	1,781	1,634	1,434	1,125
Preference stock not subject to mandatory redemption	190	190	190	190	190
Shareholders' equity	2,168	2,111	2,073	1,939	1,538
Noncontrolling interest	—	—	—	18	17
Total liabilities and shareholders' equity	$7,499	$7,203	$6,877	$6,663	$6,284

(a) BGE retrospectively reclassified certain regulatory assets and regulatory liabilities to conform to the current year presentation.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Exelon

Executive Overview

Exelon, a utility services holding company, operates through the following principal subsidiaries:

- *Generation,* whose integrated business consists of owned, contracted and investments in electric generating facilities managed through customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Exelon has nine reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and other regions in Generation), ComEd, PECO and BGE. See Note 21 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

Exelon's consolidated financial information includes the results of its four separate operating subsidiary registrants, Generation, ComEd, PECO and BGE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO and BGE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Financial Results. The following consolidated financial results reflect the results of Exelon for year ended December 31, 2012 compared to the same period in 2011. The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012. All amounts presented below are before the impact of income taxes, except as noted.

	The Years Ended December 31,							Favorable (Unfavorable)
	2012						2011	
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	Variance
Operating revenues	$ 14,437	$5,443	$3,186	$2,091	$(1,668)	$23,489	$19,063	$ 4,426
Purchased power and fuel	7,061	2,307	1,375	1,052	(1,638)	10,157	7,267	(2,890)
Revenue net of purchased power and fuel [(a)]	7,376	3,136	1,811	1,039	(30)	13,332	11,796	1,536
Other operating expenses								
Operating and maintenance	5,028	1,345	809	596	183	7,961	5,184	(2,777)
Depreciation and amortization	768	610	217	238	48	1,881	1,347	(534)
Taxes other than income	369	295	162	167	26	1,019	785	(234)
Total other operating expenses	6,165	2,250	1,188	1,001	257	10,861	7,316	(3,545)
Equity in earnings of unconsolidated affiliates	(91)	—	—	—	—	(91)	(1)	(90)
Operating income	1,120	886	623	38	(287)	2,380	4,479	(2,099)
Other income and (deductions)								
Interest expense, net	(301)	(307)	(123)	(111)	(86)	(928)	(726)	(202)
Other, net	239	39	8	19	41	346	203	143
Total other income and (deductions)	(62)	(268)	(115)	(92)	(45)	(582)	(523)	(59)
Income (loss) before income taxes	1,058	618	508	(54)	(332)	1,798	3,956	(2,158)
Income taxes	500	239	127	(23)	(216)	627	1,457	830
Net income (loss)	558	379	381	(31)	(116)	1,171	2,499	(1,328)
Net (loss) income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	(4)	—	4	11	—	11	4	(7)
Net income (loss) on common stock	$ 562	$ 379	$ 377	$ (42)	$ (116)	$ 1,160	$ 2,495	$ (1,335)

(a) The Registrants' evaluate operating performance using the measure of revenue net of purchased power and fuel expense. The Registrants' believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Exelon's net income was $1,160 million for the year ended December 31, 2012 as compared to $2,495 million for the year ended December 31, 2011, and diluted earnings per average common share were $1.42 for the year ended December 31, 2012 as compared to $3.75 for the year ended December 31, 2011.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $1,536 million primarily due to the addition of Constellation's and BGE's financial results. BGE's operating revenue net of purchased power and fuel expense was $1,039 million from March 12, 2012 to December 31, 2012, which included the $113 million impact of the residential customer rate credit in connection with the Merger. Generation's operating revenue net of

purchased power and fuel expense increased by $518 million primarily due to the New England, New York, ERCOT and Other Regions. These regions contributed $729 million and did not previously have a significant impact on Generation's revenue net of purchased power and fuel expense prior to the Merger. Generation's results were also favorably affected by $588 million of other activities, including retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities, and by $83 million in the Mid-Atlantic region also due to the addition of Constellation's operations in 2012. Generation had mark-to-market gains of $515 million in 2012 from economic hedging activities, net of intercompany eliminations, compared to $288 million in mark-to-market losses in 2011. Offsetting these favorable impacts, Generation incurred $1,098 million of amortization expense for the acquired energy contracts, net, recorded at fair value at the merger date. Also, revenue net of purchased power and fuel expenses decreased by $549 million in the Midwest region due to lower capacity revenues, increased nuclear fuel costs and lower realized power prices.

ComEd's operating revenues net of purchased power and fuel expense increased by $115 million primarily as a result of the annual reconciliation of ComEd's distribution revenue requirement pursuant to EIMA, net of lower allowed return on equity, and increased transmission revenue. PECO's operating revenues net of purchased power and fuel expense decreased by $45 million primarily as a result of unfavorable weather and a decline in electric load.

Operating and maintenance expense increased by $2,777 million primarily due to the addition of BGE and Constellation. In addition, Exelon's results were unfavorably affected by the $272 million loss on the sale of three Maryland generating stations, of which $278 million was recorded to operating and maintenance expense. Including Constellation and BGE, labor, other benefits, contracting and materials increased by $1,393 million, pension and non-pension postretirement benefits expense increased by $199 million and Constellation merger and integration costs increased by $226 million. In addition, Exelon incurred $216 million in costs incurred as part of the Maryland order approving the Merger and costs of $195 million associated with a settlement with the FERC in March, 2012, and BGE incurred $71 million of storm costs.

Depreciation and amortization expense increased by $534 million primarily due to higher plant balances resulting from the addition of BGE's and Constellation's plant balances as well as ongoing capital expenditures across the operating companies.

Equity in losses of unconsolidated affiliates increased by $90 million primarily due to the amortization of the basis difference in CENG recorded at fair value at the merger date, partially offset by net income generated from Exelon's equity investment in CENG.

Interest expense increased by $202 million due to an increase in debt obligations as a result of the Merger and an increase in debt issued at Generation and BGE in 2012. Offsetting these unfavorable impacts, interest expense at ComEd and PECO decreased due to a lower outstanding debt during 2012 and lower interest rates on long-term debt.

Exelon's effective income tax rates for the years ended December 31, 2012 and 2011 were 34.9% and 36.8%, respectively. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the years ended December 31, 2012 and 2011, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings

Exelon's adjusted (non-GAAP) operating earnings for the year ended December 31, 2012 were $2,330 million, or $2.85 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,763 million, or $4.16 per diluted share, for the same period in 2011. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2012 as compared to 2011:

	December 31,			
	2012		2011	
(All amounts after tax; in millions, except per share amounts)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income	$1,160	$ 1.42	$2,495	$ 3.75
Mark-to-Market Impact of Economic Hedging Activities [a]	(310)	(0.38)	174	0.27
Unrealized (Gains) Losses Related to NDT Fund Investments [b]	(56)	(0.07)	1	—
Plant Retirements and Divestitures [c]	236	0.29	33	0.05
Asset Retirement Obligation [d]	1	—	16	0.02
Constellation Merger and Integration Costs [e]	257	0.31	46	0.07
Other Acquisition Costs [f]	3	—	5	0.01
Wolf Hollow Acquisition [g]	—	—	(23)	(0.03)
Recovery of Costs Pursuant to ComEd Distribution Rate Case Order [h]	—	—	(17)	(0.03)
Non-Cash Remeasurement of Deferred Income Taxes [i]	(117)	(0.14)	33	0.05
Amortization of Commodity Contract Intangibles [j]	758	0.93	—	—
Amortization of the Fair Value of Certain Debt [k]	(9)	(0.01)	—	—
Maryland Commitments [l]	227	0.28	—	—
FERC Settlement [m]	172	0.21	—	—
Midwest Generation Bankruptcy Charges [n]	8	0.01	—	—
Adjusted (non-GAAP) Operating Earnings	$2,330	$ 2.85	$2,763	$ 4.16

(a) Reflects the impact of (gains) losses for the years ended December 31, 2012 and 2011, respectively, on Generation's economic hedging activities (net of taxes of $200 million and $114 million, respectively). See Note 10 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized (gains) losses for the years ended December 31, 2012 and 2011, respectively, on Generation's NDT fund investments for Non-Regulatory Agreement Units (net of taxes of $(132) million and $(3) million, respectively). See Note 13 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Primarily reflects the impact associated with the sale of three generating stations associated with certain of the regulatory approvals required for the merger for the year ended December 31, 2012 (net of taxes of $106 million). For December 31, 2012 and 2011, also reflects incremental accelerated depreciation associated with the retirement of certain fossil generating

units and compensation for operating two of the units past their planned retirement date under a FERC-approved reliability-must-run rate schedule. See Note 15 of the Combined Notes to Consolidated Financial Statements and "Results of Operations—Generation" for additional detail related to the generating unit retirements.

(d) Reflects the income statement impact for the years ended December 31, 2012 and 2011 primarily related to the increase in Generation's decommissioning obligation for spent nuclear fuel at retired nuclear units (net of taxes of $4 million and $11 million, respectively). Also reflects the reduction in Generation's asset retirement obligation for certain retired fossil-fueled generating stations in 2012 (net of taxes of $(3) million) and the reduction in PECO's asset retirement obligation in 2011 (net of taxes of $(1) million). See Note 13 of the Combined Notes to Consolidated Financial Statements for additional information.

(e) Reflects certain costs incurred in the years ended December 31, 2012 and 2011 (net of taxes of $161 million and $31 million, respectively) associated with the Constellation merger including transaction costs, employee-related expenses (e.g. severance, retirement, relocation and retention bonuses) and integration initiatives. See Note 4 of the Combined Notes to the Consolidated Financial Statements for additional information.

(f) Reflects certain costs incurred in the years ended December 31, 2012 and 2011 associated with various acquisitions (net of taxes of $2 million and $3 million, respectively). See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

(g) Reflects a non-cash bargain purchase gain (negative goodwill) for the year ended December 31, 2011 in connection with the acquisition of Wolf Hollow, net of acquisition costs (net of taxes of $15 million). See Note 4 of the Combined Notes to the Consolidated Financial Statements for additional information.

(h) Reflects a one-time benefit in 2011 to recover previously incurred costs as a result of the May 2011 ICC rate order (net of taxes of $5 million). See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information.

(i) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of the merger in 2012 and as a result of revised estimates of state apportionments in 2011. See Note 12 of the Combined Notes to the Consolidated Financial Statements for additional information.

(j) Reflects the non-cash impact for the year ended December 31, 2012 (net of taxes of $491 million) of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger date. See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information.

(k) Represents the non-cash amortization of certain debt for the year ended December 31, 2012 (net of taxes of $6 million) recorded at fair value at the Constellation merger date expected to be retired in 2013. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information.

(l) Reflects costs incurred for the year ended December 31, 2012 associated with the Constellation merger (net of taxes of $101 million) as part of the Maryland order approving the merger transaction. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

(m) Reflects costs incurred for the year ended December 31, 2012 (net of taxes of $23 million) as part of a settlement with the FERC to resolve a dispute related to Constellation's pre-merger hedging and risk management transactions. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information.

(n) Reflects estimated liabilities for the year ended December 31, 2012 (net of taxes of $5 million) pursuant to the Midwest Generation bankruptcy, primarily related to lease payments under a coal rail car lease and estimated payments for asbestos-related personal injury claims.

As discussed above, Exelon has incurred and will continue to incur costs associated with the Constellation merger, including meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former Constellation businesses into Exelon.

For the year ended December 31, 2012, expense has been recognized for costs incurred to achieve the merger as follows:

	Pre-tax Expense				
	Twelve Months Ended December 31, 2012				
Merger and Integration Costs:	**Generation [a]**	**ComEd**	**PECO**	**BGE [a]**	**Exelon [a]**
Transaction [b]	$ —	$ —	$—	$—	$ 58
Maryland Commitments	35	—	—	139	328
Employee-Related [c]	138	3	11	2	164
Other [d]	167	2	6	7	196
Total	$ 340	$ 5	$ 17	$148	$ 746

(a) For Exelon, Generation and BGE, includes the operations of the acquired businesses from the date of the merger, March 12, 2012, through December 31, 2012.

(b) External, third-party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of the transaction.
(c) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd and BGE established regulatory assets of $21 million and $22 million, respectively; the majority of these costs are expected to be recovered over a five-year period. These costs are not included in the table above.
(d) Costs to integrate Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. ComEd established a regulatory asset of $15 million for certain other merger and integration costs, which are not included in the table above.

As of December 31, 2012, Exelon projects incurring total additional merger-related expenses in 2013 and 2014 of approximately $135 million.

In addition, pursuant to conditions set forth by the MDPSC in its approval of the merger transaction, Generation expects to incur capital expenditures of $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for its competitive energy businesses (expected to be completed in 1 to 2 years) and up to $625 million for development of 285-300 MW of new electric generation facilities in Maryland (expected to be completed over the next ten years). The accounting treatment for the construction costs of the new headquarters building in Baltimore may vary depending on the structure of the transaction.

Exelon's Strategy and Outlook for 2013 and Beyond

Exelon's value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline.

On March 12, 2012, the Exelon and Constellation merger was completed. The merger creates incremental strategic value by matching Exelon's clean generation fleet with Constellation's leading customer-facing platform, as well as creating economies of scale through expansion across the energy value chain. Exelon supports customer switching to alternative electric generation suppliers and the addition of Constellation's competitive retail business provides another outlet for Exelon to grow its business in competitive markets.

Generation is managed as an integrated business and is located in multiple geographic regions, with multiple supply sources and provides various energy commodities through multiple distribution channels. Generation's nuclear, fossil fuel, hydroelectric and renewables strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding its regional and technological footprint. Generation's customer-facing activities enhance its existing customer platform, expand the business across states and develop innovative products for its customers.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. Exelon seeks to leverage its scale and expertise across the utilities platform by standardization and sharing of best practices to achieve improved operational and financial results.

Exelon's financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, and to return value to Exelon's shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

In pursuing its strategies, Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the power markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular, the prices of natural gas and coal, which drive the market prices that Generation's power plants can obtain for their output,

(2) the rate of expansion of subsidized low carbon generation in the markets in which Generation's output is sold, (3) the impacts on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel.

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Since the third quarter of 2011, forward natural gas prices for 2013 and 2014 have declined significantly; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Subsidized Generation. The rate of expansion of subsidized low carbon generation such as wind energy in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have implemented or proposed legislation, regulations or other policies to subsidize generation which thereby would artificially depress wholesale energy and capacity prices. For example, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. The CfD mandates that utilities (including BGE) pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Similarly, in January 2011, New Jersey passed legislation that provides guaranteed cost recovery through a CfD for the development of up to 2,000 MWs of new base load or mid-merit generation, so long as it clears in PJM's capacity market. Three generation developers were chosen for the New Jersey CfD, for which contracts were executed in 2011 by the state's utilities under protest. Similarly, in Illinois, legislation has been debated for over four years that passed in the Senate and is currently being considered in the House which would require consumers to subsidize the development of an Integrated Gasification Combined Cycle plant by purchasing its electricity through 30 year power purchase agreements at prices significantly above market prices. A new version was recently introduced in the current General Assembly but its prospects are unclear at this time.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others are also challenging the selection of the three generation developers in New Jersey state court proceedings and the MDPSC actions in Maryland state court.

As required under their CfDs, two of the New Jersey generator developers and one in Maryland offered and cleared in PJM's capacity market auction held in May 2012. Given the state-required customer subsidy provided under their respective CfDs, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in this auction and may continue to do so in future auctions to the detriment of Exelon's market driven position. PJM's capacity market rules include a Minimum Offer Pricing Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. However, Exelon does not believe that the existing MOPR worked effectively with respect to the abovementioned generator developers. Accordingly, Exelon worked with other market stakeholders, PJM and PJM's independent market monitor to develop a new MOPR that would more effectively preclude such artificial price suppression,

and PJM, after extensive stakeholder consideration, filed its new MOPR seeking FERC approval in December, 2012. On February 5, 2013, the FERC issued a letter finding that PJM's new MOPR filing is deficient and requested PJM provide additional information on several aspects of PJM's MOPR proposal. PJM has 30 days to respond, and a FERC decision is expected within 60 days thereafter. See Note 3 of the Combined Notes to Consolidated Financial Statements for further details of PJM's MOPR.

A continuation of these state efforts, if successful and unabated by an effective MOPR, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish similar programs, which could substantially impair Exelon's market driven position and could have a material effect on Exelon's financial results of operations, financial position and cash flows.

Energy Demand. The continued sluggish economy in the United States has led to a decline in demand for electricity. ComEd is projecting load volumes to remain essentially flat in 2013 compared to 2012, while PECO and BGE are projecting a decline of 0.5% and 2.0%, respectively, in 2013 compared to 2012. The projected declines at PECO and BGE are a result of energy efficiency initiatives, the additional day in 2012 for the leap year and weak economic conditions in their service territories. The demand for electricity has also declined due to significantly milder than normal weather in 2012 and 2011. In addition, energy efficiency and demand response programs will result in decreased demand for energy. See Note 3 of the Combined Notes to Consolidated Financial Statements for further discussion of energy efficiency and demand response programs.

Retail Competition. Generation's retail business competes for customers in a competitive environment which impacts the margins that Generation can earn and the volumes that it is able to serve. Recently, sustained low forward natural gas and power prices and low market volatility have caused retail competitors to aggressively pursue market share, and wholesale generators (including Generation) to use the retail channel to hedge generation output. These factors have negatively impacted overall gross margins and profitability in Generation's business.

Strategic Policy Alignment

Exelon routinely reviews its hedging policy, dividend policies, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's Board of Directors declared the first quarter 2013 dividend of $0.525 per share, and in response to low forward prices and weaker financial expectations, among other factors, Exelon's Board of Directors approved a revised dividend policy going forward. The first quarter dividend is payable on March 8, 2013 to shareholders of record on February 19, 2013. The first quarter dividend is based on Exelon's previous policy of $2.10 per share on an annualized basis, while the new dividend policy contemplates a regular $0.31 per share quarterly dividend beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis). Consistent with past practice, all future quarterly dividends will require approval by Exelon's Board of Directors.

If recent power price volatility and demand trends continue, they could adversely affect the Registrants' ability to fund other discretionary uses of cash such as growth projects and dividends. In addition, economic conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Generation's results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2013 and 2014. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of December 31, 2012, the percentage of expected generation hedged for the major reportable segments was 94%-97%, 62%-65% and 27%-30% for 2013, 2014, and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including sales to ComEd, PECO and BGE to serve their retail load. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal, oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2013 through 2017 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position. ComEd, PECO and BGE mitigate exposure as a result of the regulatory mechanisms that allow them to recover procurement costs from retail customers.

New Growth Opportunities

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. Using proven technologies, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the plan in light of changing market conditions. Decisions to implement uprates at particular nuclear plants, the amount of expenditures to implement the plan, and the actual MWs of additional capacity attributable to the uprate program will be determined on a project-by-project basis in accordance with Exelon's normal project evaluation standards and ultimately will depend on market conditions, economic and policy considerations, and other factors.

Based on recent reviews, the nuclear uprate implementation plan was adjusted during 2012, primarily as a result of market conditions, including low natural gas prices and the continued sluggish economy, resulting in the deferral or cancellation of certain projects. In addition, the ability to implement several projects requires the successful resolution of various technical matters. The resolution of these matters may further affect the timing and amount of the power increases associated

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with the power uprate initiative. Following these reviews, any projects that may be undertaken are expected to be completed by the end of 2021, and may result in between 1,125 and 1,200 MWs of additional capacity at an overnight cost of approximately $3.4 billion in 2013 dollars. Overnight costs do not include financing costs or cost escalation.

Approximately 75% of the planned uprate MWs projects are either complete and in service or in the installation or design and engineering phases across seven nuclear stations including Limerick and Peach Bottom in Pennsylvania and Byron, Braidwood, Dresden, LaSalle and Quad Cities in Illinois. The remaining 25% of uprate MWs, if and when completed, would come from an extended power uprate project at Limerick currently scheduled to begin in 2017. From the program announcement in 2008 through December 31, 2012, Generation has placed in service 310 MWs of nuclear generation through the uprate program at a cost of approximately $810 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's consolidated balance sheets. At December 31, 2012, an additional approximate $310 million has been capitalized to construction work in progress (CWIP) within property, plant and equipment on Exelon's and Generation's consolidated balance sheets, of which approximately $200 million (202 MWs) relates to projects currently in the installation phase. The remaining $110 million (346 MWs) in CWIP relates to projects currently in the design and engineering phase that continue to be evaluated in accordance with Exelon's normal project evaluation standards. The completion of those projects in the design and engineering phase will ultimately depend on market conditions, economic and policy considerations, and other factors. As of December 31, 2012, Generation believes it is more likely than not that all projects in CWIP will ultimately be placed in service. If a project in the design and engineering phase is expected to not be completed as planned, previously capitalized costs would be reversed through earnings as a charge to operating and maintenance expense.

Generation Renewable Development . On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which developed and will build, operate, and maintain the project. The first portion of the project began operations in December 2012, with additional blocks to come online and an expectation of full commercial operation by the end of the third quarter of 2013. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA, approved by the CPUC, with Pacific Gas & Electric Company for the full output of the plant. Upon completion, the facility will add 230 MWs to Generation's renewable generation fleet. Total costs for the facility are expected to be approximately $1.3 billion. Total costs incurred through December 31, 2012 were $679 million. Additionally, Generation constructed and placed into service six wind facilities in 2012, resulting in approximately 400 MWs of additional renewable generation. Total costs for the facilities were approximately $700 million. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Development Project. Exelon and AEP Transmission Holding Company, LLC (AEP) are working collaboratively to develop an extra high-voltage transmission project from the western Ohio border through Indiana to the northern portion of Illinois. Referred to as the Reliability Interregional Transmission Extension (RITE) Line project, the project is expected to strengthen the high-voltage transmission system and improve overall system reliability. RITELine Illinois, LLC (RITELine Illinois) and RITELine Indiana, LLC (RITELine Indiana) have been formed as project companies to develop and own the project. RITELine Illinois will own the transmission assets located in Illinois and is owned 75% by ComEd and 25% by RITELine Transmission Development Company, LLC (RTD). RITELine Indiana will own the transmission assets located in Indiana and is owned by AEP (75%) and RTD (25%). Exelon Transmission Company, LLC and AEP each own 50% of RTD. The total cost of the RITE Line project is expected to be approximately $1.6 billion, with the Illinois portion of the line expected to cost approximately $1.2 billion. The ultimate cost of the line is dependent on a

number of factors, including RTO requirements, state siting requirements, routing of the line, and equipment and commodity costs. Exelon and AEP are pursuing the project for inclusion in PJM's RTEP under yet-to-be finalized planning criteria. The current estimated in-service date is 2019.

On July 18, 2011, RITELine Illinois and RITELine Indiana filed at FERC for incentive rates and a formula rate for the RITE Line project. On October 14, 2011, FERC issued an order on the incentive and formula rate filing. The order grants a base rate of return on common equity of 9.9%, plus a 50 basis point adder for the project being in a RTO and a 100 basis point adder for the risks and challenges of the project, resulting in a total rate of return on common equity of 11.4%. The order grants a hypothetical capital structure of 45% debt and 55% equity until any part of the project enters commercial operations. The order also grants 100% recovery for construction work in progress, 100% recovery for abandonment, if the line is abandoned through no fault of the RITELine developers, and the ability to treat pre-construction costs as a regulatory asset. All incentives, including the abandonment incentive, are contingent on inclusion of the project in the PJM RTEP. The RITELine companies filed for rehearing on several rate of return on common equity issues and argued that the right to collect abandoned costs should not be subject to the project being included in the RTEP. The RITELine companies also made a compliance filing as called for in the October 14, 2011 Order. FERC accepted this filing on March 16, 2012.

Smart Meter and Smart Grid Initiatives.

ComEd's Smart Meter and Smart Grid Investments. On December 5, 2012, the ICC approved ComEd's revised AMI Deployment Plan which includes the planned installation of 4 million electric smart meters. ComEd plans to invest approximately $1.3 billion on smart meters and smart grid under EIMA, including $1.0 billion through the AMI Deployment Plan.

PECO's Smart Meter and Smart Grid Investments. In 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, under which PECO will install more than 1.6 million smart meters. PECO plans to spend up to a total of $595 million and $120 million on its smart meter and smart grid infrastructure respectively, before considering the $200 million SGIG.

BGE Smart Grid Initiative. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million electric and gas smart meters at an expected total cost of approximately $480 million, before considering the $200 million SGIG for smart grid and other related initiatives.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on the utility infrastructure projects.

Liquidity

Exelon annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade rating while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation has a bilateral credit facility with aggregate maximum availability of $0.3 billion.

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. This facility will solely be utilized by Generation to issue letters of credit. See Liquidity and Capital Resources for additional information.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets. The ongoing European debt crisis has contributed to the instability in global credit markets. Further disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2012, approximately 31%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $8.3 billion in aggregate total commitments of which $6.5 billion was available as of December 31, 2012. There were no borrowings under the Registrants' credit facilities as of December 31, 2012. See Note 11 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

Exelon has exposure related to various uncertain tax positions which Exelon manages through planning and implementation of tax planning strategies. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon supports the promulgation of certain environmental regulations by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to their low emission generation portfolio, Generation and CENG will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air Quality. In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a review of the current 2008 ozone NAAQS that is expected to result in a final revised ozone NAAQS sometime in 2014. These updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR required 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Until the U.S. EPA re-issues CSAPR, Exelon cannot determine the impacts of the rule, including any that would impact power prices.

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon has been granted permission by the Court to intervene in support of the rule. A decision by the Court is expected sometime in 2013. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

The cumulative impact of these air regulations could be to require power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO_2 and acid gases, and selective catalytic reduction technology for NO_x. Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS by January 1, 2015. In addition, Keystone already has SCR and Flue-gas desulfurization (FGD) controls in place.

On January 15, 2013, EPA issued a final rule for New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE NESHAP/NSPS). The final rule allows diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but requires units that operate over 15 hours to burn low sulfur fuel and report key engine information. The final rule eliminates after May 2014 the 50 hour exemption for peak shaving and other non-emergency demand response that was included in the proposed rule, and therefore, is not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act, including permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources that became effective January 2, 2011. On April 13, 2012, the U.S. EPA published proposed regulations for NSPS for GHG emissions from new fossil-fueled power plants greater than 25 MW that would require the plants to limit CO_2 emissions. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis. The U.S. EPA is also expected to establish in 2013 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and it is not yet known what the nature and impact of the final regulations will be.

Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On March 28, 2011, the U.S. EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by July 27, 2013. The proposed rule does not require closed cycle cooling (e.g., cooling towers) as the

best technology available, and also provides some flexibility in the use of cost-benefit considerations and site-specific factors. The proposed rule affords the state permitting agency wide discretion to determine the best technology available, which, depending on the site characteristics, could include closed cycle cooling, advanced screen technology at the intake, or retention of the current technology.

It is unknown at this time whether the final regulations will require closed-cycle cooling. The economic viability of Generation's facilities without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost—benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation.

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. The Generation plants that would be affected by the proposed rules are Keystone and Conemaugh in Pennsylvania which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has not announced a target date for finalization of the CCR rules.

See Note 19 of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

Japan Earthquake and Tsunami and the Industry's Response . On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co.

Generation believes its nuclear generating facilities do not have the same operating risks as the Fukushima Daiichi plant because they meet the NRC's requirement that specifies all plants must be able to withstand the most severe natural phenomena historically reported for each plant's surrounding area, with a significant margin for uncertainty. In addition, Generation's plants are not located in significant earthquake zones or in regions where tsunamis are a threat. Generation believes its nuclear generating facilities are able to shut down safely and keep the fuel cooled through multiple redundant systems specifically designed to maintain electric power when electricity is lost from the grid. Further, Generation's nuclear generating facilities also undergo frequent scenario drills to ensure the proper function of the redundant safety protocols.

Since the events in Japan took place, Generation has continued to work with regulators and nuclear industry organizations to understand the events in Japan and apply lessons learned. Early on, the nuclear industry took a number of specific steps to respond, including actions requested by the Institute of Nuclear Power Operations (INPO) to perform tests that verified Generation's emergency equipment is available and functional, conduct walk-downs on its procedures related to critical safety equipment, confirm event response procedures and readiness to protect the spent fuel pool, and verify current qualifications of operators and support staff needed to implement the procedures. Generation has been addressing additional actions requested by INPO for improving and maintaining core and spent fuel pool cooling during an extended loss of power for at least 24 hours.

In April 2011, the NRC named six senior managers and staff to its task force for examining the agency's regulatory requirements, programs, processes, and implementation in light of information from the Fukushima Daiichi site in Japan, following the March 11 earthquake and tsunami (Task Force). On July 12, 2011, the NRC Task Force issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The Task Force's report did not recommend any changes to the existing nuclear licensing process in the United States or changes in the storage of spent nuclear fuel within the plant's spent nuclear fuel pools. During the fourth quarter of 2011, the NRC staff issued its recommendations for prioritizing and implementing the Task Force recommendations and an implementation schedule which was approved by the NRC subject to a number of conditions. The NRC staff confirmed the Task Force's conclusions that none of the findings arising from the Task Force review presented an imminent risk to public health and safety.

In March 2012, the NRC authorized its staff to issue three immediately effective orders to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. In summary, the orders require licensees: (1) to provide sufficient onsite portable equipment and resources to maintain or restore cooling capabilities for the containment, core, and spent fuel pool until offsite equipment is available and have offsite equipment and resources available to sustain cooling functions indefinitely; (2) to improve the venting systems with boiling water reactor Mark I or Mark II containments (or for the Mark II plants, install new systems) that help prevent or mitigate core damage in the event of a serious accident by making the systems accessible and operable in the event of a prolonged station blackout and inadequate cooling; and (3) to install instrumentation to provide a reliable indication of water level in the spent fuel pool.

Additionally, the NRC has issued a detailed information request to every operating commercial nuclear power plant in the United States. The information requested requires: (1) use of the current NRC guidance to reevaluate current seismic and flood risk hazards against the design basis and provide a plan of actions to address vulnerabilities, including risks exceeding the design basis; (2) performance of walk downs to ensure the ability to respond to seismic and external flooding events and provide a corrective action plan to the NRC to address deficiencies; and (3) assessment of the means to provide power for communications equipment during a severe natural event and identify staffing required to implement the emergency plan for an event affecting all units with an extended loss of alternating current power and impeded access to the site. In November 2012, the NRC staff recommended to the NRC the installation of engineered containment filtered venting systems for boiling-water reactors with Mark I and Mark II containment structures. The NRC is currently reviewing the staff recommendations.

Generation has assessed the impacts of the orders and information requests and will continue monitoring the additional recommendations under review by the staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance is expected to be approximately $350 million and $50 million of capital and operating expense, respectively, from 2013 through 2017, as previously anticipated in Generation's planning projections. In addition, Generation estimates incremental costs of $15 to $20 million per unit at eleven Mark I and II units for the installation of filtered vents, if ultimately required by the NRC. Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors, for further discussion of the risk factors.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing, exchange trading, margin requirements, and other transparency requirements. The Dodd-Frank Act, however, also preserves the ability of end users in the energy industry to hedge their risks. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Exelon has determined that it will conduct its commercial business in a manner that does not require registration as a swap dealer or major swap participant. Notwithstanding, there are additional rulemakings that have not yet been issued, including the capital and margin rules, which will further define the scope of the regulations and provide clarity as to the impact on the Registrants' business, as well as to potential new opportunities. Depending on these final rules, the Registrants could be subject to significant new obligations.

The proposed regulations addressing collateral and capital requirements and exchange margin cash postings, when final, could require Generation to increase collateral requirements or cash postings in lieu of letters of credit currently issued to collateralize Swaps. Exelon had previously estimated that it could be required to make up to $1 billion of additional collateral postings under its bilateral credit lines. Given the swap dealer and the major swap participant definitions will not apply to Generation, the actual amount of collateral postings that will be required may be lower than Exelon's previous expectations due to the following factors: (a) the majority of Generation's physical wholesale portfolio does not meet the final CFTC Swap definition; (b) there will be minimal incremental costs associated with Generation's positions that are currently cleared and subject to exchange margin; and (c) Generation will not be a swap dealer or major swap participant and proposed capital requirements applicable to these entities will not apply to Generation.

The actual level of collateral required will depend on many factors, including but not limited to market conditions, the outcome of final margin rules for Swaps, the extent of its trading activity in Swaps, and Generation's credit ratings. Nonetheless, Generation has adequate credit facilities and flexibility in its hedging program to meet its anticipated collateral requirements estimated based on conservative assumptions.

In addition, the new regulations will impose new and ongoing compliance and infrastructure costs on Generation, which may amount to several million dollars per year.

Generation continues to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on its results of operations, cash flows or financial position.

Energy Infrastructure Modernization Act . Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. In addition, as long as ComEd is subject to EIMA, ComEd will fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

ComEd files an annual reconciliation of the revenue requirement in effect in a given year to reflect the actual costs that the ICC determines are prudently and reasonably incurred for such year. Under the terms of EIMA, ComEd's target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program. See 3 of the Combined Notes to Consolidated Financial Statements for additional information.

FERC Ameren Order. In July 2012, FERC issued an order to Ameren Corporation indicating that Ameren had improperly included acquisition premiums/ goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. Ameren has filed for rehearing regarding the July 2012 FERC order. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/ goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

Reliability and Quality of Service Standards. During its 2011 legislative session, the Maryland General Assembly passed legislation:

- directing the MDPSC to enact service quality and reliability regulations by July 1, 2012 relating to the delivery of electricity to retail electric customers,
- increasing existing penalties for failure to meet these and other MDPSC regulations, and
- directing the MDPSC to undertake certain studies addressing utility liability for certain customer damages, electric utility service restoration plans, and modifications to existing revenue decoupling mechanisms for extended service interruptions.

In May 2011, the Governor of Maryland signed this legislation into law. The related new service quality and reliability regulations became effective on May 28, 2012. These regulations could have a material impact on BGE's financial results of operations, cash flows and financial position. BGE did seek recovery of these costs in the current base rate case filed on July 27, 2012.

2012 Maryland Electric and Gas Distribution Rate Case. On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. The requested rate of return on equity in the application is 10.5%. On October, 22, 2012, BGE updated its application to request an increase of $131 million and $45 million to its electric and gas base rates, respectively. The new electric and gas distribution base rates are expected to take effect in late February 2013. BGE cannot predict how much of the requested increases, if any, the MDPSC will approve.

FERC Order No. 1000 Compliance (ComEd, PECO and BGE). In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC removed from all FERC-approved tariffs and agreements a federal right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners including ComEd, PECO and BGE (collectively, the PJM Transmission Owners) submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC's "*Mobile-Sierra*" standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. Although this heightened standard of review should make it more difficult for the FERC or any third party to override the PJM Transmission Owners' right to build such transmission projects, there is risk that the FERC will find that the heightened standard of review does not apply to protect the PJM Transmission Owners rights and/or find that whatever standard is applied has been satisfied. Such a FERC finding could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd's, PECO's and BGE's financial return on new investments in energy transmission facilities.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions with its accounting and disclosure governance committee on a regular basis and provides periodic updates on management decisions to the audit committee of the Exelon board of directors. Management believes that the areas described below require significant judgment in the application of accounting policy or in making estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation must make significant estimates and assumptions in accounting for its obligation to decommission its nuclear generating plants in accordance with the authoritative guidance for AROs. Generation's ARO associated with decommissioning its nuclear units was $4.7 billion at December 31, 2012.

The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios. The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the methodologies and significant estimates and assumptions described as follows:

Decommissioning Cost Studies. Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the costs and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within its industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years.

Cost Escalation Factors. Generation uses cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors, and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal and other costs.

Probabilistic Cash Flow Models. Generation's probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning costs, approaches and timing on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. Probabilities are assigned to alternative decommissioning approaches which assess the likelihood of performing DECON (a method of decommissioning shortly after the cessation of operation in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a LLRW landfill or decontaminated to a level that permits property to be released for unrestricted use), Delayed DECON (similar to the DECON scenario but with a delay to allow for spent fuel to be removed from the site prior to onset of decommissioning activities) or SAFSTOR (a method of decommissioning in which the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated to levels that permit release for unrestricted use generally within 60 years after cessation of operations)

decommissioning. Probabilities assigned to the timing scenarios incorporate the likelihood of continued operation through current license lives or through anticipated license renewals. Generation's probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal, which Generation assumed would begin in 2025 and 2020 in 2012 and 2011, respectively. The change in the SNF acceptance date was based on management's estimates of the amount of time required for the DOE to select a site location and develop the necessary infrastructure. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 19 of the Combined Notes to Consolidated Financial Statements.

License Renewals. Generation assumes a successful 20-year renewal for each of its nuclear generating station licenses, except for Oyster Creek, in determining its nuclear decommissioning ARO. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information on Oyster Creek. Generation has successfully secured 20-year operating license renewal extensions for ten of its nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG), and none of Generation's applications for an operating license extension have been denied. Generation is in various stages of the process of pursuing similar extensions on its remaining nine operating nuclear units. Generation's assumption regarding license extension for ARO determination purposes is based in part on the good current physical condition and high performance of these nuclear units; the favorable status of the ongoing license renewal proceedings with the NRC, and the successful renewals for ten units to date. Generation estimates that the failure to obtain license renewals at any of these nuclear units (assuming all other assumptions remain constant) would increase its ARO on average approximately $250 million per unit as of December 31, 2012. The size of the increase to the ARO for a particular nuclear unit is dependent upon the current stage in its original license term and its specific decommissioning cost estimates. If Generation does not receive license renewal on a particular unit, the increase to the ARO may be mitigated by Generation's ability to delay ultimate decommissioning activities under a SAFSTOR method of decommissioning.

Discount Rates. The probability-weighted estimated future cash flows using these various scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. The accounting guidance required Generation to establish an ARO at fair value at the time of the initial adoption of the current accounting standard. Subsequent to the initial adoption, the ARO is adjusted for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions, as described above.

Under the current accounting framework, the ARO is not required or permitted to be re-measured, from period to period, for changes in the CARFR that occur in isolation. This differs from the accounting requirements for other long-dated obligations, such as pension and other post-employment benefits that are required to be re-measured as and when corresponding discount rates change. If Generation's future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFRs, the obligation would increase from approximately $4.7 billion to approximately $7.5 billion. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon's and Generation's Consolidated Balance Sheets at December 31, 2012 at fair value of approximately $7.2 billion and have an estimated targeted annual pre-tax return of 5.3% to 6.2%.

To illustrate the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO: i) had Generation used the 2011 CARFRs rather than the 2012 CARFRs in performing its third quarter 2012 ARO update, Generation would have reduced the ARO by approximately $50 million as compared to the actual increase to the ARO of $669 million; and ii) if the CARFR used in performing the third quarter 2012 ARO update (which also reflected increases in the amounts and changes to the timing of projected cash flows) was increased or decreased by 100 basis points, the ARO would have increased by $110 million and $1.6 billion, respectively, as compared to the actual increase of $669 million.

ARO Sensitivities. Changes in the assumptions underlying the foregoing items could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions will change as well. As an example, the significant changes in the value of the ARO during 2012 were driven primarily by Generation modifying the assumed timing of the DOE acceptance of SNF for disposal from 2020 to 2025 during the third quarter 2012 annual ARO update. The modification of the assumed DOE acceptance date impacted the calculation of the ARO in isolation as follows; i) the change in the timing of DOE acceptance of SNF increased the total number of years in which decommissioning activities are estimated to occur, by five years on average, thereby increasing the total expected nominal cash flows required to decommission the units; ii) the nominal cash flows were subjected to additional escalation as a result of the extension of the decommissioning period increasing the total estimated costs required to decommission the units; and iii) the escalated cash flows were then discounted at the then current CARFRs which have dramatically decreased in 2012 given the current low interest rate environment. The change in the timing and amount of cash flows as a result of the change in the assumed DOE acceptance date in combination with the significant decrease in the 2012 CARFRs were the primary drivers of the third quarter 2012 ARO update total increase of $669 million.

The following table illustrates the effects of changing certain ARO assumptions, discussed above, while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption		Increase to ARO at December 31, 2012
Cost escalation studies		
Uniform increase in escalation rates of 25 basis points	$	820
Probabilistic cash flow models		
Increase the likelihood of the high-cost scenario by 10 percentage points and decrease the likelihood of the low-cost scenario by 10 percentage points	$	250
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$	360
Increase the likelihood of operating through current license lives by 10 percentage points and decrease the likelihood of operating through anticipated license renewals by 10 percentage points	$	490
Extend the estimated date for DOE acceptance of SNF to 2030	$	700
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with an increase in discount rates of 100 basis points	$	30
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with a decrease in discount rates of 100 basis points	$	1,570

For more information regarding accounting for nuclear decommissioning obligations, see Notes 1 and 13 of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon and ComEd)

As of December 31, 2012, Exelon's and ComEd's carrying amount of goodwill was approximately $2.6 billion, relating to the acquisition of ComEd in 2000 as part of the PECO/Unicom Merger. Under the provisions of the authoritative guidance for goodwill, ComEd is required to perform an assessment for possible impairment of its goodwill at least annually or more frequently if an event occurs, such as a significant negative regulatory outcome, or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Under the authoritative guidance, a reporting unit is an operating segment or operating component and is the level at which goodwill is tested for impairment. In September 2011, the FASB issued authoritative guidance amending existing guidance on the annual assessment of goodwill for impairment. Under the revised

guidance, which became effective January 1, 2012, entities assessing goodwill for impairment have the option of performing a qualitative assessment rather than the quantitative assessment previously required. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors, and entity-specific events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a two-step, fair value based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's business and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

ComEd performed an interim goodwill impairment assessment as of May 31, 2012, as a result of the ICC's final Order (Order) in ComEd's 2011 formula rate proceeding under the EIMA that reduced ComEd's annual revenue requirement being recovered in current rates by $168 million. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. Based on the results of the interim goodwill test performed as of May 31, 2012, the estimated fair value of ComEd would have needed to decrease by more than 10 percent for ComEd to fail the first step of the impairment test.

ComEd performed a qualitative assessment as of November 1, 2012, for its 2012 annual goodwill impairment assessment and while certain factors indicated a reduction in fair value since May 31, 2012, ComEd determined its fair value was not more likely than not less than its carrying value. Therefore, ComEd did not perform a quantitative assessment.

While neither the interim nor the annual assessments indicated an impairment of ComEd's goodwill, a change in management's assumption regarding the outcome of the IRS challenge of Exelon's and ComEd's like-kind exchange income tax position, adverse regulatory actions such as early termination of EIMA or changes in significant assumptions described above could potentially result in a future impairment of ComEd's goodwill, which could be material. ComEd will assess whether its goodwill has been impaired in the first quarter of 2013 in connection with the reassessment of the like-kind exchange position and the associated charge to ComEd's earnings. See Notes 1, 8 and 12 of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon and Generation)

In accordance with the authoritative accounting guidance, the purchase price of an acquired business is generally allocated to the assets acquired and liabilities assumed at their estimated fair values on the date of acquisition. Any unallocated purchase price amount is recognized as goodwill on the balance sheet if it exceeds the estimated fair value and as a bargain purchase gain on the income statement if it is below the estimated fair value. Determining the fair value of assets acquired and

liabilities assumed requires management's judgment, the utilization of independent valuation experts and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Assets and Liabilities (Exelon and Generation)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired. The initial amount recorded represents the fair value of the contract at the time of acquisition, and the balance is amortized over the life of the contract in relation to the present value of the underlying cash flows. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Refer to Note 4—Mergers and Acquisitions and Note 8—Intangible Assets for further discussion.

Impairment of Long-lived Assets (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE evaluate their long-lived assets and asset groups, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. Conditions that could have an adverse impact on the cash flows and fair value of the long-lived assets are deteriorating business climate, including current energy prices and market conditions, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life, among others. Continued declines in natural gas prices have impacted fundamental views of market power prices, which could indicate a potential impairment to the Registrants' long-lived assets and asset groups, which are primarily made up of generating assets. The Registrants regularly monitor their long-lived assets for these circumstances to determine whether or not an impairment evaluation is required.

The review of long-lived assets and asset groups for impairment requires significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power, costs of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could have a significant effect on the consolidated financial statements. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of other groups of assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units and associated intangible contract assets recorded on the balance sheet. The cash flows from the generation units are evaluated at a regional portfolio level with cash flows generated from Generation's customer supply and risk management activities, including cash flows from contracts that are accounted for as intangible contract assets and liabilities recorded on the balance sheet. For ComEd, PECO and BGE, the lowest level of independent cash flows is determined by evaluation of several factors including the ratemaking jurisdiction in which they operate and the type of service or commodity provided. For ComEd, the lowest level of independent cash flows is transmission and distribution and for PECO and BGE, the lowest level of independent cash flows is transmission, distribution and gas.

Impairment may occur when the carrying value of the asset or asset group exceeds the future undiscounted cash flows. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value of the long-lived asset or asset group is dependent upon a market participant's view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates. Events and circumstances frequently do not occur as expected and there will usually be differences between prospective financial information and actual results, and those differences may be material. Accordingly, to the extent that any of the information used in the fair value analysis requires adjustment, the resulting fair market value would be different. As such, the determination of fair value is driven by both internal assumptions as well as information from various public, financial and industry sources. An impairment determination would require the affected Registrant to reduce either the long-lived asset or asset group, including any intangible contract assets and liabilities, and current period earnings by the amount of the impairment.

Generation evaluates unproved gas producing properties at least annually to determine if they are impaired. Impairment for unproved gas property occurs if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience necessitates a valuation allowance.

Exelon holds certain investments in coal-fired plants in Georgia and Texas subject to long-term leases. Exelon determines the investment in these plants by incorporating an estimate of the residual values of the leased assets which equates to the fixed purchase option prices established at the inception of the leases. On an annual basis, Exelon reviews the estimated residual values of these plants to determine if the current estimate of their residual value is lower than the one originally established. In determining the current estimate of the residual value the expectation of future market conditions, including commodity prices, is considered. If the current estimate of the residual value is lower than the residual value established at the inception of the lease and the decline is considered to be other than temporary, a loss will be recognized with a corresponding reduction to the carrying amount of the investment. To date, no such losses have been recognized.

Generation also evaluates its equity method investments, including CENG, to determine whether or not they are impaired based on whether the investment has experienced an other than temporary decline in value. Additionally, if Generation's equity method investments recognize an impairment, Generation would record its proportionate share of that impairment loss through its equity earnings (losses) of unconsolidated affiliates. Generation would also evaluate the investment for an other than temporary decline in value at that time.

See Note 4 of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Generation.

Depreciable Lives of Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. Depreciation of these assets is generally provided over their estimated service lives on a straight-line basis using the composite method. The estimation of service lives requires management judgment regarding the period of time that the assets will be in use. As circumstances warrant, the estimated service lives are reviewed to determine if any changes are needed. Depreciation rates incorporate assumptions on interim retirements based on actual historical retirement experience. To the extent interim retirement patterns change, this could have a significant impact on the amount of depreciation expense recorded in the income statement. Changes to depreciation estimates resulting from a change in the estimated end of service lives could have a

significant impact on the amount of depreciation expense recorded in the income statement. See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant and equipment of the Registrants.

The estimated service lives of the nuclear generating facilities are based on the estimated useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek. While Generation has received license renewals for certain facilities, and has applied for or expects to apply for and obtain approval of license renewals for the remaining facilities, circumstances may arise that would prevent Generation from obtaining additional license renewals. Generation also evaluates every three to five years the estimated service lives of its fossil fuel generating and renewable facilities based on feasibility assessments as well as economic and capital requirements. The estimated service lives of hydroelectric facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the Conowingo and Muddy Run operating licenses. A change in depreciation estimates resulting from Generation's extension or reduction of the estimated service lives could have a significant effect on Generation's results of operations. Generation completed a depreciation rate study during the first quarter of 2010, which resulted in the implementation of new depreciation rates effective January 1, 2010. Constellation completed a depreciation rate study during the fourth quarter of 2010, which resulted in the implementation of new depreciation rates effective during the fourth quarter of 2010.

ComEd is required to file a depreciation rate study at least every five years with the ICC. ComEd filed a depreciation rate study with the ICC in January 2009, which resulted in the implementation of new depreciation rates effective January 1, 2009.

PECO is required to file a depreciation rate study at least every five years with the PAPUC. In April 2010, PECO filed a depreciation rate study with the PAPUC for both its electric and gas assets, which resulted in the implementation of new depreciation rates effective January 1, 2010 for electric transmission assets and January 1, 2011 for electric distribution and gas assets.

The MDPSC does not mandate the frequency or timing of BGE's depreciation studies. In December 2006, BGE filed revised depreciation rates with the MDPSC for both its electric distribution and gas assets. Revisions to depreciation rates from this filing were finalized July 1, 2010.

Defined Benefit Pension and Other Postretirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for substantially all Generation, ComEd, PECO, BGE and BSC employees. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and other postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit pension and other postretirement benefit plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, the anticipated rate of increase of health care costs, Exelon's expected level of contributions to the plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the long-term expected investment rate credited to employees of certain plans, among others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. The impact of assumption

changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. Pension and other postretirement benefit costs attributed to the operating companies are labor costs and are ultimately allocated to projects within the operating companies, some of which are capitalized.

Pension and other postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 14 of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification under the fair value hierarchy in accordance with authoritative guidance.

Expected Rate of Return on Plan Assets. The long-term expected rate of return on plan assets assumption used in calculating pension costs was 7.50%, 8.00% and 8.50% for 2012, 2011 and 2010, respectively. The weighted average expected return on assets assumption used in calculating other postretirement benefit costs was 6.68%, 7.08% and 7.83% in 2012, 2011 and 2010, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. The current year EROA is based on asset allocations from the prior year end. In 2010, Exelon began implementation of a liability driven investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. As a result of this modification, over time, Exelon determined that it will decrease equity investments and increase investments in fixed income securities and alternative investments in order to achieve a balanced portfolio of liability hedging and return-generating assets. The change in the overall investment strategy would tend to lower the expected rate of return on plan assets in future years as compared to the previous strategy. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's asset allocations. Exelon used an EROA of 7.50% and 6.45% to estimate its 2013 pension and other postretirement benefit costs, respectively.

Exelon calculates the expected return on pension and other postretirement benefit plan assets by multiplying the EROA by the MRV of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments to be made during the year. In determining MRV, the authoritative guidance for pensions and postretirement benefits allows the use of either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. For the majority of pension plan assets, Exelon uses a calculated value that adjusts for 20% of the difference between fair value and expected MRV of plan assets. Use of this calculated value approach enables less volatile expected asset returns to be recognized as a component of pension cost from year to year. For other postretirement benefit plan assets and certain pension plan assets, Exelon uses fair value to calculate the MRV.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across the Registrants' pension and other postretirement benefit plans for the year ended December 31, 2012 were 12.8% and 12.5%, respectively, compared to an expected long-term return assumption of 7.50% and 6.68%, respectively.

Discount Rate. The discount rates used to determine the pension and other postretirement benefit obligations were 3.92% and 4.00%, respectively, at December 31, 2012. The discount rates at December 31, 2012 represent weighted-average rates for both legacy Exelon and Constellation pension and other postretirement benefit plans. At December 31, 2012 and 2011, the discount rates were determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated

distributions under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

The discount rate assumptions used to determine the obligation at year end are used to determine the cost for the following year. Exelon will use discount rates of 3.92% and 4.00% to estimate its 2013 pension and other postretirement benefit costs, respectively.

Health Care Reform Legislation. In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers. One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer's postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, the Registrants were required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. Additionally, as a result of this deductibility change for employers and other Health Care Reform provisions that impact the federal prescription drug subsidy options provided to employers, Exelon changed the manner in which it will receive prescription drug subsidies beginning in 2013.

The Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Effective in 2002, Constellation amended its other postretirement benefit plans for all subsidiaries other than Nine Mile Point by capping retiree medical coverage for future retirees who were under the age of 55 on January 1, 2002 at 2002 levels. Therefore, the excise tax is not expected to have a material impact on the legacy Constellation other postretirement benefit plans. However, certain key assumptions are required to estimate the impact of the excise tax on the other postretirement obligation for legacy Exelon plans, including projected inflation rates (based on the CPI) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

Health Care Cost Trend Rate. Assumed health care cost trend rates have a significant effect on the costs reported for Exelon's other postretirement benefit plans. Accounting guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty, particularly when considering potential impacts of the 2010 Health Care Reform Acts. Exelon assumed an initial health care cost trend rate of 6.50% at December 31, 2012, decreasing to an ultimate health care cost trend rate of 5.00% in 2017.

Sensitivity to Changes in Key Assumptions. The following tables illustrate the effects of changing certain of the actuarial assumptions discussed above, while holding all other assumptions constant (dollars in millions):

Actuarial Assumption	Change in Assumption	Pension	Other Postretirement Benefits	Total
Change in 2012 cost:				
Discount rate [(a)]	0.5%	$ (61)	$ (26)	$ (87)
	(0.5%)	60	29	89
EROA	0.5%	(66)	(9)	(75)
	(0.5%)	66	9	75
Health care cost trend rate	1.00%	N/A	81	81
	(1.00%)	N/A	(56)	(56)
Change in benefit obligation at December 31, 2012:				
Discount rate [(a)]	0.5%	(987)	(340)	(1,327)
	(0.5%)	1,094	367	1,461
Health care cost trend rate	1.00%	N/A	845	845
	(1.00%)	N/A	(569)	(569)

(a) In general, the discount rate will have a larger impact on the pension and other postretirement benefit cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon implemented a liability-driven investment strategy for a portion of its pension asset portfolio in 2010. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

Average Remaining Service Period. For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants' average remaining service periods. The average remaining service period of defined benefit pension plan participants was 11.9 years, 12.1 years and 12.4 years for the years ended December 31, 2012, 2011 and 2010, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants' average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants' average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 8.9 years, 6.6 years and 6.8 years for the years ended December 31, 2012, 2011 and 2010, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 10.1 years, 8.7 years and 9.0 years for the years ended December 31, 2012, 2011 and 2010, respectively.

Regulatory Accounting (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE account for their regulated electric and gas operations in accordance with the authoritative guidance for accounting for certain types of regulations, which requires Exelon, ComEd, PECO and BGE to reflect the effects of cost-based rate regulation in their financial statements. This guidance is applicable to entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) a reasonable expectation that rates are set at levels that will recover the entities costs from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to

customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2012, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of those operations no longer meets the criteria of this guidance, Exelon, ComEd, PECO and BGE would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and could be material. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon, ComEd, PECO and BGE.

For each regulatory jurisdiction in which they conduct business, Exelon, ComEd, PECO and BGE assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs in ComEd's, PECO's and BGE's jurisdictions, and factors such as changes in applicable regulatory and political environments. Furthermore, Exelon, ComEd, PECO and BGE make other judgments related to the financial statement impact of their regulatory environments, such as the types of adjustments to rate base that will be acceptable to regulatory bodies, if any, to which costs will be recoverable through rates. Refer to the revenue recognition discussion below for additional information on the annual revenue reconciliations associated with ComEd's distribution formula rate tariff, pursuant to EIMA, and FERC-approved transmission formula rate tariffs for ComEd and BGE. Additionally, estimates are made in accordance with the authoritative guidance for contingencies as to the amount of revenues billed under certain regulatory orders that may ultimately be refunded to customers upon finalization of applicable regulatory or judicial processes. These assessments are based, to the extent possible, on past relevant experience with regulatory bodies in ComEd's, PECO's and BGE's jurisdictions, known circumstances specific to a particular matter and hearings held with the applicable regulatory body. If the assessments and estimates made by Exelon, ComEd, PECO and BGE are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Accounting for Derivative Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants utilize derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy-related products marketed and purchased. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd has a financial swap contract with Generation that extends into 2013 and floating-to-fixed energy swaps with several unaffiliated suppliers that extend into 2032. PECO has entered into derivative natural gas contracts to hedge its long-term price risk in the natural gas market. PECO has also entered into derivative contracts to procure electric supply through a competitive RFP process as outlined in its PAPUC-approved DSP Program. BGE has also entered into derivative contracts to procure electric supply through a competitive auction process as outlined in its MDPSC-approved SOS Program. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes. The Registrants' derivative activities are in accordance with Exelon's Risk Management Policy (RMP). See Note 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether or not a contract qualifies as a derivative under this guidance requires that management exercise significant judgment, including assessing the market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. Further, interpretive guidance related to the authoritative literature continues to evolve, including how it applies to energy and energy-related products. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance related to derivatives, could result in previously excluded contracts being subject to the provisions of the authoritative derivative guidance. Generation has determined that contracts to purchase uranium, exchange traded contracts to purchase and sell capacity in certain ISO's, certain emission products and RECs do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement and neither the uranium, certain capacity, emission nor the REC markets are sufficiently liquid to conclude that physical forward contracts are readily convertible to cash. If these markets do become sufficiently liquid in the future and Generation would be required to account for these contracts as derivative instruments, the fair value of these contracts would be accounted for consistent with Generation's other derivative instruments. In this case, if market prices differ from the underlying prices of the contracts, Generation would be required to record mark-to-market gains or losses, which may have a significant impact to Exelon's and Generation's financial positions and results of operations.

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, the normal purchases and normal sales exception. Further, derivatives that qualify and are designated for hedge accounting are classified as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all economic hedges for commodities are recorded at fair value through earnings for the combined company. For economic hedges that are not designated for hedge accounting and for energy-related derivatives entered into for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings each period except for ComEd, PECO and BGE, in which changes in the fair value each period are recorded as a regulatory asset or liability.

Normal Purchases and Normal Sales Exception. Determining whether a contract qualifies for the normal purchases and normal sales exception requires that management exercise judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and is not financially settled on a net basis. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale

markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated as normal purchases and normal sales and are thus not required to be recorded at fair value, but rather on an accrual basis of accounting. The contracts that ComEd has entered into with Generation and other suppliers as part of ComEd's energy procurement process, PECO's full requirement contracts and block contracts under the PAPUC-approved DSP program, most of PECO's natural gas supply agreements and all of BGE's full requirement contracts and natural gas supply agreements that are derivatives qualify for the normal purchases and normal sales exception. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the scope exceptions, the fair value of the related contract would be recorded on the balance sheet and immediately recognized through earnings at Generation or offset by a regulatory asset or liability at ComEd, PECO and BGE. Thereafter, future changes in fair value would be recorded in the balance sheet and recognized through earnings at Generation. Triggering events that could result in a contract's loss of the normal purchase and normal sale designation, because it is no longer probable that the contract will result in physical delivery, include changes in business requirements, changes in counterparty credit and financial rather than physical contract settlements.

Commodity Contracts. Identification of a commodity contract as an economic hedge requires Generation to determine that the contract is in accordance with the RMP and the forecasted future transaction is probable. Generation reassesses its economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

As a part of accounting for derivatives, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. In accordance with the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain non-exchange-based derivatives valued using indicative price quotations available through brokers or over-the-counter, on-line exchanges are categorized in Level 2. These price quotations reflect the average of the bid-ask mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The Registrant's non-exchange-based derivatives are traded predominately at liquid trading points. The remainder of non-exchange-based derivative contracts is valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, and assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For non-exchange-based derivatives that trade in liquid markets, such as generic forwards, swaps and options, the model inputs are generally observable. Such instruments are categorized in Level 2. For non-exchange-based derivatives that trade in less liquid markets with limited pricing information, such as the financial swap contract between Generation and ComEd, the model inputs generally would include both observable and unobservable inputs. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of credit and nonperformance risk to date have generally not been material to the financial statements.

Interest Rate Derivative Instruments. The Registrants may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve the targeted level of variable-rate debt as a percent of total debt. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings and floating to fixed swaps for project financing. In addition, Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the economic hedge and proprietary trading activity is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or change in market interest rates. The fair value of the agreements is calculated by discounting the future net cash flows to the present value based on the terms and conditions of the agreements and the forward interest rate curves. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Notes 9 and 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation (Exelon, Generation, ComEd, PECO and BGE)

Significant management judgment is required in determining the Registrants' provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of unrecognized tax benefits to be recorded in the Registrants' consolidated financial statements.

The Registrants evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and their intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. The Registrants also assess their ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. The Registrants record valuation allowances for deferred tax assets when the Registrants conclude it is more-likely-than-not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2012 and 2011 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Loss Contingencies (Exelon, Generation, ComEd, PECO and BGE)

In the preparation of their financial statements, the Registrants make judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amounts recorded may differ from the actual expense incurred when the uncertainty is resolved. The estimates that the Registrants make in accounting for loss contingencies and the actual results that they record upon the ultimate resolution of these uncertainties could have a significant effect on their consolidated financial statements.

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at ComEd, PECO and BGE to determine future remediation requirements and estimates are adjusted accordingly. In addition, periodic reviews are performed at Generation to assess the adequacy of its environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant effect on the Registrants' results of operations, financial position and cash flows. See Note 19 of the Combined Notes to Consolidated Financial Statements for further information.

Other, Including Personal Injury Claims. The Registrants are self-insured for general liability, automotive liability, workers' compensation, and personal injury claims to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. The Registrants have reserves for both open claims asserted and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible state and national legislative measures could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material effect on the Registrants' results of operations, financial position and cash flows.

Revenue Recognition (Exelon, Generation, ComEd, PECO and BGE)

Revenues related to the sale of energy are recorded when service is rendered or energy is delivered to customers. The determination of Generation's, ComEd's, PECO's and BGE's retail energy sales to individual customers, however, is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases in volumes delivered to the utilities' customers and favorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, volumes may fluctuate monthly as a result of customers electing to use an alternate supplier, which could be significant to the calculation of unbilled revenue since unbilled commodity receivables are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date would also have an effect on the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

ComEd's distribution formula rate tariff, pursuant to EIMA, provides for annual reconciliations to the distribution revenue requirement. As of the balance sheet dates, ComEd has recorded its best estimates of the distribution revenue impact resulting from changes in rates that ComEd believes are probable of approval by the ICC in accordance with the formula rate mechanism. Estimates are based

upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be impacted by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

ComEd's and BGE's transmission formula rate tariffs, pursuant to FERC, provide for annual reconciliations to the transmission revenue requirements. As of the balance sheet dates, ComEd and BGE have recorded the best estimate of their respective transmission revenue impact resulting from changes in rates that ComEd and BGE believe are probable of approval by FERC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be impacted by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliations can be impacted by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

The determination of Generation's energy sales, excluding the retail business, is based on estimated amounts delivered as well as fixed quantity sales. At the end of each month, amounts of energy delivered to customers during the month are estimated and the corresponding unbilled revenue is recorded. Increases in volumes delivered to the wholesale customers in the period, as well as price, would increase unbilled revenue.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on historical specific customer payment experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 5 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2012, 2011 and 2010 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) on Common Stock by Business Segment

	2012 [a]	2011	Favorable (unfavorable) 2012 vs. 2011 variance	2010	Favorable (unfavorable) 2011 vs. 2010 variance
Exelon	$1,160	$2,495	$ (1,335)	$2,563	$ (68)
Generation	558	1,771	(1,213)	1,972	(201)
ComEd	379	416	(37)	337	79
PECO	381	389	(8)	324	65
BGE	(9)	123	(132)	134	(11)

(a) For BGE, reflects BGE's operations for the year ended December 31, 2012. For Exelon and Generation, includes the operations of the Constellation and BGE from the date of the merger, March 12, 2012, through December 31, 2012.

Results of Operations—Generation

	2012 [b]	2011	Favorable (unfavorable) 2012 vs. 2011 variance	2010	Favorable (unfavorable) 2011 vs. 2010 variance
Operating revenues	$14,437	$10,447	$ 3,990	$10,025	$ 422
Purchased power and fuel expense	7,061	3,589	(3,472)	3,463	(126)
Revenue net of purchased power and fuel expense [a]	7,376	6,858	518	6,562	296
Other operating expenses					
Operating and maintenance	5,028	3,148	(1,880)	2,812	(336)
Depreciation and amortization	768	570	(198)	474	(96)
Taxes other than income	369	264	(105)	230	(34)
Total other operating expenses	6,165	3,982	(2,183)	3,516	(466)
Equity in losses of unconsolidated affiliates	(91)	(1)	(90)	—	(1)
Operating income	1,120	2,875	(1,755)	3,046	(171)
Other income and (deductions)					
Interest expense	(301)	(170)	(131)	(153)	(17)
Other, net	239	122	117	257	(135)
Total other income and (deductions)	(62)	(48)	(14)	104	(152)
Income before income taxes	1,058	2,827	(1,769)	3,150	(323)
Income taxes	500	1,056	556	1,178	122
Net income	558	1,771	(1,213)	1,972	(201)
Net loss attributable to noncontrolling interest	(4)	—	(4)	—	—
Net income on common stock	$ 562	$ 1,771	$ (1,209)	$ 1,972	$ (201)

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b) Includes the operations of Constellation from the date of the merger, March 12, 2012, through December 31, 2012.

Net Income

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Generation's net income decreased compared to the same period in 2011 primarily due to higher operating expenses, the loss on the sale of Brandon Shores, Wagner and C.P. Crane (collectively Maryland generating stations) and the amortization of acquired energy contracts recorded at fair value at the merger date; offset by higher revenues, net of purchased power and fuel expense and favorable NDT fund performance. The increase in operating expenses was due to the addition of Constellation's financial results from March 12, 2012, costs related to a 2012 settlement with FERC and transaction and employee-related severance costs associated with the merger. The increase in revenues, net of purchased power and fuel expense was also primarily due to the merger. See Note 4 for additional information regarding the loss on the sale of three Maryland generating stations.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. Generation's net income decreased compared to the same period in 2010 primarily due to mark-to-market losses on economic hedging activities and higher operating and maintenance expenses. Generation's 2011 results were further affected by increased nuclear fuel costs, less favorable NDT fund performance in 2011 and higher nuclear refueling outage costs associated with the increased number of refueling outage days in 2011. These unfavorable impacts were partially offset by higher revenues due to the expiration of the PECO PPA on December 31, 2010 and favorable market and portfolio conditions in the ERCOT region.

Revenue Net of Purchased Power and Fuel Expense

Generation's six reportable segments are based on the geographic location of its assets, and are largely representative of the footprints of an ISO/RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the entire United States footprint of MISO, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
    - South represents operations in the FRCC and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

- West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
- Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, energy efficiency and demand response, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems. Further, the following activities are not allocated to a region, and are reported in Other: compensation under the reliability-must-run rate schedule; results of operations from the Maryland Clean-Coal assets sold in Q4 2012; unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements.

For the year ended December 31, 2012 compared to 2011 and 2011 compared to 2010, Generation's revenue net of purchased power and fuel expense by region were as follows:

			2012 vs. 2011			2011 vs. 2010	
	2012 [a]	2011	Variance	% Change	2010	Variance	% Change
Mid-Atlantic [b] [f]	$3,433	$3,350	$ 83	2.5%	$2,501	$ 849	33.9%
Midwest [c]	2,998	3,547	(549)	(15.5)%	4,081	(534)	(13.1)%
New England	196	9	187	n.m.	11	(2)	n.m.
New York [f]	76	—	76	n.m.	—	—	n.m.
ERCOT	405	84	321	n.m.	(65)	149	n.m.
Other Regions [d]	131	(14)	145	n.m.	(66)	52	n.m.
Total electric revenue net of purchased power and fuel expense	$7,239	$6,976	$ 263	3.8%	$6,462	$ 514	8.0%
Proprietary Trading	(14)	24	(38)	n.m.	27	(3)	(11.1)%
Mark-to-market gains (losses)	515	(288)	803	n.m.	86	(374)	n.m.
Other [e]	(364)	146	(510)	n.m.	(13)	159	n.m.
Total revenue net of purchased power and fuel expense	$7,376	$6,858	$ 518	7.6%	$6,562	$ 296	4.5%

(a) Includes results for Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at merger date of $1,098 million pre-tax for the twelve months ended December 31, 2012.
(f) Includes $487 million and $306 million of purchase power from CENG in the Mid-Atlantic and New York regions, respectively. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's supply sources by region are summarized below:

Supply source (GWh)	2012 [a]	2011	2012 vs. 2011 Variance	2012 vs. 2011 % Change	2010	2011 vs. 2010 Variance	2011 vs. 2010 % Change
Nuclear generation [b]							
Mid-Atlantic	47,337	47,287	50	0.1%	47,517	(230)	(0.5)%
Midwest	92,525	92,010	515	0.6%	92,493	(483)	(0.5)%
	139,862	139,297	565	0.4%	140,010	(713)	(0.5)%
Fossil and renewables [b]							
Mid-Atlantic [b][d]	8,808	7,572	1,236	16.3%	9,426	(1,854)	(19.7)%
Midwest	971	596	375	62.9%	68	528	n.m.
New England	9,965	8	9,957	n.m.	10	(2)	(20.0)%
ERCOT [e]	6,182	2,030	4,152	n.m.	1,129	901	79.8%
Other Regions [f]	5,913	1,432	4,481	n.m.	84	1,348	n.m.
	31,839	11,638	20,201	n.m.	10,717	921	8.6%
Purchased power							
Mid-Atlantic [c]	20,830	2,898	17,932	n.m.	1,918	980	51.1%
Midwest	9,805	5,970	3,835	64.2%	7,032	(1,062)	(15.1)%
New England	9,273	—	9,273	n.m.	—	—	n.m.
New York [c]	11,457	—	11,457	n.m.	—	—	n.m.
ERCOT [e]	23,302	7,537	15,765	n.m.	9,494	(1,957)	(20.6)%
Other Regions [f]	17,327	2,503	14,824	n.m.	2,618	(115)	(4.4)%
	91,994	18,908	73,086	n.m.	21,062	(2,154)	(10.2)%
Total supply by region [g]							
Mid-Atlantic [h]	76,975	57,757	19,218	33.3%	58,861	(1,104)	(1.9)%
Midwest [i]	103,301	98,576	4,725	4.8%	99,593	(1,017)	(1.0)%
New England	19,238	8	19,230	n.m.	10	(2)	n.m.
New York	11,457	—	11,457	n.m.	—	—	n.m.
ERCOT	29,484	9,567	19,917	n.m.	10,623	(1,056)	(9.9)%
Other Regions [f]	23,240	3,935	19,305	n.m.	2,702	1,233	45.6%
Total supply	263,695	169,843	93,852	55.3%	171,789	(1,946)	(1.1)%

(a) Includes results for Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and does not include ownership through equity method investments (e.g. CENG).
(c) Purchased power includes physical volumes of 9,925 GWh in the Mid-Atlantic and 9,350 GWh in New York as a result of the PPA with CENG for the year ended December 31, 2012.
(d) Excludes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in Q4 as a result of the Exelon and Constellation merger.
(e) Generation from Wolf Hollow is included in purchased power through the acquisition date of August 24, 2011, and included within Fossil and Renewables subsequent to the acquisition date.
(f) Other Regions includes South, West and Canada, which are not considered individually significant.
(g) Excludes physical proprietary trading volumes of 12,958 GWh, 5,742 GWh and 3,625 GWh for the years ended December 31, 2012, 2011 and 2010 respectively.
(h) Includes sales to PECO through the competitive procurement process of 7,762 GWh, 7,041 GWh, and 42,003 GWh for the years ended December 31, 2012, 2011 and 2010 respectively. Sales to BGE of 3,766 GWh were included for the year ended December 31, 2012.
(i) Includes sales to ComEd under the RFP procurement of 4,152 GWh, 4,731 GWh and 8,218 GWh for the years ended December 31, 2012, 2011 and 2010 respectively.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the year ended December 31, 2012 as compared to the same period in 2011 and 2011 as compared to the same period in 2010.

$/MWh	2012 [a]	2011	2012 vs. 2011 % Change	2010	2011 vs. 2010 % Change
Mid-Atlantic [b]	$44.60	$58.00	(23.1)%	$ 42.48	36.5%
Midwest [c]	29.02	35.99	(19.4)%	40.98	(12.2)%
New England	10.19	n.m.	n.m.	—	n.m.
New York	6.63	n.m.	n.m.	—	n.m.
ERCOT	13.74	8.78	56.5%	(6.24)	n.m.
Other Regions [d]	5.64	(3.56)	n.m.	(23.97)	85.1%
Electric revenue net of purchased power and fuel expense per MWh [e][f]	$27.45	$41.07	(33.2)%	$ 37.62	9.2%

(a) Includes financial results for Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes sales to PECO of $536 million (7,762 GWh), $508 million (7,041 GWh) and $2,091 million (42,003 GWh) for the years ended December 31, 2012, 2011 and 2010, respectively. Sales to BGE of $322 million (3,766 GWH) were included for the year ended December 31, 2012. Excludes compensation under the reliability-must-run rate schedule and the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in Q4 2012 as a result of the merger.
(c) Includes sales to ComEd of $162 million (4,152 GWh), $179 million (4,731 GWh) and $288 million (8,218 GWhs) and settlements of the ComEd swap of $627 million, $474 million and $385 million for years ended December 31, 2012, 2011 and 2010, respectively.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Revenue net of purchased power and fuel expense per MWh represents the average margin per MWh of electricity sold during the years ended December 31, 2012, 2011 and 2010, respectively, and excludes the mark-to-market impact of Generation's economic hedging activities.
(f) Excludes retail gas activity, proprietary trading portfolio activity, compensation under the reliability-must-run rate schedule and fuel sales. Also excludes results from energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, excludes the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in Q4 2012 as a result of the Exelon and Constellation merger. Also excludes amortization of intangible assets relating to commodity contracts recorded at fair value at the merger date.

Mid-Atlantic

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $83 million was primarily due to the addition of Constellation in 2012 and higher capacity revenues, partially offset by lower realized power prices and increased nuclear fuel costs.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 . The $849 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to increased margins on the volumes previously sold under Generation's PPA with PECO, which expired on December 31, 2010, partially offset by increased nuclear fuel costs.

Midwest

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The decrease in revenue net of purchased power and fuel expense in the Midwest of $549 million was primarily due to lower capacity revenues, increased nuclear fuel costs, and lower realized power prices, partially offset by decreased congestion costs.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 . The $534 million decrease in revenue net of purchased power and fuel expense in the Midwest was primarily due to

decreased realized margins in 2011 for the volumes previously sold by Generation under the 2006 ComEd auction contracts and increased nuclear fuel costs. These decreases were partially offset by increased capacity revenues, favorable settlements under the ComEd swap and the additional revenue following the acquisition of Exelon Wind in December 2010.

New England

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The $187 million increase in revenue net of purchased power and fuel expense in New England was as a result of the Constellation merger. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

New York

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $76 million increase in revenue net of purchased power and fuel expense in New York was as a result of the Constellation merger. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

ERCOT

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $321 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the Constellation merger, partially offset by a decrease in revenue net of purchased power and fuel expense in the legacy Generation ERCOT portfolio driven by the performance of Generation's generating units during extreme weather events that occurred in Texas in February and August 2011.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 . The $149 million increase in revenue net of purchased power and fuel expense in the ERCOT was primarily driven by the performance of Generation's generating units during extreme weather events that occurred in Texas in February and August 2011.

Other Regions

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $145 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the Constellation merger.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The $52 million increase in revenue net of purchased power and fuel expense in Other Regions was due to the impact of additional revenue from the acquisition of Exelon Wind in December 2010, as well as higher margins due to overall favourable market conditions.

Mark-to-market

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $515 million in 2012 compared to losses of $288 million in 2011. See Notes 7 and 8 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 . Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market losses on economic hedging activities were $288 million in 2011 compared to gains of $86 million in 2010. See Notes 7 and 8 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $510 million decrease in other revenue net of purchased power and fuel was primarily due to the amortization of the acquired energy contracts recorded at fair value at the merger date. This decrease was partially offset by results from activities acquired as part of the merger including retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, other revenue net of purchased power and fuel includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in Q4 as a result of the Exelon and Constellation merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 . The $159 million increase in other revenue net of purchased power and fuel was primarily due the impacts of the impairment charge of certain emissions allowances recognized in 2010, additional other wholesale fuel sales in 2011 as well as compensation under the reliability-must-run rate schedule further described in Note 15 of the Combined Notes to Consolidated Financial Statements.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for 2012, as compared to 2011 and 2010, for the Exelon-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	2012	2011	2010
Nuclear fleet capacity factor [(a)]	92.7%	93.3%	93.9%
Nuclear fleet production cost per MWh [(a)]	$19.50	$18.86	$17.31

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC, and CENG's nuclear facilities, which are operated by CENG. Reflects ownership percentage of stations operated by Exelon.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of non-refueling outage days, partially offset by a lower number of planned refueling outage days in 2012. For 2012 and 2011, planned refueling outage days totaled 274 and 283, respectively, and non-refueling outage days totaled 73 and 52, respectively. Higher nuclear fuel costs resulted in a higher production cost per MWh during 2012 as compared to 2011.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 . The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of planned refueling outage days. For 2011 and 2010, planned refueling outage days totaled 283 and 261, respectively. Lower generation, higher nuclear fuel costs and higher plant operating and maintenance costs resulted in a higher production cost per MWh during 2011 as compared to 2010.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2012 compared to 2011, consisted of the following:

	Increase (Decrease)
Labor, other benefits, contracting and materials	$ 845
Loss on the sale of Maryland Clean Coal assets [(a)]	278
FERC settlement [(b)]	195
Constellation merger and integration costs	182
Corporate allocations [(c)]	175
Pension and non-pension postretirement benefits expense	76
Maryland commitments [(d)]	35
Nuclear refueling outage costs, including the co-owned Salem plant [(e)]	(52)
Other	146
Increase in operating and maintenance expense	$ 1,880

(a) Represents expense recorded during the third quarter of 2012 due to the reduction in book value. Upon completion of the November 30, 2012 transaction, Generation recorded a $6 million gain within Other, net in its Consolidated Statements of Operations and Comprehensive Income. The net loss on the sale of the Maryland Clean Coal assets was $272 million. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation's prior period hedging and risk management transactions.
(c) Reflects an increased share of corporate allocated costs due to the merger.
(d) Reflects costs incurred as part of the Maryland order approving the merger.
(e) Reflects the impact of decreased planned refueling outages during 2012.

The changes in operating and maintenance expense for 2011 compared to 2010, consisted of the following:

	Increase (Decrease)
Labor, other benefits, contracting and materials	$ 113
Nuclear refueling outage costs, including the co-owned Salem Plant [(a)]	74
Exelon Wind [(b)]	39
Asset retirement obligation reduction [(c)]	28
2010 nuclear insurance credit [(d)]	20
Corporate allocations [(e)]	19
Acquisition costs [(f)]	14
Other [(g)]	29
Increase in operating and maintenance expense	$ 336

(a) Reflects the impact of increased planned refueling outages during 2011.
(b) Includes $30 million in 2011 associated with labor, other benefits, contracting and materials at Exelon Wind.
(c) Reflects an increase in Generation's decommissioning obligation for spent fuel at Zion station. See Note 13 of the Combined Notes to Consolidated Financial Statements for further information.
(d) Reflects the impact of the return of property and business interruption insurance premiums in 2010. No premiums were returned for 2011.

(e) Primarily reflects increased lobbying costs related to EPA and competitive market matters.
(f) Reflects increase in certain costs associated with the acquisitions of Constellation, Exelon Wind, Wolf Hollow and Antelope Valley incurred in 2011. See Note 4 of the Combined Notes to Consolidated Financial Statements for further information.
(g) Includes additional environmental remediation costs recorded during 2011.

Depreciation and Amortization

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities; and capital additions and other upgrades to legacy plants.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 . The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the acquisition of Exelon Wind, capital additions and other upgrades to existing facilities. Higher plant balances resulted in an increase in depreciation and amortization expense of $61 million. The remaining increase in depreciation and amortization expense was due to the impact of increases in asset retirement costs (ARC) for Generation's nuclear generating facilities.

Taxes Other Than Income

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The increase was primarily due to the addition of Constellation's financial results in 2012.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 . The increase was primarily due to increased gross receipt taxes related to retail sales in the Mid-Atlantic region. These gross receipt taxes are recovered in revenue, and as a result, have no impact to Generation's results of operations.

Equity in Losses of Unconsolidated Affiliates

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . Equity in losses of unconsolidated affiliates in 2012 primarily reflected $172 million related to the amortization of the basis difference in CENG recorded at fair value at the merger date, partially offset by $73 million of net income generated from Exelon's equity investment in CENG.

Interest Expense

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 . The increase in interest expense is primarily due to debt issuances in 2010, further described in Note 11 of the Combined Notes to Consolidated Financial Statements. The increase in long-term debt resulted in higher interest expense of approximately $27 million.

Other, Net

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The increase in other, net primarily reflects net realized and unrealized gains related to the NDT funds of Generation's Non-Regulatory Agreement Units compared to net realized and unrealized losses in 2011, as described in the table below. Additionally, the increase reflects $117 million and $18 million of income in 2012 and 2011, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units, $85 million of credit facility termination fees

recorded in 2012, a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow and the impact of a $32 million one-time interest income from the NDT fund special transfer tax deduction in 2011.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 . The decrease in other, net primarily reflects net unrealized losses in 2011 related to the NDT funds of Generation's Non-Regulatory Agreement Units compared to net unrealized gains in 2010, as described in the table below. Additionally, the decrease reflects the contractual elimination of $18 million of income tax expense associated with the NDT funds of the Regulatory Agreement Units in 2011 compared to the contractual elimination of $96 million of income tax expense in 2010. These decreases are partially offset by the $32 million impact of one-time interest income from the NDT fund special transfer tax deduction recognized in 2011 and a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in other, net for 2012, 2011 and 2010:

	2012	2011	2010
Net unrealized gains (losses) on decommissioning trust funds	$105	$ (4)	$104
Net realized gains (losses) on sale of decommissioning trust funds	$ 51	$(10)	$ 2

Effective Income Tax Rate.

Generation's effective income tax rates for the years ended December 31, 2012, 2011 and 2010 were 47.3%, 37.4% and 37.4%, respectively. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—ComEd

	2012	2011	Favorable (unfavorable) 2012 vs. 2011 variance	2010	Favorable (unfavorable) 2011 vs. 2010 variance
Operating revenues	$5,443	$6,056	$ (613)	$6,204	$ (148)
Purchased power expense	2,307	3,035	728	3,307	272
Revenue net of purchased power expense [(a)]	3,136	3,021	115	2,897	124
Other operating expenses					
Operating and maintenance	1,345	1,189	(156)	1,069	(120)
Depreciation and amortization	610	554	(56)	516	(38)
Taxes other than income	295	296	1	256	(40)
Total other operating expenses	2,250	2,039	(211)	1,841	(198)
Operating income	886	982	(96)	1,056	(74)
Other income and (deductions)					
Interest expense, net	(307)	(345)	38	(386)	41
Other, net	39	29	10	24	5
Total other income and (deductions)	(268)	(316)	48	(362)	46
Income before income taxes	618	666	(48)	694	(28)
Income taxes	239	250	11	357	107
Net income	$ 379	$ 416	$ (37)	$ 337	$ 79

(a) ComEd evaluates its operating performance using the measure of revenue net of purchased power expense. ComEd believes that revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2012, Compared to Year Ended December 31, 2011. ComEd's net income for the year ended December 31, 2012, was lower than the same period in 2011 primarily due to lower electric distribution rates, effective June 20, 2012, pursuant to the ICC Order in the initial formula filing under EIMA. Offsetting the impact of the lower rates were increases in revenue resulting from the annual reconciliation of ComEd's distribution revenue requirement pursuant to EIMA, net of lower allowed return on equity. Additionally, offsetting the impacts of lower electric distribution rates was increased transmission revenue during 2012. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

The increase in operating and maintenance expenses reflect increases in contracting and labor expenses as a result of the first year of the ten-year grid modernization project related to EIMA. Operating and maintenance costs also increased as a result of increased pension and other non-pension and postretirement benefits expenses due to the impact of lower actuarially assumed discount rates and expected return on plan assets for 2012 as compared to 2011. Additionally, operating and maintenance costs were higher in 2012 due to one-time net benefits recognized in 2011 pursuant to the May 2011 ICC order in ComEd's 2010 rate case.

Year Ended December 31, 2011, Compared to Year Ended December 31, 2010. The increase in ComEd's net income was primarily due to higher electric distribution rates, effective June 1, 2011, pursuant to the ICC order in the 2010 Rate Case, and increased revenues resulting from the annual reconciliation of ComEd's distribution revenue requirement pursuant to EIMA, which became effective in the fourth quarter of 2011. Net income was also higher due to the re-measurement of uncertain income tax positions in 2010 related to the 1999 sale of ComEd's fossil generating assets. The re-measurement resulted in increased interest expense and income tax expense recorded in 2010. These increases to net income were partially offset by higher operating and maintenance expense and taxes other than income.

The increase in operating and maintenance expense reflects the benefit recorded in 2010 resulting from the ICC's approval of ComEd's uncollectible accounts expense rider mechanism, a reduction in ComEd's ARO reserve in 2010, and higher labor and contracting expenses incurred in 2011. These increases to operating and maintenance expense were partially offset by one-time net benefits recognized pursuant to the ICC order in ComEd's 2010 rate case.

Operating Revenues and Purchased Power Expense

There are certain drivers to revenue that are fully offset by their impact on purchased power expense, such as commodity procurement costs and customer choice programs. ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on electric revenue net of purchased power expense. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

Electric revenues and purchased power expense are affected by fluctuations in customers' purchases from competitive electric generation suppliers. All ComEd customers have the ability to purchase electricity from an alternative electric generation supplier. The customer choice of electric generation supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and generation services. The number of retail customers purchasing electricity from competitive electric generation suppliers was 1,627,150 and 380,262 at December 31, 2012, and 2011, respectively, representing 43% and 10% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 65% and 56% of ComEd's retail kWh sales at December 31, 2012, and 2011, respectively. On March 20, 2012, approximately 170 Illinois municipalities approved referenda regarding electric supply aggregation. This approval allowed municipal officials to identify and sign contracts with alternative retail electric suppliers. With few exceptions, these municipalities have identified and switched to alternative retail electric suppliers as of December 31, 2012. The City of Chicago and approximately 70 other municipalities and townships passed similar referenda in November 2012. The City of Chicago switching will occur in the first quarter of 2013. All or some of the other 70 municipalities and townships are also expected to switch during the first half of 2013. As contracts with new retail electric suppliers take effect, ComEd expects the percentage of retail deliveries purchased from retail electric suppliers to continue to increase. It is anticipated that by the end of the second quarter 2013 approximately 72% of retail customers and 82% of kWh sales in the ComEd region will be supplied by competitive retail electric suppliers.

The changes in ComEd's electric revenue net of purchased power expense for 2012 compared to 2011 consisted of the following:

	Increase (Decrease)
Electric distribution revenues	$ 40
Transmission	40
Regulatory required programs cost recovery	32
Revenues subject to refund, net	4
Weather delivery	2
Volume delivery	(4)
Other	1
Total increase	$ 115

Electric distribution revenues

In 2011, the ICC issued an order in the 2010 Rate Case approving an increase in ComEd's annual revenue requirement. The order became effective June 1, 2011, resulting in higher revenues for the first six months ended June 30, 2012, compared to the same period in 2011. Offsetting this increase was the lower rates which went into effect June 20, 2012, resulting from the May Order issued in ComEd's 2011 formula rate proceeding under EIMA. Additionally, electric distribution revenues increased as a result of the annual reconciliation of ComEd's distribution revenue requirement pursuant to EIMA. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission

ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update, filed in May 2012, reflects actual 2011 expenses and investments plus forecasted 2012 capital additions. Transmission revenues net of purchased power expense vary from year to year based upon fluctuations in the underlying costs, investments being recovered and

other billing determinants, such as the highest daily peak load from the previous calendar year. ComEd set a record for the highest daily peak load of 23,753 MWs on July 20, 2011, which was reflected in the determination of transmission revenues billed beginning January 1, 2012, and transmission rates that went into effect on June 1, 2012. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory required programs cost recovery

Revenues related to regulatory required programs are the recoveries from customers for costs of various legislative and/or regulatory programs on a full and current basis through approved regulated rates. Programs include ComEd's energy efficiency and demand response and purchased power administrative costs. An equal and offsetting amount has been reflected in operating and maintenance expense during the periods presented. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Revenues subject to refund, net

ComEd records revenues subject to refund based upon its best estimate of customer collections that may be required to be refunded. During the year ended December 31, 2012, ComEd did not record material revenues subject to refund associated with any matters. As a result of the September 30, 2010, Illinois Appellate Court (Court) decision in the 2007 Rate Case which ruled against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via Rider SMP, ComEd began recording revenue subject to refund prospectively. In addition, ComEd began recording revenue subject to refund on June 1, 2010, relating to the recovery of Cash Working Capital (CWC) through its energy procurement rider. Based on the 2010 Rate Case order as well as the order on remand associated with the Court order, during the third quarter 2011 ComEd reduced its revenue subject to refund reserve. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on these proceedings.

Weather—delivery

The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage and delivery of electricity. Conversely, mild weather reduces demand. The favorable weather conditions for the year ended December 31, 2012, resulted in an increase in revenues net of purchased power expense.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2012, and 2011, consisted of the following:

Heating and Cooling Degree-Days Twelve Months Ended December 31,	2012	2011	Normal	% Change From 2011	% Change From Normal
Heating Degree-Days	5,065	6,134	6,341	(17.4)%	(20.1)%
Cooling Degree-Days	1,324	1,036	842	27.8%	57.2%

Volume—delivery

Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential customer for 2012, compared to 2011.

Other

Other revenues were higher during the year ended December 31, 2012, compared to 2011. Other revenues, which can vary period to period, include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental costs associated with MGP sites and recoveries under ComEd's uncollectible accounts tariff.

The changes in ComEd's electric revenue net of purchased power expense for 2011 compared to 2010 consisted of the following:

	Increase (Decrease)
Pricing (2010 Rate Case)	$ 89
Revenues subject to refund, net	31
Distribution formula rate reconciliation	29
Regulatory required programs cost recovery	21
Transmission	18
2007 City of Chicago settlement	2
Volume—delivery	(10)
Weather—delivery	(21)
Uncollectible accounts recovery, net	(33)
Other	(2)
Total increase	$ 124

Pricing (2010 Rate Case)

The ICC issued an order in the 2010 Rate Case approving an increase in ComEd's annual electric distribution revenue requirement. The order became effective June 1, 2011, resulting in higher revenues for the year ended December 31, 2011, compared to the same period in 2010. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Revenues subject to refund, net

As a result of the September 30, 2010, Court decision in the 2007 Rate Case ComEd began recording revenue subject to refund prospectively. In addition, ComEd began recording revenue subject to refund on June 1, 2010, relating to the recovery of Cash Working Capital (CWC) through its energy procurement rider. As a result of the 2010 rate case order, ComEd reduced its revenue subject to refund reserve during the third quarter of 2011. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Distribution formula rate reconciliation

EIMA provides for a performance-based formula rate tariff. The legislation provides for an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. ComEd made its initial reconciliation filing in May

2012 and the adjusted rates will take effect in January 2013. At December 31, 2011, ComEd had recorded an estimated reconciliation of approximately $29 million which did not include the reconciliation of significant storm costs discussed under operating and maintenance expense below. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory required programs cost recovery

Revenues related to regulatory required programs are the recoveries from customers of costs for various legislative and/or regulatory programs on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating and maintenance for regulatory required programs during the period presented. See Note 3 of the Combined Notes to Financial Statements for additional information.

Transmission

ComEd's transmission rates are established based on a FERC-approved formula. ComEd's 2010 formula rate update, filed in May 2011, reflects actual 2010 expenses and investments plus forecasted 2011 capital additions. Transmission revenues net of purchased power expense vary from year to year based upon fluctuations in the underlying costs and investments being recovered.

2007 City of Chicago Settlement

ComEd paid $1 million and $3 million in 2011 and 2010, respectively, under the terms of its 2007 settlement agreement with the City of Chicago. Payments were recorded as a reduction to revenues; therefore, the lower payment in 2011 resulted in a net increase in revenues net of purchased power expense for 2011 compared to 2010.

Volume—delivery

Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential and small commercial and industrial customer for 2011 compared to 2010.

Weather—delivery

The increase in revenues net of purchased power expense in 2011 compared to 2010 were partially offset by unfavorable weather conditions, despite setting a new record for highest daily peak load of 23,753 MWs on July 20, 2011.

The changes in heating and cooling degree days in ComEd's service territory consisted of the following:

Heating and Cooling Degree-Days Twelve Months Ended December 31,	2011	2010	Normal	% Change From 2010	% Change From Normal
Heating Degree-Days	6,134	5,991	6,362	2.4%	(3.6)%
Cooling Degree-Days	1,036	1,181	855	(12.3)%	21.2%

Uncollectible accounts recovery, net

Represents recoveries under ComEd's uncollectible accounts tariff. Refer to uncollectible accounts expense discussion below for further information.

Operating and Maintenance Expense

	Year Ended December 31,		Increase 2012 vs.	Year Ended December 31,		Increase 2011 vs.
	2012	2011	2011	2011	2010	2010
Operating and maintenance expense—baseline	$1,198	$1,074	$ 124	$1,074	$ 975	$ 99
Operating and maintenance expense—regulatory required programs [a]	147	115	32	115	94	21
Total operating and maintenance expense	$1,345	$1,189	$ 156	$1,189	$1,069	$ 120

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for year ended December 31, 2012, compared to the same period in 2011 and changes for the year ended December 31, 2011, compared to the same period in 2010, consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Baseline		
Labor, other benefits, contracting and materials [b]	$ 95	$ 72
Pension and non-pension postretirement benefits expense	46	1
Discrete impacts from 2010 Rate Case order [a]	32	(32)
Corporate Allocations	—	8
Storm Related Costs [d]	(1)	2
Technology Innovation Trust [d]	(11)	15
Uncollectible accounts expense—one-time impact of 2010 ICC Order [c]	—	60
Uncollectible accounts expense, net [c]	(27)	(33)
Other	(10)	6
	124	99
Regulatory required programs		
Energy efficiency and demand response programs	33	25
Purchased power administrative costs	(1)	(4)
	32	21
Increase in operating and maintenance expense	$ 156	$ 120

(a) In May 2011, as a result of the 2010 Rate Case order, ComEd recorded one-time net benefits to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan.
(b) The increase in 2012 labor, other benefits, contracting and material costs is the result of the first year of a ten year grid modernization project associated with EIMA. See Note 3 of the Combined Notes to the Financial Statements for additional information.
(c) On February 2, 2010, the ICC issued an order adopting ComEd's proposed tariffs filed in accordance with Illinois legislation providing public utilities the ability to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and amounts collected in rates annually through a rider mechanism starting with 2008 and prospectively. As a result of this order, ComEd recorded a regulatory asset of $70 million and an offsetting reduction in operating and maintenance expense for the cumulative under-collections in 2008 and 2009. In addition, ComEd recorded a onetime contribution of $10 million associated with this legislation.
(d) Under EIMA, ComEd may recover costs associated with certain one-time events, such as large storms, over a five-year period. During the fourth quarter of 2011, ComEd recorded a net reduction in operating and maintenance expense for costs related to three significant 2011 storms. In addition, pursuant to EIMA, ComEd makes recurring payments for contribution to a Science and Technology Innovation Trust fund that will be used to fund energy innovation.

Operating and maintenance expense for regulatory required programs

Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2012 compared to 2011 and 2011 compared to 2010, consisted of the following:

	Increase 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Depreciation expense associated with higher plant balances [(a)]	$ 22	$ 20
Storm Cost Amortization	4	14
Other Regulatory Asset Amortization	14	(2)
Other	16	6
Increase in depreciation and amortization expense	$ 56	$ 38

Taxes Other Than Income

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Taxes other than income taxes decreased primarily due to decreased Illinois electricity distribution taxes. Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes, and payroll taxes.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. Taxes other than income taxes increased primarily due to the accrual of estimated future refunds of Illinois utility distribution tax recorded in 2010 for the 2008 and 2009 tax years. Previously, ComEd had recorded refunds of the Illinois utility distribution tax when received. Due to sufficient, reliable evidence, ComEd began in June 2010 recording an estimated receivable associated with anticipated Illinois utility distribution tax refunds prospectively.

Interest Expense, Net

The changes in interest expense, net for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	(Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Interest expense related to uncertain tax positions [(a)]	$ —	$ (63)
Interest expense on debt (including financing trusts) [(b)]	(26)	20
Other	(12)	2
Decrease in interest expense, net	$ (38)	$ (41)

(a) During 2010, ComEd recorded $59 million of interest expense associated with the re-measurement of uncertain income tax positions related to the 1999 sale of Fossil Generating Assets.
(b) Interest expense on debt decreased in 2012 due to more favorable interest rates on long-term debt balances year over year.

Other, Net

The changes in other, net for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Interest income related to uncertain tax positions	$ 16	$ 8
Other	(6)	(3)
Increase in Other, net	$ 10	$ 5

Effective Income Tax Rate

ComEd's effective income tax rate for the years ended December 31, 2012, 2011, and 2010 was 38.7%, 37.5% and 51.4%, respectively. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Retail Deliveries to customers (in GWhs)	2012	2011	% Change 2012 vs 2011	Weather-Normal % Change	2010	% Change 2011 vs 2010	Weather-Normal % Change
Retail Delivery and Sales [a]							
Residential	28,528	28,273	0.9%	(0.6)%	29,171	(3.1)%	(1.3)%
Small commercial & industrial	32,534	32,281	0.8%	0.2%	32,904	(1.9)%	(0.8)%
Large commercial & industrial	27,643	27,732	(0.3)%	(0.3)%	27,717	0.1%	0.6%
Street Lighting & electric railroads	1,272	1,235	3.0%	4.2%	1,273	(3.0)%	(1.2)%
Total Retail	89,977	89,521	0.5%	(0.1)%	91,065	(1.7)%	(0.5)%

Number of Electric Customers	As of December 31, 2012	2011	2010
Residential	3,455,546	3,448,481	3,438,677
Small commercial & industrial	365,357	365,824	363,393
Large commercial & industrial	1,980	2,032	2,005
Street Lighting & electric railroads	4,812	4,797	5,078
Total	3,827,695	3,821,134	3,809,153

Electric Revenue	2012	2011	% Change 2012 vs 2011	2010	% Change 2011 vs 2010
Retail Delivery and Sales [a]					
Residential	$3,037	$3,510	(13.5)%	$3,549	(1.1)%
Small commercial & industrial	1,339	1,517	(11.7)%	1,639	(7.4)%
Large commercial & industrial	395	383	3.1%	397	(3.5)%
Street Lighting & electric railroads	44	50	(12.0)%	62	(19.4)%
Total Retail	4,815	5,460	(11.8)%	5,647	(3.3)%
Other Revenue [b]	628	596	5.4%	557	7.0%
Total Electric Revenues	$5,443	$6,056	(10.1)%	$6,204	(2.4)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier. All customers are assessed charges for delivery. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other items include rental revenue, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental remediation costs associated with MGP sites.

Results of Operations—PECO

	2012	2011	Favorable (unfavorable) 2012 vs. 2011 variance	2010	Favorable (unfavorable) 2011 vs. 2010 variance
Operating revenues	$3,186	$3,720	$ (534)	$5,519	$ (1,799)
Purchased power and fuel	1,375	1,864	489	2,762	898
Revenue net of purchased power and fuel expense [(a)]	1,811	1,856	(45)	2,757	(901)
Other operating expenses					
Operating and maintenance	809	794	(15)	733	(61)
Depreciation and amortization	217	202	(15)	1,060	858
Taxes other than income	162	205	43	303	98
Total other operating expenses	1,188	1,201	13	2,096	895
Operating income	623	655	(32)	661	(6)
Other income and (deductions)					
Interest expense, net	(123)	(134)	11	(193)	59
Other, net	8	14	(6)	8	6
Total other income and (deductions)	(115)	(120)	5	(185)	65
Income before income taxes	508	535	(27)	476	59
Income taxes	127	146	19	152	6
Net income	381	389	(8)	324	65
Preferred security dividends	4	4	—	4	—
Net income on common stock	$ 377	$ 385	$ (8)	$ 320	$ 65

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by lower operating revenue net of purchased power and fuel expense and increased storm costs. The decrease in revenue net of purchased power and fuel expense was primarily related to unfavorable weather and a decline in electric load. The decrease to net income was partially offset by lower taxes other than income, interest expense and income taxes.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The increase in net income was primarily driven by new distribution rates effective January 1, 2011 as a result of the 2010 electric and natural gas rate case settlements, decreased interest expense and decreased income tax expense. The increase in net income was partially offset by increased storm costs, increased depreciation expense and the net impact of the 2010 CTC recoveries reflected in electric operating revenues net of purchased power expense and CTC amortization expense, both of which ceased at the end of the transition period on December 31, 2010.

Operating Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power and fuel expense, such as commodity procurement costs and customer choice programs. PECO's electric generation rates charged to customers were capped until December 31, 2010 in accordance with the 1998 restructuring settlement. Beginning January 1, 2011, PECO's electric generation rates are based on actual costs incurred through its approved competitive market procurement process. Electric and gas revenues and purchased power and fuel expenses are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly and are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenues net of purchased power and fuel expenses.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the customer choice program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenue net of purchase power and fuel expense. The number of retail customers purchasing energy from a competitive electric generation supplier was 496,500, 387,600 and 36,600 at December 31, 2012, 2011 and 2010, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 66%, 57% and 1% of PECO's retail kWh sales for the years ended December 31, 2012, 2011 and 2010, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 53,600, 24,800 and 6,800 at December 31, 2012, 2011 and 2010, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 16%, 11% and 7% of PECO's mmcf sales for the years ended December 31, 2012, 2011 and 2010, respectively.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (17)	$(15)	$(32)
Volume	(22)	—	(22)
Pricing	(4)	3	(1)
Regulatory required programs	29	—	29
Other	(19)	—	(19)
Total decrease	$ (33)	$(12)	$(45)

Weather

The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. Electric and gas revenues net of purchased power and fuel expense were lower due to unfavorable winter weather conditions during 2012 in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2012 compared to the same period in 2011 and normal weather consisted of the following:

Heating and Cooling Degree-Days Twelve Months Ended December 31,	2012	2011	Normal	% Change From 2011	% Change From Normal
Heating Degree-Days	3,747	4,157	4,603	(9.9)%	(18.6)%
Cooling Degree-Days	1,603	1,617	1,301	(0.9)%	23.2%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected the reduced oil refinery load in PECO's service territory and the impact of energy efficiency initiatives and weak economic conditions on customer usage. The decrease was partially offset by additional volumes due to the extra day from the leap year. See Note 3 of the Combined Notes to Consolidated Financial Statements for further information regarding energy efficiency initiatives.

Pricing

The decrease in operating revenues net of purchased power and fuel expense as a result of pricing reflects the refund of the tax cash benefit resulting from the adoption of the safe harbor method of tax accounting for electric distribution property in 2011. The refund was reflected on customer bills as a credit beginning January 1, 2012. The accounting impact of the refund is completely offset by regulatory liability amortization recorded in income tax expense. The decrease in operating revenues net of purchase power and fuel expense as a result of pricing was partially offset by higher overall effective rates due to decreased usage per customer across all customer classes.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other

The decrease in other electric revenues net of purchased power expense primarily reflected a decrease in GRT revenue as a result of lower supplied energy service and a reduction in the GRT rate. There is an equal and offsetting decrease in GRT expense included in taxes other than income.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2011 compared to the same period in 2010 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (33)	$(13)	$ (46)
Volume	(11)	3	(8)
CTC recoveries	(995)	—	(995)
Pricing	139	16	155
Regulatory required programs	17	—	17
Other	(29)	5	(24)
Total increase (decrease)	$(912)	$ 11	$(901)

Weather

Electric and gas revenues net of purchased power and fuel expense were lower due to unfavorable weather conditions during 2011 in PECO's service territory compared to 2010 despite setting a new record for highest electric peak load of 8,983 MWs on July 22, 2011.

The changes in heating and cooling degree days for the twelve months ended 2011 and 2010, consisted of the following:

Heating and Cooling Degree-Days [a]	2011	2010	Normal	% Change From 2010	% Change From Normal
Twelve Months Ended December 31,					
Heating Degree-Days	4,157	4,396	4,638	(5.4)%	(10.4)%
Cooling Degree-Days	1,617	1,817	1,292	(11.0)%	25.2%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected weak economic growth, the impact of energy efficiency initiatives on customer usage and the ramp-down of two oil refineries. See Note 3 of the Combined Notes to the Consolidated Financial Statements for further information regarding energy efficiency initiatives.

The increase in gas revenues net of fuel expense related to delivery volume, exclusive of the effects of weather, reflected increased usage per customer across all customer classes.

CTC Recoveries

The decrease in electric revenues net of purchased power expense related to CTC recoveries reflected the absence of the CTC charge component that was included in rates charged to customers in 2010. PECO fully recovered all stranded costs during the final year of the transition period that expired on December 31, 2010.

Pricing

The increase in operating revenues net of purchased power and fuel expense as a result of pricing primarily reflected an increase of new electric and natural gas distribution rates charged to customers that became effective in January 1, 2011 in accordance with the 2010 PAPUC approved electric and natural gas distribution rate case settlements. See Note 3 of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other

The decrease in electric revenues net of purchased power expense primarily reflected a decrease in GRT revenue as a result of lower supplied energy service and retail transmission revenue earned by PECO due to increased participation in the customer choice program. There is an equal and offsetting decrease in GRT expense included in taxes other than income. This decrease was partially offset by an increase in wholesale transmission revenue earned by PECO as a transmission owner for the use of PECO's transmission facilities in PJM. The rates charged for wholesale transmission are based on the prior year's peak, and the peak in 2010 was higher than in 2009.

The increase in gas operating revenues net of fuel expense primarily reflected an increase in off-system gas sales activity. Off-system gas sales revenues represent sales of excess gas supply on the wholesale market and the release of pipeline capacity.

Operating and Maintenance Expense

	Twelve Months Ended December 31,		Increase (Decrease)	Twelve Months Ended December 31,		Increase (Decrease)
	2012	2011	2012 vs. 2011	2011	2010	2011 vs. 2010
Operating and Maintenance Expense—Baseline	$ 723	$ 725	$ (2)	$ 725	$ 680	$ 45
Operating and Maintenance Expense—Regulatory Required Programs [(a)]	86	69	17	69	53	16
Total Operating and Maintenance Expense	$ 809	$ 794	$ 15	$ 794	$ 733	$ 61

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Baseline		
Labor, other benefits, contracting and materials	$ (29)	$ 26
Storm-related costs	9[a]	13
Uncollectible accounts expense	(4)	4
Constellation merger and integration costs	15	2
2010 non-cash charge resulting from Health Care Legislation	—	(2)
Other	7	2
	(2)	45
Regulatory Required Programs		
Smart Meter	12	9
Energy Efficiency	8	2
GSA	(1)	5
Consumer education program	(1)	(1)
AEPS	(1)	1
	17	16
Increase in operating and maintenance expense	$ 15	$ 61

(a) Storm-related costs include $46 million of incremental storm costs incurred in the fourth quarter of 2012 as a result of Hurricane Sandy. This expense was significantly offset by the costs incurred related to Hurricane Irene and other storms throughout 2011.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
CTC amortization [a]	$ —	$ (885)
Other [b]	15	27
Increase (decrease) in depreciation and amortization expense	$ 15	$ (858)

(a) PECO's scheduled CTC amortization was recorded in accordance with its 1998 restructuring settlement and was fully amortized as of December 31, 2010.
(b) Increase due primarily to ongoing capital expenditures.

Taxes Other Than Income

The change in taxes other than income for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
GRT expense [a]	$ (33)	$ (97)
Sales and use tax	(12) [b]	—
PURTA amortization	—	(4) [c]
Other	2	3
Decrease in taxes other than income	$ (43)	$ (98)

(a) The decrease in GRT expense for 2012 compared to 2011 and 2011 compared to 2010 was a result of lower operating revenues. In addition, there was a reduction in the GRT rate in 2012.
(b) The decrease reflects a sales and use tax reserve adjustment in the first quarter of 2012 resulting from the completion of the audit of tax years 2005 through 2010.
(c) The decrease in taxes other than income related to PURTA amortization reflects the impact of regulatory liability amortization recorded in 2011 that offsets the distribution rate reduction made to refund a 2009 PURTA Supplemental Tax settlement to customers.

Interest Expense, Net

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in interest expense, net for 2012 compared to 2011 was primarily due to the debt retirement in November 2011.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The decrease in interest expense, net for 2011 compared to 2010 was primarily due to the retirement of PETT transition bonds on September 1, 2010 and the impact of interest expense incurred in June 2010 related to the change in measurement of uncertain tax positions in accordance with accounting guidance.

See Notes 1 and 12 of the Combined Notes to Consolidated Financial Statements for further information.

Other, Net

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in Other, net for 2012 compared to 2011 was due to decreased AFUDC—Equity. See Note 20 of the Combined Notes to Consolidated Financial Statements for additional details of the components of Other, net.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The increase in Other, net for 2011 compared to 2010 was primarily due to increased investment income and AFUDC Equity. See Note 20 of the Combined Notes to Consolidated Financial Statements for further information.

Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2012, 2011 and 2010 were 25.0%, 27.3% and 31.9%, respectively. The effective income tax rate for the year ended December 31, 2012 reflects the impact of the tax benefit received from electing to change the method of accounting for gas distribution property for the 2011 tax year. Comparatively, the effective income tax rate for the

year ended December 31, 2011 includes the effect of electing the safe harbor method of tax accounting for electric distribution property for the 2010 tax year. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2012	2011	% Change 2012 vs. 2011	Weather-Normal % Change	2010	% Change 2011 vs. 2010	Weather-Normal % Change
Retail Delivery and Sales [a]							
Residential	13,233	13,687	(3.3)%	(1.7)%	13,913	(1.6)%	1.7%
Small commercial & industrial	8,063	8,321	(3.1)%	(2.3)%	8,503	(2.1)%	(0.7)%
Large commercial & industrial	15,253	15,677	(2.7)%	(2.7)%	16,372	(4.2)%	(3.3)%
Public authorities & electric railroads	943	945	(0.2)%	(0.2)%	925	2.2%	4.6%
Total Electric Retail	37,492	38,630	(2.9)%	(2.2)%	39,713	(2.7)%	(0.9)%

	As of December 31,		
Number of Electric Customers	2012	2011	2010
Residential	1,417,773	1,415,681	1,411,643
Small commercial & industrial	148,803	148,570	148,297
Large commercial & industrial	3,111	3,110	3,071
Public authorities & electric railroads	9,660	9,689	9,670
Total	1,579,347	1,577,050	1,572,681

Electric Revenue	2012	2011	% Change 2012 vs. 2011	2010	% Change 2011 vs. 2010
Retail Delivery and Sales [a]					
Residential	$1,689	$1,934	(12.7)%	$2,069	(6.5)%
Small commercial & industrial	462	585	(21.0)%	1,061	(44.9)%
Large commercial & industrial	232	308	(24.7)%	1,364	(77.4)%
Public authorities & electric railroads	31	38	(18.4)%	89	(57.3)%
Total Retail	2,414	2,865	(15.7)%	4,583	(37.5)%
Other Revenue [b]	226	244	(7.4)%	252	(3.2)%
Total Electric Revenues	$2,640	$3,109	(15.1)%	$4,835	(35.7)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2012	2011	% Change 2012 vs. 2011	Weather-Normal % Change	2010	% Change 2011 vs. 2010	Weather-Normal % Change
Retail Delivery and Sales [b]							
Retail sales	49,767	54,239	(8.2)%	(0.1)%	56,833	(4.6)%	1.2%
Transportation and other	26,687	28,204	(5.4)%	(4.8)%	30,911	(8.8)%	(7.5)%
Total Gas Deliveries	76,454	82,443	(7.3)%	(1.6)%	87,744	(6.0)%	(1.8)%

	As of December 31,		
Number of Gas Customers	2012	2011	2010
Residential	454,502	451,382	448,391
Commercial & industrial	41,836	41,373	41,303
Total Retail	496,338	492,755	489,694
Transportation	903	879	838
Total	497,241	493,634	490,532

Gas revenue	2012	2011	% Change 2012 vs. 2011	2010	% Change 2011 vs. 2010
Retail Delivery and Sales [a]					
Retail sales	$509	$576	(11.6)%	$657	(12.3)%
Transportation and other	37	35	5.7%	27	29.6%
Total Gas Deliveries	$546	$611	(10.6)%	$684	(10.7)%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

Results of Operations—BGE

	2012	2011	Favorable (unfavorable) 2012 vs. 2011 variance	2010	Favorable (unfavorable) 2011 vs. 2010 variance
Operating revenues	$2,735	$3,068	$ (333)	$3,541	$ (473)
Purchased power and fuel expense	1,369	1,593	224	2,147	554
Revenue net of purchased power and fuel expense [(a)]	1,366	1,475	(109)	1,394	81
Other operating expenses					
Operating and maintenance	728	680	(48)	595	(85)
Depreciation and amortization	298	274	(24)	249	(25)
Taxes other than income	208	207	(1)	200	(7)
Total other operating expenses	1,234	1,161	(73)	1,044	(117)
Operating income	132	314	(182)	350	(36)
Other income and (deductions)					
Interest expense, net	(144)	(129)	(15)	(131)	2
Other, net	23	26	(3)	25	1
Total other income and (deductions)	(121)	(103)	(18)	(106)	3
Income before income taxes	11	211	(200)	244	(33)
Income taxes	7	75	68	97	22
Net income	4	136	(132)	147	(11)
Preference stock dividends	13	13	—	13	—
Net (loss) income on common stock	$ (9)	$ 123	$ (132)	$ 134	$ (11)

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenue net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by decreased operating revenue net of purchased power and fuel expense related to the residential customer rate credit provided as a condition of the MDPSC's approval of Exelon's merger with Constellation. The decrease in net income was also driven by increased operating and maintenance expenses, primarily related to BGE's accrual of its portion of the charitable contributions to be provided as a condition of the MDPSC's approval of the merger as well as merger transaction costs, and increased depreciation and amortization expense. None of the customer rate credit, the charitable contributions, or the transaction costs are recoverable from BGE's customers.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The decrease in net income was primarily driven by increased storm costs, increased depreciation and amortization expense and increased merger transaction costs. Partially offsetting these unfavorable impacts were increased operating revenues primarily driven by new distribution rates as a result of the 2010 Maryland PSC rate order. None of the transaction costs are recoverable from BGE's customers.

Operating Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive EGS affects electric SOS revenues and purchased power expense. The number of customers electing to select a competitive NGS affects gas cost adjustment revenues and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive EGS. This customer choice of EGSs does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive EGS was 362,000, 314,000 and 228,000 at December 31, 2012, 2011 and 2010, respectively, representing 29%, 25% and 18% of total retail customers, respectively. Retail deliveries purchased from competitive EGSs represented 60%, 58% and 50% of BGE's retail kWh sales for the years ended December 31, 2012, 2011 and 2010, respectively. The number of retail customers purchasing natural gas from a competitive NGS was 143,000, 118,000 and 84,000 at December 31, 2012, 2011 and 2010, respectively, representing 22%, 18% and 13% of total retail customers, respectively. Retail deliveries purchased from competitive NGSs represented 56%, 52% and 49% of BGE's retail mmcf sales for the years ended December 31, 2012, 2011 and 2010, respectively.

The changes in BGE's operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Residential customer rate credit [(a)]	$ (82)	$(31)	$(113)
Commodity margin	(1)	(5)	(6)
Regulatory program cost recovery	15	4	19
Transmission	11	—	11
Other	(13)	(7)	(20)
Total decrease	$ (70)	$(39)	$(109)

(a) In accordance with the MDPSC order approving Exelon's merger with Constellation, the residential customer rate credit is not recoverable from BGE's customers. Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

Revenue Decoupling. The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Volume. Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the year ended December 31, 2012 compared to the same period in 2011 and normal weather consisted of the following:

Heating and Cooling Degree-Days Twelve Months Ended December 31,	2012	2011	Normal	% Change From 2011	% Change From Normal
Heating Degree-Days	3,960	4,326	4,711	(8.5)%	(15.9)%
Cooling Degree-Days	1,022	1,035	858	(1.3)%	19.1%

Residential Customer Rate Credit

The residential customer rate credit provided as a result of the MDPSC's order approving Exelon's merger with Constellation decreased operating revenues net of purchased power and fuel expense for year ended December 31, 2012.

Commodity Margin

The commodity margin for both electric and gas revenues decreased during the year ended December 31, 2012 compared to the same period in 2011. Commodity revenues are affected by the number of customers using competitive suppliers as well as the cost of purchased power and natural gas.

Regulatory Required Programs

This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the year ended December 31, 2012 compared to the same period in 2011 was due to the recovery of higher energy efficiency program costs.

Transmission

Transmission revenues increased during the year ended December 31, 2012 compared to the same period in 2011. BGE's transmission rates are established based on a FERC-approved formula. The rates also include transmission investment incentives approved by FERC in a number of orders covering various new transmission investment projects since 2007.

Other

Other revenues decreased during the year ended December 31, 2012 compared to the same period in 2011. Other revenues, which can vary from period to period, include miscellaneous revenues such as late payment charge revenues and all base distribution revenues, including the impact of revenue decoupling, which decreased due to lower volumes and customer mix.

The changes in BGE's operating revenues net of purchased power and fuel expense for the year ended December 31, 2011 compared to the same period in 2010 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Distribution rates increase	$ 28	$ 8	$ 36
Commodity margin	(17)	2	(15)
Regulatory program cost recovery	20	1	21
Transmission	18	—	18
Other	16	5	21
Total increase	$ 65	$ 16	$ 81

Volume

The changes in heating and cooling degree days for the twelve months ended 2011 and 2010, consisted of the following:

Heating and Cooling Degree-Days [a]				% Change	
Twelve Months Ended December 31,	2011	2010	Normal	From 2010	From Normal
Heating Degree-Days	4,326	4,716	4,720	(8.3)%	(8.3)%
Cooling Degree-Days	1,035	1,122	853	(7.8)%	21.3%

Distribution Rates Increase

The MDPSC issued an order approving an increase in BGE's annual electric distribution revenue requirement. The order became effective December 4, 2010, resulting in higher revenues for the year ended December 31, 2011 compared to the same period in 2010. See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information.

Commodity Margin

The commodity margin for electric revenues decreased during the year ended December 31, 2011 compared to the same period in 2010. Commodity revenues are affected by the number of customers using competitive suppliers as well as the cost of purchased power and natural gas. Additionally, the decrease is a result of the reinstatement of the credit for the residential return component of the administrative charge on June 1, 2010. This credit will continue through December 2016.

Regulatory Program Cost Recovery

The increase in electric revenues relating to regulatory program cost recovery was due to the recovery of higher energy efficiency program costs and demand response program costs. The costs of these programs are recoverable from customers on a full and current basis through approved regulated rates and have been reflected in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes.

Transmission

Transmission revenues increased during the year ended December 31, 2011 compared to the same period in 2010. BGE's transmission rates are established based on a FERC-approved formula. The rates also include transmission investment incentives approved by FERC in a number of orders covering various new transmission investment projects since 2007.

Other

Other revenues increased during the year ended December 31, 2011 compared to the same period in 2010. Other revenues, which can vary from period to period, include miscellaneous revenues such as late payment charge revenues and all other base distribution revenues, including the impact of revenue decoupling, which increased due to higher volumes and customer mix.

Operating and Maintenance Expense

	Twelve Months Ended December 31, 2012	2011	Increase (Decrease) 2012 vs. 2011	Twelve Months Ended December 31, 2011	2010	Increase (Decrease) 2011 vs. 2010
Operating and Maintenance Expense—Baseline	$ 728	$ 679	$ 49	$ 679	$ 591	$ 88
Operating and Maintenance Expense—Regulatory Required Programs [a]	—	1	(1)	1	4	(3)
Total Operating and Maintenance Expense	$ 728	$ 680	$ 48	$ 680	$ 595	$ 85

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Baseline		
Charitable contributions [a]	$ 28	$ —
Storm costs deferral [b]	16	(16)
Storm-related costs [c]	7	41
Pension and non-pension postretirement benefits expense	6	2
Labor, other benefits, contracting and materials	(10)	25
Merger transaction costs [a]	(9)	30
Uncollectible accounts expense	—	6
Other	11	—
	49	88
Regulatory Required Programs		
SOS	(1)	(3)
	(1)	(3)
Increase in operating and maintenance expense	$ 48	$ 85

(a) The charitable contribution accrual and merger transaction costs are not recoverable from BGE's customers.
(b) During the first quarter of 2011, the MDPSC issued a comprehensive rate order permitting the deferral of incremental distribution service restoration expenses associated with 2010 storms as a regulatory asset.
(c) On June 29, 2012, a "Derecho" storm caused extensive damage to BGE's electric distribution system and created power outages that lasted multiple days. As a result, BGE incurred $62 million of incremental costs during the year ended December 31, 2012, of which $20 million are capital costs. In the fourth quarter of 2012, BGE incurred $38 million of incremental costs as a result of Hurricane Sandy, of which $14 million are capital costs. These amounts compare to $40 million of incremental expenses incurred during the third quarter of 2011 associated with Hurricane Irene and $14 million of incremental expenses incurred during the first quarter of 2011.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Depreciation expense [(a)]	$20	$ 10
Regulatory asset amortization	6	13
Other	(2)	2
Increase in depreciation and amortization expense	$24	$ 25

(a) Depreciation and amortization expense increased due to higher plant balances year over year.

Taxes Other Than Income

The change in taxes other than income for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Property tax	$ 4	$ 5
Other	(3)	2
Increase in taxes other than income	$ 1	$ 7

Interest Expense, Net

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in interest expense, net for 2012 compared to 2011 was primarily due to higher outstanding debt balances.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The change in interest expense, net in 2011 compared to 2010 was relatively flat.

Effective Income Tax Rate

BGE's effective income tax rates for the years ended December 31, 2012, 2011 and 2010 were 63.6%, 35.5% and 39.8%, respectively. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2012	2011	% Change 2012 vs. 2011	Weather-Normal % Change	2010	% Change 2011 vs. 2010	Weather-Normal % Change
Retail Delivery and Sales [a]							
Residential	12,719	12,652	0.5%	n.m.	13,834	(8.5)%	n.m.
Small commercial & industrial	15,943	16,276	(2.0)%	n.m.	16,040	1.5%	n.m.
Large commercial & industrial	1,980	2,464	(19.6)%	n.m.	2,578	(4.4)%	n.m.
Public authorities & electric railroads	329	405	(18.8)%	n.m.	400	1.3%	n.m.
Total Electric Retail	30,971	31,797	(2.6)%	n.m.	32,852	(3.2)%	n.m.

Number of Electric Customers	As of December 31, 2012	2011	2010
Residential	1,116,233	1,116,401	1,114,712
Small commercial & industrial	119,122	118,568	118,250
Large commercial & industrial	5,452	5,823	5,534
Public authorities & electric railroads	319	326	326
Total	1,241,126	1,241,118	1,238,822

Electric Revenue	2012	2011	% Change 2012 vs. 2011	2010	% Change 2011 vs. 2010
Retail Delivery and Sales [a]					
Residential	$1,274	$1,456	(12.5)%	$1,857	(21.6)%
Small commercial & industrial	600	632	(5.1)%	687	(8.0)%
Large commercial & industrial	40	51	(21.6)%	53	(3.8)%
Public authorities & electric railroads	30	29	3.4%	30	(3.3)%
Total Retail	1,944	2,168	(10.3)%	2,627	(17.5)%
Other Revenue [b]	239	228	4.8%	204	11.8%
Total Electric Revenues	$2,183	$2,396	(8.9)%	$2,831	(15.4)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes wholesale transmission revenue and late payment charges.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2012	2011	% Change 2012 vs. 2011	Weather-Normal % Change	2010	% Change 2011 vs. 2010	Weather-Normal % Change
Retail Delivery and Sales [c]							
Retail sales	86,946	94,800	(8.3)%	n.m.	98,928	(4.2)%	n.m.
Transportation and other [d]	15,751	16,436	(4.2)%	n.m.	14,711	11.7%	n.m.
Total Gas Deliveries	102,697	111,236	(7.7)%	n.m.	113,639	(2.1)%	n.m.

	As of December 31,		
Number of Gas Customers	2012	2011	2010
Residential	610,827	608,943	608,553
Commercial & industrial	44,228	44,211	44,041
Total	655,055	653,154	652,594

Gas revenue	2012	2011	% Change 2012 vs. 2011	2010	% Change 2011 vs. 2010
Retail Delivery and Sales [c]					
Retail sales	$494	$580	(14.8)%	$620	(6.5)%
Transportation and other [d]	58	92	(37.0)%	90	2.2%
Total Gas Deliveries	$552	$672	(17.9)%	$710	(5.4)%

(c) Reflects delivery revenues and volumes from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.

(d) Transportation and other gas revenue includes off-system revenue of 15,751 mmcfs ($51 million), 16,436 mmcfs ($82 million) and 14,711 mmcfs ($80 million) for the years ended 2012, 2011 and 2010, respectively.

Liquidity and Capital Resources

Exelon and Generation activity presented below includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon and Generation activity for 2011 and 2010 is unadjusted for the effects of the merger. BGE activity presented below includes its activity for the 12 months ended December 31, 2012, 2011 and 2010.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. The Registrants' revolving credit facilities are in place until 2017. In addition, Generation has a $0.3 billion bilateral facility with a bank. The bilateral facility at Generation has expirations in December 2015 and March 2016. The Registrant's utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 11 of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

ComEd's, PECO's and BGE's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd's, PECO's and BGE's distribution services are provided to an established and diverse base of retail customers. ComEd's, PECO's and BGE's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3 and 19 of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. Exelon expects to contribute approximately $270 million to its pension plans in 2013, of which Generation, ComEd, PECO and BGE expect to contribute $119 million, $117 million, $12 million and $2 million, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2012 and 2011 pension contributions.

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued recovery). Exelon expects to contribute approximately $292 million to the other postretirement benefit plans in 2013, of which Generation, ComEd, PECO and BGE expect to contribute $117 million, $114 million, $22 million and $18 million, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2012 and 2011 other postretirement benefit contributions.

See the “Contractual Obligations” section below for management’s estimated future pension and other postretirement benefits contributions.

Tax Matters

The Registrants’ future cash flows from operating activities may be affected by the following tax matters:

- In November 2012, the IRS and Exelon finalized and executed definitive agreements to resolve Exelon’s involuntary conversion and CTC positions. Exelon expects that the IRS will assess approximately $300 million of tax and interest in the first quarter of 2013. In order to stop additional interest from accruing on the expected assessment, Exelon had previously made a payment in December 2010 to the IRS of $302 million. In addition Exelon, Generation, ComEd and PECO expect to receive tax refunds of approximately $375 million, $50 million, $350 million and $25 million, respectively, between 2013 and 2014, and the remainder paid by Exelon.
- Given the current economic environment, state and local governments are facing increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes.
- In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The newly adopted method results in a cash tax benefit of approximately $38 million and $41 million at Exelon and PECO, respectively. Exelon currently anticipates that the IRS will issue industry guidance during 2013. See Note 3 of the Combined Notes to Consolidated Financial Statements for discussion regarding the regulatory treatment of PECO’s tax benefits from the application of the method change.

The following table provides a summary of the major items affecting Exelon’s cash flows from operations for the years ended December 31, 2012, 2011 and 2010:

	2012	2011	2012 vs. 2011 Variance	2010	2011 vs. 2010 Variance
Net income	$1,171	$ 2,499	$ (1,328)	$2,563	$ (64)
Add (subtract):					
Non-cash operating activities [a]	5,588	4,848	740	4,340	508
Pension and non-pension postretirement benefit contributions	(462)	(2,360)	1,898	(959)	(1,401)
Income taxes	544	492	52	(543)	1,035
Changes in working capital and other noncurrent assets and liabilities [b]	(731)	(279)	(452)	122	(401)
Option premiums paid, net	(114)	(3)	(111)	(124)	121
Counterparty collateral received (paid), net	135	(344)	479	(155)	(189)
Net cash flows provided by operations	$6,131	$ 4,853	$ 1,278	$5,244	$ (391)

(a) Represents depreciation, amortization and accretion, mark-to-market gains and losses on derivative transactions, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, and other non-cash charges.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Cash flows provided by operations for 2012, 2011 and 2010 by Registrant were as follows:

	2012	2011	2010
Exelon	$6,131	$4,853	$5,244
Generation	3,581	3,313	3,032
ComEd	1,334	836	1,077
PECO	878	818	1,150
BGE	485	476	329

Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for 2012, 2011 and 2010 were as follows:

Generation

- During 2012, 2011 and 2010, Generation had net (payments) receipts of counterparty collateral of $95 million, $(410) million and $(1) million, respectively. Net payments during 2012 and 2011 were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.
- During 2007, Generation, along with ComEd and other generators and utilities, reached an agreement with various representatives from the State of Illinois to address concerns about higher electric bills in Illinois. Generation committed to contributing approximately $747 million over four years. As part of the agreement, Generation contributed cash of approximately $23 million in 2010. As of December 31, 2010, Generation had fulfilled its commitments under the Illinois Settlement Legislation.
- During 2012, 2011 and 2010, Generation's accounts receivable from ComEd increased (decreased) by $(15) million, $12 million and $(65) million, respectively, primarily due to changes in receivables for energy purchases related to its SFC, ICC-approved RFP contracts and financial swap contract.
- During 2012, 2011 and 2010, Generation's accounts receivable from PECO increased (decreased) by $17 million, $(210) million and $74 million, respectively.
- During 2012, 2011 and 2010, Generation had net payments of approximately $114 million, $3 million and $124 million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During 2012, 2011 and 2010, ComEd's net payables to Generation for energy purchases related to its supplier forward contract, ICC-approved RFP contracts and financial swap contract settlements increased (decreased) by $(15) million, $12 million and $(65) million, respectively. During 2012, 2011 and 2010, ComEd's payables to other energy suppliers for energy purchases increased (decreased) by $20 million, $(43) million and $58 million, respectively.

- During 2012 and 2011, ComEd received $37 million and $63 million, respectively, of incremental cash collateral from PJM due to variations in its energy transmission activity levels. As of December 31, 2012 and December 31, 2011, ComEd had $53 million and $90 million of cash collateral remaining at PJM.

PECO

- During 2012, 2011 and 2010, PECO's payables to Generation for energy purchases increased (decreased) by $17 million, $(210) million and $74 million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $(22) million, $97 million and $1 million, respectively.

BGE

- During 2012, 2011 and 2010, BGE's payables to Generation for energy purchases increased (decreased) by $23 million, $(13) million and $0 million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $40 million, $(60) million and $54 million, respectively. BGE's increase in payables to other energy suppliers in 2010 is due to the implementation of the POR program during July 2010. The decrease in payables to other energy suppliers in 2011 is due to full payment to POR suppliers due to the implementation of a new customer billing system during January 2012.

Cash Flows from Investing Activities

Cash flows used in investing activities for 2012, 2011, and 2010 by Registrant were as follows:

	2012	2011	2010
Exelon [a][b][d]	$(4,576)	$(4,603)	$(3,894)
Generation [a][d]	(2,629)	(3,077)	(2,896)
ComEd	(1,212)	(1,007)	(939)
PECO [b]	(328)	(557)	(120)
BGE	(573)	(592)	(177)

Capital expenditures by Registrant for 2012, 2011 and 2010 and projected amounts for 2013 are as follows:

	Projected 2013 [c]	2012	2011	2010
Generation [d]	$ 2,850	$3,554	$2,491	$1,883
ComEd [e]	1,400	1,246	1,028	962
PECO	569	422	481	545
BGE	663	582	592	508
Other [f]	43	67	42	(64)
Total capital expenditures	$ 5,525	$5,871	$4,634	$3,834

(a) Includes $387 million in 2011 related to acquisitions, principally acquisition of Wolf Hollow, Antelope Valley and Shooting Star; and $893 million in 2010, related to the acquisition of Exelon Wind. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Includes a cash inflow of $413 million in 2010 as a result of the consolidation of PETT on January 1, 2010. See Note 1 of the Combined Notes to Consolidated Financial Statements for additional information.
(c) Total projected capital expenditures do not include adjustments for non-cash activity.
(d) Includes nuclear fuel.

(e) The projected capital expenditures include approximately $227 million of expected incremental spending. Pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology. ComEd expects to file an updated investment plan with the ICC in April, 2013.

(f) Other primarily consists of corporate operations and BSC. The negative capital expenditures for Other in 2010 primarily relate to the transfer of information technology hardware and software assets from BSC to Generation, ComEd and PECO.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 35% and 20% of the projected 2013 capital expenditures at Generation are for the acquisition of nuclear fuel; and investments in renewable energy generation, including Antelope Valley construction costs, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Also included in the projected 2013 capital expenditures are a portion of the costs of a series of planned power uprates across Generation's nuclear fleet. See "EXELON CORPORATION—Executive Overview," for more information on nuclear uprates.

On November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC, and received net proceeds of approximately $371 million in the fourth quarter. In addition, Generation will make cash payments of approximately $32 million to Raven Power Holdings LLC over a twelve-month period beginning in June 2013. In 2012, Generation incurred transaction costs of approximately $15 million through the date of closing of the transaction. The sale will generate approximately $195 million of cash tax benefits, of which $155 million will be realized in periods through 2014 with the balance to be received in later years. Therefore, Generation expects net after-tax cash sale proceeds of approximately $495 million through 2014 and approximately $36 million in subsequent years.

ComEd, PECO and BGE

Approximately 89%, 89% and 77% of the projected 2013 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA and ComEd's, PECO's and BGE's construction commitments under PJM's RTEP. In addition, this includes for ComEd capital expenditures related to smart grid/smart meter technology required under EIMA and for PECO and BGE capital expenditures related to its smart meter program and SGIG project, net of DOE expected reimbursements. The remaining amounts are for capital additions to support new business and customer growth. See Notes 3 and 6 of the Combined Notes to Consolidated Financial Statements for additional information.

As a result of the October 3, 2012 ICC Rehearing Order, ComEd currently plans to defer approximately $400 million of smart meter and other infrastructure spend from the period beginning 2012 through 2014 to 2015 and beyond. ComEd's deferred approximately $65 million of planned spend in 2012.

In 2010, NERC provided guidance to transmission owners that recommends ComEd, PECO and BGE perform assessments of all their transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority lines by December 31, 2013. In compliance with this guidance, ComEd, PECO and BGE submitted their most recent bi-annual reports to NERC in January 2013. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the

assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2013 capital expenditures above reflect capital spending for remediation to be completed in 2013.

ComEd, PECO and BGE anticipate that they will fund capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 3 of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for 2012, 2011 and 2010 by Registrant were as follows:

	2012	2011	2010
Exelon	$(1,085)	$(846)	$(1,748)
Generation	(777)	(196)	(779)
ComEd	(212)	355	(179)
PECO	(382)	(589)	(811)
BGE	128	115	(116)

Debt. Debt activity for 2012, 2011 and 2010 by Registrant was as follows:

Company	Issuances of long-term debt in 2012	Use of proceeds
Generation	$78 million of variable rate CEU Credit Agreement project financing, due July 16, 2016	Used to fund Upstream gas activities
Generation	$220 million of fixed rate DOE Project Financing, due January 5, 2037	Used for Antelope Valley solar development
Generation	$523 million of 4.25% Senior Notes due June 15, 2022	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$788 million of 5.60% Senior Notes due June 15, 2042	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$38 million of variable rate Clean Horizons project financing due June 7, 2030	Used for funding for Maryland solar development
ComEd	$350 million of First Mortgage 3.80% Bonds, Series 113, due October 1, 2042	Used to repay outstanding commercial paper obligations and for general corporate purposes.
PECO	$350 million of First and Refunding Mortgage 2.38% Bonds due September 15, 2022	Used to pay at maturity First Mortgage Bonds due October 1, 2012 and for general corporate purposes
BGE	$250 million of fixed rate 2.80% Notes due August 15, 2022	Used to repay total outstanding commercial paper obligations and for general corporate purposes

Company	Issuances of long-term debt in 2011	Use of proceeds
ComEd	$600 million of First Mortgage 1.625% Bonds, Series 110, due January 15, 2014	Used as an interim source of liquidity for a January 2011 contribution to Exelon-sponsored pension plans.
ComEd	$250 million of First Mortgage 1.95% Bonds, Series 111, due September 1, 2016	Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes.
ComEd	$350 million of First Mortgage 3.40% Bonds, Series 112, due September 1, 2021	Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes.
BGE	$300 million of fixed rate 3.50% Notes, due November 15, 2021	Used to repay total outstanding commercial paper obligations and for general corporate purposes

Company	Issuances of long-term debt in 2010	Use of proceeds
Generation	$900 million of Senior Notes, consisting of $550 million Senior Notes, 4.00% due October 1, 2020 and $350 million Senior Notes, 5.75% due October 1, 2041	Used to finance the acquisition of Exelon Wind and for general corporate purposes.
ComEd	$500 million of First Mortgage Bonds at 4.00% due August 1, 2020	Used to refinance First Mortgage Bonds, Series 102, which matured on August 15, 2010 and for other general corporate purposes.

Company	Retirement of long-term debt in 2012
Exelon	$2 million of 7.30% fixed-rate Medium Term Notes with a maturity date of June 1, 2012.
Exelon	$442 million of 7.60% fixed-rate Senior Notes with a maturity date of April 1, 2032.
Generation	$2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
Generation	$46 million of 3-year term rate Armstrong Co. 2009 A, Pollution Control Notes at 5.00% with a final maturity of December 1, 2042.
Generation	$89 million of variable rate project financing CEU Credit Agreement with a final maturity of July 16, 2016.
Generation	$17 million of variable rate Solar Revolver project financing with a final maturity of July 7, 2014.
Generation	$75 million of variable rate MEDCO tax-exempt bonds with a final maturity of April 1, 2024.
Generation	$2 million of variable rate Sacramento Solar Promissory Note with a final maturity of March 12, 2012.
ComEd	$450 million of 6.15% First Mortgage Bonds, Series 98, due March 15, 2012

Company	Retirement of long-term debt in 2012
PECO	$225 million of 4.75% First and Refunding Mortgage Bonds, due October 1, 2012
PECO	$150 million of 4.00% First and Refunding Mortgage Bonds, due December 1, 2012
BGE	$8 million of 5.72% fixed rate Rate Stabilization Bonds, due April 1, 2016
BGE	$55 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012
BGE	$110 million of variable rate Medium Term Notes, due June 15, 2012
Generation	$2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
ComEd	$2 million of 4.75% sinking fund debentures, due December 1, 2011
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, due March 1, 2020
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 E, due May 1, 2021
ComEd	$91 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 F, due March 1, 2017
ComEd	$345 million of 5.40% First Mortgage Bonds, Series 105, due December 15, 2011
PECO	$250 million of 5.95% First and Refunding Mortgage Bonds, due November 1, 2011
BGE	$60 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012

Company	Retirement of long-term debt in 2010
Exelon Corporate	$400 million of 4.45% 2005 Senior Notes, due June 15, 2010
Generation	$1 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
Generation	$13 million of Montgomery County Series 1994 B Tax Exempt Bonds with variable interest rates, due June 1, 2029
Generation	$17 million of Indiana County Series 2003 A Tax Exempt Bonds with variable interest rates, due June 1, 2027
Generation	$19 million of York County Series 1993 A Tax Exempt Bonds with variable interest rates, due August 1, 2016
Generation	$23 million of Salem County Series 1993 A Tax Exempt Bonds with variable interest rates, due March 1, 2025
Generation	$24 million of Delaware County Series 1993 A Tax Exempt Bonds with variable interest rates, due August 1, 2016
Generation	$34 million of Montgomery County Series 1996 A Tax Exempt Bonds with variable interest rates, due March 1, 2034
Generation	$83 million of Montgomery County Series 1994 A Tax Exempt Bonds with variable interest rates, due June 1, 2029
ComEd	$1 million of 4.75% sinking fund debentures, due December 1, 2011
ComEd	$212 million of 4.74% First Mortgage Bonds, due August 15, 2010
PECO	$806 million of 6.52% PETT Transition Bonds, due September 1, 2010
BGE	$57 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective balance sheets.

Dividends. Cash dividend payments and distributions during 2012, 2011 and 2010 by Registrant were as follows:

	2012	2011	2010
Exelon	$1,733	$1,393	$1,389
Generation	1,626	172	1,508
ComEd	105	300	310
PECO	347	352	228
BGE	13	98[(a)]	13

(a) Dividends on common stock for $85 million were paid to Constellation for the year ended December 31, 2011.

First Quarter 2013 Dividend. On February 6, 2013, the Exelon Board of Directors declared a first quarter 2013 regular quarterly dividend of $0.525 per share on Exelon's common stock payable on March 8, 2013, to shareholders of record of Exelon at the end of the day on February 19, 2013.

Revised Dividend Policy. On February 6, 2013, the Exelon Board of Directors approved a revised dividend policy which contemplates a regular $0.31 per share quarterly dividend on Exelon's common stock payable beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis), subject to quarterly declarations by the Exelon Board of Directors. The second quarter 2013 quarterly dividend of $0.31 per share on Exelon's common stock is expected to be approved by the Exelon Board of Directors in the second quarter of 2013.

Short-Term Borrowings. Short-term borrowings incurred (repaid) during 2012, 2011 and 2010 by Registrant were as follows:

	2012	2011	2010
ComEd	$ —	$—	$(155)
BGE	—	—	(46)
Other [(a)]	(197)	161	—
Exelon	$(197)	$161	$(201)

(a) Other primarily consists of corporate operations and BSC.

Retirement of Long-Term Debt to Financing Affiliates. There were no retirement of long-term debt to financing affiliates during 2012, 2011 and 2010 by the Registrants.

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2012, 2011 and 2010 by Registrant were as follows:

	2012	2011	2010
Generation	$48	$ 30	$ 62
ComEd	11	11	2
PECO [(a)]	9	18	223
BGE	66	—	—

(a) Reflects payment received to reduce the receivable from parent of $180 million for the year ended December 31, 2010 and was completely repaid as of December 31, 2010.

Other. Other significant financing activities for Exelon for 2012, 2011 and 2010 were as follows:

- Exelon received proceeds from employee stock plans of $72 million, $38 million and $48 million during 2012, 2011 and 2010, respectively.

Credit Matters

Market Conditions

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large diversified credit facilities. The credit facilities include $8.3 billion in aggregate total commitments of which $3.8 billion was available as of December 31, 2012, and of which no financial institution has more than 10% of the aggregate commitments for Exelon, Generation, ComEd, PECO and BGE. The Registrants had access to the commercial paper market during 2012 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels, and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A Risk Factors for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flows from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of December 31, 2012, it would have been required to provide incremental collateral of approximately $1,920 million, which is well within its current available credit facility capacities of approximately $5.6 billion, which includes $1,920 million of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements. If ComEd lost its investment grade credit rating as of December 31, 2012, it would have been required to provide incremental collateral of approximately $218 million, which is well within its current available credit facility capacity of approximately $1.0 billion. If PECO lost its investment grade credit rating as of December 31, 2012, it would not be required to provide collateral pursuant to PJM's credit policy and could have been required to provide collateral of approximately $35 million related to its natural gas procurement contracts, which, in the aggregate, is well within PECO's current available credit facility capacity of approximately $599 million. If BGE lost its investment grade credit rating as of December 31, 2012, it would have been required to provide collateral of $3 million pursuant to PJM's credit policy and could have been required to provide collateral of approximately $124 million related to its natural gas procurement contracts, which, in the aggregate, is well within BGE's current available credit facility capacity of approximately $600 million.

Exelon Credit Facilities

See Note 11 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure . At December 31, 2012, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE
Long-term debt	45%	27%	43%	36%	46%
Long-term debt to affiliates [(a)]	2	10	2	3	5
Common equity	52	—	55	55	45
Member's equity	—	63	—	—	—
Preferred securities	—	—	—	2	4
Commercial paper and notes payable	1	—	—	4	—

(a) Includes approximately $648 million, $206 million, and $184 million owed to unconsolidated affiliates of Exelon, ComEd and PECO, respectively, and $258 million owed to a consolidated affiliate of BGE that all qualify as special purpose entities under the applicable authoritative guidance. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd, PECO and BGE. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

Intercompany Money Pool. To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. As of January 10, 2006, ComEd voluntarily suspended its participation in the money pool. Generation, PECO and BSC may participate in the intercompany money pool as lenders and borrowers, and Exelon may participate as a lender. As a result of the ring-fencing measures required by the MDPSC, BGE does not participate in the intercompany money pool. Funding of, and borrowings from, the intercompany money pool are predicated on whether the contributions and borrowings result in economic benefits. Interest on borrowings is based on short-term market rates of interest or, if from an external source, specific borrowing rates. Maximum amounts contributed to and borrowed from the intercompany money pool by participant during 2012 are described in the following table in addition to the net contribution or borrowing as of December 31, 2012:

	Maximum Contributed	Maximum Borrowed	December 31, 2012 Contributed (Borrowed)
Generation	$ —	$ 258	$ —
PECO	309	—	—
BSC	—	206	(119)
Exelon Corporate	119	N/A	119

Shelf Registration Statements. The Registrants have combined a shelf registration statement with the SEC. As of December 31, 2012, that shelf registration statement remained effective and provides for the sale of unspecified amounts of securities. The ability of each Registrant to sell securities off that shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations. The issuance by ComEd, PECO and BGE of long-term debt or equity securities requires the prior authorization of the ICC, PAPUC and MDPSC, respectively. ComEd, PECO and BGE normally obtain the required approvals on a periodic basis to cover their anticipated financing needs for a period of time or in connection with a specific financing. On February 27, 2012, ComEd received $1.3 billion in long-term debt refinancing authority from the ICC. As of December 31, 2012, ComEd had $1.4 billion available in long-term debt refinancing authority from the ICC and $106 million in new money long-term debt financing authority from the ICC. On October 24, 2012, the PAPUC approved PECO's application for long-term financing authority for $2.5

billion, which is effective through December 31, 2015. As of December 31, 2012, PECO had $1.9 billion available in long-term debt financing authority from the PAPUC. As of December 31, 2012, BGE had $1.2 billion available in long-term financing authority from MDPSC.

FERC has financing jurisdiction over ComEd's, PECO's and BGE's short-term financings and all of Generation's financings. As of December 31, 2012, ComEd and PECO had short-term financing authority from FERC that expires on December 31, 2013 of $2.5 billion and $1.5 billion, respectively. As of December 31, 2012, BGE had short-term financing authority from FERC that expires on December 31, 2014 of $0.7 billion. Generation currently has blanket financing authority that it received from FERC in connection with its market-based rate authority. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon's ability to pay dividends on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid. At December 31, 2012, Exelon had retained earnings of $9,893 million, including Generation's undistributed earnings of $3,168 million, ComEd's retained earnings of $721 million consisting of retained earnings appropriated for future dividends of $2,360 million partially offset by $1,639 million of unappropriated retained deficit, PECO's retained earnings of $593 million and BGE's retained earnings $808 million. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Contractual Obligations

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2012 under existing contractual obligations, including payments due by period. See Note 19 of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within				
	Total	2013	2014-2015	2016-2017	Due 2018 and beyond	All Other
Long-term debt [a]	$18,915	$ 976	$ 3,090	$2,495	$ 12,354	$—
Interest payments on long-term debt [b]	12,156	957	1,711	1,493	7,995	—
Liability and interest for uncertain tax positions [c]	305	1	—	—	—	304
Capital leases	30	3	6	8	13	—
Operating leases [d]	864	88	156	132	488	—
Purchase power obligations [e]	3,516	1,246	1,313	483	474	—
Fuel purchase agreements [f]	9,955	1,554	2,764	2,208	3,429	—
Electric supply procurement [f]	1,721	741	703	277	—	—
AEC purchase commitments [f]	12	4	2	2	4	—
Curtailment services commitments [f]	153	49	88	16	—	—
Long-term renewable energy and REC commitments [g]	1,659	71	148	156	1,284	—
PJM regional transmission expansion commitments [h]	914	218	442	254	—	—
Spent nuclear fuel obligation	1,020	—	—	—	1,020	—
Pension minimum funding requirement [i]	2,223	255	599	923	446	—
Total contractual obligations	$ 53,443	$6,163	$11,022	$8,447	$ 27,507	$304

(a) Includes $648 million due after 2016 to ComEd, PECO and BGE financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2012 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2012. Includes estimated interest payments due to ComEd, PECO and BGE financing trusts.

(c) As of December 31, 2012, Exelon's liability for uncertain tax positions was $305 million. Exelon was unable to reasonably estimate the timing of liability and interest payments and receipts in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. Exelon has other unrecognized tax positions that were not recorded on the Consolidated Balance Sheet in accordance with authoritative guidance. See Note 12 of the Combined Notes to Consolidated Financial Statements for further information regarding unrecognized tax positions.

(d) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO's meter reading operating lease.

(e) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2012, including those related to CENG. Expected payments include certain capacity charges that are contingent on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. These obligations do not include ComEd's SFCs as these contracts do not require purchases of fixed or minimum quantities. See Notes 3 and 19 of the Combined Notes to Consolidated Financial Statements.

(f) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services. See Note 19 of the Combined Notes to Consolidated Financial Statements for electric and gas purchase commitments.

(g) On December 17, 2010, ComEd entered into 20-year contracts with several unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(h) Under their operating agreements with PJM, ComEd, PECO and BGE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's, PECO's and BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(i) These amounts represent Exelon's estimated minimum pension contributions to its qualified plans required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. For Exelon's largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million or the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2018 are not included. See Note 14 of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

		Payment due within				
	Total	2013	2014-2015	2016-2017	Due 2018 and beyond	All Other
Long-term debt	$ 7,241	$ 25	$1,163	$ 774	$ 5,279	$—
Interest payments on long-term debt [a]	5,041	391	712	660	3,278	—
Liability and interest for uncertain tax benefits [b]	236	—	—	—	—	236
Capital leases	30	3	6	8	13	—
Operating leases [c]	553	38	76	72	367	—
Purchase power obligations [d]	3,516	1,246	1,313	483	474	—
Fuel purchase agreements [e]	8,857	1,276	2,479	2,040	3,062	—
Spent nuclear fuel obligation	1,020	—	—	—	1,020	—
Total contractual obligations	$26,494	$2,979	$5,749	$4,037	$ 13,493	$236

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2012 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2012.

(b) As of December 31, 2012, Generation's liability for uncertain tax positions and related interest payable was $216 million and $20 million, respectively. Generation was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.

(c) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations.

(d) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2012. Expected payments include certain capacity charges that are contingent on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. See Note 19 of the Combined Notes to Consolidated Financial Statements.

(e) See Note 19 of the Combined Notes to Consolidated Financial Statements for further information regarding fuel purchase agreements.

ComEd

	Total	Payment due within 2013	2014-2015	2016-2017	Due 2018 and beyond	All Other
Long-term debt [a]	$5,793	$ 252	$ 877	$1,090	$ 3,574	$—
Interest payments on long-term debt [b]	3,499	276	506	443	2,274	—
Liability and interest for uncertain tax positions [c]	67	—	—	—	—	67
Operating leases	109	13	22	17	57	—
Electric supply procurement	1,103	367	459	277	—	—
Long-term renewable energy and associated REC commitments [d]	1,661	71	147	158	1,285	—
PJM regional transmission expansion commitments [e]	525	175	221	129	—	—
Total contractual obligations	$ 12,757	$1,154	$2,232	$2,114	$ 7,190	$ 67

(a) Includes $206 million due after 2017 to a ComEd financing trust.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2012 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2012. Includes estimated interest payments due to the ComEd financing trust.
(c) As of December 31, 2012, ComEd's liability for uncertain tax positions was $67 million. ComEd was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.
(d) On December 17, 2010, ComEd entered into 20-year contracts with several unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.
(e) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's, expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

PECO

	Total	Payment due within 2013	2014-2015	2016-2017	Due 2018 and beyond	All Other
Long-term debt [a]	$2,134	$ 300	$250	$—	$ 1,584	$—
Interest payments on long-term debt [b]	1,238	105	168	158	807	—
Liability and interest for uncertain tax positions [c]	1	1	—	—	—	—
Operating leases	42	20	16	6	—	—
Fuel purchase agreements [d]	444	145	158	64	77	—
Electric supply procurement [d]	799	561	238	—	—	—
AEC purchase commitments [d]	33	12	11	4	6	—
PJM regional transmission expansion commitments [e]	140	28	49	63	—	—
Total contractual obligations	$ 4,831	$1,172	$890	$295	$ 2,474	$—

(a) Includes $184 million due after 2017 to PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2012 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) As of December 31, 2012, PECO's liability for uncertain tax positions was $1 million. PECO was unable to reasonably estimate the timing of certain liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.

(d) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information.
(e) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

BGE

		Payment due within				
	Total	2013	2014-2015	2016-2017	Due 2018 and beyond	All Other
Long-term debt [a]	$2,440	$467	$145	$420	$ 1,408	$—
Interest payments on long-term debt [b]	1,644	118	212	176	1,138	—
Liability and interest for uncertain tax positions	—	—	—	—	—	—
Operating leases	73	12	19	13	29	—
Fuel purchase agreements [c]	654	133	127	104	290	—
Electric supply procurement [c]	1,401	859	542	—	—	—
Curtailment services commitments [c]	153	49	88	16	—	—
PJM regional transmission expansion commitments [d]	249	15	172	62	—	—
Total contractual obligations	$ 6,614	$1,653	$1,305	$791	$ 2,865	$—

(a) Includes $258 million due after 2017 to the BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2012 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

See Note 19 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 11 of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 11 of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 12 of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 11 of the Combined Notes to Consolidated Financial Statements.
- operating leases, energy commitments, fuel purchase agreements, construction commitments and rate relief commitments, see Note 19 of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 13 and 19 of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3 of the Combined Notes to Consolidated Financial Statements.

- variable interest entities, see Note 1 of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 19 of the Combined Notes to Consolidated Financial Statements.
- new accounting pronouncements, see Note 1 of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief executive officer, chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Risk Oversight Committee of the Exelon Board of Directors on the scope of the risk management activities.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into physical contracts as well as financial derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges, including the ComEd financial swap contract, will occur during 2013 through 2015. Generation's energy contracts are accounted for under the accounting guidance for derivatives as further discussed in Note 10 of the Combined Notes to Consolidated Financial Statements.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over the three years leading to the spot market. As of December 31, 2012, the percentage of expected generation hedged for the major reportable segments was 94%-97%, 62%-65% and 27%-30% for 2013, 2014 and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including sales to ComEd, PECO and BGE to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on December 31, 2012, market conditions and hedged position would be a decrease in pre-tax net income of approximately $40 million, $440 million and $810 million, respectively, for 2013, 2014 and 2015. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 12,958 GWh, 5,742 GWh, and 3,625 GWh for the years ended December 31, 2012, 2011 and 2010 respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the year ended December 31, 2012, resulted in pre-tax losses of $14 million due to net mark-to-market gains of $96 million and realized losses of $110 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $1.9 million of exposure since the merger date and was deemed immaterial prior to the merger. Because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for the year ended December 31, 2012 of $7,376 million, Generation has not segregated proprietary trading activity in the following tables.

Fuel Procurement . Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2013 through 2017 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

ComEd

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd will be entitled to receive full cost recovery in rates. The change in fair value each period is recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expires on May 31, 2013.

ComEd's RFP contracts are deemed to be derivatives that qualify for the normal purchases and normal sales exception under derivative accounting guidance. ComEd does not enter into derivatives for speculative or trading purposes. ComEd is permitted full recovery of its RFP contracts from retail customers with no mark-up.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. Delivery under these contracts began in June 2012. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Notes 3 and 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3 of the Combined Notes to the Consolidated Financial Statements. PECO's full requirements contracts and block contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 10 of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 10 of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Exelon's, Generation's, ComEd's and PECO's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, ComEd's and PECO's mark-to-market net asset or liability balance sheet position from January 1, 2011, to December 31, 2012. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings, as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts. For additional information on the cash flow hedge gains and losses included within accumulated OCI and the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2012, and December 31, 2011, refer to Note 10 of the Combined Notes to Consolidated Financial Statements.

	Generation	ComEd	PECO	Intercompany Eliminations [h]	Exelon
Total mark-to-market energy contract net assets (liabilities) at January 1, 2011 [a]	$ 1,803	$(971)	$ (9)	$ —	$ 823
Total change in fair value during 2011 of contracts recorded in result of operations	241	—	—	—	241
Reclassification to realized at settlement of contracts recorded in results of operations	(541)	—	—	—	(541)
Ineffective portion recognized in income [b]	9	—	—	—	9
Reclassification to realized at settlement from accumulated OCI [c]	(968)	—	—	456	(512)
Effective portion of changes in fair value—recorded in OCI [d]	827	—	—	(170)	657
Changes in fair value—energy derivatives	—	171[e]	9[f]	(286)	(106)
Changes in collateral	411	—	—	—	411
Changes in net option premium paid/(received)	3	—	—	—	3
Option Premium Amortization [g]	(137)	—	—	—	(137)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2011 [a]	$ 1,648	$(800)	$—	$ —	$ 848
Contracts Acquired at merger date [i]	140				140
Total change in fair value during 2012 of contracts recorded in result of operations	(159)	—	—	7	(152)
Reclassification to realized at settlement of contracts recorded in results of operations	775	—	—	—	775
Ineffective portion recognized in income [b]	(5)	—	—	—	(5)

	Generation	ComEd	PECO	Intercompany Eliminations [h]	Exelon
Reclassification to realized at settlement from accumulated OCI [c]	(1,368)	—	—	621	(747)
Effective portion of changes in fair value—recorded in OCI [d]	719	—	—	(146)	573
Changes in fair value—energy derivatives	—	507[e]	—	(482)	25
Changes in collateral	(89)	—	—	—	(89)
Changes in net option premium paid/(received)	114	—	—	—	114
Option Premium Amortization [g]	(160)	—	—	—	(160)
Intercompany Elimination of Existing Derivative Contracts with Constellation	(103)				(103)
Other changes in fair value	(7)	—	—	—	(7)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2012 [a]	$ 1,505	$(293)	$—	$ —	$1,212

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) For Generation, reflects $5 million and $9 million of changes in cash flow hedge ineffectiveness, of which none was related to Generation's financial swap contract with ComEd or Generation's block contracts with PECO for the years ended December 31, 2012 and 2011, respectively.
(c) For Generation, includes $621 million and $451 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2012 and 2011, respectively, and $5 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the PECO block contracts for the year ended December 31, 2011.
(d) For Generation, includes $146 million and $170 million of gains related to the changes in fair value of the five-year financial swap with ComEd for the years ended December 31, 2012 and 2011, respectively. Effective prior to the merger, the five-year financial swap between Generation and ComEd was de-designated. As a result, all prospective changes in fair value are recorded to operating revenues and eliminated in consolidation.
(e) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2012 and 2011, ComEd recorded a regulatory liability of $293 million and $800 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. During 2012 and 2011, this includes $98 million of increases and $170 million of decreases in fair value, respectively, and $566 million and $451 million of realized gains, respectively, due to settlements of ComEd's five-year financial swap with Generation. During 2012 and 2011 this includes $34 million and $110 million, respectively, of increases in fair value, and during 2012 realized losses due to settlements of $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(f) For PECO, the changes in fair value are recorded as a change in regulatory assets or liabilities. During the year ended December 31, 2011, PECO's mark-to-market derivative liability was fully amortized, including $5 million related to PECO's block contracts with Generation, in accordance with the terms of the contracts.
(g) Includes $160 million and $137 million of amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the years ended December 31, 2012 and 2011, respectively.
(h) Amounts related to the five-year financial swap between Generation and ComEd and the block contracts between Generation and PECO are eliminated in consolidation.
(i) For Generation, includes $660 million of collateral paid to counterparties, offset by $520 million of unrealized losses on commodity derivative positions.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities) net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts [(a)(b)] *:*							
Actively quoted prices (Level 1)	$ 80	$ (63)	$ (32)	$10	$ 2	$ —	$ (3)
Prices provided by external sources (Level 2)	325	374	134	16	—	(1)	848
methods (Level 3) [(c)]	168	89	50	30	25	5	367
Total	$573	$400	$152	$56	$ 27	$ 4	$ 1,212

(a) Mark-to-market gains and losses on other non-trading hedge and trading derivative contracts that do not qualify as cash flow hedges are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $31 million at December 31, 2012.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts [(a)(b)] *:*							
Actively quoted prices (Level 1)	$ 80	$ (63)	$ (32)	$10	$ 2	$ —	$ (3)
Prices provided by external sources (Level 2)	325	374	134	16	—	(1)	848
Prices based on model or other valuation methods (Level 3)	412	106	66	44	38	(6)	660
Total	$817	$417	$168	$70	$ 40	$ (7)	$ 1,505

(a) Mark-to-market gains and losses on other non-trading hedge and trading derivative contracts are recorded in results of operations. Amounts include a $226 million gain associated with the five-year financial swap with ComEd.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $31 million at December 31, 2012.

ComEd

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and Beyond	Fair Value
Prices based on model or other valuation methods [(a)]	$(244)	$(17)	$(16)	$(14)	$(13)	$ 11	$(293)

(a) Represents ComEd's net assets (liabilities) associated with the five-year financial swap with Generation and the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 10 of the Combined Notes to Consolidated Financial Statements for a detail discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2012. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through exchanges (i.e. NYMEX, ICE, etc), which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $54 million, $56 million and $31 million, respectively. See Note 22 of the Combined Notes to Consolidated Financial Statements for further information.

Rating as of December 31, 2012	Total Exposure Before Credit Collateral	Credit Collateral [(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,984	$ 347	$ 1,637	1	$ 262
Non-investment grade	28	24	4	—	—
No external ratings					
Internally rated—investment grade	512	10	502	1	271
Internally rated—non-investment grade	41	3	38	—	—
Total	$ 2,565	$ 384	$ 2,181	2	$ 533

	Maturity of Credit Risk Exposure			
Rating as of December 31, 2012	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,553	$319	$ 112	$ 1,984
Non-investment grade	15	13	—	28
No external ratings				
Internally rated—investment grade	312	193	7	512
Internally rated—non-investment grade	41	—	—	41
Total	$ 1,921	$525	$ 119	$ 2,565

Net Credit Exposure by Type of Counterparty	As of December 31, 2012
Investor-owned utilities, marketers and power producers	$ 865
Energy cooperatives and municipalities	786
Financial Institutions	422
Other	108
Total	$ 2,181

(a) As of December 31, 2012, credit collateral held from counterparties where Generation had credit exposure included $344 million of cash and $40 million of letters of credit.

ComEd

Credit risk for ComEd is managed by credit and collection policies, which are consistent with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. The Illinois Settlement Legislation prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 1 of the following year. ComEd's ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2012. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. As of December 31, 2012, ComEd's credit exposure to energy suppliers was immaterial.

PECO

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1 of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2012.

PECO's supplier master agreements that govern the terms of its DSP Program contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2012, PECO had no net credit exposure with suppliers.

PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements; however, the natural gas asset managers have provided $20 million in parental guarantees related to these agreements. As of December 31, 2012, PECO had credit exposure of $7 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE

Credit risk for BGE is managed by credit and collection policies, which are consistent with state regulatory requirements. BGE is currently obligated to provide service to all electric customers within its franchised territory. BGE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. BGE will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1 of the Combined Notes to Consolidated Financial Statements for uncollectible accounts policy. MDPSC regulations prohibit BGE from terminating service to residential customers due to nonpayment from November 1 through March 31 if the forecasted temperature is 32 degrees or below for the subsequent 72 hour period. BGE is also prohibited by the Maryland Public Utilities Article and MDPSC regulations from terminating service to residential customers due to nonpayment if the forecasted temperature is 95 degrees or above for the subsequent 72 hour period. BGE did not have any customers representing over 10% of its revenues as of December 31, 2012.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The seller's credit exposure is calculated each business day. As of December 31, 2012, BGE had no net credit exposure with suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2012, BGE had credit exposure of $8 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third party suppliers.

Collateral (Exelon, Generation, ComEd, PECO and BGE)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 10 of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities which serve as liquidity sources to fund collateral requirements. Generation depends on access to bank credit lines which serve as liquidity sources to fund collateral requirements. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2012, Generation had $499 million of cash collateral deposits received from counterparties and Generation had $527 million of cash collateral deposits being held by counterparties, of which $31 million in net cash collateral deposits were offset against mark-to-market assets and liabilities. As of December 31, 2012, $3 million of cash collateral received was not offset against net derivative positions because it was not associated with energy-related derivatives. As of December 31, 2011, Generation was holding $542 million of cash collateral deposits received from counterparties. Net cash collateral deposits received of $540 million were offset mark-to-market assets and liabilities. As of December 31, 2011, $2 million of cash collateral received was not offset against net mark-to-market assets and liabilities. See Note 19 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 31, 2012, ComEd held immaterial amounts of cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts. See Notes 3 and 10 of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of December 31, 2012, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of December 31, 2012, BGE was not required to post collateral under its natural gas procurement contracts, nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may under certain circumstances require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon and Generation)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's consolidated balance sheets, as of December 31, 2012, included a $693 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of approximately $1.5 billion, less unearned income of $799 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms which are set at prices above the then expected fair market value of the plants. If the lessees do not exercise the fixed purchase options the lessees return the leasehold interests to Exelon and Exelon has the ability to require the lessees to arrange a service contract with a third party for a period following the lease term. In any event, Exelon is subject to residual value risk to the extent the fair value of the assets are less than the residual value. This risk is mitigated by the fair value of the fixed payments under the service contract. The term of the service contract, however, is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures including letters of credit, surety bonds and credit swaps. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Since 2008, the entity providing the credit enhancement for one of the lessees did not meet the

credit rating requirements of the lease. Consequently, Exelon has indefinitely extended a waiver and reduction of the rating requirement, which Exelon may terminate by giving 90 days notice to the lessee. Exelon monitors the continuing credit quality of the credit enhancement party.

Exelon performed annual assessments as of July 31, 2012 and 2011 of the estimated fair value of long-term lease investments and concluded that the estimated fair values at the end of the lease terms exceeded the residual values ($1.5 billion as noted above) established at the lease dates and recorded as investments on Exelon's balance sheet. Through December 31, 2012, no events have occurred or circumstances have changed that would require any formal reassessment subsequent to the July 2012 review.

Interest-Rate Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2012, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and $452 million of notional amounts of pre-issuance hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper and PECO Accounts Receivables Facility) and fixed-to-floating swaps would result in less than $2 million decrease in Exelon pre-tax income for the year ended December 31, 2012.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of December 31, 2012, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $386 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, for further discussion of equity price risk as a result of the current capital and credit market conditions.

Generation

General

Generation operates in six segments: Mid-Atlantic, Midwest, New England, New York, ERCOT, and other regions in Generation. The operation of all six segments consists of owned contracted and investments in electric generating facilities, and wholesale and retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and investments in natural gas exploration and production activities. These segments are discussed in further detail in "ITEM 1. BUSINESS—Generation" of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation's executive overview is set forth under "ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2012 Compared To Year Ended December 31, 2011 and Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

A discussion of Generation's results of operations for 2012 compared to 2011 and 2011 compared to 2010 is set forth under "Results of Operations—Generation" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.6 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 11 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Generation's capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon's pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of Generation's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in "ITEM 1. BUSINESS—ComEd" of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 and Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

A discussion of ComEd's results of operations for 2012 compared to 2011 and for 2011 compared to 2010 is set forth under "Results of Operations—ComEd" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2012, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 11 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ComEd's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of ComEd's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk— Exelon."

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in "ITEM 1. BUSINESS—PECO" of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 and Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

A discussion of PECO's results of operations for 2012 compared to 2011 and for 2011 compared to 2010 is set forth under "Results of Operations—PECO" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2012, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund PECO's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of PECO's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

BGE

General

BGE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in "ITEM 1. BUSINESS—BGE" of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 and Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

A discussion of BGE's results of operations for 2012 compared to 2011 and for 2011 compared to 2010 is set forth under "Results of Operations—BGE" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

BGE's business is capital intensive and requires considerable capital resources. BGE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2012, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund BGE's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to BGE's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to BGE's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE—Critical Accounting Policies and Estimates above for a discussion of BGE's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2012, Exelon's internal control over financial reporting was effective.

The effectiveness of the Exelon's internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 21, 2013

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Generation's management conducted an assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation's management concluded that, as of December 31, 2012, Generation's internal control over financial reporting was effective.

The effectiveness of the Generation's internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 21, 2013

Management's Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd's management concluded that, as of December 31, 2012, ComEd's internal control over financial reporting was effective.

The effectiveness of the ComEd's internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 21, 2013

Management's Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO's management concluded that, as of December 31, 2012, PECO's internal control over financial reporting was effective.

The effectiveness of the PECO's internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 21, 2013

Management's Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

BGE's management conducted an assessment of the effectiveness of BGE's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE's management concluded that, as of December 31, 2012, BGE's internal control over financial reporting was effective.

The effectiveness of BGE's internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 21, 2013

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Corporation and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 21, 2013

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Generation Company, LLC and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 21, 2013

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Commonwealth Edison Company and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 21, 2013

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PECO Energy Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of PECO Energy Company and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 21, 2013

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Baltimore Gas and Electric Company

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our audits (which was an integrated audit in 2012). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 21, 2013

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2012	2011	2010
Operating revenues	$23,489	$19,063	$18,644
Operating expenses			
Purchased power and fuel	10,157	7,267	6,435
Operating and maintenance	7,961	5,184	4,600
Depreciation and amortization	1,881	1,347	2,075
Taxes other than income	1,019	785	808
Total operating expenses	21,018	14,583	13,918
Equity in losses of unconsolidated affiliates	(91)	(1)	—
Operating income	2,380	4,479	4,726
Other income and (deductions)			
Interest expense, net	(903)	(701)	(792)
Interest expense to affiliates, net	(25)	(25)	(25)
Other, net	346	203	312
Total other income and (deductions)	(582)	(523)	(505)
Income before income taxes	1,798	3,956	4,221
Income taxes	627	1,457	1,658
Net income	1,171	2,499	2,563
Net Income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	11	4	—
Net income on common stock	1,160	2,495	2,563
Other comprehensive loss			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic costs, net of taxes of $1, $(4) and $(7). respectively	1	(5)	(11)
Actuarial loss reclassified to periodic cost, net of taxes of $110, $93 and $79, respectively	168	136	114
Transition obligation reclassified to periodic cost, net of taxes of $2, $2 and $2, respectively	2	4	3
Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $(237), $(171) and $(188), respectively	(371)	(250)	(288)
Change in unrealized gain (loss) on cash flow hedges, net of taxes of $(68), $39 and $(107), respectively	(120)	88	(151)
Change in unrealized gain (loss) on marketable securities, net of taxes of $(1), $0 and $0, respectively	2	—	(1)
Change in unrealized gain (loss) on equity investments, net of taxes of $1, $0 and $0, respectively	1	—	—
Other comprehensive loss	(317)	(27)	(334)
Comprehensive income	$ 854	$ 2,472	$ 2,229
Average shares of common stock outstanding:			
Basic	816	663	661
Diluted	819	665	663
Earnings per average common share:			
Basic	$ 1.42	$ 3.76	$ 3.88
Diluted	$ 1.42	$ 3.75	$ 3.87
Dividends per common share	$ 2.10	$ 2.10	$ 2.10

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2012	2011	2010
Cash flows from operating activities			
Net income	$ 1,171	$ 2,499	$ 2,563
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	4,079	2,316	2,943
Loss on sale of three Maryland generating stations	272	—	—
Deferred income taxes and amortization of investment tax credits	615	1,457	981
Net fair value changes related to derivatives	(604)	291	(88)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(157)	14	(105)
Other non-cash operating activities	1,383	770	609
Changes in assets and liabilities:			
Accounts receivable	243	57	(232)
Inventories	26	(58)	(62)
Accounts payable, accrued expenses and other current liabilities	(632)	(254)	472
Option premiums paid, net	(114)	(3)	(124)
Counterparty collateral received (posted), net	135	(344)	(155)
Income taxes	544	492	(543)
Pension and non-pension postretirement benefit contributions	(462)	(2,360)	(959)
Other assets and liabilities	(368)	(24)	(56)
Net cash flows provided by operating activities	6,131	4,853	5,244
Cash flows from investing activities			
Capital expenditures	(5,789)	(4,042)	(3,326)
Proceeds from nuclear decommissioning trust fund sales	7,265	6,139	3,764
Investment in nuclear decommissioning trust funds	(7,483)	(6,332)	(3,907)
Cash and restricted cash acquired from Constellation	964	—	—
Acquisitions of long lived assets	(21)	(387)	(893)
Proceeds from sale of three Maryland generating stations	371	—	—
Proceeds from sales of investments	28	6	28
Purchases of investments	(13)	(4)	(22)
Change in restricted cash	(34)	(3)	423
Other investing activities	136	20	39
Net cash flows used in investing activities	(4,576)	(4,603)	(3,894)
Cash flows from financing activities			
Payment of accounts receivable agreement	(15)	—	—
Changes in short-term debt	(197)	161	(155)
Issuance of long-term debt	2,027	1,199	1,398
Retirement of long-term debt	(1,145)	(789)	(828)
Retirement of long-term debt of variable interest entity	—	—	(806)
Dividends paid on common stock	(1,716)	(1,393)	(1,389)
Proceeds from employee stock plans	72	38	48
Other financing activities	(111)	(62)	(16)
Net cash flows used in financing activities	(1,085)	(846)	(1,748)
Increase (decrease) in cash and cash equivalents	470	(596)	(398)
Cash and cash equivalents at beginning of period	1,016	1,612	2,010
Cash and cash equivalents at end of period	$ 1,486	$ 1,016	$ 1,612

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,411	$ 1,016
Cash and cash equivalents of variable interest entities	75	—
Restricted cash and investments	86	40
Restricted cash and investments of variable interest entities	47	—
Accounts receivable, net		
Customer ($289 and $346 gross accounts receivables pledged as collateral as of December 31, 2012 and December 31, 2011, respectively)	2,787	1,613
Other	1,147	1,000
Accounts receivable, net, of variable interest entities	292	—
Mark-to-market derivative assets	938	432
Unamortized energy contract assets	886	16
Inventories, net		
Fossil fuel	246	208
Materials and supplies	768	656
Deferred income taxes	131	—
Regulatory assets	759	390
Other	560	342
Total current assets	10,133	5,713
Property, plant and equipment, net	45,186	32,570
Deferred debits and other assets		
Regulatory assets	6,497	4,518
Nuclear decommissioning trust funds	7,248	6,507
Investments	1,184	751
Investments in affiliates	22	15
Investment in CENG	1,849	—
Goodwill	2,625	2,625
Mark-to-market derivative assets	937	650
Unamortized energy contract assets	1,073	424
Pledged assets for Zion Station decommissioning	614	734
Deferred income taxes	58	—
Other	1,128	488
Total deferred debits and other assets	23,235	16,712
Total assets	$78,554	$54,995

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2012	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 163
Short-term notes payable—accounts receivable agreement	210	225
Long-term debt due within one year	975	828
Long-term debt due within one year of variable interest entities	72	—
Accounts payable	2,446	1,444
Accounts payable of variable interest entities	202	—
Mark-to-market derivative liabilities	352	112
Unamortized energy contract liabilities	455	—
Accrued expenses	1,800	1,255
Deferred income taxes	58	1
Regulatory liabilities	321	197
Dividends payable	4	349
Other	889	560
Total current liabilities	7,784	5,134
Long-term debt	17,190	11,799
Long-term debt to financing trusts	648	390
Long-term debt of variable interest entities	508	—
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,551	8,253
Asset retirement obligations	5,074	3,884
Pension obligations	3,428	2,194
Non-pension postretirement benefit obligations	2,662	2,263
Spent nuclear fuel obligation	1,020	1,019
Regulatory liabilities	3,981	3,627
Mark-to-market derivative liabilities	281	126
Unamortized energy contract liabilities	528	—
Payable for Zion Station decommissioning	432	563
Other	1,650	1,268
Total deferred credits and other liabilities	30,607	23,197
Total liabilities	56,737	40,520
Commitments and contingencies		
Preferred securities of subsidiary	87	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 855 and 663 shares outstanding at December 31, 2012 and 2011, respectively)	16,632	9,107
Treasury stock, at cost (35 shares held at December 31, 2012 and 2011, respectively)	(2,327)	(2,327)
Retained earnings	9,893	10,055
Accumulated other comprehensive loss, net	(2,767)	(2,450)
Total shareholders' equity	21,431	14,385
BGE preference stock not subject to mandatory redemption	193	—
Noncontrolling interest	106	3
Total equity	21,730	14,388
Total liabilities and shareholders' equity	$78,554	$54,995

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Preferred and Preference Stock	Total Shareholders' Equity
Balance, December 31, 2009	694,565	$ 8,923	$ (2,328)	$ 8,134	$ (2,089)	$ —	—	$ 12,640
Net income	—	—	—	2,563	—	—	—	2,563
Long-term incentive plan activity	1,380	60	1	(1)	—	—	—	60
Employee stock purchase plan issuances	644	23	—	—	—	—	—	23
Common stock dividends	—	—	—	(1,392)	—	—	—	(1,392)
Acquisition of Exelon Wind	—	—	—	—	—	3	—	3
Other comprehensive income, net of income taxes of $(221)	—	—	—	—	(334)	—	—	(334)
Balance, December 31, 2010	696,589	$ 9,006	$ (2,327)	$ 9,304	$ (2,423)	$ 3	$ —	$ 13,563
Net income	—	—	—	2,495	—	—	4	2,499
Long-term incentive plan activity	861	76	—	—	—	—	—	76
Employee stock purchase plan issuances	662	25	—	—	—	—	—	25
Common stock dividends	—	—	—	(1,744)	—	—	—	(1,744)
Preferred and preference stock dividends	—	—	—	—	—	—	(4)	(4)
Other comprehensive loss, net of income taxes of $(41)	—	—	—	—	(27)	—	—	(27)
Balance, December 31, 2011	698,112	$ 9,107	$ (2,327)	$ 10,055	$ (2,450)	$ 3	—	$ 14,388
Net income	—	—	—	1,160	—	(3)	14	1,171
Long-term incentive plan activity	2,432	126	—	—	—	—	—	126
Employee stock purchase plan issuances	857	26	—	—	—	—	—	26
Common stock dividends	—	—	—	(1,322)	—	—	—	(1,322)
Common stock issuance Constellation merger	188,124	7,365	—	—	—	—	—	7,365
Noncontrolling interest acquired	—	8	—	—	—	106	—	114
BGE preference stock acquired	—	—	—	—	—	—	193	193
Preferred and preference stock dividends	—	—	—	—	—	—	(14)	(14)
Other comprehensive loss, net of income taxes of $(192)	—	—	—	—	(317)	—	—	(317)
Balance, December 31, 2012	889,525	$ 16,632	$ (2,327)	$ 9,893	$ (2,767)	$ 106	193	$ 21,730

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2012	2011	2010
Operating revenues			
Operating revenues	$12,735	$ 9,286	$ 6,923
Operating revenues from affiliates	1,702	1,161	3,102
Total operating revenues	14,437	10,447	10,025
Operating expenses			
Purchased power and fuel	7,061	3,589	3,463
Operating and maintenance	4,398	2,827	2,521
Operating and maintenance from affiliates	630	321	291
Depreciation and amortization	768	570	474
Taxes other than income	369	264	230
Total operating expenses	13,226	7,571	6,979
Equity in losses of unconsolidated affiliates	(91)	(1)	—
Operating income	1,120	2,875	3,046
Other income and (deductions)			
Interest expense	(301)	(170)	(153)
Other, net	239	122	257
Total other income and (deductions)	(62)	(48)	104
Income before income taxes	1,058	2,827	3,150
Income taxes	500	1,056	1,178
Net income	558	1,771	1,972
Net loss attributable to noncontrolling interests	(4)	—	—
Net income on membership interest	562	1,771	1,972
Other comprehensive income (loss)			
Change in unrealized loss on cash flow hedges, net of income taxes of $(262), $(64) and $(102), respectively	(403)	(98)	(144)
Change in unrealized income on equity investments, net of income taxes of $(1), $0 and $0, respectively	1	—	—
Other comprehensive loss	(402)	(98)	(144)
Comprehensive income	$ 156	$ 1,673	$ 1,828

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2012	2011	2010
Cash flows from operating activities			
Net income	$ 558	$ 1,771	$ 1,972
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,966	1,539	1,341
Loss on sale of three Maryland generating stations	272	—	—
Deferred income taxes and amortization of investment tax credits	408	551	741
Net fair value changes related to derivatives	(611)	291	(88)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(157)	14	(105)
Other non-cash operating activities	537	421	182
Changes in assets and liabilities:			
Accounts receivable	248	(122)	—
Receivables from and payables to affiliates, net	39	208	(5)
Inventories	31	(47)	(70)
Accounts payable, accrued expenses and other current liabilities	(499)	34	(18)
Option premiums paid, net	(114)	(3)	(124)
Counterparty collateral (posted) received, net	95	(410)	(1)
Income taxes	114	193	(303)
Pension and non-pension postretirement benefit contributions	(178)	(1,070)	(445)
Other assets and liabilities	(128)	(57)	(45)
Net cash flows provided by operating activities	3,581	3,313	3,032
Cash flows from investing activities			
Capital expenditures	(3,554)	(2,491)	(1,883)
Proceeds from nuclear decommissioning trust fund sales	7,265	6,139	3,764
Investment in nuclear decommissioning trust funds	(7,483)	(6,332)	(3,907)
Cash and restricted cash acquired from Constellation	708	—	—
Proceeds from sale of three Maryland generating stations	371	—	—
Acquisitions of long lived assets	(21)	(387)	(893)
Change in restricted cash	4	—	4
Other investing activities	81	(6)	19
Net cash flows used in investing activities	(2,629)	(3,077)	(2,896)
Cash flows from financing activities			
Change in short-term debt	(52)	—	—
Issuance of long-term debt	1,076	—	898
Retirement of long-term debt	(145)	(2)	(215)
Distribution to member	(1,626)	(172)	(1,508)
Contribution from member	48	30	62
Other financing activities	(78)	(52)	(16)
Net cash flows used in financing activities	(777)	(196)	(779)
Increase (decrease) in cash and cash equivalents	175	40	(643)
Cash and cash equivalents at beginning of period	496	456	1,099
Cash and cash equivalents at end of period	$ 671	$ 496	$ 456

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 596	$ 496
Cash and cash equivalents of variable interest entities	75	—
Restricted cash and cash equivalents	—	5
Restricted cash and cash equivalents of variable interest entities	16	—
Accounts receivable, net		
Customer	1,482	578
Other	472	257
Accounts receivable, net, of variable interest entities	292	—
Mark-to-market derivative assets	938	432
Mark-to-market derivative assets with affiliate	226	503
Receivables from affiliates	141	109
Unamortized energy contract assets	886	16
Inventories, net		
Fossil fuel	130	120
Materials and supplies	626	556
Other	331	145
Total current assets	6,211	3,217
Property, plant and equipment, net	19,531	13,475
Deferred debits and other assets		
Nuclear decommissioning trust funds	7,248	6,507
Investments	420	42
Investment in CENG	1,849	—
Mark-to-market derivative assets	924	635
Mark-to-market derivative assets with affiliate	—	191
Prepaid pension asset	1,975	2,068
Pledged assets for Zion Station decommissioning	614	734
Unamortized energy contract assets	1,073	424
Other	836	140
Total deferred debits and other assets	14,939	10,741
Total assets	$40,681	$27,433

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2012	2011
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 2
Long-term debt due within one year	24	3
Long-term debt due within one year of variable interest entities	4	—
Accounts payable	1,346	753
Accounts payable of variable interest entities	202	—
Accrued expenses	1,116	779
Payables to affiliates	193	58
Deferred income taxes	128	244
Mark-to-market derivative liabilities	334	103
Unamortized energy contract liabilities	378	—
Other	372	202
Total current liabilities	4,097	2,144
Long-term debt	5,245	3,674
Long-term debt to affiliate	2,007	—
Long-term debt of variable interest entities	203	—
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,398	3,966
Asset retirement obligations	4,938	3,767
Non-pension postretirement benefit obligations	755	703
Spent nuclear fuel obligation	1,020	1,019
Payables to affiliates	2,397	2,222
Mark-to-market derivative liabilities	232	29
Unamortized energy contract liabilities	516	—
Payable for Zion Station decommissioning	432	563
Other	776	638
Total deferred credits and other liabilities	16,464	12,907
Total liabilities	28,016	18,725
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	8,876	3,556
Undistributed earnings	3,168	4,232
Accumulated other comprehensive income, net	513	915
Total member's equity	12,557	8,703
Noncontrolling interest	108	5
Total equity	12,665	8,708
Total liabilities and equity	$40,681	$27,433

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Changes in Member's Equity

(In millions)	Member's Equity			Noncontrolling Interest	Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income		
Balance, December 31, 2009	$ 3,464	$ 2,169	$ 1,157	$ 2	$ 6,792
Net Income	—	1,972	—	—	1,972
Distribution to member	—	(1,508)	—	—	(1,508)
Allocation of tax benefit from member	62	—	—	—	62
Acquisition of Exelon Wind	—	—	—	3	3
Other comprehensive income, net of income taxes of $(102)	—	—	(144)	—	(144)
Balance, December 31, 2010	$ 3,526	$ 2,633	$ 1,013	$ 5	$ 7,177
Net Income	—	1,771	—	—	1,771
Distribution to member	—	(172)	—	—	(172)
Allocation of tax benefit from member	30	—	—	—	30
Other comprehensive loss, net of income taxes of $(64)	—	—	(98)	—	(98)
Balance, December 31, 2011	$ 3,556	$ 4,232	$ 915	$ 5	$ 8,708
Net income	—	562	—	(4)	558
Distribution to member	—	(1,626)	—	—	(1,626)
Allocation of tax benefit from member	48	—	—	—	48
Acquisition of Constellation	5,264	—	—	—	5,264
Noncontrolling interest acquired	8	—	—	107	115
Other comprehensive loss, net of income taxes of $(261)	—	—	(402)	—	(402)
Balance, December 31, 2012	$ 8,876	$ 3,168	$ 513	$ 108	$12,665

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(in millions)	For the Years Ended December 31, 2012	2011	2010
Operating revenues			
Operating revenues	$5,441	$6,054	$6,202
Operating revenues from affiliates	2	2	2
Total operating revenues	5,443	6,056	6,204
Operating expenses			
Purchased power	1,518	2,382	2,297
Purchased power from affiliate	789	653	1,010
Operating and maintenance	1,182	1,031	917
Operating and maintenance from affiliate	163	158	152
Depreciation and amortization	610	554	516
Taxes other than income	295	296	256
Total operating expenses	4,557	5,074	5,148
Operating income	886	982	1,056
Other income and (deductions)			
Interest expense	(294)	(330)	(373)
Interest expense to affiliates, net	(13)	(15)	(13)
Other, net	39	29	24
Total other income and (deductions)	(268)	(316)	(362)
Income before income taxes	618	666	694
Income taxes	239	250	357
Net income	379	416	337
Other comprehensive income			
Change in unrealized gain (loss) on marketable securities, net of income taxes of $0, $0 and $0, respectively	1	—	(1)
Other comprehensive income (loss)	1	—	(1)
Comprehensive income	$ 380	$ 416	$ 336

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended 2012	2011	2010
Cash flows from operating activities			
Net income	$ 379	$ 416	$ 337
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	610	554	517
Deferred income taxes and amortization of investment tax credits	270	700	582
Other non-cash operating activities	252	184	238
Changes in assets and liabilities:			
Accounts receivable	24	5	(46)
Receivables from and payables to affiliates, net	(18)	(287)	(55)
Inventories	(11)	(9)	(1)
Accounts payable, accrued expenses and other current liabilities	59	(84)	342
Counterparty collateral received (posted), net	40	66	(154)
Income taxes	9	223	(233)
Pension and non-pension postretirement benefit contributions	(138)	(977)	(317)
Other assets and liabilities	(142)	45	(133)
Net cash flows provided by operating activities	1,334	836	1,077
Cash flows from investing activities			
Capital expenditures	(1,246)	(1,028)	(962)
Proceeds from sales of investments	28	6	28
Purchases of investments	(13)	(4)	(22)
Other investing activities	19	19	17
Net cash flows used in investing activities	(1,212)	(1,007)	(939)
Cash flows from financing activities			
Changes in short-term debt	—	—	(155)
Issuance of long-term debt	350	1,199	500
Retirement of long-term debt	(450)	(537)	(213)
Contributions from parent	—	—	2
Dividends paid on common stock	(105)	(300)	(310)
Other financing activities	(7)	(7)	(3)
Net cash flows provided by (used in) financing activities	(212)	355	(179)
Increase (decrease) in cash and cash equivalents	(90)	184	(41)
Cash and cash equivalents at beginning of period	234	50	91
Cash and cash equivalents at end of period	$ 144	$ 234	$ 50

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2012	2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 144	$ 234
Restricted cash	—	3
Accounts receivable, net		
Customer	539	655
Other	452	385
Inventories, net	91	81
Deferred income taxes	83	61
Counterparty collateral deposited	53	90
Regulatory assets	388	657
Other	25	22
Total current assets	1,775	2,188
Property, plant and equipment, net	13,826	13,121
Deferred debits and other assets		
Regulatory assets	666	699
Investments	8	21
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivable from affiliates	2,039	1,860
Prepaid pension asset	1,661	1,803
Other	299	315
Total deferred debits and other assets	7,304	7,329
Total assets	$22,905	$22,638

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2012	2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 252	$ 450
Accounts payable	379	325
Accrued expenses	295	318
Payables to affiliates	97	111
Customer deposits	136	136
Regulatory liabilities	130	137
Mark-to-market derivative liability	18	9
Mark-to-market derivative liability with affiliate	226	503
Other	122	82
Total current liabilities	1,655	2,071
Long-term debt	5,315	5,215
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,272	3,993
Asset retirement obligations	99	89
Non-pension postretirement benefits obligations	273	271
Regulatory liabilities	3,229	3,042
Mark-to-market derivative liability	49	97
Mark-to-market derivative liability with affiliate	—	191
Other	484	426
Total deferred credits and other liabilities	8,406	8,109
Total liabilities	15,582	15,601
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,014	5,003
Retained earnings	721	447
Accumulated other comprehensive loss, net	—	(1)
Total shareholders' equity	7,323	7,037
Total liabilities and shareholders' equity	$22,905	$22,638

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance, December 31, 2009	$ 1,588	$4,990	$ (1,639)	$ 1,943	$ —	$ 6,882
Net income	—	—	337	—	—	337
Common stock dividends	—	—	—	(310)	—	(310)
Allocation of tax benefit from parent	—	2	—	—	—	2
Appropriation of retained earnings for future dividends	—	—	(337)	337	—	—
Other comprehensive income, net of income taxes of $0	—	—	—	—	(1)	(1)
Balance, December 31, 2010	$ 1,588	$4,992	$ (1,639)	$ 1,970	$ (1)	$ 6,910
Net income	—	—	416	—	—	416
Common stock dividends	—	—	—	(300)	—	(300)
Allocation of tax benefit from parent	—	11	—	—	—	11
Appropriation of retained earnings for future dividends	—	—	(416)	416	—	—
Other comprehensive loss,						
Balance, December 31, 2011	$ 1,588	$5,003	$ (1,639)	$ 2,086	$ (1)	$ 7,037
Net income	—	—	379	—	—	379
Common stock dividends	—	—	—	(105)	—	(105)
Allocation of tax benefit from parent	—	11	—	—	—	11
Appropriation of retained earnings for future dividends	—	—	(379)	379	—	—
Other comprehensive income net of income taxes of $0	—	—	—	—	1	1
Balance, December 31, 2012	$ 1,588	$5,014	$ (1,639)	$ 2,360	$ —	$ 7,323

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2012	2011	2010
Operating revenues			
Operating revenues	$3,183	$3,715	$5,514
Operating revenues from affiliates	3	5	5
Total operating revenues	3,186	3,720	5,519
Operating expenses			
Purchased power and fuel	842	1,369	677
Purchased power from affiliate	533	495	2,085
Operating and maintenance	698	698	644
Operating and maintenance from affiliates	111	96	89
Depreciation and amortization	217	202	1,060
Taxes other than income	162	205	303
Total operating expenses	2,563	3,065	4,858
Operating income	623	655	661
Other income and (deductions)			
Interest expense	(111)	(122)	(181)
Interest expense to affiliates, net	(12)	(12)	(12)
Other, net	8	14	8
Total other income and (deductions)	(115)	(120)	(185)
Income before income taxes	508	535	476
Income taxes	127	146	152
Net income	381	389	324
Preferred security dividends	4	4	4
Net income on common stock	377	385	320
Comprehensive income, net of income taxes			
Net income	381	389	324
Other comprehensive income (loss)			
Amortization of realized gain on settled cash flow swaps, net of income taxes of $0, $0 and $(1), respectively	—	—	(1)
Change in unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively	1	—	—
Other comprehensive income (loss)	1	—	(1)
Comprehensive income	$ 382	$ 389	$ 323

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2012	2011	2010
Cash flows from operating activities			
Net income	$ 381	$ 389	$ 324
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	217	202	1,060
Deferred income taxes and amortization of investment tax credits	37	253	(400)
Other non-cash operating activities	125	100	108
Changes in assets and liabilities:			
Accounts receivable	(14)	225	(212)
Receivables from and payables to affiliates, net	13	(217)	86
Inventories	21	—	9
Accounts payable, accrued expenses and other current liabilities	(47)	34	85
Income taxes	174	(45)	118
Pension and non-pension postretirement benefit contributions	(45)	(137)	(106)
Other assets and liabilities	16	14	78
Net cash flows provided by operating activities	878	818	1,150
Cash flows from investing activities			
Capital expenditures	(422)	(481)	(545)
Changes in intercompany money pool contributions	82	(82)	—
Change in restricted cash	2	(2)	414
Other investing activities	10	8	11
Net cash flows used in investing activities	(328)	(557)	(120)
Cash flows from financing activities			
Payment of accounts receivable agreement	(15)	—	—
Issuance of long-term debt	350	—	—
Retirement of long-term debt	(375)	(250)	—
Retirement of long-term debt of variable interest entity	—	—	(806)
Contributions from parent	9	18	43
Dividends paid on common stock	(343)	(348)	(224)
Dividends paid on preferred securities	(4)	(4)	(4)
Repayment of receivable from parent	—	—	180
Other financing activities	(4)	(5)	—
Net cash flows used in financing activities	(382)	(589)	(811)
Increase (decrease) in cash and cash equivalents	168	(328)	219
Cash and cash equivalents at beginning of period	194	522	303
Cash and cash equivalents at end of period	$ 362	$ 194	$ 522

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 362	$ 194
Restricted cash and cash equivalents	—	2
Accounts receivable, net ($289 and $329 gross accounts receivable pledged as collateral as of December 31, 2012 and 2011, respectively)		
Customer	364	380
Other	161	376
Inventories, net		
Fossil fuel	65	87
Materials and supplies	19	18
Deferred income taxes	40	25
Receivable from Exelon intercompany money pool	—	82
Prepaid utility taxes	21	1
Regulatory assets	32	39
Other	30	39
Total current assets	1,094	1,243
Property, plant and equipment, net	6,078	5,874
Deferred debits and other assets		
Regulatory assets	1,378	1,216
Investments	22	22
Investments in affiliates	8	8
Receivable from affiliates	360	365
Prepaid pension asset	373	382
Other	40	46
Total deferred debits and other assets	2,181	2,039
Total assets	$9,353	$9,156

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2012	2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term notes payable—accounts receivable agreement	$ 210	$ 225
Long-term debt due within one year	300	375
Accounts payable	244	262
Accrued expenses	82	83
Payables to affiliates	76	62
Customer deposits	51	53
Regulatory liabilities	169	60
Other	26	25
Total current liabilities	1,158	1,145
Long-term debt	1,647	1,597
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,331	2,170
Asset retirement obligations	29	28
Non-pension postretirement benefits obligations	284	288
Regulatory liabilities	538	585
Other	113	134
Total deferred credits and other liabilities	3,295	3,205
Total liabilities	6,284	6,131
Commitments and contingencies		
Preferred securities	87	87
Shareholders' equity		
Common stock	2,388	2,379
Retained earnings	593	559
Accumulated other comprehensive income, net	1	—
Total shareholders' equity	2,982	2,938
Total liabilities and shareholders' equity	$9,353	$9,156

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Changes in Stockholders' Equity

(In millions)	Common Stock	Receivable from Parent	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2009	$ 2,318	$ (180)	$ 426	$ 1	$ 2,565
Net Income	—	—	324	—	324
Common stock dividends	—	—	(224)	—	(224)
Preferred security dividends	—	—	(4)	—	(4)
Repayment of receivable from parent	—	180	—	—	180
Allocation of tax benefit from parent	43	—	—	—	43
Other comprehensive loss, net of income taxes of $(1)	—	—	—	(1)	(1)
Balance, December 31, 2010	$ 2,361	$ —	$ 522	$ —	$ 2,883
Net Income	—	—	389	—	389
Common stock dividends	—	—	(348)	—	(348)
Preferred security dividends	—	—	(4)	—	(4)
Allocation of tax benefit from parent	18	—	—	—	18
Balance, December 31, 2011	$ 2,379	$ —	$ 559	$ —	$ 2,938
Net Income	—	—	381	—	381
Common stock dividends	—	—	(343)	—	(343)
Preferred security dividends	—	—	(4)	—	(4)
Allocation of tax benefit from parent	9	—	—	—	9
Other comprehensive income, net of income taxes of $0	—	—	—	1	1
Balance, December 31, 2012	$ 2,388	$ —	$ 593	$ 1	$ 2,982

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(In millions)	For the Years Ended December 31, 2012	2011	2010
Operating revenues			
Operating revenues	$2,725	$3,060	$3,534
Operating revenues from affiliates	10	8	7
Total operating revenues	2,735	3,068	3,541
Operating expenses			
Purchased power and fuel	973	1,245	1,719
Purchased power from affiliate	396	348	428
Operating and maintenance	622	530	469
Operating and maintenance from affiliates	106	150	126
Depreciation and amortization	298	274	249
Taxes other than income	208	207	200
Total operating expenses	2,603	2,754	3,191
Operating income	132	314	350
Other income and (deductions)			
Interest expense	(144)	(129)	(131)
Other, net	23	26	25
Total other income and (deductions)	(121)	(103)	(106)
Income before income taxes	11	211	244
Income taxes	7	75	97
Net income	4	136	147
Preference stock dividends	13	13	13
Net income (loss) on common stock	$ (9)	$ 123	$ 134
Comprehensive income	$ 4	$ 136	$ 147

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)	For the Years Ended December 31, 2012	2011	2010
Cash flows from operating activities			
Net income	$ 4	$ 136	$ 147
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	298	274	249
Deferred income taxes and amortization of investment tax credits	104	145	299
Other non-cash operating activities	193	129	144
Changes in assets and liabilities:			
Accounts receivable	(45)	60	(95)
Receivables from and payables to affiliates, net	26	(44)	(24)
Inventories	25	(10)	8
Accounts payable, accrued expenses and other current liabilities	(33)	(21)	(66)
Income taxes	14	35	(56)
Pension and non-pension postretirement benefit contributions	(16)	(67)	(214)
Other assets and liabilities	(85)	(161)	(63)
Net cash flows provided by operating activities	485	476	329
Cash flows from investing activities			
Capital expenditures	(582)	(592)	(508)
Proceeds from the sale of investments and other assets	—	—	21
Changes in intercompany money pool contributions	—	—	315
Change in restricted cash	—	—	(5)
Other investing activities	9	—	—
Net cash flows used in investing activities	(573)	(592)	(177)
Cash flows from financing activities			
Changes in short-term debt	—	—	(46)
Issuance of long-term debt	250	300	—
Repayment of long-term debt	(173)	(82)	(57)
Dividends paid on common stock	—	(85)	—
Dividends paid on preference stock	(13)	(13)	(13)
Contributions from parent	66	—	—
Other financing activities	(2)	(5)	—
Net cash flows provided by (used in) financing activities	128	115	(116)
Increase (decrease) in cash and cash equivalents	40	(1)	36
Cash and cash equivalents at beginning of period	49	50	14
Cash and cash equivalents at end of period	$ 89	$ 49	$ 50

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	December 31, 2012	2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 89	$ 49
Restricted cash and cash equivalents of variable interest entity	30	30
Accounts receivable, net		
Customer	401	428
Other	117	90
Income taxes receivable	3	21
Inventories, net		
Gas held in storage	51	74
Materials and supplies	31	34
Deferred income taxes	1	—
Prepaid utility taxes	57	56
Regulatory assets	185	175
Other	8	12
Total current assets	973	969
Property, plant and equipment, net	5,498	5,132
Deferred debits and other assets		
Regulatory assets	522	551
Investments	5	—
Investments in affiliates	8	8
Prepaid pension asset	467	514
Other	26	29
Total deferred debits and other assets	1,028	1,102
Total assets	$7,499	$7,203

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	December 31, 2012	2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 400	$ 110
Long-term debt of variable interest entity due within one year	67	63
Accounts payable	195	210
Accrued expenses	106	110
Deferred income taxes	—	59
Payables to affiliates	65	41
Customer deposits	71	84
Regulatory liabilities	22	19
Other	47	38
Total current liabilities	973	734
Long-term debt	1,446	1,596
Long-term debt to financing trust	258	258
Long-term debt of variable interest entity	265	332
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,658	1,491
Asset retirement obligations	8	1
Non-pension postretirement benefits obligations	229	233
Regulatory liabilities	214	201
Other	90	56
Total deferred credits and other liabilities	2,199	1,982
Total liabilities	5,141	4,902
Commitments and contingencies		
Shareholders' equity		
Common stock	1,360	1,294
Retained earnings	808	817
Total shareholders' equity	2,168	2,111
Preference stock not subject to mandatory redemption	190	190
Total equity	2,358	2,301
Total liabilities and shareholders' equity	$7,499	$7,203

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Noncontrolling Interests	Total Equity
Balance, December 31, 2009	$ 1,294	$ 645	$ 1,939	$ 190	$ 18	$2,147
Net income	—	147	147	—	—	147
Preference stock dividends	—	(13)	(13)	—	—	(13)
Sale of noncontrolling interest	—	—	—	—	(18)	(18)
Balance, December 31, 2010	$ 1,294	$ 779	$ 2,073	$ 190	$ —	$2,263
Net income	—	136	136	—	—	136
Common stock dividends	—	(85)	(85)	—	—	(85)
Preference stock dividends	—	(13)	(13)	—	—	(13)
Balance, December 31, 2011	$ 1,294	$ 817	$ 2,111	$ 190	$ —	$2,301
Net income	—	4	4	—	—	4
Preference stock dividends	—	(13)	(13)	—	—	(13)
Contribution from parent	66	—	66	—	—	66
Balance, December 31, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$ —	$2,358

See the Combined Notes to Consolidated Financial Statements

1. Significant Accounting Policies (Exelon, Generation, ComEd, PECO and BGE)

Description of Business (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses. Prior to March 12, 2012, Exelon's principal, wholly owned subsidiaries included ComEd, PECO and Generation. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger (the "Merger Agreement"). As a result of the merger transaction, Generation now includes the former Constellation generation and customer supply operations. BGE, formerly Constellation's regulated utility subsidiary, is now a subsidiary of Exelon. Refer to Note 4—Merger and Acquisitions for further information regarding the merger transaction.

The energy generation business includes:

- *Generation* : The integrated business consists of owned and contracted generation and investments in electric generating facilities that are marketed through its leading customer facing activities. The customer facing activities include wholesale and retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and investments in natural gas exploration and production activities.

The energy delivery businesses include:

- *ComEd* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

This is a combined annual report of Exelon, Generation, ComEd, PECO and BGE. The Notes to the Consolidated Financial Statements apply to Exelon, Generation, ComEd, PECO and BGE as indicated parenthetically next to each corresponding disclosure. When appropriate, Exelon, Generation, ComEd, PECO and BGE are named specifically for their related activities and disclosures.

Exelon did not apply push-down accounting to BGE. As a result, BGE continues to maintain its reporting requirements as an SEC registrant. The information disclosed for BGE represents the activity of the standalone entity for the twelve months ended December 31, 2012, 2011 and 2010 and the financial position as of December 31, 2012 and December 31, 2011. However, for Exelon's consolidated financial reporting, Exelon is reporting BGE activity from the acquisition date of March 12, 2012 through December 31, 2012.

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC, including support services, are directly charged or allocated to the applicable subsidiaries using a cost-causative allocation method. Corporate governance-type costs that cannot be directly assigned are allocated based on a Modified Massachusetts Formula, which is a method that utilizes a combination of gross revenues, total assets and direct labor costs for the allocation base. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

Exelon owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%, PECO, of which Exelon owns 100% of the common stock but none of PECO's preferred securities and BGE, of which Exelon owns 100% of the common stock but none of BGE's preference stock. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2012 and December 31, 2011, as equity, PECO's preferred securities as preferred securities of subsidiary, and BGE's preference stock as BGE preference stock not subject to mandatory redemption in its consolidated financial statements. BGE is subject to some ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for a retail power supply VIE for which Generation has no ownership interest but does have a controlling financial interest through contractual arrangements; Exelon SHC, Inc., of which Generation owns 99% and the remaining 1% is indirectly owned by Exelon, which is eliminated in Exelon's consolidated financial statements; and certain Exelon Wind projects, of which Generation holds a majority interest ranging from 94% to 99% for certain periods of time, and the remaining interests are included in noncontrolling interest on Exelon's and Generation's Consolidated Balance Sheets. See Note 2 for further discussion of Exelon's and Generation's VIEs and the reversionary interests of the Noncontrolling members for certain of these projects.

ComEd owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for RITELine Illinois, LLC of which ComEd owns 75% and an additional 12.5% is indirectly owned by Exelon. Exelon and ComEd have reflected the third-party interests of 12.5% and 25%, respectively, in RITELine Illinois, LLC, which both totaled less than $1 million at December 31, 2012, as equity.

Exelon consolidates the accounts of entities in which Exelon has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which Exelon can exercise control over the operations and policies of the investee, or the results of a model that identifies Exelon or one of its subsidiaries as the primary beneficiary of a VIE. Where Exelon does not have a controlling financial interest in an entity it applies proportional consolidation, equity method accounting or cost method accounting. Exelon applies proportionate consolidation when it has an undivided interest in an asset and is proportionately liable for its share of each liability associated with the asset. Exelon proportionately consolidates its undivided ownership interests in jointly owned electric plants and transmission facilities, as well as its undivided ownership interests in upstream natural gas exploration and production activities. Under proportionate consolidation, Exelon separately records its proportionate share of the assets, liabilities,

revenues and expenses related to the undivided interest in the asset. Exelon applies equity method accounting when it has significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. Exelon applies equity method accounting to certain investments and joint ventures, including the 50.01% interest in CENG, and certain financing trusts of ComEd and PECO. Under the equity method, Exelon reports its interest in the entity as an investment and Exelon's percentage share of the earnings from the entity as single line items in its financial statements. Exelon uses the cost method if it holds less than 20% of the common stock of an entity. Under the cost method, Exelon reports its investment at cost and recognizes income only to the extent Exelon receives dividends or distributions.

For the year ended December 31, 2012, BGE recorded a $2 million correcting adjustment to reduce electric distribution revenue related to decoupling of 2011 electric distribution revenue, a $3 million correcting adjustment to increase electric operations and maintenance expense related to capitalization of electric transmission costs, and a $5 million correcting adjustment to interest expense to reflect the impacts of amendments of tax positions previously taken on prior-year consolidated income tax returns. BGE has concluded these correcting adjustments are not material to its results of operations or cash flows for the year ended December 31, 2012, or any prior period.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (Exelon, Generation, ComEd, PECO and BGE)

The preparation of financial statements of each of the Registrants in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other AROs, pension and other postretirement benefits, the application of purchase accounting, inventory reserves, allowance for uncollectible accounts, goodwill and asset impairments, derivative instruments, unamortized energy contracts, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Reclassifications (Exelon, Generation, ComEd, PECO and BGE)

Certain prior year amounts in Exelon's, Generation's and BGE's Consolidated Statements of Cash Flows, Exelon's, Generation's, PECO's, ComEd's and BGE's Consolidated Statements of Operations and Comprehensive Income and in Exelon's, Generation's, ComEd's, PECO's and BGE's Consolidated Balance Sheets have been reclassified between line items for comparative purposes. The reclassifications did not affect any of the Registrants' net income or cash flows from operating activities.

Accounting for the Effects of Regulation (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulations, which requires ComEd, PECO and BGE to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria: 1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation

that rates are set at levels that will recover the entities' costs from customers. Exelon, ComEd, PECO and BGE account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, the PAPUC, and the MDPSC, in the cases of ComEd, PECO and BGE, respectively, under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense is recognized in the Consolidated Statements of Operations consistent with the recovery or refund included in customer rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. However, Exelon, ComEd, PECO and BGE continue to evaluate their respective abilities to apply the authoritative guidance for accounting for certain types of regulation, including consideration of current events in their respective regulatory and political environments. If a separable portion of ComEd's, PECO's or BGE's business was no longer able to meet the criteria discussed above, the affected entities would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which could have a material impact on their results of operations and financial positions. See Note 3—Regulatory Matters for additional information.

Revenues (Exelon, Generation, ComEd, PECO and BGE)

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimates of the distribution and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE records its best estimate of the transmission revenue impact resulting from changes in rates that BGE believes are probable of approval by FERC in accordance with its formula rate mechanism. See Notes 3—Regulatory Matters and 5—Accounts Receivable for further information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Company in the different RTOs and ISOs.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. As of the merger date, Exelon and Generation have currently elected to de-designate all of their commodity cash flow hedge positions. Premiums received and paid on option contracts are recognized as revenue or expense over the terms of the contracts. Since ComEd is entitled to full recovery of the costs of the financial swap contract with Generation in rates as settlements occur, ComEd records the fair value of the swap as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. See Note 3—Regulatory Matters for further information.

Proprietary Trading Activities. Exelon and Generation account for Generation's trading activities under the provisions of the authoritative guidance for accounting for contracts involved in energy trading and risk management activities, which require energy revenues and costs related to energy trading contracts to be presented on a net basis in the income statement. Commodity derivatives used

for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues. Refer to Note 10—Derivative Financial Instruments for further discussion.

Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

Deferred Federal and state income taxes are provided on all significant temporary differences between the book basis and the tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred on the Registrants' Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Registrants recognize accrued interest related to unrecognized tax benefits in interest expense or in other income and deductions (interest income) on their Consolidated Statements of Operations.

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 12—Income Taxes for further information.

Taxes Directly Imposed on Revenue-Producing Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE present any tax assessed by a governmental authority that is the liability of the Registrants and is directly imposed on a revenue-producing transaction between a seller and a customer on a gross (included in revenues and costs) basis. See Note 20—Supplemental Financial Information for Generation's, ComEd's, PECO's and BGE's utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE)

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Investments (Exelon, Generation, ComEd, PECO and BGE)

Restricted cash and investments represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2012 and 2011, Exelon Corporate's restricted cash and investments primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Additionally, Exelon Corporate has funds restricted for merger commitments. In addition, Exelon Corporate's investments include its direct financing lease investments. As of December 31, 2012, Generation's restricted cash and investments primarily included cash at one of its consolidated variable interest entities and, as of 2011, primarily represented funds in escrow related to the acquisition of Shooting Star Wind Project, LLC and cash for payment of certain environmental liabilities. As of December 31, 2012 and 2011, ComEd's restricted cash primarily represented cash

collateral held from suppliers associated with ComEd's energy and REC procurement contracts. As of December 31, 2011, PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's mortgage indenture. As of December 31, 2012 and 2011, BGE's restricted cash primarily represented funds restricted at its consolidated variable interest entity for repayment of rate stabilization bonds.

Restricted cash and investments not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2012 and 2011, Exelon's and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2012, Exelon, ComEd, PECO and BGE had short-term investments in Rabbi trusts classified as noncurrent assets.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable agings, historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 3—Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events,
- amends the events that trigger a reassessment of whether an entity is a VIE, and
- requires the entity that consolidates a VIE (the primary beneficiary) to present separately on the face of its balance sheet (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

Based on the above accounting guidance, Exelon has adopted the following policies related to variable interest entities:

- Exelon has presented separately on its Consolidated Balance Sheets, to the extent material, the assets of its consolidated VIEs that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of Exelon's consolidated VIEs for which creditors do not have recourse to Exelon's general credit.
- Exelon has qualitatively assessed whether the equity holders of the entity have the power to direct matters that most significantly impact the entity. Exelon has evaluated all existing entities under the new VIE accounting requirements, both those previously considered VIEs and those considered potential VIEs. Exelon's accounting for and disclosure about VIEs did not change materially as a result of these assessments.

See Note 2—Variable Interest Entities for additional information.

Inventories (Exelon, Generation, ComEd, PECO and BGE)

Inventory is recorded at the lower of weighted average cost or market. Provisions are recorded for excess and obsolete inventory.

Fossil Fuel. Fossil fuel inventory includes the weighted average costs of stored natural gas, propane and oil. The costs of natural gas, propane, coal and oil are generally included in inventory when purchased and charged to fuel expense when used or sold.

Materials and Supplies. Materials and supplies inventory generally includes the weighted average costs of transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and expensed or capitalized to property, plant and equipment, as appropriate, when installed or used.

Emission Allowances. Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) and are carried at the lower of weighted average cost or market and charged to fuel expense as they are used in operations.

Marketable Securities (Exelon, Generation, ComEd, PECO and BGE)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds and BGE's Rabbi trust investments are classified as trading securities and all other securities are classified as available-for-sale securities. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former ComEd and former PECO nuclear generating units (Regulatory Agreement Units) are included in regulatory liabilities at Exelon, ComEd and PECO and in noncurrent payables to affiliates at Generation and in noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former AmerGen nuclear generating units, the Zion generating station and portions of the Peach Bottom nuclear generating units not subject to a regulatory agreement (Non-Regulatory Agreement Units) are included in earnings at Exelon and Generation. Realized and unrealized gains and losses, net of tax, on BGE's Rabbi trust investments are included in earnings at Exelon and BGE. Unrealized gains and losses, net of tax, for ComEd's and PECO's available-for-sale securities are reported in OCI. Any decline in the fair value of ComEd's and PECO's available-for-sale securities below the cost basis is reviewed to determine if such decline is other-than-temporary. If the decline is

determined to be other-than-temporary, the cost basis of the available-for-sale securities is written down to fair value as a new cost basis and the amount of the write-down is included in earnings. See Note 13— Asset Retirement Obligations for information regarding marketable securities held by NDT funds and Note 20—Supplemental Financial Information for additional information regarding ComEd's and PECO's regulatory assets and liabilities.

Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

Property, plant and equipment is recorded at original cost. Original cost includes labor, materials and construction overhead. When appropriate, original cost also includes capitalized interest for Generation and Exelon Corporate and AFUDC for regulated property at ComEd, PECO and BGE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred. For constructed assets, Exelon capitalizes construction-related direct labor and material costs. ComEd, PECO and BGE also capitalized indirect construction costs including labor and related costs of departments associated with supporting construction activities.

Third parties reimburse ComEd, PECO and BGE for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, Plant and Equipment. DOE SGIG funds reimbursed to PECO and BGE are accounted for as CIAC.

For Generation, upon retirement, the cost of property is charged to accumulated depreciation in accordance with the composite method of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to operating and maintenance expense as incurred.

For ComEd, PECO and BGE, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. ComEd's and BGE's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. ComEd's and BGE's actual incurred removal costs are applied against a related regulatory liability. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method.

Generation's oil and gas exploration and production activities consist of working interests in gas producing fields. Generation accounts for these activities under the successful efforts method of accounting. Acquisition, development and exploration costs are capitalized. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

See Note 6—Property, Plant and Equipment, Note 7—Jointly Owned Electric Utility Plant and Note 20—Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within property, plant and equipment and charged to fuel expense using the unit-of-production method. The estimated disposal cost of SNF is established per the Standard Waste Contract with the DOE and is expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. On-site SNF storage costs are capitalized or expensed to operating and maintenance expense as incurred based upon the nature of the costs. A portion of the storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed.

Nuclear Outage Costs (Exelon and Generation)

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to operating and maintenance expense or capitalized to property, plant and equipment (based on the nature of the activities) in the period incurred.

New Site Development Costs (Exelon and Generation)

New site development costs represent the costs incurred in the assessment, design and construction of new power generating facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management's determination that the project is economically and operationally feasible, management and/or the Exelon Board of Directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. Upon commencement of construction, these costs will be charged to construction work in progress. Capitalized development costs are charged to operating and maintenance expense when project completion is no longer probable. At December 31, 2012 and 2011, Exelon's and Generation's capitalized development costs totaled approximately $1.2 billion and $376 million, respectively, which are included in Property, Plant and Equipment on Exelon's and Generation's Consolidated Balance Sheets. Costs included in the balance as of December 31, 2012 primarily relate to the development of the Antelope Valley project along with other, smaller renewable energy projects. See Note 4—Merger and Acquisitions for additional information on Antelope Valley. Costs included in the balance as of December 31, 2011 primarily relate to land rights and other third-party costs directly associated with the development of certain Exelon Wind projects. Approximately $4 million, $2 million and $6 million of costs were expensed by Exelon and Generation for the years ended December 31, 2012, 2011 and 2010, respectively. These costs primarily related to the possible development of new renewable energy projects.

Capitalized Software Costs (Exelon, Generation, ComEd, PECO and BGE)

Costs incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

Net unamortized software costs	Exelon	Generation	ComEd	PECO	BGE
December 31, 2012	$ 499	$ 143	$ 105	$ 63	$157
December 31, 2011	280	82	120	67	62

Amortization of capitalized software costs	Exelon [(a)]	Generation [(a)]	ComEd	PECO	BGE [(a)]
2012	$ 208	$81	$56	$ 30	$32
2011	122	41	50	25	25
2010	104	33	41	19	26

(a) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the year ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012. BGE activity represents the activity for the years ended December 31, 2012, 2011 and 2010.

Depreciation, Depletion and Amortization (Exelon, Generation, ComEd, PECO and BGE)

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method. ComEd's and BGE's depreciation includes a provision for estimated removal costs as authorized by the respective regulators. The estimated service lives for ComEd, PECO and BGE are primarily based on the average service lives from the most recent depreciation study for each respective company. The estimated service lives of the nuclear-fuel generating facilities are based on the remaining useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses (to the extent that such renewal has not yet been granted) for all of Generation's operating nuclear generating stations except for Oyster Creek. The estimated service lives of the hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the operating licenses. The estimated service lives of the fossil fuel and other renewable generating facilities are based on the remaining useful lives of the stations, which Generation periodically evaluates based on feasibility assessments taking into account economic and capital requirement considerations.

See Note 6—Property, Plant and Equipment for further information regarding depreciation.

Depletion of oil and gas exploration and production activities is recorded using the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for gas reserves are based on internal calculations.

Amortization of regulatory assets is recorded over the recovery period specified in the related legislation or regulatory agreement and is included in depreciation and amortization expense on ComEd's, PECO's and BGE's Consolidated Statements of Operations and Comprehensive Income.

See Note 3—Regulatory Matters and 20—Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of ComEd's, PECO's and BGE's regulatory assets.

Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years. The liabilities associated with Exelon's non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years. Changes to the recorded value of an ARO result from the passage of new laws and regulations, revisions to either the timing or amount of estimates of undiscounted cash flows, and estimates of cost escalation factors. AROs are accreted each year to reflect the time value of money for these present value obligations through a charge to operating and maintenance expense in the Consolidated Statements of Operations or, in the case of the majority of ComEd's and PECO's accretion, through an increase to regulatory assets. See Note 13—Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (Exelon, Generation, ComEd, PECO and BGE)

During construction, Exelon and Generation capitalize the costs of debt funds used to finance non-regulated construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense.

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to AFUDC that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

The following table summarizes total incurred interest, capitalized interest and credits to AFUDC by year:

		Exelon [a]	Generation [a]	ComEd	PECO	BGE [a]
2012	Total incurred interest [b]	$1,003	$ 368	$ 310	$125	$149
	Capitalized interest	67	67	—	—	—
	Credits to AFUDC debt and equity	25	—	9	6	15
2011	Total incurred interest [b]	$ 783	$ 219	$ 349	$138	$136
	Capitalized interest	49	49	—	—	—
	Credits to AFUDC debt and equity	25	—	12	13	22
2010	Total incurred interest [b]	$ 861	$ 191	$ 388	$197	$137
	Capitalized interest	38	38	—	—	—
	Credits to AFUDC debt and equity	16	—	5	11	16

(a) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the year ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012. BGE activity represents the activity for the years ended December 31, 2012, 2011 and 2010.
(b) Includes interest expense to affiliates.

Guarantees (Exelon, Generation, ComEd, PECO and BGE)

The Registrants recognize, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken in issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 19—Commitments and Contingencies for additional information.

Asset Impairments (Exelon, Generation, ComEd, PECO and BGE)

Long-Lived Assets. The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. The Registrants determine if long-lived assets and asset groups are impaired by comparing their undiscounted expected future cash flows to their carrying value. Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Cash flows from Generation plant assets are evaluated at a regional portfolio level along with cash flows generated from Generation's supply and risk management activities, including cash flows from contracts that are recorded as intangible contract assets and liabilities on the balance sheet. For ComEd, PECO, and BGE, the lowest level of independent cash flows is determined by evaluation of several factors including the ratemaking jurisdiction in which they operate and the type of service or commodity provided. For ComEd, the lowest level of independent cash flows is transmission and distribution and, for PECO and BGE, the lowest level of independent cash flows is transmission, distribution and gas.

An impairment loss is recorded if the undiscounted expected future cash flows are less than the carrying amount of the long-lived asset or asset group. The amount of the impairment loss recorded is the difference between the estimated fair value of the long-lived asset or asset group and the carrying value.

Conditions that could have an adverse impact on the expected future cash flows and the fair value of the long-lived assets and asset groups include, among other factors, a deteriorating business climate, including current energy and market conditions, revisions to regulatory laws, or plans to dispose of a long-lived asset significantly before the end of its useful life.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 8—Intangible Assets for additional information regarding Exelon's and ComEd's goodwill.

Equity Method Investments. Exelon and Generation evaluate equity method investments to determine whether or not they are impaired. An impairment must be recorded when the investment has experienced an other than temporary decline in value. Additionally, if the project in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other than temporary decline in value. Exelon and Generation continuously monitor issues that potentially could impact future profitability of the equity method investments.

Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For derivative contracts intended to serve as economic hedges and that do not qualify or are not designated for hedge accounting or the normal purchases and normal sales exception, changes in the fair value of the derivatives are recognized in earnings each period. Amounts classified in earnings are included in revenue, purchased power and fuel or other, net on the Consolidated Statement of Operations based on the activity the transaction is economically hedging. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon's Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. All amounts classified in earnings related to proprietary trading are included in revenue on the Consolidated Statement of Operations. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

For derivative commodity contracts, effective with the date of the merger with Constellation, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of

Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivatives executed to hedge economic risk for commodities are recorded at fair value with changes in fair value recognized through earnings for the combined company.

Revenues and expenses on derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the applicable requirements, the fair value of the related contract would be recorded on the balance sheet and immediately recognized through earnings at Generation or offset by a regulatory asset or liability at ComEd, PECO and BGE. See Note 10—Derivative Financial Instruments for additional information.

Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. Effective March 12, 2012, Exelon became the sponsor of all of Constellation's defined benefit pension and other postretirement benefit plans and defined contribution savings plans.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 14—Retirement Benefits for additional discussion of Exelon's accounting for retirement benefits.

Equity Investment Earnings (Losses) of Unconsolidated Affiliates (Exelon and Generation)

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities, power projects and joint ventures, including Generation's 50.01% interest in CENG, in equity in earnings (losses) of unconsolidated affiliates. Equity in earnings (losses) of unconsolidated affiliates also includes any adjustments to amortize the difference, if any, except for goodwill and land, between their cost in an equity method investment and the underlying equity in net assets of the investee at the date of investment. See Note 22—Related Party Transactions for additional discussion of Exelon's and Generation's investment in CENG.

Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such investment experiences an other than temporary decline in value.

New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

Exelon has identified the following new accounting pronouncements that have been recently adopted or issued that may affect the Registrants.

Fair Value Measurement

In May 2011, the FASB issued authoritative guidance amending existing guidance for measuring fair value and for disclosing information about fair value measurements. The new guidance does not impact the fair value measurements included in the Registrant's Consolidated Financial Statements as of December 31, 2012. The guidance was effective for the Registrants beginning with the period ended March 31, 2012 and was required to be applied prospectively. The Company updated the existing fair value disclosures during the first quarter of 2012 to comply with the new requirements for this standard. See Note 9—Fair Value of Financial Assets and Liabilities for new disclosures.

Statement of Comprehensive Income

In June 2011, the FASB issued authoritative guidance requiring entities to present net income and other comprehensive income in a single continuous statement of comprehensive income or in two separate, but consecutive, statements. The new guidance does not change the components that are recognized in net income and the components that are recognized in other comprehensive income. This guidance became effective for the Registrants for periods beginning after December 15, 2011 and was required to be applied retroactively. Each of the Registrants currently presents a single statement of comprehensive income, consistent with the new guidance.

Presentation of Items Reclassified out of Accumulated Other Comprehensive Income

In February 2013, the FASB issued authoritative guidance requiring entities to present either in the notes or parenthetically on the face of the financial statements, reclassifications from each component of accumulated other comprehensive income and the impacted income statement line items. Entities only need to disclose the impacted income statement line item for components reclassified to net income in their entirety; otherwise, a cross-reference to the related note should be provided. This guidance is effective for the Registrants for periods beginning after December 15, 2012 and is required to be applied prospectively. As this guidance provides only disclosure requirements, the adoption of this standard will not impact the Registrants' results of operations, cash flows or financial positions.

Disclosures About Offsetting Assets and Liabilities

In December 2011 (and amended in January 2013), the FASB issued authoritative guidance requiring entities to disclose both gross and net information about recognized derivative instruments, including bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing or lending transactions that are offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. This guidance is effective for the Registrants for periods beginning on or after January 1, 2013 and is required to be applied retrospectively. This guidance is primarily applicable to certain derivative transactions for Exelon and Generation. As this guidance provides only disclosure requirements, the adoption of this standard will not impact the Registrants' results of operations, cash flows or financial positions.

2. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Under the applicable authoritative guidance, a VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly impact the entity's economic performance.

As of December 31, 2012, the Registrant's consolidated five VIEs or VIE groups for which the Registrants were the primary beneficiary, and the Registrants had significant interests in nine other VIEs for which the Registrants do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary.

Consolidated Variable Interest Entities

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the Registrants' consolidated financial statements at December 31, 2012 and 2011 are as follows:

	December 31, 2012			December 31, 2011		
	Exelon [(a)]	Generation	BGE [(b)]	Exelon	Generation	BGE [(b)]
Current assets	$ 550	$ 519	$ 30	$ 15	$ 15	$ 30
Noncurrent assets	1,802	1,762	—	784	784	—
Total assets	$2,352	$ 2,281	$ 30	$ 799	$ 799	$ 30
Current liabilities	$ 685	$ 613	$ 71	$ 181	$ 181	$ 69
Noncurrent liabilities	837	532	265	77	77	332
Total liabilities	$1,522	$ 1,145	$336	$ 258	$ 258	$401

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Amounts related to BGE are presented for the standalone entity as of both December 31, 2012 and 2011.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the preceding table can only be settled using VIE resources.

RSB BondCo LLC . In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. BGE determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE consolidated BondCo.

BondCo's assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2012, 2011, and 2010, BGE remitted $85 million, $92 million, and $90 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2012 or 2011. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

Retail Gas Group . During 2009, Constellation formed two new entities, which now are part of Generation, and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third party gas supplier. While Generation owns 100% of these entities, it has been determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group's activities without the additional credit support that is provided in the form of a parental guarantee. Generation is the primary beneficiary of the retail gas entity group; accordingly, Generation consolidates the retail gas entity group as a VIE.

The third party gas supply arrangement is collateralized as follows:

- The assets of the retail gas entity group must be used to settle obligations under the third party gas supply agreement before it can make any distributions to Generation,
- The third party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- As of December 31, 2012, Exelon provided a $75 million parental guarantee to the third party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee, Exelon or Generation do not have any contractual or other obligations to provide additional financial support under the collateralized third party gas supply agreement. The third party gas supply creditors do not have any recourse to Exelon's or Generation's general credit other than the parental guarantee.

Retail Power Supply Entity. Generation also consolidates a retail power supply VIE for which Constellation became the primary beneficiary in 2008 as a result of a modification to its contractual arrangements that changed the allocation of the economic risks and rewards of the VIE among the variable interest holders. This entity now sits under Generation Consolidated and the consolidation of this VIE did not have a material impact on Generation's financial results or financial condition.

Solar Project Entity Group. In 2011, Constellation formed a group of solar project limited liability companies to build, own, and operate solar power facilities which are now part of Generation. Additionally, on September 30, 2011, Generation acquired all of the equity interests in Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar PV project in northern Los Angeles County, California, from First Solar Inc. While Generation owns 100% of these entities, it has been determined that certain of the individual solar project entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the solar project entities that qualify as VIEs because Generation controls the design, construction, and operation of the solar power facilities. Generation provides capital funding to these solar VIE entities for ongoing construction of the solar power facilities. In addition, these solar VIE entities have an aggregate amount of debt with third parties of $220 million for which the creditors have recourse to Generation.

Wind Project Entity Group. Generation owns and operates a number of wind project limited liability entities, the majority of which were acquired on December 9, 2010 when Generation completed the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind). Generation has evaluated the significant agreements and ownership structures and risks of each of its wind projects and underlying entities, and determined that certain of the entities are VIEs because either the projects have noncontrolling interest holders that absorb variability from the wind projects, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the wind project entities that qualify as VIEs because Generation controls the design, construction, and operation of the wind power facilities. While Generation owns 100% of the majority of the wind project entities, 10 of the projects have noncontrolling equity interests held by third parties, that currently range between 1% and 6%. Of these 10 projects, Generation's current economic interests in nine of the projects are significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the non-controlling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the non-controlling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the noncontrolling interests state that Generation is to provide financial support to the projects in proportion to its current economic interests in the projects that currently range between 94% and 99%. However, no additional support to these projects beyond what was contractually required has been provided during 2012. As of December 31, 2012, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of the wind VIE entities primarily relate to the wind generating assets, PPA intangible assets and working capital amounts.

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include three transaction types: (1) equity method investments, (2) energy purchase and sale contracts, and (3) fuel purchase commitments. For the equity method investments, the carrying amount of the investments is reflected on their Consolidated Balance Sheets in investments in affiliates. For the energy purchase and sale contracts and the fuel purchase commitments (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided or guaranteed the debt or equity support, or provided liquidity arrangements, performance guarantees or other commitments associated with these commercial agreements.

As of December 31, 2012, Exelon and Generation did have significant variable interests in and exposure to loss associated with nine VIEs for which they were not the primary beneficiary; including certain equity method investments and certain commercial agreements. As of December 31, 2011, Exelon and Generation had a significant variable interest in and exposure to loss associated with one VIE for which they were not the primary beneficiary. The following tables present summary information about the significant unconsolidated VIE entities for which Exelon and Generation have exposure to loss:

December 31, 2012	Commercial Agreement VIEs	Equity Method Investment VIEs	Total
Total assets [a]	$ 386	$ 354	$740
Total liabilities [a]	219	114	333
Registrants' ownership interest [a]	—	97	97
Other ownership interests [a]	167	143	310
Registrants' maximum exposure to loss:			
Letters of credit	5	—	5
Carrying amount of equity method investments	—	77	77
Contract intangible asset	8	—	8
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning [b]	50	—	50

December 31, 2011	Commercial Agreement VIEs	Equity Method Investment VIEs	Total
Registrants' maximum exposure to loss:			
Net assets pledged for Zion Station decommissioning [b]	43	—	43

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.

(b) These items represent amounts on Generation's and Exelon's balance sheet related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $614 million and $734 million as of December 31, 2012 and December 31, 2011, respectively; offset by payables to ZionSolutions LLC of $564 million and $691 million as of December 31, 2012 and December 31, 2011, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE. See Note 13—Asset Retirement Obligations for further discussion.

Exelon and Generation assess the risk of a loss equal to their maximum exposure to be remote and, accordingly have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would affect the fair value or risk of their variable interests in these variable interest entities.

Energy Purchase and Sale Agreements. In March 2005, Constellation, to which Generation is now a successor, closed a transaction in which Generation assumed from a counterparty two power sales contracts with previously existing VIEs. The VIEs previously were created by the counterparty to issue debt in order to monetize the value of the original contracts to purchase and sell power. Under the power sales contracts, Generation sells power to the VIEs which, in turn, sell that power to an electric distribution utility through 2013. In connection with this transaction, a third party acquired the equity of the VIEs and Generation loaned that party a portion of the purchase price. If the electric distribution utility were to default under its obligation to buy power from the VIEs, the equity holder

could transfer its equity interests to Generation in lieu of repaying the loan. In this event, Generation would have the right to seek recovery of its losses from the electric distribution utility. As a result, Generation has concluded that consolidation is not required.

ZionSolutions. Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 13— Asset Retirement Obligations. Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning is complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required.

Fuel Purchase Commitments. Generation's customer supply operations include the physical delivery and marketing of power obtained through its generating capacity, and long-, intermediate-and short-term contracts. Generation also has contracts to purchase fuel supplies for nuclear and fossil generation. These contracts and Generation's membership in NEIL are discussed in further detail in Note 19—Commitments and Contingencies. Generation has evaluated these contracts and its membership with NEIL and determined that it either has no variable interest in an entity or, where Generation does have a variable interest in an entity, the variable interest is not significant and it is not the primary beneficiary; therefore, consolidation is not required.

For contracts where Generation has a variable interest, the level of variability being absorbed through the contracts is not considered significant because of the small proportion of the entities' activities encompassed by the contracts with Generation. Further, Generation has considered which interest holder has the power to direct the activities that most significantly affect the economic performance of the VIE and thus is considered the primary beneficiary and is required to consolidate the entity. The primary beneficiary must also have exposure to significant losses or the right to receive significant benefits from the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of the facilities. Facilities represent power plants, sources of uranium and fossil fuels, or plants used in the uranium conversion, enrichment and fabrication process. Generation does not have control over the operation and maintenance of the facilities considered VIEs, and it does not bear operational risk of the facilities. Furthermore, Generation has no debt or equity investments in the entities and Generation does not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 19—Commitments and Contingencies. Upon consideration of these factors, Generation does not consider itself to have significant variable interests in these entities or be the primary beneficiary of these VIEs and, accordingly, has determined that consolidation is not required.

ComEd, PECO and BGE

ComEd's, PECO's, and BGE's retail operations frequently include the purchase of electricity and RECs through procurement contracts of varying durations. See Note 3—Regulatory Matters and Note 19—Commitments and Contingencies for additional information on these contracts. ComEd, PECO and BGE have evaluated these types of contracts and have historically determined that either there is no significant variable interest in the entity, or where either ComEd, PECO or BGE does have a significant variable interest in a VIE, ComEd, PECO or BGE would not be the primary beneficiary and, therefore, consolidation would not be required.

For contracts where ComEd, PECO or BGE is considered to have a significant variable interest, consideration is given to which interest holder has the power to direct the activities that most

significantly affect the economic performance of the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of their production or procurement processes related to electricity, RECs, AECs or natural gas. ComEd, PECO and BGE do not have control over the operation and maintenance of the entities and they do not bear operational risk related to the associated activities. Generally, the carrying amounts of assets and liabilities in ComEd's, PECO's, and BGE's Consolidated Balance Sheets that relate to their involvement with VIEs generally represent the amounts owed by the utilities for the purchases associated with the current billing cycles under the contracts. As of December 31, 2012, the total amount of accounts payable owed by the utilities under agreements with VIEs was not material. In addition, variability from these contracts is mitigated by the fact that the utilities are able to recover costs incurred under purchase agreements through customer rates. Furthermore, ComEd, PECO and BGE do not have any debt or equity investments in any VIEs and do not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 19—Commitments and Contingencies. Accordingly, none of ComEd, PECO or BGE considers itself to be the primary beneficiary of any VIEs as a result of commercial arrangements.

PECO

PETT, a financing trust, was created in 1998 by PECO to purchase and own intangible transition property (ITP) and to issue transition bonds to securitize $5 billion of PECO's stranded cost recovery authorized by the PAPUC pursuant to the Competition Act. PETT was consolidated in Exelon's and PECO's financial statements on January 1, 2010 pursuant to authoritative guidance relating to the consolidation of VIEs that became effective on that date. Under the guidance, PECO concluded that it was the primary beneficiary of PETT due to PECO's involvement in the design of PETT, its role as servicer, and its right to dissolve PETT and receive any of its remaining assets following retirement of the transition bonds and payment of PETT's other expenses. The consolidation of PETT did not have a significant impact on PECO's results of operations or statement of cash flows. Upon retirement of the outstanding transition bonds on September 1, 2010, the remaining cash balance was remitted to PECO, and PETT was dissolved on September 20, 2010.

3. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

The following matters below discuss the current status of material regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd).

Background

EIMA provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. EIMA allows the recovery of costs by a utility through a pre-established performance-based formula rate tariff, approved by the ICC. ComEd made an initial contribution of $15 million (recognized as expense in 2011) to a new Science and Technology Innovation Trust fund on July 31, 2012, and will make recurring annual contributions of $4 million, the first of which was made on December 31, 2012, which will be used for customer education for as long as the AMI Deployment Plan remains in effect. In addition, ComEd will contribute $10 million per year for five years, as long as ComEd is subject to EIMA, to fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates. These contributions also began in 2012.

Formula Rate Tariff

On November 8, 2011, ComEd filed its initial formula rate tariff and associated testimony based on 2010 costs and 2011 plant additions. The primary purpose of that proceeding was to establish the formula rate under which rates will be calculated going-forward, and the initial rates, which went into effect in late June 2012. On May 29, 2012, the ICC issued an Order (May Order) in that proceeding. The May Order reduced the annual revenue requirement by $168 million, or approximately $110 million more than proposed by ComEd. Of this incremental revenue requirement reduction, approximately $50 million reflected the ICC's determination that certain costs should be recovered through alternative rate recovery tariffs available to ComEd or will be reflected in a subsequent annual reconciliation, thereby primarily delaying the timing of cash flows. The incremental revenue reduction also reflected a $35 million reduction for the disallowance of return on ComEd's pension asset, a $10 million reduction for incentive compensation related adjustments, and $15 million of reductions for various adjustments for cash working capital, operating reserves, and other technical items. In the second quarter of 2012, ComEd recorded a total reduction of revenue of approximately $100 million pre-tax to decrease the regulatory asset for 2011 and for the first three months of 2012 consistent with the terms of the May Order.

On June 22, 2012, the ICC granted an expedited rehearing on some of the issues raised by the May Order, including ComEd's pension asset recovery. On October 3, 2012, the ICC issued its final order (Rehearing Order) in that rehearing, adopting ComEd's position on the return on its pension asset, resulting in an increase in ComEd's annual revenue requirement. In two other areas, the ICC ruled against ComEd by reaffirming use of an average rather than year-end rate base in ComEd's reconciliation revenue requirement; and amending its prior order to provide a short-term debt rate as the appropriate interest rate to apply to under/over recoveries of incurred costs. ComEd filed an appeal of the May Order and the Rehearing Order in court on October 4, 2012. In the fourth quarter of 2012 ComEd recorded an increase in revenue of approximately $135 million pre-tax consistent with the terms of the Rehearing Order, of which $75 million pre-tax reflects the reinstatement of the 2011 return on pension asset and $60 million pre-tax reflects the return on pension asset costs for 2012. New rates reflecting the impacts of the Rehearing Order went into effect in November 2012.

Capital Investment

On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. These investments will be incremental to ComEd's historical level of capital expenditures. The filing with the ICC specifically included ComEd's $233 million investment plan for 2012. On April 23, 2012, ComEd filed its initial AMI Deployment Plan with the ICC. On June 22, 2012, the ICC approved the AMI Deployment Plan with certain modifications. However, as a result of the Rehearing Order above, ComEd is delaying certain elements of the AMI Deployment Plan, including the installation of additional smart meters. ComEd outlined the new deployment schedule within testimony provided in the AMI Plan Rehearing on October 3, 2012. As a result of the Rehearing Order, ComEd has deferred approximately $50 million of the 2012 AMI Deployment Plan and $15 million of 2012 planned capital investment to future years. On December 5, 2012, the ICC approved ComEd's revised AMI deployment plan. Under the AMI deployment schedule, ComEd will be taking meters out of service prior to the end of their original service lives, which resulted in recording accelerated depreciation for the remaining carrying value of the meters. The Order provides for full recovery of the cost of these early retired meters and, therefore, ComEd recorded a regulatory asset of $7 million for the accelerated depreciation of these meters in the fourth quarter of 2012.

Annual Reconciliation

ComEd will file an annual reconciliation of the revenue requirement in effect in a given year to reflect actual costs that the ICC determines are prudently and reasonably incurred for such year. ComEd made its initial 2011 reconciliation filing on April 30, 2012, which reconciled the 2011 revenue requirement in effect to ComEd's actual 2011 costs incurred. The ICC's final order, issued on December 20, 2012, increased the revenue requirement by $73 million, in conformity with the formula rate structure provided in the May and Rehearing Orders. The rates took effect in January 2013. A similar reconciliation with respect to 2012 will be filed in second quarter 2013 with any adjustments to rates taking effect in January 2014. As of December 31, 2012, and December 31, 2011, ComEd recorded a net regulatory asset of $209 million and $84 million, respectively, reflecting ComEd's best estimate of the probable increase in distribution rates expected to be approved by the ICC to provide for recovery of prudent and reasonable costs incurred, consistent with the ICC's approved distribution formula rate structure per the May and Rehearing Orders.

Appeal of 2007 Illinois Electric Distribution Rate Case (Exelon and ComEd). The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via a rider (Rider SMP).

The Court held the ICC abused its discretion in not reducing ComEd's rate base to account for an additional 18 months of accumulated depreciation while including post-test year pro forma plant additions through that period (the same position ComEd took in its 2010 electric distribution rate case (2010 Rate Case) discussed below). ComEd continued to bill rates as established under the ICC's order in the 2007 Rate Case until June 1, 2011, when the rates set in the 2010 Rate Case became effective. In August 2011, ComEd filed testimony in the remand proceeding that no refunds should be required. The ICC subsequently initiated a proceeding on remand. On February 23, 2012, the ICC issued an order on remand in the proceeding requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation issue. On March 26, 2012, ComEd filed a notice of appeal with the Court.

ComEd has recognized for accounting purposes its best estimate of any refund obligation, as discussed above.

Advanced Metering Program Proceeding (Exelon and ComEd) In October 2009, the ICC approved a modified version of ComEd's system modernization rider proposed in the 2007 Rate Case, Rider AMP (Advanced Metering Program). ComEd collected approximately $24 million under Rider AMP through December 31, 2011. Several other parties, including the Illinois Attorney General, appealed the ICC's order on Rider AMP. In ComEd's 2010 electric distribution rate case, the ICC approved ComEd's transfer of other costs from recovery under Rider AMP to recovery through electric distribution rates. On March 19, 2012, the Court reversed the ICC's approval of Rider AMP, concluding that the ICC's October 2009 approval of the rider constituted single-issue ratemaking. ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court on April 23, 2012. The Illinois Supreme Court denied the Petition on September 26, 2012, and returned the matter to the ICC to calculate a refund amount. ComEd believes any refund obligation associated with Rider AMP should be prospective from no earlier than the date of the Court's order on March 19, 2012, and should not have a material impact on ComEd and Exelon.

2010 Illinois Electric Distribution Rate Case (Exelon and ComEd). On June 30, 2010, ComEd requested ICC approval for an increase of $396 million to its annual delivery services revenue requirement. This request was subsequently reduced to $343 million to account for changes in tax law, corrections, acceptance of limited adjustments proposed by certain parties and the amounts expected to be recovered in the AMI pilot program tariff discussed above. The request to increase the annual revenue requirement was to allow ComEd to recover the costs of substantial investments made since its last rate filing in 2007. The requested increase also reflected increased costs, most notably pension and OPEB, since ComEd's rates were last determined. The original requested rate of return on common equity was 11.5%. In addition, ComEd requested future recovery of certain amounts that were previously recorded as expense that would allow ComEd to recognize a one-time benefit of up to $40 million (pre-tax). The requested increase also included $22 million for increased uncollectible accounts expense, which would increase the threshold for determining over/under recoveries under ComEd's uncollectible accounts tariff.

On May 24, 2011, the ICC issued an order in ComEd's 2010 rate case, which became effective on June 1, 2011. The order approved a $143 million increase to ComEd's annual delivery services revenue requirement and a 10.5% rate of return on common equity. As expected, the ICC followed the Court's position on the post-test year accumulated depreciation issue. The order allowed ComEd to establish or reestablish a net amount of approximately $40 million of previously expensed plant balances or new regulatory assets, which is reflected as a reduction in operating and maintenance expense and income tax expense for the year ended December 31, 2012. The order also affirmed the current regulatory asset for severance costs, which was challenged by an intervener in the 2010 Rate Case. The order has been appealed to the Court by several parties. ComEd cannot predict the result of these appeals.

Utility Consolidated Billing and Purchase of Receivables (Exelon and ComEd). In November 2008, the Illinois Public Utilities Act was amended to require ComEd to file tariffs establishing Utility Consolidated Billing and Purchase of Receivables services. On December 15, 2010, the ICC approved ComEd's tariff offering Purchase of Receivables with Consolidated Billing (PORCB) services for RES. Since the first quarter of 2011, ComEd has been required to buy certain RES receivables, primarily residential and small commercial and industrial customers, at the option of the RES, for electric supply service and then include those amounts on ComEd's bill to customers. Receivables are purchased at a discount to compensate ComEd for uncollectible accounts. ComEd produces consolidated bills for the aforementioned retail customers reflecting charges for electric delivery service and purchased receivables. As of December 31, 2012, the balance of purchased accounts receivable associated with PORCB was $55 million. Under the tariff, ComEd recovers from RES and customers the costs for implementing and operating the program. A number of municipalities, including the City of Chicago, have announced their intention to switch to RES electric supply as a result of referenda voted on in November 2012. The City of Chicago switching will occur in the first quarter of 2013. The other municipalities are expected to switch during the first half of 2013. As a result, ComEd expects a significant increase in the amount of RES receivables it will be required to purchase in 2013.

Recovery of Uncollectible Accounts (Exelon and ComEd). On February 2, 2010, the ICC issued an order adopting tariffs for ComEd to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and amounts collected in rates annually. As a result of the ICC order, ComEd recorded a regulatory asset of $70 million and an offsetting reduction in operating and maintenance expense in the first quarter of 2010 for the cumulative under-collections in 2008 and 2009. In addition, ComEd recorded a one-time charge of $10 million to operating and maintenance expense in the first quarter of 2010 for a contribution to the Supplemental Low-Income Energy Assistance Fund, which is used to assist low-income residential customers.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, under the Illinois Settlement Legislation, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. In order to fulfill a requirement of the Illinois Settlement Legislation, ComEd hedged the price of a significant portion of energy purchased in the spot market with a five-year variable-to-fixed financial swap contract with Generation that expires on May 31, 2013. On February 17, 2012, the ICC approved the IPA's procurement plan covering the period June 2012 through May 2017. As of December 31, 2012, ComEd had completed the ICC-approved procurement process for its energy requirements through May 2013 as well as a portion of its requirements for each of the procurement periods ending in May 2014 and May 2015.

EIMA discussed above contains a provision for the IPA to conduct procurement events for energy and REC requirements for the June 2013 through December 2017 period. The procurement events mandated under EIMA were completed during February 2012.

The Illinois Settlement Legislation discussed below requires ComEd to purchase an increasing percentage of its electricity requirements from renewable energy resources. On December 17, 2010, ComEd entered into 20-year contracts with several unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. The long-term renewables purchased will count towards satisfying ComEd's obligation under the state's RPS and all associated costs will be recoverable from customers. As of December 31, 2012, ComEd has completed the ICC-approved procurement process for RECs through May 2013. See Note 10—Derivative Financial Instruments for additional information regarding ComEd's financial swap contract with Generation and long-term renewable energy contracts.

On December 19, 2012, the ICC issued an order directing ComEd and Ameren (the Utilities) to enter into sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The proposed term of the agreement is 20 years. The development was approved by the DOE on February 4, 2013. The sourcing agreement is currently being drafted and approved under a separate proceeding, with a final order expected in 2013. The sourcing agreement is expected to stipulate that the Utilities will pay (or receive) the difference between FutureGen's contract prices and the revenues FutureGen receives for capacity and energy from bidding the unit into the MISO markets. The order also directs the Utilities to recover (or pass along) the difference from the Utilities' distribution system customers, regardless of whether they purchase electricity from the Utility or from an alternative electric generation supplier. On January 22, 2013, ComEd filed an application for rehearing, requesting the ICC reconsider its December order by expanding the parties to the sourcing agreement to also include RES suppliers. On January 29, 2013, the ICC denied ComEd's rehearing request. Depending on the precise terms of the sourcing agreement, the eventual market conditions, and the manner of cost recovery, the sourcing agreement could have a material adverse impact on Exelon's and ComEd's cash flows and financial positions.

On December 19, 2012, the ICC approved the IPA's 2013 procurement plan. In response to the increased number of ComEd's customers purchasing their energy from alternative energy suppliers on their own or through municipal aggregation, the plan does not propose any new REC procurements for the period June 2013—May 2014. Additionally, the IPA plan provides that curtailment of the existing long-term contracts for renewable energy and RECs be considered. The ICC concluded that the

magnitude of this curtailment shall be determined based upon the March 2013 forecast update and that any such reduction shall be applied proportionately to each of the long-term contracts consistent with the terms of the contracts on an equal, pro-rata basis.

Illinois Settlement Legislation (Exelon, Generation and ComEd). The Illinois Settlement Legislation was signed into law in August 2007 following a settlement resulting from extensive discussions with legislative leaders in Illinois, ComEd, Generation and other utilities and generators in Illinois to address concerns about higher electric bills without rate freeze, generation tax or other legislation that Exelon believes would be harmful to consumers of electricity, electric utilities, generators of electricity and the State of Illinois. Various Illinois electric utilities, their affiliates and generators of electricity agreed to contribute approximately $1 billion over a period of four years that ended in 2010 to programs to provide rate relief to Illinois electricity customers and funding for the IPA. ComEd committed to issue $64 million in rate relief credits to customers or to fund various programs to assist customers. Generation committed to contribute an aggregate of $747 million, consisting of $435 million to pay ComEd for rate relief programs for ComEd customers, approximately $308 million for rate relief programs for customers of other Illinois utilities and approximately $5 million for partially funding operations of the IPA. The contributions were recognized in the financial statements of Generation and ComEd as rate relief credits were applied to customer bills by ComEd and other Illinois utilities or as operating expenses associated with the programs were incurred. As of December 31, 2010, Generation and ComEd had fulfilled their commitments under the Illinois Settlement Legislation.

During 2010, Generation and ComEd recognized net costs from their contributions pursuant to the Illinois Settlement Legislation in their Consolidated Statements of Operations as follows:

Year Ended December 31, 2010	Generation	ComEd	Total Credits Issued to ComEd Customers
Credits to ComEd customers [(a)]	$ 14	$ 1	$ 15
Credits to other Illinois utilities' customers [(a)]	7	n/a	n/a
Total incurred costs	$ 21	$ 1	$ 15

(a) Recorded as a reduction in operating revenues.

Energy Efficiency and Renewable Energy Resources (Exelon and ComEd). As a result of the Illinois Settlement Legislation, electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an incremental annual program energy savings requirement of 0.2% of energy delivered to retail customers for the year ended June 1, 2009, which increases annually to 2.0% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten-year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In February 2008, the ICC issued an order approving substantially all of ComEd's initial three-year Energy Efficiency and Demand Response Plan, including cost recovery, covering the period from June 2008 through May 2011. In December 2010, the ICC approved ComEd's second three-year Energy Efficiency and Demand Response Plan covering the period June 2011 through May 2014. The plans are designed to meet the Illinois Settlement Legislation's energy efficiency and demand response goals through May 2014, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

Since June 1, 2008, utilities have been required to procure cost-effective renewable energy resources in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers. ComEd is also required to acquire amounts of renewable energy resources that will cumulatively increase this percentage to at least 10% by June 1, 2015, with an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth in the Illinois Settlement Legislation. As of December 31, 2012, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates. See Note 19—Commitments and Contingencies for information regarding ComEd's future commitments for the procurement of RECs.

Pennsylvania Regulatory Matters

2010 Pennsylvania Electric and Natural Gas Distribution Rate Cases (Exelon and PECO). On December 16, 2010, the PAPUC approved the settlement of PECO's electric and natural gas distribution rate cases, which were filed in March 2010, providing increases in annual service revenue of $225 million and $20 million, respectively. The electric settlement provides for recovery of PJM transmission service costs on a full and current basis through a rider. The approved electric and natural gas distribution rates became effective on January 1, 2011.

In addition, the settlements included a stipulation regarding how tax benefits related to the application of any new IRS guidance on repairs deduction methodology are to be handled from a rate-making perspective. The settlements require that the expected cash benefit from the application of any new guidance to tax years prior to 2011 be refunded to customers over a seven-year period. On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for electric transmission and distribution property. PECO adopted the safe harbor and elected a method change for the 2010 tax year. The expected total refund to customers for the tax cash benefit from the application of the safe harbor to costs incurred prior to 2010 is $171 million. On October 4, 2011, PECO filed a supplement to its electric distribution tariff to execute the refund to customers of the tax cash benefit related to the IRC Section 481(a) "catch-up" adjustment claimed on the 2010 income tax return, which is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2012.

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The expected total refund to customers for the tax cash benefit from the application of the new method to costs incurred prior to 2011 is $54 million. This amount is subject to adjustment based on the outcome of IRS examinations. Credits will be reflected in customer bills beginning January 1, 2013. PECO currently anticipates that the IRS will issue guidance in 2013 providing a safe harbor method of accounting for gas transmission and distribution property.

The prospective tax benefits claimed as a result of the new methodology will be reflected in tax expense in the year in which they are claimed on the tax return and will be reflected in the determination of revenue requirements in the next electric and natural gas distribution rate cases. See Note 12 for additional information.

The 2010 electric and natural gas distribution rate case settlements did not specify the rate of return upon which the settlement rates are based, but rather provided for an increase in annual revenue. PECO has not filed a transmission rate case since rates have been unbundled.

Pennsylvania Procurement Proceedings (Exelon and PECO). PECO's current PAPUC approved DSP Program, under which PECO is providing default electric service, has a 29-month term that began on January 1, 2011 and ends May 31, 2013. On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO's second DSP Program, which was filed with the PAPUC in January 2012. The program, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129. Under the DSP Programs, PECO is permitted to recover its electric procurement costs from retail default service customers without mark-up through the GSA. The GSA provides for the recovery of energy, capacity, ancillary costs and administrative costs and is subject to adjustments at least quarterly for any over or under collections. In addition, PECO's second DSP Program provides for the recovery of AEPS compliance costs through the GSA rather than a separate AEPS rider. The filing and implementation costs of the current and second DSP Programs were recorded as regulatory assets and are being recovered through the GSA over the DSP Programs 29-month and 24-month terms, respectively.

During 2012, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its last three competitive procurements under the DSP Program for electric supply for default electric service. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Statement of Operations and Comprehensive Income.

In the second DSP Program, PECO will procure electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes will be served through competitively procured fixed price, full requirements contracts of two years or less. Similar to the current DSP Program, for the large commercial and industrial class load, PECO will competitively procure contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes beginning in June 2013.

In addition, the second DSP Program includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs beginning April 1, 2014. PECO expects to file its plan for CAP customers by May 1, 2013.

Smart Meter and Smart Grid Investments (Exelon and PECO). Pursuant to Act 129 and the follow-on Implementation Order of 2009, in April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million smart meters and an AMI communication network by 2020. The first phase of PECO's SMPIP included the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. On January 18, 2013, PECO filed with the PAPUC its universal deployment plan for approval of its proposal to deploy the remainder of the 1.6 million smart meters on an accelerated basis by the end of 2014. In total, PECO currently expects to spend up to $595 million, excluding the cost of the original meters (as further described below), on its smart meter infrastructure and approximately $120 million on smart grid investments through 2014 before considering the DOE reimbursements discussed below. As of December 31, 2012, PECO has spent $241 million and $100 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO's existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of December 31, 2012, PECO has received $144 million of the $200 million in reimbursements. PECO's outstanding receivable from the DOE for reimbursable costs was $17 million as of December 31, 2012, which has been recorded in other accounts receivable, net on Exelon's and PECO's Consolidated Balance Sheets.

On August 15, 2012, PECO suspended installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO has replaced the previously installed meters with an alternative vendor's meters. PECO intends to move forward with the alternative meters during universal deployment and continues to evaluate meters from several vendors and may use more than one meter vendor during universal deployment.

Following PECO's decision, as of October 9, 2012 PECO will no longer use the original smart meters. For the meters that will no longer be used the accounting guidance requires that any difference between the carrying value and net realizable value be recognized in the current period's earnings, before considering potential regulatory recovery. The cost of the original meters, including installation and removal costs, owned by PECO was approximately $19 million, net of approximately $16 million of reimbursements from the DOE. PECO is seeking full recovery of all incurred costs related to the original deployment of meters. For amounts not recovered from the vendor, PECO will seek regulatory rate recovery in a future filing with the PAPUC. PECO did not seek recovery of original meter costs in the January 2013 universal deployment filing, as resolution with the vendor is still pending. In November 2012, PECO requested and received approval from the DOE that the original meters continue to be allowable costs. In addition, PECO remains eligible for the full $200 million in SGIG funds.

As of December 31, 2012, PECO believes the amounts incurred for the original meters and related installation and removal costs are probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As a result, a regulatory asset of $17 million, representing the cost of the original meters, net of accumulated depreciation and DOE reimbursements, was recorded on Exelon's and PECO's Consolidated Balance Sheets as of December 31, 2012. If PECO later determines that the regulatory asset is no longer probable of recovery, PECO would be required to recognize a charge in earnings in the period in which that determination was made.

Energy Efficiency Programs (Exelon and PECO). PECO's PAPUC-approved Phase I EE&C Plan has a four-year term that began on June 1, 2009 and will conclude on May 31, 2013. Spending for Phase I totals more than $328 million pursuant to Act 129's EE&C reduction targets. The Phase I plan sets forth how PECO will meet the required reduction targets established by Act 129's EE&C provisions, which include a 3% reduction in electric consumption in PECO's service territory and a 4.5% reduction in PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013. If PECO fails to achieve the required reductions in consumption within the stated deadline, PECO will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers.

The peak demand period ended on September 30, 2012 and PECO will report its compliance with the reduction targets in a preliminary filing with the PAPUC on March 1, 2013. The final compliance report is due to the PAPUC by November 15, 2013.

On August 2, 2012, the PAPUC issued its Phase II EE&C implementation order. The order provides energy consumption reduction requirements for the second phase of Act 129's EE&C programs, which will go into effect on June 1, 2013, but defers a decision on peak demand reduction requirements until 2013. The order tentatively established PECO's three-year cumulative consumption reduction target at 2.9%. In August 2012, PECO requested an evidentiary hearing regarding the appropriateness of its 2.9% target. The target was subsequently reaffirmed by the PAPUC on December 5, 2012. In addition, on September 4, 2012, PECO filed a Petition for Reconsideration of the terms of the PAPUC's implementation order for Phase II, which was subsequently denied.

Pursuant to the Phase II implementation order, PECO filed its three-year EE&C Phase II plan with the PAPUC on November 1, 2012. The plan sets forth how PECO will reduce electric consumption by at least 2.9% in its service territory for the period June 1, 2013 through May 31, 2016, adjusted for weather and extraordinary loads. The implementation order permits PECO to apply any excess savings achieved during Phase I against its Phase II consumption reduction targets, with no reduction to its Phase II budget. In accordance with the Act 129 Phase II implementation order, at least 10% and 4.5% of the total consumption reductions must be through programs directed toward PECO's public and low income sectors, respectively. If PECO fails to achieve the required reductions in consumption, it will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers. Act 129 mandates that the total cost of the plan may not exceed 2% of the electric company's total annual revenue as of December 31, 2006.

Alternative Energy Portfolio Standards (Exelon and PECO). In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of PECO's rate cap transition period, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources ranges from approximately 3.5% to 8% and the requirement for Tier II alternative energy resources ranges from 6.2% to 10%. The required compliance percentages incrementally increase each annual compliance period, which is from June 1 through May 31, until May 31, 2021. These Tier I and Tier II alternative energy resources include acceptable energy sources as set forth in Act 129 and the AEPS Act.

PECO has entered into five-year and ten-year agreements with accepted bidders, including Generation, totaling 452,000 non-solar and 8,000 solar Tier I AECs annually in accordance with a PAPUC approved plan. The plan allowed PECO to bank AECs procured prior to 2011 and use the banked AECs to meet its AEPS Act obligations over two compliance years ending May 2013. The PAPUC also approved the procurement of Tier II AECs and supplemental AECs as well as the sale of excess AECs through independent third party auctions or brokers. On January 5, 2012, PECO successfully conducted a competitive procurement for 275,000 Tier II AECs to be available toward its AEPS Act obligations for its compliance years ended May 2012 and ending May 2013, which was approved by the PAPUC on January 17, 2012.

All AEPS administrative costs and costs of AECs incurred after December 31, 2010 are being recovered on a full and current basis from default service customers through a surcharge.

PECO's second DSP Program eliminated the AEPS rider. Beginning in June 2013, AEPS compliance costs will be recovered through the GSA.

Natural Gas Choice Supplier Tariff (Exelon and PECO). During 2011, the PAPUC approved PECO's tariff supplements to its Gas Choice Supplier Coordination Tariff and its Retail Gas Service Tariff to address the new licensing requirements for natural gas suppliers (NGS) set forth in the PAPUC's final rulemaking order, which became effective January 1, 2011. The new licensing requirements broaden the types of collateral that PECO can require to mitigate its risk related to an NGS default, as well as PECO's ability to adjust collateral when material changes in supplier creditworthiness occur. PECO has completed its creditworthiness determinations and notified affected NGSs of their new collateral levels. As a result, PECO has obtained $14 million of collateral as of December 31, 2012.

Investigation of Pennsylvania Retail Electricity Market (Exelon and PECO). On July 28, 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania's retail electric market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. On March 1, 2012, the PAPUC issued the final order describing more detailed recommendations to be implemented prior to the expiration of the electric distribution company's current default service plan and providing guidelines for electric distribution companies for development of their next default service plan. On October 12, 2012, the PAPUC approved PECO's second DSP Program, which includes several new programs to continue PECO's support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011. Further, the PAPUC issued a final order on February 14, 2013, outlining its proposed end-state for default service, which included default service pricing for residential and small commercial customers based on three month full requirements contracts, full requirement contracts using hourly spot market pricing for large commercial and industrial default service customers, and the inclusion of CAP customers in the customer choice programs.

Pennsylvania Act 11 of 2012 (Exelon and PECO). On February 13, 2012, Act 11 was signed into law by the Governor. Act 11 seeks to clarify the PAPUC's authority to approve alternative ratemaking mechanisms, which would allow for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems in Pennsylvania. Act 11 also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the first year rates are in effect. On August 2, 2012, the PAPUC issued a final order establishing rules and procedures to implement the ratemaking provisions of Act 11. The implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure, approved by the Commission prior to implementing a DSIC. PECO filed its LTIIP for its Gas Operations on February 8, 2013 with the PAPUC.

Maryland Regulatory Matters

2011 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $19 million of costs as regulatory assets.

These costs are being recovered over a 5-year period that began in December 2010 and include the deferral of $16 million of storm costs incurred in February 2010. The regulatory asset for the storm costs earns a regulated rate of return.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. Additionally, the MDPSC has determined that the cost recovery for the non-AMI meters that BGE retires will be considered in a future depreciation proceeding. The MDPSC continues to evaluate the impacts of a customer opt-out feature in BGE's Smart Grid program. The ultimate resolution related to this feature could affect BGE's ability to demonstrate cost-effectiveness of the advanced metering system. Under a grant from the DOE, BGE is a recipient of $200 million in federal funding for its smart grid and other related initiatives, which substantially reduces the total cost of these initiatives. The project to install the smart meters began in late April 2012.

As of December 31, 2012, BGE had received $142 million in reimbursements from the DOE. As of December 31, 2012, BGE's outstanding receivable from the DOE for reimbursable costs was $15 million, which has been recorded in other accounts receivable, net on Exelon's and BGE's Consolidated Balance Sheets.

New Electric Generation (Exelon and BGE). On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. The initial term of the proposed contract is 20 years. The CfD mandates that the utilities pay (or receive) the difference between CPV's contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The three Maryland utilities are required to enter into a CfD in amounts proportionate to their relative SOS load as of the date of execution. Depending on the precise terms of the CfD, the eventual market conditions, and the manner of cost recovery, the CfD could have a material adverse impact on Exelon's and BGE's results of operations, cash flows and financial positions. On April 27, 2012, a civil complaint was filed in the United States District Court for the District of Maryland by certain unaffiliated parties that challenges the actions taken by the MDPSC on federal law grounds. Among other requests for relief, the plaintiffs seek to enjoin the MDPSC from executing or otherwise putting into effect any part of its order. The MDPSC and CPV filed motions to dismiss the federal lawsuit, which were both denied by the U.S. District Court on August 3, 2012. On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order. That petition was subsequently transferred to the Circuit Court for Baltimore City, where similar appeals have been filed by other interested parties. All cases have now been consolidated and will be heard together by the Circuit Court for Baltimore City in the first quarter of 2013.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. The requested rate of return on equity in the application is 10.5%. On October 22, 2012, BGE filed an updated application to request an increase of $131 million and $45 million to its electric and gas base rates, respectively. The new electric and gas distribution base rates are expected to take effect in late February 2013. BGE cannot predict how much of the requested increases, if any, the MDPSC will approve.

Dividend Restrictions (Exelon and BGE). BGE pays dividends on its common stock after its Board of Directors declares them. However, BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd's and BGE's transmission rates are each established based on a FERC-approved formula.

ComEd's most recent annual formula rate update filed in May 2012 reflects actual 2011 expenses and investments plus forecasted 2012 capital additions. The update resulted in a revenue requirement of $450 million offset by a $5 million reduction related to the reconciliation of 2011 actual costs for a net revenue requirement of $445 million. This compares to the May 2011 updated revenue requirement of $438 million offset by a $16 million reduction related to the reconciliation of 2010 actual costs for a net revenue requirement of $422 million. The increase in the revenue requirement was primarily driven by higher depreciation, pension and operating and maintenance costs, and the absence of a one-time credit that had been included in 2010 costs. The 2012 net revenue requirement became effective June 1, 2012, and is recovered over the period extending through May 31, 2013. The regulatory liability associated with the true-up is being amortized as the associated amounts are refunded.

ComEd's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.91%, a decrease from the 9.10% return previously authorized. The decrease in return was primarily due to lower interest rates on ComEd's long-term debt outstanding. As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 55%.

BGE's most recent annual formula rate update, filed in April 2012, reflects actual 2011 expenses and investments plus forecasted 2012 capital additions on a weighted basis. This update resulted in a revenue requirement of $156 million plus an additional $2 million increase related to the reconciliation of 2011 actual costs for a net revenue requirement of $158 million. This compares to the May 2011 updated net revenue requirement of $140 million. The increase in the revenue requirement is primarily driven by higher levels of capital investment and operating expenses. The 2012 net revenue requirement became effective June 1, 2012, and is recovered over the period extending through May 31, 2013. The regulatory asset associated with the 2011 revenue requirement true-up is being amortized as the associated amounts are collected from customers.

BGE's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.43%, a decrease from the 8.96% return included in the update filed in April 2011. The decrease in return is primarily due to a reduced equity ratio and cost of debt at 2011 year-end compared to the previous year-end. BGE's formula rate includes an 11.3% rate of return on common equity for most investments included in its rate base.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, that court issued its decision affirming FERC's order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On January 21, 2010, FERC issued an order establishing paper hearing procedures to supplement the record. On March 30, 2012, FERC issued an order on remand affirming the cost allocation in its April 2007 order. A number of entities have filed requests for rehearing. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent any rate design changes are retroactive to periods prior to January 1, 2011, there may be an impact on PECO's results of operations. BGE anticipates that all impacts of any rate design changes effective after the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE's results of operations, cash flows or financial position.

On October 11, 2012, the PJM Transmission Owners filed with FERC a cost allocation for new transmission facilities asking that the new cost allocation methodology apply to all transmission approved by the PJM Board on or after February 1, 2013. The proposed methodology is a hybrid methodology that would socialize 50% of the costs of new facilities at 500kV and above and double-circuit 345kV lines, and allocate the remaining 50% to direct beneficiaries. For all other facilities, the costs would be allocated to the direct beneficiaries. On January 31, 2013, FERC issued an order stating that the transmission owner filing is interdependent with PJM's October 25, 2012 Order No. 1000 filing and thus, while FERC accepted the cost allocation for filing, it did so subject to refund, and a further order at the time FERC issues an order on PJM's Order No. 1000 Compliance Filing.

ComEd, PECO and BGE are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd, PECO and BGE will work with PJM to continue to evaluate the scope and timing of any required construction projects. ComEd, PECO and BGE's estimated commitments are as follows:

	Total	2013	2014	2015	2016	2017
ComEd	$525	$175	$86	$135	$128	$ 1
PECO	140	28	23	26	36	27
BGE	249	15	53	119	55	7

PJM Minimum Offer Price Rule (Exelon and Generation). PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The proceedings leading to the FERC's approval of the existing MOPR were extensive. The parties disputed numerous elements of the MOPR including: (i) the default price that should apply to bids found subject to the MOPR, (ii) the duration of the MOPR and (iii) the application of the MOPR to self-supplying capacity and state-sponsored capacity. The FERC orders approving the existing MOPR have been appealed to the Third Circuit Court of Appeals. A resolution of that appeal is not expected until sometime in 2013.

In May 2012, PJM announced the results of its capacity auction covering 2015 and 2016. Several new units with state-sanctioned subsidy contracts cleared in the auction at prices below the MOPR. Potentially, states will expand such state-sanctioned subsidy programs or other states may seek to establish similar programs. Generation believes that further revisions to the MOPR are necessary to ensure that the potential to reduce artificially capacity auction prices is appropriately limited in PJM. In late December 2012, PJM filed a new MOPR for approval at the FERC, which Exelon believes will be more effective in preventing state-sanctioned subsidy contracts from artificially reducing capacity prices. Generation was actively involved in the process through which the MOPR changes were developed, supports the changes and intends to continue to work with PJM and its stakeholders to obtain necessary approvals. On February 5, 2013, the FERC issued a letter finding that PJM's new MOPR filing is deficient and requested that PJM provide additional information on several aspects of PJM's MOPR proposal. PJM has 30 days to respond, and a FERC decision is expected within 60 days thereafter.

Market-Based Rates (Exelon, Generation, ComEd, PECO and BGE). Generation, ComEd, PECO and BGE are public utilities for purposes of the Federal Power Act and are required to obtain FERC's acceptance of rate schedules for wholesale electricity sales. Currently, Generation, ComEd, PECO and BGE have authority to execute wholesale electricity sales at market-based rates. As is customary with market-based rate schedules, FERC has reserved the right to suspend market-based rate authority on a retroactive basis if it subsequently determines that Generation, ComEd, PECO or BGE has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds in certain instances if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

As required by FERC's regulations, as promulgated in the Order No. 697 series, Generation, ComEd, PECO and BGE have filed market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd, PECO and BGE qualify for market-based rates in the regions where they are selling energy and capacity under market-based rate tariffs. FERC accepted the 2008 filings on September 16, 2008, January 15, 2009 and September 2, 2009 and accepted the 2009 filings on July 28, 2009, October 26, 2009, February 23, 2010 and April 30, 2010, affirming Exelon's affiliates continued right to make sales at market-based rates. These analyses must examine historic test period data and must be updated every three years on a prescribed schedule. The most recent updated analysis for the PJM and Northeast Regions was filed in late 2010, based on 2009 historic test period data. On June 22, 2011, FERC issued an order confirming Generation's continued authority to charge market based rates, based on Generation's most recent updated analysis filed in 2010, stating that any market power concerns are adequately addressed by PJM's monitoring and mitigation programs. Similarly, on June 29, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the Central Region which the FERC accepted on November 13, 2012, and on December 23, 2011, Generation filed its updated market power analysis for the Southeast Region which the FERC accepted on October 10, 2012. On December 21, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the SPP region, and the FERC has not yet acted on this filing.

Reliability Pricing Model (Exelon, Generation and BGE). PJM's RPM auctions take place 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2016 occurred in May 2012.

License Renewals (Exelon and Generation). On April 8, 2009, the NRC issued a renewed operating license for Oyster Creek that expires in April 2029. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

On June 30, 2011, the NRC issued the renewed operating licenses for Salem Units 1 and 2 expiring in 2036 and 2040, respectively. Exelon is a 42.59% owner of the Salem Units.

On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively. In June 2012, the United States District Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. The temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear plants for up to 60 years beyond the original and renewed licensed operating life of the plants and that licensing renewal decisions do not require discussion of the environmental impact of spent fuel stored on site. In August 2012, the NRC placed a hold on issuing new or renewed operating licenses that depend on the temporary storage rule until the court's decision is addressed. In September 2012, the NRC directed NRC Staff to revise the temporary storage rule through rulemaking no later than September 6, 2014. Generation does not expect the NRC to issue license renewals until September 2014, at the earliest.

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project and the Muddy Run Pumped Storage Facility Project, respectively. The FERC review process is expected to be completed by August 31, 2014, when the current Conowingo license expires.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of December 31, 2012 and 2011. Upon consummation of the merger, the Registrants reclassified certain regulatory asset and liability balances as of December 31, 2011 in order to align the reporting of the regulated utilities.

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 304	$ 3,673	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	14	1,382	5	62	—	1,255	9	65
AMI programs	3	70	3	10	—	29	—	31
AMI meter events	—	17	—	—	—	17	—	—
Under-recovered distribution service costs	18	191	18	191	—	—	—	—
Debt costs	14	68	11	62	3	6	1	9
Fair value of BGE long-term debt [(a)]	—	256	—	—	—	—	—	—
Fair value of BGE supply contract [(b)]	77	12	—	—	—	—	—	—
Severance	29	28	25	12	—	—	4	16
Asset retirement obligations	—	90	—	65	—	25	—	—
MGP remediation costs	58	232	51	197	6	33	1	2
RTO start-up costs	3	2	3	2	—	—	—	—
Under-recovered electric universal service fund costs	11	—	—	—	11	—	—	—
Financial swap with Generation	—	—	226	—	—	—	—	—
Renewable energy and associated RECs	18	49	18	49	—	—	—	—
Under-recovered energy and transmission costs	43	—	14	—	1	—	28	—
DSP Program costs	1	3	—	—	1	3	—	—
DSP II Program costs	1	2	—	—	1	2	—	—
Deferred storm costs	3	6	—	—	—	—	3	6
Electric generation-related regulatory asset	16	40	—	—	—	—	16	40
Rate stabilization deferral	67	225	—	—	—	—	67	225
Energy efficiency and demand response programs	56	126	—	—	—	—	56	126
Other	23	25	14	16	9	8	—	2
Total regulatory assets	$ 759	6,497	$ 388	$ 666	$ 32	$ 1,378	$ 185	$ 522

(a) Represents the regulatory asset recorded at Exelon Corporate for the difference in the fair value of the long-term debt of BGE as of the merger date. See Note 4—Merger and Acquisitions for additional information.

(b) Represents the regulatory asset recorded at Exelon Corporate representing the fair value of BGE's supply contracts as of the merger date. BGE is allowed full recovery of the costs of its electric and gas supply contracts through approved regulated rates. See Note 4—Merger and Acquisitions for additional information.

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$ —	$ 2,397	$ —	$ 2,037	$ —	$ 360	$ —	$ —
Removal costs	97	1,406	75	1,192	—	—	22	214
Energy efficiency and demand response programs	131	—	43	—	88	—	—	—
Electric distribution tax repairs	20	132	—	—	20	132	—	—
Gas distribution tax repairs	8	46			8	46		
Over-recovered uncollectible accounts	6	—	6	—	—	—	—	—
Over-recovered energy and transmission costs	54	—	6	—	48	—	—	—
Over-recovered gas universal service fund costs	3	—	—	—	3	—	—	—
Over-recovered AEPS costs	2	—	—	—	2	—	—	—
Total regulatory liabilities	$ 321	$ 3,981	$ 130	$ 3,229	$ 169	$ 538	$ 22	$ 214

December 31, 2011	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 204	$ 2,794	$ —	$ —	$ 7	$ —	$ 3	$ —
Deferred income taxes	5	1,176	5	66	—	1,110	8	68
AMI and smart meter programs	2	28	2	6	—	22	—	15
Under-recovered distribution service costs	14	70	14	70	—	—	—	—
Debt costs	18	81	15	73	3	8	2	10
Severance	25	38	25	38	—	—	—	1
Asset retirement obligations	—	74	—	50	—	24	—	—
MGP remediation costs	30	129	24	91	6	38	1	2
RTO start-up costs	3	4	3	4	—	—	—	—
Under-recovered electric universal service fund costs	3	—	—	—	3	—	—	—
Financial swap with Generation	—	—	503	191	—	—	—	—
Renewable energy and associated RECs	9	97	9	97	—	—	—	—
Under-recovered energy and transmission costs	57	—	48	—	9	—	50	—
DSP Program costs	3	2	—	—	3	2	—	—
Deferred storm costs	—	—	—	—	—	—	3	9
Electric generation-related regulatory asset	—	—	—	—	—	—	16	56
Rate stabilization deferral	—	—	—	—	—	—	63	295
Energy efficiency and demand response programs	—	—	—	—	—	—	29	95
Other	17	25	9	13	8	12	—	—
Total regulatory assets	$ 390	$ 4,518	$ 657	$ 699	$ 39	$ 1,216	$ 175	$ 551

December 31, 2011	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$ —	$ 2,222	$ —	$ 1,857	$ —	$ 365	$ —	$ —
Removal costs	61	1,185	61	1,185	—	—	18	200
Energy efficiency and demand response programs	49	69	49	—	—	69	—	—
Electric distribution tax repairs	19	151	—	—	19	151	—	—
Over-recovered uncollectible accounts	15	—	15	—	—	—	—	—
Over-recovered energy and transmission costs	42	—	12	—	30	—	—	—
Over-recovered gas universal service fund costs	3	—	—	—	3	—	—	—
Over-recovered AEPS costs	8	—	—	—	8	—	—	—
Other	—	—	—	—	—	—	1	1
Total regulatory liabilities	$ 197	$ 3,627	$ 137	$ 3,042	$ 60	$ 585	$ 19	$ 201

Pension and other postretirement benefits. As of December 31, 2012, Exelon recorded regulatory assets of $3,977 million related to ComEd's and BGE's portion of deferred costs associated with Exelon's pension plans and ComEd's, PECO's and BGE's portion of deferred costs associated with Exelon's other postretirement benefit plans. PECO's pension regulatory recovery is based on cash contributions and is not included in the regulatory asset balance. The regulatory asset is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses attributable to Exelon's pension and other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd, PECO and BGE will recover these costs through base rates as allowed in their most recently approved regulated rate orders. The pension and other postretirement benefit regulatory asset balance includes a regulatory asset established at the date of the merger related to BGE's portion of the deferred costs associated with legacy Constellation's pension and other postretirement benefit plans. That BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the merger. See Note 14—Retirement Benefits for additional detail. No return is earned on Exelon's regulatory asset.

Deferred income taxes. These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded under GAAP. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with the authoritative guidance for accounting for certain types of regulation and income taxes, include the deferred tax effects associated principally with liberalized depreciation accounted for in accordance with the ratemaking policies of the ICC, PAPUC and MDPSC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For ComEd and BGE, this amount includes the impacts of a reduction in the deductibility, for Federal income tax purposes, of certain retiree health care costs pursuant to the March 2010 Health Care Reform Acts. ComEd was granted recovery of these additional income taxes on May 24, 2011 in the ICC's 2010 Rate Case order. The recovery period for these costs is through May 31, 2014. For BGE, these additional income taxes are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. See Note 12—Income Taxes and Note 14—Retirement Benefits for additional information. ComEd, PECO and BGE are not earning a return on the regulatory asset in base rates.

AMI programs. For ComEd, this amount represents operating and maintenance expenses and meter costs associated with ComEd's AMI pilot program approved in the May 24, 2011, ICC order in ComEd's 2010 rate case. The recovery periods for operating and maintenance expenses and meter costs are through May 31, 2014, and January 1, 2020, respectively. In addition, ComEd recorded approximately $7 million of accelerated depreciation costs resulting from the early retirements of non-AMI meters as a regulatory asset beginning during the fourth quarter of 2012, which will be amortized over an average ten year period pursuant to the ICC approved AMI Deployment plan. ComEd is earning a return on the meter costs. For PECO, this amount represents accelerated depreciation and filing and implementation costs relating to the PAPUC-approved Smart Meter Procurement and Installation Plan as well as the return on the un-depreciated investment, taxes, and operating and maintenance expenses. The approved plan allows for recovery of filing and implementation costs incurred through December 31, 2010 during 2011 and 2012. In addition, the approved plan provides for recovery of program costs, which includes depreciation on new equipment placed in service, beginning in January 2011 on full and current basis, which includes interest income or expense on the under or over recovery. The approved plan also provides for recovery of accelerated depreciation on PECO's non-AMI meter assets over a 10-year period ending December 31, 2020. For BGE, this amount represents smart grid pilot program costs as well as the incremental costs associated with implementing full deployment of a smart grid program. Pursuant to a MDPSC order, pilot program costs of $11 million were deferred in a regulatory asset, and, beginning with the MDPSC's March 2011 rate order, is earning BGE's most current authorized rate of return. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE, authorizing BGE to establish a separate regulatory asset for incremental costs incurred to implement the initiative, including the net depreciation and amortization costs associated with the meters, and an authorized rate of return on these costs, a portion of which is not recognized under GAAP until cost recovery begins. Additionally, the MDPSC order requires that BGE prove the cost-effectiveness of the entire smart grid initiative prior to seeking recovery of the costs deferred in these regulatory assets. Therefore, the commencement and timing of the amortization of these deferred costs is currently unknown. BGE's AMI regulatory asset excludes costs for non-AMI meters being replaced by AMI meters, as the MDPSC has ordered that the cost recovery for non-AMI meters will be considered in a future depreciation proceeding.

AMI Meter Events. This amount represents the cost value of the original smart meters, net of accumulated depreciation and DOE reimbursements, purchased for the first phase of smart meter deployment that will no longer be used, including installation and removal costs. PECO is seeking full recovery of all incurred costs related to the original deployment of meters. For amounts not recovered from the vendor, PECO will seek regulatory rate recovery in a future filing with the PAPUC. PECO believes the amounts incurred for the original meters and related installation and removal costs are probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As such, PECO has deferred these costs on Exelon's and PECO's Consolidated Balance Sheet. PECO will not earn a return on the recovery of these costs.

Under-recovered distribution services costs. Under EIMA, which became effective in the fourth quarter of 2011, ComEd is allowed recovery of distribution services costs through a formula rate tariff. The legislation provides for an annual reconciliation of the revenue requirement in effect to reflect the actual costs that the ICC determines are prudently and reasonably incurred in a given year. The reconciliation will be recovered through rates over a one-year period, beginning in January 2013 for the 2011 annual reconciliation period. The regulatory asset also includes costs associated with certain one-time events, such as large storms, which will be recovered over a five-year period beginning in January 2013. ComEd is earning a return on these costs. As of December 31, 2012, the regulatory asset was comprised of $125 million for the annual reconciliation and $84 million related to significant

one-time events. In addition to $58 million in deferred storm costs, net of amortization, the December 31, 2012 balance related to significant one-time events contains $26 million of merger and integration related costs, net of amortization, incurred as a result of the merger. As of December 31, 2012, ComEd and BGE recorded regulatory assets of $5 million and $1 million, respectively, in other regulatory assets for merger and integration-related costs. See Note 4—Mergers and Acquisitions for additional information.

Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd's, PECO's and BGE's recoverable losses on reacquired long-term debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding or the life of the original issuance retired. These debt costs are used in the determination of the weighted cost of capital applied to rate base in the rate-making process. ComEd and BGE are not earning a return on the recovery of these costs.

Severance. For ComEd, these costs represent previously incurred severance costs that ComEd was granted recovery of in the December 20, 2006, ICC rehearing rate order and the May 24, 2011, ICC order in ComEd's 2010 rate case. The recovery periods are through June 30, 2014, and May 31, 2014, respectively. ComEd is not earning a return on these costs. For BGE, these costs represent deferred severance costs that BGE has either previously been granted recovery of in rates or has requested recovery in a current rate case. Costs include the portion of costs associated with a 2008 workforce reduction that relate to BGE's gas business which were deferred in 2009 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period that began in January 2009. Also included are costs associated with a 2010 workforce reduction that were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. Finally, costs associated with the 2012 BGE voluntary workforce reduction were deferred in 2012 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period that began in July 2012. BGE is earning a regulated return on the regulatory asset included in base rates.

Asset retirement obligations. These costs represent future removal costs associated with ComEd's and PECO's existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd will recover these costs through future depreciation expense and will earn a return on these costs once the removal activities have been performed. See Note 13—Asset Retirement Obligations for additional information.

MGP remediation costs . Recovery of these items was granted to ComEd in the July 26, 2006, ICC rate order. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures. ComEd and PECO are not earning a return on the recovery of these costs. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. These costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. BGE is earning a regulated return on the regulatory asset included in base rates. See Note 19—Commitments and Contingencies for additional information.

RTO start-up costs. Recovery of these RTO start-up costs was approved by FERC. The recovery period is through March 31, 2015. ComEd is earning a return on these costs.

Under (Over)-recovered universal service fund costs. The universal service fund cost is a recovery mechanism that allows PECO to recover discounts issued to electric and gas customers enrolled in assistance programs. As of December 31, 2012, PECO was under-recovered for its electric program and over-recovered for its gas program. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers.

Financial swap with Generation. To fulfill a requirement of the Illinois Settlement Legislation, ComEd entered into a five-year financial swap contract with Generation that expires on May 31, 2013. Since the swap contract was deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period are recorded by ComEd as well as an offsetting regulatory asset or liability. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price. In Exelon's consolidated financial statements, the fair value of the intercompany swap recorded by Generation and ComEd is eliminated.

Renewable Energy and Associated RECs. On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. Since the swap contracts were deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price.

Under (Over)-recovered energy and transmission costs. Starting in 2007, ComEd's energy and transmission costs are recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. ComEd earns interest on under-recovered costs and pays interest on over-recovered costs to customers. The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO's GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2012, PECO had a regulatory asset related to under-recovered electric transmission costs of $1 million and a regulatory liability that included $47 million related to over-recovered electric supply costs under the GSA and $1 million related to over-recovered natural gas supply costs under the PGC. As of December 31, 2011, PECO had a regulatory asset related to under-recovered transmission costs of $9 million and a regulatory liability that included $25 million related to over-recovered electric supply costs under the GSA and $5 million related to over-recovered natural gas supply costs under the PGC. The BGE energy costs represent the electric and gas supply related costs recoverable (refundable) from (to) customers under BGE's market-based SOS and MBR programs, respectively. BGE does not earn or pay interest on under- or over-recovered costs to customers. See "ITEM 1. BUSINESS—BGE" for further details on BGE's market-based SOS and MBR programs. As of December 31, 2012, BGE had a regulatory asset that included $9 million related to under-recovered electric supply costs and $19 million related to under-recovered natural gas supply costs.

DSP Program costs . These amounts represent recoverable administrative costs incurred relating to filing, procurement, and information technology improvements associated with PECO's PAPUC-approved DSP Program for the procurement of electric supply following the expiration of PECO's generation rate caps on December 31, 2010. The filing and implementation costs of this DSP Program are recoverable through the GSA over its 29-month term, beginning January 1, 2011. The independent evaluator costs associated with conducting procurements is recoverable over a 12-month period after the PAPUC approves the results of the procurements. Costs relating to information technology improvements are recoverable over a 5-year period beginning January 1, 2011. PECO earns a return on the recovery of information technology costs.

DSP II Program Costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO's second PAPUC-approved DSP program for the procurement of electric supply. The filing and procurement of this DSP Program are recoverable through the GSA over its 24-month term, beginning June 1, 2013. The independent evaluator costs associated with conducting procurements are recoverable over a 12-month period after the PAPUC approves the results of the procurements. PECO is not earning a return on these costs.

Deferred storm costs. In the MDPSC's March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. These costs are being amortized over a 5-year period that began in December 2010. BGE is earning a regulated return on the regulatory asset included in base rates.

Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. A portion of this regulatory asset represents income taxes recoverable through future rates that do not earn a regulated rate of return. These amounts were $47 million as of December 31, 2012, and $56 million as of December 31, 2011. BGE will continue to amortize this amount through 2017.

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006, to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007, to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2012 and 2011, BGE recovered $67 million and $57 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007.

Energy efficiency and demand response programs. These amounts represent costs recoverable (refundable) under ComEd's ICC approved Energy Efficiency and Demand Response

Plan, PECO's PAPUC-approved EE&C Plan, and BGE's Smart Energy Savers Program ®. ComEd began recovering these costs or refunding over-collections of these costs on June 1, 2008 through a rider. ComEd earns a return on the capital investment incurred under the program but does not earn (pay) interest on under (over) collections. PECO began recovering these costs through a rider in January 2010 based on projected spending under the program. Recovery will continue over the life of the program, which expires on May 31, 2013. Excess funds collected are required to be refunded no later than June 30, 2013. PECO earns a return on the capital investment incurred under the program but does not earn (pay) interest on under (over) collections. BGE's Smart Energy Savers Program ® includes both MDPSC approved demand response and energy efficiency programs. For the BGE demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Actual costs incurred in the conservation program are being amortized over a 5- year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a regulated rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

Rate case costs. The ICC generally allows ComEd to receive recovery of rate case costs over three years. The ICC has issued orders allowing recovery of these costs on July 26, 2006, September 10, 2008, and May 24, 2011. The recovery period for the two former rate case costs was through September 15, 2011. The recovery period for the 2010 Rate Case costs is through May 31, 2014. Pursuant to the approved settlements of the 2010 electric and natural gas distribution rate cases, PECO is allowed recovery of rate case costs over two years ended December 31, 2012. ComEd and PECO do not earn a return on the recovery of these costs.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will equal the associated future decommissioning costs at the time of decommissioning. See Note 13—Asset Retirement Obligations for additional information.

Removal costs. These amounts represent funds ComEd and BGE have received from customers to cover the future removal of property, plant and equipment which reduces rate base for ratemaking purposes.

Electric distribution tax repairs. PECO's 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits began being reflected in customer bills on January 1, 2012. No interest will be paid to customers.

Gas distribution tax repairs. PECO's 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits will be reflected in customer bills beginning January 1, 2013. No interest will be paid to customers.

Under (Over)-recovered uncollectible accounts. As a result of the February 2010 ICC order approving recovery of ComEd's uncollectible accounts, ComEd has the ability to adjust its rates annually to reflect the increases and decreases in annual uncollectible accounts expense starting with year 2008. ComEd recorded a regulatory asset for the cumulative under-collections in 2008 and 2009. Recovery of the initial regulatory asset was completed over an approximate 14-month time frame which began in April 2010. The recovery or refund of the difference in the uncollectible accounts expense applicable to the years starting with January 1, 2010, will take place over a 12-month time frame beginning in June of the following year. ComEd is not earning a return on these costs.

Under (Over)-recovered AEPS costs current asset (liability). The AEPS costs represent the administrative and AEC costs incurred to comply with the requirements of the AEPS Act, which are recoverable on a full and current basis. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers.

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities' consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd and BGE purchase receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO, and BGE do not record unbilled commodity receivables under their POR programs. Purchased billed receivables are classified in other accounts receivable, net on Exelon's, ComEd's, PECO's and BGE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of December 31, 2012 and 2011.

As of December 31, 2012	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 191	$ 55	$ 65	$71
Allowance for uncollectible accounts [b]	(21)	(9)	(6)	(6)
Purchased receivables, net	$ 170	$ 46	$ 59	$65

As of December 31, 2011	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 68	$ 16	$ 52	$61
Allowance for uncollectible accounts [b]	(5)	—	(5)	(3)
Purchased receivables, net	$ 63	$ 16	$ 47	$58

(a) PECO's gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.

(b) For ComEd, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing (PORCB) tariff.

4. Merger and Acquisitions

Merger with Constellation (Exelon, Generation, ComEd, PECO and BGE)

Description of Transaction

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement, among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

Constellation's shareholders received 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock outstanding as of March 12, 2012. Generally, all outstanding Constellation equity-based compensation awards were converted into Exelon equity-based compensation awards using the same ratio. See Note 17—Common Stock for further information.

Regulatory Matters

In December 2011, Exelon and Constellation reached a settlement with the State of Maryland and the City of Baltimore and other interested parties in connection with the regulatory proceedings related to the merger that were pending before the MDPSC. As part of this settlement and the application for approval of the merger by MDPSC, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of more than $1 billion.

On February 17, 2012, the MDPSC approved the merger with conditions. Many of the conditions were reflective of the settlement agreements described above. The following costs were recognized after the closing of the merger and are included in Exelon's, Generation's and BGE's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2012:

Description	Payment Period	BGE	Generation	Exelon	Statement of Operations Location
BGE rate credit of $100 per residential customer [(a)]	Q2 2012	$113	$ —	$ 113	Revenues
Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers	2012 to 2014	—	—	113.5	O&M Expense
Contribution for renewable energy, energy efficiency or related projects in Baltimore	2012 to 2014	—	—	2	O&M Expense
Charitable contributions at $7 million per year for 10 years	2012 to 2021	28	35	70	O&M Expense
State funding for offshore wind development projects	Q2 2012	—	—	32	O&M Expense
Miscellaneous tax benefits	Q2 2012	(2)	—	(2)	Taxes Other Than Income
Total		$139	$ 35	$328.5	

(a) Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

In addition to these costs, the direct investment estimate includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation's competitive energy businesses. The construction is expected to be completed in 1 to 2 years. The estimate also includes $625 million for Exelon's and Generation's commitment to develop or assist in the development of 285—300 MWs of new generation in Maryland, expected to be completed over a period of 10 years. Such costs, which are expected to be primarily capital in nature, will be recognized as incurred. As of December 31, 2012, amounts reflected in the Exelon and Generation consolidated financial statements for these commitments were immaterial.

The settlement agreement contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets, and therefore will be primarily capital in nature and recognized as incurred. If in the future Exelon determines that it is probable that it will make subsidy, compliance or liquidated damages payments related to the new generation development commitments, Exelon will record a liability at that time. As of December 31, 2012, it is reasonably possible that Exelon will be required to make subsidy or liquidated damages payments of approximately $40 million rather than build one of the generation projects contemplated by the commitments, given that the generation build is dependent upon the passage of legislation and other conditions that Exelon does not control.

Pursuant to the MDPSC merger approval conditions, BGE is restricted from paying any dividend on its common shares through the end of 2014, is required to maintain specified minimum capital and O&M expenditure levels in 2012 and 2013, and is not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process.

Associated with certain of the regulatory approvals required for the merger, Exelon and Constellation agreed to enter into contracts to sell three Constellation generating stations located in PJM within 150 days (subsequently extended 30 days by the DOJ) following the merger completion and to complete the divestitures within 30 days after receipt of regulatory approvals. These stations, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, include base-load, coal-fired generation units plus associated gas/oil units located at the same sites, and total 2,648 MW of generation capacity.

On August 8, 2012, a subsidiary of Generation reached an agreement to sell these three Maryland generating stations and associated assets to Raven Power Holdings LLC (Raven Power), a subsidiary of Riverstone Holdings LLC. The sale was completed on November 30, 2012. The sale agreement included a base price with purchase price adjustments based on fuel inventory, working capital, capital expenditures, and timing of the closing, resulting in net proceeds from the sale of approximately $371 million. Decisions by certain market participants to remove themselves from the bidding process, combined with the deadlines and limitations on the pool of potential buyers imposed by the merger approval orders, resulted in realized sales proceeds below Generation's estimated fair value of the Maryland generating stations. Consequently, Exelon and Generation recorded a pre-tax loss of $278 million in operating and maintenance expense in the third quarter of 2012 to reflect the difference between the estimated sales price at that time and carrying value. This loss amount was adjusted to $272 million to reflect the final sales price upon closing on November 30, 2012.

In connection with the sale of the Maryland generating stations, Exelon agreed to indemnify Raven Power for certain costs associated with the treatment of hazardous substances at off-site disposal facilities and any claims arising as a result of, or in connection with, any toxic tort, natural resource damages, loss of life or injury to persons due to releases of, or exposure to hazardous substances in connection with Raven Power's remediation of environmental contamination or Exelon's non-compliance with environmental laws or permits prior to the closing date of the sale.

Subsequent to the merger, Generation discovered that, for the first two weeks following the merger, due to a software error, Generation inadvertently bid certain generating units into the PJM energy market at prices that slightly exceeded the cost-based caps to which it had agreed. This error was a violation of the commitments made in connection with merger approvals by DOJ, FERC and the MDPSC. Generation reported the error to the DOJ, FERC and the MDPSC and committed to remedy the impacts of its error. The MDPSC held a hearing to review the error, and accepted Generation's proposed remediation. Subsequent close examination by Generation of its cost-based bids also revealed the need for some minor adjustments to the cost build up for certain of its PJM units. Generation has coordinated with PJM to determine the impact on Generation's revenues and the market from this error and these adjustments, and Generation has worked with PJM to reverse the financial impacts. In November 2012, Generation reached a settlement with the DOJ regarding this matter. The final resolution did not have a material impact on Exelon's or Generation's results of operations, cash flows or financial position.

In addition, in January 2012, Exelon and Constellation reached an agreement with EDF under which EDF withdrew its opposition to the Exelon-Constellation merger. The terms of the agreement address CENG, a joint venture between Constellation and EDF that owns and operates a total of three nuclear facilities with a total of five generating units in Maryland and New York. The agreement reaffirms the terms of the joint venture. The agreement did not include any exchange of monetary consideration, and Exelon does not expect the agreement will have a material effect on Exelon's and Generation's future results of operations, financial position and cash flows.

Exelon was named in suits filed in the Circuit Court of Baltimore City, Maryland alleging that individual directors of Constellation breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. Similar suits were also filed in the United States District Court for the District of Maryland. The suits sought to enjoin a Constellation shareholder vote on the proposed merger until all material information was disclosed and sought rescission of the proposed merger. During the third quarter of 2011, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. On June 26, 2012, the court approved the settlement and entered final judgment.

Accounting for the Merger Transaction

The total consideration in the merger was based on the opening price of a share of Exelon common stock on March 12, 2012 (in millions):

	Number of Shares/ Awards Issued	Total Fair Value
Issuance of Exelon common stock to Constellation shareholders and equity award holders at the exchange ratio of 0.930 shares for each share of Constellation common stock; based on the opening price of Exelon common stock on March 12, 2012 of $38.91 [(a)]	187.45	$ 7,294
Issuance of Exelon equity awards to replace existing Constellation equity awards [(b)]	11.30	71
Total purchase price		$ 7,365

(a) The number of shares issued excludes 0.7 million shares of stock that are held in a custodian account specifically for the settlement of unvested share-based restricted stock awards. The related share value is excluded from the estimated fair value as these awards have not vested and, therefore, are not in the purchase price.
(b) Includes vested Constellation stock options and restricted stock units converted at fair value to Exelon awards on March 12, 2012. The fair value of the stock options was determined using the Black-Scholes model.

All options to purchase Constellation common stock under various equity agreements were converted into options to acquire a number of shares of Exelon common stock (as adjusted for the exchange ratio) at an option price. All Constellation unvested restricted stock awards granted prior to April 28, 2011, that were outstanding immediately prior to the consummation of the Merger, became vested on a pro rata basis (determined based upon the number of months from the start of the applicable restricted period to the closing of the Initial Merger) and converted into Exelon common stock at the exchange ratio in accordance with the applicable stock plan and award agreement terms. All Constellation restricted stock awards that remained unvested on a pro rata basis pursuant to the foregoing formula, and any Constellation unvested restricted stock awards granted after April 28, 2011, have been assumed by Exelon and automatically converted into shares of unvested restricted stock of Exelon at the exchange ratio. Likewise, all restricted stock units granted prior to April 28, 2011 under the Constellation Plans and outstanding immediately prior to the completion of the Initial Merger became vested on a pro rata basis (determined based upon the number of months from the start of the applicable restricted period to the closing of the Initial Merger) and have been assumed by Exelon and automatically converted into a number of shares of Exelon common stock at the exchange ratio.

The fair value of Constellation's non-regulated business assets acquired and liabilities assumed was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The financial statements of BGE do not include fair value adjustments for assets or liabilities subject to rate-setting provisions for BGE. BGE is subject to the rate-setting authority of FERC and the MDPSC and is accounted for pursuant to the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for BGE provide revenue derived from costs including a return on investment of assets and liabilities included in rate base. Except for debt, fuel supply contracts and regulatory assets not earning a return, the fair values of BGE's tangible and intangible assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore, do not reflect any net adjustments related to these amounts. For BGE's debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE's assets acquired and liabilities assumed is recorded as a regulatory asset at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 1—Significant Accounting Policies for additional information on BGE's push-down accounting treatment. Also see Note 3 – Regulatory Matters for additional information on BGE's regulatory assets.

The valuations performed in the first quarter of 2012 to assess the fair values of certain assets acquired and liabilities assumed were considered preliminary as a result of the short time period between the closing of the merger and the end of the first quarter of 2012. The allocation of the purchase price may be modified up to one year from the date of the merger as more information is obtained about the fair value of assets acquired and liabilities assumed. The preliminary valuations performed in the first quarter of 2012 were updated in the second, third and fourth quarters of 2012, with the most significant adjustments to the preliminary valuation amounts having been made to the fair values assigned to the acquired power supply and fuel contracts, unregulated property, plant and equipment and investments in affiliates. The preliminary amounts recognized are subject to further revision until the valuations are completed and to the extent that additional information is obtained about the facts and circumstances that existed as of the merger date. Any changes to the fair value assessments may affect the purchase price allocation and material changes could require the financial statements to be retroactively amended.

The updated preliminary purchase price allocation of the Initial Merger of Exelon with Constellation and Exelon's contribution of certain subsidiaries of Constellation to Generation at December 31, 2012 was as follows:

Preliminary Purchase Price Allocation, excluding amortization	Exelon	Generation
Current assets	$ 4,936	$ 3,638
Property, plant and equipment	9,342	4,054
Unamortized energy contracts	3,218	3,218
Other intangibles, trade name and retail relationships	457	457
Investment in affiliates	1,942	1,942
Pension and OPEB regulatory asset	740	—
Other assets	2,265	1,266
Total assets	22,900	14,575
Current liabilities	3,408	2,804
Unamortized energy contracts	1,722	1,512
Long-term debt, including current maturities	5,632	2,972
Noncontrolling interest	90	90
Deferred credits and other liabilities and preferred securities	4,683	1,933
Total liabilities, preferred securities and noncontrolling interest	15,535	9,311
Total purchase price	$ 7,365	$ 5,264

Intangible Assets Recorded

For the power supply and fuel contracts acquired from Constellation, the difference between the contract price and the market price at the date of the merger was recognized as either an intangible asset or liability based on whether the contracts were in or out-of-the-money. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. The fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the merger date. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Exelon and Generation present separately in their Consolidated Balance Sheets the unamortized energy contract assets and liabilities for these contracts. Exelon's and Generation's amortization expense for the period March 12, 2012 to December 31, 2012 amounted to $1,098 million. This amortization expense excludes the $116 million in amortization of the regulatory asset and equally offsetting amortization of the fuel supply contract liability recorded at Exelon Corporate in the Consolidated Statement of Operations. The weighted-average amortization period is approximately 1.5 years.

The fair value of the Constellation trade name intangible asset was determined based on the relief from royalty method of the income approach whereby fair value is determined to be the present value of the license fees avoided by owning the assets. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. Exelon's and Generation's straight line amortization expense for the period March 12, 2012 to December 31, 2012 amounted to $20 million. The amortization period is approximately 10 years. The trade name intangible asset is included in deferred debits and other assets within Exelon's and Generation's Consolidated Balance Sheets.

The fair value of the retail relationships was determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The intangible assets are amortized as amortization expense on a straight line basis over the useful life of the underlying assets averaging approximately 12.4 years. Exelon's and Generation's amortization expense for the period March 12, 2012 to December 31, 2012 amounted to $15 million. The retail relationships intangible assets are included in deferred debits and other assets within Exelon's and Generation's Consolidated Balance Sheets.

Exelon's intangible assets and liabilities acquired through the merger with Constellation included in its Consolidated Balance Sheets, along with the future estimated amortization, were as follows as of December 31, 2012:

					Estimated amortization expense					
Description	Weighted Average Amortization	Gross	Accumulated Amortization	Net	2013	2014	2015	2016	2017	2018 and Beyond
Unamortized energy contracts, net [(a)]	1.5	$1,496	$ (982)	$514	$394	$ 74	$19	$(31)	$(22)	$ 80
Trade name	10.0	243	(20)	223	24	24	24	24	24	103
Retail relationships	12.4	214	(15)	199	19	19	19	19	19	104
Total, net		$1,953	$ (1,017)	$936	$437	$117	$62	$ 12	$ 21	$ 287

(a) Includes the fair value of BGE's power and gas supply contracts for which an offsetting Exelon Corporate regulatory asset was also recorded.

Impact of Merger

It is impracticable to determine the current quarter and year-to-date overall financial statement impact for the Constellation subsidiaries contributed down to Generation following the Upstream Merger. Upon closing of the merger, the operations of these Constellation subsidiaries were integrated into Generation's operations and are therefore not fully distinguishable after the merger.

The impact of BGE on Exelon's Consolidated Statement of Operations and Comprehensive Income includes operating revenues of $2,091 million and net loss of $31 million during the year ended December 31, 2012.

During the year ended December 31, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $746 million, $340 million, $5 million, $17 million and $160 million, respectively. These amounts do not include merger and integration-related costs of $36 million and $22 million incurred at ComEd and BGE, respectively, which have been recorded as a regulatory asset. The costs incurred are classified primarily within Operating and Maintenance Expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the BGE customer rate credit and the credit facility fees, which are included as a reduction to operating revenues and other, net, respectively, for the year ended December 31, 2012.

During the year ended December 31, 2011, Exelon, Generation and PECO incurred merger and integration-related costs of $77 million, $15 million and $2 million, respectively. These costs are classified primarily within Operating and Maintenance Expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income.

Severance Costs

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process; as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit. Exelon adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. The amount of severance expense associated with the post-merger integration recognized through December 31, 2012, for Exelon is $138 million, which includes $88 million, $16 million, $7 million and $19 million for Generation, ComEd, PECO and BGE, respectively. Estimated costs to be incurred after December 31, 2012 are not material. In addition, certain employees identified during the staffing and selection process also receive pension and other postretirement benefits that are deemed contractual termination benefits. See Note 14—Retirement Benefits for additional information on the contractual termination benefits.

For the year ended December 31, 2012, the Registrants recorded the following severance benefits costs associated with the identified job reductions within operating and maintenance expense in their Consolidated Statements of Operations, except for ComEd and BGE:

Year Ended December 31, 2012 Severance Benefits [a]	Exelon	Generation	ComEd [b]	PECO	BGE [c]
Severance charges	$ 124	$ 80	$ 14	$ 7	$ 17
Stock compensation	7	4	1	—	1
Other charges	7	4	1	—	1
Total severance benefits	$ 138	$ 88	$ 16	$ 7	$ 19

(a) The amounts above include $46 million at Generation, $14 million at ComEd, $7 million at PECO, and $7 million at BGE, for amounts billed by BSC through intercompany allocations for the year ended December 31, 2012.
(b) ComEd established regulatory assets of $16 million, as of December 31, 2012, for severance benefits costs. The majority of these costs are expected to be recovered over a five-year period.
(c) Consistent with MDPSC precedent, BGE established a regulatory asset of $19 million, as of December 31, 2012, for severance benefits costs. The majority of these costs are expected to be recovered over a five-year period.

Amounts included in the table below represent the severance liability recorded by Exelon, Generation, ComEd, PECO and BGE for employees of those Registrants and exclude amounts billed through intercompany allocations:

Year Ended December 31, 2012 Severance liability	Exelon	Generation	ComEd	PECO	BGE
Balance at December 31, 2011	$ —	$ —	$ —	$—	$—
Severance charges [a]	124	38	2	—	11
Stock compensation	7	2	—	—	—
Other charges [b]	7	2	—	—	1
Payments	(27)	(9)	(1)	—	(1)
Balance at December 31, 2012	$ 111	$ 33	$ 1	$—	$ 11

(a) Includes salary continuance and health and welfare severance benefits. Amounts represent ongoing severance plan benefits. Amounts also include one-time termination benefits of $3 million and $1 million for Exelon and Generation, respectively, which they began to recognize in the second quarter of 2012.
(b) Primarily includes life insurance, employer payroll taxes, educational assistance, and outplacement services.

Cash payments under the plan began in the second quarter of 2012. Substantially all cash payments under the plan are expected to be made by the end of 2016.

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon and Generation as if the merger with Constellation had taken place on January 1, 2011. The unaudited pro forma information was calculated after applying Exelon's and Generation's accounting policies and adjusting Constellation's, including BGE's as appropriate, results to reflect purchase accounting adjustments.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Generation		Exelon	
	Year Ended December 31,		Year Ended December 31,	
(unaudited)	2012	2011 [a]	2012	2011 [b]
Total Revenues	$ 17,013	$ 19,494	$ 26,700	$ 30,712
Net income attributable to Exelon	1,205	324	2,092	974
Basic Earnings Per Share	n.a.	n.a.	$ 2.56	$ 1.15
Diluted Earnings Per Share	n.a.	n.a.	2.55	1.14

(a) The amounts above include non-recurring costs directly related to the merger of $203 million for the year ended December 31, 2011.
(b) The amounts above include non-recurring costs directly related to the merger of $236 million for the year ended December 31, 2011.

Acquisitions (Exelon and Generation)

Consistent with the applicable accounting guidance, the fair value of the assets acquired and liabilities assumed was determined as of the acquisition date through the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including the amount and timing); discount rates reflecting the risk inherent in the future cash flows; and future power and fuel market prices. Additionally, market prices based on the Market Price Referent (MPR) established by the CPUC for renewable energy resources were used in determining the fair value of the Antelope Valley assets acquired and liabilities assumed. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and the duration of the liabilities assumed. Generation did not record any goodwill related to any of the respective acquisitions.

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for each of the companies acquired by Generation during the years ended December 31, 2011 and December 31, 2010:

	Acquisitions		
	2011		2010
	Wolf Hollow	Antelope Valley	Exelon Wind
Fair value of consideration transferred			
Cash	$ 305	$ 75	$ 893
Plus: Gain on PPA settlement	6	—	—
Contingent consideration	—	—	32
Total fair value of consideration transferred	$ 311	$ 75	$ 925
Recognized amounts of identifiable assets acquired and liabilities assumed			
Property, plant and equipment	$ 347	$ 15	$ 700
Inventory	5	—	—
Intangible assets [(a)]	—	190	224
Payable to First Solar, Inc. [(b)]	—	(135)	—
Working capital, net	(5)	—	18
Asset retirement obligations	—	—	(13)
Noncontrolling interest	—		(3)
Other Assets	—	5	(1)
Total net identifiable assets	$ 347	$ 75	$ 925
Bargain purchase gain	$ 36	$ —	$ —

(a) See Note 8—Intangible Assets for additional information.
(b) Generation concluded that the remaining, yet-to-be paid $135 million in consideration was embedded in the amounts payable under the Engineering, Procurement, Construction (EPC) agreement for First Solar, Inc. to construct the solar facility. For accounting purposes, this aspect of the transaction is considered to be akin to a "seller financing" arrangement. As such, Generation recorded a liability of $135 million associated with the portion of the future payments to First Solar, Inc. under the EPC agreement to reflect Generation's implicit amounts due First Solar, Inc. for the remainder of the value of the net assets acquired. The $135 million payable to First Solar, Inc. will be relieved as Generation makes payments for costs incurred over the project construction period. At December 31, 2012, $87 million remained payable to First Solar, Inc.

Wolf Hollow, LLC. On August 24, 2011, Generation completed the acquisition of all of the equity interests of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, for a purchase price of $311 million which increased Generation's owned capacity within the ERCOT power market by 720 MWs. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020.

Generation recognized an approximately $36 million non-cash bargain purchase gain (i.e., negative goodwill). The gain was included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

The pro forma impact of this acquisition would not have been material to Exelon's or Generation's results of operations for the years ended December 31, 2011 and 2010.

Antelope Valley Solar Ranch One. On September 30, 2011, Generation acquired Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar PV project under development in northern Los Angeles County, California, from First Solar, which developed and will build, operate, and maintain the project. The first block began operations in December 2012, with three additional blocks coming online in February 2013 and an expectation of full commercial operation by the end of the third quarter of 2013. When fully operational, Antelope Valley will be one of the largest PV solar projects in the world, with approximately 3.8 million solar panels generating enough clean, renewable electricity to power the equivalent of 75,000 average homes per year. The project has a 25-year PPA, approved by the California Public Utilities Commission, with Pacific Gas & Electric Company for the full output of the plant. The acquisition supports Exelon's commitment to renewable energy as part of Exelon 2020.

Exelon expects to invest up to $701 million in equity in the project through 2013. The DOE's Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the project. On April 5, 2012, Antelope Valley received the first DOE-guaranteed loan advance of $69 million and terminated the put option that Generation had on the Antelope Valley project. See Note 11—Debt and Credit Agreements for additional information on the DOE loan guarantee.

The pro forma impact of this acquisition would not have been material to Exelon's or Generation's results of operations for the years ended December 31, 2011 and 2010.

Exelon Wind . On December 9, 2010, Generation paid consideration of $893 million to complete the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), a leading operator and developer of wind power. Under the terms of the agreement, Generation added 735 MWs of installed, operating wind capacity located in eight states. The acquisition supports Exelon's commitment to renewable energy as part of Exelon 2020.

The contingent consideration arrangement requires that Generation pay up to $40 million related to three individual projects with an aggregate capacity of 230 MWs, contingent upon meeting certain contractual commitments related to the commencement of construction of each project. The fair value of the contingent consideration arrangement of $32 million was determined as of the acquisition date based upon a weighted average probability of meeting certain contractual commitments related to the commencement of construction of each project, which is considered an unobservable (Level 3) input pursuant to applicable accounting guidance. During the third quarter of 2011, $16 million of contingent consideration was paid to Deere & Company for one of the projects and the probability of a second project beginning construction, Harvest II, was increased to 100%. As a result, the contingent consideration included in other current liabilities within Exelon's and Generation's Consolidated Balance Sheets was adjusted to $10 million to reflect the full expected contingent payment related to the Harvest II project and subsequently paid to Deere & Company during the third quarter of 2012. Additionally, $2 million was recorded in operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The remaining $8 million of contingent consideration is included in other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.

The fair value of the assets acquired included customer receivables of $18 million. There are no outstanding customer receivables that were acquired in the Exelon Wind transaction.

The $3 million noncontrolling interest represents the noncontrolling members' proportionate share in the fair value of the assets acquired and liabilities assumed in the transaction.

The pro forma impact of this acquisition would not have been material to Exelon's or Generation's results of operations for the year ended December 31, 2010.

5. Accounts Receivable (Exelon, Generation, ComEd PECO and BGE)

Accounts receivable at December 31, 2012 and 2011 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

2012	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$1,418	$ 859	$ 213	$164	$182
Allowance for uncollectible accounts [a]	(293)	(84)	(70)	(99) [b]	(40)

2011	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$ 902	$ 493	$ 246	$163	$194
Allowance for uncollectible accounts [a]	(199)	(29)	(78)	(92) [b]	(37)

(a) Includes the allowance for uncollectible accounts on customer and other accounts receivable.
(b) Includes an allowance for uncollectible accounts of $7 million and $8 million at December 31, 2012 and 2011, respectively, related to PECO's current installment plan receivables described below.

PECO Installment Plan Receivables (Exelon and PECO). PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $18 million and $21 million as of December 31, 2012 and 2011, respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1—Significant Accounting Policies. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2012 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2011 of $17 million consists of $1 million, $3 million and $13 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of December 31, 2012 and 2011 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1—Significant Accounting Policies.

Accounts Receivable Agreement (Exelon and PECO). PECO is party to an agreement with a financial institution under which it sold an undivided interest, adjusted daily, in up to $225 million of designated accounts receivable, which is accounted for as a secured borrowing. On November 28, 2012, PECO made a principal paydown of $15 million to meet the compliance requirements for the October 2012 reporting period. The remaining principal balance of $210 million is classified as a short-

term note payable on Exelon's and PECO's Consolidated Balance Sheets. As of December 31, 2012 and 2011, the financial institution's undivided interest in PECO's gross accounts receivable was equivalent to $289 million and $329 million, respectively, which is calculated under the terms of the agreement. See Note 11—Debt and Credit Agreements for additional information regarding the accounts receivable agreement.

6. Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2012 and 2011:

	Average Service Life (years)	2012	2011
Asset Category			
Electric—transmission and distribution	5 - 90	$26,576	$21,716
Electric—generation [a]	1 - 53	19,004	13,682
Gas—transportation and distribution	5 - 90	3,108	1,793
Common—electric and gas	5 - 50	1,029	564
Nuclear fuel [b]	1 - 8	4,815	4,225
Construction work in progress	N/A	1,926	1,110
Other property, plant and equipment [c]	3 - 72	912	439
Total property, plant and equipment		57,370	43,529
Less: accumulated depreciation [d]		12,184	10,959
Property, plant and equipment, net		$45,186	$32,570

(a) Includes assets acquired through acquisitions. See Note 4—Mergers and Acquisitions for additional information.
(b) Includes nuclear fuel that is in the fabrication and installation phase of $894 million and $674 million at December 31, 2012 and 2011, respectively.
(c) Includes Generation's buildings under capital lease with a net carrying value of $20 million and $23 million at December 31, 2012 and 2011, respectively. The original cost basis of the buildings was $53 million and total accumulated amortization was $33 million and $30 million as of December 31, 2012 and 2011, respectively. Also includes land held for future use and non utility property at ComEd, PECO and BGE. These balances also include capitalized acquisition, development and exploration costs related to oil and gas production activities at Generation.
(d) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $2,078 million and $1,784 million as of December 31, 2012 and 2011, respectively.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2012	2011	2010
Electric—transmission and distribution	2.76%	2.59%	2.53%
Electric—generation	3.15%	3.12%	2.86%
Gas	2.03%	1.73%	1.75%
Common—electric and gas	7.61%	8.05%	7.25%

Generation

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2012 and 2011:

	Average Service Life (years)	2012	2011
Asset Category			
Electric—generation [a]	1 - 53	$19,004	$13,682
Nuclear fuel [b]	1 - 8	4,815	4,225
Construction work in progress	N/A	1,352	827
Other property, plant and equipment [c]	5 - 57	374	54
Total property, plant and equipment		25,545	18,788
Less: accumulated depreciation [d]		6,014	5,313
Property, plant and equipment, net		$19,531	$13,475

(a) Includes assets acquired through acquisitions. See Note 4—Mergers and Acquisitions for additional information.
(b) Includes nuclear fuel that is in the fabrication and installation phase of $894 million and $674 million at December 31, 2012 and 2011, respectively.
(c) Includes buildings under capital lease with a net carrying value of $20 million and $23 million at December 31, 2012 and 2011, respectively. The original cost basis of the buildings was $53 million and total accumulated amortization was $33 million and $30 million as of December 31, 2012 and 2011, respectively.
(d) Includes accumulated amortization of nuclear fuel in the reactor core of $2,078 million and $1,784 million as of December 31, 2012 and 2011, respectively.

The annual depreciation provisions as a percentage of average service life for electric generation assets were 3.15%, 3.12% and 2.86% for the years ended December 31, 2012, 2011 and 2010, respectively.

License Renewals. Generation's depreciation provisions are based on the estimated useful lives of its generating stations, which assume the renewal of the licenses for all nuclear generating stations (except for Oyster Creek) and the hydroelectric generating stations. As a result, the receipt of license renewals has no impact on the Consolidated Statements of Operations. See Note 3—Regulatory Matters for additional information regarding license renewals.

ComEd

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2012 and 2011:

	Average Service Life (years)	2012	2011
Asset Category			
Electric—transmission and distribution	5 - 75	$16,480	$15,637
Construction work in progress	N/A	294	187
Other property, plant and equipment [a]	72	50	47
Total property, plant and equipment		16,824	15,871
Less: accumulated depreciation		2,998	2,750
Property, plant and equipment, net		$13,826	$13,121

(a) Represents land held for future use and non utility property.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 2.79%, 2.67% and 2.64% for the years ended December 31, 2012, 2011 and 2010, respectively.

PECO

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2012 and 2011:

	Average Service Life (years)	2012	2011
Asset Category			
Electric—transmission and distribution	5 - 65	$6,355	$6,079
Gas—transportation and distribution	5 - 70	1,859	1,793
Common—electric and gas	5 - 50	568	564
Construction work in progress	N/A	76	83
Other property, plant and equipment [(a)]	50	17	17
Total property, plant and equipment		8,875	8,536
Less: accumulated depreciation		2,797	2,662
Property, plant and equipment, net		$6,078	$5,874

(a) Represents land held for future use and non utility property.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2012	2011	2010
Electric—transmission and distribution	2.51%	2.33%	2.17%
Gas	1.77%	1.73%	1.75%
Common—electric and gas	7.54%	8.05%	7.25%

BGE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2012 and 2011:

	Average Service Life (years)	2012	2011
Asset Category			
Electric—transmission and distribution	5 - 90	$5,767	$5,483
Gas—transmission and distribution	5 - 90	1,548	1,387
Common—electric and gas	5 - 40	554	415
Construction work in progress	N/A	193	298
Other property, plant and equipment [(a)]	20	31	15
Total property, plant and equipment		8,093	7,598
Less: accumulated depreciation		2,595	2,466
Property, plant and equipment, net		$5,498	$5,132

(a) Represents land held for future use and non utility property.

Average Service Life Percentage by Asset Category	2012	2011	2010
Electric—transmission and distribution	2.92%	2.89%	2.88%
Gas	2.33%	2.41%	2.42%
Common—electric and gas	7.68%	8.40%	7.24%

See Note 1—Significant Accounting Polices for further information regarding property, plant and equipment policies and accounting for capitalized software costs for Exelon, Generation, ComEd, PECO and BGE. See Note 11—Debt and Credit Agreements for further information regarding Exelon's, ComEd's, and PECO's property, plant and equipment subject to mortgage liens.

7. Jointly Owned Electric Utility Plant (Exelon, Generation, PECO and BGE)

Exelon, Generation, PECO and BGE's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2012 and 2011 were as follows:

	Nuclear generation			Fossil fuel generation			Transmission		Other
	Quad Cities	Peach Bottom	Salem [a]	Keystone [b]	Conemaugh [b]	Wyman	PA [c]	DE/NJ [d]	Other [e]
Operator	Generation	Generation	PSEG Nuclear	GenOn	GenOn	FP&L	First Energy	PSEG	
Ownership interest	75.00%	50.00%	42.59%	41.98%	31.28%	5.89%	Various	42.55%	44.24%
Exelon's share at December 3 2012:									
Plant [f]	$ 874	$ 796	$ 494	$ 624	$ 322	$ 3	$ 13	$ 65	$ 1
Accumulated depreciation [f]	187	302	119	153	158	3	7	33	—
Construction work in progress	44	115	11	10	57	—	1	—	—
Exelon's share at December 3 2011:									
Plant [f]	$ 822	$ 650	$ 420	$ 366	$ 271	$ 3	$ 5	$ 66	$ 1
Accumulated depreciation [f]	156	285	103	137	154	3	3	33	—
Construction work in progress	37	111	61	5	15	—	—	—	—

(a) Generation also owns a proportionate share in the fossil fuel combustion turbine at Salem, which is fully depreciated. The gross book value was $3 million at December 31, 2012 and 2011.
(b) Generation's ownership interest in Keystone and Conemaugh has increased as a result of Exelon's merger with Constellation in 2012. See Note 4 for additional information.
(c) PECO and BGE own a 22% and 7% share, respectively, in 127 miles of 500 kV lines located in Pennsylvania; PECO and BGE also own a 20.7% and 10.56% share, respectively, of a 500 kV substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500 kV lines including, but not limited to, the lines noted above.
(d) PECO owns a 42.55% share in 131 miles of 500 kV lines located in Delaware and New Jersey as well as a 42.55% share in a 500kV substation immediately outside of the Salem nuclear generating station in New Jersey which supplies power to the 500kV lines including, but not limited to, the lines noted above.
(e) Generation has a 44.24% ownership interest in Merrill Creek Reservoir located in New Jersey.
(f) Excludes asset retirement costs.

Exelon's, Generation's, PECO's and BGE's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. Exelon's, Generation's, PECO's and BGE's share of direct expenses of the jointly owned

plants are included in fuel and operating and maintenance expenses on Exelon's and Generation's Consolidated Statements of Operations and in operating and maintenance expenses on PECO's and BGE's Consolidated Statements of Operations.

8. Intangible Assets (Exelon, Generation, ComEd and PECO)

Goodwill

Exelon's and ComEd's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2012 and 2011 were as follows:

	2012 and 2011		
	Gross Amount [(a)]	Accumulated Impairment Losses	Carrying Amount
Balance, January 1,	$4,608	$ 1,983	$2,625
Impairment losses	—	—	—
Balance, December 31,	$4,608	$ 1,983	$2,625

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom (predecessor parent company of ComEd) merger net of amortization, resolution of tax matters and other non-impairment-related changes as allowed under previous authoritative guidance.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events or circumstances indicate that goodwill is more likely than not impaired, such as a significant negative regulatory outcome, that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount.

In September 2011, the FASB issued authoritative guidance amending existing guidance on the annual assessment of goodwill for impairment. Under the revised guidance, which became effective January 1, 2012, entities assessing goodwill for impairment have the option of performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step one of the two-step fair value based impairment test). If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step fair value based impairment test is required. Otherwise, no further testing is required.

If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a two-step, fair value based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Exelon assesses goodwill impairment at its ComEd reporting unit. Accordingly, any goodwill impairment charge at ComEd will affect Exelon's consolidated results of operations. Under the effective authoritative guidance for fair value measurement, Exelon and ComEd estimate the fair value of the ComEd reporting unit using a weighted combination of a discounted cash flow analysis and a market multiples analysis. The discounted cash flow analysis relies on a single scenario reflecting "base case"

or “best estimate” projected cash flows for ComEd’s business and includes an estimate of ComEd’s terminal value based on these expected cash flows using the generally accepted Gordon Dividend Growth formula, which derives a valuation using an assumed perpetual annuity based on the entity’s residual cash flows. The discount rate is based on the generally accepted Capital Asset Pricing Model and represents the weighted average cost of capital of comparable companies. The market multiples analysis utilizes multiples of business enterprise value to earnings, before interest, taxes, depreciation and amortization (EBITDA) of comparable companies in estimating fair value. Significant assumptions used in estimating the fair value include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd’s business and the fair value of debt. Management performs a reconciliation of the sum of the estimated fair value of all Exelon reporting units to Exelon’s enterprise value based on its trading price to corroborate the results of the discounted cash flow analysis and the market multiple analysis.

2012 Interim Goodwill Impairment Assessment. In May 2012, the ICC issued a final Order (Order) in ComEd’s 2011 formula rate proceeding under EIMA that reduced ComEd’s annual revenue requirement being recovered in current rates by $168 million. Management concluded that the Order represented an event that required an interim goodwill impairment assessment and as a result, ComEd tested its goodwill for impairment as of May 31, 2012. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. Consistent with prior annual impairment tests, the estimated fair value of ComEd was determined using a weighted combination of a discounted cash flow analysis and a market multiples analysis. The discounted cash flow analysis relies on a single scenario reflecting “base case” or management’s best estimate of projected cash flows for ComEd’s business. In performing the discounted cash flow analysis for the interim goodwill test, management assumed that ComEd would ultimately prevail in appealing certain aspects of the May Order, specifically the return on ComEd’s pension asset and the use of year-end rate base in determining ComEd’s annual revenue requirement being recovered in current rates. The disallowances related to the pension asset return and year-end rate base were estimated to reduce ComEd’s revenue requirement recovered in rates by approximately $75—$130 million annually. The assessment also reflected several favorable changes in certain market assumptions since the annual impairment assessment in 2011, including the weighted average cost of capital and market multiples.

Based on the results of the interim goodwill test, the estimated fair value of ComEd would have needed to decrease by more than 10 percent for ComEd to fail the first step of the impairment test.

On October 3, 2012, the ICC issued its Rehearing Order in response to ComEd’s expedited rehearing request. The Rehearing Order adopted ComEd’s position on the return on its pension asset resulting in an increase in ComEd’s annual revenue. See Note 3—Regulatory Matters for further detail.

2012 Annual Goodwill Impairment Assessment. ComEd performed a qualitative assessment as of November 1, 2012, for its 2012 annual goodwill impairment assessment and while certain factors indicated a reduction in fair value since May 31, 2012, ComEd determined that its fair value was not more likely than not less than its carrying value. Therefore, ComEd did not perform a quantitative assessment. As part of its qualitative assessment, ComEd evaluated, among other things, management’s best estimate of projected operating and capital cash flows for ComEd’s business (including the impacts of the Rehearing Order) as well as changes in certain other market conditions such as the discount rate and EBITDA multiples.

While neither the interim nor the annual assessments indicated an impairment of ComEd’s goodwill, a change in management’s assumption regarding the outcome of the IRS’ challenge of Exelon’s and

ComEd's like-kind exchange income tax position, adverse regulatory actions such as early termination of EIMA, or changes in the significant assumptions described above could potentially result in a future impairment of ComEd's goodwill, which could be material. ComEd will assess whether its goodwill has been impaired in the first quarter of 2013 in connection with the reassessment of the like-kind exchange position and the associated charge to ComEd's earnings. See Note 12 for additional information.

Prior Goodwill Impairment Assessments. The 2011 and 2010 annual goodwill impairment assessments were performed as of November 1, 2011 and November 1, 2010, respectively. In each case, the first step of the annual impairment analysis, comparing the fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. ComEd will assess whether its goodwill has been impaired in the first quarter of 2013 in connection with the reassessment of the like-kind exchange position and the charge to ComEd's earnings. See Note 12 for additional information.

Other Intangible Assets

For discussion surrounding Exelon's and Generation's unamortized energy contracts, trade name and retail relationships recorded in conjunction with the Merger refer to Note 4—Merger and Acquisitions.

Exelon's, Generation's and ComEd's other intangible assets, included in unamortized energy contract assets and deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2012:

				Estimated amortization expense				
	Gross	Accumulated Amortization	Net	2013	2014	2015	2016	2017
Generation								
Exelon Wind acquisition [(a)]	$224	$ (26)	$198	$14	$14	$14	$14	$14
Antelope Valley acquisition [(b)]	190	—	190	7	8	8	8	8
ComEd								
Chicago settlement–1999 agreement [(c)]	100	(72)	28	3	3	3	3	4
Chicago settlement–2003 agreement [(d)]	62	(34)	28	4	4	4	4	3
Total intangible assets	$576	$ (132)	$444	$28	$29	$29	$29	$29

(a) Refer to Note 4—Merger and Acquisitions for additional information regarding Exelon Wind.
(b) Refer to Note 4—Merger and Acquisitions for additional information regarding Antelope Valley.
(c) In March 1999, ComEd entered into a settlement agreement with the City of Chicago associated with ComEd's franchise agreement. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago each year from 1999 to 2002. The intangible asset recognized as a result of these payments is being amortized ratably over the remaining term of the franchise agreement, which ends in 2020.
(d) In February 2003, ComEd entered into separate agreements with the City of Chicago and with Midwest Generation, LLC (Midwest Generation). Under the terms of the settlement agreement with the City of Chicago, ComEd agreed to pay the City of Chicago a total of $60 million over a ten-year period, beginning in 2003. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement, which ends in 2020. As required by the settlement, ComEd also made a payment of $2 million to a third party on the City of Chicago's behalf. Under the terms of the agreement with Midwest Generation, ComEd received payments of $32 million from Midwest Generation to relieve Midwest Generation's obligation under the 1999 fossil sale agreement with ComEd to build the generation facility in the City of Chicago. The payments received by ComEd, which have been recorded in other long-term liabilities, are being recognized ratably (approximately $2 million annually) as an offset to amortization expense over the remaining term of the franchise agreement.

The following table summarizes the amortization expense related to intangible assets for each of the years ended December 31, 2012, 2011 and 2010:

For the Year Ended December 31,	Exelon	Generation	ComEd
2012	$ 20	$ 13	$ 7
2011	19	12	7
2010	8	1	7

Acquired Intangible Assets

Accounting guidance for business combinations requires that the acquirer must recognize separately identifiable intangible assets in the application of purchase accounting. The valuation of the acquired intangible assets discussed below were estimated by applying the income approach, which is based upon discounted projected future cash flows associated with the respective PPAs. Those measures are based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance.

Exelon Wind. The output of the acquired wind turbines has been sold under PPA contracts. The excess of the contract price of the PPAs over market prices was recognized as intangible assets at the acquisition date. Generation determined that the estimated acquisition-date fair value of the intangible assets was approximately $224 million, which is recorded in unamortized energy contract assets within Exelon's and Generation's Consolidated Balance Sheets.

Key assumptions used in the valuation of the intangible assets include forecasted power prices and discount rate. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. The intangible assets are amortized on a straight-line basis over the period in which the associated contract revenues are recognized. The amortization expense is reflected as a decrease in operating revenue within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The weighted-average amortization period for these intangibles is approximately 18 years.

Antelope Valley. Upon completion of the development project, all of the output will be sold under a PPA with Pacific Gas & Electric Company. The excess of the contract price of the PPA over forecasted MPR-based market prices was recognized as an intangible asset at the acquisition date. Generation determined that the estimated acquisition-date fair value of the intangible asset was approximately $190 million, which is recorded in unamortized energy contract assets within Exelon's and Generation's Consolidated Balance Sheets. While Generation expects to perform under the PPA once the construction of this project is complete, there is a risk of impairment if the project does not reach commercial operation.

Key assumptions used in the valuation of the intangible asset include forecasted MPR-based market prices and discount rate. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. The fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the acquisition date. The intangible asset will be amortized as a decrease in operating revenue within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income over the 25 year term of the underlying PPA.

Renewable Energy Credits and Alternative Energy Credits (Exelon, Generation, ComEd and PECO).

Exelon's, Generation's, ComEd's and PECO's other intangible assets, included in other current assets and other deferred debits and other assets on the Consolidated Balance Sheets, include RECs (Exelon, Generation and ComEd) and AECs (Exelon and PECO). Revenue for RECs that are part of a bundled power sale is recognized when the power is produced and delivered to the customer. As of December 31, 2012, and 2011, PECO had current AECs of $17 million and $14 million, respectively, and noncurrent AECs of $9 million and $16 million, respectively. As of December 31, 2012, and 2011, Generation had current RECs of $61 million and $0 million, respectively, and noncurrent RECs of $45 million and $6 million, respectively. As of December 31, 2012, and 2011, ComEd, had current RECs of $18 million and $9 million, respectively, and noncurrent RECs of $49 million and $97, respectively. See Notes 1—Significant Accounting Policies, 3—Regulatory Matters and Note 19—Commitments and Contingencies for additional information on RECs and AECs.

9. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures), and preferred securities as of December 31, 2012, and 2011:

Exelon

	December 31, 2012				December 31, 2011	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ 214	$ 4	$ 210	$ —	$ 737	$ 737
Long-term debt (including amounts due within one year)	18,745	—	20,244	276	12,627	14,488
Long-term debt to financing trusts	648	—	—	664	390	358
SNF obligation	1,020	—	763	—	1,019	886
Preferred securities of subsidiary	87	—	82	—	87	79

Generation

	December 31, 2012				December 31, 2011	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ —	$ —	$ —	$ —	$ 2	$ 2
Long-term debt (including amounts due within one year)	7,483	—	7,591	258	3,677	4,231
SNF obligation	1,020	—	763	—	1,019	886

ComEd

	December 31, 2012				December 31, 2011	
	Carrying	Fair Value			Carrying	
	Amount	Level 1	Level 2	Level 3	Amount	Fair Value
Long-term debt (including amounts due within one year)	$5,567	$ —	$6,530	$ 18	$5,665	$6,540
Long-term debt to financing trust	206	—	—	212	206	184

PECO

	December 31, 2012				December 31, 2011	
	Carrying	Fair Value			Carrying	
	Amount	Level 1	Level 2	Level 3	Amount	Fair Value
Short-term liabilities	$ 210	$ —	$ 210	$ —	$ 225	$ 225
Long-term debt (including amounts due within one year)	1,947	—	2,264	—	1,972	2,295
Long-term debt to financing trusts	184	—	—	188	184	174
Preferred securities	87	—	82	—	87	79

BGE

	December 31, 2012				December 31, 2011	
	Carrying	Fair Value			Carrying	
	Amount	Level 1	Level 2	Level 3	Amount	Fair Value
Long-term debt (including amounts due within one year)	$2,178	$ —	$2,468	$ —	$2,101	$2,377
Long-term debt to financing trusts	258	—	—	263	258	256

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2), short-term notes payable related to PECO's accounts receivable agreement (Level 2), and dividends payable (Level 1). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments. See Note 11—Debt and Credit Agreements for additional information on PECO's accounts receivable agreement.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

Generation has fixed rate project financing debt (Level 3), the fair value of which is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, for certain government-backed debt, discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value.

The Registrants also have tax-exempt debt (Level 3). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (i.e., political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above.

SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

Long-Term Debt to Financing Trusts. Due to low trading volume of similar securities (Level 3), qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, may be incorporated into the credit spreads that are used to obtain the fair value as described above.

Preferred Securities. The fair value of these securities is determined based on the last closing price prior to quarter end, less accrued interest. The securities are registered with the SEC and are public.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1—quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to access as of the reporting date. Financial assets and liabilities utilizing Level 1 inputs include active exchange-traded equity securities, certain exchange-based derivatives, and money market funds.
- Level 2—inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. Financial assets and liabilities utilizing Level 2 inputs include fixed income securities, non-exchange-based derivatives, commingled and mutual investment funds priced at NAV per fund share and fair value hedges.
- Level 3—unobservable inputs, such as internally developed pricing models or third party valuations for the asset or liability due to little or no market activity for the asset or liability. Financial assets and liabilities utilizing Level 3 inputs include infrequently traded non-exchange-based derivatives, investments priced using an alternative pricing mechanism, and middle market lending using third party valuations.

There were no transfers between Level 1 and Level 2 during the year ended December 31, 2012.

Exelon

The following tables present assets and liabilities measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2012 and December 31, 2011:

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 995	$ —	$ —	$ 995
Nuclear decommissioning trust fund investments				
Cash equivalents	245	—	—	245
Equity				
Equity securities	1,480	—	—	1,480
Commingled funds	—	1,933	—	1,933
Equity funds subtotal	1,480	1,933	—	3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057	—	—	1,057
Debt securities issued by states of the United States and political subdivisions of the states	—	321	—	321
Debt securities issued by foreign governments	—	93	—	93
Corporate debt securities	—	1,788	—	1,788
Federal agency mortgage-backed securities	—	24	—	24
Commercial mortgage-backed securities (non-agency)	—	45	—	45
Residential mortgage-backed securities (non-agency)	—	11	—	11
Mutual funds	—	23	—	23
Fixed income subtotal	1,057	2,305	—	3,362
Middle market lending	—	—	183	183
Other debt obligations	—	15	—	15
Nuclear decommissioning trust fund investments subtotal [b]	2,782	4,253	183	7,218
Pledged assets for Zion decommissioning				
Cash equivalents	—	23	—	23
Equity				
Equity securities	14	—	—	14
Commingled funds	—	9	—	9
Equity funds subtotal	14	9	—	23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12	—	130
Debt securities issued by states of the United States and political subdivisions of the states	—	37	—	37
Corporate debt securities	—	249	—	249
Federal agency mortgage-backed securities	—	49	—	49
Commercial mortgage-backed securities (non-agency)	—	6	—	6
Fixed income subtotal	118	353	—	471
Middle market lending	—	—	89	89
Other debt obligations	—	1	—	1

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Pledged assets for Zion decommissioning subtotal [c]	132	386	89	607
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds [d]	69	—	—	69
Rabbi trust investments subtotal	71	—	—	71
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	641	4,675
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral [f]	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal [g]	80	1,076	656	1,812
Interest rate mark-to-market derivative assets	—	114	—	114
Effect of netting and allocation of collateral	—	(51)	—	(51)
Interest rate mark-to-market derivative assets subtotal	—	63	—	63
Other Investments	2	—	17	19
Total assets	4,062	5,778	945	10,785
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(236)	(3,566)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral [f]	2,042	4,020	25	6,087
Commodity mark-to-market liabilities subtotal [g][h]	(83)	(228)	(289)	(600)
Interest rate mark-to-market derivative liabilities	—	(84)	—	(84)
Effect of netting and allocation of collateral	—	51	—	51
Interest rate mark-to-market derivative liabilities subtotal	—	(33)	—	(33)
Deferred compensation	—	(102)	—	(102)
Total liabilities	(83)	(363)	(289)	(735)
Total net assets	$ 3,979	$ 5,415	$ 656	$10,050

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 861	$ —	$ —	$ 861
Nuclear decommissioning trust fund investments				
Cash equivalents	562	—	—	562
Equity				
Equity securities	1,275	—	—	1,275
Commingled funds	—	1,822	—	1,822
Equity funds subtotal	1,275	1,822	—	3,097
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,014	33	—	1,047
Debt securities issued by states of the United States and political subdivisions of the states	—	541	—	541
Debt securities issued by foreign governments	—	16	—	16
Corporate debt securities	—	778	—	778
Federal agency mortgage-backed securities	—	357	—	357
Commercial mortgage-backed securities (non-agency)	—	83	—	83
Residential mortgage-backed securities (non-agency)	—	5	—	5
Mutual funds	—	47	—	47
Fixed income subtotal	1,014	1,860	—	2,874
Middle market lending	—	—	13	13
Other debt obligations	—	18	—	18
Nuclear decommissioning trust fund investments subtotal [b]	2,851	3,700	13	6,564
Pledged assets for Zion decommissioning Equity				
Equity securities	35	—	—	35
Commingled funds	—	30	—	30
Equity funds subtotal	35	30	—	65
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	54	26	—	80
Debt securities issued by states of the United States and political subdivisions of the states	—	65	—	65
Corporate debt securities	—	314	—	314
Federal agency mortgage-backed securities	—	121	—	121
Commercial mortgage-backed securities (non-agency)	—	10	—	10
Commingled funds	—	20	—	20
Fixed income subtotal	54	556	—	610
Middle market lending	—	—	37	37
Other debt obligations	—	13	—	13
Pledged assets for Zion decommissioning subtotal [c]	89	599	37	725
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds [d][e]	34	—	—	34

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Rabbi trust investments subtotal	36	—	—	36
Commodity mark-to-market derivative assets				
Cash flow hedges	—	857	—	857
Economic hedges	—	1,653	124	1,777
Proprietary trading	—	240	48	288
Effect of netting and allocation of collateral [f]	—	(1,827)	(28)	(1,855)
Commodity mark-to-market assets [g]	—	923	144	1,067
Interest rate mark-to-market derivative assets	—	15	—	15
Total assets	3,837	5,237	194	9,268
Liabilities				
Commodity mark-to-market derivative liabilities				
Cash flow hedges	—	(13)	—	(13)
Economic hedges	(1)	(1,137)	(119)	(1,257)
Proprietary trading	—	(236)	(28)	(264)
Effect of netting and allocation of collateral [f]	—	1,295	20	1,315
Commodity mark-to-market liabilities [h]	(1)	(91)	(127)	(219)
Interest rate mark-to-market liabilities	—	(19)	—	(19)
Deferred compensation	—	(73)	—	(73)
Total liabilities	(1)	(183)	(127)	(311)
Total net assets	$3,836	$ 5,054	$ 67	$ 8,957

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $30 million and $(57) million at December 31, 2012 and December 31, 2011, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $7 million and $9 million at December 31, 2012 and December 31, 2011, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) The mutual funds held by the Rabbi trusts include $53 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan. These funds are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(e) Excludes $28 million and $25 million of the cash surrender value of life insurance investments at December 31, 2012 and December 31, 2011, respectively.
(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $532 million and $8 million allocated to Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2011.
(g) The Level 3 balance does not include current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $226 million and $0 million at December 31, 2012 and $503 million and $191 million at December 31, 2011, respectively, related to the fair value of Generation's financial swap contract with ComEd.
(h) The Level 3 balance includes the current and noncurrent liability of $18 million and $49 million at December 31, 2012, respectively, and $9 million and $97 million at December 31, 2011, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2012 and 2011:

For the Year Ended December 31, 2012	Nuclear Decommissioning Trust Fund Investment	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives [b]	Other Investments	Total
Balance as of January 1, 2012	$ 13	$ 37	$ 17	$ —	$ 67
Total realized / unrealized gains (losses)					
Included in net income	—	—	(119) [a]	—	(119)
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	1	—	39	—	40
Included in payable for Zion Station decommissioning	—	—	—	—	—
Change in collateral	—	—	(32)	—	(32)
Purchases, sales, issuances and settlements					
Purchases	169	63	334 [c]	17	583
Sales	—	(11)	—	—	(11)
Transfers into Level 3	—	—	39	—	39
Transfers out of Level 3	—	—	89	—	89
Balance as of December 31, 2012	$ 183	$ 89	$ 367	$ 17	$ 656
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2012	$ —	$ —	$ 37	$ —	$ 37

(a) Includes the reclassification of $156 million of realized losses due to settlement of derivative contracts recorded in results of operations for the year ended December 31, 2012.

(b) Excludes $98 million of increases in fair value and $566 million of realized losses due to settlements for the year ended December 31, 2012 of Generation's financial swap contract with ComEd, which eliminates upon consolidation in Exelon's Consolidated Financial Statements. This position was de-designated as a cash flow hedge prior to the merger date. All prospective changes in fair value and reclassifications of realized amounts are being recorded to income offset by the amortization of the frozen mark in OCI.

(c) Includes $323 million of fair value from contracts and $17 million of other investments acquired as a result of the merger.

For the Year Ended December 31, 2011	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Decommissioning	Mark-to-Market Derivatives	Total
Balance as of January 1, 2011	$ —	$ —	$ 50	$ 50
Total realized / unrealized gains (losses)				
Included in income	1	—	99	100
Included in other comprehensive income	—	—	(25) [a]	(25)
Included in regulatory liabilities	2	—	(106) [b]	(104)
Change in collateral	—	—	6	6
Purchases, sales, issuances and settlements				
Purchases	10	60	10	80
Sales	—	(23)	—	(23)
Transfers out of Level 3	—	—	(17)	(17)
Balance as of December 31, 2011	$ 13	$ 37	$ 17	$ 67
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2011	$ 1	$ —	$ 131	$ 132

(a) Includes the reclassification of $32 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2011.

(b) Excludes $170 million of increases in fair value and $451 million of realized losses due to settlements associated with Generation's financial swap contract with ComEd and $5 million of changes in the fair value of Generation's block contracts with PECO for the year ended December 31, 2011. All items eliminate upon consolidation if Exelon's Consolidated Financial Statements.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2012 and 2011:

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the year ended December 31, 2012	$ (153)	$ 34
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2012	$ 13	$ 24

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the year ended December 31, 2011	$ 108	$ (8)
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2011	$ 137	$ (5)

Generation

The following tables present assets and liabilities measured and recorded at fair value on Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2012 and December 31, 2011:

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 487	$ —	$ —	$ 487
Nuclear decommissioning trust fund investments				
Cash equivalents	245	—	—	245
Equity				
Equity securities	1,480	—	—	1,480
Commingled funds	—	1,933	—	1,933
Equity funds subtotal	1,480	1,933	—	3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057	—	—	1,057
Debt securities issued by states of the United States and political subdivisions of the states	—	321	—	321
Debt securities issued by foreign governments	—	93	—	93
Corporate debt securities	—	1,788	—	1,788
Federal agency mortgage-backed securities	—	24	—	24
Commercial mortgage-backed securities (non-agency)	—	45	—	45
Residential mortgage-backed securities (non-agency)	—	11	—	11
Mutual funds	—	23	—	23
Fixed income subtotal	1,057	2,305	—	3,362
Middle market lending	—	—	183	183
Other debt obligations	—	15	—	15
Nuclear decommissioning trust fund investments subtotal [b]	2,782	4,253	183	7,218
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	23	—	23
Equity				
Equity securities	14	—	—	14
Commingled funds	—	9	—	9
Equity funds subtotal	14	9	—	23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12	—	130
Debt securities issued by states of the United States and political subdivisions of the states	—	37	—	37
Corporate debt securities	—	249	—	249
Federal agency mortgage-backed securities	—	49	—	49
Commercial mortgage-backed securities (non-agency)	—	6	—	6
Fixed income subtotal	118	353	—	471
Middle market lending	—	—	89	89
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal [c]	132	386	89	607

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Rabbi trust investments				
Cash equivalents	1	—	—	1
Mutual funds [d][e]	13	—	—	13
Rabbi trust investments subtotal	14	—	—	14
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	867	4,901
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral [f]	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal [g]	80	1,076	882	2,038
Interest Rate mark-to-market derivative assets	—	101	—	101
Effect of netting and allocation of collateral	—	(51)	—	(51)
Interest Rate mark-to-market derivative assets subtotal	—	50	—	50
Other investments	2	—	17	19
Total assets	3,497	5,765	1,171	10,433
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(169)	(3,499)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral [f]	2,042	4,020	25	6,087
Commodity mark-to-market liabilities subtotal	(83)	(228)	(222)	(533)
Interest rate mark-to-market derivative liabilities	—	(84)	—	(84)
Effect of netting and allocation of collateral	—	51	—	51
Interest rate mark-to-market derivative liabilities subtotal	—	(33)	—	(33)
Deferred compensation	—	(28)	—	(28)
Total liabilities	(83)	(289)	(222)	(594)
Total net assets	$ 3,414	$ 5,476	$ 949	$ 9,839

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 466	$ —	$ —	$ 466
Nuclear decommissioning trust fund investments				
Cash equivalents	562	—	—	562
Equity				
Equity securities	1,275	—	—	1,275
Commingled funds	—	1,822	—	1,822
Equity funds subtotal	1,275	1,822	—	3,097
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,014	33	—	1,047
Debt securities issued by states of the United States and political subdivisions of the states	—	541	—	541
Debt securities issued by foreign governments	—	16	—	16
Corporate debt securities	—	778	—	778
Federal agency mortgage-backed securities	—	357	—	357
Commercial mortgage-backed securities (non-agency)	—	83	—	83
Residential mortgage-backed securities (non-agency)	—	5	—	5
Mutual funds	—	47	—	47
Fixed income subtotal	1,014	1,860	—	2,874
Middle market lending	—	—	13	13
Other debt obligations	—	18	—	18
Nuclear decommissioning trust fund investments subtotal [b]	2,851	3,700	13	6,564
Pledged assets for Zion Station decommissioning				
Equity				
Equity securities	35	—	—	35
Commingled funds	—	30	—	30
Equity funds subtotal	35	30	—	65
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	54	26	—	80
Debt securities issued by states of the United States and political subdivisions of the states	—	65	—	65
Corporate debt securities	—	314	—	314
Federal agency mortgage-backed securities	—	121	—	121
Commercial mortgage-backed securities (non-agency)	—	10	—	10
Commingled funds	—	20	—	20
Fixed income subtotal	54	556	—	610
Middle market lending	—	—	37	37
Other debt obligations	—	13	—	13
Pledged assets for Zion Station decommissioning subtotal [c]	89	599	37	725
Rabbi trust investments [d][e]	4	—	—	4
Commodity mark-to-market derivative assets				
Cash flow hedges	—	857	694	1,551
Other derivatives	—	1,653	124	1,777
Proprietary trading	—	240	48	288
Effect of netting and allocation of collateral [f]	—	(1,827)	(28)	(1,855)
Commodity mark-to-market assets subtotal [g]	—	923	838	1,761
Total assets	3,410	5,222	888	9,520

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Liabilities				
Commodity mark-to-market derivative liabilities				
Cash flow hedges	—	(13)	—	(13)
Other derivatives	(1)	(1,137)	(13)	(1,151)
Proprietary trading	—	(236)	(28)	(264)
Effect of netting and allocation of collateral [f]	—	1,295	20	1,315
Commodity mark-to-market liabilities subtotal	(1)	(91)	(21)	(113)
Interest rate mark-to-market derivative liabilities	—	(19)	—	(19)
Deferred compensation	—	(18)	—	(18)
Total liabilities	(1)	(128)	(21)	(150)
Total net assets	$3,409	$ 5,094	$ 867	$ 9,370

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $30 million and $(57) million at December 31, 2012 and December 31, 2011, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $7 million and $9 million at December 31, 2012 December 31, 2011, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) The $13 million mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(e) Excludes $8 million and $7 million of the cash surrender value of life insurance investments at December 31, 2012 and December 31, 2011, respectively.
(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $532 million and $8 million allocated to Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2011.
(g) The Level 3 balance includes current and noncurrent assets for Generation of $226 million and $0 million at December 31, 2012 and $503 million and $191 million at December 31, 2011, respectively, related to the fair value of Generation's financial swap contract with ComEd, which eliminates upon consolidation in Exelon's Consolidated Financial Statements.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2012, and 2011:.

For the Year Ended December 31, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of January 1, 2012	$ 13	$ 37	$ 817	—	$ 867
Total unrealized / realized gains (losses)					
Included in income	—	—	(112) [a]	—	(112)
Included in other comprehensive income	—	—	(475) [b]	—	(475)
Included in noncurrent payables to affiliates	1	—	—	—	1
Change in collateral	—	—	(32)	—	(32)
Purchases, sales, issuances and settlements					
Purchases	169	63	334[c]	17	583
Sales	—	(11)	—	—	(11)
Transfers into Level 3	—	—	39		39
Transfers out of Level 3	—	—	89	—	89
Balance as of December 31, 2012	$ 183	$ 89	$ 660	$ 17	$ 949
The amount of total losses included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2012	$ —	$ —	$ (12)	$ —	$ (12)

(a) Includes the reclassification of $100 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2012.

(b) Includes $98 million of increases in fair value and realized losses due to settlements of $566 million associated with Generation's financial swap contract with ComEd for the year ended December 31, 2012. This position was de-designated as a cash flow hedge prior to the merger date. All prospective changes in fair value and reclassifications of realized amounts are being recorded to income offset by the amortization of the frozen mark in OCI. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

(c) Includes $323 million of fair value from contracts and $17 million of other investments acquired as a result of the merger.

For the Year Ended December 31, 2011	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Total
Balance as of January 1, 2011	$ —	$ —	$ 1,030	$1,030
Total realized / unrealized gains (losses)				
Included in income	1	—	99[a]	100
Included in other comprehensive income	—	—	(311) [b]	(311)
Included in payable for Zion Station decommissioning	2	—	—	2
Changes in collateral	—	—	6	6
Purchases, sales, issuances and settlements				
Purchases	10	60	10	80
Sales	—	(23)	—	(23)
Transfers out of Level 3—Liability	—	—	(17)	(17)
Balance as of December 31, 2011	$ 13	$ 37	$ 817	$ 867
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities as of December 31, 2011	$ 1	$ —	$ 131	$ 132

(a) Includes the reclassification of $32 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2011.

(b) Includes $170 million of increases in fair value and $451 million of realized losses reclassified from OCI due to settlements associated with Generation's financial swap contract with ComEd for the year ended December 31, 2011, and $5 million of decreases in fair value due to settlement of Generation's block contracts with PECO for the year ended December 31, 2011. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2012, and 2011:

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the year ended December 31, 2012	$ (146)	$ 34
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2012	$ (25)	$ 13

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the year ended December 31, 2011	$ 108	$ (8)
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2011	$ 137	$ (5)

ComEd

The following tables present assets and liabilities measured and recorded at fair value on ComEd's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2012 and December 31, 2011:

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 111	$ —	$ —	$ 111
Rabbi trust investments				
Mutual funds	8	—	—	8
Rabbi trust investment subtotal	8	—	—	8
Total assets	119	—	—	119
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities [b][c]	—	—	(293)	(293)
Total liabilities	—	(8)	(293)	(301)
Total net assets (liabilities)	$ 119	$ (8)	$(293)	$(182)

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 173	$ —	$ —	$ 173
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds	19	—	—	19
Rabbi trust investment subtotal	21	—	—	21
Total assets	194	—	—	194
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities [b][c]	—	—	(800)	(800)
Total liabilities	—	(8)	(800)	(808)
Total net assets (liabilities)	$ 194	$ (8)	$(800)	$(614)

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) The Level 3 balance includes the current and noncurrent liability of $226 million and $0 million at December 31, 2012, respectively, and $503 million and $191 million at December 31, 2011, respectively, related to the fair value of ComEd's financial swap contract with Generation which eliminates upon consolidation in Exelon's Consolidated Financial Statements.
(c) The Level 3 balance includes the current and noncurrent liability of $18 million and $49 million at December 31, 2012, respectively, and $9 million and $97 million at December 31, 2011, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the year ended and December 31, 2012, and 2011:

For the Year Ended December 31, 2012	Mark-to-Market Derivatives
Balance as of January 1, 2012	$ (800)
Total realized / unrealized gains included in regulatory assets [(a)(b)]	507
Balance as of December 31, 2012	$ (293)

(a) Includes $98 million of decreases in fair value and realized gains due to settlements of $566 million associated with ComEd's financial swap contract with Generation for the year ended December 31, 2012. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(b) Includes $34 million of increases in the fair value and realized losses due to settlements of $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2012.

Twelve Months Ended December 31, 2011	Mark-to-Market Derivatives
Balance as of January 1, 2011	$ (971)
Total realized / unrealized gains included in regulatory assets [(a)(b)]	171
Balance as of December 31, 2011	$ (800)

(a) Includes $170 million of increases in fair value and $451 million of realized gains due to settlements associated with ComEd's financial swap contract with Generation for the year ended December 31, 2011. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(b) Includes $110 million of decreases in fair value of floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2011.

PECO

The following tables present assets and liabilities measured and recorded at fair value on PECO's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2012 and December 31, 2011:

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 346	$ —	$ —	$346
Rabbi trust investments—mutual funds [(b)(c)]	9	—	—	9
Total assets	355	—	—	355
Liabilities				
Deferred compensation obligation	—	(18)	—	(18)
Total liabilities	—	(18)	—	(18)
Total net assets (liabilities)	$ 355	$ (18)	$ —	$337

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 175	$ —	$ —	$175
Rabbi trust investments—mutual funds [b][c]	9	—	—	9
Total assets	184	—	—	184
Liabilities				
Deferred compensation obligation	—	(21)	—	(21)
Total liabilities	—	(21)	—	(21)
Total net assets (liabilities)	$ 184	$ (21)	$ —	$163

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) The mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(c) Excludes $13 million of the cash surrender value of life insurance investments at December 31, 2012 and 2011, respectively.

PECO had no Level 3 assets or liabilities measured at fair value on a recurring basis during the year ended December 31, 2012.

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the year ended December 31, 2011:

Year Ended December 31, 2011	Mark-to-Market Derivatives
Balance as of January 1, 2011	$ (9)
Total realized gains included in regulatory assets	9[a]
Balance as of December 31, 2011	$ —

(a) Includes an increase of $5 million related to the settlement of PECO's block contracts with Generation, which eliminates upon consolidation in Exelon's Consolidated Financial Statements. Generation's block contracts with PECO expired on December 31, 2011.

BGE

The following tables present assets and liabilities measured and recorded at fair value on BGE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2012 and December 31, 2011:

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 33	$ —	$ —	$33
Rabbi trust investments—mutual funds	5	—	—	5
Total assets	38	—	—	38
Liabilities				
Deferred compensation obligation	—	(5)	—	(5)
Total liabilities	—	(5)	—	(5)
Total net assets (liabilities)	$ 38	$ (5)	$ —	$33

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 33	$ —	$ —	$33
Total assets	33	—	—	33
Liabilities				
Total net assets (liabilities)	$ 33	$ —	$ —	$33

BGE had no Level 3 assets or liabilities measured at fair value on a recurring basis during the year ended December 31, 2012.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE). The Registrants' cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds. Generation's investment policies place limitations on the types and investment grade ratings of the securities that may be held by the trusts. These policies limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2.

Equity and fixed income commingled funds and fixed income mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of fixed income commingled and mutual funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining equity commingled funds in which Exelon and Generation invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. In general, equity commingled funds are redeemable on the 15th of the month and the last business day of the month; however, the fund manager may designate any day as a valuation date for the purpose of purchasing or redeeming units. Commingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities.

Middle market lending are investments in loans or managed funds which invest in private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in middle market lending are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The investments in the Rabbi trusts are included in investments in the Registrants' Consolidated Balance Sheets. The investments are in fixed-income commingled funds and mutual funds, including short-term investment funds. These funds are maintained by investment companies and hold certain investments in accordance with a stated set of

fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For fixed-income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Fixed-income commingled funds and mutual funds which are publicly quoted, such as money market funds, have been categorized as Level 1 given the clear observability of the prices.

Mark-to-Market Derivatives (Exelon, Generation, ComEd and PECO). Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain non-exchange-based derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of non-exchange-based derivative contracts is valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For non-exchange-based derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' non-exchange-based derivatives are predominately at liquid trading points. For non-exchange-based derivatives that trade in less liquid markets with limited pricing information, such as the financial swap contract between Generation and ComEd, model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 10—Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO and BGE). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized in Level 2 in the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd)

Mark-to-Market Derivatives (Exelon, Generation, ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Exelon Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at Exelon. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements. Transfers in and out of levels are recognized as of the end of the reporting period the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 generally do not occur. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The most significant position is the long term intercompany swap with ComEd, which is further discussed in Note 10—Derivative Financial Instruments. The calculated fair value includes marketability discounts for margining provisions and notional size. Generation's remaining Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties, and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and

Generation's own credit quality for liabilities. The level of observability of a forward commodity price is generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are highly liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instruments market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is generally less than $4 and $.25 for power and natural gas respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 3.—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrant's mark-to-market derivative assets and liabilities.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 10—Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk. The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at December 31, 2012 [d]	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic Hedges (Generation) [a]	$ 473	Discounted Cash Flow	Forward power price	$14 - $79
			Forward gas price	$3.26 - $6.27
		Option Model	Volatility percentage	28% - 132%
Mark-to-market derivatives—Proprietary trading (Generation) [a]	$ (6)	Discounted Cash Flow	Forward power price	$15 - $106
		Option Model	Volatility percentage	16% - 48%
Mark-to-market derivatives—Transactions with affiliates (Generation and ComEd) [b]	$ 226	Discounted Cash Flow	Marketability reserve	8% - 9%
Mark-to-market derivatives (ComEd)	$ (67)	Discounted Cash Flow	Forward heat rate [c]	8% - 9.5%
			Marketability reserve	3.5% - 8.3%
			Renewable factor	81% - 123%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Includes current assets for Generation and current liabilities for ComEd of $226 million, related to the fair value of the five-year financial swap contract between Generation and ComEd, which eliminates in consolidation.
c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
d) The fair values do not include cash collateral held on Level 3 positions of $33 million as of December 31, 2012.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give us the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give us the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending the fair value of these loans is determined using a combination of valuations models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the applications of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability and relative performance.

Because Generation relies on third party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its' middle market lending, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations. For a sample of its' middle market lending, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

10. Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market fluctuations in the prices of electricity, fossil

fuels and other commodities. The Registrants employ established policies and procedures to manage their risks associated with market fluctuations by entering into physical contracts as well as financial derivative contracts including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, effective with the date of merger with Constellation, Generation will no longer utilize the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivative economic hedges for commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 19—Commitments and Contingencies. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include

derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of December 31, 2012, the percentage of expected generation hedged for the major reportable segments was 94%-97%, 62%-65% and 27%-30% for 2013, 2014, and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including, sales to ComEd, PECO and BGE to serve their retail load.

ComEd has locked in a fixed price for a significant portion of its commodity price risk through the five-year financial swap contract with Generation that expires on May 31, 2013, which is discussed in more detail below. In addition, the contracts that Generation has entered into with ComEd and that ComEd has entered into with Generation and other suppliers as part of the ComEd power procurement process, which are further discussed in Note 3—Regulatory Matters, qualify for the NPNS exception. Based on the Illinois Settlement Legislation and ICC-approved procurement methodologies permitting ComEd to recover its electricity procurement costs from retail customers with no mark-up, ComEd's price risk related to power procurement is limited.

In order to fulfill a requirement of the Illinois Settlement Legislation, Generation and ComEd entered into a five-year financial swap contract effective August 28, 2007. The financial swap is designed to hedge spot market purchases, which, along with ComEd's remaining energy procurement contracts, meet its load service requirements. The remaining swap contract volume is 3,000 MWs through May 2013. The terms of the financial swap contract require Generation to pay the around-the-clock market price for a portion of ComEd's electricity supply requirement, while ComEd pays a fixed price. The contract is to be settled net, for the difference between the fixed and market pricing, and the financial terms only cover energy costs and do not cover capacity or ancillary services. The financial swap contract is a derivative financial instrument that was originally designated by Generation as a cash flow hedge. As discussed previously, effective with the date of merger with Constellation, Generation de-designated this swap as a cash flow hedge and began recording changes in fair value through current earnings as of that date. Generation records the fair value of the swap on its balance sheet and originally recorded changes in fair value to OCI. The value frozen in OCI as of the date of merger for this swap is reclassified into Generation's earnings as the swap settles. ComEd has not elected hedge accounting for this derivative financial instrument. Since the financial swap contract was deemed prudent by the Illinois Settlement Legislation, ComEd receives full cost recovery for the contract in rates and, therefore, the change in fair value each period is recorded as a regulatory asset or liability on ComEd's Consolidated Balance Sheets. See Note 3—Regulatory Matters for additional information regarding the Illinois Settlement Legislation. In Exelon's consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge

accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3—Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts and block contracts. PECO's full requirements contracts and block contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. For block contracts designated as normal purchases after inception, the mark-to-market balances previously recorded on PECO's Consolidated Balance Sheet were amortized over the terms of the contracts, which ended on December 31, 2011.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the normal purchases and normal sales scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2012 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2012 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE's price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its Standard Offer Service requirements through full requirements contracts. BGE's full requirements contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing

(i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the market-based rates incentive mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. All of BGE's natural gas supply and asset management agreements qualify for the normal purchases and normal sales exception and result in physical delivery.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 12,958 GWh, 5,742 GWh and 3,625 Gwh for the years ended December 31, 2012, 2011 and 2010, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

Interest Rate Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2012, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and $452 million of notional amounts of pre-issuance hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper and PECO Accounts Receivables Facility) and fixed-to-floating swaps would result in less than $2 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2012. Below is a summary of the interest rate hedges as of December 31, 2012.

	Generation					Other	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (Current Assets)	$ —	$ 3	$ 20	$ (19)	$ 4	$ —	$ 4
Mark-to-market derivative assets (Noncurrent Assets)	38	$ 8	$ 32	(32)	46	13	59
Total mark-to-market derivative assets	$ 38	$ 11	$ 52	$ (51)	$ 50	$ 13	$ 63
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (19)	$ 19	$ (2)	$ —	$ (2)
Mark-to-market derivative liabilities (Noncurrent Liabilities)	(31)	$ —	$ (32)	32	(31)	—	(31)
Total mark-to-market derivative liabilities	$ (32)	$ (1)	$ (51)	$ 51	$ (33)	$ —	$ (33)
Total mark-to-market derivative net assets (liabilities)	$ 6	$ 10	$ 1	$ —	$ 17	$ 13	$ 30

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.
(b) Represents the netting of fair value balances with the same counterparty and collateral.

Fair Value Hedges. For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

	Gain (Loss) on Swaps			Gain (Loss) on Borrowings		
	Twelve Months Ended December 31,			Twelve Months Ended December 31,		
Income Statement Classification	2012	2011	2010	2012	2011	2010
Interest expense [a]	$ (6)	$ 1	$ 4	$ (6)	$ (1)	$ (4)

(a) For the year ended December 31, 2012, the loss on the swaps in the table above includes $12 million reclassified to earnings, with an immaterial amount excluded from hedge effectiveness testing.

At December 31, 2012, and December 31, 2011, Exelon had $650 million and $100 million, respectively, of notional amounts of fixed-to-floating fair value hedges outstanding related to interest rate swaps, with unrealized gain of $49 million and $15 million, respectively, which expire in 2015. Upon merger closing, $550 million of fixed-to-floating interest rate swaps previously at Constellation with a fair value of $44 million, as of March 12, 2012, were re-designated as fair value hedges. During the years ended December 31, 2012, and December 31, 2011, the impact on the results of operations as a result of ineffectiveness from fair value hedges was immaterial.

Cash Flow Hedges. In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 11—Debt and Credit Agreements, Generation entered into a floating-to-fixed forward starting interest rate swap with a notional amount of $485 million and a mandatory early termination date of April 5, 2014, by which date Generation anticipates the DOE loan to be fully drawn. The swap hedges approximately 75% of Generation's future interest rate exposure associated with the financing and was designated as a cash flow hedge. As such, the effective portion of the hedge will be recorded in other comprehensive income within Generation's Consolidated Balance Sheets, with any ineffectiveness recorded in Generation's Consolidated Statements of Operations and Comprehensive Income. Net gains (or losses) from settlement of the hedges, to the extent effective, will be amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

As Generation draws down on the loan, a portion of the cash flow hedge will be de-designated and the related gains or losses going forward will be reflected in earnings. In order to mitigate this earnings impact, a series of offsetting hedge transactions are executed as Generation draws on the loan.

Antelope Valley received its first loan advance on April 5, 2012, and several additional advances subsequently, as described in Note 11—Debt and Credit Agreements. Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $165 million, 75% of the loan advance amount to offset portions of the original interest rate hedge, which are de-designated as cash flow hedges. The remaining cash flow hedge has a notional amount of

$320 million. At December 31, 2012, Generation's mark-to-market non-current derivative liability relating to the interest rate swap in connection with the loan agreement to fund Antelope Valley was $28 million.

During the third quarter of 2011, a subsidiary of Constellation entered into floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Sacramento PV Energy. The swaps have a total notional amount of $29 million as of December 31, 2012 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At December 31, 2012, the subsidiary had a $4 million non-current derivative liability related to these swaps.

During the third quarter of 2012, a subsidiary of Exelon Generation entered into a floating-to-fixed forward starting interest rate swap to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Constellation Solar Horizons. The swap has a notional amount of $29 million as of December 31, 2012 and expires in 2030. This swap is designated as a cash flow hedge. At December 31, 2012, the subsidiary had an immaterial non-current derivative liability related to the swap.

During the third quarter of 2012, Exelon entered into $75 million floating-to-fixed forward starting interest rate hedges to manage interest rate risks associated with anticipated future debt issuance. These swaps are designated as cash flow hedges. At December 31, 2012, there is $1 million non-current derivative asset related to these swaps.

During the years ended December 31, 2012, and 2011, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Economic Hedges. At December 31, 2012, Exelon had $150 million of notional amounts of fixed-to-floating interest rate swaps that are marked-to-market, with an unrealized gain of $5 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the period from March 12 to December 31, 2012, the impact on the results of operations was immaterial.

Fair Value Measurement (Exelon, Generation, ComEd, PECO and BGE)

Fair value accounting guidance requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. In the table below, Generation's energy related cash flow hedges, economic hedges, and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty, as well as netting of collateral, is aggregated in the collateral and netting column. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2012:

	Generation				ComEd		Exelon
Derivatives	Economic Hedges [a]	Proprietary Trading	Collateral and Netting [b]	Subtotal [c]	Economic Hedges [a][d]	Intercompany Eliminations [a]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,883	$ 2,469	$(4,418)	$ 934	$ —	$ —	$ 934
Mark-to-market derivative assets with affiliate (current assets)	226	—	—	226	—	(226)	—
Mark-to-market derivative assets (noncurrent assets)	1,792	724	(1,638)	878	—	—	878
Total mark-to-market derivative assets	$ 4,901	$ 3,193	$(6,056)	$2,038	$ —	$ (226)	$ 1,812
Mark-to-market derivative liabilities (current liabilities)	$ (2,419)	$ (2,432)	$ 4,519	$ (332)	$ (18)	$ —	$ (350)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	(226)	226	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,080)	(689)	1,568	(201)	(49)	—	(250)
Total mark-to-market derivative liabilities	$ (3,499)	$ (3,121)	$ 6,087	$ (533)	$ (293)	$ 226	$ (600)
Total mark-to-market derivative net assets (liabilities)	$ 1,402	$ 72	$ 31	$1,505	$ (293)	$ —	$ 1,212

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $226 million related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation, excludes $28 million non current liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.

(b) Represents the netting of fair value balances with the same counterparty and the application of collateral.

(c) Current and noncurrent assets are shown net of collateral of $113 million and $201 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(214) million and $(131) million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $31 million at December 31, 2012.

(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2011:

	Generation					ComEd	Other		Exelon
Derivatives	Cash Flow Hedges [a]	Economic Hedges	Proprietary Trading	Collateral and Netting [b]	Subtotal [c]	Economic Hedges [a][d]	Economic Hedges	Intercompany Eliminations [a]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 438	$ 1,195	$ 217	$ (1,418)	$ 432	$ —	$ —	$ —	$ 432
Mark-to-market derivative assets with affiliate (current assets)	503	—	—	—	503	—	—	(503)	—
Mark-to-market derivative assets (noncurrent assets)	419	582	71	(437)	635	—	15	—	650
Mark-to-market derivative assets with affiliate (noncurrent assets)	191	—	—	—	191	—	—	(191)	—
Total mark-to-market derivative assets	$ 1,551	$ 1,777	$ 288	$ (1,855)	$ 1,761	$ —	$ 15	$ (694)	$ 1,082
Mark-to-market derivative liabilities (current liabilities)	$ (9)	$ (965)	$ (194)	$ 1,065	$ (103)	$ (9)	$ —	$ —	$ (112)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	—	(503)	—	503	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(4)	(186)	(70)	250	(10)	(97)	—	—	(107)
Mark-to-market derivative liability with affiliate (noncurrent liabilities)	—	—	—	—	—	(191)	—	191	—
Total mark-to-market derivative liabilities	$ (13)	$ (1,151)	$ (264)	$ 1,315	$ (113)	$ (800)	$ —	$ 694	$ (219)
Total mark-to-market derivative net assets (liabilities)	$ 1,538	$ 626	$ 24	$ (540)	$ 1,648	$ (800)	$ 15	$ —	$ 863

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $503 million and $191 million, respectively, related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation, excludes $19 million non current liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.
(b) Represents the netting of fair value balances with the same counterparty and the application of collateral.
(c) Current and noncurrent assets are shown net of collateral of $338 million and $187 million, respectively, and current and noncurrent liabilities are shown inclusive of collateral of $15 million and $0 million, respectively. The total cash collateral received net of cash collateral posted and offset against mark-to-market assets and liabilities was $540 million at December 31, 2011.
(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon, Generation and ComEd). Economic hedges that qualify as cash flow hedges primarily consist of forward power sales and power swaps on base load generation. As discussed previously, effective prior to the merger with Constellation, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective changes in the fair value of these instruments through current earnings from the date of de-designation. The net unrealized gains associated with the de-designated cash flow hedges prior to the merger was $1,928 million including $693 million related to the

intercompany swap with ComEd. Approximately $684 million of these net pre-tax unrealized gains within accumulated OCI are expected to be reclassified from accumulated OCI during the next twelve months by Generation, including approximately $219 million related to the financial swap with ComEd. Generation expects the settlement of the majority of its cash flow hedges, including the ComEd financial swap contract, will occur during 2013 through 2014.

Exelon discontinues hedge accounting prospectively when it determines that the derivative is no longer effective in offsetting changes in the cash flows of a hedged item or when it is no longer probable that the forecasted transaction will occur. For the years ended December 31, 2012 and 2011, amounts reclassified into earnings as a result of the discontinuance of cash flow hedges were immaterial.

The table below provides the activity of accumulated OCI related to cash flow hedges for the years ended December 31, 2012 and 2011, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
	Income Statement Location	Energy Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at January 1, 2011		$ 1,011[a][d]	$ 400
Effective portion of changes in fair value		504[b]	402[e]
Reclassifications from accumulated OCI to net income	Operating Revenues	(585) [c]	(309)
Ineffective portion recognized in income	Purchased Power	(5)	(5)
Accumulated OCI derivative gain at December 31, 2011		925[a][d]	488
Effective portion of changes in fair value		432[b]	330[e]
Reclassifications from accumulated OCI to net income	Operating Revenues	(828) [c]	(453)
Ineffective portion recognized in income	Operating Revenues	3	3
Accumulated OCI derivative gain at December 31, 2012		$ 532[a][d]	$ 368

(a) Includes $133 million, $420 million and $589 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2012, 2011 and 2010, respectively, and $3 million of gains, net of taxes, related to the fair value of the block contracts with PECO for the year ended December 31, 2010.

(b) Includes $88 million and $104 million of gains, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2012 and 2011, respectively, and $2 million of gains, net of taxes, of the effective portion of changes in fair value of the block contracts with PECO for the year ended December 31, 2010. As of the merger date, cash flow hedges were discontinued, as such, this amount represents changes in fair value prior to the merger date.

(c) Includes $375 million and $273 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2012 and 2011, respectively, and $3 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to settlements of the block contracts with PECO for the year ended December 31, 2011.

(d) Excludes $20 million of losses and $10 million of losses, net of taxes, related to interest rate swaps and treasury rate locks for the years ended December 31, 2012 and 2011, respectively.
(e) Includes $9 million and $12 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks at Generation for the year ended December 31, 2012 and 2011, respectively.

During the years ended December 31, 2012, 2011, and 2010 Generation's cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $1,368 million, $968 million and $1,125 million pre-tax gain, respectively. Given that the cash flow hedges had primarily consisted of forward power sales and power swaps and did not include power and gas options or sales, the ineffectiveness of Generation's cash flow hedges was primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. This price difference was actively managed through other instruments, which include financial transmission rights, whose changes in fair value are recognized in earnings each period, and auction revenue rights. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices were losses of $5 million and gains of $10 million and $1 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Exelon's energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $747 million pre-tax gain for the year ended December 31, 2012, and a $512 million and $754 million pre-tax gain for the years ended 2011 and 2010, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were losses of $5 million and gains of $10 million and $1 million for the years ended December 31, 2012, 2011 and 2010, respectively. Neither Exelon nor Generation will not incur changes in cash flow hedge ineffectiveness in future periods as all commodity cash flow hedge positions were de-designated prior to the merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, and physical forward sales and purchases. For the years ended December 31, 2012, 2011 and 2010, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the 3rd quarter of 2012, Generation completed a non-cash exchange by issuing a new in-the-money derivative with a new counterparty in exchange for novating to them existing in-the-money trades with the old counterparty for a total of $51 million. This transaction did not have any Income Statement effect to Generation. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Generation			Intercompany Eliminations	Exelon
Year Ended December 31, 2012	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues [a]	Total
Change in fair value	$ (362)	$ 215	$(147)	$ (94)	$(241)
Reclassification to realized at settlement	429	238	667	101	768
Net mark-to-market gains (losses)	$ 67	$ 453	$ 520	$ 7	$ 527

Year Ended December 31, 2011 (As Reported)	Operating Revenues	Purchased Power and Fuel	Total
Change in fair value	$ 87	$ 131	$ 218
Reclassification to realized at settlement	(296)	(219)	(515)
Net mark-to-market (losses) [b]	$ (209)	$ (88)	$(297)

	Exelon and Generation		
Year Ended December 31, 2011 (Pro Forma)	Operating Revenues	Purchased Power and Fuel	Total
Change in fair value	$ 258	$ (40)	$ 218
Reclassification to realized at settlement	(516)	1	(515)
Net mark-to-market (losses) [b]	$ (258)	$ (39)	$(297)

	Exelon and Generation		
Year Ended December 31, 2010 (As Reported)	Operating Revenues	Purchased Power and Fuel	Total
Change in fair value	$ —	$ 389	$ 389
Reclassification to realized at settlement	—	(304)	(304)
Net mark-to-market (losses) [b]	$ —	$ 85	$ 85

(a) Prior to the merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value are recorded to operating revenues and eliminated in consolidation.

(b) Exelon and Generation have historically presented mark-to-market gains and losses within purchased power expense for all non-trading, energy-related derivatives that were not accounted for as cash flow hedges. In 2011, Exelon and Generation classified the mark-to-market gains and losses for contracts, where the underlying hedged transaction was an expected sale to hedge power, to operating revenues.

Proprietary Trading Activities (Exelon and Generation). For the years ended December 31, 2012, and 2011, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on derivative instruments entered into for proprietary trading purposes. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	For the Years Ended December 31, 2012	2011	2010
Change in fair value	Operating Revenue	$ (12)	$ 23	$ 26
Reclassification to realized at settlement	Operating Revenue	108	(26)	(24)
Net mark-to-market gains	Operating Revenue	$ 96	$ (3)	$ 2

Credit Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2012. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through exchanges (i.e. NYMEX, ICE), further discussed in ITEM 7A—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $54 million, $56 million and $31 million, respectively.

Rating as of December 31, 2012	Total Exposure Before Credit Collateral	Credit Collateral [(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,984	$ 347	$ 1,637	1	$ 262
Non-investment grade	28	24	4	—	—
No external ratings					
Internally rated—investment grade	512	10	502	1	271
Internally rated—non-investment grade	41	3	38	—	—
Total	$ 2,565	$ 384	$ 2,181	2	$ 533

Net Credit Exposure by Type of Counterparty	December 31, 2012
Investor-owned utilities, marketers and power producers	$ 865
Energy cooperatives and municipalities	786
Financial Institutions	422
Other	108
Total	$ 2,181

(a) As of December 31, 2012, credit collateral held from counterparties where Generation had credit exposure included $344 million of cash and $40 million of letters of credit.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of December 31, 2012, ComEd's credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for further information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2012, PECO had no net credit exposure with suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for further information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements; however, the natural gas asset managers have provided $20 million in parental guarantees related to these agreements. As of December 31, 2012, PECO had credit exposure of $7 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for further information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap.

The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The seller's credit exposure is calculated each business day. As of December 31, 2012, BGE had no net credit exposure with suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2012, BGE had credit exposure of $8 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third party suppliers.

Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e. NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Feature	December 31, 2012		
	Gross Fair Value of Derivative Contracts Containing this Feature [a]	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements [b]	Net Fair Value of Derivative Contracts Containing This Feature [c]
	($1,849)	$1,426	($423)

Credit-Risk Related Contingent Feature	December 31, 2011		
	Gross Fair Value of Derivative Contracts Containing this Feature [a]	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements [b]	Net Fair Value of Derivative Contracts Containing This Feature [c]
	($1,014)	$928	($86)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features that are not fully collateralized by posted cash collateral on an individual, contract-by-contract basis ignoring the effects of master netting agreements.
(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation has cash collateral posted of $527 million and letters of credit posted of $563 million and cash collateral held of $499 million and letters of credit held of $45 million as of December 31, 2012 and cash collateral held of $542 million and letters of credit held of $89 million at December 31, 2011. In the event of a credit downgrade below investment grade (i.e. BB+ or Ba1), Exelon Generation Company, LLC and Constellation Energy Commodities Group, Inc. could be required to post additional collateral of $1,920 million as of December 31, 2012, and $1,612 million as of December 31, 2011. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if their debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2012, Generation's and Exelon's swaps were in an asset position, with a fair value of $17 million and $30 million, respectively.

See Note 21—Segment Information for further information regarding the letters of credit supporting the cash collateral.

Generation entered into SFCs with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of the financial swap contract between Generation and ComEd, if a party is downgraded below investment grade by Moody's or S&P, collateral postings would be required by that party depending on how market prices compare to the benchmark price levels. Under the terms of the financial swap contract, collateral postings will never exceed $200 million from either ComEd or Generation. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2012, ComEd held neither cash nor letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2012, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 1—Significant Accounting Policies for further information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2012, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2012, PECO could have been required to post approximately $35 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2012, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2012, BGE could have been required to post approximately $124 million of collateral to its counterparties.

Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon and Generation)

As of December 31, 2012, and December 31, 2011, $3 million and $2 million, respectively, of cash collateral received was not offset against derivative positions because they were not associated with energy-related derivatives.

11. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool.

Exelon, Generation, ComEd, PECO and BGE had the following amounts of commercial paper borrowings at December 31, 2012 and 2011:

Commercial Paper Issuer	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
	2012 [(a)]	2011 [(a)]	2012	2011	2012	2011
Exelon Corporate	$ 500	$ 500	$—	$161	0.47%	0.42%
Generation	5,600	5,600	—	—	0.45%	0.48%
ComEd	1,000	1,000	—	—	0.50%	0.71%
PECO	600	600	—	—	—	—
BGE	600	400	—	—	0.43%	0.38%
Total	$8,300	$8,100	$—	$161		

(a) Equals aggregate bank commitments under revolving and bilateral credit agreements. See discussion below and Credit Agreements table below for items affecting effective program size.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have revolving credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its outstanding commercial paper does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit agreement.

At December 31, 2012, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit agreements:

Borrower	Aggregate Bank Commitment [a]	Facility Draws	Outstanding Letters of Credit	Available Capacity at December 31, 2012	
				Actual	To Support Additional Commercial Paper
Exelon Corporate	$ 500	$ —	$ 2	$ 498	$ 498
Generation	5,600	—	1,818	3,782	3,782
ComEd	1,000	—	—	1,000	1,000
PECO	600	—	1	599	599
BGE	600	—	—	600	600
Total	$ 8,300	$ —	$ 1,821	$ 6,479	$ 6,479

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expire on October 19, 2013 and are solely for issuing letters of credit. As of December 31, 2012, letters of credit issued under these agreements totaled $23 million, $21 million, $21 million and $1 million for Generation, ComEd, PECO and BGE, respectively.

For the year ended December 31, 2012, there were no borrowings under the Registrants' credit facilities.

The following tables present the short-term borrowings activity for Exelon, Generation, ComEd, and BGE during 2012, 2011 and 2010. PECO did not have any short-term borrowings outstanding during 2012, 2011 or 2010.

Exelon

	2012	2011	2010
Average borrowings	$ 199	$ 218	$ 125
Maximum borrowings outstanding	505	600	346
Average interest rates, computed on a daily basis	0.48%	0.50%	0.72%
Average interest rates, at December 31	n.a.	0.44%	n.a.

Generation

	2012	2011	2010
Average borrowings	$ 4	$ 51	$ —
Maximum borrowings outstanding	165	304	—
Average interest rates, computed on a daily basis	0.45%	0.48%	n.a.
Average interest rates, at December 31	n.a.	n.a.	n.a.

ComEd

	2012	2011	2010
Average borrowings	$ 110	$ 36	$ 125
Maximum borrowings outstanding	366	407	346
Average interest rates, computed on a daily basis	0.50%	0.71%	0.72%
Average interest rates, at December 31	n.a.	n.a.	n.a.

BGE

	2012	2011	2010
Average borrowings	$ 6	$ 26	$ 1
Maximum borrowings outstanding	76	190	46
Average interest rates, computed on a daily basis	0.43%	0.38%	0.39%
Average interest rates, computed at December 31	n.a.	n.a.	n.a.

n.a. Not applicable.

Credit Agreements

In connection with the Upstream Merger, Exelon assumed all of Constellation's obligations under its three-year, unsecured revolving credit facility (the "Constellation Credit Agreement"). Effective as of the Initial Merger, the Constellation Credit Agreement was amended and restated to (1) permit Exelon and Constellation to consummate the Upstream Merger and the restructuring transaction, (2) reduce the aggregate commitments under the Constellation Credit Agreement from $2.5 billion to $1.5 billion, and (3) conform some of the representations, warranties, covenants and events of default in the Constellation Credit Agreement with representations, warranties, covenants and events of default in the Exelon credit agreement, dated as of March 23, 2011, as amended as of the Initial Merger. In connection with the Upstream Merger, Exelon also assumed Constellation's obligations under four separate bilateral credit facilities and a commodity-linked credit facility, which were also amended to conform with the Constellation Credit Agreement effective as of the Initial Merger. Effective as of the Initial Merger, the Exelon Credit Agreement and the Generation Credit Agreement were amended and restated to conform some of the representations, warranties and covenants with provisions of the Constellation Credit Agreement, as amended effective as of the Initial Merger. Exelon Corporation (as successor to Constellation Energy Group) entered into an amendment to the Amended and Restated Credit Agreement dated March 12, 2012, which changed the maturity date to December 31, 2012. See Note 4—Merger and Acquisitions for further description of the merger transaction.

On August 10, 2012, Exelon Corporate, Generation, PECO and BGE amended and extended their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively, through August 10, 2017. Under these facilities, Exelon Corporate, Generation, PECO and BGE may issue letters of credit in the aggregate of up to $200 million, $3.5 billion, $300 million and $600 million, respectively. Each credit facility permits the applicable borrower to request extensions for up to two additional one-year periods. Each credit facility also allows Exelon Corporate, Generation, PECO and BGE to request increases in aggregate commitments up to an additional $250 million, $1.0 billion, $250 million and $100 million, respectively. Any extension or increase of a credit facility is subject to the approval of the lenders party to that credit facility in their sole discretion. Costs incurred to amend and extend the facilities for Exelon Corporate, Generation, PECO and BGE were not material.

On March 28, 2012, ComEd replaced its unsecured revolving credit facility with a new unsecured facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement has an initial term expiring on March 28, 2017, and ComEd may request up to two, one-year extensions of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extensions or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to replace the credit facility for ComEd were not material.

Borrowings under each credit agreement bear interest at a rate selected by the borrower based upon the prime rate or at a fixed rate for a specified period based upon a LIBOR-based rate. As of December 31, 2012, Exelon Corporate, Generation, PECO and BGE have adders of up to 27.5, 7.5, 0.0 and 7.5 basis points for prime based borrowings and 127.5, 107.5, 100.0 and 107.5 basis points for LIBOR-based borrowings, respectively. The fee varies depending upon the respective credit ratings of each entity. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The amended covenants in the amended credit facilities are substantially consistent with the covenants in the prior facilities, with the exception of BGE, which replaced its debt to capitalization covenant with an interest coverage ratio.

On October 19, 2012, Generation, ComEd and PECO replaced their expiring minority and community bank credit facilities with new minority and community bank credit facility agreements in the amounts of $50 million, $34 million and $34 million, respectively, and BGE entered into a minority and community bank credit facility in the amount of $5 million. These facilities, which expire in October 2013, are solely utilized by the applicable Registrants to issue letters of credit.

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. This facility will solely be utilized by Generation to issue letters of credit.

An event of default under any of the Registrants' credit facilities would not constitute an event of default under any of the other Registrants' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit facility would constitute an event of default under the Exelon corporate credit facility.

Each credit facility requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and, in the case of Exelon and Generation, interest on the debt of its project subsidiaries. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2012:

	Exelon	Generation	ComEd	PECO	BGE
Credit facility threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2012, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	9.62	14.20	6.14	7.85	5.16

Accounts Receivable Agreement

PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $225 million. As of December 31, 2012 and 2011, the financial institution's undivided interest in PECO's gross accounts receivable was equivalent to $289 million and $329 million, respectively, which represents the financial institution's interest in PECO's eligible receivables as calculated under the terms of the agreement. The agreement requires PECO to maintain eligible receivables at least equivalent to the financial institution's undivided interest. Upon termination or liquidation of this agreement, the financial institution is entitled to recover up to $225 million plus the accrued yield payable from its undivided interest in PECO's receivables. On August 31, 2012, PECO entered into an Amendment to extend this agreement until August 30, 2013. This Amendment also expands the definition of a tariff receivable to include receivables that have been purchased by PECO and paid for in accordance with the Tariff and revises the compliance criteria for the eligible asset test to allow for the payment of capital within a specified period of time. On November 28, 2012, PECO made a principal paydown of $15 million to meet the eligible asset test requirement of the agreement for the October 2012 reporting period. The remaining principal balance of $210 million is classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets. As of December 31, 2012, PECO was in compliance with the requirements of the agreement. In the event the agreement is not further extended, PECO has sufficient short-term liquidity and may seek alternate financing.

Long-Term Debt

On June 18, 2012, Generation issued and sold $775 million of Senior Notes. In connection with this debt issuance, Generation entered into forward-starting interest rate swaps in the aggregate notional amount of $470 million. The interest rate swaps were settled on June 15, 2012 with Generation recording a pre-tax loss of approximately $7 million. The loss was recorded to other comprehensive income within Exelon's and Generation's Consolidated Balance Sheets and is being amortized to income over the life of the related debt as an increase to interest expense.

Concurrently with the new debt issuance, Generation engaged in private offers (the Exchange Offer) to certain eligible holders to exchange any and all of the $700 million outstanding 7.60% Senior Notes due 2032 (Old Notes) of Exelon (which were assumed by Exelon in the merger with Constellation), for:

- Generation's newly issued 4.25% Senior Notes due 2022, plus a cash payment; and
- Generation's newly issued 5.60% Senior Notes due 2042, plus a cash payment.

On June 28, 2012, pursuant to the Exchange Offer, Generation purchased $441 million of the Old Notes in exchange for issuing $535 million of Notes due in 2022 and 2042, plus a cash payment of approximately $60 million. The $441 million of Old Notes were recorded on Exelon's Consolidated Balance Sheets at $608 million, reflecting a fair value adjustment pursuant to the application of purchase accounting applied as a result of the Constellation merger which resulted in approximately $13 million gain from the Exchange Offer at Generation. The gain was recorded as an increase to Long-term Debt within Exelon's and Generation's Consolidated Balance Sheets and will be amortized to income over the life of the debt as a reduction in interest expense.

On July 13, 2012, pursuant to the Exchange Offer described above, Generation purchased an additional $1 million of Old Notes in exchange for the Senior Notes due in 2022 and 2042.

In connection with the debt obligations assumed by Exelon as part of the Upstream Merger on March 12, 2012, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-term Debt to affiliate on Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets. The third-party debt obligations are reported in Long-term Debt on Exelon's Consolidated Balance Sheets. The intercompany loan agreements are summarized as follows:

- $700 million aggregate principal amount of Old Notes, $258 million of which was outstanding as of December 31, 2012 after the Exchange Offer described above;
- $550 million aggregate principal amount of 4.55% Fixed-Rate Notes due 2015, all of which was outstanding as of December 31, 2012;
- $450 million aggregate principal amount of 8.625% Series A Junior Subordinated Debentures due 2063, all of which was outstanding as of December 31, 2012; and
- $550 million aggregate principal amount of 5.15% Notes due 2020, all of which was outstanding as of December 31, 2012.

The intercompany loan agreements and the third-party debt obligations described above were increased by $403 million for a fair value adjustment pursuant to the application of purchase accounting applied as a result of the Constellation merger, of which $199 million was outstanding as of December 31, 2012, primarily reflecting the Exchange Offer described above and amortization of purchase accounting adjustment, which is being amortized over the lives of the arrangements as a reduction to interest expense.

In November 2012, Generation filed a registration statement on Form S-4 to register senior notes to be issued in connection with an exchange offer for the senior notes that were privately issued in June and July 2012. The exchange offer was consummated on February 19, 2013. The registered notes have the same terms and maturity dates as the privately placed senior notes.

The following tables present the outstanding long-term debt at Exelon, Generation, ComEd, PECO and BGE as of December 31, 2012 and 2011:

Exelon

	Rates	Maturity Date	December 31, 2012	December 31, 2011
Long-term debt				
First Mortgage Bonds [a] [b] :				
Fixed rates	1.63% — 7.63%	2012-2042	$ 7,397	$ 7,522
Unsecured bonds:	2.80% — 6.35%	2013-2036	1,850	—
Rate stabilization bonds:	5.72% — 5.82%	2017	332	—
Senior unsecured notes	2.00% — 8.63%	2014-2063	8,021	4,902
Notes payable and other [c]	6.95% — 7.83%	2012-2020	177	174
Pollution control notes:				
Fixed rates	4.10% — 5.00%	2014-2042	20	46
Non-recourse debt:				
Fixed rates	2.33% — 5.50%	2031-2037	238	—
Variable rates	1.96% — 2.77%	2014-2030	262	—
Total long-term debt			18,297	12,644
Unamortized debt discount and premium, net			(17)	(32)
Fair value adjustment			448	—
Fair value hedge carrying value adjustment, net			17	15
Long-term debt due within one year			(1,047)	(828)
Long-term debt			$17,698	$11,799
Long-term debt to financing trusts [d]				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III	7.38%	2028	81	81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Subordinated debentures to BGE Trust	6.20%	2043	258	—
Total long-term debt to financing trusts			$ 648	$ 390

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's assets are subject to the liens of their respective mortgage indentures.
(b) Includes First Mortgage Bonds issued under the ComEd and PECO mortgage indentures securing pollution control bonds and notes.
(c) Includes capital lease obligations of $30 million and $34 million at December 31, 2012 and 2011, respectively. Lease payments of $3 million, $3 million, $3 million, $4 million, $4 million and $13 million will be made in 2013, 2014, 2015, 2016, 2017 and thereafter, respectively.
(d) Amounts owed to these financing trusts are recorded as debt to financing trusts within Exelon's Consolidated Balance Sheets.

Generation

	Rates	Maturity Date	December 31, 2012	December 31, 2011
Long-term debt				
Senior unsecured notes [b]	2.00% — 8.63%	2014-2063	$6,721	$3,602
Pollution control notes:				
Fixed rates	4.10% — 5.00%	2014-2042	20	46
Non-recourse debt:				
Fixed rates	2.33% — 5.50%	2031-2037	238	—
Variable rates	1.96% — 2.77%	2014-2030	262	—
Notes payable and other [a]	7.83%	2012-2020	30	34
Total long-term debt			7,271	3,682
Fair value adjustment [b]			199	—
Unamortized debt discount and premium, net			13	(5)
Long-term debt due within one year			(28)	(3)
Long-term debt			$7,455	$3,674

(a) Includes Generation's capital lease obligations of $30 million and $34 million at December 31, 2012 and 2011, respectively. Generation will make lease payments of $3 million, $3 million, $3 million, $4 million, $4 million and $13 million in 2013, 2014, 2015, 2016, 2017 and thereafter, respectively.
(b) Includes $2,007 million of long-term debt to affiliate, comprised of $1,808 million senior unsecured notes and $199 million fair value adjustment.

ComEd

	Rates	Maturity Date	December 31, 2012	December 31, 2011
Long-term debt				
First Mortgage Bonds [a] [b]:				
Fixed rates	1.63% — 7.63%	2012-2042	$5,447	$5,547
Notes payable	6.95%	2018	140	140
Total long-term debt			5,587	5,687
Unamortized debt discount and premium, net			(20)	(22)
Long-term debt due within one year			(252)	(450)
Long-term debt			$5,315	$5,215
Long-term debt to financing trust [c]				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206

(a) Substantially all of ComEd's assets other than expressly excepted property are subject to the lien of its mortgage indenture.
(b) Includes First Mortgage Bonds issued under the ComEd mortgage indenture securing pollution control bonds and notes.
(c) Amount owed to this financing trust is recorded as debt to financing trust within ComEd's Consolidated Balance Sheets.

PECO

	Rates	Maturity Date	December 31, 2012	December 31, 2011
Long-term debt				
First Mortgage Bonds [a] [b]:				
Fixed rates	2.38% — 5.95%	2012-2037	$1,950	$1,975
Total long-term debt			1,950	1,975
Unamortized debt discount and premium, net			(3)	(3)
Long-term debt due within one year			(300)	(375)
Long-term debt			$1,647	$1,597
Long-term debt to financing trusts [c]				
Subordinated debentures to PECO Trust III	7.38%	2028	$ 81	$ 81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Long-term debt to financing trusts			$ 184	$ 184

(a) Substantially all of PECO's assets are subject to the lien of its mortgage indenture.
(b) Includes First Mortgage Bonds issued under the PECO mortgage indenture securing pollution control bonds and notes.
(c) Amount owed to this financing trust is recorded as debt to financing trust within PECO's Consolidated Balance Sheets.

BGE

	Rates	Maturity Date	December 31, 2012	December 31, 2011
Long-term debt				
Unsecured bonds	2.80% — 6.35%	2013-2036	$1,850	$1,710
Rate stabilization bonds	5.47% — 5.82%	2012-2017	332	$ 395
Total long-term debt			2,182	2,105
Unamortized debt discount and premium, net			(4)	(4)
Long-term debt due within one year			(467)	(173)
Long-term debt			$1,711	$1,928
Long-term debt to financing trusts [a]				
Subordinated debentures to BGE Capital Trust II	6.20%	2043	$ 258	$ 258
Long-term debt to financing trusts			$ 258	$ 258

(a) Amount owed to this financing trust is recorded as debt to financing trust within BGE's Consolidated Balance Sheets.

Long-term debt maturities at Exelon, Generation, ComEd, PECO and BGE in the periods 2013 through 2017 and thereafter are as follows:

Year	Exelon	Generation	ComEd	PECO	BGE
2013	$ 979	$ 28	$ 252	$ 300	$ 467
2014	1,483	616	617	250	70
2015	1,613	553	260	—	75
2016	1,041	76	665	—	379
2017	1,462	706	425	—	41
Thereafter	12,367[a]	5,292	3,574[b]	1,584[c]	1,408[d]
Total	$18,945	$ 7,271	$5,793	$2,134	$2,440

(a) Includes $648 million due to ComEd, PECO and BGE financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.
(d) Includes $258 million due to BGE financing trust.

Exelon Non-Recourse/Limited-Recourse Debt

The following are descriptions of certain indebtedness of Exelon's project subsidiaries that are outstanding as of December 31, 2012. The indebtedness described below is non-recourse to Exelon, unless otherwise noted.

Antelope Valley Project Development Debt Agreement

The DOE Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project is expected to be completed at the end of 2013. The loan will mature on January 5, 2037. Interest rates on the loan will be fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity.

On April 5, 2012, Antelope Valley received the first DOE-guaranteed loan advance of $69 million. The loan advance terminated the put option that Generation had on the Antelope Valley project. Antelope Valley received additional advances subsequent to the initial advance, and as of December 31, 2012, has received $219 million in DOE-guaranteed funding. See Note 4—Merger and Acquisitions for additional information on Antelope Valley.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2012, Generation had $568 million in letters of credit outstanding related to the project The letters of credit balance is expected to decline over time as scheduled equity contributions for the project are made.

In connection with this agreement, Generation entered into a floating-for-fixed interest rate swap with a notional amount of $485 million to mitigate interest rate risk associated with the financing. As Generation received additional loan advances, they subsequently entered into a series of fixed-to-floating interest rate swaps to offset portions of the original interest rate hedge. See Note 10—Derivative Financial Instruments for additional information regarding interest rate swaps associated with Antelope Valley.

Sacramento PV Energy

In July, 2011, a subsidiary of Generation entered into a $41 million non-recourse project financing supported by a 30MW solar facility in Sacramento, California. As of December 31, 2012, $39 million was outstanding. Borrowings under the facility bear interest at a variable rate, payable quarterly, and are secured by equity interests and assets of the subsidiary. As of December 31, 2012, the subsidiary had interest rate swaps with a notional value of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $39 million facility. See Note 10—Derivative Financial Instruments for additional information regarding interest rate swaps.

Constellation Solar Horizons Financing

In September 2012, a subsidiary of Generation entered into an 18-year $38 million non-recourse variable interest note to recover capital used to build a 16MW solar facility in Emmitsburg, Maryland. Borrowing will incur interest at a variable rate, payable quarterly, and are secured by the equity interests and assets of the subsidiary. The subsidiary also executed interest rate swaps for a notional amount of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $38 million facility amount. See Note 10—Derivative Financial Instruments for additional information regarding interest rate swaps.

Secured Solar Credit Lending Agreement. A subsidiary of Generation has a three-year senior secured credit facility that is designed to support the growth of solar operations. The amount committed under the facility is $150 million, which may be increased up to $200 million at the subsidiary's request with additional commitments by the lenders. As of December 31, 2012, $113 million was outstanding under the facility with interest payable quarterly. The facility is secured by the equity interests in the subsidiary and the entities that own the solar projects as well as the assets of the subsidiary and the projects' entities. The obligations of the subsidiary are guaranteed by Generation and the projects' entities. The Generation guarantee will terminate upon the subsidiary obtaining a stand-alone investment grade credit rating or the satisfaction of a number of conditions, at which time the financing will become non-recourse to and Generation.

Other Solar Project Financings. Generation has the following amounts outstanding under solar project loan agreements:

- $7 million fully amortizing by June 30, 2031 related to a solar project at the Denver International Airport, and
- $11 million fully amortizing by December 31, 2031 related to a solar project in Holyoke, Massachusetts.

Upstream Gas Property Asset-Based Lending Agreement

Generation has a three year asset-based lending agreement associated with certain upstream gas properties that it owns. The borrowing base committed under the facility is $150 million and can increase to a total of $500 million if the assets support a higher borrowing base and Generation is able to obtain additional commitments from lenders. The facility was amended and extended through July 2016. Borrowings under this facility are secured by the upstream gas properties, and the lenders do not have recourse against Exelon or Generation in the event of a default. As of December 31, 2012, $72 million was outstanding under the facility with interest payable quarterly. The facility includes a provision that requires Generation entities that own the upstream gas properties subject to the agreement to maintain a current ratio of one-to-one. As of December 31, 2012, Generation was in compliant with this provision.

12. Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

Income tax expense (benefit) from continuing operations is comprised of the following components:

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 37	$ 104	$ (40)	$ 88	$ (97)
Deferred	701	326	237	25	101
Investment tax credit amortization	(11)	(6)	(2)	(2)	(1)
State					
Current	(25)	(12)	6	4	—
Deferred	(75)	88	38	12	4
Total	$ 627	$ 500	$ 239	$127	$ 7

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 1	$ 431	$(329)	$ (71)	$ (71)
Deferred	1,200	435	544	223	130
Investment tax credit amortization	(12)	(7)	(3)	(2)	(1)
State					
Current	(3)	74	(123)	(37)	—
Deferred	271	123	161	33	17
Total	$1,457	$ 1,056	$ 250	$146	$ 75

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 506	$ 372	$(203)	$ 464	$(201)
Deferred	972	635	496	(276)	279
Investment tax credit amortization	(12)	(7)	(3)	(2)	(1)
State					
Current	171	65	(22)	87	(2)
Deferred	21	113	89	(121)	22
Total	$1,658	$ 1,178	$ 357	$ 152	$ 97

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

For the Year Ended December 31, 2012	Exelon [a]	Generation [a]	ComEd	PECO	BGE [b]
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(3.6)	4.7	4.6	2.0	24.3
Qualified nuclear decommissioning trust fund income	5.4	9.1	—	—	—
Tax exempt income	(0.2)	(0.4)	—	—	—
Health care reform legislation	0.1	—	0.4	—	11.6
Amortization of investment tax credit, net deferred taxes	(1.1)	(1.3)	(0.4)	(0.3)	(8.6)
Production tax credits and other credits	(2.2)	(3.7)	—	—	—
Plant basis differences	(2.4)	—	(0.3)	(11.5)	(9.0)
Merger expenses [c]	2.4	—	—	—	24.2
Fines and Penalties	2.6	4.4	—	—	—
Other	(1.1)	(0.5)	(0.6)	(0.2)	(13.9)
Effective income tax rate	34.9%	47.3%	38.7%	25.0%	63.6%

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	4.4	4.5	3.6	(0.5)	5.2
Qualified nuclear decommissioning trust fund income	0.5	0.7	—	—	—
Domestic production activities deduction	(0.3)	(0.4)	—	—	—
Tax exempt income	(0.2)	(0.2)	—	—	—
Health care reform legislation	(0.2)	—	(1.0)	—	(0.5)
Amortization of investment tax credit	(0.3)	(0.3)	(0.4)	(0.3)	(0.5)
Production tax credits	(0.9)	(1.2)	—	—	—
Plant basis differences	(1.0)	—	(0.3)	(6.9)	(2.0)
Other	(0.2)	(0.7)	0.6	—	(1.7)
Effective income tax rate	36.8%	37.4%	37.5%	27.3%	35.5%

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	3.0	3.7	6.3	(4.7)	5.5
Qualified nuclear decommissioning trust fund income	1.7	2.3	—	—	—
Domestic production activities deduction	(1.2)	(1.5)	—	—	—
Tax exempt income	(0.1)	(0.2)	—	—	—
Health care reform legislation	1.4	0.7	1.4	1.6	1.1
Amortization of investment tax credit	(0.3)	(0.2)	(0.4)	(0.4)	(0.4)
Plant basis differences	—	—	(0.1)	0.2	(1.0)
Uncertain tax position remeasurement	—	(2.0)	9.0	—	—
Other	(0.2)	(0.4)	0.2	0.2	(0.4)
Effective income tax rate	39.3%	37.4%	51.4%	31.9%	39.8%

(a) Exelon activity for the twelve months ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the twelve months ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012.
(b) BGE activity represents the activity for the twelve months ended December 31, 2012, 2011 and 2010.
(c) Prior to the close of the merger, the Registrants recorded the applicable taxes on merger transaction costs assuming the merger would not be completed. Upon closing of the merger, the Registrants reversed such taxes for those merger transaction costs that were determined to be non tax-deductible upon successful completion of a merger.

The tax effects of temporary differences, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2012 and 2011 are presented below:

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Plant basis differences	$(10,689)	$ (3,545)	$(3,537)	$(2,437)	$(1,553)
Accrual based contracts	(389)	(389)	—	—	—
Derivatives and other financial instruments	(392)	(479)	(4)	—	—
Deferred pension and post-retirement obligation	1,225	(439)	(598)	(11)	(12)
Nuclear decommissioning activities	(604)	(604)	—	—	—
Deferred debt refinancing costs	(537)	163	(25)	(4)	(4)
Tax loss carryforward	421	226	32	14	105
Tax credit carryforward	226	226	—	—	—
Investment in CENG	(405)	(419)	—	—	—
Other, net	(25)	9	(33)	150	(186)
Deferred income tax liabilities (net)	$(11,169)	$ (5,251)	$(4,165)	$(2,288)	$(1,650)
Unamortized investment tax credits	(251)	(216)	(24)	(3)	(6)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(11,420)	$ (5,467)	$(4,189)	$(2,291)	$(1,656)

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Plant basis differences	$(7,803)	$ (2,670)	$(3,264)	$(2,238)	$(1,220)
Unrealized gains on derivative financial instruments	(468)	(737)	(4)	—	—
Deferred pension and post-retirement obligation	665	(520)	(623)	(31)	(93)
Nuclear decommissioning activities	(452)	(452)	—	—	—
Deferred debt refinancing costs	(37)	—	(31)	(6)	(4)
Other, net	41	338	16	135	(226)
Deferred income tax liabilities (net)	$(8,054)	$ (4,041)	$(3,906)	$(2,140)	$(1,543)
Unamortized investment tax credits	(200)	(169)	(26)	(5)	(8)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(8,254)	$ (4,210)	$(3,932)	$(2,145)	$(1,551)

The following table provides the Registrants' carryforwards and any corresponding valuation allowances as of December 31, 2012.

	Exelon	Generation	ComEd	PECO	BGE
Federal					
Federal net operating loss	$ 635[a]	$ 303	$ 91	$—	$154
Federal capital loss carryforward	178[b]	178	—	—	—
Federal general business credits carryforward	226[c]	226	—	—	—
State					
State net operating loss	3,365[d]	1,649[f]	—	209[h]	950[i]
State capital loss carryforward	127[e]	119[g]	—	—	—
Deferred taxes on state tax attributes (net)	187	99	—	14	51
Valuation allowance on state tax attributes	36	35	—	—	1

(a) Exelon's federal net operating loss will expire beginning in 2033
(b) Exelon's federal capital loss carryforwards will expire beginning in 2018
(c) Exelon's federal general business credit carryforwards will expire beginning in 2033
(d) Exelon's state net operating losses will expire beginning in 2014
(e) Exelon's state capital loss carryforwards will expire beginning in 2018
(f) Generation's state net operating losses will expire beginning in 2014
(g) Generation's state capital loss carryforwards will expire beginning in 2018
(h) PECO's state net operating losses will expire beginning in 2032
(i) BGE's state net operating losses will expire beginning in 2026

Tabular reconciliation of unrecognized tax benefits

The following table provides a reconciliation of the Registrants' unrecognized tax benefits as of December 31, 2012, 2011 and 2010:

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2012	$ 807	$ 683	$ 70	$ 48	$ 11
Merger Balance Transfer	195	183	—	—	—
Increases based on tax positions related to 2012	34	3	—	—	—
Change to positions that only affect timing	(88)	(69)	(3)	(4)	(11)
Increases based on tax positions prior to 2012	91	91	—	—	—
Decreases based on tax positions prior to 2012	(6)	(6)	—	—	—
Decreases related to settlements with taxing authorities	(2)	(2)	—	—	—
Decreases from expiration of statute of limitations	(7)	(7)	—	—	—
Unrecognized tax benefits at December 31, 2012	$1,024	$ 876	$ 67	$ 44	$ —

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2011	$ 787	$ 664	$ 72	$ 44	$ 73
Increases based on tax positions related to 2011	5	1	—	4	—
Change to positions that only affect timing	21	24	(2)	—	(62)
Decreases based on tax positions prior to 2011	(3)	(3)	—	—	—
Decrease from expiration of statute of limitations	(3)	(3)	—	—	—
Unrecognized tax benefits at December 31, 2011	$ 807	$ 683	$ 70	$ 48	$ 11

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2010	$1,498	$ 633	$ 471	$ 372	$112
Increases based on tax positions related to 2010	1	—	—	—	—
Decreases based on tax positions related to 2010	(2)	(2)	—	—	—
Change to positions that only affect timing	(262)	55	(3)	(328)	(39)
Increases based on tax positions prior to 2010	8	8	—	—	—
Decreases based on tax positions prior to 2010	(3)	(3)	—	—	—
Decreases related to settlements with taxing authorities	(452)	(26)	(396)	—	—
Decrease from expiration of statute of limitations	(1)	(1)	—	—	—
Unrecognized tax benefits at December 31, 2010	$ 787	$ 664	$ 72	$ 44	$ 73

Included in Exelon's unrecognized tax benefits balance at December 31, 2012 and 2011 are approximately $730 million and $804 million, respectively, of tax positions for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits. The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to, or defer the receipt of the cash tax benefit from, the taxing authority to an earlier or later period respectively.

Unrecognized tax benefits that if recognized would affect the effective tax rate

Exelon and Generation have $294 million and $263 million, respectively, of unrecognized tax benefits at December 31, 2012 that, if recognized, would decrease the effective tax rate. Exelon and Generation had $3 million and $3 million, respectively, of unrecognized tax benefits at December 31, 2011 that, if recognized, would decrease the effective tax rate.

Total amounts of interest and penalties recognized

The following table represents the net interest receivable (payable), including interest related to uncertain tax positions reflected in the Registrants' Consolidated Balance Sheets. Prior to the merger legacy Constellation recorded interest related to uncertain tax positions as a tax and not interest.

Net interest receivable (payable) as of	Exelon	Generation	ComEd	PECO	BGE
December 31, 2012	$ 31	$ (20)	$ 107	$ 2	$—
December 31, 2011	74	33	23	28	(1)

The following table sets forth the net interest expense, including interest related to uncertain tax positions, recognized in interest expense (income) in other income and deductions in the Registrants' Consolidated Statements of Operations. The Registrants have not accrued any penalties with respect to uncertain tax positions. Prior to the merger legacy Constellation recorded interest related to uncertain tax positions as a tax and not interest.

Net interest expense (income) for the years ended	Exelon	Generation	ComEd	PECO	BGE
December 31, 2012	$ (1)	$ 11	$ (20)	$ (1)	$ 9
December 31, 2011	(56)	(40)	(14)	(1)	(3)
December 31, 2010	110	6	57	35	2

Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Nuclear Decommissioning Liabilities (Exelon and Generation)

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and has disallowed the claims. In November 2008, Generation received a final determination from the Appeals division of the IRS (IRS Appeals) disallowing AmerGen's refund claims. On February 20, 2009, Generation filed a complaint in the United States Court of Federal Claims to contest this determination. In August 2009, the DOJ filed its answer denying the allegations made by Generation in its complaint. While the discovery phase of the litigation has been completed, no trial date has yet been assigned but could occur sometime in 2013.

During 2012, the parties agreed to take advantage of the court's Alternative Dispute Resolution (ADR) program in an effort to resolve the dispute. The court's ADR program provides a confidential and non-binding mediation process that tries to facilitate settlements. The parties participated in mediation discussions late in 2012 and these discussions are currently ongoing. Due to the possibility of quicker resolution through the ADR program, Generation believes that it is reasonably possible that the total amount of unrecognized tax benefits may significantly decrease in the next twelve months.

State Income Taxes

Generation has approximately $100 million of unrecognized tax benefits related to various state income tax return positions for which it is reasonably possible the unrecognized tax benefits could significantly change within 12 months due to the expiration of statutes of limitation or settlements with the state taxing authorities. Furthermore, Generation has approximately $55 million of unrecognized tax benefits related to state income tax refund claims that are currently being litigated. It is reasonably possible the unrecognized tax benefits of $55 million would decrease within 12 months.

See Other Tax Matters—Involuntary Conversion, Like Kind Exchange and Competitive Transition Charges section below for information regarding the amount of unrecognized tax benefits associated with this matter that could change significantly within the next 12 months.

Description of tax years that remain subject to examination by major jurisdiction

Taxpayer	Open Years
Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns	1999 - 2011
Constellation and subsidiaries consolidated Federal income tax returns	2005 - March 2012
Exelon and subsidiaries Illinois unitary income tax returns	2007 - 2011
Constellation combined New York corporate income tax returns	2008 - March 2012
Various separate company Pennsylvania corporate net income tax returns	2008 - March 2012
Various separate company Maryland corporate net income tax returns	2005 - March 2012

Other Tax Matters

Involuntary Conversion, Like-Kind Exchange and Competitive Transition Charges

1999 Sale of Fossil Generating Assets (Exelon and ComEd). Exelon, through its ComEd subsidiary, took two positions on its 1999 income tax return to defer approximately $2.8 billion of tax gain on the sale of ComEd's fossil generating assets. Exelon deferred approximately $1.6 billion of the gain under the involuntary conversion provisions of the IRC. Exelon believed that it was economically compelled to dispose of ComEd's fossil generating plants as a result of the Illinois Act and that the proceeds from the sale of the fossil plants were properly reinvested in qualifying replacement property such that the gain could be deferred over the lives of the replacement property under the involuntary conversion provisions. The remaining approximately $1.2 billion of the gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with both positions and asserted that the entire gain of approximately $2.8 billion was taxable in 1999.

Competitive Transition Charges (Exelon, ComEd, and PECO). Exelon contended that the Illinois Act and the Competition Act resulted in the taking of certain of ComEd's and PECO's assets used in their respective businesses of providing electricity services in their defined service areas. Exelon filed refund claims with the IRS taking the position that CTCs collected during ComEd's and PECO's transition periods represent compensation for that taking and, accordingly, were excludible from taxable income as proceeds from an involuntary conversion. The tax basis of property acquired with the funds provided by the CTCs would be reduced such that the benefits of the position are temporary in nature. The IRS disallowed the refund claims for the 1999-2001 tax years.

Status of Involuntary Conversion and CTC Positions. In the second quarter of 2010, the IRS offered to settle the disagreement over the involuntary conversion and CTC positions. Exelon concluded, based on that offer, that it had sufficient new information that a remeasurement of the involuntary conversion and CTC positions was required in accordance with applicable accounting standards. As a result of the required remeasurement, Exelon recorded $65 million (after-tax) of interest expense, of which $36 million (after-tax) and $22 million (after-tax) were recorded at ComEd and PECO, respectively. ComEd also recorded a current tax expense of $70 million offset with a tax benefit recorded at Generation of $70 million. In the third quarter of 2010, Exelon and the IRS reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion on terms consistent with the settlement offer received in the second quarter. As a result of the preliminary agreement, Exelon and ComEd eliminated any liability for unrecognized tax benefits and established a current tax payable to the IRS. In November 2012, the IRS and Exelon finalized and executed definitive agreements to resolve Exelon's involuntary conversion and CTC positions. Exelon paid $302 million in late 2010 in advance of the final settlement and the assessment.

Status of Like-Kind Exchange Position. Exelon has been unable to reach agreement with the IRS regarding the dispute over the like kind exchange position.

The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation

facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately $86 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Exelon expects to initiate litigation in 2013 to contest the IRS's disallowance of the like-kind exchange position. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, as of December 31, 2012, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison's deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon's current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it no longer meets the more-likely-than-not standard. As a result, Exelon expects to record in the first quarter of 2013 a non-cash charge to earnings of approximately $270 million, which represents the full amount of interest expense (after-tax) and incremental state tax expense in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $185 million will be recorded at ComEd and the balance at Exelon. Exelon and ComEd will continue to accrue interest on the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. Further, Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity. As a result of this hold harmless agreement, ComEd will record on its consolidated balance sheet non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. The IRS also continues to assert an $86 million penalty for a substantial understatement of tax with respect to the like-kind exchange position. Exelon continues to believe that it is unlikely that the penalty assertion will ultimately be sustained and therefore no liability for the penalty has been recorded.

This determination for accounting purposes does not alter Exelon's intent to aggressively litigate the issue through appeals, if necessary, which could take three to five years. Exelon currently expects to initiate the litigation in the United States Tax Court, whose decisions are not controlled by the Federal Circuit's decision in Consolidated Edison.

As of March 31, 2013, in the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $860 million, of which approximately $320 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

Accounting for Generation Repairs (Exelon and Generation)

In 2009, Exelon received approval from the IRS to change its method of accounting for repair costs associated with Generation's power plants. Although the IRS granted Exelon approval to change its method of accounting, the approval did not affirm the methodology used to calculate the deduction. In the second quarter of 2010, Exelon was informed that the IRS intended to issue broad industry guidance with respect to electric generation power plants. In anticipation of the issuance of this guidance, the IRS provided notice to Exelon in the third quarter of 2012 that it intended to apply the principles of Large Business & Industry Directive No. 4-0312-004, thereby deferring auditing Generation's repair deductions until after issuance of the industry guidance and after Exelon has had an opportunity to change its accounting method to conform to that new guidance. As a result, in the third quarter of 2012, Exelon reduced its unrecognized tax benefits by approximately $107 million with an offsetting increase to its deferred tax liabilities and no net impact on results of operations.

The IRS is expected to issue industry guidance during 2013. Exelon and Generation will then determine the financial statement impacts of the generation repair costs accounting method change.

2011 Illinois State Tax Rate Legislation (Exelon, Generation and ComEd)

The Taxpayer Accountability and Budget Stabilization Act, (SB 2505), enacted into law in Illinois on January 13, 2011, increases the corporate tax rate in Illinois from 7.3% to 9.5% for tax years 2011 – 2014, provides for a reduction in the rate from 9.5% to 7.75% for tax years 2015 – 2024 and further reduces the rate from 7.75% to 7.3% for tax years 2025 and thereafter. Pursuant to the rate change, Exelon reevaluated its deferred state income taxes during the first quarter of 2011. Illinois' corporate income tax rate changes resulted in a charge to state deferred taxes (net of Federal taxes) during the first quarter of 2011 of $7 million, $11 million and $4 million for Exelon, Generation and ComEd, respectively. Exelon's and ComEd's charge is net of a regulatory asset of $15 million.

In 2011, the income tax rate change increased Exelon's Illinois income tax provision (net of Federal taxes) by approximately $7 million, of which $12 million and $5 million of additional tax relates to Exelon Corporate and Generation, respectively, and a $10 million benefit for ComEd. The 2011 tax benefit at ComEd reflects the impact of a 2011 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010 and the electric transmission and distribution property repairs deduction discussed below.

Long-Term State Tax Apportionment (Exelon and Generation)

Exelon and Generation periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of Exelon's and Generation's deferred state income taxes. In 2010, the Registrants performed a review of the long-term state tax rates and noted no significant events that would materially impact state apportionment. As such, there was no update to the long-term state apportionment rates in 2010. In 2011 as a result of the 2011 Illinois State Tax Rate Legislation discussed above, Exelon and Generation re-evaluated their long-term state tax apportionment for Illinois and all other states where they have state income tax obligations. The effect of revising the long-term state tax apportionment resulted in the recording of a deferred state tax expense during the first quarter of 2011 of $22 million and $11 million (net of Federal taxes) for Exelon and Generation, respectively. The long-term state tax apportionment also was revised in the fourth quarter of 2011 pursuant to long-term state tax apportionment policy, resulting in recording an additional deferred state tax expense of $1 million and a deferred state tax benefit of $8 million (net of Federal taxes) for Exelon and Generation, respectively.

As a result of the merger with Constellation, Exelon and Generation reevaluated their long-term state tax apportionment in the first quarter of 2012 for all states where they have state income tax obligations, which include Illinois, Maryland and Pennsylvania, as well as other states. The total effect of revising the long-term state tax apportionment resulted in the recording of a deferred state tax asset of $72 million (net of Federal taxes) for Exelon. Of this, a benefit in the amount of $116 million and $14 million (net of Federal taxes) was recorded for Exelon and Generation, respectively, for the three months ended March 31, 2012. Further, Exelon and Generation recorded deferred state tax liabilities of $44 million and $14 million (net of Federal taxes), respectively, as part of purchase accounting during the three months ended March 31, 2012. The long-term state tax apportionment also was updated in the fourth quarter of 2012, resulting in the recording of a deferred state tax benefit of $3 million (net of Federal taxes) for Exelon, and a deferred state tax expense of $7 million (net of Federal taxes) for Generation. There was no change to the long-term state tax apportionment for BGE, ComEd and PECO.

Accounting for Electric Transmission and Distribution Property Repairs (Exelon, Generation, ComEd, PECO and BGE)

On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for repair costs associated with electric transmission and distribution property. ComEd and PECO adopted the safe harbor in the Revenue Procedure for the 2011 and 2010 tax years, respectively. For the year ended December 31, 2011, the adoption of the safe harbor resulted in a $35 million reduction to income tax expense at PECO, while Generation incurred additional income tax expense in the amount of $28 million due to a decrease in its manufacturer's deduction, which are reflected in the effective income tax rate reconciliation above in the plant basis differences and domestic production activities deduction lines, respectively. For Exelon, the adoption had a minimal effect on consolidated earnings. In addition, the adoption of the safe harbor resulted in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million, $95 million respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million related to a decreased domestic production activities deduction.

BGE adopted the safe harbor for the short period 2012 pre-merger tax year. For the year ended December 31, 2012, the adoption of the safe harbor resulted in a cash tax benefit at BGE in the amount of $27 million.

See Note 3—Regulatory Matters for discussion of the regulatory treatment prescribed in the 2010 electric distribution rate case settlement for PECO's cash tax benefit resulting from the application of the method change to years prior to 2010.

Accounting for Gas Distribution Property Repairs (Exelon, PECO and BGE).

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The change to the newly adopted method for the 2011 tax year and 2012 resulted in a tax benefit of $26 million at Exelon, of which $29 million in tax benefit is recorded at PECO, partially offset by an expense recorded at Generation to reflect a reduction in its domestic production activities deduction. BGE changed its method of accounting for gas distribution repairs for the 2008 tax year. The IRS is expected to issue industry guidance during 2013. Exelon, PECO and BGE will then determine the financial statement impacts of the gas distribution repair costs accounting method changes.

Allocation of Tax Benefits (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd and PECO are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2012, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $48 million and $9 million, respectively. During 2012, ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd's 2012 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010. During 2011, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $30 million and $18 million, respectively. During 2011, ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd's 2011 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010 and the electric transmission and distribution property repairs deduction discussed above. During 2010, Generation, ComEd and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $60 million, $2 million and $43 million, respectively.

ComEd received a non-cash contribution to equity from Exelon in 2012 and 2011 of $11 million and $11 million, respectively, related to tax benefits associated with capital projects constructed by ComEd on behalf of Exelon and Generation.

13. Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets, from January 1, 2011 to December 31, 2012:

	Exelon and Generation
Nuclear decommissioning ARO at January 1, 2011	$ 3,276
Accretion expense	209
Net increase due to changes in, and timing of, estimated future cash flows	198
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at December 31, 2011 [(a)]	3,680
Accretion expense	231
Net increase due to changes in, and timing of, estimated future cash flows	833
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at December 31, 2012 [(a)]	$ 4,741

(a) Includes $10 million and $5 million as the current portion of the ARO at December 31, 2012 and 2011, respectively, which is included in other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During 2012, Generation's ARO increased by $1,061 million. The increase in the ARO is largely driven by the following four factors: i) changes in the timing of the future nominal cash flows resulting from an assumed five year deferral to 2025 of the acceptance date of spent nuclear fuel by the DOE coupled with the fact that; ii) cash flows affected by this change in timing are re-measured and discounted at current credit adjusted risk free rates (CARFRs), which have dramatically decreased given the current low interest rate environment; iii) an increase in the estimated costs to decommission the Quad Cities, Dresden and Clinton nuclear units resulting from the completion of updated decommissioning costs studies received during 2012; and iv) accretion of the obligation. The increase in the ARO due to the changes in estimated cash flows resulted in $10 million of expense, which is included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During 2011, Generation recorded a net increase in the ARO of $404 million primarily due to increases for accretion and an increase in the estimated costs to decommission the Oyster Creek and Zion nuclear units resulting from the completion of updated decommissioning cost studies received in 2011 and an increase in the expected long-term escalation rates for energy, partially offset by decreases in long-term escalation rates for labor and other costs as compared to prior study periods. The increase in the Zion nuclear unit ARO resulted in $28 million of expense, which is included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, as the Zion nuclear unit is retired, and as such, is unable to record increases to the ARO through an ARC. Additionally, the Zion nuclear unit is not subject to a regulatory agreement that would provide for offset of the expense.

Zion Station Decommissioning

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those

assets, ZionSolutions assumed decommissioning and other liabilities associated with Zion Station. Pursuant to the ASA, ZionSolutions can periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. On January 7, 2013, EnergySolutions announced that it had entered a definitive acquisition agreement to be acquired by another company. Generation has reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA.

On July 14, 2011, three people filed a purported class action lawsuit in the United States District Court for the Northern District of Illinois naming ZionSolutions and Bank of New York Mellon as defendants and seeking, among other things, an accounting for use of NDT funds, an injunction against the use of NDT funds, the appointment of a trustee for the NDT funds, and the return of NDT funds to customers of ComEd to the extent legally entitled thereto. If the plaintiffs prevail on the merits of their claims, some or all of the NDT funds may no longer be available to ZionSolutions for decommissioning Zion Station, in which case, the contractual arrangement would require ZionSolutions to utilize a line of credit to complete the decommissioning. In addition, the appointment of a NDT fund trustee in this matter could impact Generation's future decommissioning activities at other stations by setting a precedent for the appointment of trustees for NDT funds. On July 20, 2012, ZionSolutions and Bank of New York Mellon filed a motion to dismiss the amended complaint for failing to state a claim. The matter is currently under review by the court.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to pledged assets for Zion Station decommissioning within Generation and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a payable to ZionSolutions in Generation and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers. Generation has retained its obligation to transfer the SNF at Zion Station to the DOE for ultimate disposal and has a liability of approximately $79 million and $65 million at December 31, 2012 and 2011, respectively, which is included within the nuclear decommissioning ARO. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station. The following table provides the pledged assets and payable to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2012 and 2011:

	Exelon and Generation	
	2012	2011
Carrying value of Zion Station pledged assets	$ 614	$ 734
Payable to Zion Solutions [(a)]	564	691
Current portion of payable to Zion Solutions [(b)]	132	128
Withdrawals by Zion Solutions to pay decommissioning costs	192	143

(a) Excludes a liability recorded within Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in other current liabilities within Generation's Consolidated Balance Sheets.

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required decommissioning work according to an established schedule and will construct a dry cask storage facility on the land for the SNF currently held in SNF pools at Zion Station. Rent payable under the Lease Agreement is $1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with Zion Station and penalty rents may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by EnergySolutions or ZionSolutions, EnergySolutions provided a $200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. EnergySolutions has also provided a performance guarantee and entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with the former ComEd, former PECO and former AmerGen units have been funded with amounts collected from ComEd customers, PECO customers and the previous owners of the former AmerGen plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO currently collects funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are expected to continue through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds. Every five years, PECO files a rate adjustment with the PaPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. With respect to the former AmerGen units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts collected from ComEd and PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation. Generation has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. This initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations

that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units, Generation retains any funds remaining in the NDTs after decommissioning.

At December 31, 2012, and 2011, Exelon and Generation had NDT fund investments totaling $7,248 million and $6,507 million, respectively.

During 2012, the NDT fixed income portfolio completed its transition from solely core fixed income investments to a blend of Treasury Inflation Protected Securities (TIPS), investment-grade corporate credit and middle market lending. There was no change in the equity investment strategy. At December 31, 2012, approximately 47% of the funds were invested in equity securities and 53% were invested in fixed income securities. At December 31, 2011, approximately 48% of the funds were invested in equity securities and 52% were invested in fixed income securities.

NRC Minimum Funding Requirements. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in the types of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2012 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2019 for Oyster Creek); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2012 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning activities are completed under three possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the assumption plants cease operating at the end of an extended license life (assuming 20-year license renewal extensions, except Oyster Creek with an assumed end-of-operations date of 2019); (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 5.3% to 6.2% (as compared to a historical 5-year annual average pre-tax return of approximately 3.6%).

Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or make additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial position may be significantly adversely affected.

On March 31, 2011, Generation, in its NRC-required biennial decommissioning funding status report, provided data from which the NRC concluded that the amount of decommissioning funding as of December 31, 2010 for Limerick Unit 1 was less than the amount required by the NRC's regulations. Generation performed the calculations again in early 2012, which reflected that the amount of decommissioning funding as of December 31, 2011, for Limerick Unit 1 was less than the amount required by the NRC's regulations. In February 2012, Generation obtained a parent guarantee in the amount of $115 million to cover the NRC minimum funding assurance requirements for Limerick Unit 1 and informed the NRC that it had addressed the minimum funding issues by, among other things, obtaining the parent guarantee. In a letter dated June 28, 2012, the NRC advised Generation of the NRC's determination that the amount of decommissioning financial assurance provided in Generation's plan was equal to or greater than the minimum required under the NRC regulations and that Generation had provided reasonable assurance that funds would be available for the Limerick Unit 1 decommissioning process.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential "apparent violations" of its regulations because of alleged inaccuracies in the Decommissioning Fund Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation's status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. The NRC invited Generation to participate in a pre-decisional enforcement conference. At that conference, Generation will have an opportunity to explain its actions to the NRC. Generation will demonstrate that it did not deliberately or intentionally provide inaccurate or incomplete information in violation of the regulations and that it applied the regulatory provisions in a reasonable manner and in good faith. The letter from the NRC does not take issue with Generation's current funding status. The NRC has publicly confirmed that Generation is currently sufficiently funded for decommissioning activities. While Generation does not believe that any sanction is appropriate, the ultimate outcome of this proceeding including the amount of a potential fine or sanction, if any, is uncertain.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO nuclear plants, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Accounting Implications of the Regulatory Agreements with ComEd and PECO. Based on the regulatory agreement with the ICC that dictates Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the NDT funds exceed the total estimated decommissioning obligation, decommissioning-related activities, including realized and unrealized gains and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's and

Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the value of the NDT fund for any former ComEd unit fall below the amount of the estimated decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial position could be material. At December 31, 2012, the NDT funds of each of the former ComEd units exceeded the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is the ARO reflected on Generation's Consolidated Balance Sheet at December 31, 2012 and is different, as described above, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

Based on the regulatory agreement supported by the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the seven former PECO nuclear units, regardless of whether the funds held in the NDT funds exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial position could be material.

The decommissioning-related activities related to the Clinton, Oyster Creek and Three Mile Island nuclear plants (the former AmerGen units) and the portions of the Peach Bottom nuclear plants that are not subject to regulatory agreements with respect to the NDT funds are reflected in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, as there are no regulatory agreements associated with these units.

Refer to Note 3—Regulatory Matters and Note 22—Related Party Transactions for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

The following table provides unrealized gains (losses) on NDT funds for 2012, 2011 and 2010:

	Exelon and Generation For the Years Ended December 31,		
	2012	2011	2010
Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units [a] [b][c]	$ 386	$ (74)	$ 294
Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units [c]	105	(4)	104

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in regulatory liabilities on Exelon's Consolidated Balance Sheets and noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $73 million and $48 million of net unrealized gains (losses) related to the Zion Station pledged assets in 2012 and 2011. Net unrealized gains (losses) related to Zion Station pledged assets are included in the payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.
(c) Net unrealized gains (losses) related to Generation's NDT funds are included within other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units, which are subject to regulatory accounting, are eliminated within other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Non-Nuclear Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. ComEd, PECO and BGE have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected on the Registrants' Consolidated Balance Sheets from January 1, 2011 to December 31, 2012:

	Exelon	Generation	ComEd	PECO	BGE
Non-nuclear AROs at January 1, 2011	$ 223	$ 86	$ 105	$ 32	$ 1
Net decrease due to changes in, and timing of, estimated future cash flows [a]	(24)	(3)	(17)	(4)	—
Development projects	7	7	—	—	—
Accretion expense [b]	9	5	3	1	—
Payments	(6)	(3)	(2)	(1)	—
Non-nuclear AROs at December 31, 2011	209	92	89	28	1
Net increase due to changes in, and timing of, estimated future cash flows [a]	27	18	8	1	7
Development projects	47	47	—	—	—
Accretion expense [b]	13	8	4	1	—
Merger with Constellation [c]	58	50			
Payments	(11)	(8)	(2)	(1)	—
Non-nuclear AROs at December 31, 2012	$ 343	$ 207	$ 99	$ 29	$ 8

(a) During the year ended December 31, 2011, PECO recorded a reduction in operating and maintenance expense of $3 million. Generation and ComEd did not record any reductions in operating and maintenance expense for the year ended December 31, 2011. During the year ended December 31, 2012, Generation recorded a reduction in operating and maintenance expense of $8 million. ComEd and PECO did not record any adjustments in operating and maintenance expense for the year ended December 31, 2012.
(b) For ComEd and PECO, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.
(c) Exelon's ARO includes $8 million of BGE costs incurred prior to the closing of Exelon's merger with Constellation. Refer to Note 4—Merger and Acquisitions for additional information.

14. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

As of December 31, 2012, Exelon sponsored qualified defined benefit pension plans, non-qualified defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation's benefit plans and its related assets. The table below shows the pension and postretirement benefit plans in which each operating company participated at December 31, 2012.

	Operating Company				
Name of Plan:	Generation	ComEd	PECO	BGE	BSC
Qualified Pension Plans:					
Exelon Corporation Retirement Program	X	X	X		X
Exelon Corporation Cash Balance Pension Plan	X	X	X		X
Exelon Corporation Pension Plan for Bargaining Unit Employees	X	X			X
Exelon New England Union Employees Pension Plan	X				
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek	X	X			X
Pension Plan of Constellation Energy Group, Inc.	X			X	X
BG New England Union Employees Pension Plan	X				
Non-Qualified Pension Plans:					
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan	X	X	X		X
Exelon Corporation Supplemental Management Retirement Plan	X	X	X		X
Benefits Restoration Plan of Constellation Energy Group	X			X	X
Senior Executive Supplemental Pension Plan	X			X	X
Other Postretirement Benefit Plans:					
PECO Energy Company Retiree Medical Plan	X		X		X
Exelon Corporation Health Care Program	X	X			X
Exelon Corporation Employees' Life Insurance Plan	X	X	X		X
Constellation Energy Group, Inc. Retiree Medical Plan	X			X	X
Constellation Energy Group, Inc. Retiree Dental Plan	X			X	X
Constellation Energy Group, Inc. Life Insurance Plan and Family Life Insurance Plan	X			X	
BG New England Post-Employment Medical Savings Account Plan	X				

Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Exelon has elected that the trusts underlying these plans be treated under the IRC as qualified trusts. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets and Funded Status

Exelon recognizes the overfunded or underfunded status of defined benefit pension and other postretirement benefit plans as an asset or liability on its balance sheet, with offsetting entries to Accumulated Other Comprehensive Income (AOCI) and regulatory assets, in accordance with the applicable authoritative guidance. The measurement date for the plans is December 31. The following table provides a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
Change in benefit obligation:				
Net benefit obligation at beginning of year	$13,538	$12,524	$ 4,062	$ 3,874
Service cost	280	212	156	142
Interest cost	698	649	205	207
Plan participants' contributions	—	—	34	25
Actuarial loss	1,520	807	313	4
Plan amendments	—	—	(103)	—
Acquisitions/divestitures	1,880		362	
Curtailments	(10)	—	(8)	—
Settlements	(169)	—	—	—
Contractual termination benefits	15	—	6	—
Gross benefits paid	(952)	(654)	(219)	(201)
Federal subsidy on benefits paid	—	—	12	11
Net benefit obligation at end of year	$16,800	$13,538	$ 4,820	$ 4,062
Change in plan assets:				
Fair value of net plan assets at beginning of year	$11,302	$ 8,859	$ 1,797	$ 1,655
Actual return on plan assets	1,484	1,003	197	29
Employer contributions	149	2,094	325	277
Plan participants' contributions	—	—	34	25
Benefits paid [(a)]	(952)	(654)	(218)	(189)
Acquisitions/divestitures	1,543	—	—	—
Settlements	(169)	—	—	—
Fair value of net plan assets at end of year	$13,357	$11,302	$ 2,135	$ 1,797

(a) Exelon's other postretirement benefits paid for the years ended December 31, 2012 and 2011 are net of $1.3 million and $12 million, respectively, of reinsurance proceeds received from the Department of Health and Human Services as part of the Early Retiree Reinsurance Program pursuant to the Affordable Care Act of 2010.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
Other current liabilities	$ 15	$ 42	$ 23	$ 2
Pension obligations	3,428	2,194	—	—
Non-pension postretirement benefit obligations	—	—	2,662	2,263
Unfunded status (net benefit obligation less net plan assets)	$3,443	$2,236	$ 2,685	$ 2,265

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets. During the fourth quarter of 2012, Exelon completed an optional lump sum election program for select participants in certain of its qualified pension plans, which reduced the obligation and plan assets associated with those plans. This program decreased pension obligations and plan assets by approximately $425 million and $260 million, respectively, resulting in approximately $165 million overall funded status improvement.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO), and fair value of plan assets for all pension plans with a PBO or ABO in excess of plan assets.

	PBO in excess of plan assets	
	2012	2011
Projected benefit obligation	$ 16,800	$ 13,538
Fair value of net plan assets	13,357	11,302

	ABO in excess of plan assets	
	2012	2011
Projected benefit obligation	$ 16,796	$ 13,538
Accumulated benefit obligation	15,657	12,616
Fair value of net plan assets	13,353	11,302

On a PBO basis, the plans were funded at 80% at December 31, 2012 compared to 83% at December 31, 2011. On an ABO basis, the plans were funded at 85% at December 31, 2012 compared to 90% at December 31, 2011. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2012, 2011 and 2010 for all plans combined. The table reflects an increase in 2012, and a reduction in 2011 and 2010 of net periodic postretirement benefit costs of approximately $(17) million, $28 million and $38 million, respectively, related to a Federal subsidy provided under the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Modernization Act), discussed further below.

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	2012	2011	2010
Components of net periodic benefit cost:						
Service cost	$ 280	$ 212	$ 190	$ 156	$ 142	$ 124
Interest cost	698	649	660	205	207	214
Expected return on assets	(988)	(939)	(799)	(115)	(111)	(109)
Amortization of:						
Transition obligation	—	—	—	11	9	9
Prior service cost (credit)	15	14	14	(17)	(38)	(56)
Actuarial loss	450	331	254	81	66	74
Curtailment charges	—	—	—	(7)	—	—
Settlement charges	31	—	5	—	—	—
Contractual termination benefits [(a)]	14	—	—	6	—	1
Net periodic benefit cost	$ 500	$ 267	$ 324	$ 320	$ 275	$ 257

(a) ComEd and BGE established regulatory assets of $1 million and $4 million, respectively, for their portion of the contractual termination benefit charge.

Through Exelon's postretirement benefit plans, the Registrants provide retirees with prescription drug coverage. The Medicare Modernization Act, enacted on December 8, 2003, introduced a prescription drug benefit under Medicare as well as a Federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit. Management believes the prescription drug benefit provided under Exelon's postretirement benefit plans meets the requirements for the subsidy. See the *Health Care Reform Legislation* section below for further discussion regarding the income tax treatment of Federal subsidies of prescription drug benefits.

The effect of the subsidy on the components of net periodic postretirement benefit cost for the years ended December 31, 2012, 2011 and 2010 included in the consolidated financial statements was as follows:

	2012	2011	2010
Amortization of the actuarial experience loss	$(17)	$ 3	$ 9
Reduction in current period service cost	—	9	10
Reduction in interest cost on the APBO	—	16	19
Total effect of subsidy on net periodic postretirement benefit cost	$(17)	$28	$38

Components of AOCI and Regulatory Assets

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets for the years ended December 31, 2012, 2011 and 2010 for all plans combined.

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	2012	2011	2010
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets:						
Current year actuarial (gain) loss	$1,693	$ 744	$ 737	$ 304	$ 74	$ —
Amortization of actuarial gain (loss)	(450)	(331)	(254)	(81)	(66)	(74)
Current year prior service (credit) cost	1	—	—	(109)	—	—
Amortization of prior service (cost) credit	(15)	(14)	(14)	17	38	56
Current year transition (asset) obligation	—			1		
Amortization of transition asset (obligation)	—	—	—	(11)	(9)	(9)
Curtailments	(10)	—	—	(1)	—	—
Settlements	(31)	—	(5)	—	—	—
Total recognized in AOCI and regulatory assets [(a)]	$1,188	$ 399	$ 464	$ 120	$ 37	$ (27)

(a) Of the $1,188 million related to pension benefits, $283 million and $904 million were recognized in AOCI and regulatory assets, respectively, during 2012. Of the $120 million related to other postretirement benefits, $39 million and $81 million were recognized in AOCI and regulatory assets, respectively, during 2012. Of the $399 million related to pension benefits, $181 million and $218 million were recognized in AOCI and regulatory assets, respectively, during 2011. Of the $37 million related to other postretirement benefits, $13 million and $24 million were recognized in AOCI and regulatory assets, respectively, during 2011. Of the $464 million related to pension benefits, $310 million and $154 million were recognized in AOCI and regulatory assets, respectively, during 2010. Of the $(27) million related to other postretirement benefits, $(9) million and $(18) million were recognized in AOCI and regulatory assets, respectively, during 2010.

The following table provides the components of Exelon's gross accumulated other comprehensive loss and regulatory assets that have not been recognized as components of periodic benefit cost at December 31, 2012 and 2011, respectively, for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
Transition obligation	$ —	$ —	$ —	$ 11
Prior service cost (credit)	76	90	(107)	(16)
Actuarial loss	7,931	6,729	1,185	963
Total [(a)]	$8,007	$6,819	$ 1,078	$ 958

(a) Of the $8,007 million related to pension benefits, $4,594 million and $3,413 million are included in AOCI and regulatory assets, respectively, at December 31, 2012. Of the $1,078 million related to other postretirement benefits, $514 million and $564 million are included in AOCI and regulatory assets, respectively, at December 31, 2012. Of the $6,819 million related to pension benefits, $4,311 million and $2,508 million are included in AOCI and regulatory assets, respectively, at December 31, 2011. Of the $958 million related to other postretirement benefits, $475 million and $483 million are included in AOCI and regulatory assets, respectively, at December 31, 2011.

The following table provides the components of Exelon's AOCI and regulatory assets at December 31, 2012 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2013. These estimates are subject to the completion of an actuarial valuation of Exelon's pension and other postretirement benefit obligations, which will reflect actual census data as of January 1, 2013 and actual claims activity as of December 31, 2012. The valuation is expected to be completed in the first quarter of 2013 for legacy Exelon plans and in the second quarter of 2013 for legacy Constellation plans.

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 14	$ (19)
Actuarial loss	568	84
Total [(a)]	$ 582	$ 65

(a) Of the $582 million related to pension benefits at December 31, 2012, $315 million and $267 million are expected to be amortized from AOCI and regulatory assets in 2013, respectively. Of the $65 million related to other postretirement benefits at December 31, 2012, $29 million and $36 million are expected to be amortized from AOCI and regulatory assets in 2013, respectively.

Assumptions

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Exelon's expected level of contributions to the plans, the long-term expected investment rate credited to employees participating in cash balance plans and the anticipated rate of increase of health care costs. Additionally, assumptions related to plan participants include the incidence of mortality, the expected remaining service period, the level of compensation and rate of compensation increases, employee age and length of service, among other factors.

Expected Rate of Return. In selecting the expected rate of return on plan assets, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

The following assumptions were used to determine the benefit obligations for all of the plans at December 31, 2012, 2011 and 2010. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	2012	2011	2010
Discount rate	3.92%	4.74%	5.26%	4.00%	4.80%	5.30%
Rate of compensation increase	[a]	3.75%	3.75%	[a]	3.75%	3.75%
Mortality table	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation
Health care cost trend on covered charges	N/A	N/A	N/A	6.50% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017	7.00% decreasing to ultimate trend of 5.00% in 2015

(a) 3.25% for 2013-2017 and 3.75% thereafter.

The following assumptions were used to determine the net periodic benefit costs for all the plans for the years ended December 31, 2012, 2011 and 2010:

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	2012	2011	2010
Discount rate	3.71% [a]	5.26%	5.83%	3.72% [a]	5.30%	5.83%
Expected return on plan assets	7.50% [b]	8.00% [b]	8.50% [b]	6.68% [b]	7.08% [b]	7.83% [b]
Rate of compensation increase	3.75%	3.75%	4.00%	3.75%	3.75%	4.00%
Mortality table	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2010 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2010 funding valuation
Health care cost trend on covered charges				6.50% decreasing to ultimate	7.00% decreasing to ultimate	7.50% decreasing to ultimate

	N/A	N/A	N/A	trend of 5.00% in 2017	trend of 5.00% in 2015	trend of 5.00% in 2015

(a) The initial discount rates used to establish Exelon's pension and other postretirement benefits costs for 2012 were 4.74% and 4.80%, respectively. Certain of the benefit plans were remeasured during the year due to the Constellation merger, plan settlement and curtailment events, and plan changes using discount rates within the indicated ranges. 2012 costs reflect the impact of these remeasurements.
(b) Not applicable to pension and other postretirement benefit plans that do not have plan assets.

Assumed health care cost trend rates have a significant effect on the costs reported for the other postretirement benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend:	
on 2012 total service and interest cost components	$ 81
on postretirement benefit obligation at December 31, 2012	845
Effect of a one percentage point decrease in assumed health care cost trend:	
on 2012 total service and interest cost components	(56)
on postretirement benefit obligation at December 31, 2012	(569)

Health Care Reform Legislation

In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers. One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer's postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, the Registrants were required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. As a result, in the first quarter of 2010, Exelon recorded total after-tax charges of approximately $65 million to income tax expense to reverse deferred tax assets previously established. Generation, ComEd, PECO and BGE recorded charges of $24 million, $11 million, $9 million and $3 million, respectively. Additionally, as a result of this deductibility change for employers and other Health Care Reform provisions that impact the federal prescription drug subsidy options provided to employers, Exelon has made a change in the manner in which it will receive prescription drug subsidies beginning in 2013.

Additionally, the Health Care Reform Acts also include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Certain key assumptions are required to estimate the impact of the excise tax on Exelon's other postretirement benefit obligation, including projected inflation rates (based on the CPI) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

Contributions

The following table provides contributions made by Generation, ComEd, PECO, BGE and BSC to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	2012 [a]	2011 [a]	2010 [a]
Generation	$ 48	$ 954	$356	$ 135	$ 121	$ 94
ComEd	25	873	260	119	108	60
PECO	13	110	73	33	28	35
BGE [b]	—	—	—	12	—	—
BSC	63	157	77	24	20	14
Exelon	$149	$2,094	$766	$ 323	$ 277	$ 203

(a) The Registrants present the cash contributions above net of Federal subsidy payments received on each of their respective Consolidated Statements of Cash Flows. Exelon, Generation, ComEd, PECO, and BGE received Federal subsidy payments of $10 million, $5 million, $4 million, $1 million and $2 million, respectively, in 2012, $11 million, $5 million, $4 million, $1 million and $3 million, respectively, in 2011, and $10 million, $5 million, $3 million, $2 million and $2 million, respectively, in 2010.

(b) BGE's pension benefit contributions for 2012, 2011, and 2010 exclude $0 million, $54 million, and $197 million, respectively, of pension contributions made by BGE prior to the closing of Exelon's merger with Constellation on March 12, 2012. BGE's other postretirement benefit payments for 2012, 2011, and 2010 exclude $4 million, $13 million, and $17 million, respectively, of other postretirement benefit payments made by BGE prior to the closing of Exelon's merger with Constellation on March 12, 2012. These pre-merger contributions are not included in Exelon's financial statements but are reflected in BGE's financial statements.

Exelon plans to contribute approximately $255 million to its qualified pension plans in 2013, of which Generation, ComEd, PECO and BGE will contribute $113 million, $116 million, $11 million and $0 million, respectively. Exelon plans to make non-qualified pension plan benefit payments of approximately $15 million in 2013, of which Generation, ComEd, PECO and BGE will pay $6 million, $1 million, $1 million and $2 million, respectively. Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). Additionally, for Exelon's largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million, which approximates service cost, or the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower minimum pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law will be applied in 2012 while others take effect in 2013. The estimated impacts of the law are reflected in the projected pension contributions.

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and

best assure continued rate recovery). Exelon expects to contribute approximately $292 million to the other postretirement benefit plans in 2013, of which Generation, ComEd, PECO and BGE expect to contribute $117 million, $114 million, $22 million and $18 million, respectively.

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2012 were:

	Pension Benefits	Other Postretirement Benefits
2013	$ 943	$ 197
2014	807	204
2015	891	212
2016	868	220
2017	902	231
2018 through 2022	5,161	1,330
Total estimated future benefit payments through 2022	$9,572	$ 2,394

Allocation to Exelon Subsidiaries

Generation, ComEd, PECO, and BGE account for their participation in Exelon's pension and other postretirement benefit plans by applying multiemployer accounting. Employee-related assets and liabilities, including both pension and postretirement liabilities, for the legacy Exelon plans were allocated by Exelon to its subsidiaries based on the number of active employees as of January 1, 2001 as part of Exelon's corporate restructuring. Exelon allocates the components of pension and other postretirement costs to the subsidiaries in the legacy Exelon plans based upon several factors, including the measures of active employee participation in each participating unit. The obligation for Generation, ComEd and PECO reflects the initial allocation and the cumulative costs incurred and contributions made since January 1, 2001. Pension and postretirement benefit contributions are allocated to legacy Exelon subsidiaries in proportion to active service costs recognized and total costs recognized, respectively. For legacy CEG plans, components of pension and other postretirement benefit costs and contributions are allocated to the subsidiaries based on employee participation (both active and retired). Pension assets are allocated such that each subsidiary has a funded status consistent with the overall plan.

The following approximate amounts were included in capital and operating and maintenance expense for the years ended December 31, 2012, 2011 and 2010, respectively, for Generation's, ComEd's, PECO's, BSC's and BGE's allocated portion of the Exelon-sponsored pension and other postretirement benefit plans. These amounts include the recognized contractual termination benefit charges, curtailment gains, and settlement charges:

For the Year Ended December 31,	Generation	ComEd	PECO	BSC (a)	BGE (b)(c)	Exelon
2012	$ 341	$ 282	$ 50	$ 99	$ 60	$ 820
2011	249	213	32	48	51	542
2010	268	215	46	52	48	581

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations.

(b) The amounts included in capital and operating and maintenance expense for the years ended 2012, 2011, and 2010 include $12 million, $51 million, and $48 million, respectively, in costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. These amounts are not included in Exelon's capital and operating and maintenance expense for the years ended 2012, 2011, and 2010.
(c) BGE's pension and other postretirement benefit costs for the year ended December 31, 2012 include a $3 million contractual termination benefit charge, which was recorded as a regulatory asset.

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented an investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. This investment strategy would tend to result in a lower expected rate of return on plan assets in future years. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Exelon used an EROA of 7.50% and 6.45% to estimate its 2013 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations and December 31, 2012 and 2011 asset allocations were as follows:

Pension Plans

		Percentage of Plan Assets at December 31,	
Asset Category	Target Allocation	2012	2011
Equity securities	34%	35%	32%
Fixed income securities	40%	40	47
Alternative investments [(a)]	26%	25	21
Total		100%	100%

Other Postretirement Benefit Plans

		Percentage of Plan Assets at December 31,	
Asset Category	Target Allocation	2012	2011
Equity securities	45%	46%	37%
Fixed income securities	40%	40	53
Alternative investments [(a)]	15%	14	10
Total		100%	100%

(a) Alternative investments include private equity, hedge funds and real estate.

Concentrations of Credit Risk. Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2012. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2012, there were no significant concentrations (defined as greater than 10 percent of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

Fair Value Measurements

The following table presents Exelon's pension and other postretirement benefit plan assets measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2012 and 2011:

At December 31, 2012 [a]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 1	$ —	$ —	$ 1
Equity securities:				
Individually held	2,562	—	—	2,562
Commingled funds	—	1,111	—	1,111
Mutual funds [c]	323	—	—	323
Equity securities subtotal	2,885	1,111	—	3,996
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,037	—	—	1,037
Debt securities issued by states of the United States and by political subdivisions of the states	—	108	—	108
Foreign debt securities	—	252	—	252
Corporate debt securities	—	3,330	—	3,330
Federal agency mortgage-backed securities	—	117	—	117
Non-Federal agency mortgage-backed securities	—	28	—	28
Commingled funds	—	274	—	274
Mutual funds [c]	4	291	—	295
Derivative instruments [b]:				
Assets	—	9	—	9
Liabilities	—	(21)	—	(21)
Fixed income securities subtotal	1,041	4,388	—	5,429
Private equity	—	—	754	754
Hedge funds	—	1,080	1,235	2,315
Real estate:				
Individually held	280	—	—	280
Commingled funds	—	75	—	75
Real estate funds	—	—	426	426
Real estate subtotal	280	75	426	781
Pension plan assets subtotal	4,207	6,654	2,415	13,276

At December 31, 2012 [a]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	44	—	—	44
Equity securities:				
Individually held	198	—	—	198
Commingled funds	—	530	—	530
Mutual funds [c]	230	—	—	230
Equity securities subtotal	428	530	—	958
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	18	—	—	18
Debt securities issued by states of the United States and by political subdivisions of the states	—	125	—	125
Foreign debt securities	—	3	—	3
Corporate debt securities	—	50	—	50
Federal agency mortgage-backed securities	—	52	—	52
Non-Federal agency mortgage-backed securities	—	6	—	6
Commingled funds	—	271	—	271
Mutual funds [c]	295	2	—	297
Fixed income securities subtotal	313	509	—	822
Private equity	—	—	1	1
Hedge funds	—	188	12	200
Real estate:				
Individually held	7	—	—	7
Commingled funds	—	2	—	2
Real estate funds	—	6	95	101
Real estate subtotal	7	8	95	110
Other postretirement benefit plan assets subtotal	792	1,235	108	2,135
Total pension and other postretirement benefit plan assets [d][e]	$4,999	$7,889	$2,523	$15,411

At December 31, 2011 (a)	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 8	$ —	$ —	$ 8
Equity securities:				
Individually held	1,985	—	—	1,985
Commingled funds	—	858	—	858
Mutual funds	—	389	—	389
Equity securities subtotal	1,985	1,247	—	3,232
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,616	48	—	1,664
Debt securities issued by states of the United States and by political subdivisions of the states	—	88	—	88
Foreign debt securities	—	224	—	224
Corporate debt securities	—	2,561	—	2,561
Federal agency mortgage-backed securities	—	156	—	156
Non-Federal agency mortgage-backed securities	—	28	—	28
Commingled funds	—	202	—	202
Mutual funds	—	277	—	277
Fixed income securities subtotal	1,616	3,584	—	5,200
Private equity	—	—	672	672
Hedge funds (f)	—	—	1,525	1,525
Real estate:				
Individually held	207	—	—	207
Commingled funds	—	125	—	125
Real estate funds	—	—	229	229
Real estate subtotal	207	125	229	561
Pension plan assets subtotal	3,816	4,956	2,426	11,198
Other postretirement benefit plan assets				
Cash equivalents	73	—	—	73
Equity securities:				
Individually held	110	—	—	110
Commingled funds	—	415	—	415
Mutual funds	—	171	—	171
Equity securities subtotal	110	586	—	696
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	26	3	—	29
Debt securities issued by states of the United States and by political subdivisions of the states	—	93	—	93
Foreign debt securities	—	4	—	4
Corporate debt securities	—	41	—	41
Federal agency mortgage-backed securities	—	34	—	34
Non-Federal agency mortgage-backed securities	—	7	—	7
Commingled funds	—	385	—	385
Mutual funds	—	256	—	256
Fixed income securities subtotal	26	823	—	849
Private equity	—	—	1	1
Hedge funds (f)	—	—	157	157
Real estate				
Individually held	4	—	—	4
Commingled funds	—	1	—	1
Real Estate funds	—	—	7	7
Real estate subtotal	4	1	7	12
Other postretirement benefit plan assets subtotal	213	1,410	165	1,788
Total pension and other postretirement benefit plan assets (d)	$4,029	$6,366	$2,591	$12,986

(a) See Note 9—Fair Value of Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Derivative instruments have a total notional amount of $2,498 million and $910 million at December 31, 2012 and 2011, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.
(c) In 2012, Exelon reassessed its policy over the criteria that mutual fund investments must meet in order to be categorized within Level 1 of the fair value hierarchy. Therefore, certain mutual fund investments that were categorized within Level 2 in prior periods have been re-categorized as Level 1 investments as of December 31, 2012. The re-categorization of these mutual fund investments resulted in a transfer out of Level 2 of $852 million.
(d) Excludes net assets of $77 million and $43 million at December 31, 2012 and 2011 respectively; which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables related to pending securities sales, interest and dividends receivable, and payables related to pending securities purchases.
(e) Includes fixed income commingled fund assets of $66 million as of December 31, 2012. The fair value of these fixed income commingled fund assets of $69 million, as of December 31, 2011, are excluded from the tables above.
(f) In 2012, Exelon refined its policy over the criteria that hedge fund investments must meet in order to be categorized within Level 2 and Level 3 of the fair value hierarchy. Therefore, certain hedge fund investments that were categorized within Level 3 in prior periods have been re-categorized as Level 2 investments as of December 31, 2012. The re-categorization of these hedge fund investments is reflected as transfers out of Level 3 of $1.1 billion.

The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2012 and 2011:

	Hedge funds	Private equity	Real estate	Total
Pension Assets				
Balance as of January 1, 2012	$ 1,525	$ 672	$ 229	$2,426
Actual return on plan assets:				
Relating to assets still held at the reporting date	138	55	24	217
Purchases, sales and settlements:				
Purchases	447	108	134	689
Sales	(6)	—	—	(6)
Settlements	(4)	(128)	(28)	(160)
Transfers into (out of) Level 3 [(a)(b)(c)]	(865)	47	67	(751)
Balance as of December 31, 2012	$ 1,235	$ 754	$ 426	$2,415
Other Postretirement Benefits				
Balance as of January 1, 2012	$ 157	$ 1	$ 7	$ 165
Actual return on plan assets:				
Relating to assets still held at the reporting date	11	—	3	14
Purchases, sales and settlements:				
Purchases	32	—	91	123
Sales	—	—	—	—
Settlements	—	—	(1)	(1)
Transfers into (out of) Level 3 [(a)(b)(c)]	(188)	—	(5)	(193)
Balance as of December 31, 2012	$ 12	$ 1	$ 95	$ 108

	Hedge funds	Private equity	Real estate	Total
Pension Assets				
Balance as of January 1, 2011	$ 329	$ 536	$ 179	$1,044
Actual return on plan assets [(d)]:				
Relating to assets still held at the reporting date	(26)	84	46	104
Purchases, sales and settlements [(d)]:				
Purchases	1,222	121	13	1,356
Sales	—	—	—	—
Settlements	—	(69)	(9)	(78)
Transfers into (out of) Level 3	—	—	—	—
Balance as of December 31, 2011	$ 1,525	$ 672	$ 229	$2,426
Other Postretirement Benefits				
Balance as of January 1, 2011	$ 5	$ —	$ 8	$ 13
Actual return on plan assets:				
Relating to assets still held at the reporting date	(3)	—	(1)	(4)
Purchases, sales and settlements:				
Purchases	155	1	—	156
Sales	—	—	—	—
Settlements	—	—	—	—
Transfers into (out of) Level 3	—	—	—	—
Balance as of December 31, 2011	$ 157	$ 1	$ 7	$ 165

(a) In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation's pension plan assets resulting in transfers into Level 3 of $141 million.
(b) In 2012, Exelon refined its policy over the criteria that hedge fund investments must meet in order to be categorized within Level 2 and Level 3 of the fair value hierarchy. Therefore, certain hedge fund investments that were categorized within Level 3 in prior periods have been re-categorized as Level 2 investments as of December 31, 2012. The re-categorization of these hedge fund investments is reflected as transfers out of Level 3 of $1.1 billion.
(c) In 2012, the liquidity terms of a certain real estate investment changed to allow redemption within a reasonable period of time from the redemption date which led to a transfer out of Level 3 to Level 2 of $5 million.
(d) Certain prior year amounts have been reclassified for comparative purposes.

Valuation Techniques Used to Determine Fair Value

Cash equivalents. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

Equity securities. With respect to individually held equity securities, including investments in U.S. and international securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity securities held individually are primarily traded on exchanges that contain only actively traded securities, due to the volume trading requirements imposed by these exchanges. Equity securities are valued based on quoted prices in active markets and are categorized as Level 1.

Equity commingled funds and mutual funds are maintained by investment companies that hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets

and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

Fixed income. For fixed income securities, which consist primarily of corporate debt securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, mutual funds and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Derivative instruments consisting primarily of interest rate swaps to manage risk are recorded at fair value. Derivative instruments are valued based on external price data of comparable securities and have been categorized as Level 2.

Fixed income commingled funds and mutual funds, including short-term investment funds, are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

Private equity. Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments and investments in natural resources. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows and market based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3.

Hedge funds. Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or ownership interest of the investments. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate. For Exelon's investments that have terms that allow redemption within a reasonable period of time from the measurement date, the hedge fund investments are categorized as Level 2. For investments that have restrictions that may limit

Exelon's ability to redeem the investments at the measurement date or within a reasonable period of time, the hedge fund investments are categorized as Level 3.

Real estate. Real estate investment trusts valued daily based on quoted prices in active markets are categorized as Level 1. Real estate commingled funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Since these funds are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Other real estate funds are funds with a direct investment in a pool of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. Since these valuation inputs are not highly observable, these real estate funds have been categorized as Level 3.

Defined Contribution Savings Plan (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE participate in a 401(k) defined contribution savings plan sponsored by Exelon. The plan is qualified under applicable sections of the IRC and allows employees to contribute a portion of their pre-tax income in accordance with specified guidelines. Exelon, Generation, ComEd, PECO and BGE match a percentage of the employee contribution up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2012, 2011 and 2010:

For the Year Ended December 31,	Exelon	Generation	ComEd	PECO	BGE
2012	$ 67	$ 30	$ 19	$ 7	$ 7
2011	78	40	22	9	7
2010	81	42	22	9	6

15. Plant Retirements (Exelon and Generation)

Schuylkill Station and Riverside Station

On October 31, 2012, Generation notified PJM of its intention to permanently retire Schuylkill Generating Station Unit 1 by February 1, 2013, and Riverside Generating Station Unit 6 by June 1, 2014. Schuylkill Unit 1 is a 166 MW peaking oil unit located in Philadelphia, Pennsylvania, which was placed in service in 1958. Riverside Unit 6 is a 115 MW peaking gas/kerosene unit located in Baltimore, Maryland, which was placed in service in 1970. The units are being retired because they are no longer economic to operate due to their age, relatively high capital and operating costs and declining revenue expectations. On November 30, 2012, PJM notified Generation that it did not identify any transmission system reliability issues associated with the proposed Schuylkill Unit 1 retirement date and as a result, Schuylkill Unit 1 was retired on January 1, 2013. On January 7, 2013, PJM notified Generation that it did not identify any transmission system reliability issues associated with the proposed Riverside Unit 6 retirement date. Exelon will determine the final retirement date for Riverside Unit 6 during the second quarter of 2013. The early retirements will not have a material impact on Generation or Exelon's results of operations, cash flows or financial position.

Oyster Creek

On December 8, 2010, in connection with the executed Administrative Consent Order (ACO) with the NJDEP, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

Eddystone Station and Cromby Station

In 2009, Exelon announced its intention to permanently retire three coal-fired generating units and one oil/gas-fired generating unit, effective May 31, 2011, in response to the economic outlook related to the continued operation of these four units. However, PJM determined that transmission reliability upgrades would be necessary to alleviate reliability impacts and that those upgrades would be completed in a manner that will permit Generation's retirement of two of the units on that date and two of the units subsequent to May 31, 2011. On May 31, 2011, Cromby Generating Station (Cromby) Unit 1 and Eddystone Generating Station (Eddystone) Unit 1 were retired; Cromby Unit 2 retired on December 31, 2011 and Eddystone Unit 2 retired on May 31, 2012. On May 27, 2011, the FERC approved a settlement providing for a reliability-must-run rate schedule, which defines compensation to be paid to Generation for continuing to operate these units. The monthly fixed-cost recovery during the reliability-must-run period for Eddystone Unit 2 is approximately $6 million. Such revenue is intended to recover total expected operating costs, plus a return on net assets, of the two units during the reliability-must-run period. In addition, Generation is reimbursed for variable costs, including fuel, emissions costs, chemicals, auxiliary power and for project investment costs during the reliability-must-run period. Eddystone Unit 2 and Cromby Unit 2 operated under the reliability-must-run agreement from June 1, 2011 until their respective retirement dates.

Since the announced retirements in December 2009, Generation recorded pre-tax expense of $44 million, which included $18 million of expense for the write down of inventory, $13 million of expense for estimated salary continuance and health and welfare severance benefits and $13 million of shut down costs recorded within operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During the year ended December 31, 2012, Generation recorded $1 million of expense for the write down of inventory and $11 million of shut down costs. During the year ended December 31, 2011, Generation recorded pre-tax expense of $4 million for estimated salary continuance and health and welfare severance benefits and $2 million of shut down costs.

The following table presents the activity of severance obligations for the announced Cromby and Eddystone retirements from January 1, 2011 through December 31, 2012:

Severance Benefits Obligation	Exelon and Generation
Balance at January 1, 2011	$ 7
Severance charges recorded	4
Cash payments	(4)
Balance at December 31, 2011	7
Cash payments	(4)
Balance at December 31, 2012	$ 3

16. Preferred and Preference Securities (Exelon, ComEd, PECO and BGE)

At December 31, 2012 and 2011, Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

Preferred and Preference Securities of Subsidiaries

At December 31, 2012 and 2011, ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

At December 31, 2012 and 2011, PECO cumulative preferred securities, no par value, consisted of 15,000,000 shares authorized and the outstanding amounts set forth below. Shares of preferred securities have full voting rights, including the right to cumulate votes in the election of directors.

	Redemption Price [a]	December 31, 2012 Shares Outstanding	December 31, 2011 Shares Outstanding	December 31, 2012 Dollar Amount	December 31, 2011 Dollar Amount
Series (without mandatory redemption)					
$4.68 (Series D)	$ 104.00	150,000	150,000	$ 15	$ 15
$4.40 (Series C)	112.50	274,720	274,720	27	27
$4.30 (Series B)	102.00	150,000	150,000	15	15
$3.80 (Series A)	106.00	300,000	300,000	30	30
Total preferred securities		874,720	874,720	$ 87	$ 87

(a) Redeemable, at the option of PECO, at the indicated dollar amounts per share, plus accrued dividends.

At December 31, 2012 and 2011, BGE cumulative preference stock, $100 par value, consisted of 6,500,000 shares authorized and the outstanding amounts set forth below. Shares of BGE preference stock have no voting power except for the following:

- The preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and
- Whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

	Redemption Price [a]	December 31, 2012 Shares Outstanding	December 31, 2011 Shares Outstanding	December 31, 2012 Dollar Amount	December 31, 2011 Dollar Amount
Series (without mandatory redemption)					
7.125%, 1993 Series	$ 100.36	400,000	400,000	$ 40	$ 40
6.97%, 1993 Series	100.35	500,000	500,000	50	50
6.70%, 1993 Series	100.67	400,000	400,000	40	40
6.99%, 1995 Series	101.05	600,000	600,000	60	60
Total preference stock		1,900,000	1,900,000	$190	$190

(a) Redeemable, at the option of BGE, at the indicated dollar amounts per share, plus accrued and unpaid dividends.

17. Common Stock (Exelon, Generation, ComEd, PECO and BGE)

At December 31, 2012 and 2011, Exelon's common stock without par value consisted of 2,000,000,000 shares authorized and 854,781,389 shares and 663,368,958, shares outstanding, respectively. At December 31, 2012 and 2011, ComEd's common stock with a $ 12.50 par value consisted of 250,000,000 shares authorized and 127,016,761 shares and 127,016,529 shares outstanding, respectively. At December 31, 2012 and 2011, PECO's common stock without par value consisted of 500,000,000 shares authorized and 170,478,507 shares outstanding. At December 31, 2012 and 2011, BGE's common stock without par value consisted of 175,000,000 shares authorized and 1,000 shares outstanding.

ComEd had 74,182 and 75,096 warrants outstanding to purchase ComEd common stock at December 31, 2012 and 2011, respectively. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants. At December 31, 2012 and 2011, 24,727 and 25,032 shares of common stock, respectively, were reserved for the conversion of warrants.

Share Repurchases

Share Repurchase Programs. In April 2004, Exelon's Board of Directors approved a discretionary share repurchase program that allowed Exelon to repurchase shares of its common stock on a periodic basis in the open market. The share repurchase program was intended to mitigate, in part, the dilutive effect of shares issued under Exelon's employee stock option plan and Exelon's ESPP. The aggregate value of the shares of common stock repurchased pursuant to the program cannot exceed the economic benefit received after January 1, 2004 due to stock option exercises and share purchases pursuant to Exelon's ESPP. The economic benefit consists of the direct cash proceeds from purchases of stock and the tax benefits associated with exercises of stock options. The 2004 share repurchase program had no specified limit on the number of shares that could be repurchased and no specified termination date. Any shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon's management.

In the third quarter of 2008, Exelon's Board of Directors approved a share repurchase program for $1.5 billion of its common stock. Subsequently, Exelon's management determined to defer indefinitely any share repurchases. This decision was made in light of a variety of factors, including: developments affecting the world economy and commodity markets, including those for electricity and gas; the continued uncertainty in capital and credit markets and the potential impact of those events on Exelon's future cash needs; projected cash needs to support investment in the business, including maintenance capital and nuclear uprates; and value-added growth opportunities.

Under the share repurchase programs dating back to 2004, 34.7 million shares of common stock are held as treasury stock with a cost of $2.3 billion at December 31, 2012. During 2012, 2011 and 2010, Exelon had no common stock repurchases.

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes performance share awards, stock options and restricted stock units. At December 31, 2012, there were approximately 20 million shares authorized for issuance under the LTIP. For the years ended December 31, 2012, 2011 and 2010, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

As the LTIP sponsor, Exelon is the sole issuer of all stock-based compensation awards. All awards are recorded as equity or a liability in Exelon's Consolidated Balance Sheets. The stock-based compensation expense specifically attributable to the employees of Generation, ComEd, PECO and BGE is directly recorded to operating and maintenance expense within each of their respective Consolidated Statements of Operations. Stock-based compensation expense attributable to BSC employees is allocated to the Registrants using a cost-causative allocation method.

In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation's 1995 Long-Term Incentive Plan, 2002 Senior Management Long-Term Incentive Plan, Amended and Restated 2007 Long-Term Incentive Plan, Amended and Restated Management Long-Term Incentive Plan and Executive Long-Term Incentive Plan (collectively and as amended, if applicable, the "Constellation Plans"). Stock-based awards granted under the Constellation Plans and held by Constellation employees were generally converted into outstanding Exelon stock-based compensation awards with the estimated fair value determined to be $71 million using the Black-Scholes model. Refer to Note 4 - Merger and Acquisitions for further information regarding the merger transaction. Specifically, as of the merger closing: (1) Exelon converted 12,037,093 outstanding shares that were subject to Constellation stock options into 11,194,151 Exelon stock options valued at $65 million; and (2) Exelon converted 165,219 Constellation no-sale restricted stock units into 153,654 Exelon no-sale restricted stock units valued at $6 million.

Exelon generally grants most of its stock options in the first quarter of each year. In connection with the merger with Constellation, the Compensation Committee of Exelon's Board of Directors elected to delay the annual equity award grant from January 2012 to the effective date of the merger on March 12, 2012, in order to ensure that a majority of eligible employees receive grants on the same date and at the same market price.

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
Components of Stock-Based Compensation Expense	**2012**	**2011**	**2010**
Performance share awards	$ 46	$ 26	$ 6
Stock options	15	8	10
Restricted stock units	50	31	21
Other stock-based awards	4	4	4
Total stock-based compensation expense included in operating and maintenance expense	115	69	41
Income tax benefit	(44)	(27)	(16)
Total after-tax stock-based compensation expense	$ 71	$ 42	$ 25

The following table presents stock-based compensation expense (pre-tax) for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
Subsidiaries	**2012 (a)**	**2011**	**2010**
Generation	$ 42	$31	$21
ComEd	11	5	3
PECO	5	5	3
BGE	5	6	4
BSC (b)	52	28	14
Total	$115	$69	$41

(a) For BGE, reflects BGE's stock-based compensation expense for the year ended December 31, 2012. For Exelon and Generation, includes the stock-based compensation expense of Constellation and BGE from the date of the merger, March 12, 2012, through December 31, 2012.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO and BGE amounts above.

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2012, 2011 and 2010.

Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon recognizes the tax benefit related to compensation costs. The tax deductions in excess of the benefits recorded throughout the requisite service period are recorded to common stock and are included in other financing activities within Exelon's Consolidated Statements of Cash Flows. The following table presents information regarding Exelon's tax benefits for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	**2011**	**2010**
Realized tax benefit when exercised/distributed:			
Stock options	$ 3	$ 2	$ 5
Restricted stock units	11	8	9
Performance share awards	7	7	13
Stock deferral plan	—	1	1
Excess tax benefits included in other financing activities of Exelon's Consolidated Statements of Cash Flows:			
Stock options	$ 2	$ 1	$ 3

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock are granted under the LTIP. The exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. Stock options granted under the LTIP generally become exercisable upon a specified vesting date. The vesting period of stock options is generally four years. All stock options expire ten years from the date of grant.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years. However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

Exelon grants most of its stock options in the first quarter of each year. Stock options granted during the remaining quarters of 2012, 2011 and 2010 were not significant.

The fair value of each option is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The following table presents the weighted average assumptions used in the pricing model for grants and the resulting weighted average grant date fair value of stock options granted for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Dividend yield	5.28%	4.84%	4.56%
Expected volatility	23.20%	24.40%	27.10%
Risk-free interest rate	1.30%	2.65%	2.96%
Expected life (years)	6.25	6.25	6.25
Weighted average grant date fair value (per share)	$ 4.18	$ 6.22	$ 8.08

The assumptions above relate to Exelon stock options granted during the period and therefore do not include stock options that were converted in connection with the merger with Constellation during the year ended December 31, 2012.

The dividend yield is based on several factors, including Exelon's most recent dividend payment at the grant date and the average stock price over the previous year. Expected volatility is based on implied volatilities of traded stock options in Exelon's common stock and historical volatility over the estimated expected life of the stock options. The risk-free interest rate for a security with a term equal to the expected life is based on a yield curve constructed from U.S. Treasury strips at the time of grant. For each year presented, the expected life represents the period of time the stock options are expected to be outstanding and is based on the simplified method. Exelon believes that the simplified method is appropriate due to several factors that result in historical exercise data not being sufficient to determine a reasonable estimate of expected term. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table presents information with respect to stock option activity for the year ended December 31, 2012:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2011	11,553,761	$ 48.49		
Options granted	2,372,000	39.66		
Converted Constellation options	11,194,151	41.35		
Options exercised	(1,776,041)	26.41		
Options forfeited	(980,986)	42.90		
Options expired	(459,104)	49.45		
Balance of shares outstanding at December 31, 2012	21,903,781	$ 45.91	5.58	$ 13
Exercisable at December 31, 2012 [a]	19,943,116	$ 46.40	5.25	$ 13

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Intrinsic value [a]	$ 19	$ 5	$ 13
Cash received for exercise price	47	13	24

(a) The difference between the market value on the date of exercise and the option exercise price.

The following table summarizes Exelon's nonvested stock option activity for the year ended December 31, 2012:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2011 [a]	877,050	$ 48.66
Granted [b]	2,372,000	39.66
Converted Constellation options	11,194,151	41.35
Vested [b][c]	(12,023,432)	41.37
Forfeited	(459,104)	49.45
Nonvested at December 31, 2012 [a]	1,960,665	$ 40.56

(a) Excludes 2,647,536 and 1,348,000 of stock options issued to retirement-eligible employees as of December 31, 2012 and December 31, 2011, respectively, as they are fully vested.
(b) Includes 8,684,709 of converted Constellation options that were vested prior to the Merger on March 12, 2012.
(c) Includes 1,699,000 of stock options issued to retirement-eligible employees in 2012 that vested immediately upon the employee reaching retirement eligibility.

At December 31, 2012, $6 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 2.4 years.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table summarizes Exelon's nonvested restricted stock unit activity for the year ended December 31, 2012:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2011 [(a)]	1,074,484	$ 48.08
Granted	1,332,214	39.94
Converted Constellation restricted stock	825,735	38.91
Vested	(479,805)	46.36
Forfeited	(76,484)	42.21
Undistributed vested awards [(b)]	(646,983)	40.75
Nonvested at December 31, 2012 [(a)]	2,029,161	$ 42.12

(a) Excludes 686,121 and 448,827 of restricted stock units issued to retirement-eligible employees as of December 31, 2012 and December 31, 2011, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2012.

The weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2012, 2011 and 2010 was $39.94, $43.33 and $44.23, respectively. At December 31, 2012 and 2011, Exelon had obligations related to outstanding restricted stock units not yet settled of $58 million and $46 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. For the years ended December 31, 2012, 2011 and 2010, Exelon settled restricted stock units with fair value totaling $25 million, $19 million and $22 million, respectively. At December 31, 2012, $43 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 1.9 years.

Performance Share Awards

Performance share awards are granted under the LTIP with the 2012 performance share awards being settled in 50% common stock and 50% cash over the three-year vesting term. The 2011 performance share awards are being settled entirely in common stock over the three-year vesting term. The performance shares granted prior to 2011 generally vest and settle over a three-year period with the holders receiving shares of common stock and/or cash annually during the vesting period.

These awards are recorded at fair value at the date of grant with the estimated grant date fair value based on the expected payout of the award, which may range from 75% to 125% of the payout target. The common stock portion is considered an equity award with the 75% payout floor being valued based on Exelon's stock price on the grant date. The cash portion of the award is considered a liability award with the 75% payout floor being remeasured each reporting period based on Exelon's current stock price. The expected payout in excess of the 75% floor for the equity and liability portions are remeasured each reporting period based on Exelon's current stock price and changes in the expected payout of the award; therefore these portions of the award are subject to volatility until the payout is established.

In 2010, the number of performance shares granted was determined based on the performance of Exelon's common stock relative to certain stock market indices during the three-year period through the end of the year of grant. These performance share awards generally vest and settle over a three-year period. The holders of these performance share awards receive shares of common stock and/or cash annually during the vesting period. Participants are eligible for partial or full distributions in cash if they meet certain stock ownership requirements.

The 2010 performance share awards that were settled in stock were recorded as common stock within the Consolidated Balance Sheets and recorded at fair value at the date of grant. The grant date fair value of equity classified performance share awards granted during the year ended 2010 was estimated using historical data for the previous two plan years and a Monte Carlo simulation model for the current plan year. This model requires assumptions regarding Exelon's total shareholder return relative to certain stock market indices and the stock beta and volatility of Exelon's common stock and all stocks represented in these indices. Volatility for Exelon and all comparable companies is based on historical volatility over one year using daily stock price observation. The 2010 performance share awards that were settled in cash were recorded as liabilities within the Consolidated Balance Sheets. The grant date fair value of liability classified performance share awards granted during the year ended 2010 was based on historical data for the previous two plan years and actual results for the current plan year. The liabilities were remeasured each reporting period throughout the requisite service period and as a result, the compensation costs for cash-settled awards were subject to volatility.

For non retirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method, a method in which the compensation cost is recognized over the requisite service period for each separately vesting tranche of the award as though the award were multiple awards. For performance shares granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period which is the year of grant.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2012:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2011 [(a)]	346,848	$ 45.37
Granted	1,429,189	39.72
Vested	(167,048)	47.46
Forfeited	(116,388)	39.78
Undistributed vested awards [(b)]	(179,867)	40.72
Nonvested at December 31, 2012 [(a)]	1,312,734	$ 40.08

(a) Excludes 204,643 and 455,418 of performance share awards issued to retirement-eligible employees as of December 31, 2012 and December 31, 2011, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2012.

The weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2012, 2011 and 2010 was $39.71, $43.52 and $60.82 respectively. During the years ended December 31, 2012, 2011 and 2010, Exelon settled performance shares with a fair value totaling $23 million, $22 million and $32 million, respectively, of which $3 million, $10 million and $20 million was paid in cash, respectively. As of December 31, 2012, $9 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 2.2 years.

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31,	
	2012	2011
Current liabilities [a]	$ 7	$ 3
Deferred credits and other liabilities [b]	11	—
Common stock	35	30
Total	$ 53	$ 33

(a) Represents the current liability related to performance share awards expected to be settled in cash.
(b) Represents the long-term liability related to performance share awards expected to be settled in cash.

18. Earnings Per Share and Equity (Exelon)

Earnings per Share

Diluted earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Year Ended December 31,		
	2012	2011	2010
Net income on common stock	$1,160	$2,495	$2,563
Weighted average common shares outstanding—basic	816	663	661
Assumed exercise and/or distributions of stock-based awards	3	2	2
Weighted average common shares outstanding—diluted	819	665	663

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 14 million in 2012, 9 million in 2011 and 8 million in 2010.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of December 31, 2012. In 2008, Exelon management decided to defer indefinitely any share repurchases.

19. Commitments and Contingencies (Exelon, Generation, ComEd, PECO and BGE)

Nuclear Insurance

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2012, the current liability limit per incident was $12.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective October 29, 2008. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of January 1, 2013, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in an additional $12.2 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $117.5 million, payable at no more than $17.5 million per reactor per incident per year. Exelon's maximum liability per incident is approximately $2.2 billion. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $12.6 billion limit for a single incident.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. No distributions were declared in 2011 or 2012. Premiums paid to NEIL by its members are subject to assessment (the retrospective premium obligation) for adverse loss experience. NEIL has never exercised this assessment since its formation in 1973, and while Generation cannot predict the level of future assessments, or if they will be imposed at all, as of December 31, 2012, the current maximum aggregate annual retrospective premium obligation for Generation is approximately $278 million.

NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. As of December 31, 2012, Generation's current limit for this coverage is $2.1 billion. For property limits in excess of the first $1.25 billion of that limit, Generation participates in an $850 million single limit blanket policy shared by all the Generation operating nuclear sites and the Salem and Hope Creek nuclear sites. This blanket limit is not subject to automatic reinstatement in the event of a loss. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is

unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. Under the terms of the various insurance agreements, Generation could be assessed up to $220 million per year for losses incurred at any plant insured by the insurance company (the retrospective premium obligation). In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery for all losses by all insureds will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses. The $3.2 billion maximum recovery limit is not applicable, however, in the event of a “certified act of terrorism” as defined in the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007. The Terrorism Risk Insurance Act expires on December 31, 2014.

Additionally, NEIL provides replacement power cost insurance in the event of a major accidental outage at an insured nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. Generation’s maximum share of any assessment is $58 million per year (the retrospective premium obligation). Recovery under this insurance for terrorist acts is subject to the $3.2 billion aggregate limit and secondary to the property insurance described above. This limit would not apply in cases of certified acts of terrorism under the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007, as described above.

Effective April 1, 2009, NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon’s and Generation’s financial condition, results of operations and liquidity.

Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation’s nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation pays the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance will be delayed significantly.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama administration devises a new strategy for long-term SNF management. In early 2010, Secretary of Energy Steven Chu appointed the Blue Ribbon Commission (BRC) on America’s Nuclear Future to evaluate and recommend a new plan for managing the back end of the nuclear fuel cycle, including used fuel storage, disposal and fees. The Commission released its final report to the U.S. Energy Secretary on January 26, 2012, detailing

comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's spent nuclear fuel and high-level radioactive waste. The strategy recommended by the Commission encompasses 8 key elements; 1) A new consent-based approach to siting storage and disposal facilities; 2) A new organization to implement the waste management program; 3) Access to utility waste disposal fees for their intended purpose; 4) Prompt efforts to develop a new geological disposal facility; 5) Prompt efforts to develop one or more consolidated storage facilities; 6) Early preparation for the eventual large-scale transport of spent nuclear fuel and high-level waste to consolidated storage and disposal facilities; 7) Support for advances in nuclear energy technology and for workforce development; and 8) Active U.S. leadership in international efforts to address safety, non-proliferation and security concerns.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that is planned to be operational in 2025.

Generation uses the 2025 date as the assumed date for when the DOE will begin accepting SNF for purposes of determining nuclear decommissioning asset retirement obligations. The extended delay in SNF acceptance by the DOE has led to Generation's adoption of dry cask storage at its Dresden, Clinton, Limerick, Oyster Creek, Peach Bottom, Byron, Braidwood, LaSalle and Quad Cities stations. Generation performed sensitivity analyses assuming that the estimated date for the DOE acceptance of SNF was delayed to 2030 and determined that Generation's aggregate nuclear ARO would be increased by approximately $700 million.

In August 2004, Generation and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation, subject to certain damage limitations based on the extent of the government's breach, for costs associated with storage of SNF at Generation's nuclear stations pending the DOE's fulfillment of its obligations. Generation submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

Under the settlement agreement, Generation has received cash reimbursements for costs incurred through April 30, 2012, totaling approximately $639 million ($543 million after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek). As of December 31, 2012, the amount of SNF storage costs for which reimbursement will be requested from the DOE under the settlement agreement is $61 million, which is recorded within accounts receivable, other. Of this amount, $13 million represents amounts owed to the co-owners of the Peach Bottom and Quad Cities generating facilities.

CENG has entered into settlement agreements with the DOE during 2011 and 2012 to recover damages caused by the DOE's failure to comply with legal and contractual obligations to dispose of spent nuclear fuel related to the Ginna, Calvert Cliffs and Nine Mile Point nuclear power plants. At December 31, 2012, Generation had approximately $22 million recorded as a receivable from CENG with respect to costs incurred by Constellation prior to November 6, 2009, for the Nine Mile Point and Calvert Cliffs nuclear power plants. CENG received the funds for the Nine Mile Point and Calvert Cliffs settlement from the DOE in January 2013 and February 2013, respectively, and remitted the $22 million to Generation.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. As of December 31, 2012, the unfunded SNF liability for the one-time fee with interest was $1,020 million. Interest accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2012, was 0.127%. The liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of the 2001 corporate restructuring. The outstanding one-time fee obligations for the Oyster Creek and TMI units remain with the former owners. Clinton has no outstanding obligation. See Note 9—Fair Value of Assets and Liabilities for additional information.

Energy Commitments

Generation's customer facing activities include the physical delivery and marketing of power obtained through its generation capacity, and long-, intermediate- and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. Generation has also contracted for access to additional generation through bilateral long-term PPAs. These agreements are firm commitments related to power generation of specific generation plants and/or are dispatchable in nature. Several of Generation's long-term PPAs, which have been determined to be operating leases, have significant contingent rental payments that are dependent on the future operating characteristics of the associated plants, such as plant availability. Generation recognizes contingent rental expense when it becomes probable of payment. Generation enters into PPAs with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to its customers. Generation has also purchased firm transmission rights to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs. The primary intent and business objective for the use of its capital assets and contracts is to provide Generation with physical power supply to enable it to deliver energy to meet customer needs. In addition to physical contracts, Generation uses financial contracts for economic hedging purposes and, to a lesser extent, as part of proprietary trading activities.

Generation has entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives and retail load aggregators. Generation also enters into contractual obligations to deliver energy to market participants who primarily focus on the resale of energy products for delivery. Generation provides for delivery of its energy to these customers through firm transmission.

As part of reaching a comprehensive agreement with EDF in October 2010, the existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements, CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the available output of CENG's nuclear plants at market prices. Generation discloses in the table below commitments to purchase from CENG at fixed prices. All commitments to purchase at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 22—Related Party Transactions for more details on this arrangement.

At December 31, 2012, Generation's short- and long-term commitments, relating to the purchases from unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following tables:

	Net Capacity Purchases [a]	Power-Related Purchases [b]	Transmission Rights Purchases [c]	Purchased Energy from CENG	Total
2013	$ 374	$ 95	$ 28	$ 777	$1,274
2014	353	69	26	516	964
2015	350	25	13	—	388
2016	266	11	2	—	279
2017	203	3	2	—	208
Thereafter	469	5	34	—	508
Total	$ 2,015	$ 208	$ 105	$ 1,293	$3,621

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2012, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. Expected payments include certain capacity charges which are contingent on plant availability.
(b) Power-Related Purchases include firm REC purchase agreements. The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

Pursuant to a PPA with Public Service Company of Oklahoma, a subsidiary of American Electric Power Company, Inc., dated as of April 17, 2009, Generation agreed to sell its rights to up to 520 MWs, or approximately two-thirds of the capacity, energy and ancillary services supplied under its existing long-term contract with Green Country Energy, LLC. The delivery of power under the PPA commenced June 1, 2012 and will run through February 28, 2022.

ComEd purchases its expected energy requirements through an ICC approved competitive bidding process administered by the IPA, existing ICC approved RFPs, and spot market purchases hedged with a financial swap contract with Generation expiring in 2013. See Note 3—Regulatory Matters for further information.

PECO's long-term PPA with Generation, under which PECO obtained all of its electric supply from Generation for a 12-year period, expired on December 31, 2010. During 2009, 2010, 2011 and 2012, PECO entered into contracts through a competitive procurement process in order to meet a portion of its default service customers' electric supply requirements for 2011 through 2015. See Note 3—Regulatory Matters for further information regarding the DSP Programs.

ComEd is subject to requirements established by the Illinois Settlement Legislation and the Energy Infrastructure Modernization Act related to the use of alternative energy resources. PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. BGE is subject to requirements established by the Public Utilities Article in Maryland related to the use of alternative energy resources; however, the wholesale suppliers that supply power to BGE through SOS procurement auctions have the obligation, by contract with BGE, to meet the RPS requirement. BGE has entered into contracts with curtailment services providers in accordance with the March 2009 MDPSC order. See Note 3—Regulatory Matters for additional information relating to electric generation procurement, alternative energy resources and energy efficiency programs.

ComEd's, PECO's and BGE's electric supply procurement, curtailment services, REC and AEC purchase commitments as of December 31, 2012 are as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
ComEd							
Electric supply procurement [a]	$1,103	$367	$323	$136	$137	$140	$ —
Renewable energy and RECs [b]	1,661	71	73	74	76	82	1,285
PECO							
Electric supply procurement [c]	799	561	200	38	—	—	—
AECs	33	12	9	2	2	2	6
BGE							
Electric supply procurement [d]	1,401	859	467	75	—	—	—
Curtailment services	153	49	47	41	16	—	—

(a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. See Note 3—Regulatory Matters for additional information.

(b) ComEd entered into 20-year contracts for renewable energy and RECs beginning June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. Per the ICC's Final Commission Order on December 19, 2012, the quantities purchased under these long-term renewable contracts should be curtailed during the June 2013—May 2014 period to avoid exceeding the statutory rate impact for affected customers as a result of an increased number of ComEd's customers purchasing their energy from alternative energy suppliers. See Note 3—Regulatory Matters for additional information.

(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2013 and 2015. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 3—Regulatory Matters for additional information.

(d) BGE entered into various contracts for the procurement of electricity beginning 2012 through 2015. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 3—Regulatory Matters for additional information.

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation (and with respect to coal, commitments to sell coal). PECO and BGE have commitments to purchase natural gas, related transportation, storage capacity and services to serve customers in their gas distribution service territory. As of December 31, 2012, these net commitments were as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Generation	$8,857	$1,276	$1,207	$1,272	$976	$1,064	$ 3,062
PECO	444	145	87	71	49	15	77
BGE	654	133	73	54	52	52	290

Other Purchase Obligations

The Registrants' other purchase obligations as of December 31, 2012, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Exelon	$716	$186	$167	$114	$ 51	$ 49	$ 149
Generation	487	127	120	94	32	29	85
ComEd	8	2	6	—	—	—	—
PECO	45	17	18	1	1	1	7
BGE	—	—	—	—	—	—	—

Commercial Commitments

Exelon's commercial commitments as of December 31, 2012, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Letters of credit (non-debt) [a]	$ 1,889	$ 1,325	$—	$564	$—	$—	$ —
Surety bonds [b]	286	225	—	1	6	4	50
Performance guarantees [c]	1,897	908	203	—	—	—	786
Energy marketing contract guarantees [d]	8,556	8,556	—	—	—	—	—
Lease guarantees [e]	48	—	—	—	—	—	48
Middle market lending commitments [f]	180	180	—	—	—	—	—
Nuclear insurance premiums [g]	2,494	—	—	—	—	—	2,494
Total commercial commitments	$15,350	$11,194	$203	$565	$ 6	$ 4	$ 3,378

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Guarantees issued to ensure performance under specific contracts, including $211 million issued on behalf of CENG nuclear generating facilities for credit support, $200 million of Trust Preferred Securities of ComEd Financing III, $178 million of Trust Preferred Securities of PECO Trust III and IV and $250 million of Trust Preferred Securities of BGE Capital Trust II.
(d) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $8.3 billion of guarantees previously issued by Constellation on behalf of its Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Exelon's estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $1.5 billion at December 31, 2012, which represents the total amount Exelon could be required to fund based on December 31, 2012 market prices.
(e) Lease guarantees—Guarantees issued to ensure payments on building leases.
(f) Middle market lending commitments—Represents commitments to investment in loans or managed funds which invest in private companies. These commitments will be funded by Generation's existing nuclear decommissioning trust funds. See Note 9—Fair Value of Financial Assets and Liabilities for more information on nuclear decommissioning trust funds and middle market lending.
(g) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

Generation's commercial commitments as of December 31, 2012, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Letters of credit (non-debt) [a]	$1,841	$1,278	$—	$563	$—	$—	$ —
Performance guarantees [b]	1,153	907	203	—	—	—	43
Energy marketing contract guarantees [c]	1,794	1,794	—	—	—	—	—
Middle market lending commitments [d]	180	180	—	—	—	—	—
Nuclear insurance premiums [e]	2,494	—	—	—	—	—	2,494
Total commercial commitments	$7,462	$4,159	$203	$563	$—	$—	$ 2,537

(a) Letters of credit (non-debt)—Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.
(b) Performance guarantees—Guarantees issued to ensure performance under specific contracts including $211 million issued on behalf of CENG nuclear generating facilities for credit support.
(c) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $1.5 billion of guarantees previously issued by Constellation on behalf of its Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Generation's estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $0.6 billion at December 31, 2012, which represents the total amount Generation could be required to fund based on December 31, 2012 market prices.
(d) Middle market lending commitments—Represents commitments to investment in loans or managed funds which invest in private companies. These commitments will be funded by Generation's existing nuclear decommissioning trust funds. See Note 9—Fair Value of Financial Assets and Liabilities for more information on nuclear decommissioning trust funds and middle market lending.
(e) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

ComEd's commercial commitments as of December 31, 2012, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Letters of credit (non-debt) [a]	$ 22	$ 22	$—	$—	$—	$—	$ —
Surety bonds [b]	8	8	—	—	—	—	—
Performance guarantees [c]	200	—	—	—	—	—	200
Total commercial commitments	$230	$ 30	$—	$—	$—	$—	$ 200

(a) Letters of credit (non-debt)—ComEd maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Reflects full and unconditional guarantees of Trust Preferred Securities of ComEd Financing III which is a 100% owned finance subsidiary of ComEd.

PECO's commercial commitments as of December 31, 2012, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Letters of credit (non-debt) [a]	$ 22	$ 22	$—	$—	$—	$—	$ —
Surety bonds [b]	3	3	—	—	—	—	—
Performance guarantees [c]	178	—	—	—	—	—	178
Total commercial commitments	$203	$ 25	$—	$—	$—	$—	$ 178

(a) Letters of credit (non-debt)—PECO maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Reflects full and unconditional guarantees of Trust Preferred Securities of PECO Trust III and IV, which is a 100% owned finance subsidiary of PECO.

BGE's commercial commitments as of December 31, 2012, representing commitments potentially triggered by future events, were as follows

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Letters of credit (non-debt) [a]	$ 2	$ 2	$—	$—	$—	$—	$ —
Surety bonds [b]	2	2	—	—	—	—	—
Performance guarantees [c]	250	—	—	—	—	—	250
Total commercial commitments	$254	$ 4	$—	$—	$—	$—	$ 250

(a) Letters of credit (non-debt)—BGE maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bond—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Reflects full and unconditional guarantees of Trust Preferred Securities of BGE Capital Trust II which is a 100% owned finance subsidiary of BGE.

Construction Commitments

Generation has committed to the construction of a solar PV facility in Los Angeles County, California. The first portion of the project began operations in December 2012, with additional phases to come online and an expectation of full commercial operation by the end of the third quarter of 2013. Generation's estimated remaining commitment for the project is $636 million for 2013. See Note 4—Merger and Acquisitions for additional information.

Refer to Note 3—Regulatory Matters for information on investment programs associated with regulatory mandates, such as ComEd's Infrastructure Investment Plan under EIMA, PECO's Smart Meter Procurement and Installation Plan, BGE's comprehensive smart grid initiative and ComEd's, PECO's and BGE's commitment to construct transmission facilities under their operating agreements with PJM.

Constellation Merger Commitments

Exelon's commercial and construction commitments shown above do not include the merger commitments made to the State of Maryland in conjunction with the Constellation merger. See Note 4—Merger and Acquisitions for additional information on the merger commitments.

Leases

Minimum future operating lease payments, including lease payments for vehicles, real estate, computers, rail cars, operating equipment and office equipment, as of December 31, 2012 were:

	Exelon	Generation	ComEd (b)	PECO (b)	BGE (b)(c)
2013	$ 88	$ 38	$ 13	$ 14	$ 12
2014	83	38	11	13	10
2015	73	38	11	3	9
2016	69	36	11	3	7
2017	63	36	6	3	6
Remaining years	488	367	57	—	29
Total minimum future lease payments	$ 864[a]	$ 553[a]	$ 109	$ 36	$ 73

(a) Excludes Generation's PPAs and other capacity contracts that are accounted for as contingent operating lease payments.
(b) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, ComEd, PECO and BGE have excluded these payments from the remaining years, as such amounts would not be meaningful. ComEd's annual obligation for these arrangements, included in each of the years 2013—2017, was $1 million. PECO's annual obligation for these agreements, included in each of the years 2013—2017, was $3 million. BGE's annual obligation for these agreements, included in each of the years 2013—2017, was $1 million.
(c) Includes all future lease payments on a 99 year real estate lease that expires in 2105.

The following table presents the Registrants' rental expense under operating leases for the years ended December 31, 2012, 2011 and 2010:

For the Year Ended December 31,	Exelon	Generation (a)	ComEd	PECO	BGE
2012	$ 930	$ 872	$ 18	$ 27	$12
2011	711	659	18	28	15
2010	722	665	19	31	13

(a) Includes Generation's PPAs and other capacity contracts that are accounted for as operating leases and are reflected as net capacity purchases in the energy commitments table above. These agreements are considered contingent operating lease payments and are not included in the minimum future operating lease payments table above. Payments made under Generation's PPAs and other capacity contracts totaled $801 million, $630 million and $641 million during 2012, 2011 and 2010, respectively.

For information regarding capital lease obligations, see Note 11—Debt and Credit Agreements.

Indemnifications Related to Sale of Sithe (Exelon and Generation)

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. Specifically, subsidiaries of Generation consummated the acquisition of Reservoir Capital Group's 50% interest in Sithe and subsequently sold 100% of Sithe to Dynegy Inc. (Dynegy).

The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at December 31, 2012. Generation believes that it is remote that it will be required to make any additional payments under the guarantee, and currently has no recorded liabilities associated with this guarantee. Generation expects that the exposure covered by this guarantee will expire in 2014. The guarantee is included above in the Commercial Commitments table under performance guarantees.

Indemnifications Related to Sale of TEG and TEP (Exelon and Generation)

On February 9, 2007, Tamuin International Inc. (TII), a wholly owned subsidiary of Generation, sold its 49.5% ownership interests in TEG and TEP to a subsidiary of AES Corporation for $95 million in cash plus certain purchase price adjustments. In connection with the transaction, Generation entered into a guarantee agreement under which Generation guarantees the timely payment of TII's obligations to the subsidiary of AES Corporation pursuant to the terms of the purchase and sale agreement relating to the sale of TII's ownership interests. Generation would be required to perform in the event that TII does not pay any obligation covered by the guarantee that is not otherwise subject to a dispute resolution process. Generation's maximum obligation under the guarantee is $95 million as of December 31, 2012. Generation believes that it is remote that it will be required to make payments under the guarantee, and has not recorded a liability associated with this guarantee. The exposures covered by this guarantee expired in part during 2008. Generation expects that the remaining exposure will expire in 2013. The guarantee of $95 million is included above in the Commercial Commitments table under performance guarantees.

Environmental Matters

General . The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For many of these sites, ComEd, PECO or BGE is one of several PRPs that may be responsible for ultimate remediation of each location.

- ComEd has identified 42 sites, 13 of which have been approved for cleanup by the Illinois EPA or the U.S. EPA and 27 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2016.
- PECO has identified 26 sites, 16 of which have been approved for cleanup by the PA DEP and 10 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2019.
- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE.

Pursuant to orders from the ICC, PAPUC and MDPSC, respectively, ComEd, PECO and BGE are authorized to and are currently recovering environmental costs for the remediation of former MGP facility sites from customers, for which they have recorded regulatory assets. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC,

are recovering environmental remediation costs of the MGP sites through a provision within customer rates. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. During the second and third quarters of 2012, ComEd and PECO completed annual studies of their future estimated MGP remediation requirements. The results of these studies indicated that additional remediation would be required at certain sites; accordingly, ComEd and PECO increased their reserves and regulatory assets by $146 million and $7 million, respectively. BGE assessed its currently and formerly owned gas manufacturing and purification sites quarterly in 2012 and determined that a loss was not probable at ten of its sites as of December 31, 2012. As discussed above, the remediation costs at two of BGE's MGP sites are not considered material. Furthermore, an estimate of a range of possible loss, if any, related to BGE's gas purification site under investigation cannot be determined as of December 31, 2012 given that the site is in the early stages of investigation and any potential contamination is currently unknown. See Note 3—Regulatory Matters for additional information regarding the associated regulatory assets.

This historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs based on probabilistic and deterministic modeling using all available information at the time of each study and the remediation standards currently required by the U.S. EPA. The increase in the reserve at ComEd was predominately tied to 6 sites with a total increase of approximately $111 million. The change was driven by the completion of additional preliminary environmental investigations that identified increases in scope for the remediation of larger areas and to greater depths, along with the requirement for additional groundwater management not previously contemplated in prior studies. ComEd also obtained new information on scope requirements for several sites where another PRP is leading remediation efforts and that ComEd shares responsibility. Prior to completion of any significant clean up, each site remediation plan is approved by the Illinois EPA.

As of December 31, 2012 and 2011, the Registrants have accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

December 31, 2012	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 338	$ 298
Generation	30	—
ComEd	260	254
PECO	47	44
BGE	1	—

December 31, 2011	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 224	$ 168
Generation	47	—
ComEd	127	121
PECO	50	47
BGE	—	—

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water Quality

Section 316(b) of the Clean Water Act . Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's and CENG's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected. For Generation, those facilities are Clinton, Dresden, Eddystone, Fairless Hills, Gould Street, Handley, Mountain Creek, Mystic 7, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. For CENG, those facilities are Calvert Cliffs, Nine Mile Point Unit 1 and R.E. Ginna.

On March 28, 2011, the U.S. EPA issued the proposed regulation under Section 316(b). The proposal does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment. The proposal provides the state permitting agency with discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The proposed rule also imposes limits on impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or similar technology at the intake. Exelon filed comments on the proposed regulation on August 18, 2011, stating its support for a number of its provisions (e.g., cooling towers not required as best technology available, and the use of site-specific and cost benefit analysis) while also noting a number of technical provisions that require revision to take into account existing unit operations and practices within the industry.

In June 2012, the U.S. EPA published two Notices of Data Availability (NODA) seeking public comment on alternate compliance technologies for impingement and the use of a public opinion survey to calculate the so-called "non-use" benefits of the rule. Exelon filed comments for each NODA, supporting the additional flexibility afforded by the impingement NODA, and opposing the NODA relating to calculation of non-use benefits due to its inaccurate and unreliable methodologies that would artificially inflate the benefits of proposed technologies that would otherwise not be cost-effective. On July 18, 2012, the U.S. EPA announced that it had agreed to extend the court approved Settlement Agreement to extend the deadline to issue a final rule until June 27, 2013. Until the rule is finalized, the state permitting agencies will continue to apply their best professional judgment to address impingement and entrainment.

Oyster Creek . On January 7, 2010, the NJDEP issued a draft NPDES permit for Oyster Creek that would have required, in the exercise of its best professional judgment, the installation of cooling towers as the best technology available within seven years after the effective date of the permit. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek no later than December 31, 2019. The current NRC license for Oyster Creek expires in 2029. In reliance upon Exelon's determination to cease generation operations no later than December 31, 2019, the NJDEP determined that closed cycle cooling is not the best technology

available for Oyster Creek given the length of time that would be required to retrofit from the existing once-through cooling system to a closed-cycle cooling system and the limited life span of the plant after installation of a closed-cycle cooling system. Based on its consideration of these and other factors, NJDEP determined that the existing measures at the plant represent the best technology available for the facility's cooling water intake through cessation of generation operations.

On December 9, 2010, Generation executed an Administrative Consent Order (ACO) with the NJDEP regarding Oyster Creek. The ACO sets forth, among other things, the agreement by Generation to permanently cease generation operations at Oyster Creek if the conditions of the ACO are satisfied. In accordance with the ACO, on December 21, 2011, the NJDEP agreed to issue a final NPDES permit that became effective on April 12, 2012 that does not require the construction of cooling towers or other closed-cycle cooling facilities. The ACO and the final permit apply only to Oyster Creek based on its unique circumstances and does not set any precedent for the ultimate compliance requirements for Section 316(b) at Exelon's other plants.

As a result of the decision and the ACO, the expected economic useful life of Oyster Creek was reduced by 10 years to correspond to Exelon's current best estimate as to the timing of ceasing generation operations at the Oyster Creek unit in 2019. The financial impacts relate primarily to accelerated depreciation and accretion expense associated with the changes in decommissioning assumptions related to Generation's asset retirement obligation over the remaining expected economic useful life of Oyster Creek.

Salem and Other Power Generation Facilities . In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG in July 2004 that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon's and Generation's share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $430 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment.

It is unknown at this time whether the NJDEP permit programs will require closed-cycle cooling at Salem. In addition, the economic viability of Generation's other power generation facilities, as well as CENG's, without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation and CENG.

Given the uncertainties associated with the requirements that will be contained in the final rule, Generation cannot predict the eventual outcome or estimate the effect that compliance with any resulting Section 316(b) or interim state requirements will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows and financial position.

Groundwater Contamination . In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Prior to the merger, Constellation recorded a liability in its Consolidated Balance Sheets of approximately $23 million to comply with the consent decree. The remaining liability as of December 31, 2012, is approximately $3 million. In addition, a private party has asserted claims relating to groundwater contamination. The company believes that these claims are without merit and is vigorously contesting them.

Alleged Conemaugh Clean Streams Act Violation . The PA DEP has alleged that GenOn Northeast Management Company (GenOn), the operator of Conemaugh Generating Station, violated the Pennsylvania Clean Streams Law. GenOn reached agreement with PA DEP on a proposed Consent Order that was approved by the Commonwealth Court of Pennsylvania on December 4, 2012. Under the Consent Order, GenOn is obligated to pay a civil penalty of $0.5 million, of which Generation's responsibility is approximately $0.2 million.

Air Quality

Cross-State Air Pollution Rule (CSAPR). On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of SO2 and NOx. The D.C. Circuit Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the D.C. Circuit Court's July 11, 2008 opinion. On July 7, 2011, the U.S. EPA published the final rule, known as the CSAPR. The CSAPR requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states.

Numerous entities challenged the CSAPR in the D.C. Circuit Court, and some requested a stay of the rule pending the Court's consideration of the matter on the merits. On December 30, 2011, the Court granted a stay of the CSAPR, and directed the U.S. EPA to continue the administration of CAIR in the interim. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. On January 24, 2013, the Court denied petitions for reconsideration of the ruling by the three-judge panel.

Under the CSAPR, Generation units were to receive allowances based on historic heat input, and intrastate and limited interstate trading of allowances was permitted. The CSAPR restricted entirely the use of pre-2012 allowances. Existing SO_2 allowances under the ARP would remain available for use under ARP. During the third quarter of 2010, Generation recognized a lower of cost or market impairment charge of $57 million on its ARP SO_2 allowances that were not expected to be used by Generation's fossil-fuel power plants and that had not been sold forward. The impairment was recorded due to the significant decline of allowance market prices because CSAPR regulations would restrict entirely the use of ARP SO_2 allowances beginning in 2012. As of December 31, 2012, Generation had $45 million of emission allowances carried at the lower of weighted average cost or market.

EPA Mercury and Air Toxics Standards (MATS). The MATS rule became final on April 16, 2012. The MATS rule reduces emissions of toxic air pollutants, and finalized the new source performance standards for fossil fuel-fired electric utility steam generating units (EGUs). The MATS rule requires coal-fired EGUs to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that smaller, older, uncontrolled coal units will retire rather than make these investments. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. In addition, the new standards will cause oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court is not expected until sometime in 2013. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS.

In addition, as of December 31, 2012, Exelon had a $693 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases extending through 2028-2032. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material.

National Ambient Air Quality Standards (NAAQS). The U.S. EPA previously announced that it would complete a review of the NAAQS by 2014. In December 2012, the U.S. EPA issued a more stringent particulate matter NAAQS. The Agency is currently evaluating its 2008 ozone NAAQS for potentially more stringent requirements as was previously recommended by the U.S. EPA Clean Air Act Scientific Advisory Committee (CASAC) when it reviewed the 2008 ozone NAAQS (that is currently the subject of litigation in the D.C. Circuit Court). These final and pending NAAQS reviews could result in more stringent emissions limits on fossil-fired electric generating stations. In July 2012, the D.C. Circuit Court issued separate rules upholding tightened NAAQS established by the U.S. EPA in 2010 for nitrogen dioxide and sulfur dioxide. The rulings clear the way for the U.S. EPA to continue work already underway with state and local agencies on implementing revised SIP's designed to achieve or maintain the required air quality levels. To the extent not already impacted by CAIR (and in the future by CSAPR after revision upon remand) and MATS, some power plants could be required to achieve further reductions of nitrogen dioxide and sulfur dioxide emissions.

In September 2011, the U.S. EPA withdrew its reconsideration of the NAAQS standard for ozone, which is next scheduled for reconsideration in 2014. Litigation of the ozone standard in the D.C. Circuit Court continues. In December 2012, the U.S. EPA issued its final revisions to the Agency's particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on

currently expected regulations, such as the MATS regulation. It is unclear if the vacatur of the CSAPR, one of the regulations that the U.S. EPA is relying on to assist with future PM reduction, would alter the U.S. EPA's view since either CAIR or a finalized CSAPR regulation would be in effect leading up to 2020.

In addition to these NAAQS, the U.S. EPA also expects to finalize initial designations for the 2010 one-hour SO_2 standard in June 2013 and require states to submit state implementation plans (SIPs) for nonattainment areas by February 2015. Compliance with the one-hour SO_2 standard is required by February 2018. While significant SO_2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the U.S. EPA's final one-hour SO_2 standard designation methodology at this point in time as the U.S. EPA continues to consider whether to used modeled or monitored data to inform the designation process, nor potential SIP requirements for areas found to be in nonattainment.

Notices and Finding of Violations and Midwest Generation Bankruptcy. In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

On August 6, 2007, ComEd received a NOV addressed to it and Midwest Generation from the U.S. EPA, alleging, in relevant part, that ComEd and Midwest Generation violated and are continuing to violate provisions of the Clean Air Act as a result of the modification and/or operation of six electric generation stations located in northern Illinois that have been owned and operated by Midwest Generation since their purchase from ComEd in 1999. In August 2009, the United States and the State of Illinois filed a complaint against Midwest Generation with the U.S. District Court for the Northern District of Illinois initiating enforcement proceedings with respect to most of the alleged Clean Air Act violations set forth in the NOV. Neither ComEd nor Exelon was named as a defendant in this original complaint. In March 2010, the District Court granted Midwest Generation's partial motion to dismiss all but one of the claims against Midwest Generation. The District Court held that Midwest Generation cannot be liable for any alleged violations relating to construction that occurred prior to Midwest Generation's ownership of the stations. In May 2010, the government plaintiffs filed an amended complaint against Midwest Generation asserting claims substantially similar to those in the original complaint, and added ComEd and EME as defendants. The amended complaint seeks injunctive relief and civil penalties against all defendants, although not all of the claims specifically pertain to ComEd. On March 16, 2011, the District Court granted ComEd's motion to dismiss the May 2010 complaint in its entirety as it relates to ComEd. On January 3, 2012, upon leave of the District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals for the Seventh Circuit. Exelon, Generation and ComEd are unable to predict the ultimate resolution of the claims alleged in the amended complaint, however, Exelon, Generation and ComEd have concluded that, in light of the March 2011 District Court decision, the likelihood of loss is remote. Therefore, no reserve has been established.

On December 17, 2012, EME and certain of its subsidiaries, including Midwest Generation, filed for protection under Chapter 11 of the U.S. Bankruptcy Code (the "Petition Date").

As a result of the bankruptcy filing, Exelon and Generation have recorded liabilities and receivable reserves as of December 31, 2012, for a total of $13 million, which consists primarily of lease payments under a coal rail car lease and estimated payments for asbestos personal injury claims filed pre-Petition Date. The Bankruptcy Court approved the rejection of the agreement under which Midwest Generation was responsible for obligations under the lease, leaving Generation as the party responsible to make remaining payments under the lease. Exelon and Generation currently expect Midwest Generation or its successor will remain responsible for asbestos personal injury claims filed post-Petition Date, and as such have recorded no liability for such amounts. Requirements for Generation to ultimately satisfy such claims could have a material adverse impact on Exelon's and Generation's future results of operations.

As of the Petition Date, Generation had wholesale power transactions with Edison Mission Marketing and Trading, an affiliate of Midwest Generation not included in the bankruptcy proceeding. Generation expects these transactions to be fully settled in the normal course.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in the 2001 restructuring to assume ComEd's rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors, including the impact of Midwest Generation's bankruptcy. Additionally, the obligations of EME and Midwest Generation to ComEd under the sale agreement, including the environmental indemnity, may be discharged in the bankruptcy proceeding. In such circumstances, ComEd (and Generation, through ComEd) may only have an unsecured claim against EME and Midwest Generation for the environmental remediation costs that would have otherwise been obligations of EME and Midwest Generation under the sale agreement. This unsecured claim may yield a fractional, or possibly no, recovery for ComEd and Generation.

ComEd and Generation continue to monitor the bankruptcy proceedings and available public information as to potential environmental exposures regarding the Midwest Generation plant sites. Midwest Generation publicly disclosed in its third quarter 2012 Form 10-Q that (i) it has accrued a probable amount of approximately $9 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at four Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to reasonably assess the potential likelihood or magnitude of any such exposures. Further, Midwest Generation's reorganization process will likely extend beyond one year and the outcome is uncertain, including whether the facilities will continue to operate and the identity or financial wherewithal of potential future plant owners. For these reasons, ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations, and no liability has been recorded at December 31, 2012. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the anticipated landfill cover remediation for the site is approximately $42 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the SFS that could take up to one year to complete, and it is unknown when the U.S. EPA will propose a remedy for public comment. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRP's to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2013 so that settlement discussions could proceed. Based on Exelon's preliminary review, it appears probable that Exelon has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the "Exelon defendants"). The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the defendants' negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which was subsequently granted. On October 23, 2012, a third lawsuit was filed in the same court on behalf of three additional plaintiffs against Cotter and seven other defendants, but not Exelon. The allegations in that complaint mirror the two previously-filed lawsuits. It is reasonably possible that Exelon would be

considered liable due to its indemnification responsibilities of Cotter described above. Due to the early stage of the litigation, Exelon cannot estimate a range of loss, if any.

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The potentially responsible parties submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. The U.S. EPA is expected to make a final selection of one of the alternatives in 2013. Based on Exelon's preliminary review, it appears probable that Exelon has liability and has established an appropriate accrual for its share of the estimated clean-up costs. BGE is indemnified by a wholly owned subsidiary of Generation for most of the costs related to this settlement and clean-up of the site.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, MD. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. The letter provided 60 days for the PRPs to decide whether or not to participate in the investigation. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On July 30, 2012, BGE along with the three other named PRP's provided the U.S. EPA with a "Good Faith Offer" along with a proposed Settlement Agreement to conduct a Remedial Investigation and a Feasibility Study at the Site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The PRPs will seek to reach agreement with the U.S. EPA to conduct the investigation. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA's position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations (the Tailoring Rule) relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a CO_2 equivalent basis, and to modifications to existing sources that result in emissions increases greater than 75,000 tons per year on a CO_2 equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. On July 2, 2012, the

U.S. EPA declined to lower GHG permit thresholds in its final "Step 3" Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per curium* decision, dismissed industry and state petitions challenging the U.S. EPA's Tailoring Rule based on petitioners' lack of standing. Further, in the same decision, the court denied all challenges to the U.S. EPA's endangerment finding, and the Agency's "Tailpipe Rule" for cars and light trucks. In August 2012, several industry parties filed petitions for an en banc rehearing of the Agency's GHG regulations with the D.C. Circuit court. On September 6, 2012, the Circuit Court ordered the U.S. EPA, intervening groups, and some states to reply to the industry petitions.

On April 13, 2012, the U.S. EPA published proposed regulations for NSPS for GHG emissions from new fossil fuel power plants, greater than 25 MW, that would require the plants to limit CO_2 emissions to a thirty year average of less than 1,000 pounds per MWh (less than 1,800 pounds per MWh for the first ten years and less than 600 pounds per MWh thereafter). Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case by case basis. Generation could be significantly affected by the regulations if it were to build new plants or modify existing plants. The U.S. EPA is also expected to establish in 2013 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon, Generation and BGE).

Exelon and Generation . Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2012 and 2011, Generation had reserved approximately $63 million and $49 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2012, approximately $14 million of this amount related to 170 open claims presented to Generation, while the remaining $49 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050 based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary. During the second quarter of 2012, Generation increased its reserve by approximately $19 million, primarily due to increased actual and projected number and severity of claims. During 2011 and 2010, the updates to this reserve did not result in material adjustments.

BGE . Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

Approximately 480 individuals who were never employees of BGE or Generation have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and Generation in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or Generation and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.

Discovery begins in these cases once they are placed on the trial docket. At present, none of the pending cases are set for trial. Given the limited discovery, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

- the identity of the facilities at which the plaintiffs allegedly worked as contractors;
- the names of the plaintiffs' employers;
- the dates on which and the places where the exposure allegedly occurred; and
- the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

Federal Energy Regulatory Commission Investigation (Exelon and Generation).

On January 30, 2012, FERC published a notice on its website regarding a non-public investigation of certain of Constellation's power trading activities in and around the ISO-NY from September 2007 through December 2008. Prior to the merger, Constellation announced on March 9, 2012, that it had resolved the FERC investigation. Under the settlement, Constellation agreed to pay a $135 million civil penalty and $110 million in disgorgement. The disgorgement amount will be disbursed in two ways. First, Constellation will provide $1 million each to six U.S. regional grid operators for the purpose of improving their surveillance and analytic capabilities. The remainder of the disgorgement amount was deposited in a fund that will be administered by a FERC ALJ. State agencies in New York, New England and PJM (the regional grid operator for 13 states and the District of Columbia) will be eligible to make claims against the fund on behalf of electric energy consumers in those states.

During the year ended December 31, 2012, Generation recorded expense of $195 million in operating and maintenance expense with the remaining $50 million recorded as a Constellation pre-acquisition contingency. As of December 31, 2012, the full amount of the civil penalty and disgorgement was paid. See Note 4—Merger and Acquisitions for additional information on the merger.

Continuous Power Interruption (ComEd)

The Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd's service territory, as well as for five other storm systems that affected ComEd's customers during June and July 2011 (Summer 2011 Storm Docket). The ICC is currently conducting a proceeding to assess

ComEd's request. In the absence of a favorable determination from the ICC, some ComEd customers affected by the outages could seek recovery of their actual, non-consequential damages, and the local governments in the areas in which those customers are located could seek recovery of emergency and contingency expenses.

On January 25, 2013 the ALJ issued a Proposed Order in the Summer 2011 Storm Docket. The ALJ found that a complete waiver of liability should apply for five of the six storms at issue, and found that for the July 2011 storm, 34,599 interruptions were preventable and therefore no waiver should apply. The ALJ also found that ComEd's system is designed, constructed and maintained in accordance with good utility practice, thereby rejecting a request by the Illinois Attorney General for the ICC to open an investigation.

In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket). On January 10, 2013, the ALJ issued a Proposed Order in the February 2011 Blizzard Docket, finding that a complete waiver of liability should apply for the storm. As with the Summer 2011 Storm Docket, the ALJ found that ComEd's system is designed, constructed and maintained in accordance with good utility practice.

The ultimate outcomes of these proceedings are uncertain, and the amount of damages, if any, which might be asserted, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows.

Securities Class Action (Exelon)

Three federal securities class action lawsuits were filed in the United States District Courts for the Southern District of New York and the District of Maryland between September 2008 and November 2008 against Constellation. The cases were filed on behalf of a proposed class of persons who acquired publicly traded securities, including the Series A Junior Subordinated Debentures (Debentures), of Constellation between January 30, 2008 and September 16, 2008, and who acquired Debentures in an offering completed in June 2008. The securities class actions generally allege that Constellation, a number of its former officers or directors, and the underwriters violated the securities laws by issuing a false and misleading registration statement and prospectus in connection with Constellation's June 27, 2008 offering of the Debentures. The securities class actions also allege that Constellation issued false or misleading statements or was aware of material undisclosed information which contradicted public statements, including in connection with its announcements of financial results for 2007, the fourth quarter of 2007, the first quarter of 2008 and the second quarter of 2008 and the filing of its first quarter 2008 Form 10-Q. The securities class actions seek, among other things, certification of the cases as class actions, compensatory damages, reasonable costs and expenses, including counsel fees, and rescission damages.

The Southern District of New York granted the defendants' motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On June 18, 2009, the court appointed a lead plaintiff, who filed a consolidated amended complaint on September 17, 2009. On November 17, 2009, the defendants moved to dismiss the consolidated amended complaint in its entirety. On August 13, 2010, the District Court of Maryland issued a ruling on the motion to dismiss, holding that the plaintiffs failed to state a claim with respect to the claims of the common shareholders under the Securities Exchange Act of 1934 and limiting the suit to those persons who purchased Debentures in

the June 2008 offering. In August 2011, plaintiffs requested permission from the court to file a third amended complaint in an effort to attempt to revive the claims of the common shareholders. Constellation filed an objection to the plaintiffs' request for permission to file a third amended complaint and, on March 28, 2012, the District Court of Maryland denied the plaintiffs' request for permission to revive the claims of the common shareholders. Given that limited discovery has occurred, that the court has not certified any class and the plaintiffs have not quantified their potential damage claims, Exelon is unable at this time to provide an estimate of the range of reasonably possible loss relating to these proceedings or to determine the ultimate outcome of the securities class actions or their possible effect on its financial results.

Fund Transfer Restrictions (Exelon, ComEd, PECO and BGE)

Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as: (1) the source of the dividends is clearly disclosed; (2) the dividend is not excessive; and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. At December 31, 2012, such capital was $3.0 billion and amounted to about 34 times the liquidating value of the outstanding preferred securities of $87 million. Additionally, PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

BGE pays dividends on its common stock after its Board of Directors declares them. However, BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

General (Exelon, Generation, ComEd, PECO and BGE).

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Income Taxes

See Note 12—Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

20. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010.

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$ 463	$ 82	$ 239	$141	$ 75
Property	227	189	22	13	111
Payroll	131	78	26	12	18
Other	198	20	8	(4)	4
Total taxes other than income	$1,019	$ 369	$ 295	$162	$208

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [a]	$ 443	$ 27	$ 243	$173	$ 79
Property	177	146	22	9	107
Payroll	123	71	25	13	17
Other	42	20	6	10	4
Total taxes other than income	$ 785	$ 264	$ 296	$205	$207

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [a]	$ 476	$ —	$ 205	$271	$ 79
Property	175	142	20	13	102
Payroll	121	70	24	12	16
Other	36	18	7	7	3
Total taxes other than income	$ 808	$ 230	$ 256	$303	$200

(a) Generation's utility tax represents gross receipts tax related to its retail operations and ComEd's, PECO's and BGE's utility taxes represent municipal and state utility taxes and gross receipts taxes related to their operating revenues, respectively. The offsetting collection of utility taxes from customers is recorded in revenues on the Registrants' Consolidated Statements of Operations.

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a] —					
Regulatory Agreement Units	$ 189	$ 189	$ —	$—	$—
Non-Regulatory Agreement Units	102	102	—	—	—
Net unrealized gains on decommissioning trust funds—					
Regulatory Agreement Units	386	386	—	—	—
Non-Regulatory Agreement Units	105	105	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	73	73	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(530)	(530)	—	—	—
Total decommissioning-related activities	325	325	—	—	—
Investment income	20	3	1	2	11[c]
Long-term lease income	29	—	—	—	—
Interest income related to uncertain income tax positions	15	2	20	—	—
AFUDC-Equity	17	—	6	4	10
Credit facility termination fees	(85)	(85)	—	—	—
Other	25	(6)	12	2	2
Other, net	$ 346	$ 239	$ 39	$ 8	$ 23

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a] —					
Regulatory Agreement Units	$ 177	$ 177	$ —	$—	$—
Non-Regulatory Agreement Units	45	45	—	—	—
Net unrealized losses on decommissioning trust funds—					
Regulatory Agreement Units	(74)	(74)	—	—	—
Non-Regulatory Agreement Units	(4)	(4)	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	48	48	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(130)	(130)	—	—	—
Total decommissioning-related activities	62	62	—	—	—
Investment income	10	1	1	3	13[c]
Long-term lease income	28	—	—	—	—
Interest income related to uncertain income tax positions	53	31	14	1	—
AFUDC-Equity	17	—	8	9	15
Bargain purchase gain related to Wolf Hollow acquisition	36	36	—	—	—
Other	(3)	(8)	6	1	(2)
Other, net	$ 203	$ 122	$ 29	$ 14	$ 26

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a] —					
Regulatory Agreement Units	$ 176	$ 176	$ —	$—	$—
Non-Regulatory Agreement Units	51	51	—	—	—
Net unrealized gains on decommissioning trust funds—					
Regulatory Agreement Units	316	316	—	—	—
Non-Regulatory Agreement Units	104	104	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(394)	(394)	—	—	—
Total decommissioning-related activities	253	253	—	—	—
Investment income	1	—	—	1	15[c]
Long-term lease income	27	—	—	—	—
Interest income related to uncertain income tax positions	—	—	6	—	—
AFUDC-Equity	11	—	4	7	10
Realized gain on Rabbi trust investments	1	—	1	—	—
Other	19	4	13	—	—
Other, net	$ 312	$ 257	$ 24	$ 8	$ 25

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 13—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE's rate stabilization deferral. See Note 3 – Regulatory Matters for additional information regarding the rate stabilization deferral.

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010.

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization and accretion					
Property, plant and equipment	$1,712	$ 733	$ 525	$207	$245
Regulatory assets	129	—	80	10	53
Amortization of intangible assets, net	40	35	5	—	—
Amortization of energy contract assets and liabilities [a]	1,110	1,110	—	—	—
Nuclear fuel [a]	848	848	—	—	—
ARO accretion [b]	240	240	—	—	—
Total depreciation, amortization and accretion	$4,079	$ 2,966	$ 610	$217	$298

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization and accretion					
Property, plant and equipment	$1,284	$ 570	$ 502	$191	$224
Regulatory assets	63	—	52	11	50
Nuclear fuel [a]	755	755	—	—	—
ARO accretion [b]	214	214	—	—	—
Total depreciation, amortization and accretion	$2,316	$ 1,539	$ 554	$202	$274

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization and accretion					
Property, plant and equipment	$1,144	$ 474	$ 473	$ 171	$214
Regulatory assets	931	—	43	889[c]	35
Nuclear fuel [a]	672	672	—	—	—
ARO accretion [b]	196	195	1	—	—
Total depreciation, amortization and accretion	$2,943	$ 1,341	$ 517	$1,060	$249

(a) Included in revenues or fuel expense on the Registrants' Consolidated Statements of Operations.
(b) Included in operating and maintenance expense on the Registrants' Consolidated Statements of Operations.
(c) For PECO, primarily reflects CTC amortization.

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 761	$ 286	$ 288	$113	$ 136
Income taxes (net of refunds)	(171)	175	(42)	(64)	(112)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 820	$ 341	$ 282	$ 50	$ 57
Loss in equity method investments	91	91	—	—	—
Provision for uncollectible accounts	164	22	42	60	44
Provision for obsolete inventory	6	6	1	—	—
Stock-based compensation costs	94	—	—	—	—
Other decommissioning-related activity [a]	(145)	(145)	—	—	—
Energy-related options [b]	160	160	—	—	—
Amortization of regulatory asset related to debt costs	18	—	13	3	2
Amortization of rate stabilization deferral	57	—	—	—	67
Amortization of debt fair value adjustment	(34)	(34)	—	—	—
Merger-related commitments [d]	141	32	—	—	27
Severance cost	99	34	—	—	—
Discrete impacts from Energy Infrastructure Modernization Act (EIMA) [c]	(96)	—	(96)	—	—
Amortization of debt costs	19	11	5	3	2
Other	(11)	19	5	9	(6)
Total other non-cash operating activities	$1,383	$ 537	$ 252	$125	$ 193
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 71	$ —	$ 28	$ 20	$ 26
Other regulatory assets and liabilities	(404)	—	(68)	18	(112)
Other current assets	213	(30)	(7)	(12)	(7)
Other noncurrent assets and liabilities	(248)	(98)	(95)	(10)	8
Total changes in other assets and liabilities	$ (368)	$ (128)	$(142)	$ 16	$ (85)

	Exelon	Generation	ComEd	PECO	BGE
Non-cash investing and financing activities:					
Change in ARC	$ 781	$ 781	$ 2	$—	$—
Change in capital expenditures not paid	160	103[e]	15	26	(4)
Merger with Constellation, common stock issued	7,365	5,264	—	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 13—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.
(c) Includes the regulatory asset, pursuant to EIMA, which represents the ICC's approved distribution formula and associated rulings as of December 31, 2012 and ComEd's best estimate of the probable increase in distribution rates to provide recovery of prudent and reasonable costs incurred for the 12 months ended December 31, 2012.
(d) See Note 4—Mergers and Acquisitions for more information on merger-related commitments.
(e) Includes $247 million of capital expenditures not paid as of December 31, 2012 related to Antelope Valley.

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 649	$ 158	$ 296	$128	$ 122
Income taxes (net of refunds)	(457)	347	(676)	(65)	(54)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 542	$ 249	$ 213	$ 32	$ 51
Provision for uncollectible accounts	121	—	57	64	44
Stock-based compensation costs	67	—	—	—	—
Other decommissioning-related activity [a]	16	16	—	—	—
Energy-related options [b]	137	137	—	—	—
Amortization of regulatory asset related to debt costs	21	—	18	3	2
Amortization of rate stabilization deferral	—	—	—	—	57
Deferral of storm costs	—	—	—	—	(16)
Uncollectible accounts recovery, net	14	—	14	—	—
Discrete impacts from 2010 Rate Case order [c]	(32)	—	(32)	—	—
Bargain purchase gain related to Wolf Hollow Acquisition	(36)	(36)	—	—	—
Discrete impacts from Energy Infrastructure Modernization Act (EIMA) [d]	(82)	—	(82)	—	—
Other	2	55	(4)	1	(9)
Total other non-cash operating activities	$ 770	$ 421	$ 184	$100	$ 129
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (45)	$ —	$ (49)	$ 4	$ (52)
Other regulatory assets and liabilities	—	—	44	26	10
Other current assets	(101)	(23)	(14)	(12)	(88)
Other noncurrent assets and liabilities	122	(34)	64	(4)	(31)
Total changes in other assets and liabilities	$ (24)	$ (57)	$ 45	$ 14	$(161)

	Exelon	Generation	ComEd	PECO	BGE
Non-cash investing and financing activities:					
Change in ARC	$ 186	$ 186	$ —	$—	$—
Change in capital expenditures not paid	96	125[e]	7	(35)	(7)

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 13—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(b) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.

(c) In May 2011, as a result of the 2010 Rate Case order, ComEd recorded one-time benefits to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan. See Note 3—Regulatory Matters for more information.

(d) Includes the establishment of a regulatory asset, pursuant to EIMA, for the 2011 annual reconciliation in ComEd's distribution formula rate tariff and the deferral of costs associated with significant 2011 storms, partially offset by an accrual to fund a new Science and Technology Innovation Trust. See Note 3—Regulatory Matters for more information.

(e) Includes $120 million of capital expenditures not paid as of December 31, 2011 related to Antelope Valley.

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 665[a]	$ 145	$ 283	$168	$128
Income taxes (net of refunds)	1,219	732	15	433	(76)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 581	$ 268	$ 215	$ 46	$ 48
Provision for uncollectible accounts	108	1	48	59	38
Provision for obsolete inventory	12	12	—	—	—
Stock-based compensation costs	44	—	—	—	—
Other decommissioning-related activity [b]	(91)	(91)	—	—	—
Energy-related options [c]	(73)	(73)	—	—	—
ARO adjustment	(19)	(8)	(10)	(1)	—
Amortization of regulatory asset related to debt costs	24	—	20	4	2
Amortization of rate stabilization deferral	—	—	—	—	62
Accrual for Illinois utility distribution tax refund [d]	(25)	—	(25)	—	—
Under-recovered uncollectible accounts, net [e]	(14)	—	(14)	—	—
ARP SO2 allowances impairment	57	57	—	—	—
Other	5	16	4	—	(6)
Total other non-cash operating activities	$ 609	$ 182	$ 238	$108	$144
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 61	$ —	$ 58	$ 3	$ 6
Other regulatory assets and liabilities	—	—	(19)	35	(64)
Other current assets	(18)	(16)	12	(19)	(7)
Other noncurrent assets and liabilities	(99)	(29)	(184) [f]	59	2
Total changes in other assets and liabilities	$ (56)	$ (45)	$(133)	$ 78	$ (63)

	Exelon	Generation	ComEd	PECO	BGE
Non-cash investing and financing activities:					
Change in ARC	$ (428)	$ (428)	$ —	$—	$—
Change in capital expenditures not paid	34	13	7	14	28
Purchase accounting adjustments	9	9	—	—	—
Exelon Wind acquisition [g]	32	32	—	—	—

(a) Excludes $167 million of interest paid to the IRS relating to a preliminary agreement reached during the third quarter of 2010. See Note 12—Income Taxes for addition information.

(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 13—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(c) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.

(d) During the second quarter of 2010, ComEd recorded a reduction of $25 million to taxes other than income to reflect management's estimate of future refunds for the 2008 and 2009 tax years associated with Illinois' utility distribution tax based on an analysis of past refunds and interpretations of the Illinois Public Utility Act. Historically, ComEd has recorded refunds of the Illinois utility distribution tax when received. ComEd believes it now has sufficient, reliable evidence to record and support an estimated receivable associated with the anticipated refund for the 2008 and 2009 tax years.

(e) Includes $70 million of under-recovered uncollectible accounts expense from 2008 and 2009 recorded in the first quarter of 2010 as well as $59 million of amortization of the associated regulatory asset. This amount also includes a credit of $3 million of under collections associated with 2010 activity. ComEd is recovering these costs through a rider mechanism authorized by the ICC. See Note 3—Regulatory Matters for additional information regarding the Illinois legislation for recovery of uncollectible accounts.

(f) Relates primarily to a decrease in interest payable associated with a change in uncertain income tax positions. See Note 12—Income Taxes for additional information.
(g) Represents contingent liability recorded in connection with the December 9, 2010 acquisition of Exelon Wind. See Note 4—Acquisition for additional information.

DOE Smart Grid Investment Grant (Exelon, PECO and BGE). For the year ended December 31, 2012, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $103 million, $56 million and $47 million, respectively, and reimbursements of $113 million, $66 million and $47 million, respectively, related to PECO's and BGE's DOE SGIG programs. For the year ended December 31, 2011, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $51 million, $51 million and $23 million, respectively, and reimbursements of $56 million, $56 million and $41 million, respectively, related to PECO's and BGE's DOE SGIG programs. See Note 3 - Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants at December 31, 2012 and 2011.

December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Investments					
Equity method investments:					
Financing trusts [(a)]	$ 22	$ —	$ 6	$ 8	$ 8
Keystone Fuels, LLC	38	38	—	—	—
Conemaugh Fuels, LLC	26	26	—	—	—
CENG	1,849	1,849	—	—	—
Safe Harbor	293	293	—	—	—
Malacha	8	8	—	—	—
Other investments	34	33	—	—	—
Total equity method investments	2,270	2,247	6	8	8
Other investments:					
Net investment in direct financing leases	685	—	—	—	—
Employee benefit trusts and investments [(b)]	100	22	8	22	5
Total investments	$3,055	$ 2,269	$ 14	$ 30	$ 13

December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Investments					
Equity method investments:					
Financing trusts [a]	$ 15	$ —	$ 6	$ 8	$ 8
Keystone Fuels, LLC	13	13	—	—	—
Conemaugh Fuels, LLC	16	16	—	—	—
Sacramento Solar	1	1	—	—	—
Total equity method investments	45	30	6	8	8
Other investments:					
Net investment in direct financing leases	656	—	—	—	—
Employee benefit trusts and investments [b]	65	11	21	22	—
Total investments	$ 766	$ 41	$ 27	$ 30	$ 8

(a) Includes investments in financing trusts, which were not consolidated within the financial statements of Exelon and are shown as investments in affiliates on the Consolidated Balance Sheets. See Note 1—Significant Accounting Policies for additional information.
(b) The Registrants' investments in these marketable securities are recorded at fair market value.

December 2010 IRS Payment (Exelon) . In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. In order to stop additional interest from accruing on the expected assessment resulting from the agreement, Exelon paid $302 million to the IRS on December 28, 2010. As of December 31, 2010, Exelon had not funded the specific bank account from which the IRS payment was disbursed resulting in a current liability. This amount was subsequently funded in January 2011. Under the authoritative guidance for offsetting balances, Exelon included this payment in Cash and cash equivalents with an offsetting amount in Other current liabilities on its Consolidated Balance Sheets. See Note 12—Income Taxes for additional information.

Like-Kind Exchange Transaction (Exelon). Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in passive generating station leases with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange a service contract with a third party for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases. At December 31, 2012 and 2011, the components of the net investment in long-term leases were as follows:

	December 31, 2012	December 31, 2011
Estimated residual value of leased assets	$1,492	$1,492
Less: unearned income	807	836
Net investment in long-term leases	$ 685	$ 656

The following tables provide additional information about liabilities of the Registrants at December 31, 2012 and 2011.

December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Accrued expenses					
Compensation-related accruals [a]	$ 708	$ 371	$ 125	$ 45	$ 38
Taxes accrued	353	247	61	3	22
Interest accrued	236	60	96	32	41
Severance accrued	91	42	4	1	5
Other accrued expenses	412[b]	396[b]	9	1	—
Total accrued expenses	$1,800	$ 1,116	$ 295	$ 82	$106

December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Accrued expenses					
Compensation-related accruals [a]	$ 520	$ 264	$ 127	$ 48	$ 42
Taxes accrued	297	241	59	5	26
Interest accrued	192	56	124	27	41
Severance accrued	15	9	2	1	—
Other accrued expenses	231[b]	209[b]	6	2	1
Total accrued expenses	$1,255	$ 779	$ 318	$ 83	$110

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.
(b) Includes $327 million and $184 million for amounts accrued related to Antelope Valley as of December 31, 2012 and December 31, 2011, respectively.

Accumulated Other Comprehensive Income (Loss)

The following tables provide information about accumulated OCI income (loss) recorded (after tax) within Exelon's Consolidated Balance Sheets at December 31, 2012 and 2011:

December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Accumulated other comprehensive income (loss)					
Net unrealized gain on cash flow hedges	$ 367	$ 513	$ —	$—	$—
Pension and non-pension postretirement benefit plans	(3,155)	(19)	—	—	—
Unrealized loss on marketable securities	21	19	—	1	—
Total accumulated other comprehensive income (loss)	$(2,767)	$ 513	$ —	$ 1	$—

December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Accumulated other comprehensive income (loss)					
Net unrealized gain on cash flow hedges	$ 488	$ 915	$ —	$—	$—
Pension and non-pension postretirement benefit plans	(2,938)	—	—	—	—
Unrealized loss on marketable securities	—	—	(1)	—	—
Total accumulated other comprehensive income (loss)	$(2,450)	$ 915	$ (1)	$—	$—

21. Segment Information (Exelon, Generation, ComEd, PECO and BGE)

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation's six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other regions not considered individually significant referred to collectively as "Other Regions"; including the South, West and Canada. Generation's expanded number of reportable segments is the result of the acquisition of Constellation on March 12, 2012. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon evaluates the performance of ComEd, PECO and BGE based on net income.

The foundation of Generation's six reportable segments is based on the geographic location of its assets, and is largely representative of the footprints of an ISO / RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the entire United States footprint of MISO, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.

- Other Regions not considered individually significant:
  - South represents operations in the FRCC and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

Exelon and Generation evaluate the performance of Generation's power marketing activities based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for our own generation and fuel costs associated with tolling agreements. Generation's other business activities, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency and demand response, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, are not allocated to regions. Further, Generation's compensation under the reliability-must-run rate schedule, results of operations from the Brandon Shores, Wagner, and C.P. Crane Maryland generating stations, and other miscellaneous revenues, mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger are also not allocated to a region.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the years ended December 31, 2012, 2011 and 2010 is as follows:

	Generation [a]	ComEd	PECO	BGE [b]	Other [c]	Intersegment Eliminations	Exelon
Operating revenues [d]:							
2012	$ 14,437	$ 5,443	$3,186	$2,091	$ 1,396	$ (3,064)	$23,489
2011	10,447	6,056	3,720	—	830	(1,990)	19,063
2010	10,025	6,204	5,519	—	755	(3,859)	18,644
Intersegment revenues [e]:							
2012	$ 1,702	$ 2	$ 3	$ 9	$ 1,381	$ (3,042)	$ 55
2011	1,161	2	5	—	831	(1,990)	9
2010	3,102	2	5	—	756	(3,859)	6
Depreciation and amortization							
2012	$ 768	$ 610	$ 217	$ 238	$ 46	$ 2	$ 1,881
2011	570	554	202	—	21	—	1,347
2010	474	516	1,060	—	25	—	2,075
Operating expenses [d]:							
2012	$ 13,226	$ 4,557	$2,563	$2,053	$ 1,662	$ (3,043)	$21,018
2011	7,571	5,074	3,065	—	863	(1,990)	14,583
2010	6,979	5,148	4,858	—	792	(3,859)	13,918
Equity in earnings (losses) of unconsolidated affiliates							
2012	$ (91)	$ —	$ —	$ —	$ —	$ —	$ (91)
2011	(1)	—	—	—	—	—	(1)
2010	—	—	—	—	—	—	—
Interest expense, net:							
2012	$ 301	$ 307	$ 123	$ 111	$ 86	$ —	$ 928
2011	170	345	134	—	77	—	726
2010	153	386	193	—	85	—	817
Income (loss) before income taxes:							
2012	$ 1,058	$ 618	$ 508	$ (54)	$ (276)	$ (56)	$ 1,798
2011	2,827	666	535	—	(59)	(13)	3,956
2010	3,150	694	476	—	(91)	(8)	4,221
Income taxes:							
2012	$ 500	$ 239	$ 127	$ (23)	$ (215)	$ (1)	$ 627
2011	1,056	250	146	—	9	(4)	1,457
2010	1,178	357	152	—	(27)	(2)	1,658
Net income (loss):							
2012	$ 558	$ 379	$ 381	$ (31)	$ (61)	$ (55)	$ 1,171
2011	1,771	416	389	—	(68)	(9)	2,499
2010	1,972	337	324	—	(64)	(6)	2,563
Capital expenditures:							
2012	$ 3,554	$ 1,246	$ 422	$ 500	$ 67	$ —	$ 5,789
2011	2,491	1,028	481	—	42	—	4,042
2010	1,883	962	545	—	14	(78) [f]	3,326
Total assets:							
2012	$ 40,681	$22,905	$9,353	$7,499	$10,432	$ (12,316)	$78,554
2011	27,433	22,638	9,156	—	6,147	(10,379)	54,995

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the year ended December 31, 2012 include revenue from sales to PECO of $543 million and sales to BGE of $322 million in the Mid-Atlantic region, and sales to ComEd of $795 million in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the years ended December 31, 2011 and 2010 intersegment revenues for Generation include revenue from sales to PECO of $508 million and $2,092 million, respectively, in the Mid-Atlantic region, and sales to ComEd of $653 million and $1,010 million, respectively, in the Midwest region.
(b) Amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through December 31, 2012.
(c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(d) For the years ended December 31, 2012, 2011 and 2010, utility taxes of $82 million, $27 million and $0 million, respectively, are included in revenues and expenses for Generation. For the years ended December 31, 2012, 2011 and 2010, utility taxes of $239 million, $243 million and $205 million, respectively, are included in revenues and expenses for ComEd. For the years ended December 31, 2012, 2011 and 2010, utility taxes of $141 million, $173 million and $271 million, respectively, are included in revenues and expenses for PECO. For the period of March 12, 2012 through December 31, 2012, utility taxes of $59 million are included in revenues and expenses for BGE.
(e) The intersegment profit associated with Generation's sale of AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 3 for additional information on AECs. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.
(f) Represents capital projects transferred from BSC to Generation, ComEd and PECO. These projects are shown as capital expenditures at Generation, ComEd and PECO and the capital expenditure is eliminated upon consolidation.

Generation total revenues:

	2012			2011			2010		
	Revenues from external customers [a]	Intersegment revenues	Total Revenues	Revenues from external customers [a]	Intersegment revenues	Total Revenues	Revenues from external customers [a]	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 5,082	$ (44)	$ 5,038	$ 4,052	$ —	$ 4,052	$ 3,232	$ —	$ 3,232
Midwest	4,824	24	4,848	5,445	—	5,445	5,762	—	5,762
New England	1,048	45	1,093	11	—	11	14	—	14
New York	582	(25)	557	—	—	—	—	—	—
ERCOT	1,365	2	1,367	575	—	575	543	—	543
Other Regions [b]	755	78	833	201	—	201	149	—	149
Total Revenues for Reportable Segments	$ 13,656	$ 80	$13,736	$ 10,284	$ —	$10,284	$ 9,700	$ —	$ 9,700
Other [c]	781	(80)	701	163	—	163	325	—	325
Total Generation Consolidated Operating Revenues	$ 14,437	$ —	$14,437	$ 10,447	$ —	$10,447	$ 10,025	$ —	$10,025

(a) Includes all electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date.

Generation total revenues net of purchased power and fuel expense:

	2012			2011			2010		
	RNF from external customers [a]	Intersegment RNF	Total RNF	RNF from external customers [a]	Intersegment RNF	Total RNF	RNF from external customers [a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 3,477	$ (44)	$3,433	$ 3,350	$ —	$3,350	$ 2,501	$ —	$2,501
Midwest	2,974	24	2,998	3,547	—	3,547	4,081	—	4,081
New England	151	45	196	9	—	9	11	—	11
New York	101	(25)	76	—	—	—	—	—	—
ERCOT	403	2	405	84	—	84	(66)	—	(66)
Other Regions [b]	53	78	131	(14)	—	(14)	(65)	—	(65)
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 7,159	$ 80	$7,239	$ 6,976	$ —	$6,976	$ 6,462	$ —	$6,462
Other [c]	217	(80)	137	(118)	—	(118)	100	—	100
Total Generation Revenues net of purchased power and fuel expense	$ 7,376	$ —	$7,376	$ 6,858	$ —	$6,858	$ 6,562	$ —	$6,562

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions includes the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date.

22. Related Party Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The financial statements of Exelon include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2012	2011	2010
Operating revenues from affiliates:			
PECO [a]	$ 6	$ 9	$ 6
CENG [b]	42	—	—
Total operating revenues from affiliates	$ 48	$ 9	$ 6
Fuel and purchased power from related parties:			
CENG [c]	$ 793	$ —	$ —
Keystone Fuels, LLC	61	68	74
Conemaugh Fuels, LLC	68	69	70
Total fuel purchases from related parties	$ 922	$ 137	$ 144
Charitable contribution to Exelon Foundation [d]	$ 7	$ —	$ 10
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
Total interest expense to affiliates, net	$ 25	$ 25	$ 25
(Loss) gain in equity method investments:			
CENG equity investment income	$ 73	$ —	—
Amortization of basis difference in CENG [e]	(172)	—	—
Other	8	(1)	—
Total loss in equity method investments	$ (91)	$ (1)	$ —

	December 31,	
	2012	2011
Investments in affiliates:		
ComEd Financing III	$ 6	$ 6
PECO Energy Capital Corporation	4	4
PECO Trust IV	4	5
BGE Capital Trust II	8	—
Total investments in affiliates	$ 22	$ 15
Receivables from affiliates (current):		
CENG [b]	$ 16	$ —
Payables to affiliates (current):		
CENG [c]	$ 83	$ —
ComEd Financing III	4	4
PECO Trust III	1	1
Total payables to affiliates (current)	$ 88	$ 5
Long-term debt to BondCo and other financing trusts (including due within one year):		
ComEd Financing III	$ 206	$ 206
PECO Trust III	81	81
PECO Trust IV	103	103
BGE Capital Trust II	258	—
Total long-term debt due to financing trusts	$ 648	$ 390

(a) The intersegment profit associated with Generation's sale of AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 3—Regulatory Matters for additional information.

(b) Exelon has a shared services agreement (SSA) with CENG, which expires in 2017. Under the SSA, BSC provides a variety of support services to CENG. Pursuant to an agreement between Exelon and EDF, the pricing in the SSA for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services.

(c) A subsidiary of Generation has an agreement under which it is purchasing 85-90% of the output of CENG's nuclear plants that is not sold to third parties under pre-existing firm and unit contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit contingent basis 50.01% of the output of CENG's nuclear plants, and EDF will purchase on a unit contingent basis 49.99% of the output.

(d) Exelon Foundation is a nonconsolidated not-for-profit Illinois corporation. The Exelon Foundation was established in 2007 to serve educational and environmental philanthropic purposes and does not serve a direct business or political purpose of Exelon.

(e) As of March 12, 2012, Generation had an initial basis difference of approximately $204 million between the initial carrying value of its investment in CENG and its underlying equity in CENG. This basis difference resulted from the requirement to record the investment in CENG at fair value under purchase accounting while the underlying assets and liabilities within CENG continue to be accounted for on a historical cost basis. Generation is amortizing this basis difference over the respective useful lives of the assets and liabilities of CENG or as those assets and liabilities impact the earnings of CENG. In future periods, Generation may be eligible for distributions from CENG in excess of its 50.01% ownership interest based on tax sharing provisions contained in the operating agreement for CENG. Through purchase accounting, Generation recorded the fair value of expected future distributions. Generation will record these distributions when realized as a reduction in its investment in CENG. Distributions realized in excess of the fair value recorded would be recorded in earnings in the period earned.

Transactions involving Generation, ComEd, PECO and BGE are further described in the tables below.

Generation

The financial statements of Generation include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2012	2011	2010
Operating revenues from affiliates:			
ComEd [a]	$ 795	$ 653	$1,010
PECO [b]	543	508	2,092
BGE [c]	322	—	—
CENG [d]	42	—	—
Total operating revenues from affiliates	$1,702	$1,161	$3,102
Fuel and purchased power from related parties:			
PECO	$ —	$ 1	$ 1
BGE	8	—	—
CENG [e]	793	—	—
Keystone Fuels, LLC	61	68	74
Conemaugh Fuels, LLC	68	69	70
Total fuel purchases from related parties	$ 930	$ 138	$ 145
Operating and maintenance from affiliates:			
ComEd [f]	$ 2	$ 2	$ 2
PECO [f]	3	5	4
BSC [g]	625	314	285
Total operating and maintenance from affiliates	$ 630	$ 321	$ 291
(Loss) gain in equity method investments			
CENG equity investment income	73	—	—
Amortization of basis difference in CENG [h]	(172)	—	—
Qualifying facilities and domestic power projects	8	(1)	—
Total loss in equity method investments	(91)	$ (1)	$ —
Cash distribution paid to member	$1,626	$ 172	$1,508
Contribution from member	$ 48	$ 30	$ 62

	December 31, 2012	December 31, 2011
Mark-to-market derivative assets with affiliates (current):		
ComEd [i]	$ 226	$ 503
Receivables from affiliates (current):		
ComEd [a][j]	$ 54	$ 70
PECO [b]	56	39
BGE [c]	31	—
Total receivables from affiliates (current)	$ 141	$ 109
Receivable from affiliate (noncurrent)		
Exelon	$ 1	$ 1
Mark-to-market derivative assets with affiliates (noncurrent):		
ComEd [i]	$ —	$ 191
Payables to affiliates (current):		
CENG [e]	$ 83	$ —
Exelon [k]	33	7
BSC [g]	77	51
Total payables to affiliates (current)	$ 193	$ 58
Payables to affiliates (noncurrent):		
ComEd [l]	$2,037	$1,857
PECO [l]	360	365
Total payables to affiliates (noncurrent)	$2,397	$2,222

(a) Generation has an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. Generation also sells RECs to ComEd. In addition, Generation had revenue from ComEd associated with the settled portion of the financial swap contract established as part of the Illinois Settlement. See Note 3—Regulatory Matters for additional information.

(b) Generation had a PPA with PECO to provide the full energy requirements to PECO through 2010. In addition, Generation has five-year and ten-year agreements with PECO to sell non-solar and solar AECs, respectively. See Note 3—Regulatory Matters for additional information.

(c) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.

(d) Exelon has a shared services agreement (SSA) with CENG, which expires in 2017. Under the SSA, BSC provides a variety of support services to CENG. Pursuant to an agreement between Exelon and EDF, the pricing in the SSA for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services.

(e) A subsidiary of Generation has an agreement under which it is purchasing 85-90% of the output of CENG's nuclear plants that is not sold to third parties under pre-existing firm and unit contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit contingent basis 50.01% of the output of CENG's nuclear plants, and EDF will purchase on a unit contingent basis 49.99% of the output.

(f) Generation requires electricity for its own use at its generating stations. Generation purchases electricity and distribution and transmission services from PECO and only distribution and transmission services from ComEd for the delivery of electricity to its generating stations.

(g) Generation receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

(h) As of March 12, 2012, Generation had an initial basis difference of approximately $204 million between the initial carrying value of its investment in CENG and its underlying equity in CENG. This basis difference resulted from the requirement to record the investment in CENG at fair value under purchase accounting while the underlying assets and liabilities within CENG continue to be accounted for on a historical cost basis. Generation is amortizing this basis difference over the respective useful lives of the assets and liabilities of CENG or as those assets and liabilities impact the earnings of CENG. In future periods, Generation may be eligible for distributions from CENG in excess of its 50.01% ownership interest based on tax sharing provisions contained in the operating agreement for CENG. Through purchase accounting, Generation recorded the fair value of expected future distributions. Generation will record these distributions when realized as a reduction in its investment in CENG. Distributions realized in excess of the fair value recorded would be recorded in earnings in the period earned.
(i) Represents the fair value of Generation's five-year financial swap contract with ComEd.
(j) Generation had a $53 million and $53 million receivable from ComEd at December 31, 2012 and 2011, respectively, associated with the completed portion of the financial swap contract entered into as part of the Illinois Settlement. See Note 3—Regulatory Matters and Note 10—Derivative Financial Instruments for additional information.
(k) In order to facilitate payment processing, Exelon processes certain invoice payments on behalf of Generation.
(l) Generation has long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 13—Asset Retirement Obligations.

ComEd

The financial statements of ComEd include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2012	2011	2010
Operating revenues from affiliates			
Generation	$ 2	$ 2	$ 2
Purchased power from affiliate			
Generation [a]	$789	$653	$1,010
Operating and maintenance from affiliate			
BSC [b]	$163	$158	$ 152
Interest expense to affiliates, net:			
Exelon	$—	$ 2	$ —
ComEd Financing III	13	13	13
Total interest expense to affiliates, net	$ 13	$ 15	$ 13
Capitalized costs			
BSC [b]	$ 92	$ 85	$ 84
Cash dividends paid to parent	$105	$300	$ 310
Contribution from parent	$ 11	$ 11	$ 2

	December 31, 2012	December 31, 2011
Prepaid voluntary employee beneficiary association trust [c]	$ 10	$ 12
Investment in affiliate		
ComEd Financing III	$ 6	$ 6
Receivable from affiliates (noncurrent):		
Generation [d]	$2,037	$1,857
Other	2	3
Total receivable from affiliates (noncurrent)	$2,039	$1,860
Payables to affiliates (current):		
Generation [a][e]	$ 54	$ 70
BSC [b]	35	35
ComEd Financing III	4	4
Other	4	2
Total payables to affiliates (current)	$ 97	$ 111
Mark-to-market derivative liability with affiliate (current)		
Generation [f]	$ 226	$ 503
Mark-to-market derivative liability with affiliate (noncurrent)		
Generation [f]	$ —	$ 191
Long-term debt to ComEd financing trust		
ComEd Financing III	$ 206	$ 206

(a) ComEd procures a portion of its electricity supply requirements from Generation under an ICC-approved RFP contract. ComEd also purchases RECs from Generation. In addition, purchased power expense includes the settled portion of the financial swap contract with Generation established as part of the Illinois Settlement Legislation. See Note 3—Regulatory Matters and Note 10—Derivative Financial Instruments for additional information.

(b) ComEd receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

(c) The voluntary employee benefit association trusts covering active employees are included in corporate operations and are funded by the operating segments. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for ComEd's contributions to the plans, being higher than actual claim expense incurred by the plans over time. The prepayment is included in other current assets.

(d) ComEd has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct for generating facilities previously owned by ComEd. To the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to ComEd for payment to ComEd's customers.

(e) ComEd had a $53 million and $53 million payable to Generation at December 31, 2012 and 2011, respectively, associated with the completed portion of the financial swap contract entered into as part of the Illinois Settlement Legislation. See Note 3—Regulatory Matters and Note 10—Derivative Financial Information for additional information.

(f) To fulfill a requirement of the Illinois Settlement Legislation, ComEd entered into a five-year financial swap with Generation.

PECO

The financial statements of PECO include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2012	2011	2010
Operating revenues from affiliates:			
Generation [a]	$ 3	$ 5	$ 5
Purchased power from affiliate			
Generation [b]	$533	$495	$2,085
Operating and maintenance from affiliates:			
BSC [c]	$107	$ 92	$ 89
Generation	4	4	—
Total operating and maintenance from affiliates	$111	$ 96	$ 89
Interest expense to affiliates, net:			
PECO Trust III	$ 6	$ 6	$ 6
PECO Trust IV	6	6	6
Total interest expense to affiliates, net	$ 12	$ 12	$ 12
Capitalized costs			
BSC [c]	$ 54	$ 60	$ 40
Cash dividends paid to parent	$343	$348	$ 224
Repayment of receivable from parent	$—	$—	$ 180
Contribution from parent	$ 9	$ 18	$ 43

	December 31,	
	2012	2011
Prepaid voluntary employee beneficiary association trust [d]	$ 2	$ 3
Investments in affiliates:		
PECO Energy Capital Corporation	$ 4	$ 4
PECO Trust IV	4	4
Total investments in affiliates	$ 8	$ 8
Receivable from affiliate (noncurrent):		
Generation [e]	$360	$365
Payables to affiliates (current):		
Generation [b]	$ 56	$ 39
BSC [c]	18	21
Exelon	1	1
PECO Trust III	1	1
Total payables to affiliates (current)	$ 76	$ 62
Long-term debt to financing trusts (including amounts due within one year):		
PECO Trust III	$ 81	$ 81
PECO Trust IV	103	103
Total long-term debt to financing trusts	$184	$184

(a) PECO provides energy to Generation for Generation's own use.

(b) PECO obtained all of its electric supply from Generation through 2010 under a PPA. Beginning January 1, 2011, PECO purchases electric supply from Generation under contracts executed through its competitive procurement process. In addition, PECO has five-year and ten-year agreements with Generation to purchase non-solar and solar AECs, respectively. See Note 3—Regulatory Matters for additional information on AECs.
(c) PECO receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) The voluntary employee beneficiary association trusts covering active employees are included in corporate operations and are funded by the operating segments. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for PECO's contributions to the plans, being higher than actual claim expense incurred by the plans over time.
(e) PECO has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct, whereby, to the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to PECO for payment to PECO's customers.

BGE

The financial statements of BGE include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2012	2011	2010
Operating revenues from affiliates:			
Generation [a]	$ 10	$ 8	$ 7
Purchased power from affiliate			
Generation [b]	$396	$348	$428
Operating and maintenance from affiliates:			
BSC [c]	$106	$150	$126
Capitalized costs			
BSC [c]	$ 21	$ 29	$ 49
Cash dividends paid to parent	$—	$ (85)	$—
Contribution from parent	$ 66	$—	$—

	December 31,	
	2012	2011
Investments in affiliates:		
BGE Capital Trust II	$ 8	$ 8
Payables to affiliates (current):		
Generation [b]	$ 31	$ 41
BSC [c]	12	—
Exelon [d]	17	—
ComEd	3	—
PECO	2	—
Total payables to affiliates (current)	$ 65	$ 41
Long-term debt to BGE financing trust		
BGE Capital Trust II	$258	$258

(a) BGE provides energy to Generation for Generation's own use.
(b) BGE procures a portion of its electricity and gas supply requirements from Generation under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.

(c) BGE receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) BGE receives a variety of corporate support services from Exelon Corporate, including payroll and benefits services.

23. Quarterly Data (Unaudited) (Exelon, Generation, ComEd and PECO)

Exelon

The data shown below, which may not equal the total for the year due to the effects of rounding and dilution, includes all adjustments that Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income on Common Stock	
	2012	2011	2012	2011	2012	2011
Quarter ended:						
March 31	$ 4,686	$ 4,956	$ 359	$ 1,202	$200	$668
June 30	5,954	4,496	714	1,034	286	620
September 30	6,565	5,254	603	1,181	296	601
December 31	6,284	4,357	704	1,062	378	606

	Average Basic Shares Outstanding (in millions)		Net Income per Basic Share	
	2012	2011	2012	2011
Quarter ended:				
March 31	705	662	$ 0.28	$ 1.01
June 30	853	663	0.34	0.93
September 30	854	663	0.35	0.91
December 31	854	664	0.44	0.91

	Average Diluted Shares Outstanding (in millions)		Net Income per Diluted Share	
	2012	2011	2012	2011
Quarter ended:				
March 31	707	664	$ 0.28	$ 1.01
June 30	856	664	0.33	0.93
September 30	857	665	0.35	0.90
December 31	857	666	0.44	0.91

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2012				2011			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$37.50	$39.82	$39.37	$43.70	$45.45	$45.27	$42.89	$43.58
Low price	28.40	34.54	36.27	38.31	39.93	39.51	39.53	39.06
Close	29.74	35.58	37.62	39.21	43.37	42.61	42.84	41.24
Dividends	0.525	0.525	0.525	0.525	0.525[a]	0.525	0.525	0.525

(a) The fourth quarter 2011 dividend does not include the first quarter 2012 regular quarterly dividend of $0.525 per share, declared by the Exelon Board of Directors on October 25, 2011. The first quarter 2012 dividend is payable on March 9, 2012, to shareholders of record of Exelon at the end of the day on February 15, 2012.

Generation

The data shown below includes all adjustments that Generation considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income on Membership Interest	
	2012	2011	2012	2011	2012	2011
Quarter ended:						
March 31	$ 2,739	$ 2,643	$ 272	$ 801	$ 168	$ 495
June 30	3,753	2,455	384	647	166	443
September 30	4,017	2,821	174	754	91	386
December 31	3,928	2,528	290	673	137	447

ComEd

The data shown below includes all adjustments that ComEd considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income	
	2012	2011	2012	2011	2012	2011
Quarter ended:						
March 31	$ 1,388	$ 1,466	$ 226	$ 200	$ 87	$ 69
June 30	1,281	1,444	142	254	42	114
September 30	1,484	1,784	218	243	90	112
December 31	1,290	1,362	300	285	160	121

PECO

The data shown below includes all adjustments that PECO considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income on Common Stock	
	2012	2011	2012	2011	2012	2011
Quarter ended:						
March 31	$ 875	$ 1,153	$ 177	$ 210	$ 96	$ 125
June 30	715	842	151	161	79	82
September 30	806	946	178	153	122	104
December 31	790	778	117	131	79	73

BGE

The data shown below includes all adjustments that BGE considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating (Loss) Income		Net (Loss) Income on Common Stock	
	2012	2011	2012	2011	2012	2011
Quarter ended:						
March 31	$ 696	$ 976	$ (11)	$ 153	$ (33)	$ 78
June 30	616	674	52	54	13	13
September 30	720	745	30	23	(4)	(2)
December 31	703	673	61	84	15	34

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Exelon, Generation, ComEd, PECO and BGE—Disclosure Controls and Procedures

During the fourth quarter of 2012, each registrant's management, including its principal executive officer and principal financial officer, evaluated the effectiveness of that registrant's disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in that registrant's periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by each registrant to ensure that (a) information relating to that registrant, including its consolidated subsidiaries, that is required to be included in filings under the Securities Exchange Act of 1934, is accumulated and made known to that registrant's management, including its principal executive officer and principal financial officer, by other employees of that registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of December 31, 2012, the principal executive officer and principal financial officer of each registrant concluded that such registrant's disclosure controls and procedures were effective to accomplish their objectives.

Exelon, Generation, ComEd, PECO and BGE—Changes in Internal Control Over Financial Reporting

Each registrant continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. However, there have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2012 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's and BGE's internal control over financial reporting.

Exelon, Generation, ComEd, PECO and BGE—Internal Control Over Financial Reporting

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2012. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2012 and, therefore, concluded that each registrant's internal control over financial reporting was effective. Management's Report on Internal Control Over Financial Reporting is included in ITEM 8. Financial Statements and Supplementary Data.

ITEM 9B. OTHER INFORMATION

Exelon, Generation and ComEd

Anne R. Pramaggiore, President and Chief Operating Officer of ComEd, Michael J. Pacilio, President, Exelon Nuclear and Chief Nuclear Officer, Generation, and Sunil Garg, President, Exelon Power and Senior Vice President, Generation, each entered into a Change in Control Employment Agreement effective as of February 10, 2011. The terms of these change in control employment agreements are substantially the same as the change in control employment agreements entered into by other senior executives and previously disclosed, except that the agreements with Ms. Pramaggiore and Messrs. Pacilio and Garg do not include excise tax gross-up provisions, consistent with a policy adopted by the compensation committee in April 2009. The form of Change in Control Employment Agreement is attached hereto as Exhibit 10-44.

PECO and BGE

None.

PART III

Exelon Generation Company, LLC and Baltimore Gas and Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section relating to Generation and BGE are not presented.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants at February 21, 2013.

Directors, Director Nomination Process, and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at the annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)), the audit committee (Item 407(d)(4) and (d)(5)) and the beneficial reporting compliance (Sec. 16(a)) is incorporated herein by reference to information to be contained in Exelon's definitive 2013 proxy statement (2013 Exelon Proxy Statement) and the ComEd and PECO information statements to be filed with the SEC before April 30, 2013 pursuant to Regulation 14A or 14C, as applicable, under the Securities Exchange Act of 1934.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to Exelon's, ComEd's, and PECO's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. The Code of Business Conduct is filed as Exhibit 14 to this report and is available on Exelon's website at *www.exeloncorp.com* . The Code of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Bruce G. Wilson, Senior Vice President, Deputy General Counsel, and Corporate Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

If any substantive amendments to the Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Code of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or Corporate Controller, Exelon will disclose the nature of such amendment or waiver on Exelon's website, *www.exeloncorp.com* , or in a report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under *Executive Compensation Data* and *Report of the Compensation Committee* in the 2013 Exelon Proxy Statement or the ComEd and PECO 2013 information statements and incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The additional information required by this item will be set forth under Ownership of Exelon Stock in the 2013 Exelon Proxy Statement or the ComEd and PECO 2013 information statements and incorporated herein by reference.

Securities Authorized for Issuance under Exelon Equity Compensation Plans

[A] Plan Category	[B] Number of securities to be issued upon exercise of outstanding options (Note 1)	[C] Weighted-average price of outstanding options	[D] Number of securities remaining available for future issuance under equity compensation plans (Note 2)
Equity compensation plans approved by security holders	13,449,422	$ 48.47	24,302,890

(1) Includes stock options, unvested performance shares, unvested restricted shares that were granted under the Exelon LTIP or predecessor company plans and shares awarded under those plans and deferred into the stock deferral plan, as well as deferred stock units granted to directors as part of their compensation plan described in Item 11, Executive Compensation—Non-employee Director Compensation. See Note 17 of the Combined Notes to Consolidated Financial Statements for additional information.

(2) Excludes securities to be issued upon exercise of outstanding options and vesting of shares or deferred stock units shown in column [B].

No ComEd or PECO securities are authorized for issuance under equity compensation plans.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The additional information required by this item will be set forth under *Related Persons Transactions and Director Independence* in the 2013 Exelon Proxy Statement or the ComEd and PECO 2013 information statements and incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under *The Ratification of PricewaterhouseCoopers LLP as Exelon's Independent Accountant for 2013* in the Proxy Statement and incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

Exelon

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 21, 2013 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2012, 2011 and 2010

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011 and 2010

   Consolidated Balance Sheets at December 31, 2012 and 2011

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2012, 2011 and 2010

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule I—Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2012 and 2011 and for the Years Ended December 31, 2012, 2011 and 2010

   Schedule II—Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Operations and Other Comprehensive Income

(In millions)	For the Years Ended December 31, 2012	2011	2010
Operating expenses			
Operating and maintenance	$ 201	$ 56	$ 13
Operating and maintenance from affiliates	72	44	22
Other	6	4	2
Total operating expenses	279	104	37
Operating loss	(279)	(104)	(37)
Other income and (deductions)			
Interest expense, net	(153)	(75)	(90)
Equity in earnings of investments	1,278	2,662	2,652
Interest income from affiliates, net	75	1	—
Other, net	7	8	6
Total other income and (deductions)	1,207	2,596	2,568
Income before income taxes	928	2,492	2,531
Income taxes	(232)	(3)	(32)
Net income	$1,160	$2,495	$2,563
Other comprehensive loss			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic costs, net of taxes of $1, $(4) and $(7), respectively	1	(5)	(11)
Actuarial loss reclassified to periodic cost, net of taxes of $110, $93 and $79, respectively	170	136	114
Transition obligation reclassified to periodic cost, net of taxes of $2, $2 and $2, respectively	2	4	3
Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $(237), $(171) and $(188), respectively	(372)	(250)	(288)
Change in unrealized gain (loss) on cash flow hedges, net of taxes of $(67), $39 and $(107), respectively	(121)	88	(151)
Change in unrealized gain (loss) on marketable securities, net of taxes of $(1), $0 and $0, respectively	1	—	—
Change in unrealized gain (loss) on equity investments, net of taxes of $(1), $0 and $0, respectively	2	—	—
Change in unrealized gain (loss) on foreign currency translation, net of taxes of $0, $0 and $0, respectively	—	—	(1)
Other comprehensive loss	(317)	(27)	(334)
Comprehensive income	$ 843	$2,468	$2,229

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2012	2011	2010
Net cash flows provided by operating activities	$ 2,131	$ 766	$ 2,014
Cash flows from investing activities			
Capital expenditures	(30)	(28)	(7)
Return on capital from equity method investee	—	(1)	92
Cash and restricted cash acquired from Constellation	679	—	—
Change in restricted cash	(38)	—	—
Investment in unconsolidated affiliates	(67)	(65)	(290)
Net cash flows used in investing activities	544	(94)	(205)
Cash flows from financing activities			
Changes in Exelon intercompany money pool	(703)	20	(5)
Changes in short-term debt	(161)	161	—
Retirement of long-term debt	(77)	—	(400)
Dividends paid on common stock	(1,716)	(1,393)	(1,389)
Proceeds from employee stock plans	73	38	48
Other financing activities	30	(1)	5
Net cash flows used in financing activities	(2,554)	(1,175)	(1,741)
Increase (decrease) in cash and cash equivalents	121	(503)	68
Cash and cash equivalents at beginning of period	38	541	473
Cash and cash equivalents at end of period	$ 159	$ 38	$ 541

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Balance Sheets

(In millions)	December 31, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 159	$ 38
Restricted cash and investments	38	—
Accounts receivable, net		
Other accounts receivable	25	111
Accounts receivable from affiliates	87	9
Deferred income taxes	—	22
Notes receivable from affiliates	119	—
Regulatory assets	381	—
Other	2	3
Total current assets	811	183
Property, plant and equipment, net	59	32
Deferred debits and other assets		
Regulatory assets	3,932	2,991
Investments in affiliates	25,576	18,951
Deferred income taxes	2,437	2,058
Notes receivable from affiliates	2,007	—
Other	42	24
Total deferred debits and other assets	33,994	24,024
Total assets	$34,864	$24,239

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Balance Sheets

(In millions)	December 31, 2012	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 161
Accounts payable	101	—
Payables to affiliates	—	30
Unamortized energy contract liabilities	77	—
Accrued expenses	110	117
Deferred income taxes	55	—
Other	60	403
Total current liabilities	403	711
Long-term debt	3,576	1,313
Deferred credits and other liabilities		
Pension obligations	8,252	6,797
Non-pension postretirement benefit obligations	1,071	965
Unamortized energy contract liabilities	12	—
Other	116	68
Total deferred credits and other liabilities	9,451	7,830
Total liabilities	13,430	9,854
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 890 and 662 shares outstanding at December 31, 2012 and 2011, respectively)	16,632	9,107
Treasury stock, at cost (35 shares held at December 31, 2012 and 2011, respectively)	(2,327)	(2,327)
Retained earnings	9,893	10,055
Accumulated other comprehensive loss, net	(2,767)	(2,450)
Total shareholders' equity	21,431	14,385
BGE preference stock not subject to mandatory redemption	3	—
Total liabilities and shareholders' equity	$34,864	$24,239

See Notes to Financial Statements

1. Basis of Presentation

Exelon Corporate is a holding company that conducts substantially all of its business operations through its subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of Exelon Corporation.

Exelon Corporate owns 100% of all of its significant subsidiaries, either directly or indirectly, except for Commonwealth Edison Company (ComEd), of which Exelon Corporate owns more than 99%, PECO Energy Company (PECO), of which Exelon Corporate owns 100% of the common stock but none of PECO's preferred securities and BGE, of which Exelon owns 100% of the common stock but none of BGE's preferred stock.

2. Merger with Constellation

On March 12, 2012, Exelon Corporation completed the merger contemplated by the Merger Agreement, among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including the customer supply and generation businesses that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

For BGE's debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE's assets acquired and liabilities assumed is recorded as a regulatory asset at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 4—Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information on the merger with Constellation. Also see Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information on BGE's push-down accounting treatment.

3. Debt and Credit Agreements

Short-Term Borrowings

Exelon Corporate meets its short-term liquidity requirements primarily through the issuance of commercial paper. Exelon Corporate had no commercial paper borrowings at December 31, 2012 and $161 million at December 31, 2011.

Credit Agreements

On August 10, 2012, Exelon Corporate amended and extended its unsecured syndicated revolving credit facility with aggregate bank commitments of $500 million through August 10, 2017. As of

December 31, 2012, Exelon Corporate had available capacity under those commitments of $498 million. See Note 11—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon Corporate's credit agreement.

Long-Term Debt

The following tables present the outstanding long-term debt for Exelon Corporate as of December 31, 2012 and 2011:

	Rates	Maturity Date	December 31, 2012	December 31, 2011
Long-term debt				
Senior unsecured notes	4.55% – 8.63%	2015-2063	$3,108	$1,300
Unamortized debt discount and premium, net			2	(1)
Fair value adjustment			455	—
Fair value hedge carrying value adjustment, net			11	14
Long-term debt			$3,576	$1,313

Exelon Corporate will not have any long-term debt maturities in periods 2013 and 2014. The debt maturities for the periods 2015, 2016, 2017 and thereafter are as follows:

2015	$1,350
2016	—
2017	—
Remaining years	1,758
Total long-term debt	$3,108

4. Commitments and Contingencies

See Note 19 of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's commitments and contingencies related to environmental matters, savings plan claim and fund transfer restrictions.

5. Related Party Transactions

The financial statements of Exelon Corporate include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2012	2011	2010
Operating and maintenance from affiliates:			
Business Services Company, LLC [a]	$ 72	$ 44	$ 22
Interest income from affiliates, net	$ 75	$ 1	$ —
Equity in earnings of investments:			
Exelon Energy Delivery Company, LLC [b]	$ 713	$ 801	$ 657
Exelon Ventures Company, LLC [c]	564	1,769	1,978
UII, LLC	25	18	23
Exelon Transmission Company, LLC	(3)	(3)	(6)
Exelon Consolidations [d]	(21)	77	—
Total equity in earnings of investments	$1,278	$2,662	$2,652
Charitable contributions to Exelon Foundation [e]	$ —	$ —	$ 10
Cash contributions received from affiliates	$2,074	$ 820	$2,056

	December 31,	
	2012	2011
Accounts receivable from affiliates (current):		
Business Services Company, LLC [a]	$ 33	$ —
Generation	33	7
ComEd	2	1
PECO	2	1
BGE	17	—
Total accounts receivable from affiliates (current)	$ 87	$ 9
Notes receivable from affiliates (current):		
Business Services Company, LLC [a]	$ 119	$ —
Investments in affiliates:		
Business Services Company, LLC [a]	$ 181	$ 160
Exelon Energy Delivery Company, LLC [b]	12,466	10,040
Exelon Ventures Company, LLC [c]	12,444	8,310
UII, LLC	472	447
Exelon Transmission Company, LLC	4	6
VEBA	9	(12)
Total investments in affiliates	$25,576	$18,951
Notes receivable from affiliates (non-current):		
Generation	$ 2,007	$ —
Payables to affiliates (current)		
Exelon Consolidations	$ —	$ 27
Business Services Company, LLC [a]	—	3
Total payables to affiliates (current)	$ —	$ 30

(a) Exelon Corporate receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead.
(b) Exelon Energy Delivery Company, LLC consists of ComEd, PECO and BGE.
(c) Exelon Ventures Company, LLC primarily consists of Generation.
(d) Equity in earnings of investments for Exelon Consolidations represents the intercompany income component that offsets the corresponding intercompany expense at Generation for upgrades in transmission assets owned by ComEd, which are reflected as assets at Exelon Corporate.
(e) Exelon Foundation is a nonconsolidated not-for-profit Illinois corporation. The Exelon Foundation was established in the fourth quarter of 2007 to serve educational and environmental philanthropic purposes and does not serve a direct business or political purpose of Exelon. Exelon contributes services (i.e. accounting, administrative, legal).

Exelon Corporation and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts [a]	$ 199	$ 144	$ 136[b][c]	$ 186[d]	$ 293
Deferred tax valuation allowance	10	18	18[b]	10	36
Reserve for obsolete materials	60	2	2[b]	11	53
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts [a]	$ 211	$ 121	$ 32[c]	$ 165[d]	$ 199
Deferred tax valuation allowance	9	1	—	—	10
Reserve for obsolete materials	56	6	—	2	60
For The Year Ended December 31, 2010					
Allowance for uncollectible accounts [a]	$ 214	$ 109	$ 19[c]	$ 131[d]	$ 211
Deferred tax valuation allowance	36	(8)	—	19	9
Reserve for obsolete materials	45	12	—	1	56

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $8 million, $9 million, $17 million and $11 million for the years ended December 31, 2012, 2011, 2010 and 2009, respectively.
(b) Primarily represents the addition of Constellation's and BGE's results as of March 12, 2012, the date of the merger.
(c) Includes charges for late payments and non-service receivables.
(d) Write-off of individual accounts receivable.

Exelon Generation Company, LLC and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Generation

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 21, 2013 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2012, 2011 and 2010

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011 and 2010

   Consolidated Balance Sheets at December 31, 2012 and 2011

   Consolidated Statements of Changes in Member's Equity for the Years Ended December 31, 2012, 2011 and 2010

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Exelon Generation Company, LLC and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts	$ 29	$ —	$ 66[(a)]	$ 11	$ 84
Deferred tax valuation allowance	—	17	18[(a)]	—	35
Reserve for obsolete materials	59	—	2[(a)]	11	50
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 32	$ —	$ —	$ 3	$ 29
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	55	4	—	—	59
For The Year Ended December 31, 2010					
Allowance for uncollectible accounts	$ 31	$ 1	$ —	$ —	$ 32
Deferred tax valuation allowance	18	—	—	18	—
Reserve for obsolete materials	43	12	—	—	55

(a) Represents the addition of Constellation's results as of March 12, 2012, the date of the merger.

Commonwealth Edison Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

ComEd

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 21, 2013 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2012, 2011 and 2010

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011 and 2010

   Consolidated Balance Sheets at December 31, 2012 and 2011

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2012, 2011 and 2010

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Commonwealth Edison Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts	$ 78	$ 42	$ 26[(a)]	$ 76[(b)]	$ 70
Reserve for obsolete materials	1	1	—	—	2
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 80	$ 57	$ 15[(a)]	$ 74[(b)]	$ 78
Reserve for obsolete materials	1	2	—	2	1
For The Year Ended December 31, 2010					
Allowance for uncollectible accounts	$ 77	$ 48	$ 16[(a)]	$ 61[(b)]	$ 80
Reserve for obsolete materials	1	—	—	—	1

(a) Primarily charges for late payments and non-service receivables.
(b) Write-off of individual accounts receivable.

PECO Energy Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

PECO

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 21, 2013 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2012, 2011 and 2010

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011 and 2010

   Consolidated Balance Sheets at December 31, 2012 and 2011

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2012, 2011 and 2010

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

PECO Energy Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts [a]	$ 92	$ 60	$ 8[b]	$ 61[c]	$ 99
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	1	—	—	—	1
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts [a]	$ 99	$ 64	$ 17[b]	$ 88[c]	$ 92
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	1	—	—	—	1
For The Year Ended December 31, 2010					
Allowance for uncollectible accounts [a]	$ 106	$ 60	$ 3[b]	$ 70[c]	$ 99
Deferred tax valuation allowance	1	—	—	1	—
Reserve for obsolete materials	1	—	—	—	1

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $8 million, $9 million, $17 million and $11 million for the years ended December 31, 2012, 2011, 2010 and 2009, respectively.
(b) Primarily charges for late payments.
(c) Write-off of individual accounts receivable.

Baltimore Gas and Electric Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

BGE

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 21, 2013 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2012, 2011 and 2010

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2012, 2011 and 2010

   Consolidated Balance Sheets at December 31, 2012 and 2011

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2012, 2011 and 2010

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Baltimore Gas and Electric Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
		(in millions)			
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts	$ 38	$ 45	$ —	$ 43[(a)]	$ 40
Deferred tax valuation allowance	—	1	—	—	1
Reserve for obsolete materials	—	1	—	—	1
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 36	$ 39	$ —	$ 37[(a)]	$ 38
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	—	—	—	—
For The Year Ended December 31, 2010					
Allowance for uncollectible accounts	$ 47	$ 46	$ —	$ 57[(a)]	$ 36
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	—	—	—	—

(a) Write-off of individual accounts receivable.

(b) Exhibits required by Item 601 of Regulation S-K:

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
2-1	Amended and Restated Agreement and Plan of Merger dated as of October 20, 2000, among PECO Energy Company, Exelon Corporation and Unicom Corporation (File No. 0-01401, Form 10-Q for the quarter ended September 30, 2000, Exhibit 2-1).
2-2	Purchase Agreement dated as of August 30, 2010 by and between Deere & Company and Generation (File No. 1-16169, Form 10-Q for the quarter ended September 30, 2010, Exhibit 2-1).
2-3	Agreement and Plan of Merger dated as of April 28, 2011 by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc. (File No. 001-16169, Form 8-K dated April 28, 2011, Exhibit No. 2-1)
2-4	Distribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Constellation Energy Group, Inc. and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-3).
2-5	Contribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Energy Delivery Company, LLC and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-4).
2-6	Contribution Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Ventures Company, LLC and Exelon Generation Company, LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-5).
2-7	Purchase Agreement dated as of August 8, 2012 by and between Constellation Power Source Generation, Inc. and Raven Power Holdings, LLC (File No. 333-85496, Form 10-Q for the quarter ended September 30, 2012, Exhibit No. 2-1).
2-8	Agreement and Plan of Reorganization and Corporate Separation (Nuclear). (Designated as Exhibit No. 2(a) to the Current Report on Form 8-K dated July 7, 2000, filed by Constellation, File Nos. 1-12869 and 1-1910.)
2-9	Agreement and Plan of Reorganization and Corporate Separation (Fossil). (Designated as Exhibit No. 2(b) to the Current Report on Form 8-K dated July 7, 2000, filed by Constellation, File Nos. 1-12869 and 1-1910.)
2-10	Asset Purchase Agreement, dated as of August 7, 2010, by and among EBG Holdings LLC, Boston Generating, LLC, Mystic I, LLC, Fore River Development, LLC, BG Boston Services, LLC, BG New England Power Services, Inc., Constellation Holdings, Inc. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated August 11, 2010, filed by Constellation, File No. 1-12869.)
2-11	Master Agreement, dated as of October 26, 2010, by and between Electricite de France, S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 1, 2010, filed by Constellation, File No. 1-12869.)
2-12	Put Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., Constellation Nuclear, LLC, and Constellation Energy Nuclear Group, LLC. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 8, 2010, filed by Constellation, File No. 1-12869.)

Exhibit No.	Description
2-13	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., Baltimore Gas and Electric Company and RF HoldCo LLC. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation, File Nos. 1-12869 and 1-1910.)
2-14	Purchase Agreement, dated as of February 4, 2010, by and between RF HoldCo LLC and GSS Holdings (Baltimore Gas and Electric Company Utility), Inc. (Designated as Exhibit No. 99.3 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation, File Nos. 1-12869 and 1-1910.
3-1	Amended and Restated Articles of Incorporation of Exelon Corporation, as amended May 8, 2007 (File No. 001-16169, Form 10-Q for the quarter ended September 30, 2008, Exhibit 3-1-2).
3-2	Exelon Corporation Amended and Restated Bylaws, effective as of March 12, 2012 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit 3-1).
3-3	Certificate of Formation of Exelon Generation Company, LLC (Registration Statement No. 333-85496, Form S-4, Exhibit 3-1).
3-4	First Amended and Restated Operating Agreement of Exelon Generation Company, LLC executed as of January 1, 2001 (File No. 333-85496, 2003 Form 10-K, Exhibit 3-8).
3-5	Restated Articles of Incorporation of Commonwealth Edison Company Effective February 20, 1985, including Statements of Resolution Establishing Series, relating to the establishment of three new series of Commonwealth Edison Company preference stock known as the “$9.00 Cumulative Preference Stock,” the “$6.875 Cumulative Preference Stock” and the “$2.425 Cumulative Preference Stock” (File No. 1-1839, 1994 Form 10-K, Exhibit 3-2).
3-6	Commonwealth Edison Company Amended and Restated By-Laws, Effective January 23, 2006 As Further Amended January 28, 2008 and July 27, 2009. (File No. 001-16169, Form 8-K dated July 27, 2009, Exhibit 3.1).
3-7	Amended and Restated Articles of Incorporation of PECO Energy Company (File No. 1-01401, 2000 Form 10-K, Exhibit 3-3).
3-8	PECO Energy Company Amended Bylaws (File 000-16844, Form 8-K dated May 6, 2009, Exhibit 99.1).
3-9	Articles of Amendment to the Charter of Baltimore Gas and Electric Company as of February 2, 2010. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation, File No. 1-1910.)
3-10	Charter of Baltimore Gas and Electric Company, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, filed by Constellation, File No. 1-1910.)
3-11	Bylaws of Baltimore Gas and Electric Company, as amended to February 4, 2010. (Designated as Exhibit No. 3.2 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation, File No. 1-1910.)
3-12	Operating Agreement, dated as of February 4, 2010, by and among RF HoldCo LLC, Constellation Energy Group, Inc. and GSS Holdings (Baltimore Gas and Electric Company Utility), Inc. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation, File Nos. 1-12869 and 1-1910.)
4-1	First and Refunding Mortgage dated May 1, 1923 between The Counties Gas and Electric Company (predecessor to PECO Energy Company) and Fidelity Trust Company, Trustee (U.S. Bank National Association, as current successor trustee), (Registration No. 2-2281, Exhibit B-1).

Exhibit No.	Description
4-1-1	Supplemental Indentures to PECO Energy Company's First and Refunding Mortgage:

Dated as of	File Reference	Exhibit No.
May 1, 1927	2-2881	B-1(c)
March 1, 1937	2-2881	B-1(g)
December 1, 1941	2-4863	B-1(h)
November 1, 1944	2-5472	B-1(i)
December 1, 1946	2-6821	7-1(j)
September 1, 1957	2-13562	2(b)-17
May 1, 1958	2-14020	2(b)-18
March 1, 1968	2-34051	2(b)-24
March 1, 1981	2-72802	4-46
March 1, 1981	2-72802	4-47
December 1, 1984	1-01401, 1984 Form 10-K	4-2(b)
March 1, 1993	1-01401, 1992 Form 10-K	4(e)-86
May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-88
May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-89
April 15, 2004	0-6844, September 30, 2004 Form 10-Q	4-1-1
September 15, 2006	000-16844, Form 8-K dated September 25, 2006	4.1
March 1, 2007	000-16844, Form 8-K dated March 19, 2007	4.1
February 15, 2008	0-16844, Form 8-K dated March 3, 2008	4.1
February 15, 2008	0-16844, Form 8-K, dated March 5, 2008	
September 15, 2008	000-16844, Form 8-K dated October 2, 2008	4.1
March 15, 2009	000-16844, Form 8-K dated March 26, 2009	4.1
September 1, 2012	000-16844, Form 8-K dated September 17, 2012	4.1
October 1, 2012	000-16844, Form 8-K dated October 1, 2012	4.1

Exhibit No.	Description
4-2	Exelon Corporation Direct Stock Purchase Plan (Registration Statement No. 333-183751, Form S-3, Prospectus).
4-3	Mortgage of Commonwealth Edison Company to Illinois Merchants Trust Company, Trustee (BNY Mellon Trust Company of Illinois, as current successor Trustee), dated July 1, 1923, as supplemented and amended by Supplemental Indenture thereto dated August 1, 1944. (Registration No. 2-60201, Form S-7, Exhibit 2-1).
4-3-1	Supplemental Indentures to Commonwealth Edison Company Mortgage.

Dated as of	File Reference	Exhibit No.
August 1, 1946	2-60201, Form S-7	2-1
April 1, 1953	2-60201, Form S-7	2-1
March 31, 1967	2-60201, Form S-7	2-1
April 1,1967	2-60201, Form S-7	2-1
February 28, 1969	2-60201, Form S-7	2-1
May 29, 1970	2-60201, Form S-7	2-1
June 1, 1971	2-60201, Form S-7	2-1
April 1, 1972	2-60201, Form S-7	2-1
May 31, 1972	2-60201, Form S-7	2-1
June 15, 1973	2-60201, Form S-7	2-1
May 31, 1974	2-60201, Form S-7	2-1
June 13, 1975	2-60201, Form S-7	2-1
May 28, 1976	2-60201, Form S-7	2-1
June 3, 1977	2-60201, Form S-7	2-1
May 17, 1978	2-99665, Form S-3	4-3
August 31, 1978	2-99665, Form S-3	4-3
June 18, 1979	2-99665, Form S-3	4-3
June 20, 1980	2-99665, Form S-3	4-3
April 16, 1981	2-99665, Form S-3	4-3
April 30, 1982	2-99665, Form S-3	4-3
April 15, 1983	2-99665, Form S-3	4-3
April 13, 1984	2-99665, Form S-3	4-3
April 15, 1985	2-99665, Form S-3	4-3
April 15, 1986	33-6879, Form S-3	4-9
April 15, 1993	33-64028, Form S-3	4-13
June 15, 1993	1-1839, Form 8-K dated May 21, 1993	4-1
January 15, 1994	1-1839, 1993 Form 10-K	4-15
March 1, 2002	1-1839, 2001 Form 10-K	4-4-1
June 1, 2002	333-99363, Form S-3	4-1-1(B)
October 7, 2002	333-9715, Form S-4	4-1-3

Dated as of	File Reference	Exhibit No.
January 13, 2003	1-1839, Form 8-K dated January 22, 2003	4-4
March 14, 2003	1-1839, Form 8-K dated April 7, 2003	4-4
February 22, 2006	1-1839, Form 8-K dated March 6, 2006	4.1
August 1, 2006	1-1839, Form 8-K dated August 28, 2006	4.1
September 15, 2006	1-1839, Form 8-K dated October 2, 2006	4.1
December 1, 2006	1-1839, Form 8-K dated December 19, 2006	4.1
March 1, 2007	1-1839, Form 8-K dated March 23, 2007	4.1
August 30, 2007	1-1839, Form 8-K dated September 10, 2007	4.1
December 20, 2007	1-1839, Form 8-K dated January 16, 2008	4.1
March 10, 2008	1-1839, Form 8-K dated March 27, 2008	4.1
July 12, 2010	001-01839, Form 8-K dated August 2, 2010	4.1
January 4, 2011	001-01839, Form 8-K dated January 18, 2011	4.1
August 22, 2011	001-01839, Form 8-K dated September 7, 2011	4.1
September 17, 2012	001-01839, Form 8-K dated October 1, 2012	4.1

Exhibit No.	Description
4-3-2	Instrument of Resignation, Appointment and Acceptance dated as of February 20, 2002, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923, and Indentures Supplemental thereto, regarding corporate trustee (File No. 1-1839, 2001 Form 10-K, Exhibit 4-4-2).
4-3-3	Instrument dated as of January 31, 1996, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923 and Indentures Supplemental thereto, regarding individual trustee (File No. 1-1839, 1995 Form 10-K, Exhibit 4-29).
4-4	Indenture dated as of September 1, 1987 between Commonwealth Edison Company and Citibank, N.A. (U.S. Bank National Association, as current successor trustee), Trustee relating to Notes (Registration No. 33-20619, Form S-3, Exhibit 4-13).

Exhibit No.	Description
4-5	Indenture dated December 19, 2003 between Generation and U.S. Bank National Association (File No. 333-85496, 2003 Form 10-K, Exhibit 4-6).
4-6	Indenture to Subordinated Debt Securities dated as of June 24, 2003 between PECO Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.1).
4-7	Form of 4.25% Senior Note due 2022. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.1).
4-8	Form of 5.60% Senior Note due 2042. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.2).
4-9	Form of 2.80% Senior Note due 2022. (File 1-1910, Form 8-K dated August 17, 2012, Exhibit 4.1).
4-10	Preferred Securities Guarantee Agreement between PECO Energy Company, as Guarantor, and U.S. Bank National Association, as Trustee, dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.2).
4-11	PECO Energy Capital Trust IV Amended and Restated Declaration of Trust among PECO Energy Company, as Sponsor, U.S. Bank Trust National Association, as Delaware Trustee and Property Trustee, and J. Barry Mitchell, George R. Shicora and Charles S. Walls as Administrative Trustees dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.3).
4-12	Indenture dated May 1, 2001 between Exelon and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 1-16169, June 30, 2005 Form 10-Q, Exhibit 4-10).
4-13	Form of $800,000,000 4.90% senior notes due 2015 dated June 9, 2005 issued by Exelon Corporation (File No. 1-16169, Form 8-K dated June 9, 2005, Exhibit 99.2).
4-14	Form of $500,000,000 5.625% senior notes due 2035 dated June 9, 2005 issued by Exelon Corporation (File No. 1-16169, Form 8-K dated June 9, 2005, Exhibit 99.3).
4-15	Indenture dated as of September 28, 2007 from Generation to U.S. Bank National Association, as trustee (File 333-85496, Form 8-K dated September 28, 2007, Exhibit 4.1).
4-16	Form of 5.20% Generation Senior Note due 2019 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.1).
4-17	Form of 6.25% Generation Senior Note due 2039 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.2).
4-18	Form of 4.00% Generation Senior Note due 2020 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.1).
4-19	Form of 5.75% Generation Senior Note due 2041 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.2).
4-20	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, filed by Constellation, File No. 333-75217.)

Exhibit No.	Description
4-21	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, filed by Constellation, File No. 333-102723.)
4-22	Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation, File No. 333-135991.)
4-23	First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (Designated as Exhibit 4(a) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation, File No. 1-12869.)
4-24	Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation, File Nos. 1-12869 and 1-1910.)
4-25	Indenture dated July 1, 1985, between Baltimore Gas and Electric Company and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, filed by Constellation, File No. 1-1910.)
4-26	Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee (including form of Baltimore Gas and Electric Company Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibit Nos. 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation, File Nos. 333-157637 and 333-157637-01.)
4-27	Indenture dated as of July 24, 2006 between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(b) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation, File No. 333-135991.)
4-28	Supplemental Indenture No. 1, dated as of October 1, 2009, to the Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Constellation, File Nos. 1-12869 and 1-1910.)
4-29	Baltimore Gas and Electric Company Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit No. 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation, File Nos. 333-157637 and 333-157637-01.)
4-30	Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (Designated as Exhibit 4.1 to the Current Report on Form 8-K dated July 5, 2007, filed by Constellation, File No. 1-1910.)

Exhibit No.	Description
4-31	Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (Designated as Exhibit No. 4(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Constellation, File No. 1 1910.)
4-32	Replacement Capital Covenant dated June 27, 2008. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation, File No. 1-12869.)
4-33	Amendment to Replacement Capital Covenant, dated as of March 12, 2012, amending the Replacement Capital Covenant, dated as of June 27, 2008 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 99.4)
4-34	Officers' Certificate, dated December 14, 2010, establishing the 5.15% Notes due December 1, 2020 of Constellation Energy Group, Inc., with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated December 14, 2010, filed by Constellation, File No. 1-12869.)
4-35	Officers' Certificate, November 16, 2011, establishing the 3.50% Notes due November 15, 2021 of Baltimore Gas and Electric Company, with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated November 16, 2011, filed by Constellation, File No. 1-1910.)
10-1	Exelon Corporation Deferred Non-Employee Directors' Deferred Stock Unit Plan (As Amended and Restated Effective January 1, 2011). *
10-2	Exelon Corporation Retirement Program (As Amended and Restated Effective January 1, 2010).
10-3	Exelon Corporation Deferred Compensation Plan for Directors (as amended and restated Effective January 1, 2011). *
10-4	Exelon Corporation Long-Term Incentive Plan As Amended and Restated Effective January 28, 2002* (File No. 1-16169, Exelon Proxy Statement dated March 13, 2002, Appendix B).
10-5-1	Form of Restricted Stock Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-1).
10-5-2	Forms of Transferable Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-2).
10-5-3	Forms of Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-3).
10-6	Exelon Corporation Employee Savings Plan (As Amended and Restated Effective January 1, 2010) (File No. 1-16169, 2010 Form 10-K, Exhibit 10-6).
10-7	Exelon Corporation Cash Balance Pension Plan (As Amended and Restated Effective January 1, 2010) (File No. 1-16169, 2010 Form 10-K, Exhibit 10-7).
10-8	Unicom Corporation Deferred Compensation Unit Plan, as amended *(File Nos. 1-11375 and 1-1839, 1995 Form 10-K, Exhibit 10-12).
10-9	Amendment Number One to the Unicom Corporation Deferred Compensation Unit Plan, as amended January 1, 2008 * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.16).
10-10	Unicom Corporation Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-12).
10-11	Commonwealth Edison Company Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-13).

Exhibit No.	Description
10-12	Exelon Corporation Supplemental Management Retirement Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.19).
10-13	PECO Energy Company Supplemental Pension Benefit Plan (As Amended and Restated Effective January 1, 2009) (File No. 000-16844, 2008 Form 10-K, Exhibit 10.20).
10-14	Exelon Corporation Annual Incentive Plan for Senior Executives Effective January 1, 2004 (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2009 Form 10-K, Exhibit 10.21).
10-15	Form of change in control employment agreement for senior executives Effective January 1, 2009 * (File No. 001-16169. 2008 Form 10-K, Exhibit 10.23).
10-16	Form of change in control employment agreement (amended and restated as of January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.24).
10-17	Restatement of the Exelon Corporation Employee Stock Purchase Plan, Effective May 1, 2004 and Appendix One thereto. (File No. 1-16169, 2004 Form 10-K, Exhibit 10-54).
10-18	Exelon Corporation 2006 Long-Term Incentive Plan (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex H).
10-19	Form of Stock Option Grant Instrument under the Exelon Corporation 2006 Long-Term Incentive Plan (File No. 1-16169, Form 8-K filed January 27, 2006, Exhibit 99.2).
10-20	Exelon Corporation Employee Stock Purchase Plan for Unincorporated Subsidiaries (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex I).
10-21	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.29).
10-22	Form of Separation Agreement under Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective January 1, 2009) * (File No, 001-16169, 2008 Form 10-K, Exhibit 10.30).
10-23	Facility Credit Agreement, dated as of November 4, 2010, among Generation and UBS AG, Stamford Branch (File No. 333-85496, Form 8-K dated February 22, 2011, Exhibit No. 10-1).
10-24	Exelon Corporation Executive Death Benefits Plan dated as of January 1, 2003 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-52).
10-25	First Amendment to Exelon Corporation Executive Death Benefits Plan, Effective January 1, 2006 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-53).
10-26	Amendment Number One to the Exelon Corporation 2006 Long-Term Incentive Plan, Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-54).
10-27	Amendment Number Two to the Exelon Corporation 2006 Long-Term Incentive Plan (As Amended and Restated Effective January 28, 2002), Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-55).
10-28	Exelon Corporation Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-56).
10-29	Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-57).
10-30	Commonwealth Edison Company Long-Term Incentive Plan, Effective January 1, 2007 (File No. 1-16169, March 31, 2007 Form 10-Q, Exhibit 10-1).

Exhibit No.	Description
10-31	Amendment Number One to the Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, June 30, 2007 Form 10-Q, Exhibit 10-3).
10-32	Restricted stock unit award agreement (File 1-16169, Form 8-K dated August 31, 2007, Exhibit 99.1).
10-33	Amended and Restated Trade Receivables Purchase and Sale Agreement among PECO, Victory Receivables Corporation and The Bank of Tokyo-Mitsubishi UFJ, Ltd. dated as of December 20, 1988, as Amended and Restated as of November 14, 1995, as of January 1, 1999, as of November 14, 2000, as of November 14, 2005 and as Further Amended and Restated as of September 19, 2008 (File 000-16844, Form 8-K dated September 22, 2008, Exhibit 10.1).
10-34	Amendment No. 1 to Amended and Restated Trade Receivables Purchase and Sale Agreement among PECO Energy Company, Victory Receivables Corporation and The Bank of Tokyo-Mitsubishi UFJ, Ltd. (File 000-16844, Form 8-K dated September 17, 2009, Exhibit 10.1).
10-35	Third Amended and Restated Employment Agreement with John W. Rowe * (File 1-16169, Fork 8-K dated October 29, 2009, Exhibit 99.1).
10-36	Exelon Corporation 2011 Long-Term Incentive Plan (File No. 1-16169, Schedule 14A dated March 18, 2010, Appendix A).
10-37	Form of Change in Control Employment Agreement Effective February 10, 2011. *
10-38	Credit Agreement for $500,000,000 dated as of March 23, 2011 between Exelon Corporation and Various Financial Institutions (File No. 001-16169, Form 8-K dated March 23, 2011, Exhibit No. 10-2).
10-39	Credit Agreement for $5,300,000,000 dated as of March 23, 2011 between Exelon Generation Company, LLC and Various Financial Institutions (File No. 333-85496, Form 8-K dated March 23, 2011, Exhibit No. 10-3).
10-40	Credit Agreement for $600,000,000 dated as of March 23, 2011 between PECO Energy Company and Various Financial Institutions (File No. 000-16844, Form 8-K dated March 23, 2011, Exhibit No. 10-4).
10-41	Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, Various Financial Institutions, as Lenders, and JP Morgan Chase Bank, N.A., as Administrative Agent (File No. 000-01839, Form 8-K dated March 28, 2012, Exhibit No. 99-1).
10-42	Amendment No. 1 to Credit Agreement, dated as of December 21, 2011, to the Credit Agreement dated as of March 23, 2011, among Exelon Generation Company, LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 4-6).
10-43	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated.* (Designated as Exhibit No. 10(b) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-44	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated.* (Designated as Exhibit No. 10(c) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation, File Nos. 1-12869 and 1-1910.)

Exhibit No.	Description
10-45	Constellation Energy Group, Inc. Benefits Restoration Plan, amended and restated effective June 1, 2010.* (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-46	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated.* (Designated as Exhibit No. 10(e) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation, File Nos. 1-12869 and 1-1910.).
10-47	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated.* (Designated as Exhibit No. 10(f) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-48	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated.* (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-49	Constellation Energy Group, Inc. Executive Supplemental Benefits Plan, as amended and restated.* (Designated as Exhibit No. 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-50	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated.* (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-51	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated.* (Designated as Exhibit 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-52	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated.* (Designated as Exhibit 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-53	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated.* (Designated as Exhibit 10(d) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-54	Constellation Energy Group, Inc. Amended and Restated 2007 Long-Term Incentive Plan.* (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated June 4, 2010, filed by Constellation, File No. 1-12869.)
10-55	Form of Grant Agreement for Stock Units with Sales Restriction.* (Designated as Exhibit No. 10(x) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-56	Rate Stabilization Property Servicing Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as servicer (Designated as Exhibit 10.2 to the Current Report on Form 8-K dated July 5, 2007, filed by Constellation, File No. 1-1910.)

Exhibit No.	Description
10-57	Administration Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as administrator (Designated as Exhibit 10.3 to the Current Report on Form 8-K dated July 5, 2007, filed by Constellation, File No. 1-1910.)
10-58	Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 12, 2009, filed by Constellation, File No. 1-12869.)
10-59	Amendment No. 1 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(s) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-60	Amendment No. 2 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(t) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation, File Nos. 1-12869 and 1-1910.)
10-61	Amendment No. 3 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation, File No. 1-12869.)
10-62	Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation, File No. 1-12869.)
10-63	Settlement Agreement between EDF Inc., Exelon Corporation, Exelon Energy Delivery Company, LLC, Constellation Energy Group, Inc. and Baltimore Gas and Electric Company dated January 16, 2012. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated January 19, 2012, File Nos. 1-12869 and 1-1910.)
12-1	Exelon Corporation Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preference Stock Dividends.
12-2	Exelon Generation Company, LLC Computation of Ratio of Earnings to Fixed Charges.
12-3	Commonwealth Edison Company Computation of Ratio of Earnings to Fixed Charges.
12-4	PECO Energy Company Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preference Stock Dividends.
12-5	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preference Stock Dividends.
14	Exelon Code of Conduct, as amended March 12, 2012 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 14-1).
	Subsidiaries
21-1	Exelon Corporation

Exhibit No.	Description
21-2	Exelon Generation Company, LLC
21-3	Commonwealth Edison Company
21-4	PECO Energy Company
21-5	Baltimore Gas and Electric Company
	Consent of Independent Registered Public Accountants
23-1	Exelon Corporation
23-2	Exelon Generation Company, LLC
23-3	Commonwealth Edison Company
23-4	PECO Energy Company
23-5	Baltimore Gas and Electric Company
	Power of Attorney (Exelon Corporation)
24-1	Ann C. Berzin
24-2	John A. Canning, Jr.
24-3	Christopher M. Crane
24-4	Yves C. de Balmann
24-5	Nicholas DeBenedictis
24-6	Nelson A. Diaz
24-7	Sue L. Gin
24-8	Paul L. Joskow
24-9	Robert J. Lawless
24-10	Richard W. Mies
24-11	William C. Richardson
24-12	Thomas J. Ridge
24-13	John W. Rogers, Jr.
24-14	Mayo A. Shattuck III
24-15	Stephen D. Steinour
24-16	Donald Thompson
	Power of Attorney (Commonwealth Edison Company)
24-17	James W. Compton
24-18	Christopher M. Crane
24-19	A. Steven Crown
24-20	Peter V. Fazio, Jr.
24-21	Sue L. Gin
24-22	Michael Moskow
24-23	Anne R. Pramaggiore
24-24	Jesse H. Ruiz
	Power of Attorney (PECO Energy Company)
24-25	Craig L. Adams
24-26	Christopher M. Crane
24-27	M. Walter D'Alessio
24-28	Nelson A. Diaz

Exhibit No.	Description
24-29	Charisse R. Lillie
24-30	Thomas J. Ridge
24-31	Ronald Rubin
	Power of Attorney (Baltimore Gas and Electric Company)
24-32	Christopher M. Crane
24-33	Michael E. Cryor
24-34	James R. Curtiss
24-35	Kenneth W. DeFontes, Jr.
24-36	Joseph Haskins, Jr.
24-37	Carla D. Hayden
	Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Annual Report on Form 10-K for the year ended December 31, 2010 filed by the following officers for the following registrants:
31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Jonathan W. Thayer for Exelon Corporation
31-3	Filed by Christopher M. Crane for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	Filed by Craig L. Adams for PECO Energy Company
31-8	Filed by Phillip S. Barnett for PECO Energy Company
31-9	Filed by Kenneth W. DeFontes Jr. for Baltimore Gas and Electric Company
31-10	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
	Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Annual Report on Form 10-K for the year ended December 31, 2010 filed by the following officers for the following registrants:
32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Jonathan W. Thayer for Exelon Corporation
32-3	Filed by Christopher M. Crane for Exelon Generation Company, LLC
32-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	Filed by Craig L. Adams for PECO Energy Company
32-8	Filed by Phillip S. Barnett for PECO Energy Company
32-9	Filed by Kenneth W. DeFontes Jr. for Baltimore Gas and Electric Company
32-10	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
101.INS**	XBRL Instance
101.SCH**	XBRL Taxonomy Extension Schema
101.CAL**	XBRL Taxonomy Extension Calculation
101.DEF**	XBRL Taxonomy Extension Definition
101.LAB**	XBRL Taxonomy Extension Labels

Exhibit No.	Description
101.PRE**	XBRL Taxonomy Extension Presentation

* Compensatory plan or arrangements in which directors or officers of the applicable registrant participate and which are not available to all employees.
** XBRL information will be considered to be furnished, not filed for the first two years of a company's submission of XBRL information.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 21st day of February, 2013.

EXELON CORPORATION

By: /s/ C HRISTOPHER M. C RANE
Name: Christopher M. Crane
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 21st day of February, 2013.

Signature	Title
/s/ C HRISTOPHER M. C RANE **Christopher M. Crane**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ J ONATHAN W. T HAYER **Jonathan W. Thayer**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ D UANE M. D ES P ARTE **Duane M. DesParte**	Vice President and Corporate Controller (Principal Accounting Officer)

This annual report has also been signed below by Darryl M. Bradford, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Yves C. de Balmann
Ann C. Berzin
John A. Canning, Jr.
Nicholas DeBenedictis
Nelson A. Diaz
Sue L. Gin
Paul L. Joskow
Robert J. Lawless
Richard W. Mies
William C. Richardson
Thomas J. Ridge
John W. Rogers, Jr.
Mayo A. Shattuck III
Stephen D. Steinour
Donald Thompson

By: /s/ D ARRYL M. B RADFORD
Name: Darryl M. Bradford

February 21, 2013

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 21st day of February, 2013.

EXELON GENERATION COMPANY, LLC

By: /s/ C HRISTOPHER M. C RANE
Name: Christopher M. Crane
Title: President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 21st day of February, 2013.

Signature	Title
/s/ C HRISTOPHER M. C RANE **Christopher M. Crane**	President (Principal Executive Officer)
/s/ B RYAN P. W RIGHT **Bryan P. Wright**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ R OBERT M. A IKEN **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 21st day of February, 2013.

COMMONWEALTH EDISON COMPANY

By: /s/ ANNE R. PRAMAGGIORE
Name: **Anne R. Pramaggiore**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 21st day of February, 2013.

Signature	Title
/s/ ANNE R. PRAMAGGIORE **Anne R. Pramaggiore**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ JOSEPH R. TRPIK, JR. **Joseph R. Trpik, Jr.**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ KEVIN J. WADEN **Kevin J. Waden**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director
/s/ DENIS P. O'BRIEN **Denis P. O'Brien**	Vice Chairman and Director

This annual report has also been signed below by Anne R. Pramaggiore, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

James W. Compton
A. Steven Crown
Peter V. Fazio, Jr.
Sue L. Gin
Michael Moskow
Jesse H. Ruiz

By: /s/ ANNE R. PRAMAGGIORE
Name: **Anne R. Pramaggiore**

February 21, 2013

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 21st day of February, 2013.

PECO ENERGY COMPANY

By: /s/ C RAIG L. A DAMS
Name: Craig L. Adams
Title: Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 21st day of February, 2013.

Signature	**Title**
/s/ C RAIG L. A DAMS **Craig L. Adams**	Chief Executive Officer and President (Principal Executive Officer) and Director
/s/ P HILLIP S. B ARNETT **Phillip S. Barnett**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ S COTT A. B AILEY **Scott A. Bailey**	Vice President and Controller (Principal Accounting Officer)
/s/ C HRISTOPHER M. C RANE **Christopher M. Crane**	Chairman and Director
/s/ D ENIS P. O'B RIEN **Denis P. O'Brien**	Vice Chairman and Director

This annual report has also been signed below by Craig L. Adams, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

M. Walter D'Alessio
Nelson A. Diaz
Charisse R. Lillie
Thomas J. Ridge
Ronald Rubin

By: /s/ C RAIG L. A DAMS
Name: Craig L. Adams

February 21, 2013

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 21st day of February, 2013.

BALTIMORE GAS AND ELECTRIC COMPANY

By: /s/ K ENNETH W. D E F ONTES , J R .
Name: Kenneth W. DeFontes Jr.
Title: Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 21st day of February, 2013.

Signature	Title
/s/ K ENNETH W. D E F ONTES , J R . **Kenneth W. DeFontes Jr.**	Chief Executive Officer and President (Principal Executive Officer) and Director
/s/ C ARIM V. K HOUZAMI **Carim V. Khouzami**	Vice President, Chief Financial Officer, and Treasurer (Principal Financial Officer)
/s/ D AVID M. V AHOS **David M. Vahos**	Vice President and Controller (Principal Accounting Officer)
/s/ C HRISTOPHER M. C RANE **Christopher M. Crane**	Chairman and Director
/s/ D ENIS P. O'B RIEN **Denis P. O'Brien**	Vice Chairman and Director

This annual report has also been signed below by Kenneth W. DeFontes, Jr., Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Michael E. Cryor
James R. Curtiss
Joseph Haskins, Jr.
Carla D. Hayden

By: /s/ K ENNETH W. D E F ONTES , J R . February 21, 2013
Name: Kenneth W. DeFontes, Jr.

Exhibit 12.1

Exelon Corporation
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2008	2009	2010	2011	2012
Pre-tax income from continuing operations	4,034	4,418	4,221	3,952	1,798
Plus: Loss from equity investees	26	27	—	1	91
Less: Capitalized interest	(33)	(55)	(43)	(57)	(75)
Preference security dividend requirements	(6)	(7)	(7)	(6)	(25)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	4,021	4,383	4,171	3,890	1,789
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	865	761	836	761	1,021
Interest component of rental expense (a)	289	230	241	237	310
Preference security dividend requirements of consolidated subsidiaries	6	7	7	6	25
Total fixed charges	1,160	998	1,084	1,004	1,356
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	5,181	5,381	5,255	4,894	3,145
Ratio of earnings to fixed charges	4.5	5.4	4.8	4.9	2.3

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exelon Generation Company, LLC
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2008	2009	2010	2011	2012
Pre-tax income from continuing operations	3,388	3,555	3,150	2,827	1,058
Plus: Loss from equity investees	1	3	—	1	91
Less: Capitalized interest	(33)	(49)	(38)	(49)	(67)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	3,356	3,509	3,112	2,779	1,082
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	170	162	191	219	402
Interest component of rental expense (a)	272	212	222	220	291
Total fixed charges	442	374	413	439	693
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	3,798	3,883	3,525	3,218	1,775
Ratio of earnings to fixed charges	8.6	10.4	8.5	7.3	2.6

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exhibit 12.3

Commonwealth Edison Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2008	2009	2010	2011	2012
Pre-tax income from continuing operations	329	602	693	666	618
Plus: Loss from equity investees	9	—	—	—	—
Less: Capitalized interest	3	(3)	(2)	(4)	(3)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	341	599	691	662	615
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	323	301	368	330	297
Interest component of rental expense (a)	8	7	6	6	6
Total fixed charges	331	308	374	336	303
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest plus fixed charges	672	907	1,065	998	918
Ratio of earnings to fixed charges	2.0	2.9	2.8	3.0	3.0

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exhibit 12.4

PECO Energy Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2008	2009	2010	2011	2012
Pre-tax income from continuing operations	475	499	476	535	508
Plus: Loss from equity investees	16	24	—	—	—
Less: Capitalized interest	(3)	(2)	(4)	(4)	(2)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	488	521	472	531	506
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	229	185	193	135	122
Interest component of rental expense (a)	9	9	10	9	9
Total fixed charges	238	194	203	144	131
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	726	715	675	675	637
Ratio of earnings to fixed charges	3.1	3.7	3.3	4.7	4.9

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

PECO Energy Company
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
	2008	2009	2010	2011	2012
Pre-tax income from continuing operations	475	499	476	535	508
Plus: Loss from equity investees	16	24	—	—	—
Less: Capitalized interest	(3)	(2)	(4)	(4)	(2)
Preference security dividend requirements	(6)	(6)	(6)	(6)	(5)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	482	515	466	525	501
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	229	185	193	135	122
Interest component of rental expense (a)	9	9	10	9	9
Preference security dividend requirements	6	6	6	6	5
Total fixed charges	244	200	209	150	136
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	726	715	675	675	637
Ratio of earnings to fixed charges and preferred stock dividends	3.0	3.6	3.2	4.5	4.7

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exhibit 12.5

BGE
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2008	2009	2010	2011	2012
Pre-tax income from continuing operations	72	155	244	211	11
Less: Capitalized interest	(4)	(4)	(6)	(7)	(5)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	68	151	238	204	6
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	149	148	137	136	149
Interest component of rental expense (a)	4	5	4	5	4
Total fixed charges	153	153	141	141	153
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	221	304	379	345	159
Ratio of earnings to fixed charges	1.4	2.0	2.7	2.4	1.0

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

BGE
Ratio of Earnings to Fixed Charges and Preference Stock Dividends

	Years Ended December 31,				
	2008	2009	2010	2011	2012
Pre-tax income from continuing operations	72	155	244	211	11
Less: Capitalized interest	(4)	(4)	(6)	(7)	(5)
Preference security dividend requirements	(19)	(22)	(20)	(20)	(20)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	49	129	218	184	(14)
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	149	148	137	136	149
Interest component of rental expense (a)	4	5	4	5	4
Preference security dividend requirements	19	22	20	20	20
Total fixed charges	172	175	161	161	173
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	221	304	379	345	159
Ratio of earnings to fixed charges and preferred stock dividends	1.3	1.7	2.4	2.1	0.9(b)

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.
(b) The ratio coverage was less than 1:1. The registrant must generate additional earnings of $14 million to achieve a coverage ratio of 1:1.

Exelon Corporation Subsidiary Listing

Affiliate	Jurisdiction of Formation
A/C Fuels Company	Pennsylvania
A/C Power	Maryland
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Alta Devices, Inc.	Delaware
APS Constellation, LLC	Delaware
Astrum, Inc.	Delaware
ATNP Finance Company	Delaware
AV Solar Ranch 1, LLC	Delaware
B & K Energy Systems, LLC	Minnesota
Baltimore Gas and Electric Company	Maryland
BC Energy LLC	Minnesota
Beebe Renewable Energy, LLC	Delaware
Bellevue Wind Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
BGE Capital Trust II	Delaware
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Breezy Bucks-I LLC	Minnesota
Breezy Bucks-II LLC	Minnesota
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
C3, LLC	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Calvert Land Corporation	Maryland
Canton Crossing District Energy LLC	Delaware
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CCG SynFuel, LLC	Delaware
CD Empire I, Inc.	Maryland
CD Empire II, Inc.	Maryland
CD Malacha I, Inc.	Maryland
CD Mammoth Lakes I, Inc.	Maryland
CD Mammoth Lakes II, Inc.	Maryland
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CD Soda I, Inc.	Maryland

CD Soda II, Inc.	Maryland
CD Soda III, Inc.	Maryland
CD Soda SLR, Inc.	Maryland
CE Central Wayne Recovery Limited Partnership	Maryland
CE Colver I, Inc.	Maryland
CE Colver II, LLC	Delaware
CE Colver III, Inc.	Maryland
CE Colver Limited Partnership	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Long Valley I, Inc.	Maryland
CE Long Valley II, Inc.	Maryland
CE Long Valley Limited Partnership	Maryland
CE Nuclear, LLC	Delaware
CE Wayne I, Inc.	Maryland
CE Wayne II, Inc.	Maryland
CECG International Holdings, Inc.	Delaware
Central Wayne Energy Recovery Limited Partnership	Maryland
CER Generation II, LLC	Delaware
CER Generation, LLC	Delaware
CER-Colorado Bend Energy LLC	Delaware
CER-Colorado Bend Energy Partners LP	Delaware
CER-Quail Run Energy LLC	Delaware
CER-Quail Run Energy Partners LP	Delaware
CEU Arkoma West, LLC	Delaware
CEU CHC, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU Development, LLC	Delaware
CEU Eagle Ford, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Offshore I, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU Trenton, LLC	Delaware
CEU W&D, LLC	Delaware
Christoffer Transmission Systems, LLC	Minnesota
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Oldco, LLC	Maryland
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton NQF, LLC	Nevada

CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
Cogenex Corporation	Massachusetts
CoLa Resources LLC	Delaware
ComEd Financing III	Delaware
ComEd Funding, LLC	Delaware
ComEd Transitional Funding Trust	Delaware
ComEd Transitional Funding Trust	Delaware
Commonwealth Edison Company	Illinois
Commonwealth Edison Company of Indiana, Inc.	Indiana
Conemaugh Fuels, LLC	Delaware
Consert, Inc.	Delaware
Constellation Alliance II, LP	Texas
Constellation Alliance, LLC	Delaware
Constellation Alliance, LP	Texas
Constellation Bulk Energy Holdings, Inc.	Marshall Islands
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Limited	United Kingdom
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Commodities Group Massachusetts, LLC	Delaware
Constellation Energy Commodities Group New Hampshire, LLC	Delaware
Constellation Energy Commodities Group, Inc.	Delaware
Constellation Energy Control and Dispatch, LLC	Delaware
Constellation Energy Gas Choice, Inc.	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Partners Holdings, LLC	Delaware
Constellation Energy Power Choice, Inc.	Delaware
Constellation Energy Projects & Services Group Advisors, LLC	Delaware
Constellation Energy Projects and Services Canada, Inc.	Federal
Constellation Energy Resources, LLC	Delaware
Constellation Green Energy, LLC	Maryland
Constellation Holdings, LLC	Maryland
Constellation International Holdings, Inc.	Marshall Islands
Constellation Investments, Inc.	Maryland
Constellation Mystic Power, LLC	Delaware
Constellation New Nuclear, LLC	Delaware
Constellation NewEnergy - Gas Division, LLC	Kentucky
Constellation NewEnergy Canada Inc.	Ontario
Constellation NewEnergy Holding, LLC	Delaware
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Operating Services	California
Constellation Operating Services International	Cayman Islands
Constellation Operating Services International - I	Cayman Islands
Constellation Operating Services, LLC	Maryland
Constellation Power International Development, Ltd.	Cayman Islands

Constellation Power Source Generation, Inc.	Maryland
Constellation Power, Inc.	Maryland
Constellation Real Estate Group, Inc.	Maryland
Constellation Real Estate, Inc.	Maryland
Constellation Sacramento Holding, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar, LLC	Delaware
COSI A/C Power, Inc.	Maryland
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
COSI Synfuels, Inc.	Maryland
COSI Ultra II, Inc.	Maryland
COSI Ultra, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP II Curacao Ltd.	Cayman Islands
CP Oleander Limited Partnership	Maryland
CP Sunnyside I, Inc.	Maryland
CP Synfuels Investor, Inc.	Maryland
CP Synfuels Investor, LLC	Maryland
CP Windfarm, LLC	Minnesota
CPI OldCo, Inc.	Maryland
CR Clearing, LLC	Missouri
CRE OldCo, Inc.	Maryland
CREG OldCo, Inc.	Maryland
Criterion Power Partners, LLC	Delaware
DAJAW Transmission LLC	Minnesota
Denver Airport Solar, LLC	Delaware
DL Windy Acres, LLC	Minnesota
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
Elbridge Wind Farm, LLC	Delaware
ENEH Services, LLC	Delaware
Energy Capital and Services II, Limited Partnership	Massachusetts
Energy Performance Services, Inc.	Pennsylvania
ETT Canada, Inc.	New Brunswick
Ewington Energy Systems LLC	Minnesota

Exelon AOG Holding #1, Inc.	Delaware
Exelon AOG Holding #2, Inc	Delaware
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Business Services Company, LLC	Delaware
Exelon Capital Trust I	Delaware
Exelon Capital Trust II	Delaware
Exelon Capital Trust III	Delaware
Exelon Edgar, LLC	Delaware
Exelon Energy Delivery Company, LLC	Delaware
Exelon Enterprises Company, LLC	Pennsylvania
Exelon Framingham Development, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, Inc.	Pennsylvania
Exelon Hamilton LLC	Delaware
Exelon International Commodities, LLC	Delaware
Exelon Investment Holdings, LLC	Illinois
Exelon Mechanical, LLC	Delaware
Exelon New Boston, LLC	Delaware
Exelon New England Development, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon New England Power Marketing, Limited Partnership	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon Nuclear Texas Holdings, LLC	Delaware
Exelon Peaker Development General, LLC	Delaware
Exelon Peaker Development Limited, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon SHC, LLC	Delaware
Exelon Solar Chicago LLC	Delaware
Exelon Transmission Company, LLC	Delaware
Exelon Ventures Company, LLC	Delaware
Exelon West Medway Development, LLC	Delaware
Exelon West Medway Expansion, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	Canada

Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
Ex-FM, Inc.	New York
Ex-FME, Inc.	Delaware
ExTel Corporation, LLC	Delaware
ExTex LaPorte Limited Partnership	Texas
ExTex Retail Services Company, LLC	Delaware
F & M Holdings Company, L.L.C.	Delaware
FloDesign	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Frontier I, L.P.	Delaware
Fuel Recovery, Inc.	Pennsylvania
G-Flow Wind, LLC	Minnesota
Ginna 2 Nuclear Project, LLC	Delaware
Grande Prairie Generation, Inc.	Alberta
Green Acres Breeze, LLC	Minnesota
Greensburg Wind Farm, LLC	Delaware
Guatemalan Generating Group - I	Cayman Islands
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho
Inter-Power/Ahlcon Partners Limited Partnership	Delaware
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
Keystone Fuels, LLC	Delaware
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
Las Vegas District Energy, LLC	Delaware
Latin American Power Partners Limited	Cayman Islands
Lilly Recovery, Inc.	Pennsylvania
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Low Country Synfuel Holdings, LLC	Delaware
Luz Solar Partners Ltd., IV	California
Luz Solar Partners Ltd., V	California
Luz Solar Partners Ltd., VI	California
Malacha Hydro Limited Partnership	Maryland
Mammoth Power Associates, L.P.	California
Maple Coal Company	Pennsylvania
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota

Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Minnesota Breeze, LLC	Minnesota
Mountain Top Wind Power, LLC	Maryland
MXENERGY (CANADA) LTD.	Nova Scotia
MxEnergy Holdings Inc.	Delaware
Newcosy, Inc.	Delaware
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Northwind Thermal Technologies Canada Inc.	New Brunswick
NuStart Energy Development, LLC	Delaware
Old Hickory District Energy, LLC	Delaware
OldcoVSI, Inc.	Delaware
OldPecoGasCo, Company	Pennsylvania
OMF 11520, LLC	Delaware
Onyx Realty Development Corporation	Delaware
Oregon Trail Windfarm, LLC	Oregon
Outback Solar, LLC	Oregon
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Palmetto Synfuel Operating Company, LLC	Delaware
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital Trust V	Delaware
PECO Energy Capital Trust VI	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Company	Pennsylvania
PECO Wireless, LLC	Delaware
Pegasus Power Company, Inc.	California
Pegasus Power Partners, a California Limited Partnership	California
Pinedale Energy, LLC	Colorado
Poseidon Interconnect, LLC	Delaware
Prairie Wind Power LLC	Minnesota
PT Constellation Energy Commodities Group Indonesia	Indonesia
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Residential Solar Holding, LLC	Delaware
Residential Solar I, LLC	Delaware
Residential Solar II, LLC	Delaware
Residential Solar III, LLC	Delaware
RF HoldCo LLC	Delaware
RITELine Illinois, LLC	Illinois
RITELine Indiana, LLC	Indiana

RITELine Transmission Development, LLC	Delaware
River Bend I, L.L.C.	Delaware
Roadrunner-I LLC	Minnesota
RSB BondCo LLC	Delaware
S & P Windfarms, LLC	Minnesota
Sacramento PV Energy, LLC	Delaware
Safe Harbor Water Power Corporation	Pennsylvania
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Salty Dog-I LLC	Minnesota
Salty Dog-II LLC	Minnesota
Sand Ranch Windfarm, LLC	Oregon
Scherer Holdings 1, LLC	Delaware
Scherer Holdings 2, LLC	Delaware
Scherer Holdings 3, LLC	Delaware
Shane's Wind Machine LLC	Minnesota
Shooting Star Wind Project, LLC	Delaware
Spruce Equity Holdings, L.P.	Delaware
Spruce Holdings G.P. 2000, L.L.C.	Delaware
Spruce Holdings L.P. 2000, L.L.C.	Delaware
Spruce Holdings Trust	Delaware
Star Electricity, Inc.	Texas
Sunbelt I, L.L.C.	Delaware
Sunnyside Cogeneration Associates	Utah
Sunnyside Generation, LLC	Delaware
Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Sunnyside Properties, LLC	Utah
Sunset Breeze, LLC	Minnesota
Tamuin International, Inc.	Delaware
TEG Holdings, LLC	Delaware
The Proprietors of the Susquehanna Canal	Maryland
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware
TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
UII, LLC	Illinois
URI, LLC	Illinois
W&D Gas Partners, LLC	Delaware
Wagon Trail, LLC	Oregon
Wally's Wind Farm LLC	Minnesota
Wansley Holdings 1, LLC	Delaware
Wansley Holdings 2, LLC	Delaware
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Windy Dog-1 LLC	Minnesota
Wolf Hollow I, L.P.	Delaware
Wolf Wind Enterprises, LLC	Minnesota
Wolf Wind Transmission, LLC	Minnesota
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Exelon Generation Company, LLC Subsidiary Listing

Affiliate	Jurisdiction of Formation
A/C Fuels Company	PA
A/C Power	MD
AgriWind LLC	IL
AgriWind Project L.L.C.	DE
Alta Devices, Inc.	DE
APS Constellation, LLC	DE
Astrum, Inc.	DE
AV Solar Ranch 1, LLC	DE
B & K Energy Systems, LLC	MN
BC Energy LLC	MN
Beebe Renewable Energy, LLC	DE
Bellevue Wind Energy, LLC	DE
Bennett Creek Windfarm, LLC	ID
BGE Home Products & Services, LLC	DE
Big Top, LLC	OR
Blue Breezes II, L.L.C.	MN
Blue Breezes, L.L.C.	MN
Braidwood 1 NQF, LLC	NV
Braidwood 2 NQF, LLC	NV
Breezy Bucks-I LLC	MN
Breezy Bucks-II LLC	MN
Butter Creek Power, LLC	OR
Byron 1 NQF, LLC	NV
Byron 2 NQF, LLC	NV
C3, LLC	DE
California PV Energy, LLC	DE
Calvert Cliffs Nuclear Power Plant, LLC	MD
Calvert Land Corporation	MD
Canton Crossing District Energy LLC	DE
Cassia Gulch Wind Park LLC	ID
Cassia Wind Farm LLC	ID
CCG SynFuel, LLC	DE
CD Empire I, Inc.	MD
CD Empire II, Inc.	MD
CD Malacha I, Inc.	MD
CD Mammoth Lakes I, Inc.	MD
CD Mammoth Lakes II, Inc.	MD
CD Panther I, Inc.	MD
CD Panther II, LLC	MD
CD Panther Partners, L.P.	DE
CD SEGS V, Inc.	MD
CD SEGS VI, Inc.	MD
CD Soda I, Inc.	MD
CD Soda II, Inc.	MD
CD Soda III, Inc.	MD
CD Soda SLR, Inc.	MD
CE Central Wayne Recovery Limited Partnership	MD

CE Colver I, Inc.	MD
CE Colver II, LLC	DE
CE Colver III, Inc.	MD
CE Colver Limited Partnership	MD
CE Culm, Inc.	MD
CE FundingCo, LLC	DE
CE Long Valley I, Inc.	MD
CE Long Valley II, Inc.	MD
CE Long Valley Limited Partnership	MD
CE Nuclear, LLC	DE
CE Wayne I, Inc.	MD
CE Wayne II, Inc.	MD
Central Wayne Energy Recovery Limited Partnership	MD
CER Generation II, LLC	DE
CER Generation, LLC	DE
CER-Colorado Bend Energy LLC	DE
CER-Colorado Bend Energy Partners LP	DE
CER-Quail Run Energy LLC	DE
CER-Quail Run Energy Partners LP	DE
CEU Arkoma West, LLC	DE
CEU CHC, LLC	DE
CEU CoLa, LLC	DE
CEU Development, LLC	DE
CEU Eagle Ford, LLC	DE
CEU East Fort Peck, LLC	DE
CEU Fayetteville, LLC	DE
CEU Floyd Shale, LLC	DE
CEU Holdings, LLC	DE
CEU Huntsville, LLC	DE
CEU Kingston, LLC	DE
CEU Offshore I, LLC	DE
CEU Ohio Shale, LLC	DE
CEU Paradigm, LLC	DE
CEU Pinedale, LLC	DE
CEU Plymouth, LLC	DE
CEU Simplicity, LLC	DE
CEU Trenton, LLC	DE
CEU W&D, LLC	DE
Christoffer Transmission Systems, LLC	MN
Christoffer Wind Energy I LLC	MN
Christoffer Wind Energy II LLC	MN
Christoffer Wind Energy III LLC	MN
Christoffer Wind Energy IV LLC	MN
CII Oldco, LLC	MD
CII Solarpower I, Inc.	MD
Cisco Wind Energy LLC	MN
Clinton NQF, LLC	NV
CLT Energy Services Group, L.L.C.	PA
CNE Gas Holdings, LLC	KY
CNE Gas Supply, LLC	DE
CNEG Holdings, LLC	DE
CNEGH Holdings, LLC	DE

Cogenex Corporation	MA
CoLa Resources LLC	DE
Conemaugh Fuels, LLC	DE
Consert, Inc.	DE
Constellation Alliance II, LP	TX
Constellation Alliance, LLC	DE
Constellation Bulk Energy Holdings, Inc.	Marshall Islands
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Limited	U.K.
Constellation Energy Commodities Group Maine, LLC	DE
Constellation Energy Commodities Group Massachusetts, LLC	DE
Constellation Energy Commodities Group New Hampshire, LLC	DE
Constellation Energy Commodities Group, Inc.	DE
Constellation Energy Control and Dispatch, LLC	DE
Constellation Energy Gas Choice, Inc.	DE
Constellation Energy Nuclear Group, LLC	MD
Constellation Energy Partners Holdings, LLC	DE
Constellation Energy Power Choice, Inc.	DE
Constellation Energy Projects & Services Group Advisors, LLC	DE
Constellation Energy Projects and Services Canada, Inc.	Federal
Constellation Energy Resources, LLC	DE
Constellation Green Energy, LLC	MD
Constellation Holdings, LLC	MD
Constellation International Holdings, Inc.	Marshall Islands
Constellation Investments, Inc.	MD
Constellation Mystic Power, LLC	DE
Constellation New Nuclear, LLC	DE
Constellation NewEnergy - Gas Division, LLC	KY
Constellation NewEnergy Canada Inc.	Ontario
Constellation NewEnergy Holding, LLC	DE
Constellation NewEnergy, Inc.	DE
Constellation Nuclear Power Plants, LLC	DE
Constellation Nuclear, LLC	DE
Constellation Operating Services	CA
Constellation Operating Services International	Cayman Islands
Constellation Operating Services International - I	Cayman Islands
Constellation Operating Services, LLC	MD
Constellation Power International Development, Ltd.	Cayman Islands
Constellation Power Source Generation, Inc.	MD
Constellation Power, Inc.	MD
Constellation Real Estate Group, Inc.	MD
Constellation Real Estate, Inc.	MD
Constellation Sacramento Holding, LLC	DE
Constellation Solar Arizona, LLC	DE
Constellation Solar California, LLC	DE
Constellation Solar Connecticut, LLC	DE
Constellation Solar DC, LLC	DE
Constellation Solar Federal, LLC	DE
Constellation Solar Holding, LLC	DE

Constellation Solar Horizons Holding, LLC	DE
Constellation Solar Horizons, LLC	DE
Constellation Solar Maryland II, LLC	DE
Constellation Solar Maryland, LLC	DE
Constellation Solar Massachusetts, LLC	DE
Constellation Solar Net Metering, LLC	DE
Constellation Solar New Jersey II, LLC	DE
Constellation Solar New Jersey III, LLC	DE
Constellation Solar New Jersey, LLC	DE
Constellation Solar Ohio, LLC	DE
Constellation Solar, LLC	DE
COSI A/C Power, Inc.	MD
COSI Central Wayne, Inc.	MD
COSI Sunnyside, Inc.	MD
COSI Synfuels, Inc.	MD
COSI Ultra II, Inc.	MD
COSI Ultra, Inc.	MD
Cow Branch Wind Power, L.L.C.	MS
CP II Curacao Ltd.	Cayman Islands
CP Sunnyside I, Inc.	MD
CP Synfuels Investor, Inc.	MD
CP Synfuels Investor, LLC	MD
CP Windfarm, LLC	MN
CPI OldCo, Inc.	MD
CR Clearing, LLC	MS
CRE OldCo, Inc.	MD
CREG OldCo, Inc.	MD
Criterion Power Partners, LLC	DE
DAJAW Transmission LLC	MN
Denver Airport Solar, LLC	DE
DL Windy Acres, LLC	MN
Dresden 1 NQF, LLC	NV
Dresden 2 NQF, LLC	NV
Dresden 3 NQF, LLC	NV
Elbridge Wind Farm, LLC	DE
ENEH Services, LLC	DE
Energy Capital and Services II, Limited Partnership	MA
Energy Performance Services, Inc.	PA
Ewington Energy Systems LLC	MN
Exelon AOG Holding #1, Inc.	DE
Exelon AOG Holding #2, Inc	DE
Exelon AVSR Holding, LLC	DE
Exelon AVSR, LLC	DE
Exelon Edgar, LLC	DE
Exelon Framingham Development, LLC	DE
Exelon Framingham, LLC	DE
Exelon Generation Acquisitions, LLC	DE
Exelon Generation Consolidation, LLC	NV
Exelon Generation Finance Company, LLC	DE
Exelon Generation International, Inc.	PA
Exelon Hamilton LLC	DE
Exelon International Commodities, LLC	DE

Exelon New Boston, LLC	DE
Exelon New England Development, LLC	DE
Exelon New England Holdings, LLC	DE
Exelon New England Power Marketing, Limited Partnership	DE
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	DE
Exelon Nuclear Security, LLC	DE
Exelon Nuclear Texas Holdings, LLC	DE
Exelon Peaker Development General, LLC	DE
Exelon Peaker Development Limited, LLC	DE
Exelon PowerLabs, LLC	PA
Exelon SHC, LLC	DE
Exelon Solar Chicago LLC	DE
Exelon West Medway Development, LLC	DE
Exelon West Medway Expansion, LLC	DE
Exelon West Medway, LLC	DE
Exelon Wind 1, LLC	TX
Exelon Wind 10, LLC	TX
Exelon Wind 11, LLC	TX
Exelon Wind 2, LLC	TX
Exelon Wind 3, LLC	TX
Exelon Wind 4, LLC	TX
Exelon Wind 5, LLC	TX
Exelon Wind 6, LLC	TX
Exelon Wind 7, LLC	TX
Exelon Wind 8, LLC	TX
Exelon Wind 9, LLC	TX
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	DE
Exelon Wyman, LLC	DE
ExTex LaPorte Limited Partnership	TX
ExTex Retail Services Company, LLC	DE
FloDesign	DE
Four Corners Windfarm, LLC	OR
Four Mile Canyon Windfarm, LLC	OR
Frontier I, L.P.	DE
Fuel Recovery, Inc.	PA
G-Flow Wind, LLC	MN
Grande Prairie Generation, Inc.	Alberta
Green Acres Breeze, LLC	MN
Greensburg Wind Farm, LLC	DE
Guatemalan Generating Group - I	Cayman Islands
Handsome Lake Energy, LLC	MD
Harvest II Windfarm, LLC	DE
Harvest Windfarm, LLC	MI
High Mesa Energy, LLC	ID
High Plains Wind Power, LLC	TX
Holyoke Solar, LLC	DE
Hot Springs Windfarm, LLC	ID
Inter-Power/Ahlcon Partners Limited Partnership	DE
K & D Energy LLC	MN
KC Energy LLC	MN

Keystone Fuels, LLC	DE
KSS Turbines LLC	MN
La Salle 1 NQF, LLC	NV
La Salle 2 NQF, LLC	NV
Las Vegas District Energy, LLC	DE
Latin American Power Partners Limited	Cayman Islands
Lilly Recovery, Inc.	PA
Limerick 1 NQF, LLC	NV
Limerick 2 NQF, LLC	NV
Loess Hills Wind Farm, LLC	MS
Low Country Synfuel Holdings, LLC	DE
Luz Solar Partners Ltd., IV	CA
Luz Solar Partners Ltd., V	CA
Luz Solar Partners Ltd., VI	CA
Malacha Hydro Limited Partnership	MD
Mammoth Power Associates, L.P.	CA
Maple Coal Company	PA
Marshall Wind 1, LLC	MN
Marshall Wind 2, LLC	MN
Marshall Wind 3, LLC	MN
Marshall Wind 4, LLC	MN
Marshall Wind 5, LLC	MN
Marshall Wind 6, LLC	MN
Michigan Wind 1, LLC	DE
Michigan Wind 2, LLC	DE
Michigan Wind 3, LLC	DE
Minnesota Breeze, LLC	MN
Mountain Top Wind Power, LLC	MD
MXENERGY (CANADA) LTD.	Nova Scotia
MxEnergy Holdings Inc.	DE
Nine Mile Point Nuclear Station, LLC	DE
North Shore District Energy, LLC	DE
NuStart Energy Development, LLC	DE
Old Hickory District Energy, LLC	DE
Onyx Realty Development Corporation	DE
Oregon Trail Windfarm, LLC	OR
Outback Solar, LLC	OR
Oyster Creek NQF, LLC	NV
Pacific Canyon Windfarm, LLC	OR
Palmetto Synfuel Operating Company, LLC	DE
Panther Creek Holdings, Inc.	DE
Panther Creek Partners	DE
Peach Bottom 1 NQF, LLC	NV
Peach Bottom 2 NQF, LLC	NV
Peach Bottom 3 NQF, LLC	NV
Pegasus Power Company, Inc.	CA
Pegasus Power Partners, a California Limited Partnership	CA
Pinedale Energy, LLC	CO
Prairie Wind Power LLC	MN
Quad Cities 1 NQF, LLC	NV
Quad Cities 2 NQF, LLC	NV
R.E. Ginna Nuclear Power Plant, LLC	MD

Residential Solar Holding, LLC	DE
Residential Solar I, LLC	DE
Residential Solar II, LLC	DE
Residential Solar III, LLC	DE
River Bend I, L.L.C.	DE
Roadrunner-I LLC	MN
S & P Windfarms, LLC	MN
Sacramento PV Energy, LLC	DE
Safe Harbor Water Power Corporation	PA
Salem 1 NQF, LLC	NV
Salem 2 NQF, LLC	NV
Salty Dog-I LLC	MN
Salty Dog-II LLC	MN
Sand Ranch Windfarm, LLC	OR
Shane's Wind Machine LLC	MN
Shooting Star Wind Project, LLC	DE
Star Electricity, Inc.	TX
Sunbelt I, L.L.C.	DE
Sunnyside Cogeneration Associates	UT
Sunnyside Generation, LLC	DE
Sunnyside II, Inc.	DE
Sunnyside II, L.P.	DE
Sunnyside III, Inc.	DE
Sunnyside Properties, LLC	UT
Sunset Breeze, LLC	MN
Tamuin International, Inc.	DE
TEG Holdings, LLC	DE
The Proprietors of the Susquehanna Canal	MD
Threemile Canyon Wind I, LLC	OR
Titan STC, LLC	DE
TMI NQF, LLC	NV
Tuana Springs Energy, LLC	ID
W&D Gas Partners, LLC	DE
Wagon Trail, LLC	OR
Wally's Wind Farm LLC	MN
Ward Butte Windfarm, LLC	OR
Water & Energy Savings Company, LLC	DE
Whitetail Wind Energy, LLC	DE
Wildcat Finance, LLC	DE
Wildcat Wind LLC	NM
Wind Capital Holdings, LLC	MS
Windy Dog-1 LLC	MN
Wolf Hollow I, L.P.	DE
Wolf Wind Enterprises, LLC	MN
Wolf Wind Transmission, LLC	MN
Zion 1 NQF, LLC	NV
Zion 2 NQF, LLC	NV

Commonwealth Edison Company Subsidiary Listing

Affiliate	Jurisdiction of Formation
ComEd Financing III	Delaware
ComEd Funding, LLC	Delaware
ComEd Transitional Funding Trust	Delaware
Commonwealth Edison Company of Indiana, Inc.	Indiana
RITELine Illinois, LLC	Illinois

PECO Energy Company Subsidiary Listing

Affiliate	Jurisdiction of Formation
ATNP Finance Company	Delaware
ExTel Corporation, LLC	Delaware
OldPecoGasCo, Company	Pennsylvania
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital Trust V	Delaware
PECO Energy Capital Trust VI	Delaware
PECO Energy Capital, LP	Delaware
PECO Wireless, LLC	Delaware

Exhibit 21.5

Baltimore Gas abd Electric Company Subisidary Listing

Affiliate	Jurisdiction of Formation
BGE Capital Trust II	Delaware
RSB BondCo LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-181749 and No.333-183751), on Form S-4 (No.333-175162) and on Form S-8 (No.333-127377, No.333-61390, No.333-37082 and No.333-49780) of Exelon Corporation of our report dated February 21, 2013 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting of Exelon Corporation, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 21, 2013

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-181749-05) and Form S-4 (No. 333-184712) of Exelon Generation Company, LLC of our report dated February 21, 2013 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Exelon Generation Company, LLC, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 21, 2013

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-181749-04) of Commonwealth Edison Company of our report dated February 21, 2013 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Commonwealth Edison Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 21, 2013

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-181749-03) of PECO Energy Company of our report dated February 21, 2013 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of PECO Energy Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 21, 2013

Exhibit 23.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-181749-09) of Baltimore Gas and Electric Company of our report dated February 21, 2013 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Baltimore Gas and Electric Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 21, 2013

Exhibit 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ann C. Berzin
Ann C. Berzin

DATE: February 11, 2013

Exhibit 24.2

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John A. Canning, Jr.** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John A. Canning, Jr.
John A. Canning, Jr.

DATE: February 8, 2013

Exhibit 24.3

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Darryl M. Bradford attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 8, 2013

Exhibit 24.4

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Yves C. de Balmann** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Yves C. de Balmann
Yves C. de Balmann

DATE: February 11, 2013

Exhibit 24.5

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis
Nicholas DeBenedictis

DATE: February 18, 2013

Exhibit 24.6

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nelson A. Diaz** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nelson A. Diaz
Nelson A. Diaz

DATE: February 12, 2013

Exhibit 24.7

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Sue L. Gin** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Sue L. Gin
Sue L. Gin

DATE: February 18, 2013

Exhibit 24.8

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Paul L. Joskow** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Paul L. Joskow
Paul L. Joskow

DATE: February 14, 2013

Exhibit 24.9

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Robert J. Lawless** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Robert J. Lawless
Robert J. Lawless

DATE: February 12, 2013

Exhibit 24.10

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Richard W. Mies** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Richard W. Mies
Richard W. Mies

DATE: February 18, 2013

Exhibit 24.11

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **William C. Richardson** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ William C. Richardson
William C. Richardson

DATE: February 13, 2013

Exhibit 24.12

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Thomas J. Ridge** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Thomas J. Ridge
Thomas J. Ridge

DATE: February 15, 2013

Exhibit 24.13

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John W. Rogers, Jr.** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John W. Rogers, Jr.
John W. Rogers, Jr.

DATE: February 12, 2013

Exhibit 24.14

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Mayo A. Shattuck III** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Mayo A. Shattuck III
Mayo A. Shattuck III

DATE: February 12, 2013

Exhibit 24.15

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Stephen D. Steinour** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Stephen D. Steinour
Stephen D. Steinour

DATE: February 18, 2013

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Donald Thompson** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Donald Thompson
Donald Thompson

DATE: February 11, 2013

Exhibit 24.17

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James W. Compton** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ James W. Compton
James W. Compton

DATE: February 11, 2013

Exhibit 24.18

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 8, 2013

Exhibit 24.19

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **A. Steven Crown** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ A. Steven Crown
A. Steven Crown

DATE: February 12, 2013

Exhibit 24.20

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Peter V. Fazio, Jr.** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Peter V. Fazio, Jr.
Peter V. Fazio, Jr.

DATE: February 11, 2013

Exhibit 24.21

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Sue L. Gin** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Sue L. Gin
Sue L. Gin

DATE: February 18, 2013

Exhibit 24.22

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael Moskow** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael Moskow
Michael Moskow

DATE: February 18, 2013

Exhibit 24.23

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anne R. Pramaggiore** , do hereby appoint Thomas S. O'Neill attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Anne R. Pramaggiore
Anne R. Pramaggiore

DATE: February 11, 2013

Exhibit 24.24

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Jesse H. Ruiz** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Jesse H. Ruiz
Jesse H. Ruiz

DATE: February 18, 2013

Exhibit 24.25

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Craig L. Adams** , do hereby appoint Romulo L. Diaz, Jr. attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Craig L. Adams
Craig L. Adams

DATE: February 12, 2013

Exhibit 24.26

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 8, 2013

Exhibit 24.27

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **M. Walter D'Alessio** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ M. Walter D'Alessio
M. Walter D'Alessio

DATE: February 8, 2013

Exhibit 24.28

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nelson A. Diaz** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nelson A. Diaz
Nelson A. Diaz

DATE: February 12, 2013

Exhibit 24.29

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Charisse R. Lillie** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Charisse R. Lillie
Charisse R. Lillie

DATE: February 11, 2013

Exhibit 24.30

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Thomas J. Ridge** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Thomas J. Ridge
Thomas J. Ridge

DATE: February 15, 2013

Exhibit 24.31

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ronald Rubin** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ronald Rubin
Ronald Rubin

DATE: February 8, 2013

Exhibit 24.32

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Baltimore Gas and Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 8, 2013

Exhibit 24.33

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael E. Cryor** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Baltimore Gas and Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael E. Cryor
Michael E. Cryor

DATE: February 12, 2013

Exhibit 24.34

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James R. Curtiss** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Baltimore Gas and Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ James R. Curtiss
James R. Curtiss

DATE: February 14, 2013

Exhibit 24.35

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Kenneth W. DeFontes, Jr.** , do hereby appoint Daniel P. Gahagan attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Baltimore Gas and Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Kenneth W. DeFontes, Jr.
Kenneth W. DeFontes, Jr.

DATE: February 11, 2013

Exhibit 24.36

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Joseph Haskins, Jr.** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Baltimore Gas and Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Joseph Haskins, Jr.
Joseph Haskins, Jr.

DATE: February 14, 2013

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Carla D. Hayden** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2012 of Baltimore Gas and Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Carla D. Hayden
Carla D. Hayden

DATE: February 15, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ C HRISTOPHER M. C RANE
President and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ J ONATHAN W. T HAYER
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ C HRISTOPHER M. C RANE
President
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ B RYAN P. W RIGHT
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ Anne R. Pramaggiore
President and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ JOSEPH R. TRPIK, JR.
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ C RAIG L. A DAMS
Chief Executive Officer and President
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ P HILLIP S. B ARNETT
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. DeFontes Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ K ENNETH W. D EFONTES J R .
Chief Executive Officer and President
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Carim V. Khouzami, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 21, 2013

/s/ C ARIM V. K HOUZAMI
Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2012, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

Date: February 21, 2013

/s/ C HRISTOPHER M. C RANE

Christopher M. Crane
President and Chief Executive Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2012, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

Date: February 21, 2013

/s/ J ONATHAN W. T HAYER

Jonathan W. Thayer
Executive Vice President and Chief Financial Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2012, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

Date: February 21, 2013

/s/ C HRISTOPHER M. C RANE
Christopher M. Crane
President

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2012, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

Date: February 21, 2013

/s/ B RYAN P. W RIGHT

Bryan P. Wright
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2012, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

Date: February 21, 2013

/s/ ANNE R. PRAMAGGIORE
Anne R. Pramaggiore
President and Chief Executive Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2012, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

Date: February 21, 2013

/s/ JOSEPH R. TRPIK, JR.

Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2012, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

Date: February 21, 2013

/s/ C RAIG L. A DAMS

Craig L. Adams
Chief Executive Officer and President

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2012, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

Date: February 21, 2013

/s/ P HILLIP S. B ARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2012, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

Date: February 21, 2013

/s/ KENNETH W. DEFONTES JR.
Kenneth W. DeFontes Jr.
Chief Executive Officer and President

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2012, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

Date: February 21, 2013

/s/ C ARIM V. K HOUZAMI

Carim V. Khouzami
Vice President, Chief Financial Officer and Treasurer

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2013

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number	Exact Name of Registrant as Specified in its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
EXELON CORPORATION:	
Common Stock, without par value	New York and Chicago
Series A Junior Subordinated Debentures	New York
PECO ENERGY COMPANY:	
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York
BALTIMORE GAS AND ELECTRIC COMPANY:	
6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, by Baltimore Gas and Electric Company	New York

Securities registered pursuant to Section 12(g) of the Act:

COMMONWEALTH EDISON COMPANY:
Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes ☒	No ☐
Exelon Generation Company, LLC	Yes ☒	No ☐
Commonwealth Edison Company	Yes ☒	No ☐
PECO Energy Company	Yes ☒	No ☐
Baltimore Gas and Electric Company	Yes ☒	No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

	Large Accelerated	Accelerated	Non-Accelerated	Small Reporting Company
Exelon Corporation	✓			
Exelon Generation Company, LLC			✓	
Commonwealth Edison Company			✓	
PECO Energy Company			✓	
Baltimore Gas and Electric Company			✓	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2013 was as follows:

Exelon Corporation Common Stock, without par value	$ 26,430,683,706
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None
Baltimore Gas and Electric Company, without par value	None

The number of shares outstanding of each registrant's common stock as of January 31, 2014 was as follows:

Exelon Corporation Common Stock, without par value	857,419,806
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,904
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company, without par value	1,000

S1-SSA-0009-12735

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2014 Annual Meeting of Shareholders and the Commonwealth Edison Company 2014 information statement are incorporated by reference in Part III.

Exelon Generation Company, LLC, PECO Energy Company and Baltimore Gas and Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form in the reduced disclosure format.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon's holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
ComEd Financing III	ComEd Financing III
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Energy Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
BGE Trust II	BGE Capital Trust II
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively

Other Terms and Abbreviations

1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended

Other Terms and Abbreviations

Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA
EE&C	Energy Efficiency and Conservation/Demand Response
EIMA	Illinois Energy Infrastructure Modernization Act
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste

Other Terms and Abbreviations

LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal

Other Terms and Abbreviations

Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
TEG	Termoelectrica del Golfo
TEP	Termoelectrica Penoles
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by the Registrants. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this Report are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a Registrant include those factors discussed herein, including those factors with respect to such Registrant discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, (c) ITEM 8. Financial Statements and Supplementary Data: Note 22 and (d) other factors discussed herein and in other filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants' websites at www.exeloncorp.com. Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I

ITEM 1. BUSINESS

General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through Generation, in the energy generation business, and through ComEd, PECO and BGE, in the energy delivery businesses discussed below. Exelon's principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603, and its telephone number is 312-394-7398.

Generation

Generation's integrated business consists of its owned and contracted electric generating facilities and investments in generation ventures that are marketed through its leading customer-facing activities. These customer-facing activities include, wholesale energy marketing operations and its competitive retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions.

Generation was formed in 2000 as a Pennsylvania limited liability company. Generation began operations as a result of a corporate restructuring, effective January 1, 2001, in which Exelon separated its generation and other competitive businesses from its regulated energy delivery businesses at ComEd and PECO. Generation's principal executive offices are located at 300 Exelon Way, Kennett Square, Pennsylvania 19348, and its telephone number is 610-765-5959.

ComEd

ComEd's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in northern Illinois, including the City of Chicago.

ComEd was organized in the State of Illinois in 1913 as a result of the merger of Cosmopolitan Electric Company into the original corporation named Commonwealth Edison Company, which was incorporated in 1907. ComEd's principal executive offices are located at 440 South LaSalle Street, Chicago, Illinois 60605, and its telephone number is 312-394-4321.

PECO

PECO's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia.

PECO was incorporated in Pennsylvania in 1929. PECO's principal executive offices are located at 2301 Market Street, Philadelphia, Pennsylvania 19103, and its telephone number is 215-841-4000.

BGE

BGE's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in central Maryland,

including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in central Maryland, including the City of Baltimore.

BGE was incorporated in Maryland in 1906. BGE's principal executive offices are located at 110 West Fayette Street, Baltimore, Maryland 21201, and its telephone number is 410-234-5000.

Operating Segments

See Note 24 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's operating segments.

Merger with Constellation Energy Group, Inc.

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information on the Constellation transaction.

Generation

Generation, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets. Generation operates as an integrated business, leveraging its owned and contracted electric generation capacity to market and sell power to wholesale and retail customers. Generation's customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation also sells natural gas and renewable energy and other energy-related products and services, and engages in natural gas exploration and production activities.

Generation is a public utility under the Federal Power Act and is subject to FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. FERC's jurisdiction over ratemaking also includes the authority to suspend the market-based rates of utilities (including Generation, which is a public utility as FERC defines that term) and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of

another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities. Additionally, ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. Specific operations of Generation are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including the NRC and Federal and state environmental protection agencies. Additionally, Generation is subject to mandatory reliability standards promulgated by the NERC, with the approval of FERC.

RTOs and ISOs exist in a number of regions to provide transmission service across multiple transmission systems. PJM, MISO, ISO-NE and SPP, have been approved by FERC as RTOs, and CAISO and ISO-NY have been approved as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems.

Significant Acquisitions

Antelope Valley Solar Ranch One **.** On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. The delay will not have a material financial effect on Exelon. Exelon expects the project to be in full commercial operation in the first half of 2014. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA, approved by the CPUC, with Pacific Gas & Electric Company for the full output of the plant. Upon completion, the facility will add 230 MWs to Generation's renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through December 31, 2013 were approximately $968 million.

Wolf Hollow Generating Station. On August 24, 2011, Generation completed the acquisition of all of the equity interests of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, for a purchase price of $311 million which increased Generation's owned capacity within the ERCOT power market by 720 MWs.

See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information on the above acquisitions.

Significant Dispositions

Maryland Clean Coal Stations. On November 30, 2012, a subsidiary of Generation sold the Brandon Shores generating station and H.A. Wagner generating station in Anne Arundel County, Maryland, and the C.P. Crane generating station in Baltimore County, Maryland to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC to comply with certain of the regulatory approvals required by the merger, for net proceeds of approximately $371 million, which resulted in a pre-tax loss of $272 million. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Generating Resources

At December 31, 2013, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [a]	
Nuclear	17,263
Fossil	12,165
Renewable (including Hydroelectric) [b]	3,710
Owned generation assets	33,138
Long-term power purchase contracts [c]	9,426
Investment in CENG [d]	1,999
Total generating resources	44,563

(a) See "Fuel" for sources of fuels used in electric generation.
(b) Includes equity method investment in certain generating facilities.
(c) Excludes contracts with CENG. See Long-Term Power Purchase Contracts table in this section for additional information.
(d) Generation owns a 50.01% interest in CENG, a joint venture with EDF. See ITEM 2. PROPERTIES—Generation and Note 25—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Generation has six reportable segments, the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions, representing the different geographical areas in which Generation's customer-facing activities are conducted and where Generation's generating resources are located.

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina (approximately 37% of capacity).
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee; and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, and the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM; and parts of Montana, Missouri and Kentucky (approximately 34% of capacity).
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 8% of capacity).
- New York represents the operations within ISO-NY, which covers the state of New York in its entirety (approximately 3% of capacity).
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas (approximately 12% of capacity).
- Other Regions is an aggregate of regions not considered individually significant (approximately 6% of capacity).

Nuclear Facilities

Generation has ownership interests in eleven nuclear generating stations currently in service, consisting of 19 units with an aggregate of 17,263 MW of capacity. Generation wholly owns all of its nuclear generating stations, except for Quad Cities Generating Station (75% ownership), Peach Bottom Generating Station (50% ownership) and Salem Generating Station (Salem) (42.59% ownership), which are consolidated on Exelon's financial statements relative to its proportionate ownership interest in each unit. Generation's nuclear generating stations are all operated by

Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. In 2013 and 2012, electric supply (in GWh) generated from the nuclear generating facilities was 57% and 53%, respectively, of Generation's total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation's electric supply sources.

Constellation Energy Nuclear Group, Inc.

Generation also owns a 50.01% interest in CENG, a joint venture with EDF. CENG is governed by a board of ten directors, five of which are appointed by Generation and five by EDF. CENG owns and operates a total of five nuclear generating facilities on three sites, Calvert Cliffs, Ginna and Nine Mile Point. CENG's ownership share in the total capacity of these units is 3,998 MW. See ITEM 2. PROPERTIES for additional information on these sites.

On July 29, 2013, Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. The Master Agreement contemplates that the parties will execute a series of additional agreements at a closing that will occur following the receipt of regulatory approvals and the satisfaction of other customary closing conditions. Exelon currently expects that the closing will occur early in the second quarter of 2014.

At the closing, Generation, CENG and subsidiaries of CENG will execute a Nuclear Operating Services Agreement pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI's rights as a member of CENG. CENG will reimburse Generation for its direct and allocated costs for such services. The Nuclear Operating Services Agreement will replace the SSA. At the closing, Nine Mile Point Nuclear Station, a subsidiary of CENG, will also assign to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with the co-owner. In addition, at the closing the PSAA will be amended and extended until the complete and permanent cessation of operation of the CENG generation plants.

At closing, Generation will make a $400 million loan to CENG bearing interest at 5.25% per annum, payable out of specified available cash flows of CENG and, in any event, payable upon settlement of the Put Option Agreement discussed below, if the put option is exercised, or payable upon the maturity date of the note (which will be 20 years from the closing), whichever occurs first. Immediately following receipt of the proceeds of such loan, CENG will make a $400 million special distribution to EDFI. The parties will also execute a Fourth Amended and Restated Operating Agreement for CENG, pursuant to which, among other things, CENG will commit to make preferred distributions to Generation (after repayment of the $400 million loan) quarterly out of specified available cash flows, until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from the date of the special distribution to EDFI.

Generation and EDFI will also enter into a Put Option Agreement at closing pursuant to which EDFI will have the option, exercisable beginning in 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. The beginning of the exercise period will be accelerated if

Exelon's affiliates cease to own a majority of CENG and exercise a related right to terminate the Nuclear Operating Services Agreement. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Generation will execute an Indemnity Agreement pursuant to which Generation will indemnify EDF and its affiliates against third party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon will guarantee Generation's obligations under this indemnity.

CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Generation currently has an agreement under which it is purchasing 85% of the nuclear plant output owned by CENG that is not sold to third parties under pre-existing firm and unit contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit contingent basis 50.01% of the nuclear plant output owned by CENG, and EDF will purchase on a unit contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA). This agreement will continue to be effective and is not affected by the Master Agreement, except that if the put option under the Master Agreement is exercised, then the EDF PPA would transfer to Generation upon the completion of the Put Option Agreement transaction.

Currently, Exelon and Generation account for its investment in CENG under the equity method of accounting. The transfer of the operational control to Exelon and Generation will result in Exelon and Generation being required to consolidate the financial position and results of operations of CENG. When that accounting change occurs, Exelon and Generation will derecognize its equity method investment in CENG and will record all assets, liabilities and the non-controlling interest in CENG at fair value on Exelon and Generation's balance sheets. Any difference between the former carrying value and newly recorded fair value at that date will be recognized as a gain or loss upon consolidation, which could be material to Exelon's and Generation's results of operations. See Note 5—Investment in CENG of the Combined Notes to Consolidated Financial Statements for additional information regarding CENG.

Nuclear Operations. Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on Generation's results of operations. As the largest generator of nuclear power in the United States, Generation can negotiate favorable terms for the materials and services that its business requires. Generation's operations from its nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

During 2013 and 2012, the nuclear generating facilities operated by Generation achieved capacity factors of 94.1% and 92.7%, respectively. Generation manages its scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for Generation's wholesale and retail marketing and trading activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations.

In addition to the rigorous maintenance and equipment upgrades performed by Generation during scheduled refueling outages, Generation has extensive operating and security procedures in place to ensure the safe operation of the nuclear units. Generation has extensive safety systems in place to protect the plant, personnel and surrounding area in the unlikely event of an accident.

Regulation of Nuclear Power Generation. Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously

assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of December 31, 2013, the NRC categorized Dresden units 2 and 3, LaSalle unit 2, and Clinton in the Regulatory Response Column, which is the second highest of five performance bands. All other units operated by Generation are categorized in the Licensee Response Column as of December 31, 2013, which is the highest performance band. On January 1, 2014, Dresden units 2 and 3 returned to the Licensee Response Column. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. For additional information on the NRC actions related to the Japan Earthquake and Tsunami and the industry's response, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Executive Overview.

Licenses **.** Generation has 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals for Peach Bottom Units 2 and 3, Dresden Units 2 and 3, Quad Cities Units 1 and 2, Oyster Creek and Three Mile Island Unit 1. Additionally, PSEG has 40-year operating licenses from the NRC and has received 20-year operating license renewals for Salem Units 1 and 2. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. The following table summarizes the current operating license expiration dates for Generation's nuclear facilities in service:

Station	Unit	In-Service Date [a]	Current License Expiration
Braidwood [b]	1	1988	2026
	2	1988	2027
Byron [b]	1	1985	2024
	2	1987	2026
Clinton	1	1987	2026
Dresden [c]	2	1970	2029
	3	1971	2031
LaSalle	1	1984	2022
	2	1984	2023
Limerick [d]	1	1986	2024
	2	1990	2029
Oyster Creek [c][e]	1	1969	2029
Peach Bottom [c]	2	1974	2033
	3	1974	2034
Quad Cities [c]	1	1973	2032
	2	1973	2032
Salem [c]	1	1977	2036
	2	1981	2040
Three Mile Island [c]	1	1974	2034

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(a) Denotes year in which nuclear unit began commercial operations.
(b) On May 29, 2013, Generation submitted applications to the NRC to extend the operating licenses of Braidwood Units 1 and 2 and Byron Units 1 and 2 by 20 years.
(c) Stations for which the NRC has issued a renewed operating licenses.
(d) In June 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years.
(e) In December 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

Generation expects to apply for and obtain approval of license renewals for the remaining nuclear units. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC's review. The NRC review process takes approximately two years from the docketing of an application. Each requested license renewal is expected to be for 20 years beyond the original license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual and assumed renewal of operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek.

In August 2012, Generation entered into an operating services agreement with the Omaha Public Power District (OPPD) to provide operational and managerial support services for the Fort Calhoun Station and a licensing agreement for use of the Exelon Nuclear Management Model. The terms for both agreements are 20 years. OPPD will continue to own the plant and remain the NRC licensee.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Under the nuclear uprate program, Generation has placed into service projects representing 316 MWs of new nuclear generation at a cost of $952 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's consolidated balance sheets. At December 31, 2013, Generation has capitalized $203 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 200 MWs of new nuclear generation, that are in the installation phase across four nuclear stations; Peach Bottom in Pennsylvania and Byron, Braidwood and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $300 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected not to be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

Nuclear Waste Disposal. There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by its nuclear generating facilities in on-site storage pools or in dry cask storage facilities. Since Generation's SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, Generation has developed dry cask storage facilities to support operations.

As of December 31, 2013, Generation had approximately 59,900 SNF assemblies (14,400 tons) stored on site in SNF pools or dry cask storage (this includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party; see Note 15 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for Clinton and Three Mile Island. Clinton and Three Mile Island will currently lose full core reserve, which is when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core, in 2015 and 2023, respectively. Dry cask storage will be in operation at Clinton and is expected to be in operation at Three Mile Island prior to the closing of their respective on-site storage pools. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites through the end of the license renewal periods and through decommissioning.

For a discussion of matters associated with Generation's contracts with the DOE for the disposal of SNF, see Note 22 of the Combined Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into such an agreement, although neither state currently has an operational site and none is anticipated to be operational until after 2020.

Generation is currently utilizing on-site storage capacity at its nuclear generation stations for limited amounts of LLRW and has been shipping its Class A LLRW, which represent 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Oyster Creek and Salem), and Connecticut. Generation has received NRC approval for its Peach Bottom and LaSalle stations that will allow storage at these sites of LLRW from its remaining stations with limited capacity. Generation now has enough storage capacity to store all Class B and C LLRW for the life of all stations in Generation's nuclear fleet. During 2012, Generation entered into a six year contract to ship Class B and Class C LLRW to Texas. The terms of the agreement will provide for disposal of all current Class B and Class C LLRW stored at the stations, as well as the waste generated during the term of the agreement. Although Texas started accepting waste for disposal in 2012, the Texas site is curie limited (3.9 million curies for 15 years). With this limit, the annual facility volume will not match industry production of activated hardware, and on-site storage is expected to be required for the Generation boiling water reactors. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize cost impacts and on-site storage.

Nuclear Insurance. Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See "Nuclear Insurance" within Note 22 of the Combined Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. PROPERTIES—Generation. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and results of operations.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview; ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates, Nuclear Decommissioning, Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Notes 3, 11 and 15 of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation's NDT funds and its decommissioning obligations.

Dresden Unit 1 and Peach Bottom Unit 1 have ceased power generation. SNF at Dresden Unit 1 is currently being stored in dry cask storage until a permanent repository under the NWPA is completed. All SNF for Peach Bottom Unit 1, which ceased operation in 1974, has been removed from the site and the SNF pool is drained and decontaminated. Generation's estimated ARO liability to decommission Dresden Unit 1 and Peach Bottom Unit 1 as of December 31, 2013 was $208 million and $114 million, respectively. As of December 31, 2013, NDT funds set aside to pay for these obligations were $436 million.

Zion Station Decommissioning. On December 11, 2007, Generation entered into an Asset Sale Agreement (ASA) with EnergySolutions, Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, LLC (ZionSolutions) under which ZionSolutions assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998.

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request reimbursement; specifically, if certain milestones as defined in the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. See Note 15 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning and see Note 2 of the Combined Notes to Consolidated Financial Statements for a discussion of variable interest entity considerations related to ZionSolutions.

Fossil and Renewable Facilities (including Hydroelectric)

Generation has ownership interests in 15,875 MW of capacity in fossil and renewable generating facilities currently in service. Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Keystone, Conemaugh, and Wyman; (2) ownership interests through equity method investments in Colver, Malacha, Safe Harbor, and Sunnyside; and (3) certain wind project entities with minority interest owners, see Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on these wind project entities. Generation's fossil and renewable generating stations are all operated by Generation, with the exception of Colver, Conemaugh, Keystone, LaPorte, Malacha, Safe Harbor, Sunnyside and Wyman, which are operated by third parties. In 2013 and 2012, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 15% and 12%, respectively, of Generation's total electric supply. The majority of this output was dispatched to support Generation's wholesale and retail power

marketing activities. For additional information regarding Generation's electric generating facilities, see ITEM 2. PROPERTIES—Generation and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview for additional information on Generation Renewable Development.

Licenses. Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid. On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Muddy Run Pumped Storage Project and the Conowingo Hydroelectric Project, respectively. Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run's current license on August 31, 2014, and the expiration of Conowingo's license on September 1, 2014. However, the stations will continue to operate under annual licenses until FERC takes action on the 46-year license applications. Refer to Note 3—Regulatory Matters for additional information.

Insurance. Generation maintains business interruption insurance for its renewable projects, and delay in start-up insurance for its renewable projects currently under construction. Generation does not purchase business interruption insurance for its wholly owned fossil and hydroelectric operations. Generation maintains both property damage and liability insurance. For property damage and liability claims for these operations, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. PROPERTIES—Generation.

Long-Term Power Purchase Contracts

In addition to energy produced by owned generation assets, Generation sources electricity and other related output from plants it does not own under long-term contracts. The following tables summarize Generation's long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2013:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic [(a)]	16	2016 - 2032	799
Midwest	7	2015 - 2022	1,734
New England	14	2014 - 2020	1,291
ERCOT	5	2014 - 2026	1,489
Other Regions	11	2014 - 2030	4,113
Total	53		9,426

	2014	2015	2016	2017	2018
Capacity Expiring (MW)	1,300	1,705	651	1,337	100

(a) Excludes contracts with CENG.

Fuel

The following table shows sources of electric supply in GWh for 2013 and 2012:

	Source of Electric Supply [a]	
	2013	2012
Nuclear	142,126	139,862
Purchases—non-trading portfolio [b]	69,791	91,994
Fossil	30,785	27,760
Renewable	6,420	4,079
Total supply	249,122	263,695

(a) Represents Generation's proportionate share of the output of its generating plants.
(b) Includes purchases pursuant to Generation's PPA with CENG. See Note 25 of the Combined Notes to Consolidated Financial Statements for additional information.

The fuel costs for nuclear generation are less than those for fossil-fuel generation. Consequently, nuclear generation is generally the most cost-effective way for Generation to meet its wholesale and retail load servicing requirements.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has uranium concentrate inventory and supply contracts sufficient to meet all of its uranium concentrate requirements through 2016. Generation's contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2020. All of Generation's enrichment requirements have been contracted through 2018. Contracts for fuel fabrication have been obtained through 2018. Generation does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures. Generation also hedges forward price risk, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation's integrated business operations include the physical delivery and marketing of power obtained through its generation capacity and through long-term, intermediate-term and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. Generation has also contracted for access to additional generation through bilateral long-term PPAs. PPAs are commitments related to power generation of specific generation plants and/or are dispatchable in nature similar to asset ownership depending on the type of underlying asset. Generation secures contracted generation as part of its overall strategic

plan, with objectives such as obtaining low-cost energy supply sources to meet its physical delivery obligations to both wholesale and retail customers and assisting customers to meet renewable portfolio standards. Generation may buy power to meet the energy demand of its customers, including ComEd, PECO and BGE. Generation sells electricity, natural gas, and related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets. Generation's customer facing operations combine a unified sales force with a customer-centric model that leverages technology to broaden the range of products and solutions offered, which Generation believes promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which provides a platform that is scalable and able to capitalize on opportunities for future growth.

Generation's purchases may be for more than the energy demanded by Generation's customers. Generation then sells this open position, along with capacity not used to meet customer demand, in the wholesale electricity markets. Where necessary, Generation also purchases transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs in markets without an organized RTO. Generation also incorporates contingencies into its planning for extreme weather conditions, including potentially reserving capacity to meet summer loads at levels representative of warmer-than-normal weather conditions. Generation actively manages these physical and contractual assets in order to derive incremental value. Additionally, Generation is involved in the development, exploration, and harvesting of oil, natural gas and natural gas liquids properties.

Price Supply Risk Management

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation also enters into transactions that are outside of this ratable sales plan. Generation is exposed to relatively greater commodity price risk in 2014 and beyond for which a larger portion of its electricity portfolio may be unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. As of December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015, and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity, including purchased power from CENG. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including sales to ComEd, PECO and BGE to serve their retail load. A portion of Generation's hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation's efforts. The trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop-loss and value-at-risk limits, to manage exposure to market risk. Additionally, the corporate risk management group and Exelon's RMC monitor the financial risks of the wholesale and retail power marketing activities. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

At December 31, 2013, Generation's short and long-term commitments relating to the purchase of energy and capacity from and to unaffiliated utilities and others were as follows:

(in millions)	Net Capacity Purchases [a]	REC Purchases [b]	Transmission Rights Purchases [c]	Purchased Energy from CENG	Total
2014	$ 412	$ 117	$ 25	$ 824	$1,378
2015	367	110	13	—	490
2016	284	76	2	—	362
2017	223	25	2	—	250
2018	112	3	2	—	117
Thereafter	414	3	32	—	449
Total	$ 1,812	$ 334	$ 76	$ 824	$3,046

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2013, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. Expected payments include certain fixed capacity charges which may be reduced on plant availability.
(b) The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

As part of reaching a comprehensive agreement with EDF in October 2010, the existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements Generation purchases 85% of the nuclear plant output owned by CENG that is not sold to third parties. CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the nuclear plant output owned by CENG at market prices. This purchase agreement will continue to be effective under the Master Agreement discussed above, except that if the put option under the Master Agreement is exercised, then the EDF PPA will be transferred to Generation upon the completion of the Put Option Agreement transaction. Generation discloses in the table above commitments to purchase from CENG at fixed prices. All commitments to purchase from CENG at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 25 of the Combined Notes to Consolidated Financial Statements for more details on this arrangement.

Capital Expenditures

Generation's business is capital intensive and requires significant investments in nuclear fuel and energy generation assets and in other internal infrastructure projects. Generation's estimated capital expenditures for 2014 are as follows:

(in millions)	
Nuclear fuel [a]	$ 900
Production plant	900
Renewable energy projects	300
Uprates	150
Maryland commitments	100
Other	50
Total	$2,400

(a) Includes Generation's share of the investment in nuclear fuel for the co-owned Salem plant.

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ComEd

ComEd is engaged principally in the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to a diverse base of residential, commercial and industrial customers in northern Illinois. ComEd is a public utility under the Illinois Public Utilities Act subject to regulation by the ICC related to distribution rates and service, the issuance of securities, and certain other aspects of ComEd's business. ComEd is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of ComEd's business. Specific operations of ComEd are also subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, ComEd is subject to NERC mandatory reliability standards.

ComEd's retail service territory has an area of approximately 11,400 square miles and an estimated population of 9 million. The service territory includes the City of Chicago, an area of about 225 square miles with an estimated population of 2.7 million. ComEd has approximately 3.8 million customers.

ComEd's franchises are sufficient to permit it to engage in the business it now conducts. ComEd's franchise rights are generally nonexclusive rights documented in agreements and, in some cases, certificates of public convenience issued by the ICC. With few exceptions, the franchise rights have stated expiration dates ranging from 2014 to 2066. ComEd anticipates working with the appropriate agencies to extend or replace the franchise agreements prior to expiration.

ComEd's kWh deliveries and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. ComEd's highest peak load occurred on July 20, 2011, and was 23,753 MWs; its highest peak load during a winter season occurred on January 6, 2014, and was 16,514 MWs.

Retail Electric Services

Electric revenues and purchased power expense are affected by fluctuations in customers' purchases from competitive electric generation suppliers. All ComEd customers have the ability to purchase electricity from a competitive electric generation supplier. The customers' choice activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense. ComEd's cost of electric supply is passed without markup directly through to those customers not served by a competitive electric generation supplier and those rates are subject to adjustment monthly to recover or refund the difference between ComEd's actual cost of electricity delivered and the amount included in rates. For those customers that choose a competitive electric generation supplier, ComEd acts as the billing agent but does not record revenues or expenses related to the electric supply. ComEd remains the distribution service provider for all customers in its service territory and charges a regulated rate for distribution service. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information on customer switching to competitive electric generation suppliers, and Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process and for additional information.

Under Illinois law, ComEd is required to deliver electricity to all customers. ComEd's obligation to provide generation supply service, which is referred to as a POLR obligation, primarily varies by customer size. ComEd's obligation to provide such service to residential customers and other small customers with demands of under 100 kWs continues for all customers who do not choose a competitive electric generation supplier or who choose to return to ComEd after taking service from a competitive electric generation supplier. ComEd does not have a fixed-price generation supply service obligation to most of its largest customers with demands of 100 kWs or greater, as this group of customers has previously been declared competitive. Customers with competitive declarations may still purchase power and energy from ComEd, but only at hourly market prices.

Energy Infrastructure Modernization Act (EIMA). Since 2011, ComEd's distribution rates are established through a performance-based rate formula pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. In addition, as long as ComEd is subject to EIMA, ComEd will fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

ComEd files an annual reconciliation of the revenue requirement in effect in a given year to reflect the actual costs that the ICC determines are prudently and reasonably incurred for such year. Under the terms of EIMA, ComEd's target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Electric Distribution Rate Cases . The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. On February 23, 2012, the ICC issued an order in the remand proceeding requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). On September 27, 2013, the Court ruled against ComEd on the accumulated depreciation issue and affirmed that ComEd owes a refund to customers of $37 million. As of December 31, 2013, and December 31, 2012, ComEd was fully reserved for this liability. ComEd will not seek rehearing or appeal on this matter and is working with the ICC on the process and timing for a refund to customers.

On May 24, 2011, the ICC issued an order in ComEd's 2010 electric distribution rate case (2010 Rate Case), which became effective on June 1, 2011. The order approved a $143 million increase to ComEd's annual delivery service revenue requirement and a 10.5% rate of return on common equity. The order has been appealed to the Court by several parties. On May 16, 2013, the Court dismissed as moot the appeals of the ICC's order in the 2010 Rate Case as ComEd now recovers distribution costs under EIMA through a pre-established formula rate tariff. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electric distribution rate cases.

Procurement-Related Proceedings. Since June 2009, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. As required by EIMA, in February 2012 the IPA completed procurement events for energy and REC requirements for the June 2013 through December 2017 period. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's procurement plans. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's energy commitments.

Continuous Power Interruption. The Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter, Smart Grid and Energy Efficiency Programs

Smart Meter and Smart Grid Programs. On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. On April 23, 2012, ComEd filed its initial AMI Deployment Plan with the ICC, which was approved by the ICC on June 22, 2012, with certain modifications. ComEd outlined the new deployment schedule within testimony provided in the AMI Plan Rehearing and filed a revised AMI deployment plan with the ICC. On December 5, 2012, the ICC approved ComEd's revised AMI deployment plan. On June 5, 2013, the ICC issued an interim Order approving ComEd's accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. The deployment plan provides for the installation of 4 million electric smart meters, of which more than 60,000 meters were installed by the end of 2013.

Energy Efficiency Programs. As a result of the Illinois Settlement Legislation, electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an incremental annual program energy savings requirement of 0.2% of energy delivered to retail customers for the year ended June 1, 2009, which increases annually to 2.0% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten-year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In December 2010, the ICC approved ComEd's second three-year Energy Efficiency and Demand Response Plan covering the period June 2011 through May 2014. The plans are designed to meet the Illinois Settlement Legislation's energy efficiency and demand response goals through May 2014, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

EIMA provides for additional energy efficiency in Illinois. Starting in the June 2013—May 2014 period and occurring annually thereafter, as part of the IPA procurement plan, ComEd is to include cost-effective expansion of current energy efficiency programs, any additional new cost-effective program and/or third-party energy efficiency programs that are identified through a request for proposal ("RFP") process. All cost-effective energy efficiency programs are included in the IPA procurement plan for consideration of implementation. While these programs are monitored separately from the Energy Efficiency Portfolio Standard (EEPS), funds for both the EEPS portfolio and IPA energy efficiency programs are collected under the same rider.

Construction Budget

ComEd's business is capital intensive and requires significant investments primarily in energy transmission and distribution facilities, to ensure the adequate capacity, reliability and efficiency of its system. Based on PJM's RTEP, ComEd has various construction commitments, as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. ComEd's most recent estimate of capital expenditures for electric plant additions and improvements for 2014 is $1,775 million, which includes RTEP projects and infrastructure modernization resulting from EIMA. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

PECO

PECO is engaged principally in the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and

the provision of gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia. PECO is a public utility under the Pennsylvania Public Utility Code subject to regulation by the PAPUC as to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of PECO's operations. PECO is a public utility under the Federal Power Act subject to regulation by FERC as to transmission rates and certain other aspects of PECO's business and by the U.S. Department of Transportation as to pipeline safety and other areas of gas operations. Specific operations of PECO are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, PECO is also subject to NERC mandatory reliability standards.

PECO's combined electric and natural gas retail service territory has an area of approximately 2,100 square miles and an estimated population of 4.0 million. PECO provides electric distribution service in an area of approximately 1,900 square miles, with a population of approximately 3.9 million, including approximately 1.5 million in the City of Philadelphia. PECO provides natural gas distribution service in an area of approximately 1,900 square miles in southeastern Pennsylvania adjacent to the City of Philadelphia, with a population of approximately 2.4 million. PECO delivers electricity to approximately 1.6 million customers and natural gas to approximately 501,000 customers.

PECO has the necessary authorizations to provide regulated electric and natural gas distribution service in the various municipalities or territories in which it now supplies such services. PECO's authorizations consist of charter rights and certificates of public convenience issued by the PAPUC and/or "grandfathered rights," which are rights generally unlimited as to time and generally exclusive from competition from other electric and natural gas utilities. In a few defined municipalities, PECO's natural gas service territory authorizations overlap with that of another natural gas utility; however, PECO does not consider those situations as posing a material competitive or financial threat.

PECO's kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. PECO's highest peak load occurred on July 22, 2011 and was 8,983 MW; its highest peak load during winter months occurred on January 7, 2014 and was 7,148 MW.

PECO's natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. PECO's highest daily natural gas send out occurred on January 7, 2014 and was 760 mmcf.

Retail Electric Services

PECO's retail electric sales and distribution service revenues are derived pursuant to rates regulated by the PAPUC. Pennsylvania permits competition by competitive electric generation suppliers for the supply of retail electricity while retail transmission and distribution service remains regulated under the Competition Act. At December 31, 2013, there were 87 competitive electric generation suppliers serving PECO customers. At December 31, 2013, the number of retail customers purchasing energy from a competitive electric generation supplier was 531,500 representing approximately 34% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 68% of PECO's retail kWh sales for the year ended December 31, 2013. Customers that choose a competitive electric generation supplier are not subject to rates for PECO's electric supply procurement costs and retail transmission service charges. PECO presents on customer bills its electric supply Price to Compare, which is updated quarterly, to assist customers with the evaluation of offers from competitive electric generation suppliers.

Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense or PECO's financial position. PECO's cost of electric supply is passed directly through to default service

customers without markup and those rates are subject to adjustment at least quarterly to recover or refund the difference between PECO's actual cost of electricity delivered and the amount included in rates through the GSA. For those customers that choose a competitive electric generation supplier, PECO acts as the billing agent but does not record revenues or purchase power expense related to this electric supply. PECO remains the distribution service provider for all customers in its service territory and charges a regulated rate for distribution service.

Procurement Proceedings. PECO's electric supply for its customers is procured through contracts executed in accordance with its PAPUC-approved DSP Programs. PECO entered into contracts with PAPUC-approved bidders, including Generation, as part of its DSP I competitive procurements conducted since June 2009 for its default electric supply beginning January 2011, which included fixed price full requirement contracts for all procurement classes, spot market price full requirements contracts for the commercial and industrial procurement classes, and block energy contracts for the residential procurement class. In September 2012, PECO completed its last competitive procurement for electric supply under its first DSP Program, which expired on May 31, 2013.

On October 12, 2012, the PAPUC approved PECO's second DSP Program, which was filed with the PAPUC in January 2012. The plan outlines how PECO is purchasing electric supply for default service customers from June 1, 2013 through May 31, 2015. Pursuant to the second DSP Program, PECO is procuring electric supply through five competitive procurements for fixed price full requirements contracts of two years or less for the residential and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in June 2013. In September 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in December 2013. In January 2014, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small, medium and large commercial classes that will begin in June 2014. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Statement of Operations and Comprehensive Income.

The second DSP Program also includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from competitive electric generation suppliers beginning April 1, 2014. On May 1, 2013, PECO filed a Petition for Approval of its CAP Shopping Plan with the PAPUC, which the PAPUC granted and denied in part on January 9, 2014. PECO and other parties to the proceeding filed petitions for reconsideration of the Commission's decision on February 10, 2014, and these petitions are currently pending before the PAPUC.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter, Smart Grid and Energy Efficiency Programs

Smart Meter and Smart Grid Programs. In April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, which was filed in accordance with the requirements of Act 129. Also, in April 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, PECO has been awarded $200 million, the maximum grant allowable under the program, for its SGIG project—Smart Future Greater Philadelphia. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. On January 18, 2013, PECO filed with the PAPUC its universal deployment plan for approval of its proposal to deploy the remainder of the 1.6 million smart meters on an accelerated basis by the

end of 2014. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC, which was approved without modification on August 15, 2013. In total, PECO currently expects to spend up to $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, before considering the $200 million SGIG.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Programs. PECO's PAPUC-approved Phase I EE&C plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I Plan sets forth how PECO would meet the required reduction targets established by Act 129's EE&C provisions, which included a 3% reduction in electric consumption in PECO's service territory and a 4.5% reduction in PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013. The peak demand period ended on September 30, 2012 and PECO communicated its compliance with the reduction targets in a preliminary report with the PAPUC on March 1, 2013. The final compliance report was filed with the PAPUC on November 15, 2013.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129's EE&C programs, which went into effect on June 1, 2013. The PAPUC deferred a decision on peak demand reduction requirements until late 2013. On February 28, 2013, the PAPUC approved PECO's three-year EE&C Phase II plan that was filed with the PAPUC on November 1, 2012, and sets forth how PECO will reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Natural Gas

PECO's natural gas sales and distribution service revenues are derived through natural gas deliveries at rates regulated by the PAPUC. PECO's purchased natural gas cost rates, which represent a significant portion of total rates, are subject to quarterly adjustments designed to recover or refund the difference between the actual cost of purchased natural gas and the amount included in rates without markup through the PGC.

PECO's natural gas customers have the right to choose their natural gas suppliers or to purchase their gas supply from PECO at cost. At December 31, 2013, the number of retail customers purchasing natural gas from a competitive natural gas supplier was 66,400, representing approximately 13% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 19% of PECO's mmcf sales for the year ended December 31, 2013. PECO provides distribution, billing, metering, installation, maintenance and emergency response services at regulated rates to all its customers in its service territory.

Procurement Proceedings . PECO's natural gas supply is purchased from a number of suppliers primarily under long-term firm transportation contracts for terms of up to three years in accordance with its annual PAPUC PGC settlement. PECO's aggregate annual firm supply under these firm transportation contracts is 34 million dekatherms. Peak natural gas is provided by PECO's liquefied natural gas (LNG) facility and propane-air plant. PECO also has under contract 21 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 30% of PECO's 2013-2014 heating season planned supplies.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Construction Budget

PECO's business is capital intensive and requires significant investments primarily in electric transmission and electric and natural gas distribution facilities to ensure the adequate capacity, reliability and efficiency of its system. PECO, as a transmission facilities owner, has various construction commitments under PJM's RTEP as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. PECO's most recent estimate of capital expenditures for plant additions and improvements for 2014 is $625 million, which includes RTEP projects and capital expenditures related to the smart meter and smart grid project net of expected SGIG DOE reimbursements.

BGE

BGE is engaged principally in the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of distribution services to retail customers in central Maryland, including the City of Baltimore. BGE is a public utility under the Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC as to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of BGE's operations. BGE is a public utility under the Federal Power Act subject to regulation by FERC as to transmission rates and certain other aspects of BGE's business and by the U.S. Department of Transportation as to pipeline safety and other areas of gas operations. Specific operations of BGE are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, BGE is also subject to NERC mandatory reliability standards.

BGE serves an estimated population of 2.8 million in its 2,300 square mile combined electric and gas retail service territory. BGE provides electric distribution service in an area of approximately 2,300 square miles and gas distribution service in an area of approximately 800 square miles, both with a population of approximately 2.8 million, including approximately 621,000 in the City of Baltimore. BGE delivers electricity to approximately 1.2 million customers and natural gas to approximately 655,000 customers.

BGE has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities and territories in which it now supplies such services. With respect to electric distribution service, BGE's authorizations consist of charter rights, a state-wide franchise grant and a franchise grant from the City of Baltimore. The franchise rights are not exclusive and are perpetual. With respect to natural gas distribution service, BGE's authorizations consist of charter rights, a perpetual state-wide franchise grant, and franchises granted by all the municipalities and/or governmental bodies in which BGE now supplies services. The franchise grants are not exclusive; some are perpetual and some are for a limited duration, which BGE anticipates being able to extend or replace prior to expiration.

BGE's kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. BGE's highest peak load occurred on July 21, 2011 and was 7,236 MW; its highest peak load during winter months occurred on January 7, 2014 and was 6,526 MW.

BGE's natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. BGE's highest daily natural gas send out occurred on February 5, 2007 and was 840 mmcf.

The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per

customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This adjustment allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period (referred to as "revenue decoupling"). Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits affected customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Retail Electric Services

BGE's retail electric sales and distribution service revenues are derived from electricity deliveries at rates regulated by the MDPSC. As a result of the deregulation of electric generation in Maryland effective July 1, 2000, all customers can choose a competitive electric generation supplier. While BGE does not sell electric supply to all customers in its service territory, BGE continues to deliver electricity to all customers and provides meter reading, billing, emergency response, and regular maintenance services. Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has minimal impact on electric revenue net of purchased power expense or BGE's financial position. At December 31, 2013, there were 73 competitive electric generation suppliers serving BGE customers. At December 31, 2013, the number of retail customers purchasing energy from a competitive electric generation supplier was approximately 399,000, representing 32% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 61% of BGE's retail kWh sales for the year ended December 31, 2013.

BGE is obligated to provide market-based SOS to all of its electric customers. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes a commercial and industrial shareholder return component and an incremental cost component. Bidding to supply BGE's market-based SOS occurs through a competitive bidding process approved by the MDPSC. Successful bidders, which may include Generation, will execute contracts with BGE for terms of three months or two years.

BGE is obligated by the MDPSC to provide several variations of SOS to commercial and industrial customers depending on customer load.

Electric Distribution Rate Cases. In December 2010, the MDPSC issued an abbreviated electric rate order authorizing BGE to increase electric distribution rates for service rendered on or after December 4, 2010 by no more than $31 million. In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated combined electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $19 million of costs as regulatory assets. These costs are being recovered over a 5-year period beginning in December 2010 and include the deferral of $16 million of storm costs incurred in February 2010. The regulatory asset for the storm costs earns the authorized rate of return.

On July 27, 2012, BGE filed an application for an increase to its electric base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE's 2012 electric rate case for increases in annual distribution service revenue of $81 million. The electric distribution rate increase was set using an allowed return on equity of 9.75%.

On May 17, 2013, BGE filed an application for an increase to its electric base rates with the MDPSC. On December 13, 2013, the MDPSC issued an order in BGE's 2013 electric distribution rate case authorizing an increase in annual distribution service revenue of $34 million. The electric distribution rate increase was set using an allowed return on equity of 9.75%. The approved electric distribution rate became effective for services rendered on or after December 13, 2013.

Smart Meter and Energy Efficiency Programs

Smart Meter Programs. In August 2010, the MDPSC approved BGE's $480 million SGIP, which includes deployment of a two-way communications network, 2 million smart electric and gas meters and modules, new customer pricing programs, a new customer web portal and numerous enhancements to BGE operations. Also, in April 2010, BGE entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, BGE has been awarded $200 million, the maximum grant allowable under the program, to support its Smart Grid, Peak Rewards and CC&B initiatives. The SGIG funding is being used to reduce significantly the rate impact of those investments on BGE customers. As of December 31, 2013, BGE has billed the entire $200 million grant to the DOE.

Energy Efficiency Programs. BGE's energy efficiency programs include a CFL program, retrofit programs, an energy efficient appliance rebate and trade-in program, rebates and energy efficiency programs for non-profit, educational, governmental and business customers, customer incentives for energy management programs and incentives to help customers reduce energy demand during peak periods. The MDPSC initially approved a full portfolio of conservation programs as well as a customer surcharge to recover the associated costs. This customer surcharge is updated annually. In December 2011, the MDPSC approved BGE's conservation programs for implementation in 2012 through 2014.

Natural Gas

BGE's natural gas sales are derived pursuant to a MBR mechanism that applies to customers who buy their gas from BGE. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. Customer choice program activity affects revenue collected from customers related to supplied natural gas; however, that activity has minimum impact on gas revenue net of purchased power expense or BGE's financial position. At December 31, 2013, there were 41 competitive natural gas suppliers serving BGE customers. At December 31, 2013, the number of retail customers purchasing fuel from a competitive natural gas supplier was approximately 172,000 representing 26% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 54% of BGE's retail mmcf sales for the year ended December 31, 2013.

BGE must secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed price contracts are recovered under the MBR mechanism and are not subject to sharing. BGE meets its natural gas load requirements through firm pipeline transportation and storage entitlements. BGE's current pipeline firm transportation entitlements to serve its firm loads are 362 mmcf per day.

BGE's current maximum storage entitlements are 284 mmcf per day. To supplement its gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, BGE has:

- a liquefied natural gas facility for the liquefaction and storage of natural gas with a total storage capacity of 1,055 mmcf and a daily capacity of 332 mmcf,
- a liquefied natural gas facility for natural gas system pressure support with a total storage capacity of 6 mmcf and a daily capacity of 6 mmcf, and
- a propane air facility and a mined cavern with a total storage capacity equivalent to 546 mmcf and a daily capacity of 85 mmcf.

BGE has under contract sufficient volumes of propane for the operation of the propane air facility and is capable of liquefying sufficient volumes of natural gas during the summer months for operations

of its liquefied natural gas facility during peak winter periods. BGE historically has been able to arrange short-term contracts or exchange agreements with other gas companies in the event of short-term disruptions to gas supplies or to meet additional demand.

BGE also participates in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between shareholders and customers. BGE makes these sales as part of a program to balance its supply of, and cost of, natural gas.

Natural Gas Distribution Rate Cases. In December 2010, the MDPSC issued a rate order authorizing BGE to increase the gas distribution base revenue requirement for service rendered on or after December 4, 2010 by no more than $9.8 million. In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated combined electric and gas distribution rate order issued in December 2010.

On July 27, 2012, BGE filed an application for an increase to its gas base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE's 2012 gas rate case for increases in annual distribution service revenue of $32 million. The electric distribution rate increase was set using an allowed return on equity of 9.60%.

On May 17, 2013, BGE filed an application for an increase to its gas base rates with the MDPSC. On December 13, 2013, the MDPSC issued an order in BGE's 2013 natural gas distribution rate case authorizing an increase in annual distribution service revenue of $12 million. The gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved natural gas distribution rate became effective for services rendered on or after December 13, 2013.

Construction Budget

BGE's business is capital intensive and requires significant investments primarily in electric and natural gas distribution and electric transmission facilities to ensure the adequate capacity, reliability and efficiency of its system. BGE, as a transmission facilities owner, has various construction commitments under PJM's RTEP as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. BGE's most recent estimate of capital expenditures for plant additions and improvements for 2014 is approximately $600 million, which includes capital expenditures related to the SGIP net of expected SGIG DOE reimbursements.

ComEd, PECO and BGE

Transmission Services

ComEd, PECO and BGE provide unbundled transmission service under rates approved by FERC. FERC has used its regulation of transmission to encourage competition for wholesale generation services and the development of regional structures to facilitate regional wholesale markets. Under FERC's open access transmission policy promulgated in Order No. 888, ComEd, PECO and BGE, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. ComEd, PECO and BGE are required to comply with FERC's Standards of Conduct regulation governing the communication of non-public information between the transmission owner's employees and wholesale merchant employees.

PJM is the ISO and the FERC-approved RTO for the Mid-Atlantic and Midwest regions. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM Tariff), operates the PJM energy, capacity and other markets, and, through central dispatch, controls

the day-to-day operations of the bulk power system for the PJM region. ComEd, PECO and BGE are members of PJM and provide regional transmission service pursuant to the PJM Tariff. ComEd, PECO, BGE and the other transmission owners in PJM have turned over control of their transmission facilities to PJM, and their transmission systems are currently under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM members at rates based on the costs of transmission service.

ComEd's transmission rates are established based on a formula that was approved by FERC in January 2008. FERC's order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

PECO default service customers are charged for retail transmission services through a rider designed to recover PECO's PJM transmission network service charges and RTEP charges on a full and current basis in accordance with the 2010 electric distribution rate case settlement.

The transmission rate in the PJM Open Access Transmission Tariff under which PECO incurs costs to serve its default service customers and earns revenue as a transmission facility owner is a FERC-approved rate. This is the rate that all load serving entities in the PECO transmission zone pay for wholesale transmission service.

BGE's transmission rates are established based on a formula that was approved by FERC in April 2006. FERC's order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding transmission services.

Employees

As of December 31, 2013, Exelon and its subsidiaries had 25,829 employees in the following companies, of which 8,602 or 33% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 [(a)]	IBEW Local 614 [(b)]	Other CBAs [(c)]	Total Employees Covered by CBAs	Total Employees
Generation	1,690	100	1,973	3,763	11,973
ComEd	3,487	—	—	3,487	5,895
PECO	—	1,254	—	1,254	2,418
BGE	—	—	—	—	3,303
Other [(d)]	71	—	27	98	2,240
Total	5,248	1,354	2,000	8,602	25,829

(a) A separate CBA between ComEd and IBEW Local 15, ratified on October 10, 2012, covers approximately 32 employees in ComEd's System Services Group. Generation's and ComEd's separate CBAs with IBEW Local 15 were extended through February 28, 2014.

(b) 1,254 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614. The CBAs expire on March 31, 2015. Additionally, Exelon Power, an operating unit of Generation, has an agreement with IBEW Local 614, which expires on November 3, 2016 and covers 107 employees.

(c) During 2013, Generation finalized a CBA with the Security Officer union at Oyster Creek, which will expire in 2016. Additionally, during 2013, three other 3-year agreements were negotiated: Power, IBEW Local 614, which will expire in 2016; New England ENEH, UWUA Local 369, which will expire in 2017; and New Energy IUOE Local 95-95A, which will expire in 2016. During 2012, Generation finalized CBAs with the Security Officer unions at Byron, Clinton and TMI, which expire between 2015 and 2016. During 2011, Generation finalized CBAs with the Security Officer unions at Braidwood,

Dresden, LaSalle and Quad Cities, which expire between 2014 and 2015. During 2010, Generation entered into a CBA with the Security Officer union at Limerick, which expires in 2014. Additionally, during 2009, a 5-year agreement was reached with Oyster Creek Nuclear Local 1289, which expires in 2015.

(d) Other includes shared services employees at BSC.

Environmental Regulation

General

Exelon, Generation, ComEd, PECO and BGE are subject to comprehensive and complex legislation regarding environmental matters by the federal government and various state and local jurisdictions in which they operate their facilities. The Registrants are also subject to regulations administered by the U.S. EPA and various state and local environmental protection agencies. Federal, state and local regulation includes the authority to regulate air, water, and solid and hazardous waste disposal.

The Exelon board of directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President, Corporate Strategy and Chief Sustainability Officer; the Corporate Environmental Strategy Director and the Environmental Regulatory Strategy Director, as well as senior management of Generation, ComEd, PECO and BGE. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. The Exelon board has delegated to its corporate governance committee authority to oversee Exelon's compliance with laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including, Exelon's climate change and sustainability policies and programs, and Exelon 2020, Exelon's comprehensive business and environmental plan, as discussed in further detail below. The Exelon board has also delegated to its generation oversight committee authority to oversee environmental, health and safety issues relating to Generation. The respective boards of ComEd, PECO and BGE, which each include directors who also serve on the Exelon board, oversee environmental, health and safety issues related to ComEd, PECO and BGE.

Air Quality

Air quality regulations promulgated by the U.S. EPA and the various state and local environmental agencies in Illinois, Maryland, Massachusetts, New York, Pennsylvania and Texas in accordance with the Federal Clean Air Act impose restrictions on emission of particulates, sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury and other pollutants and require permits for operation of emissions sources. Such permits have been obtained by Exelon's subsidiaries and must be renewed periodically. The Clean Air Act establishes a comprehensive and complex national program to reduce substantially air pollution from power plants. Advanced emission controls for SO_2 and NOx have been installed at all of Generation's co-owned bituminous coal-fired units.

See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding clean air regulation and legislation in the forms of the CSAPR and CAIR, the regulation of hazardous air pollutants from coal- and oil-fired electric generating facilities under MATS, and regulation of GHG emissions, in addition to NOVs issued to Generation and ComEd for alleged violations of the Clean Air Act.

Water Quality

Under the Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the U.S. EPA or from the state environmental agency to which the permit program has been delegated and must be renewed periodically. Certain of Generation's power generation facilities

discharge industrial wastewater into waterways and are therefore subject to these regulations and operate under NPDES permits or pending applications for renewals of such permits after being granted an administrative extension.

See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding the impact to Exelon of state permitting agencies' administration of the Phase II rule implementing Section 316(b) of the Clean Water Act.

Generation is also subject to the jurisdiction of certain other state and regional agencies and compacts, including the Delaware River Basin Commission and the Susquehanna River Basin Commission.

Solid and Hazardous Waste

The CERCLA provides for immediate response and removal actions coordinated by the U.S. EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at sites, most of which are listed by the U.S. EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with a U.S. EPA-directed cleanup, may voluntarily settle with the U.S. EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight prior to listing on the NPL. Various states, including Illinois, Maryland and Pennsylvania, have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Generation, ComEd, PECO and BGE and their subsidiaries are, or are likely to become, parties to proceedings initiated by the U.S. EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party.

See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding solid and hazardous waste regulation and legislation.

Environmental Remediation

ComEd's, PECO's and BGE's environmental liabilities primarily arise from contamination at former MGP sites. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover environmental remediation costs of the MGP sites through a provision within customer rates. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The amount to be expended in 2014 at Exelon for compliance with environmental remediation related to contamination at former MGP sites is expected to total $40 million, consisting of $33 million, $6 million and $1 million at ComEd, PECO and BGE, respectively.

Generation's environmental liabilities primarily arise from contamination at current and former generation and waste storage facilities. As of December 31, 2013, Generation has established an appropriate liability to comply with environmental remediation requirements including contamination attributable to low level radioactive residues at a storage and reprocessing facility named Latty Avenue, and at a disposal facility named West Lake Landfill, both near St. Louis, Missouri related to operations conducted by Cotter Corporation, a former ComEd subsidiary.

In addition, Generation, ComEd, PECO and BGE may be required to make significant additional expenditures not presently determinable for other environmental remediation costs.

See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' environmental remediation efforts and related impacts to the Registrants' results of operations, cash flows and financial position.

Global Climate Change

Exelon believes the evidence of global climate change is compelling and that the energy industry, though not alone, is a significant contributor to the human-caused emissions of GHGs that many in the scientific community believe contribute to global climate change, and as reported by the Intergovernmental Panel on Climate Change in their Fifth Assessment Report Summary for Policy Makers issues September 2013. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, hydroelectric, wind and solar photovoltaic), has a relatively small GHG emission profile, or carbon footprint, compared to other domestic generators of electricity. By virtue of its significant investment in low-carbon intensity assets, Generation's emission intensity, or rate of carbon dioxide equivalent (CO_2e) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its fossil fuel-fired generating plants; CO_2, methane and nitrous oxide are all emitted in this process, with CO_2 representing the largest portion of these GHG emissions. GHG emissions from combustion of fossil fuels represent the majority of Exelon's direct GHG emissions in 2013, although only a small portion of Exelon's electric supply is from fossil generating plants. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF_6) leakage in its electric transmission and distribution operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and usage of electricity at its facilities. Despite its focus on low-carbon generation, Exelon believes its operations could be significantly affected by the possible physical risks of climate change and by mandatory programs to reduce GHG emissions. See ITEM 1A. RISK FACTORS for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

Climate Change Regulation. Exelon is, or may become, subject to climate change regulation or legislation at the Federal, regional and state levels.

International Climate Change Regulation. At the international level, the United States has not yet ratified the United Nations Kyoto Protocol, which was extended at the 2012 meeting of the United Nations Framework on Climate Change Conference of the Parties (COP 18). The Kyoto Protocol now requires participating developed countries to cap GHG emissions at certain levels until 2020, when the new global agreement on emissions reduction is scheduled to become effective. This new global agreement for GHG emissions reductions was agreed to only in concept during the COP18, with a timeline for establishing the global targets by 2015. On November 22, 2013, at the 2013 COP 19 held in Warsaw, Poland, participating countries further agreed to provide their "intended nationally determined contributions" by the first quarter of 2015 in preparation for formally setting global target in 2015. The other major issues discussed at COP 19 were demands from developing countries for increased climate finance, and for a new mechanism to help especially vulnerable nations cope with unavoidable "loss and damage" resulting from climate change. Developed countries, which had previously promised to mobilize a total of $100 billion a year by 2020, refused to set a quantified interim goal for ramping up climate finance.

Federal Climate Change Legislation and Regulation. Various stakeholders, including Exelon, legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors are considering ways to address the climate change issue,

including the enactment of federal climate change legislation. It is highly uncertain whether Federal legislation to reduce GHG emissions will be enacted. If such legislation is adopted, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits. In June 2013, the White House released the President's Climate Action Plan which consists of a wide variety of executive actions targeting GHG reductions, preparing for the impacts of climate change and showing leadership internationally; but the plan did not directly trigger any new requirements or legislative action.

The U.S. EPA is addressing the issue of carbon dioxide (CO2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act. Pursuant to President Obama's June 25, 2013 memorandum to U.S. EPA, the Agency re-proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. Under the President's memorandum, the U.S. EPA is also required to propose a Section 111(d) rule no later than June 1, 2014 to establish CO2 emission regulations for existing stationary sources.

Regional and State Climate Change Legislation and Regulation. After a two-year program review, the nine northeast and mid-Atlantic states currently participating in the Regional Greenhouse Gas Reduction Initiative (RGGI) released an updated RGGI Model Rule and Program Review Recommendations Summary on February 7, 2013. Under the updated RGGI program, which must be approved pursuant to the applicable legislative and/or regulatory process in each RGGI state, the regional RGGI CO2 budget would be reduced, starting in 2014, from its current 165 million ton level to 91 million tons, with a 2.5 percent reduction in the cap level each year between 2015-2020. Included in the new program are provisions for cost containment reserve (CCR) allowances, which will become available if the total demand for allowances, above the CCR trigger price, exceeds the number of CO2 allowances available for purchase at auction. (CCR trigger prices are $4 in 2014, $6 in 2015, $8 in 2016 and $10 in 2017, rising 2.5 percent thereafter to account for inflation). Such an outcome could put modest upward pressure on wholesale power prices; however, the specifics are currently uncertain.

At the state level, the Illinois Climate Change Advisory Group, created by Executive Order 2006-11 on October 5, 2006, made its final recommendations on September 6, 2007 to meet the Governor's GHG reduction goals. At this time, the only requirements imposed by the state of Illinois are the energy efficiency and renewable portfolio standards in the Illinois Power Act that apply to ComEd.

On December 18, 2009, Pennsylvania issued the state's final Climate Change Action Plan. The plan sets as a target a 30 percent reduction in GHG emissions by 2020. The Climate Change Advisory Committee continues to meet quarterly to review Climate Action Work Plans for the residential, commercial and industrial sectors. The Climate Change Action Plan does not impose any requirements on Generation or PECO at this time.

The Maryland Commission on Climate Change released its climate action plan on August 27, 2008, recommending that the state begin implementing 42 greenhouse gas reduction strategies. One of the Plan's policy recommendations, to adopt science-based regulatory goals to reduce Maryland's GHG emissions, was realized with the passage of the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA). The law requires Maryland to reduce its GHG emissions by 25 percent below 2006 levels by 2020. It directed the MDE to work with other state agencies to prepare an implementation plan to meet this goal. The implementation plan was published in October of 2013. Maryland targeted electricity consumption reduction goals required under the "Empower Maryland" program, and mandatory State participation in the recently updated and enhanced RGGI Program are listed as that sector's contribution in the plan. The plan also advocates raising the renewable portfolio standard requirement from 22% by 2022 to 25% by 2022.

Exelon's Voluntary Climate Change Efforts . In a world increasingly concerned about global climate change and regulatory action to reduce GHG, Exelon's low-carbon generating fleet is seen by management as a competitive advantage. Exelon remains one of the largest, lowest carbon electric generators in the United States: nuclear for base load, natural gas for marginal and peak demand, hydro and pumped storage, and supplemental wind and solar renewables. As further legislation and regulation imposing requirements on emissions of GHG and air pollutants are promulgated, Exelon's low-carbon, low-emission generation fleet will position the company to benefit from its comparative advantage over other generation fleets.

With the announcement in 2008 of Exelon 2020, Exelon set a voluntary goal to reduce, offset or displace more than 15.7 million metric tonnes of GHG emissions per year by 2020. Exelon updated that goal in 2012 following the Constellation merger to account for the integration of former Constellation GHG goals. The updated Exelon 2020 goal is to reduce, offset or displace more than 17.5 million metric tonnes of GHG emissions by 2020. The Exelon 2020 goal encompasses three broad areas of focus: reducing or offsetting Exelon's own carbon footprint (with the year the asset/operations were acquired by Exelon as the baseline), helping customers and communities reduce their GHG emissions, and offering more low-carbon electricity in the marketplace. Exelon has been maintaining strong performance towards achieving the goal and anticipates reaching the 17.5 million tons of annual abatement well before 2020.

Renewable and Alternative Energy Portfolio Standards

Thirty-nine states and the District of Columbia have adopted some form of RPS requirement. As previously described, Illinois, Pennsylvania and Maryland have laws specifically addressing energy efficiency and renewable energy initiatives. In addition to state level activity, RPS legislation has been considered and may be considered again in the future by the United States Congress. Also, states that currently do not have RPS requirements may adopt such legislation in the future.

The Illinois Settlement Legislation required that procurement plans implemented by electric utilities include cost-effective renewable energy resources or approved equivalents such as RECs in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers by June 1, 2008, increasing to 10% by June 1, 2015, with a goal of 25% by June 1, 2025. Utilities are allowed to pass-through any costs from the procurement of these renewable resources or approved equivalents subject to legislated rate impact criteria. As of December 31, 2013, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. See Note 3 and Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

The AEPS Act became effective for PECO on January 1, 2011, following the expiration of PECO's transition period. During 2013, PECO was required to supply approximately 4.0% of electric energy generated from Tier I (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania) through May 31, 2013 and subsequently 4.5% beginning June 1, 2013 and continuing through May 31, 2014. PECO was also required to supply 6.2% of electric energy generated from Tier II (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing wood and by-products of the pulping process and wood, distributed generation systems and integrated combined coal gasification technology) alternative energy resources, respectively, as measured in AECs. The compliance requirements will incrementally escalate to 8.0% for Tier I and 10.0% for Tier II by 2021. In order to comply with these requirements, PECO entered into agreements with varying terms with accepted bidders, including Generation, to purchase non-solar Tier I, solar Tier 1 and Tier II AECs. PECO also purchases AECs through its DSP Program full requirement contracts.

Section 7-703 of the Public Utilities Article in Maryland sets forth the RPS requirement, which applies to all retail electricity sales in Maryland by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, biomass, methane, geothermal, ocean, fuel cell, small hydroelectric, and poultry litter) and Tier 2 sources (hydroelectric, other than pump storage generation, and waste-to-energy). The RPS requirement began in 2006, requiring that suppliers procure 1.0% and 2.5% from Tier 1 and Tier 2 sources, respectively, escalating in 2022 to 22.0% from Tier 1 sources, including at least 2.0% from solar energy, and a phase out of Tier 2 resource options by 2022. In 2013, 8.2% was required from Tier 1 renewable sources, including at least 0.25% derived from solar energy, and 2.5% from Tier 2 renewable sources. The wholesale suppliers that supply power to the state's utilities through the SOS procurement auctions have the obligation, by contract with those utilities, to comply with and provide its proportional share of the RPS requirements.

Similar to ComEd, PECO and BGE, Generation's retail electric business must source a portion of the electric load it serves in many of the states in which it does business from renewable resources or approved equivalents such as RECs. Potential regulation and legislation regarding renewable and alternative energy resources could increase the pace of development of wind and other renewable/alternative energy resources, which could put downward pressure on wholesale market prices for electricity in some markets where Exelon operates generation assets. At the same time, such developments may present some opportunities for sales of Generation's renewable power, including from wind, solar, hydroelectric and landfill gas.

See Note 3 and Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

Executive Officers of the Registrants as of February 13, 2014

Exelon

Name	Age	Position	Period
Crane, Christopher M.	55	Chief Executive Officer, Exelon;	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
		Chief Operating Officer, Exelon	2008 - 2012
		Chief Operating Officer, Generation	2007 - 2010
Cornew, Kenneth W.	48	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
O'Brien, Denis P.	53	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Vice Chairman, ComEd, PECO, BGE	2012 - Present
		Chief Executive Officer, PECO; Executive Vice President, Exelon	2007 - 2012
		President and Director, PECO	2003 - 2012

Name	Age	Position	Period
Pramaggiore, Anne R.	55	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 - 2009
Adams, Craig L.	61	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
DeFontes Jr., Kenneth W.	63	President and Chief Executive Officer, BGE	2004 - Present(a)
		Senior Vice President, Constellation Energy	2004 - 2012
Gillis, Ruth Ann M.	59	Executive Vice President, Exelon	2008 - Present
		Chief Administrative Officer, Exelon	2010 - Present
		President, Exelon Business Services Company	2005 - Present
		Chief Diversity Officer, Exelon	2009 - 2012
Von Hoene Jr., William A.	60	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
		Executive Vice President and General Counsel, Exelon	2008 - 2009
		Senior Vice President, Exelon Business Services Company	2004 - 2009
Thayer, Jonathan W.	42	Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012
Aliabadi, Paymon	51	Executive Vice President and Chief Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
		Principal and Managing Director, Gunvor International	2009 - 2011
		Chief Executive Officer, Essent Trading International	2004 - 2009
DesParte, Duane M.	50	Senior Vice President and Corporate Controller, Exelon	2008 - Present

Generation

Name	Age	Position	Period
Cornew, Kenneth W.	48	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012

Name	Age	Position	Period
Pacilio, Michael J.	53	President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - Present
		Chief Operating Officer, Exelon Nuclear	2007 - 2010
Nigro, Joseph	49	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - Present
		Senior Vice President, Portfolio Management and Strategy	2012 - 2013
		Vice President, Structuring and Portfolio Management, Exelon Power Team	2010 - 2012
DeGregorio, Ronald	51	Senior Vice President, Generation; President, Exelon Power	2012 - Present
		Chief Integration Officer, Exelon	2011 - 2012
		Chief Operating Officer, Exelon Transmission Company	2010 - 2011
		Senior Vice President, Mid-Atlantic Operations, Exelon Nuclear	2007 - 2010
Wright, Bryan P.	47	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
		Chief Accounting Officer, Constellation Energy	2009 - 2012
		Vice President and Controller, Constellation Energy	2008 - 2012
Aiken, Robert	47	Vice President and Controller, Generation	2012 - Present
		Executive Director and Assistant Controller, Constellation	2011 - 2012
		Executive Director of Operational Accounting, Constellation Energy Commodities Group	2009 - 2011
		Vice President of International Accounting, Constellation Energy Commodities Group	2007 - 2009

ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	55	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 - 2009
Donnelly, Terence R.	53	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
		Senior Vice President, Transmission and Distribution, ComEd	2007 - 2009
Trpik Jr., Joseph R.	44	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
		Vice President & Assistant Corporate Controller, Exelon Business Services Company	2007 - 2009
		Vice President and Assistant Corporate Controller, Exelon	2004 - 2009

Name	Age	Position	Period
Jensen, Val	58	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
O'Neill, Thomas S.	51	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2010 - Present
		Senior Vice President, Exelon	2009 - 2010
		Senior Vice President, New Business Development, Generation; Senior Vice President, New Business Development, Exelon	2009 - 2009
		Vice President, New Plant Development, Generation	2007 - 2009
Marquez Jr., Fidel	52	Senior Vice President, Governmental and External Affairs, Exelon	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012
		Vice President of External Affairs and Large Customer Services, ComEd	2007 - 2009
Brookins, Kevin B.	52	Senior Vice President, Strategy & Administration, ComEd	2012 - Present
		Vice President, Operational Strategy and Business Intelligence, ComEd	2010 - 2012
		Vice President, Distribution System Operations, ComEd	2008 - 2010
Anthony, J. Tyler	49	Senior Vice President, Distribution Operations, ComEd	2010 - Present
		Vice President, Transmission and Substations, ComEd	2007 - 2010
Kozel, Gerald J.	41	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013
		Director of Financial Reporting and Analysis, Exelon	2009 - 2012
		Manager of Accounting, ComEd	2008 - 2009

PECO

Name	Age	Position	Period
Adams, Craig L.	61	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	50	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	48	Senior Vice President and Chief Operations Officer, PECO	2012 - Present
		Vice President, Distribution System Operations and Smart Grid/Smart Meter, PECO	2010 - 2012
		Vice President, Distribution System Operations	2007 - 2010

Name	Age	Position	Period
Webster Jr., Richard G.	52	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	54	Vice President, Governmental and External Affairs, PECO	2012 - Present
		Director, Governmental & External Affairs, PECO	2007 - 2012
Jiruska, Frank J.	53	Vice President, Customer Operations, PECO	2013 - Present
Diaz Jr., Romulo L.	67	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
		Associate General Counsel, Exelon	2008 - 2009
Bailey, Scott A.	37	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012
		Director of Accounting, Power Team	2007 - 2011

BGE

Name	Age	Position	Period
DeFontes Jr., Kenneth W.	63	President and Chief Executive Officer, BGE	2004 - Present(a)
		Senior Vice President, Constellation Energy	2004 - 2012
Woerner, Stephen J.	46	Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - Present
		Vice President and Chief Integration Officer, Constellation Energy	2011 - 2012
		Vice President and Chief Information Officer, Constellation Energy	2010 - 2011
		Vice President, Transformation, Constellation Energy	2009 - 2010
		Senior Vice President, Gas and Electric Operations and Planning, BGE	2007 - 2009
Khouzami, Carim V.	38	Senior Vice President, Chief Financial Officer and Treasurer, BGE	2013 - Present
		Vice President, Chief Financial Officer and Treasurer, BGE	2011 - 2013
		Executive Director, Investor Relations, Constellation Energy	2009 - 2011
		Director, Corporate Strategy and Development, Constellation Energy	2008 - 2009
Butler, Calvin	44	Senior Vice President, Regulatory and External Affairs, BGE	2013 - Present(a)
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
		Senior Vice President, Human Resources, Exelon	2010 - 2011
		Senior Vice President, Corporate Affairs, ComEd	2009 - 2010

Name	Age	Position	Period
Case, Mark D.	52	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Dodson, Carol A.	49	Vice President, Customer Operations, BGE	2013 - Present
		Chief Customer Officer, BGE	2013 - Present
		Vice President, Utility Oversight, BSC	2012 - 2013
		Vice President, Engineering and Project Management, BGE	2012 - 2012
		Senior Vice President, Asset Management Services, BGE	2009 - 2012
Gahagan, Daniel P.	60	Vice President and General Counsel, BGE	2007 - Present
Vahos, David M.	41	Vice President and Controller, BGE	2012 - Present
		Executive Director, Audit, Constellation	2010 - 2012
		Director, Finance, BGE	2006 - 2010

(a) On February 12, 2014, Kenneth W. DeFontes Jr., President and Chief Executive Officer at BGE announced his retirement from BGE on February 28, 2014. Effective March 1, 2014, Calvin G. Butler Jr. will become Chief Executive Officer of BGE and an executive officer of Exelon and Stephen J. Woerner will become President and continue as Chief Operating Officer of BGE.

ITEM 1A. RISK FACTORS

Each of the Registrants operates in a market and regulatory environment that poses significant risks, many of which are beyond the Registrant's control. Management of each Registrant regularly meets with the Chief Risk Officer and the RMC, which comprises officers of the Registrants, to identify and evaluate the most significant risks of the Registrants' businesses, and the appropriate steps to manage and mitigate those risks. The Chief Risk Officer and senior executives of the Registrants discuss those risks with the finance and risk committee and audit committees of the Exelon board of directors and the ComEd, PECO and BGE boards of directors. In addition, the generation oversight committee of the Exelon board of directors' evaluates risks related to the generation business. The risk factors discussed below may adversely affect one or more of the Registrants' results of operations and cash flows and the market prices of their publicly traded securities. Each of the Registrants has disclosed the known material risks that affect its business at this time. However, there may be further risks and uncertainties that are not presently known or that are not currently believed by a Registrant to be material that may adversely affect its performance or financial condition in the future.

The Registrants' most significant risks arise as a consequence of: (1) Generation's position as a predominantly nuclear generator selling power into competitive energy markets with a concentration in select regions, and (2) the role of ComEd, PECO and BGE as operators of electric transmission and distribution systems in three of the largest metropolitan areas in the United States. The Registrants' major risks fall primarily under the following categories:

- ***Market and Financial Risks.*** Exelon's and Generation's market and financial risks include the risk of price fluctuations in the power markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular the prices of natural gas and coal, which drive the prices that Generation can obtain for the output of its power plants, (2) the rate of expansion of subsidized low-carbon generation in the markets in which Generation's output is sold, (3) the effects on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel.

- ***Regulatory and Legislative Risks.*** The Registrants' regulatory and legislative risks include changes to the laws and regulations that govern competitive markets and utility cost recovery, and that drive environmental policy. In particular, Exelon's and Generation's financial performance may be adversely affected by changes that could affect Generation's ability to sell power into the competitive wholesale power markets at market-based prices. In addition, potential regulation and legislation regarding climate change and renewable portfolio standards could increase the pace of development of wind energy facilities, which could put downward pressure in some markets on wholesale market prices for electricity from Generation's nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation's nuclear assets under a carbon constrained regulatory regime that might exist in the future. Also, regulatory actions in Illinois, Pennsylvania or Maryland could materially lower returns for ComEd, PECO and BGE, respectively.
- ***Operational Risks.*** The Registrants' operational risks include those risks inherent in running the nation's largest fleet of nuclear power reactors and large electric and gas distribution systems. The safe and effective operation of the nuclear facilities and the ability to effectively manage the associated decommissioning obligations as well as the ability to maintain the availability, reliability and safety of its energy delivery systems are fundamental to Exelon's ability to protect and grow shareholder value. Additionally, the operating costs of ComEd, PECO and BGE, and the opinions of customers and regulators of ComEd, PECO and BGE, are affected by those companies' ability to maintain the reliability and safety of their energy delivery systems.
- ***Risks Related to the Merger with Constellation and the Pending Master Agreement between Generation and CENG.*** As a result of the merger with Constellation that closed on March 12, 2012, Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals from the July 29, 2013 Master Agreement between Exelon, Generation and subsidiaries of Generation with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. Exelon and Generation are subject to the risks that integration of CENG's nuclear fleet may not achieve anticipated results, and that Exelon and Generation may not be able to fully integrate the operations of CENG in the manner expected.

A discussion of each of these risk categories and other risk factors is included below.

Market and Financial Risks

Generation is exposed to depressed prices in the wholesale and retail power markets, which may negatively affect its results of operations and cash flows. (Exelon and Generation)

Generation is exposed to commodity price risk for the unhedged portion of its electricity generation supply portfolio. As such, Generation's earnings and cash flows are therefore subject to variability as spot and forward market prices in the markets in which it operates rise and fall.

Price of Fuels : The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit. Often, the next unit of electricity will be supplied from generating stations fueled by fossil fuels. Consequently, changes in the market price of fossil fuels often result in comparable changes to the market price of power. For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing downward pressure on natural gas prices and, therefore, on power prices. The continued addition of supply from new alternative generation resources, such as wind and solar, whether mandated through RPS or otherwise subsidized or

encouraged through climate legislation or regulation, may displace a higher marginal cost plant, further reducing power prices. In addition, further delay or elimination of EPA air quality regulations could prolong the duration for which the cost of pollution from fossil fuel generation is not factored into market prices.

Demand and Supply: The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs can each depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on electricity market prices. The continued tepid economic environment and growing energy efficiency and demand response initiatives have limited the demand for electricity in Generation's markets. In addition, in some markets, the supply of electricity through wind or solar generation, when combined with other base-load generation such as nuclear, may often exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants. The risk of increased supply in excess of demand is heightened by continued or increased RPS mandates or other subsidies, including ITCs and PTCs.

Retail Competition: Generation's retail operations compete for customers in a competitive environment, which affects the margins that Generation can earn and the volumes that it is able to serve. In an environment of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including Generation) use their retail operations to hedge generation output. Increased or more aggressive competition can adversely affect overall gross margins and profitability in Generation's retail operations.

Sustained low market prices or depressed demand and over-supply could adversely affect Exelon's and Generation's results of operations and cash flows, and such impacts could be emphasized given Generation's concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect Exelon's and Generation's ability to fund other discretionary uses of cash such as growth projects or to pay dividends. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Exelon's and Generation's results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs which may be offset in whole or in part by reduced operating and maintenance expenses. A slow recovery in market conditions could result in a prolonged depression of or further decline in commodity prices, including low forward natural gas and power prices and low market volatility, which could also adversely affect Exelon's and Generation's results of operations, cash flows and financial position.

In addition to price fluctuations, Generation is exposed to other risks in the power markets that are beyond its control and may negatively affect its results of operations. (Exelon and Generation)

Credit Risk. In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money, or are obligated to purchase energy or fuel from Generation, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, Generation might be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. In the spot markets, Generation is exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs, the purpose of which is to spread such risk across all market participants. Generation is also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, Generation's retail sales subject it to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and

residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that may be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Unstable Markets. The wholesale spot markets remain evolving markets that vary from region to region and are still developing practices and procedures. Problems in or the failure of any of these markets could adversely affect Generation's business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

The Registrants are potentially exposed to emerging technologies that may over time affect or transform the energy industry, including technologies related to energy generation, distribution and consumption. (Exelon, Generation, ComEd, PECO and BGE)

Some of these technologies include, but are not limited to further shale gas development or sources, cost-effective renewable energy technologies, broad consumer adoption of electric vehicles and energy storage devices. Such developments could lower the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could materially affect the Registrants' results of operations, financial position, and cash flows through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors may decrease the value of NDT funds and employee benefit plan assets and increase the related employee benefit plan obligations, which then could require significant additional funding. (Exelon, Generation, ComEd, PECO and BGE)

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy may adversely affect the value of the investments held within Generation's NDTs and Exelon's employee benefit plan trusts. The Registrants have significant obligations in these areas and Exelon and Generation hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which may fall below the Registrants' projected return rates. A decline in the market value of the NDT fund investments may increase Generation's funding requirements to decommission its nuclear plants. A decline in the market value of the pension and other postretirement benefit plan assets will increase the funding requirements associated with Exelon's pension and other postretirement benefit plan obligations. Additionally, Exelon's pension and other postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements may also increase the costs and funding requirements of the obligations related to the pension and other postretirement benefit plans. If future increases in pension and other postretirement costs as a result of reduced plan assets or other factors cannot be recovered, or cannot be recovered in a timely manner, from ComEd, PECO and BGE customers, the results of operations and financial positions of ComEd, PECO and BGE could be negatively affected. Ultimately, if the Registrants are unable to manage the investments with the NDT funds and benefit plan assets, and unable to manage the related benefit plan liabilities, their results of operations, cash flows and financial positions could be negatively affected.

Unstable capital and credit markets and increased volatility in commodity markets may adversely affect the Registrants' businesses in several ways, including the availability and cost of short-term funds for liquidity requirements, the Registrants' ability to meet long-term commitments, Generation's ability to hedge effectively its generation portfolio, and the competitiveness and liquidity of energy markets; each could adversely affect the Registrants' financial condition, results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity needs if internal funds are not available from the Registrants' respective operations. Disruptions in the capital and credit markets in the United States or abroad can adversely affect the Registrants' ability to access the capital markets or draw on their respective bank revolving credit facilities. The Registrants' access to funds under their credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from the Registrants and other borrowers within a short period of time. The inability to access capital markets or credit facilities, and longer term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, changes to Generation's hedging strategy in order to reduce collateral-posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

In addition, the Registrants have exposure to worldwide financial markets, including Europe. Disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2013, approximately 30%, or $2.5 billion, of the Registrants' available credit facilities were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.6 billion was available as of December 31, 2013. There were no borrowings under the Registrants' credit facilities as of December 31, 2013. See Note 13 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in competitive energy markets depend heavily on active participation by multiple trading parties, which could be adversely affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that may affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to the respective businesses of the Registrants. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on Exelon's and Generation's results of operations and cash flows.

If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its trading counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs. (Exelon, Generation, ComEd, PECO and BGE)

Generation's business is subject to credit quality standards that may require market participants to post collateral for their obligations. If Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating) or otherwise fail to satisfy the credit standards of trading counterparties, it would be required under its hedging arrangements to provide collateral in the form of letters of credit or cash, which may have a material adverse effect upon its liquidity. The amount

of collateral required to be provided by Generation at any point in time is dependent on a variety of factors, including (1) the notional amount of the applicable hedge, (2) the nature of counterparty and related agreements, and (3) changes in power or other commodity prices. In addition, if Generation were downgraded, it could experience higher borrowing costs as a result of the downgrade. Generation could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the power generation industry in general, or Generation in particular, has deteriorated. Changes in ratings methodologies by the credit rating agencies could also have a negative impact on the ratings of Generation.

ComEd's operating agreement with PJM contains collateral provisions that are affected by its credit rating and market prices. If certain wholesale market conditions exist and ComEd were to lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required under the PJM operating agreement to provide collateral in the forms of letters of credit or cash, which may have a material adverse effect upon its liquidity. Collateral posting will generally increase as market prices rise and decrease as market prices fall. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if ComEd were downgraded, it could experience higher borrowing costs as a result of the downgrade.

PECO's and BGE's operating agreements with PJM and their natural gas procurement contracts contain collateral provisions that are affected by their credit ratings. If certain wholesale market conditions exist and PECO and BGE were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the form of letters of credit or cash, which may have material adverse effects upon their liquidity. PECO's and BGE's collateral requirements relating to their natural gas supply contracts are a function of market prices. Collateral posting requirements for PECO and BGE with respect to these contracts will generally increase as forward market prices fall and decrease as forward market prices rise. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if PECO or BGE were downgraded, they could experience higher borrowing costs as a result of the downgrade.

ComEd, PECO or BGE could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the utility industry in general, or ComEd, PECO, or BGE in particular, has deteriorated. ComEd, PECO or BGE could experience a downgrade if the current regulatory environments in Illinois, Pennsylvania or Maryland, respectively, become less predictable by materially lowering returns for utilities in the applicable state or adopting other measures to mitigate higher electricity prices. Additionally, the ratings for ComEd, PECO or BGE could be downgraded if their financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage their capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of ComEd, PECO or BGE.

ComEd, PECO and BGE conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that ComEd, PECO and BGE are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate ComEd, PECO and BGE from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as "ringfencing") may help avoid or limit a downgrade in the credit ratings of ComEd, PECO and BGE in the event of a reduction in the credit rating of Exelon. Despite these ringfencing measures, the credit ratings of ComEd, PECO or BGE could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of ComEd, PECO or BGE, or all three. A reduction in the credit rating of ComEd, PECO or BGE could have a material adverse effect on ComEd, PECO or BGE, respectively.

See Liquidity and Capital Resources—Recent Market Conditions and Security Ratings for further information regarding the potential impacts of credit downgrades on the Registrants' cash flows.

Generation's financial performance may be negatively affected by price volatility, availability and other risk factors associated with the procurement of nuclear and fossil fuel. (Exelon and Generation)

Generation depends on nuclear fuel and fossil fuels to operate its generating facilities. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. Coal, natural gas and oil are procured for generating plants through annual, short-term and spot-market purchases. The supply markets for nuclear fuel, coal, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default that may negatively affect the results of operations for Generation.

Generation's risk management policies cannot fully eliminate the risk associated with its commodity trading activities. (Exelon and Generation)

Generation's asset-based power position as well as its power marketing, fuel procurement and other commodity trading activities expose Generation to risks of commodity price movements. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations may be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, Generation cannot predict the impact that its commodity trading activities and risk management decisions may have on its business, operating results, cash flows or financial position.

Generation buys and sells energy and other products in the wholesale markets and enters into financial contracts to manage risk and hedge various positions in Generation's power generation portfolio. The proportion of hedged positions in its power generation portfolio may cause volatility in Generation's future results of operations.

Financial performance and load requirements may be adversely affected if Generation is unable to effectively manage its power portfolio. (Exelon and Generation)

A significant portion of Generation's power portfolio is used to provide power under procurement contracts with ComEd, PECO, BGE and other customers. To the extent portions of the power portfolio are not needed for that purpose, Generation's wholesale output is sold in the wholesale power markets. To the extent its power portfolio is not sufficient to meet the requirements of its customers under the related agreements, Generation must purchase power in the wholesale power markets. Generation's financial results may be negatively affected if it is unable to cost-effectively meet the load requirements of its customers, manage its power portfolio and effectively address the changes in the wholesale power markets.

Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could negatively impact the Registrants' results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Corporate Tax Reform. There exists the potential for comprehensive tax reform in the United States that may significantly change the tax rules applicable to U.S. domiciled corporations. Exelon cannot assess what the overall effect of such potential legislation would be on its results of operations and cash flows.

1999 sale of fossil generating assets. The IRS has challenged Exelon's 1999 tax position on its like-kind exchange transaction. Exelon and the IRS failed to reach a settlement on the like-kind exchange position and Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the like-kind exchange position. The litigation could take three to five years including appeals, if necessary.

As of December 31, 2013, if the IRS is successful in its challenge to the like-kind exchange position, Exelon's potential cash outflow, including tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $840 million, of which approximately $305 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless. In addition to attempting to impose tax on the like-kind exchange position, the IRS has asserted penalties for a substantial understatement of tax, which could result in an after-tax charge of $87 million to Exelon's and ComEd's results of operations should the IRS prevail in asserting the penalties. The timing effects of the final resolution of the like-kind exchange matter are unknown. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information.

Tax reserves and the recoverability of deferred tax assets. The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeals issues related to these tax matters. These judgments include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by the tax authorities. The Registrants also estimate their ability to utilize tax benefits, including those in the form of carryforwards and tax credits. See Notes 1 and 14 of the Combined Notes to Consolidated Financial Statements for additional information.

Increases in customer rates and the impact of economic downturns may lead to greater expense for uncollectible customer balances. Additionally, increased rates could lead to decreased volumes delivered. Both of these factors may decrease Generation's, ComEd's, PECO's and BGE's results from operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

ComEd's, PECO's and BGE's current procurement plans include purchasing power through contracted suppliers and in the spot market. ComEd's and PECO's costs of purchased power are charged to customers without a return or profit component. BGE's SOS rates charged to customers recover BGE's wholesale power supply costs and include an administrative fee which includes a shareholder return component and an incremental cost component. For PECO, purchased natural gas costs are charged to customers with no return or profit component. For BGE, purchased natural gas costs are charged to customers using a MBR mechanism that compares the actual cost of gas to a market index. The difference between the actual cost and the market index is shared equally between shareholders and customers. Purchased power and natural gas prices fluctuate based on their relevant supply and demand. Significantly higher rates related to purchased power and natural gas can result in declines in customer usage, lower revenues and potentially additional uncollectible accounts expense for ComEd, PECO and BGE. In addition, any challenges by the regulators or ComEd, PECO and BGE as to the recoverability of these costs could have a material effect on the Registrants' results of operations and cash flows. Also, ComEd's, PECO's and BGE's cash flows can be affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

Further, the impacts of economic downturns on ComEd, PECO and BGE customers and purchased natural gas costs for PECO and BGE customers, such as unemployment for residential customers and less demand for products and services provided by commercial and industrial customers, and the related regulatory limitations on residential service terminations, may result in an increase in the number of uncollectible customer balances, which would negatively impact ComEd's, PECO's and BGE's results from operations and cash flows. Generation's customer supply activities

face economic downturn risks similar to Exelon's utility businesses, such as lower volumes sold and increased expense for uncollectible customer balances. As Generation increases its customer supply footprint, economic downturn impacts could negatively affect Generation's results from operations and cash flows. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants' credit risk.

The effects of weather may impact the Registrants' results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Moderate temperatures adversely affect the usage of energy and resulting revenues at ComEd and PECO. Due to revenue decoupling, BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period, and is not affected by actual weather with the exception of major storms. Extreme weather conditions or damage resulting from storms may stress ComEd's, PECO's and BGE's transmission and distribution systems, communication systems and technology, resulting in increased maintenance and capital costs and limiting each company's ability to meet peak customer demand. These extreme conditions may have detrimental effects on ComEd's, PECO's and BGE's results of operations and cash flows. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and may make period comparisons less relevant.

Generation's operations are also affected by weather, which affects demand for electricity as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation may require greater resources to meet its contractual commitments. Extreme weather conditions or storms may affect the availability of generation and its transmission, limiting Generation's ability to source or send power to where it is sold. In addition, drought-like conditions limiting water usage can impact Generation's ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, may have an adverse effect by causing Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Certain long-lived assets and other assets recorded on the Registrants' statements of financial position may become impaired, which would result in write-offs of the impaired amounts. (Exelon, Generation, ComEd, PECO and BGE)

Long-lived assets represent the single largest asset class on the Registrants' statement of financial position. Specifically, long-lived assets account for 59%, 49%, 61%, 66% and 75% of total assets for Exelon, Generation, ComEd, PECO and BGE, respectively, as of December 31, 2013. In addition, the Registrants have significant balances related to unamortized energy contracts. See Notes 4 and 10 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's unamortized energy contracts. The Registrants evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered when evaluating long-lived assets for potential impairment. An impairment would require the Registrants to reduce the carrying value of the long-lived asset through a non-cash charge to expense by the amount of the impairment, and such an impairment could have a material adverse impact on the Registrants' results of operations.

Exelon and Generation have investments in certain generating plant projects, including the CENG nuclear joint venture with a carrying value of $1.9 billion as of December 31, 2013. These investments

were acquired in the March 2012 Constellation transaction, and were recorded as equity method investments on the balance sheet at fair value on the merger date as part of purchase accounting. Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such issues indicate an other than temporary decline in value. Such impairment could have a material adverse impact on Exelon's and Generation's results of operations.

Exelon holds investments in coal-fired plants in Georgia and Texas subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual values of the leased assets at the end of the respective lease terms. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records a non-cash impairment charge to expense if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Such an impairment could have a material adverse impact on Exelon's results of operations.

Exelon and ComEd had approximately $2.6 billion of goodwill recorded at December 31, 2013 in connection with the merger between PECO and Unicom Corporation, the former parent company of ComEd. Under GAAP, goodwill remains at its recorded amount unless it is determined to be impaired, which is generally based upon an annual analysis that compares the implied fair value of the goodwill to its carrying value. If an impairment occurs, the amount of the impaired goodwill will be written-off, reducing equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. A successful IRS challenge to Exelon's and ComEd's like-kind exchange income tax position, adverse regulatory actions such as early termination of EIMA, or changes in significant assumptions used in estimating ComEd's fair value (e.g., discount and growth rates, utility sector market performance and transactions, operating and capital expenditure requirements and the fair value of debt) could result in an impairment. Such an impairment would result in a non-cash charge to expense, which could have a material adverse impact on Exelon's and ComEd's results of operations.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Critical Accounting Policies and Estimates and Notes 7, 8 and 10 of the Combined Notes to the Consolidated Financial Statements for additional discussion on long-lived asset and goodwill impairments.

The Registrants' businesses are capital intensive, and their assets may require significant expenditures to maintain and are subject to operational failure, which could result in potential liability. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants' businesses are capital intensive and require significant investments by Generation in energy generation and by ComEd, PECO and BGE in transmission and distribution infrastructure projects. These operational systems and infrastructure have been in service for many years. Older equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Registrants' control, and may require significant expenditures to operate efficiently. The Registrants' results of operations, financial condition, or cash flows could be adversely affected if they were unable to effectively manage their capital projects or raise the necessary capital. Furthermore, operational failure could result in potential liability if such failure results in damage to property or injury to individuals. See ITEM 1. BUSINESS for further information regarding the Registrants' potential future capital expenditures.

Exelon and its subsidiaries have guaranteed the performance of third parties, which may result in substantial costs in the event of non-performance by third parties. In addition, the Registrants have rights under agreements which obligate third parties to indemnify the Registrants for various obligations, and the Registrants may incur substantial costs in the event that the applicable Registrant is unable to enforce those agreements or the applicable third-party is otherwise unable to perform. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have issued guarantees of the performance of third parties, which obligate one or more of the Registrants or their subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, the Registrants could incur substantial cost to fulfill their obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial condition, or cash flows of the Registrants.

The Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected Registrant could be held responsible for the obligations, which could impact that Registrant's results of operations, cash flows and financial position. In connection with Exelon's 2001 corporate restructuring, Generation assumed certain of ComEd's and PECO's rights and obligations with respect to their former generation businesses. Further, ComEd and PECO may have entered into agreements with third parties under which the third-party agreed to indemnify ComEd or PECO for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the restructuring. If the third-party or Generation experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, ComEd or PECO could be liable for any existing or future claims, which could impact ComEd's or PECO's results of operations, cash flows and financial position.

Generation's business may be negatively affected by competitive electric generation suppliers. (Exelon and Generation)

Because retail customers where Generation serves load can switch from their respective energy delivery company to a competitive electric generation supplier for their energy needs, planning to meet Generation's obligation to provide the supply needed to serve Generation's share of an electric distribution company's default service obligation is more difficult than planning for retail load before the advent of retail competition. Before retail competition, the primary variables affecting projections of load were weather and the economy. With retail competition, another major factor is retail customers switching to or from competitive electric generation suppliers. If fewer of such customers switch from its retail load serving counterparties than Generation anticipates, the load that Generation must serve will be greater than anticipated, which could, if market prices have increased, increase Generation's costs (due to its need to go to market to cover its incremental supply obligation) more than the increase in Generation's revenues. If more customers from its retail load serving counterparties switch than Generation anticipates, the load that Generation must serve will be lower than anticipated, which could, if market prices have decreased, cause Generation to lose opportunities in the market.

Regulatory and Legislative Risks

The Registrants' generation and energy delivery businesses are highly regulated and could be subject to adverse regulatory and legislative actions. Fundamental changes in regulation or legislation or violation of tariffs or market rules and anti-manipulation laws, could disrupt the Registrants' business plans and adversely affect their operations and financial results. (Exelon, Generation, ComEd, PECO and BGE)

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation. Further, Exelon's and Generation's operating results and

cash flows are heavily dependent upon the ability of Generation to sell power at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon's, ComEd's, PECO's and BGE's operating results and cash flows are heavily dependent on the ability of ComEd, PECO and BGE to recover their costs for the retail purchase and distribution of power to their customers. Similarly, there is risk that financial market regulations could increase the Registrants' compliance costs and limit their ability to engage in certain transactions. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, exchanges, ratemaking agencies and taxing authorities. Additionally, the Registrants need to be cognizant of rules changes or Registrant actions that could result in potential violation of tariffs, market rules and anti-manipulation laws. Fundamental changes in regulations or other adverse legislative actions affecting the Registrants' businesses would require changes in their business planning models and operations and could adversely affect their results of operations, cash flows and financial position.

Regulatory and legislative developments related to climate change and RPS may also significantly affect Exelon's and Generation's results of operations, cash flows and financial positions. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, may sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. However, national regulation or legislation addressing climate change through an RPS could also increase the pace of development of wind energy facilities in the Midwest, which could put downward pressure on wholesale market prices for electricity from Generation's Midwest nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation's nuclear assets under a carbon constrained regulatory regime that might exist in the future. Current state level climate change and renewable regulation is already providing incentives for regional wind development. The Registrants cannot predict when or whether any of these various legislative and regulatory proposals may become law or what their effect will be on the Registrants.

Generation may be negatively affected by possible Federal or state legislative or regulatory actions that could affect the scope and functioning of the wholesale markets. (Exelon and Generation)

Federal and state legislative and regulatory bodies are facing pressures to address consumer concerns, or are themselves raising concerns, that energy prices in wholesale markets are too high or insufficient generation is being built because the competitive model is not working, and, therefore, are considering some form of re-regulation or some other means of reducing wholesale market prices or subsidizing new generation. Generation is dependent on robust and competitive wholesale energy markets to achieve its business objectives.

Approximately 60% of Generation's generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Generation's future results of operations will depend on 1) FERC's continued adherence to and support for, policies that favor the preservation of competitive wholesale power markets, such as PJM's, and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competitiveness. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize new generation, such as the subsequently dismissed New Jersey Capacity Legislation and the MDPSC's RFP for new gas-fired generation in Maryland. See Note 3 of the Combined Notes to Consolidated Financial Statements for further details related to the New Jersey Capacity Legislation and the Maryland new electric generation requirements.

In addition, FERC's application of its Order 697 and its subsequent revisions could pose a risk that Generation will have difficulty satisfying FERC's tests for market-based rates. Since Order 697 became

final in June 2007, Generation has obtained orders affirming Generation's authority to sell at market-based rates and none denying that authority. On December 31, 2013, Generation submitted its triennial application seeking reauthorization to sell at market-based rates in the Northeast region (including PJM, ISO-NY and ISONE). Generation's previous submission seeking reauthorization to sell at market-based rates was accepted by FERC on June 22, 2011 for the PJM region.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank) was enacted into law on July 21, 2010. Its primary objective is to eliminate from the financial system the systemic risk that Congress believed was in part the cause of the financial crisis that unfolded during 2008. Dodd-Frank ushers in a brand new regulatory regime applicable to the over-the-counter (OTC) market for swaps. Generation relies on the OTC swaps markets as part of its program to hedge the price risk associated with its generation portfolio. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Generation has determined that it will conduct its commercial hedging business as an end user in a manner that does not require registration as a swap dealer or major swap participant.

Notwithstanding the foregoing, Generation will still face additional regulatory obligations under Dodd-Frank, including some reporting requirements, clearing some additional transactions that it would otherwise enter into over-the-counter, and having to adhere to position limits. More fundamentally, however, the total burden that the rules could impose on all market participants could cause liquidity in the bilateral OTC swaps market to decrease substantially. Dodd-Frank may require up to $1 billion of additional collateral requirements at Generation, to be met with cash rather than letters of credit in a price stressed environment. Generation continues to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on its results of operations, cash flows or financial position.

Generation's affiliation with ComEd, PECO and BGE, together with the presence of a substantial percentage of Generation's physical asset base within the ComEd, PECO and BGE service territories, could increase Generation's cost of doing business to the extent future complaints or challenges regarding ComEd, PECO and/or BGE retail rates result in settlements or legislative or regulatory requirements funded in part by Generation. (Exelon and Generation)

Generation has significant generating resources within the service areas of ComEd, PECO and BGE and makes significant sales to each of them. Those facts tend to cause Generation to be directly affected by developments in those markets. Government officials, legislators and advocacy groups are aware of Generation's affiliation with ComEd, PECO and BGE and its sales to each of them. In periods of rising utility rates, particularly when driven by increased costs of energy production and supply, those officials and advocacy groups may question or challenge costs incurred by ComEd, PECO or BGE, including transactions between Generation, on the one hand, and ComEd, PECO or BGE, on the other hand, regardless of any previous regulatory processes or approvals underlying those transactions. The prospect of such challenges may increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges may subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators may seek ways to force Generation to contribute to efforts to mitigate potential or actual rate increases, through measures such as generation-based taxes and contributions to rate-relief packages.

The Registrants may incur substantial costs to fulfill their obligations related to environmental and other matters. (Exelon, Generation, ComEd, PECO and BGE)

The businesses which the Registrants operate are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the manner in which the Registrants conduct their operations and make capital expenditures including how they handle air and water emissions and solid waste disposal. Violations of these emission and disposal

requirements can subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties' claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generate. The Registrants have incurred and expect to incur significant costs related to environmental compliance, site remediation and clean-up. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

If application of Section 316(b) of the Clean Water Act, which establishes a national requirement for reducing the adverse impacts to aquatic organisms at existing generating stations, requires the retrofitting of cooling water intake structures at Salem or other Exelon power plants, this development could result in material costs of compliance. Pursuant to discussions with the NJDEP regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029.

Additionally, Generation is subject to exposure for asbestos-related personal injury liability alleged at certain current and formerly owned generation facilities. Future legislative action could require Generation to make a material contribution to a fund to settle lawsuits for alleged asbestos-related disease and exposure.

In some cases, a third-party who has acquired assets from a Registrant has assumed the liability the Registrant may otherwise have for environmental matters related to the transferred property. If the transferee is unable, or fails, to discharge the assumed liability, a regulatory authority or injured person could attempt to hold the Registrant responsible, and the Registrant's remedies against the transferee may be limited by the financial resources of the transferee. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in ComEd's, PECO's and BGE's respective terms and conditions of service, including their respective rates, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy and subject to appeal, which lead to uncertainty as to the ultimate result and which may introduce time delays in effectuating rate changes. (Exelon, ComEd, PECO and BGE)

ComEd, PECO and BGE are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for ComEd, PECO or BGE to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates can be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs.

In certain instances, ComEd, PECO and BGE may agree to negotiated settlements related to various rate matters, customer initiatives or franchise agreements. These settlements are subject to regulatory approval.

ComEd, PECO and BGE cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania, Maryland or Federal regulators in establishing rates, including the extent, if any, to which certain costs such as significant capital projects will be recovered or what rates of return will be allowed. Nevertheless, the expectation is that ComEd, PECO and BGE will continue to be obligated to deliver electricity to customers in their respective service territories and will also retain significant POLR and default service obligations to provide electricity and natural gas to certain groups of customers in their respective service areas who do not choose an alternative supplier. The ultimate outcome and timing of regulatory rate proceedings have a significant effect on the ability of ComEd, PECO and BGE, as applicable, to recover their costs and could have a material adverse effect on ComEd's, PECO's and BGE's results of operations, cash flows and financial position. See Note 3 of the Combined Notes to the Consolidated Financial Statements for information regarding rate proceedings.

Federal or additional state RPS and/or energy conservation legislation, along with energy conservation by customers, could negatively affect the results of operations and cash flows of Generation, ComEd, PECO and BGE. (Exelon, Generation, ComEd, PECO and BGE)

Changes to current state legislation or the development of Federal legislation that requires the use of renewable and alternate fuel sources, such as wind, solar, biomass and geothermal, could significantly impact Generation, ComEd, PECO and BGE, especially if timely cost recovery is not allowed. The impact could include increased costs for RECs and purchased power and increased rates for customers.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, have increased capital expenditures and could significantly impact ComEd, PECO and BGE, if timely cost recovery is not allowed. Furthermore, regulated energy consumption reduction targets and declines in customer energy consumption resulting from the implementation of new energy conservation technologies could lead to a decline in the revenues of Exelon, ComEd, and PECO. For additional information, see ITEM 1. BUSINESS "Environmental Regulation-Renewable and Alternative Energy Portfolio Standards."

The impact of not meeting the criteria of the FASB guidance for accounting for the effects of certain types of regulation could be material to Exelon, ComEd, PECO and BGE. (Exelon, ComEd, PECO and BGE)

As of December 31, 2013, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria of the authoritative guidance for accounting for the effects of certain types of regulation. If it is concluded in a future period that a separable portion of their businesses no longer meets the criteria, Exelon, ComEd, PECO and BGE would be required to eliminate the financial statement effects of regulation for that part of their business. That action would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets and the recognition of a one-time extraordinary item in their Consolidated Statements of Operations. The impact of not meeting the criteria of the authoritative guidance could be material to the financial statements of Exelon, ComEd, PECO and BGE. At December 31, 2013, the extraordinary gain (loss) could have been as much as $(2.4) billion, $730 million and $ 453 million (before taxes) as a result of the elimination of ComEd's, PECO's and BGE's regulatory assets and liabilities, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to $2.4 billion and $568 million for ComEd and BGE, respectively, related to Exelon's regulatory assets associated with its defined benefit postretirement plans. Exelon also has a regulatory liability of $45 million (before taxes) associated with PECO's defined benefit postretirement plans that would result in an increase in OCI if reversed. The impacts and resolution of the above items could lead to an additional impairment of ComEd's goodwill, which could be significant and at least partially offset the extraordinary gain at ComEd discussed above. A significant decrease in equity as a result of any changes could limit the ability of ComEd, PECO and BGE to pay dividends under Federal

and state law and no longer meeting the regulatory accounting criteria could cause significant volatility in future results of operations. See Notes 1, 3 and 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd's goodwill, respectively.

Exelon and Generation may incur material costs of compliance if Federal and/or state regulation or legislation is adopted to address climate change. (Exelon and Generation)

Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. In 2009, select Northeast and Mid-Atlantic states implemented a model rule, developed via the RGGI, to regulate CO_2 emissions from fossil-fired generation. RGGI states are working on updated programs to further limit emissions and the EPA has introduced regulation to address greenhouse gases from new fossil plants that could potentially impact existing plants. If carbon reduction regulation or legislation becomes effective, Exelon and Generation may incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. The nature and extent of environmental regulation may also impact the ability of Exelon and its subsidiaries to meet the GHG emission reduction targets of Exelon 2020. For example, more stringent permitting requirements may preclude the construction of lower-carbon nuclear and gas-fired power plants. Similarly, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS "Global Climate Change" and Note 22 of the Combined Notes to Consolidated Financial Statements.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of ComEd, PECO, and BGE to the results of PJM's RTEP and NERC compliance requirements. (Exelon, Generation, ComEd, PECO and BGE)

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation, ComEd, PECO and BGE, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. As operators of natural gas distribution systems, PECO and BGE are also subject to mandatory reliability standards of the U.S. Department of Transportation. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards may subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC and MDPSC impose certain distribution reliability standards on ComEd, PECO and BGE, respectively. If the Registrants were found not to be in compliance with the mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

ComEd, PECO and BGE as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments may require ComEd, PECO and BGE to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. Uncertainties exist as to the construction of new transmission facilities, their cost and how those costs will be allocated to transmission system participants and customers. In accordance with a FERC order and related settlement, PJM's RTEP requires the costs of new transmission facilities to be allocated across the entire PJM footprint for new facilities greater than or equal to 500 kV, and requires costs of new facilities less than 500 kV to be allocated to the beneficiaries of the new facilities. Following a remand from the U.S. Court of Appeals for the Seventh Circuit, FERC reaffirmed its decision related to allocation of new facilities 500 kV and above. That decision is being appealed to the U.S. Court of Appeals for the Seventh Circuit. This FERC order only applies to facilities included in the PJM RTEP

prior to February 1, 2013. For facilities subsequently approved, the costs of new facilities that are double circuit 345 kV or greater than or equal to 500 kV will be allocated 50% across the entire PJM footprint and 50% allocated to identified beneficiaries. Costs for all other facilities will be allocated to all identified beneficiaries. This later decision is subject to rehearing by FERC and possible appeal.

See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants cannot predict the outcome of the legal proceedings relating to their business activities. An adverse determination could have a material adverse effect on their results of operations, financial positions and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are involved in legal proceedings, claims and litigation arising out of their business operations, the most significant of which are summarized in Note 22 of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on the Registrants' results of operations.

Generation may be negatively affected by possible Nuclear Regulatory Commission actions that could affect the operations and profitability of its nuclear generating fleet. (Exelon and Generation)

Regulatory risk **.** A change in the Atomic Energy Act or the applicable regulations or licenses may require a substantial increase in capital expenditures or may result in increased operating or decommissioning costs and significantly affect Generation's results of operations or financial position. Events at nuclear plants owned by others, as well as those owned by Generation, may cause the NRC to initiate such actions.

As an example, prior to the Fukushima Daiichi accident on March 11, 2011, the NRC had been evaluating seismic risk. After the Fukushima Daiichi accident, the NRC's focus on seismic risk intensified. As part of the NRC Near-Term Task Force (Task Force) review and evaluation of the Fukushima Daiichi accident, the Task Force recommended that plant operators conduct seismic reevaluations. In January 2012, the NRC released an updated seismic risk model that plant operators must use in performing the seismic reevaluations recommended by the Task Force. These reevaluations could result in the required implementation of additional mitigation strategies or modifications. Additionally, the Task Force provided recommendations for future regulatory action by the NRC to be taken in the near and longer term. In response, the NRC issued three immediately effective orders (Tier 1) to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. The NRC is currently evaluating the remaining Task Force recommendations and has not taken action with respect to the Tier 2 and Tier 3 recommendations. Actions to comply with the Task Force recommendations will result in increased costs and could significantly impact Generation's results of operations or financial position. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview for a more detailed discussion of the Task Force Recommendations.

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF, such as the one previously considered at Yucca Mountain, Nevada, and the timing of such facility opening, will significantly affect the costs associated with storage of SNF, and the ultimate amounts received from the DOE to reimburse Generation for these costs. The NRC's temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants. In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive

environmental review to support the rule. In September 2012, the NRC directed NRC Staff to complete a generic environmental impact statement and to revise the temporary storage rule which is now not expected until October 3, 2014.

Any regulatory action relating to the timing and availability of a repository for SNF may adversely affect Generation's ability to decommission fully its nuclear units. In accordance with the NWPA and Generation's contract with the DOE, Generation pays the DOE ongoing fees per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. On November 19, 2013, the United States Court of Appeals for the District of Columbia Circuit ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. Until such time as a new fee structure is in effect, Generation must continue to pay the current SNF disposal fees. Furthermore, under its contract with the DOE, Generation would be required to pay the DOE a one-time SNF storage fee including interest of approximately $1 billion as of December 31, 2013, prior to the first delivery of SNF. Generation currently estimates 2025 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information on the spent nuclear fuel obligation.

License renewals. Generation cannot assure that economics will support the continued operation of the facilities for all or any portion of any renewed license period. If the NRC does not renew the operating licenses for Generation's nuclear stations or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates, impairment charges and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. In addition, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments.

As discussed above, in June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

Operational Risks

The Registrants' employees, contractors, customers and the general public may be exposed to a risk of injury due to the nature of the energy industry. (Exelon, Generation, ComEd, PECO and BGE)

Employees and contractors throughout the organization work in, and customers and the general public may be exposed to, potentially dangerous environments near their operations. As a result, employees, contractors, customers and the general public are at risk for serious injury, including loss of life. Significant risks include nuclear accidents, dam failure, gas explosions, pole strikes and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events may adversely affect Exelon's results of operations, its ability to raise capital and its future growth. (Exelon, Generation, ComEd, PECO and BGE)

Generation's fleet of nuclear and fossil-fueled power plants and ComEd's, PECO's and BGE's distribution and transmission infrastructures could be affected by natural disasters, such as seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Registrants' service areas can also directly affect their capital assets, causing disruption in service to customers

due to downed wires and poles or damage to other operating equipment. Examples of such events include the June 2012 “Derecho” storm, which interrupted electric service delivery to customers in BGE’s service territory, and the October 2012 category 1 hurricane, Hurricane Sandy, which interrupted electric service delivery to customers in PECO’s and BGE’s service territories and resulted in significant costs to PECO and BGE for restoration efforts.

Other events include the 9.0 magnitude earthquake and ensuing tsunami experienced by Japan on March 11, 2011, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co., and the 5.8 magnitude earthquake and flooding associated with Hurricane Irene and Tropical Storm Lee that the Mid-Atlantic region of the United States experienced in 2011. These events increase the risk to Generation that the NRC or other regulatory or legislative bodies may change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological aspects. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for Generation’s continued operation, particularly the cooling of generating units. Additionally, natural disasters and other events that have an adverse effect on the economy in general may adversely affect the Registrants’ operations and their ability to raise capital.

Exelon does not know the impact that potential terrorist attacks could have on the industry in general and on Exelon in particular. As owner-operators of infrastructure facilities, such as nuclear, fossil and hydroelectric generation facilities and electric and gas transmission and distribution facilities, the Registrants face a risk that their operations would be direct targets of, or indirect casualties of, an act of terror. Any retaliatory military strikes or sustained military campaign may affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cyber security of Exelon’s facilities, which could adversely affect Exelon’s ability to manage its business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also may result in a decline in energy consumption, which may adversely affect the Registrants’ results of operations and its ability to raise capital. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants would be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate its generating and transmission and distribution assets could be affected, resulting in decreased service levels and increased costs.

In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property and casualty losses subject to unforeseen occurrences or catastrophic events that may damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

Generation’s financial performance may be negatively affected by matters arising from its ownership and operation of nuclear facilities. (Exelon and Generation)

Nuclear capacity factors. Capacity factors for generating units, particularly capacity factors for nuclear generating units, significantly affect Generation’s results of operations. Nuclear plant operations involve substantial fixed operating costs but produce electricity at low variable costs due to nuclear fuel costs typically being lower than fossil fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear facilities at high capacity factors. Lower capacity factors increase Generation’s operating costs by requiring Generation to produce additional energy from primarily its fossil

facilities or purchase additional energy in the spot or forward markets in order to satisfy Generation's obligations to committed third-party sales, including ComEd, PECO and BGE. These sources generally have higher costs than Generation incurs to produce energy from its nuclear stations.

Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, can have a significant impact on Generation's results of operations. When refueling outages at wholly and co-owned plants last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales.

Nuclear fuel quality . The quality of nuclear fuel utilized by Generation can affect the efficiency and costs of Generation's operations. Certain of Generation's nuclear units have previously had a limited number of fuel performance issues. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

Operational risk . Operations at any of Generation's nuclear generation plants could degrade to the point where Generation has to shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Generation may choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, Generation may not achieve the anticipated results under its series of planned power uprates across its nuclear fleet. For plants operated but not wholly owned by Generation, Generation may also incur liability to the co-owners. For plants not operated and not wholly owned by Generation, from which Generation receives a portion of the plants' output, Generation's results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by Generation could result in increased regulation and reduced public support for nuclear-fueled energy, which could significantly affect Generation's results of operations or financial position. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident can be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by Generation or owned by others, may exceed Generation's resources, including insurance coverage. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by Generation and could have a material adverse effect on Generation's results of operations or financial position. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, owned by others or Generation, may result in increased regulation and reduced public support for nuclear-fueled energy and significantly affect Generation's results of operations or financial position.

Nuclear insurance. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance. The required amount of nuclear liability insurance is $375 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.6 billion limit for a single incident.

Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation's nuclear operations. In previous years, NEIL has

made distributions to its members but Generation cannot predict the level of future distributions or if they will occur at all. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Generation is required to provide to the NRC a biennial report by unit (annually for Generation's two units that have been retired) addressing Generation's ability to meet the NRC-estimated funding levels including scheduled contributions to and earnings on the decommissioning trust funds. The NRC funding levels are based upon the assumption that decommissioning will commence after the end of the current licensed life of each unit.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results may differ significantly from current estimates. The performance of capital markets also can significantly affect the value of the trust funds. Currently, Generation is making contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from ComEd customers or from the previous owners of Clinton, TMI Unit No. 1 and Oyster Creek generating stations, if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that Generation would be unable to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if Generation no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units may be negatively affected and Exelon's and Generation's results of operations and financial position could be significantly affected. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Ultimately, if the investments held by Generation's NDTs are not sufficient to fund the decommissioning of Generation's nuclear plants, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met. As a result, Generation's cash flows and financial position may be significantly adversely affected. See Note 15 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's financial performance may be negatively affected by risks arising from its ownership and operation of hydroelectric facilities. (Exelon and Generation)

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. The license for the Conowingo Hydroelectric Project expires August 31, 2014, and the license for the Muddy Run Pumped Storage Project expires on September 1, 2014. Generation cannot predict whether it will receive all the regulatory approvals for the renewed licenses of its hydroelectric facilities. If FERC does not issue new operating licenses for Generation's hydroelectric facilities or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. Generation may also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions may be imposed as part of the license renewal process that may adversely affect operations, may require a substantial increase in capital expenditures or may result in increased operating costs and significantly affect Generation's results of operations or financial

position. Similar effects may result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by Generation.

ComEd's, PECO's and BGE's operating costs, and customers' and regulators' opinions of ComEd, PECO and BGE, respectively, are affected by their ability to maintain the availability and reliability of their delivery and operational systems. (Exelon, ComEd, PECO and BGE)

Failures of the equipment or facilities, including information systems, used in ComEd's, PECO's and BGE's delivery systems can interrupt the electric transmission and electric and natural gas delivery, which could negatively impact related revenues, and increase maintenance and capital expenditures. Equipment or facilities failures can be due to a number of factors, including weather or information systems failure. Specifically, if the implementation of advanced metering infrastructure, smart grid or other technologies in ComEd's, PECO's or BGE's service territory fail to perform as intended or are not successfully integrated with billing and other information systems, ComEd's, PECO's and BGE's financial condition, results of operations, and cash flows could be adversely affected. Furthermore, if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, ComEd's, PECO's or BGE's financial results could be adversely affected. If an employee causes the operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating the operational systems, ComEd's, PECO's or BGE's financial results could also be adversely affected. In addition, dependence upon automated systems may further increase the risk that operational system flaws or employee tampering or manipulation of those systems will result in losses that are difficult to detect.

The aforementioned failures or those of other utilities, including prolonged or repeated failures, can affect customer satisfaction and the level of regulatory oversight and ComEd's, PECO's and BGE's maintenance and capital expenditures. Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd can be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, and those damages could be material to ComEd's results of operations and cash flows. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding proceedings related to storm-related outages in ComEd's service territory.

ComEd's, PECO's and BGE's respective ability to deliver electricity, their operating costs and their capital expenditures may be negatively affected by transmission congestion. (Exelon, ComEd, PECO and BGE)

Demand for electricity within ComEd's, PECO's and BGE's service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage with consequent effects on operating costs, revenues and results of operations. Also, insufficient availability of electric supply to meet customer demand could jeopardize ComEd's, PECO's and BGE's ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring ComEd, PECO and BGE to upgrade or expand their respective transmission systems through additional capital expenditures.

Failure to attract and retain an appropriately qualified workforce may negatively impact the Registrants' results of operations. (Exelon, Generation, ComEd, PECO and BGE)

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, may lead to operating challenges and increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time

period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission and distribution operations. If the Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations could be negatively affected.

The Registrants are subject to physical and information security risks. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants face physical and information security risks as the owner-operators of generation, transmission and distribution facilities. A security breach of the physical assets or information systems of the Registrants, their competitors, RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject the Registrants to financial harm associated with theft or inappropriate release of certain types of information, including sensitive customer data. If a significant breach occurred, the reputation of Exelon and its customer supply activities may be adversely affected, customer confidence in the Registrants or others in the industry may be diminished, or Exelon and its subsidiaries may be subject to legal claims, any of which may contribute to the loss of customers and have a negative impact on the business and/or results of operations. ComEd's, PECO's and BGE's deployment of smart meters throughout their service territories may increase the risk of damage from an intentional disruption of the system by third parties. As a requirement of their SGIG grant, the DOE approved PECO's and BGE's cyber security plan related to its smart meter deployment and will review the plan annually through the expiration of the grant. As with most companies in today's environment, Exelon experiences attempts by hackers to infiltrate its corporate network. To date there have been no infiltrations that have resulted in loss of data or any significant effects on business operations. Exelon utilizes a dedicated team of cyber security professionals to ensure the protection of its information and ability to conduct business operations. Despite the measures taken by the Registrants to prevent a security breach, the Registrants cannot accurately assess the probability that a security breach may occur and are unable to quantify the potential impact of such an event. In addition, new or updated security regulations could require changes in current measures taken by the Registrants or their business operations and could adversely affect their results of operations, cash flows and financial position.

The Registrants may make investments in new business initiatives, including initiatives mandated by regulators, and markets that may not be successful, and acquisitions may not achieve the intended financial results. (Exelon, Generation, ComEd, PECO and BGE)

Generation continuously looks to invest in new business initiatives and actively participate in new markets. These include, but are not limited to, unconventional oil and gas exploration and production, residential power and gas sales, solar and wind generation, and managed load response. Such initiatives may involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market. As these markets mature, there may be new market entrants or expansion by established competitors that increase competition for customers and resources. Additionally, it is possible that FERC, state public utility commissions or others may impose certain other restrictions on such transactions. All of these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment. ComEd, PECO and BGE face risks associated with the Smart Grid mandated regulatory initiative. These risks include, but are not limited to, cost recovery, regulatory concerns, cyber security and obsolescence of technology. Due to these risks, no assurance can be given that such initiatives will be successful and will not have a material adverse effect on ComEd's, PECO's or BGE's financial results.

Risks Related to the Merger

Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the Constellation merger.

As a result of the process to obtain regulatory approvals required for the Constellation merger, Exelon is committed to various programs, contributions, investments and market mitigation measures in several settlement agreements and regulatory approval orders. It is possible that Exelon may encounter delays, unexpected difficulties or costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon's financial position and operating results.

Risks Related to the Pending Master Agreement with CENG

The integration of CENG's nuclear fleet may not achieve its anticipated results, and Exelon and Generation may not be able to fully integrate the operations of CENG in the manner expected.

Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG that will result in Generation operating the CENG nuclear generation fleet. The Master Agreement was entered into with the expectation that it will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the agreement is subject to a number of uncertainties, including whether CENG can be integrated into Generation in an efficient, effective and timely manner. Integration will take place, and additional agreements will be signed, upon receipt of regulatory approvals for the transfer of CENG's nuclear operating licences to Generation.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Generation's business, processes and systems or inconsistencies in standards, controls, procedures, practices, policies, valuation models, and compensation arrangements. In addition, Generation may have difficulty addressing possible differences in corporate cultures and management philosophies. Any of these circumstances could adversely affect Generation's ability to achieve the anticipated benefits of the agreement as and when expected. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect Generation's future business, financial condition, operating results and prospects.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 2. PROPERTIES

Generation

The following table describes Generation's interests in net electric generating capacity by station at December 31, 2013:

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,316
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,167[f]
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,006[f]
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	878[f][h]
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837
Keystone	Mid-Atlantic	Shelocta, PA	2	41.98	Coal	Base-load	714[f]
Oyster Creek	Mid-Atlantic	Forked River, NJ	1		Uranium	Base-load	625[e]
Conowingo	Mid-Atlantic	Darlington, MD	11		Hydroelectric	Base-load	572
Conemaugh	Mid-Atlantic	New Florence, PA	2	31.28	Coal	Base-load	532[f]
Criterion	Mid-Atlantic	Oakland, MD	28		Wind	Base-load	70
Colver	Mid-Atlantic	Colver Twp., PA	1	25	Waste Coal	Base-load	26[f]
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1		Solar	Base-load	16
Solar New Jersey 2	Mid-Atlantic	Various	2		Solar	Base-load	10
Solar New Jersey 1	Mid-Atlantic	Various	4		Solar	Base-load	10
Solar Maryland	Mid-Atlantic	Various	9		Solar	Base-load	9
Solar Federal	Mid-Atlantic	Trenton, NJ	1		Solar	Base-load	5
Solar Maryland 2	Mid-Atlantic	Pocomoke, MD	2		Solar	Base-load	4
Solar New York	Mid-Atlantic	Various	1		Solar	Base-load	3
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5		Solar	Base-load	2
Muddy Run	Mid-Atlantic	Drumore, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Mid-Atlantic	Eddystone, PA	2		Oil/Gas	Intermediate	760
Safe Harbor	Mid-Atlantic	Conestoga, PA	12	66.7	Hydroelectric	Intermediate	278[f]
Croydon	Mid-Atlantic	West Bristol, PA	8		Oil	Peaking	391
Perryman	Mid-Atlantic	Belcamp, MD	5		Oil/Gas	Peaking	353
Handsome Lake	Mid-Atlantic	Kennerdell, PA	5		Gas	Peaking	268
Riverside	Mid-Atlantic	Baltimore, MD	4		Oil/Gas	Peaking	228
Westport	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	115
Notch Cliff	Mid-Atlantic	Baltimore, MD	8		Gas	Peaking	118
Richmond	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	98
Gould Street	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	97
Philadelphia Road	Mid-Atlantic	Baltimore, MD	4		Oil	Peaking	61
Eddystone	Mid-Atlantic	Eddystone, PA	4		Oil	Peaking	60
Fairless Hills	Mid-Atlantic	Fairless Hills, PA	2		Landfill Gas	Peaking	60
Delaware	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	52
Falls	Mid-Atlantic	Morrisville, PA	3		Oil	Peaking	51
Moser	Mid-Atlantic	Lower PottsgroveTwp., PA	3		Oil	Peaking	51
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39
Schuylkill	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	30
Salem	Mid-Atlantic	Lower Alloways Creek Twp, NJ	1	42.59	Oil	Peaking	16[f]
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	6
Keystone	Mid-Atlantic	Shelocta, PA	4	41.98	Oil	Peaking	4[f]
Conemaugh	Mid-Atlantic	New Florence, PA	4	31.28	Oil	Peaking	3[f]
Total Mid-Atlantic							13,067
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,353
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,327
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,319
Dresden	Midwest	Morris, IL	2		Uranium	Base-load	1,843
Quad Cities	Midwest	Cordova, IL	2	75	Uranium	Base-load	1,403[f]
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,067
Michigan Wind 2	Midwest	Sanilac Co., MI	50		Wind	Base-load	90

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Beebe	Midwest	Gratiot Co., MI	34		Wind	Base-load	81
Michigan Wind 1	Midwest	Huron Co., MI	46		Wind	Base-load	69
Harvest 2	Midwest	Huron Co., MI	33		Wind	Base-load	59
Harvest	Midwest	Huron Co., MI	32		Wind	Base-load	53
Ewington	Midwest	Jackson Co., MN	10	99	Wind	Base-load	21[f]
Marshall	Midwest	Lyon Co., MN	9	99	Wind	Base-load	19[f]
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	8
Norgaard	Midwest	Lincoln Co., MN	7	99	Wind	Base-load	9[f]
AgriWind	Midwest	Bureau Co., IL	4	99	Wind	Base-load	8[f]
Cisco	Midwest	Jackson Co., MN	4	99	Wind	Base-load	8[f]
Brewster	Midwest	Jackson Co., MN	6	94-99	Wind	Base-load	6[f]
Wolf	Midwest	Nobles Co., MN	5	99	Wind	Base-load	6[f]
CP Windfarm	Midwest	Faribault Co., MN	2		Wind	Base-load	4
Blue Breezes	Midwest	Faribault Co., MN	2		Wind	Base-load	3
Cowell	Midwest	Pipestone Co., MN	1	99	Wind	Base-load	2[f]
Solar Ohio	Midwest	Toledo, OH	2		Solar	Base-load	1
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296
Total Midwest							12,055
Whitetail	ERCOT	Laredo, TX	57		Wind	Base-load	91
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3		Gas	Intermediate	704
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	565
Colorado Bend	ERCOT	Wharton, TX	1		Gas	Intermediate	498
Quail Run	ERCOT	Odessa, TX	1		Gas	Intermediate	488
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870
Mountain Creek 6, 7	ERCOT	Dallas, TX	2		Gas	Peaking	240
LaPorte	ERCOT	Laporte, TX	4		Gas	Peaking	152
Total ERCOT							4,003
Holyoke Solar	New England	Various	2		Solar	Base-load	5
Solar Massachusetts	New England	Various	5		Solar	Base-load	3
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2
Solar Connecticut	New England	Various	2		Solar	Base-load	1
Mystic 8, 9	New England	Charlestown, MA	2		Gas	Intermediate	1,418
Fore River	New England	North Weymouth, MA	1		Gas	Intermediate	726
Mystic 7	New England	Charlestown, MA	1		Oil/Gas	Intermediate	575
Wyman	New England	Yarmouth, ME	1	5.9	Oil	Intermediate	36[f]
Medway	New England	West Medway, MA	3		Oil/Gas	Peaking	117
Framingham	New England	Framingham, MA	3		Oil	Peaking	33
New Boston	New England	South Boston, MA	1		Oil	Peaking	16
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9
Total New England							2,941
Nine Mile Point	New York	Scriba, NY	2	50.01[h]	Uranium	Base-load	833[f][h]
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288[f][h]
Total New York							1,121
AVSR	Other	Lancaster, CA	1		Solar	Base-load	198[g]
Shooting Star	Other	Greensburg, KS	65		Wind	Base-load	104
Exelon Wind 4	Other	Gruver, TX	38		Wind	Base-load	80
Bluegrass Ridge	Other	King City, MO	27		Wind	Base-load	57
Conception	Other	Barnard, MO	24		Wind	Base-load	50
Cow Branch	Other	Rock Port, MO	24		Wind	Base-load	50
Mountain Home	Other	Glenns Ferry, ID	20		Wind	Base-load	42
High Mesa	Other	Elmore Co., ID	19		Wind	Base-load	40
Echo 1	Other	Echo, OR	21	99	Wind	Base-load	35[f]
Sacramento PV Energy	Other	Sacramento, CA	4		Solar	Base-load	30
Cassia	Other	Buhl, ID	14		Wind	Base-load	29
Wildcat	Other	Lovington, NM	13		Wind	Base-load	27
Sunnyside	Other	Sunnyside, UT	1	50	Waste Coal	Base-load	26[f]
Echo 2	Other	Echo, OR	10		Wind	Base-load	20

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Tuana Springs	Other	Hagerman, ID	8		Wind	Base-load	17
Greensburg	Other	Greensburg, KS	10		Wind	Base-load	13
Echo 3	Other	Echo, OR	6	99	Wind	Base-load	10[f]
Exelon Wind 1	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 2	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 3	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 5	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 6	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 7	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 8	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 9	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 10	Other	Dumas, TX	8		Wind	Base-load	10
Exelon Wind 11	Other	Dumas, TX	8		Wind	Base-load	10
High Plains	Other	Panhandle, TX	8	99.5	Wind	Base-load	10[f]
Threemile Canyon	Other	Boardman, OR	6		Wind	Base-load	10
Solar Arizona	Other	Various	20		Solar	Base-load	29
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	6
Loess Hills	Other	Rock Port, MO	4		Wind	Base-load	5
Denver Airport Solar	Other	Denver, CO	1		Solar	Base-load	4
California PV Energy	Other	Ontario, CA	2		Solar	Base-load	3
Solar California	Other	Various	4		Solar	Base-load	2
Hillabee	Other	Alexander City, AL	1		Gas	Intermediate	670
Malacha	Other	Muck Valley, CA	1	50	Hydroelectric	Intermediate	15[f][i]
West Valley	Other	Salt Lake City, UT	5		Gas	Peaking	185
Grand Prairie	Other	Alberta, Canada	1		Gas	Peaking	75
SEGS 4, 5, 6	Other	Boron, CA	3	4.2-12.2	Solar	Peaking	8[f]
Total Other							1,950
Total							35,137

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, Salem and Three Mile Island, which are pressurized water reactors.
(b) 100%, unless otherwise indicated.
(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations reflect a summer rating. Wind and solar facilities reflect name plate capacity.
(e) Generation has agreed to permanently cease generation operation at Oyster Creek by December 31, 2019.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Expected capacity upon project completion is 230MW. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(h) Reflects Generation's 50.01% interest in CENG, a joint venture with EDF. For Nine Mile Point, the co-owner owns 18% of Unit 2. Thus Exelon's ownership is 50.01% of 82% of Nine Mile Point Unit 2. Generation also has a unit-contingent PPA with CENG under which it purchases 85% of the nuclear plant output owned by CENG that is not sold to third parties under the pre-existing PPAs through 2014.
(i) In February 2014, Generation sold its remaining stake in Malacha.

The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies or generating units being temporarily out of service for inspection, maintenance, refueling, repairs or modifications required by regulatory authorities.

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see ITEM 1. Business—Generation. For its insured losses, Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on Generation's consolidated financial condition or results of operations.

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ComEd

ComEd's electric substations and a portion of its transmission rights of way are located on property that ComEd owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ComEd believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements, licenses and franchise rights; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ComEd's higher voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,642
138,000	2,292

ComEd's electric distribution system includes 35,491 circuit miles of overhead lines and 30,626 circuit miles of underground lines.

First Mortgage and Insurance

The principal properties of ComEd are subject to the lien of ComEd's Mortgage dated July 1, 1923, as amended and supplemented, under which ComEd's First Mortgage Bonds are issued.

ComEd maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ComEd is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ComEd.

PECO

PECO's electric substations and a significant portion of its transmission lines are located on property that PECO owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. PECO believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

PECO's high voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188 [(a)]
230,000	548
138,000	156
69,000	200

(a) In addition, PECO has a 22.00% ownership interest in 127 miles of 500 kV lines located in Pennsylvania and a 42.55% ownership interest in 131 miles of 500 kV lines located in Delaware and New Jersey.

PECO's electric distribution system includes 12,989 circuit miles of overhead lines and 8,915 circuit miles of underground lines.

Gas

The following table sets forth PECO's natural gas pipeline miles at December 31, 2013:

	Pipeline Miles
Transmission	31
Distribution	6,764
Service piping	6,068
Total	12,863

PECO has an LNG facility located in West Conshohocken, Pennsylvania that has a storage capacity of 1,200 mmcf and a send-out capacity of 157 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 1,980,000 gallons and a peaking capability of 25 mmcf/day. In addition, PECO owns 31 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

The principal properties of PECO are subject to the lien of PECO's Mortgage dated May 1, 1923, as amended and supplemented, under which PECO's first and refunding mortgage bonds are issued.

PECO maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, PECO is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of PECO.

BGE

BGE's electric substations and a significant portion of its transmission lines are located on property that BGE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. BGE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

BGE's high voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	Circuit Miles
500,000	218
230,000	322
138,000	54
115,000	697

BGE's electric distribution system includes 9,391 circuit miles of overhead lines and 15,933 circuit miles of underground lines.

Gas

The following table sets forth BGE's natural gas pipeline miles at December 31, 2013:

	Pipeline Miles
Transmission	163
Distribution	7,054
Service piping	6,146
Total	13,363

BGE has an LNG facility located in Baltimore, Maryland that has a storage capacity of 1,055 mmcf and a send-out capacity of 332 mmcf/day, an LNG facility located in Westminster, Maryland that has a storage capacity of 6 mmcf and a send-out capacity of 6 mmcf/day, and a propane-air plant located in Baltimore, Maryland, with a storage capacity of 546 mmcf and a send-out capacity of 85 mmcf/day. In addition, BGE owns 12 natural gas city gate stations and 20 direct pipeline customer delivery points at various locations throughout its gas service territory.

Property Insurance

BGE owns its principal headquarters building located in downtown Baltimore. BGE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, BGE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of BGE.

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long-term design changes and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country's energy systems.

ITEM 3. LEGAL PROCEEDINGS

Exelon, Generation, ComEd, PECO and BGE

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

Exelon, Generation, ComEd, PECO and BGE

Not Applicable to the Registrants.

(Dollars in millions except per share data, unless otherwise noted)

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Exelon

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2014, there were 857,419,806 shares of common stock outstanding and approximately 129,928 record holders of common stock.

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2013				2012			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 30.59	$ 32.42	$ 37.80	$ 34.56	$ 37.50	$ 39.82	$ 39.37	$ 43.70
Low price	26.64	29.42	29.84	29.10	28.40	34.54	36.27	38.31
Close	27.39	29.64	30.88	34.48	29.74	35.58	37.62	39.21
Dividends	0.310	0.310	0.310	0.525	0.525	0.525	0.525	0.525

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index for the period 2009 through 2013.

This performance chart assumes:

- $100 invested on December 31, 2008 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.

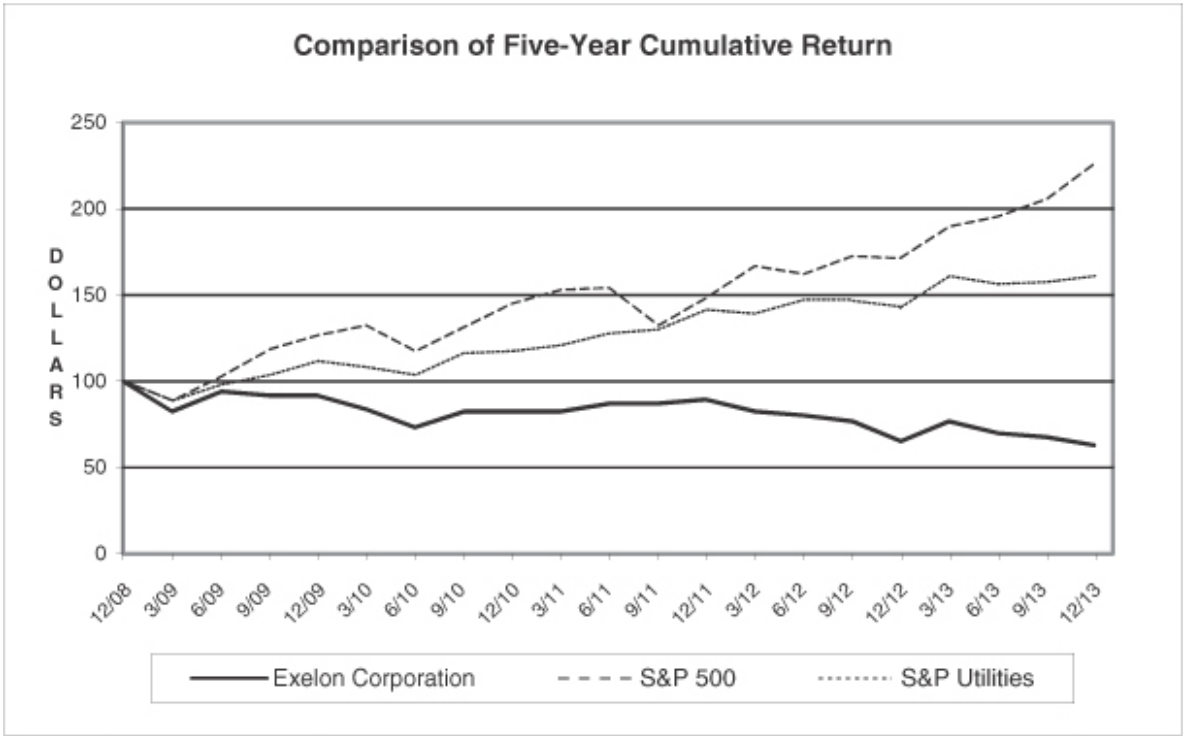

	Value of Investment at December 31,					
	2008	2009	2010	2011	2012	2013
Exelon Corporation	$100.00	$91.60	$82.04	$89.76	$65.21	$62.94
S&P 500	$100.00	$126.45	$145.49	$148.55	$172.31	$228.10
S&P Utilities	$100.00	$111.91	$118.02	$141.54	$143.37	$162.31

Generation

As of January 31, 2014, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2014, there were 127,016,904 outstanding shares of common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. At January 31, 2014, in addition to Exelon, there were 294 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2014, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2014, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

Exelon, Generation, ComEd, PECO and BGE

Dividends

Under applicable Federal law, Generation, ComEd, PECO and BGE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO or BGE may limit the dividends that these companies can distribute to Exelon.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with a financing arranged through ComEd Financing III that ComEd will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common

stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

At December 31, 2013, Exelon had retained earnings of $10,358 million, including Generation's undistributed earnings of $3,613 million, ComEd's retained earnings of $750 million consisting of retained earnings appropriated for future dividends of $2,389 million, partially offset by $1,639 million of unappropriated retained deficits, PECO's retained earnings of $649 million, and BGE's retained earnings of $1,005 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2013 and 2012:

	2013				2012			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$ 0.310	$ 0.310	$ 0.310	$ 0.525	$ 0.525	$ 0.525	$ 0.525	$ 0.525

The following table sets forth Generation's quarterly distributions and ComEd's and PECO's quarterly common dividend payments:

	2013				2012			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 75	$ 76	$ 263	$ 211	$ 242	$ 493	$ 291	$ 600
ComEd	55	55	55	55	10	10	10	75
PECO	83	83	83	83	85	86	85	87

First Quarter 2014 Dividend. On January 28, 2014, the Exelon Board of Directors declared a first quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2014, to shareholders of record of Exelon at the end of the day on February 14, 2014.

ITEM 6. SELECTED FINANCIAL DATA

Exelon

The selected financial data presented below has been derived from the audited consolidated financial statements of Exelon. This data is qualified in its entirety by reference to and should be read in conjunction with Exelon's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions, except per share data)	2013	2012 [a]	2011	2010	2009
Statement of Operations data:					
Operating revenues	$24,888	$23,489	$19,063	$18,644	$17,318
Operating income	3,656	2,380	4,479	4,726	4,750
Income from continuing operations	1,729	1,171	2,499	2,563	2,706
Income from discontinued operations	—	—	—	—	1
Net income	1,729	1,171	2,499	2,563	2,707
Earnings per average common share (diluted):					
Income from continuing operations	$ 2.00	$ 1.42	$ 3.75	$ 3.87	$ 4.09
Net income	$ 2.00	$ 1.42	$ 3.75	$ 3.87	$ 4.09
Dividends per common share	$ 1.46	$ 2.10	$ 2.10	$ 2.10	$ 2.10
Average shares of common stock outstanding—diluted	860	819	665	663	662

(a) The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012.

(In millions)	December 31, 2013	2012	2011	2010	2009
Balance Sheet data:					
Current assets	$10,137	$10,140	$ 5,713	$ 6,398	$ 5,441
Property, plant and equipment, net	47,330	45,186	32,570	29,941	27,341
Noncurrent regulatory assets	5,910	6,497	4,518	4,140	4,872
Goodwill	2,625	2,625	2,625	2,625	2,625
Other deferred debits and other assets	13,922	14,113	9,569	9,136	8,901
Total assets	$79,924	$78,561	$54,995	$52,240	$49,180
Current liabilities	$ 7,728	$ 7,791	$ 5,134	$ 4,240	$ 4,238
Long-term debt, including long-term debt to financing trusts	18,271	18,346	12,189	12,004	11,385
Noncurrent regulatory liabilities	4,388	3,981	3,627	3,555	3,492
Other deferred credits and other liabilities	26,597	26,626	19,570	18,791	17,338
Preferred securities of subsidiary	—	87	87	87	87
Non-controlling interest	15	106	3	3	—
BGE preference stock not subject to mandatory redemption	193	193	—	—	—
Shareholders' equity	22,732	21,431	14,385	13,560	12,640
Total liabilities and shareholders' equity	$79,924	$78,561	$54,995	$52,240	$49,180

Generation

The selected financial data presented below has been derived from the audited consolidated financial statements of Generation. This data is qualified in its entirety by reference to and should be read in conjunction with Generation's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

(In millions)	For the Years Ended December 31, 2013	2012 [(a)]	2011	2010	2009
Statement of Operations data:					
Operating revenues	$15,630	$14,437	$10,447	$10,025	$9,703
Operating income	1,664	1,120	2,875	3,046	3,295
Net income	1,060	558	1,771	1,972	2,122

(a) The 2012 financial results only include the operations of Constellation from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012.

(In millions)	December 31, 2013	2012	2011	2010	2009
Balance Sheet data:					
Current assets	$ 6,439	$ 6,211	$ 3,217	$ 3,087	$ 3,360
Property, plant and equipment, net	20,111	19,531	13,475	11,662	9,809
Other deferred debits and other assets	14,682	14,939	10,741	9,785	9,237
Total assets	$41,232	$40,681	$27,433	$24,534	$22,406
Current liabilities	$ 3,867	$ 4,097	$ 2,144	$ 1,843	$ 2,262
Long-term debt	7,168	7,455	3,674	3,676	2,967
Other deferred credits and other liabilities	17,455	16,464	12,907	11,838	10,385
Non-controlling interest	17	108	5	5	2
Member's equity	12,725	12,557	8,703	7,172	6,790
Total liabilities and member's equity	$41,232	$40,681	$27,433	$24,534	$22,406

ComEd

The selected financial data presented below has been derived from the audited consolidated financial statements of ComEd. This data is qualified in its entirety by reference to and should be read in conjunction with ComEd's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions)	2013	2012	2011	2010	2009
Statement of Operations data:					
Operating revenues	$4,464	$5,443	$6,056	$6,204	$5,774
Operating income	954	886	982	1,056	843
Net income	249	379	416	337	374

	December 31,				
(In millions)	2013	2012	2011	2010	2009
Balance Sheet data:					
Current assets	$ 1,540	$ 1,775	$ 2,188	$ 2,151	$ 1,579
Property, plant and equipment, net	14,666	13,826	13,121	12,578	12,125
Goodwill	2,625	2,625	2,625	2,625	2,625
Noncurrent regulatory assets	933	666	699	947	1,096
Other deferred debits and other assets	4,354	4,013	4,005	3,351	3,272
Total assets	$24,118	$22,905	$22,638	$21,652	$20,697
Current liabilities	$ 2,048	$ 1,655	$ 2,071	$ 2,134	$ 1,597
Long-term debt, including long-term debt to financing trusts	5,264	5,521	5,421	4,860	4,704
Noncurrent regulatory liabilities	3,512	3,229	3,042	3,137	3,145
Other deferred credits and other liabilities	5,766	5,177	5,067	4,611	4,369
Shareholders' equity	7,528	7,323	7,037	6,910	6,882
Total liabilities and shareholders' equity	$24,118	$22,905	$22,638	$21,652	$20,697

PECO

The selected financial data presented below has been derived from the audited consolidated financial statements of PECO. This data is qualified in its entirety by reference to and should be read in conjunction with PECO's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

	For the Years Ended December 31,				
(In millions)	2013	2012	2011	2010	2009
Statement of Operations data:					
Operating revenues	$3,100	$3,186	$3,720	$5,519	$5,311
Operating income	666	623	655	661	697
Net income	395	381	389	324	353
Net income on common stock	388	377	385	320	349

(In millions)	December 31, 2013	2012	2011	2010	2009
Balance Sheet data:					
Current assets	$ 906	$1,094	$1,243	$1,670	$1,006
Property, plant and equipment, net	6,384	6,078	5,874	5,620	5,297
Noncurrent regulatory assets	1,448	1,378	1,216	968	1,834
Other deferred debits and other assets	879	803	823	727	882
Total assets	$9,617	$9,353	$9,156	$8,985	$9,019
Current liabilities	$ 891	$1,158	$1,145	$1,163	$ 939
Long-term debt, including long-term debt to financing trusts	2,131	1,831	1,781	2,156	2,405
Noncurrent regulatory liabilities	629	538	585	418	317
Other deferred credits and other liabilities	2,901	2,757	2,620	2,278	2,706
Preferred securities	—	87	87	87	87
Shareholders' equity	3,065	2,982	2,938	2,883	2,565
Total liabilities and shareholders' equity	$9,617	$9,353	$9,156	$8,985	$9,019

BGE

The selected financial data presented below has been derived from the audited consolidated financial statements of BGE. This data is qualified in its entirety by reference to and should be read in conjunction with BGE's Consolidated Financial Statements and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

(In millions)	For the Years Ended December 31, 2013	2012	2011	2010	2009
Statement of Operations data:					
Operating revenues	$3,065	$2,735	$3,068	$3,541	$3,646
Operating income	449	132	314	350	268
Net income	210	4	136	147	91
Net income (loss) attributable to common shareholder	197	(9)	123	134	78

(In millions)	December 31, 2013	2012 (a)	2011 (a)	2010 (a)	2009 (a)
Balance Sheet data:					
Current assets	$1,011	$ 980	$ 969	$1,012	$1,205
Property, plant and equipment, net	5,864	5,498	5,132	4,754	4,470
Noncurrent regulatory assets	524	522	551	566	602
Other deferred debits and other assets	462	506	551	545	386
Total assets	$7,861	$7,506	$7,203	$6,877	$6,663
Current liabilities	$ 827	$ 980	$ 734	$ 728	$ 753
Long-term debt, including long-term debt to financing trusts and variable interest entities	2,199	1,969	2,186	2,060	2,141
Noncurrent regulatory liabilities	204	214	201	192	188
Other deferred credits and other liabilities	2,076	1,985	1,781	1,634	1,434
Preference stock not subject to mandatory redemption	190	190	190	190	190
Shareholders' equity	2,365	2,168	2,111	2,073	1,939
Non-controlling interest	—	—	—	—	18
Total liabilities and shareholders' equity	$7,861	$7,506	$7,203	$6,877	$6,663

(a) BGE retrospectively reclassified certain regulatory assets and regulatory liabilities to conform to the current year presentation.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Exelon

Executive Overview

Exelon, a utility services holding company, operates through the following principal subsidiaries:

- *Generation,* whose integrated business consists of owned, contracted and investments in electric generating facilities managed through customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Exelon has nine reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions in Generation), ComEd, PECO and BGE. See Note 24 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

Exelon's consolidated financial information includes the results of its four separate operating subsidiary registrants, Generation, ComEd, PECO and BGE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO and BGE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Financial Results. The following consolidated financial results reflect the results of Exelon for year ended December 31, 2013 compared to the same period in 2012. The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012. All amounts presented below are before the impact of income taxes, except as noted.

Results in 2013 were unfavorably impacted at Generation by continuing declines in realized power and gas prices, in part driven by the abundance of natural gas supply, continued sluggish demand and subsidized renewable generation; only partially offset by improved returns at the utilities, and the

realization of additional post-merger synergies and operational excellence across all businesses. Generation's financial results continue to be challenged by low natural gas prices, and by the impacts of excess generation from subsidized renewable energy, flat load growth and distorted market designs, especially in its Midwest markets.

	The Years Ended December 31,							Favorable (Unfavorable)
	2013						2012	
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	Variance
Operating revenues	$ 15,630	$4,464	$3,100	$3,065	$(1,371)	$24,888	$23,489	$ 1,399
Purchased power and fuel	8,197	1,174	1,300	1,421	(1,368)	10,724	10,157	(567)
Revenue net of purchased power and fuel [(a)]	7,433	3,290	1,800	1,644	(3)	14,164	13,332	832
Other operating expenses								
Operating and maintenance	4,534	1,368	748	634	(14)	7,270	7,961	691
Depreciation and amortization	856	669	228	348	52	2,153	1,881	(272)
Taxes other than income	389	299	158	213	36	1,095	1,019	(76)
Total other operating expenses	5,779	2,336	1,134	1,195	74	10,518	10,861	343
Equity in earnings/(losses) of unconsolidated affiliates	10	—	—	—	—	10	(91)	101
Operating income	1,664	954	666	449	(77)	3,656	2,380	1,276
Other income and (deductions)								
Interest expense, net	(357)	(579)	(115)	(122)	(183)	(1,356)	(928)	(428)
Other, net	368	26	6	17	56	473	346	127
Total other income and (deductions)	11	(553)	(109)	(105)	(127)	(883)	(582)	(301)
Income (loss) before income taxes	1,675	401	557	344	(204)	2,773	1,798	975
Income taxes	615	152	162	134	(19)	1,044	627	(417)
Net income (loss)	1,060	249	395	210	(185)	1,729	1,171	558
Net (loss) income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	(10)	—	7	13	—	10	11	1
Net income (loss) on common stock	$ 1,070	$ 249	$ 388	$ 197	$ (185)	$ 1,719	$ 1,160	$ 559

(a) The Registrants' evaluate operating performance using the measure of revenue net of purchased power and fuel expense. The Registrants' believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Exelon's net income on common stock was $1,719 million for the year ended December 31, 2013 as compared to $1,160 million for the year ended December 31, 2012, and diluted earnings per average common share were $ 2.00 for the year ended December 31, 2013 as compared to $1.42 for the year ended December 31, 2012.

Operating revenues net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $832 million as compared to 2012. The year-over-year increase in operating revenue net of purchased power and fuel expense reflects the inclusion of Constellation and BGE's results for the full period in 2013 and was primarily due to the following favorable factors:

- Decrease in Generation's amortization expense for the acquired energy contracts recorded at fair value at the merger date of $610 million;

- Increase in BGE's revenue net of purchased power and fuel expense of $278 million, primarily as a result of the inclusion of BGE's results for the full period in 2013, accrual of the residential customer rate credit that was a condition of the MDPSC's approval of Exelon's merger with Constellation in 2012, and the impact of the MDPSC approved electric and natural gas distribution rate increases that became effective February 23, 2013;
- Increase in Generation's revenue net of purchased power and fuel of $159 million on other activities, including proprietary trading, retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of customer sited solar facilities, primarily due to the addition of Constellation; and
- Increase in ComEd's revenue net of purchased power expense of $154 million primarily due to increased distribution revenue due to recovery of increased costs and capital investment and higher allowed ROE pursuant to the formula rate under EIMA and the enactment of Senate Bill 9.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

- Decrease in Generation's electric revenue net of purchased power and fuel expense of $565 million primarily due to lower realized energy prices, lower load volume and increased nuclear fuel expense, partially offset by higher capacity revenue, increased nuclear volumes, and lower energy supply costs as a result of the integration of the energy generation and load serving businesses following the merger;
- Reduced revenue net of purchased power and fuel at Generation of $136 million in 2013 associated with the Maryland Clean Coal assets that were sold in November 2012 and lost compensation on the reliability-must-run program with PJM for retired fossil generating assets that expired on May 31, 2012; and
- Decrease in PECO's revenue net of purchased power and fuel expense of $11 million primarily due to the decrease in effective rates due to increased usage per customer across all customer classes, decreased cost recovery for energy efficiency and demand response programs, decreased gross receipts tax revenue, and the customer refund in 2013 of the tax cash benefit related to gas property distribution repairs.

Operating and maintenance expense decreased by $691 million as compared to 2012 primarily due to the following favorable factors:

- Decrease in operating and maintenance expense associated with the generating assets retired or divested during 2012 of $442 million;
- Costs incurred in March 2012 of $216 million and $195 million as part of the Maryland order approving the merger and a settlement with the FERC, respectively;
- Decrease in Constellation merger and integration costs of $201 million in 2013; and
- Decrease in uncollectible accounts expense of $58 million at ComEd resulting from the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers.

The year-over-year decrease in operating and maintenance expense was partially offset by the following unfavorable factors:

- Increase in labor, other benefits, contracting and materials costs of $298 million, primarily due to the addition of BGE and Constellation for the full period in 2013; and
- Long-lived asset impairments and related charges of $174 million in 2013, primarily related to Generation's cancellation of nuclear uprate projects and the impairment of certain wind generating assets.

Depreciation and amortization expense increased by $272 million primarily due to the addition of BGE and Constellation for the full period in 2013, BGE's and Constellation's plant balances in 2012, ongoing capital expenditures across the operating companies, the completion of wind and solar facilities placed into service in the second half of 2012 and in 2013 at Generation, and increased regulatory asset amortization related to higher MGP remediation expenditures and higher costs for energy efficiency and demand response programs at ComEd and BGE, respectively.

The favorable increase in Equity in earnings/loss of unconsolidated affiliates of $101 million was primarily due to higher net income from Generation's equity investment in CENG in 2013 compared to the same period in 2012 and lower amortization of the basis difference of Generation's ownership interest in CENG recorded at fair value in connection with the merger.

Interest expense increased by $428 million primarily due to an increase in interest expense at ComEd related to the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013, an increase in debt obligations as a result of the merger and an increase in project financing at Generation in 2013.

Exelon's effective income tax rates for the years ended December 31, 2013 and 2012 were 37.6% and 34.9%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the years ended December 31, 2013 and 2012, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings

Exelon's adjusted (non-GAAP) operating earnings for the year ended December 31, 2013 were $2,149 million, or $2.50 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,330 million, or $2.85 per diluted share, for the same period in 2012. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2013 as compared to 2012:

(All amounts after tax; in millions, except per share amounts)	December 31, 2013	Earnings per Diluted Share	2012	Earnings per Diluted Share
Net Income	$1,719	$ 2.00	$1,160	$ 1.42
Mark-to-Market Impact of Economic Hedging Activities [a]	(310)	(0.35)	(310)	(0.38)
Unrealized Net Gains Related to NDT Fund Investments [b]	(78)	(0.09)	(56)	(0.07)
Plant Retirements and Divestitures [c]	(13)	(0.02)	236	0.29
Asset Retirement Obligation [d]	7	0.01	1	—
Merger and Integration Costs [e]	87	0.08	257	0.31
Other Acquisition Costs [f]	—	—	3	—
Reassessment of State Deferred Income Taxes [g]	4	—	(117)	(0.14)
Amortization of Commodity Contract Intangibles [h]	347	0.41	758	0.93
Amortization of the Fair Value of Certain Debt [i]	(7)	(0.01)	(9)	(0.01)
Remeasurement of Like-Kind Exchange Tax Position [j]	267	0.31	—	—
Long-Lived Asset Impairment [k]	110	0.14	—	—
Maryland Commitments [l]	—	—	227	0.28
FERC Settlement [m]	—	—	172	0.21
Midwest Generation Bankruptcy Charges [n]	16	0.02	8	0.01
Adjusted (non-GAAP) Operating Earnings	$2,149	$ 2.50	$2,330	$ 2.85

(a) Reflects the impact of (gains) losses for the years ended December 31, 2013 and 2012, respectively, on Generation's economic hedging activities (net of taxes of $201 million and $200 million, respectively). In order to better align the impacts of economic hedging with the underlying business activity (e.g. the sale of power and/or the use of fuel), these unrealized (gains) losses are excluded from operating earnings until the transactions are realized. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized gains for the years ended December 31, 2013 and 2012, respectively, on Generation's NDT fund investments for Non-Regulatory Agreement Units (net of taxes of $(144) million and $(132) million, respectively). See Note 15—Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Reflects the impacts associated with the sale or retirement of generating stations in the years ended December 31, 2013 and 2012 (net of taxes of $4 million and $106 million, respectively). See "Results of Operations—Generation" for additional detail related to the generating unit retirements.

(d) Primarily reflects the impact of an increase in Generation's asset retirement obligation for asbestos at retired fossil plants for the year ended December 31, 2013 (net of taxes of $(5) million). Primarily reflects the impact of an increase in Generation's decommissioning obligation for spent nuclear fuel at retired nuclear units for the year ended December 31, 2012 (net of taxes of $(1) million).

(e) Reflects certain costs incurred in the years ended December 31, 2013 and 2012 (net of taxes of $33 million and $161 million, respectively) associated with the merger, including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses) integration initiatives, certain pre-acquisition contingencies, and CENG transaction costs, partially offset in 2013 by a one-time benefit pursuant to the BGE 2012 electric and gas distribution rate case order for the recovery of previously incurred integration costs. See Note 4—Merger and Acquisitions of the Combined Notes to the Consolidated Financial Statements for additional information.

(f) Reflects certain costs incurred in the year ended 2012 associated with various acquisitions (net of taxes of $2 million).

(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment in 2013 and as a result of the merger in 2012. See Note 14—Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information.

(h) Reflects the non-cash impact for the years ended December 31, 2013 and 2012 (net of taxes of $219 million and $491 million, respectively) of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger date. See Note 4—Merger and Acquisitions of the Combined Notes to the Consolidated Financial Statements for additional information.

(i) Reflects the non-cash amortization of certain debt for the years ended December 31, 2013 and 2012 (net of taxes of $5 million and $6 million, respectively) recorded at fair value at the Constellation merger date which was retired in the second quarter of 2013. See Note 4—Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(j) Reflects a non-cash charge to earnings for the year ended December 31, 2013 (net of taxes of $102 million) resulting from the first quarter 2013 remeasurement of a like-kind exchange tax position taken on ComEd's 1999 sale of fossil generating assets. See Note 14 of the Combined Notes to the Consolidated Financial statements for additional information.

(k) Reflects 2013 impairment and related charges to earnings for the year ended December 31, 2013 (net of taxes of $69 million) primarily related to Generation's cancellation of nuclear uprate projects and the impairment of certain wind generating assets.

(l) Reflects costs incurred for the year ended December 31, 2012 associated with the Constellation merger (net of taxes of $101 million) as part of the Maryland order approving the merger transaction. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

(m) Reflects costs incurred for the year ended December 31, 2012 (net of taxes of $23 million) as part of a settlement with the FERC to resolve a dispute related to Constellation's pre-merger hedging and risk management transactions. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information.

(n) Reflects costs incurred to establish estimated liabilities for the years ended December 31, 2013 and December 31, 2012 (net of taxes of $10 million and $5 million, respectively) pursuant to the Midwest Generation bankruptcy, primarily related to lease payments under a coal rail car lease and estimated payments for asbestos-related personal injury claims.

As discussed above, Exelon has incurred and will continue to incur costs associated with the Constellation merger, including meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former Constellation businesses into Exelon.

For the year ended December 31, 2013, expense has been recognized for costs incurred to achieve the merger, prior to consideration of regulatory accounting treatment, as follows:

	Pre-tax Expense				
	Twelve Months Ended December 31, 2013				
Merger and Integration Costs:	**Generation [a]**	**ComEd**	**PECO**	**BGE [a]**	**Exelon [a]**
Employee-Related [b]	48	4	3	1	58
Other [c]	58	12	6	5	84
Total	$ 106	$ 16	$ 9	$ 6	$ 142

	Pre-tax Expense				
	Twelve Months Ended December 31, 2012				
Merger and Integration Costs:	**Generation**	**ComEd**	**PECO**	**BGE [a]**	**Exelon [a]**
Maryland Commitments	35	—	—	139	328
Employee-Related [b]	138	24	11	24	207
Other [c]	167	17	6	7	211
Transaction [d]	$ —	$ —	$—	$ —	$ 58
Total	$ 340	$ 41	$ 17	$ 170	$ 804

(a) For Exelon, Generation and BGE, includes the operations of the acquired businesses from the date of the merger March 12, 2012 through the year ended December 31, 2013.

(b) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd established regulatory assets of $2 million and $21 million for the years ended December 31, 2013 and December 31, 2012, respectively. BGE established regulatory assets of $0 million and $22 million for the years ended December 31, 2013 and December 31, 2012, respectively. The majority of these costs are expected to be recovered over a five-year period.

(c) Costs to integrate Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. ComEd established a regulatory asset of $9 million and $15 million for the years ended December 31, 2013 and December 31, 2012, respectively, for certain other merger and integration costs. BGE established a regulatory asset of $12 million and $0 million for the years ended December 31, 2013 and December 31, 2012, respectively, for certain other merger and integration costs.

(d) External, third-party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of the transaction.

As of December 31, 2013, Exelon expects to incur total additional Constellation merger-related expenses in 2014 and 2015 of approximately $34 million.

Pursuant to the conditions set forth by the MDPSC in its approval of the merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion. The direct investment includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a twenty-year lease agreement that is contingent upon the developer obtaining financing for the construction of the building. Once required approvals are received and financing condition is satisfied, construction of the building will commence. The building is expected to be ready for occupancy in two years following commencement of construction. The direct investment estimate also includes $625 million in expenditures relating to the development of 285-300 MW of new electric generation facilities in Maryland (expected to be completed over the next ten years).

Exelon's Strategy and Outlook for 2014 and Beyond

Exelon's value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline.

On March 12, 2012, the Exelon and Constellation merger was completed. The merger creates incremental strategic value by matching Exelon's clean generation fleet with Constellation's leading customer-facing platform, as well as creating economies of scale through expansion across the energy value chain. Exelon supports customer switching to alternative electric generation suppliers and the addition of Constellation's competitive retail operations provides another outlet for Exelon to grow its business in competitive markets.

Generation's electricity generation strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding Generation's regional and technological footprint. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help mitigate the current challenging conditions in competitive energy markets.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results. Combined, the utilities plan to invest approximately $15 billion over the next five years in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Exelon's financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, and to return value to Exelon's shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

In pursuing its strategies, Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the power markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular, the prices of natural gas and coal, which drive the market prices that Generation can obtain for the output of its power plants, (2) the rate of expansion of subsidized low-carbon generation in the markets in which Generation's output is sold, (3) the effects on energy demand due to factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these market pricing issues.

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Since the third quarter of 2011, forward natural gas prices for 2014 and 2015 have declined significantly; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Subsidized Generation. The rate of expansion of subsidized low-carbon generation such as wind and solar energy in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have implemented or proposed legislation, regulations or other policies to subsidize new generation development, which may result in artificially depressed wholesale energy and capacity prices. For example, the New Jersey legislature enacted into law in January 2011, the Long Term capacity Pilot Program (LCAPP). LCAPP provides eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market. Under LCAPP, the local utilities in New Jersey are required to pay (or receive) the difference between generators receive in the capacity market and the price guaranteed under the 15 year contract. New Jersey ultimately selected three proposals to participate in LCAPP and build new generation in the state. In addition, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. CPV has subsequently sought to extend that date. The CfD mandates that utilities (including BGE) pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others are also challenging the selection of the three generation developers in New Jersey state court proceedings and the MDPSC actions in Maryland state court. On October 25, 2013, the U.S. District Court in New Jersey issued a judgment order finding that the New Jersey legislation violates the Supremacy Clause of the United States Constitution and the New Jersey SOCA contract is unenforceable. Similarly, on October 24, 2013, the U.S. District Court in Maryland issued a judgment order finding that the MDPSC's Order directing BGE and two other Maryland electric distribution companies to enter into a CfD violates the Supremacy Clause of the United States Constitution, as described in Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements. In addition, on October 1, 2013, a Maryland State Circuit Court upheld the MDPSC Orders as being within the MDPSC's statutory authority under Maryland state law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands. The non-prevailing parties have sought appeals in federal appellate court in both the New Jersey and

Maryland federal litigation. Finally, on October 23, 2013, the New Jersey state court dismissed the New Jersey state proceeding without prejudice, subject to the final outcome of the New Jersey federal litigation.

As required under their contracts, two of the New Jersey generator developers and one in Maryland offered and cleared in PJM's capacity market auctions held in May 2012 and 2013. In addition, CPV has announced its intention to move forward with construction of its New Jersey plant, with or without the challenged state subsidy. Nonetheless to the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon's market driven position. While the U.S. District Court decisions in Maryland and New Jersey are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR), could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon's market driven position and could have a significant effect on Exelon's financial results of operations, financial position and cash flows.

PJM's capacity market rules include a MOPR, which is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. However, as described above, Exelon does not believe that the existing MOPR will work effectively with respect to generator developers who have a state-sponsored subsidy and has concerns with certain other aspects of PJM's rules related to the capacity auction. Accordingly, Exelon is working with other market stakeholders on several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sponsored subsidy contracts, excessive imported capacity resources and certain limited availability demand response resources) cannot inappropriately affect capacity auction prices in PJM.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Maryland Order.

Exelon remains active in advocating for competitive markets, opposing policies that ask either taxpayers or consumers to subsidize or give preferential treatment to specific generation providers or technologies, or that would threaten the reliability and value of the integrated electricity grid.

Energy Demand. The continued tepid economic environment and growing energy efficiency initiatives have limited the demand for electricity across each of the Exelon utility companies. ComEd is projecting load volumes to decrease by 0.2% in 2014 compared to 2013, while PECO and BGE are projecting an increase of 0.3% and 0.6%, respectively, in 2014 compared to 2013.

Retail Competition. Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Recently, sustained low forward natural gas and power prices and low market volatility have caused retail competitors to aggressively pursue market share, and wholesale generators (including Generation) to use their retail operations to hedge generation output. These factors have adversely affected overall gross margins and profitability in Generation's retail operations.

Strategic Policy Alignment

Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's board of directors declared the first quarter 2013 dividend of $0.525 per share, and in response to low forward energy prices and weaker financial expectations, among other factors, approved a revised dividend policy going forward. The first quarter dividend was paid on March 8, 2013 to shareholders of record on February 19, 2013 and was based on Exelon's previous dividend of $2.10 per share on an annualized basis. The second, third and fourth quarter dividends were based on Exelon's new dividend policy of $0.31 per share quarterly dividend ($1.24 per share on an annualized basis). All future quarterly dividends require approval by Exelon's board of directors.

Exelon and Generation evaluate the economic viability of each of their generating units on an ongoing basis. Decisions regarding the future of economically challenged generating assets will be based primarily on the economics of continued operation of the individual plants. If Exelon and Generation do not see a path to sustainable profitability in any of their plants, Exelon and Generation will take steps to retire those plants to avoid sustained losses. Retirement of plants could materially affect Exelon's and Generation's results of operations, financial position, and cash flows through among other things, potential impairment charges, accelerated depreciation and decommissioning expenses over the plants remaining useful lives, and ongoing reductions to operating revenues, operating and maintenance expenses, and capital expenditures.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2014 and 2015. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015, and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation's sales of energy to ComEd, PECO and BGE relating to their respective retail load obligations. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal, oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2014 through 2018 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position. ComEd, PECO and BGE mitigate such exposure through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

Exelon is currently pursuing growth in both the utility and generation businesses focused primarily on smart meter and smart grid initiatives at the utilities and on renewables development and the nuclear uprate program at Generation. The utilities also anticipate making significant future investments in infrastructure modernization and improvement initiatives. Management continually evaluates growth opportunities aligned with Exelon's existing businesses in electric and gas distribution, electric transmission, generation, customer supply of electric and natural gas products and services, and natural gas exploration and production activities, leveraging Exelon's expertise in those areas.

Transmission Development Project. Exelon and AEP Transmission Holding Company, LLC (AEP) are working collaboratively to develop an extra high-voltage transmission project from the western Ohio border through Indiana to the northern portion of Illinois. Referred to as the Reliability Interregional Transmission Extension (RITE) Line project, the project is expected to strengthen the high-voltage transmission system and improve overall system reliability. RITELine Illinois, LLC (RITELine Illinois) and RITELine Indiana, LLC (RITELine Indiana) have been formed as project companies to develop and own the project. RITELine Illinois will own the transmission assets located in Illinois and is owned 75% by ComEd and 25% by RITELine Transmission Development Company, LLC (RTD). RITELine Indiana will own the transmission assets located in Indiana and is owned by AEP (75%) and RTD (25%). Exelon Transmission Company, LLC and AEP each own 50% of RTD. The total cost of the RITE Line project is expected to be approximately $1.6 billion, with the Illinois portion of the line expected to cost approximately $1.2 billion. The ultimate cost and scope of the project are dependent on a number of factors, including RTO requirements, interregional transmission planning process requirements, state siting requirements, routing of the line, and equipment and commodity costs. Exelon and AEP are currently pursuing the project and other segments that are electrically equivalent in nature for inclusion in interregional planning process between PJM and MISO; if approved through that process, the project would then need to be approved through the respective planning processes of PJM and MISO.

On July 18, 2011, RITELine Illinois and RITELine Indiana filed at FERC for incentive rates and a formula rate for the RITE Line project. On October 14, 2011, FERC issued an order on the incentive and formula rate filing. The order grants a base rate of return on common equity of 9.9%, plus a 50 basis point adder for the project being in a RTO and a 100 basis point adder for the risks and challenges of the project, resulting in a total rate of return on common equity of 11.4%. The order grants a hypothetical capital structure of 45% debt and 55% equity until any part of the project enters commercial operations. The order also grants 100% recovery for construction work in progress, 100% recovery for abandonment, if the line is abandoned through no fault of the RITELine developers, and the ability to treat pre-construction costs as a regulatory asset. All incentives, including the abandonment incentive, are contingent on inclusion of the project in the PJM RTEP. The RITELine companies filed for rehearing on several rate of return on common equity issues and argued that the right to collect abandoned costs should not be subject to the project being included in the RTEP. The RITELine companies also made a compliance filing as called for in the October 14, 2011 Order. FERC accepted this filing on March 16, 2012.

Smart Meter and Smart Grid Initiatives.

ComEd's Smart Meter and Smart Grid Investments. ComEd plans to invest approximately $1.3 billion on smart meters and smart grid under EIMA, including $1.0 billion through the AMI Deployment Plan. On June 5, 2013, the ICC issued an interim order approving ComEd's accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. The deployment plan provides for the installation of 4 million electric smart meters, of which more than 60,000 meters were installed by the end of 2013.

PECO's Smart Meter and Smart Grid Investments. In 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, under which PECO will install more than 1.6 million smart

meters. PECO plans to spend up to a total of $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, of which $200 million will be funded by SGIG.

BGE Smart Grid Initiative. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million electric and gas smart meters at an expected total cost of approximately $480 million, before considering the $200 million SGIG for smart grid and other related initiatives.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

Generation Renewable Development *.* On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. The delay will not have a material financial effect on Exelon. Exelon expects the project to be in full commercial operation in the first half of 2014. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA with Pacific Gas & Electric Company for the full output of the plant, which has been approved by the CPUC. Upon completion, the facility will add 230 MWs to Generation's renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through December 31, 2013 were approximately $968 million. In addition, Generation constructed and placed into service 400 MWs of additional wind generation in 2012 at a cost of $710 million and another 50 MW will be added to Generation's wind portfolio in 2014 with the expansion of its Beebe project in Michigan, the output of which will be fully contracted under a 20-year PPA.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Under the nuclear uprate program, Generation has placed into service projects representing 316 MWs of new nuclear generation at a cost of $952 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's consolidated balance sheets. At December 31, 2013, Generation has capitalized $203 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 200 MWs of new nuclear generation, that are in the installation phase across four nuclear stations; Peach Bottom in Pennsylvania and Byron, Braidwood and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $300 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected not to be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

Liquidity

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.4 billion.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets. The ongoing European debt crisis has contributed to the instability in global credit markets. Further disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2013, approximately 30%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.6 billion was available as of December 31, 2013. There were no borrowings under the Registrants' credit facilities as of December 31, 2013. See Note 13—Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

February 5, 2014 Winter Ice Storm. On February 5, 2014, a winter storm which brought a mix of snow, ice and freezing rain to the region interrupted electric service delivery to nearly 715,000 customers in PECO's service territory. Restoration efforts are continuing and will include significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies. PECO estimates that restoration efforts will result in $60 million to $80 million of incremental operating and maintenance expense and $30 million to $40 million of incremental capital expenditures for the first quarter of 2014.

Tax Matters

See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon supports the promulgation of certain environmental regulations by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to their low emission generation portfolios, Generation and CENG will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air Quality. In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a review

of the current 2008 ozone NAAQS that is expected to result in a proposed revision of the ozone NAAQS sometime in fall 2014. These updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Until the U.S. EPA re-issues CSAPR, Exelon cannot determine the impacts of the rule, including any that would impact power prices. In June 2013, the U.S. Supreme Court granted the U.S. EPA's petition to review the D.C. Circuit Court's CSAPR decision. Oral argument was held on December 10, 2013. A decision is expected sometime during 2014.

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court will not occur until 2014. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

The cumulative impact of these air regulations could be to require power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO_2 and acid gases, and selective catalytic reduction technology for NO_x. Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS by January 1, 2015. In addition, Keystone already has SCR and Flue-gas desulfurization (FGD) controls in place.

On January 15, 2013, EPA issued a final rule for NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE NESHAP/NSPS). The final rule allows diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but requires units that operate over 15 hours to burn low sulfur fuel and report key engine information. The final rule eliminates after May 2014 the 50 hour exemption for peak shaving and other non-emergency demand response that was included in the proposed rule and, therefore, is not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act. The U.S. EPA is addressing the issue of carbon dioxide (CO2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act. Pursuant to President

Obama's June 25, 2013 memorandum to U.S. EPA, the Agency re-proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. Under the President's memorandum, the U.S. EPA is also required to propose a Section 111(d) rule no later than June 1, 2014 to establish CO2 emission regulations for existing stationary sources. Pursuant to the President's Climate Action Plan, the U.S. EPA re-proposed regulations for the GHG emissions from new fossil fueled power plants on September 20, 2013. The U.S. EPA is also expected to propose by June 2014 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and to issue final regulations by June 2015. While the nature and impact of the final regulations is not yet known, to the extent that the rule results in emission reductions from fossil fuel fired plants, imposing some form of direct or indirect price of carbon in competitive electricity markets, Exelon's overall low-carbon generation portfolio results would benefit.

Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On March 28, 2011, the U.S. EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by November 4, 2013; on October 30, 2013 the U.S. EPA invoked the *force majeure* provision of the Settlement Agreement to extend the final rule deadline until November 20, 2013 due to the early October 2013 federal government shutdown. The U.S. EPA and the plaintiffs have stated that the deadline will be extended again for a brief period, but have not yet agreed on a date. The proposed rule does not require closed cycle cooling (e.g., cooling towers) as the best technology available, and also provides some flexibility in the use of cost-benefit considerations and site-specific factors. The proposed rule affords the state permitting agency wide discretion to determine the best technology available, which, depending on the site characteristics, could include closed cycle cooling, advanced screen technology at the intake, or retention of the current technology.

It is unknown at this time whether the final regulations will require closed-cycle cooling. The economic viability of Generation's facilities without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost-benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation.

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Generation's plants that would be affected by the proposed rules are Keystone and Conemaugh in Pennsylvania, which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has entered into a Consent Decree which requires that a final rule be issued by December 19, 2014.

See Note 22 of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

Japan Earthquake and Tsunami and the Industry's Response. On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co.

In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The NRC staff and the Task Force concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The Task Force's report did not recommend any changes to the existing nuclear licensing process in the United States or changes in the storage of spent nuclear fuel within the plant's spent nuclear fuel pools.

In 2012, the NRC authorized its staff to issue three immediately effective orders (Tier 1 orders) to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. In addition, in 2012, the NRC staff recommended to the NRC the installation of engineered containment filtered venting systems for boiling-water reactors (BWR) with Mark I and Mark II containment structures. In summary, through the initial and/or subsequent orders and the NRC approved implementation guidance, the Tier 1 orders currently: (1) require licensees to provide sufficient onsite portable equipment and resources to maintain or restore cooling capabilities for the core and spent fuel pool and to maintain containment integrity until offsite equipment is available and have offsite equipment and resources available to sustain cooling functions indefinitely; (2) provide requirements for vents for BWR's with Mark I and Mark II containments to remain functional during severe accident conditions including the ability to vent the containment following core damage; and (3) require licensees to install instrumentation to provide a reliable indication of water level in the spent fuel pool. Finally, the NRC has directed the NRC staff to produce a technical evaluation to support rulemaking that considers filtering and performance-based strategies as options for BWR's with Mark I and Mark II containments. The NRC staff must then develop a final rule by March 2017.

Additionally, in 2012, the NRC had issued a detailed information request to every operating commercial nuclear power plant in the United States. The information requested requires: (1) use of the current NRC guidance to reevaluate current seismic and flood risk hazards against the design basis and provide a plan of actions to address vulnerabilities, including risks exceeding the design basis; (2) performance of walk downs to ensure the ability to respond to seismic and external flooding events and provide a corrective action plan to the NRC to address deficiencies; and (3) assessment of the means to provide power for communications equipment during a severe natural event and identify staffing required to implement the emergency plan for an event affecting all units with an extended loss of alternating current power and impeded access to the site. The nuclear industry proposed, and the NRC approved, an augmented approach to the seismic hazard analysis to accommodate industry wide availability of qualified technical resources needed to perform the required analysis. The NRC approved this augmented approach.

Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for the period from 2014 through 2018 is expected to be between approximately $350 million and $375 million of capital and $50 million of operating expense, as previously anticipated in Generation's planning projections. As Generation completes the design and installation planning for its actions, Generation will update these estimates. Further, Generation estimates incremental costs of $15 to $20 million per unit at eleven Mark I and II units for the installation of filtered vents, if ultimately required by the NRC. Generation's current assessments are specific to the Tier 1 recommendations as

the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors, for further discussion of the risk factors.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing, exchange trading, margin requirements, and other transparency requirements. The Dodd-Frank Act, however, also preserves the ability of end users in the energy industry to hedge their risks. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Exelon has determined that it will conduct its commercial business in a manner that does not require registration as a swap dealer or major swap participant. Notwithstanding, there are additional rulemakings that have not yet been issued, including the capital and margin rules, which will further define the scope of the regulations and provide clarity as to the impact on the Registrants' business, as well as to potential new opportunities. Depending on these final rules, the Registrants could be subject to significant new obligations.

The proposed regulations addressing collateral and capital requirements and exchange margin cash postings, when final, could require Generation to increase collateral requirements or cash postings in lieu of letters of credit currently issued to collateralize Swaps. Exelon had previously estimated that it could be required to make up to $1 billion of additional collateral postings under its bilateral credit lines. Given the swap dealer and the major swap participant definitions will not apply to Generation, the actual amount of collateral postings that will be required may be lower than Exelon's previous expectations due to the following factors: (a) the majority of Generation's physical wholesale portfolio does not meet the final CFTC Swap definition; (b) there will be minimal incremental costs associated with Generation's positions that are currently cleared and subject to exchange margin; and (c) Generation will not be a swap dealer or major swap participant and proposed capital requirements applicable to these entities will not apply to Generation.

The actual level of collateral required will depend on many factors, including but not limited to market conditions, the outcome of final margin rules for Swaps, the extent of its trading activity in Swaps, and Generation's credit ratings. Nonetheless, Generation has adequate credit facilities and flexibility in its hedging program to meet its anticipated collateral requirements estimated based on conservative assumptions.

In addition, the new regulations will impose new and ongoing compliance and infrastructure costs on Generation, which may amount to several million dollars per year.

Exelon and Generation continue to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on their results of operations, cash flows or financial position.

ComEd, PECO and BGE could also be subject to various Dodd-Frank Act requirements to the extent they enter into Swap transactions. However, at this time, management of ComEd, PECO and BGE do not expect to be materially affected by this legislation.

Energy Infrastructure Modernization Act. Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. Participating utilities are required to file an annual update to the performance-based

formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation.

Formula Rate Tariff

In March 2013, the Illinois legislature passed Senate Bill 9 to clarify the intent of EIMA on the three issues decided in the Rehearing Order: an allowed return on ComEd's pension asset; the use of year-end rather than average rate base and capital structure in the annual reconciliation; and the use of ComEd's weighted average cost of capital interest rate rather than a short-term debt rate to apply to the annual reconciliation. On May 22, 2013, Senate Bill 9 became effective after the Illinois legislature overrode the Governor's veto of that Bill. On June 5, 2013, the ICC approved ComEd's updated distribution formula rate structure to reflect the impacts of Senate Bill 9.

In October 2013, the ICC opened an investigation (the Investigation), in response to a complaint filed by the Illinois Attorney General, to change the formula rate structure by requesting three changes: the elimination of the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance, the netting of associated accumulated deferred income taxes against the annual reconciliation balance in calculating interest, and the use of average rather than year-end rate base for determining any ROE collar adjustment. On November 26, 2013, the ICC issued its final order in the Investigation, rejecting two of the proposed changes but accepting the proposed change to eliminate the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance. The accepted change became effective in January 2014, and is estimated to reduce ComEd's 2014 revenue by approximately $8 million. ComEd and intervenors requested rehearing, however all rehearing requests were denied by the ICC. ComEd and intervenors have filed appeals with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals. See 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Annual Reconciliation

On May 30, 2013, ComEd updated its revenue requirement allowed in the December 2012 Order to reflect the impacts of Senate Bill 9, which resulted in a reduction to the current revenue requirement in effect of $14 million. The rates took effect in July 2013.

2013 Filing. On April 29, 2013, ComEd filed its annual distribution formula rate, which was updated on May 30, 2013 to reflect the impacts of Senate Bill 9. The ICC's final order, issued on December 19, 2013, increased the revenue requirement by $341 million, reflecting an increase of $160 million for the initial revenue requirement for 2013 and an increase of $181 million for the annual reconciliation for 2012. The rate increase was set using an allowed return on capital of 6.94% (inclusive of an allowed return on common equity of 8.72%). The rates took effect in January 2014. ComEd requested a rehearing on specific issues, which was denied by the ICC. ComEd and intervenors also filed appeals. ComEd cannot predict the results of any such appeals. See 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

FERC Ameren Order. In July 2012, FERC issued an order to Ameren Corporation (Ameren) finding that Ameren had improperly included acquisition premiums/ goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make

refunds for the implied increase in rates in prior years. Ameren has filed for rehearing regarding the July 2012 FERC order. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/ goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

FERC Order No. 1000 Compliance (ComEd, PECO and BGE). In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements a right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners including ComEd, PECO and BGE (collectively, the PJM Transmission Owners) submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC's " *Mobile-Sierra* " standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order on the PJM Compliance Filing and the filing of these PJM Transmission Owners (1) rejecting the arguments of such PJM Transmission Owners that the PJM governing documents were entitled to review under the *Mobile-Sierra* standard, (2) accepting most of the PJM filing, removing the right-of-first refusal from the PJM tariffs; and (3) directing PJM to remove certain exceptions that it included in its compliance filing that FERC found did not comply with Order No. 1000. FERC's order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd's, PECO's and BGE's financial return on new investments in energy transmission facilities. Numerous parties sought rehearing of the FERC's March 22, 2013 order, including the PJM Transmission Owners who sought rehearing of the FERC's rejection of their Mobile-Sierra and related arguments. The compliance filing was made on July 22, 2013. On January 16, 2014, FERC issued an order stating that PJM's filing while subject to further orders, is effective as of January 1, 2014.

FERC Transmission Complaint. On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. As of December 31, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base return on equity, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE's base return on equity to 8.7%, the annual impact would be a reduction in revenues of approximately $10 million. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The Maryland Strategic Infrastructure Development and Enhancement Program. In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. The new surcharge rates are expected to take effect in the first quarter of 2014. BGE cannot predict the

outcome of this proceeding or how much of the requested plan and related surcharge the MDPSC will approve. The MDPSC held evidentiary hearings on BGE's proposed plan and surcharge on November 12, 2013 through November 14, 2013. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. BGE must submit a list detailing specific projects planned for 2014 to the MDPSC for approval within 30 days of the decision. Upon approval of the project list by the MDPSC, BGE will be able to implement the surcharge rates on gas customers' bills. The new surcharges are expected to take effect in the second quarter of 2014. In addition, BGE will be subject to an annual independent audit to review plan performance and progress. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions with its accounting and disclosure governance committee on a regular basis and provides periodic updates on management decisions to the audit committee of the Exelon board of directors. Management believes that the accounting policies described below require significant judgment in their application, or estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation's ARO associated with decommissioning its nuclear units was $4.9 billion at December 31, 2013. The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios. The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the methodologies and significant estimates and assumptions described as follows:

Decommissioning Cost Studies. Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the costs and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within its industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years.

Cost Escalation Factors. Generation uses cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors, and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal and other costs.

Probabilistic Cash Flow Models. Generation's probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning costs, approaches and timing on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. Probabilities are assigned to alternative decommissioning approaches which assess the likelihood of performing DECON (a method of decommissioning shortly after the cessation of operation in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a LLRW landfill or decontaminated to a level that permits property to be released for

unrestricted use), Delayed DECON (similar to the DECON scenario but with a delay to allow for spent fuel to be removed from the site prior to onset of decommissioning activities) or SAFSTOR (a method of decommissioning in which the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated to levels that permit release for unrestricted use generally within 60 years after cessation of operations) decommissioning. Probabilities assigned to the timing scenarios incorporate the likelihood of continued operation through current license lives or through anticipated license renewals. Generation's probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal, which Generation assumed would begin in 2025 in 2013 and 2012. The SNF acceptance date was based on management's estimates of the amount of time required for the DOE to select a site location and develop the necessary infrastructure. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 22 of the Combined Notes to Consolidated Financial Statements.

License Renewals. Generation assumes a successful 20-year renewal for each of its nuclear generating station licenses, except for Oyster Creek, in determining its nuclear decommissioning ARO. The current NRC license for Oyster Creek expires in 2029. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. As a result of this decision the expected economic life of Oyster Creek was reduced by 10 years to correspond to Exelon's current best estimate as to the timing of ceasing generation operations at the Oyster Creek unit in 2019. Generation has successfully secured 20-year operating license renewal extensions for ten of its nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG), and none of Generation's applications for an operating license extension have been denied. Generation is in various stages of the process of pursuing similar extensions on its remaining nine operating nuclear units. Generation's assumption regarding license extension for ARO determination purposes is based in part on the good current physical condition and high performance of these nuclear units; the favorable status of the ongoing license renewal proceedings with the NRC, and the successful renewals for ten units to date. Generation estimates that the failure to obtain license renewals at any of these nuclear units (assuming all other assumptions remain constant) would increase its ARO on average approximately $210 million per unit as of December 31, 2013. The size of the increase to the ARO for a particular nuclear unit is dependent upon the current stage in its original license term and its specific decommissioning cost estimates. If Generation does not receive license renewal on a particular unit, the increase to the ARO may be mitigated by Generation's ability to delay ultimate decommissioning activities under a SAFSTOR method of decommissioning.

Discount Rates. The probability-weighted estimated future cash flows using these various scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. The accounting guidance required Generation to establish an ARO at fair value at the time of the initial adoption of the current accounting standard. Subsequent to the initial adoption, the ARO is adjusted for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions, as described above.

Under the current accounting framework, the ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. This differs from the accounting requirements for other long-dated obligations, such as pension and other post-employment benefits that are required to be re-measured as and when corresponding discount rates change. If Generation's future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFRs, the obligation would increase from approximately $4.9 billion to approximately $5.5 billion. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon's and Generation's Consolidated Balance Sheets at December 31, 2013 at fair value of approximately $8.1 billion and have an estimated targeted annual pre-tax return of 5.9 % to 6.7 %.

To illustrate the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO: i) had

Generation used the 2012 CARFRs rather than the 2013 CARFRs in performing its third quarter 2013 ARO update, Generation would have reduced the ARO by approximately $10 million as compared to the actual decrease to the ARO of $140 million; and ii) if the CARFR used in performing the third quarter 2013 ARO update (which also reflected increases in the amounts and changes to the timing of projected cash flows) was increased or decreased by 100 basis points, the ARO would have decreased by $300 million and increased $40 million, respectively, as compared to the actual decrease of $140 million.

ARO Sensitivities. Changes in the assumptions underlying the foregoing items could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions will change as well. As an example, Exelon had a historical increase of approximately $670 million in the value of the ARO which was driven by Generation modifying the assumed timing of the DOE acceptance of SNF for disposal from 2020 to 2025. The modification of the assumed DOE acceptance date affected the calculation of the ARO in isolation as follows; i) the change in the timing of DOE acceptance of SNF increased the total number of years in which decommissioning activities are estimated to occur, by five years on average, thereby increasing the total expected nominal cash flows required to decommission the units; ii) the nominal cash flows were subjected to additional escalation as a result of the extension of the decommissioning period increasing the total estimated costs required to decommission the units; and iii) the escalated cash flows were discounted at the then current CARFRs which had dramatically decreased during that time period.

The following table illustrates the effects of changing certain ARO assumptions, discussed above, while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption	Increase (Decrease) to ARO at December 31, 2013
Cost escalation studies	
Uniform increase in escalation rates of 25 basis points	$ 560
Probabilistic cash flow models	
Increase the likelihood of the high-cost scenario by 10 percentage points and decrease the likelihood of the low-cost scenario by 10 percentage points	$ 190
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$ 290
Increase the likelihood of operating through current license lives by 10 percentage points and decrease the likelihood of operating through anticipated license renewals by 10 percentage points	$ 430
Extend the estimated date for DOE acceptance of SNF to 2030	$ 50
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with an increase in discount rates of 100 basis points	$ (230)
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with a decrease in discount rates of 100 basis points	$ 600

For more information regarding accounting for nuclear decommissioning obligations, see Notes 1 and 15 of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon and ComEd)

As of December 31, 2013, Exelon's and ComEd's carrying amount of goodwill was approximately $2.6 billion, relating to the acquisition of ComEd in 2000 as part of the PECO/Unicom Merger. Under the provisions of the authoritative guidance for goodwill, ComEd is required to perform an assessment for possible impairment of its goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit

below its carrying amount. Under the authoritative guidance, a reporting unit is an operating segment or operating component and is the level at which goodwill is tested for impairment. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors, and entity-specific events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's business and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

Management concluded the remeasurement of the like-kind exchange position and the charge to ComEd's earnings in the first quarter of 2013 triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of January 31, 2013. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

ComEd performed a quantitative assessment as of November 1, 2013, for its 2013 annual goodwill impairment assessment. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

While neither the interim nor the annual assessments indicated an impairment of ComEd's goodwill, certain assumptions used to estimate the fair value of ComEd are highly sensitive to changes. Adverse regulatory actions, such as early termination of EIMA, or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd's business, and the fair value of debt, could potentially result in a future impairment of ComEd's goodwill, which could be material. Based on the results of the annual goodwill test performed as of November 1, 2013, the estimated fair value of ComEd would have needed to decrease by more than 10% for ComEd to fail the first step of the impairment test. See Note 1—Significant Accounting Policies, Note 10—Intangible Assets and Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon and Generation)

In accordance with the authoritative accounting guidance, the purchase price of an acquired business is generally allocated to the assets acquired and liabilities assumed at their estimated fair values on the date of acquisition. Any unallocated purchase price amount is recognized as goodwill on the balance sheet if it exceeds the estimated fair value and as a bargain purchase gain on the income statement if it is below the estimated fair value. Determining the fair value of assets acquired and

liabilities assumed requires management's judgment, the utilization of independent valuation experts and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. See Note 4—Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Assets and Liabilities (Exelon and Generation)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired. The initial amount recorded represents the fair value of the contract at the time of acquisition, and the balance is amortized over the life of the contract in relation to the present value of the underlying cash flows. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Refer to Note 4—Mergers and Acquisitions and Note 10—Intangible Assets for further discussion.

Impairment of Long-lived Assets (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE regularly monitor and evaluate their long-lived assets and asset groups, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. Conditions that could have an adverse impact on the cash flows and fair value of the long-lived assets are deteriorating business climate, including current energy prices and market conditions, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life, among others.

The review of long-lived assets and asset groups for impairment requires significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power, costs of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could have a significant effect on the consolidated financial statements. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of other groups of assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units and associated intangible contract assets recorded on the balance sheet. The cash flows from the generation units are generally evaluated at a regional portfolio level with cash flows generated from Generation's customer supply and risk management activities, including cash flows from contracts that are accounted for as intangible contract assets and liabilities recorded on the balance sheet. In certain cases generation assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables).

Impairment may occur when the carrying value of the asset or asset group exceeds the future undiscounted cash flows. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value of the long-lived asset or asset group is dependent upon a market participant's view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates. Events and circumstances frequently do not occur as expected and

there will usually be differences between prospective financial information and actual results, and those differences may be material. Accordingly, to the extent that any of the information used in the fair value analysis requires adjustment, the resulting fair market value would be different. As such, the determination of fair value is driven by both internal assumptions that include significant unobservable inputs (Level 3) such as revenue and generation forecasts, projected capital, and maintenance expenditures and discount rates, as well as information from various public, financial and industry sources. An impairment determination would require the affected Registrant to reduce either the long-lived asset or asset group, including any intangible contract assets and liabilities, and current period earnings by the amount of the impairment.

Generation evaluates unproved gas producing properties at least annually to determine if they are impaired. Impairment for unproved gas property occurs if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience indicates a decline in carrying value below fair value.

Exelon holds investments in coal-fired plants in Georgia and Texas subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual values of the leased assets at the end of the respective lease terms. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments using a discounted cash flow analysis, which takes into consideration the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates.

Generation also evaluates its equity method investments to determine whether or not they are impaired based on whether the investment has experienced a decline in value that is not temporary in nature. Additionally, if one of Generation's equity method investments recognize an impairment, Generation would record its proportionate share of that impairment loss through its equity earnings (losses) of unconsolidated affiliates. Generation would also evaluate the investment for a decline in value at that time that is not temporary in nature.

See Note 8 of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Exelon.

Depreciable Lives of Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. Depreciation of these assets is generally provided over their estimated service lives on a straight-line basis using the composite method. The estimation of service lives requires management judgment regarding the period of time that the assets will be in use. As circumstances warrant, the estimated service lives are reviewed to determine if any changes are needed. Depreciation rates incorporate assumptions on interim retirements based on actual historical retirement experience. To the extent interim retirement patterns change, this could have a significant impact on the amount of depreciation expense recorded in the income statement. Changes to depreciation estimates resulting from a change in the estimated end of service lives could have a significant impact on the amount of depreciation expense recorded in the income statement. See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant and equipment of the Registrants.

The estimated service lives of the nuclear generating facilities are based on the estimated useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek. While Generation has

received license renewals for certain facilities, and has applied for or expects to apply for and obtain approval of license renewals for the remaining facilities, circumstances may arise that would prevent Generation from obtaining additional license renewals. Generation also evaluates annually the estimated service lives of its generating facilities based on feasibility assessments as well as economic and capital requirements. The estimated service lives of hydroelectric facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the Conowingo and Muddy Run operating licenses. A change in depreciation estimates resulting from Generation's extension or reduction of the estimated service lives could have a significant effect on Generation's results of operations. Generation completed a depreciation rate study during the first quarter of 2010, which resulted in the implementation of new depreciation rates effective January 1, 2010. Constellation completed a depreciation rate study during the fourth quarter of 2010, which resulted in the implementation of new depreciation rates effective during the fourth quarter of 2010.

ComEd is required to file a depreciation rate study at least every five years with the ICC. ComEd completed a depreciation study in 2014 and filed the updated depreciation rates with both FERC and the ICC in January 2014. This is expected to result in the implementation of new depreciation rates effective first quarter 2014.

PECO is required to file a depreciation rate study at least every five years with the PAPUC. In April 2010, PECO filed a depreciation rate study with the PAPUC for both its electric and gas assets, which resulted in the implementation of new depreciation rates effective January 1, 2010 for electric transmission assets and January 1, 2011 for electric distribution and gas assets.

The MDPSC does not mandate the frequency or timing of BGE's depreciation studies. In December 2006, BGE filed revised depreciation rates with the MDPSC for both its electric distribution and gas assets. Revisions to depreciation rates from this filing were finalized July 1, 2010.

Defined Benefit Pension and Other Postretirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for substantially all Generation, ComEd, PECO, BGE and BSC employees. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and other postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit pension and other postretirement benefit plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is affected by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, the anticipated rate of increase of health care costs, Exelon's expected level of contributions to the plans, the incidence of participant mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the long-term expected investment rate credited to employees of certain plans, among others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. Pension and other postretirement benefit costs attributed to the operating companies are labor costs and are ultimately allocated to projects within the operating companies, some of which are capitalized.

Pension and other postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification under the fair value hierarchy in accordance with authoritative guidance.

Expected Rate of Return on Plan Assets. The long-term expected rate of return on plan assets assumption used in calculating pension costs was 7.50%, 7.50%, and 8.00% for 2013, 2012 and 2011, respectively. The weighted average expected return on assets assumption used in calculating other postretirement benefit costs was 6.45%, 6.68%, and 7.08% in 2013, 2012 and 2011, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. The current year EROA is based on asset allocations from the prior year end. In 2010, Exelon began implementation of a liability-driven investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. As a result of this modification, over time, Exelon determined that it will decrease equity investments and increase investments in fixed income securities and alternative investments in order to achieve a balanced portfolio of liability hedging and return-generating assets. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's asset allocations. Exelon used an EROA of 7.00% and 6.59% to estimate its 2014 pension and other postretirement benefit costs, respectively.

Exelon calculates the expected return on pension and other postretirement benefit plan assets by multiplying the EROA by the MRV of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments to be made during the year. In determining MRV, the authoritative guidance for pensions and postretirement benefits allows the use of either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. For the majority of pension plan assets, Exelon uses a calculated value that adjusts for 20% of the difference between fair value and expected MRV of plan assets. Use of this calculated value approach enables less volatile expected asset returns to be recognized as a component of pension cost from year to year. For other postretirement benefit plan assets and certain pension plan assets, Exelon uses fair value to calculate the MRV.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across the Registrants' pension and other postretirement benefit plans for the year ended December 31, 2013 were 6.73% and 11.41%, respectively, compared to an expected long-term return assumption of 7.50% and 6.45%, respectively.

Discount Rate. The discount rates used to determine the pension and other postretirement benefit obligations were 4.80% and 4.90%, respectively, at December 31, 2013. The discount rates at December 31, 2013 represent weighted-average rates for both pension and other postretirement benefit plans. At December 31, 2013 and 2012, the discount rates were determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated distributions under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

The discount rate assumptions used to determine the obligation at year end are used to determine the cost for the following year. Exelon will use discount rates of 4.80% and 4.90% to estimate its 2014 pension and other postretirement benefit costs, respectively.

Health Care Reform Legislation. In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers.

One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer's postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, the Registrants were required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. Additionally, as a result of this deductibility change for employers and other Health Care Reform provisions that impact the federal prescription drug subsidy options provided to employers, Exelon changed the manner in which it will receive prescription drug subsidies beginning in 2013.

The Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Effective in 2002, Constellation amended its other postretirement benefit plans for all subsidiaries other than Nine Mile Point by capping retiree medical coverage for future retirees who were under the age of 55 on January 1, 2002 at 2002 levels. Therefore, the excise tax is not expected to have a material impact on the legacy Constellation other postretirement benefit plans. However, certain key assumptions are required to estimate the impact of the excise tax on the other postretirement obligation for legacy Exelon plans, including projected inflation rates (based on the CPI) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

Health Care Cost Trend Rate. Assumed health care cost trend rates have a significant effect on the costs reported for Exelon's other postretirement benefit plans. Accounting guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty, particularly when considering potential impacts of the 2010 Health Care Reform Acts. Exelon assumed an initial health care cost trend rate of 6.50% for 2013, decreasing to an ultimate health care cost trend rate of 5.00% in 2017.

Sensitivity to Changes in Key Assumptions. The following tables illustrate the effects of changing certain of the actuarial assumptions discussed above, while holding all other assumptions constant (dollars in millions):

Actuarial Assumption	Change in Assumption	Pension	Other Postretirement Benefits	Total
Change in 2013 cost:				
Discount rate [a]	0.5%	$ (63)	$ (34)	$ (97)
	(0.5%)	68	48	116
EROA	0.5%	(68)	(10)	(78)
	(0.5%)	68	10	78
Health care cost trend rate	1.00%	N/A	90	90
	(1.00%)	N/A	(62)	(62)
Change in benefit obligation at December 31, 2013:				
Discount rate [a]	0.5%	(904)	(297)	(1,201)
	(0.5%)	965	318	1,283
Health care cost trend rate	1.00%	N/A	858	858
	(1.00%)	N/A	(607)	(607)

(a) In general, the discount rate will have a larger impact on the pension and other postretirement benefit cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon implemented a liability-driven investment strategy for a portion of its pension asset portfolio in 2010. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

Average Remaining Service Period. For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants' average remaining service periods. The average remaining service period of defined benefit pension plan participants was 11.8 years, 11.9 years, and 12.1 years for the years ended December 31, 2013, 2012 and 2011, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants' average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants' average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 8.7 years, 8.9 years and 6.6 years for the years ended December 31, 2013, 2012 and 2011, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.8 years, 10.1 years and 8.7 years for the years ended December 31, 2013, 2012 and 2011, respectively.

Regulatory Accounting (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE account for their regulated electric and gas operations in accordance with the authoritative guidance for accounting for certain types of regulations, which requires Exelon, ComEd, PECO and BGE to reflect the effects of cost-based rate regulation in their financial statements. This guidance is applicable to entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) a reasonable expectation that rates are set at levels that will recover the entities costs from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2013, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of those operations no longer meets the criteria of this guidance, Exelon, ComEd, PECO and BGE would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and could be material. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon, ComEd, PECO and BGE.

For each regulatory jurisdiction in which they conduct business, Exelon, ComEd, PECO and BGE assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs in ComEd's, PECO's and BGE's jurisdictions, and factors such as changes in applicable regulatory and political environments. Furthermore, Exelon, ComEd, PECO and BGE make other judgments related to the financial statement impact of their regulatory environments, such as the types of adjustments to rate base that will be acceptable to regulatory bodies, if any, to which costs will be recoverable through rates. Refer to the revenue recognition discussion below for additional information on the annual revenue

reconciliations associated with ComEd's distribution formula rate tariff, pursuant to EIMA, and FERC-approved transmission formula rate tariffs for ComEd and BGE. Additionally, estimates are made in accordance with the authoritative guidance for contingencies as to the amount of revenues billed under certain regulatory orders that may ultimately be refunded to customers upon finalization of applicable regulatory or judicial processes. These assessments are based, to the extent possible, on past relevant experience with regulatory bodies in ComEd's, PECO's and BGE's jurisdictions, known circumstances specific to a particular matter and hearings held with the applicable regulatory body. If the assessments and estimates made by Exelon, ComEd, PECO and BGE are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Accounting for Derivative Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants utilize derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy-related products marketed and purchased. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd had a financial swap contract with Generation that expired May 31, 2013 and currently holds floating-to-fixed energy swaps with several unaffiliated suppliers that extend into 2032. PECO and BGE have entered into derivative natural gas contracts to hedge their long-term price risk in the natural gas market. PECO has also entered into derivative contracts to procure electric supply through a competitive RFP process as outlined in its PAPUC-approved DSP Program. BGE has also entered into derivative contracts to procure electric supply through a competitive auction process as outlined in its MDPSC-approved SOS Program. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes. The Registrants' derivative activities are in accordance with Exelon's Risk Management Policy (RMP). See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether or not a contract qualifies as a derivative under this guidance requires that management exercise significant judgment, including assessing the market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. Further, interpretive guidance related to the authoritative literature continues to evolve, including how it applies to energy and energy-related products. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance related to derivatives, could result in previously excluded contracts being subject to the provisions of the authoritative derivative guidance. Generation has determined that contracts to purchase uranium, contracts to purchase and sell capacity in certain ISO's, certain emission products and RECs do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement and neither the uranium, certain capacity, emission nor the REC markets are sufficiently liquid to conclude that physical forward contracts are readily convertible to cash. If these markets do become sufficiently liquid in the future and Generation would be required to account for these contracts as derivative instruments, the fair value of these contracts would be accounted for consistent with Generation's other derivative instruments. In this case, if market prices differ from the underlying prices of the contracts, Generation would be required to record mark-to-market gains or losses, which may have a significant impact to Exelon's and Generation's financial positions and results of operations.

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, the normal purchases and normal sales exception. Further, derivatives that qualify and are designated for hedge accounting are classified as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all economic hedges for commodities are recorded at fair value through earnings for the combined company. In addition, for energy-related derivatives entered into for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings each period. For economic hedges that are not designated for hedge accounting for ComEd, PECO and BGE, changes in the fair value each period are recorded as a regulatory asset or liability.

Normal Purchases and Normal Sales Exception. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated as normal purchases and normal sales and are thus not required to be recorded at fair value, but rather on an accrual basis of accounting. Determining whether a contract qualifies for the normal purchases and normal sales exception requires that management exercise judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and is not financially settled on a net basis. The contracts that ComEd has entered into with suppliers as part of ComEd's energy procurement process, PECO's full requirement contracts and block contracts under the PAPUC-approved DSP program, most of PECO's natural gas supply agreements and all of BGE's full requirement contracts and natural gas supply agreements that are derivatives qualify for the normal purchases and normal sales exception.

Commodity Contracts. Identification of a commodity contract as an economic hedge requires Generation to determine that the contract is in accordance with the RMP. Generation reassesses its economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

As a part of accounting for derivatives, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. In accordance with the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes

the inputs to valuation techniques used to measure fair value. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges are categorized in Level 2. These price quotations reflect the average of the bid-ask mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The Registrant's derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, and assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, the model inputs are generally observable. Such instruments are categorized in Level 2. For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of credit and nonperformance risk to date have generally not been material to the financial statements.

Interest Rate and Foreign Exchange Derivative Instruments. The Registrants may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve the targeted level of variable-rate debt as a percent of total debt. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings and floating to fixed swaps for project financing. In addition, Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the economic hedge and proprietary trading activity is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or change in market interest rates. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. The fair value of the agreements is calculated by discounting the future net cash flows to the present value based on the terms and conditions of the agreements and the forward interest rate and foreign exchange curves. As these inputs are based on observable data and valuations of similar instruments, the interest rate and foreign exchange derivatives are primarily categorized in Level 2 in the fair value hierarchy. Certain exchange based interest rate derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Notes 11 and 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation (Exelon, Generation, ComEd, PECO and BGE)

Significant management judgment is required in determining the Registrants' provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and

liabilities and valuation allowances. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of unrecognized tax benefits to be recorded in the Registrants' consolidated financial statements.

The Registrants evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and their intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. The Registrants also assess their ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. The Registrants record valuation allowances for deferred tax assets when the Registrants conclude it is more-likely-than-not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2013 and 2012 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Loss Contingencies (Exelon, Generation, ComEd, PECO and BGE)

In the preparation of their financial statements, the Registrants make judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amounts recorded may differ from the actual expense incurred when the uncertainty is resolved. The estimates that the Registrants make in accounting for loss contingencies and the actual results that they record upon the ultimate resolution of these uncertainties could have a significant effect on their consolidated financial statements.

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at ComEd, PECO and BGE to determine future remediation requirements and estimates are adjusted accordingly. In addition, periodic reviews are performed at Generation to assess the adequacy of its environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant effect on the Registrants' results of operations, financial position and cash flows. See Note 22 of the Combined Notes to Consolidated Financial Statements for further information.

Other, Including Personal Injury Claims. The Registrants are self-insured for general liability, automotive liability, workers' compensation, and personal injury claims to the extent that losses are

within policy deductibles or exceed the amount of insurance maintained. The Registrants have reserves for both open claims asserted and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible state and national legislative measures could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material effect on the Registrants' results of operations, financial position and cash flows.

Revenue Recognition (Exelon, Generation, ComEd, PECO and BGE)

Sources of Revenue and Selection of Accounting Treatment. The Registrants earn revenues from various business activities including: the sale of energy and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail) *;* the sale and delivery of electricity and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The appropriate accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable accounting standards. The Registrants primarily use accrual and mark-to-market accounting as discussed in more detail below.

Accrual Accounting. Under accrual accounting, the Registrants record revenues in the period when services are rendered or energy is delivered to customers. The Registrants generally use accrual accounting to recognize revenues for sales of electricity, natural gas, and other commodities as part of their physical delivery activities. The Registrants enter into these sales transactions using a variety of instruments, including non-derivative agreements, derivatives that qualify for and are designated as normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to utility customers under regulated service tariffs, and spot-market sales, including settlements with independent system operators.

Mark-to-Market Accounting. The Registrants record revenues using the mark-to-market method of accounting for transactions that meet the definition of a derivative for which they are not permitted, or have not elected, the NPNS exception. These mark-to-market transactions primarily relate to risk management activities and economic hedges of other accrual activities. Mark-to-market revenues include: inception gains or losses on new transactions where the fair value is observable and realized; and unrealized gains and losses from changes in the fair value of open contracts.

Use of Estimates. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliations can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Unbilled Revenues . The determination of Generation's, ComEd's, PECO's and BGE's retail energy sales to individual customers is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities' customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, volumes may fluctuate monthly as a result of customers electing to use an alternate supplier, which could be

significant to the calculation of unbilled revenue since unbilled commodity receivables are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date would also have an effect on the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

See Note 6 of the Combined Notes to Consolidated Financial Statements for additional information.

Regulated Transmission & Distribution Revenues . ComEd's EIMA distribution formula rate tariff provides for annual reconciliations to the distribution revenue requirement. As of the balance sheet dates, ComEd has recorded its best estimates of the distribution revenue impact resulting from changes in rates that ComEd believes are probable of approval by the ICC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

ComEd's and BGE's FERC transmission formula rate tariffs provide for annual reconciliations to the transmission revenue requirements. As of the balance sheet dates, ComEd and BGE have recorded the best estimate of their respective transmission revenue impact resulting from changes in rates that ComEd and BGE believe are probable of approval by FERC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 6 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2013, 2012 and 2011 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) on Common Stock by Business Segment

	2013	2012 [a]	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Exelon	$1,719	$1,160	$ 559	$2,495	$ (1,335)
Generation	1,070	562	508	1,771	(1,209)
ComEd	249	379	(130)	416	(37)
PECO	388	377	11	385	(8)
BGE	197	(9)	206	123	(132)

(a) For BGE, reflects BGE's operations for the year ended December 31, 2012. For Exelon and Generation, includes the operations of the Constellation and BGE from the date of the merger, March 12, 2012, through December 31, 2012.

Results of Operations—Generation

	2013	2012 [b]	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$15,630	$14,437	$ 1,193	$10,447	$ 3,990
Purchased power and fuel expense	8,197	7,061	(1,136)	3,589	(3,472)
Revenue net of purchased power and fuel expense [a]	7,433	7,376	57	6,858	518
Other operating expenses					
Operating and maintenance	4,534	5,028	494	3,148	(1,880)
Depreciation and amortization	856	768	(88)	570	(198)
Taxes other than income	389	369	(20)	264	(105)
Total other operating expenses	5,779	6,165	386	3,982	(2,183)
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	101	(1)	(90)
Operating income	1,664	1,120	544	2,875	(1,755)
Other income and (deductions)					
Interest expense	(357)	(301)	(56)	(170)	(131)
Other, net	368	239	129	122	117
Total other income and (deductions)	11	(62)	73	(48)	(14)
Income before income taxes	1,675	1,058	617	2,827	(1,769)
Income taxes	615	500	(115)	1,056	556
Net income	1,060	558	502	1,771	(1,213)
Net loss attributable to non-controlling interest	(10)	(4)	(6)	—	4
Net income attributable to membership interest	$ 1,070	$ 562	$ 508	$ 1,771	$ (1,209)

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides

information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b) Includes the operations of Constellation from the date of the merger, March 12, 2012, through December 31, 2012.

Net Income Attributable to Membership Interest

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Generation's net income attributable to membership interest increased compared to the same period in 2012 primarily due to higher revenues, net of purchased power and fuel expense, lower operating and maintenance expense and higher earnings from Generation's interest in CENG; partially offset by impairment of certain generating assets, higher depreciation expense, higher property taxes, and higher interest expense. The increase in revenues, net or purchased power and fuel expense was primarily due to increased capacity prices and higher nuclear volume partially offset by lower realized energy prices, higher nuclear fuel costs, and lower mark-to-market gains in 2013. The decrease in operating and maintenance expense was largely due to 2012 costs associated with a settlement with FERC in 2012 and decreases in transaction costs and employee-related costs associated with the merger.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Generation's net income attributable to membership interest decreased compared to the same period in 2012 primarily due to higher operating expenses, the loss on the sale of Brandon Shores, Wagner and C.P. Crane (collectively Maryland generating stations) and the amortization of acquired energy contracts recorded at fair value at the merger date; offset by higher revenues, net of purchased power and fuel expense and favorable NDT fund performance. The increase in operating expenses was due to the addition of Constellation's financial results from March 12, 2012, costs related to a 2012 settlement with FERC and transaction and employee-related severance costs associated with the merger. The increase in revenues, net of purchased power and fuel expense was also primarily due to the merger. See Note 4 for additional information regarding the loss on the sale of three Maryland generating stations.

Revenue Net of Purchased Power and Fuel Expense

Generation's six reportable segments are based on the geographic location of its assets, and are largely representative of the footprints of an ISO/RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within New York ISO, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
    - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of

Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

- West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
- Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems. Further, the following activities are not allocated to a region, and are reported in Other: compensation under the reliability-must-run rate schedule; results of operations from the Maryland Clean-Coal assets sold in the fourth quarter of 2012; unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities and allocates resources using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements.

For the year ended December 31, 2013 compared to 2012 and 2012 compared to 2011, Generation's revenue net of purchased power and fuel expense by region were as follows:

			2013 vs. 2012			2012 vs. 2011	
	2013	2012 [a]	Variance	% Change	2011	Variance	% Change
Mid-Atlantic [b] [f]	$3,270	$3,433	$ (163)	(4.7)%	$3,350	$ 83	2.5%
Midwest [c]	2,586	2,998	(412)	(13.7)%	3,547	(549)	(15.5)%
New England	185	196	(11)	(5.6)%	9	187	n.m.
New York [f]	(4)	76	(80)	(105.3)%	—	76	n.m.
ERCOT	436	405	31	7.7%	84	321	n.m.
Other Regions [d]	201	131	70	53.4%	(14)	145	n.m.
Total electric revenue net of purchased power and fuel expense	$6,674	$7,239	$ (565)	(7.8)%	$6,976	$ 263	3.8%
Proprietary Trading	(8)	(14)	6	42.9%	24	(38)	n.m.
Mark-to-market gains (losses)	504	515	(11)	(2.1)%	(288)	803	n.m.
Other [e]	263	(364)	627	n.m.	146	(510)	n.m.
Total revenue net of purchased power and fuel expense	$7,433	$7,376	$ 57	0.8%	$6,858	$ 518	7.6%

(a) Includes results for Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.

(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at merger date of $488 million and $1,098 million pre-tax for the twelve months ended December 31, 2013 and December 31, 2012, respectively.
(f) Includes $542 million and $450 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2013. Includes $487 million and $306 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2012. See Note 25 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's supply sources by region are summarized below:

			2013 vs. 2012			2012 vs. 2011	
Supply source (GWh)	2013	2012 [a]	Variance	% Change	2011	Variance	% Change
Nuclear generation [b]							
Mid-Atlantic	48,881	47,337	1,544	3.3%	47,287	50	0.1%
Midwest	93,245	92,525	720	0.8%	92,010	515	0.6%
	142,126	139,862	2,264	1.6%	139,297	565	0.4%
Fossil and renewables [b]							
Mid-Atlantic [b][d]	11,714	8,808	2,906	33.0%	7,572	1,236	16.3%
Midwest	1,478	971	507	52.2%	596	375	62.9%
New England	10,896	9,965	931	9.3%	8	9,957	n.m.
ERCOT	6,453	6,182	271	4.4%	2,030	4,152	n.m.
Other Regions [e]	6,664	5,913	751	12.7%	1,432	4,481	n.m.
	37,205	31,839	5,366	16.9%	11,638	20,201	n.m.
Purchased power							
Mid-Atlantic [c]	14,092	20,830	(6,738)	(32.3)%	2,898	17,932	n.m.
Midwest	4,408	9,805	(5,397)	(55.0)%	5,970	3,835	64.2%
New England	7,655	9,273	(1,618)	(17.4)%	—	9,273	n.m.
New York [c]	13,642	11,457	2,185	19.1%	—	11,457	n.m.
ERCOT	15,063	23,302	(8,239)	(35.4)%	7,537	15,765	n.m.
Other Regions [e]	14,931	17,327	(2,396)	(13.8)%	2,503	14,824	n.m.
	69,791	91,994	(22,203)	(24.1)%	18,908	73,086	n.m.
Total supply by region [f]							
Mid-Atlantic [g]	74,687	76,975	(2,288)	(3.0)%	57,757	19,218	33.3%
Midwest [h]	99,131	103,301	(4,170)	(4.0)%	98,576	4,725	4.8%
New England	18,551	19,238	(687)	(3.6)%	8	19,230	n.m.
New York	13,642	11,457	2,185	19.1%	—	11,457	n.m.
ERCOT	21,516	29,484	(7,968)	(27.0)%	9,567	19,917	n.m.
Other Regions [e]	21,595	23,240	(1,645)	(7.1)%	3,935	19,305	n.m.
Total supply	249,122	263,695	(14,573)	(5.5)%	169,843	93,852	55.3%

(a) Includes results for the Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and does not include ownership through equity method investments (e.g., CENG).
(c) Purchased power includes physical volumes of 12,067 GWh and 9,925 GWh in the Mid-Atlantic and 12,165 GWh and 9,350 GWh in New York as a result of the PPA with CENG for the years ended December 31, 2013 and 2012 respectively.
(d) Excludes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger.
(e) Other Regions includes South, West and Canada, which are not considered individually significant.
(f) Excludes physical proprietary trading volumes of 8,762 GWh, 12,958 GWh and 5,742 GWh for the years ended December 31, 2013, 2012 and 2011 respectively.

(g) Includes sales to PECO through the competitive procurement process of 5,070 GWh, 7,762 GWh, and 7,041 GWh for the years ended December 31, 2013, 2012 and 2011 respectively. Sales to BGE of 5,595 GWh and 3,766 GWh were included for the years ended December 31, 2013 and 2012 respectively.
(h) Includes sales to ComEd under the RFP procurement of 7,491 GWh, 4,152 GWh and 4,731 GWh for the years ended December 31, 2013, 2012 and 2011 respectively.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the year ended December 31, 2013 as compared to the same period in 2012 and 2012 as compared to the same period in 2011.

$/MWh	2013	2012 [a]	2013 vs. 2012 % Change	2011	2012 vs. 2011 % Change
Mid-Atlantic [b]	$43.78	$44.60	(1.8)%	$58.00	(23.1)%
Midwest [c]	26.09	29.02	(10.1)%	35.99	(19.4)%
New England	9.97	10.19	(2.1)%	n.m.	n.m.
New York	(0.29)	6.63	(104.4)%	n.m.	n.m.
ERCOT	20.26	13.74	47.5%	8.78	56.5%
Other Regions [d]	9.31	5.64	65.0%	(3.56)	n.m.
Electric revenue net of purchased power and fuel expense per MWh [e][f]	$26.79	$27.45	(2.4)%	$41.07	(33.2)%

(a) Includes financial results for the Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes sales to PECO of $405 million (5,070 GWh), $536 million (7,762 GWh) and $508 million (7,041 GWh) for the years ended December 31, 2013, 2012 and 2011, respectively. Sales to BGE of $455 million (5,595 GWh) and $322 million (3,766 GWh) were included for the years ended December 31, 2013 and 2012 respectively. Excludes compensation under the reliability-must-run rate schedule and the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the merger.
(c) Includes sales to ComEd of $283 million (7,491 GWh), $162 million (4,152 GWh) and $179 million (4,731 GWhs) and settlements of the ComEd swap of $230 million, $627 million and $474 million for years ended December 31, 2013, 2012 and 2011, respectively.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Revenue net of purchased power and fuel expense per MWh represents the average margin per MWh of electricity sold during the years ended December 31, 2013, 2012 and 2011, respectively, and excludes the mark-to-market impact of Generation's economic hedging activities.
(f) Excludes Generation's other business activities not allocated to a region, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency, energy management and demand response. Also excludes Generation's compensation under the reliability-must-run rate schedule, the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the Exelon and Constellation merger of $488 million and $1,098 million, respectively.

Mid-Atlantic

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $163 million was primarily due to lower realized power prices and increased nuclear fuel costs, partially offset by the addition of Constellation in 2012, higher capacity revenues, and higher nuclear revenues.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $83 million was primarily due to the addition of Constellation in 2012 and higher capacity revenues, partially offset by lower realized power prices and increased nuclear fuel costs.

Midwest

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The decrease in revenue net of purchased power and fuel expense in the Midwest of $412 million was primarily due to lower realized power prices, increased nuclear fuel costs, and lower capacity revenues, partially offset by higher nuclear revenues.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The decrease in revenue net of purchased power and fuel expense in the Midwest of $549 million was primarily due to lower capacity revenues, increased nuclear fuel costs, and lower realized power prices, partially offset by decreased congestion costs.

New England

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The $11 million decrease in revenue net of purchased power and fuel expense in New England is primarily due to lower realized energy prices, partially offset by the addition of Constellation in 2012. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The $187 million increase in revenue net of purchased power and fuel expense in New England was the result of the Constellation merger. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

New York

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $80 million decrease in revenue net of purchased power and fuel expense in New York was primarily due to decreased realized energy prices, partially offset by the addition of Constellation. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The $76 million increase in revenue net of purchased power and fuel expense in New York was the result of the Constellation merger. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

ERCOT

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $31 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily due to increased realized energy prices and the addition of Constellation in 2012, partially offset by a decrease due to the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $321 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the addition of Constellation in 2012, partially offset by a decrease in revenue net of purchased power and fuel expense in the legacy Generation ERCOT portfolio driven by the performance of Generation’s generating units during extreme weather events that occurred in Texas in February and August 2011.

Other Regions

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $70 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the addition of Constellation in 2012, in addition to increased renewable generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $145 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the Constellation merger.

Mark-to-market

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $504 million in 2013 compared to gains of $515 million in 2012. See Notes 11 and 12 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $515 million in 2012 compared to losses of $288 million in 2011. See Note 11 and 12 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $627 million increase in other revenue net of purchased power and fuel was primarily due to reduced amortization expense of the acquired energy contracts recorded at fair value at the merger date. In addition, the increase is also attributable to results from activities acquired as part of the 2012 merger with Constellation including retail gas, energy efficiency, energy management and demand response, upstream natural gas, and the design and construction of renewable energy facilities. These increases were partially offset by the reduction in revenues net of purchased power and fuel expense from the sale of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $510 million decrease in other revenue net of purchased power and fuel was primarily due to increased amortization expense of the acquired energy contracts recorded at fair value at the merger date. This decrease was partially offset by results from activities acquired as part of the 2012 merger with Constellation including retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, other revenue net of purchased power and fuel includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in fourth quarter of 2012 as a result of the Exelon and Constellation merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for 2013, as compared to 2012 and 2011, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined

as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	2013	2012	2011
Nuclear fleet capacity factor [(a)]	94.1%	92.7%	93.3%
Nuclear fleet production cost per MWh [(a)]	$19.83	$19.50	$18.86

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC, and CENG's nuclear facilities, which are operated by CENG. Reflects ownership percentage of stations operated by Exelon.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The nuclear fleet capacity factor, which excludes Salem, increased primarily due to a lower number of planned refueling outage days in 2013, partially offset by a higher number of non-refueling outage days. For 2013 and 2012, planned refueling outage days totaled 233 and 274, respectively, and non-refueling outage days totaled 75 and 73, respectively. Higher nuclear fuel costs and higher plant operating and maintenance costs, partially offset by higher number of net MWhs generated resulted in a higher production cost per MWh during 2013 as compared to 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of non-refueling outage days, partially offset by a lower number of planned refueling outage days in 2012. For 2012 and 2011, planned refueling outage days totaled 274 and 283, respectively, and non-refueling outage days totaled 73 and 52, respectively. Higher nuclear fuel costs resulted in a higher production cost per MWh during 2012 as compared to 2011.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2013 compared to 2012, consisted of the following:

	Increase (Decrease)
Plant retirements and divestitures [(a)]	$ (440)
FERC settlement [(b)]	(195)
Constellation merger and integration costs	(107)
Maryland commitments	(35)
Bodily injury costs [(c)]	(16)
Nuclear refueling outage costs, including the co-owned Salem plant [(d)]	(14)
Corporate allocations [(e)]	(5)
Labor, other benefits, contracting and materials [(f)]	160
Impairment and related charges of certain generating assets	160
Midwest generation bankruptcy charges	11
Pension and non-pension postretirement benefits expense	5
Other	(18)
Decrease in operating and maintenance expense	$ (494)

(a) Reflects the operating and maintenance expense associated with the generating assets retired or divested during 2012.
(b) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation's prior period hedging and risk management transactions.
(c) Reflects decreased asbestos-related bodily injury expense for 2013 compared to 2012.
(d) Reflects the impact of decreased planned refueling outage days during 2013.
(e) The decrease in cost allocations during 2013 primarily reflects merger synergy savings for Exelon's corporate operations and shared service entities, partially offset by the impact of an increased share of corporate allocated costs due to the merger.
(f) Includes cost of sales of our other business activities that are not allocated to a region.

The changes in operating and maintenance expense for 2012 compared to 2011, consisted of the following:

	Increase (Decrease)
Labor, other benefits, contracting and materials [a]	$ 845
Loss on the sale of Maryland Clean Coal assets [b]	278
FERC settlement [c]	195
Constellation merger and integration costs	182
Corporate allocations [d]	175
Pension and non-pension postretirement benefits expense	76
Maryland commitments [e]	35
Nuclear refueling outage costs, including the co-owned Salem plant [f]	(52)
Other	146
Increase in operating and maintenance expense	$ 1,880

(a) Includes cost of sales of our other business activities that are not allocated to a region.
(b) Represents expense recorded during the third quarter of 2012 due to the reduction in book value. Upon completion of the November 30, 2012 transaction, Generation recorded a $6 million gain within Other, net in its Consolidated Statements of Operations and Comprehensive Income. The net loss on the sale of the Maryland Clean Coal assets was $272 million. See 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(c) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation's prior period hedging and risk management transactions.
(d) Reflects an increased share of corporate allocated costs due to the merger.
(e) Reflects costs incurred as part of the Maryland order approving the merger.
(f) Reflects the impact of decreased planned refueling outages during 2012.

Depreciation and Amortization

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities and ongoing capital additions.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities; and capital additions and other upgrades to legacy plants.

Taxes Other Than Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The increase was primarily due to the addition of Constellation's financial results in 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The increase was primarily due to the addition of Constellation's financial results in 2012.

Equity in Earnings (Losses) of Unconsolidated Affiliates

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . Equity in earnings (losses) of unconsolidated affiliates increased primarily due to $50 million favorable net income generated from Exelon's equity investment in CENG and a reduction of $58 million of amortization of the basis difference in CENG recorded at fair value at the merger date.

Interest Expense

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger and increased project financing.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger.

Other, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The increase of $129 million in other, net primarily reflects $85 million of credit facility termination fees recorded in 2012 and increased net realized and unrealized gains related to the NDT funds of Generation's Non-Regulatory Agreement Units compared to net realized and unrealized gains in 2012, as described in the table below. Additionally, the increase reflects income related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011 . The increase of $117 million in other, net primarily reflects a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow, $32 million of interest income from a one-time NDT fund special transfer tax deduction in 2011, net realized and unrealized gains related to the NDT funds of Generation's Non-Regulatory Agreement Units compared to net realized and unrealized losses in 2011, as described in the table below, offset by $85 million of credit facility termination fees recorded in 2012. Additionally, the increase reflects income related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for 2013, 2012 and 2011:

	2013	2012	2011
Net unrealized gains (losses) on decommissioning trust funds	$146	$105	$ (4)
Net realized gains (losses) on sale of decommissioning trust funds	$ 24	$ 51	$(10)

Effective Income Tax Rate.

Generation's effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 36.7%, 47.3% and 37.4%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—ComEd

	2013	2012	Favorable (Unfavorable) 2013 vs. 2012 Variance	2011	Favorable (Unfavorable) 2012 vs. 2011 Variance
Operating revenues	$4,464	$5,443	$ (979)	$6,056	$ (613)
Purchased power expense	1,174	2,307	1,133	3,035	728
Revenues net of purchased power expense [(a)]	3,290	3,136	154	3,021	115
Other operating expenses					
Operating and maintenance	1,368	1,345	(23)	1,189	(156)
Depreciation and amortization	669	610	(59)	554	(56)
Taxes other than income	299	295	(4)	296	1
Total other operating expenses	2,336	2,250	(86)	2,039	(211)
Operating income	954	886	68	982	(96)
Other income and (deductions)					
Interest expense, net	(579)	(307)	(272)	(345)	38
Other, net	26	39	(13)	29	10
Total other income and (deductions)	(553)	(268)	(285)	(316)	48
Income before income taxes	401	618	(217)	666	(48)
Income taxes	152	239	87	250	11
Net income	$ 249	$ 379	$ (130)	$ 416	$ (37)

(a) ComEd evaluates its operating performance using the measure of revenues net of purchased power expense. ComEd believes that revenues net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of revenues net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2013, Compared to Year Ended December 31, 2012. ComEd's net income for the year ended December 31, 2013, was lower than the same period in 2012, primarily due to the remeasurement of Exelon's like-kind exchange tax position, partially offset by increased electric distribution revenues, including the impacts of Senate Bill 9, and increased transmission revenues. See Note 3—Regulatory Matters and Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Year Ended December 31, 2012, Compared to Year Ended December 31, 2011. ComEd's net income for the year ended December 31, 2012, was lower than the same period in 2011, primarily due to increased operating and maintenance expenses, partially offset by increased electric distribution revenues and increased transmission revenues.

Operating Revenues Net of Purchased Power Expense

There are certain drivers of operating revenues that are fully offset by their impact on purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on revenues net of purchased power expense. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries, but do affect ComEd's operating revenues related to supplied energy, which is fully offset in purchased power expense. Therefore, customer choice programs have no impact on revenues net of purchased power expense.

The number of retail customers participating in customer choice programs was 2,630,185, 1,627,150 and 380,262 at December 31, 2013, 2012 and 2011, respectively, representing 68%, 43% and 10% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 81%, 65% and 56% of ComEd's retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. During 2012, the City of Chicago and approximately 240 Illinois municipalities, including governmental entities such as townships and counties, approved referenda regarding electric supply aggregation. The referenda allowed governmental officials to identify and sign contracts with competitive electric generation suppliers on behalf of the eligible retail customers in the community, while also allowing customers to opt-out of the municipal aggregation program. As of December 31, 2013, there are approximately 330 municipalities that have approved a municipal aggregation referendum in the ComEd service territory. As a result, approximately 69% of residential usage as of December 31, 2013 is being supplied by competitive electric generation suppliers, and ComEd estimates that over 80% of that usage resulted from municipal aggregation activities.

The changes in ComEd's revenues net of purchased power expense for the year ended 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)
Weather	$ (17)
Volume	(2)
Electric distribution revenues, including impacts of Senate Bill 9	168
Discrete impacts of the 2012 Distribution Rate Case Order	13
Transmission revenues	14
Regulatory required programs	20
Uncollectible accounts recovery, net	(58)
Other	16
Total increase	$ 154

Weather. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the year ended December 31, 2013, the increase in revenues net of purchased power expense was offset by unfavorable weather conditions as a result of the mild weather in 2013, compared to the same period in 2012.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2013 and 2012 consisted of the following:

Heating and Cooling Degree-Days Twelve Months Ended December 31,	2013	2012	Normal	% Change From 2012	% Change From Normal
Heating Degree-Days	6,603	5,065	6,341	30.4%	4.1%
Cooling Degree-Days	933	1,324	842	(29.5)%	10.8%

Volume. Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the year ended December 31, 2013, reflecting decreased average usage per residential customer as compared to the same period in 2012.

Electric Distribution Revenues. EIMA provides for a performance-based formula rate tariff, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Distribution revenues vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. During the year ended December 31, 2013, ComEd recorded increased revenues of $168 million, primarily due to increased capital investments, increased operating expenses, and higher allowed return on common equity, including the impacts of Senate Bill 9. These amounts exclude the discrete impacts of the 2012 Distribution Rate Case Orders, discussed separately below. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Orders. On October 3, 2012, the ICC issued its final order related to ComEd's 2011 formula rate proceeding under EIMA (Rehearing Order), which reestablished ComEd's position on the return on its pension asset, resulting in an increase to revenues in 2013. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update, filed in April 2013, reflects 2012 actual costs plus forecasted 2013 capital additions. Transmission revenues vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. During the year ended December 31, 2013, ComEd recorded increased revenues of $14 million primarily due to increased capital investments and higher operating expenses. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. Revenues related to regulatory required programs are recoveries from customers for costs of various legislative and regulatory programs on a full and current basis through approved regulated rates. Programs include ComEd's energy efficiency and demand response and purchased power administrative costs. An equal and offsetting amount has been reflected in operating and maintenance expense during the periods presented. See the operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Represents recoveries under ComEd's uncollectible accounts tariff. See the operating and maintenance expense discussion below for additional information on this tariff.

Other. Other revenues, which can vary period to period, include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental costs associated with MGP sites. Other revenues were higher during the year ended December 31, 2013, compared to the same period in 2012, primarily due to recoveries of increased environmental costs associated with MGP sites, for which an equal and offsetting amount expense is reflected in depreciation and amortization expense during the periods presented.

The changes in ComEd's revenues net of purchased power expense for 2012 compared to 2011 consisted of the following:

	Increase (Decrease)
Weather	$ 2
Volume	(4)
Electric distribution revenues	53
Discrete impacts of the 2012 Distribution Rate Case Order	(13)
Transmission revenues	40
Regulatory required programs	32
Uncollectible accounts recovery, net	(28)
Other	33
Total increase	$ 115

Weather. For the year ended December 31, 2012, revenues net of purchased power expense increased due to favorable weather conditions in 2012 compared to the same period in 2011.

The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2012 and 2011 consisted of the following:

Heating and Cooling Degree-Days Twelve Months Ended December 31,	2012	2011	Normal	% Change From 2011	% Change From Normal
Heating Degree-Days	5,065	6,134	6,341	(17.4)%	(20.1)%
Cooling Degree-Days	1,324	1,036	842	27.8%	57.2%

Volume. Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the year ended December 31, 2012, reflecting decreased average usage per residential customer as compared to the same period in 2011.

Electric Distribution Revenues. Under EIMA, ComEd recorded increased revenues during the year ended December 31, 2012 of $53 million, primarily due to increased capital investments and increased operating expenses, partially offset by lower allowed return on common equity. These amounts exclude the discrete impacts of the 2012 Distribution Rate Case Orders discussed separately below. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Orders. The May and October 2012 ICC Distribution Rate Case Orders resulted in a reduction to revenues of $13 million in 2012 compared to the same period in 2011. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. Based on the FERC-approved formula, ComEd recorded increased revenues during the year ended December 31, 2012 of $40 million, primarily due to increased operating expenses. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Operating and Maintenance Expense

	Year Ended December 31,		Increase 2013 vs. 2012	Year Ended December 31,		Increase 2012 vs. 2011
	2013	2012		2012	2011	
Operating and maintenance expense—baseline	$1,202	$1,199	$ 3	$1,199	$1,075	$ 124
Operating and maintenance expense—regulatory required programs [(a)]	166	146	20	146	114	32
Total operating and maintenance expense	$1,368	$1,345	$ 23	$1,345	$1,189	$ 156

(a) Operating and maintenance expense for regulatory required programs are recoveries from customers for costs of various legislative and regulatory programs on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for year ended December 31, 2013, compared to the same period in 2012 and changes for the year ended December 31, 2012, compared to the same period in 2011, consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Baseline		
Labor, other benefits, contracting and materials [(a)]	$ 48	$ 95
Pension and non-pension postretirement benefits expense	3	46
Discrete impacts from 2010 Rate Case order [(b)]	—	32
Storm-related costs	(10)	(1)
Science and Technology Innovation Trust [(c)]	—	(11)
Uncollectible accounts expense—provision [(d)]	(10)	(14)
Uncollectible accounts expense—recovery, net [(d)]	(48)	(14)
Other	20	(9)
	3	124
Regulatory required programs		
Energy efficiency and demand response programs	20	33
Purchased power administrative costs	—	(1)
	20	32
Increase in operating and maintenance expense	$ 23	$ 156

(a) The increase includes contracting costs resulting from new projects associated with EIMA for the years ended December 31, 2013 and 2012. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding EIMA.
(b) ComEd recorded one-time net benefits in May 2012 as a result of the 2010 Rate Case order to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan.
(c) Under EIMA, ComEd makes recurring payments for contribution to a Science and Technology Innovation Trust fund that will be used to fund energy innovation.
(d) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. In 2013, ComEd recorded a net reduction in operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers as a result of municipal aggregation. An equal and offsetting reduction has been recognized in operating revenues for the periods presented.

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Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2013 compared to 2012 and 2012 compared to 2011, consisted of the following:

	Increase 2013 vs. 2012	Increase 2012 vs. 2011
Depreciation associated with higher plant balances	$ 22	$ 22
Amortization of storm-related regulatory assets [(a)]	4	4
Amortization of MGP regulatory assets [(b)]	27	8
Amortization of other regulatory assets	6	6
Other	—	16
Increase in depreciation and amortization expense	$ 59	$ 56

(a) Under EIMA, ComEd is required to recover costs associated with significant storms over a five-year period through the amortization of a regulatory asset.
(b) An equal and offsetting amount for the amortization expense related to MGP remediation expenditures is reflected in operating revenues during the periods presented.

Taxes Other Than Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income increased primarily due to increased Illinois electricity distribution taxes.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Taxes other than income taxes decreased primarily due to decreased Illinois electricity distribution taxes.

Interest Expense, Net

The changes in interest expense, net for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Interest expense related to uncertain tax positions [(a)]	$ 281	$ —
Interest expense on debt (including financing trusts)	2	(26)
Other	(11)	(12)
Increase (decrease) in interest expense, net	$ 272	$ (38)

(a) Primarily reflects the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net

The changes in other, net for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Interest income related to uncertain tax positions [(a)]	$ (20)	$ 16
Gain on asset disposal	5	—
Other	2	(6)
Increase in Other, net	$ (13)	$ 10

(a) Primarily reflects a receivable recorded in the fourth quarter of 2012 related to the final 1999-2001 IRS settlement.

Effective Income Tax Rate

ComEd's effective income tax rates for the years ended December 31, 2013, 2012 and 2011, were 37.9%, 38.7% and 37.5%, respectively. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Retail Deliveries to customers (in GWhs)	2013	2012	% Change 2013 vs 2012	Weather-Normal % Change	2011	% Change 2012 vs 2011	Weather-Normal % Change
Retail Deliveries [a]							
Residential	27,800	28,528	(2.6)%	(0.6)%	28,273	0.9%	(0.6)%
Small commercial & industrial	32,305	32,534	(0.7)%	0.2%	32,281	0.8%	0.2%
Large commercial & industrial	27,684	27,643	0.1%	(0.3)%	27,732	(0.3)%	(0.3)%
Public authorities & electric railroads	1,355	1,272	6.5%	4.2%	1,235	3.0%	4.2%
Total Retail Deliveries	89,144	89,977	(0.9)%	(0.1)%	89,521	0.5%	(0.1)%

Number of Electric Customers	As of December 31, 2013	2012	2011
Residential	3,480,398	3,455,546	3,448,481
Small commercial & industrial	367,569	365,357	365,824
Large commercial & industrial	1,984	1,980	2,032
Public authorities & electric railroads	4,853	4,812	4,797
Total	3,854,804	3,827,695	3,821,134

Electric Revenue	2013	2012	% Change 2013 vs 2012	2011	% Change 2012 vs 2011
Retail Sales [a]					
Residential	$2,073	$3,037	(31.7)%	$3,510	(13.5)%
Small commercial & industrial	1,250	1,339	(6.6)%	1,517	(11.7)%
Large commercial & industrial	427	395	8.1%	383	3.1%
Public authorities & electric railroads	48	44	9.1%	50	(12.0)%
Total Retail Sales	3,798	4,815	(21.1)%	5,460	(11.8)%
Other Revenue [b]	666	628	6.1%	596	5.4%
Total Electric Revenues	$4,464	$5,443	(18.0)%	$6,056	(10.1)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other items include wholesale revenue, rental revenue, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental remediation costs associated with MGP sites, and intercompany revenues.

Results of Operations—PECO

	2013	2012	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$3,100	$3,186	$ (86)	$3,720	$ (534)
Purchased power and fuel	1,300	1,375	75	1,864	489
Revenues net of purchased power and fuel expense [(a)]	1,800	1,811	(11)	1,856	(45)
Other operating expenses					
Operating and maintenance	748	809	61	794	(15)
Depreciation and amortization	228	217	(11)	202	(15)
Taxes other than income	158	162	4	205	43
Total other operating expenses	1,134	1,188	54	1,201	13
Operating income	666	623	43	655	(32)
Other income and (deductions)					
Interest expense, net	(115)	(123)	8	(134)	11
Other, net	6	8	(2)	14	(6)
Total other income and (deductions)	(109)	(115)	6	(120)	5
Income before income taxes	557	508	49	535	(27)
Income taxes	162	127	(35)	146	19
Net income	395	381	14	389	(8)
Preferred security dividends	7	4	3	4	—
Net income on common stock	$ 388	$ 377	$ 11	$ 385	$ (8)

(a) PECO evaluates its operating performance using the measures of revenues net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenues net of purchased power expense and revenues net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenues from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in net income was driven primarily by lower operating and maintenance expense partially offset by an increase in income taxes.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by lower operating revenues net of purchased power and fuel expense and increased storm costs. The decrease in revenues net of purchased power and fuel expense was primarily related to unfavorable weather and a decline in electric load. The decrease to net income was partially offset by lower taxes other than income, interest expense and income taxes.

Operating Revenues Net of Purchased Power and Fuel Expense

Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates

in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenues net of purchased power and fuel expense.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the customer choice program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenues collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenues net of purchase power and fuel expense. The number of retail customers purchasing energy from a competitive electric generation supplier was 531,500, 496,500, and 387,600 at December 31, 2013, 2012 and 2011, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 68%, 66%, and 57% of PECO's retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 66,400, 53,600, and 24,800 at December 31, 2013, 2012 and 2011, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 19%, 16%, and 11% of PECO's mmcf sales for the years ended December 31, 2013, 2012 and 2011, respectively.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 6	$ 31	$ 37
Volume	(3)	(3)	(6)
Pricing	(14)	2	(12)
Regulatory required programs	(6)	—	(6)
Gross receipts tax	(8)	—	(8)
Gas distribution tax repair	—	(8)	(8)
Other	(7)	(1)	(8)
Total decrease	$ (32)	$ 21	$(11)

Weather

The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. Operating revenues net of purchased power and fuel expense were higher due to the impact of favorable 2013 winter weather conditions.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2013 compared to the same period in 2012 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	2013	2012	Normal	From 2012	From Normal
Twelve Months Ended December 31,					
Heating Degree-Days	4,474	3,747	4,603	19.4%	(2.8)%
Cooling Degree-Days	1,411	1,603	1,301	(12.0)%	8.5%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflects the impact of energy efficiency initiatives on customer usages as well as a shift in the volume profile across classes from higher priced classes to lower priced classes, partially offset by the oil refineries returning to full production in 2013 as well as moderate economic growth. The decrease in gas revenues net of fuel expense related to delivery volume, exclusive of the effects of weather, primarily reflects a decline in Residential use per customer.

Pricing

The decrease in electric operating revenues net of purchased power expense as a result of pricing is primarily attributable to lower overall effective rates due to increased usage across all major customer classes.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Gross Receipts Tax

GRT is an excise tax on total electric revenues. As a result of decreases in operating revenues compared to 2012, GRT decreased. Equal and offsetting decreases in GRT have been reflected in taxes other than income.

Gas Distribution Tax Repair

The decrease in gas distribution tax repair reflects the 2012 tax benefit received from prior period gas distribution repairs for the 2011 tax year. There is an equal and offsetting tax benefit in operating revenues, see NOTE 3—Regulatory Matters for further explanation.

Other

The decrease in other electric revenues net of purchased power expense compared to the year ended December 31, 2012 reflects a decrease in wholesale transmission revenues earned by PECO due to higher peak loads in the previous years.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (17)	$(15)	$(32)
Volume	(22)	—	(22)
Pricing	(4)	3	(1)
Regulatory required programs	29	—	29
Gross receipts tax	(27)	—	(27)
Other	8	—	8
Total increase (decrease)	$ (33)	$(12)	$(45)

Weather

Electric and gas revenues net of purchased power and fuel expense were lower due to unfavorable winter weather conditions during 2012 in PECO's service territory.

The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2012 compared to the same period in 2011 and normal weather consisted of the following:

Heating and Cooling Degree-Days [a]	2012	2011	Normal	% Change From 2011	% Change From Normal
Twelve Months Ended December 31,					
Heating Degree-Days	3,747	4,157	4,603	(9.9)%	(18.6)%
Cooling Degree-Days	1,603	1,617	1,301	(0.9)%	23.2%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected the reduced oil refinery load in PECO's service territory and the impact of energy efficiency initiatives and weak economic conditions on customer usage. See Note 3 of the Combined Notes to Consolidated Financial Statements for further information regarding energy efficiency initiatives.

Pricing

The decrease in electric operating revenues net of purchased power expense as a result of pricing is primarily attributable to lower overall effective rates due to increased usage across all major customer classes.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other

The decrease in other electric revenues net of purchased power expense primarily reflected a decrease in GRT revenues as a result of lower supplied energy service and a reduction in the GRT rate. There is an equal and offsetting decrease in GRT expense included in taxes other than income.

Operating and Maintenance Expense

	Twelve Months Ended December 31, 2013	2012	Increase (Decrease) 2013 vs. 2012	Twelve Months Ended December 31, 2012	2011	Increase (Decrease) 2012 vs. 2011
Operating and Maintenance Expense—Baseline	$ 668	$ 723	$ (55)	$ 723	$ 725	$ (2)
Operating and Maintenance Expense—Regulatory Required Programs [(a)]	80	86	(6)	86	69	17
Total Operating and Maintenance Expense	$ 748	$ 809	$ (61)	$ 809	$ 794	$ 15

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Baseline		
Labor, other benefits, contracting and materials	$ 10	$ (29)
Storm-related costs	(49)	9[(a)]
Pension and non-pension postretirement benefits expense	(12)	—
Constellation merger and integration costs	(8)	15
Other	4	3
	(55)	(2)
Regulatory Required Programs		
Smart Meter	4	12
Energy Efficiency	(9)	8
GSA	—	(1)
Consumer education program	(1)	(1)
AEPS	—	(1)
	(6)	17
Increase (decrease) in operating and maintenance expense	$ (61)	$ 15

(a) Storm-related costs include $46 million of incremental storm costs incurred in the fourth quarter of 2012 as a result of Hurricane Sandy. This expense was significantly offset by the costs incurred related to Hurricane Irene and other storms throughout 2011.

Depreciation and Amortization Expense

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in depreciation and amortization expense, net for 2013, compared to 2012 was primarily due to ongoing capital expenditures.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in depreciation and amortization expense, net for 2012 compared to 2011 was primarily due to ongoing capital expenditures.

Taxes Other Than Income

The change in taxes other than income for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
GRT expense	$ (12)	$ (33)
Sales and use tax	8	(12) [a]
Other	—	2
Decrease in taxes other than income	$ (4)	$ (43)

(a) The decrease reflects a sales and use tax reserve adjustment in the first quarter of 2012 resulting from the completion of the audit of tax years 2005 through 2010.

Interest Expense, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in interest expense, net for 2013 compared to 2012 was primarily due to refinancing debt at lower interest rates during the second half of 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in interest expense, net for 2012 compared to 2011 was primarily due to the debt retirement in November 2011.

Other, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Other, net remained relatively level between periods.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in Other, net for 2012 compared to 2011 was due to decreased AFUDC—Equity. See Note 20 of the Combined Notes to Consolidated Financial Statements in the 2012 10-K for additional details of the components of Other, net.

Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 29.1%, 25.0% and 27.3%, respectively. The increase in effective income tax rate in 2013 compared 2012 reflects the 2012 impact of the tax benefit received from electing to change the method of accounting for gas distribution property for the 2011 tax year. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries [a]							
Residential	13,341	13,233	0.8%	(0.0)%	13,687	(3.3)%	(1.7)%
Small commercial & industrial	8,101	8,063	0.5%	(1.1)%	8,321	(3.1)%	(2.3)%
Large commercial & industrial	15,379	15,253	0.8%	1.5%	15,677	(2.7)%	(2.7)%
Public authorities & electric railroads	930	943	(1.4)%	(1.4)%	945	(0.2)%	(0.2)%
Total Electric Retail Deliveries	37,751	37,492	0.7%	0.3%	38,630	(2.9)%	(2.2)%

Number of Electric Customers	As of December 31, 2013	2012	2011
Residential	1,423,068	1,417,773	1,415,681
Small commercial & industrial	149,117	148,803	148,570
Large commercial & industrial	3,105	3,111	3,110
Public authorities & electric railroads	9,668	9,660	9,689
Total	1,584,958	1,579,347	1,577,050

Electric Revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales [a]					
Residential	$1,592	$1,689	(5.7)%	$1,934	(12.7)%
Small commercial & industrial	433	462	(6.3)%	585	(21.0)%
Large commercial & industrial	224	232	(3.4)%	308	(24.7)%
Public authorities & electric railroads	30	31	(3.2)%	38	(18.4)%
Total Retail	2,279	2,414	(5.6)%	2,865	(15.7)%
Other Revenue [b]	221	226	(2.2)%	244	(7.4)%
Total Electric Revenues	$2,500	$2,640	(5.3)%	$3,109	(15.1)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries [b]							
Retail sales	57,613	49,767	15.8%	(0.1)%	54,239	(8.2)%	(0.1)%
Transportation and other	28,089	26,687	5.3%	0.5%	28,204	(5.4)%	(4.8)%
Total Gas Deliveries	85,702	76,454	12.1%	0.1%	82,443	(7.3)%	(1.6)%

Number of Gas Customers	As of December 31, 2013	2012	2011
Residential	458,356	454,502	451,382
Commercial & industrial	42,174	41,836	41,373
Total Retail	500,530	496,338	492,755
Transportation	909	903	879
Total	501,439	497,241	493,634

Gas revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales [a]					
Retail sales	$562	$509	10.4%	$576	(11.6)%
Transportation and other	38	37	2.7%	35	5.7%
Total Gas Revenues	$600	$546	9.9%	$611	(10.6)%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

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Results of Operations—BGE

	2013	2012	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$3,065	$2,735	$ 330	$3,068	$ (333)
Purchased power and fuel expense	1,421	1,369	(52)	1,593	224
Revenue net of purchased power and fuel expense [(a)]	1,644	1,366	278	1,475	(109)
Other operating expenses					
Operating and maintenance	634	728	94	680	(48)
Depreciation and amortization	348	298	(50)	274	(24)
Taxes other than income	213	208	(5)	207	(1)
Total other operating expenses	1,195	1,234	39	1,161	(73)
Operating income	449	132	317	314	(182)
Other income and (deductions)					
Interest expense, net	(122)	(144)	22	(129)	(15)
Other, net	17	23	(6)	26	(3)
Total other income and (deductions)	(105)	(121)	16	(103)	(18)
Income before income taxes	344	11	333	211	(200)
Income taxes	134	7	(127)	75	68
Net income	210	4	206	136	(132)
Preference stock dividends	13	13	—	13	—
Net income (loss) attributable to common shareholder	$ 197	$ (9)	$ 206	$ 123	$ (132)

(a) BGE evaluates its operating performance using the measures of revenues net of purchased power expense for electric sales and revenues net of fuel expense for gas sales. BGE believes revenues net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenues from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in net income was driven primarily by higher distribution rates as a result of the 2012 rate order issued by MDPSC and decreased operating revenues net of purchased power and fuel expense in 2012 related to the accrual of the residential customer rate credit provided as a condition of the MDPSC's approval of Exelon's merger with Constellation. Additionally, the increase in net income was also driven by higher operating and maintenance expenses in 2012, primarily related to BGE's accrual of its portion of the charitable contributions to be provided as a condition of the MDPSC's approval of the merger and lower storm restoration costs in 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by decreased operating revenues net of purchased power and fuel expense related to the residential customer rate credit provided as a condition of the MDPSC's approval of Exelon's merger with Constellation. The decrease in net income was also driven by increased operating and maintenance expenses, primarily related to BGE's accrual of its portion of the charitable contributions to be provided as a condition of the MDPSC's approval of the merger as well

as merger transaction costs, and increased depreciation and amortization expense. None of the customer rate credit, the charitable contributions, or the transaction costs are recoverable from BGE's customers.

Operating Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive electric generation supplier affects electric SOS revenues and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenues and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric generation supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive electric generation supplier was 399,000, 362,000 and 314,000 at December 31, 2013, 2012 and 2011, respectively, representing 32%, 29% and 25% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 61%, 60% and 58% of BGE's retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 172,000, 143,000 and 118,000 at December 31, 2013, 2012 and 2011, respectively, representing 26%, 22% and 18% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 54%, 56% and 52% of BGE's retail mmcf sales for the years ended December 31, 2013, 2012 and 2011, respectively.

The changes in BGE's operating revenues net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
2012 Residential customer rate credit [(a)]	$ 82	$31	$113
Pricing	69	24	93
Regulatory program cost recovery	36	6	42
Other	26	4	30
Total increase	$ 213	$65	$278

(a) In accordance with the MDPSC order approving Exelon's merger with Constellation, the residential customer rate credit is not recoverable from BGE's customers. Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

Revenue Decoupling. The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class,

regardless of changes in consumption levels. This allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the year ended December 31, 2013 compared to the same period in 2012 and normal weather consisted of the following:

Heating and Cooling Degree-Days Twelve Months Ended December 31,	2013	2012	Normal	% Change From 2012	% Change From Normal
Heating Degree-Days	4,744	3,960	4,661	19.8%	1.8%
Cooling Degree-Days	869	1,022	864	(15.0)%	0.6%

2012 Residential Customer Rate Credit.

The increase in operating revenues net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 was due to the residential customer rate credit provided in 2012 as a result of the MDPSC's order approving Exelon's merger with Constellation.

Pricing.

The increase in operating revenues net of purchased power and fuel expense as a result of pricing for the year ended December 31, 2013 compared to the same period in 2012 was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 and December 13, 2013 in accordance with the MDPSC approved electric and natural gas distribution rate case order. See Note 3—Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs.

This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the year ended December 31, 2013 compared to the same period in 2012 was due to the recovery of higher energy efficiency program costs.

Other .

Other revenues increased during the year ended December 31, 2013 compared to the same period in 2012. Other revenues, which can vary from period to period, include miscellaneous revenues such as service application and late payment fees.

The changes in BGE's operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
2012 Residential customer rate credit	$ (82)	$(31)	$(113)
Commodity margin	(1)	(5)	(6)
Regulatory program cost recovery	15	4	19
Transmission	11	—	11
Other	(13)	(7)	(20)
Total decrease	$ (70)	$(39)	$(109)

The changes in heating and cooling degree days for the twelve months ended 2012 and 2011, consisted of the following:

Heating and Cooling Degree-Days [a]	2012	2011	Normal	% Change From 2011	% Change From Normal
Twelve Months Ended December 31,					
Heating Degree-Days	3,960	4,326	4,711	(8.5)%	(15.9)%
Cooling Degree-Days	1,022	1,035	858	(1.3)%	19.1%

2012 Residential Customer Rate Credit

The residential customer rate credit provided as a result of the MDPSC's order approving Exelon's merger with Constellation decreased operating revenues net of purchased power and fuel expense for the year ended December 31, 2012.

Commodity Margin

The commodity margin for both electric and gas revenues decreased during the year ended December 31, 2012 compared to the same period in 2011 due to an increase in the number of customers using competitive suppliers in 2012.

Regulatory Required Programs

This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the year ended December 31, 2012 compared to the same period in 2011 was due to the recovery of higher energy efficiency programs costs.

Transmission

Transmission revenues increased during the year ended December 31, 2012 compared to the same period in 2011 due to higher revenue requirements. BGE's transmission rates are established based on a FERC-approved formula. The rates also include transmission investment incentives approved by FERC in a number of orders covering various new transmission investment projects since 2007.

Other

Other revenues decreased during the year ended December 31, 2012 compared to the same period in 2011. Other revenues, which can vary from period to period, include miscellaneous revenues such as service application and late payment fees.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Charitable contributions [a]	$ (28)	$ 28
Storm costs deferral [b]	—	16
Storm-related costs [c]	(62)	7
Pension and non-pension postretirement benefits expense	—	6
Labor, other benefits, contracting and materials	20	(10)
Merger transaction costs [a]	(21)	(9)
Other	(3)	10
(Decrease) Increase in operating and maintenance expense	$ (94)	$ 48

(a) During the first quarter of 2012, BGE accrued $28 million in charitable contributions as a result of BGE's merger-related commitments. The charitable contribution accrual and merger costs are not recoverable from BGE's customers.

(b) During the first quarter of 2011, the MDPSC issued a comprehensive rate order permitting the deferral of incremental distribution service restoration expenses associated with 2010 storms as a regulatory asset.

(c) On June 29, 2012, a "Derecho" storm caused extensive damage to BGE's electric distribution system and created power outages that lasted multiple days. As a result, BGE incurred $62 million of incremental costs during the year ended December 31, 2012, of which $20 million are capital costs. In the fourth quarter of 2012, BGE incurred $38 million of incremental costs as a result of Hurricane Sandy, of which $14 million are capital costs. These amounts compare to $40 million of incremental expenses incurred during the third quarter of 2011 associated with Hurricane Irene, of which $25 million are capital costs, and $14 million of incremental expenses, of which $3 are capital costs, incurred during the first quarter of 2011.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Depreciation expense [a]	$18	$ 20
Regulatory asset amortization [b]	31	6
Other	1	(2)
Increase in depreciation and amortization expense	$50	$ 24

(a) Deprecation and amortization expense increased due to higher plant balances year over year.

(b) Regulatory asset amortization increased due to higher energy efficiency and demand response programs expenditures year over year

Taxes Other Than Income

The change in taxes other than income for 2013 compared to 2012 and 2012 compared to 2011 consisted of the following:

	Increase (Decrease) 2013 vs. 2012	Increase (Decrease) 2012 vs. 2011
Property tax	$ (2)	$ 4
Franchise tax	7	(1)
Other	—	(2)
Increase in taxes other than income	$ 5	$ 1

Interest Expense, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in interest expense, net for 2013 compared to 2012 was primarily due to the interest recorded in 2012 on prior year tax liabilities and lower effective interest rates as a result of the refinancing of debt at a lower interest rate in 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in interest expense, net in 2012 compared to 2011 was primarily due to higher outstanding debt balances and interest recorded in 2012 on prior year tax liabilities.

Effective Income Tax Rate

BGE's effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 39.0%, 63.6% and 35.5%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries [a]							
Residential	13,077	12,719	2.8%	n.m.	12,652	0.5%	n.m.
Small commercial & industrial [c]	3,035	2,990	1.5%	n.m.	3,023	(1.1)%	n.m.
Large commercial & industrial [c]	14,339	14,956	(4.1)%	n.m.	15,729	(4.9)%	n.m.
Public authorities & electric railroads	317	329	(3.6)%	n.m.	405	(18.8)%	n.m.
Total Electric Retail Deliveries	30,768	30,994	(0.7)%	n.m.	31,809	(2.6)%	n.m.

	As of December 31,		
Number of Electric Customers	2013	2012	2011
Residential	1,120,431	1,116,233	1,116,401
Small commercial & industrial [c]	112,850	112,994	113,026
Large commercial & industrial [c]	11,652	11,580	11,365
Public authorities & electric railroads	292	319	326
Total	1,245,225	1,241,126	1,241,118

Electric Revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales [a]					
Residential	$1,404	$1,274	10.2%	$1,456	(12.5)%
Small commercial & industrial [c]	257	248	3.6%	268	(7.5)%
Large commercial & industrial [c]	439	393	11.7%	416	(5.5)%
Public authorities & electric railroads	31	30	3.3%	29	3.4%
Total Retail	2,131	1,945	9.6%	2,169	(10.3)%
Other Revenue [b]	274	238	15.1%	152	56.6%
Total Electric Revenues	$2,405	$2,183	10.2%	$2,321	(5.9)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes wholesale transmission revenue and late payment charges.
(c) Certain commercial and industrial (C&I) customers were reclassified from small C&I to large C&I in prior years to conform to the current year's classification of C&I customers.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2013	2012	% Change 2013 vs. 2012	Weather-Normal % Change	2011	% Change 2012 vs. 2011	Weather-Normal % Change
Retail Deliveries [d]							
Retail sales	94,020	86,946	8.1%	n.m.	94,800	(8.3)%	n.m.
Transportation and other [e]	12,210	15,751	(22.5)%	n.m.	16,436	(4.2)%	n.m.
Total Gas Deliveries	106,230	102,697	3.4%	n.m.	111,236	(7.7)%	n.m.

Number of Gas Customers	As of December 31, 2013	2012	2011
Residential	611,532	610,827	608,943
Commercial & industrial	44,162	44,228	44,211
Total	655,694	655,055	653,154

Gas revenue	2013	2012	% Change 2013 vs. 2012	2011	% Change 2012 vs. 2011
Retail Sales [d]					
Retail sales	$592	$494	19.8%	$580	(14.8)%
Transportation and other [e]	68	58	17.2%	92	(37.0)%
Total Gas Revenues	$660	$552	19.6%	$672	(17.9)%

(d) Reflects delivery revenues and volumes from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.
(e) Transportation and other gas revenue includes off-system revenue of 12,210 mmcfs ($55 million), 15,751 mmcfs ($51 million), and 16,436 mmcfs ($82 million) for the years ended 2013, 2012 and 2011, respectively.

Liquidity and Capital Resources

Exelon's and Generation's prior year activity presented below includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon's and Generation's activity for 2011 is unadjusted for the effects of the merger. BGE's prior year activity presented below includes its activity for the 12 months ended December 31, 2012 and 2011.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. The Registrants' revolving credit facilities are in place until 2018. In addition, Generation has $0.4 billion in bilateral facilities with banks which expire in January 2015, December 2015 and March 2016. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 13 of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

ComEd's, PECO's and BGE's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd's, PECO's and BGE's distribution services are provided to an established and diverse base of retail customers. ComEd's, PECO's and BGE's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while others take effect in 2013. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to contribute approximately $264 million to its pension plans in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $118 million, $119 million, $11 million and $0 million, respectively. See Note 16 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2013 and 2012 pension contributions.

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued recovery). Exelon expects to contribute approximately $430 million to the other postretirement benefit plans in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $168 million, $197 million, $19 million and $17 million, respectively. See Note 16 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2013 and 2012 other postretirement benefit contributions.

See the "Contractual Obligations" section below for management's estimated future pension and other postretirement benefits contributions.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- Exelon, Generation, ComEd, PECO and BGE expect to receive tax refunds of approximately $380 million, $60 million, $320 million, $10 million and $20 million, respectively, between 2014 and 2015.
- Given the current economic environment, state and local governments are facing increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes.
- In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The newly adopted method results in a cash tax benefit in 2012 of approximately $38 million and $41 million at Exelon and PECO, respectively. Exelon currently anticipates that the IRS will issue industry guidance in the near future. See Note 3 of the Combined Notes to Consolidated Financial Statements for discussion regarding the regulatory treatment of PECO's tax benefits from the application of the method change.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2013, 2012 and 2011:

	2013	2012	2013 vs. 2012 Variance	2011	2012 vs. 2011 Variance
Net income	$1,729	$1,171	$ 558	$ 2,499	$ (1,328)
Add (subtract):					
Non-cash operating activities [a]	4,159	5,588	(1,429)	4,848	740
Pension and non-pension postretirement benefit contributions	(422)	(462)	40	(2,360)	1,898
Income taxes	883	544	339	492	52
Changes in working capital and other noncurrent assets and liabilities [b]	(185)	(731)	546	(279)	(452)
Option premiums paid, net	(36)	(114)	78	(3)	(111)
Counterparty collateral received (paid), net	215	135	80	(344)	479
Net cash flows provided by operations	$6,343	$6,131	$ 212	$ 4,853	$ 1,278

(a) Represents depreciation, amortization, depletion and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, and other non-cash charges.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Cash flows provided by operations for 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon [a]	$6,343	$6,131	$4,853
Generation [a]	3,887	3,581	3,313
ComEd	1,218	1,334	836
PECO	747	878	818
BGE [a]	561	485	476

(a) Exelon's and Generation's prior year activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon's and Generation's activity for 2011 is unadjusted for the effects of the merger. BGE's prior year activity includes its activity for the 12 months ended December 31, 2012 and 2011.

Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for 2013, 2012 and 2011 were as follows:

Generation

- During 2013, 2012 and 2011, Generation had net (payments) receipts of counterparty collateral of $162 million, $95 million and $(410) million, respectively. Net payments during 2013 and 2012 were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.
- During 2013, 2012 and 2011, Generation's accounts receivable from ComEd increased (decreased) by $(16) million, $(15) million and $12 million, respectively, primarily due to changes in receivables for energy purchases related to its SFC, ICC-approved RFP contracts and financial swap contract.

- During 2013, 2012 and 2011, Generation's accounts receivable from PECO increased (decreased) by $(17) million, $17 million and $(210) million, respectively.
- During 2013, 2012 and 2011, Generation's accounts receivable from BGE increased (decreased) by $(4) million, $23 million and $(13) million, respectively.
- During 2013, 2012 and 2011, Generation had net payments of approximately $36 million, $114 million and $3 million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During 2013, 2012 and 2011, ComEd's net payables to Generation for energy purchases related to its supplier forward contract, ICC-approved RFP contracts and financial swap contract settlements increased (decreased) by $(16) million, $(15) million and $12 million, respectively. During 2013, 2012 and 2011, ComEd's payables to other energy suppliers for energy purchases increased (decreased) by $35 million, $20 million and $(43) million, respectively.
- During 2013, 2012, and 2012, ComEd received $53 million, $37 million and $63 million, respectively, of incremental cash collateral from PJM due to variations in its energy transmission activity levels. As of December 31, 2013 and December 31, 2012, ComEd had cash collateral remaining at PJM of $0M and $53 million, respectively.

PECO

- During 2013, 2012 and 2011, PECO's payables to Generation for energy purchases increased (decreased) by $(17) million, $17 million and $(210) million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $33 million, $(22) million and $97 million, respectively.

BGE

- During 2013, 2012 and 2011, BGE's payables to Generation for energy purchases increased (decreased) by $(4) million, $23 million and $(13) million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $5 million, $40 million and $(60) million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for 2013, 2012, and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon [(a)(c)(f)]	$(5,394)	$(4,576)	$(4,603)
Generation [(a)(c)(f)]	(2,916)	(2,629)	(3,077)
ComEd	(1,387)	(1,212)	(1,007)
PECO	(531)	(328)	(557)
BGE [(f)]	(571)	(573)	(592)

Capital expenditures by Registrant for 2013, 2012 and 2011 and projected amounts for 2014 are as follows:

	Projected 2014 [b]	2013	2012	2011 [a]
Exelon [f]	$ 5,475	$5,395	$5,789	$4,042
Generation [c][f]	2,400	2,752	3,554	2,491
ComEd [d]	1,775	1,433	1,246	1,028
PECO	625	537	422	481
BGE [f]	600	587	582	592
Other [e]	75	86	82	42

(a) Includes $387 million in 2011 related to acquisitions, principally acquisition of Wolf Hollow, Antelope Valley and Shooting Star. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Total projected capital expenditures do not include adjustments for non-cash activity.
(c) Includes nuclear fuel.
(d) Pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology. ComEd expects to file an updated investment plan with the ICC in April, 2014.
(e) Other primarily consists of corporate operations and BSC.
(f) Exelon's and Generation's prior year activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon's and Generation's activity for 2011 is unadjusted for the effects of the merger. BGE's prior year activity includes its activity for the 12 months ended December 31, 2012 and 2011.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 38% and 11% of the projected 2014 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy generation, including Antelope Valley construction costs, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Also included in the projected 2014 capital expenditures are a portion of the costs of a series of planned power uprates across Generation's nuclear fleet. See "EXELON CORPORATION—Executive Overview," for more information on nuclear uprates.

On November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC, and received net proceeds of approximately $371. In addition, Generation will begin to make cash payments of approximately $31 million to Raven Power Holdings LLC over a twelve-month period beginning in June 2014. In 2012, Generation incurred transaction costs of approximately $15 million through the date of closing of the transaction. The sale will generate approximately $195 million of cash tax benefits, of which $155 million will be realized in periods through 2014 with the balance to be received in later years. Therefore, Generation expects net after-tax cash sale proceeds of approximately $495 million through 2014 and approximately $36 million in subsequent years.

ComEd, PECO and BGE

Approximately 91%, 72% and 89% of the projected 2014 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and ComEd's, PECO's and BGE's

construction commitments under PJM's RTEP. ComEd's capital expenditures include smart grid/smart meter technology required under EIMA. PECO and BGE capital expenditures include investments related to their respective smart meter program and SGIG project, net of DOE expected reimbursements. The remaining amounts are for capital additions to support new business and customer growth. See Notes 3 and 7 of the Combined Notes to Consolidated Financial Statements for additional information.

In 2010, NERC provided guidance to transmission owners, including ComEd, PECO, and BGE, that recommends the completion of performance assessments of their transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority lines by December 31, 2013. In compliance with this guidance, ComEd, PECO and BGE submitted their most recent bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will incur incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2014 capital expenditures above reflect capital spending for remediation to be completed in 2014.

ComEd, PECO and BGE anticipate that they will fund capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 3 of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon	$(826)	$(1,085)	$(846)
Generation	(384)	(777)	(196)
ComEd	61	(212)	355
PECO	(361)	(382)	(589)
BGE	(48)	128	115

Debt .Debt activity for 2013, 2012 and 2011 by Registrant was as follows:

Company	Issuances of long-term debt in 2013	Use of proceeds
Generation	$5 million of variable rate CEU Credit Agreement project financing, due July 22, 2016	Used to fund Upstream gas activities
Generation	$227 million of fixed rate DOE Project Financing, due January 5, 2037	Used for Antelope Valley solar development
Generation	$1 million of 2.93% Social Security Administration Project Financing, due February 18, 2015	Used to install conservation measures for the Social Security Administration Headquarters facility in Maryland
Generation	$9 million of 4.40% Energy Efficiency Financing, due August 31, 2014	Used for funding to install energy conservation measures in Beckley, West Virginia
Generation	$613 million of 6.00% Continental Wind Senior Secured Notes, due February 28, 2033	Used for general corporate purposes

Company	Issuances of long-term debt in 2013	Use of proceeds
ComEd	$350 million of First Mortgage 4.60% Bonds, Series 114, due August 15, 2043	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	$300 million of First and Refunding Mortgage 1.20% Bonds due October 15, 2016	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
PECO	$250 million of First and Refunding Mortgage 4.80% Bonds due October 15, 2043	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
BGE	$300 million of fixed rate 3.35% Notes due July 1, 2023	Used to partially refinance Notes due July 1, 2013 and for general corporate purposes

Company	Issuances of long-term debt in 2012	Use of proceeds
Generation	$78 million of variable rate CEU Credit Agreement project financing, due July 16, 2016	Used to fund Upstream gas activities
Generation	$220 million of fixed rate DOE Project Financing, due January 5, 2037	Used for Antelope Valley solar development
Generation	$523 million of 4.25% Senior Notes due June 15, 2022	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$788 million of 5.60% Senior Notes due June 15, 2042	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$38 million of variable rate Clean Horizons project financing due June 7, 2030	Used for funding for Maryland solar development
ComEd	$350 million of First Mortgage 3.80% Bonds, Series 113, due October 1, 2042	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	$350 million of First and Refunding Mortgage 2.38% Bonds due September 15, 2022	Used to pay at maturity First Mortgage Bonds due October 1, 2012 and for general corporate purposes
BGE	$250 million of fixed rate 2.80% Notes due August 15, 2022	Used to repay total outstanding commercial paper obligations and for general corporate purposes

Company	Issuances of long-term debt in 2011	Use of proceeds
ComEd	$600 million of First Mortgage 1.625% Bonds, Series 110, due January 15, 2014	Used as an interim source of liquidity for a January 2011 contribution to Exelon-sponsored pension plans
ComEd	$250 million of First Mortgage 1.95% Bonds, Series 111, due September 1, 2016	Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes

Company	Issuances of long-term debt in 2011	Use of proceeds
ComEd	$350 million of First Mortgage 3.40% Bonds, Series 112, due September 1, 2021	Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes
BGE	$300 million of fixed rate 3.50% Notes, due November 15, 2021	Used to repay total outstanding commercial paper obligations and for general corporate purposes

Company	Retirement of long-term debt in 2013
Generation	$3 million scheduled payments of 7.83% Kennett Square capital lease until September 1, 2020
Generation	$113 million of variable rate Solar Revolver project financing with a final maturity of July 7, 2014
Generation	$2 million of 2.563% project financing Clean Horizons with a final maturity of September 7, 2030
Generation	$2 million of 2.68% Sacramento Energy Loan Agreement with a final maturity of December 31, 2030
Generation [(a)]	$450 million of 8.625% Series A Junior Subordinated Debentures with a final maturity of June 15, 2063
ComEd	$125 million of 7.625% First Mortgage Bonds, Series 92, due April 15, 2013
ComEd	$127 million of 7.500% First Mortgage Bonds, Series 94, due July 1, 2013
PECO	$300 million of 5.600% First and Refunding Mortgage Bonds, due October 15, 2013
BGE	$67 million of 5.72% fixed rate Rate Stabilization Bonds, due April 1, 2017
BGE	$400 million of 6.125% Senior Notes, due July 1, 2013

Company	Retirement of long-term debt in 2012
Exelon	$2 million of 7.30% fixed-rate Medium Term Notes with a maturity date of June 1, 2012
Exelon	$442 million of 7.60% fixed-rate Senior Notes with a maturity date of April 1, 2032
Generation	$2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
Generation	$46 million of 3-year term rate Armstrong Co. 2009 A, Pollution Control Notes at 5.00% with a final maturity of December 1, 2042
Generation	$89 million of variable rate project financing CEU Credit Agreement with a final maturity of July 16, 2016
Generation	$17 million of variable rate Solar Revolver project financing with a final maturity of July 7, 2014
Generation	$75 million of variable rate MEDCO tax-exempt bonds with a final maturity of April 1, 2024
Generation	$2 million of variable rate Sacramento Solar Promissory Note with a final maturity of March 12, 2012
ComEd	$450 million of 6.15% First Mortgage Bonds, Series 98, due March 15, 2012

Company	Retirement of long-term debt in 2012
PECO	$225 million of 4.75% First and Refunding Mortgage Bonds, due October 1, 2012
PECO	$150 million of 4.00% First and Refunding Mortgage Bonds, due December 1, 2012
BGE	$8 million of 5.72% fixed rate Rate Stabilization Bonds, due April 1, 2016
BGE	$55 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012
BGE	$110 million of variable rate Medium Term Notes, due June 15, 2012

Company	Retirement of long-term debt in 2011
Generation	$2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
ComEd	$2 million of 4.75% sinking fund debentures, due December 1, 2011
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, due March 1, 2020
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 E, due May 1, 2021
ComEd	$91 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 F, due March 1, 2017
ComEd	$345 million of 5.40% First Mortgage Bonds, Series 105, due December 15, 2011
PECO	$250 million of 5.95% First and Refunding Mortgage Bonds, due November 1, 2011
BGE	$60 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012

(a) Represents debt obligations assumed by Exelon as part of the merger on March 12, 2012 that became callable at face value on June 15, 2013. Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable as of December 31, 2012 included in long-term debt to affiliate on Generation's Consolidated Balance Sheets and notes receivable from affiliates at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets. The third-party debt obligations were reported in Long-term Debt on Exelon's Consolidated Balance Sheets as of December 31, 2012. The debentures were redeemed and the intercompany loan agreements repaid on June 15, 2013.

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective balance sheets.

Dividends. Cash dividend payments and distributions during 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Exelon	$1,263	$1,733	$1,397
Generation	625	1,626	172
ComEd	220	105	300
PECO	333	347	352
BGE	13	13	98[(a)]

(a) Dividends on common stock for $85 million were paid to Constellation for the year ended December 31, 2011.

Revised Dividend Policy

On February 6, 2013, the Exelon board of directors approved a revised dividend policy which contemplates a regular $0.31 per share quarterly dividend on Exelon's common stock payable beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis), subject to quarterly declarations by the Exelon Board of Directors.

Second Quarter 2013 Dividend

On April 23, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on June 10, 2013 of $0.310 per share on Exelon's common stock.

Third Quarter 2013 Dividend

On July 23, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on September 10, 2013 of $0.310 per share on Exelon's common stock.

Fourth Quarter 2013 Dividend

On October 22, 2013, the Exelon board of directors declared a regular quarterly dividend, paid on December 10, 2013 of $0.310 per share on Exelon's common stock

First Quarter 2014 Dividend

On January 28, 2014, the Exelon Board of Directors declared a first quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2014, to shareholders of record of Exelon at the end of the day on February 14, 2014.

Short-Term Borrowings. Short-term borrowings incurred (repaid) during 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Generation	$ 13	$ (52)	$—
ComEd	184	—	—
BGE	135	—	—
Other [(a)]	—	(140)	161
Exelon	$332	$(192)	$161

(a) Other primarily consists of corporate operations and BSC.

Retirement of Long-Term Debt to Financing Affiliates. There were no retirements of long-term debt to financing affiliates during 2013, 2012 and 2011 by the Registrants.

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2013, 2012 and 2011 by Registrant were as follows:

	2013	2012	2011
Generation	$ 26	$48	$ 30
ComEd [(a)]	176	11	11
PECO	27	9	18
BGE	—	66	—

(a) In 2013, represents indemnification from Exelon in relation to the like-kind exchange transaction.

Other. Other significant financing activities for Exelon for 2013, 2012 and 2011 were as follows:

- Exelon received proceeds from employee stock plans of $47 million, $72 million and $38 million during 2013, 2012 and 2011, respectively.

Credit Matters

Market Conditions

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $8.4 billion in aggregate total commitments of which $6.6 billion was available as of December 31, 2013, and of which no financial institution has more than 8% of the aggregate commitments for Exelon, Generation, ComEd, PECO and BGE. The Registrants had access to the commercial paper market during 2013 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A Risk Factors for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of December 31, 2013, it would have been required to provide incremental collateral of $2.0 billion of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.3 billion. If ComEd lost its investment grade credit ratings as of December 31, 2013, it would have been required to provide incremental collateral of $6 million, which is well within its current available credit facility capacity of $816 million, which takes into account commercial paper borrowings as of December 31, 2013. If PECO lost its investment grade credit rating as of December 31, 2013 it would not be required to provide collateral pursuant to PJM's credit policy and could have been required to provide collateral of $42 million related to its natural gas procurement contracts, which, in the aggregate, are well within PECO's current available credit facility capacity of $599 million. If BGE lost its investment grade credit rating as of December 31, 2013, it would have been required to provide collateral of $2 million pursuant to PJM's credit policy and could have been required to provide collateral of $85 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of $465 million.

Exelon Credit Facilities

See Note 13 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure . At December 31, 2013, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE
Long-term debt	44%	30%	42%	40%	42%
Long-term debt to affiliates [(a)]	2%	8%	2%	4%	5%
Common equity	53%	—	55%	56%	49%
Member's equity	—	62%	—	—	—
Preference Stock	—	—	—	—	4%
Commercial paper and notes payable	1%	—	1%	—	—

(a) Includes approximately $648 million, $206 million, $184 million and $258 million owed to unconsolidated affiliates of Exelon, ComEd, PECO and BGE respectively. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd, PECO and BGE. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

Intercompany Money Pool. To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participants during the year ended December 31, 2013, in addition to the net contribution or borrowing as of December 31, 2013, are presented in the following table:

	Maximum Contributed	Maximum Borrowed	December 31, 2013 Contributed (Borrowed)
Generation	$ 159	$ 435	$ 44
PECO	304	—	—
BSC	—	287	(223)
Exelon Corporate	237	—	179

Investments in Nuclear Decommissioning Trust Funds. Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's investment policy establishes limits on the concentration of holdings in any one company and also in any one industry. See Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements. The Registrants maintain a combined shelf registration statement unlimited in amount, with the SEC. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations. The issuance by ComEd, PECO and BGE of long-term debt or equity securities requires the prior authorization of the ICC, PAPUC and MDPSC, respectively. ComEd, PECO and BGE normally obtain the required approvals on a periodic basis to cover their anticipated financing needs for a period of time or in connection with a specific financing. On March 1, 2013, ComEd received $470 million in long-term debt new money authority from the ICC and on February 27, 2012, ComEd received $1.3 billion in long-term debt refinancing authority from the ICC.

As of December 31, 2013, ComEd had $1.3 billion available in long-term debt refinancing authority and $218 million available in new money long-term debt financing authority from the ICC. During the fourth quarter of 2013, ComEd requested and received $1 billion in new money financing authority from the ICC. The authority is effective on January 1, 2014 and expires January 1, 2017. As of December 31, 2013, PECO had $1.4 billion available in long-term debt financing authority from the PAPUC. As of December 31, 2013, BGE had $850 million available in long-term financing authority from MDPSC.

FERC has financing jurisdiction over ComEd's, PECO's and BGE's short-term financings and all of Generation's financings. As of December 31, 2013, ComEd, PECO had BGE had short-term financing authority from FERC, which expires on December 31, 2015, of $2.5 billion, $2.5 billion and $700 million, respectively. Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon's ability to pay dividends on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid. At December 31, 2013, Exelon had retained earnings of $10,358 million, including Generation's undistributed earnings of $3,613 million, ComEd's retained earnings of $750 million consisting of retained earnings appropriated for future dividends of $2,389 million partially offset by $1,639 million of unappropriated retained deficit, PECO's retained earnings of $649 million and BGE's retained earnings $1,005 million. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Contractual Obligations

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2013 under existing contractual obligations, including payments due by period. See Note 22 of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within				
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt [(a)]	$19,367	$1,424	$ 2,953	$2,731	$ 12,259	$ —
Interest payments on long-term debt [(b)]	12,845	925	1,692	1,396	8,832	—
Liability and interest for uncertain tax positions [(c)]	1,255	—	—	—	—	1,255
Capital leases	41	4	8	10	19	—
Operating leases [(d)]	826	103	180	145	398	—
Purchase power obligations [(e)]	3,046	1,378	852	367	449	—
Fuel purchase agreements [(f)]	9,606	1,520	2,622	1,967	3,497	—
Electric supply procurement [(f)]	1,880	1,062	678	140	—	—
AEC purchase commitments [(f)]	6	1	2	2	1	—
Curtailment services commitments [(f)]	132	45	74	13	—	—
Long-term renewable energy and REC commitments [(g)]	1,589	72	150	160	1,207	—
PJM regional transmission expansion commitments [(h)]	1,019	208	597	214	—	—
Spent nuclear fuel obligation	1,021	—	—	—	1,021	—
Pension minimum funding requirement [(i)]	1,223	264	444	426	89	—
Total contractual obligations	$53,856	$7,006	$10,252	$7,571	$ 27,772	$1,255

(a) Includes $648 million due after 2016 to ComEd, PECO and BGE financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2013. Includes estimated interest payments due to ComEd, PECO and BGE financing trusts.

(c) As of December 31, 2013, Exelon's liability for uncertain tax positions and related interest payable was $906 million and $349 million, respectively. Exelon was unable to reasonably estimate the timing of liability and interest payments and receipts in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. Exelon has other unrecognized tax positions that were not recorded on the Consolidated Balance Sheet in accordance with authoritative guidance. See Note 14 of the Combined Notes to Consolidated Financial Statements for further information regarding unrecognized tax positions.

(d) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO's meter reading operating lease.

(e) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2013, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. These obligations do not include ComEd's SFCs as these contracts do not require purchases of fixed or minimum quantities. See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements.

(f) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services. See Note 22 of the Combined Notes to Consolidated Financial Statements for electric and gas purchase commitments.

(g) ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the

ICC's December 19, 2012 order, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC's December 18, 2013 order approved the reduction of ComEd's commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(h) Under their operating agreements with PJM, ComEd, PECO and BGE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's, PECO's and BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(i) These amounts represent Exelon's estimated minimum pension contributions to its qualified plans required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. For Exelon's largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million or the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2019 are not included. See Note 16 of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

		Payment due within				
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt	$ 7,519	$ 557	$ 628	$ 701	$ 5,633	$—
Interest payments on long-term debt [a]	5,362	368	693	625	3,676	—
Liability and interest for uncertain tax benefits [b]	264	—	—	—	—	264
Capital leases	33	4	8	10	11	—
Operating leases [c]	571	49	98	88	336	—
Purchase power obligations [d]	3,046	1,378	852	367	449	—
Fuel purchase agreements [e]	8,490	1,212	2,296	1,807	3,175	—
Spent nuclear fuel obligation	1,021	—	—	—	1,021	—
Total contractual obligations	$26,306	$3,568	$4,575	$3,598	$ 14,301	$264

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2013.

(b) As of December 31, 2013, Generation's liability for uncertain tax positions and related interest payable was $227 million and $37 million, respectively. Generation was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.

(c) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations.

(d) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2013. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. See Note 22 of the Combined Notes to Consolidated Financial Statements.

(e) See Note 22 of the Combined Notes to Consolidated Financial Statements for further information regarding fuel purchase agreements.

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ComEd

	Total	Payment due within 2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt [a]	$ 5,892	$ 617	$ 925	$1,265	$ 3,085	$—
Interest payments on long-term debt [b]	3,704	274	515	393	2,522	—
Liability and interest for uncertain tax positions [c]	498	—	—	—	—	498
Capital leases	8	—	—	—	8	—
Operating leases	47	13	22	9	3	—
Electric supply procurement	736	323	273	140	—	—
Long-term renewable energy and associated REC commitments [d]	1,589	72	150	160	1,207	—
PJM regional transmission expansion commitments [e]	486	134	350	2	—	—
Total contractual obligations	$12,960	$1,433	$2,235	$1,969	$ 6,825	$498

(a) Includes $206 million due after 2017 to a ComEd financing trust.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2013. Includes estimated interest payments due to the ComEd financing trust.
(c) As of December 31, 2013, ComEd's liability for uncertain tax positions and related interest payable was $324 million and $174 million, respectively. ComEd was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.
(d) ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's December 19, 2012 order, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC's December 18, 2013 order approved the reduction of ComEd's commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.
(e) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

PECO

	Total	Payment due within 2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt [a]	$2,384	$ 250	$300	$500	$ 1,334	$—
Interest payments on long-term debt [b]	1,505	104	189	160	1,052	—
Operating leases	25	13	6	6	—	—
Fuel purchase agreements [c]	507	179	210	52	66	—
Electric supply procurement [c]	681	590	91	—	—	—
AEC purchase commitments [c]	14	2	4	4	4	—
PJM regional transmission expansion commitments [d]	133	32	69	32	—	—
Total contractual obligations	$5,249	$1,170	$869	$754	$ 2,456	$—

(a) Includes $184 million due after 2017 to PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

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(d) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

BGE

		Payment due within				
	Total	2014	2015-2016	2017-2018	Due 2019 and beyond	All Other
Long-term debt [a]	$2,273	$ —	$ 300	$265	$ 1,708	$—
Interest payments on long-term debt [b]	1,608	112	220	162	1,114	—
Operating leases	61	12	20	15	14	—
Fuel purchase agreements [c]	609	129	116	108	256	—
Electric supply procurement [c]	1,256	783	473	—	—	—
Curtailment services commitments [c]	132	45	74	13	—	—
PJM regional transmission expansion commitments [d]	400	42	178	180	—	—
Total contractual obligations	$6,339	$1,123	$1,381	$743	$ 3,092	$—

(a) Includes $258 million due after 2017 to the BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

See Note 22 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 13 of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 13 of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 14 of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 13 of the Combined Notes to Consolidated Financial Statements.
- operating leases, energy commitments, fuel purchase agreements, construction commitments and rate relief commitments, see Note 22 of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 15 and 22 of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3 of the Combined Notes to Consolidated Financial Statements.
- variable interest entities, see Note 1 of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 22 of the Combined Notes to Consolidated Financial Statements.

- new accounting pronouncements, see Note 1 of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief executive officer, chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the risk oversight committee of the Exelon board of directors on the scope of the risk management activities.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2014 through 2016.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over the three years leading to the spot market. As of December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015 and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including sales to ComEd, PECO and BGE to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on December 31, 2013, market conditions and hedged position would be a decrease in pre-tax net income of approximately $30 million, $520 million and $820 million, respectively, for 2014, 2015 and 2016. Power price sensitivities are derived by

adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 8,762 GWh, 12,958 GWh, and 5,742 GWh for the years ended December 31, 2013, 2012 and 2011 respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the year ended December 31, 2013, resulted in pre-tax losses of $8 million due to net mark-to-market losses of $39 million and realized gains of $31 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $1.0 million of exposure during the year. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for the year ended December 31, 2013 of $7,433 million.

Fuel Procurement . Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2014 through 2018 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

ComEd

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd would be entitled to receive full cost recovery in rates. The change in fair value each period was recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expired on May 31, 2013. All realized impacts have been included in Generation's and ComEd's results of operations.

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19,

2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC's December 18, 2013 order approved the reduction of ComEd's commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Notes 3 and 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3 of the Combined Notes to the Consolidated Financial Statements. PECO's full requirements contracts and block contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance and as a result, are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12 of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance and as a result, are accounted for on an accrual basis of accounting. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12 of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities

The following detailed presentation of Exelon's, Generation's, ComEd's and PECO's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, and ComEd's mark-to-market net asset or liability balance sheet position from January 1, 2012, to December 31, 2013. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings, as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 12 of the Combined Notes to the Consolidated Financial Statements for more information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2013, and December 31, 2012.

	Generation	ComEd	Intercompany Eliminations (b)	Exelon
Total mark-to-market energy contract net assets (liabilities) at January 1, 2012 (a)	$ 1,648	$(800)	$ —	$ 848
Contracts acquired at merger date (c)	140	—	—	140
Total change in fair value during 2012 of contracts recorded in result of operations	(159)	—	7	(152)
Reclassification to realized at settlement of contracts recorded in results of operations	775	—	—	775
Ineffective portion recognized in income (d)	(5)	—	—	(5)
Reclassification to realized at settlement from accumulated OCI (e)	(1,368)	—	621	(747)
Effective portion of changes in fair value—recorded in OCI (f)	719	—	(146)	573
Changes in fair value—energy derivatives (g)	—	507	(482)	25
Changes in allocated collateral	(89)	—	—	(89)
Changes in net option premium paid/(received)	114	—	—	114
Option premium amortization (h)	(160)	—	—	(160)
Intercompany elimination of existing derivative contracts with Constellation	(103)	—	—	(103)
Other balance sheet reclassifications	(7)	—	—	(7)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2012 (a)	$ 1,505	$(293)	$ —	$1,212
Total change in fair value during 2013 of contracts recorded in result of operations	444	—	(6)	438
Reclassification to realized at settlement of contracts recorded in results of operations	21	—	13	34
Reclassification to realized at settlement from accumulated OCI (e)	(683)	—	219	(464)
Changes in fair value—energy derivatives (g)	—	100	(226)	(126)
Changes in allocated collateral	(175)	—	—	(175)
Changes in net option premium paid/(received)	36	—	—	36
Option premium amortization (h)	(104)	—	—	(104)
Other balance sheet reclassifications	4	—	—	4
Total mark-to-market energy contract net assets (liabilities) at December 31, 2013 (a) (i)	$ 1,048	$(193)	$ —	$ 855

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Amounts related to the five-year financial swap between Generation and ComEd.
(c) For Generation, includes $660 million of collateral paid to counterparties, offset by $520 million of unrealized losses on commodity derivative positions.

(d) For Generation, reflects $5 million of changes in cash flow hedge ineffectiveness.
(e) For Generation, includes $219 million and $621 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2013 and 2012, respectively.
(f) For Generation, includes $146 million of gains related to the changes in fair value of the five-year financial swap with ComEd for the year ended 2012. Effective prior to the merger with Constellation, the five-year financial swap between Generation and ComEd was de-designated as a cash flow hedge. As a result, all changes in fair value for the year ended December 31, 2013 were recorded to operating revenues and eliminated in consolidation.
(g) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2013 and 2012, ComEd recorded a regulatory liability of $193 million and $293 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of December 31, 2013 and 2012, this includes $11 million of decreases and $98 million of increases in fair value, respectively, and $215 million and $566 million, respectively, for reclassifications from regulatory assets to recognize cost in purchase power expense due to settlements of ComEd's five-year financial swap with Generation. As of December 31, 2013 and 2012 ComEd also recorded $126 million and $34 million, respectively, of increases in fair value, and $7 million and $5 million, respectively, of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(h) Includes $104 million and $160 million of amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the years ended December 31, 2013 and 2012, respectively.
(i) Includes the ending balance related to interest rate derivative contracts and foreign exchange currency swaps to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities) net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 11—Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts [a][b] *:*							
Actively quoted prices (Level 1)	$ (30)	$ (26)	$ 17	$ (4)	$ (2)	$ —	$ (45)
Prices provided by external sources (Level 2)	444	143	39	—	—	1	627
Prices based on model or other valuation methods (Level 3) [c]	155	151	71	25	(22)	(108)	272
Total	$569	$268	$127	$ 21	$ (24)	$ (107)	$ 854

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $144 million at December 31, 2013.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts [(a)(b)] :							
Actively quoted prices (Level 1)	$ (30)	$ (26)	$ 17	$ (4)	$ (2)	$ —	$ (45)
Prices provided by external sources (Level 2)	444	143	39	—	—	1	627
Prices based on model or other valuation methods (Level 3)	172	170	89	43	(4)	(5)	465
Total	$586	$287	$145	$ 39	$ (6)	$ (4)	$ 1,047

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $144 million at December 31, 2013.

ComEd

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Fair Value
Prices based on model or other valuation methods (Level 3) [(a)]	$(17)	$(19)	$(18)	$(18)	$(18)	$ (103)	$(193)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 12 of the Combined Notes to Consolidated Financial Statements for a detail discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE, and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $38 million, $38 million and $27 million, respectively. See Note 25 of the Combined Notes to Consolidated Financial Statements for further information.

Rating as of December 31, 2013	Total Exposure Before Credit Collateral	Credit Collateral [(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,621	$ 172	$ 1,449	1	$ 491
Non-investment grade	27	9	18	—	—
No external ratings					
Internally rated—investment grade	416	1	415	1	226
Internally rated—non-investment grade	30	2	28	—	—
Total	$ 2,094	$ 184	$ 1,910	2	$ 717

	Maturity of Credit Risk Exposure			
Rating as of December 31, 2013	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,146	$340	$ 135	$ 1,621
Non-investment grade	23	4	—	27
No external ratings				
Internally rated—investment grade	272	138	6	416
Internally rated—non-investment grade	30	—	—	30
Total	$ 1,471	$482	$ 141	$ 2,094

Net Credit Exposure by Type of Counterparty	As of December 31, 2013
Financial Institutions	$ 256
Investor-owned utilities, marketers and power producers	684
Energy cooperatives and municipalities	907
Other	63
Total	$ 1,910

(a) As of December 31, 2013, credit collateral held from counterparties where Generation had credit exposure included $155 million of cash and $29 million of letters of credit.

ComEd

Credit risk for ComEd is managed by credit and collection policies, which are consistent with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. See Note 1 of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. The Illinois Settlement Legislation prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 1 of the following year. ComEd's ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2013. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. As of December 31, 2013, ComEd's credit exposure to energy suppliers was immaterial.

PECO

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1 of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2013.

PECO's supplier master agreements that govern the terms of its DSP Program contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2013, PECO had no net credit exposure with suppliers.

PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2013, PECO had credit exposure of $9 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE

Credit risk for BGE is managed by credit and collection policies, which are consistent with state regulatory requirements. BGE is currently obligated to provide service to all electric customers within its franchised territory. BGE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. BGE will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1 of the Combined Notes to Consolidated Financial Statements for uncollectible accounts policy. MDPSC regulations prohibit BGE from terminating service to residential customers due to nonpayment from November 1 through March 31 if the forecasted temperature is 32 degrees or below for the subsequent 72 hour period. BGE is also prohibited by the Maryland Public Utilities Article and MDPSC regulations from terminating service to residential customers due to nonpayment if the forecasted temperature is 95 degrees or above for the subsequent 72 hour period. BGE did not have any customers representing over 10% of its revenues as of December 31, 2013.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The seller's credit exposure is calculated each business day. As of December 31, 2013, BGE had no net credit exposure with suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2013, BGE had credit exposure of $14 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Collateral (Exelon, Generation, ComEd, PECO and BGE)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount

of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 12 of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities which serve as liquidity sources to fund collateral requirements. See Note 13 of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2013, Generation had cash collateral of $72 million posted and cash collateral held of $206 million for counterparties with derivative positions, of which $144 million in net cash collateral deposits were offset against mark-to-market assets and liabilities. As of December 31, 2013, $10 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives. As of December 31, 2012, Generation had cash collateral held of $499 million and cash collateral posted of $527 million for counterparties with derivative positions, of which $31 million in net cash collateral deposits were offset against mark-to-market assets and liabilities. As of December 31, 2012, $3 million of cash collateral received was not offset against net mark-to-market assets and liabilities because it was not associated with energy-related derivatives. See Note 22 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 31, 2013, ComEd held immaterial amounts of cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash for both annual and long-term renewable energy contracts. See Notes 3 and 12 of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of December 31, 2013, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 12 of the Combined Notes to Consolidated Financial Statements for further information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of December 31, 2013, BGE was not required to post collateral under its natural gas procurement contracts, nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 12 of the Combined Notes to Consolidated Financial Statements for further information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers

and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon and Generation)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's consolidated balance sheet, as of December 31, 2013, included a $698 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $1,465 million, less unearned income of $767 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange for a third-party to bid on a service contract for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and, if the review indicates a fair value below the carrying value and the decline is determined to be other than temporary, must record an impairment charge in the period the estimate changed. Based on the review performed in the second quarter of 2013, the estimated residual value of one of Exelon's direct financing leases experienced an other than temporary decline resulting in a $14 million pre-tax impairment charge in the second quarter of 2013. See Note 8 of the Combined Notes to Consolidated Financial Statements for further information. Through December 31, 2013, no events have occurred that would require Exelon to review the estimated residual values of its direct financing lease investments subsequent to the review performed in the second quarter of 2013.

Interest-Rate Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the

Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2013, Exelon had $1,425 million of notional amounts of fixed-to-floating hedges outstanding and $190 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximate $5 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2013.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of December 31, 2013, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $482 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

Generation

General

Generation operates in six segments: Mid-Atlantic, Midwest, New England, New York, ERCOT, and Other Regions in Generation. The operation of all six segments consists of owned contracted and investments in electric generating facilities, and wholesale and retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and investments in natural gas exploration and production activities. These segments are discussed in further detail in "ITEM 1. BUSINESS—Generation" of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation's executive overview is set forth under "ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared To Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of Generation's results of operations for 2013 compared to 2012 and 2012 compared to 2011 is set forth under "Results of Operations—Generation" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.6 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 13 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Generation's capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon's pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of Generation's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in "ITEM 1. BUSINESS—ComEd" of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of ComEd's results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under "Results of Operations—ComEd" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2013, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 13 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ComEd's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of ComEd's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk— Exelon."

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in "ITEM 1. BUSINESS—PECO" of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of PECO's results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under "Results of Operations—PECO" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2013, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund PECO's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of PECO's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

BGE

General

BGE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in "ITEM 1. BUSINESS—BGE" of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 and Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

A discussion of BGE's results of operations for 2013 compared to 2012 and for 2012 compared to 2011 is set forth under "Results of Operations—BGE" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

BGE's business is capital intensive and requires considerable capital resources. BGE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2013, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund BGE's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to BGE's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to BGE's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE—Critical Accounting Policies and Estimates above for a discussion of BGE's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2013, Exelon's internal control over financial reporting was effective.

The effectiveness of the Exelon's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Generation's management conducted an assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation's management concluded that, as of December 31, 2013, Generation's internal control over financial reporting was effective.

The effectiveness of the Generation's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd's management concluded that, as of December 31, 2013, ComEd's internal control over financial reporting was effective.

The effectiveness of the ComEd's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO's management concluded that, as of December 31, 2013, PECO's internal control over financial reporting was effective.

The effectiveness of the PECO's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Management's Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

BGE's management conducted an assessment of the effectiveness of BGE's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE's management concluded that, as of December 31, 2013, BGE's internal control over financial reporting was effective.

The effectiveness of BGE's internal control over financial reporting as of December 31, 2013, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Corporation ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Generation Company, LLC ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Commonwealth Edison Company ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PECO Energy Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of PECO Energy Company ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 13, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Baltimore Gas and Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company ("the Company") and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control—Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our audits (which was an integrated audit in 2012). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2014

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2013	2012	2011
Operating revenues	$24,888	$23,489	$19,063
Operating expenses			
Purchased power and fuel	9,468	9,121	7,130
Purchased power and fuel from affiliates	1,256	1,036	137
Operating and maintenance	7,270	7,961	5,184
Depreciation and amortization	2,153	1,881	1,347
Taxes other than income	1,095	1,019	785
Total operating expenses	21,242	21,018	14,583
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	(1)
Operating income	3,656	2,380	4,479
Other income and (deductions)			
Interest expense, net	(1,315)	(891)	(701)
Interest expense to affiliates, net	(41)	(37)	(25)
Other, net	473	346	203
Total other income and (deductions)	(883)	(582)	(523)
Income before income taxes	2,773	1,798	3,956
Income taxes	1,044	627	1,457
Net income	1,729	1,171	2,499
Net income attributable to non-controlling interests, preferred security dividends and preference stock dividends	10	11	4
Net income attributable to common shareholders	1,719	1,160	2,495
Comprehensive income (loss), net of income taxes			
Net income	1,729	1,171	2,499
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service cost (benefit) reclassified to periodic costs, net of taxes of $0, $1 and $(4), respectively	—	1	(5)
Actuarial loss reclassified to periodic cost, net of taxes of $133, $110 and $93, respectively	208	168	136
Transition obligation reclassified to periodic cost, net of taxes of $0, $2 and $2, respectively	—	2	4
Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $430, $(237) and $(171), respectively	669	(371)	(250)
Unrealized gain (loss) on cash flow hedges, net of taxes of $(166), $(68) and $39, respectively	(248)	(120)	88
Unrealized gain (loss) on marketable securities, net of taxes of $0, $(1) and $0, respectively	2	2	—
Unrealized gain (loss) on equity investments, net of taxes of $71, $1 and $0, respectively	106	1	—
Unrealized gain (loss) on foreign currency translation, net of taxes of $0, $0 and $0, respectively	(10)	—	—
Other comprehensive income (loss)	727	(317)	(27)
Comprehensive income	$ 2,456	$ 854	$ 2,472
Average shares of common stock outstanding:			
Basic	856	816	663
Diluted	860	819	665
Earnings per average common share:			
Basic	$ 2.01	$ 1.42	$ 3.76
Diluted	$ 2.00	$ 1.42	$ 3.75
Dividends per common share	$ 1.46	$ 2.10	$ 2.10

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income	$ 1,729	$ 1,171	$ 2,499
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	3,779	4,079	2,316
Loss on sale of three Maryland generating stations	—	272	—
Deferred income taxes and amortization of investment tax credits	119	615	1,457
Net fair value changes related to derivatives	(445)	(604)	291
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(170)	(157)	14
Other non-cash operating activities	876	1,383	770
Changes in assets and liabilities:			
Accounts receivable	(97)	243	57
Inventories	(100)	26	(58)
Accounts payable, accrued expenses and other current liabilities	(90)	(632)	(254)
Option premiums paid, net	(36)	(114)	(3)
Counterparty collateral received (posted), net	215	135	(344)
Income taxes	883	544	492
Pension and non-pension postretirement benefit contributions	(422)	(462)	(2,360)
Other assets and liabilities	102	(368)	(24)
Net cash flows provided by operating activities	6,343	6,131	4,853
Cash flows from investing activities			
Capital expenditures	(5,395)	(5,789)	(4,042)
Proceeds from nuclear decommissioning trust fund sales	4,217	7,265	6,139
Investment in nuclear decommissioning trust funds	(4,450)	(7,483)	(6,332)
Cash and restricted cash acquired from Constellation	—	964	—
Acquisitions of long lived assets	—	(21)	(387)
Proceeds from sale of long-lived assets	32	371	—
Proceeds from sales of investments	22	28	6
Purchases of investments	(4)	(13)	(4)
Change in restricted cash	(43)	(34)	(3)
Distribution from CENG	115	—	—
Other investing activities	112	136	20
Net cash flows used in investing activities	(5,394)	(4,576)	(4,603)
Cash flows from financing activities			
Payment of accounts receivable agreement	(210)	(15)	—
Changes in short-term debt	332	(197)	161
Issuance of long-term debt	2,055	2,027	1,199
Retirement of long-term debt	(1,589)	(1,145)	(789)
Redemption of preferred securities	(93)	—	—
Dividends paid on common stock	(1,249)	(1,716)	(1,393)
Proceeds from employee stock plans	47	72	38
Other financing activities	(119)	(111)	(62)
Net cash flows used in financing activities	(826)	(1,085)	(846)
Increase (decrease) in cash and cash equivalents	123	470	(596)
Cash and cash equivalents at beginning of period	1,486	1,016	1,612
Cash and cash equivalents at end of period	$ 1,609	$ 1,486	$ 1,016

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,547	$ 1,411
Cash and cash equivalents of variable interest entities	62	75
Restricted cash and investments	87	86
Restricted cash and investments of variable interest entities	80	47
Accounts receivable, net		
Customer ($0 and $289 gross accounts receivables pledged as collateral as of December 31, 2013 and December 31, 2012, respectively)	2,721	2,795
Other	1,175	1,141
Accounts receivable, net, of variable interest entities	260	292
Mark-to-market derivative assets	727	938
Unamortized energy contract assets	374	886
Inventories, net		
Fossil fuel	276	246
Materials and supplies	829	768
Deferred income taxes	573	131
Regulatory assets	760	764
Other	666	560
Total current assets	10,137	10,140
Property, plant and equipment, net	47,330	45,186
Deferred debits and other assets		
Regulatory assets	5,910	6,497
Nuclear decommissioning trust funds	8,071	7,248
Investments	1,165	1,184
Investments in affiliates	22	22
Investment in CENG	1,925	1,849
Goodwill	2,625	2,625
Mark-to-market derivative assets	607	937
Unamortized energy contract assets	710	1,073
Pledged assets for Zion Station decommissioning	458	614
Deferred income taxes	—	58
Other	964	1,128
Total deferred debits and other assets	22,457	23,235
Total assets	$79,924	$78,561

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 341	$ —
Short-term notes payable—accounts receivable agreement	—	210
Long-term debt due within one year	1,424	975
Long-term debt due within one year of variable interest entities	85	72
Accounts payable	2,314	2,378
Accounts payable of variable interest entities	170	202
Payables to affiliates	116	112
Mark-to-market derivative liabilities	159	352
Unamortized energy contract liabilities	261	455
Accrued expenses	1,633	1,796
Deferred income taxes	40	58
Regulatory liabilities	327	368
Other	858	813
Total current liabilities	7,728	7,791
Long-term debt	17,325	17,190
Long-term debt to financing trusts	648	648
Long-term debt of variable interest entities	298	508
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	12,905	11,551
Asset retirement obligations	5,194	5,074
Pension obligations	1,876	3,428
Non-pension postretirement benefit obligations	2,190	2,662
Spent nuclear fuel obligation	1,021	1,020
Regulatory liabilities	4,388	3,981
Mark-to-market derivative liabilities	300	281
Unamortized energy contract liabilities	266	528
Payable for Zion Station decommissioning	305	432
Other	2,540	1,650
Total deferred credits and other liabilities	30,985	30,607
Total liabilities	56,984	56,744
Commitments and contingencies		
Preferred securities of subsidiary	—	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 857 and 855 shares outstanding at December 31, 2013 and 2012, respectively)	16,741	16,632
Treasury stock, at cost (35 shares held at December 31, 2013 and 2012, respectively)	(2,327)	(2,327)
Retained earnings	10,358	9,893
Accumulated other comprehensive loss, net	(2,040)	(2,767)
Total shareholders' equity	22,732	21,431
BGE preference stock not subject to mandatory redemption	193	193
Non-controlling interest	15	106
Total equity	22,940	21,730
Total liabilities and shareholders' equity	$79,924	$78,561

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Preferred and Preference Stock	Total Shareholders' Equity
Balance, December 31, 2010	696,589	$ 9,006	$ (2,327)	$ 9,304	$ (2,423)	$ 3	$ —	$ 13,563
Net income	—	—	—	2,495	—	—	4	2,499
Long-term incentive plan activity	861	76	—	—	—	—	—	76
Employee stock purchase plan issuances	662	25	—	—	—	—	—	25
Common stock dividends	—	—	—	(1,744)	—	—	—	(1,744)
Preferred and preference stock dividends	—	—	—	—	—	—	(4)	(4)
Other comprehensive loss, net of income taxes of $(41)	—	—	—	—	(27)	—	—	(27)
Balance, December 31, 2011	698,112	$ 9,107	$ (2,327)	$ 10,055	$ (2,450)	$ 3	$ —	$ 14,388
Net income (loss)	—	—	—	1,160	—	(3)	14	1,171
Long-term incentive plan activity	2,432	126	—	—	—	—	—	126
Employee stock purchase plan issuances	857	26	—	—	—	—	—	26
Common stock dividends	—	—	—	(1,322)	—	—	—	(1,322)
Common stock issuance Constellation merger	188,124	7,365	—	—	—	—	—	7,365
Non-controlling interest acquired	—	8	—	—	—	106	—	114
BGE preference stock acquired	—	—	—	—	—	—	193	193
Preferred and preference stock dividends	—	—	—	—	—	—	(14)	(14)
Other comprehensive loss, net of income taxes of $(192)	—	—	—	—	(317)	—	—	(317)
Balance, December 31, 2012	889,525	$ 16,632	$ (2,327)	$ 9,893	$ (2,767)	$ 106	$ 193	$ 21,730
Net income (loss)	—	—	—	1,719	—	(10)	20	1,729
Long-term incentive plan activity	1,445	81	—	—	—	—	—	81
Employee stock purchase plan issuances	1,064	28	—	—	—	—	—	28
Common stock dividends	—	—	—	(1,254)	—	—	—	(1,254)
Consolidated VIE dividend to non-controlling interest	—	—	—	—	—	(63)	—	(63)
Deconsolidation of VIE	—	—	—	—	—	(18)	—	(18)
Redemption of preferred securities	—	—	—	—	—	—	(6)	(6)
Preferred and preference stock dividends	—	—	—	—	—	—	(14)	(14)
Other comprehensive income, net of income taxes of $(468)	—	—	—	—	727	—	—	727
Balance, December 31, 2013	892,034	$ 16,741	$ (2,327)	$ 10,358	$ (2,040)	$ 15	$ 193	$ 22,940

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating revenues			
Operating revenues	$14,207	$12,735	$ 9,286
Operating revenues from affiliates	1,423	1,702	1,161
Total operating revenues	15,630	14,437	10,447
Operating expenses			
Purchased power and fuel	6,927	6,017	3,451
Purchased power and fuel from affiliates	1,270	1,044	138
Operating and maintenance	3,960	4,398	2,827
Operating and maintenance from affiliates	574	630	321
Depreciation and amortization	856	768	570
Taxes other than income	389	369	264
Total operating expenses	13,976	13,226	7,571
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	(1)
Operating income	1,664	1,120	2,875
Other income and (deductions)			
Interest expense	(298)	(226)	(170)
Interest expense to affiliates, net	(59)	(75)	—
Other, net	368	239	122
Total other income and (deductions)	11	(62)	(48)
Income before income taxes	1,675	1,058	2,827
Income taxes	615	500	1,056
Net income	1,060	558	1,771
Net loss attributable to non-controlling interests	(10)	(4)	—
Net income attributable to membership interest	1,070	562	1,771
Comprehensive income (loss), net of income taxes			
Net income	1,060	558	1,771
Other comprehensive income (loss)			
Unrealized loss on cash flow hedges, net of income taxes of $(262), $(262) and $(64), respectively	(398)	(403)	(98)
Unrealized income on equity investments, net of income taxes of $72, $(1) and $0, respectively	107	1	—
Unrealized loss on foreign currency translation, net of income taxes of $0, $0 and $0, respectively	(10)	—	—
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively	2	—	—
Other comprehensive loss	(299)	(402)	(98)
Comprehensive income	$ 761	$ 156	$ 1,673

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income	$ 1,060	$ 558	$ 1,771
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,559	2,966	1,539
Loss on sale of three Maryland generating stations	—	272	—
Deferred income taxes and amortization of investment tax credits	315	408	551
Net fair value changes related to derivatives	(448)	(611)	291
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(170)	(157)	14
Other non-cash operating activities	414	537	421
Changes in assets and liabilities:			
Accounts receivable	109	248	(122)
Receivables from and payables to affiliates, net	2	39	208
Inventories	(88)	31	(47)
Accounts payable, accrued expenses and other current liabilities	(109)	(499)	34
Option premiums paid, net	(36)	(114)	(3)
Counterparty collateral (posted) received, net	162	95	(410)
Income taxes	402	114	193
Pension and non-pension postretirement benefit contributions	(149)	(178)	(1,070)
Other assets and liabilities	(136)	(128)	(57)
Net cash flows provided by operating activities	3,887	3,581	3,313
Cash flows from investing activities			
Capital expenditures	(2,752)	(3,554)	(2,491)
Proceeds from nuclear decommissioning trust fund sales	4,217	7,265	6,139
Investment in nuclear decommissioning trust funds	(4,450)	(7,483)	(6,332)
Cash and restricted cash acquired from Constellation	—	708	—
Proceeds from sale of long-lived assets	32	371	—
Acquisitions of long lived assets	—	(21)	(387)
Change in restricted cash	(64)	4	—
Changes in Exelon intercompany money pool	(44)	—	—
Distribution from CENG	115	—	—
Other investing activities	30	81	(6)
Net cash flows used in investing activities	(2,916)	(2,629)	(3,077)
Cash flows from financing activities			
Change in short-term debt	13	(52)	—
Issuance of long-term debt	854	1,076	—
Retirement of long-term debt	(570)	(145)	(2)
Distribution to member	(625)	(1,626)	(172)
Contribution from member	26	48	30
Other financing activities	(82)	(78)	(52)
Net cash flows used in financing activities	(384)	(777)	(196)
Increase in cash and cash equivalents	587	175	40
Cash and cash equivalents at beginning of period	671	496	456
Cash and cash equivalents at end of period	$ 1,258	$ 671	$ 496

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,196	$ 596
Cash and cash equivalents of variable interest entities	62	75
Restricted cash and cash equivalents	19	—
Restricted cash and cash equivalents of variable interest entities	52	16
Accounts receivable, net		
Customer	1,429	1,482
Other	353	472
Accounts receivable, net, of variable interest entities	260	292
Mark-to-market derivative assets	727	938
Mark-to-market derivative assets with affiliate	—	226
Receivables from affiliates	108	141
Receivable from Exelon intercompany money pool	44	—
Unamortized energy contract assets	374	886
Inventories, net		
Fossil fuel	164	130
Materials and supplies	671	626
Deferred income taxes	475	—
Other	505	331
Total current assets	6,439	6,211
Property, plant and equipment, net	20,111	19,531
Deferred debits and other assets		
Nuclear decommissioning trust funds	8,071	7,248
Investments	400	420
Investment in CENG	1,925	1,849
Mark-to-market derivative assets	600	924
Prepaid pension asset	1,873	1,975
Pledged assets for Zion Station decommissioning	458	614
Unamortized energy contract assets	710	1,073
Other	645	836
Total deferred debits and other assets	14,682	14,939
Total assets	$41,232	$40,681

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 22	$ —
Long-term debt due within one year	556	24
Long-term debt due within one year of variable interest entities	5	4
Accounts payable	1,152	1,326
Accounts payable of variable interest entities	170	202
Accrued expenses	976	1,116
Payables to affiliates	181	213
Deferred income taxes	25	128
Mark-to-market derivative liabilities	142	334
Unamortized energy contract liabilities	249	378
Other	389	372
Total current liabilities	3,867	4,097
Long-term debt	5,559	5,245
Long-term debt to affiliate	1,523	2,007
Long-term debt of variable interest entities	86	203
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,295	5,398
Asset retirement obligations	5,047	4,938
Non-pension postretirement benefit obligations	850	755
Spent nuclear fuel obligation	1,021	1,020
Payables to affiliates	2,740	2,397
Mark-to-market derivative liabilities	120	232
Unamortized energy contract liabilities	266	516
Payable for Zion Station decommissioning	305	432
Other	811	776
Total deferred credits and other liabilities	17,455	16,464
Total liabilities	28,490	28,016
Commitments and contingencies		
Equity		
Member’s equity		
Membership interest	8,898	8,876
Undistributed earnings	3,613	3,168
Accumulated other comprehensive income, net	214	513
Total member’s equity	12,725	12,557
Non-controlling interest	17	108
Total equity	12,742	12,665
Total liabilities and equity	$41,232	$40,681

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Changes in Member's Equity

(In millions)	Member's Equity			Non-controlling Interest	Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income		
Balance, December 31, 2010	$ 3,526	$ 2,633	$ 1,013	$ 5	$ 7,177
Net income	—	1,771	—	—	1,771
Distribution to member	—	(172)	—	—	(172)
Allocation of tax benefit from member	30	—	—	—	30
Other comprehensive loss, net of income taxes of $(64)	—	—	(98)	—	(98)
Balance, December 31, 2011	$ 3,556	$ 4,232	$ 915	$ 5	$ 8,708
Net income	—	562	—	(4)	558
Distribution to member	—	(1,626)	—	—	(1,626)
Allocation of tax benefit from member	48	—	—	—	48
Acquisition of Constellation	5,264	—	—	—	5,264
Non-controlling interest acquired	8	—	—	107	115
Other comprehensive loss, net of income taxes of $(261)	—	—	(402)	—	(402)
Balance, December 31, 2012	$ 8,876	$ 3,168	$ 513	$ 108	$12,665
Net income	—	1,070	—	(10)	1,060
Distribution to member	—	(625)	—	—	(625)
Allocation of tax benefit from member	26	—	—	—	26
Consolidated VIE dividend to non-controlling interest	—	—		(63)	(63)
Deconsolidation of VIE	(1)	—	—	(18)	(19)
Non-controlling interest acquired	(3)	—	—	—	(3)
Other comprehensive loss, net of income taxes of $(190)	—	—	(299)	—	(299)
Balance, December 31, 2013	$ 8,898	$ 3,613	$ 214	$ 17	$12,742

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(in millions)	For the Years Ended December 31, 2013	2012	2011
Operating revenues			
Operating revenues	$4,461	$5,441	$6,054
Operating revenues from affiliates	3	2	2
Total operating revenues	4,464	5,443	6,056
Operating expenses			
Purchased power	662	1,518	2,382
Purchased power from affiliate	512	789	653
Operating and maintenance	1,211	1,182	1,031
Operating and maintenance from affiliate	157	163	158
Depreciation and amortization	669	610	554
Taxes other than income	299	295	296
Total operating expenses	3,510	4,557	5,074
Operating income	954	886	982
Other income and (deductions)			
Interest expense	(566)	(294)	(330)
Interest expense to affiliates, net	(13)	(13)	(15)
Other, net	26	39	29
Total other income and (deductions)	(553)	(268)	(316)
Income before income taxes	401	618	666
Income taxes	152	239	250
Net income	249	379	416
Other comprehensive income			
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively	—	1	—
Other comprehensive income	—	1	—
Comprehensive income	$ 249	$ 380	$ 416

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended 2013	2012	2011
Cash flows from operating activities			
Net income	$ 249	$ 379	$ 416
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	669	610	554
Deferred income taxes and amortization of investment tax credits	(57)	270	700
Other non-cash operating activities	28	252	184
Changes in assets and liabilities:			
Accounts receivable	(12)	24	5
Receivables from and payables to affiliates, net	(12)	(18)	(287)
Inventories	(18)	(11)	(9)
Accounts payable, accrued expenses and other current liabilities	74	59	(84)
Counterparty collateral received, net	53	40	66
Income taxes	178	9	223
Pension and non-pension postretirement benefit contributions	(122)	(138)	(977)
Other assets and liabilities	188	(142)	45
Net cash flows provided by operating activities	1,218	1,334	836
Cash flows from investing activities			
Capital expenditures	(1,433)	(1,246)	(1,028)
Proceeds from sales of investments	7	28	6
Purchases of investments	(4)	(13)	(4)
Change in restricted cash	(2)	—	—
Other investing activities	45	19	19
Net cash flows used in investing activities	(1,387)	(1,212)	(1,007)
Cash flows from financing activities			
Changes in short-term debt	184	—	—
Issuance of long-term debt	350	350	1,199
Retirement of long-term debt	(252)	(450)	(537)
Dividends paid on common stock	(220)	(105)	(300)
Other financing activities	(1)	(7)	(7)
Net cash flows provided by (used in) financing activities	61	(212)	355
Increase (decrease) in cash and cash equivalents	(108)	(90)	184
Cash and cash equivalents at beginning of period	144	234	50
Cash and cash equivalents at end of period	$ 36	$ 144	$ 234

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 36	$ 144
Restricted cash	2	—
Accounts receivable, net		
Customer	451	539
Other	584	452
Inventories, net	109	91
Deferred income taxes	—	83
Counterparty collateral deposited	—	53
Regulatory assets	329	388
Other	29	25
Total current assets	1,540	1,775
Property, plant and equipment, net	14,666	13,826
Deferred debits and other assets		
Regulatory assets	933	666
Investments	5	8
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivable from affiliates	2,469	2,039
Prepaid pension asset	1,583	1,661
Other	291	299
Total deferred debits and other assets	7,912	7,304
Total assets	$24,118	$22,905

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 184	$ —
Long-term debt due within one year	617	252
Accounts payable	449	379
Accrued expenses	307	295
Payables to affiliates	83	97
Customer deposits	133	136
Regulatory liabilities	170	170
Mark-to-market derivative liability	17	18
Mark-to-market derivative liability with affiliate	—	226
Deferred income taxes	16	—
Other	72	82
Total current liabilities	2,048	1,655
Long-term debt	5,058	5,315
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,116	4,272
Asset retirement obligations	99	99
Non-pension postretirement benefits obligations	381	273
Regulatory liabilities	3,512	3,229
Mark-to-market derivative liability	176	49
Other	994	484
Total deferred credits and other liabilities	9,278	8,406
Total liabilities	16,590	15,582
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,190	5,014
Retained earnings	750	721
Total shareholders' equity	7,528	7,323
Total liabilities and shareholders' equity	$24,118	$22,905

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance, December 31, 2010	$ 1,588	$4,992	$ (1,639)	$ 1,970	$ (1)	$ 6,910
Net income	—	—	416	—	—	416
Common stock dividends	—	—	—	(300)	—	(300)
Allocation of tax benefit from parent	—	11	—	—	—	11
Appropriation of retained earnings for future dividends	—	—	(416)	416	—	—
Balance, December 31, 2011	$ 1,588	$5,003	$ (1,639)	$ 2,086	$ (1)	$ 7,037
Net income	—	—	379	—	—	379
Common stock dividends	—	—	—	(105)	—	(105)
Allocation of tax benefit from parent	—	11	—	—	—	11
Appropriation of retained earnings for future dividends	—	—	(379)	379	—	—
Other comprehensive income, net of income taxes of $0	—	—	—	—	1	1
Balance, December 31, 2012	$ 1,588	$5,014	$ (1,639)	$ 2,360	$ —	$ 7,323
Net income	—	—	249	—	—	249
Common stock dividends	—	—	—	(220)	—	(220)
Parent tax matter indemnification	—	176	—	—	—	176
Appropriation of retained earnings for future dividends	—	—	(249)	249	—	—
Balance, December 31, 2013	$ 1,588	$5,190	$ (1,639)	$ 2,389	$ —	$ 7,528

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating revenues			
Operating revenues	$3,099	$3,183	$3,715
Operating revenues from affiliates	1	3	5
Total operating revenues	3,100	3,186	3,720
Operating expenses			
Purchased power and fuel	908	842	1,369
Purchased power from affiliate	392	533	495
Operating and maintenance	647	698	698
Operating and maintenance from affiliates	101	111	96
Depreciation and amortization	228	217	202
Taxes other than income	158	162	205
Total operating expenses	2,434	2,563	3,065
Operating income	666	623	655
Other income and (deductions)			
Interest expense	(103)	(111)	(122)
Interest expense to affiliates, net	(12)	(12)	(12)
Other, net	6	8	14
Total other income and (deductions)	(109)	(115)	(120)
Income before income taxes	557	508	535
Income taxes	162	127	146
Net income	395	381	389
Preferred security dividends and redemption	7	4	4
Net income attributable to common shareholder	388	377	385
Comprehensive income, net of income taxes			
Net income	395	381	389
Other comprehensive income			
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively	—	1	—
Other comprehensive income	—	1	—
Comprehensive income	$ 395	$ 382	$ 389

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income	$ 395	$ 381	$ 389
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	228	217	202
Deferred income taxes and amortization of investment tax credits	20	37	253
Other non-cash operating activities	108	125	100
Changes in assets and liabilities:			
Accounts receivable	(79)	(14)	225
Receivables from and payables to affiliates, net	(18)	13	(217)
Inventories	2	21	—
Accounts payable, accrued expenses and other current liabilities	41	(47)	34
Income taxes	87	174	(45)
Pension and non-pension postretirement benefit contributions	(31)	(45)	(137)
Other assets and liabilities	(6)	16	14
Net cash flows provided by operating activities	747	878	818
Cash flows from investing activities			
Capital expenditures	(537)	(422)	(481)
Changes in intercompany money pool	—	82	(82)
Change in restricted cash	(2)	2	(2)
Other investing activities	8	10	8
Net cash flows used in investing activities	(531)	(328)	(557)
Cash flows from financing activities			
Payment of accounts receivable agreement	(210)	(15)	—
Issuance of long-term debt	550	350	—
Retirement of long-term debt	(300)	(375)	(250)
Contributions from parent	27	9	18
Dividends paid on common stock	(332)	(343)	(348)
Dividends paid on preferred securities	(1)	(4)	(4)
Redemption of preferred securities	(93)	—	—
Other financing activities	(2)	(4)	(5)
Net cash flows used in financing activities	(361)	(382)	(589)
Increase (decrease) in cash and cash equivalents	(145)	168	(328)
Cash and cash equivalents at beginning of period	362	194	522
Cash and cash equivalents at end of period	$ 217	$ 362	$ 194

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 217	$ 362
Restricted cash and cash equivalents	2	—
Accounts receivable, net ($0 and $289 gross accounts receivable pledged as collateral as of December 31, 2013 and 2012, respectively)		
Customer	360	364
Other	107	161
Inventories, net		
Fossil fuel	60	65
Materials and supplies	21	19
Deferred income taxes	83	40
Prepaid utility taxes	3	21
Regulatory assets	17	32
Other	36	30
Total current assets	906	1,094
Property, plant and equipment, net	6,384	6,078
Deferred debits and other assets		
Regulatory assets	1,448	1,378
Investments	23	22
Investments in affiliates	8	8
Receivable from affiliates	447	360
Prepaid pension asset	363	373
Other	38	40
Total deferred debits and other assets	2,327	2,181
Total assets	$9,617	$9,353

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term notes payable—accounts receivable agreement	$ —	$ 210
Long-term debt due within one year	250	300
Accounts payable	285	244
Accrued expenses	106	82
Payables to affiliates	58	76
Customer deposits	49	51
Regulatory liabilities	106	169
Other	37	26
Total current liabilities	891	1,158
Long-term debt	1,947	1,647
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,487	2,331
Asset retirement obligations	29	29
Non-pension postretirement benefits obligations	286	284
Regulatory liabilities	629	538
Other	99	113
Total deferred credits and other liabilities	3,530	3,295
Total liabilities	6,552	6,284
Commitments and contingencies		
Preferred securities	—	87
Shareholders' equity		
Common stock	2,415	2,388
Retained earnings	649	593
Accumulated other comprehensive income, net	1	1
Total shareholders' equity	3,065	2,982
Total liabilities and shareholders' equity	$9,617	$9,353

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Changes in Stockholders' Equity

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2010	$ 2,361	$ 522	$ —	$ 2,883
Net income	—	389	—	389
Common stock dividends	—	(348)	—	(348)
Preferred security dividends	—	(4)	—	(4)
Allocation of tax benefit from parent	18	—	—	18
Balance, December 31, 2011	$ 2,379	$ 559	$ —	$ 2,938
Net income	—	381	—	381
Common stock dividends	—	(343)	—	(343)
Preferred security dividends	—	(4)	—	(4)
Allocation of tax benefit from parent	9	—	—	9
Other comprehensive income, net of income taxes of $0	—	—	1	1
Balance, December 31, 2012	$ 2,388	$ 593	$ 1	$ 2,982
Net income	—	395	—	395
Common stock dividends	—	(332)	—	(332)
Preferred security dividends	—	(1)	—	(1)
Redemption of preferred securities	—	(6)	—	(6)
Allocation of tax benefit from parent	27	—	—	27
Balance, December 31, 2013	$ 2,415	$ 649	$ 1	$ 3,065

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating revenues			
Operating revenues	$3,052	$2,725	$3,060
Operating revenues from affiliates	13	10	8
Total operating revenues	3,065	2,735	3,068
Operating expenses			
Purchased power and fuel	969	973	1,245
Purchased power from affiliate	452	396	348
Operating and maintenance	551	622	530
Operating and maintenance from affiliates	83	106	150
Depreciation and amortization	348	298	274
Taxes other than income	213	208	207
Total operating expenses	2,616	2,603	2,754
Operating income	449	132	314
Other income and (deductions)			
Interest expense	(106)	(128)	(113)
Interest expense to affiliates, net	(16)	(16)	(16)
Other, net	17	23	26
Total other income and (deductions)	(105)	(121)	(103)
Income before income taxes	344	11	211
Income taxes	134	7	75
Net income	210	4	136
Preference stock dividends	13	13	13
Net income (loss) attributable to common shareholder	$ 197	$ (9)	$ 123
Comprehensive income	$ 210	$ 4	$ 136

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income	$ 210	$ 4	$ 136
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	348	298	274
Deferred income taxes and amortization of investment tax credits	125	104	145
Other non-cash operating activities	153	193	129
Changes in assets and liabilities:			
Accounts receivable	(127)	(45)	60
Receivables from and payables to affiliates, net	(14)	26	(44)
Inventories	1	25	(10)
Accounts payable, accrued expenses and other current liabilities	(14)	(33)	(21)
Income taxes	(33)	14	35
Pension and non-pension postretirement benefit contributions	(24)	(16)	(67)
Other assets and liabilities	(64)	(85)	(161)
Net cash flows provided by operating activities	561	485	476
Cash flows from investing activities			
Capital expenditures	(587)	(582)	(592)
Change in restricted cash	2	—	—
Other investing activities	14	9	—
Net cash flows used in investing activities	(571)	(573)	(592)
Cash flows from financing activities			
Changes in short-term debt	135	—	—
Issuance of long-term debt	300	250	300
Retirement of long-term debt	(467)	(173)	(82)
Dividends paid on common stock	—	—	(85)
Dividends paid on preference stock	(13)	(13)	(13)
Contributions from parent	—	66	—
Other financing activities	(3)	(2)	(5)
Net cash flows (used in) provided by financing activities	(48)	128	115
Increase (decrease) in cash and cash equivalents	(58)	40	(1)
Cash and cash equivalents at beginning of period	89	49	50
Cash and cash equivalents at end of period	$ 31	$ 89	$ 49

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 31	$ 89
Restricted cash and cash equivalents of variable interest entity	28	30
Accounts receivable, net		
Customer	480	409
Other	114	111
Income taxes receivable	30	3
Inventories, net		
Gas held in storage	53	51
Materials and supplies	28	31
Deferred income taxes	2	1
Prepaid utility taxes	57	57
Regulatory assets	181	190
Other	7	8
Total current assets	1,011	980
Property, plant and equipment, net	5,864	5,498
Deferred debits and other assets		
Regulatory assets	524	522
Investments	5	5
Investments in affiliates	8	8
Prepaid pension asset	423	467
Other	26	26
Total deferred debits and other assets	986	1,028
Total assets	$7,861	$7,506

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2013	2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 135	$ —
Long-term debt due within one year	—	400
Long-term debt of variable interest entity due within one year	70	67
Accounts payable	270	235
Accrued expenses	111	102
Deferred income taxes	27	—
Payables to affiliates	55	69
Customer deposits	76	71
Regulatory liabilities	48	29
Other	35	7
Total current liabilities	827	980
Long-term debt	1,746	1,446
Long-term debt to financing trust	258	258
Long-term debt of variable interest entity	195	265
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,773	1,658
Asset retirement obligations	19	8
Non-pension postretirement benefits obligations	217	229
Regulatory liabilities	204	214
Other	67	90
Total deferred credits and other liabilities	2,280	2,199
Total liabilities	5,306	5,148
Commitments and contingencies		
Shareholders' equity		
Common stock	1,360	1,360
Retained earnings	1,005	808
Total shareholders' equity	2,365	2,168
Preference stock not subject to mandatory redemption	190	190
Total equity	2,555	2,358
Total liabilities and shareholders' equity	$7,861	$7,506

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statement of Changes in Shareholders' Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2010	$ 1,294	$ 779	$ 2,073	$ 190	$2,263
Net income	—	136	136	—	136
Common stock dividends	—	(85)	(85)	—	(85)
Preference stock dividends	—	(13)	(13)	—	(13)
Balance, December 31, 2011	$ 1,294	$ 817	$ 2,111	$ 190	$2,301
Net income	—	4	4	—	4
Preference stock dividends	—	(13)	(13)	—	(13)
Contribution from parent	66	—	66	—	66
Balance, December 31, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$2,358
Net income	—	210	210	—	210
Preference stock dividends	—	(13)	(13)	—	(13)
Balance, December 31, 2013	$ 1,360	$ 1,005	$ 2,365	$ 190	$2,555

See the Combined Notes to Consolidated Financial Statements

1. Significant Accounting Policies (Exelon, Generation, ComEd, PECO and BGE)

Description of Business (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses. Prior to March 12, 2012, Exelon's principal subsidiaries included ComEd, PECO and Generation. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger ("Merger Agreement"). As a result of the merger transaction, Generation now includes the former Constellation generation and customer supply operations. BGE, formerly Constellation's regulated utility subsidiary, is now a subsidiary of Exelon. Refer to Note 4—Merger and Acquisitions for further information regarding the merger transaction.

The energy generation business includes:

- *Generation* : Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other regions.

The energy delivery businesses include:

- *ComEd* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

This is a combined annual report of Exelon, Generation, ComEd, PECO and BGE. The Notes to the Consolidated Financial Statements apply to Exelon, Generation, ComEd, PECO and BGE as indicated parenthetically next to each corresponding disclosure. When appropriate, Exelon, Generation, ComEd, PECO and BGE are named specifically for their related activities and disclosures.

Exelon did not apply push-down accounting to BGE and BGE continued to be subject to reporting requirements as an SEC registrant. The information disclosed for BGE represents the activity of the standalone entity for the twelve months ended December 31, 2013, 2012 and 2011 and the financial position as of December 31, 2013 and December 31, 2012. However, for Exelon's consolidated financial reporting, Exelon is reporting BGE activity from the acquisition date of March 12, 2012 through December 31, 2013.

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC, including support services, are directly charged or allocated to the applicable subsidiaries using a cost-causative allocation method. Corporate governance-type costs that cannot be directly assigned are allocated based on a Modified Massachusetts Formula, which is a method that utilizes a combination of gross revenues, total assets and direct labor costs for the allocation base. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

Exelon owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%, and BGE, of which Exelon owns 100% of the common stock but none of BGE's preference stock. Exelon owned none of PECO's preferred securities, which PECO redeemed in 2013. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2013 and December 31, 2012, as equity, PECO's preferred securities as preferred securities of subsidiary through their redemption in 2013, and BGE's preference stock as BGE preference stock not subject to mandatory redemption in its consolidated financial statements. BGE is subject to some ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for certain Exelon Wind projects, of which Generation holds a majority interest ranging from 94% to 99% for certain periods of time, and the remaining interests are included in non-controlling interest on Exelon's and Generation's Consolidated Balance Sheets. See Note 2 for further discussion of Exelon's and Generation's VIEs and the reversionary interests of the non-controlling members for certain of these projects.

ComEd owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for RITELine Illinois, LLC, of which ComEd owns 75% and an additional 12.5% is indirectly owned by Exelon. Exelon and ComEd have reflected the third-party interests of 12.5% and 25%, respectively, in RITELine Illinois, LLC, which both totaled less than $1 million at December 31, 2013 and December 31, 2012, as equity.

Exelon consolidates the accounts of entities in which Exelon has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which Exelon can exercise control over the operations and policies of the investee, or the results of a model that identifies Exelon or one of its subsidiaries as the primary beneficiary of a VIE. Where Exelon does not have a controlling financial interest in an entity, it applies proportional consolidation, equity method accounting or cost method accounting. Exelon applies proportionate consolidation when it has an undivided interest in an asset and is proportionately liable for its share of each liability associated with the asset. Exelon proportionately consolidates its undivided ownership interests in jointly owned electric plants and transmission facilities, as well as its undivided ownership interests in upstream natural gas exploration and production activities. Under proportionate consolidation, Exelon separately records its proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. Exelon applies equity method accounting when it has significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. Exelon applies equity method accounting

to certain investments and joint ventures, including the 50.01% interest in CENG, and certain financing trusts of ComEd, PECO, and BGE. Under the equity method, Exelon reports its interest in the entity as an investment and Exelon's percentage share of the earnings from the entity as single line items in its financial statements. Exelon uses the cost method if it holds less than 20% of the common stock of an entity. Under the cost method, Exelon reports its investment at cost and recognizes income only to the extent Exelon receives dividends or distributions.

For the year ended December 31, 2013, BGE recorded a $2 million (pre-tax) correcting adjustment to decrease amortization expense related to regulatory assets that were originally recorded during 2012, an adjustment to decrease income tax expense by $4 million related to the recognition and measurement of regulatory assets that should have been recorded in periods prior to 2013, and a $4 million (pre-tax) correcting adjustment to decrease operating and maintenance expense for an overstatement of BGE's life insurance obligation related to post-employment benefits in prior years. For the year ended December 31, 2012, BGE recorded a $2 million (pre-tax) correcting adjustment to reduce electric distribution revenue related to decoupling of 2011 electric distribution revenue, a $3 million (pre-tax) correcting adjustment to increase electric operations and maintenance expense related to capitalization of electric transmission costs, and a $5 million (pre-tax) correcting adjustment to interest expense to reflect the impacts of amendments of tax positions previously taken on prior-year consolidated income tax returns. In addition, ComEd identified a disclosure adjustment within the renewable energy credits and alternative energy credits section of the 2012 Form 10-K Note 8—Intangible Assets which has been revised in Note 10 of this year's report. Exelon, ComEd and BGE have concluded these correcting adjustments are not material to its results of operations, cash flows, or financial positions for the years ended December 31, 2013, and December 31, 2012, or any prior period.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (Exelon, Generation, ComEd, PECO and BGE)

The preparation of financial statements of each of the Registrants in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other AROs, pension and other postretirement benefits, the application of purchase accounting, inventory reserves, allowance for uncollectible accounts, goodwill and asset impairments, derivative instruments, unamortized energy contracts, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Reclassifications (Exelon, ComEd, and BGE)

Certain prior year amounts in Exelon's and BGE's Consolidated Statements of Operations and Cash Flows, and Exelon's, ComEd's, and BGE's Consolidated Balance Sheets have been reclassified between line items for comparative purposes and correction of prior period classification errors identified in 2013. The reclassifications did not affect any of the Registrants' net income or cash flows from operating activities.

In 2013, Exelon and BGE corrected the presentation of interest expense related to BGE's financing trust of $12 million and $16 million, respectively, to be presented as Interest expense to

affiliates, net on their Statements of Operations and Comprehensive Income for the year ended December 31, 2012. BGE also reclassified the related Accrued expenses of $4 million to Payables to affiliates on its December 31, 2012 Balance Sheet. Similar adjustments are also reflected in Note 22 – Related Party Transactions. Exelon and Generation also corrected amounts disclosed within Note 22 – Related Party Transactions to increase Purchased power and fuel from affiliates by $114 million and to increase Payables to affiliates by $20 million. In 2013, Generation corrected the presentation of interest expense related to certain debt of $75 million to be presented as Interest expense to affiliates, net on its Statement of Operations and Comprehensive Income for the year ended December 31, 2012 and within Note 22 – Related Party Transactions.

Accounting for the Effects of Regulation (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulation, which requires ComEd, PECO and BGE to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria: 1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation that rates are set at levels that will recover the entities' costs from customers. Exelon, ComEd, PECO and BGE account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, the PAPUC, and the MDPSC, in the cases of ComEd, PECO and BGE, respectively, under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense is recognized in the Consolidated Statements of Operations consistent with the recovery or refund included in customer rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. However, Exelon, ComEd, PECO and BGE continue to evaluate their respective abilities to apply the authoritative guidance for accounting for certain types of regulation, including consideration of current events in their respective regulatory and political environments. If a separable portion of ComEd's, PECO's or BGE's business was no longer able to meet the criteria discussed above, the affected entities would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which could have a material impact on their results of operations and financial positions. See Note 3—Regulatory Matters for additional information.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Revenues (Exelon, Generation, ComEd, PECO and BGE)

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimates of the distribution and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE records its best estimate of the transmission revenue impact resulting from changes in rates that BGE believes are probable of approval by FERC in accordance with its formula rate mechanism. See Note 3—Regulatory Matters and Note 6—Accounts Receivable for further information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in

either revenues or purchased power on their Consolidated Statements of Operations, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Company in the different RTOs and ISOs.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. As of the merger date, Exelon and Generation have currently elected to de-designate all of their commodity cash flow hedge positions. As ComEd receives full cost recovery for energy procurement and related costs from retail customers, ComEd records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. Refer to Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments for further information.

Proprietary Trading Activities. Exelon and Generation account for Generation's trading activities under the provisions of the authoritative guidance for accounting for contracts involved in energy trading and risk management activities, which require energy revenues and costs related to energy trading contracts to be presented on a net basis in the income statement. Commodity derivatives used for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues. Refer to Note 12—Derivative Financial Instruments for further information.

Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

Deferred Federal and state income taxes are provided on all significant temporary differences between the book basis and the tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred on the Registrants' Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion; and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Registrants recognize accrued interest related to unrecognized tax benefits in interest expense or in other income and deductions (interest income) on their Consolidated Statements of Operations.

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 14—Income Taxes for further information.

Taxes Directly Imposed on Revenue-Producing Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes

are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, such as gross receipts taxes or other surcharges or fees, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 23—Supplemental Financial Information for Generation's, ComEd's, PECO's and BGE's utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE)

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Investments (Exelon, Generation, ComEd, PECO and BGE)

Restricted cash and investments represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2013 and 2012, Exelon Corporate's restricted cash and investments primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Additionally, Exelon Corporate has funds restricted for merger commitments. In addition, Exelon Corporate's investments include its direct financing lease investments. As of December 31, 2013, Generation's restricted cash and investments primarily included cash at Antelope Valley required for debt service and construction and cash at Continental Wind required for debt service and financing of operation and maintenance of the underlying entities. As of December 31, 2012, Generation's restricted cash primarily included cash at Antelope Valley required for debt service and construction. As of December 31, 2013 and 2012, ComEd's restricted cash primarily represented cash collateral held from suppliers associated with ComEd's REC procurement contracts. As of December 31, 2013, PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's mortgage indenture. As of December 31, 2013 and 2012, BGE's restricted cash primarily represented funds restricted at its consolidated variable interest entity for repayment of rate stabilization bonds.

Restricted cash and investments not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2013 and 2012, Exelon's and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2013, Exelon, Generation, ComEd, PECO and BGE had investments in Rabbi trusts classified as noncurrent assets.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging, historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed

is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 3—Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and
- requires the entity that consolidates a VIE (the primary beneficiary) to present separately on the face of its balance sheet (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

Based on the above accounting guidance, Exelon has adopted the following policies related to variable interest entities:

- Exelon has presented separately on its Consolidated Balance Sheets, to the extent material, the assets of its consolidated VIEs that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of Exelon's consolidated VIEs for which creditors do not have recourse to Exelon's general credit.
- Exelon has qualitatively assessed whether the equity holders of the entity have the power to direct matters that most significantly impact the entity.

See Note 2—Variable Interest Entities for additional information.

Inventories (Exelon, Generation, ComEd, PECO and BGE)

Inventory is recorded at the lower of weighted average cost or market. Provisions are recorded for excess and obsolete inventory.

Fossil Fuel. Fossil fuel inventory includes the weighted average costs of stored natural gas, propane and oil. The costs of natural gas, propane, coal and oil are generally included in inventory when purchased and charged to fuel expense when used or sold.

Materials and Supplies. Materials and supplies inventory generally includes the weighted average costs of transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and expensed or capitalized to property, plant and equipment, as appropriate, when installed or used.

Emission Allowances. Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) and are carried at the lower of weighted average cost or market and charged to fuel expense as they are used in operations.

Marketable Securities (Exelon, Generation, ComEd, PECO and BGE)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds, certain Generation Rabbi trust investments and BGE's Rabbi trust investments are classified as trading securities and all other securities are classified as available-for-sale securities. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former ComEd and former PECO nuclear generating units (Regulatory Agreement Units) are included in regulatory liabilities at Exelon, ComEd and PECO and in noncurrent payables to affiliates at Generation and in noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former AmerGen nuclear generating units, the Zion generating station and portions of the Peach Bottom nuclear generating units not subject to a regulatory agreement (Non-Regulatory Agreement Units) are included in earnings at Exelon and Generation. Realized and unrealized gains and losses, net of tax, on certain Generation Rabbi trust investments and BGE's Rabbi trust investments are included in earnings at Exelon, Generation and BGE. Unrealized gains and losses, net of tax, for Generation's, ComEd's and PECO's available-for-sale securities are reported in OCI. Any decline in the fair value of ComEd's and PECO's available-for-sale securities below the cost basis is reviewed to determine if such decline is other-than-temporary. If the decline is determined to be other-than-temporary, the cost basis of the available-for-sale securities is written down to fair value as a new cost basis and the amount of the write-down is included in earnings. See Note 15—Asset Retirement Obligations for information regarding marketable securities held by NDT funds and Note 23—Supplemental Financial Information for additional information regarding ComEd's and PECO's regulatory assets and liabilities.

Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

Property, plant and equipment is recorded at original cost. Original cost includes labor, materials and construction overhead. When appropriate, original cost also includes capitalized interest for Generation and Exelon Corporate and AFUDC for regulated property at ComEd, PECO and BGE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred. For constructed assets, Exelon capitalizes construction-related direct labor and material costs. ComEd, PECO and BGE also capitalized indirect construction costs including labor and related costs of departments associated with supporting construction activities.

Third parties reimburse ComEd, PECO and BGE for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, Plant and Equipment. DOE SGIG funds reimbursed to PECO and BGE are accounted for as CIAC.

For Generation, upon retirement, the cost of property is charged to accumulated depreciation in accordance with the composite method of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to operating and maintenance expense as incurred.

For ComEd, PECO and BGE, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. ComEd's and BGE's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. ComEd's and BGE's actual incurred removal costs are applied against a related regulatory liability. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method.

Generation's oil and gas exploration and production activities consist of working interests in gas producing fields. Generation accounts for these activities under the successful efforts method of accounting. Acquisition, development and exploration costs are capitalized. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

See Note 7—Property, Plant and Equipment, Note 9—Jointly Owned Electric Utility Plant and Note 23—Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within property, plant and equipment and charged to fuel expense using the unit-of-production method. The estimated disposal cost of SNF is established per the Standard Waste Contract with the DOE and is expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. On-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 22—Commitments and Contingencies for additional information regarding the SNF disposal fee.

Nuclear Outage Costs (Exelon and Generation)

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to operating and maintenance expense or capitalized to property, plant and equipment (based on the nature of the activities) in the period incurred.

New Site Development Costs (Exelon and Generation)

New site development costs represent the costs incurred in the assessment and design of new power generating facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management's determination that the project is economically and operationally feasible, management and/or the Exelon board of directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. Capitalized development costs are charged to Operating and maintenance expense when project completion is no longer probable. At December 31, 2013 and 2012, there were no material capitalized development costs for projects not yet under construction included in Property, plant and equipment, net on Exelon's and Generation's Consolidated Balance Sheets. Approximately $10 million, $4 million and $2 million of costs were expensed by Exelon and Generation for the years ended December 31, 2013, 2012, and 2011, respectively. These costs primarily related to the possible development of new renewable energy projects.

Capitalized Software Costs (Exelon, Generation, ComEd, PECO and BGE)

Costs incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

Net unamortized software costs	Exelon	Generation	ComEd	PECO	BGE
December 31, 2013	$ 479	$ 129	$ 101	$ 71	$155
December 31, 2012	499	143	105	63	157

Amortization of capitalized software costs	Exelon [(a)]	Generation [(a)]	ComEd	PECO	BGE [(a)]
2013	$ 198	$67	$52	$ 33	$36
2012	208	81	56	30	32
2011	122	41	50	25	25

(a) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the year ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012. BGE activity represents the activity for the years ended December 31, 2012 and 2011.

Depreciation, Depletion and Amortization (Exelon, Generation, ComEd, PECO and BGE)

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method. ComEd's and BGE's depreciation includes a provision for estimated removal costs as authorized by the respective regulators. The estimated service lives for ComEd, PECO and BGE are primarily based on the average service lives from the most recent depreciation study for each respective company. The estimated service lives of the nuclear-fuel generating facilities are based on the remaining useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses (to the extent that such renewal has not yet been granted) for all of Generation's operating nuclear generating stations except for Oyster Creek. The estimated service lives of the hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the operating licenses. The estimated service lives of the fossil fuel and other renewable generating facilities are based on the remaining useful lives of the stations, which Generation periodically evaluates based on feasibility assessments taking into account economic and capital requirement considerations.

See Note 7—Property, Plant and Equipment for further information regarding depreciation.

Depletion of oil and gas exploration and production activities is recorded using the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for gas reserves are based on internal calculations.

Amortization of regulatory assets is recorded over the recovery period specified in the related legislation or regulatory agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost would have originally been recorded

in the Registrants' Consolidated Statements of Operations and Comprehensive Income. With exception of income tax-related regulatory assets, when the recovery period is more than one year, the amortization is recorded to Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income. For income tax related regulatory assets, amortization is generally recorded to Income tax expense in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

See Note 3—Regulatory Matters and Note 23—Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of ComEd's, PECO's and BGE's regulatory assets.

Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years. The liabilities associated with Exelon's non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years. Changes to the recorded value of an ARO result from the passage of new laws and regulations, revisions to either the timing or amount of estimates of undiscounted cash flows, and estimates of cost escalation factors. AROs are accreted each year to reflect the time value of money for these present value obligations through a charge to operating and maintenance expense in the Consolidated Statements of Operations or, in the case of the majority of ComEd's, PECO's, and BGE's accretion, through an increase to regulatory assets. See Note 15—Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (Exelon, Generation, ComEd, PECO and BGE)

During construction, Exelon and Generation capitalize the costs of debt funds used to finance non-regulated construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense.

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to AFUDC that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

The following table summarizes total incurred interest, capitalized interest and credits to AFUDC by year:

		Exelon [(a)]	Generation [(a)]	ComEd	PECO	BGE [(a)]
2013	Total incurred interest [(b)]	$1,423	$ 411	$ 584	$117	$129
	Capitalized interest	54	54	—	—	—
	Credits to AFUDC debt and equity	35	—	16	6	13
2012	Total incurred interest [(b)]	$1,003	$ 368	$ 310	$125	$149
	Capitalized interest	67	67	—	—	—
	Credits to AFUDC debt and equity	25	—	9	6	15
2011	Total incurred interest [(b)]	$ 783	$ 219	$ 349	$138	$136
	Capitalized interest	49	49	—	—	—
	Credits to AFUDC debt and equity	25	—	12	13	22

(a) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the year ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012. BGE activity represents the activity for the years ended December 31, 2012, 2011 and 2010.
(b) Includes interest expense to affiliates.

Guarantees (Exelon, Generation, ComEd, PECO and BGE)

The Registrants recognize, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken in issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 22—Commitments and Contingencies for additional information.

Asset Impairments (Exelon, Generation, ComEd, PECO and BGE)

Long-Lived Assets. The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. The Registrants determine if long-lived assets and asset groups are impaired by comparing their undiscounted expected future cash flows to their carrying value. Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Cash flows from Generation plant assets are generally evaluated at a regional portfolio level along with cash flows generated from Generation's supply and risk management activities, including cash flows from contracts that are recorded as intangible contract assets and liabilities on the balance sheet. In certain cases generation assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables).

Impairment may occur when the carrying value of the asset or asset group exceeds the future undiscounted cash flows. When the undiscounted cash flow analysis indicates a long-lived asset or

asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value.

Conditions that could have an adverse impact on the expected future cash flows and the fair value of the long-lived assets and asset groups include, among other factors, a deteriorating business climate, including energy prices and market conditions, revisions to regulatory laws, or plans to dispose of a long-lived asset significantly before the end of its useful life. See Note 8—Impairment of Long-Lived Assets for additional information.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 10—Intangible Assets for additional information regarding Exelon's and ComEd's goodwill.

Equity Method Investments. Exelon and Generation regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is not temporary in nature. Additionally, if the project in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other than temporary decline in value.

Direct Financing Lease Investments. Direct financing lease investments represent the estimated residual values of leased coal-fired plants in Georgia and Texas. Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. See Note 8—Impairment of Long-Lived Assets for additional information.

Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For derivative contracts intended to serve as economic hedges and that are not designated or do not qualify for hedge accounting or the normal purchases and normal sales exception, changes in the fair value of the derivatives are recognized in earnings each period. Amounts classified in earnings are included in revenue, purchased power and fuel, interest expense or other, net on the Consolidated Statement of Operations based on the activity the transaction is economically hedging. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon's Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. All amounts classified in earnings related to proprietary trading are

included in revenue on the Consolidated Statement of Operations. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

For commodity derivative contracts, effective with the date of the merger with Constellation, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivatives executed to hedge economic risk for commodities are recorded at fair value with changes in fair value recognized through earnings for the combined company.

As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See Note 12—Derivative Financial Instruments for additional information.

Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. Effective March 12, 2012, Exelon became the sponsor of all of Constellation's defined benefit pension and other postretirement benefit plans and defined contribution savings plans.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 16—Retirement Benefits for additional discussion of Exelon's accounting for retirement benefits.

Equity Investment Earnings (Losses) of Unconsolidated Affiliates (Exelon and Generation)

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities, power projects and joint ventures, including Generation's 50.01% interest in CENG, in equity in earnings (losses) of unconsolidated affiliates. Equity in earnings (losses) of unconsolidated affiliates also includes any adjustments to amortize the difference, if any, except for goodwill and land, between

their cost in an equity method investment and the underlying equity in net assets of the investee at the date of investment. See Note 5—Investment in CENG and Note 25—Related Party Transactions for additional discussion of Exelon's and Generation's investment in CENG.

Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such investment experiences an other than temporary decline in value.

New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

Exelon has identified the following new accounting pronouncements that have been recently adopted or issued that may affect the Registrants.

Presentation of Items Reclassified out of Accumulated Other Comprehensive Income

In February 2013, the FASB issued authoritative guidance requiring entities to present either in the notes or parenthetically on the face of the financial statements, reclassifications from each component of accumulated other comprehensive income and the affected income statement line items. Entities only need to disclose the affected income statement line item for components reclassified to net income in their entirety; otherwise, a cross-reference to the related note should be provided. This guidance was effective for the Registrants for periods beginning after December 15, 2012 and was required to be applied prospectively. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants' results of operations, cash flows or financial positions. See Note 21—Changes in Accumulated Other Comprehensive Income for the new disclosures.

Disclosures About Offsetting Assets and Liabilities

In December 2011 (and amended in January 2013), the FASB issued authoritative guidance requiring entities to disclose both gross and net information about recognized derivative instruments, including bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing or lending transactions that are offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. The guidance was effective for the Registrants for periods beginning on or after January 1, 2013 and was required to be applied retrospectively. This guidance is primarily applicable to certain derivative transactions for Exelon and Generation. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants' results of operations, cash flows or financial positions. See Note 12—Derivative Financial Instruments for the new disclosures.

Inclusion of the Fed Funds Effective Swap Rate as a Benchmark Interest Rate for Hedge Accounting Purposes

In July 2013, the FASB issued authoritative guidance permitting entities to designate the Fed Funds Effective Swap Rate as a U.S. benchmark interest rate for hedge accounting purposes. Prior to the issuance of this guidance, only interest rates on direct treasury obligations of the U.S. government and the LIBOR swap rate were considered benchmark interest rates in the U.S. This guidance was effective immediately and can be applied prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. Currently, the Registrants do not use the Fed Funds Effective Swap Rate as a benchmark interest rate, but may in the future.

The following recently issued accounting standard is not yet required to be reflected in the combined financial statements of the Registrants.

Presentation of Unrecognized Tax Benefits When Net Operating Loss Carryforwards, Similar Tax Losses or Tax Credit Carryforwards Exist

In July 2013, the FASB issued authoritative guidance requiring entities to present unrecognized tax benefits as a reduction to deferred tax assets for losses or other tax carryforwards that would be available to offset the uncertain tax positions at the reporting date. Currently, the Registrants present their unrecognized tax benefits as liabilities on a gross basis unless an unrecognized tax benefit is directly associated with a tax position taken in a tax year that results in the recognition of a net operating loss or other tax carryforward for that year. This guidance is effective for the Registrants for periods beginning after December 15, 2013 and is required to be applied prospectively, with retroactive application permitted. The Registrants will not retroactively adopt this guidance. This guidance is currently not expected to have an impact on the Registrants upon adoption with the exception of Exelon and Generation in which approximately $11 million of unrecognized tax benefits will be offset against current deferred income assets. The adoption of this standard will not impact the Registrants' results of operations.

2. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Under the applicable authoritative guidance, a VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly impact the entity's economic performance.

At December 31, 2013 and 2012, the Exelon, Generation, and BGE consolidated four and five VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary. As of December 31, 2013, the Registrants had one VIE for which the Registrants were the primary beneficiary, however, the VIE is immaterial and was not included in the consolidated financial statements or in the consolidated VIE table below. As of December 31, 2013 and 2012, the Registrants had significant interests in eight and nine other VIEs for which the Registrants do not have the power to direct the entities' activities, respectively, and accordingly, were not the primary beneficiary.

Consolidated Variable Interest Entities

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the Registrants' consolidated financial statements at December 31, 2013 and 2012 are as follows:

	December 31, 2013			December 31, 2012		
	Exelon [(a)]	Generation	BGE	Exelon [(a)(b)]	Generation [(b)]	BGE
Current assets	$ 484	$ 446	$ 28	$ 550	$ 519	$ 30
Noncurrent assets	1,905	1,884	3	1,719	1,680	—
Total assets	$ 2,389	$ 2,330	$ 31	$ 2,269	$ 2,199	$ 30
Current liabilities	$ 566	$ 481	$ 74	$ 684	$ 612	$ 71
Noncurrent liabilities	774	562	195	775	470	265
Total liabilities	$ 1,340	$ 1,043	$269	$ 1,459	$ 1,082	$336

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total assets of $146 million and total liabilities of $42 million as of December 31, 2012 related to a retail supply company that is not a consolidated VIE as of December 31, 2013. See additional information below.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the preceding table can only be settled using VIE resources.

RSB BondCo LLC . In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. BGE has determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE consolidates BondCo.

BondCo's assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2013, 2012, and 2011, BGE remitted $83 million, $85 million, and $92 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2013. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

Retail Gas Group . During 2009, Constellation formed two new entities, which now are part of Generation, and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third-party gas supplier. While Generation owns 100% of these entities, it has been determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group's activities without the additional credit support that is provided in the form of a parental guarantee. Generation is the primary beneficiary of the retail gas entity group; accordingly, Generation consolidates the retail gas entity group as a VIE.

The third-party gas supply arrangement is collateralized as follows:

- The assets of the retail gas entity group must be used to settle obligations under the third-party gas supply agreement before it can make any distributions to Generation,
- The third-party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- As of December 31, 2013 Exelon provided a $75 million parental guarantee to the third-party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee, Exelon or Generation do not have any contractual or other obligations to provide additional financial support under the collateralized third-party gas supply agreement. The third-party gas supply creditors do not have any recourse to Exelon's or Generation's general credit other than the parental guarantee.

Solar Project Entity Group. In 2011, Constellation formed a group of solar project limited liability companies to build, own, and operate solar power facilities, which are now part of Generation. Additionally, on September 30, 2011, Generation acquired all of the equity interests in Antelope Valley Solar Ranch One (Antelope Valley) from First Solar, Inc., a 230-MW solar PV project under construction in northern Los Angeles County, California. While Generation owns 100% of these entities, it has been determined that certain of the individual solar project entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the solar project entities that qualify as VIEs because Generation controls the design, construction, and operation of the solar power facilities. Generation provides capital funding to these solar VIE entities for ongoing construction of the solar power facilities. In addition, these solar VIE entities have an aggregate amount of outstanding debt with third parties of $536 million, as of December 31, 2013, for which the creditors have no recourse to Generation, however there is limited recourse to Generation with respect to remaining equity contributions necessary to complete the Antelope Valley project. For additional information on these project-specific financing arrangements refer to Note 13—Debt and Credit Agreements.

Retail Power Supply Entity. In August 2013, Generation executed an agreement to terminate its energy supply contract with a retail power supply company that was previously a consolidated VIE. Generation did not have an ownership interest in the entity, but was the primary beneficiary through the energy supply contract. As a result of the termination, Generation no longer has a variable interest in the retail power supply company and ceased consolidation of the entity during the third quarter of 2013. Upon deconsolidation, there was no gain or loss recognized. The assets, liabilities, and non-controlling interest were removed from Exelon's and Generation's balance sheet and the change in non-controlling interest is also reflected on the Statement of Changes in Shareholders' Equity and the Statement of Changes in Member's Equity for Exelon and Generation, respectively.

Wind Project Entity Group. Generation owns and operates a number of wind project limited liability entities, the majority of which were acquired on December 9, 2010 when Generation completed the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind). Generation has evaluated the significant agreements and ownership structures and risks of each of its wind projects and underlying entities, and determined that certain of the entities are VIEs because either the projects have non-controlling interest holders that absorb variability from the wind projects, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the wind project entities that

qualify as VIEs because Generation controls the design, construction, and operation of the wind power facilities. While Generation owns 100% of the majority of the wind project entities, 10 of the projects have non-controlling equity interests held by third parties, that currently range between 1% and 6%. Of these 10 projects, Generation's current economic interests in nine of the projects are significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the non-controlling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the non-controlling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the non-controlling interests state that Generation is to provide financial support to the projects in proportion to its current economic interests in the projects that currently range between 94% and 99%. However, no additional support to these projects beyond what was contractually required has been provided during 2013. As of December 31, 2013, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of the wind VIE entities primarily relate to the wind generating assets, PPA intangible assets and working capital amounts.

As of December 31, 2013 and 2012, ComEd and PECO did not have any consolidated VIEs.

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include three transaction types: (1) equity investments, (2) energy purchase and sale contracts, and (3) fuel purchase commitments. For the equity investments, the carrying amount of the investments is reflected on their Consolidated Balance Sheets in Investments in affiliates. For the energy purchase and sale contracts and the fuel purchase commitments (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of December 31, 2013 and 2012, Exelon and Generation had significant unconsolidated variable interests in eight and nine, respectively, VIEs for which they were not the primary beneficiary; including certain equity investments and certain commercial agreements. The change in the number of unconsolidated variable interests is driven by the completion of certain obligations which cause the entities to no longer be unconsolidated variable interests offset by the addition of an equity investment in a residential solar provider. The following tables present summary information about the significant unconsolidated VIE entities:

December 31, 2013	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 128	$ 332	$460
Total liabilities [a]	17	123	140
Registrants' ownership interest [a]	—	86	86
Other ownership interests [a]	111	123	234
Registrants' maximum exposure to loss:			
Carrying amount of equity investments	7	67	74
Contract intangible asset	9	—	9
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning [b]	44	—	44

December 31, 2012	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 386	$ 354	$740
Total liabilities [a]	219	114	333
Registrants' ownership interest [a]	—	97	97
Other ownership interests [a]	167	143	310
Registrants' maximum exposure to loss:			
Letters of credit	5	—	5
Carrying amount of equity investments	—	77	77
Contract intangible asset	8	—	8
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning [b]	50	—	50

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.

(b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $458 million and $614 million as of December 31, 2013 and December 31, 2012, respectively; offset by payables to ZionSolutions LLC of $414 million and $564 million as of December 31, 2013 and December 31, 2012, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE. See Note 15—Asset Retirement Obligations for further discussion.

For each unconsolidated VIE, Exelon and Generation assess the risk of a loss equal to their maximum exposure to be remote and, accordingly Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would materially affect the fair value or risk of their variable interests in these variable interest entities.

Energy Purchase and Sale Agreements. In March 2005, Constellation, to which Generation is now a successor, closed a transaction in which Generation assumed from a counterparty two power sales contracts with previously existing VIEs. The VIEs previously were created by the counterparty to issue debt in order to monetize the value of the original contracts to purchase and sell power. Under the power sales contracts, Generation sold power to the VIEs which, in turn, sold that power to an electric distribution utility through 2013. In connection with this transaction, a third-party acquired the equity of the VIEs and Generation loaned that party a portion of the purchase price. If the electric distribution utility were to default under its obligation to buy power from the VIEs, the equity holder could transfer its equity interests to Generation in lieu of repaying the loan. In this event, Generation would have the right to seek recovery of its losses from the electric distribution utility. As a result, Generation has concluded that consolidation was not required. During 2013, the third-party repaid their obligations of the loan with Generation which caused the entities to no longer be unconsolidated VIEs.

ZionSolutions. Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 15—Asset Retirement Obligations. Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning is complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required. Other than the asset sale agreement, Exelon or Generation do not have any contractual or other obligations to provide additional financial support and ZionSolutions' creditors do not have any recourse to Exelon's or Generation's general credit.

Fuel Purchase Commitments. Generation's customer supply operations include the physical delivery and marketing of power obtained through its generating capacity, and long-, intermediate- and short-term contracts. Generation also has contracts to purchase fuel supplies for nuclear and fossil generation. These contracts and Generation's membership in NEIL are discussed in further detail in Note 22—Commitments and Contingencies. Generation has evaluated these contracts and its membership with NEIL and determined that it either has no variable interest in an entity or, where Generation does have a variable interest in an entity, the variable interest is not significant and it is not the primary beneficiary; therefore, consolidation is not required.

For contracts where Generation has a variable interest, the level of variability being absorbed through the contracts is not considered significant because of the small proportion of the entities' activities encompassed by the contracts with Generation. Further, Generation has considered which interest holder has the power to direct the activities that most significantly affect the economic performance of the VIE and thus is considered the primary beneficiary and is required to consolidate the entity. The primary beneficiary must also have exposure to significant losses or the right to receive significant benefits from the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of the facilities. Facilities represent power plants, sources of uranium and fossil fuels, or plants used in the uranium conversion, enrichment and fabrication process. Generation does not have control over the operation and maintenance of the facilities considered VIEs, and it does not bear operational risk of the facilities. Furthermore, Generation has no debt or equity investments in the entities and Generation does not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 22—Commitments and Contingencies. Upon consideration of these factors, Generation does not consider itself to have significant variable interests in these entities or be the primary beneficiary of these VIEs and, accordingly, has determined that consolidation is not required.

Investment in Energy Development Projects. Generation has several equity investments in energy generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each of its equity investments, and determined that certain of the entities are VIEs because Generation guarantees the debt of the entity, provides equity support, or provides operating services to the entity. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the entities that qualify as VIEs because Generation does not have the power to direct the activities of the VIEs that most significantly impact the VIEs economic performance.

Residential Solar Provider. Generation has an equity investment in a residential solar provider. Generation has evaluated the significant agreements, ownership structure and risks of the entity, and determined that the entity is a VIE because it does not have sufficient equity at risk to fund its operations. Generation has determined that its equity investment in the entity is a variable interest. However, Generation has concluded that we are not the primary beneficiary because Generation does not have the power to direct the activities of the VIE that most significantly impact the entity's economic performance. Exelon or Generation do not have any contractual or other obligations to provide additional financial support and the residential solar provider's creditors do not have any recourse to Exelon's or Generation's general credit.

ComEd, PECO and BGE

ComEd's, PECO's, and BGE's retail operations frequently include the purchase of electricity and RECs through procurement contracts of varying durations. See Note 3—Regulatory Matters and Note 22—Commitments and Contingencies for additional information on these contracts. ComEd, PECO

and BGE have evaluated these types of contracts and have historically determined that either there is no significant variable interest in the entity, or where either ComEd, PECO or BGE does have a significant variable interest in a VIE, ComEd, PECO or BGE would not be the primary beneficiary and, therefore, consolidation would not be required.

For contracts where ComEd, PECO or BGE is considered to have a significant variable interest, consideration is given to which interest holder has the power to direct the activities that most significantly affect the economic performance of the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of their production or procurement processes related to electricity, RECs, AECs or natural gas. ComEd, PECO and BGE do not have control over the operation and maintenance of the entities and they do not bear operational risk related to the associated activities. Generally, the carrying amounts of assets and liabilities in ComEd's, PECO's, and BGE's Consolidated Balance Sheets that relate to their involvement with VIEs as a result of commercial arrangements represent the amounts owed by the utilities for the purchases associated with the current billing cycles under the contracts. As of December 31, 2013, the total amount of accounts payable owed by the utilities under agreements with these VIEs was not material. In addition, variability from these contracts is mitigated by the fact that the utilities are able to recover costs incurred under purchase agreements through customer rates. Furthermore, ComEd, PECO and BGE do not have any debt or equity investments in these VIEs and do not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 22—Commitments and Contingencies. Accordingly, none of ComEd, PECO or BGE considers itself to be the primary beneficiary of any VIEs as a result of commercial arrangements.

The financing trust of ComEd, ComEd Financing III, the financing trusts of PECO, PECO Trust III and PECO Trust IV, and the financing trust of BGE, BGE Capital Trust II are not consolidated in Exelon's, ComEd's, PECO's or BGE's financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd, PECO, and BGE have concluded that they do not have a significant variable interest in ComEd Financing III, PECO Trust III, PECO Trust IV or BGE Capital Trust II as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk. See Note 13—Debt and Credit Agreements for additional information.

3. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

The following matters below discuss the current status of material regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd).

Background

Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and

corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. As of December 31, 2013, and December 31, 2012, ComEd had a net regulatory asset associated with the distribution formula rate of $463 million and $209 million, respectively.

Formula Rate Tariff

On November 8, 2011, ComEd filed its initial formula rate tariff and associated testimony based on 2010 costs and 2011 plant additions. The primary purpose of that proceeding was to establish the formula rate under which rates will be calculated going-forward, and the initial rates, which went into effect in late June 2012. On May 29, 2012, the ICC issued an Order (May Order) in that proceeding. The May Order reduced the annual revenue requirement by $168 million, or approximately $110 million more than the proposed reduction by ComEd. Of this incremental revenue requirement reduction, approximately $50 million reflected the ICC's determination that certain costs should be recovered through alternative rate recovery tariffs available to ComEd or will be reflected in a subsequent annual reconciliation, thereby primarily delaying the timing of cash flows. The incremental revenue reduction also reflected a $35 million reduction for the disallowance of return on ComEd's pension asset, a $10 million reduction for incentive compensation related adjustments, and $15 million of reductions for various adjustments for cash working capital, operating reserves, and other technical items. In the second quarter of 2012, ComEd recorded a decrease in revenue of approximately $100 million pre-tax to decrease the regulatory asset for 2011 and for the first three months of 2012 consistent with the terms of the May Order.

On June 22, 2012, the ICC granted an expedited rehearing on three of the issues decided in the May Order. On October 3, 2012, the ICC issued its final order (Rehearing Order) in that rehearing, adopting ComEd's position on the return on its pension asset, resulting in an increase in the annual revenue requirement. For the two other issues, the ICC ruled against ComEd by reaffirming use of an average rather than year-end rate base in the annual reconciliation and amending its prior order to provide a short-term debt rate to apply to the annual reconciliation. In the fourth quarter of 2012, ComEd recorded an increase in revenue of approximately $135 million pre-tax consistent with the terms of the Rehearing Order, of which $75 million pre-tax reflects the reinstatement of the return on pension asset for 2011 and $60 million pre-tax reflects the return on pension asset for 2012. New rates reflecting the impacts of the Rehearing Order went into effect in November 2012. ComEd has filed an appeal with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals.

In March 2013, the Illinois legislature passed Senate Bill 9 to clarify the intent of EIMA on the three issues decided in the Rehearing Order: an allowed return on ComEd's pension asset; the use of year-end rather than average rate base and capital structure in the annual reconciliation; and the use of ComEd's weighted average cost of capital interest rate rather than a short-term debt rate to apply to the annual reconciliation. On May 22, 2013, Senate Bill 9 became effective after the Illinois legislature overrode the Governor's veto of that Bill. On June 5, 2013, the ICC approved ComEd's updated distribution formula rate structure to reflect the impacts of Senate Bill 9.

In October 2013, the ICC opened an investigation (the Investigation), in response to a complaint filed by the Illinois Attorney General, to change the formula rate structure by requesting three changes: the elimination of the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance, the netting of associated accumulated deferred income taxes against the annual reconciliation balance in calculating interest, and the use of average rather than year-end rate base for determining any ROE collar adjustment. On November 26, 2013, the ICC

issued its final order in the Investigation, rejecting two of the proposed changes but accepting the proposed change to eliminate the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance. The accepted change became effective in January 2014, and is estimated to reduce ComEd's 2014 revenue by approximately $8 million. This change had no financial statement impact on ComEd in 2013. ComEd and intervenors requested rehearing, however all rehearing requests were denied by the ICC. ComEd and intervenors have filed appeals with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals.

Annual Reconciliation

2012 Filing. On April 30, 2012, ComEd filed its annual distribution formula rate. On December 20, 2012, the ICC, issued its final order, which increased the revenue requirement by $73 million, in conformity with the formula rate structure provided in the May 2012 and Rehearing Orders. The $73 million reflected an increase of $80 million for the initial revenue requirement for 2012 and a decrease of $7 million for the annual reconciliation for 2011. The rate increase was set using an allowed return on capital of 7.54% (inclusive of an allowed return on common equity of 9.81%). The rates took effect in January 2013. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC. ComEd and intervenors also filed appeals with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals.

On May 30, 2013, ComEd updated its revenue requirement allowed in the December 2012 Order to reflect the impacts of Senate Bill 9, which resulted in a reduction to the current revenue requirement in effect of $14 million. The rates took effect in July 2013.

2013 Filing. On April 29, 2013, ComEd filed its annual distribution formula rate, which was updated in August 2013, to request a total increase to the revenue requirement of $353 million of which approximately $42 million related to Senate Bill 9. On December 19, 2013, the ICC issued its final order which increased the revenue requirement by $341 million, reflecting an increase of $160 million for the initial revenue requirement for 2013 and an increase of $181 million for the annual reconciliation for 2012. The rate increase was set using an allowed return on capital of 6.94% (inclusive of an allowed return on common equity of 8.72%). The rates took effect in January 2014. ComEd requested a rehearing on specific issues, which was denied by the ICC. ComEd also filed an appeal. ComEd cannot predict the results of any such appeals.

Expenditures and Capital Investment

As part of the enactment of EIMA legislation ComEd made an initial contribution of $15 million (recognized as expense in 2011) to a new Science and Technology Innovation Trust fund on July 31, 2012, and will make recurring annual contributions of $4 million, the first of which was made on December 31, 2012, which will be used for customer education for as long as the AMI Deployment Plan remains in effect. In addition, ComEd will contribute $10 million per year for five years, as long as ComEd is subject to EIMA, to fund customer assistance programs for low-income customers, which will not be recoverable through rates. These contributions began in 2012.

On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. On April 23, 2012, ComEd filed its initial AMI Deployment Plan with the ICC, which was approved by the ICC on June 22, 2012, with certain modifications. ComEd outlined the new deployment schedule within testimony provided in the AMI Plan Rehearing and filed a revised AMI deployment plan. The deployment plan provides for the installation of 4 million electric smart meters, of which more than 60,000 meters were installed by the end of 2013.

Appeal of 2007 Illinois Electric Distribution Rate Case (Exelon and ComEd). The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via a rider (Rider SMP).

The court held the ICC abused its discretion in not reducing ComEd's rate base to account for an additional 18 months of accumulated depreciation while including post-test year pro forma plant additions through that period. ComEd continued to bill rates as established under the ICC's order in the 2007 Rate Case until June 1, 2011 when the rates set in the 2010 electric distribution rate case (2010 Rate Case) became effective. In subsequent ICC proceedings, the ICC issued an order requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation issue. On March 26, 2012, ComEd filed a notice of appeal with the Court.

However, on September 27, 2013 the Court ruled against ComEd on the accumulated depreciation issue and affirmed that ComEd owes a refund to customers of $37 million. As of December 31, 2013, and December 31, 2012, ComEd was fully reserved for this liability. ComEd will not seek rehearing or appeal on this matter and is working with the ICC on the process and timing for a refund to customers.

Advanced Metering Program Proceeding (Exelon and ComEd) ComEd's 2007 Rate Case filing included a system modernization rider, which permitted investments in AMI to study the costs and benefits and to develop the cost estimate of full system-wide implementation. In October 2009, the ICC approved a modified version of ComEd's system modernization rider proposed in the 2007 Rate Case, Rider AMP (Advanced Metering Program). ComEd collected approximately $24 million under Rider AMP through December 31, 2013. Several other parties, including the Illinois Attorney General, appealed the ICC's order on Rider AMP. In ComEd's 2010 electric distribution rate case, the ICC approved ComEd's transfer of other costs from recovery under Rider AMP to recovery through electric distribution rates. On March 19, 2012, the Court reversed the ICC's approval of Rider AMP, concluding that the ICC's October 2009 approval of the rider constituted single-issue ratemaking. ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court on April 23, 2012, which was denied in September 2012, and the matter was returned to the ICC to calculate a refund amount. ComEd believes any refund obligation associated with Rider AMP should be prospective from no earlier than the date of the Appellate Court's order on March 19, 2012. As a result, ComEd recorded a regulatory liability of approximately $0.4 million at December 31, 2013, which represents the amounts collected from customers since March 19, 2012. ComEd cannot predict the ultimate outcome of the ICC proceeding and therefore, actual refunds may differ from the estimated accrual recorded at December 31, 2013.

2010 Illinois Electric Distribution Rate Case (Exelon and ComEd). On May 24, 2011, the ICC issued an order in ComEd's 2010 Rate Case, which became effective on June 1, 2011. The order approved a $143 million increase to ComEd's annual delivery services revenue requirement and a 10.5% rate of return on common equity. ComEd originally requested a $396 million increase, although it was subsequently reduced to $343 million to account for various adjustments. As expected, the ICC followed the Court's ruling on ComEd's 2007 Rate Case on the post-test year accumulated depreciation issue. The order allowed ComEd to establish or reestablish a net amount of approximately

$40 million of previously expensed plant balances or new regulatory assets, which is reflected as a reduction in operating and maintenance expense and income tax expense in 2011. The order also affirmed the current regulatory asset for severance costs, which was challenged by an intervener in the 2010 Rate Case. The order was appealed to the Court by several parties on a number of issues. On May 16, 2013, the Court dismissed as moot the appeals of the ICC's order in the 2010 Rate Case as ComEd now recovers distribution costs under EIMA through a pre-established formula rate tariff.

Utility Consolidated Billing and Purchase of Receivables (Exelon and ComEd). Since the first quarter of 2011, ComEd has been required to buy certain RES receivables, primarily residential and small commercial and industrial customers, at the option of the RES, for electric supply service and then include those amounts on ComEd's bill to customers. Receivables are purchased at a discount to compensate ComEd for uncollectible accounts. ComEd produces consolidated bills for the aforementioned retail customers reflecting charges for electric delivery service and purchased receivables. As of December 31, 2013, the balance of purchased accounts receivable was $105 million. Under the applicable tariff, ComEd recovers from RES and customers the costs for implementing and operating the program. A number of municipalities, including the City of Chicago have switched to RES electric supply. As a result, ComEd experienced a significant increase in the amount of RES receivables it purchased in 2013.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, as a result of the Illinois Settlement Legislation, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. On December 21, 2011, the ICC approved the IPA's procurement plan covering the period June 2012 through May 2017.

The Illinois Settlement Legislation requires ComEd to purchase an increasing percentage of the electricity it purchases for customer deliveries from renewable energy resources. Purchases by customers of electricity from competitive generation suppliers, whether as a result of the customers' own actions or as a result of municipal aggregation, are not included in this calculation and have the effect of reducing ComEd's purchase obligation. ComEd entered into several 20-year contracts with unaffiliated suppliers in December 2010 regarding the procurement of long-term renewable energy and associated RECs in order to meet its obligations under the state's RPS. Under the Illinois Settlement Legislation, all associated costs are recoverable from customers.

As a result of reduced ComEd load forecasts, purchases under the existing long-term contracts for energy and the associated RECs were reduced on a pro-rata basis under the terms of those contracts for the June 2013—May 2014 period to keep the purchases under the statutory rate impact cap. The curtailment's impact on ComEd's financial position and cash flows was immaterial.

On December 18, 2013, the ICC approved the IPA's 2014-2019 procurement plan. The plan provides for two separate energy procurements during 2014 to address potential fluctuations in energy demand due to customer switching between ComEd and competitive electric generation suppliers. The Commission also approved the IPA's expansion of energy efficiency programs for both ComEd and Ameren. The ICC did not require the acquisition of additional renewable resources in 2014-2015 due to insufficient available funds to procure those resources. Further, the ICC again approved a reduction of purchases under the existing long-term contracts for energy and the associated RECs on a pro-rata basis under the terms of those contracts for the June 2014—May 2015 period to keep the purchases under the statutory rate impact cap; however the amount of the reduction will not be finalized and approved by the ICC until March 2014. The curtailment's impact on ComEd's financial position and

cash flows is expected to be immaterial. See Note 12—Derivative Financial Instruments for additional information regarding ComEd's financial swap contract with Generation, which expired in May 2013, and long-term renewable energy contracts.

During 2013, the ICC approved, and directed ComEd and Ameren (the Utilities) to enter into 20-year sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The sourcing agreement provides that the Utilities will pay FutureGen's contract prices, which are set annually pursuant to a formula rate. The contract prices are based on the difference between the costs of the facility and the revenues FutureGen receives from selling capacity and energy from the unit into the MISO or other markets, as well as any other revenue FutureGen receives from the operation of the facility. The order also directs the Utilities to recover (or pass along) these costs from the Utilities' distribution system customers, regardless of whether they purchase electricity from the utility or from competitive electric generation suppliers. In February 2013, ComEd filed an appeal with the Illinois Appellate Court questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers.

On August 22, 2013, the Utilities executed the sourcing agreement with FutureGen in accordance with the ICC order. However, in the event the order is reversed as a result of the appeal, ComEd's obligations under the sourcing agreement should be suspended. Depending on the ultimate outcome of the appeals, the eventual market conditions and the cost of the facility, the sourcing agreement could have a material adverse impact on Exelon's and ComEd's cash flows and financial positions.

See Note 22—Commitments and Contingencies for additional information on ComEd's energy commitments.

Energy Efficiency and Renewable Energy Resources (Exelon and ComEd). As a result of the Illinois Settlement Legislation, electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an incremental annual program energy savings requirement of 0.2% of energy delivered to retail customers for the year ended June 1, 2009, which increases annually to 2.0% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten-year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In December 2010, the ICC approved ComEd's second three-year Energy Efficiency and Demand Response Plan covering the period June 2011 through May 2014. The plans are designed to meet the Illinois Settlement Legislation's energy efficiency and demand response goals through May 2014, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

EIMA provides for additional energy efficiency in Illinois. Starting in the June 2013—May 2014 period and occurring annually thereafter, as part of the IPA procurement plan, ComEd is to include cost-effective expansion of current energy efficiency programs, and additional new cost-effective program and/or third-party energy efficiency programs that are identified through a request for proposal process. All cost-effective energy efficiency programs are included in the IPA procurement plan for consideration of implementation. While these programs are monitored separately from the Energy Efficiency Portfolio Standard (EEPS), funds for both the EEPS portfolio and IPA energy efficiency programs are collected under the same rider.

Since June 1, 2008, utilities have been required to procure cost-effective renewable energy resources in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers. ComEd is also required to acquire amounts of renewable energy resources that will cumulatively increase this percentage to at least 10% by June 1, 2015, with an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth in the Illinois Settlement Legislation. As of December 31, 2013, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates. See Note 22—Commitments and Contingencies for information regarding ComEd's future commitments for the procurement of RECs.

Pennsylvania Regulatory Matters

2010 Pennsylvania Electric and Natural Gas Distribution Rate Cases (Exelon and PECO). On December 16, 2010, the PAPUC approved the settlement of PECO's electric and natural gas distribution rate cases, which were filed in March 2010, providing increases in annual service revenue of $225 million and $20 million, respectively. The electric settlement provides for recovery of PJM transmission service costs on a full and current basis through a rider. The approved electric and natural gas distribution rates became effective on January 1, 2011.

In addition, the settlements included a stipulation regarding how tax benefits related to the application of any new IRS guidance on repairs deduction methodology are to be handled from a rate-making perspective. The settlements require that the expected cash benefit from the application of any new guidance to tax years prior to 2011 be refunded to customers over a seven-year period. On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for electric transmission and distribution property. PECO adopted the safe harbor and elected a method change for the 2010 tax year. The expected total refund to customers for the tax cash benefit from the application of the safe harbor to costs incurred prior to 2010 is $171 million. On October 4, 2011, PECO filed a supplement to its electric distribution tariff to execute the refund to customers of the tax cash benefit related to the IRC Section 481(a) "catch-up" adjustment claimed on the 2010 income tax return, which is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2012.

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The expected total refund to customers for the tax cash benefit from the application of the new method to costs incurred prior to 2011 is $54 million. This amount is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2013. PECO currently anticipates that the IRS will issue guidance in early 2014 providing a safe harbor method of accounting for gas transmission and distribution property.

The prospective tax benefits claimed as a result of the new methodology will be reflected in tax expense in the year in which they are claimed on the tax return and will be reflected in the determination of revenue requirements in the next electric and natural gas distribution rate cases. See Note 14 for additional information.

The 2010 electric and natural gas distribution rate case settlements did not specify the rate of return upon which the settlement rates are based, but rather provided for an increase in annual revenue. PECO has not filed a transmission rate case since rates have been unbundled.

Pennsylvania Procurement Proceedings (Exelon and PECO). PECO's first PAPUC approved DSP Program, under which PECO was providing default electric service, had a 29-month term that ended May 31, 2013. On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO's second DSP Program, which was filed with the PAPUC in January 2012. The program, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129. Under the DSP Programs, PECO is permitted to recover its electric procurement costs from retail default service customers without mark-up through the GSA. The GSA provides for the recovery of energy, capacity, ancillary costs and administrative costs and is subject to adjustments at least quarterly for any over or under collections. In addition, PECO's second DSP Program provides for the recovery of AEPS compliance costs through the GSA rather than a separate AEPS rider.

In the second DSP Program, PECO is procuring electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes is served through competitively procured fixed price, full requirements contracts of two years or less. For the large commercial and industrial class load, PECO has competitively procured contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in June 2013. In September 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in December 2013. In January 2014, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small, medium, and large commercial classes that will begin in June 2014. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Statement of Operations and Comprehensive Income.

In addition, the second DSP Program includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from electric generation suppliers beginning April 1, 2014. On May 1, 2013, PECO filed a Petition for Approval of its CAP Shopping Plan with the PAPUC, which the PAPUC granted and denied in part on January 9, 2014. PECO and other parties to the proceeding filed petitions for reconsideration of the Commission's decision on February 10, 2014, and these petitions are currently pending before the PAPUC.

Smart Meter and Smart Grid Investments (Exelon and PECO). Pursuant to Act 129 and the follow-on Implementation Order of 2009, in April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million smart meters and an AMI communication network by 2020. The first phase of PECO's SMPIP, which was completed on June 19, 2013, included the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC which was approved without modification on August 15, 2013. The Joint Petition for Settlement supports all material aspects of PECO's universal deployment plan, including cost recovery, excluding certain amounts discussed below. Universal deployment is the second phase of PECO's SMPIP, under which PECO will deploy the remainder of the 1.6 million smart meters on an accelerated basis by the end of 2014. In total, PECO currently expects to spend up to $595 million, excluding the cost of the original meters (as further described below), on its smart meter infrastructure and approximately

$120 million on smart grid investments through 2014 of which $200 million will be funded by SGIG as discussed below. As of December 31, 2013, PECO has spent $423 million and $116 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO's existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of December 31, 2013, PECO has received $190 million of the $200 million in reimbursements. PECO's outstanding receivable from the DOE for reimbursable costs was $3 million as of December 31, 2013, which has been recorded in Other accounts receivable, net on Exelon's and PECO's Consolidated Balance Sheets.

On August 15, 2012, PECO suspended installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO has replaced the previously installed meters with an alternative vendor's meters. PECO is moving forward with the alternative meters during universal deployment and continues to evaluate meters from several vendors and may use more than one meter vendor during universal deployment.

Following PECO's decision, as of October 9, 2012 PECO will no longer use the original smart meters. For the meters that will no longer be used, the accounting guidance requires that any difference between the carrying value and net realizable value be recognized in the current period's earnings, before considering potential regulatory recovery. The cost of the original meters, including installation and removal costs, owned by PECO was approximately $17 million, net of approximately $16 million of reimbursements from the DOE and approximately $2 million of depreciation. PECO requested and received approval from the DOE that the original meters continue to be allowable costs and that any agreement with the vendor will not be considered project income. In addition, PECO remains eligible for the full $200 million in SGIG funds. On August 15, 2013, PECO entered into an agreement with the original vendor, which was part of the final agreement discussed below, under which PECO transferred the original uninstalled meters to the vendor and will receive $12 million in return, of which $7 million has been received as of December 31, 2013. On January 23, 2014, PECO entered a final agreement with the vendor pursuant to which PECO will be reimbursed for amounts incurred for the original meters and related installation and removal costs, via cash payments and rebates on future purchases of licenses, goods and services primarily through 2017. PECO previously had intended to seek regulatory rate recovery in a future filing with the PAPUC of amounts not recovered from the vendor. As PECO believed such costs were probable of rate recovery based on applicable case law and past precedent on reasonably and prudently incurred costs, a regulatory asset was established at the time of the removals. As of December 31, 2013 and 2012, $5 million and $17 million, respectively, was recorded on Exelon's and PECO's Consolidated Balance Sheets. Pursuant to the January 23, 2014, vendor agreement, PECO will reclassify the regulatory asset balance as a receivable, with no gain or loss impacts on future results of operations.

Energy Efficiency Programs (Exelon and PECO). PECO's PAPUC-approved Phase I EE&C Plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I plan set forth how PECO would meet the required reduction targets established by Act 129's EE&C provisions,

which included a 3% reduction in electric consumption in PECO's service territory and a 4.5% reduction in PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013.

The peak demand period ended on September 30, 2012 and PECO communicated its compliance with the reduction targets in a preliminary filing with the PAPUC on March 1, 2013. The final compliance report for all Phase I targets, was filed with the PAPUC on November 15, 2013.

On March 29, 2013, PECO filed a Petition with the PAPUC to change the recovery period of certain Direct Load Control (DLC) Program costs necessary to implement the Phase I Plan. The Petition sought approval to allow PECO to recover $12 million in equipment, installation and information technology costs for its Residential DLC program with the amounts collected for the Phase I Plan. As the Phase I Plan was implemented at a cost less than originally budgeted, PECO proposed to recover these expenses from its Phase I Energy Efficiency Program Charge over-collection consistent with PAPUC guidance to recover all Phase I costs through Phase I funding. The PAPUC approved PECO's Petition on May 9, 2013. A regulatory liability was established for the DLC program costs that will be amortized as a credit to the income statement to offset the related depreciation expense during the same period.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129's EE&C programs, which went into effect on June 1, 2013. The order tentatively established PECO's three-year cumulative consumption reduction target at 1,125,852 MWh, which was reaffirmed by the PAPUC on December 5, 2012.

Pursuant to the Phase II implementation order, PECO filed its three-year EE&C Phase II plan with the PAPUC on November 1, 2012. The plan sets forth how PECO will reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016, adjusted for weather and extraordinary loads. The implementation order permits PECO to apply any excess savings achieved during Phase I against its Phase II consumption reduction targets, with no reduction to its Phase II budget. In accordance with the Act 129 Phase II implementation order, at least 10% and 4.5% of the total consumption reductions must be through programs directed toward PECO's public and low income sectors, respectively. If PECO fails to achieve the required reductions in consumption, it will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers. Act 129 mandates that the total cost of the plan may not exceed 2% of the electric company's total annual revenue as of December 31, 2006.

On March 15, 2013, PECO filed a Petition for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers from June 1, 2013 to May 31, 2014. PECO proposed to fund the estimated $10 million costs of the one-year program by modifying incentive levels for other Phase II programs. On May 9, 2013, the PAPUC approved PECO's amended EE&C Phase II plan. The costs of DLC program will be recovered through PECO's Energy Efficiency Program Charge along with all other Phase II Plan costs.

On November 14, 2013, the PAPUC issued a Tentative Order on Act 129 demand reduction programs which seeks comments on a proposed demand response program methodology for future Act 129 demand reduction programs as well as demand response potential and wholesale prices suppression studies. The comment process is scheduled to be completed in the first quarter of 2014. Any decision reached would affect PECO's EE&C Plan subsequent to its Phase II Plan.

Alternative Energy Portfolio Standards (Exelon and PECO). In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of

PECO's rate cap transition period, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources ranges from approximately 3.5% to 8% and the requirement for Tier II alternative energy resources ranges from 6.2% to 10%. The required compliance percentages incrementally increase each annual compliance period, which is from June 1 through May 31, until May 31, 2021. These Tier I and Tier II alternative energy resources include acceptable energy sources as set forth in Act 129 and the AEPS Act.

PECO has entered into five-year and ten-year agreements with accepted bidders, including Generation, totaling 452,000 non-solar and 8,000 solar Tier I AECs annually in accordance with a PAPUC approved plan. The plan allowed PECO to bank AECs procured prior to 2011 and use the banked AECs to meet its AEPS Act obligations over two compliance years ending May 2013. The PAPUC also approved the procurement of Tier II AECs and supplemental AECs as well as the sale of excess AECs through independent third-party auctions or brokers.

All AEPS administrative costs and costs of AECs incurred after December 31, 2010 are being recovered on a full and current basis from default service customers through a surcharge.

PECO's second DSP Program eliminated the AEPS surcharge. Beginning in June 2013, AEPS compliance costs are being recovered through the GSA.

Investigation of Pennsylvania Retail Electricity Market (Exelon and PECO). On July 28, 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania's retail electric market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. On March 1, 2012, the PAPUC issued the final order describing more detailed recommendations to be implemented prior to the expiration of the electric distribution company's current default service plan and providing guidelines for electric distribution companies for development of their next default service plan. On October 12, 2012, the PAPUC approved PECO's second DSP Program, which includes several new programs to continue PECO's support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011. Further, the PAPUC issued a final order on February 14, 2013, outlining its proposed end-state for default service, which included default service pricing for residential and small commercial customers based on three month full requirements contracts, full requirement contracts using hourly spot market pricing for large commercial and industrial default service customers, and the inclusion of CAP customers in the customer choice programs.

Pennsylvania Act 11 of 2012 (Exelon and PECO). On February 13, 2012, Act 11 was signed into law by the Governor. Act 11 seeks to clarify the PAPUC's authority to approve alternative ratemaking mechanisms, which would allow for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems in Pennsylvania. Act 11 also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the first year rates are in effect. On August 2, 2012, the PAPUC issued a final order establishing rules and procedures to implement the ratemaking provisions of Act 11. The implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) which outlines how the utility is planning to increase its investment for repairing, improving, or replacing

aging infrastructure, approved by the Commission prior to implementing a DSIC. On May 9, 2013, the PAPUC approved PECO's LTIIP for its Gas Operations, which was filed on February 8, 2013.

Maryland Regulatory Matters

2011 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $19 million of costs as regulatory assets. These costs are being recovered over a 5-year period that began in December 2010 and include the deferral of $16 million of storm costs incurred in February 2010. The regulatory asset for the storm costs earns a regulated rate of return.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE's 2012 electric and natural gas distribution rate case for increases in annual distribution service revenue of $81 million and $32 million, respectively. The electric distribution rate increase was set using an allowed return on equity of 9.75% and the gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved electric and natural gas distribution rates became effective for services rendered on or after February 23, 2013. As part of the rate order, the MDPSC approved both recovery of and return on merger integration costs incurred during the test year, including severance. As a result, the order affirmed the treatment of $20 million of severance-related costs that BGE had recorded as a regulatory asset in 2012, consistent with prior MDPSC decisions. Additionally, BGE established a new regulatory asset of $8 million related to non-severance merger integration costs, which includes $6 million of costs incurred during 2012. Current MDPSC treatment of these merger integration regulatory assets is to provide recovery over a five year period.

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, BGE filed an application for increases of $101 million and $30 million to its electric and gas base rates, respectively, with the MDPSC. The requested rates of return on equity in the application were 10.50% and 10.35% for electric and gas distribution, respectively. In addition to these requested rate increases, BGE's application includes a request for recovery of incremental capital expenditures and operating costs associated with BGE's proposed short-term reliability improvement plan in response to a MDPSC order through a surcharge separate from base rates. On August 23, 2013, BGE filed an update to its rate request which altered the requested increase to electric base rates from $101 million to $83 million and the requested increase to gas base rates from $30 million to $24 million. On December 13, 2013, the MDPSC issued an order in BGE's 2013 electric and natural gas distribution rate case for increases in annual distribution service revenue of $34 million and $12 million, respectively. The electric distribution rate increase was set using an allowed return on equity of 9.75% and the gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved electric and natural gas distribution rates became effective for services rendered on or after December 13, 2013. The MDPSC also conditionally approved five of the eight programs included in BGE's proposed short-term reliability improvement plan. Commencement of the program and recovery are dependent on final MDPSC approval with the surcharge starting no earlier than April 1, 2014.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation

and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of December 31, 2013 and December 31, 2012, BGE recorded a regulatory asset of $66 million and $31 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. Additionally, the MDPSC has determined that the cost recovery for the non-AMI meters that BGE retires will be considered in a future depreciation proceeding. The MDPSC continues to evaluate the impacts of a customer opt-out feature in BGE's Smart Grid program. In March 2013, BGE filed a description of the overall additional costs associated with allowing customers to retain their current meter, and for radio frequency (RF)-Free and RF-Minimizing options related to the installation of their smart meters as well as a proposed cost recovery mechanism. The MDPSC held a hearing in August 2013 to consider the filings made by BGE and other Maryland electric utilities. The ultimate resolution related to this feature could affect BGE's ability to demonstrate cost-effectiveness of the advanced metering system. Overall, BGE continues to believe the recovery of smart grid initiative costs in future rates is probable as BGE expects to be able to demonstrate that the program benefits exceed costs. Pursuant to the ARRA of 2009, BGE is a recipient of $200 million in federal funding from the DOE for its smart grid and other related initiatives, which substantially reduces the total cost of these initiatives to BGE's ratepayers. The project to install the smart meters began in late April 2012. As of December 31, 2013, BGE had received $200 million in reimbursements from the DOE.

New Electric Generation (Exelon and BGE). On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that CPV projected will be in commercial operation by June 1, 2015. The initial term of the proposed contract is 20 years. The CfD mandates that BGE and the other utilities pay (or receive) the difference between CPV's contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The MDPSC's Order requires the three Maryland utilities to enter into a CfD in amounts proportionate to their relative SOS load.

On April 16, 2013, the MDPSC issued an order that required BGE to execute a specific form of contract with CPV, and the parties executed the contract as of June 6, 2013. As of December 31, 2013, there is no impact on Exelon's and BGE's results of operations, cash flows and financial positions. Furthermore, the agreement does not become effective until the resolution of certain items, including all current litigation.

On April 27, 2012, a civil complaint was filed in the U.S. District Court for the District of Maryland by certain unaffiliated parties that challenges the actions taken by the MDPSC on Federal law grounds. On October 24, 2013, the U.S. District Court issued a judgment order finding that the MDPSC's Order directing BGE and the two other Maryland utilities to enter into a CfD, which assures that CPV receives a guaranteed fixed price regardless of the price set by the federally regulated wholesale market, violates the Supremacy Clause of the United States Constitution. On November 22, 2013, the MDPSC and CPV appealed the District Court's ruling to the United States Court of Appeals for the Fourth Circuit.

On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order under state law. That petition was subsequently transferred to the Circuit Court for Baltimore City and consolidated with similar appeals that have been filed by other interested parties. On October 1, 2013, the Circuit Court Judge issued a Memorandum Opinion and Order finding the decisions of the MDPSC were within its statutory authority under

Maryland law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD is unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands. On October 29, 2013, BGE and the two other Maryland utilities appealed the Circuit Court's ruling to the Maryland Court of Special Appeals.

Depending on the ultimate outcome of the pending state and federal litigation, on the eventual market conditions, and on the manner of cost recovery as of the effective date of the agreement, the CfD could have a material impact on Exelon and BGE's results of operations, cash flows and financial positions.

Exelon believes that this and other states' projects may have artificially suppressed capacity prices in PJM and may continue to do so in future auctions to the detriment of Exelon's market driven position. In addition to this litigation, Exelon is working with other market participants to implement market rules that will appropriately limit the market suppressing effect of such state activities.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 requiring BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improve reliability and grid resiliency that were due at various times before August 30, 2013.

On September 3, 2013, BGE filed a comprehensive long term assessment examining potential alternatives for improving the resiliency of the electric grid and a staffing analysis reviewing historical staffing levels as well as forecasting staffing levels necessary under various storm scenarios. BGE currently cannot predict the outcome of these proceedings, which may result in increased capital expenditures and operating costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law; which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. The MDPSC held evidentiary hearings on BGE's proposed plan and surcharge from November 12, 2013 through November 14, 2013. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. BGE must submit a list detailing specific projects planned for 2014 to the MDPSC for approval within 30 days of the decision. Upon approval of the project list by the MDPSC, BGE will be able to implement the surcharge rates on gas customers' bills. The new surcharges are expected to take effect in second quarter of 2014. In addition, BGE will be subject to an annual independent audit to review plan performance and progress.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd's and BGE's transmission rates are each established based on a FERC-approved formula.

ComEd's most recent annual formula rate update filed in April 2013 reflects 2012 actual costs plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $488 million plus a $25 million adjustment related to the reconciliation of 2012 actual costs for a net revenue requirement of $513 million. This compares to the May 2012 updated revenue requirement of $450 million offset by a $5 million reduction related to the reconciliation of 2011 actual costs for a net revenue requirement of $445 million. The increase in the revenue requirement was primarily driven by increased capital investment, higher pension and post-retirement healthcare costs, and higher operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory asset associated with the true-up is being amortized as the associated amounts are recovered through rates.

ComEd's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.70%, a decrease from the 8.91% return previously authorized. The decrease in return was primarily due to lower interest rates on ComEd's long-term debt outstanding. As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 55%.

BGE's most recent annual formula rate update filed in April 2013 reflects actual 2012 expenses and investments plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $158 million offset by a $1 million reduction related to the reconciliation of 2012 actual costs for a net revenue requirement of $157 million. This compares to the April 2012 updated revenue requirement of $156 million increased by $2 million related to the reconciliation of 2011 actual costs for a net revenue requirement of $158 million. The decrease in the revenue requirement was primarily driven by a lower allowed rate of return associated with a reduced equity ratio and reduced rate base, offset partially by higher depreciation and operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory liability associated with the true-up is being amortized as the associated amounts are recovered through rates.

BGE's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.35%, a decrease from the 8.43% included in the prior year formula update. The decrease in return was primarily due to a debt issuance in 2012 and lower interest rates on BGE's debt outstanding. As part of the FERC-approved settlement in 2006 of BGE's 2005 transmission rate case, the base rate of return on common equity for BGE's electric transmission business for new transmission projects placed in service on and after January 1, 2006 is 11.3%, inclusive of a 50 basis point incentive for participating in PJM.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) for most investments included in its rate base and 11.3% for the remaining transmission investment (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the

base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the earliest date from which the base return on equity could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint. As of December 31, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base return on equity, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE's base return on equity to 8.7% (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the estimated annual impact would be a reduction in revenues of approximately $10 million.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, that court issued its decision affirming FERC's order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On March 30, 2012, FERC issued an order on remand affirming the cost allocation in its April 2007 order. On March 22, 2013, FERC issued an order denying rehearing of its March 30, 2012 Order and made it clear that the cost allocation at issue concerns only projects approved prior to February 1, 2013. A number of entities have filed appeals of the FERC orders. ComEd, and BGE anticipate that all impacts of any rate design changes effective after December 31, 2006 and June 30, 2006, respectively, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on their respective results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent that any rate design changes are retroactive to periods prior to January 1, 2011, however, there may be an impact on PECO's results of operations.

On October 11, 2012, the PJM Transmission Owners filed with FERC a cost allocation for new transmission facilities asking that the new cost allocation methodology apply to all transmission approved by the PJM Board on or after February 1, 2013. The proposed methodology is a hybrid methodology that would socialize 50% of the costs of new facilities at 500kV and above and double-circuit 345kV lines, and allocate the remaining 50% to direct beneficiaries. For all other facilities, the costs would be allocated to the direct beneficiaries. On March 22, 2013, FERC issued an order accepting the cost allocation with minor exceptions and requiring a compliance filing on those few issues within 120 days of the order. The compliance filing was made on July 22, 2013.

ComEd, PECO and BGE are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd, PECO and BGE will work with

PJM to continue to evaluate the scope and timing of any required construction projects. ComEd, PECO and BGE's estimated commitments are as follows:

	Total	2014	2015	2016	2017	2018
ComEd	$486	$134	$173	$177	$ 2	$—
PECO	133	32	29	40	24	8
BGE	400	42	83	95	87	93

PJM Minimum Offer Price Rule (Exelon and Generation). PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The proceedings leading to FERC's approval of the MOPR were extensive, and there have been numerous changes to the MOPR and litigation related to it since it was originally implemented. For example, in 2011 the parties disputed numerous elements of the MOPR including: (i) the default price that should apply to bids found subject to the MOPR, (ii) the duration of the MOPR and (iii) the application of the MOPR to self-supplying capacity and state-sponsored capacity. The FERC orders approving that MOPR have been appealed to the United States Court of Appeals for the Third Circuit. A resolution of that appeal is not expected until sometime in 2014.

In May 2012 (based on the MOPR provisions the FERC approved in 2011), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2016. Several new units with state-sanctioned subsidy contracts cleared in the auction at prices below the MOPR. Potentially, these states could expand such state-sanctioned subsidy programs or other states may seek to establish similar programs. Generation believed that further revisions to that MOPR were necessary to ensure that the potential to artificially reduce capacity auction prices is appropriately limited in PJM. In early December 2012, PJM filed a new MOPR for approval at the FERC, which Exelon believed would be more effective in preventing state-sanctioned subsidy contracts from artificially reducing capacity prices. Generation was actively involved in the process through which those MOPR changes were developed and supported the changes. On May 3, 2013, the FERC issued its order. While the FERC order accepted certain aspects of the proposal that Exelon supported (such as applying the MOPR to all of PJM and not just certain zones within PJM), the FERC required PJM to retain a key element of its previous MOPR structure, the unit-specific exemption, an element that Exelon had supported removing. Several entities, including two capacity suppliers that Exelon has been working with sought rehearing of that order.

In May 2013 (based on the MOPR provisions the FERC approved earlier that month), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2017. Exelon is working with PJM stakeholders on several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts, excessive imported capacity resources and certain limited availability demand response resources) cannot inappropriately affect capacity auction prices in PJM.

Market-Based Rates (Exelon, Generation, ComEd, PECO and BGE). Generation, ComEd, PECO and BGE are public utilities for purposes of the Federal Power Act and are required to obtain FERC's acceptance of rate schedules for wholesale electricity sales. Currently, Generation, ComEd, PECO and BGE have authority to execute wholesale electricity sales at market-based rates. As is customary with market-based rate schedules, FERC has reserved the right to suspend market-based rate authority on a retroactive basis if it subsequently determines that Generation, ComEd, PECO or BGE has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds in certain instances if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

As required by FERC's regulations, as promulgated in the Order No. 697 series, Generation, ComEd, PECO and BGE file market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd, PECO and BGE qualify for market-based rates in the regions where they are selling energy, capacity, and ancillary services under market-based rate tariffs. FERC accepted the 2008 filings on September 16, 2008, January 15, 2009 and September 2, 2009 and accepted the 2009 filings on July 28, 2009, October 26, 2009, February 23, 2010 and April 30, 2010, affirming Exelon's affiliates continued right to make sales at market-based rates. These analyses must examine historic test period data and must be updated every three years on a prescribed schedule. Generation, ComEd, PECO and BGE filed an updated analysis for the Northeast Region, which includes PJM, in late 2010, based on 2009 historic test period data. On June 22, 2011, FERC issued an order confirming Generation's continued authority to charge market based rates, based on Generation's most recent updated analysis filed in 2010, stating that any market power concerns are adequately addressed by PJM's monitoring and mitigation programs. On December 30, 2013, Generation, ComEd, PECO and BGE filed its updates analysis for the Northeast Region, based on 2012 historic test period data and FERC has not yet acted on the filing. Similarly, on June 29, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the Central Region which the FERC accepted on November 13, 2012, and on December 23, 2011, Generation filed its updated market power analysis for the Southeast Region which the FERC accepted on October 10, 2012. On December 21, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the SPP region, which the FERC accepted on October 8, 2013.

Reliability Pricing Model (Exelon, Generation and BGE). PJM's RPM Base Residual Auctions take place approximately 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2017 occurred in May 2013.

License Renewals (Exelon and Generation). On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively. In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. The temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear plants for up to 60 years beyond the original and renewed licensed operating life of the plants and that licensing renewal decisions do not require discussion of the environmental impact of spent fuel stored on site. In August 2012, the NRC placed a hold on issuing new or renewed operating licenses that depend on the temporary storage rule until the court's decision is addressed. In September 2012, the NRC directed NRC Staff to revise the temporary storage rule which is now not expected until October 3, 2014. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

On May 29, 2013, Generation submitted applications to the NRC to extend the operating licenses of Byron Units 1 and 2 and Braidwood Units 1 and 2 by 20 years. The current operating licenses for Byron Units 1 and 2 expire in 2024 and 2026, respectively. The current operating licenses for Braidwood Units 1 and 2 expire in 2026 and 2027, respectively. Generation does not expect the NRC to issue license renewals for Byron and Braidwood until 2015 at the earliest.

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively.

The FERC extended the deadline to January 31, 2014 to file a water quality certification application pursuant to Section 401 of the Clean Water Act (CWA) with the MDE for Conowingo. Generation is working with stakeholders to resolve licensing issues, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On January 30, 2014, Exelon filed a water quality certification application pursuant to Section 401 of the CWA with MDE for Conowingo, addressing these and other issues, although Generation cannot currently predict the conditions that ultimately may be imposed. Resolution of these issues relating to Conowingo may have a material effect on Generation's results of operations and financial position through an increase in capital expenditures and operating costs.

On August 29, 2013, Exelon filed a water quality certification application pursuant to Section 401 of the CWA with PA DEP for Muddy Run, addressing these and other issues that included certain commitments made by Generation. The financial impact associated with these commitments is estimated to be in the range of $20 million to $30 million, and will include both an increase in capital expenditures as well as an increase in operating expenses. Exelon anticipates that the PA DEP will issue the water quality certification pursuant to Section 401 of the CWA for Muddy Run in the first quarter of 2014.

Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run's current license on August 31, 2014, and the expiration of Conowingo's license on September 1, 2014. However, the stations would continue to operate under annual licenses until FERC takes action on the 46-year license applications. The stations are currently being depreciated over their useful lives, which includes the license renewal period. As of December 31, 2013, $33 million of direct costs associated with relicensing efforts have been capitalized.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of December 31, 2013 and 2012.

December 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 221	$ 2,794	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	10	1,459	2	65	—	1,317	8	77
AMI programs	5	159	5	35	—	58	—	66
AMI meter events	—	5	—	—	—	5	—	—
Under-recovered distribution service costs	178	285	178	285	—	—	—	—
Debt costs	12	56	9	53	3	3	1	8
Fair value of BGE long-term debt	—	219	—	—	—	—	—	—
Fair value of BGE supply contract	12	—	—	—	—	—	—	—
Severance	16	12	12	—	—	—	4	12
Asset retirement obligations	1	102	1	67	—	25	—	10
MGP remediation costs	40	212	33	178	6	33	1	1
RTO start-up costs	2	—	2	—	—	—	—	—
Under-recovered uncollectible accounts	—	48	—	48	—	—	—	—
Under-recovered electric universal Renewable energy	17	176	17	176	—	—	—	—
Energy and transmission programs	53	—	52	—	—	—	1	—
Deferred storm costs	3	3	—	—	—	—	3	3
Electric generation-related regulatory asset	13	30	—	—	—	—	13	30
Rate stabilization deferral	71	154	—	—	—	—	71	154
Energy efficiency and demand response programs	73	148	—	—	—	—	73	148
Merger integration costs	2	9			—	—	2	9
Other	31	39	18	26	8	7	4	6
Total regulatory assets	$ 760	$ 5,910	$ 329	$ 933	$ 17	$ 1,448	$ 181	$ 524

December 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Other postretirement benefits	$ 2	$ 43	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	—	2,740	—	2,293	—	447	—	—
Removal costs	99	1,423	78	1,219	—	—	21	204
Energy efficiency and demand response programs	53	—	45	—	8	—	—	—
DLC program costs	1	10	—	—	1	10	—	—
Energy efficiency phase II	—	21	—	—	—	21	—	—
Electric distribution tax repairs	20	114	—	—	20	114	—	—
Gas distribution tax repairs	8	37	—	—	8	37	—	—
Energy and transmission programs	78	—	9	—	58	—	11	—
Over-recovered gas and electric universal service fund costs	8	—	—	—	8	—	—	—
Revenue subject to refund	38	—	38	—	—	—	—	—
Over-recovered electric and gas revenue decoupling	16	—	—	—	—	—	16	—
Other	4	—	—	—	3	—	—	—
Total regulatory liabilities	$ 327	$ 4,388	$ 170	$ 3,512	$ 106	$ 629	$ 48	$ 204

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 304	$ 3,673	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	14	1,382	5	62	—	1,255	9	65
AMI programs	3	70	3	10	—	29	—	31
AMI meter events	—	17	—	—	—	17	—	—
Under-recovered distribution service costs	18	191	18	191	—	—	—	—
Debt costs	14	68	11	62	3	6	1	9
Fair value of BGE long-term debt	—	256	—	—	—	—	—	—
Fair value of BGE supply contracts	77	12	—	—	—	—	—	—
Severance	29	28	25	12	—	—	4	16
Asset retirement obligations	—	90	—	65	—	25	—	—
MGP remediation costs	58	232	51	197	6	33	1	2
RTO start-up costs	3	2	3	2	—	—	—	—
Under-recovered electric universal service fund costs	11	—	—	—	11	—	—	—
Financial swap with Generation	—	—	226	—	—	—	—	—
Renewable energy	18	49	18	49	—	—	—	—
Energy and transmission programs	43	—	14	—	1	—	28	—
DSP Program costs	1	3	—	—	1	3	—	—
DSP II Program costs	1	2	—	—	1	2	—	—
Deferred storm costs	3	6	—	—	—	—	3	6
Electric generation-related regulatory asset	16	40	—	—	—	—	16	40
Rate stabilization deferral	67	225	—	—	—	—	67	225
Energy efficiency and demand response programs	56	126	—	—	—	—	56	126
Under-recovered electric revenue decoupling	5	—	—	—	—	—	5	—
Other	23	25	14	16	9	8	—	2
Total regulatory assets	$ 764	$ 6,497	$ 388	$ 666	$ 32	$ 1,378	$ 190	$ 522

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$ —	$ 2,397	$ —	$ 2,037	$ —	$ 360	$ —	$ —
Removal costs	97	1,406	75	1,192	—	—	22	214
Energy efficiency and demand response programs	131	—	43	—	88	—	—	—
Electric distribution tax repairs	20	132	—	—	20	132	—	—
Gas distribution tax repairs	8	46	—	—	8	46	—	—
Over-recovered uncollectible accounts	6	—	6	—	—	—	—	—
Energy and transmission programs	54	—	6	—	48	—	—	—
Over-recovered gas universal service fund costs	3	—	—	—	3	—	—	—
Over-recovered AEPS costs	2	—	—	—	2	—	—	—
Revenue subject to refund	40	—	40	—	—	—	—	—
Over-recovered gas revenue decoupling	7	—	—	—	—	—	7	—
Total regulatory liabilities	$ 368	$ 3,981	$ 170	$ 3,229	$ 169	$ 538	$ 29	$ 214

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Pension and other postretirement benefits. As of December 31, 2013, Exelon had regulatory assets of $3,015 million and regulatory liabilities of $45 million related to ComEd's and BGE's portion of deferred costs associated with Exelon's pension plans and ComEd's, PECO's and BGE's portion of deferred costs associated with Exelon's other postretirement benefit plans. PECO's pension regulatory recovery is based on cash contributions and is not included in the regulatory asset (liability) balances. The regulatory asset (liability) is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses (gains) attributable to Exelon's pension and other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd, PECO and BGE will recover these costs through base rates as allowed in their most recently approved regulated rate orders. The pension and other postretirement benefit regulatory asset balance includes a regulatory asset established at the date of the merger related to BGE's portion of the deferred costs associated with legacy Constellation's pension and other postretirement benefit plans. The BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the merger. See Note 16—Retirement Benefits for additional detail. No return is earned on Exelon's regulatory asset.

Deferred income taxes. These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded under GAAP. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with the authoritative guidance for accounting for certain types of regulation and income taxes, include the deferred tax effects associated principally with accelerated depreciation accounted for in accordance with the ratemaking policies of the ICC, PAPUC and MDPSC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For ComEd and BGE, this amount includes the impacts of a reduction in the deductibility, for Federal income tax purposes, of certain retiree health care costs pursuant to the March 2010 Health Care Reform Acts. ComEd was granted recovery of these additional income taxes on May 24, 2011 in the ICC's 2010 Rate Case order. The recovery period for these costs is through May 31, 2014. For BGE, these additional income taxes are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. See Note 14—Income Taxes and Note 16—Retirement Benefits for additional information. ComEd, PECO and BGE are not earning a return on the regulatory asset in base rates.

AMI programs. For ComEd, this amount represents operating and maintenance expenses and meter costs associated with ComEd's AMI pilot program approved in the May 24, 2011, ICC order in ComEd's 2010 rate case. The recovery periods for operating and maintenance expenses and meter costs are through May 31, 2014, and January 1, 2020, respectively. As of December 31, 2013, ComEd had regulatory assets of $35 million related to accelerated depreciation costs resulting from the early retirements of non-AMI meters, which will be amortized over an average ten year period pursuant to the ICC approved AMI Deployment plan. ComEd is earning a return on the meter costs. For PECO, this amount represents accelerated depreciation and filing and implementation costs relating to the PAPUC-approved Smart Meter Procurement and Installation Plan as well as the return on the un-depreciated investment, taxes, and operating and maintenance expenses. The approved plan allows for recovery of filing and implementation costs incurred through December 31, 2012. In addition, the approved plan provides for recovery of program costs, which includes depreciation on new equipment placed in service, beginning in January 2011 on full and current basis, which includes interest income or expense on the under or over recovery. The approved plan also provides for recovery of accelerated depreciation on PECO's non-AMI meter assets over a 10-year period ending December 31, 2020. For BGE, this amount represents smart grid pilot program costs as well as the incremental costs associated with implementing full deployment of a smart grid program. Pursuant to a MDPSC order,

pilot program costs of $11 million were deferred in a regulatory asset, and, beginning with the MDPSC's March 2011 rate order, is earning BGE's most current authorized rate of return. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE, authorizing BGE to establish a separate regulatory asset for incremental costs incurred to implement the initiative, including the net depreciation and amortization costs associated with the meters, and an authorized rate of return on these costs, a portion of which is not recognized under GAAP until cost recovery begins. Additionally, the MDPSC order requires that BGE prove the cost-effectiveness of the entire smart grid initiative prior to seeking recovery of the costs deferred in these regulatory assets. Therefore, the commencement and timing of the amortization of these deferred costs is currently unknown. BGE's AMI regulatory asset excludes costs for non-AMI meters being replaced by AMI meters, as the MDPSC has ordered that the cost recovery for non-AMI meters will be considered in a future depreciation proceeding.

AMI Meter Events. This amount represents the remaining cost value of the original smart meters, net of accumulated depreciation, DOE reimbursements and amounts recovered from the vendor, of smart meter deployment that will no longer be used, including installation and removal costs. PECO intended to seek through regulatory rate recovery in a future filing with the PAPUC, any amounts no recovered from the vendor. PECO believed the amounts incurred for the original meters and related installation and removal costs were probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As such, PECO has deferred these costs on Exelon's and PECO's Consolidated Balance Sheet. PECO will not earn a return on the recovery of these costs.

Under-recovered distribution services costs. Under EIMA, which became effective in the fourth quarter of 2011, ComEd is allowed recovery of distribution services costs through a formula rate tariff. The legislation provides for an annual reconciliation of the revenue requirement in effect to reflect the actual costs that the ICC determines are prudently and reasonably incurred in a given year. The over recovery associated with the 2011 reconciliation was recovered through rates over a one-year period, that began in January 2013. The under recovery associated with the 2012 reconciliation will be recovered through rates over a one-year period beginning in January 2014. ComEd is earning a return on these costs. The regulatory asset also includes costs associated with certain one-time events, such as large storms, which will be recovered over a five-year period. As of December 31, 2013, the regulatory asset was comprised of $377 million for the annual reconciliation and $86 million related to significant one-time events. In addition to $58 million in deferred storm costs, net of amortization, the December 31, 2013 balance related to significant one-time events contains $28 million of merger and integration related costs, net of amortization, incurred as a result of the merger. As of December 31, 2012, the regulatory asset was comprised of $125 million for the annual reconciliation and $84 million related to significant one-time events. In addition to $58 million in deferred storm costs, net of amortization, the December 31, 2012 balance related to significant one-time events contains $26 million of merger and integration related costs, net of amortization, incurred as a result of the merger. See Note 4—Mergers and Acquisitions for additional information.

Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd's, PECO's and BGE's recoverable losses on reacquired long-term debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding or the life of the original issuance retired. These debt costs are used in the determination of the weighted cost of capital applied to rate base in the rate-making process. ComEd and BGE are not earning a return on the recovery of these costs, while PECO is earning a return on the premium of the cost of the reacquired debt through base rates.

Fair value of BGE long-term debt. These amounts represent the regulatory asset recorded at Exelon for the difference in the fair value of the long-term debt of BGE as of the merger date based on the MDPSC practice to allow BGE to recover its debt costs through rates. Exelon is amortizing the regulatory asset and the associated fair value over the life of the underlying debt.

Fair value of BGE supply contract. These amounts represent the regulatory asset recorded at Exelon representing the fair value of BGE's supply contracts as of the close of the merger date based on the MDPSC practice to allow BGE to recover its supply contracts through rates. Exelon is amortizing the regulatory asset and the associated fair value over a period of approximately three years.

Severance. For ComEd, these costs represent previously incurred severance costs that ComEd was granted recovery of in the December 20, 2006, ICC rehearing rate order and the May 24, 2011, ICC order in ComEd's 2010 rate case. The recovery periods are through June 30, 2014, and May 31, 2014, respectively. ComEd is not earning a return on these costs. For BGE, these costs represent deferred severance costs that BGE has previously been granted recovery of in rates. Costs include the portion of costs associated with a 2008 workforce reduction that relate to BGE's gas business which were deferred in 2009 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period that began in January 2009. Also included are costs associated with a 2010 workforce reduction that were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. Finally, costs associated with the 2012 BGE voluntary workforce reduction were deferred in 2012 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period that began in July 2012. BGE is earning a regulated return on the regulatory asset included in base rates.

Asset retirement obligations. These costs represent future legally required removal costs associated with existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd and BGE will recover these costs through future depreciation rates and will earn a return on these costs once the removal activities have been performed. See Note 15—Asset Retirement Obligations for additional information.

MGP remediation costs . Recovery of these items was granted to ComEd in the July 26, 2006, ICC rate order. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures. ComEd and PECO are not earning a return on the recovery of these costs. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. These costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. BGE is earning a return on this regulatory asset. See Note 22—Commitments and Contingencies for additional information.

RTO start-up costs. Recovery of these RTO start-up costs was approved by FERC. The recovery period is through March 31, 2015. ComEd is earning a return on these costs.

Under (Over)-recovered universal service fund costs. The universal service fund cost is a recovery mechanism that allows PECO to recover discounts issued to electric and gas customers

enrolled in assistance programs. As of December 31, 2013, PECO was over-recovered for both its electric and gas programs. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers.

Financial swap with Generation. To fulfill a requirement of the Illinois Settlement Legislation, ComEd entered into a five-year financial swap contract with Generation that expired on May 31, 2013. Since the swap contract was deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period were recorded by ComEd as well as an offsetting regulatory asset or liability. ComEd did not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position was based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price. In Exelon's consolidated financial statements, the fair value of the intercompany swap recorded by Generation and ComEd was eliminated.

Renewable Energy. On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy. Delivery under the contracts began in June 2012. Since the swap contracts were deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price.

Energy and transmission programs. Starting in 2007, ComEd's energy and transmission costs are recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. ComEd earns interest on under-recovered costs and pays interest on over-recovered costs to customers. The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO's GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. In addition, beginning in 2013, the deferred DSP I and II Program costs are presented on a net basis with PECO's GSA under (over)-recovered energy costs. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2013, PECO had a regulatory liability that included the over-recovered electric transmission costs of $8 million, $34 million related to the DSP program and $16 million related to over-recovered natural gas supply costs under the PGC. As of December 31, 2012, PECO had a regulatory asset related to under-recovered transmission costs of $1 million and a regulatory liability that included $47 million related to over-recovered electric supply costs under the GSA and $1 million related to over-recovered natural gas supply costs under the PGC. The BGE energy costs represent the electric and gas supply related costs recoverable (refundable) from (to) customers under BGE's market-based SOS and MBR programs, respectively. BGE does not earn or pay interest on under- or over-recovered costs to customers. As of December 31, 2013, BGE had a regulatory asset of $1 million related to under-recovered electric supply costs and a regulatory liability of $11 million related to over-recovered natural gas supply costs. As of December 31, 2012, BGE had a regulatory asset of $9 million related to under-recovered electric supply costs and a regulatory asset of $19 million related to under-recovered natural gas supply costs.

DSP Program costs **.** These amounts represent recoverable administrative costs incurred relating to filing, procurement, and information technology improvements associated with PECO's PAPUC-

approved DSP Program for the procurement of electric supply following the expiration of PECO's generation rate caps on December 31, 2010. The filing and implementation costs of this DSP Program are recoverable through the GSA over its 29-month term, that began January 1, 2011. The independent evaluator costs associated with conducting procurements is recoverable over a 12-month period after the PAPUC approves the results of the procurements. Costs relating to information technology improvements are recoverable over a 5-year period that began January 1, 2011. PECO earns a return on the recovery of information technology costs. Beginning in 2013, these costs are included within the energy and transmission programs line item.

DSP II Program Costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO's second PAPUC-approved DSP program for the procurement of electric supply. The filing and procurement of this DSP Program are recoverable through the GSA over its 24-month term, that began June 1, 2013. The independent evaluator costs associated with conducting procurements are recoverable over a 12-month period after the PAPUC approves the results of the procurements. PECO is not earning a return on these costs. Beginning in 2013, these costs are included within the energy and transmission programs line item.

Deferred storm costs. In the MDPSC's March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. These costs are being amortized over a 5-year period that began in December 2010. BGE is earning a return on this regulatory asset.

Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. The portion of this regulatory asset that does not earn a regulated rate of return were $37 million as of December 31, 2013, and $47 million as of December 31, 2012. BGE will continue to amortize this amount through 2017.

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006, to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007, to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2013 and 2012, BGE recovered $66 million and $67 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007.

Energy efficiency and demand response programs. These amounts represent costs recoverable (refundable) under ComEd's ICC approved Energy Efficiency and Demand Response Plan, PECO's PAPUC-approved EE&C Plan, and the BGE Smart Energy Savers Program ®. ComEd

began recovering these costs or refunding over-collections of these costs on June 1, 2008 through a rider. ComEd earns a return on the capital investment incurred under the program but does not earn (pay) interest on under (over) collections. For PECO, this amount represents an over-collection of program costs related to both Phase I and Phase II of its EE&C Plan. PECO does not earn (pay) interest on under (over) collections. PECO began recovering the costs of its Phase I and Phase II EE&C Plans through a surcharge in January 2010 and June 2013, respectively, based on projected spending under the programs. Phase I recovery continued over the life of the program, which expired on May 31, 2013 and excess funds collected began being refunded in June 2013. Phase II of the program began on June 1, 2013, and will continue over the life of the program, which will expire on May 31, 2016. Excess funds collected are required to be refunded beginning in June 2016. PECO earned a return on the capital investment incurred under Phase I of the program. BGE's Smart Energy Savers Program ® includes both MDPSC approved demand response and energy efficiency programs. For the BGE Peak Rewards SM demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Also included in the demand response program are customer bill credits related to BGE's Smart Energy Rewards program which began in July 2013. Actual costs incurred in the conservation program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

Merger integration costs. These amounts represent integration costs to achieve distribution synergies related to the merger transaction. As a result of the MDPSC's February 2013 rate order, BGE deferred $8 million related to non-severance merger integration costs incurred during 2012 and the first quarter of 2013. Of these costs, $4 million was authorized to be amortized over a 5-year period that began in March 2013. The recovery of the remaining $4 million was deferred. In the MDPSC's December 2013 rate order, BGE was authorized to recover the remaining $4 million and an additional $4 million of non-severance merger integration costs incurred during 2013. These costs are being amortized over a 5-year period that began in December 2013. BGE is earning a return on this regulatory asset included in base rates.

Under (Over)-recovered electric and gas revenue decoupling. These amounts represent the electric and gas distribution costs recoverable from or refundable to customers under BGE's decoupling mechanism, which does not earn a rate of return. As of December 31, 2013, BGE had a regulatory liability of $7 million related to over-recovered electric revenue decoupling and $9 million related to over-recovered natural gas revenue decoupling. As of December 31, 2012, BGE had a regulatory asset of $5 million related to under-recovered electric revenue decoupling and a regulatory liability of $7 million related to over-recovered natural gas revenue decoupling.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs for former ComEd and PECO plants that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will be sufficient to fund the associated future decommissioning costs at the time of decommissioning. See Note 15—Asset Retirement Obligations for additional information.

Removal costs. These amounts represent funds ComEd and BGE have received from customers through depreciation rates to cover the future non-legally required cost of removal of property, plant

and equipment which reduces rate base for ratemaking purposes. This liability is reduced as costs are incurred.

DLC Program Costs. The DLC program costs include equipment, installation, and information technology costs necessary to implement the DLC Program under PECO's EE&C Phase I Plans. PECO received full cost recovery through Phase I collections and will amortize the costs as a credit to the income statement to offset the related depreciation expense during the same period through September 2025, which is the remaining useful life of the assets. PECO is not paying interest on these over-recovered costs.

Electric distribution tax repairs. PECO's 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits began being reflected in customer bills on January 1, 2012. No interest will be paid to customers.

Gas distribution tax repairs. PECO's 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits began being reflected in customer bills on January 1, 2013. No interest will be paid to customers.

Under (Over)-recovered uncollectible accounts. As a result of the February 2010 ICC order approving recovery of ComEd's uncollectible accounts, ComEd has the ability to adjust its rates annually to reflect the increases and decreases in annual uncollectible accounts expense starting with year 2008. ComEd recorded a regulatory asset for the cumulative under-collections in 2008 and 2009. Recovery of the initial regulatory asset was completed over an approximate 14-month time frame which began in April 2010. The recovery or refund of the difference in the uncollectible accounts expense applicable to the years starting with January 1, 2010, will take place over a 12-month time frame beginning in June of the following year. ComEd is not earning a return or paying interest on these under (over)-recovered costs.

Under (Over)-recovered AEPS costs current asset (liability). The AEPS costs represent the administrative and AEC costs incurred to comply with the requirements of the AEPS Act, which are recoverable on a full and current basis. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. Beginning in 2013, these costs are included within the energy and transmission programs line item.

Revenue subject to refund. These amounts represent refunds of $37 million and associated interest of $1 million ComEd owes to customers primarily related to the treatment of post-test year accumulated depreciation issue in the 2007 Rate Case. See above discussion of the 2007 Rate Case for further information.

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities' consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd purchases receivables at

a discount to primarily recover uncollectible accounts expense from the suppliers. BGE's tariff provides that receivables are to be purchased at a discount, primarily to recover uncollectible accounts expense from the suppliers. However, if the discount rate is negative, the tariff provides that the receivable is purchased at a zero discount rate. BGE is currently purchasing certain receivables at a zero discount rate. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO, and BGE do not record unbilled commodity receivables under their POR programs. Purchased billed receivables are classified in other accounts receivable, net on Exelon's, ComEd's, PECO's and BGE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of December 31, 2013 and 2012.

As of December 31, 2013	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 263	$ 105	$ 72	$86
Allowance for uncollectible accounts [b]	(30)	(16)	(7)	(7)
Purchased receivables, net	$ 233	$ 89	$ 65	$79

As of December 31, 2012	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 191	$ 55	$ 65	$71
Allowance for uncollectible accounts [b]	(21)	(9)	(6)	(6)
Purchased receivables, net	$ 170	$ 46	$ 59	$65

(a) PECO's gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.

(b) For ComEd and BGE, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing (PORCB) tariff.

4. Merger and Acquisitions

Merger with Constellation (Exelon, Generation, ComEd, PECO and BGE)

Description of Transaction

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

Regulatory Matters

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion.

The following costs were recognized after the closing of the merger and are included in Exelon's, Generation's and BGE's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2012.

Description	Payment Period	BGE	Generation	Exelon	Statement of Operations Location
BGE rate credit of $100 per residential customer [(a)]	Q2 2012	$113	$ —	$ 113	Revenues
Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers	2012 to 2014	—	—	113.5	O&M Expense
Contribution for renewable energy, energy efficiency or related projects in Baltimore	2012 to 2014	—	—	2	O&M Expense
Charitable contributions at $7 million per year for 10 years	2012 to 2021	28	35	70	O&M Expense
State funding for offshore wind development projects	Q2 2012	—	—	32	O&M Expense
Miscellaneous tax benefits	Q2 2012	(2)	—	(2)	Taxes Other Than Income
Total		$139	$ 35	$328.5	

(a) Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

The direct investment estimate includes $95 million to $120 million relating to the construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a 20 year lease agreement that is contingent upon the developer obtaining all required approvals, permits and financing for the construction of the building. Once required approvals are received and financing conditions are met, construction will commence and the building is expected to be ready for occupancy in approximately 2 years after building construction commences.

The direct investment estimate also includes $600 million to $650 million for Exelon's and Generation's commitment to develop or assist in development of 285—300 MWs of new generation in Maryland, expected to be completed over a period of 10 years. The MDPSC Order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. If in the future Exelon determines that it is probable that it will make subsidy, compliance or liquidated damages payments related to the new generation development commitments, Exelon will record a liability at that time. As of December 31, 2013, it is reasonably possible that Exelon will be required to make subsidy or

liquidated damages payments of approximately $40 million rather than build one of the generation projects contemplated by the commitments, given that the generation build is dependent upon the passage of legislation and other conditions that Exelon does not control.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland site with 120MW of new natural gas-fired generation to satisfy certain of these commitments and achievement of commercial operation is expected in 2015. In December 2013, Generation acquired the Fourmile Ridge Project in western Maryland and executed a wind turbine supply agreement for construction of a 32.5 MW project targeted for commercial operation in November 2014. This project will satisfy a portion of the 125 MW Tier I land-based renewables commitment. See Note 22—Commitments and Contingencies for additional information. As of December 31, 2013, amounts reflected in the Exelon and Generation consolidated financial statements include $24 million of capital expenditures and $6 million of development costs included within operating and maintenance expense associated with pursuit of these commitments for new generation in the State of Maryland.

Associated with certain of the regulatory approvals required for the merger, on November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, to Raven Power Holdings LLC (Raven Power), a subsidiary of Riverstone Holdings LLC. The sale agreement included a base price with purchase price adjustments based on fuel inventory, working capital, capital expenditures, and timing of the closing, resulting in net proceeds from the sale of approximately $371 million. Decisions by certain market participants to remove themselves from the bidding process, combined with the deadlines and limitations on the pool of potential buyers imposed by the merger approval orders, resulted in realized sales proceeds below Generation's estimated fair value of the Maryland generating stations. Consequently, Exelon and Generation recorded a pre-tax loss of $272 million in 2012 to reflect the difference between the sales price and the carrying value of the generating stations and associated assets. In the first quarter of 2013, Exelon and Generation recorded a pre-tax gain of $8 million to reflect the final settlement of the sales price with Raven Power.

In connection with the sale of the Maryland generating stations, Exelon agreed to indemnify Raven Power for certain costs associated with the treatment of hazardous substances at off-site disposal facilities and any claims arising as a result of, or in connection with, any toxic tort, natural resource damages, loss of life or injury to persons due to releases of, or exposure to hazardous substances in connection with Raven Power's remediation of environmental contamination or Exelon's non-compliance with environmental laws or permits prior to the closing date of the sale.

Pursuant to the MDPSC merger approval conditions, BGE is restricted from paying any dividend on its common shares through the end of 2014, was required to maintain specified minimum capital and O&M expenditure levels in 2012 and 2013, and is not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process for two years following the closing of the merger. Additionally, BGE is subject to other merger approval conditions to enhance BGE's ring-fencing measures established by order of the MDPSC.

Subsequent to the merger, Generation discovered that, for the first two weeks following the merger, due to a software error, Generation inadvertently bid certain generating units into the PJM energy market at prices that slightly exceeded the cost-based caps to which it had agreed. This error was a violation of the commitments made in connection with merger approvals by DOJ, FERC and the MDPSC. Generation reported the error to the DOJ, FERC and the MDPSC and committed to remedy

the impacts of its error. The MDPSC held a hearing to review the error, and accepted Generation's proposed remediation. Subsequent close examination by Generation of its cost-based bids also revealed the need for some minor adjustments to the cost build up for certain of its PJM units. Generation has coordinated with PJM to determine the impact on Generation's revenues and the market from this error and these adjustments, and Generation has worked with PJM to reverse the financial impacts. In November 2012, Generation reached a settlement with the DOJ regarding this matter. The final resolution did not have a material impact on Exelon's or Generation's results of operations, cash flows or financial position.

Exelon was named in suits filed in the Circuit Court of Baltimore City, Maryland alleging that individual directors of Constellation breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. Similar suits were also filed in the United States District Court for the District of Maryland. The suits sought to enjoin a Constellation shareholder vote on the proposed merger until all material information was disclosed and sought rescission of the proposed merger. During the third quarter of 2011, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. On June 26, 2012, the court approved the settlement and entered final judgment.

Accounting for the Merger Transaction

The fair value of Constellation's non-regulated business assets acquired and liabilities assumed was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The financial statements of BGE do not include fair value adjustments for assets or liabilities subject to rate-setting provisions for BGE. BGE is subject to the rate-setting authority of FERC and the MDPSC and is accounted for pursuant to the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for BGE provide revenue derived from costs including a return on investment of assets and liabilities included in rate base. Except for debt, fuel supply contracts and regulatory assets not earning a return, the fair values of BGE's tangible and intangible assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore, do not reflect any net adjustments related to these amounts. For BGE's debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE's assets acquired and liabilities assumed is recorded as a regulatory asset and liability at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 1—Significant Accounting Policies for additional information on BGE's push-down accounting treatment. Also see Note 3—Regulatory Matters for additional information on BGE's regulatory assets.

The preliminary valuations performed in the first quarter of 2012 were updated in the second, third and fourth quarters of 2012, with the most significant adjustments to the preliminary valuation amounts having been made to the fair values assigned to the acquired power supply and fuel contracts, unregulated property, plant and equipment and investments in affiliates. There were no significant adjustments to the purchase price allocation in the first quarter of 2013 and the purchase price allocation was final as of March 31, 2013.

The final purchase price allocation of the Merger of Exelon with Constellation and Exelon's contribution of certain subsidiaries of Constellation to Generation was as follows:

Preliminary Purchase Price Allocation, excluding amortization	Exelon	Generation
Current assets	$ 4,936	$ 3,638
Property, plant and equipment	9,342	4,054
Unamortized energy contracts	3,218	3,218
Other intangibles, trade name and retail relationships	457	457
Investment in affiliates	1,942	1,942
Pension and OPEB regulatory asset	740	—
Other assets	2,265	1,266
Total assets	22,900	14,575
Current liabilities	3,408	2,804
Unamortized energy contracts	1,722	1,512
Long-term debt, including current maturities	5,632	2,972
Non-controlling interest	90	90
Deferred credits and other liabilities and preferred securities	4,683	1,933
Total liabilities, preferred securities and non-controlling interest	15,535	9,311
Total purchase price	$ 7,365	$ 5,264

Intangible Assets Recorded

For the power supply and fuel contracts acquired from Constellation, the difference between the contract price and the market price at the date of the merger was recognized as either an intangible asset or liability based on whether the contracts were in or out-of-the-money. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. The fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the merger date. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues.

Exelon and Generation present separately in their Consolidated Balance Sheets the unamortized energy contract assets and liabilities for these contracts. Generation's amortization expense for the year ended December 31, 2013 amounted to $470 million. Generation's amortization expense for the period March 12, 2012 to December 31, 2012 amounted to $1,101 million. In addition, Exelon Corporate has established a regulatory asset and an unamortized energy contract liability related to BGE's power supply and fuel contracts. The power supply and fuel contracts regulatory asset amortization was $77 million for the year ended December 31, 2013 and $116 million for the period March 12, 2012 to December 31, 2012. An equally offsetting amortization of the unamortized energy contract liability has been recorded at Exelon Corporate in the Consolidated Statement of Operations.

The fair value of the Constellation trade name intangible asset was determined based on the relief from royalty method of the income approach whereby fair value is determined to be the present value of the license fees avoided by owning the assets. The measure is based upon certain unobservable

inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. Exelon's and Generation's straight line amortization expense for the fair value of the Constellation trade name intangible asset for the year ended December 31, 2013 and for the period March 12, 2012 to December 31, 2012 amounted to $26 million and $20 million, respectively. The trade name intangible asset is included in deferred debits and other assets within Exelon's and Generation's Consolidated Balance Sheets.

The fair value of the retail relationships was determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The intangible assets for the fair value of the retail relationships are amortized as amortization expense on a straight line basis over the useful life of the underlying assets. Exelon's and Generation's straight line amortization expense for year ended December 31, 2013 and for the period March 12, 2012 to December 31, 2012 amounted to $21 million and $15 million, respectively. The retail relationships intangible assets are included in deferred debits and other assets within Exelon's and Generation's Consolidated Balance Sheets.

Exelon's intangible assets and liabilities acquired through the merger with Constellation included in its Consolidated Balance Sheets, along with the future estimated amortization, were as follows as of December 31, 2013:

					Estimated amortization expense					
Description	Weighted Average Amortization (Years) [b]	Gross	Accumulated Amortization	Net	2014	2015	2016	2017	2018	2019 and Beyond
Unamortized energy contracts, net [a]	1.5	$1,499	$ (1,378)	$121	$ 75	$18	$(31)	$(21)	$11	$ 69
Trade name	10.0	243	(46)	197	24	24	24	24	24	77
Retail relationships	12.4	214	(36)	178	19	18	18	18	18	87
Total, net		$1,956	$ (1,460)	$496	$118	$60	$ 11	$ 21	$53	$ 233

(a) Includes the fair value of BGE's power and gas supply contracts of $12 million for which an offsetting Exelon Corporate regulatory asset was also recorded.
(b) Weighted average amortization period was calculated as of the date of acquisition.

Impact of Merger

It is impracticable to determine the overall financial statement impact for the Constellation subsidiaries contributed down to Generation following the Upstream Merger for the year ended December 31, 2012. Upon closing of the merger, the operations of these Constellation subsidiaries were integrated into Generation's operations and are therefore not fully distinguishable after the merger.

The impact of BGE on Exelon's Consolidated Statement of Operations and Comprehensive Income includes operating revenues of $3,065 million and $2,091 million and net income (loss) of $210 million and $(31) million during the years ended December 31, 2013 and December 31, 2012, respectively.

During the year ended December 31, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $142 million, $106 million, $16 million, $9 million and $6 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $17 million, $11 million and $6

million, respectively, as a regulatory asset as of December 31, 2013. Additionally, Exelon and BGE established a regulatory asset of $6 million as of December 31, 2013 for previously incurred 2012 merger and integration-related costs.

During the year ended December 31, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $804 million, $340 million, $41 million, $17 million and $182 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $58 million, $36 million and $22 million, respectively, as a regulatory asset as of December 31, 2012.

The costs incurred are classified primarily within Operating and Maintenance Expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the BGE customer rate credit and the credit facility fees, which are included as a reduction to operating revenues and other, net, respectively, for years ended December 31, 2013 and 2012. See Note 22—Commitments and Contingencies for additional information.

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon and Generation as if the merger with Constellation had taken place on January 1, 2011. The unaudited pro forma information was calculated after applying Exelon's and Generation's accounting policies and adjusting Constellation's results to reflect purchase accounting adjustments.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Generation		Exelon	
	Year Ended December 31,		Year Ended December 31,	
(unaudited)	2012	2011 [a]	2012	2011 [b]
Total Revenues	$ 17,013	$ 19,494	$ 26,700	$ 30,712
Net income attributable to Exelon	1,205	324	2,092	974
Basic Earnings Per Share	n.a.	n.a.	$ 2.56	$ 1.15
Diluted Earnings Per Share	n.a.	n.a.	2.55	1.14

(a) The amounts above include non-recurring costs directly related to the merger of $203 million for the year ended December 31, 2011.
(b) The amounts above include non-recurring costs directly related to the merger of $236 million for the year ended December 31, 2011.

Acquisitions (Exelon and Generation)

Consistent with the applicable accounting guidance, the fair value of the assets acquired and liabilities assumed was determined as of the acquisition date through the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including the amount and timing); discount rates reflecting the risk inherent in the future cash flows; and future power and fuel market prices. Additionally, market prices based on the Market Price Referent (MPR) established by the CPUC for renewable energy resources were used in determining the fair value of the Antelope Valley assets acquired and liabilities assumed. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and the duration of the liabilities assumed. Generation did not record any goodwill related to any of the respective acquisitions.

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for each of the companies acquired by Generation during the year ended December 31, 2011:

	Acquisitions 2011	
	Wolf Hollow	Antelope Valley
Fair value of consideration transferred		
Cash	$ 305	$ 75
Plus: Gain on PPA settlement	6	—
Total fair value of consideration transferred	$ 311	$ 75
Recognized amounts of identifiable assets acquired and liabilities assumed		
Property, plant and equipment	$ 347	$ 15
Inventory	5	—
Intangible assets [(a)]	—	190
Payable to First Solar, Inc. [(b)]	—	(135)
Working capital, net	(5)	—
Other Assets	—	5
Total net identifiable assets	$ 347	$ 75
Bargain purchase gain	$ 36	$ —

(a) See Note 10—Intangible Assets for additional information.
(b) Generation concluded that the remaining, yet-to-be paid $135 million in consideration was embedded in the amounts payable under the Engineering, Procurement, Construction (EPC) agreement for First Solar, Inc. to construct the solar facility. For accounting purposes, this aspect of the transaction is considered to be akin to a "seller financing" arrangement. As such, Generation recorded a liability of $135 million associated with the portion of the future payments to First Solar, Inc. under the EPC agreement to reflect Generation's implicit amounts due First Solar, Inc. for the remainder of the value of the net assets acquired. The $135 million payable to First Solar, Inc. will be relieved as Generation makes payments for costs incurred over the project construction period. At December 31, 2012, $87 million remained payable to First Solar, Inc. During 2013, a subsidiary of Generation paid off the remaining balance of the payable to First Solar, Inc.

Wolf Hollow, LLC. On August 24, 2011, Generation completed the acquisition of all of the equity interests of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, for a purchase price of $311 million which increased Generation's owned capacity within the ERCOT power market by 720 MWs. The acquisition supports the Exelon commitment to low-carbon generation as part of Exelon 2020.

Generation recognized an approximately $36 million non-cash bargain purchase gain (i.e., negative goodwill). The gain was included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

The pro forma impact of this acquisition would not have been material to Exelon's or Generation's results of operations for the year ended December 31, 2011.

Antelope Valley Solar Ranch One. On September 30, 2011, Generation announced the completion of its acquisition of all of the interests in Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar PV project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first

portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. When fully operational, Antelope Valley will be one of the largest PV solar projects in the world, with approximately 3.8 million solar panels generating enough clean, renewable electricity to power the equivalent of 75,000 average homes per year. The project has a 25-year PPA, approved by the California Public Utilities Commission, with Pacific Gas & Electric Company for the full output of the plant. The acquisition supports Exelon's commitment to renewable energy as part of Exelon 2020.

Exelon expects to invest up to $650 million in equity in the project through 2014. The DOE's Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the project. See Note 13—Debt and Credit Agreements for additional information on the DOE loan guarantee.

The pro forma impact of this acquisition would not have been material to Exelon's or Generation's results of operations for the year ended December 31, 2011.

5. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation's total equity in earnings (losses) on the investment in CENG is as follows:

	Year Ended December 31, 2013	Period March 12, through December 31, 2012
Equity investment income	$ 123	$ 73
Amortization of basis difference in CENG	(114)	(172)
Total equity in earnings (losses)—CENG	$ 9	$ (99)

As of March 12, 2012, Generation had an initial basis difference of approximately $204 million between the initial carrying value of its investment in CENG and its underlying equity in CENG. This basis difference resulted from the requirement to record the investment in CENG at fair value under purchase accounting while the underlying assets and liabilities within CENG continue to be accounted for on a historical cost basis. Generation is amortizing this basis difference over the respective useful lives of the assets and liabilities of CENG or as those assets and liabilities affect the earnings of CENG.

Based on tax sharing provisions contained in the operating agreement for CENG, Generation may be eligible for distributions from its investment in CENG in excess of its 50.01% ownership interest. Through purchase accounting, Generation has recorded the fair value of expected future distributions. When these distributions are realized, Generation will record a reduction in its investment in CENG. Any distributions in excess of Generation's investment in CENG would be recorded in earnings.

Generation has various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements see Note 25—Related Party Transactions.

On July 29, 2013, Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. The Master Agreement contemplates that the parties will execute a series of additional agreements at a closing that will occur following the receipt of regulatory approvals and the satisfaction of other customary closing conditions. Exelon currently expects that the closing will occur early in the second quarter of 2014.

The Master Agreement requires CENG to make two pre-closing cash distributions to EDF and Generation, if CENG has cash in excess of reserves and the amount of an outstanding credit facility are available, through one of its wholly owned subsidiaries, as owners of the joint venture. Generation received the first distribution of $115 million in December 2013 and recorded it as a reduction to the Investment in CENG on Exelon's and Generation's Consolidated Balance Sheets. A second distribution will occur prior to the closing provided that CENG has sufficient available cash.

At the closing, Generation, CENG and subsidiaries of CENG will execute a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI's rights as a member of CENG. CENG will reimburse Generation for its direct and allocated costs for such services. The NOSA will replace the SSA. At the closing, Nine Mile Point Nuclear Station, a subsidiary of CENG, will also assign to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with the co-owner. In addition, at the closing the PSAA will be amended and extended until the permanent cessation of power generation by the CENG generation plants.

In addition, at closing, Generation will make a $400 million loan to CENG, bearing interest at 5.25% per annum and payable out of specified available cash flows of CENG and in any event, payable upon the settlement of the Put Option Agreement discussed below, if the put option is exercised, or payable upon the maturity date of the note (which will be 20 years from the closing), whichever occurs first. Immediately following receipt of the proceeds of such loan, CENG will make a $400 million special distribution to EDFI. The parties will also execute a Fourth Amended and Restated Operating Agreement for CENG, pursuant to which, among other things, CENG will commit to make preferred distributions to Generation (after repayment of the $400 million loan) quarterly out of specified available cash flows, until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from the date of the special distribution to EDFI.

Generation and EDFI will also enter into a Put Option Agreement at closing pursuant to which EDFI will have the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. The beginning of the exercise period will be accelerated if Exelon's affiliates cease to own a majority of CENG and exercise a related right to terminate the Nuclear Operating Services Agreement. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Also at closing, Generation will execute an Indemnity Agreement pursuant to which Generation will indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon will guarantee Generation's obligations under this indemnity.

Currently, Exelon and Generation account for their investment in CENG under the equity method of accounting. The transfer of the operating licenses and corresponding operational control to Exelon and Generation will result in Exelon and Generation being required to consolidate the financial position and results of operations of CENG. When that accounting change occurs, Exelon and Generation will derecognize their equity method investment in CENG and will record all assets, liabilities and the non-controlling interest in CENG at fair value on Exelon and Generation's balance sheets. Any difference between the former carrying value and newly recorded fair value at that date will be recognized as a gain or loss upon consolidation, which could be material to Exelon's and Generation's results of operations.

6. Accounts Receivable (Exelon, Generation, ComEd PECO and BGE)

Accounts receivable at December 31, 2013 and 2012 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

2013	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$1,151	$584[a]	$201	$161	$205
Allowance for uncollectible accounts [b]	(272)	(57)	(62)	(107) [c]	(46)

2012	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$1,094	$535[a]	$213	$164	$182
Allowance for uncollectible accounts [b]	(293)	(84)	(70)	(99) [c]	(40)

(a) Represents unbilled portion of retail receivables estimated under Exelon's unbilled critical accounting policy.
(b) Includes the allowance for uncollectible accounts on customer and other accounts receivable.
(c) Includes an allowance for uncollectible accounts of $8 million and $7 million at December 31, 2013 and 2012, respectively, related to PECO's current installment plan receivables described below.

PECO Installment Plan Receivables (Exelon and PECO). PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $19 million and $18 million as of December 31, 2013 and 2012, respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1—Significant Accounting Policies. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2013 of $18 million consists of $1 million, $4 million and $13 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2012 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of December 31, 2013 and 2012 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1—Significant Accounting Policies.

Accounts Receivable Agreement (Exelon and PECO). PECO was party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $210 million, which was classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets as of December 31, 2012. The agreement terminated on August 30, 2013 and PECO paid down the outstanding principal of $210 million. The financial institution no longer has an undivided interest in the accounts receivable designated under the agreement. As of December 31, 2012, the financial institution's undivided interest in Exelon's and PECO's gross accounts receivable was equivalent to $289 million, which represented the financial institution's interest in PECO's eligible receivables as calculated under the terms of the agreement. The agreement required PECO to maintain eligible receivables at least equivalent to the financial institution's undivided interest.

7. Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

Asset Category	Average Service Life (years)	2013	2012
Electric—transmission and distribution	5 - 90	$28,123	$26,576
Electric—generation	1 - 52	20,420	19,004
Gas—transportation and distribution	5 - 90	3,296	3,108
Common—electric and gas	5 - 50	1,101	1,029
Nuclear fuel [(a)]	1 - 8	5,196	4,815
Construction work in progress	N/A	1,890	1,926
Other property, plant and equipment [(b)]	1 - 51	1,017	912
Total property, plant and equipment		61,043	57,370
Less: accumulated depreciation [(c)]		13,713	12,184
Property, plant and equipment, net		$47,330	$45,186

(a) Includes nuclear fuel that is in the fabrication and installation phase of $947 million and $894 million at December 31, 2013 and 2012, respectively.
(b) Includes Generation's buildings under capital lease with a net carrying value of $23 million and $20 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $59 million and total accumulated amortization was $36 million and $33 million as of December 31, 2013 and 2012, respectively. Also includes ComEd's buildings under capital lease with a net carrying value of $8 million and $0 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $8 million and total accumulated amortization was $0 million and $0 million as of December 31, 2013 and 2012, respectively. Includes land held for future use and non utility property at PECO and BGE. These balances also include capitalized acquisition, development and exploration costs related to oil and gas production activities at Generation.
(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $2,371 million and $2,078 million as of December 31, 2013 and 2012, respectively.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2013	2012	2011
Electric—transmission and distribution	2.91%	2.76%	2.59%
Electric—generation	3.35%	3.15%	3.12%
Gas	2.06%	2.03%	1.73%
Common—electric and gas	7.53%	7.61%	8.05%

Generation

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

	Average Service Life (years)	2013	2012
Asset Category			
Electric—generation	1 - 52	$20,420	$19,004
Nuclear fuel [(a)]	1 - 8	5,196	4,815
Construction work in progress	N/A	1,129	1,352
Other property, plant and equipment [(b)]	1 - 51	400	374
Total property, plant and equipment		27,145	25,545
Less: accumulated depreciation [(c)]		7,034	6,014
Property, plant and equipment, net		$20,111	$19,531

(a) Includes nuclear fuel that is in the fabrication and installation phase of $947 million and $894 million at December 31, 2013 and 2012, respectively.
(b) Includes buildings under capital lease with a net carrying value of $23 million and $20 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $59 million and total accumulated amortization was $36 million and $33 million as of December 31, 2013 and 2012, respectively. These balances also include capitalized acquisition, development and exploration costs related to oil and gas production activities.
(c) Includes accumulated amortization of nuclear fuel in the reactor core of $2,371 million and $2,078 million as of December 31, 2013 and 2012, respectively.

The annual depreciation provisions as a percentage of average service life for electric generation assets were 3.35%, 3.15% and 3.12% for the years ended December 31, 2013, 2012 and 2011, respectively.

License Renewals. Generation's depreciation provisions are based on the estimated useful lives of its generating stations, which assume the renewal of the licenses for all nuclear generating stations (except for Oyster Creek) and the hydroelectric generating stations. As a result, the receipt of license renewals has no impact on the Consolidated Statements of Operations. See Note 3—Regulatory Matters for additional information regarding license renewals.

Plant Retirements

Schuylkill Station and Riverside Station . On October 31, 2012, Generation notified PJM of its intention to permanently retire Schuylkill Generating Station Unit 1 by February 1, 2013, and Riverside Generating Station Unit 6 by June 1, 2014. Schuylkill Unit 1 is a 166 MW peaking oil unit located in

Philadelphia, Pennsylvania, which was placed in service in 1958. Riverside Unit 6 is a 115 MW peaking gas/kerosene unit that was placed in service in 1970, located in Baltimore, Maryland. On December 1, 2013, Generation notified PJM of its intention to permanently retire Riverside Generating Station Unit 4 by June 1, 2016. Riverside Unit 4 is a 74 MW intermediate gas unit that was placed in service in 1951 also located in Baltimore, Maryland. The units are being retired because they are no longer economic to operate due to their age, relatively high capital and operating costs and declining revenue expectations. On November 30, 2012, PJM notified Generation that it did not identify any transmission system reliability issues associated with the proposed Schuylkill Unit 1 retirement date, and as a result, Schuylkill Unit 1 was retired on January 1, 2013. On January 7, 2013 and December 23, 2013, PJM notified Generation that it did not identify any transmission system reliability issues associated with the retirements of Riverside Units 6 and 4, respectively. The early retirements will not have a material impact on Generation or Exelon's results of operations, cash flows or financial position.

Eddystone Station and Cromby Station . In December 2009, Exelon announced its intention to permanently retire three coal-fired generating units and one oil/gas-fired generating unit, effective May 31, 2011, in response to the economic outlook related to the continued operation of these four units. However, PJM determined that transmission reliability upgrades would be necessary to alleviate reliability impacts and that those upgrades would be completed in a manner that will permit Generation's retirement of two of the units on that date and two of the units subsequent to May 31, 2011. On May 31, 2011, Cromby Generating Station (Cromby) Unit 1 and Eddystone Generating Station (Eddystone) Unit 1 were retired. On May 27, 2011, the FERC approved a settlement providing for a reliability-must-run rate schedule, which defined compensation to be paid to Generation for continuing to operate Cromby Unit 2 and Eddystone Unit 2. The monthly fixed-cost recovery during the reliability-must-run period for Eddystone Unit 2 was approximately $6 million, and covered operating costs, plus a return on net assets, of the two units during the reliability-must-run period. In addition, Generation was reimbursed for variable costs, including fuel, emissions costs, chemicals, auxiliary power and for project investment costs during the reliability-must-run period. Eddystone Unit 2 and Cromby Unit 2 operated under the reliability-must-run agreement from June 1, 2011 until their respective retirement dates, Cromby Unit 2 on December 31, 2011 and Eddystone Unit 2 on May 31, 2012.

During the years ended December 31, 2013, 2012, and 2011, Generation incurred $1 million, $11 million, and $2 million of shut down costs reflected within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Expense for the write down of inventory was not material for the years ended December 31, 2013, 2012 and 2011.

ComEd

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

	Average Service Life (years)	2013	2012
Asset Category			
Electric—transmission and distribution	5 - 75	$17,334	$16,480
Construction work in progress	N/A	456	294
Other property, plant and equipment [a]	50	60	50
Total property, plant and equipment		17,850	16,824
Less: accumulated depreciation		3,184	2,998
Property, plant and equipment, net		$14,666	$13,826

(a) Includes buildings under capital lease with a net carrying value of $8 million and $0 million at December 31, 2013 and 2012, respectively. The original cost basis of the buildings was $8 million and total accumulated amortization was $0 million and $0 million as of December 31, 2013 and 2012, respectively.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 2.97%, 2.79% and 2.67% for the years ended December 31, 2013, 2012 and 2011, respectively.

PECO

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

	Average Service Life (years)	2013	2012
Asset Category			
Electric—transmission and distribution	5 - 65	$6,669	$6,355
Gas—transportation and distribution	5 - 70	1,932	1,859
Common—electric and gas	5 - 50	600	568
Construction work in progress	N/A	101	76
Other property, plant and equipment [a]	50	17	17
Total property, plant and equipment		9,319	8,875
Less: accumulated depreciation		2,935	2,797
Property, plant and equipment, net		$6,384	$6,078

(a) Represents land held for future use and non utility property.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2013	2012	2011
Electric—transmission and distribution	2.73%	2.51%	2.33%
Gas	1.79%	1.77%	1.73%
Common—electric and gas	6.65%	7.54%	8.05%

BGE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2013 and 2012:

	Average Service Life (years)	2013	2012
Asset Category			
Electric—transmission and distribution	5 - 90	$6,100	$5,767
Gas—distribution	5 -90	1,660	1,548
Common—electric and gas	5 - 40	578	554
Construction work in progress	N/A	196	193
Other property, plant and equipment [(a)]	20	32	31
Total property, plant and equipment		8,566	8,093
Less: accumulated depreciation		2,702	2,595
Property, plant and equipment, net		$5,864	$5,498

(a) Represents land held for future use and non utility property.

Average Service Life Percentage by Asset Category	2013	2012	2011
Electric—transmission and distribution	2.91%	2.92%	2.89%
Gas	2.36%	2.33%	2.41%
Common—electric and gas	8.45%	7.68%	8.40%

See Note 1—Significant Accounting Polices for further information regarding property, plant and equipment policies and accounting for capitalized software costs for Exelon, Generation, ComEd, PECO and BGE. See Note 13—Debt and Credit Agreements for further information regarding Exelon's, ComEd's, and PECO's property, plant and equipment subject to mortgage liens.

8. Impairment of Long-Lived Assets (Exelon and Generation)

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the third quarter of 2013, lower projected wind production and a decline in power prices suggested that the carrying value of certain wind projects may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of eleven wind projects, primarily located in West Texas and Minnesota, were less than their respective carrying values at September 30, 2013. The fair value analysis was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result, long-lived assets held and used with a carrying amount of approximately $75 million were written down to their fair value of $32 million and a pre-tax impairment charge of $43 million was recorded during the third quarter in operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations. Of the $43 million, $4 million was attributable to non-controlling interests for certain of the wind projects.

Nuclear Uprate Program (Exelon and Generation)

Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture (MUR) uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Like-Kind Exchange Transaction (Exelon)

Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in coal-fired generating station leases located in Georgia and Texas with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. See Note 14—Income Taxes for further information. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange for a third-party to bid on a service contract for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon’s exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

Based on the review performed in the second quarter of 2013, the estimated residual value of one of Exelon's direct financing leases experienced an other than temporary decline given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $14 million pre-tax impairment charge in the second quarter of 2013, which was recorded in investments and operating and maintenance expense in the Consolidated Balance Sheet and the Consolidated Statement of Operations, respectively. Changes in the assumptions described above could potentially result in future impairments of Exelon's direct financing lease investments, which could be material. Through December 31, 2013, no events have occurred that would require Exelon to review the estimated residual values of its direct financing lease investments subsequent to the review performed in the second quarter of 2013.

As of December 31, 2012, Exelon concluded that the estimated fair values of the residual values at the end of the lease terms exceeded the residual values established at the lease dates.

At December 31, 2013 and December 31, 2012, the components of the net investment in long-term leases were as follows:

	December 31, 2013	December 31, 2012
Estimated residual value of leased assets	$ 1,465	$ 1,492
Less: unearned income	767	807
Net investment in long-term leases	$ 698	$ 685

9. Jointly Owned Electric Utility Plant (Exelon, Generation, PECO and BGE)

Exelon, Generation, PECO and BGE's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2013 and 2012 were as follows:

	Nuclear generation			Fossil fuel generation			Transmission		Other
	Quad Cities	Peach Bottom	Salem [a]	Keystone [b]	Conemaugh [b]	Wyman	PA [c]	DE/NJ [d]	Other [e]
Operator	Generation	Generation	PSEG Nuclear	GenOn	GenOn	FP&L	First Energy	PSEG	
Ownership interest	75.00%	50.00%	42.59%	41.98%	31.28%	5.89%	Various	42.55%	44.24%
Exelon's share at December 31, 2013:									
Plant [f]	$ 941	$ 883	$ 501	$ 725	$ 399	$ 3	$ 14	$ 64	$ 2
Accumulated depreciation [f]	226	326	134	268	220	3	7	34	1
Construction work in progress	27	174	24	6	121	—	—	—	—
Exelon's share at December 31, 2012:									
Plant [f]	$ 874	$ 796	$ 494	$ 624	$ 322	$ 3	$ 13	$ 65	$ 1
Accumulated depreciation [f]	187	302	119	153	158	3	7	33	—
Construction work in progress	44	115	11	10	57	—	1	—	—

(a) Generation also owns a proportionate share in the fossil fuel combustion turbine at Salem, which is fully depreciated. The gross book value was $3 million at December 31, 2013 and 2012.

(b) Generation's ownership interest in Keystone and Conemaugh has increased as a result of Exelon's merger with Constellation in 2012. See Note 4—Merger and Acquisitions for additional information.

(c) PECO and BGE own a 22% and 7% share, respectively, in 127 miles of 500 kV lines located in Pennsylvania; PECO and BGE also own a 20.7% and 10.56% share, respectively, of a 500 kV substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500 kV lines including, but not limited to, the lines noted above.

(d) PECO owns a 42.55% share in 131 miles of 500 kV lines located in Delaware and New Jersey as well as a 42.55% share in a 500kV substation immediately outside of the Salem nuclear generating station in New Jersey which supplies power to the 500kV lines including, but not limited to, the lines noted above.
(e) Generation has a 44.24% ownership interest in Merrill Creek Reservoir located in New Jersey.
(f) Excludes asset retirement costs.

Exelon's, Generation's, PECO's and BGE's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. Exelon's, Generation's, PECO's and BGE's share of direct expenses of the jointly owned plants are included in fuel and operating and maintenance expenses on Exelon's and Generation's Consolidated Statements of Operations and in operating and maintenance expenses on PECO's and BGE's Consolidated Statements of Operations.

10. Intangible Assets (Exelon, Generation, ComEd and PECO)

Goodwill

Exelon's and ComEd's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2013 and 2012 were as follows:

	Gross Amount [(a)]	Accumulated Impairment Losses	Carrying Amount
Balance, January 1, 2012	$ 4,608	$ 1,983	$2,625
Impairment losses	—	—	—
Balance, December 31, 2013	$ 4,608	$ 1,983	$2,625

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom (predecessor parent company of ComEd) merger net of amortization, resolution of tax matters and other non-impairment-related changes as allowed under previous authoritative guidance.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Under the authoritative guidance for goodwill, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and is regularly reviewed by segment management. ComEd has a single operating segment for its combined business. There is no level below this operating segment for which discrete financial information is regularly reviewed by segment management. Therefore, ComEd's operating segment is considered its only reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step one of the two-step fair value based impairment test). If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step fair value based impairment test is required. Otherwise, no further testing is required.

If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit

exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Any goodwill impairment charge at ComEd will affect Exelon's consolidated results of operations.

ComEd's valuation approach is based on a market participant view, pursuant to authoritative guidance for fair value measurement, and utilizes a weighted combination of a discounted cash flow analysis and a market multiples analysis. The discounted cash flow analysis relies on a single scenario reflecting "base case" or "best estimate" projected cash flows for ComEd's business and includes an estimate of ComEd's terminal value based on these expected cash flows using the generally accepted Gordon Dividend Growth formula, which derives a valuation using an assumed perpetual annuity based on the entity's residual cash flows. The discount rate is based on the generally accepted Capital Asset Pricing Model and represents the weighted average cost of capital of comparable companies. The market multiples analysis utilizes multiples of business enterprise value to earnings, before interest, taxes, depreciation and amortization (EBITDA) of comparable companies in estimating fair value. Significant assumptions used in estimating the fair value include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd's business and the fair value of debt. Management performs a reconciliation of the sum of the estimated fair value of all Exelon reporting units to Exelon's enterprise value based on its trading price to corroborate the results of the discounted cash flow analysis and the market multiple analysis.

2013 Goodwill Impairment Assessments. Management concluded the remeasurement of the like-kind exchange position and the charge to ComEd's earnings in the first quarter of 2013 triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of January 31, 2013. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

ComEd performed a quantitative assessment as of November 1, 2013, for its 2013 annual goodwill impairment assessment. The first step of the annual impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

In both the interim and annual assessments, the discounted cash flow analysis reflected Exelon's indemnity to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts related to the like-kind exchange position on ComEd's equity. While neither the interim nor the annual assessments indicated an impairment of ComEd's goodwill, certain assumptions used to estimate the fair value of ComEd are highly sensitive to changes. Adverse regulatory actions, such as early termination of EIMA, or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd's business, and the fair value of debt could potentially result in a future impairment of ComEd's goodwill, which could be material. Based on the results of the annual goodwill test performed as of November 1, 2013, the estimated fair value of ComEd would have needed to decrease by more than 10% for ComEd to fail the first step of the impairment test.

Prior Goodwill Impairment Assessments. Management concluded that the May 2012 ICC final Order in ComEd's 2011 formula rate proceeding triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of May 31, 2012. The first step of the

interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. ComEd performed a qualitative assessment as of November 1, 2012, for its 2012 annual goodwill impairment assessment and determined that its fair value was not more likely than not less than its carrying value. Therefore, ComEd did not perform a quantitative assessment. As part of its qualitative assessment, ComEd evaluated, among other things, management's best estimate of projected operating and capital cash flows for ComEd's business (including the impacts of the May 2012 Order) as well as changes in certain other market conditions, such as the discount rate and EBITDA multiples.

Other Intangible Assets

For discussion surrounding Exelon's and Generation's unamortized energy contracts, trade name and retail relationships recorded in conjunction with the Merger, refer to Note 4—Merger and Acquisitions.

Exelon's, Generation's and ComEd's other intangible assets, included in unamortized energy contract assets and deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2013:

	Weighted Average Amortization Years [e]	Gross	Accumulated Amortization	Net	Estimated amortization expense 2014	2015	2016	2017	2018
Generation [f]									
Exelon Wind acquisition [a]	18.0	$224	$ (41)	$183	$ 14	$ 14	$ 14	$ 14	$ 14
Antelope Valley acquisition [b]	25.0	190	(4)	186	8	8	8	8	8
ComEd									
Chicago settlement—1999 agreement [c]	21.8	100	(76)	24	3	3	3	4	4
Chicago settlement—2003 agreement [d]	17.9	62	(38)	24	4	4	4	3	3
Total intangible assets		$576	$ (159)	$417	$ 29	$ 29	$ 29	$ 29	$ 29

(a) In December 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (later named Exelon Wind), adding 735 MWs of installed, operating wind capacity located in eight states.
(b) Refer to Note 4—Merger and Acquisitions for additional information regarding Antelope Valley.
(c) In March 1999, ComEd entered into a settlement agreement with the City of Chicago associated with ComEd's franchise agreement. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago each year from 1999 to 2002. The intangible asset recognized as a result of these payments is being amortized ratably over the remaining term of the franchise agreement, which ends in 2020.
(d) In February 2003, ComEd entered into separate agreements with the City of Chicago and with Midwest Generation, LLC (Midwest Generation). Under the terms of the settlement agreement with the City of Chicago, ComEd agreed to pay the City of Chicago a total of $60 million over a ten-year period, beginning in 2003. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement, which ends in 2020. As required by the settlement, ComEd also made a payment of $2 million to a third-party on the City of Chicago's behalf. Under the terms of the agreement with Midwest Generation, ComEd received payments of $32 million from Midwest Generation to relieve Midwest Generation's obligation under the 1999 fossil sale agreement with ComEd to build the generation facility in the City of Chicago. The payments received by ComEd, which have been recorded in other long-term liabilities, are being recognized ratably (approximately $2 million annually) as an offset to amortization expense over the remaining term of the franchise agreement.
(e) Weighted-average amortization period was calculated at the date of acquisition for acquired assets or settlement agreement.
(f) Excludes $67 million of other miscellaneous unamortized energy contracts that have been acquired at various points in time.

The following table summarizes the amortization expense related to intangible assets for each of the years ended December 31, 2013, 2012 and 2011:

For the Year Ended December 31,	Exelon	Generation	ComEd
2013	$ 27	$ 20	$ 7
2012	20	13	7
2011	19	12	7

Acquired Intangible Assets

Accounting guidance for business combinations requires that the acquirer must recognize separately identifiable intangible assets in the application of purchase accounting. The valuation of the acquired intangible assets discussed below were estimated by applying the income approach, which is based upon discounted projected future cash flows associated with the respective PPAs. Key assumptions used in the valuation of these intangible assets include forecasted power prices and discount rates. Those measures are based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. The intangible assets are amortized as a decrease in operating revenue within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income over the term of the underlying PPAs.

Exelon Wind. The output of the acquired wind turbines has been sold under PPA contracts. The excess of the contract price of the PPAs over market prices was recognized as intangible assets at the acquisition date. Generation determined that the estimated acquisition-date fair value of the intangible assets was approximately $224 million, which is recorded in unamortized energy contract assets within Exelon's and Generation's Consolidated Balance Sheets. The intangible assets are amortized on a straight-line basis over the period in which the associated contract revenues are recognized.

Antelope Valley. Upon completion of the development project, all of the output will be sold under a PPA with Pacific Gas & Electric Company. The excess of the contract price of the PPA over forecasted MPR-based market prices was recognized as an intangible asset at the acquisition date. Generation determined that the estimated acquisition-date fair value of the intangible asset was approximately $190 million, which is recorded in unamortized energy contract assets within Exelon's and Generation's Consolidated Balance Sheets. The fair value is amortized over the life of the contract in relation to the present value of the underlying cash flows as of the acquisition date.

Renewable Energy Credits and Alternative Energy Credits (Exelon, Generation, ComEd and PECO).

Exelon's, Generation's, ComEd's and PECO's other intangible assets, included in other current assets and other deferred debits and other assets on the Consolidated Balance Sheets, include RECs (Exelon, Generation and ComEd) and AECs (Exelon and PECO). Revenue for RECs that are part of a bundled power sale is recognized when the power is produced and delivered to the customer. As of December 31, 2013, and 2012, PECO had current AECs of $19 million and $17 million, respectively, and noncurrent AECs of $5 million and $9 million, respectively. As of December 31, 2013, and 2012, Generation had current RECs of $158 million and $61 million, respectively, and noncurrent RECs of $0 million and $45 million, respectively. As of December 31, 2013, and 2012, ComEd, had current RECs of $3 million and $4 million, respectively. See Note 3—Regulatory Matters and Note 22—Commitments and Contingencies for additional information on RECs and AECs.

11. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures), and preferred securities as of December 31, 2013, and 2012:

Exelon

	December 31, 2013				December 31, 2012	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ 344	$ 3	$ 341	$ —	$ 214	$ 214
Long-term debt (including amounts due within one year)	19,132	—	18,672	1,079	18,745	20,520
Long-term debt to financing trusts	648	—	—	631	648	664
SNF obligation	1,021	—	790	—	1,020	763
Preferred securities of subsidiary	—	—	—	—	87	82

Generation

	December 31, 2013				December 31, 2012	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ 22	$ —	$ 22	$ —	$ —	$ —
Long-term debt (including amounts due within one year)	7,729	—	6,586	1,062	7,483	7,849
SNF obligation	1,021	—	790	—	1,020	763

ComEd

	December 31, 2013				December 31, 2012	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ 184	$ —	$ 184	$ —	$ —	$ —
Long-term debt (including amounts due within one year)	5,675	—	6,238	17	5,567	6,548
Long-term debt to financing trust	206	—	—	202	206	212

PECO

	December 31, 2013				December 31, 2012	
	Carrying Amount	Fair Value			Carrying Amount	Fair Value
		Level 1	Level 2	Level 3		
Short-term liabilities	$ —	$ —	$ —	$ —	$ 210	$ 210
Long-term debt (including amounts due within one year)	2,197	—	2,358	—	1,947	2,264
Long-term debt to financing trusts	184	—	—	180	184	188
Preferred securities	—	—	—	—	87	82

BGE

	December 31, 2013				December 31, 2012	
	Carrying	Fair Value			Carrying	
	Amount	Level 1	Level 2	Level 3	Amount	Fair Value
Short-term liabilities	$ 138	$ 3	$ 135	$ —	$ —	$ —
Long-term debt (including amounts due within one year)	2,011	—	2,148	—	2,178	2,468
Long-term debt to financing trusts	258	—	—	249	258	263

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2), short-term notes payable related to PECO's accounts receivable agreement (Level 2), and dividends payable (Level 1). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments. See Note 13—Debt and Credit Agreements for additional information on PECO's accounts receivable agreement.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

The fair value of Generation's non-government-backed fixed rate project financing debt (Level 3) is based on market and quoted prices for its own and other project financing debt with similar risk profiles. Given the low trading volume in the project financing debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-back fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value.

The Registrants also have tax-exempt debt (Level 3). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (i.e., political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above.

SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation

estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

Long-Term Debt to Financing Trusts. Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Preferred Securities. The fair value of these securities is determined based on the last closing price prior to quarter end, less accrued interest. The securities are registered with the SEC and are public. PECO redeemed all outstanding series of preferred securities on May 1, 2013. See Note 20—Earnings Per Share and Equity for additional information.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1—quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to access as of the reporting date. Financial assets and liabilities utilizing Level 1 inputs include active exchange-traded equity securities and funds, certain exchange-based derivatives, and money market funds.
- Level 2—inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. Financial assets and liabilities utilizing Level 2 inputs include fixed income securities, derivatives, commingled and mutual investment funds priced at NAV per fund share and fair value hedges.
- Level 3—unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability. Financial assets and liabilities utilizing Level 3 inputs include infrequently traded securities and derivatives, and investments priced using an alternative pricing mechanism or third party valuation.

Exelon

The following tables present assets and liabilities measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$1,230	$ —	$ —	$1,230
Nuclear decommissioning trust fund investments				
Cash equivalents	459	—	—	459
Equity				
Individually held	1,776	—	—	1,776
Exchange traded funds	115	—	—	115
Commingled funds	—	2,271	—	2,271
Equity funds subtotal	1,891	2,271	—	4,162
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	882	—	—	882
Debt securities issued by states of the United States and political subdivisions of the states	—	294	—	294
Debt securities issued by foreign governments	—	87	—	87
Corporate debt securities	—	1,753	31	1,784
Federal agency mortgage-backed securities	—	10	—	10
Commercial mortgage-backed securities (non-agency)	—	40	—	40
Residential mortgage-backed securities (non-agency)	—	7	—	7
Mutual funds	—	18	—	18
Fixed income subtotal	882	2,209	31	3,122
Middle market lending	—	—	314	314
Private Equity	—	—	5	5
Other debt obligations	—	14	—	14
Nuclear decommissioning trust fund investments subtotal [b]	3,232	4,494	350	8,076
Pledged assets for Zion decommissioning				
Cash equivalents	—	26	—	26
Equity				
Individually held	16	—	—	16
Equity funds subtotal	16	—	—	16
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	45	4	—	49
Debt securities issued by states of the United States and political subdivisions of the states	—	20	—	20
Corporate debt securities	—	227	—	227
Fixed income subtotal	45	251	—	296
Middle market lending	—	—	112	112
Other debt obligations	—	1	—	1
Pledged assets for Zion decommissioning subtotal [c]	61	278	112	451

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds [(d)(e)]	54	—	—	54
Rabbi trust investments subtotal	56	—	—	56
Commodity mark-to-market derivative assets				
Economic hedges	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761
Effect of netting and allocation of collateral [(f)]	(863)	(3,131)	(430)	(4,424)
Commodity mark-to-market assets subtotal	(46)	766	577	1,297
Interest rate mark-to-market derivative assets	30	39	—	69
Effect of netting and allocation of collateral	(30)	(2)	—	(32)
Interest rate mark-to-market derivative assets subtotal	—	37	—	37
Other Investments	—	—	15	15
Total assets	4,533	5,575	1,054	11,162
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(540)	(1,890)	(590)	(3,020)
Proprietary trading	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral [(f)]	869	3,007	404	4,280
Commodity mark-to-market liabilities subtotal [(h)]	1	(139)	(305)	(443)
Interest rate mark-to-market derivative liabilities	(31)	(17)	—	(48)
Effect of netting and allocation of collateral	31	1	—	32
Interest rate mark-to-market derivative liabilities subtotal	—	(16)	—	(16)
Deferred compensation obligation	—	(114)	—	(114)
Total liabilities	1	(269)	(305)	(573)
Total net assets	$4,534	$ 5,306	$ 749	$10,589

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 995	$ —	$ —	$ 995
Nuclear decommissioning trust fund investments				
Cash equivalents	245	—	—	245
Equity				
Individually held	1,480	—	—	1,480
Commingled funds	—	1,933	—	1,933
Equity funds subtotal	1,480	1,933	—	3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057	—	—	1,057
Debt securities issued by states of the United States and political subdivisions of the states	—	321	—	321
Debt securities issued by foreign governments	—	93	—	93
Corporate debt securities	—	1,788	—	1,788
Federal agency mortgage-backed securities	—	24	—	24
Commercial mortgage-backed securities (non-agency)	—	45	—	45
Residential mortgage-backed securities (non-agency)	—	11	—	11
Mutual funds	—	23	—	23
Fixed income subtotal	1,057	2,305	—	3,362
Middle market lending	—	—	183	183
Other debt obligations	—	15	—	15
Nuclear decommissioning trust fund investments subtotal [b]	2,782	4,253	183	7,218
Pledged assets for Zion decommissioning				
Cash equivalents	—	23	—	23
Equity				
Individually held	14	—	—	14
Commingled funds	—	9	—	9
Equity funds subtotal	14	9	—	23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12	—	130
Debt securities issued by states of the United States and political subdivisions of the states	—	37	—	37
Corporate debt securities	—	249	—	249
Federal agency mortgage-backed securities	—	49	—	49
Commercial mortgage-backed securities (non-agency)	—	6	—	6
Fixed income subtotal	118	353	—	471
Middle market lending	—	—	89	89
Other debt obligations	—	1	—	1
Pledged assets for Zion decommissioning subtotal [c]	132	386	89	607
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds [d][e]	69	—	—	69
Rabbi trust investments subtotal	71	—	—	71

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	641	4,675
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral [f]	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal [g]	80	1,076	656	1,812
Interest rate mark-to-market derivative assets	—	114	—	114
Effect of netting and allocation of collateral	—	(51)	—	(51)
Interest rate mark-to-market derivative assets subtotal	—	63	—	63
Other Investments	2	—	17	19
Total assets	4,062	5,778	945	10,785
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(236)	(3,566)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral [f]	2,042	4,020	25	6,087
Commodity mark-to-market liabilities [g][h]	(83)	(228)	(289)	(600)
Interest rate mark-to-market liabilities	—	(84)	—	(84)
Effect of netting and allocation of collateral	—	51	—	51
Interest rate mark-to-market derivative liabilities subtotal	—	(33)	—	(33)
Deferred compensation obligation	—	(102)	—	(102)
Total liabilities	(83)	(363)	(289)	(735)
Total net assets	$ 3,979	$ 5,415	$ 656	$10,050

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $(5) million and $30 million at December 31, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $7 million at both December 31, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) The mutual funds held by the Rabbi trusts include $53 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at December 31, 2013, and $53 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan at December 31, 2012.
(e) Excludes $32 million and $28 million of the cash surrender value of life insurance investments at December 31, 2013 and December 31, 2012, respectively.
(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $6 million, $(124) million and $(26) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2013. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.
(g) The Level 3 balance does not include current assets for Generation and current liabilities for ComEd of $226 million at December 31, 2012 related to the fair value of Generation's financial swap contract with ComEd.
(h) The Level 3 balance includes the current and noncurrent liability of $17 million and $176 million at December 31, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2013 and 2012:

For the Year Ended December 31, 2013	Nuclear Decommissioning Trust Fund Investment	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of January 1, 2013	$ 183	$ 89	$ 367	$ 17	$ 656
Total realized / unrealized gains (losses)					
Included in net income	2	—	(44) [a]	—	(42)
Included in other comprehensive income	—	—	—	2	2
Included in regulatory assets	8	—	(126) [b]	—	(118)
Change in collateral	—	—	7	—	7
Purchases, sales, issuances and settlements					
Purchases	203	62	28	4	297
Sales	(28)	(39)	(11)	(8)	(86)
Settlements	(18)	—	—	—	(18)
Transfers into Level 3	—	—	86 [c]	1	87
Transfers out of Level 3	—	—	(35)	(1)	(36)
Balance as of December 31, 2013	$ 350	$ 112	$ 272	$ 15	$ 749
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held as of December 31, 2013	$ 1	$ —	$ 167	$ —	$ 168

(a) Includes a reduction for the reclassification of $211 million of realized gains due to settlement of derivative contracts recorded in results of operations for the year ended December 31, 2013.
(b) Excludes decreases in fair value of $11 million of and realized losses reclassified due to settlements of $215 million associated with Generation's financial swap contract with ComEd for the year ended December 31, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes an increase of transfers into Level 3 arising from reductions in market liquidity, which resulted in less observable contract tenures in various locations.

For the Year Ended December 31, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Decommissioning	Mark-to-Market Derivatives [b]	Other Investments	Total
Balance as of January 1, 2012	$ 13	$ 37	$ 17	$ —	$ 67
Total realized / unrealized gains (losses)					
Included in income	—	—	59[a]	—	59
Included in regulatory liabilities	1	—	39	—	40
Change in collateral	—	—	(32)	—	(32)
Purchases, sales, issuances and settlements					
Purchases	169	63	334[c]	17	583
Sales	—	(11)	—	—	(11)
Transfers into Level 3	—	—	39	—	39
Transfers out of Level 3	—	—	(89)	—	(89)
Balance as of December 31, 2012	$ 183	$ 89	$ 367	$ 17	$656
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities as of December 31, 2012	$ —	$ —	$ 214	$ —	$214

(a) Includes a reduction for the reclassification of $155 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2012.
(b) Excludes $98 million of increases in fair value and $566 million of realized losses due to settlements for the year ended December 31, 2012 of Generation's financial swap contract with ComEd, which eliminates upon consolidation in Exelon's Consolidated Financial Statements. This position was de-designated as a cash flow hedge prior to the merger date.
(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2013 and 2012:

	Operating Revenue	Purchased Power and Fuel	Other, net [a]
Total gains (losses) included in income for the year ended December 31, 2013	$ (152)	$ 108	$ 2
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2013	$ 40	$ 127	$ 1

	Operating Revenue	Purchased Power and Fuel	Other, net
Total gains included in income for the year ended December 31, 2012	$ 54	$ 5	$—
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2012	$ 230	$ (16)	$—

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

Generation

The following tables present assets and liabilities measured and recorded at fair value on Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$1,006	$ —	$ —	$1,006
Nuclear decommissioning trust fund investments				
Cash equivalents	459	—	—	459
Equity				
Individually held	1,776	—	—	1,776
Exchange traded funds	115	—	—	115
Commingled funds	—	2,271	—	2,271
Equity funds subtotal	1,891	2,271	—	4,162
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	882	—	—	882
Debt securities issued by states of the United States and political subdivisions of the states	—	294	—	294
Debt securities issued by foreign governments	—	87	—	87
Corporate debt securities	—	1,753	31	1,784
Federal agency mortgage-backed securities	—	10	—	10
Commercial mortgage-backed securities (non-agency)	—	40	—	40
Residential mortgage-backed securities (non-agency)	—	7	—	7
Mutual funds	—	18	—	18
Fixed income subtotal	882	2,209	31	3,122
Middle market lending	—	—	314	314
Private Equity	—	—	5	5
Other debt obligations	—	14	—	14
Nuclear decommissioning trust fund investments subtotal [(b)]	3,232	4,494	350	8,076
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	26	—	26
Equity				
Individually held	16	—	—	16
Equity funds subtotal	16	—	—	16
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	45	4	—	49
Debt securities issued by states of the United States and political subdivisions of the states	—	20	—	20
Corporate debt securities	—	227	—	227

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Fixed income subtotal	45	251	—	296
Middle market lending	—	—	112	112
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal [c]	61	278	112	451
Rabbi trust investments				
Mutual funds [d]	13	—	—	13
Rabbi trust investments subtotal	13	—	—	13
Commodity mark-to-market derivative assets				
Economic hedges	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761
Effect of netting and allocation of collateral [e]	(863)	(3,131)	(430)	(4,424)
Commodity mark-to-market assets subtotal	(46)	766	577	1,297
Interest Rate mark-to-market derivative assets	30	32	—	62
Effect of netting and allocation of collateral	(30)	(2)	—	(32)
Interest Rate mark-to-market derivative assets subtotal	—	30	—	30
Other investments	—	—	15	15
Total assets	4,266	5,568	1,054	10,888
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(540)	(1,890)	(397)	(2,827)
Proprietary trading	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral [e]	869	3,007	404	4,280
Commodity mark-to-market liabilities subtotal	1	(139)	(112)	(250)
Interest rate mark-to-market derivative liabilities	(31)	(13)	—	(44)
Effect of netting and allocation of collateral	31	1	—	32
Interest rate mark-to-market derivative liabilities subtotal	—	(12)	—	(12)
Deferred compensation obligation	—	(29)	—	(29)
Total liabilities	1	(180)	(112)	(291)
Total net assets	$4,267	$ 5,388	$ 942	$10,597

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 487	$ —	$ —	$ 487
Nuclear decommissioning trust fund investments				
Cash equivalents	245	—	—	245
Equity				
Individually held	1,480	—	—	1,480
Commingled funds	—	1,933	—	1,933
Equity funds subtotal	1,480	1,933	—	3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057	—	—	1,057
Debt securities issued by states of the United States and political subdivisions of the states	—	321	—	321
Debt securities issued by foreign governments	—	93	—	93
Corporate debt securities	—	1,788	—	1,788
Federal agency mortgage-backed securities	—	24	—	24
Commercial mortgage-backed securities (non-agency)	—	45	—	45
Residential mortgage-backed securities (non-agency)	—	11	—	11
Mutual funds	—	23	—	23
Fixed income subtotal	1,057	2,305	—	3,362
Middle market lending	—	—	183	183
Other debt obligations	—	15	—	15
Nuclear decommissioning trust fund investments subtotal [b]	2,782	4,253	183	7,218
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	23	—	23
Equity				
Individually held	14	—	—	14
Commingled funds	—	9	—	9
Equity funds subtotal	14	9	—	23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12	—	130
Debt securities issued by states of the United States and political subdivisions of the states	—	37	—	37
Corporate debt securities	—	249	—	249
Federal agency mortgage-backed securities	—	49	—	49
Commercial mortgage-backed securities (non-agency)	—	6	—	6
Fixed income subtotal	118	353	—	471
Middle market lending	—	—	89	89
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal [c]	132	386	89	607
Rabbi trust investments				
Cash equivalents	1	—	—	1
Mutual funds [d]	13	—	—	13

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Rabbi trust investments subtotal	14	—	—	14
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	867	4,901
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral [f]	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal	80	1,076	882	2,038
Interest rate mark-to-market derivative assets	—	101	—	101
Effect of netting and allocation of collateral	—	(51)	—	(51)
Interest rate mark-to-market derivative assets subtotal	—	50	—	50
Other investments	2	—	17	19
Total assets	3,497	5,765	1,171	10,433
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(169)	(3,499)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral [f]	2,042	4,020	25	6,087
Commodity mark-to-market liabilities subtotal	(83)	(228)	(222)	(533)
Interest rate mark-to-market derivative liabilities	—	(84)	—	(84)
Effect of netting and allocation of collateral	—	51	—	51
Interest rate mark-to-market derivative liabilities subtotal	—	(33)	—	(33)
Deferred compensation obligation	—	(28)	—	(28)
Total liabilities	(83)	(289)	(222)	(594)
Total net assets	$ 3,414	$ 5,476	$ 949	$ 9,839

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $(5) million and $30 million at December 31, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $7 million at both December 31, 2013 December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) Excludes $10 million and $8 million of the cash surrender value of life insurance investments at December 31, 2013 and December 31, 2012, respectively.
(e) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $6 million, $(124) million and $(26) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2013. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.
(f) The Level 3 balance includes current assets for Generation of $226 million at December 31, 2012 related to the fair value of Generation's financial swap contract with ComEd, which eliminates upon consolidation in Exelon's Consolidated Financial Statements.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2013, and 2012:

For the Year Ended December 31, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of January 1, 2013	$ 183	$ 89	$ 660	$ 17	$ 949
Total unrealized / realized gains (losses)					
Included in income	2	—	(51) [a][b]	—	(49)
Included in other comprehensive income	—	—	(219) [b]	2	(217)
Included in noncurrent payables to affiliates	8	—	—	—	8
Change in collateral	—	—	7	—	7
Purchases, sales, issuances and settlements					
Purchases	203	62	28	4	297
Sales	(28)	(39)	(11)	(8)	(86)
Settlements	(18)	—	—	—	(18)
Transfers into Level 3	—	—	86[c]	1	87
Transfers out of Level 3	—	—	(35)	(1)	(36)
Balance as of December 31, 2013	$ 350	$ 112	$ 465	$ 15	$ 942
The amount of total losses included in income attributed to the change in unrealized gains related to assets and liabilities held as of December 31, 2013	$ 1	$ —	$ 156	$ —	$ 157

(a) Includes a reduction for the reclassification of $207 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2013.
(b) Includes $11 million of increases in fair value and realized losses due to settlements of $215 million associated with Generation's financial swap contract with ComEd for the year ended December 31, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes an increase of transfers into Level 3 arising from reductions in market liquidity, which resulted in less observable contract tenures in various locations.

For the Year Ended December 31, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of January 1, 2012	$ 13	$ 37	$ 817	$ —	$ 867
Total realized / unrealized gains (losses)					
Included in income	—	—	66[a]	—	66
Included in other comprehensive income	—	—	(475) [b]	—	(475)
Included in noncurrent payables to affiliates	1	—	—	—	1
Changes in collateral	—	—	(32)	—	(32)
Purchases, sales, issuances and settlements					
Purchases	169	63	334[c]	17	583
Sales	—	(11)	—	—	(11)
Transfers into Level 3	—	—	39	—	39
Transfers out of Level 3	—	—	(89)	—	(89)
Balance as of December 31, 2012	$ 183	$ 89	$ 660	17	$ 949
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities as of December 31, 2012	$ —	$ —	$ 165	$ —	$ 165

(a) Includes a reduction for the reclassification of $99 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2012.
(b) Includes $98 million of increases in fair value and $566 million of realized losses reclassified from OCI due to settlements associated with Generation's financial swap contract with ComEd for the year ended December 31, 2012. This position was de-designated as a cash flow hedge prior to the merger date. All prospective changes in fair value and reclassifications of realized amounts are being recorded to income offset by the amortization of the frozen mark in OCI. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2013, and 2012:

	Operating Revenue	Purchased Power and Fuel	Other - net [a]
Total gains (losses) included in income for the year ended December 31, 2013	$ (158)	$ 107	$ 2
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2013	$ 30	$ 126	$ 1

	Operating Revenue	Purchased Power and Fuel	Other - net [a]
Total gains included in income for the year ended December 31, 2012	$ 61	$ 5	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2012	$ 181	$ (16)	$ —

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

ComEd

The following tables present assets and liabilities measured and recorded at fair value on ComEd's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Rabbi trust investments				
Mutual funds	5	—	—	5
Rabbi trust investments subtotal	5	—	—	5
Total assets	5	—	—	5
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities [(b)]	—	—	(193)	(193)
Total liabilities	—	(8)	(193)	(201)
Total net assets (liabilities)	$ 5	$ (8)	$(193)	$(196)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 111	$ —	$ —	$ 111
Rabbi trust investments				
Mutual funds	8	—	—	8
Rabbi trust investments subtotal	8	—	—	8
Total assets	119	—	—	119
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities [(a)(b)]	—	—	(293)	(293)
Total liabilities	—	(8)	(293)	(301)
Total net assets (liabilities)	$ 119	$ (8)	$(293)	$(182)

(a) The Level 3 balance includes the current liability of $226 million at December 31, 2012, related to the fair value of ComEd's financial swap contract with Generation which eliminates upon consolidation in Exelon's Consolidated Financial Statements.
(b) The Level 3 balance includes the current and noncurrent liability of $17 million and $176 million at December 31, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the year ended and December 31, 2013, and 2012:

For the Year Ended December 31, 2013	Mark-to-Market Derivatives
Balance as of January 1, 2013	$ (293)
Total realized / unrealized gains included in regulatory assets [(a)(b)]	100
Balance as of December 31, 2013	$ (193)

(a) Includes $11 million of decreases in fair value and realized gains due to settlements of $215 million associated with ComEd's financial swap contract with Generation for the year ended December 31, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

(b) Includes $133 million of increases in the fair value and realized losses due to settlements of $7 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2013.

Twelve Months Ended December 31, 2012	Mark-to-Market Derivatives
Balance as of January 1, 2012	$ (800)
Total realized / unrealized gains included in regulatory assets [(a)(b)]	507
Balance as of December 31, 2012	$ (293)

(a) Includes $98 million of increases in fair value and $566 million of realized gains due to settlements associated with ComEd's financial swap contract with Generation for the year ended December 31, 2012. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(b) Includes $34 million of decreases in the fair value and realized losses due to settlements of $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2012.

PECO

The following tables present assets and liabilities measured and recorded at fair value on PECO's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 175	$ —	$ —	$175
Rabbi trust investments				
Mutual funds [(a)]	9	—	—	9
Rabbi trust investments subtotal	9	—	—	9
Total assets	184	—	—	184
Liabilities				
Deferred compensation obligation	—	(17)	—	(17)
Total liabilities	—	(17)	—	(17)
Total net assets (liabilities)	$ 184	$ (17)	$ —	$167

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 346	$ —	$ —	$346
Rabbi trust investments				
Mutual funds [(a)]	9	—	—	9
Rabbi trust investments subtotal	9	—	—	9
Total assets	355	—	—	355
Liabilities				
Deferred compensation obligation	—	(18)	—	(18)
Total liabilities	—	(18)	—	(18)
Total net assets (liabilities)	$ 355	$ (18)	$ —	$337

(a) Excludes $14 million and $13 million of the cash surrender value of life insurance investments at December 31, 2013 and 2012, respectively.

PECO had no Level 3 assets or liabilities measured at fair value on a recurring basis during the year ended December 31, 2013 and 2012.

BGE

The following tables present assets and liabilities measured and recorded at fair value on BGE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2013 and December 31, 2012:

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 31	$ —	$ —	$31
Rabbi trust investments				
Mutual funds	6	—	—	6
Rabbi trust investments subtotal	6	—	—	6
Total assets	37	—	—	37
Liabilities				
Deferred compensation obligation	—	(6)	—	(6)
Total liabilities	—	(6)	—	(6)
Total net assets (liabilities)	$ 37	$ (6)	$ —	$31

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 33	$ —	$ —	$33
Rabbi trust investments				
Mutual funds	5	—	—	5
Rabbit trust investments subtotal	5	—	—	5
Total assets	38	—	—	38
Liabilities				
Deferred compensation obligation	—	(5)	—	(5)
Total liabilities	—	(5)	—	(5)
Total net assets (liabilities)	$ 38	$ (5)	$ —	$33

BGE had no Level 3 assets or liabilities measured at fair value on a recurring basis during the year ended December 31, 2013.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE). The Registrants' cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds. Generation's investment policies place limitations on the types and investment grade ratings of the securities that may be held by the trusts. These policies limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The fair values of private placement fixed income securities are determined using a third party valuation that contains certain significant unobservable inputs and are categorized in Level 3.

Equity and fixed income commingled funds and fixed income mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of fixed income commingled and mutual funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining equity commingled funds in which Exelon and Generation invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. Commingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities.

Middle market lending are investments in loans or managed funds which invest in private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in middle market lending are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The investments in the Rabbi trusts are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of mutual funds. These funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices.

Mark-to-Market Derivatives (Exelon, Generation, and ComEd) . Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' derivatives are predominately at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Transfers in and out of levels are recognized as of the end of the reporting period the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of

future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 12—Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO and BGE). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd)

Mark-to-Market Derivatives (Exelon, Generation, ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Exelon board of directors on the scope of the risk management activities and is responsible for approving all valuation procedures at Exelon. Forward price curves for the power market utilized by the front office to manage the portfolio are reviewed and verified by the middle office and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and notional size. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, certain transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price is generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are highly liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $3.92 and $0.12 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 7A.—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrant's mark-to-market derivative assets and liabilities.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 12—Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at December 31, 2013 [c]	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic Hedges (Generation) [a]	$ 488	Discounted Cash Flow	Forward power price	$8 - $176[d]
			Forward gas price	$2.98 - $16.63[d]
		Option Model	Volatility percentage	15% - 142%
Mark-to-market derivatives—Proprietary trading (Generation) [a]	$ 3	Discounted Cash Flow	Forward power price	$10 - $176[d]
		Option Model	Volatility percentage	14% - 19%
Mark-to-market derivatives (ComEd)	$ (193)	Discounted Cash Flow	Forward heat rate [b]	8 - 9
			Marketability reserve	3.5% - 8%
			Renewable factor	84% -128%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
c) The fair values do not include cash collateral held on Level 3 positions of $26 million as of December 31, 2013.
d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas would be approximately $100 and $5.70, respectively.

Type of trade	Fair Value at December 31, 2012 [d]	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic Hedges (Generation) [a]	$ 473	Discounted Cash Flow	Forward power price	$14 - $79
			Forward gas price	$3.26 - $6.27
		Option Model	Volatility percentage	28% - 132%
Mark-to-market derivatives—Proprietary trading (Generation) [a]	$ (6)	Discounted Cash Flow	Forward power price	$15 - $106
		Option Model	Volatility percentage	16% - 48%
Mark-to-market derivatives—Transactions with affiliates (Generation and ComEd) [b]	$ 226	Discounted Cash Flow	Marketability reserve	8% - 9%
Mark-to-market derivatives (ComEd)	$ (67)	Discounted Cash Flow	Forward heat rate [c]	8% - 9.5%
			Marketability reserve	3.5% - 8.3%
			Renewable factor	81% - 123%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Includes current assets for Generation and current liabilities for ComEd of $226 million, related to the fair value of the five-year financial swap contract between Generation and ComEd that ended in May 2013, which eliminates in consolidation.
c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
d) The fair values do not include cash collateral held on Level 3 positions of $33 million as of December 31, 2012.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending, certain corporate debt securities, and private equity investments the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its' Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations. For a sample of its' Level 3 investments, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

As of December 31, 2013, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, and private equity investments of approximately $448 million. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

12. Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. The Registrants employ established policies and procedures to manage their risks associated with market fluctuations by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivative economic hedges for commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 22—Commitments and Contingencies. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to

differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015, and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including Generation's sales to ComEd, PECO and BGE to serve their retail load.

In order to fulfill a requirement of the Illinois Settlement Legislation, Generation and ComEd entered into a five-year financial swap contract that expired May 31, 2013. The financial swap was designed to hedge spot market purchases, which, along with ComEd's remaining energy procurement contracts, met its load service requirements. The terms of the financial swap contract required Generation to pay the around-the-clock market price for a portion of ComEd's electricity supply requirement, while ComEd paid a fixed price.

As the contract expired May 31, 2013, all realized impacts have been included in Generation's and ComEd's results of operations. In Exelon's consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

In addition, the physical contracts that Generation has entered into with ComEd and that ComEd has entered into with Generation and other suppliers as part of the ComEd power procurement process, which are further discussed in Note 3—Regulatory Matters, qualify and are accounted for under the NPNS exception. Based on the Illinois Settlement Legislation and ICC-approved procurement methodologies permitting ComEd to recover its electricity procurement costs from retail customers with no mark-up, ComEd's price risk related to power procurement is limited.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts for energy and associated RECs were reduced in the first quarter of 2013. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3—Regulatory Matters for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3—Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting

PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts and block contracts. PECO has certain full requirements contracts and block contracts, that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2013 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2013 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE's price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. All of BGE's natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 8,762 GWh, 12,958 GWh and 5,742 Gwh for the years ended December 31, 2013, 2012 and 2011, are a complement to

Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2013, Exelon had $1,425 million of notional amounts of fixed-to-floating hedges outstanding and $190 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximate $5 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2013. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign currency hedges as of December 31, 2013.

	Generation					Other	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (Current Assets)	$ —	$ 3	$ 15	$ (19)	$ (1)	$ —	$ (1)
Mark-to-market derivative assets (Noncurrent Assets)	26	3	15	(13)	31	7	38
Total mark-to-market derivative assets	$ 26	$ 6	$ 30	$ (32)	$ 30	$ 7	$ 37
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (18)	$ 19	$ (1)	$ —	$ (1)
Mark-to-market derivative liabilities (Noncurrent Liabilities)	(10)	(1)	(13)	13	(11)	(4)	(15)
Total mark-to-market derivative liabilities	$ (11)	$ (2)	$ (31)	$ 32	$ (12)	$ (4)	$ (16)
Total mark-to-market derivative net assets (liabilities)	$ 15	$ 4	$ (1)	$ —	$ 18	$ 3	$ 21

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

The following table provides a summary of the interest rate hedge balances recorded by the Registrants as of December 31, 2012:

	Generation					Other	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (Current Assets)	$ —	$ 3	$ 20	$ (19)	$ 4	$ —	$ 4
Mark-to-market derivative assets (Noncurrent Assets)	38	8	32	(32)	46	13	59
Total mark-to-market derivative assets	$ 38	$ 11	$ 52	$ (51)	$ 50	$ 13	$ 63
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (19)	$ 19	$ (2)	$ —	$ (2)
Mark-to-market derivative liabilities (Noncurrent Liabilities)	(31)	—	(32)	32	(31)	—	(31)
Total mark-to-market derivative liabilities	(32)	(1)	(51)	51	(33)	—	(33)
Total mark-to-market derivative net assets (liabilities)	$ 6	$ 10	$ 1	$ —	$ 17	$ 13	$ 30

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

Fair Value Hedges . For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

		Twelve Months Ended December 31,					
		2013	2012	2011	2013	2012	2011
	Income Statement Location	Gain (Loss) on Swaps			Gain (Loss) on Borrowings		
Generation	Interest expense [a]	$ (15)	$ (6)	$ —	$ —	$ (6)	$ —
Exelon	Interest expense	$ (24)	$ (9)	$ 1	$ 11	$ (3)	$ (1)

(a) For the years ended December 31, 2013 and 2012, the loss on Generation swaps included $16 million and $12 realized in earnings, respectively, with $2 million and an immaterial amount excluded from hedge effectiveness testing, respectively.

During the third and fourth quarters of 2013, Exelon entered into $625 million of notional amounts of fixed-to-floating fair value hedges related to interest rate swaps, which expire in 2020. At December 31, 2013, Exelon and Generation had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,275 million and $550 million, with unrealized gains of $26 million and $23 million, respectively. At December 31, 2012, Exelon and Generation had outstanding fixed-to-floating fair value hedges related to interest rate swaps of $650 million and $550 million that expire in 2015, with unrealized gains of $49 million and $38 million, respectively. During the years ended December 31, 2013 and 2012, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $2 million gain and immaterial, respectively.

Cash Flow Hedges . In anticipation of the Continental Wind, LLC non-recourse project financing that was completed on September 30, 2013, Exelon entered into forward-starting interest rate swaps that were designated as cash flow hedges to hedge the change in benchmark interest rates. Upon settlement of the swaps, a $26 million effective gain in OCI was deferred and will be amortized into interest expense over the life of the debt. See Note 13—Debt and Credit Agreements for additional information on the project financing.

In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 13—Debt and Credit Agreements, Generation entered into a floating-to-fixed forward starting interest rate swap with a notional amount of $485 million and a mandatory early termination date of April 5, 2014. The swap hedges approximately 75% of Generation's future interest rate exposure associated with the financing and was designated as a cash flow hedge. As such, the effective portion of the hedge is recorded in other comprehensive income within Generation's Consolidated Balance Sheets, with any ineffectiveness recorded in Generation's Consolidated Statements of Operations and Comprehensive Income. Net gains (or losses) from settlement of the hedges, to the extent effective, are amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

Every time Generation draws down on the loan, an offsetting hedge (fixed-to-floating) is executed and a portion of the cash flow hedge with a notional amount equal to the offsetting hedge, is de-designated and the related gains or losses going forward are reflected in earnings, which are largely offset by the losses or gains in the offsetting hedge.

Antelope Valley received its first loan advance on April 5, 2012, and a series of additional advances subsequently. Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $350 million, approximately 75% of the loan advance amount to offset portions of the original interest rate hedge, which are not designated as cash flow hedges. The remaining cash flow hedge has a notional amount of $135 million. At December 31, 2013, Generation's mark-to-market non-current derivative liability relating to the interest rate swaps in connection with the loan agreement to fund Antelope Valley was $10 million.

During the third quarter of 2011, a subsidiary of Constellation entered into floating-to-fixed interest rate swaps to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Sacramento PV Energy. The swaps have a total notional amount of $28 million as of December 31, 2013 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At December 31, 2013, the subsidiary had a $1 million derivative liability related to these swaps.

During the third quarter of 2012, a subsidiary of Exelon Generation entered into a floating-to-fixed interest rate swap to manage a portion of the interest rate exposure of anticipated long-term borrowings to finance Constellation Solar Horizons. The swap has a notional amount of $27 million as of December 31, 2013, and expires in 2030. This swap is designated as a cash flow hedge. At December 31, 2013, the subsidiary had a $2 million derivative asset related to the swap.

During the years ended December 31, 2013, and 2012, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Economic Hedges. At December 31, 2013, Generation had $144 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate

component of commodity positions and $195 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

At December 31, 2013, Exelon and Generation had $150 million in notional amounts of fixed-to-floating interest rate swaps that are marked-to-market, with unrealized gains of $2 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the year ended December 31, 2013, and the period from March 12 to December 31, 2012, the impact on the results of operations was immaterial.

Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon, Generation, ComEd, PECO and BGE)

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place either as the contracts deliver, when collateral is requested or in the event of default. Generation's use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e. to BB+ or Ba1). In the table below, Generation's energy-related economic hedges and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, is aggregated in the collateral and netting column. As of December 31, 2013 and 2012, $10 million of cash collateral posted and $3 million of cash collateral received, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e. to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in a non affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2013:

	Generation				ComEd	Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting [a]	Subtotal [b]	Economic Hedges [c]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,616	$ 1,476	$ (3,364)	$ 728	$ —	$ 728
Mark-to-market derivative assets (noncurrent assets)	1,344	285	(1,060)	569	—	569
Total mark-to-market derivative assets	$ 3,960	$ 1,761	$ (4,424)	$ 1,297	$ —	$ 1,297
Mark-to-market derivative liabilities (current liabilities)	$ (2,023)	$ (1,410)	$ 3,292	$ (141)	$ (17)	$ (158)
Mark-to-market derivative liabilities (noncurrent liabilities)	(804)	(293)	988	(109)	(176)	(285)
Total mark-to-market derivative liabilities	$ (2,827)	$ (1,703)	$ 4,280	$ (250)	$ (193)	$ (443)
Total mark-to-market derivative net assets (liabilities)	$ 1,133	$ 58	$ (144)	$ 1,047	$ (193)	$ 854

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $84 million and $72 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(12) million and $0 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $144 million at December 31, 2013.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2012:

	Generation				ComEd		Exelon
Derivatives	Economic Hedges [a]	Proprietary Trading	Collateral and Netting [b]	Subtotal [c]	Economic Hedges [a][d]	Intercompany Eliminations [a]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,883	$ 2,469	$ (4,418)	$ 934	$ —	$ —	$ 934
Mark-to-market derivative assets with affiliate (current assets)	226	—	—	226	—	(226)	—
Mark-to-market derivative assets (noncurrent assets)	1,792	724	(1,638)	878	—	—	878
Total mark-to-market derivative assets	$ 4,901	$ 3,193	$ (6,056)	$ 2,038	$ —	$ (226)	$ 1,812
Mark-to-market derivative liabilities (current liabilities)	$ (2,419)	$ (2,432)	$ 4,519	$ (332)	$ (18)	$ —	$ (350)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	(226)	226	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,080)	(689)	1,568	(201)	(49)	—	(250)
Total mark-to-market derivative liabilities	$ (3,499)	$ (3,121)	$ 6,087	$ (533)	$ (293)	$ 226	$ (600)
Total mark-to-market derivative net assets (liabilities)	$ 1,402	$ 72	$ 31	$ 1,505	$ (293)	$ —	$ 1,212

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $226 million related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation, excludes $28 million of noncurrent liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit. These are not reflected in the table above.

(c) Current and noncurrent assets are shown net of collateral of $113 million and $201 million, respectively, and current and noncurrent liabilities are shown net of collateral of $ (214) million and $ (131) million, respectively. The total cash collateral received, net of cash collateral posted and offset against mark-to-market assets and liabilities was $ (31) million at December 31, 2012.

(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon, Generation and ComEd). As discussed previously, effective prior to the merger with Constellation, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and is reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective

changes in the fair value of these instruments through current earnings from the date of de-designation. Approximately $195 million of these net pre-tax unrealized gains within accumulated OCI are expected to be reclassified from accumulated OCI during the next twelve months by Generation. Generation expects the settlement of the majority of its cash flow hedges will occur during 2013 through 2014.

Exelon discontinues hedge accounting when it determines that the derivative is no longer effective in offsetting changes in the cash flows of a hedged item or when it is no longer probable that the forecasted transaction will occur. For the year ended 2012, the amount reclassified into earnings as a result of the discontinuance of cash flow hedges was immaterial.

The tables below provide the activity of accumulated OCI related to cash flow hedges for the years ended December 31, 2013 and 2012, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
	Income Statement Location	Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at January 1, 2012		$ 925[a][d]	$ 488
Effective portion of changes in fair value		432[b]	330[e]
Reclassifications from accumulated OCI to net income	Operating Revenues	(828) [c]	(453)
Ineffective portion recognized in income	Operating Revenues	3	3
Accumulated OCI derivative gain at December 31, 2012		532[a][d]	368
Effective portion of changes in fair value		—	29[e]
Reclassifications from accumulated OCI to net income	Operating Revenues	(413) [c]	(277)
Accumulated OCI derivative gain at December 31, 2013		$ 119[d]	$ 120

(a) Includes $133 million and $420 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2012 and 2011 .
(b) Includes $88 million of gains, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the year ended December 31, 2012. As of the merger date, cash flow hedges were discontinued, as such, this amount represents changes in fair value prior to the merger date.
(c) Includes $133 million and $375 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2013 and 2012, respectively.
(d) Excludes $5 million of losses and $20 million of losses, net of taxes, related to interest rate swaps and treasury rate locks for the years ended December 31, 2013 and 2012, respectively.
(e) Includes $15 million and $9 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks at Generation for the year ended December 31, 2013 and 2012, respectively.

During the years ended December 31, 2013, 2012, and 2011 Generation’s former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $683 million, $1,368 million and $968 million pre-tax gain, respectively. Given that the cash flow hedges had primarily consisted of forward power sales and

power swaps and did not include power and gas options or sales, the ineffectiveness of Generation's cash flow hedges was primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. Changes in cash flow hedge ineffectiveness were losses of $5 million and a gain of $10 million for the years ended 2012 and 2011, respectively.

Exelon's former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $464 million, $747 million and $512 million pre-tax gain for the years ended December 31, 2013, 2012 and 2011, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were losses of $5 million and gains of $10 million for the years ended 2012 and 2011, respectively. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods as all energy-related cash flow hedge positions were de-designated prior to the merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars. For the years ended December 31, 2013, 2012 and 2011, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Generation			Intercompany Eliminations	Exelon
Year Ended December 31, 2013	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues [a]	Total
Change in fair value	$ 285	$ 180	$ 465	$ (6)	$ 459
Reclassification to realized at settlement	(65)	104	39	13	52
Net mark-to-market gains	$ 220	$ 284	$ 504	$ 7	$ 511

	Generation			Intercompany Eliminations	Exelon
Year Ended December 31, 2012	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues [a]	Total
Change in fair value	$ (362)	$ 215	$(147)	$ (94)	$(241)
Reclassification to realized at settlement	429	238	667	101	768
Net mark-to-market gains	$ 67	$ 453	$ 520	$ 7	$ 527

	Exelon and Generation		
Year Ended December 31, 2011 (As Reported)	Operating Revenues	Purchased Power and Fuel	Total
Change in fair value	$ 87	$ 131	$ 218
Reclassification to realized at settlement	(296)	(219)	(515)
Net mark-to-market (losses) [b]	$ (209)	$ (88)	$(297)

	Exelon and Generation		
Year Ended December 31, 2011 (Pro Forma)	Operating Revenues	Purchased Power and Fuel	Total
Change in fair value	$ 258	$ (40)	$ 218
Reclassification to realized at settlement	(516)	1	(515)
Net mark-to-market (losses) [b]	$ (258)	$ (39)	$(297)

(a) Prior to the merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value are recorded to operating revenues and eliminated in consolidation.

(b) Exelon and Generation have historically presented mark-to-market gains and losses within purchased power expense for all non-trading, energy-related derivatives that were not accounted for as cash flow hedges. In 2011, Exelon and Generation classified the mark-to-market gains and losses for contracts, where the underlying hedged transaction was an expected sale to hedge power, to operating revenues.

Proprietary Trading Activities (Exelon and Generation). For the years ended December 31, 2013, and 2012, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on derivative instruments entered into for proprietary trading purposes. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	For the Years Ended December 31,		
		2013	2012	2011
Change in fair value	Operating Revenue	$(21)	$ (12)	$ 23
Reclassification to realized at settlement	Operating Revenue	(18)	108	(26)
Net mark-to-market gains (losses)	Operating Revenue	$(39)	$ 96	$ (3)

Credit Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically,

each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 7A—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $38 million, $38 million and $27 million, respectively.

Rating as of December 31, 2013	Total Exposure Before Credit Collateral	Credit Collateral [(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,621	$ 172	$ 1,449	$ 1	$ 491
Non-investment grade	27	9	18	—	—
No external ratings					
Internally rated—investment grade	416	1	415	1	226
Internally rated—non-investment grade	30	2	28	—	—
Total	$ 2,094	$ 184	$ 1,910	$ 2	$ 717

Net Credit Exposure by Type of Counterparty	December 31, 2013
Financial Institutions	$ 256
Investor-owned utilities, marketers, power producers	684
Energy cooperatives and municipalities	907
Other	63
Total	$ 1,910

(a) As of December 31, 2013, credit collateral held from counterparties where Generation had credit exposure included $155 million of cash and $29 million of letters of credit .

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at

the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of December 31, 2013, ComEd's credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents PECO's net credit exposure. As of December 31, 2013, PECO had no net credit exposure with suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2013, PECO had credit exposure of $9 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents BGE's net credit exposure. The seller's credit exposure is calculated each business day. As of December 31, 2013, BGE had no net credit exposure to suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2013, BGE had credit exposure of $14 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e. NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

	For the Years Ended December 31,	
Credit-Risk Related Contingent Feature	**2013**	**2012**
Gross Fair Value of Derivative Contracts Containing this Feature [(a)]	$ (1,056)	$ (1,849)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements [(b)]	$ 846	$ 1,426
Net Fair Value of Derivative Contracts Containing This Feature [(c)]	$ (210)	$ (423)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent ignoring the effects of master netting agreements.
(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of $72 million, letters of credit posted of $364 million, cash collateral held of $206 million and letters of credit held of $34 million as of December 31, 2013 for counterparties with derivative positions. Generation had cash collateral posted of $527 million and

letters of credit posted of $563 million and cash collateral held of $499 million and letters of credit held of $45 million at December 31, 2012 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e. BB+ or Ba1), Generation could be required to post additional collateral of $2.0 billion as of December 31, 2013 and December 31, 2012. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2013, Generation's and Exelon's swaps were in an asset position, with a fair value of $18 million and $21 million, respectively.

See Note 24—Segment Information for additional information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2013, ComEd held neither cash nor letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2013, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 1—Significant Accounting Policies for additional information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2013, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2013, PECO could have been required to post approximately $42 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2013, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2013, BGE could have been required to post approximately $85 million of collateral to its counterparties.

13. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool.

Exelon, Generation, ComEd, PECO and BGE had the following amounts of commercial paper borrowings at December 31, 2013 and 2012:

Commercial Paper Issuer	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
	2013 [(a)]	2012 [(a)]	2013	2012	2013	2012
Exelon Corporate	$ 500	$ 500	$—	$—	0.27%	0.47%
Generation	5,600	5,600	—	—	0.32%	0.45%
ComEd	1,000	1,000	184	—	0.40%	0.50%
PECO	600	600	—	—	n.a.	n.a.
BGE	600	600	135	—	0.31%	0.43%
Total	$8,300	$8,300	$319	$—		

(a) Equals aggregate bank commitments under the revolving and bilateral credit agreements (with the exception of a $75 million bilateral agreement) that backstop the commercial paper program. See discussion below and Credit Agreements table below for items affecting effective program size.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have revolving credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its outstanding commercial paper does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit agreement.

At December 31, 2013, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit agreements:

Borrower	Aggregate Bank Commitment [a]	Facility Draws	Outstanding Letters of Credit	Available Capacity at December 31, 2013	
				Actual	To Support Additional Commercial Paper [b]
Exelon Corporate	$ 500	$ —	$ 2	$ 498	$ 498
Generation	5,675	—	1,413	4,262	4,187
ComEd	1,000	—	—	1,000	816
PECO	600	—	1	599	599
BGE	600	—	—	600	465
Total	$ 8,375	$ —	$ 1,416	$ 6,959	$ 6,565

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expire on October 17, 2014 and are solely for issuing letters of credit. As of December 31, 2013, letters of credit issued under these agreements totaled $20 million, $18 million, $21 million and $1 million for Generation, ComEd, PECO and BGE, respectively.

(b) Excludes $75 million bilateral credit facility that does not back Generation's commercial paper program.

For the year ended December 31, 2013, there were no borrowings under the Registrants' credit facilities.

The following tables present the short-term borrowings activity for Exelon, Generation, ComEd, and BGE during 2013, 2012 and 2011. PECO did not have any short-term borrowings outstanding during 2013, 2012 or 2011.

Exelon

	2013	2012	2011
Average borrowings	$ 254	$ 199	$ 218
Maximum borrowings outstanding	682	505	600
Average interest rates, computed on a daily basis	0.37%	0.48%	0.50%
Average interest rates, at December 31	0.35%	n.a.	0.44%

Generation

	2013	2012	2011
Average borrowings	$ 42	$ 4	$ 51
Maximum borrowings outstanding	291	165	304
Average interest rates, computed on a daily basis	0.32%	0.45%	0.48
Average interest rates, at December 31	n.a.	n.a.	n.a.

ComEd

	2013	2012	2011
Average borrowings	$ 203	$ 110	$ 36
Maximum borrowings outstanding	446	366	407
Average interest rates, computed on a daily basis	0.40%	0.50%	0.71%
Average interest rates, at December 31	0.37%	n.a.	n.a.

BGE

	2013	2012	2011
Average borrowings	$ 35	$ 6	$ 26
Maximum borrowings outstanding	135	76	190
Average interest rates, computed on a daily basis	0.31%	0.43%	0.38%
Average interest rates, computed at December 31	0.31%	n.a.	n.a.

Credit Agreements

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. The credit agreement expires in January 2015. This facility will solely be utilized by Generation to issue letters of credit.

On March 14, 2013, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2018, and ComEd may request another one-year extension of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extension or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

On August 10, 2013, Exelon Corporate, Generation, PECO and BGE amended and extended their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively. The new covenants are substantially consistent with existing covenants. Costs incurred to amend and extend the facilities for Exelon Corporate, Generation, PECO and BGE were not material.

Effective August 10, 2013, Exelon and ComEd entered into amendments to each of their respective revolving credit facilities (the Amendments). The Amendments relate to the IRS's challenge to the position taken by Exelon on its 1999 federal income tax return with respect to the sale of ComEd's fossil generating assets in a like-kind exchange tax position. The Amendments are intended to exclude the non-cash impact of the like-kind exchange tax position from the calculation of the interest coverage ratio under each of Exelon and ComEd's respective credit facilities. See Note 12—Income Taxes for additional information.

On January 27, 2014 ComEd began the process of extending its unsecured syndicated revolving credit facility, with aggregate bank commitments of $1.0 billion. The transaction is expected to close and become effective in March 2014, with a maturity of five years from the close of the transaction. No changes are expected to be made to the facility other than extension of the term for an additional one year period. Generally, it is expected that costs incurred to extend the facility will be amortized over the newly extended life of the facility.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular registrant's credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 27.5, 0.0 and 7.5 basis points for prime based borrowings and 127.5, 127.5, 127.5, 100.0 and 107.5 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

An event of default under any of the Registrants' credit facilities would not constitute an event of default under any of the other Registrants' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit facility would constitute an event of default under the Exelon Corporate credit facility.

On October 18, 2013, Generation, ComEd, PECO and BGE refinanced their respective minority and community bank credit facility agreements in the amounts of $50 million, $34 million, $34 million and $5 million, respectively. These facilities, which expire in October 2014, are solely utilized to issue letters of credit.

Each credit facility requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and, in the case of Exelon and Generation, interest on the debt of its project subsidiaries. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2013:

	Exelon	Generation	ComEd	PECO	BGE
Credit facility threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2013, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	7.67	11.45	5.20	8.29	7.85

Accounts Receivable Agreement

PECO was party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $210 million, which was classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets as of December 31, 2012. The agreement terminated on August 30, 2013 and PECO paid down the outstanding principal of $210 million. The financial institution no longer has an undivided interest in the accounts receivable designated under the agreement. As of December 31, 2012, the financial institution's undivided interest in Exelon's and PECO's gross accounts receivable was equivalent to $289 million, which represented the financial institution's interest in PECO's eligible receivables as calculated under the terms of the agreement. The agreement required PECO to maintain eligible receivables at least equivalent to the financial institution's undivided interest.

Willis Tower Capital Lease

In the second quarter of 2013, ComEd entered into a 20-year capital lease for distribution substation space at Willis Tower in Chicago, Illinois. Exelon and ComEd recorded $8 million on their Consolidated Balance Sheets within property plant and equipment and long-term debt at the inception of the lease. ComEd will make lease payments of less than $1 million annually in 2013-2017 and approximately $7 million in aggregate thereafter.

Long-Term Debt

The following tables present the outstanding long-term debt at Exelon, Generation, ComEd, PECO and BGE as of December 31, 2013 and 2012:

Exelon

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
First Mortgage Bonds [a][b]:				
Fixed rates	1.20% — 7.63%	2013-2043	$ 7,746	$ 7,397
Unsecured bonds	2.80% — 6.35%	2013-2036	1,750	1,850
Rate stabilization bonds	5.68% — 5.82%	2016-2017	265	332
Senior unsecured notes	2.00% — 7.60%	2014-2042	7,571	8,021
Pollution control notes:				
Fixed rates	4.10%	2014	20	20
Non-recourse debt:				
Fixed rates	2.33% — 5.50%	2031-2037	1,077	238
Variable rates	1.96% — 2.77%	2013-2053	150	262
Notes payable and other [c]	4.50% — 7.83%	2014-2053	181	177
Total long-term debt			18,760	18,297
Unamortized debt discount and premium, net			(19)	(17)
Fair value adjustment			384	448
Fair value hedge carrying value adjustment, net			7	17
Long-term debt due within one year			(1,509)	(1,047)
Long-term debt			$17,623	$17,698
Long-term debt to financing trusts [d]				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III	7.38%	2028	81	81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Subordinated debentures to BGE Trust	6.20%	2043	258	258
Total long-term debt to financing trusts			$ 648	$ 648

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's assets are subject to the liens of their respective mortgage indentures.
(b) Includes First Mortgage Bonds issued under the ComEd and PECO mortgage indentures securing pollution control bonds and notes.

(c) Includes capital lease obligations of $41 million and $30 million at December 31, 2013 and 2012, respectively. Lease payments of $4 million, $4 million, $4 million, $5 million, $5 million and $19 million will be made in 2014, 2015, 2016, 2017, 2018 and thereafter, respectively.
(d) Amounts owed to these financing trusts are recorded as debt to financing trusts within Exelon's Consolidated Balance Sheets.

Generation

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
Senior unsecured notes	2.00% — 7.60	2014-2042	$6,271	$6,721
Social Security Administration	2.93%	2015	1	—
Pollution control notes:				
Fixed rates	4.10%	2014	20	20
Non-recourse debt:				
Fixed rates	2.33% — 5.50%	2031-2037	1,077	238
Variable rates	1.96% — 2.77%	2014-2030	150	262
Notes payable and other [a]	4.50% — 7.83%	2014-2022	33	30
Total long-term debt			7,552	7,271
Fair value adjustment			166	199
Unamortized debt discount and premium, net			11	13
Long-term debt due within one year			(561)	(28)
Long-term debt			$7,168	$7,455

(a) Includes Generation's capital lease obligations of $33 million and $30 million at December 31, 2013 and 2012, respectively. Generation will make lease payments of $4 million, $4 million, $4 million, $5 million, $5 million and $11 million in 2014, 2015, 2016, 2017, 2018 and thereafter, respectively.

During January 2014, Generation redeemed its $20 million 4.10% pollution control revenue bonds due July 1, 2014 and its $500 million 5.35% senior unsecured notes at maturity.

ComEd

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
First Mortgage Bonds [a][b]:				
Fixed rates	1.63% — 7.63%	2013-2043	$5,546	$5,447
Notes payable and other [c]	6.95% — 7.49%	2014-2053	148	140
Total long-term debt			5,694	5,587
Unamortized debt discount and premium, net			(19)	(20)
Long-term debt due within one year			(617)	(252)
Long-term debt			$5,058	$5,315
Long-term debt to financing trust [d]				
Subordinated debentures to ComEd Financing III	6.35%	2042	$ 206	$ 206

(a) Substantially all of ComEd's assets other than expressly excepted property are subject to the lien of its mortgage indenture.
(b) Includes First Mortgage Bonds issued under the ComEd mortgage indenture securing pollution control bonds and notes.
(c) Includes ComEd's capital lease obligations of $8 million at December 31, 2013. Lease payments of less than $1 million will be made from 2014 through expiration at 2053.
(d) Amount owed to this financing trust is recorded as debt to financing trust within ComEd's Consolidated Balance Sheets.

On January 10, 2014, ComEd issued $300 million aggregate principal amount of its First Mortgage 2.150% Bonds, Series 115, due January 15, 2019, and $350 million aggregate principal amount of its First Mortgage 4.700% Bonds, Series 116, due January 15, 2044. The proceeds of the Bonds were used by ComEd to refinance the $17 million outstanding principal amount of its First Mortgage 5.850% Bonds, Pollution Control Series 1994C, due January 15, 2014, and the $600 million outstanding principal amount of its First Mortgage 1.625% Bonds, Series 110, due January 15, 2014, and to fund other general corporate purposes in 2014.

PECO

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
First Mortgage Bonds [(a)(b)]:				
Fixed rates	1.20% — 5.95%	2013-2043	$2,200	$1,950
Total long-term debt			2,200	1,950
Unamortized debt discount and premium, net			(3)	(3)
Long-term debt due within one year			(250)	(300)
Long-term debt			$1,947	$1,647
Long-term debt to financing trusts [(c)]				
Subordinated debentures to PECO Trust III	7.38%	2028	$ 81	$ 81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Long-term debt to financing trusts			$ 184	$ 184

(a) Substantially all of PECO's assets are subject to the lien of its mortgage indenture.
(b) Includes First Mortgage Bonds issued under the PECO mortgage indenture securing pollution control bonds and notes.
(c) Amounts owed to this financing trust are recorded as debt to financing trusts within PECO's Consolidated Balance Sheets.

BGE

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
Unsecured bonds	2.80% — 6.35%	2013-2036	$1,750	$1,850
Rate stabilization bonds	5.68% 5.82%	2016-2017	265	$ 332
Total long-term debt			2,015	2,182
Unamortized debt discount and premium, net			(4)	(4)
Long-term debt due within one year			(70)	(467)
Long-term debt			$1,941	$1,711
Long-term debt to financing trusts [(a)]				
Subordinated debentures to BGE Capital Trust II	6.20%	2043	$ 258	$ 258

(a) Amount owed to this financing trust is recorded as debt to financing trust within BGE's Consolidated Balance Sheets.

Long-term debt maturities at Exelon, Generation, ComEd, PECO and BGE in the periods 2014 through 2018 and thereafter are as follows:

Year	Exelon	Generation	ComEd	PECO	BGE
2014	$ 1,428	$ 561	$ 617	$ 250	$ —
2015	1,615	555	260	—	—
2016	1,346	81	665	300	300
2017	1,396	706	425	—	265
2018	1,345	5	840	500	—
Thereafter	12,278[a]	5,644	3,093[b]	1,334[c]	1,708[d]
Total	$19,408	$ 7,552	$5,900	$2,384	$2,273

(a) Includes $648 million due to ComEd, PECO and BGE financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.
(d) Includes $258 million due to BGE financing trust.

Non-Recourse Debt

The following are descriptions of activity with respect to certain indebtedness of Exelon's project subsidiaries that is outstanding as of December 31, 2013. The indebtedness described below is specific to certain generating facilities pledged as collateral with a net book value of approximately $1.9 billion at December 31, 2013, and all associated project financing liabilities are non-recourse to Exelon and Generation.

Continental Wind. On September 30, 2013, Continental Wind, LLC (Continental Wind), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million aggregate principal amount of Continental Wind's 6.00% senior secured notes due February 28, 2033. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667 MW. The net proceeds were distributed to Generation for its general business purposes. In connection with this non-recourse project financing, Exelon terminated existing interest rate swaps with a total notional amount of $350 million during the third quarter of 2013, and realized a total gain of $26 million upon termination. The gain on the interest rate swaps was recorded within OCI and will reduce the effective interest rate over the life of the debt for Exelon. See Note 12—Derivative Financial Instruments for additional information on the interest rate swaps.

In addition, Continental Wind entered into a $131 million letter of credit facility and $10 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2013, the Continental Wind letter of credit facility had $93 million in letters of credit outstanding related to the project.

ExGen Renewables Energy I LLC. On February 6, 2014, ExGen Renewables I, LLC (EGR), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $300 million aggregate principal amount of EGR's LIBOR plus 425 bps non-recourse senior secured loan, due February 6, 2021. EGR indirectly owns Continental Wind LLC (Continental).

Antelope Valley Project Development Debt Agreement. The DOE Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project is expected to be

completed in the first half of 2014. The loan will mature on January 5, 2037. Interest rates on the loan are fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2013, Generation had $334 million in letters of credit outstanding related to the project The letters of credit balance is expected to decline over time as scheduled equity contributions for the project are made.

In connection with this agreement, Generation entered into a floating-for-fixed interest rate swap with a notional amount of $485 million to mitigate interest-rate risk associated with the financing. As Generation received additional loan advances, it subsequently entered into a series of fixed-to-floating interest rate swaps to offset portions of the original interest rate hedge. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps associated with Antelope Valley.

Sacramento PV Energy. In July, 2011, a subsidiary of Generation entered into a $41 million non-recourse project financing for a 30MW solar facility in Sacramento, California. As of December 31, 2013, $37 million was outstanding. Borrowings under the facility bear interest at a variable rate, payable quarterly, and are secured by equity interests and assets of the subsidiary. As of December 31, 2013, the subsidiary had interest rate swaps with a notional value of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $41 million facility. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

Constellation Solar Horizons Financing. In September 2012, a subsidiary of Generation entered into an 18-year $38 million non-recourse variable interest note to recover capital used to build a 16 MW solar facility in Emmitsburg, Maryland. Interest is payable quarterly, and the note is secured by the equity interests and assets of the subsidiary. As of December 31, 2013, $36 million was outstanding. The subsidiary also executed interest rate swaps for a notional amount of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $38 million facility amount. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

Secured Solar Credit Lending Agreement. In December 2013, a Generation subsidiary, Constellation Solar, LLC, paid off the remaining balance of the three-year senior secured credit facility that is designed to support the growth of solar operations in the amount of $94 million and terminated the facility. The facility was scheduled to mature in June of 2014.

Other Solar Project Financings. Generation has the following amounts outstanding under solar project loan agreements:

- $7 million fully amortizing by June 30, 2031 related to a solar project at the Denver International Airport, and
- $10 million fully amortizing by December 31, 2031 related to a solar project in Holyoke, Massachusetts.

Upstream Gas Property Asset-Based Lending Agreement

Generation has a five year asset-based lending agreement associated with certain upstream gas properties that it owns. The borrowing base committed under the facility is $110 million and can increase to a total of $500 million if the assets support a higher borrowing base and Generation is able

to obtain additional commitments from lenders. The facility was amended and extended through January 2019. Borrowings under this facility are secured by the upstream gas properties, and the lenders do not have recourse against Exelon or Generation in the event of a default. As of December 31, 2013, $77 million was outstanding under the facility with interest payable quarterly. The facility includes a provision that requires the Generation entities owning the upstream gas properties subject to the agreement to maintain a current ratio of one-to-one. As of December 31, 2013, Generation was in compliance with this provision.

14. Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

Income tax expense (benefit) from continuing operations is comprised of the following components:

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 744	$ 250	$ 160	$126	$ 9
Deferred	140	360	(27)	23	100
Investment tax credit amortization	(15)	(11)	(2)	(1)	(1)
State					
Current	181	50	50	16	—
Deferred	(6)	(34)	(29)	(2)	26
Total	$1,044	$ 615	$ 152	$162	$134

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 37	$ 104	$ (40)	$ 88	$ (97)
Deferred	701	326	237	25	101
Investment tax credit amortization	(11)	(6)	(2)	(2)	(1)
State					
Current	(25)	(12)	6	4	—
Deferred	(75)	88	38	12	4
Total	$ 627	$ 500	$ 239	$127	$ 7

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 1	$ 431	$(329)	$ (71)	$ (71)
Deferred	1,200	435	544	223	130
Investment tax credit amortization	(12)	(7)	(3)	(2)	(1)
State					
Current	(3)	74	(123)	(37)	—
Deferred	271	123	161	33	17
Total	$1,457	$ 1,056	$ 250	$146	$ 75

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	4.7	1.6	3.4	1.6	4.9
Qualified nuclear decommissioning trust fund income	3.7	6.1	—	—	—
Tax exempt income	(0.2)	(0.3)	—	—	—
Health care reform legislation	0.1	—	0.7	—	0.2
Amortization of investment tax credit, net deferred taxes	(1.9)	(3.0)	(0.6)	(0.1)	—
Production tax credits and other credits	(2.1)	(3.4)	(0.1)	—	—
Plant basis differences	(1.6)	—	(0.8)	(7.1)	(0.2)
Other	(0.1)	0.7	0.3	(0.3)	(0.9)
Effective income tax rate	37.6%	36.7%	37.9%	29.1%	39.0%

For the Year Ended December 31, 2012	Exelon [a]	Generation [a]	ComEd	PECO	BGE [b]
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(3.6)	4.7	4.6	2.0	24.3
Qualified nuclear decommissioning trust fund income	5.4	9.1	—	—	—
Tax exempt income	(0.2)	(0.4)	—	—	—
Health care reform legislation	0.1	—	0.4	—	11.6
Amortization of investment tax credit, net deferred taxes	(1.1)	(1.3)	(0.4)	(0.3)	(8.6)
Production tax credits and other credits	(2.2)	(3.7)	—	—	—
Plant basis differences	(2.4)	—	(0.3)	(11.5)	(9.0)
Merger expenses [c]	2.4	—	—	—	24.2
Fines and Penalties	2.6	4.4	—	—	—
Other	(1.1)	(0.5)	(0.6)	(0.2)	(13.9)
Effective income tax rate	34.9%	47.3%	38.7%	25.0%	63.6%

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE [b]
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	4.4	4.5	3.6	(0.5)	5.2
Qualified nuclear decommissioning trust fund income	0.5	0.7	—	—	—
Domestic production activities deduction	(0.3)	(0.4)	—	—	—
Tax exempt income	(0.2)	(0.2)	—	—	—
Health care reform legislation	(0.2)	—	(1.0)	—	(0.5)
Amortization of investment tax credit	(0.3)	(0.3)	(0.4)	(0.3)	(0.5)
Production tax credits	(0.9)	(1.2)	—	—	—
Plant basis differences	(1.0)	—	(0.3)	(6.9)	(2.0)
Other	(0.2)	(0.7)	0.6	—	(1.7)
Effective income tax rate	36.8%	37.4%	37.5%	27.3%	35.5%

(a) Exelon activity for the twelve months ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the twelve months ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012.
(b) BGE activity represents the activity for the twelve months ended December 31, 2012 and 2011.
(c) Prior to the close of the merger, the Registrants recorded the applicable taxes on merger transaction costs assuming the merger would not be completed. Upon closing of the merger, the Registrants reversed such taxes for those merger transaction costs that were determined to be non tax-deductible upon successful completion of a merger.

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2013 and 2012 are presented below:

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Plant basis differences	$(11,612)	$ (3,879)	$(3,523)	$(2,573)	$(1,538)
Accrual based contracts	(214)	(214)	—	—	—
Derivatives and other financial instruments	(509)	(505)	(4)	—	—
Deferred pension and post-retirement obligation	1,489	(362)	(522)	—	(74)
Nuclear decommissioning activities	(647)	(646)	—	—	—
Deferred debt refinancing costs	173	79	(21)	(3)	(5)
Regulatory	(1,611)	—	(241)	42	(253)
Tax loss carryforward	252	76	47	11	52
Tax credit carryforward	534	534	—	—	—
Investment in CENG	(541)	(541)	—	—	—
Other, net	804	67	154	122	26
Deferred income tax liabilities (net)	$(11,882)	$ (5,391)	$(4,110)	$(2,401)	$(1,792)
Unamortized investment tax credits	(490)	(454)	(22)	(3)	(6)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(12,372)	$ (5,845)	$(4,132)	$(2,404)	$(1,798)

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Plant basis differences	$(10,689)	$ (3,545)	$(3,537)	$(2,437)	$(1,553)
Accrual based contracts	(389)	(389)	—	—	—
Derivatives and other financial instruments	(392)	(479)	(4)	—	—
Deferred pension and post-retirement obligation	2,356	(439)	(598)	(11)	(12)
Nuclear decommissioning activities	(604)	(604)	—	—	—
Deferred debt refinancing costs	(537)	163	(25)	(4)	(4)
Regulatory	(1,857)	—	(116)	50	(253)
Tax loss carryforward	421	226	32	14	105
Tax credit carryforward	226	226	—	—	—
Investment in CENG	(405)	(419)	—	—	—
Other, net	701	9	83	100	67
Deferred income tax liabilities (net)	$(11,169)	$ (5,251)	$(4,165)	$(2,288)	$(1,650)
Unamortized investment tax credits	(251)	(216)	(24)	(3)	(6)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(11,420)	$ (5,467)	$(4,189)	$(2,291)	$(1,656)

The following table provides the Registrants' carryforwards and any corresponding valuation allowances as of December 31, 2013.

	Exelon	Generation	ComEd	PECO	BGE
Federal					
Federal net operating loss	$ 377[a]	$ 36	$ 139	$—	$ 31
Deferred taxes on Federal net operating loss	132	13	49	—	11
Federal general business credits carryforward	556[b]	556	—	—	—
State					
State net operating losses and other credit carryforwards	3,061[c]	1,498[d]	—	167[e]	768[f]
Deferred taxes on state tax attributes (net)	161	82	—	11	41
Valuation allowance on state tax attributes	13	11	—	—	1

(a) Exelon's federal net operating loss will expire beginning in 2031
(b) Exelon's federal general business credit carryforwards will expire beginning in 2032
(c) Exelon's state net operating losses and other carryforwards, which are presented on a post-apportioned basis, will expire beginning in 2014
(d) Generation's state net operating losses and other carryforwards, which are presented on a post-apportioned basis, will expire beginning in 2014
(e) PECO's state net operating losses will expire beginning in 2031
(f) BGE's state net operating losses will expire beginning in 2026

Tabular reconciliation of unrecognized tax benefits

The following table provides a reconciliation of the Registrants' unrecognized tax benefits as of December 31, 2013, 2012 and 2011:

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2013	$1,024	$ 876	$ 67	$ 44	$—
Increases based on tax positions related to 2013	19	19	—	—	—
Change to positions that only affect timing	649	36	257	—	—
Increases based on tax positions prior to 2013	493	493	—	—	—
Decreases based on tax positions prior to 2013	(6)	(5)	—	—	—
Decreases from expiration of statute of limitations	(4)	(4)	—	—	—
Unrecognized tax benefits at December 31, 2013	$2,175	$ 1,415	$ 324	$ 44	$—

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2012	$ 807	$ 683	$ 70	$ 48	$ 11
Merger Balance Transfer	195	183	—	—	—
Increases based on tax positions related to 2012	34	3	—	—	—
Change to positions that only affect timing	(88)	(69)	(3)	(4)	(11)
Increases based on tax positions prior to 2012	91	91	—	—	—
Decreases based on tax positions prior to 2012	(6)	(6)	—	—	—
Decreases related to settlements with taxing authorities	(2)	(2)	—	—	—
Decreases from expiration of statute of limitations	(7)	(7)	—	—	—
Unrecognized tax benefits at December 31, 2012	$1,024	$ 876	$ 67	$ 44	$—

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2011	$ 787	$ 664	$ 72	$ 44	$ 73
Increases based on tax positions related to 2011	5	1	—	4	—
Change to positions that only affect timing	21	24	(2)	—	(62)
Decreases based on tax positions prior to 2011	(3)	(3)	—	—	—
Decrease from expiration of statute of limitations	(3)	(3)	—	—	—
Unrecognized tax benefits at December 31, 2011	$ 807	$ 683	$ 70	$ 48	$ 11

Included in Exelon's unrecognized tax benefits balance at December 31, 2013 and 2012 are approximately $1,387 million and $730 million, respectively, of tax positions for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits. The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to, or defer the receipt of the cash tax benefit from, the taxing authority to an earlier or later period respectively.

Unrecognized tax benefits that if recognized would affect the effective tax rate

Exelon and Generation have $788 million and $768 million, respectively, of unrecognized tax benefits at December 31, 2013 that, if recognized, would decrease the effective tax rate. Exelon and Generation had $294 million and $263 million, respectively, of unrecognized tax benefits at December 31, 2012 that, if recognized, would decrease the effective tax rate.

Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Nuclear Decommissioning Liabilities (Exelon and Generation)

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and has disallowed the claims. In November 2008, Generation received a final determination from the Appeals division of the IRS (IRS Appeals) disallowing AmerGen's refund claims. Generation filed a complaint in the United States Court of Federal Claims on February 20, 2009 to contest this determination. During the first and second quarters of 2013, AmerGen and the DOJ completed and filed cross motions for summary judgment. On September 17, 2013, the Court granted the government's motion denying AmerGen's claims for refund. Exelon is expecting to appeal this decision to the United States Court of Appeals for the Federal Circuit during 2014.

Due to the possibility of final resolution through an appellate decision, Generation continues to believe that it is reasonably possible that the total amount of unrecognized tax benefits will significantly decrease in the next twelve months.

Settlement of Income Tax Audits and Litigation

As of December 31, 2013, Exelon and Generation had approximately $256 million of other federal and state unrecognized tax benefits that could significantly increase or decrease within the 12 months

after the reporting date as a result of completing federal and state audits and expected statute of limitation expirations that if recognized would decrease the effective tax rate. In January 2014, certain of these unrecognized tax benefits were effectively settled and thus will result in reduced tax expense of $33 million at Generation in the first quarter of 2014.

See Other Tax Matters—Like Kind Exchange section below for information regarding the amount of unrecognized tax benefits associated with this matter that could change significantly within the next 12 months.

Total amounts of interest and penalties recognized

The following table represents the net interest receivable (payable), including interest related to uncertain tax positions reflected in the Registrants' Consolidated Balance Sheets. Prior to the merger legacy Constellation recorded interest related to uncertain tax positions as a tax and not interest.

Net interest receivable (payable) as of	Exelon	Generation	ComEd	PECO	BGE
December 31, 2013	$(349)	$ (37)	$(174)	$ 3	$—
December 31, 2012	31	(20)	107	2	—

The following table sets forth the net interest expense, including interest related to uncertain tax positions, recognized in interest expense (income) in other income and deductions in the Registrants' Consolidated Statements of Operations. The Registrants have not accrued any penalties with respect to uncertain tax positions. Prior to the merger legacy Constellation recorded interest related to uncertain tax positions as a tax and not interest.

Net interest expense (income) for the years ended	Exelon	Generation	ComEd	PECO	BGE
December 31, 2013	$ 391	$ 17	$ 281	$ (1)	$—
December 31, 2012	(1)	11	(20)	(1)	9
December 31, 2011	(56)	(40)	(14)	(1)	(3)

Description of tax years that remain open to assessment by major jurisdiction

Taxpayer	Open Years
Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns	1999-2012
Constellation and subsidiaries consolidated Federal income tax returns	2009-March 2012
Exelon and subsidiaries Illinois unitary income tax returns	2007-2012
Constellation combined New York corporate income tax returns	2008-2012
Various separate company Pennsylvania corporate net income tax returns	2008-2012
BGE Maryland Corporate net income tax returns	2004-2007, 2009-2012
Various other (Non-BGE) Maryland Corporate net income tax returns	2009-2012

Other Tax Matters

Like-Kind Exchange

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $2.8 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by

Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with this position and asserted that the entire gain of approximately $2.8 billion was taxable in 1999.

Exelon has been unable to reach agreement with the IRS regarding the dispute over the like kind exchange position. The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a “listed transaction” that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately $87 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like-kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison’s deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon’s current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013, Exelon recorded a non-cash charge to earnings of approximately $265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $170 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd’s equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition ComEd will continue to record non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. Exelon continues to believe that it is unlikely that the $87 million penalty assertion will ultimately be sustained and therefore no liability for the penalty has been recorded.

On September 30, 2013, the Internal Revenue Service issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue. The litigation could take three to five years including appeals, if necessary. Decisions in the Tax Court are not controlled by the Federal Circuit’s decision in Consolidated Edison.

As of December 31, 2013, in the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $840 million, of which approximately $305 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash impacts would likely change by a material amount.

Accounting for Generation Repairs (Exelon and Generation)

On April 30, 2013, the IRS issued Revenue Procedure 2013-24 providing guidance for determining the appropriate tax treatment of costs incurred to repair electric generation assets. Generation expects to change its method of accounting for deducting repairs in accordance with this guidance beginning with its 2014 tax year. Generation has estimated that adoption of the new method will result in a cash tax detriment of approximately $100 - $120 million.

Accounting for Electric Transmission and Distribution Property Repairs (Exelon, Generation, ComEd, PECO and BGE)

On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for repair costs associated with electric transmission and distribution property. ComEd and PECO adopted the safe harbor in the Revenue Procedure for the 2011 and 2010 tax years, respectively. For the year ended December 31, 2011, the adoption of the safe harbor resulted in a $35 million reduction to income tax expense at PECO, while Generation incurred additional income tax expense in the amount of $28 million due to a decrease in its domestic production activities deduction, which are reflected in the effective income tax rate reconciliation above in the plant basis differences and domestic production activities deduction lines, respectively. For Exelon, the adoption had a minimal effect on consolidated earnings. In addition, the adoption of the safe harbor resulted in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million, $95 million respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million related to a decreased domestic production activities deduction.

BGE adopted the safe harbor for the short period 2012 pre-merger tax year. For the year ended December 31, 2012, the adoption of the safe harbor resulted in a cash tax benefit at BGE in the amount of $27 million.

See Note 3—Regulatory Matters for discussion of the regulatory treatment prescribed in the 2010 electric distribution rate case settlement for PECO's cash tax benefit resulting from the application of the method change to years prior to 2010.

Accounting for Gas Distribution Property Repairs (Exelon, PECO and BGE).

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The change to the newly adopted method for the 2011 tax year and 2012 resulted in a tax benefit of $26 million at Exelon, of which $29 million in tax benefit is recorded at PECO, partially offset by an expense recorded at Generation to reflect a reduction in its domestic production activities deduction. BGE changed its method of accounting for gas distribution repairs for the 2008 tax year. The IRS is expected to issue industry guidance in the near future. Exelon, PECO and BGE will then determine the financial statement impacts of the gas distribution repair costs accounting method changes after guidance is issued.

Accounting for Final Tangible Property Regulations (Exelon, Generation, ComEd, PECO, and BGE)

On September 19, 2013, the Treasury Department and the IRS published final regulations regarding the tax treatment of costs incurred to acquire, produce, or improve tangible property. The Registrants have assessed the financial impact of this guidance and do not expect it to have a material impact. Any changes in method of accounting required to conform to the final regulations will be made for the Registrant's 2014 taxable year.

2011 Illinois State Tax Rate Legislation (Exelon, Generation and ComEd)

The Taxpayer Accountability and Budget Stabilization Act, (SB 2505), enacted into law in Illinois on January 13, 2011, increases the corporate tax rate in Illinois from 7.3% to 9.5% for tax years 2011—2014, provides for a reduction in the rate from 9.5% to 7.75% for tax years 2015—2024 and further reduces the rate from 7.75% to 7.3% for tax years 2025 and thereafter. Pursuant to the rate change, Exelon re-evaluated its deferred state income taxes during the first quarter of 2011. Illinois' corporate income tax rate changes resulted in a charge to state deferred taxes (net of Federal taxes) during the first quarter of 2011 of $7 million, $11 million and $4 million for Exelon, Generation and ComEd, respectively. Exelon's and ComEd's charge is net of a regulatory asset of $15 million.

In 2011, the income tax rate change increased Exelon's Illinois income tax provision (net of Federal taxes) by approximately $7 million, of which $12 million and $5 million of additional tax relates to Exelon Corporate and Generation, respectively, and a $10 million benefit for ComEd. The 2011 tax benefit at ComEd reflects the impact of a 2011 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010 and the electric transmission and distribution property repairs deduction discussed below.

Long-Term State Tax Apportionment (Exelon and Generation)

Exelon and Generation periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of Exelon's and Generation's deferred state income taxes. In 2011 as a result of the 2011 Illinois State Tax Rate Legislation discussed above, Exelon and Generation re-evaluated their long-term state tax apportionment for Illinois and all other states where they have state income tax obligations, resulting in recording a deferred state tax expense during the first quarter of 2011 of $22 million and $11 million (net of Federal taxes) for Exelon and Generation, respectively. The long-term state tax apportionment also was revised in the fourth quarter of 2011 pursuant to long-term state tax apportionment policy, resulting in recording an additional deferred state tax expense of $1 million and a deferred state tax benefit of $8 million (net of Federal taxes) for Exelon and Generation, respectively.

As a result of the merger with Constellation, Exelon and Generation re-evaluated their long-term state tax apportionment in the first quarter of 2012. The total effect of revising the long-term state tax apportionment resulted in the recording of a deferred state tax asset of $72 million (net of Federal taxes) for Exelon. Of this, a benefit in the amount of $116 million and $14 million (net of Federal taxes) was recorded for Exelon and Generation, respectively, for the three months ended March 31, 2012. Further, Exelon and Generation recorded deferred state tax liabilities of $44 million and $14 million (net of Federal taxes), respectively, as part of purchase accounting during the three months ended March 31, 2012. The long-term state tax apportionment also was updated in the fourth quarter of 2012, resulting in the recording of a deferred state tax benefit of $3 million (net of Federal taxes) for Exelon, and a deferred state tax expense of $7 million (net of Federal taxes) for Generation. There was no change to the long-term state tax apportionment for BGE, ComEd and PECO.

The long-term state tax apportionment was revised in the fourth quarter of 2013 pursuant to its long-term state tax apportionment policy, resulting in the recording of amounts that are immaterial for Exelon and Generation, respectively.

Allocation of Tax Benefits (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2013, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $26 million and $27 million, respectively. During 2013, ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd's and BGE's 2013 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010. During 2012, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $48 million and $9 million, respectively. During 2012, ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd's and BGE's 2012 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010.

ComEd received a non-cash contribution to equity from Exelon in 2012 of $11, related to tax benefits associated with capital projects constructed by ComEd on behalf of Exelon and Generation.

15. Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets, from January 1, 2012 to December 31, 2013:

	Exelon and Generation
Nuclear decommissioning ARO at January 1, 2012	$ 3,680
Accretion expense	231
Net increase due to changes in, and timing of, estimated future cash flows	833
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at December 31, 2012 [(a)]	4,741
Accretion expense	259
Net decrease due to changes in, and timing of, estimated future cash flows	(140)
Costs incurred to decommission retired plants	(5)
Nuclear decommissioning ARO at December 31, 2013 [(a)]	$ 4,855

(a) Includes $9 million and $10 million as the current portion of the ARO at December 31, 2013 and 2012, respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During 2013, Generation's ARO increased by approximately $114 million. The increase is largely driven by an increase in the estimated costs to decommission the Limerick and Three Mile Island nuclear units resulting from the completion of updated decommissioning costs studies received during 2013 and an increase for accretion of the obligation. These increases in the ARO were offset by decreases to the ARO due to changes in long-term escalation rates, primarily for labor and energy costs, as well as changes in the timing of the future nominal cash flows coupled with the fact that cash flows affected by this change in timing are re-measured and discounted at current credit adjusted risk free rates (CARFRs), which have increased from the prior year. The decrease in the ARO due to the changes in, and timing of, estimated cash flows were entirely offset by decreases in Property, plant and equipment within Exelon's and Generation's Consolidated Balance Sheets.

During 2012, Generation's ARO increased by $1,061 million. The increase in the ARO was largely driven by four factors: i) changes in the timing of the future nominal cash flows resulting from an assumed five year deferral to 2025 of the acceptance date of spent nuclear fuel by the DOE coupled with the fact that; ii) cash flows affected by this change in timing are re-measured and discounted at current CARFRs, which had dramatically decreased given the lower interest rate environment; iii) an increase in the estimated costs to decommission the Quad Cities, Dresden and Clinton nuclear units resulting from the completion of updated decommissioning costs studies received during 2012; and iv) accretion of the obligation. The increase in the ARO due to the changes in, and timing of, estimated cash flows resulted in $10 million of expense, which is included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with the former ComEd, former PECO and former AmerGen units have been funded with amounts collected from ComEd customers, PECO customers and the previous owners of the former AmerGen plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO is authorized to collect funds, in

revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of approximately $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. With respect to the former AmerGen units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts collected from ComEd and PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third-party (see Zion Station Decommissioning below). Generation has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise Generation will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units, Generation retains any funds remaining in the funds after decommissioning.

During 2012, the NDT fixed income portfolio completed its transition from solely core fixed income investments to a blend of Treasury Inflation Protected Securities (TIPS), investment-grade corporate credit and middle market lending. There was no change in the equity investment strategy. At December 31, 2013, approximately 48% of the funds were invested in equity securities and 52% were invested in fixed income securities. At December 31, 2012, approximately 47% of the funds were invested in equity securities and 53% were invested in fixed income securities.

At December 31, 2013, and 2012, Exelon and Generation had NDT fund investments totaling $8,071 million and $7,248 million, respectively.

The following table provides unrealized gains (losses) on NDT funds for 2013, 2012 and 2011:

	Exelon and Generation		
	For the Years Ended December 31,		
	2013	2012	2011
Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units [a]	$ 406	$ 386	$ (74)
Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units [b][c]	146	105	(4)

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $7 million, $73 million and $48 million of net unrealized gains related to the Zion Station pledged assets in 2013, 2012 and 2011, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.
(c) Net unrealized gains (losses) related to Generation's NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Accounting Implications of the Regulatory Agreements with ComEd and PECO . Based on the regulatory agreement with the ICC that dictates Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the NDT funds are expected to exceed the total estimated decommissioning obligation, decommissioning-related activities, including realized and unrealized gains and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial position could be material. As of December 31, 2013, the NDT funds of each of the former ComEd units are expected to exceed the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is different, as described below, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

Based on the regulatory agreement supported by the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the seven former PECO nuclear units, regardless of whether the funds held in the NDT funds are expected to exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial position could be material.

The decommissioning-related activities related to the Clinton, Oyster Creek and Three Mile Island nuclear plants (the former AmerGen units) and the portions of the Peach Bottom nuclear plants that are not subject to regulatory agreements with respect to the NDT funds are reflected in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, as there are no regulatory agreements associated with these units.

Refer to Note 3—Regulatory Matters and Note 25—Related Party Transactions for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. During 2013, EnergySolutions entered a definitive acquisition agreement and was acquired by another Company. Generation reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA.

On July 14, 2011, three people filed a purported class action lawsuit in the United States District Court for the Northern District of Illinois naming ZionSolutions and Bank of New York Mellon as defendants and seeking, among other things, an accounting for use of NDT funds, an injunction against the use of NDT funds, the appointment of a trustee for the NDT funds, and the return of NDT funds to customers of ComEd to the extent legally entitled thereto. On July 20, 2012, ZionSolutions and Bank of New York Mellon filed a motion to dismiss the amended complaint for failing to state a claim. On July 29, 2013, United States District Court for the Northern District of Illinois dismissed the amended complaint. On August 26, 2013, the plaintiffs filed a notice of appeal with the United States Court of Appeals for the Seventh Circuit. On January 31, 2014, the United States Court of Appeals for the Seventh Circuit dismissed the appeal.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a payable to ZionSolutions in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation to the SNF following ZionSolutions completion of its contractual obligations, to transfer the SNF at Zion Station to the DOE for ultimate disposal, and to complete all remaining decommissioning activities associated with the SNF

storage facility. Generation has a liability of approximately $82 million, which is included within the nuclear decommissioning ARO at December 31, 2013. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payable to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2013 and 2012:

	Exelon and Generation	
	2013	2012
Carrying value of Zion Station pledged assets	$ 458	$ 614
Payable to Zion Solutions [(a)]	414	564
Current portion of payable to Zion Solutions [(b)]	109	132
Withdrawals by Zion Solutions to pay decommissioning costs [(c)]	498	335

(a) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.
(c) Cumulative withdrawals since September 1, 2010.

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required decommissioning work according to an established schedule and will construct a dry cask storage facility on the land for the SNF currently held in SNF pools at Zion Station. Rent payable under the Lease Agreement is $1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with Zion Station and penalty rents may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by EnergySolutions or ZionSolutions, EnergySolutions provided a $200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. EnergySolutions has also provided a performance guarantee and entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

NRC Minimum Funding Requirements . NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in the type of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2013 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease

operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2019 for Oyster Creek); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2013 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning activities are completed under three possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the assumption plants cease operating at the end of an extended license life (assuming 20-year license renewal extensions, except Oyster Creek with an assumed end-of-operations date of 2019); (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 5.9% to 6.7% (as compared to a historical 5-year annual average pre-tax return of approximately 11.7%).

Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or make additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial position may be significantly adversely affected.

On April 1, 2013, Generation submitted its NRC-required biennial decommissioning funding status report as of December 31, 2012. As of December 31, 2012, Generation provided adequate funding assurance for all of its units, including Limerick Unit 1, where Generation has in place a $115 million parent guarantee to cover the NRC minimum funding assurance requirements. On October 2, 2013, the NRC issued summary findings from the NRC Staff's review of the 2013 decommissioning funding status reports for all 104 operating reactors, including the Generation operating units. Based on that review, the NRC Staff determined that Generation provided decommissioning funding assurance under the NRC regulations for all of its operating units, including Limerick Unit 1.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential "apparent violations" of its regulations because of alleged inaccuracies in the Decommissioning Funding Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation's status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. Generation met with the NRC on April 30, 2013 for a pre-decisional enforcement conference to provide additional information to explain why Generation believes that it complied with the regulatory requirements and did not deliberately or otherwise provide incomplete or inaccurate information in its decommissioning funding status reports. While Generation does not believe that any sanction is appropriate, the ultimate outcome of this proceeding including the amount of a potential fine or sanction, if any, is uncertain. The January 31, 2013 letter from the NRC does not take issue with

Generation's current funding status, and as reflected in Generation's April 1, 2013 decommissioning funding status report referenced above, Generation continues to provide adequate funding assurance for each of its units. In the normal course of NRC review, Generation has received a series of data requests that are unrelated to the potential apparent violations and the pre-decisional enforcement conference. Generation continues to cooperate with the NRC and provide the requested information. Generation does not have a definite date on which it will receive a response from the NRC.

In addition, on June 24, 2013, Exelon received a subpoena from the SEC requesting that Exelon provide the SEC with certain documents generally relating to Exelon and Generation's reporting and funding of the future decommissioning of Exelon's nuclear power plants. Exelon and Generation are cooperating with the SEC and providing the requested documents.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO nuclear plants, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Non-Nuclear Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. ComEd, PECO and BGE have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected on the Registrants' Consolidated Balance Sheets from January 1, 2012 to December 31, 2013:

	Exelon	Generation	ComEd	PECO	BGE
Non-nuclear AROs at January 1, 2012	$ 209	$ 92	$ 89	$ 28	$ 1
Net increase due to changes in, and timing of, estimated future cash flows [(a)]	27	18	8	1	7
Development projects	47	47	—	—	—
Accretion expense [(b)]	13	8	4	1	—
Merger with Constellation [(c)]	58	50	—	—	—
Payments	(11)	(8)	(2)	(1)	—
Non-nuclear AROs at December 31, 2012	343	207	99	29	8
Net increase due to changes in, and timing of, estimated future cash flows [(a)]	1	(11)	—	—	12
Development projects	2	2	—	—	—
Accretion expense [(b)]	18	13	4	1	—
Payments	(13)	(10)	(2)	—	(1)
Non-nuclear AROs at December 31, 2013 [(d)]	$ 351	$ 201	$ 101	$ 30	$ 19

(a) During the year ended December 31, 2013, Generation recorded an increase in operating and maintenance expense of $13 million. ComEd and PECO did not record any adjustments in operating and maintenance expense for the year ended December 31, 2013. During the year ended December 31, 2012, Generation recorded a reduction in operating and maintenance expense of $8 million. ComEd, PECO, and BGE did not record any reductions in operating and maintenance expense for the year ended December 31, 2012.

(b) For ComEd, PECO, and BGE, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.
(c) Exelon's ARO includes $8 million of BGE costs incurred prior to the closing of Exelon's merger with Constellation. Refer to Note 4—Merger and Acquisitions for additional information.
(d) Includes $2 million, $1 million, and $0 million as the current portion of the ARO at December 31, 2013 for ComEd, PECO, and BGE, respectively, which is included in other current liabilities on Exelon's and each of the respective utilities' Consolidated Balance Sheets.

16. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

As of December 31, 2013, Exelon sponsored defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation's benefit plans and its related assets. The table below shows the pension and postretirement benefit plans in which each operating company participated at December 31, 2013.

	Operating Company				
Name of Plan:	Generation	ComEd	PECO	BGE	BSC
Qualified Pension Plans:					
Exelon Corporation Retirement Program	X	X	X		X
Exelon Corporation Cash Balance Pension Plan	X	X	X		X
Exelon Corporation Pension Plan for Bargaining Unit Employees	X	X			X
Exelon New England Union Employees Pension Plan	X				
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek	X	X			X
Pension Plan of Constellation Energy Group, Inc.	X			X	X
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B	X				
Non-Qualified Pension Plans:					
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan	X	X	X		X
Exelon Corporation Supplemental Management Retirement Plan	X	X	X		X
Constellation Energy Group, Inc. Senior Executive Supplemental Plan	X			X	X
Constellation Energy Group, Inc. Supplemental Pension Plan	X			X	X
Constellation Energy Group, Inc. Benefits Restoration Plan	X			X	X
Baltimore Gas & Electric Company Executive Benefit Plan	X			X	X
Baltimore Gas & Electric Company Manager Benefit Plan	X			X	X
Other Postretirement Benefit Plans:					
PECO Energy Company Retiree Medical Plan	X		X		X
Exelon Corporation Health Care Program	X	X			X
Exelon Corporation Employees' Life Insurance Plan	X	X	X		X
Constellation Energy Group, Inc. Retiree Medical Plan	X			X	X
Constellation Energy Group, Inc. Retiree Dental Plan	X			X	X
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan	X			X	X
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan	X				
Exelon New England Union Post-Employment Medical Savings Account Plan	X				

Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Exelon has elected that the trusts underlying these plans be treated under the IRC as qualified trusts. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets and Funded Status

Exelon recognizes the overfunded or underfunded status of defined benefit pension and other postretirement benefit plans as an asset or liability on its balance sheet, with offsetting entries to Accumulated Other Comprehensive Income (AOCI) and regulatory assets (liabilities), in accordance with the applicable authoritative guidance. The measurement date for the plans is December 31.

During the first quarter of 2013, Exelon received an updated valuation of its legacy pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $8 million and a decrease to the other postretirement benefit obligation of $39 million. Additionally, accumulated other comprehensive loss decreased by approximately $75 million (after tax) and regulatory assets increased by approximately $93 million. During the second quarter of 2013, Exelon received the updated valuation for the legacy Constellation pension and other postretirement obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $23 million and a decrease to the other postretirement benefit obligation of $12 million. Additionally, accumulated other comprehensive loss increased by approximately $2 million (after tax) and regulatory assets increased by approximately $14 million.

The following table provides a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Change in benefit obligation:				
Net benefit obligation at beginning of year	$16,800	$13,538	$ 4,820	$ 4,062
Service cost	317	280	162	156
Interest cost	650	698	194	205
Plan participants' contributions	—	—	34	34
Actuarial loss (gain)	(1,363)	1,520	(551)	313
Plan amendments	1	—	15	(103)
Acquisitions/divestitures	—	1,880	—	362
Curtailments	—	(10)	—	(8)
Settlements [(a)]	(69)	(169)	—	—
Contractual termination benefits	—	15	—	6
Gross benefits paid	(877)	(952)	(223)	(219)
Federal subsidy on benefits paid	—	—	—	12
Net benefit obligation at end of year	$15,459	$16,800	$ 4,451	$ 4,820

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Change in plan assets:				
Fair value of net plan assets at beginning of year	$13,357	$11,302	$ 2,135	$ 1,797
Actual return on plan assets	821	1,484	209	197
Employer contributions	339	149	83	325
Plan participants' contributions	—	—	34	34
Benefits paid [b]	(877)	(952)	(223)	(218)
Acquisitions/divestitures	—	1,543	—	—
Settlements [a]	(69)	(169)	—	—
Fair value of net plan assets at end of year	$13,571	$13,357	$ 2,238	$ 2,135

(a) Represents cash settlements only.
(b) Exelon's other postretirement benefits paid for the year ended December 31, 2012 are net of $1.3 million of reinsurance proceeds received from the Department of Health and Human Services as part of the Early Retiree Reinsurance Program pursuant to the Affordable Care Act of 2010. In 2013, the Program was no longer accepting applications for reimbursement.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Other current liabilities	$ 12	$ 15	$ 23	$ 23
Pension obligations	1,876	3,428	—	—
Non-pension postretirement benefit obligations	—	—	2,190	2,662
Unfunded status (net benefit obligation less net plan assets)	$1,888	$3,443	$ 2,213	$ 2,685

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO), and fair value of plan assets for all pension plans with a PBO or ABO in excess of plan assets.

	PBO in excess of plan assets	
	2013	2012
Projected benefit obligation	$ 15,452	$ 16,800
Fair value of net plan assets	13,564	13,357

	ABO in excess of plan assets	
	2013	2012
Projected benefit obligation	$ 15,452	$ 16,796
Accumulated benefit obligation	14,552	15,657
Fair value of net plan assets	13,564	13,353

On a PBO basis, the plans were funded at 88% at December 31, 2013 compared to 80% at December 31, 2012. On an ABO basis, the plans were funded at 93% at December 31, 2013 compared to 85% at December 31, 2012. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table presents the components of Exelon's net periodic benefit costs for the years ended December 31, 2013, 2012 and 2011. The table reflects an increase in 2012 and a reduction in 2011 of net periodic postretirement benefit costs of approximately $(17) million and $28 million, respectively, related to a Federal subsidy provided under the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Modernization Act), discussed further below.

The 2013 pension benefit cost for all plans is calculated using an expected long-term rate of return on plan assets of 7.50% and a discount rate of 3.92%. Certain plans were remeasured during the year using a discount rate of 4.21%. The 2013 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.45% for funded plans and a discount rate of 4.00% for all plans. Certain plans were remeasured during the year using a discount rate of 4.66%. Certain other postretirement benefit plans are not funded. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Components of net periodic benefit cost:						
Service cost	$ 317	$ 280	$ 212	$ 162	$ 156	$ 142
Interest cost	650	698	649	194	205	207
Expected return on assets	(1,015)	(988)	(939)	(132)	(115)	(111)
Amortization of:						
Transition obligation	—	—	—	—	11	9
Prior service cost (credit)	14	15	14	(19)	(17)	(38)
Actuarial loss	562	450	331	83	81	66
Curtailment benefits	—	—	—	—	(7)	—
Settlement charges	9	31	—	—	—	—
Contractual termination benefits [(a)]	—	14	—	—	6	—
Net periodic benefit cost	$ 537	$ 500	$ 267	$ 288	$ 320	$ 275

(a) ComEd and BGE established regulatory assets of $1 million and $4 million, respectively, for their portion of the contractual termination benefit charge in 2012.

Through Exelon's postretirement benefit plans, the Registrants provide retirees with prescription drug coverage. The Medicare Modernization Act, enacted on December 8, 2003, introduced a prescription drug benefit under Medicare as well as a Federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit. Management believes the prescription drug benefit provided under Exelon's postretirement benefit plans meets the requirements for the subsidy. In December 2011, the Company decided that beginning in 2013, it will no longer elect to take the direct Part D subsidy. Beginning in 2013, eligible employees are offered an Employee Group Waiver Plan, a Medicare Part D Plan, with a supplemental "wrap" that closely matches the current prescription drug plan design. See the *Health*

Care Reform Legislation section below for further discussion regarding the income tax treatment of Federal subsidies of prescription drug benefits.

The effect of the subsidy on the components of net periodic postretirement benefit cost for the years ended December 31, 2013, 2012 and 2011 included in the consolidated financial statements was as follows:

	2013	2012	2011
Amortization of the actuarial experience loss	$—	$(17)	$ 3
Reduction in current period service cost	—	—	9
Reduction in interest cost on the APBO	—	—	16
Total effect of subsidy on net periodic postretirement benefit cost	$—	$(17)	$28

Components of AOCI and Regulatory Assets

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets (liabilities) for the years ended December 31, 2013, 2012 and 2011 for all plans combined.

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial (gain) loss	$(1,169)	$1,693	$ 744	$(628)	$ 304	$ 74
Amortization of actuarial gain (loss)	(562)	(450)	(331)	(83)	(81)	(66)
Current year prior service (credit) cost	—	1	—	15	(109)	—
Amortization of prior service (cost) credit	(14)	(15)	(14)	19	17	38
Current year transition (asset) obligation	—	—	—	—	1	—
Amortization of transition asset (obligation)	—	—	—	—	(11)	(9)
Curtailments	—	(10)	—	—	(1)	—
Settlements	(8)	(31)	—	—	—	—
Total recognized in AOCI and regulatory assets (liabilities) [(a)]	$(1,753)	$1,188	$ 399	$(677)	$ 120	$ 37

(a) Of the $1,753 million gain related to pension benefits, $1,071 million and $682 million were recognized in AOCI and regulatory assets, respectively, during 2013. Of the $677 million gain related to other postretirement benefits, $352 million and $325 million were recognized in AOCI and regulatory assets (liabilities), respectively, during 2013. Of the $1,188 million loss related to pension benefits, $283 million and $904 million were recognized in AOCI and regulatory assets, respectively, during 2012. Of the $120 million loss related to other postretirement benefits, $39 million and $81 million were recognized in AOCI and regulatory assets, respectively, during 2012. Of the $399 million loss related to pension benefits, $181 million and $218 million were recognized in AOCI and regulatory assets, respectively, during 2011. Of the $37 million loss related to other postretirement benefits, $13 million and $24 million were recognized in AOCI and regulatory assets, respectively, during 2011.

The following table provides the components of Exelon's gross accumulated other comprehensive loss and regulatory assets (liabilities) that have not been recognized as components of periodic benefit cost at December 31, 2013 and 2012, respectively, for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	2013	2012
Prior service cost (credit)	$ 62	$ 76	$ (73)	$ (107)
Actuarial loss	6,192	7,931	474	1,185
Total [a]	$6,254	$8,007	$ 401	$ 1,078

(a) Of the $6,254 million related to pension benefits, $3,523 million and $2,731 million are included in AOCI and regulatory assets, respectively, at December 31, 2013. Of the $401 million related to other postretirement benefits, $161 million and $240 million are included in AOCI and regulatory assets (liabilities), respectively, at December 31, 2013. Of the $8,007 million related to pension benefits, $4,594 million and $3,413 million are included in AOCI and regulatory assets, respectively, at December 31, 2012. Of the $1,078 million related to other postretirement benefits, $514 million and $564 million are included in AOCI and regulatory assets, respectively, at December 31, 2012.

The following table provides the components of Exelon's AOCI and regulatory assets at December 31, 2013 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2014. These estimates are subject to the completion of an actuarial valuation of Exelon's pension and other postretirement benefit obligations, which will reflect actual census data as of January 1, 2014 and actual claims activity as of December 31, 2013. The valuation is expected to be completed in the first quarter of 2014 for legacy Exelon plans and in the second quarter of 2014 for legacy Constellation plans.

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 14	$ (16)
Actuarial loss	427	32
Total [a]	$ 441	$ 16

(a) Of the $441 million related to pension benefits at December 31, 2013, $232 million and $209 million are expected to be amortized from AOCI and regulatory assets in 2013, respectively. Of the $16 million related to other postretirement benefits at December 31, 2013, $7 million and $9 million are expected to be amortized from AOCI and regulatory assets in 2013, respectively.

Assumptions

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Exelon's expected level of contributions to the plans, the long-term expected investment rate credited to employees participating in cash balance plans and the anticipated rate of increase of health care costs. Additionally, assumptions related to plan participants include the incidence of mortality, the expected remaining service period, the level of compensation and rate of compensation increases, employee age and length of service, among other factors.

Expected Rate of Return. In selecting the expected rate of return on plan assets, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

The following assumptions were used to determine the benefit obligations for all of the plans at December 31, 2013, 2012 and 2011. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Discount rate	4.80%	3.92%	4.74%	4.90%	4.00%	4.80%
Rate of compensation increase	(a)	(b)	3.75%	(a)	(b)	3.75%
Mortality table	IRS required mortality table for 2014 funding valuation	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2014 funding valuation	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation
Health care cost trend on covered charges	N/A	N/A	N/A	6.00% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017

(a) 3.25% for 2014-2018 and 3.75% thereafter.
(b) 3.25% for 2013-2017 and 3.75% thereafter.

The following assumptions were used to determine the net periodic benefit costs for all the plans for the years ended December 31, 2013, 2012 and 2011:

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011	2013	2012	2011
Discount rate	3.92% (a)	4.74% (b)	5.26%	4.00% (a)	4.80% (b)	5.30%
Expected return on plan assets	7.50% (c)	7.50% (c)	8.00% (c)	6.45% (c)	6.68% (c)	7.08% (c)
Rate of compensation increase	(d)	3.75%	3.75%	(d)	3.75%	3.75%
Mortality table	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation
Health care cost trend				6.50%	6.50%	7.00%

on covered charges						
	N/A	N/A	N/A	decreasing to ultimate trend of 5.00% in 2017	decreasing to ultimate trend of 5.00% in 2017	decreasing to ultimate trend of 5.00% in 2015

(a) The discount rates above represent the initial discount rates used to establish Exelon's pension and other postretirement benefits costs for the year ended December 31, 2013. Certain of the benefit plans were remeasured during the year using discount rates of 4.21% and 4.66% for pension and other postretirement benefits, respectively. Costs for the year ended December 31, 2013 reflect the impact of these remeasurements.
(b) The discount rates above represent the initial discounts rates used to establish Exelon's pension and other postretirement benefits costs for 2012. Certain of the benefit plans were remeasured during the year due to the Constellation merger, plan settlement and curtailment events, and plan changes using discount rates of 3.71% and 3.72% for pension and other postretirement benefits, respectively. Costs for the year ended December 31, 2012 reflect the impact of these remeasurements.
(c) Not applicable to pension and other postretirement benefit plans that do not have plan assets.
(d) 3.25% for 2013-2017 and 3.75% thereafter.

Assumed health care cost trend rates have a significant effect on the costs reported for the other postretirement benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend:	
on 2013 total service and interest cost components	$ 90
on postretirement benefit obligation at December 31, 2013	858
Effect of a one percentage point decrease in assumed health care cost trend:	
on 2013 total service and interest cost components	(62)
on postretirement benefit obligation at December 31, 2013	(607)

Health Care Reform Legislation

In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers. One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer's postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, the Registrants were required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. As a result, in the first quarter of 2010, Exelon recorded total after-tax charges of approximately $65 million to income tax expense to reverse deferred tax assets previously established. Generation, ComEd, PECO and BGE recorded charges of $24 million, $11 million, $9 million and $3 million, respectively. Additionally, as a result of this deductibility change for employers and other Health Care Reform provisions that impact the federal prescription drug subsidy options provided to employers, Exelon has made a change in the manner in which it will receive prescription drug subsidies beginning in 2013.

Additionally, the Health Care Reform Acts also include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Certain key assumptions are required to estimate the impact of the excise tax on Exelon's other postretirement benefit obligation, including projected inflation rates (based on the CPI) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

Contributions

The following table provides contributions made by Generation, ComEd, PECO, BGE and BSC to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2013	2012	2011 [c]	2013 [a]	2012 [a]	2011 [a]
Generation	$119	$ 48	$ 954	$ 30	$ 135	$ 121
ComEd	118	25	873	4	119	108
PECO	11	13	110	20	33	28
BGE [b]	—	—	—	24	12	—
BSC	91	63	157	5	24	20
Exelon	$339	$149	$2,094	$ 83	$ 323	$ 277

(a) The Registrants present the cash contributions above net of Federal subsidy payments received on each of their respective Consolidated Statements of Cash Flows. Exelon, Generation, ComEd, PECO, and BGE received Federal subsidy payments of $10 million, $5 million, $4 million, $1 million and $2 million, respectively, in 2012, and $11 million, $5 million, $4 million, $1 million and $3 million, respectively, in 2011. Effective January 1, 2013, Exelon is no longer receiving this subsidy.

(b) BGE's pension benefit contributions for 2012 and 2011 exclude $0 million and $54 million, respectively, of pension contributions made by BGE prior to the closing of Exelon's merger with Constellation on March 12, 2012. BGE's other postretirement benefit payments for 2012 and 2011 exclude $4 million and $13 million, respectively, of other postretirement benefit payments made by BGE prior to the closing of Exelon's merger with Constellation on March 12, 2012. These pre-merger contributions are not included in Exelon's financial statements but are reflected in BGE's financial statements.

(c) The increase in 2011 pension contributions was related to Exelon's $2.1 billion contribution to its pension plans as a result of accelerated cash benefits associated with the Tax Relief Act of 2010.

Exelon plans to contribute $264 million to its qualified pension plans in 2014, of which Generation, ComEd, PECO and BGE will contribute $118 million, $119 million, $11 million and $0 million, respectively. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon plans to make non-qualified pension plan benefit payments of $12 million in 2014, of which Generation, ComEd, PECO and BGE will make payments of $5 million, $1 million, $0 million and $1 million, respectively. Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). Additionally, for Exelon's largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million, which approximates service cost, or the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower minimum pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while others were applied in 2013. The estimated impacts of the law are reflected in the projected pension contributions.

Unlike the qualified pension plans, other postretirement plans are not subject to statutory minimum contribution requirements. Exelon's management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and

best assure continued rate recovery). In 2014, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $430 million in 2014, of which Generation, ComEd, PECO, and BGE expect to contribute $168 million, $197 million, $19 million, and $17 million, respectively.

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2013 were:

	Pension Benefits	Other Postretirement Benefits
2014	$ 929	$ 204
2015	851	210
2016	873	219
2017	902	228
2018	1,015	238
2019 through 2023	5,257	1,383
Total estimated future benefit payments through 2023	$9,827	$ 2,482

Allocation to Exelon Subsidiaries

Generation, ComEd, PECO, and BGE account for their participation in Exelon's pension and other postretirement benefit plans by applying multiemployer accounting. Employee-related assets and liabilities, including both pension and postretirement liabilities, for the legacy Exelon plans were allocated by Exelon to its subsidiaries based on the number of active employees as of January 1, 2001 as part of Exelon's corporate restructuring. Exelon allocates the components of pension and other postretirement costs to the subsidiaries in the legacy Exelon plans based upon several factors, including the measures of active employee participation in each participating unit. The obligation for Generation, ComEd and PECO reflects the initial allocation and the cumulative costs incurred and contributions made since January 1, 2001. Pension and postretirement benefit contributions are allocated to legacy Exelon subsidiaries in proportion to active service costs recognized and total costs recognized, respectively. For legacy CEG plans, components of pension and other postretirement benefit costs and contributions are allocated to the subsidiaries based on employee participation (both active and retired).

The amounts below were included in capital expenditures and operating and maintenance expense for the years ended December 31, 2013, 2012 and 2011, respectively, for Generation's, ComEd's, PECO's, BSC's and BGE's allocated portion of the pension and postretirement benefit plan costs. These amounts include the recognized contractual termination benefit charges, curtailment gains, and settlement charges:

For the Year Ended December 31,	Generation	ComEd	PECO	BSC [a]	BGE [b][c]	Exelon
2013	$ 347	$ 309	$ 43	$ 71	$ 55	$ 825
2012	341	282	50	99	60	820
2011	249	213	32	48	51	542

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above. As of December 31, 2012, ComEd and BGE each reported a regulatory asset of $1 million related to their BSC-billed portion of the second quarter 2012 contractual termination benefit charge.
(b) The amounts included in capital and operating and maintenance expense for the years ended December 31, 2012 and 2011 include $12 million and $51 million, respectively, in costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. These amounts are not included in Exelon's capital expenditures and operating and maintenance expense for the years ended December 31, 2012 and 2011.
(c) BGE's pension and other postretirement benefit costs for the year ended December 31, 2012 include a $3 million contractual termination benefit charge, which was recorded as a regulatory asset as of December 31, 2012.

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Exelon used an EROA of 7.00% and 6.59% to estimate its 2014 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations and December 31, 2013 and 2012 asset allocations were as follows:

Pension Plans

		Percentage of Plan Assets at December 31,	
Asset Category	Target Allocation	2013	2012
Equity securities	31%	35%	35%
Fixed income securities	38%	37	40
Alternative investments [(a)]	31%	28	25
Total		100%	100%

Other Postretirement Benefit Plans

		Percentage of Plan Assets at December 31,	
Asset Category	Target Allocation	2013	2012
Equity securities	41%	45%	46%
Fixed income securities	39%	37	40
Alternative investments [(a)]	20%	18	14
Total		100%	100%

(a) Alternative investments include private equity, hedge funds and real estate.

Concentrations of Credit Risk. Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2013. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2013, there were no significant concentrations (defined as greater than 10 percent of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

Fair Value Measurements

The following table presents Exelon's pension and other postretirement benefit plan assets measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2013 and 2012:

At December 31, 2013 [a]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Equity securities:				
Individually held	3,090	—	2	3,092
Commingled funds	—	1,167	—	1,167
Mutual funds	270	—	—	270
Equity securities subtotal	3,360	1,167	2	4,529
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	908	9	—	917
Debt securities issued by states of the United States and by political subdivisions of the states	—	88	—	88
Foreign debt securities	—	205	—	205
Corporate debt securities	—	2,927	41	2,968
Federal agency mortgage-backed securities	—	90	—	90
Non-Federal agency mortgage-backed securities	—	26	—	26
Commingled funds	—	558	—	558
Mutual funds	5	315	—	320
Derivative instruments [b] :				
Assets	—	7	—	7
Liabilities	—	(134)	—	(134)
Fixed income securities subtotal	913	4,091	41	5,045
Private equity	—	—	806	806
Hedge funds	—	1,266	1,039	2,305
Real estate:				
Individually held	264	—	—	264
Commingled funds	—	2	—	2
Real estate funds	—	—	582	582
Real estate subtotal	264	2	582	848
Pension plan assets subtotal	4,537	6,526	2,470	13,533

At December 31, 2013 [a]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	51	—	—	51
Equity securities:				
Individually held	286	—	—	286
Commingled funds	—	515	—	515
Mutual funds	164	—	—	164
Equity securities subtotal	450	515	—	965
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	17	1	—	18
Debt securities issued by states of the United States and by political subdivisions of the states	—	149	—	149
Foreign debt securities	—	2	—	2
Corporate debt securities	—	50	—	50
Federal agency mortgage-backed securities	—	45	—	45
Non-Federal agency mortgage-backed securities	—	7	—	7
Commingled funds	—	218	—	218
Mutual funds	305	—	—	305
Fixed income securities subtotal	322	472	—	794
Private equity	—	—	2	2
Hedge funds	—	295	4	299
Real estate:				
Individually held	8	—	—	8
Real estate funds	—	5	109	114
Real estate subtotal	8	5	109	122
Other postretirement benefit plan assets subtotal	831	1,287	115	2,233
Total pension and other postretirement benefit plan assets [c]	$5,368	$7,813	$2,585	$15,766

At December 31, 2012 [a]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 1	$ —	$ —	$ 1
Equity securities:				
Individually held	2,562	—	—	2,562
Commingled funds	—	1,111	—	1,111
Mutual funds	323	—	—	323
Equity securities subtotal	2,885	1,111	—	3,996
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,037	—	—	1,037
Debt securities issued by states of the United States and by political subdivisions of the states	—	108	—	108
Foreign debt securities	—	252	—	252
Corporate debt securities	—	3,330	—	3,330
Federal agency mortgage-backed securities	—	117	—	117
Non-Federal agency mortgage-backed securities	—	28	—	28
Commingled funds	—	274	—	274
Mutual funds	4	291	—	295
Derivative instruments [b] :				
Assets	—	9	—	9
Liabilities	—	(21)	—	(21)
Fixed income securities subtotal	1,041	4,388	—	5,429
Private equity	—	—	754	754
Hedge funds	—	1,080	1,235	2,315
Real estate:				
Individually held	280	—	—	280
Commingled funds	—	75	—	75
Real estate funds	—	—	426	426
Real estate subtotal	280	75	426	781
Pension plan assets subtotal	4,207	6,654	2,415	13,276

At December 31, 2012 [a]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	44	—	—	44
Equity securities:				
Individually held	198	—	—	198
Commingled funds	—	530	—	530
Mutual funds	230	—	—	230
Equity securities subtotal	428	530	—	958
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	18	—	—	18
Debt securities issued by states of the United States and by political subdivisions of the states	—	125	—	125
Foreign debt securities	—	3	—	3
Corporate debt securities	—	50	—	50
Federal agency mortgage-backed securities	—	52	—	52
Non-Federal agency mortgage-backed securities	—	6	—	6
Commingled funds	—	271	—	271
Mutual funds	295	2	—	297
Fixed income securities subtotal	313	509	—	822
Private equity	—	—	1	1
Hedge funds	—	188	12	200
Real estate:				
Individually held	7	—	—	7
Commingled funds	—	2	—	2
Real estate funds	—	6	95	101
Real estate subtotal	7	8	95	110
Other postretirement benefit plan assets subtotal	792	1,235	108	2,135
Total pension and other postretirement benefit plan assets [c]	$4,999	$7,889	$2,523	$15,411

(a) See Note 11—Fair Value of Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Derivative instruments have a total notional amount of $2,651 million and $2,498 million at December 31, 2013 and 2012, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.
(c) Excludes net assets of $43 million and $81 million at December 31, 2013 and 2012, respectively, which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables related to pending securities sales, interest and dividends receivable, and payables related to pending securities purchases.

The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2013 and 2012:

	Hedge funds	Private equity	Real estate	Debt securities	Preferred stock	Total
Pension Assets						
Balance as of January 1, 2013	$1,235	$ 754	$426	$ —	$ —	$2,415
Actual return on plan assets:						
Relating to assets still held at the reporting date	143	86	63	—	—	292
Relating to assets sold during the period	3	—	(4)	—	—	(1)
Purchases, sales and settlements:						
Purchases	360	123	226	41	2	752
Sales	(76)	—	(91)	—	—	(167)
Settlements [a]	(3)	(157)	(38)	—	—	(198)
Transfers into (out of) Level 3 [b]	(623)	—	—	—	—	(623)
Balance as of December 31, 2013	$1,039	$ 806	$582	$ 41	$ 2	$2,470
Other Postretirement Benefits						
Balance as of January 1, 2013	$ 12	$ 1	$ 95	$ —	$ —	$ 108
Actual return on plan assets:						
Relating to assets still held at the reporting date	1	—	11	—	—	12
Relating to assets sold during the period	—	—	—	—	—	—
Purchases, sales and settlements:						
Purchases	—	1	3	—	—	4
Sales	(1)	—	—	—	—	(1)
Settlements [a]	(4)	—	—	—	—	(4)
Transfers into (out of) Level 3 [b]	(4)	—	—	—	—	(4)
Balance as of December 31, 2013	$ 4	$ 2	$109	$ —	$ —	$ 115

	Hedge funds	Private equity	Real estate	Debt securities	Preferred stock	Total
Pension Assets						
Balance as of January 1, 2012	$1,525	$ 672	$229	$ —	$ —	$2,426
Actual return on plan assets:						
Relating to assets still held at the reporting date	138	55	24	—	—	217
Purchases, sales and settlements:						
Purchases	447	108	134	—	—	689
Sales	(6)	—	—	—	—	(6)
Settlements [a]	(4)	(128)	(28)	—	—	(160)
Transfers into (out of) Level 3 [c][d][e]	(865)	47	67	—	—	(751)
Balance as of December 31, 2012	$1,235	$ 754	$426	$ —	$ —	$2,415
Other Postretirement Benefits						
Balance as of January 1, 2012	$ 157	$ 1	$ 7	$ —	$ —	$ 165
Actual return on plan assets:						
Relating to assets still held at the reporting date	11	—	3	—	—	14
Purchases, sales and settlements:						
Purchases	32	—	91	—	—	123
Sales	—	—	—	—	—	—
Settlements [a]	—	—	(1)	—	—	(1)
Transfers into (out of) Level 3 [c][d][e]	(188)	—	(5)	—	—	(193)
Balance as of December 31, 2012	$ 12	$ 1	$ 95	$ —	$ —	$ 108

(a) Represents cash settlements only.
(b) As of December 31, 2012, hedge fund investments that contained redemption restrictions limiting Exelon's ability to redeem the investments within a reasonable period of time were classified as Level 3 investments. As of December 31, 2013, restrictions for certain investments no longer applied, therefore allowing redemption within a reasonable period of time from the measurement date at NAV. As such, these hedge fund investments are reflected as transfers out of Level 3 to Level 2 of $627 million in 2013.
(c) In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation's pension plan assets resulting in transfers into Level 3 of $141 million.
(d) In 2012, Exelon refined its policy over the criteria that hedge fund investments must meet in order to be categorized within Level 2 and Level 3 of the fair value hierarchy. Therefore, certain hedge fund investments that were categorized within Level 3 in prior periods have been re-categorized as Level 2 investments as of December 31, 2012. The re-categorization of these hedge fund investments is reflected as transfers out of Level 3 of $1.1 billion.
(e) In 2012, the liquidity terms of a certain real estate investment changed to allow redemption within a reasonable period of time from the redemption date which led to a transfer out of Level 3 to Level 2 of $5 million.

Valuation Techniques Used to Determine Fair Value

Cash equivalents . Investments with maturities of three months or less when purchased, including certain short—term fixed income securities and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

Equity securities . With respect to individually held equity securities, including investments in U.S. and international securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity

securities held individually are primarily traded on exchanges that contain only actively traded securities, due to the volume trading requirements imposed by these exchanges. Equity securities are valued based on quoted prices in active markets and are categorized as Level 1. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies that hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

Fixed income . For fixed income securities, which consist primarily of corporate debt securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The fair values of fixed income securities, excluding U.S. Treasury securities and privately placed fixed income securities, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Derivative instruments consisting primarily of interest rate swaps to manage risk are recorded at fair value. Derivative instruments are valued based on external price data of comparable securities and have been categorized as Level 2.

Fixed income commingled funds and mutual funds, including short-term investment funds, are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

Private equity . Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments and investments in natural resources. Private

equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows and market based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3.

Hedge funds . Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or ownership interest of the investments. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate. For Exelon's investments that have terms that allow redemption within a reasonable period of time from the measurement date, the hedge fund investments are categorized as Level 2. For investments that have restrictions that may limit Exelon's ability to redeem the investments at the measurement date or within a reasonable period of time, the hedge fund investments are categorized as Level 3.

Real estate . Real estate investment trusts valued daily based on quoted prices in active markets are categorized as Level 1. Real estate commingled funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Since these funds are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Other real estate funds are funds with a direct investment in a pool of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. Since these valuation inputs are not highly observable, these real estate funds have been categorized as Level 3.

Defined Contribution Savings Plan (Exelon, Generation, ComEd, PECO and BGE)

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2013, 2012 and 2011:

For the Year Ended December 31,	Exelon	Generation	ComEd	PECO	BGE [a]	BSC [b]
2013	$ 85	$ 40	$ 22	$ 8	$ 8	$ 7
2012	67	30	19	7	7	5
2011	78	40	22	9	7	7

(a) BGE's matching contributions for the years ended December 31, 2012 and 2011 include $1 million and $7 million of costs, respectively, incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. These costs are not included in Exelon's matching contributions for the years ended December 31, 2012 and 2011.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, or BGE amounts above.

17. Severance (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence

and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

Merger-Related Severance

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit. Exelon adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. In addition, certain employees identified during the staffing and selection process also receive pension and other postretirement benefits that are deemed contractual termination benefits, which the Registrants recorded during the second quarter of 2012.

The amount of severance expense associated with the post-merger integration recognized for the year ended December 31, 2013 for Exelon and Generation was $6 million and $6 million, respectively. For Generation, $5 million represents amounts billed by BSC through intercompany allocations. There was no severance expense associated with post-merger integration recognized for the year ended December 31, 2013 for ComEd, PECO and BGE. Estimated costs to be incurred after December 31, 2013 are not material.

For the year ended December 31, 2012, the Registrants recorded the following severance benefit costs associated with the identified job reductions within operating and maintenance expense in their Consolidated Statements of Operations, except for those costs that were capitalized as regulatory assets related to ComEd and BGE:

Year Ended December 31, 2012 Severance Benefits [a]	Exelon [b]	Generation	ComEd [b]	PECO	BGE [b]
Severance charges	$ 124	$ 80	$ 14	$ 7	$ 17
Stock compensation	7	4	1	—	1
Other charges	7	4	1	—	1
Total severance benefits	$ 138	$ 88	$ 16	$ 7	$ 19

(a) The amounts above include $46 million at Generation, $14 million at ComEd, $7 million at PECO, and $7 million at BGE, for amounts billed by BSC through intercompany allocations for the year ended December 31, 2012.

(b) Exelon, ComEd and BGE established regulatory assets of $35 million, $16 million and $19 million, respectively, for severance benefits costs for the year ended December 31, 2012. The majority of these costs are expected to be recovered over a five-year period.

Amounts included in the table below represent the severance liability recorded by Exelon, Generation, ComEd, PECO and BGE for employees of those Registrants and exclude amounts billed through intercompany allocations:

Severance liability	Exelon	Generation	ComEd	PECO	BGE
Balance at December 31, 2011	$ —	$ —	$ —	$—	$—
Severance charges [a]	124	38	2	—	11
Stock compensation	7	2	—	—	—
Other charges [b]	7	2	—	—	1
Payments	(27)	(9)	(1)	—	(1)
Balance at December 31, 2012	$ 111	$ 33	$ 1	$—	$ 11
Severance charges	5	1	—	—	—
Stock compensation	1	—	—	—	—
Payments	(64)	(24)	(1)	—	(5)
Balance at December 31, 2013	$ 53	$ 10	$ —	$—	$ 6

(a) Includes salary continuance and health and welfare severance benefits. Amounts primarily represent benefits provided for under Exelon's ongoing severance plan. One-time termination benefits were not material for the years ended December 31, 2012 and December 31, 2013.
(b) Primarily includes life insurance, employer payroll taxes, educational assistance, and outplacement services.

Cash payments under the plan began in the second quarter of 2012. Substantially all cash payments under the plan are expected to be made by the end of 2016.

Ongoing Severance Plans

The Registrants provide severance and health and welfare benefits under Exelon's ongoing severance benefit plans to terminated employees in the normal course of business, which were not directly related to the merger with Constellation. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the years ended December 31, 2013, 2012, and 2011, the Registrants recorded the following severance costs associated with these ongoing severance benefits within operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

Severance Benefits [a]	Exelon	Generation	ComEd	PECO	BGE
Severance charges—2013	$ 18	$ 16	$ 2	$—	$—
Severance charges—2012	19	14	2	1	3
Severance charges—2011	5	5	—	—	4

(a) The amounts above for Generation include $2 million, $0 million, and $1 million for amounts billed by BSC through intercompany allocations for the years ended December 31, 2013, December 31, 2012, and December 31, 2011, respectively. Amounts billed by BSC to ComEd, PECO and BGE were not material.

The severance liability balances associated with these ongoing severance benefits as of December 31, 2013 and 2012 are not material.

18. Preferred and Preference Securities (Exelon, ComEd, PECO and BGE)

At December 31, 2013 and 2012, Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

Preferred and Preference Securities of Subsidiaries

At December 31, 2013 and 2012, ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

At December 31, 2012, PECO cumulative preferred securities, no par value, consisted of 15,000,000 shares authorized and the outstanding amounts set forth below. Shares of preferred securities have full voting rights, including the right to cumulate votes in the election of directors. On May 1, 2013, PECO redeemed all of its outstanding preferred securities. PECO had $87 million of cumulative preferred securities that were redeemable at its option at any time for the redemption price established when each series was issued. The redemption premium is treated as a reduction to Net income to arrive at Net income attributable to common shareholders utilized in the calculation of the earnings per share for Exelon.

	Redemption Price [(a)]	December 31, 2013 Shares Outstanding	December 31, 2012 Shares Outstanding	December 31, 2013 Dollar Amount	December 31, 2012 Dollar Amount
Series (without mandatory redemption)					
$4.68 (Series D)	$ 104.00	—	150,000	$ —	$ 15
$4.40 (Series C)	112.50	—	274,720	—	27
$4.30 (Series B)	102.00	—	150,000	—	15
$3.80 (Series A)	106.00	—	300,000	—	30
Total preferred securities		—	874,720	$ —	$ 87

(a) Redeemable, at the option of PECO, at the indicated dollar amounts per share, plus accrued dividends.

At December 31, 2013 and 2012, BGE cumulative preference stock, $100 par value, consisted of 6,500,000 shares authorized and the outstanding amounts set forth below. Shares of BGE preference stock have no voting power except for the following:

- The preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and
- Whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

	Redemption Price [a]	December 31, 2013 Shares Outstanding	December 31, 2012 Shares Outstanding	December 31, 2013 Dollar Amount	December 31, 2012 Dollar Amount
Series (without mandatory redemption)					
7.125%, 1993 Series	$ 100.00	400,000	400,000	$ 40	$ 40
6.97%, 1993 Series	100.00	500,000	500,000	50	50
6.70%, 1993 Series	100.34	400,000	400,000	40	40
6.99%, 1995 Series	100.70	600,000	600,000	60	60
Total preference stock		1,900,000	1,900,000	$ 190	$ 190

(a) Redeemable, at the option of BGE, at the indicated dollar amounts per share, plus accrued and unpaid dividends.

19. Common Stock (Exelon, Generation, ComEd, PECO and BGE)

The following table presents common stock authorized and outstanding as of December 31, 2013 and 2012:

	Par Value	Shares Authorized	December 31, 2013 Shares Outstanding	December 31, 2012 Shares Outstanding
Common Stock				
Exelon	no par value	2,000,000,000	857,290,484	854,781,389
ComEd	$12.50	250,000,000	127,016,896	127,016,761
PECO	no par value	500,000,000	170,478,507	170,478,507
BGE	no par value	175,000,000	1,000	1,000

ComEd had 73,709 and 74,182 warrants outstanding to purchase ComEd common stock at December 31, 2013 and 2012, respectively. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants. At December 31, 2013 and 2012, 24,570 and 24,727 shares of common stock, respectively, were reserved for the conversion of warrants.

Share Repurchases

Share Repurchase Programs . In April 2004, Exelon's Board of Directors approved a discretionary share repurchase program that allowed Exelon to repurchase shares of its common stock on a periodic basis in the open market. The share repurchase program was intended to mitigate, in part, the dilutive effect of shares issued under Exelon's employee stock option plan and Exelon's ESPP. The aggregate value of the shares of common stock repurchased pursuant to the program cannot exceed the economic benefit received after January 1, 2004 due to stock option exercises and share purchases pursuant to Exelon's ESPP. The economic benefit consists of the direct cash proceeds from purchases of stock and the tax benefits associated with exercises of stock options. The 2004 share repurchase program had no specified limit on the number of shares that could be repurchased and no specified termination date. In 2008, Exelon management decided to defer indefinitely any share repurchases. Any shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon's management. Under the share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion at December 31, 2013. During 2013, 2012 and 2011, Exelon had no common stock repurchases.

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At December 31, 2013, there were approximately 16 million shares authorized for issuance under the LTIP. For the years ended December 31, 2013, 2012 and 2011, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

The Compensation Committee of Exelon's Board of Directors changed the mix of awards granted under the LTIP in 2013 by eliminating stock options in favor of the use of full value shares, consisting of performance shares and restricted stock. The performance share awards granted in 2013 will cliff vest at the end of a three-year performance period. The performance share awards granted in 2012 and earlier had a one-year performance period and vested ratably over three years. To address the reduction in annual award opportunity resulting from the transition to a three-year cliff vesting performance period, the Compensation Committee also approved a one-time grant of performance share transition awards in 2013, which will vest one-third after one year, with the remaining balance vesting over a two-year performance period.

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
Components of Stock-Based Compensation Expense	2013	2012	2011
Performance share awards	$ 48	$ 46	$ 26
Restricted stock units	61	50	31
Stock options	3	15	8
Other stock-based awards	6	4	4
Total stock-based compensation expense included in operating and maintenance expense	118	115	69
Income tax benefit	(44)	(44)	(27)
Total after-tax stock-based compensation expense	$ 74	$ 71	$ 42

The following table presents stock-based compensation expense (pre-tax) for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
Subsidiaries	2013	2012 (a)	2011 (d)
Generation	$ 48	$ 42	$ 31
ComEd	9	11	5
PECO	5	5	5
BGE	6	5	6
BSC (b)	50	52	28
Total (c)	$118	$115	$ 69

(a) BGE's stock-based compensation expense (pre-tax) for December 31, 2012 excludes $2 million of cost incurred in 2012 prior to the closing of Exelon's merger with Constellation on March 12, 2012. This amount is not included in Exelon's stock-based compensation expense for the year ended December 31, 2012 shown in the tables titled Components of Stock-Based Compensation Expense and Subsidiaries above.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO and BGE amounts above.
(c) The stock-based compensation expense (pre-tax) for December 31, 2013 reflects the impact of changes to the retirement eligibility requirements for employees participating in the LTIP. In addition, the stock-based compensation expense at ComEd does not reflect the impact of the ComEd Key Manager Long-Term Performance Program in 2013 for certain employees, which is not considered stock-based compensation expense under the applicable authoritative guidance. In 2012, these employees participated in the Exelon Restricted Stock Award Program.
(d) The total stock-based compensation expense (pre-tax) for December 31, 2011 of $69 million does not include the $6 million expense for BGE as those costs were incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012.

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2013, 2012 and 2011.

Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and the distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon recognizes the tax benefit related to compensation costs. The tax deductions in excess of the benefits recorded throughout the requisite service period are recorded to common stock and are included in other financing activities within Exelon's Consolidated Statements of Cash Flows. The following table presents information regarding Exelon's tax benefits for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Realized tax benefit when exercised/distributed:			
Stock options	$—	$ 3	$ 2
Restricted stock units	11	11	8
Performance share awards	11	7	7
Stock deferral plan	1	—	1
Excess tax benefits included in other financing activities of Exelon's Consolidated Statements of Cash Flows:			
Stock options	$—	$ 2	$ 1

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock are granted under the LTIP. The exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. The vesting period of stock options is generally four years. All stock options expire ten years from the date of grant.

There were no stock options granted in 2013. The Compensation Committee eliminated stock option grants by changing the mix of long-term incentives for senior vice presidents (SVPs) and higher officers from 75% performance shares and 25% stock options to 67% performance shares and 33% restricted stock units.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years. However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

Historically, Exelon has granted most of its stock options in the first quarter of each year. Stock options granted during the remaining quarters of 2012 and 2011 were not significant.

The fair value of each option is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The following table presents the weighted average assumptions used in the pricing model for grants and the resulting weighted average grant date fair value of stock options granted for the years ended 2012 and 2011:

	Year Ended December 31,	
	2012	2011
Dividend yield	5.28%	4.84%
Expected volatility	23.20%	24.40%
Risk-free interest rate	1.30%	2.65%
Expected life (years)	6.25	6.25
Weighted average grant date fair value (per share)	$ 4.18	$ 6.22

The assumptions above relate to Exelon stock options granted during the periods presented and therefore do not include stock options that were converted in connection with the merger with Constellation during the year ended 2012.

The dividend yield is based on several factors, including Exelon's most recent dividend payment at the grant date and the average stock price over the previous year. Expected volatility is based on implied volatilities of traded stock options in Exelon's common stock and historical volatility over the estimated expected life of the stock options. The risk-free interest rate for a security with a term equal to the expected life is based on a yield curve constructed from U.S. Treasury strips at the time of grant. For each year presented, the expected life represents the period of time the stock options are expected to be outstanding and is based on the simplified method. Exelon believes that the simplified method is appropriate due to several factors that result in historical exercise data not being sufficient to determine a reasonable estimate of expected term. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table presents information with respect to stock option activity for the year ended December 31, 2013:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2012	21,903,781	$ 45.91		
Options reinstated	751,122	38.60		
Options exercised	(670,957)	28.02		
Options forfeited	(54,743)	39.36		
Options expired	(893,758)	49.08		
Balance of shares outstanding at December 31, 2013	21,035,445	$ 46.07	4.72	$ 10
Exercisable at December 31, 2013 (a)	20,188,327	$ 46.31	4.58	$ 10

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Intrinsic value [(a)]	$ 4	$19	$ 5
Cash received for exercise price	19	47	13

(a) The difference between the market value on the date of exercise and the option exercise price.

The following table summarizes Exelon's nonvested stock option activity for the year ended December 31, 2013:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2012 (a)	1,960,665	$ 40.56
Vested	(1,058,804)	40.89
Forfeited	(54,743)	39.36
Nonvested at December 31, 2013 (a)	847,118	$ 40.22

(a) Excludes 1,348,913 and 2,647,536 of stock options issued to retirement-eligible employees as of December 31, 2013 and December 31, 2012, respectively, as they are fully vested.

At December 31, 2013, $2 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 1.6 years.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table summarizes Exelon's nonvested restricted stock unit activity for the year ended December 31, 2013:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2012 (a)	2,029,161	$ 42.12
Granted	2,828,187	31.06
Vested	(842,439)	42.90
Forfeited	(108,199)	36.37
Undistributed vested awards (b)	(520,013)	32.62
Nonvested at December 31, 2013 (a)	3,386,697	$ 34.10

(a) Excludes 931,628 and 686,121 of restricted stock units issued to retirement-eligible employees as of December 31, 2013 and December 31, 2012, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2013.

The weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2013, 2012 and 2011 was $31.06, $39.94 and $43.33, respectively. At December 31, 2013 and 2012, Exelon had obligations related to outstanding restricted stock units not yet settled of $77 million and $58 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. For the years ended December 31, 2013, 2012 and 2011, Exelon settled restricted stock units with fair value totaling $28 million, $25 million and $19 million, respectively. At December 31, 2013, $64 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.5 years.

Performance Share Awards

Performance share awards are granted under the LTIP. The 2013 and 2012 performance share awards are being settled 50% in common stock and 50% in cash at the end of the three-year performance period except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. The performance shares granted prior to 2012 generally vest and settle over a three-year period with the holders receiving shares of common stock and/or cash annually during the vesting period.

The one-time 2013 performance share transition awards, which provide an opportunity to earn an award contingent on company performance, will be settled 50% in common stock and 50% in cash, except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. One-third of the award vests and is payable after a one-year performance period while the remaining two-thirds vests and is payable after a two-year performance period.

The payout of the 2013 performance share awards and one-time performance share transition awards are based on the Company's performance against specific operational and financial goals set annually during the respective performance periods. As a result, the 2013 performance share awards have been divided into equal tranches for the purpose of expense recognition as though the respective award were multiple awards; with each tranche representing a corresponding fiscal year. The one-time performance share transition awards have also been divided into multiple tranches for the purpose of expense recognition. One tranche reflects the one-third of the awards that vests and are payable after a one-year period. The two-thirds of the one-time performance share transition awards that are subject to a two-year performance period have also been divided into equal tranches; with each tranche representing a corresponding fiscal year. The grant date for each tranche of the 2013 performance share and one-time performance share transition awards is the date in which the performance goals for that fiscal year are approved and communicated, which typically occurs at the corresponding January Compensation Committee meeting.

The 2013 performance share awards and one-time performance share transition awards are recorded at fair value at the grant dates for each tranche, with the estimated grant date fair value based on the expected payout of the award, which may range from 50% to 150% of the payout target. The 2013 performance share awards also include a total shareholder return modifier (TSR) that may increase or decrease the award up to 25% and an individual performance modifier (IPM) that can

decrease the award by up to 50% or increase the award by up to 10% for SVPs and higher officers or up to 20% for vice presidents. The one-time performance share transition award is not affected by either TSR or the IPM.

The common stock portion of the performance share and one-time performance share transition awards is considered an equity award being valued based on Exelon's stock price on the grant date. The cash portion of the awards is considered a liability award which is remeasured each reporting period based on Exelon's current stock price. As the value of the common stock and cash portions of the awards are based on Exelon's stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

The 2012 performance share awards are recorded at fair value at the date of grant with the estimated grant date fair value based on the expected payout of the award, which may range from 75% to 125% of the payout target. The common stock portion is considered an equity award with the 75% payout floor being valued based on Exelon's stock price on the grant date. The cash portion of the award is considered a liability award with the 75% payout floor being remeasured each reporting period based on Exelon's current stock price. The expected payout in excess of the 75% floor for the equity and liability portions are remeasured each reporting period based on Exelon's current stock price and changes in the expected payout of the award; therefore these portions of the award are subject to volatility until the payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share and one-time performance share transition awards granted to retirement-eligible employees, the value of the performance shares in recognized ratably over the vesting period, which is the year of grant.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2013:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2012 (a)	1,312,734	$ 40.08
Granted	2,629,171	31.55
Vested	(612,624)	40.13
Forfeited	(24,451)	32.17
Undistributed vested awards (b)	(1,290,640)	34.28
Nonvested at December 31, 2013 (a)	2,014,190	$ 32.74

(a) Excludes 1,411,824 and 204,643 of performance share awards issued to retirement-eligible employees as of December 31, 2013 and December 31, 2012, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2013.

The weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2013, 2012 and 2011 was $31.55, $39.71, and $43.52, respectively. During the years ended December 31, 2013, 2012 and 2011, Exelon settled performance shares with a fair value totaling $26 million, $23 million and $22 million, respectively, of which $12 million, $3 million and $10 million was paid in cash, respectively. As of December 31, 2013, $34 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.7 years.

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31, 2013	December 31, 2012
Current liabilities [a]	$ 13	$ 7
Deferred credits and other liabilities [b]	24	11
Common stock	32	35
Total	$ 69	$ 53

(a) Represents the current liability related to performance share awards expected to be settled in cash.
(b) Represents the long-term liability related to performance share awards expected to be settled in cash.

20. Earnings Per Share and Equity (Exelon)

Earnings per Share

Diluted earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Year Ended December 31, 2013	2012	2011
Net income attributable to common shareholders	$1,719	$1,160	$2,495
Weighted average common shares outstanding—basic	856	816	663
Assumed exercise and/or distributions of stock-based awards	4	3	2
Weighted average common shares outstanding—diluted	860	819	665

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 20 million in 2013, 14 million in 2012 and 9 million in 2011.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of December 31, 2013. In 2008, Exelon management decided to defer indefinitely any share repurchases.

Preferred Securities Redemption (Exelon and PECO)

On May 1, 2013, PECO redeemed all of its outstanding preferred securities. PECO had $87 million of cumulative preferred securities that were redeemable at its option at any time for the redemption price established when each series of securities were issued. The redemption premium of $6 million is treated as a reduction to Net income to arrive at Net income attributable to common shareholders utilized in the calculation of earnings per share for Exelon for the year ending December 31, 2013. As a result of the redemption, PECO is now indirectly, wholly-owned by Exelon.

21. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, and PECO)

The following table presents changes in accumulated other comprehensive income (loss) (AOCI) by component for the year ended December 31, 2013:

	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon [a]						
Beginning balance	$ 368	$ —	$ (3,137)	$ —	$ 2	$(2,767)
OCI before reclassifications	29	2	669	(10)	101	791
Amounts reclassified from AOCI [b]	(277)	—	208	—	5	(64)
Net current-period OCI	(248)	2	877	(10)	106	727
Ending balance	$ 120	$ 2	$ (2,260)	$ (10)	$ 108	$(2,040)
Generation [a]						
Beginning balance	$ 512	$ —	$ —	$ —	$ 1	$ 513
OCI before reclassifications	15	2	—	(10)	102	109
Amounts reclassified from AOCI [b]	(413)	—	—	—	5	(408)
Net current-period OCI	(398)	2	—	(10)	107	(299)
Ending balance	$ 114	$ 2	$ —	$ (10)	$ 108	$ 214
PECO [a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI [b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See next table for details about these reclassifications.

ComEd, PECO, and BGE did not have any reclassifications out of AOCI to Net Income during the year ended December 31, 2013. The following table presents amounts reclassified out of AOCI to Net Income for Exelon and Generation during the year ended December 31, 2013:

Details about AOCI components	Items reclassified out of AOCI [a]		Affected line item in the statement where Net Income is presented
	Exelon	Generation	
Gains and (losses) on cash flow hedges			
Energy related hedges	$ 464	$ 683	Operating revenues
Other cash flow hedges	(3)	—	Interest expense
	461	683	Total before tax
	(184)	(270)	Tax expense
	$ 277	$ 413	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs	$ (2)	$ —	(b)
Actuarial losses	(339)	—	(b)
Deferred compensation unit plan	(1)	—	(c)
	(342)	—	Total before tax
	134	—	Tax benefit
	$ (208)	$ —	Net of tax
Equity investments			
Capital activity	$ (8)	$ (8)	Equity in losses of unconsolidated affiliates
	(8)	(8)	Total before tax
	3	3	Tax benefit
	$ (5)	$ (5)	Net of tax
Total Reclassifications	$ 64	$ 408	Net of Tax

(a) Amounts in parenthesis represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see note 16 for additional details).
(c) Amortization of the deferred compensation unit plan is allocated to capital and operating and maintenance expense.

22. Commitments and Contingencies (Exelon, Generation, ComEd, PECO and BGE)

Nuclear Insurance

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2013, the current liability limit per incident was $13.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once

every 5 years and the last inflation adjustment was made effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of January 1, 2013, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in an additional $13.2 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $127.3 million, payable at no more than $19 million per reactor per incident per year. Exelon's maximum liability per incident is approximately $2.4 billion.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.6 billion limit for a single incident.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. NEIL declared a distribution for 2013, of which Generation's portion was $18.5 million. The distribution was recorded as a reduction to Operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income. No distributions were declared in 2011 or 2012. Premiums paid to NEIL by its members are subject to assessment for adverse loss experience (the retrospective premium obligation). NEIL has never exercised this assessment since its formation in 1973, and while Generation cannot predict the level of future assessments, or if they will be imposed at all, as of December 31, 2013, the current maximum aggregate annual retrospective premium obligation for Generation is approximately $287 million.

NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. As of December 31, 2013, Generation's current limit for this coverage is $2.1 billion. For property limits in excess of the first $1.25 billion of that limit, Generation participates in an $850 million single limit blanket policy shared by all the Generation operating nuclear sites and the Salem and Hope Creek nuclear sites. This blanket limit is not subject to automatic reinstatement in the event of a loss. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. Under the terms of the various insurance agreements, Generation could be assessed up to $229 million per year for losses incurred at any plant insured by the insurance company (the retrospective premium obligation). In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental

property damage under one or more policies for all insured plants, the maximum recovery for all losses by all insureds will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses. The $3.2 billion maximum recovery limit is not applicable, however, in the event of a "certified act of terrorism" as defined in the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007. The Terrorism Risk Insurance Act expires on December 31, 2014.

Additionally, NEIL provides replacement power cost insurance in the event of a major accidental outage at an insured nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. Generation's maximum share of any assessment is $58 million per year (the retrospective premium obligation). Recovery under this insurance for terrorist acts is subject to the $3.2 billion aggregate limit and secondary to the property insurance described above. This limit would not apply in cases of certified acts of terrorism under the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007, as described above.

NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon's and Generation's financial condition, results of operations and liquidity.

Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation pays the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance will be delayed significantly. On November 19, 2013, the United States Court of Appeals for the District of Columbia Circuit ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On January 3, 2014, the DOE filed a petition for rehearing. On the same date, as ordered by the court, the DOE submitted a proposal to Congress to reduce the current SNF disposal fee to zero, subject to any further judicial decision. The DOE's submitted proposal becomes effective after the 90-days of continuous session of the Congress unless there is Congressional action contrary to the DOE proposal. However, if the court grants the petition for rehearing, the proposal to eliminate the fee (and the review period) will be held in suspense until after the court rules. Until such time as a new fee structure is in effect, Generation must continue to pay the current SNF disposal fees.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama administration devised a new strategy for long-term SNF management. A Blue Ribbon Commission (BRC) on America's Nuclear

Future, appointed by the U.S. Energy Secretary, released a report on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's spent nuclear fuel and high-level radioactive waste.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that is planned to be operational in 2025.

Generation uses the 2025 date as the assumed date for when the DOE will begin accepting SNF for purposes of determining nuclear decommissioning asset retirement obligations. The extended delay in SNF acceptance by the DOE has led to Generation's adoption of dry cask storage at its Dresden, Clinton, Limerick, Oyster Creek, Peach Bottom, Byron, Braidwood, LaSalle and Quad Cities stations.

In August 2004, Generation and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation, subject to certain damage limitations based on the extent of the government's breach, for costs associated with storage of SNF at Generation's nuclear stations pending the DOE's fulfillment of its obligations. Generation submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

Under the settlement agreement, Generation has received cash reimbursements for costs incurred through April 30, 2013, totaling approximately $712 million ($601 million after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek). As of December 31, 2013, the amount of SNF storage costs for which reimbursement will be requested from the DOE under the settlement agreement is $71 million, which is recorded within Accounts receivable, other. Of this amount, $18 million represents amounts owed to the co-owners of the Peach Bottom and Quad Cities generating facilities.

CENG entered into settlement agreements with the DOE during 2011 and 2012 to recover damages caused by the DOE's failure to comply with legal and contractual obligations to dispose of spent nuclear fuel related to the Ginna, Calvert Cliffs and Nine Mile Point nuclear power plants. At December 31, 2012, Generation had approximately $22 million recorded as a receivable from CENG with respect to costs incurred by Constellation prior to the formation of the CENG joint venture for the Nine Mile Point and Calvert Cliffs nuclear power plants. CENG received the funds for the Nine Mile Point and Calvert Cliffs settlement from the DOE in January 2013 and February 2013, respectively, and remitted the $22 million to Generation.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. As of December 31, 2013, the unfunded SNF liability for the one-time fee with interest was $1,021 million. Interest accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2013, was 0.051%. The liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of Exelon's 2001 corporate restructuring. The outstanding one-time fee obligations for the Oyster Creek and TMI units remain with the former owners. Clinton has no outstanding obligation. See Note 11—Fair Value of Assets and Liabilities for additional information.

Energy Commitments

Generation's customer facing activities include the physical delivery and marketing of power obtained through its generation capacity, and long-, intermediate- and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. Generation has also contracted for access to additional generation through bilateral long-term PPAs. These agreements are firm commitments related to power generation of specific generation plants and/or are dispatchable in nature. Several of Generation's long-term PPAs, which have been determined to be operating leases, have significant contingent rental payments that are dependent on the future operating characteristics of the associated plants, such as plant availability. Generation recognizes contingent rental expense when it becomes probable of payment. Generation enters into PPAs with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to its customers. Generation has also purchased firm transmission rights to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs. The primary intent and business objective for the use of its capital assets and contracts is to provide Generation with physical power supply to enable it to deliver energy to meet customer needs. In addition to physical contracts, Generation uses financial contracts for economic hedging purposes and, to a lesser extent, as part of proprietary trading activities.

Generation has entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives and retail load aggregators. Generation also enters into contractual obligations to deliver energy to market participants who primarily focus on the resale of energy products for delivery. Generation provides for delivery of its energy to these customers through firm transmission.

As part of reaching a comprehensive agreement with EDF in October 2010, the existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements, CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the nuclear plant output owned by CENG at market prices. Generation discloses in the table below commitments to purchase from CENG at fixed prices. All commitments to purchase at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 5—Investment in Constellation Energy Nuclear Group, LLC and Note 25—Related Party Transactions for more details on this arrangement.

At December 31, 2013, Generation's short- and long-term commitments, relating to the purchases from unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following tables:

	Net Capacity Purchases [a]	REC Purchases [b]	Transmission Rights Purchases [c]	Purchased Energy from CENG	Total
2014	$ 412	$ 117	$ 25	$ 824	$1,378
2015	367	110	13	—	490
2016	284	76	2	—	362
2017	223	25	2	—	250
2018	112	3	2	—	117
Thereafter	414	3	32	—	449
Total	$ 1,812	$ 334	$ 76	$ 824	$3,046

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2013, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.
(b) The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

ComEd purchases its expected energy requirements through an ICC approved competitive bidding process administered by the IPA and spot market purchases. See Note 3—Regulatory Matters for further information.

Since 2009, PECO has entered into contracts through a competitive procurement process in order to meet a portion of its default service customers' electric supply requirements for 2011 through 2016. See Note 3—Regulatory Matters for further information regarding the DSP Programs.

ComEd is subject to requirements established by the Illinois Settlement Legislation and the Energy Infrastructure Modernization Act related to the use of alternative energy resources. PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. BGE is subject to requirements established by the Public Utilities Article in Maryland related to the use of alternative energy resources; however, the wholesale suppliers that supply power to BGE through SOS procurement auctions have the obligation, by contract with BGE, to meet the RPS requirement. BGE has entered into contracts with curtailment services providers in accordance with the March 2009 MDPSC order. See Note 3—Regulatory Matters for additional information relating to electric generation procurement, alternative energy resources and energy efficiency programs.

ComEd's, PECO's and BGE's electric supply procurement, curtailment services, REC and AEC purchase commitments as of December 31, 2013 are as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
ComEd							
Electric supply procurement [a]	$ 736	$323	$136	$137	$140	$—	$ —
Renewable energy and RECs [b]	1,589	72	74	76	77	83	1,207
PECO							
Electric supply procurement [c]	681	590	91	—	—	—	—
AECs [d]	14	2	2	2	2	2	4
BGE							
Electric supply procurement [e]	1,256	783	400	73	—	—	—
Curtailment services [f]	132	45	40	34	13	—	—

(a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. See Note 3—Regulatory Matters for additional information.
(b) ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. The ICC's December 18, 2013 order approved the reduction of ComEd's commitments under the long-term contracts for the June 2014 through May 2015 procurement period, however the amount of the reduction will not be finalized and approved by the ICC until March 2014. See Note 3—Regulatory Matters for additional information.

(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2014 and 2015. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 3—Regulatory Matters for additional information.
(d) PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. See Note 3—Regulatory Matters for additional information.
(e) BGE entered into various contracts for the procurement of electricity beginning 2013 through 2016. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 3—Regulatory Matters for additional information.
(f) BGE has entered into various contracts with curtailment services providers related to transactions in PJM's capacity market. See Note 3—Regulatory Matters for additional information.

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation. PECO and BGE have commitments to purchase natural gas, related transportation, storage capacity and services to serve customers in their gas distribution service territory. As of December 31, 2013, these net commitments were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Generation	$8,490	$1,212	$1,256	$1,040	$1,044	$763	$ 3,175
PECO	507	179	112	98	37	15	66
BGE	609	129	59	57	57	51	256

Other Purchase Obligations

The Registrants' other purchase obligations as of December 31, 2013, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Exelon	$262	$ 61	$ 34	$32	$31	$ 26	$ 78
Generation	504	170	131	45	42	30	86
ComEd [a]	122	88	5	5	5	5	14
PECO [a]	40	30	1	1	1	1	6
BGE [a]	53	44	2	5	2	—	—

(a) Purchase obligations include commitments related to smart meter installation. See Note 3 - Regulatory Matters for additional information.

Commercial Commitments

Exelon's commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [a]	$1,520	$1,217	$298	$—	$ 5	$—	$ —
Surety bonds [b]	339	301	2	6	4	1	25
Performance guarantees [c]	1,107	350	—	—	—	—	757
Energy marketing contract guarantees [d]	3,161	3,161	—	—	—	—	—
Lease guarantees [e]	44	—	—	—	—	—	44
Nuclear insurance premiums [f]	3,529	—	—	—	—	—	3,529
Total commercial commitments	$9,700	$5,029	$300	$ 6	$ 9	$ 1	$ 4,355

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Guarantees issued to ensure performance under specific contracts, including $211 million issued on behalf of CENG nuclear generating facilities for credit support, $200 million of Trust Preferred Securities of ComEd Financing III, $178 million of Trust Preferred Securities of PECO Trust III and IV and $250 million of Trust Preferred Securities of BGE Capital Trust II.
(d) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $3 billion of guarantees previously issued by Constellation on behalf of its Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Exelon's estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $463 million at December 31, 2013, which represents the total amount Exelon could be required to fund based on December 31, 2013 market prices.
(e) Lease guarantees—Guarantees issued to ensure payments on building leases.
(f) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

Generation's commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [a]	$1,477	$1,174	$298	$—	$ 5	$—	$ —
Performance guarantees [b]	357	343	—	—	—	—	14
Energy marketing contract guarantees [c]	832	832	—	—	—	—	—
Nuclear insurance premiums [d]	3,529	—	—	—	—	—	3,529
Total commercial commitments	$6,195	$2,349	$298	$—	$ 5	$—	$ 3,543

(a) Letters of credit (non-debt)—Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.
(b) Performance guarantees—Guarantees issued to ensure performance under specific contracts including $211 million issued on behalf of CENG nuclear generating facilities for credit support.

(c) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $749 million of guarantees previously issued by Constellation on behalf of its Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Generation's estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $0.2 billion at December 31, 2013, which represents the total amount Generation could be required to fund based on December 31, 2013 market prices.
(d) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

ComEd's commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [a]	$ 19	$ 19	$—	$—	$—	$—	$ —
Surety bonds [b]	9	9	—	—	—	—	—
Performance guarantees [c]	200	—	—	—	—	—	200
Total commercial commitments	$228	$ 28	$—	$—	$—	$—	$ 200

(a) Letters of credit (non-debt)—ComEd maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Reflects full and unconditional guarantee of Trust Preferred Securities of ComEd Financing III which is a 100% owned finance subsidiary of ComEd.

PECO's commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [a]	$ 22	$ 22	$—	$—	$—	$—	$ —
Surety bonds [b]	3	3	—	—	—	—	—
Performance guarantees [c]	178	—	—	—	—	—	178
Total commercial commitments	$203	$ 25	$—	$—	$—	$—	$ 178

(a) Letters of credit (non-debt)—PECO maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Reflects full and unconditional guarantee of Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.

BGE's commercial commitments as of December 31, 2013, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Letters of credit (non-debt) [a]	$ 1	$ 1	$—	$—	$—	$—	$ —
Surety bonds [b]	9	9	—	—	—	—	—
Performance guarantees [c]	250	—	—	—	—	—	250
Total commercial commitments	$260	$ 10	$—	$—	$—	$—	$ 250

(a) Letters of credit (non-debt)—BGE maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bond—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantee—Reflects full and unconditional guarantee of Trust Preferred Securities of BGE Capital Trust which is an unconsolidated VIE of BGE.

Construction Commitments

Generation has committed to the construction of the Antelope Valley solar PV facility in Los Angeles County, California. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013 and an expectation of full commercial operation in the first half of 2014. Generation's estimated remaining commitment for the project is $110 million.

On July 3, 2013, Generation executed a Turbine Supply Agreement to expand its Beebe wind project in Michigan. The estimated remaining commitment under the contract is $50 million and achievement of commercial operations is expected in 2014.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland generation site with 120 MW of new natural gas-fired generation to satisfy certain merger commitments. The estimated remaining commitment under the contract is $80 million and achievement of commercial operation is expected in 2015. See 4—Merger and Acquisitions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the merger.

On December 27, 2013, Generated executed a Turbine Supply Agreement for construction of the 32.5MW Fourmile Wind project in western Maryland. The estimated remaining commitment under the contract is $26 million and achievement of commercial operations is expected in 2014. See 4—Merger and Acquisitions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the merger.

Refer to Note 3—Regulatory Matters for information on investment programs associated with regulatory mandates, such as ComEd's Infrastructure Investment Plan under EIMA, PECO's Smart Meter Procurement and Installation Plan, and BGE's comprehensive smart grid initiative.

Constellation Merger Commitments

Exelon's commercial and construction commitments shown above do not include the merger commitments made to the State of Maryland in conjunction with the Constellation merger. See Note 4—Merger and Acquisitions for additional information on the mergers commitments.

Leases

Minimum future operating lease payments, including lease payments for vehicles, real estate, computers, rail cars, operating equipment and office equipment, as of December 31, 2013 were:

	Exelon	Generation	ComEd (b)	PECO (b)	BGE (b)(c)
2014	$ 103	$ 49	$ 13	$ 13	$ 12
2015	91	50	11	3	11
2016	89	49	11	3	9
2017	82	48	7	3	8
2018	63	40	2	3	7
Remaining years	398	336	3	—	14
Total minimum future lease payments	$ 826[a]	$ 572[a]	$ 47	$ 25	$ 61

(a) Excludes Generation's PPAs and other capacity contracts that are accounted for as contingent operating lease payments.
(b) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, ComEd, PECO and BGE have excluded these payments from the remaining years, as such amounts would not be meaningful. ComEd's, PECO's, and BGE's annual obligation for these arrangements, included in each of the years 2014—2018, was $1 million, $3 million, and $1 million respectively.
(c) Includes all future lease payments on a 99 year real estate lease that expires in 2105.

The following table presents the Registrants' rental expense under operating leases for the years ended December 31, 2013, 2012 and 2011:

For the Year Ended December 31,	Exelon	Generation (a)	ComEd	PECO	BGE
2013	$ 806	$ 744	$ 15	$ 21	$11
2012	930	872	18	27	12
2011	711	659	18	28	15

(a) Includes Generation's PPAs and other capacity contracts that are accounted for as operating leases and are reflected as net capacity purchases in the energy commitments table above. These agreements are considered contingent operating lease payments and are not included in the minimum future operating lease payments table above. Payments made under Generation's PPAs and other capacity contracts totaled $694 million, $801 million and $630 million during 2013, 2012 and 2011, respectively.

For information regarding capital lease obligations, see Note 13—Debt and Credit Agreements.

Indemnifications Related to Sale of Sithe (Exelon and Generation)

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. Specifically, subsidiaries of Generation consummated the acquisition of Reservoir Capital Group's 50% interest in Sithe and subsequently sold 100% of Sithe to Dynegy Inc. (Dynegy).

The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at December 31, 2013. Generation believes that it is remote that it will be required to make any additional payments under the guarantee, and currently has no recorded liabilities associated with this guarantee. Generation expects that the exposure covered by this guarantee will expire in 2014. The guarantee is included above in the Commercial Commitments table under performance guarantees.

Indemnifications Related to Sale of TEG and TEP (Exelon and Generation)

On February 9, 2007, Tamuin International Inc. (TII), a wholly owned subsidiary of Generation, sold its 49.5% ownership interests in TEG and TEP to a subsidiary of AES Corporation for $95 million in cash plus certain purchase price adjustments. In connection with the transaction, Generation entered into a guarantee agreement under which Generation guarantees the timely payment of TII's obligations to the subsidiary of AES Corporation pursuant to the terms of the purchase and sale agreement relating to the sale of TII's ownership interests. Generation was required to perform in the event that TII did not pay any obligation covered by the guarantee that was not otherwise subject to a dispute resolution process. Portions of the exposures covered by this guarantee expired in 2008, and the remaining guarantee expired in the third quarter of 2013. Generation was not required to make payments under the guarantee, and therefore, has no further obligation related to this guarantee as of December 31, 2013.

Environmental Matters

General. The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property currently or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For many of these sites, ComEd, PECO or BGE is one of several PRPs that may be responsible for ultimate remediation of each location.

- ComEd has identified 42 sites, 16 of which have been approved for cleanup by the Illinois EPA or the U.S. EPA and 26 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2016.
- PECO has identified 26 sites, 16 of which have been approved for cleanup by the PA DEP and 10 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2020.
- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. BGE is authorized to and is currently recovering environmental costs for the remediation of former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. ComEd, PECO and BGE have recorded regulatory assets for the recovery of these

costs. During the third quarter of 2013, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. The results of these studies indicated that additional remediation would be required at certain sites; accordingly, ComEd and PECO increased their reserves and regulatory assets by less than $1 million and $6 million, respectively. BGE assessed its currently and formerly owned gas manufacturing and purification sites quarterly in 2013 and determined that a loss was not probable at ten of its sites as of December 31, 2013. As discussed above, the remediation costs at two of BGE's MGP sites are not considered material. Furthermore, an estimate of a range of possible loss, if any, related to BGE's gas purification site under investigation cannot be determined as of December 31, 2013 given that the site is in the early stages of investigation and the extent of contamination is currently unknown. See Note 3—Regulatory Matters for additional information regarding the associated regulatory assets.

The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial action. Management determines its best estimate of remediation costs based on probabilistic modeling and deterministic estimates using all available information at the time of each study and the remediation standards currently required by the U.S. EPA. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

As of December 31, 2013 and 2012, the Registrants have accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

December 31, 2013	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 338	$ 273
Generation	56	—
ComEd	234	229
PECO	47	44
BGE	1	—

December 31, 2012	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 351	$ 298
Generation	42	—
ComEd	261	254
PECO	47	44
BGE	1	—

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water Quality

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of

Generation's and CENG's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. For Generation, those facilities are Clinton, Dresden, Eddystone, Fairless Hills, Gould Street, Handley, Mountain Creek, Mystic 7, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. For CENG, those facilities are Calvert Cliffs, Nine Mile Point Unit 1 and R.E. Ginna.

On March 28, 2011, the U.S. EPA issued the proposed regulation under Section 316(b). The proposal does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment. The proposal provides the state permitting agency with discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The proposed rule also imposes limits on impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or another technology at the intake. Exelon filed comments on the proposed regulation on August 18, 2011, stating its support for a number of its provisions (e.g., cooling towers not required as best technology available, and the use of site-specific and cost benefit analysis) while also noting a number of technical provisions that require revision to take into account existing unit operations and practices within the industry.

In June 2012, the U.S. EPA published two Notices of Data Availability (NODA) seeking public comment on alternate compliance technologies for impingement and the use of a public opinion survey to calculate the so-called "non-use" benefits of the rule. Exelon filed comments for each NODA, supporting the additional flexibility afforded by the impingement NODA, and opposing the NODA relating to calculation of non-use benefits due to its inaccurate and unreliable methodologies that would artificially inflate the benefits of proposed technologies that would otherwise not be cost-effective. On June 27, 2013, the U.S. EPA agreed to amend the court approved Settlement Agreement to extend the deadline to issue a final rule until November 4, 2013 and on October 30, 2013 the U.S. EPA invoked the *force majeure* provision of the Settlement Agreement to extend the final rule deadline until January 14, 2014 due to the early October 2013 federal government shutdown. The U.S. EPA and the plaintiffs have again agreed to extend the date for issuance of the final rule until April 17, 2014. Until the rule is finalized, the state permitting agencies will continue to apply their best professional judgment to address impingement and entrainment.

Salem and Other Power Generation Facilities. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG, in July 2004 that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon's and Generation's share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $430 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment.

It is unknown at this time whether the NJDEP permit programs will require closed-cycle cooling at Salem. In addition, the economic viability of Generation's other power generation facilities, as well as CENG's, without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation and CENG.

Given the uncertainties associated with the requirements that will be contained in the final rule, Generation cannot predict the eventual outcome or estimate the effect that compliance with any resulting Section 316(b) or interim state requirements will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows and financial position.

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Prior to the Merger, Constellation recorded in its Consolidated Balance Sheets total liabilities of approximately $30 million to comply with the consent decree with an additional $3 million recognized through purchase accounting. During third quarter of 2013, Generation increased its reserve by $2 million based on an update of future estimated remediation costs. The remaining liability as of December 31, 2013, is approximately $14 million. In addition, a private party asserted claims relating to groundwater contamination. Generation has reached an agreement in principle to resolve these claims. The amount of the settlement is not material to the financial condition of Generation.

Alleged Conemaugh Clean Streams Act Violation. The PA DEP has alleged that GenOn Northeast Management Company (GenOn), the operator of Conemaugh Generating Station, violated the Pennsylvania Clean Streams Law. GenOn reached agreement with PA DEP on a proposed Consent Decree that was approved by the Commonwealth Court of Pennsylvania on December 4, 2012. Under the Consent Decree, GenOn is obligated to pay a civil penalty of $0.5 million, of which Generation's responsibility was approximately $0.2 million. Generation made the final payment in January 2014 and is complying with the Consent Decree.

Air Quality

Cross-State Air Pollution Rule (CSAPR). On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of SO_2 and NO_x. The D.C. Circuit Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the D.C. Circuit Court's July 11, 2008 opinion. On July 7, 2011, the U.S. EPA published the final rule, known as the CSAPR. The CSAPR requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states.

Numerous entities challenged the CSAPR in the D.C. Circuit Court, and some requested a stay of the rule pending the Court's consideration of the matter on the merits. On December 30, 2011, the Court granted a stay of the CSAPR, and directed the U.S. EPA to continue the administration of CAIR in the interim. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA

has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. The Court's order was appealed to the U.S. Supreme Court, where oral argument was held on December 10, 2013. A decision is expected sometime during 2014.

Under the CSAPR, generation units were to receive allowances based on historic heat input and intrastate, and limited interstate, trading of allowances was permitted. The CSAPR restricted entirely the use of pre-2012 allowances. Existing SO_2 allowances under the ARP would remain available for use under ARP. As of December 31, 2013, Generation had $56 million of emission allowances carried at the lower of weighted average cost or market.

EPA Mercury and Air Toxics Standards (MATS). The MATS rule became final on April 16, 2012. The MATS rule reduces emissions of toxic air pollutants, and finalized the new source performance standards for fossil fuel-fired electric utility steam generating units (EGUs). The MATS rule requires coal-fired EGUs to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that smaller, older, uncontrolled coal units will retire rather than make these investments. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. In addition, the new standards will require oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court is expected sometime during 2014. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS.

In addition, as of December 31, 2013, Exelon had a $698 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases extending through 2028-2032. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, after the impairment recorded in the second quarter of 2013, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material.

National Ambient Air Quality Standards (NAAQS). The U.S. EPA previously announced that it would complete a review of all NAAQS by 2014. Oral argument in the litigation (*State of Miss. v. EPA*) of the final 2008 ozone standard occurred in the D.C. Circuit Court in November 2012 and a final Court decision was issued on July 23, 2013 with the 2008 primary ozone standard upheld, but the secondary standard remanded to EPA for reconsideration. Concurrent with litigation of the 2008 ozone standard, the U.S. EPA continues its regular, periodic review of the ozone NAAQS and is expected to propose revisions in the fall of 2014, with preliminary indications that the U.S. EPA will likely propose a tightened standard. It is unclear at this point in time whether the U.S. EPA will be able to respond to the Court remand of the secondary 2008 ozone standard on a timeframe that would be any quicker than

that of the U.S. EPA's current, periodic review schedule. In December 2012, the U.S. EPA issued its final revisions to the Agency's particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation. It is unclear if the vacatur of the CSAPR, one of the regulations that the U.S. EPA is relying on to assist with future PM reduction, would alter the U.S. EPA's view since either CAIR or a finalized CSAPR regulation would be in effect leading up to 2020. In March 2013, a number of industry coalitions filed a joint lawsuit challenging the new PM2.5 standard. Also during early 2013, the D.C. Circuit remanded several rules for implementation of earlier PM2.5 NAAQS to the U.S. EPA for revision of certain aspects of the rules, with a requirement that the U.S. EPA re-promulgate regulations in conformance with the correct subparts of the Clean Air Act.

In addition to these NAAQS, the U.S. EPA also finalized nonattainment designations for certain areas in the United States for the 2010 one-hour SO_2 standard on August 5, 2013, and indicated that additional nonattainment areas will be designated in a future rulemaking. U.S. EPA will require states to submit state implementation plans (SIPs) for nonattainment areas by April 2015. With regard to Texas and Maryland, no nonattainment areas were identified in U.S. EPA's final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. The U.S. EPA will follow the approach outlined in a February 2013 U.S. EPA strategy document that establishes a process and timeline for the Agency to address additional designations in states' counties under a future rulemaking. Nonattainment county compliance with the one-hour SO_2 standard is required by October 2018. While significant SO_2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the requirements of pending states' SIPs to further reduce SO_2 emissions in support of attainment of the one hour SO_2 standard.

Notices and Finding of Violations and Midwest Generation Bankruptcy. In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third-party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

On December 17, 2012 (Petition Date), EME and certain of its subsidiaries, including Midwest Generation, filed for protection under Chapter 11 of the U.S. Bankruptcy Code.

In 2012, the Bankruptcy Court approved the rejection of a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations. The rejection left Generation as the party responsible to make remaining payments under the lease. In January 2013, Generation made the final $10 million payment due under the lease agreement which had been accrued at December 31, 2012.

During the second quarter of 2013, Exelon filed proofs of claim of $21 million with the Bankruptcy Court for amounts owed by EME and Midwest Generation for the coal rail car lease, ComEd utility payments and certain legal costs. Further, Exelon filed an environmental claim with an unspecified amount that listed the indemnifications that were in place pre-Petition Date and other factors associated with the remediation. As of December 31, 2013, Exelon has not recorded a receivable for the filed proofs of claim because recovery of any amount cannot be assured at this point in the bankruptcy. Exelon will not record claim recoveries unless and until they are realized.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in Exelon's 2001 corporate restructuring to assume ComEd's rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions at the stations requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors, including the impact of Midwest Generation's bankruptcy. On January 17, 2014, Midwest Generation filed a plan supplement to its bankruptcy filing that included a request to reject the sale agreement, including the environmental indemnity. ComEd and Generation have reviewed available public information as to potential environmental exposures regarding the Midwest Generation station sites. Midwest Generation publicly disclosed in its quarter ending September 30, 2013 Form 10-Q that (i) it has accrued a probable amount of approximately $8 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at four Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Crawford, Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted. For these reasons, ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations and as a result no liability has been recorded as of December 31, 2013. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Under a supplemental agreement reached in 2003, Midwest Generation agreed to reimburse ComEd and Generation for 50% of the specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. In addition to the sale agreement, Midwest Generation also requested to reject this supplemental agreement in the January 17, 2014 plan supplement to its bankruptcy filing. Exelon and Generation had previously expected Midwest Generation or its successor would remain responsible for asbestos personal injury claims filed post-Petition Date, and as a result had not recorded a liability for such amounts. Exelon and Generation now believe that the rejection of the 1999 sale and supplemental agreements is probable, and as a result, Generation has increased its reserve for asbestos-related bodily injury claims at December 31, 2013 by $25 million. The increase in the reserve was estimated using actuarial assumptions and analyses available to Generation. Generation's exposure could differ to the extent new information is received or made available. Midwest Generation publicly disclosed in its quarter ending September 30, 2013 Form 10-Q that they had $53 million recorded related to asbestos bodily injury claims under the contractual indemnity with ComEd. If the agreements are rejected, Exelon and

Generation may be entitled to damages associated with the agreement terminations. These amounts are considered to be contingent gains and would not be recognized until realized.

On October 18, 2013, NRG Energy entered into an agreement to buy EME's portfolio of generation subject to regulatory approvals. Exelon continues to monitor all aspects of the bankruptcy; the proposed purchase by NRG has not impacted any accounting conclusions as of December 31, 2013.

In May 2010, the United States and State of Illinois initiated a lawsuit against Midwest Generation, ComEd and EME alleging Clean Air Act violations relating to the modification and/or operation of six (coal) electric generation plants in Northern Illinois, which ComEd sold to Midwest Generation/EME in 1999. The government parties sought injunctive relief and civil penalties against all defendants, although not all of the claims specifically pertained to ComEd. On March 16, 2011, the District Court granted ComEd's motion to dismiss the May 2010 complaint in its entirety as it relates to ComEd. On January 3, 2012, upon leave of the District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals for the Seventh Circuit. On July 8, 2013, the Circuit Court affirmed the District Court's dismissal of the complaint against ComEd. On September 19, 2013, the Circuit Court denied the petition for a rehearing filed by the governmental parties. The government parties did not seek United States Supreme Court review of the Seventh Circuit's decision. The deadline for seeking such review was in December 2013. In light of the Circuit Court decision resolving this matter in favor of ComEd, no reserve has been established.

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the anticipated landfill cover remediation for the site is approximately $42 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the supplemental feasibility study that could take up to one year to complete, and subsequently requested additional analysis sampling and modeling to be conducted into 2014. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty

Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2014 so that settlement discussions could proceed. Based on Exelon's preliminary review, it appears probable that Exelon has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the "Exelon defendants") and Cotter. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the defendants' negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which were subsequently granted. Since May 30, 2012, several related lawsuits have been filed in the same court on behalf of various plaintiffs against Cotter and other defendants, but not Exelon. The allegations in these related lawsuits mirror the initially filed lawsuits. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price-Anderson Act. On July 8, 2013, the plaintiffs filed amended complaints under the Price-Anderson Act. Cotter moved to dismiss the amended complaints and has motions currently pending before the court. At this stage of the litigation, Exelon cannot estimate a range of loss, if any.

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The PRPs submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. On September 30, 2013, U.S. EPA issued the Record of Decision identifying its preferred remedial alternative for the site. The estimated cost for the alternative chosen by U.S. EPA is consistent with the PRPs estimated range of costs noted above. Based on Exelon's preliminary review, it appears probable that Exelon has liability and has established an appropriate accrual for its share of the estimated clean-up costs. BGE is indemnified by a wholly owned subsidiary of Generation for most of the costs related to this settlement and clean-up of the site.

Rossville Ash Site. The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC(CPSG). In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately $6 million, which has been fully reserved as of December 31, 2013.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRP's signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRP's to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA's position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations (the Tailoring Rule) relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a CO_2 equivalent basis, and to modifications to existing sources that result in emissions increases greater than 75,000 tons per year on a CO_2 equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. On July 2, 2012 the U.S. EPA declined to lower GHG permit thresholds in its final "Step 3" Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per curium* decision, dismissed industry and state petitions challenging the U.S. EPA's "Tailpipe Rule" for cars and light duty trucks, the endangerment finding for GHG's from stationary sources, and the Tailoring Rule. On October 15, 2013 the U.S. Supreme Court granted industry petitions to review one aspect of the PSD permitting regulations. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case by case basis. Generation could be significantly affected by the regulations if it were to build new plants or modify existing plants.

On June 25, 2013, President Obama announced "The President's Climate Action Plan," a summary of executive branch actions intended to: reduce carbon emissions; prepare the United States

for the impacts of climate change; and lead international efforts to combat global climate change and prepare for its impacts. Concurrent with the announcement of the Administration's plan, the President also issued a Memorandum for the Administrator of the Environmental Protection Agency that focused on power generation sector carbon reductions under the Section 111 New Source Performance Standards (NSPS) section of the federal Clean Air Act. The memorandum directs the U.S. EPA Administrator to issue two sets of proposed rulemakings with regard to power plant carbon emissions under Section 111 of the Clean Air Act.

The first rulemaking, under Section 111(b) of the Clean Air Act is to focus on establishing carbon regulations for new fossil-fuel power plants. This rulemaking was proposed on September 20, 2013 and is to be finalized "in a timely fashion." In the proposed rule U.S.EPA sets separate standards for fossil-fuel fired utility boilers and natural gas fired stationary combustion turbines.

The second rulemaking, under Section 111(d) of the Clean Air Act is to focus on modified, reconstructed and existing fossil power plants. The rulemaking is to be proposed no later than June 1, 2014, be finalized no later than June 1, 2015, and require that states submit to U.S. EPA their implementation plans no later than June 30, 2016. In developing this rulemaking, U.S. EPA is directed to consider a number of factors, including options to reduce costs, options to ensure the continued use of a range of energy sources and technologies, options that are consistent with reliable and affordable power, and options that allow for the use of market-based instruments, performance standards and other regulatory flexibilities.

To the extent that the final Section 111(d) rule results in emission reductions from fossil fuel fired plants, and thereby imposes some form of direct or indirect price of carbon in competitive electricity markets, Exelon's overall low-carbon generation portfolio results could benefit.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon, Generation, PECO and BGE).

Exelon and Generation. Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2013 and 2012, Generation had reserved approximately $90 million and $63 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2013, approximately $19 million of this amount related to 224 open claims presented to Generation, while the remaining $71 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee's disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee's last employment-based exposure, and that therefore the exclusivity provision of the Act does not apply to preclude such employee from suing his or her employer in court. The Supreme

Court's ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee's last employment-based exposure to asbestos. Currently, Exelon, Generation and PECO are unable to predict whether and to what extent they may experience additional claims in the future as a result of this ruling; as such no increase to the asbestos-related bodily injury liability has been recorded as of December 31, 2013. Increased claims activity resulting from this ruling could have a material adverse impact on Exelon, Generation's and PECO's future results of operations and cash flows.

BGE. Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

Approximately 486 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.

Discovery begins in these cases after they are placed on the trial docket. At present, only two of the pending cases are set for trial. Given the limited discovery in these cases, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

- the identity of the facilities at which the plaintiffs allegedly worked as contractors;
- the names of the plaintiffs' employers;
- the dates on which and the places where the exposure allegedly occurred; and
- the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

Federal Energy Regulatory Commission Investigation (Exelon and Generation).

On January 30, 2012, FERC published a notice on its website regarding a non-public investigation of certain of Constellation's power trading activities in and around the ISO-NY from September 2007 through December 2008. Prior to the merger, Constellation announced on March 9, 2012, that it had resolved the FERC investigation. Under the settlement, Constellation agreed to pay, and has paid, a $135 million civil penalty and $110 million in disgorgement.

During the year ended December 31, 2012, Generation recorded expense of $195 million in operating and maintenance expense with the remaining $50 million recorded as a Constellation pre-acquisition contingency. See Note 4—Merger and Acquisitions for additional information on the merger.

Continuous Power Interruption (ComEd)

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd's service territory, as well as for five other storm systems that affected ComEd's customers during June and July 2011 (Summer 2011 Storm Docket). In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket).

On June 5, 2013, the ICC approved a complete waiver of liability for five of the six summer storms and the February 2011 blizzard. However, the ICC held that for the July 11, 2011 storm, 34,559 interruptions were preventable and therefore no waiver should apply. As required by the ICC's Order, ComEd notified relevant customers that they may be entitled to seek reimbursement of incurred costs in accordance with a claims procedure established under ICC rules and regulations. In addition, the ICC found that ComEd did not systematically fail in its duty to provide adequate, reliable and safe service. As a result, the ICC rejected the Illinois Attorney General's request for the ICC to open an investigation into ComEd's infrastructure and storm hardening investments.

Following the ICC's June 26, 2013 denial of ComEd's request for rehearing, on June 27, 2013 ComEd filed an appeal of both the summer and winter storm dockets with the Illinois Appellate Court regarding the ICC's interpretation of Section 16-125 of the Illinois Public Utilities Act. ComEd cannot predict the outcome of appeals.

As a result of the ICC's June 5, 2013 ruling, ComEd established a liability, which was not material, for potential reimbursements for actual damages incurred by the 34,559 customers covered by the ICC's June 5, 2013 Order. The liability recorded represents the low end of a range of potential losses given that no amount within the range represents a better estimate. ComEd's ultimate liability will be based on actual claims eligible for reimbursement as well as the outcome of the appeal. Although reimbursements for actual damages will differ from the estimated accrual recorded, at this time ComEd does not expect the difference to be material to ComEd's results of operations or cash flows.

ComEd has not recorded an accrual for reimbursement of local governmental emergency and contingency expenses as a range of loss, if any, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows.

Telephone Consumer Protection Act Lawsuit (ComEd)

On November 19, 2013, a class action complaint was filed in Cook County on behalf of a single individual and a presumptive class that would include all customers in ComEd's service territory who

were enrolled by the Company in ComEd's Outage Alert text message program. The complaint alleges that ComEd violated the Telephone Consumer Protection Act ("TCPA") by sending approximately 1.2 million text messages to customers without first obtaining their consent to receive such messages. The complaint seeks certification of a class along with statutory damages, attorneys' fees, and an order prohibiting ComEd from sending additional text messages. Such statutory damages could range from $500 to $1,500 per text. However, ComEd is preparing a motion to dismiss this class action complaint and will vigorously contest the allegations of this suit. The ultimate outcome of this proceeding is uncertain, and an amount, if any, which might be asserted, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows. As a result, ComEd has not established a reserve for this complaint as of December 31, 2013.

Securities Class Action (Exelon)

Three federal securities class action lawsuits were filed in the United States District Courts for the Southern District of New York and the District of Maryland between September 2008 and November 2008 against Constellation. The cases were filed on behalf of a proposed class of persons who acquired publicly traded securities, including the Series A Junior Subordinated Debentures (Debentures), of Constellation between January 30, 2008 and September 16, 2008, and who acquired Debentures in an offering completed in June 2008. The securities class actions generally allege that Constellation, a number of its former officers or directors, and the underwriters violated the securities laws by issuing a false and misleading registration statement and prospectus in connection with Constellation's June 27, 2008 offering of the Debentures. The securities class actions also allege that Constellation issued false or misleading statements or was aware of material undisclosed information which contradicted public statements, including in connection with its announcements of financial results for 2007, the fourth quarter of 2007, the first quarter of 2008 and the second quarter of 2008 and the filing of its first quarter 2008 Form 10-Q. The securities class actions sought, among other things, certification of the cases as class actions, compensatory damages, reasonable costs and expenses, including counsel fees, and rescission damages.

The Southern District of New York granted the defendants' motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On May 9, 2013, the federal court in Maryland preliminarily approved the settlement of Constellation's 2008 Securities Class Action for a payment of $4 million, which will be paid by Constellation's insurer. Notice of the settlement was provided to class members in June 2013 and the court approved the final settlement on November 4, 2013. This settlement will resolve all of Constellation's litigation arising from the 2008 Securities Class Action lawsuit.

Fund Transfer Restrictions (Exelon, Generation, ComEd, PECO and BGE)

Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as: (1) the source of the dividends is clearly disclosed;

(2) the dividend is not excessive; and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. On May 1, 2013, PECO redeemed all outstanding preferred securities. As a result, the above ratio calculation is no longer applicable. Additionally, PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

BGE pays dividends on its common stock after its board of directors declares them. However, BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

Baltimore City Franchise Taxes (BGE)

The City of Baltimore claims that BGE has maintained electric facilities in the City's public right-of-ways for over one hundred years without the proper franchise rights from the City. BGE is currently reviewing the merits of this claim. BGE has not recorded an accrual for payment of franchise fees for past periods as a range of loss, if any, cannot be reasonably estimated at this time. Franchise fees assessed in future periods may be material to BGE's results of operations and cash flows.

General (Exelon, Generation, ComEd, PECO and BGE).

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Income Taxes

See Note 14—Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

23. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations for the years ended December 31, 2013, 2012 and 2011.

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$ 449	$ 79	$ 241	$129	$ 82
Property	302	205	24	14	112
Payroll	159	89	27	13	15
Other	185	16	7	2	4
Total taxes other than income	$1,095	$ 389	$ 299	$158	$213

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$ 463	$ 82	$ 239	$141	$ 75
Property	227	189	22	13	111
Payroll	131	78	26	12	18
Other	198	20	8	(4)	4
Total taxes other than income	$1,019	$ 369	$ 295	$162	$208

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [a]	$ 443	$ 27	$ 243	$173	$ 79
Property	177	146	22	9	107
Payroll	123	71	25	13	17
Other	42	20	6	10	4
Total taxes other than income	$ 785	$ 264	$ 296	$205	$207

(a) Generation's utility tax represents gross receipts tax related to its retail operations and ComEd's, PECO's and BGE's utility taxes represent municipal and state utility taxes and gross receipts taxes related to their operating revenues, respectively. The offsetting collection of utility taxes from customers is recorded in revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a] —					
Regulatory agreement units	$ 256	$ 256	$ —	$—	$—
Non-regulatory agreement units	77	77	—	—	—
Net unrealized gains on decommissioning trust funds—					
Regulatory agreement units	406	406	—	—	—
Non-regulatory agreement units	146	146	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	7	7	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(546)	(546)	—	—	—
Total decommissioning-related activities	346	346	—	—	—
Investment income	8	(1)	—	(1)	9[c]
Long-term lease income	28	—	—	—	—
Interest income related to uncertain income tax positions	24	4	—	—	—
AFUDC—Equity	22	—	11	4	7
Other	45	19	15	3	1
Other, net	$ 473	$ 368	$ 26	$ 6	$ 17

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a] —					
Regulatory agreement units	$ 189	$ 189	$ —	$—	$—
Non-regulatory agreement Units	102	102	—	—	—
Net unrealized gains on decommissioning trust funds—					
Regulatory agreement units	386	386	—	—	—
Non-regulatory agreement units	105	105	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	73	73	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(530)	(530)	—	—	—
Total decommissioning-related activities	325	325	—	—	—

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Investment income	20	3	1	2	11[c]
Long-term lease income	29	—	—	—	—
Interest income related to uncertain income tax positions	15	2	20	—	—
AFUDC—Equity	17	—	6	4	10
Credit facility termination fees	(85)	(85)	—	—	—
Other	25	(6)	12	2	2
Other, net	$ 346	$ 239	$ 39	$ 8	$ 23

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a] —					
Regulatory agreement units	$ 177	$ 177	$ —	$—	$—
Non-regulatory agreement units	45	45	—	—	—
Net unrealized losses on decommissioning trust funds—					
Regulatory agreement units	(74)	(74)	—	—	—
Non-regulatory agreement units	(4)	(4)	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	48	48	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(130)	(130)	—	—	—
Total decommissioning-related activities	62	62	—	—	—
Investment income	10	1	1	3	13[c]
Long-term lease income	28	—	—	—	—
Interest income related to uncertain income tax positions	53	31	14	1	—
AFUDC—Equity	17	—	8	9	15
Bargain purchase gain related to Wolf Hollow acquisition	36	36	—	—	—
Other	(3)	(8)	6	1	(2)
Other, net	$ 203	$ 122	$ 29	$ 14	$ 26

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE's rate stabilization deferral. See Note 3—Regulatory Matters for additional information regarding the rate stabilization deferral.

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011.

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,893	$ 813	$ 545	$219	$264
Regulatory assets	212	—	119	9	84
Amortization of intangible assets, net	48	43	5	—	—
Amortization of energy contract assets and liabilities [(a)]	430	507	—	—	—
Nuclear fuel [(a)]	921	921	—	—	—
ARO accretion [(b)]	275	275	—	—	—
Total depreciation, amortization, accretion and depletion	$3,779	$ 2,559	$ 669	$228	$348

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,712	$ 733	$ 525	$207	$245
Regulatory assets	129	—	80	10	53
Amortization of intangible assets, net	40	35	5	—	—
Amortization of energy contract assets and liabilities [(a)]	1,110	1,110	—	—	—
Nuclear fuel [(a)]	848	848	—	—	—
ARO accretion [(b)]	240	240	—	—	—
Total depreciation, amortization, accretion and depletion	$4,079	$ 2,966	$ 610	$217	$298

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization and accretion					
Property, plant and equipment	$1,284	$ 570	$ 502	$191	$224
Regulatory assets	63	—	52	11	50
Nuclear fuel [(a)]	755	755	—	—	—
ARO accretion [(b)]	214	214	—	—	—
Total depreciation, amortization and accretion	$2,316	$ 1,539	$ 554	$202	$274

(a) Included in revenues or fuel expense, or operating revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 866	$ 291	$ 283	$ 95	$130
Income taxes (net of refunds)	112	(18)	33	70	42
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 825	$ 345	$ 308	$ 43	$ 56
Earnings from equity method investments	(10)	(10)	—	—	—
Provision for uncollectible accounts	101	10	(15)	61	44
Provision for excess and obsolete inventory	9	9	—	—	—
Stock-based compensation costs	120	—	—	—	—
Other decommissioning-related activity [(a)]	(169)	(169)	—	—	—
Energy-related options [(b)]	104	104	—	—	—
Amortization of regulatory asset related to debt costs	12	—	9	3	—
Amortization of rate stabilization deferral	66	—	—	—	66
Amortization of debt fair value adjustment	(34)	(34)	—	—	—
Discrete impacts from EIMA [(c)]	(271)	—	(271)	—	—
Amortization of debt costs	18	10	1	2	2
Impairment of investments in direct financing leases [(e)]	14	—	—	—	—
Impairment charges [(f)]	149	149	—	—	—
Other	(58)	—	(4)	(1)	(15)
Total other non-cash operating activities	$ 876	$ 414	$ 28	$108	$153
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 12	$ —	$ (35)	$ 9	$ 38
Other regulatory assets and liabilities	(64)	—	(43)	(16)	(71)
Other current assets	(165)	(151)	(2)	13	(8)
Other noncurrent assets and liabilities	322	15	268[(g)]	(12)	(23)
Total changes in other assets and liabilities	$ 105	$ (136)	$ 188	$ (6)	$ (64)

	Exelon	Generation	ComEd	PECO	BGE
Non-cash investing and financing activities:					
Change in ARC	$(128)	$ (128)	$ —	$—	$ 4
Change in capital expenditures not paid	(38)	(107) [(h)]	(8)	13	(48)
Consolidated VIE dividend to non-controlling interest	63	63	—	—	—
Indemnification of like-kind exchange position [(i)]	—	—	176	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 3—Regulatory Matters for more information.
(d) Relates to integration costs to achieve distribution synergies related to the merger transaction. See Note 3—Regulatory Matters for more information.
(e) Relates to an other than temporary decline in the estimated residual value of one of Exelon's direct financing leases. See Note 8—Impairment of Long-Lived Assets for more information.
(f) Relates to the cancellation of uprate projects and write down of certain wind projects at Generation. See Note 8— Impairment of Long-Lived Assets for more information.

(g) Relates primarily to interest payable related to like-kind exchange tax position. See Note 14—Income Taxes for discussion of the like-kind exchange tax position.
(h) Includes $55 million of changes in capital expenditures not paid between December 31, 2013 and 2012 related to Antelope Valley.
(i) See Note 14—Income Taxes for discussion of the like-kind exchange tax position.

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 761	$ 286	$ 288	$113	$ 136
Income taxes (net of refunds)	(171)	175	(42)	(64)	(112)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 820	$ 341	$ 282	$ 50	$ 57
Loss in equity method investments	91	91	—	—	—
Provision for uncollectible accounts	164	22	42	60	44
Provision for excess and obsolete inventory	6	6	1	—	—
Stock-based compensation costs	94	—	—	—	—
Other decommissioning-related activity [a]	(145)	(145)	—	—	—
Energy-related options [b]	160	160	—	—	—
Amortization of regulatory asset related to debt costs	18	—	13	3	2
Amortization of rate stabilization deferral	57	—	—	—	67
Amortization of debt fair value adjustment	(34)	(34)	—	—	—
Merger-related commitments [d]	141	32	—	—	27
Severance costs	99	34	—	—	—
Discrete impacts from EIMA [c]	(96)	—	(96)	—	—
Amortization of debt costs	19	11	5	3	2
Other	(11)	19	5	9	(6)
Total other non-cash operating activities	$1,383	$ 537	$ 252	$125	$ 193
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 71	$ —	$ 28	$ 20	$ 26
Other regulatory assets and liabilities	(404)	—	(68)	18	(112)
Other current assets	213	(30)	(7)	(12)	(7)
Other noncurrent assets and liabilities	(248)	(98)	(95)	(10)	8
Total changes in other assets and liabilities	$ (368)	$ (128)	$(142)	$ 16	$ (85)

	Exelon	Generation	ComEd	PECO	BGE
Non-cash investing and financing activities:					
Change in ARC	$ 781	$ 781	$ 2	$—	$—
Change in capital expenditures not paid	160	103[e]	15	26	(4)
Merger with Constellation, common stock issued	7,365	5,264	—	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 3—Regulatory Matters for more information.

(d) Relates to the integration costs to achieve distribution synergies related to the merger transaction. See Note 4—Mergers and Acquisitions for more information on merger-related commitments.
(e) Includes $127 million of changes in capital expenditures not paid between December 31, 2012 and 2011 related to Antelope Valley.

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 649	$ 158	$ 296	$128	$ 122
Income taxes (net of refunds)	(457)	347	(676)	(65)	(54)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 542	$ 249	$ 213	$ 32	$ 51
Provision for uncollectible accounts	121	—	57	64	44
Stock-based compensation costs	67	—	—	—	—
Other decommissioning-related activity [(a)]	16	16	—	—	—
Energy-related options [(b)]	137	137	—	—	—
Amortization of regulatory asset related to debt costs	21	—	18	3	2
Amortization of rate stabilization deferral	—	—	—	—	57
Deferral of storm costs	—	—	—	—	(16)
Uncollectible accounts recovery, net	14	—	14	—	—
Discrete impacts from 2010 Rate Case Order [(c)]	(32)	—	(32)	—	—
Bargain purchase gain related to Wolf Hollow Acquisition	(36)	(36)	—	—	—
Discrete impacts from EIMA [(d)]	(82)	—	(82)	—	—
Other	2	55	(4)	1	(9)
Total other non-cash operating activities	$ 770	$ 421	$ 184	$100	$ 129
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (45)	$ —	$ (49)	$ 4	$ (52)
Other regulatory assets and liabilities	—	—	44	26	10
Other current assets	(101)	(23)	(14)	(12)	(88)
Other noncurrent assets and liabilities	122	(34)	64	(4)	(31)
Total changes in other assets and liabilities	$ (24)	$ (57)	$ 45	$ 14	$(161)

	Exelon	Generation	ComEd	PECO	BGE
Non-cash investing and financing activities:					
Change in ARC	$ 186	$ 186	$ —	$—	$—
Change in capital expenditures not paid	96	125[(e)]	7	(35)	(7)

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) In May 2011, as a result of the 2010 Rate Case order, ComEd recorded one-time benefits to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan. See Note 3—Regulatory Matters for more information.
(d) Includes the establishment of a regulatory asset, pursuant to EIMA, for the 2011 annual reconciliation in ComEd's distribution formula rate tariff and the deferral of costs associated with significant 2011 storms, partially offset by an accrual to fund a new Science and Technology Innovation Trust. See Note 3—Regulatory Matters for more information.
(e) Includes $120 million of changes in capital expenditures not paid between December 31, 2011 and 2010 related to Antelope Valley.

DOE Smart Grid Investment Grant (Exelon, PECO and BGE). For the year ended December 31, 2013, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $74 million, $27 million and $47 million, respectively, and reimbursements of $95 million, $37 million and $58 million, respectively, related to PECO's and BGE's DOE SGIG programs. For the year ended December 31, 2012, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $103 million, $56 million and $47 million, respectively, and reimbursements of $113 million, $66 million and $47 million, respectively, related to PECO's and BGE's DOE SGIG programs. See Note 3—Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants at December 31, 2013 and 2012.

December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Investments					
Equity method investments:					
Financing trusts [a]	$ 22	$ —	$ 6	$ 8	$ 8
Keystone Fuels, LLC	32	32	—	—	—
Conemaugh Fuels, LLC	21	21	—	—	—
CENG	1,925	1,925	—	—	—
Safe Harbor	285	285	—	—	—
Malacha	8	8	—	—	—
Other investments	31	31	—	—	—
Total equity method investments	2,324	2,302	6	8	8
Other investments:					
Net investment in direct financing leases	698	0	—	—	—
Employee benefit trusts and investments [b]	90	23	5	23	5
Total investments	$3,112	$ 2,325	$ 11	$ 31	$ 13

December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Investments					
Equity method investments:					
Financing trusts [a]	$ 22	$ —	$ 6	$ 8	$ 8
Keystone Fuels, LLC	38	38	—	—	—
Conemaugh Fuels, LLC	26	26	—	—	—
CENG	1,849	1,849	—	—	—
Safe Harbor	293	293	—	—	—
Malacha	8	8	—	—	—
Other investments	34	33	—	—	—
Total equity method investments	2,270	2,247	6	8	8
Other investments:					
Net investment in direct financing leases	685	—	—	—	—
Employee benefit trusts and investments [b]	100	22	8	22	5
Total investments	$3,055	$ 2,269	$ 14	$ 30	$ 13

(a) Includes investments in financing trusts, which were not consolidated within the financial statements of Exelon and are shown as investments in affiliates on the Consolidated Balance Sheets. See Note 1—Significant Accounting Policies for additional information.
(b) The Registrants' investments in these marketable securities are recorded at fair market value.

The following tables provide additional information about liabilities of the Registrants at December 31, 2013 and 2012.

December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Accrued expenses					
Compensation-related accruals [a]	$ 683	$ 337	$ 135	$ 47	$ 55
Taxes accrued	315	212	62	24	16
Interest accrued	234	72	95	32	29
Severance accrued	66	31	3	1	4
Other accrued expenses	335[b]	324[b]	12	2	7
Total accrued expenses	$1,633	$ 976	$ 307	$106	$111

December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Accrued expenses					
Compensation-related accruals [a]	$ 708	$ 371	$ 125	$ 45	$ 38
Taxes accrued	353	247	61	3	22
Interest accrued	232	60	96	32	37
Severance accrued	91	42	4	1	5
Other accrued expenses	412[b]	396[b]	9	1	—
Total accrued expenses	$1,796	$ 1,116	$ 295	$ 82	$102

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.
(b) Includes $228 million and $327 million for amounts accrued related to Antelope Valley as of December 31, 2013 and December 31, 2012, respectively.

24. Segment Information (Exelon, Generation, ComEd, PECO and BGE)

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker (s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants.

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation's six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other regions not considered individually significant referred to collectively as "Other Regions"; including the South, West and Canada. Generation's expanded number of reportable segments is the result of the acquisition of Constellation on March 12, 2012. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon evaluates the performance of ComEd, PECO and BGE based on net income.

The CODMs for ComEd, PECO, and BGE evaluate performance and allocate resources for their respective companies based on net income and return on equity for ComEd, PECO, and BGE each as single integrated businesses.

The foundation of Generation's six reportable segments is based on the geographic location of its assets, and is largely representative of the footprints of an ISO / RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
    - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
    - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
    - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The CODMs for Exelon and Generation evaluate the performance of Generation's power marketing activities and allocate resources based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's own generation and fuel costs associated with tolling agreements. Generation's other business activities, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, and investments in energy-related proprietary technology are not allocated to regions. Further, Generation's compensation under the reliability-must-run rate schedule,

results of operations from the Brandon Shores, Wagner, and C.P. Crane Maryland generating stations, and other miscellaneous revenues, mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger are also not allocated to a region.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the years ended December 31, 2013, 2012 and 2011 is as follows:

	Generation [a]	ComEd	PECO	BGE [b]	Other [c]	Intersegment Eliminations	Exelon
Operating revenues [d]:							
2013	$ 15,630	$ 4,464	$3,100	$3,065	$ 1,241	$ (2,612)	$24,888
2012	14,437	5,443	3,186	2,091	1,396	(3,064)	23,489
2011	10,447	6,056	3,720	—	830	(1,990)	19,063
Intersegment revenues [e]:							
2013	$ 1,367	$ 3	$ 1	$ 13	$ 1,237	$ (2,607)	$ 14
2012	1,660	2	3	9	1,381	(3,049)	6
2011	1,161	2	5	—	831	(1,990)	9
Depreciation and amortization							
2013	$ 856	$ 669	$ 228	$ 348	$ 52	$ —	$ 2,153
2012	768	610	217	238	48	—	1,881
2011	570	554	202	—	21	—	1,347
Operating expenses [d]:							
2013	$ 13,976	$ 3,510	$2,434	$2,616	$ 1,324	$ (2,618)	$21,242
2012	13,226	4,557	2,563	2,053	1,662	(3,043)	21,018
2011	7,571	5,074	3,065	—	863	(1,990)	14,583
Equity in earnings (losses) of unconsolidated affiliates							
2013	$ 10	$ —	$ —	$ —	$ —	$ —	$ 10
2012	(91)	—	—	—	—	—	(91)
2011	(1)	—	—	—	—	—	(1)
Interest expense, net:							
2013	$ 357	$ 579	$ 115	$ 122	$ 183	$ —	$ 1,356
2012	301	307	123	111	86	—	928
2011	170	345	134	—	77	—	726
Income (loss) before income taxes:							
2013	$ 1,675	$ 401	$ 557	$ 344	$ (191)	$ (13)	$ 2,773
2012	1,058	618	508	(54)	(325)	(7)	1,798
2011	2,827	666	535	—	(59)	(13)	3,956
Income taxes:							
2013	$ 615	$ 152	$ 162	$ 134	$ (20)	$ 1	$ 1,044
2012	500	239	127	(23)	(215)	(1)	627
2011	1,056	250	146	—	9	(4)	1,457
Net income (loss):							
2013	$ 1,060	$ 249	$ 395	$ 210	$ (171)	$ (14)	$ 1,729
2012	558	379	381	(31)	(110)	(6)	1,171
2011	1,771	416	389	—	(68)	(9)	2,499
Capital expenditures:							
2013	$ 2,752	$ 1,433	$ 537	$ 587	$ 86	$ —	$ 5,395
2012	3,554	1,246	422	500	67	—	5,789
2011	2,491	1,028	481	—	42	—	4,042
Total assets:							
2013	$ 41,232	$24,118	$9,617	$7,861	$ 8,317	$ (11,221)	$79,924
2012	40,681	22,905	9,353	7,506	10,432	(12,316)	78,561

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the year ended December 31, 2013 include revenue from sales to PECO of $405 and sales to BGE of $455 million in the Mid-Atlantic region, and sales to ComEd of $506 in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the year ended December 31, 2012 include revenue from sales to PECO of $543 and sales to BGE of $322 million in the Mid-Atlantic region, and sales to ComEd of $795 in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the year ended 2011 intersegment revenues for Generation include revenue from sales to PECO of $508 million in the Mid-Atlantic region, and sales to ComEd of $653 million in the Midwest region.
(b) Amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through December 31, 2013.
(c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(d) For the years ended December 31, 2013, 2012 and 2011, utility taxes of $79 million, $82 million and $27 million, respectively, are included in revenues and expenses for Generation. For the years ended December 31, 2013, 2012 and 2011, utility taxes of $241 million, $239 million and $243 million, respectively, are included in revenues and expenses for ComEd. For the years ended December 31, 2013, 2012 and 2011, utility taxes of $129 million, $141 million and $173 million, respectively, are included in revenues and expenses for PECO. For the year ended December 31, 2013 and for the period of March 12, 2012 through December 31, 2012, utility taxes of $82 million and $59 million are included in revenues and expenses for BGE, respectively.
(e) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.

Generation total revenues:

	2013			2012			2011		
	Revenues from external customers [a]	Intersegment revenues	Total Revenues	Revenues from external customers [a]	Intersegment revenues	Total Revenues	Revenues from external customers [a]	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 5,182	$ 22	$ 5,204	$ 5,082	$ (44)	$ 5,038	$ 4,052	$ —	$ 4,052
Midwest	4,280	(10)	4,270	4,824	24	4,848	5,445	—	5,445
New England	1,245	(8)	1,237	1,048	45	1,093	11	—	11
New York	735	(21)	714	582	(25)	557	—	—	—
ERCOT	1,222	(6)	1,216	1,365	2	1,367	575	—	575
Other Regions [b]	946	22	968	755	78	833	201	—	201
Total Revenues for Reportable Segments	$ 13,610	$ (1)	$13,609	$ 13,656	$ 80	$13,736	$ 10,284	$ —	$10,284
Other [c]	2,020	1	2,021	781	(80)	701	163	—	163
Total Generation Consolidated Operating Revenues	$ 15,630	$ —	$15,630	$ 14,437	$ —	$14,437	$ 10,447	$ —	$10,447

(a) Includes all electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of $767 million and $1,505 million for the years ended December 31, 2013 and 2012, respectively, and elimination of intersegment revenues.

Generation total revenues net of purchased power and fuel expense:

	2013			2012			2011		
	RNF from external customers [a]	Intersegment RNF	Total RNF	RNF from external customers [a]	Intersegment RNF	Total RNF	RNF from external customers [a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 3,273	$ (3)	$3,270	$ 3,477	$ (44)	$3,433	$ 3,350	$ —	$3,350
Midwest	2,585	1	2,586	2,974	24	2,998	3,547	—	3,547
New England	217	(32)	185	151	45	196	9	—	9
New York	14	(18)	(4)	101	(25)	76	—	—	—
ERCOT	604	(168)	436	403	2	405	84	—	84
Other Regions [b]	334	(133)	201	53	78	131	(14)	—	(14)
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 7,027	$ (353)	$6,674	$ 7,159	$ 80	$7,239	$ 6,976	$ —	$6,976
Other [c]	406	353	759	217	(80)	137	(118)	—	(118)
Total Generation Revenues net of purchased power and fuel expense	$ 7,433	$ —	$7,433	$ 7,376	$ —	$7,376	$ 6,858	$ —	$6,858

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of $488 million and $1,098 million, for the years ended December 31, 2013 and 2012, respectively, and the elimination of intersegment revenues.

25. Related Party Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The financial statements of Exelon include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2013	2012	2011
Operating revenues from affiliates:			
PECO [a]	$ 10	$ 6	$ 9
CENG [b]	56	42	—
BGE	4	—	—
Total operating revenues from affiliates	$ 70	$ 48	$ 9
Purchase power and fuel from affiliates:			
CENG [c]	$ 992	$ 793	$—
Keystone Fuels, LLC	144	119	68
Conemaugh Fuels, LLC	98	101	69
Safe Harbor Water Power Corp	22	23	—
Total purchase power and fuel from affiliates	$1,256	$1,036	$137
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
BGE Capital Trust II [f]	16	12	—
Total interest expense to affiliates, net	$ 41	$ 37	$ 25
Earnings (losses) in equity method investments:			
CENG [e]	$ 9	$ (99)	$—
Qualifying facilities and domestic power projects	1	8	(1)
Total earnings (losses) in equity method investments	$ 10	$ (91)	$ (1)

	December 31, 2013	December 31, 2012
Investments in affiliates:		
ComEd Financing III	$ 6	$ 6
PECO Energy Capital Corporation	4	4
PECO Trust IV	4	4
BGE Capital Trust II	8	8
Total investments in affiliates	$ 22	$ 22
Receivables from affiliates (current):		
CENG [b]	$ 3	$ 16
Payables to affiliates (current):		
CENG [c]	$ 85	$ 83
ComEd Financing III	4	4
PECO Trust III	1	1
BGE Capital Trust II	4	4
Keystone Fuels, LLC	12	11
Conemaugh Fuels, LLC	9	9
Other	1	—
Total payables to affiliates (current)	$116	$112
Long-term debt due to financing trusts:		
ComEd Financing III	$206	$206
PECO Trust III	81	81
PECO Trust IV	103	103
BGE Capital Trust II	258	258
Total long-term debt due to financing trusts	$648	$648

(a) The intersegment profit associated with the sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statement of Operations. See Note 3—Regulatory Matters for additional information.

(b) Exelon has a shared services agreement (SSA) with CENG, which expires in 2017. Pursuant to an agreement between Exelon and EDF, the pricing in the SSA for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services subject to an annual cap for most SSA services provided. In addition to the SSA, Generation has a power services agency agreement (PSAA) with the CENG plants, which expires on December 31, 2014. The PSAA is a five-year agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services. At the closing, as described under the Master Agreement, the PSAA will be amended and extended until the complete and permanent cessation of operation of the CENG generation plants. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(c) CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Generation has a PPA under which it is purchasing 85% of the nuclear plant output owned by CENG that is not sold to third parties under pre-existing firm and unit-contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit-contingent basis 50.01% of the nuclear plant output owned by CENG and a subsidiary of EDF will purchase on a unit-contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA). This agreement will continue to be effective and is not affected by the Master Agreement, except that if the put option under the Master Agreement is exercised, then the EDF PPA would transfer to Generation upon completion of the Put Option Agreement transaction. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(d) Exelon Foundation is a nonconsolidated not-for-profit Illinois corporation. The Exelon Foundation was established in 2007 to serve educational and environmental philanthropic purposes and does not serve a direct business or political purpose of Exelon.

(e) Generation's total gain (loss) in equity method investments includes equity investment income (loss) and amortization of basis difference. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.
(f) The BGE Capital Trust II portion of Exelon's interest expense to affiliates, net, for December 31, 2012 excludes $4 million of expense incurred in 2012 prior to the closing of Exelon's merger with Constellation on March 12, 2012.

Transactions involving Generation, ComEd, PECO and BGE are further described in the tables below.

Generation

The financial statements of Generation include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2013	2012	2011
Operating revenues from affiliates:			
ComEd [a]	$ 506	$ 795	$ 653
PECO [b]	405	543	508
BGE [c]	455	322	—
CENG [d]	56	42	—
BSC	1	—	—
Total operating revenues from affiliates	$1,423	$1,702	$1,161
Purchase power and fuel from affiliates:			
PECO	$ —	$ —	$ 1
ComEd	1	—	—
BGE	13	8	—
CENG [e]	992	793	—
Keystone Fuels, LLC	144	119	68
Conemaugh Fuels, LLC	98	101	69
Safe Harbor Water Power Corporation	22	23	—
Total purchase power and fuel from affiliates	$1,270	$1,044	$ 138
Operating and maintenance from affiliates:			
ComEd [f]	$ 2	$ 2	$ 2
PECO [f]	1	3	5
BSC [g]	571	625	314
Total operating and maintenance from affiliates	$ 574	$ 630	$ 321
Interest expense to affiliates, net:			
Exelon Corporate	$ 59	$ 75	$ —
Earnings (losses) in equity method investments			
CENG [h]	9	(99)	—
Qualifying facilities and domestic power projects	1	8	(1)
Total earnings (losses) in equity method investments	$ 10	$ (91)	$ (1)
Cash distribution paid to member	$ 625	$1,626	$ 172
Contribution from member	$ 26	$ 48	$ 30

	December 31, 2013	December 31, 2012
Mark-to-market derivative assets with affiliates (current):		
ComEd [i]	$ —	$ 226
Receivables from affiliates (current):		
CENG [d]	$ 3	$ —
ComEd [a][j]	38	54
PECO [b]	38	56
BGE [c]	27	31
Other	2	—
Total receivables from affiliates (current)	$ 108	$ 141
Receivable from affiliate (noncurrent)		
Exelon Corporate	$ —	$ 1
Payables to affiliates (current):		
CENG [e]	$ 85	$ 83
Exelon Corporate [k]	7	33
BSC [g]	66	77
Keystone Fuels, LLC	12	11
Conemaugh Fuels, LLC	9	9
Other	2	—
Total payables to affiliates (current)	$ 181	$ 213
Payables to affiliates (noncurrent):		
ComEd [l]	$2,293	$2,037
PECO [l]	447	360
Total payables to affiliates (noncurrent)	$2,740	$2,397

(a) Generation has an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. Generation also sells RECs to ComEd. In addition, Generation had revenue from ComEd associated with the settled portion of the financial swap contract established as part of the Illinois Settlement. See Note 3—Regulatory Matters for additional information.

(b) Generation provides electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, Generation has five-year and ten-year agreements with PECO to sell non-solar and solar AECs, respectively. See Note 3—Regulatory Matters for additional information.

(c) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.

(d) Exelon has a shared services agreement with CENG, which expires in 2017. Pursuant to an agreement between Exelon and EDF, the pricing in the SSA for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services subject to an annual cap for most SSA services provided. In addition to the SSA, Generation has a power services agency agreement with the CENG plants, which expires on December 31, 2014. The PSAA is a five-year agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services. At the closing, as described under the Master Agreement, the PSAA will be amended and extended until the complete and permanent cessation of operation of the CENG generation plants. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(e) CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Generation has a PPA under which it is purchasing 85% of the nuclear plant output owned by CENG that is not sold to third parties under pre-existing firm and unit-contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit-contingent basis 50.01% of the nuclear plant output owned by CENG and a subsidiary of EDF will purchase on a unit-contingent basis 49.99% of the nuclear plant output

owned by CENG. This agreement will continue to be effective and is not affected by the Master Agreement, except that if the put option under the Master Agreement is exercised, then the EDF PPA would transfer to Generation upon completion of the Put Option Agreement transaction. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(f) Generation requires electricity for its own use at its generating stations. Generation purchases electricity and distribution and transmission services from PECO and only distribution and transmission services from ComEd for the delivery of electricity to its generating stations.

(g) Generation receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

(h) Generation's total gain (loss) in equity method investments includes equity income (loss) and amortization of basis difference. For further information regarding the Investment in CENG see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(i) Represents the fair value of Generation's five-year financial swap contract with ComEd, which ended in 2013.

(j) Generation had a $53 million receivable from ComEd at December 31, 2012 associated with the completed portion of the financial swap contract entered into as part of the Illinois Settlement. See Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments for additional information.

(k) As of December 31, 2013 and 2012, the balance consists of interest owed to Exelon Corporation related to the senior unsecured notes. In addition, the balance at December 31, 2012, includes expense related to certain invoices Exelon Corporation processed on behalf of Generation.

(l) Generation has long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 15—Asset Retirement Obligations.

ComEd

The financial statements of ComEd include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2013	2012	2011
Operating revenues from affiliates			
Generation	$ 3	$ 2	$ 2
Purchased power from affiliate			
Generation [a]	$512	$789	$653
Operating and maintenance from affiliate			
BSC [b]	$157	$163	$158
Interest expense to affiliates, net:			
Exelon Corporate	$—	$—	$ 2
ComEd Financing III	13	13	13
Total interest expense to affiliates, net	$ 13	$ 13	$ 15
Capitalized costs			
BSC [b]	$ 69	$ 92	$ 85
Cash dividends paid to parent	$220	$105	$300
Contribution from parent	$—	$ 11	$ 11

	December 31, 2013	December 31, 2012
Prepaid voluntary employee beneficiary association trust [c]	$ 13	$ 10
Investment in affiliate		
ComEd Financing III	$ 6	$ 6
Receivable from affiliates (current):		
Voluntary employee beneficiary association trust	$ 3	$ —
BGE	—	3
Total receivable from affiliates (current)	$ 3	$ 3
Receivable from affiliates (noncurrent):		
Generation [d]	$2,293	$2,037
Exelon Corporate [g]	176	2
Total receivable from affiliates (noncurrent)	$2,469	$2,039
Payables to affiliates (current):		
Generation [a][e]	$ 38	$ 54
BSC [b]	30	35
ComEd Financing III	4	4
Exelon Corporate	9	2
Other	2	2
Total payables to affiliates (current)	$ 83	$ 97
Mark-to-market derivative liability with affiliate (current)		
Generation [f]	$ —	$ 226
Mark-to-market derivative liability with affiliate (noncurrent)		
Long-term debt to ComEd financing trust		
ComEd Financing III	$ 206	$ 206

(a) ComEd procures a portion of its electricity supply requirements from Generation under an ICC-approved RFP contract. ComEd also purchases RECs from Generation. In addition, purchased power expense includes the settled portion of the financial swap contract with Generation established as part of the Illinois Settlement Legislation. See Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments for additional information.
(b) ComEd receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(c) The voluntary employee benefit association trusts covering active employees are included in corporate operations and are funded by the operating segments. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for ComEd's contributions to the plans, being higher than actual claim expense incurred by the plans over time. The prepayment is included in other current assets.
(d) ComEd has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct for generating facilities previously owned by ComEd. To the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to ComEd for payment to ComEd's customers.
(e) ComEd had a $53 million payable to Generation at December 31, 2012, associated with the completed portion of the financial swap contract entered into as part of the Illinois Settlement Legislation. See Note 3—Regulatory Matters and Note 12—Derivative Financial Information for additional information.
(f) To fulfill a requirement of the Illinois Settlement Legislation, ComEd entered into a five-year financial swap with Generation, which ended in 2013.
(g) In 2013, represents indemnification from Exelon Corporate related to the like-kind exchange transaction.

PECO

The financial statements of PECO include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2013	2012	2011
Operating revenues from affiliates:			
Generation [a]	$ 1	$ 3	$ 5
Purchased power from affiliate			
Generation [b]	$392	$533	$495
Operating and maintenance from affiliates:			
BSC [c]	$ 98	$107	$ 92
Generation	3	4	4
Total operating and maintenance from affiliates	$101	$111	$ 96
Interest expense to affiliates, net:			
PECO Trust III	$ 6	$ 6	$ 6
PECO Trust IV	6	6	6
Total interest expense to affiliates, net	$ 12	$ 12	$ 12
Capitalized costs			
BSC [c]	$ 46	$ 54	$ 60
Cash dividends paid to parent	$332	$343	$348
Contribution from parent	$ 27	$ 9	$ 18

	December 31,	
	2013	2012
Prepaid voluntary employee beneficiary association trust [d]	$ 3	$ 2
Investments in affiliates:		
PECO Energy Capital Corporation	$ 4	$ 4
PECO Trust IV	4	4
Total investments in affiliates	$ 8	$ 8
Receivable from affiliate (noncurrent):		
BGE	$ 3	$ 2
Receivable from affiliate (noncurrent):		
Generation [e]	$447	$360
Payables to affiliates (current):		
Generation [b]	$ 38	$ 56
BSC [c]	17	18
Exelon Corporate	2	1
PECO Trust III	1	1
Total payables to affiliates (current)	$ 58	$ 76
Long-term debt to financing trusts:		
PECO Trust III	$ 81	$ 81
PECO Trust IV	103	103
Total long-term debt to financing trusts	$184	$184

(a) PECO provides energy to Generation for Generation's own use.

(b) PECO purchases electric supply from Generation under contracts executed through its competitive procurement process. In addition, PECO has five-year and ten-year agreements with Generation to purchase non-solar and solar AECs, respectively. See Note 3—Regulatory Matters for additional information on AECs.
(c) PECO receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) The voluntary employee beneficiary association trusts covering active employees are included in corporate operations and are funded by the operating segments. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for PECO's contributions to the plans, being higher than actual claim expense incurred by the plans over time.
(e) PECO has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct, whereby, to the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to PECO for payment to PECO's customers.

BGE

The financial statements of BGE include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2013	2012	2011
Operating revenues from affiliates:			
Generation [a]	$ 13	$ 10	$ 8
Purchased power from affiliate			
Generation [b]	$452	$396	$348
Operating and maintenance from affiliates:			
BSC [c]	$ 83	$106	$150
Interest expense to affiliates, net:			
BGE Capital Trust II	$ 16	$ 16	$ 16
Capitalized costs			
BSC [c]	$ 15	$ 21	$ 29
Cash dividends paid to parent	$—	$—	$ (85)
Contribution from parent	$—	$ 66	$—

	December 31,	
	2013	2012
Prepaid voluntary employee beneficiary association trust [d]	$ 1	$—
Investments in affiliates:		
BGE Capital Trust II	$ 8	$ 8
Payables to affiliates (current):		
Generation [b]	$ 27	$ 31
BSC [c]	20	12
Exelon [d]	1	17
ComEd	—	3
PECO	3	2
BGE Capital Trust II	4	4
Total payables to affiliates (current)	$ 55	$ 69
Long-term debt to BGE financing trust		
BGE Capital Trust II	$258	$258

(a) BGE provides energy to Generation for Generation's own use.

(b) BGE procures a portion of its electricity and gas supply requirements from Generation under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.
(c) BGE receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) BGE receives a variety of corporate support services from Exelon Corporate, including payroll and benefits services.

26. Quarterly Data (Unaudited) (Exelon, Generation, ComEd and PECO)

Exelon

The data shown below, which may not equal the total for the year due to the effects of rounding and dilution, includes all adjustments that Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net (Loss) Income on Common Stock	
	2013	2012	2013	2012	2013	2012
Quarter ended:						
March 31	$ 6,082	$ 4,690	$ 508	$ 359	$ (4)	$ 200
June 30	6,141	5,966	1,005	714	490	286
September 30	6,502	6,579	1,254	603	738	296
December 31	6,163	6,254	889	704	495	378

	Average Basic Shares Outstanding (in millions)		Net (Loss) Income per Basic Share	
	2013	2012	2013	2012
Quarter ended:				
March 31	855	705	$ (0.01)	$ 0.28
June 30	856	853	0.57	0.34
September 30	857	854	0.86	0.35
December 31	856	854	0.60	0.44

	Average Diluted Shares Outstanding (in millions)		Net (Loss) Income per Diluted Share	
	2013	2012	2013	2012
Quarter ended:				
March 31	855	707	$ (0.01)	$ 0.28
June 30	860	856	0.57	0.33
September 30	860	857	0.86	0.35
December 31	860	857	0.59	0.44

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2013				2012			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 30.59	$ 32.42	$ 37.80	$ 34.56	$ 37.50	$ 39.82	$ 39.37	$ 43.70
Low price	26.64	29.42	29.84	29.10	28.40	34.54	36.27	38.31
Close	27.39	29.64	30.88	34.48	29.74	35.58	37.62	39.21
Dividends	0.310	0.310	0.310	0.525	0.525	0.525	0.525	0.525

Generation

The data shown below includes all adjustments that Generation considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating (Loss) Income		Net (Loss) Income on Membership Interest	
	2013	2012	2013	2012	2013	2012
Quarter ended:						
March 31	$ 3,533	$ 2,743	$ (64)	$ 272	$ (18)	$ 168
June 30	4,070	3,765	603	384	330	166
September 30	4,255	4,031	721	174	490	91
December 31	3,772	3,898	405	290	269	137

ComEd

The data shown below includes all adjustments that ComEd considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net (Loss) Income	
	2013	2012	2013	2012	2013	2012
Quarter ended:						
March 31	$ 1,160	$ 1,388	$ 209	$ 226	$ (81)	$ 87
June 30	1,080	1,281	232	142	96	42
September 30	1,156	1,484	278	218	126	90
December 31	1,068	1,290	236	300	109	160

PECO

The data shown below includes all adjustments that PECO considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income on Common Stock	
	2013	2012	2013	2012	2013	2012
Quarter ended:						
March 31	$ 895	$ 875	$ 203	$ 177	$121	$ 96
June 30	672	715	138	151	72	79
September 30	728	806	155	178	92	122
December 31	805	790	168	117	102	79

BGE

The data shown below includes all adjustments that BGE considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income (Loss)		Net Income (Loss) attributable to Common Shareholders	
	2013	2012	2013	2012	2013	2012
Quarter ended:						
March 31	$ 880	$ 697	$ 163	$ (11)	$ 77	$ (33)
June 30	653	616	69	52	22	13
September 30	737	720	114	30	50	(4)
December 31	794	703	101	61	47	15

27. Subsequent Events (Exelon and PECO)

On February 5, 2014, a winter storm which brought a mix of snow, ice and freezing rain to the region interrupted electric service delivery to nearly 715,000 customers in PECO's service territory. Restoration efforts are continuing and will include significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies. PECO estimates that restoration efforts will have a material impact to Exelon's and PECO's results of operations and cash flows for the first quarter of 2014.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Exelon, Generation, ComEd, PECO and BGE—Disclosure Controls and Procedures

During the fourth quarter of 2013, each registrant's management, including its principal executive officer and principal financial officer, evaluated the effectiveness of that registrant's disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in that registrant's periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by each registrant to ensure that (a) information relating to that registrant, including its consolidated subsidiaries, that is required to be included in filings under the Securities Exchange Act of 1934, is accumulated and made known to that registrant's management, including its principal executive officer and principal financial officer, by other employees of that registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of December 31, 2013, the principal executive officer and principal financial officer of each registrant concluded that such registrant's disclosure controls and procedures were effective to accomplish their objectives.

Exelon, Generation, ComEd, PECO and BGE—Changes in Internal Control Over Financial Reporting

Each registrant continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. However, there have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's and BGE's internal control over financial reporting.

Exelon, Generation, ComEd, PECO and BGE—Internal Control Over Financial Reporting

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2013. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2013 and, therefore, concluded that each registrant's internal control over financial reporting was effective. Management's Report on Internal Control Over Financial Reporting is included in ITEM 8. Financial Statements and Supplementary Data.

ITEM 9B. OTHER INFORMATION

Exelon, Generation and ComEd

Anne R. Pramaggiore, President and Chief Operating Officer of ComEd, Michael J. Pacilio, President, Exelon Nuclear and Chief Nuclear Officer, Generation, and Sunil Garg, President, Exelon Power and Senior Vice President, Generation, each entered into a Change in Control Employment Agreement effective as of February 10, 2011. The terms of these change in control employment agreements are substantially the same as the change in control employment agreements entered into by other senior executives and previously disclosed, except that the agreements with Ms. Pramaggiore and Messrs. Pacilio and Garg do not include excise tax gross-up provisions, consistent with a policy adopted by the compensation committee in April 2009. The form of Change in Control Employment Agreement is attached hereto as Exhibit 10-44.

PECO and BGE

None.

PART III

Exelon Generation Company, LLC, Baltimore Gas and Electric Company, and PECO Energy Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section relating to Generation, BGE, and PECO are not presented.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants at February 13, 2014.

Directors, Director Nomination Process, and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at the annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)), the audit committee (Item 407(d)(4) and (d)(5)) and the beneficial reporting compliance (Sec. 16(a)) is incorporated herein by reference to information to be contained in Exelon's definitive 2014 proxy statement (2014 Exelon Proxy Statement) and the ComEd information statements to be filed with the SEC before April 30, 2014 pursuant to Regulation 14A or 14C, as applicable, under the Securities Exchange Act of 1934.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to Exelon's and ComEd's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. The Code of Business Conduct is filed as Exhibit 14 to this report and is available on Exelon's website at *www.exeloncorp.com* . The Code of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Bruce G. Wilson, Senior Vice President, Deputy General Counsel, and Corporate Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

If any substantive amendments to the Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Code of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or Corporate Controller, Exelon will disclose the nature of such amendment or waiver on Exelon's website, *www.exeloncorp.com* , or in a report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under *Executive Compensation Data* and *Report of the Compensation Committee* in the 2014 Exelon Proxy Statement or the ComEd 2014 information statements and incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The additional information required by this item will be set forth under *Ownership of Exelon Stock* in the 2014 Exelon Proxy Statement or the ComEd 2014 information statements and incorporated herein by reference.

Securities Authorized for Issuance under Exelon Equity Compensation Plans

[A] Plan Category	[B] Number of securities to be issued upon exercise of outstanding Options, warrants and rights (Note 1)	[C] Weighted-average price of outstanding Options, warrants and rights (note 2)	[D] Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column [B] (Note 3)
Equity compensation plans approved by security holders	29,447,000	$ 37.12	36,556,000

(1) Balance includes stock options, unvested performance shares, and unvested restricted shares that were granted under the Exelon LTIP or predecessor company plans and shares awarded under those plans and deferred into the stock deferral plan, as well as deferred stock units granted to directors as part of their compensation. For performance shares and performance share transition awards granted in 2013, the total includes the maximum number of shares that could be granted, if performance, total shareholder return modifier, and individual performance multipliers were all at maximum, a total of 4,599,000 shares. At target, the number of securities to be issued for such awards is 2,586,000. The deferred stock units granted to directors includes 286,600 shares to be issued upon the conversion of deferred stock units awarded to members of the Exelon board of directors, and 94,200 shares to be issued upon the conversion of stock units held by members of the Exelon board of directors that were earned under a legacy Constellation Energy Group plan. Conversion of stock units to shares will occur after the director terminates service to the Exelon board or the board of any of its subsidiary companies. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information about the material features of the plans.

(2) Includes outstanding restricted stock units and performance shares that can be exercised for no consideration. Without such instruments, the weighted-average price of outstanding options, warrants and rights shown in column [C] would be $46.07.

(3) Includes 24,441,000 shares available for issuance from the company's employee stock purchase plan.

No ComEd securities are authorized for issuance under equity compensation plans.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The additional information required by this item will be set forth under *Related Persons Transactions* and *Director Independence* in the 2014 Exelon Proxy Statement or the ComEd 2014 information statements and incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under *The Ratification of PricewaterhouseCoopers LLP as Exelon's Independent Accountant for 2014* in the Proxy Statement and incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

Exelon

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2014 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Balance Sheets at December 31, 2013 and 2012

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2013, 2012 and 2011

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule I—Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2013 and 2012 and for the Years Ended December 31, 2013, 2012 and 2011

   Schedule II—Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Operations and Other Comprehensive Income

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating expenses			
Operating and maintenance	$ 9	$ 201	$ 56
Operating and maintenance from affiliates	34	72	44
Other	12	6	4
Total operating expenses	55	279	104
Operating loss	(55)	(279)	(104)
Other income and (deductions)			
Interest expense, net	(116)	(153)	(75)
Equity in earnings of investments	1,903	1,278	2,662
Interest income from affiliates, net	36	75	1
Other, net	(78)	7	8
Total other income	1,745	1,207	2,596
Income before income taxes	1,690	928	2,492
Income taxes	(29)	(232)	(3)
Net income	$1,719	$1,160	$2,495
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service cost (benefit) reclassified to periodic costs, net of taxes of $0, $1 and $(4), respectively	—	1	(5)
Actuarial loss reclassified to periodic cost, net of taxes of $133, $110 and $93, respectively	208	168	136
Transition obligation reclassified to periodic cost, net of taxes of $0, $2 and $2, respectively	—	2	4
Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $430, $(237) and $(171), respectively	669	(371)	(250)
Unrealized gain (loss) on cash flow hedges, net of taxes of $(166), $(68) and $39, respectively	(248)	(120)	88
Unrealized gain on marketable securities, net of taxes of $0, $(1) and $0, respectively	2	2	—
Unrealized gain (loss) on equity investments, net of taxes of $71, $1 and $0, respectively	106	1	—
Unrealized gain (loss) on foreign currency translation, net of taxes of $0, $0 and $0, respectively	(10)	—	—
Other comprehensive income (loss)	727	(317)	(27)
Comprehensive income	$2,446	$ 843	$2,468

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2013	2012	2011
Net cash flows provided by operating activities	$ 1,053	$ 2,131	$ 766
Cash flows from investing activities			
Changes in Exelon intercompany money pool	(60)	—	—
Note receivable from affiliates	484	—	—
Capital expenditures	—	(30)	(28)
Return on capital from equity method investee	—	—	(1)
Cash and restricted cash acquired from Constellation	—	679	—
Change in restricted cash	38	(38)	—
Investment in affiliates	(38)	(67)	(65)
Other investing activities	15	—	—
Net cash flows provided by (used in) investing activities	439	544	(94)
Cash flows from financing activities			
Cash receipts from intercompany money pool	—	(703)	20
Changes in short-term debt	10	(161)	161
Retirement of long-term debt	(450)	(77)	—
Dividends paid on common stock	(1,249)	(1,716)	(1,393)
Proceeds from employee stock plans	47	73	38
Other financing activities	(6)	30	(1)
Net cash flows used in financing activities	(1,648)	(2,554)	(1,175)
Increase (decrease) in cash and cash equivalents	(156)	121	(503)
Cash and cash equivalents at beginning of period	159	38	541
Cash and cash equivalents at end of period	$ 3	$ 159	$ 38

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 3	$ 159
Restricted cash and investments	—	38
Accounts receivable, net		
Other accounts receivable	72	25
Accounts receivable from affiliates	22	87
Deferred income taxes	27	—
Notes receivable from affiliates	179	119
Regulatory assets	233	381
Other	1	2
Total current assets	537	811
Property, plant and equipment, net	57	59
Deferred debits and other assets		
Regulatory assets	3,005	3,932
Investments in affiliates	26,390	25,576
Deferred income taxes	1,890	2,437
Notes receivable from affiliates	1,522	2,007
Other	17	42
Total deferred debits and other assets	32,824	33,994
Total assets	$33,418	$34,864

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Balance Sheets

(In millions)	December 31, 2013	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 10	$ —
Accounts payable	43	101
Unamortized energy contract liabilities	12	77
Accrued expenses	106	110
Deferred income taxes	26	55
Regulatory liabilities	2	—
Other	54	60
Total current liabilities	253	403
Long-term debt	3,033	3,576
Long-term debt to affiliate	176	—
Deferred credits and other liabilities		
Regulatory liabilities	43	—
Pension obligations	6,444	8,252
Non-pension postretirement benefit obligations	393	1,071
Unamortized energy contract liabilities	—	12
Deferred income taxes	70	—
Other	271	116
Total deferred credits and other liabilities	7,221	9,451
Total liabilities	10,683	13,430
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 857 and 855 shares outstanding at December 31, 2013 and 2012, respectively)	16,741	16,632
Treasury stock, at cost (35 shares held at December 31, 2013 and 2012, respectively)	(2,327)	(2,327)
Retained earnings	10,358	9,893
Accumulated other comprehensive loss, net	(2,040)	(2,767)
Total shareholders' equity	22,732	21,431
BGE preference stock not subject to mandatory redemption	3	3
Total liabilities and shareholders' equity	$33,418	$34,864

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

1. Basis of Presentation

Exelon Corporate is a holding company that conducts substantially all of its business operations through its subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of Exelon Corporation.

Exelon Corporate owns 100% of all of its significant subsidiaries, either directly or indirectly, except for Commonwealth Edison Company (ComEd), of which Exelon Corporate owns more than 99%, and BGE, of which Exelon owns 100% of the common stock but none of BGE's preferred stock. Exelon owned none of PECO's preference securities, which PECO redeemed in 2013.

2. Merger with Constellation

On March 12, 2012, Exelon Corporation completed the merger contemplated by the Merger Agreement, among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including the customer supply and generation businesses that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

For BGE's debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE's assets acquired and liabilities assumed is recorded as a regulatory asset at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 4—Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information on the merger with Constellation. Also see Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information on BGE's push-down accounting treatment.

3. Debt and Credit Agreements

Short-Term Borrowings

Exelon Corporate meets its short-term liquidity requirements primarily through the issuance of commercial paper. Exelon Corporate had no commercial paper borrowings at both December 31, 2013 and December 31, 2012.

Credit Agreements

On August 10, 2013, Exelon Corporate amended and extended its unsecured syndicated revolving credit facility with aggregate bank commitments of $500 million through August 10, 2018. As of December 31, 2013, Exelon Corporate had available capacity under those commitments of $498 million. See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon Corporate's credit agreement.

Long-Term Debt

The following tables present the outstanding long-term debt for Exelon Corporate as of December 31, 2013 and December 31, 2012:

	Rates	Maturity Date	December 31, 2013	December 31, 2012
Long-term debt				
Senior unsecured notes	4.55% – 7.60%	2015-2035	$2,658	$3,108
Unamortized debt discount and premium, net			2	2
Fair value adjustment			383	455
Fair value hedge carrying value adjustment, net			—	11
Long-term debt due within one year			(10)	—
Long-term debt			$3,033	$3,576

Exelon Corporate will not have any long-term debt maturities in 2014. The debt maturities for the periods 2015, 2016, 2017, 2018 and thereafter are as follows:

2015	$1,350
2016	—
2017	—
2018	—
Remaining years	1,308
Total long-term debt	$2,658

4. Commitments and Contingencies

See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's commitments and contingencies related to environmental matters and fund transfer restrictions.

5. Related Party Transactions

The financial statements of Exelon Corporate include related party transactions as presented in the tables below:

(In millions)	For the Years Ended December 31, 2013	2012	2011
Operating and maintenance from affiliates:			
Business Services Company, LLC [a]	$ 34	$ 72	$ 44
Interest income from affiliates, net	$ 36	$ 75	$ 1
Equity in earnings of investments:			
Exelon Energy Delivery Company, LLC [b]	$ 834	$ 713	$ 801
Exelon Ventures Company, LLC [c]	1,076	564	1,769
UII, LLC	(2)	25	18
Exelon Transmission Company, LLC	(5)	(3)	(3)
Exelon Consolidations [d]	—	(21)	77
Total equity in earnings of investments	$1,903	$1,278	$2,662
Cash contributions received from affiliates	$1,175	$2,074	$ 820

(in millions)	December 31, 2013	2012
Accounts receivable from affiliates (current):		
Business Services Company, LLC [a]	$ 3	$ 33
Generation	7	33
ComEd	9	2
PECO	2	2
BGE	1	17
Total accounts receivable from affiliates (current)	$ 22	$ 87
Notes receivable from affiliates (current):		
Business Services Company, LLC [a]	$ 179	$ 119
Investments in affiliates:		
Business Services Company, LLC [a]	$ 201	$ 181
Exelon Energy Delivery Company, LLC [b]	12,956	12,466
Exelon Ventures Company, LLC [c]	12,750	12,444
UII, LLC	470	472
Exelon Transmission Company, LLC	3	4
VEBA	10	9
Total investments in affiliates	$26,390	$25,576
Notes receivable from affiliates (non-current):		
Generation	$ 1,522	$ 2,007
Long-term debt to affiliates (non-current):		
ComEd	$ 176	$ —

(a) Exelon Corporate receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead.
(b) Exelon Energy Delivery Company, LLC consists of ComEd, PECO and BGE.
(c) Exelon Ventures Company, LLC primarily consists of Generation.
(d) Equity in earnings of investments for Exelon Consolidations represents the intercompany income component that offsets the corresponding intercompany expense at Generation for upgrades in transmission assets owned by ComEd, which are reflected as assets at Exelon Corporate.

Exelon Corporation and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2013					
Allowance for uncollectible accounts [(a)]	$ 293	$ 121	$ 37[(c)]	$ 179[(d)]	$ 272
Deferred tax valuation allowance	36	1		24	13
Reserve for obsolete materials	53	17	—	12	58
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts [(a)]	$ 199	$ 144	$ 136[(b)(c)]	$ 186[(d)]	$ 293
Deferred tax valuation allowance	10	18	18[(b)]	10	36
Reserve for obsolete materials	60	2	2[(b)]	11	53
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts [(a)]	$ 211	$ 121	$ 32[(c)]	$ 165[(d)]	$ 199
Deferred tax valuation allowance	9	1	—	—	10
Reserve for obsolete materials	56	6	—	2	60

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $9 million, $8 million, and $9 million for the years ended December 31, 2013, 2012, and 2011, respectively.
(b) Primarily represents the addition of Constellation's and BGE's results as of March 12, 2012, the date of the merger.
(c) Includes charges for late payments and non-service receivables.
(d) Write-off of individual accounts receivable.

Exelon Generation Company, LLC and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Generation

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2014 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Balance Sheets at December 31, 2013 and 2012

   Consolidated Statements of Changes in Member's Equity for the Years Ended December 31, 2013, 2012 and 2011

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Exelon Generation Company, LLC and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2013					
Allowance for uncollectible accounts	$ 84	$ (16)	$ —	$ 11	$ 57
Deferred tax valuation allowance	35	1	—	25	11
Reserve for obsolete materials	50	16	—	11	55
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts	$ 29	$ —	$ 66[(a)]	$ 11	$ 84
Deferred tax valuation allowance	—	17	18[(a)]	—	35
Reserve for obsolete materials	59	—	2[(a)]	11	50
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 32	$ —	$ —	$ 3	$ 29
Reserve for obsolete materials	55	4	—	—	59

(a) Represents the addition of Constellation's results as of March 12, 2012, the date of the merger.

Commonwealth Edison Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

ComEd

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2014 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Balance Sheets at December 31, 2013 and 2012

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2013, 2012 and 2011

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Commonwealth Edison Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2013					
Allowance for uncollectible accounts	$ 70	$ 33	$ 29[(a)]	$ 70[(b)]	$ 62
Reserve for obsolete materials	2	1	—	1	2
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts	$ 78	$ 42	$ 26[(a)]	$ 76[(b)]	$ 70
Reserve for obsolete materials	1	1	—	—	2
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 80	$ 57	$ 15[(a)]	$ 74[(b)]	$ 78
Reserve for obsolete materials	1	2	—	2	1

(a) Primarily charges for late payments and non-service receivables.
(b) Write-off of individual accounts receivable.

PECO Energy Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

PECO

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2014 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Balance Sheets at December 31, 2013 and 2012

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2013, 2012 and 2011

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

PECO Energy Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2013					
Allowance for uncollectible accounts [a]	$ 99	$ 61	$ 7[b]	$ 60[c]	$ 107
Reserve for obsolete materials	1	—	—	—	1
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts [a]	$ 92	$ 60	$ 8[b]	$ 61[c]	$ 99
Reserve for obsolete materials	1	—	—	—	1
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts [a]	$ 99	$ 64	$ 17[b]	$ 88[c]	$ 92
Reserve for obsolete materials	1	—	—	—	1

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $9 million, $8 million, and $9 million for the years ended December 31, 2013, 2012, and 2011, respectively.
(b) Primarily charges for late payments.
(c) Write-off of individual accounts receivable.

Baltimore Gas and Electric Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

BGE

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2014 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011

   Consolidated Balance Sheets at December 31, 2013 and 2012

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2013, 2012 and 2011

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Baltimore Gas and Electric Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2013					
Allowance for uncollectible accounts	$ 40	$ 43	$ 1[(b)]	$ 38[(a)]	$ 46
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	1	—	—	—	1
For The Year Ended December 31, 2012					
Allowance for uncollectible accounts	$ 38	$ 45	$ —	$ 43[(a)]	$ 40
Deferred tax valuation allowance	—	1	—	—	1
Reserve for obsolete materials	—	1	—	—	1
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 36	$ 39	$ —	$ 37[(a)]	$ 38

(a) Write-off of individual accounts receivable.
(b) Primarily charges for late payments.

Exhibits required by Item 601 of Regulation S-K:

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
2-1	Agreement and Plan of Merger dated as of April 28, 2011 by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc. (File No. 001-16169, Form 8-K dated April 28, 2011, Exhibit No. 2-1)
2-2	Distribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Constellation Energy Group, Inc. and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-3).
2-3	Contribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Energy Delivery Company, LLC and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-4).
2-4	Contribution Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Ventures Company, LLC and Exelon Generation Company, LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-5).
2-5	Purchase Agreement dated as of August 8, 2012 by and between Constellation Power Source Generation, Inc. and Raven Power Holdings, LLC. (File No. 333-85496, Form 10-Q for the quarter ended September 30, 2012, Exhibit 2-1).
2-6	Master Agreement, dated as of October 26, 2010, by and between Electricite de France, S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 1, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
2-7	Put Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., Constellation Nuclear, LLC, and Constellation Energy Nuclear Group, LLC. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 8, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
2-8	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., Baltimore Gas and Electric Company and RF HoldCo LLC. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
2-9	Purchase Agreement, dated as of February 4, 2010, by and between RF HoldCo LLC and GSS Holdings (Baltimore Gas and Electric Company Utility), Inc. (Designated as Exhibit No. 99.3 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.
3-1	Amended and Restated Articles of Incorporation of Exelon Corporation, as amended May 8, 2007 (File No. 001-16169, Form 10-Q for the quarter ended September 30, 2008, Exhibit 3-1-2).
3-2	Exelon Corporation Amended and Restated Bylaws, effective as of March 12, 2012 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit 3-1).
3-3	Certificate of Formation of Exelon Generation Company, LLC (Registration Statement No. 333-85496, Form S-4, Exhibit 3-1).

Exhibit No.	Description
3-4	First Amended and Restated Operating Agreement of Exelon Generation Company, LLC executed as of January 1, 2001 (File No. 333-85496, 2003 Form 10-K, Exhibit 3-8).
3-5	Restated Articles of Incorporation of Commonwealth Edison Company Effective February 20, 1985, including Statements of Resolution Establishing Series, relating to the establishment of three new series of Commonwealth Edison Company preference stock known as the "$9.00 Cumulative Preference Stock," the "$6.875 Cumulative Preference Stock" and the "$2.425 Cumulative Preference Stock" (File No. 1-1839, 1994 Form 10-K, Exhibit 3-2).
3-6	Commonwealth Edison Company Amended and Restated By-Laws, Effective January 23, 2006 As Further Amended January 28, 2008 and July 27, 2009. (File No. 001-1839, Form 8-K dated July 27, 2009, Exhibit 3.1).
3-7	Amended and Restated Articles of Incorporation of PECO Energy Company (File No. 1-01401, 2000 Form 10-K, Exhibit 3-3).
3-8	PECO Energy Company Amended Bylaws (File 000-16844, Form 8-K dated May 6, 2009, Exhibit 99.1).
3-9	Articles of Amendment to the Charter of Baltimore Gas and Electric Company as of February 2, 2010. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
3-10	Articles of Restatement to the Charter of Baltimore Gas and Electric Company, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
3-11	Bylaws of Baltimore Gas and Electric Company, as amended and restated as of May 10, 2012.
3-12	Operating Agreement, dated as of February 4, 2010, by and among RF HoldCo LLC, Constellation Energy Group, Inc. and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File Nos. 1-12869 and 1-1910.)
4-1	First and Refunding Mortgage dated May 1, 1923 between The Counties Gas and Electric Company (predecessor to PECO Energy Company) and Fidelity Trust Company, Trustee (U.S. Bank National Association, as current successor trustee), (Registration No. 2-2281, Exhibit B-1).
4-1-1	Supplemental Indentures to PECO Energy Company's First and Refunding Mortgage:

Dated as of	File Reference	Exhibit No.
May 1, 1927	2-2881	B-1(c)
March 1, 1937	2-2881	B-1(g)
December 1, 1941	2-4863	B-1(h)
November 1, 1944	2-5472	B-1(i)
December 1, 1946	2-6821	7-1(j)
September 1, 1957	2-13562	2(b)-17
May 1, 1958	2-14020	2(b)-18
March 1, 1968	2-34051	2(b)-24
March 1, 1981	2-72802	4-46
March 1, 1981	2-72802	4-47

Dated as of	File Reference	Exhibit No.
December 1, 1984	1-01401, 1984 Form 10-K	4-2(b)
March 1, 1993	1-01401, 1992 Form 10-K	4(e)-86
May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-88
May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-89
April 15, 2004	0-6844, September 30, 2004 Form 10-Q	4-1-1
September 15, 2006	000-16844, Form 8-K dated September 25, 2006	4.1
March 1, 2007	000-16844, Form 8-K dated March 19, 2007	4.1
March 15, 2009	000-16844, Form 8-K dated March 26, 2009	4.1
September 1, 2012	000-16844, Form 8-K dated September 17, 2012	4.1
September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1
September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1

4-2 Exelon Corporation Direct Stock Purchase Plan (Registration Statement No. 333-183751, Form S-3, Prospectus).

4-3 Mortgage of Commonwealth Edison Company to Illinois Merchants Trust Company, Trustee (BNY Mellon Trust Company of Illinois, as current successor Trustee), dated July 1, 1923, as supplemented and amended by Supplemental Indenture thereto dated August 1, 1944. (Registration No. 2-60201, Form S-7, Exhibit 2-1).

4-3-1 Supplemental Indentures to Commonwealth Edison Company Mortgage.

Dated as of	File Reference	Exhibit No.
August 1, 1946	2-60201, Form S-7	2-1
April 1, 1953	2-60201, Form S-7	2-1
March 31, 1967	2-60201, Form S-7	2-1
April 1,1967	2-60201, Form S-7	2-1
February 28, 1969	2-60201, Form S-7	2-1
May 29, 1970	2-60201, Form S-7	2-1
June 1, 1971	2-60201, Form S-7	2-1
April 1, 1972	2-60201, Form S-7	2-1
May 31, 1972	2-60201, Form S-7	2-1
June 15, 1973	2-60201, Form S-7	2-1
May 31, 1974	2-60201, Form S-7	2-1
June 13, 1975	2-60201, Form S-7	2-1

Dated as of	File Reference	Exhibit No.
May 28, 1976	2-60201, Form S-7	2-1
June 3, 1977	2-60201, Form S-7	2-1
May 17, 1978	2-99665, Form S-3	4-3
August 31, 1978	2-99665, Form S-3	4-3
June 18, 1979	2-99665, Form S-3	4-3
June 20, 1980	2-99665, Form S-3	4-3
April 16, 1981	2-99665, Form S-3	4-3
April 30, 1982	2-99665, Form S-3	4-3
April 15, 1983	2-99665, Form S-3	4-3
April 13, 1984	2-99665, Form S-3	4-3
April 15, 1985	2-99665, Form S-3	4-3
April 15, 1986	33-6879, Form S-3	4-9
January 15, 1994	1-1839, 1993 Form 10-K	4-15
January 13, 2003	1-1839, Form 8-K dated January 22, 2003	4-4
March 14, 2003	1-1839, Form 8-K dated April 7, 2003	4-4
February 22, 2006	1-1839, Form 8-K dated March 6, 2006	4.1
August 1, 2006	1-1839, Form 8-K dated August 28, 2006	4.1
September 15, 2006	1-1839, Form 8-K dated October 2, 2006	4.1
March 1, 2007	1-1839, Form 8-K dated March 23, 2007	4.1
August 30, 2007	1-1839, Form 8-K dated September 10, 2007	4.1
December 20, 2007	1-1839, Form 8-K dated January 16, 2008	4.1
March 10, 2008	1-1839, Form 8-K dated March 27, 2008	4.1
July 12, 2010	001-01839, Form 8-K dated August 2, 2010	4.1
January 4, 2011	001-01839, Form 8-K dated January 18, 2011	4.1
August 22, 2011	001-01839, Form 8-K dated September 7, 2011	4.1
September 17, 2012	001-01839, Form 8-K dated October 1, 2012	4.1
August 1, 2013	001-01839, Form 8-K dated August 19, 2013	4.1
January 2, 2014	001-01839, Form 8-K dated January 10, 2014	4.1

Exhibit No.	Description
4-3-2	Instrument of Resignation, Appointment and Acceptance dated as of February 20, 2002, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923, and Indentures Supplemental thereto, regarding corporate trustee (File No. 1-1839, 2001 Form 10-K, Exhibit 4-4-2).
4-3-3	Instrument dated as of January 31, 1996, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923 and Indentures Supplemental thereto, regarding individual trustee (File No. 1-1839, 1995 Form 10-K, Exhibit 4-29).
4-4	Indenture dated as of September 1, 1987 between Commonwealth Edison Company and Citibank, N.A. (U.S. Bank National Association, as current successor trustee), Trustee relating to Notes (Registration No. 33-20619, Form S-3, Exhibit 4-13).
4-5	Indenture dated December 19, 2003 between Exelon Generation Company, LLC and U.S. Bank National Association (File No. 333-85496, 2003 Form 10-K, Exhibit 4-6).
4-6	Indenture to Subordinated Debt Securities dated as of June 24, 2003 between PECO Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.1).
4-7	Form of 4.25% Senior Note due 2022 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.1).
4-8	Form of 5.60% Senior Note due 2042 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.2).
4-9	Form of 2.80% Senior Note due 2022 issued by Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated August 17, 2012, Exhibit 4.1).
4-10	Form of 3.35% Senior Note due 2023 Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated June 17, 2013, Exhibit 4.1)
4-11	Form of 6.000% Senior Secured Notes due 2033 issued by Exelon Generation Company, LLC (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.2)
4-12	Preferred Securities Guarantee Agreement between PECO Energy Company, as Guarantor, and U.S. Bank National Association, as Trustee, dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.2).
4-13	PECO Energy Capital Trust IV Amended and Restated Declaration of Trust among PECO Energy Company, as Sponsor, U.S. Bank Trust National Association, as Delaware Trustee and Property Trustee, and J. Barry Mitchell, George R. Shicora and Charles S. Walls as Administrative Trustees dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.3).
4-14	Indenture dated May 1, 2001 between Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 1-16169, June 30, 2005 Form 10-Q, Exhibit 4-10).
4-15	Form of $800,000,000 4.90% senior notes due 2015 dated June 9, 2005 issued by Exelon Corporation (File No. 1-16169, Form 8-K dated June 9, 2005, Exhibit 99.2).
4-16	Form of $500,000,000 5.625% senior notes due 2035 dated June 9, 2005 issued by Exelon Corporation (File No. 1-16169, Form 8-K dated June 9, 2005, Exhibit 99.3).
4-17	Indenture dated as of September 28, 2007 from Exelon Generation Company, LLC to U.S. Bank National Association, as trustee (File 333-85496, Form 8-K dated September 28, 2007, Exhibit 4.1).
4-18	Form of 5.20% Exelon Generation Company, LLC Senior Note due 2019 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.1).

Exhibit No.	Description
4-19	Form of 6.25% Exelon Generation Company, LLC Senior Note due 2039 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.2).
4-20	Form of 4.00% Exelon Generation Company, LLC Senior Note due 2020 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.1).
4-21	Form of 5.75% Exelon Generation Company, LLC Senior Note due 2041 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.2).
4-22	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, filed by Constellation Energy Group, Inc., File No. 333-75217.)
4-23	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, filed by Constellation Energy Group, Inc., File No. 333-102723.)
4-24	Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991.)
4-25	First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (Designated as Exhibit 4(a) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869.)
4-26	Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
4-27	Indenture, dated as of September 30, 2013, among Continental Wind, LLC, the guarantors party thereto and Wilmington Trust, National Association, as trustee (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.1)
4-28	Indenture dated July 1, 1985, between Baltimore Gas and Electric Company and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
4-29	Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee (including form of Baltimore Gas and Electric Company Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibit Nos. 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01.)
4-30	Indenture dated as of July 24, 2006 between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(b) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991.)

Exhibit No.	Description
4-31	Supplemental Indenture No. 1, dated as of October 1, 2009, to the Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
4-32	Baltimore Gas and Electric Company Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit No. 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01.)
4-33	Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (Designated as Exhibit 4.1 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
4-34	Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (Designated as Exhibit No. 4(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Baltimore Gas and Electric Company, File No. 1 1910.)
4-35	Replacement Capital Covenant dated June 27, 2008. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869.)
4-36	Amendment to Replacement Capital Covenant, dated as of March 12, 2012, amending the Replacement Capital Covenant, dated as of June 27, 2008 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 99.4)
4-37	Officers' Certificate, dated December 14, 2010, establishing the 5.15% Notes due December 1, 2020 of Constellation Energy Group, Inc., with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated December 14, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
4-38	Officers' Certificate, November 16, 2011, establishing the 3.50% Notes due November 15, 2021 of Baltimore Gas and Electric Company, with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated November 16, 2011, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
10-1	Exelon Corporation Non-Employee Directors' Deferred Stock Unit Plan (As Amended and Restated Effective January 1, 2011). * (File No. 001-16169, 2010 Form 10-K, Exhibit 10.1)
10-2	Exelon Corporation Retirement Program (As Amended and Restated Effective January 1, 2013).
10-3	Exelon Corporation Unfunded Deferred Compensation Plan for Directors (as amended and restated Effective January 1, 2011). * (File No. 001-16169, 2010 Form 10-K, Exhibit 10.3)
10-4	Exelon Corporation Long-Term Incentive Plan As Amended and Restated Effective January 28, 2002* (File No. 1-16169, Exelon Proxy Statement dated March 13, 2002, Appendix B).
10-5-1	Form of Restricted Stock Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-1).

Exhibit No.	Description
10-5-2	Forms of Transferable Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-2).
10-5-3	Forms of Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-3).
10-6	Exelon Corporation Employee Savings Plan (As Amended and Restated Effective January 1, 2013).
10-7	Exelon Corporation Cash Balance Pension Plan (As Amended and Restated Effective January 1, 2013).
10-8	Unicom Corporation Deferred Compensation Unit Plan, as amended *(File Nos. 1-11375 and 1-1839, 1995 Form 10-K, Exhibit 10-12).
10-9	Amendment Number One to the Unicom Corporation Deferred Compensation Unit Plan, as amended January 1, 2008 * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.16).
10-10	Unicom Corporation Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-12).
10-11	Commonwealth Edison Company Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-13).
10-12	Exelon Corporation Supplemental Management Retirement Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.19).
10-13	PECO Energy Company Supplemental Pension Benefit Plan (As Amended and Restated Effective January 1, 2009) (File No. 000-16844, 2008 Form 10-K, Exhibit 10.20).
10-14	Exelon Corporation Annual Incentive Plan for Senior Executives Effective January 1, 2004 (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2009 Form 10-K, Exhibit 10.21).
10-15	Form of change in control employment agreement for senior executives effective January 1, 2009 * (File No. 001-16169. 2008 Form 10-K, Exhibit 10.23).
10-16	Form of change in control employment agreement (amended and restated as of January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.24).
10-17	Exelon Corporation Employee Stock Purchase Plan, as amended and restated effective July 1, 2013. (File No. 1-16169, Schedule 14A dated March 14, 2013 Appendix A).
10-18	Exelon Corporation 2006 Long-Term Incentive Plan (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex H).
10-19	Form of Stock Option Grant Instrument under the Exelon Corporation 2006 Long-Term Incentive Plan (File No. 1-16169, Form 8-K filed January 27, 2006, Exhibit 99.2).
10-20	Exelon Corporation Employee Stock Purchase Plan for Unincorporated Subsidiaries (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex I).
10-21	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective April 1, 2013).*
10-22	Form of Separation Agreement under Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective January 1, 2009) * (File No, 001-16169, 2008 Form 10-K, Exhibit 10.30).
10-23	Facility Credit Agreement, dated as of November 4, 2010, among Exelon Generation Company, LLC and UBS AG, Stamford Branch (File No. 333-85496, Form 8-K dated February 22, 2011, Exhibit No. 10-1).

Exhibit No.	Description
10-24	Exelon Corporation Executive Death Benefits Plan dated as of January 1, 2003 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-52).
10-25	First Amendment to Exelon Corporation Executive Death Benefits Plan, Effective January 1, 2006 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-53).
10-26	Amendment Number One to the Exelon Corporation 2006 Long-Term Incentive Plan, Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-54).
10-27	Amendment Number Two to the Exelon Corporation 2006 Long-Term Incentive Plan (As Amended and Restated Effective January 28, 2002), Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-55).
10-28	Exelon Corporation Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-56).
10-29	Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-57).
10-30	Commonwealth Edison Company Long-Term Incentive Plan, Effective January 1, 2007 (File No. 1-16169, March 31, 2007 Form 10-Q, Exhibit 10-1).
10-31	Amendment Number One to the Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, June 30, 2007 Form 10-Q, Exhibit 10-3).
10-32	Restricted stock unit award agreement (File 1-16169, Form 8-K dated August 31, 2007, Exhibit 99.1).
10-33	Reserved.
10-34	Exelon Corporation 2011 Long-Term Incentive Plan (File No. 1-16169, Schedule 14A dated March 18, 2010, Appendix A).
10-35	Form of Change in Control Employment Agreement Effective February 10, 2011. * (File 1-16169, 2011 Form 10-K, Exhibit 10-44).
10-36	Credit Agreement for $500,000,000 dated as of March 23, 2011 between Exelon Corporation and Various Financial Institutions (File No. 001-16169, Form 8-K dated March 23, 2011, Exhibit No. 10-2).
10-37	Credit Agreement for $5,300,000,000 dated as of March 23, 2011 between Exelon Generation Company, LLC and Various Financial Institutions (File No. 333-85496, Form 8-K dated March 23, 2011, Exhibit No. 10-3).
10-38	Credit Agreement for $600,000,000 dated as of March 23, 2011 between PECO Energy Company and Various Financial Institutions (File No. 000-16844, Form 8-K dated March 23, 2011, Exhibit No. 10-4).
10-39	Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, Various Financial Institutions, as Lenders, and JP Morgan Chase Bank, N.A., as Administrative Agent (File No. 001-01839, Form 8-K dated March 28, 2012, Exhibit No. 99-1).
10-40	Amendment No. 3 to Credit Agreement dated as of March 23, 2011 among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated August 10, 2013, Exhibit No. 99-1)
10-41	Amendment No. 1 to Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, as Borrower, the various financial institutions named therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-1839, Form 8-K dated August 10, 2013, Exhibit No. 99-2).

Exhibit No.	Description
10-42	Amendment No. 1 to Credit Agreement, dated as of December 21, 2011, to the Credit Agreement dated as of March 23, 2011, among Exelon Generation Company, LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 4-6).
10-43	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-44	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. * (Designated as Exhibit No. 10(c) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-45	Constellation Energy Group, Inc. Benefits Restoration Plan, amended and restated effective June 1, 2010. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-46	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. * (Designated as Exhibit No. 10(e) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.).
10-47	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. * (Designated as Exhibit No. 10(f) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-48	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. * (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-49	Constellation Energy Group, Inc. Executive Supplemental Benefits Plan, as amended and restated. * (Designated as Exhibit No. 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-50	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-51	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-52	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-53	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(d) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)

Exhibit No.	Description
10-54	Constellation Energy Group, Inc. Amended and Restated 2007 Long-Term Incentive Plan. * (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated June 4, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
10-55	Form of Grant Agreement for Stock Units with Sales Restriction. * (Designated as Exhibit No. 10(x) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-56	Rate Stabilization Property Servicing Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as servicer (Designated as Exhibit 10.2 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
10-57	Administration Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as administrator (Designated as Exhibit 10.3 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910.)
10-58	Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 12, 2009, filed by Constellation Energy Group, Inc., File No. 1-12869.)
10-59	Amendment No. 1 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(s) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-60	Amendment No. 2 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(t) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910.)
10-61	Amendment No. 3 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
10-62	Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869.)
10-63	Settlement Agreement between EDF Inc., Exelon Corporation, Exelon Energy Delivery Company, LLC, Constellation Energy Group, Inc. and Baltimore Gas and Electric Company dated January 16, 2012. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated January 19, 2012, File Nos. 1-12869 and 1-1910.)
10-64	Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012)*

Exhibit No.	Description
10-65	First Amendment to the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012)*
10-66	Second Amendment to the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012)*
10-67	Third Amendment to the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012)*
10-68	Constellation Energy Group, Inc. Employee Savings Plan (Amended and Restated Effective January 31, 2012)*
10-69	First Amendment to the Constellation Energy Group, Inc. Employee Savings Plan (Amended and Restated Effective January 31, 2012)*
10-70	Second Amendment to the Constellation Energy Group, Inc. Employee Savings Plan (Amended and Restated Effective January 31, 2012)*
12-1	Exelon Corporation Computation of Ratio of Earnings to Fixed Charges.
12-2	Exelon Generation Company, LLC Computation of Ratio of Earnings to Fixed Charges.
12-3	Commonwealth Edison Company Computation of Ratio of Earnings to Fixed Charges.
12-4	PECO Energy Company Computation of Ratio of Earnings to Fixed Charges.
12-5	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preference Stock Dividends.
14	Exelon Code of Conduct, as amended March 12, 2012 (File No. 1-16169, Form 8-K dated March 14, 2012, Exhibit No. 14-1).
	Subsidiaries
21-1	Exelon Corporation
21-2	Exelon Generation Company, LLC
21-3	Commonwealth Edison Company
21-4	PECO Energy Company
21-5	Baltimore Gas and Electric Company
	Consent of Independent Registered Public Accountants
23-1	Exelon Corporation
23-2	Exelon Generation Company, LLC
23-3	Commonwealth Edison Company
23-4	PECO Energy Company
23-5	Baltimore Gas and Electric Company
	Power of Attorney (Exelon Corporation)
24-1	Anthony K. Anderson
24-2	Ann C. Berzin
24-3	John A. Canning, Jr.
24-4	Christopher M. Crane
24-5	Yves C. de Balmann
24-6	Nicholas DeBenedictis
24-7	Nelson A. Diaz

Exhibit No.	Description
24-8	Sue L. Gin
24-9	Paul L. Joskow
24-10	Robert J. Lawless
24-11	Richard W. Mies
24-12	William C. Richardson
24-13	John W. Rogers, Jr.
24-14	Mayo A. Shattuck III
24-15	Stephen D. Steinour
	Power of Attorney (Commonwealth Edison Company)
24-16	James W. Compton
24-17	Christopher M. Crane
24-18	A. Steven Crown
24-19	Nicholas DeBenedictis
24-20	Peter V. Fazio, Jr.
24-21	Sue L. Gin
24-22	Michael Moskow
24-23	Denis O'Brien
24-24	Anne R. Pramaggiore
24-25	Jesse H. Ruiz
	Power of Attorney (PECO Energy Company)
24-26	Craig L. Adams
24-27	Christopher M. Crane
24-28	M. Walter D'Alessio
24-29	Nicholas DeBenedictis
24-30	Nelson A. Diaz
24-31	Rosemarie B. Greco
24-32	Charisse R. Lillie
24-33	Denis O'Brien
24-34	Ronald Rubin
	Power of Attorney (Baltimore Gas and Electric Company)
24-35	Ann C. Berzin
24-36	Christopher M. Crane
24-37	Michael E. Cryor
24-38	James R. Curtiss
24-39	Kenneth W. DeFontes, Jr.
24-40	Joseph Haskins, Jr.
24-41	Carla D. Hayden
24-42	Denis O'Brien

Exhibit No.	Description
	Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Annual Report on Form 10-K for the year ended December 31, 2013 filed by the following officers for the following registrants:
31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Jonathan W. Thayer for Exelon Corporation
31-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	Filed by Craig L. Adams for PECO Energy Company
31-8	Filed by Phillip S. Barnett for PECO Energy Company
31-9	Filed by Kenneth W. DeFontes Jr. for Baltimore Gas and Electric Company
31-10	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
	Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Annual Report on Form 10-K for the year ended December 31, 2013 filed by the following officers for the following registrants:
32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Jonathan W. Thayer for Exelon Corporation
32-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
32-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	Filed by Craig L. Adams for PECO Energy Company
32-8	Filed by Phillip S. Barnett for PECO Energy Company
32-9	Filed by Kenneth W. DeFontes Jr. for Baltimore Gas and Electric Company
32-10	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

* Compensatory plan or arrangements in which directors or officers of the applicable registrant participate and which are not available to all employees.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2014.

EXELON CORPORATION

By: /s/ Christopher M. Crane
Name: **Christopher M. Crane**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2014.

Signature	**Title**
/s/ Christopher M. Crane **Christopher M. Crane**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ Jonathan W. Thayer **Jonathan W. Thayer**	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Duane M. DesParte **Duane M. DesParte**	Vice President and Corporate Controller (Principal Accounting Officer)

This annual report has also been signed below by Darryl M. Bradford, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Anthony K. Anderson
Ann C. Berzin
John A. Canning, Jr.
Yves C. de Balmann
Nicholas DeBenedictis
Nelson A. Diaz
Sue L. Gin
Paul L. Joskow
Robert J. Lawless
Richard W. Mies
William C. Richardson
John W. Rogers, Jr.
Mayo A. Shattuck III
Stephen D. Steinour

By: /s/ Darryl M. Bradford
Name: **Darryl M. Bradford**

February 13, 2014

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2014.

EXELON GENERATION COMPANY, LLC

By: /s/ Kenneth W. Cornew
Name: **Kenneth W. Cornew**
Title: **President**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2014.

Signature	**Title**
/s/ Kenneth W. Cornew **Kenneth W. Cornew**	President (Principal Executive Officer)
/s/ Bryan P. Wright **Bryan P. Wright**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Robert M. Aiken **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2014.

COMMONWEALTH EDISON COMPANY

By: /s/ ANNE R. PRAMAGGIORE
Name: **Anne R. Pramaggiore**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2014.

Signature	**Title**
/s/ ANNE R. PRAMAGGIORE **Anne R. Pramaggiore**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ JOSEPH R. TRPIK, JR. **Joseph R. Trpik, Jr.**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ GERALD KOZEL **Gerald J. Kozel**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director
/s/ DENIS P. O'BRIEN **Denis P. O'Brien**	Vice Chairman and Director

This annual report has also been signed below by Anne R. Pramaggiore, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

James W. Compton
A. Steven Crown
Nicholas DeBenedictis
Peter V. Fazio, Jr.
Sue L. Gin
Michael Moskow
Jesse H. Ruiz

By: /s/ ANNE R. PRAMAGGIORE
Name: **Anne R. Pramaggiore**

February 13, 2014

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2014.

PECO ENERGY COMPANY

By: /s/ C RAIG L. A DAMS
Name: **Craig L. Adams**
Title: **Chief Executive Officer and President**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2014.

Signature	**Title**
/s/ C RAIG L. A DAMS **Craig L. Adams**	Chief Executive Officer and President (Principal Executive Officer) and Director
/s/ P HILLIP S. B ARNETT **Phillip S. Barnett**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ S COTT A. B AILEY **Scott A. Bailey**	Vice President and Controller (Principal Accounting Officer)
/s/ C HRISTOPHER M. C RANE **Christopher M. Crane**	Chairman and Director
/s/ D ENIS P. O'B RIEN **Denis P. O'Brien**	Vice Chairman and Director

This annual report has also been signed below by Craig L. Adams, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

M. Walter D'Alessio
Nelson A. Diaz
Nicholas DeBenedictis
Rosemarie B. Greco
Charisse R. Lillie
Ronald Rubin

By: /s/ C RAIG L. A DAMS
Name: **Craig L. Adams**

February 13, 2014

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2014.

BALTIMORE GAS AND ELECTRIC COMPANY

By: /s/ K ENNETH W. D E F ONTES , J R .
Name: Kenneth W. DeFontes Jr.
Title: Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2014.

Signature	Title
/s/ K ENNETH W. D E F ONTES , J R . **Kenneth W. DeFontes Jr.**	Chief Executive Officer and President (Principal Executive Officer) and Director
/s/ C ARIM V. K HOUZAMI **Carim V. Khouzami**	Senior Vice President, Chief Financial Officer, and Treasurer (Principal Financial Officer)
/s/ D AVID M. V AHOS **David M. Vahos**	Vice President and Controller (Principal Accounting Officer)
/s/ C HRISTOPHER M. C RANE **Christopher M. Crane**	Chairman and Director
/s/ D ENIS P. O'B RIEN **Denis P. O'Brien**	Vice Chairman and Director

This annual report has also been signed below by Kenneth W. DeFontes, Jr., Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Ann C. Berzin
Michael E. Cryor
James R. Curtiss
Joseph Haskins, Jr.
Carla D. Hayden

By: /s/ K ENNETH W. D E F ONTES , J R . February 13, 2014
Name: Kenneth W. DeFontes, Jr.

Exhibit 3.11

BYLAWS
OF
Baltimore Gas and Electric Company
Amended and Restated as of May 10, 2012

Bylaws of
Baltimore Gas and Electric Company

ARTICLE I

MEETINGS OF STOCKHOLDERS

Section 1.— *Annual Meeting.*

The annual meeting of the stockholders for the election of Directors and for the transaction of general business shall be held on any date as determined year to year by the Board of Directors. The time and location of the meeting shall be determined by the Board of Directors.

The Chief Executive Officer of the Company shall prepare, or cause to be prepared, an annual report containing a full and correct statement of the affairs of the Company, including a balance sheet and a financial statement of operations for the preceding fiscal year, which shall be submitted to the stockholders at the annual meeting.

Section 2.— *Special Meeting.*

Special meetings of the stockholders may be held in the City of Baltimore or in any county in which the Company provides service or owns property upon call by the Chairman of the Board, if one is elected, the President, or a majority of the Board of Directors whenever they deem expedient, or upon the written request of the holders of shares entitled to not less than twenty-five percent of all the votes entitled to be cast at such a meeting. Such request of the stockholders shall state the purpose or purposes of the meeting and the matters proposed to be acted on thereat and shall be delivered to the Secretary, who shall inform such stockholders of the reasonably estimated cost of preparing and mailing such notice of the meeting, and upon payment to the Company of such costs the Secretary shall give notice stating the purpose or purposes of the meeting to all stockholders entitled to vote at such meeting. No special meeting need be called upon the request of the holders of the shares entitled to cast less than a majority of all votes entitled to be cast to such meeting, to consider any matter which is substantially the same as a matter voted upon at any special meeting of the stockholders held during the preceding twelve months. The business at all special meetings shall be confined to that specifically named in the notice thereof.

Section 3.— *Notice of Meetings.*

Written or printed notice of every meeting of the stockholders, whether annual or special, stating the place, day, and hour of such meeting and (in the case of special meetings) the business proposed to be transacted shall be given by the Secretary to each stockholder entitled to vote at such meeting not less than ten days but no more than ninety days before the date fixed for such meeting, by electronic mail at his or her e-mail address as it appears on the records of the Company or by depositing such notice in the United States mail addressed to him or her at his or her post office address as it appears on the records of the Company, with postage thereon prepaid.

Section 4.— *Organization of Meeting.*

All meetings of the stockholders shall be called to order by the Chairman of the Board, or if one is not elected or is absent, by the President, or in his or her absence by a Vice President, or in the case of the absence of such officers, then by any stockholder, whereupon the meeting shall organize by electing a chairman. The Secretary of the Company, if present, shall act as secretary of the meeting, unless some other person shall be elected by the meeting to so act. An accurate record of the meeting shall be kept by the secretary thereof, and placed in the record books of the Company.

Section 5.— *Quorum.*

At any meeting of the stockholders, the presence in person or by proxy of stockholders entitled to cast a majority of the votes thereat shall constitute a quorum for the transaction of business. If a quorum be not present at any meeting, holders of a majority of the shares of stock so present or represented may adjourn the meeting either *sine die* or to a date certain.

Section 6.— *Voting.*

At all meetings of the stockholders, each stockholder shall be entitled to one vote for each share of common stock standing in his or her name and, when the preferred or preference stock is entitled to vote, such number of votes as shall be provided in the charter of the Company for each share of preferred and preference stock standing in his or her name, and the votes shall be cast by stockholders in person or by lawful proxy.

Section 7.— *Judge of Election and Tellers.*

The Directors, at a regular or special meeting of stockholders, may (but shall not be required to) appoint a Judge of Election and two Tellers to serve at each meeting of stockholders. If the Directors fail to make such appointments, or if the Judge of Election and/or Tellers, or any of them, fail to appear at the meeting, the chairman of the meeting shall appoint a Judge of Election and/or a Teller or Tellers to serve at that meeting. It shall be the duty of the Tellers to receive the ballots of all the holders of stock entitled to vote and present at a meeting either in person or by proxy, and to count and tally said ballots by the official record of stockholders of the Company, or by a summary prepared therefrom and certified by the Stock Transfer Agent or the Secretary of the Company showing the number of shares of common and, if entitled to vote, preferred and preference stock owned of record by each stockholder, who may be designated therein by name, code number, or otherwise, and certify them to the Judge of Election, and the said Judge shall communicate in writing the result of the balloting so certified by the Tellers to the chairman who shall at once announce the same to the meeting. This certificate, signed by the Tellers and countersigned by the Judge, shall be duly recorded as part of the minutes of the meeting and filed among the records of the Company.

Section 8.— *Record Date for Stockholders and Closing of Transfer Books.*

The Board of Directors may fix, in advance, a date as the record for the determination of the stockholders entitled to notice of, or to vote at, any meeting of stockholders, or entitled to receive payment of any dividend, or entitled to the allotment of any rights, or for any other

proper purpose. Such date in any case shall not be more than ninety days (and in the case of a meeting of stockholders not less than ten days) prior to the date on which the particular action requiring such determination of stockholders is to be taken. Only stockholders of record on such date shall be entitled to notice of or to vote at such meeting or to receive such dividends or rights, as the case may be. In lieu of fixing a record date, the Board of Directors may close the stock transfer books of the Company for a period not exceeding twenty days or less than ten days preceding the date of any meeting of stockholders or not exceeding twenty days preceding any other of the above mentioned events.

ARTICLE II

BOARD OF DIRECTORS AND COMMITTEES

Section 1.— *Powers of Directors.*

The business and affairs of the Company shall be managed by a Board of Directors which shall have and may exercise all the powers of the Company, except such as are expressly conferred upon or reserved to the stockholders by law, by the charter, or by these bylaws. Except as otherwise provided herein, the Board of Directors shall appoint the officers for the conduct of the business of the Company, determine their duties and responsibilities and fix their compensation. The Board of Directors may remove any officer.

Section 2.— *Number and Election of Directors.*

The number of Directors (including each Independent Director) shall be set at eight; *provided, however* , that the number of Directors may be increased or decreased by the Board of Directors without an amendment to these bylaws but in no event will there be less than three Directors or more than fifteen Directors. The Directors (including each Independent Director) shall be elected at each Annual Meeting of the Stockholders except as otherwise provided in these bylaws. They shall hold their offices for one year and until their successors are elected and qualified.

Section 3.— *Director Independence and Residency.*

(a) At all times subsequent to the first meeting of the Board of Directors after March 12, 2012, in accordance with the provisions of these bylaws, at least one-third of the Directors in office, and no less than two Directors, shall meet the standards for independence set forth in the New York Stock Exchange Listing Standards, and shall be neither employees nor directors of Exelon Corporation (“Exelon”) or any Exelon affiliate (each such Director, an “Independent Director”). No resignation or removal of an Independent Director at any time when such resignation or removal would result in less than one-third of the Directors in office, or less than two Directors, being Independent Directors shall be effective until as many successor Independent Directors as needed to have at least one-third, and no less than two, of the Directors be Independent Directors shall have accepted their appointments as Independent Directors. In the event that less than one-third of the Directors in office, or less than two Directors, meeting the qualifications therefor are then holding the position of Independent Director, the Board of Directors shall, as soon as practicable, appoint as many successor Independent Directors as

needed to have at least one-third, and no less than two, of the Directors be Independent Directors, and until each such vacancy is filled, the Board of Directors shall be prohibited from voting on any action specified in Section 6(b) of this Article II or the proviso to Article VIII. No Independent Director shall at any time serve as trustee in bankruptcy for any affiliate of the Company.

(b) At all times on and after the date hereof, a majority of the Directors in office shall have primary residence or principal place of business or employment in the Company's service territory.

Section 4.— *Removals and Vacancies.*

The stockholders, at any meeting duly called and at which a quorum is present, may remove any Director or Directors from office by the affirmative vote of the holders of a majority of the outstanding shares entitled to the vote thereon, and may elect a successor or successors to fill any resulting vacancies for the unexpired terms of the removed Directors.

Any vacancy occurring in the Board of Directors from any cause other than by reason of removal by the stockholders or an increase in the number of Directors may be filled by a majority of the remaining Directors although such majority is less than a quorum. Any vacancy occurring by reason of an increase in the number of Directors may be filled by action of a majority of Directors. A Director elected to fill a vacancy shall hold office until the next annual meeting of stockholders or until his successor is elected and qualified.

Section 5.— *Meetings of the Board of Directors.*

A regular meeting of the Board of Directors shall be held immediately after the annual meeting of stockholders or any special meeting of the stockholders at which the Board of Directors is elected, and thereafter regular meetings of the Board of Directors shall be held on such dates during the year as may be designated from time to time by the Board of Directors. All meetings of the Board of Directors shall be held at the general offices of the Company in the City of Baltimore or elsewhere, as ordered by the Board of Directors. Of all such meetings (except: the regular meeting held immediately after the election of Directors) the Secretary shall give notice to each Director personally or by electronic mail, by telephone, by telegram directed to, or by written notice deposited in the United States mail addressed to, his residence or business address on record with the Company at least 48 hours before such meeting. Special meetings may be held at any time or place upon the call of the Chairman of the Board or the Chief Executive Officer.

The Chairman of the Board shall preside at all meetings of the Board of Directors, or, if one is not elected or is absent, the President, or one of the Vice Presidents (if a member of the Board of Directors) shall preside. If at any meeting none of the foregoing persons is present, the Directors present shall designate one of their number to preside at such meeting.

Section 6.— *Quorum and Voting.*

(a) A majority of the Directors in office shall constitute a quorum of the Board of Directors for the transaction of business, with the exception of any meeting at which any action described in Section 6(b) of this Article II is considered, at which meeting a quorum shall consist of all Directors. All actions of the Board of Directors (other than those described in Section 6(b) of this Article II) shall require the affirmative vote of a majority of the Directors in attendance at a meeting at which a quorum is present. If a quorum be not present at any meeting, a majority of the Directors present may adjourn to any time and place they may see fit.

(b) Notwithstanding any other provision of these bylaws and any provision of law that otherwise so empowers the Company, the stockholders, the Board of Directors, any Director, any officer or any other person, neither the stockholders nor the Board of Directors nor any Director nor any officer nor any other person shall be authorized or empowered, nor shall they permit the Company, without the unanimous prior approval of the Board of Directors, including the Independent Directors, to (A) commence any case, proceeding or other action on behalf of the Company under any existing or future law of any jurisdiction relating to bankruptcy, insolvency, reorganization, or relief for debtors; (B) institute proceedings to have the Company adjudicated as bankrupt or insolvent; (C) consent to or acquiesce in the institution of bankruptcy or insolvency proceedings against the Company; (D) file a petition or consent to a petition seeking reorganization, arrangement, adjustment, winding up, dissolution, composition, liquidation, or other relief on behalf of the Company of its debts under any federal or state law relating to bankruptcy; (E) apply for, or consent to, or acquiesce in the appointment of, a receiver, liquidator, sequestrator, trustee or other officer with similar powers of such person with respect to the Company; (F) make any assignment for the benefit of the Company's creditors; (G) admit in writing the Company's inability to pay its debts generally as they become due; or (H) remove the unanimous consent requirement set forth above in this Section 6(b) of Article II.

Section 7.— *Committees.*

The Board of Directors is authorized to appoint from among its members such committees as it may, from time to time, deem advisable and to delegate to such committee or committees any of the powers of the Board of Directors which it may lawfully delegate. Each such committee shall consist of at least one Director.

Section 8.— *Fees and Expenses.*

Each member of the Board of Directors, other than salaried officers and employees, shall be paid an annual retainer fee, payable in such amount as shall be specified from time to time by the Board of Directors.

Each member of the Board of Directors, other than salaried officers and employees, shall be paid such fee as shall be specified from time to time by the Board of Directors for attending each regular or special meeting of the Board of Directors and for attending, as a committee member, each meeting of any committee appointed by the Board of Directors. Each Director shall be paid reasonable traveling expenses incident to attendance at meetings of the Board of Directors.

ARTICLE III

OFFICERS

Section 1.— *Officers.*

The Company may have a Chairman of the Board and a Vice Chairman and shall have a President, one or more Vice Presidents, a Treasurer, and a Secretary, who shall be elected by, and hold office at the will of, the Board of Directors. The Chairman of the Board and the Vice Chairman, if one is elected, shall be chosen from among the Directors, and the Board of Directors shall designate either the Chairman of the Board, the Vice Chairman or the President to be the Chief Executive Officer of the Company; provided that the Chief Executive Officer shall reside within the Company's service territory. The Board of Directors shall also elect such other officers as they may deem necessary for the conduct of the business and affairs of the Company. Any two offices, except those of President and Vice President, may be held by the same person, but no person shall sign checks, drafts and promissory notes, or execute, acknowledge or verify any other instrument in more than one capacity, if such instrument is required by law, the charter, these bylaws, a resolution of the Board of Directors or order of the Chief Executive Officer to be signed, executed, acknowledged or verified by two or more officers.

Section 2.— *Duties of the Officers.*

(a) *Chairman of the Board of Directors; Vice Chairman.*

The Chairman of the Board of Directors, if one is elected, shall preside at all meetings of the Board of Directors and of the stockholders, and shall also have such other powers and duties as from time to time may be assigned to him or her by the Board of Directors. The Vice Chairman, if one is elected, shall, in the absence of the Chairman of the Board, or if one is not elected, perform the duties of the Chairman of the Board, and shall also have such other powers and duties as from time to time may be assigned to him or her by the Board of Directors.

(b) *President.*

The President shall have general executive powers, as well as specific powers conferred by these bylaws. The President, any Vice President, or such other persons as may be designated by the Board of Directors, shall sign all special contracts of the Company, countersign checks, drafts and promissory notes, and such other papers as may be directed by the Board of Directors. The President, or any Vice President, together with the Treasurer or an Assistant Treasurer, shall have authority to sell, assign or transfer and deliver any bonds, stocks or other securities owned by the Company. The President shall also have such other powers and duties as from time to time may be assigned to him or her by the Board of Directors. In the absence of the Chairman of the Board and the Vice Chairman, or if one (or both) is (or are) not elected, the President shall perform all the duties of the Chairman of the Board.

(c) *Vice Presidents.*

Each Vice President shall have such powers and duties as may be assigned to him or her by the Board of Directors, or the Chief Executive Officer, as well as the specific powers assigned by these bylaws. A Vice President may be designated by the Board of Directors or the Chief Executive Officer to perform, in the absence of the President, all the duties of the President.

(d) *Treasurer.*

The Treasurer shall have the care and the custody of the funds and valuable papers of the Company, and shall receive and disburse all moneys in such a manner as may be prescribed by the Board of Directors or the Chief Executive Officer. The Treasurer shall have such other powers and duties as may be assigned to him or her by the Board of Directors, or the Chief Executive Officer, as well as specific powers assigned by these bylaws.

(e) *Secretary.*

The Secretary shall attend all meetings of the stockholders and the Board of Directors and shall notify the stockholders and Directors of such meetings in the manner provided in these bylaws. The Secretary shall record the proceedings of all such meetings in books kept for that purpose. The Secretary shall have such other powers and duties as may be assigned to him or her by the Board of Directors or the Chief Executive Officer, as well as the specific powers assigned by these bylaws.

Section 3.— *Removals and Vacancies.*

Any officer may be removed by the Board of Directors whenever, in its judgment, the best interest of the Company will be served thereby. In case of removal, the salary of such officer shall cease. Removal shall be without prejudice to the contractual rights, if any, of the person so removed, but election of an officer shall not of itself create contractual rights.

Any vacancy occurring in any office of the Company shall be filled by the Board of Directors and the officer so elected shall hold office for the unexpired term in respect of which the vacancy occurred or until his or her successor shall be duly elected and qualified.

In any event of absence or temporary disability of any officer of the Company, the Board of Directors may authorize some other person to perform the duties of that office.

ARTICLE IV

L IMITATIONS ON A CTIVITIES

The Company shall:

(a) not participate in the cash pool operated by Exelon or any other Exelon affiliate (other than a subsidiary of the Company) and shall not commingle funds with Exelon or any other Exelon affiliate (other than a subsidiary of the Company);

(b) hold itself out as a separate entity from Exelon, Exelon Energy Delivery Company LLC ("EEDC") and RF HoldCo LLC ("HoldCo"), conduct business in its own name and not assume liability for future debts of Exelon, EEDC or HoldCo;

(c) maintain a separate name from and not use the trademarks, service marks or other intellectual property of Exelon, EEDC or HoldCo;

(d) maintain separate books, accounts and financial statements reflecting its separate assets and liabilities;

(e) maintain arms-length relationships with Exelon, EEDC and HoldCo; and

(f) not (i) guarantee the debt or credit instruments of Exelon or any other Exelon affiliate (other than a subsidiary of the Company); (ii) grant a mortgage or other lien on any property used and useful in providing retail or wholesale utility service to, or otherwise pledge such assets as security for repayment of the principal or interest of any loan or credit instrument of, Exelon or any other Exelon affiliate (other than a subsidiary of the Company); (iii) include in any of the Company's debt or credit agreements cross-default provisions between the Company's securities and the securities of Exelon or any other Exelon affiliate (other than a subsidiary of the Company); or (iv) include in its debt or credit agreements any financial covenants or rating-agency triggers related to Exelon or any other Exelon affiliate (other than a subsidiary of the Company).

ARTICLE V

INDEMNIFICATION

Section 1.— *Procedure.*

The Company shall indemnify any present or former Director or officer of the Company and each Director or elected officer of any direct or indirect wholly-owned subsidiary of the Company who is made, or threatened to be made, a party to a proceeding by reason of his or her service in that capacity or by reason of service, while a Director or officer of the Company and at the request of the Company, as a director or officer of another company, corporation, limited liability company, partnership, trust, employee benefit plan or other enterprise, and the Company shall pay or reimburse reasonable expenses incurred in advance of final disposition of the proceeding, in each case to the fullest extent permitted by the laws of the State of Maryland. The Company may indemnify, and advance reasonable expenses to, other employees and agents of the Company and employees and agents of any subsidiary of the Company to the extent authorized by the Board of Directors. The Company shall follow the procedures required by applicable law in determining persons eligible for indemnification and in making indemnification payments and advances.

Section 2.— *Exclusivity, etc.*

The indemnification and advancement of expenses provided by these bylaws (a) shall not be deemed exclusive of any other rights to which a person seeking indemnification or advance of expenses may be entitled under any law (common or statutory), or any agreement, vote of

stockholders or disinterested Directors or other provision that is consistent with law, both as to action in his or her official capacity and as to action in another capacity while holding office or while employed or acting as agent for the Company, (b) shall continue in respect of all events occurring while a person was a Director or officer after such person has ceased to be a Director or officer, and (c) shall inure to the benefit of the estate, heirs, executors and administrators of such person. All rights to indemnification and advance of expenses hereunder shall be deemed to be a contract between the Company and each Director or officer of the Company who serves or served in such capacity at any time while this Article V is in effect. Nothing herein shall prevent the amendment of this Article V, *provided* that no such amendment shall diminish the rights of any person hereunder with respect to events occurring or claims made before its adoption or as to claims made after its adoption in respect of events occurring before its adoption. Any repeal or modification of this Article V shall not in any way diminish any rights to indemnification or advancement of expenses of a Director or officer or the obligations of the Company arising hereunder with respect to events occurring, or claims made, while this Article V or any provision hereof is in effect.

Section 3.— *Severability.*

The invalidity or unenforceability of any provision of this Article V shall not affect the validity or enforceability of any other provision hereof.

ARTICLE VI

C APITAL S TOCK

Section 1.— *Evidence of Stock Ownership.*

Evidence of ownership of stock in the Company shall be pursuant to certificate(s), each of which shall represent the number of shares of stock owned by a stockholder of the Company. Stockholders may request that their stock ownership be represented by certificate(s). Each certificate shall be signed on behalf of the Company by the President or a Vice President and countersigned by the Secretary or the Treasurer, and shall be sealed with the corporate seal. The signatures may be either manual or facsimile. In case any officer who signed any certificate, in facsimile or otherwise, ceases to be such officer of the Company before the certificate is issued, the certificate may nevertheless be issued by the Company with the same effect as if the officer had not ceased to be such officer as of the date of its issue.

Section 2.— *Transfer of Shares.*

Stock shall be transferable only on the books of the Company by assignment in writing by the registered holder thereof, his or her legally constituted attorney, or his or her legal representative, either upon surrender and cancellation of the certificate(s) therefor, if such stock is represented by a certificate, or upon receipt of such other documentation for stock not represented by a certificate as the Board of Directors and the law of the State of Maryland may, from time to time, require.

Section 3.— *Lost, Stolen or Destroyed Certificates.*

No certificate for shares of stock of the Company shall be issued in place of any other certificate alleged to have been lost, stolen, or destroyed, except upon production of such evidence of the loss, theft or destruction and upon indemnification of the Company to such extent and in such manner as the Board of Directors may prescribe.

Section 4.— *Transfer Agents and Registrars.*

The Board of Directors shall appoint a person or persons, or any incorporated trust company or companies or both, as transfer agents and registrars and, if stock is represented by a certificate, may require that such certificate bear the signatures or the counter-signatures of such transfer agents and registrars, or either of them.

Section 5.— *Stock Ledger*.

The Company shall maintain at its principal office in Baltimore, Maryland, a stock record containing the names and addresses of all stockholders and the numbers of shares of each class held by each stockholder.

ARTICLE VII

S EAL

The Board of Directors shall provide, subject to change, a suitable corporate seal which may be used by causing it, or facsimile thereof, to be impressed or affixed or reproduced one the Company's stock certificates, bonds, or any other documents on which the seal may be appropriate.

ARTICLE VIII

A MENDMENTS

These bylaws, or any of them, may be amended or repealed, and new bylaws may be made or adopted at any meeting of the Board of Directors, by vote of a majority of the Directors, or by the stockholders at any annual meeting, or at any special meeting called for that purpose; *provided, however* , that, in the case of any amendment, repeal or replacement of Sections 3 and 6 of Article II or any part of Article IV or this Article VIII, each Independent Director must also have approved such amendment, repeal or replacement.

EXELON CORPORATION RETIREMENT PROGRAM

As Amended and Restated Effective January 1, 2013

EXELON CORPORATION RETIREMENT PROGRAM

INTRODUCTION

The title of this Plan shall be the "Exelon Corporation Retirement Program." This Plan is an amendment and restatement of the Commonwealth Edison Company Service Annuity System as in effect on December 30, 2001 and reflects the merger of the Service Annuity Plan of PECO Energy Company into the Plan effective December 31, 2001, and as previously amended and restated, and subsequent amendments and restatements. This amendment and restatement, except as otherwise provided herein, shall apply to Employees whose employment is terminated on or after January 1, 2013 and to the surviving spouses and surviving dependent children of such Employees. The rights and benefits of Employees whose employment terminates on or before December 31, 2012 and of the surviving spouses and surviving dependent children of such Employees shall, except as otherwise provided herein, be determined under the Plan as in effect at the time of such Employees' termination, including any provisions of this Plan effective at such time.

Subject to the foregoing, individuals who are "Participants" as defined in the document designated as the Commonwealth Edison Company Service Annuity System and attached hereto as Appendix A shall have their benefit under the Plan determined exclusively by the terms of Appendix A hereto. Individuals who are "Participants" as defined in the document designated as the Service Annuity Plan of PECO Energy Company and attached hereto as Appendix B shall have their benefit under the Plan determined exclusively by the terms of Appendix B hereto.

COMMONWEALTH EDISON COMPANY

SERVICE ANNUITY SYSTEM

Under the Exelon Corporation Retirement Program

(Amended and Restated as of January 1, 2013)

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COMMONWEALTH EDISON COMPANY

SERVICE ANNUITY SYSTEM

ARTICLE 1

ESTABLISHMENT AND PURPOSE

The title of this Plan shall be the "Commonwealth Edison Company Service Annuity System". This Plan is an amendment and restatement of the Commonwealth Edison Company Service Annuity System as in effect on December 31, 2012 and, except as otherwise provided, shall apply to Employees whose employment is terminated on or after January 1, 2013 and to the surviving Spouses and surviving dependent children of such Employees. The benefits of Employees whose employment terminates before January 1, 2013 and of the surviving Spouses and surviving dependent children of such Employees shall be determined under the Commonwealth Edison Company Service Annuity System as in effect at the time of such Employees' termination, including any provisions of this Plan effective at such time; provided, however, that the provisions of Article 7 (relating to limitations on benefits), Article 9 (relating to special rules relating to participation of and distribution to certain terminated or transferred employees), Article 10 (relating to administration), Article 13 (relating to miscellaneous provisions) and Article 15 (relating to amendment and termination of the Plan) shall be effective for all such persons.

For purposes of the Plan, the phrase "a member of IBEW Local Union 15" shall mean an employee whose terms of employment are subject to a collective bargaining agreement between IBEW Local Union 15 and his or her employer.

ARTICLE 2

DEFINITIONS

Section 2.1. Defined Terms . As used herein the following words and phrases shall have the following respective meanings when capitalized unless the context clearly indicates otherwise:

(1) Administrator . The Company acting through its Vice President, Health & Benefits or such other person appointed pursuant to Section 10.1.

(2) Affiliate . (a) A corporation which is a member of the same controlled group of corporations (within the meaning of Section 414(b) of the Code) as an Employer, (b) a trade or business (whether or not incorporated) under common control (within the meaning of Section 414 (c) of the Code) with an Employer, (c) an organization (whether or not incorporated) that is a member of an affiliated service group (within the meaning of Section 414(m) of the Code) that includes an Employer, a corporation described in clause (a) of this subdivision or a trade or business described in clause (b) of this subdivision, or (d) any other entity that is required to be aggregated with an Employer pursuant to Regulations promulgated under Section 414(o) of the Code.

(3) Annuity Starting Date . The first day on which a Service Annuity is payable to a Participant.

(4) Basic Compensation . A Participant's base pay rate per pay period, as determined by the Administrator. For purposes of the preceding sentence, a Participant's base pay rate per pay period shall include (i) any amount contributed by the Participant's Employer on behalf of such Participant for such year to the Participant's Before-Tax Contributions Account under the Exelon Corporation Employee Savings Plan, a qualified transportation fringe benefit plan described in section 132(f) of the Code, the Exelon Corporation Benefits Contribution Options or the Exelon Corporation Key Choices Program and (ii) such other types of compensation or payments as may be determined by the Administrator from time to time or as may be set forth from time to time in Exhibit 1 attached hereto, and shall exclude (i) bonuses (other than meter readers' bonuses, other bonuses included in Basic Compensation as described in Exhibit 1 and any payment for ratification of a collective bargaining agreement), (ii) overtime pay, (iii) shift premiums and (iv) such other types of compensation or payments as may be determined by the Administrator from time to time or as may be set forth from time to time in Exhibit 1 attached hereto. In the case of a Participant who is absent from employment due to either an authorized leave of absence (including a leave of absence for participation in Military Service) or employment by a union that represents any group of Employees, Basic Compensation shall mean, for the

period during which the Participant is absent due to an authorized leave of absence or employment by such union, the Participant's base pay rate per pay period in effect immediately preceding the first day of the Participant's authorized leave of absence or employment by a union, as the case may be. A Participant whose Termination of Employment occurs on account of a Total and Permanent Disability, but who is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45) or Section 5.5 (relating to disability retirement before age 45) shall not be treated as having any Basic Compensation for periods of Credited Service after such Termination of Employment. A Participant whose Termination of Employment occurs on account of a Total and Permanent Disability and who is receiving benefits under any Employer's long term disability plan shall be treated for periods of Credited Service after such Termination of Employment as having Basic Compensation determined under Section 5.2(c).

(5) Beneficiary . A Participant's Spouse or the Participant's Dependent Minor Child or Dependent Disabled Child entitled, in the event of the death of the Participant, to receive a Service Annuity, under Section 6.3 (relating to the pre-retirement surviving spouse benefit), Section 6.4 (relating to the pre-retirement surviving child benefits) or Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65). To the extent required by law and where applicable in the Plan, an alternate payee entitled to receive a Service Annuity under paragraph (b) of Section 13.2 (relating to exception to non-assignability for qualified domestic relations orders) shall also be a Beneficiary.

(6) CEG. Constellation Energy Group, Inc. and any of its affiliates that was an affiliate immediately before the Effective Time (as such term is defined in the Merger Agreement).

(7) Child . A Participant's natural child born prior to the time payment of the Participant's Service Annuity commences hereunder or a child adopted by a Participant prior to the time payment of the Participant's Service Annuity commences hereunder.

(8) Code . The Internal Revenue Code of 1986, as amended.

(9) Company . Exelon Corporation, a Pennsylvania corporation, or any successor or successors.

(10) Consumer Price Index . The United States Bureau of Labor Statistics Consumer Price Index (U.S. City Average 1967 = 100). Such term shall also mean such index as it may from time to time be changed or, if it shall be discontinued, the most nearly comparable index, appropriately adjusted to yield results comparable with those which would have been produced if the index as defined in the preceding sentence had been used, as determined by the Investment Office.

(11) Corporate Investment Committee . The Company acting through the committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

(12) Credited Service . The period of a Participant's employment as an Eligible Employee which is used to compute the Participant's Service Annuity and eligibility for commencement of payment of such Service Annuity under Article 5 (relating to Service Annuities) and Article 6 (relating to Service Annuity forms). A Participant's Credited Service includes (a) the Participant's Credited Service prior to the Effective Date determined in accordance with the provisions of the Plan as in effect prior to the Effective Date, (b) to the extent not duplicative, for a Participant who terminated employment prior to January 1, 2003, any additional service for actual employment credited to such Participant prior to the Effective Date in an Employer's employment records pursuant to Commonwealth Edison Company's service bridging policy, and (c) the period beginning on the Effective Date during which the Participant shall have been an Eligible Employee, including, (i) any period during which the Participant is in Military Service, provided that the Participant returns to the employ of an Employer within the period prescribed by laws relating to the reemployment rights of persons in Military Service, (ii) any period during which the Participant is employed by a union that represents any group of Employees, (iii) any period for which back pay is awarded to the Participant and pursuant to which award the Participant is required to receive Credited Service under the Plan, (iv) the period following Termination of Employment on account of a Total and Permanent Disability during which the Participant is receiving benefits under any Employer's long term disability plan and (v) as and to the extent provided by resolutions of the board of directors of the Company, (1) any period of employment by Affiliates or other companies, and (2) any period of authorized absence from such employment or from employment as an Eligible Employee. A Participant's periods of Credited Service before and after a period of absence from employment that is not included in the Participant's Credited Service pursuant to the preceding sentences shall be aggregated only if (i) the Participant completes at least one year of Credited Service after such period of absence and (ii) the number of years of such period of absence from employment is less than five.

(13) Dependent Minor Child . A Child who, as of the time of the Participant's retirement or death, is under the age of 21 and qualifies as a dependent of the Participant within the meaning of Section 152 of the Code.

(14) Dependent Disabled Child . A Child who, as of the time of the Participant's retirement or death, has a permanent physical or mental disability, as certified by the medical director of the Company or by such other licensed physician designated by the Administrator, that causes such Child to be unable to engage in substantial gainful employment, and is a dependent of the Participant within the meaning of Section 152 of the Code (determined by disregarding any age limitation contained in Section 152 of the Code).

(15) Earnings . The Participant's earnings during the Participant's period of Credited Service on and before December 25, 1994 determined in accordance with the provisions of the Plan as in effect prior to April 1, 1995.

(16) Effective Date . Except as otherwise specifically provided herein, the Effective Date of this amendment and restatement of the Plan with respect to the Company and any other entity that was an Employer on December 31, 2012 shall be January 1, 2012 and in the case of any other Employer shall be the date designated by such Employer.

(17) Eligible Employee . (a) Any Employee who was an Eligible Employee on December 31, 2000, and who is receiving regular salary or wages from and rendering services to an Employer, or any such individual who is on an authorized leave of absence, and (b) on or after January 1, 2001, any Employee whose first Hour of Service with an Employer is prior to January 1, 2009 and who (i) is a member of IBEW Local Union 15 who becomes initially employed at a facility that, as of October 19, 2000, was owned by Commonwealth Edison Company, Unicom Corporation or any affiliate of Unicom Corporation, (ii) elects to participate in this Plan and (iii) is either receiving regular salary or wages from and rendering services to an Employer, or is on an authorized leave of absence; but, in either case excluding (i) an Employee the terms of whose employment are subject to a collective bargaining agreement that does not provide for participation in this Plan, (ii) an Employee paid on the temporary payroll of an Employer who has never completed at least 1,000 Hours of Service in any period of twelve consecutive months beginning with the Employee's date of hire or anniversary thereof, (iii) an Employee who executes a written waiver of his or her right to participate in the Plan; (iv) an individual who performs services for an Employer, pursuant to an agreement (written or oral) that classifies such individual's relationship with the Employer as other than an Employee regardless of whether such individual is at any time determined to be an Employee; (v) on or after the Effective Time, an individual who was employed immediately prior to the Effective Time (as such term is defined in the Merger Agreement) at CEG or a facility owned immediately before the Effective Time by CEG and (vi) an individual who is newly employed on or after the Effective Time (as such term is defined in the Merger Agreement) at a facility owned immediately before the Effective Time by CEG. Notwithstanding anything contained in the Plan to the contrary, any Employer may, at the time such Employer elects to participate in this Plan in the manner described in Section 11.1 (relating to adoption of the Plan), designate, with the consent of the Company, a specified group of Employees who will be Eligible Employees. In the case of Unicom Thermal Technologies Inc. ("Unicom Thermal"), the term "Eligible Employee" shall mean only those persons rendering service to Unicom Thermal who (i) formerly were employed by the Company, (ii) transferred from the employment of the Company to the employment of Unicom Thermal at the request of the Company, (iii) are

otherwise described in the definition of Eligible Employee set forth in this subdivision (16) and (iv) completed at least ten years of Credited Service under the Plan at the time of transfer from the employment of the Company to the employment of Unicom Thermal; provided, however, any such Employee who had at least eight years of Credited Service at the time of such transfer shall continue to be an Eligible Employee in the Plan until such Employee completes ten years of Credited Service. In the case of any individual who, as of December 31, 2000, was an Employee of Commonwealth Edison Company and who subsequently transfers employment to employment with the Exelon Power Team, such individual shall remain an Eligible Employee through the second anniversary of the date of such transfer of employment, and shall not thereafter be an Eligible Employee. Notwithstanding the preceding sentence, an individual who, as of December 31, 2000, was an Employee of Commonwealth Edison Company and who transferred employment to employment with the Exelon Power Team shall be an Eligible Employee as of January 1, 2004, and, without limiting the preceding clause, an individual who transfers employment from employment with an Employer to employment with the Exelon Power Team during 2003 and who was an Eligible Employee immediately prior to such transfer shall continue to be an Eligible Employee until December 31, 2003 and each individual who transfers employment from the Exelon Power Team to an Employer during 2003 shall not be an Eligible Employee prior to January 1, 2004. In the case of Exelon Services Inc., the term "Eligible Employee" shall be limited to those Employees of Exelon Services Inc. who were on the payroll of Unicom Energy Solutions as of April 1, 2001 and are otherwise Eligible Employees. Notwithstanding anything contained herein to the contrary, an Eligible Employee shall not include an individual who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 6.9 (relating to Special Lump Sum Payment Option).

(18) Employee . An individual whose relationship with an Employer is, under common law, that of an employee.

(19) Employer . The Company and any other Affiliate set forth on Appendix I hereto that, with the consent of the Company, elects to participate in the Plan in the manner described in Section 11.1 (relating to adoption of the Plan) either with respect to all Employees or a specified group of Employees of such Affiliate and any successor Affiliate that adopts this Plan pursuant to Article 12 (relating to continuance by a successor). If any entity described in the preceding sentence withdraws from participation in the Plan pursuant to Section 15.3 (relating to termination of the Plan by an Employer), such entity shall thereupon cease to be an Employer. Appendix I shall be updated from time to time by the Company to reflect any adoption pursuant to Section 11.1, but the failure to so update such Appendix shall not affect the effectiveness of any such adoption. Such adoptions will be effective whether occurring before, on or after the Effective Date and whether or not reflected in Appendix I.

(20) ERISA . The Employee Retirement Income Security Act of 1974, as amended.

(21) Federal Benefit . The annual amount of full old age benefits which would be payable to the Participant under the Federal Social Security Act at the age at which full old age benefits would be payable to such Participant under such Act. Except as provided in the following sentence, the amount of the Federal Benefit and the age at which full old age benefits become payable shall be determined as of December 25, 1994 in accordance with the provisions of the Plan as in effect on such date. Notwithstanding the preceding sentence, solely for purposes of Section 5.6 (relating to Federal Benefit supplemental payments), the amount of Federal Benefit and the age at which full old age benefits become payable shall be determined at the time of a Participant's Termination of Employment by using the terms of the Federal Social Security Act as in effect at such time. For purposes of the preceding sentence, the amount of Federal Benefit shall be computed (a) with respect to a member of IBEW Local Union 15 whose Termination of Employment occurs on or after January 1, 2011, by using the Participant's compensation subject to tax under the Federal Insurance Contributions Act (other than the Medicare portion), and (b) with respect to any other Participant, by using an estimated wage history determined by applying a salary scale based on the actual change in the average national wage from year to year as determined by the Social Security Administration, projected backwards, to the Participant's compensation subject to tax under the Federal Insurance Contributions Act (other than the Medicare portion) for the calendar year ending immediately prior to the Participant's Termination of Employment. Notwithstanding the preceding sentence, in no event shall a Participant's Federal Benefit be greater than the Federal Benefit determined by using a wage history that assumes the Participant earned no compensation for periods prior to employment with the Company and Affiliates and uses actual compensation paid by the Company and Affiliates for periods of employment with the Company and Affiliates and, in the case of a Participant who is absent from employment due to employment by a union that represents any group of Employees, uses actual compensation paid by such union for periods of employment with such union

(22) Highest Average Annual Pay . The sum of a Participant's average annual Basic Compensation and Incentive Pay (a) with respect to any Participant who, as of the date of the Participant's Termination of Employment, is not a member of IBEW Local Union 15, during the four consecutive years (104 biweekly pay periods), and (b) with respect to any Participant who, as of the date of the Participant's Termination of Employment, is a member of IBEW Local Union 15, during which such average annual Basic Compensation and Incentive Pay was the highest, or (c) during all years of the Participant's Credited Service if such Credited Service is less than 104 or 78 biweekly pay periods, as applicable. In determining whether a Participant has 104 or 78 consecutive biweekly pay periods, as applicable, any period of uncompensated absence from employment with an Employer, other than an absence due to participation in Military Service shall be disregarded. In computing "Highest Average Annual Pay," the total of

the Basic Compensation and Incentive Pay for a Participant for the applicable consecutive pay periods shall be multiplied, in the case of 104 pay periods by 0.25068654 and in the case of 78 pay periods by 0.33424872; provided, that in the case of a Participant whose years of Credited Service include fewer than 104 or 78 pay periods, as applicable, the multiplier shall be a fraction the numerator of which is one and the denominator of which is the quotient of (a) the number of 14-day periods during each 365-day period (or if less, during the Participant's Credited Service) and (b) the number of pay periods during the Participant's years of Credited Service. In addition, notwithstanding anything herein to the contrary, in computing an Employee's Highest Average Annual Pay, the aggregate amount of the Employee's Basic Compensation and Incentive Pay in excess of the following limits shall not be taken into account: (i) for Plan Years ending before January 1, 1996, $200,000 (as adjusted for increases in the cost of living pursuant to Section 415(d) of the Code for the year in which the computation of Basic Compensation and Incentive Pay is being made), (ii) for Plan Years beginning on or after January 1, 1996 and before January 1, 2002, $150,000 (adjusted for increases in the cost of living in accordance with Section 401(a)(17) of the Code), and (iii) for all Plan Years beginning on or after January 1, 2002, $200,000 (adjusted for increases in the cost of living in accordance with Section 401(a)(17) of the Code). For purposes of the preceding sentence, the limit determined with respect to clause (i) for the last year for which the computation is made shall be applied for such year and all preceding years. For Plan Years beginning before January 1, 1997, the Basic Compensation and Incentive Pay of an Employee who is a 5% owner of Commonwealth Edison Company or any Affiliate or one of the ten employees of Commonwealth Edison Company and all Affiliates who was paid the greatest compensation (as defined in Section 415 of the Code) for the Plan Year shall include the Basic Compensation and Incentive Pay of the Employee's spouse and any lineal descendants of the Employee who have not attained age 19 before the close of the Plan Year.

(23) Hour of Service . (a) Each hour for which an Employee is paid, or entitled to payment, for the performance of duties (such hours to be credited to the Employee for the computation period or periods in which the duties are performed); (b) each hour for which an Employee is paid, or entitled to payment, on account of a period of time during which no duties are performed (irrespective of whether a Termination of Employment has occurred) due to vacation, holiday, illness, incapacity (including disability), layoff, jury duty, military duty or leave of absence (such hours to be credited to the Employee for the computation period or periods in which the period of time during which no duties are performed occurs); and (c) each hour for which back pay, irrespective of mitigation of damages, is either awarded or agreed to by an Employer (such hours to be credited to the Employee for the computation period or periods in which the award or agreement pertains rather than the computation period in which the award, agreement or payment is made). Hours of Service shall be computed in accordance with paragraphs (b) and (c) of Section 2530.200b-2 of the Department of Labor Regulations.

(24) Incentive Pay . The payments, if any, earned by the Participant with respect to each year of Credited Service after 1994, regardless of when paid, under the plans set forth in Exhibit 2 attached hereto. Incentive Pay shall also include with respect to each year of Credited Service commencing after December 31, 2002, lump sum merit increases paid during such year of Credited Service. In the case of a Participant who is absent from employment due to employment by a union that represents any group of Employees, Incentive Pay shall mean, for the period during which the Participant is absent from employment, the payments the Participant would have received under the applicable plan set forth in Exhibit 2 attached hereto, as determined by the union employing such Participant.

(25) Investment Office . The Company acting through the Exelon Investment Office.

(26) Merger Agreement . That Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc

(27) Military Service . The performance of duty on a voluntary or involuntary basis in a "uniformed service" (as defined below) under competent authority of the United States government and includes active duty, active duty for training, initial active duty for training, inactive duty training, full-time National Guard duty, and a period for which a person is absent from employment for the purpose of an examination to determine the fitness of the person to perform any such duty. For purposes of the preceding sentence, the term "uniformed service" means the Armed Forces, the Army National Guard and the Air National Guard when engaged in active duty for training, inactive duty training, or full-time National Guard duty, the commissioned corps of the Public Health Service, and any other category of persons designated by the President of the United States in time of war or emergency.

(28) Normal Retirement Age . A Participant's 65th birthday.

(29) Participant . An Employee described in Article 3 (relating to participation). An individual shall cease to be a Participant upon the date the individual is no longer eligible to receive a benefit from this Plan (including, without limitation, upon his or her receipt of a Special Lump Sum Payment as defined in Section 6.9 (relating to Special Lump Sum Payment Option)) or upon the individual's Termination of Employment if the individual has not completed at least five years of Vesting Service upon the date of his or her Termination of Employment and is not otherwise eligible to receive a benefit from this Plan.

(30) Plan . The Plan herein set forth, as from time to time amended, which is part of the Exelon Corporation Retirement Program.

(31) Plan Year . The calendar year.

(32) Regulations . Written promulgations of the Department of Labor construing Title I of ERISA or the Internal Revenue Service construing the Code.

(33) Retiree . A Participant or Beneficiary receiving a Service Annuity.

(34) Service Annuity . The amount payable to a Retiree from the Service Annuity Fund under the Plan. Except as otherwise indicated by the context, such term includes an annuity payable pursuant to paragraph (b) of Section 6.1 (relating to annuities payable to married Participants), Section 6.2 (relating to optional Service Annuity forms), Section 6.3 (relating to surviving spouse annuities, Section 5.6 (relating to Federal Benefit supplemental payments), Section 5.7 (relating to deferred vested termination) and Section 6.4 (relating to a surviving Child annuity). Notwithstanding the foregoing, a Participant shall not be entitled to any amount payable from the Service Annuity Fund under the Plan following the Participant's receipt of a Special Lump Sum Payment within the meaning of Section 6.9 (relating to Special Lump Sum Payment Option).

(35) Service Annuity Fund . All money and property of every kind held by the Trustee under the Trust Agreement.

(36) Spouse . The individual who is the husband or wife of a Participant as the result of a legal union between one man and one woman, within the meaning of the Defense of Marriage Act, on the Participant's Pension Starting Date, or if earlier, on the date of the Participant's death. While the Spouse is living and, except as otherwise provided in a qualified domestic relations order as described in paragraph (b) of Section 13.2 (relating to exception to nonassignability in the case of a qualified domestic relations order) or paragraph (c) of Section 6.6 (relating to automatic cancellation of elections), such Spouse shall be treated as the Participant's Spouse for all purposes of this Service Annuity System without regard to whether such Spouse remains married to the Participant after the Participant's Annuity Starting Date.

(37) Termination of Employment . A Participant's ceasing to be an Employee of any Employer or any Affiliate. A transfer between employment by an Employer and employment by an Affiliate or between employment by Employers or Affiliates shall not constitute a Termination of Employment.

(38) Total and Permanent Disability . A disability which, in the opinion of the Administrator, renders the Participant unable to perform the principal duties of the Participant's regular job classification or such other job classification as may be made available to the Participant by an Employer or an Affiliate and which results from a cause other than one or more of the following, as determined by the Administrator, in its sole discretion:

(i) excessive or habitual use of drugs, intoxicants, narcotics or alcohol;

(ii) injury or disease sustained while participating in illegal activities; or

(iii) injury or disease sustained while employed by another Employer and arising out of such other employment.

(39) Trust Agreement . The agreement between the Company and the Trustee governing the Service Annuity Fund.

(40) Trustee . The trustee of the Service Annuity Fund or, if there shall be more than one trustee acting at any time, all of such trustees collectively.

(41) Vesting Service . The period of an Employee's employment which is used to determine whether the Employee is entitled to receive a Service Annuity under Article 5 (relating to Service Annuities). An Employee's Vesting Service includes (a) the Participant's vesting service prior to the Effective Date determined in accordance with the provisions of the Plan as in effect prior to the Effective Date, (b) to the extent not duplicative, for an Employee who terminated prior to January 1, 2003, any additional service for actual employment credited to such Employee prior to the Effective Date in an Employer's employment records pursuant to Commonwealth Edison Company's service bridging policy and (c) the aggregate of the periods beginning on or after the Effective Date during which the Employee is employed by an Employer or an Affiliate, provided that in the case of an Employee who has no vested right to any benefits under this Plan, such Employee's periods of Vesting Service before and after a period of absence from employment shall be aggregated only when the Employee's number of consecutive one-year periods of absence from employment is less than five and the Employee has at least one year of Vesting Service after such period of absence from employment. For purposes of the preceding sentence, an Employee shall be deemed to be employed by an Employer or an Affiliate during (a) any period of absence from employment by an Employer or an Affiliate which is of less than twelve months' duration, (b) the first twelve months of any period of absence from employment for any reason other than the Employee's quitting, retiring or being discharged, except as provided in clause (f) below, (c) any period during which the Employee is in Military Service, provided that the Employee returns to the employ of an Employer or an Affiliate within the period prescribed by laws relating to the reemployment rights of persons in Military Service, (d) any period, whether less than or greater than twelve months, during which the Participant is employed by a union that represents any group of Employees, (e) the period following Termination of Employment on account of a Total and Permanent Disability during which the Participant is receiving benefits under any Employer's long term disability plan and (f) as and to the extent provided by resolutions of the board of directors of the Company, any period of authorized absence from employment as an Eligible Employee. The Administrator may require certification from an Employee, as a condition of granting Vesting Service under this subdivision (39), that the leave was taken for one of the reasons enumerated in the preceding sentence. Notwithstanding the preceding sentences, in

determining an Employee's period of absence from employment by an Employer or an Affiliate, the following shall be disregarded: the first twenty-four months of any period of absence from employment by reason of (i) the Employee's pregnancy, (ii) the birth of the Employee's child, (iii) the placement of a child with the Employee in connection with the adoption of such child by such Employee or (iv) caring for such child for a period beginning immediately following such birth or placement.

Section 2.2. Gender and Plurals . Wherever used in this Plan, words in the masculine gender shall include masculine or feminine gender, and, unless the context otherwise requires, words in the singular shall include the plural, and words in the plural shall include the singular.

Section 2.3. Definition of "Highly Compensated Employee" . Wherever applicable for purposes of satisfying legal requirements applicable to the Plan, the term "highly compensated employee" shall mean any Employee who performs service in the determination year and who (a) is a 5%-owner (as determined under section 416(i)(1)(A)(iii) of the Code) at any time during the Plan Year or the preceding Plan Year or (b) both (1) is paid compensation in excess of $80,000 (as adjusted for increases in the cost of living in accordance with section 414(q)(1)(B)(ii) of the Code) from an Employer for the preceding Plan Year, and (2) is in the group of employees consisting of the top 20% of the employees of the Employer and its Affiliates when ranked on the basis of compensation paid during such preceding Plan Year.

ARTICLE 3

PARTICIPATION

Section 3.1. Employees Represented by IBEW Local Union 15 . Each Eligible Employee who is a member of a collective bargaining unit represented by IBEW Local Union 15 and who was a Participant in the Plan on December 31, 2000 shall continue to be a Participant as of January 1, 2001. Each other Eligible Employee who is a member of IBEW Local Union 15

shall become a Participant as of the first day that such Eligible employee completes an Hour of Service with an Employer as an Eligible Employee, provided that such Eligible Employee does not elect, in the time and manner prescribed by the Administrator for such an election, to participate in the Exelon Corporation Pension Plan for Bargaining Unit Employees. Notwithstanding the foregoing, effective January 1, 2009, an Employee who is a member of a collective bargaining unit represented by IBEW Local Union 15 and whose first Hour of Service with an Employer is on or after January 1, 2009 shall not be an Eligible Employee and shall not be eligible to become a Participant at any time.

Section 3.2. Management Employees . (a) In General . Each Participant who is not a member of a collective bargaining unit represented by IBEW Local Union 15 and who is, as of January 1, 2002, an Eligible Employee shall be permitted to elect, in the time and manner prescribed by the 'Committee', as such term was defined in the Plan prior to June 1, 2006, to either (i) continue participating in the Plan on and after January 1, 2002 or (ii) cease participating in the Plan as of December 31, 2001 and begin participating in the Exelon Corporation Cash Balance Pension Plan as of January 1, 2002. Each Eligible Employee who elects to continue participating in the Plan or who is offered and fails to make any such election shall continue to be a Participant as of January 1, 2002. Each Eligible Employee who elects to participate in the Exelon Corporation Cash Balance Pension Plan in lieu of participation in this Plan shall cease participation in the Plan as of December 31, 2001 and shall not be entitled to any benefit under the Plan, unless such Participant receives a notification (the "Notice") from an Employer that his or her employment with the Employers and their Affiliates will be terminated on or before December 31, 2002 and that such Participant is eligible for severance benefits under the Exelon Corporation Merger Separation Plan for Designated Management Employees or any other

severance plan maintained by an Employer or an Affiliate. An Eligible Employee who receives a Notice shall continue to be a Participant in the Plan until his or her Termination of Employment, notwithstanding such Eligible Employee's election to participate in the Exelon Corporation Cash Balance Pension Plan. An Eligible Employee (i) who receives a Notice, but whose employment does not terminate on or before December 31, 2002, or (ii) whose employment terminates before December 31, 2002 without the Employee receiving a Notice shall cease participation in the Plan as of December 31, 2001 if such Employee elects, in the time and manner prescribed by the 'Committee', as such term was defined in the Plan prior to June 1, 2006, to participate in the Exelon Corporation Cash Balance Pension Plan.

Effective as of January 1, 2004, each Eligible Employee (i) who is an employee of the Exelon Power Team, (ii) who, as of December 31, 2000, was an Employee of Commonwealth Edison Company and is, as of January 1, 2004, an Eligible Employee, (iii) who was, at any time prior to January 1, 2004, a Participant and (iv) who did not previously make a valid election pursuant to the preceding paragraph shall be permitted to elect, in the time and manner prescribed by the 'Committee', as such term was defined in the Plan prior to June 1, 2006, to either (A) resume or continue participation in the Plan as of January 1, 2004 or (B) participate in the Exelon Corporation Cash Balance Pension Plan as of January 1, 2004. Each such Eligible Employee who affirmatively elects to resume or continue participation in the Plan in lieu of participation in the Exelon Corporation Cash Balance Pension Plan shall resume or continue participation in this Plan as of January 1, 2004.

(b) Transfer of Benefits and Assets to Cash Balance Pension Plan . If an Eligible Employee described in paragraph (a) above elects to participate in the Exelon Corporation Cash Balance Pension Plan in lieu of participating in the Plan, the Employee's Service Annuity, determined as of December 31, 2001, or December 31, 2003, as the case may be, based on the Employee's Credited Service and Highest Annual Average Pay as of such date but without giving effect to Section 5.6, shall be transferred to the Exelon Corporation Cash Balance Pension Plan and such Employee shall not accrue any additional benefit under the Plan. An amount of assets that is equal to the present value of the Participant's Service Annuity described in the preceding sentence, determined using the methods and assumptions prescribed by Section 4044 of ERISA, shall also be transferred to the Exelon Corporation Cash Balance Pension Plan. Such transfer of benefits and assets related thereto shall occur as soon as administratively practicable after the Eligible Employee makes the election described in paragraph (a) above. In the event that an Eligible Employee whose Service Annuity and related assets are transferred to the Exelon Corporation Cash Balance Pension Plan receives a Notice and has a Termination of Employment on or before December 31, 2002, the Service Annuity and related assets that were transferred to the Exelon Corporation Cash Balance Pension Plan shall be transferred back to the Plan and the amount of the pension benefit accrued by such Employee during 2002 (if any) shall be determined under the terms of this Plan rather than the Exelon Corporation Cash Balance Pension Plan. Such transfer shall occur as soon as administratively practicable.

Section 3.3. Cessation of Participation . An individual's participation in the Plan shall cease upon the date the individual is no longer eligible to receive a benefit from this Plan or upon the individual's Termination of Employment if the individual has not completed at least five years of Vesting Service upon the date of his or her Termination of Employment and is not otherwise eligible to receive a benefit from this Plan.

Section 3.4. Certain Rehired Employees . Notwithstanding anything contained herein to the contrary, no Employee who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 6.9 (relating to Special Lump Sum Payment Option) shall be eligible to become a Participant pursuant to this Article 3.

ARTICLE 4

CONTRIBUTIONS

Section 4.1. Amount of Contributions . The Employers intend to make contributions to the Service Annuity Fund of amounts which, in the aggregate over a period of time, are sufficient to finance the benefits provided by the Plan. All such contributions shall be in such amounts and shall be made in such manner and at such time as the Company shall from time to time determine in accordance with the funding policy it establishes and consistent with minimum funding standards under Section 412 of the Code. the Company may rely on the advice of actuaries in establishing and carrying out a funding policy. Forfeitures arising under the Plan for any reason shall be applied to reduce the cost of the Plan, not to increase the Service Annuities payable to Participants, Beneficiaries or Retirees.

Section 4.2. Return of Contributions . Any contribution made to the Service Annuity Fund by an Employer by reason of a good faith mistake of fact, or any contribution made to the Service Annuity Fund by an Employer which exceeds the maximum amount for which a deduction is allowable to the Employer for federal income tax purposes by reason of a good faith mistake in determining the maximum deductible amount, shall upon the request of the Employer be returned by the Trustee to the Employer. The Employer's request and the return of any such contribution must be made within one year after such contribution was mistakenly made or after the deduction of such excess portion of such contribution was disallowed, as the case may be. The amount to be returned to the Employer pursuant to this Section 4.2 shall be the excess of (a) the amount contributed over (b) the amount that would have been contributed had there not been a mistake of fact or a mistake in determining the maximum allowable deduction. Earnings attributable to the amount contributed by mistake shall not be returned to the Employer, but losses attributable thereto shall reduce the amount so returned.

ARTICLE 5

SERVICE ANNUITIES

Section 5.1. Description of Service Annuities . Each Participant whose Termination of Employment occurs on or after his or her Normal Retirement Age shall be entitled to a Service Annuity as described in Section 5.2 (relating to normal and deferred retirement). Each Participant whose Termination of Employment occurs prior to the Participant's 65th birthday but after the Participant has completed at least ten years of Credited Service and has attained age 50 shall be entitled to a Service Annuity as described in Section 5.3 (relating to early retirement). Each Participant whose Termination of Employment occurs on or after the Participant's 45th birthday on account of a Total and Permanent Disability shall be entitled to a Service Annuity as described in Section 5.4 (relating to disability retirement at or after age 45), provided such Participant has satisfied the conditions set forth in Section 5.4. Each Participant who has completed at least ten years of Credited Service and whose Termination of Employment occurs prior to the Participant's 45th birthday on account of Total and Permanent Disability shall be entitled to a Service Annuity as described in Section 5.5 (relating to disability retirement before age 45), provided such Participant has satisfied the conditions set forth in Section 5.5. Each Participant whose Termination of Employment occurs after the Participant has completed at least five years of Vesting Service but who is not described in any of the preceding sentences shall be entitled to a Service Annuity described in Section 5.7 (relating to deferred vested termination).

Section 5.2. Normal and Deferred Retirement . (a) In General . Each Participant whose Termination of Employment occurs on or after the Participant's Normal Retirement Age shall be entitled, subject to Section 6.1 (relating to the basic Service Annuity form of payment), to receive a Service Annuity payable in semi-monthly payments for the Participant's lifetime commencing on the Service Annuity payment date immediately following the day the Participant's status on the Human Resource system of the Company is changed to "inactive." The annual amount of such Service Annuity shall equal, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), the sum of the amounts described in subparagraphs (A), (B) and (C) below:

(A) 1.25% of the Participant's Earnings, reduced by 25% (less 1% for each year, if any, by which the Participant's years of Credited Service as of December 25, 1994 are less than 35, computed to the nearest full year) of the Participant's Federal Benefit, determined as of December 25, 1994.

(B) 1.60% (1.62% for Participants who terminate employment on or after October 1, 2008 and were a member of a collective bargaining unit represented by IBEW Local Union 15 immediately prior to termination of employment) of the Participant's Highest Average Annual Pay, multiplied by the number of years of the Participant's Credited Service (not in excess of 40 years).

(C) 0.5% of the Participant's Highest Average Annual Pay, multiplied by the number of years, if any, by which the Participant's years of Credited Service (not in excess of 40) exceed the limitation on the number of years of Credited Service taken into account under subparagraph (B) of paragraph (a) of this Section 5.2.

Notwithstanding the preceding, the annual amount of the Service Annuity for a Participant who has at least 10 years of Credited Service shall not be less than the applicable amount stated in Table A.

(b) Special Rule for Participants Who Attain Age 70- 1/2 While Employed . If a Participant remains employed by an Employer or an Affiliate beyond April 1 of the year following the year in which the Participant attains age 70- 1/2 , distribution of such Participant's Service Annuity (i) shall commence, in the case of a Participant who is a 5-percent owner as defined in Section 416(i) of the Code, or (ii) may commence, upon any other such Employee's election, in either case, not later than April 1 next following the calendar year in which the Participant attains age 70- 1/2 .

The annual amount of the Participant's Service Annuity that commences under the preceding paragraph shall be recomputed pursuant to this Section 5.1 (relating to normal and deferred retirement) as of each succeeding April 1 to reflect any increase in the Participant's Credited Service and Highest Average Annual Pay attributable to the Participant's employment since the preceding April 1.

Notwithstanding anything in the Plan to the contrary, the form and timing of all distributions under the Plan to any Participant shall be in accordance with Section 401(a)(9) of the Code and regulations issued thereunder, including the incidental death benefit requirements of Section 401 (a)(9)(G) of the Code and Treasury Regulation §1.401(a)(9)-2 through Treasury Regulation §1.401(a)(9)-9.

(c) Basic Compensation for Participant with Total and Permanent Disability . In the case of a Participant whose Termination of Employment is on account of a Total and Permanent Disability and who is entitled to a Service Annuity under either paragraph (b) of Section 5.4 (relating to disability retirement at or after age 45 for management Employees) or paragraph (b) of Section 5.5 (relating to disability retirement before age 45 for management Employees), Basic Compensation shall mean, for the period following the Participant's

Termination of Employment and during which the Participant is receiving benefits under any Employer's long term disability plan, the Participant's base pay rate per pay period in effect immediately preceding the first day of the Participant's absence due to such Total and Permanent Disability increased each October 1 following the Participant's Termination of Employment at a rate equal to the cost of living adjustment described in the following sentence. For purposes of the preceding sentence, the cost of living adjustment shall equal, for each October 1, the percentage by which the Consumer Price Index for the July immediately preceding such October 1 exceeds the Consumer Price Index for the July immediately preceding the twelve month period beginning October 1 in which the Participant's Termination of Employment occurred; provided, however, that:

(i) If, as of such October 1, there shall be no such excess, the adjustment percentage shall be deemed to be zero for the twelve-month period beginning on such October 1.

(ii) There shall be no negative adjustment percentage.

(iii) The aggregate adjustment percentage for any twelve-month period beginning October 1 shall never be lower than the aggregate adjustment percentage for the preceding such period.

(iv) If the percentage increase in the Consumer Price Index computed for the twelve-month period beginning on October 1 does not exceed the aggregate adjustment percentage for the preceding twelve-month period by at least three percentage points, the aggregate adjustment percentage for the preceding twelve-month period shall continue in effect during such twelve-month period beginning on October 1.

(v) The aggregate adjustment percentage for any twelve-month period beginning on October 1 shall not be more than seven percentage points greater than that for the preceding twelve-month period. If the aggregate adjustment percentage for any twelve-month period beginning on October 1 exceeds by more than seven percentage points the aggregate adjustment percentage for the preceding twelve-month period, the excess shall be carried over to succeeding twelve-month periods until such excess is reduced to zero.

(vi) The adjustment percentage for the twelve-month period beginning with the October 1 next following the date the Participant's Termination of Employment occurs shall be the adjustment percentage determined in accordance with the preceding provisions of this Section 5.2(c) multiplied by a fraction the numerator of which shall be the number of full calendar months between such date and such October 1 and the denominator of which shall be twelve.

The adjustment described in this Section 5.2(c) shall continue to be made unless and until the Participant ceases to be eligible to receive benefits under any Employer's long term disability plan. Notwithstanding the preceding sentence, if a Participant returns to employment with any Employer and ceases to be eligible to receive benefits under any Employer's long term disability plan but again becomes eligible to receive such benefits as a continuation of the same Total and Permanent Disability, as determined under the provisions, or interpretations, of the Employer's long term disability plan, the adjustments described in this Section 5.2(c) shall continue to be made as though the Participant had never ceased to be eligible for such benefits, provided that an adjustment shall be made for any earnings received by the Participant while the Participant was employed by any Employer.

Section 5.3. Early Retirement . Each Participant whose Termination of Employment occurs prior to the Participant's 65 th birthday but after the Participant has completed at least ten years of Credited Service and has attained age 50 shall be entitled to elect, subject to Section 6.1 (relating to the basic Service Annuity form of payment), to receive an early retirement Service Annuity payable in semi-monthly payments for the Participant's lifetime commencing no earlier than the Service Annuity payment date immediately following the day the Participant's status on the Human Resource system of the Company is changed to "inactive" and no later than the Service Annuity payment date coinciding with or immediately following the date the Participant attains age 65. The annual amount of such early retirement Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary

restrictions on benefits in the case of termination or curtailment) be the amount computed pursuant to Section 5.2 (relating to normal and deferred retirement) multiplied by the applicable factor (determined with reference to the Participant's attained age at the time benefits commence to be paid) from (a) with respect to any Participant who is not a member of IBEW Local Union 15, Table B, and (b) with respect to any Participant who is a member of IBEW Local Union 15, Table B-1.

Section 5.4. Disability Retirement at or After Age 45 . (a) Rules Applicable to Union Employees . Each Eligible Participant (as defined in the following paragraph) whose Termination of Employment occurs on or after the Eligible Participant's 45th birthday on account of a Total and Permanent Disability and who is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement) or Section 5.3 (relating to early retirement) shall be entitled to elect, subject to Section 6.1 (relating to the basic Service Annuity form of payment), without regard to the number of the Eligible Participant's years of Credited Service, to receive a disability Service Annuity payable in semi-monthly payments for the Eligible Participant's lifetime commencing no earlier than the Service Annuity payment date immediately following the day the Eligible Participant's status on the Human Resource system of the Company is changed to "inactive" and no later than the Service Annuity payment date coinciding with or immediately following the date the Eligible Participant attains age 65. The annual amount of such disability Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), be the amount computed pursuant to Section 5.3 (relating to early retirement), except that if the Eligible Participant's employment terminated on account of a Total and Permanent Disability prior to the Eligible Participant's 55th birthday, the Eligible Participant shall be treated as though he or she attained age 55 for purposes of determining the applicable factor from Table B.

For purposes of this Section 5.4, an "Eligible Participant" shall mean a Participant who, at the time the Participant's employment terminates, is a member of Local Union 15, International Brotherhood of Electrical Workers.

(b) Rules Applicable to Management Employees . Each Participant who is a management Employee, whose Termination of Employment occurs on or after the Participant's 45th birthday on account of a Total and Permanent Disability and who is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement) or Section 5.3 (relating to early retirement) shall be entitled to elect, subject to Section 6.1 (relating to the basic Service Annuity form of payment), without regard to the number of the Participant's years of Credited Service, to receive a disability Service Annuity payable in semi-monthly payments for the Participant's lifetime commencing no earlier than the Service Annuity payment date immediately following the day the Participant's status on the Human Resource system of the Company is changed to "inactive", provided that such Participant (i) shall have qualified for and received long-term disability benefits under the Exelon Corporation Disability Benefit Plan for Management Employees (the "LTD Plan"), (ii) shall be eligible to receive Social Security benefits on account of such disability and (iii) shall no longer be eligible to receive benefits under the LTD Plan because such benefits have been exhausted. In no event shall the semi-monthly payments described in the preceding sentence commence later than the later of (a) the Service Annuity payment date coinciding with or immediately following the date the Participant attains age 65 and (b) the date the Participant ceases to be eligible to receive benefits under the

LTD Plan because such benefits have been exhausted. The annual amount of such disability Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), be the amount computed pursuant to Section 5.3 (relating to early retirement), except that if the Participant's employment terminated on account of a Total and Permanent Disability prior to the Participant's 55th birthday, the Participant shall be treated as though he or she attained age 55 for purposes of determining the applicable factor from Table B.

Section 5.5. Disability Retirement Before Age 45 . (a) Rules Applicable to Union Employees . Each Eligible Participant (as defined in the following paragraph) who has completed at least 10 years of Credited Service and whose Termination of Employment occurs prior to the Eligible Participant's 45th birthday on account of a Total and Permanent Disability shall be entitled to elect, subject to Section 6.1 (relating to the basic Service Annuity form of payment), to receive a reduced disability Service Annuity payable in semi-monthly payments for the Eligible Participant's lifetime commencing no earlier than the Service Annuity payment date immediately following the day the Eligible Participant's status on the Human Resource system of the Company is changed to "inactive" and no later than the Service Annuity payment date coinciding with or immediately following the date the Eligible Participant attains age 65. The annual amount of such reduced disability Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), be the sum of (a) the amount computed pursuant to Section 5.4 (relating to disability retirement at or after age 45) plus (b) the excess, if any, of (i) 25% of the Eligible

Participant's Highest Average Annual Pay over (ii) the sum of the annual amount computed under Section 5.4 (relating to disability retirement at or after age 45) plus the aggregate annual amount of the Federal Benefit supplemental payments payable to such Eligible Participant pursuant to Section 5.6 (relating to the Federal Benefit supplemental payments).

For purposes of this Section 5.5, an "Eligible Participant" shall mean a Participant who, at the time the Participant's employment terminates, is a member of Local Union 15, International Brotherhood of Electrical Workers.

(b) Rules Applicable to Management Employees . Each Participant who is a management Employee, who has completed at least 10 years of Credited Service and whose Termination of Employment occurs prior to the Participant's 45th birthday on account of a Total and Permanent Disability shall be entitled to elect, subject to Section 6.1 (relating to the basic Service Annuity form of payment), to receive a reduced disability Service Annuity payable in semi-monthly payments for the Participant's lifetime commencing no earlier than the Service Annuity payment date immediately following the day the Participant's status on the Human Resource system of the Company is changed to "inactive" and no later than the Service Annuity payment date coinciding with or immediately following the date the Participant attains age 65 provided, that such Participant (i) shall have qualified for and received long-term disability benefits under the LTD Plan, (ii) shall be eligible to receive Social Security benefits on account of such disability and (iii) shall no longer be eligible to receive benefits under the LTD Plan because such benefits have been exhausted. The annual amount of such reduced disability Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), be the sum of (a) the

amount computed pursuant to Section 5.4 (relating to disability retirement at or after age 45) plus (b) the excess, if any, of (i) 25% of the Participant's Highest Average Annual Pay over (ii) the sum of the annual amount computed under Section 5.4 (relating to disability retirement at or after age 45) plus the aggregate annual amount of the Federal Benefit supplemental payments payable to such Participant pursuant to Section 5.6 (relating to the Federal Benefit supplemental payments).

Section 5.6. Federal Benefit Supplemental Payments Prior to Age 65 . Each Participant whose Service Annuity is computed pursuant to Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45) or Section 5.5 (relating to disability retirement before age 45) and which commences prior to the Participant's attainment of age 65 shall receive supplemental monthly payments each in an amount equal to 80% of the amount of the Participant's monthly Federal Benefit and, except in the case of a Participant whose Service Annuity is computed under Section 5.5 (relating to disability retirement before age 45), shall have his or her Service Annuity reduced by an amount equal to the product of (a) the aggregate annual amount of such supplemental monthly payments multiplied by (b) the applicable factor (determined with reference to the Participant's attained age at the time benefits commence to be paid) from (i) with respect to any Participant who is not a member of IBEW Local Union 15, Table B-2, and (ii) with respect to any Participant who is a member of IBEW Local Union 15, Table B-3.

Section 5.7. Deferred Vested Termination . Each Participant whose Termination of Employment occurs after the Participant has completed at least five years of Vesting Service and who is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability

retirement at or after age 45) or Section 5.5 (relating to disability retirement before age 45) shall be entitled, subject to Section 6.1 (relating to the basic Service Annuity form of payment), to receive a deferred Service Annuity payable in semi-monthly payments for the Participant's lifetime commencing as soon as practicable after the date elected, in the manner prescribed by the Administrator, by the Participant but not earlier than the later of (i) the day the Participant's status on the Human Resource system of the Company is changed to "inactive" and (ii) the Participant's 60th birthday or, in the case of a Participant who completed at least ten years of Credited Service, the Participant's 50th birthday. The annual amount of such deferred Service Annuity shall, subject to Section 5.8 (relating to special rules for computation of Service Annuities), Section 7.1 (relating to maximum annual benefits) and Section 7.2 (relating to temporary restrictions on benefits in case of termination or curtailment), be the amount computed under Section 5.2 (relating to normal and deferred retirement) multiplied by the applicable factor from Table F to reflect the Participant's age, if less than 65, at the date upon which payment of the Participant's deferred Service Annuity commences. In no event shall a Participant's election hereunder to begin receiving payment of his or her Service Annuity permit such payments to begin later than April 1 of the calendar year following the calendar year in which the Participant attains age 70- $^{1}/_{2}$. Notwithstanding anything herein to the contrary, if a Participant entitled to a deferred Service Annuity under this Section 5.7 fails to make an election to begin receiving his or her deferred Service Annuity, payment of the Participant's Service Annuity shall commence no later than 60 days following the Plan Year in which the Participant attains age 65.

Each Participant whose employment is terminated before the Participant completes at least five years of Vesting Service and who is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45) or Section 5.5 (relating to disability retirement before age 45) shall be entitled to no benefits whatsoever under this Plan. Such a Participant's vested interest in his or her benefit under the Plan shall have a value of zero and such Participant shall be deemed to receive immediately upon the Participant's Termination of Employment a lump sum distribution of such vested interest and concurrent therewith the Participant shall forfeit his or her accrued benefit under the Plan.

Section 5.8. Special Rules Applicable to the Computation of Service Annuities . (a) Minimum Normal, Early Retirement and Deferred Vested Termination Benefits . The Service Annuity to which a Participant is entitled under Section 5.2 (relating to normal or deferred retirement) or Section 5.3 (relating to early retirement) shall in no event be less than the hypothetical Service Annuity which the Participant would have been entitled to receive had the Participant retired under Section 5.3 (relating to early retirement) at any time prior to the Participant's actual date of retirement and elected to have such hypothetical Service Annuity commence on the Participant's hypothetical early retirement date; provided , however , that any difference between such Service Annuities which is attributable to an increase in the amount of the Participant's Federal Benefit due to changes in the Federal Social Security Act between such hypothetical early retirement date and the Participant's date of retirement shall be disregarded.

(b) Termination of Employment During Authorized Absence . In computing the annual amount of the Service Annuity pursuant to Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45) or Section 5.5 (relating to deferred vested termination) for a Participant whose Termination of Employment occurs during an authorized absence from employment which is included in the Participant's years of Credited Service pursuant to

subdivision (12) of Section 2.1 (relating to the definition of Credited Service), such Participant shall be considered to have terminated employment on the earliest of (i) the date the authorized absence ends, (ii) the date that is twelve months after the day the authorized absence began and (iii) the date of the Participant's Termination of Service.

(c) Service Annuities Based on Compensation In Excess of the Section 401(a)(17) Limits . In the case of a Participant whose Service Annuity was computed under this Article 5 as of the last day of any Plan Year (the "grandfather date") prior to the January 1, 1989 effective date of Section 401(a)(17) of the Code, which sets forth a compensation limit, or prior to the January 1, 1996 effective date of the reduction in the compensation limit set forth in Section 401(a)(17) of the Code (the applicable limit being referred to as the "new compensation limit"), based on Earnings or the aggregate amount of Base Pay and Incentive Pay in excess of the new compensation limit, such Participant's Service Annuity under this Article 5 (relating to Service Annuities) for periods after the applicable grandfather date shall be the greater of:

(i) the sum of (a) the Participant's Service Annuity determined as of such grandfather date, plus (b) the Participant's Service Annuity determined after such date by applying the new compensation limit and based only on the Participant's years of Credited Service after such date; and

(ii) the Service Annuity determined after the grandfather date by applying the new compensation limit and based on all of the Participant's years of Credited Service.

(d) Participants Formerly Employed at the Company's Fossil-Fired Generation Facilities .

(i) Participants entitled to a Service Annuity Under Section 5.7 . Notwithstanding anything contained in the Plan to the contrary, a "Terminated Participant" (as defined below) who, but for this subparagraph (i) of Section 5.8(d), would have his or her Service Annuity computed under Section 5.7 (relating to Deferred Vested Termination), shall have his or her Service Annuity computed under (a) Section 5.2 (relating to normal and deferred retirement) if the Participant is at least age 65 on the date his or her Service Annuity payments commence or (b) Section 5.3 (relating to early retirement) if the Participant is at

least age 50, but not yet age 65, on the date his or her Service Annuity payments commence, in either case, treating the Participant (solely for purposes of Section 5.2 or 5.3, as the case may be, but not for any other purpose) as though his or her Termination of Employment occurred on the day immediately preceding the date that such Participant's Service Annuity payments commence; provided, however, that such Participant's Service Annuity shall be computed taking into account his Highest Average Annual Pay and Credited Service determined as of the date of his actual Termination of Employment. For purposes of the preceding sentence, a "Terminated Participant" shall mean a Participant whose Termination of Employment with the Company occurs as a result of the sale of any of the assets sold as part of a divestiture process commencing in 1998 of the Company's fossil-fired generation facilities to one or more purchasers, provided that, on the "Determination Date" (defined in subparagraph (iii) below), (a) the sum of such Participant's years of age and years of Credited Service, including as Credited Service any period between the Participant's actual Termination of Employment date and the "Determination Date" (defined in subparagraph (iii) below) equals or exceeds 60 and (b) such Participant is not then eligible for a Service Annuity under Section 5.2 (relating to normal and deferred retirement) or Section 5.3 (relating to early retirement).

(ii) "Determination Date" Used to Determine Eligibility for a Service Annuity Under Section 5.3 . Further notwithstanding anything contained herein to the contrary, for purposes of determining whether an "Eligible Participant" (as defined below) is entitled to a Service Annuity under Section 5.3 (relating to early retirement), such Eligible Participant shall be treated (solely for purposes of Section 5.3) as though his or her Termination of Employment occurred on the "Determination Date" (defined in subparagraph (iii) below). For purposes of the preceding sentence, an "Eligible Participant" shall mean a Participant whose Termination of Employment occurs as a result of the sale of any of the assets sold as part of a divestiture process commencing in 1998 of the Company's fossil-fired generation facilities to one or more purchasers, provided that, on the "Determination Date" (defined in subparagraph (iii) below), such Participant (a) has attained at least age 50 and (b) has at least ten years of Credited Service, including as Credited Service any period between the Participant's actual Termination of Employment date and the "Determination Date" (defined in subparagraph (iii) below).

(iii) Definition of Determination Date . For purposes of this Section 5.8(d), the "Determination Date" shall mean the later of the date on which the transfer of ownership of all FGG assets offered as part of a sale process commencing in 1998 has been completed or the date any remaining FGG assets have been removed by the Company from such sale process.

(iv) As required under Section 5.5(b)(i) of that certain Asset Sale Agreement By and Between Commonwealth Edison Company and Edison Mission Energy as to Fossil Fuel Generating Assets dated as of March 22, 1999, (A) the benefits payable under the Plan to any Participant who becomes employed

by Edison Mission Energy or any subsidiary thereof on the date the transactions contemplated by that Agreement are consummated (a "Transferred Participant") shall be fully vested and nonforfeitable, effective as of the Determination Date (as defined in subparagraph (iii), above), and (B) no Transferred Participant shall accrue additional benefits under the Plan after the Determination Date, or, if later, the date of such Transferred Participant's Termination of Employment.

(e) Rehired Participants . Notwithstanding anything contained herein to the contrary, if a Participant terminates employment and is reemployed as an Employee under circumstances that satisfy the applicable conditions for continuation of payment of retirement benefits set forth in the Company's policy regarding the rehiring of retirees, including that the Participant waives participation in, or additional benefits and accruals under the Plan, such Participant's Service Annuity shall be computed by excluding all service completed, and compensation earned, during such period of reemployment.

(f) Participant's Death During Qualified Military Service . Effective January 1, 2007, in the case of a Participant who dies while performing Military Service, the Beneficiaries of such Participant shall be entitled to any additional benefits, if any (other than benefit accruals relating to the period of Military Service), provided under the Plan had the Participant resumed employment with an Employer and then terminated such employment on account of such Participant's death.

Section 5.9. Post Retirement Adjustments . The annual Service Annuity payable pursuant to this Article 5 (relating to Service Annuities) and Article 6 (relating to Service Annuity forms) that commences by reason of (a) the Termination of Employment of a Participant after the Effective Date under circumstances that entitle the Participant to a Service Annuity under Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45), Section 5.5 (relating to disability retirement before age 45) or Section 5.7 (relating to deferred vested terminations), or

(b) the Termination of Employment of the Participant after the Effective Date by reason of the Participant's death shall, subject to the limitations set forth in this Section 5.9, be adjusted each October 1 for the twelve-month period then beginning by adding a post-retirement cost of living adjustment computed by applying an adjustment percentage to the appropriate base specified in this Section 5.9.

(a) The adjustment percentage shall equal, for each October 1, the percentage by which the Consumer Price Index for the July immediately preceding such October 1 exceeds the Consumer Price Index for the July immediately preceding the twelve-month period beginning October 1 in which the Participant terminated employment under circumstances described in the first sentence of this Section 5.9 or payment of a Service Annuity commenced; provided, however, that:

(i) If, as of such October 1, there shall be no such excess, the adjustment percentage shall be deemed to be zero for the twelve-month period beginning on such October 1.

(ii) There shall be no negative adjustment percentage.

(iii) The aggregate adjustment percentage for any twelve-month period beginning October 1 shall never be lower than the aggregate adjustment percentage for the preceding such period.

(iv) If the percentage increase in the Consumer Price Index computed for the twelve-month period beginning on October 1 does not exceed the aggregate adjustment percentage for the preceding twelve-month period by at least three percentage points, the aggregate adjustment percentage for the preceding twelve-month period shall continue in effect during such twelve-month period beginning on October 1.

(v) The aggregate adjustment percentage for any twelve-month period beginning on October 1 shall not be more than seven percentage points greater than that for the preceding twelve-month period. If the aggregate adjustment percentage for any twelve-month period beginning on October 1 exceeds by more than seven percentage points the aggregate adjustment percentage for the preceding twelve-month period, the excess shall be carried over to succeeding twelve-month periods until such excess is reduced to zero.

(vi) The adjustment percentage for the twelve-month period beginning with the October 1 next following the date the Participant's Service Annuity commences shall be the adjustment percentage determined in accordance with the preceding provisions of this Section 5.9 multiplied by a fraction the numerator of which shall be the number of full calendar months between such date and such October 1 and the denominator of which shall be twelve.

(b) To determine the amount of the monthly cost of living adjustment made after the Effective Date with respect to any employee who, on the date of his or her Termination of Employment is a member of IBEW Local Union 15, in the case of a Service Annuity payable to a Participant pursuant to this Article 5 (relating to Service Annuities) or Article 6 (relating to Service Annuity forms), the adjustment percentage shall be applied to the first $500 per month (effective December 1, 2000 for each Participant who is a member of IBEW Local Union 15, $1,000 per month) of his or her Service Annuity, computed pursuant to this Article 5 (relating to Service Annuities), subject to a maximum monthly adjustment of $1,000 or, if the monthly amount of such Service Annuity is less than $1,000 per month, subject to a maximum monthly adjustment equal to the monthly Service Annuity payment. To determine the amount of the adjustment made after the Effective Date in the case of a marital annuity under paragraph (b) of Section 6.1 or under Section 6.2 or surviving spouse annuity payable pursuant to Section 6.3 to the surviving Spouse of a deceased Participant, a family annuity payable pursuant to Section 6.2 to a surviving Dependent Minor Child or Children of a deceased Participant or a surviving dependent's annuity payable pursuant to Section 6.4 to a surviving Dependent Disabled Child or Children of a deceased Participant, the adjustment percentage shall be applied to the first $250 per month of such annuity or benefit, subject to a maximum monthly adjustment of $350 ($500 in the case of a marital annuity under paragraph (b) of Section 6.1 or under Section 6.2) or, if the monthly amount of such annuity or benefit is less than $350 ($500 in the case of marital annuity under paragraph (b) of Section 6.1 or under Section 6.2), subject to a maximum monthly

adjustment equal to the monthly Service Annuity payment. Cost of living adjustments with respect to Service Annuities not described in the first sentence of this Section 5.9(a) shall be determined under the terms of the Plan as in effect at the time the adjustment was made. Notwithstanding anything herein to the contrary, the cost of living adjustments provided under this Section 5.9(a) may be the subject of bargaining between Commonwealth Edison Company and IBEW Local Union 15 beginning no earlier than the date negotiations commence regarding the successor agreement to the first collective bargaining agreement between the parties that expires on or after January 1, 2006.

(c) To determine the amount of the monthly cost of living adjustment made after the Effective Date with respect to any employee who is not described in paragraph (b), above, to in the case of a Service Annuity payable to a Participant pursuant to this Article 5 (relating to Service Annuities) or Article 6 (relating to Service Annuity forms), the adjustment percentage shall be applied to the first $500 per month of his or her Service Annuity, computed pursuant to this Article 5 (relating to Service Annuities), subject to a maximum monthly adjustment of $500 or, if the monthly amount of such Service Annuity is less than $500 per month, subject to a maximum monthly adjustment equal to the monthly Service Annuity payment. To determine the amount of the adjustment made after the Effective Date in the case of a marital annuity under paragraph (b) of Section 6.1 or under Section 6.2 or surviving spouse annuity payable pursuant to Section 6.3 to the surviving Spouse of a deceased Participant, a family annuity payable pursuant to Section 6.2 to a surviving Dependent Minor Child or Children of a deceased Participant or a surviving dependent’s annuity payable pursuant to Section 6.4 to a surviving Dependent Disabled Child or Children of a deceased Participant, the adjustment percentage shall be applied to the first $250 per month of such annuity or benefit, subject to a maximum monthly

adjustment of $175 ($250 in the case of a marital annuity under paragraph (b) of Section 6.1 or under Section 6.2) or, if the monthly amount of such annuity or benefit is less than $175 ($250 in the case of marital annuity under paragraph (b) of Section 6.1 or under Section 6.2), subject to a maximum monthly adjustment equal to the monthly Service Annuity payment. Cost of living adjustments with respect to Service Annuities not described in the first sentence of this Section 5.9(a) shall be determined under the terms of the Plan as in effect at the time the adjustment was made.

ARTICLE 6

SERVICE ANNUITY FORMS

Section 6.1. Basic Service Annuity Form . (a) Unmarried Participants . A Participant who on his or her Annuity Starting Date is not married shall receive a Service Annuity payable in semi-monthly payments for the Participant's lifetime unless the Participant is eligible for and elects an optional form of Service Annuity under Section 6.2 (relating to optional Service Annuity forms) at the time and in the manner prescribed by paragraph (b) of Section 6.6 (relating to election of optional form of Service Annuity).

(b) Married Participants . A Participant who is married on his or her Annuity Starting Date and does not elect an optional form of Service Annuity under Section 6.2 (relating to optional Service Annuity forms) at the time and in the manner prescribed in paragraph (b) of Section 6.6 (relating to election of optional form of Service Annuity) shall receive in lieu of a Service Annuity payable in semi-monthly payments for the Participant's lifetime an annual marital annuity payable in semi-monthly payments for the Participant's lifetime equal to the Participant's annual Service Annuity computed pursuant to Article 5 (relating to Service Annuities) reduced by the product of (1) 50% of the annual amount of Service Annuity the

Participant would have received under Article 5 (relating to Service Annuities) multiplied by (2) 40% of the applicable factor set forth in Table D. Thereafter, if the Participant's Spouse shall survive the Participant, such Spouse shall receive during the remainder of the Spouse's lifetime an annual Service Annuity payable in semi-monthly payments equal to 50% of the annual amount of Service Annuity the Participant would have received under Article 5 (relating to Service Annuities) if the Participant's Service Annuity were payable in semi-monthly payments for the Participant's lifetime.

Section 6.2. Optional Service Annuity Forms . Upon written request to the Administrator made at the time and in the manner prescribed in paragraph (b) of Section 6.6 (relating to election of optional form of Service Annuity), a Participant may elect to receive, in lieu of the basic Service Annuity form described in Section 6.1, a Service Annuity in one of the following optional forms, provided that the Participant is eligible therefor:

Service Annuity Payable for the Life of the Participant : A Participant who is married on the Participant's Annuity Starting Date may elect, with spousal consent, to receive, in lieu of the marital annuity described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants), a Service Annuity payable in semi-monthly payments for the Participant's lifetime.

Optional Marital Annuity : A Participant who is married on the Participant's Annuity Starting Date may elect to receive a marital annuity described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) with a Service Annuity payable to the Participant's Spouse, if the Participant predeceases such Spouse, of a percentage less than 50 of the Service Annuity the Participant would have received under Article 5 (relating to Service Annuities) if the Participant's Service Annuity were payable in semi-monthly payments for the Participant's lifetime. A marital annuity described in this Section 6.2 shall be payable at the same time and in the same manner as described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) and shall be computed in the same manner as described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants), except that the lesser percentage of Service Annuity designated by the Participant shall be used.

75% Marital Annuity : A Participant who is married on the Participant's Annuity Starting Date may elect to receive a 75% marital annuity with a Service Annuity payable to the Participant's Spouse, if the Participant predeceases such Spouse, of a percentage equal to 75 of the Service Annuity the Participant would have received under Article 5 (relating to Service Annuities) if the Participant's Service Annuity were payable in semi-monthly payments for the Participant's lifetime. A 75% marital annuity described in this Section 6.2 shall be payable at the same time and in the same manner as described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) and shall be the actuarial equivalent of the Service Annuity the Participant would have received under Article 5 (relating to Service Annuities), determined by using the annual interest rate specified under section 417(e) of the Code for the November preceding the calendar year in which such distribution is made or commences, and the mortality table prescribed for purposes of section 417(e)(3)(A)(ii)(I) of the Code.

Family Annuity : A Participant who is not married on the Participant's Annuity Starting Date and who, as of such date, has a Dependent Minor Child or Dependent Minor Children may elect to receive a family annuity payable in semi-monthly payments for the Participant's lifetime and, thereafter, payable in semi-monthly payments in equal shares to each of the Participant's Dependent Minor Children who have not yet attained age 21. The annual amount of the family annuity payable to the Participant shall be the Participant's annual Service Annuity computed pursuant to Article 5 (relating to Service Annuities), reduced by the product of (1) the annual amount of the family annuity designated by the Participant for the Participant's surviving Dependent Minor Child or Children which amount shall be a percentage, not to exceed 50, of the annual amount of the Participant's Service Annuity computed pursuant to Article 5 (relating to Service Annuities) multiplied by (2) the applicable factor set forth in Table E. The annual amount of the family annuity payable after the Participant's death to the Participant's Dependent Minor Child or Children who have not yet attained age 21 shall equal the percentage designated by the Participant, not to exceed 50, of the annual amount of the Participant's Service Annuity computed pursuant to Article 5 (relating to Service Annuities).

Surviving Dependent's Annuity : A Participant who is not married on the Participant's Annuity Starting Date and who, as of such date, has a Dependent Disabled Child or Dependent Disabled Children may elect to receive a surviving dependent's annuity payable in semi-monthly payments for the Participant's lifetime and, thereafter, payable in semi-monthly payments in equal shares to each of the Participant's Dependent Disabled Children who remain disabled. The annual amount of the surviving dependent's annuity payable to the Participant shall be the Participant's annual Service Annuity computed pursuant to Article 5 (relating to Service Annuities) reduced by the product of (1) the annual amount of the surviving dependent's annuity designated by the Participant for the Participant's Dependent Disabled Child or Children, which amount shall be a percentage, not to exceed 50, of the annual amount of the Participant's Service Annuity computed pursuant to Article 5 multiplied by (2) 50% of the applicable

factor set forth in Table D, such factor to be determined based on the age of the other parent of such Child or Children, at the Participant's Annuity Starting Date or the age such other parent would have attained had such other parent survived or if, in either case, the age of such other parent cannot be determined, the age of the Participant. The annual amount of the surviving dependent's annuity payable after the Participant's death to the Participant's Dependent Disabled Child or Children who remain disabled shall equal the percentage designated by the Participant, not to exceed 50, of the annual amount of the Participant's Service Annuity computed pursuant to Article 5 (relating to Service Annuities).

Section 6.3. Pre-retirement Surviving Spouse Benefit . (a) Death Occurring During Employment after Completion of Ten Years of Credited Service . Except as provided in Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65), if the Termination of Employment of a Participant who completed at least ten years of Credited Service shall occur by reason of the Participant's death, the Participant's Spouse, if the Participant is married on the date of the Participant's death, shall receive a surviving spouse annuity payable in semi-monthly payments for the surviving Spouse's lifetime commencing on the Service Annuity payment date immediately following the later of the Participant's death and the date the Participant would have attained age 65 or, in the event that the Participant dies prior to attainment of age 65, such earlier Service Annuity payment date elected by the surviving Spouse in writing in the manner specified by the Administrator. The annual amount of such surviving spouse annuity shall be 50% of the annual amount of the Service Annuity, computed pursuant to Section 5.2 (relating to normal and deferred retirement), that would have been payable to such Participant (i) had the Participant terminated employment the day before the Participant's death; or (ii) in the case of a Participant who dies before attaining age 55, had the Participant's Service Annuity commenced on the date the Participant would have attained age 55, in either case, reduced by 2% for each year (computed to the nearest full year), if any, by which the age of such Participant exceeds that of the Participant's surviving Spouse. Notwithstanding the preceding sentence, in no event shall the annual amount of the surviving

spouse annuity computed pursuant to this paragraph (a) of Section 6.3 be less than 50% of the annual amount of the marital annuity, computed pursuant to paragraph (b) of Section 6.1 (relating to annuities payable to married Participants), that would have been payable to such Participant (i) had payment of the Participant's marital annuity commenced the day before the Participant's death or (ii) in the case of a Participant who dies before attaining age 55, had payment of such marital annuity commenced at age 55 reduced by 1/2% for each month (but not to exceed 120 months) that the Participant's death precedes the date the Participant would have attained age 55 had the Participant survived, 1/6% for each month (but not to exceed 120 months) that the Participant's death precedes the date that the Participant would have attained age 45 had the Participant survived, and 1/12% for each month the Participant's death precedes the date that the Participant would have attained age 35 had the Participant survived.

(b) Death Occurring After Termination of Employment and Completion of Ten Years of Credited Service . If a Participant who completed at least ten Years of Credited Service and who is entitled to a deferred Service Annuity under Section 5.7 (relating to deferred vested termination) shall die before the Participant's Annuity Starting Date, the Participant's Spouse, if the Participant is married on the date of the Participant's death, shall be entitled to receive a surviving spouse annuity payable in semi-monthly payments for the surviving Spouse's lifetime commencing on or about the first Service Annuity payment date immediately following the later of the date of the Participant's death and the date the Participant would have attained age 65. Notwithstanding the preceding sentence, in the case of a Participant described in the preceding sentence who dies prior to attaining age 65, such Participant's surviving Spouse may elect, in writing in the manner specified by the Administrator, to receive payment of the surviving spouse annuity on any Service Annuity payment date following the later of the date of the Participant's

death and the date the Participant would have attained age 50, but in no event later than the first Service Annuity payment date immediately following the date the Participant would have attained age 65. The annual amount of the surviving spouse annuity shall be 50% of the annual Service Annuity computed pursuant to Section 5.7 (relating to deferred vested termination), that would have been payable to such Participant (i) had payment of such deferred Service Annuity commenced the day before the Participant's death, or (ii) in the case of a Participant who dies before attaining age 50, had payment of the Participant's deferred Service Annuity commenced at age 50, in either case, reduced by 2% for each year (computed to the nearest full year), if any, by which the age of such Participant exceeds the age of the Participant's surviving Spouse. Notwithstanding the preceding sentence, in no event shall the annual amount of the surviving spouse annuity computed pursuant to this paragraph (b) of Section 6.3 be less than 50% of the annual amount of the marital annuity, computed pursuant to paragraph (b) of Section 6.1 (relating to annuities payable to married Participants), that would have been payable to such Participant (i) had payment of the Participant's marital annuity commenced the day before the Participant's death or (ii) in the case of a Participant who dies before attaining age 50, had payment of such a marital annuity commenced at age 50.

(c) Death Occurring after Completion of at Least Five Years of Vesting Service but Less than Ten Years of Credited Service . Except as provided in Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65), if a Participant who has at least five years of Vesting Service but less than ten years of Credited Service shall die prior to the Participant's Annuity Starting Date, the Participant's Spouse, if the Participant is married on the date of the Participant's death, shall be entitled to receive a surviving spouse annuity payable in semi-monthly payments for the surviving Spouse's lifetime

commencing on or about the first Service Annuity payment date immediately following the later of the date of the Participant's death and the date the Participant would have attained age 65. Notwithstanding the preceding sentence, the surviving Spouse of a Participant who is described in the preceding sentence and who dies before the Participant's 65th birthday may elect, in writing in the manner specified by the Administrator, to receive payment of the surviving spouse annuity on any Service Annuity payment date following the later of the date of the Participant's death and the date the Participant would have attained age 60, but in no event later than the first Service Annuity payment date immediately following the date the Participant would have attained age 65. The annual amount of the surviving spouse annuity shall be 50% of the annual Service Annuity computed pursuant to Section 5.7 (relating to deferred vested termination) that would have been payable to such Participant had payment of such deferred Service Annuity commenced at age 65, in either case, reduced by 2% for each year (computed to the nearest full year), if any, by which the age of such Participant exceeds the age of the Participant's surviving Spouse. Notwithstanding the preceding sentence, in no event shall the annual amount of the surviving spouse annuity computed pursuant to this paragraph (c) of Section 6.3 be less than 50% of the annual amount of the marital annuity, computed pursuant to paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) that would have been payable to such Participant had payment of such marital annuity commenced at age 65.

Except as provided in Section 6.4 (relating to pre-retirement surviving Child benefits) or Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65), no Service Annuity or other benefit shall be payable under this Plan with respect to a Participant who dies prior to the Participant's Annuity Starting Date and who on the date of the Participant's death has no surviving Spouse. In addition, except as

provided in Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65), no Service Annuity or other benefit shall be payable under this Plan with respect to a Participant who dies prior to completion of at least five years of Vesting Service.

Section 6.4. Pre-retirement Surviving Child Benefits . In the event of the death of any Participant who (i) has at least ten years of Credited Service and (ii) has on file with the Plan Administrator either a family annuity or a surviving dependent's annuity or, for Plan Years beginning on and after January 1, 2007, meets the eligibility conditions to elect a family annuity or surviving dependent's annuity, then, except as provided in Section 6.5 (relating to death benefits with respect to certain Participants who die during employment and after age 65), such Participant's surviving Dependent Minor Children or Dependent Disabled Children, as the case may be, shall receive a surviving child annuity payable in semi-monthly payments commencing on the Service Annuity payment date immediately following the Participant's death and ending with the Service Annuity payment for the period next preceding the date on which (i) in the case of a family annuity, all of the Participant's Children have attained age 21 and (ii) in the case of a surviving dependent's annuity, all of the Participant's Children cease to be Dependent Disabled Children. The annual amount of such surviving child annuity shall be the annual annuity the Participant's Child or Children would have received (i) had the Participant terminated employment on the date of the Participant's death under circumstances entitling the Participant to a Service Annuity under Section 5.2 (relating to Normal and Deferred Retirement) or Section 5.3 (relating to Early

Retirement) and died subsequently, or (ii) in the case of a Participant who dies before attaining age 55, had the Participant terminated employment at age 55 under circumstances entitling the Participant to a Service Annuity under Section 5.3 (relating to Early Retirement) and died subsequently, in either case, reduced by 2% for each year (computed to the nearest full year), if any, by which the age of such Participant exceeds the age of the other parent of such Child or Children at the Participant's death or the age such other parent would have attained on such date had such other parent survived or if, in either case, the age of such other parent cannot be determined, the age shall be deemed to be the same as the Participant.

Section 6.5. Death Benefits for Spouse or Child of Participant Who Dies During Employment After Age 65 . Notwithstanding any provision of this Plan to the contrary, in the event of the death of any Participant who (a) has attained age 65 and (b) on the date of his or her death the Participant is married or has on file with the Plan Administrator an election for a family annuity or a surviving dependent's annuity or, for Plan Years beginning on and after January 1, 2007, meets the eligibility conditions to elect a family annuity or surviving dependent's annuity, the Participant's surviving Spouse, Dependent Minor Children or Dependent Disabled Children, as the case may be, shall receive the annuities they would have received had the Participant terminated employment on the date of the Participant's death under circumstances entitling the Participant to a Service Annuity under Section 5.2 (relating to Normal and Deferred Retirement) and died subsequently, or, in the case of a surviving Spouse, a surviving spouse annuity computed pursuant to the applicable paragraph of Section 6.3 (relating to pre-retirement surviving spouse benefits), if greater.

Section 6.6. Election Procedure . (a) Notice of Availability of Elections . No less than 30 days and no more than 90 days before the Participant's Annuity Starting Date, the Administrator shall give the Participant by mail or personal delivery written notice in nontechnical language that, if the Participant is eligible, the Participant may elect an optional form of Service Annuity set forth in Section 6.2 (relating to optional Service Annuity forms).

Notwithstanding the preceding sentence, the Administrator may deliver such notice to the Participant less than 30 days before the Participant's Annuity Starting Date, provided that (i) the Participant and the Participant's spouse (if any) waive any requirement that such notice be provided no less than 30 days before the Participant's Annuity Starting Date and (ii) payment of the Participant's Service Annuity commences more than 7 days after such notice is received by the Participant. The notice referred to herein shall mean a notice written in nontechnical language that includes a general description of the benefit forms provided under the Plan, including the terms and conditions of the basic benefit forms provided under the Plan and the circumstances under which such forms will be provided unless the Participant elects otherwise, with applicable spousal consent, a description of the eligibility conditions for and any material features of the optional forms of benefit, general information on the relative financial effect upon a Participant's benefit if he elects an optional form of benefit or revokes any prior election, and a description of the relative value of the optional forms of benefit as compared to a marital annuity. In no event shall payment of a Participant's monthly benefits commence before the notice is made available to the Participant and he has had an opportunity to make the election described in Section 6.1(b). Notwithstanding the foregoing, the notice described in the previous paragraph may be provided to the Participant subsequent to the Participant's Annuity Starting Date, if the Participant so elects, provided that the following conditions are satisfied:

(i) the date the on which the first payment to be received by the Participant is made (the "initial payment date") shall be no earlier than thirty (30) days following the date that the notice is furnished to the Participant, except that the initial payment date may be as early as the seventh day after such notice is provided if (i) such notice clearly indicates that the Participant has a right to a period of thirty (30) days after receiving the notice to consider to waive the basic forms of distribution provided under the Plan and to elect (with spousal consent) an optional form of benefit, (ii) the Participant affirmatively elects a form of distribution with the consent of his or her spouse (if required) to commence as of the initial payment date, and (iii) the Participant is permitted to revoke such election until the initial payment date;

(ii) the notice shall be provided to the Participant no more than ninety (90) days before the initial payment date, however, the Plan will not fail to satisfy the ninety (90)- day requirement if the delay in providing the distribution is due solely to an administrative delay;

(iii) the Participant is not permitted to elect an Annuity Starting Date that precedes the date upon which the Participant could have otherwise started receiving benefits under the terms of the Plan as in effect on the Annuity Starting Date;

(iv) to the extent that a Participant has not received any payments for the period from the Annuity Starting Date to the initial payment date, the Participant shall receive a one-time payment to reflect any such missed payments (a "make-up payment"). Such make-up payment shall be adjusted for interest from the period beginning on the Annuity Starting Date and ending on the initial payment date, which shall be calculated with respect to such payments that would have been received prior to the initial payment date. The interest rate used to compute the adjustment described in the preceding sentence shall equal the 30 Year Treasury rate for December of the preceding Plan Year. Notwithstanding the foregoing, with respect to any Annuity Starting Date on or after January 1, 2008, the interest rate used to compute the adjustment described in the sentence above shall be the interest rate as specified or prescribed by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3) of the Code, in revenue rulings, notices or other guidance for November of the preceding Plan Year. For purposes of Section 7.1 of the Plan, the limitations set forth therein shall comply with the adjustments required thereto pursuant to Treasury Regulation 1.417(e)-1 with respect to any Annuity Starting Date described in this paragraph which is a "retroactive annuity starting date" as defined for purposes of such Regulation; and

(v) if a Participant who is married elects to commence the Participant's benefit as of the initial payment date pursuant to this paragraph, then the Participant's spouse (including an alternate payee who is treated as the Participant's spouse under a qualified domestic relations order), determined as of the initial payment date, must consent to such election if the survivor benefits payable as of the Annuity Starting Date are less than the survivor benefits payable under the benefit described in Section 6.2(b) of the Plan as of the initial payment date.

(b) Election of Optional Form of Service Annuity . Subject to the terms of, and except as otherwise provided by, this paragraph, a Participant may, at any time during the 90-day period ending on the Participant's Annuity Starting Date, elect, change or revoke (i) any form of

Service Annuity provided under this Plan and (ii) the percentage of the Participant's Service Annuity to be paid to a Spouse under a marital annuity, to a Dependent Minor Child under a family annuity or to a Dependent Disabled Child under a surviving dependent's annuity. Notwithstanding the preceding sentence, if the written notice described in paragraph (a) of this Section 6.6 is delivered to the Participant within 30 days of, or after, the Participant's Annuity Starting Date, the Participant may make an election, change or revocation as described in the preceding sentence at any time within 30 days after the date the written notice described in paragraph (a) of this Section 6.6 is delivered to the Participant. The Participant and the Participant's Spouse, if any, may waive the 30 day period described in the preceding sentence and begin receiving payment of the Participant's Service Annuity prior to the expiration of such 30-day period, provided that distribution of the Participant's Service Annuity commences more than 7 days after the notice described in paragraph (a) of this Section 6.6 is delivered to the Participant. An election, change or revocation described in this paragraph (b) shall be made by delivering a written notice describing the election, change or revocation to the Administrator. Notwithstanding the foregoing, if the Participant is married on the Participant's Annuity Starting Date, the Participant's election to receive an optional form of Service Annuity under Section 6.2 (relating to optional Service Annuity forms) in lieu of the marital annuity described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) shall not be effective unless (i) it shall have been consented to at the time of such election in writing by the Participant's Spouse and such consent acknowledges the effect of such election and is witnessed by either a Plan representative or a notary public, or (ii) it is established to the satisfaction of a Plan representative that such consent cannot be obtained because the Participant's Spouse cannot be located or because of such other circumstances as may be prescribed in Regulations. An

election of an optional Service Annuity form shall be deemed a rejection of the basic Service Annuity form provided in Section 6.1 (relating to the basic Service Annuity form of payment). The consent of a Spouse required by this paragraph shall not be necessary for a distribution required by a qualified domestic relations order described in paragraph (b) of Section 13.2.

(c) Automatic Cancellation of Elections . If a Participant's Service Annuity is payable in the form of a marital annuity and if, prior to the Participant's Annuity Starting Date, the Participant's spouse dies or the Participant and such spouse divorce, the Participant's election or deemed election to receive a marital annuity shall, upon the Participant's notice to the Administrator of such death or divorce, be automatically cancelled, unless, subsequent to such spouse's death or the Participant's divorce and prior to the Participant's Annuity Starting Date, the Participant remarries and notice of such new marriage is timely received by the Administrator.

If a Participant's Service Annuity is payable in the form of a marital annuity and if, after the Participant's Annuity Starting Date, the Participant's Spouse predeceases the Participant or the Participant's Spouse, pursuant to a duly entered divorce decree, specifically relinquishes all rights to receive any Service Annuity in the event of the Participant's death, the Participant's Service Annuity shall be recomputed prospectively as if the Participant were not married on the Annuity Starting Date. Any marriage by the Participant after the Participant's Annuity Starting Date shall not affect the payment of the Participant's Service Annuity or require any payment to the Participant's new spouse.

If a Participant has elected to receive a family annuity and, either before or after payment of such annuity commences, all of the Participant's previously Dependent Minor Children have predeceased the Participant or have ceased to be dependent, within the meaning of Section 152 of the Code, the Participant's election to receive a family annuity shall, upon the Participant's notice to the Administrator of such death or cessation of being a dependent, be automatically cancelled.

If a Participant has elected to receive a surviving dependent's annuity and either before or after payment of such annuity commences, all of the Participant's previously Dependent Disabled Children have predeceased the Participant or have ceased to be Dependent Disabled Children, as certified by the medical director of the Company or by such other licensed physician designated by the Company, the Participant's election to receive a surviving dependent's annuity shall, upon the Participant's notice to the Administrator of such death or cessation of being a Dependent Disabled Child, be automatically cancelled.

A Participant whose election has been automatically cancelled pursuant to this paragraph (c) shall be entitled to receive the Service Annuity described in Section 6.1 (relating to the basic Service Annuity form of payment) or, in the case of an election that is automatically cancelled prior to the Participant's Annuity Starting Date and subject to Section 6.1 (relating to the basic Service Annuity form of payment), such other form of Service Annuity described in Section 6.2 (relating to optional Service Annuity forms) for which the Participant is eligible and elects in accordance with this Section 6.6.

Section 6.7. Lump Sum Payment . Notwithstanding anything herein to the contrary, if the monthly amount of any Service Annuity shall initially be or at any time become $10 or less, the Participant, Beneficiary or Retiree may, in lieu of such annuity, elect to receive, and within 30 days after such election there shall be paid to such Participant, Beneficiary or Retiree, an amount equal to the lump sum equivalent of such annuity calculated on the basis of the "applicable interest rate" as defined in Section 417 of the Code and the Regulations

promulgated thereunder and the applicable mortality table. Notwithstanding the foregoing, for purposes of computing single sum payments on or after January 1, 2008, (i) the interest rate used shall be the interest rate as defined in Section 417(e)(3)(C) of the Code for the second month preceding the calendar year in which such distribution is made or commences and (ii) the mortality table shall be the mortality table specified by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3)
of the Code as in effect on the first day of the Plan Year in which the Annuity Starting Date occurs. Notwithstanding the foregoing, for purposes of computing single sum payments on or after December 1, 2012, other than under Section 6.9 (relating to Special Lump Sum Payment Option), (i) the interest rate used shall be the interest rate as defined in Section 417(e)(3)(C) of the Code for the fifth month (or, if more favorable to the recipient of a single sum payment between December 1, 2012 and December 1, 2013), the second month) preceding the calendar year in which such distribution is made or commences and (ii) the mortality table shall be the mortality table specified by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3) of the Code as in effect on the first day of the Plan Year in which the Annuity Starting Date occurs.

In the case of a distribution pursuant to this Section 6.7 that is an “eligible rollover distribution” within the meaning of Section 402 of the Code and that is at least $200, an eligible distributee (as defined below) may elect that all or any portion of such distribution shall be directly transferred as a rollover contribution from the Service Annuity Fund to (i) an individual retirement account described in Section 408(a) of the Code, (ii) an individual retirement annuity described in Section 408(b) of the Code, (iii) an annuity plan described in Section 403(a) of the Code, (iv) an annuity contract described in Section 403(b) of the Code, (v) a retirement plan qualified under Section 401(a) of the Code, (vi) an eligible plan under Section 457(b) of the Code which is maintained by an eligible employer described in Section 457(e)(1)(A)

of the Code (the terms of which permit the acceptance of rollover contributions) or (vii) effective January 1, 2008, a Roth IRA described in Section 408A of the Code; provided, however, that (x) with respect to a plan described in clause (vii), for transfers occurring before January 1, 2010, the Participant (or surviving Spouse of a Participant or a former Spouse who is an alternate payee under a qualified domestic relations order as defined in Section 414(p) of the Code) meets the requirements of Section 408A(c)(3)(B) of the Code and (y) with respect to a distribution (or portion of a distribution) to a person who is not the Participant or the surviving Spouse of the Participant, "eligible retirement plan" shall mean only a plan described in clause (i) or (ii) or effective January 1, 2010, clause (vii), that, in either case, is established for the purpose of receiving such distribution on behalf of such person. For purposes of the preceding sentence, the term "Spouse" shall include the Participant's surviving Spouse and the Participant's Spouse or former Spouse who is the alternate payee under a qualified domestic relations order. In addition, in the case of a distribution that occurs on or after January 1, 2008, a Beneficiary who is not the Spouse of the Participant may elect that all or any portion of such distribution shall be directly transferred as a rollover contribution from this Plan to (i) an individual retirement account described in section 408(a) of the Code or (ii) an individual retirement annuity described in section 408(b) of the Code that, in either case, is established for the purpose of receiving such distribution on behalf of the Beneficiary. Notwithstanding the foregoing, an eligible distributee shall not be entitled to elect to have less than the total amount of such distribution transferred as a rollover contribution unless the amount to be transferred equals at least $500. At least 30 days but no more than 90 days prior to the date on which the eligible distributee is entitled to receive a distribution described in this Section 6.7, a written

explanation shall be provided to the eligible distributee of the availability of the direct rollover option, the rules that require income tax withholding on distributions, the rules under which the eligible distributee may roll over the distribution within 60 days of receipt and, if applicable, other special tax rules that may apply to the distribution.

For purposes of this Section 6.7, "eligible distributee" shall include the Participant, his Spouse or his alternate payee under a qualified domestic relations order within the meaning of Section 414(p) of the Code and, effective January 1, 2008, the Participant's Beneficiary who is not the Participant's Spouse.

Section 6.8. Distributions to Dependent Minor and Disabled Children . Any distribution under this Plan to a Dependent Minor Child or Dependent Disabled Child, or payment to any person for the account of a Dependent Minor Child or Dependent Disabled Child, as the case may be, shall discharge all obligations in respect of such payment, and none of the Company, the Trustee, the Administrator, the Investment Office or the Corporate Investment Committee, shall have any duty to see to the application by any third party of any distribution made to or for the benefit of such Dependent Minor Child or Dependent Disabled Child.

Section 6.9. Special Lump Sum Payment Option . (a) Eligibility . A Participant (but not his or her Beneficiary) may elect to receive, during the election period described in paragraph (b) of this Section 6.9, his or her deferred Service Annuity ("Deferred Service Annuity") under Section 5.7 (relating to deferred vested termination) in the form of a lump sum payment ("Special Lump Sum Payment") or, an "Immediately Commencing Annuity" (as defined below); provided, however, that:

(i) the Participant has a Termination of Employment on or prior to June 30, 2012 and does not die and is not rehired during the period beginning July 1, 2012 and ending on the date payment is made or commences in accordance with this Section 6.9;

(ii) such Termination of Employment is not on account of the Participant's disability, following which the Participant is receiving long-term disability payments under any long-term disability program of an Employer, including on June 30, 2012;

(iii) the Participant's Deferred Service Annuity is not subject to a qualified domestic relations order as defined in Section 414(p) of the Code;

(iv) the Participant is not immediately, as of his or her Termination of Employment, eligible for early retirement benefits in accordance with Section 5.3 (relating to early retirement);

(v) the Participant is not on a leave of absence or layoff from an Employer on June 30, 2012;

(vi) the Participant is not 70 $^{1}/_{2}$ years of age or older as of October 1, 2012; and

(vii) the Participant can be located, after a diligent search, as necessary, by the Plan Administrator before July 1, 2012.

For each such Participant described in this paragraph (a) of Section 6.9, the term "Immediately Commencing Annuity" shall mean, as applicable, either:

(i) with respect to a Participant eligible to commence receipt of his or her Deferred Service Annuity as of December 1, 2012, in accordance with the requirements of Section 5.7 (relating to deferred vested termination), any applicable optional form of annuity described in Sections 6.1 (relating to basic service annuity forms) or 6.2 (relating to optional service annuity forms); or

(ii) with respect to any other Participant, a "Service Annuity Payable for the Life of the Participant," an "Optional Marital Annuity" or a "75% Martial Annuity," each as described in the first paragraph of Section 6.2 (relating to optional service annuity forms).

(b) Election and Election Period . To receive the distribution of benefits described in paragraph (a) of this Section 6.9, an eligible Participant must voluntarily elect to receive a distribution pursuant to this Section 6.9 by completing an election form and spousal waiver, if required, provided by the Administrator, and submitting such forms to the Administrator after October 1, 2012 and before the following dates, as applicable,

(i) November 15, 2012, with respect to a Participant whose Termination of Employment occurs on or after April 1, 1995 and who elects a Special Lump Sum Payment;

(ii) November 30, 2012, with respect to a Participants whose Termination of Employment occurs before April 1, 1995 and who elects a Special Lump Sum Payment; and

(iii) December 15, 2012, with respect to a Participant who elects an Immediately Commencing Annuity,

or such other period during 2012 determined by the Administrator.

The Administrator shall provide each eligible Participant, not less than 30 days and not more than 180 days before the Annuity Starting Date, an application form including a general description of the material features, as well as an explanation of the relative values and financial effect, of the optional forms of benefit available under this Section 6.9, in a manner that satisfies the notice requirements of Section 417(a)(3) of the Code and the Regulations thereunder. The form shall indicate the Participant's right to waive a survivor annuity, his surviving Spouse's right to consent to such waiver or refuse such consent, and the right to revoke any waiver, within the 180 day period preceding the Annuity Starting Date, and shall include a description of the right of the Participant, if any, to defer receipt of a distribution and the consequences of failure to defer such receipt, in accordance with Treasury guidance under Section 411(a)(11) of the Code.

(c) Amount of Payment . The Special Lump Sum Payment shall equal the actuarial equivalent of the Participant's nonforfeitable Deferred Service Annuity, based on the following factors:

(i) the applicable interest rate described in Section 417(e)(3) of the Code for August of 2011;

(ii) an assumed commencement date of the later of (A) age 62, with respect to a Participant whose Termination of Employment occurs on or after April 1, 1995, or 65, with respect to a Participant whose Termination of Employment occurs before April 1, 1995, and (B) the Participant's age as of December 1, 2012;

(iii) the applicable mortality table, as defined in Section 417 of the Code and the Regulations promulgated thereunder; and

(iv) an assumed cost of living adjustment of 2.5% for purposes of Section 5.9 (relating to post retirement adjustments).

The Immediately Commencing Annuity shall be calculated:

(i) in accordance with the applicable terms of the Plan, for a Participant who is eligible to immediately commence benefits under the terms of the Plan as of the payment date set forth in paragraph (d) of this Section 6.9; and

(ii) as the actuarial equivalent of the Special Lump Sum Payment, for each other Participant.

(d) Payment of Benefit . If an eligible Participant elects the distribution of his or her Deferred Service Annuity in accordance with this Section 6.9, payment shall be made, or commence to be made, on or before December 1, 2012, or as soon as administratively practicable thereafter.

(e) Death and Rehire . If an eligible Participant elects the distribution of his or her Deferred Service Annuity in accordance with this Section 6.9 and subsequently dies or is rehired as an Employee before distributions commence, his or her election shall be null and void and the Participant's benefit shall be paid pursuant to the Plan without regard to this Section 6.9. Notwithstanding anything contained herein to the contrary, upon distribution of a Special Lump Sum Payment or an Immediately Commencing Annuity made to an individual in accordance with this Section 6.9, in the event of the individual's rehire with an Employer following the date such distribution is made, the individual shall not be eligible to participate in the Plan during such period of rehire and may be eligible to participate in the Exelon Corporation Cash Balance Pension Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees (or such other plan that applies to employees of an Employer hired on or after December 1, 2012), as applicable, in accordance with their terms and conditions.

ARTICLE 7

LIMITATIONS ON BENEFITS

Section 7.1. Maximum Annual Benefits . Notwithstanding any other provision of the Plan to the contrary, the amount of the Participant's annual benefit (as defined below) accrued, distributed or payable at any time under the Plan shall be limited to an amount such that such annual benefit and the aggregate annual benefit of the Participant under all other defined benefit plans maintained by the Employer or any other Affiliate does not exceed the lesser of:

(i) $160,000 (as increased to reflect the cost of living adjustments provided under Section 415(d) of the Code), multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of participation (within the meaning of Section 1.415(b)-1(g)(1)(ii) of the Regulations) and the denominator of which is 10; or

(ii) an amount equal to 100% of the Participant's average compensation for the 3 consecutive calendar years in which his or her compensation was the highest (as determined in accordance with Section 1.415(b)-1(a)(5) of the Regulations) and which are included in his or her years of service (within the meaning of Section 1.415(b)-1(g)(2)(ii) of the Regulations) with the Employers multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of service with the Employers and the denominator of which is 10.

The dollar amount set forth in clause (i) of the preceding paragraph shall be actuarially reduced in accordance with Section 1.415(b)-1(d) of the Regulations if the Participant's Pension Starting Date occurs prior to the Participant's attainment of age 62. If the Participant's Pension Starting Date occurs after the Participant's attainment of age 65, such dollar amount shall be actuarially increased in accordance with Section 1.415(b)-1(e) of the Regulations.

A Participant's "annual benefit" shall mean the Participant's accrued benefit payable annually in the form of a straight life annuity, as determined in, and accordance with, Section 1.415(b)-1(b) of the Regulations. If the annual benefit is payable in a form other than a single life annuity, the annual benefit shall be adjusted to the actuarial equivalent of a single life annuity using the assumptions of the following sentences; provided , however , that no adjustment shall be required for survivor benefits payable to a surviving spouse under a qualified joint and survivor annuity (as described in Section 6.1(b)) to the extent such benefits would not be payable if the Participant's annual benefit were paid in another form.

Effective for Plan Years beginning January 1, 2004 and January 1, 2005, for any form of benefit subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be the greater of (i) the amount computed using the annual interest rate specified under section 417(e) of the Code for the November preceding the calendar year in which such distribution is made or commences, and the mortality table prescribed for purposes of section 417(e)(3)(A)(ii)(I) of the Code (the "Actuarial Equivalent") and (ii) the amount computed using an interest rate assumption of 5.5% and the applicable mortality table under Section 1.417(e)-1(d)(2) of the Regulations (the "Applicable Mortality Table"). Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be the greatest of (i) the amount computed using the Actuarial Equivalent under the Plan, (ii) the amount computed using an interest rate assumption of 5.5% and the Applicable Mortality Table and (iii) the amount computed using the applicable interest rate under Section 1.417(e)-1(d)(3) of the Regulations and the Applicable Mortality

Table, divided by 1.05. Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit not subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be determined in accordance with Section 1.415(b)-1(c) of the Regulations. An individual's "annual benefit" under any other defined benefit plan maintained by the Employer and Affiliate shall be as determined pursuant to the provisions of Section 415 of the Code and the Regulations issued thereunder the terms of such plan.

Notwithstanding the foregoing provisions of this Section, the limitation provided by this Section shall not apply to a Participant who has not at any time participated in a defined contribution plan maintained by any Employer and whose annual benefit under the Plan does not exceed $10,000 multiplied by a fraction (not exceeding 1 and not less than 1/10th) the numerator of which is the Participant's years of years of service (within the meaning of Section 1.415(b)-1(g)(2)(ii) of the Regulations) and the denominator of which is 10.

For purposes of this Section, the term "compensation" shall have the meaning set forth in Section 415(c)(3) of the Code and the applicable Regulations, the term "defined contribution plan" shall have the meaning set forth in Section 1.415(c)-1(a)(2) of the Regulations, the term "defined benefit plan" shall have the meaning set forth in Section 1.415(b)-1(a)(2) of the Regulations and the term "Employer" shall include the Employers and all corporations and entities required to be aggregated with any of the Employers pursuant to Section 414(b) and (c) of the Code as modified by Section 415(h) of the Code. Section 415 of the Code and the Regulations thereunder are hereby incorporated by reference.

Section 7.2. Temporary Restrictions on Benefits in Case of Termination or Curtailment . This Section 7.2 sets forth restrictions required by the Internal Revenue Service on the Service Annuity payable for a Plan Year to a highly compensated employee or highly compensated former employee, as described in Section 414(q) of the Code and Regulations who is among the twenty-five highest paid nonexcludable employees in the service of the Employers for the Plan Year. The restrictions set forth in this Section 7.2 shall not become applicable if:

(1) after payment to such highly compensated employee of any Service Annuity, the value of Plan assets equals or exceeds 110 percent of the value of current liabilities (as defined in Section 412(l)(7) of the Code),

(2) the value of the Service Annuity paid to such highly compensated employee is less than one percent of the value of current liabilities of the Plan, or

(3) the value of the Service Annuity payable to or on behalf of such highly compensated employee does not exceed the amount described in Section 411(a)(11)(A) of the Code.

If the Service Annuity payable to a Participant is subject to the restrictions set forth in this Section 7.2, the Service Annuity provided from the Plan shall not exceed the payments that would be made on behalf of such Participant under a single life annuity that is the actuarial equivalent of the sum of the Participant's Service Annuity and the Participant's other benefits under the Plan.

The foregoing conditions do not restrict the full payment of any death or survivor's benefits on behalf of a Participant who dies while the Plan is in full effect and its full current costs have been met.

Any amounts that become due but because of the limitations of this Section 7.2, if applicable, cannot be made available to or for the Participant (either currently or later) shall be applied to reduce subsequent contributions of the Employers; but if the Employers have ceased contributions to the Plan, such amounts shall be applied for the benefit of Participants not affected by this Section 7.2 in an equitable and nondiscriminatory manner.

This Section 7.2 is inserted solely for the purpose of complying with the requirements of the Internal Revenue Service and shall not be applied except to the extent necessary to comply with such requirements.

Section 7.3 Benefit Restrictions as a Result of Funding . (a) Notwithstanding any provision of the Plan to the contrary, the following benefit restrictions shall apply if the Plan's "Adjusted Funding Target Attainment Percentage" (the "AFTAP"), as defined in Section 436(j) of the Code, is at or below the following levels.

(i) If the Plan's AFTAP is 60% or greater but less than 80% for a Plan Year, the Plan shall not pay any prohibited payment (as defined in subsection 7.3(a)(iv) below) after the valuation date for the Plan Year to the extent the amount of the payment exceeds the lesser of (x) 50% of the amount of the payment which could be made without regard to the restrictions under this subsection 7.3 and (y) the present value (determined pursuant to guidance prescribed by the Pension Benefit Guaranty Corporation, using the interest and mortality assumptions under Section 417(e) of the Code) of the maximum guarantee with respect to the Participant under Section 4022 of ERISA. Notwithstanding the preceding sentence, only one such prohibited payment may be made with respect to any Participant during any period of consecutive Plan Years to which the limitations under either clause (x) or (y) of the preceding sentence apply. For purposes of this subsection 7.3(a)(i), a Participant, his Beneficiary and any alternate payee (as defined in Section 414(p)(8) of the Code) shall be deemed a single "Participant."

(ii) If the Plan's AFTAP is less than 60% for a Plan Year, the Plan shall not pay any prohibited payment after the valuation date for the Plan Year.

(iii) During any period in which the Company is a debtor in a case under Title 11, United States Code (or similar federal or state law), the Plan shall not make any prohibited payment. The preceding sentence shall not apply on or after the date on which the Plan's enrolled actuary certifies that the AFTAP is not less than 100%.

(iv) For purposes of this subsection 7.3(a), the term "prohibited payment" means (x) any payment, in excess of the monthly amount paid under a single life annuity (plus any supplements described in Section 6.2), to a Participant or Beneficiary whose annuity starting date (as defined in Section 417(f)(2) of the Code and any regulations promulgated thereunder) occurs during any period a limitation under subsection 7.3(a)(ii) or (iii) is in effect, (y) any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or (z) any other payment specified by the Secretary of the Treasury by regulations.

(b) In any Plan Year in which the Plan's AFTAP for such Plan Year is less than 60%, benefit accruals under the Plan shall cease as of the valuation date for the Plan Year. This restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year, upon payment by the Company or the Employers of a contribution (in addition to any minimum required contribution under Section 430 of the Code) equal to the amount sufficient to result in an AFTAP of 60%.

(c) No amendment which has the effect of increasing Plan liabilities by reason of increases in benefits, establishment of new benefits, changing the rate of benefit accruals or the rate at which benefits become nonforfeitable shall take effect during any Plan Year if the Plan's AFTAP for such Plan Year is less than 80% or would be less than 80% after taking into account such amendment; provided, however, that the preceding restriction shall not apply to an amendment which provides for an increase in benefits under a formula which is not based on a Participant's compensation if the rate of such increase is not in excess of the contemporaneous rate of increase in average wages of Participants covered by the amendment; and provided, further, that such restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year (or if later, the effective date of the amendment), upon payment by the Company or the Employers of a contribution as described in Section 436(c)(2) of the Code.

(d) The Plan shall not provide an unpredictable contingent event benefit payable with respect to any event occurring during any Plan Year if the AFTAP for such Plan Year is less than 60% or would be less than 60% after taking into account such occurrence; provided, however, such restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year, upon payment by the Company or the Employers of a

contribution as described in Section 436(b)(2) of the Code. For purposes of this subsection 7.3(d), the term "unpredictable contingent event benefit" means any benefit payable solely by reason of a plant shutdown (or similar event, as determined by the Secretary of the Treasury), or any event other than the attainment of any age, performance of any service, receipt or derivation of any compensation, or occurrence of death or disability.

(e) To avoid benefit restrictions, the Company may take any action permitted by Section 436 of the Code and the regulations promulgated thereunder.

(f) The provisions of this subsection 7.3 are intended to comply with Section 436 of the Code and any regulations promulgated thereunder, and shall be construed to comply therewith.

ARTICLE 8

SERVICE ANNUITY FUND

The Service Annuity Fund is the Service Annuity Fund created by the Company for the payment of Service Annuities. All contributions under this Plan shall be paid to the Trustee. The Trustee shall hold all monies and other property received by it and shall invest and reinvest the same, together with the income therefrom, on behalf of the Participants collectively in accordance with the directions of the Investment Office. The Investment Office shall be a "named fiduciary" under the Plan for purposes of ERISA and, as such, may, in its discretion, delegate to one or more investment managers, as defined in ERISA, the authority to hold, manage, acquire and dispose of all or any part of the Service Annuity Fund. Any investment manager appointed by the Investment Office pursuant to this Article 8 which is a bank or trust company supervised by a State or Federal agency is authorized and empowered to invest and reinvest all or any part of the Service Annuity Fund allocated to it for investment in any

common, collective or commingled trust qualified under the provisions of Section 401(a) and exempt from tax under Section 501(a) of the Code which is maintained by such investment manager ("common trust"). During such period of time as all or any portion of the Service Annuity Fund shall be invested in a common trust, the trust document governing such common trust shall govern any investment therein and such trust document shall be a part hereof. Investment of the common trust in deposits of the trustee of the common trust is hereby expressly authorized.

In addition, the Investment Office is authorized and empowered to direct the Trustee as to the investment and reinvestment all or any part of the Service Annuity Fund in the Commonwealth Edison Pooled Fund (the "Pooled Fund"). During such period of time as all or any portion of the Service Annuity Fund is invested in the Pooled Fund, the trust document governing the Pooled Fund shall govern any investment therein and such trust document shall be a part hereof. On and after November 1, 2010, the Service Annuity Fund shall be invested in the Exelon Corporation Pension Master Retirement Trust (the "Master Trust"), which is an amendment and restatement of the Pooled Fund, and the Master Trust document shall govern any investment therein. The Investment Office may delegate to one or more investment managers, as defined in ERISA, the authority to hold, manage, acquire and dispose of all or any part of the Service Annuity Fund invested in the Pooled Fund or, on and after November 1, 2010, in the Master Trust.

The Trustee shall make distributions from the Service Annuity Fund at such time or times to such person or persons and in such amounts as the Administrator shall direct in accordance with this Plan.

ARTICLE 9

SPECIAL RULES RELATING TO PARTICIPATION OF AND DISTRIBUTION TO

CERTAIN TERMINATED OR TRANSFERRED EMPLOYEES

Section 9.1. Employment After Commencement of Service Annuity . A retired Employee or former Employee, other than an Employee described in either of the following paragraphs, receiving, or eligible to begin receiving, a Service Annuity may be employed in any business, including that of an Employer or an Affiliate, without in any way affecting the payment to him or her of his or her Service Annuity, provided however, that if he or she is employed by an Employer or an Affiliate, such employment satisfies the applicable conditions for continuation of payment of retirement benefits as set forth in the Company's policy regarding the rehiring of retirees.

A retired bargaining unit Employee or former bargaining unit Employee, if such bargaining unit Employee was a member of Local Union 15 (or a predecessor union), International Brotherhood of Electrical Workers, receiving a Service Annuity may be employed in any business, other than that of the Company, without in any way affecting the payment to him or her of his or her Service Annuity. Such retired bargaining unit Employee, or former bargaining unit Employee, receiving a Service Annuity may be employed in the temporary service of an Employer or an Affiliate, but, except as otherwise provided in paragraph (b) of Section 5.2, during the term of such employment, he or she shall not receive any Service Annuity payments unless such employment is for less than 40 Hours of Service per calendar month. Upon the conclusion of such temporary service employment, Service Annuity payments shall again be made to him or her, as described in Section 9.4 (relating to suspension of Service Annuities).

Notwithstanding anything contained herein to the contrary, a retired Employee or former Employee who becomes re-employed by an Employer or an Affiliate after his or her Service Annuity payments have commenced shall not, under any circumstances, have the right to elect to participate in the Exelon Corporation Cash Balance Pension Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees or any plan sponsored by CEG. In addition, a retired Employee or former Employee who becomes re-employed by an Employer after payments have begun to be paid to him or her under the Exelon Corporation Cash Balance Pension Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees or any plan sponsored by CEG shall not, under any circumstances, have the right to elect to participate in this Plan.

Section 9.2. Social Security Increases . The Service Annuity of a Retiree or a Participant who has terminated employment under circumstances that entitle the Participant to a deferred Service Annuity under Section 5.7 (relating to deferred vested termination) shall not be recomputed to reflect any change in the benefit levels payable under Title II of the Federal Social Security Act or any change in the wage base under such Title II if such change takes place after the earlier of the date payment of such Service Annuity commences or the date of such termination, as the case may be.

Section 9.3. Leased Employees . A leased employee (within the meaning of section 414(n)(2) of the Code) shall not be eligible to participate in the Plan. If a person who performed services as a leased employee (as defined below) of any Employer or Affiliate becomes an Employee, or if an Employee becomes such a leased employee, then any period during which such services were so performed shall be taken into account solely for the purposes of determining whether and when such person is eligible to participate in this Plan under

Article 3 (relating to participation), measuring such person's years of Vesting Service and determining when such person has terminated his or her employment for purposes of Article 5 (relating to Service Annuities) and Article 6 (relating to Service Annuity forms) to the same extent it would have been had such service been as an Employee. In addition, any contributions or benefits provided under another plan to such leased employee by his or her leasing organization shall be treated as provided under this Plan and shall be taken into account under Section 7.1 to the extent required under Section 1.415(a)-1(f)(3) of the Regulations. This Section 9.3 shall not apply to any period of service during which such a leased employee was covered by a plan described in Section 414(n)(5) of the Code and during which the total number of leased employees did not constitute more than 20% of the Employer's non-highly compensated work force within the meaning of Section 414(n)(1)(C)(ii) of the Code. For purposes of this Plan, a "leased employee" shall mean any person who is not an employee of an Employer and who pursuant to an agreement between an Employer or Affiliate has performed services for an Employer or an Affiliate on a substantially full-time basis for a period of at least one year, which services were performed under the primary direction or control of an Employer or an Affiliate.

Section 9.4. Suspension of Service Annuities . (a) Notwithstanding anything contained in the Plan to the contrary and except as provided in paragraph (b) of Section 5.2 (relating to special rule for Participants who attain age 70-1/2 while employed), a Participant who remains an Employee after the Participant's Normal Retirement Age without having any Termination of Employment that results in the Participant beginning to receive his or her Service Annuity shall not be entitled to receive any Service Annuity for any calendar month of employment by an Employer or an Affiliate during which the Participant completes at least 40 Hours

of Service. If the Service Annuity payments of a Participant described in the preceding sentence or a Participant described in either of the second or third paragraph of Section 9.1 (relating to employment after commencement of Service Annuity System) are suspended, then such payments shall resume at the earlier of (i) such Participant's actual retirement, or (ii) such Participant's ceasing to work 40 Hours of Service or more per calendar month. A Participant's Service Annuity payments which have been suspended pursuant to this Section 9.4 or Section 9.1 (relating to employment after commencement of Service Annuity System) shall be resumed not later than the third calendar month after the calendar month in which the Participant ceases to be employed as described in the preceding sentence. The initial payment upon resumption of the Service Annuity payments shall include any amounts withheld during the period between the cessation of the period during which his or her Service Annuity was suspended and the resumption of payments, but shall not be actuarially adjusted for such delay in resumption of his or Service Annuity nor shall any Service Annuity payment be made with respect to any month during which his or her Service Annuity was suspended pursuant to this Section 9.4 or Section 9.1 (relating to employment after commencement of Service Annuity System).

(b) No Service Annuity shall be suspended under this Section 9.4 or Section 9.1 (relating to employment after commencement of Service Annuity System) unless the Participant is notified by personal delivery or first class mail during the first calendar month or payroll period in which the Service Annuity is being suspended. Such notice will contain such information as may from time to time be required by Section 2530.203-3(b)(4) of the regulations of the Department of Labor or any amendment thereto.

(c) If a Participant erroneously receives Service Annuity payments for a month during which such payments should have been suspended pursuant to this Section 9.4 or Section 9.1 (relating to employment after commencement of Service Annuity System), then the Administrator may deduct from future Service Annuity payments such erroneously received payments. However, no such deduction may exceed in any one month 25 percent of that month's payment to which the Participant or the Participant's Beneficiary, as the case may be, would have been entitled.

Section 9.5. Reemployment Before Commencement of Service Annuity . (a) Employees Represented by IBEW Local Union 15 . The following rules shall apply to an Eligible Employee who is a member of a collective bargaining unit represented by IBEW Local Union 15 who incurs a Termination of Employment and who is rehired by an Employer prior to commencing his or her Service Annuity or any benefits under the Exelon Corporation Pension Plan for Bargaining Unit Employees:

(i) Rehire Date Before Absence of 5 Years . If an Employee terminates employment and is later rehired by an Employer before having an absence from employment with the Employers and their Affiliates of five years and, on the date of such Employee's rehire, the Employee is a member of a collective bargaining unit represented by IBEW Local Union 15, then either: (1) if such Employee was a Participant on the date his or her employment terminated, such Employee shall become a Participant in the Plan as of his or her rehire date or (2) if such Employee was not a Participant on the date his or her employment terminated, such Employee shall not be an Eligible Employee and shall not become a Participant.

(ii) Rehire Date After Absence of at Least 5 Years . If an Eligible Employee terminates employment, regardless of whether such Eligible Employee was a Participant on the date that his or her employment terminated, and is later rehired by an Employer after having an absence from employment with the Employers and their Affiliates of at least five years and, on the date of such Employee's rehire, the Employee is a member of a collective bargaining unit represented by IBEW Local Union 15, such Eligible Employee shall (A) if he or she was a Participant with a vested Service Annuity as of his or her termination date, become a Participant as of his or her rehire date, (B) if he or she was not a Participant as of his or her termination date and was a participant entitled to a vested benefit under the Exelon Corporation Pension Plan for Bargaining Unit Employees as of his or her termination date, he or she shall not be an Eligible Employee and shall not become a Participant, or (C) if he or she was neither a

Participant with a vested Service Annuity nor a participant entitled to a vested benefit under the Exelon Corporation Pension Plan for Bargaining Unit Employees as of his or her termination date, then, (1) if he or she is rehired prior to January 1, 2009, be permitted to elect, in accordance with procedures established by the Administrator or, for periods prior to June 1, 2006, the 'Committee', as such term was defined in the Plan prior to such date, to participate in the Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees as of his or her rehire date, or (2) if he or she is rehired on or after January 1, 2009, he or she shall not be an Eligible Employee and shall not become a Participant.

(b) Management Employees . The following rules shall apply to an Eligible Employee who is not a member of a collective bargaining unit represented by IBEW Local Union 15 and who is rehired by an Employer after a Termination of Employment and prior to commencing his or her Service Annuity or any benefits under the Exelon Corporation Cash Balance Pension Plan, as applicable:

(i) Rehire Date Before Absence of 5 Years . If an Employee terminates employment and is later rehired by an Employer before having an absence from employment with the Employers and their Affiliates of five years and, on the date of his or her rehire, such Employee is not a member of a collective bargaining unit represented by IBEW Local Union 15, then either: (1) if such Employee was a Participant on the date his or her employment terminated, such Employee shall be Participant in the Plan as of his or her rehire date if he or she is then an Eligible Employee or (2) if such Employee was not a Participant on the date his or her employment terminated, such Employee shall not be an Eligible Employee and shall not become a Participant. Notwithstanding clause (1) of the preceding sentence, if an Eligible Employee described in the preceding sentence was not at any time permitted to make the election described in Section 3.2(a) or was permitted to make such election and elected to participate in the Exelon Corporation Cash Balance Pension Plan but such election was not given effect as a result of such Employee's Termination of Employment, such Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator or, for periods prior to June 1, 2006, the 'Committee', as such term was defined in the Plan prior to such date, to either (1) participate in the Plan as of his or her rehire date or (2) participate in the Exelon Corporation Cash Balance Pension Plan at the time prescribed therein and have his or her Service Annuity and related assets transferred to such plan in the manner described in Section 3.2(b).

(ii) Rehire Date After Absence of at Least 5 Years . If an Employee terminates employment with the Employers and their Affiliates and the Employee was not a Participant or was a Participant who did not have a vested Service Annuity as of the date his or her employment terminated, and such Employee is rehired by an Employer after having an absence from employment with the Employers and their Affiliates of at least five years and, on the date of his or her rehire, such Employee is not a member of a collective bargaining unit represented by IBEW Local Union 15, such Employee shall not be an Eligible Employee and shall not become a Participant upon such rehire. If a Participant with a vested Service Annuity terminates employment with the Employers and their Affiliates and the Participant is rehired after having an absence from employment with the Employers and their Affiliates of at least five years, such Participant shall remain a Participant upon his or her rehire. Notwithstanding the preceding sentence if a Participant described in the preceding sentence was not at any time permitted to make the election described in Section 3.2(a) or was permitted to make such election and elected to participate in the Exelon Corporation Cash Balance Pension Plan but such election was not given effect as a result of such Employee's Termination of Employment, such Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator or, for periods prior to June 1, 2006, the 'Committee', as such term was defined in the Plan prior to such date, to either (1) participate in the Plan as of his or her rehire date or (2) participate in the Exelon Corporation Cash Balance Pension Plan at the time prescribed therein and have his or her Service Annuity and related assets transferred to such plan in the manner described in Section 3.2(b).

Section 9.6. Employees whose Representation by IBEW Local Union 15 Changes . Except as provided in the last paragraph of Section 9.1 (relating to employment after commencement of Service Annuity) if an Employee who, on the day he or she first performed an Hour of Service with an Employer, was not a member of a collective bargaining unit represented by IBEW Local Union 15 and was not an Eligible Employee later becomes an Eligible Employee as a result of becoming a member of a collective bargaining unit represented by IBEW Local Union 15 and being employed at a facility that, as of October 19, 2000, was owned by Commonwealth Edison Company, Unicom Corporation or any affiliate of Unicom Corporation, such Employee shall become a Participant as of the date he or she first becomes a member of a collective bargaining unit represented by IBEW Local Union 15, provided that such Employee becomes a member of a collective bargaining unit represented by IBEW Local Union 15 prior to January 1, 2009 and does not elect, in the time and manner prescribed by the Administrator or, for periods prior to June 1, 2006, the 'Committee', as such term was defined in the Plan prior to

such date for such an election, to participate in the Exelon Corporation Pension Plan for Bargaining Unit Employees. Except as provided in the last paragraph of Section 9.1 (relating to employment after commencement of Service Annuity) if an Employee who was a member of a collective bargaining unit represented by IBEW Local Union 15 and who first became employed by an Employer prior to January 1, 2001 later ceases to be a member of a collective bargaining unit represented by IBEW Local Union 15, such Employee shall be permitted to elect, in the time and manner prescribed by the Administrator or, for periods prior to June 1, 2006, the 'Committee', as such term was defined in the Plan prior to such date, to either (a) continue to participate in the Plan as of the date he or she ceases to be a member of a collective bargaining unit represented by IBEW Local Union 15 or (b) participate in the Exelon Corporation Cash Balance Pension Plan at the time prescribed therein and have his or her Service Annuity and related assets transferred to such plan in the manner described in Section 3.2(b).

Section 9.7. Transfer of Employment to or Reemployment in Positions Eligible for Participation in the Plan or the Service Annuity Plan of PECO Energy Company by Certain Individuals Who Were Participants in Such a Plan on December 31, 2000 . If a Participant who was a Participant on December 31, 2000 transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in the Service Annuity Plan of PECO Energy Company (or would be so eligible but for their election to participate in the Exelon Corporation Cash Balance Pension Plan), then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the Service Annuity Plan of PECO Energy Company. If a participant in the Service Annuity Plan of PECO Energy Company who was a participant in such

plan on December 31, 2000 transfers employment to or is reemployed by an Employer or an Affiliate in a management job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in such plan but are instead eligible to participate in the Plan (or would be so eligible but for their election to participate in the Exelon Corporation Cash Balance Pension Plan), then such individual shall upon such transfer or reemployment remain a participant in the Service Annuity Plan of PECO Energy Company and shall not participate in the Plan.

Section 9.8. Change in Employment Status or Transfer to Affiliate . Except as otherwise provided in Sections 9.9, 9.10 and elsewhere in the Plan, if an Employee who was a Participant transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead either eligible to participate in another plan maintained by such Employer or Affiliate or are not eligible to participate in any plan, then such individual shall upon such transfer or reemployment participate in the plan, if any, determined pursuant to rules established by the Company, which rules may be set forth in a Supplement hereto.

Section 9.9. Certain Rehired Employees . Notwithstanding anything contained herein to the contrary, an Employee who is reemployed by an Employer after December 1, 2012 and has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 6.9 (relating to Special Lump Sum Payment Option) shall not be eligible to become a Participant pursuant to Article 3.

Section 9.10. Transfer of Employment to or from Facilities formerly Owned by CEG. Effective as of the Effective time (as such term is defined in the Merger Agreement), if a Participant who was a Participant on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in a Company Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be a defined benefit pension plan qualified under Section 401(a) of the Code (each such plan, a "CEG Pension Plan") , then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the CEG Pension Plan. If a participant in the CEG Pension Plan who was a participant in such plan on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the CEG Pension Plan and shall not participate in the Plan.

ARTICLE 10

ADMINISTRATION

Section 10.1. The Administrator, the Investment Office and the Corporate Investment Committee . (a) The Administrator . The Company, acting through its Vice President, Health & Benefits, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such vice president or other person or committee, the "Administrator"), shall be the "administrator" of the Plan, within the meaning of such term as used in ERISA. In addition, the Administrator shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan's assets. The Administrator shall have the following duties, responsibilities and rights:

(i) The Administrator shall have the duty and discretionary authority to interpret and construe this Plan in regard to all questions of eligibility, the status and rights of Participants, Retirees, Beneficiaries and other persons under this Plan, and the manner, time, and amount of payment of any distributions under this Plan. The determination of the Administrator with respect to an Employee's years of Credited Service, the amount of the Employee's Earnings, Highest Average Annual Pay, Federal Benefit and any other matter affecting payments under the Plan shall be final and binding. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Administrator, in his or her discretion, determines that such person is entitled to benefits.

(ii) Each Employer shall, from time to time, upon request of the Administrator, furnish to the Administrator such data and information as the Administrator shall require in the performance of his or her duties.

(iii) The Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust under Article 6 (relating to Service Annuity forms). In addition, it shall be the duty of the Administrator to certify to the Trustee the names and addresses of all Retirees, the amounts of all Service Annuities, the dates of death of Retirees and all proceedings and acts of the Administrator necessary or desirable for the Trustee to be fully informed as to the Service Annuities to be paid out of the Service Annuity Fund.

(iv) The Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Office, the Corporate Investment Committee or the Trustee.

(v) The Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Administrator and to furnish such information requested by the Administrator. The Administrator and the Plan may rely upon all such information so furnished to the Administrator.

(vi) The Administrator shall be the Plan's agent for service of legal process and forward all necessary communications to the Trustee.

(b) Removal of Administrator . The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Administrator (including any member of a committee that constitutes the Administrator). The Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer or upon the Administrator's termination of employment with the Employers. Upon the resignation, removal or failure or inability for any reason of the Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any officer, employee or member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Administrator.

(c) The Investment Office . The Investment Office shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in Sections 404(a)(2) of ERISA and the terms of the Plan and all other applicable limitations. In addition to the duties, responsibilities and rights of the Investment Office set forth in Article 8, the Investment Office shall have the following duties, responsibilities and rights:

(i) The Investment Office shall be the "named fiduciary" for purposes of directing the Trustee as to the investment of amounts held in the Trust Fund and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Office shall submit to the Corporate Investment Committee annual manager review results and such other reports and documents as may be necessary for the Corporate Investment Committee to monitor the activities and performance of the Investment Office.

(iii) Each Employer shall, from time to time, upon request of the Investment Office, furnish to the Investment Office such data and information as the Investment Office shall require in the performance of its duties.

(d) The Corporate Investment Committee . The Company acting through the Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Office. The Corporate Investment Committee shall have the following duties, responsibilities and rights:

(i) The Corporate Investment Committee shall monitor the activities and performance of the Investment Office and shall review annual manager review results and any other reports and documents submitted by the Investment Office.

(ii) The Corporate Investment Committee shall have authority to approve asset allocation recommendations of the Investment Office, and approve the retention or firing of any investment consultant (but not any investment manager), custodian or trustee, as recommended by the Investment Office.

(iii) The Corporate Investment Committee and the Company's Chief Investment Officer shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Office. Any successor Investment Office employee shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor.

The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the employees of the Investment Office and approval of the recommendations specified in clause (ii) above. The Corporate Investment Committee shall have no responsibility for making investment decisions, appointing or firing investment managers or for any other duties or responsibilities with respect to the Plan, other than those specifically listed herein.

(e) Status of Administrator, the Investment Office and the Corporate Investment Committee . The Administrator, any person acting as, or on behalf of, the Investment Office, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee or officer of an Employer and such status shall not disqualify such person from taking any action

hereunder or render such person accountable for any distribution or other material advantage received by him or her under this Plan, provided that no Administrator, person acting as, or on behalf of, the Investment Office, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Administrator or the Investment Office on any matter involving solely his or her rights under this Plan.

(f) Notice to Trustee of Members . The Trustee shall be notified as to the names of the Administrator and the person or persons authorized to act on behalf of the Investment Office.

(g) Allocation of Responsibilities . Each of the Administrator, the Investment Office and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

(h) General Governance . The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Administrator, the Investment Office and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

(i) Indemnification . The Employers hereby jointly and severally indemnify the Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

(j) No Compensation . None of the Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Administrator, Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Affiliate for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

(k) Employ of Counsel and Agents . The Administrator, the Investment Office and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

Section 10.2. Claims Procedure . Any Participant or distributee who believes he or she is entitled to benefits in an amount greater than those which he or she is receiving or has received may file a claim with the Administrator. Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Administrator shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the Administrator's decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable Regulations. If the Administrator determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Administrator expects to render the benefit determination. The notice of the decision of the Administrator with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, the Administrator shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right (subject to the limitations described in Section 13.8 and 13.9) to bring a civil action under Section 502 of ERISA following an adverse benefit determination on review. The Administrator shall also advise the claimant that the claimant or the claimant's duly authorized representative may request a review by the Chief Human Resources Officer (or such other officer

designated from time to time by the Chief Human Resources Officer) of the adverse benefit determination by filing with such officer, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he or she (a) may be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit to the officer written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by the officer within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the officer's final decision. If the officer determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the officer expects to render the determination on review. The review of the officer shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

Section 10.3. Procedures for Domestic Relations Orders . If the Administrator shall receive any judgment, decree or order (including approval of a property settlement agreement) pursuant to State domestic relations or community property law relating to the provision of child support, alimony or marital property rights of a spouse, former spouse, child or other dependent of a Participant and purporting to provide for the payment of all or a portion of the Participant's Service Annuity to or on behalf of one or more of such persons (such judgment, decree or order being hereinafter called a "domestic relations order"), the Administrator shall promptly notify the Participant and each other payee specified in such domestic relations order of its receipt and of the following procedures. After receipt of a domestic relations order, the Administrator shall determine whether such order constitutes a "qualified domestic relations order" as defined in paragraph (b) of Section 13.2, and shall notify the Participant and each payee named in such order in writing of the Administrator's determination within a reasonable time after receipt of such order. Such notice shall be written in a manner calculated to be understood by the parties and shall contain an explanation of the review procedure under this Plan. If the Administrator determines that the order is not a "qualified domestic relations order," such notice also shall set forth specific reasons for the Administrator's determination. The Administrator shall advise each party that each party or a duly authorized representative of such party may request a review by the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) of the Administrator's determination by filing with such officer within 60 days of receipt of the Administrator's determination a written request for such review. The Administrator shall give every party affected by any such request for review notice of such request. Each party also shall be informed that he or she may have reasonable access to pertinent documents and submit comments in writing to the officer in connection with such request for review. Within 60 days after a request for review, each party shall be given written notice of the officer's final determination, which notice shall be written in a manner calculated to be understood by the parties and shall include specific reasons for such final determination.

Section 10.4. Computation of Benefits . The benefit formula, factors contained in any Tables or Schedules and the Federal Benefit taken into account in determining the amount of a Participant's Service Annuity (including the amount paid under the applicable form of payment of such Service Annuity) or the amount of any surviving spouse or surviving child annuity payable with respect to any Participant shall be the formula, factors and/or Federal Benefit, as applicable, in effect on the date of the Participant's Termination of Employment.

Section 10.5. Actuary to Be Employed . The Company or the Investment Office shall engage an actuary to do such technical and advisory work as the Company or the Investment Office may request, including analyses of the experience of this Plan from time to time, the preparation of actuarial tables for the making of computations thereunder, and the submission to the Company or the Investment Office of an annual actuarial report, which report shall contain information showing the financial condition of this Plan, a statement of the contributions to be made by the Employers for the ensuing year, and such other information as may be requested by the Company or the Investment Office.

Section 10.6. Funding Policy . The Company shall establish a funding policy and method consistent with the objectives of this Plan and the requirements of Title I of ERISA and shall communicate such policy and method, and any changes in such policy and method, to the Investment Office.

Section 10.7. Notices to Participants, Etc. All notices, reports and statements given, made, delivered or transmitted to a Participant or any other person entitled to or claiming benefits under this Plan shall be deemed to have been duly given, made or transmitted when mailed by first class mail with postage prepaid and addressed to the Participant or such other person at the address last appearing on the records of the Administrator.

Section 10.8. Notices to Employers or Administrator . Written directions, notices and other communications from Participants or any other person entitled to or claiming benefits under this Plan to the Employers or Administrator shall be deemed to have been duly given, made or transmitted either when delivered to such location as shall be specified upon the forms prescribed by the Administrator for the giving of such directions, notices and other communications or when mailed by first class mail with postage prepaid and addressed to the addressee at the address specified upon such forms.

Section 10.9. Records . Each of the Administrator, the Investment Office and the Corporate Investment Committee shall keep a record of all of their respective proceedings, if any, and shall keep or cause to be kept all books of account records and other data as may be necessary or advisable in their respective judgment for the administration of the Plan, the administration of the investments of the Plan or the monitoring of the investment activities of the Plan, as applicable.

Section 10.10. Responsibility to Advise Administrator of Current Address . Each person entitled to receive a payment under this Plan shall file with the Administrator in writing such person's complete mailing address and each change therein. A check or communication mailed to any person at such person's address on file with the Administrator shall be deemed to have been received by such person for all purposes of this Plan. Although neither the Administrator nor the Trustee shall be obliged to search for or ascertain the location of any

person, the Administrator shall make reasonable efforts to locate any missing Participant or Beneficiary entitled to benefits hereunder. If the Administrator is in doubt as to whether payments are being received by the person entitled thereto, it shall, by registered mail addressed to the person concerned at his or her last address known to the Administrator, notify such person that all future payments will be withheld until such person submits to the Administrator evidence of his or her continued life and proper mailing address.

Section 10.11. Electronic Media . Notwithstanding any provision of the Plan to the contrary and for all purposes of the Plan, to the extent permitted by the Administrator and any applicable law or Regulation, the use of electronic technologies shall be deemed to satisfy any written notice, consent, delivery, signature, disclosure or recordkeeping requirement under the Plan, the Code or ERISA to the extent permitted by or consistent with applicable law and Regulations. Any transmittal by electronic technology shall be deemed delivered when successfully sent to the recipient, or such other time specified by the Administrator.

Section 10.12. Correction of Error . If it comes to the attention of the Administrator that an error has been made in the amount of benefits payable, or paid, to any Participant or Beneficiary under the Plan, the Administrator shall be permitted to correct such error by whatever means that the Administrator, in its sole discretion determines, including by offsetting future benefits payable to the Participant or Beneficiary or requiring repayment of benefits to the Plan, except that no adjustment need be made with respect to any Participant or Beneficiary whose benefit has been distributed in full prior to the discovery of such error.

ARTICLE 11

PARTICIPATION BY OTHER EMPLOYERS

Section 11.1. Adoption of Plan . With the consent of the Company, any entity may become a participating Employer under this Plan with respect to all or a designated group of its employees by taking such action as shall be necessary or desirable to adopt this Plan and executing and delivering such instruments as may be necessary or desirable to put this Plan into effect with respect to such entity.

Section 11.2. Withdrawal from Participation . Any Employer shall terminate its participation in the Plan at any time, under such circumstances as the Company may provide, by delivering to the Company a duly certified copy of a resolution of its board of directors (or other governing body) to that effect, or by ceasing to be a member of the same controlled group as the Company (within the meaning of section 1563(a) if the Code).

Section 11.3. Company and Administrator Agent for Employers . Each corporation which shall become a participating Employer pursuant to Section 11.1 (relating to adoption of the Plan) or Article 12 (relating to continuance by a successor) by so doing shall be deemed to have appointed the Company and the Administrator its agent to exercise on its behalf all of the powers and authorities hereby conferred upon the Company and the Administrator by the terms of this Plan, including, but not by way of limitation, the power to amend and terminate this Plan. The authority of the Company and the Administrator to act as such agent shall continue unless and until the portion of the Service Annuity Fund held for the benefit of Employees of the particular Employer and their Beneficiaries is set aside in a separate trust as provided in Section 15.2 (relating to establishment of separate plan).

ARTICLE 12

CONTINUANCE BY A SUCCESSOR

In the event that any Employer shall be reorganized by way of merger, consolidation, transfer of assets or otherwise, so that a corporation, partnership or person other than an Employer shall succeed to all or substantially all of such Employer's business, such successor may be substituted for such Employer under this Plan by adopting this Plan and, if necessary, becoming a party to the Service Annuity Fund. Contributions by such Employer shall be automatically suspended from the effective date of any such reorganization until the date upon which the substitution of such successor corporation for the Employer under this Plan becomes effective. If, within 90 days following the effective date of any such reorganization, such successor shall not have elected to become a party to this Plan, or if such successor shall adopt a plan of complete liquidation other than in connection with a reorganization, this Plan shall be automatically terminated with respect to employees of such Employer as of the close of business on the 90th day following the effective date of such reorganization or as of the close of business on the date of adoption of such plan of complete liquidation, as the case may be, and the Administrator shall direct the Trustee to distribute the portion of the Service Annuity Fund applicable to such Employer in the manner provided in Section 15.2 (relating to establishment of separate plan).

ARTICLE 13

MISCELLANEOUS

Section 13.1. Expenses . The expenses of the Trustee in the administration of the Service Annuity Fund, including compensation, if any, to the Trustee for its services, shall be paid by the Company or the Employers. All costs and expenses incurred in the operation of the Service Annuity Fund, to the extent not described in the preceding sentence, and all costs and expenses incurred in the operation of the Plan, the Service Annuity Fund, the Pooled Fund or the Master Trust, as applicable, including, but not limited to, "direct expenses" incurred in administering the Plan, the Service Annuity Fund, the Pooled Fund and the Master Trust (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan, the Service Annuity Fund, the Pooled Fund or the Master Trust), the expenses of the Administrator, the Investment Office and the Corporate Investment Committee, the fees of counsel and any agents for the Trustee, the Administrator, the Investment Office or the Corporate Investment Committee, and the fees of investment managers that manage assets of the Pooled Fund or the Master Trust, as applicable, shall be paid by the Trustee from the Service Annuity Fund or the Pooled Fund or the Master Trust, as applicable, in such proportion as the Investment Office, in its sole discretion, shall determine, to the extent such expenses are not paid by the Employers and to the extent permitted under ERISA, Regulations and other applicable laws. Any such expenses that are borne by the Employers shall be paid out of their own funds in such proportions as the Administrator shall determine. In the event that the Company or any other Employer advances money on behalf of the Service Annuity Fund for the payment of any expenses incurred in the operation of the Plan, the Trustee shall reimburse the Company or such other Employer from the Service Annuity Fund for any amount so advanced, without interest or fees.

Section 13.2. Non-Assignability . (a) It is a condition of this Plan, and all rights of each Participant, Beneficiary and Retiree shall be subject thereto, that no right or interest of any Participant, Beneficiary or Retiree in this Plan shall be assignable or transferable in whole or in part, either directly or by operation of law or otherwise, including, but not by way of

limitation, execution, levy, garnishment, attachment, pledge or bankruptcy, but excluding devolution by death or mental incompetency, and no right or interest of any Participant, Beneficiary or Retiree in this Plan shall be liable for, or subject to, any obligation or liability of such Participant, Beneficiary or Retiree, including claims for alimony or the support of any spouse or child, except as provided in paragraph (b) of this Section 13.2 (relating to exception for qualified domestic relations orders).

(b) Exception for Qualified Domestic Relations Orders . Notwithstanding any provision of this Plan to the contrary, if a Participant's Service Annuity under this Plan, or any portion thereof, shall be the subject of one or more qualified domestic relations orders, as defined below, such Service Annuity or portion thereof shall be paid to the person at the time and in the manner specified in any such order. For purposes of this paragraph (b), "qualified domestic relations order" shall mean any "domestic relations order" as defined in Section 10.3 (relating to procedures for domestic relations orders) which creates (or recognizes the existence of) or assigns to a person other than the Participant (an "alternate payee") rights to all or a portion of the Participant's Service Annuity under this Plan, and:

(A) clearly specifies

(i) the name and last known mailing address (if any) of the Participant and each alternate payee covered by such order,

(ii) the amount or percentage of the Participant's Service Annuity to be paid by this Plan to each such alternate payee, or the manner in which such amount or percentage is to be determined,

(iii) the number of payments to, or period of time for which, such order applies, and

(iv) each plan to which such order applies;

(B) does not require

(i) this Plan to provide any type or form of benefit or any option not otherwise provided under this Plan at the time such order is issued,

(ii) this Plan to provide increased benefits (determined on the basis of actuarial equivalence), or

(iii) the payment of benefits to an alternate payee which at the time such order is issued already are required to be paid to a different alternate payee under a prior qualified domestic relations order; and

(C) does not require the payment of benefits to any alternate payee before the first to occur of (i) the earliest date as of which payment of the Participant's Service Annuity could commence after his or her Termination of Employment, and (ii) the Participant's attainment of age 50,

all as determined by the Company pursuant to the procedures contained in Section 10.3 (relating to procedures for domestic relations orders). Any amounts subject to a domestic relations order prior to determination of its status as a qualified domestic relations order which but for such order would be paid to the Participant shall be segregated in a separate account or an escrow account pending such determination. If, within a reasonable time after receipt of written evidence of such order by the Company, it is determined that a domestic relations order constitutes a qualified domestic relations order, the amount so segregated (plus any interest thereon) shall be paid to the alternate payee in accordance with the terms of the order. If, within a reasonable time after receipt of a domestic relations order by the Company, it is determined that a domestic relations order does not constitute a qualified domestic relations order, then the amount so segregated (plus any interest thereon) shall, as soon as practicable, be paid to the Participant. Any subsequent determination that such order constitutes a qualified domestic relations order shall apply only to payments made on or after the date of such subsequent determination.

Section 13.3. Employment Non-Contractual . Neither this Plan nor any action taken by the Administrator or the Investment Office confers any right upon any Employee to continue in employment with any Employer.

Section 13.4. Limitation of Rights . No Participant, Beneficiary or Retiree shall have any right, title, interest or claim in or to any part of the Service Annuity Fund at any time, but shall have the right only to distributions from the Service Annuity Fund on the terms and conditions herein provided. Neither this Plan nor any action taken by the Administrator or the Investment Office shall obligate any Employer to make contributions to the Service Annuity Fund in excess of the contributions authorized by the board of directors of the Company or create any liability on an Employer for the payment of Service Annuities under this Plan.

Section 13.5. Merger or Consolidation with or Transfer to Another Plan . A merger or consolidation with, or transfer of assets or liabilities to, any other Plan shall not be effected unless the terms of such merger, consolidation or transfer are such that each Participant, Beneficiary, Retiree or other person entitled to receive benefits from this Plan would, if this Plan were to terminate immediately after the merger, consolidation or transfer, receive a benefit equal to or greater than the benefit such person would be entitled to receive if this Plan were to terminate immediately before the merger, consolidation, or transfer.

If an Employee or a group of Employees ceases to be an Employee or Employees of an Employer and becomes an employee or employees of an Affiliate that is not an Employer but that maintains its own pension plan, there shall be transferred from the Service Annuity Fund to the trust fund for the pension plan of such Affiliate assets in an amount equal to the proportion of the amount of the total assets of the Service Annuity Fund, after deducting therefrom the

amount actuarially determined to be necessary for the payment in full of Service Annuities theretofore granted to all Retirees and Participants, which the actuarial reserve allocable to such Employee or such group of Employees, as the case may be, bears to the actuarial reserve allocable to all Employees. If, however, any such group of Employees shall include all of the Employees of all Employers, all of the assets of the Service Annuity Fund shall be so transferred.

If and when a separate pension plan and trust fund is created by the Company for supervisory, administrative and management Employees, there shall be transferred from the Service Annuity Fund to such separate trust fund assets in an amount equal to the sum of (a) that proportion of the amount of the total assets of the Service Annuity Fund, after deducting therefrom the amount actuarially determined to be necessary for the payment in full of Service Annuities theretofore granted to all Retirees and Participants, which the actuarial reserve allocable to such supervisory, administrative and management Employees bears to the actuarial reserve allocable to all Employees, and (b) the amount of assets actuarially determined to be necessary for the payment in full of Service Annuities theretofore granted to Retirees who were supervisory, administrative or management Employees at the time of the granting of such Service Annuities. If and when an Employee shall thereafter be transferred to or from the management payroll, there shall be transferred from the Service Annuity Fund to such separate trust fund or from such separate trust fund to the Service Annuity Fund, as the case may be, assets in an amount determined in the same manner as described in the preceding sentence (and the Employee's Service Annuity or benefits in the nature of a service annuity shall subsequently be paid out of the Service Annuity Fund or such separate trust fund, as the case may be).

If and when an employee or a group of employees of an Affiliate that is not an Employer shall cease to be an employee or employees of such Affiliate and shall become an Employee or Employees of an Employer, the Trustee under the Service Annuity Fund shall accept, upon transfer from the trust fund of the pension plan of such Affiliate, assets in an amount equivalent to that proportion of the amount of the total assets of such trust fund, after deducting therefrom the amount actuarially determined to be necessary for the payment in full of benefits theretofore granted, which the actuarial reserve allocable to such Employee or such groups of Employees, as the case may be, bears to the actuarial reserve allocable to all employees. If, however, any such group of Employees shall include all of the employees of such Affiliate, all of the assets of such trust fund shall be so accepted.

In the case of each transfer of assets made or accepted pursuant to the provisions of this Section 13.5, the amount of the total assets and (if less than all assets are to be transferred) the proportion thereof to be transferred shall be determined as of a date not earlier than December 31 of the preceding calendar year.

All assets accepted, upon transfer, by the Trustee under the Service Annuity Fund, pursuant to the provisions of this Section 13.5, shall be held and applied in accordance with the provisions of the Trust Agreement relating to the Service Annuity Fund.

Section 13.6. Medical Examination . A Participant or Beneficiary for whom a determination or verification of physical or medical condition is in the opinion of the Administrator relevant to the application of this Plan shall, if and when reasonably requested by the Administrator, submit to medical examination by a physician appointed by the Administrator.

Section 13.7. Applicable Law . Except to the extent preempted by applicable federal law or otherwise provided under the terms of the Plan, the Plan and all rights hereunder shall be governed by and construed in accordance with the laws of the State of Illinois.

Section 13.8. Statute of Limitations for Actions under the Plan . Except for actions to which the statute of limitations prescribed by Section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under Section 502 of ERISA may be commenced later than one year after the claimant receives a final decision from the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

Section 13.9. Forum for Legal Actions under the Plan . Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in the Northern District of Illinois or the Eastern District of Pennsylvania, whichever is most convenient, and no other federal or state court.

Section 13.10. Legal Fees . Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied

a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, the Investment Office, the Corporate Investment Committee, any Plan fiduciary, the Chief Human Resources Officer, any Plan administrator, the Company, its affiliates or their respective officers, directors, employees, or agents (the "Plan Parties"), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

ARTICLE 14

TOP-HEAVY PLAN REQUIREMENTS

Section 14.1. Top-Heavy Plan Determination . If, as of the determination date (as hereinafter defined) for any Plan Year, the aggregate present value of (a) the accrued Service Annuities under this Plan and the accrued benefits under all other defined benefit plans in the aggregation group (as defined below) and (b) the aggregate account balances under all defined contribution plans in such aggregation group, in each case with respect to all participants in such plans who are key employees (as defined in Section 416(i) of the Code) for such Plan Year, exceeds 60% of the aggregate of the present value of the Service Annuities, accrued benefits and account balances of all participants in such plans as of the determination date, then this Plan shall be a top-heavy plan for such Plan Year, and the requirements of Section 14.2 (relating to minimum benefit for top-heavy years), Section 14.3 (relating to top-heavy vesting requirements) and Section 14.4 (relating to special rules for applying statutory limitations on benefits) shall be applicable for such Plan Year as of the first day thereof. An employee's compensation, as defined in Section 1.415 (c)-2 of the Regulations, from the Company and its Affiliates for a Plan Year shall be used, where applicable, in determining whether such employee is a key employee.

For purposes of the first sentence of the preceding paragraph, for any Plan Year, the Service Annuity accrued in respect of any Employee shall be the amount calculated as of the determination date, and the present value of such amount shall be based on the actuarial assumptions used in the actuarial valuation as of such determination date. The calculation of the present value of the Service Annuity accrued in respect of any Employee shall be subject to adjustments required under Section 416 of the Code.

If this Plan shall be a top-heavy plan for any Plan Year and not be a top-heavy plan for any subsequent Plan Year, the requirements of this Article shall not be applicable for such subsequent Plan Year except to the extent provided in Section 14.3 (relating to top-heavy vesting requirements).

For purposes of this Article, (a) the aggregation group shall consist of (i) if a key employee was a Participant in this Plan during the Plan Year containing the determination date (defined below) or any of the four preceding Plan Years, then this Plan and each other plan of an Employer which is qualified under Section 401(a) of the Code and in which a key employee is a participant during any of such Plan Years, (ii) this Plan and each other plan which enables this Plan to meet the requirements of Section 401(a)(4) or 410(b) of the Code during the Plan Year containing the determination date (defined below) or any of the four preceding Plan Years, and (iii) this Plan and each other plan of an Employer which it shall so designate and which together with this Plan shall satisfy the requirements of Sections 401(a)(4) and 410 of the Code; (b) the determination date for all plans in the aggregation group shall be the last day of the preceding plan year; and (c) the valuation date applicable to a determination date shall be (i) in the case of a defined benefit plan, the date as of which the most recent actuarial valuation for the plan year including the determination date is prepared, and (ii) in the case of a defined contribution plan,

the date as of which account balances are determined which is coincident with or immediately precedes the determination date, except that if any such plan specifies a different determination or valuation date, such different date shall be used with respect to such plan. For the purpose of determining the Service Annuity, accrued benefit or account balance of a participant, any person who received a distribution from a plan in the aggregation group during the one-year period ending on the last day of the preceding plan year shall be treated as a participant in such plan, and any such distribution shall be included in such participant's Service Annuity, accrued benefit or account balance as the case may be, except that in the case of any distribution made for a reason other than severance from employment, death or disability, this sentence shall be applied by substituting "five-year period" for the "one-year period" stated herein.

Section 14.2. Minimum Benefit for Top-Heavy Years . (a) Subject to paragraph (b) of this Section 14.2 and the applicable reductions set forth in Article 5 (relating to Service Annuities) and Article 6 (relating to Service Annuity forms), the annual amount of Service Annuity on a single life basis to which an eligible employee (other than an eligible employee who is a key employee as defined in Section 416(i) of the Code) is entitled at age 65 under Section 5.2 (relating to normal and deferred retirement), Section 5.3 (relating to early retirement), Section 5.4 (relating to disability retirement at or after age 45), Section 5.5 (relating to disability retirement before age 45) or Section 5.7 (relating to deferred vested termination) shall in no event be less than (i) the product of (A) 2% of such eligible employee's average compensation, as described in Section 416(c) of the Code, from the Company and its Affiliates during such eligible employee's five highest-paid consecutive calendar years of service beginning after January 1, 1983 and while the Plan is top-heavy, multiplied by (B) the number of such eligible employee's years of Credited Service (but not in excess of ten) ending after

December 31, 1983 while the Plan is top-heavy less (ii) the annual actuarial equivalent of the eligible employee's vested portion of such eligible employee's account balances attributable to employer contributions and forfeitures, and earnings and losses thereon (including prior distributions thereof) and accrued benefits to which such eligible employee is entitled on Termination of Employment under all other qualified plans maintained by the Company or its Affiliates.

For purposes of this Article 14 (relating to top-heavy plan requirements), "eligible employee" shall mean any employee other than an employee who is included in a unit of employees covered by a collective bargaining agreement between employee representatives and an Employer, if there is evidence that retirement benefits have been the subject of good faith bargaining between such employee representatives and such Employer.

(b) The provisions of paragraph (a) shall not apply with respect to an eligible employee if, for each year in which this Plan is top-heavy, (i) the eligible employee's Employer also maintains a defined contribution plan which is included in the aggregation group for such year, and (ii) contributions made on behalf of each eligible employee other than key employees and forfeitures allocated to such eligible employee during such Plan Year are at least 5% of such eligible employee's compensation.

Section 14.3. Top-Heavy Vesting Requirements . Not-withstanding any provision of this Plan to the contrary, if an eligible employee's Termination of Employment occurs during a Plan Year in which this Plan is top-heavy and after the eligible employee has completed at least two years of Vesting Service but before the eligible employee has completed five years of Vesting Service, or after this Plan has been top-heavy and during the time this Plan was top-heavy such eligible employee has completed three years of Vesting Service, then such eligible

employee shall be entitled, subject to Article 6 (relating to Service Annuity forms) and Article 7 (relating to limitation on benefits), to receive, determined in accordance with the following table, the vested percentage of the eligible employee's Service Annuity computed pursuant to Section 5.7 (relating to deferred vested termination):

Years of Vesting Service	Vested Percentage
2 but less than 3	20%
3 but less than 4	40%
4 but less than 5	60%
5 or more	100%

Section 14.4. Special Rules for Applying Statutory Limitations on Benefits . In any Plan Year for which this Plan is top-heavy, clauses (C)(I) and (D)(I) of the first paragraph of Section 7.1 (relating to maximum annual benefits) shall be applied by substituting "100%" for "125%" appearing therein unless, for such Plan Year (i) the percentage of Service Annuities accrued by Participants who are key employees does not exceed 90% of the Service Annuities accrued by all Participants, and (ii) the minimum accrued benefit of each Participant under all defined benefit plans in the aggregation group is at least 3% of such Participant's average compensation multiplied by each year of such Participant's Credited Service after 1983, not in excess of 10, while such plans are top-heavy.

ARTICLE 15

AMENDMENT AND TERMINATION

Section 15.1. Amendment . The board of directors of the Company (or a committee thereof) may at any time and from time to time amend or modify this Plan in any manner deemed by the board of directors of the Company to be necessary or desirable, provided, however, that in the case of any amendment or modification that would not result in an aggregate

annual cost to the Company of more than $50,000,000, the Plan may be amended or modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability account balance exceeding $250,000) or another executive officer holding title of equivalent or greater responsibility and, provided, further, that no amendment shall be made that affects Employees who are represented by IBEW Local Union 15 that is not consistent with that portion of the Company's collective bargaining agreements with IBEW Local Union 15 concerning the Plan. Any such amendment or modification shall become effective on such date as the board of directors of the Company shall determine and may apply to Participants in this Plan at the time thereof as well as to future Participants, provided, however, that no such amendment or modification which reduces the basis for the computation of Service Annuities shall be retroactive as to service prior to the date of such amendment or modification.

In addition, the Administrator may amend or modify subdivision (4) of Section 2.1 (relating to the definition of Basic Compensation) and subdivision (24) of Section 2.1 (relating to the definition of Incentive Pay) by changing such subdivisions as described therein.

Section 15.2. Establishment of Separate Plan . If an Employer shall withdraw from this Plan under Section 11.2 (relating to withdrawal from participation), the Investment Office shall determine the portion of the Service Annuity Fund held by the Trustee which is applicable to the Participants and Retirees of such Employer and direct the Trustee to segregate such portion in a separate trust. Such separate trust shall thereafter be held and administered as a part of the separate plan of such Employer.

Section 15.3. Termination of the Plan by an Employer . The Company may at any time, by resolution adopted by its board of directors, terminate this Plan in its entirety. In addition, any Employer may at any time terminate its participation in this Plan by resolution adopted by its board of directors to that effect. If the Internal Revenue Service shall refuse to issue an initial favorable determination letter that this Plan and the Service Annuity Fund as adopted by the Company meets the requirements of Section 401(a) of the Code and that the Service Annuity Fund is exempt from tax under Section 501(a) of the Code, any Employer may terminate its participation in this Plan and direct the Trustee to pay and deliver to that Employer the portion of the Service Annuity Fund applicable to its contributions.

Section 15.4. Distribution upon Termination or Partial Termination . Upon termination or partial termination of this Plan, the Service Annuities accrued as of the date of termination or partial termination, as the case may be, of all affected Participants shall be fully vested. After providing for any expenses of the termination of this Plan, or, in the event of the partial termination of this Plan, any expenses of such partial termination which are to be borne by the portion of the Service Annuity Fund applicable to those Employees affected by the partial termination, the remainder of such portion of the Service Annuity Fund (the “asset value”) shall be allocated pursuant to the priority categories set forth in Section 4044 of ERISA and PBGC Regulations. In the event that after the termination of this Plan there is any asset value remaining after such allocation, the assets representing such asset value shall be paid over and applied for the benefit of the Employees of the Employers. The portion of the asset value allocated to provide Service Annuities to any person or group of persons may be applied for the benefit of such person or persons by the distribution of cash, continuance of the Service Annuity Fund, establishment of a new trust fund, purchase of annuities from an insurance company, or otherwise, as determined by the Company in its sole discretion. Notwithstanding the preceding sentences, if the Plan is terminated, the Service Annuity of each highly compensated employee as defined in Section 414(q) of the Code (and any former highly compensated employee) is limited to a Service Annuity that is nondiscriminatory under Section 401(a)(4) of the Code.

Section 15.5. Trust to Be Applied Exclusively for Participants and Their Beneficiaries . Subject only to the provisions of Section 4.2 (relating to return of contributions), Section 15.3 (relating to termination of the Plan by an Employer), Section 15.4 (relating to distribution upon termination or partial termination of the Plan) and any other provision of this Plan to the contrary notwithstanding, it shall be impossible for any part of the Service Annuity Fund to be used for or diverted to any purpose not for the exclusive benefit of Participants and their Beneficiaries either by operation or termination of this Plan, power of amendment or other means.

IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its duly authorized officer on this _____day of December, 2012.

EXELON CORPORATION

By_____
Chief Human Resources Officer

Exhibit 1

Items Included as Basic Compensation

Effective on and after April 1, 1995, the payments to Participants which shall be included in “Basic Compensation” for purposes of subdivision (4) of Section 2.1 of the Plan shall be as follows:

1. Regular earnings,
2. Nuclear license bonuses, and
3. Meter reader bonuses.
4. Payroll deductions for any commuter benefit offered to management employees pursuant to Section 132(f)(4) of the Code.

In addition, to the extent they relate to but are not a part of regular earnings for a given period which otherwise have been used in calculating Basic Compensation, the following items shall be included in the determination of “Basic Compensation” for purposes of subdivision (4) of Section 2.1 of the Plan:

1. Payments for disability absences,
2. Back pay included that is not subject to FICA and any other back pay which is awarded to the Participant and pursuant to which award the Participant is required to have such back pay included as Basic Compensation under the Plan,
3. Paid and unpaid absences,
4. Permissible rest period payments,
5. Credit for service by union officials on union business,
6. Payments allowed for military duty and
7. Credits allowed upon return from a military leave of absence.

Exhibit 2

Plans Included for Incentive Pay

Payments under the following plans shall be considered in determining a Participant's Incentive Pay, as defined in subdivision (24) of Section 2.1 of the Plan:

1. the Unicom Corporation 1995 Variable Compensation Award for Management Employees Under the Unicom Corporation Long-Term Incentive Plan,
2. any annual incentive award provided under the Unicom Corporation Long Term Incentive Plan or any other successor or other plan that provides annual incentive awards to Participants; provided, however that awards payable under any such plans with respect to any period beginning on or after January 1, 2001 to a Participant who is a member of IBEW Local Union 15 shall not be Incentive Pay for Plan purposes,
3. the Commonwealth Edison Pension Fund Management Incentive Pay Plan (effective January 1, 1993),
4. the Pension Fund Management Deferred Incentive Pay Plan (effective January 1, 1994),
5. the Commonwealth Edison Company Bulk Power Marketing Incentive Plan (effective April 1, 1994),
6. any variable pay plan negotiated by the Company with respect to its union Employees, and
7. Quarterly Incentive Awards paid to a management Employee pursuant to the Exelon Corporation Quarterly Incentive Award.

Supplement 1

Early Retirement Window for Certain Employees

This Supplement 1 sets forth the early retirement benefits available to each "Eligible Participant" (as defined below) who is at least age 50 and has completed at least 5 years of Credited Service (after taking into account the grant of any "Service Equivalent" under Section II below) and who submits a signed election and waiver and release of claims to the Company no earlier than the date of the Eligible Participant's "Termination Date" (as defined below), or, if later, 45 days after the Participant receives a summary of the benefits provided hereunder, on forms prescribed by the Company, electing one of the Options set forth below and waiving all employment-related claims against the Employers.

I. Definitions . As used in this Supplement 1, the following words and phrases shall have the following respective meanings when capitalized unless the context clearly indicates otherwise:

A. Cause . Willful commission of acts or omissions which have, have had, or are likely to have, a material adverse effect on the business, operations, financial condition or reputation of an Employer; or conviction (including a plea of guilty or *nolo contendere*) of a felony or any crime of fraud, theft, dishonesty or moral turpitude.

B. Eligible Participant . A Participant (i) whose employment with the Employers is terminated other than for Cause as a result of either (A) his or her Employer's restructuring related to the merger or pending merger of Unicom Corporation and PECO Energy or (B) the Participant's rejection of an offer of a Significant Transfer, (ii) who is notified that his or her Termination Date shall occur on or before December 31, 2002 and is eligible for the normal retirement benefits or early retirement benefits set forth in this Supplement 1, (iii) who continues employment with the Employers until the Termination Date set forth in the Participant's notification of eligibility (or until such earlier date permitted by the Employers) and who does not accept before such Termination Date (or, if later, the date the Eligible Employee's waiver of claims becomes effective) another position with any Employer, Exelon Corporation or any of their respective affiliates and (iv) who maintains an acceptable level of performance during the period ending on his or her Termination Date.

C. Service Equivalent . An amount equal to 12 months plus, if applicable, one additional week for each year of an Eligible Participant's Credited Service in excess of 10; provided, however, that only that portion of the Service Equivalent necessary to satisfy the eligibility requirements for an early retirement Service Annuity (granted under Section 5.3 or under the pension enhancement described in Section III B.2.b.) shall be taken into account for purposes of determining the amount of an Eligible Participant's early retirement Service Annuity.

D. Significant Transfer . An offer of a position with Exelon Corporation or a transfer (between or within business units) that, in either case, results in one or more of the following;

1. an increase in the Participant's one-way commuting distance of more than 50 miles;

2. a substantial change in the Participant's major position responsibilities and duties (as determined by the head of the Participant's business unit);

3. a salary band for the Participant that is lower than the salary band for the Participant's previous position; or

4. a reduction in the Participant's annual base salary or hourly compensation rate, as applicable.

E. Termination Date . The date on which an Eligible Participant's Termination of Employment occurs.

F. Week of Base Salary . In the case of an Eligible Participant who is a full-time Employee, a "Week of Base Salary" shall be determined by dividing (i) the Participant's annual base salary in effect on the his or her Termination Date, excluding any additives, premiums or other adjustments, by (ii) 52. In the case of an Eligible Participant who is a part-time Employee, a "Week of Base Salary" shall equal the product of (i) his or hourly compensation rate in effect on his or her Termination Date multiplied by (ii) the number of hours each week that such Participant is regularly scheduled to work with an Employer.

II. Grant of Service Equivalent . An Eligible Participant shall be granted a Service Equivalent only if, after addition of the Service Equivalent, the Participant would become eligible for an early retirement Service Annuity under Section 5.3 or would be deemed to be age 50 with at least 5 years of Credited Service. The Service Equivalent shall not be granted to a Participant if such Participant, as of his or her Termination Date, is eligible, without the addition of the Service Equivalent, for an early retirement Service Annuity under Section 5.3 or, as of his or her Termination Date, he or she has attained age 50 and has at least 5 years of Credited Service, unless in the latter case, the grant of the Service Equivalent would qualify the Eligible Participant for an early retirement Service Annuity under Section 5.3 pursuant to Section IIIb hereof.

III. Benefits .

A. Eligible Participants who are Age 50 with at Least 10 Years of Credited Service . Notwithstanding anything contained in the Plan to the contrary, if an Eligible Participant, after taking into account the Service Equivalent granted to such Eligible Participant under Section II hereof, is at least age 50 on his or her Termination Date and has at least 10 years of Credit Service as of such date or would be deemed to be age 50 with at least 10 years of Credited Service as of such date, such Eligible Participant shall be entitled to an early retirement Service Annuity under Section 5.3. Payment of the Eligible Participant's early retirement Service

Annuity under Section 5.3 shall commence at the time elected by the Eligible Participant, provided that the Eligible Participant has had a Termination of Employment and has attained at least age 50 (determined, for this purpose, by disregarding any Service Equivalent granted to the Eligible Participant). Payment shall be made in any form provided under the Plan.

B. Eligible Participants who are Age 50 with at Least 5, but Less than 10, Years of Credited Service . Notwithstanding anything contained in the Plan to the contrary, if an Eligible Participant, after taking into account the Service Equivalent granted to such Eligible Participant under Section II hereof, is at least age 50 on his or her Termination Date and has completed at least 5 but less than 10 years of Credited Service as of such date or would be deemed to be age 50 with at least 5 but less than 10 years of Credited Service as of such date, such Eligible Participant shall be entitled to elect one of the following normal or early retirement benefit under the Plan:

1. O ption 1—Unreduced Additional Benefit . An additional benefit equal to 52 weeks of Base Salary. An Eligible Participant may elect to receive the additional benefit in the form of a lump sum distribution (which shall be paid in the same manner and subject to the terms provided under Section 6.7) or in any other form provide under the Plan. An Eligible Participant who elects this Option 1 shall not be eligible for an early retirement Service Annuity under Section 5.3.

2. Option 2 – Reduced Additional Benefit and Pension Enhancement . An Eligible Participant who elects Option 2 shall be entitled to the following two benefits:

   a. Reduced Additional Benefit . An additional benefit equal to 26 Weeks of Base Salary. An Eligible Participant may elect to receive the additional benefit in the form of a lump sum distribution (which shall be paid in the same manner and subject to the terms provided under Section 6.7) or in any other form provided under the Plan.

   b. Pension Enhancement . In lieu of a deferred Service Annuity under Section 5.7, a normal retirement Service Annuity under Section 5.2 or an early retirement Service Annuity under Section 5.3, using the Eligible Participant's age and years of Credited Service (including any Service Equivalent granted to the Eligible Participant under Section II hereof) as of his or her Termination Date (or, if later, the date that the Eligible Participant begins receiving his or her normal retirement Service Annuity under Section 5.2 or early retirement Service Annuity under Section 5.3). Payment of the Eligible Participant's normal retirement or early retirement Service Annuity shall commence at the time elected by the Eligible Participant,

provided that the Eligible Participant has had a Termination of Employment and has attained at least age 50 or age 65, as applicable (determined, for this purpose, by disregarding an Service Equivalent granted to the Eligible Participant). Payment shall be made in any form provided under the Plan.

C. Eligible Participants who are not Age 50 or who do not have at Least 5 Years of Credited Service . An Eligible Participant who, (after the addition of any Service Equivalent) as of his or her Termination Date, is not age 50 or does not have at least 5 years of Credited Service shall not be entitled to any benefits under this Supplement 1.

D. Adjustments to Comply with Nondiscrimination Rules . If payment of the benefits described in this Supplement 1 to any Eligible Participant who is a "highly compensated employee," as defined in section 414(q) of the Code would cause the Plan to fail any nondiscrimination requirements of section 401(a) of the Code, the benefits otherwise payable under this Supplement 1 shall be restricted in any manner determined by the Administrator so as to permit the Plan to satisfy such nondiscrimination requirements.

Table B
Early Retirement Service Factors
Applicable Monthly Payments to Age 65

The following factors shall be applied (a) to determine the reductions applicable to the early retirement Service Annuity of any Participant who is not a member of IBEW Local Union 15, and whose Termination of Employment occurs on or after April 1, 1995, and (b) to determine the reductions applicable to the early retirement Service Annuity of any Participant who is a member of IBEW Local Union 15 and whose Termination of Employment occurred after April 1, 1995 and before October 1, 1999:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.7200	.7225	.7250	.7275	.7300	.7325	.7350	.7375	.7400	.7425	.7450	.7475
51	.7500	.7525	.7550	.7575	.7600	.7625	.7650	.7675	.7700	.7725	.7750	.7775
52	.7800	.7825	.7850	.7875	.7900	.7925	.7950	.7975	.8000	.8025	.8050	.8075
53	.8100	.8125	.8150	.8175	.8200	.8225	.8250	.8275	.8300	.8325	.8350	.8375
54	.8400	.8425	.8450	.8475	.8500	.8525	.8550	.8575	.8600	.8625	.8650	.8675
55	.8700	.8725	.8750	.8775	.8800	.8825	.8850	.8875	.8900	.8925	.8950	.8975
56	.9000	.9025	.9050	.9075	.9100	.9125	.9150	.9175	.9200	.9225	.9250	.9275
57	.9300	.9325	.9350	.9375	.9400	.9425	.9450	.9475	.9500	.9525	.9550	.9575
58	.9600	.9617	.9633	.9650	.9667	.9683	.9700	.9717	.9733	.9750	.9767	.9783
59	.9800	.9817	.9833	.9850	.9867	.9883	.9900	.9917	.9933	.9950	.9967	.9983
60	1.0000											

Table B1
Early Retirement Service Factors
Applicable Monthly Payments to Age 65

The following factors shall be applied to determine the reductions applicable to the early retirement Service Annuity of any Participant who is a member of IBEW Local Union 15 whose Termination of Employment occurs on or after October 1, 1999:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.7900	.7925	.7950	.7975	.8000	.8025	.8050	.8075	.8100	.8125	.8150	.8175
51	.8200	.8225	.8250	.8275	.8300	.8325	.8350	.8375	.8400	.8425	.8450	.8475
52	.8500	.8525	.8550	.8575	.8600	.8625	.8650	.8675	.8700	.8725	.8750	.8775
53	.8800	.8825	.8850	.8875	.8900	.8925	.8950	.8975	.9000	.9025	.9050	.9075
54	.9100	.9125	.9150	.9175	.9200	.9225	.9250	.9275	.9300	.9325	.9350	.9375
55	.9400	.9425	.9450	.9475	.9500	.9525	.9550	.9575	.9600	.9625	.9650	.9675
56	.9700	.9725	.9750	.9775	.9800	.9825	.9850	.9875	.9900	.9925	.9950	.9975
57	1.0000											

Table B2
Early Retirement Supplemental Factors
Applicable Monthly Payments to Age 65

The following factors shall be applied (a) to determine supplemental monthly payments to age 65 for any Participant who is not a member of IBEW Local Union 15 and whose Termination of Employment occurs on or after April 1, 1995, and (b) to determine the supplemental monthly payments to age 65 for any participant who is a member of IBEW Local Union 15 whose Termination of Employment occurred after April 1, 1995 and before October 1, 1999:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.4200	.4175	.4150	.4125	.4100	.4075	.4050	.4025	.4000	.3975	.3950	.3925
51	.3900	.3875	.3850	.3825	.3800	.3775	.3750	.3725	.3700	.3675	.3650	.3625
52	.3600	.3575	.3550	.3525	.3500	.3475	.3450	.3425	.3400	.3375	.3350	.3325
53	.3300	.3275	.3260	.3225	.3200	.3175	.3150	.3125	.3100	.3075	.3050	.3025
54	.3000	.2975	.2950	.2925	.2900	.2875	.2850	.2825	.2800	.2775	.2760	.2725
55	.2700	.2675	.2650	.2625	.2600	.2575	.2550	.2525	.2500	.2475	.2450	.2425
56	.2400	.2375	.2350	.2325	.2300	.2275	.2250	.2225	.2200	.2175	.2150	.2125
57	.2100	.2075	.2050	.2025	.2000	.1975	.1950	.1925	.1900	.1875	.1850	.1825
58	.1800	.1775	.1750	.1725	.1700	.1675	.1650	.1625	.1600	.1575	.1550	.1525
59	.1500	.1479	.1458	.1438	.1417	.1396	.1375	.1354	.1333	.1313	.1292	.1271
60	.1250	.1229	.1208	.1188	.1167	.1146	.1125	.1104	.1083	.1063	.1042	.1021
61	.1000	.0979	.0958	.0938	.0917	.0896	.0875	.0854	.0833	.0813	.0792	.0771
62	.0750	.0729	.0708	.0688	.0667	.0646	.0625	.0604	.0583	.0563	.0542	.0521
63	.0500	.0479	.0458	.0438	.0417	.0396	.0375	.0354	.0333	.0313	.0292	.0271
64	.0250	.0229	.0208	.0188	.0167	.0146	.0125	.0104	.0083	.0063	.0042	.0021

Table B3
Early Retirement Supplemental Factors
Applicable Monthly Payments to Age 65

The following factors shall be applied to determine the supplemental monthly payments to age 65 for any Participant who is a member of IBEW Local Union 15 whose Termination of Employment occurs on or after October 1, 1999:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.4100	.4075	.4050	.4025	.4000	.3975	.3950	.3925	.3900	.3875	.3850	.3825
51	.3800	.3775	.3750	.3725	.3700	.3675	.3650	.3625	.3600	.3575	.3550	.3525
52	.3500	.3475	.3450	.3425	.3400	.3375	.3350	.3325	.3300	.3275	.3250	.3225
53	.3200	.3175	.3150	.3125	.3100	.3075	.3050	.3025	.3000	.2975	.2950	.2925
54	.2900	.2875	.2850	.2825	.2800	.2775	.2750	.2725	.2700	.2675	.2650	.2625
55	.2600	.2575	.2550	.2525	.2500	.2475	.2450	.2425	.2400	.2375	.2350	.2325
56	.2300	.2275	.2250	.2225	.2200	.2175	.2150	.2125	.2100	.2075	.2050	.2025
57	.2000	.1979	.1958	.1938	.1917	.1896	.1875	.1854	.1833	.1803	.1782	.1761
58	.1750	.1729	.1708	.1688	.1667	.1646	.1625	.1604	.1583	.1563	.1542	.1521
59	.1500	.1479	.1458	.1438	.1417	.1396	.1375	.1354	.1333	.1313	.1292	.1271
60	.1250	.1229	.1208	.1188	.1167	.1146	.1125	.1104	.1083	.1063	.1042	.1021
61	.1000	.0979	.0958	.0938	.0917	.0896	.0875	.0854	.0833	.0813	.0792	.0771
62	.0750	.0729	.0708	.0688	.0667	.0646	.0625	.0604	.0583	.0563	.0542	.0521
63	.0500	.0479	.0458	.0438	.0417	.0396	.0375	.0354	.0333	.0313	.0292	.0271
64	.0250	.0229	.0208	.0188	.0167	.0146	.0125	.0104	.0083	.0063	.0042	.0021

SERVICE ANNUITY PLAN
OF
PECO ENERGY COMPANY
Under the Exelon Corporation Retirement Program
Amended and Restated Effective January 1, 2013

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SERVICE ANNUITY PLAN

OF

PECO ENERGY COMPANY

As Amended and Restated Effective January 1, 2013

The name of the plan set forth herein shall be the "Service Annuity Plan of PECO Energy Company" (the "Plan"). This Plan is an amendment and restatement of the Service Annuity Plan of PECO Energy Company as in effect on December 31, 2012 and, except as otherwise provided, shall apply to Employees whose employment is terminated on or after January 1, 2013 and to the beneficiaries of such Employees. The rights and benefits of Employees whose employment terminates before January 1, 2013 and of the beneficiaries of such Employees shall be determined under the Service Annuity Plan of PECO Energy Company as in effect at the time of such Employees' termination, including any provisions of this Plan effective at such time; provided, however, that certain provisions of Articles 4 and 9 (relating to limitations on benefits), certain provisions of Article 2 (relating to special participation and distribution rules relating to recommencement of employment and employment by related entities), Article 8 (relating to administration), Article 9 (relating to amendment and termination of the Plan) and Article 10 (relating to miscellaneous provisions) shall be effective for all such persons.

ARTICLE I Definitions.

Whenever used in this Plan:

1.1 "Accrued Benefit" means the amount of pension payable in the form of a Single Life Annuity commencing on a Participant's Normal Retirement Date (or, immediately, if the Participant has passed his Normal Retirement Date) accrued by a Participant under Article III as of the date of reference. Accrued Benefits shall only be payable in accordance with Articles IV and V.

1.2 "Active Participant" means a Participant who is an Eligible Employee.

1.3 "Actuarial Equivalent" means a benefit of equal actuarial value under the assumptions set forth in Appendix A.

1.4 "Administrator" means the Company acting through its Vice President, Health & Benefits or such other person appointed pursuant to Section 8.1.

1.5 "Affiliate" means, as of any time of reference: (a) any corporation included with the Company in a controlled group of corporations within the meaning of Section 414(b) of the Code, (b) any trade or business (whether or not incorporated) which is under common control with the Company within the meaning of Section 414(c) of the Code, (c) any member of any affiliated service group of which the Company is a member within the meaning of Section 414(m) of the Code, and (d) any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code; provided, however, that for purposes of Section 4.6, when applying Sections 414(b) and (c) of the Code, the phrase "more than 50%" shall be substituted for the phrase "at least 80%" each place it appears in Section 1563(a)(1) of the Code.

1.6 “Age” means age on last birthday, except that an individual attains age 70-1/2 on the corresponding date in the sixth calendar month following the month in which his seventieth birthday occurs (or the last day of such sixth month if there is no such corresponding date therein). Notwithstanding the preceding sentence, solely for purposes of determining whether a Participant is eligible to elect the Contingent Annuity Option under Section 5.3, “Age” means the Participant’s age on his nearest birthday, rounding his actual age up or down as appropriate.

1.7 “Benefit Accrual Computation Period” means the portion of a calendar year that begins on the latest of (a) January 1, (b) the date on which an Employee becomes an Eligible Employee or (c) the date an Active Participant resumes work after receiving benefits under the Company’s Disabilitant Plan (or June 1, 1992, for an Active Participant who is receiving benefits under the Company’s Disabilitant Plan on June 1, 1992) and ends on the earliest of (1) December 31, (2) the date an Employee ceases to be an Eligible Employee, (3) the date an Active Participant commences receiving benefits under the Company’s Disabilitant Plan (except with respect to Participants described in the proviso to the penultimate sentence of Section 1.9(b)), (4) an Employee’s Normal Retirement Date (in the case of an Employee who does not complete an Hour of Service on or after January 1, 1988), or (5) the date of an Employee’s death.

1.8 “Benefit Commencement Date” means, for any Participant, the date as of which his first periodic benefit payment or single sum payment is due. “Benefit Commencement Date” also means, with respect to a surviving Spouse or other beneficiary, the date on which the survivor’s benefit under Section 5.3 or 5.4 commences to the surviving Spouse or other beneficiary.

1.9 “Benefit Year” means a credit awarded as follows, subject to Article VI:

(a) Each Employee as of December 31, 1975 shall be credited with a number of Benefit Years equal to his years of service under the Plan as of that date;

(b) Each Active Participant shall be credited with one Benefit Year for each 12 month Benefit Accrual Computation Period after December 31, 1975 during which he completes 1,000 or more Hours of Service and 1/12th of a Benefit Year for each month or part of a month of a Benefit Accrual Computation Period of less than 12 months during which his Hours of Service equal or exceed 83 1/3 times the number of full months in the period. Benefit Years are not credited with respect to any period during which an Active Participant is receiving benefits under the Company’s Disabilitant Plan; provided, however, that Benefit Years shall be credited to an Active Participant who is receiving benefits under the Company’s Disabilitant Plan on June 1, 1992, with respect to any period after May 31, 1992 for which such benefits are received. Effective January 1, 2002, Benefit Years are credited with respect to any period following an Active Participant’s Separation from Service or absence on account of a disability for illness or accident during which the Participant is eligible for and receiving benefits under any long-term disability benefit plan sponsored by the Company.

(c) A Power Team Employee shall not receive credit for any Benefit Year that accrues while he is a Power Team Employee. Notwithstanding the foregoing, for the purposes of Section 5.3 only, a Power Team Employee shall be deemed to receive credit for Benefit Years to the extent such Power Team Employee otherwise would have earned such credit but for the provisions of this Section 1.9(c).

(d) An EIS Senior Management Employee shall not receive credit for any Benefit Year, or portion of a Benefit Year, that accrues after October 31, 1999, or the date on which such Participant becomes an EIS Senior Management Employee, if later, and the Benefit Accrual Computation Period for such Participant that would otherwise include such date shall end on such date. Notwithstanding the foregoing, for the purposes of Section 5.3 only, an EIS Senior Management Employee shall be deemed to receive credit for Benefit Years to the extent such EIS Senior Management Employee otherwise would have earned such credit but for the provisions of this Section 1.9(d).

(e) Notwithstanding the foregoing, for purposes of calculating a Participant's Benefit Years, each period of Qualified Military Service served by a Participant is, upon reemployment by the Company or an Affiliate within the time during which the Participant's right to reemployment is protected by applicable law, deemed to constitute service with the Company for such purposes.

1.10 "CEG" means Constellation Energy Group, Inc. and any of its affiliates that was an affiliate immediately before the Effective Time (as such term is defined in the CEG Merger Agreement.)

1.11 "CEG Merger Agreement" means that Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc.

1.12 "Code" means the Internal Revenue Code of 1986, as amended, or any superseding provision of law.

1.13 "Company" means, (i) prior to the Merger Date, PECO Energy Company, a Pennsylvania corporation (known prior to January 1, 1994 as the "Philadelphia Electric Company"), and any Affiliate of PECO Energy Company which adopts this Plan, and (ii) on and after the Merger Date, Exelon Corporation, PECO Energy Company, and any Affiliate of Exelon Corporation set forth on Appendix I which adopts this Plan either with respect to all Employees or a particular group of Employees of such Affiliate. Appendix I shall be updated from time to time by the Company to reflect any such adoption, but the failure to so update such Appendix shall not affect the effectiveness of any such adoption. Such adoptions will be effective whether occurring before, on or after the Effective Date and whether or not reflected in Appendix I.

1.14 “Compensation” means:

(a) for service prior to January 1, 1939 – normal full-time wages or salary at the established payroll rates;

(b) for service subsequent to December 31, 1938 wages, salary, and any other remuneration actually paid or credited to the Employee in recompense for his services as an Employee, including such amounts contributed at the direction of the Employee to the PECO Energy Company Employee Savings Plan, the Exelon Corporation Employee Savings Plan, the PECO Energy Company Employees’ Section 125 Plan, the Exelon Corporation Benefits Contributions Options, the Exelon Corporation Flexible Benefits Program or, effective January 1, 2002, amounts contributed on a pre-tax basis to a qualified transportation fringe benefit plan under Code Section 132(f)(4);

(c) effective for plan years beginning on or after December 12, 1994, for purposes of subsection (b) above, a Participant’s Compensation shall include the Compensation that the Participant would have received during a period of Qualified Military Service (or, if the amount of such Compensation is not reasonably certain, the Participant’s average earnings from the Company or an Affiliate for the twelve-month period immediately preceding the Participant’s period of Qualified Military Service); provided, however, that the Participant returns to work within the period during which his right to reemployment is protected by law.

The remuneration of an Employee who is absent for the purposes described in one of Sections 1.22(a) through 1.22(e) shall be deemed to continue at his base rate in effect immediately prior to the start of his absence; provided, however, that no Compensation shall be imputed under this sentence for any period prior to June 1, 1992 during which the Employee is receiving benefits under the Company’s Disabilitant Plan. Effective January 1, 1990, Compensation shall not include any lump sum payment of an Employee’s vacation pay or sick pay, nor any severance payment made by the Company or an Affiliate or pursuant to any plan maintained by the Company or an Affiliate. Compensation shall include annual incentive award payments under the Exelon Corporation Annual Incentive Award Program and quarterly incentive payments under the Exelon Corporation Quarterly Incentive Award Program payable with respect to years beginning on or after January 1, 2002.

Notwithstanding the foregoing, (i) Compensation for a Power Team Employee shall not include any Compensation earned while such Employee is a Power Team Employee; (ii) for an individual who retires after December 31, 1993 and prior to January 1, 1996, “Compensation” shall include all accrued vacation, accrued sick pay and severance payments for purposes of Section 3.1(a)(2) and 4C.3(a)(1)(A)(II); and (iii) Compensation for an EIS Senior Management Employee shall not include any Compensation earned after October 31, 1999 or the date on which such Participant becomes an EIS Senior Management Employee, if later.

1.15 “Corporate Investment Committee” means the Company acting through the Committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

1.16 “Covered Compensation” means, as of any date of reference, the average of the taxable wage base in effect under the Social Security Act, as amended, in each of the thirty-five (35) consecutive years ending with the year prior to such Plan Year; provided however, that (i) for any Participant who has attained Age 65, “Covered Compensation” will at all times thereafter be “Covered Compensation” for the Plan Year in which the Participant attained Age 65, (ii) for any Participant who retires after December 31, 1993 and on or before January 1, 1995, Covered Compensation will be determined as of the year-end 1993, and (iii) for any Participant who retires after December 31, 1994 and on or before January 1, 1996, Covered Compensation will be determined as of year-end 1994.

1.12A “EIS” means Exelon Infrastructure Services, Inc.

1.12B “EIS Senior Management Employee” means an Employee of PECO Energy Company who is assigned to perform services for EIS on a full-time basis in a position that is eligible to participate in the EIS Long Term Incentive Plan.

1.17 “Eligibility Computation Period” means, with respect to any Employee, the twelve-month period beginning on his Employment Date and all calendar years beginning after his Employment Date.

1.18 “Eligibility Year” means a credit awarded as follows, subject to Article VI:

(a) Each Employee as of December 31, 1975, shall be credited with a number of Eligibility Years equal to the greater of:

(1) one Eligibility Year for each full year of the Employee’s service as of that date under the Plan as then in effect; or

(2) one Eligibility Year for each Eligibility Computation Period beginning before January 1, 1976, in which the Employee completed at least 1,000 Hours of Service, disregarding any Eligibility Computation Period that would have been disregarded under Article VI if it had applied at the time in question.

(b) Each Employee shall be credited with one Eligibility Year for each Eligibility Computation Period beginning after December 31, 1975, in which he completes 1,000 or more Hours of Service.

1.19 “Eligible Employee” means an Employee employed by the Company or on leave during a period of Qualified Military Service and, for the time period beginning on the Merger Date, who (a) was an Eligible Employee prior to the Merger Date or (b) first becomes an Employee on or after the Merger Date and is employed initially at a facility owned immediately before the Merger Date by PECO Energy Company or an Affiliate that was an Affiliate of PECO Energy Company immediately before the Merger Date.

Notwithstanding the foregoing, an Eligible Employee shall not include (i) an Employee who is employed by a joint venture in which the Company is a joint venturer, (ii) an Employee whose wages are subject to collective bargaining except to the extent a collective bargaining agreement

relating to him so provides, (iii) a probationary Employee, (iv) an Employee who is an Employee solely by reason of being a leased employee within the meaning of Section 414(n) or 414(o) of the Code, (v) an Employee who executes a written waiver of his right to participate in the Plan (vi) an individual who is an independent contractor or any other person who is not treated by the Company or an Affiliate as an Employee for the purposes of withholding federal employment taxes, regardless of any contrary governmental or judicial determination relating to such employment status or tax withholding, (vii) on or after the Effective Time, an individual who was employed immediately prior to the Effective Time (as such term is defined in the CEG Merger Agreement) at CEG or a facility owned immediately before the Effective Time by CEG or (viii) an individual who is newly employed on or after the Effective Time (as such term is defined in the CEG Merger Agreement) at a facility owned immediately before the Effective Time by CEG.

Notwithstanding the foregoing, an Eligible Employee shall not include any Power Team Employee while he is a Power Team Employee, or any Employee of the Exelon Generation Company, LLC Power Team division who is a participant in the Commonwealth Edison Company Service Annuity System.

Notwithstanding the foregoing, effective October 31, 1999, an Eligible Employee shall not include any EIS Senior Management Employee. EIS Senior Management Employees hired on or after October 1, 1999 shall not be eligible to participate in the Plan.

Notwithstanding anything herein to the contrary, subject to the provisions relating to rehired employees in Section 2.10, no Employee who was not a Participant before January 1, 2001 shall be eligible to participate in the Plan after December 31, 2000.

An Eligible Employee who transfers employment to the Exelon Generation Company, LLC Power Team division during 2003 shall remain an Eligible Employee until December 31, 2003. An individual who has a benefit under this Plan and who transfers employment from the Exelon Generation, LLC Power Team division to a participating employer in this Plan shall not be an Eligible Employee prior to January 1, 2004.

Notwithstanding anything contained herein to the contrary, an Eligible Employee shall not include an individual who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 5.11.

1.20 “Employee” means a person who is employed by the Company or an Affiliate or is absent under circumstances included in his Employment. An individual shall be deemed to be actively employed by the Company or an Affiliate if such individual is employed directly by the Company or an Affiliate or is a leased employee within the meaning of Section 414(n) or 414(o) of the Code with respect to whose services the Company or Affiliate is the recipient and to whom Section 414(n)(5) of the Code does not apply. An individual who receives a back pay award from the Company or an Affiliate shall be deemed to be an Employee for the period for which back pay is awarded. An Employee shall cease to be such on his retirement, resignation, discharge, or death. Notwithstanding the foregoing, the term “Employee” shall not include independent contractors or any other persons who are not treated by the Employer as employees for purposes of withholding federal employment taxes, regardless of any contrary governmental or judicial determination relating to such employment status or tax withholding.

1.21 “Employer” means the Company.

1.22 “Employment” means active employment by the Company or an Affiliate. In addition, any of the following types of absence shall be counted as Employment (on the same work schedule under which the Employee was employed by the Company or Affiliate immediately prior to the absence) if it immediately follows a period of active employment with the Company or an Affiliate:

(a) absence due to a period of Qualified Military Service, if the Employee resumes work with the Company or an Affiliate, following discharge, within the time specified by then applicable laws.

(b) absence resulting from disability on account of illness or accident during which the Employee is eligible for and receives disability benefits under a disability benefit plan sponsored by the Company or an Affiliate.

(c) absence which the Company or an Affiliate certifies was for good cause.

(d) leave of absence granted by the Company or an Affiliate.

(e) lay-off, if the Employee returns to work within such period as may be specified in the rules of the Company or Affiliate in effect at the time of reference.

(f) absence during which regular remuneration is paid.

1.23 “Employment Date” means the day on which an Employee completes his first Hour of Service.

1.24 “Fund” means the assets accumulated for purposes of the Plan.

1.25 “Highly Compensated Employee” means, effective January 1, 2006, an Employee who performs services for the Company or an Affiliate during the current Plan Year who was:

(a) an Employee who was, at any time during the current Plan Year or in the immediately preceding Plan Year, a 5% owner, as defined in Section 416(i)(1) of the Code; or

(b) an Employee who, during the immediately preceding Plan Year, both (1) received compensation (as defined in Section 415(c)(3) of the Code plus, for Plan Years beginning after December 31, 2000, amounts excluded from income under Section 132(f)(4) of the Code) from the Company or an Affiliate in excess of $80,000, as adjusted by the Secretary of the Treasury in accordance with Section 415(d) of the Code, and (2) was in the group of employees consisting of the top 20% of the employees of the Company and its Affiliates when ranked on the basis of compensation paid during the preceding Plan Year.

1.26 “Hour of Service” means, for each Employee, a credit used to measure his service for various purposes under the Plan. Hours of Service are credited as follows:

(a) Each hour which is not included in a period described in Paragraph (b), below, but for which the Employee is directly or indirectly paid or entitled to payment by the Company or an Affiliate, for the performance of duties or otherwise, including back pay, without regard to mitigation of damages, shall count as one Hour of Service. Notwithstanding the preceding sentence, no Hours of Service shall be credited under this Paragraph (a) to the extent such credit will cause the Employee to be credited with more than 501 Hours of Service (including Hours of Service credited under Paragraph (b)) with respect to any single continuous period during which the Employee performs no duties; provided, however, that this limit shall not apply in the case of an award of back pay to the extent the award so specifies.

(b) Each week of absence for Qualified Military Service from which the Employee returns to the Company or an Affiliate with legally protected reemployment rights shall count as a number of Hours of Service determined under subsection (e) if the Employee was employed in a position designated as full-time immediately before the period of Qualified Military Service or, if subsection (e) does not apply, a number of Hours of Service equal to the number of hours of work in the Employee’s customary week of work at the time the absence began.

(c) Hours of Service for the performance of duties shall be credited to the Employee for the computation period or periods in which the services are performed. Hours of Service for non-performance of duties shall be credited to the Employee for the computation period or computation periods in which the non-performance of duties occurs. Hours of Service for back pay shall be credited to the Employee for the computation period or computation periods to which the award or agreement pertains rather than the computation period or periods in which it was made.

(d) Solely for purposes of determining whether a One-Year Break in Service (as defined in Article VI) has occurred in an Eligibility Computation Period or a Vesting Computation Period, an Employee who is absent from work for Maternity/Paternity Leave shall receive credit for the Hours of Service which would otherwise have been credited to such Employee but for such absence, or in any case in which such Hours of Service cannot be determined, eight Hours of Service per day of such absence. An Employee shall be credited with Hours of Service under this Paragraph (d) in the computation period in which the absence begins if necessary to prevent a Break in Service in that period, or, in all other cases, in the following computation period.

(e) An Employee who is employed by the Company or an Affiliate shall be credited with forty-five (45) Hours of Service for each week during which he is otherwise entitled to be credited with at least one Hour of Service. Paragraphs (a)-(c) notwithstanding, Hours of Service shall be credited at least as liberally as required by Department of Labor Regulation §2530.200b-2(b) and (c).

(f) In the case of an Employee who is such solely by reason of service as a leased employee (within the meaning of Section 414(n) or 414(o) of the Code), Hours of Service shall be credited as if such Employee were employed and paid with respect to such service (or with respect to any related absences or entitlement) by the Company or the Affiliate that is the recipient thereof.

1.27 “Investment Office” means the Company acting through the Exelon Investment Office.

1.28 “Maternity/Paternity Leave” means, for any Employee, an absence:

(a) by reason of the Employee’s pregnancy;

(b) by reason of the birth of the child of the Employee;

(c) by reason of placement of the child with the Employee in connection with the adoption of such child by the Employee; or

(d) for purposes of caring for such child for a period immediately following such birth or placement.

1.22A “Merger Date” means the effective date of the merger of Unicom Corporation with and into Exelon Corporation.

1.29 “Normal Retirement Date” means, for each Employee, the first day of the calendar month coincident with or next following the date he attains Age 65, except that the Normal Retirement Date of an Employee who becomes an Active Participant in the Plan after attaining Age 60 shall be the first day of the calendar month coincident with or next following the fifth anniversary of the date on which the Employee became an Active Participant.

1.30 “Participant” means (a) an Eligible Employee who has become an Active Participant under Article II, and (b) a former Active Participant whose Accrued Benefit and Benefit Years have not been canceled under Section 6.2 or have been restored under Section 6.5. An individual shall cease to be a Participant upon the date the individual is no longer eligible to receive a benefit from this Plan (including, without limitation, upon his or her receipt of a Special Lump Sum Payment as defined in Section 5.11).

1.31 “Plan” means the Service Annuity Plan set forth herein, provided that, on and after January 1, 1994, the Plan shall be known as the “Service Annuity Plan of PECO Energy Company” and on and after January 1, 2003, the Plan shall be known as the “Service Annuity Plan of PECO Energy Company under the Exelon Corporation Retirement Program.”

1.32 “Plan Year” means a calendar year after 1975. The Plan Year shall be the limitation year for purposes of computing limitations on contributions, benefits and allocations.

1.26A “Power Team Employee” means an Employee who is employed by the Exelon Generation Company, LLC Power Team division or its successor, and (i) who was not eligible to participate in the Plan before January 1, 2001, or (ii) who was eligible to participate in the Plan before January 1, 2001 but is eligible to participate in the performance share award program for Power Team employees under the Exelon Corporation Long Term Incentive Plan or any predecessor or successor incentive compensation program applicable to employees of the Power Team division. An Employee who is described in clause (ii) of the preceding sentence will be a Power Team Employee only during the period in which he satisfies clause (ii).

1.33 “Qualified Joint and Survivor Annuity” means the form of pension benefit described in this Section. Under a Qualified Joint and Survivor Annuity payments begin on the date provided in Article IV and continue until the first day of the month following the month in which the Participant’s death occurs. On the first day of the second month following the month of the Participant’s death, payments in an amount equal to 50% of the amount payable to the Participant begin to his surviving Spouse, but only if the Spouse was married to the Participant on the Participant’s Benefit Commencement Date. Such payments to the Spouse shall end on the first day of the month following the month in which the Spouse’s death occurs. The anticipated payments under a Qualified Joint and Survivor Annuity shall be the Actuarial Equivalent of a pension in the form of a Single Life Annuity in the amount set forth in Article IV.

1.27A “Qualified Military Service” means any service in the uniformed services (as defined in chapter 43 of title 38, United States Code) where the Participant’s right to reemployment is protected by law.

1.34 “Required Beginning Date” means April 1 of the calendar year following the later of (a) the calendar year in which the Participant attains Age 70-1/2; or (b) in the case of a Participant who is not a 5% owner (within the meaning of Section 416(i) of the Code), the calendar year in which the Participant’s Separation from Service occurs. Notwithstanding the foregoing, a Participant who is not a 5% owner (as defined above), reached age 70-1/2 in 1999 or 2000, and has not incurred a Separation from Service may elect April 1, 2000 or April 1, 2001, respectively, as his Required Beginning Date.

1.35 “Separation from Service” means the termination of an Employee’s status as an Employee or any absence of an Employee in Employment which is not described in Section 1.22.

1.36 “Single Life Annuity” means a form of pension benefit under which payments begin on the date provided in Article IV and end on the first day of the month following the month in which the Participant’s death occurs.

1.37 “Social Security Retirement Age” means (a) for any individual born before January 1, 1938, Age 65, (b) for any individual born after December 31, 1937, but before January 1, 1955, Age 66, or (c) for any individual born after December 31, 1954, Age 67.

1.38 “Spouse” means the individual who is a husband or wife of a Participant as the result of a legal union between one man and one woman, within the meaning of the Defense of Marriage Act.

1.39 “TXU Participant” means a Participant who participated in the TXU Pension Plan immediately prior to the closing date of the acquisition of TXU by the company and whose benefit under the TXU Pension Plan was determined using the final average pay formula (and not the cash balance plan formula).

1.40 “Vesting Computation Period” means a calendar year.

1.41 “Vesting Year” means a credit awarded as follows, subject to Article VI:

(a) Each Employee as of December 31, 1975, shall be credited with a number of Vesting Years equal to his years of service (with fractions rounded to the next full year) under the Plan as in effect on that date.

(b) Each Employee shall be credited with one Vesting Year for each Vesting Computation Period after 1975 in which he completes 1,000 or more Hours of Service.

(c) If an Employee is credited with an Eligibility Year for an Eligibility Computation Period that overlaps two Vesting Computation Periods, but he is not credited with a Vesting Year for either of those Vesting Computation Periods, the Employee shall be credited with one Vesting Year. An Employee may have only one Vesting Year to his credit under this Paragraph at any time.

(d) An Employee shall be deemed to have completed a Vesting Year when he completes his one-thousandth Hour of Service in the relevant Vesting Computation Period.

1.42 The masculine gender shall include the feminine.

ARTICLE II Participation.

2.1 Each Eligible Employee who is covered by the Plan as of December 31, 1975 shall be an Active Participant as of January 1, 1976.

2.2 Each other Eligible Employee shall become an Active Participant on the later of January 1, 1976 or January 1 of the first Eligibility Computation Period in which he completes 1,000 Hours of Service.

2.3 If a former Eligible Employee is not an Eligible Employee on the date on which he would otherwise become an Active Participant under Section 2.2, he shall not then become an Active Participant but shall become an Active Participant on the first day thereafter on which he is an Eligible Employee, provided that if he has a Separation from Service before becoming an Active Participant, Section 6.4 shall apply.

2.4 Participation Freeze for Power Team Employees. Notwithstanding the foregoing, all participation in the Plan by Power Team Employees shall be frozen as of the date the Employee becomes a Power Team Employee.

2.5 Participation Freeze for EIS Senior Management Employees. Notwithstanding the foregoing, all participation in the Plan by EIS Senior Management Employees shall be frozen as of October 31, 1999, or the date such Participant becomes an EIS Senior Management Employee, if later, and no Employee who is an EIS Senior Management Employee shall be eligible to become a Participant in the Plan after October 31, 1999.

2.6 Participation Freeze for all Employees after December 31, 2000. Notwithstanding anything herein to the contrary, but subject to the provisions of Section 2.10 or 2.11, no Employee who is not a Participant on December 31, 2000 shall be eligible to participate in the Plan after December 31, 2000.

2.7 Transfer of Employment to or Reemployment in Positions Eligible for Participation in the Plan or the Commonwealth Edison Company Service Annuity System by Certain Individuals Who Were Participants in Such a Plan on December 31, 2000. If a Participant who was a Participant on December 31, 2000 transfers employment to or is reemployed by the Company or an Affiliate in a job classification with respect to which similarly situated employees of the Company or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in the Commonwealth Edison Company Service Annuity System (or would be so eligible but for their election to participate in the Exelon Corporation Cash Balance Pension Plan), then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the Commonwealth Edison Company Service Annuity System. If a participant in the Commonwealth Edison Company Service Annuity System who was a participant in such plan on December 31, 2000 transfers employment to or is reemployed by the Company or an Affiliate in a management job classification with respect to which similarly situated employees of the Company or Affiliate are eligible to participate in the Plan (or would be so eligible but for their election to participate in the Exelon Corporation Cash Balance Pension Plan), then such individual shall upon such transfer or reemployment remain a participant in the Commonwealth Edison Company Service Annuity System and shall not participate in the Plan.

2.8 Pension Choice Election.

(a) In General. Each Participant who is, as of January 1, 2002, an Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator, to either (i) continue participating in the Plan on and after January 1, 2002 or (ii) cease participating in the Plan as of December 31, 2001 and begin participating in the Exelon Corporation Cash Balance Pension Plan as of January 1, 2002. Each Eligible Employee who elects to continue participating in the Plan or who is offered and fails to make any such election shall continue to be a Participant as of January 1, 2002. Each Eligible Employee who elects to participate in the Exelon Corporation Cash Balance Pension Plan in lieu of participation in this Plan shall cease participation in the Plan as of December 31, 2001 and shall not be entitled to any benefit under the Plan, unless such Participant receives a notification (the "Notice") from the Company that his employment with the Company and the Affiliates will be terminated on or before December 31, 2002 and that such Participant is eligible for benefits under Article IVE of the Plan or any severance plan maintained by the Company or an Affiliate. An Eligible Employee who receives a Notice shall continue to be a Participant in the Plan until his Separation from

Service, notwithstanding such Eligible Employee's election to participate in the Exelon Corporation Cash Balance Pension Plan. An Eligible Employee (i) who receives a Notice, but whose employment does not terminate on or before December 31, 2002, or (ii) whose employment terminates before December 31, 2002 without the Employee receiving a Notice, shall cease participation in the Plan as of December 31, 2001 if such Employee elects, in the time and manner prescribed by the Administrator, to participate in the Exelon Corporation Cash Balance Pension Plan.

Effective as of January 1, 2004, each Eligible Employee who (i) was eligible to participate in the Plan as of December 31, 2000, (ii) ceases to be a Power Team Employee as of January 1, 2004 because such Eligible Employee is no longer eligible to participate in the performance share award program for Power Team employees under the Exelon Corporation Long Term Incentive Plan and (iii) did not previously make a valid election pursuant to the preceding paragraph shall be permitted to elect, in the time and manner prescribed by the Committee, to either (i) participate in the Exelon Corporation Cash Balance Pension Plan in lieu of this Plan as of January 1, 2004 or (ii) continue or resume participation in the Plan as of January 1, 2004. Each such Eligible Employee who affirmatively elects to continue or resume participation in this Plan in lieu of participation in the Exelon Corporation Cash Balance Pension Plan shall continue or resume participation in this Plan as of January 1, 2004.

(b) Transfer of Benefits and Assets to Cash Balance Pension Plan. If an Eligible Employee described in paragraph (a) above elects to participate in the Exelon Corporation Cash Balance Pension Plan in lieu of participating in the Plan, the Employee's pension, determined as of December 31, 2001, or December 31, 2003, as the case may be, based on the Employee's Benefit Years, Compensation and average annual base salary as of such date, shall be transferred to the Exelon Corporation Cash Balance Pension Plan, and such Employee shall not accrue any additional benefit under the Plan. An amount of assets that is equal to the present value of the Participant's pension described in the preceding sentence, determined using the methods and assumptions prescribed by Section 4044 of ERISA, shall also be transferred to the Exelon Corporation Cash Balance Pension Plan. Such transfer of benefits and assets related thereto shall occur as soon as administratively practicable after the Eligible Employee makes the election described in paragraph (a) above. In the event that an Eligible Employee whose pension and related assets are transferred to the Exelon Corporation Cash Balance Pension Plan receives a Notice and has a Separation from Service on or before December 31, 2002, the pension and related assets that were transferred to the Exelon Corporation Cash Balance Pension Plan shall be transferred back to the Plan and the amount of the pension benefit accrued by such Employee during 2002 (if any) shall be determined under the terms of this Plan rather than the Exelon Corporation Cash Balance Pension Plan. Such transfer shall occur as soon as administratively practicable.

2.9 Cessation of Participation. An individual's participation in the Plan shall cease upon the first to occur of (i) the date the individual is no longer eligible to receive a benefit from this Plan or (ii) the individual's Separation from Service if the individual has not completed at least five Vesting Years upon the date of his Separation from Service.

2.10 Rehire of Employees. The following rules shall apply to an Eligible Employee who is rehired by the Company after a Separation from Service and prior to commencing his pension or any benefits under the Exelon Corporation Cash Balance Pension Plan, as applicable:

(a) Rehire Date Before Absence of 5 Consecutive One-Year Breaks in Service. If an Employee terminates employment and is later rehired by the Company before having an absence from employment with the Company and the Affiliates of five consecutive One-Year Breaks in Service, then either: (1) if such Employee was a Participant on the date his employment terminated, such Employee shall be a Participant in the Plan as of his rehire date if he is then an Eligible Employee, or (2) if such Employee was not a Participant on the date his employment terminated, such Employee shall not be an Eligible Employee and shall not become a Participant. Notwithstanding clause (1) of the preceding sentence, if an Eligible Employee described in the preceding sentence was not at any time permitted to make the election described in Section 2.8(a) or was permitted to make such election and elected to participate in the Exelon Corporation Cash Balance Pension Plan but such election was not given effect as a result of such Employee's Separation from Service, such Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator, to either (1) participate in the Plan as of his rehire date or (2) participate in the Exelon Corporation Cash Balance Pension Plan at the time prescribed therein and have his pension and related assets transferred to such plan in the manner described in Section 2.8(b).

(b) Rehire Date After Absence of at Least 5 Consecutive One-Year Breaks in Service. If an Employee terminates employment with the Company and the Affiliates and the Employee was not a Participant or was a Participant who did not have a vested pension as of the date his employment terminated, and such Employee is rehired by the Company after having an absence from employment with the Company and the Affiliates of at least five consecutive One-Year Breaks in Service, such Employee shall not be an Eligible Employee and shall not become a Participant upon such rehire. If a Participant with a vested pension terminates employment with the Company and the Affiliates and the Participant is rehired after having an absence from employment with the Company and the Affiliates of at least five consecutive One-Year Breaks in Service, such Participant shall remain a Participant upon his rehire. Notwithstanding the preceding sentence if a Participant described in the preceding sentence was not at any time permitted to make the election described in Section 2.8(a), or was permitted to make such election and elected to participate in the Exelon Corporation Cash Balance Pension Plan but such election was not given effect as a result of such Employee's Separation from Service, such Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator, to either (1) participate in the Plan as of his rehire date or (2) participate in the Exelon Corporation Cash Balance Pension Plan at the time prescribed therein and have his pension and related assets transferred to such plan in the manner described in Section 2.8(b).

(c) Circumstances Permitting Commencement of Pension. Notwithstanding anything contained herein to the contrary, if a Participant terminates employment and is reemployed as an Employee under circumstances that satisfy the applicable conditions for continuation of payment of retirement benefits set forth in the Company's policy regarding the rehiring or retirees, such Participant may elect to commence his pension during such period of reemployment if he is otherwise eligible to commence such pension.

(d) Rehire After Receipt of Benefit Under Section 5.11. Notwithstanding anything contained herein to the contrary, an Employee who is reemployed by an Employer after December 1, 2012 and has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 5.11 shall not be eligible to become a Participant pursuant to this Article 2.

2.11 Change in Employment Status or Transfer to Affiliate. Except as otherwise provided herein, if an Employee who was a Participant transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead either eligible to participate in another plan maintained by such Employer or Affiliate or are not eligible to participate in any plan, then such individual shall upon such transfer or reemployment participate in the plan, if any, determined pursuant to rules established by the Company, which rules may be set forth in a Supplement hereto.

2.12 Certain Rehired Employees. Notwithstanding anything contained herein to the contrary, no Employee who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 5.11 shall be eligible to become a Participant pursuant to this Article 2.

2.13 Transfer of Employment to or from Facilities formerly Owned by CEG. Effective as of the Effective Time (as such term is defined in the CEG Merger Agreement), if a Participant who was a Participant on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in a Company Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be a defined benefit pension plan qualified under Section 401(a) of the Code (each such plan, a "CEG Pension Plan") , then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the CEG Pension Plan. If a participant in the CEG Pension Plan who was a participant in such plan on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the CEG Pension Plan and shall not participate in the Plan.

ARTICLE III Accrual of Benefits.

3.1 Accrued Benefit. Except as otherwise provided in this Article or in Article VI, each Participant shall have an Accrued Benefit equal to one-twelfth of the greater of:

(a) The sum of (1) 2% of his average annual Compensation during the period of his service, if any, between January 1, 1930 and December 31, 1938, inclusive, multiplied by his Benefit Years before January 1, 1939, and (2) 2% of his aggregate Compensation for employment as an Eligible Employee after December 31, 1938, or

(b) The sum of (1) a percentage of his average annual base salary plus, after December 31, 2001, amounts earned (whether paid in the current or subsequent period) under the Exelon Corporation Annual Incentive Award Program for Management Employees, and the Exelon Corporation Quarterly Incentive Award Program (but excluding amounts earned under any other business or group incentive or bonus programs) during his 60 consecutive months of employment with the Company that yield the highest twelve month average equal to 5% plus 1.2% for each of his first forty Benefit Years, and (2) 0.35% of such highest average in excess of Covered Compensation as of the date of reference, multiplied by his Benefit Years (up to a maximum of 14%). (For the purposes of this Paragraph (b), (A) employment during the most recent 5 years shall include absences which are included in Employment, except an absence prior to June 1, 1992 during which an Employee receives benefits under the Company's Disabilitant Plan, and the average annual base salary of an Employee on an included absence shall be calculated as if his base salary continued during any period of such absence for which he did not receive compensation, such salary to be that in effect when such period began, adjusted for increases applicable to his job classification which occur prior to the end of such period, (B) with respect to a Participant who is employed by the Company for less than 60-consecutive months, the Participant's average annual base salary shall be determined by averaging the Participant's annual base salary for each calendar year in which the Participant was at any time an Employee, determined as if the Participant had remained an Employee for the entire year, provided, that, if there are more than 5 such calendar years, the 5 years which result in the highest average will be used, (C) for purposes of determining consecutive months of employment, months in which the Participant performs no services, other than months for which salary is imputed under (A) above, shall be disregarded, (D) annual base salary shall be determined prior to reduction by amounts contributed at the direction of the Employee to the PECO Energy Company Employee Savings Plan, the Exelon Corporation Employee Savings Plan, the PECO Energy Company Employees' Section 125 Plan, the Exelon Corporation Benefits Contributions Options, the Exelon Corporation Flexible Benefits Program, or for Plan Years beginning after December 31, 2001, amounts contributed to a qualified transportation fringe benefit plan under Section 132(f)(4) of the Code, (E) effective January 1, 1990, a Participant's annual base salary shall not include any lump sum payment of his accrued vacation pay or sick pay, nor any severance payment made by the Company or an Affiliate or pursuant to any plan maintained by the Company or any Affiliate), (F) effective January 1, 1996 for purposes of calculating average annual base salary, any raise received during the month shall be deemed to have been received on the first of such month and (G) amounts earned under the Exelon Corporation Annual Incentive Award Program for Management Employees and the Exelon Corporation Quarterly Incentive Award Program shall be credited for the period such amounts are earned, regardless of when such amounts are actually paid).

A Participant's Accrued Benefit, however, shall not be less than the largest early retirement benefit that he could at any time elect to receive under the Plan. For purposes of the preceding sentence, the early retirement benefit that a Participant may elect to receive at any time of reference is the monthly annuity which, assuming he had a Separation from Service on the date of reference, would be payable to him in the form of a Single Life Annuity beginning as of the later of the day ten years prior to his Normal Retirement Date or the first day of the month following the date of reference.

Notwithstanding the foregoing, the Accrued Benefit of a Power Team Employee shall be frozen as of the date the Employee becomes a Power Team Employee and no Power Team Employee shall earn any additional Accrued Benefit under the Plan while the Employee is a Power Team Employee. The calculation of the benefit of a Power Team Employee under subsection (a) and (b) shall be made without regard to any Compensation, annual base salary or earnings attributable to any period while the Employee is a Power Team Employee.

Notwithstanding the foregoing, an EIS Senior Management Employee's Accrued Benefit shall be frozen as of October 31, 1999, or the date such Participant becomes an EIS Senior Management Employee, if later, and no EIS Senior Management Employee shall earn any additional Accrued Benefit under the Plan after such date. The calculation of an EIS Senior Management Employee's benefit under subsection (a) and (b) shall be made without regard to any Compensation, annual base salary or earnings attributable to any period after October 31, 1999, or the date such Participant becomes an EIS Senior Management Employee, if later.

Notwithstanding the foregoing provisions of this Section 3.1, the Accrued Benefit for a TXU Participant shall be equal to the greater of (1) such Participant's accrued benefit under the TXU Pension Plan immediately prior to the closing date of the acquisition of TXU by the Company, and (2) such Participant's Accrued Benefit determined under subsection (b) above, calculated by including compensation earned by the Participant while he was employed by TXU to the extent such compensation would have been included under subsection (b) if TXU had been part of the Company during the relevant time period and by including the years of service that were credited to the Participant under the TXU Pension Plan immediately prior to the closing date of the acquisition of TXU by the Company.

3.2 Minimum Accrued Benefit. Except as provided in Section 6.5:

(a) as a result of the imposition of the $200,000 cap on compensation under Section 401(a)(17) of the Code effective January 1, 1989 pursuant to Section 3.3, the Accrued Benefit of a Section 401(a)(17) Employee determined as of any date on or after January 1, 1989 and prior to January 1, 1994 shall not be less than the sum of:

(1) his Accrued Benefit determined as of December 31, 1988 under the provisions of the Plan as in effect through December 31, 1988; plus

(2) the Participant's Accrued Benefit determined under Section 3.1 based on the Participant's Benefit Years earned on and after January 1, 1989 and before January 1, 1994;

(b) as a result of the reduction of the $200,000 cap on compensation under Section 401(a)(17) of the Code to $150,000 effective January 1, 1994 pursuant to Section 3.3, the Accrued Benefit of a Section 401(a)(17) Employee determined as of any date on or after January 1, 1994 shall not be less than the sum of:

(3) his Accrued Benefit under Section 3.1 as of December 31, 1993 or, to the extent applicable, his Accrued Benefit under Section 3.2(a) as of December 31, 1993, if greater, determined in each case under the provisions of the Plan as in effect through December 31, 1993; provided, however, that, notwithstanding any provision of the Plan to the contrary, base salary for any determination period (as defined in Section 3.3) that is taken into account in determining an Employee's average annual base salary as of December 31, 1993 shall be subject to the Section 401(a)(17) Compensation Limit (as defined in Section 3.3) in effect for 1993; plus

(4) the Participant's Accrued Benefit determined under Section 3.1 based on the Participant's Benefit Years earned on and after January 1, 1994.

For purposes of Section 3.2(a), a 'Section 401(a)(17) Employee' means an Eligible Employee who completes an Hour of Service on or after January 1, 1989 and whose Accrued Benefit as of a date on or after January 1, 1989 and prior to January 1, 1994 is based on annual Compensation or base salary for a determination period (as defined in Section 3.3) beginning prior to January 1, 1989 that exceeds $200,000. For purposes of Section 3.2(b), a 'Section 401(a)(17) Employee' means an Eligible Employee who completes an Hour of Service on or after January 1, 1994 and whose Accrued Benefit as of a date on or after January 1, 1994 is based on annual Compensation or base salary for a determination period (as defined in Section 3.3) beginning prior to January 1, 1994 that exceeds $150,000.

3.3 Application of Section 401(a)(17) Compensation Limit. Annual Compensation taken into account for purposes of Section 3.1(a) (and Articles IVA, IVB and IVC) and annual base salary taken into account for purposes of Section 3.1(b) (and Articles IVA, IVB and IVC) shall not exceed $200,000 ($150,000, effective January 1, 1994), or such other amount as may be applicable under Code Section 401(a)(17) (the 'Section 401(a)(17) Compensation Limit'). Except as provided below, the Section 401(a)(17) Compensation Limit in effect for a calendar year applies to any period, not exceeding 12 months, over which Compensation or base salary is determined ('determination period') and which begins in such calendar year. Annual base salary for any determination period beginning prior to 1989 that is taken into account in determining an Employee's average annual base salary for purposes of determining the Employee's Accrued Benefit as of a date on or after January 1, 1989 but prior to January 1, 1994 shall be subject to the Section 401(a)(17) Compensation Limit in effect for 1989. Annual base salary for any determination period beginning prior to 1994 that is taken into account in determining an Employee's average annual base salary for purposes of determining the Employee's Accrued Benefit as of a date on or after January 1, 1994 shall be subject to the Section 401(a)(17) Compensation Limit in effect for 1994.

If a determination period consists of fewer than 12 months, the Section 401(a)(17) Compensation Limit will be multiplied by a fraction, the numerator of which is the number of months in the determination period, and the denominator of which is 12. For Plan Years beginning before January 1, 1997, the family aggregation rules of Sections 401(a)(17)(A) of the Code, as in effect on December 31, 1996, shall apply.

3.4 Transferred Employees. The Accrued Benefit of a Participant who has ceased to be an Eligible Employee but who is still an Employee shall be calculated on the basis of his Compensation, average annual base salary, Benefit Years, and the formula in effect under this Article III as of the last date on which he is an Eligible Employee.

3.5 Rehired Employees. A Participant who is reemployed as an Employee and who continues, or commences, his pension payments during the period of his reemployment shall, as required to continue pension payments in accordance with the Company's policy regarding the rehiring of retirees, waive participation in, or additional benefits and accruals under the Plan and accordingly, shall not be entitled to accrue any additional benefits under the Plan during his period of reemployment.

ARTICLE IV. Benefits.

4.1 Normal Retirement. If an Active Participant has not already become vested pursuant to Section 4.4, he shall become fully vested in his Accrued Benefit when he attains Age 65, or, if later, upon the fifth anniversary of the date upon which he first became an Active Participant and may retire on his Normal Retirement Date. Upon retiring, the Participant shall be entitled to a monthly annuity that begins as of the first day of the month following the month in which his Normal Retirement Date occurs and is equal to his Accrued Benefit.

4.2 Postponed Retirement.

(a) An employee may continue in service after his Normal Retirement Date. Except as provided in Section 4.11, an Active Participant who continues in service after his Normal Retirement Date shall receive an annuity commencing as of the first day of the month following actual retirement, or as of his Required Beginning Date, if earlier. Such annuity shall be based upon service, Compensation, average annual base salary and Covered Compensation measured as of the date he retires or his Required Beginning Date, whichever applies, and the benefit formula under Section 3.1 in effect as of such date. Effective as of January 1, 2000, the annuity for an Employee whose Retirement Beginning Date is April 1 of the calendar year following the year in which he incurs a Separation from Service shall include an Actuarial Equivalent adjustment to reflect commencement of payments after April 1 following the calendar year in which he attained age 70 $^{1}/_{2}$. The Actuarial Equivalent adjustment described in the preceding sentence shall be made to Participant's Accrued Benefit as of each December 31 following his Required Beginning Date and preceding his Separation from Service, with the last such adjustment made as of his Separation from Service, and for each such year or portion of a year, shall reduce (but not below zero) any increase in the Participant's Accrued Benefit for the year or portion of a year attributable to Benefit Years, Compensation, annual base salary, or changes in Covered Compensation for that year or portion of a year.

(b) Notwithstanding Paragraph (a), effective January 1, 1994, an executive shall continue as an Employee after his Normal Retirement Date only with the consent of the Company or an Affiliate. For purposes of this Paragraph (b), an "executive" means a Participant who:

(1) Is (A) bona fide executive as defined in Title 29 Code of Federal Regulations §§541.1 and 1625.12 or (B) employed in a high policy making position in the Company or an Affiliate within the meaning of Title 29 Code of Federal Regulations §1625.12;

(2) Has attained Age 65;

(3) Has been in a position described in Paragraph (1) for the two-year period immediately prior to his retirement; and

(4) Is entitled to an immediate vested annual retirement pension, commencing at Age 65 (or retirement, if later), from all employee pension, profit sharing, savings and deferred compensation plans sponsored by the Company and all Affiliates which equals, in the aggregate, at least $44,000 (or such other amount as may be prescribed pursuant to Title 29 Code of Federal Regulations §541.1 from time to time). In calculating the annual retirement pension, (A) all benefits shall be adjusted in accordance with regulations prescribed by the Equal Employment Opportunity Commission so that the benefit is the equivalent of a Single Life Annuity (with no ancillary benefits) under a plan to which employees do not contribute and under which no rollover contributions have been made and (B) there shall be excluded from the calculation of the retirement pension amounts attributable to Social Security, employee contributions, contributions of prior employers, rollover contributions, and contributions described in Code §402(e)(3).

(a) If a Participant's Benefit Commencement Date precedes his actual retirement, the pension payable to the Participant shall be determined as of the December 31 preceding his Benefit Commencement Date and adjusted as of January 1 in each calendar year following his Benefit Commencement Date, with the final adjustment to be made as of the date of his actual retirement. Such annual adjustment shall include any increase (but not any decrease) in the Participant's Accrued Benefit, determined in accordance with Article III, as a result of additional Benefit Years and Compensation and changes to average annual base salary, since the Participant's Benefit Commencement Date or the last such annual adjustment, whichever applies.

4.3 Early Retirement.

(a) Effective August 1, 2000, an Active Participant who terminates after he has attained Age 50 and has to his credit at least 10 Vesting Years may retire and shall upon so retiring be entitled to a monthly annuity that begins, at his election, as of the first day of the month following his retirement or as of the first day of any subsequent

month, but not after the first month following his Normal Retirement Date. Such election may be made no earlier than 90 days prior to the Benefit Commencement Date elected by the Participant and in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a). The amount of the annuity under this Subsection 4.3(a) shall be equal to the Participant's Accrued Benefit determined as of his Benefit Commencement Date reduced as follows:

Attained Age at Benefit Commencement Date	Reduction Factor
64–60	1.00
59	0.98
58	0.96
57	0.93
56	0.90
55	0.87
54	0.84
53	0.81
52	0.78
51	0.75
50	0.72

Notwithstanding the foregoing provisions of this subsection (a), effective January 1, 2002, there shall be no reduction to the Accrued Benefit of an Active Participant who is an hourly, nonexempt Eligible Employee and who has attained age 59 at the time of his Benefit Commencement Date.

(b) Notwithstanding any other provision of the Plan to the contrary, a Participant who has ceased to be an Active Participant because he is an EIS Senior Management Employee, or because he has ceased to be an Employee of the Company and has thereupon become an Employee of EIS, shall continue to be treated as an Active Participant for purposes of this Section 4.3 and, effective January 1, 2002, Section 5.3, but not for any other provision of the Plan, so long as (i) he continuously remains an Employee of EIS or a wholly owned subsidiary of EIS and (ii) EIS continuously remains an Affiliate.

(c) Notwithstanding any other provision of the Plan to the contrary, a Participant who has ceased to be an Eligible Employee and Active Participant because he is a Power Team Employee, shall continue to be treated as an Active Participant for purposes of this Section 4.3 and, effective December 31, 1996, Section 5.3, but not for any other provision of the Plan, so long as he continuously remains a Power Team Employee.

4.4 Deferred Annuity. Effective as of August 1, 2000, any Participant who has a Separation from Service prior to satisfying the requirements for retirement under Sections 4.1-4.3 but at a time when he has to his credit at least five Vesting Years shall upon his Separation from Service be entitled to receive a monthly annuity that begins as of the first day of the month

following his Normal Retirement Date and is equal to his Accrued Benefit determined as of his Separation from Service. Alternatively, a Participant described in the preceding sentence may, at his election, receive a monthly annuity that begins as of the first day of the month following his fiftieth birthday or, at his option, on the first day of any month thereafter but not after the first month following his Normal Retirement Date that is equal to the Actuarial Equivalent of the Participant's Accrued Benefit determined as of his Separation from Service. Any election of a Benefit Commencement Date prior to Normal Retirement Date made under this Section may be made no earlier than 90 days prior to the Benefit Commencement Date elected by the Participant and in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a).

4.5 Disabled Eligible Employees. A Participant who has become disabled within the meaning of the Company's Disabilitant benefit plans while an Eligible Employee shall continue to be credited with Benefit Years and Vesting Years during his period of Disabilitant to the extent set forth in Sections 1.7 (relating to Benefit Accrual Computation Period), 1.9 (relating to Benefit Year), 1.22 (relating to Employment) and 1.40 (relating to Vesting Service). If a disabled Participant has met the requirements to receive a pension under any Section of this Article IV (determined as if his Separation from Service had occurred on the date of reference), such Participant may elect as his Benefit Commencement Date any date as may be provided under the applicable Section. If a disabled Participant continues to be credited with Benefit Years after his Benefit Commencement Date, the amount of annuity payable to the Participant shall be determined as of his Benefit Commencement Date and shall be adjusted annually as of January 1 in each calendar year following his Benefit Commencement Date, up to and including the January 1 next following the date the disabled Participant ceases to be credited with Benefit Years. Such annual adjustment shall include any increase (but not any decrease) in the Participant's Accrued Benefit, determined in accordance with Article III, as a result of additional Benefit Years and Compensation and changes to average annual base salary, since the Participant's Benefit Commencement Date or the last such annual adjustment, whichever applies. In addition, such annual adjustment shall be reduced (but not below zero) by the Actuarial Equivalent of any benefit paid to the Participant since his Benefit Commencement Date during any period (a) prior to Normal Retirement Date or (b) after Normal Retirement Date that would have constituted "Section 202(a)(3)(B) Service" under Title 29 Code of Federal Regulations §2530.203-3(c)(1), to the extent not previously taken into account under this Section; provided, however, that the amount, if any, of the benefits paid to the Participant which exceeds the amount the Participant would have received if distribution had been made in the normal form of benefits described in Section 5.1 or 5.2(a), whichever applies to the Participant, shall be disregarded in determining the Actuarial Equivalent of such benefits for purposes of the reduction described in this sentence.

4.6 Maximum Annuity. Notwithstanding any other provision of the Plan to the contrary, the amount of the Participant's annual benefit (as defined below) accrued, distributed or payable at any time under the Plan shall be limited to an amount such that such annual benefit and the aggregate annual benefit of the Participant under all other defined benefit plans maintained by the Employer or any other Affiliate does not exceed the lesser of:

(i) $160,000 (as increased to reflect the cost of living adjustments provided under Section 415(d) of the Code), multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of participation (within the meaning of Treas. Reg. § 1.415(b)-1(g)(1)(ii)) and the denominator of which is 10; or.

(ii) an amount equal to 100% of the Participant's average compensation for the 3 consecutive calendar years in which his compensation was the highest (as determined in accordance with Treas. Reg. § 1.415(b)-1(a)(5)) and which are included in his years of service (within the meaning of Treas. Reg. § 1.415(b)-1(g)(2)(ii)) with the Employers multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of service with the Employers and the denominator of which is 10.

The dollar amount set forth in clause (i) of the preceding paragraph shall be actuarially reduced in accordance with Treas. Reg. § 1.415(b)-1 (d) if pension benefits commence prior to the Participant's attainment of age 62. If a Participant's pension benefit payments commence after the Participant's attainment of age 65, such dollar amount shall be actuarially increased in accordance with Treas. Reg. § 1.415(b)-1(e).

A Participant's "annual benefit" shall mean the Participant's accrued benefit payable annually in the form of a straight life annuity, as determined in, and accordance with, Treas. Reg. § 1.415(b)-1(b). If the annual benefit is payable in a form other than a single life annuity, the annual benefit shall be adjusted to the Actuarial Equivalent of a single life annuity using the assumptions of the following sentences; provided , however , that no adjustment shall be required for survivor benefits payable to a surviving Spouse under a Qualified Joint and Survivor Annuity (as described in Section 5.2) to the extent such benefits would not be payable if the Participant's annual benefit were paid in another form.

Effective for Plan Years beginning January 1, 2004 and January 1, 2005, for any form of benefit subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be the greater of (i) the amount computed using the interest rate and mortality table used to determine actuarial equivalence under the Plan and (ii) the amount computed using an interest rate assumption of 5.5% and the applicable mortality table under Treas. Reg. § 1.417(e)-1(d)(2) (the "Applicable Mortality Table"). Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be the greatest of (i) the amount computed using the interest rate and mortality table used to determine actuarial equivalence under the Plan, (ii) the amount computed using an interest rate assumption of 5.5% and the Applicable Mortality Table and (iii) the amount computed using the applicable interest rate under Treas. Reg. § 1.417(e)-1(d)(3) and the Applicable Mortality Table, divided by 1.05. Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit not subject to Section 417(e)(3) of the Code, a Participant's annual benefit shall be determined in accordance with Treas. Reg. § 1.415(b)-1(c). An individual's "annual benefit" under any other defined benefit plan maintained by the Employer and Affiliate shall be as determined pursuant to the provisions of Section 415 of the Code and the regulations issued thereunder the terms of such plan.

Notwithstanding the foregoing provisions of this Section, the limitation provided by this Section shall not apply to a Participant who has not at any time participated in a defined contribution plan maintained by any Employer and whose annual benefit under the Plan does not exceed $10,000 multiplied by a fraction (not exceeding 1 and not less than 1/10th) the numerator of which is the Participant's years of service (within the meaning of Treas. Reg. § 1.415(b)-1(g)(2)(ii)) and the denominator of which is 10.

For purposes of this Section, the term "compensation" shall have the meaning set forth in Section 415(c)(3) of the Code and the applicable Regulations, the term "defined contribution plan" shall have the meaning set forth in Treas. Reg. § 1.415(c)-1(a)(2), the term "defined benefit plan" shall have the meaning set forth in Treas. Reg. § 1.415(b)-1(a)(2) and the term "Employer" shall include the Employers and all corporations and entities required to be aggregated with any of the Employers pursuant to Section 414(b) and (c) of the Code as modified by Section 415(h) of the Code. Section 415 of the Code and the Regulations thereunder are hereby incorporated by reference.

4.7 Benefit Commencement Date. Unless the Participant elects otherwise, the pension to which he is entitled under this Article IV or Articles IVA or IVB shall begin within sixty days of the close of the Plan Year in which falls the later of his Normal Retirement Date or his Separation from Service. The failure of the Participant to apply for his benefit pursuant to Section 5.9 by the date prescribed in the preceding sentence shall be deemed an election to defer payment to a later date. Notwithstanding the above, payment of such pension shall begin no later than a Participant's Required Beginning Date, or the first day of the month following the date the Participant first becomes entitled to such pension, if later.

4.8 Post-Retirement Adjustment.

(a) Commencing with installments due September 1, 1978, benefit payments to Participants who retired under Sections 4.1, 4.2 or 4.3, or corresponding prior Sections, prior to January 1, 1978 and their Contingent Annuity Option beneficiaries are increased by 2% for each calendar year of retirement to a maximum of 4%.

(b) Commencing with installments due September 1, 1980, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1980 and their Contingent Annuity Option beneficiaries are increased by 3% for each calendar year of retirement to a maximum of 6%.

(c) Commencing with installments due September 1, 1982, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1982 and their Contingent Annuity Option beneficiaries are increased by 3% for each calendar year of retirement to a maximum of 6%.

(d) Commencing with installments due September 1, 1984, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1984, and their Contingent Annuity Option beneficiaries are increased by 2% for each calendar year of retirement to a maximum of 4%.

(e) Commencing with installments due September 1, 1986, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1986, and their Contingent Annuity Option beneficiaries are increased by 2% for each calendar year of retirement to a maximum of 4%.

(f) Commencing with installments due February 1, 1991, benefit payments to:

(1) Participants who retired under Section 4.1, 4.2 or 4.3 of the Plan (or corresponding prior Sections) prior to January 1, 1990;

(2) Contingent Annuity Option beneficiaries of deceased Participants who died or retired under the foregoing provisions prior to January 1, 1990;

(3) Qualified Joint and Survivor Annuity beneficiaries of deceased Participants who retired under the foregoing provisions prior to January 1, 1990; and

(4) surviving Spouses receiving benefits under Section 5.4 due to the death of a Participant while an Active Participant prior to January 1, 1990, are increased by a factor of 3/4 of 1% multiplied by the difference obtained by subtracting the Participant's year of retirement or death, as appropriate, from 1990. A Participant or beneficiary described in this Paragraph (f) may irrevocably elect to waive this increase in benefit payments by written notice to the Company made no later than 60 days after the Participant or beneficiary is first notified of the increase by the Company.

(g) Commencing with installments due February 1, 1997, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1994, and Contingent Annuity Option beneficiaries of deceased Participants who died or retired under the foregoing provisions of the Plan prior to January 1, 1994, are increased by fifty dollars ($50) per month.

(h) Commencing with installments due January 1, 2000, benefit payments to Participants who retired under the foregoing provisions of the Plan prior to January 1, 1994, and Contingent Annuity Option beneficiaries of deceased Participants who died or retired under the foregoing provisions of the Plan prior to January 1, 1994, are increased by fifty dollars ($50) per month.

4.9 Special Early Retirement Benefit. The annuity (and any Contingent Annuity Option benefit) of a Participant who retires under the early retirement provisions of Section 4.3 between February 1, 1978 and June 1, 1978, inclusive, shall be computed without the 4% per year reduction described in the last sentence of Section 4.3. In addition, the monthly benefit paid to such a Participant (but not the benefit to any Contingent Annuity Option beneficiary) shall be supplemented by a monthly payment equal to the Social Security old age insurance benefit to which the Participant would be entitled at Age 65 based on earnings received as an Employee of the Company, assuming he has no wages for Social Security purposes after his retirement and there is no change in the Social Security law or rates subsequent to his retirement. The supplemental benefit described in the preceding sentence shall end with the payment on the first day of the month preceding the month in which the Participant first receives (or could have

received if he had applied) Social Security old age insurance benefits unreduced on account of age, or with the payment last preceding the Participant's death, if earlier. The special benefits described in this Section shall also be paid with respect to a Participant who elects early retirement during the period February 1, 1978 through June 1, 1978, inclusive, but whose actual retirement is postponed at the request of the Company in order to provide for personnel replacement and training.

4.10 Minimum Annuity. The annuity of a Participant who retires or has retired under Sections 4.1, 4.2 or 4.3, or corresponding prior Sections regardless of the form of his benefit under Article V, and who is not at any time a Highly Compensated Employee, shall not be less than $150 per month.

4.11 Suspension of Benefits. With respect to any Participant whose employment by the Company or an Affiliate continues past his Normal Retirement Date, or who is receiving benefits under the Plan and again becomes an Employee, the following rules shall apply:

(a) If the reemployed Participant has not reached his Normal Retirement Date, his pension shall be suspended and recomputed under the Plan upon his subsequent Separation from Service.

(b) If the Participant has reached his Normal Retirement Date, for each calendar month or for each four or five week payroll period ending in a calendar month during which the Participant either completes forty or more Hours of Service (counting each day of Employment as five Hours of Service), or receives payment for any such Hours of Service performed on each of eight or more days or separate work shifts in such month or payroll period, (referred to herein as "Suspension Service") no pension payment shall be made, and no adjustment to the Participant's pension shall be made on account of such non-payment. No payment shall be withheld pursuant to this Paragraph (b) until the Employee is notified by personal delivery or first class mail during the first calendar month or payroll period in which payments are suspended that his benefits are suspended. Such notification shall contain a description of the specific reasons why benefit payments are being suspended, a general description of the Plan provisions relating to the suspension of payments and a copy of such provisions (or a reference to the relevant pages of the summary plan description providing such information), and a statement to the effect that applicable Department of Labor Regulations may be found in Section 2530.203-3 of the Code of Federal Regulations. In addition, the suspension notification shall inform the Employee of the Plan's procedure for affording a review of the suspension of benefits.

(c) The pension of a reemployed Participant whose benefits were suspended under this Section 4.11 shall begin again no later than the earlier of (1) the first day of the third month following the month in which the Participant first fails to satisfy the service requirements described in Paragraph (b) or has a Separation from Service or (2) his Required Beginning Date. The resumed pension shall be recalculated to reflect Compensation, average annual base salary and Benefit Years earned under the Plan as in effect during such period of reemployment and shall be reduced by the

Actuarial Equivalent of any payment received by the Employee under the Plan prior to his Normal Retirement Date; provided, however, that in no event shall the Participant's monthly pension payable in the form of a single life annuity when reemployment ends be less than the monthly pension that was payable to the Participant in the form of a single life annuity prior to his period of reemployment. The full amount of the resumed pension shall be paid in the form determined pursuant to Article V at the time payments are resumed, without regard to the form of payment in effect for the Participant prior to his reemployment. The pension of any Participant whose employment continued past his Normal Retirement Date (and whose benefits are not suspended because of employment as described in Paragraph (b)) shall be paid pursuant to Section 4.2.

(d) Notwithstanding the foregoing provisions of this Section 4.11, a Participant who received a pension while the Participant worked for Linden Chapel Corporation (formerly known as VSI Group, Inc., a Maryland corporation) before the assets of Linden Chapel Corporation (formerly known as VSI Group, Inc., a Maryland corporation) were acquired by EIS or its Affiliate, shall not have his pension suspended under this Section 4.11 solely as a result of the acquisition of the assets of Linden Chapel Corporation (formerly known as VSI Group, Inc., a Maryland corporation) by EIS or its Affiliate, so long as the Participant remains continuously employed thereafter by the Company or an Affiliate. Notwithstanding the foregoing provisions of this Section 4.11, this Section 4.11 shall not apply to a Participant who is reemployed by an Affiliated Company that does not maintain a defined benefit pension plan.

(e) Notwithstanding the foregoing provisions of this Section 4.11, a reemployed Participant who is employed under circumstances that satisfy the applicable conditions for continuation of payment of retirement benefits set forth in the Company's policy regarding the rehiring of retirees shall not have his pension suspended under this Section 4.11 nor shall such reemployed Participant be prohibited from commencing his pension if he is otherwise eligible to commence such pension.

4.12. Benefit Restrictions as a Result of Funding. (a) Notwithstanding any provision of the Plan to the contrary, the following benefit restrictions shall apply if the Plan's "Adjusted Funding Target Attainment Percentage" (the "AFTAP"), as defined in Section 436(j) of the Code, is at or below the following levels.

(i) If the Plan's AFTAP is 60% or greater but less than 80% for a Plan Year, the Plan shall not pay any prohibited payment (as defined in Section 4.12(a)(iv)) after the valuation date for the Plan Year to the extent the amount of the payment exceeds the lesser of (x) 50% of the amount of the payment which could be made without regard to the restrictions under this subsection 4.13 and (y) the present value (determined pursuant to guidance prescribed by the Pension Benefit Guaranty Corporation, using the interest and mortality assumptions under Section 417(e) of the Code) of the maximum guarantee with respect to the Participant under Section 4022 of ERISA. Notwithstanding the preceding sentence, only one such prohibited payment may be made with respect to any Participant during any period of consecutive Plan Years to which the limitations under either clause (x) or (y) of the preceding sentence apply. For purposes of this Section 4.12(a)(i), a Participant, his beneficiary and any alternate payee (as defined in Section 414(p)(8) of the Code) shall be deemed a single "Participant."

(ii) If the Plan's AFTAP is less than 60% for a Plan Year, the Plan shall not pay any prohibited payment after the valuation date for the Plan Year.

(iii) During any period in which the Company is a debtor in a case under Title 11, United States Code (or similar federal or state law), the Plan shall not make any prohibited payment. The preceding sentence shall not apply on or after the date on which the Plan's enrolled actuary certifies that the AFTAP is not less than 100%.

(iv) For purposes of this Section 4.12(a), the term "prohibited payment" means (x) any payment, in excess of the monthly amount paid under a single life annuity (plus any social security supplements described in the last sentence of Section 411(a)(9) of the Code) to a Participant or beneficiary whose annuity starting date (as defined in Section 417(f)(2) of the Code and any regulations promulgated thereunder) occurs during any period a limitation under Section 4.12(a)(ii) or (iii) is in effect, (y) any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or (z) any other payment specified by the Secretary of the Treasury by regulations.

(b) In any Plan Year in which the Plan's AFTAP for such Plan Year is less than 60%, benefit accruals under the Plan shall cease as of the valuation date for the Plan Year. This restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year, upon payment by the Company of a contribution (in addition to any minimum required contribution under Section 430 of the Code) equal to the amount sufficient to result in an AFTAP of 60%.

(c) No amendment which has the effect of increasing Plan liabilities by reason of increases in benefits, establishment of new benefits, changing the rate of benefit accruals or the rate at which benefits become nonforfeitable shall take effect during any Plan Year if the Plan's AFTAP for such Plan Year is less than 80% or would be less than 80% after taking into account such amendment; provided, however, that the preceding restriction shall not apply to an amendment which provides for an increase in benefits under a formula which is not based on a Participant's compensation if the rate of such increase is not in excess of the contemporaneous rate of increase in average wages of Participants covered by the amendment; and provided, further, that such restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year (or if later, the effective date of the amendment), upon payment by the Company of a contribution as described in Section 436(c)(2) of the Code.

(d) The Plan shall not provide an unpredictable contingent event benefit payable with respect to any event occurring during any Plan Year if the AFTAP for such Plan Year is less than 60% or would be less than 60% after taking into account such occurrence; provided, however, such restriction shall cease to apply with respect to any Plan Year, effective as of the first day of the Plan Year, upon payment by the Company of a contribution as described in Section 436(b)(2) of the Code. For purposes of this Section 4.12(d), the term "unpredictable contingent event benefit" means any benefit payable solely by reason of a plant shutdown (or similar event, as determined by the Secretary of the Treasury), or any event other than the attainment of any age, performance of any service, receipt or derivation of any compensation, or occurrence of death or disability.

(e) To avoid benefit restrictions, the Company may take any action permitted by Section 436 of the Code and the regulations promulgated thereunder.

(f) The provisions of this Section 4.12 are intended to comply with Section 436 of the Code and any regulations promulgated thereunder, and shall be construed to comply therewith.

4.13. Participant's Death During Qualified Military Service. Effective January 1, 2007, in the case of a Participant who dies while performing Qualified Military Service, the Beneficiaries of such Participant shall be entitled to any additional benefits, if any (other than benefit accruals relating to the period of Qualified Military Service), provided under the Plan had the Participant resumed employment with an Employer and then terminated such employment on account of such Participant's death.

ARTICLE IVA. Special Limited Duration Early Retirement Benefit.

4A.1 Eligibility.

(a) The special limited duration early retirement benefit described in Section 4A.3 shall be available to any Active Participant who:

(1) as of December 31, 1990, has attained Age 50 and has to his credit at least five Benefit Years; and

(2) makes a Special Early Retirement Election in accordance with the provisions of Section 4A.2 and does not withdraw such Election on or before September 15, 1990 as provided in Section 4A.2(b).

(b) The Accrued Benefit of an Active Participant who satisfies the requirements of Paragraph (a)(1) above and who dies after July 14, 1990, but before September 16, 1990, shall be calculated under Section 4A.3 as of the date of his death for purposes of determining any death benefit payable on behalf of the Participant pursuant to Section 5.3 or 5.4, notwithstanding his failure to satisfy the requirement of Paragraph (a)(2) above.

4A.2 Special Early Retirement Election.

(a) for the purposes of this Article, a "Special Early Retirement Election" is a written election that:

(1) is submitted to the Plan Administrator on or after July 15, 1990 and on or before September 15, 1990; and

(2) that indicates the Active Participant's intent to retire from employment with the Company:

(A) if the Active Participant elects to participate in the Company's Service Completion Plan, on his "Service Completion Date" (as defined in Section 4A.4(c)(2) below); or

(B) if the Active Participant does not elect to participate in the Company's Service Completion Plan, on August 1, 1990, September 1, 1990, or October 1, 1990;

provided, however, that the election described in Section 4A.2(a)(2)(A) shall not be available to an Active Participant described in Section 4A.4(c)(1)(B).

(b) An Active Participant's Special Early Retirement Election shall become irrevocable as of September 15, 1990 if it has not been withdrawn by the Active Participant on or before such date.

4A.3 Benefits. Notwithstanding anything to the contrary contained in the Plan, each Active Participant who satisfies the requirements of Section 4A.1 shall be entitled to retire on the following terms:

(a) (1) Notwithstanding the provisions of Section 3.1, each Active Participant who satisfies the requirements of Section 4A.1 shall have an Accrued Benefit equal to one-twelfth of the greater of:

(A) the sum of (i) 2% of his average annual Compensation during the period of his service, if any, between January 1, 1930 and December 31, 1938, inclusive, multiplied by his Benefit Years before January 1, 1939, and (ii) 2% of his aggregate Compensation for employment after December 31, 1938, or

(B) the sum of (i) a percentage of his average annual base salary during his 60 consecutive months of employment with the Company that yield the highest twelve month average equal to 5%, plus 1.2% multiplied by the sum of five plus his number of Benefit Years determined as of his Separation from Service (to a maximum of 45), and (ii) 0.35% of such highest average annual base salary in excess of Covered Compensation as of the date of reference, multiplied by his Benefit Years (up to a maximum of 14%);

(2) Notwithstanding the above, the Accrued Benefit of an Active Participant who satisfies the requirements of Section 4A.1 shall not exceed the maximum amount permissible under Sections 401(l) and 415 of the Code when such limitations are applied as follows:

(A) The limitations of Sections 401(l) and 415 shall be applied in the following order of priority: (I) prior to August 3, 1992, the ten-year phase-in limitation applicable to changes in the benefit structure under Section 415(b)(1)(5)(D) of the Code; (II) the limitations on the maximum excess allowance applicable when unreduced benefits are payable prior to social security retirement age as described under Section 401(l)(5)(F)(i) of the Code; and (III) the limitation described in Section 415(b)(1) of the Code;

(B) The ten-year phase-in limitation described in Subsection (A)(I) above shall apply to changes in benefits resulting from the crediting of five additional Benefit Years under Section 4A.3(a)(1)(B)(I); provided, however, that such limitation shall cease to apply on and after August 3, 1992;

(C) The limitations on the maximum excess allowance described in Subsection (A)(II) above shall apply only to such Participants who are Highly Compensated Employees at any time after 1989 and prior to Separation from Service; and

(D) For purposes of the limitations described in Subsections (A)(I) and (A)(III) above, the following actuarial assumptions shall be used to determine adjusted limitations for Participants whose benefit payments commence prior to Age 55: (I) 5% interest; and (II) the 1971 Forecast Mortality Table with a one-year age rating.

(3) For the purposes of Section 4A.3(a)(1)(B) above:

(A) employment during the most recent five years shall include absences which are included in Employment, except an absence during which an Employee receives benefits under the Company's Disabilitant Plan, and the average annual base salary of an Employee on an included absence shall be calculated as if his base salary continued during any period of such absence for which he did not receive Compensation, such salary to be that in effect when such period began, adjusted for increases applicable to his job classification which occur prior to the end of such period;

(B) for any 12-consecutive-month period taken into account in determining a Participant's average annual base salary, a Participant's annual base salary shall not exceed $200,000 (or such other amount as may apply under Section 401(a)(17) of the Code for the calendar year in which the last of such 12-consecutive-month periods ends.) In determining annual base salary, the family aggregation rules of Section 401(a)(17)(A) of the Code, as in effect prior to January 1, 1997, shall apply.

(C) a Participant's annual base salary shall not include any lump sum payment of accrued vacation or sick pay, nor any severance payment made by the Company or an Affiliate or pursuant to any plan maintained by the Company or an Affiliate.

(b) for the purposes of determining the date as of which the Active Participant may commence receiving his pension pursuant to Article IV, and his ability to elect a Contingent Annuity Option pursuant to Section 5.3, the Active Participant:

(1) shall be credited with his actual number of Vesting Years as of his Separation from Service, plus five Vesting Years; and

(2) shall be deemed to be his actual Age as of the later of his Separation from Service or December 31, 1990, plus five years; provided, however, that the Actuarial Equivalent of his Accrued Benefit shall be calculated based on his actual Age as of his Benefit Commencement Date.

(c) If the Participant's annuity (including any Contingent Annuity Option benefit) is paid pursuant to Section 4.3, such annuity shall be computed without regard to the 4% per year reduction described in the last sentence of such Section.

4A.4 Special Rules. Notwithstanding anything to the contrary contained in the Plan:

(a) The minimum pension payable to an Active Participant who makes a Special Early Retirement Election shall be equal to the pension otherwise payable to him under the Plan, determined without regard to the provisions of this Article IVA (other than the limitations described in Section 4A.3(a)(2)), multiplied by one hundred five percent (105%).

(b) If, at the time of making a Special Early Retirement Election under Section 4A.2, an Active Participant elects any Contingent Annuity Option, the election of such option shall become effective immediately.

(c) The following additional definitions shall apply for purposes of this Article IVA:

(1) An "Active Participant" shall mean an Active Participant as defined in Section 1.2, including (A) a Participant who is an Eligible Employee at least one day on or after July 15, 1990 and on or before September 15, 1990 and (B) a Participant not described in (A) who is absent from Employment by reason of his Disabilitant on account of illness or accident.

(2) An Active Participant's "Service Completion Date" shall be the date specified by the Company as the date as of which his services will no longer be required by the Company. In no event, however, will any Active Participant's Service Completion Date be later than December 1, 1992. Each Active Participant who makes a Special Early Retirement Election shall receive written notification from the Company on or before December 1, 1990 specifying the calendar quarter in which or the date on which his services will no longer be required by the Company.

ARTICLE IVB. Nuclear Voluntary Retirement Incentive Plan.

4B.1 Eligibility.

(a) The voluntary retirement incentive plan benefit described in Section 4B.3 shall be available to any Participant who:

(1) as of December 1, 1992 is on the Nuclear Group payroll;

(2) as of March 31, 1993, will have attained Age 50 and have to his credit at least 5 Benefit Years; and

(3) makes a Voluntary Early Retirement Election in accordance with the provisions of Section 4B.2 and does not withdraw such Election as provided in Section 4B.2(b).

(b) The Accrued Benefit of a Participant who satisfies the requirements of Paragraphs (a)(1) and (2) above and who dies after December 9, 1992, but before January 26, 1993, shall be calculated under Section 4B.3 as of the date of his death for purposes of determining any death benefit payable on behalf of the Participant pursuant to Section 5.3 or 5.4, notwithstanding his failure to satisfy the requirement of Paragraph (a)(3) above.

4B.2 Voluntary Early Retirement Election.

(a) For the purposes of this Article, a "Voluntary Early Retirement Election" is a written election that:

(1) is submitted to the Plan Administrator on or after December 10, 1992 and on or before January 25, 1993, together with a signed full waiver and release of claims form; and

(2) indicates the Participant's intent to retire from employment with the Company on March 1, 1993, May 1, 1993 or July 1, 1993, as prescribed for the Participant in the personal election form provided to the Participant by the Company.

(b) A Participant's Voluntary Early Retirement Election shall become irrevocable if it is not withdrawn by the Participant, in writing in a form acceptable to the Plan Administrator, within seven (7) days following the date such Voluntary Early Retirement Election is submitted to the Administrator by the Participant.

4B.3 Benefits. Notwithstanding anything to the contrary contained in the Plan, each Participant who satisfies the requirements of Section 4B.1 shall be entitled to retire on the following terms:

(a) (1) Notwithstanding the provisions of Section 3.1 (other than the last sentence of Section 3.1(b)), each Participant who satisfies the requirements of Section 4B.1 shall have an Accrued Benefit equal to one-twelfth of the greater of:

(A) the sum of (I) 2% of his average annual Compensation during the period of his service, if any, between January 1, 1930 and December 31, 1938, inclusive, multiplied by his Benefit Years before January 1, 1939, and (II) 2% of his aggregate Compensation for employment after December 31, 1938, or

(B) the sum of (I) a percentage of his average annual base salary during his 60 consecutive months of employment with the Company that yield the highest twelve month average equal to 5%, plus 1.2% multiplied by the sum of five plus his number of Benefit Years determined as of his Separation from Service (to a maximum of 45 Benefit Years), and (II) 0.35% of such highest average annual base salary in excess of Covered Compensation as of the date of reference, multiplied by his Benefit Years (up to a maximum of 14%);

(2) Notwithstanding the above, the Accrued Benefit of a Participant who satisfies the requirements of Section 4B.1 shall not exceed the maximum amount permissible under Sections 401(l) and 415 of the Code when such limitations are applied as follows:

(A) The limitations of Sections 401(l) and 415 shall be applied in the following order of priority: (I) the limitations on the maximum excess allowance applicable when unreduced benefits are payable prior to social security retirement age as described under Section 401(l)(5)(F)(i) of the Code; and (II) the limitation described in Section 415(b)(1) of the Code;

(B) The limitations on the maximum excess allowance described in Subparagraph (A)(I) above shall apply only to such Participants who are Highly Compensated Employees at any time after 1991 and prior to Separation from Service; and

(C) For purposes of the limitation described in Subparagraph (A)(II) above, the following actuarial assumptions shall be used to determine the adjusted limitation for Participants whose benefit payments commence prior to Age 62: (I) 5% interest; and (II) the 1971 Forecast Mortality Table with a one-year age rating.

(3) For purposes of Section 4B.3(a)(1) above, for any 12-consecutive-month period taken into account in determining a Participant's average annual base salary, a Participant's annual base salary shall not exceed $200,000 (or such other amount as may apply under Section 401(a)(17) of the Code for the calendar year in which the last of such 12-consecutive-month periods ends). In determining annual base salary, the family aggregation rules of Section 401(a)(17)(A) of the Code, as in effect prior to January 1, 1997, shall apply.

(b) For the purposes of determining the date as of which the Participant may commence receiving his pension pursuant to Article IV, and his ability to elect a Contingent Annuity Option pursuant to Section 5.3, the Participant:

(1) shall be credited with his actual number of Vesting Years as of his Separation from Service, plus 5 Vesting Years; and

(2) shall be deemed to be his actual Age as of the later of his Separation from Service or March 31, 1993, plus 5 years; provided, however, that the Actuarial Equivalent of his Accrued Benefit shall be calculated based on his actual Age as of his Benefit Commencement Date.

(c) If the Participant's annuity (including any Contingent Annuity Option benefit) is paid pursuant to Section 4.3, such annuity shall be computed without regard to the 4% per year reduction described in the last sentence of such Section.

4B.4 Special Rules. Notwithstanding anything to the contrary contained in the Plan, if, at the time of making a Voluntary Early Retirement Election under Section 4B.2, a Participant elects any Contingent Annuity Option, the election of such option shall become effective immediately.

ARTICLE IVC. Voluntary Retirement Incentive Program.

4C.1 Eligibility.

(a) The voluntary retirement incentive program benefit described in Section 4C.3 shall be available to any Participant who:

(1) is an Eligible Employee employed on a regular, part-time or intermittent basis, whether actively employed or absent under circumstances included in Employment, during the period beginning on July 5, 1994 and ending on September 16, 1994, other than an Eligible Employee who is laid off due to loss of employment qualifications and whose recall period ends prior to the date described for the Eligible Employee in Section 4C.2(a)(2);

(2) was born before January 1, 1946, became an Eligible Employee before January 1, 1991, and, as of December 31, 1995, will have to his credit at least 5 Benefit Years;

(3) makes a Voluntary Early Retirement Election in accordance with the provisions of Section 4C.2 and does not withdraw such Election as provided in Section 4C.2(b); and

(4) continues in employment with the Company in the same position (unless transferred at the direction of the Company) until, but not beyond, the date described in Section 4C.2(a)(2); provided, however, that this requirement shall not apply in the event the Participant ceases active employment with the Company (which shall apply to both direct and indirect employment (e.g., a leased employee)) earlier (A) due to a Disabilitant on account of illness or accident during which the Participant is eligible for and receives Disabilitant benefits under a Disabilitant benefit plan sponsored by the Company; (B) because the Company declares the Participant excess before the date described for the Participant in Section 4C.2(a)(2); or (C) because the Company has discharged the Participant for any reason, other than for willful misconduct, on or after July 5, 1994.

(b) (1) The Accrued Benefit of a Participant who satisfies the requirements of Paragraphs (a)(1) and (a)(2) above and who dies after July 4, 1994, but before September 17, 1994, shall be calculated under Section 4C.3 as of the date of his death for purposes of determining any death benefit payable on behalf of the Participant pursuant to Section 5.3 (but not Section 5.4), notwithstanding his failure to satisfy the requirements of Paragraph (a)(3) and/or (a)(4) above.

(2) The Accrued Benefit of a Participant who satisfies the requirements of Paragraphs (a)(1), (a)(2) and (a)(3) above and who dies after July 4, 1994, but before the date described for the Participant in Section 4C.2(a)(2), shall be calculated under Section 4C.3 as of the date of his death for purposes of determining any death benefit payable on behalf of the Participant pursuant to Section 5.3 or 5.4, notwithstanding his failure to satisfy the requirements of Paragraph (a)(4) above.

4C.2 Voluntary Early Retirement Election.

(a) For the purposes of this Article, a "Voluntary Early Retirement Election" is a written election that:

(1) is submitted to and accepted by the Plan Administrator on or after July 5, 1994 and on or before September 16, 1994, together with a signed full waiver and release of claims form; and

(2) indicates the Participant's intent to retire from employment with the Company (including both direct and indirect employment (e.g., as a leased employee)) on the first of the month following the later of (A) the Participant's release date determined from the table below or (B) the date the Participant attains Age 50.

STRATEGIC BUSINESS UNIT	RELEASE DATE
CONSUMER ENERGY SERVICE GROUP	
• Majority (except below	• 12/31/94
• Gas Utilization Job Family	• 3/31/95
NUCLEAR	
• Majority (except below)	• 12/31/94
• Limerick (other than below) • Operations • Mtce/I&C	• 12/31/94 6/30/95 6/30/95

STRATEGIC BUSINESS UNIT	RELEASE DATE
• Station Support (other than below)	• 12/31/94
• Mtce/I&C	6/30/95
• Peach Bottom (other than below	• 12/31/94
• Operations	12/31/95
• Mtce/I&C	12/31/95
POWER GENERATION GROUP	
• Majority (except below)	• 12/31/94
• Operations – Cromby Station	• 6/30/95
CENTRAL	
• Information Systems	• 10/31/94
• Human Resources-	• 12/31/94
Benefits Division	6/30/95
• Corp. & Public Affairs	• 12/31/94
• Quality Management	• 12/31/94
• Finance	• 12/31/94
• Legal	• 12/31/94
• Support Services	• 12/31/94
• Gas “Meter Shop”	• 12/31/94
• Gas	• 6/30/95
• Bulk	• 6/30/95

(b) A Participant’s Voluntary Early Retirement Election shall become irrevocable if it is not withdrawn by the Participant, in writing in a form acceptable to the Plan Administrator:

(1) within seven (7) days following the date such Voluntary Early Retirement Election is submitted to the Administrator by the Participant, in the case of Elections submitted to the Administrator before September 2, 1994; or

(2) within seven (7) days following the date such Voluntary Early Retirement Election is accepted by the Administrator, in the case of Elections submitted to the Administrator on or after September 2, 1994.

4C.3 Benefits. Notwithstanding anything to the contrary contained in the Plan, each Participant who satisfies the requirements of Section 4C.1 shall be entitled to retire on the following terms:

(a) (1) Notwithstanding the provisions of Section 3.1 (other than the last sentence of Section 3.1(b)), each Participant who satisfies the requirements of Section 4C.1 shall have an Accrued Benefit equal to one-twelfth of the greater of:

(A) the sum of (I) 2% of his average annual Compensation during the period of his service, if any, between January 1, 1930 and December 31, 1938, inclusive, multiplied by his Benefit Years before January 1, 1939, and (II) 2% of his aggregate Compensation for employment after December 31, 1938, or

(B) the sum of (I) a percentage of his average annual base salary during his 60 consecutive months of employment with the Company that yield the highest twelve month average equal to 5%, plus 1.2% multiplied by the sum of three plus his number of Benefit Years determined as of his Separation from Service (to a maximum of 43 Benefit Years), and (II) 0.35% of such highest average annual base salary in excess of Covered Compensation as of the date of reference, multiplied by his Benefit Years (up to a maximum of 14%);

(2) Notwithstanding the above:

(A) the Accrued Benefit of a Participant who satisfies the requirements of Section 4C.1 shall not exceed the maximum amount permissible under Section 415 of the Code. For purposes of this limitation, the following actuarial assumptions shall be used to determine the adjusted limitation under Section 415(b)(1) of the Code for Participants whose benefit payments commence prior to Age 62: (I) 5% interest; and (II) the 1971 Forecast Mortality Table with a one-year age rating.

(B) Plan benefits provided under this Article IVC for Participants described in Section 4C.1 who are Highly Compensated Employees at any time after 1993 shall be limited to the extent necessary to satisfy the nondiscriminatory amount requirements of Section 401(a)(4) of the Code applying the general test described in Treas. Reg. §1.401(a)(4)-3(c) to the portion of the Plan covering Participants described in Section 4C.1.

(3) The Section 401(a)(17) Compensation Limit described in Section 3.3 of the Plan shall apply for purposes of determining benefits under Section 4C.3(a)(1) above; provided, however, that a Participant's Accrued Benefit shall in no event be less than the amount described in Section 3.2(b).

(b) For purposes of determining the date as of which the Participant may commence receiving his pension pursuant to Article IV, and his ability to elect a Contingent Annuity Option pursuant to Section 5.3, the Participant:

(1) shall be deemed to have completed 10 Vesting Years for purposes of Article IV and shall be deemed to have completed 14 Benefit Years for purposes of Section 5.3; and

(2) shall be deemed to be his actual Age as of his Separation from Service plus 5 years.

(c) If the Participant's annuity (including any Contingent Annuity Option benefit) is paid pursuant to Section 4.3, such annuity shall be computed without regard to the 4% per year reduction described in the last sentence of such Section.

4C.4 Special Rules. Notwithstanding anything to the contrary contained in the Plan, if, at the time of making a Voluntary Early Retirement Election under Section 4C.2, a Participant elects any Contingent Annuity Option, the election of such option shall become effective immediately.

ARTICLE IVD. 1998 Workforce Reduction Program.

4D.1 Purpose. This Article IVD is intended to provide certain Active Participants with additional benefits in recognition of the Company's need to reduce its workforce to address the competitive business conditions facing the Company and the Affiliates. In general, this Article IVD provides additional retirement benefits to Active Participants whose Employment with the Company terminates between June 1, 1998 and June 30, 2000, inclusive, because they have been declared "excess" by the Company.

4D.2 Definitions. The following capitalized terms, when used in this Article IVD, shall have the following meanings, notwithstanding any different definitions of such terms elsewhere in the Plan.

(a) "CTAC Employee" means an Active Participant employed by the Company in a craft, technical, administrative or clerical position.

(b) "Disabled Employee" means an Active Participant who is receiving benefits pursuant to the Company's Disabilitant Plan or Long Term Disabilitant Plan during the period from August 1, 1998, through June 30, 2000, inclusive.

(c) "Election Period" means the 14-day period beginning on the date an Eligible Participant receives a Program enrollment package.

(d) "Eligible Participant" means each PSM Employee, CTAC Employee or Disabled Employee who satisfies the following applicable requirements:

(1) In the case of a Disabled Employee, he is described in Schedule 1 to the Plan and terminates Employment on his Qualified Retirement Date or Qualified Separation Date, whichever is applicable, pursuant to his irrevocable written election to participate in the Program, which election shall be made in the form and manner provided by the Company and during the applicable Election Period.

(2) In the case of a PSM Employee or a CTAC Employee, he continues in Employment with the Company (or an Affiliate) in the same position (unless transferred at the direction of the Company) until, but not beyond, his Qualified Retirement Date or Qualified Separation Date, if any, whichever applies; provided, however, that this requirement shall not apply in the event the PSM Employee or CTAC Employee ceases active employment with the Company (or an Affiliate) earlier due to a Disabilitant on account of illness or accident for which such Employee is eligible for and receives Disabilitant benefits under a Disabilitant benefit plan sponsored by the Company.

(3) In the case of a PSM Employee, he satisfies both (A) and (B), below:

(A) He is declared "excess" by the Company based on the following criteria:

(i) his 1997 job performance; or

(ii) the elimination of his position or a position in his job classification; or

(iii) failure to be selected for an available position.

(B) He does not reject an offer from the Company or an Affiliate to work in a position that is within two salary grades of his current position.

A description of the PSM Employees who are declared "excess" by the Company in accordance with the foregoing criteria is set forth on Schedule 1 to the Plan.

(4) In the case of a CTAC Employee, he satisfies both (A) and (B), below:

(A) He is declared "excess" by the Company based on the following criteria:

(i) his 1997 job performance; or

(ii) the elimination of one or more positions in his job classification, and

(I) if there are multiple positions that are identified as excess in his job classification and the number of such CTAC Employees who elect to participate in the Program exceeds the number identified as excess, his seniority; or

(II) if there are multiple positions that are identified as excess in his job classification and the number of such CTAC Employees who elect to participate in the Program is less than the number identified as excess, the criteria described in the Company's suspended Reduction in Force Policy.

A description of the CTAC Employees who are declared "excess" by the Company in accordance with the foregoing criteria is set forth on Schedule 1 to the Plan.

(B) In the case of a CTAC Employee described in subclause (iv)(A)(ii) above, either:

(i) he elects in writing, in the form and manner provided by the Company and during the applicable Election Period, to participate in the Program and does not revoke such election within the time period prescribed by the Company; or

(ii) he irrevocably elects in writing not to participate in the Program and the Company subsequently terminates his Employment because he is declared "excess" in accordance with the criteria set forth in paragraph (4)(A) above;

(5) His Employment, if any, is not terminated prior to his Qualified Retirement Date or Qualified Separation Date, if any, because of unsatisfactory job performance or one or more violations of the Company's Disciplinary Guidelines or Code of Conduct.

(6) He executes a written release and waiver of claims in favor of the Company and the Affiliates in a form provided by the Company and within the time period required by the Company. Such release and waiver of claims shall become irrevocable if it is not withdrawn, in writing in a form acceptable to the Plan Administrator, within seven (7) calendar days following its submission to the Plan Administrator.

(7) His Employment, or his Employer's status as an Affiliate, is not terminated as a result of a sale of assets or stock, a merger or any other business transaction which provides him an opportunity to be employed by an employer that is not the Company or an Affiliate.

(e) "Program" refers to the enhanced benefits provided pursuant to this Article IVD.

(f) "PSM Employee" means an Active Participant employed by the Company in a professional, supervisory or managerial position.

(g) "Qualified Retirement Date" means the date between June 1, 1998 and June 30, 2000, inclusive, as set forth on Schedule 1 of the Plan, that a Retirement-Eligible Participant may retire from the Company and receive Retirement Benefits.

(h) “Qualified Separation Date” means the date between June 1, 1998 and June 30, 2000, inclusive, as set forth on Schedule 1 of the Plan, that a Separation-Eligible Participant may terminate his Employment and receive Separation Benefits.

(i) “Retirement Benefits” means the benefits described in Section 4D.4.

(j) “Retirement-Eligible Participant” means an Eligible Participant who, as of December 31, 1999:

(1) is Age 50 or older; and

(2) is credited with at least five (5) Vesting Years.

For purposes of this paragraph (j), the Age of an Eligible Participant shall be his actual Age (without regard to the provisions of Section 4D.4).

(k) “SEP Annuity” means an annuity that is the Actuarial Equivalent of the SEP Lump Sum, determined on the basis of the actuarial assumptions applicable under Section 5.6 of the Plan.

(l) “SEP Lump Sum” means a fixed dollar amount equal to the following:

(1) in the case of a Separation-Eligible Participant who has not received payment for the 90-day search period under the Company’s Reduction in Force Policy prior to the suspension of that policy, a lump sum equal to the total amount such Separation-Eligible Participant would have received during the 90-day search period under the Company’s suspended Reduction in Force Policy if such policy had remained in effect; and

(2) (A) for a Separation-Eligible Participant who has fewer than ten (10) Benefit Years, two (2) multiplied by the number of full or partial Benefit Years as of his Separation from Service, multiplied by his Weekly Base Pay; or

(B) for a Separation-Eligible Participant who has ten (10) or more Benefit Years, three (3) multiplied by the number of full or partial Benefit Years as of his Separation from Service multiplied by his Weekly Base Pay.

Notwithstanding the foregoing, no Separation-Eligible Participant shall be entitled to receive a SEP Lump Sum under clause (2) (A) above that is less than eight (8) multiplied by his Weekly Base Pay.

(m) “Separation Benefits” means the benefits described in Section 4D.5.

(n) “Separation-Eligible Participant” means an Eligible Participant who:

(1) is not a Retirement-Eligible Participant; or

(2) is a Retirement-Eligible Participant who, in accordance with Section 4D.3, elects to receive Separation Benefits.

(o) “Weekly Base Pay” means:

(1) in the case of an Eligible Participant who was compensated on a salaried basis as of May 26, 1998, the Eligible Participant’s weekly base salary as of May 26, 1998, adjusted for any subsequent merit increases (or for a pro rata portion of such merit increases if such increases are based on a greater regularly scheduled workweek than the Eligible Participant’s regularly scheduled workweek as of May 26, 1998);

(2) in the case of an Eligible Participant who was compensated on a non-salaried basis as of May 26, 1998, the number of hours per week such Eligible Participant was regularly scheduled to work as of May 26, 1998 multiplied by his regular hourly rate in effect on the day

4D.3 Elections of the Retirement and Separation Benefits. Any Retirement-Eligible Participant shall be entitled to elect to receive Retirement Benefits or Separation Benefits, but not both. A Retirement-Eligible Participant must submit to the Company’s Human Resources Department a completed and signed election form, in such form and manner and at such time as may be required by the Administrator.

4D.4 Computation of Retirement Benefits Under the Program.

(a) Each Retirement-Eligible Participant who has not elected Separation Benefits in accordance with Section 4D.3 shall be entitled to early retirement benefits determined under Section 4.3 of the Plan, regardless of the number of Vesting Years with which he has been credited; provided, however, that for the purpose of determining any applicable reduction in the amount received upon early retirement, such Participant’s Age on his Benefit Commencement Date shall be deemed to be his actual Age on such date plus 60 additional months.

(b) The Accrued Benefit of a Retirement-Eligible Participant who satisfies the requirements of an Eligible Participant, other than paragraphs 4D.2(d)(2) and 4D.2(d)(6), and who dies before his Qualified Retirement Date, shall be calculated by applying paragraph 4D.4(a) as of the date of his death for purposes of determining any death benefit payable on behalf of such Participant pursuant to Sections 5.3 or 5.4, notwithstanding his failure to satisfy paragraphs 4D.2(d)(2) and/or 4D.2(d)(6).

4D.5 Computation, Payment and Form of Separation Benefits Under the Program.

(a) Each Separation-Eligible Participant shall be entitled to receive a SEP Annuity in addition to his Accrued Benefit.

(b) A Separation-Eligible Participant shall receive payment of his SEP Annuity in accordance with the following:

(1) A Separation-Eligible Participant shall receive the sum of (I) the Actuarial Equivalent of his SEP Annuity in the form of a Single Life Annuity commencing on his Normal Retirement Date (determined on the basis of the actuarial assumptions applicable under Appendix A of the Plan) and (II) his Accrued Benefit, with such sum payable at such time, in such form and subject to such adjustments as may otherwise be applicable under Articles IV and V of the Plan. In lieu of receiving such Actuarial Equivalent of his SEP Annuity at such time and in such form as he receives his Accrued Benefit, a Separation-Eligible Participant may instead elect to receive immediate payment of his SEP Annuity in accordance with paragraph (2) below or an immediate distribution of his SEP Lump Sum in accordance with paragraph (3) below.

(2) A Separation-Eligible Participant may elect, in accordance with the procedure described in Section 4.3, to receive his SEP Annuity immediately, with payment to begin as of his Qualified Separation Date in the following form:

(A) The SEP Annuity of a Separation-Eligible Participant who is unmarried on his Benefit Commencement Date shall be paid in the form of a Single Life Annuity.

(B) The SEP Annuity of a Separation-Eligible Participant who is married on his Benefit Commencement Date shall be paid in the form of a Qualified Joint and Survivor Annuity.

(3) In lieu of his SEP Annuity, a Separation-Eligible Participant may elect to receive an immediate payment of his SEP Lump Sum, with payment to be made as of his Qualified Separation Date in a single sum. Any such election by a Separation-Eligible Participant who is married on his Benefit Commencement Date shall be subject to the spousal consent requirements described in Section 5.7, shall be made in writing in a manner prescribed by the Company and may be made or revoked at any time within the 90-day period preceding the Benefit Commencement Date but in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a).

(c) In the case of a Separation-Eligible Participant who satisfies the requirements of an Eligible Participant, other than paragraphs 4D.2 (d)(ii) and 4D.2(d)(vi), and who dies before his Qualified Separation Date, the Actuarial Equivalent of such Participant's SEP Annuity in the form of a Single Life Annuity commencing on his Normal Retirement Date (determined on the basis of the actuarial assumptions applicable under Appendix A of the Plan) shall be added to his Accrued Benefit for the purpose of determining any death benefit payable on behalf of such Participant pursuant to Sections 5.3 or 5.4, notwithstanding his failure to satisfy paragraphs 4D.2(d)(ii) and/or 4D.2(d)(vi).

ARTICLE IVE. Merger Separation Program.

4E.1 Purpose. This Article IVE is intended to provide certain Participants with additional benefits in recognition of the Company's need to reduce its workforce in connection with the merger of the Company and Unicom Corporation. In general, this Article IVE provides additional retirement benefits to certain Participants whose Employment with the Company terminates between 60 days after the Merger Date and December 31, 2002, inclusive.

4E.2 Definitions. The following capitalized terms, when used in this Article IVE, shall have the following meanings, notwithstanding any different definitions of such terms elsewhere in the Plan.

(a) "Annuity" means an annuity that is the Actuarial Equivalent of the Lump Sum, determined on the basis of the actuarial assumptions applicable under Section 5.6 of the Plan.

(b) "Disabled Employee" means an Active Participant who is receiving benefits pursuant to the Company's Disabilitant Plan or Long Term Disabilitant Plan at any time during the Merger Separation Period.

(c) "Election Period" means the 45-day period beginning on the date an Eligible Participant receives a Program enrollment package.

(d) "Eligible Participant" means each Participant, other than an intermittent employee, who satisfies the following applicable requirements:

(1) In the case of a Disabled Employee, he terminates Employment on his Qualified Retirement Date or Qualified Separation Date, whichever applies, pursuant to his irrevocable written election to participate in the Program, which election shall be made in the form and manner provided by the Company and during the applicable Election Period.

(2) In the case of a Participant other than a Disabled Employee or a Participant described in (3) below, he satisfies (A) or (B), and each of (C) and (D), below:

(A) His current position is eliminated as part of the restructuring program related to the merger between the Company and Unicom Corporation; or

(B) He is offered a position or a transfer (either between or within business units) as part of the merger between the Company and Unicom Corporation that results in one or more of the following:

(i) an increase in one-way commuting distance of more than 50 miles;

(ii) a substantial change in major position responsibilities and duties, as determined by the Company acting as employer and not as a fiduciary;

(iii) a lower job band; or

(iv) a lower annual base salary.

(C) His position is identified by the Company for elimination, transfer or change, whichever applies, he is notified of such elimination, transfer or change no later than sixty days before December 31, 2002 and, in the case of a transfer described in paragraph (2)(B) above, he elects in writing, in the form and manner provided by the Company and during the Election Period, to participate in the Program.

(D) He continues in Employment with the Company or an Affiliate in the same position (unless transferred at the direction of the Company) until, but not beyond, his Qualified Retirement Date or Qualified Separation Date, if any, whichever applies; provided, however, that this requirement shall not apply in the event the Participant ceases active employment with the Company or an Affiliate earlier due to a disability on account of illness or accident which such Employee is eligible and receives disability benefits under a disability benefit plan sponsored by the Company.

(3) In the case of an Active Participant who is a nonexempt, hourly craft employee, one or more positions in his job classification are eliminated as part of the restructuring program related to the merger between the Company and Unicom Corporation, and

(A) if there are multiple such positions that are eliminated in his job classification and the number of such Active Participants who elect to participate in the Program exceeds the number of positions eliminated, Eligible Participants will be identified based on seniority; or

(B) if there are multiple such positions that arc eliminated in his job classification and the number of such Active Participants who elect to participate in the Program is less than the number of positions eliminated, Eligible Participants will be identified based on the criteria described in the Company's suspended Reduction in Force Policy.

(4) His Employment, if any, is not terminated prior to his Qualified Retirement Date or Qualified Separation Date, whichever applies, for any reason not related to the merger between the Company and Unicom Corporation.

(5) He executes a written release and waiver of claims in favor of the Company and the Affiliates in a form provided by the Company and within the time period required by the Company. Such release and waiver of claims shall become irrevocable if it is not withdrawn, in writing in a form acceptable to the Plan Administrator, within seven (7) calendar days following its submission to the Plan Administrator.

(e) “Enhanced Age” means:

(1) in the case of a Retirement-Eligible Participant, his actual Age plus twelve (12) additional months; and

(2) in the case of a Separation-Eligible Participant, his actual Age plus the number of months included in his Special Payment Period.

(f) “Enhanced Benefit Years” means:

(1) in the case of a Retirement-Eligible Participant, his actual Benefit Years (up to a maximum of 40) plus twelve (12) additional months; and

(2) in the case of a Separation-Eligible Participant, his actual Benefit Years (up to a maximum of 40) plus the number of months equal to one-fourth of the number of weeks included in Section 4E.2(r)(2) (up to a maximum of twenty-four (24) weeks), rounded to the nearest whole number of months (with remainders of one-half(l/2) rounded to the next higher whole number).

(g) “Enhanced Vesting Years” means:

(1) in the case of a Retirement-Eligible Participant, his actual Vesting Years plus twelve (12) additional months; and

(2) in the case of a Separation-Eligible Participant, his actual Vesting Years plus the number of months equal to one-fourth of the number of weeks included in Section 4E.2(r)(2) (up to a maximum of twenty-four (24) weeks), rounded to the nearest whole number of months (with remainders of one-half (1/2) rounded to the next higher whole number).

(h) “Lump Sum” means a fixed dollar amount equal to the following:

(1) in the case of a Retirement-Eligible Participant, 26 multiplied by his Weekly Base Pay; and

(2) in the case of a Separation-Eligible Participant, the sum of (A) and (B) below:

(A) 52 multiplied by his Weekly Base Pay; and

(B) the number of full Vesting Years as of his Qualified Separation Date that are in excess often (10) but not in excess of thirty-six (36), if any, multiplied by his Weekly Base Pay.

(i) “Merger Separation Period” means the time period beginning sixty (60) days before the Merger Date and ending on December 31, 2002, inclusive.

(j) “Program” refers to the enhanced benefits provided pursuant to this Article IVE.

(k) “Qualified Retirement Date” means the date during the Merger Separation Period. as determined by the Company, that a Retirement-Eligible Participant may retire from the Company and receive Retirement Benefits.

(l) “Qualified Separation Date” means the date during the Merger Separation Period, as determined by the Company, that a Separation-Eligible Participant may terminate his Employment and receive Separation Benefits.

(m) “Retirement Benefits” means the benefits described in Section 4E.4.

(n) “Retirement-Eligible Participant” means an Eligible Participant who:

(1) is at least Age 50 with five (5) or more Vesting Years as of his Qualified Retirement Date; or

(2) satisfies the requirements of paragraph (1) above after taking into account his Enhanced Age and/or his Enhanced Vesting Years.

(o) “Separation Benefits” means the benefits described in Section 4E.5.

(p) “Separation-Eligible Participant” means an Eligible Participant who:

(1) is not a Retirement-Eligible Participant; or

(2) is a Retirement-Eligible Participant who, in accordance with Section 4E.3, elects to receive Separation Benefits.

(q) “Special Payment Period” means, for a Separation-Eligible Participant, the sum of (1) and (2) below:

(1) twelve (12) months; and

(2) one (1) week for each full Vesting Year as of his Qualified Separation Date in excess often (10) but not in excess of thirty-six (36), if any.

(r) “Weekly Base Pay” means:

(1) in the case of an Eligible Participant who was compensated on a salaried basis as of the later of his Employment Date or August 1, 2000, the Eligible Participant’s weekly base salary as of such date, adjusted for any subsequent merit increases (or for a pro rata portion of such merit increases if such increases are based on a greater regularly scheduled workweek than the Eligible Participant’s regularly scheduled workweek as of the later of his Employment Date or August 1, 2000);

(2) in the case of an Eligible Participant who was compensated on a non-salaried basis as of the later of his Employment Date or August 1, 2000, the number of hours per week such Eligible Participant was regularly scheduled to work as of such date multiplied by his regular hourly rate in effect on the day before his Separation from Service, and

(3) in the case of a Disabled Participant, the amount calculated in accordance with (1) or (2) above, whichever applies, determined as of the last day the Participant performed services for the Company immediately prior to the occurrence of his disability.

4E.3 Elections of the Retirement and Separation Benefits. Any Retirement-Eligible Participant shall be entitled to elect to receive Retirement Benefits or Separation Benefits, but not both. A Retirement-Eligible Participant must submit to the Company's Human Resources Department a completed and signed election form, in such form and manner and at such time as may be required by the Administrator.

4E.4 Computation of Retirement Benefits Under the Program.

(a) Each Retirement-Eligible Participant who has not elected Separation Benefits in accordance with Section 4E.3 shall be entitled to early retirement benefits regardless of the number of Vesting Years with which he has been credited. Such early retirement benefits shall be determined under Section 4.3; provided, however, that for purposes of calculating such Retirement-Eligible Participant's Accrued Benefit and determining any applicable reduction in the amount received upon early retirement: (1) such Participant's Age on his Benefit Commencement Date shall be deemed to be his Enhanced Age, (2) such Participant's Benefit Years on his Benefit Commencement Date shall be deemed to be his Enhanced Benefit Years for purposes of Section 3.1(b), (3) such Participant's aggregate Compensation for purposes of Section 3.1(a)(2) shall he deemed to include an additional amount equal to his annual Compensation for the calendar year ending on or immediately preceding his Qualified Retirement Date, and (4) such Participant's early retirement benefits shall be determined using the early retirement reduction factors set forth on Schedule A. The Benefit Commencement Date of a Retirement-Eligible Participant shall not be earlier than the date he attains Age 50, determined without regard to his Enhanced Age.

(b) The Accrued Benefit of a Retirement-Eligible Participant who has not elected Separation Benefits, who satisfies the requirements of an Eligible Participant, other than paragraphs 4E.2(d)(2)(D) and 4E.2(d)(5), and who dies before his Qualified Retirement Date shall be calculated by applying paragraph 4E.4(a) as of the date of his death for purposes of determining any death benefit payable on behalf of such Participant pursuant to Sections 5.3 or 5.4, notwithstanding his failure to satisfy paragraphs 4E.2(d)(2)(D) and/or 4E.2(d)(5).

(c) Each Retirement-Eligible Participant who has not elected Separation Benefits and who is not employed by the Company under a change in control agreement shall be entitled to receive an Annuity in addition to his Accrued Benefit, which Annuity shall be paid in accordance with Section 4E.6.

4E.5 Computation of Separation Benefits Under the Program

(a) Each Separation-Eligible Participant shall be entitled to pension benefits determined in accordance with the terms of the Plan; provided, however, that for purposes of calculating such Separation-Eligible Participant's Accrued Benefit: (1) such Participant's Age on his Benefit Commencement Date shall be deemed to be his Enhanced Age, (2) such Participant's Benefit Years on his Benefit Commencement Date shall be deemed to be his Enhanced Benefit Years for purposes of Section 3.1(b), and (3) such Participant's aggregate Compensation for purposes of Section 3.1(a)(2) shall be deemed to include an additional amount equal to the product of (i) one-twelfth (1/12) of his annual Compensation for the calendar year ending on or immediately preceding his Qualified Separation Date and (ii) the difference between the number of months included in his Enhanced Benefit Years and the number of months included in his actual Benefit Years (up to a maximum of 480).

For purposes of determining any reduction in the amount received by a Separation-Eligible Participant, if the Separation-Eligible Participant's Enhanced Age as of his Qualified Separation Date is at least 45, he is credited with at least ten (10) Enhanced Vesting Years as of his Qualified Separation Date and his Benefit Commencement Date occurs on or after the date he attains Age 50, determined without regard to his Enhanced Age, such Participant's pension benefits shall be determined using the enhanced vested pension factors set forth on Schedule B.

(b) The Accrued Benefit of a Separation-Eligible Participant who satisfies the requirements of an Eligible Participant, other than paragraphs 4E.2(d)(2)(D) and 4E.2(d)(5), and who dies before his Qualified Separation Date shall be calculated by applying paragraph 4E.5 (a) as of the date of his death for purposes of determining any death benefit payable on behalf of such Participant pursuant to Sections 5.3 or 5.4, notwithstanding his failure to satisfy paragraphs 4E.2(d)(2)(D) and/or 4E.2(d)(5).

(c) Each Separation-Eligible Participant who is not employed by the Company under a change in control agreement shall be entitled to receive an Annuity in addition to his Accrued Benefit, which Annuity shall be paid in accordance with Section 4E.6.

4E.6 Payment and Form of Annuities Under the Program.

(a) Each Eligible Participant described in Sections 4E.4(c) and 4E.5(c) shall receive the sum of (l) the Actuarial Equivalent of his Annuity in the form of a Single Life Annuity commencing on his Normal Retirement Date (determined on the basis of the actuarial assumptions applicable under Appendix A of the Plan) and (2) his Accrued Benefit, with such sum payable at such time, in such form and subject to such adjustments as may otherwise be applicable under Articles IV, IVE and V of the Plan.

In. lieu of receiving such Actuarial Equivalent of his Annuity at such time and in such form as he receives his Accrued Benefits, such Eligible Participant may instead elect to receive immediate payment of his Annuity in accordance with paragraph (b) below or an immediate distribution of his Lump Sum in accordance with paragraph (c) below.

(b) An Eligible Participant may elect) in accordance with the procedure described in Section 4.3, to receive his Annuity immediately, with payment to begin as of his Qualified Retirement Date or his Qualified Separation Date, whichever applies, in the following form:

(1) The Annuity of an Eligible Participant who is unmarried on his Benefit Commencement Date shall be paid in the form of a Single Life Annuity.

(2) The Annuity of an Eligible Participant who is married on his Benefit Commencement Date shall be paid in the form of a Qualified Joint and Survivor Annuity.

(3) In lieu of payment in the form described in (1) above, an Eligible Participant who is unmarried on his Benefit Commencement Date may elect to receive an immediate payment of his Annuity in the form of a contingent annuity, with 50% of the annuity payable upon his death to a contingent beneficiary designated by him. The annuity described in the preceding sentence will be actuarially reduced using the factors described in Appendix A to reflect the payments which may become payable to the beneficiary.

(4) In lieu of payment in the form described in (2) above, an Eligible Participant who is married on his Benefit Commencement Date may elect to receive an immediate payment of his Annuity in the form of a Single Life Annuity.

(c) In lieu of his Annuity, an Eligible Participant may elect to receive an immediate payment of his Lump Sum, with payment to be made as of his Qualified Separation Date or Qualified Retirement Date, whichever applies, in a single sum.

(d) Any election pursuant to paragraph (b)(3),(b)(4) or (c) above by an Eligible Participant shall be made in writing in a manner prescribed by the Company and may be made or revoked at any time within the 90-day period preceding the Benefit Commencement Date but in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a) and, in the case of an Eligible Participant who is married on his Benefit Commencement Date, shall be subject to the spousal consent requirements described in Section 5.7.

(e) In the case of an individual who satisfies the requirements of an Eligible Participant, other than paragraphs 4E.2(d)(2)(D) and 4E.2 (d)(5), and who dies before his Qualified Separation Date or Qualified Retirement Date, whichever applies, the Actuarial Equivalent of such Participant's Annuity in the form of a Single Life Annuity commencing on his Normal Retirement Date (determined on the basis of the actuarial assumptions applicable under Appendix A of the Plan) shall be added to his Accrued Benefit for the purpose of determining any death benefit payable on behalf of such Participant pursuant to Sections 5.3 and 5.4, notwithstanding his failure to satisfy paragraphs 4E.2(d) (2)(D) and/or 4E.2(d)(5).

ARTICLE V. Form of Pensions.

5.1 Unmarried Participants. The monthly annuity of a Participant who is unmarried on his Benefit Commencement Date shall be paid as a Single Life Annuity unless he elects an optional form of benefit under Section 5.3 or receives a lump sum distribution under Section 5.6.

5.2 Married Participants.

(a) The monthly annuity of a Participant who is married on his Benefit Commencement Date, shall be paid as a Qualified Joint and Survivor Annuity, unless he elects an optional form of benefit under Paragraph (b) or Section 5.3 or receives a lump sum distribution under Section 5.6.

(b) A Participant described in Paragraph (a) may elect to waive the Qualified Joint and Survivor Annuity and receive his annuity in the form of a Single Life Annuity. Any such election shall be subject to the spousal consent requirements described in Section 5.7, shall be made in writing in a manner prescribed by the Company and may be made or revoked at any time within the 90 day period preceding the Benefit Commencement Date elected by the Participant but in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a).

5.3 Contingent Annuity Option.

(a) An Active Participant (including a Participant who is treated as an Active Participant for purposes of Section 4.3 and this Section 5.3, but not for any other provision of the Plan) who has at least 14 Benefit Years, or who has attained Age 65 and has at least 5 Benefit Years, or a Participant (including a Participant who continues to be treated as an Active Participant for purposes of Section 4.3 and Section 5.3, but not for any other provision of the Plan) who had a Separation from Service after becoming eligible for early retirement under Section 4.3 (hereinafter referred to as an "Eligible Participant"), may elect, in writing on a form prescribed by the Administrator, a Contingent Annuity Option under which he may designate a percentage of his annuity to be paid upon his death to a contingent beneficiary designated by him. The percentage so designated shall be 25%, 50%, 75% or 100%, as the Participant elects, and may be changed by an Eligible Participant at any time prior to the later of the Participant's Normal Retirement Date or Separation from Service. The annuity otherwise payable to a Participant electing a Contingent Annuity Option or to his contingent beneficiary will be actuarially reduced using the factors described in Appendix A to reflect the payments which may become payable to the beneficiary. Notwithstanding the above, if the Eligible Participant's Spouse is designated as contingent beneficiary, the actuarial reduction will not reflect the cost of a joint and survivor annuity option providing a survivor annuity to the Participant's Spouse of (1) 50% of the amount payable to the Participant, if a 50%, 75% or 100% contingent annuity option is elected, or (2) 25% of the amount payable to

the Participant, if a 25% contingent annuity option is elected; provided, however, that the subsidy described in this sentence shall not apply to a former spouse who is to be treated as a Participant's spouse pursuant to a qualified domestic relations order, unless the qualified domestic relations order specifically provides that such subsidy applies to the former spouse. If the contingent beneficiary is other than the Spouse, the percentage payable to the contingent beneficiary after the Participant's death may not exceed the applicable percentage from Appendix B. The Contingent Annuity Option of an electing Participant who has a Separation from Service and is not eligible for early retirement under Section 4.3 shall be canceled.

(b) (1) An Eligible Participant's election or change in election under Paragraph (a) shall become effective on the first of the month next following the date such election or change is properly filed with the Administrator.

(2) An Eligible Participant's election under Paragraph (a) shall not be valid upon a Participant's Benefit Commencement Date if such election is not confirmed in writing by such Participant, with spousal consent as described in Section 5.7, within the 90 day period preceding the Benefit Commencement Date, and in no event earlier than the date on which the Participant receives the notice described in Section 5.5(a). If an Eligible Participant has made no election under Paragraph (a), or has made an invalid election, as of his Benefit Commencement Date, such Participant's pension shall be paid as described in Section 5.1 or 5.2, whichever applies.

(3) (A) The election under Paragraph (a) in effect for an Eligible Participant who is married on the date of his death shall not be valid upon the Participant's death unless (i) the spousal consent requirements of Section 5.7 are satisfied; (ii) if the Participant's death occurs after the first day of the Plan Year in which the Participant attains Age 35, the Participant's election was made or confirmed in writing (with the applicable spousal consent) on or after the first day of such Plan Year, and (iii) in the event that the election in effect under Paragraph (a) does not provide for a survivor benefit to the Participant's surviving Spouse, the Participant has made no change to his election under Paragraph (a) that has not yet taken effect which would result in a survivor benefit payable to his Spouse. If an Eligible Participant who is married at the time of his death has made no election, or has made an invalid election, the Participant's surviving Spouse shall receive the benefit described in Section 5.4. With respect to an Eligible Participant described in the preceding sentence, no additional benefit shall be payable to any other contingent beneficiary or to the Participant's estate.

(B) If an Eligible Participant (1) is unmarried at the time of his death, (2) is survived by one or more children, (3) has not begun receiving any benefits hereunder, and (4) either has failed to make a valid election under Paragraph (A) or is not survived by a designated contingent beneficiary, a benefit equal to the amount that would be payable assuming that the Participant made a valid election under Paragraph (a) and designated a percentage of 100% shall be paid to the Participant's surviving children, if any, in equal shares. For all purposes of the Plan, where applicable, the person to whom benefits are payable pursuant to this Paragraph (b) shall be treated as the Participant's contingent beneficiary.

(c) Except as provided in Paragraph (b):

(1) If an electing Participant who has had a Separation from Service whose Contingent Annuity Option has not been canceled dies on or after the effective date of the option, his contingent beneficiary, if surviving, will receive an annuity for life beginning as of the first day of the second month following his death and based upon the designated percentage of the annuity which the Participant was receiving or to which he would have been entitled; provided, however, that, if the contingent beneficiary is the Participant's surviving Spouse and the designated percentage is at least 50%, payment to the Spouse shall not begin prior to what would have been the Participant's Normal Retirement Date without the Spouse's written consent made within the 90-day period preceding the Benefit Commencement Date.

(2) If an electing Active Participant dies on or after the effective date of the option, his contingent beneficiary, if living, shall receive an annuity, for life, beginning as of the first day of the second month following the month in which the Participant's death occurs, based upon the designated percentage of the benefit to which the Participant would have been immediately entitled if he had retired on the date of his death; provided, however, that, if the contingent beneficiary is the Participant's surviving Spouse, the designated percentage shall be deemed to be 100%, and payment to such Spouse shall not begin prior to what would have been the Participant's Normal Retirement Date without the Spouse's written consent made within the 90-day period preceding the Benefit Commencement Date. For purposes of this Subparagraph only, the annuity to which a Participant would have been entitled shall be his Accrued Benefit reduced in accordance with Section 4.3 and, if applicable, reduced further by 4% per year (to the nearest one-twelfth year) for any period by which his age at the time of his death is less than 50.

(d) (1) If the contingent beneficiary dies after the effective date of the option and after the later of the Participant's Normal Retirement Date or his Separation from Service, the reduced annuity payable to the Participant will remain in effect.

(2) If the contingent beneficiary dies after the effective date of the option, but prior to the later of the Participant's Normal Retirement Date or his Separation from Service, the option shall be canceled upon receipt of proof of death. If the Participant has not then reached his Normal Retirement Date or has not had a Separation from Service, the Participant may elect a subsequent Contingent Annuity Option effective immediately upon notice to the Company, subject to the conditions stated herein. If he has reached his Normal Retirement Date and has had a Separation from Service, the Participant may not make any further elections.

(e) Subject to the conditions of Paragraph (a), an Eligible Participant may make or change his election and designate or change a beneficiary and/or designate a revised benefit percentage at any time prior to the later of the Participant's Normal Retirement Date or Separation from Service. An Eligible Participant may, regardless of whether he has previously made a different election under this Section 5.3, elect in writing to receive his annuity in the form provided in Section 5.1 or 5.2, whichever applies, or in such other form as is permitted under Paragraph (a), subject to the provisions of Section 5.7. The Participant may make such an election at any time before the Benefit Commencement Date but such an election may not be revoked after the Benefit Commencement Date, except as provided in Paragraph (d)(2). Notwithstanding the foregoing, effective July 15, 1990, a Participant who has not reached his Normal Retirement Date and who elects a form of benefit under this Section 5.3 may waive any right to change his election in the future and irrevocably elect a specific Contingent Annuity Option as of his Benefit Commencement Date.

(f) Commencing with payments due September 1, 1986, the minimum monthly annuity to which a designated beneficiary under a Contingent Annuity Option described in this Section 5.3 shall be entitled is $150.

5.4 Death Benefits for Other Vested Participants.

(a) Eligibility. A death benefit shall be payable under this Section 5.4 with respect to a Participant who dies prior to his Benefit Commencement Date if on the date of his death he is married and:

(1) he does not meet the requirements for the Contingent Annuity Option described in Section 5.3, and

(A) he is an Employee who has met the requirements for early or normal retirement under the Plan; or

(B) he is a former Employee who has had a Separation from Service after meeting the requirements of Section 4.3; or

(C) he has been married for at least one year to the same Spouse and has at least five Vesting Years to his credit, or

(2) he does meet the requirements described in Section 5.3 but has made no election, or has made an invalid election, under that Section.

(b) Amount of Benefit. Upon the death of a Participant described in Section 5.4(a), the Participant's surviving Spouse, if living on the date set forth in Subparagraph (1)-(4) of this Section, whichever shall apply, shall receive a pension in accordance with the following rules:

(1) If the Participant is an Employee who has met the requirements for retirement under Sections 4.1-4.3, the pension to the surviving Spouse shall begin, as elected in writing by the Spouse not more than 90 days prior to the Spouse's Benefit Commencement Date, on the first day of the month following the month in which the Participant's death occurs or the first day of any month thereafter, shall end with the

payment on the first day of the month in which the Spouse's death occurs, and shall be in a monthly amount equal to the amount the Spouse would have received if the Participant had a Separation from Service on the date of his death, had survived and retired on the Benefit Commencement Date elected by the Spouse and had elected an immediate pension in the form of a 100% Contingent Annuity Option; provided, however, that (A) the Spouse's Benefit Commencement Date shall not be later than the later of (i) the Participant's Normal Retirement Date or (ii) the first day of the month following the month in which the Participant's death occurs and (B) the benefit payable to the Spouse of a Participant described in Section 5.4(a)(2) shall be determined without regard to any otherwise applicable actuarial reduction reflecting the cost of the 100% Contingent Annuity Option.

(2) If the Participant is an Employee who has not met the requirements for retirement under Sections 4.1-4.3, the pension to the surviving Spouse shall begin, as elected in writing by the Spouse not more than 90 days prior to the Spouse's Benefit Commencement Date, on the first day of the month following the month in which the Participant would have first been eligible to receive his pension under Section 4.4 if he had a Separation from Service on the date of his death and had not died, or the first day of any month thereafter, shall end with the payment on the first day of the month in which the Spouse's death occurs, and shall be in a monthly amount equal to the amount the Spouse would have received if the Participant's Separation from Service had occurred on the day of his death and he had survived and elected to begin receiving his pension in the form of a 100% Contingent Annuity Option on the Benefit Commencement Date elected by the Spouse; provided, however, that (A) the Spouse's Benefit Commencement Date shall not be later than what would have been the Participant's Normal Retirement Date and (B) the benefit payable to the Spouse of a Participant described in Section 5.4 (a)(2) shall be determined without regard to any otherwise applicable actuarial reduction reflecting the cost of the 100% Contingent Annuity Option.

(3) If the Participant is a former Employee who retired under Sections 4.1-4.3, the pension to the surviving Spouse shall begin, as elected in writing by the Spouse not more than 90 days prior to the Spouse's Benefit Commencement Date, on the first day of the month following the month in which the Participant's death occurs or the first day of any month thereafter, shall end with the payment on the first day of the month in which the Spouse's death occurs, and shall be in a monthly amount equal to the amount the Spouse would have received if the Participant had elected to begin receiving his pension in the form of a 100% Contingent Annuity Option on the Benefit Commencement Date elected by the Spouse; provided, however, that (A) the Spouse's Benefit Commencement Date shall not be later than the later of (i) the Participant's Normal Retirement Date or (ii) the first day of the month following the month in which the Participant's death occurs and (B) the benefit payable to the Spouse of a Participant described in Section 5.4(a)(2) shall be determined without regard to any otherwise applicable actuarial reduction reflecting the cost of the 100% Contingent Annuity Option.

(4) If the Participant is a former Employee who did not meet the requirements for retirement under Sections 4.1-4.3, the pension to the surviving Spouse shall begin, as elected in writing by the Spouse not more than 90 days prior to the Spouse's Benefit Commencement Date, on the first day of the month following the month in which the Participant would have first been eligible to receive his pension under Section 4.4 if he had not died or the first day of any month thereafter, shall end with the payment on the first day of the month in which the Spouse's death occurs, and shall be in a monthly amount equal to the amount the Spouse would have received if the Participant elected to begin receiving his actual pension in the form of a 100% Contingent Annuity Option on the Benefit Commencement Date elected by the Spouse; provided, however, that the Spouse's Benefit Commencement Date shall not be later than what would have been the Participant's Normal Retirement Date.

5.5 Notice to Participants.

(a) Each Participant shall receive in written nontechnical language a general description or explanation of (1) the forms of payment described in Sections 5.1, 5.2 and 5.3, including information explaining the relative values of each form of payment, (2) the Participant's right to waive the form of payment described in Section 5.1 or 5.2(a), whichever applies, and elect an optional form of payment and the financial effect of such an election on his pension, (3) the rights of the Participant's Spouse, if any, with respect to the waiver and election, (4) the Participant's right to revoke an election to receive an optional form of payment and the effect of such revocation, (5) if the Participant has not reached his Normal Retirement Date, the Participant's right to defer commencement of his pension until his Normal Retirement Date and the financial effect of such deferment, and (6) a description of the relative value of the optional forms of benefit as compared to the Qualified Joint and Survivor Annuity. Such information shall be furnished to the Participant not less than 30 days and not more than 90 days prior to the Participant's Benefit Commencement Date, and the time for an election under this Section shall begin no earlier than the date such information is furnished.

Notwithstanding the foregoing, effective for Plan Years beginning on or after January 1, 1997, the Participant's Benefit Commencement Date may be fewer than 30 days after the explanation described in this Section is provided if:

(1) the Participant is given notice of his right to a 30-day period in which to consider whether to (i) waive the normal form of benefit and elect an optional form and (ii) to the extent applicable, consent to the distribution;

(2) the Participant affirmatively elects a distribution and a form of benefit and the Spouse, if necessary, consents to the form of the benefit elected;

(3) the Participant is permitted to revoke his affirmative election at any time prior to his Benefit Commencement Date, or if later, the expiration of a 7-day period beginning on the day after the explanation described in this Section is provided to the Participant;

(4) the Benefit Commencement Date is after the date the Administrator receives written notice of the Participant's intent to begin receiving benefits; and

(5) distribution to the Participant does not commence before the expiration of the 7-day period described in paragraph (3) above.

Notwithstanding the foregoing, effective for Plan Years beginning on or after January 1, 2004, the Participant's Benefit Commencement Date may precede the explanation described in this Section, if the Participant so elects, provided that the following conditions are satisfied:

(5) the date the on which the first payment to be received by the Participant is made (the "initial payment date") shall be no earlier than thirty (30) days following the date that the notice is furnished to the Participant, except that the initial payment date may be as early as the seventh day after such notice is provided if (i) such notice clearly indicates that the Participant has a right to a period of thirty (30) days after receiving the notice to consider to waive the basic forms of distribution provided under the Plan and to elect (with spousal consent) an optional form of benefit, (ii) the Participant affirmatively elects a form of distribution with the consent of his Spouse (if required) to commence as of the initial payment date, and (iii) the Participant is permitted to revoke such election until the initial payment date;

(6) the notice shall be provided to the Participant no more than ninety (90) days before the initial payment date, however, the Plan will not fail to satisfy the ninety (90)- day requirement if the delay in providing the distribution is due solely to an administrative delay;

(7) the Participant is not permitted to elect an Benefit Commencement Date that precedes the date upon which the Participant could have otherwise started receiving benefits under the terms of the Plan as in effect on the Benefit Commencement Date;

(8) to the extent that a Participant has not received any payments for the period from the Benefit Commencement Date to the initial payment date, the Participant shall receive a one-time payment to reflect any such missed payments (a "make-up payment"). Such make-up payment shall be adjusted for interest from the period beginning on the Benefit Commencement Date and ending on the initial payment date, which shall be calculated with respect to such payments that would have been received prior to the initial payment date. The interest rate used to compute the adjustment described in the preceding sentence shall equal the 30 Year Treasury rate for December of the preceding Plan Year. Notwithstanding the foregoing, with respect to any Annuity Starting Date on or after January 1, 2008, the interest rate used to compute the adjustment described in the sentence above shall be the interest rate as specified or prescribed by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3) of the Code, in revenue rulings, notices or other guidance for November of the preceding Plan Year. For purposes of Section 4.6 of the Plan, the limitations set forth

therein shall comply with the adjustments required thereto pursuant to Treasury Regulation 1.417(e)-1 with respect to any Benefit Commencement Date described in this paragraph which is a "retroactive annuity starting date" as defined for purposes of such Regulation; and

(9) if a Participant who is married elects to commence the Participant's benefit as of the initial payment date pursuant to this paragraph, then the Participant's Spouse (including an alternate payee who is treated as the Participant's spouse under a qualified domestic relations order), determined as of the initial payment date, must consent to such election if the survivor benefits payable as of the Benefit Commencement Date are less than the survivor benefits payable under the benefit described in Section 5.2(a) of the Plan as of the initial payment date.

(b) Each Eligible Participant described in Section 5.3(a) shall receive a written explanation of (1) the terms and conditions of the pre-retirement survivor annuity described in Section 5.4, (2) the Participant's right to waive such survivor annuity in favor of the death benefit under a Contingent Annuity Option and the effect of such waiver, (3) the rights of the Participant's Spouse with respect to such waiver, and (4) the Participant's right to revoke such waiver and the effect of such revocation. Such explanation shall be provided when the Participant first becomes an Eligible Participant described in Section 5.3(a) and, if the Eligible Participant has not attained Age 32 at the time of the first notice, again within the three-year period that begins on the first day of the Plan Year in which the Participant attains Age 32.

5.6 Cash-Outs. Effective on such date as shall be determined by the Company, if the Actuarial Equivalent single-sum value, determined as of the date of distribution, of the vested Accrued Benefit of a Participant who has had a Separation from Service, or of the benefit payable to a Spouse or other beneficiary under Section 5.3 or 5.4 by reason of the Participant's death prior to his Benefit Commencement Date, is $5,000 or less, or, for distributions occurring on or after March 28, 2005, $1,000 or less, the benefit shall be paid, as soon as administratively practicable following the later of (a) the Participant's Separation from Service or death, or (b) the effective date of this Section 5.6, as a single-sum in settlement of all liabilities of the Plan in connection with the Participant; provided, however, that no such payment shall be made after such benefit has commenced in any other form.

5.7 Spousal Consent. No Participant's election:

(a) to waive the Qualified Joint and Survivor Annuity in favor of a form of payment other than a Contingent Annuity Option providing for payment of at least 50% of the Participant's annuity to his surviving Spouse, or

(b) to waive the death benefit described in Section 5.4 in favor of the death benefit payable under a form of payment other than a Contingent Annuity Option described in Paragraph (a), above,

shall be effective with respect to a Participant who is married unless the Participant's Spouse (as of the Benefit Commencement Date or date of death, whichever applies) consents thereto in writing, and such consent (1) acknowledges the effect of the election, (2) specifies the designated beneficiary or consents to such designation and consents prospectively to any subsequent designation of beneficiary made by the Participant, acknowledging the Spouse's right to limit consent to a specific alternate beneficiary, (3) specifies the optional form of payment or consents to such election and consents prospectively to any subsequent choice of optional form made by the Participant, acknowledging the Spouse's right to limit consent to a specific optional form, and (4) is witnessed by a Plan representative or by a notary public, or the Administrator finds that the Spouse cannot be located.

5.8 Minimum Distribution Requirements. Notwithstanding anything in the Plan to the contrary, the form and timing of all distributions under the Plan to any Participant, including a Participant whose Separation from Service occurred prior to January 1, 1989, shall be in accordance with Section 401(a)(9) of the Code and regulations issued thereunder, including the incidental death benefit requirements of Section 401(a)(9)(G) of the Code and Treas. Reg. §1.401(a)(9)-2.

5.9 Application for Benefits. Except as provided in Section 5.6 or in Section 5.3(c) for a non-Spouse contingent beneficiary, benefit payments shall commence when properly written application for same is received by the Administrator. In the event that a Participant, or the Spouse of a deceased Participant entitled to benefits under the Plan fails to apply to the Administrator by the earlier of (a) the Participant's Normal Retirement Date or the date of the Participant's Separation from service, if later, or (b) the end of the calendar year in which the Participant attains age 70-1/2, the Administrator shall make diligent efforts to locate such Participant or Spouse and obtain such application. In the event the Participant or Spouse fails to make application by the Participant's Required Beginning Date, subject to Section 10.6, the Administrator shall commence distribution as of the Required Beginning Date without such application. No payments shall be made for the period in which benefits would have been payable if the Participant or Spouse had made timely application therefor; provided, however, that, if the Participant's Benefit Commencement Date or, if the Participant has died, his Spouse's Benefit Commencement Date, has been delayed until after the Participant's Normal Retirement Date solely by reason of failure to make application, and not by reason of Suspension Service as described in Section 4.11(b), the benefit payable (i) to the Participant on and after his Benefit Commencement Date, or (ii) to the Participant's Spouse on and after the Spouse's Benefit Commencement Date, shall be equal to the Actuarial Equivalent of the benefit the Participant or the Spouse would have received had benefits commenced on the Participant's Normal Retirement Date, as determined to reflect the deferral of benefit commencement.

5.10 Direct Rollovers. In the event any payment or payments under the Plan to be made to a "eligible distributee" would constitute an "eligible rollover distribution," such eligible distributee may request that, in lieu of payment to the eligible distributee, all or part of such payment or payments be rolled over directly from the Trustee to the trustee of an "eligible retirement plan." Any such request shall be made at the time and in the manner prescribed by the Administrator or its delegate, subject to such requirements and restrictions as may be prescribed by applicable Treasury regulations. For purposes of this Section 5.10:

(a) "eligible distributee" shall include the Participant, his Spouse or his alternate payee under a qualified domestic relations order within the meaning of Section 414(p) of the Code or, effective January 1, 2008, the Participant's beneficiary who is not the Participant's Spouse;

(b) “eligible rollover distribution” shall mean a distribution from the Plan, excluding (i) any distribution that is one of a series of substantially equal periodic payments (not less frequently than annually) over the life (or life expectancy) of the eligible distributee, the joint lives (or joint life expectancies) of the eligible distributee and eligible distributee’s designated beneficiary, or a specified period of ten (10) or more years, and (ii) any distribution to the extent such distribution is required under Section 401(a)(9) of the Code; and

(c) “eligible retirement plan” shall mean (i) an individual retirement account described in Section 408(a) of the Code, (ii) an individual retirement annuity described in Section 408(b) of the Code, (iii) an annuity plan described in Section 403(a) of the Code, (iv) a qualified plan the terms of which permit the acceptance of rollover distributions, (v) an eligible deferred compensation plan described in Section 457(b) of the Code that is maintained by an eligible employer described in Section 457(e)(i)(A) of the Code that shall separately account for the distribution, (vi) an annuity contract described in Section 403(b) of the Code or (vii) an individual retirement plan described in Section 408A (b) of the Code; provided, however, that (x) with respect to a plan described in clause (vii), for transfers occurring before January 1, 2010, the eligible distributee meets the requirements of Section 408A(c)(3)(B) of the Code and (y) with respect to a distribution (or portion of a distribution) to a person who is not the Participant or the surviving Spouse of the Participant, “eligible retirement plan” shall mean only a plan described in clause (i) or (ii) or, effective January 1, 2010, clause (vii), that, in either case, is established for the purpose of receiving such distribution on behalf of such person.

5.11. Special Lump Sum Payment Option. (a) Eligibility. A Participant (but not his or her Beneficiary) may elect to receive, during the election period described in Paragraph (b), his or her deferred Accrued Benefit (“Deferred Annuity”) under Section 4.4 of the Plan in the form of a lump sum payment (“Special Lump Sum Payment”) or, an “Immediately Commencing Annuity” (as defined below); provided, however, that:

(i) the Participant has a termination of employment on or prior to June 30, 2012 and does not die and is not rehired during the period beginning July 1, 2012 and ending on the date payment is made or commences in accordance with this Section 5.11;

(ii) such termination of employment is not on account of the Participant’s disability, following which the Participant is receiving long-term disability payments under any long-term disability program of an Employer, including on June 30, 2012;

(iii) the Participant’s Deferred Annuity is not subject to a qualified domestic relations order as defined in Section 414(p) of the Code;

(iv) the Participant is not immediately, as of his or her termination of employment, eligible for early retirement benefits in accordance with this Article IV;

(v) the Participant is not on a leave of absence or layoff from an Employer on June 30, 2012;

(vi) the Participant is not 70 1/2 years of age or older as of October 1, 2012; and

(vii) the Participant can be located, after a diligent search, as necessary, by the Plan Administrator before July 1, 2012.

For each such Participant described in this Paragraph (a), the term "Immediately Commencing Annuity" shall mean, as applicable, either:

(i) with respect to a Participant eligible to commence receipt of his or her Deferred Annuity as of December 1, 2012, in accordance with the requirements of Section 4.4, any applicable optional form of annuity described in Article V; or

(ii) with respect to any other Participant, a single life annuity, 50% "qualified joint and survivor annuity" (within the meaning Section 417(b) of the Code) or a 75% "qualified optional survivor annuity" (within the meaning Section 417(g) of the Code).

(b) Election and Election Period. To receive the distribution of benefits described in Paragraph (a), an eligible Participant must voluntarily elect to receive a distribution pursuant to this Section 5.11 by completing an election form and spousal waiver, if required, provided by the Administrator, and submitting such forms to the Administrator after October 1, 2012 and before the following dates, as applicable,

(i) November 15, 2012, with respect to a Participant who elects a Special Lump Sum Payment; and

(iii) December 15, 2012, with respect to a Participant who elects an Immediately Commencing Annuity,

or such other period during 2012 determined by the Administrator.

The Administrator shall provide each eligible Participant, not less than 30 days and not more than 180 days before the Benefit Commencement Date, an application form including a general description of the material features, as well as an explanation of the relative values and financial effect, of the optional forms of benefit available under this Section 5.11, in a manner that satisfies the notice requirements of Section 417(a)(3) of the Code and the regulations thereunder. The form shall indicate the Participant's right to waive a survivor annuity, his or her surviving Spouse's right to consent to such waiver or refuse such consent, and the right to revoke any waiver, within the 180 day period

preceding the Benefit Commencement Date, and shall include a description of the right of the Participant, if any, to defer receipt of a distribution and the consequences of failure to defer such receipt, in accordance with Treasury guidance under Section 411(a)(11) of the Code.

(c) Amount of Payment. The Special Lump Sum Payment shall equal the actuarial equivalent of the Participant's nonforfeitable Deferred Annuity, based on the following factors:

(i) the applicable interest rate described in Section 417(e)(3) of the Code for August of 2011;

(ii) an assumed commencement date of the later of (A) age 65, and (B) the Participant's age as of December 1, 2012; and

(iii) the applicable mortality table, as defined in Section 417 of the Code and the regulations promulgated thereunder.

The Immediately Commencing Annuity shall be calculated:

(i) in accordance with the applicable terms of the Plan, for a Participant who is eligible to immediately commence benefits under the terms of the Plan as of the payment date set forth in Paragraph (d); and

(ii) as the actuarial equivalent of the Special Lump Sum Payment, for each other Participant.

(d) Payment of Benefit. If an eligible Participant elects the distribution of his or her Deferred Annuity in accordance with this Section 5.11, payment shall be made, or commence to be made, on or before December 1, 2012, or as soon as administratively practicable thereafter.

(e) Death and Rehire. If an eligible Participant elects the distribution of his or her Deferred Annuity in accordance with this Section 5.11 and subsequently dies or is rehired as an Employee before distributions commence, his or her election shall be null and void and the Participant's benefit shall be paid pursuant to the Plan without regard to this Section 5.11. Notwithstanding anything contained herein to the contrary, upon distribution of a Special Lump Sum Payment or an Immediately Commencing Annuity made to an individual in accordance with this Section 5.11, in the event of the individual's rehire with an Employer following the date such distribution is made, the individual shall not be eligible to participate in the Plan during such period of rehire and may be eligible to participate in the Exelon Corporation Cash Balance Pension Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees (or such other plan that applies to employees of an Employer hired on or after December 1, 2012), as applicable, in accordance with their terms and conditions.

ARTICLE VI. Breaks in Service.

6.1 Whenever used in this Article:

(a) “One-Year Break in Service” means a calendar year in which an Employee completes 500 or fewer Hours of Service.

(b) “Reemployment Date” means the first day on which an Employee who has had a Separation from Service completes an Hour of Service in a calendar year that is not a One-Year Break in Service.

(c) “Reemployment Eligibility Computation Period” means an Eligibility Computation Period determined as if the Employee’s Employment Date were his Reemployment Date.

6.2 If an Employee has a Separation from Service before he has met the requirements for retirement under Sections 4.1-4.3 or for a deferred annuity under Section 4.4, he shall be deemed to have received a distribution of his entire nonforfeitable Accrued Benefit of zero dollars upon such Separation from Service and his Eligibility Years, Accrued Benefit, Benefit Years, and Vesting Years shall be canceled.

6.3 If an Employee completes at least 1000 Hours of Service in a Reemployment Eligibility Computation Period he shall be credited with an Eligibility Year.

6.4 (a) The Eligibility Years of an Employee whose Eligibility Years have been canceled shall be restored if:

(1) he is credited with an Eligibility Year with respect to a Reemployment Eligibility Computation Period that begins on or after his Reemployment Date; and

(2) he again becomes an Employee at a time when the number of consecutive One-Year Breaks in Service he has incurred is less than the greater of five or the number of Eligibility Years the Employee had to his credit on account of his employment prior to the first One-Year Break in Service.

(b) If a former Employee whose Eligibility Years were not canceled under Section 6.2 or are restored under this Section becomes an Eligible Employee, he shall become an Active Participant as of the later of the day he so becomes an Eligible Employee or the day he would have become an Active Participant under Article II if he had been an Eligible Employee at all times since his prior Separation from Service. If a former Employee whose Eligibility Years were canceled under Section 6.2 and are not restored under this Section becomes an Eligible Employee, he shall become an Active Participant as provided in Article II, except that his Reemployment Date shall be treated as his Employment Date.

6.5 The Benefit Years and Accrued Benefit of an Employee whose Benefit Years have been canceled shall be restored upon his reemployment if his Eligibility Years are restored under Section 6.4. If a Participant's Benefit Years and Accrued Benefit were not canceled pursuant to Section 6.2 upon his prior Separation from Service, his Benefit Years earned prior to his Separation from Service shall be aggregated with his Benefit Years earned after his Reemployment Date for purposes of determining the Participant's Accrued Benefit; provided, however, that:

(a) if the Participant previously received a single-sum distribution under Section 5.6 on or before the close of the second Plan Year following the Plan Year in which the Participant's Separation from Service occurred, the Participant's Benefit Years earned prior to his Separation from Service shall be disregarded upon his reemployment; or

(b) if the Participant received a single-sum distribution under Section 5.6 on a date later than that described in Paragraph (a), the Participant's Accrued Benefit determined on and after his reemployment shall be reduced by the Actuarial Equivalent of the distribution received by the Participant under Section 5.6 upon his prior Separation from Service.

6.6 The Vesting Years of an Employee whose Vesting Years have been canceled shall be restored if:

(a) he is credited with a Vesting Year after his Reemployment Date; and

(b) he again becomes an Employee at a time when the number of consecutive One-Year Breaks in Service he has incurred is less than the greater of five or the number of Vesting Years the Employee had to his credit on account of his employment prior to the first One-Year Break in Service.

6.7 Notwithstanding any provision in the Plan to the contrary, effective January 1, 1996, an Employee who was transferred to COPCO and whose benefits were transferred from the Plan in connection with the sale of COPCO shall receive, upon such Employee's Reemployment Date, credit for years of service with the Company prior to such transfer for purposes of calculating Eligibility Years and Vesting Years (but not Benefit Years).

ARTICLE VII. Contributions.

7.1 Contributions by the Company. The Company shall contribute each year an amount actuarially determined to be sufficient to provide the benefits under the Plan. All Company contributions to the Plan are conditioned upon their deductibility for Federal income tax purposes. The Company reserves the right, however, to reduce, suspend or discontinue its contributions under the Plan for any reason at any time. Except as provided in this Section or Section 9.2, it shall be impossible for any part of the Company's contributions to revert to the Company, or to be used for, or diverted to, any purpose other than for the exclusive benefit of Participants, annuitants and their beneficiaries. In the case of a contribution (a) made by the Company as a mistake of fact, or (b) for which a tax deduction is disallowed, in whole or in part, by the Internal Revenue Service, the Company shall receive a refund of said contribution within one year after payment of a contribution as a mistake of fact, or within one year after disallowance of a tax deduction, to the extent of such disallowance, as the case may be.

7.2 Source of Benefits. All benefits under the Plan shall be paid exclusively from the Fund, and the Company shall have no duty to contribute thereto except as provided in this Article.

ARTICLE VIII. Administration.

8.1 The Administrator. (a) In General . The Company acting through its Vice President, Health & Benefits, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such vice president or other person or committee, the "Administrator"), shall be the "administrator" of the Plan, within the meaning of such term as used in ERISA. In addition, the Administrator shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan's assets. The Administrator shall have the following duties, responsibilities and rights:

(i) The Administrator shall have the duty and discretionary authority to interpret and construe this Plan in regard to all questions of eligibility, the status and rights of Participants, Retirees, Beneficiaries and other persons under this Plan, and the manner, time, and amount of payment of any distributions under this Plan. The determination of the Administrator with respect to an Employee's years of Credited Service, the amount of the Employee's Earnings, Highest Average Annual Pay, Federal Benefit and any other matter affecting payments under the Plan shall be final and binding. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Administrator, in his discretion, determines that such person is entitled to benefits.

(ii) Each Employer shall, from time to time, upon request of the Administrator, furnish to the Administrator such data and information as the Administrator shall require in the performance of his duties.

(iii) The Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust under Article 6 (relating to Service Annuity forms). In addition, it shall be the duty of the Administrator to certify to the Trustee the names and addresses of all Retirees, the amounts of all Service Annuities, the dates of death of Retirees and all proceedings and acts of the Administrator necessary or desirable for the Trustee to be fully informed as to the Service Annuities to be paid out of the Trust.

(iv) The Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Office, the Corporate Investment Committee or the Trustee.

(v) The Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Administrator and to furnish such information requested by the Administrator. The Administrator and the Plan may rely upon all such information so furnished to the Administrator.

(vi) The Administrator shall be the Plan's agent for service of legal process and forward all necessary communications to the Trustee.

(b) Removal of Administrator . The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Administrator (including any member of a committee that constitutes the Administrator). The Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer or upon the Administrator's termination of employment with the Employers. Upon the resignation, removal or failure or inability for any reason of the Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any officer, employee or member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Administrator.

8.2 The Investment Office. The Investment Office shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in Section 404(a)(2) of ERISA and all other applicable limitations. In addition to the duties, responsibilities and rights of the Investment Office set forth in Article 8, the Investment Office shall have the following duties, responsibilities and rights:

(i) The Investment Office shall be the "named fiduciary" for purposes of directing the Trustee as to the investment of amounts held in the Fund and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Office shall submit to the Corporate Investment Committee annual manager review results and such other reports and documents as may be necessary for the Corporate Investment Committee to monitor the activities and performance of the Investment Office.

(iii) Each Employer shall, from time to time, upon request of the Investment Office, furnish to the Investment Office such data and information as the Investment Office shall require in the performance of its duties.

8.3 The Corporate Investment Committee. The Company acting through the Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Office. The Corporate Investment Committee shall have the following duties, responsibilities and rights:

(i) The Corporate Investment Committee shall monitor the activities and performance of the Investment Office and shall review annual manager review results and any other reports and documents submitted by the Investment Office.

(ii) The Corporate Investment Committee shall have authority to approve asset allocation recommendations of the Investment Office, and approve the retention or firing of any investment consultant (but not any investment manager), custodian or trustee, as recommended by the Investment Office.

(iii) The Corporate Investment Committee and the Company's Chief Investment Officer shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Office. Any successor Investment Office employee shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor.

The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the employees of the Investment Office and approval of the recommendations specified in clause (ii) above. The Corporate Investment Committee shall have no responsibility for making investment decisions, appointing or firing investment managers or for any other duties or responsibilities with respect to the Plan, other than those specifically listed herein.

8.4 Status of Administrator, the Investment Office and the Corporate Investment Committee. The Administrator, any person acting as, or on behalf of, the Investment Office, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee or officer of an Employer and such status shall not disqualify such person from taking any action hereunder or render such person accountable for any distribution or other material advantage received by him under this Plan, provided that no Administrator, person acting as, or on behalf of, the Investment Office, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Administrator or the Investment Office on any matter involving solely his rights under this Plan.

8.5 Notice to Trustee of Members. The Trustee shall be notified as to the names of the Administrator and the person or persons authorized to act on behalf of the Investment Office.

8.6 Allocation of Responsibilities. Each of the Administrator, the Investment Office and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

8.7 General Governance. The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Administrator, the Investment Office and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

8.8 Indemnification. The Employers hereby jointly and severally indemnify the Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

8.9 No Compensation. None of the Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Administrator, Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Affiliate for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

8.10 Employ of Counsel and Agents. The Administrator, the Investment Office and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

8.11 Claims Procedures. Any Participant or distributee who believes he is entitled to benefits in an amount greater than those which he is receiving or has received may file a claim with the Administrator (or its delegate). Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Administrator (or its delegate) shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable regulations. If it is determined that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which it is expected that the benefit determination will be rendered. The notice of the decision with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right to bring a civil action under Section 502 of ERISA following an adverse benefit determination on review. The notice shall also advise the

claimant that the claimant or the claimant's duly authorized representative may request a review by the Administrator (or its delegate) of the adverse benefit determination by filing, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he (a) may be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by the Administrator (or its delegate) within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the final decision. If it is determined that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the determination on review is expected to be rendered. The review shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

8.12 Actuary to Be Employed. The Company or the Investment Office shall engage an actuary to do such technical and advisory work as the Company or the Investment Office may request, including analyses of the experience of this Plan from time to time, the preparation of actuarial tables for the making of computations thereunder, and the submission to the Company or the Investment Office of an annual actuarial report, which report shall contain information showing the financial condition of this Plan, a statement of the contributions to be made by the Employers for the ensuing year, and such other information as may be requested by the Company or the Investment Office.

8.13 Funding Policy. The board of directors of the Company shall establish a funding policy and method consistent with the objectives of this Plan and the requirements of Title I of ERISA and shall communicate such policy and method, and any changes in such policy and method, to the Investment Office.

8.14 Notices to Participants, Etc. All notices, reports and statements given, made, delivered or transmitted to a Participant or any other person entitled to or claiming benefits under this Plan shall be deemed to have been duly given, made or transmitted when mailed by first class mail with postage prepaid and addressed to the Participant or such other person at the address last appearing on the records of the Administrator.

8.15 Notices to Employers or Administrator. Written directions, notices and other communications from Participants or any other person entitled to or claiming benefits under this Plan to the Employers or Administrator shall be deemed to have been duly given, made or transmitted either when delivered to such location as shall be specified upon the forms prescribed by the Administrator for the giving of such directions, notices and other communications or when mailed by first class mail with postage prepaid and addressed to the addressee at the address specified upon such forms.

8.16 Records. Each of the Administrator, the Investment Office and the Corporate Investment Committee shall keep a record of all of their respective proceedings, if any, and shall keep or cause to be kept all books of account records and other data as may be necessary or advisable in their respective judgment for the administration of the Plan, the administration of the investments of the Plan or the monitoring of the investment activities of the Plan, as applicable.

8.17 Responsibility to Advise Administrator of Current Address. Each person entitled to receive a payment under this Plan shall file with the Administrator in writing such person's complete mailing address and each change therein. A check or communication mailed to any person at such person's address on file with the Administrator shall be deemed to have been received by such person for all purposes of this Plan. Although neither the Administrator nor the Trustee shall be obliged to search for or ascertain the location of any person, the Administrator shall make reasonable efforts to locate any missing Participant or Beneficiary entitled to benefits hereunder. If the Administrator is in doubt as to whether payments are being received by the person entitled thereto, it shall, by registered mail addressed to the person concerned at his last address known to the Administrator, notify such person that all future payments will be withheld until such person submits to the Administrator evidence of his continued life and proper mailing address.

8.18 Electronic Media. Notwithstanding any provision of the Plan to the contrary and for all purposes of the Plan, to the extent permitted by the Administrator and any applicable law or Regulation, the use of electronic technologies shall be deemed to satisfy any written notice, consent, delivery, signature, disclosure or recordkeeping requirement under the Plan, the Code or ERISA to the extent permitted by or consistent with applicable law and Regulations. Any transmittal by electronic technology shall be deemed delivered when successfully sent to the recipient, or such other time specified by the Administrator.

8.19 Correction of Error. If it comes to the attention of the Administrator that an error has been made in the amount of benefits payable, or paid, to any Participant or Beneficiary under the Plan, the Administrator shall be permitted to correct such error by whatever means that the Administrator, in its sole discretion determines, including by offsetting future benefits payable to the Participant or Beneficiary or requiring repayment of benefits to the Plan, except that no adjustment need be made with respect to any Participant or Beneficiary whose benefit has been distributed in full prior to the discovery of such error.

8.20 Applicable Law. Except to the extent preempted by applicable federal law or otherwise provided under the terms of the Plan, the Plan and all rights hereunder shall be governed by and construed in accordance with the laws of the State of Illinois.

8.21 Statute of Limitations for Actions under the Plan. Except for actions to which the statute of limitations prescribed by Section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under Section 502 of ERISA may be commenced later than one year after the claimant receives a final decision from the Chief Human Resources

Officer (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

8.22 Forum for Legal Actions under the Plan. Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in the Northern District of Illinois or the Eastern District of Pennsylvania, whichever is most convenient, and no other federal or state court.

8.23 Legal Fees. Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, the Investment Office, the Corporate Investment Committee, any Plan fiduciary, the Chief Human Resources Officer, any Plan administrator, the Company, its affiliates or their respective officers, directors, employees, or agents (the "Plan Parties"), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

ARTICLE IX. Amendment and Termination.

9.1 Amendment. Exelon Corporation may amend the Plan at any time for any reason. Each amendment to the Plan shall be adopted by Exelon Corporation's Board of Directors (or a committee thereof); provided, however, that in the case of any amendment or modification that would not result in an aggregate annual cost to the Company of more than $50,000,000, the Plan may be amended or modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability account balance exceeding $250,000) or another executive officer holding title of equivalent or greater responsibility. If an amendment changes the vesting provisions of the Plan, any person who is a Participant on the later of the date the amendment is adopted or becomes effective shall have at all times a vested interest in his Accrued Benefit as of that date determined without regard to the amendment. In addition, within a reasonable period determined by the Exelon Corporation in accordance with regulations issued by the Secretary of the Treasury, any Participant who has at least three Vesting Years to his credit on the last day of the election period may elect to have his vested interest in his entire Accrued Benefit determined without regard to the amendment. Except as otherwise permitted by law, no amendment shall reduce a Participant's Accrued Benefit nor result in the elimination or reduction of a benefit "protected" under Section 411(d)(6) of the Code.

9.2 Termination. Exelon Corporation may terminate or partially terminate the Plan through resolutions adopted by Exelon Corporation's Board of Directors. If the Plan is terminated or partially terminated, the assets of the Plan shall be allocated, subject to Section 9.3, as provided in Section 4044 of the Employee Retirement Income Security Act of 1974 (as it may be from time to time amended or construed by any appropriate governmental agency or corporation), without subclasses. Any amount remaining after all fixed and contingent liabilities of the Plan have been satisfied shall be returned to Exelon Corporation. Allocations under this Section shall be nonforfeitable. Except as otherwise required by law, the time and manner of distribution of the assets shall be determined by Exelon Corporation by amendment to the Plan pursuant to Section 9.1.

9.3 Limitation on Benefits. The following provisions shall be effective with respect to distributions made on or after May 14, 1990; distributions made prior to May 14, 1990 shall be subject to the restrictions described in Treas. Reg. §1.401-4(c).

(a) In the event of Plan termination, the benefit payable to any Highly Compensated Employee shall be limited to a benefit that is nondiscriminatory under Section 401(a)(4) of the Code. If payment of benefits is restricted in accordance with this Paragraph (a), assets in excess of the amount required to provided such restricted benefits shall become a part of the assets available under Section 9.2 for allocation among Participants and beneficiaries of Participants whose benefits are not restricted under this Paragraph (a).

(b) The restrictions of this Paragraph (b) shall apply prior to termination of the Plan to any Participant who is a Highly Compensated Employee and who is one of the 25 highest paid employees or former employees of the Company and all Affiliates for any Plan Year. The annual payments made from the Plan on behalf of any such Participant shall be limited to an amount equal to (1) the payments that would have been made under a single life annuity that is the Actuarial Equivalent of the sum of the Participant's Accrued Benefit and any other benefits under the Plan (other than a social security supplement) and (2) the payments that the Participant is entitled to receive under a social security supplement.

(c) The restrictions in Paragraph (b) shall not apply:

(1) if, after the payment of benefits to or on behalf of such Participant, the value of the Plan assets equals or exceeds 110 percent of the value of the current liabilities (within the meaning of Section 412(l)(7) of the Code);

(2) if the value of the benefits payable to or on behalf of the Participant is less than one percent (1%) of the value of current liabilities before distribution; or

(3) if the value of the benefits payable to or on behalf of the Participant does not exceed $5,000.

ARTICLE X. Miscellaneous.

10.1 Forfeitures. All forfeitures arising under the Plan shall be used as soon as possible to reduce the Company's contributions and shall not be applied to increase the benefits any person would otherwise receive under the Plan.

10.2 Mergers, Etc. No merger or consolidation with, or transfer of any of the Plan's assets or liabilities to, any other plan shall occur at any time unless each Participant and annuitant would (if the Plan had then terminated) receive a benefit immediately after the merger, consolidation, or transfer which is equal to or greater than the benefit he would have been entitled to receive immediately before the merger, consolidation, or transfer (if the Plan had then terminated).

10.3 Nonalienation of Benefits. Except (a) to the extent permitted by the Employee Retirement Income Security Act of 1974, (b) pursuant to a qualified domestic relations order, (c) to the extent required to satisfy a Federal tax levy made pursuant to Section 6331 of the Code, or (d) effective as of January 1, 1997, pursuant to Section 401(a)(13) of the Code, to the extent a judgment relates to the Participant's conviction of a crime involving the Plan, or a judgment, order, decree or settlement agreement between the Participant and the Secretary of Labor or the Pension Benefit Guaranty Corporation relates to a violation of part 4 of subtitle B of title I of ERISA, no benefit under this Plan may be voluntarily or involuntarily assigned or alienated. Notwithstanding the above, a Participant may authorize the Administrator to deduct from benefit payments under the Plan up to 10% of each such payment as contributions to a Company political action committee. Any such authorization shall be revocable by the Participant at any time.

10.4 Effect on Employment. This Plan shall not confer upon any person any right to be continued in the employment of the Company.

10.5 Facility of Payment. If the Company deems any person incapable of receiving benefits to which he is entitled by reason of minority, illness, infirmity, or other incapacity, it may direct that payment be made directly for the benefit of such person or to any person selected by the Company to disburse it, whose receipt shall be a complete acquittance therefor. Such payments shall, to the extent thereof, discharge all liability of the Company and the party making the payment.

10.6 Lost Payees. If a Participant, Spouse or other beneficiary to whom a benefit is payable under the Plan cannot be located following a reasonable effort to do so by the Administrator, such benefit shall be forfeited. Whether or not efforts to locate a Participant have previously been made, the Administrator shall make reasonable efforts to locate the Participant (or the Spouse of a deceased Participant) during the one-year period preceding the Participant's Required Beginning Date. If such efforts fail to locate the Participant or Spouse, such Participant or Spouse shall be presumed dead as of the Required Beginning Date and any benefit payable to the Participant or Spouse shall be forfeited. In any case, if a claim for a forfeited benefit is subsequently filed by the Participant, Spouse or beneficiary, such benefit shall be reinstated and paid in accordance with the appropriate provisions of the Plan.

10.7 Effective Date. The provisions of this instrument apply only to individuals who complete an Hour of Service on or after the effective date stated under the title of the Plan on page one. The eligibility and benefits of any other person shall be determined under the Plan as in effect when he last separated from service except as expressly provided with respect to him by amendment adopted thereafter; and except that the provisions of Section 2.10 (relating to rehire of Employees), Section 2.11 (relating to change in employment status or transfer to affiliate), Section 4.6 (relating to maximum annuity), Section 4.12 (relating to benefit restrictions as a result of funding), Article VIII (relating to administration), Article IX (relating to amendment and termination of the Plan), and this Article X (relating to miscellaneous provisions) shall be effective for all such persons.

10.8 Expenses. The expenses of the Trustee in the administration of the Trust, including compensation, if any, to the Trustee for its services, shall be paid by the Company or the Employers. All costs and expenses incurred in the operation of the Trust, to the extent not described in the preceding sentence, and all costs and expenses incurred in the operation of the Plan and the Trust, including, but not limited to, "direct expenses" incurred in administering the Plan and the Trust (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan or the Trust), the expenses of the Administrator, the Investment Office and the Corporate Investment Committee, the fees of counsel and any agents for the Trustee, the Administrator, the Investment Office or the Corporate Investment Committee, and the fees of investment managers that manage assets of the Trust shall be paid by the Trustee from the Trust in such proportion as the Investment Office, in its sole discretion, shall determine, to the extent such expenses are not paid by the Employers and to the extent permitted under ERISA, Regulations and other applicable laws. Any such expenses that are borne by the Employers shall be paid out of their own funds in such proportions as the Administrator shall determine. In the event that the Company or any other Employer advances money on behalf of the Trust for the payment of any expenses incurred in the operation of the Plan, the Trustee shall reimburse the Company or such other Employer from the Trust for any amount so advanced, without interest or fees.

ARTICLE XI. Top-Heavy Provisions.

11.1 Definitions. Whenever used in this Article:

"Determination Date" means, with respect to any Plan Year, the last day of the preceding Plan Year.

"Key Employee" means any Participant who, at any time during the Plan Year or any of the four preceding Plan Years, is an individual described in Section 416(i) of the Code and the regulations thereunder.

"Permissive Aggregation Group" means a group of qualified retirement plans maintained by the Company or any Affiliate, which group consists of the Required Aggregation group and any other plan or plans which, considered together with the Required Aggregation Group, meet the requirements of Sections 401(a)(4) and 410 of the Code.

"Required Aggregation Group" means the group of qualified retirement plans maintained by the Company or an Affiliate, including a frozen plan or a plan that has been terminated during the five-year period ending on the Determination Date, which group consists of this Plan, each other plan in which a Key Employee is a participant (or, in the case of a terminated plan was a participant in such five-year period) and each other plan that enables any such plan to meet the requirements of Section 401(a)(4) or 410 of the Code, but only if such group includes this Plan. Otherwise, the Required Aggregation Group consists of this Plan only.

"Top-Heavy Plan Year" means a Plan Year that begins after December 31, 1983, in which the Plan is top-heavy. The Plan is top-heavy for a given Plan Year if for that Plan Year (1) the Required Aggregation Group is top-heavy, and (2) the Required Aggregation Group is not part of a Permissive Aggregation Group that is not top-heavy. The Required Aggregation Group or a Permissive Aggregation Group (the "Group") is top-heavy for a given Plan Year if the present value of the cumulative accrued benefits (or, the aggregate of the accounts, in the case of a defined contribution plan included in such Group) of participants who are Key Employees exceeds 60% of the like amount determined for all participants in all plans included in such Group. For purposes of this definition:

(a) the present value of the accrued benefit or the account of any participant shall be increased by the amount of all plan distributions to such participant during the five year period ending on the Determination Date; provided that no such increase shall arise from any rollover contribution or plan-to-plan transfer from this Plan that is not initiated by the participant or is made to another plan maintained by the Company or an Affiliate;

(b) the present value of the accrued benefit or the account of a participant who has been a Key Employee but no longer is a Key Employee shall not be taken into account;

(c) the present value of the accrued benefit or the account of any Participant who has not performed services for the Company or an Affiliate at any time during the five-year period that ends on the Determination Date shall not be taken into account;

(d) any rollover contribution or plan-to-plan transfer to this Plan that is initiated by a participant and made from a plan that is not maintained by the Company or an Affiliate after December 31, 1983 shall not be taken into account;

(e) the five year period referenced above shall be changed to a one year period for all distributions made on account of a severance from employment, death, or disability; and

(f) the present value of accrued benefits shall be determined, effective January 1, 1987, under the method used for accrual purposes for all plans maintained by the Company and all Affiliates if a single method is used by all such plans, or, otherwise, the slowest accrual method permitted under Section 411(b)(1)(C) of the Code.

11.2 Top-Heavy Operating Rules. Anything in the Plan to the contrary notwithstanding, the following rules shall apply in a Top-Heavy Plan Year:

(a) For purposes of determining benefits under this Article XI, “compensation” shall mean compensation as reported on Forms W-2 by the Company or any Affiliate for such Plan Year and the maximum amount of compensation of any Participant who is an Employee during such Plan Year shall be $150,000, or such other amount as may apply to such Participant pursuant to Section 401(a)(17) of the Code and regulations issued thereunder.

(b) For purposes of determining the maximum annuity in Section 4.6 for Plan years beginning before January 1, 2000, “1.0” shall be substituted for “1.25”, wherever it appears.

(c) The Accrued Benefit which each Participant who is an Employee but not a Key Employee under this Plan derives from contributions by the Company shall be increased by the amount necessary to cause the Accrued Benefits payable to each Participant in such year, when expressed as a benefit payable annually in the form of a Single Life Annuity, to equal at least the required minimum benefit, where the required minimum benefit is the product of:

(1) the average of the Participant’s compensation for the five consecutive Plan Years that yield the highest average, disregarding Plan Years which begin before January 1, 1984, and Plan Years which are not Top-Heavy Plan Years, and

(2) the lesser of:

(A) 2 percent multiplied by the number of Vesting Years with the Company which were also Top-Heavy Plan Years and which were completed after January 1, 1984; or

(B) 20 percent.

For purposes of determining whether an increase in benefit accrual is required, all plans included in the Required Aggregation Group shall be treated as one plan.

(d) Anything in the Plan to the contrary notwithstanding, in any Top-Heavy Plan Year, a Participant who does not otherwise have a nonforfeitable right to 100% of his Accrued Benefit shall have a nonforfeitable right to a percentage of his Accrued Benefit in accordance with the following schedule:

Vesting Years	Nonforfeitable Percentage
2	20
3	40
4	60
5	100

In any Plan Year following the last Top-Heavy Plan Year, any Employee who is a Participant on the last day of the last Top-Heavy Plan Year shall have at all times a vested interest in his Accrued Benefit as of that date determined under the schedule set forth above. In addition, within a reasonable period determined by the Company, any Participant who has at least three Vesting Years to his credit on that date may elect to have his vested interest in his entire Accrued Benefit determined under the schedule set forth above.

ARTICLE XII. Post Retirement Health Benefits.

12.1 Eligibility

(a) Effective December 1, 1994, post-retirement health befits may be paid under this Article, to the extent the Company elects to fund benefits under this Article, to any Participant, who is receiving or has received pension benefits under this Plan, and if applicable, to the Spouse or dependents of such Participant; provided, however, that the Company may, in its discretion, decide not to provide post-retirement health benefits under this Article for Key Employees (as defined in Section 11.1) and, if applicable, their Spouses and dependents.

(b) In addition to satisfying the requirements of Subsection (a), any person claiming post-retirement health benefits under this Plan must meet all applicable requirements imposed in the post-retirement health plans maintained by the Company. All determinations of benefit levels and eligibility for benefits shall be made pursuant to the terms of such post-retirement health plans.

(c) The establishment of an account under this Article XII to provide payment for post-retirement health benefits shall not obligate the Company to maintain its post-retirement health plans, and the Company shall retain the same ability to amend or terminate such post-retirement health plans as if this Article XII did not exist.

Notwithstanding the foregoing, post-retirement health benefits shall not be available for any Power Team Employee.

12.2 Benefits Provided.

(a) Benefits under this Article shall include all health benefits provided by the post-retirement health plans maintained by the Company, including payment of Medicare Part B premiums to the extent provided by such post-retirement health plans, to the extent such benefits are not otherwise provided by the Company.

(b) Benefits under this Article shall be provided using any method or combination of methods as the Company shall deem appropriate, including, but not limited to , purchase of insurance and the payment of premiums for such insurance, direct reimbursement of costs incurred by the provider of such benefits or reimbursement to the individual to whom such benefits were provided.

(c) Benefits and coverage under this Article shall not be discriminatory in favor of officers, shareholders, supervisory employees or highly compensated employees.

12.3 Establishment of Accounts.

(a) A separate account shall be maintained with respect to the contributions to fund benefits under this Article. This account is to be maintained for accounting purposes only. Funds accounted for in such account may be invested on a commingled basis with pension benefit contributions under this Plan without identification of which investments are allocable to each account, provided that earnings on all Plan assets are allocated in a reasonable manner.

(b) If the Company elects to fund post-retirement health benefits for Key Employees under this Article, as separate account shall be maintained for post-retirement health benefits payable to each Key Employee, his Spouse and dependents. Benefits under this Article shall be payable to such Key Employee, Spouse and dependents only from such account. The separate account maintained under this Subsection (b) shall be a true separate account, and not maintained merely for accounting purposes. Commingling of assets held in such account with any other Plan assets is not permitted. For purposes of Section 415 of the Code contributions allocated to any separate account under this Subsection (b) shall be treated as an annual addition to a defined contribution plan.

12.4 Funding.

(a) Contributions to provide benefits under this Article may be contributory or non-contributory, in accordance with the terms of the post-retirement health plans maintained by the Company.

(b) Amounts contributed to fund post-retirement health benefits shall be reasonable and ascertainable. The total amount contributed to fund post-retirement health benefits under this Article shall not exceed the cost of providing such benefits. The total cost of providing such benefits shall be determined in accordance with a generally accepted actuarial method selected by the Company which is reasonable in view of the provisions and coverage of the Plan, the funding medium and other relevant considerations, including, but not limited to, applicable Treasury regulations. For purposes of determining the cost of providing post-retirement health benefits, the actuarial method may take into account reasonable projected increases in the cost of providing health benefits. Forfeitures, if any, under this Article shall be applied as soon as possible to reduce employer contributions to fund benefits under this Article.

(c) Post-retirement health benefits provided under this Article, when added to life insurance protection provided under the Plan, shall be incidental and subordinate to pension benefits provided under the Plan. For purposes of this Article, post-retirement health benefits shall be considered incidental and subordinate if the aggregate of the contributions for post-retirement health benefits provided under this Article plus the contributions for life insurance protection under this Plan does not exceed 25 percent of the total contributions to the Plan (other than for past service credit) made on or after December 1, 1994.

(d) Until the satisfaction of all liabilities to be provided under this Article, neither amounts contributed to fund post-retirement health benefits under this Article nor earnings thereon shall be used for or diverted to any purpose other than providing such benefits or payment of necessary or appropriate expenses attributable to the administration of post-retirement health accounts under this Article. Any amounts contributed to fund medical benefits under this Article remaining in a post-retirement health account after the satisfaction of all liabilities arising under this Article must be returned to the Company.

(e) Nothing in this Article shall obligate the Company to pay benefits described in Section 12.2 to the extent those benefits exceed assets contributed to the Fund to provide post-retirement health benefits under this Article. Furthermore, nothing in this Article shall imply that amounts contributed to the Fund to provide pension or other benefits (other than post-retirement health benefits) available under the Plan will be used to provide post-retirement health benefits under this Article. The Company may, in its discretion, fund all or any part of the benefits described in Section 12.2 from other sources or may pay such benefits out of its general assets as the benefits become payable.

(f) If in any proceeding subsequent to December 1, 1994, under Section 1308 of the Pennsylvania Public Utility Code, the Company is not permitted to fully recover in rates the contributions made to the separate account maintained to fund benefits under this Article, the Company, at its discretion, may elect to defer or discontinue funding the benefits under this Article.

IN WITNESS WHEREOF, the Company has caused this instrument to be executed by its duly authorized officer on this ____day of December, 2012.

EXELON CORPORATION

By _____
Sr. Vice President &
Chief Human Resources Officer

ATTEST:

_____

Title _____

SERVICE ANNUITY PLAN

APPENDIX A

Actuarial equivalence under this Plan shall mean a benefit of equivalent value when computed using a 7% interest rate and the mortality tables attached to the Plan as Exhibit A (for pensioners) and B (for beneficiaries, if applicable), with such exceptions as specifically set forth in the Plan.

For distributions on and after December 1, 2012, the lump sum Actuarial Equivalent of a Participant's Accrued Benefit for purposes of Section 5.6 only shall be determined using (i) the interest rate used shall be the interest rate as defined in Section 417(e)(3)(C) of the Code for the fifth month (or, if more favorable to the recipient of a lump sum payment between December 1, 2012 and December 1, 2013), the second month) preceding the calendar year in which such distribution is made or commences and (ii) the mortality table shall be the mortality table specified by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3) of the Code as in effect on the first day of the Plan Year in which the Benefit Commencement Date occurs. For distributions on or after January 1, 2008 and on or before November 30, 2012, the lump sum Actuarial Equivalent of a Participant's Accrued Benefit for purposes of Section 5.6 shall be determined by using (i) the interest rate as defined in Section 417 (e)(3)(C) of the Code for the second month preceding the calendar year in which such distribution is made or commences and (ii) the mortality table specified by the Commissioner of the Internal Revenue Service for purposes of Section 417(e)(3) of the Code as in effect on the first day of the Plan Year in which the Benefit Commencement Date occurs.

For distributions on or after January 1, 2000 and on or before December 31, 2007, the lump sum Actuarial Equivalent of a Participant's Accrued Benefit for purposes of Section 5.6 shall be determined using the annual rate of interest on 30-year Treasury securities as specified by the Commissioner of the Internal Revenue Service pursuant to Section 417(e)(3)(A) of the Code and regulations issued thereunder for the second full calendar month preceding the first day of the Plan Year containing the date of distribution, and the mortality table shall be the mortality table prescribed by the Commissioner of Internal Revenue Service pursuant to Section 417(e)(3)(A) of the Code on the date as of which the single sum payment is being determined, if the use of such assumptions would result in a greater benefit.

For the period beginning on or after January 1, 2000, and ending on or before December 31, 2001, and ending on the date of adoption of this amendment and restatement, the lump sum Actuarial Equivalent of a Participant's Accrued Benefit for purposes of Section 5.6 shall be determined on the basis of the assumptions which would be used as of the first day of the Plan Year containing the date of distribution by the Pension Benefit Guaranty Corporation for purposes of determining the present value of a lump sum distribution upon plan termination, if the use of such assumptions would result in a greater benefit.

APPENDIX B

MINIMUM DISTRIBUTION INCIDENTAL BENEFIT TABLE

Excess if Age of Participant over Age of Beneficiary	Applicable Percentage
10 years or less	100%
11	96%
12	93%
13	90%
14	87%
15	84%
16	82%
17	79%
18	77%
19	75%
20	73%
21	72%
22	70%
23	68%
24	67%
25	66%
26	64%
27	63%
28	62%
29	61%
30	60%
31	59%
32	59%
33	58%
34	57%
35	56%
36	56%
37	55%
38	55%
39	54%
40	54%
41	53%
42	53%
43	53%
44 and greater	52%

SCHEDULE A – RETIREMENT FACTORS

ENHANCED AGE AT BENEFIT COMMENCEMENT DATE	ENHANCED RETIREMENT FACTORS
50	80%
51	84%
52	88%
53	92%
54	96%
55	100%
56	100%
57	100%
58	100%
59	100%
60	100%
61	100%
62	100%
62	100%
63	100%
64	100%
65	100%

The foregoing factors will be interpolated based on the Eligible Participant’s Age rounded to the nearest month.

SCHEDULE B – ENHANCED DEFERRED VESTED PENSION FACTORS

	ACTUAL AGE VESTED BENEFITS BEGIN										
ENHANCED AGE AT TERMINATION	50	51	52	53	54	55	56	57	58	59	>=60
>=49	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%	88.0%	91.0%	94.0%	97.0%	100.0%
48	69.0%	72.1%	75.2%	78.3%	81.4%	84.5%	87.6%	90.7%	93.8%	96.9%	100.0%
47	68.0%	71.2%	74.4%	77.6%	80.8%	84.0%	87.2%	90.4%	93.6%	96.8%	100.0%
46	67.0%	70.3%	73.6%	76.9%	80.2%	83.5%	86.8%	90.1%	93.4%	96.7%	100.0%
45	66.0%	69.4%	72.8%	76.2%	79.6%	83.0%	86.4%	89.8%	93.2%	96.6%	100.0%
>45	Reverts to Standard Deferred Vested Pension Plan factors under the regular terms of the Service Annuity Plan.										

The foregoing factors will be interpolated on the Eligible Participant’s Age rounded to the nearest months.

Exhibit 10.6

EXELON CORPORATION
EMPLOYEE SAVINGS PLAN

Amended and Restated Effective as of January 1, 2013

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ARTICLE 1

TITLE, PURPOSE AND EFFECTIVE DATES

The title of this Plan shall be the "Exelon Corporation Employee Savings Plan." This Plan is an amendment and restatement of the Plan as in effect on December 31, 2012, and shall be effective January 1, 2013 in respect of Participants whose employment terminates on or after such date, provided , however, that any provision that specifies a different effective date shall be effective as of such date; and provided , further that, the provisions of Article 9 (relating to participants' stockholders rights), Article 10 (relating to special participation and distribution rules relating to reemployment of terminated employees and employment by related entities), Article 11 (relating to administration), Article 14 (relating to miscellaneous provisions) and Article 16 (relating to amendment and termination of the Plan) shall be effective for all such persons.

This Plan is designated as a "profit sharing plan" within the meaning of section 1.401-1(a)(2)(ii) of the Regulations; and is also designated as an ERISA section 404(c) Plan within the meaning of section 2550.404c-1 of the Regulations. In addition, the portion of the Plan invested in the Employer Stock Fund described in Section 6.2 is designated as an "employee stock ownership plan" within the meaning of section 4975(e)(7) of the Code and, as such, is designed to invest primarily in "qualifying employer securities" as defined in section 4975(e)(8) of the Code.

ARTICLE 2

DEFINITIONS

As used herein, the following words and phrases shall have the following respective meanings when capitalized:

(1) Administrator . The Company acting through its Director, Employee Benefit Plans & Programs, or such other person or committee appointed pursuant to Section 11.1 (relating to the Administrator, the Investment Office and the Corporate Investment Committee).

(2) Affiliate . (a) A corporation that is a member of the same controlled group of corporations (within the meaning of section 414(b) of the Code) as an Employer, (b) a trade or business (whether or not incorporated) under common control (within the meaning of section 414(c) of the Code) with an Employer, (c) any organization (whether or not incorporated) that is a member of an affiliated service group (within the meaning of section 414(m) of the Code) that includes an Employer, a corporation described in clause (a) of this subdivision or a trade or business described in clause (b) of this subdivision or (d) any other entity that is required to be aggregated with an Employer pursuant to Regulations promulgated under section 414(o) of the Code.

(3) After-Tax Contributions . Contributions made by a Participant pursuant to Section 5.1.

(4) After-Tax Contributions Account . The account established pursuant to Section 7.1 to which shall be credited (i) a Participant's After-Tax Contributions, (ii) any after-tax contributions transferred to the Plan from the PECO Energy Company Employee Savings Plan (including any after-tax contributions transferred to such plan from the Philadelphia Electric Company Tax Reduction Act Stock Ownership Plan) on behalf of such Participant and (iii) earnings (or losses) thereon.

(5) Before-Tax Contributions . Contributions made on behalf of a Participant pursuant to Section 4.1. The term "Before-Tax Contributions" includes Designated Roth Contributions, if any, including Catch-Up Contributions.

(6) Before-Tax Contributions Account . The account established pursuant to Section 7.1 to which shall be credited (i) a Participant's Before-Tax Contributions other than Catch-Up Contributions, (ii) any before-tax contributions transferred to the Plan from the PECO Energy Company Employee Savings Plan on behalf of such Participant and (iii) earnings (or losses) thereon.

(7) Beneficiary . The person or persons entitled under Section 8.5 to receive benefits in the event of the death of a Participant. For any period in which the Plan is not an "ERISA section 404(c) Plan" as defined in the Regulations under section 404(c) of ERISA, each Beneficiary shall be a "named fiduciary" within the meaning of section 402(a)(1) of ERISA for the sole purpose of directing the Trustee with respect to the exercise of shareholder rights pursuant to Article 9 (relating to Participants' stockholder rights).

(8) Catch-Up Contributions . Before-Tax Contributions made pursuant to paragraph (d) of Section 4.1 (relating to Catch-Up Contributions) by a Participant who has attained age 50 before the close of the relevant Plan Year.

(9) Catch-Up Contributions Account . The account established pursuant to Section 7.1 for each Participant who has attained age 50 to which shall be credited a Participant's Catch-Up Contributions

(10) CEG . Constellation Energy Group, Inc. and any of its affiliates that was an affiliate immediately before the Effective Time (as such term is defined in the Merger Agreement).

(11) Code . The Internal Revenue Code of 1986, as amended.

(12) Common Stock . The common stock, without par value, of Exelon Corporation.

(12) Company . Exelon Corporation, a Pennsylvania corporation, or any successor to such corporation that adopts the Plan pursuant to Article 13 (relating to continuance by a successor).

(13) Compensation . The normal base pay under the applicable Exelon East or West payroll of an Employee from an Employer for personal services rendered, including (i) nuclear license premiums for management employees, (ii) meter readers' bonuses, (iii) payments attributable to worker's compensation received from an Employer, (iv) taxable payments received by an employee under the Exelon Corporation Disability Benefit Plan, (v) solely for employees who are employed by Exelon Boston Services LLC who are represented by Local 369 of the Utility Workers Union of America, AFL-CIO, overtime pay, (vi) solely for employees who are represented by IBEW Local Union 15 and covered under the collective bargaining agreement between Commonwealth Edison Company and IBEW Local Union 15, overtime pay, but only amounts paid with respect to hours worked in excess of an Employee's normally scheduled hours, (vii) effective January 1, 2009, differential wage payments (as defined in section 3401(h) of the Code), and excluding (i) salary continuation or lump sum payments under a severance benefit plan, or other severance arrangement, of an Employer, (ii) bonuses or incentive awards (other than meter readers' bonuses), (iii) overtime pay for management employees, (iv) shift premiums, (v) fringe benefits, (vi) other extraordinary payments and (vii) payments made in a form other than cash, but without reduction on account of the Employee's election to have his or her pay reduced pursuant to a qualified cash or deferred arrangement described in section 401(k) of the Code (including any such election to make a Designated Roth Contribution), a qualified transportation fringe benefit program described in section 132(f) of the Code or a cafeteria plan described in section 125 of the Code. For purposes of the preceding sentence, the normal base pay of an Employee who works and is compensated based on a shift schedule other than a basic work week consisting of five regularly scheduled eight-hour work days shall be computed by multiplying the number of regularly scheduled basic work hours for which such Employee is paid by his or her basic hourly rate, determined without regard to any premium payments made at an overtime rate for such work. An Employee's "compensation" (within the meaning of section 415 of the Code) for any Plan Year in excess of the applicable dollar limitation contained in Section 401(a)(17) of the Code (as adjusted for changes in the cost of living pursuant to section 401(a)(17) of the Code), shall be not be taken into account for any purpose under the Plan. Notwithstanding the preceding, effective January 1, 2003, normal base pay shall also include lump sum merit increases to base pay. Notwithstanding the foregoing, an amount classified as Compensation under the preceding paragraphs shall not be Compensation for purposes of the Plan if such amount is paid to an Employee after the Employee's severance from employment unless (i) such amount is regular compensation for services during the Employee's regular working hours or compensation for services outside the Employee's regular working hours and (ii) such amount is paid on or before the later of (A) 2 $^{1}/_{2}$ months after the Employee's severance from employment and (B) the last day of the Plan Year during which the Employee's severance from employment occurs. Finally, in no event shall Compensation for purposes of this Plan include any amount that is not "compensation" within the meaning of section 415(c)(3) of the Code and section 1.415(c)-2 of the Regulations.

(14) Corporate Investment Committee . The Company acting through the Committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

(15) Designated Roth Contributions. Before-Tax Contributions designated as Roth contributions pursuant to Section 4.2(e) (relating to Untaxed Contributions and Designated Roth Contributions) by a Participant.

(16) Designated Roth Contributions Account. The account established pursuant to Section 7.1 for each Participant to which shall be credited all Designated Roth Contributions made on behalf of such Participant pursuant to Section 4.2(c) for Plan Years beginning on or after January 1, 2006 and earnings (or losses) thereon for each Participant who is not represented by IBEW Local Union 15 and covered under the collective bargaining agreement between Commonwealth Edison Company and IBEW Local Union 15 ("Local 15 Member") and (b) for Plan Years beginning on or after January 1, 2009 and earning (or losses) thereon for each Participant who is a Local 15 Member.

(17) Disability . A physical or mental condition which, in the judgment of the Administrator, based upon medical reports and other evidence satisfactory to the Administrator, permanently prevents a Participant from satisfactorily performing his or her usual duties or the duties of such other position available to him and for which he is qualified by reason of his or her training, education or experience.

(18) Effective Date . January 1, 2010.

(19) Eligible Employee . An Employee other than (i) an Employee the terms of whose employment are subject to a collective bargaining agreement that does not provide for participation in this Plan, (ii) an Employee on an unpaid leave of absence (except as required by applicable law respecting Military Service), (iii) an Employee paid on the temporary payroll of an Employer who has never completed 1,000 Hours of Service in any period of twelve consecutive months beginning with the Employee's date of employment or any anniversary thereof, (iv) an individual rendering services to an Employer who is not on the payroll of any Employer, (v) as of the Effective Time, an individual who was employed immediately prior to the Effective Time (as such term is defined in the Merger Agreement) at CEG or a facility owned immediately before the Effective Time by CEG and (vi) an individual who is newly employed on or after the Effective Time (as such term is defined in the Merger Agreement) at a facility owned immediately before the Effective Time by CEG. It is expressly intended that an individual rendering services to an Employer pursuant to any of the following agreements shall be excluded from Plan participation pursuant to clause (iv) of this subdivision even if a court or administrative agency determines that such individual is an Employee: (a) an agreement providing that such services are to be rendered as an independent contractor, (b) an agreement with an entity, including a leasing organization within the meaning of section 414(n)(2) of the Code, that is not an Employer or (c) an agreement that contains a waiver of participation in the Plan.

(20) Employee . An individual whose relationship with an Employer is, under common law, that of an employee.

(21) Employer . The Company and any other Affiliate set forth on Appendix I hereto that, with the consent of the Company elects to participate in the Plan in the manner described in Article 12 either with respect to all Employees or a particular group of Employees of such Affiliate and any successor Affiliate that adopts the Plan pursuant to Article 13. If any entity described in the preceding sentence withdraws from participation in the Plan pursuant to Section 12.2, such entity shall thereupon cease to be an Employer.

(22) Employer Matching Contributions . Contributions made by an Employer pursuant to Section 4.3.

(23) Employer Matching Contributions Account . The account established pursuant to Section 7.1 to which shall be credited (i) any Employer Matching Contributions made on behalf of a Participant, (ii) any employer matching contributions transferred to the Plan from the PECO Energy Company Employee Savings Plan (including any employer matching contributions transferred to such plan from the Philadelphia Electric Company Tax Reduction Act Stock Ownership Plan) on behalf of such Participant and (iii) earnings (or losses) thereon.

(24) ERISA . The Employee Retirement Income Security Act of 1974, as amended.

(25) Hour of Service . Each hour for which an Employee is directly or indirectly compensated by, or entitled to receive compensation from, an Employer. For purposes of this subdivision, compensation shall mean the total earnings paid, directly or indirectly, to the Employee by an Employer, including any back pay, irrespective of mitigation of damages, either awarded to the Employee or agreed to by an Employer. The computation of Hours of Service and the periods to which Hours of Service are credited shall be determined under uniform rules adopted by the Administrator in accordance with Department of Labor regulations §2530.200b-2(b), (c) and (f).

(26) Investment Office . The Company acting through the Exelon Investment Office.

(27) Merger Agreement . That Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc.

(28) Military Service . The performance of duty on a voluntary or involuntary basis in a “uniformed service” (as defined below) under competent authority of the United States government and includes active duty, active duty for training, initial active duty for training, inactive duty training, full-time National Guard duty, and a period for which a person is absent from employment for the purpose of an examination to determine the fitness of the person to perform any such duty. For purposes of the preceding sentence, the term “uniformed service” means the Armed Forces, the Army National Guard and the Air National Guard when engaged in active duty for training, inactive duty training, or full-time National Guard duty, the commissioned corps of the Public Health service, and any other category of persons designated by the President of the United States in time of war or emergency.

(29) Participant . An Eligible Employee who satisfies the conditions set forth in Section 3.1 (relating to eligibility for Participation). An individual shall cease to be a Participant upon the complete distribution, or transfer of his or her account under the Plan. For any period in which the

Plan is not an "ERISA section 404(c) Plan" as defined in Regulations under section 404(c) of ERISA, each Participant shall be a "named fiduciary" within the meaning of section 402(a)(1) of ERISA for the sole purpose of directing the Trustee with respect to the exercise of shareholder rights pursuant to Article 9 (relating to Participants' stockholder rights).

(30) Plan . The plan herein set forth, and as from time to time amended.

(31) Plan Year . The twelve-month period beginning on each January 1.

(32) Qualified Reservist . The term "Qualified Reservist" shall mean an individual who is (i) a member of a reserve component (as defined in chapter 1 of title 37, United States Code) and (ii) ordered or called to active duty for a period in excess of 179 days or for an indefinite period, after September 11, 2001.

(33) Regulations . Written final or temporary promulgations of the Department of Labor construing Title I of ERISA or the Internal Revenue Service construing the Code.

(34) Rollover Account . The account established pursuant to Section 7.1 to which shall be credited (i) any rollover contribution made by or on behalf of an Eligible Employee or a Participant, (ii) any rollover contribution transferred to the Plan from the PECO Energy Company Employee Savings Plan on behalf of such Participant and (iii) earnings (or losses) thereon.

(35) Spouse . The individual who is a husband or wife of a Participant as the result of a legal union between one man and one woman, within the meaning of the Defense of Marriage Act.

(36) Termination Date . (a) The date an Employee quits, retires, is discharged from employment by an Employer or dies, (b) the date the Employee's employer ceases to be an Employer on account of its sale to a party or parties that do not qualify as an Affiliate of any Employer, (c) the first anniversary of the Employee's first date of absence from employment by an Employer for any other reason, except as provided in clause (d) or (e) below, (d) in the case of an Employee who is absent from employment for maternity or paternity reasons, the second anniversary of the first date of such absence or (e) the last date following a period of Military Service as of which the Employee has reemployment rights under applicable law. For purposes of this subdivision, an absence from employment for maternity or paternity reasons means an absence (1) by reason of the pregnancy of the Employee, (2) by reason of the birth of a child of the Employee, (3) by reason of the placement of a child with the Employee in connection with the adoption of such child by such Employee or (4) for purposes of caring for such child for a period beginning immediately following such birth or placement. Notwithstanding the foregoing sentences, an Employee's absence from employment for maternity or paternity reasons or for Military Service shall not be considered in determining the Employee's Termination Date unless the Employee, upon the Administrator's request, provides certification that the leave was taken for one of the reasons enumerated in the preceding sentence.

(37) Trust . The trust created by agreement between the Company and the Trustee, as from time to time amended.

(38) Trust Fund . All money and property of every kind of the Trust held by the Trustee pursuant to the terms of the Trust agreement.

(39) Trustee . The trustee that executes the Trust instrument provided for in Article 6, or any successor trustee or, if there is more than one trustee acting at any time, all of such trustees collectively.

(40) Untaxed Contributions. Before-Tax Contributions not designated as Designated Roth Contributions pursuant to Section 4.2(e) (relating to Untaxed Contributions and Designated Roth Contributions) by a Participant.

(41) Untaxed Contributions Account. The account established pursuant to Section 7.1 for each Participant to which shall be credited (a) all Before-Tax Contributions that are made on behalf of the Participant pursuant to Section 4.2 for Plan Years beginning prior to January 1, 2006 with respect to a Participant who is not a Local 15 Member and for Plan Years beginning before January 1, 2009 with respect to a Participant who is a Local 15 Member, (b) any before-tax contributions transferred to the Plan from the PECO Energy Company Employee Savings Plan on behalf of such Participant, (c) all Before-Tax Contributions that are Untaxed Contributions made pursuant to Section 4.2 for Plan Years beginning on or after January 1, 2006 with respect to a Participant who is not a Local 15 Member and for Plan Years beginning before January 1, 2009 with respect to a Participant who is a Local 15 Member, and (d) earnings (or losses) thereon.

(42) Valuation Date . Each business day, as determined by the Trustee, or such other days as the Administrator may designate.

(43) VRU . The telephonic voice response unit designated by the Administrator, which may be used to make certain elections under the Plan. The VRU shall require each Participant, or Beneficiary, as the case may be, to provide such identification data as may, from time to time, be required by the VRU. The Administrator shall cause to be kept such records of VRU activity as it shall deem necessary or appropriate, and such records shall constitute valid authorization of the elections made by each Participant and Beneficiary for all purposes of the Plan and applicable Regulations. No written authorization shall be required from a Participant or Beneficiary after an election has been made by calling the VRU.

ARTICLE 3

PARTICIPATION

Section 3.1 . Eligibility for Participation .

Each Eligible Employee who immediately before the Effective Date was a Participant in the Plan shall continue to be a Participant as of the Effective Date. Each other Eligible Employee who is a member of a bargaining unit represented by IBEW Local Union 15 shall be eligible to become a Participant on the first day of the payroll period coinciding with or next following the date he or she has completed three months of employment with an Employer (regardless of the

number of Hours of Service actually performed). Each other Eligible Employee who is not a member of a bargaining unit represented by IBEW Local Union 15 shall be eligible to become a Participant on the first day of the payroll period coinciding with or next following the date of his or her employment.

Section 3.2 . Applications for Before-Tax Contributions and After-Tax Contributions .

(a) Regular Payroll Before-Tax and After-Tax Contributions . Each Eligible Employee who desires to commence Before-Tax Contributions or After-Tax Contributions shall make a request in the manner prescribed by the Administrator specifying the Employee's chosen rate of Before-Tax Contributions for each payroll period or his or her chosen rate of After-Tax Contributions for each payroll period, or both. Such request shall authorize the Employee's Employer to reduce the Eligible Employee's Compensation by the amount of any such Before-Tax Contributions, to make regular payroll deductions of any such After-Tax Contributions or both, as the case may be. The request shall also specify the Employee's investment elections pursuant to Section 7.1(b) and shall evidence the Employee's acceptance of and agreement to all provisions of the Plan. In addition, an Eligible Employee who is not a member of a bargaining unit represented by IBEW Local Union 15 on the date of his or her employment may elect, in accordance with the provisions of this paragraph (a), to become a Participant on the first day of the payroll period coinciding with or next following such date. All requests to commence contributions pursuant to this paragraph (a) shall be effective as of such time after the Administrator (or its delegate) receives such request as shall be established by the Administrator, provided , that all such requests shall be effective on the first day of a payroll period commencing not more than 30 days after receipt thereof by the Administrator (or its delegate).

(b) Quarterly Incentive Award Before-Tax Contributions . With respect to quarterly incentive awards earned prior to January 1, 2002, each Eligible Employee may request, in the manner prescribed by the Administrator, to reduce his or her compensation by an amount equal to 100 percent of any such quarterly incentive awards that would otherwise be paid to such Participant; provided, however, that for the 2001 Plan Year, such reduction shall be available solely with respect to quarterly incentive awards payable on or after the later of (i) March 31, 2001 and (ii) the first date thereafter which the Administrator determines is administratively practicable with respect to Employees of such Participant's Employer. Before-Tax Contributions pursuant to this paragraph (b) shall be invested in accordance with the Participant's investment election under paragraph (a) of this Section 3.2 (or, if no such election is in effect, in accordance with an investment election made by such Participant in the manner prescribed by the Administrator).

(c) Automatic Enrollment for Certain Employees . (i) Deemed Election of Default Before-Tax Contributions . A Participant whose hire date is on or after April 6, 2009 and who does not make an election pursuant to paragraph (a) of this Section 3.2 to make Before-Tax Contributions or After-Tax Contributions shall be deemed to have elected to make Before-Tax Contributions ("Default Before-Tax Contributions") equal to 3 percent ("Default Percentage") of his or her Compensation for each payroll period and to have his or her Employer reduce his or her Compensation by the amount thereof. Such Participant's Default Percentage will increase by 1 percent each Plan Year, beginning with the second Plan Year that begins after the Default Percentage first applies to the Participant, until it reaches 5 percent. The increase will be effective March 1 of each applicable Plan Year. Notwithstanding the foregoing, in the event a Participant's initial Default Before-Tax Contribution occurs during the period commencing on December 1 and ending the last day of February, the initial increase to such Participant's Default Percentage shall commence on the March 1 of the calendar year following the first anniversary of the Participant's initial Default Before-Tax Contribution. The effective date of such Participant's deemed election shall be 90 days after the Participant receives a notice of his or her rights and obligations under

this paragraph (c)(i) (the "Automatic Enrollment Notice"). During the 90-day period after the Participant receives the Automatic Enrollment Notice, the Participant shall have an opportunity to make an affirmative election to (1) not have any Default Before-Tax Contributions made on his or her behalf or (2) have Before-Tax Contributions made in a different amount or percentage of Compensation by giving direction to the Administrator (or its delegate) in the manner prescribed by the Administrator. Any deemed election described in this paragraph (c)(i) shall be effective only with respect to Compensation not currently available to the Participant. Each Participant whose hire date is on or after April 6, 2009 shall be a "covered employee" for purposes of section 1.414(w)-1(e)(3) of the Regulations, regardless of whether such Participant makes an affirmative election regarding Before-Tax Contributions. Notwithstanding the foregoing, an Employee who on or after April 6, 2009 becomes eligible to participate in the Plan as a result of the Employee's rehire by an Employer shall not be deemed to have made an election automatically to have Before-Tax Contributions made on his or her behalf pursuant to this paragraph (c)(i) or deemed to be a "covered employee."

(ii) Withdrawal of Default Before-Tax Contributions . A covered employee deemed to elect Default Before-Tax Contributions pursuant to paragraph (c)(i) may elect, no later than 90 days after the first payroll date that the first Default Before-Tax Contributions on behalf of the covered employee occurs, to receive a distribution equal to the amount of all such contributions (adjusted for earnings and losses and reduced by any applicable fees) made with respect to the covered employee through the earlier of (1) the pay date for the second payroll period that begins after the covered employee's withdrawal request and (2) the first pay date that occurs after 30 days following the covered employee's request. An election by a covered employee to withdraw Default Before-Tax Contributions pursuant to this paragraph (c)(ii) shall be deemed to be an election by the covered employee, as of the date of the withdrawal election, to reduce his Before-Tax Contribution percentage to 0 percent (subject to any affirmative election by the covered employee to the contrary).

Section 3.3 . Transfer to Affiliates .

If a Participant is transferred from one Employer to another Employer or from an Employer to an Affiliate, such transfer shall not terminate the Participant's participation in the Plan and such Participant shall continue to participate in the Plan until an event occurs that would have terminated his or her participation had the Participant continued in the service of an Employer until the occurrence of such event; provided , however , that a Participant shall not be entitled (i) to make contributions to the Plan, or (ii) to have contributions made on his or her behalf to the Plan during any period of employment by any Affiliate that is not an Employer with respect to such Participant. Periods of employment with an Affiliate shall be taken into account only to the extent set forth in Section 10.4 (relating to employment by Affiliates). Payments received by a Participant from an Affiliate that is not an Employer with respect to such Participant shall not be treated as compensation for any purposes under the Plan.

ARTICLE 4

EMPLOYER CONTRIBUTIONS

Section 4.1 . Before-Tax Contributions .

(a) Initial Election Respecting Regular Payroll Before-Tax Contributions . Subject to the limitations set forth in Sections 4.2 (relating to the 402(g) annual limit on Before-Tax Contributions), 4.4 (relating to limitations on contributions for highly compensated Eligible Employees), 4.5 (relating to the limitation on Employer contributions) and 7.4 (relating to limitations on allocations imposed by section 415 of the Code), each Employer shall contribute (i) on behalf of each Participant who is an Eligible Employee of such Employer and is a member of a bargaining unit represented by IBEW Local Union 15 an amount equal to a whole percentage not

less than 1 and not more than 15 percent of such Participant's Compensation for each payroll period as designated by the Participant in his or her request pursuant to Section 3.2(a), and (ii) on behalf of any other Participant who is an Eligible Employee of such Employer an amount equal to a whole percentage not less than 1 and not more than 20 percent and, effective as of January 1, 2006, 50 percent, of such Participant's Compensation for each payroll period as designated by the Participant on his or her request pursuant to Section 3.2(a). Before-Tax Contributions described in the preceding sentence shall be delivered to the Trustee no less frequently than bi-weekly. In addition, if back-pay is awarded to a Participant who is an Eligible Employee and any portion of such back-pay constitutes Compensation as defined in subdivision (13) of Article 2 (relating to the definition of Compensation), the Employer of such Participant shall contribute on behalf of such Participant an amount equal to the Before-Tax Contribution percentage, which was most recently chosen by the Participant in his or her request pursuant to Section 3.2(a), of such back-pay that constitutes Compensation. A Before-Tax Contribution described in the preceding sentence shall be treated under the Plan in the same manner as all other Before-Tax Contributions and shall be delivered to the Trustee as soon as practicable after the back-pay is paid to the Participant.

If a Participant receives a hardship withdrawal pursuant to Section 8.1(a), then: (1) all Before-Tax Contributions made on behalf of such Participant pursuant to this Section 4.1 and After-Tax Contributions made by the Participant pursuant to Section 5.1 shall cease beginning with the first payroll period beginning after the date on which the Participant receives such hardship withdrawal; and (2) such Participant shall not again be eligible to elect such contributions until the first payroll period that coincides with or follows the date on which contributions ceased by six months.

(b) Changes in the Rate or Suspension of Regular Payroll Before-Tax Contributions . A Participant's Before-Tax Contributions pursuant to paragraph (a) of this Section 4.1 shall continue in effect at the rate designated by a Participant in his or her request until the Participant changes such designation or suspends such contributions. A Participant may change such designation at any time by giving direction to the Administrator (or its delegate) in the manner prescribed by the Administrator. Any such direction shall be limited to the contribution rates described in paragraph (a) of this Section 4.1.

A Participant may suspend future Before-Tax Contributions pursuant to paragraph (a) of this Section 4.1 by giving notice to the Administrator (or its delegate) in the manner prescribed by the Administrator. A Participant who has ceased Before-Tax Contributions pursuant to this subsection may resume Before-Tax Contributions by so directing the Administrator (or its delegate) in the manner prescribed by the Administrator. All such directions to change the rate of, suspend or resume Before-Tax Contributions shall be effective as of such time after the Administrator (or its delegate) receives any such direction as shall be established by the Administrator, provided that such direction shall be effective on the first day of a payroll period commencing not more than 30 days after receipt thereof by the Administrator (or its delegate).

(c) Elections Respecting Quarterly Incentive Award Before-Tax Contributions . With respect to quarterly incentive awards earned prior to January 1, 2002, and subject to the limitations set forth in subdivision (13) of Article 2 (relating to the $170,000 limitation on Compensation) and Sections 4.2 (relating to the 402(g) limit on Before-Tax Contributions), 4.4 (relating to limitations on contributions for highly compensated Eligible Employees), 4.5 (relating to the limitation on Employer contributions) and 7.4 (relating to limitations on allocations imposed by section 415 of the Code), each Employer shall contribute on behalf of each Participant who has filed a request in accordance with Section 3.2(b) an amount equal to 100 percent of the amount of any such quarterly incentive awards payable to such Participant on or after the effective date of such request. A Participant's Before-Tax Contributions pursuant to this paragraph (c) shall continue in

effect until the Participant suspends such contributions. A Participant may suspend such contributions by giving direction to the Administrator (or its delegate) in the manner prescribed by the Administrator. Any such direction to suspend Before-Tax Contributions pursuant to this paragraph (c) shall be effective beginning with the quarterly incentive award payable in the calendar quarter immediately following the calendar quarter in which such direction is received by the Administrator (or its delegate). Before-Tax Contributions pursuant to this paragraph (c) shall be delivered to the Trustee not later than the fifteenth business day of the month following the month in which the related quarterly incentive award is payable.

(d) Catch-Up Contributions . Effective for payroll periods beginning on or after August 1, 2002, each Participant who pursuant to paragraph (a) of this Section 4.1 is eligible to make Before-Tax Contributions for any Plan Year and who shall attain age 50 before the close of such Plan Year shall be eligible to have Before-Tax Contributions made in addition to those described in paragraph (a) of this Section 4.1 ("Additional Before-Tax Contributions") if no other Before-Tax Contributions to be made pursuant to paragraph (a) of this Section 4.1 may be made to the Plan for such payroll period by reason of the limitations of Section 4.2 (relating to the 402(g) annual limit on Before-Tax Contributions). Notwithstanding the preceding sentence, in no event shall the amount of Additional Before-Tax Contributions exceed (i) in the case of a Participant who is represented by IBEW Local Union 15 and covered under that certain Collective Bargaining Agreement dated September 15, 2000 between Commonwealth Edison Company and IBEW Local Union 15, 40 percent of such Participant's Compensation for any payroll period, and (ii) in the case of any other Participant, 50 percent of such Participant's Compensation for any payroll period. Such Additional Before-Tax Contributions shall be elected, made, suspended, resumed and credited in a manner similar to that described in paragraphs (a), (b) and (c) of this Section 4.1 and in accordance with and subject to such additional rules and limitations of section 414(v) of the

Code and otherwise as the Administrator determines. To the extent such Additional Before-Tax Contributions are not "Catch-Up Contributions" as defined for purposes of section 414(v) of the Code, they shall be taken into account, and to the extent such Additional Before-Tax Contributions are Catch-Up Contributions they shall not be taken into account, for purposes of Article 4 or 7 or other provisions of the Plan implementing the required limitations of sections 401(k)(3), 401(k)(11), 401(k)(12), 402(g), 404, 410(b), 415 or 416 of the Code, as applicable.

Section 4.2 . 402(g) Annual Limit on Before-Tax Contributions .

(a) General Rule . Notwithstanding the provisions of Section 4.1 (relating to Before-Tax Contributions), a Participant's Before-Tax Contributions for any calendar year, together with amounts contributed under all other plans and arrangements maintained by an Employer or Affiliate and described in sections 401(k), 408(k), 408(p) or 403(b) of the Code, and excluding any Additional Before-Tax Contributions made to the Plan pursuant to paragraph (d) of Section 4.1 which are Catch-Up Contributions described in such paragraph or Default Before-Tax Contributions that are withdrawn pursuant to paragraph (c)(ii) of Section 3.2, shall not exceed the applicable dollar amount under section 402(g) of the Code (as adjusted for cost-of-living increases in accordance with section 402(g)(5) of the Code) for such calendar year.

(b) Correction of Excess Before-Tax Contributions . If for any calendar year a Participant determines that the aggregate of the (i) Before-Tax Contributions to this Plan, excluding any Additional Before-Tax Contributions made to the Plan pursuant to paragraph (d) of Section 4.1 which are Catch-Up Contributions described in such paragraph, and (ii) amounts contributed under other plans or arrangements described in sections 401(k), 408(k) or 403(b) of the Code will exceed the limit imposed by paragraph (a) of this Section 4.2 for the calendar year in which such contributions were made ("Excess Before-Tax Contributions"), such Participant shall, pursuant to such rules and at such time following such calendar year as determined by the

Administrator, be allowed to submit a written request that the Excess Before-Tax Contributions plus any income and minus any loss allocable thereto be distributed to him or her. The request described in this subsection shall be made in the manner and form prescribed by the Administrator and shall state the amount of the Participant's Excess Before-Tax Contributions for the calendar year. The request shall be accompanied by the Participant's written statement that if such Excess Before-Tax Contributions are not distributed, such Excess Before-Tax Contributions, when added to amounts deferred under other plans or arrangements described under sections 401(k), 408(k), or 403(b) of the Code, excluding any contributions which are Catch-Up Contributions described in section 414(v) of the Code, will exceed the limit for such Participant under section 402(g) of the Code. A distribution of Excess Before-Tax Contributions (reduced by any amounts recharacterized or distributed pursuant to paragraph (e)(1) of Section 4.4 (relating to adjustments to comply with section 401(k)(3) of the Code)) shall be made no later than the applicable time period set forth in the Code and Regulations thereunder following the end of the Plan Year for which such Excess Before-Tax Contributions were made, plus any income and minus any loss allocable thereto through the end of such Plan Year. The amount of any income or loss allocable to such Excess Before-Tax Contributions shall be determined pursuant to applicable Regulations. If Excess Before-Tax Contributions are distributed pursuant to this Section 4.2, any corresponding Employer Matching Contributions allocated to the Participant's Employer Matching Contributions Account, adjusted for income or loss pursuant to Regulations, to which such Participant would be entitled under Section 8.3 (relating to distributions upon termination of employment) if such Participant had terminated employment on the last day of the calendar year during which contributions were made (or earlier if such Participant actually terminated employment at an earlier date) shall be distributed to such Participant and any remaining amount of such corresponding Employer Matching Contributions, adjusted for income or loss, shall be forfeited.

Notwithstanding the provisions of this paragraph, any such Excess Before-Tax Contributions shall be treated as "annual additions" for purposes of Section 7.4 (relating to limitations on allocations imposed by section 415 of the Code) and shall not be disregarded as Before-Tax Contributions for purposes of determining the average deferral percentage described in Section 4.4(d)(1) or, to the extent applicable, the average contribution percentage described in Section 4.4(d)(2), except that in the case of a non-highly compensated eligible employee, as that term is defined in Section 4.4(d)(4), such Excess Before-Tax Contributions shall be ignored to the extent that such contributions are prohibited pursuant to section 401 (a)(30) of the Code, which requires that Before-Tax Contributions not exceed the limit described in paragraph (a) of Section 4.2 (relating to the annual limit on Before-Tax Contributions). Any distribution of Excess Before-Tax Contributions to a Participant shall be treated as a distribution of the Untaxed Contributions, up to the extent Untaxed Contributions have been made by such Participant to the Plan for such Plan Year and, to the extent that distributions of Excess Before-Tax Contributions to such Participant exceed the Participant's Untaxed Contributions for such Plan Year, the distributions of Excess Before-Tax Contributions shall be treated as Designated Roth Contributions made by the Participant to the Plan for the Plan Year.

(c) Untaxed Contributions and Designated Roth Contributions. Effective for Before-Tax Contributions made (i) in the case of a Participant who is not a Local 15 Member, for the 2006 Plan Year and thereafter, and (ii) in the case of a Participant who is a Local 15 Member, for the 2009 Plan Year and thereafter, an election made by a Participant to commence, change, suspend or resume Before-Tax Contributions pursuant to this Section 4.2 shall designate the portion of such contributions that are to be Designated Roth Contributions includible in the Participant's gross income when made pursuant to section 402A of the Code. Such designation is irrevocable with respect to contributions made or to be made with respect to Compensation

currently available. Any such election made by a Participant which does not expressly designate a portion of Before-Tax Contributions as Designated Roth Contributions shall be deemed to designate no portion of Before-Tax Contributions as Designated Roth Contributions. Any Before-Tax Contributions that are not Designated Roth Contributions are referred to herein as Untaxed Contributions.

Section 4.3 . Employer Matching Contributions .

(a) Amount of Contributions . Subject to the limitations set forth in Sections 4.4 (relating to limitations on contributions for highly compensated Eligible Employees), 4.5 (relating to the limitations on Employer contributions) and 7.4 (relating to limitations on allocations imposed by section 415 of the Code), and except as otherwise provided below, each Employer shall contribute the following for each payroll period on behalf of each Participant who is an Employee of such Employer:

(i) Effective beginning with the first payroll period in January 1, 2009, for each Participant who is a member of a bargaining unit represented by IBEW Local Union 15, an amount equal to 100 percent of Matched Contributions, as defined below, but only to the extent that Matched Contributions do not exceed 5 percent of the Participant's Compensation for the payroll period;

(ii) For each Participant who is covered under the collective bargaining agreement between Exelon Power Services LLC and Local 369 of the Utility Workers Union of America, AFL-CIO, if such Participant has completed less than 5 months of service with an Employer, no contribution shall be made; if such Participant has completed more than 5 months of service but fewer than 12 months of service with an Employer, an amount equal to 50% of Matched Contributions, as defined below, but only the extent that Matched Contributions do not exceed 3 percent of the Participant's Compensation for the payroll period; if such Participant has completed at least 12 months of service with an Employer, an amount equal to 100% of Matched Contributions, but only to the extent that Matched Contributions do not exceed 3 percent of the Participant's Compensation for the payroll period. For purposes of this paragraph, a month of service shall mean a consecutive period of employment during which the Employee is employed by an Employer ending on the monthly anniversary of the Employee's date of hire. A Participant who is credited with an additional month of service during a pay period and becomes eligible to receive an increased Employer Matching Contribution, shall not be entitled to receive an increased Employer Matching Contribution until the first full payroll period following the payroll period in which such Participant is credited with such additional month of service;

(iii) For each Participant who is classified as a non-exempt craft employee or clerical employee assigned to the Peachbottom, Limerick, Outage Services East or Texas generating plant, an amount equal to 100 percent of Matched Contributions, as defined below, but only to the extent that Matched Contributions do not exceed 5 percent of the Participant's Compensation for the payroll period; and

(iv) For each other Participant, an amount equal to 60 percent of Matched Contributions, as defined below, but only to the extent that Matched Contributions do not exceed 5 percent of the Participant's Compensation for the payroll period.

In addition, each Participant described in clause (iv) of the preceding paragraph shall be eligible to receive a "Profit Sharing Matching Contribution," provided that such Participant either (i) is an Employee of such Employer on the last day of such Plan Year, (ii) is not employed on such day as a result of an approved unpaid leave of absence during such Plan Year, (iii) terminates employment during such Plan Year (1) after attaining age 50 and completing at least 10 years of service, as determined by the Administrator, (2) as a result of circumstances entitling the Participant to separation benefits under an Employer's severance benefit plan, (3) as a result of a disability that entitles the Participant to benefits under an Employer's long-term disability plan, or (4) on account of the Participant's death. The "Profit Sharing Matching Contribution" shall be an amount (if any) determined by the Board of Directors of the Company (or the Compensation Committee thereof) in its sole discretion based on attainment of specified performance goals, and not exceeding 60% of a Participant's Matched Contributions, as defined below, for each payroll period, but only to the extent that such Matched Contributions do not exceed 5 percent of the Participant's Compensation for the payroll period.

For purposes of this Section 4.3, "Matched Contributions" means the sum of (i) the Before-Tax Contributions made on behalf of the Participant for a payroll period, excluding Before-Tax Contributions made with respect to any quarterly incentive awards pursuant to paragraph (b) of Section 3.2, excluding Additional Before-Tax Contributions which are Catch-Up Contributions described in section 414(v) of the Code and excluding Default Before-Tax Contributions distributed pursuant to paragraph (c)(ii) of Section 3.2 (relating to withdrawal of Default Before-Tax Contributions), and (ii) the After-Tax Contributions made by the Participant for such payroll period. Any Employer Matching Contributions made by an Employer with respect to Default Before-Tax Contributions that are withdrawn pursuant to paragraph (c)(ii) of Section 3.2, plus any earnings, shall be forfeited and used to reduce future Employer Matching Contributions made by an Employer pursuant to this Section.

In addition to the Employer Matching Contributions described above, in the case of a New England Plan Participant, as defined in Supplement IV attached hereto, whose Before-Tax Contributions exceed the limit described in Section 4.2 (relating to the 402(g) annual limit on Before-Tax Contributions), an additional Employer Matching Contribution shall be made on behalf of such Participant in an amount equal to the amount described in clause (iii) above assuming that such Participant had continued making the same rate of Before-Tax Contributions that were in effect with respect to such Participant at the time such Before-Tax Contributions exceeded the limit described in Section 4.2.

(b) Special Part-Time Employees . Notwithstanding paragraph (a) hereof, no Employer shall make a contribution pursuant to this Section 4.3 on behalf of any Participant who is a "part-time regular employee" as defined in an Agreement dated July 23, 1993 between the Company and the System Council U-25, I.B.E.W. (the "July 23, 1993 Agreement"), unless one of the following applies:

(1) the Participant had in effect on July 23, 1993 an authorization to make contributions under the Plan as then in effect and elected pursuant to the July 23, 1993 Agreement and request by the Company to become a part-time regular employee during the initial staffing period that began July 23, 1993 and ended December 31, 1993 (the "Initial Staffing Period");

(2) the Participant had in effect on the date the Participant became a part-time regular employee an authorization to make contributions under the Plan as then in effect and chose the Option II Benefits Package as described in the July 23, 1993 Agreement, as amended;

(3) the Participant did not have in effect on the date the Participant became a part-time regular employee an authorization to make contributions under the Plan as then in effect and elected pursuant to the July 23, 1993 Agreement and request by the Company to become a part-time regular employee during the Initial Staffing Period; provided such Participant had in effect on any date after December 24, 1995 and before February 20, 1996 an authorization to make contributions under the Plan; or

(4) the Participant elected other than pursuant to the July 23, 1993 Agreement to become a part-time regular employee during the Initial Staffing Period; provided that such Participant had in effect on any date after December 24, 1995 and before February 20, 1996 and authorization to make contributions under the Plan.

(c) Time of Delivery of Contributions . Employer Matching Contributions for any Plan Year shall be delivered to the Trustee at the same time the Before-Tax contributions or After-Tax Contributions to which such Employer Matching Contributions relate are delivered to the Trustee.

Section 4.4 . Limitations on Contributions for Highly-Compensated Eligible Employees .

(a) Limits Imposed by Section 401(k)(3) of the Code . Notwithstanding the provisions of Section 4.1 (relating to Before-Tax Contributions), if the Before-Tax Contributions for a Plan Year fail, or in the judgment of the Administrator are likely to fail, to satisfy both of the tests set forth in paragraphs (1) and (2) of this subsection, the adjustments prescribed in paragraph (e)(1) of this Section 4.4 shall be made.

(1) The average deferral percentage for the group consisting of highly compensated eligible employees of all Employers does not exceed the product of the average deferral percentage for the group consisting of non-highly compensated eligible employees multiplied by 1.25.

(2) The average deferral percentage for the group consisting of highly compensated eligible employees of all Employers (i) does not exceed the average deferral percentage for the group consisting of non-highly compensated eligible employees by more than two percentage points, and (ii) does not exceed two times the average deferral percentage for such group.

Effective for payroll periods beginning on or after August 1, 2002, any Additional Before-Tax Contributions which are "Catch-Up Contributions" described in paragraph (d) of Section 4.1 shall not be considered as Before-Tax Contributions for purposes of determining whether the tests set forth in paragraphs (1) and (2) of this subsection are satisfied or for purposes of making any adjustments prescribed in paragraph (e) of this Section 4.4.

(b) Limits Imposed by Section 401(m) of the Code . Notwithstanding the provisions of Section 4.3 (relating to Employer Matching Contributions) and Section 5.1 (relating to After-Tax Contributions), if the Employer Matching Contributions and After-Tax Contributions for a Plan Year fail, or in the judgment of the Administrator are likely to fail, to satisfy both of the tests set forth in paragraphs (1) and (2) of this subsection, the adjustments prescribed in paragraph (e)(2) of this Section 4.4 shall be made.

(1) The average contribution percentage for the group consisting of highly compensated eligible employees of all Employers does not exceed the product of the average contribution percentage for the group consisting of non-highly compensated eligible employees multiplied by 1.25.

(2) The average contribution percentage for the group consisting of highly compensated eligible employees of all Employers (i) does not exceed the average contribution percentage for the group consisting of non-highly compensated eligible employees by more than two percentage points, and (ii) does not exceed two times the average contribution percentage for such group.

(c) Aggregate Limit on Contributions . **Deleted in its entirety.**

(d) Definitions . For purposes of this Section 4.4:

(1) the "average deferral percentage" for a group of Eligible Employees with respect to a Plan Year shall be the average of the ratios, calculated separately for each Eligible Employee in such group to the nearest one-hundredth of one percent, of the Before-Tax Contributions made for the benefit of such Eligible Employee to the total compensation paid to such Eligible Employee for the portion of such Plan Year during which such Eligible Employee was a Participant, except that no Additional Before-Tax Contributions which are "Catch-Up Contributions" described in paragraph (d) of Section 4.1 or Default Before-Tax Contributions that are withdrawn pursuant to paragraph (c)(ii) of Section 3.2 shall be considered as Before-Tax Contributions for purposes of determining a Participant's average deferral percentage;

(2) the "average contribution percentage" for a group of Eligible Employees with respect to a Plan Year shall be the average of the ratios, calculated separately for each Eligible Employee in such group to the nearest one-hundredth of one percent, of the Employer Matching Contributions made, After-Tax Contributions made and, in the Administrator's sole discretion, to the extent permitted under Regulations or otherwise under the Code, the Before-Tax Contributions made during such year for the benefit of such Eligible Employee, except that no Additional Before-Tax Contributions which are "Catch-Up Contributions" described in paragraph (d) of Section 4.1, shall be considered as Before-Tax Contributions for purposes of determining a Participant's average contribution percentage, to such Eligible Employee's compensation for the portion of such Plan Year during which such Eligible Employee was a Participant;

(3) the term "highly compensated eligible employee" shall mean any Eligible Employee who is a Participant, who performs service in the determination year and who (a) is a 5%-owner (as determined under section 416(i)(1)(A)(iii) of the Code) at any time during the Plan Year or the preceding Plan Year or (b) both (1) is paid compensation in excess of $80,000 (as adjusted for increases in the cost of living in accordance with section 414(q) of the Code) from an Employer for the preceding Plan Year, and (2) is in the group of employees consisting of the top 20% of the employees of the Employer and its Affiliates when ranked on the basis of compensation paid during such preceding Plan Year;

(4) the term "non-highly compensated eligible employee" shall mean any Eligible Employee who is a Participant, who performs services in the determination year and is not a highly compensated eligible employee;

(5) the term "compensation" shall have the meaning set forth in section 414(s) of the Code or, in the discretion of the Administrator, any other meaning in accordance with the Code for these purposes, except that for purposes of determining whether an Eligible Employee is a "highly compensated eligible employee", as described in paragraph (d)(3) of this Section 4.4, "compensation" shall have the meaning set forth in section 415(c)(3) of the Code;

(6) if this Plan and one or more other plans of the Employer to which Before-Tax Contributions, After-Tax Contributions, or qualified nonelective contributions (as such term is defined in section 401(m)(4)(C) of the Code) are made are treated as one plan for purposes of section 410(b) of the Code, such plans shall be treated as one plan for purposes of this Section. If a highly compensated eligible employee participates in this Plan and one or more other plans of the Employer to which any such contributions are made, all such contributions shall be aggregated for purposes of this Section 4.4; and

(7) if this Plan benefits Employees who are included in a unit of employees covered by a collective bargaining agreement and employees who are not included in such collective bargaining unit, this Plan shall be treated as comprising two or more separate plans, as determined by the Administrator in accordance with applicable Regulations, for purposes of this Section 4.4. If such other plan has a plan year that is different from the Plan Year of this Plan, then the highly compensated eligible employee's contributions made to such other plan during the Plan Year of this Plan shall be aggregated with contributions of the same type made to this Plan for such Plan Year for purposes of determining the average deferral percentage and average contribution percentage for this Plan for such Plan Year for the group of highly compensated eligible employees.

This paragraph is inserted at the request of the Internal Revenue Service in order to obtain a favorable determination letter. In computing the "average deferral percentage" for a group of Eligible Employees with respect to a Plan Year, the Before-Tax Contributions that will be taken into account for such Plan Year will be only those that relate to compensation that would have been received by the Eligible Employee in the Plan Year or is attributable to services performed by the Eligible Employee in the Plan Year and would have been received by the Eligible Employee within 2-1/2 months after the close of the Plan Year. In computing the "average contribution percentage" for a group of Eligible Employees with respect to a Plan Year, (i) an After-Tax Contribution will be taken into account only if it is paid to the Trust during such Plan Year or paid to an agent of the Plan and transmitted to the Trust within a reasonable time after the end of the Plan Year; (ii) an excess contribution that is recharacterized will be taken into account during the Plan Year in which the contribution would have been received in cash by the Eligible Employee had

the Eligible Employee not elected to defer the contribution; (iii) an Employer Matching Contribution will be taken into account only if it is made on account of the Eligible Employee's Before-Tax Contributions or After-Tax Contributions, allocated to the Eligible Employee's Account as of a date within that Plan Year and paid to the Trust by the end of the twelfth month following the close of such Plan Year; and (iv) qualified matching contributions which are used to meet the requirements of section 401(k)(3)(A) of the Code are not to be taken into account for purposes of the actual deferral percentage test of section 401(m) of the Code. To the extent required by law, the following will be treated as separate plans for purposes of sections 401(a)(4) and 410(b) of the Code: (i) the portion of the Plan that is a 401(k) plan, (ii) the portion of the Plan that is a section 401(m) plan; (iii) the portion of the plan that provides for contributions other than elective, employee or matching; (iv) the portion of the Plan that is an ESOP; and (v) the portion of the plan that is not an ESOP.

(e) Adjustments to Comply with Limits .

(1) Adjustments to Comply with Section 401(k)(3) of the Code . The Administrator shall cause to be made such periodic computations as it shall deem necessary or appropriate to determine whether either of the tests set forth in paragraph (a)(1) or (a)(2) of this Section 4.4 shall be satisfied during a Plan Year, and, if it appears to the Administrator that neither of such tests will be satisfied, the Administrator shall take such steps as it deems necessary or appropriate to reduce or otherwise adjust the Before-Tax Contributions contributed or to be contributed for all or a portion of such Plan Year on behalf of Participants who are highly compensated eligible employees to the extent necessary in order for one of such tests to be satisfied. If, as of the end of the Plan Year, the Administrator determines that, notwithstanding any adjustments made pursuant to the

preceding sentence, neither of the tests set forth in paragraph (a)(1) and (a)(2) of this Section 4.4 shall be satisfied with respect to such Plan Year, the total amount by which Before-Tax Contributions must be reduced in order to satisfy either such test shall be calculated in the manner prescribed by section 401(k)(8)(B) of the Code (the "excess contributions amount"). The Before-Tax Contributions made on behalf of the Participant who is a highly compensated eligible employee and whose actual dollar amount of Before-Tax Contributions is the highest shall be reduced until such dollar amount equals the next highest actual dollar amount of Before-Tax Contributions made for such Plan Year on behalf of any highly compensated employee, or until the total reduction equals the excess contributions amount. If further reductions are necessary, then the Before-Tax Contributions on behalf of each Participant who is a highly compensated eligible employee and whose actual dollar amount of Before-Tax Contributions is the highest (after the reduction described in the preceding sentence) shall be reduced in accordance with the previous sentence. Such reductions shall continue to be made to the extent necessary so that the total reduction equals the excess contributions amount.

To the extent that the sum of such reductions with respect to a Participant and the amount of other After-Tax Contributions allocated to such Participant's After-Tax Contributions Account does not exceed 20 percent (10 percent in the case of a Participant who is a member of a bargaining unit represented by IBEW Local Union 15) of the Participant's Compensation, the amount of such reductions shall be treated as an After-Tax Contribution. To the extent such amount cannot be treated as an After-Tax Contribution because of the limitation described in the preceding sentence, such amount, plus any income and minus any loss allocable thereto through the end of the Plan Year for which the After-Tax Contribution was made, shall be distributed to such Participant no later than

the last day of the subsequent Plan Year and the Participant shall forfeit any corresponding Employer Matching Contributions related thereto plus any income and minus any loss allocable thereto through the end of the Plan Year for which the Employer Matching Contribution was made. The Participant shall designate the extent to which such distributed excess contributions are treated as Untaxed Contributions or Designated Roth Contributions (but only up to the extent that such types of contributions were made by the Participant to the Plan for the Plan Year) and, in the event that any such designation is not made or is incomplete, such distributed excess contributions shall be treated as Untaxed Contributions up to the extent Untaxed Contributions were made to the Plan for the Plan Year and, to the extent that such distributed excess contributions exceed such Untaxed Contributions, such excess contributions shall be treated as distributions of Designated Roth Contributions made to the Plan for the Plan Year.

The amount of Before-Tax Contributions to be distributed to a Participant pursuant to this Section shall be reduced by any Before-Tax Contributions previously distributed to such Participant pursuant to Section 4.2(b) (relating to correction of Excess Before-Tax Contributions) for such Plan Year. The amount of any income or loss allocable to any such reductions to be so distributed shall be determined pursuant to Regulations. The unadjusted amount of any such reductions so distributed shall be treated as "annual additions" for purposes of Section 7.4 (relating to limitations on allocations imposed by section 415 of the Code).

(2) Adjustments to Comply with Section 401(m) of the Code . The Administrator shall cause to be made such periodic computations as it shall deem necessary or appropriate to determine whether either of the tests set forth in paragraph (b)(1) or (b)(2) of this Section 4.4 shall be satisfied during a Plan Year, and, if it appears to the Administrator that neither of such tests will be satisfied, the Administrator shall take such steps as it deems necessary or appropriate to adjust the Employer Matching Contributions made, After-Tax Contributions made, and any Before-Tax Contributions treated as Employer Matching Contributions pursuant to paragraph (d)(2) of this Section 4.4 for all or a portion of such Plan Year on behalf of Participants who are highly compensated eligible employees to the extent necessary in order for one of such tests to be satisfied. If after the end of a Plan Year it is determined that regardless of any steps taken neither of the tests set forth in paragraph (b)(1) or (b)(2) of this Section 4.4 shall be satisfied with respect to such Plan Year, the Administrator shall calculate the total amount by which any such contributions on behalf of Participants who are highly compensated eligible employees must be reduced in order to satisfy either such test, in the manner prescribed by section 401(m)(6) of the Code (the "excess aggregate contributions amount"). The amount to be reduced with respect to Participants who are highly compensated eligible employees shall be determined by first reducing the After-Tax Contributions (including Before-Tax Contributions recharacterized as After-Tax Contributions pursuant to paragraph (e)(1) of this Section 4.4) and then by reducing the Employer Matching Contributions for each Participant whose actual dollar amount of such aggregate contributions for such Plan Year is highest until such reduced dollar amount equals the next highest dollar amount of such contributions for such Plan Year on behalf of any other highly compensated eligible employee, or until the total reduction equals the excess aggregate contributions amount. If further reductions are necessary, such contributions on behalf of each Participant who is a highly compensated eligible employee and whose actual dollar amount of such contributions is the highest (after the reduction described in the preceding sentence) shall be reduced in accordance with the preceding

sentence. Such reductions shall continue to be made to the extent necessary until the total reduction equals the excess aggregate contributions amount. If After-Tax Contributions are distributed pursuant to this paragraph (e)(2), any corresponding Employer Matching Contributions related thereto plus any income and minus any loss allocable through the end of the Plan Year for which the Employer Matching Contributions were made to which such Participant would be entitled under Section 8.3 (relating to distributions upon termination of employment) if such Participant had terminated employment on the last day of the Plan Year for which contributions were made (or earlier if any such Participant actually terminated employment at any earlier date) shall also be distributed with such After-Tax Contributions (and taken into account to determine whether further reductions are necessary), and any remaining amount of such corresponding Employer Matching Contributions plus any income and minus any loss allocable through the end of the Plan Year for which the Employer Matching Contributions were made shall be forfeited. If the reductions required by this subparagraph exceed the amount of After-Tax Contributions made or to be made by any Participant for such Plan Year and the amount of Employer Matching Contributions made or to be made on behalf of such Participant for such Plan Year, any Before-Tax Contributions made on behalf of such Participant that the Administrator has elected to treat as Employer Matching Contributions pursuant to paragraph (d)(2) of this Section 4.4 shall also be adjusted and taken into account in accordance with this subparagraph, except that such Before-Tax Contributions may not be recharacterized as After-Tax Contributions.

Section 4.5 . Limitation on Employer Contributions .

The contributions of an Employer for any Plan Year shall not exceed the maximum amount for which a deduction is allowable to such Employer for federal income tax purposes for the fiscal year of such Employer that coincides with such Plan Year.

Any contribution made by an Employer by reason of a good faith mistake of fact, or the portion of any contribution made by an Employer that exceeds the maximum amount for which a deduction is allowable to such Employer for federal income tax purposes by reason of a good faith mistake in determining the maximum allowable deduction, shall upon the request of such Employer be returned by the Trustee to the Employer. An Employer's request and the return of any such contribution must be made within one year after such contribution was mistakenly made or after the deduction of such excess portion of such contribution was disallowed, as the case may be. The amount to be returned to an Employer pursuant to this paragraph shall be the excess of (i) the amount contributed over (ii) the amount that would have been contributed had there not been a mistake of fact or a mistake in determining the maximum allowable deduction. Earnings attributable to the mistaken contribution shall not be returned to the Employer, but losses attributable thereto shall reduce the amount to be so returned. If the return to the Employer of the amount attributable to the mistaken contribution would cause the balance of any Participant's account as of the date such amount is to be returned (determined as if such date coincided with the close of a Plan Year) to be reduced to less than what would have been the balance of such account as of such date had the mistaken amount not been contributed, the amount to be returned to the Employer shall be limited so as to avoid such reduction.

Any Before-Tax Contributions returned to an Employer pursuant to this Section 4.5 shall be treated as the return of Untaxed Contributions, up to the extent Untaxed Contributions were made by such Participant to the Plan for such Plan Year and, to the extent that the returned contributions exceed such Untaxed Contributions, such returned contributions shall be treated as Designated Roth Contributions made by the Participant to the Plan for the Plan Year.

ARTICLE 5

EMPLOYEE CONTRIBUTIONS

Section 5.1 . After-Tax Contributions .

Subject to the limitations set forth in Section 4.4 (relating to limitations on contributions for highly-compensated Eligible Employees) and Section 7.4 (relating to limitations on allocations imposed by section 415 of the Code), each Participant who is an Eligible Employee may elect in accordance with Section 3.2(a) to make After-Tax Contributions under the Plan by payroll deduction. After-Tax Contributions made by a Participant who is a member of a bargaining unit represented by IBEW Local Union 15 for any payroll period shall equal a whole percentage not less than 1 nor more than 10 percent of the Participant's Compensation for such payroll period, as designated by the Participant in his or her request pursuant to Section 3.2(a). After-Tax Contributions made by any other Participant for any payroll period shall equal a whole percentage not less than 1 nor more than 20 percent and, effective as of January 1, 2006, 50 percent, of the Participant's Compensation for such payroll period, as designated by the Participant in his or her request pursuant to Section 3.2(a). Except as set forth below, After-Tax Contributions shall be delivered to the Trustee no less frequently than bi-weekly. In addition, if back-pay is awarded to a Participant who is an Eligible Employee and any portion of such back-pay constitutes Compensation as defined in subsection (13) of Article 2 (relating to the definition of compensation), After-Tax Contributions shall be made for such Participant in an amount equal to the After-Tax Contribution percentage, which was most recently chosen by the Participant in his or her request pursuant to Section 3.2(a), of such back-pay that constitutes Compensation. An

After-Tax Contribution described in the preceding sentence shall be treated under the Plan in the same manner as all other After-Tax Contributions and shall be delivered to the Trustee as soon as practicable after the back-pay is paid to the Participant. Except as provided in the following sentence and in Section 4.1, After-Tax Contributions shall be subject to the same provisions regarding commencement, change and suspension applicable to Before-Tax Contributions as set forth in Section 4.1. If a Participant who has not attained age 59 $^{1}/_{2}$ makes a withdrawal of After-Tax Contributions pursuant to Section 8.1(c), then: (a) After-Tax Contributions made by such Participant pursuant to this Section 5.1 shall cease beginning with the first payroll period beginning after the date on which the Participant receives such withdrawal and (b) such Participant shall not again be eligible to elect such contributions until the first payroll period that coincides with or follows the date on which contributions ceased by 6 months.

Section 5.2 . Rollover Contributions .

(a) The Trustee shall be authorized to receive, hold and distribute in accordance with the Plan, a direct rollover contribution consisting of cash, transferred to the Plan by (i) a qualified plan described in section 401(a) or 403(a) of the Code, including after-tax employee contributions to such plan, (ii) an annuity contract described in section 403(b) of the Code, excluding after-tax employee contributions or (iii) an eligible plan under section 457(b) of the Code which is maintained by a state, political subdivision of a state, or any agency or instrumentality of a state or political subdivision of a state. The Trustee shall also be authorized to receive, hold and distribute in accordance with the Plan, a Participant contribution of an eligible rollover distribution from (A) a qualified plan described in section 401(a) or 403(a) of the Code, (B) an annuity contract described in section 403(b) of the Code, (C) an eligible plan under section 457(b) of the Code which is maintained by a state, political subdivision of a state, or any agency or instrumentality of a state or political subdivision of a state or (D) an individual retirement account or annuity

described in section 408(a) or 408(b) of the Code that is eligible to be rolled over and would otherwise be includible in gross income. The amounts transferred must be eligible rollover distributions, as defined in section 402(c) of the Code. Effective December 1, 2012, an eligible rollover distribution of a lump sum amount from a qualified defined benefit plan sponsored by the Company also may be contributed to this Plan in accordance with administrative rules established by the Administrator. Notwithstanding any provision of the Plan to the contrary, a rollover contribution shall not include "designated Roth contributions" described in section 402A of the Code or any related earnings with respect to such contributions.

(b) Delivery of Rollover Contributions to Administrator . Except as otherwise provided in paragraph (a) of this Section 5.2, if an individual desires to make a rollover contribution pursuant to such paragraph (a), such contribution either (i) shall be delivered by the individual to the Administrator and by the Administrator to the Trustee on or before the 60th day after the day on which the Employee receives the distribution or on or before such later date as may be prescribed by law, or (ii) shall be transferred on behalf of the individual directly from the trust from which the eligible rollover distribution is made. Any contribution that is delivered by the Eligible Employee must be accompanied by (i) a statement of the Employee that to the best of his or her knowledge the amount so transferred meets the conditions specified in paragraph (a) of this Section 5.2, (ii) a copy of such documents as may have been received by the Employee advising him or her of the amount of and the character of such distribution and (iii) any investment election with respect to such contribution in such form and manner as may be required by the Administrator. Notwithstanding the foregoing, the Administrator shall not accept a rollover contribution if in its judgment accepting such contribution would cause the Plan to violate any provision of the Code or Regulations, and the Administrator shall not be required to accept such a contribution to the extent it consists of property other than cash.

Section 5.3 . Special Accounting Rules for Rollover Contributions .

If a rollover contribution is made by or on behalf of an Employee, the Administrator shall cause a Rollover Account to be established and maintained for such Employee to which shall be credited all rollover contributions made pursuant to Section 5.2. A rollover contribution shall be credited to such Rollover Account as of the Valuation Date coinciding with or next following the date on which such contribution is delivered to the Trustee.

If a rollover contribution is made by, or a direct transfer is made on behalf of, an Eligible Employee prior to becoming a Participant, such Eligible Employee shall until such time as he or she becomes a Participant be deemed to be a Participant, and his or her Rollover Account and After-Tax Contributions Account, if any, shall be deemed to be an account of a Participant, for all purposes of the Plan except for the purposes of the allocation of contributions provided for in paragraphs (a), (b), (c), (d) and (e) of Section 7.3 and any determination of when he or she becomes a Participant pursuant to Article 3.

ARTICLE 6

TRUST AND INVESTMENT FUNDS

Section 6.1 . Trust .

A Trust shall be created by the execution of a trust agreement between the Company and the Trustee. All contributions under the Plan shall be paid to the Trustee. The Trustee shall hold all monies and other property received by it and invest and reinvest the same, together with the income therefrom, on behalf of the Participants collectively in accordance with the provisions of the trust agreement. The Trustee shall make distributions from the Trust Fund at such time or times to such person or persons and in such amounts as the Administrator directs in accordance with the Plan.

Section 6.2 . Investment Funds .

The Trustee shall establish and maintain, or shall cause to be established and maintained, an investment fund herein called the "Employer Stock Fund" which shall be invested in Common Stock, and shall also include such short-term obligations and short-term liquid investments purchased by the Trustee, in accordance with the Trust Agreement, pending the selection and purchase of the Common Stock or as otherwise determined by the Trustee to be necessary to satisfy such fund's cash needs. In addition, as directed by the Investment Office, one or more additional separate investment funds shall be established and maintained and shall be invested as directed by the Investment Office. The Investment Office also may, from time to time, and in its sole discretion, segregate any of the assets held under any investment fund established pursuant to this Section 6.2 and allocate the investment results from such segregated assets among all or a portion of the accounts of Participants in such manner as it shall determine to be appropriate. All charges and expenses incurred in connection with the purchase and sale of investments for a fund shall be charged to such fund except to the extent such charges and expenses are paid by the Employers or from other revenue available to the Plan.

ARTICLE 7

PARTICIPANT ACCOUNTS AND INVESTMENT ELECTIONS

Section 7.1 . Participant Accounts and Investment Elections .

(a) Participant Accounts . For each Participant the Administrator shall establish and maintain, or shall cause to be established and maintained, investment accounts to which amounts contributed under the Plan shall be credited according to each Participant's investment elections pursuant to paragraph (b) of this Section 7.1, subject to the penultimate sentence of the first paragraph of Section 6.2 (relating to the Investment Office's authority to segregate any of the assets held under any investment fund).

Each such investment account shall, to the extent appropriate, be composed of the following accounts: (A) a Before-Tax Contributions Account, which shall be divided into an Untaxed Contribution Account and a Designated Roth Contributions Account, (B) a Catch-Up Contributions Account, (C) an Employer Matching Contributions Account, (D) an After-Tax Contributions Account, and (E) a Rollover Account. Earnings and losses on investment of funds in each account shall be credited or debited to that account.

All such accounts and subaccounts shall be for accounting purposes only, and there shall be no segregation of assets within the investment funds among the separate Participants' accounts.

(b) Investment Election . Each Participant, as part of his or her request for participation described in Section 3.2 (or in connection with the delivery of a rollover contribution pursuant to Section 5.2), shall make an investment election that shall apply to the investment of contributions to be made on his or her behalf or by him or her pursuant to Article 4 (relating to Employer contributions) or Article 5 (relating to Employee contributions) and any earnings on such contributions. Such election shall specify that such contributions be invested either (i) wholly in one of the funds maintained or employed by the Trustee pursuant to paragraph (a) of this Section 7.1 or (ii) divided among such funds in 1 percent increments or in such other increments established by the Administrator or the Investment Office from time to time. Each Eligible Employee for whom a Rollover Account is established before such Eligible Employee has become a Participant shall, in the manner prescribed by the Administrator, make such investment election as of the Valuation Date on which such account is established. During any period in which no direction as to the investment of an Employee's account is on file with the Administrator, contributions or direct transfers made by him or her, or on his or her behalf, to the Plan will be invested in such manner as the Investment Office shall determine.

(c) Change of Investment Election . Subject to such restrictions as may be imposed by the Administrator or the Investment Office (including, without limitation, any restrictions imposed with respect to transfers of funds to or from the Employer Stock Fund described in Section 6.2 by individuals who are subject to Rule16b-3 under section 16 of the Securities Exchange Act of 1934), a Participant may elect to change as of any Valuation Date his or her investment election applicable to all or any portion of his or her current account balance. In addition, a Participant may elect to change as of the first day of any payroll period his or her investment election applicable to future contributions made pursuant to Articles 4 (relating to Employer contributions) or 5 (relating to Employee contributions), or both, as specified by the Participant. Such changes shall be limited to the investment funds then maintained or employed by the Trustee pursuant to paragraph (a) of this Section 7.1. A Participant's change of investment election must be made in the manner and at the time prescribed by the Administrator (or its delegate). Any such change shall specify that such contributions be invested either (i) wholly in one of the funds maintained or employed by the Trustee pursuant to paragraph (a) of this Section 7.1, or (ii) divided among such funds in 1 percent increments or such other increments established by the Administrator or the Investment Office from time to time.

Section 7.2 . Allocation of Net Income of Trust Fund and Fluctuation in Value of Trust Fund Assets .

In the event that contributions, income and losses are not otherwise specifically allocated to Participant accounts by the Trustee, as soon as practical after each Valuation Date, the net worth of each investment fund (as defined in Section 6.2) as of such Valuation Date shall be determined. If the net worth of such investment fund as so determined is more or less than the total of all

balances credited as of such Valuation Date to the subaccounts of Participants invested in the investment fund as of such Valuation Date who are Participants as of such Valuation Date, the amount of any excess or deficiency shall be prorated and credited or charged to such subaccounts proportionally to the balances of such subaccounts as of the preceding Valuation Date after making all allocations for such preceding Valuation Date prescribed by this Article and after decreasing each such subaccount by any loans, withdrawals or distributions from such subaccount during such period (but not less than zero), with all of such decreases to be made in such manner as the Administrator determines in its discretion to be necessary.

Notwithstanding any provision of this Article 7, any Designated Roth Contributions Account shall be maintained in a manner that satisfies the separate accounting requirement, and any Regulations or other requirements promulgated, under section 402A of the Code. Accordingly, gains, losses and other credits and charges shall be separately allocated on a reasonable basis to each such account and other accounts under the Plan, the Plan shall keep a record of each Participant's Designated Roth Contributions that have not been withdrawn, and contributions and withdrawals of Designated Roth Contributions, and related earnings, shall be accounted for with respect to Designated Roth Contributions Accounts. However, forfeitures shall not be allocated to any Designated Roth Contributions Account. These separate accounting requirements apply with respect to a Participant from the time the Participant makes his or her first Designated Roth Contribution until the time the Participant's Designated Roth Contributions Account is distributed.

Section 7.3 . Allocations of Contributions Among Participants' Accounts .

(a) Allocation of Before-Tax Contributions . Before-Tax Contributions shall be allocated to the Before-Tax Contributions Account of each Participant for whom such contributions are made as soon as practical after such contributions are delivered to the Trustee or insurer maintaining a group annuity contract. The Before-Tax Contributions that consist of (i) Before-Tax Contributions made on behalf of the Participant pursuant to Section 4.1 for Plan Years beginning prior to (A) in the case of a Participant who is not a Local 15 Member, January 1, 2006, and (B) in the case of a Participant who is a Local 15 Member, January 1, 2009, (ii) any Before-Tax Contributions transferred to the Plan from the PECO Energy Company Employee Savings Plan on behalf of such Participant, and (iii) any Before-Tax Contributions that are Untaxed Contributions made pursuant to Section 4.2 for Plan Years beginning on or after (A) in the case of a Participant who is not a Local 15 Member, January 1, 2006, and (B) in the case of a Participant who is a Local 15 Member, January 1, 2009, shall be allocated to the Untaxed Contributions Account of such Participant. The Before-Tax Contributions that consist of Designated Roth Contributions made on behalf of the Participant pursuant to paragraph (c) Section 4.2 (relating to Untaxed Contributions and Designated Roth Contributions) for Plan Years beginning on or after (A) in the case of a Participant who is not a Local 15 Member, January 1, 2006, and (B) in the case of a Participant who is a Local 15 Member, January 1, 2009, January 1, 2006 shall be allocated to the Designated Roth Contributions Account of such Participant.

(b) Allocation of Catch-Up Contributions . Catch-Up Contributions shall be allocated to the Catch-Up Contributions Account of each Participant for whom such contributions are made as soon as practical after such contributions are delivered to the Trustee or insurer maintaining a group annuity contract.

(c) Allocation of Employer Matching Contributions . Employer Matching Contributions shall be allocated to the Employer Matching Contributions Account of each Participant for whom such contributions are made as soon as practical after such contributions are delivered to the Trustee or insurer maintaining a group annuity contract.

(d) Allocation of After-Tax Contributions . After-Tax Contributions shall be allocated to the After-Tax Contributions Account of the Participant who makes such contributions as soon as practical after such contributions are delivered to the Trustee or insurer maintaining a group annuity contract.

(e) Allocation of Rollover Contributions and Direct Transfers . Rollover contributions made pursuant to Article 5 (relating to Employee contributions) shall be credited to the Rollover Account of the Participant on whose behalf such contribution is made as of the Valuation Date coinciding with or next following the date on which the contribution is delivered to the Trustee.

(f) Allocation of Forfeitures . The total amount forfeited during any Plan Year shall be used to (i) pay the expenses incurred by the Trustee for the administration of the Trust Fund not paid by the Company, (ii) held to pay the expenses reasonably estimated by the Trustee for the administration of the Trust Fund during the next following Plan Year but not expected to be paid by the Company, or (iii) used to reduce Employer Matching Contributions as determined by the Administrator.

Section 7.4 . Limitations on Allocations Imposed by Section 415 of the Code .

Notwithstanding any other provision of the Plan, the amount allocated to a Participant's accounts under the Plan for each Plan Year shall be limited so that the aggregate annual additions to the Participant's accounts under this Plan and in all other defined contribution plans maintained by an Employer shall not exceed the lesser of: (A) $46,000 (as adjusted pursuant to section 415(d) of the Code) and (B) 100% of the Participant's compensation for such Plan Year.

If the amount to be allocated to a Participant's accounts pursuant to Section 7.3 (relating to allocations of contributions among Participant's accounts) for a Plan Year would exceed the limitation set forth in this Section 7.4, then such excess shall be reduced before allocations are made to the Participant's accounts. If, in any Plan Year, the annual additions actually allocated to the Participant's accounts exceed the limitation set forth in this Section 7.4, then such annual additions shall be corrected in accordance with the Employee Plans Compliance Resolution System of the Internal Revenue Service.

For purposes of this Section 7.4, the "annual additions" for a Plan Year to a Participant's accounts in this Plan and in any other defined contribution plan maintained by an Employer is the sum during such Plan Year of:

(a) the amount of Employer contributions (including Before-Tax Contributions and Designated Roth Contributions and excluding any Default Before-Tax Contributions that are withdrawn pursuant to paragraph (c)(ii) of Section 3.2) allocated to the Participant's accounts, excluding, however, (X) Before-Tax Contributions and Designated Roth Contributions that are "catch-up contributions" made pursuant to section 414(v) of the Code, (Y) excess deferrals that are distributed in accordance with section 402(g) of the Code and (Z) restorative payments (within the meaning of section 1.415(c)-1(b)(2)(ii)(C) of the Regulations),

(b) the amount of forfeitures allocated to the Participant's accounts,

(c) the amount of Employee contributions allocated to the Participant accounts, but excluding any rollover contributions, direct transfers or loan repayments, and

(d) the contributions allocated on behalf of the Participant to any individual medical benefit account (as defined in section 415(l) of the Code) or, if the Participant is a key employee within the meaning of section 419A(d)(3) of the Code, to any post-retirement medical benefits account established pursuant to section 419A(d)(1) of the Code.

For purposes of this Section 7.4, "defined contribution plan" shall have the meaning set forth in section 415 of the Code and Regulations, and the term "Employer" shall include all Affiliates except that in defining Affiliates "more than 50 percent" shall be substituted for "at least 80 percent" where required by section 415(g) of the Code. In addition, for purposes of this Section 7.4, "compensation" shall mean a Participant's compensation as defined under section 415(c)(3) of the Code (as amended from time to time).

Section 7.5 . Correction of Error .

If it comes to the attention of the Administrator that an error has been made in any of the allocations prescribed by this Article or an error has been made in any other respect, appropriate adjustment shall be made to the accounts of all Participants and designated Beneficiaries that are affected by such error, except that no adjustment need be made with respect to any Participant or Beneficiary whose account has been distributed in full prior to the discovery of such error.

ARTICLE 8

WITHDRAWALS AND DISTRIBUTIONS

Section 8.1 . Withdrawals and Distributions Prior to Termination of Employment .

(a) Hardship Withdrawals . An Employee who has not attained age 59 1/2 may make a request by calling the VRU, or in such other manner as may be prescribed by the Administrator, to withdraw as of any date all or a portion of the balance of his or her Before-Tax Contributions Account (other than earnings credited to such account after December 31, 1988), Catch-Up Contributions Account and Employer Matching Contributions Account only if the Participant has incurred a financial hardship, except that while any loan to the Participant under Section 8.2 remains outstanding, the amount available for withdrawal under this paragraph (a) shall be the balance in such account less the balance of all outstanding loans to the Participant. The determination of the existence of financial hardship and the amount required to be distributed to satisfy the need created by the hardship will be made by the Administrator in a uniform and non-discriminatory manner subject to the following rules:

(A) A financial hardship shall be deemed to exist if, and only if, the Participant certifies to the Committee that the financial need is on account of:

(i) medical expenses described in section 213(d) of the Code incurred or anticipated to be incurred by the Participant, the Participant's Spouse or any dependents of the Participant (as defined in section 152 of the Code) or primary beneficiary;

(ii) funeral or burial expenses incurred by the Participant for the Participant's deceased parent, Spouse, children or dependent (as defined in section 152 of the Code, without regard to section 152(d)(1)(B) of the Code) or primary beneficiary;

(iii) the purchase (excluding mortgage payments) of a principal residence of the Participant;

(iv) the payment of tuition, related educational fees, and room and board expenses for up to the next twelve months of post-secondary education for the Participant, the Participant's Spouse, children or dependents (as defined in section 152 of the Code, without regard to sections 152(b)(1) and (2) and 152(d)(1)(B) of the Code) or primary beneficiary;

(v) the need to prevent eviction of the Participant from his or her principal residence or foreclosure of mortgage of the Participant's principal residence; or

(vi) expenses for the repair of damage to the Participant's principal residence that would qualify for the casualty deduction under section 165 of the Code (determined without regard to whether the loss exceeds 10% of adjusted gross income).

For purposes of the foregoing, an individual is a Participant's "primary beneficiary" if the Participant has designated him or her as a "Beneficiary" under Section 8.5 and such individual has an unconditional right to all or a portion of the Participant's accounts upon the Participant's death.

(B) A distribution shall be deemed to be necessary to satisfy a financial need of the Participant if, and only if, the Participant:

(i) has obtained all distributions, other than hardship withdrawals, and all nontaxable loans under any Employer's plan in which the Participant participates, and

(ii) demonstrates to the satisfaction of the Administrator that the distribution is not in excess of the amount of the immediate and heavy financial need, which need shall include amounts necessary to pay any federal, state and local income taxes, excise taxes and penalties.

If a Participant receives a hardship withdrawal pursuant to this paragraph (a), then, in addition to the cessation of Before-Tax Contributions and After-Tax Contributions required by paragraph (a) of Section 4.1 (relating to initial election regarding regular payroll Before-Tax Contributions), contributions by the Participant to qualified or nonqualified plans of deferred compensation, including a stock option, stock purchase or similar plan, maintained by an Employer also shall (except where excused by regulation) cease beginning with the first payroll period beginning after the date on which the Participant receives such hardship withdrawal and continuing until the first payroll period that coincides with or follows the date on which contributions ceased by six months.

The Participant shall designate the extent to which the hardship withdrawal pursuant to this paragraph (a) are Designated Roth Contributions from the Participant's Designated Roth Contributions Account and the extent that such withdrawals are Untaxed Contributions from the Participant Untaxed Contributions Account and in the event that any such designation is not made or is incomplete, such hardship withdrawals shall be treated as withdrawals of Designated Roth Contributions to the extent Designated Roth Contributions were made to the Plan and, to the extent that the hardship withdrawal exceeds such Designated Roth Contributions, such hardship withdrawal shall be treated as Untaxed Contributions.

(b) Withdrawals After Age 59 1/2. An Employee who has attained age 59 1/2 may make a request by calling the VRU, or in such other manner as may be prescribed by the Administrator, to withdraw as of any date an amount which is not greater than the balance of his or her Before-Tax Contributions Account, Catch-Up Contributions Account and Employer Matching Contributions Account as of the most recent Valuation Date determined by the Administrator, except that while any loan to the Participant under Section 8.2 remains outstanding, the amount available for withdrawal shall be the balance in such accounts less the balance of all outstanding loans to the Participant.

The Participant shall designate the extent to which the withdrawal pursuant to this paragraph (b) are Designated Roth Contributions from the Participant's Designated Roth Contributions Account and the extent that such withdrawals are Untaxed Contributions from the Participant's Untaxed Contributions Account and in the event that any such designation is not made or is incomplete, such withdrawals shall be treated as withdrawals of Designated Roth Contributions to the extent Designated Roth Contributions were made to the Plan and, to the extent that the withdrawal exceeds such Designated Roth Contributions, such withdrawal shall be treated as Untaxed Contributions.

(c) Withdrawals From the After-Tax Contributions Account . An Employee may make a request by calling the VRU, or in such other manner as may be prescribed by the Administrator, no more than once during any Plan Year, to withdraw from his or her After-Tax Contributions Account an amount which is not greater than the balance of the Participant's After-Tax Contributions Account as of the most recent Valuation Date determined by the Administrator, except that while any loan to the Participant under Section 8.2 remains outstanding, the amount available for withdrawal shall be the balance in such account less the balance of all outstanding loans to the Participant.

(d) Withdrawals from the Rollover Account . A Participant may make a request by calling the VRU, or in such other manner as may be prescribed by the Administrator, to withdraw an amount which is not greater than the balance in his or her Rollover Account as of the most recent Valuation Date determined by the Administrator, except that while any loan to the Participant under Section 8.2 remains outstanding, the amount available for withdrawal shall be the balance in such account less the balance of all outstanding loans to the Participant.

(e) Qualified Reservist Withdrawals . A Participant who is a Qualified Reservist may make a request by calling VRU, or in such manner as may be prescribed by the Administrator, to withdraw any portion of his or her Before-Tax Contributions Account or his or her Designated Roth Contributions Account, and the amount requested shall not be subject to the 10 percent additional tax imposed pursuant to section 72(t)(2)(G) of the Code, provided that the amount requested is distributed during the period beginning on the date the Participant is ordered or called to active duty and ending at the close of his or her active duty.

(f) Withdrawals of Employer Matching Contributions for Members of IBEW Local Union 614 . Notwithstanding any provision in the Plan to the contrary, effective April 16, 2010, a Participant who is a member of a bargaining unit represented by IBEW Local Union 614 and who has completed 60 months as a Participant may elect, in accordance with procedures established by the Administrator, to receive a distribution of all or any part of his or her Employer Matching Contributions Account, as adjusted for gains, earnings and losses attributable thereto determined as of the Valuation Date next succeeding the date of receipt of the request for distribution.

Additionally, effective April 16, 2010, a Participant who is a member of a bargaining unit represented by IBEW Local Union 614, regardless of whether he or she has completed 60 months as a Participant, may elect, in accordance with procedures established by the Administrator, to receive a distribution of all or any part of that portion of the Employer Matching Contributions Account that is derived from Employer Matching Contributions in excess of Employer Matching Contributions allocated to his or her Employer Matching Contributions Account during the two Plan Years preceding the Plan Year in which the withdrawal takes place, adjusted for gains, earnings and losses attributable thereto determined as of the Valuation Date next succeeding the date of receipt of the request for distribution.

No distribution made pursuant to this paragraph (f) may be for an amount which is less than the lesser of (i) $200; and (ii) the balance of the Participant's Employer Matching Contributions Account, as adjusted for gains, earnings and losses attributable thereto. In addition, a Participant may not make more than one withdrawal pursuant to this paragraph (f) in any Plan Year.

(g) Provisions Applicable to All Withdrawals . Any withdrawal made pursuant to this Section 8.1 shall be made at such time as prescribed by the Administrator and shall be made pro-rata from each of the investment funds in which as of the date of the withdrawal (i) in the case of a withdrawal pursuant to paragraph (a) or (b) of this Section 8.1, the Participant's Before-Tax Contributions Account, Catch-Up Contributions Account (and, if applicable, Employer Matching Contributions Account) is invested, (ii) in the case of a withdrawal pursuant to paragraph (c) of this Section 8.1, the Participant's After-Tax Contributions Account is invested, (iii) in the case of a withdrawal pursuant to paragraph (d) of this Section 8.1, the Participant's Rollover Account is invested, (iv) in the case of a withdrawal pursuant to paragraph (e) of this Section 8.1, the Participant's Before Tax Contributions Account and Designated Roth Contributions Account, and (v) the case of a withdrawal pursuant to paragraph (f) of this Section 8.1, the Participant's Employer Matching Contribution Account. Notwithstanding anything in the Plan to the contrary, the Administrator or the Investment Office may impose any restrictions it deems necessary or appropriate with respect to withdrawals by individuals who have any portion of their accounts invested in the Employer Stock Fund described in Section 6.2 and who are subject to Rule 16b-3 under section 16 of the Securities Exchange Act of 1934.

(h) Dividend Distributions in Respect of the Employer Stock Fund . Dividends shall be allocated to the accounts of each Participant, any portion of whose account balance is invested in the Employer Stock Fund in accordance with paragraph (b) of Section 7.1, based upon the total number of shares of Common Stock represented by the Participant's proportionate share of the Employer Stock Fund as of such date as may be determined from time to time by the Administrator on or before each dividend record date. Cash dividends shall be reinvested in Common Stock (through the Employer Stock Fund) unless the Participant (or his or her Beneficiary) elects, at the time and in the manner prescribed by the Administrator, to receive a cash distribution in an amount equal to such dividend, payable not later than 90 days after the end of the Plan Year in which such dividend was paid.

Section 8.2 . Loans to Participants .

(a) Making of Loans . Subject to the restrictions set forth in this Section 8.2, the Administrator shall establish a loan program whereby any Participant who is a party-in-interest (within the meaning of section 3(14) of ERISA) or any Beneficiary who is a party-in-interest and any such Participant's Beneficiary may request, in the manner and form prescribed by the Administrator, to borrow funds from the Plan. The principal amount of such loan shall be not less than $1,000 and the aggregate amount of all outstanding loans to a Participant or Beneficiary shall not exceed the lesser of: (1) 50% of the value of the aggregate of the Participant's vested account balances as of the Valuation Date coinciding with or immediately preceding the day on which the loan is made; and (2) $50,000, reduced by the excess, if any, of the highest outstanding loan balances of the Participant under all plans maintained by the Employer during the period of time beginning one year and one day prior to the date such loan is to be made and ending on the date such loan is to be made over the outstanding balance of loans from all such plans on the date on which such loan was made.

(b) Restrictions . Any loan approved by the Administrator pursuant to the preceding paragraph (a) shall be made only upon the following terms and conditions:

(1) The period for repayment of the loan shall be arrived at by mutual agreement between the Administrator and the Participant but such period shall not exceed five years or, in the case of a loan to acquire a principal place of residence, shall not be less than five years or more than 15 years, from the date of the loan. Such loan may be prepaid at any time, without penalty, by delivery to the Administrator of a check in an amount equal to the entire unpaid balance of such loan. No partial prepayment shall be permitted. Except as otherwise provided under uniform and nondiscriminatory procedures established by the Administrator, any loan to a Participant who is an Employee is due in full immediately after termination of employment.

(2) No loan shall be made to a Participant who is an Employee unless such Participant consents to have such loan repaid in substantially equal installments deducted from the regular payments of the Participant's compensation during the term of the loan. A Participant who (a) was an Employee at the time the Participant received a loan from the Plan, (b) is no longer an Employee and no longer receives compensation from an Employer, but (c) continues to perform services for an Employer, shall consent, either at the time the loan is taken or prior to the date prescribed by the Administrator, to have the balance of any loan outstanding at the time the Participant no longer is an Employee repaid in substantially equal installments over the remaining life of the loan. Such installments shall be paid in the manner specified by the Administrator.

(3) Each loan shall be evidenced by the Participant's collateral promissory note, in the form prescribed by the Administrator, for the amount of the loan, with interest, payable to the order of the Plan, and shall be secured by an assignment of 50% of the Participant's vested account balance.

(4) Each loan shall bear a fixed interest rate commensurate with the interest rates then being charged by persons in the business of lending money for loans made under similar circumstances, as determined by the Administrator.

(5) Except as otherwise provided in this Plan, no withdrawal (other than a withdrawal from a Participant's accounts to the extent that such withdrawal would not reduce the Participant's vested account balances to less than the then outstanding balance of any loan to such Participant or such higher amount determined by the Administrator to be appropriate security for such loan) or distribution shall be made to any Participant who has borrowed from the Trust, or to a Beneficiary of any such Participant, unless and until the loan, including interest, has been repaid.

(6) A charge shall be made against the account of each Participant requesting a loan equal to such reasonable loan application fee (and loan acceptance fee, if required by the Administrator) as shall be set from time to time by the Administrator.

(7) A Participant is permitted only one loan in any calendar year, provided, however, that no more than five loans to a Participant may be outstanding at any time, except that for a Participant described in the following sentence, no more than three loans may be outstanding at any time (for the period beginning April 1, 2009 and ending August 31, 2010, only one of such outstanding loans may be for the purpose of acquiring a principal place of residence and only two of such outstanding loans may be for other

purposes). A Participant described in the preceding sentence is any of the following: (A) a Participant who is a member of a bargaining unit represented by IBEW Local Union 15, (B) a Participant who is employed at Byron in Nuclear Security and is a member of United Security System Union Local 1, (C) a Participant who is employed at Oyster Creek in Nuclear Security and is a member of United Government Security Officers of America Local 17, (D) a Participant who is employed at Three Mile Island in Nuclear Security in Nuclear Security and is a member of United Government Security Officers of America Local 18, and (E) a Participant who is classified by an Employer as a management employee.

(8) Loan repayments shall be invested in the various investment funds as elected by the Participant.

(9) The Administrator may, in its sole discretion, restrict the amount to be disbursed pursuant to any loan request to the extent it deems necessary to take into account any fluctuations in the value of a Participant's accounts since the Valuation Date immediately preceding the date on which such loan is to be made.

(10) Any restrictions the Administrator or the Investment Office determines are necessary or appropriate with respect to loans requested by individuals who have any portion of their accounts invested in the Employer Stock Fund described in Section 6.2 and who are subject to Rule 16b-3 under section 16 of the Securities Exchange Act of 1934.

If any loan or portion of a loan made to a Participant under the Plan, together with the accrued interest thereon, is in default (taking into account any grace period permitted by law, and as determined by the Administrator), the Administrator shall take appropriate steps to collect on the note and foreclose on the security. If upon a Participant's termination of employment entitling the Participant to a distribution under Section 8.3 (relating to distributions upon termination of employment), death or retirement, any loan or portion of a loan made to such Participant under the Plan, together with the accrued interest thereon, remains unpaid, such unpaid amount may be repaid to the Plan no later than the last day of the calendar quarter following the calendar quarter in which such termination of employment occurred or as of such later date or dates permitted under uniform and nondiscriminatory procedures established by the Administrator. If full repayment is not so made, an amount equal to the unpaid portion of such loan, together with the accrued interest thereon, shall be charged to the Participant's accounts after all other adjustments required under the Plan, but before any distribution pursuant to Section 8.3 (relating to distributions upon termination of employment).

(c) Loan Subaccount . The Trustee shall establish and maintain a loan subaccount on behalf of each Participant or Beneficiary to whom a loan is made under this Section 8.2. Such subaccount shall represent the investment of the Participant's or Beneficiary's account in such loan. As of the Valuation Date immediately preceding the date on which a loan is approved, the Participant's or Beneficiary's loan subaccount shall be credited with the amount of the loan and thereafter shall be debited with repayments of the principal of such loan. The various accounts maintained for the Participant or Beneficiary shall be invested in the loan subaccount and debited by the amount of the loan and credited with payments of interest on, and repayments of principal of, such loan in accordance with uniform rules established by the Administrator.

(d) Sarbanes-Oxley . Notwithstanding any provision of the Plan to the contrary, the Administrator reserves the right to deny the request of a Participant for a loan that, in the judgment of the Administrator, would violate any provision of the Sarbanes-Oxley Act of 2002.

Section 8.3 . Distributions Upon Termination of Employment .

(a) Termination of Employment under Circumstances Entitling Participant to Full Distribution of His or Her Account Balance . If a Participant terminates employment, the Participant, or his or her designated Beneficiary, as the case may be, shall be entitled to receive the entire balance of the Participant's accounts, at the time set forth in Section 8.4 (relating to time of distribution) and in the manner set forth in paragraph (b) of this Section 8.3.

(b) Form of Distribution . (1) Subject to paragraph (d) of this Section 8.3 (relating to small benefits payable in lump sum), any distribution to which a Participant or Beneficiary, as the case may be, becomes entitled upon termination of employment shall be distributed by whichever of the following forms of distribution the Participant or Beneficiary, as the case may be, elects by calling the VRU, or in such other manner as may be prescribed by the Administrator:

(A) By payment in a lump sum.

(B) By payment in a series of approximately equal annual, quarterly, or monthly installments, over a period of up to 15 years; provided that installments shall not be available with respect to amounts invested in the CNA 1997 guaranteed investment contract.

A Participant who elected to receive distribution of his or her vested account balance in the form of installments may, at any time after such election is made, elect to receive the remaining amount of his or her vested account balance in the form of a lump sum payment. If no election is made by a Participant or Beneficiary, as the case may be, as to the form of distribution, the Participant's vested account balance shall be distributed in the form of a lump sum payment.

The amount distributed hereunder shall be paid in cash, except that if the Participant's account is paid in a lump sum, then the Participant may request that all of his or her account invested in the Employer Stock Fund be distributed in whole shares of Common Stock held in such Fund with any fractional share being paid in cash. The number of shares of Common Stock to be distributed shall be based on the current fair market value of a share of Common Stock as determined by the Trustee under Section 7.2 (relating to allocation of net income of Trust Fund and fluctuation in value of Trust assets) as of the Valuation Date coinciding with or immediately preceding the date payment of the Participant's account is to be made. Requests for distribution in the form of Common Stock shall be made at such time and in such manner as the Administrator shall determine under rules and regulations which are uniformly applied.

Notwithstanding the preceding paragraphs, no distribution shall be made in the form of installments with respect to a Participant's Rollover Account that was established to hold the amount distributed or directly transferred from the Commonwealth Edison Company Employee Stock Ownership Plan upon such plan's termination if the Participant elected not to receive distribution of such amount until his or her 65th birthday.

(c) Notice of Availability of Election of Optional Forms of Benefits . No less than 30 days (or such shorter period as permitted by law) and no more than 90 days before distribution is to be made hereunder, the Administrator, or its designee, shall explain to the Participant that he or she may elect either form of distribution set forth in paragraph (b) of this Section 8.3. Such explanation shall include a general description of the eligibility conditions and other material features of the optional forms of distribution provided under the Plan. Notwithstanding the first sentence of this paragraph (c), distribution may commence less than 30 days after the description described above is given, provided that: (i) the Administrator, or its designee, clearly informs the Participant that the Participant has a right to a period of at least 30 days after receiving the explanation to consider the decision of whether or not to elect a distribution (and, if applicable, a particular distribution option), and (ii) the Participant, after receiving the explanation, affirmatively elects a distribution. The description referred to in this paragraph (c), as well as the explanation of the participant's right to a period of at least 30 days to consider such explanation before electing a distribution, shall be provided to the Participant through the VRU or in such other manner prescribed by the Administrator.

(d) Small Benefits Payable in Lump Sum . Notwithstanding any provision of the Plan to the contrary, if the vested amount of the Participant's account balances does not exceed $5,000, not including the value of the Participant's Rollover Account or, for distributions occurring on or after March 28, 2005, $1,000, including the value of the Participant's Rollover Account (such amount referred to herein as the "small benefit amount"), such vested amount shall be distributed in a lump sum cash payment as soon as administratively practicable after the Participant's termination of employment in accordance with such procedures as may be established by the Administrator.

(e) Direct Rollover Option . In the case of a distribution from the Plan (excluding any amount offset against the Participant's account balance to repay the outstanding balance of any unpaid loan) which is an "eligible rollover distribution" within the meaning of section 402(c)(4) of the Code, a Participant (or surviving Spouse of a Participant or a former Spouse who is an alternate payee under a qualified domestic relations order as defined in section 414(p) of the Code) may elect that all or any portion of such distribution shall be directly transferred as a rollover contribution from this Plan to (i) an individual retirement account described in section 408(a) of the Code, (ii) an individual retirement annuity described in section 408(b) of the Code, (iii) an annuity plan described in section 403(a) of the Code, (iv) an annuity contract described in section 403(b) of the Code, (v) a retirement plan qualified under section 401(a) of the Code (the terms of which permit the acceptance of rollover contributions), (vi) an eligible plan under section 457(b) of the Code which is maintained by an eligible employer described in section 457(e)(1)(A) of the Code (the terms of which permit the acceptance of rollover contributions) or (vii) effective January 1, 2008, a Roth IRA described in section 408A of the Code. However, in the case of a distribution of a Participant's After-Tax Contributions Account prior to January 1, 2007, such distribution shall only be directly transferred as a rollover contribution from this Plan to an account or annuity described in section 408 of the Code, or to such a retirement or annuity plan described in section 401(a) or 403(a) of the Code that is a defined contribution plan that agrees to separately account for amounts so transferred, including separately accounting for the portion of such amount which is includible in gross income and the portion of such distribution which is not so includible. In the case of a distribution of a Participant's After-Tax Contributions Account on or after January 1, 2007, such distribution shall only be directly transferred as a rollover

contribution to an account or annuity described in section 408 of the Code, or to such a qualified retirement or annuity plan described in section 401 (a) or 403(a) of the Code that agrees to separately account for amounts so transferred, including separately accounting for the portion of such amount which is includible in gross income and the portion of such distribution which is not so includible. Notwithstanding any provision of this paragraph (e), in the case of any eligible rollover distribution that includes all or any portion of the Participant's Designated Roth Contributions Account, a Participant or surviving Spouse or a former Spouse who is an alternate payee under a qualified domestic relations order as defined in section 414(p) of the Code may elect to transfer such portion only to another plan which accounts for Designated Roth Contributions described in section 402A of the Code or to a Roth IRA described in section 408A of the Code and only to the extent the rollover is permitted by the rules of section 402(c) of the Code. In addition, in the case of a distribution described in the preceding sentence that occurs on or after January 1, 2008, a Beneficiary who is not the surviving Spouse of the Participant may elect that all or any portion of such distribution shall be directly transferred as a rollover contribution from this Plan to (i) an individual retirement account described in section 408(a) of the Code, (ii) an individual retirement annuity described in section 408(b) of the Code or (iii) effective January 1, 2010, a Roth IRA described in section 408A of the Code, that, in either case, is established for the purpose of receiving such distribution on behalf of the Beneficiary.

Section 8.4 . Time of Distribution .

A Participant who has terminated employment shall commence receiving distribution of his or her vested account balance as soon as administratively practical after the Valuation Date coinciding with or immediately following the date on which the Participant attains age 65, except as provided below.

(1) Early Distribution . Except as provided in subparagraph (7), a Participant whose Termination Date is prior to his or her 65th birthday may elect by calling the VRU, or in such other manner as may be prescribed by the Administrator, prior to his or her termination of employment to have distribution of his or her vested account balance commence within 60 days after the Valuation Date coinciding with or immediately following the Participant's Termination Date.

(2) Deferral of Distribution . A Participant may elect by calling the VRU, or in such other manner as may be prescribed by the Administrator, which election shall be made at the time prescribed by the Administrator, that distribution of his or her vested account balance commence as soon as practicable after the Participant's attainment of age 70 $^{1}/_{2}$.

(3) Elections After Termination Date . Except as provided in subparagraph (7), a Participant who has terminated employment and whose distribution is to commence either after the Participant's attainment of age 65 or 70 $^{1}/_{2}$ may elect at any time by calling the VRU, or in such other manner as may be prescribed by the Administrator, to have distribution of his or her vested account balance made within 60 days after the date such election is made.

(4) Required Beginning Date . Distributions paid or commencing during the Participant's lifetime shall commence not later than April 1 of the calendar year following the calendar year in which the Participant attains age 70 $^{1}/_{2}$, except that distributions made to a Participant who is not a "five percent owner" (as defined in section 416(i) of the Code) may commence on April 1 of the calendar year following the later of the calendar year in which the Participant attains age 70 $^{1}/_{2}$ or the calendar year in which the Participant retires. Notwithstanding any provision of the Plan to the contrary, any distributions required by this subparagraph shall be made not less rapidly than in accordance with the final Regulations under Section 401(a)(9). The Participant shall designate the extent to which the distribution of Before-Tax Contributions pursuant to this subparagraph 4 are Designated Roth Contributions from the Participant's Designated Roth Contributions Account and the extent that such withdrawals are Untaxed Contributions from the Participant's Untaxed Contributions Account and in the event that any such designation is not made or is incomplete, such distribution shall be treated as a distribution of Designated Roth Contributions to the extent Designated Roth Contributions were made to the Plan and, to the extent that the distribution of Before-Tax Contributions exceeds such Designated Roth Contributions, such distribution shall be treated as Untaxed Contributions.

(5) Distributions Commencing After Participant's Death . Distributions commencing after the Participant's death shall be completed within five years after the death of the Participant, except that (i) effective with respect to any Participant whose death occurs on or after January 1, 1995, regardless of when such Participant's employment terminated, if the Participant's Beneficiary is the Participant's Spouse, distribution may be deferred until the date on which the Participant would have attained age 70 $^{1}/_{2}$ had he or she survived and (ii) if the Participant's Beneficiary is a natural person other than the Participant's Spouse and distributions commence not

later than one year after the Participant's death, such distributions may be made over a period not longer than the life expectancy of such Beneficiary. If at the time of the Participant's death, distribution of the Participant's benefit has commenced, the remaining portion of the Participant's benefit shall be paid in the manner elected by the Participant's Beneficiary, but at least as rapidly as was the method of distribution being used prior to the Participant's death.

(6) Distribution of Rollover Account After Termination Date . A Participant who has terminated employment or the Beneficiary of such Participant, as the case may be, may elect by calling the VRU, or in such other manner as may be prescribed by the Administrator prior to the time his or her vested account balance is distributed under this Section 8.4 to have distribution of the balance of his or her Rollover Account commence at such prior time as the Participant or Beneficiary shall elect, provided that, while any loan to the Participant under Section 8.2 remains outstanding, such distribution shall be made only to the extent that the balance of such Participant's vested account balance remaining after such distribution will equal or exceed the balance of all outstanding loans to the Participant.

(7) Compliance with Section 401(a)(9) of the Code . Notwithstanding any provision of the Plan to the contrary, all distributions will be made in accordance with section 401(a)(9) of the Code and the regulations promulgated thereunder, including the minimum distribution incidental death benefit requirement thereof. Notwithstanding the foregoing, any amount that would be a required minimum distribution described in section 401(a)(9) of the Code which is attributable to the 2009 calendar year will not be distributed to a Participant, or his or her Beneficiary, as applicable, unless such individual elects to receive such distribution. In addition, the five-year period described in subparagraph (5) above shall be determined without regard to calendar year 2009.

Notwithstanding anything contained herein to the contrary and except as provided in subparagraph (4) above, in the event that the recordkeeper for the Plan is changed, distributions may be made at such time as prescribed by the Administrator in order to accommodate the transfer of records to the new recordkeeper.

Section 8.5 . Designation of Beneficiary .

Each Participant shall have the right to designate a Beneficiary or Beneficiaries (who may be designated contingently or successively and that may be an entity other than a natural person) to receive any distribution to be made under Section 8.3 (relating to distributions upon termination of employment) upon the death of such Participant or, in the case of a Participant who dies subsequent to termination of his or her employment but prior to the distribution of the entire

amount to which he or she is entitled under the Plan, any undistributed balance to which such Participant would have been entitled, provided , however , that no such designation (or change thereof) shall be effective if the Participant was married on the date of the Participant's death unless such designation (or change thereof) was consented to at the time of such designation (or change thereof) by the person who was the Participant's Spouse, in writing, acknowledging the effect of such consent and witnessed by a notary public or a Plan representative, or it is established to the satisfaction of the Administrator that such consent could not be obtained because the Participant's Spouse cannot be located or such other circumstances as may be prescribed in Regulations. Subject to the preceding sentence, a Participant may from time to time, without the consent of any Beneficiary, change or cancel any such designation. Such designation and each change therein shall be made in the form prescribed by the Administrator and shall be filed with the Administrator. A Participant's beneficiary designation in effect under the PECO Energy Company Employee Savings Plan immediately prior to March 31, 2001 shall remain in effect under the Plan on and after March 31, 2001 until such time as such designation is changed or canceled in accordance with this Section 8.5. If (i) no Beneficiary has been named by a deceased Participant, (ii) such designation is not effective pursuant to the proviso contained in the first sentence of this section, or (iii) the designated Beneficiary has predeceased the Participant, any undistributed balance of the deceased Participant shall be distributed by the Trustee at the direction of the Administrator (a) to the surviving Spouse of such deceased Participant, if any, or (b) if there is no surviving Spouse, to the surviving children of such deceased Participant, if any, in equal shares, or (c) if there is no surviving Spouse or surviving children, to the surviving parents of such deceased Participant, if any, in equal shares, or (d) if there is no surviving Spouse, surviving children or surviving parents, to the executor or administrator of the estate of such deceased Participant or (e) if no executor or administrator has been appointed for the estate of such

deceased Participant within six months following the date of the Participant's death, in equal shares to the person or persons who would be entitled under the intestate succession laws of the state of the Participant's domicile to receive the Participant's personal estate. The marriage of a Participant shall be deemed to revoke any prior designation of a Beneficiary made by him or her and a divorce shall be deemed to revoke any prior designation of the Participant's divorced Spouse if written evidence of such marriage or divorce is timely received by the Administrator.

Section 8.6 . Distributions to Minor and Disabled Distributees .

Any distribution under this Article that is payable to a distributee who is a minor or to a distributee who, in the opinion of the Administrator, is unable to manage his or her affairs by reason of illness or mental incompetency may be made to or for the benefit of any such distributee at such time consistent with the provisions of Section 8.4 (relating to time of distribution) and in such of the following ways as the legal representative of such distributee shall direct: (a) directly to any such minor distributee if, in the opinion of such legal representative, the distributee is able to manage his or her affairs, (b) to such legal representative, (c) to a custodian under a Uniform Gifts to Minors Act for any such minor distributee, or (d) to some near relative of any such distributee to be used for the latter's benefit. Neither the Administrator nor the Trustee shall be required to see to the application by any third party other than the legal representative of a distributee of any distribution made to or for the benefit of such distributee pursuant to this Section.

Section 8.7 . "Lost" Participants and Beneficiaries .

If within a period of five years following the death or other termination of employment of any Participant the Administrator in the exercise of reasonable diligence has been unable to locate the person or persons entitled to benefits under this Article 8, the rights of such person or persons shall be forfeited, provided , however , that the Plan shall reinstate and pay to such person or

persons the amount of the benefits so forfeited upon a claim for such benefits made by such person or persons. The amount to be so reinstated shall be obtained from the total amount that shall have been forfeited pursuant to Section 8.3 (relating to distribution upon termination of employment) during the Plan Year that the claim for such forfeited benefit is made. If the amount to be reinstated exceeds the amount of such forfeitures, the Employer in respect of whose Employee the claim for forfeited benefit is made shall make a contribution in an amount equal to the remainder of such excess. Any such contribution shall be made without regard to whether or not the limitations set forth in Section 4.5 (relating to limitation on Employer contributions) will be exceeded by such contribution.

Section 8.8 . Death Benefits Under USERRA

Effective January 1, 2007, in the case of a Participant who dies while performing Military Service, the Beneficiaries of such Participant shall be entitled to any additional benefits, if any, (other than benefit accruals relating to the period of qualified military service) provided under the Plan had the Participant resumed employment with an Employer and then terminated such employment on account of such Participant's death.

ARTICLE 9

PARTICIPANTS' STOCKHOLDER RIGHTS

Section 9.1 . Voting Shares of Common Stock .

Each Participant and Beneficiary shall be entitled to direct the Trustee as to the exercise of any voting rights attributable to shares of Common Stock then allocated to his or her account and the Trustee shall vote such shares according to the voting directions of the Participant or Beneficiary that have been timely submitted to the Trustee on forms provided by the Trustee for such purpose. Participants and Beneficiaries shall be permitted to direct the Trustee as to the exercise of any voting rights, including, but not limited to, any corporate matter that involves the

voting of shares of Common Stock with respect to the approval or disapproval of any corporate merger or consolidation, recapitalization, reclassification, liquidation, dissolution, sale of substantially all assets of a trade or business, or similar transaction prescribed in Regulations. The Trustee shall with respect to any matter vote the shares of Common Stock credited to Participants' accounts with respect to which the Trustee does not timely receive voting instructions in the same proportion as to shares the Trustee has received voting instructions. Written notice of any meeting of stockholders of the Company and a request for voting instructions shall be given by the Administrator or the Trustee, at such time and in such manner as the Administrator shall determine, to each Participant or Beneficiary entitled to give instructions for voting shares of Common Stock at such meeting. The Administrator shall establish and pay for a means by which Participants and Beneficiaries can expeditiously deliver such voting instructions to the Trustee. All instructions delivered by Participants or Beneficiaries shall be confidential and shall not be disclosed to any person, including the Employer.

Section 9.2 . Tender Offers .

(a) In the event a tender offer is made generally to the stockholders of the Company to transfer all or a portion of their shares of Common Stock in return for valuable consideration, including but not limited to, offers regulated by section 14(d) of the Securities Exchange Act of 1934, as amended, each Participant or Beneficiary shall be entitled to direct the Trustee regarding how to respond to any such tender offer with respect to the number of shares of Common Stock then allocated to his or her account and the Trustee shall vote such shares according to the voting directions of the Participant or Beneficiary that have been timely submitted to the Trustee on forms provided by the Trustee for such purpose. A Participant or Beneficiary shall not be limited in the number of directions to tender or withdraw from tender that he or she can give, but shall not have the right to give directions to tender or withdraw from tender after a reasonable time

established by the Trustee pursuant to paragraph (c) of this Section 9.2. The Trustee shall with respect to a tender offer decline to vote the shares of Common Stock credited to Participants' accounts with respect to which the Trustee does not timely receive directions on how to respond to any such tender offer. All such directions shall be confidential and shall not be disclosed to any person, including the Employer.

(b) Within a reasonable time after the commencement of a tender offer, the Administrator shall provide to each Participant and Beneficiary:

(i) the offer to purchase as distributed by the offeror to the stockholders of the Company,

(ii) a statement of the shares of Common Stock allocated to his or her account, and

(iii) directions as to the means by which a Participant can give directions with respect to the tender offer.

The Administrator shall establish and pay for a means by which a Participant and Beneficiary can expeditiously deliver directions to the Trustee with respect to a tender offer. The Administrator shall transmit or cause to be transmitted to the Trustee aggregate numbers of shares to be tendered or withheld from tender representing directions of Participants and Beneficiaries. The Administrator, at its election, may engage an agent to receive directions from Participants and Beneficiaries and transmit them to the Trustee.

(c) The Trustee may establish a reasonable time, taking into account the time restrictions of the tender offer, after which it shall not accept directions of Participants or Beneficiaries.

(d) Notwithstanding the foregoing, with respect to a tender offer for the purchase or exchange of less than five percent (5%) of the outstanding shares of Common Stock, the Investment Office shall direct the Trustee with respect to the sale, exchange or transfer of the shares of Common Stock held in the Trust Fund, and the Trustee shall follow the direction of the Investment Office.

ARTICLE 10

SPECIAL PARTICIPATION AND DISTRIBUTION RULES RELATING

TO REEMPLOYMENT OF TERMINATED EMPLOYEES AND

EMPLOYMENT BY RELATED ENTITIES

Section 10.1 . Change of Employment Status .

If an Employee who is not a Participant becomes eligible to participate because of a change in his or her employment status, such Employee shall become a Participant as of the date of such change if either the Employee is not a member of a bargaining unit represented by IBEW Local Union 15 or the Employee has satisfied the eligibility service requirement set forth in Section 3.1; otherwise the Employee shall become a Participant in accordance with Section 3.1 following satisfaction of the eligibility service requirement.

Section 10.2 . Reemployment of an Eligible Employee Whose Employment Terminated Prior to His or Her Becoming a Participant .

(a) If the employment of an Eligible Employee who is a member of a bargaining unit represented by IBEW Local Union 15 terminated before the Employee satisfied the eligibility service requirement set forth in Section 3.1 and such Employee is thereafter reemployed by an Employer, such Employee shall be eligible to become a Participant in accordance with Section 3.1.

(b) If the employment of an Eligible Employee who is a member of a bargaining unit represented by IBEW Local Union 15 terminated after he or she had satisfied the eligibility service requirement set forth in Section 3.1 but prior to becoming a Participant is reemployed by an Employer, he or she shall not be required to satisfy again such requirement and shall be eligible to become a Participant upon filing an application in accordance with Section 3.2 (relating to application for Before-Tax Contributions and After-Tax Contributions).

Section 10.3 . Reemployment of a Terminated Participant .

If a terminated Participant is reemployed, the Participant shall not be required to satisfy again the eligibility service requirement set forth in Section 3.1 and shall again become a Participant upon filing an application in accordance with Section 3.2 (relating to application for Before-Tax Contributions and After-Tax Contributions).

Section 10.4 . Employment by an Affiliate .

If an individual is employed by an Affiliate, then any period of such employment shall be taken into account solely for the purposes of determining whether and when such individual is eligible to participate in the Plan under Article 3 (relating to participation), when such individual has retired or otherwise terminated his or her employment for purposes of Article 8 (relating to withdrawals and distributions) to the same extent it would have been had such period of employment been as an Employee of his or her Employer.

Section 10.5 . Leased Employees .

A leased employee (as defined below) shall not be eligible to participate in the Plan. If an individual who performed services as a leased employee (as defined below) of an Employer or an Affiliate becomes an Employee, or if an Employee becomes such a leased employee, then any period during which such services were so performed shall be taken into account solely for the purposes of determining whether and when such individual is eligible to participate in the Plan under Article 3 (relating to participation) and determining when such individual has retired or otherwise terminated his or her employment for purposes of Article 8 (relating to withdrawals and distributions) to the same extent it would have been had such service been as an Employee. This Section shall not apply to any period of service during which such a leased employee was covered

by a plan described in section 414(n)(5) of the Code. Any contributions or benefits provided under such plan to a leased employee by his or her leasing organization shall be treated as provided under this Plan and shall be taken into account under Section 7.4 (relating to limitation on allocations imposed by Section 415 of the Code) to the extent required under section 1.415(a)-1(f)(3) of the Regulations. For purposes of this Plan, a "leased employee" shall mean any person who is not an employee of an Employer and who pursuant to an agreement between an Employer or Affiliate has performed services for an Employer or an Affiliate on a substantially full-time basis for a period of at least one year, which services were performed under the primary direction or control of an Employer or an Affiliate.

Section 10.6 . Reemployment of Veterans .

(a) General . The provisions of this Section shall apply in the case of the reemployment by an Employer of an Eligible Employee, within the period prescribed by the Uniformed Service Employment and Reemployment Rights Act ("USERRA"), after the Employee's completion of a period of Military Service. The provisions of this Section are intended to provide such Employees with the rights required USERRA and section 414(u) of the Code, and shall be interpreted in accordance with such intent.

(b) Make Up of Before-Tax and After-Tax Contributions . Such Employee shall be entitled to make contributions under the Plan ("Make-Up Employee Contributions"), in addition to Before-Tax and After-Tax Contributions which the Employee elects to have made under the Plan pursuant to Section 4.1 (relating to Before-Tax Contributions). From time to time while employed by an Employer, such Employee may elect to contribute Make-Up Employee Contributions during the period beginning on the date of such Employee's reemployment and ending on the earlier of:

(i) the end of the period equal to the product of three and such Employee's period of Military Service, and

(ii) the fifth anniversary of the date of such reemployment.

Such Employee shall not be permitted to contribute Make-Up Employee Contributions to the Plan in excess of the amount which the Employee could have elected to have made under the Plan in the form of Before-Tax and After-Tax Contributions if the Employee had continued in employment with his or her Employer during such period of Military Service. Such Employee shall be deemed to have earned "Compensation" from his or her Employer during such period of Military Service for this purpose in the amount prescribed by sections 414(u)(2)(B) and 414(u)(7) of the Code. The manner in which an Eligible Employee may elect to contribute Make-Up Employee Contributions pursuant to this paragraph (b) shall be prescribed by the Administrator.

(c) Make Up of Employer Matching Contributions . An Eligible Employee who contributes Make-Up Employee Contributions as described in paragraph (b) shall be entitled to an allocation of Employer Matching Contributions ("Make-Up Matching Contributions") in an amount equal to the amount of Employer Matching Contributions which would have been allocated to the Employer Matching Contributions Account of such Eligible Employee under the Plan if such Make-Up Employee Contributions had been made in the form of Before-Tax or After-Tax Contributions (as applicable) during the period of such Employee's Military Service. The amounts necessary to make such allocation of Make-Up Matching Contributions shall be derived from any forfeitures not yet applied towards Employer Matching Contributions for the Plan Year in which the Make-Up Employee Contributions are made, and if such forfeitures are not sufficient for this purpose, then the Eligible Employee's Employer shall make a special contributions which shall be utilized solely for purposes of such allocation.

(d) Application of Limitations and Nondiscrimination Rules . Any contributions made by an Eligible Employee or an Employer pursuant to this Section on account of a period of Military Service in a prior Plan Year shall not be subject to the limitations prescribed by Sections 4.2, 4.5 and 7.4 of the Plan (relating to sections 402(g), 404 and 415 of the Code) for the Plan Year in which such contributions are made. The Plan shall not be treated as failing to satisfy the nondiscrimination rules of Section 4.4 of the Plan (relating to limitations on contributions for highly compensated Eligible Employees) for any Plan Year solely on account of any make up contributions made by an Eligible Employee or an Employer pursuant to this Section 10.6.

Section 10.7 Transfer of Employment to or from Facilities formerly Owned by CEG . Effective as of the Effective time (as such term is defined in the Merger Agreement), if a Participant who was a Participant on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in a Company Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be a savings plan qualified under Section 401(a) or 401(k) of the Code (each such plan, a “CEG Savings Plan”) , then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the CEG Savings Plan. If a participant in the CEG Savings Plan who was a participant in such plan on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the CEG Savings Plan and shall not participate in the Plan.

ARTICLE 11

ADMINISTRATION

Section 11.1 . The Administrator, the Investment Office and the Corporate Investment Committee .

(a) The Administrator . The Company acting through its Director, Employee Benefit Plans & Programs, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such director or other person or committee, the "Administrator"), shall be the "administrator" of the Plan, within the meaning of such term as used in ERISA. In addition, the Administrator shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan's assets. The Administrator shall have the following duties, responsibilities and rights:

(i) The Administrator shall have the duty and discretionary authority to interpret and construe the Plan in regard to all questions of eligibility, the status and rights of Participants, distributees and other persons under the Plan, and the manner, time, and amount of payment of any distribution under the Plan. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Administrator, in its discretion, determines that such person is entitled to benefits.

(ii) The Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust under Article 8 (relating to withdrawals and distributions).

(iii) The Administrator shall supervise the collection of Participants' contributions made pursuant to Article 5 (relating to Employee contributions) and the delivery of such contributions to the Trustee.

(iv) The Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Office, the Corporate Investment Committee or the Trustee.

(v) Each Employer shall, from time to time, upon request of the Administrator, furnish to the Administrator such data and information as the Administrator shall require in the performance of its duties.

(vi) The Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Administrator and to furnish such information requested by the Administrator. The Administrator and the Plan may rely upon all such information so furnished to the Administrator.

(vii) The Administrator shall be the Plan's agent for service of legal process and forward all necessary communications to the Trustee.

(b) Removal of Administrator . The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Administrator (including any member of a committee that constitutes the Administrator). The Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer or upon the Administrator's termination of employment with the Employers. Upon the resignation, removal or failure or inability for any reason of the Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any officer, employee or member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Administrator.

(c) The Investment Office . The Investment Office, shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in Sections 404(a)(2) and 404(c) of ERISA and the terms of the Plan, and all other applicable limitations. The Investment Office shall have the following duties, responsibilities and rights:

(i) The Investment Office shall be the "named fiduciary" for purposes of designating the investment funds under Section 6.2 and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Office shall be solely responsible for all matters involving investment of the Employer Stock Fund described in Section 6.2 and no other person shall have any responsibility with respect to investment of such fund; provided, however, that effective June 21, 2012, the Investment Office has appointed an independent investment manager under section 3(38) of ERISA to manage the investment of the Common Stock in the Employer Stock Fund and such investment manager (rather than the Investment Office) shall be solely responsible for any and all investment decisions relating thereto.

(iii) Each Employer shall, from time to time, upon request of the Investment Office, furnish to the Investment Office such data and information as the Investment Office shall require in the performance of its duties.

(d) The Corporate Investment Committee . The Company acting through the Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Office. The Corporate Investment Committee and the Company's Chief Investment Officer shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Office. Any successor Investment Office employee shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the employees of the Investment Office and the Corporate Investment Committee shall have no other duties or responsibilities with respect to the Plan. None of the Company, any officer, employee or member of the board of directors who is not a member of the Corporate Investment Committee, nor any other person shall have any responsibility regarding the appointment or removal of the employees of Investment Office.

(e) Status of Administrator, the Investment Office and the Corporate Investment Committee . The Administrator, any person acting as, or on behalf of, the Investment Office, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee or officer of an Employer and such status shall not disqualify such person from taking any action

hereunder or render such person accountable for any distribution or other material advantage received by him or her under this Plan, provided that no Administrator, person acting as, or on behalf of, the Investment Office, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Administrator or the Investment Office on any matter involving solely his or her rights under this Plan.

(f) Notice to Trustee of Members . The Trustee shall be notified as to the names of the Administrator and the person or persons authorized to act on behalf of the Investment Office.

(g) Allocation of Responsibilities . Each of the Administrator, the Investment Office and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

(h) General Governance . The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Administrator, the Investment Office and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

(i) Indemnification . The Employers hereby jointly and severally indemnify the Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not

limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

(j) No Compensation . None of the Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Administrator, the Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Employer for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

(k) Employ of Counsel and Agents . The Administrator, the Investment Office and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

Section 11.2 . Claims Procedure .

Any Participant or distributee who believes he or she is entitled to benefits in an amount greater than those which he or she is receiving or has received may file a claim with the Administrator. Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Administrator

shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the Administrator's decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable Regulations. If the Administrator determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Administrator expects to render the benefit determination. The notice of the decision of the Administrator with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, the Administrator shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right (subject to the limitations described in Sections 13.11 and 13.12) to bring a civil action under Section 502 of ERISA following an adverse benefit determination on review. The Administrator shall also advise the claimant that the claimant or the claimant's duly authorized representative may request a review by the by the Vice President, Health & Benefits (or such other officer designated from time to time by the Chief Human Resources Officer) of the adverse benefit determination by filing with such officer, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he or she (a) may be

provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit to such officer written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by such officer within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the officer's final decision. If the reviewing officer determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the officer expects to render the determination on review. The review of the officer shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

Section 11.3 . Procedures for Domestic Relations Orders .

If the Administrator receives any written judgment, decree or order (including approval of a property settlement agreement) pursuant to domestic relations or community property laws of any state relating to the provision of child support, alimony or marital property rights of a Spouse, former Spouse, child or other dependent of a Participant and purporting to provide for the payment of all or a portion of the Participant's benefit under the Plan to or on behalf of one or more of such persons (such judgment, decree or order being hereinafter called a "domestic relations order"), the Administrator shall promptly notify the Participant and each other payee specified in such

domestic relations order of its receipt and of the following procedures. After receipt of a domestic relations order, the Administrator shall determine whether such order constitutes a "qualified domestic relations order," as defined in paragraph (b) Section 14.2 (relating to exception for qualified domestic relations orders), and shall notify the Participant and each payee named in such order in writing of its determination. Such notice shall be written in a manner calculated to be understood by the parties and shall set forth specific reasons for the Administrator's determination, and shall contain an explanation of the review procedure under the Plan. The Administrator shall also advise each party that the party or his or her duly authorized representative may request a review by the Vice President, Health & Benefits (or such other officer designated from time to time by the Chief Human Resources Officer) of the Administrator's determination by filing a written request for such review. The Administrator shall give each party affected by such request notice of such request for review. Each party also shall be informed that he or she may have reasonable access to pertinent documents and submit comments in writing to such officer in connection with such request for review. Each party shall be given written notice of the officer's final determination, which notice shall be written in a manner calculated to be understood by the parties and shall include specific reasons for such final determination. Any amounts subject to a domestic relations order which would be payable to the alternate payee prior to the determination that such order is a qualified domestic relations order shall be separately accounted for and not distributed prior to such determination. If within a reasonable time after receipt of written evidence of such order it is determined that such domestic order constitutes a qualified domestic relations order, the amounts so separately accounted for (plus any interest thereon) shall be paid to the alternate payee. If within such reasonable period of time it is determined that such order does not constitute a qualified domestic relations order, the amounts so separately accounted for (plus any interest thereon) shall be paid to such other persons,

if any, entitled to such amounts at such time. Prior to the issuance of regulations, the Administrator shall establish the time periods in which the Administrator's determination, a request for review thereof and the review by the Administrator shall be made, provided that the total of such time periods shall not be longer than 18 months from the date written evidence of a domestic relations order is received by the Administrator.

The duties of the Administrator under this Section 11.3 may be delegated by the Administrator to one or more persons other than the Administrator.

Section 11.4 . Notices to Participants, Et c.

All notices, reports and statements given, made, delivered or transmitted to a Participant or distributee or any other person entitled to or claiming benefits under the Plan shall be deemed to have been duly given, made or transmitted when mailed by first class mail with postage prepaid and addressed to the Participant or distributee or such other person at the address last appearing on the records of the Administrator. A Participant or distributee or other person may record any change of his or her address from time to time by written notice filed with the Administrator.

Section 11.5 . Notices to Administrator .

Written directions, notices and other communications from Participants or distributees or any other person entitled to or claiming benefits under the Plan to the Administrator shall be deemed to have been duly given, made or transmitted either when delivered to such location as shall be specified upon the forms prescribed by the Administrator for the giving of such directions, notices and other communications or when mailed by first class mail with postage prepaid and addressed to the addressee at the address specified upon such forms.

Section 11.6 . Records .

Each of the Administrator and the Investment Office shall keep a record of all of their respective proceedings, if any, and shall keep or cause to be kept all books of account, records and other data as may be necessary or advisable in their respective judgment for the administration of the Plan or the administration of the investments of the Plan.

Section 11.7 . Reports of Trustee and Accounting to Participants .

The Administrator shall keep on file, in such form as it shall deem convenient and proper, all reports concerning the Trust Fund received by it from the Trustee, and the Administrator will, as soon as practicable after the last day of each quarter of each Plan Year furnish each Participant and Beneficiary with a statement reflecting the condition of his or her accounts as of that date.

Section 11.8 . Electronic Media .

Notwithstanding any provision of the Plan to the contrary and for all purposes of the Plan, to the extent permitted by the Administrator and any applicable law or Regulation, the use of electronic technologies shall be deemed to satisfy any written notice, consent, delivery, signature, disclosure or recordkeeping requirement under the Plan, the Code or ERISA to the extent permitted by or consistent with applicable law and Regulations. Any transmittal by electronic technology shall be deemed delivered when successfully sent to the recipient, or such other time specified by the Administrator.

ARTICLE 12

PARTICIPATION BY OTHER EMPLOYERS

Section 12.1 . Adoption of Plan .

With the consent of the Company, any entity may become a participating Employer under the Plan by (a) taking such action as shall be necessary to adopt the Plan and (b) executing and delivering such instruments and taking such other action as may be necessary or desirable to put the Plan into effect with respect to such entity.

Section 12.2 . Withdrawal from Participation .

Any Employer shall terminate its participation in the Plan at any time, under such circumstances as the Company may provide, by delivering to the Company a duly certified copy of a resolution of its board of directors (or other governing body) to that effect, or by ceasing to be a member of the same controlled group as the Company (within the meaning of section 1563(a) of the Code).

Section 12.3 . Company as Agent for Employers .

Each entity that becomes a participating Employer pursuant to Section 12.1 (relating to adoption of Plan) or Article 13 (relating to continuance by a successor) by so doing shall be deemed to have appointed the Company its agent to exercise on its behalf all of the powers and authorities hereby conferred upon the Company by the terms of the Plan, including, but not by way of limitation, the power to amend and terminate the Plan. The authority of the Company to act as such agent shall continue unless and until the portion of the Trust Fund held for the benefit of Employees of the particular Employer and their Beneficiaries is set aside in a separate Trust Fund as provided in Section 16.2 (relating to establishment of separate trust).

ARTICLE 13

CONTINUANCE BY A SUCCESSOR

In the event that the Employer is reorganized by way of merger, consolidation, transfer of assets or otherwise, so that another entity succeeds to all or substantially all of the Employer’s business, such successor entity may be substituted for the Employer under the Plan by adopting the Plan and becoming a party to the Trust agreement. Contributions by the Employer shall be automatically suspended from the effective date of any such reorganization until the date upon which the substitution of such successor entity for the Employer under the Plan becomes effective.

If, within 90 days following the effective date of any such reorganization, such successor entity shall not have elected to become a party to the Plan, or if the Employer adopts a plan of complete liquidation other than in connection with a reorganization, the Plan shall be automatically terminated with respect to Employees of such Employer as of the close of business on the 90th day following the effective date of such reorganization or as of the close of business on the date of adoption of such plan of complete liquidation, as the case may be, and the Administrator shall direct the Trustee to distribute the portion of the Trust Fund applicable to such Employer in the manner provided in Article 16 (relating to establishment of separate plan and termination).

If such successor entity is substituted for an Employer by electing to become a party to the Plan as described above, then, for all purposes of the Plan, employment of such Employee with such Employer, including service with and compensation paid by such Employer, shall be considered to be employment with an Employer.

ARTICLE 14

MISCELLANEOUS

Section 14.1 . Expenses .

Except as provided in the last sentence of Section 6.2 (relating to expenses of investments for an investment fund), all costs and expenses incurred in administering the Plan and the Trust, including, but not limited to, "direct expenses" incurred in administering the Plan and the Trust (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan or the Trust), the expenses of the Administrator and the Investment Office, the fees of counsel and any agents for the Administrator and the Investment Office, the fees and expenses of the Trustee, the fees of counsel for the Trustee and other administrative expenses shall, to the extent permitted by law, be paid from the Trust Fund to the extent such

expenses are not paid by the Employers. Notwithstanding the foregoing, the Administrator may authorize an Employer to pay any expenses, and the Employer shall be reimbursed from the Trust Fund for such payments. The Administrator, in its discretion, having regard to the nature of a particular expense, shall determine the portion of the expense that is to be borne by each Employer.

Section 14.2 . Non-Assignability .

(a) In general . It is a condition of the Plan, and all rights of each Participant and Beneficiary shall be subject thereto, that no right or interest of any Participant or Beneficiary in the Plan shall be assignable or transferable in whole or in part, either directly or by operation of law or otherwise, including, but not by way of limitation, execution, levy, garnishment, attachment, pledge or bankruptcy, but excluding devolution by death or mental incompetency, and no right or interest of any Participant or Beneficiary in the Plan shall be liable for, or subject to, any obligation or liability of such Participant or Beneficiary, including claims for alimony or the support of any Spouse, except as provided below.

(b) Exception for Qualified Domestic Relations Orders . Notwithstanding any provision of the Plan to the contrary, if a Participant's account balance under the Plan, or any portion thereof, is the subject of one or more qualified domestic relations orders, as defined below, such account balance or portion thereof shall be paid to the person and at the time and in the manner specified in any such order. For purposes of this paragraph (b), "qualified domestic relations order" shall mean any "domestic relations order" as defined in Section 11.3 (relating to procedures for domestic relations orders) that creates (or recognizes the existence of) or assigns to a person other than the Participant (an "alternate payee") rights to all or a portion of the Participant's account balance under the Plan, and:

(A) clearly specifies

(i) the name and last known mailing address (if any) of the Participant and each alternate payee covered by such order,

(ii) the amount or percentage of this Participant's benefits to be paid by the Plan to each such alternate payee, or the manner in which such amount or percentage is to be determined,

(iii) the number of payments to, or period of time for which, such order applies, and

(iv) each plan to which such order applies;

(B) does not require

(i) the Plan to provide any type or form of benefit or any option not otherwise provided under the Plan at the time such order is issued,

(ii) the Plan to provide increased benefits (determined on the basis of actuarial equivalence), and

(iii) the payment of benefits to an alternate payee that at the time such order is issued already are required to be paid to a different alternate payee under a prior qualified domestic relations order; and

(C) does not require the commencement of payment of benefits to any alternate payee before the earlier of (I) the date on which the Participant is entitled to a distribution under the Plan and (II) the date the Participant attains age 50, except that the order may require the commencement of payment of benefits as soon as administratively practicable after the date such order is determined by the Administrator to be a "qualified domestic relations order";

all as determined by the Administrator pursuant to the procedures contained in Section 11.3 (relating to procedures for domestic relations orders). Any amounts subject to a domestic relations order prior to determination of its status as a qualified domestic relations order that but for such order would be paid to the Participant shall be segregated in a separate account or an escrow account pending such determination. If within the reasonable time period beginning with the date on which the first payment would be required to be made under a domestic relations order the Administrator determines that the domestic relations order constitutes a qualified domestic relations order, the amount so segregated (plus any interest thereof) shall be paid to the alternate payee. If such determination is not made within such reasonable time period, then the amount so

segregated (plus any interest thereon), shall, as soon as practicable after the end of such reasonable time period, be paid to the Participant. Any determination regarding the status of such order after such reasonable time period shall be applied only to payments on or after the date of such determination.

Section 14.3 . Employment Non-Contractual .

The Plan confers no right upon an Employee to continue in employment.

Section 14.4 . Limitation of Rights .

A Participant or distributee shall have no right, title or claim in or to any specific asset of the Trust Fund, but shall have the right only to distributions from the Trust Fund on the terms and conditions herein provided.

Section 14.5 . Merger or Consolidation with Another Plan .

A merger or consolidation with, or transfer of assets or liabilities to, any other plan shall not be effected unless the terms of such merger, consolidation or transfer are such that each Participant, distributee, Beneficiary or other person entitled to receive benefits from the Plan would, if the Plan were to terminate immediately after the merger, consolidation or transfer, receive a benefit equal to or greater than the benefit such person would be entitled to receive if the Plan were to terminate immediately before the merger, consolidation, or transfer.

Section 14.6 . Gender and Plurals .

Wherever used in the Plan, words in the masculine gender shall include masculine or feminine gender, and, unless the context otherwise requires, words in the singular shall include the plural, and words in the plural shall include the singular.

Section 14.7 . Applicable Law .

Except to the extent preempted by applicable federal law or otherwise provided under the terms of the Plan, the Plan and all rights hereunder shall be governed by and construed in accordance with the laws of the State of Illinois.

Section 14.8 . Severability .

If a provision of the Plan shall be held illegal or invalid, the illegality or invalidity shall not affect the remaining parts of the Plan and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included in the Plan.

Section 14.9 . No Guarantee .

Neither the Administrator or the Investment Office, the Employer, nor the Trustee in any way guarantees the Trust from loss or depreciation nor the payment of any money that may be or become due to any person from the Trust Fund. Nothing herein contained shall be deemed to give any Participant, distributee, or Beneficiary an interest in any specific part of the Trust Fund or any other interest except the right to receive benefits out of the Trust Fund in accordance with the provisions of the Plan and the Trust Fund.

Section 14.10 . Statute of Limitations for Actions under the Plan .

Except for actions to which the statute of limitations prescribed by Section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under Section 502 of ERISA may be commenced later than one year after the claimant receives a final decision from the Company's Vice President, Health & Benefits (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

Section 14.11 . Forum for Legal Actions under the Plan .

Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in the Northern District of Illinois or the Eastern District of Pennsylvania, whichever is most convenient, and no other federal or state court.

Section 14.12 . Legal Fees .

Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, the Investment Office, the Vice President, Health & Benefits, any Plan fiduciary, the Chief Human Resources Officer, the Company, its affiliates or their respective officers, directors, employees, or agents (the “Plan Parties”), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

ARTICLE 15

TOP-HEAVY PLAN REQUIREMENTS

Section 15.1 . Top-Heavy Plan Determination .

If as of the determination date (as defined in Section 15.2) for any Plan Year (a) the sum of the account balances under the Plan and all other defined contribution plans in the aggregation group (as defined in Section 15.2) and (b) the present value of accrued benefits under all defined benefit plans in such aggregation group of all Participants in such plans who are key employees (as defined in Section 15.2) for such Plan Year exceeds 60 percent of the aggregate of the account balances and present value of accrued benefits of all participants in such plans as of the determination date (as defined in Section 15.2), then this Plan shall be a top-heavy plan for such Plan Year, and the requirements of Sections 15.3 (relating to minimum contribution for top-heavy years) shall be applicable for such Plan Year as of the first day thereof. If the Plan shall be a top-heavy plan for any Plan Year and not be a top-heavy plan for any subsequent Plan Year, the requirements of this Article shall not be applicable for such subsequent Plan Year.

Section 15.2 . Definitions and Special Rules .

(a) Definitions . For purposes of this Article, the following definitions shall apply:

(1) Determination Date . The determination date for all plans in the aggregation group shall be the last day of the preceding Plan Year, and the valuation date applicable to a determination date shall be (i) in the case of a defined contribution plan, the date as of which account balances are determined which is coincident with or immediately precedes the determination date, and (ii) in the case of a defined benefit plan, the date as of which the most recent actuarial valuation for the Plan Year that includes the determination date is prepared, except that if any such plan specifies a different determination or valuation date, such different date shall be used with respect to such plan.

(2) Aggregation Group . The aggregation group shall consist of (a) each plan of an Employer in which a key Employee is a participant, (b) each other plan that enables such a plan to be qualified under section 401(a) of the Code, and (c) any other plans of an Employer that the Company designates as part of the aggregation group and that shall permit the aggregation group to continue to meet the requirements of sections 401(a) and 410 of the Code with such other plan being taken into account.

(3) Key Employee . Key Employee shall have the meaning set forth in section 416(i) of the Code.

(4) Compensation . Compensation shall have the meaning set forth in section 1.415(c)-2 of the Regulations.

(b) Special Rules . For the purpose of determining the accrued benefit or account balance of a Participant, the accrued benefit or account balance of any person who has not performed services for an employer at any time during the 1-year period ending on the determination date shall not be taken into account pursuant to this Section. Any person who received a distribution from a plan (including a plan that has terminated) in the aggregation group during the 1-year period ending on the last day of the preceding Plan Year shall be treated as a Participant in such plan, and any such distribution shall be included in such Participant's account balance or accrued benefit, except that in the case of any distribution made for a reason other than separation from service, death or disability, this sentence shall be applied by substituting "5-year period" for the "1-year period" stated herein.

Section 15.3 . Minimum Contribution for Top-Heavy Years .

Notwithstanding any provision of the Plan to the contrary, the sum of the Employer contributions under Article 4 (other than Before-Tax Contributions described in Section 4.1) allocated to the account of each Participant (other than a key Employee) during any Plan Year and the forfeitures allocated to the account of such Participant (other than a key Employee) during any Plan Year for which the Plan is a top-heavy plan shall in no event be less than the lesser of (i) 3% of such Participant's compensation during such Plan Year and (ii) the highest percentage at which contributions are made on behalf of any key Employee for such Plan Year. Notwithstanding the preceding sentence, if the percentage determined pursuant to clause (ii) of the preceding sentence is less than 3%, such percentage shall be recalculated by including Before-Tax Contributions made

on behalf of key employees. Such minimum contribution shall be made even if, under other provisions of the Plan, the Participant would not otherwise be entitled to receive an allocation or would receive a lesser allocation for the year because of (i) the Participant's failure to complete 1,000 Hours of Service, or (ii) compensation of less than a stated amount. If, during any Plan Year for which this Section 15.3 is applicable, a defined benefit plan is included in the aggregation group and such defined benefit plan is a top-heavy plan for such Plan Year, the percentage set forth in clause (i) of the first sentence of this Section shall be 5%. The percentage referred to in clause (ii) of the first sentence of this Section shall be obtained by dividing the aggregate of contributions made pursuant to Article 4 and pursuant to any other defined contribution plan that is required to be included in the aggregation group (other than a defined contribution plan that enables a defined benefit plan that is required to be included in such group to be qualified under section 401(a) of the Code) during the Plan Year on behalf of such key Employee by such key Employee's compensation for the Plan Year. Notwithstanding the above, the provisions of this Section 15.3 shall not apply for any Plan Year with respect to an Eligible Employee who has accrued the defined benefit minimum provided under section 416 of the Code under a qualified defined benefit plan maintained by an Employer or Affiliate.

ARTICLE 16

AMENDMENT, ESTABLISHMENT OF SEPARATE PLAN AND TERMINATION

Section 16.1 . Amendment .

The Company may at any time and from time to time amend or modify the Plan by resolution of the Board of Directors of the Company or the Compensation Committee thereof; provided , however, that in the case of any amendment or modification that would not result in an aggregate annual cost to the Company of more than $50,000,000, the Plan may be amended or

modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability exceeding $250,000) or another executive officer holding title of equivalent or greater responsibility. No amendment shall be made in respect of Eligible Employees who are members of a bargaining unit represented by IBEW Local Union 15 that is inconsistent with that portion of the collective bargaining agreement between such an Employer and IBEW Local Union 15 concerning the Plan.

Section 16.2 . Establishment of Separate Plan .

If an Employer withdraws from the Plan under Section 12.2 (relating to withdrawal from participation), the Administrator may determine the portion of the Trust Fund held by the Trustee that is applicable to the Participants and former Participants of such Employer and direct the Trustee to segregate such portion in a separate Trust Fund. Such separate Trust Fund shall thereafter be held and administered as a part of the separate plan of such Employer.

The portion of the Trust Fund applicable to the Participants and former Participants of a particular Employer shall be the sum of:

(a) the total amount credited to all accounts that are applicable to the Participants and former Participants of such Employer and

(b) an amount that bears the same ratio to the excess, if any, of

(i) the total value of the Trust Fund over

(ii) the total amount credited to all accounts

as the total amount credited to the accounts that are applicable to the Participants of such Employer bears to the total amount credited to such accounts of all Participants.

Section 16.3 . Termination and Distributions upon Termination of the Plan .

The Company has established the Plan with the bona fide intention and expectation that contributions will be continued indefinitely, but the Company will not have any obligation or liability whatsoever to maintain the Plan for any given length of time and may terminate the Plan at any time by resolution of the Board of Directors or the Compensation Committee thereof, to that effect, without any liability whatsoever for any such termination. Notwithstanding the preceding sentence, the Plan shall not be terminated in respect of Eligible Employees who are members of a bargaining unit represented by IBEW Local Union 15 if such termination is inconsistent with the portion of the collective bargaining agreement between the Employer of such Eligible Employees and IBEW Local Union 15 concerning the Plan. The Plan will be deemed terminated: (a) if and when the Company is judicially declared bankrupt, or (b) upon dissolution of the Company.

Upon termination of the Plan by the Company or withdrawal from participation in the Plan by any Employer pursuant to Section 12.2 (relating to withdrawal from participation) or the partial termination of the Plan with respect to a group of Employees or complete discontinuance of contributions hereunder, distributions shall be made to each affected Participant or other persons entitled to distributions pursuant to Article 8 (relating to withdrawals and distributions). If the entire Plan is terminating, upon the completion of distribution to all Participants, the Trust will terminate, the Trustee will be relieved from all liability under the Trust, and no Participant or other person will have any claims thereunder, except as required by applicable law.

Notwithstanding the preceding paragraph, no distribution shall be made to any Participant (i) until he or she attains age 59 $^{1}/_{2}$ except as otherwise provided in Section 8.3 (relating to distributions upon termination of employment) or (ii) if a successor plan, as defined in Regulations, is established or maintained by the Participant's Employer.

To the extent that no discrimination in value results, any distribution after termination or partial termination of the Plan may be made, in whole or in part, in cash, in securities or other assets in kind, or in non-transferable annuity contracts, as the Administrator (in its discretion) may determine. All non-cash distributions shall be valued at fair market value at date of distribution.

If the Internal Revenue Service refuses to issue an initial, favorable determination letter that the Plan and Trust Fund as adopted by an Employer meet the requirements of section 401(a) of the Code and that the Trust Fund is exempt from tax under section 501(a) of the Code, the Employer may terminate its participation in the Plan and shall direct the Trustee to pay and deliver the portion of the Trust Fund applicable to the Participants of such Employer, determined pursuant to Section 16.2 (relating to establishment of separate plan) to such Employer and such Employer shall pay to Participants or their beneficiaries the part of such Employer's portion of the Trust Fund as is attributable to contributions made by Participants.

Notwithstanding any provision of this Plan to the contrary, no distribution shall be made pursuant to this Section 16.3 (relating to termination and distribution upon termination of the Plan) solely due to the termination of this Plan if, within the meaning of applicable Regulations, the employer establishes or maintains an alternative defined contribution plan.

Section 16.4 . Trust Fund to Be Applied Exclusively for Participants and Their Beneficiaries .

Subject only to the provisions of Section 4.5 (relating to the limitation on Employer contributions), 7.4 (relating to limitations on allocations imposed by section 415 of the Code) and 16.3 (relating to termination and distributions upon termination of the Plan), and any other provision of the Plan to the contrary notwithstanding, it shall be impossible for any part of the Trust Fund to be used for or diverted to any purpose not for the exclusive benefit of Participants and their Beneficiaries either by operation or termination of the Plan, power of amendment or other means.

IN WITNESS WHEREOF, the Company has caused this instrument to be executed by its duly authorized officer on this _____day of December, 2012.

EXELON CORPORATION

By _____
Chief Human Resources Officer

SUPPLEMENT I

Transfers from Other Plans

With the consent of the Administrator, whenever a participant in any other qualified savings or profit sharing plan maintained for employees of an entity any of whose assets or stock are acquired by an Employer (the "Other Plan") becomes a Participant in this Plan, then such Participant's interest in the Other Plan may be transferred to the Trustee of this Plan and credited to administrative subaccounts to be held, invested, reinvested and distributed pursuant to the terms of the Plan and the Trust and, as of the date of the transfer of any such Participant's interest in the Other Plan,

(a) there shall be credited to the Before-Tax Contributions Account of such Participant that portion of his interest in the Other Plan which is transferred to the Trustee and which represents the Participant's salary reduction contributions, if any, made to the Other Plan on behalf of the Participant,

(b) there shall be credited to the After-Tax Account of such Participant that portion of his interest in the Other Plan which is transferred to the Trustee and which represents the Participant's after-tax contributions, if any, made to the Other Plan,

(c) there shall be credited to the Employer Matching Contributions Account of such Participant that portion of his interest in the Other Plan which is transferred to the Trustee and which represents the matching contributions and other employer contributions, if any, made to the Other Plan on behalf of the Participant, and

(d) there shall be credited to the Rollover Account of such Participant that portion of his interest in the Other Plan which is transferred to the Trustee and which represents the Participant's rollover contributions, if any, to the Other Plan.

Any amounts credited to a Participant's Before-Tax Contributions Account, After-Tax Contributions Account, Employer Matching Contributions Account and Rollover Account shall be credited to the administrative subaccounts in accordance with such Participant's investment direction in effect as of the date of such transfer. Any salary reduction contributions credited to the Before-Tax Contributions Account that are designated Roth contributions within the meaning of section 402A of the Code shall be maintained in a manner that satisfies the separate accounting requirement, and any Regulations or other requirements promulgated, under section 402A of the Code. Any special provisions applicable to amounts transferred to the Trustee from any Other Plan shall be set forth in an Exhibit hereto.

SUPPLEMENT II

Elective Transfers Between This Plan and Plans of Affiliates or the TXU 401(k) Plan

A. Transfers to this Plan . Whenever an individual who is employed by an Affiliate that is not an Employer has a change in employment status that results in such individual (a) becoming an Eligible Employee and (b) being ineligible to make additional elective contributions under a plan maintained by such Affiliate (an "Affiliate Plan"), such Eligible Employee may elect to transfer his or her benefits under the Affiliate Plan to this Plan. Such election must be conditioned upon a voluntary, fully-informed election by the Eligible Employee. In the event that the Eligible Employee makes such election, his or her benefits under the Affiliate Plan shall be credited to his account under this Plan, and such benefits shall be subject to the terms of, and paid as prescribed by, this Plan, and the terms of the Affiliate Plan shall not apply with respect to such benefits.

An individual who becomes an Eligible Employee in connection with the Company's 2002 acquisition of from Texas Utilities, Inc. ("TXU") may elect to transfer his or her benefits under TXU's 401(k) plan (the "TXU Plan") to this Plan. Such election must be conditioned upon a voluntary, fully-informed election by the Eligible Employee. In the event that the Eligible Employee makes such election, his or her benefits under the TXU Plan shall be credited to his account under this Plan, and such benefits shall be subject to the terms of, and paid as prescribed by, this Plan, and the terms of the TXU Plan shall not apply with respect to such benefits.

B. Transfers from this Plan . Whenever a Participant has a change in employment status that results in such Participant (a) ceasing to be an Eligible Employee and (b) becoming eligible to participate in an Affiliate Plan, such Participant may elect to transfer his or her benefits under this Plan to the Affiliate Plan. Such election must be conditioned upon a voluntary, fully-informed election by the Participant. In the event that the Participant makes such election, the Participant, effective at the time of the transfer, shall not be entitled to any benefits under this Plan and the benefits transferred to the Affiliate Plan shall be subject to the terms of, and paid as prescribed by, the Affiliate Plan, and the terms of this Plan shall not apply with respect to such benefits.

SUPPLEMENT III

Merger of Certain AmerGen Plans into this Plan

Purpose . The purpose of this Supplement III is to reflect the merger of the AmerGen Clinton Employee Savings Plan for Nonbargaining Employees (the "Clinton Plan") and the AmerGen TMI and Oyster Creek Employee Savings Plan for Nonbargaining Employees (collectively, the "AmerGen Plans") into the Plan effective February 1, 2004 (the "Merger Date") and to preserve those provisions of the AmerGenPlans that cannot be eliminated by amendment without violating section 411(d)(6) of the Internal Revenue Code and applicable Treasury regulations thereunder.

Definitions . Unless the context clearly indicates otherwise, a term defined in the Plan shall have the same meanings for purposes of this Supplement III.

Conflicts Between the Plan and this Supplement III . This Supplement III and the Plan together comprise the Plan with respect to AmerGen Plan Participants (as defined below). In case of any conflict between the provisions of the Plan and this Supplement III, the terms and provisions of this Supplement III shall govern to the extent necessary to eliminate such conflict.

AmerGen Plan Participants . This Supplement III shall be applicable to all AmerGen Plan Participants. "AmerGen Plan Participants" are participants in the Plan who were participants in the AmerGen Plans and whose account balances under the AmerGen Plans were merged into the Plan.

Vesting . All AmerGen Plan Participants shall be fully vested in their accounts under the Plan.

Withdrawals of Employer Matching Contributions . Notwithstanding any provision in the Plan to the contrary, an AmerGen Plan Participant who, immediately prior to the Merger Date was a participant in the Clinton Plan ("Clinton Participant") who has completed 60 months as either a participant in the Clinton Plan or a participant in this Plan may elect, in accordance with

procedures established by the Administrator, to receive a distribution of all or any part of his or her Employer Matching Contributions Account that is attributable to contributions made under the Clinton Plan, as adjusted for gains, earnings and losses attributable thereto determined as of the Valuation Date next succeeding the date of receipt of the request for distribution. Additionally, a Clinton Participant, regardless of his or her period of participation in the Clinton Plan or this Plan, may elect, in accordance with procedures established by the Administrator, to receive a distribution of all or any part of that portion of the Employer Matching Contributions Account that is attributable to contributions made under the Clinton Plan and that is derived from Employer Matching Contributions in excess of Employer Matching Contributions allocated to his or her Employer Matching Contributions Account during the two Plan Years preceding the Plan Year in which the withdrawal takes place, adjusted for gains, earnings and losses attributable thereto determined as of the Valuation Date next succeeding the date of receipt of the request for distribution.

No distribution made pursuant to this paragraph F may be for an amount which is less than the lesser of (i) $200; or (ii) that portion of the Participant's Employer Matching Contributions Account that is attributable to contributions made under the Clinton Plan, as adjusted for gains, earnings and losses attributable thereto. In addition, a Participant may not make more than one withdrawal pursuant to this paragraph F in any Plan Year.

Loans . With respect to any loan to an AmerGen Plan Participant that is outstanding at the Merger Date, the terms of such loan shall continue to be governed by the note evidencing such loan and the terms applicable to such loan as in effect under the AmerGen Plans as of the Merger Date. All loans made after the Merger Date shall be governed by and in accordance with the terms of the Plan and any loan policy issued thereunder by the Administrator.

SUPPLEMENT IV

Merger of New England Plan into this Plan

Purpose . The purpose of this Supplement IV is to reflect the merger of the Exelon New England Union Retirement 401(k) Plan (the "New England Plan") into the Plan effective November 1, 2004 (the "Merger Date").

Definitions . Unless the context clearly indicates otherwise, a term defined in the Plan shall have the same meanings for purposes of this Supplement IV.

Conflicts Between the Plan and this Supplement IV . This Supplement IV and the Plan together comprise the Plan with respect to New England Plan Participants (as defined below). In case of any conflict between the provisions of the Plan and this Supplement IV, the terms and provisions of this Supplement IV shall govern to the extent necessary to eliminate such conflict.

New England Plan Participants . This Supplement IV shall be applicable to all New England Plan Participants. "New England Plan Participants" are participants in the Plan who were participants in the New England Plan and whose account balances under the New England Plan were merged into the Plan.

Vesting . All New England Plan Participants shall be fully vested in their accounts under the Plan.

Loans . With respect to any loan to a New England Plan Participant that is outstanding at the Merger Date, the terms of such loan shall continue to be governed by the note evidencing such loan and the terms applicable to such as in effect under the New England Plan as of the Merger Date. All loans made after the Merger Date shall be governed by and in accordance with the terms of the Plan and any loan policy issued thereunder by the Administrator.

SUPPLEMENT V

Transfers from the Exelon Corporation 401(k) Profit Sharing Plan No. 2

A. Purpose . The purpose of this Supplement IV is to reflect the transfer to the Plan of assets allocated to certain accounts under the Exelon Corporation 401(k) Profit Sharing Plan No. 2 (the "InfraSource Plan No. 2"), which was terminated on November 30, 2007.

B. Definitions . All capitalized terms used in this Supplement IV, but not separately defined herein, shall have the same meanings assigned to such terms in the Plan.

C. Applicability . This Supplement shall apply to any individual ("Affected Participant") whose benefit under the InfraSource Plan No. 2 is transferred pursuant to Section D of this Supplement IV. An Affected Participant shall be treated as a Participant under the Plan for all purposes of the Plan except, unless the Affected Participant is otherwise eligible to participate in the Plan, for purposes related to making or receiving contributions as set forth in Articles 4 and 5 of the Plan.

D. Transfer . Notwithstanding any provision in the Plan to the contrary, assets allocated to the InfraSource Plan No. 2 accounts of any individual who, in connection with the termination of the InfraSource Plan No. 2, elected to transfer his or her benefits thereunder to the Plan or who did not make a timely election with respect to his or her benefits under the InfraSource Plan No. 2, shall be transferred to the Plan as soon as administratively practicable after November 30, 2007 and credited to a separate account ("Affected Account") under this Plan.

E. Conflicts Between the Plan and this Supplement IV . This Supplement IV and the Plan together comprise the Plan with respect to Affected Accounts. In case of any conflict between the provisions of the Plan and this Supplement IV, the terms and provisions of this Supplement IV shall govern to the extent necessary to eliminate such conflict.

F. Vesting . Each Affected Participant shall be fully vested in his or her Affected Account.

EXELON CORPORATION CASH BALANCE PENSION PLAN

Amended and Restated Effective as of January 1, 2013

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ARTICLE 1
TITLE AND PURPOSE

The name of the plan set forth herein shall be the "Exelon Corporation Cash Balance Pension Plan" (the "Plan"). This Plan, as in effect on December 31, 2012, was previously amended and restated effective generally as of January 1, 2013 and this document represents the subsequent amendment and restatement of the Exelon Corporation Cash Balance Pension Plan as in effect on December 31, 2012 and, except as otherwise provided, shall control and apply to Employees whose employment is terminated on or after January 1, 2013 and to the Beneficiaries of such Employees. The rights and benefits of Employees whose employment terminates before January 1, 2013 and of the Beneficiaries of such Employees shall be determined under the Exelon Corporation Cash Balance Pension Plan as in effect at the time of such Employees' termination, including any provisions of this Plan effective at such time; provided, however, that the provisions of Section 6.1(d) (relating to Investment Credits), Article 8 (relating to limitations on benefits), Article 9 (relating to special participation and distribution rules relating to recommencement of employment and employment by related entities), Article 10 (relating to administration), Article 13 (relating to miscellaneous provisions) and Article 15 (relating to amendment and termination of the Plan) shall be effective for all such persons.

ARTICLE 2
DEFINITIONS

As used herein, the following words and phrases shall have the following respective meanings when capitalized:

(1) Accrued Benefit . Except as provided in Section 9.2 (relating to suspension of benefits), the amount payable under the Plan commencing on the first day of the month coinciding with or next following a Participant's Normal Retirement Age, determined as of a date not later than such Participant's Normal Retirement Age as if the Participant had elected Option

1 (the life annuity) under Section 7.2(c) (relating to optional forms of benefit), that is the Actuarial Equivalent of the sum of the balance credited to the Participant's Cash Balance Account as of the date of determination plus Investment Credits (at the rate in effect under Section 6.1(d) (relating to investment credits) on the date of determination) from the date of determination until such assumed date of commencement, plus the Additional Credit, if any, determined as of the date of commencement, subject to adjustment pursuant to Section 7.2(d)(2) (relating to special rules regarding pensions). Notwithstanding the preceding sentence, the Participant's Accrued Benefit attributable to his or her Cash Balance Account, determined as of any date prior to the Participant's Normal Retirement Age, shall be the greater of (a) the amount that would be payable with respect to the sum of the Transition Credit, if any, the Service Credits and the Investment Credits credited to such Participant's Cash Balance Account (the "Account Balance") if the Participant had elected Option 1 (the life annuity) under Section 7.2(c) (relating to optional forms of benefit), that is the Actuarial Equivalent of the Account Balance as of the date of determination projected to the Participant's Normal Retirement Age by crediting such Account Balance with interest calculated on the date of determination to the Participant's Normal Retirement Age, and (b) the amount determined pursuant to the preceding sentence. In addition, a Participant's Accrued Benefit shall include the Participant's Accrued Frozen Benefit. Notwithstanding the preceding sentences or anything contained herein to the contrary, a Participant's Accrued Benefit attributable to his or her Cash Balance Account, determined as of any date on or after August 18, 2006, shall be the Participant's Cash Balance Account.

(2) Accrued Frozen Benefit . The meaning given such term in the applicable Schedule.

(3) Actuarial Equivalent . A benefit of value equivalent to the value of the benefit being replaced, computed using the table specified by the Commissioner of Internal Revenue for purposes of section 417(e)(3) of the Code (which, as of the Effective Date, is the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female) and, as of January 1, 2003, is the 1994 Group Annuity Reserving (GAR) table (unisex basis)) in effect on the date of determination and an interest rate assumption using the "applicable interest rate" as defined in section 417(e)(3) of the Code for the month of November of the Plan Year immediately preceding the Plan Year in which the determination occurs.

(4) Additional Credit . The amount, if any, credited to a Participant's Cash Balance Account pursuant to Section 6.1(e).

(5) Administrator . The Company acting through its Vice President, Health & Benefits or such other person appointed pursuant to Section 10.1 (relating to the Administrator, the Investment Office and the Corporate Investment Committee).

(6) Affiliate . (a) A corporation that is a member of the same controlled group of corporations (within the meaning of section 414(b) of the Code) as an Employer, (b) a trade or business (whether or not incorporated) under common control (within the meaning of section 414(c) of the Code) with an Employer, (c) any organization (whether or not incorporated) that is a member of an affiliated service group (within the meaning of section 414(m) of the Code) that includes (i) an Employer, (ii) a corporation described in clause (a) of this definition or (iii) a trade or business described in clause (b) of this definition, or (d) any other entity that is required

to be aggregated with an Employer pursuant to Regulations promulgated under section 414(o) of the Code. A corporation, trade or business entity shall be an Affiliate only for such period or periods of time during which such corporation, trade or business entity is described in the preceding sentence, but not prior to such time.

(7) Beneficiary . The person or persons entitled to receive a benefit under Section 7.2 (relating to form of distribution) or Section 7.3 (relating to death benefits) in the event of the death of a Participant.

(8) Cash Balance Account . The hypothetical account established for each Participant pursuant to Section 6.1(a) (relating to establishment of accounts).

(9) CEG . Constellation Energy Group, Inc. and any of its affiliates that was an affiliate immediately before the Effective Time (as such term is defined in the Merger Agreement).

(10) Code . The Internal Revenue Code of 1986, as amended.

(11) ComEd Plan . The Commonwealth Edison Company Service Annuity System under the Exelon Corporation Retirement Program.

(12) Company . Exelon Corporation, a Pennsylvania corporation, and any successor to such Company that shall adopt the Plan pursuant to Article 12 (relating to continuance by successor entities).

(13) Compensation . The regular base salary or base wages, as applicable, paid by an Employer to an Eligible Employee for a Plan Year, increased by all payments made during such Plan Year by an Employer to such Eligible Employee under any of the plans set forth in Exhibit A attached hereto, all nuclear license bonuses paid during such Plan Year by an Employer to such Eligible Employee and all amounts not includible in such Eligible Employee's regular base salary or base wages solely on account of his or her election to have compensation reduced pursuant to any qualified cash or deferred arrangement described in section 401(k) of the Code, a qualified transportation fringe benefit program described in section 132(f) of the Code or a cafeteria plan as described in section 125 of the Code, in each case, maintained by an Employer, but excluding any reimbursements or other allowances for automobile, relocation, travel or education expenses (even if includible in the Employee's regular base salary or base wages) and any amount awarded under the Performance Share Award Program for Power Team Employees under the Exelon Corporation Long Term Incentive Plan (or any predecessor or successor program). Notwithstanding the preceding sentence, an Employee's Compensation in excess of the dollar amount prescribed by section 401(a)(17) of the Code (as adjusted for increases in the cost-of-living) shall not be taken into account for any purposes under the Plan. In the case of a Participant who is absent from employment due to a leave of absence for participation in Military Service, Compensation shall mean, for the period during which the Participant is absent due to Military Service, the Participant's Compensation, as defined above, for the twelve-month period preceding the first day of the Participant's absence. Compensation shall also include lump sum merit increases to base salary paid on or after January 1, 2003.

(14) Corporate Investment Committee . The Company acting through the Committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

(15) Craft Employee . An Employee who is a non-represented, non-exempt craft or clerical employee assigned to the Peachbottom, Limerick, Outage Services East, Philadelphia Electric Company or Texas generating plant.

(16) Effective Date . Except as otherwise specifically provided herein, January 1, 2013.

(17) Eligible Employee . Except as otherwise provided herein, (a) any Employee who (i) was an Eligible Employee on December 31, 2012, and (ii) is either receiving regular salary or wages from and rendering services to an Employer or is on authorized leave of absence, and (b) on and after January 1, 2013, any Employee who (i) has not, prior to January 1, 2013, had an Hour of Service with any Affiliate, (ii) completed his or her first Hour of Service with an Employer on or after January 1, 2013 and (iii) is either receiving regular salary or wages from and rendering services to an Employer or is on authorized absence. Notwithstanding the preceding sentences, an Eligible Employee shall not include (a) an Employee the terms of whose employment are subject to a collective bargaining agreement that does not provide for participation in this Plan, (b) an Employee paid on the temporary payroll of an Employer who has never completed at least 1,000 Hours of Service in any period of twelve consecutive months beginning with the Employee's date of employment or anniversary thereof, (c) an Employee who executes a written waiver of his or her right to participate in the Plan, (d) an individual rendering services to an Employer who is not on the payroll of any Employer, (e) an Employee employed by Exelon Generation Company, LLC in the Nuclear Security Division or employed by Exelon Corporation Nuclear Security LLC as an hourly non-exempt nuclear security guard, (f) on or after the Effective Time (as such term is defined in the Merger Agreement), an individual who was employed immediately prior to the Effective Time at CEG or a facility owned immediately before the Effective Time by CEG, (g) an individual who is newly employed on or after the Effective Time (as such term is defined in the Merger Agreement) and prior to January 1, 2013 at a facility owned immediately before the Effective Time by CEG, and (h) an Employee who is newly employed on or after January 1, 2013 by either BGE Home Products & Services, LLC or Constellation Mystic Power, LLC. It is expressly intended that an individual rendering services to an Employer pursuant to any of the following agreements shall be excluded from Plan participation pursuant to clause (d) of this subdivision even if a court or administrative agency determines that such individual is an Employee: (i) an agreement providing that such services are to be rendered as an independent contractor, (ii) an agreement with an entity, including a leasing organization within the meaning of section 414(n)(2) of the Code, that is not an Employer or (iii) an agreement that contains a waiver of participation in the Plan. Notwithstanding anything contained in the Plan to the contrary, any Employer may, at any time, designate, with the consent of the Administrator, a specified group of Employees who will be Eligible Employees.

(18) Employee . An individual whose relationship with an Employer is, under common law, that of an employee.

(19) Employer . The Company and any other Affiliate set forth on Appendix I hereto that, with the consent of the Company, elects to participate in the Plan in the manner described in Article 11 (relating to participation by other employers) either with respect to all Employees or a particular group of Employees of such Affiliate and any successor Affiliate that adopts the Plan pursuant to Article 12 (relating to continuance by successor entities). If any entity described in the preceding sentence withdraws from participation in the Plan pursuant to Section 11.2 (relating to withdrawal from participation) or terminates its participation in the Plan pursuant to Section 15.3 (relating to termination of the Plan by an Employer), such entity shall thereupon cease to be an Employer. Appendix I shall be updated from time to time by the Company to reflect any adoption pursuant to Section 11.1, but the failure to so update such Appendix shall not affect the effectiveness of any such adoption. Such adoptions will be effective whether occurring before, on or after the Effective Date and whether or not reflected in Appendix I.

(20) ERISA . The Employee Retirement Income Security Act of 1974, as amended.

(21) Hour of Service . (a) Each hour for which an Employee is paid, or entitled to payment, for the performance of duties (such hours to be credited to the Employee for the computation period or periods in which the duties are performed); (b) each hour for which an Employee is paid, or entitled to payment, on account of a period of time during which no duties are performed (irrespective of whether a Termination of Employment has occurred) due to vacation, holiday, illness, incapacity (including disability), layoff, jury duty, military duty or leave of absence (such hours to be credited to the Employee for the computation period or periods in which the period of time during which no duties are performed occurs); and (c) each hour for which back pay, irrespective of mitigation of damages, is either awarded or agreed to by an Employer (such hours to be credited to the Employee for the computation period or periods in which the award or agreement pertains rather than the computation period in which the award, agreement or payment is made). Hours of Service shall be computed in accordance with paragraphs (b) and (c) of section 2530.200b-2 of the Department of Labor Regulations.

(22) Investment Credits . The amounts credited to a Participant's Cash Balance Account pursuant to Section 6.1(d).

(23) Investment Office . The Company acting through the Exelon Investment Office.

(24) Merger Agreement . That Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc.

(25) Military Service . The performance of duty on a voluntary or involuntary basis in a "uniformed service" (as defined below) under competent authority of the United States government and includes active duty, active duty for training, initial active duty for training, inactive duty training, full-time National Guard duty, and a period for which a person is absent from employment for the purpose of an examination to determine the fitness of the person to perform any such duty. For purposes of the preceding sentence, the term "uniformed service" means the Armed Forces, the Army National Guard and the Air National Guard when engaged in active duty for training, inactive duty training, or full-time National Guard duty, the commissioned corps of the Public Health Service, and any other category of persons designated by the President of the United States in time of war or emergency.

(26) Normal Retirement Age . With respect to a Participant's Cash Balance Account, (a) for periods prior to May 23, 2007, the earlier of (a) the date the Participant completes five years of Vesting Service and (b) the later of (i) the Participant's 65th birthday, and (ii) the fifth anniversary of the date the Participant commenced participation in the Plan; and (b) for periods beginning on and after May 23, 2007, the later of (i) the Participant's 62nd birthday, and (ii) the fifth anniversary of the date the Participant commenced participation in the Plan.

(27) Participant . An Eligible Employee who has satisfied the requirements set forth in Article 3 (relating to participation). An Eligible Employee who becomes a Participant shall cease to be a Participant upon the distribution of his or her entire vested benefit under the Plan. Any Participant who upon his or her Termination of Employment has not satisfied the Vesting Requirement shall cease to be a Participant upon such Termination of Employment. Notwithstanding anything in the Plan to the contrary, no Eligible Employee who is hired on or after January 1, 2013 shall become a Participant in the Plan.

(28) PECO Plan . The Service Annuity Plan of PECO Energy Company under the Exelon Corporation Retirement Program.

(29) Pension . A monthly payment continuing for the lifetime of the payee.

(30) Pension Starting Date . The first day as of which an amount becomes payable to a Participant or Beneficiary in accordance with Article 7 (relating to distributions). A Participant or Beneficiary shall have only one Pension Starting Date with respect to the Participant's Accrued Benefit.

(31) Period of Severance . Any twelve-month period commencing on the date an Employee terminates employment or any twelve-month period beginning on the anniversary of such date during which the Employee does not perform any Hours of Service for an Employer. For purposes of this definition, an Employee shall be credited with Hours of Service for any period of absence from an Employer during which such Employee (a) is in Military Service, provided that the Employee returns to the employ of an Employer within the period prescribed by laws relating to the reemployment rights of persons in Military Service, (b) is on an uncompensated leave of absence duly granted by an Employer, or (c) is absent from work for a maximum of twenty-four consecutive months because of (i) the pregnancy of the Employee, (ii) the birth of the Employee's child, (iii) the placement of a child with the Employee in connection with the Employee's adoption of such child, or (iv) the need to care for any such child for a period beginning immediately following such birth or placement. Notwithstanding the foregoing, no Hours of Service shall be credited to an Employee under clause (c) of this subdivision unless the Employee timely furnishes to the Administrator a certificate of birth, proof of adoption or other appropriate legal documentation setting forth parentage or adoption.

(32) Plan . The plan herein set forth and as from time to time amended.

(33) Plan Year . The calendar year.

(34) Qualified Domestic Relations Order . Any domestic relations order which the Administrator has determined, in accordance with procedures established by the Administrator to be a "qualified domestic relations order" defined in section 414(p) of the Code.

(35) Qualified Joint and Survivor Annuity . The form of distribution described in Section 7.2(b) (relating to manner of distribution with respect to married Participants).

(36) Regulations . Written temporary or final regulations of (i) the Department of Labor construing ERISA or (ii) the Treasury Department construing the Code.

(37) Schedule . If a Participant's accrued benefit under the ComEd Plan was transferred to the Plan pursuant to Section 3.1(c) (relating to transfer of benefits and assets to Plan) or Section 9.1 (relating to recommencement of employment by terminated employee), Schedule A and, if a Participant's accrued benefit under the PECO Plan was transferred to the Plan pursuant to Section 3.1(c) or Section 9.1, Schedule B.

(38) Schedule Equivalent . A benefit of value equivalent to the value of the benefit being replaced, computed using the actuarial factors and rules set forth in the applicable Schedule.

(39) Service Credits . The amounts, if any, credited to a Participant's Cash Balance Account pursuant to Section 6.1(c).

(40) Spouse . For periods prior to September 16, 2013, "Spouse" means the individual who is the husband or wife of a Participant as a result of the legal union between one man and one woman, within the meaning of the Defense of Marriage Act, on the Participant's Pension Starting Date or, if earlier, on the date of the Participant's death. Effective September 16, 2013, "Spouse" means the individual who, on a Participant's Pension Starting Date, or if earlier, on the date of the Participant's death, is lawfully married to the Participant under the laws of the state or foreign jurisdiction where the individual and the Participant were married, without regard to the laws of the state where the individual and the Participant are domiciled. For the avoidance of doubt, the term "Spouse" shall not include a person who, with the Participant, is in a domestic partnership, civil union or other similar formal relationship recognized by applicable law. While the Spouse is living and, except as otherwise provided in a qualified domestic relations order as described in Section 13.2(b) (relating to exception to nonassignability in the case of a qualified domestic relations order) or Section 7.4(h) (relating to automatic cancellation of elections), such Spouse shall be treated as the Participant's Spouse for all purposes of the Plan without regard to whether such Spouse remains married to the Participant after the Participant's Pension Starting Date.

(41) Target Income . (a) In the case of a Participant who participated in the ComEd Plan prior to becoming a Participant, Target Income means the sum of (i) the total of the Participant's "basic compensation" as defined in the ComEd Plan for all pay periods ending during calendar year 2001 (for a Participant who was on an authorized leave of absence during calendar year 2001, basic compensation for any pay period during which such Participant did not receive compensation shall be the Participant's average base pay rate per pay period for the twelve-month period preceding the first day of the Participant's leave of absence) and (ii)

"incentive pay" as defined in the ComEd Plan, except that incentive pay shall equal 100% of the target incentive pay the Participant would receive for calendar year 2002 under the applicable plans if the target goals were achieved during 2002, except that incentive pay shall equal 100% of the target incentive pay the Participant would receive for calendar year 2002 under the applicable plans if the target goals were achieved during 2002.

(b) In the case of a Participant who participated in the PECO Plan prior to becoming a Participant, Target Income means the sum of (i) the Participant's "annual base salary" for 2001 determined in accordance with Section 3.1(b) of the PECO Plan (for a Participant who was on an authorized leave of absence during calendar year 2001, annual base salary for 2001 shall be determined by assuming that for any pay period during which such Participant did not receive compensation, the Participant was paid the base rate in effect immediately prior to the start of the Participant's leave of absence) and (ii) incentive pay under any Employer's incentive pay plan (excluding the Performance Share Award Program for Power Team Employees under the Exelon Corporation Long Term Incentive Plan), except that incentive pay shall equal 100% of the target incentive pay the Participant would receive for calendar year 2002 under the applicable plans if the target goals were achieved during 2002.

In determining "incentive pay" for purposes of the preceding subparagraphs, (i) if the Participant's incentive pay is determined by multiplying his or her compensation by a percentage, the target percentage for 2002 (based on pay-grade in effect as of December 31, 2001) shall be used for such Participant and such target percentage shall be multiplied by the Participant's 2001 "basic compensation" or "annual base salary", as applicable, (ii) if the Participant's incentive pay is defined as a flat dollar amount, the Participant's incentive pay shall be the 2002 target incentive pay, (iii) if the Participant's incentive pay is determined by adding quarterly bonus targets and an annual target incentive, the Participant's incentive pay shall equal the sum of the target quarterly bonuses for calendar year 2002 and the target annual incentive for calendar year 2002, and (iv) if any limits apply to the payment of incentive compensation to a Participant under any applicable incentive pay plan, such limits will apply for purposes of this Plan.

(42) Termination of Employment . A Participant's ceasing to be an Employee of all Employers and all Affiliates. A transfer between employment by an Employer and employment by an Affiliate or between employment by Employers or Affiliates shall not constitute a Termination of Employment.

(43) Transition Credit . An amount equal to the product of the following: (a) a Participant's "credited service" under the ComEd Plan or the Participant's "benefit years" under the PECO Plan, as applicable, determined as of December 31, 2001, (b) the percentage applicable to the Participant determined pursuant to Table T and (c) the Participant's Target Income. Notwithstanding the preceding sentence, in no event shall a Participant's Transition Credit exceed 100% of his or her Target Income.

(44) Trust . The Directed Retirement Trust under the Exelon Corporation Cash Balance Pension Plan, as from time to time amended and, effective November 1, 2010, the Exelon Corporation Pension Master Retirement Trust.

(45) Trust Fund . All money and property of every kind held by the Trustee pursuant to the terms of the agreement governing the Trust.

(46) Trustee . The trustee provided for in Article 5 (relating to the Trust) or any successor trustee or, if there is more than one such trustee acting at any time, all of such trustees collectively.

(47) Vesting Requirement . For periods beginning prior to May 23, 2007, a Participant's attainment, during the time such Participant is an Employee, of his or her Normal Retirement Age. For periods beginning on and after May 23, 2007, the earlier of (a) the date a Participant completes the applicable years of Vesting Service described in the following sentence and (b) the date the Participant's attains, during the time such Participant is an Employee, his or her Normal Retirement Age. For purposes of the preceding sentence, the applicable years of Vesting Service are, for Plan Years beginning before January 1, 2008, five years, and for Plan Years beginning on and after January 1, 2008, three years.

(48) Vesting Service . The period of an Employee's employment which is used to determine whether the Employee has satisfied the Vesting Requirement. An Employee's Vesting Service includes the aggregate of the periods during which the Employee is employed by an Employer or an Affiliate beginning on the day on which the Employee first performs an Hour of Service with an Employer or Affiliate, provided that in the case of an Employee who has no vested right to any benefits under this Plan, such Employee's periods of employment before and after a period of absence from employment shall be aggregated only when the Employee's number of consecutive one-year Periods of Severance is less than five and the Employee has at least one year of Vesting Service after such period of absence from employment. For purposes of the preceding sentence, an Employee shall be deemed to be employed by an Employer or an Affiliate during (a) any period of absence from employment by an Employer or an Affiliate which is of less than twelve months' duration, (b) the first twelve months of any period of absence from employment for any reason other than the Employee's quitting, retiring or being discharged, (c) the period during which the Employee is not rendering services to any Employer or Affiliate as a result of a disability during which period the Employee is receiving benefits under any Employer's or Affiliate's long-term disability plan and (d) any period during which the Employee is in Military Service, provided that the Employee returns to the employ of an Employer or an Affiliate within the period prescribed by laws relating to the reemployment rights of persons in Military Service. The Administrator may require certification from an Employee, as a condition of granting Vesting Service under this subdivision, that the leave was taken for one of the reasons enumerated in the preceding sentence. Notwithstanding the preceding sentences, in determining an Employee's period of absence from employment by an Employer or an Affiliate, the following shall be disregarded: the first twenty-four months of any period of absence from employment by reason of (i) the Employee's pregnancy, (ii) the birth of the Employee's child, (iii) the placement of a child with the Employee in connection with the adoption of such child by such Employee or (iv) caring for such child for a period beginning immediately following such birth or placement. Notwithstanding anything in this definition to the contrary, the Vesting Service for a Participant who elects to participate in the Plan pursuant to Section 3.1(b) (relating to eligibility for participation for employees other than new hires) and whose accrued benefit under the PECO Plan is transferred to the Plan pursuant to Section 3.1(c) (relating to transfer of benefits and assets to Plan) shall be (a) for periods prior to January 1,

2002, the vesting service credited to the Participant under the terms of the PECO Plan, as in effect on December 31, 2001, and (b) for the Participant's "eligibility computation period" (as defined in the PECO Plan) that ends during the 2002 Plan Year, the greater of (i) the Vesting Service, for such period, determined pursuant to this subdivision and (ii) the vesting service, for such period, determined pursuant to the terms of the PECO Plan.

ARTICLE 3
PARTICIPATION

Section 3.1 Eligibility for Participation . (a) General . Each Eligible Employee who immediately before the Effective Date was a Participant in the Plan shall continue to be a Participant as of the Effective Date. Each other Eligible Employee who has not, prior to the Effective Date, had an Hour of Service with any Affiliate and whose first Hour of Service with an Employer is on or after the Effective Date shall become a Participant as of the first day that such Eligible Employee completes an Hour of Service with an Employer as an Eligible Employee.

(b) Other Employees Prior to the Effective Date . Each individual who (a) is, at any time between January 1, 2002 and April 30, 2002, an Employee and (b) was, on December 31, 2000, a participant in either the ComEd Plan (other than a participant the terms of whose employment are subject to a collective bargaining agreement) or the PECO Plan, or would have been a participant in the PECO Plan if the age and service requirements for participation in the PECO Plan were disregarded, shall be permitted to elect, in the time and manner prescribed by the "Committee," as such term was defined in the Plan prior to June 1, 2006, to either (i) continue participating in the ComEd Plan or the PECO Plan, as the case may be, on and after January 1, 2002 (or begin participating in the PECO Plan, in the case of an Employee who will satisfy the eligibility and age and service requirements for participation in such plan on January 1, 2002) or (ii) cease participating in the applicable Plan described in clause (i) hereof as of

December 31, 2001 and begin participating in the Plan as of January 1, 2002 (or, if later, his or her employment or reemployment date). Each such Eligible Employee who affirmatively elects to participate in the Plan in lieu of participation in the ComEd Plan or the PECO Plan shall become a Participant as of January 1, 2002 (or, if later, his or her employment or reemployment date), unless such Participant receives a notification (the "Notice") from an Employer that his or her employment with the Employers and their Affiliates will be terminated on or before December 31, 2002 and that such Participant is eligible for severance benefits under the Exelon Corporation Merger Separation Plan for Designated Management Employees or any other severance plan maintained by an Employer or an Affiliate. An Eligible Employee who receives a Notice shall not become a Participant, notwithstanding such Eligible Employee's election to participate in the Plan. An Eligible Employee (i) who receives a Notice, but whose employment does not terminate on or before December 31, 2002, or (ii) whose employment terminates before December 31, 2002 without the Employee receiving a Notice shall become a Participant as of January 1, 2002 (or, if later, his or her employment or reemployment date) if such Employee elects, in the time and manner prescribed by the "Committee," as such term was defined in the Plan prior to June 1, 2006, to participate in the Plan.

In the case of an Eligible Employee who became an employee of the Power Team during 2003 pursuant to Exelon Way, such Eligible Employee shall continue to be a Participant. In addition, each Eligible Employee who was an employee of the Power Team on any date in 2003 and who became an employee of a participating business unit of an Employer during 2003 in connection with Exelon Way shall continue to be a Participant only if such Employee was a Participant prior to the date on which such Employee became an employee of a participating business unit of an Employer. Effective as of January 1, 2004, each individual (i) who either (A)

is an employee of the Power Team or (B) transferred employment from the Power Team to a participating business unit of an Employer during 2003 pursuant to Exelon Way, (ii) who became an Eligible Employee on or after January 1, 2004 and (iii) who either (A) has a frozen accrued benefit under this Plan or (B) does not have an accrued benefit under either the ComEd Plan or the PECO Plan shall become a Participant as of the later of January 1, 2004 and the date the Eligible Employee completes an Hour of Service with an Employer as an Eligible Employee. In addition, each Eligible Employee (i) who either (A) is an employee of the Power Team or (B) transferred employment from the Power Team to a participating business unit of an Employer during 2003 pursuant to Exelon Way, (ii) who became an Eligible Employee on January 1, 2004, (iii) who has an accrued benefit under either the ComEd Plan or the PECO Plan, (iv) who is not described in the preceding sentence and (v) who did not previously make a valid election pursuant to the preceding paragraph shall be permitted to elect, in the time and manner prescribed by the "Committee," as such term was defined in the Plan prior to June 1, 2006, to either (A) resume or continue participation in the ComEd Plan or the PECO Plan, as the case may be, as of January 1, 2004 or (B) participate in the Plan as of January 1, 2004. Each such Eligible Employee who affirmatively elects to participate in the Plan in lieu of participation in the ComEd Plan or the PECO Plan shall become a Participant as of January, 1, 2004.

(c) Transfer of Benefits and Assets to Plan . If an Employee described in paragraph (b) above elects to participate in the Plan in lieu of participating in the ComEd Plan or the PECO Plan, as the case may be, the Employee's accrued benefit under either such plan, determined as of December 31, 2001, or December 31, 2003, as the case may be, in accordance with the provisions of the applicable plan, shall be transferred to the Plan. An amount of assets that is equal to the present value of the Employee's accrued benefit described in the preceding sentence

determined using the methods and assumptions prescribed by section 4044 of ERISA shall also be transferred to the Plan. Such transfer of benefits and assets related thereto shall occur as soon as practicable after the Eligible Employee makes the election described in paragraph (b) above. Each Participant whose benefits are so transferred shall be permitted to have his or her Accrued Frozen Benefit paid in any of the optional forms of benefit listed in the applicable Schedule in lieu of the forms provided hereunder. The provisions set forth in the applicable Schedule shall govern all matters relating to a Participant's Accrued Frozen Benefit.

In the event that an Eligible Employee whose accrued benefit under the ComEd Plan or the PECO Plan, and related assets, is transferred to the Plan receives a Notice and has a Termination of Employment on or before December 31, 2002, the accrued benefit, and related assets, transferred to the Plan shall be transferred back to the ComEd Plan or the PECO Plan, as the case may be, and the amount of the pension benefit accrued by such Employee during 2002 (if any) shall be determined under the terms of the ComEd Plan or the PECO Plan, as applicable, rather than the Plan. Such transfer shall occur as soon as administratively practicable.

Section 3.2 Transfer to Affiliates . If a Participant is transferred from one Employer to another Employer or from an Employer to an Affiliate that is not an Employer, then such transfer shall not terminate the Participant's participation in the Plan and the Participant shall continue to participate in the Plan until an event occurs that would have entitled the Participant to a complete distribution of the Participant's vested Pension had the Participant continued to be employed by an Employer until the occurrence of such event. Nevertheless, except to the extent provided in Section 9.3 (relating to employment by related entities) or Section 9.7 (relating to change in employment status or transfer to affiliate), a Participant shall not be entitled to receive Service Credits under Section 6.1(c) (relating to Service Credits) during any period of employment by

any Affiliate that is not an Employer with respect to such Participant, and periods of employment with an Affiliate that is not an Employer with respect to such Participant shall be taken into account only to the extent set forth in Section 9.3 (relating to employment by related entities) or Section 9.7 (relating to change in employment status or transfer to affiliate).

Section 3.3 Cessation of Participation . An individual's participation in the Plan shall cease upon the date the individual is no longer eligible to receive a benefit from this Plan or upon the individual's Termination of Employment if the individual has not satisfied the Vesting Requirement upon the date of his or her Termination of Employment.

Section 3.4 Rehired Participants . Notwithstanding anything contained herein to the contrary, if a Participant terminates employment and is reemployed as an Employee under circumstances that satisfy the applicable conditions for continuation of payment of retirement benefits set forth in the Company's policy regarding the rehiring of retirees, including that the Participant waives participation in, or additional benefits and accruals under the Plan, such Participant shall not be entitled to receive any Service Credits under Section 6.1(c) (relating to Service Credits) during such period of reemployment.

ARTICLE 4
SOURCE OF CONTRIBUTIONS

Section 4.1 Source of Contributions . The Employers intend to make contributions to the Trust of amounts which, in the aggregate over a period of time, shall be sufficient to finance the benefits provided by the Plan. Any such contributions shall be in such amounts and shall be made in such manner and at such time as the Company may from time to time determine in accordance with the funding policy it establishes and consistent with minimum funding standards under section 412 of the Code, provided, however, that all contributions made by the Employers

for any Plan Year shall be made prior to the due date, including extensions thereof, of the Employers' federal income tax return for the taxable year of the Employers which coincides with such Plan Year. The Company may rely on the advice of actuaries in establishing and carrying out a funding policy. Forfeitures arising under the Plan for any reason shall be applied to reduce the cost of the Plan, not to increase the benefits otherwise payable to the Participants.

Section 4.2 Limitation on Contributions . The contributions of an Employer for any Plan Year shall not exceed the maximum amount for which a deduction is allowable to such Employer for federal income tax purposes for the taxable year of such Employer that ends with or within such Plan Year. Any contribution made by an Employer by reason of a good faith mistake of fact, or the portion of any contribution made by an Employer that exceeds the maximum amount for which a deduction is currently allowable to such Employer for federal income tax purposes, shall upon the request of such Employer be returned by the Trustee to the Employer. An Employer's request and the return of any such contribution must be made within one year after such contribution was mistakenly made or after the deduction of such excess portion of such contribution was disallowed, as the case may be. The amount to be returned to an Employer pursuant to this Section shall be the excess of (i) the amount contributed over (ii) the amount that would have been contributed had there not been a mistake of fact or the maximum amount that is so deductible, as the case may be. Earnings attributable to the mistaken contribution shall not be returned to the Employer, but losses attributable thereto shall reduce the amount to be so returned.

ARTICLE 5
TRUST

A trust (the "Trust") has been created by the execution of a trust agreement between the Company and a trustee (the "Trustee") for purposes of holding and administering the assets of the Plan. All contributions under the Plan shall be paid to the Trustee. The Trustee shall hold all monies and other property received by it and invest and reinvest the same, together with the income therefrom, on behalf of the Participants collectively in accordance with the provisions of such trust agreement. The Trustee shall make distributions from the Trust Fund at such time or times to such person or persons and in such amounts as the Administrator directs in accordance with the Plan.

ARTICLE 6
PARTICIPANT ACCOUNTS

Section 6.1 Cash Balance Accounts . (a) Establishment of Accounts . A separate Cash Balance Account shall be established for each Participant. Each such account shall have an initial balance of zero until credited with any Transition Credit, if applicable, or Service Credit as provided herein. Each such account shall be for accounting purposes only, and there shall be no segregation of assets among such accounts. A Participant's Cash Balance Account shall cease to be maintained as of the Participant's Pension Starting Date (except to the extent such Pension Starting Date is required by Section 7.1(b) (relating to distributions to five percent owners)), in which case the Participant's Cash Balance Account shall cease to be maintained as of the first January 1 following the Participant's Termination of Employment).

(b) Transition Credit . A Participant's Cash Balance Account shall be credited, as of the first day of the Plan Year in which such Participant becomes a Participant, with an amount equal to the Participant's Transition Credit, provided that (a) the Participant is an Employee on January 1, 2002 and becomes a Participant pursuant to Section 3.1(b) (relating to eligibility for

participation for employees who are not new hires) and (b) the Participant is not an employee of the Power Team. An Employee who becomes a Participant pursuant to Section 3.1(a) (relating to eligibility for participation for new hires) shall not be credited with a Transition Credit at any time and a rehired Employee who becomes a Participant pursuant to Section 9.1 (relating to recommencement of employment by terminated employee) shall not be credited with a Transition Credit at the time of his or her rehire.

(c) Service Credits . A Participant's Cash Balance Account shall be credited, as of the last day of each Plan Year during which the Participant is a Participant and an Eligible Employee, with an amount equal to the following percentage of Compensation received by such Participant during such portion of such Plan Year that the Participant was an Eligible Employee: (i) for each Plan Year beginning before January 1, 2008 and, in the case of a Participant whose employment is subject to a collective bargaining agreement that provides for participation in this Plan, for each Plan Year thereafter, 5.75%, (ii) for each Plan Year beginning on and after January 1, 2008 if the Participant's employment is not subject to a collective bargaining agreement and either the Participant first became a Participant prior to January 1, 2013 or the Participant is a Craft Employee, 7.00%, and (iii) for each Plan Year beginning on and after January 1, 2013 for a Participant who first becomes a Participant on or after January 1, 2013, other than a Craft Employee or an Employee subject to a collective bargaining agreement, the applicable amount specified below:

For Participants Who Become Participants on or After January 1, 2013 (Other than Craft Employees)

Participant's Age as of the End of the Plan Year	Annual Service Credit
Under age 30	3%
Age 30 to 34	4%
Age 35 to 39	5%
Age 40 to 44	6%
Age 45 to 49	7%
Age 50 and older	8%

Notwithstanding the foregoing, if a Participant's Pension Starting Date occurs other than on the last day of a Plan Year and if the Participant is entitled to have an amount credited to his or her Cash Balance Account for such Plan Year pursuant to the preceding sentence, such amount shall be credited to the Participant's Cash Balance Account as of the last day of the month before such Pension Starting Date (and prior to the crediting of any Investment Credit for such Plan Year). No amount shall be credited pursuant to this paragraph (c) to the Cash Balance Account of a Participant who is not rendering services to any Employer or Affiliate as a result of a disability, regardless of whether such Participant is receiving benefits under any Employer's or Affiliate's long-term disability plan.

(d) Investment Credits . (1) For Participants who were Participants Prior to January 1, 2013 or are Craft Employees . The provisions of this paragraph shall apply only with respect to the Cash Balance Account of a Participant who was a Participant prior to January 1, 2013 or is a Craft Employee. For each Plan Year beginning before January 1, 2008, the Cash Balance Account of a Participant described in this paragraph (d)(1) shall be credited, as of the last day of each Plan Year during which the Participant is a Participant, whether or not such Participant is an Eligible Employee during such Plan Year, with an amount equal to the product of (i) the "Pre-

2008 Plan Interest Rate" (as defined below) multiplied by (ii) the balance of such Participant's Cash Balance Account as of the first day of such Plan Year. For each Plan Year beginning on and after January 1, 2008, such Participant's Cash Balance Account shall be credited, as of the last day of each Plan Year during which the Participant is a Participant, whether or not such Participant is an Eligible Employee during such Plan Year, with an amount equal to the sum of the following amounts: (i) the product of (A) the "Pre-2008 Plan Interest Rate" (as defined below) multiplied by (B) the balance of such Participant's Cash Balance Account as of December 31, 2007, if any; and (ii) the product of (A) the "Post-2007 Plan Interest Rate" (as defined below) multiplied by (B) the portion of such Participant's Cash Balance Account attributable to Service Credits credited after December 31, 2007, determined as of the first day of such Plan Year. A Participant described in this paragraph (d)(1) who is not rendering Services to any Employer or Affiliate as a result of a disability with respect to which such Participant is receiving benefits under any Employer's or Affiliate's long-term disability plan shall be credited with the amount described in the first and second sentences of this paragraph (d), as applicable. Notwithstanding the preceding sentences, if a Participant's Pension Starting Date occurs other than on the last day of a Plan Year, the amount to be credited to the Participant's Cash Balance Account pursuant to this paragraph (d)(1) for the Plan Year in which the Participant's Pension Starting Date occurs shall be equal to the product of (i) 4% (or, for Plan Years beginning on and after January 1, 2008, the "Post-2007 Plan Interest Rate," as defined below, for the immediately preceding Plan Year) multiplied by (ii) a fraction, the numerator of which is the number of whole calendar months during such Plan Year prior to and including the month which contains the date immediately preceding the Participant's Pension Starting Date and the denominator of which is twelve, and such Investment Credit shall be made as of the last day of the month before such Pension

Starting Date prior to the crediting of any Service Credit for such year. Except to the extent provided in Section 7.2(d)(2) (relating to special rules regarding pensions), a Participant's Cash Balance Account shall not be credited with Investment Credits after the Participant's Pension Starting Date.

For purposes of this paragraph (d)(1), the "Pre-2008 Plan Interest Rate" for any Plan Year shall mean a percentage equal to the greater of (i) 4% and (ii) the average of (A) the "applicable interest rate" as defined in section 417(e)(3) of the Code for the month of November of such Plan Year and (B) the annual percentage rate of return for the S&P 500 Stock Index for the 12-month period ending on December 31 of such Plan Year, as reported in The Wall Street Journal on the first business day of the succeeding year. For purposes of this paragraph (d)(1), the "Post-2007 Plan Interest Rate" for any Plan Year shall mean a percentage equal to the third segment rate of interest on long-term investment grade corporate bonds, as provided for in section 430(h)(2)(C) of the Code for the month of November of such Plan Year (determined by not taking into account any adjustment under clause (iv) thereof).

(2) For Participants who Became Participants on or After January 1, 2013 (Other than Craft Employees) . The provisions of this paragraph shall apply only with respect to the Cash Balance Account of a Participant who became a Participant on or after January 1, 2013, other than a Craft Employee. The Cash Balance Account of a Participant described in this paragraph (d)(2) shall be credited, as of the last day of each Plan Year during which the Participant is a Participant, whether or not such Participant is an Eligible Employee during such Plan Year, with an amount equal to the product of (i) the "Plan Interest Rate" (as defined below) multiplied by (ii) the balance of such Participant's Cash Balance Account as of the first day of such Plan Year. A Participant described in this paragraph (d)(2) who is not rendering Services to any Employer

or Affiliate as a result of a disability with respect to which such Participant is receiving benefits under any Employer's or Affiliate's long-term disability plan shall be credited with the amount described in the preceding sentence. Notwithstanding the preceding sentences, if a Participant's Pension Starting Date occurs other than on the last day of a Plan Year, the amount to be credited to the Participant's Cash Balance Account pursuant to this paragraph (d)(2) for the Plan Year in which the Participant's Pension Starting Date occurs shall be equal to the product of (i) the Plan Interest Rate multiplied by (ii) a fraction, the numerator of which is the number of whole calendar months during such Plan Year prior to and including the month which contains the date immediately preceding the Participant's Pension Starting Date and the denominator of which is twelve, and such Investment Credit shall be made as of the last day of the month before such Pension Starting Date prior to the crediting of any Service Credit for such year. Except to the extent provided in Section 7.2(d)(2) (relating to special rules regarding pensions), a Participant's Cash Balance Account shall not be credited with Investment Credits after the Participant's Pension Starting Date.

For purposes of this paragraph (d)(2), the "Plan Interest Rate" for any Plan Year shall mean a percentage equal to the greater of (i) 3.8%, and (ii) the lesser of (A) the second segment rate of interest on long-term corporate bonds, as determined under Section 430(h)(2)(C) of the Code for the month of November of such Plan Year (determined by not taking into account any adjustment under clause (iv) thereof), and (B) 7%.

(e) Additional Credit . If, as of a Participant's Pension Starting Date, the amount described in (1) below exceeds the amount described in (2) below, an amount equal to the difference between such amounts shall be credited the Participant's Cash Balance Account as of the day before such Pension Starting Date:

(1) The cumulative amount that would have been credited to the Participant's Cash Balance Account if the Plan Interest Rate described in Section 6.1(d) of the Plan (relating to Investment Credits) were credited to the Participant's "Opening Credit" (as defined below) for each Plan Year during which the Participant is a Participant at the Plan Interest Rate then in effect, whether or not such Participant is an Eligible Employee during such Plan Year.

(2) The cumulative amount that would have been credited to the Participant's Cash Balance Account if 6.5% interest were credited to the Participant's "Opening Credit" (as defined below) for all Plan Years during which the Participant is a Participant, whether or not such Participant is an eligible Employee during such Plan Year.

If the amount described in (1) above is equal to or less than the amount described in (2) above, no amount shall be credited to the Participant's Cash Balance Account pursuant to this paragraph (e). In addition, no amount shall be credited pursuant to this paragraph (e) if a Participant does not have an Accrued Frozen Benefit.

For purposes of this paragraph (e), "Opening Credit" shall mean an amount equal to the present value of a Participant's Accrued Frozen Benefit determined as of December 31, 2001 using a 6.5% discount rate and the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female) assuming the Accrued Frozen Benefit otherwise payable at the Schedule A Retirement Date would commence at the later of the Participant's attained age as of December 31, 2001 or age 60.

ARTICLE 7
DISTRIBUTIONS

Section 7.1 Time of Distribution . (a) In General . A Participant who has satisfied the Vesting Requirement shall be entitled to receive a distribution of the aggregate of the balance of his or her Cash Balance Account and his or her Accrued Frozen Benefit in the manner provided by Section 7.2 (relating to form of distribution) commencing as soon as practicable after the first day of the month immediately following the date on which the Participant's Termination of

Employment occurs. Notwithstanding the preceding sentence, a Participant whose Termination of Employment occurs prior to such Participant's attainment of age 70-1/2 shall be deemed to have elected to defer receipt of his or her Cash Balance Account and Accrued Frozen Benefit until the April 1 next following the date the Participant attains age 70-1/2, unless the Participant elects, in the time and manner described in the following sentence, to receive a distribution prior to such date. The Participant may elect to commence such distribution by giving the Administrator not less than 30 nor more than 90 days advance written notice of the Pension Starting Date desired by the Participant; provided, however, that the Administrator may waive such advance written notice requirement if the Participant submits the appropriate form to the Administrator in accordance with the requirements set forth in Section 7.4(d) (relating to notice of availability of optional forms of benefit). A Participant who has satisfied the Vesting Requirement and who does not make an election as described in the preceding sentence prior to such Participant's attainment of age 70-1/2 shall receive a distribution of the aggregate of the balance of his or her Cash Balance Account and his or her Accrued Frozen Benefit in the manner provided by Section 7.2 (relating to form of distribution) commencing no later than April 1 next following the date the Participant attains age 70-1/2.

(b) Distributions to Five Percent Owners . Notwithstanding any provision of the Plan to the contrary, if a Participant who has satisfied the Vesting Requirement and who is a "five percent owner" (as described in section 416(i) of the Code) remains employed by an Employer through April 1 of the year following the year in which the Participant attains age 70 $^{1}/_{2}$, distribution of the balance of the Participant's Cash Balance Account and his or her Accrued Frozen Benefit shall commence on such April 1 (or such later date as may be provided by the Code or Regulations). Any other Participant who remains in such employment shall not be permitted to commence distribution of such Participant's Cash Balance Account or Accrued Frozen Benefit at the time specified in the preceding sentence unless required by the Code or Regulations.

(c) Immediate Distribution of Small Benefits . Notwithstanding any provision of the Plan to the contrary, if, as of the date of a Participant's Termination of Employment (including on account of death), the aggregate of the balance of the Participant's Cash Balance Account and the lump sum Schedule Equivalent of the Participant's Accrued Frozen Benefit does not exceed $5,000 or, for distributions occurring on or after March 28, 2005, $1,000, such Participant or, in the event of the Participant's death, such Participant's Beneficiary or Beneficiaries, shall receive a distribution in the amount and in the form described in Option 2 of Section 7.2(c) (relating to lump sum distribution) as soon as practicable following such Termination of Employment in satisfaction of all benefits to which the Participant or his or her Beneficiaries, as the case may be, is entitled under the Plan.

(d) Deemed Distributions . If a Participant has not satisfied the Vesting Requirement upon his or her Termination of Employment, such Participant's vested interest in his or her benefit under the Plan shall have a value of zero, such Participant shall be deemed to have received immediately after such termination a lump sum distribution of such vested interest and concurrent therewith shall forfeit all benefits hereunder, and the Participant's Cash Balance Account and Accrued Frozen Benefit shall no longer be maintained.

Section 7.2 Form of Distribution . (a) Manner of Distribution With Respect to Unmarried Participants . A Participant who is not married on his or her Pension Starting Date shall have the Actuarial Equivalent of the Participant's Accrued Benefit attributable to his or her Cash Balance Account and the Schedule Equivalent of his or her Accrued Frozen Benefit, if any, distributed in the form of a Pension for the life of the Participant unless the Participant elects an optional form of distribution described in paragraph (c) of this Section (relating to optional forms of distributions) at the time and in the manner described in Section 7.4 (relating to election and waiver procedures).

(b) Manner of Distribution With Respect to Married Participants . A Participant who is married on his or her Pension Starting Date shall have the Actuarial Equivalent of the Participant's Accrued Benefit attributable to his or her Cash Balance Account and the Schedule Equivalent of his or her Accrued Frozen Benefit, if any, distributed in the form of a Pension payable to the Participant for the life of the Participant and, thereafter, if the Participant's Spouse survives the Participant, a Pension payable to the Spouse during the remaining lifetime of such Spouse equal to 50% of the Pension payable to the Participant during the Participant's lifetime. Notwithstanding the preceding sentence, the Participant, with the consent of his or her Spouse, may elect an optional form of distribution described in paragraph (c) of this Section (relating to optional forms of distributions) at the time and in the manner described in Section 7.4 (relating to election and waiver procedures).

(c) Optional Forms of Distribution . Upon written request to the Administrator made at the time and in the manner prescribed in Section 7.4 (relating to election and waiver procedures), a Participant may elect to receive a distribution of the Participant's benefit under the Plan in one of the following optional forms in lieu of the form described in paragraph (a) or (b) of this Section (relating to manner of distribution with respect to unmarried Participants and married Participants, respectively):

Option 1 : Life Annuity . If the Participant is married on his or her Pension Starting Date, a Pension payable for the life of the Participant in an amount that is the Actuarial Equivalent of the Participant's Accrued Benefit attributable to his or her Cash Balance Account and the Schedule Equivalent of his or her Accrued Frozen Benefit, if any.

Option 2 : Lump Sum Distribution . Except as otherwise provided in Section 7.8 (relating to special rules applicable to calculations of lump sum distributions), a single, lump sum distribution in an amount equal to the sum of (a) the balance credited to the Participant's Cash Balance Account as of the last day of the month immediately preceding the date of such distribution and (b) the lump sum Schedule Equivalent of the Participant's Accrued Frozen Benefit.

Option 3 : Survivor Annuity . A reduced Pension payable to the Participant during the Participant's lifetime and, thereafter, if the designated Beneficiary survives the Participant, a Pension equal to 100%, 75% or 50% (whichever is specified when this option is elected) of such reduced Pension payable to the Designated Beneficiary during the remaining lifetime of such Designated Beneficiary, the aggregate amount of which are the Actuarial Equivalent of the Participant's Accrued Benefit attributable to his or her Cash Balance Account and the Schedule Equivalent of his or her Accrued Frozen Benefit, if any.

(d) Special Rules Regarding Pensions .

(1) If a Participant's spouse dies before the Participant's Pension Starting Date and the Participant has not elected an optional form of distribution described in paragraph (c) of this Section (relating to optional forms of distribution), the Participant shall again be entitled to make an election under this Section.

(2) If a Pension commences pursuant to Section 7.1(b) (relating to distributions to five percent owners) while a Participant remains employed by an Employer, such Pension shall be actuarially adjusted as of January 1 following the end of each calendar year during which such Participant remains employed by an Employer to reflect any additional Service Credits and Investment Credits credited to the Participant's Cash Balance Account as of December 31 of the preceding calendar year.

(3) If a Participant elects Option 3 under Section 7.2(c) and the Participant's Beneficiary is other than the Participant's Spouse, the Pension payable to the Participant and to the Beneficiary shall be adjusted as is necessary to satisfy the incidental benefit requirement under section 401(a)(9) of the Code. Notwithstanding anything in the Plan to the contrary, the form and timing of all distributions under the Plan to any Participant shall be in accordance with Section 401(a)(9) of the Code and regulations issued thereunder, including the incidental death benefit requirements of Section 401(a)(9)(G) of the Code and Treasury Regulation §1.401(a)(9)-2 through Treasury Regulation §1.401(a)(9)-9.

Section 7.3 Death Benefits . (a) Eligibility . If a Participant who has satisfied the Vesting Requirement dies prior to his or her Pension Starting Date, the Participant's surviving Beneficiary shall be entitled to receive a benefit under this Section. In addition, if a Participant dies while an Employee, the Participant's surviving Beneficiary shall be entitled to receive a benefit under this Section, regardless of whether the Participant has satisfied the Vesting Requirement.

(b) Form of Payment . A surviving Beneficiary who is entitled to a distribution of the Participant's benefit under this Section shall receive the following, as applicable:

(1) Lump Sum Payment . Except as otherwise provided in Section 7.8 (relating to special rules applicable to calculations of lump sum distributions), a lump sum payment that is equal to the sum of (a) the balance credited to the Participant's Cash Balance Account as of the last day of the month immediately preceding the date of such distribution and (b) the lump sum Schedule Equivalent of the Participant's Accrued Frozen Benefit shall be payable to the Participant's surviving Beneficiary not later than the fifth anniversary of the Participant's death, except that if the Participant's surviving Beneficiary is the Participant's surviving Spouse, distribution to such surviving Spouse may commence at the same time as described in subparagraph (2). Notwithstanding the foregoing, should any benefit be payable pursuant to subparagraph (2) of this Section 7.3(b) (relating to statutory surviving Spouse's benefit), the amount of any benefit payable pursuant to this subparagraph (1) shall be reduced by the Actuarial Equivalent of the benefit payable pursuant to such subparagraph (2).

(2) Statutory Surviving Spouse's Benefit . If the Participant is survived by a Spouse to whom the Participant was married throughout the one-year period ending on the date of the Participant's death, then, unless such Participant has with his or her Spouse's consent waived the benefit described herein in the manner described in Section 7.4(e) (relating to waiver of statutory surviving Spouse's benefit), such Spouse shall be entitled to receive a survivor's Pension commencing as of any January 1 coinciding with or following the date of the Participant's death or any succeeding January 1 (but not later than the January 1 immediately preceding or coinciding with the date the Participant would have attained age 70-1/2 had he or she survived) and continuing for the lifetime of such Spouse in an amount equal to the Pension such Spouse would have received pursuant to a Qualified Joint and Survivor Annuity if the Participant had survived until such day and such Qualified Joint and Survivor Annuity had commenced on such day and the Participant had died immediately after such annuity commenced, but determined without regard to any Service Credits that would have been credited to the Participant's Cash Balance Account with respect to any periods subsequent to the Participant's Termination of Employment.

(c) The death benefits provided by this Section shall not be effective to the extent required to comply with the terms of a Qualified Domestic Relations Order.

Section 7.4 Election and Waiver Procedures . (a) Election of Optional Form of Benefit . Subject to paragraph (c) of this Section (relating to spousal consent to election of optional form of benefit or beneficiary designation), a Participant may elect, change or revoke any form of distribution provided under Section 7.2 (relating to forms of distribution) at any time during the 90-day period ending on the later of the Participant's Pension Starting Date and the date the Participant's benefit is paid or commences. Such an election, change or revocation shall be made by the Participant delivering a written notice describing the election, change or revocation to the Administrator on a form provided by the Administrator for this purpose.

(b) Beneficiary Designation . Subject to paragraph (e) below (relating to waiver of statutory surviving spouse's benefit), each Participant may designate one or more Beneficiaries to receive any payment pursuant to Section 7.3(b)(1) (relating to lump sum pre-retirement death benefit) in the event of his or her death. A Participant may from time to time, without the consent of any Beneficiary, change or cancel any such designation. Such designation and each change therein shall be made in the form prescribed by the Administrator and shall be filed with the Administrator. If no Beneficiary has been designated by a deceased Participant, or the designated Beneficiary has predeceased the Participant, any payment pursuant to Section 7.3(b)(1) (relating to lump sum pre-retirement death benefit) shall be made by the Trustee at the direction of the Administrator (i) to the surviving Spouse of such deceased Participant, if any, or (ii) if there shall be no surviving Spouse, to the surviving children of such deceased Participant,

if any, in equal shares, or (iii) if there shall be no surviving Spouse or surviving children, to the executor or administrator of the estate of such deceased Participant, or (iv) if no executor or administrator shall have been appointed for the estate of such deceased Participant within six months following the date of the Participant's death, in equal shares to the person or persons who would be entitled under the intestate succession laws of the state of the Participant's domicile to receive the Participant's personal estate. The marriage of a Participant shall be deemed to revoke any prior designation of a Beneficiary made by him or her and a divorce shall be deemed to revoke any prior designation of the Participant's divorced Spouse if written evidence of such marriage or divorce shall be received by the Administrator before distribution shall have been made in accordance with such designation. If, within a period of three years following any Participant's death or other termination of employment by an Employer, the Administrator in the exercise of reasonable diligence has been unable to locate the person or persons entitled to benefits under this Article in respect of such Participant, the rights of such person or persons shall be forfeited and the Administrator shall direct the Trustee to pay such benefit or benefits to the person or persons next entitled thereto under the succession prescribed by this Section.

(c) Spousal Consent to Election of Optional Form of Benefit or Beneficiary Designation . If a Participant is married on his or her Pension Starting Date, and if after giving effect to an election, revocation or change described in paragraph (a) of this Section (relating to election of optional form of benefit) the Participant's Spouse would not be entitled to receive a survivor's benefit at least equal to that provided by Section 7.2 (b) (relating to manner of distribution with respect to married Participants), such election, revocation or change shall not be effective unless it shall have been consented to at the time of such election, revocation or change in writing by the Participant's Spouse and such consent acknowledges the effect of such election

and is witnessed by a notary public. The consent of a Spouse to such an election, revocation or change shall not be required if it is established to the satisfaction of the Administrator that such consent cannot be obtained because there is no Spouse, the Spouse cannot be located or such other circumstances as may be prescribed in Regulations. If the Spouse is legally incompetent to give consent, the consent may be executed by the Spouse's legal guardian (including the Participant, if the Participant is the legal guardian). An election of an optional form of distribution shall be deemed a rejection of the distribution form provided by paragraph (a) or (b) of Section 7.2 (relating to manner of distribution with respect to unmarried Participants and manner of distribution with respect to married Participants). The consent of a Spouse otherwise required by this paragraph shall not be necessary for a distribution required by a Qualified Domestic Relations Order.

(d) Notice of Availability of Optional Forms of Benefit . No less than 30 days (or such shorter period as may be permitted by applicable law) and no more than 90 days before the later of a Participant's Pension Starting Date and the date the Participant's benefit is paid or commences, the Administrator shall give the Participant by mail or personal delivery written notice in non-technical language that he or she may elect an optional form of distribution set forth in Section 7.2 (relating to form of distribution); provided, however, that the Participant may waive (with applicable spousal consent) such 30-day notice period as long as the Participant's distribution commences not less than eight days after such notice is provided. Such notice shall include a general description of the eligibility conditions and other material features of the optional forms of distribution provided under the Plan; the circumstances under which the basic forms of distribution set forth in Section 7.2 (relating to form of distribution) will be provided unless a Participant, with the consent of the Participant's Spouse, elects otherwise; the

Participant's right to revoke any such election; and information regarding the financial effect, in terms of dollars per payment, upon his or her distribution if he or she elects an optional form of distribution or revokes any prior election. Notwithstanding the foregoing, the notice described in the previous paragraph may be provided to the Participant subsequent to the Participant's Pension Starting Date, if the Participant so elects, provided that the following conditions are satisfied:

(i) the date on which the first payment to be received by the Participant is made (the "initial payment date") shall be no earlier than thirty (30) days following the date that the notice is furnished to the Participant, except that the initial payment date may be as early as the eighth day after such notice is provided if (i) such notice clearly indicates that the Participant has a right to a period of thirty (30) days after receiving the notice to consider to waive the basic forms of distribution provided under the Plan and to elect (with spousal consent) an optional form of benefit, (ii) the Participant affirmatively elects a form of distribution with the consent of his or her spouse (if required) to commence as of the initial payment date, and (iii) the Participant is permitted to revoke such election until the initial payment date;

(ii) the notice shall be provided to the Participant no more than ninety (90) days before the initial payment date, however, the Plan will not fail to satisfy the ninety (90)-day requirement if the delay in providing the distribution is due solely to an administrative delay;

(iii) the Participant is not permitted to elect a Pension Starting Date that precedes the date upon which the Participant could have otherwise started receiving benefits under the terms of the Plan as in effect on the Pension Starting Date;

(iv) to the extent that a Participant has not received any payments for the period from the Pension Starting Date to the initial payment date, the Participant shall receive a one-time payment to reflect any such missed payments (a "make-up payment"). Such make-up payment shall be adjusted for interest from the period beginning on the Pension Starting Date and ending on the initial payment date, which shall be calculated with respect to such payments that would have been received prior to the initial payment date. The interest rate used to compute the adjustment described in the preceding sentence shall equal the 30 Year Treasury rate for December of the preceding Plan Year. For purposes of Section 8.1 (relating to statutory limits), the limitations set forth therein shall comply with the adjustments required thereto pursuant to Treasury Regulation 1.417(e)-1 with respect to any Pension Starting Date described in this paragraph which is a "retroactive annuity starting date" as defined for purposes of such Regulation; and

(v) if a Participant who is married elects to commence the Participant's benefit as of the initial payment date pursuant to this paragraph, then the Participant's spouse (including an alternate payee who is treated as the Participant's spouse under a qualified domestic relations order), determined as of the initial payment date, must consent to such election if the survivor benefits payable as of the Pension Starting Date are less than the survivor benefits payable under the benefit described in Option 3 of Section 7.2(b) of the Plan as of the initial payment date.

(e) Waiver of Statutory Surviving Spouse's Benefit . A Participant may waive the statutory surviving spouse's benefit provided by Section 7.3 (b)(2) at any time prior to the Participant's death, provided, however, that if such waiver is made prior to the Plan Year in which the Participant attains age 35, such waiver shall become invalid on the first day of such year unless the Participant has terminated employment by the Employers prior to such day. A Participant whose waiver becomes invalid pursuant to the preceding sentence may elect, at any time after the waiver becomes invalid, to again waive the statutory surviving spouse's benefit provided by Section 7.3(b)(2). A waiver made pursuant to this paragraph (e) shall be made by delivering a written notice thereof to the Administrator on a form provided by the Administrator for this purpose with a written consent of the Participant's Spouse which satisfies the requirements of paragraph (b) of this Section (relating to beneficiary designation) (unless it is determined pursuant to paragraph (c) of this Section that such consent is not needed). Such a waiver shall cease to be effective if, subsequent to the execution of such waiver, the Participant shall make any other Beneficiary designation pursuant to paragraph (b) of this Section (relating to beneficiary designation) which diminishes the rights or contingent rights of the Participant's Spouse, which are specified in the Beneficiary designation in effect at the time such Spouse consented to such waiver, to all or part of the benefit provided under Section 7.3(b) (relating to form of payment of pre-retirement death benefits), provided, however, that in no event shall such

other Beneficiary designation affect the effectiveness of such waiver if such Spouse shall have so specified at the time of consent. A waiver described in this paragraph shall cease to be effective on (i) the date on which the Participant is subsequently married to a person other than the Spouse who consented to such waiver, (ii) the Participant's Pension Starting Date, or (iii) the date of the Participant's revocation of such waiver.

(f) Notice of Right to Waive Statutory Surviving Spouse's Benefit . Not later than twelve months after the day on which an Employee has become a Participant, the Administrator shall give the Participant by mail or personal delivery written notice in nontechnical language that he or she may waive the statutory surviving spouse's benefit provided by Section 7.3(b)(2). Such notice shall include a general description of terms and conditions of such benefit and the circumstances under which it will be provided unless waived and the Participant's right to revoke any such waiver and general information on the relative financial effect, if any, upon the Participant's Pension of such benefit and its waiver. Such notice shall also advise the Participant that, upon written request to the Administrator prior to the end of the waiver period set forth in paragraph (e) of this Section (relating to waiver of statutory surviving spouse's benefit), he or she will be given a written explanation in nontechnical language of the terms and conditions of such benefit and the financial effect, in terms of dollars per payment, upon his or her other death benefits if he or she does not waive such benefit. Such explanation shall be mailed or personally delivered to the Participant within 30 days from the date his or her written request is received by the Administrator.

(g) Election of Optional Form of Statutory Surviving Spouse's Benefit . A surviving Spouse may elect to have the statutory surviving spouse's benefit provided by Section 7.3(b)(2) payable in the form of Option 2 of Section 7.2(c) (relating to optional forms of distribution). Such an election may be made at any time prior to the commencement of such benefit and not thereafter. Such an election shall be made by delivering a written notice thereof to the Administrator on a form provided by the Administrator for this purpose.

(h) Automatic Cancellation of Elections . If a Participant's Pension is payable in the form of a joint and survivor annuity and if, prior to the Participant's Pension Starting Date, the Participant's Spouse dies or the Participant and such Spouse divorce, the Participant's election or deemed election to receive a joint and survivor annuity shall, upon the Participant's notice to the Administrator of such death or divorce, be automatically cancelled, unless, subsequent to such Spouse's death or the Participant's divorce and prior to the Participant's Pension Starting Date, the Participant remarries and notice of such new marriage is timely received by the Administrator.

Section 7.5 Distributions to Minor and Disabled Distributees . Any distribution under this Article that is payable to a distributee who is a minor or to a distributee who, in the opinion of the Administrator, is unable to manage his or her affairs by reason of illness or mental incompetency may be made to or for the benefit of any such distributee at such time consistent with the provisions of Section 7.2 (relating to form of distribution) and in such of the following ways as the legal representative of such distributee shall direct: (i) directly to any such minor distributee if, in the opinion of such legal representative, he or she is able to manage his or her affairs, (ii) to such legal representative, (iii) to a custodian under a Uniform Gifts to Minors Act for any such minor distributee, or (iv) directly in payment of expenses of support or maintenance of such person. Neither the Administrator nor the Trustee shall be required to see to the application by any third party other than the legal representative of a distributee of any distribution made to or for the benefit of such distributee pursuant to this Section.

Section 7.6 Direct Rollover Distributions . In the case of a distribution under this Plan that is an "eligible rollover distribution" within the meaning of section 402 of the Code and that is at least $200, an eligible distributee (as defined below) may elect that all or any portion of such distribution to which such eligible distributee is entitled shall be directly transferred as a rollover contribution from the Plan to (i) an individual retirement account described in section 408(a) of the Code, (ii) an individual retirement annuity described in section 408(b) of the Code, (iii) an annuity plan described in section 403(a) of the Code, (iv) a retirement plan qualified under section 401(a) of the Code, (v) an annuity contract described in section 403(b) of the Code, (vi) an eligible plan under section 457(b) of the Code which is maintained by an eligible employer described in section 457(e)(1)(A) of the Code (the terms of which permit the acceptance of rollover contributions) or (vii) effective January 1, 2008, a Roth IRA described in section 408A of the Code; provided, however, that (x) with respect to a plan described in clause (vii), for transfers occurring before January 1, 2010, the Participant (or surviving spouse of a Participant or a former spouse who is an alternate payee under a qualified domestic relations order as defined in section 414(p) of the Code) meets the requirements of section 408A(c)(3)(B) of the Code and (y) with respect to a distribution (or portion of a distribution) to a person who is not the Participant or the surviving spouse or former spouse of the Participant, "eligible retirement plan" shall mean only a plan described in clause (i), (ii) or (vii) that, in either case, is established for the purpose of receiving such distribution on behalf of such person. For purposes of this Section, "eligible distributee" shall include the Participant, his or her spouse or his or her former spouse who is an alternate payee under a qualified domestic relations order within the meaning of section 414(p) of the Code and, effective January 1, 2010, the Participant's Beneficiary who is not the Participant's spouse or former spouse. Notwithstanding the foregoing, an eligible distributee shall not be entitled to elect to have less than the total amount of such distribution transferred as a rollover contribution unless the amount to be transferred equals at least $500.

Section 7.7 Withholding Requirements . Any benefit payment made under the Plan will be subject to any applicable income tax withholding requirements.

Section 7.8 Special Rules Applicable to Calculations of Lump Sum Distributions . Notwithstanding anything contained herein to the contrary, if a lump sum distribution is paid to a Participant prior to the Participant's Normal Retirement Age and prior to May 23, 2007, the portion of any lump sum payment made under Section 7.2(c), Option 2, or Section 7.3(b)(1) that, in either case, is attributable to the Participant's Cash Balance Account shall be the greater of (x) the balance credited to the Participant's Cash Balance Account as of the last day of the month immediately preceding the date of such distribution and (y) the Actuarial Equivalent of the Participant's Accrued Benefit.

Section 7.9 Participant's Death During Qualified Military Service . Effective January 1, 2007, in the case of a Participant who dies while performing Military Service, the Beneficiaries of such Participant shall be entitled to any additional benefits, if any (other than benefit accruals relating to the period of Military Service), provided under the Plan had the Participant resumed employment with an Employer and then terminated such employment on account of such Participant's death.

ARTICLE 8
LIMITATIONS ON BENEFITS

Section 8.1 Statutory Limits . The provisions of this Section shall be effective for any "Limitation Year" (as defined below) solely to the extent required by the Code or Regulations for such year.

Notwithstanding any other provision of the Plan to the contrary, the amount of the Participant's annual benefit (as defined below) accrued, distributable or payable at any time under the Plan shall be limited to an amount such that such annual benefit and the aggregate annual benefit of the Participant under all other defined benefit plans maintained by the Employer or any other Affiliate does not exceed the lesser of:

(i) $160,000 (as increased to reflect the cost of living adjustments provided under section 415(d) of the Code), multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of participation (within the meaning of Treasury Regulation section 1.415(b)-1(g)(1)(ii)) and the denominator of which is 10; or

(ii) an amount equal to 100% of the Participant's average compensation for the three consecutive calendar years in which his or her compensation was the highest (as determined in accordance with Treasury Regulation section 1.415(b)-1(a)(5)) and which are included in his or her years of service (within the meaning of Treasury Regulation section 1.415(b)-1(g)(2)(ii)) with the Employers multiplied by a fraction (not exceeding 1 and not less than 1/10th), the numerator of which is the Participant's years of service and the denominator of which is 10.

The dollar amount set forth in clause (i) of the preceding paragraph shall be actuarially reduced in accordance with Treasury Regulation section 1.415(b)-1(d) if the Participant's Pension Starting Date occurs prior to the Participant's attainment of age 62. If the Participant's Pension Starting Date occurs after the Participant attains age 65, such dollar amount shall be actuarially increased in accordance with Treasury Regulation section 1.415(b)-1(e).

A Participant's "annual benefit" shall mean the Participant's accrued benefit payable annually in the form of a straight life annuity, as determined in, and accordance with, Treasury Regulation section 1.415(b)-1(b). If the annual benefit is payable in a form other than a single life annuity, the annual benefit shall be adjusted to the Actuarial Equivalent of a single life annuity using the assumptions of the following sentences; provided , however , that no adjustment shall be required for survivor benefits payable to a surviving Spouse under a Qualified Joint and Survivor Annuity (as described in Section 7.2(b)) to the extent such benefits would not be payable if the Participant's annual benefit were paid in another form.

Effective for Plan Years beginning January 1, 2004 and January 1, 2005, for any form of benefit subject to section 417(e)(3) of the Code, a Participant's annual benefit shall be the greater of (i) the amount computed using the interest rate and mortality table specified under subdivision (3) of Article 2 (relating to definition of Actuarial Equivalent) as in effect and (ii) the amount computed using an interest rate assumption of 5.5% and the applicable mortality table under Treasury Regulation section 1.417(e)-1(d)(2) (the "Applicable Mortality Table"). Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit subject to section 417(e)(3) of the Code, a Participant's annual benefit shall be the greatest of (i) the amount computed using the interest rate and mortality table specified under subdivision (3) of Article 2 (relating to definition of Actuarial Equivalent) as in effect, (ii) the amount computed using an interest rate assumption of 5.5% and the Applicable Mortality Table and (iii) the amount computed using the applicable interest rate under Treasury Regulation section 1.417(e)-1(d)(3) and the Applicable Mortality Table, divided by 1.05. Effective for Plan Years beginning on or after January 1, 2006, for any form of benefit not subject to section 417(e)(3) of the Code, a Participant's annual benefit shall be determined in accordance with Treasury Regulation section 1.415(b)-1(c). An individual's "annual benefit" under any other defined benefit plan maintained by the Employer and Affiliate shall be as determined pursuant to the provisions of section 415 of the Code and the Regulations issued thereunder the terms of such plan.

Notwithstanding the foregoing provisions of this Section, the limitation provided by this Section shall not apply to a Participant who has not at any time participated in a defined contribution plan maintained by any Employer and whose annual benefit under the Plan does not exceed $10,000 multiplied by a fraction (not exceeding 1 and not less than 1/10th) the numerator of which is the Participant's years of service (within the meaning of Treasury Regulation section 1.415(b)-1(g)(2)(ii))) and the denominator of which is 10.

For purposes of this Section, the term "compensation" shall have the meaning set forth in section 415(c)(3) of the Code and the applicable Regulations, the term "defined contribution plan" shall have the meaning set forth in Treasury Regulation section 1.415(c)-1(a)(2), the term "defined benefit plan" shall have the meaning set forth in Treasury Regulation section 1.415(b)-1(a)(2) and the term "Employer" shall include the Employers and all corporations and entities required to be aggregated with any of the Employers pursuant to section 414(b) and (c) of the Code as modified by section 415(h) of the Code. Section 415 of the Code and the Regulations thereunder are hereby incorporated by reference.

Section 8.2 Restrictions on Benefits . (a) The annual Plan payments to a Participant in the Restricted Group (as defined below) for any Plan Year may not exceed an amount equal to the annual payments that would be made to or on behalf of the Participant under:

(i) a single life annuity that is equal to the Participant's Accrued Benefit and any other Benefits (as defined below) to which the Participant is entitled under the Plan (disregarding any Social Security supplement within the meaning of section 1.411(a)-7(c)(4)(ii) of the Treasury Regulations), plus

(ii) the amount of any payment to which the Participant is entitled as a Social Security supplement under the Plan.

(b) Application of Restriction . The restriction set forth in paragraph (a) of this Section (relating to restrictions on benefits) shall not apply to any payment if any of the following conditions is satisfied at the date as of which the payment is to be made:

(i) after reduction to reflect the present value of all Benefits payable to or on behalf of the Participant under the Plan, the value of the Plan's assets would equal or exceed 110% of the value of the Plan's current liabilities, as defined in section 412(l)(7) of the Code;

(ii) the present value of the Benefits payable to or on behalf of the Participant under the Plan is less than 1% of the value of the Plan's current liabilities, as defined in section 412(l)(7) of the Code; or

(iii) the present value of the Benefits payable to or on behalf of the Participant under the Plan does not exceed $5,000 (or such greater amount as may be set forth in section 411(a)(11)(A) of the Code).

(c) Plan Termination Rule . In the event of termination of the Plan, the benefit of any Participant in the Restricted Group shall be limited to a benefit that is nondiscriminatory under section 401(a)(4) of the Code.

(d) Definitions . For purposes of this Section:

(i) "Restricted Group" consists of the highly compensated employees and highly compensated former employees (within the meaning of section 414(q) of the Code) of the Employer and its Affiliates, but the total number in the Restricted Group for any calendar year shall be limited to 25 and shall consist of those highly compensated active and highly compensated former employees with the greatest compensation in the current or any prior year for which compensation information is available.

(ii) The term "Benefit" includes, without limitation, any periodic income from the Plan, any withdrawal values payable to a living employee under the Plan, any Plan loans in excess of the amounts set forth in section 72(p)(2)(A) of the Code and any Plan death benefits not provided for by insurance on the employee's or former employee's life.

(iii) The "current liability" of the Plan as of any date may be based on the current liability reported on Schedule B of the Plan's most recent, timely-filed Form 5500 or 5500 C/R. For purposes of this Section, the value of the Plan's assets shall be determined on the same date as of which the current liability is determined.

(e) Effective Date . The restrictions set forth in this Section shall cease to be in effect when (i) a condition set forth in subparagraph (b)(i), (b)(ii) or (b)(iii) above is satisfied, (ii) the Participant is not in the Restricted Group, (iii) the Plan is terminated and the benefit received by the Participant is nondiscriminatory or (iv) such restrictions are not required to be applied to such payment under the Code or Regulations.

Section 8.3 Benefit Restrictions as a Result of Funding . Effective January 1, 2010, notwithstanding any provision of the Plan to the contrary, the following benefit restrictions shall apply if the Plan's adjusted funding target attainment percentage is at or below the following levels.

(a) Limitations Applicable If the Plan's Adjusted Funding Target Attainment Percentage Is Less Than 80%, But Not Less Than 60% . If the Plan's adjusted funding target attainment percentage for a Plan Year is less than 80% (or would be less than 80% to the extent described in subparagraph (a)(2) below) but is not less than 60%, then the limitations set forth in this paragraph (a) apply.

(1) 50% Limitation on Single Sum Payments, Other Accelerated Forms of Distribution, and Other Prohibited Payments . A Participant or Beneficiary is not permitted to elect, and the Plan shall not pay, a lump sum distribution or other optional form of distribution that includes a prohibited payment with an annuity starting date on or after the applicable section 436 measurement date, and the Plan shall not make any

payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment, unless the present value of the portion of the benefit that is being paid in a prohibited payment does not exceed the lesser of:

(i) 50% of the present value of the benefit payable in the optional form of benefit that includes the prohibited payment; or

(ii) 100% of the PBGC maximum benefit guarantee amount (as defined in Treasury Regulation section 1.436-1(d)(3)(iii)(C)).

The limitation set forth in this subparagraph (a)(1) does not apply to any payment of a benefit which under section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant. If an optional form of benefit that is otherwise available under the terms of the Plan is not available to a Participant or Beneficiary as of the annuity starting date because of the application of the requirements of this subparagraph (a)(1), the Participant or Beneficiary is permitted to elect to bifurcate the benefit into unrestricted and restricted portions (as described in Treasury Regulation section 1.436-1(d)(3)(iii)(D)). The Participant or Beneficiary may also elect any other optional form of benefit otherwise available under the Plan at that annuity starting date that would satisfy the 50% limitation described in subparagraph (a)(1)(i) above or the PBGC maximum benefit guarantee amount described in subparagraph (a)(1)(ii) above, or may elect to defer the benefit in accordance with any general right to defer commencement of benefits under the Plan.

(2) Plan Amendments Increasing Liability for Benefits . No amendment to the Plan that has the effect of increasing liabilities of the Plan by reason of increases in benefits, establishment of new benefits, changing the rate of benefit accrual, or changing the rate at which benefits become nonforfeitable shall take effect in a Plan Year if the adjusted funding target attainment percentage for the Plan Year is:

(i) Less than 80%; or

(ii) 80% or more, but would be less than 80% if the benefits attributable to the amendment were taken into account in determining the adjusted funding target attainment percentage.

The limitation set forth in this subparagraph (a)(2) does not apply to any amendment to the Plan that provides a benefit increase under a Plan formula that is not based on compensation, provided that the rate of such increase does not exceed the contemporaneous rate of increase in the average wages of Participants covered by the amendment.

(b) Limitations Applicable If the Plan's Adjusted Funding Target Attainment Percentage Is Less Than 60% . If the Plan's adjusted funding target attainment percentage for a Plan Year is less than 60% (or would be less than 60% to the extent described in subparagraph (b)(2) below), then the limitations in this paragraph (b) apply.

(1) Single Sums, Other Accelerated Forms of Distribution, and Other Prohibited Payments Not Permitted . A Participant or Beneficiary is not permitted to elect, and the Plan shall not pay, a single sum payment or other optional form of benefit that includes a prohibited payment with an annuity starting date on or after the applicable section 436 measurement date, and the Plan shall not make any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment. The limitation set forth in this subparagraph (b)(1) does not apply to any payment of a benefit which under section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant.

(2) Shutdown Benefits and Other Unpredictable Contingent Event Benefits Not Permitted to Be Paid . An unpredictable contingent event benefit with respect to an unpredictable contingent event occurring during a Plan Year shall not be paid if the adjusted funding target attainment percentage for the Plan Year is:

(i) Less than 60%; or

(ii) 60% or more, but would be less than 60% if the adjusted funding target attainment percentage were redetermined applying an actuarial assumption that the likelihood of occurrence of the unpredictable contingent event during the Plan Year is 100%.

(3) Benefit Accruals Frozen . Benefit accruals under the Plan shall cease as of the applicable section 436 measurement date. In addition, if the Plan is required to cease benefit accruals under this subparagraph (b)(3), then the Plan is not permitted to be amended in a manner that would increase the liabilities of the Plan by reason of an increase in benefits or establishment of new benefits.

(c) Limitations Applicable If the Plan Sponsor Is In Bankruptcy . Notwithstanding any other provisions of the Plan, a Participant or Beneficiary is not permitted to elect, and the Plan shall not pay, a single sum payment or other optional form of benefit that includes a prohibited payment with an annuity starting date that occurs during any period in which the Plan sponsor is a debtor in a case under title 11, United States Code, or similar Federal or state law, except for payments made within a Plan Year with an annuity starting date that occurs on or after the date on which the Plan's enrolled actuary certifies that the Plan's adjusted funding target attainment

percentage for that Plan Year is not less than 100%. In addition, during such period in which the Plan sponsor is a debtor in a case under title 11, United States Code, or similar Federal or state law, the Plan shall not make any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment, except for payments that occur on a date within a Plan Year that is on or after the date on which the Plan's enrolled actuary certifies that the Plan's adjusted funding target attainment percentage for that Plan Year is not less than 100%. The limitation set forth in this paragraph (c) does not apply to any payment of a benefit which under section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant.

(d) Provisions Applicable After Limitations Cease to Apply .

(1) Resumption of Prohibited Payments . If a limitation on prohibited payments under subparagraph (a)(1), (b)(1), or (c) of this Section applied to the Plan as of a section 436 measurement date, but that limit no longer applies to the Plan as of a later section 436 measurement date, then that limitation does not apply to benefits with annuity starting dates that are on or after that later section 436 measurement date.

(2) Resumption of Benefit Accruals . If a limitation on benefit accruals under subparagraph (b)(3) of this Section applied to the Plan as of a section 436 measurement date, but that limitation no longer applies to the Plan as of a later section 436 measurement date, then benefit accruals shall resume prospectively and that limitation does not apply to benefit accruals that are based on service on or after that later section 436 measurement date, except as otherwise provided under the Plan. The Plan shall comply with the rules relating to partial years of participation and the prohibition on double proration under Department of Labor Regulation section 2530.204-2(c) and (d).

(3) Shutdown and Other Unpredictable Contingent Event Benefits . If an unpredictable contingent event benefit with respect to an unpredictable contingent event that occurs during the Plan Year is not permitted to be paid after the occurrence of the event because of the limitation of subparagraph (b)(2) of this Section, but is permitted to be paid later in the same Plan Year (as a result of additional contributions or pursuant to the enrolled actuary's certification of the adjusted funding target attainment percentage for the Plan Year that meets the requirements of Treasury Regulation section 1.436-1(g)(5)(ii)(B)), then that unpredictable contingent event benefit shall be paid, retroactive to the period that benefit would have been payable under the terms of the Plan (determined without regard to subparagraph (b)(2) of this Section). If the unpredictable contingent event benefit does not become payable during the Plan Year in accordance with the preceding sentence, then the Plan is treated as if it does not provide for that benefit.

(4) Treatment of Plan Amendments That Do Not Take Effect . If a Plan amendment does not take effect as of the effective date of the amendment because of the limitation of subparagraph (a)(2) or (b)(3) of this Section, but is permitted to take effect later in the same Plan Year (as a result of additional contributions or pursuant to the enrolled actuary's certification of the adjusted funding target attainment percentage for the Plan Year that meets the requirements of Treasury Regulation section 1.436-1(g)(5)(ii)(C)), then the Plan amendment must automatically take effect as of the first day of the Plan Year (or, if later, the original effective date of the amendment). If the Plan amendment cannot take effect during the same Plan Year, then it shall be treated as if it were never adopted, unless the Plan amendment provides otherwise.

(e) Notice Requirement . Written notice to Participants and Beneficiaries shall be provided within 30 days, in accordance with section 101(j) of ERISA, if the Plan becomes subject to a limitation described in subparagraph (a)(1), (b), or (c) of this Section.

(f) Methods to Avoid or Terminate Benefit Limitations . Application of one or more of the benefit limitations set forth in paragraphs (a), (b) and (c) of this Section for a Plan Year may be avoided or terminated through the use of employer contributions, by increasing the amount of Plan assets which are taken into account in determining the adjusted funding target attainment percentage and by other methods in accordance with sections 436(b)(2), (c)(2), (e)(2) and (f) of the Code and Treasury Regulation section 1.436-1(f).

(g) Plan Operations for Periods Prior to and After Certification of Plan's Adjusted Funding Target Attainment Percentage .

(1) In General . For any period during which a presumption under section 436(h) of the Code and Treasury Regulation section 1.436-1 (h) applies to the Plan, the limitations under paragraphs (a) through (c) of this Section are applied to the Plan as if the adjusted funding target attainment percentage for the Plan Year were the presumed adjusted funding target attainment percentage determined under the rules of section 436(h) of the Code and Treasury Regulation section 1.436-1(h)(1), (2), or (3). These presumptions are set forth in subparagraphs (g) (2) though (g)(4) below.

(2) Presumption of Continued Underfunding Beginning First Day of Plan Year . If a limitation under paragraph (a), (b) or (c) of this Section applied to the Plan on the last day of the preceding Plan Year, then, commencing on the first day of the current Plan Year and continuing until the Plan's enrolled actuary issues a certification of the adjusted funding target attainment percentage for the Plan for the current Plan Year, or, if earlier, the date subparagraph (g)(3) or (g)(4) below applies to the Plan:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be the adjusted funding target attainment percentage in effect on the last day of the preceding Plan Year; and

(ii) The first day of the current Plan Year is a section 436 measurement date.

(3) Presumption of Underfunding Beginning First Day of Fourth Month . If the Plan's enrolled actuary has not issued a certification of the adjusted funding target attainment percentage for the Plan Year before the first day of the fourth month of the Plan Year and the Plan's adjusted funding target attainment percentage for the preceding Plan Year was either at least 60% but less than 70% or at least 80% but less than 90%, or is described in Treasury Regulation section 1.436-1(h)(2)(ii), then, commencing on the first day of the fourth month of the current Plan Year and continuing until the Plan's enrolled actuary issues a certification of the adjusted funding target attainment percentage for the Plan for the current Plan Year, or, if earlier, the date subparagraph (g)(4) below applies to the Plan:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be the Plan's adjusted funding target attainment percentage for the preceding Plan Year reduced by 10 percentage points; and

(ii) The first day of the fourth month of the current Plan Year is a section 436 measurement date.

(4) Presumption of Underfunding On and After First Day of 10th Month . If the Plan's enrolled actuary has not issued a certification of the adjusted funding target attainment percentage for the Plan Year before the first day of the 10th month of the Plan Year (or if the Plan's enrolled actuary has issued a range certification for the Plan Year pursuant to Treasury Regulation section 1.436-1(h)(4)(ii) but has not issued a certification of the specific adjusted funding target attainment percentage for the Plan by the last day of the Plan Year), then, commencing on the first day of the 10th month of the current Plan Year and continuing through the end of the Plan Year:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be less than 60%; and

(ii) The first day of the 10th month of the current Plan Year is a section 436 measurement date.

(h) Plan Termination and Other Special Rules .

(1) Plan Termination . The limitations on prohibited payments in subparagraphs (a)(1), (b)(1), and (c) of this Section do not apply to prohibited payments that are made to carry out the termination of the Plan in accordance with applicable law. Any other limitations under this Section do not cease to apply as a result of termination of the Plan.

(2) Special Rules Relating to Unpredictable Contingent Event Benefits and Plan Amendments Increasing Benefit Liability . During any period in which none of the presumptions under paragraph (g) of this Section apply to the Plan and the Plan's enrolled actuary has not yet issued a certification of the Plan's adjusted funding target attainment percentage for the Plan Year, the limitations under subparagraphs (a)(2) and (b)(2) of this Section shall be based on the "inclusive presumed adjusted funding target attainment percentage" for the Plan, as such term is described in, and calculated in accordance with the rules of, Treasury Regulation section 1.436-1(g)(2)(iii).

(3) Payments Under Social Security Leveling Options . For purposes of determining whether the limitations under subparagraph (a)(1) or (b)(1) of this Section apply to payments under a social security leveling option, within the meaning of section 436(j)(4)(C)(i) of the Code, the adjusted funding target attainment percentage for a Plan Year shall be determined in accordance with the "Special Rule for Certain Years" under section 436(j)(3) of the Code and any Treasury Regulations or other published guidance thereunder issued by the Internal Revenue Service.

(4) Limitation on Benefit Accruals . For purposes of determining whether the accrual limitation under subparagraph (b)(3) of this Section applies to the Plan, the adjusted funding target attainment percentage for a Plan Year shall be determined in accordance with the "Special Rule for Certain Years" under section 436 of the Code (except as provided under section 203(b) of the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010, if applicable).

(5) Interpretation of Provisions . The limitations imposed by this Section shall be interpreted and administered in accordance with section 436 of the Code and Treasury Regulation section 1.436-1.

(i) Definitions . The definitions in the following Treasury Regulations apply for purposes of this Section: section 1.436-1(j)(1) defining adjusted funding target attainment percentage; section 1.436-1(j)(2) defining annuity starting date; section 1.436-1(j)(6) defining prohibited payment; section 1.436-1(j)(8) defining section 436 measurement date; and section 1.436-1(j)(9) defining an unpredictable contingent event and an unpredictable contingent event benefit.

(j) Effective Date . The rules in this Section are effective for Plan Years beginning after December 31, 2009.

ARTICLE 9
SPECIAL PARTICIPATION AND DISTRIBUTION RULES RELATING TO RECOMMENCEMENT OF EMPLOYMENT AND EMPLOYMENT BY RELATED ENTITIES

Section 9.1 Recommencement of Employment by a Terminated Employee . (a) Rehire Date Before Absence of 5 Years . If an Employee who has a Termination of Employment recommences employment with an Employer before having a Period of Severance of five years and, on the date of his or her rehire, the terms of such Employee's employment are not subject to a collective bargaining agreement that does not provide for participation in this Plan, then either: (1) if such Employee was a Participant on the date his or her employment terminated, such Employee shall be Participant in the Plan as of his or her rehire date if he or she is then an Eligible Employee or (2) if such Employee was not a Participant on the date his or her employment terminated, such Employee shall not be an Eligible Employee and shall not become a Participant. Notwithstanding clause (1) of the preceding sentence, if an Employee described in the preceding sentence who first became an employed by an Employer prior to January 1, 2001 was not at any time permitted to make the election described in Section 3.1(b) (relating to eligibility for participation for employees who are not new hires) or was permitted to make such election and elected to participate in the Plan but such election was not given effect as a result of such Employee's Termination of Employment, such Eligible Employee shall be permitted to elect, in the time and manner prescribed by the Administrator, to either (1) participate in the Plan

as of his or her rehire date or (2) participate in the ComEd Plan or the PECO Plan, as applicable, at the time prescribed therein and have his or her accrued benefit under the ComEd Plan or PECO Plan, as applicable, and related assets transferred to the Plan in the manner described in Section 3.1 (c) (relating to transfer of benefits and assets to Plan). If an Employee makes the election described in clause (1) of the preceding sentence, (a) the applicable Schedule shall apply with respect to the Participant's Accrued Frozen Benefit and (b) such Employee shall not be entitled to a Transition Credit.

(b) Rehire Date After Absence of at Least 5 Years . If a Participant who has a vested benefit under the Plan has a Termination of Employment and thereafter is rehired by an Employer, such Participant shall remain a Participant upon his or her rehire. If an Employee who has a Termination of Employment did not have a vested benefit under the Plan or under either the ComEd Plan or the PECO Plan recommences employment with an Employer after having a Period of Severance of at least five years, such Employee shall become a Participant as of the date of his or her rehire if he or she is then an Eligible Employee. If an Employee who has a Termination of Employment had a vested benefit under either the ComEd Plan or the PECO Plan recommences employment with an Employer after having a Period of Severance of at least five years, such Employee shall not be an Eligible Employee and shall not become a Participant upon such recommencement of employment. Notwithstanding the preceding sentence, if an Employee described in the preceding sentence who first became employed by an Employer prior to January 1, 2001 was not at any time permitted to make the election described in Section 3.1(b) (relating to eligibility for participation for employees who are not new hires) or was permitted to make such election and elected to participate in the Plan but such election was not given effect as a result of such Employee's Termination of Employment, such Eligible Employee shall be

permitted to elect, in the time and manner prescribed by the Administrator, to either (1) participate in the Plan as of his or her rehire date or (2) participate in the ComEd Plan or the PECO Plan, as applicable, at the time prescribed therein and have his or her accrued benefit under the ComEd Plan or PECO Plan, as applicable, transferred to the Plan in the manner described in Section 3.1(c) (relating to transfer of benefits and assets to Plan). The accrued benefit under the ComEd Plan or the PECO Plan, as applicable, of an Employee who elects to participate in the Plan shall be transferred to the Plan, along with an appropriate amount of assets, and (a) the applicable Schedule shall apply with respect to the Participant's Accrued Frozen Benefit and (b) such Employee shall not be entitled to a Transition Credit.

(c) Reestablishment of Cash Balance Account for Rehired Participant . If a Participant whose Termination of Employment occurs before his or her satisfaction of the Vesting Requirement recommences employment with an Employer and becomes a Participant pursuant to paragraph (a) above, such Participant's Cash Balance Account shall be reinstated and credited with Investment Credits for the Participant's Period of Severance. If a Participant whose Termination of Employment occurs after his or her satisfaction of the Vesting Requirement receives a complete distribution of his or her benefit under the Plan and subsequently recommences employment with an Employer as an Employee and becomes a Participant pursuant to paragraph (b) above, a new Cash Balance Account shall be established for such Participant as of such recommencement of employment. Such new Cash Balance Account shall have an initial balance of zero and shall be credited with Service Credits and Investment Credits solely for the Participant's period of employment thereafter.

Section 9.2 Suspension of Benefits . (a) Generally . If a Participant continues employment by an Employer beyond the Participant's Normal Retirement Age or, except as provided in paragraph (b) below, if a former Employee again becomes an Employee after his or her Normal Retirement Age, such Participant shall not be entitled to receive any Pension during such employment. If such a Participant was receiving a Pension, the Participant's Cash Balance Account as of his or her Pension Starting Date shall be restored and thereafter credited with Service Credits and Investment Credits with respect to such period of employment and Investment Credits from the Participant's prior Pension Starting Date to the date the Participant's Cash Balance Account is so restored. Upon the Participant's Termination of Employment or subsequent Termination of Employment, as the case may be, the Participant's Accrued Benefit shall be the larger of (i) the Participant's Accrued Benefit as of the first day of the month coinciding with or next following the Participant's date of rehire, or Normal Retirement Age, as the case may be, actuarially increased to reflect the later termination date (for purposes of this clause (i), the Investment Credits described in Section 6.1(d) with respect to such period of employment shall be the actuarial increase to the Participant's Accrued Benefit), and (ii) the Actuarial Equivalent of the Participant's Cash Balance Account, and the Accrued Frozen Benefit, as of the Participant's Termination of Employment, or subsequent Termination of Employment, as the case may be, reduced in either case by the sum of any Pension previously paid to the Participant plus interest thereon at the rate described in subdivision (3) of Article 2 (relating to definition of Actuarial Equivalent).

(b) Circumstances under which a Rehired Employee's Pension Payments may Continue . Notwithstanding paragraph (a) above, a reemployed Participant who is employed under circumstances that satisfy the applicable conditions for continuation of payment of retirement benefits set forth in the Company's policy regarding the rehiring of retirees shall not have his or her Pension suspended under this Section nor shall such reemployed Participant be prohibited from commencing his or her Pension if he or she is otherwise eligible to commence such Pension.

Section 9.3 Employment by Related Entities . If an individual is employed by an entity that is an Affiliate, then any period of employment by such entity (but only after such entity became an Affiliate) shall be taken into account solely for the purpose of determining when or whether and when such individual is eligible to participate in the Plan under Article 3 (relating to eligibility), measuring such individual's years of Vesting Service for purposes of the Vesting Requirement and determining when such individual's Termination of Employment occurs for purposes of Article 7 (relating to distributions) to the same extent such period would have been taken into account had such employment been with an Employer.

Section 9.4 Leased Employees . If an individual who performed services as a leased employee (within the meaning of section 414(n)(2) of the Code) of an Affiliate becomes an Employee, or if an Employee becomes such a leased employee, then any period as a leased employee shall be taken into account solely for the purposes of determining whether and when such individual is eligible to participate in the Plan under Article 3 (relating to eligibility), measuring such individual's years of Vesting Service for purposes of the Vesting Requirement and determining when such individual's Termination of Employment occurs for purposes of Article 7 (relating to distributions) to the same extent such period would have been taken into account had such service or employment been with an Employer. In addition, any contributions or benefits provided under another plan to such leased employee by his or her leasing organization shall be treated as provided under this Plan and shall be taken into account under Section 8.1 (relating to statutory limits) to the extent required under Treasury Regulation section 1.415(a)-1(f)(3). This Section shall not apply to any period during which such a leased

employee was covered by a plan described in section 414(n)(5) of the Code and leased employees do not constitute more than 20% of the Employer's nonhighly compensated work force. Notwithstanding the preceding sentences, an individual who performed services only as a leased employee prior to January 1, 2001 shall be treated as not performing an Hour of Service prior to January 1, 2001 solely for the purposes of determining whether such individual qualifies as an Eligible Employee under subdivision (16) of Article 2.

Section 9.5 Employees who Become Eligible Employees as a Result of Ceasing to be Represented by IBEW Local Union 15 . If an Employee who, on the day he or she first performed an Hour of Service with an Employer, was a member of a collective bargaining unit represented by IBEW Local Union 15 and who first became employed by an Employer prior January 1, 2001 later ceases to be a member of a collective bargaining unit represented by IBEW Local Union 15, such Employee shall be permitted to elect, in the time and manner prescribed by the Administrator, to either (a) continue to participate in the ComEd Plan or (b) participate in this Plan as of the date he or she ceases to be a member of a collective bargaining unit represented by IBEW Local Union 15 and have his or her accrued benefit under the ComEd Plan and related assets transferred to the Plan in the manner described in Section 3.1(c) (relating to transfer of benefits and assets to Plan). If an Employee who, on the day he or she first performed an Hour of Service with an Employer, was a member of a collective bargaining unit represented by IBEW Local Union 15 and who first became employed by an Employer on or after January 1, 2001 and participated in the Exelon Corporation Pension Plan for Bargaining Unit Employees later becomes an Eligible Employee as a result of ceasing to be a member of a collective bargaining unit represented by IBEW Local Union 15, such Employee shall become a Participant as of the date he or she ceases to be a member of a collective bargaining unit represented by IBEW Local

Union 15 and shall have his or her accrued benefit under the Exelon Corporation Pension Plan for Bargaining Unit Employees and related assets transferred to the Plan. If an Employee who, on the day he or she first performed an Hour of Service with an Employer, was a member of a collective bargaining unit represented by IBEW Local Union 15 and who first became employed by an Employer on or after January 1, 2001 and who was a participant in the Commonwealth Edison Company Service Annuity System later becomes a member of a collective bargaining unit represented by IBEW Local Union 15, such Employee shall not become a Participant in this Plan.

Section 9.6 Employees who Cease to be Eligible Employees as a Result of Becoming Represented by IBEW Local Union 15 . If an Employee ceases to be an Eligible Employee as a result of becoming a member of a collective bargaining unit represented by IBEW Local Union 15 and becomes a participant in the Exelon Corporation Pension Plan for Bargaining Unit Employees or the Commonwealth Edison Company Service Annuity System, such Employee shall have his or her accrued benefit under this Plan and related assets transferred to the applicable plan.

Section 9.7 Change in Employment Status or Transfer to Affiliate . Except as otherwise provided in Section 9.8 and elsewhere in the Plan, if an Employee who was a Participant transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead either eligible to participate in another plan maintained by such Employer or Affiliate or are not eligible to participate in any plan, then such individual shall upon such transfer or reemployment participate in the plan, if any, determined pursuant to rules established by the Company, which rules may be set forth in a Supplement hereto.

Section 9.8 Transfer of Employment to or from Facilities formerly Owned by CEG . Effective as of the Effective Time (as such term is defined in the Merger Agreement), if a Participant who was a Participant on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in the Plan but are instead eligible to participate in a Company Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be a defined benefit pension plan qualified under Section 401(a) of the Code (each such plan, a "CEG Pension Plan") , then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the CEG Pension Plan. If a participant in the CEG Pension Plan who was a participant in such plan on or prior to the Effective Time transfers employment to or is reemployed by an Employer or an Affiliate in a job classification with respect to which similarly situated employees of such Employer or Affiliate are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the CEG Pension Plan and shall not participate in the Plan.

ARTICLE 10
ADMINISTRATION

Section 10.1 The Administrator, the Investment Office and the Corporate Investment Committee .

(a) The Administrator . The Company's Vice President, Health & Benefits, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such vice president or other person or committee, the "Administrator"), shall be the "administrator" of the Plan, within the meaning of such term as used in ERISA. In addition, the

Administrator shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan's assets. The Administrator shall have the following duties, responsibilities and rights:

(i) The Administrator shall have the duty and discretionary authority to interpret and construe this Plan in regard to all questions of eligibility, the status and rights of Participants, Beneficiaries and other persons under this Plan, and the manner, time, and amount of payment of any distributions under this Plan. The determination of the Administrator with respect to an Employee's years of Vesting Service, the amount of the Employee's Compensation, and any other matter affecting payments under the Plan shall be final and binding. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Administrator, in his or her discretion, determines that such person is entitled to benefits.

(ii) Each Employer shall, from time to time, upon request of the Administrator, furnish to the Administrator such data and information as the Administrator shall require in the performance of his or her duties.

(iii) The Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust Fund under Article 7 (relating to distributions). In addition, it shall be the duty of the Administrator to certify to the Trustee the names and addresses of all Participants, the amounts of all Pensions, the dates of death of Participants and all proceedings and acts of the Administrator necessary or desirable for the Trustee to be fully informed as to the Pension to be paid out of the Trust Fund.

(iv) The Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Office, the Corporate Investment Committee or the Trustee.

(v) The Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Administrator and to furnish such information requested by the Administrator. The Administrator and the Plan may rely upon all such information so furnished to the Administrator.

(vi) The Administrator shall be the Plan's agent for service of legal process and forward all necessary communications to the Trustee.

(b) Removal of Administrator . The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Administrator (including any member of a committee that constitutes the Administrator). The Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer or upon the Administrator's termination of employment with the Employers. Upon the resignation, removal or failure or inability for any reason of the Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any officer, employee or member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Administrator.

(c) The Investment Office . The Investment Office, shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in section 404(a)(2) of ERISA and all other applicable limitations. The Investment Office shall have the following duties, responsibilities and rights:

(i) The Investment Office shall be the "named fiduciary" for purposes of directing the Trustee as to the investment of amounts held in the Trust Fund and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Office shall submit to the Corporate Investment Committee annual manager review results and such other reports and documents as may be necessary for the Corporate Investment Committee to monitor the activities and performance of the Investment Office.

(iii) Each Employer shall, from time to time, upon request of the Investment Office, furnish to the Investment Office such data and information as the Investment Office shall require in the performance of its duties.

(d) The Corporate Investment Committee . The Company acting through the Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Office. The Corporate Investment Committee shall have the following duties, responsibilities and rights:

(i) The Corporate Investment Committee shall monitor the activities and performance of the Investment Office and shall review annual manager review results and any other reports and documents submitted by the Investment Office.

(ii) The Corporate Investment Committee shall have authority to approve asset allocation recommendations of the Investment Office, and approve the retention or firing of any investment consultant (but not any investment manager), custodian or trustee, as recommended by the Investment Office.

(iii) The Corporate Investment Committee and the Company's Chief Investment Officer shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Office. Any successor Investment Office employee shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor.

The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the Investment Office and approval of the recommendations specified in clause (ii) above. The Corporate Investment Committee shall have no responsibility for making investment decisions, appointing or firing investment managers or for any other duties or responsibilities with respect to the Plan, other than those specifically listed herein.

(e) Status of Administrator, the Investment Office and the Corporate Investment Committee . The Administrator, any person acting as, or on behalf of, the Investment Office, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee

or officer of an Employer and such status shall not disqualify such person from taking any action hereunder or render such person accountable for any distribution or other material advantage received by him or her under this Plan, provided that no Administrator, person acting as, or on behalf of, the Investment Office, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Administrator or the Investment Office on any matter involving solely his or her rights under this Plan.

(f) Notice to Trustee of Members . The Trustee shall be notified as to the names of the Administrator and the person or persons authorized to act on behalf of the Investment Office.

(g) Allocation of Responsibilities . Each of the Administrator, the Investment Office and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

(h) General Governance . The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Administrator, the Investment Office and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

(i) Indemnification . The Employers hereby jointly and severally indemnify the Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

(j) No Compensation . None of the Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Administrator, Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Affiliate for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

(k) Employ of Counsel and Agents . The Administrator, the Investment Office and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

Section 10.2 Claims Procedure . Any Participant or distributee who believes he or she is entitled to benefits in an amount greater than those which he or she is receiving or has received may file a claim with the Administrator. Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Administrator shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the Administrator's decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable Regulations. If the Administrator determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Administrator expects to render the benefit determination. The notice of the decision of the Administrator with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, the Administrator shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right (subject to the limitations described in Section 13.11 (relating to statute of limitations for actions under the Plan) and 13.12 (relating to forum for legal actions under the Plan)) to bring a civil action

under section 502 of ERISA following an adverse benefit determination on review. The Administrator shall also advise the claimant that the claimant or the claimant's duly authorized representative may request a review by the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) of the adverse benefit determination by filing with such officer, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he or she (a) may be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit to the officer written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by the officer within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the officer's final decision. If the officer determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the officer expects to render the determination on review. The review of the officer shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

Section 10.3 Notices to Participants, Etc . All written notices, reports and statements given, made, delivered or transmitted to a Participant or Beneficiary or any other person entitled to or claiming benefits under the Plan shall be deemed to have been duly given, made or transmitted when mailed by first class mail with postage prepaid and addressed to the Participant or Beneficiary or such other person at the address last appearing on the records of the Administrator. A Participant or Beneficiary or other person may record any change of his or her address from time to time by written notice filed with the Administrator.

Section 10.4 Responsibility to Advise Administrator of Current Address . Each person entitled to receive a payment under the Plan shall file with the Administrator in writing his or her complete mailing address and each change therein. A check or communication mailed to any person at his or her address on file with the Administrator shall be deemed to have been received by such person for all purposes of the Plan, and neither the Administrator, the Employers nor the Trustee shall be obliged to search for or ascertain the location of any person. If the Administrator shall be in doubt as to whether payments are being received by the person entitled thereto, it shall, by registered mail addressed to the person concerned at his or her last address known to the Administrator, notify such person that all future Pension payments will be withheld until such person submits to the Administrator evidence of his or her continued life and his or her proper mailing address.

Section 10.5 Notices to Employers or Administrator . Written directions, notices and other communications from Participants or Beneficiaries or any other persons entitled to or claiming benefits under the Plan to the Employers or the Administrator shall be deemed to have been duly given, made or transmitted either when delivered to such location as shall be specified upon the form prescribed by the Administrator for the giving of such directions, notices and other communications or when mailed by first class mail with postage prepaid and addressed to the addressee at the address specified upon such forms.

Section 10.6 Responsibility to Furnish Information and Sign Documents . Each person entitled to a payment under the Plan shall furnish such information and data, including birth certificates or other evidence of age satisfactory to the Administrator, and sign such documents as may reasonably be requested by the Administrator or the Trustee in connection with the administration of the Plan.

Section 10.7 Records . Each of the Administrator, the Investment Office and the Corporate Investment Committee shall keep a record of all of their respective proceedings, if any, and shall keep or cause to be kept all books of account, records and other data as may be necessary or advisable in their respective judgment for the administration of the Plan, the administration of the investments of the Plan or the monitoring of the investment activities of the Plan, as applicable.

Section 10.8 Actuary to be Employed . The Company or the Investment Office shall engage an actuary to do such technical and advisory work as the Company or the Investment Office may request, including analyses of the experience of the Plan from time to time, the preparation of actuarial tables for the making of computations thereunder, and the submission to the Company or the Investment Office of an annual actuarial report, which report shall contain information showing the financial condition of the Plan, a statement of the contributions to be made by the Employers for the ensuing year, and such other information as may be requested by the Company or the Investment Office.

Section 10.9 Funding Policy . The Company shall establish a funding policy and method consistent with the objectives of the Plan and the requirements of Title I of ERISA and shall communicate such policy and method, and any changes in such policy and method, to the Investment Office.

Section 10.10 Electronic Media . Notwithstanding any provision of the Plan to the contrary and for all purposes of the Plan, to the extent permitted by the Administrator and any applicable law or Regulation, the use of electronic technologies shall be deemed to satisfy any written notice, consent, delivery, signature, disclosure or recordkeeping requirement under the Plan, the Code or ERISA to the extent permitted by or consistent with applicable law and Regulations. Any transmittal by electronic technology shall be deemed delivered when successfully sent to the recipient, or such other time specified by the Administrator.

Section 10.11 Correction of Error . If it comes to the attention of the Administrator that an error has been made in the amount of benefits payable, or paid, to any Participant or Beneficiary under the Plan, the Administrator shall be permitted to correct such error by whatever means that the Administrator, in its sole discretion determines, including by offsetting future benefits payable to the Participant or Beneficiary or requiring repayment of benefits to the Plan, except that no adjustment need be made with respect to any Participant or Beneficiary whose benefit has been distributed in full prior to the discovery of such error.

ARTICLE 11
PARTICIPATION BY OTHER EMPLOYERS

Section 11.1 Adoption of Plan . With the consent of the Company, any entity may become a participating Employer under the Plan with respect to all or a designated group of its employees by taking such action as shall be necessary or desirable to adopt the Plan and executing and delivering such instruments as may be necessary or desirable to put the Plan into effect with respect to such entity.

Section 11.2 Withdrawal from Participation . Any Employer shall terminate its participation in the Plan at any time, under such circumstances as the Company may provide, by delivering to the Company a duly certified copy of a resolution of its board of directors (or other governing body) to that effect, or by ceasing to be a member of the same controlled group as the Company (within the meaning of section 1563(a) of the Code).

Section 11.3 Company and Administrator as Agent for Employers . Each entity which shall become a participating Employer pursuant to Section 11.1 (relating to adoption of the Plan) or Article 12 (relating to continuance by a successor) by so doing shall be deemed to have appointed the Company and the Administrator its agent to exercise on its behalf all of the powers and authorities hereby conferred upon the Company and the Administrator by the terms of the Plan, including, but not by way of limitation, the power to amend and terminate the Plan. The authority of the Company and the Administrator to act as such agent shall continue unless and until the portion of the Trust held for the benefit of Employees of the particular Employer and their Beneficiaries is set aside in a separate trust as provided in Section 15.2 (relating to establishment of separate plan).

ARTICLE 12
CONTINUANCE BY A SUCCESSOR

In the event that an Employer is reorganized by way of merger, consolidation, transfer of assets or otherwise, so that another entity succeeds to all or substantially all of the Employer's business, such successor entity may be substituted for the Employer under the Plan by adopting the Plan and becoming a party to the Trust agreement. If, within 90 days following the effective

date of any such reorganization, such successor entity shall not have elected to become a party to the Plan, or if the Employer adopts a plan of complete liquidation other than in connection with a reorganization, the Plan shall be automatically terminated with respect to Employees of such Employer as of the close of business on the 90th day following the effective date of such reorganization or as of the close of business on the date of adoption of such plan of complete liquidation, as the case may be. If such successor entity is substituted for the Employer by electing to become a party to the Plan as described above, then, for all purposes of the Plan, employment with such successor entity and compensation paid by such successor entity shall be considered to be employment with, and Compensation paid by, an Employer.

ARTICLE 13
MISCELLANEOUS

Section 13.1 Expenses . The expenses of the Trustee in the administration of the Trust Fund, including compensation, if any, to the Trustee for its services, shall be paid by the Company or the Employers. All costs and expenses incurred in the operation of the Trust Fund, to the extent not described in the preceding sentence, and all costs and expenses incurred in the operation of the Plan or the Trust Fund, as applicable, including, but not limited to, “direct expenses” incurred in administering the Plan and the Trust Fund (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan or the Trust Fund), the expenses of the Administrator, the Investment Office and the Corporate Investment Committee, the fees of counsel and any agents for the Trustee, the Administrator, the Investment Office or the Corporate Investment Committee, and the fees of investment managers that manage assets of the Trust Fund, as applicable, shall be paid by the Trustee from the Trust Fund in such proportion as the Investment Office, in its sole discretion, shall determine, to the extent such expenses are not paid by the Employers and to the extent permitted under ERISA,

Regulations and other applicable laws. Notwithstanding the foregoing, the Administrator or the Investment Office may authorize an Employer to act as an agent of the Plan to pay any expenses, and the Employer shall be reimbursed from the Trust Fund for such payments.

Section 13.2 Non-Assignability . (a) In General . It is a condition of the Plan, and all rights of each Participant and Beneficiary shall be subject thereto, that no right or interest of any Participant or Beneficiary in the Plan shall be assignable or transferable in whole or in part, either directly or by operation of law or otherwise, including, but not limited to, by way of limitation, execution, levy, garnishment, attachment, pledge or bankruptcy, but excluding devolution by death or mental incompetency, and no right or interest of any Participant or Beneficiary in the Plan shall be liable for, or subject to, any obligation or liability of such Participant or Beneficiary, including claims for alimony or the support of any Spouse.

(b) Exception for Qualified Domestic Relations Orders . Notwithstanding any provision of the Plan to the contrary, if a Participant's Accrued Benefit under the Plan, or any portion thereof, shall be the subject of one or more Qualified Domestic Relations Orders, such Accrued Benefit or portion thereof shall be paid to the person and at the time and in the manner specified in any such order. The Administrator or its agent, in its sole discretion, shall determine whether any order constitutes a Qualified Domestic Relations Order under this paragraph (b). A domestic relations order shall not fail to constitute a Qualified Domestic Relations Order under this paragraph (b) solely because such order provides for immediate payment to an alternate payee of the portion of the Participant's Accrued Benefit assigned to the alternate payee under the terms of such order.

Section 13.3 Employment Non-Contractual . Neither this Plan nor any action taken by the Administrator or the Investment Office confers any right upon an Employee to continue in employment with any Employer.

Section 13.4 Limitation of Rights . A Participant or distributee shall have no right, title or claim in or to any specific asset of the Trust Fund, but shall have the right only to distributions from the Trust Fund on the terms and conditions he or she herein provided. Neither this Plan nor any action taken by the Administrator or the Investment Office shall obligate any Employer to make contributions to the Trust in excess of the contributions authorized by the board of directors of the Company or create any liability on an Employer for the payment of Pensions under this Plan.

Section 13.5 Merger or Consolidation with Another Plan . A merger or consolidation with, or transfer of assets or liabilities to, any other plan shall not be effected unless the terms of such merger, consolidation or transfer are such that each Participant, distributee, Beneficiary or other person entitled to receive benefits from the Plan would, if the Plan were to terminate immediately after the merger, consolidation or transfer, receive a benefit equal to or greater than the benefit such person would be entitled to receive if the Plan were to terminate immediately before the merger, consolidation, or transfer.

Section 13.6 Construction . (a) General . Wherever used in the Plan, words in the masculine gender shall include masculine or feminine gender, and, unless the context otherwise requires, words in the singular shall include the plural, and words in the plural shall include the singular. All references to employment or the rehire or termination thereof shall refer to employment by any and all Employers, and to the extent provided herein, and, to the extent required by Section 3.2 (relating to transfers to affiliates) and Section 9.3 (relating to employment by related entities), any and all Affiliates, unless the context requires otherwise.

(b) Definition of "Highly Compensated Employee" . Wherever applicable for purposes of satisfying legal requirements applicable to the Plan, the term "highly compensated employee" shall mean any Employee who performs service in the determination year and who (a) is a 5%-owner (as determined under section 416(i)(1)(A)(iii) of the Code) at any time during the Plan Year or the preceding Plan Year or (b) both (1) is paid compensation in excess of $80,000 (as adjusted for increases in the cost of living in accordance with section 414(q)(1)(B)(ii) of the Code) from an Employer for the preceding Plan Year, and (2) is in the group of employees consisting of the top 20% of the employees of the Employer and its Affiliates when ranked on the basis of compensation paid during such preceding Plan Year.

Section 13.7 Applicable Law . Except to the extent preempted by applicable federal law or otherwise provided under the terms of the Plan, the Plan and all rights hereunder shall be governed by and construed in accordance with the laws of the State of Illinois.

Section 13.8 Severability . If a provision of the Plan shall be held illegal or invalid, the illegality or invalidity shall not affect the remaining parts of the Plan and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included in the Plan.

Section 13.9 No Guarantee . None of the Administrator, the Investment Office, the Corporate Investment Committee, the Employers, nor the Trustee in any way guarantees the Trust from loss or depreciation nor the payment of any money that may be or become due to any person from the Trust Fund or pursuant to the Plan. Nothing herein contained shall be deemed to give any Participant, distributee, or Beneficiary an interest in any specific part of the Trust Fund or any other interest, right or claim except the right to receive benefits out of the Trust Fund in accordance with the provisions of the Plan and the Trust Fund.

Section 13.10 Military Service . Notwithstanding any provision of the Plan to the contrary, contributions, benefits and Service with respect to Military Service shall be provided in accordance with section 414(u) of the Code.

Section 13.11 Statute of Limitations for Actions under the Plan . Except for actions to which the statute of limitations prescribed by section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under section 502 of ERISA may be commenced later than one year after the claimant receives a final decision from the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

Section 13.12 Forum for Legal Actions under the Plan . Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in the Northern District of Illinois or the Eastern District of Pennsylvania, whichever is most convenient, and no other federal or state court.

Section 13.13 Legal Fees . Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, any member of the Exelon Investment Office, any member of the Corporate Investment Committee, the Chief Human Resources Officer, any Plan fiduciary, the Company, its affiliates or their respective officers, directors, employees, or agents (the "Plan Parties"), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

ARTICLE 14
TOP-HEAVY PLAN REQUIREMENTS

Section 14.1 Top-Heavy Plan Determination . If as of the determination date (as hereinafter defined) for any Plan Year the aggregate present value of (i) the accrued benefits under the Plan and under all other defined benefit plans in the aggregate group (as hereinafter defined) and (ii) the aggregate account balances under all defined contribution plans in such aggregation group, in each case with respect to all participants in such plans who are key employees (as defined in section 416(i) of the Code) for such Plan Year, exceeds 60% of the aggregate present value of accrued benefits and the account balances of all participants in all such plans as of the determination date, then the Plan shall be a top-heavy plan for such Plan

Year and the requirements of Sections 14.3 (relating to minimum benefits for top-heavy years) and 14.4 (relating to top-heavy vesting requirements) shall be applicable for such Plan Year as of the first day thereof. If the Plan shall be a top-heavy plan for any Plan Year, such requirements shall not be applicable for such subsequent Plan Year except to the extent provided in Section 14.3 (relating to minimum benefits for top-heavy years).

Section 14.2 Definitions and Special Rules . (a) Definitions . For purposes of this Article, the following definitions shall apply:

(i) Determination Date . The determination date for all plans in the aggregation group shall be the last day of the preceding plan year, and the valuation date applicable to a determination date shall be (a) in the case of a defined contribution plan, the date as of which account balances are determined that is coinciding with or immediately precedes the determination date, and (b) in the case of a defined benefit plan, the date as of which the most recent actuarial valuation for the plan year that includes the determination date is prepared, except that if any such plan specifies a different determination or valuation date, such different date shall be used with respect to such plan.

(ii) Aggregation Group . The aggregation group shall consist of (a) each plan of an Employer in which a key employee is a participant, (b) each other plan that enables such a plan to be qualified under section 401(a) of the Code, and (c) any other plans of an Employer that the Company designates as part of the aggregation group.

(iii) Key Employee . Key employee shall have the meaning set forth in section 416(i) of the Code.

(iv) Top-Heavy Compensation . Top-heavy compensation shall have the meaning set forth in section 1.415(c)-2 of the Treasury Regulations.

(b) Special Rules . For the purpose of determining the accrued benefit or account balance of a participant, the accrued benefit or account balance of any person who has not been actively at work with an Employer at any time during the one-year period ending on the determination date shall not be taken into account pursuant to this Section, and any person who received a distribution from a plan (including a plan that has terminated) in the aggregation

group during the one-year period ending on the determination date shall be treated as a participant in such plan, and any such distribution shall be included in such participant's account balance or accrued benefit, as the case may be; provided , however , that in the case of a distribution made for a reason other than a Participant's severance from employment, death or disability, this sentence shall be applied by substituting "five-year period" for "one-year period".

Section 14.3 Minimum Benefit for Top-Heavy Years . (a) The Pension to which a Participant is entitled at Normal Retirement Age under Section 7.2 (relating to form of distribution) shall in no event be less than two percent of the Participant's highest average compensation (as hereinafter defined) multiplied by the number of the Participant's years of Vesting Service, determined as provided below, not in excess of ten. For purposes of this Section, (i) a Participant's years of Vesting Service shall mean his or her years of Vesting Service but excluding any year of Vesting Service completed in a Plan Year for which the Plan was not a top-heavy plan, and (ii) a Participant's highest average compensation shall be the annual average of his or her top heavy compensation for the period of consecutive calendar years not exceeding 5 during which the Participant's top heavy compensation was the greatest, except that calendar years after the last Plan Year for which the Plan was top-heavy shall be disregarded.

(b) The provisions of paragraph (a) of this Section shall not apply with respect to a Participant if, for each year in which the Plan is a top-heavy plan, (i) the eligible employee's Employer also maintains a defined contribution plan which is included in the aggregation group for such year and (ii) under such plan, contributions made and forfeitures allocated to each eligible employee (other than key employees) equal 5% of such Participant's top heavy compensation for each Plan Year the Plan is top-heavy.

Section 14.4 Top-Heavy Vesting Requirements . If a Participant's Termination of Employment shall occur during a Plan Year for which a Plan is a top-heavy plan as defined in section 416(i) of the Code and after the Participant shall have completed at least three years of Vesting Service, the Participant shall be deemed to have satisfied the Vesting Requirement and shall be entitled to the Pension described in Section 7.2 (relating to form of distribution).

ARTICLE 15
AMENDMENT, ESTABLISHMENT OF SEPARATE PLAN AND TERMINATION

Section 15.1 Amendment . The board of directors of the Company (or a committee thereof) may at any time and from time to time amend or modify this Plan in any manner deemed by the board of directors of the Company to be necessary or desirable, provided, however, that in the case of any amendment or modification that would not result in an aggregate annual cost to the Company of more than $50,000,000, the Plan may be amended or modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability account balance exceeding $250,000) or another executive officer holding title of equivalent or greater. Any such amendment or modification shall become effective on such date as the board (or committee thereof) or executive shall determine and may apply to Participants in this Plan at the time thereof as well as to future Participants, provided, however, that, unless permitted by applicable law, no such amendment or modification which reduces the basis for the computation of Pensions shall be retroactive as to service prior to the date of such amendment or modification.

Section 15.2 Establishment of Separate Plan . If an Employer shall withdraw from this Plan under Section 11.2 (relating to withdrawal from participation), the Investment Office shall determine the portion of the Trust Fund held by the Trustee which is applicable to the Participants of such Employer and direct the Trustee to segregate such portion in a separate trust. Such separate trust shall thereafter be held and administered as a part of the separate plan of such Employer.

Section 15.3 Termination of the Plan by an Employer . The Company may at any time, by resolution adopted by its board of directors, terminate this Plan in its entirety. In addition, any Employer may at any time terminate its participation in this Plan by resolution adopted by its board of directors to that effect. Contributions of an Employer to the Plan are conditioned on the receipt from the Internal Revenue Service of an initial favorable determination letter that this Plan and the Trust Fund as adopted by the Company meets the requirements of section 401(a) of the Code and that the Trust Fund is exempt from tax under section 501(a) of the Code, and if the Internal Revenue Service shall refuse to issue such letter, any Employer may terminate its participation in this Plan and direct the Trustee to pay and deliver to that Employer the portion of the Trust Fund applicable to its contributions.

Section 15.4 Vesting and Distribution Upon Termination or Partial Termination . Upon termination or partial termination of the Plan, the benefit as of the date of termination or partial termination, as the case may be, of all affected Participants shall be fully vested; provided, however, that full vesting shall be required with respect to a termination or partial termination only to the extent the Plan is then funded.

Allocation and distribution of the terminated portion of the Trust Fund shall thereafter be made in accordance with the applicable requirements of ERISA and the Code and with any applicable approval of the Pension Benefit Guaranty Corporation (the “PBGC”). If the

Administrator is notified by PBGC that PBGC is unable to determine that the Trust Fund is sufficient to discharge when due all obligations of the Plan with respect to benefits guaranteed by PBGC pursuant to section 4022 of ERISA, then the allocation and distribution of such portion of the Trust Fund shall be made only under the direction of PBGC or a United States district court pursuant to section 4044 of ERISA.

In the event that, after the termination of the Plan, any assets remain after such allocation, such assets shall be paid to the Company. The portion of the assets allocated to provide benefits to any person or group of persons may be applied for the benefit of such person or persons by the distribution of cash, continuance of the Trust Fund, establishment of a new Trust Fund, purchase of annuities from an insurance company, or otherwise, as determined by the Investment Office in its sole discretion; provided, however, that the benefit of any Participant or former Participant who is married and has satisfied the Vesting Requirement shall, unless such person shall elect otherwise, be paid in the form set forth in Section 7.2 (b) (relating to manner of distribution with respect to married Participants) and, if the surviving Spouse of a deceased Participant or deceased former Participant is entitled to receive a benefit pursuant to Section 7.2(b) (relating to manner of distribution with respect to married Participants) or Section 7.3 (relating to pre-retirement death benefits), as the case may be, such benefit shall, unless such person shall elect otherwise, be paid in the form set forth therein.

Contributions of an Employer to the Plan are conditioned on the receipt from the Internal Revenue Service of an initial favorable determination letter that the Plan and Trust Fund as adopted by the Company meet the requirements of section 401(a) of the Code and that the Trust Fund is exempt from tax under section 501(a) of the Code, and, in the event that the Internal Revenue Service shall refuse to issue such letter, the Company may terminate the Plan and shall direct the Trustee to pay and deliver the Trust Fund to the Company.

Section 15.5 Trust Fund to Be Applied Exclusively for Participants and Their Beneficiaries . Subject only to the provisions of Section 4.2 (relating to limitation on contributions) and 15.4 (relating to vesting and distribution upon termination or partial termination), and any other provision of the Plan to the contrary notwithstanding, it shall be impossible for any part of the Trust Fund to be used for or diverted to any purpose not for the exclusive benefit of Participants and their beneficiaries and the payment of expenses in accordance with Section 13.1 (relating to expenses) either by operation or termination of the Plan, power of amendment or otherwise.

IN WITNESS WHEREOF, the Company has caused this instrument to be executed by its duly authorized officer on this _____day of December, 2013.

EXELON CORPORATION

By:_____
Amy E. Best
Senior Vice President and
Chief Human Resources Officer

Incentive Pay Plans

Exelon Corporation Annual Incentive Award Plan (or the equivalent cash incentive award program applicable to employees in salary band VII or higher)

Exelon Corporation Quarterly Incentive Award Program

Appendix I

List of Employers

Table T

Transition Credit Factors

Age on 12/31/2001	Percentage	Age on 12/31/2001	Percentage
<31	2.0	41	4.6
31	2.4	42	4.7
32	2.8	43	4.8
33	3.2	44	4.9
34	3.6	45	5.0
35	4.0	46	5.2
36	4.1	47	5.4
37	4.2	48	5.6
38	4.3	49	5.8
39	4.4	50+	6.0
40	4.5		

SCHEDULE A

PROVISIONS APPLICABLE TO
ACCRUED FROZEN BENEFIT
UNDER THE COMMONWEALTH EDISON COMPANY
SERVICE ANNUITY SYSTEM

1. APPLICATION

This Schedule shall apply only to a Participant who elects to participate in the Plan pursuant to Section 3.1(b) of the Plan (relating to eligibility for participation for employees other than new hires) or Section 9.1 of the Plan (relating to recommencement of employment by terminated employee) and whose accrued benefit under the ComEd Plan is transferred to the Plan pursuant to Section 3.1(c) of the Plan (relating to transfer of benefits and assets to Plan) or Section 9.1 of the Plan. The provisions of this Schedule shall govern with respect to all matters relating to such a Participant's Accrued Frozen Benefit.

2. DEFINED TERMS

For purposes of this Schedule A, capitalized terms used herein shall have their respective meanings set forth in the Plan, except that the following words and phrases shall have the following respective meanings when capitalized unless the context clearly indicates otherwise:

A. Accrued Frozen Benefit . The amount payable with respect to a Participant's accrued benefit under the ComEd Plan determined as of December 31, 2001 commencing on the first day of the month coinciding with or next following a Participant's Schedule A Normal Retirement Age, determined as if such amount were payable in the form of a single life annuity for the life of the Participant.

B. Child . A Participant's natural child born prior to the Participant's Pension Starting Date or a child adopted by a Participant prior to the Participant's Pension Starting Date.

C. Consumer Price Index . The United States Bureau of Labor Statistics Consumer Price Index (U.S. City Average 1967 = 100). Such term shall also mean such index as it may from time to time be changed or, if it shall be discontinued, the most nearly comparable index, appropriately adjusted to yield results comparable with those which would have been produced if the index as defined in the preceding sentence had been used, as determined by the Investment Office.

D. Credited Service . A Participant's Credited Service includes the Participant's "credited service" as of the date he or she becomes a Participant, determined in accordance with the provisions of the ComEd Plan as in effect on such date, and the period beginning on the date the Participant becomes a Participant during which the Participant shall have been an Employee, including, (a) any period

during which the Participant is in Military Service, provided that the Participant returns to the employ of an Employer within the period prescribed by laws relating to the reemployment rights of persons in Military Service, (b) any period for which back pay is awarded to the Participant and pursuant to which award the Participant is required to receive credited service under the Plan, (c) the period following Termination of Employment on account of a total and permanent disability during which the Participant is receiving benefits under any Employer's long term disability plan and (d) as and to the extent provided by resolutions of the board of directors of the Company, (i) any period of employment by Affiliates or other companies, and (ii) any period of authorized absence from such employment or from employment as an Eligible Employee. A Participant's periods of Credited Service before and after a Period of Severance that is not included in the Participant's Credited Service pursuant to the preceding sentences shall be aggregated only if (i) the Participant completes at least one year of Credited Service after such period of absence and (ii) the number of years of such Period of Severance is less than five.

E. Dependent Minor Child . A Child who, as of the time of the Participant's retirement or death, is under the age of 21 and qualifies as a dependent of the Participant within the meaning of Section 152 of the Code.

F. Dependent Disabled Child . A Child who, as of the time of the Participant's retirement or death, has a permanent physical or mental disability, as certified by the medical director of the Company or by such other licensed physician designated by the Administrator, that causes such Child to be unable to engage in substantial gainful employment, and is a dependent of the Participant within the meaning of Section 152 of the Code (determined by disregarding any age limitation contained in Section 152 of the Code).

G. Early Retirement Date . The date on which a Participant completes at least ten years of Credited Service and attains at least age 50.

H. Schedule A Actuarial Factors . The table specified by the Commissioner of Internal Revenue for purposes of section 417(e)(3) of the Code (which, as of the Effective Date, is the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female)) in effect on the date a determination hereunder occurs and an interest rate assumption using the "applicable interest rate" as defined in section 417(e)(3) of the Code for the month of November of the Plan Year immediately preceding the Plan Year in which a determination hereunder occurs.

I. Schedule A Normal Retirement Age . A Participant's 65th birthday.

3. SPECIAL RULES REGARDING COMPUTATION OF BENEFIT

A. Factors to Calculate Pension Paid Before Schedule A Normal Retirement Age

1. Pension Starting Date on or After Early Retirement Date and Prior to Schedule A Normal Retirement Age . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Termination of Employment occurs on or after his or her Early Retirement Date and whose Pension commences prior to his or her Schedule A Normal Retirement Age shall be computed by multiplying such Participant's Accrued Frozen Benefit by the applicable factor from Table B-1.

2. Pension Starting Date After Attainment of Age 60 but Prior to Early Retirement Date . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Pension Starting Date occurs on or after such Participant's attainment of age 60 but prior to such Participant's attainment of his or her Early Retirement Date shall be such Participant's Accrued Frozen Benefit without any actuarial reduction.

3. Pension Starting Date After Completion of Ten Years of Credited Service but Prior to Attainment of Age 60 . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Pension Starting Date occurs prior to such Participant's attainment of age 60 and prior to his or her attainment of his or her Early Retirement Date, but after the Participant has completed at least ten years of Credited Service, shall be (a) if the Participant's Pension Starting Date occurs on or after his or her attainment of age 50, the amount determined by multiplying such Participant's Accrued Frozen Benefit by the applicable factor in Table F and (b) if the Participant's Pension Starting Date occurs prior to his or her attainment of age 50, the amount determined by actuarially reducing the Participant's Accrued Frozen Benefit using the factors in Table F to reduce the Accrued Frozen Benefit from age 60 to age 50 and using the Schedule A Actuarial Factors to reduce the Accrued Frozen Benefit to the Participant's Pension Starting Date.

4. Pension Starting Date Prior to Attainment of Age 60 and Prior to Completion of Ten Years of Credited Service . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Pension Starting Date occurs prior to such Participant's attainment of age 60 and prior to such Participant's completion of ten years of Credited Service shall be computed by reducing the Participant's Accrued Frozen Benefit by using the Schedule A Actuarial Factors to reduce the Accrued Frozen Benefit to the Pension Starting Date.

B. Distribution with Respect to Married Participants . Notwithstanding Section 7.2(b) of the Plan, if a Participant will receive his or her Accrued Benefit in the form of a Qualified Joint and Survivor Annuity, the payments attributable to the Participant's Accrued Frozen Benefit shall be calculated and paid as follows:

1. Pension Starting Date After Attainment of Age 50 . Annuity payments will be made during the Participant's lifetime in an amount equal to the annual Accrued Frozen Benefit the Participant would have received if the Participant's Accrued Frozen Benefit were payable in the form of a single

life annuity for the Participant's lifetime reduced by the product of (i) 50% of the annual amount of Accrued Frozen Benefit the Participant would have received if the Participant's Accrued Frozen Benefit were payable in the form of a single life annuity for the Participant's lifetime multiplied by (ii) 40% of the applicable factor set forth in Table D.

Thereafter, if the Participant's Spouse shall survive the Participant, such Spouse shall receive during the remainder of the Spouse's lifetime an annual amount, payable monthly, equal to 50% of the annual amount the Participant would have received if the Participant's Accrued Frozen Benefit were payable as a single life annuity for the Participant's lifetime.

If the Participant survives the Spouse, such Participant shall receive during the remainder of the Participant's lifetime an annual amount payable monthly equal to the annual amount the Participant would have received if the Participant's Frozen Benefit were payable as a single life annuity for the Participant's lifetime.

2. Pension Starting Date Prior to Attainment of Age 50 . Annuity payments will be made during the Participant's lifetime in an amount equal to the annual Accrued Frozen Benefit the Participant would have received if the Participant's Accrued Frozen Benefit were payable in the form of a single life annuity for the Participant's lifetime multiplied by (i) an applicable factor determined by using the Schedule A Actuarial Factors.

Thereafter, if the Participant's Spouse shall survive the Participant, such Spouse shall receive during the remainder of the Spouse's lifetime an annual amount, payable monthly, equal to 50% of the annuity payment prior to the Participant's death.

If the Participant survives the Spouse, the monthly annuity will continue to be paid without any further adjustments during the remainder of the Participant's lifetime.

C. Post Retirement Adjustments . If a Participant's Pension Starting Date occurs on or after his or her 50 th birthday and the Participant's Accrued Frozen Benefit is paid in a form other than a lump sum distribution, the annual Accrued Frozen Benefit payable pursuant to this Schedule shall, subject to the limitations set forth in this paragraph C., be adjusted each October 1 for the twelve-month period then beginning by adding a post-retirement cost of living adjustment computed by applying an adjustment percentage to the appropriate base specified in this paragraph C. A Participant whose Pension Starting Date occurs prior to his or her 50 th birthday or who receives his or her Accrued Frozen Benefit in the form of a lump sum distribution shall not be entitled to any post-retirement cost of living adjustment under this Schedule. In addition, the post-retirement cost of living adjustment shall apply only to the portion of a Participant's Accrued Benefit that is attributable to his or her Accrued Frozen Benefit.

1. The adjustment percentage shall equal, for each October 1, the percentage by which the Consumer Price Index for the July immediately preceding such October 1 exceeds the Consumer Price Index for the July immediately preceding the twelve-month period beginning October 1 in which the Participant terminated employment or payment of a Pension commenced; provided, however, that:

   (a) If, as of such October 1, there shall be no such excess, the adjustment percentage shall be deemed to be zero for the twelve-month period beginning on such October 1.

   (b) There shall be no negative adjustment percentage.

   (c) The aggregate adjustment percentage for any twelve-month period beginning October 1 shall never be lower than the aggregate adjustment percentage for the preceding such period.

   (d) If the percentage increase in the Consumer Price Index computed for the twelve-month period beginning on October 1 does not exceed the aggregate adjustment percentage for the preceding twelve-month period by at least three percentage points, the aggregate adjustment percentage for the preceding twelve-month period shall continue in effect during such twelve-month period beginning on October 1.

   (e) The aggregate adjustment percentage for any twelve-month period beginning on October 1 shall not be more than seven percentage points greater than that for the preceding twelve-month period. If the aggregate adjustment percentage for any twelve-month period beginning on October 1 exceeds by more than seven percentage points the aggregate adjustment percentage for the preceding twelve-month period, the excess shall be carried over to succeeding twelve-month periods until such excess is reduced to zero.

   (f) The adjustment percentage for the twelve-month period beginning with the October 1 next following the date the Participant's Pension Starting Date shall be the adjustment percentage determined in accordance with the preceding provisions of this paragraph C. multiplied by a fraction the numerator of which shall be the number of full calendar months between such date and such October 1 and the denominator of which shall be twelve.

2. To determine the amount of the monthly cost of living adjustment, the adjustment percentage shall be applied to the first $500 per month of a Participant's Accrued Frozen Benefit, subject to a maximum monthly adjustment of $500 or, if the monthly amount of such Accrued Frozen Benefit is less than $500 per month, subject to a maximum monthly adjustment equal to the monthly Accrued Frozen Benefit payment. To

determine the amount of the adjustment made in the case of a Qualified Joint and Survivor Annuity or surviving Spouse annuity payable pursuant to Section 7.3 of the Plan to the surviving Spouse of a deceased Participant, a family pension payable pursuant to Section 4.B. of this Schedule to a surviving Dependent Minor Child or Children of a deceased Participant or a surviving dependent's pension payable pursuant to Section 4.C. of this Schedule to a surviving Dependent Disabled Child or Children of a deceased Participant, the adjustment percentage shall be applied to the first $250 per month of such annuity or pension, subject to a maximum monthly adjustment of $175 ($250 in the case of a Qualified Joint and Survivor Annuity) or, if the monthly amount of such annuity or pension is less than $175 ($250 in the case of a Qualified Joint and Survivor Annuity), subject to a maximum monthly adjustment equal to the monthly Accrued Frozen Benefit payment.

D. Lump Sum Value . If a Participant elects to receive his or her Accrued Frozen Benefit in the form of a lump sum distribution as described in Option 2 of Section 7.2(c) of the Plan, the amount of the lump sum attributable to the Participant's Accrued Frozen Benefit shall be the greater of:

1. the lump sum actuarial equivalent of the Participant's Accrued Frozen Benefit determined using the Schedule A Actuarial Factors, and

2. an amount equal to the present value of the Participant's Accrued Frozen Benefit determined as of December 31, 2001 using a 6.5% discount rate and the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female), assuming the Accrued Frozen Benefit otherwise payable at the Schedule A Normal Retirement Age would commence at the later of the Participant's attained age at December 31, 2001 or age 60 and credited with 6.5% interest for each Plan Year subsequent to December 31, 2001 during which the Participant is a Participant, whether or not such Participant is an Eligible Employee during such Plan Year.

With respect to a Participant's lump sum value determined under subparagraph 1. above, if the Participant's Pension Starting Date occurs on or after his or her 50 th birthday, the actuarial equivalent of the Participant's Accrued Frozen Benefit shall reflect the post retirement adjustments, if any, defined in Paragraph 3.C of this Schedule.

4. OPTIONAL FORMS OF BENEFIT PAYABLE UPON RETIREMENT

In lieu of the forms of benefit available under Section 7.2 of the Plan, a Participant may elect to have the portion of his or her Accrued Benefit attributable to his or her Accrued Frozen Benefit paid in the following forms, subject to Section 7.4 (relating to election and waiver procedures):

A. Optional Qualified Joint and Survivor Annuity : A Participant who is married on the Participant's Pension Starting Date may elect to receive a Qualified Joint and

Survivor Annuity described in Section 7.2(b) of the Plan (relating to manner of distribution with respect to married Participants) with the portion of the Pension payable to the Participant's Spouse that is attributable to the Participant's Accrued Frozen Benefit of a percentage less than 50 of the Pension the Participant would have received if the Participant's Pension attributable to his or her Accrued Frozen Benefit were payable in the form of a single-life annuity for the Participant's lifetime. A Qualified Joint and Survivor Annuity described in this paragraph shall be payable at the same time and in the same manner as described in Section 7.2(b) of the Plan (relating to manner of distribution with respect to married Participant) and shall be computed in the same manner as described in Section 3.B. of this Schedule (relating to special rules regarding computation of benefits), except that the lesser percentage of Pension designated by the Participant shall be used.

B. Family Pension : A Participant who is not married on the Participant's Pension Starting Date and who, as of such date, has a Dependent Minor Child or Dependent Minor Children may elect to receive his or her Accrued Frozen Benefit in the form of a family pension payable in monthly payments for the Participant's lifetime and, thereafter, payable in monthly payments in equal shares to each of the Participant's Dependent Minor Children who have not yet attained age 21. The annual amount of the family pension payable to the Participant shall be the annual Accrued Frozen Benefit the Participant would have received if the Participant's Pension were payable in the form of a single life annuity for the Participant's lifetime, reduced by the product of (1) the annual amount of the family pension designated by the Participant for the Participant's surviving Dependent Minor Child or Children which amount shall be a percentage, not to exceed 50, of the annual amount of the Participant's Pension payable in the form of a single life annuity for the Participant's lifetime multiplied by (2) (i) if the Participant is at least age 50 on his or her Pension Starting Date, the applicable factor set forth in Table E or (ii) if the Participant is not at least age 50 on his or her Pension Starting Date, the applicable factor determined by using the Schedule A Actuarial Factors. The annual amount of the family pension payable after the Participant's death to the Participant's Dependent Minor Child or Children who have not yet attained age 21 shall equal the percentage designated by the Participant, not to exceed 50, of the annual amount of the Pension the Participant would have received if the Participant's Pension were payable in the form of a single life annuity for the Participant's lifetime.

C. Surviving Dependent's Pension : A Participant who is not married on the Participant's Pension Starting Date and who, as of such date, has a Dependent Disabled Child or Dependent Disabled Children may elect to receive his or her Accrued Frozen Benefit in the form of a surviving dependent's pension payable in monthly payments for the Participant's lifetime and, thereafter, payable in monthly payments in equal shares to each of the Participant's Dependent Disabled Children who remain disabled. The annual amount of the surviving dependent's pension payable to the Participant shall be the annual Accrued Frozen Benefit the Participant would have received if the Participant's Pension were payable in the

form of a single life annuity for the Participant's lifetime, reduced by the product of (1) the annual amount of the surviving dependent's pension designated by the Participant for the Participant's Dependent Disabled Child or Children, which amount shall be a percentage, not to exceed 50, of the annual amount of the Participant's Pension payable in the form of a single life annuity for the Participant's lifetime multiplied by (2) (i) if the Participant is at least age 50 on his or her Pension Starting Date, 50% of the applicable factor set forth in Table D, such factor to be determined based on the age of the other parent of such Child or Children, at the Participant's Pension Starting Date or the age such other parent would have attained had such other parent survived or if, in either case, the age of such other parent cannot be determined, the age of the Participant or (ii) if the Participant is not at least age 50 on his or her Pension Starting Date, the applicable factor determined by using the Schedule A Actuarial Factors. The annual amount of the surviving dependent's pension payable after the Participant's death to the Participant's Dependent Disabled Child or Children who remain disabled shall equal the percentage designated by the Participant, not to exceed 50, of the annual amount of the Pension the Participant would have received if the Participant's Pension were payable in the form of a single life annuity for the Participant's lifetime.

D. 75% Marital Annuity : A Participant who is married on the Participant's Annuity Starting Date may elect to receive a 75% marital annuity with a Service Annuity payable to the Participant's Spouse, if the Participant predeceases such Spouse, of a percentage equal to 75 of the Service Annuity the Participant would have received under Article 5 (relating to Service Annuities) if the Participant's Service Annuity were payable in semi-monthly payments for the Participant's lifetime. A 75% marital annuity described in this Section 6.2 shall be payable at the same time and in the same manner as described in paragraph (b) of Section 6.1 (relating to annuities payable to married Participants) and shall be the actuarial equivalent of the Service Annuity the Participant would have received under Article 5 (relating to Service Annuities), determined by using the annual interest rate specified under section 417(e) of the Code for the November preceding the calendar year in which such distribution is made or commences, and the mortality table prescribed for purposes of section 417(e)(3)(A)(ii)(I) of the Code.

Table B1
Early Retirement Service Factors
Applicable Monthly Payments to Age 65

For purposes of Schedule A, in the case of a Pension commencing after a Participant's Early Retirement Date but prior to his or her Schedule A Normal Retirement Age, the following factors shall be applied to determine the reductions applicable to the benefit accrued while a Participant is not a member of IBEW Local Union 15 and, for purposes of Schedule B, in the case of a Pension commencing after a Participant's Early Retirement Date but prior to his or her Schedule B Normal Retirement Age, the following factors shall be applied to determine the reductions applicable to the Participant's benefit accrued under the PECO Plan*:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.7200	.7225	.7250	.7275	.7300	.7325	.7350	.7375	.7400	.7425	.7450	.7475
51	.7500	.7525	.7550	.7575	.7600	.7625	.7650	.7675	.7700	.7725	.7750	.7775
52	.7800	.7825	.7850	.7875	.7900	.7925	.7950	.7975	.8000	.8025	.8050	.8075
53	.8100	.8125	.8150	.8175	.8200	.8225	.8250	.8275	.8300	.8325	.8350	.8375
54	.8400	.8425	.8450	.8475	.8500	.8525	.8550	.8575	.8600	.8625	.8650	.8675
55	.8700	.8725	.8750	.8775	.8800	.8825	.8850	.8875	.8900	.8925	.8950	.8975
56	.9000	.9025	.9050	.9075	.9100	.9125	.9150	.9175	.9200	.9225	.9250	.9275
57	.9300	.9325	.9350	.9375	.9400	.9425	.9450	.9475	.9500	.9525	.9550	.9575
58	.9600	.9617	.9633	.9650	.9667	.9683	.9700	.9717	.9733	.9750	.9767	.9783
59*	.9800	.9817	.9833	.9850	.9867	.9883	.9900	.9917	.9933	.9950	.9967	.9983
60	1.0000											

*** Effective January 1, 2002, for Craft, Craft/Technical, Technical Support and Professional Support Employees with an accrued benefit under the PECO Plan, factor shall be 1.0000 at ages 59 and above**

For purposes of Schedule A, in the case of a Pension commencing after a Participant's Early Retirement Date but prior to his or her Schedule A Normal Retirement Age, the following factors shall be applied to determine the reductions applicable to the benefit accrued while the Participant is a member of IBEW Local Union 15:

AGE	0	1	2	3	4	5	6	7	8	9	10	11
50	.7900	.7925	.7950	.7975	.8000	.8025	.8050	.8075	.8100	.8125	.8150	.8175
51	.8200	.8225	.8250	.8275	.8300	.8325	.8350	.8375	.8400	.8425	.8450	.8475
52	.8500	.8525	.8550	.8575	.8600	.8625	.8650	.8675	.8700	.8725	.8750	.8775
53	.8800	.8825	.8850	.8875	.8900	.8925	.8950	.8975	.9000	.9025	.9050	.9075
54	.9100	.9125	.9150	.9175	.9200	.9225	.9250	.9275	.9300	.9325	.9350	.9375
55	.9400	.9425	.9450	.9475	.9500	.9525	.9550	.9575	.9600	.9625	.9650	.9675
56	.9700	.9725	.9750	.9775	.9800	.9825	.9850	.9875	.9900	.9925	.9950	.9975
57	1.0000											

Table D
Qualified Joint and Survivor Annuity Factors

YOUNGER (-) OR OLDER (+) THAN EMPLOYEE AT RETIREMENT	AGE OF EMPLOYEE AT RETIREMENT															
	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65
-20	.1334	.1432	.1537	.1650	.1771	.1901	.2040	.2189	.2349	.2520	.2703	.2897	.3103	.3322	.3554	.3799
-19	.1324	.1420	.1524	.1636	.1756	.1884	.2022	.2169	.2326	.2495	.2675	.2866	.3070	.3285	.3514	.3754
-18	.1312	.1408	.1511	.1621	.1739	.1866	.2002	.2147	.2302	.2469	.2646	.2835	.3035	.3247	.3471	.3707
-17	.1301	.1395	.1496	.1605	.1722	.1847	.1981	.2124	.2277	.2441	.2616	.2801	.2998	.3206	.3427	.3658
-16	.1288	.1381	.1481	.1589	.1704	.1827	.1959	.2100	.2250	.2412	.2583	.2766	.2959	.3164	.3380	.3607
-15	.1275	.1367	.1465	.1571	.1685	.1806	.1936	.2074	.2222	.2381	.2550	.2729	.2918	.3119	.3331	.3553
-14	.1261	.1351	.1448	.1553	.1664	.1784	.1911	.2048	.2193	.2349	.2514	.2690	.2876	.3073	.3280	.3498
-13	.1246	.1335	.1431	.1533	.1643	.1761	.1886	.2020	.2162	.2315	.2478	.2650	.2832	.3024	.3227	.3440
-12	.1231	.1318	.1412	.1513	.1621	.1736	.1859	.1990	.2130	.2280	.2439	.2608	.2786	.2974	.3172	.3379
-11	.1214	.1301	.1393	.1492	.1598	.1711	.1831	.1960	.2097	.2244	.2399	.2564	.2738	.2921	.3115	.3317
-10	.1198	.1282	.1373	.1470	.1574	.1684	.1802	.1928	.2062	.2206	.2358	.2519	.2688	.2867	.3056	.3253
-9	.1180	.1263	.1352	.1447	.1548	.1657	.1772	.1895	.2026	.2166	.2315	.2472	.2637	.2812	.2995	.3187
-8	.1162	.1243	.1330	.1423	.1522	.1628	.1741	.1861	.1989	.2126	.2271	.2424	.2585	.2755	.2933	.3120
-7	.1143	.1222	.1307	.1398	.1495	.1599	.1709	.1826	.1951	.2084	.2225	.2374	.2531	.2696	.2869	.3051
-6	.1123	.1201	.1284	.1372	.1467	.1568	.1676	.1790	.1911	.2041	.2178	.2323	.2475	.2636	.2804	.2980
-5	.1103	.1178	.1259	.1346	.1438	.1537	.1641	.1752	.1871	.1997	.2130	.2271	.2419	.2575	.2738	.2909
-4	.1082	.1155	.1234	.1319	.1409	.1504	.1606	.1714	.1829	.1951	.2081	.2217	.2361	.2512	.2671	.2836
-3	.1060	.1132	.1209	.1291	.1378	.1471	.1570	.1675	.1786	.1905	.2031	.2163	.2302	.2449	.2602	.2762
-2	.1038	.1108	.1182	.1262	.1347	.1437	.1533	.1635	.1743	.1858	.1980	.2108	.2243	.2385	.2533	.2687
-1	.1015	.1083	.1155	.1233	.1315	.1403	.1496	.1594	.1699	.1811	.1928	.2053	.2183	.2320	.2463	.2612
0	.0992	.1057	.1128	.1203	.1283	.1367	.1457	.1553	.1654	.1762	.1876	.1996	.2122	.2254	.2393	.2536
+1	.0968	.1032	.1100	.1172	.1250	.1332	.1419	.1511	.1609	.1713	.1824	.1939	.2061	.2188	.2322	.2460
+2	.0944	.1005	.1071	.1142	.1216	.1296	.1380	.1469	.1563	.1664	.1771	.1882	.1999	.2122	.2250	.2383
+3	.0919	.0979	.1042	.1110	.1182	.1259	.1340	.1426	.1517	.1615	.1717	.1825	.1938	.2056	.2179	.2307
+4	.0894	.0952	.1013	.1079	.1148	.1222	.1300	.1383	.1471	.1565	.1664	.1767	.1876	.1989	.2107	.2230
+5	.0869	.0925	.0984	.1047	.1114	.1185	.1261	.1340	.1425	.1515	.1610	.1709	.1813	.1922	.2036	.2153
+6	.0844	.0897	.0954	.1015	.1080	.1148	.1221	.1297	.1379	.1465	.1556	.1652	.1751	.1856	.1964	.2077
+7	.0819	.0870	.0925	.0983	.1045	.1111	.1181	.1254	.1332	.1415	.1503	.1594	.1690	.1789	.1893	.2000
+8	.0793	.0843	.0895	.0951	.1011	.1074	.1141	.1211	.1286	.1366	.1449	.1537	.1628	.1724	.1823	.1924
+9	.0768	.0815	.0866	.0920	.0977	.1037	.1101	.1169	.1240	.1316	.1396	.1480	.1567	.1658	.1752	.1848
+10	.0742	.0788	.0836	.0888	0943	.1001	.1062	.1126	.1195	.1267	.1344	.1423	.1506	.1593	.1682	.1773
+11	.0717	.0761	.0807	.0856	.0909	.0964	.1022	.1084	.1149	.1219	.1292	.1367	.1446	.1528	.1612	.1698
+12	.0692	.0734	.0778	.0825	.0875	.0928	.0984	.1042	.1105	.1171	.1240	.1312	.1386	.1463	.1543	.1624
+13	.0667	.0707	.0749	.0794	.0842	.0892	.0945	.1001	.1060	.1123	.1189	.1257	.1327	.1400	.1474	.1550
+14	.0643	.0680	.0721	.0764	.0809	.0857	.0907	.0960	.1016	.1076	.1138	.1202	.1268	.1337	.1407	.1479
+15	.0618	.0654	.0693	.0733	.0776	.0822	.0870	.0920	.0973	.1029	.1088	.1148	.1210	.1274	.1341	.1408
+16	.0594	.0629	.0665	.0704	.0744	.0788	.0833	.0881	.0931	.0983	.1038	.1095	.1153	.1214	.1276	.1340
+17	.0571	.0603	.0638	.0674	.0713	.0754	.0797	.0841	.0888	.0938	.0990	.1043	.1098	.1155	.1214	.1275
+18	.0547	.0578	.0611	.0646	.0682	.0721	.0761	.0803	.0847	.0894	.0942	.0992	.1044	.1098	.1154	.1212
+19	.0525	.0554	.0585	.0618	.0652	.0688	.0726	.0765	.0806	.0850	.0895	.0943	.0991	.1042	.1096	.1151
+20	.0502	.0530	.0559	.0590	.0622	.0656	.0691	.0728	.0767	.0808	.0850	.0895	.0941	.0989	.1040	.1093

FACTORS FOR AGE COMBINATIONS NOT SHOWN ARE COMPUTED ON THE SAME ACTUARIAL BASIS AS THAT USED FOR COMPUTATION OF THE FACTORS STATED IN THE ABOVE TABLE. AS PROVIDED IN SECTION 3.B. OF SCHEDULE A, 40% OF THE APPROPRIATE FACTOR PROVIDED FOR BY THIS TABLE IS TO BE USED IN DETERMINING THE AMOUNT OF THE QUALIFIED JOINT AND SURVIVOR ANNUITY ATTRIBUTABLE TO A PARTICIPANT'S ACCRUED FROZEN BENEFIT.

Table E
Family Annuity Factors

AGE OF YOUNGEST CHILD	AGE OF EMPLOYEE AT RETIREMENT															
	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65
20	.0012	.0014	.0016	.0018	.0020	.0023	.0027	.0030	.0034	.0038	.0043	.0049	.0055	.0063	.0071	.0080
19	.0033	.0037	.0041	.0046	.0052	.0058	.0065	.0072	.0081	.0090	.0102	.0114	.0128	.0143	.0161	.0181
18	.0055	.0061	.0068	.0076	.0084	.0094	.0104	.0116	.0129	.0145	.0162	.0181	.0203	.0227	.0255	.0287
17	.0078	.0086	.0096	.0106	.0118	.0131	.0146	.0162	.0180	.0201	.0225	.0252	.0282	.0315	.0354	.0398
16	.0101	.0112	.0124	.0138	.0153	.0170	.0188	.0209	.0233	.0260	.0291	.0325	.0364	.0408	.0458	.0514
15	.0126	.0139	.0153	.0170	.0189	.0209	.0233	.0259	.0288	.0322	.0360	.0402	.0450	.0504	.0565	.0634
14	.0151	.0166	.0184	.0204	.0226	.0251	.0279	.0310	.0345	.0386	.0431	.0482	.0540	.0604	.0677	.0758
13	.0176	.0195	.0215	.0238	.0264	.0294	.0326	.0363	.0405	.0452	.0505	.0565	.0632	.0708	.0792	.0886
12	.0203	.0224	.0247	.0274	.0304	.0338	.0376	.0418	.0466	.0521	.0582	.0651	.0728	.0815	.0911	.1016
11	.0230	.0254	.0281	`.0311	.0346	.0384	.0427	.0475	.0530	.0592	.0662	.0740	.0827	.0924	.1032	.1149
10	.0258	.0285	.0315	.0350	.0388	.0431	.0480	.0534	.0596	.0666	.0744	.0832	.0929	.1036	.1154	.1284
9	.0287	.0317	.0351	.0389	.0432	.0480	.0534	.0595	.0664	.0742	.0828	.0925	.1032	.1149	.1279	.1419
8	.0316	.0350	.0387	.0430	.0477	.0531	.0591	.0658	.0734	.0819	.0915	.1020	.1136	.1264	.1404	.1556
7	.0347	.0383	.0425	.0471	.0524	.0583	.0649	.0722	.0805	.0899	.1002	.1116	.1241	.1379	.1530	.1694
6	.0378	.0418	.0463	.0514	.0572	.0636	.0708	.0788	.0878	.0979	.1090	.1213	.1347	.1495	.1656	.1831
5	.0410	.0454	.0503	.0559	.0621	.0691	.0768	.0855	.0952	.1060	.1179	.1310	.1453	.1611	.1782	.1969
4	.0443	.0490	.0544	.0604	.0671	.0746	.0830	.0923	.1027	.1142	.1268	.1407	.1559	.1726	.1908	.2105
3	.0476	.0528	.0585	.0650	.0722	.0803	.0892	.0991	.1101	.1223	.1357	.1504	.1669	.1841	.2032	.2240
2	.0511	.0566	.0628	.0697	.0774	.0860	.0955	.1060	.1176	.1305	.1446	.1601	.1770	.1954	.2155	.2372
1	.0546	.0605	.0671	.0745	.0826	.0917	.1018	.1128	.1251	.1386	.1534	.1696	.1873	.2066	.2275	.2501

FACTORS FOR AGE COMPUTATIONS NOT SHOWN ARE COMPUTED ON THE SAME ACTUARIAL BASIS AS THAT USED FOR COMPUTATION OF THE FACTORS STATED IN THE ABOVE TABLE. AS PROVIDED IN SECTION 4.B. OF SCHEDULE A, 100% OF THE APPROPRIATE FACTOR PROVIDED FOR BY THIS TABLE IS TO BE USED IN DETERMINING THE AMOUNT OF THE FAMILY ANNUITY ATTRIBUTABLE TO A PARTICIPANT'S ACCRUED FROZEN BENEFIT.

Table F
Deferred Vesting Schedule

AGE AT TERMINATION	AGE THAT VESTED BENEFITS BEGIN										
	50	51	52	53	54	55	56	57	58	59	60
49	70.0%	73.0%	76.0%	79.0%	82.0%	85.0%	88.0%	91.0%	94.0%	97.0%	100%
48	69.0%	72.1%	75.2%	78.3%	81.4%	84.5%	87.6%	90.7%	93.8%	96.9%	100%
47	68.0%	71.2%	74.4%	77.6%	80.8%	84.0%	87.2%	90.4%	93.6%	96.8%	100%
46	67.0%	70.3%	73.6%	76.9%	80.2%	83.5%	86.8%	90.1%	93.4%	96.7%	100%
45	66.0%	69.4%	72.8%	76.2%	79.6%	83.0%	86.4%	89.8%	93.2%	96.6%	100%
44	65.0%	68.5%	72.0%	75.5%	79.0%	82.5%	86.0%	89.5%	93.0%	96.5%	100%
43	64.0%	67.6%	71.2%	74.8%	78.4%	82.0%	85.6%	89.2%	92.8%	96.4%	100%
42	63.0%	66.7%	70.4%	74.1%	77.8%	81.5%	85.2%	88.9%	92.6%	96.3%	100%
41	62.0%	65.8%	69.6%	73.4%	77.2%	81.0%	84.8%	88.6%	92.4%	96.2%	100%
40	61.0%	64.9%	68.8%	72.7%	76.6%	80.5%	84.4%	88.3%	92.2%	96.1%	100%
39	60.0%	64.0%	68.0%	72.0%	76.0%	80.0%	84.0%	88.0%	92.0%	96.0%	100%
38	59.0%	63.1%	67.2%	71.3%	75.4%	79.5%	83.6%	87.7%	91.8%	95.9%	100%
37	58.0%	62.2%	66.4%	70.6%	74.8%	79.0%	83.2%	87.4%	91.6%	95.8%	100%
36	57.0%	61.3%	65.6%	69.9%	74.2%	78.5%	82.8%	87.1%	91.4%	95.7%	100%
35	56.0%	60.4%	64.8%	69.2%	73.6%	78.0%	82.4%	86.8%	91.2%	95.6%	100%
34	55.0%	59.5%	64.0%	68.5%	73.0%	77.5%	82.0%	86.5%	91.0%	95.5%	100%
33	54.0%	58.6%	63.2%	67.8%	72.4%	77.0%	81.6%	86.2%	90.8%	95.4%	100%
32	53.0%	57.7%	62.4%	67.1%	71.8%	76.5%	81.2%	85.9%	90.6%	95.3%	100%
31	52.0%	56.8%	61.6%	66.4%	71.2%	76.0%	80.8%	85.6%	90.4%	95.2%	100%
30	51.0%	55.9%	60.8%	65.7%	70.6%	75.5%	80.4%	85.3%	90.2%	95.1%	100%
29	50.0%	55.0%	60.0%	65.0%	70.0%	75.0%	80.0%	85.0%	90.0%	95.0%	100%
28	49.0%	54.1%	59.2%	64.3%	69.4%	74.5%	79.6%	84.7%	89.8%	94.9%	100%
27	48.0%	53.2%	58.4%	63.6%	68.8%	74.0%	79.2%	84.4%	89.6%	94.8%	100%
26	47.0%	52.3%	57.6%	62.9%	68.2%	73.5%	78.8%	84.1%	89.4%	94.7%	100%
25	46.0%	51.4%	56.8%	62.2%	67.6%	73.0%	78.4%	83.8%	89.2%	94.6%	100%
24	45.0%	50.5%	56.0%	61.5%	67.0%	72.5%	78.0%	83.5%	89.0%	94.5%	100%
23	44.0%	49.6%	55.2%	60.8%	66.4%	72.0%	77.6%	83.2%	88.8%	94.4%	100%
22	43.0%	48.7%	54.4%	60.1%	65.8%	71.5%	77.2%	82.9%	88.6%	94.3%	100%
21	42.0%	47.8%	53.6%	59.4%	65.2%	71.0%	76.8%	82.6%	88.4%	94.2%	100%
20	41.0%	46.9%	52.8%	58.7%	64.6%	70.5%	76.4%	82.3%	88.2%	94.1%	100%

NOTE: EMPLOYEES MUST HAVE 5 YEARS OF SERVICE TO QUALIFY FOR VESTING

SCHEDULE INDICATES PERCENTAGE OF VESTED BENEFIT PAYABLE
INTERPOLATION WILL BE MADE TO THE NEAREST MONTH

SCHEDULE B

**PROVISIONS APPLICABLE TO
ACCRUED FROZEN BENEFIT
UNDER THE SERVICE ANNUITY PLAN
OF PECO ENERGY COMPANY**

1. APPLICATION

This Schedule shall apply only to a Participant who elects to participate in the Plan pursuant to Section 3.1(b) of the Plan (relating to eligibility for participation for employees other than new hires) or Section 9.1 of the Plan (relating to recommencement of employment by terminated employee) and whose accrued benefit under the PECO Plan is transferred to the Plan pursuant to Section 3.1(c) of the Plan (relating to transfer of benefits and assets to Plan) or Section 9.1 of the Plan. The provisions of this Schedule shall govern with respect to all matters relating to such a Participant's Accrued Frozen Benefit.

2. DEFINED TERMS

For purposes of this Schedule B, capitalized terms used herein shall have their respective meanings set forth in the Plan, except that the following words and phrases shall have the following respective meanings when capitalized unless the context clearly indicates otherwise:

A. Accrued Frozen Benefit . The amount payable with respect to a Participant's accrued benefit under the PECO Plan determined as of December 31, 2001 commencing on the first day of the month coinciding with or next following a Participant's Schedule B Normal Retirement Age, determined as if such amount were payable in the form of a single life annuity for the life of the Participant.

B. Benefit Years . For periods prior to January 1, 2002, a Participant's Benefit Years includes the Participant's "benefit years" as of the date he or she becomes a Participant, determined in accordance with the provisions of the PECO Plan as in effect on December 31, 2001. For the Participant's 12 month "benefit accrual computation period" (as defined in the PECO Plan) that ends during the 2002 Plan Year, the greater of (i) the Vesting Service, for such period, determined pursuant to subdivision (47) of Article 2 of the Plan (relating to definition of Vesting Service) and (ii) the "benefit years", for such period, determined pursuant to the terms of the PECO Plan as in effect on December 31, 2001. For periods after the 12 month period described in the preceding sentence, a Participant's Benefit Years shall equal his or her Vesting Service for such periods.

C. Early Retirement Date . The date on which a Participant completes at least ten years of Vesting Service and attains at least age 50.

D. Schedule B Actuarial Factors . An interest rate assumption of seven percent and a mortality assumption of the TPF&C mortality table in effect as of the date a determination hereunder occurs set back one year for participants and five years for beneficiaries.

E. Schedule B Normal Retirement Age . A Participant's 65th birthday.

3. SPECIAL RULES REGARDING COMPUTATION OF BENEFIT

A. Factors to Calculate Pension Paid Before Schedule B Normal Retirement Age

1. Pension Starting Date on or After Early Retirement Date and Prior to Schedule B Normal Retirement Age . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Termination of Employment occurs on or after his or her Early Retirement Date and whose Pension commences prior to his or her Schedule B Normal Retirement Age shall be computed by multiplying such Participant's Accrued Frozen Benefit by the applicable factor from Table B-1.

2. Pension Starting Date After Attainment of Age 50 but Prior to Early Retirement Date . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Pension Starting Date occurs on or after such Participant's attainment of age 50 but prior to such Participant's attainment of his or her Early Retirement Date and whose Pension commences prior to his or her Schedule B Normal Retirement Age shall be computed by multiplying such Participant's Accrued Frozen Benefit by the applicable factor from Table G.

3. Pension Starting Date Prior to Attainment of Age 50 . The amount determined by actuarially reducing the Participant's Accrued Frozen Benefit using the factors in Table G to reduce the Accrued Frozen Benefit from age 65 to age 50 and using the Schedule B Actuarial Factors to reduce the Accrued Frozen Benefit from age 50 to the Participant's Pension Starting Date.

B. Lump Sum Value . If a Participant elects to receive his or her Accrued Frozen Benefit in the form of a lump sum distribution as described in Option 2 of Section 7.2(c) of the Plan, the amount of the lump sum attributable to the Participant's Accrued Frozen Benefit shall be the greater of:

1. the actuarial equivalent of the Participant's Accrued Frozen Benefit using the Schedule B Actuarial Factors, and

2. an amount equal to the present value of the Participant's Accrued Frozen Benefit determined as of December 31, 2001 using a 6.5% discount rate and the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female), assuming the Accrued Frozen Benefit otherwise payable at the Schedule B Normal Retirement Age would commence at the later of the Participant's attained age at December 31, 2001 or age 60 (or, effective January 1, 2002, age 59 for Craft, Craft/Technical, Technical Support and Professional Support Employees with an Accrued Frozen Benefit) and credited with 6.5% for each Plan Year subsequent to December 31, 2001 during which the Participant is a Participant, whether or not such Participant is an Eligible Employee during such Plan Year.

4. OPTIONAL FORMS OF BENEFIT PAYABLE UPON RETIREMENT

In lieu of the optional forms of benefit available under Section 7.2(c) of the Plan, a Participant may elect to have the portion of his or her Accrued Benefit attributable to his or her Accrued Frozen Benefit paid in the following form, subject to Section 7.4 (relating to election and waiver procedures):

A. Contingent Annuity Option : A Participant (each, an "Eligible Participant") who has a Termination of Employment after he or she (1) has completed at least 14 Benefit Years, or (2) has attained age 65 and has completed at least 5 Benefit Years, or (3) has attained his or her Early Retirement Date may elect a contingent annuity option under which the Participant may designate a percentage equal to 25%, 50%, 75% or 100% of his or her Pension to be paid upon his or her death to a contingent Beneficiary designated by such Participant. The annuity otherwise payable to a Participant electing a Contingent Annuity Option or to his or her contingent Beneficiary will be actuarially reduced using the Schedule B Actuarial Factors to reflect the payments which may become payable to the Beneficiary. Notwithstanding the preceding sentence, if the Participant's Spouse is designated as the contingent Beneficiary, the actuarial reduction will not reflect the cost of a joint and survivor annuity option providing a survivor annuity to the Participant's Spouse of

(1) 50% of the amount payable to the Participant, if a 50%, 75% or 100% contingent annuity option is elected, or (2) 25% of the amount payable to the Participant, if a 25% contingent annuity option is elected; provided, however, that the subsidy described in this sentence shall not apply to a former spouse who is to be treated as a Participant's spouse pursuant to a qualified domestic relations order, unless the qualified domestic relations order specifically provides that such subsidy applies to the former spouse. If the contingent Beneficiary is other than the Spouse, the percentage payable to the contingent Beneficiary after the Participant's death may not exceed the applicable percentage from Appendix B. The contingent annuity option of an electing Participant who has a Termination of Employment before he or she attains his or her Early Retirement Date shall be canceled.

APPENDIX B

MINIMUM DISTRIBUTION INCIDENTAL BENEFIT TABLE

Excess if Age of Participant over Age of Beneficiary	Applicable Percentage
10 years or less	100%
11	96%
12	93%
13	90%
14	87%
15	84%
16	82%
17	79%
18	77%
19	75%
20	73%
21	72%
22	70%
23	68%
24	67%
25	66%
26	64%
27	63%
28	62%
29	61%
30	60%
31	59%
32	59%
33	58%
34	57%
35	56%
36	56%
37	55%
38	55%
39	54%
40	54%
41	53%
42	53%
43	53%
44 and greater	52%

Table G

Reduction Factors Applicable to Accrued Frozen Benefit under Schedule B
For Pension Starting Date on or after Age 50 and before Early Retirement Age*

Months

Age	0	1	2	3	4	5	6	7	8	9	10	11
50	0.235	0.237	0.239	0.240	0.242	0.244	0.246	0.247	0.249	0.251	0.253	0.254
51	0.256	0.258	0.260	0.262	0.264	0.266	0.268	0.269	0.271	0.273	0.275	0.277
52	0.279	0.281	0.283	0.286	0.288	0.290	0.292	0.294	0.296	0.299	0.301	0.303
53	0.305	0.307	0.310	0.312	0.314	0.317	0.319	0.321	0.324	0.326	0.328	0.331
54	0.333	0.336	0.338	0.341	0.344	0.346	0.349	0.352	0.354	0.357	0.360	0.362
55	0.365	0.368	0.371	0.374	0.377	0.380	0.383	0.385	0.388	0.391	0.394	0.397
56	0.400	0.403	0.407	0.410	0.413	0.417	0.420	0.423	0.427	0.430	0.433	0.437
57	0.440	0.444	0.447	0.451	0.455	0.458	0.462	0.466	0.469	0.473	0.477	0.480
58	0.484	0.488	0.492	0.496	0.500	0.504	0.509	0.513	0.517	0.521	0.525	0.529
59	0.533	0.538	0.542	0.547	0.552	0.556	0.561	0.566	0.570	0.575	0.580	0.584
60	0.589	0.594	0.599	0.605	0.610	0.615	0.620	0.625	0.630	0.636	0.641	0.646
61	0.651	0.657	0.663	0.669	0.675	0.681	0.687	0.692	0.698	0.704	0.710	0.716
62	0.722	0.729	0.736	0.742	0.749	0.756	0.763	0.769	0.776	0.783	0.790	0.796
63	0.803	0.811	0.818	0.826	0.834	0.841	0.849	0.857	0.864	0.872	0.880	0.887
64	0.895	0.904	0.913	0.921	0.930	0.939	0.948	0.956	0.965	0.974	0.983	0.991
65 and Over	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

* Factors above are to be multiplied by the Frozen Accrued Benefit applicable to Schedule B. The Basis for the above Factors is the 1971 TPF&C Projection Mortality Table for Males with 1-Year Setback, and 7.00% Interest.

SCHEDULE C
PROVISIONS APPLICABLE TO
ACCRUED FROZEN BENEFIT
UNDER THE CASH BALANCE PROVISIONS
OF THE TXU RETIREMENT PLAN

1. APPLICATION

This Schedule C shall apply only to a Participant who, immediately prior to becoming a Participant, was a participant in the TXU Retirement Plan (the "TXU Plan"). The provisions of this Schedule C shall govern with respect to all matters relating to such a Participant's Cash Balance Account that is attributable to the Participant's accrued benefit under the TXU Plan.

2. DEFINED TERMS

For purposes of this Schedule C, capitalized terms used herein shall have their respective meanings set forth in the Plan, except that the following words and phrases shall have the following respective meanings when capitalized unless the context clearly indicates otherwise:

A. Accrued Frozen Benefit . The amount payable with respect to a Participant's accrued benefit under the TXU Plan determined as of the date such Participant became a Participant commencing on the first day of the month coinciding with or next following a Participant's Schedule C Normal Retirement Age, determined as if such amount were payable in the form of a single life annuity for the life of the Participant.

B. Accredited Service . A Participant's Accredited Service includes the Participant's "Accredited Service" as of the date he or she becomes a Participant, determined in accordance with the provisions of the TXU Plan as in effect on such date, and the number of years and full calendar months of service beginning on the date the Participant becomes a Participant and ending on the Participant's Severance from Service Date (as defined below) but not to exceed, in the aggregate, a maximum of 40 years. A Participant's Severance from Service is the earlier of the first day of the month coincident with or next following the date on which an Employee quits, retires or is discharged or dies, or the first day of the month coincident with or next following the first anniversary of the first day of absence for any other reason. Severance from Service shall not occur if an Employee leaves the employ of an Employer and is eligible for disability benefits as defined in and determined under the TXU Corp. Employee Long-Term Disability Income Plan (or any successor plan), so long as such Employee remains eligible for disability benefits. Accredited Service shall not include any Period of Service for which the Accrued Frozen Benefit has been settled by a cash payment, unless, within the latter of: (a) 5 years of reemployment, or (b) 5 consecutive one-year breaks in service, the full cash payment is repaid together with interest at the annual compound rate of interest as may be specified by law from the date of the cash payment to the date of repayment.

C. Earlier Than Normal Retirement Date . The date on which a Participant attains age 55 and completes at least 15 years of Accredited Service.

D. Schedule C Actuarial Factors . With respect to the computation of lump sum benefit payments, the mortality table prescribed in Revenue Ruling 2001-62 and an interest rate equal to the annual rate on 30-year U.S. Treasury securities for the month of November prior to the Plan Year for which the lump sum payment is being determined. With respect to the computation of monthly benefit payments, a unisex rate taken from the 1983 Group Annuity Mortality Table weighted to reflect a fixed blend of 85% males and 15% females and interest rate equal to 8%.

E. Schedule C Normal Retirement Age . Age 65.

3. SPECIAL RULES REGARDING COMPUTATION OF BENEFIT

A. Factors to Calculate Pension Paid Before Schedule C Normal Retirement Age

1. Pension Starting Date on or After the Earlier Than Normal Retirement Date and Attainment of Age 62, but Prior to Schedule C Normal Retirement Age . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Termination of Employment occurs on or after his or her Earlier Than Normal Retirement Date and whose Pension commences after his or her attainment of age 62, but prior to his or her Schedule C Normal Retirement Age shall be such Participant's Accrued Frozen Benefit without any actuarial reduction.

2. Pension Starting Date on or After the Earlier Than Normal Retirement Date and Prior to Attainment of Age 62 . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Termination of Employment occurs on or after his or her Earlier Than Normal Retirement Date and whose Pension commences before his or her attainment of age 62 shall be such Participant's Accrued Frozen Benefit reduced at the annual rate of 4% for each of the years and full calendar months (taken as twelfths of a year) by which his Earlier Than Normal Retirement Date precedes the first day of the month coincident with or next following his 62 nd birthday.

3. Pension Starting Date Prior to the Earlier Than Normal Retirement Date . The Pension attributable to the Accrued Frozen Benefit of a Participant whose Termination of Employment occurs prior to his or her Earlier than Normal Retirement Date shall be the Participant's Accrued Frozen Benefit reduced at the annual rate of 4% for each of the years and full calendar months (taken as twelfths of a year) to the greater of his age as of his Pension Starting Date or age 55 and further reduced (if applicable) on an actuarial basis from age 55 to the Participant's Pension Starting Date.

B. Lump Sum Value . If a Participant elects to receive his or her Accrued Frozen Benefit in the form of a lump sum distribution as described in Option 2 of Section 7.2(c) of the Plan, the amount of the lump sum attributable to the Participant's Accrued Frozen Benefit shall be the greater of:

1. the lump sum actuarial equivalent of the Participant's Accrued Frozen Benefit determined using the Schedule C Actuarial Factors, and

2. an amount equal to the present value of the Participant's Accrued Frozen Benefit determined as the date the Participant became a Participant in the Plan using a 6.75% discount rate and the 1983 Group Annuity (unisex) Mortality Table (50% male, 50% female). assuming the Accrued Frozen Benefit otherwise payable at the Schedule C Normal Retirement Age would commence at the later of the Participant's attained age as of the date the Participant became a Participant in the Plan or age 62.

4. OPTIONAL FORMS OF BENEFIT PAYABLE UPON RETIREMENT

In lieu of the forms of benefit available under Section 7.2 of the Plan, a Participant may elect to have the portion of his or her Accrued Benefit attributable to his or her Accrued Frozen Benefit paid in the following forms, subject to Section 7.4 (relating to election and waiver procedures):

A. Ten- Year Certain Option : A Participant may elect to receive his or her Accrued Frozen Benefit in the form of a reduced amount which is the Actuarial Equivalent, determined using the Schedule C Actuarial Assumptions, of his or her Accrued Frozen Benefit during his or her lifetime and, in the event of the Participant's death prior to the expiration of ten years following his or her Pension Starting Date, such Accrued Frozen Benefit shall continue for any unexpired portion of such ten-year period to his designated Beneficiary or Beneficiaries. Subject to Section 7.4, the Participant shall have the right to change or redesignate his or her Beneficiary or successive Beneficiaries at any time prior to the expiration of the ten-year period described above. If the Beneficiary or successive Beneficiaries shall survive the retired Participant but die prior to the expiration of the ten-year period described above, the commuted value of the remaining payments due the Beneficiaries shall be paid to the estate of such Beneficiaries. If the Participant shall die within the ten-year period described above without any surviving designated Beneficiary, the commuted value of the payments which would otherwise have been paid during the remaining portion of said ten-year period shall be paid by the Trustee at the direction of the Administrator (i) to the surviving Spouse of such deceased Participant, if any, or (ii) if there shall be no surviving Spouse, to the surviving children of such deceased Participant, if any, in equal shares, or (iii) if there shall be no surviving Spouse or surviving children, to the executor or administrator of the estate of such deceased Participant, or (iv) if no executor or administrator shall have been appointed for the estate of such deceased Participant within six months following the date of the Participant's death, in equal shares to the person or persons who would be entitled under the intestate succession laws of the state of the Participant's domicile to receive the Participant's personal estate.

B. Social Security Adjustment Option : A Participant whose Pension Starting Date occurs after his or her Earlier Than Normal Retirement Date and prior to his or her attainment of age 62 may elect, at any time prior to his or Earlier Than Normal Retirement Date, to have the amount of his or her Accrued Frozen Benefit increased during the period prior to becoming eligible to receive monthly benefits under the Social Security Act, and decreased during the period after becoming eligible to receive monthly benefits under the Social Security Act, so as to provide for the Participant an essentially uniform total retirement benefit composed of his Accrued Frozen Benefit and monthly benefits under the Social Security Act. For purposes of this optional form of benefit, the monthly benefits under the Social Security Act shall mean the old age insurance benefit that a Participant might be entitled to receive at the earliest age the Participant will be eligible to begin receiving monthly benefit under the Social Security Act as of the date he or she elects this optional form of benefit and the Accrued Frozen Benefit shall not be adjusted because of any subsequent change in the actual monthly benefits received under the Social Security Act. If the Participant elects the Social Security Adjustment Option, his or her Accrued Frozen Benefit shall be the greater of (i) the Accrued Frozen Benefit reduced as described in Paragraph 3.A.2 of this Schedule C and applying the Schedule C Actuarial Assumptions for computing monthly benefit payments; and (ii) the Accrued Frozen Benefit actuarially reduced to the Participant's age at retirement and converted to the Social Security Adjustment Option applying the Schedule C Actuarial Assumptions for calculating lump sum benefit payments.

EXELON CORPORATION
SENIOR MANAGEMENT
SEVERANCE PLAN
(As Amended and Restated)

EXELON CORPORATION
SENIOR MANAGEMENT SEVERANCE PLAN
(As Amended and Restated)

1. PURPOSE OF THE PLAN

The Exelon Corporation Senior Management Severance Plan, as amended and restated herein (the " Plan "), is effective as of April 1, 2013 (the " Effective Date ") except as otherwise specifically provided herein, and supersedes in its entirety all prior versions of the Plan with respect to terminations of employment occurring any time on or after the Effective Date (or such other date as set forth herein). The Plan provides severance benefits to eligible executives of Exelon Corporation (" Exelon ") and its subsidiaries of which Exelon owns at least 80% of the outstanding voting power that are designated by the Plan Administrator as participating employers in the Plan (Exelon and such subsidiaries jointly and severally referred to as the " Company ") who submit a Notice of Termination or who are notified of their termination of employment on or after the Effective Date (or such other date as set forth herein), and to provide additional protection in the event of a Change in Control of Exelon or an Imminent Control Change of Exelon.

2. ELIGIBILITY

2.1. Eligibility in General . Subject to the remaining provisions of this Section 2.1, eligibility to participate in the Plan is limited to each employee of the Company whose position is in Salary Band E09 (or equivalent executive grade) or above (an " Executive ") who executes and returns to the Company by the later of 90 days after becoming an Executive, or 90 days after delivery thereof to the Executive, non-competition, non-solicitation, confidential information and intellectual property covenants (" Restrictive Covenants ") which are acceptable to Exelon and are either substantially in the form attached hereto and made a part hereof as Exhibit I (as may be modified from time to time by Exelon in its sole discretion) or set forth in another agreement between the Company and the Executive. Notwithstanding any provision of the Plan to the contrary, eligibility for benefits under the Plan shall be subject to the provisions of any agreement (including but not limited to an offer of employment or grant instrument) between an Executive and the Company providing that that such Executive would be ineligible for (or waives) all or a portion of the benefits under the Plan or "change in control" benefits in the event of a termination of employment, or under which the Executive had agreed, prior to the Applicable Trigger Date, to terminate his or her employment.

2.2. Eligibility Under Section 4 . Subject to Section 2.1, each Executive shall be eligible for the benefits provided under Section 4 hereof in the event such Executive has a Termination of Employment; provided, however, that any Executive whose Termination of Employment is covered under Section 5 hereof or a change in control agreement entered into between such Executive and the Company (an " Individual Change in Control Agreement "), or who is an interim employee separating under the change in control provisions of another severance plan, shall not be eligible for benefits under Section 4, except as expressly provided in Section 5 or such Individual Change in Control Agreement (which expressly refers to the benefits under Section 4 of this Plan).

2.3. Eligibility Under Section 5 . Eligibility for the benefits provided under Section 5 hereof due to a Termination of Employment during a Post-Change Period or an Imminent Control Change Period shall be subject to Section 2.1, and shall be limited to persons who are Executives immediately prior to the Applicable Trigger Date and who are not subject to Individual Change in Control Agreements.

3. PARTICIPATION

Each eligible Executive shall become a participant in the Plan (" Participant ") upon his or her execution of a separation agreement with the Company in such form as the Company, in its sole discretion, shall require or permit (the " Severance Agreement "), provided such Severance Agreement is executed not later than 45 days after the Executive's Termination Date. Notwithstanding anything herein to the contrary, each Executive shall also be required to execute, not later than 45 days after the Executive's Termination Date, a waiver and release of claims against the Company (" Waiver and Release ") which is substantially in the form attached hereto and made a part hereof as Exhibit II, as may from time to time be modified by the Company in its sole discretion. Such Waiver and Release shall also include, with respect to an executive who was employed by Constellation Energy Group, Inc., or its subsidiary or affiliate (collectively, "Constellation") immediately prior to March 12, 2012, a release of any and all claims for additional severance, incentive and change in control payments or benefits of any kind (other than any previous vesting of equity awards). An Executive's right to the payments and benefits under this Plan shall be contingent upon (a) Executive having timely executed and delivered to the Company the Severance Agreement, Waiver and Release and Restrictive Covenants, (b) Executive not revoking the Waiver and Release and (c) Executive not violating any of Executive's on-going obligations under the Plan, the Waiver and Release and the Restrictive Covenants. To the extent that the Company makes payments and provides benefits to an Executive prior to receipt of the Waiver and Release and/or the expiration of the revocation period and the Executive either does not timely execute and deliver the Waiver and Release to the Company or revokes the Waiver and Release in accordance with its terms, Executive shall pay to the Company within 10 days following the expiration of the 45-day consideration period or the date such release was revoked, a lump sum payment of all payments and the value of all benefits received by Executive to date hereunder.

4. **BENEFITS**

A Participant described in Section 2.2 shall be entitled to all Accrued Obligations and, subject to Section 6, benefits pursuant to this Section 4 upon the Participant's Termination of Employment.

4.1. Severance Pay .

(a) In General . Each Participant other than a Participant described in Section 4.1(b) shall receive severance pay at a monthly rate equal to 1/12 of the sum of (a) the Participant's annual base salary in effect as of the date of Termination of Employment, plus, if the Executive is a participant in the Annual Incentive Award Plan with respect to the year in which the Termination Date occurs, (b) the Severance Incentive. Subject to Section 13.13 below, payment shall be made in regular payroll installments for the duration of the applicable Salary Continuation Period, as indicated below, commencing no later than the second paydate which occurs after the Participant's Termination Date. Payment will be made in accordance with the Company's normal payroll practices, net of applicable taxes and other deductions.

Participant Level	Salary Continuation Period
Senior Executive Management	24 months
Senior Vice Presidents of Exelon	18 months
Other Executives	15 months

(b) Participants Employed for Less Than Two Years . Each Participant who has been continuously employed by the Company for less than twenty-four months as of the Participant's Termination Date shall receive severance pay at a monthly rate equal to 1/12 of the Participant's annual base salary in effect as of the Termination Date. Subject to Section 13.13 below, payment shall be made in regular payroll installments for the duration of the applicable Salary Continuation Period, as indicated below, commencing no later than the second paydate which occurs after the Participant's Termination Date. Payment will be made in accordance with the Company's normal payroll practices, net of applicable taxes and other deductions.

Participant Level	Salary Continuation Period
Senior Executive Management	18 months (12 months if employed < 12 months)
Other Executives	12 months (6 months if employed < 12 months)

4.2. Annual Incentive Awards . Each Participant who is a participant in the Annual Incentive Award Plan for the year in which the Termination Date occurs shall receive an Annual Incentive which shall be prorated by multiplying the amount of such Annual Incentive by a fraction the numerator of which is the number of days elapsed during such year as of the Participant's Termination Date and the number of days in the year in which Termination Date occurs. Payment of Annual

Incentives under this Section 4.2 shall be made in a lump sum net of applicable taxes and other deductions at the time awards under the Annual Incentive Award Plan are paid to active employees for such performance period (but not later than March 15 of the year following the last day of such performance period), and shall be considered a "short-term deferral" within the meaning of Section 409A of the Code. A Participant who is not a participant in the Annual Incentive Award Plan for the year in which the Termination Date occurs shall not be entitled to an Annual Incentive, and the amount (if any) payable under any other Incentive Plan for such year shall be determined by the Company in its sole discretion.

4.3. Stock Options . No Participant shall be entitled to participate in any new grants of Stock Options (as defined in Section 5.1(b)) made after such Participant's notification of his or her Termination of Employment. Except as provided below, any Stock Options previously granted to the Participant shall be exercisable only to the extent such Stock Options are exercisable as of the date of such Participant's Termination Date and shall thereafter be exercised in accordance with the provisions of the LTIP. Stock Options which remain unexercisable as of the Participant's Termination Date shall be forfeited. Notwithstanding the preceding, if, as of the last day of the Salary Continuation Period, such Participant has attained at least age 50 (age 55 with respect to Stock Options granted on or after January 1, 2013) and completed at least 10 years of service as defined under the tax-qualified defined benefit plan maintained by Exelon in which the Executive is a participant (the " Pension Plan ") or SERP, then any Stock Options granted to such Participant which have not become exercisable prior to the Participant's Termination Date shall (i) become fully vested, and (ii) remain exercisable until the fifth anniversary of the Termination Date or, if earlier, the option expiration date, provided that this Section 4.3 shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

4.4. Other Awards . Awards of Performance Shares, Restricted Stock (as defined in Sections 5.1(c) and 5.1(d), respectively) and/or Cash Performance Awards, as applicable, shall be payable to a Participant solely to the extent provided under the terms of such awards and the applicable plan under which such awards are granted; provided, however, that to the extent the Company determines that a Participant is a Specified Employee and that any such payment is deferred compensation, each within the meaning of Section 409A of the Code, such payment shall not be made prior to the earlier to occur of (i) the six-month anniversary of the Termination Date or (ii) the date of the Participant's death.

4.5. Health Care Coverage . During the Salary Continuation Period, a Participant (and his or her dependents) shall be eligible to participate in the health care plans under which they were covered immediately prior to his or her Termination of Employment, in accordance with and subject to the terms and conditions of such plans as in effect from time to time. The Participant's out of pocket costs (including premiums, deductibles and co-payments) for such coverage shall be the same as that in effect from time to time for active peer employees during such period. Coverage under this Paragraph 4.5 shall be provided for the duration of

the Salary Continuation Period in lieu of continuation coverage under Section 4980B of the Code and Section 601 to 609 of ERISA (" COBRA ") for the same period. At the end of the Salary Continuation Period, COBRA continuation coverage may be elected for the remaining balance of the statutory coverage period, if any; provided, however that a Participant who, as of the last day of the Salary Continuation Period, has attained at least age 50 and completed at least 10 years of service (or who has completed such other age and service requirement then in effect under the Exelon Corporation Severance Benefit Plan or any successor plan as of the relevant time set forth in such plan) under the terms of the Pension Plan (or who, pursuant to the terms of an offer of employment or employment agreement or under any provision of the Pension Plan or SERP, is credited with a number of additional years of age and/or service that would enable such Participant to satisfy the above eligibility requirements) shall be entitled to elect such Company group health care programs for retirees as are in effect as of the Termination Date and are applicable to such Participant by the programs' eligibility terms and conditions as though such Participant had attained such programs' age and service requirements. The eligibility for coverage and availability of programs or plans, the amounts charged for coverage, and the other terms, conditions and limitations under the Company's group health care programs or plans shall remain subject to the Company's right to amend, change or terminate such programs or plans at any time.

4.6. SERP / Other Deferred Compensation . For purposes of the Participant's SERP benefit, the Salary Continuation Period shall be taken into account as service solely for purposes of determining whether the Participant is vested (i.e., 3 or 5 years of service) and, to the extent relevant under the Pension Plan covering the Participant, the amount of the Participant's regular accrued benefit, but not for purposes of determining eligibility for early retirement benefits (including any social security supplement) or any other purpose. In determining the amount of the Participant's vested benefit, if any, the severance payments made under Section 4.1 shall be taken into account as if such payments were normal base salary and incentive payments. Payment shall be made in accordance with the SERP and the Participant's distribution election in effect thereunder as of the Termination Date (or, if no affirmative election is in effect as of such date, the default election applicable to the Participant). All amounts previously deferred by, or accrued to the benefit of, such Participant under the Exelon Corporation Deferred Compensation Plan, the Exelon Corporation Stock Deferral Plan or the Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan shall, to the extent vested, be paid in accordance with the Participant's distribution election in effect thereunder as of the Termination Date (or, if no affirmative election is in effect as of such date, the default election applicable to the Participant).

4.7. Life Insurance and Disability Coverage . A Participant shall be eligible for continued coverage under the applicable life insurance and long term disability plans sponsored by the Company (or other equivalent coverage or benefits) shall be extended to each Participant through the last day of the Salary Continuation Period applicable to such Participant on the same terms and subject to the same

terms and conditions as are applicable to active peer employees (including, without limitation, submission of proof by an Executive who seeks long term disability benefits that such Executive would have satisfied the conditions for such benefits had the Executive been an employee during the Salary Continuation Period and terminated employment on or before the last day of such period).

4.8. Executive Perquisites . Executive perquisites shall terminate effective as of the Participant's Termination Date, and any Company-owned property shall be required to be returned to the Company no later than such date.

4.9. Outplacement Services . Each Participant shall be entitled to outplacement services at the expense of the Company for twelve months and subject to such terms and conditions as the Plan Administrator, in its sole discretion, determines are appropriate. No cash shall be paid in lieu of such fees and costs.

4.10. Restrictions on In-Kind Benefits . The in-kind benefits provided under each of Sections 4.5, 4.7 and 4.8 during any calendar year shall not affect the benefits to be provided under such section in any subsequent calendar year. The right to such benefits shall not be subject to liquidation or exchange for any other benefit

4.11. Other Coverage . Notwithstanding the foregoing, if such Participant is eligible to obtain a specific type of coverage under welfare plan (s) sponsored by another employer of such Participant (e.g. medical, prescription, vision, dental, disability, individual life insurance benefits, group life insurance benefits, but excluding for the purposes of this sentence retiree benefits if such Participant is so eligible), then the Company shall not be obligated to provide any such specific type of coverage. The Participant shall promptly notify the Plan Administrator of any such coverage.

5. CHANGE IN CONTROL BENEFITS

A Participant described in Section 2.3 shall be entitled to all Accrued Obligations and, subject to Section 6, benefits pursuant to this Section 5 if such a Participant has a Termination of Employment during a Post-Change Period or Imminent Control Change Period, and such Participant shall not be eligible for benefits under Section 4 unless so expressly provided in this Section 5.

5.1. Termination During a Post-Change Period . If, during a Post-Change Period, an eligible Executive has a Termination of Employment and becomes a Participant, the Company's sole obligations under Section 4 and Sections 5.1 and 5.2 shall be as set forth in this Section 5.1 (subject to Sections 5.3, 5.5, 5.6 and 6.0.

(a) Severance Payments . The Company shall pay or provide (or cause to be provided) to such Participant, according to the payment terms set forth in Section 5.3 below, the following:

(i) Annual Incentive for Year of Termination . An amount equal to the Annual Incentive applicable to such Participant under the Incentive Plan for the performance period in which the Termination Date occurs;

(ii) Deferred Compensation and Non-Qualified Defined Contribution Plans . All amounts previously deferred by, or accrued to the benefit of, such Participant under the Exelon Corporation Deferred Compensation Plan, the Exelon Corporation Stock Deferral Plan or the Constellation Energy Group Inc. Deferred Compensation Plan, any successor plan, or under any other non-qualified defined contribution or deferred compensation plan of the Company, whether vested or non-vested, together with any accrued earnings thereon, to the extent that such amounts and earnings have not been previously paid by the Company and are not provided under the terms of any such non-qualified plan;

(iii) SERP Enhancement . An amount payable under the SERP equal to the positive difference, if any, between:

(1) the lump sum value of such Participant's benefit, if any, under the SERP, calculated as if such Participant had:

(a) become fully vested in all Pension Plan and SERP benefits,

(b) to the extent age is relevant under the Pension Plan covering the Participant, attained as of the Termination Date an age that is two years greater than such Participant's actual age and that includes the number of years of age credited to such Participant pursuant to any other agreement between the Company and such Participant,

(c) to the extent service is relevant under the Pension Plan covering the Participant, accrued a number of years of service (for purposes of determining the amount of such benefits, entitlement to—but not commencement of—early retirement benefits, and all other purposes of the Pension Plan and SERP) that is two years greater than the number of years of service actually accrued by such Participant as of the Termination Date and that includes the number of years of service credited to such Participant pursuant to any other agreement between the Company and such Participant, and

(d) received the severance benefits specified in Sections 5.1(a)(i) and 5.1(a)(v) as covered compensation in regular installments during the Severance Period, minus

(2) the aggregate amounts paid or payable to such Participant under the SERP;

(iv) Non-vested Benefits Under Pension Plan . An amount equal to the actuarial equivalent present value of any non-vested portion of such Participant's accrued benefit under the Pension Plan as of the Termination Date and forfeited by such Participant by reason of the Termination of Employment; and

(v) Multiple of Salary and Severance Incentive . An amount equal to two (2) times the sum of (x) the Participant's Base Salary plus, if the Participant is a participant in the Annual Incentive Award Plan for the year in which the Termination Date occurs, (y) the Severance Incentive, net of applicable taxes and other deductions.

(b) Stock Options . Each of such Participant's stock options granted under the LTIP (" Stock Options ") shall (i) become fully vested, and (ii) remain exercisable until the fifth anniversary of the Termination Date or, if earlier, the expiration date of any such Stock Option, provided that this Section 5.1(b) shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

(c) Performance Share Vesting . On the Termination Date, all of the performance share units granted to such Participant under the Exelon Long Term Performance Share Award Program under the LTIP (" Performance Shares ") prior to January 1, 2013 to the extent earned by and awarded to such Participant (i.e. as to which the applicable performance cycle has elapsed) as of the Termination Date, shall become fully vested at the actual level earned and awarded, and, to the extent not yet earned by and awarded to such Participant (i.e. as to which the current performance cycle has not elapsed) as of the Termination Date, shall become fully vested at the earned level determined as of the last day of the applicable performance cycle. With respect to all Performance Shares granted on or after January 1, 2013, such Performance Shares shall become vested and earned as set forth in the LTIP, as if the Executive had been involuntarily terminated without cause.

(d) Other Awards . All forfeiture conditions that as of the Termination Date are applicable to any shares of restricted stock or restricted stock units awarded to such Participant by Exelon other than under the Exelon Long Term Performance Share Award Program under the LTIP (" Restricted Stock ") shall (except as expressly provided to the contrary in the applicable awards) lapse immediately and all such awards will become fully vested. All Cash Performance Awards shall become fully vested in accordance with their terms.

(e) Continuation of Welfare Benefits . During the Severance Period, the Executive and the Executive's dependents shall be eligible for participation in the Company's welfare plans, including medical, prescription, dental, disability, employee life, group life and accidental death benefits but excluding any severance pay (" Welfare Plans ") that covered the Participant or such Participant's dependents as of the Termination Date, in accordance with the terms and conditions of such plans and applicable law. Such provision of welfare benefits shall be subject to the following:

(i) In determining benefits applicable under such Welfare Plans, such Participant's annual compensation attributable to base salary and incentives for any plan year or calendar year, as applicable, shall be deemed to be not less than such Participant's Base Salary and annual incentive for the year in which the Termination Date occurs.

(ii) The cost of such welfare benefits to such Participant and dependents under this Section 5.1(e) shall not exceed the cost of such benefits to peer executives who are actively employed during the Severance Period.

(iii) Health care coverage under this Section 5.1(e) shall be provided for the duration of the Severance Period in lieu of continuation coverage under Section 4980B of the Code and Section 601 to 609 of ERISA (" COBRA ") for the same period. At the end of the Severance Period, COBRA continuation coverage may be elected for the remaining balance of the statutory coverage period, if any, at the Participant's sole expense.

(iv) If such Participant has, as of the last day of the Severance Period, attained age 50 and completed at least 10 years of service with the Company, such Participant shall be entitled to elect coverage under such Company group health care programs for retirees as are in effect as of the Termination Date and are applicable to such Participant by the programs' eligibility terms and conditions as though such Participant had attained such programs' age and service requirements ; provided, however, that for purposes hereof, any years of age and/or credited service granted to such Participant in any other plan or agreement between such Participant and the Company shall be taken into account. For purposes of determining eligibility for (but not the time of commencement of) such retiree benefits, such Participant shall also be considered (1) to have remained employed until the last day of the Severance Period and to have retired on the last day of such period, and (2) to have attained at least the age such Participant would have attained on the last day of the Severance Period. The eligibility for coverage and availability of programs or plans, the amounts charged for coverage, and the other terms, conditions and limitations under the Company's group health care programs or plans shall remain subject to the Company's right to amend, change or terminate such programs or plans at any time.

Notwithstanding the foregoing, if such Participant is eligible to obtain a specific type of coverage under welfare plan(s) sponsored by another employer of such Participant (e.g. medical, prescription, vision, dental, disability, individual life insurance benefits, group life insurance benefits, but excluding for the purposes of this sentence retiree benefits if such Participant is so eligible), then the Company shall not be obligated to provide any such specific type of coverage. The Participant shall promptly notify the Plan Administrator of any such coverage.

(f) Outplacement . To the extent actually incurred by such Participant, the Company shall pay or cause to be paid on behalf of such Participant, as incurred, all reasonable fees and costs charged by a nationally recognized outplacement firm selected by such Participant for outplacement services provided for up to 12 months after the Termination Date. No cash shall be paid in lieu of such fees and costs.

(g) Indemnification . Such Participant shall be indemnified and held harmless by the Company to the greatest extent permitted under applicable law and the Company's by-laws if such Participant was, is, or is threatened to be, made a party to any pending, completed or threatened action, suit, arbitration, alternate dispute resolution mechanism, investigation, administrative hearing or any other proceeding brought by a third party (and not by or on behalf of the Company or its shareholders) whether civil, criminal, administrative or investigative, and whether formal or informal, by reason of the fact that such Participant is or was, or had agreed to become, a director, officer, employee, agent, or fiduciary of the Company or any other entity which such Participant is or was serving at the request of the Company (" Proceeding "), against all expenses (including all reasonable attorneys' fees) and all claims, damages, liabilities and losses incurred or suffered by such Participant or to which such Participant may become subject for any reason; provided, that the Participant provides the Company written notice of any such Proceeding promptly after receipt and such that the Company's ability to defend shall not be prejudiced in any fashion and the Company shall have the right to direct the defense, approve any settlement and shall not be required to indemnify the Participant in connection with any proceeding initiated by the Participant, including a counterclaim or crossclaim, unless such proceeding was authorized by the Company, and that the Participant fully cooperates in the investigation and defense of such Proceeding.

(h) Directors' and Officers' Liability Insurance . For a period of six years after the Termination Date, the Company shall provide such Participant with coverage under a directors' and officers' liability insurance policy in an amount no less than, and on terms no less favorable than, those provided to peer executives of the Company from time to time.

5.2. Termination During an Imminent Control Change Period . If, during an Imminent Control Change Period, a Participant has a Termination of Employment, then such Participant shall receive benefits at the time and in the manner provided in Section 4 and the Company's sole obligations to such Participant under Sections 5.1 and 5.2 shall be as set forth in this Section 5.2 (and subject to Sections 5.3, 5.5, 5.6 and 6). The Company's obligations to such Participant under this Section 5.2 shall in all events be reduced by any amounts or benefits paid or provided pursuant to Section 4.

(a) Cash Severance Payments . If the Imminent Control Change Period culminates in a Change Date, the Company shall pay (or cause to be paid) to such Participant the amounts described in Section 5.1(a)(i) through (v). Such amounts shall be paid to such Participant as described in Section 5.3, provided that amounts that would have been paid prior to the Change Date shall be paid in a lump sum (without interest) within 30 business days after the Change Date.

(b) Vested Stock Options . Such Participant's Stock Options, to the extent vested on the Termination Date,

(i) will not expire (unless such Stock Options would have expired had such Participant remained an employee of the Company) during the Imminent Control Change Period; and

(ii) will continue to be exercisable after the Termination Date to the extent provided in the applicable grant agreement or the LTIP, and thereafter such Stock Options shall not be exercisable during the Imminent Control Change Period.

If the Imminent Control Change Period lapses without a Change Date, then such Participant's Stock Options, to the extent vested on the Termination Date, may be exercised, in whole or in part, during the 30-day period following the lapse of the Imminent Control Change Period, or, if longer, the period during which such Participant's vested Stock Options could otherwise be exercised under the terms of the applicable grant agreement or the LTIP (but in no case shall any Stock Options remain exercisable after the date on which such Stock Options would have expired if such Participant had remained an employee of the Company).

If the Imminent Control Change Period culminates in a Change Date, then effective upon the Change Date, such Participant's Stock Options, to the extent vested on the Termination Date, may be exercised in whole or in part by such Participant at any time until the earlier of the fifth anniversary of the Change Date or the option expiration date for such Stock Options, provided that this Section 5.2(b) shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

(c) Non-vested Stock Options . Such Participant's Stock Options that are not vested on the Termination Date:

(i) will not expire (unless such Stock Options would have expired had such Participant remained an employee of the Company) during the Imminent Control Change Period; and

(ii) will not continue to vest and will not be exercisable during the Imminent Control Change Period.

If the Imminent Control Change lapses without a Change Date, such non-vested Stock Options will thereupon expire.

If the Imminent Control Change culminates in a Change Date, then immediately prior to the Change Date, such non-vested Stock Options shall become fully vested, and may thereupon be exercised in whole or in part by such Participant at any time until the earlier of the fifth anniversary of the Change Date, or the option expiration date for such Stock Options, provided that this Section 5.2(c) shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

(d) Performance Shares . Such Participant's Performance Shares granted under the Exelon Long Term Performance Share Award Program under the LTIP will not be forfeited during the Imminent Control Change Period, and will not continue to vest during the Imminent Control Change Period. If the Imminent Control Change lapses without a Change Date, such Performance Shares shall be governed according to the terms of Section 4. If the Imminent Control Change Period culminates in a Change Date:

(i) All Performance Shares granted to such Participant under the Exelon Long Term Performance Share Award Program under the LTIP prior to January 1, 2013, which, as of the Termination Date, have been earned by and awarded to such Participant, shall become fully vested at the actual earned level on the Change Date, and

(ii) All of the Performance Shares granted to such Participant under the Exelon Long Term Performance Share Award Program under the LTIP prior to January 1, 2013 which, as of the Termination Date, have not been earned by and awarded to such Participant shall become fully vested on the Change Date at the actual earned level as of the last day of the applicable performance cycle, and

(iii) With respect to all Performance Shares granted on or after January 1, 2013, such Performance Shares shall become vested and earned as set forth in the LTIP, as if the Executive had been involuntarily terminated without cause.

(e) Restricted Stock . Such Participant's non-vested Restricted Stock will:

(i) not be forfeited during the Imminent Control Change Period; and

(ii) not continue to vest during the Imminent Control Change Period.

If the Imminent Control Change Period lapses without a Change Date, such non-vested Restricted Stock shall thereupon be forfeited.

If the Imminent Control Change Period culminates in a Change Date, then immediately prior to the Change Date, such Participant's Restricted Stock shall (except as expressly provided to the contrary in the award) become fully vested, and within ten business days after the Change Date, the Company shall deliver to such Participant all of such shares theretofore held by or on behalf of the Company, which will be subject to the same terms which other stockholders of the Company receive in the transaction.

(f) Cash Performance Awards . All Cash Performance Awards shall become fully vested in accordance with the terms of the underlying award documents.

(g) Continuation of Welfare Benefits . The Participant and the Participant's dependents shall be eligible for welfare benefits (other than any severance pay that may be considered a welfare benefit) in accordance with the terms and conditions of the applicable plans during the Imminent Control Change Period, to the same extent as if such Participant had remained employed during such period, subject to the following:

(i) in determining benefits applicable under such Welfare Plans, such Participant's annual compensation attributable to base salary and incentives for any plan year or calendar year, as applicable, shall be deemed to be not less than such Participant's Base Salary and annual incentive for the year in which the Termination Date occurs;

(ii) the cost of such welfare benefits to such Participant and dependents under this Section 5.2(g) shall not exceed the cost of such benefits to peer executives who are actively employed by the Company during the Imminent Control Change Period; and

(iii) Health care coverage under this Section 5.2(g) shall be provided for the duration of the Severance Period in lieu of continuation coverage under Section 4980B of the Code and Section 601 to 609 of ERISA (" COBRA ") for the same period. At the end of the Severance Period, COBRA continuation coverage may be elected for the remaining balance of the statutory coverage period, if any.

If the Imminent Control Change Period lapses without a Change Date, welfare benefit plan coverage under this Section 5.2(g) shall thereupon cease, subject to such Participant's rights, if any, to continued coverage under a Welfare Plan, Section 4, or applicable law. If the Imminent

Control Change Period culminates in a Change Date, then for the remainder of the Severance Period, the Participant and his or her dependents shall continue to be eligible for welfare benefits as described in, and subject to the limitations of Section 5.1(e).

Notwithstanding the foregoing, if such Participant obtains a specific type of coverage under welfare plan(s) sponsored by another employer of such Participant (e.g. medical, prescription, vision, dental, disability, individual life insurance benefits, group life insurance benefits, but excluding for the purposes of this sentence retiree benefits if such Participant is so eligible), then the Company shall not be obligated to provide any such specific type of coverage. The Participant shall immediately notify the Plan Administrator of any such coverage.

(h) Indemnification . Such Participant shall be indemnified and held harmless by the Company to the same extent as provided in Section 5.1(g), but only during the Imminent Control Change Period (or greater period provided under the Company's by-laws) if the Imminent Control Change Period lapses without a Change Date.

(i) Termination During an Imminent Control Change Period: Directors' and Officers' Liability Insurance . The Company shall provide the same level of directors' and officers' liability insurance for such Participant as provided in Section 5.1(h), but only during the Imminent Control Change Period (or greater period provided under the Company's by-laws) if the Imminent Control Change Period lapses without a Change Date.

5.3. Timing of Severance Payments . Unless otherwise specified herein, the Accrued Obligations and the amount described in Section 5.1(a)(i) shall be paid within 30 business days of the Termination Date, and such amounts shall be considered "short-term deferrals" within the meaning of Section 409A of the Code. The amounts described in Sections 5.1(a)(ii), (iii) and (iv) shall be paid in accordance with the applicable deferred compensation plan or the SERP and the Participant's distribution election thereunder as of the Termination Date (or, if no affirmative election is in effect as of such date, the default election in effect with respect to the Participant as of such date). Subject to Section 13.13, the severance payments described in Section 5.1(a)(v) shall be paid during the Severance Period, beginning no later than the second paydate which occurs after the Termination Date, in periodic payments to a Participant according to the Company's normal payroll practices at a monthly rate equal to 1/12 of the sum of (i) such Participant's Base Salary plus (ii) the Severance Incentive (if any). The in-kind benefits and reimbursements provided under each of Sections 5.1(e), 5.1(h), 5.2(g) and 5.2(i) during any calendar year shall not affect the benefits or reimbursements to be provided under such section in any subsequent calendar year. The right to such benefits and reimbursements shall not be subject to liquidation or exchange for any other benefit.

5.4. Other Terminations of Employment by the Company or a Participant .

(a) Obligations . If, during a Post-Change Period or an Imminent Control Change Period, (i) the Company terminates an eligible Executive's employment for Cause (or causes a Participant to be terminated for Cause) (" Cause Termination ") or disability (as determined by the Plan Administrator in good faith), (ii) an Executive elects to retire or otherwise terminate employment other than for Good Reason, disability or death, or (iii) an eligible Executive's employment terminates on account of death, the Company shall have no obligations to such Executive under Section 5. The remaining applicable provisions of this Plan (including the Restrictive Covenants) shall continue to apply.

(b) Procedural Requirements . The Company shall strictly observe or cause to be strictly observed each of the following procedures in connection with any Cause Termination during a Post-Change Period or an Imminent Control Change Period: an eligible Executive's termination of employment shall not be deemed to be for Cause under this Section 5.4 unless and until there shall have been delivered to such Executive a written notice of the determination of the Chief Executive Officer of the Executive's employer (" CEO ") (after reasonable written notice of such consideration by the CEO of acts or omissions alleged to constitute Cause is provided to such Executive and such Executive is given an opportunity to present a written response to the CEO regarding such allegations), finding that, in his or her good faith opinion, such Executive's acts, or failure to act, constitutes Cause and specifying the particulars thereof in detail.

5.5. Sole and Exclusive Obligations . The obligations of the Company under this Plan with respect to any Termination of Employment occurring during a Post-Change Period or Imminent Control Change Period shall supersede any severance obligations of the Company in any other plan of the Company or agreement between such Participant and the Company, including, without limitation, Section 4, any offer of employment or employment contract of the Company which provides for severance benefits, except as explicitly provided in Section 5.2 or to the extent such Participant is ineligible for such benefits or such benefits are waived pursuant to Section 2.1.

5.6. Payment Capped . If at any time or from time to time, it shall be determined by the Company's independent auditors that any payment or other benefit to a Participant pursuant to Section 4 or 5 of this Plan or otherwise (" Potential Parachute Payment ") is or will become subject to the excise tax imposed by Section 4999 of the Code or any similar tax payable under any United States federal, state, local, foreign or other law (" Excise Taxes "), then the Potential Parachute Payments payable to such Participant shall be reduced to the largest amount which would both (a) not cause any Excise Tax to be payable by such Participant and (b) not cause any Potential Parachute Payments to become nondeductible by the Company by reason of Section 280G of the Code (or any successor provision).

6. **TERMINATION OF PARTICIPATION; CESSATION OF BENEFITS**

A Participant's benefits under Section 4 of the Plan shall terminate on the last day of the Participant's Salary Continuation Period; provided that a Participant's right to benefits shall terminate immediately on such date as the Company discovers that the Participant has breached any of the Restrictive Covenants or the Waiver and Release, or if at any time the Company determines that in the course of his or her employment the Executive engaged in conduct described in Section 7.11(b), (c), (d) or (e) or the Executive fails to comply with Section 13.2, in which case the Company may require the repayment of amounts paid pursuant to Section 4.1 prior to such breach or other conduct, and shall discontinue the payment of any additional amounts under Section 4 of the Plan.

A Participant's benefits under Section 5 of the Plan shall terminate on the later of the last day of the Participant's Severance Period or the date all benefits to which the Participant is entitled to have been paid from the Plan; provided that a Participant's right to benefits shall terminate immediately on the date the Company discovers that the Participant has breached any of the Restrictive Covenants or the Waiver and Release, or if at any time the Company determines, in accordance with the procedural requirements set forth in Section 5.4(b) that in the course of his or her employment the Executive engaged in conduct described in Section 7.11(b), (c), (d) or (e) or the Executive fails to comply with Section 13.2, in which case the Company may require the repayment of amounts paid pursuant to Section 5 prior to such breach or other conduct, and shall discontinue the payment of any additional amounts under Section 5 of the Plan.

Benefits paid or payable to a Participant under Section 4 and Section 5 of the Plan shall be subject to any executive or officer incentive compensation recoupment policy of the Board of Directors as in effect as of the Termination Date.

7. **DEFINITIONS**

In addition to terms previously defined, when used in the Plan, the following capitalized terms shall have the following meanings unless the context clearly indicates otherwise:

7.1. " Accrued Annual Incentive " means the amount of any annual incentive earned but not yet paid with respect to the Company's latest fiscal year ended prior to the Termination Date.

7.2. " Accrued Base Salary " means the amount of a Participant's Base Salary that is accrued but not yet paid as of the Termination Date.

7.3. " Accrued Obligations " means, as of any date, the sum of a Participant's Accrued Base Salary, Accrued Annual Incentive and any accrued but unpaid paid time off

7.4. " Annual Incentive " as of a certain date means an amount to which a Participant would have been entitled under the Annual Incentive Award Plan (or, with respect to a termination pursuant to Section 5, such other Incentive Plan applicable to such Participant) for the applicable performance period based on the actual achievement performance goals established pursuant to such plan as of the end of the applicable performance period had the Participant remained employed through the last day of such period; provided, however, that any reduction in a Participant's Base Salary or annual incentive that would qualify as Good Reason shall be disregarded for purposes of this definition

7.5. " Annual Incentive Award Plan ", means the Exelon Corporation Annual Incentive Award Plan, or any successor plan thereto (including but not limited to any annual incentive plan of a successor to a Company pursuant to a Change in Control).

7.6. " Applicable Trigger Date " means

(a) the Change Date, with respect to a Post-Change Period; or

(b) the date of an Imminent Control Change, with respect to the Imminent Control Change Period.

7.7. " Base Salary " for purposes of Section 5, means not less than 12 times the highest monthly base salary paid or payable to a Participant by the Company in respect of the 12-month period immediately before the Applicable Trigger Date.

7.8. " Beneficial Owner " means such term as defined in Rule 13d-3 of the SEC under the Exchange Act.

7.9. " Board " means the Board of Directors of Exelon or, from and after the effective date of a Corporate Transaction (as defined in the definition of Change in Control), the Board of Directors of the corporation resulting from a Corporate Transaction or, if securities representing at least 50% of the aggregate voting power of such resulting corporation are directly or indirectly owned by another corporation, such other corporation.

7.10. "Cash Performance Award" means any cash performance award granted to a Participant in lieu of an award of Performance Shares or Restricted Stock under the LTIP during employment by Commonwealth Edison Company.

7.11. " Cause " means, with respect to any Executive:

(a) the refusal to perform or habitual neglect in the performance of the Executive's duties or responsibilities, or of specific directives of the officer or other executive of Exelon or any of its affiliates to whom the Executive reports which are not materially inconsistent with the scope and nature of the Executive's employment duties and responsibilities;

(b) an Executive's willful or reckless commission of act(s) or omission(s) which have resulted in or are likely to result in, a material loss to, or material damage to the reputation of, Exelon or any of its affiliates, or that compromise the safety of any employee or other person;

(c) the Executive's commission of a felony or any crime involving dishonesty or moral turpitude;

(d) an Executive's material violation of Exelon's or any of its affiliate's Code of Business Conduct (including the corporate policies referenced therein) which would constitute grounds for immediate termination of employment, or of any statutory or common law duty of loyalty to Exelon or any of its affiliates; or

(e) any breach by the Executive of any one or more of the Restrictive Covenants.

7.12. "Change Date" means each date on which a Change in Control occurs after the Effective Date.

7.13. "Change in Control" means:

(a) any SEC Person becomes the Beneficial Owner of 20% or more of the then outstanding common stock of Exelon or of Voting Securities representing 20% or more of the combined voting power of all the then outstanding Voting Securities of Exelon (such an SEC Person, a "20% Owner"); provided, however, that for purposes of this subsection (a), the following acquisitions shall not constitute a Change in Control: (1) any acquisition directly from Exelon (excluding any acquisition resulting from the exercise of an exercise, conversion or exchange privilege unless the security being so exercised, converted or exchanged was acquired directly from Exelon), (2) any acquisition by Exelon, (3) any acquisition by an employee benefit plan (or related trust) sponsored or maintained by Exelon or any corporation controlled by Exelon (a "Company Plan"), or (4) any acquisition by any corporation pursuant to a transaction which complies with clauses (i), (ii) and (iii) of subsection (c) of this definition; provided further, that for purposes of clause (2), if any 20% Owner of Exelon other than Exelon or any Company Plan becomes a 20% Owner by reason of an acquisition by Exelon, and such 20% Owner of Exelon shall, after such acquisition by Exelon, become the beneficial owner of any additional outstanding common shares of Exelon or any additional outstanding Voting Securities of Exelon (other than pursuant to any dividend reinvestment plan or arrangement maintained by Exelon) and such beneficial ownership is publicly announced, such additional beneficial ownership shall constitute a Change in Control; or

(b) Individuals who, as of the date hereof, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Incumbent Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by Exelon's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest (as such terms are used in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(c) Consummation of a reorganization, merger or consolidation (" Merger "), or the sale or other disposition of more than 50% of the operating assets of Exelon (determined on a consolidated basis), other than in connection with a sale-leaseback or other arrangement resulting in the continued utilization of such assets (or the operating products of such assets) by Exelon (such reorganization, merger, consolidation, sale or other disposition, a " Corporate Transaction "); excluding, however, a Corporate Transaction pursuant to which:

(i) all or substantially all of the individuals and entities who are the Beneficial Owners, respectively, of the outstanding common stock of Exelon and outstanding Voting Securities of Exelon immediately prior to such Corporate Transaction beneficially own, directly or indirectly, more than 60% of, respectively, the then-outstanding shares of common stock and the combined voting power of the then-outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Corporate Transaction (including, without limitation, a corporation which, as a result of such transaction, owns Exelon or all or substantially all of the assets of Exelon either directly or through one or more subsidiaries) in substantially the same proportions as their ownership immediately prior to such Corporate Transaction of the outstanding common stock of Company and outstanding Voting Securities of Exelon, as the case may be;

(ii) no SEC Person (other than the corporation resulting from such Corporate Transaction, and any Person which beneficially owned, immediately prior to such corporate Transaction, directly or indirectly, 20% or more of the outstanding common stock of Exelon or the outstanding Voting Securities of Exelon, as the case may be) becomes a 20% Owner, directly or indirectly, of the then-outstanding common stock of the corporation resulting from such Corporate Transaction or the combined voting power of the outstanding voting securities of such corporation; and

(iii) individuals who were members of the Incumbent Board will constitute at least a majority of the members of the board of directors of the corporation resulting from such Corporate Transaction; or

(d) Approval by Exelon's shareholders of a plan of complete liquidation or dissolution of Exelon, other than a plan of liquidation or dissolution which results in the acquisition of all or substantially all of the assets of Exelon by an affiliated company.

Notwithstanding the occurrence of any of the foregoing events, a Change in Control shall not occur with respect to a Participant if, in advance of such event, such Participant agrees in writing that such event shall not constitute a Change in Control.

7.14. " Code " means the Internal Revenue Code of 1986, as amended.

7.15. "ComEd Key Manager Plan" means the ComEd Key Manager Long-Term Performance Plan, or any successor thereto.

7.16. " ERISA " means the Employee Retirement Income Security Act of 1974, as amended.

7.17. " Exchange Act " means the Securities Exchange Act of 1934, as amended.

7.18. " Good Reason " means:

(a) for purposes of Section 4 hereof,

(i) a material reduction of an Executive's salary unless such reduction is part of a policy, program or arrangement applicable to peer executives of the Company or of the Executive's business unit; and

(ii) with respect to an Executive whose title with respect to a Company is Senior Vice President or above, a material adverse reduction in the Executive's position or duties that is not applicable to peer executives of the Company or of the Executive's business unit, but excluding any change (A) resulting from a reorganization or realignment of all or a significant portion of the business, operations or senior management of the Company or of the business unit that employs the Executive or (B) that generally places the Executive in substantially the same level of responsibility. Notwithstanding the foregoing, no change in the position or level of officer to whom an Executive reports shall constitute grounds for Good Reason.

(b) for purposes of Section 5 hereof, the occurrence of any one or more of the following actions or omissions that occurs during a Post-Change Period or an Imminent Control Change Period:

(i) a material reduction of an Executive's salary, incentive compensation opportunity or aggregate benefits unless such reduction is part of a policy, program or arrangement applicable to peer executives (including peer executives of any successor to Exelon);

(ii) a material adverse reduction in the Executive's position, duties or responsibilities (excluding a change in the position or level of officer to whom the Executive reports), unless such reduction is part of a policy, program or arrangement applicable to peer executives (including peer executives of any successor to Exelon);

(iii) a relocation by more than 50 miles of (A) the Executive's primary workplace, or (B) the principal offices of Exelon or its successor (if such offices are such Executive's workplace), in each case without the Executive's consent; provided, however, in both cases of (A) and (B) of this subsection (b)(iv), such new location is farther from the Executive's residence than the prior location; or

(iv) a material breach of this Plan by Exelon or its successor.

(c) Application of "Good Reason" Definition During the Imminent Control Change Period . During the Imminent Control Change Period, "Good Reason" shall not include the events or conditions described in subsection (b)(i), (b)(ii) or (b)(iv) above unless the Imminent Control Change Period culminates in a Change Date.

(d) Limitations on Good Reason . Notwithstanding the foregoing provisions of this Section, no act or omission shall constitute a material breach of this Plan by Exelon, nor grounds for "Good Reason":

(i) unless the Executive gives the Plan Administrator a Notice of Termination at least 30 days prior to the Executive's Termination Date, and the Company fails to cure such act or omission within the 30-day period;

(ii) if the Executive first acquired knowledge of such act or omission more than 90 days before such Participant gives the Plan Administrator such Notice or Termination; or

(iii) if the Executive has consented in writing to such act or omission.

7.19. " Imminent Control Change " means, as of any date on or after the Effective Date and prior to the Change Date, the occurrence of any one or more of the following:

(a) Exelon enters into an agreement the consummation of which would constitute a Change in Control;

(b) Any SEC Person commences a "tender offer" (as such term is used in Section 14(d) of the Exchange Act) or exchange offer, which, if consummated, would result in a Change in Control; or

(c) Any SEC Person files with the SEC a preliminary or definitive proxy solicitation or election contest to elect or remove one or more members of the Board, which, if consummated or effected, would result in a Change in Control;

provided, however, that an Imminent Control Change will lapse and cease to qualify as an Imminent Control Change:

(i) With respect to an Imminent Control Change described in clause (a) of this definition, the date such agreement is terminated, cancelled or expires without a Change Date occurring;

(ii) With respect to an Imminent Control Change described in clause (b) of this definition, the date such tender offer or exchange offer is withdrawn or terminates without a Change Date occurring;

(iii) With respect to an Imminent Control Change described in clause (c) of this definition, (1) the date the validity of such proxy solicitation or election contest expires under relevant state corporate law, or (2) the date such proxy solicitation or election contest culminates in a shareholder vote, in either case without a Change Date occurring; or

(iv) The date a majority of the members of the Incumbent Board make a good faith determination that any event or condition described in clause (a), (b), or (c) of this definition no longer constitutes an Imminent Control Change, provided that such determination may not be made prior to the first anniversary of the occurrence of such event.

7.20. " Imminent Control Change Period " means the period commencing on the date of an Imminent Control Change, and ending on the first to occur thereafter of

(a) a Change Date, provided

(i) such date occurs no later than the first anniversary of the Termination Date, and

(ii) either the Imminent Control Change has not lapsed, or the Imminent Control Change in effect upon such Change Date is the last Imminent Control Change in a series of Imminent Control Changes unbroken by any period of time between the lapse of an Imminent Control Change and the occurrence of a new Imminent Control Change;

(b) the date an Imminent Control Changes lapses without the prior or concurrent occurrence of a new Imminent Control Change; or

(c) the first anniversary of the Termination Date.

7.21. " Incentive Plan " means the Exelon Corporation Annual Incentive Award Plan, or such other annual cash bonus arrangement of the Company in which the Executive is a participant in lieu of the Annual Incentive Award Plan, but excluding any supplemental incentive plans.

7.22. " including " means including without limitation.

7.23. " Incumbent Board "—see definition of Change in Control.

7.24. " LTIP " means the Exelon Corporation Long-Term Incentive Plan, as amended from time to time, or any successor thereto.

7.25. " LTIP Performance Period " means the performance period applicable to an LTIP award, as designated in accordance with the LTIP.

7.26. " LTIP Target Level " means, in respect of any grant of Performance Shares under the Exelon Long Term Performance Share Award Program under the LTIP, the number of Performance Shares which a Participant would have been awarded (prior to the Termination Date) for the LTIP Performance Period corresponding to such grant if the business and personal performance goals related to such grant were achieved at the 100% (target) level as of the end of the LTIP Performance Period.

7.27. " Merger "—see definition of Change in Control.

7.28. " Notice of Termination " means a written notice given by an Executive in accordance with Sections 7.18(d)(i) and 13.10 which sets forth in reasonable detail the specific facts and circumstances claimed to provide a basis for a Termination of Employment for Good Reason.

7.29. " Performance Shares "—see Section 5.1(c).

7.30. " Person " means any individual, sole proprietorship, partnership, joint venture, limited liability company, trust, unincorporated organization, association, corporation, institution, public benefit corporation, entity or government instrumentality, division, agency, body or department.

7.31. " Plan Administrator "—See Section 9.

7.32. " Post-Change Period " means the period commencing on a Change Date and ending on the earlier of (a) the Termination Date or (b) the second anniversary of such Change Date; provided that no duplicate benefits shall be paid with respect to simultaneous or overlapping Post-Change Periods.

7.33. " Restricted Stock "—see Section 5.1(d).

7.34. " Retiree " means a Participant who, as of his or her Termination Date, is eligible for "retirement" as defined in the LTIP.

7.35. " Salary Continuation Period " means the applicable period designated in Section 4.1 during which severance is payable.

7.36. " SEC " means the United States Securities and Exchange Commission.

7.37. " SEC Person " means any person (as such term is used in Rule 13d-5 of the SEC under the Exchange Act) or group (as such term is defined in Sections 3(a)(9) and 13(d)(3) of the Exchange Act), other than (a) Exelon or any Person that directly or indirectly controls, is controlled by, or is under common control with, Exelon (an " Affiliate "). For purposes of this definition the term "control" with respect to any Person means the power to direct or cause the direction of management or policies of such Person, directly or indirectly, whether through the ownership of Voting Securities, by contract or otherwise, or (b) any employee benefit plan (or any related trust) of Exelon or any of its Affiliates.

7.38. " Section " means, unless the context otherwise requires, a section of this Plan.

7.39. " Senior Executive Management " means (a) an Executive whose title with respect to Exelon is Executive Vice President or above, (b) an Executive whose title with respect to a Company other than Exelon is Chief Executive Officer or President, and (c) such other Executive who was described in subparagraph (a) or (b) and has been grandfathered by the Plan Administrator.

7.40. " SERP " means the Constellation Energy Group, Inc. Benefit Restoration Plan, the PECO Energy Company Supplemental Retirement Plan or the Exelon Corporation Supplemental Executive Retirement Plan, whichever is applicable to a Participant, or any successor thereto.

7.41. " Severance Incentive " means the Target Incentive for the performance period in which the Termination Date occurs; provided, however, that for purposes of Section 5, " Severance Incentive " shall mean the greater of (a) the Target Incentive for the performance period in which the Termination Date occurs, or (b) the average of the actual Annual Incentives paid (or payable, to the extent not previously paid) to a Participant under the Annual Incentive Award Plan for each of the two calendar years preceding the calendar year in which the Termination Date occurs.

7.42. " Severance Period " means the period beginning on a Participant's Termination Date, provided such Participant's Termination of Employment entitles such Participant to benefits under Section 5.1 or 5.2, and ending on the second anniversary thereof.

7.43. " Specified Employee " means a "specified employee" within the meaning of Section 409A of the Code.

7.44. " Stock Options "—see Section 5.1(b).

7.45. " Target Incentive " as of a certain date means an amount equal to the product of Base Salary determined as of such date multiplied by the percentage of such Base Salary (if any) to which a Participant would have been entitled immediately prior to such date under the Annual Incentive Award Plan for the applicable performance period if the performance goals established pursuant to such plan were achieved at the 100% (target) level as of the end of the applicable performance period; provided, however, that any reduction in a Participant's Base Salary or annual incentive that would qualify as Good Reason shall be disregarded for purposes of this definition.

7.46. " Taxes " means the incremental federal, state, local and foreign income, employment, excise and other taxes payable by a Participant with respect to any applicable item of income.

7.47. " Termination Date " means the effective date of an eligible Executive's Termination of Employment with the Company for any or no reason, which shall be the date on which such Executive has a "separation from service," within the meaning of Section 409A of the Code; provided, however, that if the Executive terminates his or her employment for Good Reason, the Termination Date shall not be earlier than the thirtieth day following the Company's receipt of such Executive's Notice of Termination, unless the Exelon consents in writing to an earlier Termination Date.

7.48. " Termination of Employment " means:

(a) a termination of an eligible Executive's employment by the Company for reasons other than for Cause; or

(b) a resignation by an eligible Executive for Good Reason.

The following shall not constitute a Termination of Employment for purposes of the Plan: (i) a termination of employment for Cause, (ii) an Executive's resignation for any reason other than for Good Reason, (iii) the cessation of an Executive's employment with the Company or any Affiliate due to death or disability (as determined by the Plan Administrator in good faith), or (iv) the cessation of an Executive's employment with the Company or any subsidiary thereof as the result of the sale, spin-off or other divestiture of a plant, division, business unit or subsidiary or a merger or other business combination followed by employment or reemployment with the purchaser or successor in interest to the Executive's employer with regard to such plant, division, business unit or subsidiary, or an offer of employment by such purchaser or successor in interest on terms and conditions comparable in the aggregate (as determined by the Plan Administrator in its sole discretion) to the terms and conditions of the Executive's employment with the Company or its subsidiary immediately prior to such transaction.

7.49. " 20% Owner "—see paragraph (a) of the definition of "Change in Control."

7.50. " Voting Securities " means with respect to a corporation, securities of such corporation that are entitled to vote generally in the election of directors of such corporation.

8. FUNDING

The Plan is an unfunded employee welfare benefit plan maintained for the purpose of providing severance benefits to a select group of management or highly compensated employees. Nothing in the Plan shall be interpreted as requiring the Company to set aside any of its assets for the purpose of funding its obligations under the Plan. No person entitled to benefits under the Plan shall have any right, title or claim in or to any specific assets of the Company, but shall have the right only as a general creditor to receive benefits from the Company on the terms and conditions provided in the Plan.

9. **ADMINISTRATION OF THE PLAN**

The Plan shall be administered on a day-to-day basis by the Vice President, Corporate Compensation of Exelon (the " Plan Administrator "). The Plan Administrator has the sole and absolute power and authority to interpret and apply the provisions of this Plan to a particular circumstance, make all factual and legal determinations, construe uncertain or disputed terms and make eligibility and benefit determinations in such manner and to such extent as the Plan Administrator, in his or her sole discretion may determine. Benefits under the Plan will be paid only if the Plan Administrator, in his or her discretion, determines that an individual is entitled to them; provided, however, that any dispute after the claims procedure under Section 10 has been exhausted regarding whether an Executive's termination of employment for purposes of Section 5 is based on either Good Reason or Cause may, at the election of the Executive, be submitted to binding arbitration pursuant to Section 11.

The Plan Administrator may promulgate any rules and regulations it deems necessary to carry out the purposes of the Plan or to interpret the terms and conditions of the Plan; provided, however, that no rule, regulation or interpretation shall be contrary to the provisions of the Plan. The rules, regulations and interpretations made by the Plan Administrator shall, where appropriate, be applied on a consistent basis with respect to similarly situated Executives, and shall be final and binding on any Executive or former Executive and any successor in interest.

The Plan Administrator may delegate any administrative duties, including, without limitation, duties with respect to the processing, review, investigation, approval and payment of severance pay and provision of severance benefits, to designated individuals or committees. The Plan Administrator may amend any Participant's Severance Agreement to the extent the Plan Administrator determines it is reasonably necessary or appropriate to do so to comply with section 409A of the Code.

10. **CLAIMS PROCEDURE**

The Plan Administrator shall determine the status of an individual as an Executive and the eligibility and rights of any Executive or former Executive as a Participant to any severance pay or benefits hereunder. Any Executive or former Executive who believes that he or she is entitled to receive severance pay or benefits under the Plan, including severance pay or benefits other than those initially determined by the Plan Administrator, may file a claim in writing with the Plan Administrator. Within 90 days after the receipt of the claim the Plan Administrator shall either allow or deny the claim in writing, unless special circumstances require an extension of time for processing, in which case a decision shall be rendered as soon as practicable, but not later than 180 days after receipt of a request for review.

A claimant whose claim is denied (or his or her duly authorized representative) may, within 60 days after receipt of the denial of his or her claim, request a review upon written application to Exelon's Chief Human Resources Officer or other officer designated by Exelon and specified in the claim denial; review (without charge) relevant documents; and submit written comments, documents, records and other information relating to the claim.

The Chief Human Resources Officer or other designated officer shall notify the claimant of his or her decision on review within 60 days after receipt of a request for review unless special circumstances require an extension of time for processing, in which case a decision shall be rendered as soon as possible, but not later than 120 days after receipt of a request for review. Notice of the decision on review shall be in writing. The officer's decision on review shall be final and binding on any claimant or any successor in interest.

In reviewing a claim or an appeal of a claim denial, the Plan Administrator and the Chief Human Resources Officer or other designated by Exelon shall have all of the powers and authority granted to the Plan Administrator pursuant to Section 9.

11. ARBITRATION

Any dispute, controversy or claim between the parties hereto concerning whether an Executive's termination of employment for purposes of Section 5 is based on either Good Reason or Cause may, after the claims procedure under Section 10 has been exhausted and at the election of the Executive, be settled by binding arbitration in Chicago, Illinois, before an impartial arbitrator pursuant to the rules and regulations of the American Arbitration Association (" AAA ") pertaining to the arbitration of employee benefit plan disputes. The costs and fees of the arbitrator shall be borne equally by the parties, regardless of the result of the arbitration. No arbitration shall be commenced after the date when institution of legal or equitable proceedings based upon such subject matter would be barred by the applicable statutes of limitations. Notwithstanding anything to the contrary contained in this Section or elsewhere in this Plan, any party may seek relief in the form of specific performance, injunctive or other equitable relief in order to enforce the decision of the arbitrator, and the Company may seek injunctive relief to enforce the above-referenced statutes of limitations.

12. AMENDMENT OR TERMINATION OF PLAN

Exelon's Chief Human Resources Officer or another designated officer of the Company may amend, modify or terminate the Plan at any time by written instrument; provided, however, that no amendment, modification or termination shall deprive any Participant of any payment or benefit that the Plan Administrator previously has determined is payable under the Plan. Notwithstanding the foregoing, no amendment or termination that reduces the severance payments or materially adversely affects any Participant's other benefits under Section 5 shall become effective as to such Participant during: (a) the 24-month period following a Change Date or (b) during an Imminent Control Change Period (unless such Participant consents to such termination or amendment). Any purported Plan termination or amendment in violation of this Section 12 shall be void and of no effect.

13. MISCELLANEOUS

13.1. Limitation on Rights . Participation in the Plan is limited to the individuals described in Sections 2 and 3, and the benefits under the Plan shall not be payable with respect to any voluntary or involuntary termination of employment that is not a Termination of Employment.

13.2. Cooperation By Participants . During the Salary Continuation Period or Severance Period, as applicable, the Executive shall (a) be reasonably available to the Company to respond to requests by them for information pertaining to or relating to matters which may be within the knowledge of the Executive and (b) cooperate with the Company in connection with any existing or future litigation or other proceedings brought by or against the Company, its subsidiaries or affiliates, to the extent the Company deems the Executive's cooperation reasonably necessary.

13.3. No Set-off by Company . This Section shall apply solely with respect to a Termination of Employment during a Post-Change Period or an Imminent Control Change Period that culminates in a Change Date. Except as provided in Section 6, a Participant's right to receive when due the payments and other benefits provided for under Section 5 of this Plan is absolute, unconditional and subject to no setoff, counterclaim or legal or equitable defense.

13.4. No Mitigation . A Participant shall not have any duty to mitigate the amounts payable by the Company under this Plan by seeking new employment following termination. Except as specifically otherwise provided in this Plan, all amounts payable pursuant to this Plan shall be paid without reduction regardless of any amounts of salary, compensation or other amounts which may be paid or payable to the Executive as the result of the Executive's employment by another, unaffiliated employer.

13.5. Headings . Headings of sections in this document are for convenience only, and do not constitute any part of the Plan.

13.6. Severability . If any one or more Sections, subsections or other portions of this Plan are declared by any court or governmental authority to be unlawful or invalid, such unlawfulness or invalidity shall not serve to invalidate any Section, subsection or other portion not so declared to be unlawful or invalid. Any Section, subsection or other portion so declared to be unlawful or invalid shall be construed so as to effectuate the terms of such Section, subsection or other portion to the fullest extent possible while remaining lawful and valid. Notwithstanding the foregoing, in the event a determination is made that the Restrictive Covenants are invalid or unenforceable in whole or in part, then the Severance Agreement with respect to the Participant subject to such determination shall be void and the Company shall have no obligation to provide benefits under this Plan to such Participant.

13.7. Governing Law . The Plan shall be construed and enforced in accordance with the applicable provisions of ERISA and Section 409A of the Code.

13.8. No Right to Continued Employment . Nothing in this Plan shall guarantee the right of a Participant to continue in employment, and the Company retains the right to terminate a Participant's employment at any time for any reason or for no reason.

13.9. Successors and Assigns . This Plan shall be binding upon and inure to the benefit of Exelon and its successors and assigns and shall be binding upon and inure to the benefit of a Participant and his or her legal representatives, heirs and legatees.

Exelon shall cause any successor to assume the Plan. No rights, obligations or liabilities of a Participant hereunder shall be assignable without the prior written consent of Exelon Corporation. In the event of the death of a Participant prior to receipt of severance pay or benefits to which he or she is entitled hereunder (and, with respect to benefits under Section 4 or Section 5, after he or she has signed the Waiver and Release), the severance pay described in Sections 4.1, 5.1, or 5.2, as applicable, shall be paid to his or her estate, and the Participant's dependents who are covered under any health care plans maintained by the Company shall be entitled to continued rights under Section 4.5 or Section 5.1(e) or Section 5.2(g), as applicable; provided that the estate or other successor of the Participant has not revoked such Waiver and Release.

13.10. Notices . All notices and other communications under this Plan shall be in writing and delivered by hand, by nationally-recognized delivery service that promises overnight delivery, or by first-class registered or certified mail, return receipt requested, postage prepaid, addressed as follows:

If to a Participant, to such Participant at his most recent home address on file with the Company.

If to the Company: to the Plan Administrator.

or to such other address as either party shall have furnished to the other in writing. Notice and communications shall be effective when actually received by the addressee.

13.11. Number and Gender . Wherever appropriate, the singular shall include the plural, the plural shall include the singular, and the masculine shall include the feminine.

13.12. Tax Withholding . The Company may withhold from any amounts payable under this Plan or otherwise payable to a Participant or beneficiary any Taxes the Company determines to be appropriate under applicable law and may report all such amounts payable to such authority in accordance with any applicable law or regulation.

13.13. Section 409A . This Plan shall be interpreted and construed in a manner that avoids the imposition of additional taxes and penalties under Section 409A of the Code ("409A Penalties"). In the event the terms of this Plan would subject a Participant to 409A Penalties, the Company may amend the terms of the Plan to avoid such 409A Penalties, to the extent possible. The payments to a Participant pursuant to this Plan are intended to be exempt from Section 409A of the Code to the maximum extent possible, under either the separation pay exemption pursuant to Treasury regulation §1.409A-1(b)(9)(iii) or as a short-term deferral pursuant to Treasury regulation §1.409A-1(b)(4), and for purposes of the separation pay exemption, each installment paid to a Participant shall be considered a separate payment. Notwithstanding any other provision in this Plan, if on the date of a Participant's Termination Date the Participant is a Specified Employee, then to the extent any amount payable under this Plan constitutes the payment of

nonqualified deferred compensation, within the meaning of Section 409A of the Code, that under the terms of this Plan would be payable prior to the six-month anniversary of the Termination Date, such payment shall be delayed until the earlier to occur of (A) the six-month anniversary of the Termination Date or (B) the date of the Participant's death. Any reimbursement (including any advancement) payable to a Participant pursuant to this Plan shall be conditioned on the submission by the Participant of all expense reports reasonably required by the Company under any applicable expense reimbursement policy, and shall be paid to the Participant within 30 days following receipt of such expense reports (or invoices), but in no event later than the last day of the calendar year following the calendar year in which the Participant incurred the reimbursable expense. Any amount of expenses eligible for reimbursement during a calendar year shall not affect the expenses eligibility for reimbursement during any other calendar year. The right to reimbursement pursuant to this Plan shall not be subject to liquidation or exchange for any other benefit.

EXELON CORPORATION

By: _____

Amy E. Best
Senior Vice President and
Chief Human Resources Officer

PENSION PLAN
OF
CONSTELLATION ENERGY GROUP, INC.

(Amended and Restated Effective January 31, 2012)

PENSION PLAN

OF

CONSTELLATION ENERGY GROUP, INC.

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INTRODUCTION

The Plan, which was initially effective on January 1, 1948, was amended and restated effective January 1, 2000 to include the Pension Equity formula, and has been amended and restated from time to time thereafter. The Plan was restated on January 22, 2007, effective January 1, 2000, to incorporate all amendments made since January 1, 2000. The plan was amended and restated on January 30, 2012, effective January 31, 2012, to incorporate all amendments made since the prior restatement.

ARTICLE I—Participation

1.1 Automatic PEP Participation —Except as provided in 1.2, each Full-Time Employee of the Company, or of those subsidiaries and affiliates of the Company which are designated by the Board of Directors (as reflected in Appendix G), shall become a Participant in PEP on the date he/she becomes a Full-Time Employee. (Notwithstanding the previous sentence, effective July 23, 2010, Executive Group may designate such subsidiaries and affiliates if such designations have less than a $10 million impact on the Plan's accumulated benefit obligation per designation. At least annually, the Company's Chief Executive Officer shall report all such subsidiary and affiliate designations to the Board of Directors. An Employee classified in a job description as an On-Call Employee, a leased employee within the meaning of Code Section 414(n)(2), or a co-op, work study or summer Employee shall not become a Participant in the Plan while classified in the sole judgment of the Employer as an On-Call Employee, a leased employee, or a co-op, work study or summer Employee.

1.2 Election: Traditional Pension Plan or PEP — Each individual who is both a Participant on December 31, 1999 and an Employee on January 1, 2000 shall elect in the manner determined by the Plan Administrator to participate in either PEP or the Traditional Pension Plan. Each individual who is a Participant on December 31, 1999 and who has a Severance From Service Date on December 31, 1999, and who, at the Severance From Service Date, had attained age 55 and completed at least 20 years of Credited Service shall elect in the manner determined by the Plan Administrator to participate in either PEP or the Traditional Pension Plan. Such Participant shall make his/her election on or after January 1, 2000 and on or before the earlier of June 30, 2000 or his/her Benefit Commencement Date. The last election made on or before the earlier of June 30, 2000 or his/her Benefit Commencement Date is irrevocable, except that, in the case of a Participant whose Severance From Service Date is on or after January 1, 2000 and on or before June 30, 2000 the first election made after the Severance From Service Date is irrevocable. Any election shall be effective as of January 1, 2000. Notwithstanding anything above, any Participant who does not affirmatively make a valid election on or before June 30, 2000 will participate in PEP effective January 1, 2000.

ARTICLE II—Types of Retirement

2.1 Normal Retirement: Generally —A Participant who, on the day preceding his/her Normal Retirement Date, is actively employed or a Disabled Participant and has at least five years of Credited Service, is eligible for Normal Retirement.

2.1(a) Effective Date —Normal Retirement is effective as of the first day of the month following a Participant's Severance From Service Date, or if later, the date a Disabled Participant ceases receiving benefits under the Disability Plan.

2.2 Early Retirement: Generally —A Participant who, on his/her Severance From Service Date, is at least age 55, and has at least ten years of Credited Service, is eligible for Early Retirement.

2.2(a) Effective Date —Early Retirement is effective as of the first day of the month designated in writing by the Participant, which is after the date that the Participant becomes eligible for Early Retirement, and not later than the Participant's Normal Retirement Date. Such written designation must be received by the Plan Administrator before the beginning of the designated month. If a written designation is not received, Early Retirement will be effective on the Participant's Normal Retirement Date.

2.3 Disability Retirement: Traditional Pension Plan —A Disabled Participant who (i) prior to receiving benefits under the Disability Plan, has at least ten years of Credited Service, and (ii) is at least age 50 but has not yet reached age 65 when he/she is determined to be no longer disabled under the terms of the Disability Plan, is eligible for Disability Retirement in the Traditional Pension Plan.

2.3(a) Effective Date —Disability Retirement in the Traditional Pension Plan is effective on the first day of the month designated in writing by the Participant, which is after the date that the Participant becomes eligible for Disability Retirement, and not later than the Participant's Normal Retirement Date. Such written designation must be received by the Plan Administrator before the beginning of the designated month. If a written designation is not received, Disability Retirement will be effective on the Participant's Normal Retirement Date.

ARTICLE III—Pension Payments

3.1(a) Form of Pension Payments: Traditional Pension Plan —Except as provided in 3.3(h), all pension payments to Participants in the Traditional Pension Plan are paid in monthly installments.

3.1(b) Form of Pension Payments: PEP —Except as provided in 3.3(h), all pension payments to Participants in PEP are paid in monthly installments unless the Participant elects, within 60 days of the Participant's Severance From Service Date and in the manner determined by the Plan Administrator, a payment in the form of a lump sum.

3.2 Timing of Pension Payments: Traditional Pension Plan —Except as provided in 3.3(h), pension payments to Participants in the Traditional Pension Plan commence as of the applicable effective date set forth in Article II.

3.2(a) Timing of Pension Payments: PEP —Except as provided in 3.3(h), pension payments to Participants in PEP commence as of the applicable effective date set forth in Article II unless the Participant elects, within 60 days of the later of (i) the date of the letter provided by the Plan Administrator to the Participant that describes the Participant's Plan distribution options or (ii) the Participant's Severance From Service Date, and in the manner determined by the Plan Administrator, to receive a lump sum or to commence to receive monthly installments as of the first day of the month following the Participant's Severance From Service Date.

3.2(b) Timing of Pension Payments: Active Employees —Pension payments to a Participant who is an Employee and who attains age 70 $^{1}/_{2}$ before January 1, 2000, shall commence on April 1 of the year following the year during which the Participant attains age 70 $^{1}/_{2}$. The pension payments will be recalculated and increased if appropriate as of

each January 1 (and as of the Participant's Severance From Service Date) to reflect increases in the Normal Retirement Service Percentage and changes in Final Average Pay in the case of a Participant in the Traditional Pension Plan, and to reflect increases in Total Pension Credits and changes in Final Average Annual Pay in the case of a Participant in PEP.

Pension payments to a Participant who is an Employee and who attains age 70 $^{1}/_{2}$ after December 31, 1999 shall commence as of the first day of the month following the Participant's Severance From Service Date. The pension payments of a Participant in the Traditional Pension Plan will be actuarially increased to reflect the period described below during which the Participant does not receive any payments under the Plan. The period begins on the April 1 of the year following the year during which the Participant attains age 70 $^{1}/_{2}$ and ends on the Benefit Commencement Date. The actuarial increase shall be calculated based on the interest rate and mortality table used in determining Present Value.

Notwithstanding the foregoing, pension payments to a Participant who owns more than 5 percent of the outstanding stock of an Employer or stock possessing more than 5 percent of the total combined voting power of all stock of an Employer, shall commence on April 1 of the year following the year during which the Participant attains age 70 $^{1}/_{2}$.

The pension payments of a Participant in the Traditional Pension Plan who is employed after Normal Retirement Date shall be actuarially increased to reflect any month in which the Participant completes an hour of service described in Section 202(a)(3)(B) of ERISA on fewer than eight days. The actuarial increase shall be calculated based on the interest rate and mortality table used in determining Present Value.

Notwithstanding any provision in the Plan to the contrary, all distributions from the Plan, including distributions under Article V of the Plan, shall be made in accordance with Code Section 401(a)(9) and the regulations thereunder, including the incidental benefit requirement of Section 1.401(a)(9)-2 of the Proposed Income Tax Regulations.

3.2(c) Timing of Pension Payments: Mandatory Commencement —Notwithstanding anything in the Plan to the contrary, unless the Participant otherwise elects, pension payments to the Participant will begin not later than 60 days after the latest of the close of the Plan Year in which (i) occurs the date on which the Participant attains the earlier of age 65 or the Participant's Normal Retirement Date; (ii) occurs the 10 th annual anniversary of the year in which the Participant commenced participation in the Plan; or (iii) the Participant terminates service with the Employer.

3.2(d) Cessation of Pension Payments —Except as provided in Article V, monthly pension payments shall permanently cease upon the death of the Participant, effective with the pension payment for the month following the month of the Participant's death. Monthly pension payments shall cease upon the Employer's reemployment of a Participant as an Employee. Upon the Participant's subsequent termination of employment with the Employer, the Participant's Gross Pension shall be recalculated and adjusted (including the adjustment described in 3.4(a)) and the Participant shall be given a new election with respect to the form and timing of his/her pension payments if such election otherwise would be available to the Participant.

3.3 Amount of Pension Payments —The pension payments to which a Participant is entitled are calculated based on the Participant's Gross Pension, adjusted as provided in 3.4. The calculation of a Participant's Gross Pension is different depending upon the type of retirement to which the Participant is entitled.

3.3(a) Normal Retirement in the Traditional Pension Plan —The Gross Pension of a Participant in the Traditional Pension Plan entitled to Normal Retirement is calculated as follows:

Gross Pension	=	Normal Retirement Service Percentage	X	Final Average Pay

3.3(b) Early Retirement in the Traditional Pension Plan —The Gross Pension of a Participant in the Traditional Pension Plan entitled to Early Retirement is calculated as follows:

Gross Pension	=	Normal Retirement Service Percentage	X	Final Average Pay	X	Early Retirement Adjustment Factor

3.3(c) Disability Retirement in the Traditional Pension Plan —The Gross Pension of a Participant in the Traditional Pension Plan entitled to Disability Retirement is calculated as follows:

Gross Pension	=	Normal Retirement Service Percentage	X	Final Average Pay	X	Early Retirement Adjustment Factor

Notwithstanding the foregoing calculation, the Gross Pension shall not be less than the lesser of 20% of Final Average Pay, or the Gross Pension the Participant would be entitled to if he/she worked until his/her Normal Retirement Date and had the same Final Average Pay.

3.3(d) Termination Benefits in the Traditional Pension Plan —The Gross Pension of a Participant in the Traditional Pension Plan who has a Severance From Service Date before the Participant is eligible for Normal Retirement, Early Retirement or Disability Retirement, but after accumulating at least five years of Vesting Service (effective January 1, 2008, three years of Vesting Service), is equal to the Participant's Gross Pension as described in 4.1.

Except as provided in 3.3(h), such pension payments shall commence as of the Participant's Normal Retirement Date and, except as provided in 3.3(h), shall be made in monthly installments. If the Participant has, however, at least ten years of Credited Service prior to the Participant's Severance From Service Date, then such pension payments shall commence as of the first day of the month designated in writing by the Participant. The month so designated must be a month (i) no earlier than the month following the attainment of age 55, and (ii) no later than the Participant's Normal Retirement Date. Such written designation must be received by the Plan Administrator before the beginning of the designated month. If a written designation is not received, such pension payments will commence as of the Participant's Normal Retirement Date. Such pension payments are subject to the adjustment under the early receipt provisions set forth in 3.4(c).

3.3(e) Lump Sum in PEP —The Gross Pension of a Participant in PEP who elects an immediate lump sum is calculated as follows:

Gross Pension = Total Pension Credits X Final Average Annual Pay

Notwithstanding the foregoing, the Gross Pension shall not be less than the Present Value of the Participant's Accrued Gross Pension which would have been payable as of the Participant's Normal Retirement Date based on the Participant's Final Average Pay and Credited Service as of December 31, 1999, the definition of Present Value and Accrued Gross Pension in the Plan in effect on January 1, 2000, and the other provisions of the Plan in effect on December 31, 1999. Also, the Gross Pension shall not be less than the Present Value of the deferred annuity under 3.3(g) that would be payable as of the Participant's Normal Retirement Date. If the Participant is subsequently reemployed by the Employer, the Participant shall not be given the option to repay the lump sum payment.

3.3(f) Immediate Annuity in PEP — The Gross Pension of a Participant in PEP who elects an immediate annuity is calculated as 1/12 of the following:

Gross Pension = Total Pension Credits X Final Average Annual Pay **X** Annuity Factor

Notwithstanding the foregoing, the Gross Pension of a Participant who is eligible for Early Retirement or Normal Retirement shall not be less than the Participant's Accrued Gross Pension which would have been payable as of the Benefit Commencement Date based on the Participant's Final Average Pay and Credited Service as of December 31, 1999, the definition of Accrued Gross Pension in the Plan in effect on January 1, 2000, and the other provisions of the Plan in effect on December 31, 1999.

3.3(g) Deferred Annuity in PEP —The Gross Pension of a Participant in PEP who elects a deferred annuity is calculated as 1/12 of the following:

Gross Pension	=	Total Pension Credits	X	Final Average Annual Pay	X	Deferred Annuity Factor	X	Annuity Factor

Notwithstanding the foregoing, the Gross Pension shall not be less than the Participant's Accrued Gross Pension which would have been payable as of the Benefit Commencement Date based on the Participant's Final Average Pay and Credited Service as of December 31, 1999, the definition of Accrued Gross Pension in the Plan in effect on January 1, 2000, and the other provisions of the Plan in effect on December 31, 1999.

3.3(h) Automatic Lump Sum Cash-Out —Notwithstanding anything in the Plan to the contrary, an immediate lump sum payment, in lieu of monthly payments will be made to a Participant (i) in the Traditional Pension Plan, if the Present Value of the Participant's Gross Pension, computed as of the Severance From Service Date, does not exceed $1,000, and (ii) in PEP, if the PEP Gross Pension lump sum under 3.3(e), computed as of the Severance From Service Date, does not exceed $1,000. If the Participant is subsequently reemployed by the Employer, the Participant shall not be

given the option to repay the lump sum payment. No payment shall be made from the Traditional Pension Plan, if the Present Value of the Participant's Gross Pension, computed as of the Severance From Service Date, equals or exceeds $1,000, or the PEP, if the PEP Gross Pension lump sum under 3.3(e), computed as of the Severance From Service Date, equals or exceeds $1,000, absent the Participant's affirmative consent prior to the Participant's Normal Retirement Date.

3.4 Miscellaneous Gross Pension Calculation Provisions

3.4(a) Reemployment —As described in 3.2(d), monthly pension payments shall cease upon the Employer's reemployment of a Participant as an Employee, and the Participant's Gross Pension shall be recalculated and adjusted upon the Participant's subsequent termination of employment with the Employer. The Gross Pension of the Participant upon subsequent termination of employment shall be reduced by the value of monthly pension payments received prior to reemployment. The value shall be determined based on the interest rate and mortality table described in Present Value as of the Benefit Commencement Date following the subsequent termination of employment.

3.4(b) Adjustment for Part-Time Schedule —If a Traditional Pension Plan Participant worked a Part-Time Schedule at any time during the period that the Participant was accumulating Credited Service, the Participant's Average Pay described in A-9(i) shall be adjusted by multiplying such Average Pay described in A-9(i) by the following fraction:

Total of Participant's Regularly Scheduled Hours per Workweek During 35 Years of Credited Service With Highest Number of Regularly Scheduled Hours Total of All Regularly Scheduled Hours in Same Period of Credited Service Assuming Workweek of Standard Length Not in Excess of 40 Hours

If a PEP Participant worked a Part-Time Schedule at any time during the period that the Participant was accumulating Credited Service, the Participant's Gross Pension shall equal the sum of (i) the Participant's Total Pension Credits, adjusted as described below, times that portion of the Participant's Average Annual Pay described in A-8(i), and (ii) the Participant's Total Pension Credits, not adjusted as described below, times that portion of the Participant's Average Annual Pay described in A-8(ii). The Participant's Total Pension Credits shall equal the sum of the amounts attributable to each age category in the definition of Total Pension Credits times the following fraction in each age category:

Total of Participant's Regularly Scheduled Hours per Workweek During Years of Credited Service in Each Age Category Total of All Regularly Scheduled Hours in Same Period of Credited Service Assuming Workweek of Standard Length Not in Excess of 40 Hours

For the purposes of computing the Gross Pension of a Participant who worked a Part-Time Schedule, base rate of pay shall be adjusted to reflect a 40-hour workweek.

3.4(c) Adjustment For Early Receipt in Traditional Pension Plan —If a Participant in the Traditional Pension Plan who is entitled to pension payments under 3.3(d) elects to begin receipt of his/her monthly pension payments prior to the date that the Participant attains age 65, the Participant's Gross Pension shall be reduced to offset the cost of early receipt. Such reduction shall be determined in accordance with the table included in Appendix E.

3.4(d) Adjustment For Survivor Annuity Coverage —A Participant's Gross Pension in the Traditional Pension Plan shall be reduced to offset the cost of providing (i) additional Preretirement Survivor Annuity coverage, and (ii) any Post-retirement Survivor Annuity coverage. A Participant's Gross Pension in PEP shall be reduced to offset the cost of providing any Post-retirement Survivor Benefit coverage. Post-retirement Survivor Annuity and Post-retirement Survivor Benefit coverage reductions shall be determined in accordance with the table included in Appendix F. Preretirement Survivor Annuity coverage reductions shall be determined in accordance with the table included in Appendix H.

3.4(e) Benefit and Benefit Accrual Limitations . Notwithstanding any other provision of the Plan to the contrary, the Gross Pension accrued on behalf of and provided to a Participant under the Plan shall at all times comply with applicable benefit payment and accrual limitations in accordance with Section 401(a)(29) of the Code.

3.5 Severance Plan Payments —Notwithstanding any other provision in the Plan or any Appendix to the contrary, the Gross Pension for a Participant in the PEP who receives severance payments under the Constellation Energy Group, Inc. Severance Plan shall not be less than the "minimum amount" which is the amount of the Participant's Gross Pension as of the Participant's Severance From Service Date based on (i) the Participant's Final Average Annual Pay as of the Participant's Severance From Service Date; (ii) the Participant's age projected to the Participant's Severance End Date (but not older than the greater of the Participant's actual age on the Participant's Severance From Service Date or 65); and (iii) the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date, and for a Participant who (x) elects an immediate or deferred annuity, the "minimum amount" shall be computed assuming that the Annuity Factor used to convert the PEP Gross Pension lump sum to an annuity is based on the Participant's age and

Credited Service as of the Participant's Severance End Date and that the Annual Interest Rate used will be as specified by the Plan (i.e., based on the Participant's Severance From Service Date); and (y) elects a deferred annuity to commence later than the first of the month following the Participant's Severance From Service Date the "minimum amount" shall be computed assuming a Deferred Annuity Factor of 1. For purposes of computing the "minimum amount", any reduction for Survivor Annuity coverage will be based on the factors specified by the Plan using the Participant's and the spouse's or the beneficiary's age as of the Participant's Benefit Commencement Date.

Notwithstanding any other provision in the Plan or any Appendix to the contrary, the Gross Pension for a Participant in the Traditional Pension Plan who receives severance payments under the Constellation Energy Group, Inc. Severance Plan shall not be less than the "minimum amount" which is the amount of the Participant's Gross Pension as of the Participant's Severance From Service Date based on (i) the Participant's Final Average Pay as of the Participant's Severance From Service Date (ii) the Participant's age projected to the Participant's Severance End Date (but not older than the greater of the Participant's actual age on the Participant's Severance From Service Date or 65); and (iii) the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date, and for a Participant who (x) is eligible for Normal Retirement based on the Participant's age projected to the Participant's Severance End Date and based on the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date, for purposes of computing the "minimum amount" the Participant's Benefit Commencement Date shall be assumed to be the later of the first of

the month following the Participant's Severance from Service Date or the Participant's Normal Retirement Date; (y) is eligible for Early Retirement based on the Participant's age projected to the Participant's Severance End Date and based on the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date, for purposes of computing the "minimum amount" the Participant's Benefit Commencement Date shall be assumed to be the first of the month following the Participant's Severance End Date for purposes of determining the Early Retirement Adjustment Factor; and (z) is not eligible for Normal Retirement or Early Retirement based on the Participant's age projected to the Participant's Severance End Date and based on the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date, for purposes of computing the "minimum amount" the Participant's Benefit Commencement Date shall be assumed to be the earliest possible date permitted under the Plan based on the Participant's age projected to the Participant's Severance End Date and based on the Participant's Credited Service and Vesting Service computed assuming the Participant were employed until the Participant's Severance End Date. For purposes of computing the "minimum amount", any reduction for Survivor Annuity coverage will be based on the factors specified by the Plan using the Participant's and the spouse's age as of the Participant's Benefit Commencement Date.

For purposes of calculating the "minimum amount" above, Severance End Date means the last day of the month that includes the end of the severance period under the Constellation Energy Group, Inc. Severance Plan (notwithstanding the termination of the receipt severance benefits due to the Participant's return to employment).

A Participant's "minimum amount" shall be payable on any Benefit Commencement Date allowable under the Plan without regard to this 3.5.

Except as expressly set forth above in this 3.5, this 3.5 will not affect any other provision of the Plan or the Appendix relating to the calculation of a Participant's benefit, including the Severance From Service Date, Final Average Annual Pay, Final Average Pay, the Deferred Annuity Factor, the adjustment for survivor coverage under 3.4(d), or the Annual Interest Rate.

This 3.5 is effective for Participants who commence receiving benefits under the Constellation Energy Group, Inc. Severance Plan on or after June 1, 2003.

ARTICLE IV — Gross Pension Calculation and Vesting

4.1 Termination Gross Pension Calculation and Service: Traditional Pension Plan —The Gross Pension of a Participant in the Traditional Pension Plan who has a Severance From Service Date before the Participant is eligible for Normal Retirement, Early Retirement or Disability Retirement, but after accumulating at least five years of Vesting Service (effective January 1, 2008, three years of Vesting Service), is calculated as follows:

$$\text{Gross Pension} = \frac{\text{Projected Gross Pension at Normal Retirement Date}}{\text{Projected Credited Service from the Date of hire to Normal Retirement Date}} \times \text{Credited Service from Date of Hire to Calculation Date}$$

In computing the "projected Gross Pension at Normal Retirement Date," it will be assumed that a Participant in the Traditional Pension Plan will continue to work for the Employer until the Participant's Normal Retirement Date, and that the Participant's Final Average Pay at such date will be equal to the Participant's Average Pay as of the calculation date. If the Participant works a Part-Time Schedule as of the calculation date, it will be assumed that the Participant will continue to work a Part-Time Schedule until the Participant's Normal Retirement Date for purposes of the computation.

4.2 Vested Right to Receive a Pension: Generally —A Participant will have a nonforfeitable right to receive a pension under the Plan if he/she has completed at least five years of Vesting Service (effective January 1, 2008, three years of Vesting Service), or is an Employee on or after the later of age 65, or the date which is the fifth anniversary of the Participant's Employment Commencement Date (or, if applicable, the Adjusted Employment Commencement Date).

4.3 Credited Service —Credited Service accumulated by a Participant is used in the computation of a Participant's Gross Pension. Under the Traditional Pension Plan, Participant's Credited Service is equal to the aggregate of all time periods, while classified as a Full-Time Employee, that commence with the Employment Commencement Date (or, if applicable, the Adjusted Employment Commencement Date) and end with the Severance From Service Date. Under PEP, a Participant's Credited Service is equal to the number of months during which an Employee works at least one hour while classified as a Full-Time Employee. Service while an Employee of a subsidiary or affiliate of the Company that is not designated by the Board of Directors (as reflected in Appendix G) under 1.1 shall not be counted in determining Credited Service. Service while an Employee of a subsidiary or affiliate of the Company that is designated by the Board of Directors (as reflected in Appendix G) under 1.1 shall be counted in determining Credited Service only if the Employee is eligible to participate in the Plan because of such service. Credited Service shall not be given to an Employee while classified by the Employer as a leased employee described in Code Section 414(n) or a co-op, work study or summer Employee. Credited Service shall be accumulated in whole years and twelfths of a year.

Notwithstanding the foregoing, a Participant who has at least ten years of Credited Service prior to the date as of which the Participant first receives benefits under the Disability Plan, and who becomes a Disabled Participant on or after January 1, 1994, will continue to accrue Credited Service while a Disabled Participant. The pension

payments made on and after August 1, 1999 on behalf of such a Participant who had a Severance From Service Date before January 1, 2000 shall be adjusted to reflect the accruing of Credited Service while a Disabled Participant. The pension payments made on and after August 1, 1999 on behalf of such a Participant who had a Severance From Service Date before January 1, 2000 shall also be adjusted so that the payments are no less than the amount the pension payments would be if the provisions of 3.3(c) had been applicable at the time of such Severance From Service Date.

4.4 Vesting Service —Vesting Service accumulated by a Participant is used in the determination of whether a Participant has a vested right to receive pension payments. A Participant's Vesting Service is determined using the elapsed time method. Under the elapsed time method, the Participant is credited with service equal to the aggregate of all time periods that commence with the Employment Commencement Date (or, if applicable, the Adjusted Employment Commencement Date) and end with the Severance From Service Date.

If a Participant is reemployed within one year from his/her Severance From Service Date, the Participant shall be deemed to have been continuously employed by the Employer during such period, but only for purposes of accumulating Vesting Service. If a Participant dies while performing qualified military service (within the meaning of Section 414(u)(5) of the Code), such Participant shall be credited with Vesting Service for the period of his qualified military service.

4.5 Forfeiture and Restoration of Credited Service and Vesting Service —Once a Participant has at least five years of Vesting Service (effective January 1, 2008, three years of Vesting Service), all Credited Service and Vesting Service, including all subsequently accumulated Credited Service and Vesting Service, is exempt from forfeiture. If an Employee's Severance From Service Date occurs while he/she is zero percent vested under the Plan, such Employee's Credited Service and Vesting Service accumulated prior to such Severance From Service Date shall be forfeited. All amounts so forfeited by a Participant who has a Severance From Service Date shall be deemed distributed to the Participant as of the Participant's Severance From Service Date for purposes of determining whether the Participant received a distribution of his/her entire accrued benefit under the Plan. Any forfeited Credited Service and Vesting Service shall be restored upon reemployment, if the period of time elapsed between the Severance From Service Date and the date of reemployment does not exceed five Plan Years.

Notwithstanding the foregoing, a Participant who received a lump sum payment under 3.3(e) or 3.3(h) shall not be entitled to restoration of Credited Service accumulated prior to the termination of employment that gave rise to the lump sum payment.

Notwithstanding the foregoing, for purposes of computing Credited Service and Vesting Service, the Severance From Service Date of an Employee who is absent from service beyond the first anniversary of the first day of absence by reason of a maternity or paternity absence, is the second anniversary of the first day of such absence. The period of time between the first and second anniversaries of the first day of absence from work is neither a period of service nor a period of severance.

4.6 Military Service —Notwithstanding any provision of this Plan to the contrary, benefits and service credit with respect to qualified military service will be provided in accordance with Code Section 414(u). Effective January 1, 2007, in the case of a Participant who dies while performing qualified military service (as defined in Code Section 414(u)), the survivors of the Participant are entitled to any additional benefits (other than benefit accruals relating to the period of military service) provided under the Plan had the Participant resumed and then terminated employment on account of death.

ARTICLE V—Survivor Coverage

5.1 Preretirement Survivor Annuity: Traditional Pension Plan

5.1(a) Eligibility —If a Participant in the Traditional pension Plan with a vested right to receive a pension dies before the Participant's Benefit Commencement Date (i) the Surviving Spouse or (ii) the Alternate Beneficiary (for a Participant who is not married on his/her date of death or who is married, and who has the appropriate spousal waiver and who names an Alternate Beneficiary that does not predecease the Participant) will be entitled to a Preretirement Survivor Annuity.

A Traditional Plan Participant may name more than one Alternate Beneficiary for a Preretirement Survivor Annuity. If more than one Alternate Beneficiary is named, the Participant must designate the percentage of Preretirement Survivor Annuity attributable to each recipient by delivering an Appropriate Request to the Plan Administrator.

For a Participant who is not married and who either does not name an Alternate Beneficiary or names one or more Alternate Beneficiaries and such Alternate Beneficiary (ies) predeceases the Participant, the default beneficiary for the Preretirement Survivor Annuity will be the Participant's beneficiary under the Company's employee life insurance plan

5.1(b) Value of Coverage —The Preretirement Survivor Annuity is equal to 50% of the deceased Participant's adjusted Gross Pension. The deceased Participant's Gross Pension is adjusted in accordance with the early receipt provisions set forth in 3.4(c) to the extent the Surviving Spouse's Benefit Commencement Date or the Alternate Beneficiary's Benefit Commencement Date is before the Participant's Normal Retirement Date and is permanently reduced for the cost of providing the contingent annuitant reduction factors pursuant to Appendix F.

5.1(c) Duration of Coverage —Coverage under 5.1(b) commences as of the date that the Participant has a vested right to receive a pension. With respect to a particular spouse of the Participant, coverage will cease upon the earliest of (i) the date of death of the spouse, (ii) the date of the divorce of the spouse from the Participant, (iii) the Participant's Benefit Commencement Date or (iv) the date on which a waiver of coverage becomes effective. With respect to an Alternate Beneficiary, coverage will cease upon the earliest of (i) the date of death of the Alternate Beneficiary, (ii) the date on which the Participant revokes his/her election to provide survivor coverage to the Alternate Beneficiary, (iii) the date of marriage of the Participant which date is after the date the Participant named the Alternate Beneficiary and the Participant's spouse has not waived coverage, or (iv) the Participant's Benefit Commencement Date.

5.1(d) Cost of Coverage —A Participant's Gross Pension is not reduced to offset the cost of providing coverage under 5.1(b).

5.2 Preretirement Survivor Annuity: Special Rules in the Traditional Pension Plan

5.2(a) Value of Coverage —Notwithstanding 5.1(b), if a Participant in the Traditional Pension Plan dies after he/she is eligible for Early Retirement, but before the Participant's Benefit Commencement Date, the Preretirement Survivor Annuity is calculated as described in 5.1(b) except that instead of adjusting the deceased Participant's Gross Pension by the early receipt provisions set forth in 3.4(c), the Participant's Gross Pension will be multiplied by the Early Retirement Adjustment Factor, but in no event shall such factor be less than 85%.

5.2(b) Duration of Coverage —Coverage under 5.2(a) commences with the Participant is eligible for Early Retirement. With respect to a particular spouse of the Participant, coverage will cease upon the earliest of (i) the date of death of the spouse, (ii) the date of the divorce of the spouse from the Participant, (iii) the Participant's Benefit Commencement Date or (iv) the date on which a waiver of coverage becomes effective. With respect to an Alternate Beneficiary, coverage will cease upon the earliest of (i) the date of death of the Alternate Beneficiary, (ii) the date on which the Participant revokes his/her election to provide survivor coverage to the Alternate Beneficiary, (iii) the date of marriage of the Participant which date is after the date the Participant named the Alternate Beneficiary and the Participant's spouse has not waived coverage, or (iv) the Participant's Benefit Commencement Date.

5.2(c) Cost of Coverage —A Participant's Gross Pension is not reduced to offset the cost of providing coverage under 5.2(a).

5.2(d) Additional Coverage —A Participant who is eligible for Early Retirement may elect additional Preretirement Survivor Annuity coverage for his/her Surviving Spouse or Alternate Beneficiary. The 50% factor in 5.1(b) may, at the election of such Participant, be increased by a multiple of 5% to a total factor not to exceed 100% and the permanent reduction to the deceased Participant's Gross Pension will be determined as set forth in 3.4(d). The additional coverage commences on the day of receipt of the Participant's election by the Plan Administrator. With respect to a particular spouse, such coverage will cease upon the earliest of (i) the date of death of the spouse, (ii) the date of

the divorce of the spouse from the Participant, (iii) the Participant's Benefit Commencement Date, (iv) the date upon which a cancellation of additional coverage in accordance with 6.3(a) becomes effective or (v) the date on which a waiver of coverage becomes effective. With respect to an Alternate Beneficiary, coverage will cease upon the earliest of (i) the date of death of the Alternate Beneficiary, (ii) the date on which the Participant revokes his/her election to provide survivor coverage to the Alternate Beneficiary, (iii) the date of marriage of the Participant which date is after the date the Participant named the Alternate Beneficiary and the Participant's spouse has not waived coverage, (iv) the Participant's Benefit Commencement Date or (v) the date upon which a cancellation of additional coverage in accordance with 6.3(a) becomes effective.

5.2(e) Cost of Additional Coverage —A Traditional Pension Plan Participant's Gross Pension is permanently reduced to offset the cost of providing the additional coverage under 5.2(d). Such reduction is determined as set forth in 3.4(d). The reduction in the Participant's Gross Pension to offset the cost of providing the additional Preretirement Survivor Annuity coverage will only reflect the period, if any, during which the additional coverage is effective.

5.2(f) Lump Sum Payment: Traditional Pension Plan —A Surviving Spouse or an Alternate Beneficiary entitled to a Preretirement Survivor Annuity may elect in writing to receive the Present Value of the Preretirement Survivor Annuity in a lump sum, if the following requirements are satisfied:

(i) The Participant's death occurs prior to the month before the Participant's 55th birthday; and

(ii) The Present Value of the Preretirement Survivor Annuity, computed as of the end of the month of the Participant's death, exceeds $5,000. If the Present Value of the Preretirement Survivor Annuity computed as set forth in (ii) is an amount that does not exceed $5,000, a lump sum payment for such amount will be made to the Surviving Spouse or the Alternate Beneficiary in lieu of monthly installments.

5.3 Post-retirement Survivor Annuity: Traditional Pension Plan

5.3(a) Eligibility —If a Participant in the Traditional Pension Plan who is receiving monthly pension payments under the Plan dies on or after the Participant's Benefit Commencement Date, the Surviving Spouse or the Alternate Beneficiary will be entitled to a Post-retirement Survivor Annuity unless coverage was waived. However, the Surviving Spouse or the Alternate Beneficiary of a Traditional Pension Plan Participant who received a lump sum payment is not entitled to a Post-retirement Survivor Annuity.

5.3(b) Value of Coverage —The Post-retirement Survivor Annuity is equal to 50% of the Participant's monthly pension payments.

5.3(c) Duration of Coverage —Coverage under 5.3(b) commences as of the Participant's Benefit Commencement Date. Coverage will cease upon the date of death of the Surviving Spouse or the Alternate Beneficiary.

5.3(d) Cost of Coverage —A Participant's Gross Pension is permanently reduced to offset the cost of providing coverage under 5.3(b). Such reduction is determined as set forth in 3.4(d).

5.4 Post-retirement Survivor Annuities: Special Rules for the Traditional Pension Plan

5.4(a) Additional Coverage —A Participant in the Traditional Pension Plan may elect additional Post-retirement Survivor Annuity coverage for his/her Surviving Spouse or his/her Alternate Beneficiary. The 50% factor in 5.3(b) may, at the election of such Participant, be increased by a multiple of 5% to a total factor not to exceed 100%. The additional coverage commences as of the Participant's Benefit Commencement Date. Such coverage will cease as set forth in 5.3(c).

5.4(b) Cost of Additional Coverage —A Participant's Gross Pension is permanently reduced to offset the cost of providing the additional coverage under 5.4(a). Such reduction is determined as set forth in 3.4(d).

5.5 Form of Survivor Annuity Payments: Traditional Pension Plan —Except as provided in 5.2(f), all Survivor Annuity payments under the Traditional Pension Plan are paid in monthly installments.

5.6 Timing of Survivor Annuity Payments: Traditional Pension Plan

5.6(a) Commencement of Preretirement Survivor Annuity Payments – Preretirement Survivor Annuity payments in the Traditional Pension Plan shall commence as of the first day of the month designated by the Surviving Spouse in writing. The date designated may be no earlier than the later of (i) the first day of the month following the month of the Participant's death or (ii) the first day of the month following the date the deceased Participant would have attained age 55, and may be no later than the later of (i) the Participant's Normal Retirement Date, or (ii) the first day of the month following the month of the Participant's death. The Preretirement Survivor Annuity payments in the Traditional Pension Plan to an Alternate Beneficiary shall be made as of the first day of the month following the Participant's death.

5.6(b) Cessation of Survivor Annuity Payments —Survivor Annuity payments shall permanently cease upon the death of the Surviving Spouse or the Alternate Beneficiary, effective with the Survivor Annuity payment for the month following the month of the Surviving Spouse's or the Alternate Beneficiary's death.

5.7 Change in Survivor Annuity Recipient: Traditional Pension Plan —If subsequent to the date of the commencement of (i) pension payments that were reduced to offset the cost of providing Post-retirement Survivor Annuity coverage or (ii) Preretirement Survivor Annuity payments, a person (other than the individual taken into account in determining the amount of such payments) asserts a right to a Survivor Annuity, no Survivor Annuity payments will be made to such person until the Plan has been repaid the cumulative additional reduction, if any, in pension payments that should have been made to offset the cost of providing Survivor Annuity coverage or payments for such person.

5.8 Preretirement Survivor Benefit: PEP

5.8(a) Eligibility —If a Participant in PEP with a vested right to receive a pension dies before the Participant's Benefit Commencement Date (i) the Surviving Spouse or (ii) the Alternate Beneficiary (for a Participant who is not married on his/her date of death or who is married, and who has the appropriate spousal waiver and who names an Alternate Beneficiary that does not predecease the Participant) will be entitled to a Preretirement Survivor Benefit.

A PEP Participant may name more than one Alternate Beneficiary for a Preretirement Survivor Benefit. If more than one Alternate Beneficiary is named, the Participant must designate the percentage of Preretirement Survivor Benefit attributable to each recipient by delivering an Appropriate Request to the Plan Administrator.

For a Participant who is not married and who either does not name an Alternate Beneficiary or names one or more Alternate Beneficiaries and such Alternate Beneficiary(ies) predeceases the Participant, the default beneficiary for the Preretirement Survivor Benefit will be the Participant's beneficiary under the Company's employee life insurance plan.

5.8(b) Value of Coverage —The Preretirement Survivor Benefit is equal to 100% of the deceased Participant's Gross Pension. If a married PEP Participant dies and does not have a spousal waiver, the Surviving Spouse will receive a deferred annuity described in 3.3(g), unless the Surviving Spouse elects within 60 days of the Participant's date of death to receive a lump sum described in 3.3(e) or an immediate annuity described in 3.3(f). The deferred annuity will begin as of the first day of the month designated in writing by the Surviving Spouse, which is after the date the Participant would have attained age 55 and not later than the Participant's Normal Retirement Date. The immediate or deferred annuity will be calculated based on the Surviving Spouse's age as of the date the annuity begins. If a PEP Participant who is not married or who is married and has a spousal waiver dies, the Alternate Beneficiary will receive a lump sum described in 3.3(e).

5.8(c) Duration of Coverage —Coverage under 5.8(b) commences as of the date that the Participant has a vested right to receive a pension.

With respect to a particular spouse of the Participant, coverage will cease upon the earliest of (i) the date of death of the spouse, (ii) the date of the divorce of the spouse from the Participant, (iii) the date on which a waiver of coverage becomes effective, or (iv) the Participant's Benefit Commencement Date. With respect to an Alternate Beneficiary, coverage will cease upon the earliest of (i) the date of death of the Alternate Beneficiary, (ii) the date on which the Participant revokes his/her election to provide survivor coverage to the Alternate Beneficiary, (iii) the date of marriage of the Participant and his/her spouse, which date is after the date the Participant named the Alternate Beneficiary, or (iv) the Participant's Benefit Commencement Date.

5.8(d) Cost of Coverage —A Participant's PEP payments are not reduced to offset the cost of providing coverage under 5.8.

5.9 Post-retirement Survivor Benefit: PEP

5.9(a) Eligibility —If a Participant in PEP who is receiving monthly pension payments under the Plan dies on or after the Participant's Benefit Commencement Date, (i) the Surviving Spouse will be entitled to a Post-retirement Survivor Benefit unless it is waived or (ii) any named Alternate Beneficiary (for a Participant who is not married, or who is married and who has the appropriate spousal waiver and who names an Alternate Beneficiary) will be entitled to a Post-retirement Survivor Benefit.

A PEP Participant may name only one Alternate Beneficiary for the Post-retirement Survivor Benefit. Only an individual may be named as an Alternate Beneficiary. If the Participant received a lump sum payment, then no Post-retirement Survivor Benefit is available.

5.9(b) Value of Coverage —The Post-retirement Survivor Benefit is equal to 50% of the Participant's monthly pension payments.

5.9(c) Duration of Coverage —Coverage under 5.9(b) commences as of the Participant's Benefit Commencement Date. Coverage will cease upon the date of death of the Surviving Spouse or the date of death of the Alternate Beneficiary, whichever is applicable.

5.9(d) Cost of Coverage —A Participant's Gross Pension is permanently reduced to offset the cost of providing coverage under 5.9(b). Such reduction is determined as set forth in 3.4(d).

5.10 Post-retirement Survivor Benefit: Special Rules for PEP

5.10(a) Additional Coverage —A Participant in PEP may elect additional Post-retirement Survivor Benefit coverage for his/her Surviving Spouse or Alternate Beneficiary. The 50% factor in 5.9(b) may, at the election of such Participant, be increased by a multiple of 5% to a total factor not to exceed 100%. The additional coverage commences as of the Participant's Benefit Commencement Date. Such coverage will cease as set forth in 5.9(c).

5.10(b) Cost of Additional Coverage —A Participant's Gross Pension is permanently reduced to offset the cost of providing the additional coverage under 5.10(a). Such reduction is determined as set forth in 3.4(d).

5.11 Form of Survivor Benefit Payments: PEP —Except as provided in 5.12, Preretirement Survivor Benefit payments under PEP are payable in the form described in 5.8(b). Post-retirement Survivor Benefits under PEP are paid in monthly installments.

5.12 Automatic Cash-Out: PEP —If a Participant in PEP dies before his/her Benefit Commencement Date and the PEP Gross Pension lump sum amount described in 3.3(e) computed as of the end of the month of the Participant's death does not exceed $5,000, then the Preretirement Survivor Benefit will be paid in a lump sum.

5.13 Timing of Survivor Benefit Payments: PEP

5.13(a) Commencement of Preretirement Survivor Benefit Payments —Preretirement Survivor Benefit payments to a Surviving Spouse shall commence as of the first day of the month designated in writing by the Surviving Spouse. The date so designated must be later than the month of the Participant's death but not later than the later of (i) the Participant's Normal Retirement Date, or (ii) the first day of the month following the month of the Participant's death. The Preretirement Survivor Annuity payment in PEP to an Alternate Beneficiary shall be made as of the first day of the month following the Participant's death.

5.13(b) Cessation of Survivor Benefit Payments —Preretirement Survivor Benefit payments and Post-retirement Survivor Benefit payments shall permanently cease upon the death of the Surviving Spouse or Alternate Beneficiary, effective with the Survivor Benefit payment for the month following the month of the Surviving Spouse's or Alternate Beneficiary's death.

5.14 Election Period Survivor Benefits —If an active Participant dies during the election period referenced in 1.2, then regardless of any election that the Participant may have already made, the Participant's Surviving Spouse will have the option of electing the Preretirement Survivor Annuity under the Traditional Pension Plan or the Preretirement Survivor Benefit under PEP. The Surviving Spouse must make his/her choice by the later of (i) 60 days after the date the Plan Administrator notifies the Surviving Spouse of the option, or (ii) June 30, 2000. If an active Participant dies during the election period referenced in 1.2 and is not married, then the Alternate Beneficiary will receive the Preretirement Survivor Benefit under PEP. For the purposes of this 5.14, if the Participant is not married and did not name an Alternate Beneficiary then the default beneficiary will be the Participant's beneficiary under the Company's employee life insurance plan. If no beneficiary under the life insurance plan exists, then the default beneficiary will be the Participant's estate.

ARTICLE VI—Procedures; Administration; Claims

6.1 Procedures: Commencement of Payments Under the Plan —Any payment required to be made under the Plan may, at the discretion of the Plan Administrator, be suspended until the name and address of the recipient and all information necessary to determine the amount payable (including, when applicable, but not limited to, the recipient's age, proof of marital status and, if married, an Appropriate Request that includes the name, birth date and current address of the Participant's spouse and which either rejects the 50% Post-retirement Survivor Annuity or Post-retirement Survivor Benefit or accepts such coverage and requests or declines additional coverage) has been received by the Plan Administrator. Generally the Appropriate Request must be executed by the Participant and spouse (or their guardian, attorney-in-fact, or other legal representative), under oath, before a notary public. The signature of a legal representative must be supported by a copy of the instrument effecting the appointment. However, for the purpose of the 50% spousal election for Post-retirement Survivor Annuity or Post-retirement Survivor Benefit, the Appropriate Request does not need to be notarized. Payments that were suspended will be made in a lump sum, without interest, as soon as possible after the Plan Administrator receives such information. The Plan Administrator may, in his/her sole discretion, require assurances in the form of an indemnity agreement or bond, prior to the commencement of any payments, if the accuracy of certain information has not been in his/her opinion conclusively established. To the extent payments have not been claimed during a three year period, all payments will be forfeited. However, if the recipient subsequently files a proper claim with the Plan Administrator for such amounts, and the claim is filed prior to the termination of the Plan, payments that were suspended will be made in a lump sum, without interest, as soon as possible after the Plan Administrator receives such claim.

6.1(a) Proof of Marital Status —The Plan Administrator may rely on a notarized written declaration made on an Appropriate Request that a Participant is presently unmarried unless (i) the Participant's spouse is currently a designated beneficiary under any Employer-sponsored life insurance, or (ii) the Participant's spouse is currently a dependent under any Employer-sponsored group health insurance. If (i) or (ii) above indicate that a spouse exists, the resulting presumption will be overcome if the notarized written declaration is supported by a copy of a death certificate or final decree of divorce or annulment which, in the Plan Administrator's sole discretion, appears to have been properly issued. If an allegedly estranged spouse can't be reached by certified mail, return receipt requested, at the last known address of the spouse, the Plan Administrator, in his/her sole discretion, may accept the Appropriate Request without the signature of the spouse (or the spouse's legal representative).

6.2 Procedures: Written Explanation of Survivor Annuity Coverage —

6.2(a) Additional Preretirement Survivor Annuity Coverage —Within one year of the date the Participant in the Traditional Pension Plan becomes eligible for additional Preretirement Survivor Annuity coverage, the Plan Administrator shall furnish to the Participant a written explanation of (i) the terms and conditions of the additional Preretirement Survivor Annuity coverage, and (ii) the Participant's right to elect or change or cancel an election of the additional Preretirement Survivor Annuity coverage.

6.2(b) Preretirement Survivor Benefit —The Plan Administrator shall furnish to the Participant in PEP a written explanation of (i) the terms and conditions of the Preretirement Survivor Benefit, (ii) the Participant's right to designate the beneficiary of the Preretirement Survivor Benefit, (iii) the rights of the Participant's spouse, and (iv) the right to change or revoke a beneficiary designation. The written explanation shall be provided to the Participant (A) as soon as practicable after the Participant begins to participate in PEP, (B) between January 1 of the year the Participant attains age 32 and December 31 of the year the Participant attains age 34, unless the date in (A) is subsequent to January 1 of the year the Participant attains age 32, (C) within one year after the Participant's Severance From Service Date provided that (a) the Participant's Severance From Service Date occurs before the Participant attains age 35, (b) the Participant is vested at his/her Severance From Service Date, (c) the Participant does not have a Benefit Commencement Date before the written explanation is provided, and (d) the written explanation was not otherwise provided within one year before the Participant's Severance From Service Date, and (D) as soon as practicable after the Participant is rehired.

6.2 (c) Post-retirement Survivor Annuity or Post-retirement Survivor Benefit —(i) The Plan Administrator shall furnish to the Participant a written explanation of (A) the terms and conditions of the Post-retirement Survivor Annuity or Post-retirement Survivor Benefit, (B) the Participant's right to make and the effect of an election to waive the Post-retirement Survivor Annuity or the Post-retirement Survivor Benefit, (C) the rights of the Participant's spouse, and (D) the right to make, and the effect of, a withdrawal of a previous election to waive the Post-retirement Survivor Annuity or Post-retirement Survivor Benefit.

(ii) The written explanation shall be provided to the Participant no more than 180 and no less than 30 days before the Participant's Benefit Commencement Date, subject to the following exception:

(A) The written explanation may be provided less than 30 days before the Benefit Commencement Date provided that the Participant is given a specified period of at least 30 days to make the election (and that other Plan requirements are satisfied); and

(B) A Participant may affirmatively elect, with the Participant's Spouse's consent, to waive the minimum 30-day election period. The waiver of the minimum 30-day period will be effective only if:

(I) the Participant and the Participant's Spouse have been clearly informed of the right to have a minimum 30-day election period to consider whether to waive the Post-retirement Survivor Annuity or Post-retirement Survivor Benefit;

(II) the distribution begins at least 7 days after the date that the written explanation is provided; and

(III) the Participant is permitted to revoke an election, and the Spouse is permitted to revoke a consent, until the later of the Benefit Commencement Date or the expiration of the 7-day period that begins the day after the written explanation is provided.

6.3 Procedures: Election of Survivor Annuity Coverage —

6.3(a) Additional Preretirement Survivor Annuity Coverage —As described in 5.2(d), a Participant in the Traditional Pension Plan may elect to change or cancel an election of the additional Preretirement Survivor Annuity coverage on an Appropriate Request at any time between the date the Participant becomes eligible for the additional Preretirement Survivor Annuity coverage and the Participant's Benefit Commencement Date. Such election, change or cancellation shall not require the consent of the Participant's spouse.

6.3(b) Preretirement Survivor Benefit —A Participant in PEP may select his/her spouse, an individual or a trust to be his/her beneficiary of the Preretirement Survivor Benefit, and may change his/her selection, on an Appropriate Request, at any time before his/her Benefit Commencement Date. If the Participant selects a beneficiary other than his/her spouse, the selection shall be effective only if the Participant is not married on his/her date of death or the individual who is the spouse of the Participant on the Participant's date of death has consented to the selection in writing and such consent was witnessed by a notary public. Notwithstanding the preceding sentence, if the Participant selects a beneficiary other than the Participant's spouse and the Participant's spouse consents to such election prior to January 1 of the year the Participant attains age 35, the designation and waiver shall become ineffective on such January 1, unless the Participant does not have a surviving spouse on the Participant's date of death.

6.3(c) Post-retirement Survivor Annuity or Post-retirement Survivor Benefit —After the Plan Administrator provides the Participant with the written explanation in 6.2(c)(i) during the period in 6.2(c)(ii), a Participant in the Traditional Pension Plan may waive the Post-retirement Survivor Annuity or may elect additional Post-retirement Survivor Annuity coverage by an Appropriate Request. A Participant in the Traditional Pension Plan may revoke such waiver or election and make a new election until the

Participant's Benefit Commencement Date (or, if later, the expiration of the 7-day period that begins after the written explanation is provided), without limit on the number of changes that may be made. After the Plan Administrator provides the Participant with the written explanation in 6.2 (c)(i) during the period in 6.2(c)(ii), a Participant in PEP may waive the Post-retirement Survivor Benefit with the Participant's spouse as beneficiary or may elect additional Post-retirement Survivor Benefit coverage with the Participant's spouse as beneficiary, or may select a beneficiary other than the Participant's spouse by an Appropriate Request. A Participant in PEP may revoke such waiver or election and make a new election until the latest of the Participant's Benefit Commencement Date, the expiration of the 7-day period that begins after the written explanation is provided), and 60 days after the Participant's Severance From Service Date (but not later than the date of distribution) without limit on the number of changes that may be made. If the Participant waives the Post-retirement Survivor Annuity or the Post-retirement Survivor Benefit with his/her spouse as beneficiary or selects a beneficiary other than his/her spouse for the Post-retirement Survivor Benefit, the waiver or selection shall be effective only if the Participant is not married on his/her Benefit Commencement Date or the Participant's spouse on the Participant's Benefit Commencement Date has consented to the waiver or selection in writing and such consent was witnessed by a notary public.

6.4 Plan Administration: The Administrative Committee

6.4(a) Generally —The Administrative Committee shall consist of members of senior management of the Company appointed from time to time by the Chief Executive Officer of the Company. The Chairman of the Committee shall be the Chief Human Resources Officer of the Company. A member of the Committee may resign by delivering his/her written resignation to the Chairman of the Committee. A written resignation shall become effective as of the date specified therein. No member of the Committee shall receive compensation from the Plan for his/her services as a member.

6.4(b) The Administrative Committee: Authority and Duties —The Administrative Committee has the authority to adjudicate claims appeals as set forth in Section 6.8, and to delegate, in writing, any part of its authority and duties to one or more designees.

6.5 Plan Administration: The Investment Committee

6.5(a) Generally —The Investment Committee shall consist of members of senior management of the Company appointed from time to time by the Chief Executive Officer of the Company. The Chairman of the Committee shall be the Chief Financial Officer of the Company. A member of the Committee may resign by delivering his/her written resignation to the Chairman of the Committee. A written resignation shall become effective as of the date specified therein. No member of the Committee shall receive compensation from the Plan for his/her services as a member.

6.5(b) Authority and Duties —The Investment Committee has the authority and responsibility, subject to the review and modification of the Board of Directors:

(i) to develop and implement strategies for the custody and management of Plan assets in accordance with its investment policy statement,

(ii) to engage in negotiations related to the custody or management of Plan assets,

(iii) to exercise all rights reserved to the Company as party to a contract or trust instrument related to the custody or management of its assets,

(iv) to delegate, in writing, any part of its authority and duties to one or more designees, and

(v) to report annually to the Board of Directors.

6.6 Plan Administration: The Plan Administrator

6.6(a) Generally —The Plan will be administered by the Director – Benefits of the Company (or the successor to that function) as Plan Administrator, under the direct supervision of the Chief Human Resources Officer of the Company (or under the supervision of the officer succeeding to that function).

6.6(b) Authority and Duties —The Plan Administrator will establish policies and procedures necessary to efficiently operate the Plan. The Plan Administrator is responsible for the day to day operation of the Plan. The Plan Administrator will:

(i) furnish when due all required information and reports to Participants and regulatory agencies, and

(ii) receive all communications from Participants and regulatory agencies about the Plan and take appropriate action in response thereto. The Plan Administrator may, in writing, delegate any part of his/her authority and duties to one or more designees. The designee or the Plan Administrator may withdraw the designation in writing.

6.7 Plan Administration: Indemnification —The Plan Administrator (and his/her designees), the Board of Directors, Chairman of the Board of Directors, Vice Chairman of the Board of Directors, Administrative Committee and Investment Committee members, the –Chief Human Resources Officer (or the officer succeeding to that function) of the Company and all employees of the Employer whose duties involve Plan matters, shall be indemnified by the Company, or from the proceeds under insurance policies purchased by the Company, against any and all liabilities arising by reason of any act or failure to act made in good faith pursuant to the provisions of the Plan, including expenses reasonably incurred in the defense of any claim relating thereto.

6.8 Plan Administration: Claims

6.8(a) Denial of Claim —If after a Participant makes a written claim for benefits, such claim is denied in full or in part, the Plan Administrator shall, within 90 days after receipt of the claim, provide the Participant (at the Participant's last address appearing on the records of the Plan) with written notice by mail, in language calculated to be understood by the Participant, of the denial of the claim stating (i) the specific reasons for the denial, (ii) the specific references to pertinent Plan provisions on which the denial is based, (iii) any additional material or information necessary for the Participant to resubmit the claim, including an explanation of why such material or information is necessary, and (iv) an explanation of the claims appeal procedure. If special circumstances require an extension of time to process the claim, within 90 days after receipt of the claim, the Plan Administrator shall provide the Participant with written notice by mail specifying the reasons for the need for an extension of time, and a date by which he/she expects to render a decision. In that event, the initial 90 day period for notice of denial shall be extended by an additional 90 days.

6.8(b) Appeal of Claim —If a Participant's written claim has been denied or if the Participant has not received written notice of denial within the period prescribed by 6.8(a), he/she may file an appeal with the –Administrative Committee. The Participant or his/her duly authorized representative may request to review pertinent documents. The appeal must be submitted in writing within 60 days of the date the Participant receives or should have received notice of the denial. The appeal may be made by the Participant or his/her duly authorized representative. The appeal must state the reasons for the appeal and shall be accompanied by any evidence or documentation to support the Participant's position. The –Administrative Committee shall review the Participant's appeal promptly and shall advise the Participant of his/her decision in writing, in language calculated to be understood by the Participant, stating the specific reasons for his/her decision withspecific reference to pertinent Plan provisions on which the decision is based. This written decision shall be sent to the Participant (at his/her last address appearing on the records of the Plan) by mail no later than 60 days after receipt of the written appeal, unless special circumstances require an extension of time for processing the appeal, obtaining more information or conducting an investigation of the facts. In no event shall the written decision be sent to the Participant later than 120 days after receipt by the –Administrative Committee of the written appeal. The determination of the –Administrative Committee shall be final and binding on all parties and not subject to further appeal.

6.8(c) Exclusive Method —The procedure for review of claims outlined in this 6.8 is the exclusive method available for resolving claims under the Plan, notwithstanding the existence of other Employer procedures applicable to Employee grievances in other areas. No Participant or beneficiary is entitled to bring any action, whether at law or in equity against any Employer or their respective agents, officers, directors or employees, including the Administrative Committee, the Investment Committee, the Plan Administrator, his/her designees, or the –Chief Human Resources Officer of the Company (or any officer succeeding to that function) in connection with any right, privilege or benefit provided under this Plan unless and until, as a condition precedent, all the remedies provided under this Section 6.8 have been exhausted.

6.9 Direct Rollover of Eligible Rollover Distributions —This 6.9 applies to distributions made on or after January 1, 1993, or such other effective date as specified herein. Notwithstanding any provision of the Plan to the contrary that would otherwise limit a distributee's election under this 6.9; a distributee may elect, at the time and in the manner prescribed by the Plan Administrator, to have any portion of an eligible rollover distribution paid directly to an eligible retirement plan specified by the distributee in a direct rollover.

For purposes of this 6.9, eligible rollover distribution means any distribution of all or any portion of the balance to the credit of the distributee, except that an eligible rollover distribution does not include: any distribution that is one of a series of substantially equal periodic payments (not less frequently than annually) made for the life (or life expectancy) of the distributee or the joint lives (or joint life expectancies) of the distributee and the distributee's designated beneficiary, or for a specified period of ten years or more; any distribution to the extent such distribution is required under Code Section 401(a)(9); and the portion of any distribution that is not includible in gross income (determined without regard to the exclusion for net unrealized appreciation with respect to employer securities).

For purposes of this 6.9, eligible retirement plan means an individual retirement account described in Code Section 408(a), a Roth individual retirement account described in Code Section 408A(b) (subject to current Roth individual retirement account conversion rules), an individual retirement annuity described in Code Section 408(b), an individual retirement annuity described in Code Section 403(a), or a qualified trust described in Code Section 401(a), that accepts the distributee's eligible rollover distribution. Eligible retirement plan shall also mean an eligible deferred compensation plan described in Code Section 457(b) that is maintained by a state, political subdivision of a state, or an agency or instrumentality of a state or an entity exempt from federal income tax, or an annuity contract described in Code section 403(b).

For purposes of this 6.9, a distributee means an Employee or Former Employee. In addition, a Surviving Spouse (or, effective for distributions made after December 31, 2009, a non-spouse beneficiary as described in Code Section 402(c)(11)) and the Employee's or Former Employee's spouse or former spouse who is the alternate payee under a qualified domestic relations order, as defined in Code Section 414(p), are distributees with regard to the interest of the spouse or former spouse.

For purposes of this 6.9, a direct rollover is a payment by the Plan to the eligible retirement plan specified by the distributee.

ARTICLE VII—Plan Funding

7.1 Contributions —No contributions from any Participant shall be required or permitted under the Plan. The Employer shall make contributions in such amounts and at such times as determined by the Investment Committee in accordance with a funding method and policy to be established by the Investment Committee. Forfeitures arising under this Plan shall be applied to reduce the expenses of Plan administration, not to increase the benefits otherwise payable to Participants.

7.2 Payments to the Trustee —All contributions made by the Employer under this Plan shall be paid to the Trustee and shall become assets of the Trust.

ARTICLE VIII—Miscellaneous Provisions

8.1 Inalienability of Benefits: Generally —No benefit or interest available under the Plan will be subject to assignment, attachment, alienation, or other legal process, either voluntarily or involuntarily. Except as provided in 8.1(a), the preceding sentence will also apply to the creation, assignment or recognition of a right to any benefit payable with respect to a Participant pursuant to a domestic relations order. Except as provided in 8.1(b) and 8.7, payments required under the Plan will be made to and in the name of the person entitled to such payments under the terms of the Plan, or to and in the name of such person's authorized representative. Payments to any financial institution to the credit of such person will constitute payments to and in the name of the person entitled to such payments under the terms of the Plan.

8.1(a) Qualified Domestic Relations Orders —The anti-alienation provisions of 8.1 do not apply to qualified domestic relations orders, as the term is defined in Code Section 414(p). The Plan Administrator has established and will maintain written procedures to determine the qualified status of domestic relations orders and to administer distributions under such qualified orders. To the extent provided under a qualified domestic relations order, a former spouse of a Participant shall be treated as the spouse or Surviving Spouse for all purposes under the Plan.

A qualified domestic relations order will not require the Plan to provide any type or form of benefit, or any option, not otherwise provided under the Plan.

Notwithstanding the preceding paragraph, if provided under a qualified domestic relations order, an alternate payee as described in Code Section 414(p) may receive his/her entire interest under the order as a lump sum payment as soon as administratively possible after a domestic relation order is qualified by the Plan Administrator. Such lump sum payment will be limited to (i) in the case of a Participant in the Traditional Pension Plan, the Present Value of the Participant's Gross Pension under 3.3(a), calculated as of the date as of which the lump sum is paid, and (ii) in the case of a Participant in PEP, the PEP Gross Pension lump sum under 3.3(e), calculated as of the date as of which the lump sum is paid. Unless unambiguously stated otherwise in the qualified domestic relations order, such lump sum will equal a percentage or portion (as specified in the order) of the amount described in (i) or (ii) above.

A Participant's Gross Pension (payable at the time and in the form such Gross Pension is actually paid to the Participant or, if the Participant dies before his/her Benefit Commencement Date, payable at the time and in the form the Preretirement Survivor Annuity or Preretirement Survivor Benefit is actually paid to the Surviving Spouse or Alternate Beneficiary) will be reduced by the benefits provided to an alternate payee described in Code Section 414(p)(8) under a qualified domestic relations order. Such Gross Pension will be reduced as follows:

(i) If the alternate payee receives a lump sum payment, the Gross Pension will be reduced by accumulating such lump sum payment with the Annual Interest Rate from the date as of which the lump sum is paid to the Participant's (or the Surviving Spouse's or Alternate Beneficiary's) Benefit Commencement Date, and converting such accumulated amount to the form of payment paid to the Participant (or Surviving Spouse or Alternate Beneficiary) using the Annual Interest Rate and the mortality table described in Code Section 417(e)(3). The Annual Interest Rate in

the preceding sentence will be (1) on and after January 1, 2008, the rate of interest specified under Code Section 417(e) as amended by the Pension Protection Act of 2006 and clarified by Revenue Ruling 2007-67 and (2) prior to January 1, 2008, the annual rate of interest on 30-year Treasury securities, in each case for the November of the Plan Year immediately preceding the Plan Year in which the lump sum payment is made to the alternate payee. For distributions with a Benefit Commencement Date on or after January 1, 2003 and prior to January 1, 2008, the mortality table shall be as prescribed in Revenue Ruling 2001-62 and for distributions with a Benefit Commencement Date on or after January 1, 2008, the mortality table shall be as prescribed in Revenue Ruling 2007-67.

(ii) If the alternate payee receives monthly annuity payments and the Participant also receives monthly annuity payments, the alternate payee's monthly annuity payments have a Benefit Commencement Date that is on or after the Participant's Benefit Commencement Date, the alternate payee's monthly annuity payments are payable until a date that is no later than the Participant's date of death, and the alternate payee's monthly annuity payments are no greater than the monthly payment the Participant would receive if the qualified domestic relations order did not exist, the Participant's monthly annuity payments will be reduced by the dollar amount of the monthly annuity payments provided to the alternate payee.

(iii) If the alternate payee receives monthly annuity payments and the conditions in (ii) are not satisfied, the Gross Pension will be reduced by accumulating the Present Value of the alternate payee's monthly annuity payments (with such Present Value being determined as of the date such annuity payments begin to be paid to the alternate payee) with the Annual Interest Rate from the date as of which such Present Value is determined to the Participant's (or Surviving Spouse's or Alternate Beneficiary's) Benefit Commencement Date, and converting such accumulated amount to the form of payment paid to the Participant (or Surviving Spouse or Alternate Beneficiary) using the Annual Interest Rate and the mortality table described in Code Section 417(e)(3). The Annual Interest Rate in the preceding sentence will be (1) on and after January 1, 2008, the rate of interest specified under Code Section 417(e)(3) as amended by the Pension Protection Act of 2006 and clarified by Revenue Ruling 2007-67 and (2) prior to January 1, 2008, the annual rate of interest on 30-year Treasury securities, in each case, for the November of the Plan Year immediately preceding the Plan Year in which the Present Value is determined. For distributions with a Benefit Commencement Date on or after January 1, 2003 and prior to January 1, 2008, the mortality table shall be as prescribed in Revenue Ruling 2001-62 and for distributions with a Benefit Commencement Date on or after January 1, 2008, the mortality table shall be as prescribed in Revenue Ruling 2007-67.

8.1(b) Miscellaneous Exceptions —The anti-alienation provisions of 8.1 do not apply to certain voluntary and revocable assignments or alienations or other arrangements permitted under the Code and ERISA, including under Code Section 401(a)(13) and the applicable Treasury regulations.

8.2 Exclusive Benefit: Generally —Except as provided in 8.2(a), all contributions made by any Employer to any insurance company or Trustee for the purpose of funding the Plan are irrevocable and shall not revert to the Employer. Prior to the satisfaction of all liabilities under the Plan, such contributions, as well as the corpus and income of the Trust, shall not be diverted to or used for purposes other than the exclusive benefit of Participants and their beneficiaries and defraying reasonable expenses of Plan administration, including expenses of service providers who support plan administrative or fiduciary functions.

8.2(a) Exceptions —Any contribution made by an Employer by mistake of fact shall be returned to the Employer provided the return is made within one year after the payment of such contribution to the insurance company or Trustee, and provided further that earnings attributable to the excess contribution may not be returned to the Employer, but losses attributable to the excess contribution must reduce the amount returned.

Any contribution made by an Employer shall be returned to the Employer to the extent the deduction of such contribution is disallowed under Code Section 404, provided the return is made within one year after the disallowance of the deduction by the Internal Revenue Service. For purposes of this provision, all contributions made by an Employer to the Plan are expressly conditioned upon their deductibility under Code Section 404, and any nondeductible contributions must be returned to the Employer.

Any excess assets shall be returned to the Employer upon the Plan's termination, but only after satisfaction of all Plan liabilities to Participants and their beneficiaries.

8.3 No Right to Employment —Nothing contained in the Plan shall be construed as a contract of employment between an Employer and any Employee, or as a right of any Employee to continue in the employment of an Employer or as a limitation of the right of an Employer to discharge an Employee with or without cause.

8.4 Controlling Law —The Plan and its administration shall be governed by the laws of the State of Maryland except to the extent preempted by Federal law.

8.5 Number —Words used in the singular are intended to include the plural, whenever appropriate.

8.6 Titles and Headings —Titles of Articles and headings to Sections in the Plan are placed herein solely for convenience of reference and, in any case of conflict, the text of the Plan, rather than such titles and headings, shall control.

8.7 Payment of Benefits to Incompetents —If the Plan Administrator determines that any participant, spouse or beneficiary is unable to care for his affairs because of minority, illness, infirmity, accident or any other reason, any distributions due may be made at the direction of the Plan Administrator to the guardian, conservator, legal representative, spouse, child, parent or other blood relative or to any person deemed by the Plan Administrator to have incurred expenses for such participant, spouse, or beneficiary entitled to distributions under the Plan. Such distribution shall, to the extent thereof, be a complete discharge of all liabilities of the Plan, the Employer, the Plan Administrator, the Trustee and the Trust.

ARTICLE IX—Amendment, Termination, Mergers or Consolidations

9.1 Amendment —In the event of the amendment of the Plan as permitted under Article VI, such amendment shall not cause the elimination or reduction of any Plan benefit as prohibited under the provisions of Code Section 411(d)(6).

Unless an amendment or Plan provision specifically provides otherwise, no Plan amendment will have a retroactive or prospective effect on the rights of former Employees whose active employment with the Employer terminated prior to the effective date of the amendment.

9.1(a) Amendment Authority of the Board of Directors —The Board of Directors reserves the right, at their exclusive discretion:

(i) to discontinue or terminate, merge or consolidate the Plan, in whole or in part,

(ii) to determine whether, and to what extent, employees of subsidiaries of the Company will be eligible to participate in the Plan,

(iii) to amend the Plan, in whole or in part, on advice of counsel, and except as otherwise provided herein, the Board of Directors may delegate the right to amend the Plan with respect to certain matters, and

(iv) to delegate to special committees or subcommittees the power to exercise the rights otherwise reserved to the Board of Directors in this Section 9.1(a).

9.1(b) Amendment Authority of the Chairman of the Board of Directors —The Chairman of the Board of Directors has the right, subject to the review and modification of the Board of Directors:

(i) to amend the Plan, from time to time, as shall be necessary or advisable in the interpretation, administration or operation thereof or as required by law, on the advice of counsel.

(ii) to exercise all rights and authority related to the operation of the Plan that are not expressly reserved to the Board of Directors or otherwise delegated by the Board of Directors,

(iii) to appoint the members of the Investment and Administrative Committees, as set forth in Sections 6.4 and 6.5, and

(iii) to delegate, in writing, any part of his/her authority to one or more designees.

9.1(c) Amendment Authority of the Executive Group —Effective July 23, 2010 the Executve Group may approve amendments to the Plan that have less than a $10 million impact on the Plan's accumulated benefit obligation per amendment.

9.1(d) Amendment Authority of the Chief Human Resources Officer —The Chief Human Resources Officer may make any amendment to the Plan that does not increase the annual liabilities of the Plan materially, or as required by law, upon the advice of counsel.

9.1(e) Amendment Authority of the Plan Administrator —The Plan Administrator may make any amendment to the Plan as required by law, upon the advice of counsel.

9.1(f) Report to the Board —At least annually, the Company's Chief Executive Officer shall report all amendments made pursuant to the authorities set forth in Sections 9.1(b) and (c) to the Board of Directors.

9.2 Termination —In the event of the termination or partial termination of the Plan, the rights of all affected Participants entitled to benefits accrued to the date of such termination or partial termination (to the extent funded as of such date) shall be nonforfeitable. A Participant whose benefits were forfeited, in accordance with 4.5, prior to the date of termination or partial termination, shall not be entitled to nonforfeitable benefits as a result of the preceding sentence. In the event of the termination of the Plan, the benefit of any highly compensated employee (and any former highly compensated employee) as those terms are defined in Code Section 414(q) and the related regulations, is limited to a benefit that is nondiscriminatory under Code Section 401(a)(4).

9.3 Merger or Consolidation —In the event of a merger or consolidation of the Plan with, or transfer of assets and liabilities of the Plan to, any other plan, each Participant will receive a benefit immediately after such merger, consolidation, or transfer (computed as if the Plan had then terminated) which is equal to or greater than the benefit the Participant was entitled to immediately before such merger, consolidation, or transfer (computed as if the Plan had then terminated) to the extent required under Section 414(*l*) of the Code.

9.4 Spin Offs To and From the CENG Plan —This 9.4 is effective as of the CENG Effective Date. In any case where assets and liabilities are spun off from or to this Plan, each Participant (whether or not vested) will be entitled to an accrued benefit immediately after such spin off or transfer (computed as if this Plan or the transferee

plan, as applicable, had then terminated) that satisfies the requirements of 9.3; provided that such accrued benefit will be payable from the applicable plan if and only if all applicable requirements for payment under the applicable plan are satisfied including, without limitation, applicable vesting requirements. Under no circumstances shall any individual be entitled to duplicate benefits under this Plan and the CENG Plan (or any other qualified defined benefit pension plan sponsored by the Company, CENG or any of their subsidiaries or affiliates).

9.4(a) Introduction —Effective as of the CENG Effective Date, ÉLECTRICITÉ DE FRANCE INTERNATIONAL, SA and its affiliates acquired 49.99 of the membership interests of CENG from the Company; CENG and certain of its affiliates ceased to be Employers or otherwise participate in the Plan; and CENG established and adopted the CENG Plan for the benefit of its employees and certain former Participants in this Plan. As of the CENG Effective Date, the CENG Plan and its related trust received a spin off of assets and liabilities with respect to each employee, former employee, and surviving spouse of a former employee of CENG (or any affiliate or subsidiary thereof the employees of which participated in this Plan prior to the CENG Effective Date) who, immediately prior to the CENG Effective Date, was either (1) an active Participant under this Plan, (2) an inactive Participant or Disabled Participant under this Plan who was entitled to a benefit under this Plan immediately prior to the CENG Effective Date and who was an Employee of an Employer immediately prior to his or her Severance From Service Date or (3) a Surviving Spouse of an individual who would have been described in (1) or (2) had he or she not died prior to the CENG Effective Date. No individual described in the previous sentence shall be entitled to a benefit under or continued

participation in the Plan after the CENG Effective Date (except to the extent such individual's benefit is subsequently spun off from the CENG Plan back to this Plan pursuant to 9.4(b) or to the extent such individual is entitled to participate and earn only future benefits under this Plan because he or she is rehired by the Company (or any subsidiary or affiliate thereof the employees of which then participate in the Plan in accordance with the designation of the Board of Directors as reflected in Appendix G) under circumstances where his or her benefit is not spun off from the CENG Plan to this Plan pursuant to this 9.4).

9.4(b) Direct Transfers from CENG —This Plan and the associated Trust will receive a spin off of assets and liabilities from the CENG Plan with respect to each eligible Full-Time Employee of the Company or those designated subsidiaries and affiliates of the Company reflected in Appendix G whose employment is transferred by CENG directly from CENG (or any affiliate or subsidiary thereof the employees of which participate in the CENG Plan) to an Employer after the CENG Effective Date and this Plan and the associated Trust will spin off assets and liabilities to the CENG Plan and its trust with respect to each Former Employee whose employment is transferred by the Company directly from the Company (or a designated subsidiary or affiliate of the Company reflected in Appendix G) to CENG (or any affiliate or subsidiary thereof the employees of which participate in the Prior Plan) after the CENG Effective Date. No Employee or Former Employee of the Employer shall be entitled to a benefit or continued participation in the Plan (or CENG Plan, as the case may be) after the date the assets and liabilities with respect to such employee's benefit are spun off from this Plan and its Trust to the CENG Plan and its trust (or from the CENG Plan and its trust to the Plan and

its Trust, as the case may be, and in all cases except to the extent such employee's benefit is subsequently spun back to the other plan pursuant to this paragraph). Under no circumstances shall any individual transferred pursuant to this paragraph be entitled to benefits under this Plan and the CENG Plan (or any other qualified defined benefit pension plan sponsored by the Company, CENG or any of their subsidiaries or affiliates).

9.4(c) Automatic PEP Participation —Except as provided in the next sentence, each Transferred Participant shall become a Participant in the PEP on the date he/she becomes a Full-Time Employee pursuant to the transfer of employment described in 9.4(b). Notwithstanding the foregoing, each Transferred Participant that was a participant in the Traditional Pension Plan immediately prior to the CENG Effective Date and subsequently remained a participant in the corresponding component of the CENG Plan continuously from the CENG Effective Date until the Participant's Transfer Date shall become a Participant in the Traditional Pension Plan on the date he/she becomes a Full-Time Employee pursuant to the transfer of employment described in 9.4(b).

9.4(d) Minimum Benefit —

(i) Traditional Pension Plan —Notwithstanding anything in the Plan to the contrary, the Gross Pension payable to a Transferred Participant in the Traditional Pension Plan under 3.3(a), 3.3(b), 3.3(c), or 3.3(d) shall not be less than the Gross Pension payable to such Participant at the applicable retirement date under the CENG Plan determined immediately prior to such Participant's Transfer Date. For a Transferred Participant in the Traditional Pension Plan, any applicable actuarial adjustment under 3.2(b) shall include periods of active employment recognized as such for purposes of the corresponding actuarial adjustment under the CENG Plan prior to the Transfer Date.

(ii) PEP —Notwithstanding anything in the Plan to the contrary: (a) the Gross Pension payable to a Transferred Participant in the PEP under 3.3(f) or 3.3(g) shall not be less than the Gross Pension or single life annuity payable to such Participant at the Benefit Commencement Date determined under the applicable CENG Plan formula based on the plan provisions, factors and all components of such formula as in effect immediately prior to the Participant's Transfer Date including, for a PEP formula, the Participant's Total Pension Credits and Final Average Annual Pay determined under the applicable CENG Plan as of such date and the provisions of the applicable CENG Plan (including, as applicable, the Annuity Factor and Deferred Annuity Factor) as in effect on such date, and (b) the Gross Pension payable to a Transferred Participant in the PEP under 3.3(e) shall not be less than the Present Value of the deferred annuity payable as of the Participant's Normal Retirement Date under the applicable CENG Plan formula, where such annuity shall be determined immediately prior to the Participant's Transfer Date based on the plan provisions, factors and all components of such formula as in effect immediately prior to the Participant's Transfer Date including, for a PEP formula, the Participant's Total Pension Credits and Final Average Annual Pay determined under the applicable CENG Plan formula and the other provisions of the applicable CENG Plan as in effect on such date.

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IN WITNESS WHEREOF, this restatement and the appendices attached thereto, effective January 31, 2012, were duly executed on this _____day of January, 2012.

Mary Lauria
Chief Human Resources Officer

APPENDIX A

DEFINITIONS

A-1 “Adjusted Employment Commencement Date” means, with respect to an Employee who terminates employment with the Employer and is subsequently reemployed, the date that is determined by subtracting the period of Credited Service and/or Vesting Service that is restored upon reemployment from the date on which the Employee accumulated one hour of service (i.e., each hour for which an Employee is directly or indirectly paid or entitled to payment by an Employer for the performance of duties) after reemployment.

A-2 “Administrative Committee” means the committee appointed by the Chief Executive Officer of the Company as set forth in 6.4.

A-3 “Alternate Beneficiary” means an individual person(s) and/or trust(s) who is entitled to receive distributions under this Plan upon or after the death of a PEP Participant or Traditional Plan Participant.

A-4 “Annual Interest Rate” means (1) on and after January 1, 2008, the rate of interest specified under Code Section 417(e)(3) as amended by the Pension Protection Act of 2006 and clarified by Revenue Ruling 2007-67 and (2) prior to January 1, 2008, the annual rate of interest on 30-year Treasury securities, in each case, for the November of the Plan Year immediately preceding the Plan Year in which the first day of the month following the Participant’s Severance From Service Date occurs. Effective January 1, 2008, if the Plan is terminated, for purposes of converting a lump sum benefit to an annuity or converting an annuity to a lump sum, the Annual Interest Rate shall be equal to the average of the rates of interest used under this A-4 during the 5-year period ending on the termination date.

A-5 “Annuity Factor” means the factor which is used to convert a PEP Gross Pension lump sum to an annuity. The factor is based on a Participant’s age at the Benefit Commencement Date, the mortality table described in Code Section 417(e)(3), and the Annual Interest Rate. For distributions with a Benefit Commencement Date on or after January 1, 2003 and prior to January 1, 2008, the mortality table used for purposes of satisfying the requirement of Code Section 417(e)(3) is the table prescribed in Revenue Ruling 2001-62 and for distributions with a Benefit Commencement Date on or after January 1, 2008, the mortality table used for purposes of satisfying the requirements of Code Section 417(e)(3) is the table prescribed in Revenue Ruling 2007-67. Notwithstanding the foregoing, the following increase is made to the Annual Interest Rate in determining the Annuity Factor: if (i) the Participant is eligible for Early Retirement under 2.2 on his/her Severance From Service Date or (ii) the Participant becomes a Disabled Participant on or after January 1, 1994, the Participant completes at least ten years of Credited Service prior to the date the Participant first benefits under the Disability Plan, and the Participant ceases to be a Disabled Participant on or after age 55 and prior to age 65.

Age at Benefit Commencement Date	Increase in Annual Interest Rate
50 to 62	+1.0%
63	+0.6%
64	+0.3%
65 or older	+0.0%

If the Surviving Spouse of a Participant in PEP chooses to receive an annuity under 5.8, the Surviving Spouse's age as of the date the annuity begins shall be used in place of the Participant's age at the Benefit Commencement Date to determine the Annuity Factor and the increase in the Annual Interest Rate in determining the Annuity Factor described in the preceding sentence is not applicable.

A-6 "Applicable Interest Rate" means, as set forth in Code Section 417(e)(3)(B), the interest rate which would be used (as of the effective date of the distribution) by the Pension Benefit Guaranty Corporation for purposes of determining the present value of a lump sum distribution on plan termination.

A-7 "Appropriate Request" means a written request by a Participant delivered to the Plan Administrator or his/her designated representative.

A-8 "Average Annual Pay" means for a PEP Participant the average, as described in the next sentence, of the following forms of eligible pay: (i) the base rate of pay of an Employee (before any reductions, and excluding (a) overtime, (b) bonuses and incentives other than certain license bonuses set forth in Appendix I, Part 1 and (c) other forms of extra compensation) plus (ii) bonuses and/or incentives set forth in Appendix I, Part 2, paid by the Employer to an Employee, plus (iii) any military differential wage payments (as defined in Section 3401(h)(2) of the Code). The average is calculated by computing the above amounts paid during the 60-month period (in five consecutive 12 month increments) ending on the last day of the month which includes the Severance From Service Date (the date as of which benefits begin under the Disability Plan in the

case of a Disabled Participant) including the base rate of pay described in (i) which the Employee would have been paid for the month which includes the Severance From Service Date if he/she had worked to the end of such month to the last 12 month increment, and then taking the average of the three 12-month periods during which the highest amounts were paid. The base salary of an Employee on unpaid leave of absence shall be considered paid for purposes of calculating Average Annual Pay. For purposes of (i), only license bonuses set forth in Appendix I, Part 1 will be included in the computation of Average Annual Pay. For purposes of (ii), only bonuses and/or incentives that are set forth in Appendix I, Part 2 will be included in the computation of Average Annual Pay. The eligible pay of each Participant for each 12-month increment shall not exceed the limitations set forth in Appendix B, Section B-3. To determine Average Annual Pay for a Transferred Participant, amounts described in (i) and (ii) of this section shall include amounts paid by CENG or other Employer under the applicable CENG Plan, but only to the extent that such amounts (x) would be included for purposes of calculating the Transferred Participant's Average Annual Pay under the applicable CEG PEP Plan if such amounts had been paid by an Employer under this Plan, and (y) were paid during the 60-month period (in five consecutive 12-month increments) ending on the last day of the month that includes the Transferred Participant's Severance From Service Date described above. For a Transferred Participant, depending on the Participant's Severance From Service Date, the Participant's Transfer Date may be within the 60-month period described in A-8 or such period may be entirely after the Participant's Transfer Date.

A-9 “Average Pay” means for a Traditional Pension Plan Participant (i) the base rate of pay of an Employee (before any reductions, and excluding (a) overtime, (b) bonuses and incentives other than certain license bonuses set forth in Appendix I, Part 1 and (c) other forms of extra compensation), for the most current 730 days of active employment (but ending on the date as of which benefits begin under the Disability Plan in the case of a Disabled Participant) excluding any February 29ths, divided by 24, plus (ii) certain bonuses and/or incentives set forth in Appendix I, Part 2 paid by the Employer to an Employee during the same period described in (i), but including any February 29ths, divided by 24, plus (iii) any military differential wage payments (as defined in Section 3401(h)(2) of the Code). The base salary of an Employee on unpaid leave of absence shall be considered paid for purposes of calculating Average Pay. For purposes of (i), only license bonuses set forth in Appendix I, Part 1 will be included in the computation of Average Pay. For purposes of (ii), only bonuses and/or incentives set forth in Appendix I, Part 2 will be included in the computation of Average Pay. The eligible pay of each Participant for the most current 12-month period of active employment and for the immediately preceding 12-month period shall not exceed the limitations set forth in Appendix B, Section B-3. To determine Average Pay for a Transferred Participant, amounts described in (i) and (ii) shall include amounts paid by CENG or other Employer under the CENG Traditional Plan, but only to the extent that such amounts (x) would be included for purposes of calculating the Transferred Participant’s Average Pay under the CEG Traditional Plan if such amounts had been paid by an Employer under this Plan, and (y) were paid during the most current 730 days of active employment described above. For a Transferred Participant, depending on the Participant’s Severance From Service Date, the Participant’s Transfer Date may be within the 730 day period described in A-9 or such period may be entirely after the Participant’s Transfer Date.

A-10 “Benefit Commencement Date” means the date as of which the Participant’s benefits, if any, under the Plan commence.

A-11 “Board of Directors” means the Board of Directors of the Company.

A-11a “CENG” means Constellation Energy Nuclear Group, LLC, and its successors and assigns.

A-11b “CENG Effective Date” means November 6, 2009.

A-11c “CENG Plan” means the applicable plan sponsored by CENG under which a Transferred Participant participated immediately prior to his or her Transfer Date, which plan is either (a) the Pension Plan of Constellation Energy Nuclear Group, LLC, which has two parts known as the “CENG Traditional Plan” and the “CEG PEP Plan,” (b) Appendix Ginna of the Pension Plan of Constellation Energy Nuclear Group, LLC or (c) the Nine Mile Point Pension Plan, each of which is intended to be a defined benefit pension plan qualified under Section 401(a) of the Code and its related trust is intended to be tax-exempt under Section 501(a) of the Code. A-12 “Code” means the Internal Revenue Code of 1986, as amended or replaced from time to time.

A-13 “Company” means Constellation Energy Group, Inc., and its successors and assigns.

A-14 “Credited Service” means the period that is taken into account to determine a Participant’s Gross Pension: (i) during a Participant’s employment with the Employer while classified as a Full-Time Employee (other than a leased employee described in Code Section 414(n) or a co-op, work study or summer employee), or (ii) while a Disabled Participant if such Participant has at least ten years of Credited Service prior to the date as of which the Participant first receives benefits under the Disability

Plan, and becomes a Disabled Participant on or after January 1, 1994. Credited Service is computed as described in 4.3. A Transferred Participant's Credited Service shall include Credited Service under the applicable CENG Plan as determined immediately prior to the Transfer Date. Credited Service shall exclude any periods of military service as described in Section 4.4, unless otherwise required by applicable law.

A-15 "Deferred Annuity Factor" means 1.04^{η} where η equals the number of years and fractions of a year between the Participant's Severance From Service Date and Benefit Commencement Date. If the Participant works less than a full month,, then full credit will be given for the entire month.

A-16 "Disability Plan" means the Constellation Energy Group, Inc. Long-Term Disability Plan, the Constellation Energy Group, Inc. Disability Insurance Plan, or any successor plan.

A-17 "Disabled Participant" means a Participant who is disabled as that term is defined in the Disability Plan and who is receiving benefits under the Disability Plan. Participants who became Disabled Participants prior to January 1, 1994 are subject to the provisions at Appendix C, Section C-10.

A-18 "Disability Retirement" means a type of retirement available to a Disabled Participant (i) who became a Disabled Participant on or after January 1, 1994, (ii) who is a Participant in the Traditional Pension Plan, (iii) who has at least ten years of Credited Service prior to the date as of which the Participant first receives benefits under the Disability Plan, and (iv) who is at least age 50 (but not yet age 65) when he/she ceases benefiting under the Disability Plan because he/she is determined to be no longer disabled under the terms of such plan.

A-19 “Early Retirement” means a type of retirement available to a Participant who, on his/her Severance From Service Date is at least age 55, and has at least ten years of Credited Service.

A-20 “Early Retirement Adjustment Factor” means, for a Participant in the Traditional Pension Plan with a Benefit Commencement Date that is on or after the date that the Participant attains age 55, or for a Disabled Participant who is age 50 or older, 100 percent less 1/4 of one percent for each month that the Participant is less than age 65 on the Participant’s Benefit Commencement Date. Notwithstanding anything to the contrary, the Early Retirement Adjustment Factor for a Participant in the Traditional Pension Plan who has completed at least 35 years of Credited Service as of his/her Severance From Service Date is 100 percent less 1/4 of one percent for each month that the Participant is less than age 62 on the Participant’s Benefit Commencement Date. For purposes of these calculations, the month of the Participant’s 62nd or 65th birthdays, as appropriate, is excluded.

A-21 “Employee” means any person who is employed by the Employer, but excludes any person who is in the sole judgment of the Employer an independent contractor. Employee shall include leased employees within the meaning of Code Section 414(n)(2), which, effective for Plan Years beginning on or after January 1, 1997, includes any person (other than an Employee of an Employer) who pursuant to an agreement between an Employer and any other person has performed services for an Employer on a substantially full-time basis for a period of at least one year, and such

services are performed under the primary direction or control of an Employer, unless the leased employees are covered by a plan described in Code Section 414(n)(5) and such leased employees do not constitute more than 20% of the Employer's nonhighly compensated work force described in Code Section 414(n)(5)(C)(ii).

An Employee may be a Full-Time Employee or an On-Call Employee. A Full-Time Employee is any Employee employed on an ongoing and regular basis who has a basic workweek generally consisting of 40 hours, although Employees who work a Part-Time Schedule with a basic workweek of less than 40 hours are also considered to be Full-Time Employees. On-Call Employees constitute a reasonable classification of Employees who do not have a basic workweek, but rather work on an irregular, "on call" basis and do not participate in any "time off" or related benefit plans and are compensated only for those hours actually worked.

A-22 "Employer" means the Company and any successor which shall maintain this Plan, and any subsidiaries or other affiliates required to be aggregated with the Company under Code Section 414(b), (c), (m) or (o).

A-23 "Employment Commencement Date" means, with respect to an Employee who is not described in "Adjusted Employment Commencement Date," the date on which an Employee first performs an hour of service (i.e., each hour for which an Employee is directly or indirectly paid or entitled to payment by an Employer for the performance of duties) for the Employer.

A-24 "ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time.

A-24a “Executive Group” means the Company’s Chief Executive Officer, Chief Financial Officer, General Counsel and Chief Human Resources Officer, collectively.

A-25 “Final Average Annual Pay” means for a Participant in PEP, the Average Annual Pay computed as of the Participant’s Severance From Service Date.

A-26 “Final Average Pay” means for a Participant in the Traditional Pension Plan, the Average Pay computed as of the Participant’s Severance From Service Date. A-27 “Former Employee” means an individual who was formerly an Employee, but who has ceased employment with the Employer.

A-28 “Full-Time Employee” see the definition of “Employee.”

A-29 “Gross Pension” means the monthly benefit or the lump sum benefit computed under a pension formula, before any adjustments.

A-30 “Investment Committee” means the committee appointed by the Chief Executive Officer of the Company as set forth in 6.5.

A-31 “Normal Retirement” means a type of retirement available to a Participant who, on the day preceding his/her Normal Retirement Date, is actively employed or a Disabled Participant and has at least five years of Credited Service.

A-32 “Normal Retirement Date” means the first day of the first month after the later of (i) the date of the Participant’s 65th birthday or (ii) the date which is the fifth anniversary of the Participant’s Employment Commencement Date (or, if applicable, the Adjusted Employment Commencement Date).

A-33 “Normal Retirement Service Percentage” means (i) 1/12 of 1-1/2 percent for each of a Traditional Pension Plan Participant’s first 240 months of Credited Service, plus (ii) 1/12 of 1-1/3 percent for each of the next 180 months of Credited Service.

A-34 “On-Call Employee” —see the definition of “Employee.”

A-34a “Part-Time Schedule” means a job that is scheduled for fewer than either eight hours per base tour or five base tours per payroll week on a regular and ongoing basis. It is intended that this definition conform to the usage of the term part-time in the Company’s Employee Handbook.

A-35 “Participant” means any Employee or Former Employee who is entitled to benefits under the Plan.

A-36 “Pension Equity Plan or ‘PEP’” means the Plan in effect as of January 1, 2000, for those who become Participants pursuant to 1.1 and those Participants who choose it pursuant to 1.2. For a Transferred Participant, “Pension Equity Plan” or “PEP” also means the Plan in effect for those who become Participants pursuant to 9.4(c) who did not become participants in the Traditional Pension Plan pursuant to 9.4(c).

A-37 “Plan” means the Pension Plan of Constellation Energy Group, Inc., which includes the both the Pension Equity Plan and the Traditional Pension Plan.

A-38 “Plan Administrator” means the Director—Benefits of the Company (or the successor to that function).

A-39 “Plan Year” means the Plan’s accounting year of 12 months beginning on January 1 of each year and ending the following December 31.

A-40 “Post-retirement Survivor Annuity” means a Survivor Annuity paid when a Participant with vested benefits under the Traditional Pension Plan dies on or after the Participant’s Benefit Commencement Date.

A-41 “Post-retirement Survivor Benefit” means a survivor benefit paid when a Participant with vested benefits under PEP dies on or after the Participant’s Benefit Commencement Date.

A-42 “Preretirement Survivor Annuity” means a Survivor Annuity paid when a Participant with vested benefits under the Traditional Pension Plan dies before the Participant’s Benefit Commencement Date.

A-43 “Preretirement Survivor Benefit” means a survivor benefit paid when a Participant with vested benefits under PEP dies before the Participant’s Benefit Commencement Date.

A-44 “Present Value” means, as set forth in Code Section 417(e)(3), an amount calculated by using the UP-1984 Mortality Table and (i) by using an interest rate equal to the Applicable Interest Rate if such Present Value is not in excess of $25,000, and (ii) by using an interest rate equal to 120 percent of the Applicable Interest Rate if such Present Value exceeds $25,000 (as determined under (i)). In no event shall the Present Value determined under (ii) be less than $25,000.Notwithstanding the preceding, for payments made as of a date on or after January 1, 2000, “Present Value” means an amount calculated using the interest rate described below and the mortality table described in Code Section 417(e)(3). Prior to January 1, 2008, the interest rate shall be the lesser of (i) the annual interest rate on 30-year Treasury securities for November of the Plan Year immediately preceding the Plan Year that contains the date as of which the payment is made, and (ii) for payments made as of a date on or after January 1, 2000 and before January 1, 2001, the annual interest rate on 30-year Treasury securities for the first full calendar month preceding the date as of which the payment is made. On and after

January 1, 2008, the interest rate shall be rate of interest specified under Code Section 417(e)(3) as amended by the Pension Protection Act of 2006 and clarified by Revenue Ruling 2007-67. Effective January 1, 2008, if the Plan is terminated, for purposes of converting a lump sum benefit to an annuity or converting an annuity to a lump sum, the interest rate described above shall be equal to the average of the rates of interest used under this A-44 during the 5-year period ending on the termination date.

In calculating the "Present Value" of a benefit payable to a Participant, the benefit shall be treated as commencing as of the later of the Participant's Normal Retirement Date and the Benefit Commencement Date. In calculating the "Present Value" of a benefit payable to the Surviving Spouse of a Participant in the Traditional Pension Plan, the benefit shall be treated as commencing as of the first day of the month following the Participant's 55th birthday.

For distributions with a Benefit Commencement Date on or after January 1, 2003 and prior to January 1, 2008, the mortality table used for purposes of satisfying the requirements of Code Section 417(e)(3) is the table prescribed in Revenue Ruling 2001-62. For distributions with a Benefit Commencement Date on or after January 1, 2008, the mortality table used for purposes of satisfying the requirements of Code Section 417(e)(3) is the table prescribed in Revenue Ruling 2007-67.

A-44a "Section 415(c) Compensation" means all amounts required to be reported under Code Sections 6041, 6051, and 6052 (wages, tips, and other compensation as reported on Form W-2). This includes wages, within the meaning of Code Section 3401(a), and all other payments of compensation to an Employee by the Employer (in the course of the Employer's trade or business) for which the Employer is required to furnish

the Employee a written statement under Code Sections 6041(d), 6051(a)(3), and 6052. In addition, an Employee's compensation includes any elective deferrals (as defined in Code Section 402(g)(3)), and any amount which is contributed or deferred by the Employer at the election of the Employee and which is not includible in gross income of the Employee by reason of Code Sections 125 or 132(f)(4). An Employee's compensation shall be determined without regard to any rules under Code Section 3401(a) that limit the remuneration included in wages based on the nature or location of the employment or the services performed.

To the extent applicable, Section 415(c) Compensation shall not include amounts in excess of the statutory dollar limitation under Code Section 401(a)(17), as described in Section B-3. Section 415 Compensation includes any differential wage payments (as defined in Section 3401(h)(2) of the Code).

A-45 "Severance From Service Date" means the date on which a Participant ends active employment with the Employer for purposes of the Plan. A Participant ends active employment on the earliest of the date that the Participant quits, retires, is discharged, dies, or the first anniversary of the first date of a period in which the Employee remains absent from service with the Employer for any reason other than quit, retirement, discharge or death.

A-46 Deleted.

A-47 "Surviving Spouse" means, with respect to a Preretirement Survivor Annuity or the Preretirement Survivor Benefit, the person married to a Participant on the Participant's date of death. Surviving Spouse means, with respect to a Post-retirement Survivor Annuity or the Post-retirement Survivor Benefit, the person married to a Participant on the Participant's Benefit Commencement Date.

A-48 “Survivor Annuity” means a monthly benefit payable to the Surviving Spouse or Alternate Beneficiary for the life of the Surviving Spouse or Alternate Beneficiary.

A-49 “Total Pension Credits” means the pension credits provided to a Participant in PEP. A Participant’s pension credits shall equal the sum of (i) 0.05 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (ii) 0.10 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (iii) 0.15 times the Credited Service earned in each Plan Year after the Participant reaches age 49.

A-50 “Traditional Pension Plan” means the Plan in effect as of January 1, 2000, for those Participants who choose it pursuant to Section 1.2, which is the enhancement to the Plan in effect prior to that date.

A-50a “Transfer Date” means the effective date of the spin off of a Transferred Participant’s benefit from the applicable CENG Plan and merger into this Plan pursuant to 9.4(b).

A-50b “Transferred Participant” means each (a) Full-Time Employee of the Company or those designated subsidiaries and affiliates of the Company reflected in Appendix G with respect to whom assets and liabilities are spun off from the applicable CENG Plan and its related trust and merged into this Plan and its Trust pursuant to 9.4(b) of this Plan.

A-51 “Treasury” means the Federal Treasury Department.

A-52 “Trust” means the trust established for the purpose of holding and managing Plan assets.

A-53 “Trustee” means Citibank, N.A. or any successor Trustee appointed by the Board of Directors.

A-54 “Vesting Service” means the period of a Participant’s employment with the Employer that is taken into account to determine whether a Participant has a vested right to receive a pension. Vesting Service is computed as described in 4.4. A Transferred Participant’s Vesting Service shall include Vesting Service under the applicable CENG Plan as determined immediately prior to the Transfer Date.

APPENDIX B

LIMITATIONS

B-1 Maximum Pension Payment: Code Limits —

(a) Notwithstanding any other provision in the Plan to the contrary, the limitations, adjustments and other requirements prescribed in this B-1 shall at all times be administered in a manner which will result in compliance with the provisions of Code Section 415 and the regulations thereunder, the terms of which are specifically incorporated herein by reference.

(b) For limitation years beginning on or after July 1, 2007, in addition to other limitations set forth in the Plan and notwithstanding any other provisions of the Plan, the "Annual Benefit" otherwise payable to a Participant under the Plan shall not exceed the "Maximum Permissible Benefit" (as defined below). If the benefit the Participant would otherwise accrue in a limitation year would produce an Annual Benefit in excess of the Maximum Permissible Benefit, the benefit shall be limited (or the rate of accrual reduced) to a benefit that does not exceed the Maximum Permissible Benefit. If the Participant is, or ever has been, a participant in another qualified defined benefit plan (without regard to whether the plan has been terminated) maintained by the Employer or its predecessor (within the meaning of Section 1.415(f)-1(c) of the Treasury Regulations), the sum of the Participant's annual benefit from all such plans may not exceed the Maximum Permissible Benefit. The Annual Benefit of a Participant may be increased as the Maximum Permissible Benefit is adjusted in accordance with Code Section 415(d), but only prior to the commencement of pension payments.

(c) For purposes of this B-1 for limitation years beginning on or after July 1, 2007, the "Annual Benefit" means the Gross Pension payable annually under the terms of the Plan in the form of a straight life annuity (exclusive of any benefit not required to be considered for purposes of applying the limitations of Section 415 of the Code). Where the Gross Pension is payable other than a straight life annuity, the benefit shall be adjusted (pursuant to B-1(g)) to an actuarially equivalent straight life annuity that begins at the same time as such other form of benefit and is payable on the first day of each month before applying the limitations of this B-1. The determination of the Annual Benefit shall take into account benefits transferred from another defined benefit plan, other than transfers of distributable benefits pursuant to Section 1.411(d)-4, Q&A-3(c) of the Treasury Regulations, but shall disregard benefits, if any, attributable to employee contributions or rollover contributions.

(d) For limitation years beginning on or after July 1, 2007 for purposes of this B-1, "Maximum Permissible Amount" means the lesser of (i) or (ii) below:

(i) $180,000, adjusted under Section 415(d) of the Code effective January 1 of each year and payable in the form of a straight life annuity. This limitation as adjusted under Section 415(d) of the Code will apply to limitation years ending with or within the calendar year for which the adjustment applies.

(ii) 100% of the Participant's high three-year compensation, or, if the Participant does not have three consecutive years of service, 100% of the Participant's average compensation over the longest consecutive period of service (including fractions of years, but not less than one year), payable in the form of a straight life annuity. In the case of a Participant who is rehired by the Employer after a severance from employment,

the Participant's high three-year average compensation shall be calculated excluding all years for which the Participant performs no services for and receives no compensation from the Employer and by treating the years immediately preceding and following the break as consecutive.

(iii) Notwithstanding anything in this section to the contrary, the benefit otherwise accrued or payable to the Participant under the Plan shall be deemed not to exceed the Maximum Permissible Benefit if the retirement benefits payable for a limitation year under any form of benefit with respect to such Participant under this Plan and all other defined benefit plans (without regard to whether a plan as been terminated) ever maintained by the Employer do not exceed $10,000 multiplied by a fraction, the numerator of which is the Participant's number of years (or part thereof, but not less than one year) of service (not to exceed 10) with the Employer, and the denominator of which is 10; and the Employer (or predecessor employer) has not at any time maintained a defined contribution plan in which the Participant participated.

(e) For limitation years beginning on or after July 1, 2007 for purposes of this B-1, "compensation" means Section 415(c) Compensation. In addition, for purposes of this B-1 for limitation years beginning on or after July 1, 2007, compensation shall also include amounts paid by the later of 2 1/2 months after a Participant's severance from employment with the Employer or the end of the limitation year that includes the date of such severance from employment if the payment is regular compensation for services (within the meaning of Section 1.415(c)-2(e)(3)(ii) of the Treasury Regulations), commissions, bonuses or other similar payments paid after the Participant's severance from employment (but by the later of 2 1/2 months after such severance from employment or the end of the limitation year that includes the date of such severance from employment) that would have been paid to the Participant absent such severance from employment had the Participant continued in employment with the Employer.

Any payments not described above shall not be considered compensation for purposes of this B-1 for limitation years beginning on or after July 1, 2007 if paid after severance from employment, even if paid by the later of 2 1/2 months after the date of severance from employment or the end of the limitation year that includes the date of such severance from employment, except:

(i) payments to an individual who does not currently perform services for the employer by reason of qualified military service (within the meaning of Code Section 414(u)(1)) to the extent these payments do not exceed amounts the individual would have received if the individual would had continued to perform services for the Employer rather than entering qualified military service; or

(ii) compensation paid to a Participant who is permanently and totally disabled, as defined in Code Section 22(e)(3), provided that salary continuation applies to all Participants who are permanently and totally disabled for a fixed or determinable period, or the Participant was not a highly compensated employee immediately before becoming disabled.

Back pay, within the meaning of Section 1.415(c)-2(g)(8) of the Treasury Regulations, shall be treated as compensation for the limitation year to which the back pay relates to the extent that back pay represents wages and compensation that would otherwise be included as “compensation” as defined herein.

(f) For purposes of complying with Code Section 415, a limitation year means the calendar year.

(g) Adjustments to Annual Benefit and Limitations

(i) For purposes of applying the limits of Code Section 415 and this B-1, for limitation years beginning on or after July 1, 2007, a benefit that is payable in any form other than a straight life annuity and that is not subject to Section 417(e)(3) of the Code must be adjusted to an actuarially equivalent straight life annuity that equals the greater of the annual amount of the straight life annuity (if any) payable under the Plan at the same annuity starting date, and the annual amount of a straight life annuity commencing at the same annuity starting date that has the same actuarial present value as the Participant's form of benefit computed using an interest rate of 5% and the applicable mortality table for that annuity starting date.

(ii) For Plan benefits subject to Section 417(e)(3) of the Code, the actuarially equivalent straight life annuity for annuity starting dates beginning after 2005 is equal to the greatest of (i) the annual amount of the straight life annuity commencing at the same annuity starting date that has the same actuarial present value as the Participant's form of benefit, computed using the interest rate and mortality table (or other tabular factor) specified in the Plan for adjusting benefits in the same form; (ii) the annual amount of the straight life annuity commencing at the same annuity starting date that has the same actuarial present value as the Participant's form of benefit, computed using a 5.5 % interest rate assumption and the applicable mortality table; and (iii) the annual amount of the straight life annuity commencing at the same annuity starting date that has the same actuarial present value as the Participant's form of benefit, computed using the applicable interest rate and applicable mortality table, divided by 1.05.

(iii) For Plan benefits subject to Section 417(e)(3) of the Code with an annuity starting date in a Plan Year beginning in 2004 or 2005, the actuarially equivalent straight life annuity is equal to the annual amount of the straight life annuity commencing at the same annuity starting date that has the same actuarial present value as the Participant's form of benefit, computed using whichever of the following produces the greater annual amount: (i) the interest rate and mortality table (or other tabular factor) specified in the Plan for adjusting benefits in the same form; and (ii) a 5.5 % interest rate assumption and the applicable mortality table.

(iv) For limitation years beginning on or after July 1, 2007, if the benefit of a Participant begins prior to age 62, the defined benefit dollar limitation (described in B-1(d)(i) above, adjusted as applicable) applicable to the Participant at such earlier age is limited to the lesser of (1) the annual amount of a benefit payable in the form of a straight life annuity commencing at the Participant's annuity starting date that is the actuarial equivalent of the defined benefit dollar limitation (as adjusted under B-1(g)(vi) for years of participation less than 10, if required), with actuarial equivalence computed using a 5% interest rate assumption and the applicable mortality table and expressing the Participant's age based on completed calendar months as of the annuity starting date or (2) the product of the defined benefit dollar limitation (as adjusted under B-1(g)(vi) for years of participation less than 10, if required) multiplied by the ratio of the annual amount of the immediately commencing straight life annuity at the Participant's annuity starting date to the annual amount of the immediately commencing straight life annuity at age 62, both determined without applying the limitations of Code Section 415.

(v) For limitation years beginning on or after July 1, 2007, if the benefit of a Participant begins after the Participant attains age 65, the defined benefit dollar limitation (described in B-1(d)(i) above, adjusted as applicable) is the lesser of (1) the annual amount of a benefit payable in the form of a straight life annuity commencing at the Participant's annuity starting date that is the actuarial equivalent of the defined benefit dollar limitation (as adjusted under B-1(g)(vi) for years of participation less than 10, if required), with actuarial equivalence computed using a 5% interest rate assumption and the applicable mortality table for that annuity starting date (and expressing the Participant's age based on completed calendar months as of the annuity starting date) or (2) the defined benefit dollar limitation (as adjusted under B-1(g)(vi) for years of participation less than 10, if required) multiplied by the ratio of the annual amount of the adjusted immediately commencing straight life annuity under the Plan at the Participant's annuity starting date to the annual amount of the adjusted immediately commencing straight life annuity under the Plan at age 65, both determined without applying the limitations of Code Section 415. For this purpose, the adjusted immediately commencing straight life annuity under the Plan at the Participant's annuity starting date is the annual amount of such annuity payable to the Participant, computed disregarding the Participant's accruals after age 65 but including actuarial adjustments even if those actuarial adjustments are used to offset accruals; and the adjusted immediately commencing straight life annuity under the Plan at age 65 is the annual amount of such annuity that would be payable under the Plan to a hypothetical Participant who is age 65 and has the same accrued benefit as the Participant.

(vi) If the Participant has less than 10 years of participation in the Plan, the defined benefit dollar limitation (described in B-1(d)(i) above, adjusted as applicable) shall be multiplied by a fraction, the numerator of which is the number of years (or part thereof, but not less than one year) of participation in the Plan, and the denominator of which is 10. If the Participant has less than 10 years of service, the defined benefit compensation limit (described in B-1(d)(ii) above) shall be multiplied by a fraction, the numerator of which is the number of years (or part thereof, but not less than one year) of service with the employer, and the denominator of which is 10.

(vii) In applying the limitations in Code Section 415(b), the Code Section 415(b)(2)(E) changes made by the Uruguay Round Agreements Act (GATT) and Small Business Job Protection Act of 1996 shall be effective as of January 1, 2000. For this purpose, the time for determining the applicable interest rate under Code Section 417(e)(3) shall be the November of the Plan Year immediately preceding the Plan Year that contains the Benefit Commencement Date. For distributions with a Benefit Commencement Date on or after January 1, 2003, the applicable mortality table used for purposes of adjusting any benefit or limitation under Code Sections 415(b)(2)(B), (C), or (D) is the table prescribed in Revenue Ruling 2001-62. For limitation years beginning on or after July 1, 2007, the applicable interest rate shall be the first, second, and third segment rates described in Code Section 417(e)(3)(C), for the November of the Plan Year immediately preceding the Plan Year that contains the Benefit Commencement Date and the applicable mortality table shall be the mortality table, as modified by the Secretary of Treasury, described in Section 417(e)(3)(B) of the Code that applies as of the Benefit Commencement Date.

(h) All members of a controlled group of corporations (as defined in Code Section 414(b), commonly controlled trades or businesses (as defined in Code Section 414(c)), or affiliated service groups (as defined in Code Section 414(m)) that include the Employer, and any other entity required to be aggregated with the Employer pursuant to Code Section 414(o) shall be considered as a single employer for purposes of applying the limitations described in Section 415 of the Code and this B-1.

(i) If (i) a Participant is also benefiting under another defined benefit plan sponsored by the Employer or its predecessor, and (ii) reductions in either the amount of the Participant's annual benefit under the Plan or the amount of the Participant's annual benefit under such other plan (or both) are necessary to comply with Code Section 415, a reduction in the Participant's annual benefit under the Plan shall be made to the extent necessary to comply with Code Section 415, prior to any reduction in the Participant's annual benefit any other plan(s).

(j) The application of the provisions of this B-1 shall not cause the Maximum Permissible Benefit for any Participant to be less than the Participant's accrued benefit as of the end of the last limitation year beginning before July 1, 2007 under the provisions of the Plan that were adopted and in effect before April 5, 2007.

B-2 Maximum Pension Payment: Treasury Regulation Limits —Notwithstanding any other provision in the Plan to the contrary, pension payments to the top 25 highly compensated employees and former highly compensated employees, as those terms are defined in Code Section 414 (q) and the related regulations, with the greatest compensation (as that term is defined in Code Section 414(s) and the related regulations) in the current Plan Year and any prior Plan Year, shall be restricted as required under Section 1.401(a)(4)-5(b)(3) of the Treasury regulations, unless the exception set forth in such section applies.

B-3 Compensation Limitation Under Code Section 401(a)(17) —In addition to other applicable limitations set forth in the Plan, and notwithstanding any other provision of the Plan to the contrary, for Plan Years beginning on or after January 1, 1994, the annual compensation of each Employee taken into account under the Plan shall not exceed the Omnibus Budget Reconciliation Act of 1993 (hereinafter referred to in this Section B-4 as "OBRA '93") annual compensation limit. The OBRA '93 annual compensation limit is $150,000, as adjusted by the Commissioner of the Internal Revenue Service for increases in the cost of living in accordance with Code Section 401(a)(17)(B). The cost-of-living adjustment in effect for a calendar year applies to any period, not exceeding 12 months, over which compensation is determined (hereinafter referred to as "Determination Period") beginning in such calendar year.

For Plan Years beginning on or after January 1, 1994, any reference in this Plan to the limitation under Code Section 401(a)(17) shall mean the OBRA '93 annual compensation limit set forth in this provision.

If compensation for any prior Determination Period is taken into account in determining an Employee's benefits accruing in the current Plan Year, the compensation for that prior Determination Period is subject to the OBRA '93 annual compensation limit in effect for that prior Determination Period. For this purpose, for Determination Periods beginning before the first day of the first Plan Year beginning on or after January 1, 1994, the OBRA '93 annual compensation limit is $150,000.

Unless otherwise provided under the Plan, each Code Section 401(a)(17) employee's accrued benefit under this Plan will be the greater of the accrued benefit determined for such Employee under 1 or 2 below:

1. The Employee's accrued benefit determined with respect to the benefit formula applicable for the Plan Year beginning on or after January 1, 1994, as applied to the Employee's total years of service taken into account under the Plan for the purposes of benefit accruals, or

2. the sum of:

(a) the Employee's accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994, frozen in accordance with Section 1.401(a)(4)-13 of the Treasury regulations; and

(b) the Employee's accrued benefit determined under the benefit formula applicable for the Plan Year beginning on or after January 1, 1994, as applied to the Employee's years of service credited to the Employee for Plan Years beginning on or after January 1, 1994, for purposes of benefit accruals.

For purposes of making the calculation in 2. above, the following rules shall apply:

1. An Employee's accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994 shall be determined after limiting Average Pay to $228,860 for 1992 and $235,840 for 1993;

2. An Employee's accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994 shall be determined by assuming the Employee is eligible for the early retirement benefits and the early retirement reductions for which the Employee is eligible at the Employee's Severance From Service Date;

3. An Employee's accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994 shall be determined based on the project and prorate method (i.e., the projected Gross Pension on December 31, 1993 assuming employment until Normal Retirement Date times Credited Service as of December 31, 1993, divided by projected Credited Service at Normal Retirement Date) if the Employee is not eligible for Early Retirement on December 31, 1993. If such an Employee is eligible for Early Retirement on the Employee's Severance From Service Date, the Employee's accrued benefit as applied to the Employee's years of service credited to the Employee for Plan Years beginning on or after January 1, 1994 shall be calculated by subtracting the December 31, 1993 benefit, calculated using the $150,000 compensation limit (reflecting cost-of-living increases in the $150,000 compensation limit) from the benefit at the Employee's Severance From Service Date based on all service;

4. An Employee who participates in the PEP may receive a lump-sum payment of the Employee's accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994 based on the assumptions in the Plan used to convert an immediate lump sum to a deferred annuity beginning at the Employee's Normal Retirement Date; and

5. The Employee's accrued benefit as of the last day of the last Plan Year beginning before January 1, 1994 for an Employee who participates in the PEP is converted to a lump sum based on the assumptions used to determine the Present Value of an accrued benefit or the assumptions that are used to convert a lump-sum benefit under the PEP to a life annuity beginning at the Employee's Normal Retirement Date, whichever results in the larger lump sum.

A Code Section 401(a)(17) employee means an Employee whose current accrued benefit as of a date on or after the first day of the first Plan Year beginning on or after January 1, 1994, is based on compensation for a year beginning prior to the first day of the first Plan Year beginning on or after January 1, 1994, that exceeds $150,000.

Notwithstanding the foregoing, for Plan Years beginning on or after January 1, 2002, the annual compensation of each Employee taken into account under the Plan shall not exceed $200,000, as adjusted for cost of living increases in accordance with Code section 401(a)(17)(B). The cost-of-living adjustment in effect for a calendar year applies to annual compensation for the Determination Period beginning in such calendar year. For purposes of determining benefit accruals in a Plan Year beginning on or after January 1, 2002, the annual compensation taken into account in any Plan Year preceding the Plan Year beginning on January 1, 2002 shall be limited to $200,000.

APPENDIX C

TRANSITION AND HISTORICAL PROVISIONS

C-1 Normal Retirement Service Percentage —Notwithstanding any other provision in the Plan to the contrary, each Participant who (i) was an active Employee of the Employer on December 31, 1975, (ii) continuously accrues Credited Service from such date through the Participant's Normal Retirement Date, and (iii) has accumulated Credited Service on the day prior to the Participant's Normal Retirement Date equal to at least 15 years but less than 20 years, has a Normal Retirement Service Percentage of 30%, adjusted for Part-Time Schedule as provided in 3.4(b) if applicable. This C-1 will not be effective after December 31, 1995.

C-2 Part-Time Schedule Adjustment —Notwithstanding any other provision in the Plan to the contrary, each Participant who (i) was an active Employee of the Employer on December 31, 1975, (ii) continuously accrues Credited Service from such date through the date the Participant quits, retires, is discharged, becomes disabled, or dies, and (iii) could receive a larger Gross Pension if the Part-Time Schedule adjustment provisions of the Plan in effect on December 31, 1975 were currently applicable, will be entitled to such larger Gross Pension.

C-3 Former Susquehanna Transmission Company Employees —Notwithstanding any other provision in the Plan to the contrary, service with the Susquehanna Transmission Company by an Employee who became employed by the Employer because of Baltimore Gas and Electric Company's acquisition of such company, will count as Credited Service and Vesting Service, to the same extent and

subject to the same limitations as if such service had been rendered for the Employer. The Gross Pension of any Participant affected by this provision who quits, retires, is discharged, becomes disabled or dies with a vested right to a benefit under the Plan, and who is entitled to an annuity under another arrangement by virtue of such Participant's previous employment with the Susquehanna Transmission Company, will be reduced by the amount of such annuity.

C-4 Voluntary Retirement—Early Receipt of Pension Payments —Notwithstanding any other provisions of the Plan, a Participant who retired under the Voluntary Retirement provisions that were in effect prior to July 1, 1986, may elect to begin receipt of his/her monthly pension payments prior to the Participant's Normal Retirement Date, subject to the adjustment under the early receipt provisions in 3.4(c). Such pension payments shall commence as of the first day of the month designated in writing by the Participant. The month so designated must be a month (i) later than the month during which the Plan Administrator receives the Participant's written election, and (ii) before the Participant's Normal Retirement Date.

C-5 Preretirement Survivor Annuity Coverage For Certain Participants —The provisions of this C-5, and not 5.1 or 5.2, shall apply to a Participant who quit or was discharged from employment with the Employer after September 1, 1974 and before January 1, 1985. If such Participant (i) terminated employment with a vested right to receive a pension payment equal to the Participant's Gross Pension (as computed under the terms of the Plan on the date the Participant terminated active employment), (ii) dies prior to the Participant's Benefit Commencement Date, (iii) was not eligible to elect Preretirement Survivor Annuity coverage while an active Employee, and (iv) makes the

election in the following paragraph, then the Surviving Spouse of such Participant will receive a Preretirement Survivor Annuity equal to 50% of such pension (actuarially reduced if necessary to account for the age of the Surviving Spouse and for payment prior to the Participant's Normal Retirement Date).

The Participant's election for the 50% Preretirement Survivor Annuity coverage must be made prior to the Participant's Benefit Commencement Date. The coverage commences on the first day of the month following receipt of the Participant's election by the Plan Administrator. Such coverage automatically ceases as set forth in 5.1(c). The Participant may cancel the coverage, without the consent of the Participant's spouse, by delivering an Appropriate Request to the Plan Administrator prior to the Participant's Benefit Commencement Date. Such cancellation is effective as of the first day of the month following receipt by the Plan Administrator of the Appropriate Request. Cancellation is automatic if the Participant's spouse dies prior to the effective date of the coverage. A Participant's pension payments are not reduced for the cost of coverage.

C-6 Post-retirement Survivor Annuity Coverage for Certain Participants —The provisions of this C-6, and not 5.3 or 5.4, shall apply to a Participant who quit or was discharged from employment with the Employer after September 1, 1974 and prior to January 1, 1976. If such Participant (i) terminates employment with a vested right to receive a pension payment equal to the Participant's Gross Pension (as computed under the terms of the Plan on the date the Participant terminated active employment), (ii) dies on or before the Participant's Benefit Commencement Date, and (iii) makes the election in the following paragraph, then the Surviving Spouse of such Participant will receive a Post-retirement Survivor Annuity equal to 50% of such pension (actuarially reduced if necessary to account for the age of the Surviving Spouse and for payment prior to the Participant's Normal Retirement Date).

The Participant's election for the 50% Post-retirement Survivor Annuity must be made prior to the Participant's Benefit Commencement Date. The Participant may revoke an election, without the consent of the Participant's spouse, by delivering an Appropriate Request to the Plan Administrator prior to the Participant's Benefit Commencement Date. Cancellation is automatic if the Participant's spouse dies prior to the effective date of the coverage. The coverage commences on the Participant's Benefit Commencement Date. Such coverage automatically ceases upon the date of death of the spouse. A Participant's pension payments are reduced to offset the cost of coverage.

Within 90 days prior to such Participant's Benefit Commencement Date, the Plan Administrator will mail to the Participant's last known address (i) written explanation of the terms and conditions of the Post-retirement Survivor Annuity and (ii) an estimate of the relative values of the various optional forms of benefit under the Plan if the fact of marriage and the age of the spouse are known to the Plan Administrator. In the case of a Participant whose Benefit Commencement Date is before or after the Participant's Normal Retirement Date, the Plan Administrator shall mail the written explanation to the Participant by the later of (i) 90 days prior to the Participant's Benefit Commencement Date, or (ii) 7 days after the Plan Administrator is notified of the Participant's intention to retire.

C-7 Participants Who Terminated Employment Before 1989 —A Participant who terminated employment prior to January 1, 1989 without a vested right to the Participant's Gross Pension, and who is subsequently reemployed by the Employer, will be subject to the service forfeiture, restoration and vesting provisions currently under this Plan, retroactive to the Employee's original Employment Commencement Date. If retroactive application of these provisions results in a vested right to the Participant's Gross Pension prior to the date of the Participant's termination of employment, Credited Service taken into account to determine such vesting, and Credited Service subsequently accumulated through the date of termination of employment, shall be restored.

A Participant who terminated employment prior to January 1, 1989 with a vested right to the Participant's Gross Pension, and who is subsequently reemployed by the Employer, will be subject to the forfeiture, restoration and vesting provisions currently under this Plan, retroactive to the Employee's original Employment Commencement Date. If retroactive application of these provisions results in a larger amount of potentially restorable Credited Service than the amount of Credited Service actually accumulated prior to the date of the Participant's termination of employment, the larger amount of Credited Service will be restored.

C-8 Voluntary Special Early Retirement Program —Notwithstanding any other provision in the Plan or any Appendix to the contrary, each Participant who under the terms of the Plan is eligible to commence Early Retirement, and who voluntarily elects to commence Early Retirement on or after February 1, 1992 and on or before April 1, 1992, shall be entitled to an enhanced benefit, subject to the Employer's right to limit benefits to the extent necessary to satisfy tax law limitations. The Employer also reserves the right to delay the Early Retirement commencement date of eligible Participants until no later than April 1, 1992, if operating condition requirements warrant such a delay. For purposes of this C-8, the enhanced benefit is determined based on the calculation of the

Gross Pension of a Participant entitled to Early Retirement as set forth under 3.3(b), except that the Early Retirement Adjustment Factor shall be computed as follows:

> The Early Retirement Adjustment Factor for Participants with a Benefit Commencement Date that is on or after the date that the Participant attains age 60, is 100 percent. For all other Participants, the Early Retirement Adjustment Factor is 100 percent less 1/4 of 1 percent for each month that the Participant is less than age 60 on the Participant's Benefit Commencement Date. For purposes of this calculation, the month of the Participant's 60th birthday is excluded.

The amount of pension payments for Participants entitled to an enhanced benefit under this C-8 is computed taking into account all other adjustments required under the terms of the Plan in the computation of pension payments. A Participant who commences Early Retirement under this C-8, and who is subsequently reemployed by the Employer, will be entitled to benefits under the Plan based on the provisions in effect at the time that the Participant subsequently retires.

C-9 Voluntary Special Early Retirement Program —Notwithstanding any other provision in the Plan or any Appendix to the contrary, certain Participants who meet the conditions set forth in the next sentence are eligible for Early Retirement if, as of February 1, 1994 they satisfy the requirements of 2.2 after substituting age 50 for age 55 and 15 years of Credited Service for 20 years of Credited Service. The conditions such Participants must meet are as follows: (1) the Participant makes an election between October 15, 1993 and December 15, 1993 to voluntarily commence Early Retirement on February 1, 1994, and such election shall be irrevocable effective December 15, 1993,

and (2) the Participant does not elect to participate in the Baltimore Gas and Electric Company Voluntary Severance Plan. Participants who satisfy the requirements and conditions set forth in the two preceding sentences shall be entitled to an enhanced benefit, subject to the Employer's right to limit benefits to the extent necessary to satisfy tax law limitations.

For purposes of this C-9, the enhanced benefit for eligible Participants is determined based on the calculation of the Gross Pension of a Participant entitled to Early Retirement as set forth under 3.3(b), except that the Early Retirement Adjustment Factor shall be computed as follows:

The Early Retirement Adjustment Factor for Participants with a Benefit Commencement Date that is on or after the date that the Participant attains age 60, is 100 percent. For Participants with a Benefit Commencement Date that is on or after the date that the Participant attains age 55 but before the date that the Participant attains age 60, the Early Retirement Adjustment Factor is 100 percent less 1/4 of 1 percent for each month that the Participant is less than age 60 on the Participant's Benefit Commencement Date. For all other Participants, the Early Retirement Adjustment Factor is 100 percent less the percentage equal to (i) 15 percent plus (ii) 1/2 of 1 percent for each month that the Participant is less than age 55 on the Participant's Benefit Commencement Date. For purposes of this calculation, the month of the Participant's 55th and 60th birthdays is excluded.

In addition, the enhanced benefit for eligible Participants who have not attained age 62 as of February 1, 1994 will include an additional monthly payment from the Plan. The amount of the payment shall be equal to one-half of the Participant's estimated monthly age 62 Social Security benefits computed assuming no earnings after 1993. The amount of such estimated age 62 Social Security benefits shall be provided to Baltimore Gas and Electric Company by the Social Security Administration and shall be final and not subject to challenge. The payments shall cease effective when the Participant is first eligible to receive reduced old-age insurance benefits under title II of the Social Security Act. The payments shall not be subject to the Post-retirement Survivor Annuity provisions of Article V and shall not be subject to the pension payment adjustment provisions of 3.4(e). Notwithstanding the foregoing provisions of this paragraph, if a Participant who is otherwise entitled to a monthly payment under this paragraph fails to submit to the Employer by December 15, 1993, a completed and signed Social Security Administration Request for Earnings and Benefit Estimate Statement, then the amount of such payment shall be $200.

Except as otherwise provided in the preceding paragraph, the amount of pension payments for Participants entitled to an enhanced benefit under this C-9 is computed taking into account all other adjustments required under the terms of the Plan in the computation of pension payments. A Participant who commences Early Retirement under this C-9, and who is subsequently reemployed by the Employer, will be entitled to benefits under the Plan based on the provisions in effect at the time that the Participant subsequently retires.

C-10 Pre-1994 Disability Retirement —This Appendix C-10 applies to Participants who became a Disabled Participant prior to January 1, 1994. Benefits under the Plan for Participants who became Disabled Participants on or after January 1, 1994 are determined in accordance with the provisions of the Plan except this Appendix C-10. All defined terms used in this C-10 that are not separately defined in this C-10 have the meaning set forth in Appendix A.

Types of Retirement:

Disabled Participants —A Disabled Participant who is eligible for Early Retirement on or before his/her Severance From Service Date, may elect Early Retirement if certain requirements are satisfied. To be eligible to elect Early Retirement, such Disabled Participant must retire either (i) during the period that is within one year following both classification as a Disabled Participant and a reduction in the amount of benefits payable to the Disabled Participant under the Disability Plan due to that plan's offset provisions, or (ii) following termination of the Disability Plan and the failure of the Company to establish a successor plan or policy to provide similar benefits.

Disability Retirement: Generally —A Disabled Participant who is at least age 65 and who, prior to his/her Severance From Service Date, has at least ten years of Credited Service, is eligible for Disability Retirement.

Effective Date —Disability Retirement is effective on the first day of the first month after the Participant reaches age 65.

Early Disability Retirement —A Disabled Participant who, (i) prior to his/her Severance From Service Date, has at least 20 years of Credited Service, and (ii) is at least age 55 but has not yet reached age 65 when he/she is determined to be no longer disabled under the terms of the Disability Plan, is eligible for Early Disability Retirement.

Effective Date —Early Disability Retirement is effective on the first day of the month of retirement designated in writing by the Participant, which is on or after the date that the Participant becomes eligible for Early Disability Retirement, and on or before the Participant's Normal Retirement Date. Such written designation must be received by the Plan Administrator before the beginning of the designated month.

Pension Payments

Disability Retirement —The Gross Pension of a Participant entitled to Disability Retirement is calculated as follows:

Gross Pension =	Disability Retirement Service Percentage	X	Final Average Pay

Early Disability Retirement —The Gross Pension of a Participant entitled to Early Disability Retirement is calculated as follows:

Gross Pension =	Disability Retirement X Service Percentage	Final Average Pay	X	Early Retirement Adjustment Factor

Accrued Gross Pension Calculation and Vesting :

Disability Retirement —A Participant who immediately prior to his/her Benefit Commencement Date is benefiting under the Disability Plan, and who has at least ten years of Credited Service before his/her Severance From Service Date, has a vested right to a Disability Retirement pension on the Participant's Normal Retirement Date.

Early Disability Retirement —A Participant who immediately prior to his/her Benefit Commencement Date is at least age 55 and ceases benefiting under the Disability Plan because he/she is determined to be no longer disabled under the terms of such plan, and who has at least 20 years of Credited Service before his/her Severance From Service Date, has a vested right to an Early Disability Retirement on the Participant's Benefit Commencement Date.

The following definitions apply to the disability benefits under this Plan prior to January 1, 1994:

"Disability Retirement" means a type of retirement available to a Disabled Participant who is at least age 65 prior to his/her Severance From Service Date, and has at least ten years of Credited Service.

"Disability Retirement Service Percentage" means the greater of (i) the percentage equal to (x) the Normal Retirement Service Percentage, less (y) 1/12 of 1 percent for each month that the Participant was less than age 65 on the Participant's Severance From Service Date, or (ii) 30 percent. For purposes of this calculation, the month of the Severance From Service Date is excluded, and the month of the Participant's 65th birthday is included.

"Disabled Participant" means a Participant who is disabled as that term is defined in the Disability Plan.

"Early Disability Retirement" means a type of retirement available to a Disabled Participant who, on the day preceding his/her Severance From Service Date, has at least 20 years of Credited Service, and who is at least age 55 (but not yet age 65) when he/she ceases benefiting under the Disability Plan because he/she is determined to be no longer disabled under the terms of such plan.

C-11 Prior Plan —Except as provided in 1.2 and the last paragraph of 4.3, Participants who do not earn Credited Service on or after January 1, 2000 are covered by the provisions in the Plan in effect before January 1, 2000.

C-12 Accrued Gross Pension Calculation in the Traditional Pension Plan —Prior to January 1, 2000, for each month of Credited Service, a Participant will accrue a portion of the Participant's projected Gross Pension at the Participant's Normal Retirement Date. Subject to the limitations in Appendix B, Section B-2, a Participant's Accrued Gross Pension is calculated as follows:

Accrued = Gross Pension	Projected – Gross Pension at Normal Retirement Date	Accrued X Gross Pension as of 12/31/75	Credited + Service Accumulated To Date After 12/31/75	Accrued Gross Pension as of 12/31/75

Projected Credited Service Accumulated After 12/31/75 To Normal Retirement Date

In computing the "Projected Gross Pension at Normal Retirement Date," it will be assumed that the Participant will continue to work for the Employer until the Participant's Normal Retirement Date, and that the Participant's Final Average Pay at such date will be equal to the Participant's Average Pay as of the date of the computation. If the Participant works a Part-Time Schedule as of the date of the computation, it will be assumed that the Participant will continue to work a Part-Time Schedule until the Participant's Normal Retirement Date for purposes of the computation.

The "Accrued Gross Pension as of 12/31/75" is equal to the greater of A or B below:

- A -

Accrued Gross Pension as of 12/31/75	=	Projected Gross Pension as of 12/31/75	X	Credited Service Accumulated Prior To 1/1/76 / Credited Service Projected To Be Accumulated To Normal Retirement Date		

2

OR

- B -

Accrued Gross Pension as of 12/31/75	=	0.00125	X	Actual Earnings From 1/1/40 12/31/75	-	Federal Old-Age Benefit Offset

In computing the "Projected Gross Pension as of 12/31/75", it will be assumed that the Participant will continue to work for the Employer until the Participant's Normal Retirement Date, and that the Participant's Final Average Pay at the Participant's Normal Retirement Date will be equal to the Participant's Average Pay as of 12/31/75.

Minimum Pension Payment: Generally —Prior to January 1, 2000, if as of the Participant's Benefit Commencement Date, the Participant's Gross Pension is less than the Participant's Accrued Gross Pension reduced in accordance with the adjustments set forth in 3.4(b) and 3.4(c), the Participant's pension payments will be based on the adjusted Accrued Gross Pension.

C-13 Targeted Voluntary Special Early Retirement Program —Notwithstanding any other provision in the Plan or any Appendix to the contrary, certain Participants who meet the conditions set forth in the next sentence are eligible for an enhanced Plan benefit described below, if as of May 31, 2000 they are age 55 or older with at least ten years of Credited Service. The conditions such Participants must meet are as follows: (1) on January 14, 2000, the Participant is an Employee of Baltimore Gas and Electric Company in a job or skill group in the Utility Operations Group (UOG) that has been identified by UOG management for reduction; (2) the Participant receives a written notification from UOG management that his/her job or skill group has been identified for such reduction; (3) the Participant makes an election on or after March 1, 2000 and on or before April 14, 2000 to voluntarily retire on June 1, 2000, and such election shall be irrevocable effective April 14, 2000; (4) the Participant executes (and does not subsequently revoke) in writing and submits to the Plan Administrator, in the form, manner, and subject to the timing established by the Plan Administrator, an agreement releasing legal claims, including those against the Company and its subsidiaries/affiliates, including but not limited to claims arising out of his/her employment with the Employer or termination of such employment; and (5) the Participant is not eligible for the Constellation Energy Group, Inc. Severance Plan.

Traditional Pension Plan :

For purposes of this C-13, the enhanced benefit for eligible Participants is determined based on the calculation of the Gross Pension of a Participant entitled to Early Retirement as set forth under 3.3(b), except that the Early Retirement Adjustment Factor shall be computed as follows:

The Early Retirement Adjustment Factor for Participants in the Traditional Pension Plan with a Benefit Commencement Date that is on or after the date that the

Participant attains age 60, is 100 percent. For Participants with a Benefit Commencement Date that is on or after the date that the Participant attains age 55 but before the date that the Participant attains age 60, the Early Retirement Adjustment Factor is 100 percent less 1/4 of one percent for each month that the Participant is less than age 60 on the Participant's Benefit Commencement Date; provided, however, that for a Participant with at least 35 years of Credited Service as of his/her Severance From Service Date, the Early Retirement Adjustment Factor is 100 percent less 1/4 of one percent for each month that the Participant is less than age 57 on the Participant's Benefit Commencement Date. For purposes of this calculation, the month of the Participant's 55th, 57th and 60th birthdays, as appropriate, is excluded.

PEP:

For purposes of this C-13, the enhanced benefit for eligible PEP Participants is determined as follows:

The Gross Pension referenced in 3.3(e), 3.3(f) and 3.3(g) shall be adjusted by computing Total Pension Credits assuming that on the Participant's Employment Commencement Date (or, if applicable, Adjusted Employment Commencement Date) and thereafter, the Participant's age is the Participant's actual age plus five years.

Social Security Bridge :

In addition, the enhanced benefit for eligible Participants who have not attained age 62 as of June 1, 2000 will include an additional monthly payment equal to one-half of the Participant's estimated monthly age 62 Social Security benefits computed assuming no earnings after 1999. The amount of such estimated age 62 Social Security benefits shall be requested from the Social Security Administration by the Participant and

furnished by the Participant to the Company and shall be final and not subject to challenge. The payments shall commence as of the Participant's Benefit Commencement Date and shall cease effective at the earlier of (i) when the Participant is first eligible to receive reduced old-age insurance benefits under title II of the Social Security Act, or (ii) upon the Participant's death. The payments shall not be subject to the Post-retirement Survivor Annuity or the Post-retirement Survivor Benefit provisions of Article V.

Notwithstanding the foregoing provisions, if a Participant who is otherwise entitled to a monthly Social Security bridge payment fails to submit to the Employer by May 31, 2000, an original Social Security Administration Benefit Statement, then the amount of such monthly payment shall be $200.

If a PEP Participant elects a lump sum form of payment pursuant to 3.3(e) of the Plan, then the Social Security bridge payment will be payable in a lump sum as of the Benefit Commencement Date. The lump sum will equal the present value of the additional monthly Social Security bridge payments the Participant would otherwise receive. Such present value shall be calculated based on the mortality table and interest rate described in Present Value as of the Benefit Commencement Date.

Generally:

Except as otherwise provided above, the amount of pension payments for Participants entitled to an enhanced benefit under this C-13 is computed taking into account all other adjustments required under the terms of the Plan in the computation of pension payments. A Participant who commences payments under this C-13, and who is subsequently reemployed by the Employer will cease to receive such payments and will be entitled to benefits under the Plan based on the provisions in effect at the time that the Participant subsequently retires.

C-14 Voluntary Special Early Retirement Program —Notwithstanding any other provision in the Plan or any Appendix to the contrary, certain Participants who meet the conditions set forth in the next sentence, who under the terms of the Plan are eligible to commence Early Retirement as of February 1, 2002, and who voluntarily elect to commence Early Retirement on February 1, 2002 (or such later date on or before July 1, 2002 as required in the sole discretion of management of the Employer) shall be entitled to an enhanced benefit. Applicable Participants are Employees of the following Employers: Baltimore Gas and Electric Company (BGE), Constellation Energy Group, Inc. (excluding Employees above the Co-President level), Constellation Energy Source, Inc., Constellation Investments, Inc., Constellation Nuclear, LLC (CN) (excluding Employees above the Vice-President level), Constellation Nuclear Services, Inc. (CNS), Calvert Cliffs Nuclear Power Plant, Inc. (CCNPP), Constellation Power, Inc., Constellation Power Source, Inc., Constellation Power Source Generation, Inc. (CPSG), and Constellation Power Source Holdings, Inc. (collectively, the Companies). The conditions such Participants must meet are as follows: (1) the Participant on November 1, 2001 is an active employee of one of the Companies; (2) the Participant makes an election on or after: (a) November 1, 2001 and on or before December 16, 2001 for CPSG; (b) November 15 and on or before December 31, 2001 for CN, CNS and CCNPP; and (c) November 26, 2001 and on or before December 31, 2001 for the remainder of the Companies, to voluntarily retire on February 1, 2001, and such election shall be irrevocable effective December 16, 2001 for CPSG, and December 31, 2001 for the rest

of the Companies; (3) the Participant executes (and does not subsequently revoke) in writing and submits to the Plan Administrator, in the form, manner, and subject to the timing established by the Plan Administrator, an agreement releasing legal claims, including those against the Company and its subsidiaries/affiliates, including but not limited to claims arising out of his/her employment with the Employer or termination of such employment; and (4) the Participant is not eligible for the Constellation Energy Group, Inc. Severance Plan or any other Employer severance plan or arrangement. In addition, Participants who are employees of BGE, CN, CNS, CCNPP or CPSG, and who are involuntarily displaced in connection with a workforce reduction between December 17, 2001 for CPSG (January 2, 2002 for BGE, CN, CNS and CCNPP) and January 31, 2002 (February 28, 2002 for BGE), and who otherwise satisfy all of the foregoing requirements and conditions (except under 2(a) above, December 16, 2001 is replaced with January 31, 2002, and under 2(b) above, December 31, 2001 is replaced with February 28, 2002, and under 2 (c) above, December 16, 2001 and December 31, 2001 are replaced with February 28, 2002), are also entitled to an enhanced benefit. Participants who satisfy the requirements and conditions set forth in the preceding sentences shall be entitled to an enhanced benefit, subject to the Employer's right to limit benefits to the extent necessary to satisfy tax law limitations.

For purposes of this C-14, the enhanced benefit for eligible Participants is determined based on the calculation of the Gross Pension of a Participant entitled to Early Retirement as set forth under the Plan, except that (1) the Participant's regular unenhanced Gross Pension shall be computed using average base rate of pay computed as of February 1, 2002 or if later, the Participant's Severance From Service Date, whichever

produces the highest amount, and using bonus and/or incentives (i) for purposes of determining Average Pay, that were earned (rather than paid) during the calendar years (a) 1999 and 2000 (including Annual Incentive Awards earned during such years) , or (b) for Participants retiring after March, 2002, if higher, 2000 and 2001 (including Annual Incentive Awards earned during such years); and (ii) for purposes of determining Average Annual Pay, in accordance with the Plan provisions except that Annual Incentive Awards paid during all applicable prior years shall be included; and (2) the Participant shall also be entitled to an additional Gross Pension amount under the Plan, computed as an immediate lump sum equal to: (a) the number of whole years of Credited Service (*i.e.* , partial years of Credited Service are disregarded) multiplied by three, and (b) multiply the product in (a) by the sum of (i) the base rate of pay on the Participant's Severance From Service Date determined as a weekly amount, plus (ii) bonuses and/or incentives (that have previously been approved in writing by the Administrative Committee and the Chairman of the Board of Directors for inclusion in the computation of Average Annual Pay) that were earned during calendar years 1999 and 2000 (including Annual Incentive Awards earned during such calendar years), divided by 104.

Such immediate lump sum amount shall also be available as an immediate annuity using the same formula set forth under Section 3.3(f) of the Plan or as a deferred annuity using the same formula set forth under Section 3.3(g) of the Plan; provided, however, that any Participant in PEP who elects an immediate lump sum must make such election for his/her entire Gross Pension.

Except as otherwise provided above, the amount of pension payments for Participants entitled to an enhanced benefit under this C-14 is computed taking into account all other adjustments required under the terms of the Plan in the computation of pension payments. The enhanced benefit does not accrue until the Participant makes an irrevocable election to retire under the program; therefore, preretirement survivor annuity coverage is not available with respect to such enhanced benefit prior to such election. A Participant who commences payments under this C-14, and who is subsequently reemployed by the Employer, will be entitled to benefits under the Plan based on the provisions in effect at the time that the Participant subsequently retires.

C-15 Voluntary Special Early Retirement Program —Notwithstanding any other provision in the Plan or any Appendix to the contrary, certain Participants who meet the conditions set forth in the next sentence are eligible for Early Retirement if, between January 31, 2002 and February 28, 2002, they satisfy the requirements of Section 2.2 after substituting age 50 for age 55, and voluntarily elect to commence Early Retirement on March 1, 2002 (or such later date on or before July 1, 2002 as required in the sole discretion of Baltimore Gas and Electric Company (BGE) or Constellation Power Source Generation, Inc. (CPSG) management) shall be entitled to an enhanced benefit. The conditions such Participants must meet are as follows: (1) the Participant on January 2, 2002 is an employee of BGE (excluding manager- or executive-level employees) or CPSG; (2) the Participant is at least age 50 and no older than age 54 with 20 or more years of service between January 31, 2002 and February 28, 2002; (3) the Participant makes an election on or after January 2, 2002 and on or before February 15, 2002 to voluntarily retire on March 1, 2002, and such election shall be irrevocable effective February 15, 2002; (4) the Participant executes (and does not subsequently revoke) in writing and submits to the Plan Administrator, in the form, manner, and subject to the

timing established by the Plan Administrator, an agreement releasing legal claims, including those against the Company and its subsidiaries/affiliates, including but not limited to claims arising out of his/her employment with the Employer or termination of such employment; and (5) the Participant is not eligible for the Constellation Energy Group, Inc. Severance Plan or any other Employer severance plan or arrangement. In addition, Participants who are employees of CPSG, BGE, Constellation Energy Group, Inc., Constellation Investments, Inc., Constellation Power, Inc., Constellation Power Source, Inc., or Constellation Power Source Holdings, Inc., and who are involuntarily displaced in connection with a workforce reduction between January 2, 2002 and February 28, 2002, and who otherwise satisfy all of the foregoing requirements and conditions (except under (3) above, February 15, 2002 is replaced with February 28, 2002), are also entitled to an enhanced benefit. Participants who satisfy the requirements and conditions set forth in the preceding sentences shall be entitled to an enhanced benefit, subject to the Employer's right to limit benefits to the extent necessary to satisfy tax law limitations.

For purposes of this C-15, the enhanced benefit for eligible Participants is determined based on the calculation of the Gross Pension of a Participant entitled to Early Retirement as set forth under the Plan, except that (1) the Participant's regular unenhanced Gross Pension shall be computed using average base rate of pay computed as of March 1, 2002 or if later, the Participant's Severance From Service Date, whichever produces the highest amount, and using bonus and/or incentives (i) for purposes of determining Average Pay, that were earned (rather than paid) during the calendar years (a) 1999 and 2000 (including Annual Incentive Awards earned during such years), or (b)

for Participants retiring after March 2002, if higher, 2000 and 2001 (including Annual Incentive Awards earned during such years); and (ii) for purposes of determining Average Annual Pay, in accordance with the Plan provisions except that Annual Incentive Awards paid during all applicable prior years shall be included; and (2) the Participant shall also be entitled to an additional Gross Pension amount under the Plan, computed as an immediate lump sum equal to: (a) the number of whole years of Credited Service (*i.e.* , partial years of Credited Service are disregarded) multiplied by two, and (b) multiply the product in (a) by the sum of (i) the base rate of pay on the Participant's Severance From Service Date determined as a weekly amount, plus (ii) bonuses and/or incentives (that have previously been approved in writing by the Administrative Committee and the Chairman of the Board of Directors for inclusion in the computation of Average Annual Pay) that were earned during calendar years 1999 and 2000 (including Annual Incentive Awards earned during such calendar years), divided by 104.

Such immediate lump sum amount shall also be available as an immediate annuity using the same formula set forth under Section 3.3(f) of the Plan or as a deferred annuity using the same formula set forth under Section 3.3(g) of the Plan; provided, however, that any Participant in PEP who elects an immediate lump sum must make such election for his/her entire Gross Pension. The enhanced benefit for applicable participants shall also be computed by substituting age 50 for age 55 in Section A-20.

Except as otherwise provided above, the amount of pension payments for Participants entitled to an enhanced benefit and under this C-15 is computed taking into account all other adjustments required under the terms of the Plan in the computation of pension payments. The enhanced benefit does not accrue until the Participant makes an

irrevocable election to retire under the program; therefore, preretirement survivor annuity coverage is not available with respect to such enhanced benefit prior to such election. A Participant who commences payments under this C-15, and who is subsequently reemployed by the Employer, will be entitled to benefits under the Plan based on the provisions in effect at the time that the Participant subsequently retires.

APPENDIX D

TOP HEAVY PROVISIONS

D-1 Purpose —If the Plan is or becomes top-heavy in any Plan Year beginning after December 31, 1983, the following provisions will supersede any conflicting provisions in the Plan.

D-2 Definitions —As used in the Plan, the following terms shall have the meaning set forth below, unless a different meaning is clearly required by the context in which the term is used.

D-2.2 " Anniversary Date " means December 31, the last day of the Plan Year.

D-2.4 " Key Employee " means any person who meets the requirements of Code Section 416(i), and the regulations promulgated thereunder, which are hereby incorporated by reference as if fully set out herein. For purposes of determining whether or not the Plan meets the requirements of Section D-3.2, the term Key Employee shall also include the beneficiary of a Key Employee.

D-2.5 " Permissive Aggregation Group " means all plans in the Required Aggregation Group and any other Qualified Plans maintained by the Company, but only if such group of plans would satisfy, in the aggregate, the requirements of Code Sections 401(a)(4) and 410. The Plan Administrator shall determine which plan or plans shall be taken into account in determining the Permissive Aggregation Group.

D-2.6 " Qualified Plan " means any Plan which is qualified under Code Section 401(a).

D-2.7 " Required Aggregation Group " means:

(a) Each Qualified Plan of the Company in which at least one Key Employee participates; and

(b) Any other Qualified Plan of the Company which enables a Plan described in Section D-2.7(a) to meet the requirements of Code Section 401(a)(4) or 410.

D-2.8 " Top-Heavy Plan " means the Plan, for any Plan Year in which the Plan meets the requirements of Section D-3.2.

D-3 Top-Heavy Plan Requirements and Determination

D-3.1 Top Heavy Plan Requirements —For any Plan Year in which the Plan is determined to be a Top-Heavy Plan in accordance with Section D-3.2, the Plan shall be subject to the following:

(a) special vesting requirements in D-4; and

(b) special minimum benefit requirements of D-4.

D-3.2 Top-Heavy Plan Determination

(a) The Plan shall be considered a Top-Heavy Plan and shall be subject to the additional requirements of Section D-3.1, with respect to any Plan Year, if, as of the Anniversary Date of the preceding Plan Year (hereinafter referred to as the "determination date"), (i) the present value of accrued benefits of Key Employees in this Plan exceeds 60 percent of the present value of the accrued benefits of all Employees in this Plan ("60% Test"); or (ii) the Plan is part of a Required Aggregation Group and the sum of the present value of accrued benefits and the value of the aggregate accounts of Key Employees in all plans in the Required Aggregation Group exceeds 60% of a similar sum for all Employees. For this purpose, the present value of accrued benefits and the value of the aggregate accounts shall be determined as of the valuation date for the Plan Year that includes the determination date.

(b) For purposes of this Section D-3.2, the aggregate account of a Participant is determined under applicable provisions of the defined contribution plan used in determining whether the Plan is a Top Heavy Plan.

(c) For purposes of this Section D-3.2, present value of accrued benefits shall be determined, in the case of a defined benefit pension plan, under the provisions of such a plan or plans and shall include any part of any accrued benefit distributed in the 5-year period ending on the determination date. Effective January 1, 2002, the present value of accrued benefits shall include any part of any accrued benefit distributed in the 1-year period ending on the determination date, or, in the case of a distribution made for a reason other than severance from employment, death or disability, during the 5-year period ending on the determination date.

(d) For purposes of this Section D-3.2, the present value of a participant's accrued benefits under a defined benefit plan shall be based upon reasonable interest and mortality assumptions specified by the plan. The Top-Heavy calculations for this Plan shall be based on the same assumptions specified in the definition of Present Value in Section A-44. Where one or more defined benefit plans are aggregated with this Plan for purposes of Top-Heavy calculations, the actuarial assumptions specified in the definition of Present Value in Section A-44 shall be applied to all plans in the aggregation group.

(e) For purposes of this Section D-3.2, the accrued benefit of a participant who is not a Key Employee shall be determined under the method, if any, that uniformly applies for determining benefit accruals under all defined benefit plans maintained by the Employer, or if there is no such method, as if the benefit accrued not more rapidly than the slowest accrual rate permitted under the fractional accrual rule of Section 411(b)(1)(C) of the Code.

(f) For purposes of this Section D-3.2, the accrued benefit of a participant in a plan who is not a Key Employee but who was a Key Employee in a prior year shall be disregarded.

(g) For purposes of this Section D-3.2, the accrued benefits of all plan participants who have not performed services for any employer maintaining the plan at any time during the 5-year period (1-year period, effective January 1, 2002) ending on the determination date shall be disregarded.

(h) Notwithstanding the provisions of subsection (a) herein above, the Plan shall not be a Top-Heavy Plan, if the Plan Administrator elects to treat the Plan as part of a Permissive Aggregation Group, and the Permissive Aggregation Group is not determined to be Top-Heavy using the criteria of the "60% Test" herein above.

(i) Where more than one plan is involved in the determination, only determination dates that fall within the same calendar year shall be considered in order to determine whether the Plan is a Top-Heavy Plan.

(j) The provisions of Code section 416 and applicable regulations are incorporated with respect to any additional requirements with respect to the determination as to how the top heavy ratio is computed.

D-4 Additional Top-Heavy Provisions —For purposes of determining whether or not the Plan meets the requirements of Section D-3.2, the term "Participant" as defined in Appendix A, shall also include the beneficiary of a Participant.

Notwithstanding any other provisions of the Plan if the Plan is a Top-Heavy Plan:

(i) Each Participant who has at least three years of Vesting Service as of the determination date will be fully vested in a pension benefit on the day following the determination date. Each Participant who subsequently accumulates at least three years of Vesting Service shall immediately be fully vested in such pension benefit.

(ii) Each Participant who is not a Key Employee will be deemed to have an Gross Pension after the determination date equal to 1/12 of the lesser of (A) 20% of such Participant's average compensation or (B) such average compensation multiplied by 2% for each year of Credited Service accumulated to the date of the calculation. For purposes of this calculation, average compensation is the Participant's highest average compensation for the five consecutive years for which the Participant had the highest compensation. For purposes of this paragraph, compensation means Section 415(c) Compensation. Effective January 1, 2002, in determining service for purposes of this minimum benefit calculation, any service shall be disregarded to the extent that such service occurs during a plan year when the Plan benefits (within the meaning of Code section 410(b)) no Key Employee or former Key Employee.

APPENDIX G

DESIGNATED SUBSIDIARIES

Except as otherwise provided below, Employees of the following subsidiaries are eligible to participate in the Plan on the same terms and conditions as set forth therein.

Constellation Power, Inc.

Constellation Energy Commodities Group, Inc. (formerly known as Constellation Power Source, Inc.) Constellation Power Source Generation, Inc.

Constellation Energy Source, Inc.

BGE Home Products and Services, LLC (formerly known as BGE Home Products and Services, Inc.) [1]

BGE Commercial Building Systems, Inc. [2]

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[1] a. An individual who is a Participant on December 31, 1999 and an Employee of BGE Home Products & Services, Inc. on January 1, 2000, is subject to 1.2 of the Plan except that PEP is modified as described in b. below. Notwithstanding the preceding sentence, an individual who is an Employee of Constellation Energy Source, Inc. on December 31, 1999, who transfers to BGE Home Products & Services, Inc. effective January 1, 2000, and was hired by Constellation Energy Source, Inc. after December 31, 1994, shall participate in PEP as modified in b. below. An individual who is a Participant in the Traditional Pension Plan after December 31, 1999 by reason of the preceding will cease participating in the Traditional Plan once he/she ceases to earn Credited Service. If such an individual again earns Credited Service, he/she shall participate in PEP as modified in b. below. All other individuals shall participate in PEP as modified in b. below.

b. Participants who are Employees of BGE Home Products & Services, Inc. shall have the following modifications to PEP:

(i) A Participant's Total Pension Credits in Appendix A for the period of time during which the Participant is employed by BGE Home Products & Services, Inc. shall equal the sum of (1) 0.025 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (2) 0.05 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (3) 0.075 times the Credited Service earned in each Plan Year after the Participant reaches age 49.

(ii) The only form of pension payments that a Participant may elect under PEP pursuant to 3.1(b) is monthly installments; lump sum payment is not available except if pursuant to the automatic lump sum cash-out provisions of 3.3(e); 3.3(h) therefore is not applicable. This (ii) is not applicable to a Participant who accrued any benefits under PEP while employed by an Employer whose Employee Participants were eligible to elect under PEP pursuant to 3.1(b) a lump sum, and then after January 1, 2000 transferred employment to BGE Home Products & Services, Inc. This (ii) is not applicable to a Participant who received benefits under the Special Window for Employees Employed by BGE Home (as part of BGE Home's closing of its retail appliance and merchandise stores and the reorganization of BGE Home because of that closing) under the Constellation Energy Group, Inc. Severance Plan.

(iii) The Preretirement Survivor Benefit under 5.8 may be paid as a lump sum.

(iv) The third sentence in the definition of Annuity Factor in Appendix A is not applicable unless the Participant transferred employment to BGE Home Products & Services, Inc. after January 1, 2000, and was eligible for Early Retirement under 2.2 at the time he/she was employed by the Company or a subsidiary listed in this Appendix G other than BGE Home Products & Services, Inc. or BGE Commercial Building Systems, Inc.

[2] a. An individual who is a Participant on December 31, 1999 and an Employee of BGE Commercial Building Systems, Inc. on January 1, 2000, is subject to 1.2 of the Plan except that PEP is modified as described in b. below. An individual who is a Participant in the Traditional Pension Plan after December 31, 1999 by reason of the preceding sentence will cease participating in the Traditional Plan once he/she ceases to earn Credited Service. If such an individual again earns Credited Service, he/she shall participate in PEP as modified in b. below. All other individuals shall participate in PEP as modified in b. below.

b. Participants who are Employees of BGE Commercial Building Systems, Inc. shall have the following modifications to PEP:

(i) A Participant's Total Pension Credits in Appendix A for the period of time during which the Participant is employed by BGE Commercial Building Systems, Inc. shall equal the sum of (1) 0.025 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (2) 0.05 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (3) 0.075 times the Credited Service earned in each Plan Year after the Participant reaches age 49.

(ii) The only form of pension payments that a Participant may elect under PEP pursuant to 3.1(b) is monthly installments; lump sum payment is not available except if pursuant to the automatic lump sum cash-out provisions of 3.3(e). 3.3(h) therefore is not applicable. This (ii) is not applicable to a Participant who accrued any benefits under PEP while employed by an Employer whose Employee Participants were eligible to elect under PEP pursuant to 3.1(b) a lump sum, and then after January 1, 2000 transferred employment to BGE Commercial Building Systems, Inc. The Preretirement Survivor Benefit under 5.8 may be paid as a lump sum.

(iii) The third sentence in the definition of Annuity Factor in Appendix A is not applicable unless the Participant transferred employment to BGE Commercial Building Systems, Inc. after January 1, 2000, and was eligible for Early Retirement under 2.2 at the time he/she was employed by the Company or a subsidiary listed in this Appendix G other than BGE Home Products & Services, Inc. or BGE Commercial Building Systems, Inc.

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Baltimore Gas and Electric Company [3]

Constellation Nuclear Services, Inc.

Constellation Generation Group, LLC

Constellation Operating Services, Inc.; Constellation Operating Services; COSI Central Wayne, Inc. (Employees represented by a union under a collective bargaining agreement are not eligible to participate); COSI Synfuels, Inc.; COSI Sunnyside, Inc.; COSI Puna, Inc.; PCI Operating Company Partnership [4]

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[3] With respect to an Employee of the Comfort Link division of Baltimore Gas and Electric Company, only individuals who are both a Participant on December 31, 1999 and an Employee of the Comfort Link division of Baltimore Gas and Electric Company on January 1, 2000, shall be eligible to participate in the Plan. Notwithstanding anything in the Plan to the contrary, the Vice-Chairman of Baltimore Gas and Electric Company will not be eligible to participate in this Plan.

[4] Employees of each listed subsidiary are eligible for participation in PEP effective January 1, 2003.
For purposes of 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which an Employee first performed an hour of service for the subsidiary. However, if the Participant was an Employee on January 1, 2003 and was employed by one of the following entities on the day immediately preceding the date the Employee became employed by the subsidiary, by A/C Power or by Trona Operating Partners, G.P. (or one of their subsidiaries), the Employment Commencement Date shall be the date on which the Employee first performed an hour of service for such entity (but in no event prior to any date noted in parentheses below):

Malacha Power Project, Inc.
Sunnyside Operating Associates
Niagara Mohawk Power Corporation
Consolidated Edison Company of New York (but only if the Employee was hired by COSI Astoria after August 20, 1999)
OESI Power (but only if the Employee was transferred to Constellation Operating Services, Inc. or one of its subsidiaries from OESI Power on January 6, 1993)
Kerr McGee Corporation—(but only if the Employee became an employee of Constellation Operating Services, Inc., A/C Power, or Trona Operating Partners, G.P. on December 1, 1990)
Ahlstrom Pyropower (or any other employer wholly or partially owned directly or indirectly, by
Ahlstrom Pyropower (or any successor thereto))
Ultrasystems, Inc.
Hadson Corporation
LG&E Power, Inc
LUZ International
U C Operating Services
Panther Creek Fuels Company
Nevada Operations, Inc.
Central Wayne County Sanitation Authority
U. S. Generating (COSI Carr Street)
Ormat Energy Systems, Inc.
Ormat Systems, Inc.
Baltimore Gas and Electric Company (or any other employer wholly or partially owned directly or indirectly, by Baltimore Gas and Electric Company (or any successor thereto))
A/C Power

For purposes of 2.1 and A-31, Vesting Service shall be used instead of Credited Service to determine whether a Participant is eligible for Normal Retirement.

For purposes of 2.2 and A-19, Vesting Service shall be used instead of Credited Service to determine whether a Participant is eligible for Early Retirement.

For purposes of 4.3, Credited Service shall only include months beginning on or after January 1, 2003 during which an Employee works at least one hour for the Employer while classified as a Full-Time Employee.

Constellation NewEnergy, Inc. (Note: Effective April 1, 2011. For purposes of Section 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which the Employee first performed an hour of service for this subsidiary. For purposes of Section 4.3, Credited Service for work performed as an Employee of this subsidiary shall only include months beginning on or after April 1, 2011 during which the Employee works at least one hour while classified as a Full-Time Employee.)

CNE Gas Holdings, Inc. (Note: Effective April 1, 2011. For purposes of Section 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which the Employee first performed an hour of service for this subsidiary. For purposes of Section 4.3, Credited Service for work performed as an Employee of this subsidiary shall only include months beginning on or after April 1, 2011 during which the Employee works at least one hour while classified as a Full-Time Employee.)

APPENDIX I

BONUSES, INCENTIVE AND OTHER PAY

Part 1

The following types of license and other special bonuses are included in the base rate of pay definition of Average Annual Pay (set forth in Section A-8(i)) or Average Pay (set forth in Section A-9(i)), as applicable.

- NRC License Bonus
- Electrician License Bonus
- Plumber License Bonus

Part 2

The following types of bonuses and/or incentives are included in the bonuses and incentives definition of Average Annual Pay (set forth in Section A-8(ii))or Average Pay (set forth in Section A-9(ii)), as applicable.

Baltimore Gas and Electric Company

- Promotion Recognition Award
- Results Incentive Award
- Lump Sum Pay Adjustment
- Commission Payments
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

BGE Home Products & Services, Inc .

- Commission payments (includes draw payments, administrative time, vacation time, non-selling time, and training time payments)
- Sales Incentive Award
- Results Incentive Award
- Scale Rate Payment
- Piece Work Payment
- Emergency Work Payment
- Sales Bonus
- Lump Sum Pay Adjustment
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Calvert Cliffs Nuclear Power Plant, Inc.

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

CER Generation, LLC

- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award
- Annual Incentive Award

CNE Gas Holdings, Inc. *

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Commission Payments
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Building Systems, Inc.

- Commission Payments (includes draw payments, administrative time, vacation time, non-selling time, and training time payments)
- Results Incentive Award
- Scale Rate Payment
- Piece Work Payment
- Emergency Work Payment
- Sales Bonus
- Lump Sum Pay Adjustment
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Energy Commodities Group, Inc. (formerly known as Constellation Power Source, Inc.) *

- Results Incentive Award
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Energy Group, Inc.

- Promotion Recognition Award
- Results Incentive Award
- Lump Sum Pay Adjustment
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Energy Nuclear Group

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

* For Employees of this subsidiary who were Participants in the Plan on or before March 31, 2011, bonuses and/or incentives included in Average Annual Pay or Average Pay as applicable, shall be capped at $200,000 beginning with bonuses paid on or after April 1, 2011. For Employees of this subsidiary who became participants in the Plan on or after April 1, 2011, bonuses and/or incentives included in Average Annual Pay shall be capped at $200,000 beginning with bonuses paid on or after January 1, 2007.

Constellation Energy Projects & Services Group, Inc .

- Annual Incentive Award (includes Sales Bonuses paid to Participants employed as Business Developers, Major Account Executives, and Senior Account Executives. The Sales Bonus maximum percentage equals 30% of the eligible Participant's annual base pay.)
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Energy Projects & Services Group Advisors, LLC *

- Annual Incentive Award (includes Sales Bonuses paid to Participants employed as Business Developers, Major Account Executives, and Senior Account Executives. The Sales Bonus maximum percentage equals 30% of the eligible Participant's annual base pay.)
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation NewEnergy, Inc . *

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Commission Payments
- Sales Bonus
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Nuclear Services, Inc.

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Contract Incentive Rate Award
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Operating Services

- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award
- Annual Incentive Award

Constellation Power, Inc.

- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award
- Annual Incentive Award

Constellation Power Source Generation, Inc.

- Promotion Recognition Award
- Results Incentive Award/Annual Incentive Award
- Lump Sum Pay Adjustment
- Commission Payments
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Power Source Holdings, Inc.

- Annual Incentive Award
- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award

Constellation Real Estate, Inc.

- Annual Incentive Award

COSI Sunnyside, Inc.

- Executive Annual Incentive Plan of Constellation Energy Group Award
- Senior Management Annual Incentive Plan of Constellation Energy Group Award
- Annual Incentive Award

FIRST AMENDMENT TO THE
PENSION PLAN OF
CONSTELLATION ENERGY GROUP, INC.
(Amended and Restated Effective January 31, 2012)

WHEREAS, Constellation Energy Group, Inc. (the "Company") sponsors the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective as of January 31, 2012) (the "Plan"), which is intended to meet the requirements of the provisions of the Internal Revenue Code of 1986, (as amended) (the "Code"); and

WHEREAS, the Company intended to provide all employees who are eligible for severance benefits on or after June 1, 2003, under its Company-sponsored severance plan pension benefits based on their age and years of service at the end of their severance period, as set forth in Section 3.5 of the Plan; and;

WHEREAS, a new severance plan was established on September 19, 2008; and

WHEREAS, the Plan Administrator of the Plan, pursuant to the authority granted to her in Section 6.6(b) of the Plan, has consistently interpreted Section 3.5 to apply to participants eligible for severance under the new severance plan even though it wasn't specifically referenced in the Plan; and

WHEREAS, pursuant to Section 9.1, the Chief Human Resources Officer may amend the Plan in ways that do not materially affect liabilities; and

WHEREAS, an actuarial determination has been made that the cost of providing such benefits to participants in the new severance plan is immaterial;

NOW, THEREFORE, BE IT RESOLVED, that for purposes of clarity, the Plan is hereby amended as follows, effective September 19, 2008, except where noted:

1. By amending Section 3.5, Severance Plan Payments, to delete the phrase “Constellation Energy Group, Inc. Severance Plan” each time it occurs, and to insert in its place the term, “Severance Plan”.

2. By replacing section A-46 Deleted with the following:

   A-46 “Severance Plan” shall mean either of the Constellation Energy Group, Inc. Severance Plan or the Constellation Energy Group, Inc. Severance Plan for Constellation Energy Resources, LLC and Other Employees.

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IN WITNESS WHEREOF, this Amendment to the Plan was executed on this ____day of March, 2012.

Mary L. Lauria
Chief Human Resources Officer

SECOND AMENDMENT TO THE
PENSION PLAN OF
CONSTELLATION ENERGY GROUP, INC.
(Amended and Restated Effective January 31, 2012)

WHEREAS, .Exelon Corporation (the "Company") sponsors the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012) (the "Plan"); and

WHEREAS, the Company desires to amend the Plan to incorporate the provisions of a special lump sum payment option and to reflect changes necessary to comply with Section 436 of the Internal Revenue Code of 1986, as amended, and the final regulations thereunder.

NOW, THEREFORE, RESOLVED, that pursuant to the power of amendment contained in Article IX of the Plan, the Plan is amended, effective October 1, 2012, except as otherwise stated below:

1. Effective on and after January 1, 2013, Section 1.1 of the Plan is amended by inserting the following at the end thereof:

No Employee hired on or after January 1, 2013 shall be eligible to participate in the Plan, with the exception of Employees of the Employer listed on Appendix G.

2. Effective on and after the Effective Time, Article 1 of the Plan is amended by inserting the following new Section 1.3 at the end thereof:

1.3 Effect of Merger Agreement — If an Employee who was an Employee on or prior to the Effective Time transfers employment to or is reemployed by Exelon in a job classification with respect to which similarly situated employees of Exelon are not eligible to participate in the Plan but are instead eligible to participate in a Parent Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be qualified under Section 401(a) or 401(k) of the Code (each such plan, an "Exelon Retirement Plan"), then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the Exelon Retirement Plan. If a participant in an Exelon Retirement Plan who was a participant in such plan on or prior to the

Effective Time transfers employment to or is reemployed by a Participating Employer in a job classification with respect to which similarly situated employees of such Participating Employer are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the Exelon Retirement Plan and shall not participate in the Plan.

3. Article I of the Plan is amended by inserting the following new Section 1.4 at the end thereof:

Section 1.4 . Certain Rehired Employees . Notwithstanding anything contained herein to the contrary, no individual who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 3.6 shall be eligible to become a Participant pursuant to this Article 1.

4. Article III of the Plan is amended by adding the following new Section 3.6 at the end thereof:

Section 3.6 . Special Lump Sum Payment Option . (a) Eligibility . A Participant may elect to receive, during the election period described in this Section 3.6, his or her deferred Gross Pension as a terminated vested participant under the Plan ("Deferred Gross Pension") in the form of a lump sum payment ("Special Lump Sum Payment") or, an "Immediately Commencing Annuity" (as defined below); provided, however, that:

(i) the Participant has a Severance From Service Date prior to June 30, 2012 and does not die and is not rehired during the period beginning July 1, 2012 and ending on the date payment is made or commences in accordance with this Section 3.6;

(ii) the Participant has not otherwise commenced receiving pension benefits under the Plan on or prior to the date payment is made or commences in accordance with this Section 3.6;

(iii) such Severance From Service Date is not on account of the Participant's disability, following which the Participant is receiving long-term disability payments under any long-term disability program of an Employer, including on June 30, 2012;

(iv) the Participant's Deferred Gross Pension is not subject to a qualified domestic relations order as defined in Section 414(p) of the Code

(v) the Participant is not immediately, as of his or her Severance From Service Date, eligible for early retirement benefits in accordance with 3.3(b) above;

(vi) the Participant is not on a leave of absence or layoff from an Employer on June 30, 2012;

(vii) the Participant is not 70 1/2 years of age or older as of October 1, 2012; and

(viii) the Participant can be located, after a diligent search, as necessary, by the Plan Administrator before July 1, 2012.

For each such Participant described in this paragraph (a) of this Section 3.6, the term "Immediately Commencing Annuity" shall mean, as applicable, either:

(i) with respect to a Participant eligible to commence receipt of his or her Deferred Gross Pension as of December 1, 2012, any applicable optional form of annuity available to the Participant under this Article III; or

(ii) with respect to any other Participant, a single life annuity, 50% "qualified joint and survivor annuity" (within the meaning of Code Section 417(b)) or a 75% "qualified optional survivor annuity" (within the meaning of Code Section 417(g)).

For purposes of this Section 3.6, a "Participant" shall also include a beneficiary of a Participant who otherwise satisfies the requirements of this Section 3.6 but for the Participant's death prior to July 1, 2012.

3.6(b) Election and Election Period . To receive the distribution of benefits described in paragraph (a) of this Section 3.6, an eligible Participant must voluntarily elect to receive a distribution pursuant to this Section 3.6 by completing an election form and spousal waiver, if required, provided by the Administrator, and submitting such forms to the Administrator after October 1, 2012 and before the following dates, as applicable,

(i) November 15, 2012, with respect to a Participant who elects a Special Lump Sum Payment; and

(iii) December 15, 2012, with respect to a Participant who elects an Immediately Commencing Annuity,

or such other period during 2012 determined by the Administrator.

The Administrator shall provide each eligible Participant, not less than 30 days and not more than 180 days before the Benefit Commencement Date, an application form including a general description of the material features, as well as an explanation of the relative values and financial effect, of the optional forms of benefit available under this Section 3.6, in a manner that satisfies the notice requirements of Section 417(a)(3) of the Code and the Treasury Regulations thereunder. The form shall indicate the Participant's right to waive a survivor annuity, his Surviving Spouse's right to consent to such waiver or refuse such consent, and the right to revoke any waiver, within the 180 day period preceding the Benefit Commencement Date, and shall include a description of the right of the Participant, if any, to defer receipt of a distribution and the consequences of failure to defer such receipt, in accordance with Treasury guidance under Section 411(a)(11) of the Code.

3.6(c) Amount of Payment . The Special Lump Sum Payment shall equal the actuarial equivalent of the Participant's nonforfeitable Deferred Gross Pension, based on the following factors:

(i) the applicable interest rate described in Section 417(e)(3) of the Code for August of 2011;

(ii) an assumed commencement date of the later of (A) age 65, and (B) the Participant's age as of December 1, 2012;

(iii) the applicable mortality table, as defined in Section 417 of the Code and the Treasury Regulations promulgated thereunder; and

(iv) the Gross Pension of a Participant in the PEP shall be calculated, in accordance with the terms of the existing terms of the Plan, as the present value of the age 65 deferred annuity (within the meaning of 3.3(g)).

The Immediately Commencing Annuity shall be calculated:

(i) in accordance with the applicable terms of the Plan, for a Participant who is eligible to immediately commence benefits under the terms of the Plan as of the payment date set forth in paragraph (d) of this Section 3.6 and

(ii) as the actuarial equivalent of the Special Lump Sum Payment, for each other Participant.

3.6(d) Payment of Benefit . If an eligible Participant elects the distribution of his or her Deferred Gross Pension in accordance with this Section 3.6, payment shall be made, or commence to be made, on or before December 1, 2012, or as soon as administratively practicable thereafter.

3.6(e) Death and Rehire . If an eligible Participant elects the distribution of his or her Deferred Gross Pension in accordance with this Section 3.6 and subsequently dies or is rehired as an Employee before distributions commence, his or her election shall be null and void and the Participant's benefit shall be paid pursuant to the Plan without regard to this Section 3.6. Notwithstanding anything contained herein to the contrary, upon distribution of a Special Lump Sum Payment or an Immediately Commencing Annuity made to an individual in accordance with this Section 3.6, in the event of the individual's rehire with an Employer following the date such distribution is made, the individual shall not be eligible to participate in the Plan during such period of rehire and may be eligible to participate in the Exelon Corporation Cash Balance Pension Plan or the Exelon Corporation Pension Plan for Bargaining Unit Employees (or such other plan that applies to employees of an Employer hired on or after December 1, 2012), as applicable, in accordance with their terms and conditions.

5. Effective on and after the Effective Time, Section 6.1 shall be amended by adding a sentence before the first sentence, as follows:

Each person entitled to a payment under the Plan shall furnish such information and data, including birth certificates or other evidence of age satisfactory to the Administrator, and sign such documents as may reasonably be requested by the Administrator or the Trustee in connection with the administration of the Plan.

6. Effective on and after the Effective Time, Sections 6.4, 6.5, 6.6, 6.7 and 6.8 shall be deleted in their entirety, and new Sections 6.4 through 6.12 shall be added as follows, and the remaining sections shall be renumbered:

6.4 The Administrator, the Investment Fiduciary and the Corporate Investment Committee

6.4(a) The Administrator — The Company's Vice President, Health & Benefits, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such vice president or other person or committee, the "Administrator"), shall be the "administrator" of the Plan, within the meaning of such term as used in ERISA. In addition, the Administrator shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan's assets. The Administrator shall have the following duties, responsibilities and rights:

(i) The Administrator shall have the duty and discretionary authority to interpret and construe this Plan in regard to all questions of eligibility, the status and rights of Participants, Beneficiaries and other persons under this Plan, and the manner, time, and amount of payment of any distributions under this Plan.

The determination of the Administrator with respect to an Employee's years of Vesting Service, the amount of the Employee's Compensation, and any other matter affecting payments under the Plan shall be final and binding. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Administrator, in his or her discretion, determines that such person is entitled to benefits.

(ii) Each Employer shall, from time to time, upon request of the Administrator, furnish to the Administrator such data and information as the Administrator shall require in the performance of his or her duties.

(iii) The Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust Fund under Article 7 (relating to distributions). In addition, it shall be the duty of the Administrator to certify to the Trustee the names and addresses of all Participants, the amounts of all Pensions, the dates of death of Participants and all proceedings and acts of the Administrator necessary or desirable for the Trustee to be fully informed as to the Pension to be paid out of the Trust Fund.

(iv) The Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Fiduciary, the Corporate Investment Committee or the Trustee.

(v) The Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Administrator and to furnish such information requested by the Administrator. The Administrator and the Plan may rely upon all such information so furnished to the Administrator.

(vi) The Administrator shall be the Plan's agent for service of legal process and forward all necessary communications to the Trustee.

6.4(b) Removal of Administrator — The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Administrator (including any member of a committee that constitutes the Administrator). The Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer. Upon the resignation, removal or failure or inability for any reason of the Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Administrator.

6.4(c) The Investment Fiduciary — The Company, acting through the Exelon Investment Office, shall be the Investment Fiduciary and the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in section 404(a)(2) of ERISA and all other applicable limitations. The Investment Fiduciary shall have the following duties, responsibilities and rights:

(i) The Investment Fiduciary shall be the "named fiduciary" for purposes of directing the Trustee as to the investment of amounts held in the Trust Fund and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Fiduciary shall submit to the Corporate Investment Committee annual manager review results and such other reports and documents as may be necessary for the Corporate Investment Committee to monitor the activities and performance of the Investment Fiduciary.

(iii) Each Employer shall, from time to time, upon request of the Investment Fiduciary, furnish to the Investment Fiduciary such data and information as the Investment Fiduciary shall require in the performance of its duties.

6.4(d) The Corporate Investment Committee — The Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Fiduciary. The Corporate Investment Committee shall have the following duties, responsibilities and rights:

(i) The Corporate Investment Committee shall monitor the activities and performance of the Investment Fiduciary and shall review annual manager review results and any other reports and documents submitted by the Investment Fiduciary.

(ii) The Corporate Investment Committee shall have authority to approve asset allocation recommendations of the Investment Fiduciary, and approve the retention or firing of any investment consultant (but not any investment manager), custodian or trustee, as recommended by the Investment Fiduciary.

(iii) The Corporate Investment Committee shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Fiduciary. Any successor Investment Fiduciary shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor.

The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the Investment Fiduciary and approval of the recommendations specified in clause (ii) above. The Corporate Investment Committee shall have no responsibility for making investment decisions, appointing or firing investment managers or for any other duties or responsibilities with respect to the Plan, other than those specifically listed herein.

6.4(e) Status of Administrator, the Investment Fiduciary and the Corporate Investment Committee — The Administrator, any person acting as, or on behalf of, the Investment Fiduciary, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee or officer of an Employer and such status shall not disqualify such person from taking any action hereunder or render such person accountable for any distribution or other material advantage received by him or her under this Plan, provided that no Administrator, person acting as, or on behalf of, the Investment Fiduciary, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Administrator or the Investment Fiduciary on any matter involving solely his or her rights under this Plan.

6.4(f) Notice to Trustee of Members — The Trustee shall be notified as to the names of the Administrator and the person or persons authorized to act on behalf of the Investment Fiduciary.

6.4(g) Allocation of Responsibilities . Each of the Administrator, the Investment Fiduciary and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

6.4(h) General Governance — Each of the Administrator, the Investment Fiduciary and the Corporate Investment Committee may act at a meeting or by written consent approved by a majority of its respective members, as applicable. The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. The secretary of the Corporate Investment Committee shall keep a record of all meetings and forward all necessary communications to the Employers or the Trustee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Administrator, the Investment Fiduciary and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

6.4(i) Indemnification — The Employers hereby jointly and severally indemnify the Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

6.4(j) No Compensation . None of the Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Administrator, Investment Fiduciary or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Affiliate for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

6.4(k) Employ of Counsel and Agents . The Administrator, the Investment Fiduciary and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

6.5 Claims Procedure . Any Participant or distributee who believes he or she is entitled to benefits in an amount greater than those which he or she is receiving or has received may file a claim with the Administrator. Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Administrator shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the Administrator's decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable Regulations. If the Administrator determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Administrator expects to render the benefit determination. The notice of the decision of the Administrator with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, the Administrator shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right (subject to the limitations described in Section 8.9 (relating to statute of limitations for actions under the Plan) and 8.10 (relating to forum for legal actions under the Plan)) to

bring a civil action under section 502 of ERISA following an adverse benefit determination on review. The Administrator shall also advise the claimant that the claimant or the claimant's duly authorized representative may request a review by the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) of the adverse benefit determination by filing with such officer, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he or she (a) may be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit to the officer written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by the officer within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the officer's final decision. If the officer determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the officer expects to render the determination on review. The review of the officer shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

6.6 Notices to Participants, Etc . — All written notices, reports and statements given, made, delivered or transmitted to a Participant or Beneficiary or any other person entitled to or claiming benefits under the Plan shall be deemed to have been duly given, made or transmitted when mailed by first class mail with postage prepaid and addressed to the Participant or Beneficiary or such other person at the address last appearing on the records of the Administrator. A Participant or Beneficiary or other person may record any change of his or her address from time to time by written notice filed with the Administrator.

6.7 Responsibility to Advise Administrator of Current Address — Each person entitled to receive a payment under the Plan shall file with the Administrator in writing his or her complete mailing address and each change therein. A check or communication mailed to any person at his or her address on file with the Administrator shall be deemed to have been received by such person for all purposes of the Plan, and neither the Administrator, the Employers nor the Trustee shall be obliged to search for or ascertain the location of any person. If the Administrator shall be in doubt as to whether payments are being received by the person entitled thereto, it shall, by registered mail addressed to the person concerned at his or her last address known to the Administrator, notify such person that all future Pension payments will be withheld until such person submits to the Administrator evidence of his or her continued life and his or her proper mailing address.

6.8 Notices to the Firm or Administrator — Written directions, notices and other communications from Participants or Beneficiaries or any other persons entitled to or claiming benefits under the Plan to the Employers or the Administrator shall be deemed to have been duly given, made or transmitted either when delivered to such location as shall be specified upon the form prescribed by the Administrator for the giving of such directions, notices and other communications or when mailed by first class mail with postage prepaid and addressed to the addressee at the address specified upon such forms.

6.9 Records . Each of the Administrator, the Investment Fiduciary and the Corporate Investment Committee shall keep a record of all of their respective proceedings, if any, and shall keep or cause to be kept all books of account, records and other data as may be necessary or advisable in their respective judgment for the administration of the Plan, the administration of the investments of the Plan or the monitoring of the investment activities of the Plan, as applicable.

6.10 Actuary to be Employed — The Company or the Investment Fiduciary shall engage an actuary to do such technical and advisory work as the Company or the Investment Fiduciary may request, including analyses of the experience of the Plan from time to time, the preparation of actuarial tables for the making of computations thereunder, and the submission to the Company or the Investment Fiduciary of an annual actuarial report, which report shall contain information showing the financial condition of the Plan, a statement of the contributions to be made by the Employers for the ensuing year, and such other information as may be requested by the Company or the Investment Fiduciary.

6.11 Electronic Media — Notwithstanding any provision of the Plan to the contrary and for all purposes of the Plan, to the extent permitted by the Administrator and any applicable law or Regulation, the use of electronic technologies shall be deemed to satisfy any written notice, consent, delivery, signature, disclosure or recordkeeping requirement under the Plan, the Code or ERISA to the extent permitted by or consistent with applicable law and Regulations. Any transmittal by electronic technology shall be deemed delivered when successfully sent to the recipient, or such other time specified by the Administrator.

6.12 Correction of Error — If it comes to the attention of the Administrator that an error has been made in the amount of benefits payable, or paid, to any Participant or Beneficiary under the Plan, the Administrator shall be permitted to correct such error by whatever means that the Administrator, in its sole discretion determines, including by offsetting future benefits payable to the Participant or Beneficiary or requiring repayment of benefits to the Plan, except that no adjustment need be made with respect to any Participant or Beneficiary whose benefit has been distributed in full prior to the discovery of such error.

7. Effective on and after of the Effective Time, Section 7.1 shall be deleted in its entirety, and shall be replaced as follows:

7.1 Contributions and Funding Policy — No contributions from any Participant shall be required or permitted under the Plan. The Company shall establish a funding policy and method consistent with the objectives of the Plan and the requirements of Title I of ERISA and shall communicate such policy and method, and any changes in such policy and method, to the Investment Fiduciary. Forfeitures arising under this Plan shall be applied to reduce the expenses of Plan administration, not to increase the benefits otherwise payable to Participants.

8. Effective on and after the Effective Time, Section 8.2(a) shall be amended to delete the third paragraph thereof.

9. Article VIII of the Plan is amended by adding the following new Sections 8.8 at the end thereof:

8.8. Certain Rehired Employees . Notwithstanding anything contained herein to the contrary, an individual who is reemployed by an Employer after December 19, 2012 and has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 3.6 shall not be eligible to become a Participant pursuant to Article 1.

10. Effective on and after the Effective Time, Article VIII of the Plan is amended by adding the following new Sections 8.9, 8.10, 8.11, and 8.12 at the end thereof, as follows:

8.9 Expenses . The expenses of the Trustee in the administration of the Trust Fund, including compensation, if any, to the Trustee for its services, shall be paid by the Company or the Employers. All costs and expenses incurred in the operation of the Trust Fund, to the extent not described in the preceding sentence, and all costs and expenses incurred in the operation of the Plan or the Trust Fund, as applicable, including, but not limited to, “direct expenses” incurred in

administering the Plan and the Trust Fund (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan or the Trust Fund), the expenses of the Administrator, the Investment Office and the Corporate Investment Committee, the fees of counsel and any agents for the Trustee, the Administrator, the Investment Office or the Corporate Investment Committee, and the fees of investment managers that manage assets of the Trust Fund, as applicable, shall be paid by the Trustee from the Trust Fund in such proportion as the Investment Office, in its sole discretion, shall determine, to the extent such expenses are not paid by the Employers and to the extent permitted under ERISA, Regulations and other applicable laws. Notwithstanding the foregoing, the Administrator or the Investment Office may authorize an Employer to act as an agent of the Plan to pay any expenses, and the Employer shall be reimbursed from the Trust Fund for such payments.

8.10 Statute of Limitations for Actions under the Plan . Except for actions to which the statute of limitations prescribed by section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under section 502 of ERISA may be commenced later than one year after the claimant receives a final decision from the Chief Human Resources Officer (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

8.11 Forum for Legal Actions under the Plan . Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in District of Maryland, and no other federal or state court.

8.12 Legal Fees . Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, any member of the Exelon Investment Office, any member of the Corporate Investment Committee, the Chief Human Resources Officer, any Plan fiduciary, the Company, its affiliates or their respective officers, directors, employees, or agents (the "Plan Parties"), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

11. Effective on and after the Effective Time, Section 9.1 and 9.2 shall be deleted in their entirety, and shall be replaced as follows

9.1 Amendment — The Board of Directors of the Company (or a committee thereof) may at any time and from time to time amend or modify this Plan in any manner deemed by the board of directors of the Company to be necessary or desirable, provided, however, that in the case of any amendment or modification that would not result in an aggregate annual cost to the Company of more than $50,000,000, the Plan may be amended or modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability account balance exceeding $250,000) or another executive officer holding title of equivalent or greater responsibility and, provided further, that no amendment shall be made that is not consistent with any applicable collective bargaining agreement. Any such amendment or modification shall become effective on such date as the Board (or committee thereof) or executive shall determine and may apply to Participants in this Plan at the time thereof as well as to future Participants, provided, however, that, unless permitted by applicable law, no such amendment or modification which reduces the basis for the computation of benefits shall be retroactive as to service prior to the date of such amendment or modification.

9.2 Termination

9.2(a) Termination of the Plan by an Employer . The Company may at any time, by resolution adopted by its board of directors, terminate this Plan in its entirety. In addition, any Employer may at any time terminate its participation in this Plan by resolution adopted by its board of directors to that effect. Contributions of an Employer to the Plan are conditioned on the receipt from the Internal Revenue Service of an initial favorable determination letter that this Plan and the Trust as adopted by the Company meets the requirements of section 401(a) of the Code and that the Trust is exempt from tax under section 501(a) of the Code, and if the Internal Revenue Service shall refuse to issue such letter, any Employer may terminate its participation in this Plan and direct the Trustee to pay and deliver to that Employer the portion of the Trust applicable to its contributions.

9.2(b) Vesting and Distribution Upon Termination or Partial Termination . Upon termination or partial termination of the Plan, the benefit as of the date of termination or partial termination, as the case may be, of all affected Participants shall be fully vested; provided, however, that full vesting shall be required with respect to a termination or partial termination only to the extent the Plan is then funded.

Allocation and distribution of the terminated portion of the Trust Fund shall thereafter be made in accordance with the applicable requirements of ERISA and the Code and with any applicable approval of the Pension Benefit Guaranty Corporation (the "PBGC"). If the Administrator is notified by PBGC that PBGC is unable to determine that the Trust Fund is sufficient to discharge when due all obligations of the Plan with respect to benefits guaranteed by PBGC pursuant to section 4022 of ERISA, then the allocation and distribution of such portion of the Trust shall be made only under the direction of PBGC or a United States district court pursuant to section 4044 of ERISA.

In the event that, after the termination of the Plan, any assets remain after such allocation, such assets shall be paid to the Company. The portion of the assets allocated to provide benefits to any person or group of persons may be applied for the benefit of such person or persons by the distribution of cash, continuance of the Trust, establishment of a new Trust, purchase of annuities from an insurance company, or otherwise, as determined by the Investment Fiduciary in its sole discretion; provided, however, that the benefit of any Participant or former Participant who is married and has satisfied the vesting requirement shall, unless such person shall elect otherwise, be paid in the form set forth in the Plan relating to manner of distribution with respect to married Participants and, if the surviving Spouse of a deceased Participant or deceased former Participant is entitled to receive a benefit pursuant to the Plan provisions relating to manner of distribution with respect to married Participants or to pre-retirement death benefits, as the case may be, such benefit shall, unless such person shall elect otherwise, be paid in the form set forth therein.

Contributions of an Employer to the Plan are conditioned on the receipt from the Internal Revenue Service of an initial favorable determination letter that the Plan and Trust Fund as adopted by the Company meet the requirements of section 401(a) of the Code and that the Trust is exempt from tax under section 501(a) of the Code, and, in the event that the Internal Revenue Service shall refuse to issue such letter, the Company may terminate the Plan and shall direct the Trustee to pay and deliver the Trust to the Company.

12. Effective on and after the Effective Time, the text of Appendix A-2 of the Plan is deleted and replaced as follows: "Reserved," and all references to the "Administrative Committee" shall be deleted.

13c. Effective on and after the Effective Time, Appendix A-13 is amended by replacing the entirety of the text as follows:

A-13 “Company” means Exelon Corporation, and its successor and assigns.

14. Effective on and afterthe Effective Time, Appendix A-16 is amended by replacing the entirety of the text as follows:

A-16 “Disability Plan” means the Constellation Energy Group, Inc. Long-Term Disability Plan, the Exelon Corporation Long Term Disability Plan, or any successor plan.

15. Effective on and after November 30, 2012, Appendix A-20 is amended by adding the following at the end thereof:

For employees who employees who were Transferred Employees as that term is defined in the Purchase and Sale Agreement by and between Constellation Power Source Generation, Inc. as Seller, and Raven Power Holdings LLC as Buyer, dated as of August 8, 2012, Credited Service for purposes of determining the Early Retirement Adjustment Factor shall include all time periods while employed by the Buyer, and dit for age attained during employment with the Buyer until such time as the Transferred Employee elects to receive benefits under the Plan; and (ii)

16. Effective on and after the Effective Time, a new Appendix A-20a shall be added immediately following Appendix A-20 as follows:

A-20a “Effective Time ” means the effective time of the transaction that is the subject of the Merger Agreement, as such term is defined in the Merger Agreement.

17. Effective on and after the Effective Time, Appendix A-21 shall be amended by adding a sentence after the first sentence as follows:

Effective as of the Effective Time, Employee shall not include any person who was: (i) employed immediately prior to the Effective Time at Exelon or a facility owned immediately before the Effective Time by Exelon or (ii) initially employed on or after the Effective Time at a facility owned immediately before the Effective Time by Exelon.

18. Effective on and after the Effective Time, the text of Appendix A-24a is deleted and replaced as follows, and all references to the "Executive Group" shall be deleted.

A-24a "Exelon" means Exelon Corporation and any of its affiliates that was an affiliate immediately before the Effective Time.

19. Appendix A-21 of the Plan is amended by adding the following new sentence at the end thereof:

Notwithstanding anything contained herein to the contrary, an Employee shall not include an individual who has received a Special Lump Sum Payment or an Immediately Commencing Annuity in accordance with Section 3.6.

20. Appendix A-29 of the Plan is amended by inserting the following new sentence at the end thereof:

Notwithstanding the foregoing, a Participant shall not be entitled to any amount payable from the Trust under the Plan following the Participant's receipt of a Special Lump Sum Payment within the meaning of Section 3.6.

21. Effective on and after the Effective Time, Appendix A-30 is amended by replacing the entirety of its text as follows:

A-30 "Investment Fiduciary" means the Company acting through the Exelon Investment Office.

22. Effective on and after the Effective Time, a new Appendix A-30a shall be added immediately following Appendix A-30 as follows:

A-30a "Merger Agreement" means that Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc.

23. Appendix A-35 of the Plan is amended by adding the following new sentence at the end thereof:

An individual shall cease to be a Participant upon the date the individual is no longer eligible to receive a benefit from this Plan (including, without limitation, upon his or her receipt of a Special Lump Sum Payment as defined in Section 3.6) or upon the individual's Severance From Service Date if the individual is not eligible to receive a benefit from this Plan.

24. Effective January 1, 2013, Appendix A-35 of the Plan is amended by adding the following sentence to the end thereof:

No Employee hired on or after January 1, 2013 shall be a Participant, with the exception of Employees of the Employer set forth in Appendix G.

25. Effective on and after the Effective Time, Appendix A-38 of the Plan is amended by replacing the entirety of the text as follows:

A-38"Plan Administrator" means the Director, Employee Plans and Programs of the Company (or the position succeeding to that function).

26. Appendix A-44 of the Plan is amended by inserting the following new sentence before the last sentence of the first paragraph therein:

For distributions with a Benefit Commencement Date on or after December 1, 2012, other than as set forth in Section 3.6, the interest rate shall be the rate as defined in Section 417(e)(3)(C) of the Code for the fifth month preceding the calendar year in which such distribution is made or commences; provided, however, that the rate as defined in Section 417(e)(3)(C) of the Code for the month in which such distribution is made or commences shall be used if more favorable to the distributee during the period beginning December 1, 2012 through December 1, 2013.

27. Effective as of the June 1, 2012, Appendix A-45 is amended by replacing the entirety of the text as follows:

A-45 “Trustee” means the Northern Trust Company or any successor Trustee appointed by the Board of Directors.

28. Appendix G shall be deleted in its entirety, and replaced with a new Appendix G, attached hereto.

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IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its duly authorized officer on this ____day of _____, 2012.

CONSTELLATION ENERGY GROUP, INC.

By:_____
Amy E. Best
Senior Vice President and
Chief Human Resource Officer

APPENDIX G

DESIGNATED SUBSIDIARIES

Employees of the following subsidiary are eligible to participate in the Plan on the same terms and conditions as set forth therein, except as otherwise provided below:

BGE Home Products and Services, LLC:

a. An individual who is a Participant on December 31, 1999 and an Employee of BGE Home Products & Services, Inc. on January 1, 2000, is subject to 1.2 of the Plan except that PEP is modified as described in b. below. Notwithstanding the preceding sentence, an individual who is an Employee of Constellation Energy Source, Inc. on December 31, 1999, who transfers to BGE Home Products & Services, Inc. effective January 1, 2000, and was hired by Constellation Energy Source, Inc. after December 31, 1994, shall participate in PEP as modified in b. below. An individual who is a Participant in the Traditional Pension Plan after December 31, 1999 by reason of the preceding will cease participating in the Traditional Plan once he/she ceases to earn Credited Service. If such an individual again earns Credited Service, he/she shall participate in PEP as modified in b. below. All other individuals shall participate in PEP as modified in b. below.

b. Participants who are Employees of BGE Home Products & Services, Inc. shall have the following modifications to PEP:

(i) A Participant's Total Pension Credits in Appendix A for the period of time during which the Participant is employed by BGE Home Products & Services, Inc. shall equal the sum of (1) 0.025 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (2) 0.05 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (3) 0.075 times the Credited Service earned in each Plan Year after the Participant reaches age 49.

(ii) The only form of pension payments that a Participant may elect under PEP pursuant to 3.1(b) is monthly installments; lump sum payment is not available except if pursuant to the automatic lump sum cash-out provisions of 3.3(e); 3.3(h) therefore is not applicable. This (ii) is not applicable to a Participant who accrued any benefits under PEP while employed by an Employer whose Employee Participants were eligible to elect under PEP pursuant to 3.1(b) a lump sum, and then after January 1, 2000 transferred

employment to BGE Home Products & Services, Inc. This (ii) is not applicable to a Participant who received benefits under the Special Window for Employees Employed by BGE Home (as part of BGE Home's closing of its retail appliance and merchandise stores and the reorganization of BGE Home because of that closing) under the Constellation Energy Group, Inc. Severance Plan.

(iii) The Preretirement Survivor Benefit under 5.8 may be paid as a lump sum.

(iv) The third sentence in the definition of Annuity Factor in Appendix A is not applicable unless the Participant transferred employment to BGE Home Products & Services, Inc. after January 1, 2000, and was eligible for Early Retirement under 2.2 at the time he/she was employed by the Company or a subsidiary listed in this Appendix G other than BGE Home Products & Services, Inc. or BGE Commercial Building Systems, Inc.

Employees of the following subsidiaries who were hired prior to January 1, 2013 are eligible to participate in the Plan on the same terms and conditions set forth therein, except as set forth below.

Constellation Power, Inc.

Constellation Energy Commodities Group, Inc. (formerly known as Constellation Power Source, Inc.) Constellation Power Source Generation, Inc.

Constellation Energy Source, Inc.

BGE Home Products and Services, LLC (formerly known as BGE Home Products and Services, Inc.) [1]

[1] a. An individual who is a Participant on December 31, 1999 and an Employee of BGE Home Products & Services, Inc. on January 1, 2000, is subject to 1.2 of the Plan except that PEP is modified as described in b. below. Notwithstanding the preceding sentence, an individual who is an Employee of Constellation Energy Source, Inc. on December 31, 1999, who transfers to BGE Home Products & Services, Inc. effective January 1, 2000, and was hired by Constellation Energy Source, Inc. after December 31, 1994, shall participate in PEP as modified in b. below. An individual who is a Participant in the Traditional Pension Plan after December 31, 1999 by reason of the preceding will cease participating in the Traditional Plan once he/she ceases to earn Credited Service. If such an individual again earns Credited Service, he/she shall participate in PEP as modified in b. below. All other individuals shall participate in PEP as modified in b. below.
b. Participants who are Employees of BGE Home Products & Services, Inc. shall have the following modifications to PEP:
(i) A Participant's Total Pension Credits in Appendix A for the period of time during which the Participant is employed by BGE Home Products & Services, Inc. shall equal the sum of (1) 0.025 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (2) 0.05 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (3) 0.075 times the Credited Service earned in each Plan Year after the Participant reaches age 49.
(ii) The only form of pension payments that a Participant may elect under PEP pursuant to 3.1(b) is monthly installments; lump sum payment is not available except if pursuant to the automatic lump sum cash-out provisions of 3.3(e); 3.3(h) therefore is not applicable. This (ii) is not applicable to a Participant who accrued any benefits under PEP while employed by an Employer whose Employee Participants were eligible to elect under PEP pursuant to 3.1(b) a lump sum, and then after January 1, 2000 transferred employment to BGE Home Products & Services, Inc. This (ii) is not applicable to a Participant who received benefits under the Special Window for Employees Employed by BGE Home (as part of BGE Home's closing of its retail appliance and merchandise stores and the reorganization of BGE Home because of that closing) under the Constellation Energy Group, Inc. Severance Plan.
(iii) The Preretirement Survivor Benefit under 5.8 may be paid as a lump sum.
(iv) The third sentence in the definition of Annuity Factor in Appendix A is not applicable unless the Participant transferred employment to BGE Home Products & Services, Inc. after January 1, 2000, and was eligible for Early Retirement under 2.2 at the time he/she was employed by the Company or a subsidiary listed in this Appendix G other than BGE Home Products & Services, Inc. or BGE Commercial Building Systems, Inc.

[2] a. An individual who is a Participant on December 31, 1999 and an Employee of BGE Commercial Building Systems, Inc. on January 1, 2000, is subject to 1.2 of the Plan except that PEP is modified as described in b. below. An individual who is a Participant in the Traditional Pension Plan after December 31, 1999 by reason of the preceding sentence will cease participating in the Traditional Plan once he/she ceases to earn Credited Service. If such an individual again earns Credited Service, he/she shall participate in PEP as modified in b. below. All other individuals shall participate in PEP as modified in b. below.

b. Participants who are Employees of BGE Commercial Building Systems, Inc. shall have the following modifications to PEP:

(i) A Participant's Total Pension Credits in Appendix A for the period of time during which the Participant is employed by BGE Commercial Building Systems, Inc. shall equal the sum of (1) 0.025 times the Credited Service earned in each Plan Year prior to the Plan Year in which the Participant reaches age 40, (2) 0.05 times the Credited Service earned in each Plan Year after the Plan Year in which the Participant reaches age 39 and before the Plan Year in which the Participant reaches age 50, and (3) 0.075 times the Credited Service earned in each Plan Year after the Participant reaches age 49.

(ii) The only form of pension payments that a Participant may elect under PEP pursuant to 3.1(b) is monthly installments; lump sum payment is not available except if pursuant to the automatic lump sum cash-out provisions of 3.3(e). 3.3(h) therefore is not applicable. This (ii) is not applicable to a Participant who accrued any benefits under PEP while employed by an Employer whose Employee Participants were eligible to elect under PEP pursuant to 3.1(b) a lump sum, and then after January 1, 2000 transferred employment to BGE Commercial Building Systems, Inc. The Preretirement Survivor Benefit under 5.8 may be paid as a lump sum.

(iii) The third sentence in the definition of Annuity Factor in Appendix A is not applicable unless the Participant transferred employment to BGE Commercial Building Systems, Inc. after January 1, 2000, and was eligible for Early Retirement under 2.2 at the time he/she was employed by the Company or a subsidiary listed in this Appendix G other than BGE Home Products & Services, Inc. or BGE Commercial Building Systems, Inc.

Baltimore Gas and Electric Company [3]

Constellation Nuclear Services, Inc.

Constellation Generation Group, LLC

Constellation Operating Services, Inc.; Constellation Operating Services; COSI Central Wayne, Inc. (Employees represented by a union under a collective bargaining agreement are not eligible to participate); COSI Synfuels, Inc.; COSI Sunnyside, Inc.; COSI Puna, Inc.; PCI Operating Company Partnership [4]

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[3] With respect to an Employee of the Comfort Link division of Baltimore Gas and Electric Company, only individuals who are both a Participant on December 31, 1999 and an Employee of the Comfort Link division of Baltimore Gas and Electric Company on January 1, 2000, shall be eligible to participate in the Plan. Notwithstanding anything in the Plan to the contrary, the Vice-Chairman of Baltimore Gas and Electric Company will not be eligible to participate in this Plan.

[4] Employees of each listed subsidiary are eligible for participation in PEP effective January 1, 2003.

For purposes of 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which an Employee first performed an hour of service for the subsidiary. However, if the Participant was an Employee on January 1, 2003 and was employed by one of the following entities on the day immediately preceding the date the Employee became employed by the subsidiary, by A/C Power or by Trona Operating Partners, G.P. (or one of their subsidiaries), the Employment Commencement Date shall be the date on which the Employee first performed an hour of service for such entity (but in no event prior to any date noted in parentheses below):
Malacha Power Project, Inc.
Sunnyside Operating Associates
Niagara Mohawk Power Corporation
Consolidated Edison Company of New York (but only if the Employee was hired by COSI Astoria after August 20, 1999)
OESI Power (but only if the Employee was transferred to Constellation Operating Services, Inc. or one of its subsidiaries from OESI Power on January 6, 1993)
Kerr McGee Corporation—(but only if the Employee became an employee of Constellation Operating Services, Inc., A/C Power, or Trona Operating Partners, G.P. on December 1, 1990)
Ahlstrom Pyropower (or any other employer wholly or partially owned directly or indirectly, by Ahlstrom Pyropower (or any successor thereto))
Ultrasystems, Inc.
Hadson Corporation
LG&E Power, Inc
LUZ International
U C Operating Services
Panther Creek Fuels Company
Nevada Operations, Inc.
Central Wayne County Sanitation Authority
U. S. Generating (COSI Carr Street)
Ormat Energy Systems, Inc.
Ormat Systems, Inc.
Baltimore Gas and Electric Company (or any other employer wholly or partially owned directly or indirectly, by Baltimore Gas and Electric Company (or any successor thereto)) A/C Power
For purposes of 2.1 and A-31, Vesting Service shall be used instead of Credited Service to determine whether a Participant is eligible for Normal Retirement.
For purposes of 2.2 and A-19, Vesting Service shall be used instead of Credited Service to determine whether a Participant is eligible for Early Retirement.
For purposes of 4.3, Credited Service shall only include months beginning on or after January 1, 2003 during which an Employee works at least one hour for the Employer while classified as a Full-Time Employee.

[5] Effective April 1, 2011. For purposes of Section 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which the Employee first performed an hour of service for this subsidiary. For purposes of Section 4.3, Credited Service for work performed as an Employee of this subsidiary shall only include months beginning on or after April 1, 2011 during which the Employee works at least one hour while classified as a Full-Time Employee.

CNE Gas Holdings, Inc. [6]

Exelon Business Services Corporation [7]

Exelon Generation Company, LLC [8]

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6 Effective April 1, 2011. For purposes of Section 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which the Employee first performed an hour of service for this subsidiary. For purposes of Section 4.3, Credited Service for work performed as an Employee of this subsidiary shall only include months beginning on or after April 1, 2011 during which the Employee works at least one hour while classified as a Full-Time Employee.

7 For Employees who were Employees of Constellation Energy Group, Inc. immediately prior to the Effective Time.

8 For Employees who were Employees of Constellation Energy Group, Inc. immediately prior to the Effective Time.

THIRD AMENDMENT TO THE
PENSION PLAN OF
CONSTELLATION ENERGY GROUP, INC.
(Amended and Restated Effective January 31, 2012)

WHEREAS, Exelon Corporation (the "Company") sponsors the Pension Plan of Constellation Energy Group, Inc. (Amended and Restated Effective January 31, 2012) (the "Plan"); and

WHEREAS, the Company desires to amend the Plan to reflect additional guidance issued with respect to Section 436 of the Internal Revenue Code of 1986, as amended, to clarify the definition of "highly compensated employee" applicable under the Plan, to clarify the benefit formula for rehired employees, to limit participation in the Plan on and after January 1, 2013 and to make certain other changes.

NOW, THEREFORE, RESOLVED, that pursuant to the power of amendment contained in Article IX of the Plan, the Plan is amended effective January 1, 2013, except as otherwise stated below, as follows:

1. Section 1.1 of the Plan is amended to read as follows:

1.1 Automatic PEP Participation —Except as provided in 1.2 and the last sentence below, each Full-Time Employee of the Company, or of those subsidiaries and affiliates of the Company which are designated by the Board of Directors (as reflected in Appendix G), shall become a Participant in PEP on the date he/she becomes a Full-Time Employee. (Notwithstanding the previous sentence, effective July 23, 2010, Executive Group may designate such subsidiaries and affiliates if such designations have less than a $10 million impact on the Plan's accumulated benefit obligation per designation. At least annually, the Company's Chief Executive Officer shall report all such subsidiary and affiliate designations to the Board of Directors.) In addition, each Employee who is reemployed as a Full-Time Employee of the Company, or those subsidiaries and affiliates of the Company which are designated by the Board of Directors shall become a Participant in PEP on the date of his/her Adjusted Employment Commencement Date and shall not be eligible to participant in the Traditional Pension Plan with respect to his/her period of reemployment. An Employee

classified in a job description as an On-Call Employee, a leased employee within the meaning of Code Section 414(n)(2), or a co-op, work study or summer Employee shall not become a Participant in the Plan while classified in the sole judgment of the Employer as an On-Call Employee, a leased employee, or a co-op, work study or summer Employee. Notwithstanding anything contained herein to the contrary, no Employee whose Employment Commencement Date is on or after January 1, 2013 shall be eligible to participate in the Plan, with the exception of an Employee employed by BGE Home Products & Services, LLC.

2. Section 1.2 of the Plan is amended by adding the following new sentence at the end thereof:

Notwithstanding anything contained herein to the contrary, a Participant who is reemployed as an Employee shall not be a Participant in the Traditional Pension Plan, and shall not accrue any benefits under the Traditional Pension Plan, with respect to his/her period of reemployment. The Participant's Gross Pension under the Traditional Pension Plan shall be computed based solely on such Participant's Credited Service and Average Pay during the Employee's period of participation in the Traditional Pension Plan.

3. The second and third sentences of Section 3.2(d) of the Plan are amended to read as follows:

Except as provided in 3.2(e), monthly pension payments shall cease upon the Employer's reemployment of a Participant as an Employee. If the Participant's monthly pension payments cease as provided in the preceding sentence, upon the Participant's subsequent termination of employment with the Employer, the Participant's Gross Pension shall be recalculated and adjusted (including the adjustment described in 3.4 (a)) and the Participant shall be given a new election with respect to the form and timing of his/her pension payments if such election otherwise would be available to the Participant

4. Section 3.2 of the Plan is amended by inserting the following new paragraph (e) at the end thereof:

3.2(e) Continued Payment of Benefits for Certain Rehired Participants . Notwithstanding anything contained herein to the contrary, a Participant who is reemployed as an Employee while receiving monthly pension payments may continue receiving such payments during his/her reemployment if the Participant executes a written waiver of his/her rights to participate in, and accrue benefits under, the Plan with respect to the Participant's period of reemployment. The Gross Pension of a Participant described in this 3.2(e) shall not be recalculated, adjusted or increased upon the Participant's subsequent termination of employment and such Participant shall not have an Adjusted Employment Commencement Date for purposes of the Plan.

5. The first sentence of Section 3.4(a) of the Plan is amended to read as follows:

The provisions of this 3.4(a) apply if, as described in 3.2(d), monthly pension payments cease upon the Employer's reemployment of a Participant as an Employee, and the Participant's Gross Pension is required to be recalculated and adjusted upon the Participant's subsequent termination of employment with the Employer.

6. A new Section 8.13 shall be added immediately following Section 8.12 as follows:

8.13 Definition of Highly Compensated Employee for Purposes of Legal Requirements . Wherever applicable for purposes of satisfying legal requirements applicable to the Plan, the term "highly compensated employee" shall mean any Employee who performs service in the determination year and who (a) is a 5%-owner (as determined under section 416(i)(1)(A)(iii) of the Code) at any time during the Plan Year or the preceding Plan Year or (b) both (1) is paid compensation in excess of $80,000 (as adjusted for increases in the cost of living in accordance with section 414(q)(1)(B)(ii) of the Code) from an Employer for the preceding Plan Year, and (2) is in the group of employees consisting of the top 20% of the employees of the Employer and its affiliates when ranked on the basis of compensation paid during such preceding Plan Year.

7. Appendix A-35 of the Plan is amended by replacing the last sentence thereof with the following new sentence:

No Employee whose Employment Commencement Date is on or after January 1, 2013 shall be a Participant, with the exception of an Employee employed by BGE Home Products & Services, LLC.

8. Effective January 1, 2010, a new Appendix B-4 shall be added immediately following Appendix B-3 as follows:

B-4 Benefit Restrictions as a Result of Funding – Notwithstanding any provision of the Plan to the contrary, the following benefit restrictions shall apply if the Plan's adjusted funding target attainment percentage is at or below the following levels.

(a) Limitations Applicable If the Plan's Adjusted Funding Target Attainment Percentage Is Less Than 80%, But Not Less Than 60% . If the Plan's adjusted funding target attainment percentage for a Plan Year is less than 80% (or would be less than 80% to the extent described in subparagraph (a) 2. below) but is not less than 60%, then the limitations set forth in this paragraph (a) apply

1. 50% Limitation on Single Sum Payments, Other Accelerated Forms of Distribution, and Other Prohibited Payments . A Participant or Alternate Beneficiary is not permitted to elect, and the Plan shall not pay, a lump sum distribution or other optional form of distribution that includes a prohibited payment with an annuity starting date on or after the applicable section 436 measurement date, and the Plan shall not make any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment, unless the present value of the portion of the benefit that is being paid in a prohibited payment does not exceed the lesser of:

(i) 50% of the present value of the benefit payable in the optional form of benefit that includes the prohibited payment; or

(ii) 100% of the PBGC maximum benefit guarantee amount (as defined in Section 1.436-1(d)(3)(iii)(C) of the Treasury Regulations).

The limitation set forth in this subparagraph (a) 1. does not apply to any payment of a benefit which under Section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant. If an optional form of benefit that is otherwise available under the terms of the Plan is not available to a Participant or Alternate Beneficiary as of the annuity starting date because of the application of the requirements of this subparagraph (a) 1., the Participant or Alternate Beneficiary is permitted to elect to bifurcate the benefit into unrestricted and restricted portions (as described in Section 1.436-1(d)(3)(iii)(D) of the Treasury Regulations). The Participant or Alternate Beneficiary may also elect any other optional form of benefit otherwise available under the Plan at that annuity starting date that would satisfy the 50% limitation described in subparagraph (a) 1. (i) above or the PBGC maximum benefit guarantee amount described in subparagraph (a) 1. (ii) above, or may elect to defer the benefit in accordance with any general right to defer commencement of benefits under the Plan.

2. Plan Amendments Increasing Liability for Benefits . No amendment to the Plan that has the effect of increasing liabilities of the Plan by reason of increases in benefits, establishment of new benefits, changing the rate of benefit accrual, or changing the rate at which benefits become nonforfeitable shall take effect in a Plan Year if the adjusted funding target attainment percentage for the Plan Year is:

(i) Less than 80%; or

(ii) 80% or more, but would be less than 80% if the benefits attributable to the amendment were taken into account in determining the adjusted funding target attainment percentage.

The limitation set forth in this subparagraph (a) 2. does not apply to any amendment to the Plan that provides a benefit increase under a Plan formula that is not based on compensation, provided that the rate of such increase does not exceed the contemporaneous rate of increase in the average wages of Participants covered by the amendment.

(b) Limitations Applicable If the Plan's Adjusted Funding Target Attainment Percentage Is Less Than 60% . If the Plan's adjusted funding target attainment percentage for a Plan Year is less than 60% (or would be less than 60% to the extent described in subparagraph (b) 2. below), then the limitations in this paragraph (b) apply.

1. Single Sums, Other Accelerated Forms of Distribution, and Other Prohibited Payments Not Permitted . A Participant or Alternate Beneficiary is not permitted to elect, and the Plan shall not pay, a single sum payment or other optional form of benefit that includes a prohibited payment with an annuity starting date on or after the applicable section 436 measurement date, and the Plan shall not make any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment. The limitation set forth in this subparagraph (b) 1. does not apply to any payment of a benefit which under Section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant.

2. Shutdown Benefits and Other Unpredictable Contingent Event Benefits Not Permitted to Be Paid . An unpredictable contingent event benefit with respect to an unpredictable contingent event occurring during a Plan Year shall not be paid if the adjusted funding target attainment percentage for the Plan Year is:

(i) Less than 60%; or

(ii) 60% or more, but would be less than 60% if the adjusted funding target attainment percentage were redetermined applying an actuarial assumption that the likelihood of occurrence of the unpredictable contingent event during the Plan Year is 100%.

3. Benefit Accruals Frozen . Benefit accruals under the Plan shall cease as of the applicable section 436 measurement date. In addition, if the Plan is required to cease benefit accruals under this subparagraph (b) 3., then the Plan is not permitted to be amended in a manner that would increase the liabilities of the Plan by reason of an increase in benefits or establishment of new benefits.

(c) Limitations Applicable If the Plan Sponsor Is In Bankruptcy . Notwithstanding any other provisions of the Plan, a Participant or Alternate Beneficiary is not permitted to elect, and the Plan shall not pay, a single sum payment or other optional form of benefit that includes a prohibited payment with an annuity starting date that occurs during any period in which the Plan sponsor is a debtor in a case under title 11, United States Code, or similar Federal or state law, except for payments made within a Plan Year with an annuity starting date that occurs on or after the date on which the Plan's enrolled actuary certifies that the Plan's adjusted funding target attainment percentage for that Plan Year is not less than 100%. In addition, during such period in which the Plan sponsor is a debtor in a case under title 11, United States Code, or similar Federal or state law, the Plan shall not make any payment for the purchase of an irrevocable commitment from an insurer to pay benefits or any other payment or transfer that is a prohibited payment, except for payments that occur on a date within a Plan Year that is on or after the date on which the Plan's enrolled actuary certifies that the Plan's adjusted funding target attainment percentage for that Plan Year is not less than 100%. The limitation set forth in this paragraph (c) does not apply to any payment of a benefit which under Section 411(a)(11) of the Code may be immediately distributed without the consent of the Participant.

(d) Provisions Applicable After Limitations Cease to Apply .

1. Resumption of Prohibited Payments . If a limitation on prohibited payments under subparagraph (a) 1., (b) 1., or (c) of this Section applied to the Plan as of a section 436 measurement date, but that limit no longer applies to the Plan as of a later section 436 measurement date, then that limitation does not apply to benefits with annuity starting dates that are on or after that later section 436 measurement date.

2. Resumption of Benefit Accruals . If a limitation on benefit accruals under subparagraph (b) 3. of this Section applied to the Plan as of a section 436 measurement date, but that limitation no longer applies to the Plan as of a later section 436 measurement date, then benefit accruals shall resume prospectively and that limitation does not apply to benefit accruals that are based on service on or after that later section 436 measurement date, except as otherwise provided under the Plan. The Plan shall comply with the rules relating to partial years of participation and the prohibition on double proration under Department of Labor Regulation Section 2530.204-2(c) and (d).

3. Shutdown and Other Unpredictable Contingent Event Benefits . If an unpredictable contingent event benefit with respect to an unpredictable contingent event that occurs during the Plan Year is not permitted to be paid after the occurrence of the event because of the limitation of subparagraph (b) 2. of this Section, but is permitted to be paid later in the same Plan Year (as a result of additional contributions or pursuant to the enrolled actuary's certification of the adjusted funding target attainment percentage for the Plan

Year that meets the requirements of Section 1.436-1(g)(5)(ii)(B) of the Treasury Regulations), then that unpredictable contingent event benefit shall be paid, retroactive to the period that benefit would have been payable under the terms of the Plan (determined without regard to subparagraph (b) 2. of this Section). If the unpredictable contingent event benefit does not become payable during the Plan Year in accordance with the preceding sentence, then the Plan is treated as if it does not provide for that benefit.

4. Treatment of Plan Amendments That Do Not Take Effect . If a Plan amendment does not take effect as of the effective date of the amendment because of the limitation of subparagraph (a) 2. or (b) 3. of this Section, but is permitted to take effect later in the same Plan Year (as a result of additional contributions or pursuant to the enrolled actuary's certification of the adjusted funding target attainment percentage for the Plan Year that meets the requirements of Section 1.436-1(g)(5)(ii)(C) of the Treasury Regulations), then the Plan amendment must automatically take effect as of the first day of the Plan Year (or, if later, the original effective date of the amendment). If the Plan amendment cannot take effect during the same Plan Year, then it shall be treated as if it were never adopted, unless the Plan amendment provides otherwise.

(e) Notice Requirement . Written notice to Participants and Beneficiaries shall be provided within 30 days, in accordance with Section 101(j) of ERISA, if the Plan becomes subject to a limitation described in subparagraph (a) 1., (b), or (c) of this Section.

(f) Methods to Avoid or Terminate Benefit Limitations . Application of one or more of the benefit limitations set forth in paragraphs (a), (b) and (c) of this Section for a Plan Year may be avoided or terminated through the use of employer contributions, by increasing the amount of Plan assets which are taken into account in determining the adjusted funding target attainment percentage and by other methods in accordance with Sections 436(b)(2), (c)(2), (e)(2) and (f) of the Code and Section 1.436-1(f) of the Treasury Regulations.

(g) Plan Operations for Periods Prior to and After Certification of Plan's Adjusted Funding Target Attainment Percentage .

1. In General . For any period during which a presumption under Section 436(h) of the Code and Section 1.436-1(h) of the Treasury Regulations applies to the Plan, the limitations under paragraphs (a) through (c) of this Section are applied to the Plan as if the adjusted funding target attainment percentage for the Plan Year were the presumed adjusted funding target attainment percentage determined under the rules of Section 436(h) of the Code and Section 1.436-1(h)(1), (2), or (3) of the Treasury Regulations. These presumptions are set forth in subparagraphs (g) 2. though (g) 4. below.

2. Presumption of Continued Underfunding Beginning First Day of Plan Year . If a limitation under paragraph (a), (b) or (c) of this Section applied to the Plan on the last day of the preceding Plan Year, then, commencing on the first day of the current Plan Year and continuing until the Plan's enrolled actuary issues a certification of the adjusted funding target attainment percentage for the Plan for the current Plan Year, or, if earlier, the date subparagraph (g) 3. or (g) 4. below applies to the Plan:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be the adjusted funding target attainment percentage in effect on the last day of the preceding Plan Year; and

(ii) The first day of the current Plan Year is a section 436 measurement date.

3. Presumption of Underfunding Beginning First Day of Fourth Month . If the Plan's enrolled actuary has not issued a certification of the adjusted funding target attainment percentage for the Plan Year before the first day of the fourth month of the Plan Year and the Plan's adjusted funding target attainment percentage for the preceding Plan Year was either at least 60% but less than 70% or at least 80% but less than 90%, or is described in Section 1.436-1(h)(2)(ii) of the Treasury Regulations, then, commencing on the first day of the fourth month of the current Plan Year and continuing until the Plan's enrolled actuary issues a certification of the adjusted funding target attainment percentage for the Plan for the current Plan Year, or, if earlier, the date subparagraph (g) 4. below applies to the Plan:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be the Plan's adjusted funding target attainment percentage for the preceding Plan Year reduced by 10 percentage points; and

(ii) The first day of the fourth month of the current Plan Year is a section 436 measurement date.

4. Presumption of Underfunding On and After First Day of 10th Month . If the Plan's enrolled actuary has not issued a certification of the adjusted funding target attainment percentage for the Plan Year before the first day of the 10th month of the Plan Year (or if the Plan's enrolled actuary has issued a range certification for the Plan Year pursuant to Section 1.436-1(h)(4)(ii) of the Treasury Regulations but has not issued a certification of the specific adjusted funding target attainment percentage for the Plan by the last day of the Plan Year), then, commencing on the first day of the 10th month of the current Plan Year and continuing through the end of the Plan Year:

(i) The adjusted funding target attainment percentage of the Plan for the current Plan Year is presumed to be less than 60%; and

(ii) The first day of the 10th month of the current Plan Year is a section 436 measurement date.

(h) Plan Termination and Other Special Rules .

1. Plan Termination . The limitations on prohibited payments in subparagraphs (a) 1., (b) 1., and (c) of this Section do not apply to prohibited payments that are made to carry out the termination of the Plan in accordance with applicable law. Any other limitations under this Section do not cease to apply as a result of termination of the Plan.

2. Special Rules Relating to Unpredictable Contingent Event Benefits and Plan Amendments Increasing Benefit Liability . During any period in which none of the presumptions under paragraph (g) of this Section apply to the Plan and the Plan's enrolled actuary has not yet issued a certification of the Plan's adjusted funding target attainment percentage for the Plan Year, the limitations under subparagraphs (a) 2. and (b) 2. of this Section shall be based on the "inclusive presumed adjusted funding target attainment percentage" for the Plan, as such term is described in, and calculated in accordance with the rules of, Section 1.436-1(g)(2)(iii) of the Treasury Regulations.

3. Payments Under Social Security Leveling Options . For purposes of determining whether the limitations under subparagraph (a) 1. or (b) 1. of this Section apply to payments under a social security leveling option, within the meaning of Section 436(j)(4)(C)(i) of the Code, the adjusted funding target attainment percentage for a Plan Year shall be determined in accordance with the "Special Rule for Certain Years" under Section 436(j)(3) of the Code and any Treasury Regulations or other published guidance thereunder issued by the Internal Revenue Service.

4. Limitation on Benefit Accruals . For purposes of determining whether the accrual limitation under subparagraph (b) 3. of this Section applies to the Plan, the adjusted funding target attainment percentage for a Plan Year shall be determined in accordance with the "Special Rule for Certain Years" under Section 436(j)(3) of the Code (except as provided under section 203(b) of the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010, if applicable).

5. Interpretation of Provisions . The limitations imposed by this Section shall be interpreted and administered in accordance with Section 436 of the Code and Section 1.436-1 of the Treasury Regulations.

(i) Definitions . The definitions in the following Treasury Regulations apply for purposes of this Section: Section 1.436-1(j)(1) defining adjusted funding target attainment percentage; Section 1.436-1(j)(2) defining annuity starting date; Section 1.436-1(j)(6) defining prohibited payment; Section 1.436-1(j)(8) defining section 436 measurement date; and Section 1.436-1(j)(9) defining an unpredictable contingent event and an unpredictable contingent event benefit.

(j) Effective Date . The rules in this Section are effective for Plan Years beginning after December 31, 2007.

9. Appendix G is amended by adding the following after “Exelon Generation Company, LLC” and adding a footnote corresponding to each item on the list to read as below:

CER Generation, LLC

Footnote: Effective April 1, 2008. For purposes of Section 4.2, Vesting Service shall be computed using as the Employment Commencement Date the date on which the Employee first performed an hour of service for this entity.

*****

IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its Senior Vice President and Chief Human Resources Officer, on this ____day of December, 2013.

EXELON CORPORATION

By: _____

Amy E. Best
Senior Vice President and
Chief Human Resource Officer

Exhibit 10.68

CONSTELLATION ENERGY GROUP, INC.
EMPLOYEE SAVINGS PLAN

Amended and Restated Effective January 31, 2012

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CONSTELLATION ENERGY GROUP, INC.

EMPLOYEE SAVINGS PLAN

Article I – Purpose and Nature of the Plan

1.1 Purpose of the Plan

The Plan is designed as a stock bonus plan. Eligible Employees have the opportunity to save on a regular and long-term basis, and in the process acquire or sustain a proprietary interest in the success of the Company. The Plan is intended to meet the requirements of the provisions of Code Section 401(a). The Plan is also intended to meet the requirements of an Employee Stock Ownership Plan under Code Section 4975(e)(7) as well through February 28, 2002. Effective February 1, 2006, the portion of the Plan consisting of the CEG Common Stock Fund is intended to be an Employee Stock Ownership Plan under Code Section 4975(e)(7). That portion of the Plan is intended to be primarily invested in Common Stock which constitutes employer securities (within the meaning of Code Section 409(l).

1.2 Nature of the Plan – General

The Plan is structured to permit three (3) general categories of Employee participation. First, eligible Employees may elect to participate by choosing to contribute to the Plan under the After-Tax Option, the Before-Tax Option, or a combination of both. Company Matching Contributions, as provided under the Plan, are made with respect to a Participant's contributions under the After-Tax and/or Before-Tax Options. Second, eligible Employees may elect to participate by contributing to the Plan through the rollover of an Eligible Rollover Distribution from an Eligible Retirement Plan as provided under the rollover provisions of the Plan. Third, Employees or former Employees may participate by virtue of having a balance established in an Employee Stock Account.

1.3 After-Tax and Before-Tax Options

1.3(a) After-Tax Option

Under the After-Tax Option, an eligible Employee may contribute a percentage of Eligible Compensation to the Plan through payroll deduction, subject to the limitations of Articles III and IV and Appendix B of the Plan. Amounts contributed under the After-Tax Option are contributions described in Code Section 401(m) and are included in the taxable income of the Employee in the year of the contribution. Earnings on After-Tax Option contributions are taxed to the Employee when distributed or withdrawn from the Plan.

1.3(b) Before-Tax Option

Under the Before-Tax Option, an eligible Employee may contribute a percentage of Eligible Compensation to the Plan through payroll deduction, subject to the limitations of Articles III and IV and Appendix B of the Plan. Amounts contributed under the Before-Tax Option are contributions described in Code Section 401(k) and are not included in the federal taxable income of the Employee in the year of the contribution. Before-Tax Option contributions and earnings thereon are taxed to the Employee when distributed or withdrawn from the Plan.

1.3(c) Company Matching Contributions

Under the Company Matching Contribution provisions of the Plan, the Company contributes a Company Matching Contribution with respect to each eligible Employee, subject to the limitations of Articles III and IV and Appendix B of the Plan. Company Matching Contributions are contributions described in Code Section 401(m) and are not included in the taxable income of the Employee in the year of the contribution. Company Matching Contributions and earnings thereon are taxed to the Employee when distributed or withdrawn from the Plan.

1.4 Rollover

Under the rollover provisions of the Plan, an eligible Employee may establish a Rollover Account within the Plan by transferring all or a portion of an Eligible Rollover Distribution (except any portion of any distribution that is not includable in gross income unless specifically provided for under Section 3.3) from another Eligible Retirement Plan. Such transfers can only be in the form of cash, except as otherwise provided in Appendix E or under Section 3.3.

1.5 Employee Stock Account

An Employee Stock Account was automatically established within the Plan for each Employee or former Employee upon the Plan's receipt of (i) Baltimore Gas and Electric Company contributions made on behalf of such Employee under the Corporate Performance Award Program, and/or (ii) transfers of the Employee's or former Employee's account balance in the Baltimore Gas and Electric Company Employee Stock Ownership Plan upon such plan's Termination.

1.6 Plan Mergers

The following plans (or portions thereof) have been merged into this Plan as of the corresponding effective dates:

Merged Plan Name	Merger Effective Date
Constellation Operating Services, Inc. Retirement Plan	April 1, 2003
A/C Power Retirement Plan	April 1, 2003
Trona Operating Partners Retirement Plan	April 1, 2003
Non-Represented Employee Savings Plan for Nine Mile Point	October 1, 2005
Cornerstone Energy, Inc. 401(k) Plan	July 1, 2007

Article II – Eligibility and Participation

2.1 Eligibility

2.1(a) Eligibility In General

Each Full-Time Employee of the Company, or of those other Employers which are designated as Participating Employers by the Designating Authority, as reflected in Appendix E, is eligible to become a Participant in the Plan through the After-Tax and Before-Tax Options and/or rollover provisions beginning on the first day of the first pay period as soon as practicable following his date of hire by a Participating Employer; provided, however, that any person whose conditions of employment are covered by any collective bargaining agreement to which the Employer is a party shall be ineligible to become a Participant unless and until that agreement specifically provides for such person's participation in the Plan. Each such Full-Time Employee of a Participating Employer is eligible to become a Participant only in those aspects of the Plan specified by the Designating Authority.

An Employee classified in a job description as an On-Call Employee or an Employee who is a leased employee within the meaning of Code Sections 414(n)(2) and 414(o)(2), is not eligible to participate in the Plan while classified in the sole judgment of the Employer as an On-Call Employee or leased employee.

2.1(b) Eligibility After Reemployment

If an Employee who terminated service is reemployed as a Full-Time Employee of the Company or another Participating Employer, as reflected in Appendix E, the Employee shall be eligible to participate through the After-Tax and Before-Tax Options and/or rollover provisions beginning on the first day of the first pay period as soon as practicable following his date of reemployment. This reemployment rule applies whether the Employee was a Participant, was eligible to be a Participant, or was ineligible to be a Participant due to failure to meet the Plan's service requirement for eligibility, on the date of termination.

2.1(c) Change in Status

An Employee who becomes represented by a collective bargaining agreement with the Employer shall have the accounts maintained under this Plan transferred to the plan established pursuant to the collective bargaining agreement as soon as administratively feasible.

An Employee who ceases to be represented by a collective bargaining agreement with the Employer shall become eligible to participate in the Plan, and the accounts maintained under the plan established pursuant to the collective bargaining agreement shall be transferred to the Plan as soon as administratively feasible. Such an Employee shall become a Participant in the Plan as of the date of such transfer and shall be eligible to make contributions to the Plan in accordance with Article III of the Plan as soon as administratively feasible

2.2 Participation

2.2(a) After-Tax and Before-Tax Options

Participation in the After-Tax and Before-Tax Options is voluntary. An Employee who satisfies the eligibility requirements of Section 2.1 can elect to become a Participant by submitting an Appropriate Request with the Plan Administrator. In making the Appropriate Request, the Employee must (i) designate the rate of contribution under the After-Tax and/or Before-Tax Options; (ii) indicate the Investment Funds to which contributions under the After-Tax and/or Before-Tax Options will be allocated and the percentage allocated to each Investment Fund; and (iii) agree to be bound by the terms and conditions of the Plan, a copy of which will be furnished to the Employee upon request.

After-Tax Option contributions, which are taxed to the Participant when contributed to the Plan, are treated as direct contributions to the Plan by the Participant. Therefore, an Appropriate Request submitted with respect to the After-Tax Option authorizes the Company to deduct a stated percentage of the Participant's Eligible Compensation from his pay and transmit the amount deducted to the Plan to be invested.

Before-Tax Option contributions, which are not taxed to the Participant (for federal income tax purposes) until distributed from the Plan, are treated as reductions in the salary of the Participant which are then contributed to the Plan by the Company on behalf of the Participant. Therefore, pursuant to an Appropriate Request submitted with respect to the Before-Tax Option, the Participant undertakes to forego the receipt of a stated percentage of Eligible Compensation. In return, the Company will contribute to the Plan an amount equal to the deferral.

An eligible Employee who does not elect to become a Participant in the After-Tax and/or Before-Tax Options at the earliest possible eligibility date as provided in Section 2.1, may elect to become a Participant at a later date by submitting an Appropriate Request with the Plan Administrator. The election to participate will become effective beginning on the first day of the first pay period as soon as practicable following the date on which the Appropriate Request is received by the Plan Administrator.

2.2(b) Rollover

A Participant who satisfies the eligibility requirements of Section 2.1 and who wishes to roll over all or a portion of an Eligible Rollover Distribution (except any portion of any distribution that is not includable in gross income unless specifically allowed under Section 3.3) as provided in Section 3.3 may do so by submitting an Appropriate Request with the Plan Administrator. A Participant will continue to be considered a Participant for purposes of eligibility for rollovers as long as amounts are

held in the Participant's Plan accounts, regardless of such Participant's eligibility to make further contributions to the Plan. The Participant will be required to submit documentation necessary to support the qualification of the rollover as requested by the Plan Administrator, or designees of the Plan Administrator, before the Plan Administrator will authorize the establishment of a Rollover Account for the Participant. If, in the judgment of the Plan Administrator or the Plan Administrator's designees, the documentation does not adequately support the qualification of the rollover amount, the Plan Administrator has the authority under the Plan to disallow a rollover contribution to the Plan.

The Participant must indicate as part of the Appropriate Request the Investment Funds to which rollover contributions will be allocated and the percentage or dollar amount allocated to each Investment Fund. The Participant must also agree to be bound by the terms and conditions of the Plan, a copy of which will be furnished to the Employee upon request.

2.2(c) Employee Stock Account

An Employee or former Employee for whom a balance in an Employee Stock Account has been established under the Plan is automatically a Participant. Participation in the Plan through the establishment of an Employee Stock Account does not affect an Employee's eligibility for or participation in the After-Tax and Before-Tax Options or the rollover provision.

Article III – Contributions to the Plan

3.1 After-Tax and Before-Tax Options

3.1(a) Rate of Contribution

Subject to the limitations described in Article IV and Appendix B, a Participant may contribute to the After-Tax Option of the Plan an amount equal to not more than fifteen percent (15%) of the Participant's Eligible Compensation, and to the Before-Tax Option of the Plan an amount equal to not more than fifty percent (50%) of the Participant's Eligible Compensation; provided, however, that a Participant may contribute to the After-Tax and/or Before-Tax Options of the Plan an amount equal in aggregate to not more than fifty (50%) of the Participant's Eligible Compensation.

Notwithstanding anything else in the Plan including the above, Participants who have attained age 50 before the close of the Plan Year are eligible to make "catch-up contributions" in accordance with, and subject to the limitations of, Section 414(v) of the Code. Such catch-up contributions shall be treated for purposes of the Plan as Before-Tax Option contributions, but shall not be subject to the Company Matching Contribution provisions, and shall not be taken into account for purposes of the required limitations of Sections 402(g) and 415 of the Code. The Plan will not be treated as failing to satisfy the provisions of the Plan implementing the requirements of Sections 401(k)(3), 401(k)(11), 401(k)(12), 410(b), or 416 of the Code, as applicable, by reason of the making of such catch-up contributions.

The rate of contribution must be in multiples of one percent (1%); provided, however, that "catch-up contributions" must be in a specified dollar amount per pay period. In the event a Participant's Compensation in any Payroll Period is insufficient to make contributions at the rate elected by the Participant, the amount not contributed as a result of the insufficiency may not be contributed in the succeeding Payroll Period(s). A Participant's contributions shall be paid into the Plan as soon as practicable and shall be allocated to the Participant Contribution Account(s) in accordance with the Participant's instructions as indicated by the Appropriate Request submitted with the Plan Administrator.

3.1(b) Basic and Supplemental Contributions Under the After-Tax and Before-Tax Options

For purposes of determining the Company Matching Contributions as well as for various withdrawal and loan provisions found in Articles VII and IX of the Plan, a Participant's contributions made through the After-Tax and/or Before-Tax Options are characterized as either Basic Contributions or Supplemental Contributions.

When, in accordance with a Participant's instructions, the total contribution is split in whole percentage points between the After-Tax and the Before-Tax Options, the contribution under the Before-Tax Option, up to and including the maximum amount permitted as a Basic Contribution, will be treated as a Basic Contribution. Should the contribution under the Before-Tax Option be less than the maximum amount permitted as a Basic Contribution, then a portion of the After-Tax Option contribution percentage (if any) equal to the difference between the Before-Tax Option contribution percentage and the maximum amount permitted as a Basic Contribution will be characterized as a Basic Contribution.

3.1(c) Change in Rate of Contribution

A Participant may elect to change his contribution rate in multiples of one percent (1%), or in such other multiples as may be specified by the Plan Administrator, by submitting an Appropriate Request to the Plan Administrator. Unless otherwise specified by the Plan Administrator, the change in the rate of contribution will become effective the first day of the first pay period as soon as practicable following the date on which the Appropriate Request is received by the Plan Administrator.

3.1(d) Suspension of Participant Contributions

A Participant may elect to suspend his contributions to the After-Tax and/or Before-Tax Options of the Plan by submitting an Appropriate Request to the Plan Administrator. The suspension of contributions shall become effective the first day of the first pay period as soon as practicable following the date on which the Appropriate Request is received by the Plan Administrator. A Participant may also elect to resume contributions by submitting an Appropriate Request to the Plan Administrator. Such a Participant's contributions will resume on the first day of the first pay period as soon as practicable following the date on which the Appropriate Request is received by the Plan Administrator. A Participant may not make up contributions relating to the period in which contributions were suspended.

3.1(e) Leave of Absence

An authorized leave of absence shall not constitute a termination of employment, but shall, except as provided in Section 3.1(f), operate to suspend Participant contributions and related Company Matching Contributions. At the end of an authorized leave of absence, a Participant's After-Tax and/or Before-Tax Option contributions shall be automatically restarted based on the Participant's contribution election at the time the leave of absence began.

3.1(f) Military Leave of Absence

In accordance with the provisions of the Uniformed Services Employment and Reemployment Rights Act of 1994, an Employee returning from a military leave of absence may elect to contribute to the Plan, under the After-Tax and/or Before-Tax Options, an amount not to exceed the amount such Employee would have been permitted to contribute had the Employee not taken a military leave of absence. The election to make a contribution for the period of the military leave of absence is made by filing an Appropriate Request with the Plan Administrator. Contributions under this Section must

be made in accordance with Code Section 414(u). At the time such contribution is made, the Employee must (i) designate the portion of the contribution made under the After-Tax and/or Before-Tax Options, and (ii) indicate the Investment Funds to which contributions under the After-Tax and/or Before-Tax Options shall be allocated. A Company Matching Contribution will be made in accordance with Section 3.2 on the portion of the Employee contribution that represents Basic Contributions. Any contribution to the Plan under this Section must be made during the period beginning with the date of return from the leave of absence and whose duration is three times the period of the Employee's service in the uniformed services, not to exceed five years.

An individual receiving a differential wage payment, as defined by Code Section 3401(h)(2) is treated as an Employee of the Employer. The differential wage payment is treated as Compensation, to the extent required under law, and the Plan is not treated as failing to meet the requirements of any provision described in Code Section 414(u)(1)(C) by reason of any contribution or benefit which is based on the differential wage payment. This paragraph applies only if the requirements of Code Section 414(u)(12)(B) and (C) are satisfied.

3.2 Company Matching Contributions

Subject to the limitations described in Article IV and Appendix B, the Company will contribute the Company Matching Contribution to the Plan on behalf of each Participant and as soon as practicable.

Company Matching Contributions will be made completely in cash or in shares of Common Stock having an aggregate value equal to the contribution the Company is required to make to the Plan under this Section 3.2. Prior to January 1, 2012, Company Matching Contributions are invested initially in the CEG Common Stock Fund. On and after January 1, 2012, Company Matching Contributions are invested in the Investment Funds designated by the Participant.

3.3 Rollover Contributions

A Participant may contribute to the Plan, in cash (or other property as set forth in Appendix E or as set forth below), all or a portion of an amount determined to be an Eligible Rollover Distribution (except any portion of any distribution that is not includable in gross income unless specifically allowed below). A Participant who rolls over an Eligible Rollover Distribution from the Employee Savings Plan for Constellation Energy Nuclear Group, LLC and the Represented Employee Savings Plan of Nine Mile Point to the Plan may rollover shares of CEG Common Stock in kind and may also rollover any promissory notes evidencing any loans under those plans in-kind. The Plan may accept a direct transfer of an Eligible Rollover Distribution that consists of after-tax employee contributions from the Employee Savings Plan for Constellation Energy Nuclear Group, LLC and the Represented Employee Savings Plan for Nine Mile Point, qualified plans, subject to any procedure established by the Plan. The Plan will account separately for any amounts so transferred.

A Participant may execute a rollover to the Plan of an Eligible Rollover Distribution (including, without limitation, an Eligible Rollover Distribution from the Pension Plan of Constellation Energy Group, Inc.) by either (i) contributing all or a portion of the distribution received by the Participant to the Plan within 60 days from the date the distribution is received, or (ii) having the Eligible Retirement Plan from which the Eligible Rollover Distribution is to be made, transfer the Eligible Rollover Distribution directly to the Plan. The Plan Administrator may designate the manner in which a direct transfer to the Plan can be made.

It is the intent of the Plan that any distribution eligible for rollover to the Plan meet the tax-free rollover requirements as set forth in the Code and the regulations promulgated thereunder, so that the amounts rolled over into the Plan will not jeopardize the tax-exempt status of the Plan or Trust or result in adverse tax consequences to the Company. The Plan Administrator may require the Employee to establish that amounts contributed to the Plan under the rollover provisions, meet the tax-free rollover requirements set forth in the Code.

3.4 Return of Company Contributions

At the discretion of the Plan Administrator, in the case of a Company contribution which is made under a mistake of fact, such contribution exclusive of earnings may be returned to the Company within one year after the payment of the contribution.

All Company contributions to the Plan shall be conditioned on their deductibility under Code Section 404 and, in the event the deduction for the contributions is disallowed by the Secretary of the Treasury, such contributions will be returned to the Company within one year of the disallowance.

Article IV – Limitations on Contributions to the Plan

4.1 General

In addition to the limitations on contributions imposed by the Plan under Article III, and subject to the "catch-up contributions" provisions in Section 3.1(a), contributions to the Plan under the After-Tax Option, the Before-Tax Option, and the Company Matching Contribution provisions will be limited by the Plan Administrator, to the extent necessary to enable the Plan to comply with the limitations prescribed by the Code. These limitations are summarized in Section 4.2 below and detailed in Appendix B.

4.2 Internal Revenue Code Limitations

To determine that the limitations on contributions to the Plan under the Code are not exceeded in any Plan Year, the following limitations will be monitored by the Plan Administrator or his designees no less frequently than annually.

4.2(a) Limitation on Participants' Before-Tax Option Contributions

Before-Tax Option contributions on behalf of any Participant may not exceed the Code Section 402(g) limit ($13,000 in 2004 and as further adjusted under Code Section 402(g)(5)) for any Plan Year. The Plan Administrator may prospectively limit, during the Plan Year, Before-Tax Option contributions if it is determined that the Code Section 402(g) limitation would otherwise be exceeded for such Plan Year. Participants whose Before-Tax Option contributions are limited under this Section 4.2(a) are automatically treated as electing to increase their contributions under the After-Tax Option by an amount equal to the Participant's Before-Tax Option contribution percentage in excess of the limitation. If necessary, the Plan Administrator may distribute any excess amounts to the Participant in a post-Plan Year distribution. Detailed provisions governing the operation of this limitation under the Plan are set forth in Appendix B-1: Dollar Limitation on Participants' Before-Tax Option Contributions .

4.2(b) Limitation on Total Annual Additions

The annual additions to a Participant's account during the Plan Year resulting from After-Tax Option contributions, Before-Tax Option contributions, and Company Matching Contributions may not under Code Section 415(c) exceed the Code Section 415(c)(1) limit.

As used in this Section 4.2(b) and Appendix B-2, compensation means compensation under Code Section 415(c)(3), including any items required to be included in compensation and excluding any items required to be excluded from compensation under Code Section 415(c)(3) and the regulations issued thereunder, and specifically incorporating the safe harbor definition of compensation under Treas. Reg. § 1.415(c)-2(d)(4) relating to information required to be reported under Code Sections 6041, 6051, and 6052. Any differential wage payments (as defined in Code Section 3401(h)(2)) shall be included in compensation for purposes of Code Section 415. Payments made by the later of 2-1/2 months after severance from employment or the end of the limitation year that includes the date of severance from employment are included in compensation for the limitation year if, absent a severance from employment, such payments would have been paid to the Participant while the Participant continued in employment with the Employer and are regular compensation for services during the Participant's regular working hours, compensation for services outside the Participant's regular working hours (such as overtime or shift differential), commissions, bonuses, or other similar compensation.

Compensation as used in this section 4.2(b) and Appendix B-2 is not permitted to reflect compensation that is in excess of the limitation under Code Section 401(a)(17) that applies to that limitation year.

4.2(c) Limitation on Participant Contributions Under the Before-Tax Option (ADP Test)

The actual deferral percentage of eligible Highly Compensated Employees may not exceed the actual deferral percentage of eligible Nonhighly Compensated Employees by an amount greater than the limitations of the Actual Deferral Percentage (ADP) Test under Code Section 401(k)(3). The Plan Administrator may prospectively limit, during the Plan Year, Before-Tax Option contributions of certain Highly Compensated Employees if it is determined that the ADP Test limitation would otherwise be exceeded for such Plan Year. Participants whose Before-Tax Option contributions are prospectively limited under this Section 4.2(d) are automatically treated as electing to increase their contributions under the After-Tax Option by an amount equal to the Participant's Before-Tax Option contribution percentage in excess of the limitation.

The Plan Administrator may also correct any excess Before-Tax Option contributions by distributing the excess amounts applicable to such Highly Compensated Employees in a post-Plan Year distribution, by making a Qualified Nonelective Contribution, or by recharacterizing excess amounts as After-Tax Option contributions. Detailed provisions governing the operation of this limitation under the Plan are set forth in Appendix B-4: Limitation on Participant Contributions Under the Before-Tax Option (ADP Test).

4.2(d) Limitation on After-Tax Option Contributions and Company Matching Contributions (ACP Test)

The actual contribution percentage of eligible Highly Compensated Employees may not exceed the actual contribution percentage of eligible Nonhighly Compensated Employees by an amount greater than the limitations of the Actual Contribution Percentage (ACP) Test under Code Section 401(m). The Plan

Administrator may prospectively limit, during the Plan Year, After-Tax Option contributions or Company Matching Contributions of certain Highly Compensated Employees if it is determined that the ACP Test limitation would otherwise be exceeded for such Plan Year. The Plan Administrator may also correct any excess After-Tax Option contributions or Company Matching Contributions by distributing the excess amounts to such Highly Compensated Employees in a post-Plan Year distribution. Detailed provisions governing the operation of this limitation under the Plan are set forth in Appendix B-5: Limitation on Participant Contributions Under the After-Tax Option and Company Matching Contributions (ACP Test).

Article V – Investment of Contributions and Determination of Account Balances

5.1 Investment of Contributions

5.1(a) Investment Funds

Contributions to the Plan will be invested in one or more of the following Investment Funds under the Plan:

(1) the CEG Common Stock Fund;

(2) the Default Investment Fund; or

(3) any Other Investment Fund(s) selected by the Investment Committee from time to time.

Dividends, interest, or other income, if any, received by the Trustee with respect to contributions in each Investment Fund shall be reinvested in the same Investment Fund, except to the extent distributed in accordance with Section 8.5(a).

In the event a Participant fails to make any investment elections with respect to any Participant Contributions, rollover contributions and, for periods on or after January 1, 2012, Company Matching Contributions, the portion of the Participant's accounts over which the Participant has not directed the investment shall first be invested in accordance with elections under the Before-Tax Option, then in elections under the After-Tax Option and then, if no elections are made under either the Before-Tax or After-Tax Option, invested in the Default Investment Fund. Any material provided to the Plan relating to a Participant's investment in the Default Investment Fund as a default investment as described above, including account statements, prospectuses and proxy voting material, will be provided to such Participant. The Default Fund is and has been intended to constitute a "qualified default investment alternative" as defined in DOL Reg. 2550.404c-5 and is intended to meet all requirements necessary to satisfy applicable law.

5.1(b) Investment of Participant Contributions

A Participant's contributions to the Plan under either the After-Tax Option or the Before-Tax Option, or under the rollover provisions of the Plan, shall be invested in one or more of the Investment Funds under the Plan, in accordance with instructions furnished to the Plan Administrator by the Participant as provided under Article II. Participant contributions to the Plan shall be allocated to the Investment Funds in any increments of one percent (1%) of the total contribution or in any other increments at the discretion of the Plan Administrator as selected by the Participant. A Participant may choose to invest contributions to the Plan under the After-Tax Option in the same different Investment Funds and at different percentages than contributions under the Before-Tax Option. Likewise, contributions under the rollover provisions of the Plan are not required to be invested in the same Investment Funds or in the same percentages as Participant Contributions under the After-Tax and/or the Before-Tax Options.

With respect to After-Tax Option, Before-Tax Option, or rollover contributions held by the Company pending transfer to the Trustee, no interest will be paid on such accumulated contributions prior to transfer to the Trustee. A Participant will not be able to withdraw under any circumstances monies contributed but not yet transferred to the Trustee.

Participant contributions shall be posted to Participants' accounts as soon as administrative feasible after such contributions are transferred to the Trustee.

5.1(c) Change in Investment of Participant Contributions

A Participant may change investment percentages for future contributions to the Investment Funds under the After-Tax and/or Before-Tax Options within the limits set forth in Section 5.1(b). Investment percentages may be changed at any time, by submitting an Appropriate Request in the form and manner prescribed by the Plan Administrator. The change will become effective as soon as administratively feasible.

5.1(d) Investment of Company Matching Contributions

Prior to January 1, 2012, all Company Matching Contributions shall be initially invested in the CEG Common Stock Fund. Participants may elect to transfer these contributions to other Investment Funds as soon as these contributions have been posted to provide for diversification of the Participant's investment pursuant to the interfund transfers provisions of Section 5.3(a).

Effective on and after January 1, 2012, all Company Matching Contributions shall be invested in accordance with instructions furnished to the Plan Administrator by the Participant as provided under Article III and this Article V for contributions to the Plan under the Before-Tax Option. Company Matching Contributions shall be posted as soon as administratively feasible after the date the contributions are transferred to the Trustee. Company Matching Contributions shall be allocated to the Investment Funds in any increments of one percent (1%) of the total contribution or in any other increments at the discretion of the Plan Administrator as selected by the Participant.

5.1(e) Investment of Employee Stock Account

A Participant's Employee Stock Account consists of Company contributions that were made under the Corporate Performance Award Program, amounts that were directly transferred by the Trustee of the terminated Baltimore Gas and Electric Company Employee Stock Ownership Plan, and earnings thereon. All contributions, transfers, and earnings in the Employee Stock Account were initially invested in the CEG Common Stock Fund. As with Company Matching Contributions, Participants may elect to transfer these contributions to other Investment Funds to provide for diversification of the Participant's investments pursuant to the interfund transfers provisions of Section 5.3(a).

5.1(f) Investment of Recharacterized Employee Contributions

Amounts contributed by a Participant under the Before-Tax Option which are subsequently recharacterized as contributions under the After-Tax Option because the limitations under Section 4.2(d) are exceeded, shall remain invested in the same Investment Funds in which such contributions were invested immediately prior to the recharacterization.

5.1(g) Investment of After-Tax Option Contributions Made Pursuant to Automatic Provisions of Section 4.2(a) and Section 4.2(d)

Amounts contributed by a Participant under the After-Tax Option pursuant to the automatic provision contained in Sections 4.2(a) and 4.2(d) relating to prospective limitations, shall be invested in the same Investment Funds using the same investment percentages as elected by the Participant for other contributions being made under the After-Tax Option. Lacking instructions from the Participant regarding investments under the After-Tax Option, such contributions shall be invested in the same Investment Funds using the same investment percentages elected by the Participant under the Before-Tax Option.

5.2 Investment Fund Accounts

5.2(a) Participant Contribution Account

A Participant Contribution Account will be established in each Investment Fund to which Participant Contributions under the After-Tax and/or Before-Tax Options are invested.

5.2(b) Company Matching Contribution Account

Prior to January 1, 2012, a Company Matching Contribution Account will be established in the CEG Common Stock Fund for each Participant. This account will contain all Company Matching Contributions made on behalf of the Participant prior to January 1, 2012 with respect to Basic Contributions under the After-Tax and/or Before -Tax Options.

Company Matching Contribution Accounts will also be established in the Default Investment Fund and the Other Investment Funds as elected by the Participant for Participants requesting transfer for amounts from the Company Matching Contribution Account in the CEG Common Stock Fund to other Investment Funds under the provisions of Section 5.3(a) and for all Company Matching Contributions made on behalf of the Participant on and after January 1, 2012 with respect to Basic Contributions under the After-Tax and/or Before-Tax Options.

5.2(c) Employee Stock Account

Contributions were made to an Employee Stock Account that was established in the CEG Common Stock Fund on behalf of the Participant under the Corporate Performance Award Program. The Employee Stock Account also includes any amounts directly transferred by the Trustee of the terminated Baltimore Gas and Electric Company Employee Stock Ownership Plan.

Dividends, if any, received by the Trustee (on or before the January 1, 2002 Common Stock dividend payment date) with respect to amounts in the Employee Stock Account in the CEG Common Stock Fund shall be distributed to Participants as provided in Section 8.5. The Trustee shall invest, no less frequently than quarterly, any interest earned on such dividends prior to their distribution, in shares of Common Stock, and allocate such shares to the Participant's Employee Stock Account in the CEG Common Stock Fund. Employee Stock Accounts will also be established in the Default Investment Fund and the Other Investment Funds for Participants requesting transfer of amounts from the Employee Stock Account in the CEG Common Stock Fund to other Investment Funds under the provisions of Section 5.3(a).

5.2(d) Rollover Account

A Rollover Account will be established in each Investment Fund to which Participant rollover contributions under the rollover provisions of the Plan are invested in accordance with Participant instructions.

5.3 Interfund Transfers

5.3(a) Generally

Upon submitting an Appropriate Request to the Plan Administrator, a Participant may elect to transfer from one Investment Fund to another, in whole or in part, in multiples of 1 percentage, whole number of shares or whole dollar amounts that have already been contributed by the Participant to the Plan under the After-Tax Option, the Before-Tax Option, and/or the rollover provisions of the Plan, and by the Company to the Plan under the Company Matching Contribution Account and Employee Stock Account. Amounts may not be transferred between the Participant Contribution Account, the Company Matching Contribution Account, the Employee Stock Account, or the Rollover Account. Amounts in the Participant Contribution Account, may not be transferred between the After-Tax Option and the Before-Tax Option. An Appropriate Request for Investment Fund transfer may be submitted to the Plan Administrator at any time.

5.3(b) Valuation of Interfund Transfers

The value of the account balances transferred under the interfund transfer provisions shall be determined in the following manner:

If the Participant makes an Appropriate Request for an interfund transfer *prior to* the close of the New York Stock Exchange, (i) transfers from the Default Investment Fund and/or the Other Investment Funds shall be valued based on the Closing Price for the funds on the day the Appropriate Request is received, (ii) transfers from the

CEG Common Stock Fund shall be valued based on the Transaction Price on the next business day after the Appropriate Request is received, (iii) transfers to the Default Investment Fund and/or the Other Investment Funds shall be valued based on the Closing Price for the funds on the day the Appropriate Request is received, unless the transfer to such funds is from the CEG Common Stock Fund, in which case the value shall be the Closing Price of the funds on the day the proceeds from the sale of the Common Stock are received by the Trustee, and (iv) transfers to the CEG Common Stock Fund shall be valued based on the Transaction Price on the next business day following the day the Appropriate Request is received.

If the Participant makes an Appropriate Request for an interfund transfer *on or after* the close of the New York Stock Exchange, (i) transfers from the Default Investment Fund and/or the Other Investment Funds shall be valued based on the Closing Price for the funds on the next business day after the Appropriate Request is received, (ii) transfers from the CEG Common Stock Fund shall be valued based on the Transaction Price on the second business day after the Appropriate Request is received, (iii) transfers to the Default Investment Fund and/or the Other Investment Funds shall be valued based on the Closing Price for the funds on the next business day after the Appropriate Request is received, unless the transfer to such funds is from the CEG Common Stock Fund, in which case, the value shall be the Closing Price of the funds on the day the proceeds from the sale of the Common Stock are received by the Trustee, and (iv) transfers to the CEG Common Stock Fund shall be valued based on the Transaction Price on the second business day following the day the Appropriate Request is received.

5.4 Fractional Shares

The Company does not issue fractional shares of Common Stock. However, to facilitate full investment of monies in the CEG Common Stock Fund, the Plan accounting system allocates fractional shares of Common Stock to Participants' accounts. Participants' fractional shares are aggregated so that only whole shares are actually held by the Plan. The aggregate value of all Participants' whole and allocated fractional shares will not exceed the value of the sum of the shares and cash held by the CEG Common Stock Fund.

Article VI – Vesting

6.1 Participant Contributions

A Participant is 100% vested at all times with respect to amounts in his Participant Contribution Accounts and Rollover Accounts.

6.2 Company Contributions

A Participant is 100% vested at all times with respect to amounts in his Company Matching Contribution Accounts and Employee Stock Accounts.

6.3 Participant's Election to Use Pre-Amendment Vesting Schedule

In the event the Plan is amended to change or modify the Plan's vesting schedule, or the Plan is amended in any way that directly or indirectly affects the computation of the nonforfeitable percentage of the Participant's accrued benefit or if the Plan is deemed amended by an automatic change to or from a top-heavy (see Appendix D) vesting schedule, a Participant with at least three (3) Years of Service as of the date the amendment is adopted or as of the amendment's effective date, may elect to be subject to the pre-amendment vesting schedule. For Participants who do not have at least one (1) Hour of Service in any Plan Year beginning after December 31, 1988, the preceding sentence shall be applied by substituting "five (5) Years of Service" for "three (3) Years of Service." If a Participant fails to make the election described in this Section, then the Participant will be subject to the new vesting schedule. The election of the pre-amendment vesting schedule shall be made by giving written notice to the Plan Administrator during the election period. The election period shall begin on the date such amendment is adopted and shall end no earlier than the latest of the following dates:

(a) The date which is sixty (60) days after the date the Plan amendment is adopted,

(b) The date which is sixty (60) days after the date the Plan amendment becomes effective, or

(c) The date which is sixty (60) days after the date the Participant is issued written notice of the Plan amendment by the Company or Plan Administrator.

Such election shall be made only by an individual who is a Participant at the time such election is made and such election shall be irrevocable. Such Plan amendment shall not reduce the vested percentage of a Participant's accrued benefit as of the later of the date on which such Plan amendment is adopted or the effective date of such Plan amendment.

6.4 Qualified Military Service

If a Participant dies while performing qualified military service (within the meaning of Section 414(u)(5) of the Code), such Participant shall be credited with years of service for the period of his/her qualified military service.

Article VII – Withdrawals

7.1 General

7.1(a) Eligibility

A Participant is eligible to make regular and/or hardship withdrawals from the Plan, subject to the provisions of this Article VII. A Participant will continue to be considered a Participant for purposes of eligibility for withdrawals as long as amounts are held in the Participant's Plan accounts, regardless of such Participant's eligibility to make further contributions to the Plan.

7.1(b) Form and Valuation

Amounts invested in the CEG Common Stock Fund may be withdrawn in whole shares of the Company's Common Stock, with cash in lieu of any fractional share, or, at the Participant's election, the amount may be withdrawn wholly in cash. Withdrawals from the Default Investment Fund and the Other Investment Funds will be made only in cash.

The amounts withdrawn by the Participant will be taken from the Participant's accounts in the order specified in Section 7.4 for regular withdrawals and Section 7.6 for hardship withdrawals and will be subject to any applicable restrictions imposed by the Plan. The Trustee shall sell or purchase securities to meet the Participants' withdrawal requests but must do so over the period of time necessary to insure that such purchases or sales are made in accordance with applicable law, rules and regulations and do not disrupt the trading market for the Common Stock.

The value received by a Participant requesting a withdrawal shall be determined in the following manner:

If the Participant makes an Appropriate Request for a withdrawal *prior to* 4:00 p.m. E.T., (i) withdrawals from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the day the

Appropriate Request is received; provided, however, that if the withdrawal consists of amounts from the CEG Common Stock Fund, withdrawals from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the next business day after the Appropriate Request is received, and (ii) withdrawals from the CEG Common Stock Fund shall be valued based on the Transaction Price on the next business day after the Appropriate Request is received.

If the Participant makes an Appropriate Request for a withdrawal *on or after* 4:00 p.m. E.T., (i) withdrawals from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the next business day after the Appropriate Request is received; provided, however, that if the withdrawal consists of amounts from the CEG Common Stock Fund, withdrawals from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the second business day following receipt of the Appropriate Request, and (ii) withdrawals from the CEG Common Stock Fund shall be valued based on the Transaction Price on the second business day following receipt of the Appropriate Request.

In the case of a hardship withdrawal as described in Section 7.5, an Appropriate Request is not treated as having been made for purposes of the above valuation procedures until the Plan Administrator approves the withdrawal for payment.

7.1(c) Maturity

For employees with less than 5 years of service, Participant Contributions and Company Matching Contributions do not mature until 24 months after the date of contributions. For employees with 5 or more years of service, Participant Contributions and Matching Contributions shall mature immediately upon the date of contribution. All contributions made to a Rollover Account shall mature immediately upon the date of contribution. All Supplemental Contributions made prior to October 1, 2004 are mature.

All contributions made to the Employee Stock Account matured prior to October 1, 2004. If a Participant dies while performing qualified military service (within the meaning of Section 414(u)(5) of the Code), such Participant shall be credited with years of service for the period of his/her qualified military service

7.2 Regular Withdrawals

A Participant may make a regular withdrawal at any time by submitting an Appropriate Request to the Plan Administrator. A regular withdrawal is a withdrawal other than a hardship withdrawal and does not include distributions upon termination of employment as described in Article VIII.

Each regular withdrawal request received by the Plan Administrator will be paid out as soon as practicable after the request is received.

7.3 Restrictions on Regular Withdrawals

7.3(a) Regular Withdrawal of Contributions Under the Before-Tax Option

Before-Tax Option contributions, whether Basic or Supplemental, and related earnings may not be paid out of the Plan as part of a regular withdrawal unless the Participant is at least age 59-1/2, has retired, has been placed on long-term disability, or has terminated employment for any other reason. A Participant on a leave of absence is not considered to have terminated employment. The source of the amounts withdrawn from the Plan by a Participant who is at least age 59-1/2 or who has retired, been placed on long-term disability, or terminated employment for any other reason, must conform to the order of withdrawal specified in Section 7.4.

7.3(b) Consequences of Withdrawals of Unmatured Participant Contributions

If, in following the order of withdrawal specified in Section 7.4, any unmatured Participant Contributions are withdrawn, the Participant will be suspended from making contributions to the Plan under the After-Tax Option and the Before-Tax Option for (i) six (6) months following the month in which the Appropriate Request for the regular withdrawal is received by the Plan Administrator, if such withdrawal is made after September 30, 2004, and (ii) twelve (12) months following the month in which the Appropriate Request for the regular withdrawal is received by the Plan Administrator, if such withdrawal is made before October 1, 2004. There are no other penalties or restrictions under the Plan for withdrawing amounts that are eligible for withdrawal.

7.3(c) Withdrawals of Certain Other Unmatured Contributions

Withdrawals of unmatured contributions and related earnings from a Participant's Company Matching Contribution Account are not permitted under the Plan. The restriction on withdrawal lapses once these contributions mature.

7.4 Source of Regular Withdrawals

A Participant's regular withdrawals from the Plan will be taken from the Participant's accounts in the order listed below. For each level in the order of withdrawal, the entire account balance must be exhausted before amounts may be withdrawn from the next level. The meaning of matured and unmatured accounts as used below relates to the status of the contributions as explained in Section 7.1(c). Unless specifically indicated otherwise, an account includes both contributions and earnings thereon.

First	After-Tax Option Account with respect to Participant Contributions made prior to January 1, 1987, followed by earnings thereon.
Second	Matured After-Tax Option Account with respect to Participant Contributions made after December 31, 1986, followed by earnings thereon.
Third	Rollover Account.

Fourth	Employee Stock Account. Withdrawals from the Employee Stock Account will be made first from the portion of the account representing the Participant's investment in the account (i.e., amounts transferred from the terminated Baltimore Gas and Electric Company Employee Stock Ownership Plan that consist of after-tax contributions made by employees to such plan), and then from the remainder of the account.
Fifth	Matured Company Matching Contribution Account.
Sixth	Matured Before-Tax Option Account, but only if the Participant has reached age 59-1/2, retired, been placed on long-term disability or terminated employment for any other reason.
Seventh	Unmatured After-Tax Option Account with respect to Participant Contributions, followed by earnings thereon.
Eighth	Unmatured Before-Tax Option Account with respect to Participant Contributions, but only if the Participant has reached age 59-1/2, retired, been placed on long-term disability or terminated employment for any other reason.

The Participant will be permitted to make a regular withdrawal only to the extent funds eligible for withdrawal are available in the Participant's Plan accounts.

Withdrawals will be made pro rata in proportion to the Participant's respective investment in each Investment Fund under the account applicable to the level of withdrawal.

7.5 Hardship Withdrawals

7.5(a) General

A Participant will be eligible to receive a withdrawal under the hardship withdrawal provisions of the Plan if the Participant submits an Appropriate Request to the Plan Administrator and receives the Plan Administrator's express sanction and approval for the withdrawal. To obtain approval, the Participant will be required to demonstrate that the hardship withdrawal is necessary to satisfy an immediate and heavy financial need.

Because a Participant must withdraw all amounts available under the regular withdrawal provisions of the Plan and obtain any available loans under the Plan's loan provisions, prior to withdrawing amounts under the hardship withdrawal provisions, hardship withdrawals are limited to the Participant's contributions under the Before-Tax Option and earnings thereon which are not otherwise available as regular withdrawals or loans. However, earnings on Before-Tax Option contributions are available for hardship withdrawal only if allocated to the Participant's account as of December 31, 1988.

Following receipt of a hardship withdrawal, the Participant will be suspended from making contributions to the Plan under the After-Tax Option and the Before-Tax Option and to certain other plans of the Employer, as defined in Treasury Regulation Section 1.401(k)-1(d)(3)(iv)(F), for six (6) full months beginning with the first Payroll Period in the month following the month in which the hardship withdrawal is approved for payment by the Plan Administrator. A hardship withdrawal will be paid out as soon as practicable after Plan Administrator approval.

7.5(b) Immediate and Heavy Financial Need

In order to receive a hardship withdrawal, the Participant must demonstrate an immediate and heavy financial need. The following financial needs will automatically qualify as immediate and heavy.

1) Medical expenses described in Code Section 213(d) which have been previously incurred or are necessary to obtain medical care by the Participant, the Participant's Spouse, or any dependents of the Participant as defined in Code Section 152, without regard to subsections (b)(1), (b)(2), and (d)(1)(B) thereof.

2) The purchase (excluding mortgage payments) of a principal residence for the Participant.

3) The payment of tuition and related educational fees for the next twelve (12) months of post-secondary education for the Participant, the Participant's Spouse, or dependents as defined in Code section 152, without regard to subsections (b)(1), (b)(2), and (d)(1)(B) thereof.

4) Mortgage payments or rental payments that must be paid to prevent foreclosure on the mortgage of the Participant's principal residence or eviction of the Participant from his principal residence.

5) Certain other specified events that are deemed to be of an immediate and heavy financial need as determined by the Internal Revenue Service and published in revenue rulings, notices, and other documents of general applicability.

Other financial needs may qualify as immediate and heavy, based on all relevant facts and circumstances and subject to the approval of the Plan Administrator. Generally, for example, the need to pay funeral expenses for a family member may qualify as an immediate and heavy financial need.

The amount of an immediate and heavy financial need may include amounts necessary to pay any federal, state, or local income taxes or penalties reasonably anticipated to result from the hardship withdrawal.

It is the intent of the Plan that the definition of an "immediate and heavy financial need" will conform to the meaning of the term under the provisions of Treasury Regulation Section 1.401(k)-1(d)(3).

7.5(c) Withdrawal Deemed Necessary to Satisfy an Immediate and Heavy Financial Need – Requirements

After a Participant demonstrates that an immediate and heavy financial need exists, the Participant must also demonstrate that a hardship withdrawal from the Plan is necessary to satisfy that need.

Hardship withdrawals under the Plan will automatically be deemed necessary to satisfy an immediate and heavy financial need if all of the following requirements are met.

1) The withdrawal does not exceed the amount of the immediate and heavy financial need of the Participant.

2) The Participant has elected to receive all dividend distributions currently available under the Plan pursuant to Section 8.5(a), and has obtained all withdrawals, other than hardship withdrawals, and all nontaxable loans currently available under the Plan.

3) The Participant's contributions under the After-Tax and Before-Tax Options of the Plan and contributions to certain other plans of the Employer, as defined in Treasury Regulation Section 1.401(k)-1(d)(3)(iv)(F), are suspended for six (6) months following the month of receipt of the hardship withdrawal.

Notwithstanding the above, the Plan Administrator may, at his discretion, determine that a hardship withdrawal is necessary to satisfy an immediate and heavy financial need after a review of all relevant facts and circumstances.

It is the intent of the Plan that the withdrawals deemed necessary to satisfy the immediate and heavy financial need under this Section 7.5(c), will conform to the withdrawals deemed to satisfy this need under Treasury Regulation Section 1.401(k)-1(d)(3).

7.6 Source of Hardship Withdrawals

A Participant's hardship withdrawals from the Plan will be taken from the Participant's Before-Tax Option Account, but only after all available amounts have been withdrawn under the regular withdrawal provisions of the Plan and all available nontaxable loans have been taken under the loan provisions of the Plan. For purposes of this Section, the Before-Tax Option Account includes contributions and earnings allocated thereon as of December 31, 1988. Earnings allocated to the Before-Tax Option Account after December 31, 1988 are not available for hardship withdrawal and, accordingly, are excluded therefrom.

Qualified Nonelective Contributions and earnings thereon are not available for hardship withdrawal and, accordingly, are excluded therefrom.

The Participant will be permitted to make a hardship withdrawal only to the extent funds eligible for withdrawal are available in the Participant's Before-Tax Option Account.

Hardship withdrawals will be made pro rata in proportion to the Participant's respective investment in each Investment Fund under the Before-Tax Option Account.

Unmatured amounts not available for regular withdrawal under Section 7.3(c) will also not be available to the Participant for any hardship withdrawal.

7.7 Direct Rollover of Withdrawals

Notwithstanding any provision of the Plan to the contrary that would otherwise limit a Distributee's election under this Section, a Distributee may elect, at the time and manner prescribed by the Plan Administrator, to have any portion of a withdrawal from the Plan that is an Eligible Rollover Distribution paid directly to an Eligible Retirement Plan specified by the Distributee in a Direct Rollover.

7.8 In-Service Distributions for Active Duty Members of the Uniformed Services.

An individual who is on active duty for more than 30 days in accordance with Section 414(u)(12)(B) of the Code is treated as having been severed from employment during such period and may elect a distribution in accordance with and subject to the limitations of Section 414(u)(12)(B) of the Code. If a Participant elects a 30-day deemed distribution period, the Participant's right to make contributions under the After-Tax and Before-Tax Options following such distribution and while on leave must be suspended for a six-month period after the distribution.

Article VIII – Distributions

8.1 Eligibility

A Participant will continue to be considered a Participant for purposes of eligibility for distributions as long as amounts are held in the Participant's Plan accounts, regardless of such Participant's eligibility to make further contributions to the Plan.

A Participant is eligible to receive final distributions of all amounts in the Plan when the Participant either reaches age 70-1/2, retires, is placed on long-term disability, or terminates employment for any other reason. If a Participant dies, the Participant's beneficiary is entitled to any undistributed amounts from the Plan, as provided in Section 8.7. A Participant on a leave of absence is not considered to have terminated employment and will not be entitled to a distribution from the Plan under the provisions of this Article VIII.

8.2 Required Distributions

8.2(a) Distributions After Attaining Age 70-1/2

A Participant's entire Plan balance shall be distributed, or installment payments shall begin, not later than April 1st of the calendar year following the calendar year in which the Participant attains age 70-1/2, unless such Participant is employed by an Employer (in which case such distribution or installment payments shall commence upon employment termination). However, if there ever is a Participant who is a 5% owner (as defined in Code Section 416(i)), payment must commence no later than April 1 st of the Plan Year after the Plan Year in which such Participant attains age 70-1/2, even if the Participant is still employed.

8.2(b) Mandatory Distribution for Plan Balances of $1,000 or less

A Participant who retires, is placed on long-term disability, or terminates employment for any other reason will automatically receive a final lump-sum distribution of all amounts held in the Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, and Rollover Account, if the aggregate value of the accounts is $1,000 or less as of the end of the calendar month in which retirement, placement on long-term disability, or termination for any other reason occurs. The aggregate value of a Participant's Plan accounts will be determined in accordance with the Trust Agreement and will include the value of any outstanding Plan loans to the Participant. Any distributions from a Participant's accounts that are invested in the CEG Common Stock Fund will be made in the form of a lump-sum cash payment in lieu of shares of Common Stock, unless the Participant elects a distribution of Common Stock representing investments in the CEG Common Stock Fund by filing an Appropriate Request with the Plan Administrator. A distribution under this Section 8.2(b) will be made within 90 days after the end of the month in which retirement, placement on long-term disability, or termination for any other reason occurs.

8.3 Distributions Elected by Participant

8.3(a) Time of Distribution

Participants eligible to receive final distributions from the Plan and who are not subject to the required distribution provisions of Section 8.2 may elect a distribution by submitting an Appropriate Request with the Plan Administrator. Distributions will commence as soon as practicable after the Appropriate Request is received by the Plan Administrator.

The Participant's final distribution will be made within sixty (60) days after the later of the end of the Plan Year in which: (i) the Participant attains age 65, (ii) the Participant ceases active employment, or (iii) the tenth (10th) anniversary of the year in which the Participant's participation in the Plan occurs. Notwithstanding the preceding sentence, a distribution will not be made unless the Participant submits an Appropriate Request for a distribution with the Plan Administrator. In any case, distributions must begin by the date prescribed in Section 8.2(a).

8.3(b) Method of Distribution

Participants who are not subject to the mandatory distribution requirements of Section 8.2(b) may elect to receive distributions as lump-sum payments, or as installment payments as provided in Section 8.4(c) made over a period not to exceed ten (10) years. Partial payments may also be made from time to time as requested under the withdrawal provisions of Article VII.

8.3(c) Required Minimum Distributions

Notwithstanding any other provision in the Plan to the contrary, distributions under the Plan shall comply with the requirements of Code section 401(a)(9) (including the incidental death benefit requirements of Code section 401(a)(9)(G)) and the regulations thereunder. Notwithstanding anything in the Plan to the contrary, a Participant or beneficiary who would have been required to receive required minimum distributions for 2009 but for the enactment of Section 401(a)(9)(H) of the Code ('2009 RMDs'), and who would have satisfied that requirement by receiving distributions that are (1) equal to the 2009 RMDs or (2) one or more payments in a series of substantially equal distributions (that include the 2009 RMDs) made at least annually and expected to last for the life (or life expectancy) of the Participant, the joint lives (or joint life expectancy) of the Particpant and the beneficiary, or for a period of at least 10 years ('Extended RMDs'), will receive those distributions for 2009. In addition, solely for purposes of applying the Direct Rollover provisions of the Plan, 2009 RMDs and Extended RMDs will not be treated as Eligible Rollover distributions.

8.4 Form and Valuation of Distribution

8.4(a) CEG Common Stock Fund

Except as provided in Section 8.2(b) under the mandatory distribution requirement or Section 8.4(c) under the installment payment option, any distributions from a Participant Contribution Account, Company Matching Account, Employee Stock Account, or Rollover Account that are invested in the CEG Common Stock Fund will be made in a lump-sum payment constituting shares of Common Stock with cash paid in lieu of fractional shares.

The portion of the distribution representing investments in the CEG Common Stock Fund may, at the election of the Participant, be received entirely in cash in lieu of shares of Common Stock upon submitting an Appropriate Request with the Plan Administrator.

8.4(b) Default Investment Fund and Other Investment Funds

Except as provided in Section 8.4(c) under the installment payment option, any distributions from a Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, or Rollover Account that are invested in the Default Investment Fund and/or the Other Investment Funds will be made in the form of a lump-sum cash payment.

8.4(c) Installment Payment Option

Participants who are not subject to the mandatory distribution requirements of Section 8.2(b) and who are retired, have been placed on long-term disability, or terminated employment for any other reason, may elect to receive their distributions in annual, quarterly, or monthly installments over a period not to exceed ten (10) years. The election to receive such installments must be made prior to receiving a distribution and by means of an Appropriate Request submitted with the Plan Administrator.

Participants who have elected the installment payment option and selected an installment payment period may change the number of years, quarters, or months over which installments will be made at any time after the installment payments have commenced, provided that such change will not result in an installment payment period in excess of ten (10) years from the date the installments began. The election to change the installment payment period is made by submitting an Appropriate Request with the Plan Administrator. Any change in the installment payment period will be effective as soon as practicable following receipt of the Appropriate Request by the Plan Administrator.

A Participant who has elected the installment payment option may, at any time, submit an Appropriate Request with the Plan Administrator to receive a lump-sum payment of the remaining balance in the Participant's accounts.

The amounts included in installment payments to a Participant will be taken from the Participant's Plan accounts in the same order specified in Section 7.4 for regular withdrawals. Unmatured Company Matching Contribution Account amounts remaining in the Participant's accounts after such ordering rules are applied are included in installment payments. The meaning of unmatured accounts relates to the status of contributions as explained in Section 7.1(c). Unless specifically indicated otherwise, an account includes both contributions and earnings thereon.

Amounts invested in the CEG Common Stock Fund may be received under the installment payment option either in whole shares of the Company's Common Stock with cash in lieu of any fractional share, or, at the Participant's election, in cash. A Participant's election to receive cash or not to receive cash for amounts invested in the CEG Common Stock Fund will apply to all installment payments made to the Participant subsequent to such election, unless the Participant submits an Appropriate Request with the Plan Administrator prior to the installment payment date requesting that the Participant's election be changed.

Installment payments that consist of amounts from the Default Investment Fund and the Other Investment Funds will be made only in cash.

Amounts included in installment payments will be withdrawn from a Participant's investment funds pro rata in proportion to the Participant's respective investment in each Investment Fund under the account applicable to the level of installment payment.

8.4(d) Valuation of Distributions

The value received by a Participant requesting a lump-sum distribution shall be determined in the following manner:

If the Participant makes an Appropriate Request for a distribution *prior to* 4:00 p.m. E.T., (i) distributions from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the day the Appropriate Request is received; provided, however, that if the distribution consists of amounts from the CEG Common Stock Fund, distributions from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the next business day after the Appropriate Request is received, and (ii) distributions from the CEG Common Stock Fund shall be valued based on the Transaction Price on the next business day after the Appropriate Request is received.

If the Participant makes an Appropriate Request for a distribution *on or after 4:00* p.m. E.T., (i) distributions from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the next business day after the Appropriate Request is received; provided, however, that if the distribution consists of amounts from the CEG Common Stock Fund, distributions from the Default Investment Fund and Other Investment Funds shall be valued based on

Closing Price for such funds on the second business day following receipt of the Appropriate Request, and (ii) distributions from the CEG Common Stock Fund shall be valued based on the Transaction Price on the second business day following receipt of the Appropriate Request.

For a Participant electing the installment distribution option, the value received for the first installment payment shall be determined in accordance with the above valuation procedures. For installment payments in subsequent years, the value received shall be determined in accordance with the above valuation procedures.

The valuation procedures described above shall be applied by substituting the term "Plan Administrator action" for each place the term "Appropriate Request" appears, in the case of (i) Participants subject to the required distribution provisions of Section 8.2, and (ii) beneficiaries who fail to elect an earlier distribution as described in Section 8.7(a).

8.5 Employee Stock Account Dividend Distributions

This Section 8.5 applies through, but is no longer effective after, the Common Stock dividend payment on January 1, 2002.

Any dividends declared and paid on shares of Common Stock in the Employee Stock Account in the CEG Common Stock Fund held by the Trustee pursuant to the Plan shall be invested by the Trustee pursuant to the Trust Agreement in interest bearing accounts. After the final dividend payment in each year has been made by the Company, the Trustee will distribute to each Participant by not later than December 31st of that year the dividend amounts declared and paid on the shares of Common Stock allocated to the Participant's Employee Stock Account in the CEG Common Stock Fund. The Trustee shall invest, no less frequently than quarterly, any interest earned on such dividends prior to their distribution, in shares of Common Stock, and allocate such shares to the Participant's Employee Stock Account in the CEG Common Stock Fund.

When a Participant receives final distributions of all amounts in the Plan allocated to his accounts, any additional dividends which have been declared and paid on shares of Common Stock in the Employee Stock Account and any related interest in the CEG Common Stock Fund which has not yet been distributed under the provisions of this Section 8.5, will be distributed in cash at the same time as the distribution of the shares of Common Stock in the Participant's Employee Stock Account in the CEG Common Stock Fund.

8.5(a) CEG Common Stock Fund Employee Election

Effective February 1, 2006, any dividend paid with respect to shares of the CEG Common Stock Fund allocated to the Participant's accounts as of the record of such dividend will be, as elected by the Participant prior to the payment date (1) distributed in cash to the Participant as soon as administratively practicable following the date such dividend is paid by the Company or (2) retained by the Trustee and reinvested in Company stock for credit to the Participant's account in the CEG Common Stock Fund. The amount distributed to the Participant pursuant to clause (1) of the preceding sentence shall be the lesser of (A) the original amount of the dividends attributable to that Participant and (B) the amount of such dividends as adjusted for any investment losses while held in the Trust or reduced for any withholdings. In accordance with such procedures as the Plan Administrator may provide, a Participant shall be given a reasonable opportunity to make an election under this Section 8.5(a) before the beginning of each quarter of the Company's taxable year with respect to dividends paid in such

quarter. A Participant may have only one election in effect for his or her account at any time (and may not make separate elections with respect to the different portions of his or her account). If a Participant who has previously made a timely election under this Section 8.5(a) does not make a new election with respect to dividends paid in a subsequent period, the Participant's prior election shall remain in effect for such subsequent period (and shall apply to all dividends paid on Company Stock during such period with respect to which an election is offered). In the absence of a timely election, the Participant shall be deemed to have elected to have the dividends with respect to which an election is offered accumulated in his or her account and reinvested in Company Stock.

8.6 Unlocated Participants

If and when the balance in a Participant's account(s) under the Plan becomes payable and the Plan Administrator is unable to locate a Participant or his designated beneficiary or beneficiaries to whom such amounts are payable, the Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, and Rollover Account of the Participant will be closed after three (3) years from the date amounts in the Plan first become payable under Sections 8.2, 8.3, or 8.7. The balances in the closed accounts will be forfeited and thereafter applied to reduce Company contributions to the Plan. However, if the Participant or his designated beneficiary or beneficiaries subsequently files a proper claim with the Plan Administrator for such amounts, and the claim is filed prior to the termination of the Plan, the Company will restore the Participant's accounts to the balances that existed when they were closed.

Once the amounts have been restored, the balances will be available for distribution in accordance with the distribution provisions of the Plan.

8.7 Distribution Upon Death of Participant

8.7(a) Payment to Beneficiary

When a Participant dies, the deceased Participant's beneficiary is entitled to a distribution of all amounts held in the Participant's accounts.

Unless the Participant's beneficiary requests an earlier distribution to be made or commenced as soon as possible after an Appropriate Request is submitted to the Plan Administrator, all amounts held in the Participant's accounts will be distributed to the beneficiary within sixty (60) days after the end of the Plan Year in which the Participant dies.

Amounts held in the CEG Common Stock Fund will be paid to the Participant's beneficiary in Common Stock or in cash in accordance with the provisions of Section 8.4(a). If the beneficiary wishes to receive the distribution in cash, an Appropriate Request must be submitted by the beneficiary to the Plan Administrator. Amounts held in the Default Investment Fund and the Other Investment Funds will be paid to the Participant's beneficiary in the form of a lump-sum cash payment in accordance with the provisions of Section 8.4(b). A beneficiary may not elect to receive the distribution under the installment payment option.

If a Participant elected a distribution under the installment payment option provisions of Section 8.4(c) and dies during the installment payment period, or before the installment payment period begins, the remaining balance in the Investment Funds that was to be paid out under the installment payment option will be paid to the Participant's beneficiary in a lump-sum. Any amounts remaining in the CEG Common Stock Fund will be paid to the beneficiary in Common Stock or in cash in accordance with the Participant's most recent election under Section 8.4(c). If the beneficiary wishes to receive the distribution in a different form than that which will be received under the Participant's most recent election, an Appropriate Request must be submitted by the beneficiary with the Plan Administrator. Amounts remaining in the Default Investment Fund and the Other Investment Funds will be paid to the Participant's beneficiary in the form of a lump-sum cash payment.

In the event any Participant is deceased at the time of a dividend distribution from the Participant's Employee Stock Account paid under the dividend distribution provisions of Section 8.5(b), the distribution will be made to the Participant's beneficiary, as determined in accordance with this Section 8.7(a).

In the case of a Participant who dies while performing qualified military service (as defined in Code Section 414(u)), the survivors of the Participant are entitled to any additional benefits (other than benefit accruals relating to the period of qualified military service) provided under the Plan had the Participant resumed and then terminated employment on account of death.

8.7(b) Designation of Beneficiaries

Any interests in the Plan which have not been distributed to a Participant prior to his death will be distributed to the Participant's surviving Spouse, unless the Participant and his Spouse have jointly designated some other beneficiary or beneficiaries. A joint designation must be made on a special form provided by the Plan Administrator and duly witnessed by a notary public.

The consent of the Spouse of the Participant will not be required if it is established to the satisfaction of the Plan Administrator that the consent of the Spouse may not be obtained because there is no Spouse, because the Spouse cannot be located, or because of such other circumstances as the Secretary of the Treasury may by regulations prescribe. Any consent of a Spouse (or establishment that the consent of a Spouse may not be obtained) as provided above shall be effective only with respect to such Spouse. For purposes of this Section 8.7(b), the Spouse or surviving Spouse of the Participant is the Spouse at the time of the Participant's death, except that a former Spouse will be treated as the Spouse or surviving Spouse to the extent provided under a qualified domestic relations order as described in Code Section 414(p). The designation of a beneficiary may be changed at any time by the proper completion and forwarding to the Plan Administrator of the beneficiary-designation form.

If a Participant dies and does not leave a surviving Spouse, any undistributed interests will be paid to any beneficiary or beneficiaries that the Participant has designated on the beneficiary-designation form provided by the Plan Administrator. If a Participant dies and leaves no surviving Spouse and no beneficiary is effectively designated in connection with the benefits due under the Plan, the benefits provided under the Plan will be distributed to any effectively designated beneficiary (as indicated

on the life insurance beneficiary-designation form) of any Company-sponsored life insurance of the Participant. If there is no beneficiary effectively designated to take the proceeds of such life insurance, the benefits due under the Plan shall be distributed to the personal representative, if any, of the deceased Participant. In any case where the exact intention of a Participant is in doubt in connection with the designation of a beneficiary, the Plan Administrator shall have full authority to determine such probable intention. The effectiveness of the Participant's beneficiary designation and the Plan Administrator's determination of the intention of the Participant shall be final and binding upon all parties.

The Plan Administrator may require such proper proof of death and such evidence of the right of any person to receive payment of the value of the account of a deceased Participant as the Plan Administrator may deem desirable. The Plan Administrator's determination of death and of the right of any person to receive payment shall be conclusive.

8.8 Direct Rollover of Distributions

Notwithstanding any provision of the Plan to the contrary that would otherwise limit a Distributee's election under this Section, a Distributee may elect, at the time and manner prescribed by the Plan Administrator, to have any portion of a distribution from the Plan that is an Eligible Rollover Distribution paid directly to an Eligible Retirement Plan specified by the Distributee in a Direct Rollover, including, for distributions made after December 31, 2009, an individual retirement plan described in Code Section 408(a) or (b) for non-spouse beneficiary Distributees as described in Code Section 402(c)(11). Effective for distributions made after October 30, 2009 and subject to the provisions of Section 3.3 of the Plan, an Eligible Rollover Distribution that includes amounts that are not includable in gross income may be transferred pursuant to this Section 8.8 if the qualified trust or annuity contract described in section 403(b) of the

Code receiving such Direct Rollover separately accounts for the portions of the distribution that are and are not includable in gross income. Effective for calendar years beginning on or after December 31, 2008, solely for purposes of applying the direct rollover provisions of the Plan, 2009 required minimum distributions pursuant to Code Section 401(a)(9)(H) and extended 2009 required minimum distributions will be treated as Eligible Rollover Distributions in 2009.

8.9 Qualified Reservist Distributions

The Plan permits a Participant to elect a Qualified Reservist Distribution. For purposes of this Section 8.9, a Qualified Reservist Distribution is any distribution to an individual who is ordered or called to active duty after September 11, 2001, if: (i) the distribution is from amounts attributable to elective deferrals including After-Tax and Before-Tax Options; (ii) the individual was (by reason of being a member of a reserve component, as defined in Section 101 of Title 37, United States Code) ordered or called to active duty for a period in excess of 179 days or for an indefinite period; and (iii) the Plan makes the distribution during the period beginning on the date of such order or call, and ending at the close of the active duty period. A Participant that meets the requirements for a Qualified Reservist Distribution under this Section 8.9 will be treated as taking a distribution under this Section 8.9 regardless of whether such Participant is also entitled to distribution under Section 7.8.

Article IX – Loans to Participants

9.1 General

A Participant will continue to be considered a Participant for purposes of this Article IX as long as the Participant continues to be a Party in Interest.

At the direction of the Plan Administrator, the Trustee may make loans to Participants from the Plan. Plan loans will in all cases meet the following requirements.

a) Loans will be available to all Participants on a reasonably equivalent basis.

b) Loans will not be made available to Participants who are Highly Compensated Employees in an amount greater than the amount made available to other Participants.

c) Loans will be made in accordance with all other specific provisions regarding Participant Loans under the Plan.

d) Loans will bear a reasonable rate of interest as provided under Section 9.3.

e) Loans will be adequately secured as provided under Section 9.4.

9.2 Amount

A Participant may apply for a loan from his account balance in the Plan subject to the limitations and other provisions of this Article IX or as may be adopted by the Plan Administrator. Application for loans is made by submitting an Appropriate Request with the Plan Administrator. The Plan Administrator's action in approving or disapproving any application for a loan shall be final. The Plan Administrator, in his sole discretion, may direct the Trustee to lend a Participant an amount which does not exceed fifty percent (50%) of the Participant's Total Account Balance; provided, however, that the minimum loan amount shall be $1,000 and the maximum loan amount shall be $50,000.

For purposes of determining whether a loan exceeds $50,000, such loan shall be added to the highest outstanding balance of all other loans from the Plan or any other plans of the Employer during the twelve-month period preceding the date on which the loan is made (i.e., the date of the check). Participants making application for a loan from the Plan may be required to demonstrate their creditworthiness to the satisfaction of the Plan Administrator.

A Participant may have no more than two loans outstanding at a time. A Participant who has an existing loan and qualifies for a hardship withdrawal may be required to obtain a second loan pursuant to Section 7.5(c).

Loan proceeds may not be used for the purpose of investing in stocks, securities, or other similar or intangible investments. All loans shall be subject to the approval of the Plan Administrator, or his designee, who shall review each application for a loan. The Plan Administrator shall adopt such rules, procedures and documents as he may deem advisable in regard to the granting of loans, provided such rules, procedures, and documents are consistent with the provisions of this Article IX.

9.3 Reasonable Rate of Interest

Each loan will bear a reasonable rate of interest on the unpaid balance during the term of the loan which (except as provided in Section 9.14) will be equal to the prime rate plus one percent (1%), as reported in the Eastern Edition of the Wall Street Journal on the last day of the month preceding the month in which the Participant submits an Appropriate Request for a loan with the Plan Administrator. The interest rate on a loan will remain in effect for the term of the loan.

9.4 Adequate Security

The Participant shall grant to the Trustee a security interest in the loan account to the extent of his outstanding principal loan balance. The security interest will secure repayment of the loan and will remain in effect until the loan, together with accrued interest, is paid in full. The amounts in a Participant's loan account used to secure the loan balance are not available for withdrawal or distribution.

9.5 Source of Funds

Each loan shall be treated as a separate investment of the portion of the Participant's Plan account balance borrowed and the Plan Administrator shall direct the Trustee to reduce the Participant's Plan account balance by an amount equal to the amount borrowed. A loan account will be established for the Participant reflecting the amount of his loan. The money borrowed will be taken from the Participant's Plan accounts in the order shown below. The meaning of matured and unmatured accounts as used below relates to the status of contributions as explained in Section 7.1(c). Unless specifically indicated otherwise, an account includes both contributions and earnings thereon. Loan amounts will be taken from a Participant's Investment Funds on a pro rata basis.

First	Before-Tax Option Account.
Second	Unmatured After-Tax Option Account.
Third	Company Matching Contributions Account.
Fourth	Employee Stock Account, except the Participant's investment in the account.
Fifth	Employee Stock Account representing the Participant's investment in the account.
Sixth	Rollover Account.
Seventh	Matured After-Tax Option Account.

9.6 Valuation of Loans

The value received by a Participant requesting a loan shall be determined in accordance with this Section. Loans will be processed as soon as practicable after the Participant's properly executed loan agreement is received by the Plan Administrator. Loans from the Default Investment Fund and Other Investment Funds shall be valued based on the Closing Price for such funds on the day the loan is processed. Loans from the CEG Common Stock Fund shall be valued based on the Transaction Price on the day the loan is processed.

9.7 Loan Repayment

For Participants who are active Employees, payments of principal and interest on the loan must be made by payroll deduction, whichever is applicable. Participants who are not active Employees are required to make regular monthly payments of principal and interest on the loan by personal check or money order payable to the Company or its designee, as directed by the Plan Administrator. Each loan shall by its terms require that repayment (principal and interest) be amortized in level payments over a loan term that is arrived at by mutual agreement between the Plan Administrator and the Participant. In no event (other than as provided under Section 9.14), however, will the term of the loan exceed five (5) years unless the loan is to be used to acquire a Participant's principal residence, in which case, the term of the loan may not exceed thirty (30) years.

A Participant may repay the entire outstanding balance of a loan, plus any accrued interest, at any time by personal check or money order made payable to the Plan or the Trustee. Loan repayments constituting a repayment of principal will be allocated to the Participant's Plan accounts in the reverse order from which borrowed. Within the accounts, principal repayments will be allocated among the various Investment Funds in accordance with the Participant's most recent investment directions. The interest portion

of the loan repayment will be allocated to the Participant's Plan accounts on a pro rata basis in accordance with the amounts originally withdrawn from the Participant's accounts in order to fund the loan. Within such accounts, interest payments will be allocated among the various Investment Funds in accordance with the Participant's most recent investment directions.

9.8 Default

A default occurs if a Participant fails to make a loan payment within 90 days after its due date or a beneficiary fails to continue the loan repayments or to repay the loan in full within 90 days after the payment's due date. Upon the occurrence of a default, the Participant or beneficiary, as the case may be, will be subject to any legal remedies available for collecting the debt. In addition, the outstanding principal amount of the loan may be treated as a distribution, reportable to the Internal Revenue Service. If a Participant defaults on a loan while an active Employee, the Participant will be suspended from making contributions to, and taking loans from, the Plan for two (2) years from the date of default. If a Participant who is not an active Employee defaults on a loan, the Participant will be unable to take loans from the Plan for two (2) years from the date of default. The Plan Administrator shall have the discretion to allow additional time for repayment, subject to the requirements of Code Section 72(p) and the Treasury Regulations promulgated thereunder.

9.9 Death of a Participant

If a Participant dies prior to repaying a loan, the outstanding loan principal will be treated, and reported to the Internal Revenue Service, as a distribution to the beneficiary unless the beneficiary elects either to continue to make monthly loan repayments until the Plan balance is distributed to the beneficiary under the provisions of Section 8.7(a), or to repay the outstanding principal balance, plus accrued interest, within 90 days after the last loan repayment was made.

9.10 Loan Agreement and Amendments

A Participant's loan will be evidenced by a loan agreement, which will include a promissory note and security agreement and payroll deduction authorization, if applicable. Participants will be required to execute a document, or otherwise evidence their agreement electronically (in such form and manner as the Plan Administrator shall specify), specifying the terms of the loan. Amendments to the loan terms must be authorized by both parties; provided, however, that amendments required as a result of a change to any applicable law or regulation or the issuance of any new ruling or interpretation by any governmental agency may be made unilaterally to the Plan and the loan agreement upon written notice to the Participant. The loan is at all times subject to such other conditions as may be required by the Internal Revenue Service or any other governmental agency.

9.11 Assignment of Interest

A Participant cannot assign his loan or obligation to repay his loan to any other person, corporation, or entity. Any attempted assignment of a Plan loan or obligation to repay will be void.

9.12 Prohibited Transactions

No loan shall be made unless such loan is exempt from the tax imposed on prohibited transactions by Code Section 4975.

9.13 Loan Initiation Fees

A Participant who applies for a loan will be charged a loan initiation fee, as determined from time to time by the Plan Administrator, which will be deducted from the Participant's Plan account balance in the same manner set forth in Section 9.5.

9.14 Leaves of Absence

9.14(a) Non-Military Leaves of Absence

Participants who are on an approved leave of absence other than a Military Leave of Absence must continue to make loan repayments during such leave. Interest continues to accrue during such leave of absence at the original interest rate.

9.14(b) Military Leaves of Absence

Participants may elect to discontinue making loan repayments during a Military Leave of Absence, in which case the loan termination date shall be extended for a period equal to the length of the Military Leave of Absence (not to exceed the number of months of missed repayments). In addition, the loan interest rate for any Participant who is on a Military Leave of Absence and who does not elect otherwise shall, while the Participant is on such Military Leave of Absence, be the lesser of 6% per annum or the original interest rate.

Article X – Plan Administration

10.1 Plan Administrator

The Plan will be administered by the Director – Benefits of the Company (or the position succeeding to that function) as a fiduciary and as Plan Administrator. The Plan Administrator shall discharge his duties for the exclusive benefit of Participants and their beneficiaries. The Plan Administrator shall be authorized to delegate his duties and responsibilities hereunder.

10.2 Rules and Regulations

The Plan Administrator may adopt such rules and regulations as he may deem necessary or advisable for the administration of the Plan on a consistent and non-discriminatory basis.

10.3 Powers and Duties of the Plan Administrator

The Plan Administrator shall administer the Plan in accordance with its provisions and shall have all powers necessary for that purpose, including, but not limited to, the power (i) to interpret the Plan, (ii) to resolve all questions concerning eligibility for benefits or loans under the Plan and to require any person to furnish such information as he may reasonably request as a condition to receiving any benefit or loan under the Plan, (iii) to compute or cause to be computed the amount of benefits payable or loans available here under to Participants or their beneficiaries, and (iv) to direct the Trustee concerning all payments that shall be made out of the Investment Funds pursuant to the provisions of the Plan. The Plan Administrator may, in writing, delegate any part of his responsibilities and duties (including but not limited to the approval of loans to Participants) to one or more designees and may withdraw such authority by a subsequent writing.

10.4 Records and Reports

The Plan Administrator shall cause to be furnished to each Participant, on at least a semiannual basis and upon any withdrawal, distribution, or loan to him, a detailed report, indicating the current value of the Participant's interest in the Plan, as well as any other reports now or hereafter required by law to be furnished to each Participant or any regulatory agency.

10.5 Procedure for Review of Claim

10.5(a) Denial of Claim

If after a Participant makes a claim for benefits by submitting an Appropriate Request, such claim is denied in full or in part, the Plan Administrator shall, within ninety (90) days after receipt of the claim, provide the Participant (at the Participant's last address appearing on the records of the Plan) with written notice by mail, in language calculated to be understood by the Participant, of the denial of the claim stating (i) the specific reasons for the denial, (ii) the specific references to pertinent Plan provisions on which the denial is based, (iii) any additional material or information necessary for the Participant to resubmit the claim, including an explanation of why such material or information is necessary, and (iv) an explanation of the claims appeal procedure, including a statement of the Participant's right to bring a civil action under Section 502(a) of ERISA following an adverse benefit determination on review. If special circumstances require an extension of time to process the claim, within 90 days after receipt of the claim, the Plan Administrator shall provide the Participant with written notice by mail specifying the reasons for the need for an extension of time, and a date by which he expects to render a decision. In that event, the initial 90-day period for notice of denial shall be extended by an additional 90 days.

10.5(b) Appeal of Claim

If a Participant's claim has been denied or if the Participant has not received written notice of denial within the period prescribed by Section 10.5(a), he may file an appeal with the Administrative Committee. The Participant or his duly authorized representative may request to review pertinent documents. The appeal must be submitted in writing within sixty (60) days of the date the Participant receives notice of the denial. The appeal may be made by the Participant or his duly authorized representative. The appeal must state the reasons for the appeal and shall be accompanied by any evidence or documentation to support the Participant's position. The Administrative Committee shall review the Participant's appeal promptly and shall advise the Participant of his decision in writing, in language calculated to be understood by the Participant, stating (i) the specific reasons for his decision with specific reference to pertinent Plan provisions on which the decision is based, (ii) that the Participant is entitled to receive, upon request and free of charge, reasonable access to and copies of all documents, records, and other information relevant to his claim, and (iii) that the Participant has a right to bring an action under Section 502(a) of ERISA.

This written decision shall be sent to the Participant (at his last address appearing on the records of the Plan) by mail no later than 60 days after receipt of the written appeal, unless special circumstances require an extension of time for processing the appeal, obtaining more information or conducting an investigation of facts. In no event shall the written decision be sent to the Participant later than 120 days after receipt by the Administrative Committee of the written appeal. The determination of the Administrative Committee shall be final and binding on all parties and not subject to further appeal.

10.5(c) Exclusive Method

The procedure for review of claims outlined in this Section 10.5 is the exclusive method available for resolving claims under the Plan, notwithstanding the existence of other Employer procedures applicable to Employee grievances in other areas. No Participant or beneficiary is entitled to bring any action, whether at law or in equity, against any Employer or the Trustee or any of their respective agents, officers or employees, including the Plan Administrator, his designees, or the Chief Human Resources Officer in connection with any right, privilege, or benefit provided under this Plan unless and until, as a condition precedent, all of the remedies provided under this Section 10.5 have been exhausted.

10.6 Plan Expenses

The Company may, in its sole discretion, determine from time to time which expenses incident to the operation and maintenance of the Plan, and the fees and expenses of the Trustee will be paid by either the Company or the Plan Participants. Any fees and expenses not paid by the Company shall be paid by Plan Participants.

All brokerage fees and commissions, stock transfer taxes, and other charges incurred by the Trustee in connection with the purchase and sale of shares of Common Stock for the CEG Common Stock Fund shall be borne by the CEG Common Stock Fund. All expenses and other charges incurred by the Other Investment Funds shall be borne by the respective fund.

Administrative fees charged by the institutions which issue contracts for the Default Investment Fund shall be borne by the Default Investment Fund and shall be reflected in the interest rate for such Fund.

Loan initiation fees will be paid by Plan Participants as set forth in Section 9.13.

The Plan Administrator shall not receive any compensation for his services as Plan Administrator.

10.7 Fiduciary Responsibilities

The Plan Administrator is the named fiduciary under the Plan within the meaning of Section 402(a) of ERISA, and shall control and manage the operation and administration of the Plan.

The Plan Administrator (and his delegatees), the Investment Committee, the Administrative Committee, the Trustee, and any other person who is deemed to be a fiduciary under the Plan, shall not be liable for a breach of fiduciary responsibility of another fiduciary under the Plan except to the extent it or he (a) shall have participated knowingly in, or shall have knowingly undertaken to conceal, an act or omission of such fiduciary, knowing such act or omission was a breach of the fiduciary's fiduciary responsibilities, (b) shall have, through a breach of its or his fiduciary responsibilities, enabled such fiduciary to commit a breach of its or his fiduciary responsibilities, or (c) shall have knowledge of a breach of fiduciary responsibilities by such fiduciary, unless it or he has made reasonable efforts to remedy the breach.

This Plan is an ERISA Section 404(c) plan, as described in Section 404(c) of ERISA and defined by Section 2550.404(c)-1 of Title 29 of the Code of Federal Regulations. Under ERISA Section 404(c), Plan Participants and beneficiaries are generally deemed to be responsible for the results of their investment decisions, and fiduciaries of the Plan may be relieved of liability for any loss, or with respect to any breach of part 4 of Title I of ERISA, that is the direct and necessary result of the exercise of control by Plan Participants and beneficiaries over assets in their Plan accounts.

10.8 Indemnification

The Plan Administrator (and his delegatees), members of the Board of Directors, the Executive Group, and the Investment Committee, the Administrative Committee, and any other officer or employee of any Employer shall be indemnified by the Company or from proceeds under insurance policies purchased by the Company against any and all liabilities arising by reason of any act or failure to act made in good faith pursuant to the provisions of the Plan, including expenses reasonably incurred in the defense of any claim relating thereto.

Article XI – Management of Funds

11.1 Trust Fund

The Company shall maintain a Trust Agreement with a Trustee, pursuant to which a Trust shall be established to hold the assets of the Plan. All cash contributions made by Participants and the Company under the Plan shall be paid over to the Trustee as soon as administratively practicable for the purpose of providing benefits under the Plan. No part of the corpus of or income from these funds shall be used for, or diverted to, purposes other than for the exclusive benefit of the Participants and their beneficiaries.

11.2 Trust Agreement; Powers of Trustee

The Trust Agreement shall be subject to the approval of the Board of Directors prior to execution of the Trust Agreement by the Company. The Company or the Plan Administrator may from time to time amend the Trust Agreement and shall give written notice of any such amendment to the Trustee. The Trust Agreement, as amended from time to time, shall contain provisions appropriate to carrying out the purposes of the Plan, including, but not limited to, provisions with respect to (i) the power and authority of the Trustee, (ii) the investment, reinvestment, control, and disbursement of the Trust assets, (iii) the contract or contracts with one or more financial institutions for the Default Investment Fund, and (iv) the authority of the Company or the Plan Administrator to amend the Trust Agreement, review the performance of the Trustee, and to terminate the Trust Agreement and settle the account of the Trustee.

11.3 Removal and Resignation of Trustee

The Company shall have the power, without terminating the Trust Agreement, to remove the Trustee and to designate a successor Trustee upon such removal or in the event the Trustee elects to resign.

11.4 Accounts and Records Maintained by Trustee

The Trustee or the Plan Administrator shall keep complete and accurate records of all of the assets of, and transactions involving, the Investment Funds with respect to Participant Contribution Accounts under the After-Tax and/or Before-Tax Options, the Company Matching Contribution Accounts, the Employee Stock Accounts and Rollover Accounts. If the records are maintained by the Trustee, it shall, in a timely manner, prepare and render all reports and accounting required by law or regulation and shall provide the Plan Administrator with such reports, accountings, and other information as he may reasonably request. All such records shall be available for inspection and copying during the Trustee's normal business hours by the Plan Administrator, who may elect to employ an independent certified public accounting firm to review the accounts and records maintained by the Trustee as of the close of each Plan Year and report the results of such review to the Plan Administrator. This report shall be made available by the Plan Administrator to the Board of Directors, along with such other reports and information as the Board of Directors shall, from time to time, request.

11.5 Voting Rights

11.5(a) Common Stock

Each Participant shall have the right, and shall be afforded the opportunity (on the prescribed form) to instruct the Trustee how to vote or whether or not to tender shares of the Company's Common Stock allocated to his Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, and Rollover Account in the CEG Common Stock Fund. To the extent possible, fractional shares will be combined and voted by the Trustee to reflect the instructions of the Participants whose Participant Contribution Accounts, Company Matching Contribution Accounts, Employee Stock Accounts, and Rollover Accounts in the CEG Common Stock Fund have been allocated with such fractional shares. Shares of Common Stock with

respect to which no instructions are received shall be tendered by the Trustee, but shall be voted by the Trustee in the same proportions as the Trustee was instructed to vote with respect to the shares for which it received instructions. At the time of the mailing of any notice of an annual or special meeting of the Company's Common Stockholders, a copy of such notice and all accompanying proxy solicitation material, together with the prescribed voting instruction form, shall be furnished to each Participant.

In the case of a tender offer, or other right or option with respect to Common Stock, a Participant who does not issue valid directions to the Trustee to sell, offer to sell, exchange or otherwise dispose of such Participant's Common Stock, shall be deemed to have directed the Trustee that shares of Common Stock allocated to his Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, and Rollover Account remain invested in the CEG Common Stock Fund. A Participant's instruction to tender shares of Common Stock invested in the CEG Common Stock Fund shall not constitute an Appropriate Request for a withdrawal or distribution pursuant to Articles VII and VIII, respectively. Any proceeds received as a result of the sale of Common Stock pursuant to a tender offer shall be credited to the Participant's accounts from which the tendered shares were taken and shall be reinvested in the CEG Common Stock Fund provided Common Stock is available for purchase and continues to be traded on a national securities exchange. In the event that, subsequent to any tender offer, Common Stock is no longer available and traded on a national securities exchange, Participants may elect to invest the proceeds received from the tendered Common Stock in one or more of the other available Investment Funds other than the CEG Common Stock Fund, by submitting an Appropriate Request to the Plan Administrator. Until such time that the Appropriate Request is received by the Plan Administrator, the proceeds received from the tendered Common Stock shall be invested in the Default Investment Fund.

11.5(b) Other Investment Funds

Each Participant shall have the right, and shall be afforded the opportunity (on the prescribed form), to instruct the Trustee how to vote (if applicable) the Other Investment Fund shares held in his Participant Contribution Account, Company Matching Contribution Account, Employee Stock Account, and Rollover Account. Shares of Other Investment Funds with respect to which no instructions are received shall be voted (if applicable) by the Company. At the time of the mailing of any notice of an annual or special meeting of any Other Investment Fund, a copy of such notice and all accompanying proxy solicitation material, together with the prescribed voting instruction form, shall be furnished by the Trustee to each Participant holding shares in the Other Investment Fund.

Article XII – Amendment, Termination, Mergers, or Consolidations

12.1 Amendment

The Plan may be amended, from time to time, by the Plan Administrator as shall be necessary or advisable in the interpretation, administration, or operation thereof or as required by law upon the advice of counsel. Further, the bonuses and incentives includable in Eligible Compensation in Appendix C may be amended by the Chief Executive Officer of the Company and the Chief Human Resources Officer of the Company, acting together. The Executive Group may make any amendment to the Plan that does not increase annual Plan liabilities by more than $1 million per amendment; the Company's Chief Executive Officer shall report all such amendments to the Board of Directors no less frequently than annually. The Chief Human Resources Officer may make any amendment to the Plan that does not increase the annual Plan liabilities materially, or as required by law upon the advice of counsel. In all other cases, the Plan may only be amended by resolution of the Board of Directors, who shall be entitled to delegate such authority. Under no circumstances shall the Plan be amended to cause any of the assets of the Investment Funds to be used for or be diverted to any purpose other than the exclusive benefit of Participants or their beneficiaries and defraying reasonable expenses of administering the Plan, or to cause the elimination or reduction of any Plan benefit as prohibited under the provisions of Code Section 411(d)(6). Furthermore, no amendment may retroactively reduce the rate at which a Participant shall make contributions to such Investment Funds, or, except as may be required to conform with future governmental regulations, adversely affect the rights of any Participant with respect to contributions made on his behalf prior to the date of such amendment.

12.2 Termination

The Plan may be terminated, in whole or in part, at any time, by resolution of the Board of Directors. The Trustee will thereafter be directed to liquidate the Investment Funds. Upon any termination of the Plan other than as provided in Section 13.9, all Participant Contribution Accounts, Company Matching Contribution Accounts, Employee Stock Accounts, Rollover Accounts, and dividends, if any, accumulated under the provisions of Section 8.5(b), shall be deemed to be matured, and distribution of the balances in such accounts shall be promptly made by the Trustee in accordance with direction from the Plan Administrator. In making such distribution, any and all determinations, divisions, appraisals, apportionments, and allotments so made shall be final and conclusive.

12.3 Merger or Consolidation

In the event of any merger or consolidation of the Plan with, or transfer of any assets or liabilities of the Plan to, any other plan, each Participant shall be entitled to receive a benefit immediately after such merger, consolidation, or transfer (computed as if such other plan had then terminated) which is equal to or greater than the benefit he would have been entitled to receive immediately before such merger, consolidation, or transfer (computed as if the Plan had then terminated).

Article XIII – General Provisions

13.1 Source of Payment

Benefits under the Plan shall be payable only out of the Investment Funds. The Company shall have no responsibility or liability (legal or otherwise) to make any payment of benefits under the Plan. No persons shall have any rights under the Plan with respect to such Investment Funds, or against the Plan Administrator (and his delegatees), the Company, any other Employer, the Board of Directors, the Executive Group, the Investment Committee, the Administrative Committee, or the Trustee, except as specifically provided for under the Plan.

13.2 Inalienability of Benefits

13.2(a) General

No benefit or interest available under the Plan will be subject to assignment, attachment, alienation, or other legal process, either voluntarily or involuntarily. Except as provided in Section 13.2(b), the preceding sentence will also apply to the creation, assignment, or recognition of a right to any benefit payable with respect to a Participant pursuant to a domestic relations order. Except as provided in Section 13.2(c), benefits under the Plan will be made available to and in the name of the person entitled to such benefits under the terms of the Plan, or to and in the name of such person's authorized representative. Payments to any financial institution to the credit of such person will constitute payments to and in the name of the person entitled to such payments under the terms of the Plan.

In addition, to the extent permitted by Code Section 401(a)(13), a Participant's benefits may be offset against an amount that the Participant is ordered or required to pay to this Plan pursuant to a judgment in a criminal action involving this Plan, a civil judgment in connection with a violation or alleged violation of Part 4 of Subtitle B of Title I of ERISA, or a settlement agreement between the Secretary of Labor

and the Participant in connection with a violation or alleged violation of such Part. Furthermore, this Section 13.2(a) shall not preclude either (i) the enforcement of a Federal tax levy made pursuant to Code Section 6331, or (ii) the collection by the United Sates on a judgment resulting from an unpaid tax assessment, to the extent permitted under Code Section 401(a)(13) and the regulations thereunder.

13.2(b) Qualified Domestic Relations Orders

The anti-alienation provisions of Section 13.2(a) do not apply to qualified domestic relations orders, as the term is defined in Code Section 414(p), ERISA 206(d)(3) and any applicable regulations thereunder. The Plan Administrator has established and will maintain written procedures to determine the qualified status of domestic relations orders and to administer distributions under such qualified orders. Further, to the extent provided under a qualified domestic relations order, a former Spouse of a Participant shall be treated as the Spouse or surviving Spouse for all purposes under the Plan.

13.2(c) Miscellaneous Exceptions

The anti-alienation provisions of Section 13.2(a) do not apply to the payment of taxes to any governmental agency, to the extent such payment is authorized by the person entitled to such payment under the terms of the Plan, or is otherwise required by a law that is not preempted by the ERISA anti-alienation provisions.

13.3 Section 16 of the Securities Exchange Act of 1934

Each Participant who is subject to Section 16 of the Securities Exchange Act of 1934 and the rules and regulations promulgated thereunder shall, in effecting any transaction in the Plan, comply with all applicable provisions of such law, rules, and regulations in addition to the applicable Plan provisions.

13.4 Put Option Rights Applicable to Common Stock

Effective February 1, 2006, but only to the extent required under the applicable rules of Code section 4975(e)(7) with regard to an employee stock ownership plan of the type represented by the CEG Common Stock Fund, shares of Company Stock distributed to a Participant or Beneficiary with respect to the CEG Common Stock Fund (including a distribution that is a withdrawal) that at the time of the distribution, are not readily tradable on an established market within the meaning of Code section 409(h), as determined by the Plan Administrator, shall be subject to a put option which shall permit the Participant or Beneficiary to sell such stock to the Company at any time during two option periods, at the fair market value of such shares (as of the most recent valuation date). The first period shall be for at least 60 days beginning on the date of distribution. The second period shall be for at least 60 days beginning on the first valuation date in the calendar year following the year in which the distribution was made. The Plan Administrator may direct the Trustee to purchase shares tendered to the Company under a put option. Notwithstanding the foregoing, the period during which the put option is exercisable shall not include any time when the shares are determined by the Plan Administrator to be readily tradable, or when a Participant or Beneficiary is unable to exercise the put option because the Company is prohibited from honoring it, as determined by the Company's chief legal officer, by applicable federal or state laws, including for these purposes any insider trading policy adopted by the Company in furtherance of applicable federal or state laws. Payment for any shares of stock sold under a put option shall be made in a lump sum or in substantially equal annual installments over a period not exceeding five years, with interest payable at a reasonable

rate (as determined by the Plan Administrator). For purposes of this Section, shares of Company Stock that are listed on a national securities exchange registered under Section 6 of the Securities Exchange Act of 1934 or that are quoted on a system sponsored by a national securities association registered under section 15A(b) of the Securities Exchange Act of 1934 shall not be treated as ceasing to be readily tradable for these purposes merely because the Participant or Beneficiary who receives a distribution of such shares (i) is subject to a stock ownership policy of the Company, (ii) would be subject to liability under Section 16(b) of the Securities Exchange Act of 1934 if the Participant or Beneficiary transferred such shares, or (iii) is subject to volume limitation or manner of sale requirements pursuant to Rule 144 under the Securities Act of 1933 with respect to transfers of such shares. Except as may be permitted under applicable law or regulations, the rights of a Distributee of Company Stock under this Section 13.4 shall survive the termination of the Plan and any amendment of the Plan. The Plan is not obligated to acquire securities from a Participant or Beneficiary at an indefinite time that is determined upon the happening of an event, such as the death of the Participant or Beneficiary.

13.5 Loss or Decline in Value

Neither the Plan Administrator, the Company, the Board of Directors, the Executive Group, the Investment Committee, the Administrative Committee, any officer or employee of any Employer, the Trustee, nor their delegatees, guarantees the assets of the Trust in any manner against loss or decline in value.

13.6 No Right to Employment

Nothing contained in this Plan shall be construed as a contract of employment between any Participating Employer and any Employee, or as a right of any Employee to continue in the employment of any Participating Employer or as a limitation of the right of any Participating Employer to discharge any Employee with or without cause.

13.7 Controlling Law

The Plan and its administration shall be governed by the laws of the State of Maryland, except to the extent preempted by Federal law.

13.8 Gender and Number

The masculine pronoun, when used herein, refers to both men and women, and words used in the singular are intended to include the plural, whenever appropriate.

13.9 Titles and Headings

Titles of Articles and headings to Sections in the Plan are placed herein solely for convenience of reference and, in any case of conflict, the text of the Plan, rather than such titles and headings, shall control.

13.10 Approvals and Effective Date

This Plan as amended and restated shall become effective, provisionally, on September 1, 2006, and shall be submitted to the Internal Revenue Service for its review and approval. The Company may make further amendments to this Plan which it deems necessary or advisable to achieve Internal Revenue Service approval. Upon such approval, the effectiveness of this Plan as amended and restated shall become final. If such approval is not forthcoming in a form satisfactory to the Company, this Plan as amended and restated shall be treated as null and void ab initio; and the Plan as previously approved by the Internal Revenue Service shall be deemed to have continued in operation in all respects and without change from that day forward.

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IN WITNESS WHEREOF, this restatement and the appendices attached thereto, effective January 31, 2012, were duly executed on this _____day of January, 2012.

Mary Lauria
Chief Human Resources Officer

APPENDIX A

DEFINITIONS

As used in the Plan, the following terms shall have the meaning set forth below, unless a different meaning is clearly required by the context in which the term is used.

1 "Administrative Committee" means the Adminstrative Committee consisting of members appointed from time to time by the Chief Executive Officer of the Company, or his delegate.

2 "After-Tax Option" (formerly known as the "Thrift Option") means the portion of the Plan under which an eligible Employee may contribute after-tax amounts to the Plan through payroll deduction.

3 "Appropriate Request" is a request by a Participant, in the written, electronic, telephonic, or other form and manner provided by the Plan Administrator that is appropriate for the intended purpose. To constitute an Appropriate Request, such request must be completed correctly and, if required to be in writing, duly executed and delivered to the Plan Administrator or his designated representative.

4 "Basic Contribution" means a Participant's contribution to the Plan through the After-Tax and/or Before-Tax Options in an amount up to six percent (6%) of the Participant's Eligible Compensation.

5 "Board of Directors" means the Board of Directors of the Company.

6 "Before-Tax Option" (formerly known as the "Deferred Compensation Option") means the portion of the Plan under which an eligible Employee may contribute pre-tax amounts to the Plan through payroll deduction.

7 "CEG Common Stock Fund" means the Investment Fund under the Plan composed of shares of Common Stock and any amounts allocated to the CEG Common Stock Fund but not yet invested in Common Stock. The CEG Common Stock Fund also includes the earnings on amounts not yet invested in Common Stock. The shares of Common Stock held by the CEG Common Stock Fund are purchased by the Trustee either in the open market or otherwise acquired.

8 "Closing Price" means the price as of the close of the New York Stock Exchange as determined by the Trustee based upon valuations provided by Investment Managers (as that term is defined in the Trust Agreement), trustee of group trusts, sponsors of Mutual Funds, records of securities exchanges or valuation services, market data providers or qualified appraisers.

9 "Code" means the Internal Revenue Code of 1986, as amended or replaced from time to time.

10 "Common Stock" means the Common Stock of the Company.

11 "Company" means Constellation Energy Group, Inc. and its successors and assigns.

12 "Company Matching Contribution Account" means an account established for each Participant into which Company Matching Contributions are made. A Company Matching Contribution Account is established for each Participant in the Default Investment Fund, the CEG Common Stock Fund and the Other Investment Funds pursuant to the Participant's investment designations. Prior to January 1, 2012, it meant an account established for each Participant in the CEG Common Stock Fund, into which shares of Common Stock purchased or acquired by the Trustee with Company Matching Contributions, loan repayments, or dividends on shares of Common Stock already in such account are invested, or an account established for each Participant in the Default Investment Fund and the Other Investment Funds pursuant to the interfund transfer provisions as set forth in the Plan.

13 "Company Matching Contributions" means contributions made by the Company to the Plan in an amount equal to one-half (1/2) of each Participant's Basic Contribution ($.50 for each $1.00).

14 "Compensation" as used throughout this Plan is intended to have the same meaning as under Code Section 414(s), and is limited to amounts earned while an Employee.

In addition to other applicable limitations set forth in the Plan, and notwithstanding any other provision of the Plan to the contrary, annual Compensation of each Employee taken into account for any Plan Year beginning after December 31, 2001 under the Plan shall not exceed $200,000, as adjusted for cost-of-living increases in accordance with Code Section 401(a)(17)(B). The cost-of-living adjustment in effect for a calendar year applies to annual compensation for such Plan Year.

Compensation shall also include any elective deferrals, within the meaning of Code Section 402(g)(3), of the Employer with respect to the Employee, and any amount which is contributed or deferred by the Employer at the election of the Employee and which is not includable in the gross income of the Employee by reasons of Code Sections 125 or 132(f)(4). A differential wage payment (as defined in Code Section 3401(h)(2)) shall not be included in the definition of Compensation.

15 "Corporate Performance Award Program" means the program established by the Company through which the Company made an annual contribution to the Employee Stock Account of each eligible Employee based on the attainment of certain annual performance goals established by the management of the Company. Corporate Performance Award Program contributions and earnings thereon are taxed to the Employee when distributed or withdrawn from the Plan. The Company ceased making Corporate Performance Award Program contributions to the Plan after 1992.

16 "Default Investment Fund" means the T. Rowe Price Retirement Fund dated nearest to the year of the Participant's 65 th birthday, or such other fund as may be designated by the Investment Committee.

17 "Designating Authority" means the Board of Directors or the Executive Group; provided, however, that (i) the Executive Group shall be a Designating Authority only if the designation of a Participating Employer does not increase annual Plan liabilities by more than $1 million, and (ii) the Company's Chief Executive Officer shall report all designations of Participating Employers by the Executive Group to the Board of Directors no less frequently than annually.

18 "Direct Rollover" means a payment by the Plan to the Eligible Retirement Plan specified by the Distributee.

19 "Distributee" means an Employee or former Employee. In addition, the Employee's or former Employee's surviving Spouse (or a non-spouse beneficiary as described in Section 402(c)(11) of the Code) and the Employee's or former Employee's Spouse or former Spouse who is the alternate payee under a qualified domestic relations order, as defined in Section 414(p) of the Code, are Distributees with regard to the interest of the Spouse or former Spouse.

20 " Effective Date " means October 1, 2004.

21 "Eligible Compensation" means the base rate of pay paid by the Employer to an Employee for the Plan Year, before any reductions, but excluding overtime, and certain bonuses, incentives, or other forms of extra compensation. The bonuses and incentives to be included in Eligible Compensation are those forms of compensation enumerated in Appendix C attached hereto.

In addition to other applicable limitations set forth in the Plan, and notwithstanding any other provision of the Plan to the contrary, annual Compensation of each Employee taken into account for any Plan Year beginning after December 31, 2001 under the Plan shall not exceed $200,000, as adjusted for cost-of-living increases in accordance with Code Section 401(a)(17)(B). The cost of living adjustment in effect for a calendar year applies to annual compensation for such Plan Year.

22 " Eligible Retirement Plan" means an individual retirement account described in Section 408(a) of the Code, a Roth individual retirement account described in 408A(b) of the Code (subject to current Roth individual retirement account conversion rules), an individual retirement annuity described in Section 408(b) of the Code, an annuity plan described in Section 403(a) of the Code, an annuity contract described in Section 403(b) of the Code, an eligible plan under Section 457(b) of the Code which is maintained by a state, political subdivision of a state, or any agency or instrumentality of a state or political subdivision of a state and which agrees to separately account for amounts transferred into such plan from this Plan, or a qualified trust described in Section 401(a) of the Code, that accepts the Distributee's Eligible Rollover Distribution. The definition of Eligible Retirement Plan shall also apply in the case of a distribution to a surviving Spouse, or to a Spouse or former Spouse who is the alternate payee under a qualified domestic relations order, as defined in Section 414(p) of the Code.

23 "Eligible Rollover Distribution" means any distribution from an Eligible Retirement Plan of all or any portion of the balance to the credit of a Distributee, except that an Eligible Rollover Distribution does not include: any distribution that is one of a series of substantially equal periodic payments (not less frequently than annually) made for the life (or life expectancy) of the Distributee or the joint lives (or joint life expectancies) of the Distributee and the Distributee's designated beneficiary, or for a specified period of ten years or more; any distribution to the extent such distribution is required under Section 401(a)(9) of the Code; any amount that is distributed on account of hardship; and the portion of any distribution that is not includible in gross income unless specifically allowed under Section 3.3 (determined without regard to the exclusion for net unrealized appreciation with respect to employer securities).

24 "Employee" means any person who is employed by the Employer maintaining the Plan or any other Employer required to be aggregated with such Employer under Code Sections 414(b), (c), (m), or (o), but excludes any person who is paid and classified by the Employer as an independent contractor (regardless of whether such person is classified prospectively or retroactively by any court, governmental agency, or other authority as an employee under any federal, state, or local law, regulation, or rule for any income tax, wage withholding, wage and hour, or other purposes). Employee shall include a leased employee within the meaning of Code Sections 414(n)(2). Notwithstanding the foregoing, if leased employees are covered by a plan described in Code Section 414(n)(5) and such leased employees do not constitute more than 20% of the Employer's Nonhighly Compensated Employee work force, the term "leased employee" shall not include such leased employees.

An Employee may be a Full-Time Employee or an On-Call Employee. A Full-Time Employee is any Employee employed on an ongoing and regular basis who has a basic workweek generally consisting of 40 hours, although Employees who work part-time on a regular and ongoing basis with a basic workweek of less than 40 hours are also considered to be Full-Time Employees. On-Call Employees constitute a reasonable classification of Employees who do not have a basic workweek, but rather work on an irregular, "on call" basis and do not participate in any "time off" or related benefit plans and are compensated only for those hours actually worked.

25 "Employee Stock Account" means an account established for each Participant in the CEG Common Stock Fund, into which shares of Common Stock purchased or acquired by the Trustee with Corporate Performance Award Program contributions, loan repayments, or with dividends on shares of Common Stock already in

such account are invested. The Employee Stock Account in the CEG Common Stock Fund is also comprised of amounts for an Employee or former Employee who elected to direct the transfer of the entire balance of his account in the Baltimore Gas and Electric Company Employee Stock Ownership Plan (ESOP) to this Plan upon termination of the ESOP. An Employee Stock Account is also established for each Participant in the Default Investment Fund and the Other Investment Funds pursuant to the interfund transfer provisions as set forth in the Plan.

26 "Employer" means the Company and any successor which shall maintain this Plan, and any subsidiaries or other affiliates required to be aggregated with the Company under Code Sections 414(b), (c), (m), or (o).

27 "ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time, and the pertinent rules and regulations promulgated thereunder.

28 "Executive Group" means the Company's Chief Executive Officer, Chief Financial Officer, General Counsel, and Chief Human Resources Officer (or the positions succeeding to those functions), acting collectively.

29 "Full-Time Employee" – See definition of "Employee."

30 "Highly Compensated Employee", for purposes of the operation of the Plan, generally means an Employee who either received compensation greater than the amount prescribed in Code Section 414(q)(1) in the year preceding the current Plan Year (e.g., $90,000 for 2003 to determine who is a Highly Compensated Employee in 2004). As used in this definition, compensation means compensation under Code Section 414 (q)(4) and the accompanying regulations.

As used below in describing a Highly Compensated Employee, the "determination year" is the Plan Year for which testing is performed, and the "look-back year" is the immediately preceding 12-month period. Highly Compensated Employees may include both active and former Highly Compensated Employees.

As provided under Code Section 414(q), an active Highly Compensated Employee includes any Employee who performed services for the Employer during the determination year and who is described in either paragraphs (a) or (b) below.

(a) Employees who at any time during the determination year or look-back year were 5-percent owners of the Employer, within the meaning of Code Section 414(q)(2).

(b) Employees who received compensation during the look-back year from the Employer in excess of $80,000 (as adjusted under Code Section 414(q)(1)).

A former Highly Compensated Employee includes any former Employee who separated from service (or was deemed to have separated) prior to the determination year, performs no service for the Employer during the determination year, and was an active Highly Compensated Employee for either the separation year or any determination year ending on or after the day the Employee reaches age fifty-five (55).

Unless otherwise specified, the term Highly Compensated Employee as used throughout the Plan shall refer to an active Highly Compensated Employee.

The determination of who is a Highly Compensated Employee will be made in accordance with Code Section 414(q) and the regulations thereunder.

31 "Hour(s) of Service" means: (1) each hour for which an Employee is directly or indirectly compensated or is entitled to receive Compensation from the Employer for the performance of duties during the applicable computation period; (2) each hour for which an Employee is directly or indirectly compensated or entitled to receive Compensation from the Employer (irrespective of whether the employment

relationship has terminated) for reasons other than performance of duties (such as vacation, holidays, sickness, jury duty, disability, lay-off, military duty, or leave of absence) during the applicable computation period; (3) each hour otherwise recognized under one or more of the medical or time-off fringe benefit plans maintained by the Employer; and (4) each hour for which back pay is awarded or agreed to by the Employer without regard to mitigation of damages. The same Hour of Service shall not be credited under (1), (2), or (3), as the case may be, and under (4).

Notwithstanding (2) above, no more than 501 Hours of Service are required to be credited to an Employee on account of any single continuous period during which the Employee performs no duties (whether or not such period occurs in a single computation period). An hour for which an Employee is directly or indirectly paid, or is entitled to payment on account of a period during which no duties are performed is not required to be credited to the Employee if such payment is made or due under a plan maintained solely for the purpose of complying with applicable worker's compensation, or unemployment compensation or disability insurance laws. An Hour of Service is not required to be credited for a payment which solely reimburses an Employee for medical or medically related expenses incurred by the Employee.

For purposes of (2) above, a payment shall be deemed to be made by or due from the Employer regardless of whether such payment is made by or due from the Employer directly, or indirectly through, among others, a trust fund, or insurer, to which the Employer contributes or pays premiums and regardless of whether contributions made or due to the trust fund, insurer, or other entity are for the benefit of particular Employees or are on behalf of a group of Employees.

An Hour of Service must be counted for the purpose of determining employment commencement date (or reemployment commencement date). The provisions of Department of Labor Regulations 2530.200b-2(b) and (c) are incorporated herein by reference.

32 Reserved.

33 "Investment Committee" means the Investment Committee consisting of members of senior management of the Company appointed from time to time by the Chief Executive Officer of the Company. The Investment Committee shall have the authority to delegate its duties and responsibilities hereunder in writing.

34 "Investment Fund(s)" means, dependent upon the context in which used, one or more of the following funds:

(1) CEG Common Stock Fund,

(2) Default Investment Fund, or

(3) any Other Investment Fund.

35 "Military Leave of Absence" means a leave of absence from an Employer for a period of "qualified military service" as defined under Code Section 414(u)(5).

36 "Mutual Fund" means any mutual fund selected by the Investment Committee as an Investment Fund (other than the CEG Common Stock Fund and the Default Investment Fund).

37 "Nonhighly Compensated Employee" means any Employee who is not a Highly Compensated Employee.

38 "On-Call Employee" – See definition of "Employee."

39 "Other Investment Fund" means any Mutual Fund, common, collective, or master trust fund, or other pooled investment fund selected by the Investment Committee as an Investment Fund (other than the CEG Common Stock Fund and Default Investment Fund).

40 "Participant" means, except as provided in Articles VII, VIII, and IX, any eligible Employee who has completed the length-of-service requirements and become a member of the Plan under the provisions of Article II.

41 "Participant Contribution Account" means an account(s) established to receive contributions made by a Participant, or made by the Company on the Participant's behalf, under the After-Tax and/or Before-Tax Options, and to which loan repayments and earnings on amounts held in the respective accounts are allocated. A Participant Contribution Account is established in one or more of the Investment Funds at the election of the Participant. Where the Participant Contribution Account is established in the CEG Common Stock Fund, shares of Common Stock are allocated to the account. The Common Stock allocated to the account is purchased by the Trustee with cash contributions and with dividends received on shares of Common Stock already in such account. Where a Participant Contribution Account is established in one of the other Investment Funds, cash contributions and earnings on amounts already in the Participant Contribution Account, are allocated to the Account. A Participant Contribution Account is also comprised of allocations of any cash contributed during a Payroll Period by the Participant, or by the Company on the Participant's behalf, but not yet transferred to the Trustee.

42 "Participant Contributions" means a Participant's Basic Contributions and Supplemental Contributions, as applicable.

43 "Participating Employer" means any Employer that has been designated as a Participating Employer by the Designating Authority, as set forth in Appendix E.

44 "Party in Interest" is an active Employee and any other person described as a party in interest under ERISA Section 3(14).

45 "Payroll Period" means the basic work period of an Employee, which (i) for Employees paid on a weekly basis consists of seven (7) twenty-four (24) hour days, Monday through Sunday, (ii) for Employees paid on a bi-weekly basis consists of fourteen (14) twenty-four (24) hour days, Monday through the second following Sunday, and (iii) for Employees paid on a monthly basis consists of the days of each calendar month.

46 "Plan" means the Constellation Energy Group, Inc. Employee Savings Plan.

47 "Plan Administrator" means the Director – Corporate Benefits of the Company (or the position succeeding to that function) appointed by the Board of Directors.

48 "Plan Year" means the Plan's accounting year of twelve (12) months beginning on January 1 of each year and ending the following December 31.

49 "Qualified Nonelective Contributions" means the contributions, if any, made by the Company to the Plan in the Company's sole discretion, provided that such contributions are:

(i) allocated uniformly on the basis of Compensation to the Participant Contribution Account of each Participant who is a Nonhighly Compensated Employee and is eligible to participate in the Before-Tax Option under the Plan; and

(ii) for all purposes under the Plan, except as provided in Section 7.6 with respect to hardship withdrawals, treated as amounts contributed under the Before-Tax Option.

50 "Rollover Account" means an account(s) established when a Participant transfers, in cash, all or a portion of an Eligible Rollover Distribution to the Plan in accordance with the rollover provisions of the Plan as set forth in Article III. A Rollover Account is established in one or more of the Investment Funds at the election of the Participant. Where the Rollover Account is established in the CEG Common Stock

Fund, shares of Common Stock are allocated to the Account. Such shares are purchased by the Trustee with the transferred cash and with dividends received on shares of Common Stock already in such Account. Where a Rollover Account is established in one of the other Investment Funds, transferred cash and earnings on amounts already in the Rollover Account, are allocated to the Account.

51 "Spouse" means a person of the opposite sex recognized as a Participant's spouse under Federal law on the determination date.

52 "Supplemental Contribution" means a Participant's contribution to the Plan through the After-Tax and/or Before-Tax Options in excess of the Participant's Basic Contributions.

53 "Total Account Balance" means, for purposes of determining the maximum loan available under the Plan, the total dollar value of the Participant's Plan accounts (except dividends, if any, accumulated under the provisions of Section 8.5) as of the date the Plan receives the Participant's executed loan agreement.

54 "Transaction Price" means the actual price, net of commissions, the Trustee receives or pays for Common Stock when the Trustee sells or buys Common Stock on the open market in order to satisfy Plan provisions relating to contributions, interfund transfers, withdrawals, distributions and loans.

55 "Treasury" means the federal Treasury Department.

56 "Trust" means the trust established under the provisions of Article XI of the Plan.

57 "Trust Agreement" means the agreement between the Company and the Trustee, under which the assets of the Plan are held and managed pursuant to Article XI of the Plan.

58 "Trustee" means T. Rowe Price Trust Company or any successor Trustee appointed by the Board of Directors.

APPENDIX B

CODE LIMITATIONS ON CONTRIBUTIONS TO THE PLAN

B-1 Dollar Limitation on Participants' Before-Tax Option Contributions – During any Plan Year, a Participant's contributions under the Before-Tax Option of the Plan, when combined with his elective deferrals within the meaning of Code Section 402(g)(3) under all other plans of the Employer and any other employer during the Plan Year, may not exceed the limitation of Code Section 402(g) (e.g., $13,000 in 2004). This dollar limitation will be adjusted annually at the same time and in the same manner as provided under Code Section 402(g)(5). To prevent the limitation from being exceeded in any Plan Year, the Plan Administrator may prospectively limit the rate of contribution which a Participant may elect to contribute under the Before-Tax Option. Participants whose Before-Tax Option contributions are limited by this Section B-1 are automatically treated as electing to increase their contributions under the After-Tax Option by an amount equal to the Participant's Before-Tax Option contribution percentage in excess of the limitation.

If due to an administrative error a Participant's contributions under the Before-Tax Option exceed the limitation of Code Section 402(g) as of the close of any Plan Year, the Participant will receive a distribution from the Plan of the amount constituting such excess Before-Tax Option contributions and any income or loss allocable thereto by no later than April 15th following the close of the Plan Year to which such excess deferrals relate.

If during the Plan Year in which such excess Before-Tax Option contributions occurred, or prior to March 1st following the close of such Plan Year, a Participant submits a written certification to the Plan Administrator stating that all or a portion of the Participant's contributions to the Plan under the Before-Tax Option constitute excess

deferrals within the meaning of Code Section 402(g), the Participant will receive a distribution of such excess deferrals, which will be designated as such by the Company, and any income or loss allocable to such excess deferrals by no later than April 15th following the close of the Plan Year to which the excess deferrals relate.

To the extent any Company Matching Contributions were allocable to the Participant's account as a result of excess deferrals, such Company Matching Contributions and any income or loss allocable thereto will be forfeited and thereafter applied to reduce future Company contributions to the Plan.

Distributions of excess deferrals required under this Section B-1 shall be made first from Participant's Supplemental Contributions made under the Before-Tax Option and income or loss allocable thereto and, thereafter, from Participant's Basic Contributions made under the Before-Tax Option, and income or loss allocable thereto.

Income or loss allocable to excess deferrals for the Plan Year will be computed using either a reasonable method that meets the requirements of Treasury Regulation Section 1.402(g)-1(e)(5)(ii) or the fractional method under Treasury Regulation Section 1.402(g)-1(e)(5)(iii). For the purposes of clarity, the income or loss allocable to excess deferrals will not be calculated for the period after the close of the Plan Year in which the excess deferral occurred and prior to the distribution (i.e. the 'gap period').

For purposes of computing the Section B-2 limitations under Code Section 415(c), excess deferrals under Code Section 402(g) will be treated as contributions under the Before-Tax Option, unless a distribution of such excess deferrals and any income or loss allocable thereto is made no later than April 15th following the close of the Plan Year to which such excess deferrals relate. Excess deferrals under Code Section 402(g) will be treated as contributions under the Before-Tax Option for purposes of computing the Code Section 401(k) limitations as provided in Section B-4.1, but only for contributions on behalf of Highly Compensated Employees, even if such excess deferrals and any income or loss allocable thereto is distributed by April 15th following the close of the Plan Year to which such excess deferrals relate. Excess deferrals by Nonhighly Compensated Employees will not be taken into account.

It is the intent of the Plan that the limitations set forth above will conform to the limitations prescribed by Code Section 402(g). As of the date of any adjustment in the limitations prescribed by Code Section 402(g), the provisions of this Section B-1 will be deemed to have been amended to reflect such adjustment.

B-2 Limitation on Total Annual Additions

B-2.1 Maximum Annual Additions – The total annual additions to a Participant's account under this Plan and any and all other defined contribution plans of the Employer shall not in any limitation year exceed the lesser of the limitation in effect under Code Section 415(c)(1)(A) ($49,000 for 2009) as adjusted for cost of living increases pursuant to Code Section 415(d) or 100% of the Compensation as defined in Section 4.2 (b) of the Plan actually paid or made available to the Participant during such limitation year. "Annual addition", for purposes of this Appendix B-2, means the sum of the following amounts allocated to the Participant's Plan accounts for the limitation year:

(a) Employer contributions,

(b) Employee contributions, and

(c) Forfeitures.

Amounts contributed by the Participant under the rollover provisions of the Plan are not considered to be annual additions to a Participant's account for purposes of determining the limitations under this Section. Catch-up contributions under Section 3.1(a) of the Plan and repayment of loans to Participants under Article IX of the Plan are not annual additions to a Participant's account for purposes of determining the limitations under this Section.

B-2.2 Elimination of Excess Annual Additions — To the extent necessary to prevent the limitation of this Section B-2 from being exceeded in any limitation year, the Plan Administrator may prospectively reduce contributions under the Plan during such limitation year. A Participant's prospective Supplemental Contributions under the After-Tax Option will be reduced first, followed in order by Supplemental Contributions under the Before-Tax Option, Basic Contributions under the After-Tax Option, and Basic Contributions under the Before-Tax Option until such reductions eliminate any excess annual additions.

B-2.3 Limitation Year — For purposes of applying the limitations of Code Section 415 to the Plan, the "limitation year" shall be the calendar year.

If the Employer maintains multiple defined contribution plans that are aggregated with the Plan for purposes of Code Section 415 pursuant to Appendix B-2.4 and that have different limitation years, the rules of Code Section 415(c) will be applied to the limitation year of the Plan, and are to be applied with respect to each limitation year of each other such plan. For each limitation year of the Plan, the requirements of Code Section 415 are applied to annual additions that are made for that time period with respect to the Participant under all such aggregated plans.

B-2.4 Aggregated Plans — The sum of the annual additions credited to a Participant's account in any limitation year for all of the qualified defined contribution plans of the Employer or a predecessor employer (as such term in used in Code Section 415(f) and the regulations thereunder), regardless of whether a plan is terminated, may not exceed the limitations of Code Section 415(c).

B-2.5 Incorporation by Reference — Notwithstanding anything contained in this Appendix B or Article IV of the Plan to the contrary, the limitations, adjustments, and other requirements prescribed in this Appendix B-2 shall at all times comply with the provisions of Code Section 415 and the regulations thereunder, the terms of which are specifically incorporated herein by reference. As of the date of any adjustment in the limitations prescribed by Code Section 415(c), the provisions of this Appendix B-2 will be deemed to have been amended to reflect such adjustment.

B-3 Reserved .

B-4 Limitation on Participant Contributions Under the Before-Tax Option (ADP Test)

B-4.1 Maximum Annual Contributions — For each Plan Year, annual Participant contributions under the Before-Tax Option shall satisfy one of the following actual deferral percentage (ADP) tests:

(1) The actual deferral percentage for the group of Highly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year shall not be more than 125 percent of the actual deferral percentage for the group of Nonhighly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year, or

(2) The excess of the actual deferral percentage for the group of Highly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year over the actual deferral percentage for the group of Nonhighly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year shall not be more than two (2) percentage points. Additionally, the actual deferral percentage for the group of Highly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year shall not exceed the actual deferral percentage for the group of Nonhighly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year, multiplied by two (2).

In determining whether the Plan satisfies the limitation under this Section B-4, all Before-Tax Option contributions and other elective deferrals, that are made to the Plan and any other plans of the Employer that are aggregated with the Plan for purposes of Code Section 401(a)(4) and 410(b) (other than Code Section 410(b)(2)(A)(ii)), are to be treated as made under a single plan. If the Plan and any other plans of the Employer are permissively aggregated for purposes of satisfying this limitation under Section B-4, the aggregated plans must also satisfy Code Sections 401(a)(4) and 410(b) as though they were a single plan.

For the purposes of this Section "actual deferral percentage" means, with respect to the group of Highly Compensated Employees who are eligible to participate under the Before-Tax Option and the group of Nonhighly Compensated Employees who are eligible to participate under the Before-Tax Option for the Plan Year, the average of the actual deferral ratios, calculated separately for each Employee who is eligible to participate under the Before-Tax Option for the Plan Year in each group.

The "actual deferral ratio" for each such Employee is equal to the annual Participant contributions under the Before-Tax Option and any "Qualified Nonelective Contribution" made on behalf of such Participant divided by the Participant's Compensation. For purposes of this Section, Compensation generally means an Employee's total Compensation for the Plan Year; however, Compensation does not include amounts related to any portion of the Plan Year in which an Employee was not eligible to

participate in the Before-Tax Option of the Plan. The actual deferral ratio of a Highly Compensated Employee is determined by treating all plans of the Employer that are subject to Code Section 401(k) under which the Highly Compensated Employee is eligible to participate (other than those that may not be permissively aggregated) as a single plan.

The actual deferral ratio for each Employee who is eligible to participate under the Before-Tax Option and the actual deferral percentage for the Highly Compensated Employee group and the Nonhighly Compensated Employee group shall be calculated to the nearest one-hundredth of one percent.

B-4.2 Elimination of Excess Contributions – To prevent the limitation under this Section B-4 from being exceeded in any Plan Year, the Plan Administrator may prospectively limit the rate of contribution which a Highly Compensated Employee may elect to contribute under the Before-Tax Option.

The Plan Administrator will establish a maximum rate of contribution for Highly Compensated Employees to avoid exceeding the limits of this Section B-4.

The maximum rate of contribution for Highly Compensated Employees will be determined by first reducing by 1/10 of a percent the rate of contribution under the Before-Tax Option of the Highly Compensated Employees having the highest actual deferral ratio. The rate of contribution will be reduced until the ADP test is satisfied, or until the actual deferral ratio is reduced to the point where it equals the ratio of the Highly Compensated Employee with the next highest actual deferral ratio. This "leveling" process will be repeated until the ADP test is satisfied.

Highly Compensated Employee Participants whose Before-Tax Option contributions are prospectively limited by this Section B-4 are automatically treated as electing to increase their contributions under the After-Tax Option by an amount equal to the Participant's Before-Tax Option contribution percentage in excess of the limitation.

If, after the end of the Plan Year, it is determined that the limitation of this Section B-4 has been exceeded, the Plan Administrator may authorize the Trustee to distribute the excess contributions and the income or loss allocable thereto to the Highly Compensated Employees with the highest dollar deferral amounts. Excess contributions are determined by first determining how much the actual deferral ratio of the Highly Compensated Employee with the highest actual deferral ratio would have to be reduced to satisfy the ADP test or cause such ratio to equal the actual deferral ratio of the Highly Compensated Employee with the next highest ratio. Second, this process is repeated until the ADP test would be satisfied. The amount of excess contributions is equal to the sum of these hypothetical reductions multiplied by the Highly Compensated Employee's Compensation. Excess contributions shall be distributed or recharacterized as contributions under the After-Tax Option (each as set forth below), starting with the Highly Compensated Employee with the greatest dollar amount of contributions under the Before-Tax Option during the Plan Year until the amount of excess contributions has been accounted for. At the discretion of the Plan Administrator, the excess contributions may be distributed on or before March 15th following the end of the Plan Year for which the limitation of this Section B-4 is exceeded. With respect to the distribution of excess contributions, such distribution may be postponed, but not later than the close of the Plan Year following the Plan Year to which the contributions are allocable. To the extent any Company Matching Contributions were allocable to the Participant's account as a result of excess contributions, such Company Matching Contributions and income or loss allocable thereto will be forfeited and thereafter applied to reduce Company contributions to the Plan.

Distributions required under this Section B-4.2 shall be made first from Participants' Supplemental Contributions made under the Before-Tax Option and income or loss allocable thereto and, thereafter, from Participants' Basic Contributions made under the Before-Tax Option, and income or loss allocable thereto.

Income or loss allocable to excess contributions for the Plan Year will be computed using either a reasonable method that meets the requirements of Treasury Regulation Section 1.401(k)-2(b)(2)(iv)(B) or the fractional method under Treasury Regulation Section 1.401(k)-2(b)(2)(iv)(C). Income allocable to excess contributions shall be determined on a date that is no more than 7 days before such contributions are distributed.

In the event a distribution of excess contributions occurs, the Company will designate that the distribution is comprised of excess contributions and income or loss allocable thereto.

As an alternative to the distribution of amounts exceeding the limitation of this Section B-4.2 after the end of the Plan Year, the Plan Administrator may cause the excess contributions to be recharacterized first as "catch-up contributions" in accordance with, and subject to the limitations of, Section 414(v) of the Code to the extent that the Participant would otherwise be eligible to make such catch-up contributions under Section 3.1(a) of the Plan, and then as contributions under the After-Tax Option. The option to recharacterize excess contributions is provided at the sole discretion of the Plan Administrator.

The limitation set forth in this Section B-4 will be determined and the computation of any distribution or recharacterization of contributions required under this Section B-4.2 will be made after adjustments are made to contributions under the Before-Tax Option as necessary to avoid exceeding the Code Section 402(g) dollar limitations on contributions as provided in Section B-1.

It is the intent of the Plan that the limitations set forth in Section B-4.1 and the corrective measures set forth in Section B-4.2 will conform to the respective provisions of Code Section 401(k) and the accompanying regulations. As of the date of any adjustment in the limitations prescribed by Code Section 401(k), the provisions of this Section B-4 will be deemed to have been amended to reflect such adjustment.

B-5 Limitation on Participant Contributions Under the After-Tax Option and Company Matching Contributions (ACP Test)

B-5.1 Maximum Annual Contribution – For each Plan Year, the actual contribution percentage (ACP) for the group of Highly Compensated Employees who are eligible to participate through Payroll Deduction for the Plan Year shall not exceed the greater of :

(1) 125 percent of the actual contribution percentage for the group of Nonhighly Compensated Employees who are eligible to participate through Payroll Deduction for the Plan Year; or

(2) the lesser of (a) 200 percent of the actual contribution percentage for the group of Nonhighly Compensated Employees who are eligible to participate through Payroll Deduction for the Plan Year, or (b) the actual contribution percentage for the group of Nonhighly Compensated Employees who are eligible to participate through Payroll Deduction for the Plan Year plus two (2) percentage points.

In determining whether the Plan satisfies the limitation under this Section B-5, all employee and matching contributions that are made to the Plan and any other plans of the Employer that are aggregated with the Plan for purposes of Code Sections 401(a)(4) and 410(b) (other than Code Section 410(b)(2)(A)(ii)), are to be treated as made under a single plan. If the Plan and any other plans of the Employer are permissively aggregated for purposes of satisfying this limitation under Section B-5, the aggregated plans must also satisfy Code Sections 401(a)(4) and 410(b) as though they were a single plan.

For purposes of this Section, “actual contribution percentage” for a Plan Year means, with respect to the group of Highly Compensated Employees who are eligible to participate through the After-Tax and/or Before-Tax Options and the group of Nonhighly Compensated Employees who are eligible to participate through the After-Tax and/or Before-Tax Options for the Plan Year, the average of the actual contribution ratios, calculated separately for each Employee who is eligible to participate through the After-Tax and/or Before-Tax Options for the Plan Year in each group.

The “actual contribution ratio” for each such Employee is equal to the sum of their annual Participant contributions under the After-Tax Option and the Company Matching Contributions allocated to their accounts, divided by the Participant’s Compensation. For purposes of this Section, Compensation generally means an Employee’s total Compensation for the Plan Year; however, Compensation does not include amounts related to any portion of the Plan Year in which an Employee was not eligible to participate under the After-Tax Option of the Plan or to have Company Matching Contributions allocated to his account. The actual contribution ratio of a Highly Compensated Employee is determined by treating all plans of the Employer that are subject to Code Section 401(m) under which the Highly Compensated Employee is eligible to participate (other than those that may not be permissively aggregated) as a single plan.

The actual contribution ratio for each Employee who is eligible to participate through the After-Tax and/or Before-Tax Options and the actual contribution percentage for the Highly Compensated Employee group and the Nonhighly Compensated Employee group shall be calculated to the nearest one-hundredth of one percent.

To the extent provided by Treasury regulations, the Plan Administrator may elect to apply the limitation under this Section by including Employee elective deferrals under the Before-Tax Option.

B-5.2 Elimination of Excess Contributions – To prevent the limitation under this Section B-5 from being exceeded in any Plan Year, the Plan Administrator may prospectively limit the rate of contribution which a Highly Compensated Employee may elect to contribute under the After-Tax Option and, if necessary, may reduce amounts which would otherwise be contributed for a Highly Compensated Employee as a Company Matching Contribution.

The Plan Administrator will establish a maximum rate of contribution for Highly Compensated Employees to avoid exceeding the limits of this Section B-5.

The maximum rate of contribution for Highly Compensated Employees will be determined by first reducing by 1/10 of a percent the rate of contribution under the After-Tax Option, and any related Company Matching Contribution, of the Highly Compensated Employees having the highest actual contribution ratio. The rate of contribution will be reduced until the ACP test is satisfied, or until the actual contribution ratio is reduced to the point where it equals the ratio of the Highly Compensated Employee with the next highest actual contribution ratio. This "leveling" process will be repeated until the ACP test is satisfied.

Any After-Tax Option contributions resulting from the recharacterization of Before-Tax Option contributions under the provisions of Section B-4.2 are included in the computation of the actual contribution percentage and are subject to limitation under this Section B-5. If the After-Tax Option contributions of the Highly Compensated Employee with the highest average contribution ratio have been reduced to zero, and further reduction is necessary to avoid exceeding the limitation, then Company Matching Contributions relating to Before-Tax Option contributions will be reduced also.

Highly Compensated Employees whose After-Tax Option contributions are limited by this Section B-5, may elect to either prospectively increase their contributions under the Before-Tax Option or increase their cash compensation by an amount equal to the percentage of Eligible Compensation in excess of the limitation. If the Participant fails to make an election regarding such excess, the excess will be paid to the Participant as cash compensation. Any recharacterization elected by the Participant will be permitted only if it does not cause any other limitations described in Appendix B to be exceeded.

If, after the end of the Plan Year, it is determined that the limitation of this Section B-5 has been exceeded, the Plan Administrator may authorize the Trustee to distribute the excess aggregate contributions and income or loss allocable thereto to the Highly Compensated Employees with the highest dollar contribution amounts. Excess contributions are determined by first determining how much the actual contribution ratio of the Highly Compensated Employee with the highest actual contribution ratio would have to be reduced to satisfy the ACP test or cause such ratio to equal the actual contribution ratio of the Highly Compensated Employee with the next highest ratio. Second, this process is repeated until the ACP test would be satisfied. The amount of excess contributions is equal to the sum of these hypothetical reductions multiplied by the Highly Compensated Employee's Compensation. Excess contributions shall be distributed as set forth below, starting with the Highly Compensated Employee with the greatest dollar amount of contributions under the After-Tax Option during the Plan Year until the amount of excess contributions has been accounted for. At the discretion of the Plan Administrator, the excess aggregate contributions may be distributed on or before March 15th following the end of the Plan Year for which the limitation of this Section B-5 was exceeded. With respect to the distribution of excess aggregate contributions, such distribution may be postponed, but not later than the close of the Plan Year following the Plan Year to which the contributions are allocable.

Distributions required under this Section B-5.2 shall be made first from Participants' Supplemental Contributions made under the After-Tax Option and income or loss allocable thereto, and, thereafter, from Basic Contributions made under the After-Tax Option and income or loss allocable thereto, and Company Matching Contributions and income or loss allocable thereto.

Income or loss allocable to excess aggregate contributions for the Plan Year will be computed using either a reasonable method that meets the requirements of Treasury Regulation Section 1.401(m)-2(b)(2)(iv)(B) or the fractional method under Treasury Regulation Section 1.401(m)-2(b)(2)(iv)(C). Income allocable to excess aggregate contributions shall be determined on a date that is no more than 7 days before such contributions are distributed.

In the event a distribution of excess aggregate contributions occurs, the Company will designate that the distribution is comprised of excess aggregate contributions and income or loss allocable thereto.

The limitation of this Section B-5 will be determined and the computation of any distribution of contributions required under this Section B-5.2 will be made after adjustments are made to contributions under the Before-Tax Option as necessary to avoid exceeding Code Section 402(g) dollar limitations on contributions as provided in Section B-1 or the Code Section 401(k) limitations on contributions as provided in Section B-4.

It is the intent of the Plan that the limitations set forth in Section B-5.1 and the corrective measures set forth in Section B-5.2 will conform to the respective provisions of Code Section 40l(m) and the accompanying regulations. As of the date of any adjustment in the limitations prescribed by Code Section 40l(m), the provisions of this Section B-5 will be deemed to have been amended to reflect such adjustment.

B-6 Gap Period Income on Excess Contributions and Excess Aggregate Contributions — The Plan Administrator will not calculate and distribute allocable income for the gap period (*i.e.* , the period after the close of the Plan Year in which the excess contribution or excess aggregate contribution occurred and prior to the distribution). For purposes of this Appendix B-6, the term excess contribution is defined as in Code Section 401(k)(8)(B) and excess aggregate contribution is defined as in Code Section 401(m)(6)(B).

APPENDIX C

EMPLOYEE SAVINGS PLAN
BONUSES AND INCENTIVES
INCLUDABLE IN BASIC COMPENSATION
FOR PARTICIPATING EMPLOYERS

The base rate of pay in the calculation of Eligible Compensation paid by the Participating Employer to an Employee includes the following:

- NRC License Bonus
- Electrician License Bonus
- Plumber License Bonus
- Service Operators Bonus
- Outage Schedulers Bonus
- Fire and Safety Responder (FASER) Bonus

The following bonuses and/or incentive awards paid by the respective Participating Employers are includable in the calculation of Eligible Compensation for purposes of determining a Participant's After-Tax and Before-Tax Option contributions and Company Matching Contributions:

1. Annual Bonuses*
2. Annual Incentive Award (excluding Nine Mile Point Nuclear Station, LLC)*
3. Annual Performance Award*
4. Commission Payments
5. Contract Incentive Rate Award
6. Emergency Work Payment
7. Lump Sum Pay Adjustments
8. Piece Work Payment
9. Promotion Recognition Award
10. Reliability Award*
11. Results Incentive Award*
12. Sales Bonus

13. Sales Incentive Award

14. Scale Rate Payment

* Prior to January 1, 2004, each Participant employed by the applicable Participating Employer may elect to exclude the indicated bonus/award from Eligible Compensation, pursuant to an election which may be made available to all Employees of such Participating Employer at the Plan Administrator’s discretion.

APPENDIX D

TOP HEAVY PROVISIONS

D-1 Purpose – If the Plan is or becomes top-heavy in any Plan Year, the following provisions will supersede any conflicting provisions in the Plan.

D-2 Definitions – As used in the Plan, the following terms shall have the meaning set forth below, unless a different meaning is clearly required by the context in which the term is used.

D-2.1 RESERVED

D-2.2 "Anniversary Date" means December 31, the last day of the Plan Year.

D-2.3 " Controlled Group " shall mean any group of corporations, partnerships or proprietorships which, together with the Company, are members of a Controlled Group within the meaning of Code Section 1563(a), determined without regard to Code Section 1563(a)(4) or (e)(3)(C) or would be a part of such a group if Code Section 1563(a) applied to partnerships or proprietorships.

D-2.4 " Key-Employee " shall mean any person who meets the requirements of Code Section 416(i), and the regulations promulgated thereunder, which are hereby incorporated by reference as if fully set out herein. For purposes of determining whether or not the Plan meets the requirements of Section D-3.2, the term Key-Employee shall also include the beneficiary of a Key-Employee.

D-2.5 " Permissive Aggregation Group " shall mean all plans in the Required Aggregation Group and any other Qualified Plan maintained by the Company or by any member of the Controlled Group or Affiliated Service Group, but only if such group of plans would satisfy, in the aggregate, the requirements of Code Sections 401(a)(4) and 410 and contributions or benefits in the other Qualified Plans are comparable to contributions or benefits in the plans of the Required Aggregation Group. The Plan Administrator shall determine which plan or plans shall be taken into account in determining the Permissive Aggregation Group.

D-2.6 " Qualified Plan " shall mean any plan which is qualified under Code Section 401(a).

D-2.7 " Required Aggregation Group " shall mean:

(a) Each Qualified Plan of the Company or any member of the Controlled Group or the Affiliated Service Group in which at least one (1) Key-Employee participates; and

(b) Any other Qualified Plan of the Company or any member of the Controlled Group or the Affiliated Service Group which enables a Plan described in Section D-2.7(a) to meet the requirements of Code Sections 401(a)(4) and 410.

D-2.8 " Top-Heavy Plan " shall mean the Plan, for any Plan Year in which the Plan meets the requirements of Section D-3.2.

D-3 Top-Heavy Plan Requirements and Determination

D-3.1 Top-Heavy Plan Requirements – For any Plan Year in which the Plan is determined to be a Top-Heavy Plan in accordance with Section D-3.2, the Plan shall be subject to the following:

(a) special vesting requirements of Code Section 416(b); and

(b) special minimum allocation requirements of Code Section 416(c).

D-3.2 Top-Heavy Plan Determination

(a) The Plan shall be considered a Top-Heavy Plan and shall be subject to the additional requirements of Section D-3.1, with respect to any Plan Year, if, as of the Anniversary Date of the preceding Plan Year (hereinafter referred to as the "determination date") either:

(i) the sum of the value of the aggregate accounts of Key-Employees exceeds sixty percent (60%) of a similar sum determined for all Participants (the "60% Test"); or

(ii) the Plan is part of a Required Aggregation Group, and the sum of the present value of accrued benefits and the value of the aggregate accounts of Key-Employees in all Plans in such group exceeds sixty percent (60%) of a similar sum determined for all Participants.

(b) For purposes of this Section D-3.2, the aggregate account of a Participant as of the determination date is the sum of:

(i) the Company Matching Contribution Account and Employee Stock Account of such Participant as of the determination date adjusted for any contributions due as of the determination date, and further adjusted by including any Plan distributions made during a (1) year period ending on the most recent determination date, except that in the case of any distribution made for a reason other than severance from employment, death, or disability, this provision shall be applied by substituting five (5) year period for (1) year period; and

(ii) the Participant Contribution Account of such Participant.

(c) For purposes of this Section D-3.2, present value of accrued benefits shall be determined, in the case of a defined benefit pension plan, under the provisions of such a plan or plans.

(d) Notwithstanding the provisions of subsection (a) hereinabove, the Plan shall not be a Top-Heavy Plan, if the Plan Administrator elects to treat the Plan as part of a Permissive Aggregation Group, and the Permissive Aggregation Group is not determined to be Top-Heavy using the criteria of the "60% Test" hereinabove.

(e) Only those plans in which the determination dates fall within the same calendar year shall be included in a Required or a Permissive Aggregation Group in order to determine whether the Plan is a Top-Heavy Plan.

(f) The account (and any accrued benefit) of an individual who has not performed services for the Employer at any time during the one (1) year period ending on the determination date shall not be taken into account for purposes of Section D-3.2.

D-4 Additional Top-Heavy Provisions – For purposes of determining whether or not the Plan meets the requirements of Section D-3.2, the term "Participant" as defined in Appendix A of the Plan shall also include the beneficiary of a Participant.

Notwithstanding the provisions in Section 3.2(a) regarding the rate of Company Matching Contributions, for any Plan Year in which the Plan, or any Permissive or Required Aggregation Group of which this Plan is a member, is a Top-Heavy Plan, the Company contributions to provide the minimum allocation or benefit requirement applicable to Top-Heavy Plans for allocation on behalf of any Participant who is not a Key-Employee and who is employed by the Company on the last day of the Plan Year

will be provided under the Company's defined benefit pension plan. In the event the Company's defined benefit pension plan should be amended to not include the above minimum allocation or benefit requirement, then the minimum allocation or benefit will be provided under this Plan less any Company contribution that might be provided in any other Company defined contribution plan pursuant to Code Section 416(c).

APPENDIX E

PARTICIPATING EMPLOYERS

The following Employers are Participating Employers as of the corresponding effective dates:

Participating Employers	Employer Code	Participation Effective Date
(a) Baltimore Gas and Electric Company	001	July 1, 1978
(b) BGE Home Products & Services, LLC (formerly known as BGE Home Products & Services, Inc.)	006	July 1, 1994
(c) CER Generation, LLC	464	February 14, 2008
(d) CNE Gas Holdings, Inc. (formerly known as Fellon-McCord Associates, Inc.)	035	January 1, 2003
(e) Constellation Energy Commodities Group, Inc. (formerly known as Constellation Power Source, Inc.)	013	March 1, 1997
(f) Constellation Energy Group, Inc.	018	April 30, 1999
(g) Constellation Energy Projects and Services Group Advisors, LLC	603	March 28, 2011
(h) Constellation Energy Projects and Services Group, Inc. (formerly known as Constellation Energy Source, Inc.)	011	December 1, 1995
(i) Constellation NewEnergy, Inc.	034	September 1, 2002

Special Provisions :

- Under Section 3.3, Participants who are active employees of Constellation NewEnergy, Inc. on the date of the closing of the transaction contemplated in the Stock Purchase Agreement, may also roll over as part of a distribution from the AES Corporation Profit Sharing and Stock Ownership Plan ("DC Plan") notes evidencing such employee's DC Plan loans and the portion of such distribution that is not includable in gross income.
- Under Section 7.1(c), rollover of a distribution from the DC Plan for Participants who are active employees of Constellation NewEnergy, Inc. on the date of the closing of the transaction contemplated in the Stock Purchase Agreement mature immediately.

(j)	Constellation Operating Services	023	April 1, 2003
(k)	Constellation Power, Inc.	014	June 1, 1998
(l)	Constellation Power Source Generation, Inc.	028	April 1, 2001
(m)	COSI Sunnyside, Inc.	024	April 1, 2003

The following Employers were Participating Employers as of the corresponding effective dates, but are no longer:

	Participating Employers	**Employer Code**	**Participation Effective Date**
(a)	BGE Commercial Building Systems, Inc.	008	January 1, 1996 through October 31, 2003
(b)	Constellation Investments, Inc.	012	January 1, 1997 through December 31, 1999
(c)	Constellation Operating Services, Inc.	029	April 1, 2003 through October 1, 1999
(d)	Constellation Power Source Holdings, Inc.	032	July 1, 2000
(e)	Constellation Real Estate, Inc.	017	April 1, 2001 through December 31, 2003
(f)	COSI Central Wayne, Inc. (Employees represented by a union under a collective bargaining agreement are not eligible to participate.)	021	April 1, 2003 through September 8, 2003
(g)	COSI Puna, Inc.	022	April 1, 2003 through June 6, 2004
(h)	COSI Synfuels, Inc.	025	April 1, 2003 through June 10, 2008

(i)	PCI Operating Company Partnership	026	April 1, 2003 through March 31, 2008
(j)	Robinson Bend Operating Two, LLC	349	November 14, 2005 through November 12, 2006

FIRST AMENDMENT TO THE
CONSTELLATION ENERGY GROUP, INC.
EMPLOYEE SAVINGS PLAN

(Amended and Restated Effective January 31, 2012)

WHEREAS, Exelon Corporation (the "Company") sponsors the Constellation Energy Group, Inc. Employee Savings Plan for (Amended and Restated Effective as of January 31, 2012) (the "Plan"), which is intended to meet the requirements of the provisions of the Internal Revenue Code of 1986, (as amended) (the "Code"); and

WHEREAS, the Company desires to amend the Plan in certain respects; and

WHEREAS, pursuant to Section 12.1 of the Plan the Chief Human Resources Officer may authorize any amendment to the Plan that does not increase Plan liabilities materially;

NOW, THEREFORE, BE IT RESOLVED, that the Plan is hereby amended as follows, effective January 1, 2012:

1. By adding a new paragraph at the end of Section 11.5(a) as follows:

Notwithstanding the foregoing, with respect to a tender offer for the purchase or exchange of less than five percent (5%) of the outstanding shares of Common Stock, the Company shall direct the Trustee with respect to the sale, exchange or transfer of the shares of Common Stock held in the Trust Fund, and the Trustee shall follow the direction of the Company.

****

IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its Senior Vice President & Chief Human Resources Officer, on this ____day of June, 2012.

EXELON CORPORATION

By:_____
Senior Vice President &
Chief Human Resources Officer

SECOND AMENDMENT TO THE
CONSTELLATION ENERGY GROUP, INC.
EMPLOYEE SAVINGS PLAN

(Amended and Restated Effective January 31, 2012)

WHEREAS , Exelon Corporation (the "Company"), a Pennsylvania corporation, sponsors and maintain a qualified retirement plan for the benefit of employees of the Company and certain of its subsidiaries titled, "Constellation Energy Group, Inc. Employee Savings Plan" (the "Plan"), which has been amended and restated effective as of January 31, 2012;

WHEREAS , the Company has entered into that Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation (the "Merger Sub") and Constellation Energy Group, Inc. ("Constellation") (the "Merger Agreement");

WHEREAS , pursuant to the Merger Agreement, the Merger Sub merged with and into Constellation and the separate existence of the Merger Sub ceased; Constellation merged with and into Exelon, and the separate existence of Constellation ceased; and Exelon continued as the surviving corporation; and

WHEREAS , the Company desires to amend the Plan to restrict participation in the Plan to individuals participating in the Plan immediately before the Effective Time (as such term is defined in the Merger Agreement) and to other eligible individuals who are initially employed on or after the Effective Time at a facility owned immediately before the Effective Time by: (i) the Constellation, or (ii) an affiliate that was an affiliate of Constellation immediately before the Effective Time; and

WHEREAS , the Company desires to amend the Plan in certain aspects to resemble more closely the Company's Employee Savings Plan, a profit sharing plan with a qualified cash or deferred arrangement, and to reflect the Company's administrative and fiduciary practices;

WHEREAS , pursuant to the January 24, 2012 resolutions of the Company Board of Directors, Company officers are authorized to take such actions and execute such documents, including amendments to the Constellation plan as deemed necessary to meet the goals set forth therein;

NOW, THEREFORE, BE IT RESOLVED , that the Plan is hereby amended as follows, effective as of the Effective Time, unless otherwise noted:

1. By replacing the word "CEG" with the word "Company" in the phrases "CEG Common Stock" and "CEG Common Stock Fund" in each instance that it appears.

2. By adding a sentence to the end of Section 1.1, as follows:

> Effective as of the Effective Time, shares of common stock of Constellation Energy Group, Inc. were converted to common shares of Exelon Corporation, pursuant to the Merger Agreement, at a conversion rate of .9300. Effective January 1, 2013, the Plan is designated as a "profit sharing plan" within the meaning of section 1.401-1(a)(2)(ii) of the Regulations; and is also designated as an ERISA section 404(c) Plan within the meaning of section 2550.404c-1 of the Regulations.

3. Effective January 1, 2013, by adding the phrase "and Profit Sharing Matching Contributions" after the phrase "Company Matching Contributions" in the third sentence of Section 1.2.

4. Effective January 1, 2013, by renaming Section 1.3(c) from “Company Matching Contributions” to “Employer Contributions” and adding a second paragraph to the end of the section, as follows:

In addition, and likewise subject to the limitations of Articles III and IV and Appendix B of the Plan, each Participant shall be eligible to receive a Profit Sharing Matching Contribution, provided that such Participant either (i) is an Employee on the last day of such Plan Year, (ii) is not employed on such day as a result of an approved unpaid leave of absence during such Plan Year, (iii) terminates employment during such Plan Year (1) after attaining age 50 and completing at least 10 years of service, as determined by the Plan Administrator, (2) as a result of circumstances entitling the Participant to separation benefits under an Employer’s severance benefit plan, (3) as a result of a disability that entitles the Participant to benefits under an Employer’s long-term disability plan, or (4) on account of the Participant’s death. Participants shall be eligible for Matching Contributions beginning with any such contribution made in 2014 based on Plan Year 2013 performance in accordance with Section A-48(a).

5. By adding a new section 2.1(d), as follows:

2.1(d) Effect of Merger Agreement

If an Employee who was an Employee on or prior to the Effective Time transfers employment to or is reemployed by Exelon in a job classification with respect to which similarly situated employees of Exelon are not eligible to participate in the Plan but are instead eligible to participate in a Parent Benefit Plan (as such term is defined in the Merger Agreement) that is intended to be qualified under Section 401(a) or 401(k) of the Code (each such plan, an “Exelon Retirement Plan”), then such individual shall upon such transfer or reemployment remain a Participant in the Plan and shall not participate in the Exelon Retirement Plan. If a participant in an Exelon Retirement Plan who was a participant in such plan on or prior to the Effective Time transfers employment to or is reemployed by a Participating Employer in a job classification with respect to which similarly situated employees of such Participating Employer are not eligible to participate in such plan but are instead eligible to participate in the Plan, then such individual shall upon such transfer or reemployment remain a participant in the Exelon Retirement Plan and shall not participate in the Plan.

6. Effective January 1, 2013, by deleting and replacing the first sentence of Section 3.1(e) as follows:

An authorized leave of absence shall not constitute a termination of employment, but shall, except as provided in Section 3.1(f), operate to suspend Participant contributions, related Company Matching Contributions, and Profit Sharing Matching Contributions (the latter as set forth in Section 1.3(c)).

7. Effective January 1, 2013, by adding a new sentence immediately before the last sentence in the first paragraph of Section 3.1, as follows:

A Profit Sharing Matching Contribution will be made in accordance with Section 3.3.

8. Effective January 1, 2013, by adding a new Section 3.3, as follows, and re-numbering the subsequent sections:

3.3 Profit Sharing Matching Contributions

Beginning with any Profit Sharing Matching Contribution made in 2014 based on Plan Year 2013 performance in accordance with Section A-48(a) and subject to the limitations described in Article IV and Appendix B, the Company will contribute the Profit Sharing Matching Contribution to the Plan on behalf of each Participant at its discretion.

Profit Sharing Matching Contributions will be made completely in cash and are invested in the Investment Funds designated by the Participant.

9. Effective 1/1/2012, by adding a sentence after the first sentence of current Section 3.3 (to be renumbered as Section 3.4), and correcting any cross-references to former section 3.3, as follows:

A Participant who rolls over an Eligible Rollover Distribution from a qualified retirement plan, or on whose behalf a direct transfer is made, in conjunction with a corporate transaction shall also be permitted to rollover or transfer in-kind any promissory notes evidencing any loans under that plan, to the extent the agreement memorializing the transaction so provides.

10. By replacing the phrase “Investment Committee” with the phrase “Investment Office” in Sections 5.1(a)(3) and 13.1.

11. Effective January 1, 2013, reference to “Company Matching Contributions” and “Company Matching Contributions Account” shall be replaced by reference to “Employer Contributions” and “Employer Contribution Account” in Sections 4.1, 4.2(b), 4.2(d), 5.1(a), the heading and Paragraph 2 of 5.1(d), 5.2(b), 5.3(a), 6.2), 7.1(c), 7.3(c), 7,4, 8,2(b), 8.4(b), 8.4(c), 8.6, 9.5, 11.4, 11.5(a), 11.5(b), 12.2), Appendix B-1, Appendix B-4.2, Appendix B-5, Appendix C, Appendix D-3.2(b)(i), Appendix D-4

12. Effective January 1, 2013 by deleting “As with Company Matching Contributions,” from the last sentence of Section 5.1(e).

13. By deleting Sections 10.1, 10.2, 10.3, 10.4, 10.5, 10.7 and 10.8, and replacing them as follows, and re-numbering the remaining, subsequent sections:

Section 10.1 The Plan Administrator, the Investment Office and the Corporate Investment Committee.

10.1(a) The Plan Administrator

The Company, acting through its Director, Employee Benefit Plans & Programs, or such other person or committee appointed by the Chief Human Resources Officer from time to time (such director or other person or committee, the “Plan Administrator”), shall be the “administrator” of the Plan, within the meaning of such term as used in ERISA. In addition, the Plan Administrator shall be the “named fiduciary” of the Plan, within the meaning of such term as used in ERISA, solely with respect to administrative matters involving the Plan and not with respect to any investment of the Plan’s assets. The Plan Administrator shall have the following duties, responsibilities and rights:

(i) The Plan Administrator shall have the duty and discretionary authority to interpret and construe the Plan in regard to all questions of eligibility, the status and rights of Participants, distributees and other persons under the Plan, and the manner, time, and amount of payment of any distribution under the Plan. Benefits under the Plan shall be paid to a Participant or Beneficiary only if the Plan Administrator, in its discretion, determines that such person is entitled to benefits.

(ii) The Plan Administrator shall direct the Trustee to make payments of amounts to be distributed from the Trust under Article 8 (relating to withdrawals and distributions).

(iii) The Plan Administrator shall supervise the collection of Participants' contributions made pursuant to Article 5 (relating to Employee contributions) and the delivery of such contributions to the Trustee.

(iv) The Plan Administrator shall have all powers and responsibilities necessary to administer the Plan, except those powers that are specifically vested in the Investment Office, the Corporate Investment Committee or the Trustee.

(v) Each Employer shall, from time to time, upon request of the Plan Administrator, furnish to the Plan Administrator such data and information as the Plan Administrator shall require in the performance of its duties.

(vi) The Plan Administrator may require a Participant or Beneficiary to complete and file certain applications or forms approved by the Plan Administrator and to furnish such information requested by the Plan Administrator. The Plan Administrator and the Plan may rely upon all such information so furnished to the Plan Administrator.

(vii) The Plan Administrator shall be the Plan's agent for service of legal process and forward all necessary communications to the Trustee.

10.1(b) Removal of Plan Administrator

The Chief Human Resources Officer shall have the right at any time, with or without cause, to remove the Plan Administrator (including any member of a committee that constitutes the Plan Administrator). The Plan Administrator may resign and the resignation shall be effective upon delivery of the written resignation to the Chief Human Resources Officer or upon the Administrator's termination of employment with the Employers. Upon the resignation, removal or failure or inability for any reason of the Plan Administrator to act hereunder, the Chief Human Resources Officer shall appoint a successor. Any successor Plan Administrator shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. None of the Company, any officer, employee or member of the board of directors of the Company who is not the Chief Human Resources Officer, nor any other person shall have any responsibility regarding the retention or removal of the Plan Administrator.

10.1(c) The Investment Office

The Investment Office, shall be the "named fiduciary" of the Plan, within the meaning of such term as used in ERISA, solely with respect to matters involving the investment of assets of the Plan and, any contrary provision of the Plan notwithstanding, in all events subject to the limitations contained in Sections 404(a)(2) and 404(c) of ERISA, the terms of the Plan, and all other applicable limitations. The Investment Office shall have the following duties, responsibilities and rights:

(i) The Investment Office shall be the "named fiduciary" for purposes of designating the investment funds under Section 6.2 and for purposes of appointing one or more investment managers as described in ERISA.

(ii) The Investment Office shall be solely responsible for all matters involving investment of the Employer Stock Fund described in Section 6.2 and no other person shall have any responsibility with respect to investment of such fund; provided, however, that effective June 21, 2012, the Investment Office has appointed an independent investment manager under section 3(38) of ERISA to manage the investment of the Common Stock in the Company Common Stock Fund and such investment manager (rather than the Investment Office) shall be solely responsible for any and all investment decisions relating thereto.

(iii) Each Employer shall, from time to time, upon request of the Investment Office, furnish to the Investment Office such data and information as the Investment Office shall require in the performance of its duties.

10.1(d) The Corporate Investment Committee

The Company acting through the Corporate Investment Committee shall be responsible for overall monitoring of the performance of the Investment Office. The Corporate Investment Committee and the Company's Chief Investment Officer shall have the right at any time, with or without cause, to remove one or more employees of the Exelon Investment Office or to appoint another person or committee to act as Investment Office. Any successor Investment Office employee shall have all the rights, privileges and duties of the predecessor, but shall not be held accountable for the acts of the predecessor. The power and authority of the Corporate Investment Committee with respect to the Plan shall be limited solely to the monitoring and removal of the employees of the Investment Office and the Corporate Investment Committee shall have no other duties or responsibilities with respect to the Plan. None of the Company, any officer employee, or member of the board of directors who is not a member of the Corporate Investment Committee, nor any other person shall have any responsibility regarding the appointment or removal of the employees of Investment Office.

10.1(e) Status of Plan Administrator, the Investment Office and the Corporate Investment Committee

The Plan Administrator, any person acting as, or on behalf of, the Investment Office, and any member of the Corporate Investment Committee may, but need not, be an Employee, trustee or officer of an Employer and such status shall not disqualify such person from taking any action hereunder or render such person accountable for any distribution or other material advantage received by him or her under this Plan, provided that no Plan Administrator, person acting as, or on behalf of, the Investment Office, or any member of the Corporate Investment Committee who is a Participant shall take part in any action of the Plan Administrator or the Investment Office on any matter involving solely his or her rights under this Plan.

10.1(f) Notice to Trustee of Members

The Trustee shall be notified as to the names of the Plan Administrator and the person or persons authorized to act on behalf of the Investment Office.

10.1(g) Allocation of Responsibilities

Each of the Plan Administrator, the Investment Office and the Corporate Investment Committee may allocate their respective responsibilities and may designate any person, persons, partnership or corporation to carry out any of such responsibilities with respect to the Plan. Any such allocation or designation shall be reduced to writing and such writing shall be kept with the records of the Plan.

10.1(h) General Governance

The Corporate Investment Committee shall elect one of its members as chairman and appoint a secretary, who may or may not be a member of such Committee. All decisions of the Corporate Investment Committee shall be made by the majority, including actions taken by written consent. The Plan Administrator, the Investment Office and the Corporate Investment Committee may adopt such rules and procedures as it deems desirable for the conduct of its affairs, provided that any such rules and procedures shall be consistent with the provisions of the Plan.

10.1(i) Indemnification

The Employers hereby jointly and severally indemnify the Plan Administrator, the persons employed in the Exelon Investment Office, the members of the Corporate Investment Committee, the Chief Human Resources Officer, and the directors, officers and employees of the Employers and each of them, from the effects and consequences of their acts, omissions and conduct in their official capacity with respect to the Plan (including but not limited to judgments, attorney fees and costs with respect to any and all related claims, subject to the Company's notice of and right to direct any litigation, select any counsel or advisor, and approve any settlement), except to the extent that such effects and consequences result from their own willful misconduct. The foregoing indemnification shall be in addition to (and secondary to) such other rights such persons may enjoy as a matter of law or by reason of insurance coverage of any kind.

10.1(j) No Compensation

None of the Plan Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Plan Administrator, the Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Employer for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Plan Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

10.1(k) Employ of Counsel and Agents

The Plan Administrator, the Investment Office and the Corporate Investment Committee may employ such counsel (who may be counsel for an Employer) and agents and may arrange for such clerical and other services as each may require in carrying out its respective duties under the Plan.

10.2 Claims Procedure

Any Participant or distributee who believes he or she is entitled to benefits in an amount greater than those which he or she is receiving or has received may file a claim with the Plan Administrator. Such a claim shall be in writing and state the nature of the claim, the facts supporting the claim, the amount claimed, and the address of the claimant. The Plan Administrator shall review the claim and, unless special circumstances require an extension of time, within 90 days after receipt of the claim, give notice to the claimant, either in writing by registered or certified mail or in an electronic notification, of the Plan Administrator's decision with respect to the claim. Any electronic notice delivered to the claimant shall comply with the standards imposed by applicable Regulations. If the Plan Administrator determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 90-day period and in no event shall such an extension exceed 90 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Plan Administrator expects to render the benefit determination. The notice of the decision of the Plan Administrator with respect to the claim shall be written in a manner calculated to be understood by the claimant and, if the claim is wholly or partially denied, the Plan Administrator shall notify the claimant of the adverse benefit determination and shall set forth the specific reasons for the adverse determination, the references to the specific Plan provisions on which the determination is based, a description of any additional material or information necessary for the claimant to perfect the claim, an explanation of why such material or information

is necessary, and a description of the claim review procedure under the Plan and the time limits applicable to such procedures, including a statement of the claimant's right (subject to the limitations described in Sections 13.11 and 13.13) to bring a civil action under Section 502 of ERISA following an adverse benefit determination on review. The Plan Administrator shall also advise the claimant that the claimant or the claimant's duly authorized representative may request a review by the by the Vice President, Health & Benefits (or such other officer designated from time to time by the Chief Human Resources Officer) of the adverse benefit determination by filing with such officer, within 60 days after receipt of a notification of an adverse benefit determination, a written request for such review. The claimant shall be informed that, within the same 60-day period, he or she (a) may be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records and other information relevant to the claimant's claim for benefits and (b) may submit to such officer written comments, documents, records and other information relating to the claim for benefits. If a request is so filed, review of the adverse benefit determination shall be made by such officer within, unless special circumstances require an extension of time, 60 days after receipt of such request, and the claimant shall be given written notice of the officer's final decision. If the reviewing officer determines that special circumstances require an extension of time for processing the claim, the claimant shall be so advised in writing within the initial 60-day period and in no event shall such an extension exceed 60 days. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the officer expects to render the determination on review. The review of the officer shall take into account all comments, documents, records and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. The notice of the final decision shall include specific reasons for the determination and references to the specific Plan provisions on which the determination is based and shall be written in a manner calculated to be understood by the claimant.

14. By deleting paragraph 1 of current Section 10.6 (now renumbered 10.3), and replacing it in its entirety as follows:

Except as provided below (relating to expenses of various investments), all costs and expenses incurred in administering the Plan and the Trust, including, but not limited to, "direct expenses" incurred in administering the Plan and the Trust (including compensation paid to any employee of an Employer or an Affiliate who is engaged in the administration of the Plan or the Trust), the expenses of the Plan Administrator and the Investment Office, the fees of counsel and any agents for the Plan Administrator and the Investment Office, the fees and expenses of the Trustee, the fees of counsel for the Trustee and other administrative expenses shall, to the extent permitted by law, be paid from the Trust Fund to the extent such expenses are not paid by the Participating Employers. Notwithstanding the foregoing, the Plan Administrator may authorize

Employer to pay any expenses, and Employer shall be reimbursed from the Trust Fund for such payments. The Plan Administrator, in its discretion, having regard to the nature of a particular expense, shall determine the portion of the expense that is to be borne by each Participating Employer.

16. By deleting paragraph 5 of Section 10.6 (now renumbered 10.3) and replacing it in its entirety as follows:

None of the Plan Administrator, any person employed in the Exelon Investment Office nor any member of the Corporate Investment Committee may receive any compensation or fee from the Plan for services as the Plan Administrator, the Investment Office or a member of the Corporate Investment Committee; provided, however that nothing contained herein shall preclude the Plan from reimbursing the Company or any Employer for compensation paid to any such person if such compensation constitutes "direct expenses" for purposes of ERISA. The Employers shall reimburse the Plan Administrator, the persons employed in the Exelon Investment Office and the members of the Corporate Investment Committee for any reasonable expenditures incurred in the discharge of their duties hereunder.

17. By deleting the first five sentences of Section 12.1, and replacing them as follows:

The Company may at any time and from time to time amend or modify the Plan by resolution of the Board of Directors of the Company or the Compensation Committee thereof; provided , however, that in the case of any amendment or modification that would not result in an aggregate annual cost to the Company of more than $50,000,000, the Plan may be amended or modified by action of the Chief Human Resources Officer (with the consent of the Chief Executive Officer in the case of a discretionary amendment or modification expected to result in an increase in annual expense or liability account balance exceeding $250,000) or another executive officer holding title of equivalent or greater responsibility.

18. By adding the following sentence to the end of Section 13.2(b), as follows:

A Participant who submits a qualified domestic relations order for certification may be charged an order processing fee, as determined from time to time by the Plan Administrator, which will be deducted from the Participant's Plan account balance in the same manner set forth in Section 9.5.

19. By inserting new Sections 13.11, 13.12, and 13.13 as follows:

13.11 Statute of Limitations for Actions under the Plan

Except for actions to which the statute of limitations prescribed by Section 413 of ERISA applies, (a) no legal or equitable action relating to a claim for benefits under Section 502 of ERISA may be commenced later than one year after the claimant

receives a final decision from the Company's Vice President, Health & Benefits (or such other officer designated from time to time by the Chief Human Resources Officer) in response to the claimant's request for review of the adverse benefit determination and (b) no other legal or equitable action involving the Plan may be commenced later than two years from the time the person bringing an action knew, or had reason to know, of the circumstances giving rise to the action. This provision shall not be interpreted to extend any otherwise applicable statute of limitations, nor to bar the Plan or its fiduciaries from recovering overpayments of benefits or other amounts incorrectly paid to any person under the Plan at any time or bringing any legal or equitable action against any party.

13.12 Forum for Legal Actions under the Plan.

Any legal action involving the Plan that is brought by any Participant, any Beneficiary or any other person shall be litigated in the federal courts located in the District of Maryland.

13.13 Legal Fees.

Any award of legal fees in connection with an action involving the Plan shall be calculated pursuant to a method that results in the lowest amount of fees being paid, which amount shall be no more than the amount that is reasonable. In no event shall legal fees be awarded for work related to (a) administrative proceedings under the Plan, (b) unsuccessful claims brought by a Participant, Beneficiary or any other person, or (c) actions that are not brought under ERISA. In calculating any award of legal fees, there shall be no enhancement for the risk of contingency, nonpayment or any other risk nor shall there be applied a contingency multiplier or any other multiplier. In any action brought by a Participant, Beneficiary or any other person against the Plan, the Administrator, the Investment Office, the Vice President, Health & Benefits, any Plan fiduciary, the Chief Human Resources Officer, the Company, its affiliates or their respective officers, directors, employees, or agents (the "Plan Parties"), legal fees of the Plan Parties in connection with such action shall be paid by the Participant, Beneficiary or other person bringing the action, unless the court specifically finds that there was a reasonable basis for the action.

20. By deleting the definition set forth in Section Appendix A-1, and labeling it "Reserved," and deleting references to the "Administrative Committee" from Sections 13.1 and 13.5.

21. By deleting the definition set forth in Section Appendix A-17, and labeling it "Reserved."

22. By adding a new Section Appendix A-14(a), immediately after Appendix A-14, as follows:

14(a) "Corporate Investment Committee" means the Company acting through the Committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

23. By deleting the definition set forth Section Appendix A-28 and labeling it "Reserved," all deleting all references to the "Executive Group."

24. By adding a new section Appendix A-20(a), immediately after Appendix A-20, as follows:

20(a) "Effective Time" means the effective time of the transaction that is the subject of the Merger Agreement, as such term is defined in the Merger Agreement.

25. By adding a new section Appendix A-28(a), immediately after Appendix A-28, as follows:

28(a) "Exelon" means Exelon Corporation and any of its affiliates that was an affiliate immediately before the Effective Time.

26. By adding a new section Appendix A-34(a), immediately after Appendix A-34, as follows:

34(a) "Merger Agreement" means that Agreement and Plan of Merger, dated as of April 28, 2011, by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc.

27. By adding a sentence after the first sentence of section Appendix A-24, as follows:

Effective as of the Effective Time, Employee shall not include any person who was: (i) employed immediately prior to the Effective Time at Exelon or a facility owned immediately before the Effective Time by Exelon or (ii) initially employed on or after the Effective Time at a facility owned immediately before the Effective Time by Exelon.

28. By replacing section Appendix A-47 in its entirety as follows:

47 "Plan Administrator" means the Director, Employee Plans and Programs of Exelon (or the position succeeding to that function).

29. By deleting Section Appendix A-33 and replacing it with a new section Appendix A-33, as follows:

33 "Investment Office" mean the Company acting through the Exelon Investment Office.

30. By adding a new section Appendix A-14(a), as follows, and adding the word "Corporate" in front of the words "Investment Committee" in Sections 5.1(a)(3), 13.1 and 13.5:

14(a) "Corporate Investment Committee" means the Committee consisting of the executives or other persons designated from time to time in the charter of such Committee.

31. Effective January 1, 2013, by adding a new Section Appendix A-48(a), as follows:

48(a) "Profit Sharing Matching Contribution" means an amount (if any) determined by the Board of Directors of the Company (or the Compensation Committee thereof) in its sole discretion based on attainment of specified performance goals, and not exceeding one-half of each Participant's Basic Contribution.

32. Effective January 1, 2013, by adding a new section Appendix A-26(a), as follows:

26(a) "Employer Contribution" means the aggregate of Company Matching Contributions and Profit Sharing Matching Contributions.

33. By adding a sentence to the end of the footnote in Appendix C as follows:

Effective on and after January 1, 2013, bonuses indicated by an asterisk (*) payable in 2014 and thereafter shall no longer be Eligible Compensation.

34. By amending Appendix E to add the following:

(n) Exelon Business Services Corporation [1]

(o) Exelon Generation Company, LLC [2]

[1] For Employees who were Employees of Constellation Energy Group, Inc. immediately prior to the Effective Time.
[2] For Employees who were Employees of Constellation Energy Group, Inc. immediately prior to the Effective Time.

****

IN WITNESS WHEREOF , Exelon Corporation has caused this instrument to be executed by its Senior Vice President, Human Resources, on this ____day of December, 2012.

EXELON CORPORATION

Amy E. Best
Senior Vice President and
Chief Human Resource Officer

Exelon Corporation
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	4,418	4,221	3,952	1,798	2,773
Plus: Loss from equity investees	27	—	1	91	(10)
Less: Capitalized interest	(55)	(43)	(57)	(75)	(67)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	4,390	4,178	3,896	1,814	2,696
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	761	836	761	1,021	1,436
Interest component of rental expense (a)	230	241	237	310	269
Total fixed charges	991	1,077	998	1,331	1,705
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	5,381	5,255	4,894	3,145	4,401
Ratio of earnings to fixed charges	5.4	4.9	4.9	2.4	2.6

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exelon Corporation
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	4,418	4,221	3,952	1,798	2,773
Plus: Loss from equity investees	27	—	1	91	(10)
Less: Capitalized interest	(55)	(43)	(57)	(75)	(67)
Preference security dividend requirements	(7)	(7)	(6)	(26)	(32)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	4,383	4,171	3,890	1,788	2,664
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	761	836	761	1,021	1,436
Interest component of rental expense (a)	230	241	237	310	269
Preference security dividend requirements of consolidated subsidiaries	7	7	6	26	32
Total fixed charges	998	1,084	1,004	1,357	1,737
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	5,381	5,255	4,894	3,145	4,401
Ratio of earnings to fixed charges and preferred stock dividends	5.4	4.8	4.9	2.3	2.5

Exelon Generation Company, LLC
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	3,555	3,150	2,827	1,058	1,675
Plus: (Income) or loss from equity investees	3	—	1	91	(10)
Less: Capitalized interest	(49)	(38)	(49)	(67)	(54)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	3,509	3,112	2,779	1,082	1,611
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	162	191	219	402	445
Interest component of rental expense (a)	212	222	220	291	248
Total fixed charges	374	413	439	693	693
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	3,883	3,525	3,218	1,775	2,304
Ratio of earnings to combined fixed charges	10.4	8.5	7.3	2.6	3.3

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exhibit 12.3

Commonwealth Edison Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	602	693	666	618	401
Plus: Loss from equity investees	—	—	—	—	—
Less: Capitalized interest	(3)	(2)	(4)	(3)	(5)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	599	691	662	615	396
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness (a)	301	368	330	297	575
Interest component of rental expense (b)	7	6	6	6	5
Total fixed charges	308	374	336	303	580
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest plus fixed charges	907	1,065	998	918	976
Ratio of earnings to fixed charges	2.9	2.8	3.0	3.0	1.7

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.
(b) Includes interest expense of $294 million for the year ended December 31, 2013, related to the remeasurement of the like-kind exchange tax position. See Note 14 — Income taxes of the Exelon Form 10-K for the year ended December 31, 2013, for additional information regarding the like-kind exchange tax position.

PECO Energy Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	499	476	535	508	557
Plus: Loss from equity investees	24	—	—	—	—
Less: Capitalized interest	(2)	(4)	(4)	(2)	(2)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	521	472	531	506	555
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	185	193	135	122	114
Interest component of rental expense (a)	9	10	9	9	7
Total fixed charges	194	203	144	131	121
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	715	675	675	637	676
Ratio of earnings to combined fixed charges	3.7	3.3	4.7	4.9	5.6

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

PECO Energy Company
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
	2009	2010	2011	2012	2013
Pre-tax income from continuing operations	499	476	535	508	557
Plus: Loss from equity investees	24	—	—	—	—
Less: Capitalized interest	(2)	(4)	(4)	(2)	(2)
Preference security dividend requirements	(6)	(6)	(6)	(5)	(10)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	515	466	525	501	545
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	185	193	135	122	114
Interest component of rental expense (a)	9	10	9	9	7
Preference security dividend requirements	6	6	6	5	10
Total fixed charges	200	209	150	136	131
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	715	675	675	637	676
Ratio of earnings to fixed charges and preferred stock dividends	3.6	3.2	4.5	4.6	5.2

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exhibit 12.5

BGE
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2009	**2010**	**2011**	**2012**	**2013**
Pre-tax income from continuing operations	155	244	211	11	344
Less: Capitalized interest	(4)	(6)	(7)	(5)	(6)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	151	238	204	6	338
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	148	137	136	149	127
Interest component of rental expense (a)	5	4	5	4	4
Total fixed charges	153	141	141	153	131
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	304	379	345	159	469
Ratio of earnings to fixed charges	2.0	2.7	2.4	1.0	3.6

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

BGE
Ratio of Earnings to Fixed Charges and Preference Stock Dividends

	Years Ended December 31,				
	2009	**2010**	**2011**	**2012**	**2013**
Pre-tax income from continuing operations	155	244	211	11	344
Less: Capitalized interest	(4)	(6)	(7)	(5)	(6)
Preference security dividend requirements	(22)	(20)	(20)	(20)	(21)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	129	218	184	(14)	317
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	148	137	136	149	127
Interest component of rental expense (a)	5	4	5	4	4
Preference security dividend requirements	22	20	20	20	21
Total fixed charges	175	161	161	173	152
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	304	379	345	159	469
Ratio of earnings to fixed charges and preferred stock dividends	1.7	2.4	2.1	0.9(b)	3.1

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.
(b) The ratio coverage was less than 1:1. The registrant must generate additional earnings of $14 million to achieve a coverage ratio of 1:1.

Exelon Corporation

Name	Jurisdiction
A/C Fuels Company	Pennsylvania
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Alta Devices, Inc.	Delaware
APS Constellation, LLC	Delaware
Astrum, Inc.	Delaware
ATNP Finance Company	Delaware
AV Solar Ranch 1, LLC	Delaware
B & K Energy Systems, LLC	Minnesota
Baltimore Gas and Electric Company	Maryland
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bellevue Wind Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
BGE Capital Trust II	Delaware
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Breezy Bucks-I LLC	Minnesota
Breezy Bucks-II LLC	Minnesota
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
C3, LLC	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Canton Crossing District Energy LLC	Delaware
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CCG SynFuel, LLC	Delaware
CD Malacha I, Inc.	Maryland
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Central Wayne Energy Recovery Limited Partnership	Maryland
CE Colver I, Inc.	Maryland
CE Colver II, LLC	Delaware
CE Colver III, Inc.	Maryland
CE Colver Limited Partnership	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Long Valley I, Inc.	Maryland
CE Long Valley II, Inc.	Maryland
CE Long Valley Limited Partnership	Maryland
CE Nuclear, LLC	Delaware
CE Wayne I, Inc.	Maryland
CE Wayne II, Inc.	Maryland
CECG International Holdings, Inc.	Delaware
Central Wayne Energy Recovery Limited Partnership	Maryland
CER Generation II, LLC	Delaware
CER Generation, LLC	Delaware

CER-Colorado Bend Energy LLC	Delaware
CER-Colorado Bend Energy Partners LP	Delaware
CER-Quail Run Energy LLC	Delaware
CER-Quail Run Energy Partners LP	Delaware
CEU Arkoma West, LLC	Delaware
CEU CHC, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU Development, LLC	Delaware
CEU Eagle Ford, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Offshore I, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU Trenton, LLC	Delaware
CEU W&D, LLC	Delaware
Christoffer Transmission Systems, LLC	Minnesota
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Oldco, LLC	Maryland
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton NQF, LLC	Nevada
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
Cogenex Corporation	Massachusetts
CoLa Resources LLC	Delaware
ComEd Financing III	Delaware
Commonwealth Edison Company	Illinois
Commonwealth Edison Company of Indiana, Inc.	Indiana
Conemaugh Fuels, LLC	Delaware
Consert, Inc.	Delaware
Constellation Alliance II, LP	Texas
Constellation Alliance, LLC	Delaware
Constellation Bulk Energy Holdings, Inc.	Marshall Islands
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Limited	United Kingdom
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Control and Dispatch, LLC	Delaware
Constellation Energy Gas Choice, Inc.	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Partners Holdings, LLC	Delaware
Constellation Energy Power Choice, Inc.	Delaware

Constellation Energy Projects & Services Group Advisors, LLC	Delaware
Constellation Energy Projects and Services Canada, Inc.	Federal
Constellation Energy Resources, LLC	Delaware
Constellation Holdings, LLC	Maryland
Constellation International Holdings, Inc.	Marshall Islands
Constellation Investments, Inc.	Maryland
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy—Gas Division, LLC	Kentucky
Constellation NewEnergy Canada Inc.	Ontario
Constellation NewEnergy Holding, LLC	Delaware
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Operating Services	California
Constellation Operating Services, LLC	Maryland
Constellation Operating Services International	Grand Cayman
Constellation Operating Services International—I	Grand Cayman
Constellation Power International Development, Ltd	Grand Cayman
Constellation Power Source Generation, Inc.	Maryland
Constellation Power Source Generation, LLC	Maryland
Constellation Power, Inc.	Maryland
Constellation Sacramento Holding, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
COSI Ultra II, Inc.	Maryland
COSI Ultra, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP II Curacao Ltd	Grand Cayman
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CPI OldCo, Inc.	Maryland
CR Clearing, LLC	Missouri
Criterion Power Partners, LLC	Delaware
DAJAW Transmission LLC	Minnesota
Denver Airport Solar, LLC	Delaware
DL Windy Acres, LLC	Minnesota
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
Elbridge Wind Farm, LLC	Delaware

ENEH Services, LLC	Delaware
Energy Capital and Services II, Limited Partnership	Massachusetts
Energy Performance Services, Inc.	Pennsylvania
ETT Canada, Inc.	New Brunswick
Ewington Energy Systems LLC	Minnesota
Exelon AOG Holding #1, Inc.	Delaware
Exelon AOG Holding #2, Inc	Delaware
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Business Services Company, LLC	Delaware
Exelon Capital Trust I	Delaware
Exelon Capital Trust II	Delaware
Exelon Capital Trust III	Delaware
Exelon Corporation	Pennsylvania
Exelon Edgar	Delaware
Exelon Energy Delivery Company, LLC	Delaware
Exelon Enterprises Company, LLC	Pennsylvania
Exelon Framingham Development, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, Inc.	Pennsylvania
Exelon Hamilton LLC	Delaware
Exelon Investment Holdings, LLC	Illinois
Exelon Mechanical, LLC	Delaware
Exelon New Boston, LLC	Delaware
Exelon New England Development, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon Peaker Development General, LLC	Delaware
Exelon Peaker Development Limited, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon SHC, LLC	Delaware
Exelon Solar Chicago LLC	Delaware
Exelon Transmission Company, LLC	Delaware
Exelon Ventures Company, LLC	Delaware
Exelon West Medway Development, LLC	Delaware
Exelon West Medway Expansion, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
Ex-FM, Inc.	New York
Ex-FME, Inc.	Delaware
ExGen Renewables I Holding, LLC	Delaware

ExGen Renewables I, LLC	Delaware
ExTel Corporation, LLC	Delaware
ExTex LaPorte Limited Partnership	Texas
F & M Holdings Company, L.L.C.	Delaware
Fair Wind Power Partners, LLC	Delaware
FloDesign	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
Fuel Recovery, Inc.	Pennsylvania
G-Flow Wind, LLC	Minnesota
Grande Prairie Generation, Inc.	Alberta
Green Acres Breeze, LLC	Minnesota
Greensburg Wind Farm, LLC	Delaware
Guatemalan Generating Group—I	Grand Cayman
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho
Inter-Power/Ahlcon Partners Limited Partnership	Delaware
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
Keystone Fuels, LLC	Delaware
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
Las Vegas District Energy, LLC	Delaware
Latin American Power Partners Limited	Grand Cayman
Lilly Recovery, Inc.	Pennsylvania
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Low Country Synfuel Holdings, LLC	Delaware
Luz Solar Partners Ltd., IV	California
Luz Solar Partners Ltd., V	California
Luz Solar Partners Ltd., VI	California
Malcha Hydro Limited Partnership	Maryland
Maple Coal Company	Pennsylvania
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Minnesota Breeze, LLC	Minnesota
Mountain Top Wind Power, LLC	Maryland
MXENERGY (CANADA) LTD.	Nova Scotia
MxEnergy Holdings Inc.	Delaware
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Northwind Thermal Technologies Canada Inc.	New Brunswick
Old Hickory District Energy, LLC	Delaware
OMF 11520, LLC	Delaware
Oregon Trail Windfarm, LLC	Oregon

Outback Solar, LLC	Oregon
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Palmetto Synfuel Operating Company, LLC	Delaware
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital Trust V	Delaware
PECO Energy Capital Trust VI	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Company	Pennsylvania
PECO Wireless, LLC	Delaware
Pegasus Power Company, Inc.	California
Pegasus Power Partners, a California Limited Partnership	California
Pinedale Energy, LLC	Colorado
Prairie Wind Power LLC	Minnesota
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Residential Solar Holding, LLC	Delaware
Residential Solar I, LLC	Delaware
Residential Solar II, LLC	Delaware
Residential Solar III, LLC	Delaware
RF HoldCo LLC	Delaware
RITELine Illinois, LLC	Illinois
RITELine Indiana, LLC	Indiana
RITELine Transmission Development, LLC	Delaware
River Bend I, L.L.C.	Delaware
Roadrunner-I LLC	Minnesota
RSB BondCo LLC	Delaware
S & P Windfarms, LLC	Minnesota
Sacramento PV Energy, LLC	Delaware
Safe Harbor Water Power Corporation	Pennsylvania
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Salty Dog-I LLC	Minnesota
Salty Dog-II LLC	Minnesota
Sand Ranch Windfarm, LLC	Oregon
Scherer Holdings 1, LLC	Delaware
Scherer Holdings 2, LLC	Delaware
Scherer Holdings 3, LLC	Delaware
Shane’s Wind Machine LLC	Minnesota
Shooting Star Wind Project, LLC	Delaware
Simmons & Eastern, LLC	Delaware
Spruce Equity Holdings, L.P.	Delaware
Spruce Holdings G.P. 2000, L.L.C.	Delaware
Spruce Holdings L.P. 2000, L.L.C.	Delaware
Spruce Holdings Trust	Delaware
Star Electricity, Inc.	Texas
Sunbelt I, L.L.C.	Delaware
Sunnyside Cogeneration Associates	Utah
Sunnyside Generation, LLC	Delaware

Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Sunnyside Properties, LLC	Utah
Sunset Breeze, LLC	Minnesota
Tamuin International, Inc.	Delaware
TEG Holdings, LLC	Delaware
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware
TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
UII, LLC	Illinois
W&D Gas Partners, LLC	Delaware
Wagon Trail, LLC	Oregon
Wally's Wind Farm LLC	Minnesota
Wansley Holdings 1, LLC	Delaware
Wansley Holdings 2, LLC	Delaware
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Windy Dog-1 LLC	Minnesota
Wolf Hollow I, L.P.	Delaware
Wolf Wind Enterprises, LLC	Minnesota
Wolf Wind Transmission, LLC	Minnesota
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Exelon Generation Company, LLC

Name	Jurisdiction
A/C Fuels Company	Pennsylvania
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Alta Devices, Inc.	Delaware
APS Constellation, LLC	Delaware
Astrum, Inc.	Delaware
AV Solar Ranch 1, LLC	Delaware
B & K Energy Systems, LLC	Minnesota
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bellevue Wind Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Breezy Bucks-I LLC	Minnesota
Breezy Bucks-II LLC	Minnesota
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
C3, LLC	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Canton Crossing District Energy LLC	Delaware
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CCG SynFuel, LLC	Delaware
CD Malacha I, Inc.	Maryland
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Central Wayne Energy Recovery Limited Partnership	Maryland
CE Colver I, Inc.	Maryland
CE Colver II, LLC	Delaware
CE Colver III, Inc.	Maryland
CE Colver Limited Partnership	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Long Valley I, Inc.	Maryland
CE Long Valley II, Inc.	Maryland
CE Long Valley Limited Partnership	Maryland
CE Nuclear, LLC	Delaware
CE Wayne I, Inc.	Maryland
CE Wayne II, Inc.	Maryland
CECG International Holdings, Inc.	Delaware
Central Wayne Energy Recovery Limited Partnership	Maryland
CER Generation II, LLC	Delaware
CER Generation, LLC	Delaware
CER-Colorado Bend Energy LLC	Delaware
CER-Colorado Bend Energy Partners LP	Delaware
CER-Quail Run Energy LLC	Delaware
CER-Quail Run Energy Partners LP	Delaware

CEU Arkoma West, LLC	Delaware
CEU CHC, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU Development, LLC	Delaware
CEU Eagle Ford, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Offshore I, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU Trenton, LLC	Delaware
CEU W&D, LLC	Delaware
Christoffer Transmission Systems, LLC	Minnesota
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Oldco, LLC	Maryland
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton NQF, LLC	Nevada
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
Cogenex Corporation	Massachusetts
CoLa Resources LLC	Delaware
Conemaugh Fuels, LLC	Delaware
Consert, Inc.	Delaware
Constellation Alliance II, LP	Texas
Constellation Alliance, LLC	Delaware
Constellation Bulk Energy Holdings, Inc.	Marshall Islands
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Limited	United Kingdom
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Control and Dispatch, LLC	Delaware
Constellation Energy Gas Choice, Inc.	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Partners Holdings, LLC	Delaware
Constellation Energy Power Choice, Inc.	Delaware
Constellation Energy Projects & Services Group Advisors, LLC	Delaware
Constellation Energy Projects and Services Canada, Inc.	Federal
Constellation Energy Resources, LLC	Delaware
Constellation Holdings, LLC	Maryland
Constellation International Holdings, Inc.	Marshall Islands
Constellation Investments, Inc.	Maryland
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy—Gas Division, LLC	Kentucky

Constellation NewEnergy Canada Inc.	Ontario
Constellation NewEnergy Holding, LLC	Delaware
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Operating Services	California
Constellation Operating Services, LLC	Maryland
Constellation Operating Services International	Grand Cayman
Constellation Operating Services International—I	Grand Cayman
Constellation Power International Development, Ltd	Grand Cayman
Constellation Power Source Generation, Inc.	Maryland
Constellation Power Source Generation, LLC	Maryland
Constellation Power, Inc.	Maryland
Constellation Sacramento Holding, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
COSI Ultra II, Inc.	Maryland
COSI Ultra, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP II Curacao Ltd	Grand Cayman
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CPI OldCo, Inc.	Maryland
CR Clearing, LLC	Missouri
Criterion Power Partners, LLC	Delaware
DAJAW Transmission LLC	Minnesota
Denver Airport Solar, LLC	Delaware
DL Windy Acres, LLC	Minnesota
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
Elbridge Wind Farm, LLC	Delaware
ENEH Services, LLC	Delaware
Energy Capital and Services II, Limited Partnership	Massachusetts
Energy Performance Services, Inc.	Pennsylvania
Ewington Energy Systems LLC	Minnesota
Exelon AOG Holding #1, Inc.	Delaware
Exelon AOG Holding #2, Inc	Delaware

Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Edgar	Delaware
Exelon Framingham Development, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, Inc.	Pennsylvania
Exelon Hamilton LLC	Delaware
Exelon New Boston, LLC	Delaware
Exelon New England Development, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon Peaker Development General, LLC	Delaware
Exelon Peaker Development Limited, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon SHC, LLC	Delaware
Exelon Solar Chicago LLC	Delaware
Exelon West Medway Development, LLC	Delaware
Exelon West Medway Expansion, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
ExGen Renewables I Holding, LLC	Delaware
ExGen Renewables I, LLC	Delaware
ExTex LaPorte Limited Partnership	Texas
Fair Wind Power Partners, LLC	Delaware
FloDesign	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
Fuel Recovery, Inc.	Pennsylvania
G-Flow Wind, LLC	Minnesota
Grande Prairie Generation, Inc.	Alberta
Green Acres Breeze, LLC	Minnesota
Greensburg Wind Farm, LLC	Delaware
Guatemalan Generating Group—I	Grand Cayman
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho

Inter-Power/Ahlcon Partners Limited Partnership	Delaware
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
Keystone Fuels, LLC	Delaware
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
Las Vegas District Energy, LLC	Delaware
Latin American Power Partners Limited	Grand Cayman
Lilly Recovery, Inc.	Pennsylvania
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Low Country Synfuel Holdings, LLC	Delaware
Luz Solar Partners Ltd., IV	California
Luz Solar Partners Ltd., V	California
Luz Solar Partners Ltd., VI	California
Malcha Hydro Limited Partnership	Maryland
Maple Coal Company	Pennsylvania
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Minnesota Breeze, LLC	Minnesota
Mountain Top Wind Power, LLC	Maryland
MXENERGY (CANADA) LTD.	Nova Scotia
MxEnergy Holdings Inc.	Delaware
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Old Hickory District Energy, LLC	Delaware
Oregon Trail Windfarm, LLC	Oregon
Outback Solar, LLC	Oregon
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Palmetto Synfuel Operating Company, LLC	Delaware
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada
Pegasus Power Company, Inc.	California
Pegasus Power Partners, a California Limited Partnership	California
Pinedale Energy, LLC	Colorado
Prairie Wind Power LLC	Minnesota
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Residential Solar Holding, LLC	Delaware
Residential Solar I, LLC	Delaware
Residential Solar II, LLC	Delaware
Residential Solar III, LLC	Delaware
River Bend I, L.L.C.	Delaware
Roadrunner-I LLC	Minnesota
S & P Windfarms, LLC	Minnesota

Sacramento PV Energy, LLC	Delaware
Safe Harbor Water Power Corporation	Pennsylvania
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Salty Dog-I LLC	Minnesota
Salty Dog-II LLC	Minnesota
Sand Ranch Windfarm, LLC	Oregon
Shane's Wind Machine LLC	Minnesota
Shooting Star Wind Project, LLC	Delaware
Simmons & Eastern, LLC	Delaware
Star Electricity, Inc.	Texas
Sunbelt I, L.L.C.	Delaware
Sunnyside Cogeneration Associates	Utah
Sunnyside Generation, LLC	Delaware
Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Sunnyside Properties, LLC	Utah
Sunset Breeze, LLC	Minnesota
Tamuin International, Inc.	Delaware
TEG Holdings, LLC	Delaware
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware
TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
W&D Gas Partners, LLC	Delaware
Wagon Trail, LLC	Oregon
Wally's Wind Farm LLC	Minnesota
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Windy Dog-1 LLC	Minnesota
Wolf Hollow I, L.P.	Delaware
Wolf Wind Enterprises, LLC	Minnesota
Wolf Wind Transmission, LLC	Minnesota
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Commonwealth Edison Company

Name	Jurisdiction
ComEd Financing III	Delaware
Commonwealth Edison Company	Illinois
Commonwealth Edison Company of Indiana, Inc.	Indiana
RITELine Illinois, LLC	Illinois

PECO Energy Company

Name	Jurisdiction
ATNP Finance Company	Delaware
ExTel Corporation, LLC	Delaware
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital Trust V	Delaware
PECO Energy Capital Trust VI	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Company	Pennsylvania
PECO Wireless, LLC	Delaware

Baltimore Gas and Electric Company

Name	Jurisdiction
Baltimore Gas and Electric Company	Maryland
BGE Capital Trust II	Delaware
RSB BondCo LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No.333-181749 and No. 333-183751), on Form S-4 (No.333-175162) and on Form S-8 (No.333-189849, No.333-175162, No.333-127377, No.333-37082 and No.333-49780) of Exelon Corporation of our report dated February 13, 2014 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting of Exelon Corporation, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2014

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-181749-05) and Form S-4 (No. 333-184712) of Exelon Generation Company, LLC of our report dated February 13, 2014 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Exelon Generation Company, LLC, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2014

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-181749-04) of Commonwealth Edison Company of our report dated February 13, 2014 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Commonwealth Edison Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2014

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-181749-03) of PECO Energy Company of our report dated February 13, 2014 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of PECO Energy Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 13, 2014

Exhibit 23.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-181749-09) of Baltimore Gas and Electric Company of our report dated February 13, 2014 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Baltimore Gas and Electric Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2014

Exhibit 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anthony K. Anderson** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Anthony K. Anderson
Anthony K. Anderson

DATE: February 3, 2014

Exhibit 24.2

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ann C. Berzin
Ann C. Berzin

DATE: February 7, 2014

Exhibit 24.3

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John A. Canning, Jr.** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John A. Canning, Jr

John A. Canning, Jr.

DATE: February 3, 2014

Exhibit 24.4

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Darryl M. Bradford attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 6, 2014

Exhibit 24.5

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Yves C. de Balmann** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Yves C. de Balmann

Yves C. de Balmann

DATE: February 1, 2014

Exhibit 24.6

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis
Nicholas DeBenedictis

DATE: February 7, 2014

Exhibit 24.7

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nelson A. Diaz** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nelson A. Diaz
Nelson A. Diaz

DATE: February 3, 2014

Exhibit 24.8

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Sue L. Gin** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Sue L. Gin
Sue L. Gin

DATE: February 10, 2014

Exhibit 24.9

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Paul Joskow** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Paul Joskow
Paul Joskow

DATE: February 8, 2014

Exhibit 24.10

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Robert J. Lawless** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Robert J. Lawless
Robert J. Lawless

DATE: February 2, 2014

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Richard W. Mies** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Richard W. Mies
Richard W. Mies

DATE: February 10, 2014

Exhibit 24.12

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **William C. Richardson** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ William C. Richardson
William C. Richardson

DATE: February 2, 2014

Exhibit 24.13

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John W. Rogers, Jr.** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John W. Rogers, Jr.
John W. Rogers, Jr.

DATE: February 3, 2014

Exhibit 24.14

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Mayo A. Shattuck III** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Mayo A. Shattuck III

Mayo A. Shattuck III

DATE: February 5, 2014

Exhibit 24.15

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Stephen D. Steinour** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Stephen D. Steinour
Stephen D. Steinour

DATE: February 10, 2014

Exhibit 24.16

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James W. Compton** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ James W. Compton
James W. Compton

DATE: February 10, 2014

Exhibit 24.17

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 6, 2014

Exhibit 24.18

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **A. Steven Crown** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ A. Steven Crown

A. Steven Crown

DATE: February 3, 2014

Exhibit 24.19

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis
Nicholas DeBenedictis

DATE: February 7, 2014

Exhibit 24.20

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Peter V. Fazio, Jr.** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Peter V. Fazio, Jr.
Peter V. Fazio, Jr.

DATE: February 1, 2014

Exhibit 24.21

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Sue L. Gin** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Sue L. Gin
Sue L. Gin

DATE: February 10, 2014

Exhibit 24.22

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael H. Moskow** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael H. Moskow
Michael H. Moskow

DATE: February 3, 2014

Exhibit 24.23

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien
Denis P. O'Brien

DATE: February 4, 2014

Exhibit 24.24

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anne R. Pramaggiore** , do hereby appoint Thomas S. O'Neill attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Anne R. Pramaggiore
Anne R. Pramaggiore

DATE: January 31, 2014

Exhibit 24.25

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Jesse H. Ruiz** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Jesse H. Ruiz

Jesse H. Ruiz

DATE: February 10, 2014

Exhibit 24.26

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Craig L. Adams** , do hereby appoint Romulo L. Diaz, Jr. attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Craig L. Adams
Craig L. Adams

DATE: February 1, 2014

Exhibit 24.27

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 6, 2014

Exhibit 24.28

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **M. Walter D'Alessio** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ M. Walter D'Alessio
M. Walter D'Alessio

DATE: February 3, 2014

Exhibit 24.29

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis
Nicholas DeBenedictis

DATE: February 7, 2014

Exhibit 24.30

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nelson A. Diaz** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nelson A. Diaz
Nelson A. Diaz

DATE: February 3, 2014

Exhibit 24.31

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Rosemarie B. Greco** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Rosemarie B. Greco

Rosemarie B. Greco

DATE: February 8, 2014

Exhibit 24.32

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Charisse R. Lillie** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Charisse R. Lillie
Charisse R. Lillie

DATE: February 1, 2014

Exhibit 24.33

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien
Denis P. O'Brien

DATE: February 4, 2014

Exhibit 24.34

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ronald Rubin** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ronald Rubin
Ronald Rubin

DATE: February 3, 2014

Exhibit 24.35

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ann C. Berzin

Ann C. Berzin

DATE: February 7, 2014

Exhibit 24.36

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 6, 2014

Exhibit 24.37

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael E. Cryor** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael E. Cryor
Michael E. Cryor

DATE: February 4, 2014

Exhibit 24.38

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James R. Curtiss** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ James R. Curtiss

James R. Curtiss

DATE: February 4, 2014

Exhibit 24.39

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Kenneth W. DeFontes, Jr.** , do hereby appoint Daniel P. Gahagan attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Kenneth W. DeFontes, Jr.
Kenneth W. DeFontes, Jr.

DATE: February 3, 2014

Exhibit 24.40

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Joseph Haskins, Jr.** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Joseph Haskins, Jr.
Joseph Haskins, Jr.

DATE: February 3, 2014

Exhibit 24.41

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Carla D. Hayden** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Carla D. Hayden
Carla D. Hayden

DATE: February 6, 2014

Exhibit 24.42

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Kenneth W. DeFontes, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2013 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien
Denis P. O'Brien

DATE: February 4, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ C HRISTOPHER M. C RANE
President and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ J ONATHAN W. T HAYER
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ K ENNETH W. C ORNEW
President
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ B RYAN P. W RIGHT
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ Anne R. Pramaggiore
President and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ JOSEPH R. TRPIK, JR.
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ C RAIG L. A DAMS
Chief Executive Officer and President
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ P HILLIP S. B ARNETT
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. DeFontes Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ KENNETH W. DEFONTES JR.
Chief Executive Officer and President
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Carim V. Khouzami, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ C ARIM V. K HOUZAMI
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

Date: February 13, 2014

/s/ Christopher M. Crane

Christopher M. Crane
President and Chief Executive Officer

Exhibit 32-2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

Date: February 13, 2014

/s/ J ONATHAN W. T HAYER

Jonathan W. Thayer
Executive Vice President and Chief Financial Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

Date: February 13, 2014

/s/ K ENNETH W. C ORNEW

Kenneth W. Cornew
President

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

Date: February 13, 2014

/s/ B RYAN P. W RIGHT

Bryan P. Wright
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

Date: February 13, 2014

/s/ ANNE R. PRAMAGGIORE

Anne R. Pramaggiore
President and Chief Executive Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

Date: February 13, 2014

/s/ J OSEPH R. T RPIK , J R .

Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

Date: February 13, 2014

/s/ C RAIG L. A DAMS

Craig L. Adams
Chief Executive Officer and President

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

Date: February 13, 2014

/s/ P HILLIP S. B ARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

Date: February 13, 2014

/s/ K ENNETH W. D EFONTES J R .
Kenneth W. DeFontes Jr.
Chief Executive Officer and President

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

Date: February 13, 2014

/s/ C ARIM V. K HOUZAMI

Carim V. Khouzami
Senior Vice President, Chief Financial Officer and Treasurer

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2014

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number	Exact Name of Registrant as Specified in its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
EXELON CORPORATION:	
Common Stock, without par value	New York and Chicago
Series A Junior Subordinated Debentures	New York
Corporate Units	New York
PECO ENERGY COMPANY:	
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York
BALTIMORE GAS AND ELECTRIC COMPANY:	
6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, by Baltimore Gas and Electric Company	New York

Securities registered pursuant to Section 12(g) of the Act:

COMMONWEALTH EDISON COMPANY:
Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes ☒	No ☐
Exelon Generation Company, LLC	Yes ☒	No ☐
Commonwealth Edison Company	Yes ☒	No ☐
PECO Energy Company	Yes ☒	No ☐
Baltimore Gas and Electric Company	Yes ☒	No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

	Large Accelerated	Accelerated	Non-Accelerated	Small Reporting Company
Exelon Corporation	✓			
Exelon Generation Company, LLC			✓	
Commonwealth Edison Company			✓	
PECO Energy Company			✓	
Baltimore Gas and Electric Company			✓	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2014 was as follows:

Exelon Corporation Common Stock, without par value	$31,319,710,373
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None
Baltimore Gas and Electric Company, without par value	None

The number of shares outstanding of each registrant's common stock as of January 31, 2015 was as follows:

Exelon Corporation Common Stock, without par value	859,833,343
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,950
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company, without par value	1,000

S1-SSA-0009-14075

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2015 Annual Meeting of Shareholders and the Commonwealth Edison Company 2015 information statement are incorporated by reference in Part III.

Exelon Generation Company, LLC, PECO Energy Company and Baltimore Gas and Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form in the reduced disclosure format.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon's holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Antelope Valley, AVSR	Antelope Valley Solar Ranch One
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
ComEd Financing III	ComEd Financing III
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Energy Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
BGE Trust II	BGE Capital Trust II
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively

Other Terms and Abbreviations

1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended

Other Terms and Abbreviations

CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
DC Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA
EE&C	Energy Efficiency and Conservation/Demand Response
EGR	ExGen Renewables I, LLC
EGS	Electric Generation Supplier
EGTP	ExGen Texas Power, LLC
EIMA	Illinois Energy Infrastructure Modernization Act
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
Integrys	Integrys Energy Services, Inc.
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service

Other Terms and Abbreviations

ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste
LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Standard Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting including the CENG units (Calvert Cliffs, Nine Mile Point, and R.E. Ginna),Clinton, Oyster Creek, Three Mile Island, Zion (a former ComEd unit), and portions of Peach Bottom (a former PECO unit)
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort

Other Terms and Abbreviations

POR	Purchase of Receivables
PPA	Power Purchase Agreement
PPL	PPL Holtwood, LLC
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting including the former ComEd units (Braidwood, Byron, Dresden, LaSalle, Quad Cities) and the former PECO units (Limerick, Peach Bottom, Salem)
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOA	Society of Actuaries
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
Upstream	Natural gas and oil exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by the Registrants. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

This Report contains certain forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a Registrants include those factors discussed herein, including those factors discussed with respect to such Registrant discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; and (d) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants' websites at www.exeloncorp.com. Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I

ITEM 1. BUSINESS

General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through Generation, in the energy generation business, and through ComEd, PECO and BGE, in the energy delivery businesses discussed below. Exelon's principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603, and its telephone number is 312-394-7398.

Generation

Generation's integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream). Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions.

Generation was formed in 2000 as a Pennsylvania limited liability company. Generation began operations as a result of a corporate restructuring, effective January 1, 2001, in which Exelon separated its generation and other competitive businesses from its regulated energy delivery businesses at ComEd and PECO.

Generation's principal executive offices are located at 300 Exelon Way, Kennett Square, Pennsylvania 19348, and its telephone number is 610-765-5959.

ComEd

ComEd's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in northern Illinois, including the City of Chicago.

ComEd was organized in the State of Illinois in 1913 as a result of the merger of Cosmopolitan Electric Company into the original corporation named Commonwealth Edison Company, which was incorporated in 1907. ComEd's principal executive offices are located at 440 South LaSalle Street, Chicago, Illinois 60605, and its telephone number is 312-394-4321.

PECO

PECO's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia.

PECO was incorporated in Pennsylvania in 1929. PECO's principal executive offices are located at 2301 Market Street, Philadelphia, Pennsylvania 19103, and its telephone number is 215-841-4000.

BGE

BGE's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in central Maryland, including the City of Baltimore.

BGE was incorporated in Maryland in 1906. BGE's principal executive offices are located at 110 West Fayette Street, Baltimore, Maryland 21201, and its telephone number is 410-234-5000.

Operating Segments

See Note 24—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's operating segments.

Pending Merger with Pepco Holdings, Inc.

On April 29, 2014, Exelon and PHI signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. The merger is expected to be completed in the second or third quarter of 2015. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the pending transaction.

Generation

Generation, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Constellation sells electricity and natural gas to both wholesale and retail customers. The retail sales include commercial, industrial and residential customers. Generation's electricity generation strategy is to pursue opportunities that provide generation-to-load matching and that diversify the generation fleet by expanding Generation's regional and technological footprint. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Generation's fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the challenging conditions emanating from competitive energy markets. Generation's customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream).

Generation is a public utility under the Federal Power Act and is subject to FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. FERC's jurisdiction over ratemaking also includes the authority to suspend the market-based rates of utilities and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are

not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities. Additionally, ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. Specific operations of Generation are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including the NRC and Federal and state environmental protection agencies. Additionally, Generation is subject to mandatory reliability standards promulgated by the NERC, with the approval of FERC.

RTOs and ISOs exist in a number of regions to provide transmission service across multiple transmission systems. PJM, MISO, ISO-NE and SPP, have been approved by FERC as RTOs, and CAISO and ISO-NY have been approved as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems.

Merger with Constellation Energy Group, Inc.

On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger. Since the merger transaction, Generation includes the former Constellation generation and customer supply operations. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the Constellation merger.

Constellation Energy Nuclear Group, Inc.

Generation owns a 50.01% interest in CENG, a joint venture with EDF. CENG is governed by a board of ten directors, five of which are appointed by Generation and five by EDF. CENG owns a total of five nuclear generating facilities on three sites, Calvert Cliffs, R.E. Ginna and Nine Mile Point. CENG's ownership share in the total capacity of these units is 3,998 MW. See ITEM 2. PROPERTIES for additional information on these sites.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interest in CENG at fair value on Exelon's and Generation's Consolidated Balance Sheets. Refer to Note 5—Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for further information regarding the integration transaction.

Significant Acquisitions

Integrys Energy Services, Inc. On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (Integrys) for a purchase price of $332 million, including net working capital. The generation and solar asset businesses of Integrys are excluded from the transaction. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the above acquisition.

Antelope Valley Solar Ranch One. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 242-MW solar project under development in northern Los Angeles County, California, from First Solar, Inc. The facility became fully operational in 2014. The project has a 25-year PPA with Pacific Gas & Electric Company for the full output of the plant, which has been approved by the CPUC. Total capitalized costs for the facility incurred as of December 31, 2014 were approximately $1.1 billion.

Wolf Hollow Generating Station. On August 24, 2011, Generation completed the acquisition of all of the equity interests of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, for a purchase price of $311 million which increased Generation's owned capacity within the ERCOT power market by 704 MWs.

Significant Dispositions

Asset Divestitures. As of December 31, 2014, Generation sold or entered into agreements to divest certain generating assets with total expected pre-tax proceeds of $1.8 billion (after-tax proceeds of approximately $1.4 billion). The proceeds are expected to be used primarily to finance a portion of the acquisition of PHI.

Maryland Clean Coal Stations. On November 30, 2012, a subsidiary of Generation sold the Brandon Shores generating station and H.A. Wagner generating station in Anne Arundel County, Maryland, and the C.P. Crane generating station in Baltimore County, Maryland to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC to comply with certain of the regulatory approvals required by the merger with Constellation Energy Group, Inc. for net proceeds of approximately $371 million, which resulted in a pre-tax impairment charge of $272 million.

See Note 4—Mergers, Acquisitions, and Dispositions and Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Generating Resources

At December 31, 2014, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [a][b]	
Nuclear	19,316
Fossil [c]	9,515
Renewable [d]	3,434
Owned generation assets	32,265
Long-term power purchase contracts	9,574
Total generating resources	41,839

(a) See "Fuel" for sources of fuels used in electric generation.
(b) Net generation capacity is stated at proportionate ownership share. See ITEM 2. PROPERTIES—Generation for additional information.
(c) Comprised primarily of natural gas generating assets. Excludes Quail Run, which was sold on January 21, 2015.
(d) Includes hydroelectric, wind, and solar generating assets.

Generation has six reportable segments, the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions, representing the different geographical areas in which Generation's customer-facing activities are conducted and where Generation's generating resources are located.

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina (approximately 35% of capacity).

- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee; and the United States footprint of MISO (excluding MISO's Southern Region), which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, and the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM; and parts of Montana, Missouri and Kentucky (approximately 38% of capacity).
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 7% of capacity).
- New York represents the operations within ISO-NY, which covers the state of New York in its entirety (approximately 3% of capacity).
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas (approximately 11% of capacity).
- Other Regions is an aggregate of regions not considered individually significant (approximately 6% of capacity).

See Note 24—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers and revenues net of purchased power and fuel expense for each of Generation's reportable segments.

Nuclear Facilities

Generation has ownership interests in fourteen nuclear generating stations currently in service, consisting of 24 units with an aggregate of 19,316 MW of capacity. Generation wholly owns all of its nuclear generating stations, except for Quad Cities Generating Station (75% ownership), Peach Bottom Generating Station (50% ownership), and Salem Generating Station (Salem) (42.59% ownership), which are consolidated on Exelon's and Generation's financial statements relative to its proportionate ownership interest in each unit. In addition, Generation owns a 50.01% interest, collectively, in the CENG generating stations (Calvert Cliff Nuclear Power Plant, Nine Mile Point Nuclear Station [excluding LIPA's 18% ownership interest in Nine Mile Point Unit 2] and R.E. Ginna) which are 100% consolidated on Exelon and Generation's financial statements as of April 1, 2014. See Note 5—Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's nuclear generating stations are all operated by Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. In 2014, 2013, and 2012 electric supply (in GWh) generated from the nuclear generating facilities was 67%, 57% and 53%, respectively, of Generation's total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation's electric supply sources.

Nuclear Operations. Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on Generation's results of operations. As the largest generator of nuclear power in the United States, Generation can negotiate favorable terms for the materials and services that its business requires. Generation's operations from its nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

During 2014 and 2013, the nuclear generating facilities operated by Generation achieved capacity factors of 94.3% and 94.1%, respectively. The capacity factors reflect ownership percentage of stations operated by Generation and include CENG as of April 1, 2014. Generation manages its scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for Generation's wholesale and retail marketing and trading activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations.

In addition to the rigorous maintenance and equipment upgrades performed by Generation during scheduled refueling outages, Generation has extensive operating and security procedures in place to ensure the safe operation of the nuclear units. Generation has extensive safety systems in place to protect the plant, personnel and surrounding area in the unlikely event of an accident.

Regulation of Nuclear Power Generation. Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of December 31, 2014, the NRC categorized Calvert Cliffs unit 2, Clinton, Limerick units 1 and 2, and Oyster Creek in the Regulatory Response Column, which is the second highest of five performance bands. All other units operated by Generation are categorized in the Licensee Response Column as of December 31, 2014, which is the highest performance band. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. For additional information on the NRC actions related to the Japan Earthquake and Tsunami and the industry's response, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Executive Overview.

Licenses **.** Generation has 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals for Peach Bottom Units 2 and 3, Dresden Units 2 and 3, Quad Cities Units 1 and 2, Oyster Creek Unit 1, Calvert Cliffs Units 1 and 2, Nine Mile Point Units 1 and 2, R.E. Ginna Unit 1, Three Mile Island Unit 1 and Limerick Units 1 and 2. Additionally, PSEG has 40-year operating licenses from the NRC and has received 20-year operating license renewals for Salem Units 1 and 2. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. The following table summarizes the current operating license expiration dates for Generation's nuclear facilities in service:

Station	Unit	In-Service Date [(a)]	Current License Expiration
Braidwood [(b)]	1	1988	2026
	2	1988	2027
Byron [(b)]	1	1985	2024
	2	1987	2026
Calvert Cliffs [(c)]	1	1975	2034
	2	1977	2036
Clinton	1	1987	2026
Dresden [(c)]	2	1970	2029
	3	1971	2031
LaSalle [(d)]	1	1984	2022
	2	1984	2023
Limerick [(c)]	1	1986	2044
	2	1990	2049
Nine Mile Point [(c)]	1	1969	2029
	2	1988	2046
Oyster Creek [(c)(e)]	1	1969	2029
Peach Bottom [(c)]	2	1974	2033
	3	1974	2034
Quad Cities [(c)]	1	1973	2032
	2	1973	2032
R.E. Ginna [(c)]	1	1970	2029
Salem [(c)]	1	1977	2036
	2	1981	2040
Three Mile Island [(c)]	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) In May 2013, Generation submitted applications to the NRC to extend the operating licenses of Braidwood Units 1 and 2 and Byron Units 1 and 2 by 20 years.
(c) Stations for which the NRC has issued renewed operating licenses.
(d) In December 2014, Generation submitted applications to the NRC to extend the operating licenses of LaSalle Units 1 and 2 by 20 years.
(e) In December 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

Generation currently has license renewal applications pending for Braidwood Units 1 and 2, Byron Units 1 and 2, and LaSalle Units 1 and 2. Generation has advised the NRC that any license renewal application for Clinton would not be filed until the first quarter of 2021. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC's review. The NRC review process takes approximately two years from the docketing of an application. Each requested license renewal is expected to be for 20 years beyond the original operating license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual and assumed renewal of operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek.

In August 2012, Generation entered into an operating services agreement with the Omaha Public Power District (OPPD) to provide operational and managerial support services for the Fort Calhoun Station and a licensing agreement for use of the Exelon Nuclear Management Model. The terms for both agreements are 20 years. OPPD will continue to own the plant and remain the NRC licensee.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Under the nuclear uprate program, Generation has placed into service projects representing 393 MWs of new nuclear generation at a cost of $1,193 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's Consolidated Balance Sheets. At December 31, 2014, Generation has capitalized $122 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 139 MWs of new nuclear generation that is in the installation phase at one nuclear station, Peach Bottom in Pennsylvania. The remaining spend associated with this project is expected to be approximately $125 million through the end of 2016. Generation believes that it is probable that this project will be completed. If a project is expected not to be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

Nuclear Waste Disposal. There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by its nuclear generating facilities in on-site storage pools or in dry cask storage facilities. Since Generation's SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, Generation has developed dry cask storage facilities to support operations.

As of December 31, 2014, Generation had approximately 73,800 SNF assemblies (18,300 tons) stored on site in SNF pools or dry cask storage (this includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party; see Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for Clinton and Three Mile Island. Clinton and Three Mile Island are anticipated to lose full core reserve, which is when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core, in 2015 and 2023, respectively. Dry cask storage will be in operation at Clinton and is expected to be in operation at Three Mile Island prior to losing full core offload capability in their respective on-site storage pools. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites through the end of the license renewal periods and through decommissioning.

For a discussion of matters associated with Generation's contracts with the DOE for the disposal of SNF, see Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into such an agreement, although neither state currently has an operational site and none is anticipated to be operational until after 2020.

Generation ships its Class A LLRW, which represents 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Oyster Creek and Salem), and Connecticut.

Generation utilizes on-site storage capacity at its Peach Bottom and LaSalle stations to store Class B and Class C LLRW for all stations in Generation's nuclear fleet, as approved by the NRC. Generation has a contract through 2032 to ship Class B and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all current Class B and Class C LLRW currently stored at the Peach Bottom and LaSalle stations as well as the Class B and Class C LLRW generated during the term of the agreement. However, because the production of LLRW from Generation's nuclear fleet will exceed the capacity at the Texas site (3.9 million curies for 15 years beginning in 2012), Generation will still be required to utilize on-site storage at its Peach Bottom and LaSalle stations for Class B and Class C LLRW. Generation currently has enough storage capacity to store all Class B and C LLRW for the life of all stations in Generation's nuclear fleet. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize cost impacts and on-site storage.

Nuclear Insurance. Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See "Nuclear Insurance" within Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. PROPERTIES—Generation. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and results of operations.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview; ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates, Nuclear Decommissioning, Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Note 3—Regulatory Matters, Note 11—Fair Value of Financial Assets and Liabilities and Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation's NDT funds and its decommissioning obligations.

Dresden Unit 1 and Peach Bottom Unit 1 have ceased power generation. SNF at Dresden Unit 1 is currently being stored in dry cask storage until a permanent repository under the NWPA is completed. All SNF for Peach Bottom Unit 1, which ceased operation in 1974, has been removed from the site and the SNF pool is drained and decontaminated. Generation's estimated ARO liabilities to

decommission Dresden Unit 1 and Peach Bottom Unit 1 as of December 31, 2014 were $188 million and $111 million, respectively. As of December 31, 2014, NDT funds set aside to pay for these obligations were $459 million.

Zion Station Decommissioning. On December 11, 2007, Generation entered into an Asset Sale Agreement (ASA) with EnergySolutions, Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, LLC (ZionSolutions) under which ZionSolutions assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998.

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request reimbursement; specifically, if certain milestones as defined in the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. See Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning and see Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for a discussion of variable interest entity considerations related to ZionSolutions.

Fossil and Renewable Facilities (including Hydroelectric)

Generation has ownership interests in 12,949 MW of capacity in fossil and renewable generating facilities currently in service (excluding Quail Run, which was sold on January 21, 2015). Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Wyman; (2) an ownership interest through an equity method investment in Sunnyside; and (3) certain wind project entities with minority interest owners, see Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information on these wind project entities. Generation's fossil and renewable generating stations are all operated by Generation, with the exception of LaPorte, Sunnyside and Wyman, which are operated by third parties. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information relating to the sale of the Quail Run generating facility. In 2014 and 2013, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 13% and 15%, respectively, of Generation's total electric supply. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. For additional information regarding Generation's electric generating facilities, see ITEM 2. PROPERTIES—Exelon Generation Company, LLC and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview for additional information on Generation Renewable Development.

Licenses. Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid. On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively. Based on the FERC procedural schedule, the FERC licensing process was not completed prior to the expiration of Muddy Run's license on August 31, 2014, and the expiration of Conowingo's license on September 1, 2014. FERC is required to issue annual licenses for the facilities

until the new licenses are issued. On September 10, 2014, FERC issued annual licenses for Conowingo and Muddy Run, effective as of the expiration of the previous licenses. If FERC does not issue new licenses prior to the expiration of annual licenses, the annual licenses will renew automatically. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. Refer to Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Insurance. Generation maintains business interruption insurance for its renewable projects, and delay in start-up insurance for its renewable projects currently under construction. Generation does not purchase business interruption insurance for its wholly owned fossil and hydroelectric operations, unless required by financing agreements. Generation maintains both property damage and liability insurance. For property damage and liability claims for these operations, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. PROPERTIES—Exelon Generation Company, LLC.

Long-Term Power Purchase Contracts

In addition to energy produced by owned generation assets, Generation sources electricity and other related output from plants it does not own under long-term contracts. The following tables summarize Generation's long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2014:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	19	2015 - 2032	860
Midwest	7	2015 - 2022	1,734
New England	15	2015 - 2020	1,401
ERCOT	5	2020 - 2031	1,534
Other Regions	15	2015 - 2030	4,045
Total	61		9,574

	2015	2016	2017	2018	2019
Capacity Expiring (MW)	2,726	73	1,965	101	631

Fuel

The following table shows sources of electric supply in GWh for 2014 and 2013:

	Source of Electric Supply	
	2014	2013
Nuclear [(a)]	166,454	142,126
Purchases—non-trading portfolio [(b)]	48,200	69,791
Fossil (primarily natural gas)	26,324	30,785
Renewable [(c)]	6,429	6,420
Total supply	247,407	249,122

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g., CENG). Nuclear generation for 2014 and 2013 includes physical volumes of 25,053 GWh and 0 GWh, respectively, for CENG.

(b) Purchased power for 2014 and 2013 includes physical volumes of 5,346 GWh and 24,232 GWh, respectively, as a result of the PPA with CENG. On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, 100% of CENG volumes are included in nuclear generation.

(c) Includes hydroelectric, wind, and solar generating assets.

The fuel costs per MWh for nuclear generation are less than those for fossil-fuel generation. Consequently, nuclear generation is generally the most cost-effective way for Generation to meet its wholesale and retail load servicing requirements.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has uranium concentrate inventory and supply contracts sufficient to meet all of its uranium concentrate requirements through 2016. Generation's contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2015. All of Generation's enrichment requirements have been contracted through 2020. Contracts for fuel fabrication have been obtained through 2018. Generation does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures. Generation also hedges forward price risk, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation's integrated business operations include the physical delivery and marketing of power obtained through its generation capacity and through long-term, intermediate-term and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. Generation has also contracted for access to additional generation through bilateral long-term PPAs. PPAs, including tolling agreements, are commitments related to power generation of specific generation plants and/or are dispatchable in nature similar to asset ownership depending on the type of underlying asset. Generation secures contracted generation as part of its overall strategic plan, with objectives such as obtaining low-cost energy supply sources to meet its physical delivery obligations to both wholesale and retail customers and assisting customers to meet renewable portfolio standards. Generation may also buy power to meet the energy demand of its customers. Generation sells electricity, natural gas, and related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets. Generation's customer facing operations combine a unified sales force with a customer-centric model that leverages technology to broaden the range of products and solutions offered, which Generation believes promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which provides a platform that is scalable and able to capitalize on opportunities for future growth.

Generation's purchases may be for more than the energy demanded by Generation's customers. Generation then sells this open position, along with capacity not used to meet customer demand, in the wholesale electricity markets. Where necessary, Generation also purchases transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet

customer delivery needs in markets without an organized RTO. Generation also incorporates contingencies into its planning for extreme weather conditions, including potentially reserving capacity to meet summer loads at levels representative of warmer-than-normal weather conditions. Additionally, Generation is involved in the development, exploration, and harvesting of oil, natural gas and natural gas liquids properties (Upstream).

Price Supply Risk Management

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation also enters into transactions that are outside of this ratable sales plan. Generation is exposed to commodity price risk in 2015 and beyond for portions of its electricity portfolio that are unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. This strategy has not changed as a result of recent and pending asset divestitures. As of December 31, 2014, the percentage of expected generation hedged for the major reportable segments was 93%-96%, 61%-64% and 31%-34% for 2015, 2016, and 2017, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation (which reflects the divestiture impact of Quail Run). Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including sales to ComEd, PECO and BGE to serve their retail load. A portion of Generation's hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. The corporate risk management group and Exelon's RMC monitor the financial risks of the wholesale and retail power marketing activities. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation's efforts. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop-loss and value-at-risk limits, to manage exposure to market risk. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

At December 31, 2014, Generation's short and long-term commitments relating to the purchase of energy and capacity from and to unaffiliated utilities and others were as follows:

(in millions)	Net Capacity Purchases [a]	REC Purchases [b]	Transmission Rights Purchases [c]	Total
2015	$ 418	$ 152	$ 20	$ 590
2016	283	228	15	526
2017	222	121	15	358
2018	112	29	16	157
2019	117	5	16	138
Thereafter	279	1	35	315
Total	$ 1,431	$ 536	$ 117	$2,084

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2014, net of fixed capacity payments expected to be received ("Capacity offsets") by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. As of December 31, 2014, capacity offsets were $132 million, $133 million, $136 million, $137 million,$138 million, and $591 million for years 2015, 2016, 2017, 2018, 2019, and thereafter, respectively. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.

(b) The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

Capital Expenditures

Generation's business is capital intensive and requires significant investments in nuclear fuel and energy generation assets and in other internal infrastructure projects. Generation's estimated capital expenditures for 2015 are as follows:

(in millions)	
Nuclear fuel [(a)]	$1,250
Production plant	1,800
Renewable energy projects	225
Maryland commitments	225
Other	125
Total	$3,625

(a) Includes Generation's share of the investment in nuclear fuel for the co-owned Salem plant.

ComEd

ComEd is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to a diverse base of residential, commercial and industrial customers in northern Illinois. ComEd is a public utility under the Illinois Public Utilities Act subject to regulation by the ICC related to distribution rates and service, the issuance of securities, and certain other aspects of ComEd's business. ComEd is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of ComEd's business. Specific operations of ComEd are also subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, ComEd is subject to NERC mandatory reliability standards.

ComEd's retail service territory has an area of approximately 11,400 square miles and an estimated population of 9 million. The service territory includes the City of Chicago, an area of about 225 square miles with an estimated population of 2.7 million. ComEd has approximately 3.8 million customers.

ComEd's franchises are sufficient to permit it to engage in the business it now conducts. ComEd's franchise rights are generally nonexclusive rights documented in agreements and, in some cases, certificates of public convenience issued by the ICC. With few exceptions, the franchise rights have stated expiration dates ranging from 2015 to 2066. ComEd anticipates working with the appropriate governmental bodies to extend or replace the franchise agreements prior to expiration.

ComEd's kWh deliveries and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. ComEd's highest peak load occurred on July 20, 2011, and was 23,753 MWs; its highest peak load during a winter season occurred on January 6, 2014, and was 16,515 MWs.

Retail Electric Services

Electric revenues and purchased power expense are affected by fluctuations in customers' purchases from competitive electric generation suppliers. All ComEd customers have the ability to purchase electricity from a competitive electric generation supplier. The number of retail customers

participating in customer choice programs was 2,426,921, 2,630,185 and 1,627,150 at December 31, 2014, 2013 and 2012, respectively, representing 63.0%, 68% and 43% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 80%, 81% and 65% of ComEd's retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively.

The customers' choice activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense or ComEd's financial position. ComEd's cost of electric supply is passed without markup directly through to those customers not served by a competitive electric generation supplier and those rates are subject to adjustment monthly to recover or refund the difference between ComEd's actual cost of electricity delivered and the amount included in rates. For those customers that choose a competitive electric generation supplier, ComEd acts as the billing agent but does not record revenues or expenses related to the electric supply. ComEd remains the distribution service provider for all customers in its service territory and charges a regulated rate for distribution service.

See Note 24—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers, net income and total assets.

Under Illinois law, ComEd is required to deliver electricity to all customers within ComEd's service territory. ComEd's obligation to provide generation supply service, which is referred to as a POLR obligation, primarily varies by customer size. ComEd's obligation to provide such service to residential customers and other small customers with demands of under 100 kWs continues for all customers who do not choose a competitive electric generation supplier or who choose to return to ComEd after taking service from a competitive electric generation supplier. ComEd does not have a fixed-price generation supply service obligation to most of its largest customers with demands of 100 kWs or greater, as this group of customers has previously been declared competitive. Customers with competitive declarations may still purchase power and energy from ComEd, but only at hourly market prices.

Energy Infrastructure Modernization Act (EIMA). Since 2011, ComEd's distribution rates are established through a performance-based rate formula pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. In addition, as long as ComEd is subject to EIMA, ComEd will fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

EIMA is scheduled to sunset, ending ComEd's performance based rate formula and investment commitment, at December 31, 2017, unless approved to continue through 2022 by the Illinois General Assembly. During the fourth quarter of 2014, the Illinois House and Senate each passed House Bill 3975 which extends the date of the EIMA sunset from 2017 to 2019. The bill was presented to the Governor on February 11, 2015. The Governor can either act on the bill or, after 60 days, the bill will automatically become law.

ComEd files an annual reconciliation of the revenue requirement in effect in a given year to reflect the actual costs that the ICC determines are prudently and reasonably incurred for such year. ComEd's allowed rate of return on common equity is the annual average rate on 30-year treasury notes plus 580 basis points, subject to a (collar) of plus or minus 50 basis points. The collar, therefore limits favorable and unfavorable impacts of weather and load on distribution revenue. In addition, ComEd's allowed rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Procurement-Related Proceedings. ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on ComEd's Statement of operations and Comprehensive Income.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's procurement plans.

Continuous Power Interruption. The Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter, Smart Grid and Energy Efficiency

Smart Meter and Smart Grid Programs. On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. On June 11, 2014, the ICC approved ComEd's request to accelerate the deployment, which allows for the installation of more than four million smart meters throughout ComEd's service territory by 2018, three years in advance of the originally scheduled 2021 completion date. To date, nearly 550,000 smart meters have been installed in the Chicago area by ComEd.

Energy Efficiency Programs. Electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an incremental annual program energy savings requirement of 0.2% of energy delivered to retail customers for the year ended June 1, 2009, which increases annually to 2.0% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten-year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In January 2014, the ICC approved ComEd's third three-year Energy Efficiency and Demand Response Plan covering the period June 2014 through May 2017. The plans are designed to meet Illinois' energy efficiency and demand response goals through May 2017, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

EIMA provides for additional energy efficiency in Illinois. Starting in the June 2013 through May 2014 period and occurring annually thereafter, as part of the IPA procurement plan, ComEd is to include cost-effective expansion of current energy efficiency programs, and additional new cost-effective and/or third-party energy efficiency programs that are identified through a request for proposal process. All cost-effective energy efficiency programs are included in the IPA procurement plan for consideration of implementation. While these programs are monitored separately from the Energy Efficiency Portfolio Standard (EEPS), funds for both the EEPS portfolio and IPA energy efficiency programs are collected under the same rider.

Construction Budget

ComEd's business is capital intensive and requires significant investments, primarily in electricity transmission and electricity distribution facilities, to ensure the adequate capacity, reliability and efficiency of its system. Such investments include capital program and modernization pursuant to EIMA, and transmission upgrades and expansion including the Grand Prairie Gateway Transmission Line project, and PJM's RTEP. ComEd's most recent estimate of capital expenditures for electric plant additions and improvements for 2015 is $2,200 million.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional details. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

PECO

PECO is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia. PECO is a public utility under the Pennsylvania Public Utility Code subject to regulation by the PAPUC as to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of PECO's operations. PECO is a public utility under the Federal Power Act subject to regulation by FERC as to transmission rates and certain other aspects of PECO's business and by the U.S. Department of Transportation as to pipeline safety and other areas of gas operations. Specific operations of PECO are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, PECO is also subject to NERC mandatory reliability standards.

PECO's combined electric and natural gas retail service territory has an area of approximately 2,100 square miles and an estimated population of 4.0 million. PECO provides electric distribution service in an area of approximately 1,900 square miles, with a population of approximately 4.0 million, including approximately 1.6 million in the City of Philadelphia. PECO provides natural gas distribution service in an area of approximately 1,900 square miles in southeastern Pennsylvania adjacent to the City of Philadelphia, with a population of approximately 2.4 million. PECO delivers electricity to approximately 1.6 million customers and natural gas to approximately 506,000 customers.

PECO has the necessary authorizations to provide regulated electric and natural gas distribution service in the various municipalities or territories in which it now supplies such services. PECO's authorizations consist of charter rights and certificates of public convenience issued by the PAPUC and/or "grandfathered rights," with all of such rights generally unlimited as to time and generally exclusive from competition from other electric and natural gas utilities. In a few defined municipalities, PECO's natural gas service territory authorizations overlap with that of another natural gas utility; however, PECO does not consider those situations as posing a material competitive or financial threat.

PECO's kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. PECO's highest peak load occurred on July 22, 2011 and was 8,983 MW; its highest peak load during winter months occurred on January 7, 2014 and was 7,166 MW.

PECO's natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. PECO's highest daily natural gas send out occurred on January 7, 2014 and was 760 mmcf.

Retail Electric Services

PECO's retail electric sales and distribution service revenues are derived pursuant to rates regulated by the PAPUC. Pennsylvania permits competition by competitive electric generation suppliers for the supply of retail electricity while retail transmission and distribution service remains regulated under the Competition Act. At December 31, 2014, there were 101 competitive electric generation suppliers serving PECO customers. At December 31, 2014, the number of retail customers purchasing energy from a competitive electric generation supplier was 546,900 representing approximately 34% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 70% of PECO's retail kWh sales for the year ended December 31, 2014. Customers that choose a competitive electric generation supplier are not subject to rates for PECO's electric supply procurement costs and retail transmission service charges. PECO presents on customer bills its electric supply Price to Compare, which is updated quarterly, to assist customers with the evaluation of offers from competitive electric generation suppliers.

Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on PECO's electric revenue net of purchased power expense or financial position. PECO's cost of electric supply is passed directly through to default service customers without markup and those rates are subject to adjustment at least quarterly to recover or refund the difference between PECO's actual cost of electricity delivered and the amount included in rates through the GSA. For those customers that choose a competitive electric generation supplier, PECO acts as the billing agent but does not record revenue or purchased power expense related to this electric supply. PECO remains the distribution service provider for all customers in its service territory and charges a regulated rate for distribution service.

See Note 24—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers, net income and total assets.

Procurement-Related Proceedings. PECO's electric supply for its customers is procured through contracts executed in accordance with its PAPUC-approved DSP Programs.

On October 12, 2012, the PAPUC approved PECO's second DSP Program, which was filed with the PAPUC in January 2012. The plan outlined how PECO purchased electric supply for default service customers from June 1, 2013 through May 31, 2015. Pursuant to the second DSP Program, PECO procured electric supply through five competitive procurements for fixed price full requirements contracts of two years or less for the residential and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. PECO entered into contracts with PAPUC approved bidders, including Generation, for its five competitive procurements. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on PECO's Statement of Operations and Comprehensive Income.

The second DSP Program also includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from competitive electric generation suppliers beginning April 1, 2014. On May 1, 2013, PECO filed a Petition for Approval of its CAP Shopping Plan with the PAPUC. By Order entered on January 24, 2014, the PAPUC approved PECO's plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court, claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On March 28, 2014, the Commonwealth Court issued the requested stay, pending a full review of the appeal. Pending the Commonwealth Court's review, PECO will not implement CAP Shopping. The Commonwealth Court's decision is expected in 2015.

On March 10, 2014, PECO filed its third DSP Program with the PAPUC. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. On August 28, 2014, PECO filed a Joint Petition for Partial Settlement, which affirmed PECO's procurement plan for residential and small commercial customers. On December 4, 2014, the PAPUC approved PECO's third DSP Program, as modified by the Joint Petition for Partial Settlement, without modification or limitation. Separate from the Joint Petition for Partial Settlement, the PAPUC also approved other items related to the program. The plan outlines how PECO will purchase electric supply for default service customers. PECO will procure electric supply through four competitive procurements for fixed price full requirements contracts of two years or less for the residential classes and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter, Smart Grid and Energy Efficiency Programs

Smart Meter and Smart Grid Programs. In April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, which was filed in accordance with the requirements of Act 129. Also, in April 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, PECO was awarded $200 million, the maximum grant allowable under the program, for its SGIG project—Smart Future Greater Philadelphia. As of December 31, 2014, PECO has received all of the $200 million, including $4 million for sub-recipients, in reimbursements. The SGIG funds have been used by PECO to offset the total impact to ratepayers of the smart meter deployment required by Act 129. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC, which was approved without modification on August 15, 2013. Under PECO's universal deployment plan, PECO will deploy all of the 1.7 million electric smart meters on an accelerated basis by the second quarter of 2015. In total, PECO currently expects to spend up to $583 million and $155 million on its smart meter and smart grid infrastructure, respectively, before considering the $200 million SGIG funds. As of December 31, 2014, PECO has spent $540 million and $119 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Programs. PECO's PAPUC-approved Phase I EE&C plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I Plan set forth how PECO would meet the required reduction targets established by Act 129's EE&C provisions, which included a 3.0% reduction in electric consumption in PECO's service territory and a 4.5% reduction in PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013. On March 20, 2014, the PAPUC issued its final report stating that PECO was in full compliance with all Phase I targets.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129's EE&C programs, which went into effect on June 1, 2013 with a three-year cumulative consumption reduction target of 1,125,852 MWh.

On November 14, 2013, the PAPUC issued a Tentative Order on Act 129 demand reduction programs which seeks comments on a proposed demand response program methodology for future Act 129 demand reduction programs as well as demand response potential and wholesale prices suppression studies. In its February 20, 2014 Final Order, the PAPUC stated that it does not expect to

make a decision as to whether it will prescribe additional demand response obligations until 2015. Any decision reached would affect PECO's EE&C Plan subsequent to its Phase II Plan.

On February 28, 2014, PECO filed a Petition for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers from June 1, 2014 to May 31, 2016. PECO proposed to fund the estimated $10 million annual costs of the program by modifying incentive levels for other Phase II programs. The costs of the DLC program will be recovered through PECO's Energy Efficiency Program Charge along with other Phase II Plan costs. The PAPUC granted PECO's Petition in an Order that became final on May 5, 2014.

Pennsylvania Retail Electricity Market. The extreme weather experienced in early 2014 resulted in increased commodity costs causing certain shopping customers to receive unexpectedly high utility bills. In response to a significant number of customer complaints throughout Pennsylvania, on April 3, 2014, the PAPUC unanimously voted to adopt two rulemaking orders to address the issue. The first rulemaking order requires electric generation suppliers to provide more consumer education regarding their contracts. The second rulemaking order requires electric distribution companies to enable customers to switch suppliers within three business days (known as accelerated switching). The improved customer education and accelerated switching were to be in place within 30 days and six months of approval of the orders, respectively. The orders became final on June 14, 2014. On December 4, 2014, the PAPUC approved PECO's implementation plan (known as Bill on Supplier Switch), allowing PECO to implement accelerated switching by the December 15, 2014 deadline.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Natural Gas

PECO's natural gas sales and distribution service revenues are derived through natural gas deliveries at rates regulated by the PAPUC. PECO's purchased natural gas cost rates, which represent a significant portion of total rates, are subject to quarterly adjustments designed to recover or refund the difference between the actual cost of purchased natural gas and the amount included in rates without markup through the PGC.

PECO's natural gas customers have the right to choose their natural gas suppliers or to purchase their gas supply from PECO at cost. At December 31, 2014, the number of retail customers purchasing natural gas from a competitive natural gas supplier was 78,400, representing approximately 15% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 22% of PECO's mmcf sales for the year ended December 31, 2014. PECO provides distribution, billing, metering, installation, maintenance and emergency response services at regulated rates to all its customers in its service territory.

Procurement-Related Proceedings. PECO's natural gas supply is purchased from a number of suppliers primarily under long-term firm transportation contracts for terms of up to three years in accordance with its annual PAPUC PGC settlement. PECO's aggregate annual firm supply under these firm transportation contracts is 32 million dekatherms. Peak natural gas is provided by PECO's liquefied natural gas (LNG) facility and propane-air plant which provide 1.2 billion cubic feet and 181,441 dekatherms, respectively, on an annual basis. PECO also has under contract 21 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 29% of PECO's 2014-2015 heating season planned supplies.

Gas Main Extension Program . On November 6, 2014, PECO filed a plan with the PAPUC requesting approval of three initiatives to provide more incentives to customers interested in switching to natural gas service. If approved, local customers would pay significantly less initially to have natural gas installed at their homes and businesses.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Construction Budget

PECO's business is capital intensive and requires significant investments primarily in electric transmission and electric and natural gas distribution facilities to ensure the adequate capacity, reliability and efficiency of its system. PECO, as a transmission facilities owner, has various construction commitments under PJM's RTEP. PECO's most recent estimate of capital expenditures for plant additions and improvements for 2015 is $550 million, which includes RTEP projects and capital expenditures related to the smart meter and smart grid project.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional details. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

BGE

BGE is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in central Maryland, including the City of Baltimore. BGE is a public utility under the Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC as to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of BGE's operations. BGE is a public utility under the Federal Power Act subject to regulation by FERC as to transmission rates and certain other aspects of BGE's business and by the U.S. Department of Transportation as to pipeline safety and other areas of gas operations. Specific operations of BGE are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, BGE is also subject to NERC mandatory reliability standards.

BGE serves an estimated population of 2.8 million in its 2,300 square mile combined electric and gas retail service territory. BGE provides electric distribution service in an area of approximately 2,300 square miles and gas distribution service in an area of approximately 800 square miles, both with a population of approximately 2.8 million, including approximately 621,000 in the City of Baltimore. BGE delivers electricity to approximately 1.2 million customers and natural gas to approximately 655,000 customers.

BGE has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities and territories in which it now supplies such services. With respect to electric distribution service, BGE's authorizations consist of charter rights, a state-wide franchise grant and a franchise grant from the City of Baltimore. The franchise rights are nonexclusive and are perpetual. With respect to natural gas distribution service, BGE's authorizations consist of charter rights, a perpetual state-wide franchise grant, and franchises granted by all the municipalities and/or governmental bodies in which BGE now supplies services. The franchise grants are not exclusive; some are perpetual and some are for a limited duration, which BGE anticipates being able to extend or replace prior to expiration.

BGE's kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. BGE's highest peak load occurred on July 21, 2011 and was 7,236 MW; its highest peak load during winter months occurred on January 7, 2014 and was 6,526 MW.

BGE's natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. BGE's highest daily natural gas send out occurred on February 5, 2007 and was 840 mmcf.

The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service commercial gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This adjustment allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period (referred to as "revenue decoupling"). Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits affected customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Retail Electric Services

BGE's retail electric sales and distribution service revenues are derived from electricity deliveries at rates regulated by the MDPSC. As a result of the deregulation of electric generation in Maryland effective July 1, 2000, all customers can choose a competitive electric generation supplier. While BGE does not sell electric supply to all customers in its service territory, BGE continues to deliver electricity to all customers and provides meter reading, billing, emergency response, and regular maintenance services. Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has minimal impact on BGE's electric revenue net of purchased power expense or financial position. At December 31, 2014, there were 59 competitive electric generation suppliers serving BGE customers. At December 31, 2014, the number of retail customers purchasing energy from a competitive electric generation supplier was approximately 364,000, representing 29% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 60% of BGE's retail kWh sales for the year ended December 31, 2014.

See Note 24—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers, net income and total assets.

Procurement Related Proceedings. BGE is obligated to provide market-based SOS to all of its electric customers. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes a commercial and industrial shareholder return component and an incremental cost component. Bidding to supply BGE's market-based SOS occurs through a competitive bidding process approved by the MDPSC. Successful bidders, which may include Generation, will execute contracts with BGE for terms of three months or two years. BGE is obligated by the MDPSC to provide several variations of SOS to commercial and industrial customers depending on customer load. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on BGE's Statement of Operations and Comprehensive Income.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on BGE's procurement plan.

Electric Distribution Rate Case. On July 2, 2014, and as amended on September 15, 2014, BGE filed for an electric base rate increase with the MDPSC, ultimately requesting an increase of $99 million. On October 17, 2014, BGE filed with the MDPSC a unanimous settlement agreement (the

Settlement Agreement) reached with all parties to the case under which it would receive an increase of $22 million in electric base rates. The Settlement Agreement establishes new depreciation rates which have the effect of decreasing annual electric depreciation expense by approximately $22 million. On December 4, 2014, the Public Utility Law Judge issued a proposed order approving the Settlement Agreement without modification, which became a final order on December 12, 2014. The approved electric distribution rate became effective for services rendered on or after December 15, 2014.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter and Energy Efficiency Programs

Smart Meter Programs. In August 2010, the MDPSC approved BGE's $480 million SGIP, which includes deployment of a two-way communications network, 2 million smart electric and gas meters and modules, new customer pricing programs, a new customer web portal and numerous enhancements to BGE operations. Also, in April 2010, BGE entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, BGE was awarded $200 million, the maximum grant allowable under the program, to support its Smart Grid, Peak Rewards and CC&B initiatives, of which BGE had been fully reimbursed for as of December 31, 2013. The SGIG funding significantly reduced the rate impact of those investments on BGE customers.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding BGE's Smart Meter Programs.

Energy Efficiency Programs. BGE's energy efficiency programs include a lighting program, retrofit programs, incentives for energy efficient new homes, rebates for heating and cooling systems, energy audits, an energy efficient appliance rebate and trade-in program, customer incentives for non-profit, educational, governmental and business customers, energy management programs and bill credits to help residential customers reduce energy demand during peak periods. The MDPSC initially approved a full portfolio of conservation programs in 2008 as well as a customer surcharge to recover the associated costs in 2009. This customer surcharge is updated annually. In December 2011, the MDPSC approved BGE's conservation programs for implementation in 2012 through 2014. On December 23, 2014, the MDPSC approved BGE's proposal for the 2015-2017 programs with minor modifications.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding BGE's Energy Efficiency Programs.

Natural Gas

BGE's natural gas sales are derived pursuant to a MBR mechanism that applies to customers who buy their gas from BGE. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must secure fixed price contracts for at least 10% but not more than 20% of forecasted system supply requirements for flowing (i.e. non-storage) gas for the November through March period. These fixed price contracts are recovered under the MBR mechanism and are not subject to sharing.

Customer choice program activity affects revenue collected from customers related to supplied natural gas; however, that activity has minimal impact on BGE's gas revenue net of purchased power expense or financial position. At December 31, 2014, there were 40 competitive natural gas suppliers serving BGE customers. At December 31, 2014, the number of retail customers purchasing fuel from a

competitive natural gas supplier was approximately 161,000 representing 25% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 53% of BGE's retail mmcf sales for the year ended December 31, 2014.

BGE meets its natural gas load requirements through firm pipeline transportation and storage entitlements. BGE's current pipeline firm transportation entitlements to serve its firm loads are 354 mmcf per day.

BGE's current maximum storage entitlements are 312 mmcf per day. To supplement its gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, BGE has:

- a liquefied natural gas facility for the liquefaction and storage of natural gas with a total storage capacity of 1,055 mmcf and a daily capacity of 332 mmcf,
- a liquefied natural gas facility for natural gas system pressure support with a total storage capacity of 6 mmcf and a daily capacity of 6 mmcf, and
- a propane air facility and a mined cavern with a total storage capacity equivalent to 546 mmcf and a daily capacity of 85 mmcf.

BGE has under contract sufficient volumes of propane for the operation of the propane air facility and is capable of liquefying sufficient volumes of natural gas during the summer months for operations of its liquefied natural gas facility during peak winter periods. BGE historically has been able to arrange short-term contracts or exchange agreements with other gas companies in the event of short-term disruptions to gas supplies or to meet additional demand.

BGE also participates in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between shareholders and customers. BGE makes these sales as part of a program to balance its supply of, and cost of, natural gas.

Natural Gas Distribution Rate Case . On July 2, 2014, and as amended on September 15, 2014, BGE filed for a gas base rate increase with the MDPSC, ultimately requesting an increase of $68 million. On October 17, 2014, BGE filed with the MDPSC the Settlement Agreement reached with all parties to the case under which it would receive an increase of $38 million in gas base rates. The Settlement Agreement establishes new depreciation rates which have the effect of increasing annual gas depreciation expense by approximately $2 million. On December 14, 2014, the Public Utility Law Judge issued a proposed order approving the Settlement Agreement without modification, which became a final order on December 12, 2014. The approved gas distribution rate became effective for services rendered on or after December 15, 2014.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Construction Budget

BGE's business is capital intensive and requires significant investments primarily in electric and natural gas distribution and electric transmission facilities to ensure the adequate capacity, reliability and efficiency of its system. BGE, as a transmission facilities owner, has various construction commitments under PJM's RTEP as discussed in BGE's most recent estimate of capital expenditures for plant additions and improvements for 2015 is approximately $700 million.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional details. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

ComEd, PECO and BGE

Transmission Services

ComEd, PECO and BGE provide unbundled transmission service under rates approved by FERC. FERC has used its regulation of transmission to encourage competition for wholesale generation services and the development of regional structures to facilitate regional wholesale markets. Under FERC's open access transmission policy promulgated in Order No. 888, ComEd, PECO and BGE, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. ComEd, PECO and BGE are required to comply with FERC's Standards of Conduct regulation governing the communication of non-public information between the transmission owner's employees and wholesale merchant employees.

PJM is the ISO and the FERC-approved RTO for the Mid-Atlantic and Midwest regions. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM Tariff), operates the PJM energy, capacity and other markets, and, through central dispatch, controls the day-to-day operations of the bulk power system for the PJM region. ComEd, PECO and BGE are members of PJM and provide regional transmission service pursuant to the PJM Tariff. ComEd, PECO, BGE and the other transmission owners in PJM have turned over control of their transmission facilities to PJM, and their transmission systems are currently under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM members at rates based on the costs of transmission service.

ComEd's transmission rates are established based on a formula that was approved by FERC in January 2008. FERC's order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

PECO default service customers are charged for retail transmission services through a rider designed to recover PECO's PJM transmission network service charges and RTEP charges on a full and current basis in accordance with PECO's 2010 electric distribution rate case settlement.

The transmission rate in the PJM Open Access Transmission Tariff under which PECO incurs costs to serve its default service customers and earns revenue as a transmission facility owner is a FERC-approved rate. This is the rate that all load serving entities in the PECO transmission zone pay for wholesale transmission service.

BGE's transmission rates are established based on a formula that was approved by FERC in April 2006. FERC's order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding transmission services.

Employees

As of December 31, 2014, Exelon and its subsidiaries had 28,993 employees in the following companies, of which 9,276 or 32% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 [a]	IBEW Local 614 [b]	Other CBAs [c]	Total Employees Covered by CBAs	Total Employees
Generation [e]	1,690	96	2,353	4,139	14,370
ComEd	3,739	—	—	3,739	6,403
PECO	—	1,282	—	1,282	2,458
BGE	—	—	—	—	3,252
Other [d]	72	—	44	116	2,510
Total	5,501	1,378	2,397	9,276	28,993

(a) A separate CBA between ComEd and IBEW Local 15 covers approximately 55 employees in ComEd's System Services Group and expires in 2015. Generation's and ComEd's separate CBAs with IBEW Local 15 was renewed in 2014 and expires in 2019.
(b) 1,378 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614. The CBAs expire in 2019. Additionally, Exelon Power, an operating unit of Generation, has an agreement with IBEW Local 614, which expires in 2016 and covers 96 employees.
(c) During 2014, Generation finalized CBAs with TMI Local 777 and Oyster Creek Local 1289, expiring in 2019 and 2021, respectively and CENG finalized its CBA with Nine Mile Point which will expire in 2020. Additionally, during 2014, Generation finalized CBAs with the Security Officer unions at Dresden, LaSalle, Limerick and Quad Cities, which expire between 2017 and 2018. Lastly, during 2014, an agreement was negotiated with Las Vegas District Energy and IUOE Local 501, which will expire in 2018. During 2013, two other 3-year agreements were negotiated: New England ENEH, UWUA Local 369, which will expire in 2017; and New Energy IUOE Local 95-95A, which will expire in 2016. During 2012, Generation finalized CBAs with the Security Officer unions at Byron, Clinton and TMI, which expire between 2015 and 2016. During 2011, Generation finalized a CBA with the Security Officer unions at Braidwood, which expires in 2015.
(d) Other includes shared services employees at BSC.
(e) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the total includes CENG employees as of December 31, 2014.

Environmental Regulation

General

Exelon, Generation, ComEd, PECO and BGE are subject to comprehensive and complex legislation regarding environmental matters by the federal government and various state and local jurisdictions in which they operate their facilities. The Registrants are also subject to regulations administered by the U.S. EPA and various state and local environmental protection agencies. Federal, state and local regulation includes the authority to regulate air, water, and solid and hazardous waste disposal.

The Exelon Board of Directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President, Corporate Strategy and Chief Sustainability Officer; the Corporate Environmental Strategy Director and the Environmental Regulatory Strategy Director, as well as senior management of Generation, ComEd, PECO and BGE. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. The Exelon Board has delegated to its corporate governance committee authority to oversee Exelon's compliance with laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including Exelon's climate change and sustainability policies and programs, as discussed in further detail below. The Exelon Board has also delegated to its Generation Oversight Committee authority to oversee environmental, health and safety issues relating to Generation. The respective Boards of ComEd, PECO and BGE, which each include directors who also serve on the Exelon board, oversee environmental, health and safety issues related to ComEd, PECO and BGE.

Air Quality

Air quality regulations promulgated by the U.S. EPA and the various state and local environmental agencies in Illinois, Maryland, Massachusetts, New York, Pennsylvania and Texas in accordance with the Federal Clean Air Act impose restrictions on emission of particulates, sulfur dioxide (SO2), nitrogen oxides (NOx), mercury and other pollutants and require permits for operation of emissions sources. Such permits have been obtained by Exelon's subsidiaries and must be renewed periodically. The Clean Air Act establishes a comprehensive and complex national program to reduce substantially air pollution from power plants.

See ITEM 7.—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding clean air regulation in the forms of the CSAPR, the regulation of hazardous air pollutants from coal- and oil-fired electric generating facilities under MATS, and regulation of GHG emissions, in addition to NOVs issued to Generation and ComEd for alleged violations of the Clean Air Act.

Water Quality

Under the Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the U.S. EPA or from the state environmental agency to which the permit program has been delegated and must be renewed periodically. Certain of Generation's power generation facilities discharge industrial wastewater into waterways and are therefore subject to these regulations and operate under NPDES permits or pending applications for renewals of such permits after being granted an administrative extension. Generation is also subject to the jurisdiction of certain other state and regional agencies and compacts, including the Delaware River Basin Commission and the Susquehanna River Basin Commission.

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's and CENG's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. For Generation, those facilities are Clinton, Dresden, Eddystone, Fairless Hills, Gould Street, Handley, Mountain Creek, Mystic 7, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. For CENG, those facilities are Calvert Cliffs, Nine Mile Point Unit 1 and R.E. Ginna.

On October 14, 2014, the U.S. EPA's final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed to determine the best technology available, followed by an implementation period. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

The rule does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment of aquatic life at a facility's cooling water intake structure. The rule provides the state permitting director with significant discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The rule also provides a number of flexible compliance options to reduce impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or other technology at the intake. A number of concerns raised by the electric generation industry about the proposed rule were resolved favorably in the final rule.

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, Generation cannot estimate the effect that compliance with the rule will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows capital expenditures, and financial position. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility's economic viability would be called into question. However, the likely impact of the rule has been significantly decreased since the final rule does not mandate cooling towers as a national standard, and the state permitting director is required to apply a cost-benefit test and can take into consideration site-specific factors.

New York Facilities. In July 2011, the New York Department of Environmental Conservation (DEC) issued a policy regarding the best available technology for cooling water intake structures. Through its policy, the DEC established closed-cycle cooling or its equivalent as the performance goal for all existing facilities, but also provided that the DEC will select a feasible technology whose costs are not wholly disproportionate to the environmental benefits to be gained and allows for a site-specific determination where the entrainment performance goal cannot be achieved. Each of CENG's New York facilities received renewals of their SPDES permits in 2014.

Salem and Other Power Generation Facilities. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG, in July 2004, that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon's and Generation's share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $430 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment. However, it is unknown at this time whether implementation of the final EPA rule will result in a requirement to install closed cycle cooling at Salem.

Solid and Hazardous Waste

CERCLA provides for immediate response and removal actions coordinated by the U.S. EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at sites, most of which are listed by the U.S. EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with a U.S. EPA-directed cleanup, may voluntarily settle with the U.S. EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight prior to listing on the NPL. Various states, including Illinois, Maryland and Pennsylvania, have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Generation, ComEd, PECO and BGE and their subsidiaries are, or are likely to become, parties to proceedings initiated by the U.S. EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party.

See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding solid and hazardous waste regulation and legislation.

Environmental Remediation

ComEd's, PECO's and BGE's environmental liabilities primarily arise from contamination at former MGP sites. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover environmental remediation costs of the MGP sites through a provision within customer rates. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The amount to be expended in 2015 at Exelon for compliance with environmental remediation related to contamination at former MGP sites is expected to total $35 million, consisting of $29 million, $6 million and $0 million at ComEd, PECO and BGE, respectively.

Generation's environmental liabilities primarily arise from contamination at current and former generation and waste storage facilities. As of December 31, 2014, Generation has established an appropriate liability to comply with environmental remediation requirements including contamination attributable to low level radioactive residues at a storage and reprocessing facility named Latty Avenue, and at a disposal facility named West Lake Landfill, both near St. Louis, Missouri related to operations conducted by Cotter Corporation, a former ComEd subsidiary.

In addition, Generation, ComEd, PECO and BGE may be required to make significant additional expenditures not presently determinable for other environmental remediation costs.

See Notes 3—Regulatory Matters and 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' environmental remediation efforts and related impacts to the Registrants' results of operations, cash flows and financial positions.

Global Climate Change

Exelon believes the evidence of global climate change is compelling and that the energy industry, though not alone, is a significant contributor to the human-caused emissions of GHGs that many in the scientific community believe contribute to global climate change, and as reported by the Intergovernmental Panel on Climate Change in their Fifth Assessment Report Summary for Policy Makers issued in September 2013. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, hydroelectric, wind and solar photovoltaic), has a relatively small GHG emission profile, or carbon footprint, compared to other domestic generators of electricity. By virtue of its significant investment in low-carbon intensity assets, Generation's emission intensity, or rate of carbon dioxide equivalent (CO2e) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its fossil fuel-fired generating plants; CO2, methane and nitrous oxide are all emitted in this process, with CO2 representing the largest portion of these GHG emissions. GHG emissions from combustion of fossil fuels represent the majority of Exelon's direct GHG emissions in 2014, although only a small portion of Exelon's electric supply is from fossil generating plants. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF6) leakage in its electric transmission and distribution operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and usage of electricity at its facilities. Despite its focus on low-carbon generation, Exelon believes its operations could be significantly affected by the possible physical risks of climate change and by mandatory programs to reduce GHG emissions. See ITEM 1A. RISK FACTORS for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

Climate Change Regulation. Exelon is, or may become, subject to climate change regulation or legislation at the Federal, regional and state levels.

International Climate Change Regulation. At the international level, the United States has not yet ratified the United Nations Kyoto Protocol, which was extended at the 2012 meeting of the United Nations Framework on Climate Change Conference of the Parties (COP 18). The Kyoto Protocol now requires participating developed countries to cap GHG emissions at certain levels until 2020, when the new global agreement on emissions reduction is scheduled to become effective. This new global agreement for GHG emissions reductions was agreed to only in concept during the COP18, with a timeline for establishing the global targets by 2015. On November 22, 2013, at the 2013 COP 19 held in Warsaw, Poland, participating countries further agreed to provide their "intended nationally determined contributions" by the first quarter of 2015 in preparation for formally setting global target in 2015. At COP 20 held in Lima, Peru, in December 2014, participating countries outlined the universal GHG reduction agreement to be finalized in 2015 at COP 21 in Paris. On November 11, 2014, President Obama and President Xi Jinping of China jointly announced their respective "intended nationally determined contributions" for post 2020 greenhouse gas emission reductions. The US announced net greenhouse gas emission reductions of 26-28 percent below 2005 levels by 2025, while China announced targets to peak CO_2 emissions around 2030, and to increase the non-fossil fuel share of all energy to around 20 percent by 2030. Together, the U.S. and China account for over one–third of global greenhouse gas emissions.

Federal Climate Change Legislation and Regulation. Various stakeholders, including Exelon, legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors are considering ways to address the climate change issue, including the enactment of federal climate change legislation. It is highly uncertain whether Federal legislation to reduce GHG emissions will be enacted. If such legislation is adopted, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits. In June 2013, the White House released the President's Climate Action Plan which consists of a wide variety of executive actions targeting GHG reductions, preparing for the impacts of climate change and showing leadership internationally; but the plan did not directly trigger any new requirements or legislative action.

The U.S. EPA is addressing the issue of carbon dioxide (CO_2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act. Pursuant to President Obama's June 25, 2013 memorandum to U.S. EPA, the Agency re-proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO_2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. Under the President's memorandum, the U.S. EPA was also required to propose a Section 111(d) rule no later than June 1, 2014 to establish CO_2 emission regulations for existing stationary sources. The second rulemaking, under Section 111(d) of the Clean Air Act, focuses on modified, reconstructed and existing fossil power plants. The proposed rule was published in the Federal Register on June 18, 2014, and the public comment period closed on December 1, 2014. The Climate Action Plan calls for the rule to be finalized no later than June 1, 2015, and requires that states submit to U.S. EPA their implementation plans no later than June 30, 2016.

Regional and State Climate Change Legislation and Regulation. After a two-year program review, the nine northeast and mid-Atlantic states currently participating in the Regional Greenhouse Gas Reduction Initiative (RGGI) released an updated RGGI Model Rule and Program Review Recommendations Summary on February 7, 2013. Under the updated RGGI program the regional RGGI CO_2 budget was reduced, starting in 2014, from its previous 165 million ton level to 91 million tons, with a 25 percent reduction in the cap level each year between 2015-2020. Included in the new program are provisions for cost containment reserve (CCR) allowances, which will become available if the total demand for allowances, above the CCR trigger price, exceeds the number of CO_2 allowances

available for purchase at auction. (CCR trigger prices are $4 in 2014, $6 in 2015, $8 in 2016 and $10 in 2017, after 2017 the CCR price increases by 2.5 percent each year). Such an outcome could put modest upward pressure on wholesale power prices; however, the specifics are currently uncertain.

At the state level, the Illinois Climate Change Advisory Group, created by Executive Order 2006-11 on October 5, 2006, made its final recommendations on September 6, 2007 to meet the Governor's GHG reduction goals. At this time, the only requirements imposed by the state of Illinois are the energy efficiency and renewable portfolio standards in the Illinois Power Act that apply to ComEd.

On December 18, 2009, Pennsylvania issued the state's final Climate Change Action Plan. The plan sets as a target a 30 percent reduction in GHG emissions by 2020. The Climate Change Advisory Committee continues to meet quarterly to review Climate Action Work Plans for the residential, commercial and industrial sectors. The Climate Change Action Plan does not impose any requirements on Generation or PECO at this time.

The Maryland Commission on Climate Change was chartered in 2007 and released a 42 greenhouse gas reduction strategy, climate action plan, on August 27, 2008. The plan's primary policy recommendation to formally adopt science-based regulatory goals to reduce Maryland's GHG emissions, was realized with the passage of the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA) which requires Maryland to reduce its GHG emissions by 25 percent below 2006 levels by 2020. It also directed the Maryland Department of Environment to prepare and implement an action plan which was published in October of 2013. Maryland's electricity consumption reduction goals, required under the "Empower Maryland" program, and mandatory State participation in RGGI Program, are listed as the energy sector's contribution in the plan. The plan also advocated raising the renewable portfolio standard requirement from 20% by 2022 to 25% by 2022. The Department of Environment is required to submit a December 2015 report to the Governor and General Assembly on progress towards the 25% mandate; its costs and benefits; the need for target adjustments; and the status of federal programs. In 2016, the Legislature will review the progress report, its economic impacts on manufacturing sector and other information and determine whether to continue, adjust or eliminate the requirement to achieve a 25% reduction by 2020.

Exelon's Voluntary Climate Change Efforts. In a world increasingly concerned about global climate change and regulatory action to reduce GHG, Exelon's low-carbon generating fleet is seen by management as a competitive advantage. Exelon remains one of the largest, lowest carbon electric generators in the United States: nuclear for base load, natural gas for marginal and peak demand, hydro and pumped storage, and supplemental wind and solar renewables. As further legislation and regulation imposing requirements on emissions of GHG and air pollutants are promulgated, Exelon's low-carbon, low-emission generation fleet will position the company to benefit from its comparative advantage over other generation fleets.

Based on an independent third-party verification of Exelon's GHG performance through year-end 2013, it achieved the Exelon 2020 goal of abating 17.5 million tonnes of GHG emissions annually, seven years ahead of plan. Exelon's approach for addressing the issue of climate change is currently focused on continuing to manage its GHG emissions from internal operations, contributing to reducing overall grid GHG emissions and ensuring the resiliency of its infrastructure in response to the physical impacts of climate change.

Renewable and Alternative Energy Portfolio Standards

Thirty-nine states and the District of Columbia have adopted some form of RPS requirement. Illinois, Pennsylvania and Maryland have laws specifically addressing energy efficiency and renewable energy initiatives. In addition to state level activity, RPS legislation has been considered and may be considered again in the future by the United States Congress. Also, states that currently do not have RPS requirements may adopt such legislation in the future.

Illinois utilities are required to procure cost-effective renewable energy resources in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers. ComEd is also required to acquire amounts of renewable energy resources that will cumulatively increase this percentage to at least 10% by June 1, 2015, with an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth by Illinois legislation. As of December 31, 2014, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois legislation. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's procurement plans. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding ComEd's future commitments for the procurement of RECs.

The AEPS Act became effective for PECO on January 1, 2011. During 2014, PECO was required to supply approximately 4.5% of electric energy generated from Tier I (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania) through May 31, 2014 and subsequently 5.0% beginning June 1, 2014 and continuing through May 31, 2015. PECO was also required to supply 6.2% of electric energy generated from Tier II (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing wood and by-products of the pulping process and wood, distributed generation systems and integrated combined coal gasification technology) alternative energy resources, as measured in AECs. The compliance requirements will incrementally escalate to 8.0% for Tier I and 10.0% for Tier II by 2021. In order to comply with these requirements, PECO entered into agreements with varying terms with accepted bidders, including Generation, to purchase non-solar Tier I, solar Tier 1 and Tier II AECs. PECO also purchases AECs through its DSP Program full requirement contracts.

Section 7-703 of the Public Utilities Article in Maryland sets forth the RPS requirement, which applies to all retail electricity sales in Maryland by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, biomass, methane, geothermal, ocean, fuel cell, small hydroelectric, and poultry litter) and Tier 2 sources (hydroelectric, other than pump storage generation, and waste-to-energy). The RPS requirement began in 2006, requiring that suppliers procure 1.0% and 2.5% from Tier 1 and Tier 2 sources, respectively, escalating in 2022 to 22.0% from Tier 1 sources, including at least 2.0% from solar energy, and a phase out of Tier 2 resource options by 2022. In 2014, 10.3% was required from Tier 1 renewable sources, including at least 0.35% derived from solar energy, and 2.5% from Tier 2 renewable sources. BGE is subject to requirements established by the Public Utilities Article in Maryland related to the use of alternative energy resources; however, the wholesale suppliers that supply power to BGE through SOS procurement auctions have the obligation, by contract with BGE, to meet the RPS requirements.

Similar to ComEd, PECO and BGE, Generation's retail electric business must source a portion of the electric load it serves in many of the states in which it does business from renewable resources or approved equivalents such as RECs. Potential regulation and legislation regarding renewable and alternative energy resources could increase the pace of development of wind and other renewable/alternative energy resources, which could put downward pressure on wholesale market prices for electricity in some markets where Exelon operates generation assets. At the same time, such developments may present some opportunities for sales of Generation's renewable power, including from wind, solar, hydroelectric and landfill gas.

See Note 3—Regulatory Matters and Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Executive Officers of the Registrants as of February 13, 2015

Exelon

Name	Age	Position	Period
Crane, Christopher M.	56	Chief Executive Officer, Exelon;	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
		Chief Operating Officer, Exelon	2008 - 2012
		Chief Operating Officer, Generation	2007 - 2010
Cornew, Kenneth W.	49	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
O'Brien, Denis P.	54	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Vice Chairman, ComEd, PECO, BGE	2012 - Present
		Chief Executive Officer, PECO; Executive Vice President, Exelon	2007 - 2012
		President and Director, PECO	2003 - 2012
Pramaggiore, Anne R.	56	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Adams, Craig L.	62	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Butler, Calvin G.	45	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
		Senior Vice President, Human Resources, Exelon	2010 - 2011
		Senior Vice President, Corporate Affairs, ComEd	2009 - 2010
Von Hoene Jr., William A.	61	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
Thayer, Jonathan W.	43	Senior Executive Vice President and Chief Financial Officer, Exelon	2012 - Present [(a)]
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012
Aliabadi, Paymon	52	Executive Vice President and Chief Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
		Principal and Managing Director, Gunvor International	2009 - 2011
DesParte, Duane M.	51	Senior Vice President and Corporate Controller, Exelon	2008 - Present

Generation

Name	Age	Position	Period
Cornew, Kenneth W.	49	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
Nigro, Joseph	50	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - Present
		Senior Vice President, Portfolio Management and Strategy	2012 - 2013
		Vice President, Structuring and Portfolio Management, Exelon Power Team	2010 - 2012
Pacilio, Michael J.	54	Executive Vice President and Chief Operating Officer, Exelon Generation	2015 - Present
		President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - 2015
		Chief Operating Officer, Exelon Nuclear	2007 - 2010
Hanson, Bryan C.	49	President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Exelon Generation	2015 - Present
		Chief Operating Officer, Exelon Nuclear	2014 - 2015
		Senior Vice President of Operations, Generation	2010 - 2013
		Vice President of Operations, Generation	2009 - 2010
DeGregorio, Ronald	52	Senior Vice President, Generation; President, Exelon Power	2012 - Present
		Chief Integration Officer, Exelon	2011 - 2012
		Chief Operating Officer, Exelon Transmission Company	2010 - 2011
		Senior Vice President, Mid-Atlantic Operations, Exelon Nuclear	2007 - 2010
Wright, Bryan P.	48	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
		Chief Accounting Officer, Constellation Energy	2009 - 2012
		Vice President and Controller, Constellation Energy	2008 - 2012
Aiken, Robert	48	Vice President and Controller, Generation	2012 - Present
		Executive Director and Assistant Controller, Constellation	2011 - 2012
		Executive Director of Operational Accounting, Constellation Energy Commodities Group	2009 - 2011

ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	56	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Donnelly, Terence R.	54	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
Trpik Jr., Joseph R.	45	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
Jensen, Val	59	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
O'Neill, Thomas S.	52	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2010 - Present
		Senior Vice President, Exelon	2009 - 2010
Marquez Jr., Fidel	53	Senior Vice President, Governmental and External Affairs, ComEd	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012
Brookins, Kevin B.	53	Senior Vice President, Strategy & Administration, ComEd	2012 - Present
		Vice President, Operational Strategy and Business Intelligence, ComEd	2010 - 2012
		Vice President, Distribution System Operations, ComEd	2008 - 2010
Anthony, J. Tyler	50	Senior Vice President, Distribution Operations, ComEd	2010 - Present
		Vice President, Transmission and Substations, ComEd	2007 - 2010
Kozel, Gerald J.	42	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013
		Director of Financial Reporting and Analysis, Exelon	2009 - 2012

PECO

Name	Age	Position	Period
Adams, Craig L.	62	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	51	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	49	Senior Vice President and Chief Operations Officer, PECO	2012 - Present
		Vice President, Distribution System Operations and Smart Grid/Smart Meter, PECO	2010 - 2012
		Vice President, Distribution System Operations	2007 - 2010

Name	Age	Position	Period
Webster Jr., Richard G.	53	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	55	Vice President, Governmental and External Affairs, PECO	2012 - Present
		Director, Governmental & External Affairs, PECO	2007 - 2012
Jiruska, Frank J.	54	Vice President, Customer Operations, PECO	2013 - Present
		Director of Energy and Marketing Services, PECO	2010 - 2013
Diaz Jr., Romulo L.	68	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
Bailey, Scott A.	38	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012
		Director of Accounting, Power Team	2007 - 2011

BGE

Name	Age	Position	Period
Butler, Calvin G.	45	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
		Senior Vice President, Human Resources, Exelon	2010 - 2011
		Senior Vice President, Corporate Affairs, ComEd	2009 - 2010
Woerner, Stephen J.	47	President, BGE	2014 - Present
		Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - 2014
		Vice President and Chief Integration Officer, Constellation Energy	2011 - 2012
		Vice President and Chief Information Officer, Constellation Energy	2010 - 2011
		Vice President, Transformation, Constellation Energy	2009 - 2010
Vahos, David M.	42	Chief Financial Officer and Treasurer	2014 - Present
		Vice President and Controller, BGE	2012 - 2014
		Executive Director, Audit, Constellation	2010 - 2012
		Director, Finance, BGE	2006 - 2010
Case, Mark D.	53	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Biagiotti, Robert D.	45	Vice President, Customer Operations and Chief Customer Officer, BGE	2015 - Present
		Vice President, Gas Distribution, BGE	2011-2015
		Director, Gas and Electric Field Services, BGE	2008-2011

Name	Age	Position	Period
Gahagan, Daniel P.	61	Vice President and General Counsel, BGE	2007 - Present
Bauer, Matthew N.	38	Vice President and Controller, BGE	2014 - Present
		Vice President of Power Finance, Exelon Power	2012 - 2014
		Director, FP&A and Retail, Constellation	2012 - 2012
		Executive Director, Corporate Development, Constellation	2009 - 2012

(a) Effective July 1, 2014, Jonathan W. Thayer's title was changed from Executive Vice President and Chief Financial Officer, Exelon to Senior Executive Vice President and Chief Financial Officer, Exelon.

ITEM 1A. RISK FACTORS

Each of the Registrants operates in a market and regulatory environment that poses significant risks, many of which are beyond that Registrant's control. Management of each Registrant regularly meets with the Chief Risk Officer and the RMC, which comprises officers of the Registrants, to identify and evaluate the most significant risks of the Registrants' businesses, and the appropriate steps to manage and mitigate those risks. The Chief Risk Officer and senior executives of the Registrants discuss those risks with the finance and risk committee and audit committee of the Exelon board of directors and the ComEd, PECO and BGE boards of directors. In addition, the generation oversight committee of the Exelon board of directors evaluates risks related to the generation business. The risk factors discussed below may adversely affect one or more of the Registrants' results of operations and cash flows and the market prices of their publicly traded securities. Each of the Registrants has disclosed the known material risks that affect its business at this time. However, there may be further risks and uncertainties that are not presently known or that are not currently believed by a Registrant to be material that may adversely affect its performance or financial condition in the future.

Exelon's financial condition and results of operations are affected to a significant degree by: (1) Generation's position as a predominantly nuclear generator selling power into competitive energy markets with a concentration in select regions, and (2) the role of ComEd, PECO and BGE as operators of electric transmission and distribution systems in three of the largest metropolitan areas in the United States. Factors that affect the financial condition and results of operations of the Registrants fall primarily under the following categories, all of which are discussed in further detail below:

- ***Market and Financial Factors.*** Exelon's and Generation's results of operations are affected by price fluctuations in the energy markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular the price of natural gas, which affects the prices that Generation can obtain for the output of its power plants, (2) the presence of other generation resources in the markets in which Generation's output is sold, (3) the demand for electricity in the markets where the Registrants conduct their business, and (4) the impacts of on-going competition in the retail channel.
- ***Regulatory and Legislative Factors.*** The regulatory and legislative factors that may affect the Registrants include changes to the laws and regulations that govern competitive markets and utility cost recovery, and that drive environmental policy. In particular, Exelon's and Generation's financial performance may be affected by changes in the design of competitive wholesale power markets or Generation's ability to sell power in those markets. In addition, potential regulation and legislation, including legislation or regulation regarding climate change and renewable portfolio standards, could have significant effects on the Registrants. Also, returns for ComEd, PECO and BGE are influenced significantly by state regulation and regulatory proceedings.

- ***Operational Factors.*** The Registrants' operational performance is subject to those factors inherent in running the nation's largest fleet of nuclear power reactors and large electric and gas distribution systems. The safe and effective operation of the nuclear facilities and the ability to effectively manage the associated decommissioning obligations as well as the ability to maintain the availability, reliability and safety of its energy delivery systems are fundamental to Exelon's ability to protect and grow shareholder value. Additionally, the operating costs of ComEd, PECO and BGE, and the opinions of their customers and regulators, are affected by those companies' ability to maintain the reliability and safety of their energy delivery systems.
- ***Risks Related to the Pending Merger with PHI.*** There are various risks and uncertainties associated with the merger agreement announced with PHI on April 29, 2014.

A discussion of each of these risk categories and other risk factors is included below.

Market and Financial Factors

Generation is exposed to depressed prices in the wholesale and retail power markets, which may negatively affect its results of operations and cash flows. (Exelon and Generation)

Generation is exposed to commodity price risk for the unhedged portion of its electricity generation supply portfolio. Generation's earnings and cash flows are therefore subject to variability as spot and forward market prices in the markets in which it operates rise and fall.

Price of Fuels : The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit. Often, the next unit of electricity will be supplied from generating stations fueled by fossil fuels. Consequently, changes in the market price of fossil fuels often result in comparable changes to the market price of power. For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing downward pressure on natural gas prices and, therefore, on power prices. The continued addition of supply from new alternative generation resources, such as wind and solar, whether mandated through RPS or otherwise subsidized or encouraged through climate legislation or regulation, may displace a higher marginal cost plant, further reducing power prices. In addition, further delay or elimination of EPA air quality regulations could prolong the duration for which the cost of pollution from fossil fuel generation is not factored into market prices.

Demand and Supply: The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs can each depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on electricity market prices. The tepid economic environment in recent years and growing energy efficiency and demand response initiatives have limited the demand for electricity in Generation's markets. In addition, in some markets, the supply of electricity through wind or solar generation, when combined with other base-load generation such as nuclear, may often exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants. The risk of increased supply in excess of demand is heightened by continued or increased RPS mandates or other subsidies, including ITCs and PTCs.

Retail Competition: Generation's retail operations compete for customers in a competitive environment, which affects the margins that Generation can earn and the volumes that it is able to serve. In periods of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and

wholesale generators (including Generation) use their retail operations to hedge generation output. Increased or more aggressive competition can adversely affect overall gross margins and profitability in Generation's retail operations.

Sustained low market prices or depressed demand and over-supply could adversely affect Exelon's and Generation's results of operations and cash flows, and such impacts could be emphasized given Generation's concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect Exelon's and Generation's ability to fund other discretionary uses of cash such as growth projects or to pay dividends. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Exelon's and Generation's results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs which may be offset in whole or in part by reduced operating and maintenance expenses. A slow recovery in market conditions could result in a prolonged depression of or further decline in commodity prices, including low forward natural gas and power prices and low market volatility, which could also adversely affect Exelon's and Generation's results of operations, cash flows and financial position.

In addition to price fluctuations, Generation is exposed to other risks in the power markets that are beyond its control and may negatively affect its results of operations. (Exelon and Generation)

Credit Risk. In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money, or are obligated to purchase energy or fuel from Generation, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, Generation might be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. In the spot markets, Generation is exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs, the purpose of which is to spread such risk across all market participants. Generation is also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, Generation's retail sales subject it to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that may be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Market Designs. The wholesale markets remain evolving markets that vary from region to region and are still developing rules, practices and procedures. Changes in these market rules, problems with rule implementation, or failure of any of these markets could adversely affect Generation's business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

The Registrants are potentially affected by emerging technologies that may over time affect or transform the energy industry, including technologies related to energy generation, distribution and consumption. (Exelon, Generation, ComEd, PECO and BGE)

Some of these technologies include, but are not limited to further shale gas development or sources, cost-effective renewable energy technologies, broad consumer adoption of electric vehicles and energy storage devices. Such developments could affect the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions

of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could materially affect the Registrants' results of operations, financial position, and cash flows through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors may decrease the value of NDT funds and employee benefit plan assets and may increase the related employee benefit plan obligations, which then could require significant additional funding. (Exelon, Generation, ComEd, PECO and BGE)

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy may adversely affect the value of the investments held within Generation's NDTs and Exelon's employee benefit plan trusts. The Registrants have significant obligations in these areas and Exelon and Generation hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which may fall below the Registrants' projected return rates. A decline in the market value of the NDT fund investments may increase Generation's funding requirements to decommission its nuclear plants. A decline in the market value of the pension and OPEB plan assets will increase the funding requirements associated with Exelon's pension and OPEB plan obligations. Additionally, Exelon's pension and OPEB plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements may also increase the costs and funding requirements of the obligations related to the pension and OPEB plans. If future increases in pension and other postretirement costs as a result of reduced plan assets or other factors cannot be recovered, or cannot be recovered in a timely manner, from ComEd, PECO and BGE customers, the results of operations and financial positions of ComEd, PECO and BGE could be negatively affected. Ultimately, if the Registrants are unable to manage the investments with the NDT funds and benefit plan assets, and are unable to manage the related benefit plan liabilities, their results of operations, cash flows and financial positions could be negatively affected.

Unstable capital and credit markets and increased volatility in commodity markets may adversely affect the Registrants' businesses in several ways, including the availability and cost of short-term funds for liquidity requirements, the Registrants' ability to meet long-term commitments, Generation's ability to hedge effectively its generation portfolio, and the competitiveness and liquidity of energy markets; each could adversely affect the Registrants' financial condition, results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity needs if internal funds are not available from the Registrants' respective operations. Disruptions in the capital and credit markets in the United States or abroad can adversely affect the Registrants' ability to access the capital markets or draw on their respective bank revolving credit facilities. The Registrants' access to funds under their credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from the Registrants and other borrowers within a short period of time. The inability to access capital markets or credit facilities, and longer term disruptions in the capital and credit markets as a result of uncertainty, changing or increased

regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, changes to Generation's hedging strategy in order to reduce collateral-posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

In addition, the Registrants have exposure to worldwide financial markets, including Europe. Disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2014, approximately 29%, or $2.5 billion of the Registrants' available credit facilities were with European banks, excluding the unsecured bridge facility to provide financing for the proposed PHI acquisition. The credit facilities include $8.5 billion in aggregate total commitments of which $7.3 billion was available as of December 31, 2014. There were no borrowings under the Registrants' credit facilities as of December 31, 2014. See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in energy markets depend heavily on active participation by multiple trading parties, which could be adversely affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that may affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to the respective businesses of the Registrants. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on Exelon's and Generation's results of operations and cash flows.

If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its trading counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs. (Exelon, Generation, ComEd, PECO and BGE)

Generation's business is subject to credit quality standards that may require market participants to post collateral for their obligations. If Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating) or otherwise fail to satisfy the credit standards of trading counterparties, it would be required under its hedging arrangements to provide collateral in the form of letters of credit or cash, which may have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time is dependent on a variety of factors, including (1) the notional amount of the applicable hedge, (2) the nature of counterparty and related agreements, and (3) changes in power or other commodity prices. In addition, if Generation were downgraded, it could experience higher borrowing costs as a result of the downgrade. Generation could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the power generation industry in general, or Generation in particular, has deteriorated. Changes in ratings methodologies by the credit rating agencies could also have a negative impact on the ratings of Generation.

ComEd's, PECO's and BGE's operating agreements with PJM and PECO's and BGE's natural gas procurement contracts contain collateral provisions that are affected by their credit rating and market prices. If certain wholesale market conditions were to exist and ComEd, PECO and BGE were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the forms of letters of credit or cash, which may have a material

adverse effect upon their liquidity. Collateral posting requirements will generally increase as market prices rise and decrease as market prices fall. Collateral posting requirements for PECO and BGE, with respect to their natural gas supply contracts, will generally increase as forward market prices fall and decrease as forward market prices rise. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if ComEd, PECO and BGE were downgraded, they could experience higher borrowing costs as a result of the downgrade.

ComEd, PECO or BGE could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the utility industry in general, or ComEd, PECO, or BGE in particular, has deteriorated. ComEd, PECO or BGE could experience a downgrade if the current regulatory environments in Illinois, Pennsylvania or Maryland, respectively, become less predictable by materially lowering returns for utilities in the applicable state or adopting other measures to mitigate higher electricity prices. Additionally, the ratings for ComEd, PECO or BGE could be downgraded if their financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage their capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of ComEd, PECO or BGE.

ComEd, PECO and BGE conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that ComEd, PECO and BGE are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate ComEd, PECO and BGE from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as “ring-fencing”) may help avoid or limit a downgrade in the credit ratings of ComEd, PECO and BGE in the event of a reduction in the credit rating of Exelon. Despite these ring-fencing measures, the credit ratings of ComEd, PECO or BGE could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of ComEd, PECO or BGE, or all three. A reduction in the credit rating of ComEd, PECO or BGE could have a material adverse effect on ComEd, PECO or BGE, respectively.

See Liquidity and Capital Resources—Recent Market Conditions and Security Ratings for further information regarding the potential impacts of credit downgrades on the Registrants’ cash flows.

Generation’s financial performance may be negatively affected by price volatility, availability and other risk factors associated with the procurement of nuclear and fossil fuel. (Exelon and Generation)

Generation depends on nuclear fuel and fossil fuels to operate its generating facilities. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. Coal, natural gas and oil are procured for generating plants through annual, short-term and spot-market purchases. The supply markets for nuclear fuel, coal, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default that may negatively affect the results of operations and cash flows for Generation.

Generation’s risk management policies cannot fully eliminate the risk associated with its commodity trading activities. (Exelon and Generation)

Generation’s asset-based power position as well as its power marketing, fuel procurement and other commodity trading activities expose Generation to risks of commodity price movements. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned

and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations may be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, Generation cannot predict the impact that its commodity trading activities and risk management decisions may have on its business, operating results, cash flows or financial position.

Generation buys and sells energy and other products and enters into financial contracts to manage risk and hedge various positions in Generation's power generation portfolio. The proportion of hedged positions in its power generation portfolio may cause volatility in Generation's future results of operations.

Financial performance and load requirements may be adversely affected if Generation is unable to effectively manage its power portfolio. (Exelon and Generation)

A significant portion of Generation's power portfolio is used to provide power under procurement contracts with ComEd, PECO, BGE and other customers. To the extent portions of the power portfolio are not needed for that purpose, Generation's output is sold in the wholesale power markets. To the extent its power portfolio is not sufficient to meet the requirements of its customers under the related agreements, Generation must purchase power in the wholesale power markets. Generation's financial results may be negatively affected if it is unable to cost-effectively meet the load requirements of its customers, manage its power portfolio and effectively address the changes in the wholesale power markets.

Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could negatively impact the Registrants' results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Corporate Tax Reform. There exists the potential for comprehensive tax reform in the United States that may significantly change the tax rules applicable to U.S. domiciled corporations. Exelon cannot assess what the overall effect of such potential legislation might be on its results of operations and cash flows.

1999 sale of fossil generating assets. The IRS has challenged Exelon's 1999 tax position on its like-kind exchange transaction. Exelon and the IRS failed to reach a settlement on the like-kind exchange position and Exelon filed a petition on December 31, 2013 to initiate litigation in the United States Tax Court. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the like-kind exchange position. The litigation could take three to five years including appeals, if necessary.

As of December 31, 2014, if the IRS is successful in its challenge to the like-kind exchange position, Exelon's potential cash outflow, including tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $810 million, of which approximately $310 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless. In addition to attempting to impose tax on the like-kind exchange position, the IRS has asserted penalties for a substantial understatement of tax, which could result in an after-tax charge of $90 million to Exelon's and ComEd's results of operations should the IRS prevail in asserting the penalties. The timing effects of the final resolution of the like-kind exchange matter are unknown. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Tax reserves and the recoverability of deferred tax assets. The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeals issues related to these tax matters. These judgments include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by the tax authorities. The Registrants also estimate their ability to utilize tax benefits, including those in the form of carryforwards and tax credits. See Notes 1—Significant Accounting Policies and Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Increases in customer rates and the impact of economic downturns may lead to greater expense for uncollectible customer balances. Additionally, increased rates could lead to decreased volumes delivered. Both of these factors may decrease Generation's, ComEd's, PECO's and BGE's results from operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

ComEd's, PECO's and BGE's current procurement plans include purchasing power through contracted suppliers and in the spot market. ComEd's and PECO's costs of purchased power are charged to customers without a return or profit component. BGE's SOS rates charged to customers recover BGE's wholesale power supply costs and include a return component. For PECO, purchased natural gas costs are charged to customers with no return or profit component. For BGE, purchased natural gas costs are charged to customers using a MBR mechanism that compares the actual cost of gas to a market index. The difference between the actual cost and the market index is shared equally between shareholders and customers. Purchased power and natural gas prices fluctuate based on their relevant supply and demand. Significantly higher rates related to purchased power and natural gas can result in declines in customer usage, lower revenues and potentially additional uncollectible accounts expense for ComEd, PECO and BGE. In addition, any challenges by the regulators or ComEd, PECO and BGE as to the recoverability of these costs could have a material effect on the Registrants' results of operations and cash flows. Also, ComEd's, PECO's and BGE's cash flows can be affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

Further, the impacts of economic downturns on ComEd, PECO and BGE customers and purchased natural gas costs for PECO and BGE customers, such as unemployment for residential customers and less demand for products and services provided by commercial and industrial customers, and the related regulatory limitations on residential service terminations, may result in an increase in the number of uncollectible customer balances, which would negatively impact ComEd's, PECO's and BGE's results from operations and cash flows. Generation's customer supply activities face economic downturn risks similar to Exelon's utility businesses, such as lower volumes sold and increased expense for uncollectible customer balances. As Generation increases its customer supply footprint, economic downturn impacts could negatively affect Generation's results from operations and cash flows. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants' credit risk.

The effects of weather may impact the Registrants' results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Moderate temperatures adversely affect the usage of energy and resulting revenues at ComEd and PECO. Due to revenue decoupling, BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what

actual distribution volumes are for a billing period, and is not affected by actual weather with the exception of major storms. Extreme weather conditions or damage resulting from storms may stress ComEd's, PECO's and BGE's transmission and distribution systems, communication systems and technology, resulting in increased maintenance and capital costs and limiting each company's ability to meet peak customer demand. These extreme conditions may have detrimental effects on ComEd's, PECO's and BGE's results of operations and cash flows. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and may make period comparisons less relevant.

Generation's operations are also affected by weather, which affects demand for electricity as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation may require greater resources to meet its contractual commitments. Extreme weather conditions or storms may affect the availability of generation and its transmission, limiting Generation's ability to source or send power to where it is sold. In addition, drought-like conditions limiting water usage can impact Generation's ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, may have an adverse effect by causing Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Certain long-lived assets and other assets recorded on the Registrants' statements of financial position may become impaired, which would result in write-offs of the impaired amounts. (Exelon, Generation, ComEd, PECO and BGE)

Long-lived assets represent the single largest asset class on the Registrants' statement of financial position. Specifically, long-lived assets account for 60%, 51%, 62%, 68% and 77% of total assets for Exelon, Generation, ComEd, PECO and BGE, respectively, as of December 31, 2014. In addition, Exelon and Generation have significant balances related to unamortized energy contracts. See Note 4—Mergers, Acquisitions, and Dispositions and Note 10—Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's unamortized energy contracts. The Registrants evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered when evaluating long-lived assets for potential impairment. An impairment would require the Registrants to reduce the carrying value of the long-lived asset through a non-cash charge to expense by the amount of the impairment, and such an impairment could have a material adverse impact on the Registrants' results of operations.

Exelon holds investments in coal-fired plants in Georgia that are subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual value of the leased assets at the end of the lease term. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records a non-cash impairment charge to expense if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Such an impairment could have a material adverse impact on Exelon's results of operations.

Exelon and ComEd had approximately $2.7 billion of goodwill recorded at December 31, 2014 in connection with the merger between PECO and Unicom Corporation, the former parent company of ComEd. Under GAAP, goodwill remains at its recorded amount unless it is determined to be impaired, which is generally based upon an annual analysis that compares the implied fair value of the goodwill to its carrying value. If an impairment occurs, the amount of the impaired goodwill will be written-off to expense, which will also reduce equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. A successful IRS challenge to

Exelon's and ComEd's like-kind exchange income tax position, adverse regulatory actions such as early termination of EIMA, or changes in significant assumptions used in estimating ComEd's fair value (e.g., discount and growth rates, utility sector market performance and transactions, operating and capital expenditure requirements and the fair value of debt) could result in an impairment. Such an impairment would result in a non-cash charge to expense, which could have a material adverse impact on Exelon's and ComEd's results of operations.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Critical Accounting Policies and Estimates and Note 7—Property, Plant and Equipment, Note 8—Impairment of Long Lived Assets and Note 10—Intangible Assets of the Combined Notes to the Consolidated Financial Statements for additional discussion on long-lived asset and goodwill impairments.

The Registrants' businesses are capital intensive, and their assets may require significant expenditures to maintain and are subject to operational failure, which could result in potential liability. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants' businesses are capital intensive and require significant investments by Generation in electric generating facilities and by ComEd, PECO and BGE in transmission and distribution infrastructure projects. These operational systems and infrastructure have been in service for many years. Older equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Registrants' control, and may require significant expenditures to operate efficiently. The Registrants' results of operations, financial condition, or cash flows could be adversely affected if they were unable to effectively manage their capital projects or raise the necessary capital. Furthermore, operational failure of electric or gas systems or infrastructure could result in potential liability if such failure results in damage to property or injury to individuals. See ITEM 1. BUSINESS for further information regarding the Registrants' potential future capital expenditures.

Exelon and its subsidiaries have guaranteed the performance of third parties, which may result in substantial costs in the event of non-performance by third parties. In addition, the Registrants have rights under agreements which obligate third parties to indemnify the Registrants for various obligations, and the Registrants may incur substantial costs in the event that the applicable Registrant is unable to enforce those agreements or the applicable third-party is otherwise unable to perform. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have issued guarantees of the performance of third parties, which obligate one or more of the Registrants or their subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, the Registrants could incur substantial cost to fulfill their obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial condition, or cash flows of the Registrants.

The Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected Registrant could be held responsible for the obligations, which could impact that Registrant's results of operations, cash flows and financial position. In connection with Exelon's 2001 corporate restructuring, Generation assumed certain of ComEd's and PECO's rights and obligations with respect to their former generation businesses. Further, ComEd and PECO may have entered into agreements with third parties under which the third-party agreed to indemnify ComEd or PECO for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the

restructuring. If the third-party or Generation experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, ComEd or PECO could be liable for any existing or future claims, which could impact ComEd's or PECO's results of operations, cash flows and financial position.

Generation's business may be negatively affected by competitive electric generation suppliers. (Exelon and Generation)

Because retail customers where Generation serves load can switch from their respective energy delivery company to a competitive electric generation supplier for their energy needs, planning to meet Generation's obligation to provide the supply needed to serve Generation's share of an electric distribution company's default service obligation is more difficult than planning for retail load before the advent of retail competition. Before retail competition, the primary variables affecting projections of load were weather and the economy. With retail competition, another major factor is retail customers switching to or from competitive electric generation suppliers. If fewer of such customers switch from its retail load serving counterparties than Generation anticipates, the load that Generation must serve will be greater than anticipated, which could, if market prices have increased, increase Generation's costs (due to its need to go to market to cover its incremental supply obligation) more than the increase in Generation's revenues. If more customers from its retail load serving counterparties switch than Generation anticipates, the load that Generation must serve will be lower than anticipated, which could, if market prices have decreased, cause Generation to lose opportunities in the market.

Regulatory and Legislative Factors

The Registrants' generation and energy delivery businesses are highly regulated and could be subject to adverse regulatory and legislative actions. Fundamental changes in regulation or legislation or violation of tariffs or market rules and anti-manipulation laws, could disrupt the Registrants' business plans and adversely affect their operations and financial results. (Exelon, Generation, ComEd, PECO and BGE)

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation. Further, Exelon's and Generation's operating results and cash flows are heavily dependent upon the ability of Generation to sell power at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon's, ComEd's, PECO's and BGE's operating results and cash flows are heavily dependent on the ability of ComEd, PECO and BGE to recover their costs for the retail purchase and distribution of power to their customers. Similarly, there is risk that financial market regulations could increase the Registrants' compliance costs and limit their ability to engage in certain transactions. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, exchanges, ratemaking agencies and taxing authorities. Additionally, the Registrants need to be cognizant of rules changes or Registrant actions that could result in potential violation of tariffs, market rules and anti-manipulation laws. Fundamental changes in regulations or other adverse legislative actions affecting the Registrants' businesses would require changes in their business planning models and operations and could adversely affect their results of operations, cash flows and financial position.

Regulatory and legislative developments related to climate change and RPS may also significantly affect Exelon's and Generation's results of operations, cash flows and financial positions. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, may sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. However, national regulation or legislation addressing climate change through

an RPS could also increase the pace of development of wind energy facilities in the Midwest, which could put downward pressure on wholesale market prices for electricity from Generation's Midwest nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation's nuclear assets under a carbon constrained regulatory regime that might exist in the future. Similarly, final regulations under Section 111(d) of the Clean Air Act may not provide sufficient incentives for states to utilize carbon-free nuclear power as a means of meeting greenhouse gas emission reduction requirements, while continuing a policy of favoring renewable energy sources. Current state level climate change and renewable regulation is already providing incentives for regional wind development. The Registrants cannot predict when or whether any of these various legislative and regulatory proposals may become law or what their effect will be on the Registrants.

Generation may be negatively affected by possible Federal or state legislative or regulatory actions that could affect the scope and functioning of the wholesale markets. (Exelon and Generation)

Federal and state legislative and regulatory bodies are facing pressures to address consumer concerns, or are themselves raising concerns, that energy prices in wholesale markets are too high or insufficient generation is being built because the competitive model is not working, and, therefore, are considering some form of re-regulation or some other means of reducing wholesale market prices or subsidizing new generation. Generation is dependent on robust and competitive wholesale energy markets to achieve its business objectives.

Approximately 60% of Generation's generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Generation's future results of operations will depend on (1) FERC's continued adherence to and support for, policies that favor the preservation of competitive wholesale power markets, such as PJM's, and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competitiveness. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize new generation, such as the subsequently dismissed New Jersey Capacity Legislation and the MDPSC's RFP for new gas-fired generation in Maryland. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details related to the New Jersey Capacity Legislation and the Maryland new electric generation requirements.

In addition, FERC's application of its Order 697 and its subsequent revisions could pose a risk that Generation will have difficulty satisfying FERC's tests for market-based rates. Since Order 697 became final in June 2007, Generation has obtained orders affirming Generation's authority to sell at market-based rates and none denying that authority. As of December 31, 2014, Generation has submitted its triennial application seeking reauthorization to sell at market-based rates in the Southeast region. Generation's previous submission seeking reauthorization to sell at market-based rates was accepted by FERC on August 5, 2014 for the Northeast region (including PJM).

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted in July 2010. The part of the Act that applies to Exelon is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires the creation of a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing for certain categories of Swaps, incentives to shift Swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. For non security-based Swaps including commodity Swaps, Dodd-Frank empowers the Commodity Futures Trading Commission (CFTC) to promulgate regulations implementing the law's objectives. The primary aim of Dodd-Frank is to regulate the key intermediaries in the Swaps market, which entities are either swap dealers (SDs), major swap participants (MSPs), and certain other financial entities, but the law also applies to a lesser

degree to end-users of Swaps. On January 12, 2015, President Obama signed into law a bill that exempts from margin requirements Swaps used by end-users to hedge or mitigate commercial risk. Moreover, the CFTC's Dodd-Frank regulations preserve the ability of end users in the energy industry to hedge their risks using Swaps without being subject to mandatory clearing, and excepts or exempts end-users from many of the other substantive regulations. Accordingly, as an end-user, Generation is conducting its commercial business in a manner that does not require registration with the CFTC as an SD or MSP. Generation does not anticipate transacting in the future in a manner in which it would become a SD or MSP.

There are, however, some rulemakings that have not yet been finalized, including the capital and margin rules for (non-cleared) Swaps. Generation does not expect these rules to directly impact its collateral requirements. However, depending on the substance of these final rules in addition to certain international regulatory requirements still under development and that are similar to Dodd-Frank, Generation's Swap counterparties could be subject to additional and potentially significant capitalization requirements. These regulations could motivate the SDs and MSPs to increase collateral requirements or cash postings from their counterparties, including Generation.

Generation continues to monitor the rulemaking proceedings with respect to the capital and margin rules, but cannot predict to what extent, if any, further refinements to Dodd-Frank requirements may impact its cash flows or financial position, but such impacts could be material.

ComEd, PECO and BGE could also be subject to some Dodd-Frank requirements to the extent they were to enter into Swaps. However, at this time, management of ComEd, PECO and BGE continue to expect that their companies will not be materially affected by Dodd-Frank.

Generation's affiliation with ComEd, PECO and BGE, together with the presence of a substantial percentage of Generation's physical asset base within the ComEd, PECO and BGE service territories, could increase Generation's cost of doing business to the extent future complaints or challenges regarding ComEd, PECO and/or BGE retail rates result in settlements or legislative or regulatory requirements funded in part by Generation. (Exelon and Generation)

Generation has significant generating resources within the service areas of ComEd, PECO and BGE and makes significant sales to each of them. Those facts tend to cause Generation to be directly affected by developments in those markets. Government officials, legislators and advocacy groups are aware of Generation's affiliation with ComEd, PECO and BGE and its sales to each of them. In periods of rising utility rates, particularly when driven by increased costs of energy production and supply, those officials and advocacy groups may question or challenge costs and transactions incurred by ComEd, PECO, or BGE, with Generation, irrespective of any previous regulatory processes or approvals underlying those transactions. The prospect of such challenges may increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges may subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators may seek ways to force Generation to contribute to efforts to mitigate potential or actual rate increases, through measures such as generation-based taxes and contributions to rate-relief packages.

The Registrants may incur substantial costs to fulfill their obligations related to environmental and other matters. (Exelon, Generation, ComEd, PECO and BGE)

The businesses which the Registrants operate are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the manner in which the Registrants conduct their operations and make capital expenditures including how they

handle air and water emissions and solid waste disposal. Violations of these emission and disposal requirements can subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties' claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generate. The Registrants have incurred and expect to incur significant costs related to environmental compliance, site remediation and clean-up. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

If application of Section 316(b) of the Clean Water Act, which establishes a national requirement for reducing the adverse impacts to aquatic organisms at existing generating stations, requires the retrofitting of cooling water intake structures at Salem or other Exelon power plants, this development could result in material costs of compliance. Pursuant to discussions with the NJDEP regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029.

Additionally, Generation is subject to exposure for asbestos-related personal injury liability alleged at certain current and formerly owned generation facilities. Future legislative action could require Generation to make a material contribution to a fund to settle lawsuits for alleged asbestos-related disease and exposure.

In some cases, a third-party who has acquired assets from a Registrant has assumed the liability the Registrant may otherwise have for environmental matters related to the transferred property. If the transferee is unable, or fails, to discharge the assumed liability, a regulatory authority or injured person could attempt to hold the Registrant responsible, and the Registrant's remedies against the transferee may be limited by the financial resources of the transferee. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in ComEd's, PECO's and BGE's respective terms and conditions of service, including their respective rates, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy and subject to appeal, which lead to uncertainty as to the ultimate result and which may introduce time delays in effectuating rate changes. (Exelon, ComEd, PECO and BGE)

ComEd, PECO and BGE are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for ComEd, PECO or BGE to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates can be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, bad debt, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs.

In certain instances, ComEd, PECO and BGE may agree to negotiated settlements related to various rate matters, customer initiatives or franchise agreements. These settlements are subject to regulatory approval.

ComEd, PECO and BGE cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania, Maryland or Federal regulators in establishing rates, including the extent, if any, to which certain costs such as significant capital projects will be recovered or what rates of return will be allowed. Nevertheless, the expectation is that ComEd, PECO and BGE will continue to be obligated to deliver electricity to customers in their respective service territories and will also retain significant POLR and default service obligations to provide electricity and natural gas to certain groups of customers in their respective service areas who do not choose an alternative supplier. The ultimate outcome and timing of regulatory rate proceedings have a significant effect on the ability of ComEd, PECO and BGE, as applicable, to recover their costs and could have a material adverse effect on ComEd's, PECO's and BGE's results of operations, cash flows and financial position. See Note 3—Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for information regarding rate proceedings.

Federal or additional state RPS and/or energy conservation legislation, along with energy conservation by customers, could negatively affect the results of operations and cash flows of Generation, ComEd, PECO and BGE. (Exelon, Generation, ComEd, PECO and BGE)

Changes to current state legislation or the development of Federal legislation that requires the use of renewable and alternate fuel sources, such as wind, solar, biomass and geothermal, could significantly impact Generation, ComEd, PECO and BGE, especially if timely cost recovery is not allowed. The impact could include increased costs for RECs and purchased power and increased rates for customers.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, have increased capital expenditures and could significantly impact ComEd, PECO and BGE, if timely cost recovery is not allowed. Furthermore, regulated energy consumption reduction targets and declines in customer energy consumption resulting from the implementation of new energy conservation technologies could lead to a decline in the revenues of Exelon, ComEd, and PECO. For additional information, see ITEM 1. BUSINESS "Environmental Regulation-Renewable and Alternative Energy Portfolio Standards."

The impact of not meeting the criteria of the FASB guidance for accounting for the effects of certain types of regulation could be material to Exelon, ComEd, PECO and BGE. (Exelon, ComEd, PECO and BGE)

As of December 31, 2014, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria of the authoritative guidance for accounting for the effects of certain types of regulation. If it is concluded in a future period that a separable portion of their businesses no longer meets the criteria, Exelon, ComEd, PECO and BGE would be required to eliminate the financial statement effects of regulation for that part of their business. That action would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets and the recognition of a one-time charge in their Consolidated Statements of Operations. The impact of not meeting the criteria of the authoritative guidance could be material to the financial statements of Exelon, ComEd, PECO and BGE. At December 31, 2014, the gain (loss) could have been as much as $(2.6) billion, $811 million and $480 million (before taxes) as a result of the elimination of ComEd's, PECO's and BGE's regulatory assets and liabilities, respectively.

Further, Exelon would record a charge against OCI (before taxes) of up to $2.6 billion and $663 million for ComEd and BGE, respectively, related to Exelon's net regulatory assets associated with its defined benefit postretirement plans. Exelon also has a net regulatory liability of $53 million (before taxes) associated with PECO's defined benefit postretirement plans that would result in an increase in OCI if reversed. The impacts and resolution of the above items could lead to an additional impairment of ComEd's goodwill, which could be significant and at least partially offset the gain at ComEd discussed above. A significant decrease in equity as a result of any changes could limit the ability of ComEd, PECO and BGE to pay dividends under Federal and state law and no longer meeting the regulatory accounting criteria could cause significant volatility in future results of operations. See Notes 1—Significant Accounting Policies, 3—Regulatory Matters and 10—Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd's goodwill, respectively.

Exelon and Generation may incur material costs of compliance if Federal and/or state regulation or legislation is adopted to address climate change. (Exelon and Generation)

Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. In 2009, select Northeast and Mid-Atlantic states implemented a model rule, developed via the RGGI, to regulate CO2 emissions from fossil-fired generation. RGGI states are working on updated programs to further limit emissions and the EPA has introduced regulation to address greenhouse gases from new fossil plants that could potentially impact existing plants. If carbon reduction regulation or legislation becomes effective, Exelon and Generation may incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. For example, more stringent permitting requirements may preclude the construction of lower-carbon nuclear and gas-fired power plants. Similarly, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS "Global Climate Change" and Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of ComEd, PECO, and BGE to the results of PJM's RTEP and NERC compliance requirements. (Exelon, Generation, ComEd, PECO and BGE)

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation, ComEd, PECO and BGE, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. As operators of natural gas distribution systems, PECO and BGE are also subject to mandatory reliability standards of the U.S. Department of Transportation. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards may subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC and MDPSC impose certain distribution reliability standards on ComEd, PECO and BGE, respectively. If the Registrants were found not to be in compliance with the mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

ComEd, PECO and BGE as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments may require ComEd, PECO and BGE to incur incremental capital or

operating and maintenance expenditures to ensure their transmission lines meet NERC standards. Uncertainties exist as to the construction of new transmission facilities, their cost and how those costs will be allocated to transmission system participants and customers. In accordance with a FERC order and related settlement, PJM's RTEP requires the costs of new transmission facilities to be allocated across the entire PJM footprint for new facilities greater than or equal to 500 kV, and requires costs of new facilities less than 500 kV to be allocated to the beneficiaries of the new facilities. Following a remand from the U.S. Court of Appeals for the Seventh Circuit, FERC reaffirmed its decision related to allocation of new facilities 500 kV and above. The U.S. Court of Appeals for the Seventh Circuit remanded this decision a second time. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the issue of the cost allocation for facilities 500 kV and above. This FERC order only applies to facilities included in the PJM RTEP prior to February 1, 2013. For facilities subsequently approved, the costs of new facilities that are double circuit 345 kV or greater than or equal to 500 kV will be allocated 50% across the entire PJM footprint and 50% allocated to identified beneficiaries. Costs for all other facilities will be allocated to all identified beneficiaries. This later decision is subject to rehearing by FERC and possible appeal.

See Note 3—Regulatory Matters and Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants cannot predict the outcome of the legal proceedings relating to their business activities. An adverse determination could have a material adverse effect on their results of operations, financial positions and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are involved in legal proceedings, claims and litigation arising out of their business operations, the most significant of which are summarized in Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on the Registrants' results of operations.

Generation may be negatively affected by possible Nuclear Regulatory Commission actions that could affect the operations and profitability of its nuclear generating fleet. (Exelon and Generation)

Regulatory risk **.** A change in the Atomic Energy Act or the applicable regulations or licenses may require a substantial increase in capital expenditures or may result in increased operating or decommissioning costs and significantly affect Generation's results of operations or financial position. Events at nuclear plants owned by others, as well as those owned by Generation, may cause the NRC to initiate such actions.

As an example, prior to the Fukushima Daiichi accident on March 11, 2011, the NRC had been evaluating seismic risk. After the Fukushima Daiichi accident, the NRC's focus on seismic risk intensified. As part of the NRC Near-Term Task Force (Task Force) review and evaluation of the Fukushima Daiichi accident, the Task Force recommended that plant operators conduct seismic reevaluations. In January 2012, the NRC released an updated seismic risk model that plant operators must use in performing the seismic reevaluations recommended by the Task Force. These reevaluations could result in the required implementation of additional mitigation strategies or modifications.

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF, such as the one previously considered at Yucca Mountain, Nevada, and the timing of such facility opening, will

significantly affect the costs associated with storage of SNF, and the ultimate amounts received from the DOE to reimburse Generation for these costs. The NRC's temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants. In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. On September 19, 2014, the NRC issued a revised rule codifying the NRC's generic determinations regarding the environmental impacts of continued storage of spent nuclear fuel beyond a reactor's licensed operating life. The Continued Storage Rule became effective on October 20, 2014.

Any regulatory action relating to the timing and availability of a repository for SNF may adversely affect Generation's ability to decommission fully its nuclear units. Through May 15, 2014, in accordance with the NWPA and Generation's contract with the DOE, Generation paid the DOE a fee per kWh of net nuclear generation for the cost of SNF disposal. On November 19, 2013, the United States Court of Appeals for the District of Columbia Circuit ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On January 3, 2014, the DOE filed a petition for rehearing which was denied by the D.C. Circuit Court on March 18, 2014. Also, on January 3, 2014, the DOE submitted a proposal to Congress to reduce the current SNF disposal fee to zero. On May 9, 2014, the DOE notified Generation that the SNF disposal fee was set to zero, effective May 16, 2014. Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. Generation currently estimates 2025 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the spent nuclear fuel obligation. Generation cannot predict what, if any, fee will be established in the future for SNF disposal. However, such a fee could be material to Generation's results of operations and cash flows.

License renewals. Generation cannot assure that economics will support the continued operation of the facilities for all or any portion of any renewed license period. If the NRC does not renew the operating licenses for Generation's nuclear stations or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates, impairment charges and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. In addition, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments.

Operational Factors

The Registrants' employees, contractors, customers and the general public may be exposed to a risk of injury due to the nature of the energy industry. (Exelon, Generation, ComEd, PECO and BGE)

Employees and contractors throughout the organization work in, and customers and the general public may be exposed to, potentially dangerous environments near their operations. As a result, employees, contractors, customers and the general public are at risk for serious injury, including loss of life. Significant risks include nuclear accidents, dam failure, gas explosions, pole strikes and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events may adversely affect Exelon's results of operations, its ability to raise capital and its future growth. (Exelon, Generation, ComEd, PECO and BGE)

Generation's fleet of power plants and ComEd's, PECO's and BGE's distribution and transmission infrastructures could be affected by natural disasters, such as seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Registrants' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. An example of such an event was the February 5, 2014 ice storm, which interrupted electric service delivery to customers in PECO's service territory and resulted in significant restoration costs.

Another example of such an event includes the 9.0 magnitude earthquake and ensuing tsunami experienced by Japan on March 11, 2011, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. Natural disasters and other significant events increase the risk to Generation that the NRC or other regulatory or legislative bodies may change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological aspects. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for Generation's continued operation, particularly the cooling of generating units. Additionally, natural disasters and other events that have an adverse effect on the economy in general may adversely affect the Registrants' operations and their ability to raise capital.

Exelon does not know the impact that potential terrorist attacks could have on the industry in general and on Exelon in particular. As owner-operators of infrastructure facilities, such as nuclear, fossil and hydroelectric generation facilities and electric and gas transmission and distribution facilities, the Registrants face a risk that their operations would be direct targets or indirect casualties of, an act of terror. Any retaliatory military strikes or sustained military campaign may affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cyber security of Exelon's facilities, which could adversely affect Exelon's ability to manage its business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also may result in a decline in energy consumption, which may adversely affect the Registrants' results of operations and its ability to raise capital. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants would be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate its generating and transmission and distribution assets could be affected, resulting in decreased service levels and increased costs.

In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property and casualty losses subject to unforeseen occurrences or catastrophic events that may damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

Generation's financial performance may be negatively affected by matters arising from its ownership and operation of nuclear facilities. (Exelon and Generation)

Nuclear capacity factors. Capacity factors for generating units, particularly capacity factors for nuclear generating units, significantly affect Generation's results of operations. Nuclear plant operations involve substantial fixed operating costs but produce electricity at low variable costs due to nuclear fuel costs typically being lower than fossil fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear facilities at high capacity factors. Lower capacity factors increase Generation's operating costs by requiring Generation to produce additional energy from primarily its fossil facilities or purchase additional energy in the spot or forward markets in order to satisfy Generation's obligations to committed third-party sales, including ComEd, PECO and BGE. These sources generally have higher costs than Generation incurs to produce energy from its nuclear stations.

Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, can have a significant impact on Generation's results of operations. When refueling outages at wholly and co-owned plants last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales.

Nuclear fuel quality **.** The quality of nuclear fuel utilized by Generation can affect the efficiency and costs of Generation's operations. Certain of Generation's nuclear units have previously had a limited number of fuel performance issues. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

Operational risk **.** Operations at any of Generation's nuclear generation plants could degrade to the point where Generation has to shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Generation may choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, Generation may not achieve the anticipated results under its series of planned power uprates across its nuclear fleet. For plants operated but not wholly owned by Generation, Generation may also incur liability to the co-owners. For plants not operated and not wholly owned by Generation, from which Generation receives a portion of the plants' output, Generation's results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by Generation could result in increased regulation and reduced public support for nuclear-fueled energy, which could significantly affect Generation's results of operations or financial position. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident can be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by Generation or owned by others, may exceed Generation's resources, including insurance coverage. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by Generation and could have a material adverse effect on Generation's results of operations or financial position. Additionally, an accident or other significant

event at a nuclear plant within the United States or abroad, owned by others or Generation, may result in increased regulation and reduced public support for nuclear-fueled energy and significantly affect Generation's results of operations or financial position.

Nuclear insurance. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance. The required amount of nuclear liability insurance is $375 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.6 billion limit for a single incident.

Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation's nuclear operations. In previous years, NEIL has made distributions to its members but Generation cannot predict the level of future distributions or if they will occur at all. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Generation is required to provide to the NRC a biennial report by unit (annually for Generation's two units that have been retired) addressing Generation's ability to meet the NRC-estimated funding levels including scheduled contributions to and earnings on the decommissioning trust funds. The NRC funding levels are based upon the assumption that decommissioning will commence after the end of the current licensed life of each unit.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results may differ significantly from current estimates. The performance of capital markets also can significantly affect the value of the trust funds. Currently, Generation is making contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation, through PECO, has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from utility customers for any of its other nuclear units if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that Generation would be unable to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if Generation no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units may be negatively affected and Exelon's and Generation's results of operations and financial position could be significantly affected. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Ultimately, if the investments held by Generation's NDTs are not sufficient to fund the decommissioning of Generation's nuclear units, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met. As a result, Generation's cash flows and financial position may be significantly adversely affected. Additionally, if the pledged assets are not sufficient to fund the Zion station decommissioning activities under the Asset Sale Agreement (ASA), Generation may have to seek remedies available under the ASA to reduce the risk of default by ZionSolutions and its parent. See Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's financial performance may be negatively affected by risks arising from its ownership and operation of hydroelectric facilities. (Exelon and Generation)

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. The license for the Conowingo Hydroelectric Project expires August 31, 2015, and the license for the Muddy Run Pumped Storage Project expires on September 1, 2015. Generation cannot predict whether it will receive all the regulatory approvals for the renewed licenses of its hydroelectric facilities. If FERC does not issue new operating licenses for Generation's hydroelectric facilities or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. Generation may also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions may be imposed as part of the license renewal process that may adversely affect operations, may require a substantial increase in capital expenditures or may result in increased operating costs and significantly affect Generation's results of operations or financial position. Similar effects may result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by Generation.

ComEd's, PECO's and BGE's operating costs, and customers' and regulators' opinions of ComEd, PECO and BGE, respectively, are affected by their ability to maintain the availability and reliability of their delivery and operational systems. (Exelon, ComEd, PECO and BGE)

Failures of the equipment or facilities, including information systems, used in ComEd's, PECO's and BGE's delivery systems can interrupt the electric transmission and electric and natural gas delivery, which could negatively impact related revenues, and increase maintenance and capital expenditures. Equipment or facilities failures can be due to a number of factors, including weather or information systems failure. Specifically, if the implementation of advanced metering infrastructure, smart grid or other technologies in ComEd's, PECO's or BGE's service territory fail to perform as intended or are not successfully integrated with billing and other information systems, ComEd's, PECO's and BGE's financial condition, results of operations, and cash flows could be adversely affected. Furthermore, if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, ComEd's, PECO's or BGE's financial results could be adversely affected. If an employee causes the operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating the operational systems, ComEd's, PECO's or BGE's financial results could also be adversely affected. In addition, dependence upon automated systems may further increase the risk that operational system flaws or employee tampering or manipulation of those systems will result in losses that are difficult to detect.

The aforementioned failures or those of other utilities, including prolonged or repeated failures, can affect customer satisfaction and the level of regulatory oversight and ComEd's, PECO's and BGE's maintenance and capital expenditures. Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd can be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, and those damages could be material to ComEd's results of operations and cash flows. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding proceedings related to storm-related outages in ComEd's service territory.

ComEd's, PECO's and BGE's respective ability to deliver electricity, their operating costs and their capital expenditures may be negatively affected by transmission congestion. (Exelon, ComEd, PECO and BGE)

Demand for electricity within ComEd's, PECO's and BGE's service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage with consequent effects on operating costs, revenues and results of operations. Also, insufficient availability of electric supply to meet customer demand could jeopardize ComEd's, PECO's and BGE's ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring ComEd, PECO and BGE to upgrade or expand their respective transmission systems through additional capital expenditures.

Failure to attract and retain an appropriately qualified workforce may negatively impact the Registrants' results of operations. (Exelon, Generation, ComEd, PECO and BGE)

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, may lead to operating challenges and increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission and distribution operations. If the Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations could be negatively affected.

The Registrants are subject to physical and information security risks. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants face physical and information security risks as the owner-operators of generation, transmission and distribution facilities. A security breach of the physical assets or information systems of the Registrants, their competitors, RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject the Registrants to financial harm associated with theft or inappropriate release of certain types of information, including sensitive customer data. If a significant breach occurred, the reputation of Exelon and its customer supply activities may be adversely affected, customer confidence in the Registrants or others in the industry may be diminished, or Exelon and its subsidiaries may be subject to legal claims, any of which may contribute to the loss of customers and have a negative impact on the business and/or results of operations. ComEd's, PECO's and BGE's deployment of smart meters throughout their service territories may increase the risk of damage from an intentional disruption of the system by third parties. As with most companies in today's environment, Exelon experiences attempts by hackers to infiltrate its corporate network. To date there have been no infiltrations that have resulted in loss of data or any significant effects on business operations. Exelon utilizes a dedicated team of cyber security professionals to ensure the protection of its information and ability to conduct business operations. Despite the measures taken by the Registrants to prevent a security breach, the Registrants cannot accurately assess the probability that a security breach may occur and are unable to quantify the potential impact of such an event. In addition, new or updated security regulations could require changes in current measures taken by the Registrants or their business operations and could adversely affect their results of operations, cash flows and financial position.

The Registrants may make investments in new business initiatives, including initiatives mandated by regulators, and markets that may not be successful, and acquisitions may not achieve the intended financial results. (Exelon, Generation, ComEd, PECO and BGE)

Generation continues to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain. Generation is pursuing investment opportunities in renewables, development of natural gas generation, distributed generation, potential expansion of the existing natural gas and oil Upstream and wholesale gas businesses, and entry into liquefied natural gas. Such initiatives may involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market. As these markets mature, there may be new market entrants or expansion by established competitors that increase competition for customers and resources. Additionally, it is possible that FERC, state public utility commissions or others may impose certain other restrictions on such transactions. All of these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment.

ComEd, PECO and BGE face risks associated with their regulatory-mandated Smart Grid initiatives. These risks include, but are not limited to, cost recovery, regulatory concerns, cyber security and obsolescence of technology. Due to these risks, no assurance can be given that such initiatives will be successful and will not have a material adverse effect on ComEd's, PECO's or BGE's financial results.

Risks Related to the Pending Merger with PHI

Exelon and PHI may encounter difficulties in satisfying the conditions for the completion of the Merger and the Merger may not be completed within the expected time frame or at all.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (1) the approval of the Merger by the holders of a majority of the outstanding shares of the PHI common stock, (2) the receipt of regulatory approvals required to consummate the Merger, (3) the expiration or termination of the applicable waiting period under the HSR Act and (4) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement. In addition, the obligation of Exelon to consummate the Merger is subject to the required regulatory approvals not, individually or in the aggregate, imposing terms, conditions, obligations or commitments that constitute a burdensome condition (as defined in the Merger Agreement).

In addition, conditions to the completion of the Merger may fail to be satisfied. Exelon or PHI may terminate the Merger Agreement if the Merger is not completed by July 29, 2015 except that, under certain circumstances, the date may be extended by Exelon or PHI to October 29, 2015. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information regarding the status of the merger.

The Merger is subject to the receipt of consent or approval from governmental entities that could delay the completion of the Merger or impose conditions that could have a material adverse effect on the combined company or that could cause abandonment of the Merger.

Completion of the Merger is conditioned upon the receipt of consents, orders, approvals or clearances, to the extent required, from the FERC, the FCC, the District of Columbia Public Service Commission, and the public utility commissions or similar entities in certain states in which the companies operate, including the Delaware Public Service Commission, MDPSC, the New Jersey Board of Public Utilities and the Virginia Department of Public Utilities. The Merger is also subject to

review by the DOJ Antitrust Division, under the HSR Act, and the expiration or earlier termination of the waiting period (and any extension of the waiting period) applicable to the Merger is a condition to closing the Merger. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information regarding the status of regulatory approvals.

Exelon and PHI have proposed conditions for approval in some of the regulatory filings that have been made and may subsequently propose or agree to further conditions, even if such conditions could have an adverse effect on Exelon, PHI or the combined company.

Exelon cannot provide assurance that all required regulatory consents or approvals will be obtained or that these consents or approvals will not contain terms, conditions or restrictions that would be detrimental to the combined company after the completion of the Merger. The Merger Agreement generally permits Exelon to terminate the Merger Agreement if the final terms of any of the required regulatory consents or approvals include burdensome conditions (as defined in the Merger Agreement). Any substantial delay in obtaining satisfactory approvals or the imposition of any terms or conditions in connection with such approvals could cause a material reduction in the expected benefits of the Merger.

Failure to obtain regulatory approval may result in Exelon's payment of a reverse termination fee.

If the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals, the failure to obtain regulatory approvals without burdensome conditions, or the breach by Exelon of its obligations in respect of obtaining regulatory approvals, Exelon will be required to pay PHI a reverse termination fee of up to $180 million, which would occur by means of PHI's election to redeem the outstanding nonvoting preferred securities purchased by Exelon in connection with the execution of the Merger Agreement for no consideration other than the nominal par value of the stock.

Failure to complete the Merger could negatively affect the share price and the future business and financial results of Exelon.

Completion of the Merger is not assured and is subject to risks, including the risks that approval of the transaction by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If the Merger is not completed, the ongoing businesses of Exelon may be adversely affected and Exelon will be subject to several risks, including:

- having to pay certain significant costs relating to the Merger without receiving the benefits of the Merger, including, in certain circumstances, a termination fee of up to $180 million payable by Exelon to PHI under certain circumstances; and
- the share price of Exelon may decline if and to the extent that the current market prices reflect an assumption by the market that the Merger will be completed.

Exelon and PHI have incurred and will incur significant transaction and Merger-related costs in connection with the Merger.

Exelon and PHI have incurred and expect to incur additional non-recurring costs associated with combining the operations of the two companies. Most of these costs will be transaction costs, including fees paid to financial and legal advisors related to the Merger and related financing arrangements, and employment-related costs, including change-in- control related payments made to certain PHI executives. In addition, if the closing of the Merger is materially delayed, Exelon may be required to pay financing costs without having realized any benefits from the Merger during the period of delay.

Exelon will also incur transaction fees and costs related to formulating integration plans. Additional unanticipated costs may be incurred in the integration of the two companies' businesses. Although Exelon expects that the elimination of costs, as well as the realization of other efficiencies related to the integration of the businesses, will exceed incremental transaction and Merger-related costs over time, this net benefit may not be achieved in the near term, or at all.

Exelon may not realize the expected benefits of the Merger because of integration difficulties and other challenges.

The success of the PHI acquisition will depend, in part, on Exelon's ability to realize all or some of the anticipated benefits from integrating PHI's business with Exelon's existing businesses. The integration process may be complex, costly and time-consuming. The challenges associated with integrating the operations of PHI's business include, among others:

- delay in implementation of our business plan for the combined business;
- unanticipated issues or costs in integrating financial, information technology, communications and other systems;
- possible inconsistencies in standards, controls, procedures and policies, and compensation structures between PHI' s structure and our structure;
- unanticipated changes in applicable laws and regulations;
- difficulties in retention of key employees;
- operating risks inherent in PHI's business and our business; and
- unexpected regulatory requirements.

Exelon and PHI will be subject to various uncertainties while the Merger is pending that may adversely affect their ability to attract and retain key employees, and potentially affect the company's financial results.

Uncertainty about the effect of the Merger on employees, suppliers and customers may have an adverse effect on Exelon and/or PHI. These uncertainties may impair Exelon's and/or PHI's ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter, as employees and prospective employees may experience uncertainty about their future roles with the combined company. In addition, current and prospective Exelon and PHI employees may determine that they do not desire to work for the combined company for a variety of possible reasons.

The Merger may divert attention of management at Exelon and PHI, which could detract from efforts to meet business goals.

The pursuit of the Merger and the preparation for the integration may place a burden on management and internal resources. Any significant diversion of management attention away from ongoing business concerns and any difficulties encountered in the transition and integration process could affect Exelon's and/or PHI's financial results. The process of integrating the operations of PHI may require a disproportionate amount of resources and management attention. Exelon's future operations and cash flows will depend to a significant degree upon Exelon's ability to operate PHI efficiently, achieve the strategic operating objectives for the business and realize cost savings and synergies. Exelon's management team may encounter unforeseen difficulties in managing the integration. In order to successfully integrate PHI, Exelon's management team will need to focus on realizing anticipated synergies and cost savings on a timely basis while maintaining the efficiency of operations. Any substantial diversion of management attention could affect Exelon's ability to achieve operational, financial and strategic objectives.

We are obligated to complete the Merger whether or not we have obtained the required financing.

Exelon intends to fund the cash consideration in the Merger using a combination of approximately $3.5 billion of debt, up to $1.0 billion in cash from asset sales, and the remainder through issuance of equity (including mandatory convertible securities). See Note 4—Mergers, Acquisitions, and Dispositions and Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information regarding the merger financing.

The combined company's assets, liabilities or results of operations could be adversely affected by unknown or unexpected events, conditions or actions that might occur at PHI prior to the closing of the Merger.

The PHI assets, liabilities, business, financial condition, cash flows, operating results and prospects to be acquired or assumed by Exelon by reason of the merger could be adversely affected before or after the Merger closing as a result of previously unknown events or conditions occurring or existing before the Merger closing. Adverse changes in PHI's business or operations could occur or arise as a result of actions by PHI, legal or regulatory developments including the emergence or unfavorable resolution of pre-acquisition loss contingencies, deteriorating general business, market, industry or economic conditions, and other factors both within and beyond the control of PHI. A significant decline in the value of PHI assets to be acquired by Exelon or a significant increase in PHI liabilities to be assumed by Exelon could adversely affect the combined company's future business, financial condition, cash flows, operating results and prospects.

Exelon may record goodwill that could become impaired and adversely affect its operating results.

In accordance with GAAP, the Merger will be accounted for as an acquisition of PHI common stock by Exelon and will follow the acquisition method of accounting for business combinations. The assets and liabilities of PHI will be consolidated with those of Exelon. The excess of the purchase price over the fair values of PHI's assets and liabilities, if any, will be recorded as goodwill.

The amount of goodwill, which could be material, will be allocated to the appropriate reporting units of the combined company. Exelon is required to assess goodwill for impairment at least annually by comparing the fair value of reporting units to the carrying value of those reporting units. To the extent the carrying value of any of those reporting units is greater than the fair value, a second step comparing the implied fair value of goodwill to the carrying amount would be required to determine if the goodwill is impaired. Such a potential impairment could result in a material non-cash charge that would have a material impact on Exelon's future operating results and consolidated balance sheet.

Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could delay or prevent the completion of the Merger.

One of the conditions to the closing of the Merger is that no judgment (whether preliminary, temporary or permanent) or other order by any court or other governmental entity shall be in effect that restrains, enjoins or otherwise prohibits or makes illegal the consummation of the Merger.

PHI and its directors have been named as defendants in purported class action lawsuits filed on behalf of named plaintiffs and other public stockholders challenging the proposed Merger and seeking, among other things, to enjoin the defendants from consummating the Merger on the agreed-upon terms. Exelon has been named as a defendant in these lawsuits. Exelon has also been named in a federal court case with similar claims. In September 2014, the parties reached a proposed settlement which is subject to court approval. Final court approval of the proposed settlement is not expected to occur until the second quarter of 2015, at the earliest.

If a plaintiff in these or any other litigation claims that may be filed in the future is successful in obtaining an injunction prohibiting the parties from completing the Merger on the terms contemplated by the Merger Agreement, the injunction may prevent the completion of the Merger in the expected time frame or altogether. If completion of the Merger is prevented or delayed, it could result in substantial costs to Exelon. In addition, Exelon could incur significant costs in connection with the lawsuits, including costs associated with the indemnification of PHI's directors and officers.

Private parties who may believe they are adversely affected by the Merger and individual states may bring legal actions under the antitrust laws in certain circumstances or intervene in regulatory proceedings. Although Exelon and PHI believe the completion of the Merger will not conflict with any antitrust law, there can be no assurance that a challenge to the Merger on antitrust grounds will not be made or, if a challenge is made, what the result will be. Under the Merger Agreement, Exelon and PHI have agreed to use their reasonable best efforts to obtain all regulatory clearances necessary to complete the Merger as promptly as practicable. In addition, in order to complete the Merger, Exelon and PHI may be required to comply with conditions, terms, obligations or restrictions imposed by regulatory agencies and any such conditions, terms, obligations or restrictions may have the effect of delaying completion of the Merger, imposing additional material costs on or materially limiting Exelon's revenues after the completion of the Merger, or otherwise reducing the anticipated benefits from the Merger. In addition, any such conditions, terms, obligations or restrictions could result in the delay or abandonment of the Merger.

The Merger may be completed on terms different from those contained in the Merger Agreement.

Prior to the completion of the Merger, Exelon and PHI may, by their mutual agreement, amend or alter the terms of the Merger Agreement, including with respect to, among other things, the Merger consideration to be received by PHI stockholders or any covenants or agreements with respect to the parties' respective operations pending completion of the Merger. In addition, Exelon may choose to waive requirements of the Merger Agreement, including some conditions to closing of the Merger. Any such amendments, alterations or waivers may have negative consequences to Exelon.

Risks Related to the Merger with Constellation

Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the Constellation merger.

As a result of the process to obtain regulatory approvals required for the Constellation merger, Exelon is committed to various programs, contributions, investments and market mitigation measures in several settlement agreements and regulatory approval orders. It is possible that Exelon may encounter delays, unexpected difficulties or costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon's financial position and operating results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 2. PROPERTIES

Generation

The following table describes Generation's interests in net electric generating capacity by station at December 31, 2014:

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,317
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,165[f]
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,005[f]
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	878[f][g]
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837
Oyster Creek	Mid-Atlantic	Forked River, NJ	1		Uranium	Base-load	625[e]
Conowingo	Mid-Atlantic	Darlington, MD	11		Hydroelectric	Base-load	572
Criterion	Mid-Atlantic	Oakland, MD	28		Wind	Base-load	70
Fourmile	Mid-Atlantic	Garrett County, MD	16		Wind	Base-load	40
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1		Solar	Base-load	14
Solar New Jersey 2	Mid-Atlantic	Various, NJ	2		Solar	Base-load	9
Solar New Jersey 1	Mid-Atlantic	Various, NJ	4		Solar	Base-load	8
Solar Maryland	Mid-Atlantic	Various, MD	9		Solar	Base-load	7
Solar Federal	Mid-Atlantic	Trenton, NJ	1		Solar	Base-load	4
Solar Maryland 2	Mid-Atlantic	Pocomoke, MD	2		Solar	Base-load	3
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5		Solar	Base-load	1
Muddy Run	Mid-Atlantic	Drumore, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Mid-Atlantic	Eddystone, PA	2		Oil/Gas	Intermediate	760
Croydon	Mid-Atlantic	West Bristol, PA	8		Oil	Peaking	391
Perryman	Mid-Atlantic	Belcamp, MD	5		Oil/Gas	Peaking	353
Handsome Lake	Mid-Atlantic	Kennerdell, PA	5		Gas	Peaking	268
Riverside	Mid-Atlantic	Baltimore, MD	3		Oil/Gas	Peaking	113[h]
Westport	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	115
Notch Cliff	Mid-Atlantic	Baltimore, MD	8		Gas	Peaking	118
Richmond	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	98
Gould Street	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	97
Philadelphia Road	Mid-Atlantic	Baltimore, MD	4		Oil	Peaking	61
Eddystone	Mid-Atlantic	Eddystone, PA	4		Oil	Peaking	60
Fairless Hills	Mid-Atlantic	Fairless Hills, PA	2		Landfill Gas	Peaking	60
Delaware	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	52
Falls	Mid-Atlantic	Morrisville, PA	3		Oil	Peaking	51
Moser	Mid-Atlantic	Lower PottsgroveTwp., PA	3		Oil	Peaking	51
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39
Schuylkill	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	30
Salem	Mid-Atlantic	Lower Alloways Creek Twp, NJ	1	42.59	Oil	Peaking	16[f]
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	6
Total Mid-Atlantic							11,420
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,378
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,327
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,344
Dresden	Midwest	Morris, IL	2		Uranium	Base-load	1,845
Quad Cities	Midwest	Cordova, IL	2	75	Uranium	Base-load	1,403[f]
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,069
Michigan Wind 2	Midwest	Sanilac Co., MI	50		Wind	Base-load	90

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Beebe	Midwest	Gratiot Co., MI	34		Wind	Base-load	81
Michigan Wind 1	Midwest	Huron Co., MI	46		Wind	Base-load	69
Harvest 2	Midwest	Huron Co., MI	33		Wind	Base-load	59
Harvest	Midwest	Huron Co., MI	32		Wind	Base-load	53
Beebe 1B	Midwest	Gratiot Co., MI	21		Wind	Base-load	50
Ewington	Midwest	Jackson Co., MN	10	99	Wind	Base-load	21[f]
Marshall	Midwest	Lyon Co., MN	9	99	Wind	Base-load	19[f]
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	8
Norgaard	Midwest	Lincoln Co., MN	7	99	Wind	Base-load	9[f]
AgriWind	Midwest	Bureau Co., IL	4	99	Wind	Base-load	8[f]
Cisco	Midwest	Jackson Co., MN	4	99	Wind	Base-load	8[f]
Wolf	Midwest	Nobles Co., MN	5	99	Wind	Base-load	6[f]
CP Windfarm	Midwest	Faribault Co., MN	2		Wind	Base-load	4
Blue Breezes	Midwest	Faribault Co., MN	2		Wind	Base-load	3
Cowell	Midwest	Pipestone Co., MN	1	99	Wind	Base-load	2[f]
Solar Ohio	Midwest	Toledo, OH	2		Solar	Base-load	1
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296
Total Midwest							12,153
Whitetail	ERCOT	Laredo, TX	57		Wind	Base-load	91
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3		Gas	Intermediate	704
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	565
Colorado Bend	ERCOT	Wharton, TX	6		Gas	Intermediate	498
Quail Run	ERCOT	Odessa, TX	6		Gas	Intermediate	488[i]
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870
Mountain Creek 6, 7	ERCOT	Dallas, TX	2		Gas	Peaking	240
LaPorte	ERCOT	Laporte, TX	4		Gas	Peaking	152
Total ERCOT							4,003
Holyoke Solar	New England	Various, MA	2		Solar	Base-load	4
Solar Massachusetts	New England	Various, MA	15		Solar	Base-load	7
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2
Solar Connecticut	New England	Various, CT	2		Solar	Base-load	1
Mystic 8, 9	New England	Charlestown, MA	6		Gas	Intermediate	1,418
Mystic 7	New England	Charlestown, MA	1		Oil/Gas	Intermediate	575
Wyman	New England	Yarmouth, ME	1	5.9	Oil	Intermediate	36[f]
Medway	New England	West Medway, MA	3		Oil/Gas	Peaking	117
Framingham	New England	Framingham, MA	3		Oil	Peaking	33
New Boston	New England	South Boston, MA	1		Oil	Peaking	16
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9
Total New England							2,218
Solar New York	New York	Bethlehem, NY	1		Solar	Base-load	2
Nine Mile Point	New York	Scriba, NY	2	50.01	Uranium	Base-load	835[f][g]
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288[f][g]
Total New York							1,125
AVSR	Other	Lancaster, CA	1		Solar	Base-load	242
Shooting Star	Other	Greensburg, KS	65		Wind	Base-load	104
Exelon Wind 4	Other	Gruver, TX	38		Wind	Base-load	80
Bluegrass Ridge	Other	King City, MO	27		Wind	Base-load	57
Conception	Other	Barnard, MO	24		Wind	Base-load	50
Cow Branch	Other	Rock Port, MO	24		Wind	Base-load	50
Mountain Home	Other	Glenns Ferry, ID	20		Wind	Base-load	42
High Mesa	Other	Elmore Co., ID	19		Wind	Base-load	40
Echo 1	Other	Echo, OR	21	99	Wind	Base-load	35[f]
Sacramento PV Energy	Other	Sacremento, CA	4		Solar	Base-load	26
Cassia	Other	Buhl, ID	14		Wind	Base-load	29
Wildcat	Other	Lovington, NM	13		Wind	Base-load	27
Sunnyside	Other	Sunnyside, UT	1	50	Waste Coal	Base-load	26[f]
Echo 2	Other	Echo, OR	10		Wind	Base-load	20

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Tuana Springs	Other	Hagerman, ID	8		Wind	Base-load	17
Greensburg	Other	Greensburg, KS	10		Wind	Base-load	13
Echo 3	Other	Echo, OR	6	99	Wind	Base-load	10[f]
Exelon Wind 1	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 2	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 3	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 5	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 6	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 7	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 8	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 9	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 10	Other	Dumas, TX	8		Wind	Base-load	10
Exelon Wind 11	Other	Dumas, TX	8		Wind	Base-load	10
High Plains	Other	Panhandle, TX	8	99.5	Wind	Base-load	10[f]
Three Mile Canyon	Other	Boardman, OR	6		Wind	Base-load	10
Solar Arizona	Other	Various, AZ	31		Solar	Base-load	27
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	5
Loess Hills	Other	Rock Port, MO	4		Wind	Base-load	5
Denver Airport Solar	Other	Denver, CO	1		Solar	Base-load	4
California PV Energy	Other	Various, CA	37		Solar	Base-load	16
Solar California	Other	Various, CA	4		Solar	Base-load	2
Solar Georgia	Other	Various, GA	10		Solar	Base-load	9
Hillabee	Other	Alexander City, AL	3		Gas	Intermediate	695
Grande Prairie	Other	Alberta, Canada	1		Gas	Peaking	75
SEGS 4, 5, 6	Other	Boron, CA	3	4.2-12.2	Solar	Peaking	8[f]
Total Other							1,834
Total							32,753

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, Salem and Three Mile Island, which are pressurized water reactors.
(b) 100%, unless otherwise indicated.
(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations reflect a summer rating. Wind and solar facilities reflect name plate capacity.
(e) Generation has agreed to permanently cease generation operation at Oyster Creek by December 31, 2019.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Reflects Generation's 50.01% interest in CENG, a joint venture with EDF. For Nine Mile Point, the co-owner owns 18% of Unit 2. Thus Exelon's ownership is 50.01% of 82% of Nine Mile Point Unit 2. Generation also had a unit-contingent PPA with CENG under which it purchased 85% of the nuclear plant output owned by CENG that was not sold to third parties under the pre-existing PPAs through 2014.
(h) Generation has agreed to retire and cease generation operation at the Riverside 6 unit effective June 1, 2014.
(i) As of December 31, 2014, the assets and liabilities of Quail Run are reported as Assets held for sale and within Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies or generating units being temporarily out of service for inspection, maintenance, refueling, repairs or modifications required by regulatory authorities.

In addition to the electric generating stations, Generation has working interests in 9 natural gas and oil exploration and production properties (Upstream) across the United States. Production volumes will vary from year to year due to the timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, asset sales, weather events, price effects and other factors.

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see ITEM 1. BUSINESS—Exelon Generation Company, LLC. For its insured losses, Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on Generation's consolidated financial condition or results of operations.

ComEd

ComEd's electric substations and a portion of its transmission rights of way are located on property that ComEd owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ComEd believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements, licenses and franchise rights; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ComEd's higher voltage electric transmission lines owned and in service at December 31, 2014 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,656
138,000	2,306

ComEd's electric distribution system includes 35,464 circuit miles of overhead lines and 30,778 circuit miles of underground lines.

First Mortgage and Insurance

The principal properties of ComEd are subject to the lien of ComEd's Mortgage dated July 1, 1923, as amended and supplemented, under which ComEd's First Mortgage Bonds are issued.

ComEd maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ComEd is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ComEd.

PECO

PECO's electric substations and a significant portion of its transmission lines are located on property that PECO owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. PECO believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

PECO's high voltage electric transmission lines owned and in service at December 31, 2014 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188 [(a)]
230,000	548
138,000	156
69,000	200

(a) In addition, PECO has a 22.00% ownership interest in 127 miles of 500 kV lines located in Pennsylvania and a 42.55% ownership interest in 131 miles of 500 kV lines located in Delaware and New Jersey.

PECO's electric distribution system includes 12,989 circuit miles of overhead lines and 8,948 circuit miles of underground lines.

Gas

The following table sets forth PECO's natural gas pipeline miles at December 31, 2014:

	Pipeline Miles
Transmission	30
Distribution	6,792
Service piping	6,128
Total	12,950

PECO has an LNG facility located in West Conshohocken, Pennsylvania that has a storage capacity of 1,200 mmcf and a send-out capacity of 157 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 1,980,000 gallons and a peaking capability of 25 mmcf/day. In addition, PECO owns 31 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

The principal properties of PECO are subject to the lien of PECO's Mortgage dated May 1, 1923, as amended and supplemented, under which PECO's first and refunding mortgage bonds are issued.

PECO maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, PECO is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of PECO.

BGE

BGE's electric substations and a significant portion of its transmission lines are located on property that BGE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. BGE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

BGE's high voltage electric transmission lines owned and in service at December 31, 2014 were as follows:

Voltage (Volts)	Circuit Miles
500,000	218
230,000	322
138,000	54
115,000	697

BGE's electric distribution system includes 9,386 circuit miles of overhead lines and 16,148 circuit miles of underground lines.

Gas

The following table sets forth BGE's natural gas pipeline miles at December 31, 2014:

	Pipeline Miles
Transmission	163
Distribution	7,114
Service piping	6,179
Total	13,456

BGE has an LNG facility located in Baltimore, Maryland that has a storage capacity of 1,055 mmcf and a send-out capacity of 332 mmcf/day, an LNG facility located in Westminster, Maryland that has a storage capacity of 6 mmcf and a send-out capacity of 6 mmcf/day, and a propane-air plant located in Baltimore, Maryland, with a storage capacity of 546 mmcf and a send-out capacity of 85 mmcf/day. In addition, BGE owns 12 natural gas city gate stations and 20 direct pipeline customer delivery points at various locations throughout its gas service territory.

Property Insurance

BGE owns its principal headquarters building located in downtown Baltimore. BGE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, BGE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of BGE.

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long-term design changes and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country's energy systems.

ITEM 3. LEGAL PROCEEDINGS

Exelon, Generation, ComEd, PECO and BGE

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Note 3—Regulatory Matters and Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

Exelon, Generation, ComEd, PECO and BGE

Not Applicable to the Registrants.

PART II

(Dollars in millions except per share data, unless otherwise noted)

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Exelon

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2015, there were 859,833,343 shares of common stock outstanding and approximately 123,997 record holders of common stock.

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2014				2013			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$38.93	$36.26	$37.73	$33.94	$30.59	$32.42	$37.80	$34.56
Low price	33.07	30.66	33.11	26.45	26.64	29.42	29.84	29.10
Close	37.08	34.09	36.48	33.56	27.39	29.64	30.88	34.48
Dividends	0.310	0.310	0.310	0.310	0.310	0.310	0.310	0.525

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index for the period 2010 through 2014.

This performance chart assumes:

- $100 invested on December 31, 2009 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.

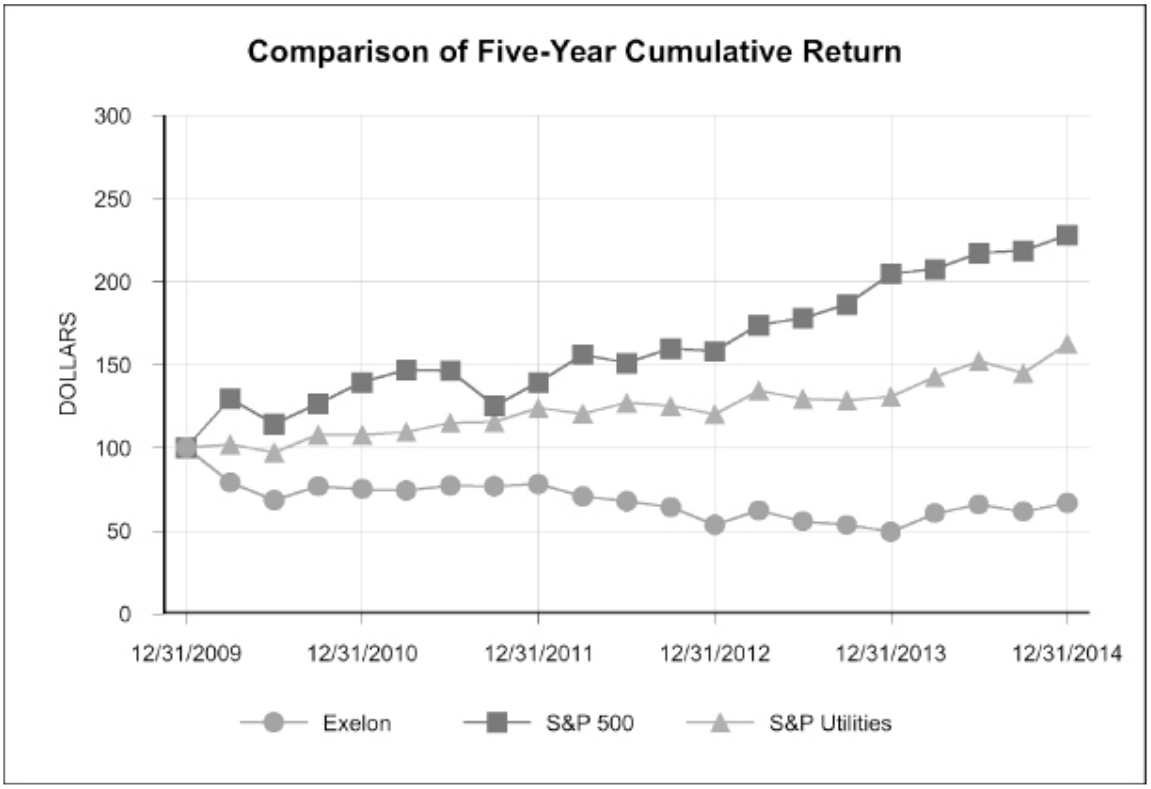

	Value of Investment at December 31,					
	2009	2010	2011	2012	2013	2014
Exelon Corporation	$100	$74.88	$77.99	$53.48	$49.25	$66.68
S&P 500	$100	$139.23	$139.23	$157.89	$204.63	$227.94
S&P Utilities	$100	$107.71	$123.69	$120.09	$130.60	$162.33

Generation

As of January 31, 2015, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2015, there were 127,016,950 outstanding shares of common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. At January 31, 2015, in addition to Exelon, there were 297 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2015, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2015, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

Exelon, Generation, ComEd, PECO and BGE

Dividends

Under applicable Federal law, Generation, ComEd, PECO and BGE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO or BGE may limit the dividends that these companies can distribute to Exelon.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with a financing arranged through ComEd Financing III that ComEd will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to certain dividend restrictions established by the MDPSC. First, in connection with the Constellation merger, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid and notify the MDPSC that BGE's equity ratio is at least 48% within five business days after dividend payment. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer

interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

At December 31, 2014, Exelon had retained earnings of $10,910 million, including Generation's undistributed earnings of $3,803 million, ComEd's retained earnings of $851 million consisting of retained earnings appropriated for future dividends of $2,490 million, partially offset by $(1,639) million of unappropriated retained deficits, PECO's retained earnings of $681 million, and BGE's retained earnings of $1,203 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2014 and 2013:

	2014				2013			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$0.310	$0.310	$0.310	$0.310	$0.310	$0.310	$0.310	$0.525

The following table sets forth Generation's quarterly distributions and ComEd's and PECO's quarterly common dividend payments:

	2014				2013			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 205	$ 205	$ 205	$ 30	$ 75	$ 76	$ 263	$ 211
ComEd	77	77	77	76	55	55	55	55
PECO	80	80	80	80	83	83	83	83

First Quarter 2015 Dividend. On January 27, 2015, the Exelon Board of Directors declared a first quarter 2015 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2015, to shareholders of record of Exelon at the end of the day on February 13, 2015.

ITEM 6. SELECTED FINANCIAL DATA

Exelon

The selected financial data presented below has been derived from the audited consolidated financial statements of Exelon. This data is qualified in its entirety by reference to and should be read in conjunction with Exelon's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions, except per share data)	2014 [a]	2013	2012 [b]	2011	2010
Statement of Operations data:					
Operating revenues	$27,429	$24,888	$23,489	$19,063	$18,644
Operating income	3,096	3,669	2,373	4,479	4,726
Income from continuing operations	1,820	1,729	1,171	2,499	2,563
Net income	1,820	1,729	1,171	2,499	2,563
Net income attributable to common shareholders	1,623	1,719	1,160	2,495	2,563
Earnings per average common share (diluted):					
Income from continuing operations	$ 1.88	$ 2.00	$ 1.42	$ 3.75	$ 3.87
Net income	$ 1.88	$ 2.00	$ 1.42	$ 3.75	$ 3.87
Dividends per common share	$ 1.24	$ 1.46	$ 2.10	$ 2.10	$ 2.10
Average shares of common stock outstanding—diluted	864	860	819	665	663

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis.
(b) 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

(In millions)	December 31, 2014	2013	2012	2011	2010
Balance Sheet data:					
Current assets	$12,097	$10,137	$10,140	$ 5,713	$ 6,398
Property, plant and equipment, net	52,087	47,330	45,186	32,570	29,941
Noncurrent regulatory assets	6,076	5,910	6,497	4,518	4,140
Goodwill	2,672	2,625	2,625	2,625	2,625
Other deferred debits and other assets	13,882	13,922	14,113	9,569	9,136
Total assets	$86,814	$79,924	$78,561	$54,995	$52,240
Current liabilities	$ 8,762	$ 7,728	$ 7,791	$ 5,134	$ 4,240
Long-term debt, including long-term debt to financing trusts	20,010	18,271	18,346	12,189	12,004
Noncurrent regulatory liabilities	4,550	4,388	3,981	3,627	3,555
Other deferred credits and other liabilities	29,359	26,597	26,626	19,570	18,791
Preferred securities of subsidiary	—	—	87	87	87
Noncontrolling interest	1,332	15	106	3	3
BGE preference stock not subject to mandatory redemption	193	193	193	—	—
Shareholders' equity	22,608	22,732	21,431	14,385	13,560
Total liabilities and shareholders' equity	$86,814	$79,924	$78,561	$54,995	$52,240

Generation

The selected financial data presented below has been derived from the audited consolidated financial statements of Generation. This data is qualified in its entirety by reference to and should be read in conjunction with Generation's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	For the Years Ended December 31, 2014 [a]	2013	2012 [b]	2011	2010
Statement of Operations data:					
Operating revenues	$17,393	$15,630	$14,437	$10,447	$10,025
Operating income	1,176	1,677	1,113	2,875	3,046
Net income	1,019	1,060	558	1,771	1,972
Net income attributable to membership interest	835	1,070	562	1,771	1,972

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis.
(b) 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

(In millions)	December 31, 2014	2013	2012	2011	2010
Balance Sheet data:					
Current assets	$ 7,638	$ 6,439	$ 6,211	$ 3,217	$ 3,087
Property, plant and equipment, net	22,945	20,111	19,531	13,475	11,662
Other deferred debits and other assets	14,765	14,682	14,939	10,741	9,785
Total assets	$45,348	$41,232	$40,681	$27,433	$24,534
Current liabilities	$ 4,459	$ 3,867	$ 4,097	$ 2,144	$ 1,843
Long-term debt	7,652	7,168	7,455	3,674	3,676
Other deferred credits and other liabilities	19,186	17,455	16,464	12,907	11,838
Noncontrolling interest	1,333	17	108	5	5
Member's equity	12,718	12,725	12,557	8,703	7,172
Total liabilities and member's equity	$45,348	$41,232	$40,681	$27,433	$24,534

ComEd

The selected financial data presented below has been derived from the audited consolidated financial statements of ComEd. This data is qualified in its entirety by reference to and should be read in conjunction with ComEd's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	For the Years Ended December 31, 2014	2013	2012	2011	2010
Statement of Operations data:					
Operating revenues	$4,564	$4,464	$5,443	$6,056	$6,204
Operating income	980	954	886	982	1,056
Net income	408	249	379	416	337

(In millions)	December 31, 2014	2013	2012	2011	2010
Balance Sheet data:					
Current assets	$ 1,723	$ 1,540	$ 1,775	$ 2,188	$ 2,151
Property, plant and equipment, net	15,793	14,666	13,826	13,121	12,578
Goodwill	2,625	2,625	2,625	2,625	2,625
Noncurrent regulatory assets	852	933	666	699	947
Other deferred debits and other assets	4,399	4,354	4,013	4,005	3,351
Total assets	$25,392	$24,118	$22,905	$22,638	$21,652
Current liabilities	$ 1,986	$ 2,048	$ 1,655	$ 2,071	$ 2,134
Long-term debt, including long-term debt to financing trusts	5,904	5,264	5,521	5,421	4,860
Noncurrent regulatory liabilities	3,655	3,512	3,229	3,042	3,137
Other deferred credits and other liabilities	5,940	5,766	5,177	5,067	4,611
Shareholders' equity	7,907	7,528	7,323	7,037	6,910
Total liabilities and shareholders' equity	$25,392	$24,118	$22,905	$22,638	$21,652

PECO

The selected financial data presented below has been derived from the audited consolidated financial statements of PECO. This data is qualified in its entirety by reference to and should be read in conjunction with PECO's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions)	2014	2013	2012	2011	2010
Statement of Operations data:					
Operating revenues	$3,094	$3,100	$3,186	$3,720	$5,519
Operating income	572	666	623	655	661
Net income	352	395	381	389	324
Net income attributable to common shareholder	352	388	377	385	320

	December 31,				
(In millions)	2014	2013	2012	2011	2010
Balance Sheet data:					
Current assets	$ 714	$ 906	$1,094	$1,243	$1,670
Property, plant and equipment, net	6,801	6,384	6,078	5,874	5,620
Noncurrent regulatory assets	1,529	1,448	1,378	1,216	968
Other deferred debits and other assets	899	879	803	823	727
Total assets	$9,943	$9,617	$9,353	$9,156	$8,985
Current liabilities	$ 653	$ 891	$1,158	$1,145	$1,163
Long-term debt, including long-term debt to financing trusts	2,430	2,131	1,831	1,781	2,156
Noncurrent regulatory liabilities	657	629	538	585	418
Other deferred credits and other liabilities	3,082	2,901	2,757	2,620	2,278
Preferred securities	—	—	87	87	87
Shareholders' equity	3,121	3,065	2,982	2,938	2,883
Total liabilities and shareholders' equity	$9,943	$9,617	$9,353	$9,156	$8,985

BGE

The selected financial data presented below has been derived from the audited consolidated financial statements of BGE. This data is qualified in its entirety by reference to and should be read in conjunction with BGE's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions)	2014	2013	2012	2011	2010
Statement of Operations data:					
Operating revenues	$3,165	$3,065	$2,735	$3,068	$3,541
Operating income	439	449	132	314	350
Net income	211	210	4	136	147
Net income (loss) attributable to common shareholder	198	197	(9)	123	134

(In millions)	December 31, 2014	2013	2012 [a]	2011 [a]	2010 [a]
Balance Sheet data:					
Current assets	$ 957	$1,011	$ 980	$ 969	$1,012
Property, plant and equipment, net	6,204	5,864	5,498	5,132	4,754
Noncurrent regulatory assets	510	524	522	551	566
Other deferred debits and other assets	407	462	506	551	545
Total assets	$8,078	$7,861	$7,506	$7,203	$6,877
Current liabilities	$ 846	$ 827	$ 980	$ 734	$ 728
Long-term debt, including long-term debt to financing trusts and variable interest entities	2,125	2,199	1,969	2,186	2,060
Noncurrent regulatory liabilities	200	204	214	201	192
Other deferred credits and other liabilities	2,154	2,076	1,985	1,781	1,634
Preference stock not subject to mandatory redemption	190	190	190	190	190
Shareholders' equity	2,563	2,365	2,168	2,111	2,073
Total liabilities and shareholders' equity	$8,078	$7,861	$7,506	$7,203	$6,877

(a) BGE retrospectively reclassified certain regulatory assets and regulatory liabilities to conform to the current year presentation.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Exelon

Executive Overview

Exelon, a utility services holding company, operates through the following principal subsidiaries:

- *Generation,* whose integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream).
  - As a result of the Constellation merger, Generation owns a 50.01% interest in CENG. During 2014, Generation assumed the operating licenses and corresponding operational control of CENG's nuclear fleet. As a result, Exelon and Generation fully consolidated CENG's financial position and results of operations into their businesses beginning on April 1, 2014.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in northern Illinois, including the City of Chicago.
- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE,* whose business consists of the purchase and regulated retail sale of electricity and natural gas and the provision of electricity distribution and transmission and gas distribution services in central Maryland, including the City of Baltimore.

Exelon has nine reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and other regions in Generation), ComEd, PECO and BGE. See Note 24—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

Exelon's consolidated financial information includes the results of its four separate operating subsidiary registrants, Generation, ComEd, PECO and BGE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO and BGE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Financial Results. The following consolidated financial results reflect the results of Exelon for the year ended December 31, 2014 compared to the same period in 2013. The 2014 financial results only include the operations of CENG on a fully consolidated basis from the date Generation assumed operational control, April 1, 2014, through December 31, 2014. All amounts presented below are before the impact of income taxes, except as noted.

	The Years Ended December 31,							
	2014						2013	Favorable (Unfavorable) Variance
	Generation [a]	ComEd	PECO	BGE	Other	Exelon	Exelon	
Operating revenues	$ 17,393	$4,564	$3,094	$3,165	$(787)	$27,429	$24,888	$ 2,541
Purchased power and fuel expense	9,925	1,177	1,261	1,417	(777)	13,003	10,724	(2,279)
Revenue net of purchased power and fuel expense [b]	7,468	3,387	1,833	1,748	(10)	14,426	14,164	262
Other operating expenses								
Operating and maintenance	5,566	1,429	866	717	(10)	8,568	7,270	(1,298)
Depreciation and amortization	967	687	236	371	53	2,314	2,153	(161)
Taxes other than income	465	293	159	221	16	1,154	1,095	(59)
Total other operating expenses	6,998	2,409	1,261	1,309	59	12,036	10,518	(1,518)
Equity in (losses) earnings of unconsolidated affiliates	(20)	—	—	—	—	(20)	10	(30)
Gain (loss) on sales of assets	437	2	—	—	(2)	437	13	424
Gain on consolidation and acquisition of businesses	289	—	—	—	—	289	—	289
Operating income (loss)	1,176	980	572	439	(71)	3,096	3,669	(573)
Other income and (deductions)								
Interest expense, net	(356)	(321)	(113)	(106)	(169)	(1,065)	(1,356)	291
Other, net	406	17	7	18	7	455	460	(5)
Total other income and (deductions)	50	(304)	(106)	(88)	(162)	(610)	(896)	286
Income (loss) before income taxes	1,226	676	466	351	(233)	2,486	2,773	(287)
Income taxes	207	268	114	140	(63)	666	1,044	378
Net income (loss)	1,019	408	352	211	(170)	1,820	1,729	91
Net income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	184	—	—	13	—	197	10	(187)
Net income (loss) attributable to common shareholders	$ 835	$ 408	$ 352	$ 198	$(170)	$ 1,623	$ 1,719	$ (96)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.

(b) The Registrants' evaluate operating performance using the measure of revenue net of purchased power and fuel expense. The Registrants' believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Exelon's net income attributable to common shareholders was $1,623 million for the year ended December 31, 2014 as compared to $1,719 million for the year ended December 31, 2013, and diluted earnings per average common share were $1.88 for the year ended December 31, 2014 as compared to $2.00 for the year ended December 31, 2013.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $262 million as compared to 2013. The year-over-year increase reflects the inclusion of CENG's results beginning April 1, 2014 and was primarily due to the following favorable factors:

- Increase of $815 million at Generation primarily due to the inclusion of CENG's results beginning April 1, 2014 through December 31, 2014, a decrease in fuel costs related to the cancellation of DOE spent nuclear fuel disposal fees, increased capacity prices related to the Reliability Pricing Model (RPM) for the PJM Interconnection, LLC (PJM) market, and favorable portfolio management activities in the New England and South regions; partially offset by higher procurement costs for replacement power related to the extreme cold weather in the first quarter of 2014 and lower realized energy prices related to executing Generation's ratable hedging strategy;
- Increase of $365 million at Generation related to the reduction in amortization of in-the-money energy contracts recorded at fair value at the Constellation merger date and an increase related to the amortization of out-of-the money energy contracts recorded at fair value upon the consolidation of CENG;
- Increase of $30 million at ComEd primarily reflecting higher transmission revenue due to increased capital investment and an increase of $93 million as a result of increased cost recovery associated with energy efficiency programs and uncollectible accounts expense (both offset below in operating and maintenance expense);
- Increase of $33 million at PECO primarily due to increased recovery from regulatory programs (offset below primarily in operating and maintenance expense); and
- Increase of $104 million at BGE primarily due to increased distribution revenue as a result of the 2013 and 2014 electric and natural gas distribution rate case orders issued by the Maryland PSC, increased cost recovery for energy efficiency and demand response programs (offset below in depreciation and amortization expense), and increased transmission revenue pursuant to increased rates effective June 2014.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

- Decrease of $1,095 million at Generation due to mark-to-market losses of $591 million in 2014 from economic hedging activities compared to $504 million in mark-to-market gains in 2013.
- Decrease of $16 million at ComEd due to unfavorable weather in the ComEd service territory.

Operating and maintenance expense increased by $1,298 million as compared to 2013 primarily due to the following unfavorable factors:

- Increase in Generation's labor, contracting and materials costs of $361 million primarily due to the inclusion of CENG's results from April 1, 2014 through December 31, 2014, an increase of $44 million resulting from expenses recorded for a Constellation merger commitment, an increase of $54 million as a result of an increase in the number of planned nuclear refueling outage days at Generation, primarily related to the inclusion of CENG's plants beginning April 1, 2014, and an increase of $16 million in the reserve for future asbestos-related bodily injury claims;
- Increase in labor, contracting and materials costs of $56 million at ComEd associated with EIMA smart meter projects and $22 million at BGE due to increased maintenance activities;
- Increase in Generation's accretion expense of $78 million primarily due to the inclusion of CENG's results from April 1, 2014 through December 31, 2014;

- Long-lived asset impairments at Generation of $663 million in 2014 compared to $157 million in 2013.
- Increased storm costs at PECO and BGE of $100 million and $21 million, respectively;
- Increased spending on energy and efficiency programs and increased uncollectible accounts expense at ComEd of $93 million; and
- Increased uncollectible accounts expense at BGE of $17 million.

The year-over-year increase in operating and maintenance expense was partially offset by the following favorable factor:

- A reduction in pension and non-pension postretirement benefits expense of $178 million primarily at Exelon, Generation, and ComEd, resulting from plan design changes for certain OPEB plans and the favorable impact of higher actuarially assumed pension and OPEB discount rates for 2014, partially offset by the inclusion of CENG's pension and non-pension postretirement benefits expense from April 1, 2014 through December 31, 2014.

Depreciation and amortization expense increased by $161 million primarily as a result of the inclusion of CENG's results from April 1, 2014 through December 31, 2014, increased depreciation expense across the operating companies for ongoing capital expenditures, and higher regulatory asset amortization related to energy efficiency and demand response expenditures.

Exelon recorded $437 million at Generation as a result of gains recorded on the sales of ownership interest in certain generating stations in 2014.

Exelon recorded a $261 million gain upon consolidation of CENG resulting from the difference in fair value of CENG's net assets as of April 1, 2014, and the equity method investment previously recorded on Generation's and Exelon's books and the settlement of pre-existing transactions between Generation and CENG. Additionally, Exelon recorded a $28 million bargain-purchase gain related to the Integrys acquisition.

Interest expense decreased by $291 million primarily as a result of a decrease in 2014 given ComEd's 2013 remeasurement of Exelon's like-kind exchange tax positions, offset at Exelon by an increase in 2014 related to financing activities associated with the pending PHI merger.

Other, net increased by $5 million primarily at Generation as a result of favorable settlements in 2014 of certain income tax positions on Constellation's pre-acquisition 2009-2012 tax returns and the change in realized and unrealized gains and losses on NDT funds.

Exelon's effective income tax rates for the years ended December 31, 2014 and 2013 were 26.8% and 37.6%, respectively. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the years ended December 31, 2014 and 2013, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings

Exelon's adjusted (non-GAAP) operating earnings for the year ended December 31, 2014 were $2,068 million, or $2.39 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,149 million, or $2.50 per diluted share, for the same period in 2013. In addition to net income,

Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2014 as compared to 2013:

	For the years ended December 31,			
	2014		2013	
(All amounts after tax; in millions, except per share amounts)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$1,623	$ 1.88	$1,719	$ 2.00
Mark-to-Market Impact of Economic Hedging Activities [a]	363	0.42	(310)	(0.35)
Unrealized Gains Related to NDT Fund Investments [b]	(86)	(0.10)	(78)	(0.09)
Plant Retirements and Divestitures [c]	(245)	(0.28)	(13)	(0.02)
Asset Retirement Obligation [d]	(13)	(0.02)	7	0.01
Merger and Integration Costs [e]	185	0.21	87	0.08
Amortization of Commodity Contract Intangibles [f]	64	0.07	347	0.41
Reassessment of State Deferred Income Taxes [g]	(27)	(0.03)	4	—
Long-Lived Asset Impairments [h]	435	0.50	110	0.14
Bargain-Purchase Gain on Integrys acquisition [i]	(28)	(0.03)	—	—
Gain on CENG Integration [j]	(159)	(0.18)	—	—
Tax Settlements [k]	(106)	(0.12)	—	—
CENG Non-Controlling Interest [l]	62	0.07	—	—
Remeasurement of Like-Kind Exchange Tax Position [m]	—	—	267	0.31
Midwest Generation Bankruptcy Charges [n]	—	—	16	0.02
Amortization of the Fair Value of Certain Debt [o]	—	—	(7)	(0.01)
Adjusted (non-GAAP) Operating Earnings	$2,068	$ 2.39	$2,149	$ 2.50

(a) Reflects the impact of losses (gains) for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $232 million and ($201) million, respectively) on Generation's economic hedging activities. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized gains for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $(77) million and $(144) million, respectively) on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Reflects the impacts associated with the sales of Generation's ownership interests in generating stations for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $(163) million and ($4) million, respectively).

(d) Reflects the impacts of a decrease in Generation's decommissioning obligation for the year ended December 31, 2014 (net of taxes of $(4) million). Reflects the impacts of an increase in Generation's asset retirement obligation for asbestos at retired fossil plants for the year ended December 31, 2013 (net of taxes of $5 million).

(e) Reflects certain costs incurred for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $84 million and $33 million, respectively) including professional fees, employee-related expenses, integration activities, upfront credit facilities, merger commitments, and certain pre-acquisition contingencies, if and when applicable to the Constellation merger in 2013 and the Constellation merger, CENG integration, acquisition of Integrys Energy Services, Inc. (Integrys) and pending PHI acquisition in 2014.
(f) Reflects the non-cash impact for the years ended December 31, 2014 and December 31, 2013 (net of taxes of $68 million and $219 million, respectively) of the amortization of intangibles assets, net, related to commodity contracts recorded at fair value at the 2012 Constellation merger date, the 2014 CENG integration date, and the 2014 Integrys acquisition date.
(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment.
(h) In 2014, reflects charges to earnings related to the impairments of certain generating assets held for sale, Upstream assets, and wind generating assets (net of taxes of $250 million). In 2013, reflects a charge to earnings primarily related to the cancellation of previously capitalized nuclear uprate projects and the impairment of certain wind generating assets (net of taxes of $69 million).
(i) Reflects the excess of the fair value of assets and liabilities acquired over the purchase price for the Integrys acquisition (net of taxes of $(16) million) on November 1, 2014.
(j) Reflects the non-cash gain recorded upon consolidation of CENG in accordance with the execution of the NOSA on April 1, 2014 (net of taxes of $(102) million).
(k) Reflects a benefit related to the favorable settlement in 2014 of certain income tax positions on Constellation's pre-acquisition 2009-2012 tax returns.
(l) Pursuant to the April 1, 2014 consolidation, represents adjustments to account for the CENG interest not owned by Generation, where applicable.
(m) For 2013, reflects a non-cash charge to earnings (net of taxes of $102 million) resulting from the remeasurement of a like-kind exchange tax position taken on ComEd's 1999 sale of fossil generating assets. See Note 14—Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information.
(n) Reflects costs incurred in 2013 to establish estimated liabilities (net of taxes of $10 million) pursuant to the Midwest Generation bankruptcy, primarily related to lease payments under a coal rail car lease and estimated payments for asbestos-related personal injury claims.
(o) Reflects the 2013 non-cash amortization of certain debt (net of taxes of ($5) million) recorded at fair value at the Constellation merger date which was retired in the second quarter of 2013. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information.

Merger and Acquisition Costs

As discussed above, Exelon has incurred and will continue to incur costs associated with the Integrys and PHI acquisitions including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses), financing costs, integration initiatives, and certain pre-acquisition contingencies.

For the year ended December 31, 2014, expense has been recognized for costs incurred to achieve the Constellation merger, CENG integration, Integrys acquisition and proposed PHI acquisition as follows:

	Pre-tax Expense Twelve Months Ended December 31, 2014				
Merger Integration and Acquisition Costs:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Financing [a]	$ —	$ —	$—	$—	$ 131
Regulatory Commitments [b]	44	—	—	—	44
Transaction [c]	—	—	—	—	26
Employee-Related [d]	5	—	—	—	5
Other [e]	56	4	2	2	65
Total	$ 105	$ 4	$ 2	$ 2	$ 271

	Pre-tax Expense Twelve Months Ended December 31, 2013				
Merger Integration Costs:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Employee-Related [d]	$ 48	$ 4	$ 3	$ 1	$ 58
Other [e]	58	12	6	5	84
Total	$ 106	$ 16	$ 9	$ 6	$ 142

(a) Reflects costs incurred at Exelon related to the financing of the PHI merger, including upfront credit facility fees.
(b) Reflects costs incurred at Generation for a Constellation merger commitment.
(c) External, third party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of transactions.
(d) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd established regulatory assets of $2 million for the year ended December 31, 2013. The majority of these costs are expected to be recovered over a five-year period. These costs are not included in the table above.
(e) Costs to integrate CENG and Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. For the year ended December 31, 2014, also includes professional fees primarily related to integration for the proposed PHI acquisition. ComEd and BGE established regulatory assets of $9 million and $12 million, respectively, for the year ended December 31, 2013, for certain other merger and integration costs, which are not included in the table above.

As of December 31, 2014, Exelon projects incurring total additional PHI acquisition and integration related expenses of $650 million, of which approximately $100 million is expected to be capitalized to property, plant and equipment excluding the direct investment Exelon and PHI have proposed to the PHI utilities respective customers.

Pursuant to the conditions set forth by the MDPSC in its approval of the merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion. The direct investment estimate includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a twenty-year lease agreement that was contingent upon the developer obtaining all required approvals, permits and

financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. The building is expected to be ready for occupancy in approximately 2 years. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information related to the lease commitments.

Exelon's Strategy and Outlook for 2015 and Beyond

Exelon's value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline. Exelon's strategy is to leverage its integrated business model to create value and diversify its business. Exelon's competitive and regulated businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- Generation's competitive businesses provide commodity exposure and a platform to diversify into adjacent markets, while providing residual dividend support.
- Exelon's utilities provide a foundation for stable earnings and dividend support, which translates to a stable currency in our stock.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change. While enhancing Exelon's core value, it enables it to take advantage of a myriad of opportunities, rather than focusing on any one segment of the energy industry value chain.

Generation's competitive businesses create value for customers by providing innovative solutions and reliable, clean and affordable energy. Generation's electricity generation strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding Generation's regional and technological footprint. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation's customer-facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The Exelon utilities only invest in rate base where it provides a net benefit to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. The Exelon utilities make these investments prudently and at the lowest reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results. Combined, the utilities plan to invest approximately $16 billion over the next five years in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Exelon's financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, and to return value to Exelon's shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

Various market, financial, and other factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS for additional information regarding market and financial factors.

Proposed Merger with Pepco Holdings, Inc. (Exelon)

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI's shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. Exelon intends to fund the all-cash transaction using a combination of approximately $3.5 billion of debt, up to $1 billion cash from asset sales primarily at Generation, and the remainder through issuance of equity (including mandatory convertible securities). In addition, Exelon entered into a 364-day $7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing, which has subsequently been reduced to $3.2 billion as a result of execution of the debt and equity security issuances and the net after-tax cash proceeds from generating asset divestitures during the second half of 2014. See Note 4—Mergers, Acquisitions, and Divestitures, Note 13—Debt and Credit Agreements, and Note 19—Common Stock of the Combined Notes to Consolidated Financial Statements for further information related to these transactions. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $126 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities in PHI as of December 31, 2014, with additional investments of $18 million to be made quarterly up to a maximum aggregate investment of $180 million. As part of the applications for approval of the merger, Exelon and PHI proposed a package of benefits to the PHI utilities' respective customers, providing for direct investment of more than $100 million with the actual amount and timing of any related payments dependent upon settlement discussions in merger regulatory approval proceedings and the terms of regulatory orders approving the merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU) and the FERC have approved the merger of PHI and Exelon. The Federal Communications Commission has also approved the transfer of certain PHI communications licenses. On February 11, 2015, the NJBPU approved the proposed merger and the previously filed settlement signed and filed by Exelon, PHI, Atlantic City Electric (ACE), NJBPU staff, and the Independent Energy Coalition. The settlement provides a package of benefits to ACE customers and the state of New Jersey. This package of benefits includes the establishment of customer rate credit programs, with an aggregate value of $62 million for ACE customers and energy efficiency programs that will provide savings for ACE customers of $15 million.

Completion of the transaction also remains conditioned upon approval by the Public Services Commissions of the District of Columbia, Delaware and Maryland. Procedural schedules have been set in these commission proceedings and final approval decisions are expected in the first half of 2015.

On October 9, 2014, PHI and Exelon each received a request for additional information from the DOJ. The request had the effect of extending the DOJ review period until 30 days after PHI and Exelon each has certified that it has substantially complied with the request. On November 21, 2014, Exelon and PHI each certified that it had substantially complied with the request. Accordingly, the HSR Act waiting period expired on December 22, 2014, and the HSR Act no longer precludes completion of the merger. Although the DOJ allowed the waiting period under the HSR Act to expire without taking any action with respect to the merger, the DOJ has not advised Exelon or PHI that it has concluded its investigation. Exelon and PHI will continue to work cooperatively with the DOJ regarding the proposed merger.

Exelon and PHI continue to expect to complete the merger in the second or third quarter of 2015.

Through December 31, 2014, Exelon has incurred approximately $179 million of expense associated with the proposed merger, including $48 million related to acquisition and integration costs and $131 million of costs incurred to finance the transaction. The Merger Agreement also provides for termination rights for both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the transaction does not close due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities of PHI described above, as a result of PHI redeeming the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock.

Exelon has listed various potential risks relating to the pending merger with PHI (see Item 1A. Risk Factors), including difficulties that may be encountered in satisfying the conditions to completion of the merger and the potential for developments that might have an adverse effect on Exelon and the ability to realize the expected benefits of the merger. Exelon is taking steps to manage these risks and expects that the merger can be completed on a basis favorable to the company's shareholders and customers. Accordingly, Exelon anticipates closing the transaction in the second or third quarter of 2015. Refer to Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the merger transaction.

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Capacity Market Changes in PJM. In the wake of the January 2014 Polar Vortex that blanketed much of the Eastern and Midwestern United States, it became clear that while a major outage event was narrowly avoided, resources in PJM were not providing the level of reliability expected by customers. To address this disconnect, on December 12, 2014, PJM filed at FERC a proposal to make significant changes to its current capacity market construct, the Reliability Pricing Model (RPM). PJM's proposed changes generally seek to improve resource performance and reliability largely by limiting the excuses for non-performance and by increasing the penalties for performance failures. To cover capital and other costs and risks that suppliers would incur to meet these higher reliability standards, suppliers would be allowed to include adders for such costs as well as risk premiums in their capacity market offers. While offers are expected to put upward pressure on capacity clearing prices, operational improvements made as a result of PJM's proposal are expected to improve reliability, to reduce energy production costs as a result of more efficient operations and to reduce the need for out of market energy payments to suppliers. Exelon participated actively in PJM's stakeholder process through which PJM developed the proposal and is also actively participating in the FERC proceeding including filing comments. PJM asked for a FERC order approving the proposal by April 1, 2015 so PJM can implement the proposal prior to its next capacity auction in May 2015. However, it is not clear when or how the FERC will respond to PJM's proposal or, if it responds within PJM's timeframe, whether FERC will require changes.

Subsidized Generation. The rate of expansion of subsidized generation, including low-carbon generation such as wind and solar energy, in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have attempted to implement or propose legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices. For example, the New Jersey legislature enacted in to law in January 2011, the Long Term Capacity Pilot Program Act (LCAPP). LCAPP provides eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market. Under LCAPP, the local utilities in New Jersey are required to pay (or receive) the difference between the price eligible generators receive in the capacity market and the price guaranteed under the 15-year contract. New Jersey ultimately selected three proposals to participate in LCAPP and build new generation in the state. In addition, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. CPV has subsequently sought to extend that date. The CfD mandated that utilities (including BGE) pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Exelon and others have challenged the constitutionality and other aspects of the New Jersey legislation and the actions taken by the MDPCS in state and federal courts. Ultimately, the Exelon parties prevailed in obtaining orders from the U.S. Court of Appeals for the Third Circuit and the U.S. Court of Appeals for the Fourth Circuit effectively undoing the actions taken by the New Jersey legislature and the MDPSC respectively. The matter has been appealed to the U.S. Supreme Court, and while the Court of Appeals decisions are helpful, there remains risk the Supreme Court will overrule the lower Courts.

As required under their contracts, generator developers who were selected in the New Jersey and Maryland programs (including CPV) offered and cleared in PJM's capacity market auctions held in May 2012, 2013, and 2014. In addition, CPV has announced its intention to move forward with construction of its New Jersey and Maryland plants, with or without the challenged state subsidy. Nonetheless to the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon's market driven position. While the court decisions in New Jersey and Maryland are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR) for future capacity auctions, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon's market driven position and could have a significant effect on Exelon's financial results of operations, financial position and cash flows. Exelon continues to monitor developments and participate in stakeholder and other processes to ensure that similar state subsidies are not developed. In addition, Exelon remains active in advocating for competitive markets, while opposing policies that require taxpayers and/ or consumers to subsidize or give preferential treatment to specific generation providers or technologies, or that would threaten the reliability and value of the integrated electricity grid.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Maryland Order.

Energy Demand. Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for ComEd and PECO, and no projected growth for electricity for BGE. ComEd, PECO and BGE are projecting load volumes to increase by 0.4%, 0.8% and (0.2)%, respectively, in 2015 compared 2014.

Retail Competition. Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to

serve. The market experienced high price volatility in the first quarter of 2014 which contributed to bankruptcies and consolidations within the industry during the year. However, forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

Strategic Policy Alignment

Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's board of directors declared the second quarter 2014 dividend of $0.31 per share on Exelon's common stock. The second quarter dividend was paid on June 10, 2014 to shareholders of record on May 16, 2014. All future quarterly dividends require approval by Exelon's board of directors.

Exelon's board of directors declared the third quarter 2014 dividend of $0.31 per share on Exelon's common stock. The third quarter dividend was paid on September 10, 2014 to shareholders of record on August 15, 2014.

Exelon's board of directors declared the fourth quarter 2014 dividend of $0.31 per share on Exelon's common stock. The fourth quarter dividend was paid on December 10, 2014 to shareholders of record on November 14, 2014.

Exelon's board of directors declared the first quarter 2015 dividend of $0.31 per share on Exelon's common stock. The first quarter dividend will be paid on March 10, 2015, to shareholders of record on February 13, 2015.

Exelon and Generation evaluate the economic viability of each of their generating units on an ongoing basis. Decisions regarding the future of economically challenged generating assets will be based primarily on the economics of continued operation of the individual plants. If Exelon and Generation do not see a path to sustainable profitability in any of their plants, Exelon and Generation will take steps to retire those plants to avoid sustained losses. Retirement of plants could materially affect Exelon's and Generation's results of operations, financial position, and cash flows through, among other things, potential impairment charges, accelerated depreciation and decommissioning expenses over the plants remaining useful lives, and ongoing reductions to operating revenues, operating and maintenance expenses, and capital expenditures.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2014 and 2015. This strategy has not changed as a result of recent and pending asset divestitures. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of December 31, 2014, the percentage of

expected generation hedged for the major reportable segments was 93%-96%, 61%-64% and 31%-34% for 2015, 2016, and 2017 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation (which reflects the divestiture impact of Quail Run). Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well. See Note 4—Mergers, Acquisition and Dispositions for more detail regarding the divestitures.

Generation procures oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 50% of Generation's uranium concentrate requirements from 2015 through 2019 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position.

ComEd, PECO and BGE mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

With an emphasis on innovation and entrepreneurship, Exelon is currently pursuing growth in both the utility and competitive energy businesses. Identifying and capitalizing on emerging trends and technologies, Exelon plans to invest in new innovative technologies to compete with a new breed of energy players, leverage new technologies to create new or expand existing businesses, and improve productivity and efficiencies within our existing businesses. Management continually evaluates growth opportunities aligned with Exelon's businesses, assets and markets, leveraging Exelon's expertise in those areas.

Competitive Energy Businesses

Generation continues to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain.

- *Leveraging its competencies,*
  - Generation's 2014 acquisition of Integrys allows Generation to expand its retail footprint further in an industry sector that continues to mature and consolidate and provides hedging and diversification benefits to its existing portfolio.
  - Generation continues to pursue investment opportunities in renewables, in its nuclear uprate program and in the development of natural gas generation plants that is supported by the trend of increasing natural gas supply.

- *Investing in business diversification to position the company for the future,*
  - Generation has launched a business in competitive distributed generation that capitalizes on the push toward a decentralized system.
  - Generation is also making investments across the natural gas value chain throughout North America, focusing initially on expansion of the existing Upstream and wholesale gas businesses, as well as entry into liquefied natural gas.

Regulated Energy Businesses

The proposed acquisition of PHI provides an opportunity to accelerate Exelon's regulated growth and provide stable cash flows, earnings accretion, and dividend stability. Additionally, ComEd, PECO and BGE anticipate making significant future investments in infrastructure modernization, including smart meter and smart grid initiatives, storm hardening, and advanced reliability technologies. Upon obtaining various approvals, ComEd also plans to invest approximately $280 million to construct the Grand Prairie Gateway Transmission Line in Illinois alleviating identified congestion and enhancing reliability. ComEd, PECO and BGE invest in rate base where it provides a net benefit to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made prudently and at the lowest reasonable cost to customers.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

Liquidity

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and OPEB obligations and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.5 billion. See Liquidity and Capital Resources—Credit Matters—Exelon Credit Facilities below.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets including European banks. Disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2014, approximately 29%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks, excluding the unsecured bridge facility to provide financing for the proposed PHI acquisition. The credit facilities include $8.5 billion in aggregate total commitments of which $7.3 billion was available as of December 31, 2014, due to outstanding letters of credit. There were no borrowings under the Registrants' credit facilities as of December 31, 2014. See Note 13—Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon supports the promulgation of certain environmental regulations by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to their low emission generation portfolios, Generation and CENG will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air Quality. In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NOx, SO2 and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a tightened ozone NAAQS, to be finalized in late 2015, proposed for public comment in December 2014. These recently finalized or proposed updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Numerous entities challenged the CSAPR in the D.C. Circuit Court. On August 21, 2012, the D.C. Circuit Court of Appeals held that the U.S. EPA has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. On April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit Court decision and upheld CSAPR, and remanded the case to the D.C. Circuit Court to resolve the remaining implementation issues On November 21, 2014, the U.S. EPA issued an Interim Final Rule in which the Agency announced that it was tolling the effective dates for the CSAPR. The first phase of the CSAPR program started on January 1, 2015, with the second phase starting January 1, 2017. Also released on November 21, 2014, was a Notice of Data Availability under which the Agency proposed CSAPR allowance allocations to generating units for the first five years of the program, 2015-2020; these were identical to those previously identified in prior final rules related to the CSAPR.

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may

need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. On April 15, 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety.

In November 2014, the U.S. Supreme Court granted a petition for review of the MATS Rule filed by 20 states and a coalition of coal-fired electric generators. The U.S. Supreme Court announced that it will review a single, yet critical, aspect of the MATS Rule—whether the U.S. EPA properly considered compliance costs (e.g., pollution control capital expenditures and on-going operations and maintenance expense) in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. If the Court finds that the U.S. EPA acted unreasonably, then implementation of the rule would be delayed until the U.S. EPA corrects any deficiencies. It is likely that the U.S. Supreme Court will issue a decision sometime in 2015. Exelon has been participating in the case as an intervenor in support of the rule.

The U.S. EPA continued its regular, periodic review of the NAAQS standards. On November 25, 2014, the Agency proposed, for public comment, the establishment of a revised primary ozone standard in the range of 65-70 parts per billion (ppb) 8-hour average, a reduction from the 2008 ozone standard level of 75 ppb 8-hour average standard. The Agency is also requesting public comment on levels as low as 60 ppb 8-hour average. In its proposal, the Agency is also proposing to extend the “ozone season” on a state-by-state basis from its current May-September five-month period to include months before, and after, the traditional ozone season, depending on air quality monitoring data. Most CSAPR states are proposed to be subjected to a March to October “ozone season.” In its proposed rule, the Agency also elected to set the secondary standard at the same level and form as the primary standard. The Agency is expected to issue its final ozone NAAQS revision in October 2015. In December 2012, the U.S. EPA issued its final revisions to the Agency’s particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation.

In addition to these NAAQS, the U.S. EPA also finalized nonattainment designations for certain areas in the United States for the 2010 one-hour SO2 standard on August 5, 2013, and indicated that additional nonattainment areas will be designated in a future rulemaking. U.S. EPA will require states to submit state implementation plans (SIPs) for nonattainment areas by March 25, 2015. With regard to Texas and Maryland, no nonattainment areas were identified in EPA’s final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. Since the 2010 one-hour SO2 standard was finalized, EPA has issued a series of guidance documents, and proposed a Data Requirement Rule that will be finalized in the summer of 2015 related to requirements for states related to the application of air quality monitoring and modeling in state implementation plans. Nonattainment county compliance with the one-hour SO2 standard is required by March 25, 2018. While significant SO2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the requirements of pending states’ SIPs to further reduce SO2 emissions in support of attainment of the one hour SO2 standard.

The cumulative impact of these air regulations could be to require fossil fuel-fired power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO2 and acid gases, and selective catalytic reduction technology for NOx.

In addition, as of December 31, 2014, Exelon had a $361 million net investment in coal-fired plants in Georgia subject to long-term leases extending through 2028 and 2030. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, after the impairments recorded in the second quarter of 2013 and 2014, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material.

On January 15, 2013, EPA issued a final rule for NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE NESHAP/NSPS). The final rule allows diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but requires units that operate over 15 hours to burn low sulfur fuel and report key engine information. The final rule eliminates after May 2014 the 50 hour exemption for peak shaving and other non-emergency demand response that was included in the proposed rule and, therefore, is not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act. On June 25, 2013, President Obama announced “The President’s Climate Action Plan,” a summary of executive branch actions intended to: reduce carbon emissions; prepare the United States for the impacts of climate change; and lead international efforts to combat global climate change and prepare for its impacts. Concurrent with the announcement of the Administration’s plan, the President also issued a Memorandum for the Administrator of the Environmental Protection Agency that focused on power generation sector carbon reductions under the Section 111 New Source Performance Standards (NSPS) section of the federal Clean Air Act. The memorandum directs the U.S. EPA Administrator to issue two sets of proposed rulemakings with regard to power plant carbon emissions under Section 111 of the Clean Air Act.

The U.S. EPA proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. The Climate Action Plan also required the U.S. EPA to propose by June 2014 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and to issue final regulations by June 2015. That proposed rule was published in the Federal Register on June 16, 2014. The proposed rule establishes emission reduction targets for each state and provides flexibility for each state to determine how to achieve its required reductions, including heat rate improvements at coal-fired power plants, fuel switching from coal to gas, renewable generation and new nuclear facilities, demand side energy efficiency, and the use of market-based instruments. While the nature and impact of the final regulations is not yet known, to the extent that the rule results in emission reductions from fossil fuel fired plants, imposing some form of direct or indirect price of carbon in competitive electricity markets, Exelon’s overall low-carbon generation portfolio results would benefit.

Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On October 14, 2014, the U.S. EPA’s final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed at each facility to determine the best technology available, followed by an implementation period. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, the impact of compliance with the final rule is unknown. Should a state permitting director determine that a facility is required to install cooling towers to comply with the rule, that facility's economic viability would be called into question. However, the likely impact of the rule has been significantly decreased since the final rule does not mandate cooling towers as a national standard, and the state permitting director is required to apply a cost-benefit test and take into consideration site-specific factors.

Hazardous and Solid Waste. On December 19, 2014, the U.S. EPA issued the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants, including the classification of CCR as non-hazardous waste under RCRA. The EPA ruling is effective 180 days after publication in the Federal Register, which is anticipated in early 2015. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded reserves consistent with state regulation for its owned coal ash sites, and as such, the regulation is not expected to impact Exelon's and Generation's financial results. Generation is evaluating what, if any, incremental costs will be incurred for coal ash disposal sites formerly owned by Generation that have not yet been closed by their current owners. At this time, however, Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted for these former sites under the new federal regulations. For these reasons, Generation is unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations, and as a result no new liability has been recorded as of December 31, 2014.

See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

NRC Task Force Insights from the Fukushima Daiichi Accident. In July 2011, an NRC Task Force formed in the aftermath of the March 11, 2011, 9.0 magnitude earthquake and ensuing tsunami, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, issued a report of its review of the accident, including tiered recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for Generation, net of expected co-owner reimbursements, for the period from 2015 through 2019 is expected to be between approximately $325 million and $350 million of capital (including approximately $75 million for the CENG plants) and $75 million of operating expense (including approximately $25 million for the CENG plants). As Generation completes the design and installation planning for its actions, Generation will update these estimates. Further, Generation estimates incremental costs of $15 to $20 million per unit at thirteen Mark 1 and II units (including two CENG units) for the installation of filters on vents, if ultimately required by the NRC. Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2

and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Executive Overview of the Exelon 2014 Form 10-K, for additional information.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted in July 2010. The part of the Act that applies to Exelon is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires the creation of a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing for certain categories of Swaps, incentives to shift Swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. For non security-based Swaps including commodity Swaps, Dodd-Frank empowers the Commodity Futures Trading Commission (CFTC) to promulgate regulations implementing the law's objectives. The primary aim of Dodd-Frank is to regulate the key intermediaries in the Swaps market, which entities are either swap dealers (SDs), major swap participants (MSPs), and certain other financial entities, but the law also applies to a lesser degree to end-users of Swaps. On January 12, 2015, President Obama signed into law a bill that exempts from margin requirements Swaps used by end-users to hedge or mitigate commercial risk. Moreover, the CFTC's Dodd-Frank regulations preserve the ability of end users in the energy industry to hedge their risks using Swaps without being subject to mandatory clearing, and excepts or exempts end-users from many of the other substantive regulations. Accordingly, as an end-user, Generation is conducting its commercial business in a manner that does not require registration with the CFTC as an SD or MSP. Generation does not anticipate transacting in the future in a manner in which it would become a SD or MSP.

There are, however, some rulemakings that have not yet been finalized, including the capital and margin rules for (non-cleared) Swaps. Generation does not expect these rules to directly impact its collateral requirements. However, depending on the substance of these final rules in addition to certain international regulatory requirements still under development and that are similar to Dodd-Frank, Generation's Swap counterparties could be subject to additional and potentially significant capitalization requirements. These regulations could motivate the SDs and MSPs to increase collateral requirements or cash postings from their counterparties, including Generation.

Generation continues to monitor the rulemaking proceedings with respect to the capital and margin rules, but cannot predict to what extent, if any, further refinements to Dodd-Frank requirements may impact its cash flows or financial position, but such impacts could be material.

ComEd, PECO and BGE could also be subject to some Dodd-Frank requirements to the extent they were to enter into Swaps. However, at this time, management of ComEd, PECO and BGE continue to expect that their companies will not be materially affected by Dodd-Frank.

Energy Infrastructure Modernization Act . Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. In addition, ComEd's earned rate of return on common equity is required to be within plus or minus 50 basis points ("the collar") of the target rate of return determined as the annual average rate on 30-year treasury notes plus 580 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on distribution revenue. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation.

Formula Rate Tariff and Annual Reconciliation. On April 16, 2014, ComEd filed its annual distribution formula rate to request a total increase to the revenue requirement of $269 million. On December 11, 2014, the ICC issued its final order which increased the revenue requirement by $232 million, reflecting an increase of $160 million for the initial revenue requirement for 2014 and an increase of $72 million related to the annual reconciliation for 2013. Approximately $23 million of the total $37 million revenue requirement disallowance is recoverable through other rider-based mechanisms. The rate increase was set using an allowed return on capital of 7.06% (inclusive of an allowed return on common equity of 9.25% for 2014 less a performance metrics penalty of 5 basis points for the 2013 reconciliation). The rates took effect in January 2015. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC on January 28, 2015.

Grand Prairie Gateway Transmission Line. On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. On October 22, 2014, the ICC issued an order approving ComEd's Grand Prairie Gateway Project over the objection of numerous landowners and the City of Elgin. Four parties filed timely applications for rehearing before the ICC. On November 25, 2014, the ICC denied the rehearing application filed by the Forest Preserve District of Kane County, but granted rehearing on the application of certain landowners who requested that the ICC consider an alternate route for a three-mile segment of the line in Kane County. The rehearing proceeding is currently pending and , the ICC must enter a final order on rehearing by April 24, 2015. On December 10, 2014, the ICC denied the remaining two applications for rehearing. On January 15, 2015, those two parties, the City of Elgin and the SKP landowner group and Utility Risk Management Corporation (collectively, the SKP/URMC party), each filed a Notice of Appeal with the Second District Appellate Court. On February 3, 2015, the ICC filed motions with the Second District Appellate Court seeking to extend the time for the ICC to file the record on appeal until after the ICC issues its Order on rehearing. The ICC also filed a motion to consolidate those appeals. ComEd expects to begin construction of the line in the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

FERC Ameren Order. In July 2012, FERC issued an order to Ameren Corporation (Ameren) finding that Ameren had improperly included acquisition premiums/goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. Ameren filed for rehearing of the July 2012 order, which was denied in June 2014. FERC and Ameren are in the process of determining the amount of any potential refund. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

FERC Order No. 1000 Compliance. In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements of a right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day,

certain of the PJM transmission owners, including ComEd, PECO and BGE (collectively, the PJM Transmission Owners), submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC's " *Mobile-Sierra* " standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order on the PJM Compliance Filing and the filing of these PJM Transmission Owners (1) rejecting the arguments of those PJM Transmission Owners that changes to the PJM governing documents were entitled to review under the *Mobile-Sierra* standard, (2) accepting most of the PJM filing, removing the right-of-first refusal from the PJM tariffs, and (3) directing PJM to remove certain exceptions that it included in its compliance filing that FERC found did not comply with Order No. 1000. FERC's order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd's, PECO's and BGE's financial return on new investments in energy transmission facilities. Numerous parties sought rehearing of the FERC's March 22, 2013 order, including the PJM Transmission Owners who sought rehearing of the FERC's rejection of their Mobile-Sierra and related arguments. PJM's compliance filing was made on July 22, 2013. On May 15, 2014, FERC denied the rehearing requests except with respect to one issue on when PJM could consider state and local laws in evaluating projects. FERC generally accepted the July 22, 2013, Compliance Filing but required several minor additional changes. FirstEnergy and at least one other party filed an appeal of the May 15, 2014, Order upholding PJM's right of first refusal language in the DC Circuit. Exelon has intervened in the FirstEnergy appeal. Several parties have filed requests for rehearing or clarification concerning the changes set forth in the May 15, 2014, Order. On December 18, 2014, FERC issued an order conditionally accepting part of the PJM-MISO interregional Order No. 1000 compliance filing, rejecting a MISO proposal concerning cost allocation for cross-border reliability projects and directing a further compliance filing by PJM and MISO.

FERC Transmission Complaint. On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) and a 50 basis point incentive for participating in PJM (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the revenues subject to refund are limited to a fifteen month period, the earliest date from which the base ROE could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint.

On August 21, 2014, FERC issued an order in the BGE and PHI companies' proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013. BGE, the PHI companies and the parties began settlement discussions under the guidance of a FERC administrative law judge on September 23, 2014. On November 24, 2014, the Settlement Judge informed FERC and the Chief Judge that the parties had reached an impasse and determined that a settlement was not possible. The Settlement Judge recommended termination of settlement proceedings. On November 26, 2014, the Chief Judge issued an order terminating the settlement proceeding, designating a presiding judge at the hearings and directing that an initial decision be issued by November 25, 2015.

On December 8, 2014, various state agencies in Delaware, Maryland, New Jersey, and D.C. filed a second complaint against BGE regarding the base ROE of the transmission business seeking a

reduction from 10.8% to 8.8%. The filing of the second complaint creates a second refund window. By order issued on February 9, 2015, FERC established a hearing on the second complaint with the complainants' requested refund effective date of December 8, 2014.

Based on the current status of the complaint filings, BGE believes it is probable that BGE's base ROE rate will be adjusted, and that a refund to customers of transmission revenue for the two maximum fifteen month periods will be required. However, BGE is unable to estimate the most likely refund amount for either complaint at this time, and has therefore established a reserve, which is not material, representing the low end of a reasonably possible estimated range of loss. Additionally, management is unable to estimate the maximum exposure of a potential refund at this time, which may have a material impact on BGE's results of operations and cash flows. The estimated annual ongoing reduction in revenues if FERC approved the ROEs requested by the parties in their filings is approximately $11 million. If FERC were to order a reduction of BGE's base ROE to 8.7% as sought in the first complaint (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result of the first fifteen month refund window would be a refund to customers of approximately $13 million. If FERC were to order a reduction in BGE's base ROE to 8.8% as sought in the second complaint (while retaining 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment) and the refund period extended for a full fifteen months, the result would be a refund to customers of approximately $14 million. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The Maryland Strategic Infrastructure Development and Enhancement Program. In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law; which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On March 26, 2014, the MDPSC approved as filed BGE's proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge that became effective April 1, 2014. On November 17, 2014, BGE filed a surcharge update including a true-up of costs estimates included in the 2014 surcharge, along with its 2015 project list and cost estimates to be included in the 2015 surcharge. The filing was approved with a revised surcharge effective January 1, 2015. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2015 project list and the proposed surcharge for 2015. BGE will defer the difference between the surcharge revenues and program costs as a regulated asset or liability, which was immaterial to Exelon and BGE as of December 31, 2014.

In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE's infrastructure replacement plan. On September 5, 2014, the Baltimore City Circuit Court affirmed the MDPSC decision on BGE's infrastructure replacement plan and associated surcharge. On October 10, 2014, the residential

consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court, however, a procedural schedule for the matter has not yet been set.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions with its accounting and disclosure governance committee on a regular basis and provides periodic updates on management decisions to the audit committee of the Exelon board of directors. Management believes that the accounting policies described below require significant judgment in their application, or estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation's ARO associated with decommissioning its nuclear units was $7.0 billion at December 31, 2014. The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios. The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the methodologies and significant estimates and assumptions described as follows:

Decommissioning Cost Studies. Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the costs and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within its industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years.

Cost Escalation Factors. Generation uses cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors, and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal and other costs.

Probabilistic Cash Flow Models. Generation's probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning costs, approaches and timing on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. Probabilities are assigned to alternative decommissioning approaches which assess the likelihood of performing DECON (a method of decommissioning shortly after the cessation of operation in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a LLRW landfill or decontaminated to a level that permits property to be released for unrestricted use), Delayed DECON (similar to the DECON scenario but with a delay to allow for spent fuel to be removed from the site prior to onset of decommissioning activities) or SAFSTOR (a method of decommissioning in which the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated to levels that permit release for unrestricted use generally within 60 years after cessation of operations) decommissioning. Probabilities assigned to the timing scenarios incorporate

the likelihood of continued operation through current license lives or through anticipated license renewals. Generation's probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal. Generation assumes DOE will begin accepting SNF in 2025. The SNF acceptance date was based on management's estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

License Renewals. Generation assumes a successful 20-year renewal for each of its nuclear generating station licenses, except for Oyster Creek, in determining its nuclear decommissioning ARO. The current NRC license for Oyster Creek expires in 2029. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. As a result of this decision the expected economic life of Oyster Creek was reduced by 10 years to correspond to Exelon's current best estimate as to the timing of ceasing generation operations at the Oyster Creek unit in 2019. Generation has successfully secured 20-year operating license renewal extensions for seventeen of its nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG), and none of Generation's applications for an operating license extension has been denied. For its remaining seven operating units, Generation is in various stages of the process of pursuing similar extensions and has filed license renewal applications for six operating nuclear units and has until 2021 to seek license renewal for one operating nuclear unit. Generation's assumption regarding license extension for ARO determination purposes is based in part on the good current physical condition and high performance of these nuclear units, the favorable status of the ongoing license renewal proceedings with the NRC, and the successful renewals for seventeen units to date. Generation estimates that the failure to obtain license renewals at any of these nuclear units (assuming all other assumptions remain constant) would increase its ARO on average approximately $300 million per unit as of December 31, 2014. The size of the increase to the ARO for a particular nuclear unit is dependent upon the current stage in its original license term and its specific decommissioning cost estimates. If Generation does not receive license renewal on a particular unit, the increase to the ARO may be mitigated by Generation's ability to delay ultimate decommissioning activities under a SAFSTOR method of decommissioning.

Discount Rates. The probability-weighted estimated future cash flows using these various scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. The accounting guidance required Generation to establish an ARO at fair value at the time of the initial adoption of the current accounting standard. Subsequent to the initial adoption, the ARO is adjusted for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions, as described above.

Under the current accounting framework, the ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. This differs from the accounting requirements for other long-dated obligations, such as pension and other post-employment benefits that are required to be re-measured as and when corresponding discount rates change. If Generation's future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFRs, the obligation would increase from approximately $7.0 billion to approximately $8.6 billion. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon's and Generation's Consolidated Balance Sheets at December 31, 2014 at fair value of approximately $10.5 billion and have an estimated targeted annual pre-tax return of 6.0% to 6.3%.

To illustrate the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO: i) had Generation used the 2013 CARFRs rather than the 2014 CARFRs in performing its third quarter 2014 ARO update, Generation would have reduced the ARO by approximately $190 million as compared to

the actual decrease to the ARO of $125 million; and ii) if the CARFR used in performing the third quarter 2014 ARO update (which also reflected increases in the amounts and changes to the timing of projected cash flows) was increased or decreased by 100 basis points, the ARO would have decreased by $230 million and increased $40 million, respectively, as compared to the actual decrease of $125 million.

ARO Sensitivities. Changes in the assumptions underlying the foregoing items could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions will change as well.

The following table illustrates the effects of changing certain ARO assumptions, discussed above, while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption	Increase (Decrease) to ARO at December 31, 2014
Cost escalation studies	
Uniform increase in escalation rates of 25 basis points	$ 810
Probabilistic cash flow models	
Increase the likelihood of the high-cost scenario by 10 percentage points and decrease the likelihood of the low-cost scenario by 10 percentage points	$ 290
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$ 420
Increase the likelihood of operating through current license lives by 10 percentage points and decrease the likelihood of operating through anticipated license renewals by 10 percentage points	$ 630
Extend the estimated date for DOE acceptance of SNF to 2030	$ 230
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with an increase in discount rates of 100 basis points	$ (270)
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with a decrease in discount rates of 100 basis points	$ 1,100

For more information regarding accounting for nuclear decommissioning obligations, see Note 1—Significant Accounting Policies and Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon and ComEd)

As of December 31, 2014, Exelon's and ComEd's carrying amount of goodwill was approximately $2.7 billion, relating to the acquisition of ComEd in 2000 as part of the PECO/Unicom Merger. Under the provisions of the authoritative guidance for goodwill, ComEd is required to perform an assessment for possible impairment of its goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Under the authoritative guidance, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and its operating results are regularly reviewed by segment management. ComEd has a single operating segment for its combined business. There is no level below this operating segment for which operating results are regularly reviewed by segment management. Therefore, ComEd's operating segment is considered its only reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors, and entity-specific events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's business and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit. See Note 1—Significant Accounting Policies, Note 10—Intangible Assets and Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon and Generation)

In accordance with the authoritative accounting guidance, the assets acquired and liabilities assumed in an acquired business are recorded at their estimated fair values on the date of acquisition. The difference between the purchase price amount and the net fair value of assets acquired and liabilities assumed is recognized as goodwill on the balance sheet if it exceeds the estimated fair value and as a bargain purchase gain on the income statement if it is below the estimated fair value. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, the utilization of independent valuation experts and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Assets and Liabilities (Exelon and Generation)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired. The initial amount recorded represents the fair value of the contract at the time of acquisition, and the balance is amortized over the life of the contract in relation to the present value of the underlying cash flows. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Refer to Note 4—Mergers, Acquisitions, and Dispositions and Note 10—Intangible Assets of the Combined Notes to Consolidated Financial Statements for further discussion.

Impairment of Long-lived Assets (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE regularly monitor and evaluate their long-lived assets and asset groups, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. Indicators for impairment may include a deteriorating business climate, including current energy prices and market conditions, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life, among others.

The review of long-lived assets and asset groups for impairment requires significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power, costs of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could have a significant effect on the consolidated financial statements. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of other groups of assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units as well as the associated intangible contract assets recorded on the balance sheet. The cash flows from the generating units are generally evaluated at a regional portfolio level with cash flows generated from the customer supply and risk management activities, including cash flows from contracts that are accounted for as intangible contract assets and liabilities recorded on the balance sheet. In certain cases generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generating assets (typically contracted renewables).

On a quarterly basis, Generation assesses its asset groups for indicators of impairment. If indicators are present, a recoverability test is performed. Impairment may occur if the carrying value of the asset or asset group exceeds the future undiscounted cash flows. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value of the long-lived asset or asset group is dependent upon a market participant's view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates. Events and circumstances often do not occur as expected and there will usually be differences between prospective financial information and actual results, and those differences may be material. Accordingly, to the extent that any of the information used in the fair value analysis requires judgment, the resulting fair market value would be different. As such, the determination of fair value is driven by both internal assumptions that include significant unobservable inputs (Level 3) such as revenue and generation forecasts, projected capital, and maintenance expenditures and discount rates, as well as information from various public, financial and industry sources. An impairment determination would require the affected Registrant to reduce the value of either the long-lived asset or asset group, including any associated intangible contract assets and liabilities, as well as current period earnings by the amount of the impairment.

Generation evaluates natural gas and oil Upstream properties at least annually to determine if they are impaired. Impairment for natural gas and oil Upstream properties occurs if there are no firm plans to continue drilling, lease expiration is at risk, historical experience indicates a decline in carrying value below fair value or the price of the underlying commodity significantly declines.

Exelon holds investments in coal-fired plants in Georgia subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual values of the leased assets at the end of the respective lease terms. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, that takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contracts associated with the plants given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

Generation also evaluates its equity method investments to determine whether or not they are impaired based on whether the investment has experienced a decline in value that is not temporary in nature. Additionally, if one of Generation's equity method investments recognizes an impairment, Generation would record its proportionate share of that impairment loss through its equity earnings (losses) of unconsolidated affiliates.

See Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Exelon.

Depreciable Lives of Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. Depreciation of these assets is generally provided over their estimated service lives on a straight-line basis using the composite method. The Registrants complete depreciation studies every five years, or more frequently in an event, regulation action, or change in retirement patterns indicate an update is necessary. The estimation of service lives requires management judgment regarding the period of time that the assets will be in use. As circumstances warrant, the estimated service lives are reviewed to determine if any changes are needed. Depreciation rates incorporate assumptions on interim retirements based on actual historical retirement experience. To the extent interim retirement patterns change, this could have a significant impact on the amount of depreciation expense recorded in the income statement. Changes to depreciation estimates resulting from a change in the estimated end of service lives could have a significant impact on the amount of depreciation expense recorded in the income statement. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant and equipment of the Registrants.

The estimated service lives of the nuclear generating facilities are based on the estimated useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek. While Generation has received license renewals for certain facilities, and has applied for or expects to apply for and obtain approval of license renewals for the remaining facilities, circumstances may arise that would prevent Generation from obtaining additional license renewals. Generation also evaluates annually the estimated service lives of its generating facilities based on feasibility assessments as well as economic and capital requirements. The estimated service lives of hydroelectric facilities are based on the

remaining useful lives of the stations, which assume a license renewal extension of the Conowingo and Muddy Run operating licenses. A change in depreciation estimates resulting from Generation's extension or reduction of the estimated service lives could have a significant effect on Generation's results of operations.

Generation completed a depreciation rate study during the first quarter of 2010, which resulted in the implementation of new depreciation rates effective January 1, 2010. Constellation completed a depreciation rate study during the fourth quarter of 2010, which resulted in the implementation of new depreciation rates effective during the fourth quarter of 2010.

ComEd is required to file a depreciation rate study at least every five years with the ICC. ComEd completed a depreciation study and filed the updated depreciation rates with both FERC and the ICC in January 2014. This resulted in the implementation of new depreciation rates effective first quarter 2014.

PECO is required to file a depreciation rate study at least every five years with the PAPUC. In April 2010, PECO filed a depreciation rate study with the PAPUC for both its electric and gas assets, which resulted in the implementation of new depreciation rates effective January 1, 2010 for electric transmission assets and January 1, 2011 for electric distribution and gas assets. PECO expects to complete an updated depreciation study in 2015 and expects this to result in new depreciation rates effective in the first quarter of 2015 for electric transmission assets and first quarter 2016 for electric distribution and gas assets.

The MDPSC does not mandate the frequency or timing of BGE's depreciation studies. In July 2014, BGE filed revised depreciation rates with the MDPSC for both its electric distribution and gas assets. Revisions to depreciation rates from this filing were finalized and effective December 15, 2014.

Defined Benefit Pension and Other Postretirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for substantially all Generation, ComEd, PECO, BGE and BSC employees. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and other postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit pension and other postretirement benefit plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is affected by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, the anticipated rate of increase of health care costs, Exelon's expected level of contributions to the plans, the incidence of participant mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the long-term expected investment rate credited to employees of certain plans, among others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. Pension and other postretirement benefit costs attributed to the operating companies are labor costs and are ultimately allocated to projects within the operating companies, some of which are capitalized.

Pension and other postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification under the fair value hierarchy in accordance with authoritative guidance.

Expected Rate of Return on Plan Assets. The long-term EROA assumption used in calculating pension costs was 7.00%, 7.50% and 7.50% for 2014, 2013 and 2012, respectively. The weighted average EROA assumption used in calculating other postretirement benefit costs was 6.59%, 6.45% and 6.68% in 2014, 2013 and 2012, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. The current year EROA is based on asset allocations from the prior year end. In 2010, Exelon began implementation of a liability-driven investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. Over time, Exelon has decreased its equity investments and increased its investments in fixed income securities and alternative investments within the pension asset portfolio in order to achieve a balanced portfolio of liability hedging and return-generating assets. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's asset allocations. Exelon used an EROA of 7.00% and 6.46% to estimate its 2015 pension and other postretirement benefit costs, respectively.

Exelon calculates the expected return on pension and other postretirement benefit plan assets by multiplying the EROA by the MRV of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments to be made during the year. In determining MRV, the authoritative guidance for pensions and postretirement benefits allows the use of either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. For the majority of pension plan assets, Exelon uses a calculated value that adjusts for 20% of the difference between fair value and expected MRV of plan assets. Use of this calculated value approach enables less volatile expected asset returns to be recognized as a component of pension cost from year to year. For other postretirement benefit plan assets and certain pension plan assets, Exelon uses fair value to calculate the MRV.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across the Registrants' pension and other postretirement benefit plans for the year ended December 31, 2014 were 10.93% and 5.01%, respectively, compared to an expected long-term return assumption of 7.00% and 6.59%, respectively.

Discount Rate. The discount rates used to determine the majority pension and other postretirement benefit obligations were 3.94% and 3.92%, respectively, at December 31, 2014. The discount rates at December 31, 2014 represent weighted-average rates for the majority of pension and other postretirement benefit plans. At December 31, 2014 and 2013, the discount rates were determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated distributions under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

The discount rate assumptions used to determine the obligation at year end are used to determine the cost for the following year. Exelon used discount rates ranging from 3.94% and 3.92% to estimate the majority its 2015 pension and other postretirement benefit costs, respectively.

Health Care Reform Legislation. In March 2010, the Health Care Reform Acts (the Acts) were signed into law. The Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Effective in 2002, Constellation amended its other postretirement benefit plans for all subsidiaries other than Nine Mile Point by capping retiree medical coverage for future retirees who were under the age of 55 on January 1, 2002 at 2002 levels. Therefore, the excise tax is not expected to have a material impact on the legacy Constellation other postretirement benefit plans. Although Exelon has capped the rate of claims growth for certain legacy Exelon plan participants over age 65, exposure to the excise tax remains. Certain key assumptions are required to estimate the impact of the excise tax on the other postretirement obligation for legacy Exelon plans, including projected inflation rates (based on the CPI), and under what circumstances pre- and post-65 retiree benefits can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

Health Care Cost Trend Rate. Assumed health care cost trend rates impact the costs reported for Exelon's other postretirement benefit plans for participant populations with plan designs that do not have a cap on cost growth. Accounting guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty. Exelon assumed an initial health care cost trend rate of 6.00% for 2014, decreasing to an ultimate health care cost trend rate of 5.00% in 2017.

Mortality. The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. Exelon historically used a mortality base table for its accounting valuation that is consistent with the IRS required table for funding (referred to as RP-2000) and its corresponding improvement scale. During 2014, the Society of Actuaries (SOA) issued an updated mortality table (referred to as RP-2014) and improvement scale that suggests significant mortality improvement over the prior table. Exelon has a substantial employee population that provides a credible basis for mortality evaluation. Exelon engaged its actuaries to conduct a mortality study of Exelon's actual experience over a five year period as compared to the RP-2000 and RP-2014 tables, which resulted in a determination that the RP-2000 more closely aligns with Exelon's actual mortality experience. The study also considered available improvement scales. Management concluded that the RP-2000 and a more recent improvement scale issued by the SOA with certain adjustments to long-term improvement rates represent its best estimate of mortality. Exelon is utilizing the Scale BB 2-Dimensional improvement scale with long-term improvements of 0.75% (as compared to the 1% incorporated in the issued table) for its mortality improvement assumption. The change in assumption resulted in increases of $361 million and $117 million in the pension and other postretirement benefits obligations, respectively and an increase in 2015 cost of $45 million and $20 million for pension and other postretirement benefits, respectively.

Sensitivity to Changes in Key Assumptions. The following tables illustrate the effects of changing certain of the actuarial assumptions discussed above, while holding all other assumptions constant (dollars in millions):

Actuarial Assumption	Change in Assumption	Pension	Other Postretirement Benefits	Total
Change in 2014 cost:				
Discount rate [a]	0.5%	$ (71)	$ (34)	$ (105)
	(0.5)%	69	31	100
EROA	0.5%	(71)	(12)	(83)
	(0.5)%	71	12	83
Health care cost trend rate [b]	1.00%	N/A	35	35
	(1.00)%	N/A	(24)	(24)
Change in benefit obligation at December 31, 2014:				
Discount rate [a]	0.5%	(1,053)	(245)	(1,298)
	(0.5)%	1,156	271	1,427
Health care cost trend rate [b]	1.00%	N/A	162	162
	(1.00)%	N/A	(113)	(113)

(a) In general, the discount rate will have a larger impact on the pension and other postretirement benefit cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon implemented a liability-driven investment strategy for a portion of its pension asset portfolio in 2010. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

(b) Changes in the plan design of certain other postretirement benefit plans have resulted in reduced sensitivity to the health care cost trend rate.

Average Remaining Service Period. For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants' average remaining service periods. The average remaining service period of defined benefit pension plan participants was 11.8 years, 11.8 years and 11.9 years for the years ended December 31, 2014, 2013 and 2012, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants' average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants' average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 9.1 years, 8.7 years and 8.9 years for the years ended December 31, 2014, 2013 and 2012, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 10.1 years, 9.8 years and 10.1 years for the years ended December 31, 2014, 2013 and 2012, respectively.

Regulatory Accounting (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE account for their regulated electric and gas operations in accordance with the authoritative guidance for accounting for certain types of regulations, which requires Exelon, ComEd, PECO and BGE to reflect the effects of cost-based rate regulation in their financial statements. This guidance is applicable to entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) a reasonable expectation that rates are set at levels that will recover the entities costs from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) the excess recovery of costs or

accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2014, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of those operations no longer meets the criteria of this guidance, Exelon, ComEd, PECO and BGE would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and could be material. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon, ComEd, PECO and BGE.

For each regulatory jurisdiction in which they conduct business, Exelon, ComEd, PECO and BGE assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs in ComEd's, PECO's and BGE's jurisdictions, and factors such as changes in applicable regulatory and political environments. Furthermore, Exelon, ComEd, PECO and BGE make other judgments related to the financial statement impact of their regulatory environments, such as the types of adjustments to rate base that will be acceptable to regulatory bodies, if any, to which costs will be recoverable through rates. Refer to the revenue recognition discussion below for additional information on the annual revenue reconciliations associated with ComEd's distribution formula rate tariff, pursuant to EIMA, and FERC-approved transmission formula rate tariffs for ComEd and BGE. Additionally, estimates are made in accordance with the authoritative guidance for contingencies as to the amount of revenues billed under certain regulatory orders that may ultimately be refunded to customers upon finalization of applicable regulatory or judicial processes. These assessments are based, to the extent possible, on past relevant experience with regulatory bodies in ComEd's, PECO's and BGE's jurisdictions, known circumstances specific to a particular matter and hearings held with the applicable regulatory body. If the assessments and estimates made by Exelon, ComEd, PECO and BGE are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Accounting for Derivative Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants utilize derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy-related products marketed and purchased. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd had a financial swap contract with Generation that expired May 31, 2013 and currently holds floating-to-fixed energy swaps with several unaffiliated suppliers that extend into 2032. PECO and BGE have entered into derivative natural gas contracts to hedge their long-term price risk in the natural gas market. PECO has also entered into derivative contracts to procure electric supply through a competitive RFP process as outlined in its PAPUC-approved DSP Program. BGE has also entered into derivative contracts to procure electric supply through a competitive auction process as outlined in its MDPSC-approved SOS Program. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes. The

Registrants' derivative activities are in accordance with Exelon's Risk Management Policy (RMP). See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether or not a contract qualifies as a derivative under this guidance requires that management exercise significant judgment, including assessing the market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. Further, interpretive guidance related to the authoritative literature continues to evolve, including how it applies to energy and energy-related products. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance related to derivatives, could result in previously excluded contracts being subject to the provisions of the authoritative derivative guidance. Generation has determined that contracts to purchase uranium, contracts to purchase and sell capacity in certain ISO's, certain emission products and RECs do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement and neither the uranium, certain capacity, emission nor the REC markets are sufficiently liquid to conclude that physical forward contracts are readily convertible to cash. If these markets do become sufficiently liquid in the future and Generation would be required to account for these contracts as derivative instruments, the fair value of these contracts would be accounted for consistent with Generation's other derivative instruments. In this case, if market prices differ from the underlying prices of the contracts, Generation would be required to record mark-to-market gains or losses, which may have a significant impact to Exelon's and Generation's financial positions and results of operations.

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, the normal purchases and normal sales exception. Further, derivatives that qualify and are designated for hedge accounting are classified as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For commodity transactions, effective with the date of the Constellation merger, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the Constellation merger. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the Constellation merger were re-designated as cash flow hedges. The effect of this decision is that all economic hedges for commodities are recorded at fair value through earnings for the combined company. In addition, for energy-related derivatives entered into for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings each period. For economic hedges that are not designated for hedge accounting for ComEd, PECO and BGE, changes in the fair value each period are recorded as a regulatory asset or liability.

Normal Purchases and Normal Sales Exception. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated as normal purchases and normal sales and are thus not required to be recorded at fair value, but rather

on an accrual basis of accounting. Determining whether a contract qualifies for the normal purchases and normal sales exception requires that management exercise judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and is not financially settled on a net basis. The contracts that ComEd has entered into with suppliers as part of ComEd's energy procurement process, PECO's full requirement contracts and block contracts under the PAPUC-approved DSP program, most of PECO's natural gas supply agreements and all of BGE's full requirement contracts and natural gas supply agreements that are derivatives qualify for the normal purchases and normal sales exception.

Commodity Contracts. Identification of a commodity contract as an economic hedge requires Generation to determine that the contract is in accordance with the RMP. Generation reassesses its economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

As a part of accounting for derivatives, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. In accordance with the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges are categorized in Level 2. These price quotations reflect the average of the bid-ask mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The Registrant's derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, and assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, the model inputs are generally observable. Such instruments are categorized in Level 2. For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of credit and nonperformance risk to date have generally not been material to the financial statements.

Interest Rate and Foreign Exchange Derivative Instruments. The Registrants may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve the targeted level of variable-rate debt as a percent of total debt. Additionally, the Registrants

may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings and floating to fixed swaps for project financing. In addition, Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the economic hedge and proprietary trading activity is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or change in market interest rates. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. The fair value of the agreements is calculated by discounting the future net cash flows to the present value based on the terms and conditions of the agreements and the forward interest rate and foreign exchange curves. As these inputs are based on observable data and valuations of similar instruments, the interest rate and foreign exchange derivatives are primarily categorized in Level 2 in the fair value hierarchy. Certain exchange based interest rate derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 11—Fair Value of Financial Assets and Liabilities and Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation (Exelon, Generation, ComEd, PECO and BGE)

Significant management judgment is required in determining the Registrants' provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of unrecognized tax benefits to be recorded in the Registrants' consolidated financial statements.

The Registrants evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and their intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. The Registrants also assess their ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. The Registrants record valuation allowances for deferred tax assets when the Registrants conclude it is more-likely-than-not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2014 and 2013 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or

unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Loss Contingencies (Exelon, Generation, ComEd, PECO and BGE)

In the preparation of their financial statements, the Registrants make judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amounts recorded may differ from the actual expense incurred when the uncertainty is resolved. The estimates that the Registrants make in accounting for loss contingencies and the actual results that they record upon the ultimate resolution of these uncertainties could have a significant effect on their consolidated financial statements.

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at ComEd, PECO and BGE to determine future remediation requirements and estimates are adjusted accordingly. In addition, periodic reviews are performed at Generation to assess the adequacy of its environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant effect on the Registrants' results of operations, financial position and cash flows. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information.

Other, Including Personal Injury Claims. The Registrants are self-insured for general liability, automotive liability, workers' compensation, and personal injury claims to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. The Registrants have reserves for both open claims asserted and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible state and national legislative measures could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material effect on the Registrants' results of operations, financial position and cash flows.

Revenue Recognition (Exelon, Generation, ComEd, PECO and BGE)

Sources of Revenue and Selection of Accounting Treatment. The Registrants earn revenues from various business activities including: the sale of energy and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail) *;* the sale and delivery of electricity and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The appropriate accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable accounting standards. The Registrants primarily use accrual and mark-to-market accounting as discussed in more detail below.

Accrual Accounting. Under accrual accounting, the Registrants record revenues in the period when services are rendered or energy is delivered to customers. The Registrants generally use accrual accounting to recognize revenues for sales of electricity, natural gas, and other commodities as part of their physical delivery activities. The Registrants enter into these sales transactions using a variety of instruments, including non-derivative agreements, derivatives that qualify for and are designated as

normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to utility customers under regulated service tariffs, and spot-market sales, including settlements with independent system operators.

Mark-to-Market Accounting. The Registrants record revenues and expenses using the mark-to-market method of accounting for transactions that meet the definition of a derivative for which they are not permitted, or have not elected, the NPNS exception. These mark-to-market transactions primarily relate to risk management activities and economic hedges of other accrual activities. revenues and expenses include: inception gains or losses on new transactions where the fair value is observable and realized; and unrealized gains and losses from changes in the fair value of open contracts.

Use of Estimates. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliations can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Unbilled Revenues . The determination of Generation's, ComEd's, PECO's and BGE's retail energy sales to individual customers is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities' customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, volumes may fluctuate monthly as a result of customers electing to use an alternate supplier, which could be significant to the calculation of unbilled revenue since unbilled commodity receivables are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date would also have an effect on the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

See Note 6—Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

Regulated Transmission & Distribution Revenues **.** ComEd's EIMA distribution formula rate tariff provides for annual reconciliations to the distribution revenue requirement. As of the balance sheet dates, ComEd has recorded its best estimates of the distribution revenue impact resulting from changes in rates that ComEd believes are probable of approval by the ICC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

ComEd's and BGE's FERC transmission formula rate tariffs provide for annual reconciliations to the transmission revenue requirements. As of the balance sheet dates, ComEd and BGE have recorded the best estimate of their respective transmission revenue impact resulting from changes in rates that ComEd and BGE believe are probable of approval by FERC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. At December 31, 2013, BGE estimated the allowance for uncollectible accounts on customer receivables by assigning a reserve factor for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. At December 31, 2014, BGE changed to a methodology for estimating the allowance for uncollectible accounts, which was consistent with ComEd and PECO, as described above. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 6—Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2014, 2013 and 2012 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income Attributable to Common Shareholders by Registrant

	2014 [b]	2013	Favorable (unfavorable) 2014 vs. 2013 variance	2012 [a]	Favorable (unfavorable) 2013 vs. 2012 variance
Exelon	$1,623	$1,719	$ (96)	$1,160	$ 559
Generation	835	1,070	(235)	562	508
ComEd	408	249	159	379	(130)
PECO	352	388	(36)	377	11
BGE	198	197	1	(9)	206

(a) For BGE, reflects BGE's operations for the year ended December 31, 2012. For Exelon and Generation, includes the operations of the Constellation and BGE from the date of the merger, March 12, 2012, through December 31, 2012.

(b) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis from April 1, 2014, through December 31, 2014.

Results of Operations—Generation

	2014 [c]	2013	Favorable (unfavorable) 2014 vs. 2013 variance	2012 [b]	Favorable (unfavorable) 2013 vs. 2012 variance
Operating revenues	$17,393	$15,630	$ 1,763	$14,437	$ 1,193
Purchased power and fuel expense	9,925	8,197	(1,728)	7,061	(1,136)
Revenue net of purchased power and fuel expense [a]	7,468	7,433	35	7,376	57
Other operating expenses					
Operating and maintenance	5,566	4,534	(1,032)	5,028	494
Depreciation and amortization	967	856	(111)	768	(88)
Taxes other than income	465	389	(76)	369	(20)
Total other operating expenses	6,998	5,779	(1,219)	6,165	386
Equity in (losses) earnings of unconsolidated affiliates	(20)	10	(30)	(91)	101
Gain (loss) on sales of assets	437	13	424	(7)	20
Gain on consolidation and acquisition of businesses	289	—	289	—	—
Operating income	1,176	1,677	(501)	1,113	564
Other income and (deductions)					
Interest expense	(356)	(357)	1	(301)	(56)
Other, net	406	355	51	246	109
Total other income and (deductions)	50	(2)	52	(55)	53
Income before income taxes	1,226	1,675	(449)	1,058	617
Income taxes	207	615	408	500	(115)
Net income	1,019	1,060	(41)	558	502
Net income (loss) attributable to noncontrolling interest	184	(10)	194	(4)	(6)
Net income attributable to membership interest	$ 835	$ 1,070	$ (235)	$ 562	$ 508

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.
(b) Includes the operations of Constellation from the date of the merger, March 12, 2012.
(c) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.

Net Income Attributable to Membership Interest

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Generation's net income attributable to membership interest decreased compared to the same period in 2013 primarily due to higher operating and maintenance expense and higher depreciation expense; partially offset by higher revenue, net of purchase power and fuel expense, higher other income, the gains recorded on the sale of Generation's ownership interest in generating stations, the bargain-purchase gain recorded related to the Integrys acquisition, and the gain recorded upon consolidation of CENG. The increase in operating and maintenance expense was largely due to increased labor contracting and materials expense due to the inclusion of CENG's results beginning April 1, 2014 and impairment charges related to 1) generating assets held-for-sale, 2) certain Upstream assets, and 3) wind generating assets. The increase in revenue, net of purchased power and fuel expense was primarily due to the inclusion of CENG's results beginning April 1, 2014, a decrease in fuel costs related to the cancellation of DOE spent nuclear fuel disposal fees, an increase in capacity prices, and favorable portfolio management activities in the New England an South regions, partially offset by lower realized energy prices related to executing Exelon's ratable hedging strategy, higher procurement costs for replacement power due to extreme cold weather in the first quarter of 2014, and unrealized mark-to-market losses in 2014. The increase in other income is primarily the result of increased realized and unrealized gain on NDT funds.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Generation's net income attributable to membership interest increased compared to the same period in 2012 primarily due to higher revenue, net of purchased power and fuel expense, lower operating and maintenance expense and higher earnings from Generation's interest in CENG; partially offset by impairment of certain generating assets, higher depreciation expense, higher property taxes, and higher interest expense. The increase in revenue, net of purchased power and fuel expense was primarily due to increased capacity prices and higher nuclear volume, partially offset by lower realized energy prices, higher nuclear fuel costs, and lower mark-to-market gains in 2013. The decrease in operating and maintenance expense was largely due to 2012 costs associated with a settlement with FERC in 2012 and decreases in transaction costs and employee-related costs associated with the merger.

Revenue Net of Purchased Power and Fuel Expense

Generation's six reportable segments are based on the geographic location of its assets, and are largely representative of the footprints of an ISO/RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within New York ISO, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.

- Other Regions not considered individually significant:
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in gas and oil exploration and production activities, proprietary trading, distributed generation, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems and investments in energy-related proprietary technology. Further, the following activities are not allocated to a region, and are reported in Other: compensation under the reliability-must-run rate schedule; results of operations from the Maryland Clean-Coal assets sold in the fourth quarter of 2012; unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities and allocates resources using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements.

For the years ended December 31, 2014 compared to 2013 and December 31, 2013 compared to 2012, Generation's revenue net of purchased power and fuel expense by region were as follows:

			2014 vs. 2013			2013 vs. 2012	
	2014	2013	Variance	% Change	2012 [a]	Variance	% Change
Mid-Atlantic [b][c][g]	$3,417	$3,270	$ 147	4.5%	$3,433	$ (163)	(4.7)%
Midwest [d]	2,594	2,586	8	0.3%	2,998	(412)	(13.7)%
New England	351	185	166	89.7%	196	(11)	(5.6)%
New York [b][g]	483	(4)	487	n.m.	76	(80)	(105.3)%
ERCOT	317	436	(119)	(27.3)%	405	31	7.7%
Other Regions [e]	327	201	126	62.7%	131	70	53.4%
Total electric revenue net of purchased power and fuel expense	7,489	6,674	815	12.2%	7,239	(565)	(7.8)%
Proprietary Trading	42	(8)	50	n.m.	(14)	6	42.9%
Mark-to-market gains (losses)	(591)	504	(1,095)	n.m.	515	(11)	(2.1)%
Other [f]	528	263	265	100.8%	(364)	627	n.m.
Total revenue net of purchased power and fuel expense	$7,468	$7,433	$ 35	0.5%	$7,376	$ 57	0.8%

(a) Includes results for Constellation beginning on March 12, 2012, the date the merger was completed.
(b) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.
(c) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
(d) Results of transactions with ComEd are included in the Midwest region.
(e) Other Regions includes South, West and Canada, which are not considered individually significant.
(f) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of $124 million, $488 million, and $1,098 million pre-tax for the twelve months ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively.
(g) Includes $113 million and $169 million of purchased power from CENG prior to its consolidation on April 1, 2014 in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2014. Includes $542 million and $450 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2013. Includes $487 million and $306 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2012. See Note 25—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's supply sources by region are summarized below:

Supply source (GWh)	2014	2013	2014 vs. 2013 Variance	2014 vs. 2013 % Change	2012 [a]	2013 vs. 2012 Variance	2013 vs. 2012 % Change
Nuclear generation [b]							
Mid-Atlantic	58,809	48,881	9,928	20.3%	47,337	1,544	3.3%
Midwest	94,000	93,245	755	0.8%	92,525	720	0.8%
New York	13,645	—	13,645	n.m.	—	—	— %
	166,454	142,126	24,328	17.1%	139,862	2,264	1.6%
Fossil and renewables [b]							
Mid-Atlantic [b][d]	11,025	11,714	(689)	(5.9)%	8,808	2,906	33.0%
Midwest	1,372	1,478	(106)	(7.2)%	971	507	52.2%
New England	5,233	10,896	(5,663)	(52.0)%	9,965	931	9.3%
New York	4	—	4	n.m.	—	—	n.m.
ERCOT	7,164	6,453	711	11.0%	6,182	271	4.4%
Other Regions [e]	7,955	6,664	1,291	19.4%	5,913	751	12.7%
	32,753	37,205	(4,452)	(12.0)%	31,839	5,366	16.9%
Purchased power							
Mid-Atlantic [c]	6,082	14,092	(8,010)	(56.8)%	20,830	(6,738)	(32.3)%
Midwest	2,004	4,408	(2,404)	(54.5)%	9,805	(5,397)	(55.0)%
New England	12,354	7,655	4,699	61.4%	9,273	(1,618)	(17.4)%
New York [c]	2,857	13,642	(10,785)	(79.1)%	11,457	2,185	19.1%
ERCOT	10,108	15,063	(4,955)	(32.9)%	23,302	(8,239)	(35.4)%
Other Regions [e]	14,795	14,931	(136)	(0.9)%	17,327	(2,396)	(13.8)%
	48,200	69,791	(21,591)	(30.9)%	91,994	(22,203)	(24.1)%
Total supply by region [f]							
Mid-Atlantic [g]	75,916	74,687	1,229	1.6%	76,975	(2,288)	(3.0)%
Midwest [h]	97,376	99,131	(1,755)	(1.8)%	103,301	(4,170)	(4.0)%
New England	17,587	18,551	(964)	(5.2)%	19,238	(687)	(3.6)%
New York	16,506	13,642	2,864	21.0%	11,457	2,185	19.1%
ERCOT	17,272	21,516	(4,244)	(19.7)%	29,484	(7,968)	(27.0)%
Other Regions [e]	22,750	21,595	1,155	5.3%	23,240	(1,645)	(7.1)%
Total supply	247,407	249,122	(1,715)	(0.7)%	263,695	(14,573)	(5.5)%

(a) Includes results for Constellation beginning on March 12, 2012, the date the merger was completed.
(b) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG). Nuclear generation for the year ended December 31, 2014 includes physical volumes of 11,408 GWh in Mid-Atlantic and 13,645 GWh in New York for CENG.
(c) Purchased power includes physical volumes of 2,489 GWh, 12,067 GWh, and 9,925 GWh in the Mid-Atlantic and 2,857 GWh, 12,165 GWh, and 9,350 GWh in New York as a result of the PPA with CENG for the years ended December 31, 2014, 2013, and 2012, respectively. On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, 100% of CENG volumes are included in nuclear generation.
(d) Excludes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger.
(e) Other Regions includes South, West and Canada, which are not considered individually significant.
(f) Excludes physical proprietary trading volumes of 10,571 GWh, 8,762 GWh, and 12,958 GWh for the years ended December 31, 2014, 2013, and 2012, respectively.
(g) Includes sales to PECO through the competitive procurement process of 2,520 GWh, 5,070 GWh, and 7,762 GWh for the years ended December 31, 2014, 2013, and 2012, respectively. Sales to BGE of 5,093 GWh, 5,595 GWh, and 3,766 GWh were included for the years ended December 31, 2014, 2013, and 2012, respectively.
(h) Includes sales to ComEd under the RFP procurement of 5,259 GWh, 7,491 GWh and 4,152 GWh for the years ended December 31, 2014, 2013, and 2012, respectively.

Mid-Atlantic

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $147 million was primarily due to the consolidation of CENG, the cancellation of the DOE spent nuclear fuel disposal fees, and favorable portfolio management optimization activities, partially offset by higher procurement costs for replacement power, lower nuclear volumes (excluding CENG), lower capacity revenues, and lower realized energy prices related to executing Generation's ratable hedging strategy.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $163 million was primarily due to lower realized energy prices and increased nuclear fuel costs, partially offset by the addition of Constellation in 2012, higher capacity revenues, and higher nuclear revenues.

Midwest

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase in revenue net of purchased power and fuel expense in the Midwest of $8 million was primarily due to higher capacity prices, higher nuclear volumes, and the cancellation of the DOE spent nuclear fuel disposal fee, partially offset by lower realized energy prices related to executing Generation's ratable hedging strategy.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The decrease in revenue net of purchased power and fuel expense in the Midwest of $412 million was primarily due to lower realized energy prices, increased nuclear fuel costs, and lower capacity revenues, partially offset by higher nuclear revenues.

New England

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The $166 million increase in revenue net of purchased power and fuel expense in New England is primarily due to higher realized energy prices and favorable impacts from the restructuring of a fuel supply contract, partially offset by lower generation volume.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The $11 million decrease in revenue net of purchased power and fuel expense in New England is primarily due to lower realized energy prices, partially offset by the addition of Constellation in 2012. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

New York

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $487 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the consolidation of CENG.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The $80 million decrease in revenue net of purchased power and fuel expense in New York was primarily due to decreased realized energy prices, partially offset by the addition of Constellation. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

ERCOT

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $119 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to higher procurement costs for replacement power in the second quarter of 2014 and the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013. The decreases were partially offset by higher generation volume in the first quarter of 2014.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $31 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily due to increased realized energy prices and the addition of Constellation in 2012, partially offset by a decrease due to the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013.

Other Regions

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $126 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily due to higher generation volumes and higher realized energy prices.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $70 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the addition of Constellation in 2012, in addition to increased renewable generation.

Mark-to-market

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market losses on economic hedging activities were $591 million in 2014 compared to gains of $504 million in 2013. See Note 11—Fair Value of Financial Assets and Liabilities and Note 12—Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $504 million in 2013 compared to gains of $515 million in 2012. See Note 11—Fair Value of Financial Assets and Liabilities and Note 12—Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $265 million increase in other revenue net of purchased power and fuel was primarily due to a reduction in amortization of in-the-money energy contracts recorded at fair value at the Constellation merger date and an increase related to the amortization of out-of-the money energy contracts recorded at fair value

upon the consolidation of CENG partially offset by a loss on gas inventory from lower of cost or market adjustments in 2014. See Note 10—Intangible Assets of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $627 million increase in other revenue net of purchased power and fuel was primarily due to reduced amortization expense of the acquired energy contracts recorded at fair value at the merger date. In addition, the increase is also attributable to results from activities acquired as part of the 2012 merger with Constellation including retail gas, energy efficiency, energy management and demand response, Upstream natural gas, and the design and construction of renewable energy facilities. These increases were partially offset by the reduction in revenues net of purchased power and fuel expense from the sale of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger. See Note 10—Intangible Assets of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for 2014, as compared to 2013 and 2012, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation, required capital investment, benefits costs associated with labor, insurance, property taxes, unit contingent costs, suspended DOE nuclear waste storage fee (as discussed further in Note 22—Commitments and Contingencies), and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	2014	2013	2012
Nuclear fleet capacity factor [(a)]	94.3%	94.1%	92.7%
Nuclear fleet production cost per MWh [(a)]	$19.33	$19.83	$19.50

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. As of April 1, 2014, CENG is included at ownership.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The nuclear fleet capacity factor, which excludes Salem, increased in 2014 compared to 2013. While total days offline are greater in 2014 as compared to 2013, the larger capacity units were online for more days in 2014. Additionally, with the addition of the CENG nuclear facilities there were more days offline in 2014 associated with units where Exelon's ownership percentage diminishes the impact on capacity factor. For 2014 and 2013, planned refueling outage days totaled 275 and 233, respectively, and non-refueling outage days totaled 92 and 75, respectively. Production cost per MWh was lower in 2014 compared to 2013 due to elimination of the SNF disposal fee in 2014, partially offset by inclusion of the ownership share of CENG.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The nuclear fleet capacity factor, which excludes Salem, increased primarily due to a lower number of planned refueling outage days in 2013, partially offset by a higher number of non-refueling outage days. For 2013 and

2012, planned refueling outage days totaled 233 and 274, respectively, and non-refueling outage days totaled 75 and 73, respectively. Higher nuclear fuel costs and higher plant operating and maintenance costs, partially offset by higher number of net MWhs generated resulted in a higher production cost per MWh during 2013 as compared to 2012.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2014 compared to 2013, consisted of the following:

	Increase (Decrease) [a]
Impairment and related charges of certain generating assets [b]	$ 506
Labor, other benefits, contracting and materials [c]	361
Accretion expense	78
Corporate allocations [d]	69
Regulatory fees and assessments	51
Maryland merger commitments	44
Nuclear refueling outage costs, including the co-owned Salem plant [e]	54
Increase in asbestos bodily injury reserve	16
Midwest Generation bankruptcy charges	(26)
ARO update	(29)
Merger and integration costs	(29)
Pension and non-pension postretirement benefits expense	(81)
Other	18
Increase in operating and maintenance expense	$ 1,032

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 operating results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.
(b) Reflects the operating and maintenance expense associated with the impairment of certain generating assets held-for-sale, Upstream assets, and wind generating assets during 2014.
(c) Reflects an increase of labor, other benefits, contracting and materials costs primarily due to the inclusion of CENG beginning April 1, 2014. Also includes cost of sales of our other business activities that are not allocated to a region.
(d) Reflects an increased share of corporate allocated costs primarily due to the 2014 CENG integration.
(e) Reflects the impact of increased nuclear outage days primarily due to the inclusion of CENG beginning April 1, 2014.

The changes in operating and maintenance expense for 2013 compared to 2012, consisted of the following:

	Increase (Decrease)
Plant retirements and divestitures [a]	$ (440)
FERC settlement [b]	(195)
Constellation merger and integration costs	(107)
Maryland commitments	(35)
Asbestos bodily injury costs [c]	(16)
Nuclear refueling outage costs, including the co-owned Salem plant [d]	(14)
Corporate allocations [e]	(5)
Labor, other benefits, contracting and materials [f]	160
Impairment and related charges of certain generating assets	160
Midwest Generation bankruptcy charges	11
Pension and non-pension postretirement benefits expense	5
Other	(18)
Decrease in operating and maintenance expense	$ (494)

(a) Reflects the operating and maintenance expense associated with the generating assets retired or divested during 2012.
(b) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation's prior period hedging and risk management transactions.
(c) Reflects decreased asbestos-related bodily injury expense for 2013 compared to 2012.
(d) Reflects the impact of decreased planned refueling outages during 2013.
(e) The decrease in cost allocations during 2013 primarily reflects merger and energy savings for Exelon's corporate operations and shared service entities, partially offset by the impact of an increased share of corporate allocated costs due to the merger.
(f) Includes cost of sales of our other business activities that are not allocated to a region.

Depreciation and Amortization

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase in depreciation and amortization expense was primarily due to the inclusion of CENG's results on a fully consolidated basis beginning April 1, 2014 and an increase in ongoing capital expenditures.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities and ongoing capital additions.

Taxes Other Than Income

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase was primarily due to the inclusion of CENG's results on a fully consolidated basis beginning April 1, 2014.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The increase was primarily due to the addition of Constellation's financial results in 2012.

Equity in Earnings (Losses) of Unconsolidated Affiliates

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The year-over-year change in Equity in earnings (losses) of unconsolidated affiliates is primarily the result of the consolidation of CENG's results of operations beginning April 1, 2014, which were previously accounted for under the equity method of accounting.

Gain (Loss) on Sales of Assets

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The year-over-year change in Gain (loss) on sales of assets reflects $411 million of gains recorded on the sale of Generation's ownership interests in Safe Harbor Water Power Corporation, Fore River and West Valley generating stations in 2014. Refer to Note 4—Mergers, Acquisitions and Dispositions in the Combined Notes to Consolidated Financial Statements for additional information.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The year-over-year change in Gain (loss) on sales of assets primarily reflects an $8 million gain recorded on the sale of Maryland Clean Coal in 2013.

Gain on Consolidation and Acquisition of Businesses

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The increase in Gain on consolidation and acquisition of businesses is primarily related to a $261 million gain upon consolidation of CENG resulting from the difference in fair value of CENG's net assets as of April 1, 2014 and the equity method investment previously recorded on Generation's and Exelon's books and the settlement of pre-existing transactions between Generation and CENG, and a $28 million bargain-purchase gain related to the Integrys acquisition.

Interest Expense

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . Interest expense for the year ended December 31, 2014 compared to the same period in 2013 remained relatively level.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger and increased project financing.

Other, Net

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase in Other, net primarily reflects $31 million of favorable tax settlements related to Constellation's pre-acquisition 2009-2012 tax returns and the net increase in realized and unrealized gains related to the NDT funds of Generation's Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $67 million and $122 million for the year ended December 31, 2014 and 2013, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT funds.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012 . The increase in Other, net primarily reflects $85 million of credit facility termination fees recorded in 2012 and increased net realized and unrealized gains related to the NDT funds of Generation's Non-Regulatory Agreement Units compared to net realized and unrealized gains in 2012, as described in the table below. Other, net also reflects $122 million and $117 million for the year ended December 31, 2013 and 2012, respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT funds.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for 2014, 2013 and 2012:

	2014	2013	2012
Net unrealized gains on decommissioning trust funds	$134	$146	$105
Net realized gains on sale of decommissioning trust funds	$ 77	$ 24	$ 51

Effective Income Tax Rate.

Generation's effective income tax rates for the years ended December 31, 2014, 2013 and 2012 were 16.9%, 36.7% and 47.3%, respectively. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—ComEd

	2014	2013	Favorable (Unfavorable) 2014 vs. 2013 Variance	2012	Favorable (Unfavorable) 2013 vs. 2012 Variance
Operating revenue	$4,564	$4,464	$ 100	$5,443	$ (979)
Purchased power expense	1,177	1,174	(3)	2,307	1,133
Revenue net of purchased power expense [(a)]	3,387	3,290	97	3,136	154
Other operating expenses					
Operating and maintenance	1,429	1,368	(61)	1,345	(23)
Depreciation and amortization	687	669	(18)	610	(59)
Taxes other than income	293	299	6	295	(4)
Total other operating expenses	2,409	2,336	(73)	2,250	(86)
Gain on sales of assets	2	—	2	—	—
Operating income	980	954	26	886	68
Other income and (deductions)					
Interest expense, net	(321)	(579)	258	(307)	(272)
Other, net	17	26	(9)	39	(13)
Total other income and (deductions)	(304)	(553)	249	(268)	(285)
Income before income taxes	676	401	275	618	(217)
Income taxes	268	152	(116)	239	87
Net income	$ 408	$ 249	$ 159	$ 379	$ (130)

(a) ComEd evaluates its operating performance using the measure of revenue net of purchased power expense. ComEd believes that revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2014, Compared to Year Ended December 31, 2013. ComEd's Net income for the year ended December 31, 2014, was higher than the same period in 2013, primarily due

to the 2013 remeasurement of Exelon's like-kind exchange tax position, and increased electric distribution and transmission earnings resulting from increased capital investment, partially offset by unfavorable weather.

Year Ended December 31, 2013, Compared to Year Ended December 31, 2012. ComEd's Net income for the year ended December 31, 2013, was lower than the same period in 2012, primarily due to the remeasurement of Exelon's like-kind exchange tax position and unfavorable weather, partially offset by increased electric distribution and transmission earnings resulting from increased costs and capital investments and higher allowed ROE. See Note 3—Regulatory Matters and Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements in the 2013 10-K for additional information.

Operating Revenue Net of Purchased Power Expense

There are certain drivers of Operating revenue that are fully offset by their impact on Purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on Revenue net of purchased power expense. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries, but do affect ComEd's Operating revenue related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

The number of retail customers participating in customer choice programs was 2,426,921, 2,630,185 and 1,627,150 at December 31, 2014, 2013 and 2012, respectively, representing 63%, 68% and 43% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 80%, 81% and 65% of ComEd's retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively.

The changes in ComEd's Revenue net of purchased power expense for the year ended 2014 compared to the same period in 2013 consisted of the following:

	Increase
Weather	$ (16)
Electric distribution revenue	(2)
Transmission revenue	30
Regulatory required programs	52
Revenue subject to refund	(9)
Pricing and customer mix	5
Uncollectible accounts recovery, net	41
Other	(4)
Increase in revenue net of purchased power	$ 97

Weather

The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions"

because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the year ended December 31, 2014, unfavorable weather conditions, primarily during the summer months, reduced Operating revenue net of purchased power expense when compared to prior year.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2014 and 2013 consisted of the following:

	Twelve Months Ended December 31,			% Change	
Heating and Cooling Degree-Days	2014	2013	Normal	From 2013	From Normal
Heating Degree-Days	7,027	6,603	6,341	6.4%	10.8%
Cooling Degree-Days	799	933	842	(14.4)%	(5.1)%

Volume

For the year ended December 31, 2014 Revenue net of purchased power expense remained relatively consistent, as compared to the same period in 2013.

Electric Distribution Revenue

EIMA provides for a performance-based formula rate tariff, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under EIMA, distribution revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, allowed ROE, and other billing determinants. In addition, ComEd's allowed rate of return on common equity is the annual average rate on 30-year treasury notes plus 580 basis points, subject to a collar of plus or minus 50 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on revenue. During the year ended December 31, 2014, distribution revenue decreased $2 million at ComEd, primarily due to lower Operating and maintenance expenses primarily driven by the impacts of certain OPEB plan design changes, partially offset by increased capital investment. See Operating and Maintenance Expense below, ITEM 1. BUSINESS—Commonwealth Edison Company, Note 3—Regulatory Matters and Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue

Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. During the year ended December 31, 2014, ComEd recorded increased revenue of $30 million due to increased capital investments. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs

This represents the change in Operating revenue collected under approved riders to recover costs incurred for regulatory programs such as ComEd's energy efficiency and demand response and purchase power administrative costs. The riders are designed to provide full and current cost recovery.

The costs of these programs are included in Operating and maintenance expense. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net

Uncollectible accounts recovery, net represents recoveries under ComEd's uncollectible accounts tariff. See the Operating and maintenance expense discussion below for additional information on this tariff.

Pricing and Customer Mix

The increase in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes and change in customer mix for the years ended December 31, 2014, and 2013, respectively.

Revenue Subject to Refund

ComEd records revenue subject to refund based upon its best estimate of customer collections that may be required to be refunded. For the year ended December 31, 2014, ComEd recorded $9 million of revenue subject to refund associated with Rider AMP. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial statements for additional information.

Other

Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental costs associated with MGP sites, recovery of energy procurement costs, for which an equal and offsetting amount is reflected in Depreciation and amortization expense during the periods presented.

The changes in ComEd's Revenue net of purchased power expense for 2013 compared to 2012 consisted of the following:

	Increase
Weather	$ (17)
Volume	(2)
Electric distribution revenue	168
Discrete impacts of the 2012 distribution rate case order	13
Transmission revenue	14
Regulatory required programs	20
Uncollectible accounts recovery, net	(58)
Other	16
Increase in revenue net of purchased power	$ 154

Weather

For the year ended December 31, 2013, the increase in Revenue net of purchased power expense was offset by unfavorable weather conditions as a result of the mild weather in 2013 compared to the same period in 2012.

The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2013 and 2012 consisted of the following:

Heating and Cooling Degree-Days	Twelve Months Ended December 31, 2013	2012	Normal	% Change From 2012	% Change From Normal
Heating Degree-Days	6,603	5,065	6,341	30.4%	4.1%
Cooling Degree-Days	933	1,324	842	(29.5)%	10.8%

Volume

Revenue net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the year ended December 31, 2013, reflecting decreased average usage per residential customer as compared to the same period in 2012.

Electric Distribution Revenue

During the year ended December 31, 2013, ComEd recorded increased revenue of $168 million under EIMA, primarily due to increased capital investments, increased operating expenses, and higher allowed ROE. These amounts exclude the discrete impacts of the 2012 Distribution Rate Case Orders discussed separately below. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Orders

On October 3, 2012, the ICC issued its final order related to ComEd's 2011 formula rate proceeding under EIMA, which reestablished ComEd's position on the return on its pension asset, resulting in an increase to revenue in 2013. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue

During the year ended December 31, 2013, ComEd recorded increased revenue during the year ended December 31, 2013 of $14 million, primarily due to increased capital investments and higher operating expenses. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Operating and Maintenance Expense

	Year Ended December 31, 2014	2013	Increase 2014 vs. 2013	Year Ended December 31, 2013	2012	Increase 2013 vs. 2012
Operating and maintenance expense—baseline	$1,211	$1,202	$ 9	$1,202	$1,199	$ 3
Operating and maintenance expense—regulatory required programs [(a)]	218	166	52	166	146	20
Total operating and maintenance expense	$1,429	$1,368	$ 61	$1,368	$1,345	$ 23

(a) Operating and maintenance expense for regulatory required programs are recoveries from customers for costs of various legislative and regulatory programs on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenue.

The changes in Operating and maintenance expense for year ended December 31, 2014, compared to the same period in 2013 and changes for the year ended December 31, 2013, compared to the same period in 2012, consisted of the following:

	Increase 2014 vs. 2013	Increase 2013 vs. 2012
Baseline		
Labor, other benefits, contracting and materials [a]	$ 56	$ 48
Pension and non-pension postretirement benefits expense [b]	(85)	3
Storm-related costs	(11)	(10)
Uncollectible accounts expense—provision [c]	12	(10)
Uncollectible accounts expense—recovery, net [c]	29	(48)
Other	8	20
	9	3
Regulatory required programs		
Energy efficiency and demand response programs	52	20
Increase in operating and maintenance expense	$ 61	$ 23

(a) Reflects decreased contracting costs resulting from new projects associated with EIMA for the years ended December 31, 2014 and 2013. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding EIMA.
(b) Primarily reflects decreased non-pension costs associated with OPEB plan design changes during 2014. See Note 16—Retirement Benefits of the Combined Notes to the Consolidated Financial Statements for additional information regarding plan changes.
(c) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. In 2013, ComEd recorded a net reduction in Operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers as a result of municipal aggregation. An equal and offsetting reduction has been recognized in Operating revenue for the periods presented.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2014 compared to 2013 and 2013 compared to 2012, consisted of the following:

	Increase 2014 vs. 2013	Increase 2013 vs. 2012
Depreciation associated with higher plant balances	$ 46	$ 22
Amortization of storm-related regulatory assets [a]	—	4
Amortization of MGP regulatory assets [b]	(18)	27
Amortization of other regulatory assets	(3)	6
Other	(7)	—
Increase in depreciation and amortization expense	$ 18	$ 59

(a) Under EIMA, ComEd is required to recover costs associated with significant storms over a five-year period through the amortization of a regulatory asset.
(b) An equal and offsetting amount for the amortization expense related to MGP remediation expenditures is reflected in Operating revenue during the periods presented.

Taxes Other Than Income

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income remained relatively flat for the twelve months ended December 31, 2014, compared to the same periods in 2013.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Taxes other than income taxes increased primarily due to increased Illinois electricity distribution taxes.

Interest Expense, Net

The changes in Interest expense, net for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Interest expense related to uncertain tax positions [a]	$ (275)	$ 281
Interest expense on debt (including financing trusts) [b]	16	2
Other	1	(11)
Increase (decrease) in interest expense, net	$ (258)	$ 272

(a) Primarily reflects the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Primarily reflects interest expense related to the First Mortgage Bonds. See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's debt obligations.

Other, Net

The changes in Other, net for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Interest income related to uncertain tax positions [a]	$ —	$ (20)
AFUDC—Equity	(8)	—
Other	(1)	7
Increase (decrease) in Other, net	$ (9)	$ (13)

(a) Primarily reflects a receivable recorded in the fourth quarter of 2012 related to the final 1999-2001 IRS settlement.

Effective Income Tax Rate

ComEd's effective income tax rates for the years ended December 31, 2014, 2013 and 2012, were 39.6%, 37.9% and 38.7%, respectively. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2014	2013	% Change 2014 vs 2013	Weather-Normal % Change	2012	% Change 2013 vs 2012	Weather-Normal % Change
Retail Deliveries [a]							
Residential	27,230	27,800	(2.1)%	0.3%	28,528	(2.6)%	(0.6)%
Small commercial & industrial	32,146	32,305	(0.5)%	(0.3)%	32,534	(0.7)%	0.2%
Large commercial & industrial	27,847	27,684	0.6%	0.7%	27,643	0.1%	(0.3)%
Public authorities & electric railroads	1,358	1,355	0.2%	(0.7)%	1,272	6.5%	4.2%
Total retail deliveries	88,581	89,144	(0.6)%	0.2%	89,977	(0.9)%	(0.1)%

Number of Electric Customers	As of December 31, 2014	2013	2012
Residential	3,502,386	3,480,398	3,455,546
Small commercial & industrial	369,053	367,569	365,357
Large commercial & industrial	1,998	1,984	1,980
Public authorities & electric railroads	4,815	4,853	4,812
Total	3,878,252	3,854,804	3,827,695

Electric Revenue	2014	2013	% Change 2014 vs 2013	2012	% Change 2013 vs 2012
Retail Sales [a]					
Residential	$2,074	$2,073	— %	$3,037	(31.7)%
Small commercial & industrial	1,335	1,250	6.8%	1,339	(6.6)%
Large commercial & industrial	434	427	1.6%	395	8.1%
Public authorities & electric railroads	46	48	(4.2)%	44	9.1%
Total retail sales	3,889	3,798	2.4%	4,815	(21.1)%
Other revenue [b]	675	666	1.4%	628	6.1%
Total electric revenue	$4,564	$4,464	2.2%	$5,443	(18.0)%

(a) Reflects delivery revenue and volume from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other items include wholesale revenue, rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental remediation costs associated with MGP sites, and intercompany revenue.

Results of Operations—PECO

	2014	2013	Favorable (unfavorable) 2014 vs. 2013 variance	2012	Favorable (unfavorable) 2013 vs. 2012 variance
Operating revenue	$3,094	$3,100	$ (6)	$3,186	$ (86)
Purchased power and fuel	1,261	1,300	39	1,375	75
Revenue net of purchased power and fuel expense [(a)]	1,833	1,800	33	1,811	(11)
Other operating expenses					
Operating and maintenance	866	748	(118)	809	61
Depreciation and amortization	236	228	(8)	217	(11)
Taxes other than income	159	158	(1)	162	4
Total other operating expenses	1,261	1,134	(127)	1,188	54
Operating income	572	666	(94)	623	43
Other income and (deductions)					
Interest expense, net	(113)	(115)	2	(123)	8
Other, net	7	6	1	8	(2)
Total other income and (deductions)	(106)	(109)	3	(115)	6
Income before income taxes	466	557	(91)	508	49
Income taxes	114	162	48	127	(35)
Net income	352	395	(43)	381	14
Preferred security dividends and redemption	—	7	7	4	(3)
Net income attributable to common shareholder	$ 352	$ 388	$ (36)	$ 377	$ 11

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The decrease in Net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense partially offset by an increase in Operating revenue net of purchase power and fuel expense and a decrease in Income tax expense.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in Net income was driven primarily by lower Operating and maintenance expense partially offset by an increase in income taxes.

Operating Revenue Net of Purchased Power and Fuel Expense

Electric and gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenue net of purchased power and fuel expense.

Electric and gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer Choice Program activity has no impact on electric and gas revenue net of purchase power and fuel expense. The number of retail customers purchasing energy from a competitive electric generation supplier was 546,900, 531,500, and 496,500 at December 31, 2014, 2013 and 2012, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 70%, 68%, and 66% of PECO's retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 78,400, 66,400, and 52,700 at December 31, 2014, 2013 and 2012, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 22%, 19%, and 16% of PECO's mmcf sales for the years ended December 31, 2014, 2013 and 2012, respectively.

The changes in PECO's Operating revenue net of purchased power and fuel expense for the year ended December 31, 2014 compared to the same period in 2013 consisted of the following:

	Increase		
	Electric	Gas	Total
Weather	$ (15)	$ 13	$ (2)
Volume	2	5	7
Pricing	(1)	(3)	(4)
Regulatory required programs	33	—	33
Other	(1)	—	(1)
Total increase	$ 18	$ 15	$ 33

Weather

The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. Operating revenue net of purchased power and fuel expense was lower due to the impact of unfavorable 2014 summer and fourth quarter weather conditions, partially offset by the impact of favorable first quarter 2014 winter weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2014 compared to the same period in 2013 and normal weather consisted of the following:

	Twelve Months Ended December 31,			% Change	
Heating and Cooling Degree-Days	2014	2013	Normal	From 2013	From Normal
Heating Degree-Days	4,749	4,474	4,603	6.1%	3.2%
Cooling Degree-Days	1,311	1,411	1,301	(7.1)%	0.8%

Volume

The increase in Operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for gas and residential electric and a shift in the volume profile across classes from commercial and industrial classes to residential classes for electric.

Pricing

The decrease in gas operating revenue net of fuel expense as a result of pricing is primarily attributable to lower overall effective rates due to increased retail gas usage.

Regulatory Required Programs

This represents the change in operating revenue collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

The changes in PECO's operating revenue net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 6	$ 31	$ 37
Volume	(3)	(3)	(6)
Pricing	(14)	2	(12)
Regulatory required programs	(6)	—	(6)
Gross receipts tax	(8)	—	(8)
Gas distribution tax repair	—	(8)	(8)
Other	(7)	(1)	(8)
Total increase (decrease)	$ (32)	$ 21	$(11)

Weather

Operating revenue net of purchased power and fuel expense were higher due to the impact of favorable 2013 winter weather conditions.

The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2013 compared to the same period in 2012 and normal weather consisted of the following:

	Twelve Months Ended December 31,			% Change	
Heating and Cooling Degree-Days	2013	2012	Normal	From 2012	From Normal
Heating Degree-Days	4,474	3,747	4,603	19.4%	(2.8)%
Cooling Degree-Days	1,411	1,603	1,301	(12.0)%	8.5%

Volume

The decrease in electric revenue net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected the impact of energy efficiency initiatives on customer usages as well as a shift in the volume profile across classes from residential classes to commercial and industrial classes, partially offset by the oil refineries returning to full production in 2013 as well as moderate economic growth. The decrease in gas revenue net of fuel expense related to delivery volume, exclusive of the effects of weather, primarily reflected a decline in residential use per customer.

Pricing

The decrease in electric operating revenue net of purchased power expense as a result of pricing is primarily attributable to lower overall effective rates due to increased usage across all major customer classes.

Regulatory Required Programs

This represents the change in operating revenue collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

Gross Receipts Tax

GRT is an excise tax on total electric revenue. As a result of decreases in operating revenue compared to 2012, GRT decreased. Equal and offsetting decreases in GRT have been reflected in Taxes other than income.

Gas Distribution Tax Repair

The decrease in gas distribution tax repair reflected the 2012 tax benefit received from prior period gas distribution repairs for the 2011 tax year. There is an equal and offsetting tax benefit in Operating revenue, see Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further explanation.

Other

The decrease in other electric revenue net of purchased power expense compared to the year ended December 31, 2012 reflected a decrease in wholesale transmission revenue earned by PECO due to higher peak loads in the previous years.

Operating and Maintenance Expense

	Twelve Months Ended December 31, 2014	2013	Increase 2014 vs. 2013	Twelve Months Ended December 31, 2013	2012	(Decrease) 2013 vs. 2012
Operating and maintenance expense—baseline	$ 761	$ 668	$ 93	$ 668	$ 723	$ (55)
Operating and maintenance expense—regulatory required programs [(a)]	105	80	$ 25	80	86	$ (6)
Total operating and maintenance expense	$ 866	$ 748	$ 118	$ 748	$ 809	$ (61)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenue.

The changes in Operating and maintenance expense for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Baseline		
Labor, other benefits, contracting and materials	$ 12	$ 10
Storm-related costs	100[(a)]	(49)
Pension and non-pension postretirement benefits expense	(5)	(12)
Merger and integration costs	(7)	(8)
Corporate allocation	5	—
Uncollectible accounts expense	(9)	—
Other	(3)	4
	93	(55)
Regulatory required programs		
Smart meter	7	4
Energy efficiency	17	(9)
Consumer education program	—	(1)
Other	1	—
	25	(6)
Increase (decrease) in operating and maintenance expense	$ 118	$ (61)

(a) Total storm-related costs include approximately $85 million of incremental storm costs, including the February 5, 2014 ice storm and the significant July storms.

Depreciation and Amortization Expense

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The increase in Depreciation and amortization expense, net for 2014, compared to 2013 was primarily due to ongoing capital expenditures and regulatory required programs.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in Depreciation and amortization expense, net for 2013 compared to 2012 was primarily due to ongoing capital expenditures.

Taxes Other Than Income

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Taxes other than income remained relatively consistent.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in Taxes other than income for 2013 compared to 2012 was primarily due to GRT expense slightly offset by sales and use tax.

Interest Expense, Net

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Interest expense, net remained relatively consistent.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in Interest expense, net for 2013 compared to 2012 was primarily due to refinancing debt at lower interest rates during the second half of 2012.

Other, Net

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Other, net remained relatively consistent.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Other, net remained relatively consistent.

Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2014, 2013 and 2012 were 24.5%, 29.1% and 25.0%, respectively. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2014	2013	% Change 2014 vs. 2013	Weather-Normal % Change	2012	% Change 2013 vs. 2012	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	13,222	13,341	(0.9)%	0.5%	13,233	0.8%	— %
Small commercial & industrial	8,025	8,101	(0.9)%	— %	8,063	0.5%	(1.1)%
Large commercial & industrial	15,310	15,379	(0.4)%	(0.1)%	15,253	0.8%	1.5%
Public authorities & electric railroads	937	930	0.8%	0.8%	943	(1.4)%	(1.4)%
Total electric retail deliveries	37,494	37,751	(0.7)%	0.1%	37,492	0.7%	0.3%

Number of Electric Customers	As of December 31, 2014	2013	2012
Residential	1,434,011	1,423,068	1,417,773
Small commercial & industrial	149,149	149,117	148,803
Large commercial & industrial	3,103	3,105	3,111
Public authorities & electric railroads	9,734	9,668	9,660
Total	1,595,997	1,584,958	1,579,347

Electric Revenue	2014	2013	% Change 2014 vs. 2013	2012	% Change 2013 vs. 2012
Retail Sales [a]					
Residential	$1,555	$1,592	(2.3)%	$1,689	(5.7)%
Small commercial & industrial	423	433	(2.3)%	462	(6.3)%
Large commercial & industrial	217	224	(3.1)%	232	(3.4)%
Public authorities & electric railroads	32	30	6.7%	31	(3.2)%
Total retail	2,227	2,279	(2.3)%	2,414	(5.6)%
Other revenue [b]	221	221	— %	226	(2.2)%
Total electric revenue	$2,448	$2,500	(2.1)%	$2,640	(5.3)%

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflect the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenue.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2014	2013	% Change 2014 vs. 2013	Weather-Normal % Change	2012	% Change 2013 vs. 2012	Weather-Normal % Change
Retail Deliveries [a]							
Retail sales	62,734	57,613	8.9%	2.2%	49,767	15.8%	(0.1)%
Transportation and other	27,208	28,089	(3.1)%	(1.0)%	26,687	5.3%	0.5%
Total gas deliveries	89,942	85,702	4.9%	1.2%	76,454	12.1%	0.1%

Number of Gas Customers	As of December 31, 2014	2013	2012
Residential	462,663	458,356	454,502
Commercial & industrial	42,686	42,174	41,836
Total retail	505,349	500,530	496,338
Transportation	855	909	903
Total	506,204	501,439	497,241

Gas revenue	2014	2013	% Change 2014 vs. 2013	2012	% Change 2013 vs. 2012
Retail Sales [a]					
Retail sales	$608	$562	8.2%	$509	10.4%
Transportation and other	38	38	— %	37	2.7%
Total gas revenue	$646	$600	7.7%	$546	9.9%

(a) Reflects delivery volumes and revenue from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflect the cost of natural gas.

Results of Operations—BGE

	2014	2013	Favorable (unfavorable) 2014 vs. 2013 variance	2012	Favorable (unfavorable) 2013 vs. 2012 variance
Operating revenue	$3,165	$3,065	$ 100	$2,735	$ 330
Purchased power and fuel expense	1,417	1,421	4	1,369	(52)
Revenue net of purchased power and fuel expense [(a)]	1,748	1,644	104	1,366	278
Other operating expenses					
Operating and maintenance	717	634	(83)	728	94
Depreciation and amortization	371	348	(23)	298	(50)
Taxes other than income	221	213	(8)	208	(5)
Total other operating expenses	1,309	1,195	(114)	1,234	39
Operating income	439	449	(10)	132	317
Other income and (deductions)					
Interest expense, net	(106)	(122)	16	(144)	22
Other, net	18	17	1	23	(6)
Total other income and (deductions)	(88)	(105)	17	(121)	16
Income before income taxes	351	344	7	11	333
Income taxes	140	134	(6)	7	(127)
Net income	211	210	1	4	206
Preference stock dividends	13	13	—	13	—
Net income (loss) attributable to common shareholder	$ 198	$ 197	$ 1	$ (9)	$ 206

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenue net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income (Loss) Attributable to Common Shareholder

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Net income attributable to common shareholder remained relatively consistent primarily due to an increase in Revenue net of purchased power and fuel expense as a result of the December 2013 and 2014 electric and gas distribution rate order issued by the MDPSC offset by increases in Operating and maintenance expense and Depreciation expense.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in Net income was driven primarily by higher distribution rates as a result of the 2012 rate order issued by MDPSC and decreased Revenue net of purchased power and fuel expense in 2012 related to the accrual of the residential customer rate credit provided as a condition of the MDPSC's approval of Exelon's merger with Constellation. Additionally, the increase in Net income was also driven by higher Operating and maintenance expenses in 2012, primarily related to BGE's accrual of its portion of the charitable contributions to be provided as a condition of the MDPSC's approval of the merger and lower storm restoration costs in 2013.

Operating Revenue Net of Purchased Power and Fuel Expense

There are certain drivers to Operating revenue that are offset by their impact on Purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenue and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive electric generation supplier affects electric SOS revenue and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenue and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric generation supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive electric generation supplier was 364,000, 399,000 and 362,000 at December 31, 2014, 2013 and 2012, respectively, representing 29%, 32% and 29% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 60%, 61% and 60% of BGE's retail kWh sales for the years ended December 31, 2014, 2013 and 2012, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 161,000, 172,000 and 143,000 at December 31, 2014, 2013 and 2012, respectively, representing 25%, 26% and 22% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 53%, 54% and 56% of BGE's retail mmcf sales for the years ended December 31, 2014, 2013 and 2012, respectively.

The changes in BGE's Operating revenue net of purchased power and fuel expense for the year ended December 31, 2014 compared to the same period in 2013 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Distribution rate increases	$ 57	$ 28	$ 85
Commodity margin	(1)	12	11
Regulatory required programs	13	(1)	12
Transmission revenue	10	—	10
Other	$ (12)	$ (2)	$ (14)
Total increase	$ 67	$ 37	$104

Revenue Decoupling.

The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of changes in consumption levels. This allows BGE to recognize revenue at MDPSC-approved levels per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while this revenue is affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the year ended December 31, 2014 compared to the same period in 2013 and normal weather consisted of the following:

	Twelve Months Ended December 31,			% Change	
Heating and Cooling Degree-Days	2014	2013	Normal	From 2013	From Normal
Heating Degree-Days	5,091	4,744	4,662	7.3%	9.2%
Cooling Degree-Days	732	869	876	(15.8)%	(16.4)%

Distribution Rate Increases.

The increase in Operating revenue net of purchased power and fuel expense was primarily due to MDPSC rate orders effective December 13, 2013 and December 15, 2014 approving increases to electric and natural gas distribution rates charged to customers. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Commodity Margin.

The increase in Revenue net of purchased power and fuel expense as a result of commodity margin for the year ended December 31, 2014 compared to the same period in 2013 was primarily due the higher gas margins earned due to extreme cold weather during the first quarter of 2014 under BGE's market-based rate incentive mechanism. See Note 12—Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs.

This represents the change in revenue collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in electric revenue during the year ended December 31, 2014 compared to the same period in 2013 was due to the recovery of higher energy efficiency program costs.

Transmission.

The increase in transmission revenue rates for the year ended December 31, 2014 compared to the same period in 2013 was primarily due to the impact of new transmission rates charged to customers that became effective in June 2014. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other .

Other revenue decreased during the year ended December 31, 2014 compared to the same period in 2013. Other revenue, which can vary from period to period, includes miscellaneous revenue such as service application and late payment fees.

The changes in BGE's Revenue net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
2012 residential customer rate credit	$ 82	$31	$113
Distribution rate increases	69	24	93
Regulatory required programs	36	6	42
Other	26	4	30
Total increase	$ 213	$65	$278

The changes in heating and cooling degree days for the twelve months ended 2013 and 2012, consisted of the following:

	Twelve Months Ended December 31,			% Change	
Heating and Cooling Degree-Days [a]	2013	2012	Normal	From 2012	From Normal
Heating Degree-Days	4,744	3,960	4,661	19.8%	1.8%
Cooling Degree-Days	869	1,022	864	(15.0)%	0.6%

2012 Residential Customer Rate Credit.

The increase in Revenue net of purchased power and fuel expense for the year ended December 31, 2013 compared to the same period in 2012 was due to the residential customer rate credit provided in 2012 as a result of the MDPSC's order approving Exelon's merger with Constellation.

Distribution Rate Increases.

The increase in Revenue net of purchased power and fuel expense as a result of distribution rate increases for the year ended December 31, 2013 compared to the same period in 2012 was primarily due to MDPSC rate orders effective February 23, 2013 and December 13, 2013 approving increases to electric and natural gas distribution rates charged to customers. See Note 3—Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs.

This represents the change in revenue collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenue during the year ended December 31, 2013 compared to the same period in 2012 was due to the recovery of higher energy efficiency programs costs.

Other.

Other revenue increased during the year ended December 31, 2013 compared to the same period in 2012. Other revenue, which can vary from period to period, includes miscellaneous revenue such as service application and late payment fees.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Baseline		
Labor, other benefits, contracting and materials	$ 22	$ 20
Pension and non-pension postretirement benefits expense	8	—
Storm-related costs [(a)]	21	(62)
Uncollectible accounts expense	17	—
Merger transaction costs	5	(21)
Charitable contributions [(b)]	—	(28)
Other	10	(3)
Increase (Decrease) in operating and maintenance expense	$ 83	$ (94)

(a) On June 29, 2012, a "Derecho" storm caused extensive damage to BGE's electric distribution system and created power outages that lasted multiple days. As a result, BGE incurred $62 million of incremental costs during the year ended December 31, 2012, of which $20 million were capital costs. In the fourth quarter of 2012, BGE incurred $38 million of incremental costs as a result of Hurricane Sandy, of which $14 million were capital costs.

(b) During the first quarter of 2012, BGE accrued $28 million in charitable contributions as a result of BGE's merger-related commitments. The charitable contribution accrual and merger costs are not recoverable from BGE's customers.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Depreciation expense [(a)]	$ 25	$ 18
Regulatory asset amortization	(1)	31[(b)]
Other	(1)	1
Increase in depreciation and amortization expense	$ 23	$ 50

(a) Depreciation expense increased due to higher plant balances year over year.

(b) Regulatory asset amortization for the year ended December 31, 2013 compared to the same period in 2012 increased due to higher energy efficiency and demand response programs expenditures year over year.

Taxes Other Than Income

The change in taxes other than income for 2014 compared to 2013 and 2013 compared to 2012 consisted of the following:

	Increase (Decrease) 2014 vs. 2013	Increase (Decrease) 2013 vs. 2012
Property tax	$ 2	$ (2)
Franchise tax	4	7
Other	2	—
Increase in taxes other than income	$ 8	$ 5

Interest Expense, Net

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The decrease in Interest expense, net for 2014 compared to 2013 was primarily due to favorable interest rates in 2014 on long-term debt balances.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in Interest expense, net in 2013 compared to 2012 was primarily due to interest recorded in 2012 on prior year tax liabilities and lower effective interest rates as a result of the refinancing of debt at a lower interest rate in 2013.

Effective Income Tax Rate

BGE's effective income tax rates for the years ended December 31, 2014, 2013 and 2012 were 39.9%, 39.0% and 63.6%, respectively. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2014	2013	% Change 2014 vs. 2013	Weather-Normal % Change	2012	% Change 2013 vs. 2012	Weather-Normal % Change
Retail Deliveries [a]							
Residential	12,974	13,077	(0.8)%	n.m.	12,719	2.8%	n.m.
Small commercial & industrial	3,086	3,035	1.7%	n.m.	2,990	1.5%	n.m.
Large commercial & industrial	14,191	14,339	(1.0)%	n.m.	14,956	(4.1)%	n.m.
Public authorities & electric railroads	311	317	(1.9)%	n.m.	329	(3.6)%	n.m.
Total electric deliveries	30,562	30,768	(0.7)%	n.m.	30,994	(0.7)%	n.m.

Number of Electric Customers	As of December 31, 2014	2013	2012
Residential	1,125,369	1,120,431	1,116,233
Small commercial & industrial	112,972	112,850	112,994
Large commercial & industrial	11,730	11,652	11,580
Public authorities & electric railroads	290	292	319
Total	1,250,361	1,245,225	1,241,126

Electric Revenue	2014	2013	% Change 2014 vs. 2013	2012	% Change 2013 vs. 2012
Retail Sales [a]					
Residential	$1,404	$1,404	— %	$1,274	10.2%
Small commercial & industrial	271	257	5.4%	248	3.6%
Large commercial & industrial	491	439	11.8%	393	11.7%
Public authorities & electric railroads	32	31	3.2%	30	3.3%
Total retail	2,198	2,131	3.1%	1,945	9.6%
Other revenue	262	274	(4.4)%	238	15.1%
Total electric revenue	$2,460	$2,405	2.3%	$2,183	10.2%

(a) Reflects delivery revenue and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2014	2013	% Change 2014 vs. 2013	Weather-Normal % Change	2012	% Change 2013 vs. 2012	Weather-Normal % Change
Retail Deliveries [d]							
Retail sales	99,194	94,020	5.5%	n.m.	86,946	8.1%	n.m.
Transportation and other [e]	9,242	12,210	(24.3)%	n.m.	15,751	(22.5)%	n.m.
Total gas deliveries	108,436	106,230	2.1%	n.m.	102,697	3.4%	n.m.

Number of Gas Customers	As of December 31, 2014	2013	2012
Residential	609,626	611,532	610,827
Commercial & industrial	44,200	44,162	44,228
Total	653,826	655,694	655,055

Gas revenue	2014	2013	% Change 2014 vs. 2013	2012	% Change 2013 vs. 2012
Retail Sales [d]					
Retail sales	$622	$592	5.1%	$494	19.8%
Transportation and other [e]	83	68	22.1%	58	17.2%
Total gas revenue	$705	$660	6.8%	$552	19.6%

(d) Reflects delivery revenue and volumes from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.

(e) Transportation and other gas revenue includes off-system revenue of 9,242 mmcfs ($72 million), 12,210 mmcfs ($55 million), and 15,751 mmcfs ($51 million) for the years ended 2014, 2013 and 2012, respectively.

Liquidity and Capital Resources

Exelon's and Generation's current year activity presented below includes the activity of CENG, from the integration date effective April 1, 2014 through December 31, 2014. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1 billion, $0.6 billion and $0.6 billion, respectively. The Registrants' revolving credit facilities are in place until 2019. In addition, Generation has $0.5 billion in bilateral facilities with banks which have various expirations between October 2015 and January 2017. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time.

See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

ComEd's, PECO's and BGE's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd's, PECO's and BGE's distribution services are provided to an established and diverse base of retail customers. ComEd's, PECO's and BGE's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3—Regulatory Matters and 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while others took effect in 2013. On August 8, 2014, this funding relief was extended for five years. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to make qualified pension plan contributions of $447 million to its qualified pension plans in 2015, of which Generation, ComEd, PECO and BGE expect to contribute $230 million, $138 million, $40 million and $1 million, respectively. Exelon's and Generation's expected qualified pension plan contributions above include $36 million related to legacy CENG plans that will be funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $15 million in 2015, of which Generation, ComEd, PECO and BGE will make payments of $6 million, $1 million, $1 million, and $1 million respectively. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants' 2014 and 2013 pension contributions.

To the extent interest rates decline significantly or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase, especially in years 2017 and beyond. Additionally, the contributions above could change if Exelon changes its pension funding strategy.

Unlike qualified pension plans, other postretirement benefit plans are not subject to statutory minimum contribution requirements and certain plans are not funded. Exelon's management has historically considered several factors in determining the level of contributions to its funded other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $37 million in 2015, of which Generation, ComEd, PECO, and BGE expect to contribute $17 million, $2 million, $0 million, and $17 million, respectively. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants' 2014 and 2013 other postretirement benefit contributions.

See the "Contractual Obligations" section for management's estimated future pension and other postretirement benefits contributions.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable as of December 31, 2014 may be as much as $810 million, of which approximately $310 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts will increase by a material amount.
- Exelon, Generation, and ComEd expect to receive tax refunds of approximately $430 million, $190 million, and $260 million, respectively, in 2015. PECO expects to make tax payments of approximately $6 million related to IRS positions settling in 2015.
- Given the current economic environment, state and local governments are facing increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes.
- On December 19th, 2014, President Obama signed H.R. 5771, The Tax Increase Prevention Act. The Act included an extension of 50% bonus depreciation for 2014. As a result of the 50% bonus depreciation extension, Exelon, ExGen, ComEd, PECO, and BGE are estimated to generate incremental cash of approximately $600 million, $272 million, $217 million, $53 million, and $46 million, respectively. The resulting cash benefits are expected primarily in 2015. The cash generated is an acceleration of tax benefits that Registrants would have received over the normal depreciable life of the property. Furthermore, the extension of 50% bonus depreciation will result in a decrease to Generation's Domestic Production Activities Deduction, reducing cash tax benefits and increasing income tax expense by approximately $30 million for 2014. ComEd's 2014 revenue requirement is expected to decrease by approximately $12 million (after-tax) due to the extension of 50% bonus depreciation.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2014, 2013 and 2012:

			2014 vs. 2013		2013 vs. 2012
	2014 (d)	2013	Variance	2012 (c)	Variance
Net income	$ 1,820	$1,729	$ 91	1,171	$ 558
Add (subtract):					
Non-cash operating activities [a]	5,884	4,159	1,725	5,588	(1,429)
Pension and non-pension postretirement benefit contributions	(617)	(422)	(195)	(462)	40
Income taxes	(143)	883	(1,026)	544	339
Changes in working capital and other noncurrent assets and liabilities [b]	(1,047)	(185)	(862)	(731)	546
Option premiums paid, net	38	(36)	74	(114)	78
Counterparty collateral received (paid), net	(1,478)	215	(1,693)	135	80
Net cash flows provided by operations	$ 4,457	$6,343	$ (1,886)	$6,131	$ 212

(a) Represents depreciation, amortization, depletion and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, and other non-cash charges. See note 23 —Supplemental Financial Information for further detail on non-cash operating activity.
(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.
(c) Exelon's 2012 activity includes the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.
(d) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

Cash flows provided by operations for the year ended December 31, 2014, 2013 and 2012 by Registrant were as follows:

	2014	2013	2012
Exelon [a][b]	$4,457	$6,343	$6,131
Generation [a][b]	1,826	3,887	3,581
ComEd	1,326	1,218	1,334
PECO	712	747	878
BGE [b]	740	561	485

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) Exelon's and Generation's 2012 activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. BGE's 2012 activity includes its activity for the twelve months ended December 31, 2012.

Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for 2014, 2013 and 2012 were as follows:

Generation

- Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on the exchange or in the OTC markets. During 2014, 2013 and 2012, Generation had net collections (payments) receipts of counterparty cash collateral of $(1,507) million, $162 million and $95 million, respectively. Net collections (payments) each year were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position. In addition, in 2014 the exchanges increased initial margin rates, which required Generation to post higher amounts of initial margin.
- During 2014, 2013 and 2012, Generation had net collections (payments) of approximately $38 million, $(36) million and $(114) million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- For the year ended December 31, 2014 and 2013, ComEd had a working capital deficit of $263 million and $508 million, respectively. The working capital deficit is primarily attributable to the increase in short-term borrowings in 2014 and an increase in short-term borrowings and short-term debt due within one year in 2013. Cash flows from operating activities are sufficient to meet operating requirements; however, increased capital investment in infrastructure improvements and modernization pursuant to EIMA, transmission upgrades and expansion may require external debt financing or additional capital contributions from parent.
- During 2014, 2013 and 2012, ComEd's net payables to Generation for energy purchases related to its supplier forward contract and ICC-approved RFP contracts increased/(decreased) by $5 million, $(16) million and $(15) million, respectively. During 2014, 2013 and 2012 ComEd's payables to other energy suppliers for energy purchases increased by $27 million, $35 million and $20 million, respectively.

PECO

- During 2014, 2013 and 2012, PECO's payables to Generation for energy purchases increased/(decreased) by $(9) million, $(17) million and $17 million, respectively, and payables to other energy suppliers for energy purchases increased/(decreased) by $10 million, $39 million and $(22) million, respectively.

BGE

- During 2014, 2013 and 2012, BGE's payables to Generation for energy purchases increased/(decreased) by $13 million, $(4) million and $23 million, respectively, and payables to other energy suppliers for energy purchases increased/(decreased) by $(7) million, $(12) million and $40 million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for the year ended December 31, 2014, 2013, and 2012 by Registrant were as follows:

	2014	2013	2012
Exelon [(a)(b)]	$(4,599)	$(5,394)	$(4,576)
Generation [(a)(b)]	(1,767)	(2,916)	(2,629)
ComEd	(1,655)	(1,387)	(1,212)
PECO	(649)	(531)	(328)
BGE [(b)]	(622)	(571)	(573)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

(b) Exelon's and Generation's 2012 activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. BGE's 2012 activity includes its activity for the twelve months ended December 31, 2012.

Generation

As a result of consolidating CENG during the second quarter of 2014, Generation recorded $129 million of cash from CENG, reflected in Generation's cash flows from investing activities above. See Note 5—Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for further information.

Generation closed on the sale of its 67% equity interest in the 417 MW Safe Harbor Water Power Corporation hydroelectric facility on the Susquehanna River in Pennsylvania for a purchase price of approximately $615 million during the third quarter of 2014. The proceeds from the sale are reflected in Generation's cash flows from investing activities above. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

During the third quarter of 2014, Generation established $65 million in restricted cash as part of the EGTP project financing which is reflected in Generation's cash flows from investing activities above. See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for more information.

Generation closed on the sale of its 41.98% and 31.28% ownership interests in the Keystone and Conemaugh coal-fired power plants and related equity interests in Keystone Fuels, LLC and Conemaugh Fuels, LLC, respectively, for a purchase price of approximately $473 million during the fourth quarter of 2014. The proceeds from the sale are reflected in Generation's cash flows from investing activities above. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

During the fourth quarter of 2014, Generation closed on the sale of its fully-owned equity interest in Fore River and West Valley generating stations, for a combined purchase price of approximately $577 million. The proceeds from the sale are reflected in Generation's cash flows from investing activities above. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

During the fourth quarter of 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. for a purchase price of $332 million, including net working capital. The acquisition costs from the sale are reflected in Generation's cash flows from investing activities above. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for further information.

Generation has entered into several agreements to acquire equity interests in privately held and development stage entities which develop energy-related technology. The agreements include a series of scheduled investment commitments, including in-kind services contributions, totaling approximately $167 million through 2018 to fund anticipated planned capital and operating needs of the associated companies.

Generation has executed, or expects to execute, construction and services contracts to build new gas turbine units in Texas and Maryland and a new biomass-fueled cogeneration facility in Georgia. The total estimated expenditures for these projects are approximately $1.8 billion and achievement of commercial operations is expected between 2015 and 2017 for all these projects.

Capital expenditures by Registrant for the year ended December 31, 2014, 2013, and 2012 and projected amounts for 2015 are as follows:

	Projected 2015 [a]	2014	2013	2012
Exelon [b][e][f]	$ 7,200	$6,077	$5,395	$5,789
Generation [b][e][f]	3,625	3,012	2,752	3,554
ComEd [c]	2,200	1,689	1,433	1,246
PECO	550	661	537	422
BGE [e]	700	620	587	582
Other [d]	125	95	86	(15)

(a) Total projected capital expenditures do not include adjustments for non-cash activity.
(b) Includes nuclear fuel.
(c) The projected capital expenditures include $617 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology.
(d) Other primarily consists of corporate operations and BSC.
(e) Exelon's and Generation's 2012 activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. BGE's 2012 activity includes its activity for the twelve months ended December 31, 2012.
(f) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, CENG is included on a fully consolidated basis beginning April 1, 2014.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

In 2014, Exelon and its affiliates initiated a comprehensive project to ensure corporate-wide compliance with Version 5 of the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection Standards (CIP V.5) which will become effective on April 1, 2016. Generation, ComEd, PECO and BGE will be incurring incremental capital expenditures in 2014 through 2016 associated with the CIP V.5 compliance implementation project, which are included in projected capital expenditures above.

Generation

Approximately 33% and 7% of the projected 2015 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy and natural gas generation, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

ComEd, PECO and BGE

Approximately 85%, 95% and 96% of the projected 2014 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and ComEd's, PECO's and BGE's construction commitments under PJM's RTEP. ComEd's capital expenditures include smart grid/smart meter technology required under EIMA. PECO's and BGE's capital expenditures include investments related to their respective smart meter programs. The remaining amounts are for capital additions to support new business and customer growth. See Notes 3 and 7 of the Combined Notes to Consolidated Financial Statements for additional information.

In 2010, NERC provided guidance to transmission owners that recommends ComEd, PECO, and BGE, perform assessments of their transmission lines. In compliance with this guidance, ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2015 capital expenditures above reflect capital spending for remediation to be completed in 2017.

ComEd, PECO and BGE anticipate that they will fund capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 3 of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the year ended December 31, 2014, 2013, and 2012 by Registrant were as follows:

	2014	2013	2012
Exelon [(a)(b)]	411	(826)	(1,085)
Generation [(a)(b)]	(537)	(384)	(777)
ComEd	359	61	(212)
PECO	(250)	(361)	(382)
BGE [(b)]	(85)	(48)	128

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

(b) Exelon's and Generation's 2012 activity includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. BGE's 2012 activity includes its activity for the twelve months ended December 31, 2012.

Debt .

See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements. Debt activity for 2014, 2013 and 2012 by Registrant was as follows:

During the year ended December 31, 2014, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Junior Subordinated Notes [a]	2.50%	June 1, 2024	$ 1,150	Used to finance a portion of the acquisition of PHI and for general corporate purposes
Generation	Nuclear Fuel Procurement Contract	3.35%	June 30, 2018	38	Used for procurement of uranium
Generation	ExGen Renewables I Nonrecourse Debt [b]	LIBOR + 4.25%	February 6, 2021	300	Used for general corporate purposes
Generation	ExGen Texas Power Nonrecourse Debt [b]	LIBOR + 4.75%	September 18, 2021	675	Used for general corporate purposes
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	12	Funding to install energy conservation measures in Washington, DC
Generation	AVSR DOE Nonrecourse Debt [b]	2.78 - 3.14%	January 5, 2037	126	Used for Antelope Valley solar development
Generation	Nuclear Fuel Procurement Contract	3.25%	June 30, 2018	32	Used for procurement of uranium
ComEd	First Mortgage Bonds Series 115	2.15%	January 15, 2019	300	Used to refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds Series 116	4.70%	January 15, 2044	350	Used to refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds Series 117	3.10%	November 1, 2024	250	Used to repay commercial paper and general corporate purposes
PECO	First and Refunding Mortgage Bonds	4.15%	October 1, 2044	300	Used to repay at maturity first and refunding mortgage bonds due October 1, 2014, and general corporate purposes

(a) See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the Junior Subordinated Notes and related forward equity purchase contract, which are expected to be remarketed in 2017.
(b) See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.

On January 13, 2015, Generation issued $750 million in aggregate principal amount of Senior Notes. The Senior Notes carry an annual interest rate of 2.950%, payable semi-annually, commencing July 15, 2015 and due January 15, 2020. The proceeds of the Senior Notes will be used to fund the optional redemption of Exelon's $550 million, 4.550% Senior Notes due June 15, 2015, expected to occur on February 17, 2015, and for general corporate purposes. In addition to the issuance, Exelon terminated floating-to-fixed interest rate swaps that had been designated as cash flow hedges. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments at this time are probable not to occur. As a result Exelon will reclassify $26 million of deferred losses in AOCI to Other, net in the first quarter of 2015.

During the year ended December 31, 2013, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	CEU Upstream Nonrecourse Debt	2.210 - 2.440%	July 22, 2016	$ 5	Used to fund Upstream gas activities
Generation	AVSR DOE Nonrecourse Debt	2.535 - 3.353%	January 5, 2037	227	Used for Antelope Valley solar development
Generation	Social Security Administration Project Financing	2.93%	February 18, 2015	1	Used to install conservation measures for the Social Security Administration Headquarters facility in Maryland
Generation	Energy Efficiency Project Financing	4.40%	August 31, 2014	9	Used for funding to install energy conservation measures in Beckley, West Virginia
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	613	Used for general corporate purposes
ComEd	First Mortgage Bonds, Series 114	4.60%	August 15, 2043	350	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	First and Refunding Mortgage Bonds due	1.20%	October 15, 2016	300	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
PECO	First and Refunding Mortgage Bonds	4.80%	October 15, 2043	250	Used to pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
BGE	Notes	3.35%	July 1, 2023	300	Used to partially refinance Notes due July 1, 2013 and for general corporate purposes

During the year ended December 31, 2012, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	CEU Upstream Nonrecourse Debt	Variable Rate	July 16, 2016	$ 78	Used to fund Upstream gas activities
Generation	AVSR DOE Nonrecourse Debt	Fixed Rate	January 5, 2037	220	Used for Antelope Valley solar development
Generation	Senior Notes	4.25%	June 15, 2022	523	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	Senior Notes	5.60%	June 15, 2042	788	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	Constellation Solar Horizons Nonrecourse Debt	2.50%	June 7, 2030	38	Used for funding for Maryland solar development
ComEd	First Mortgage Bonds, Series 113	3.80%	October 1, 2042	350	Used to repay outstanding commercial paper obligations and for general corporate purposes
PECO	First and Refunding Mortgage Bonds	2.38%	September 15, 2022	350	Used to pay at maturity First Mortgage Bonds due October 1, 2012 and for general corporate purposes
BGE	Notes	2.80%	August 15, 2022	250	Used to repay total outstanding commercial paper obligations and for general corporate purposes

During the year ended December 31, 2014, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	2003 Senior Notes	5.35%	January 15, 2014	$ 500
Generation	Pollution Control Loan	4.10%	July 1, 2014	20
Generation	Continental Wind Nonrecourse Debt [(a)]	6.00%	February 28, 2033	20
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	3
Generation	ExGen Renewables I Nonrecourse Debt [(a)]	LIBOR + 4.25%	February 6, 2021	18
Generation	ExGen Texas Power Nonrecourse Debt [(a)]	LIBOR + 4.75%	September 18, 2021	2
Generation	AVSR DOE Nonrecourse Debt [(a)]	2.33% - 3.55%	January 5, 2037	15
Generation	Constellation Solar Horizons Nonrecourse Debt [(a)]	2.56%	September 7, 2030	2
Generation	Sacramento PV Energy Nonrecourse Debt [(a)]	2.56%	December 31, 2030	2
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	12
ComEd	Mortgage Bonds Series 110	1.63%	January 15, 2014	600
ComEd	Pollution Control Series 1994C	5.85%	January 15, 2014	17
PECO	First and Refunding Mortgage Bonds	5.00%	October 1, 2014	250
BGE	Rate Stabilization Bonds	5.72%	April 1, 2017	35
BGE	Rate Stabilization Bonds	5.72%	October 1, 2014	35

(a) See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.

During the year ended December 31, 2013, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	Kennett Square Capital Lease	7.83%	September 1, 2020	$ 3
Generation	Solar Revolver Nonrecourse Debt	Variable Rate	July 7, 2014	113
Generation	Constellation Solar Horizons Nonrecourse Debt	2.56%	September 7, 2030	2
Generation	Sacramento Energy Nonrecourse Debt	2.68%	December 31, 2030	2
Generation [(a)]	Series A Junior Subordinated Debentures	8.63%	June 15, 2063	450
Generation	Energy Efficiency Project Financing	4.40%	August 31, 2014	9
ComEd	First Mortgage Bonds, Series 92	7.63%	April 15, 2013	125
ComEd	First Mortgage Bonds, Series 94	7.50%	July 1, 2013	127
PECO	First and Refunding Mortgage Bonds	5.60%	October 15, 2013	300
BGE	Rate Stabilization Bonds	5.72%	April 1, 2017	67
BGE	Notes	6.13%	July 1, 2013	400

(a) Represents debt obligations assumed by Exelon as part of the merger on March 12, 2012 that became callable at face value on June 15, 2013. Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable as of December 31, 2012 included in long-term debt to affiliate on Generation's Consolidated Balance Sheets and notes receivable from affiliates at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets. The third-party debt obligations were reported in Long-term Debt on Exelon's Consolidated Balance Sheets as of December 31, 2012. The debentures were redeemed and the intercompany loan agreements repaid on June 15, 2013.

During the year ended December 31, 2012, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon	Fixed rate Medium Term Notes	7.30%	June 1, 2012	$ 2
Exelon	Fixed rate Senior Notes	7.60%	April 1, 2032	442
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	2
Generation	3-year term rate Armstrong Co. 2009 A, Pollution Control Notes	5.00%	December 1, 2042	46
Generation	CEU Upstream Nonrecourse Debt	Variable Rate	July 16, 2016	89
Generation	Solar Revolver Nonrecourse Debt	Variable Rate	July 7, 2014	17
Generation	MEDCO Tax-Exempt Bonds	Variable Rate	April 1, 2024	75
Generation	Sacramento PV Energy Nonrecourse Debt	Variable Rate	March 12, 2012	2
ComEd	First Mortgage Bonds, Series 98	6.15%	March 15, 2012	450
PECO	First and Refunding Mortgage Bonds	4.75%	October 1, 2012	225
PECO	First and Refunding Mortgage Bonds	4.00%	December 1, 2012	150
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	8
BGE	Rate Stabilization Bonds	5.47%	October 1, 2012	55
BGE	Medium Term Notes	Variable Rate	June 15, 2012	110

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective balance sheets.

Dividends.

Cash dividend payments and distributions during for the year ended December 31, 2014, 2013 and 2012 by Registrant were as follows:

	2014	2013	2012
Exelon [(a)]	$1,486	$1,249	1,716
Generation [(a)]	1,066	625	1,626
ComEd	307	220	105
PECO	320	333	347
BGE [(b)]	13	13	13

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014. As such, includes $421 million of distributions to EDF in 2014.
(b) Relates to dividends paid on BGE's preference stock.

First Quarter 2014 Dividend

On January 28, 2014, the Exelon Board of Directors declared a first quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2014, to shareholders of record of Exelon at the end of the day on February 14, 2014.

Second Quarter 2014 Dividend

On May 6, 2014, the Exelon Board of Directors declared a second quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on June 10, 2014, to shareholders of record of Exelon at the end of the day on May 16, 2014.

Third Quarter 2014 Dividend

On July 29, 2014, the Exelon Board of Directors declared a third quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on September 10, 2014 to shareholders of record of Exelon at the end of the day on August 15, 2014.

Fourth Quarter 2014 Dividend

On October 21, 2014, the Exelon Board of Directors declared a fourth quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on December 10, 2014 to shareholders of record of Exelon at the end of the day on November 14, 2014.

First Quarter 2015 Dividend

On January 27, 2015, the Exelon Board of Directors declared a first quarter 2015 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2015, to shareholders of record of Exelon at the end of the day on February 13, 2015.

Short-Term Borrowings. Short-term borrowings incurred (repaid) during 2014, 2013 and 2012 by Registrant were as follows:

	2014	2013	2012
Generation [(a)]	$ 17	$ 13	$ (52)
ComEd	120	184	—
BGE	(15)	135	—
Other [(b)]	—	—	(145)
Exelon [(a)]	$122	$332	$(197)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) Other primarily consists of corporate operations and BSC.

Retirement of Long-Term Debt to Financing Affiliates. There were no retirements of long-term debt to financing affiliates during 2014, 2013 and 2012 by the Registrants.

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2014, 2013 and 2012 by Registrant were as follows:

	2014	2013	2012
Generation	$ 53	$ 26	$48
ComEd [(a)]	278	176	11
PECO	24	27	9
BGE	—	—	66

(a) In 2014 and 2013, represents indemnification from Exelon in relation to the like-kind exchange transaction. For 2014 , also represents contributions from Exelon to support expanded capital programs.

Distributions to Noncontrolling Interests of Consolidated VIE. On April 1, 2014, Generation loaned $400 million to CENG, the proceeds of which were used to make a distribution to EDFI of $400 million. See Note 5—Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for additional information on the integration of CENG.

Other. For the year ended December 31, 2014, other financing activities primarily consisted of financing costs associated with the acquisition of PHI, other project financing and various debt issuance costs. See notes 4, 13, and 19 of the Combined Notes to Consolidated Financial Statements' for additional information.

Credit Matters

Market Conditions

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $8.5 billion in aggregate total commitments of which $7.3 billion was available as of December 31, 2014, and of which no financial institution has more than 8% of the aggregate commitments for Exelon, Generation, ComEd, PECO and BGE. The Registrants had access to the commercial paper market during 2014 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. Risk Factors for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of December 31, 2014, it would have been required to provide incremental collateral of $2.4 billion of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.6 billion. If ComEd lost its investment grade credit ratings as of December 31, 2014, it would have been required to provide incremental collateral of $14 million, which is well within its current available credit facility capacity of $998 million. If PECO lost its investment grade credit rating as of December 31, 2014 it would not be required to provide collateral pursuant to PJM's credit policy and could have been required to provide collateral of $36 million related to its natural gas procurement contracts, which, in the aggregate, are well within PECO's current available credit facility capacity of $599 million. If BGE lost its investment grade credit rating as of December 31, 2014 it would have been required to provide collateral of $2 million pursuant to PJM's credit policy and could have been required to provide collateral of $79 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of $600 million.

Exelon Credit Facilities

See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure. At December 31, 2014, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE
Long-term debt	46%	30%	42%	41%	36%
Long-term debt to affiliates [(a)]	1%	7%	1%	3%	5%
Common equity	52%	—	55%	56%	53%
Member's equity	—	63%	—	—	—
Preference Stock	—	—	—	—	4%
Commercial paper and notes payable	1%	—	2%	—	2%

(a) Includes approximately $648 million, $206 million, $184 million and $258 million owed to unconsolidated affiliates of Exelon, ComEd, PECO and BGE respectively. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd, PECO and BGE. See Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

Intercompany Money Pool. To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participants during the year ended December 31, 2014, in addition to the net contribution or borrowing as of December 31, 2014, are presented in the following table:

	Maximum Contributed	Maximum Borrowed	December 31, 2014 Contributed (Borrowed)
Generation	$ 84	$ 573	$ —
PECO	129	35	—
BSC	15	360	(261)
Exelon Corporate	780	N/A	261

Investments in Nuclear Decommissioning Trust Funds. Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's and CENG's investment policies establishes limits on the concentration of holdings in any one company and also in any one industry. See Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements. The Registrants maintain a combined shelf registration statement unlimited in amount, with the SEC. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations. The issuance by ComEd, PECO and BGE of long-term debt or equity securities requires the prior authorization of the ICC, PAPUC and MDPSC, respectively. ComEd, PECO and BGE normally obtain the required approvals on a periodic basis to cover their anticipated financing needs for a period of time or in connection with a specific financing. As of December 31, 2014, ComEd had $702 million available in long-term debt refinancing authority and

$943 million available in new money long-term debt financing authority from the ICC. During the fourth quarter of 2014, ComEd requested an extension of the expiration date of the refinancing authority from the ICC. In January 2015, the ICC approved the extension of the refinancing authority, which now expires on February 27, 2017. As of December 31, 2014, PECO had $1.1 billion available in long-term debt financing authority from the PAPUC. As of December 31, 2014, BGE had $1.4 billion available in long-term financing authority from MDPSC.

FERC has financing jurisdiction over ComEd's, PECO's and BGE's short-term financings and all of Generation's financings. As of December 31, 2014, ComEd, PECO had BGE had short-term financing authority from FERC, which expires on December 31, 2015, of $2.5 billion, $2.5 billion and $700 million, respectively. Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon's ability to pay dividends on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid. At December 31, 2014, Exelon had retained earnings of $10,910 million, including Generation's undistributed earnings of $3,803 million, ComEd's retained earnings of $851 million consisting of retained earnings appropriated for future dividends of $2,490 million partially offset by $1,639 million of unappropriated retained deficit, PECO's retained earnings of $681 million and BGE's retained earnings $1,203 million. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Contractual Obligations

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2014 under existing contractual obligations, including payments due by period. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within				
	Total	2015	2016-2017	2018-2019	Due 2020 and beyond	All Other
Long-term debt [a]	$21,372	$1,736	$ 3,661	$2,387	$ 13,588	$—
Interest payments on long-term debt [b]	13,105	922	1,755	1,435	8,993	—
Liability and interest for uncertain tax positions [c]	779	—	—	—	—	779
Capital leases	32	3	8	9	12	—
Operating leases [d]	1,158	99	204	156	699	—
Purchase power obligations [e]	2,084	590	884	295	315	—
Fuel purchase agreements [f]	10,020	1,661	2,555	2,048	3,756	—
Electric supply procurement [f]	1,510	1,057	453	—	—	—
AEC purchase commitments [f]	8	1	2	2	3	—
Curtailment services commitments [f]	115	40	63	12	—	—
Long-term renewable energy and REC commitments [g]	1,516	75	152	162	1,127	—
Other purchase obligations [h]	894	336	408	66	84	—
Construction commitments [i]	1,143	43	1,100	—	—	—
PJM regional transmission expansion commitments [j]	786	259	414	113	—	—
Spent nuclear fuel obligation [k]	1,021	—	—	—	1,021	—
Pension minimum funding requirement [l]	1,892	447	782	424	239	—
Total contractual obligations	$57,435	$7,269	$12,441	$7,109	$ 29,837	$779

(a) Includes $648 million due after 2020 to ComEd, PECO and BGE financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2014 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2014. Includes estimated interest payments due to ComEd, PECO and BGE financing trusts.

(c) As of December 31, 2014, Exelon's liability for uncertain tax positions and related interest payable was $469 million and $310 million, respectively. Exelon was unable to reasonably estimate the timing of liability and interest payments and receipts in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. Exelon has other unrecognized tax positions that were not recorded on the Consolidated Balance Sheet in accordance with authoritative guidance. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for further information regarding unrecognized tax positions.

(d) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO's meter reading operating lease.

(e) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2014, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. These obligations do not include ComEd's SFCs as these contracts do not require purchases of fixed or minimum quantities. See Notes 3—Regulatory Matters and 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

(f) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for electric and gas purchase commitments.
(g) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(h) Represents commitments for services, materials, information technology, smart meter installation and commitments related to assets-held-for-sale. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.
(i) Represents commitments for Generation's ongoing investments in renewables development, new natural gas and biomass generation construction. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
(j) Under their operating agreements with PJM, ComEd, PECO and BGE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's, PECO's and BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(k) See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding spent nuclear fuel obligations.
(l) These amounts represent Exelon's expected contributions to its qualified pension plans. For Exelon's largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million until the plan is fully funded on an accumulated benefit obligation basis, and the minimum amounts under ERISA to avoid benefit restrictions and at-risk status thereafter. The remaining qualified pension plans' contributions are generally based on the estimated minimum pension contributions required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2020 are not included. See Note 16—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

		Payment due within				
	Total	2015	2016-2017	2018-2019	Due 2020 and beyond	All Other
Long-term debt	$ 8,110	$ 601	$ 701	$ 747	$ 6,061	$—
Interest payments on long-term debt [a]	5,392	391	772	683	3,546	—
Liability and interest for uncertain tax benefits [b]	58	—	—	—	—	58
Capital leases	24	3	8	9	4	—
Operating leases [c]	899	51	120	100	628	—
Purchase power obligations [d]	2,084	590	884	295	315	—
Fuel purchase agreements [e]	8,981	1,404	2,243	1,889	3,445	—
Other purchase obligations [f]	396	163	109	54	70	—
Construction commitments [g]	1,143	43	1,100	—	—	—
Spent nuclear fuel obligation [h]	1,021	—	—	—	1,021	—
Total contractual obligations	$28,108	$3,246	$5,937	$3,777	$ 15,090	$ 58

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2014 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2014.
(b) As of December 31, 2014, Generation's liability for uncertain tax positions and related interest receivable was $98 million and $40 million, respectively. Generation was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.
(c) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations.
(d) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2014. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

(e) See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding fuel purchase agreements.
(f) Represents commitments for services, materials, information technology and commitments related to assets-held-for-sale. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.
(g) See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding Generation's ongoing investments in renewables development, new natural gas and biomass generation construction.
(h) See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding spent nuclear fuel obligations.

ComEd

		Payment due within				
	Total	2015	2016-2017	2018-2019	Due 2020 and beyond	All Other
Long-term debt [a]	$ 6,175	$ 260	$1,090	$1,140	$ 3,685	$—
Interest payments on long-term debt [b]	3,882	292	536	379	2,675	—
Liability and interest for uncertain tax positions [c]	385	—	—	—	—	385
Capital leases	8	—	—	—	8	—
Operating leases	45	14	21	8	2	—
Electric supply procurement	620	329	291	—	—	—
Long-term renewable energy and associated REC commitments [d]	1,517	75	153	162	1,127	—
Other purchase obligations [e]	148	63	78	2	5	—
PJM regional transmission expansion commitments [f]	335	150	177	8	—	—
Total contractual obligations	$13,115	$1,183	$2,346	$1,699	$ 7,502	$385

(a) Includes $206 million due after 2020 to a ComEd financing trust.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2014 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2014. Includes estimated interest payments due to the ComEd financing trust.
(c) As of December 31, 2014, ComEd's liability for uncertain tax positions and related interest payable was $182 million and $203 million respectively. ComEd was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.
(d) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(e) Represents commitments for services, materials, information technology, and smart meter installation. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.
(f) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

PECO

	Total	Payment due within 2015	2016-2017	2018-2019	Due 2020 and beyond	All Other
Long-term debt [a]	$2,434	$—	$300	$500	$ 1,634	$—
Interest payments on long-term debt [b]	1,773	107	210	158	1,298	—
Operating leases	14	3	6	5	—	—
Fuel purchase agreements [c]	428	146	163	48	71	—
Electric supply procurement [c]	609	527	82	—	—	—
AEC purchase commitments [c]	13	2	4	4	3	—
Other purchase obligations [d]	7	3	4	—	—	—
PJM regional transmission expansion commitments [e]	100	32	56	12	—	—
Total contractual obligations	$5,378	$820	$825	$727	$ 3,006	$—

(a) Includes $184 million due after 2020 to PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Represents commitments for services, materials, information technology, and smart meter installation. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.
(e) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

BGE

	Total	Payment due within 2015	2016-2017	2018-2019	Due 2020 and beyond	All Other
Long-term debt [a]	$2,203	$ 75	$ 420	$—	$ 1,708	$—
Interest payments on long-term debt [b]	1,477	104	181	159	1,033	—
Liability and interest for uncertain tax positions [c]	1	—	—	—	—	1
Operating leases	77	13	21	16	27	—
Fuel purchase agreements [d]	611	111	149	111	240	—
Electric supply procurement [d]	1,315	779	536	—	—	—
Curtailment services commitments [d]	115	40	63	12	—	—
Other purchase obligations [e]	343	107	217	10	9	—
PJM regional transmission expansion commitments [f]	351	77	181	93	—	—
Total contractual obligations	$6,493	$1,306	$1,768	$401	$ 3,017	$ 1

(a) Includes $258 million due after 2020 to the BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2014 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) As of December 31, 2014, BGE's liability for interest payable was $1 million. BGE was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.
(d) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

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(e) Represents commitments for services, materials, information technology, and smart meter installation. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.
(f) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- operating leases, energy commitments, fuel purchase agreements, construction commitments and rate relief commitments, see Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 15—Asset Retirement Obligations and 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.
- variable interest entities, see Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- new accounting pronouncements, see Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2015 through 2017.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over the three years leading to the spot market. As of December 31, 2014, the percentage of expected generation hedged for the major reportable segments was 93%-96%, 61%-64% and 31%-34% for 2015, 2016 and 2017, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation (which reflects the divestiture impact of Quail Run). Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including sales to ComEd, PECO and BGE to serve their retail load. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for more detail regarding divestitures.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on December 31, 2014, market conditions and hedged position would be a decrease in pre-tax net income of approximately $10 million, $350 million and $670 million, respectively, for 2015, 2016 and 2017. Power price sensitivities are derived by

adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 10,571 GWh, 8,762 GWh, and 12,958 GWh for the years ended December 31, 2014, 2013 and 2012 respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the year ended December 31, 2014, resulted in pre-tax gains of $42 million due to net mark-to-market losses of $26 million and realized gains of $68 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $0.4 million of exposure during the year. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for the year ended December 31, 2014 of $7,468 million.

Fuel Procurement . Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 50% of Generation's uranium concentrate requirements from 2015 through 2019 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

ComEd

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd would be entitled to receive full cost recovery in rates. The change in fair value each period was recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expired on May 31, 2013. All realized impacts have been included in Generation's and ComEd's results of operations.

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable

energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014. See Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3—Regulatory Matters of the Combined Notes to the Consolidated Financial Statements. PECO has certain full requirements contracts and block contracts, which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance and as a result, are accounted for on an accrual basis of accounting. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities

The following detailed presentation of Exelon's, Generation's, ComEd's and PECO's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, and ComEd's commodity mark-to-market net asset or liability balance sheet position from January 1, 2013 to December 31, 2014. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings, as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in Accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2014 and December 31, 2013.

	Generation	ComEd	Intercompany Eliminations [b]	Exelon
Total mark-to-market energy contract net assets (liabilities) at January 1, 2013 [a]	$ 1,505	$(293)	$ —	$1,212
Total change in fair value during 2013 of contracts recorded in result of operations	444	—	(6)	438
Reclassification to realized at settlement of contracts recorded in results of operations	25	—	13	38
Reclassification to realized at settlement from accumulated OCI [c]	(683)	—	219	(464)
Changes in fair value—energy derivatives [d]	—	100	(226)	(126)
Changes in allocated collateral	(175)	—	—	(175)
Changes in net option premium paid/(received)	36	—	—	36
Option premium amortization	(104)	—	—	(104)
Other balance sheet reclassifications	(1)	—	—	(1)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2013 [a]	1,047	$(193)	$ —	854
Contracts acquired at merger date [e]	128			128
Total change in fair value during 2014 of contracts recorded in result of operations	(608)	—	—	(608)
Reclassification to realized at settlement of contracts recorded in results of operations	(21)	—	—	(21)
Reclassification to realized at settlement from accumulated OCI	(195)	—	—	(195)
Changes in fair value—energy derivatives [d]	—	(14)	—	(14)
Changes in allocated collateral	1,503	—	—	1,503
Changes in net option premium paid/(received)	(38)	—	—	(38)
Option premium amortization	(122)	—	—	(122)
Other balance sheet reclassifications	18	—	—	18
Total mark-to-market energy contract net assets (liabilities) at December 31, 2014 [a]	$ 1,712	$(207)	$ —	$1,505

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Amounts related to the five-year financial swap between Generation and ComEd.
(c) For Generation, includes $219 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the year ended December 31, 2013.

(d) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2014 and 2013, ComEd recorded a regulatory liability of $207 million and $193 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of December 31, 2013, this includes $11 million of decreases in fair value and $215 million for reclassifications from regulatory assets to recognize cost in purchase power expense due to settlements of ComEd's five-year financial swap with Generation. As of December 31, 2014 and 2013 ComEd also recorded $13 million and $133 million, respectively, of increases in fair value, and $1 million and $7 million, respectively, of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(e) Includes $81 million of fair value from contracts acquired and $47 million of cash collateral as a result of the Integrys acquisition.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities) net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 11—Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						Total Fair
	2015	2016	2017	2018	2019	2020 and Beyond	Value
Normal Operations, Commodity derivative contracts [(a)(b)]:							
Actively quoted prices (Level 1)	$ (118)	$ (5)	$ 3	$(10)	$ (5)	$ 1	$ (134)
Prices provided by external sources (Level 2)	522	244	21	7	—	2	796
Prices based on model or other valuation methods (Level 3) [(c)]	625	217	140	(21)	(21)	(97)	843
Total	$1,029	$456	$164	$(24)	$(26)	$ (94)	$ 1,505

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $1,406 million at December 31, 2014.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						Total Fair Value
	2015	2016	2017	2018	2019	2020 and Beyond	
Normal Operations, Commodity derivative contracts [(a)(b)]:							
Actively quoted prices (Level 1)	$ (118)	$ (5)	$ 3	$(10)	$ (5)	$ 1	$ (134)
Prices provided by external sources (Level 2)	522	244	21	7	—	2	796
Prices based on model or other valuation methods (Level 3)	645	236	157	(4)	(4)	20	1,050
Total	$1,049	$475	$181	$ (7)	$ (9)	$ 23	$ 1,712

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $1,406 million at December 31, 2014.

ComEd

	Maturities Within						Fair Value
	2015	2016	2017	2018	2019	2020 and Beyond	
Prices based on model or other valuation methods (Level 3) [(a)]	$(20)	$(19)	$(17)	$(17)	$(17)	$ (117)	$(207)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2014. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE, and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of $43 million, $29 million and $40 million, respectively. See Note 25—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Rating as of December 31, 2014	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,629	$ 62	$ 1,567	1	$ 452
Non-investment grade	49	19	30	—	—
No external ratings					
Internally rated—investment grade	479	—	479	—	—
Internally rated—non-investment grade	60	4	56	—	—
Total	$ 2,217	$ 85	$ 2,132	1	$ 452

	Maturity of Credit Risk Exposure			
Rating as of December 31, 2014	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,196	$379	$ 54	$ 1,629
Non-investment grade	35	11	3	49
No external ratings				
Internally rated—investment grade	388	90	1	479
Internally rated—non-investment grade	60	—	—	60
Total	$ 1,679	$480	$ 58	$ 2,217

Net Credit Exposure by Type of Counterparty	As of December 31, 2014
Financial institutions	$ 295
Investor-owned utilities, marketers, power producers	958
Energy cooperatives and municipalities	862
Other	17
Total	$ 2,132

(a) As of December 31, 2014, credit collateral held from counterparties where Generation had credit exposure included $69 million of cash and $16 million of letters of credit.

ComEd

Credit risk for ComEd is managed by credit and collection policies, which are consistent with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. The Illinois Settlement Legislation prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 1 of the following year. ComEd's ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2014. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. As of December 31, 2014, ComEd's credit exposure to energy suppliers was immaterial.

PECO

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2014.

PECO's supplier master agreements that govern the terms of its DSP Program contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2014, PECO had no net credit exposure with suppliers.

PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2014, PECO had credit exposure of $8 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE

Credit risk for BGE is managed by credit and collection policies, which are consistent with state regulatory requirements. BGE is currently obligated to provide service to all electric customers within its franchised territory. BGE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. BGE will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for uncollectible accounts policy. MDPSC regulations prohibit BGE from terminating service to residential customers due to nonpayment from November 1 through March 31 if the forecasted temperature is 32 degrees or below for the subsequent 72 hour period. BGE is also prohibited by the Public Utilities Article of the Annotated Code of Maryland and MDPSC regulations from terminating service to residential customers due to nonpayment if the forecasted temperature is 95 degrees or above for the subsequent 72 hour period. BGE did not have any customers representing over 10% of its revenues as of December 31, 2014.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The seller's credit exposure is calculated each business day. As of December 31, 2014, BGE had no net credit exposure with suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2014, BGE had credit exposure of $8 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Collateral (Exelon, Generation, ComEd, PECO and BGE)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and

circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above or fall below contracted price levels, Generation or its counterparties may be required to post collateral with one another. In order to post collateral, Generation depends on access to bank credit facilities which serve as liquidity sources to fund collateral requirements. See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2014, Generation had cash collateral of $1,497 million posted and cash collateral held of $77 million for counterparties with derivative positions, of which $1,406 million and $6 million in net cash collateral deposits were offset against energy mark-to-market and interest rate and foreign exchange derivative assets and liabilities related to underlying energy contracts, respectively. As of December 31, 2014, $8 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives or as of the balance sheet date there were no positions to offset. As of December 31, 2013, Generation had cash collateral posted of $72 million and cash collateral held of $206 million for counterparties with derivative positions, of which $144 million in net cash collateral deposits were offset against mark-to-market assets and liabilities. As of December 31, 2013, $10 million of cash collateral posted was not offset against net mark-to-market assets and liabilities because it was not associated with energy-related derivatives or at the balance sheet date there were no positions to offset. See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 31, 2014, ComEd held approximately $2 million of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash for both annual and long-term renewable energy contracts. See Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

PECO

As of December 31, 2014, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of December 31, 2014, BGE was not required to post collateral under its natural gas procurement contracts nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon and Generation)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk. In 2014 the exchanges increased initial margin rates, which required Generation to post higher amounts of initial margin collateral. Generation believes that increased market volatility and extreme weather events, such as the Polar Vortex, contributed to the rate increases.

Long-Term Leases (Exelon)

Exelon's Consolidated Balance Sheet, as of December 31, 2014, included a $361 million net investment in coal-fired plants in Georgia subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $685 million, less unearned income of $324 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessee does not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessee to arrange for a third-party to bid on a service contract for a period following the lease term. Exelon will be subject to residual value risk if the lessee does not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

Exelon's Consolidated Balance Sheet, as of December 31, 2013, also included a net investment in a coal-fired plant in Texas subject to a long-term lease. In February 2014, Exelon and the City Public Service Board of San Antonio, Texas (CPS) finalized an agreement to terminate the leases prior to their expiration dates. As a result of the lease termination, Exelon received a net early termination amount of $335 million from CPS and wrote off the net investment in the CPS long-term lease of $336 million; resulting in a pre-tax loss of $1 million. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for the impact of the lease termination on income taxes.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and, if the review indicates a

fair value below the carrying value and the decline is determined to be other than temporary, must record an impairment charge in the period the estimate changed. Based on the annual reviews performed in 2014 and 2013, the estimated residual value of Exelon's direct financing leases for the Georgia generating stations experienced other than temporary declines given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $24 million and $14 million pre-tax impairment charge in 2014 and 2013, respectively, for these stations. See Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for further information.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2014, Exelon and Generation had $1,450 million and $550 million of notional amounts of fixed-to-floating hedges outstanding, respectively, and $3,070 million and $770 million of notional amounts of floating-to-fixed hedges outstanding, respectively. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $8 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2014. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of December 31, 2014, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $617 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Generation

General

Generation's integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. These segments are discussed in further detail in "ITEM 1. BUSINESS—Exelon Generation Company, LLC" of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation's executive overview is set forth under "ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2014 Compared To Year Ended December 31, 2013 and Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

A discussion of Generation's results of operations for 2014 compared to 2013 and 2013 compared to 2012 is set forth under "Results of Operations—Generation" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.8 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 13 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Generation's capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon's pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of Generation's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in "ITEM 1. BUSINESS—ComEd" of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 and Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

A discussion of ComEd's results of operations for 2014 compared to 2013 and for 2013 compared to 2012 is set forth under "Results of Operations—ComEd" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2014, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 13 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ComEd's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of ComEd's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk— Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in "ITEM 1. BUSINESS—PECO" of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 and Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

A discussion of PECO's results of operations for 2014 compared to 2013 and for 2013 compared to 2012 is set forth under "Results of Operations—PECO" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2014, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund PECO's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of PECO's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BGE

General

BGE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in "ITEM 1. BUSINESS—BGE" of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 and Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

A discussion of BGE's results of operations for 2014 compared to 2013 and for 2013 compared to 2012 is set forth under "Results of Operations—BGE" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

BGE's business is capital intensive and requires considerable capital resources. BGE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2014, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund BGE's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to BGE's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to BGE's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE—Critical Accounting Policies and Estimates above for a discussion of BGE's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2014, Exelon's internal control over financial reporting was effective.

We excluded Integrys, which we acquired on November 1, 2014, from management's assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2014. This exclusion is in accordance with the SEC's general guidance that an assessment of a recently acquired business may be omitted from our scope in the year of acquisition.

The effectiveness of the Exelon's internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2015

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Generation's management conducted an assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation's management concluded that, as of December 31, 2014, Generation's internal control over financial reporting was effective.

We excluded Integrys, which we acquired on November 1, 2014, from management's assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2014. This exclusion is in accordance with the SEC's general guidance that an assessment of a recently acquired business may be omitted from our scope in the year of acquisition.

The effectiveness of the Generation's internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2015

Management's Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd's management concluded that, as of December 31, 2014, ComEd's internal control over financial reporting was effective.

The effectiveness of the ComEd's internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2015

Management's Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO's management concluded that, as of December 31, 2014, PECO's internal control over financial reporting was effective.

The effectiveness of the PECO's internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2015

Management's Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

BGE's management conducted an assessment of the effectiveness of BGE's internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE's management concluded that, as of December 31, 2014, BGE's internal control over financial reporting was effective.

The effectiveness of BGE's internal control over financial reporting as of December 31, 2014, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2015

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Corporation (the "Company") and its subsidiaries at December 31, 2014 and 2013 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control over Financial Reporting appearing under Item 8, management has excluded Integrys Energy Services, Inc. ("Integrys") from its

assessment of internal control over financial reporting as of December 31, 2014 because it was acquired by the Company in a purchase business combination on November 1, 2014. We have also excluded Integrys from our audit of internal control over financial reporting. Integrys is a wholly-owned subsidiary whose total assets and total revenues represent 0.74% and 1.41%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2014.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2015

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Generation Company, LLC (the "Company") and its subsidiaries at December 31, 2014 and 2013 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control over Financial Reporting appearing under Item 8, management has excluded Integrys Energy Services, Inc. ("Integrys") from its assessment of internal control over financial reporting as of December 31, 2014 because it was acquired by the Company in a purchase business combination on November 1, 2014. We have also excluded Integrys from our audit of internal control over financial reporting. Integrys is a wholly-owned subsidiary whose total assets and total revenues represent 1.42% and 2.22%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2014.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2015

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Commonwealth Edison Company (the "Company") and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2015

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PECO Energy Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of PECO Energy Company (the "Company") and its subsidiaries at December 31, 2014 and 2013 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 13, 2015

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Baltimore Gas and Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company (the "Company") and its subsidiaries at December 31, 2014 and 2013 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2015

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Exelon Corporation and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2014	2013	2012
Operating revenues	$27,429	$24,888	$23,489
Operating expenses			
Purchased power and fuel	12,472	9,468	9,121
Purchased power and fuel from affiliates	531	1,256	1,036
Operating and maintenance	8,568	7,270	7,961
Depreciation and amortization	2,314	2,153	1,881
Taxes other than income	1,154	1,095	1,019
Total operating expenses	25,039	21,242	21,018
Equity in (losses) earnings of unconsolidated affiliates	(20)	10	(91)
Gain (loss) on sales of assets	437	13	(7)
Gain on consolidation and acquisition of businesses	289	—	—
Operating income	3,096	3,669	2,373
Other income and (deductions)			
Interest expense, net	(1,024)	(1,315)	(891)
Interest expense to affiliates, net	(41)	(41)	(37)
Other, net	455	460	353
Total other income and (deductions)	(610)	(896)	(575)
Income before income taxes	2,486	2,773	1,798
Income taxes	666	1,044	627
Net income	1,820	1,729	1,171
Net income attributable to noncontrolling interest, preferred security dividends and preference stock dividends	197	10	11
Net income attributable to common shareholders	1,623	1,719	1,160
Comprehensive income (loss), net of income taxes			
Net income	1,820	1,729	1,171
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service (benefit) cost reclassified to periodic benefit cost	(30)	—	1
Actuarial loss reclassified to periodic cost	147	208	168
Transition obligation reclassified to periodic cost	—	—	2
Pension and non-pension postretirement benefit plan valuation adjustment	(497)	669	(371)
Unrealized loss on cash flow hedges	(148)	(248)	(120)
Unrealized gain on marketable securities	1	2	2
Unrealized gain on equity investments	8	106	1
Unrealized loss on foreign currency translation	(9)	(10)	—
Reversal of CENG equity method AOCI	(116)	—	—
Other comprehensive (loss) income	(644)	727	(317)
Comprehensive income	$ 1,176	$ 2,456	$ 854
Average shares of common stock outstanding:			
Basic	860	856	816
Diluted	864	860	819
Earnings per average common share:			
Basic	$ 1.89	$ 2.01	$ 1.42
Diluted	$ 1.88	$ 2.00	$ 1.42
Dividends per common share	$ 1.24	$ 1.46	$ 2.10

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2014	2013	2012
Cash flows from operating activities			
Net income	$ 1,820	$ 1,729	$ 1,171
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	3,868	3,779	4,079
Impairment of long-lived assets	687	171	284
Gain on consolidation and acquisition of businesses	(296)	—	—
(Gain) loss on sales of assets	(437)	(13)	7
Deferred income taxes and amortization of investment tax credits	502	119	615
Net fair value changes related to derivatives	716	(445)	(604)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(210)	(170)	(157)
Other non-cash operating activities	1,054	718	1,364
Changes in assets and liabilities:			
Accounts receivable	(318)	(97)	243
Inventories	(380)	(100)	26
Accounts payable, accrued expenses and other current liabilities	209	(90)	(632)
Option premiums received (paid), net	38	(36)	(114)
Counterparty collateral (posted) received, net	(1,478)	215	135
Income taxes	(143)	883	544
Pension and non-pension postretirement benefit contributions	(617)	(422)	(462)
Other assets and liabilities	(558)	102	(368)
Net cash flows provided by operating activities	4,457	6,343	6,131
Cash flows from investing activities			
Capital expenditures	(6,077)	(5,395)	(5,789)
Proceeds from termination of direct financing lease investment	335	—	—
Proceeds from nuclear decommissioning trust fund sales	7,396	4,217	7,265
Investment in nuclear decommissioning trust funds	(7,551)	(4,450)	(7,483)
Cash and restricted cash acquired from consolidations and acquisitions	140	—	964
Acquisitions of businesses	(386)	—	(21)
Proceeds from sales of long-lived assets	1,719	32	371
Proceeds from sales of investments	7	22	28
Purchases of investments	(3)	(4)	(13)
Change in restricted cash	(104)	(43)	(34)
Distribution from CENG	13	115	—
Other investing activities	(88)	112	136
Net cash flows used in investing activities	(4,599)	(5,394)	(4,576)
Cash flows from financing activities			
Payment of accounts receivable agreement	—	(210)	(15)
Changes in short-term borrowings	122	332	(197)
Issuance of long-term debt	3,463	2,055	2,027
Retirement of long-term debt	(1,545)	(1,589)	(1,145)
Redemption of preferred securities	—	(93)	—
Distributions to noncontrolling interest of consolidated VIE	(421)	—	—
Dividends paid on common stock	(1,065)	(1,249)	(1,716)
Proceeds from employee stock plans	35	47	72
Other financing activities	(178)	(119)	(111)
Net cash flows provided by (used in) financing activities	411	(826)	(1,085)
Increase in cash and cash equivalents	269	123	470
Cash and cash equivalents at beginning of period	1,609	1,486	1,016
Cash and cash equivalents at end of period	$ 1,878	$ 1,609	$ 1,486

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2014	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,878	$ 1,609
Restricted cash and cash equivalents	271	167
Accounts receivable, net		
Customer	3,482	2,981
Other	1,227	1,175
Mark-to-market derivative assets	1,279	727
Unamortized energy contract assets	254	374
Inventories, net		
Fossil fuel	579	276
Materials and supplies	1,024	829
Deferred income taxes	244	573
Regulatory assets	847	760
Assets held for sale	147	14
Other	865	652
Total current assets	12,097	10,137
Property, plant and equipment, net	52,087	47,330
Deferred debits and other assets		
Regulatory assets	6,076	5,910
Nuclear decommissioning trust funds	10,537	8,071
Investments	544	1,187
Investment in CENG	—	1,925
Goodwill	2,672	2,625
Mark-to-market derivative assets	773	607
Unamortized energy contract assets	549	710
Pledged assets for Zion Station decommissioning	319	458
Other	1,160	964
Total deferred debits and other assets	22,630	22,457
Total assets [(a)]	$86,814	$79,924

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2014	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 460	$ 341
Long-term debt due within one year	1,802	1,509
Accounts payable	3,048	2,484
Accrued expenses	1,539	1,633
Payables to affiliates	8	116
Deferred income taxes	—	40
Regulatory liabilities	310	327
Mark-to-market derivative liabilities	234	159
Unamortized energy contract liabilities	238	261
Other	1,123	858
Total current liabilities	8,762	7,728
Long-term debt	19,362	17,623
Long-term debt to financing trusts	648	648
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,019	12,905
Asset retirement obligations	7,295	5,194
Pension obligations	3,366	1,876
Non-pension postretirement benefit obligations	1,742	2,190
Spent nuclear fuel obligation	1,021	1,021
Regulatory liabilities	4,550	4,388
Mark-to-market derivative liabilities	403	300
Unamortized energy contract liabilities	211	266
Payable for Zion Station decommissioning	155	305
Other	2,147	2,540
Total deferred credits and other liabilities	33,909	30,985
Total liabilities [(a)]	62,681	56,984
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 860 and 857 shares outstanding at December 31, 2014 and 2013, respectively)	16,709	16,741
Treasury stock, at cost (35 shares held at December 31, 2014 and 2013)	(2,327)	(2,327)
Retained earnings	10,910	10,358
Accumulated other comprehensive loss, net	(2,684)	(2,040)
Total shareholders' equity	22,608	22,732
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	1,332	15
Total equity	24,133	22,940
Total liabilities and shareholders' equity	$86,814	$79,924

(a) Exelon's consolidated assets include $8,160 million and $1,755 million at December 31, 2014 and December 31, 2013, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $2,723 million and $658 million at December 31, 2014 and December 31, 2013, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 2—Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Preferred and Preference Stock	Total Shareholders' Equity
Balance, December 31, 2011	698,112	$ 9,107	$ (2,327)	$ 10,055	$ (2,450)	$ 3	$ —	$ 14,388
Net income (loss)	—	—	—	1,160	—	(3)	14	1,171
Long-term incentive plan activity	2,432	126	—	—	—	—	—	126
Employee stock purchase plan issuances	857	26	—	—	—	—	—	26
Common stock dividends	—	—	—	(1,322)	—	—	—	(1,322)
Common stock issuance Constellation merger	188,124	7,365	—	—	—	—	—	7,365
Noncontrolling interest acquired	—	8	—	—	—	106	—	114
BGE preference stock acquired	—	—	—	—	—	—	193	193
Preferred and preference stock dividends	—	—	—	—	—	—	(14)	(14)
Other comprehensive loss, net of income taxes	—	—	—	—	(317)	—	—	(317)
Balance, December 31, 2012	889,525	$ 16,632	$ (2,327)	$ 9,893	$ (2,767)	$ 106	$ 193	$ 21,730
Net income (loss)	—	—	—	1,719	—	(10)	20	1,729
Long-term incentive plan activity	1,445	81	—	—	—	—	—	81
Employee stock purchase plan issuances	1,064	28	—	—	—	—	—	28
Common stock dividends	—	—	—	(1,254)	—	—	—	(1,254)
Consolidated VIE dividend to noncontrolling interest	—	—	—	—	—	(63)	—	(63)
Deconsolidation of VIE	—	—	—	—	—	(18)	—	(18)
Redemption of preferred securities	—	—	—	—	—	—	(6)	(6)
Preferred and preference stock dividends	—	—	—	—	—	—	(14)	(14)
Other comprehensive income, net of income taxes	—	—	—	—	727	—	—	727
Balance, December 31, 2013	892,034	$ 16,741	$ (2,327)	$ 10,358	$ (2,040)	$ 15	$ 193	$ 22,940
Net income (loss)	—	—	—	1,623	—	184	13	1,820
Long-term incentive plan activity	1,574	72	—	—	—	—	—	72
Employee stock purchase plan issuances	960	35	—	—	—	—	—	35
Tax benefit on stock compensation	—	(8)	—	—	—	—	—	(8)
Acquisition of noncontrolling interest	—	(2)	—	—	—	6	—	4
Common stock dividends	—	—	—	(1,071)	—	—	—	(1,071)
Preferred and preference stock dividends	—	—	—	—	—	—	(13)	(13)
Fair value of financing contract payments	—	(131)	—	—	—	—	—	(131)
Noncontrolling interest established upon consolidation of CENG	—	—	—	—	—	1,548	—	1,548
Transfer of CENG pension and non-pension postretirement benefit obligations	—	2	—	—	—	—	—	2
Consolidated VIE dividend to noncontrolling interest	—	—	—	—	—	(421)	—	(421)
Reversal of CENG equity method AOCI, net of income taxes	—	—	—	—	(116)	—	—	(116)
Other comprehensive loss, net of income taxes	—	—	—	—	(528)	—	—	(528)
Balance, December 31, 2014	894,568	$ 16,709	$ (2,327)	$ 10,910	$ (2,684)	$ 1,332	$ 193	$ 24,133

See the Combined Notes to Consolidated Financial Statements

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Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2014	2013	2012
Operating revenues			
Operating revenues	$16,614	$14,207	$12,735
Operating revenues from affiliates	779	1,423	1,702
Total operating revenues	17,393	15,630	14,437
Operating expenses			
Purchased power and fuel	9,368	6,927	6,017
Purchased power and fuel from affiliates	557	1,270	1,044
Operating and maintenance	4,943	3,960	4,398
Operating and maintenance from affiliates	623	574	630
Depreciation and amortization	967	856	768
Taxes other than income	465	389	369
Total operating expenses	16,923	13,976	13,226
Equity in (losses) earnings of unconsolidated affiliates	(20)	10	(91)
Gain (loss) on sales of assets	437	13	(7)
Gain on consolidation and acquisition of businesses	289	—	—
Operating income	1,176	1,677	1,113
Other income and (deductions)			
Interest expense	(303)	(298)	(226)
Interest expense to affiliates, net	(53)	(59)	(75)
Other, net	406	355	246
Total other income and (deductions)	50	(2)	(55)
Income before income taxes	1,226	1,675	1,058
Income taxes	207	615	500
Net income	1,019	1,060	558
Net income (loss) attributable to noncontrolling interests	184	(10)	(4)
Net income attributable to membership interest	835	1,070	562
Comprehensive income (loss), net of income taxes			
Net income	1,019	1,060	558
Other comprehensive income (loss), net of income taxes			
Unrealized loss on cash flow hedges	(132)	(398)	(403)
Unrealized gain on equity investments	8	107	1
Unrealized loss on foreign currency translation	(9)	(10)	—
Unrealized gain (loss) on marketable securities	(1)	2	—
Reversal of CENG equity method AOCI	(116)	—	—
Other comprehensive loss	(250)	(299)	(402)
Comprehensive Income	$ 769	$ 761	$ 156

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2014	2013	2012
Cash flows from operating activities			
Net income	$ 1,019	$ 1,060	$ 558
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,519	2,559	2,966
Impairment of long-lived assets	663	157	284
Gain on consolidation and acquisition of businesses	(296)	—	—
(Gain) loss on sales of assets	(437)	(13)	7
Deferred income taxes and amortization of investment tax credits	(198)	315	408
Net fair value changes related to derivatives	635	(448)	(611)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(210)	(170)	(157)
Other non-cash operating activities	346	270	518
Changes in assets and liabilities:			
Accounts receivable	(215)	109	248
Receivables from and payables to affiliates, net	15	2	39
Inventories	(359)	(88)	31
Accounts payable, accrued expenses and other current liabilities	94	(109)	(499)
Option premiums received (paid), net	38	(36)	(114)
Counterparty collateral (posted) received, net	(1,507)	162	95
Income taxes	265	402	114
Pension and non-pension postretirement benefit contributions	(297)	(149)	(178)
Other assets and liabilities	(249)	(136)	(128)
Net cash flows provided by operating activities	1,826	3,887	3,581
Cash flows from investing activities			
Capital expenditures	(3,012)	(2,752)	(3,554)
Proceeds from nuclear decommissioning trust fund sales	7,396	4,217	7,265
Investment in nuclear decommissioning trust funds	(7,551)	(4,450)	(7,483)
Cash and restricted cash acquired from consolidations and acquisitions	140	—	708
Proceeds from sales of long-lived assets	1,719	32	371
Acquisitions of businesses	(386)	—	(21)
Change in restricted cash	(87)	(64)	4
Changes in Exelon intercompany money pool	44	(44)	—
Distribution from CENG	13	115	—
Other investing activities	(43)	30	81
Net cash flows used in investing activities	(1,767)	(2,916)	(2,629)
Cash flows from financing activities			
Change in short-term borrowings	17	13	(52)
Issuance of long-term debt	1,112	854	1,076
Retirement of long-term debt	(586)	(570)	(145)
Distribution to member	(645)	(625)	(1,626)
Contribution from member	53	26	48
Distribution to noncontrolling interest of consolidated VIE	(421)	—	—
Other financing activities	(67)	(82)	(78)
Net cash flows used in financing activities	(537)	(384)	(777)
Increase (decrease) in cash and cash equivalents	(478)	587	175
Cash and cash equivalents at beginning of period	1,258	671	496
Cash and cash equivalents at end of period	$ 780	$ 1,258	$ 671

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2014	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 780	$ 1,258
Restricted cash and cash equivalents	158	71
Accounts receivable, net		
Customer	2,295	1,689
Other	318	353
Mark-to-market derivative assets	1,276	727
Receivables from affiliates	113	108
Receivable from Exelon intercompany money pool	—	44
Unamortized energy contract assets	254	374
Inventories, net		
Fossil fuel	465	164
Materials and supplies	847	671
Deferred income taxes	327	475
Assets held for sale	147	14
Other	658	491
Total current assets	7,638	6,439
Property, plant and equipment, net	22,945	20,111
Deferred debits and other assets		
Nuclear decommissioning trust funds	10,537	8,071
Investments	104	400
Investment in CENG	—	1,925
Goodwill	47	—
Mark-to-market derivative assets	771	600
Prepaid pension asset	1,704	1,873
Pledged assets for Zion Station decommissioning	319	458
Unamortized energy contract assets	549	710
Deferred income taxes	3	—
Other	731	645
Total deferred debits and other assets	14,765	14,682
Total assets [(a)]	$45,348	$41,232

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2014	2013
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 36	$ 22
Long-term debt due within one year	58	561
Long-term debt to affiliates due within one year	556	—
Accounts payable	1,759	1,322
Accrued expenses	886	976
Payables to affiliates	107	181
Deferred income taxes	—	25
Mark-to-market derivative liabilities	214	142
Unamortized energy contract liabilities	238	249
Other	605	389
Total current liabilities	4,459	3,867
Long-term debt	6,709	5,645
Long-term debt to affiliate	943	1,523
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,034	6,295
Asset retirement obligations	7,146	5,047
Non-pension postretirement benefit obligations	915	850
Spent nuclear fuel obligation	1,021	1,021
Payables to affiliates	2,880	2,740
Mark-to-market derivative liabilities	105	120
Unamortized energy contract liabilities	211	266
Payable for Zion Station decommissioning	155	305
Other	719	811
Total deferred credits and other liabilities	19,186	17,455
Total liabilities [(a)]	31,297	28,490
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	8,951	8,898
Undistributed earnings	3,803	3,613
Accumulated other comprehensive income (loss), net	(36)	214
Total member's equity	12,718	12,725
Noncontrolling interest	1,333	17
Total equity	14,051	12,742
Total liabilities and equity	$45,348	$41,232

(a) Generation's consolidated assets include $8,119 million and $1,695 million at December 31, 2014 and December 31, 2013, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $2,507 million and $362 million at December 31, 2014 and December 31, 2013, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 2—Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Changes in Member's Equity

(In millions)	Member's Equity			Noncontrolling Interest	Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income (loss)		
Balance, December 31, 2011	$ 3,556	$ 4,232	$ 915	$ 5	$ 8,708
Net income	—	562	—	(4)	558
Distribution to member	—	(1,626)	—	—	(1,626)
Allocation of tax benefit from member	48	—	—	—	48
Constellation Merger	5,264	—	—	—	5,264
Noncontrolling interest acquired	8	—	—	107	115
Other comprehensive loss, net of income taxes	—	—	(402)	—	(402)
Balance, December 31, 2012	$ 8,876	$ 3,168	$ 513	$ 108	$12,665
Net income	—	1,070	—	(10)	1,060
Distribution to member	—	(625)	—	—	(625)
Allocation of tax benefit from member	26	—	—	—	26
Consolidated VIE dividend to noncontrolling interest	—	—	—	(63)	(63)
Deconsolidation of VIE	(1)	—	—	(18)	(19)
Noncontrolling interest acquired	(3)	—	—	—	(3)
Other comprehensive loss, net of income taxes	—	—	(299)	—	(299)
Balance, December 31, 2013	$ 8,898	$ 3,613	$ 214	$ 17	$12,742
Net income	—	835	—	184	1,019
Acquisition of noncontrolling interest	—	—	—	5	5
Allocation of tax benefit from member	53	—	—	—	53
Distribution to member	—	(645)	—	—	(645)
Noncontrolling interest established upon consolidation of CENG	—	—	—	1,548	1,548
Consolidated VIE dividend to noncontrolling interest	—	—	—	(421)	(421)
Reversal of CENG equity method AOCI, net of income taxes of $(77)	—	—	(116)	—	(116)
Other comprehensive loss, net of income taxes	—	—	(134)	—	(134)
Balance, December 31, 2014	$ 8,951	$ 3,803	$ (36)	$ 1,333	$14,051

See the Combined Notes to Consolidated Financial Statements

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Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(in millions)	For the Years Ended December 31, 2014	2013	2012
Operating revenues			
Operating revenues	$4,560	$4,461	$5,441
Operating revenues from affiliates	4	3	2
Total operating revenues	4,564	4,464	5,443
Operating expenses			
Purchased power	1,001	662	1,518
Purchased power from affiliate	176	512	789
Operating and maintenance	1,263	1,211	1,182
Operating and maintenance from affiliate	166	157	163
Depreciation and amortization	687	669	610
Taxes other than income	293	299	295
Total operating expenses	3,586	3,510	4,557
Gain on sales of assets	2	—	—
Operating income	980	954	886
Other income and (deductions)			
Interest expense	(308)	(566)	(294)
Interest expense to affiliates, net	(13)	(13)	(13)
Other, net	17	26	39
Total other income and (deductions)	(304)	(553)	(268)
Income before income taxes	676	401	618
Income taxes	268	152	239
Net income	408	249	379
Other comprehensive income			
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively	—	—	1
Other comprehensive income	—	—	1
Comprehensive income	$ 408	$ 249	$ 380

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended 2014	2013	2012
Cash flows from operating activities			
Net income	$ 408	$ 249	$ 379
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	687	669	610
Deferred income taxes and amortization of investment tax credits	433	(57)	270
Other non-cash operating activities	255	28	252
Changes in assets and liabilities:			
Accounts receivable	(121)	(12)	24
Receivables from and payables to affiliates, net	(11)	(12)	(18)
Inventories	(16)	(18)	(11)
Accounts payable, accrued expenses and other current liabilities	53	74	59
Income taxes	(159)	178	9
Pension and non-pension postretirement benefit contributions	(248)	(122)	(138)
Other assets and liabilities	45	241	(102)
Net cash flows provided by operating activities	1,326	1,218	1,334
Cash flows from investing activities			
Capital expenditures	(1,689)	(1,433)	(1,246)
Proceeds from sales of investments	7	7	28
Purchases of investments	(3)	(4)	(13)
Change in restricted cash	(2)	(2)	—
Other investing activities	32	45	19
Net cash flows used in investing activities	(1,655)	(1,387)	(1,212)
Cash flows from financing activities			
Changes in short-term borrowings	120	184	—
Issuance of long-term debt	900	350	350
Retirement of long-term debt	(617)	(252)	(450)
Contributions from parent	273	—	—
Dividends paid on common stock	(307)	(220)	(105)
Other financing activities	(10)	(1)	(7)
Net cash flows provided by (used in) financing activities	359	61	(212)
Increase (decrease) in cash and cash equivalents	30	(108)	(90)
Cash and cash equivalents at beginning of period	36	144	234
Cash and cash equivalents at end of period	$ 66	$ 36	$ 144

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheet

(In millions)	December 31, 2014	2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 66	$ 36
Restricted cash	4	2
Accounts receivable, net		
Customer	477	451
Other	648	581
Receivables from affiliates	14	3
Inventories, net	125	109
Regulatory assets	349	329
Other	40	29
Total current assets	1,723	1,540
Property, plant and equipment, net	15,793	14,666
Deferred debits and other assets		
Regulatory assets	852	933
Investments	6	11
Goodwill	2,625	2,625
Receivable from affiliates	2,571	2,469
Prepaid pension asset	1,551	1,583
Other	271	291
Total deferred debits and other assets	7,876	7,912
Total assets	$25,392	$24,118

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2014	2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 304	$ 184
Long-term debt due within one year	260	617
Accounts payable	598	449
Accrued expenses	331	307
Payables to affiliates	84	83
Customer deposits	128	133
Regulatory liabilities	125	170
Mark-to-market derivative liability	20	17
Deferred income taxes	63	16
Other	73	72
Total current liabilities	1,986	2,048
Long-term debt	5,698	5,058
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,498	4,116
Asset retirement obligations	103	99
Non-pension postretirement benefits obligations	263	381
Regulatory liabilities	3,655	3,512
Mark-to-market derivative liability	187	176
Other	889	994
Total deferred credits and other liabilities	9,595	9,278
Total liabilities	17,485	16,590
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,468	5,190
Retained earnings	851	750
Total shareholders' equity	7,907	7,528
Total liabilities and shareholders' equity	$25,392	$24,118

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance, December 31, 2011	$ 1,588	$5,003	$ (1,639)	$ 2,086	$ (1)	$ 7,037
Net income	—	—	379	—	—	379
Common stock dividends	—	—	—	(105)	—	(105)
Allocation of tax benefit from parent	—	11	—	—	—	11
Appropriation of retained earnings for future dividends	—	—	(379)	379	—	—
Other comprehensive income, net of income taxes of $0	—	—	—	—	1	1
Balance, December 31, 2012	$ 1,588	$5,014	$ (1,639)	$ 2,360	$ —	$ 7,323
Net income	—	—	249	—	—	249
Common stock dividends	—	—	—	(220)	—	(220)
Parent tax matter indemnification	—	176	—	—	—	176
Appropriation of retained earnings for future dividends	—	—	(249)	249	—	—
Balance, December 31, 2013	$ 1,588	$5,190	$ (1,639)	$ 2,389	$ —	$ 7,528
Net income	—	—	408	—	—	408
Common stock dividends	—	—	—	(307)	—	(307)
Contribution from parent	—	273	—	—	—	273
Parent tax matter indemnification	—	5	—	—	—	5
Appropriation of retained earnings for future dividends	—	—	(408)	408	—	—
Balance, December 31, 2014	$ 1,588	$5,468	$ (1,639)	$ 2,490	$ —	$ 7,907

See the Combined Notes to Consolidated Financial Statements

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PECO Energy Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2014	2013	2012
Operating revenues			
Operating revenues	$3,092	$3,099	$3,183
Operating revenues from affiliates	2	1	3
Total operating revenues	3,094	3,100	3,186
Operating expenses			
Purchased power and fuel	1,067	908	842
Purchased power from affiliate	194	392	533
Operating and maintenance	767	647	698
Operating and maintenance from affiliates	99	101	111
Depreciation and amortization	236	228	217
Taxes other than income	159	158	162
Total operating expenses	2,522	2,434	2,563
Operating income	572	666	623
Other income and (deductions)			
Interest expense	(101)	(103)	(111)
Interest expense to affiliates, net	(12)	(12)	(12)
Other, net	7	6	8
Total other income and (deductions)	(106)	(109)	(115)
Income before income taxes	466	557	508
Income taxes	114	162	127
Net income	352	395	381
Preferred security dividends and redemption	—	7	4
Net income attributable to common shareholder	352	388	377
Comprehensive income, net of income taxes			
Net income	352	395	381
Other comprehensive income			
Unrealized gain on marketable securities, net of income taxes of $0, $0 and $0, respectively	—	—	1
Other comprehensive income	—	—	1
Comprehensive income	$ 352	$ 395	$ 382

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2014	2013	2012
Cash flows from operating activities			
Net income	$ 352	$ 395	$ 381
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	236	228	217
Deferred income taxes and amortization of investment tax credits	88	20	37
Other non-cash operating activities	92	108	125
Changes in assets and liabilities:			
Accounts receivable	(16)	(79)	(14)
Receivables from and payables to affiliates, net	(6)	(18)	13
Inventories	2	2	21
Accounts payable, accrued expenses and other current liabilities	54	41	(47)
Income taxes	(57)	87	174
Pension and non-pension postretirement benefit contributions	(16)	(31)	(45)
Other assets and liabilities	(17)	(6)	16
Net cash flows provided by operating activities	712	747	878
Cash flows from investing activities			
Capital expenditures	(661)	(537)	(422)
Changes in intercompany money pool	—	—	82
Change in restricted cash	—	(2)	2
Other investing activities	12	8	10
Net cash flows used in investing activities	(649)	(531)	(328)
Cash flows from financing activities			
Payment of accounts receivable agreement	—	(210)	(15)
Issuance of long-term debt	300	550	350
Retirement of long-term debt	(250)	(300)	(375)
Contributions from parent	24	27	9
Dividends paid on common stock	(320)	(332)	(343)
Dividends paid on preferred securities	—	(1)	(4)
Redemption of preferred securities	—	(93)	—
Other financing activities	(4)	(2)	(4)
Net cash flows used in financing activities	(250)	(361)	(382)
Increase (decrease) in cash and cash equivalents	(187)	(145)	168
Cash and cash equivalents at beginning of period	217	362	194
Cash and cash equivalents at end of period	$ 30	$ 217	$ 362

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2014	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 30	$ 217
Restricted cash and cash equivalents	2	2
Accounts receivable, net		
Customer	320	360
Other	141	104
Receivables from affiliates	3	3
Inventories, net		
Fossil fuel	57	60
Materials and supplies	22	21
Deferred income taxes	69	83
Prepaid utility taxes	10	3
Regulatory assets	29	17
Other	31	36
Total current assets	714	906
Property, plant and equipment, net	6,801	6,384
Deferred debits and other assets		
Regulatory assets	1,529	1,448
Investments	31	31
Receivable from affiliates	490	447
Prepaid pension asset	344	363
Other	34	38
Total deferred debits and other assets	2,428	2,327
Total assets	$9,943	$9,617

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2014	2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ —	$ 250
Accounts payable	337	285
Accrued expenses	91	106
Payables to affiliates	52	58
Customer deposits	52	49
Regulatory liabilities	90	106
Other	31	37
Total current liabilities	653	891
Long-term debt	2,246	1,947
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,671	2,487
Asset retirement obligations	29	29
Non-pension postretirement benefits obligations	287	286
Regulatory liabilities	657	629
Other	95	99
Total deferred credits and other liabilities	3,739	3,530
Total liabilities	6,822	6,552
Commitments and contingencies		
Shareholders' equity		
Common stock	2,439	2,415
Retained earnings	681	649
Accumulated other comprehensive income, net	1	1
Total shareholders' equity	3,121	3,065
Total liabilities and shareholders' equity	$9,943	$9,617

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Changes in Stockholders' Equity

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2011	$ 2,379	$ 559	$ —	$ 2,938
Net income	—	381	—	381
Common stock dividends	—	(343)	—	(343)
Preferred security dividends	—	(4)	—	(4)
Allocation of tax benefit from parent	9	—	—	9
Other comprehensive income, net of income taxes of $0	—	—	1	1
Balance, December 31, 2012	$ 2,388	$ 593	$ 1	$ 2,982
Net income	—	395	—	395
Common stock dividends	—	(332)	—	(332)
Preferred security dividends	—	(1)	—	(1)
Redemption of Preferred Dividends	—	(6)	—	(6)
Allocation of tax benefit from parent	27	—	—	27
Balance, December 31, 2013	$ 2,415	$ 649	$ 1	$ 3,065
Net income	—	352	—	352
Common stock dividends	—	(320)	—	(320)
Allocation of tax benefit from parent	24	—	—	24
Balance, December 31, 2014	$ 2,439	$ 681	$ 1	$ 3,121

See the Combined Notes to Consolidated Financial Statements

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Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2014	2013	2012
Operating revenues			
Operating revenues	$3,140	$3,052	$2,725
Operating revenues from affiliates	25	13	10
Total operating revenues	3,165	3,065	2,735
Operating expenses			
Purchased power and fuel	1,035	969	973
Purchased power from affiliate	382	452	396
Operating and maintenance	614	551	622
Operating and maintenance from affiliates	103	83	106
Depreciation and amortization	371	348	298
Taxes other than income	221	213	208
Total operating expenses	2,726	2,616	2,603
Operating income	439	449	132
Other income and (deductions)			
Interest expense	(90)	(106)	(128)
Interest expense to affiliates, net	(16)	(16)	(16)
Other, net	18	17	23
Total other income and (deductions)	(88)	(105)	(121)
Income before income taxes	351	344	11
Income taxes	140	134	7
Net income	211	210	4
Preference stock dividends	13	13	13
Net income (loss) attributable to common shareholder	$ 198	$ 197	$ (9)
Comprehensive income	$ 211	$ 210	$ 4

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2014	2013	2012
Cash flows from operating activities			
Net income	$ 211	$ 210	$ 4
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	371	348	298
Deferred income taxes and amortization of investment tax credits	116	125	104
Other non-cash operating activities	180	153	193
Changes in assets and liabilities:			
Accounts receivable	46	(127)	(45)
Receivables from and payables to affiliates, net	(1)	(14)	26
Inventories	(6)	1	25
Accounts payable, accrued expenses and other current liabilities	(70)	(14)	(33)
Counterparty collateral received, net	27	—	—
Income taxes	45	(33)	14
Pension and non-pension postretirement benefit contributions	(16)	(24)	(16)
Other assets and liabilities	(163)	(64)	(85)
Net cash flows provided by operating activities	740	561	485
Cash flows from investing activities			
Capital expenditures	(620)	(587)	(582)
Change in restricted cash	(22)	2	—
Other investing activities	20	14	9
Net cash flows used in investing activities	(622)	(571)	(573)
Cash flows from financing activities			
Changes in short-term borrowings	(15)	135	—
Issuance of long-term debt	—	300	250
Retirement of long-term debt	(70)	(467)	(173)
Dividends paid on preference stock	(13)	(13)	(13)
Contributions from parent	—	—	66
Other financing activities	13	(3)	(2)
Net cash flows (used in) provided by financing activities	(85)	(48)	128
Increase (decrease) in cash and cash equivalents	33	(58)	40
Cash and cash equivalents at beginning of period	31	89	49
Cash and cash equivalents at end of period	$ 64	$ 31	$ 89

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2014	2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 64	$ 31
Restricted cash and cash equivalents	50	28
Accounts receivable, net		
Customer	390	480
Other	82	114
Income taxes receivable	—	30
Inventories, net		
Gas held in storage	57	53
Materials and supplies	30	28
Deferred income taxes	6	2
Prepaid utility taxes	59	57
Regulatory assets	214	181
Other	5	7
Total current assets	957	1,011
Property, plant and equipment, net	6,204	5,864
Deferred debits and other assets		
Regulatory assets	510	524
Investments	12	13
Prepaid pension asset	370	423
Other	25	26
Total deferred debits and other assets	917	986
Total assets [(a)]	$8,078	$7,861

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2014	2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 120	$ 135
Long-term debt due within one year	75	70
Accounts payable	215	270
Accrued expenses	131	111
Deferred income taxes	52	27
Payables to affiliates	66	55
Customer deposits	92	76
Regulatory liabilities	44	48
Other	51	35
Total current liabilities	846	827
Long-term debt	1,867	1,941
Long-term debt to financing trust	258	258
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,865	1,773
Asset retirement obligations	17	19
Non-pension postretirement benefits obligations	212	217
Regulatory liabilities	200	204
Other	60	67
Total deferred credits and other liabilities	2,354	2,280
Total liabilities [(a)]	5,325	5,306
Commitments and contingencies		
Shareholders' equity		
Common stock	1,360	1,360
Retained earnings	1,203	1,005
Total shareholders' equity	2,563	2,365
Preference stock not subject to mandatory redemption	190	190
Total equity	2,753	2,555
Total liabilities and shareholders' equity	$8,078	$7,861

(a) BGE's consolidated assets include $24 million and $31 million at December 31, 2014 and December 31, 2013, respectively, of BGE's consolidated VIE that can only be used to settle the liabilities of the VIE. BGE's consolidated liabilities include $197 million and $269 million at December 31, 2014 and December 31, 2013, respectively, of BGE's consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note 2—Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statement of Changes in Shareholders' Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2011	$ 1,294	$ 817	$ 2,111	$ 190	$2,301
Net income	—	4	4	—	4
Preference stock dividends	—	(13)	(13)	—	(13)
Contribution from parent	66	—	66	—	66
Balance, December 31, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$2,358
Net income	—	210	210	—	210
Preference stock dividends	—	(13)	(13)	—	(13)
Balance, December 31, 2013	$ 1,360	$ 1,005	$ 2,365	$ 190	$2,555
Net income	—	211	211	—	211
Preference stock dividends	—	(13)	(13)	—	(13)
Balance, December 31, 2014	$ 1,360	$ 1,203	$ 2,563	$ 190	$2,753

See the Combined Notes to Consolidated Financial Statements

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)

Index to Combined Notes to Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the registrants to which the footnotes apply:

Applicable Notes

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Exelon Corporation	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Exelon Generation Company, LLC	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•		•		•	•	•	•	•	•
Commonwealth Edison Company	•	•	•	•		•	•			•	•	•	•	•	•	•	•	•	•			•	•	•	•	•
PECO Energy Company	•	•	•	•		•	•		•	•	•	•	•	•	•	•	•	•	•		•	•	•	•	•	•
Baltimore Gas And Electric Company	•	•	•	•		•	•		•		•	•	•	•	•	•	•	•	•			•	•	•	•	•

1. Significant Accounting Policies (Exelon, Generation, ComEd, PECO and BGE)

Description of Business (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses. Prior to March 12, 2012, Exelon's principal subsidiaries included ComEd, PECO and Generation. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger ("Merger Agreement"). As a result of the merger transaction, Generation now includes the former Constellation generation and customer supply operations. BGE, formerly Constellation's regulated utility subsidiary, is now a subsidiary of Exelon. Refer to Note 4—Mergers, Acquisitions, and Dispositions for further information regarding the merger transaction.

On April 1, 2014, Generation assumed the operating licenses and corresponding operational control of CENG's nuclear fleet. As a result, Exelon and Generation consolidated CENG's financial position and results of operations into their businesses. Prior to April 1, 2014, Exelon and Generation accounted for CENG as an equity method investment. Refer to Note 5—Investment in Constellation Energy Nuclear Group, LLC for further information regarding the integration transaction.

The energy generation business includes:

- *Generation* : Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other regions.

The energy delivery businesses include:

- *ComEd* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

This is a combined annual report of Exelon, Generation, ComEd, PECO and BGE. The Notes to the Consolidated Financial Statements apply to Exelon, Generation, ComEd, PECO and BGE as indicated parenthetically next to each corresponding disclosure. When appropriate, Exelon, Generation, ComEd, PECO and BGE are named specifically for their related activities and disclosures.

Exelon did not apply push-down accounting to BGE and BGE continued to be subject to reporting requirements as an SEC registrant. The information disclosed for BGE represents the activity of the standalone entity for the twelve months ended December 31, 2014, 2013 and 2012 and the financial position as of December 31, 2014 and December 31, 2013. However, for Exelon's consolidated financial reporting, Exelon is reporting BGE activity from the acquisition date of March 12, 2012 through December 31, 2014.

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC, including support services, are directly charged or allocated to the applicable subsidiaries using a cost-causative allocation method. Corporate governance-type costs that cannot be directly assigned are allocated based on a Modified Massachusetts Formula, which is a method that utilizes a combination of gross revenues, total assets and direct labor costs for the allocation base. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

Exelon owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%, and BGE, of which Exelon owns 100% of the common stock but none of BGE's preference stock. Exelon owned none of PECO's preferred securities, which PECO redeemed in 2013. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2014 and December 31, 2013, as equity, PECO's preferred securities as preferred securities of subsidiary through their redemption in 2013, and BGE's preference stock as BGE preference stock not subject to mandatory redemption in its consolidated financial statements. BGE is subject to some ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for certain Exelon Wind projects, of which Generation holds a majority interest of 99% for certain periods of time, and CENG, of which Generation holds a 50.01% interest. The remaining interests are included in noncontrolling interest on Exelon's and Generation's Consolidated Balance Sheets. See Note 2—Variable Interest Entities for further discussion of Exelon's and Generation's VIEs and the reversionary interests of the noncontrolling members for these certain subsidiaries.

ComEd owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for RITELine Illinois, LLC, of which ComEd owns 75% and an additional12.5% is indirectly owned by Exelon. Exelon and ComEd have reflected the third-party interests of 12.5% and 25%, respectively, in RITELine Illinois, LLC, which both totaled less than $1 million at December 31, 2014 and December 31, 2013, as equity.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Exelon consolidates the accounts of entities in which Exelon has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which Exelon can exercise control over the operations and policies of the investee, or the results of a model that identifies Exelon or one of its subsidiaries as the primary beneficiary of a VIE. Where Exelon does not have a controlling financial interest in an entity, it applies proportional consolidation, equity method accounting or cost method accounting. Exelon applies proportionate consolidation when it has an undivided interest in an asset and is proportionately liable for its share of each liability associated with the asset. Exelon proportionately consolidates its undivided ownership interests in jointly owned electric plants and transmission facilities, as well as its undivided ownership interests in Upstream natural gas exploration and production activities. Under proportionate consolidation, Exelon separately records its proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. Exelon applies equity method accounting when it has significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. Exelon applies equity method accounting to certain investments and joint ventures, including certain financing trusts of ComEd, PECO, and BGE. Under the equity method, Exelon reports its interest in the entity as an investment and Exelon's percentage share of the earnings from the entity as single line items in its financial statements. Exelon uses the cost method if it holds less than 20% of the common stock of an entity. Under the cost method, Exelon reports its investment at cost and recognizes income only to the extent Exelon receives dividends or distributions.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (Exelon, Generation, ComEd, PECO and BGE)

The preparation of financial statements of each of the Registrants in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other AROs, pension and other postretirement benefits, the application of purchase accounting, inventory reserves, allowance for uncollectible accounts, goodwill and asset impairments, derivative instruments, unamortized energy contracts, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Reclassifications (Exelon, Generation, ComEd, PECO and BGE)

Certain prior year amounts in the registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows have been reclassified between line items for comparative purposes. The reclassifications did not affect any of the Registrants' net income, financial positions, or cash flows from operating activities.

Accounting for the Effects of Regulation (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulation, which requires ComEd, PECO and BGE to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria: 1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

that rates are set at levels that will recover the entities' costs from customers. Exelon, ComEd, PECO and BGE account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, the PAPUC, and the MDPSC, in the cases of ComEd, PECO and BGE, respectively, under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the Consolidated Statements of Operations consistent with the recovery or refund included in customer rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. However, Exelon, ComEd, PECO and BGE continue to evaluate their respective abilities to apply the authoritative guidance for accounting for certain types of regulation, including consideration of current events in their respective regulatory and political environments. If a separable portion of ComEd's, PECO's or BGE's business was no longer able to meet the criteria discussed above, the affected entities would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which could have a material impact on their results of operations and financial positions. See Note 3—Regulatory Matters for additional information.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Revenues (Exelon, Generation, ComEd, PECO and BGE)

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimates of the distribution and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE records its best estimate of the transmission revenue impact resulting from changes in rates that BGE believes are probable of approval by FERC in accordance with its formula rate mechanism. See Note 3—Regulatory Matters and Note 6—Accounts Receivable for further information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Company in the different RTOs and ISOs.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. As of the Constellation merger date, Exelon and Generation have currently elected to de-designate all of their commodity cash flow hedge positions. As ComEd receives full cost recovery for energy procurement and related costs from retail customers, ComEd records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. Refer to Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments for further information.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Proprietary Trading Activities. Exelon and Generation account for Generation's trading activities under the provisions of the authoritative guidance for accounting for contracts involved in energy trading and risk management activities, which require energy revenues and costs related to energy trading contracts to be presented on a net basis in the income statement. Commodity derivatives used for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues. Refer to Note 12—Derivative Financial Instruments for further information.

Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

Deferred Federal and state income taxes are provided on all significant temporary differences between the book basis and the tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred on the Registrants' Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion; and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Registrants recognize accrued interest related to unrecognized tax benefits in Interest expense or Other income and deductions (interest income) on their Consolidated Statements of Operations and Comprehensive Income.

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 14—Income Taxes for further information.

Taxes Directly Imposed on Revenue-Producing Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, such as gross receipts taxes or other surcharges or fees, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 23—Supplemental Financial Information for Generation's, ComEd's, PECO's and BGE's utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE)

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Restricted Cash and Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE)

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2014 and 2013, Exelon Corporate's restricted cash and cash equivalents primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Additionally, as of December 31, 2014 and 2013, Generation's restricted cash and cash equivalents primarily included cash at Antelope Valley required for debt service and construction and cash at Continental Wind and ExGen Texas Power, which is required for debt service and financing of operation and maintenance of the underlying entities. As of December 31, 2014 and 2013, ComEd's restricted cash primarily represented cash collateral held from suppliers associated with ComEd's energy and REC procurement contracts. As of December 31, 2014, PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's mortgage indenture. As of December 31, 2014 and 2013, BGE's restricted cash primarily represented funds restricted at its consolidated variable interest entity for repayment of rate stabilization bonds and cash collateral held from suppliers.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2014 and 2013, Exelon's and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2014, Exelon, Generation, ComEd, PECO and BGE had investments in Rabbi trusts classified as noncurrent assets.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging, historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. At December 31, 2013, BGE estimated the allowance for uncollectible accounts on customer receivables by assigning a reserve factor for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. At December 31, 2014, BGE changed to a methodology for estimating the allowance for uncollectible accounts, which was consistent with ComEd and PECO, as described above. For additional information regarding the change in estimate, refer to Note 6—Accounts Receivable. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 3—Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and
- requires the entity that consolidates a VIE (the primary beneficiary) to disclose (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

Based on the above accounting guidance, Exelon has adopted the following policies related to variable interest entities:

- Exelon has disclosed, to the extent material, the assets of its consolidated VIEs that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of Exelon's consolidated VIEs for which creditors do not have recourse to Exelon's general credit.
- Exelon has qualitatively assessed whether the equity holders of the entity have the power to direct matters that most significantly impact the entity.

See Note 2—Variable Interest Entities for additional information.

Inventories (Exelon, Generation, ComEd, PECO and BGE)

Inventory is recorded at the lower of weighted average cost or market. Provisions are recorded for excess and obsolete inventory.

Fossil Fuel. Fossil fuel inventory includes the weighted average costs of stored natural gas, propane, coal and oil. The costs of natural gas, propane, coal and oil are generally included in inventory when purchased and charged to fuel expense when used or sold.

Materials and Supplies. Materials and supplies inventory generally includes the weighted average costs of transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and expensed or capitalized to property, plant and equipment, as appropriate, when installed or used.

Emission Allowances. Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) and are carried at the lower of weighted average cost or market and charged to fuel expense as they are used in operations.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Marketable Securities (Exelon, Generation, ComEd, PECO and BGE)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds, certain Generation Rabbi trust investments and BGE's Rabbi trust investments are classified as trading securities and all other securities are classified as available-for-sale securities. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the Regulatory Agreement Units are included in regulatory liabilities at Exelon, ComEd and PECO and in noncurrent payables to affiliates at Generation and in noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the Non-Regulatory Agreement Units are included in earnings at Exelon and Generation. Realized and unrealized gains and losses, net of tax, on certain Generation Rabbi trust investments and BGE's Rabbi trust investments are included in earnings at Exelon, Generation and BGE. Unrealized gains and losses, net of tax, for Generation's, ComEd's and PECO's available-for-sale securities are reported in OCI. Any decline in the fair value of ComEd's and PECO's available-for-sale securities below the cost basis is reviewed to determine if such decline is other-than-temporary. If the decline is determined to be other-than-temporary, the cost basis of the available-for-sale securities is written down to fair value as a new cost basis and the amount of the write-down is included in earnings. See Note 15—Asset Retirement Obligations for information regarding marketable securities held by NDT funds and Note 23—Supplemental Financial Information for additional information regarding ComEd's and PECO's regulatory assets and liabilities.

Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

Property, plant and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. ComEd, PECO and BGE also include indirect construction costs including labor and related costs of departments associated with supporting construction activities. When appropriate, original cost also includes capitalized interest for Generation and Exelon Corporate and AFUDC for regulated property at ComEd, PECO and BGE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred.

Third parties reimburse ComEd, PECO and BGE for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, Plant and Equipment. DOE SGIG funds reimbursed to PECO and BGE are accounted for as CIAC.

For Generation, upon retirement, the cost of property is charged to accumulated depreciation in accordance with the composite method of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to operating and maintenance expense as incurred.

For ComEd, PECO and BGE, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. ComEd's and BGE's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. ComEd's and BGE's actual incurred removal costs are applied against a related regulatory liability. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation's oil and gas exploration and production activities consist of working interests in gas producing fields. Generation accounts for these activities under the successful efforts method of accounting. Acquisition, development and exploration costs are capitalized. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

See Note 7—Property, Plant and Equipment, Note 9—Jointly Owned Electric and Note 23—Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within property, plant and equipment and charged to fuel expense using the unit-of-production method. Prior to May 16, 2014, the estimated disposal cost of SNF was established per the Standard Waste Contract with the DOE and was expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. Effective May 16, 2014, the SNF disposal fee was set to zero by the DOE and Exelon and Generation are not accruing any further costs related to SNF disposal fees until a new fee structure goes into effect. On-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 22—Commitments and Contingencies for additional information regarding the SNF disposal fee.

Nuclear Outage Costs (Exelon and Generation)

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to operating and maintenance expense or capitalized to property, plant and equipment (based on the nature of the activities) in the period incurred.

New Site Development Costs (Exelon and Generation)

New site development costs represent the costs incurred in the assessment and design of new power generating facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management's determination that the project is economically and operationally feasible, management and/or the Exelon board of directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. Capitalized development costs are charged to Operating and maintenance expense when project completion is no longer probable. At December 31, 2014 and 2013, there were not material capitalized development costs for projects not yet under construction included in Property, plant and equipment, net on Exelon's and Generation's Consolidated Balance Sheets. Approximately $13 million, $10 million and $4 million of costs were expensed by Exelon and Generation for the years ended December 31, 2014, 2013, and 2012, respectively. These costs primarily related to the possible development of new renewable energy projects.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Capitalized Software Costs (Exelon, Generation, ComEd, PECO and BGE)

Costs incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

Net unamortized software costs	Exelon [a]	Generation [a]	ComEd	PECO	BGE
December 31, 2014	$ 596	$ 193	$ 133	$ 84	$ 163
December 31, 2013	479	129	101	71	155

Amortization of capitalized software costs	Exelon [a][b]	Generation [a][b]	ComEd	PECO	BGE [b]
2014	$ 186	$ 59	$ 45	$ 28	$ 43
2013	198	67	52	33	36
2012	208	81	56	30	32

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's financial position and results of operations beginning April 1, 2014.
(b) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the year ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012. BGE activity represents the activity for the year ended December 31, 2012.

Depreciation, Depletion and Amortization (Exelon, Generation, ComEd, PECO and BGE)

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method. ComEd's and BGE's depreciation includes a provision for estimated removal costs as authorized by the respective regulators. The estimated service lives for ComEd, PECO and BGE are primarily based on the average service lives from the most recent depreciation study for each respective company. The estimated service lives of the nuclear-fuel generating facilities are based on the remaining useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses (to the extent that such renewal has not yet been granted) for all of Generation's operating nuclear generating stations except for Oyster Creek. The estimated service lives of the hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the operating licenses. The estimated service lives of the fossil fuel and other renewable generating facilities are based on the remaining useful lives of the stations, which Generation periodically evaluates based on feasibility assessments taking into account economic and capital requirement considerations.

See Note 7—Property, Plant and Equipment for further information regarding depreciation.

Depletion of oil and gas exploration and production activities is recorded using the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for oil and gas reserves are based on internal calculations.

Amortization of regulatory assets and liabilities are recorded over the recovery or refund period specified in the related legislation or regulatory agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost or income would

have originally been recorded in the Registrants' Consolidated Statements of Operations and Comprehensive Income. With exception of income tax-related regulatory assets, generally, when the recovery period is more than one year, the amortization is recorded to Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income. Amortization of ComEd's distribution formula rate regulatory asset and ComEd's and BGE's transmission formula rate regulatory assets is recorded to Operating revenues. Amortization of income tax related regulatory assets and liabilities is generally recorded to Income tax expense. With the exception of the regulatory assets and liabilities discussed above, when the recovery period is more than one year, the amortization is recorded to Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

See Note 3—Regulatory Matters and Note 23—Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of ComEd's, PECO's and BGE's regulatory assets.

Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years. The liabilities associated with Exelon's non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years. Changes to the recorded value of an ARO result from the passage of new laws and regulations, revisions to either the timing or amount of estimates of undiscounted cash flows, and estimates of cost escalation factors. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through a charge to operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income or, in the case of the majority of ComEd's, PECO's, and BGE's accretion, through an increase to regulatory assets. See Note 15—Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (Exelon, Generation, ComEd, PECO and BGE)

During construction, Exelon and Generation capitalize the costs of debt funds used to finance non-regulated construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense.

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to AFUDC that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table summarizes total incurred interest, capitalized interest and credits to AFUDC by year:

		Exelon [a][b]	Generation [a][b]	ComEd	PECO	BGE [b]
2014	Total incurred interest [c]	$ 1,144	$ 419	$ 323	$115	$ 118
	Capitalized interest	63	63	—	—	—
	Credits to AFUDC debt and equity	37	—	5	8	24
2013	Total incurred interest [c]	$ 1,423	$ 411	$ 584	$117	$ 129
	Capitalized interest	54	54	—	—	—
	Credits to AFUDC debt and equity	35	—	16	6	13
2012	Total incurred interest [c]	$ 1,003	$ 368	$ 310	$125	$ 149
	Capitalized interest	67	67	—	—	—
	Credits to AFUDC debt and equity	25	—	9	6	15

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's financial position and results of operations beginning April 1, 2014.
(b) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the year ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012. BGE activity represents the activity for the year ended December 31, 2012.
(c) Includes interest expense to affiliates.

Guarantees (Exelon, Generation, ComEd, PECO and BGE)

The Registrants recognize, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken in issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 22—Commitments and Contingencies for additional information.

Asset Impairments (Exelon, Generation, ComEd, PECO and BGE)

Long-Lived Assets. The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, current energy prices and market conditions, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. The Registrants determine if long-lived assets and asset groups are impaired by comparing their undiscounted expected future cash flows to their carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value less costs to sell.

Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generating units are generally evaluated at a regional portfolio level along with cash flows generated from the customer supply and risk management activities, including cash flows

from contracts that are accounted for as intangible contract assets and liabilities recorded on the balance sheet. In certain cases, generation assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables). See Note 8—Impairment of Long-Lived Assets for additional information.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 10—Intangible Assets for additional information regarding Exelon's, Generation's and ComEd's goodwill.

Equity Method Investments. Exelon and Generation regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other than temporary in nature. Additionally, if the project in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other than temporary decline in value.

Direct Financing Lease Investments. Direct financing lease investments represent the estimated residual values of leased coal-fired plants in Georgia. Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. See Note 8—Impairment of Long-Lived Assets for additional information.

Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For derivative contracts intended to serve as economic hedges and that are not designated or do not qualify for hedge accounting or the normal purchases and normal sales exception, changes in the fair value of the derivatives are recognized in earnings each period. Amounts classified in earnings are included in revenue, purchased power and fuel, interest expense or other, net on the Consolidated Statement of Operations based on the activity the transaction is economically hedging. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon's Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. All amounts classified in earnings related to proprietary trading are included in revenue on the Consolidated Statement of Operations. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

Combined Notes to Consolidated Financial Statements—(Continued)
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For commodity derivative contracts Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the Constellation merger. Because the underlying forecasted transactions remained probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred. The effect of this decision is that all derivatives executed to hedge economic risk related to commodities are recorded at fair value with changes in fair value recognized through earnings for the combined company.

As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See Note 12—Derivative Financial Instruments for additional information.

Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. Effective July 14, 2014, Exelon became the sponsor of all of CENG's pension and other postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 16—Retirement Benefits for additional discussion of Exelon's accounting for retirement benefits.

Equity Investment Earnings (Losses) of Unconsolidated Affiliates (Exelon and Generation)

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities, power projects and joint ventures, in equity in earnings (losses) of unconsolidated affiliates. Equity in earnings (losses) of unconsolidated affiliates also includes any adjustments to amortize the difference, if any, except for goodwill and land, between their cost in an equity method investment and the underlying equity in net assets of the investee at the date of investment.

Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such investment experiences an other than temporary decline in value.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

Exelon has identified the following new accounting pronouncements that have been recently adopted or issued that management believes may significantly affect the Registrants.

Presentation of Unrecognized Tax Benefits When Net Operating Loss Carryforwards, Similar Tax Losses or Tax Credit Carryforwards Exist

In July 2013, the FASB issued authoritative guidance requiring entities to present unrecognized tax benefits as a reduction to deferred tax assets for losses or other tax carryforwards that would be available to offset the uncertain tax positions at the reporting date. This guidance was effective for the Registrants for periods beginning after December 15, 2013 and was required to be applied prospectively. The adoption of this standard had an immaterial effect on the presentation of deferred tax assets at Exelon and Generation and no effect on ComEd, PECO and BGE. There was no effect on the Registrants' results of operations or cash flows.

Pushdown Accounting (a consensus of the FASB Emerging Issues Task Force)

In November 2014, the FASB issued authoritative guidance that allows acquired entities to apply pushdown accounting (i.e., reflecting the acquirer's basis of accounting for the acquired entity's assets and liabilities) when an acquirer obtains control of them. At the same time, the SEC rescinded its guidance on pushdown accounting. The SEC's guidance had required pushdown accounting in certain circumstances, made it optional in others and prevented it in still other circumstances. The new guidance is effective immediately for any future transaction or to the most recent event in which an acquirer obtains or obtained control of the acquired entity. The adoption of the guidance had no impact to the financial statements of the Registrants; however, the Registrants will assess the potential impact of the guidance on future acquisitions.

The following recently issued accounting standard is not yet required to be reflected in the combined financial statements of the Registrants.

Revenue from Contracts with Customers

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. The new guidance replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing and uncertainty of revenue and the related cash flows. The guidance is effective for the Registrants for the first interim period within annual reporting periods beginning on or after December 15, 2016. Early adoption is not permitted. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their financial positions, results of operations, cash flows and disclosures as well as the transition method that they will use to adopt the guidance.

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2. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Under the applicable authoritative guidance, a VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly affect the entity's economic performance.

At December 31, 2014 and 2013, Exelon, Generation, and BGE collectively consolidated six and four VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary. As of December 31, 2014 and 2013, the Registrants had significant interests in six and eight other VIEs, respectively, for which the Registrants do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary.

Consolidated Variable Interest Entities

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the Registrants' consolidated financial statements at December 31, 2014 and 2013 are as follows:

	December 31, 2014			December 31, 2013		
	Exelon [a][b]	Generation [b]	BGE	Exelon [a]	Generation	BGE
Current assets	$ 1,271	$ 1,242	$ 21	$ 484	$ 446	$ 28
Noncurrent assets	7,580	7,566	3	1,905	1,884	3
Total assets	$ 8,851	$ 8,808	$ 24	$ 2,389	$ 2,330	$ 31
Current liabilities	$ 611	$ 526	$ 77	$ 566	$ 481	$ 74
Noncurrent liabilities	2,730	2,600	120	774	562	195
Total liabilities	$ 3,341	$ 3,126	$197	$ 1,340	$ 1,043	$269

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total assets of $6.1 billion and total liabilities of $2.1 billion due to the consolidation of CENG. See Note 5— Investment in Constellation Energy Nuclear Group, LLC for additional information.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the table can only be settled using VIE resources.

Exelon, Generation and BGE's consolidated VIEs consist of:

RSB BondCo LLC. In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. BGE has determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE consolidates BondCo.

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(Dollars in millions, except per share data unless otherwise noted)

BondCo's assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2014, 2013, and 2012, BGE remitted $85 million, $83 million, and $85 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2014. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

Retail Gas Group. During 2009, Constellation formed two new entities, which now are part of Generation, and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third-party gas supplier. While Generation owns 100% of these entities, it has been determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group's activities without the additional credit support that is provided in the form of a parental guarantee. Generation is the primary beneficiary of the retail gas entity group; accordingly, Generation consolidates the retail gas entity group as a VIE.

The third-party gas supply arrangement is collateralized as follows:

- The assets of the retail gas entity group must be used to settle obligations under the third-party gas supply agreement before it can make any distributions to Generation,
- The third-party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- Generation provides a $75 million parental guarantee to the third-party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee, Exelon or Generation do not have any contractual or other obligations to provide additional financial support under the collateralized third-party gas supply agreement. The third-party gas supply creditors do not have any recourse to Exelon's or Generation's general credit other than the parental guarantee.

Solar Project Entity Group. In 2011, Constellation formed a group of solar project limited liability companies to build, own, and operate solar power facilities, which are now part of Generation. Additionally, on September 30, 2011, Generation acquired all of the equity interests in Antelope Valley Solar Ranch One (Antelope Valley) from First Solar, Inc., a 242-MW solar PV project under construction in northern Los Angeles County, California. While Generation owns 100% of these entities, it has been determined that certain of the individual solar project entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the solar project entities that qualify as VIEs because Generation controls the design, construction, and operation of the solar power facilities. Generation provides operating and capital funding to the solar entities for ongoing construction, operations and maintenance of the solar power facilities and provides limited recourse related to the Antelope Valley project. In addition, these solar VIE entities have an aggregate amount of outstanding debt with third parties of $642 million, as of December 31, 2014, for which the creditors have no

recourse to Generation, however there is limited recourse to Generation with respect to remaining equity contributions necessary to complete the Antelope Valley project. For additional information on these project-specific financing arrangements refer to Note 13—Debt and Credit Agreements.

Retail Power Companies. In March 2014, Generation began consolidating retail power VIEs for which Generation is the primary beneficiary as a result of energy supply contracts that give Generation the power to direct the activities that most significantly affect the economic performance of the entities. Generation does not have an equity ownership interest in these entities, but provides approximately $5 million in credit support for the retail power companies. These entities are included in Generation's consolidated financial statements, and the consolidation of the VIEs does not have a material impact on Generation's financial results or financial condition.

Wind Project Entity Group. Generation owns and operates a number of wind project limited liability entities, the majority of which were acquired on December 9, 2010 with the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind). Generation has evaluated the significant agreements and ownership structures and the risks of each of its wind projects and underlying entities, and determined that certain of the entities are VIEs because either the projects have noncontrolling equity interest holders that absorb variability from the wind projects, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the wind project entities that qualify as VIEs because Generation controls the design, construction, and operation of the wind generation facilities. While Generation owns 100% of the majority of the wind project entities, nine of the projects have noncontrolling equity interests of 1% held by third parties. Generation's current economic interests in eight of these projects is significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the noncontrolling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the noncontrolling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the noncontrolling interests state that Generation is to provide financial support to the projects in proportion to its current 99% economic interests in the projects. However, no additional support to these projects beyond what was contractually required has been provided during 2014. As of December 31, 2014, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of the wind VIE entities primarily relates to the wind generating assets, PPA intangible assets and working capital amounts.

CENG. Through March 31, 2014, CENG was operated as a joint venture with EDF Inc. (EDFI) (a subsidiary of EDF) and was governed by a board of ten directors, five of which were appointed by Generation and five by EDF. CENG was designed to operate under joint and equal control of Generation and EDFI through the Board of Directors, subject to the Chairman of the Board's final decision making authority on certain special matters; therefore, CENG was not subject to VIE guidance. Accordingly, Generation's 50.01% interest in CENG was accounted for as an equity method investment. On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the Nuclear Operating Services Agreement (NOSA) pursuant to which Generation now conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDFI. As a result of executing the NOSA, CENG now qualifies as a VIE due to the disproportionate relationship between Generation's 50.01% equity ownership interest and its role in conducting the operational activities of CENG and the CENG fleet conveyed through the NOSA. Further, since Generation is conducting the operational activities of CENG and the CENG fleet, Generation qualifies as the primary beneficiary of CENG and,

therefore, is required to consolidate the financial position and results of operations of CENG. On April 1, 2014, Exelon and Generation derecognized Generation's equity method investment in CENG and reflected all assets, liabilities, and the EDFI noncontrolling interest in CENG at fair value on the consolidated balance sheets of Exelon and Generation, resulting in the recognition of a $261 million gain in their respective Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2014. For additional information on this transaction refer to Note 5—Investment in Constellation Energy Nuclear Group, LLC.

Generation and Exelon, where indicated, provide the following support to CENG (See Note 25—Related Party Transactions and Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information regarding Generation and Exelon's transactions with CENG):

- under the NOSA, Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life and decommissioning of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDFI,
- under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management, and billing services to the CENG fleet for the remaining operating life of the CENG nuclear plants,
- under power purchase agreements with CENG, Generation purchased 85% of the available output generated by the CENG nuclear plants through the end of 2014 and will purchase 50.01% from 2015 through the end of the operating life of each respective plant,
- Generation provided a $400 million loan to CENG (see Note 5—Investment in Constellation Energy Nuclear Group, LLC for more details),
- Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. (See Note 22—Commitments and Contingencies for more details),
- in connection with CENG's severance obligations, Generation has agreed to reimburse CENG for a total of approximately $6 million of the severance benefits paid or to be paid from 2013 through 2016. As of December 31, 2014, the remaining obligation is approximately $3 million,
- Generation and EDFI share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance (See Note 22—Commitments and Contingencies for more details),
- Generation provides a guarantee of approximately $7 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDFI executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,
- Generation and EDFI are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (see Note 22—Commitments and Contingencies for more details), and

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- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

For each of the consolidated VIEs, except as otherwise noted:

- The assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;
- Exelon, Generation and BGE did not provide any additional material financial support to the VIEs;
- Exelon, Generation and BGE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and
- the creditors of the VIEs did not have recourse to Exelon's, Generation's or BGE's general credit.

As of December 31, 2014 and 2013, ComEd and PECO did not have any material consolidated VIEs.

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Assets and Liabilities of Consolidated VIEs

Included within the consolidated VIE table above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of December 31, 2014 and 2013, these assets and liabilities primarily consisted of the following:

	December 31, 2014			December 31, 2013		
	Exelon	Generation	BGE	Exelon	Generation	BGE
Cash and cash equivalents	$ 392	$ 392	$—	$ 62	$ 62	$—
Restricted cash	117	96	21	80	52	28
Accounts receivable, net						
Customer	297	297	—	260	260	—
Other	57	57	—	—	—	—
Mark-to-market derivatives assets	171	171	—	21	21	—
Inventory						
Materials and supplies	172	172	—	—	—	—
Other current assets	33	26	—	34	23	—
Total current assets	1,239	1,211	21	457	418	28
Property, plant and equipment, net	4,638	4,638	—	1,171	1,171	—
Nuclear decommissioning trust funds	2,097	2,097	—	—	—	—
Goodwill	47	47	—	—	—	—
Mark-to-market derivatives assets	44	44	—	—	—	—
Other noncurrent assets	95	82	3	127	106	3
Total noncurrent assets	6,921	6,908	3	1,298	1,277	3
Total assets	$8,160	$ 8,119	$ 24	$1,755	$ 1,695	$ 31
Long-term debt due within one year	$ 87	$ 5	$ 75	$ 85	$ 5	$ 70
Accounts payable	292	292	—	170	170	—
Accrued expenses	111	108	2	26	22	4
Mark-to-market derivative liabilities	24	24	—	29	29	—
Unamortized energy contracts (liabilities)	22	22	—	5	5	—
Other current liabilities	25	25	—	5	5	—
Total current liabilities	561	476	77	320	236	74
Long-term debt	212	81	120	298	86	195
Asset retirement obligations	1,763	1,763	—	—	—	—
Pension obligation [(a)]	9	9	—	—	—	—
Unamortized energy contracts (liabilities)	51	51	—	28	28	—
Other noncurrent liabilities	127	127	—	12	12	—
Noncurrent liabilities	2,162	2,031	120	338	126	195
Total liabilities	$2,723	$ 2,507	$197	$ 658	$ 362	$269

(a) Includes the CNEG Retail Gas' pension obligation, which is presented as a net asset balance within the Prepaid Pension asset line item on Generation's balance sheet. See Note 16—Retirement Benefits for additional details.

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount

Combined Notes to Consolidated Financial Statements—(Continued)
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of the investments is reflected on Exelon's and Generation's Consolidated Balance Sheets in Investments and Other assets. For the energy purchase and sale contracts and the fuel purchase commitments (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of December 31, 2014 and 2013, Exelon and Generation had significant unconsolidated variable interests in six and eight VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity method investments and certain commercial agreements. The decrease in the number of unconsolidated VIEs is due to the sale of Generation's ownership interest in four unconsolidated VIEs in 2014, offset by the execution of an energy purchase and sale agreement with an unconsolidated VIE and an equity investment in another unconsolidated VIE. The following tables present summary information about Exelon and Generation's significant unconsolidated VIE entities:

December 31, 2014	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 506	$ 91	$597
Total liabilities [a]	237	49	286
Exelon's ownership interest in VIE [a]	—	9	9
Other ownership interests in VIE [a]	269	33	302
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	13	13
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning [b]	27	—	27

December 31, 2013	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 128	$ 332	$460
Total liabilities [a]	17	123	140
Exelon's ownership interest in VIE [a]	—	86	86
Other ownership interests in VIE [a]	111	123	234
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	7	67	74
Contract intangible asset	9	—	9
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning [b]	44	—	44

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.

(b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $319 million and $458 million as of December 31, 2014 and December 31, 2013, respectively; offset by payables to ZionSolutions LLC of $292 million and $414 million as of December 31, 2014 and December 31, 2013, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

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For each unconsolidated VIE, Exelon and Generation assessed the risk of a loss equal to their maximum exposure to be remote and, accordingly Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would materially affect the fair value or risk of their variable interests in these variable interest entities.

Energy Purchase and Sale Agreements. Generation has several energy purchase and sale agreements with generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each entity, and determined that certain of the entities are VIEs because the entity absorbs risk through the sale of fixed price power and renewable energy credits. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

In March 2005, Constellation, to which Generation is now a successor, closed a transaction in which Generation assumed from a counterparty two power sales contracts with previously existing VIEs. The VIEs previously were created by the counterparty to issue debt in order to monetize the value of the original contracts to purchase and sell power. Under the power sales contracts, Generation sold power to the VIEs which, in turn, sold that power to an electric distribution utility through 2013. In connection with this transaction, a third-party acquired the equity of the VIEs and Generation loaned that party a portion of the purchase price. If the electric distribution utility were to default under its obligation to buy power from the VIEs, the equity holder could transfer its equity interests to Generation in lieu of repaying the loan. In this event, Generation would have the right to seek recovery of its losses from the electric distribution utility. As a result, Generation has concluded that consolidation was not required. During 2013, the third-party repaid their obligations of the loan with Generation which caused the entities to no longer be unconsolidated VIEs.

ZionSolutions . Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 15—Asset Retirement Obligations. Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning is complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required. Other than the asset sale agreement, Exelon and Generation do not have any contractual or other obligations to provide additional financial support and ZionSolutions' creditors do not have any recourse to Exelon's or Generation's general credit.

Fuel Purchase Commitments. Generation's customer supply operations include the physical delivery and marketing of power obtained through its generating capacity, and long-, intermediate- and short-term contracts. Generation also has contracts to purchase fuel supplies for nuclear and fossil generation. These contracts and Generation's membership in NEIL are discussed in further detail in Note 22—Commitments and Contingencies. Generation has evaluated these contracts and its membership with NEIL and determined that it either has no variable interest in an entity or, where Generation does have a variable interest in an entity, the variable interest is not significant and it is not the primary beneficiary; therefore, consolidation is not required.

For contracts where Generation has a variable interest, the level of variability being absorbed through the contracts is not considered significant because of the small proportion of the entities' activities encompassed by the contracts with Generation. Further, Generation has considered which

interest holder has the power to direct the activities that most significantly affect the economic performance of the VIE and thus is considered the primary beneficiary and is required to consolidate the entity. The primary beneficiary must also have exposure to significant losses or the right to receive significant benefits from the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of the facilities. Facilities represent power plants, sources of uranium and fossil fuels, or plants used in the uranium conversion, enrichment and fabrication process. Generation does not have control over the operation and maintenance of the facilities considered VIEs, and it does not bear operational risk of the facilities. Furthermore, Generation has no debt or equity investments in the entities and Generation does not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 22—Commitments and Contingencies. Upon consideration of these factors, Generation does not consider itself to have significant variable interests in these entities or be the primary beneficiary of these VIEs and, accordingly, has determined that consolidation is not required.

Investment in Energy Development Projects and Energy Generating Facilities. Generation has several equity investments in energy development projects and energy generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each of its equity investments, and determined that certain of the entities are VIEs because the entity has an insufficient amount of equity at risk to finance its activities, Generation guarantees the debt of the entity, provides equity support, or provides operating services to the entity. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the entities that qualify as VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

ComEd, PECO and BGE

The financing trust of ComEd, ComEd Financing III, the financing trusts of PECO, PECO Trust III and PECO Trust IV, and the financing trust of BGE, BGE Capital Trust II are not consolidated in Exelon's, ComEd's, PECO's or BGE's financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd, PECO, and BGE have concluded that they do not have a significant variable interest in ComEd Financing III, PECO Trust III, PECO Trust IV or BGE Capital Trust II as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk. See Note 13—Debt and Credit Agreements for additional information.

3. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

The following matters below discuss the current status of material regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd).

Background

Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities to modernize Illinois' electric utility infrastructure. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in

January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. As of December 31, 2014, and December 31, 2013, ComEd had a regulatory asset associated with the distribution formula rate of $371 million and $463 million, respectively. The regulatory asset associated with distribution true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

Annual Reconciliation

2014 Filing. On April 16, 2014, ComEd filed its annual distribution formula rate to request a total increase to the revenue requirement of $269 million. On December 11, 2014, the ICC issued its final order which increased the revenue requirement by $232 million, reflecting an increase of $160 million for the initial revenue requirement for 2014 and an increase of $72 million related to the annual reconciliation for 2013. Approximately $23 million of the total $37 million revenue requirement disallowance is recoverable through other rider-based mechanisms. The rate increase was set using an allowed return on capital of 7.06% (inclusive of an allowed return on common equity of 9.25% for 2014 less a performance metrics penalty of 5 basis points for the 2013 reconciliation). The rates took effect in January 2015. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC on January 28, 2015.

2013 Filing. On April 29, 2013, ComEd filed its annual distribution formula rate, which was updated in August 2013, to request a total increase to the revenue requirement of $353 million. On December 19, 2013, the ICC issued its final order which increased the revenue requirement by $341 million, reflecting an increase of $160 million for the initial revenue requirement for 2013 and an increase of $181 million for the annual reconciliation for 2012. The final revenue requirement reflected the impacts of Senate Bill 9, which became effective in May 2013 and clarified the intent of EIMA on three issues: an allowed return on ComEd's pension asset; the use of year-end rather than average rate base and capital structure in the annual reconciliation; and the use of ComEd's weighted average cost of capital interest rate rather than a short-term debt rate to apply to the annual reconciliation. The rate increase was set using an allowed return on capital of 6.94% (inclusive of an allowed return on common equity of 8.72%). The rates took effect in January 2014. ComEd requested a rehearing on specific issues, which was denied by the ICC. ComEd also filed an appeal, which was subsequently withdrawn.

2012 Filing. On April 30, 2012, ComEd filed its annual distribution formula rate. On December 20, 2012, the ICC, issued its final order, which increased the revenue requirement by $73 million, reflecting an increase of $80 million for the initial revenue requirement for 2012 and a decrease of $7 million for the annual reconciliation for 2011. The rate increase was set using an allowed return on capital of 7.54% (inclusive of an allowed return on common equity of 9.81%). The rates took effect in January 2013. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC. ComEd and intervenors also filed appeals with the Illinois Appellate Court. The Illinois Appellate Court upheld the ICC's decision on the issues on appeal. On May 30, 2013, ComEd updated its revenue requirement allowed in the December 2012 Order to reflect the impacts of Senate Bill 9, which resulted in a reduction to the current revenue requirement in effect of $14 million. The rates took effect in July 2013. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC. ComEd and intervenors also filed appeals with the Illinois Appellate Court. The Illinois Appellate Court reaffirmed the ICC's order.

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Formula Rate Structure Investigation

In October 2013, the ICC opened an investigation (the Investigation), in response to a complaint filed by the Illinois Attorney General, to change the formula rate structure by requesting three changes: the elimination of the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance, the netting of associated accumulated deferred income taxes against the annual reconciliation balance in calculating interest, and the use of average rather than year-end rate base for determining any ROE collar adjustment. On November 26, 2013, the ICC issued its final order in the Investigation, rejecting two of the proposed changes but accepting the proposed change to eliminate the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance. The accepted change became effective in January 2014, and reduced ComEd's 2014 revenue by approximately $8 million. This change had no financial statement impact on ComEd in 2013. ComEd and intervenors requested rehearing, however all rehearing requests were denied by the ICC. ComEd and intervenors have filed appeals with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals.

Appeal of Initial Formula Rate Tariff

On March 26, 2014, the Illinois Appellate Court issued an opinion with respect to ComEd's appeal of the ICC's order relating to ComEd's initial formula rate tariff. The most significant financial issues under appeal related to ICC findings that were counter to the formula rate legislation and were clarified by subsequent legislation (Senate Bill 9). Therefore, only a subset of the issues originally appealed remained. The Court found against ComEd on each of the remaining issues: compensation related adjustments, billing determinants and the use of certain allocators. The Court's opinion has no accounting impact as ComEd recorded the distribution formula regulatory asset consistent with the ICC's final Order.

ComEd asked the Illinois Supreme Court to hear the issue of allocation between State and Federal regulatory jurisdictions. On June 4, 2014, ComEd filed a Petition for Leave to Appeal with the Illinois Supreme Court solely on the issue of allocation between FERC and ICC jurisdictional costs. On July 2, 2014, the ICC filed its Answer to the Petition, arguing that Supreme Court review is not necessary or appropriate. Under the procedural rules of the Illinois Supreme Court, ComEd is not allowed to reply to the ICC filing. There is no set time by which the Court must rule on the Petition. ComEd cannot predict whether the Court will grant the appeal, or if it does, the ultimate outcome.

Expenditures and Capital Investment

As part of the enactment of EIMA legislation ComEd made an initial contribution of $15 million (recognized as expense in 2011) to a new Science and Technology Innovation Trust fund on July 31, 2012, and will make recurring annual contributions of $4 million, the first of which was made on December 31, 2012, which will be used for customer education for as long as the AMI Deployment Plan remains in effect. In addition, ComEd will contribute $10 million per year for five years, as long as ComEd is subject to EIMA, to fund customer assistance programs for low-income customers, which will not be recoverable through rates. These contributions began in 2012.

EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. Participating utilities are required to file an annual update on their AMI implementation progress. In March 2014, ComEd filed a petition with the ICC for approval to accelerate the deployment of AMI meters. On June 11, 2014, the ICC approved ComEd's

accelerated deployment plan which allows for the installation of more than four million smart meters throughout ComEd's service territory by 2018, three years in advance of the originally scheduled 2021 completion date. To date, nearly 550,000 smart meters have been installed in the Chicago area.

Appeal of 2007 Illinois Electric Distribution Rate Case (Exelon and ComEd). The ICC issued an order in ComEd's 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd's annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via a rider (Rider SMP).

The court held the ICC abused its discretion in not reducing ComEd's rate base to account for an additional 18 months of accumulated depreciation while including post-test year pro forma plant additions through that period. ComEd continued to bill rates as established under the ICC's order in the 2007 Rate Case until June 1, 2011 when the rates set in the 2010 electric distribution rate case became effective. In subsequent ICC proceedings, the ICC issued an order requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation issue. On March 26, 2012, ComEd filed a notice of appeal with the Court. However, on September 27, 2013 the Court ruled against ComEd on the accumulated depreciation issue and affirmed that ComEd owes a refund to customers of approximately $37 million, including interest. On September 18, 2014, the ICC issued an order requiring the refund to occur in November 2014, rather than the eight month period previously approved. The refund was included with the Rider AMP refund discussed below. Former ComEd customers were eligible for a refund. ComEd was fully reserved for this liability at December 31, 2013. As of December 31, 2014 ComEd had refunded substantially all amounts to customers.

Advanced Metering Program Proceeding (Exelon and ComEd). As part of ComEd's 2007 Rate Case, the ICC approved recovery of costs associated with ComEd's Rider SMP for the limited purpose of implementing a pilot program for AMI. In October 2009, the ICC approved ComEd's AMI pilot program and associated rider (Rider AMP). ComEd collected approximately $24 million under Rider AMP and had no collections under Rider SMP through December 31, 2014. In ComEd's 2010 electric distribution rate case, the ICC approved ComEd's transfer of certain other costs from recovery under Rider AMP to recovery through electric distribution rates.

Several parties, including the Illinois Attorney General, appealed the ICC's orders on Rider SMP and Rider AMP. The Illinois Appellate Court reversed the ICC's approval of the cost recovery provisions of Rider SMP and Rider AMP on September 30, 2010 and March 19, 2012, respectively. In both cases, the Court ruled that the ICC's approval of the rider constituted single-issue ratemaking. ComEd filed Petitions for Leave to Appeal to the Illinois Supreme Court, which were denied.

In October 2013, the ICC opened an investigation on Rider AMP to determine if a refund is required and if so, to determine the appropriate refund amount. The ALJ presiding over the investigation requested each party provide a pre-trial memorandum describing their positions, which were submitted on April 10, 2014. The ICC Staff and the Illinois Attorney General proposed a refund of $14.6 million, representing the amount they claim was collected under Rider AMP since September 30, 2010, the date the Illinois Appellate Court reversed the ICC's approval of the cost recovery provisions of Rider SMP. During the second quarter of 2014, ComEd reached a tentative agreement to jointly resolve the disputed refund claim. On September 18, 2014, the ICC approved a refund of $9.5 million

plus interest to be issued to current customers in November 2014. Former ComEd customers also were eligible for a refund. As of December 31, 2014 ComEd had refunded substantially all amounts to customers.

Grand Prairie Gateway Transmission Line (ComEd). On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. On October 22, 2014, the ICC issued an order approving ComEd's Grand Prairie Gateway Project over the objection of numerous landowners and the City of Elgin. Four parties filed timely applications for rehearing before the ICC. On November 25, 2014, the ICC denied the rehearing application filed by the Forest Preserve District of Kane County, but granted rehearing on the application of certain landowners who requested that the ICC consider an alternate route for a three-mile segment of the line in Kane County. The rehearing proceeding is currently pending and the ICC must enter a final order on rehearing by April 24, 2015. On December 10, 2014, the ICC denied the remaining two applications for rehearing. On January 15, 2015, those two parties, the City of Elgin and the SKP landowner group and Utility Risk Management Corporation (collectively, the SKP/URMC party), each filed a Notice of Appeal with the Second District Appellate Court. On February 3, 2015, the ICC filed motions with the Second District Appellate Court seeking to extend the time for the ICC to file the record on appeal until after the ICC issues its Order on rehearing. The ICC also filed a motion to consolidate those appeals. ComEd expects to begin construction of the line in the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

Utility Consolidated Billing and Purchase of Receivables (Exelon and ComEd). ComEd is required to buy certain RES receivables, primarily residential and small commercial and industrial customers, at the option of the RES, for electric supply service and then include those amounts on ComEd's bill to customers. Receivables are purchased at a discount to compensate ComEd for uncollectible accounts. ComEd produces consolidated bills for the aforementioned retail customers reflecting charges for electric delivery service and purchased receivables. As of December 31, 2014, the balance of purchased accounts receivable was $139 million. ComEd recovers from RES and customers the costs for implementing and operating the program under an ICC approved tariff. A number of municipalities, including the City of Chicago have switched to RES electric supply. As a result, ComEd experienced a significant increase in the amount of RES receivables it purchased in 2013.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation.

ComEd is required to purchase an increasing percentage of the electricity for customer deliveries from renewable energy resources. Purchases by customers of electricity from competitive generation suppliers, whether as a result of the customers' own actions or as a result of municipal aggregation, are not included in this calculation and have the effect of reducing ComEd's purchase obligation.

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ComEd entered into several 20-year contracts with unaffiliated suppliers in December 2010 regarding the procurement of long-term renewable energy and associated RECs in order to meet its obligations under the state's RPS. All associated costs are recoverable from customers.

On December 18, 2013, the ICC approved the IPA's 2014-2019 procurement plan, which provided for two separate energy procurements during 2014 to address potential fluctuations in energy due to customers switching between ComEd and competitive electric generation suppliers. During May and September 2014, ComEd conducted energy procurements to meet the IPA's 2014-2019 procurement plan. On December 17, 2014, the ICC approved the IPA's 2015-2020 procurement plan. See Note 22—Commitments and Contingencies for additional information on ComEd's energy commitments.

FutureGen Industrial Alliance, Inc (Exelon and ComEd). During 2013, the ICC approved, and directed ComEd and Ameren (the Utilities) to enter into 20-year sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The sourcing agreement provides that ComEd and Ameren will pay FutureGen's contract prices, which are set annually pursuant to a formula rate. The contract prices are based on the difference between the costs of the facility and the revenues FutureGen receives from selling capacity and energy from the unit into the MISO or other markets, as well as any other revenue FutureGen receives from the operation of the facility. The order also directs ComEd and Ameren to recover these costs from their electric distribution customers through the use of a tariff, regardless of whether they purchase electricity from ComEd or Ameren, or from competitive electric generation suppliers.

In February 2013, ComEd filed an appeal with the Illinois Appellate Court questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers. On July 22, 2014, the Illinois Appellate Court issued its ruling re-affirming the ICC's order requiring ComEd to enter into the sourcing agreement with FutureGen and allowing the use of a tariff to recover its costs. ComEd decided not to appeal the Illinois Appellate Court's decision to the Illinois Supreme Court. However, the competitive electric generation suppliers and several large consumers petitioned for leave to appeal the Illinois Appellate Court's decision. On November 26, 2014, the Illinois Supreme Court granted the petition. A decision from the Illinois Appellate Court is expected in late 2015.

A significant portion of the cost of the development of FutureGen was being funded by the DOE under the American Recovery and Reinvestment Act of 2009. In early February 2015, the DOE suspended funding for the project until further clarity could be obtained on certain significant hurdles facing the project, including the outcome of the litigation described above. Whether or not the DOE funding will be reinstated at some later date is unknown at this time.

ComEd executed the sourcing agreement with FutureGen in accordance with the ICC's order. In addition, ComEd filed a petition with the ICC seeking approval of the tariff allowing for the recovery of its costs associated with the FutureGen contract from all of its electric distribution customers, which was approved by the ICC on September 30, 2014. Depending on eventual market conditions and the cost of the facility, the sourcing agreement could have a material adverse impact on Exelon's and ComEd's cash flows and financial positions.

See Note 22—Commitments and Contingencies for additional information on ComEd's energy commitments.

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Energy Efficiency and Renewable Energy Resources (Exelon and ComEd). Electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an incremental annual program energy savings requirement of 0.2% of energy delivered to retail customers for the year ended June 1, 2009, which increases annually to 2.0% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten-year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In January 2014, the ICC approved ComEd's third three-year Energy Efficiency and Demand Response Plan covering the period June 2014 through May 2017. The plans are designed to meet Illinois' energy efficiency and demand response goals through May 2017, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

EIMA provides for additional energy efficiency in Illinois. Starting in the June 2013 through May 2014 period and occurring annually thereafter, as part of the IPA procurement plan, ComEd is to include cost-effective expansion of current energy efficiency programs, and additional new cost-effective and/or third-party energy efficiency programs that are identified through a request for proposal process. All cost-effective energy efficiency programs are included in the IPA procurement plan for consideration of implementation. While these programs are monitored separately from the Energy Efficiency Portfolio Standard (EEPS), funds for both the EEPS portfolio and IPA energy efficiency programs are collected under the same rider.

Illinois utilities are required to procure cost-effective renewable energy resources in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers. ComEd is also required to acquire amounts of renewable energy resources that will cumulatively increase this percentage to at least 10% by June 1, 2015, with an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth by Illinois legislation. As of December 31, 2014, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois legislation. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates. See Note 22—Commitments and Contingencies for information regarding ComEd's future commitments for the procurement of RECs.

Pennsylvania Regulatory Matters

2010 Pennsylvania Electric and Natural Gas Distribution Rate Cases (Exelon and PECO). On December 16, 2010, the PAPUC approved the settlement of PECO's electric and natural gas distribution rate cases, which were filed in March 2010, providing increases in annual service revenue of $225 million and $20 million, respectively. The electric settlement provides for recovery of PJM transmission service costs on a full and current basis through a rider. The approved electric and natural gas distribution rates became effective on January 1, 2011.

In addition, the settlements included a stipulation regarding how tax benefits related to the application of any new IRS guidance on repairs deduction methodology are to be handled from a rate-making perspective. The settlements require that the expected cash benefit from the application of any new guidance to tax years prior to 2011 be refunded to customers over a seven-year period. On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for electric transmission and distribution property. PECO adopted the safe harbor and

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elected a method change for the 2010 tax year. The expected total refund to customers for the tax cash benefit from the application of the safe harbor to costs incurred prior to 2010 is $171 million. On October 4, 2011, PECO filed a supplement to its electric distribution tariff to execute the refund to customers of the tax cash benefit related to the IRC Section 481(a) “catch-up” adjustment claimed on the 2010 income tax return, which is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2012.

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The expected total refund to customers for the tax cash benefit from the application of the new method to costs incurred prior to 2011 is $54 million. This amount is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2013. PECO currently anticipates that the IRS will issue guidance during 2015 providing a safe harbor method of accounting for gas transmission and distribution property.

The prospective tax benefits claimed as a result of the new methodology will be reflected in tax expense in the year in which they are claimed on the tax return and will be reflected in the determination of revenue requirements in the next electric and natural gas distribution rate cases. See Note 14—Income Taxes for additional information.

The 2010 electric and natural gas distribution rate case settlements did not specify the rate of return upon which the settlement rates are based, but rather provided for an increase in annual revenue. PECO has not filed a transmission rate case since rates have been unbundled.

Pennsylvania Procurement Proceedings (Exelon and PECO). PECO’s first PAPUC approved DSP Program, under which PECO was providing default electric service, had a 29-month term that ended May 31, 2013. On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO’s second DSP Program, which was filed with the PAPUC in January 2012. The program, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129. Under the DSP Programs, PECO is permitted to recover its electric procurement costs from retail default service customers without mark-up through the GSA. The GSA provides for the recovery of energy, capacity, ancillary costs and administrative costs and is subject to adjustments at least quarterly for any over or under collections. In addition, PECO’s second DSP Program provides for the recovery of AEPS compliance costs through the GSA rather than a separate AEPS rider.

In the second DSP Program, PECO procured electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes is served through competitively procured fixed price, full requirements contracts of two years or less. For the large commercial and industrial class load, PECO has competitively procured contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. PECO entered into contracts with PAPUC approved bidders, including Generation, for its five competitive procurements. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO’s Statement of Operations and Comprehensive Income.

In addition, the second DSP Program includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to submit a plan to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs beginning in April 2014. On May 1, 2013,

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PECO filed its CAP Shopping Plan with the PAPUC. By Order entered on January 24, 2014, the PAPUC approved PECO's plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, the Office of Consumer Advocate (OCA) and low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court, claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On March 28, 2014, the Commonwealth Court issued the requested stay, pending a full review of the appeal. Pending the Commonwealth Court's review, PECO will not implement CAP Shopping. The Commonwealth Court's decision is expected in 2015.

On March 10, 2014, PECO filed its third DSP Program with the PAPUC. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. On August 28, 2014, PECO filed a Joint Petition for Partial Settlement, which affirmed PECO's procurement plan for Residential and Small Commercial customers. On December 4, 2014, the PAPUC approved PECO's third DSP Program, as modified by the Joint Petition for Partial Settlement, without modification or limitation. Separate from the Joint Petition for Partial Settlement, the PAPUC also approved other items related to the program. The plan outlines how PECO will purchase electric supply for default service customers. PECO will procure electric supply through four competitive procurements for fixed price full requirements contracts of two years or less for the residential classes and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load.

Smart Meter and Smart Grid Investments (Exelon and PECO). Pursuant to Act 129 and the follow-on Implementation Order of 2009, in April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million electric smart meters and an AMI communication network by 2020. The first phase of PECO's SMPIP, which was completed on June 19, 2013, included the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC which was approved without modification on August 15, 2013. The Joint Petition for Settlement supports all material aspects of PECO's universal deployment plan, including cost recovery, excluding certain amounts discussed below. Universal deployment is the second phase of PECO's SMPIP, under which PECO will deploy all of the remaining smart meters, for a total of 1.7 million smart meters, on an accelerated basis by the second quarter of 2015. In total, PECO currently expects to spend up to $583 million, excluding the cost of the original meters (as further described below), on its smart meter infrastructure and approximately $155 million on smart grid investments through final deployment of which $200 million has been funded by SGIG as discussed below. As of December 31, 2014, PECO has spent $540 million and $119 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO's existing mortgage. The SGIG funds were used by PECO to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of the third quarter of 2014, PECO received all of the $200 million, including $4 million for sub-recipients, in reimbursements. On October 15, 2014, the DOE issued a Close Out of Post-Award Project Cost Verification Audit, in which it was determined that PECO fully met its required cost share, and the audit was closed with no further action required.

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On August 15, 2012, PECO suspended installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO has replaced the previously installed meters with an alternative vendor's meters. PECO is moving forward with the alternative meters during universal deployment and continues to evaluate meters from several vendors and may use more than one meter vendor during universal deployment.

Following PECO's decision, as of October 9, 2012 PECO will no longer use the original smart meters. For the meters that will no longer be used, the accounting guidance requires that any difference between the carrying value and net realizable value be recognized in the current period's earnings, before considering potential regulatory recovery. The cost of the original meters, including installation and removal costs, owned by PECO was approximately $17 million, net of approximately $16 million of reimbursements from the DOE and approximately $2 million of depreciation. PECO requested and received approval from the DOE that the original meters continue to be allowable costs and that any agreement with the vendor will not be considered project income. In addition, PECO remained eligible for the full $200 million in SGIG funds. On August 15, 2013, PECO entered into an agreement with the original vendor, which was part of the final agreement discussed below, under which PECO transferred the original uninstalled meters to the vendor and will receive $12 million in return. On January 23, 2014, PECO entered a final agreement with the vendor pursuant to which PECO will be reimbursed for amounts incurred for the original meters and related installation and removal costs, via cash payments and rebates on future purchases of licenses, goods and services primarily through 2017. PECO previously had intended to seek regulatory rate recovery in a future filing with the PAPUC of amounts not recovered from the vendor. As PECO believed such costs were probable of rate recovery based on applicable case law and past precedent on reasonably and prudently incurred costs, a regulatory asset was established at the time of the removals. Pursuant to the January 23, 2014, vendor agreement, PECO reclassified the regulatory asset balance as a receivable, which has been fully collected, with no gain or loss impacts on future results of operations. On March 14, 2014, PECO filed its quarterly smart meter recovery surcharge with the PAPUC which included PECO's proposed treatment of the final agreement with the vendor. On March 27, 2014, the PAPUC approved the surcharge as proposed by PECO.

Energy Efficiency Programs (Exelon and PECO). PECO's PAPUC-approved Phase I EE&C Plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I plan set forth how PECO would meet the required reduction targets established by Act 129's EE&C provisions, which included a 3% reduction in electric consumption in PECO's service territory and a 4.5% reduction in PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013.

The peak demand period ended on September 30, 2012 and PECO communicated its compliance with the reduction targets in a preliminary filing with the PAPUC on March 1, 2013. The final compliance report for all Phase I targets, was filed with the PAPUC on November 15, 2013.

On March 29, 2013, PECO filed a Petition with the PAPUC to change the recovery period of certain Direct Load Control (DLC) Program costs necessary to implement the Phase I Plan. The Petition sought approval to allow PECO to recover $12 million in equipment, installation and information technology costs for its Residential DLC program with the amounts collected for the Phase I Plan. As the Phase I Plan was implemented at a cost less than originally budgeted, PECO proposed to recover these expenses from its Phase I Energy Efficiency Program Charge over-

collection consistent with PAPUC guidance to recover all Phase I costs through Phase I funding. The PAPUC approved PECO's Petition on May 9, 2013. A regulatory liability was established for the DLC program costs that will be amortized as a credit to the income statement to offset the related depreciation expense during the same period.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129's EE&C programs, which went into effect on June 1, 2013. The order tentatively established PECO's three-year cumulative consumption reduction target at 1,125,852 MWh, which was reaffirmed by the PAPUC on December 5, 2012.

Pursuant to the Phase II implementation order, PECO filed its three-year EE&C Phase II plan with the PAPUC on November 1, 2012. The plan sets forth how PECO will reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016, adjusted for weather and extraordinary loads. The implementation order permits PECO to apply any excess savings achieved during Phase I against its Phase II consumption reduction targets, with no reduction to its Phase II budget. In accordance with the Act 129 Phase II implementation order, at least 10% and 4.5% of the total consumption reductions must be through programs directed toward PECO's public and low income sectors, respectively. If PECO fails to achieve the required reductions in consumption, it will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers. Act 129 mandates that the total cost of the plan may not exceed 2% of the electric company's total annual revenue as of December 31, 2006.

On March 15, 2013, PECO filed a Petition for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers from June 1, 2013 to May 31, 2014. PECO proposed to fund the estimated $10 million costs of the one-year program by modifying incentive levels for other Phase II programs. On May 9, 2013, the PAPUC approved PECO's amended EE&C Phase II plan. The costs of DLC program will be recovered through PECO's Energy Efficiency Program Charge along with all other Phase II Plan costs.

On November 14, 2013, the PAPUC issued a Tentative Order on Act 129 demand reduction programs which seeks comments on a proposed demand response program methodology for future Act 129 demand reduction programs as well as demand response potential and wholesale prices suppression studies. In its February 20, 2014 Final Order, the PAPUC stated that it does not expect to make a decision as to whether it will prescribe additional demand response obligations until 2015. Any decision reached would affect PECO's EE&C Plan subsequent to its Phase II Plan.

On February 28, 2014, PECO filed a Petition for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers from June 1, 2014 to May 31, 2016. PECO proposed to fund the estimated $10 million annual costs of the program by modifying incentive levels for other Phase II programs. The costs of the DLC program will be recovered through PECO's Energy Efficiency Program Charge along with other Phase II Plan costs. In an April 23, 2014 Tentative Order, the PAPUC granted PECO's Petition. The Order became final on May 5, 2014.

Alternative Energy Portfolio Standards (Exelon and PECO). In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of PECO's rate cap transition period, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources ranges

from approximately 3.5% to 8% and the requirement for Tier II alternative energy resources ranges from 6.2% to 10%. The required compliance percentages incrementally increase each annual compliance period, which is from June 1 through May 31, until May 31, 2021. These Tier I and Tier II alternative energy resources include acceptable energy sources as set forth in Act 129 and the AEPS Act.

PECO has entered into five-year and ten-year agreements with accepted bidders, including Generation, totaling 452,000 non-solar and 8,000 solar Tier I AECs annually in accordance with a PAPUC approved plan. The plan allowed PECO to bank AECs procured prior to 2011 and use the banked AECs to meet its AEPS Act obligations over two compliance years ending May 2013. The PAPUC also approved the procurement of Tier II AECs and supplemental AECs as well as the sale of excess AECs through independent third-party auctions or brokers.

All AEPS administrative costs and costs of AECs are being recovered on a full and current basis from default service customers through a surcharge.

PECO's second DSP Program eliminated the AEPS surcharge. Beginning in June 2013, AEPS compliance costs are being recovered through the GSA.

Pennsylvania Retail Electricity and Gas Markets (Exelon and PECO). Beginning in 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania's retail electricity market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. Through various orders, the PAPUC issued default electric service pricing for customers in PECO's service territory. See Pennsylvania procurement proceedings discussed above for additional details.

In early 2014, the extreme weather in PECO's service territory resulted in increased electricity commodity costs causing certain shopping customers to receive unexpectedly high utility bills. In response to a significant number of customer complaints throughout Pennsylvania, on April 3, 2014, the PAPUC unanimously voted to adopt two rulemaking orders to address the issue. The first rulemaking order requires electric generation suppliers to provide more consumer education regarding their contract. The second rulemaking order requires electric distribution companies to enable customers to switch suppliers within three business days (known as accelerated switching). The improved customer education and accelerated switching were to be in place within 30 days and six months of approval of the orders, respectively. The orders became final on June 14, 2014. On December 4, 2014, the PAPUC approved PECO's implementation plan (known as Bill on Supplier Switch), allowing PECO to implement accelerated switching by the December 15, 2014 deadline.

On September 12, 2013, the PAPUC issued an Order that initiated an investigation into Pennsylvania's natural gas retail market, including the role of the existing default service model and opportunities for market enhancements. On December 18, 2014, the PAPUC issued a Final Order directing the Office of Competitive Market Oversight to continue its investigation, confirming that natural gas distribution companies should remain with the default service model for the time being and directing establishment of a working group to examine other competitive issues. Comments on the Final Order were due on February 2, 2015. PECO will continue to monitor the Order and assess compliance, as necessary.

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Pennsylvania Act 11 of 2012 (Exelon and PECO). On February 13, 2012, Act 11 was signed into law by the Governor. Act 11 seeks to clarify the PAPUC's authority to approve alternative ratemaking mechanisms, which would allow for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems in Pennsylvania. Act 11 also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the first year rates are in effect. On August 2, 2012, the PAPUC issued a Final Order establishing rules and procedures to implement the ratemaking provisions of Act 11. The implementation order requires a utility to have a long-term infrastructure improvement plan (LTIIP) which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure, approved by the Commission prior to implementing a DSIC. On May 9, 2013, the PAPUC approved PECO's LTIIP for its gas operations, which was filed on February 8, 2013. On February 5, 2015, PECO filed a petition to modify its approved Gas LTIIP with the PAPUC. If approved, the modification would allow PECO to further accelerate the replacement of existing gas mains and also included a plan for the relocation of meters from indoors to outside in accordance with a recent PAPUC rulemaking.

Maryland Regulatory Matters

2014 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 2, 2014, and as amended on September 15, 2014, BGE filed for electric and gas base increases with the MDPSC, ultimately requesting increases of $99 million and $68 million, respectively.

On October 17, 2014, BGE filed with the MDPSC a unanimous settlement agreement (the Settlement Agreement) reached with all parties to the case under which it would receive an increase of $22 million in electric base rates and an increase of $38 million in gas base rates. The Settlement Agreement establishes new depreciation rates which have the effect of decreasing annual depreciation expense by approximately $20 million, primarily for electric. On December 4, 2014, the Public Utility Law Judge issued a proposed order approving the Settlement Agreement without modification, which became a final order on December 12, 2014. The approved distribution rate order authorizing BGE to increase electric and gas distribution rates became effective for services rendered on or after December 15, 2014.

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, and as amended on August 23, 2013, BGE filed for electric and gas base increases with the MDPSC, ultimately requesting increases of $83 million and $24 million, respectively. In addition to these requested rate increases, BGE's application includes a request for recovery of incremental capital expenditures and operating costs associated with BGE's proposed short-term reliability improvement plan (the "ERI initiative") in response to a MDPSC order through a surcharge separate from base rates.

On December 13, 2013, the MDPSC issued an order in BGE's 2013 electric and natural gas distribution rate case for increases in annual distribution service revenue of $34 million and $12 million, respectively, and an allowed return on equity of 9.75% and 9.60%, respectively. Rates became effective for services rendered on or after December 13, 2013. The MDPSC also authorized BGE to recover through a surcharge mechanism costs associated with five ERI initiative programs designed to accelerate electric reliability improvements premised upon the condition that the MDPSC approve specific projects in advance of cost recovery. On March 31, 2014, after reviewing comments filed by the parties and conducting a hearing on the matter, the MDPSC approved all but one project proposed

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for completion in 2014 as part of the ERI initiative. The ERI initiative surcharge became effective June 1, 2014. On November 3, 2014, BGE filed a surcharge update including a true-up of cost estimates included in the 2014 surcharge, along with its work plan and cost estimates for 2015, to be included in the 2015 surcharge. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2014 annual report, 2015 work plan and the 2015 surcharge.

In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE's 2013 electric and gas distribution rate cases. The residential consumer advocate filed its related legal memorandum on August 22, 2014, challenging the MDPSC's approval of the ERI initiative surcharge. BGE submitted a response to the appeal on October 15, 2014, and a hearing was held on November 17, 2014. BGE cannot predict the outcome of this appeal. If the residential consumer advocate's appeal is successful, BGE could recover ERI expenditures through other regulatory mechanisms.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order for increases in annual distribution service revenue of $81 million and $32 million, respectively, and an allowed return on equity of 9.75% and 9.60%, respectively. The rates became effective for services rendered on or after February 23, 2013. As part of the rate order, the MDPSC approved both recovery of and return on the merger integration costs, including severance, incurred during the test year for the Exelon and Constellation merger. As a result, the order affirmed the treatment of $20 million of severance-related costs that BGE had recorded as a regulatory asset in 2012, consistent with prior MDPSC decisions. Additionally, BGE established a new regulatory asset of $8 million related to non-severance merger integration costs, which includes $6 million of costs incurred during 2012. Current MDPSC treatment of these merger integration regulatory assets is to provide recovery over a five year period.

2011 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $19 million of costs as regulatory assets. These costs are being recovered over a 5-year period that began in December 2010 and include the deferral of $16 million of storm costs incurred in February 2010. The regulatory asset for the storm costs earns a regulated rate of return.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million of which $200 million was recovered through a grant from the DOE. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of December 31, 2014 and December 31, 2013, BGE recorded a regulatory asset of $128 million and $66 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. As part of the settlement in BGE's 2014 electric and gas distribution rate case discussed above, the cost of the retired non-AMI meters will be amortized over 10 years.

On February 26, 2014, the MDPSC issued an order authorizing BGE to impose a $75 upfront fee and an $11 recurring fee to customers electing to opt-out of BGE's smart meter installation program,

effective the later of the first full billing cycle following July 1, 2014, or the AMI installation date in a customer's community. The fees authorized by the order will be reviewed after an initial 12 to 18 month period. On November 25, 2014, the MDPSC issued a decision approving BGE's proposal to automatically enroll unresponsive customers into the opt-out program and to charge those customers opt-out fees after BGE has exhausted attempts to schedule a meter installation. The ultimate impact of opt-out could affect BGE's ability to demonstrate cost-effectiveness of the advanced metering system.

Overall, BGE continues to believe the recovery of smart grid initiative costs in future rates is probable as BGE expects to be able to demonstrate that the program benefits exceed costs.

New Electric Generation (Exelon and BGE). On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that CPV projected will be in commercial operation by June 1, 2015. The initial term of the proposed contract is 20 years. The CfD mandates that BGE and the other utilities pay (or receive) the difference between CPV's contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The MDPSC's order requires the three Maryland utilities to enter into a CfD in amounts proportionate to their relative SOS load.

On April 16, 2013, the MDPSC issued an order that required BGE to execute a specific form of contract with CPV, and the parties executed the contract as of June 6, 2013. As of December 31, 2014, there is no impact on Exelon's and BGE's results of operations, cash flows and financial positions. Furthermore, the agreement does not become effective until the resolution of certain items, including all current litigation.

On April 27, 2012, a civil complaint was filed in the U.S. District Court for the District of Maryland by certain unaffiliated parties that challenged the actions taken by the MDPSC on Federal law grounds. On October 24, 2013, the U.S. District Court issued a judgment order finding that the MDPSC's Order directing BGE and the two other Maryland utilities to enter into a CfD, which assures that CPV receives a guaranteed fixed price regardless of the price set by the federally regulated wholesale market, violates the Supremacy Clause of the United States Constitution. On November 22, 2013, the MDPSC and CPV appealed the District Court's ruling to the United States Court of Appeals for the Fourth Circuit.

On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order under state law. That petition was subsequently transferred to the Circuit Court for Baltimore City and consolidated with similar appeals that have been filed by other interested parties. On October 1, 2013, the Circuit Court Judge issued a Memorandum Opinion and Order finding the decisions of the MDPSC were within its statutory authority under Maryland law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD is unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands. On October 29, 2013, BGE and the two other Maryland utilities appealed the Circuit Court's ruling to the Maryland Court of Special Appeals.

Depending on the ultimate outcome of the pending state and federal litigation, on the eventual market conditions, and on the manner of cost recovery as of the effective date of the agreement, the CfD could have a material impact on Exelon and BGE's results of operations, cash flows and financial positions.

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Exelon believes that this and other states' projects may have artificially suppressed capacity prices in PJM and may continue to do so in future auctions to the detriment of Exelon's market driven position. In addition to this litigation, Exelon is working with other market participants to implement market rules that will appropriately limit the market suppressing effect of such state activities.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 requiring BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improve reliability and grid resiliency that were due at various times before August 30, 2013.

On September 3, 2013, BGE filed a comprehensive long term assessment examining potential alternatives for improving the resiliency of the electric grid and a staffing analysis reviewing historical staffing levels as well as forecasting staffing levels necessary under various storm scenarios. During the summer of 2014, an evaluation of the reports filed by BGE and other Maryland utilities was undertaken by consultants on behalf of the MDPSC and MDPSC Staff. The MDPSC Staff also proposed standards for reliability during major events and estimated times of restoration as well as undertaking an evaluation of performance-based ratemaking principles and methodologies that would more directly and transparently align reliable service with the utilities' distribution rates and that reduce returns or otherwise penalize sub-standard performance. The MDPSC held hearings in September 2014. BGE currently cannot predict the outcome of these proceedings, which may result in increased capital expenditures and operating costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law; which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On March 26, 2014, the Maryland PSC approved as filed BGE's proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge that became effective April 1, 2014. On November 17, 2014, BGE filed a surcharge update including a true-up of costs estimates included in the 2014 surcharge, along with its 2015 project list and cost estimates to be included in the 2015 surcharge. The filing was approved with a revised surcharge effective January 1, 2015. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2015 project list and the proposed surcharge for 2015. BGE will defer the difference between the surcharge revenues and program costs as a regulated asset or liability, which was immaterial to Exelon and BGE as of December 31, 2014.

In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE's infrastructure replacement

plan. On September 5, 2014, the Baltimore City Circuit Court affirmed the MDPSC decision on BGE's infrastructure replacement plan and associated surcharge. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court, however, a procedural schedule for the matter has not yet been set.

New York Regulatory Matters

Ginna Nuclear Power Plant Reliability Support Services Agreement (Exelon and Generation). Ginna Nuclear Power Plant's (Ginna) prior period fixed-price PPA contract with Rochester Gas & Electric Company (RG&E) expired in June 2014. In light of the expiration of the agreement, Ginna advised the New York Public Service Commission (NYPSC) and ISO-NY that in absence of a reliability need, Ginna management would make a recommendation, subject to approval by the CENG board, that Ginna be retired as soon as practicable. A formal study conducted by the ISO-NY and RG&E concluded that the Ginna nuclear plant needs to remain in operation to maintain the reliability of the transmission grid in the Rochester region through 2018 when planned transmission system upgrades are expected to be completed. In November, in response to a petition filed by Ginna, the NYPSC directed Ginna and RG&E to negotiate a Reliability Support Services Agreement (RSSA). On February 13, 2015, regulatory filings, including RSSA terms negotiated between Ginna and RG&E, to support the continued operation of Ginna for reliability purposes were made with the NYPSC and with FERC for their approval. While the RSSA is expected to be approved, in absence of such an agreement and in the event the plant was retired before the current license term ends in 2029, Exelon's and Generation's results of operations could be adversely affected by increased depreciation rates, impairment charges, severance costs, and accelerated future decommissioning costs, among other items. However, it is not expected that such impacts would be material to Exelon's or Generation's results of operations.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd's and BGE's transmission rates are each established based on a FERC-approved formula. ComEd and BGE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd and BGE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd's and BGE's best estimate of the revenue requirement expected to be approved by the FERC for that year's reconciliation. As of December 31, 2014, and 2013, ComEd had a regulatory asset associated with the transmission formula rate of $21 million and $17 million, respectively, and BGE had a net regulatory asset associated with the transmission formula rate of $1 million and a net regulatory liability which was not material as of December 31, 2013. The regulatory asset associated with transmission true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

In April 2014, ComEd filed its annual 2014 formula rate update with the FERC, reflecting an increased revenue requirement of $22 million, including an increase of $36 million for the initial revenue requirement, offset by a decrease of $14 million related to the annual reconciliation. The filing established the revenue requirement used to set rates that took effect in June 2014. ComEd's 2014

formula transmission rate provides for a weighted average debt and equity return on transmission rate base of 8.62%, inclusive of an allowed return on common equity of 11.50%, a decrease from the 8.70% average debt and equity return previously authorized. The time period for any challenges to ComEd's annual 2014 formula rate update expired in October 2014 with no challenges submitted.

In April 2013, ComEd filed its annual 2013 formula rate update with the FERC, reflecting an increased revenue requirement of $68 million, including an increase of $38 million for the initial revenue requirement and an increase of $30 million related to the annual reconciliation. The filing established the revenue requirement used to set rates that took effect in June 2013. ComEd's 2013 formula transmission rate provides for a weighted average debt and equity return on transmission rate base of 8.70%, inclusive of an allowed return on common equity of 11.50%, a decrease from the 8.91% average debt and equity return previously authorized. The time period for any challenges to ComEd's annual 2013 formula rate update expired in October 2013 with no challenges submitted.

As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%.

In April 2014, BGE filed its 2014 formula rate update with the FERC reflecting an increased revenue requirement of $14 million, including an increase of $9 million for the initial revenue requirement and an increase of $5 million related to the annual reconciliation. The annual update established the revenue requirement used to set rates that took effect in June 2014. The time period for any challenges to BGE's annual update expired in October 2014 with no challenges submitted.

BGE's 2014 formula transmission rate provides for a weighted average debt and equity return on transmission rate base of 8.53%, an increase from the 8.35% average debt and equity return previously authorized. As part of the FERC-approved settlement of BGE's 2005 transmission rate case in 2006, the rate of return on common equity for BGE's electric transmission business for new transmission projects placed in service on and after January 1, 2006 is 11.3%, inclusive of a 50 basis point incentive for participating in PJM.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) and a 50 basis point incentive for participating in PJM (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint.

On August 21, 2014, FERC issued an order in the BGE and PHI companies' proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013. BGE, the PHI companies and the parties began settlement discussions under the guidance of a FERC administrative law judge on September 23, 2014. On November 24, 2014, the

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Settlement Judge informed FERC and the Chief Judge that the parties had reached an impasse and determined that a settlement was not possible. On November 26, 2014, the Chief Judge issued an order terminating the settlement proceeding, designating a presiding judge at the hearings and directing that an initial decision be issued by November 25, 2015.

On December 8, 2014, various state agencies in Delaware, Maryland, New Jersey, and D.C. filed a second complaint against BGE regarding the base ROE of the transmission business seeking a reduction from 10.8% to 8.8%. The filing of the second complaint creates a second refund window. By order issued on February 9, 2015, FERC established a hearing on the second complaint with the complainants' requested refund effective date of December 8, 2014.

Based on the current status of the complaint filings, BGE believes it is probable that BGE's base ROE rate will be adjusted, and that a refund to customers of transmission revenue for the two maximum fifteen month periods will be required. However, BGE is unable to estimate the most likely refund amount for either complaint at this time, and has therefore established a reserve, which is not material, representing the low end of a reasonably possible estimated range of loss. Additionally, management is unable to estimate the maximum exposure of a potential refund at this time, which may have a material impact on BGE's results of operations and cash flows. The estimated annual ongoing reduction in revenues if FERC approved the ROEs requested by the parties in their filings is approximately $11 million. If FERC were to order a reduction of BGE's base ROE to 8.7% as sought in the first complaint (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result of the first fifteen month refund window would be a refund to customers of approximately $13 million. If FERC were to order a reduction in BGE's base ROE to 8.8% as sought in the second complaint (while retaining 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment) and the refund period extended for a full fifteen months, the result would be a refund to customers of approximately $14 million.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, that court issued its decision affirming FERC's order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On March 30, 2012, FERC issued an order on remand affirming the cost allocation in its April 2007 order. On March 22, 2013, FERC issued an order denying rehearing and made it clear that the cost allocation at issue concerns only projects approved prior to February 1, 2013. A number of entities have filed appeals of the FERC orders. On June 25, 2014, the U.S. Court of Appeals for the Seventh Circuit issued a decision once again remanding to FERC the cost allocation of new facilities 500 kV and above. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the issue of the cost allocation for facilities 500 kV and above. The hearing only concerns new facilities approved

by the PJM Board prior to February 1, 2013. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent any rate design changes are retroactive to periods prior to January 1, 2011, there may be an impact on PECO's results of operations. BGE anticipates that all impacts of any rate design changes effective after the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE's results of operations, cash flows or financial position.

ComEd, PECO and BGE are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd, PECO and BGE will work with PJM to continue to evaluate the scope and timing of any required construction projects. ComEd, PECO and BGE's estimated commitments are as follows:

	Total	2015	2016	2017	2018	2019
ComEd	$335	$150	$172	$ 5	$ 4	$ 4
PECO	100	32	31	25	8	4
BGE	351	77	104	77	57	36

PJM Minimum Offer Price Rule (Exelon and Generation). PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The FERC orders approving the MOPR were upheld by the United States Court of Appeals for the Third Circuit in February 2014.

Exelon continues to work with PJM stakeholders and through the FERC process to implement several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts and capacity market speculators) cannot inappropriately affect capacity auction prices in PJM.

Demand Response Resource Order (Exelon, Generation, ComEd, PECO, BGE). On May 23, 2014, the D.C. Circuit Court issued an opinion vacating the FERC Order No. 745 ("D.C. Circuit Decision"). Order No. 745 established uniform compensation levels for demand response resources that participate in the day ahead and real-time wholesale energy markets. Under Order No. 745, buyers in ISO and RTO markets were required to pay demand response resources the full Locational Marginal Price when the demand response replaced a generation resource and was cost-effective.

In addition to invalidating the compensation structure established by Order No. 745, the D.C. Circuit Court, in broad language, explained that demand response is part of the retail market and FERC is restricted from regulating retail markets. The full implication of the D.C. Circuit Decision for both energy and capacity markets regulated by FERC is not yet known and will depend on how FERC and the RTOs and ISOs implement the decision. FERC and several other parties sought rehearing of the D.C. Circuit Decision, which was denied in September 2014. In addition, on September 22, 2014, FERC and another party sought to stay the issuance of the D.C. Circuit Court's mandate so that FERC may appeal the decision to the U.S. Supreme Court. The stay was granted with respect to the FERC's request only. In January 2015, the FERC sought to appeal the decision to the U.S. Supreme Court.

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Thus, the stay will be extended at least until the U.S. Supreme Court determines whether to allow the appeal. In addition, contemporaneously with the D.C. Circuit Court's decision on May 23, 2014, First Energy filed a complaint at FERC asking FERC to direct PJM to remove all PJM Tariff provisions that allow or require PJM to compensate demand response providers as a form of supply in the PJM capacity market effective May 23, 2014. FirstEnergy also asked FERC to declare the results of PJM's May 2014 Base Residual Auction for the 2017/2018 Delivery Year, void and illegal to the extent that demand response resources cleared that auction. On November 14, 2014, the New England Power Generators Association, Inc. ("NEPGA") filed a similar complaint at FERC asking FERC to disqualify demand response from the upcoming capacity auction in New England and to revise the New England tariff to remove demand response from participation in the capacity market. FERC's response to the FirstEnergy complaint and the NEPGA complaint and its response to address the D.C. Circuit Court's decision in all markets could preclude demand response resources from receiving any future capacity market revenues and also subject such resources to refund obligations. In addition, there is uncertainty as to how FERC might treat already settled capacity market auctions as well as future auctions, both for demand response resources and generation resources. FERC could grant all or a portion of the relief requested by FirstEnergy and may grant relief retroactively or only prospectively. FERC could also pursue alternative means for allowing demand response to effectively participate in capacity markets it regulates. Due to these uncertainties, the Registrants are unable to predict the outcome of these proceedings, and the final outcome is not expected for several months. Nonetheless, the final decision and its implementation by FERC and the RTOs and ISOs, could be material to Exelon, Generation, ComEd, PECO and BGE's results of operations and cash flows.

Market-Based Rates (Exelon, Generation, ComEd, PECO and BGE). Generation, ComEd, PECO and BGE are public utilities for purposes of the Federal Power Act and are required to obtain FERC's acceptance of rate schedules for wholesale electricity sales. Currently, Generation, ComEd, PECO and BGE have authority to execute wholesale electricity sales at market-based rates. As is customary with market-based rate schedules, FERC has reserved the right to suspend market-based rate authority on a retroactive basis if it subsequently determines that Generation, ComEd, PECO or BGE has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds in certain instances if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

As required by FERC's regulations, as promulgated in the Order No. 697 series, Generation, ComEd, PECO and BGE file market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd, PECO and BGE qualify for market-based rates in the regions where they are selling energy, capacity, and ancillary services under market-based rate tariffs. On June 29, 2012, Generation, ComEd, PECO and BGE filed their updated market power analysis for the Central Region which the FERC accepted on November 13, 2012. On December 21, 2012, Generation, ComEd, PECO, and BGE filed their updated market power analysis for the SPP region, which the FERC accepted on October 8, 2013. On December 30, 2013, Generation, ComEd, PECO and BGE filed its updated analysis for the Northeast Region, based on 2012 historic test period data which the FERC accepted on August 5, 2014. On December 23, 2014, Generation filed its updated market power analysis for the Southeast Region and the FERC has not yet acted on the filing.

Reliability Pricing Model (Exelon, Generation and BGE). PJM's RPM Base Residual Auctions take place approximately 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2018 occurred in May 2014.

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New England Capacity Market Results (Exelon and Generation). Each year, ISO New England, Inc. (ISO-NE) files the results of its annual capacity auction at the FERC which is required to include documentation regarding the competitiveness of the auction. Consistent with this requirement, on February 28, 2014, ISO-NE filed the results of its eighth capacity auction (covering the June 1, 2017 through May 30, 2018 delivery period). On June 27, 2014, the FERC issued a letter to ISO-NE noting that ISO-NE's February 28, 2014 filing was deficient and that ISO-NE must file additional information before the FERC can process the filing. ISO-NE filed the information on July 17, 2014, and the ISO-NE's filings became effective by operation of law pursuant to a notice issued by the FERC's secretary on September 16, 2014. Several parties sought rehearing of the secretary's notice which was effectively denied in October 2014 and have since appealed the matter to the U.S. D.C. Circuit Court of Appeals. It is not clear whether such appeal would be effective as there is no action by the Commission to be considered. Nonetheless, while we think any change in the auction results to be unlikely, Exelon and Generation cannot predict with certainty what further action the court may take concerning the results of that auction, but any court action could be material to Exelon's and Generation's expected revenues from the capacity auction.

License Renewals (Exelon and Generation). In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. The temporary storage rule (also referred to as the "waste confidence decision") recognized that licensees can safely store spent nuclear fuel at nuclear plants for up to 60 years beyond the original and renewed licensed operating life of the plants and that licensing renewal decisions do not require discussion of the environmental impact of spent fuel stored on site. In August 2012, the NRC placed a hold on issuing new or renewed operating licenses that depend on the temporary storage rule until the court's decision is addressed. On August 26, 2014, the NRC Commissioners approved the issuance of a revised rule codifying the NRC's generic determinations regarding the environmental impacts of continued storage of spent nuclear fuel beyond a reactor's licensed operating life and removed the hold on final licensing decision as of the effective date of the final rule. On September 19, 2014, the NRC issued the Continued Storage Rule, which became effective on October 20, 2014. On October 24, 2014, New York, Vermont, and Connecticut filed a petition for review in federal court which alleges that the Continued Storage Rule violates various federal laws and regulations. The petition additionally challenges the Continued Storage Rule's supporting generic environmental impact statement (GEIS) as well as the August 26, 2014 NRC order lifting the suspension of all final licensing decisions for affected applications in view of the rule and GEIS.

On May 29, 2013, Generation submitted applications to the NRC to extend the current operating licenses of Byron Units 1 and 2, which are currently set to expire in 2024 and 2026, respectively, and Braidwood Units 1 and 2, currently set to expire in 2026 and 2027, respectively, by 20 years. Generation does not expect the NRC to issue license renewals for Byron and Braidwood until late 2015 at the earliest.

On October 20, 2014, the NRC approved Generation's request to extend the operating licenses of Limerick Units 1 and 2 by 20 years to 2044 and 2049, respectively.

On December 9, 2014, Generation submitted applications to the NRC to extend the operating licenses of LaSalle Units 1 and 2 by 20 years, which are currently set to expire in 2022 and 2023, respectively. Generation does not expect the NRC to issue license renewals for LaSalle until 2016 at the earliest.

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On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively.

Generation is working with stakeholders to resolve water quality licensing issues with the MDE for Conowingo, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On January 30, 2014, Generation filed a water quality certification application pursuant to Section 401 of the CWA with MDE for Conowingo, addressing these and other issues, although Generation cannot currently predict the conditions that ultimately may be imposed. MDE indicated that it believed it did not have sufficient information to process Generation's application. As a result, on December 5, 2014, Generation withdrew its pending application for a water quality certification. FERC policy requires that an applicant resubmit its request for a water quality certification within 90 days of the date of withdrawal. Accordingly, Generation is working with MDE to coordinate the refiling of its application for certification within the 90-day period. In addition, Generation has entered into an agreement with MDE to work with state agencies in Maryland, the U.S. Army Corps of Engineers, the U.S. Geological Survey, the University of Maryland Center for Environmental Science and the U.S. Environmental Protection Agency Chesapeake Bay Program to design, conduct and fund an additional multi-year sediment study. Exelon has agreed to contribute up to $3.5 million to fund the additional study. Resolution of these issues relating to Conowingo may have a material effect on Exelon's and Generation's results of operations and financial position through an increase in capital expenditures and operating costs.

On June 3, 2014, subsequently amended December 9, 2014, the PA DEP issued its water quality certificate for Muddy Run, which is a necessary step in the FERC licensing process and included certain commitments made by Generation. The financial impact associated with these commitments is estimated to be in the range of $25 million to $35 million, and will include both capital expenditures and operating expenses, primarily relating to fish passage and habitat improvement projects.

The FERC licenses for Muddy Run and Conowingo were set to expire on August 31, 2014 and September 1, 2014 respectively. FERC is required to issue annual licenses for the facilities until the new licenses are issued. On September 10, 2014, FERC issued annual licenses for Conowingo and Muddy Run, effective as of the expiration of the previous licenses. If FERC does not issue new licenses prior to the expiration of annual licenses, the annual licenses will renew automatically. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. As of December 31, 2014, $39 million of direct costs associated with licensing efforts have been capitalized.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

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The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of December 31, 2014 and 2013.

December 31, 2014	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 247	$ 3,009	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	6	1,536	—	64	—	1,400	6	72
AMI programs	25	271	10	81	15	62	—	128
Under-recovered distribution service costs	251	120	251	120	—	—	—	—
Debt costs	8	49	6	47	2	2	1	8
Fair value of BGE long-term debt	7	183	—	—	—	—	—	—
Severance	4	8	—	—	—	—	4	8
Asset retirement obligations	1	115	1	73	—	26	—	16
MGP remediation costs	36	221	30	189	6	31	—	1
Under-recovered uncollectible accounts	—	67	—	67	—	—	—	—
Renewable energy	20	187	20	187	—	—	—	—
Energy and transmission programs	37	11	26	7	—	—	11	4
Deferred storm costs	1	2	—	—	—	—	1	2
Electric generation-related regulatory asset	10	20	—	—	—	—	10	20
Rate stabilization deferral	75	85	—	—	—	—	75	85
Energy efficiency and demand response programs	89	159	—	—	—	—	89	159
Merger integration costs	2	6	—	—	—	—	2	6
Conservation voltage reduction	1	1	—	—	—	—	1	1
Under-recovered electric revenue decoupling	7	—			—	—	7	—
Other [(a)]	20	26	5	17	6	8	7	—
Total regulatory assets	$ 847	$ 6,076	$ 349	$ 852	$ 29	$ 1,529	$ 214	$ 510

December 31, 2014	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Other postretirement benefits	$ 51	$ 37	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	—	2,879	—	2,389	—	490	—	—
Removal costs	118	1,448	94	1,249	—	—	24	199
Energy efficiency and demand response programs	25	2	25	—	—	2	—	—
DLC program costs	—	10	—	—	—	10	—	—
Energy efficiency phase II	—	32	—	—	—	32	—	—
Electric distribution tax repairs	8	94	—	—	8	94	—	—
Gas distribution tax repairs	20	29	—	—	20	29	—	—
Energy and transmission programs	68	16	3	16	58	—	7	—
Over-recovered electric universal service fund costs	2	—	—	—	2	—	—	—
Revenue subject to refund	3	—	3	—	—	—	—	—
Over-recovered gas revenue decoupling	12	—	—	—	—	—	12	—
Other	3	3	—	1	2	—	1	1
Total regulatory liabilities	$ 310	$ 4,550	$ 125	$ 3,655	$ 90	$ 657	$ 44	$ 200

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December 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 221	$ 2,794	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	10	1,459	2	65	—	1,317	8	77
AMI programs	5	159	5	35	—	58	—	66
AMI meter events	—	5	—	—	—	5	—	—
Under-recovered distribution service costs	178	285	178	285	—	—	—	—
Debt costs	12	56	9	53	3	3	1	8
Fair value of BGE long-term debt	—	219	—	—	—	—	—	—
Fair value of BGE supply contracts	12	—	—	—	—	—	—	—
Severance	16	12	12	—	—	—	4	12
Asset retirement obligations	1	102	1	67	—	25	—	10
MGP remediation costs	40	212	33	178	6	33	1	1
RTO start-up costs	2	—	2	—	—	—	—	—
Under-recovered uncollectible accounts	—	48	—	48	—	—	—	—
Renewable energy	17	176	17	176	—	—	—	—
Energy and transmission programs	53	9	52	6	—	—	1	3
Deferred storm costs	3	3	—	—	—	—	3	3
Electric generation-related regulatory asset	13	30	—	—	—	—	13	30
Rate stabilization deferral	71	154	—	—	—	—	71	154
Energy efficiency and demand response programs	73	148	—	—	—	—	73	148
Merger integration costs	2	9	—	—	—	—	2	9
Other [(a)]	31	30	18	20	8	7	4	3
Total regulatory assets	$ 760	$ 5,910	$ 329	$ 933	$ 17	$ 1,448	$ 181	$ 524

December 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Other postretirement benefits	$ 2	$ 43	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	—	2,740	—	2,293	—	447	—	—
Removal costs	99	1,423	78	1,219	—	—	21	204
Energy efficiency and demand response programs	53	—	45	—	8	—	—	—
DLC Program Costs	1	10	—	—	1	10	—	—
Energy efficiency phase II	—	21	—	—	—	21	—	—
Electric distribution tax repairs	20	114	—	—	20	114	—	—
Gas distribution tax repairs	8	37	—	—	8	37		
Energy and transmission programs	78	—	9	—	58	—	11	—
Over-recovered gas universal service fund costs	8	—	—	—	8	—	—	—
Revenue subject to refund	38	—	38	—	—	—	—	—
Over-recovered electric and gas revenue decoupling	16	—	—	—	—	—	16	—
Other	4	—	—	—	3	—	—	—
Total regulatory liabilities	$ 327	$ 4,388	$ 170	$ 3,512	$ 106	$ 629	$ 48	$ 204

(a) For ComEd and BGE, includes Purchase of Receivable Program regulatory assets. As of December 31, 2014, ComEd and BGE had a regulatory asset related to the Purchase of Receivable Program of $14 million and $7 million, respectively. As of December 31, 2013, ComEd and BGE had a regulatory asset related to the Purchase of Receivable Program of $27 million and $0 million, respectively.

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Pension and other postretirement benefits. As of December 31, 2014, Exelon had regulatory assets of $3,256 million and regulatory liabilities of $88 million related to ComEd's and BGE's portion of deferred costs associated with Exelon's pension plans and ComEd's, PECO's and BGE's portion of deferred costs associated with Exelon's other postretirement benefit plans. PECO's pension regulatory recovery is based on cash contributions and is not included in the regulatory asset (liability) balances. The regulatory asset (liability) is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses (gains) attributable to Exelon's pension and other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd, PECO and BGE will recover these costs through base rates as allowed in their most recently approved regulated rate orders. The pension and other postretirement benefit regulatory asset balance includes a regulatory asset established at the date of the Constellation merger related to BGE's portion of the deferred costs associated with legacy Constellation's pension and other postretirement benefit plans. The BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the Constellation merger. See Note 16—Retirement Benefits for additional detail. No return is earned on Exelon's regulatory asset.

Deferred income taxes. These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded under GAAP. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with the authoritative guidance for accounting for certain types of regulation and income taxes, include the deferred tax effects associated principally with accelerated depreciation accounted for in accordance with the ratemaking policies of the ICC, PAPUC and MDPSC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For ComEd and BGE, this amount includes the impacts of a reduction in the deductibility, for Federal income tax purposes, of certain retiree health care costs pursuant to the March 2010 Health Care Reform Acts. ComEd was granted recovery of these additional income taxes on May 24, 2011 in the ICC's 2010 Rate Case order. The recovery period for these costs was through May 31, 2014. For BGE, these additional income taxes are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. For PECO, this amount includes the impacts of electric and gas distribution repairs in the deductibility pursuant to PUC's 2010 rate case settlement agreement. See Note 14—Income Taxes and Note 16—Retirement Benefits for additional information. ComEd, PECO and BGE are not earning a return on the regulatory asset in base rates.

AMI programs. For ComEd, this amount represents operating and maintenance expenses and meter costs associated with ComEd's AMI pilot program approved in the May 24, 2011, ICC order in ComEd's 2010 rate case. The recovery periods for operating and maintenance expenses and meter costs through May 31, 2014, and January 1, 2020, respectively. As of December 31, 2014 and December 31, 2013, ComEd had regulatory assets of $88 million and $35 million, respectively, related to accelerated depreciation costs resulting from the early retirements of non-AMI meters, which will be amortized over an average ten year period pursuant to the ICC approved AMI Deployment plan. ComEd is earning a return on the regulatory asset. For PECO, this amount represents accelerated depreciation and filing and implementation costs relating to the PAPUC-approved Smart Meter Procurement and Installation Plan as well as the return on the un-depreciated investment, taxes, and operating and maintenance expenses. The approved plan allows for recovery of filing and implementation costs incurred through December 31, 2012. In addition, the approved plan provides for recovery of program costs, which includes depreciation on new equipment placed in service, beginning in January 2011 on full and current basis, which includes interest income or expense on the under or

over recovery. The approved plan also provides for recovery of accelerated depreciation on PECO's non-AMI meter assets over a 10-year period ending December 31, 2020. For BGE, this amount represents smart grid pilot program costs as well as the incremental costs associated with implementing full deployment of a smart grid program. Pursuant to a MDPSC order, pilot program costs of $11 million were deferred in a regulatory asset, and, beginning with the MDPSC's March 2011 rate order, is earning BGE's most current authorized rate of return. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE, authorizing BGE to establish a separate regulatory asset for incremental costs incurred to implement the initiative, including the net depreciation and amortization costs associated with the meters, and an authorized rate of return on these costs, a portion of which is not recognized under GAAP until cost recovery begins. Additionally, the MDPSC order requires that BGE prove the cost-effectiveness of the entire smart grid initiative prior to seeking recovery of the costs deferred in these regulatory assets. Therefore, the commencement and timing of the amortization of these deferred costs is currently unknown. BGE's AMI regulatory asset excludes costs for non-AMI meters being replaced by AMI meters, as recovery of those costs commenced with the new rates approved and implemented with the MDPSC order in BGE's 2014 electric and gas distribution case.

AMI Meter Events. This amount represents the remaining cost value of the original smart meters, net of accumulated depreciation, DOE reimbursements and amounts recovered from the vendor, of smart meter deployment that will no longer be used, including installation and removal costs. PECO intended to seek through regulatory rate recovery in a future filing with the PAPUC, any amounts not recovered from the vendor. PECO believed the amounts incurred for the original meters and related installation and removal costs were probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As such, PECO deferred these costs on Exelon's and PECO's Consolidated Balance Sheet, beginning in 2012. PECO did not earn a return on the recovery of these costs. Pursuant to the January 23, 2014, vendor agreement, PECO reclassified the regulatory asset balance as a receivable, which has been fully collected, with no gain or loss impacts on future results of operations.

Under-recovered distribution services costs. Under EIMA, ComEd is allowed recovery of distribution services costs through a formula rate tariff. The legislation provides for an annual reconciliation of the revenue requirement in effect to reflect the actual costs that the ICC determines are prudently and reasonably incurred in a given year. The over recovery associated with the 2011 reconciliation was recovered through rates over a one-year period, that began in January 2013. The under recovery associated with the 2012 reconciliation was recovered through rates over a one-year period that began in January 2014. The under recovery associated with the 2013 reconciliation will be recovered through rates over a one-year period beginning in January 2015. ComEd is earning a return on these costs. The regulatory asset also includes costs associated with certain one-time events, such as large storms, which will be recovered over a five-year period. As of December 31, 2014, the regulatory asset was comprised of $286 million for the applicable annual reconciliations and $85 million related to significant one-time events. In addition to $66 million in deferred storm costs, net of amortization, the December 31, 2014 balance related to significant one-time events contains $19 million of Constellation merger and integration related costs, net of amortization, incurred as a result of the Constellation merger. As of December 31, 2013, the regulatory asset was comprised of $377 million for the applicable annual reconciliations and $86 million related to significant one-time events. In addition to $58 million in deferred storm costs, net of amortization, the December 31, 2013 balance related to significant one-time events contains $28 million of Constellation merger and integration related costs, net of amortization, incurred as a result of the Constellation merger. See Note 4—Mergers, Acquisitions, and Dispositions for additional information.

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Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd's, PECO's and BGE's recoverable losses on reacquired long-term debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding or the life of the original issuance retired. These debt costs are used in the determination of the weighted cost of capital applied to rate base in the rate-making process. ComEd and BGE are not earning a return on the recovery of these costs, while PECO is earning a return on the premium of the cost of the reacquired debt through base rates.

Fair value of BGE long-term debt. These amounts represent the regulatory asset recorded at Exelon for the difference in the fair value of the long-term debt of BGE as of the Constellation merger date based on the MDPSC practice to allow BGE to recover its debt costs through rates. Exelon is amortizing the regulatory asset and the associated fair value over the life of the underlying debt and is not earning a return on the recovery of these costs.

Fair value of BGE supply contract. These amounts represent the regulatory asset recorded at Exelon representing the fair value of BGE's supply contracts as of the close of the Constellation merger date based on the MDPSC practice to allow BGE to recover its supply contracts through rates. Exelon amortized the regulatory asset and the associated fair value through December 31, 2014 and was not earning a return on the recovery of these contracts.

Severance. For ComEd, these costs represent previously incurred severance costs that ComEd was granted recovery of in the December 20, 2006, ICC rehearing rate order and the May 24, 2011, ICC order in ComEd's 2010 rate case, and such costs were fully recovered as of December 31, 2014. ComEd did not earn a return on these costs. For BGE, these costs represent deferred severance costs that BGE has previously been granted recovery of in rates. Costs include the portion of costs associated with a 2008 workforce reduction that relate to BGE's gas business which were deferred in 2009 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period through December 31, 2013. Also included are costs associated with a 2010 workforce reduction that were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. Finally, costs associated with the 2012 BGE voluntary workforce reduction were deferred in 2012 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period that began in July 2012. BGE is earning a regulated return on the regulatory asset included in base rates.

Asset retirement obligations. These costs represent future legally required removal costs associated with existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd and BGE will recover these costs through future depreciation rates and will earn a return on these costs once the removal activities have been performed. See Note 15—Asset Retirement Obligations for additional information.

MGP remediation costs . ComEd is allowed recovery of these costs under ICC approved rates. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures. ComEd and PECO are not earning a return on the recovery of these costs. While BGE does not have a rider for MGP clean-up costs, BGE has historically received

recovery of actual clean-up costs on a site-specific basis in distribution rates. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. These costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. BGE is earning a return on this regulatory asset. See Note 22—Commitments and Contingencies for additional information.

RTO start-up costs. Recovery of these RTO start-up costs was approved by FERC. The recovery period is through March 31, 2015. ComEd is earning a return on these costs.

Under (Over)-recovered universal service fund costs. The universal service fund cost is a recovery mechanism that allows PECO to recover discounts issued to electric and gas customers enrolled in assistance programs. As of December 31, 2014, PECO was under-recovered for its gas program and over-recovered for its electric program. Whereas, as of December 31, 2013, PECO was over-recovered for both its electric and gas programs PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers.

Under (Over)-recovered uncollectible accounts. ComEd adjusts its rates annually to reflect the increases and decreases in annual uncollectible accounts costs. The recovery or refund of the difference in the uncollectible accounts costs takes place over a 12-month time frame beginning in June of the following year. ComEd is not earning a return or paying interest on these under (over)-recovered costs.

Renewable Energy. On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy. Delivery under the contracts began in June 2012. Since the swap contracts were deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price.

Energy and transmission programs. ComEd's energy and transmission costs are recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. ComEd earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2014, ComEd's regulatory asset of $33 million included $4 million related to under-recovered energy costs for non-hourly customers, $22 million associated with transmission costs recoverable through its FERC-approved formulate rate, and $7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2014, ComEd's regulatory liability of $19 million included $3 million related to over-recovered energy costs for hourly customers and $16 million associated with revenues received for renewable energy requirements. As of December 31, 2013, ComEd's regulatory asset of $58 million included $35 million related to under-recovered energy costs for hourly and non-hourly customers, $17 million associated with transmission costs recoverable through its FERC-approved formula rate, and $6 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2013, ComEd's regulatory liability of $9 million related to revenues received for renewable energy requirements.

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The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO's GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. In addition, beginning in 2013, the deferred DSP I and II Program costs are presented on a net basis with PECO's GSA under (over)-recovered energy costs. See discussion below of each program. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2014, PECO had a regulatory liability that included $39 million related to the DSP program, $16 million related to over-recovered natural gas supply costs under the PGC and $3 million related to over-recovered electric transmission costs. As of December 31, 2013, PECO had a regulatory liability that included $34 million related to the DSP program, $8 million related the over-recovered electric transmission costs and $16 million related to over-recovered natural gas supply costs under the PGC.

DSP Program costs . These amounts represent recoverable administrative costs incurred relating to filing, procurement, and information technology improvements associated with PECO's PAPUC- approved DSP Program for the procurement of electric supply following the expiration of PECO's generation rate caps on December 31, 2010. The filing and implementation costs of this DSP Program are recoverable through the GSA over its 29-month term that began January 1, 2011. The independent evaluator costs associated with conducting procurements is recoverable over a 12-month period after the PAPUC approves the results of the procurements. Costs relating to information technology improvements are recoverable over a 5-year period that began January 1, 2011. PECO earns a return on the recovery of information technology costs. These costs are included within the energy and transmission programs line item.

DSP II Program Costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO's second PAPUC-approved DSP program for the procurement of electric supply. The filing and procurement of this DSP Program are recoverable through the GSA over its 24-month term that began June 1, 2013. The independent evaluator costs associated with conducting procurements are recoverable over a 12-month period after the PAPUC approves the results of the procurements. PECO is not earning a return on these costs. These costs are included within the energy and transmission programs line item.

The BGE energy costs represent the electric and gas supply related costs recoverable (refundable) from (to) customers under BGE's market-based SOS and MBR programs, respectively. BGE does not earn or pay interest on under- or over-recovered costs to customers. As of December 31, 2014, BGE's regulatory asset of $15 million included $10 million related to under-recovered electric energy costs, $4 million of Constellation merger and integration costs and $1 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2014, BGE's regulatory liability of $7 million related to over-recovered natural gas supply costs. As of December 31, 2013, BGE's regulatory asset of $4 million included $3 million of Constellation merger and integration costs and $1 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2013, BGE's regulatory liability of $11 million related to over-recovered natural gas supply costs.

Deferred storm costs. In the MDPSC's March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. These costs are being amortized over a 5-year period that began in December 2010. BGE is earning a return on this regulatory asset.

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Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. The portion of this regulatory asset that does not earn a regulated rate of return was $28 million as of December 31, 2014, and $37 million as of December 31, 2013. BGE will continue to amortize this amount through 2017.

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006 to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007 to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2014 and 2013, BGE recovered $65 million and $66 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007.

Energy efficiency and demand response programs. These amounts represent costs recoverable (refundable) under ComEd's ICC approved Energy Efficiency and Demand Response Plan, PECO's PAPUC-approved EE&C Plan, and the BGE Smart Energy Savers Program ®. ComEd recovers these costs through a rider. ComEd earns a return on the capital investment incurred under the program but does not earn (pay) interest on under (over) collections. For PECO, this amount represents an over-collection of program costs related to both Phase I and Phase II of its EE&C Plan. PECO does not earn (pay) interest on under (over) collections. PECO began recovering the costs of its Phase I and Phase II EE&C Plans through a surcharge in January 2010 and June 2013, respectively, based on projected spending under the programs. Phase I recovery continued over the life of the program, which expired on May 31, 2013 and excess funds collected began being refunded in June 2013. Phase II of the program began on June 1, 2013, and will continue over the life of the program, which will expire on May 31, 2016. Excess funds collected are required to be refunded beginning in June 2016. PECO earned a return on the capital investment incurred under Phase I of the program. BGE's Smart Energy Savers Program ® includes both MDPSC approved demand response and energy efficiency programs. For the BGE Peak Rewards SM demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Also included in the demand response program are customer bill credits related to BGE's Smart Energy Rewards program which began in July 2013. Actual costs incurred in the conservation program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

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Merger integration costs. These amounts represent integration costs to achieve distribution synergies related to the Constellation merger transaction. As a result of the MDPSC's February 2013 rate order, BGE deferred $8 million related to non-severance merger integration costs incurred during 2012 and the first quarter of 2013. Of these costs, $4 million was authorized to be amortized over a 5-year period that began in March 2013. The recovery of the remaining $4 million was deferred. In the MDPSC's December 2013 rate order, BGE was authorized to recover the remaining $4 million and an additional $4 million of non-severance merger integration costs incurred during 2013. These costs are being amortized over a 5-year period that began in December 2013. BGE is earning a return on this regulatory asset included in base rates.

Under (Over)-recovered electric and gas revenue decoupling. These amounts represent the electric and gas distribution costs recoverable from or (refundable) to customers under BGE's decoupling mechanism, which does not earn a rate of return. As of December 31, 2014, BGE had a regulatory asset of $7 million related to under-recovered electric revenue decoupling and a regulatory liability of $12 million related to over-recovered natural gas revenue decoupling. As of December 31, 2013, BGE had a regulatory liability of $7 million related to over-recovered electric revenue decoupling and $9 million related to over-recovered natural gas revenue decoupling.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs for the Regulatory Agreement Units that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will be sufficient to fund the associated future decommissioning costs at the time of decommissioning. See Note 15—Asset Retirement Obligations for additional information.

Removal costs. These amounts represent funds ComEd and BGE have received from customers through depreciation rates to cover the future non-legally required cost of removal of property, plant and equipment which reduces rate base for ratemaking purposes. This liability is reduced as costs are incurred.

DLC Program Costs. The DLC program costs include equipment, installation, and information technology costs necessary to implement the DLC Program under PECO's EE&C Phase I Plans. PECO received full cost recovery through Phase I collections and will amortize the costs as a credit to the income statement to offset the related depreciation expense during the same period through September 2025, which is the remaining useful life of the assets. PECO is not paying interest on these over-recovered costs.

Electric distribution tax repairs. PECO's 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits began being reflected in customer bills on January 1, 2012. No interest will be paid to customers.

Gas distribution tax repairs. PECO's 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits began being reflected in customer bills on January 1, 2013. No interest will be paid to customers.

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Under (Over)-recovered AEPS costs current asset (liability). The AEPS costs represent the administrative and AEC costs incurred to comply with the requirements of the AEPS Act, which are recoverable on a full and current basis. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. These costs are included within the energy and transmission programs line item.

Revenue subject to refund. These amounts represent refunds and associated interest ComEd owes to customers primarily related to the treatment of the post-test year accumulated depreciation issue in the 2007 Rate Case. As of December 31, 2014, and December 31, 2013, ComEd owed $3 million and $37 million with $1 million of interest, respectively. See above discussion of the 2007 Rate Case for further information.

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities' consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd purchases receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. BGE's tariff provides that receivables are to be purchased at a discount, primarily to recover uncollectible accounts expense from the suppliers. However, if the discount rate is negative, the tariff provides that the receivable is purchased at a zero discount rate. BGE is currently purchasing certain receivables at a zero discount rate. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO, and BGE do not record unbilled commodity receivables under their POR programs. Purchased billed receivables are classified in other accounts receivable, net on Exelon's, ComEd's, PECO's and BGE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of December 31, 2014 and 2013.

As of December 31, 2014	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 290	$ 139	$ 76	$ 75
Allowance for uncollectible accounts [b]	(42)	(21)	(8)	(13)
Purchased receivables, net	$ 248	$ 118	$ 68	$ 62

As of December 31, 2013	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 263	$ 105	$ 72	$ 86
Allowance for uncollectible accounts [b]	(30)	(16)	(7)	(7)
Purchased receivables, net	$ 233	$ 89	$ 65	$ 79

(a) PECO's gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.

(b) For ComEd and BGE, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing (PORCB) tariff.

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4. Mergers, Acquisitions, and Dispositions

Proposed Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI's shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $126 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI as of December 31, 2014, with additional investments of $18 million to be made quarterly up to a maximum aggregate investment of $180 million. The preferred securities are included in Other non-current assets on Exelon's Consolidated Balance Sheet. PHI has the right to redeem the preferred securities at its option for the purchase price paid plus accrued dividends, if any. Exelon expects total cash required to fund the acquisition of common stock and preferred securities plus other related acquisition costs to total approximately $7.2 billion. As part of the applications for approval of the merger, Exelon and PHI proposed a package of benefits to the PHI utilities' respective customers, providing for direct investment of more than $100 million with the actual amount and timing of any related payments dependent upon settlement discussions in merger regulatory approval proceedings and the terms of regulatory orders approving the merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU) and the FERC have approved the merger of PHI and Exelon. The Federal Communications Commission has also approved the transfer of certain PHI communications licenses. On February 11, 2015, the NJBPU approved the proposed merger and the previously filed settlement signed and filed by Exelon, PHI, Atlantic City Electric (ACE), NJBPU staff, and the Independent Energy Coalition. The settlement provides a package of benefits to ACE customers and the state of New Jersey. This package of benefits includes the establishment of customer rate credit programs, with an aggregate value of $62 million for ACE customers and energy efficiency programs that will provide savings for ACE customers of $15 million.

Completion of the transaction also remains conditioned upon approval by the Public Services Commissions of the District of Columbia, Delaware and Maryland. Procedural schedules have been set in these commission proceedings and final approval decisions are expected in the first half of 2015.

On October 9, 2014, PHI and Exelon each received a request for additional information from the DOJ. The request had the effect of extending the DOJ review period until 30 days after PHI and Exelon each has certified that it had substantially complied with the request. On November 21, 2014, Exelon and PHI each certified that it had substantially complied with the request. Accordingly, the HSR Act waiting period expired on December 22, 2014, and the HSR Act no longer precludes completion of the merger. Although the DOJ allowed the waiting period under the HSR Act to expire without taking any action with respect to the merger, the DOJ has not advised Exelon or PHI that it has concluded its investigation. Exelon and PHI will continue to work cooperatively with the DOJ regarding the proposed merger.

Exelon and PHI continue to expect to complete the merger in the second or third quarter of 2015.

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Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. In September 2014, the parties reached a proposed settlement which is subject to court approval. Final court approval of the proposed settlement is not expected to occur until the second quarter of 2015, at the earliest. Exelon has also been named in a federal court case with similar claims and is in the process of negotiating a settlement. Exelon does not believe these suits will impact the completion of the transaction, and they are not expected to have a material impact on Exelon's results of operations.

Through December 31, 2014, Exelon has incurred approximately $179 million of expense associated with the proposed merger, primarily $48 million related to acquisition and integration costs and $131 million of costs incurred to finance the transaction. The Merger Agreement also provides for termination rights on behalf of both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the Merger Agreement does not close due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities of PHI described above, through the redemption by PHI of the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock.

Merger Financing

Exelon intends to fund the all-cash transaction using a combination of approximately $3.5 billion of debt, up to $1.0 billion in cash from asset sales primarily at Generation, and the remainder through issuance of equity (including mandatory convertible securities). On June 11, 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share in connection with forward sales agreements and $1.2 billion of junior subordinated notes in the form of 23 million equity units. In addition, Exelon signed a 364-day $7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing, which has subsequently been reduced to a $3.2 billion facility as a result of the execution of the debt and equity security issuances and the net after-tax cash proceeds from generating asset divestitures during the second half of 2014. See Note 13—Debt and Credit Agreements and Note 19—Common Stock for more information.

Acquisitions (Exelon and Generation)

Acquisition of Integrys Energy Services, Inc. (Exelon and Generation)

On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (Integrys) for a purchase price of $332 million, including net working capital. Generation has elected to account for the transaction as an asset acquisition for federal income tax purposes. As of December 31, 2014, Generation had remitted $319 million to Integrys Energy Group, Inc. and the remaining balance of $13 million, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets, will be paid during the first or second quarter of 2015. The generation and solar asset businesses of Integrys are excluded from the transaction. The Purchase Agreement also includes various representations, warranties, covenants, indemnification and other provisions customary for a transaction of this nature.

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Consistent with the applicable accounting guidance, the fair value of the assets acquired and liabilities assumed was determined as of the acquisition date through the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including the amount and timing); discount rates reflecting the risk inherent in the future cash flows; and future power and fuel market prices.

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the Integrys acquisition by Generation:

Total consideration transferred	$ 332
Identifiable assets acquired and liabilities assumed	
Working capital assets	$ 389
Mark-to-market derivative assets	185
Unamortized energy contract assets	115
Customer relationships	48
Working capital liabilities	(195)
Mark-to-market derivative liabilities	(57)
Unamortized energy contract liabilities	(109)
Deferred tax liability	(16)
Total net identifiable assets, at fair value	$ 360
Bargain purchase gain (after-tax)	$ 28

The purchase accounting is preliminary, and although not expected, may be further adjusted from what is shown above.

The after-tax bargain purchase gain of $28 million is primarily the result of IES executing additional contract volumes between the date the acquisition agreement was signed and the closing of the transaction resulting in an increase in the fair value of the net assets acquired as of the acquisition date. The after-tax gain is included within Gain on consolidation and acquisition of businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

IES's operating revenue and net loss included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the period from November 1, 2014 to December 31, 2014 were approximately $386 million and $(42) million, respectively. The net loss includes pre-tax unrealized losses on derivative contracts of $108 million and the bargain purchase gain of $28 million. Exelon and Generation incurred approximately $7 million of merger and integration related costs which are included within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Merger with Constellation (Exelon, Generation, ComEd, PECO and BGE)

Description of Constellation Merger Transaction

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial

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Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

Regulatory Matters from the Constellation Merger

In February 2012, the MDPSC issued an order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion.

The following costs were recognized after the closing of the merger and are included in Exelon's, Generation's and BGE's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2012:

Description	Payment Period	BGE	Generation	Exelon	Statement of Operations Location
BGE rate credit of $100 per residential customer [(a)]	Q2 2012	$113	$ —	$ 113	Revenues
Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers	2012 to 2014	—	—	114	O&M Expense
Contribution for renewable energy, energy efficiency or related projects in Baltimore	2012 to 2014	—	—	2	O&M Expense
Charitable contributions at $7 million per year for 10 years	2012 to 2021	28	35	70	O&M Expense
State funding for offshore wind development projects	Q2 2012	—	—	32	O&M Expense
Miscellaneous tax benefits	Q2 2012	(2)	—	(2)	Taxes Other Than Income
Total		$139	$ 35	$ 329	

(a) Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

The direct investment estimate includes $95 million to $120 million relating to the construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a 20 year lease agreement that was contingent upon the developer obtaining all required approvals, permits and financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. See Note 22—Commitments and Contingencies for further information regarding Generation's total commitments under the lease agreement.

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The direct investment estimate also includes $600 million to $650 million for Exelon's and Generation's commitment to develop or assist in development of 285—300MWs of new generation in Maryland, expected to be completed over a period of 10 years. The MDPSC order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed or certain specified provisions are elected, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. However, during the third quarter of 2014, the conditions associated with one of the generation development commitments changed such that Exelon and Generation now believe that the most likely outcome will involve making subsidy payments and/or liquidated damages payments rather than constructing the specified generating plant. As a result, Exelon and Generation recorded a pre-tax $44 million loss contingency related to this generation development commitment which is included in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. While this $44 million loss contingency represents Generation's best estimate of the future obligation, it is reasonably possible that Exelon and Generation could ultimately be required to make cumulative subsidy payments of up to a maximum of approximately $105 million over a 20-year period dependent on actual generating output from a successfully constructed generating plant.

To date, Generation has placed into service 40MW and has commenced development of 150MW of new generation in Maryland towards the 300MW commitment. In July 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland site with at least 120MW of natural gas-fired generation to satisfy one of the commitments to Maryland with achievement of commercial operation expected in 2015. In December 2013, Generation entered into contracts associated with the construction of the 40MW Fourmile Wind project, which was placed in service in December 2014. In December 2014, Generation entered into contracts associated with the construction of the 30MW Fair Wind project in western Maryland with achievement of commercial operations expected in 2015. The wind projects will satisfy a portion of the 125MW Tier I land-based renewables commitment. See Note 22—Commitments and Contingencies for additional information. Exelon's and Generation's consolidated financial statements include $185 million and $24 million of capitalized expenditures within Property, plant and equipment, net as of December 31, 2014 and 2013, respectively, and $3 million and $6 million of development costs within Operating and maintenance expense for the periods ended December 31, 2014 and 2013, respectively, associated with the pursuit of these commitments for new generation in the State of Maryland.

Associated with certain of the regulatory approvals required for the merger, on November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, to Raven Power Holdings LLC (Raven Power), a subsidiary of Riverstone Holdings LLC. The sale agreement included a base price with purchase price adjustments based on fuel inventory, working capital, capital expenditures, and timing of the closing, resulting in net proceeds from the sale of approximately $371 million. Decisions by certain market participants to remove themselves from the bidding process, combined with the deadlines and limitations on the pool of potential buyers imposed by the merger approval orders, resulted in realized sales proceeds below Generation's estimated fair value of the Maryland generating stations. Consequently, Exelon and Generation recorded a pre-tax loss of $272 million in 2012 to reflect the difference between the sales price and the carrying value of the generating stations and associated assets. In the first quarter of 2013, Exelon and Generation recorded a pre-tax gain of $8 million to reflect the final settlement of the sales price with Raven Power.

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In connection with the sale of the Maryland generating stations, Exelon agreed to indemnify Raven Power for certain costs associated with the treatment of hazardous substances at off-site disposal facilities and any claims arising as a result of, or in connection with, any toxic tort, natural resource damages, loss of life or injury to persons due to releases of, or exposure to hazardous substances in connection with Raven Power's remediation of environmental contamination or Exelon's non-compliance with environmental laws or permits prior to the closing date of the sale.

Pursuant to the MDPSC merger approval conditions, BGE was restricted from paying any dividend on its common shares through the end of 2014, was required to maintain specified minimum capital and O&M expenditure levels in 2012 and 2013, and was not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process for two years following the closing of the merger. Additionally, BGE is subject to other merger approval conditions to enhance BGE's ring-fencing measures established by order of the MDPSC.

Subsequent to the merger, Generation discovered that, for the first two weeks following the merger, due to a software error, Generation inadvertently bid certain generating units into the PJM energy market at prices that slightly exceeded the cost-based caps to which it had agreed. This error was a violation of the commitments made in connection with merger approvals by DOJ, FERC and the MDPSC. Generation reported the error to the DOJ, FERC and the MDPSC and committed to remedy the impacts of its error. The MDPSC held a hearing to review the error, and accepted Generation's proposed remediation. Subsequent close examination by Generation of its cost-based bids also revealed the need for some minor adjustments to the cost build up for certain of its PJM units. Generation has coordinated with PJM to determine the impact on Generation's revenues and the market from this error and these adjustments, and Generation has worked with PJM to reverse the financial impacts. In November 2012, Generation reached a settlement with the DOJ regarding this matter. The final resolution did not have a material impact on Exelon's or Generation's results of operations, cash flows or financial position.

Exelon was named in suits filed in the Circuit Court of Baltimore City, Maryland alleging that individual directors of Constellation breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. Similar suits were also filed in the United States District Court for the District of Maryland. The suits sought to enjoin a Constellation shareholder vote on the proposed merger until all material information was disclosed and sought rescission of the proposed merger. During the third quarter of 2011, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. On June 26, 2012, the court approved the settlement and entered final judgment.

Accounting for the Constellation Merger

The fair value of Constellation's non-regulated business assets acquired and liabilities assumed was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The financial statements of BGE do not include fair value adjustments for assets or liabilities subject to ratesetting provisions for BGE. BGE is subject to the rate-setting authority of FERC and the MDPSC and is accounted for pursuant to the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for BGE provide revenue derived from costs

including a return on investment of assets and liabilities included in rate base. Except for debt, fuel supply contracts and regulatory assets not earning a return, the fair values of BGE's tangible and intangible assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore, do not reflect any net adjustments related to these amounts. For BGE's debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE's assets acquired and liabilities assumed is recorded as a regulatory asset and liability at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 1—Significant Accounting Policies for additional information on BGE's push-down accounting treatment. Also see Note 3—Regulatory Matters for additional information on BGE's regulatory assets.

The preliminary valuations performed in the first quarter of 2012 were updated in the second, third and fourth quarters of 2012, with the most significant adjustments to the preliminary valuation amounts having been made to the fair values assigned to the acquired power supply and fuel contracts, unregulated property, plant and equipment and investments in affiliates. There were no significant adjustments to the purchase price allocation in the first quarter of 2013 and the purchase price allocation was final as of March 31, 2013.

The final purchase price allocation of the Merger of Exelon with Constellation and Exelon's contribution of certain subsidiaries of Constellation to Generation was as follows:

Preliminary Purchase Price Allocation, excluding amortization	Exelon	Generation
Current assets	$ 4,936	$ 3,638
Property, plant, and equipment	9,342	4,054
Unamortized energy contracts	3,218	3,218
Other intangibles, trade name and retail relationships	457	457
Investment in affiliates	1,942	1,942
Pension and OPEB regulatory asset	740	—
Other assets	2,265	1,266
Total assets	22,900	14,575
Current liabilities	3,408	2,804
Unamortized energy contracts	1,722	1,512
Long-term debt, including current maturities	5,632	2,972
Noncontrolling interest	90	90
Deferred credits and other liabilities and preferred securities	4,683	1,933
Total liabilities, preferred securities and noncontrolling interest	15,535	9,311
Total purchase price	$ 7,365	$ 5,264

Impact of the Constellation Merger

It is impracticable to determine the overall financial statement impact for the Constellation subsidiaries contributed down to Generation following the Upstream Merger for the year ended December 31, 2012. Upon closing of the merger, the operations of these Constellation subsidiaries were integrated into Generation's operations and are therefore not fully distinguishable after the merger.

The impact of BGE on Exelon's Consolidated Statement of Operations and Comprehensive Income includes operating revenues of $3,165 million, $3,065 million and $2,091 million and net

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income (loss) $211 million, $210 million and $(31) million during the years ended December 31, 2014, 2013 and 2012, respectively.

During the year ended December 31, 2014, Exelon and Generation both incurred merger and integration-related costs of $22 million. Of these amounts, nothing was deferred as a regulatory asset as of December 31, 2014.

During the year ended December 31, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $142 million, $106 million, $16 million, $9 million and $6 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $17 million, $11 million and $6 million, respectively, as a regulatory asset as of December 31, 2013. Additionally, Exelon and BGE established a regulatory asset of $6 million as of December 31, 2013 for previously incurred 2012 merger and integration-related costs.

During the year ended December 31, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $804 million, $340 million, $41 million, $17 million and $182 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $58 million, $36 million and $22 million, respectively, as a regulatory asset as of December 31, 2012.

The costs incurred are classified primarily within Operating and maintenance expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the BGE customer rate credit and the credit facility fees, which are included as a reduction to Operating revenues and Other, net, respectively, for years ended December 31, 2014, 2013, and 2012. See Note 22—Commitments and Contingencies for additional information.

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Pro-forma Impact of the Constellation Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon and Generation as if the merger with Constellation had taken place on January 1, 2011. The unaudited pro forma information was calculated after applying Exelon's and Generation's accounting policies and adjusting Constellation's results to reflect purchase accounting adjustments.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Exelon		Generation	
	Year Ended December 31,		Year Ended December 31,	
(unaudited)	2012	2011 [a]	2012	2011 [a]
Total revenues	26,700	30,712	17,013	19,494
Net income attributable to Exelon	2,092	974	1,205	324
Basic earnings per share	2.56	1.15	n.a.	n.a.
Diluted earnings per share	2.55	1.14	n.a.	n.a.

(a) The amounts above include non-recurring costs directly related to the merger of $236 million for the year ended December 31, 2011.
(b) The amounts above include non-recurring costs directly related to the merger of $203 million for the year ended December 31, 2011.

Asset Divestitures (Exelon and Generation)

Including the Quail Run generating facility that was sold on January 21, 2015, Generation has sold certain generating assets with a total net book value of approximately $1.8 billion prior to consideration of asset impairments (See Note 8—Impairment of Long-Lived Assets for further information), for total pre-tax proceeds of approximately $1.8 billion (after-tax proceeds of approximately $1.4 billion), which resulted in cumulative pre-tax gains on sale of approximately $412 million, which are included in Gain (loss) on sales of assets on Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income. The proceeds are expected to be used primarily to finance a portion of the acquisition of PHI.

Station	Net Generation Capacity	Location	Operating Segment	Percent Owned
Fore River	726 MW	North Weymouth, MA	New England	100%
West Valley	185 MW	Salt Lake City, UT	Other	100%
Keystone	714 MW	Shelocta, PA	Mid-Atlantic	41.98%
Conemaugh	532 MW	New Florence, PA	Mid-Atlantic	31.28%
Safe Harbor	278 MW	Conestoga, PA	Mid-Atlantic	66.7%
Quail Run	488 MW	Odessa, TX	ERCOT	100%

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At December 31, 2014, the assets and liabilities of the Quail Run generating facility were reported as Assets held for sale and within Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets. The table below presents the major classes of assets and liabilities held for sale at December 31, 2014.

	December 31, 2014
Assets:	
Property, plant and equipment, net [(a)]	$ 143
Inventory	4
Total assets held for sale	$ 147
Liabilities:	
Accrued expenses	$ 1
Asset retirement obligations	4
Total liabilities held for sale [(b)]	$ 5

(a) The total aggregate book value of property, plant and equipment is net of a $50 million pre-tax impairment loss recorded within Operating and maintenance expense on Exelon's and Generation's Statements of Operations and Comprehensive Income. See Note 8—Impairment of Long-Lived Assets for further information.
(b) Included within Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

5. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation has historically had various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements, see Note 25—Related Party Transactions.

On April 1, 2014, Generation and subsidiaries of Generation, EDF, EDF, Inc. (EDFI) (a subsidiary of EDF) and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI's rights as a member of CENG (the Integration Transaction). CENG will reimburse Generation for its direct and allocated costs for such services. As part of the arrangement, Nine Mile Point Nuclear Station, LLC, a subsidiary of CENG, also assigned to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with Long Island Power Authority, the Unit 2 co-owner. In addition, on April 1, 2014, the Power Services Agency Agreement (PSAA) was amended and extended until the permanent cessation of power generation by the CENG generation plants.

In addition, on April 1, 2014, Generation made a $400 million loan to CENG, bearing interest at 5.25% per annum and payable out of specified available cash flows of CENG and, in any event, payable upon the settlement of the Put Option Agreement discussed below (if the put option is exercised) or payable upon the maturity date of April 1, 2034, whichever occurs first. Immediately following receipt of the proceeds of such loan, CENG made a $400 million special distribution to EDFI.

Exelon, Generation, and subsidiaries of Generation, EDFI and its parent (E.D.F. International S.A.S.), and CENG also executed a Fourth Amended and Restated Operating Agreement for CENG on April 1, 2014, pursuant to which, among other things, CENG committed to make preferred

distributions to Generation (after repayment of the $400 million loan and associated interest) quarterly out of specified available cash flows until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from April 1, 2014 (Preferred Distribution Rights).

Generation and EDFI also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDFI has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. The beginning of the exercise period will be accelerated if Exelon's affiliates cease to own a majority of CENG and exercise a related right to terminate the NOSA. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

On April 1, 2014, Generation also executed an Indemnity Agreement pursuant to which Generation indemnified EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity.

In addition, on April 1, 2014, Generation, EDFI, CENG and Nine Mile Point Nuclear Station, LLC entered into an Employee Matters Agreement (EMA) that provides for the transfer of CENG employees to Exelon or one of its affiliates and Exelon's assumption of the sponsorship of the employee benefit plans (including certain incentive, health and welfare, and postemployment benefit plans, among others) and their related trusts by Exelon as the plan sponsor as of July 14, 2014. The EMA also generally requires CENG to fund the obligation related to pre-transfer service of employees, including the underfunded balance of the pension and other postretirement welfare benefit plans measured as of July 14, 2014 by making periodic payments to Generation. These payments will be made on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG.

As a condition to obtaining regulatory approval for the NOSA and related transactions from the NRC, Exelon executed a support agreement pursuant to which Exelon may be required under specified circumstances to provide up to $245 million of financial support to CENG (Exelon Support Agreement). The Exelon Support Agreement supersedes a previous support agreement under which Generation had agreed to provide up to $205 million of financial support for CENG. In addition, Exelon executed a Guarantee pursuant to which Exelon may be required under specified circumstances to provide up to $165 million in additional financial support for CENG. A previous support agreement executed by an affiliate of EDF remains in effect under which the EDF affiliate may be required to provide up to approximately $145 million of financial support for CENG under specified circumstances. The agreements were executed on April 1, 2014 when the NRC licenses were transferred to Generation. No liability has been recognized by Exelon for the guarantees.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. From January 1, 2014, through March 31, 2014, Generation recorded $19 million of equity in losses of unconsolidated affiliates related to its investment in CENG and recorded $17 million of revenues from CENG. For the twelve months ended December 31, 2013, Generation recorded $9 million of equity in losses of unconsolidated affiliates related to its investment

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in CENG and $56 million of revenues from CENG. The book value of Generation's investment in CENG prior to the consolidation was $1.9 billion, and the book value of the AOCI related to CENG prior to consolidation was $116 million, net of taxes of $77 million.

As a result of the consolidation of CENG on April 1, 2014, there are several additional transactions included in Exelon's and Generation's Consolidated Financial Statements between CENG and EDF that are considered related party transactions to Generation. As further described in Note 25—Related Party Transactions EDF and Generation had a PPA with CENG under which they purchased 15% and 85% (through December 31, 2014), respectively, of the nuclear output owned by CENG that was not sold to third parties under pre-existing PPAs. Beginning January 1, 2015 and continuing through the life of the respective plants, EDF and Generation will purchase 49.99% and 50.01%, respectively, of the nuclear output owned by CENG. Beginning April 1, 2014, sales to Generation are eliminated in consolidation. For the year ended December 31, 2014, Generation had sales to EDF of $137 million. See discussion above and Note 2—Variable Interest Entities for additional information regarding other transactions, between CENG and EDF included within Exelon and Generation's financial statements.

See Note 2—Variable Interest Entities for additional information about the Registrant's VIEs.

Accounting for the Consolidation of CENG

The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interest in CENG at fair value on Exelon's and Generation's Consolidated Balance Sheets. As a result of the consolidation, Exelon and Generation recorded a net gain of $261 million within their respective Consolidated Statements of Operations and Comprehensive Income. This gain consists of approximately $136 million related to the step up to fair value basis of our ownership interest in CENG, and approximately $132 million related to the settlement of pre-existing transactions between CENG and Generation. The net gain on the consolidation of CENG of $261 million is net of a $7 million payment to EDF.

The fair value of CENG's assets and liabilities recorded in consolidation was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The valuations necessary to assess the fair values of certain assets and liabilities are considered preliminary as a result of the short time period between the execution of the NOSA and the end of the second quarter of 2014. The estimates of the fair value of assets and liabilities may be modified up to one year from April 1, 2014, as more information is obtained about the fair value of assets and liabilities. The principal items that have been revised include the asset retirement obligation liabilities and related asset retirement costs. These items have been updated with inputs from a third party engineering firm with corresponding adjustments recorded in 2014. See Note 15—Asset Retirement Obligations for discussion of the impacts of adjustments recorded during 2014 related to updated estimates of the CENG asset retirement obligation liabilities. In the period of such revisions, these and any other material changes to the fair value assessments have resulted in adjustments to the amounts recorded upon consolidation. In addition, the asset or liability adjustments impacting depreciation and/or accretion expense recorded after the consolidation date have impacted Generation's post-consolidation results of operations. No material changes are expected to the fair value of assets and liabilities.

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Generation recorded the assets and liabilities of CENG at fair value as of April 1, 2014. The following assets and liabilities of CENG were recorded within Generation's Consolidated Balance Sheets as of the date of integration, adjusted for the modifications discussed above:

Fair Values	Exelon and Generation
Current assets	$ 499
Nuclear decommissioning trust fund	1,955
Property, plant and equipment	3,017
Nuclear fuel	482
Other assets	10
Total assets	5,963
Current liabilities	237
Asset retirement obligation	1,760
Pension and other employee benefit obligations	281
Unamortized energy contract liabilities	171
Other liabilities	114
Total liabilities	2,563
Total net assets	$ 3,400

Generation also recorded the fair value of the noncontrolling interest on its Consolidated Balance Sheets of approximately $1.5 billion, net of the fair value of $152 million for certain specified additional distribution rights under the Operating Agreement. In addition, the noncontrolling interest was further reduced by the $400 million special cash distribution to EDF.

Due to the Preferred Distribution Rights that Generation has on CENG's available cash, the earnings attributable to the noncontrolling interest on the Statements of Operations and Comprehensive Income as well as the corresponding adjustment to Noncontrolling interest on the Consolidated Balance Sheets will not be in proportion to Generation's and EDF's equity ownership interests. Rather, the attribution will consider Generation's Preferred Distribution Rights and allocate net income based on each owner's rights to CENG'S net assets. For the year ended December 31, 2014, Generation reduced by $13 million the amount of Net income attributable to noncontrolling interests on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. As a result of the consolidation, Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income includes CENG's incremental operating revenues of $218 million and CENG's net income, prior to any intercompany eliminations and any adjustments for noncontrolling interest, of $407 million during the year ended December 31, 2014.

Exelon and Generation incurred integration-related costs of $26 million for the year ended December 31, 2014. The costs incurred are classified primarily within Operating and maintenance expense in Exelon's and Generation's respective Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2014.

See Note 17—Severance for integration-related severance costs incurred by Exelon and Generation during the year ended December 31, 2014.

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6. Accounts Receivable (Exelon, Generation, ComEd, PECO and BGE)

Accounts receivable at December 31, 2014 and 2013 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

2014	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$1,381	$ 823[a]	$ 204	$ 140	$214
Allowance for uncollectible accounts [b]	(311)	(60)	(84)	(100) [c]	(67) [d]

2013	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$1,151	$ 584[a]	$ 201	$ 161	$205
Allowance for uncollectible accounts [b]	(272)	(57)	(62)	(107) [c]	(46) [d]

(a) Represents unbilled portion of retail receivables estimated under Exelon's unbilled critical accounting policy.
(b) Includes the allowance for uncollectible accounts on customer and other accounts receivable.
(c) Includes an allowance for uncollectible accounts of $7 million and $8 million at December 31, 2014 and 2013, respectively, related to PECO's current installment plan receivables described below.
(d) At December 31, 2014, as explained in Note 1—Significant Accounting Policies, BGE estimated the allowance for uncollectible accounts on customer receivables by applying loss rates to the outstanding receivable balance by risk segment. The change in estimate resulted in a $19 million pre-tax charge to BGE's provision for uncollectible accounts expense for the year ended December 31, 2014, which is included in Operating and maintenance expense on BGE's Consolidated Statements of Operations and Comprehensive Income.

PECO Installment Plan Receivables (Exelon and PECO). PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $15 million and $19 million as of December 31, 2014 and 2013, respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1—Significant Accounting Policies. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2014 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2013 of $18 million consists of $1 million, $4 million and $13 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of December 31, 2014 and 2013 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1—Significant Accounting Policies.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

7. Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2014 and 2013:

Asset Category	Average Service Life (years)	2014	2013
Electric—transmission and distribution	5-90	$30,157	$28,123
Electric—generation	1-56	22,911	20,420
Gas—transportation and distribution	5-90	3,505	3,296
Common—electric and gas	5-50	1,169	1,101
Nuclear fuel [(a)]	1-8	5,947	5,196
Construction work in progress	N/A	2,167	1,890
Other property, plant and equipment [(b)]	5-50	973	1,017
Total property, plant and equipment		66,829	61,043
Less: accumulated depreciation [(c)]		14,742	13,713
Property, plant and equipment, net		$52,087	$47,330

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,003 million and $947 million at December 31, 2014 and 2013, respectively.
(b) Includes Generation's buildings under capital lease with a net carrying value of $15 million and $23 million at December 31, 2014 and 2013, respectively. The original cost basis of the buildings was $52 million and $59 million, and total accumulated amortization was $37 million and $36 million, as of December 31, 2014 and 2013, respectively. Also includes ComEd's buildings under capital lease with a net carrying value at both December 31, 2014 and 2013, of $8 million. The original cost basis of the buildings was $8 million and total accumulated amortization was immaterial as of December 31, 2014 and 2013, respectively. Includes land held for future use and non utility property at ComEd, PECO, and BGE of $57 million, $21 million, and $32 million, respectively. These balances also include capitalized acquisition, development and exploration costs of $242 million related to oil and gas production activities at Generation.
(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $2,673 million and $2,371 million as of December 31, 2014 and 2013, respectively.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2014	2013	2012
Electric—transmission and distribution	2.93%	2.91%	2.76%
Electric—generation	3.50%	3.35%	3.15%
Gas	2.13%	2.06%	2.03%
Common—electric and gas	7.32%	7.53%	7.61%

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2014 and 2013:

Asset Category	Average Service Life (years)	2014	2013
Electric—generation	1-56	$22,911	$20,420
Nuclear fuel [a]	1-8	5,947	5,196
Construction work in progress	N/A	1,404	1,129
Other property, plant and equipment [b]	6-31	295	400
Total property, plant and equipment		30,557	27,145
Less: accumulated depreciation [c]		7,612	7,034
Property, plant and equipment, net		$22,945	$20,111

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,003 million and $947 million at December 31, 2014 and 2013, respectively.
(b) Includes buildings under capital lease with a net carrying value of $15 million and $23 million at December 31, 2014 and 2013, respectively. The original cost basis of the buildings was $52 million and $59 million, and total accumulated amortization was $37 million and $36 million, as of December 31, 2014 and 2013, respectively. These balances also include capitalized acquisition, development and exploration costs of $242 million related to oil and gas production activities.
(c) Includes accumulated amortization of nuclear fuel in the reactor core of $2,673 million and $2,371 million as of December 31, 2014 and 2013, respectively.

The annual depreciation provisions as a percentage of average service life for electric generation assets were 3.5%, 3.35% and 3.15% for the years ended December 31, 2014, 2013 and 2012, respectively.

License Renewals. Generation's depreciation provisions are based on the estimated useful lives of its generating stations, which assume the renewal of the licenses for all nuclear generating stations (except for Oyster Creek) and the hydroelectric generating stations. As a result, the receipt of license renewals has no impact on the Consolidated Statements of Operations. See Note 3—Regulatory Matters for additional information regarding license renewals.

ComEd

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2014 and 2013:

Asset Category	Average Service Life (years)	2014	2013
Electric—transmission and distribution	5-80	$18,884	$17,334
Construction work in progress	N/A	276	456
Other property, plant and equipment [a]	39-50	65	60
Total property, plant and equipment		19,225	17,850
Less: accumulated depreciation		3,432	3,184
Property, plant and equipment, net		$15,793	$14,666

(a) Includes buildings under capital lease with a net carrying value at both of December 31, 2014 and 2013, of $8 million. The original cost basis of the buildings was $8 million and total accumulated amortization was immaterial as of December 31, 2014 and 2013, respectively.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 3.05%, 2.97% and 2.79% for the years ended December 31, 2014, 2013 and 2012, respectively.

PECO

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2014 and 2013:

	Average Service Life (years)	2014	2013
Asset Category			
Electric—transmission and distribution	5-65	$6,886	$6,669
Gas—transportation and distribution	5-70	2,039	1,932
Common—electric and gas	5-50	618	600
Construction work in progress	N/A	154	101
Other property, plant and equipment [(a)]	50	21	17
Total property, plant and equipment		9,718	9,319
Less: accumulated depreciation		2,917	2,935
Property, plant and equipment, net		$6,801	$6,384

(a) Represents land held for future use and non utility property.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2014	2013	2012
Electric—transmission and distribution	2.55%	2.73%	2.51%
Gas	1.84%	1.79%	1.77%
Common—electric and gas	5.16%	6.65%	7.54%

BGE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2014 and 2013:

	Average Service Life (years)	2014	2013
Asset Category			
Electric—transmission and distribution	5-90	$6,339	$6,100
Gas—distribution	5-90	1,761	1,660
Common—electric and gas	5-40	623	578
Construction work in progress	N/A	317	196
Other property, plant and equipment [(a)]	20	32	32
Total property, plant and equipment		9,072	8,566
Less: accumulated depreciation		2,868	2,702
Property, plant and equipment, net		$6,204	$5,864

(a) Represents land held for future use and non utility property.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Average Service Life Percentage by Asset Category	2014	2013	2012
Electric—transmission and distribution	2.96%	2.91%	2.92%
Gas	2.47%	2.36%	2.33%
Common—electric and gas	9.49%	8.45%	7.68%

See Note 1—Significant Accounting Policies for further information regarding property, plant and equipment policies and accounting for capitalized software costs for Exelon, Generation, ComEd, PECO and BGE. See Note 13—Debt and Credit Agreements for further information regarding Exelon's, ComEd's, and PECO's property, plant and equipment subject to mortgage liens.

8. Impairment of Long-Lived Assets (Exelon and Generation)

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In 2014, updates to the long-term fundamental energy prices, which included a thorough evaluation of key assumptions including gas prices, load growth, plant retirements and renewable growth, suggested that the carrying value of certain wind assets with market price exposure may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of twelve wind projects, primarily located in West Texas, were less than their respective carrying values at May 31, 2014. As a result, long-lived assets held and used with a carrying amount of approximately $151 million were written down to their fair value of $65 million and a pre-tax impairment charge of $86 million was recorded in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

In 2013, lower projected wind production and a decline in power prices suggested that the carrying value of certain wind projects with market price exposure for either all or a portion of the life of the asset may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of eleven wind projects, primarily located in West Texas and Minnesota, were less than their respective carrying values at September 30, 2013. As a result, long-lived assets held and used with a carrying amount of approximately $75 million were written down to their fair value of $32 million and a pre-tax impairment charge of $43 million, net of the impairment amount attributable to noncontrolling interests for certain of the projects, was recorded in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

In 2014, certain non-nuclear generating assets were identified as assets held for sale on Exelon's and Generation's Consolidated Balance Sheets. When long-lived assets are held for sale, an impairment loss is recognized to the extent that the asset's carrying value exceeds its estimated fair value less costs to sell. Long-lived assets with a carrying amount of approximately $1 billion were written down to their fair value of $556 million and a pre-tax impairment charge of $450 million was recorded in Operating and maintenance expense on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

In 2012, a subsidiary of Generation sold three Maryland generating stations in connection with the Constellation merger. As a result of the transaction, Exelon and Generation recorded a pre-tax impairment charge of $272 million to reflect the difference between the sales price and the carrying value of the generating stations, which was included in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

See Note 4—Mergers, Acquisitions, and Dispositions for further information on asset sales.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

In the fourth quarter of 2014, a significant decline in oil prices suggested that the carrying value of certain Upstream assets may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of various Upstream properties, primarily located in Oklahoma and Texas, were less than their respective carrying values at December 31, 2014. As a result, long-lived assets with a combined net book value of approximately $163 million were written down to their fair value of $39 million and a pre-tax impairment charge of $124 million was recorded in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. After reflecting the impairment, Generation has $189 million of Upstream assets remaining on its Consolidated Balance Sheets at December 31, 2014. Further declines in commodity prices could potentially result in future impairments of the Upstream assets.

The fair value analysis used in the above impairments was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue, generation and production forecasts, projected capital and maintenance expenditures and discount rates. Changes in the assumptions described above could potentially result in future impairments of Exelon's long-lived assets, which could be material.

Nuclear Uprate Program (Exelon and Generation)

Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture (MUR) uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to Operating and maintenance expense and Interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Like-Kind Exchange Transaction (Exelon)

Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in coal-fired generating station leases located in Georgia and Texas with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. See Note 14—Income Taxes for further information. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessees to arrange for a third-party to bid on a service contract for a period following the lease term. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. In 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases.

On February 26, 2014, UII and the City Public Service Board of San Antonio, Texas (CPS) finalized an agreement to terminate the leases on the generating station located in Texas, as described above, prior to its expiration dates. As a result of the lease termination, UII received a net early termination amount of $335 million from CPS and wrote down the net investment in the CPS long-term lease of $336 million in Investments in Exelon's Consolidated Balance Sheets in 2014; resulting in a pre-tax loss of $1 million being reflected in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income in 2014.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

Based on the annual reviews performed in 2014 and 2013, the estimated residual value of Exelon's direct financing leases for the Georgia generating stations experienced other than temporary declines given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $24 million and $14 million pre-tax impairment charge in 2014 and 2013, respectively, for these stations. These impairment charges were recorded in Investments and Operating and maintenance expense in Exelon's Consolidated Balance Sheets and the Consolidated Statements of Operations and Comprehensive Income, respectively. Changes in the assumptions described above could potentially result in future impairments of Exelon's direct financing lease investments, which could be material. Through December 31, 2014, no events have occurred that would require Exelon to review the estimated residual values of its direct financing lease investments subsequent to the review performed in the second quarter of 2014.

At December 31, 2014 and 2013, the components of the net investment in long-term leases were as follows:

	December 31, 2014	December 31, 2013
Estimated residual value of leased assets	$ 685	$ 1,465
Less: unearned income	324	767
Net investment in long-term leases	$ 361	$ 698

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

9. Jointly Owned Electric Utility Plant (Exelon, Generation, PECO and BGE)

Exelon, Generation, PECO and BGE's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2014 and 2013 were as follows:

	Nuclear generation				Fossil fuel generation			Transmission		Other
	Quad Cities	Peach Bottom	Salem [a]	Nine Mile Point Unit 2 [g]	Keystone [f]	Conemaugh [f]	Wyman	PA [b]	DE/NJ [c]	Other [d]
Operator	Generation	Generation	PSEG Nuclear	Generation	GenOn	GenOn	FP&L	First Energy	PSEG	
Ownership interest	75.00%	50.00%	42.59%	82.00%	—	—	5.89%	Various	42.55%	44.24%
Exelon's share at December 31, 2014:										
Plant [e]	$ 995	$ 1,095	$ 531	$ 676	$ —	$ —	$ 3	$ 14	$ 64	$ 2
Accumulated depreciation [e]	266	343	150	14	—	—	3	7	34	1
Construction work in progress	15	133	29	48	—	—	—	—	—	—
Exelon's share at December 31, 2013:										
Plant [e]	$ 941	$ 883	$ 501	$ —	$ 725	$ 399	$ 3	$ 14	$ 64	$ 2
Accumulated depreciation [e]	226	326	134	—	268	220	3	7	34	1
Construction work in progress	27	174	24	—	6	121	—	—	—	—

(a) Generation also owns a proportionate share in the fossil fuel combustion turbine at Salem, which is fully depreciated. The gross book value was $3 million at December 31, 2014 and 2013.
(b) PECO and BGE own a 22% and 7% share, respectively, in 127 miles of 500kV lines located in Pennsylvania; PECO and BGE also own a 20.7% and 10.56% share, respectively, of a 500kV substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500kV lines including, but not limited to, the lines noted above.
(c) PECO owns a 42.55% share in 131 miles of 500kV lines located in Delaware and New Jersey as well as a 42.55% share in a 500kV substation immediately outside of the Salem nuclear generating station in New Jersey which supplies power to the 500kV lines including, but not limited to, the lines noted above.
(d) Generation has a 44.24% ownership interest in assets located at Merrill Creek Reservoir located in New Jersey.
(e) Excludes asset retirement costs.
(f) As of December 31, 2014, Generation sold its ownership interest in Keystone and Conemaugh. At December 31, 2013, Generation held 41.98% and 31.28% ownership interest in Keystone and Conemaugh, respectively. See Note 4—Mergers, Acquisitions, and Dispositions for additional information.
(g) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet, and as of that date, CENG's operations are consolidated into Generation's financial statements. As of December 31, 2013, Generation's ownership interest in CENG, including Nine Mile Point, was treated as an equity method investment, and thus did not represent an undivided Interest. See Note 5 - Investment in Constellation Energy Nuclear Group, LLC for additional information.

Exelon's, Generation's, PECO's and BGE's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. Exelon's, Generation's, PECO's and BGE's share of direct expenses of the jointly owned plants are included in Purchased power and fuel and Operating and maintenance expenses on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and in Operating and maintenance expenses on PECO's and BGE's Consolidated Statements of Operations and Comprehensive Income.

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10. Intangible Assets (Exelon, Generation, ComEd and PECO)

Goodwill

Exelon's and ComEd's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2014 and 2013 were as follows:

	ComEd			Generation		Exelon		
	Gross Amount [(a)]	Accumulated Impairment Losses	Carrying Amount	Gross Amount	Carrying Amount	Gross Amount	Accumulated Impairment Losses	Carrying Amount
Balance, January 1, 2013	$4,608	$ 1,983	$2,625	$ —	$ —	$4,608	$ 1,983	$2,625
Goodwill from business combination	—	—	—	47	47	47	—	47
Balance, December 31, 2014	$4,608	$ 1,983	$2,625	$ 47	$ 47	$4,655	$ 1,983	$2,672

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom (predecessor parent company of ComEd) merger net of amortization, resolution of tax matters and other non-impairment-related changes as allowed under previous authoritative guidance.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Under the authoritative guidance for goodwill, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and its operating results are regularly reviewed by segment management. ComEd has a single operating segment for its combined business. There is no level below this operating segment for which operating results are regularly reviewed by segment management. Therefore, ComEd's operating segment is considered its only reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step one of the two-step fair value based impairment test). If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step fair value based impairment test is required. Otherwise, no further testing is required.

If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Any goodwill impairment charge at ComEd will affect Exelon's consolidated results of operations.

ComEd's valuation approach is based on a market participant view, pursuant to authoritative guidance for fair value measurement, and utilizes a weighted combination of a discounted cash flow

analysis and a market multiples analysis. The discounted cash flow analysis relies on a single scenario reflecting “base case” or “best estimate” projected cash flows for ComEd’s business and includes an estimate of ComEd’s terminal value based on these expected cash flows using the generally accepted Gordon Dividend Growth formula, which derives a valuation using an assumed perpetual annuity based on the entity’s residual cash flows. The discount rate is based on the generally accepted Capital Asset Pricing Model and represents the weighted average cost of capital of comparable companies. The market multiples analysis utilizes multiples of business enterprise value to earnings, before interest, taxes, depreciation and amortization (EBITDA) of comparable companies in estimating fair value. Significant assumptions used in estimating the fair value include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd’s business and the fair value of debt. Management performs a reconciliation of the sum of the estimated fair value of all Exelon reporting units to Exelon’s enterprise value based on its trading price to corroborate the results of the discounted cash flow analysis and the market multiple analysis.

2014 Goodwill Impairment Assessment . Pursuant to authoritative guidance, ComEd is required to test its goodwill for impairment annually and more frequently if an event occurs or circumstances change that suggest an impairment is more likely than not. ComEd performed a qualitative assessment as of November 1, 2014, for its 2014 annual goodwill impairment assessment and determined that its fair value was not more likely than not less than its carrying value. Therefore, ComEd did not perform a quantitative assessment. As part of its qualitative assessment, ComEd evaluated, among other things, management’s best estimate of projected operating and capital cash flows for ComEd’s business as well as changes in certain market conditions, including the discount rate and EBITDA multiples, while also considering the passing margin from its last quantitative assessment performed as of November 1, 2013.

Prior Goodwill Impairment Assessments . Management concluded the remeasurement of the like-kind exchange position and the charge to ComEd’s earnings in the first quarter of 2013 triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of January 31, 2013. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

ComEd performed a quantitative assessment as of November 1, 2013, for its 2013 annual goodwill impairment assessment. The first step of the annual impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

In both the interim and annual assessments, the discounted cash flow analysis reflected Exelon’s indemnity to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts related to the like-kind exchange position on ComEd’s equity. While neither the interim nor the annual assessments indicated an impairment of ComEd’s goodwill, certain assumptions used to estimate the fair value of ComEd are highly sensitive to changes. Adverse regulatory actions, such as early termination of EIMA, or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd’s business, and the fair value of debt could potentially result in a future impairment of ComEd’s goodwill, which could be material. Based on the results of the annual goodwill test performed as of November 1, 2013, the estimated fair value of ComEd would have needed to decrease by more than 10% for ComEd to fail the first step of the impairment test.

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Management concluded that the May 2012 ICC final Order in ComEd's 2011 formula rate proceeding triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of May 31, 2012. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. ComEd performed a qualitative assessment as of November 1, 2012, for its 2012 annual goodwill impairment assessment and determined that its fair value was not more likely than not less than its carrying value. Therefore, ComEd did not perform a quantitative assessment. As part of its qualitative assessment, ComEd evaluated, among other things, management's best estimate of projected operating and capital cash flows for ComEd's business (including the impacts of the May 2012 Order) as well as changes in certain other market conditions, such as the discount rate and EBITDA multiples.

Other Intangible Assets

Exelon's, Generation's and ComEd's other intangible assets and liabilities, included in Unamortized energy contract assets and Other long-term assets and liabilities in their Consolidated Balance Sheets, consisted of the following as of December 31, 2014:

	Weighted Average Amortization Years [h]	Gross	Accumulated Amortization	Net	Estimated amortization expense 2015	2016	2017	2018	2019
Exelon and Generation									
Unamortized Energy Contracts [a]									
Exelon Wind [b]	18.0	$ 224	$ (55)	$169	$ 14	$ 14	$ 14	$ 14	$ 14
Antelope Valley [c]	25.0	190	(12)	178	8	8	8	8	8
Constellation [d]	1.5	1,499	(1,451)	48	19	(31)	(21)	11	8
CENG [e]	1.7	(97)	29	(68)	(20)	(11)	(15)	(18)	(15)
Integrys [d]	2.4	6	(5)	1	(8)	6	1	1	—
Customer Relationships									
Constellation [d]	12.4	214	(58)	156	18	18	18	18	17
Integrys [d]	10.0	48	(1)	47	5	5	5	5	5
Trade Names									
Constellation [d]	10.0	243	(79)	164	23	23	23	23	23
ComEd									
Chicago settlement—1999 agreement [f]	21.8	100	(79)	21	3	3	4	4	4
Chicago settlement—2003 agreement [g]	17.9	62	(40)	22	4	4	3	3	3
Total intangible assets		$2,489	$ (1,751)	$738	$ 66	$ 39	$ 40	$ 69	$ 67

(a) Includes unamortized energy contract assets and liabilities on Exelon's and Generation's Consolidated Balance Sheets. Excludes $26 million of other miscellaneous unamortized energy contracts that have been acquired at various points in time. The estimated amortization for these miscellaneous unamortized energy contracts is $4 million, $3 million, $0 million, $2 million and $2 million for 2015, 2016, 2017, 2018 and 2019, respectively.
(b) In December 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (later named Exelon Wind), adding 735MWs of installed, operating wind capacity located in eight states.
(c) In September 2011, Generation acquired all of the interest in Antelope Valley Solar Ranch One, a 230 MW solar project under development in northern Los Angeles County, CA from First Solar, Inc.
(d) See Note 4—Mergers, Acquisitions, and Dispositions for further information on these acquisitions.
(e) See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.
(f) In March 1999, ComEd entered into a settlement agreement with the City of Chicago associated with ComEd's franchise agreement. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago each year from 1999 to 2002. The intangible asset recognized as a result of these payments is being amortized ratably over the remaining term of the franchise agreement, which ends in 2020.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(g) In February 2003, ComEd entered into separate agreements with the City of Chicago and with Midwest Generation, LLC (Midwest Generation). Under the terms of the settlement agreement with the City of Chicago, ComEd agreed to pay the City of Chicago a total of $60 million over a ten-year period, beginning in 2003. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement, which ends in 2020. As required by the settlement, ComEd also made a payment of $2 million to a third-party on the City of Chicago's behalf. Under the terms of the agreement with Midwest Generation, ComEd received payments of $32 million from Midwest Generation to relieve Midwest Generation's obligation under the 1999 fossil sale agreement with ComEd to build the generation facility in the City of Chicago. The payments received by ComEd, which have been recorded in Other deferred credits and other liabilities, and other long-term liabilities on Exelon's and ComEd's Consolidated Balance Sheets are being recognized ratably (approximately $2 million annually) as an offset to amortization expense over the remaining term of the franchise agreement.

(h) Weighted-average amortization period was calculated at the date of a) acquisition for acquired assets or b) settlement agreement.

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2014, 2013 and 2012:

For the Year Ended December 31,	Exelon [(a)]	Generation [(a)]	ComEd
2014	$ 179	$ 179	$ 7
2013	478	550	7
2012	1,150	1,145	7

(a) At Exelon, amortization of unamortized energy contracts totaling $135 million, $430 million and $1,110 million for the years ended December 31, 2014, 2013 and 2012, respectively, was recorded in Purchase power and fuel expense or Operating revenues within Exelon's Consolidated Statement of Operations and Comprehensive Income. At Generation, amortization of unamortized energy contracts totaling $135 million, $507 million and $1,110 million for the years ended December 31, 2014, 2013 and 2012, respectively, was recorded in Purchase power and fuel expense or Operating revenues within Generation's Consolidated Statement of Operations and Comprehensive Income

Acquired Intangible Assets

Accounting guidance for business combinations requires the acquirer to separately recognize identifiable intangible assets in the application of purchase accounting.

Unamortized Energy Contracts. Unamortized energy contract assets and liabilities represent the remaining unamortized fair value of non-derivative energy contracts that Generation has acquired. The valuation of unamortized energy contracts was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise, the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. The Exelon Wind unamortized energy contracts are amortized on a straight line basis over the period in which the associated contract revenues are recognized as a decrease in Operating revenue within Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income. In the case of Antelope Valley, Constellation, CENG and Integrys, the fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the acquisition dates through either Purchase power and fuel expense or Operating revenues within Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Customer Relationships. The customer relationship intangible was determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The accounting guidance requires that customer-based intangibles be amortized over the period expected to be benefited using the pattern of economic benefit. The amortization of the customer relationships is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Trade Name. The Constellation trade name intangible was determined based on the relief from royalty method of income approach whereby fair value is determined to be the present value of the license fees avoided by owning the assets. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. The Constellation trade name intangible is amortized on a straight-line basis over a period of 10 years. The amortization of the trade name is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Renewable Energy Credits and Alternative Energy Credits (Exelon, Generation, ComEd and PECO).

Exelon's, Generation's, ComEd's and PECO's other intangible assets, included in Other current assets and Other deferred debits and other assets on the Consolidated Balance Sheets, include RECs (Exelon, Generation and ComEd) and AECs (Exelon and PECO). Purchased RECs are recorded at cost on the date they are purchased. The cost of RECs purchased on a stand-alone basis is based on the transaction price, while the cost of RECs acquired through PPAs represents the difference between the total contract price and the market price of energy at contract inception. Revenue for RECs that are part of a bundled power sale is recognized when the power is produced and delivered to the customer. As of December 31, 2014, and 2013, PECO had current AECs of $13 million and $19 million, respectively. PECO had no noncurrent AECs and $5 million as of December 31, 2014, and 2013, respectively. As of December 31, 2014, and 2013, Generation had current RECs of $191 million and $158 million, respectively, and $44 million of noncurrent REC's as of December 31, 2014. As of December 31, 2014, and 2013, ComEd, had current RECs of $4 million and $3 million, respectively. See Note 3—Regulatory Matters and Note 22—Commitments and Contingencies for additional information on RECs and AECs.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

11. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of December 31, 2014 and 2013:

Exelon

	December 31, 2014					December 31, 2013	
	Carrying Amount	Fair Value				Carrying Amount	Fair Value
		Level 1	Level 2	Level 3	Total		
Short-term liabilities	$ 463	$ 3	$ 448	$ 12	$ 463	$ 344	$ 344
Long-term debt (including amounts due within one year)	21,164	1,208	20,417	1,311	22,936	19,132	19,751
Long-term debt to financing trusts	648	—	—	648	648	648	631
SNF obligation	1,021	—	833	—	833	1,021	790

Generation

	December 31, 2014					December 31, 2013	
	Carrying Amount	Fair Value				Carrying Amount	Fair Value
		Level 1	Level 2	Level 3	Total		
Short-term liabilities	$ 36	$ —	$ 24	$ 12	$ 36	$ 22	$ 22
Long-term debt (including amounts due within one year)	8,266	—	7,511	1,311	8,822	7,729	7,648
SNF obligation	1,021	—	833	—	833	1,021	790

ComEd

	December 31, 2014					December 31, 2013	
	Carrying Amount	Fair Value				Carrying Amount	Fair Value
		Level 1	Level 2	Level 3	Total		
Short-term liabilities	$ 304	$ —	$ 304	$ —	$ 304	$ 184	$ 184
Long-term debt (including amounts due within one year)	5,958	—	6,788	—	6,788	5,675	6,255
Long-term debt to financing trust	206	—	—	213	213	206	202

PECO

	December 31, 2014					December 31, 2013	
	Carrying Amount	Fair Value				Carrying Amount	Fair Value
		Level 1	Level 2	Level 3	Total		
Long-term debt (including amounts due within one year)	$2,246	$ —	$2,537	$ —	$2,537	$2,197	$2,358
Long-term debt to financing trusts	184	—	—	199	199	184	180

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

	December 31, 2014					December 31, 2013	
	Carrying Amount	Fair Value				Carrying Amount	Fair Value
		Level 1	Level 2	Level 3	Total		
Short-term liabilities	$ 123	$ 3	$ 120	$ —	$ 123	$ 138	$ 138
Long-term debt (including amounts due within one year)	1,942	—	2,178	—	2,178	2,011	2,148
Long-term debt to financing trusts	258	—	—	236	236	258	249

Short-Term Liabilities . The short-term liabilities included in the tables above are comprised of dividends payable (included in other current liabilities) (Level 1), short-term borrowings (Level 2) and third party financing (Level 3). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. The fair value of Exelon's equity units (Level 1) are valued based on publicly traded securities issued by Exelon.

The fair value of Generation's non-government-backed fixed rate project financing debt, including nuclear fuel procurement contracts, (Level 3) is based on market and quoted prices for its own and other project financing debt with similar risk profiles. Given the low trading volume in the project financing debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-backed fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value (Level 2).

SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Long-Term Debt to Financing Trusts. Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1—quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to access as of the reporting date.
- Level 2—inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3—unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts. There were no transfers between Level 1 and Level 2 during the year ended December 31, 2014 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation and Exelon

The following tables present assets and liabilities measured and recorded at fair value on Exelon's and Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2014 and 2013:

	Generation				Exelon			
As of December 31, 2014	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents [a]	$ 405	$ —	$ —	$ 405	$1,119	$ —	$ —	$ 1,119
Nuclear decommissioning trust fund investments								
Cash equivalents	208	37	—	245	208	37	—	245
Equity								
Domestic	2,423	2,207	—	4,630	2,423	2,207	—	4,630
Foreign	612	—	—	612	612	—	—	612
Equity funds subtotal	3,035	2,207	—	5,242	3,035	2,207	—	5,242
Fixed income								
Corporate debt securities	—	2,023	239	2,262	—	2,023	239	2,262
U.S. Treasury and agencies	996	—	—	996	996	—	—	996
Foreign governments	—	95	—	95	—	95	—	95
State and municipal debt	—	438	—	438	—	438	—	438
Other	—	511	—	511	—	511	—	511
Fixed income subtotal	996	3,067	239	4,302	996	3,067	239	4,302
Middle market lending	—	—	366	366	—	—	366	366
Private equity	—	—	83	83	—	—	83	83
Real estate	—	—	3	3	—	—	3	3
Other	—	301	—	301	—	301	—	301
Nuclear decommissioning trust funds subtotal [b]	4,239	5,612	691	10,542	4,239	5,612	691	10,542
Pledged assets for Zion Station decommissioning								
Cash equivalents	—	15	—	15	—	15	—	15
Equities	6	1	—	7	6	1	—	7
Fixed income								
U.S. Treasury and agencies	5	3	—	8	5	3	—	8
Corporate debt	—	89	—	89	—	89	—	89
State and municipal debt	—	10	—	10	—	10	—	10
Other	—	3	—	3	—	3	—	3
Fixed income subtotal	5	105	—	110	5	105	—	110
Middle market lending	—	—	184	184	—	—	184	184
Pledged assets for Zion Station decommissioning subtotal [c]	11	121	184	316	11	121	184	316
Rabbi trust investments [d]								
Cash equivalents	—	—	—	—	1	—	—	1
Mutual funds [e]	16	—	—	16	46	—	—	46
Rabbi trust investments subtotal	16	—	—	16	47	—	—	47

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation				Exelon			
As of December 31, 2014	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Commodity derivative assets								
Economic hedges	1,667	3,465	1,681	6,813	1,667	3,465	1,681	6,813
Proprietary trading	201	284	27	512	201	284	27	512
Effect of netting and allocation of collateral [f]	(1,982)	(2,757)	(557)	(5,296)	(1,982)	(2,757)	(557)	(5,296)
Commodity derivative assets subtotal	(114)	992	1,151	2,029	(114)	992	1,151	2,029
Interest rate and foreign currency derivative assets								
Derivatives designated as hedging instruments	—	8	—	8	—	31	—	31
Economic hedges	—	12	—	12	—	13	—	13
Proprietary trading	18	9	—	27	18	9	—	27
Effect of netting and allocation of collateral	(17)	(12)	—	(29)	(17)	(31)	—	(48)
Interest rate and foreign currency derivative assets subtotal	1	17	—	18	1	22	—	23
Other investments	—	—	3	3	2	—	3	5
Total assets	4,558	6,742	2,029	13,329	5,305	6,747	2,029	14,081
Liabilities								
Commodity derivative liabilities								
Economic hedges	(2,241)	(3,458)	(788)	(6,487)	(2,241)	(3,458)	(995)	(6,694)
Proprietary trading	(195)	(295)	(42)	(532)	(195)	(295)	(42)	(532)
Effect of netting and allocation of collateral [f]	2,416	3,557	729	6,702	2,416	3,557	729	6,702
Commodity derivative liabilities subtotal	(20)	(196)	(101)	(317)	(20)	(196)	(308)	(524)
Interest rate and foreign currency derivative liabilities	—	—	—	—	—	—	—	—
Derivatives designated as hedging instruments	—	(12)	—	(12)	—	(41)	—	(41)
Economic hedges	—	(2)	—	(2)	—	(103)	—	(103)
Proprietary trading	(14)	(9)	—	(23)	(14)	(9)	—	(23)
Effect of netting and allocation of collateral	25	10	—	35	25	29	—	54
Interest rate and foreign currency derivative liabilities subtotal	11	(13)	—	(2)	11	(124)	—	(113)
Deferred compensation obligation	—	(31)	—	(31)	—	(107)	—	(107)
Total liabilities	(9)	(240)	(101)	(350)	(9)	(427)	(308)	(744)
Total net assets	$ 4,549	$ 6,502	$1,928	$12,979	$ 5,296	$ 6,320	$1,721	$13,337

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation				Exelon			
As of December 31, 2013	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents [a]	$1,006	$ —	$ —	$ 1,006	$1,230	$ —	$ —	$ 1,230
Nuclear decommissioning trust fund investments								
Cash equivalents	459	—	—	459	459	—	—	459
Equities								
Domestic	1,642	2,271	—	3,913	1,642	2,271	—	3,913
Foreign	249	—	—	249	249	—	—	249
Equity funds subtotal	1,891	2,271	—	4,162	1,891	2,271	—	4,162
Fixed income								
Corporate debt securities	—	1,753	31	1,784	—	1,753	31	1,784
U.S. Treasury and agencies	882	—	—	882	882	—	—	882
Foreign governments	—	87	—	87	—	87	—	87
State and municipal debt	—	294	—	294	—	294	—	294
Other	—	75	—	75	—	75	—	75
Fixed income subtotal	882	2,209	31	3,122	882	2,209	31	3,122
Middle market lending	—	—	314	314	—	—	314	314
Private equity	—	—	5	5	—	—	5	5
Other	—	14	—	14	—	14	—	14
Nuclear decommissioning trust funds subtotal [b]	3,232	4,494	350	8,076	3,232	4,494	350	8,076
Pledged assets for Zion Station decommissioning								
Cash equivalents	—	26	—	26	—	26	—	26
Equities	16	—	—	16	16	—	—	16
Fixed income								
U.S. Treasury and agencies	45	4	—	49	45	4	—	49
Corporate debt	—	227	—	227	—	227	—	227
State and municipal debt	—	20	—	20	—	20	—	20
Fixed income subtotal	45	251	—	296	45	251	—	296
Middle market lending	—	—	112	112	—	—	112	112
Other	—	1	—	1	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal [c]	61	278	112	451	61	278	112	451
Rabbi trust investments [d]								
Cash equivalents	—	—	—	—	2	—	—	2
Mutual funds [e]	13	—	—	13	54	—	—	54
Rabbi trust investments subtotal	13	—	—	13	56	—	—	56
Commodity derivative assets				—				—
Economic hedges	493	2,582	885	3,960	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761	324	1,315	122	1,761
Effect of netting and allocation of collateral [f]	(863)	(3,131)	(430)	(4,424)	(863)	(3,131)	(430)	(4,424)
Commodity derivative assets subtotal	(46)	766	577	1,297	(46)	766	577	1,297

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation				Exelon			
As of December 31, 2013	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Interest rate and foreign currency derivative assets	30	32	—	62	30	39	—	69
Effect of netting and allocation of collateral	(30)	(2)	—	(32)	(30)	(2)	—	(32)
Interest rate and foreign currency derivative assets subtotal	—	30	—	30	—	37	—	37
Other investments	—	—	15	15	—	—	15	15
Total assets	4,266	5,568	1,054	10,888	4,533	5,575	1,054	11,162
Liabilities								
Commodity derivative liabilities								
Economic hedges	(540)	(1,890)	(397)	(2,827)	(540)	(1,890)	(590)	(3,020)
Proprietary trading	(328)	(1,256)	(119)	(1,703)	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral [f]	869	3,007	404	4,280	869	3,007	404	4,280
Commodity derivative liabilities subtotal	1	(139)	(112)	(250)	1	(139)	(305)	(443)
Interest rate and foreign currency derivative liabilities	(31)	(13)	—	(44)	(31)	(17)	—	(48)
Effect of netting and allocation of collateral	31	1	—	32	31	1	—	32
Interest rate and foreign currency derivative liabilities subtotal	—	(12)	—	(12)	—	(16)	—	(16)
Deferred compensation obligation	—	(29)	—	(29)	—	(114)	—	(114)
Total liabilities	1	(180)	(112)	(291)	1	(269)	(305)	(573)
Total net assets	$4,267	$ 5,388	$ 942	$10,597	$4,534	$ 5,306	$ 749	$10,589

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net liabilities of $5 million at both December 31, 2014 and 2013. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $3 million and $7 million at December 31, 2014 and 2013, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) Excludes $35 million and $32 million of cash surrender value of life insurance investment at December 31, 2014 and 2013, respectively, at Exelon Consolidated. Excludes $11 million and $10 million of cash surrender value of life insurance investment at December 31, 2014 and 2013, respectively, at Generation.
(e) The mutual funds held by the Rabbi trusts at Exelon Consolidated include $45 million related to deferred compensation and $1 million related to a Supplemental Executive Retirement Plan at December 31, 2014, and $53 million related to deferred compensation and $1 million related to a Supplemental Executive Retirement Plan at December 31, 2013.
(f) Includes collateral postings (received) to/from counterparties. Collateral posted (received) to/from counterparties, net of collateral paid to counterparties, totaled $434 million, $800 million and $172 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2014. Collateral posted (received) to/from counterparties, net of collateral paid to counterparties, totaled $6 million, $(124) million and $(26) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2013.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on the Utilities' Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2014 and 2013:

	ComEd				PECO				BGE			
As of December 31, 2014	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents	$ 25	$ —	$ —	$ 25	$ 12	$ —	$ —	$ 12	$ 103	$ —	$ —	$103
Rabbi trust investments in Mutual funds [a]	—	—	—	—	9	—	—	9	5	—	—	5
Total assets	25	—	—	25	21	—	—	21	108	—	—	108
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(15)	—	(15)	—	(5)	—	(5)
Mark-to-market derivative liabilities [b]	—	—	(207)	(207)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(207)	(215)	—	(15)	—	(15)	—	(5)	—	(5)
Total net assets (liabilities)	$ 25	$ (8)	$(207)	$(190)	$ 21	$ (15)	$ —	$ 6	$ 108	$ (5)	$ —	$103

	ComEd				PECO				BGE			
As of December 31, 2013	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents	$ —	$ —	$ —	$ —	$ 175	$ —	$ —	$175	$ 31	$ —	$ —	$ 31
Rabbi trust investments in Mutual funds [a]	5	—	—	5	9	—	—	9	6	—	—	6
Total assets	5	—	—	5	184	—	—	184	37	—	—	37
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(17)	—	(17)	—	(6)	—	(6)
Mark-to-market derivative liabilities [b]	—	—	(193)	(193)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(193)	(201)	—	(17)	—	(17)	—	(6)	—	(6)
Total net assets (liabilities)	$ 5	$ (8)	$(193)	$(196)	$ 184	$ (17)	$ —	$167	$ 37	$ (6)	$ —	$ 31

(a) At PECO, excludes $14 million of the cash surrender value of life insurance investments at both December 31, 2014 and 2013.
(b) The Level 3 balance includes the current and noncurrent liability of $20 million and $187 million, respectively, at December 31, 2014, and $17 million and $176 million, respectively, at December 31, 2013, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the year ended December 31, 2014 and 2013:

	Generation					ComEd		Exelon
For The Year Ended December 31, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Other-ComEd[b]	Eliminated in Consolidation	Total
Balance as of January 1, 2014	$ 350	$ 112	$ 465	$ 15	$ 942	$ (193)	$ —	$ 749
Total realized / unrealized gains (losses)								
Included in net income	6	—	526[a]	—	532	—	—	532
Included in noncurrent payables to affiliates	14	—	—	—	14	—	(14)	—
Included in payable for Zion Station decommissioning	—	2	—	—	2	—	—	2
Included in regulatory assets/liabilities	—	—	—	—	—	(14)	14	—
Change in collateral	—	—	198	—	198	—	—	198
Purchases, sales, issuances and settlements								
Purchases	400	120	76[c]	2	598	—	—	598
Sales	(15)	(50)	(7)	(8)	(80)	—	—	(80)
Settlements	(64)	—	—	—	(64)	—	—	(64)
Transfers into Level 3	—	—	(7)	—	(7)	—	—	(7)
Transfers out of Level 3	—	—	(201)	(6)	(207)	—	—	(207)
Balance as of December 31, 2014	$ 691	$ 184	$ 1,050	$ 3	$ 1,928	$ (207)	$ —	$1,721
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2014	$ 4	$ —	$ 640	$ —	$ 644	$ —	$ —	$ 644

Combined Notes to Consolidated Financial Statements—(Continued)
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	Generation					ComEd		Exelon
For The Year Ended December 31, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives [d]	Other Investments	Total Generation	Other-ComEd [b][f]	Eliminated in Consolidation	Total
Balance as of January 1, 2013	$ 183	$ 89	$ 660	$ 17	$ 949	$ (293)	$ —	$ 656
Total realized / unrealized gains (losses)								
Included in net income	2	—	(51) [a]	—	(49)	—	7	(42)
Included in other comprehensive income	—	—	(219)	2	(217)	—	219	2
Included in noncurrent payables to affiliates	8	—	—	—	8	—	(8)	—
Included in payable for Zion Station decommissioning	—	—	—	—	—	—	—	—
Included in regulatory assets/liabilities	—	—	—	—	—	100	(218)	(118)
Change in collateral	—	—	7	—	7	—	—	7
Purchases, sales, issuances and settlements								
Purchases	203	62	28	4	297	—	—	297
Sales	(28)	(39)	(11)	(8)	(86)	—	—	(86)
Settlements	(18)	—	—	—	(18)	—	—	(18)
Transfers into Level 3	—	—	86[e]	1	87	—	—	87
Transfers out of Level 3	—	—	(35)	(1)	(36)	—	—	(36)
Balance as of December 31, 2013	$ 350	$ 112	$ 465	$ 15	$ 942	$ (193)	$ —	$ 749
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2013	$ 1	$ —	$ 156	$ —	$ 157	$ —	$ —	$ 168

(a) Includes the reclassification of $114 million and $207 million of realized gains due to the settlement of derivative contracts for the years ended December 31, 2014 and 2013, respectively.
(b) Includes $13 million and $133 million of decreases in fair value and $1 million and ($7) million of realized gains (losses) due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the years ended December 31, 2014 and 2013, respectively.
(c) Includes $34 million of fair value from contracts acquired as a result of the Integrys acquisition.
(d) Includes $11 million of decreases in fair value and realized gains due to settlements of $215 million associated with Generation's financial swap contract with ComEd for the year ended December 31, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(e) Includes an increase of transfers into Level 3 arising from reductions in market liquidity, which resulted in less observable contract tenures in various locations.
(f) Includes $11 million of increases in fair value and realized losses due to settlements of $215 million associated with Generation's financial swap contract with ComEd for the year ended December 31, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2014 and 2013:

	Generation			Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net [(a)]	Operating Revenues	Purchased Power and Fuel	Other, net [(a)]
Total gains (losses) included in net income for the year ended December 31, 2014	$ 614	$ (88)	$ 6	$ 614	$ (88)	$ 6
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2014	$ 663	$ (23)	$ 4	$ 663	$ (23)	$ 4

	Generation			Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net [(a)]	Operating Revenues	Purchased Power and Fuel	Other, net [(a)]
Total gains (losses) included in net income for the year ended December 31, 2013	$ (158)	$ 107	$ 2	$ (152)	$ 108	$ 2
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2013	$ 30	$ 126	$ 1	$ 40	$ 127	$ 1

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE) . The Registrants' cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in Equities, Fixed Income and Other. Generation's and CENG's investment policies place limitations on the types and investment grade ratings of the securities that may be held by the trusts. These policies limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

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With respect to individually held equity securities, which are included in Domestic or Foreign equities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The fair values of private placement fixed income securities, which are included in Corporate debt, are determined using a third party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity, balanced and fixed income commingled funds and fixed income mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of fixed income commingled and mutual funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining equity commingled funds in which Exelon, Generation, and CENG invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. Commingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities.

Middle market lending are investments in loans or managed funds which invest in private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in middle market lending are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Private equity investments include investments in operating companies that are not publicly traded on a stock exchange. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows and market based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3.

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As of December 31, 2014, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, private equity investments, and real estate investments of approximately $290 million. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

See Note 15—Asset Retirement Obligations for further discussion on the NDT fund investments.

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The investments in the Rabbi trusts are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of mutual funds. These funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices.

Mark-to-Market Derivatives (Exelon, Generation, and ComEd). Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' derivatives are predominately at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 12—Derivative Financial Instruments for further discussion on mark-to-market derivatives.

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Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO and BGE). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd)

Mark-to-Market Derivatives (Exelon, Generation, ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Exelon Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at Exelon. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, certain transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location.

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When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price is generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $2.75 and $0.34 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 7A.—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrant's mark-to-market derivative assets and liabilities.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 12—Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at December 31,2014	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic hedges (Generation) [a][c]	$ 893	Discounted Cash Flow	Forward power price	$ 15 - $120[d]
			Forward gas price	$1.52 - $14.02[d]
		Option Model	Volatility percentage	8% - 257%
Mark-to-market derivatives—Proprietary trading (Generation) [a][c]	$ (15)	Discounted Cash Flow	Forward power price	$ 15 - $117[d]
Mark-to-market derivatives (ComEd)	$ (207)	Discounted Cash Flow	Forward heat rate [b]	8x - 9x
			Marketability reserve	3.5% - 8%
			Renewable factor	86% - 126%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
(c) The fair values do not include cash collateral held on level three positions of $172 million as of December 31, 2014.
(d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas would be approximately $97 and $8.14, respectively, and would be approximately $76 for power proprietary trading.

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Type of trade	Fair Value at December 31, 2013	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic hedges (Generation) [a][c]	$ 488	Discounted Cash Flow	Forward power price	$ 8 - $176[d]
			Forward gas price	$2.98 - $16.63[d]
		Option Model	Volatility percentage	15% - 142%
Mark-to-market derivatives—Proprietary trading (Generation) [a][c]	$ 3	Discounted Cash Flow	Forward power price	$ 10 - $176[d]
Mark-to-market derivatives (ComEd)	$ (193)	Discounted Cash Flow	Forward heat rate [b]	8x - 9x
			Marketability reserve	3.5% - 8%
			Renewable factor	84% - 128%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
(c) The fair values do not include cash collateral held on level three positions of $26 million as of December 31, 2013
(d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas would be approximately $100 and $5.70, respectively.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending, certain corporate debt securities, and private equity investments the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to

Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations. For a sample of its Level 3 investments, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

12. Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use derivative instruments to manage commodity price risk and interest rate risk related to ongoing business operations.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. The Registrants employ established policies and procedures to manage their risks associated with market fluctuations by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, Generation no longer utilizes the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the Constellation merger. Because the underlying forecasted transactions remained probable, the fair value of the effective portion of these cash flow hedges was frozen in Accumulated OCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred. The effect of this decision is that all derivative economic hedges related to commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 22—Commitments and Contingencies. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall energy marketing activities.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of

derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of December 31, 2014, the percentage of expected generation hedged for the major reportable segments was 93%-96%, 61%-64% and 31%-34% for 2015, 2016, and 2017, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation (which reflects the divestiture impact of Quail Run). Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including Generation's sales to ComEd, PECO and BGE to serve their retail load. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for more detail regarding divestitures.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts for energy and associated RECs were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reductions was approved in March 2014. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3—Regulatory Matters for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3—Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's

price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts and block contracts. PECO has certain full requirements contracts and block contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2014 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2014 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE's price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. All of BGE's natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 10,571 GWh, 8,762 GWh and 12,958 GWh for the years ended December 31, 2014, 2013 and 2012, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2014, Exelon and Generation had $1,450 million and $550 million of notional amounts of fixed-to-floating hedges outstanding, respectively, and $3,070 million and $770 million of notional amounts of floating-to-fixed hedges outstanding, respectively. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximate $8 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2014. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign exchange hedges as of December 31, 2014:

	Generation					Other				Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Economic Hedges	Collateral and Netting [b]	Subtotal	Total
Mark-to-market derivative assets (current assets)	$ 7	$ 7	$ 20	$ (22)	$ 12	$ 3	$ —	$ —	$ 3	$ 15
Mark-to-market derivative assets (noncurrent assets)	1	5	7	(7)	6	20	1	(19)	2	8
Total mark-to-market derivative assets	8	12	27	(29)	18	23	1	(19)	5	23
Mark-to-market derivative liabilities (current liabilities)	(8)	(2)	(14)	25	1	—	—	—	—	1
Mark-to-market derivative liabilities (noncurrent liabilities)	(4)	—	(9)	10	(3)	(29)	(101)	19	(111)	(114)
Total mark-to-market derivative liabilities	(12)	(2)	(23)	35	(2)	(29)	(101)	19	(111)	(113)
Total mark-to-market derivative net assets (liabilities)	$ (4)	$ 10	$ 4	$ 6	$ 16	$ (6)	$ (100)	$ —	$ (106)	$ (90)

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.
(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2013:

	Generation					Other	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$ —	$ 3	$ 15	$ (19)	$ (1)	$ —	$ (1)
Mark-to-market derivative assets (noncurrent assets)	26	3	15	(13)	31	7	38
Total mark-to-market derivative assets	26	6	30	(32)	30	7	37
Mark-to-market derivative liabilities (current liabilities)	(1)	(1)	(18)	19	(1)	—	(1)
Mark-to-market derivative liabilities (noncurrent liabilities)	(10)	(1)	(13)	13	(11)	(4)	(15)
Total mark-to-market derivative liabilities	(11)	(2)	(31)	32	(12)	(4)	(16)
Total mark-to-market derivative net assets (liabilities)	$ 15	$ 4	$ (1)	$ —	$ 18	$ 3	$ 21

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.
(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

Fair Value Hedges . For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

		Year Ended December 31,					
		2014	2013	2012	2014	2013	2012
	Income Statement Location	Gain (Loss) on Swaps			Gain (Loss) on Borrowings		
Generation	Interest expense [a]	$ (16)	$ (15)	$ (6)	$ 2	$ (6)	$ —
Exelon	Interest expense	$ 3	$ (24)	$ (9)	$ 15	$ (3)	$ (1)

(a) For the years ended December 31, 2014 and 2013, the loss on Generation swaps included $(17) million and $16 million realized in earnings, respectively, with $4 million and $2 million excluded from hedge effectiveness testing, respectively.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

During 2014, Exelon entered into $100 million and $75 million of notional amounts of fixed-to-floating fair value hedges related to interest rate swaps, which expire in 2019 and 2020, respectively. At December 31, 2014, Exelon and Generation had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,450 million and $550 million, with a derivative asset of $29 million and $7 million, respectively. At December 31, 2013, Exelon and Generation had outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,275 million and $550 million, with a derivative asset of $26 million and $23 million, respectively. During the years ended December 31, 2014 and 2013, the impact on the results of operations, as a result of the ineffectiveness from fair value hedges, was a $18 million gain and $2 million gain, respectively.

Cash Flow Hedges . In connection with the DOE guaranteed loan for the Antelope Valley project financings, as discussed in Note 13—Debt and Credit Agreements, Generation entered into a floating-to-fixed forward starting interest rate swap with a notional amount of $485 million and a mandatory early termination date of September 30, 2014. The interest rate swap was designated as a cash flow hedge, and as a result, unrealized losses of approximately $21 million have been recorded to Accumulated OCI, net on Exelon's and Generation's Consolidated Balance Sheets. During the third quarter of 2014, the interest rate swap was terminated consistent with the agreements. The unrealized loss of $21 million will be amortized into Interest expense on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income over the term of the DOE guaranteed loan.

During the third quarter of 2011, Sacramento PV Energy, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 13—Debt and Credit Agreements for additional information regarding the financing. The swaps have a total notional amount of $26 million as of December 31, 2014 and expire in 2027. After the closing of the Constellation merger, the swaps were re-designated as cash flow hedges. At December 31, 2014, the subsidiary had a $3 million derivative liability related to these swaps.

During the third quarter of 2012, Constellation Solar Horizons, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 13—Debt and Credit Agreements for additional information regarding the financing. The swap has a notional amount of $26 million as of December 31, 2014, and expires in 2030. This swap is designated as a cash flow hedge. At December 31, 2014, the derivative asset related to the swap was immaterial.

During the first quarter of 2014, ExGen Renewables I, LLC, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 13—Debt and Credit Agreements for additional information regarding the financing. The swaps have a notional amount of $213 million as of December 31, 2014 and expire in 2020. The swaps are designated as cash flow hedges. At December 31, 2014, the subsidiary had a $2 million derivative liability related to the swaps.

During the third quarter of 2014, ExGen Texas Power, LLC, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowing. See Note 13—Debt and Credit Agreements for additional information regarding the financing. The swaps have a notional amount of $505 million as of December 31, 2014 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. At December 31, 2014, the subsidiary had a $8 million derivative liability related to the swap.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

During 2014, Exelon entered into $400 million of floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with the anticipated refinance of existing debt. The swaps are designated as cash flow hedges. At December 31, 2014, Exelon had a $28 million derivative liability related to the swaps.

During the years ended December 31, 2014 and 2013, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Economic Hedges. During 2014, Exelon entered into $1,900 million of floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with the anticipated future debt issuance related to the proposed PHI acquisition. At December 31, 2014, Exelon had a $100 million derivative liability related to the swaps.

During the fourth quarter, fixed-to-floating interest rate swaps, which were marked-to-market, acquired as part of the Constellation merger, expired for Exelon and Generation. The notional amounts of the swaps was $150 million.

At December 31, 2014, Generation had $126 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $349 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon Generation, ComEd, PECO and BGE)

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation's use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e. to BB+ or Ba1). In the table below, Generation's energy related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral including initial margin on exchange positions, is aggregated in the collateral and netting column. As of December 31, 2014 and 2013, $8 million and $10 million of cash collateral posted, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e. to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in a non affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2014:

	Generation				ComEd	Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting [a]	Subtotal [b]	Economic Hedges [c]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 4,992	$ 456	$(4,184)	$ 1,264	$ —	$ 1,264
Mark-to-market derivative assets (noncurrent assets)	1,821	56	(1,112)	765	—	765
Total mark-to-market derivative assets	6,813	512	(5,296)	2,029	—	2,029
Mark-to-market derivative liabilities (current liabilities)	(4,947)	(468)	5,200	(215)	(20)	(235)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,540)	(64)	1,502	(102)	(187)	(289)
Total mark-to-market derivative liabilities	(6,487)	(532)	6,702	(317)	(207)	(524)
Total mark-to-market derivative net assets (liabilities)	$ 326	$ (20)	$ 1,406	$ 1,712	$ (207)	$ 1,505

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $(416) million and $(171) million, respectively, and current and noncurrent liabilities are shown net of collateral of $(599) million and $(220) million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $1,406 million at December 31, 2014.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Combined Notes to Consolidated Financial Statements—(Continued)
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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2013:

	Generation				ComEd	Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting [a]	Subtotal [b]	Economic Hedges [c]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,616	$ 1,476	$ (3,364)	$ 728	$ —	$ 728
Mark-to-market derivative assets (noncurrent assets)	1,344	285	(1,060)	569	—	569
Total mark-to-market derivative assets	3,960	1,761	(4,424)	1,297	—	1,297
Mark-to-market derivative liabilities (current liabilities)	(2,023)	(1,410)	3,292	(141)	(17)	(158)
Mark-to-market derivative liabilities (noncurrent liabilities)	(804)	(293)	988	(109)	(176)	(285)
Total mark-to-market derivative liabilities	(2,827)	(1,703)	4,280	(250)	(193)	(443)
Total mark-to-market derivative net assets (liabilities)	$ 1,133	$ 58	$ (144)	$ 1,047	$ (193)	$ 854

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $84 million and $72 million, respectively. Current liabilities are shown net of collateral of $(12) million. Collateral related to noncurrent liabilities was $0 million. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $144 million at December 31, 2013.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon, Generation and ComEd). As discussed previously, effective prior to the Constellation merger, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably probable, the fair value of the effective portion of these cash flow hedges was frozen in Accumulated OCI and is reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective changes in the fair value of these instruments through current earnings from the date of de-designation. Approximately $2 million of these net pre-tax unrealized gains within Accumulated OCI are expected to be reclassified from Accumulated OCI during the next twelve months by Generation. See Note 13—Debt and Credit Agreements for information about reclassifications from Accumulated OCI on interest rate swap activity that occurred after December 31, 2014.

Combined Notes to Consolidated Financial Statements—(Continued)
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The tables below provide the activity of Accumulated OCI related to cash flow hedges for the years ended December 31, 2014 and 2013, containing information about the changes in the fair value of cash flow hedges and the reclassification from Accumulated OCI into results of operations. The amounts reclassified from Accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
	Income Statement Location	Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at January 1, 2013		$ 532[a][d]	$ 368
Effective portion of changes in fair value		—	29[e]
Reclassifications from accumulated OCI to net income	Operating Revenues	(413) [c][b]	(277)
Ineffective portion recognized in income	Operating Revenues	—	—
Accumulated OCI derivative gain at December 31, 2013		119[d]	120
Effective portion of changes in fair value		—	(31) [e]
Reclassifications from accumulated OCI to net income	Operating Revenues	(117) [b]	(117)
Accumulated OCI derivative gain at December 31, 2014		$ 2[d]	$ (28)

(a) Includes $133 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2012.
(b) Amount is net of related income tax expense of $78 million and $270 million for the years ended December 31, 2014 and 2013, respectively.
(c) Includes $133 million of losses, net of taxes, reclassified from Accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the year ended December 31, 2013.
(d) Excludes $20 million and $5 million, of losses, net of taxes, related to interest rate swaps and treasury rate locks for the years ended December 31, 2014 and 2013, respectively.
(e) Includes $15 million and $15 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks at Generation for the years ended December 31, 2014 and 2013, respectively.

During the years ended December 31, 2014, 2013, and 2012, Generation's former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from Accumulated OCI to earnings was a $195 million, $683 million and $1,368 million pre-tax gain, respectively. Given that the cash flow hedges had primarily consisted of forward power sales and power swaps and did not include power and gas options or sales, the ineffectiveness of Generation's cash flow hedges was primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. Changes in cash flow hedge ineffectiveness were losses of $5 million for the year ended December 31, 2012.

The effect of Exelon's former energy-related cash flow hedge activity impact on pre-tax earnings based on the reclassification adjustment from Accumulated OCI to earnings was a $195 million, $464 million and $747 million pre-tax gain for the years ended December 31, 2014, 2013 and 2012, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were losses of $5 million for the year ended December 31, 2012. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods as all energy-related cash flow hedge positions were de-designated prior to the Constellation merger date.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps ("treasury") to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars. Exelon entered into floating-to-fixed forward starting interest rate swaps to manage interest rate risks associated with anticipated future debt issuance related to the proposed PHI acquisition. For the years ended December 31, 2014, 2013 and 2012, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense, or interest expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Generation				Intercompany Eliminations	Exelon Corporate	Exelon
Year Ended December 31, 2014	Operating Revenues	Purchased Power and Fuel	Interest Expense	Total	Operating Revenues [(a)]	Interest Expense	Total
Change in fair value of commodity positions	$ (413)	$ (194)	$ —	$(607)	$ —	$ —	$(607)
Reclassification to realized at settlement of commodity positions	231	(223)	—	8	—	—	8
Net commodity mark-to-market gains (losses)	(182)	(417)	—	(599)	—	—	(599)
Change in fair value of treasury positions	10	—	(2)	8	—	(100)	(92)
Reclassification to realized at settlement of treasury positions	(2)	—	—	(2)	—	—	(2)
Net treasury mark-to market gains (losses)	8	—	(2)	6	—	(100)	(94)
Net mark-to market gains (losses)	$ (174)	$ (417)	$ (2)	$(593)	$ —	$ (100)	$(693)

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Year Ended December 31, 2013	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	Intercompany Eliminations Operating Revenues [a]	Exelon Corporate Interest Expense	Exelon Total
Change in fair value of commodity positions	$ 286	$ 180	$ —	$466	$ (6)	$ —	$ 460
Reclassification to realized at settlement of commodity positions	(64)	104	—	40	13	—	53
Net commodity mark-to-market gains (losses)	222	284	—	506	7	—	513
Change in fair value of treasury positions	(1)	—	(4)	(5)	—	—	(5)
Reclassification to realized at settlement of treasury positions	(1)	—	—	(1)	—	—	(1)
Net treasury mark-to market gains (losses)	(2)	—	(4)	(6)	—	—	(6)
Net mark-to market gains (losses)	$ 220	$ 284	$ (4)	$500	$ 7	$ —	$ 507

Year Ended December 31, 2012	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	Intercompany Eliminations Operating Revenues [a]	Exelon Corporate Interest Expense	Exelon Total
Change in fair value of commodity positions	$ (362)	$ 215	$ —	$(147)	$ (94)	$ —	$(241)
Reclassification to realized at settlement of commodity positions	432	238	—	670	101	—	771
Net commodity mark-to-market gains (losses)	70	453	—	523	7	—	530
Change in fair value of treasury positions	—	—	6	6	—	—	6
Reclassification to realized at settlement of treasury positions	(3)	—	—	(3)	—	—	(3)
Net treasury mark-to market gains (losses)	(3)	—	6	3	—	—	3
Net mark-to market gains (losses)	$ 67	$ 453	$ 6	$ 526	$ 7	$ —	$ 533

(a) Prior to the Constellation merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value were recorded to operating revenues and eliminated in consolidation.

Proprietary Trading Activities (Exelon and Generation). For the years ended December 31, 2014, 2013, and 2012 Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on commodity derivative instruments entered into for proprietary trading purposes and interest rate derivative contracts to hedge risk associated with the interest rate component of underlying commodity positions. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes

related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	For the Years Ended December 31, 2014	2013	2012
Change in fair value of commodity positions	Operating Revenues	$ (1)	$(22)	$ (13)
Reclassification to realized at settlement of commodity positions	Operating Revenues	(29)	(15)	108
Net commodity mark-to-market gains (losses)	Operating Revenues	(30)	(37)	95
Change in fair value of treasury positions	Operating Revenues	1	1	1
Reclassification to realized at settlement of treasury positions	Operating Revenues	3	(3)	—
Net treasury mark-to market gains (losses)	Operating Revenues	4	(2)	1
Net mark-to market gains (losses)	Operating Revenues	$(26)	$(39)	$ 96

Credit Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2014. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below exclude credit risk exposure from individual retail counterparties, Nuclear fuel procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 7A.—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of $43 million, $29 million and $40 million, respectively.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Rating as of December 31, 2014	Total Exposure Before Credit Collateral	Credit Collateral [a]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,629	$ 62	$ 1,567	1	$ 452
Non-investment grade	49	19	30	—	—
No external ratings					
Internally rated—investment grade	479	—	479	—	—
Internally rated—non-investment grade	60	4	56	—	—
Total	$ 2,217	$ 85	$ 2,132	1	$ 452

Net Credit Exposure by Type of Counterparty	December 31, 2014
Financial institutions	$ 295
Investor-owned utilities, marketers, power producers	958
Energy cooperatives and municipalities	862
Other	17
Total	$ 2,132

(a) As of December 31, 2014, credit collateral held from counterparties where Generation had credit exposure included $69 million of cash and $16 million of letters of credit.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of December 31, 2014, ComEd's net credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents PECO's net credit exposure. As of December 31, 2014, PECO had no net credit exposure with suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2014, PECO had credit exposure of $8 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents BGE's net credit exposure. The seller's credit exposure is calculated each business day. As of December 31, 2014, BGE had no net credit exposure to suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2014, BGE had credit exposure of $8 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e. NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the

Combined Notes to Consolidated Financial Statements—(Continued)
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demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

	For the Years Ended December 31,	
Credit-Risk Related Contingent Feature	2014	2013
Gross Fair Value of Derivative Contracts Containing this Feature [(a)]	$ (1,433)	$ (1,056)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements [(b)]	1,140	846
Net Fair Value of Derivative Contracts Containing This Feature [(c)]	$ (293)	$ (210)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features ignoring the effects of master netting agreements.
(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of $1,497 million and letters of credit posted of $672 million, and cash collateral held of $77 million and letters of credit held of $24 million as of December 31, 2014 for counterparties with derivative positions. Generation had cash collateral posted of $72 million and letters of credit posted of $364 million and cash collateral held of $206 million and letters of credit held of $34 million at December 31, 2013 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e. to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of $2.4 billion and $2.0 billion as of December 31, 2014 and 2013, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2014, Generation's and Exelon's swaps were in a liability position, with a fair value of $16 million and $90 million, respectively.

See Note 24—Segment Information for further information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices

rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2014, ComEd held approximately $2 million collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2014, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 3—Regulatory Matters for additional information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2014, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2014, PECO could have been required to post approximately $36 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2014, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2014, BGE could have been required to post approximately $79 million of collateral to its counterparties.

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13. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool.

Exelon, Generation, ComEd, PECO and BGE had the following amounts of commercial paper borrowings at December 31, 2014 and 2013:

Commercial Paper Issuer	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
	2014 [a][b]	2013 [a][b]	2014	2013	2014	2013
Exelon Corporate	$ 500	$ 500	$—	$—	— %	0.27%
Generation	5,600	5,600	—	—	0.32%	0.32%
ComEd	1,000	1,000	304	184	0.33%	0.40%
PECO	600	600	—	—	n.a.	n.a.
BGE	600	600	120	135	0.29%	0.31%
Total	$8,300	$8,300	$424	$319		

(a) Reflects aggregate bank commitments under the revolving and bilateral credit agreements (with the exception of $200 million bilateral agreements for Generation) that backstop the commercial paper program. See discussion below and Credit Agreements table below for items affecting effective program size.

(b) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expired on October 17, 2014 and were renewed at the same amount through October 16, 2015. These facilities are solely utilized to issue letters of credit. As of December 31, 2014, letters of credit issued under these agreements totaled $9 million, $16 million, $21 million and $1 million for Generation, ComEd, PECO and BGE, respectively. Also, excludes the unsecured bridge credit facility of $3.2 billion at December 31, 2014, to support the PHI transaction discussed below.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have revolving credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its outstanding commercial paper does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit agreement.

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At December 31, 2014, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit agreements:

Borrower	Aggregate Bank Commitment [a]	Facility Draws	Outstanding Letters of Credit [c]	Available Capacity at December 31, 2014	
				Actual	To Support Additional Commercial Paper [b]
Exelon Corporate	$ 500	$ —	$ 6	$ 494	$ 494
Generation	5,800	—	1,181	4,619	4,504
ComEd	1,000	—	2	998	694
PECO	600	—	1	599	599
BGE	600	—	—	600	480
Total	$ 8,500	$ —	$ 1,190	$7,310	$ 6,771

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expired on October 17, 2014 and were renewed at the same amount through October 16, 2015. These facilities are solely utilized to issue letters of credit. As of December 31, 2014, letters of credit issued under these agreements totaled $9 million, $16 million, $21 million and $1 million for Generation, ComEd, PECO and BGE, respectively. Also, excludes the unsecured bridge credit facility of $3.2 billion at December 31, 2014, to support the PHI transaction discussed below.
(b) Excludes $200 million bilateral credit facilities that do not back Generation's commercial paper program.
(c) Excludes nonrecourse debt letters of credit, see discussion below on Continental Wind.

As of December 31, 2014, there were no borrowings under the Registrants' credit facilities.

The following tables present the short-term borrowings activity for Exelon, Generation, ComEd, and BGE during 2014, 2013 and 2012. PECO did not have any short-term borrowings during 2014, 2013 or 2012.

Exelon

	2014	2013	2012
Average borrowings	$ 571	$ 254	$ 199
Maximum borrowings outstanding	1,164	682	505
Average interest rates, computed on a daily basis	0.32%	0.37%	0.48%
Average interest rates, at December 31	0.53%	0.35%	n.a.

Generation

	2014	2013	2012
Average borrowings	$ 93	$ 42	$ 4
Maximum borrowings outstanding	552	291	165
Average interest rates, computed on a daily basis	0.32%	0.32%	0.45%
Average interest rates, at December 31	n.a.	n.a.	n.a.

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ComEd

	2014	2013	2012
Average borrowings	$ 415	$ 203	$ 110
Maximum borrowings outstanding	597	446	366
Average interest rates, computed on a daily basis	0.33%	0.40%	0.50%
Average interest rates, at December 31	0.50%	0.37%	n.a.

BGE

	2014	2013	2012
Average borrowings	$ 64	$ 35	$ 6
Maximum borrowings outstanding	180	135	76
Average interest rates, computed on a daily basis	0.29%	0.31%	0.43%
Average interest rates, computed at December 31	0.61%	0.31%	n.a.

Credit Facilities

On March 28, 2014, ComEd extended for an additional year the expiration date of its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2019. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

On May 30, 2014, each of Exelon Corporate, Generation, PECO and BGE extended the expiration date of its unsecured revolving credit facility with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively, into May 2019, with the exception of a cumulative amount of $315 million in commitments, which expire in April 2018. Costs incurred to extend these facilities were not material.

On October 24, 2014, a $100 million bilateral CENG credit facility was amended and extended for an additional year. This facility has been utilized by CENG to fund working capital and capital projects. This facility does not back Generation's commercial paper program.

On November 24, 2014, Generation entered into a $25 million bilateral credit facility, scheduled to mature in December of 2016. This facility does not currently back Generation's commercial paper program.

On January 9, 2015, Generation amended and extended its $75 million bilateral credit facility for an additional two years. This facility does not back Generation's commercial paper program.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular registrant's credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 7.5, 0.0 and 0.0 basis points for prime based borrowings and 127.5, 127.5, 107.5, 90.0 and 100.0 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings

and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

An event of default under any of the Registrants' revolving credit facilities would not constitute an event of default under any of the other Registrants' revolving credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its revolving credit facility would constitute an event of default under the Exelon Corporation revolving credit facility.

Each credit facility requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and, in the case of Exelon and Generation, interest on the debt of its project subsidiaries. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2014:

	Exelon	Generation	ComEd	PECO	BGE
Credit facility threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2014, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	9.19	12.35	7.03	8.72	9.28

Credit Agreements

In May 2014, concurrently and in connection with entering into the agreement to acquire PHI, Exelon entered into a credit facility to which the lenders committed to provide Exelon a 364-day senior unsecured bridge credit facility of $7.2 billion to support the contemplated transaction and provide flexibility for timing of permanent financing. The bridge credit facility was subsequently reduced to $3.2 billion as a result of the June 2014 debt and equity security issuances discussed below, as well as, the net after-tax proceeds from generating asset divestitures during the second half of 2014. During the year ended December 31, 2014, Exelon recorded $31 million to interest expense in connection with the bridge facility to temporarily finance the PHI acquisition. It is not currently expected that Exelon will be required to draw upon this credit facility to finance the proposed PHI acquisition.

Junior Subordinated Notes

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Net proceeds from the issuance were $1.11 billion, net of a $35 million underwriter fee. The net proceeds are expected to be used to finance a portion of the acquisition of PHI and for general corporate purposes.

Each equity unit represents an undivided beneficial ownership interest in Exelon's 2.5% junior subordinated notes due in 2024 and a forward equity purchase contract which settles in 2017. The junior subordinated notes are expected to be remarketed in 2017. In connection with the remarketing, Exelon may modify the maturity date of the notes to a date earlier than June 1, 2024 but not earlier

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than June 1, 2020, remove redemption provisions of the notes, or change the interest rate on the notes, including changing the interest rate from fixed to floating. Investors that participate in the remarketing receive the remarketing proceeds and may use those funds to either settle the equity forward upon settlement date or invest in the remarketed debt and use other funds for the share purchase. Exelon intends to use the remarketing proceeds to repay debt issued or for other corporate purposes as soon as practical following such settlements. If the remarketing fails, holders of the notes will have the right to put their notes to Exelon for an amount equal to the principal amount of notes held by such holder plus accrued interest. The equity units carry a total annual distribution rate of 6.5%, which is comprised of a quarterly coupon rate of interest of 2.5% and a quarterly contract payment of 4.0% (contract payments).

Each purchase contract obligates the holder to purchase, and Exelon to sell, for $50.00 a number of shares of Exelon's common stock in accordance with the conversion ratios set forth below:

- If the market price equals or exceeds $43.7484, then 1.1429 shares.
- If the market price is less than $43.7484 but greater than $35.00, a number of shares of common stock having a value, based on the market price, equal to $50.00.
- If the market price is less than or equal to $35.00, then 1.4286 shares.

A holder's ownership interest in the notes is pledged to Exelon to secure the holder's obligation under the related forward equity purchase contract. If a holder of the forward equity purchase contract chooses at any time to no longer be a holder of the notes, such holder's obligation under the purchase contract must be secured by a U.S. Treasury security.

At the time of issuance, Exelon determined that the forward equity purchase contract had no value and therefore the entire $1.15 billion of junior subordinated notes were allocated to debt and recorded within Long-term debt on Exelon's Consolidated Balance Sheet. Additionally, at the time of issuance, the present value of the contract payments of $131 million were recorded to Long-term debt, representing the obligation to make contract payments, with an offsetting reduction to Common stock. The obligation for the contract payments will be accreted to interest expense over the 3 year period ending in 2017 in Exelon's Consolidated Statement of Operations and Comprehensive Income. The Long-term debt recorded for the contract payments is considered a non-cash financing transaction that was excluded from Exelon's Consolidated Statements of Cash Flows. Until settlement of the equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method.

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Long-Term Debt

The following tables present the outstanding long-term debt at Exelon, Generation, ComEd, PECO and BGE as of December 31, 2014 and 2013:

Exelon

	Rates	Maturity Date	December 31, 2014	December 31, 2013
Long-term debt				
Rate stabilization bonds	5.72% — 5.82%	2017	$ 195	$ 265
First mortgage bonds [(a)(b)]	1.20% — 6.45%	2015 - 2044	8,079	7,746
Senior unsecured notes	2.00% — 7.60%	2015 - 2042	7,071	7,571
Unsecured bonds	2.80% — 6.35%	2016 - 2036	1,750	1,750
Pollution control note	4.10%	2014	—	20
Nuclear fuel procurement contracts	3.25% — 3.35%	2018	70	—
Junior subordinated notes	6.50%	2017	1,150	—
Nonrecourse debt:				
Fixed rates	2.33% — 6.00%	2031 - 2037	1,166	1,077
Variable rates	2.41% — 5.00%	2019 - 2030	1,101	150
Notes payable and other [(c)]	6.95% — 7.83%	2015 - 2053	174	181
Total long-term debt			20,756	18,760
Unamortized debt discount and premium, net			(37)	(19)
Fair value adjustment			441	384
Fair value hedge carrying value adjustment, net			4	7
Long-term debt due within one year			(1,802)	(1,509)
Long-term debt			$19,362	$17,623
Long-term debt to financing trusts [(d)]				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III	7.38%	2028	81	81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Subordinated debentures to BGE Trust	6.20%	2043	258	258
Total long-term debt to financing trusts			$ 648	$ 648

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's assets are subject to the liens of their respective mortgage indentures.
(b) Includes first mortgage bonds issued under the ComEd and PECO mortgage indentures securing pollution control bonds and notes.
(c) Includes capital lease obligations of $32 million and $41 million at December 31, 2014 and 2013, respectively. Lease payments of $3 million, $4 million, $4 million, $4 million, $5 million and $12 million will be made in 2015, 2016, 2017, 2018, 2019 and thereafter, respectively.
(d) Amounts owed to these financing trusts are recorded as Long-term debt to financing trusts within Exelon's Consolidated Balance Sheets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation

	Rates	Maturity Date	December 31, 2014	December 31, 2013
Long-term debt				
Senior unsecured notes	2.00% — 7.60%	2015 - 2042	$5,771	$6,271
Social Security Administration	2.93%	2015	—	1
Pollution control notes	4.10%	2014	—	20
Nuclear fuel procurement contracts	3.25% — 3.35%	2018	70	—
Nonrecourse debt:				
Fixed rates	2.33% — 6.00%	2031 - 2037	1,166	1,077
Variable rates	2.41% — 5.00%	2019 - 2030	1,101	150
Notes payable and other [(a)]	7.83%	2014 - 2020	26	33
Total long-term debt			8,134	7,552
Fair value adjustment			146	166
Unamortized debt discount and premium, net			(14)	11
Long-term debt due within one year			(614)	(561)
Long-term debt			$7,652	$7,168

(a) Includes Generation's capital lease obligations of $24 million and $33 million at December 31, 2014 and 2013, respectively. Generation will make lease payments of $3 million, $4 million, $4 million, $4 million, $5 million and $4 million in 2015, 2016, 2017, 2018, 2019 and thereafter, respectively.

On January 13, 2015, Generation issued $750 million in aggregate principal amount of Senior Notes. The Senior Notes carry an annual interest rate of 2.950%, payable semi-annually, commencing July 15, 2015 and due January 15, 2020. The proceeds of the Senior Notes will be used to fund the optional redemption of Exelon's $550 million, 4.550% Senior Notes due June 15, 2015 and for general corporate purposes. In addition to the issuance, Exelon terminated $400 million of floating-to-fixed interest rate swaps that had been designated as cash flow hedges. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments at this time are probable not to occur. As a result Exelon will reclassify $26 million of deferred losses in AOCI to Other, net in the first quarter of 2015.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd

	Rates	Maturity Date	December 31, 2014	December 31, 2013
Long-term debt				
First mortgage bonds [(a)(b)]	1.95% — 6.45%	2015 - 2044	$5,829	$5,546
Notes payable and other [(c)]	6.95% — 7.49%	2015 - 2053	148	148
Total long-term debt			5,977	5,694
Unamortized debt discount and premium, net			(19)	(19)
Long-term debt due within one year			(260)	(617)
Long-term debt			$5,698	$5,058
Long-term debt to financing trust [(d)]				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206

(a) Substantially all of ComEd's assets other than expressly excepted property are subject to the lien of its mortgage indenture.
(b) Includes first mortgage bonds issued under the ComEd mortgage indenture securing pollution control bonds and notes.
(c) Includes ComEd's capital lease obligations of $8 million at both December 31, 2014 and 2013, respectively. Lease payments of less than $1 million will be made from 2015 through expiration at 2053.
(d) Amount owed to this financing trust is recorded as Long-term debt to financing trust within ComEd's Consolidated Balance Sheets.

PECO

	Rates	Maturity Date	December 31, 2014	December 31, 2013
Long-term debt				
First mortgage bonds [(a)(b)]	1.20% — 5.95%	2016 - 2044	$2,250	$2,200
Total long-term debt			2,250	2,200
Unamortized debt discount and premium, net			(4)	(3)
Long-term debt due within one year			—	(250)
Long-term debt			$2,246	$1,947
Long-term debt to financing trusts [(c)]				
Subordinated debentures to PECO Trust III	7.38%	2028	$ 81	$ 81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Long-term debt to financing trusts			$ 184	$ 184

(a) Substantially all of PECO's assets are subject to the lien of its mortgage indenture.
(b) Includes first mortgage bonds issued under the PECO mortgage indenture securing pollution control bonds and notes.
(c) Amounts owed to this financing trust are recorded as Long-term debt to financing trusts within PECO's Consolidated Balance Sheets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

	Rates	Maturity Date	December 31, 2014	December 31, 2013
Long-term debt				
Rate stabilization bonds	5.72% — 5.82%	2017	195	$ 265
Notes	2.80% — 6.35%	2016 - 2036	$1,750	$1,750
Total long-term debt			1,945	2,015
Unamortized debt discount and premium, net			(3)	(4)
Long-term debt due within one year			(75)	(70)
Long-term debt			$1,867	$1,941
Long-term debt to financing trusts [(a)]				
Subordinated debentures to BGE Capital Trust II	6.20%	2043	$ 258	$ 258

(a) Amount owed to this financing trust is recorded as Long-term debt to financing trust within BGE's Consolidated Balance Sheets.

Long-term debt maturities at Exelon, Generation, ComEd, PECO and BGE in the periods 2014 through 2019 and thereafter are as follows:

Year	Exelon	Generation	ComEd	PECO	BGE
2015	$ 1,739	$ 604	$ 260	$ —	$ 75
2016	1,269	4	665	300	300
2017	2,400	705	425	—	120
2018	1,415	75	840	500	—
2019	982	682	300	—	—
Thereafter	13,599[(a)]	6,064	3,693[(b)]	1,634[(c)]	1,708[(d)]
Total	$21,404	$ 8,134	$6,183	$2,434	$2,203

(a) Includes $648 million due to ComEd, PECO and BGE financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.
(d) Includes $258 million due to BGE financing trust.

Nonrecourse Debt

Exelon and Generation have issued nonrecourse debt financing, in which approximately $2.7 billion of generating assets have been pledged as collateral at December 31, 2014.

Denver Airport. In June 2011, Generation entered into a 20-year, $7 million solar loan agreement, fully amortizing by June 30, 2031 related to a solar construction project in Denver, Colorado. The agreement bears interest at a fixed rate of 5.50% annually with interest payable annually. As of December 31, 2014, $7 million was outstanding.

CEU Upstream. In July 2011, Generation entered into a five year asset-based lending agreement associated with certain Upstream gas properties that it owns. The borrowing base committed under the facility is $110 million and can increase to a total of $500 million if the assets

support a higher borrowing base and Generation is able to obtain additional commitments from lenders. The facility was amended and extended through January 2019. Borrowings under this facility are secured by the Upstream gas properties, and the lenders do not have recourse against Exelon or Generation in the event of a default. The agreement is scheduled to expire on January 14, 2019, at a fixed rate of 2.41% annually with interest payable quarterly. As of December 31, 2014, $77 million was outstanding under the facility. The facility includes a provision that requires the Generation entities owning the Upstream gas properties subject to the agreement to maintain a current ratio of one-to-one. As of December 31, 2014, Generation was in compliance with this provision.

Sacramento PV Energy. In July 2011, a subsidiary of Generation entered into a 19-year, $41 million nonrecourse note to finance a 30MW solar facility in Sacramento, California. The note bears interest at a variable rate equal to the six-month LIBOR plus 2.25%. Interest is payable quarterly and is secured by the equity interests and assets of the subsidiary. The note is scheduled to mature on December 31, 2030. As of December 31, 2014, $35 million was outstanding. The subsidiary also executed interest rate swaps with an initial notional value of $30 million in order to convert the variable interest payments to fixed payments on 75% of the $41 million facility amount, as required by the debt covenants. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

Holyoke Solar Cooperative. In October 2011, Generation entered into a 20-year, $10 million solar loan agreement, fully amortizing by December 31, 2031 related to a solar construction project in Holyoke, Massachusetts. The agreement bears interest at a fixed rate of 5.25% annually with interest payable monthly. As of December 31, 2014, $10 million was outstanding. The agreement includes a provision that requires Generation to establish and maintain a reserve fund to be held by Holyoke Solar Cooperative. As of December 31, 2014, Generation was in compliance with this provision.

Antelope Valley Solar Ranch One. In December 2011, the DOE Loan Programs Office issued a guarantee for up to $646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational in the first half of 2014. The loan will mature on January 5, 2037. Interest rates on the loan are fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity. As of December 31, 2014, $557 million was outstanding.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2014, Generation had $156 million in letters of credit outstanding related to the project. The letters of credit balance is expected to decline over time as scheduled equity contributions for the project are made. Generation expects to contribute approximately $2 million in additional equity contributions.

In connection with this agreement, on September 28, 2011, Generation entered into a floating-to-fixed interest rate swap with a notional amount of $485 million to mitigate interest-rate risk associated with the financing. As Generation received additional loan advances, it subsequently entered into a series of fixed-to-floating interest rate swaps to offset portions of the original interest rate hedge. During the third quarter of 2014, the original interest rate swap was terminated, consistent with the agreements. See Note 12—Derivative Financial Instruments for additional information regarding the interest rate swaps associated with Antelope Valley.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Constellation Solar Horizons. In September 2012, a subsidiary of Generation entered into an 18-year $38 million nonrecourse note to recover capital used to build a 16MW solar facility in Emmitsburg, Maryland. The note is schedule to mature on September 7, 2030. The note bears interest at a variable rate equal to the three-month LIBOR plus 2.25%. Interest is payable quarterly, and the note is secured by the equity interests and assets of the subsidiary. As of December 31, 2014, $34 million was outstanding. The subsidiary also executed interest rate swaps for an initial notional amount of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $38 million facility amount, as required by the debt covenants. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

Continental Wind. In September 2013, Continental Wind, LLC (Continental Wind), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million aggregate principal amount of Continental Wind's 6.00% senior secured notes due February 28, 2033 with interest payable semi-annually. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667MW. The net proceeds were distributed to Generation for its general business purposes. As of December 31, 2014, $592 million was outstanding. In connection with this nonrecourse project financing, Exelon terminated existing interest rate swaps with a total notional amount of $350 million during the third quarter of 2013, and realized a total gain of $26 million upon termination. The gain on the interest rate swaps was recorded within OCI and will reduce the effective interest rate over the life of the debt for Exelon. See Note 12—Derivative Financial Instruments for additional information on the interest rate swaps.

In addition, Continental Wind entered into a $131 million letter of credit facility and $10 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2014, the Continental Wind letter of credit facility had $47 million in letters of credit outstanding related to the project.

ExGen Renewables I. On February 6, 2014, ExGen Renewables I, LLC (EGR), an indirect subsidiary of Exelon and Generation, borrowed $300 million aggregate principal amount pursuant to a nonrecourse senior secured loan, due February 6, 2021. The proceeds were distributed to Generation for its general business purposes. The loan bears interest at a variable rate equal to LIBOR plus 4.25%, subject to a 1% floor with interest payable quarterly. EGR indirectly owns Continental Wind. As of December 31, 2014, $282 million was outstanding. In addition to the financing, EGR entered into interest rate swaps with an initial notional amount of $240 million at an interest rate of 2.03% to manage a portion of the interest rate exposure in connection with the financing. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

ExGen Texas Power. In September 2014, ExGen Texas Power, LLC (EGTP), an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan, scheduled to mature on September 18, 2021. The net proceeds were distributed to Generation for general business purposes. The term loan bears interest at a variable rate equal to LIBOR plus 4.75%, subject to a 1% LIBOR floor with interest payable quarterly. As of December 31, 2014, $673 million was outstanding. As part of the agreement, a revolving credit facility was established for the amount of $20 million available through, and scheduled to mature on September 18, 2019. In addition to the financing, EGTP entered into interest rate swaps with an initial notional amount of approximately $505 million at an interest rate of 2.34% to hedge a portion of the interest rate exposure in connection with this financing, as required by the debt covenants. See Note 12—Derivative Financial Instruments for additional information regarding interest rate swaps.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

14. Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

Income tax expense (benefit) from continuing operations is comprised of the following components:

For the Year Ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 121	$ 360	$(171)	$ 28	$ 24
Deferred	576	(35)	395	87	90
Investment tax credit amortization	(20)	(16)	(2)	—	(1)
State					
Current	42	35	7	(2)	—
Deferred	(53)	(137)	39	1	27
Total	$ 666	$ 207	$ 268	$114	$140

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 744	$ 250	$ 160	$126	$ 9
Deferred	140	360	(27)	23	100
Investment tax credit amortization	(15)	(11)	(2)	(1)	(1)
State					
Current	181	50	50	16	—
Deferred	(6)	(34)	(29)	(2)	26
Total	$1,044	$ 615	$ 152	$162	$134

For the Year Ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 37	$ 104	$ (40)	$ 88	$ (97)
Deferred	701	326	237	25	101
Investment tax credit amortization	(11)	(6)	(2)	(2)	(1)
State					
Current	(25)	(12)	6	4	—
Deferred	(75)	88	38	12	4
Total	$ 627	$ 500	$ 239	$127	$ 7

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

For the Year Ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	1.3	(1.9)	4.5	(0.1)	5.0
Qualified nuclear decommissioning trust fund income	2.4	4.8	—	—	—
Tax exempt income	(0.2)	(0.5)	—	—	—
Domestic production activities deduction	(2.0)	(4.1)	—	—	—
Health care reform legislation	0.1	—	0.2	—	0.2
Amortization of investment tax credit, net deferred taxes	(1.1)	(2.0)	(0.3)	(0.1)	(0.3)
Plant basis differences	(1.9)	—	(0.1)	(10.4)	0.2
Production tax credits and other credits	(2.4)	(4.8)	—	—	—
Non-controlling interest	(1.8)	(3.7)	—	—	—
Statute of limitations expiration	(2.6)	(5.3)	—	—	—
Other	—	(0.6)	0.3	0.1	(0.2)
Effective income tax rate	26.8%	16.9%	39.6%	24.5%	39.9%

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	4.8	1.8	3.4	1.6	4.9
Qualified nuclear decommissioning trust fund income	3.7	6.1	—	—	—
Tax exempt income	(0.2)	(0.3)	—	—	—
Domestic production activities deduction	—	—	—	—	—
Health care reform legislation	0.1	—	0.7	—	0.2
Amortization of investment tax credit, net deferred taxes	(1.9)	(3.0)	(0.6)	(0.1)	—
Plant basis differences	(1.6)	—	(0.8)	(7.1)	(0.2)
Production tax credits and other credits	(2.1)	(3.4)	(0.1)	—	—
Statute of limitations expiration	(0.1)	(0.2)	—	—	—
Other	(0.1)	0.7	0.3	(0.3)	(0.9)
Effective income tax rate	37.6%	36.7%	37.9%	29.1%	39.0%

For the Year Ended December 31, 2012	Exelon [a]	Generation [a]	ComEd	PECO	BGE [b]
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(3.5)	4.9	4.6	2.0	24.3
Qualified nuclear decommissioning trust fund income	5.4	9.1	—	—	—
Tax exempt income	(0.2)	(0.4)	—	—	—
Domestic production activities deduction	—	—	—	—	—
Health care reform legislation	0.1	—	0.4	—	11.6
Amortization of investment tax credit	(1.1)	(1.3)	(0.4)	(0.3)	(8.6)
Plant basis differences	(2.4)	—	(0.3)	(11.5)	(9.0)
Production tax credits and other credits	(2.2)	(3.7)	—	—	—
Fines and Penalties	2.6	4.4	—	—	—
Merger expenses [c]	2.4	—	—	—	24.2
Statute of limitations expiration	(0.1)	(0.3)	—	—	—
Other	(1.1)	(0.4)	(0.6)	(0.2)	(13.9)
Effective income tax rate	34.9%	47.3%	38.7%	25.0%	63.6%

(a) Exelon activity for the twelve months ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012. Generation activity for the twelve months ended December 31, 2012 includes the results of Constellation for March 12, 2012—December 31, 2012.
(b) BGE activity represents the activity for the twelve months ended December 31, 2012.
(c) Prior to the close of the merger, the Registrants recorded the applicable taxes on merger transaction costs assuming the merger would not be completed. Upon closing of the merger, the Registrants reversed such taxes for those merger transaction costs that were determined to be non tax-deductible upon successful completion of a merger.

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2014 and 2013 are presented below:

For the Year Ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Plant basis differences	$(12,143)	$ (3,834)	$(3,945)	$(2,749)	$(1,661)
Accrual based contracts	(178)	(178)	—	—	—
Derivatives and other financial instruments	(46)	(79)	(4)	—	—
Deferred pension and postretirement obligation	1,914	(390)	(543)	2	(53)
Nuclear decommissioning activities	(726)	(726)	—	—	—
Deferred debt refinancing costs	112	57	(18)	(2)	(4)
Regulatory assets and liabilities	(1,824)	—	(286)	27	(258)
Tax loss carryforward	111	48	—	11	39
Tax credit carryforward	97	143	—	—	—
Investment in CENG	(563)	(563)	—	—	—
Other, net	1,029	346	255	111	30
Deferred income tax liabilities (net)	$(12,217)	$ (5,176)	$(4,541)	$(2,600)	$(1,907)
Unamortized investment tax credits	(555)	(528)	(20)	(2)	(5)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(12,772)	$ (5,704)	$(4,561)	$(2,602)	$(1,912)

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Plant basis differences	$(11,612)	$ (3,879)	$(3,523)	$(2,573)	$(1,538)
Accrual based contracts	(214)	(214)	—	—	—
Derivatives and other financial instruments	(509)	(505)	(4)	—	—
Deferred pension and postretirement obligation	1,489	(362)	(522)	—	(74)
Nuclear decommissioning activities	(647)	(646)	—	—	—
Deferred debt refinancing costs	173	79	(21)	(3)	(5)
Regulatory assets and liabilities	(1,611)	—	(241)	42	(253)
Tax loss carryforward	252	76	47	11	52
Tax credit carryforward	534	534	—	—	—
Investment in CENG	(541)	(541)	—	—	—
Other, net	804	67	154	122	26
Deferred income tax liabilities (net)	$(11,882)	$ (5,391)	$(4,110)	$(2,401)	$(1,792)
Unamortized investment tax credits	(490)	(454)	(22)	(3)	(6)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(12,372)	$ (5,845)	$(4,132)	$(2,404)	$(1,798)

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides the Registrants' carryforwards and any corresponding valuation allowances as of December 31, 2014.

	Exelon	Generation	ComEd	PECO	BGE
Federal					
Federal general business credits carryforward	184[a]	184	—	—	—
State					
State net operating losses and other credit carryforwards	3,141[b]	1,693[c]	—	170[d]	730[e]
Deferred taxes on state tax attributes (net)	169	96	—	11	39
Valuation allowance on state tax attributes	50	48	—	—	1

(a) Exelon's federal general business credit carryforwards will expire beginning in 2032.
(b) Exelon's state net operating losses and other carryforwards, which are presented on a post-apportioned basis, will expire beginning in 2015
(c) Generation's state net operating losses and other carryforwards, which are presented on a post-apportioned basis, will expire beginning in 2015.
(d) PECO's state net operating losses will expire beginning in 2031.
(e) BGE's state net operating losses will expire beginning in 2026.

Tabular reconciliation of unrecognized tax benefits

The following table provides a reconciliation of the Registrants' unrecognized tax benefits as of December 31, 2014, 2013 and 2012:

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2014	$2,175	$ 1,415	$ 324	$ 44	$—
Increases based on tax positions related to 2014	15	15	—	—	—
Change to positions that only affect timing	(255)	33	(175)	—	—
Increases based on tax positions prior to 2014	18	18	—	—	—
Decreases based on tax positions prior to 2014	(1)	(2)	—	—	—
Decrease from settlements with taxing authorities	(35)	(34)	—	—	—
Decreases from expiration of statute of limitations	(88)	(88)	—	—	—
Unrecognized tax benefits at December 31, 2014	$1,829	$ 1,357	$ 149	$ 44	$—

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2013	$1,024	$ 876	$ 67	$ 44	$—
Increases based on tax positions related to 2013	19	19	—	—	—
Change to positions that only affect timing	649	36	257	—	—
Increases based on tax positions prior to 2013	493	493	—	—	—
Decreases based on tax positions prior to 2013	(6)	(5)	—	—	—
Decreases from expiration of statute of limitations	(4)	(4)	—	—	—
Unrecognized tax benefits at December 31, 2013	$2,175	$ 1,415	$ 324	$ 44	$—

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2012	$ 807	$ 683	$ 70	$ 48	$ 11
Merger balance transfer	195	183	—	—	—
Increases based on tax positions related to 2012	34	3	—	—	—
Change to positions that only affect timing	(88)	(69)	(3)	(4)	(11)
Increases based on tax positions prior to 2012	91	91	—	—	—
Decreases based on tax positions prior to 2012	(6)	(6)	—	—	—
Decreases related to settlements with taxing authorities	(2)	(2)	—	—	—
Decreases from expiration of statute of limitations	(7)	(7)	—	—	—
Unrecognized tax benefits at December 31, 2012	$1,024	$ 876	$ 67	$ 44	$—

Included in Exelon's unrecognized tax benefits balance at December 31, 2014 and 2013 are approximately $1,129 million and $1,387 million, respectively, of tax positions for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits. The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to, or defer the receipt of the cash tax benefit from, the taxing authority to an earlier or later period respectively.

Unrecognized tax benefits that if recognized would affect the effective tax rate

Exelon and Generation have $701 million and $672 million, respectively, of unrecognized tax benefits at December 31, 2014 that, if recognized, would decrease the effective tax rate. Exelon and Generation had $788 million and $768 million, respectively, of unrecognized tax benefits at December 31, 2013 that, if recognized, would decrease the effective tax rate.

Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Nuclear Decommissioning Liabilities (Exelon and Generation)

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and has disallowed the claims. In November 2008, Generation received a final determination from the Appeals division of the IRS (IRS Appeals) disallowing AmerGen's refund claims. Generation filed a complaint in the United States Court of Federal Claims on February 20, 2009 to contest this determination. During the first and second quarters of 2013, AmerGen and the DOJ completed and filed cross motions for summary judgment. On September 17, 2013, the Court granted the government's motion denying AmerGen's claims for refund. In the first quarter of 2014, Exelon filed an appeal of the decision to the United States Court of Appeals for the Federal Circuit and oral arguments were heard in January of 2015.

Due to the possibility of final resolution through an appellate decision, Generation continues to believe that it is reasonably possible that the $661 million of total unrecognized tax benefits will significantly decrease in the next twelve months.

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(Dollars in millions, except per share data unless otherwise noted)

Settlement of Income Tax Audits and Litigation

As of December 31, 2014, Exelon and Generation have approximately $188 million of state unrecognized tax benefits that could significantly increase or decrease within the 12 months after the reporting date as a result of completing audits and expected statute of limitation expirations that if recognized would decrease the effective tax rate.

See Other Tax Matters—Like Kind Exchange section below for information regarding the amount of unrecognized tax benefits associated with this matter that could change significantly within the next 12 months.

Total amounts of interest and penalties recognized

The following table represents the net interest receivable (payable), including interest related to tax positions reflected in the Registrants' Consolidated Balance Sheets.

Net interest receivable (payable) as of	Exelon	Generation	ComEd	PECO	BGE
December 31, 2014	$(310)	$ 40	$(203)	$ 3	$ (1)
December 31, 2013	(349)	(37)	(174)	3	—

The following table sets forth the net interest expense, including interest related to tax positions, recognized in interest expense (income) in other income and deductions in the Registrants' Consolidated Statements of Operations and Comprehensive Income. The Registrants have not accrued any material penalties with respect to uncertain tax positions.

Net interest expense (income) for the years ended	Exelon	Generation	ComEd	PECO	BGE
December 31, 2014	$ (36)	$ (50)	$ 6	$—	$ 1
December 31, 2013	391	17	281	(1)	—
December 31, 2012	(1)	11	(20)	(1)	9

Description of tax years that remain open to assessment by major jurisdiction

Taxpayer	Open Years
Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns	1999, 2001-2013
Constellation and subsidiaries consolidated Federal income tax returns	2011-March 2012
Exelon and subsidiaries Illinois unitary income tax returns	2007-2013
Constellation combined New York corporate income tax returns	2008-2013
Various separate company Pennsylvania corporate net income tax returns	2010-2013
BGE Maryland corporate net income tax returns	2011-2013
Various Exelon Maryland corporate net income tax returns	2012-2013
Various Constellation (Non-BGE) Maryland corporate net income tax returns	2011-2013

Other Tax Matters

Like-Kind Exchange

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $1.2 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was

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deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with this position and asserted that the entire gain of approximately $1.2 billion was taxable in 1999.

Exelon has been unable to reach agreement with the IRS regarding the dispute over the like kind exchange position. The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a “listed transaction” that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately $90 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like-kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison’s deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon’s current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013, Exelon recorded a non-cash charge to earnings of approximately $265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $170 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd’s equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the unpaid tax liabilities related to the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition, ComEd will continue to record non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. Exelon continues to believe that it is unlikely that the IRS’s assertion of penalties will ultimately be sustained and therefore no liability for the penalty has been recorded.

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On September 30, 2013, the IRS issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue. The litigation could take three to five years including appeals, if necessary. Decisions in the Tax Court are not controlled by the Federal Circuit's decision in Consolidated Edison.

In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable as of December 31, 2014 may be as much as $810 million, of which approximately $310 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts will increase by a material amount.

In the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of $335 million. The termination resulted in a 2014 tax payment of approximately $285 million by Exelon, including approximately $155 million by ComEd representing the remaining gain deferred pursuant to the like-kind exchange transaction. In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, Exelon will be required to pay the full amount of tax and after-tax interest discussed in the preceding paragraph but will ultimately be entitled to a refund of the 2014 tax payment. See Note 8—Impairment of Long-Lived Assets for further details.

Accounting for Generation Repairs (Exelon and Generation)

On April 30, 2013, the IRS issued Revenue Procedure 2013-24 providing guidance for determining the appropriate tax treatment of costs incurred to repair electric generation assets. Generation will change its method of accounting for deducting repairs in accordance with this guidance beginning with its 2014 tax year. Generation has calculated that adoption of the new method will result in a cash tax detriment of approximately $120 million.

Accounting for Electric Transmission and Distribution Property Repairs (Exelon, Generation, ComEd, PECO and BGE)

On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for repair costs associated with electric transmission and distribution property. ComEd and PECO adopted the safe harbor in the Revenue Procedure for the 2011 and 2010 tax years, respectively. For the year ended December 31, 2011, the adoption of the safe harbor resulted in a $35 million reduction to income tax expense at PECO, while Generation incurred additional income tax expense in the amount of $28 million due to a decrease in its domestic production activities deduction, which was reflected in the effective income tax rate reconciliation in 2011 in the plant basis differences and domestic production activities deduction lines, respectively. For Exelon, the adoption had a minimal effect on consolidated earnings. In addition, the adoption of the safe harbor resulted in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million, and $95 million, respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million related to a decreased domestic production activities deduction.

BGE adopted the safe harbor for the short period 2012 pre-merger tax year. For the year ended December 31, 2012, the adoption of the safe harbor resulted in a cash tax benefit at BGE in the amount of $27 million.

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See Note 3—Regulatory Matters for discussion of the regulatory treatment prescribed in the 2010 electric distribution rate case settlement for PECO's cash tax benefit resulting from the application of the method change to years prior to 2010.

Accounting for Gas Distribution Property Repairs (Exelon, PECO and BGE).

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The change to the newly adopted method for the 2011 tax year and 2012 resulted in a tax benefit of $26 million at Exelon, of which $29 million in tax benefit is recorded at PECO, partially offset by an expense recorded at Generation to reflect a reduction in its domestic production activities deduction. BGE changed its method of accounting for gas distribution repairs for the 2008 tax year. The IRS is expected to issue industry guidance in the near future. Exelon, PECO and BGE will determine the financial statement impacts of the gas distribution repair costs accounting method changes after guidance is issued.

Accounting for Final Tangible Property Regulations (Exelon, Generation, ComEd, PECO, and BGE)

On September 19, 2013, the Treasury Department and the IRS published final regulations regarding the tax treatment of costs incurred to acquire, produce, or improve tangible property. The Registrants have assessed the financial impact of this guidance and do not expect it to have a material impact. Any changes in method of accounting required to conform to the final regulations will be made for the Registrant's 2014 taxable year.

Long-Term State Tax Apportionment (Exelon and Generation)

As a result of the merger with Constellation, Exelon and Generation re-evaluated their long-term state tax apportionment in the first quarter of 2012. The total effect of revising the long-term state tax apportionment resulted in the recording of a deferred state tax asset of $72 million (net of Federal taxes) for Exelon. Of this, a benefit in the amount of $116 million and $14 million (net of Federal taxes) was recorded for Exelon and Generation, respectively, for the three months ended March 31, 2012. Further, Exelon and Generation recorded deferred state tax liabilities of $44 million and $14 million (net of Federal taxes), respectively, as part of purchase accounting during the three months ended March 31, 2012. The long-term state tax apportionment also was updated in the fourth quarter of 2012, resulting in the recording of a deferred state tax benefit of $3 million (net of Federal taxes) for Exelon, and a deferred state tax expense of $7 million (net of Federal taxes) for Generation. There was no change to the long-term state tax apportionment for BGE, ComEd and PECO.

The long-term state tax apportionment was revised in the fourth quarter of 2014 pursuant to Exelon's long-term state tax apportionment policy, resulting in the recording of a deferred state tax benefit for Exelon and Generation of $28 million (net of Federal taxes) and $40 million (net of Federal taxes), respectively. The amounts recorded for 2013 in accordance with the policy were immaterial.

Allocation of Tax Benefits (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any

net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2014, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $55 million and $25 million, respectively. ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of tax net operating losses.

During 2013, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $26 million and $27 million, respectively. During 2013, ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd's and BGE's tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010.

During 2012, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $48 million and $9 million, respectively. During 2012, ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd's and BGE's tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010.

ComEd received a non-cash contribution to equity from Exelon in 2012 of $11 million, related to tax benefits associated with capital projects constructed by ComEd on behalf of Exelon and Generation.

15. Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

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The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets, from January 1, 2013 to December 31, 2014:

	Exelon and Generation
Nuclear decommissioning ARO at January 1, 2013	$ 4,741
Accretion expense	259
Net decrease due to changes in, and timing of, estimated future cash flows	(140)
Costs incurred to decommission retired plants	(5)
Nuclear decommissioning ARO at December 31, 2013 [(a)]	4,855
Consolidation of CENG [(b)]	1,760
Accretion expense	334
Net increase due to changes in, and timing of, estimated future cash flows	19
Costs incurred to decommission retired plants	(7)
Nuclear decommissioning ARO at December 31, 2014 [(a)]	$ 6,961

(a) Includes $8 million and $9 million as the current portion of the ARO at December 31, 2014 and 2013, respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.
(b) Represents the fair value of the CENG ARO liability as of April 1, 2014, the date of consolidation. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.

During 2014, Generation's ARO increased by approximately $2.1 billion. The increase is largely driven by the recording of an ARO on Exelon's and Generation's Consolidated Balance Sheets at fair value, including subsequent purchase accounting adjustments, upon consolidation of CENG (see Note 5—Investment in Constellation Energy Nuclear Group, LLC). The change in the ARO was also driven by an increase for accretion of the obligation and an increase in the estimated costs to decommission Byron, Braidwood, and LaSalle nuclear units resulting from the completion of updated decommissioning costs studies received during 2014 as part of the annual assessment. These increases in the ARO were partially offset by decreases in the ARO due to a reduction in estimated escalation rates, primarily for labor and energy costs. The increase in the ARO due to the changes in, and timing of, estimated cash flows was offset within Property, plant and equipment on Exelon's and Generation's Consolidated Balance Sheets, aside from an approximate $16 million credit to income, which is included in Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During 2013, Generation's ARO increased by approximately $114 million. The increase is largely driven by an increase in the estimated costs to decommission the Limerick and Three Mile Island nuclear units resulting from the completion of updated decommissioning costs studies received during 2013 and an increase for accretion of the obligation. These increases in the ARO were offset by decreases to the ARO due to changes in long-term escalation rates, primarily for labor and energy costs, as well as changes in the timing of the future nominal cash flows coupled with the fact that cash flows affected by this change in timing are re-measured and discounted at current credit adjusted risk free rates (CARFRs), which have increased from the prior year. The decrease in the ARO due to the changes in, and timing of, estimated cash flows was entirely offset by decreases in Property, plant and equipment within Exelon's and Generation's Consolidated Balance Sheets.

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Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with Generation's nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of approximately $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. Aside from the former PECO units, Generation does not currently collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from utility customers. Apart from the contributions made to the NDT funds from amounts previously collected from ComEd and currently collected from PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third-party (see Zion Station Decommissioning below) and the CENG units, where any shortfall is required to be funded by both Generation and EDF. Generation, through PECO, has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise Generation will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, compared to decommissioning costs, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units. The initial $50 million and up to 5% of any additional shortfalls, would be borne by Generation. No recourse exists to collect additional amounts for any of Generation's other nuclear units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to Generation's other nuclear units, Generation retains any funds remaining after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to nuclear decommissioning trust funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions

are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. Generation expects to comply with applicable regulations and timely commence and complete all required decommissioning activities.

At December 31, 2014, and 2013, Exelon and Generation had NDT fund investments totaling $10,537 million and $8,071 million, respectively. At December 31, 2014, approximately 52% of the funds were invested in equity securities and 48% were invested in fixed income securities. At December 31, 2013, approximately 48% of the funds were invested in equity securities and 52% were invested in fixed income securities. During 2012, the NDT fixed income portfolio completed its transition from solely core fixed income investments to a blend of Treasury Inflation Protected Securities (TIPS), investment-grade corporate credit and middle market lending. There was no change in the equity investment strategy.

The following table provides unrealized gains on NDT funds for 2014, 2013 and 2012:

	Exelon and Generation		
	For the Years Ended December 31,		
	2014	2013	2012
Net unrealized gains on decommissioning trust funds—Regulatory Agreement Units [a]	$ 180	$ 406	$ 386
Net unrealized gains on decommissioning trust funds—Non-Regulatory Agreement Units [b][c]	134	146	105

(a) Net unrealized gains related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $29 million, $7 million and $73 million of net unrealized gains related to the Zion Station pledged assets in 2014, 2013 and 2012, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.
(c) Net unrealized gains related to Generation's NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Accounting Implications of the Regulatory Agreements with ComEd and PECO . Based on the regulatory agreement with the ICC that dictates Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the NDT funds are expected to exceed the total estimated decommissioning obligation, decommissioning-related activities, including realized and unrealized gains and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the expected value of the NDT fund for

any former ComEd unit fall below the amount of the expected decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial position could be material. As of December 31, 2014, the NDT funds of each of the former ComEd units, except for Zion (see Zion Station Decommissioning below), are expected to exceed the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is different, as described below, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

Based on the regulatory agreement supported by the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the former PECO units, regardless of whether the funds held in the NDT funds are expected to exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial position could be material.

The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Refer to Note 3—Regulatory Matters and Note 25—Related Party Transactions for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF and decommission the SNF dry storage facility, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to its decommissioning efforts at Zion Station. During 2013, EnergySolutions entered a definitive acquisition agreement and was acquired by another Company. Generation reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA.

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ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to Pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a Payable for Zion Station decommissioning in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the Payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately $86 million, which is included within the nuclear decommissioning ARO at December 31, 2014. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2014 and 2013:

	Exelon and Generation	
	2014	2013
Carrying value of Zion Station pledged assets	$ 319	$ 458
Payable to Zion Solutions [(a)]	292	414
Current portion of payable to Zion Solutions [(b)]	137	109
Cumulative withdrawals by Zion Solutions to pay decommissioning costs	666	498

(a) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required decommissioning work according to an established schedule and constructed a dry cask storage facility on the land and has loaded the SNF from the SNF pools onto the dry cask storage facility at Zion Station. Rent payable under the Lease Agreement is $1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with Zion Station and penalty rents may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by ZionSolutions, EnergySolutions provided a $200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. EnergySolutions and its parent company have also provided a performance guarantee and EnergySolutions has entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

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NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in the type of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2014 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2019 for Oyster Creek); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2014 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning activities are completed under three possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the assumption plants cease operating at the end of an extended license life (assuming 20-year license renewal extensions, except Oyster Creek with an assumed end-of-operations date of 2019); (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 6% to 6.3% (as compared to a historical 5-year annual average pre-tax return of approximately 9%).

Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or make additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial position may be significantly adversely affected.

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On April 1, 2013, Generation submitted its NRC-required biennial decommissioning funding status report as of December 31, 2012. As of December 31, 2012, Generation provided adequate funding assurance for all of its units, including Limerick Unit 1, where Generation had in place a $115 million parent guarantee to cover the NRC minimum funding assurance requirements. On October 2, 2013, the NRC issued summary findings from the NRC Staff's review of the 2013 decommissioning funding status reports for all 104 operating reactors, including the Generation operating units. Based on that review, the NRC Staff determined that Generation provided decommissioning funding assurance under the NRC regulations for all of its operating units, including Limerick Unit 1. On March 26, 2014, in accordance with a NRC requirement with respect to units involved in a merger or acquisition, CENG submitted its NRC-required decommissioning funding status report as of December 31, 2013 and no additional financial assurance was required.

On March 31, 2014, Generation submitted its NRC required annual decommissioning funding report as of December 31, 2013 for reactors that have been shut down except for Zion Station which is included on a separate report to the NRC submitted by EnergySolutions (see Zion Station Decommissioning above). This submittal also included the required updated financial tests for the Limerick Unit 1 parent guarantee. There was no change to the amount of the parent guarantee, or the funding status of these reactors. Adequate decommissioning funding assurance is in place for all reactors owned by Generation. During 2014, the operating license for Limerick Unit 1 was extended by 20 years. As a result of this extension, and the subsequent funding assurance calculation performed by the NRC, it was found that the parent company guarantee was no longer required and thus the parent guarantee for Limerick Unit 1 will be cancelled effective March 13, 2015. See Note 3—Regulatory Matters for additional information regarding the operating license extension for Limerick Unit 1.

Generation will file its next biennial decommissioning funding status report with the NRC on or before March 31, 2015. That report will reflect the status of decommissioning funding assurance as of December 31, 2014. Due to increased cost estimates received in the second half of 2014, Braidwood Unit 1, Braidwood Unit 2, and Byron Unit 2 do not have adequate funding assurance based on the most recent calculations as of December 31, 2014. NRC guidance provides licensees with two years or by the time of submitting the next biennial report (on or before March 31, 2017) to resolve funding assurance shortfalls. During this period, Generation will monitor funding assurance and new developments, including the impact of a 20-year license renewal for Braidwood and Byron, to assess the status of funding assurance and to take steps, if necessary, to address any funding shortfall on these funds on or before March 31, 2017.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential "apparent violations" of its regulations because of alleged inaccuracies in the Decommissioning Funding Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation's status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. The January 31, 2013 letter from the NRC does not take issue with Generation's current funding status, and as reflected in Generation's April 1, 2013 decommissioning funding status report referenced above, Generation continues to provide adequate funding assurance for each of its units. Generation met with the NRC on April 30, 2013 for a pre-decisional enforcement conference to provide additional information to explain why Generation believes that it complied with the regulatory requirements and did not deliberately or otherwise provide incomplete or inaccurate information in its decommissioning funding status reports. On May 1, 2014, the NRC issued its final determination. Although the NRC determined that these historical status reports did not provide complete and accurate information, the

violation of the regulatory requirements was not a deliberate violation. The NRC noted the low safety significance and Generation's corrective actions to satisfy the NRC Staff's expectations and issued a Severity Level IV violation, with no monetary penalty. A Severity Level IV violation is the lowest level of violation.

In addition, on June 24, 2013, Exelon received a subpoena from the SEC requesting that Exelon provide the SEC with certain documents generally relating to Exelon and Generation's reporting and funding of the future decommissioning of Generation's nuclear power plants. Exelon and Generation have cooperated with the SEC and provided the requested documents. On February 13, 2014, Exelon received a letter from the SEC confirming that it had concluded its investigation and that no further action was anticipated based on information provided by Exelon.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO units, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Non-Nuclear Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. ComEd, PECO and BGE have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

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The following table provides a rollforward of the non-nuclear AROs reflected on the Registrants' Consolidated Balance Sheets from January 1, 2013 to December 31, 2014:

	Exelon	Generation	ComEd	PECO	BGE
Non-nuclear AROs at January 1, 2013	$ 343	$ 207	$ 99	$ 29	$ 8
Net increase (decrease) due to changes in, and timing of, estimated future cash flows [a]	1	(11)	—	—	12
Development projects [b]	2	2	—	—	—
Accretion expense [c]	18	13	4	1	—
Payments	(13)	(10)	(2)	—	(1)
Non-nuclear AROs at December 31, 2013 [d]	351	201	101	30	19
Net increase (decrease) due to changes in, and timing of, estimated future cash flows [a]	(1)	(2)	2	—	(1)
Development projects [b]	11	11	—	—	—
Accretion expense [c]	15	11	3	1	—
Liabilities held for sale [e]	(4)	(4)	—	—	—
Sale of generating assets [f]	(20)	(20)	—	—	—
Payments	(6)	(3)	(2)	(1)	—
Non-nuclear AROs at December 31, 2014 [d]	$ 346	$ 194	$ 104	$ 30	$ 18

(a) During the year ended December 31, 2014, Generation recorded a decrease of $(2) million and ComEd recorded an increase of $1 million in Operating and maintenance expense. PECO, and BGE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2014. During the year ended December 31, 2013, Generation recorded an increase in Operating and maintenance expense of $13 million. ComEd, PECO, and BGE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2013.
(b) Relates to new AROs recorded due to the construction of solar, wind and other non-nuclear generating sites.
(c) For ComEd, PECO, and BGE, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.
(d) During the year ended December 31, 2014, Generation, ComEd, PECO and BGE recorded $1 million, $1 million, $1 million, and $1 million, respectively, as the current portion of the ARO. During December 31, 2013 Generation, ComEd, PECO and BGE recorded $0 million, $2 million, $1 million, and $0 million, respectively, as the current portion of the ARO. This is included in Other current liabilities on the Registrants' respective Consolidated Balance Sheets.
(e) Represents AROs related to generating stations classified as held for sale as of December 31, 2014. See Note 4—Mergers, Acquisitions, and Dispositions for further information.
(f) Reflects a reduction to the ARO resulting primarily from the sales of the Keystone and Conemaugh generating stations. See Note 4—Mergers, Acquisitions, and Dispositions for further information.

16. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

As of December 31, 2014, Exelon sponsored defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. The table below shows the pension and postretirement benefit plans in which each operating company participated at December 31, 2014.

On April 1, 2014, as a result of the consolidation of CENG into Generation, the obligations associated with CENG's pension and other postretirement plans are reflected in the disclosures below based on an April 1, 2014 valuation adjusted for subsequent activity. Exelon assumed sponsorship of the CENG pension and other postretirement benefit plans in the third quarter of 2014 when the employees transferred to Exelon. CENG will fund the underfunded balances of the pension and other postretirement benefit plans measured at July 14, 2014 on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG. Payments received from CENG related to the funded plans will be contributed to the appropriate benefit trusts.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Name of Plan:	Operating Company				
	Generation	ComEd	PECO	BGE	BSC
Qualified Pension Plans:					
Exelon Corporation Retirement Program [a]	X	X	X	X	X
Exelon Corporation Cash Balance Pension Plan [a]	X	X	X	X	X
Exelon Corporation Pension Plan for Bargaining Unit Employees [a]	X	X			X
Exelon New England Union Employees Pension Plan [a]	X				
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek [a]	X	X			X
Pension Plan of Constellation Energy Group, Inc. [b]	X	X	X	X	X
Pension Plan of Constellation Energy Nuclear Group, LLC [c]	X			X	X
Nine Mile Point Pension Plan [c]	X				X
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B [b]	X				
Non-Qualified Pension Plans:					
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan [a]	X	X	X		X
Exelon Corporation Supplemental Management Retirement Plan [a]	X	X	X	X	X
Constellation Energy Group, Inc. Senior Executive Supplemental Plan [b]	X			X	X
Constellation Energy Group, Inc. Supplemental Pension Plan [b]	X			X	X
Constellation Energy Group, Inc. Benefits Restoration Plan [b]	X			X	X
Constellation Nuclear Plan, LLC Executive Retirement Plan [c]	X				X
Constellation Energy Nuclear Plan, LLC Benefits Restoration Plan [c]	X				X
Baltimore Gas & Electric Company Executive Benefit Plan [b]	X			X	X
Baltimore Gas & Electric Company Manager Benefit Plan [b]	X			X	X
Other Postretirement Benefit Plans:					
PECO Energy Company Retiree Medical Plan [a]	X	X	X	X	X
Exelon Corporation Health Care Program [a]	X	X		X	X
Exelon Corporation Employees' Life Insurance Plan [a]	X	X	X	X	X
Constellation Energy Group, Inc. Retiree Medical Plan [b]	X	X	X	X	X
Constellation Energy Group, Inc. Retiree Dental Plan [b]	X			X	X
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan [b]	X	X	X	X	X
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan [b]	X				
Exelon New England Union Post-Employment Medical Savings Account Plan [a]	X				
Retiree Medical Plan of Constellation Energy Nuclear Group LLC [c]	X			X	X
Retiree Dental Plan of Constellation Energy Nuclear Group LLC [c]	X			X	X
Nine Mile Point Nuclear Station, LLC Medical Care and Prescription Drug Plan for Retired Employees [c]	X				X

(a) These plans are collectively referred to as the Legacy Exelon plans.
(b) These plans are collectively referred to as the Legacy Constellation Energy Group (CEG) Plans.
(c) These plans are collectively referred to as the Legacy CENG plans.

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Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Exelon has elected that the trusts underlying these plans be treated under the IRC as qualified trusts. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets and Funded Status

Exelon recognizes the overfunded or underfunded status of defined benefit pension and OPEB plans as an asset or liability on its balance sheet, with offsetting entries to Accumulated other comprehensive income (AOCI) and regulatory assets (liabilities), in accordance with the applicable authoritative guidance. The measurement date for the plans is December 31.

During the first quarter of 2014, Exelon received an updated valuation of its legacy pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2014. This valuation resulted in an increase to the pension obligation of $35 million and an increase to the other postretirement benefit obligation of $12 million. Additionally, Accumulated other comprehensive loss (AOCL) increased by approximately $12 million (after tax), regulatory assets increased by approximately $34 million, and regulatory liabilities increased by approximately $5 million. During the second quarter of 2014, Exelon received an updated valuation for the remainder of its pension and other postretirement obligations to reflect actual census data as of January 1, 2014. This valuation resulted in an increase to the pension obligation of $13 million and an increase to the other postretirement benefit obligation of $3 million. Additionally, AOCL increased by approximately $1 million (after tax) and regulatory assets increased by approximately $15 million.

In April 2014, Exelon announced plan design changes for certain other postretirement benefit plans, which required an interim remeasurement of the benefit obligation for those plans using assumptions as of April 30, 2014, including updated discount rates and asset values. The remeasurement resulted in a decrease to Exelon's non-pension postretirement benefit obligations, regulatory assets, and AOCL of approximately $790 million, $240 million, and $259 million (after tax), respectively, and an increase in regulatory liabilities of approximately $125 million.

The following table provides a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Change in benefit obligation:				
Net benefit obligation at beginning of year	$15,459	$16,800	$ 4,451	$ 4,820
Service cost	293	317	117	162
Interest cost	749	650	186	194
Plan participants' contributions	—	—	42	34
Actuarial loss (gain)	2,095	(1,363)	502	(551)
Plan amendments	—	1	(1,012)	15
Acquisitions/divestitures [(a)]	594	—	142	—
Curtailments	(8)	—	—	—
Settlements	(30)	(69)	—	—
Gross benefits paid	(896)	(877)	(231)	(223)
Net benefit obligation at end of year	$18,256	$15,459	$ 4,197	$ 4,451

Combined Notes to Consolidated Financial Statements—(Continued)
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	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Change in plan assets:				
Fair value of net plan assets at beginning of year	$13,571	$13,357	$ 2,238	$ 2,135
Actual return on plan assets	1,443	821	90	209
Employer contributions	332	339	291	83
Plan participants' contributions	—	—	42	34
Benefits paid	(896)	(877)	(231)	(223)
Acquisitions/divestitures [(a)]	454	—	—	—
Settlements	(30)	(69)	—	—
Fair value of net plan assets at end of year	$14,874	$13,571	$ 2,430	$ 2,238

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, Exelon became a sponsor of CENG's pension and OPEB plans effective July 14, 2014. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for further information.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Other current liabilities	$ 16	$ 12	$ 25	$ 23
Pension obligations	3,366	1,876	—	—
Non-pension postretirement benefit obligations	—	—	1,742	2,190
Unfunded status (net benefit obligation less net plan assets)	$3,382	$1,888	$ 1,767	$ 2,213

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO), and fair value of plan assets for all pension plans with a PBO or ABO in excess of plan assets.

	PBO in excess of plan assets	
	2014	2013
Projected benefit obligation	$ 18,256	$ 15,452
Fair value of net plan assets	14,874	13,564

	ABO in excess of plan assets	
	2014	2013
Projected benefit obligation	$ 18,256	$ 15,452
Accumulated benefit obligation	17,191	14,552
Fair value of net plan assets	14,874	13,564

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On a PBO basis, the plans were funded at 81% at December 31, 2014 compared to 88% at December 31, 2013. On an ABO basis, the plans were funded at 87% at December 31, 2014 compared to 93% at December 31, 2013. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The majority of the 2014 pension benefit cost for Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 4.80%. Certain of the pension plans were remeasured as of October 31, 2014 using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 3.95%. Costs incurred during the year ended December 31, 2014 reflect the impact of this remeasurement. The majority of the 2014 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.59% for funded plans and a discount rate of 4.90% for all plans. Certain of the other postretirement benefit plans were remeasured as of April 30, 2014 using an expected long-term rate of return on plan assets of 6.59% and a discount rate of 4.30%. Costs for December 31, 2014 reflect the impact of this remeasurement.

On July 14, 2014 Exelon became the sponsor of the pension and other postretirement plans formerly sponsored by CENG. The components of cost for the CENG plans are included in the table below for the period from April 1, 2014 to December 31, 2014, and reflect the valuation performed on April 1, 2014 upon consolidation of CENG. Refer to Note 5—Investment in Constellation Energy Nuclear Group, LLC for further details on the consolidation of CENG. The 2014 pension benefit cost for these plans is calculated using an expected long-term rate of return on plan assets of 7.75% and discount rates ranging from 3.60%—4.30%. The majority of the 2014 other postretirement benefit cost for the CENG plans is calculated using a discount rate of 4.55%.

A portion of the net periodic benefit cost for all pension and OPEB plans are capitalized within each of the Registrant's Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to any capitalization, for the years ended December 31, 2014, 2013 and 2012.

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Components of net periodic benefit cost:						
Service cost	$ 293	$ 317	$ 280	$ 117	$ 162	$ 156
Interest cost	749	650	698	186	194	205
Expected return on assets	(994)	(1,015)	(988)	(154)	(132)	(115)
Amortization of:						
Transition obligation	—	—	—	—	—	11
Prior service cost (credit)	14	14	15	(122)	(19)	(17)
Actuarial loss	420	562	450	50	83	81
Curtailment benefits	—	—	—	—	—	(7)
Settlement charges	2	9	31	—	—	—
Contractual termination benefits [(a)]	—	—	14	—	—	6
Net periodic benefit cost	$ 484	$ 537	$ 500	$ 77	$ 288	$ 320

(a) ComEd and BGE established regulatory assets of $1 million and $4 million, respectively, for their portion of the contractual termination benefit charge in 2012.

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Through Exelon's postretirement benefit plans, the Registrants provide retirees with prescription drug coverage. The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Modernization Act), enacted on December 8, 2003, introduced a prescription drug benefit under Medicare as well as a Federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit (Part D subsidy). Management believes the prescription drug benefit provided under Exelon's postretirement benefit plans meets the requirements for the subsidy. In December 2011, the Company decided that beginning in 2013, it would no longer elect to take the direct Part D subsidy. This resulted in a $17 million increase in cost for the year ended December 31, 2012 related to the amortization of an actuarial loss. Beginning in 2013, eligible employees are offered an Employee Group Waiver Plan (EGWP), a standard Medicare Part D Plan, with a supplemental "wrap," which contains a wraparound prescription drug design that allows the company to provide benefits above those available under the EGWP.

Components of AOCI and Regulatory Assets

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets (liabilities) for the years ended December 31, 2014, 2013 and 2012 for all plans combined.

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial (gain) loss	$1,639	$(1,169)	$1,693	$ 561	$(628)	$ 304
Amortization of actuarial loss	(420)	(562)	(450)	(50)	(83)	(81)
Current year prior service (credit) cost	—	—	1	(1,012)	15	(109)
Amortization of prior service (cost) credit	(14)	(14)	(15)	122	19	17
Current year transition (asset) obligation	—	—	—	—	—	1
Amortization of transition asset (obligation)	—	—	—	—	—	(11)
Curtailments	—	—	(10)	—	—	(1)
Settlements	(2)	(8)	(31)	—	—	—
Total recognized in AOCI and regulatory assets (liabilities) [(a)]	$1,203	$(1,753)	$1,188	$ (379)	$(677)	$ 120

(a) Of the $1,203 million loss related to pension benefits, $788 million and $415 million were recognized in AOCI and regulatory assets, respectively, during 2014. Of the $379 million gain related to other postretirement benefits, $162 million and $217 million were recognized in AOCI and regulatory assets (liabilities), respectively, during 2014. Of the $1,753 million gain related to pension benefits, $1,071 million and $682 million were recognized in AOCI and regulatory assets, respectively, during 2013. Of the $677 million gain related to other postretirement benefits, $352 million and $325 million were recognized in AOCI and regulatory assets (liabilities), respectively, during 2013. Of the $1,188 million loss related to pension benefits, $283 million and $904 million were recognized in AOCI and regulatory assets, respectively, during 2012. Of the $120 million loss related to other postretirement benefits, $39 million and $81 million were recognized in AOCI and regulatory assets, respectively, during 2012.

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The following table provides the components of Exelon's gross accumulated other comprehensive loss and regulatory assets (liabilities) that have not been recognized as components of periodic benefit cost at December 31, 2014 and 2013, respectively, for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2014	2013	2014	2013
Prior service cost (credit)	$ 49	$ 62	$ (963)	$ (73)
Actuarial loss	7,407	6,192	985	474
Total [a]	$7,456	$6,254	$ 22	$ 401

(a) Of the $7,456 million related to pension benefits, $4,310 million and $3,146 million are included in AOCI and regulatory assets, respectively, at December 31, 2014. Of the $22 million related to other postretirement benefits, $22 million is included in regulatory assets (liabilities) at December 31, 2014. Of the $6,254 million related to pension benefits, $3,523 million and $2,731 million are included in AOCI and regulatory assets, respectively, at December 31, 2013. Of the $401 million related to other postretirement benefits, $161 million and $240 million are included in AOCI and regulatory assets (liabilities), respectively, at December 31, 2013.

The following table provides the components of Exelon's AOCI and regulatory assets at December 31, 2014 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2015. These estimates are subject to the completion of an actuarial valuation of Exelon's pension and other postretirement benefit obligations, which will reflect actual census data as of January 1, 2015 and actual claims activity as of December 31, 2014. The valuation is expected to be completed in the first quarter of 2015 for the majority of the benefit plans.

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 13	$ (175)
Actuarial loss	562	74
Total [a]	$ 575	$ (101)

(a) Of the $575 million related to pension benefits at December 31, 2014, $329 million and $246 million are expected to be amortized from AOCI and regulatory assets in 2015, respectively. Of the $101 million related to other postretirement benefits at December 31, 2014, $(51) million and $(50) million are expected to be amortized from AOCI and regulatory assets (liabilities) in 2015, respectively.

Assumptions

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term EROA, Exelon's expected level of contributions to the plans, the long-term expected investment rate credited to employees participating in cash balance plans and the anticipated rate of increase of health care costs. Additionally, assumptions related to plan participants include the incidence of mortality, the expected remaining service period, the level of compensation and rate of compensation increases, employee age and length of service, among other factors.

Expected Rate of Return. In selecting the EROA, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

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Mortality. For the December 31, 2014 actuarial valuation, Exelon changed its assumption of mortality to reflect more recent expectations of future improvements in life expectancy. The change was supported through completion of an experience study and supplemental analyses performed by its actuaries. The change in assumption resulted in increases of $361 million and $117 million in the pension and other postretirement benefits obligations, respectively.

The following assumptions were used to determine the benefit obligations for the plans at December 31, 2014, 2013 and 2012. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Discount rate	3.94%	4.80%	3.92%	3.92%	4.90%	4.00%
Rate of compensation increase	(a)	(b)	(c)	(a)	(b)	(c)
Mortality table	RP-2000 table with Scale BB-2D improvements (adjusted)	RP-2000 table with Scale AA improvements	RP-2000 table with Scale AA improvements	RP-2000 table with Scale BB-2D improvements (adjusted)	RP-2000 table with Scale AA improvements	RP-2000 table with Scale AA improvements
Health care cost trend on covered charges	N/A	N/A	N/A	6.00% decreasing to ultimate trend of 5.00% in 2017	6.00% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017

(a) 3.25% for 2015-2019 and 3.75% thereafter.
(b) 3.25% for 2014-2018 and 3.75% thereafter.
(c) 3.25% for 2013-2017 and 3.75% thereafter.

The following assumptions were used to determine the net periodic benefit costs for all the plans for the years ended December 31, 2014, 2013 and 2012:

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Discount rate	4.80% (a)	3.92% (b)	4.74% (c)	4.90% (a)	4.00% (b)	4.80% (c)
Expected return on plan assets	7.00% (d)	7.50% (d)	7.50% (d)	6.59% (d)	6.45% (d)	6.68% (d)
Rate of compensati increase	(e)	(f)	3.75%	(e)	(f)	3.75%
Mortality table	RP-2000 table with Scale AA improvements	RP-2000 table with Scale AA improvements	RP-2000 table with Scale AA improvements	RP-2000 table with Scale AA improvements	RP-2000 table with Scale AA improvements	RP-2000 table with Scale AA improvements
Health care cost trend on covered charges	N/A	N/A	N/A	6.00% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2014

(a) The discount rates above represent the initial discount rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2014. Certain of the other postretirement benefit plans were

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remeasured as of April 30, 2014 using an expected long-term rate of return on plan assets of 6.59% and a discount rate of 4.30%. Costs for the year ended December 31, 2014 reflect the impact of this remeasurement. On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, Exelon became the sponsor of CENG's legacy pension and OPEB plans effective July 14, 2014; discount rates for those plans, impacting 2014 costs, ranged from 3.60%-4.30% and 4.09%-4.55%, respectively. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for further information.

(b) The discount rates above represent the initial discount rates used to establish Exelon's pension and other postretirement benefits costs for the year ended December 31, 2013. Certain of the benefit plans were remeasured during the year using discount rates of 4.21% and 4.66% for pension and other postretirement benefits, respectively. Costs for the year ended December 31, 2013 reflect the impact of these measurements.

(c) The discount rates above represent the initial discounts rates used to establish Exelon's pension and other postretirement benefits costs for the year ended December 31, 2012. Certain of the benefit plans were remeasured during the year due to the Constellation merger, plan settlement and curtailment events, and plan changes using discount rates of 3.71% and 3.72% for pension and other postretirement benefits, respectively. Costs for the year ended December 31, 2012 reflect the impact of these remeasurements.

(d) Not applicable to pension and other postretirement benefit plans that do not have plan assets.

(e) 3.25% for 2014-2018 and 3.75% thereafter.

(f) 3.25% for 2013-2017 and 3.75% thereafter.

Assumed health care cost trend rates impact the costs reported for Exelon's other postretirement benefit plans for participants populations with plan designs that do not have a cap on cost growth. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend:	
on 2014 total service and interest cost components	$ 35
on postretirement benefit obligation at December 31, 2014	162
Effect of a one percentage point decrease in assumed health care cost trend:	
on 2014 total service and interest cost components	(24)
on postretirement benefit obligation at December 31, 2014	(113)

Health Care Reform Legislation

In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers. One such provision imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Certain key assumptions are required to estimate the impact of the excise tax on Exelon's other postretirement benefit obligation, including projected inflation rates (based on the CPI) and whether pre- and post- 65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

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Contributions

The following table provides contributions made by Generation, ComEd, PECO, BGE and BSC to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2014 (c)	2013	2012	2014	2013	2012 (a)
Generation	$173	$119	$ 48	$ 124	$ 30	$ 135
ComEd	122	118	25	125	4	119
PECO	11	11	13	5	20	33
BGE (b)	—	—	—	17	24	12
BSC (d)	26	91	63	20	5	24
Exelon	$332	$339	$149	$ 291	$ 83	$ 323

(a) The Registrants present the cash contributions above net of Federal subsidy payments received on each of their respective Consolidated Statements of Cash Flows. Exelon, Generation, ComEd, PECO, and BGE received Federal subsidy payments of $10 million, $5 million, $4 million, $1 million and $2 million, respectively, in 2012. Effective January 1, 2013, Exelon is no longer receiving this subsidy.
(b) BGE's other postretirement benefit payments for 2012 exclude $4 million, of other postretirement benefit payments made by BGE prior to the closing of the Constellation merger on March 12, 2012. These pre-Constellation merger contributions are not included in Exelon's financial statements but are reflected in BGE's financial statements.
(c) Exelon's and Generation's pension contributions include $43 million related to the legacy CENG plans that was funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG.
(d) Includes $9 million, $72 million, and $13 million of pension contributions funded by Exelon Corporate, for the years ended December 31, 2014, 2013, and 2012, respectively.

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). Additionally, for Exelon's largest qualified pension plan, until the plan is fully funded on an ABO basis, the projected contribution reflects a funding strategy of contributing $250 million. This level funding strategy helps minimize volatility of future period required pension contributions.

Exelon plans to contribute $447 million to its qualified pension plans in 2015, of which Generation, ComEd, PECO, and BGE will contribute $230 million, $138 million, $40 million, and $1 million, respectively. Exelon's and Generation's expected qualified pension plan contributions above include $36 million related to the legacy CENG plans that will be funded by CENG as provided in an EMA between Exelon and CENG.

Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon plans to make non-qualified pension plan benefit payments of $15 million in 2015, of which Generation, ComEd, PECO, and BGE will make payments of $6 million, $1 million, $1 million and $1 million, respectively.

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Unlike the qualified pension plans, other postretirement plans are not subject to statutory minimum contribution requirements. Exelon's management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). In 2015, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $37 million in 2015, of which Generation, ComEd, PECO, and BGE expect to contribute $17 million, $2 million, $0 million, and $17 million, respectively.

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2014 were:

	Pension Benefits	Other Postretirement Benefits
2015	$ 1,064	$ 217
2016	962	223
2017	979	230
2018	1,004	236
2019	1,032	247
2020 through 2024	5,825	1,373
Total estimated future benefit payments through 2024	$10,866	$ 2,526

Allocation to Exelon Subsidiaries

Generation, ComEd, PECO, and BGE account for their participation in Exelon's pension and other postretirement benefit plans by applying multi-employer accounting. Employee-related assets and liabilities, including both pension and postretirement liabilities, for the legacy Exelon plans were allocated by Exelon to its subsidiaries based on the number of active employees as of January 1, 2001 as part of Exelon's corporate restructuring. The obligation for Generation, ComEd and PECO reflects the initial allocation and the cumulative costs incurred and contributions made since January 1, 2001. Historically, Exelon has allocated the components of pension and other postretirement costs to the subsidiaries in the legacy Exelon plans based upon several factors, including the measures of active employee participation in each participating unit. Pension and postretirement benefit contributions were allocated to legacy Exelon subsidiaries in proportion to active service costs recognized and total costs recognized, respectively. Beginning in 2015, Exelon is allocating costs related to its legacy Exelon pension and postretirement benefit plans to its subsidiaries based on both active and retired employee participation and contributions are being allocated based on accounting cost. The impact of this allocation methodology change is not material to any Registrant. For legacy CEG and legacy CENG plans, components of pension and other postretirement benefit costs and contributions have been, and will continue to be, allocated to the subsidiaries based on employee participation (both active and retired).

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The amounts below were included in capital expenditures and Operating and maintenance expense for the years ended December 31, 2014, 2013 and 2012, respectively, for Generation's, ComEd's, PECO's, BSC's and BGE's allocated portion of the pension and postretirement benefit plan costs. These amounts include the recognized contractual termination benefit charges, curtailment gains, and settlement charges:

For the Year Ended December 31,	Generation	ComEd	PECO	BSC [a]	BGE [b][c]	Exelon
2014	$ 250	$ 162	$ 36	$ 46	$ 67	561
2013	347	309	43	71	55	825
2012	341	282	50	99	60	820

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above. As of December 31, 2012, ComEd and BGE each reported a regulatory asset of $1 million related to their BSC-billed portion of the second quarter 2012 contractual termination benefit charge.
(b) The amounts included in capital and Operating and maintenance expense for the years ended December 31, 2012 include $12 million in costs incurred prior to the closing of the Constellation merger on March 12, 2012. These amounts are not included in Exelon's capital expenditures and Operating and maintenance expense for the year ended December 31, 2012.
(c) BGE's pension and other postretirement benefit costs for the year ended December 31, 2012 include a $3 million contractual termination benefit charge, which was recorded as a regulatory asset as of December 31, 2012.

Plan Assets

Investment Strategy . On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Exelon used an EROA of 7.00% and 6.46% to estimate its 2015 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations and December 31, 2014 and 2013 asset allocations were as follows:

Pension Plans

		Percentage of Plan Assets at December 31,	
Asset Category	Target Allocation	2014	2013
Equity securities	32%	33%	35%
Fixed income securities	37%	37	37
Alternative investments [a]	31%	30	28
Total		100%	100%

Other Postretirement Benefit Plans

Asset Category	Target Allocation	Percentage of Plan Assets at December 31, 2014	2013
Equity securities	41%	42%	45%
Fixed income securities	34%	34	37
Alternative investments [a]	25%	24	18
Total		100%	100%

(a) Alternative investments include private equity, hedge funds and real estate.

Concentrations of Credit Risk . Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2014. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2014, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

Fair Value Measurements

The following table presents Exelon's pension and other postretirement benefit plan assets measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2014 and 2013:

At December 31, 2014 [a]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 1	$ —	$ —	$ 1
Equities:				
Domestic	1,556	1,133	2	2,691
Foreign	1,705	316	—	2,021
Equities subtotal	3,261	1,449	2	4,712
Fixed income:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,051	88	—	1,139
Debt securities issued by states of the United States and by political subdivisions of the states	—	80	—	80
Corporate debt securities	—	3,125	120	3,245
Other	—	942	152	1,094
Derivative instruments [b] :				
Assets	—	4	—	4
Liabilities	—	(16)	—	(16)
Fixed income subtotal	1,051	4,223	272	5,546
Private equity	—	—	904	904
Hedge funds	—	1,355	1,329	2,684
Real estate	243	—	744	987
Pension plan assets subtotal	4,556	7,027	3,251	14,834

Combined Notes to Consolidated Financial Statements—(Continued)
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At December 31, 2014 [a]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	11	—	—	11
Equities:				
Domestic	296	378	—	674
Foreign	184	147	—	331
Equities subtotal	480	525	—	1,005
Fixed income:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	15	59	—	74
Debt securities issued by states of the United States and by political subdivisions of the states	—	197	—	197
Corporate debt securities	—	42	—	42
Other	253	272	—	525
Fixed income subtotal	268	570	—	838
Hedge funds	—	339	110	449
Real estate	8	—	116	124
Other postretirement benefit plan assets subtotal	767	1,434	226	2,427
Total pension and other postretirement benefit plan assets [c]	$5,323	$8,461	$3,477	$17,261

At December 31, 2013 [a]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Equities:				
Domestic	$1,587	$ 865	$ 2	$ 2,454
Foreign	1,773	302	—	2,075
Equities subtotal	3,360	1,167	2	4,529
Fixed income:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	908	99	—	1,007
Debt securities issued by states of the United States and by political subdivisions of the states	—	88	—	88
Foreign debt securities	—	205	—	205
Corporate debt securities	—	2,927	41	2,968
Other	5	899	—	904
Derivative instruments [b]:				
Assets	—	7	—	7
Liabilities	—	(134)	—	(134)
Fixed income subtotal	913	4,091	41	5,045
Private equity	—	—	806	806
Hedge funds	—	1,266	1,039	2,305
Real estate	264	2	582	848
Pension plan assets subtotal	4,537	6,526	2,470	13,533

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At December 31, 2013 [a]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	51	—	—	51
Equities:				
Domestic	296	345	—	641
Foreign	154	170	—	324
Equities subtotal	450	515	—	965
Fixed income:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	17	46	—	63
Debt securities issued by states of the United States and by political subdivisions of the states	—	149	—	149
Foreign debt securities	—	2	—	2
Corporate debt securities	—	50	—	50
Other	305	225	—	530
Fixed income subtotal	322	472	—	794
Private equity	—	—	2	2
Hedge funds	—	295	4	299
Real estate	8	5	109	122
Other postretirement benefit plan assets subtotal	831	1,287	115	2,233
Total pension and other postretirement benefit plan assets [c]	$5,368	$7,813	$2,585	$15,766

(a) See Note 11—Fair Value of Financial Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Derivative instruments have a total notional amount of $1,491 million and $2,651 million at December 31, 2014 and 2013, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.
(c) Excludes net assets of $42 million and $43 million at December 31, 2014 and 2013, respectively, which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables related to pending securities sales, interest and dividends receivable, and payables related to pending securities purchases.

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The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2014 and 2013:

	Hedge funds	Private equity	Real estate	Fixed income	Equities	Total
Pension Assets						
Balance as of January 1, 2014	$1,039	$ 806	$582	$ 41	$ 2	$2,470
Actual return on plan assets:						
Relating to assets still held at the reporting date	77	112	83	7	—	279
Relating to assets sold during the period	3	—	—	—	—	3
Purchases, sales and settlements:						
Purchases	311	173	136	227	—	847
Sales	(38)	—	(19)	(3)	—	(60)
Settlements [a]	(33)	(203)	(65)	—	—	(301)
Transfers into (out of) Level 3 [b][c]	(30)	16	27	—	—	13
Balance as of December 31, 2014	$1,329	$ 904	$744	$ 272	$ 2	$3,251
Other Postretirement Benefits						
Balance as of January 1, 2014	$ 4	$ 2	$109	$ —	$ —	$ 115
Actual return on plan assets:						
Relating to assets still held at the reporting date	1	—	13	—	—	14
Purchases, sales and settlements:						
Purchases	109	1	1	—	—	111
Sales	(4)	(2)	(7)	—	—	(13)
Settlements [a]	—	(1)	—	—	—	(1)
Balance as of December 31, 2014	$ 110	$ —	$116	$ —	$ —	$ 226

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	Hedge funds	Private equity	Real estate	Fixed income	Equities	Total
Pension Assets						
Balance as of January 1, 2013	$1,235	$ 754	$426	$ —	$ —	$2,415
Actual return on plan assets:						
Relating to assets still held at the reporting date	143	86	63	—	—	292
Relating to assets sold during the period	3	—	(4)	—	—	(1)
Purchases, sales and settlements:						
Purchases	360	123	226	41	2	752
Sales	(76)	—	(91)	—	—	(167)
Settlements [(a)]	(3)	(157)	(38)	—	—	(198)
Transfers into (out of) Level 3 [(c)]	(623)	—	—	—	—	(623)
Balance as of December 31, 2013	$1,039	$ 806	$582	$ 41	$ 2	$2,470
Other Postretirement Benefits						
Balance as of January 1, 2013	$ 12	$ 1	$ 95	$ —	$ —	$ 108
Actual return on plan assets:						
Relating to assets still held at the reporting date	1	—	11	—	—	12
Purchases, sales and settlements:						
Purchases	—	1	3	—	—	4
Sales	(1)	—	—	—	—	(1)
Settlements [(a)]	(4)	—	—	—	—	(4)
Transfers into (out of) Level 3 [(c)]	(4)	—	—	—	—	(4)
Balance as of December 31, 2013	$ 4	$ 2	$109	$ —	$ —	$ 115

(a) Represents cash settlements only.
(b) In connection with the Employee Matters Agreement between EDF and Exelon, Exelon assumed the pension plan assets of Nine Mile Point Nuclear Station, LLC and Constellation Energy Nuclear Group, LLC resulting in transfers into Level 3 of $56 million.
(c) As of January 1, 2014 and January 1, 2013, hedge fund investments that contained redemption restrictions limiting Exelon's ability to redeem the investments within a reasonable period of time were classified as Level 3 investments. As of December 31, 2014 and December 31, 2013, restrictions for certain investments no longer applied, therefore allowing redemption within a reasonable period of time from the measurement date at NAV. As such, these hedge fund investments are reflected as transfers out of Level 3 to Level 2 of $43 million and $627 million in 2014 and 2013 respectively.

There were no transfers between Level 1 and Level 2 during the twelve months ended December 31, 2014 for the pension and other postretirement benefit plan assets.

Valuation Techniques Used to Determine Fair Value

Cash equivalents . Investments with maturities of three months or less when purchased, including certain short-term fixed income securities and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

Equities . Equities consist of individually held equity securities, equity mutual funds and equity commingled funds in domestic and foreign markets. With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from

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market exchanges, which Exelon is able to independently corroborate. Equity securities held individually, including rights and warrants, are primarily traded on exchanges that contain only actively traded securities due to the volume trading requirements imposed by these exchanges. Equity securities are valued based on quoted prices in active markets and are categorized as Level 1. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies that hold certain investments in accordance with a stated set of fund objectives, which are consistent with the plans' overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

Fixed income . For fixed income securities, which consist primarily of corporate debt securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The remaining fixed income securities, including certain other fixed income investments, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2

Other fixed income investments primarily consist of fixed income commingled funds, mutual funds, and short-term investment funds, which are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Certain fixed income commingled funds are valued using the NAV per fund share, which is based on the valuation of the underlying investments and include significant unobservable inputs. These funds have been categorized as Level 3.

Derivative instruments consisting primarily of interest rate swaps to manage risk are recorded at fair value. Derivative instruments are valued based on external price data of comparable securities and have been categorized as Level 2.

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Private equity . Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments and investments in natural resources. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows and market based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3.

Hedge funds . Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or ownership interest of the investments. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate. For Exelon's investments that have terms that allow redemption within a reasonable period of time from the measurement date, the hedge fund investments are categorized as Level 2. For investments that have restrictions that may limit Exelon's ability to redeem the investments at the measurement date or within a reasonable period of time, the hedge fund investments are categorized as Level 3.

Real estate . Real estate investment trusts valued daily based on quoted prices in active markets are categorized as Level 1. Real estate commingled funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Since these funds are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Other real estate funds are funds with a direct investment in a pool of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. Since these valuation inputs are not highly observable, these real estate funds have been categorized as Level 3.

As of December 31, 2014, Exelon has outstanding commitments to invest in private equity and real estate investments of approximately $825 million. These commitments will be funded by Exelon's existing pension and other postretirement benefit trusts.

Defined Contribution Savings Plan (Exelon, Generation, ComEd, PECO and BGE)

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2014, 2013 and 2012:

For the Year Ended December 31,	Exelon	Generation	ComEd	PECO	BGE (a)	BSC (b)
2014	$ 103	$ 51	$ 26	$ 8	$ 8	$ 10
2013	85	40	22	8	8	7
2012	67	30	19	7	7	5

(a) BGE's matching contributions for the year ended December 31, 2012 include $1 million incurred prior to the closing of the Constellation merger on March 12, 2012. These costs are not included in Exelon's matching contributions for the year ended December 31, 2012.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, or BGE amounts above.

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17. Severance (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

CENG Integration-Related Severance

In connection with the Master Agreement, Generation and CENG recorded a severance accrual in the fourth quarter of 2013 for the anticipated employee position reductions as a result of the integration of $2 million and $16 million, respectively. The majority of these positions are corporate and support positions at CENG. On April 1, 2014, the date the NOSA was executed, Generation consolidated the $19 million CENG severance liability pursuant to the Master Agreement. For the years ended December 31, 2014 and 2013, respectively, Exelon and Generation recorded severance benefit costs associated with the employee reductions of $3 million and $2 million within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income. The estimated amount of severance payments associated with this plan is expected to be approximately $24 million. As of December 31, 2014, management recorded its best estimate of severance benefits, which could be adjusted through the completion of the integration process if additional employee position reductions are identified or if employees resign prior to their agreed upon service termination date. Estimated costs to be incurred after December 31, 2014 are not material.

Amounts included in the table below represent the severance liability recorded by Exelon and Generation related to the CENG integration:

Year Ended December 31, 2014 Severance Liability	Exelon and Generation
Balance at December 31, 2013	$ 2
Integration of CENG [(a)]	19
Severance charges	3
Payments	(11)
Balance at December 31, 2014	$ 13

(a) Includes the fair value of the CENG integration-related obligation as of April 1, 2014, the date of consolidation. Note this includes an additional $3 million of severance charges incurred in the first quarter of 2014 by CENG. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.

Cash payments under the severance plan began in 2014. Substantially all cash payments under the plan are expected to be made by the end of 2015.

Constellation Merger-Related Severance

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified

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specific employees to be severed pursuant to the merger-related staffing and selection process as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit. Exelon adjusts its accrual each quarter to reflect its best estimate of remaining severance costs.

The amount of severance expense associated with the post-merger integration recognized for the twelve months ended December 31, 2014 and 2013 is not material. Estimated costs to be incurred after December 31, 2014 are not immaterial.

For the year ended December 31, 2012, the Registrants recorded the following severance benefit costs associated with identified job reductions within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, except for those costs that were capitalized as regulatory assets related to ComEd and BGE:

Year Ended December 31, 2012 Severance Benefits [a]	Exelon [b]	Generation	ComEd [b]	PECO	BGE [b]
Severance charges	$ 124	$ 80	$ 14	$ 7	$ 17
Stock compensation	7	4	1	—	1
Other charges	7	4	1	—	1
Total severance benefits	$ 138	$ 88	$ 16	$ 7	$ 19

(a) The amounts above include $46 million at Generation, $14 million at ComEd, $7 million at PECO, and $7 million at BGE, for amounts billed by BSC through intercompany allocations for the year ended December 31, 2012.
(b) Exelon, ComEd and BGE established regulatory assets of $35 million, $16 million and $19 million, respectively, for severance benefits costs for the year ended December 31, 2012. The majority of these costs are expected to be recovered over a five-year period.

Amounts included in the table below represent the severance liability recorded by Exelon, Generation, ComEd, PECO and BGE for employees of those Registrants and exclude amounts billed through intercompany allocations:

Severance liability	Exelon	Generation	ComEd	PECO	BGE
Balance at December 31, 2012	$ 111	$ 33	$ 1	$—	$ 11
Severance charges [a]	5	1	—	—	—
Stock compensation	1	—	—	—	—
Payments	(64)	(24)	(1)	—	(5)
Balance at December 31, 2013	$ 53	$ 10	$ —	$—	$ 6
Payments	(41)	(7)	—	—	(4)
Balance at December 31, 2014	$ 12	$ 3	$ —	$—	$ 2

(a) Includes salary continuance and health and welfare severance benefits. Amounts primarily represent benefits provided for under Exelon's ongoing severance plan. One-time termination benefits were not material for the years ended December 31, 2014 and December 31, 2013.

Substantially all cash payments under the plan are expected to be made by the end of 2016.

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Ongoing Severance Plans

The Registrants provide severance, health and welfare benefits under Exelon's ongoing severance benefit plans to terminated employees in the normal course of business, which were not directly related to the merger with Constellation or with the integration of CENG. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the years ended December 31, 2014, 2013, and 2012, the Registrants recorded the following severance costs associated with these ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

Severance Benefits [a]	Exelon	Generation	ComEd	PECO	BGE
Severance Charges—2014	$ 7	$ 5	$ 1	$—	$ 1
Severance Charges—2013	18	16	2	—	—
Severance Charges—2012	19	14	2	1	3

(a) The amounts above for Generation include $1 million, $2 million, and $0 million for amounts billed by BSC through intercompany allocations for the years ended December 31, 2014, December 31, 2013, and December 31, 2012, respectively. Amounts billed by BSC to ComEd, PECO and BGE were not material.
(b) The amount of ongoing severance for Generation for the year ended December 31, 2014 includes a $3 million severance reserve as a result of anticipated employee position reductions due to recent acquisitions.

The severance liability balances associated with these ongoing severance benefits as of December 31, 2014 and 2013 are not material.

18. Preferred and Preference Securities (Exelon, ComEd, PECO and BGE)

At December 31, 2014 and 2013, Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

Preferred and Preference Securities of Subsidiaries

At December 31, 2014 and 2013, ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

On May 1, 2013, PECO redeemed all of its outstanding preferred securities. PECO had $87 million of cumulative preferred securities that were redeemable at its option at any time for the redemption price established when each series was issued. The redemption premium was treated as a reduction to Net income to arrive at Net income attributable to common shareholders utilized in the calculation of the earnings per share for Exelon.

At December 31, 2014 and 2013, BGE cumulative preference stock, $100 par value, consisted of 6,500,000 shares authorized and the outstanding amounts set forth below. Shares of BGE preference stock have no voting power except for the following:

- The preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and

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- Whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

	Redemption Price [(a)]	December 31, 2014 Shares Outstanding	December 31, 2013 Shares Outstanding	December 31, 2014 Dollar Amount	December 31, 2013 Dollar Amount
Series (without mandatory redemption)					
7.125%, 1993 Series	$ 100.00	400,000	400,000	$ 40	$ 40
6.97%, 1993 Series	100.00	500,000	500,000	50	50
6.70%, 1993 Series	100.00	400,000	400,000	40	40
6.99%, 1995 Series	100.35	600,000	600,000	60	60
Total preference stock		1,900,000	1,900,000	$ 190	$ 190

(a) Redeemable, at the option of BGE, at the indicated dollar amounts per share, plus accrued and unpaid dividends.

19. Common Stock (Exelon, Generation, ComEd, PECO and BGE)

The following table presents common stock authorized and outstanding as of December 31, 2014 and 2013:

	Par Value	Shares Authorized	December 31, 2014 Shares Outstanding	December 31, 2013 Shares Outstanding
Common Stock				
Exelon	no par value	2,000,000,000	859,833,343	857,290,484
ComEd	$12.50	250,000,000	127,016,947	127,016,896
PECO	no par value	500,000,000	170,478,507	170,478,507
BGE	no par value	175,000,000	1,000	1,000

ComEd had 73,533 and 73,709 warrants outstanding to purchase ComEd common stock at December 31, 2014 and 2013, respectively. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants. At December 31, 2014 and 2013, 24,511 and 24,570 shares of common stock, respectively, were reserved for the conversion of warrants.

Equity Securities Offering

In June 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share. In connection with such offering, Exelon entered into forward sale agreements requiring Exelon to, at its election, prior to October 29, 2015; i) physically settle the transaction through the issuance of 57.5 million shares of its common stock in exchange for net proceeds at the forward price specified in the agreements of between approximately $1.8 billion and $1.9 billion, after consideration of underwriters discount of approximately $60 million and subject to certain adjustments as provided in the forward sales agreement, or ii) net settle the transaction either through the payment of cash or shares of its common stock based on the then current market value of

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the shares minus the value of the shares at the forward price, net of the underwriters discount and the daily accretion rate. No amounts have or will be recorded in Exelon's consolidated financial statements with respect to the equity offering until settlement of the forward sale agreements occurs. If Exelon elected to net share settle the contract as of December 31, 2014, Exelon would have been required to issue 4 million shares. If Exelon elects to cash settle the contract, the transaction costs will be recorded as a charge to earnings in the period in which it becomes probable that Exelon will cash settle. Otherwise, all transaction costs will be reflected as a reduction to the value of the common stock issued in Exelon's Consolidated Balance Sheet. The net proceeds received upon settlement are expected to be used to finance a portion of the acquisition of PHI and for general corporate purposes. Until settlement, earnings per share dilution resulting from the forward sales agreement, if any, will be determined under the treasury stock method.

Concurrent with the forward equity transaction, Exelon also issued $1.15 billion of junior subordinated notes in the form of 23 million equity units. See Note 13—Debt and Credit Agreements for further information on the equity units.

Share Repurchases

Share Repurchase Programs . In April 2004, Exelon's Board of Directors approved a discretionary share repurchase program that allowed Exelon to repurchase shares of its common stock on a periodic basis in the open market. The share repurchase program was intended to mitigate, in part, the dilutive effect of shares issued under Exelon's employee stock option plan and Exelon's ESPP. The aggregate value of the shares of common stock repurchased pursuant to the program cannot exceed the economic benefit received after January 1, 2004 due to stock option exercises and share purchases pursuant to Exelon's ESPP. The economic benefit consists of the direct cash proceeds from purchases of stock and the tax benefits associated with exercises of stock options. The 2004 share repurchase program had no specified limit on the number of shares that could be repurchased and no specified termination date. In 2008, Exelon management decided to defer indefinitely any share repurchases. Any shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon's management. Under the share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion at December 31, 2014. During 2014, 2013 and 2012, Exelon had no common stock repurchases.

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At December 31, 2014, there were approximately 16 million shares authorized for issuance under the LTIP. For the years ended December 31, 2014, 2013 and 2012, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

The Compensation Committee of Exelon's Board of Directors changed the mix of awards granted under the LTIP in 2013 by eliminating stock options in favor of the use of full value shares, consisting of 67% performance shares and 33% restricted stock units. The performance share awards granted in 2013 will cliff vest at the end of a three-year performance period. The performance share awards granted in 2012 and earlier had a one-year performance period and vested ratably over three years. To address the reduction in annual award opportunity resulting from the transition to a three-year cliff vesting performance period, the Compensation Committee also approved a one-time grant of

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performance share transition awards in 2013, which vested one-third after one year, with the remaining balance vesting over a two-year performance period. These one-time 2013 performance share transition awards will be settled 50% in common stock and 50% in cash, except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain Exelon stock ownership requirements are satisfied. In addition to this change, in 2013 ComEd and in 2014 PECO and BGE transitioned from Exelon stock-based awards to cash award programs with payouts based on the performance of each respective utility. The following tables do not include expense related to these plans as they are not considered stock-based compensation plans under the applicable accounting guidance.

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
Components of Stock-Based Compensation Expense	2014	2013	2012
Performance share awards	$ 59	$ 48	$ 46
Restricted stock units	61	61	50
Stock options	2	3	15
Other stock-based awards	5	6	4
Total stock-based compensation expense included in operating and maintenance expense	127	118	115
Income tax benefit	(47)	(44)	(44)
Total after-tax stock-based compensation expense	$ 80	$ 74	$ 71

The following table presents stock-based compensation expense (pre-tax) for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
Subsidiaries	2014	2013	2012 (a)
Generation	$ 52	$ 48	$ 42
ComEd	7	9	11
PECO	3	5	5
BGE	5	6	5
BSC (b)	60	50	52
Total	$127	$118	$115

(a) BGE's stock-based compensation expense (pre-tax) for December 31, 2012 excludes $2 million of cost incurred in 2012 prior to the closing of Exelon's merger with Constellation on March 12, 2012. This amount is not included in Exelon's stock-based compensation expense for the year ended December 31, 2012 shown in the table titled Components of Stock-Based Compensation Expense and the breakout by subsidiary above.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO and BGE amounts above.

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2014, 2013 and 2012.

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Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and the distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon recognizes the tax benefit related to compensation costs. The tax deductions in excess of the benefits recorded throughout the requisite service period are recorded to common stock and are included in other financing activities within Exelon's Consolidated Statements of Cash Flows. The following table presents information regarding Exelon's tax benefits for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
Realized tax benefit when exercised/distributed:			
Stock options	$—	$—	$ 3
Restricted stock units	17	11	11
Performance share awards	11	11	7
Stock deferral plan	—	1	—
Excess tax benefits included in other financing activities of Exelon's Consolidated Statements of Cash Flows:			
Stock options	$—	$—	$ 2

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock were granted under the LTIP through 2012. Due to changes in the LTIP, there were no stock options granted in 2013 or 2014. For all stock options granted through 2012, the exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. The vesting period of stock options is generally four years. All stock options expire ten years from the date of grant.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years. However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

The fair value of each option is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The following table presents the weighted average assumptions used in the pricing model for grants and the resulting weighted average grant date fair value of stock options granted for the year ended 2012:

	Year ended December 31, 2012
Dividend yield	5.28%
Expected volatility	23.20%
Risk-free interest rate	1.30%
Expected life (years)	6.25
Weighted average grant date fair value (per share)	4.18

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The assumptions above relate to Exelon stock options granted in 2012 and therefore do not include stock options that were converted in connection with the merger with Constellation during the year ended 2012.

The dividend yield is based on several factors, including Exelon's most recent dividend payment at the grant date and the average stock price over the previous year. Expected volatility is based on implied volatilities of traded stock options in Exelon's common stock and historical volatility over the estimated expected life of the stock options. The risk-free interest rate for a security with a term equal to the expected life is based on a yield curve constructed from U.S. Treasury strips at the time of grant. For each year presented, the expected life represents the period of time the stock options are expected to be outstanding and is based on the simplified method. Exelon believes that the simplified method is appropriate due to several factors that result in historical exercise data not being sufficient to determine a reasonable estimate of expected term. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table presents information with respect to stock option activity for the year ended December 31, 2014:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2013	21,035,445	$ 46.07		
Options exercised	(291,805)	25.27		
Options forfeited	(8,886)	55.78		
Options expired	(1,903,787)	41.47		
Balance of shares outstanding at December 31, 2014	18,830,967	$ 46.85	4.11	$ 29
Exercisable at December 31, 2014 [a]	18,398,932	$ 47.01	4.04	$ 29

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2014, 2013 and 2012:

	Year Ended December 31,		
	2014	2013	2012
Intrinsic value [a]	$ 3	$ 4	$19
Cash received for exercise price	7	19	47

(a) The difference between the market value on the date of exercise and the option exercise price.

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The following table summarizes Exelon's nonvested stock option activity for the year ended December 31, 2014:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2013 [a]	847,118	$ 40.22
Vested	(406,197)	40.21
Forfeited	(8,886)	55.78
Nonvested at December 31, 2014 [a]	432,035	$ 39.91

(a) Excludes 746,140 and 1,348,913 of stock options issued to retirement-eligible employees as of December 31, 2014 and December 31, 2013, respectively, as they are fully vested.

At December 31, 2014, $1 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 1.0 year.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table summarizes Exelon's nonvested restricted stock unit activity for the year ended December 31, 2014:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2013 [a]	3,386,697	$ 34.10
Granted	2,252,574	28.71
Vested	(1,216,016)	35.36
Forfeited	(86,094)	31.99
Undistributed vested awards [b]	(578,943)	29.17
Nonvested at December 31, 2014 [a]	3,758,218	$ 31.27

(a) Excludes 975,116 and 931,628 of restricted stock units issued to retirement-eligible employees as of December 31, 2014 and December 31, 2013, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2014.

The weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2014, 2013 and 2012 was $28.71, $31.06 and $39.94, respectively. At

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December 31, 2014 and 2013, Exelon had obligations related to outstanding restricted stock units not yet settled of $85 million and $77 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. For the years ended December 31, 2014, 2013 and 2012, Exelon settled restricted stock units with fair value totaling $43 million, $28 million and $25 million, respectively. At December 31, 2014, $59 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.1 years.

Performance Share Awards

Performance share awards are granted under the LTIP. The 2014 and 2013 performance share awards are being settled 50% in common stock and 50% in cash at the end of the three-year performance period except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. The performance shares granted prior to 2012 generally vest and settle over a three-year period with the holders receiving shares of common stock and/or cash annually during the vesting period.

The common stock portion of the performance share and one-time 2013 performance share transition awards is considered an equity award and is valued based on Exelon's stock price on the grant date. The cash portion of the awards is considered a liability award which is remeasured each reporting period based on Exelon's current stock price. As the value of the common stock and cash portions of the awards are based on Exelon's stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share and one-time performance share transition awards granted to retirement-eligible employees, the value of the performance shares in recognized ratably over the vesting period, which is the year of grant.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2014:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2013 [a]	2,014,190	$ 32.74
Granted	1,712,085	28.75
Change in performance	98,227	31.85
Vested	(497,714)	35.05
Forfeited	(29,476)	30.16
Undistributed vested awards [b]	(601,215)	28.96
Nonvested at December 31, 2014 [a]	2,696,097	$ 30.62

(a) Excludes 1,535,791 and 1,411,824 of performance share awards issued to retirement-eligible employees as of December 31, 2014 and December 31, 2013, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2014.

The weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2014, 2013 and 2012 was $28.75, $31.55, and $39.71,

respectively. During the years ended December 31, 2014, 2013 and 2012, Exelon settled performance shares with a fair value totaling $27 million, $26 million and $23 million, respectively, of which $13 million, $12 million and $3 million was paid in cash, respectively. As of December 31, 2014, $54 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.6 years.

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31,	
	2014	2013
Current liabilities [a]	$ 28	$ 13
Deferred credits and other liabilities [b]	36	24
Common stock	33	32
Total	$ 97	$ 69

(a) Represents the current liability related to performance share awards expected to be settled in cash.
(b) Represents the long-term liability related to performance share awards expected to be settled in cash.

20. Earnings Per Share and Equity (Exelon)

Earnings per Share

Diluted earnings per share is calculated by dividing Net income attributable to common shareholders by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of the stock options, performance share awards and restricted stock on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Year Ended December 31,		
	2014	2013	2012
Net income attributable to common shareholders	$1,623	$1,719	$1,160
Weighted average common shares outstanding—basic	860	856	816
Assumed exercise and/or distributions of stock-based awards	4	4	3
Weighted average common shares outstanding—diluted	864	860	819

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 17 million in 2014, 20 million in 2013, and 14 million in 2012. The number of equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect was less than 1 million for the year ended December 31, 2014 since issuance. Additionally, there were no forward units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the year ended December 31, 2014 since issuance. Refer to Note 19—Common Stock for further information regarding the equity units and equity forward units.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of December 31, 2014. In 2008, Exelon management decided to defer indefinitely any share repurchases.

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21. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, and PECO)

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the years ended December 31, 2014 and 2013:

For the Year Ended December 31, 2014	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon [a]						
Beginning balance	$ 120	$ 2	$ (2,260)	$ (10)	$ 108	$(2,040)
OCI before reclassifications	(31)	(1)	(498)	(9)	11	(528)
Amounts reclassified from AOCI [b]	(117)	2	118	—	(119)	(116)
Net current-period OCI	(148)	1	(380)	(9)	(108)	(644)
Ending balance	$ (28)	$ 3	$ (2,640)	$ (19)	$ —	$(2,684)
Generation [a]						
Beginning balance	$ 114	$ 2	$ —	$ (10)	$ 108	$ 214
OCI before reclassifications	(15)	(1)	—	(9)	11	(14)
Amounts reclassified from AOCI [b]	(117)	—	—	—	(119)	(236)
Net current-period OCI	(132)	(1)	—	(9)	(108)	(250)
Ending balance	$ (18)	$ 1	$ —	$ (19)	$ —	$ (36)
PECO [a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI [b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

Combined Notes to Consolidated Financial Statements—(Continued)
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For the Year Ended December 31, 2013	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon [a]						
Beginning balance	$ 368	$ —	$ (3,137)	$ —	$ 2	$(2,767)
OCI before reclassifications	29	2	669	(10)	101	791
Amounts reclassified from AOCI [b]	(277)	—	208	—	5	(64)
Net current-period OCI	(248)	2	877	(10)	106	727
Ending balance	$ 120	$ 2	$ (2,260)	$ (10)	$ 108	$(2,040)
Generation [a]						
Beginning balance	$ 512	$ —	$ —	$ —	$ 1	513
OCI before reclassifications	15	2	—	(10)	102	109
Amounts reclassified from AOCI [b]	(413)	—	—	—	5	(408)
Net current-period OCI	(398)	2	—	(10)	107	(299)
Ending balance	$ 114	$ 2	$ —	$ (10)	$ 108	$ 214
PECO [a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI [b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See next tables for details about these reclassifications.

Combined Notes to Consolidated Financial Statements—(Continued)
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ComEd, PECO, and BGE did not have any reclassifications out of AOCI to Net income during the years ended December 31, 2014 and 2013. The following tables present amounts reclassified out of AOCI to Net income for Exelon and Generation during the years ended December 31, 2014 and 2013:

For the Year Ended December 31, 2014

Details about AOCI components	Items reclassified out of AOCI [a]		Affected line item in the Statements of Operations and Comprehensive Income
	Exelon	Generation	
Gains and (losses) on cash flow hedges			
Energy related hedges	$ 195	$ 195	Operating revenues
	195	195	Total before tax
	(78)	(78)	Tax expense
	$ 117	$ 117	Net of tax
Gains and (losses) on available for sale securities			
Other available securities for sale	$ (2)	$ —	Other Income and Deductions
	$ (2)	$ —	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs [b]	$ 46	$ —	
Actuarial losses [b]	(239)	—	
	(193)	—	Total before tax
	75	—	Tax benefit
	$ (118)	$ —	Net of tax
Equity investments			
Sale of equity method investment	$ 5	$ 5	
Reversal of CENG equity method AOCI	193	193	Equity in losses of unconsolidated affiliates
	198	198	Total before tax
	(79)	(79)	Tax expense
	$ 119	$ 119	Net of tax
Total Reclassifications	$ 116	$ 236	Net of tax

Combined Notes to Consolidated Financial Statements—(Continued)
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For the Year Ended December 31, 2013

Details about AOCI components	Items reclassified out of AOCI [a]		Affected line item in the Statements of Operations and Comprehensive Income
	Exelon	Generation	
Gains and (losses) on cash flow hedges			
Energy related hedges	$ 464	$ 683	Operating revenues
Other cash flow hedges	(3)	—	Interest expense
	461	683	Total before tax
	(184)	(270)	Tax expense
	$ 277	$ 413	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs [b]	$ (2)	$ —	
Actuarial losses [b]	(339)	—	
Deferred compensation unit plan [c]	(1)	—	
	(342)	—	Total before tax
	134	—	Tax benefit
	$ (208)	$ —	Net of tax
Equity investments			
Capital activity	$ (8)	$ (8)	Equity in losses of unconsolidated affiliates
	(8)	(8)	Total before tax
	3	3	Tax benefit
	$ (5)	$ (5)	Net of tax
Total Reclassifications	$ 64	$ 408	Net of tax

(a) Amounts in parenthesis represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see Note 16—Retirement Benefits for additional details).
(c) Amortization of the deferred compensation unit plan is allocated to capital and operating and maintenance expense.

Combined Notes to Consolidated Financial Statements—(Continued)
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The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the years ended December 31, 2014 and 2013:

	For the Years Ended December 31,		
	2014	2013	2012
Exelon			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	$ 19	$ —	$ (1)
Actuarial loss reclassified to periodic cost	(93)	(133)	(110)
Transition obligation reclassified to periodic cost	—	—	(2)
Pension and non-pension postretirement benefit plans valuation adjustment	317	(430)	237
Change in unrealized loss on cash flow hedges	96	166	68
Change in marketable securities	—	—	1
Change in unrealized income on equity investments	73	(71)	(1)
Total	$ 412	$ (468)	$ 192
Generation			
Change in unrealized loss on cash flow hedges	$ 84	$ 262	$ 262
Change in unrealized income on equity investments	73	(72)	1
Total	$ 157	$ 190	$ 263

22. Commitments and Contingencies (Exelon, Generation, ComEd, PECO and BGE)

Nuclear Insurance

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has mitigated its financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2014, the current liability limit per incident was $13.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of January 1, 2013, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in an additional $13.2 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $127.3 million, payable at no more than $19 million per reactor per incident per year. Exelon's maximum liability per incident is approximately $2.7 billion, including CENG's related liability.

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In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.6 billion limit for a single incident.

As part of the execution of NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information on Generation's operations relating to CENG.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. NEIL declared a distribution for 2014 and 2013, of which Generation's portion was $18.3 million and $18.5 million respectively. No distributions were declared in 2012. The distributions were recorded as a reduction to Operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income. Premiums paid to NEIL by its members are subject to assessment for adverse loss experience (the retrospective premium obligation). NEIL has never exercised this assessment since its formation in 1973, and while Generation cannot predict the level of future assessments, or if they will be imposed at all, as of December 31, 2014, the current maximum aggregate annual retrospective premium obligation for Generation is approximately $319 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery for all losses by all insureds will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon's and Generation's financial condition, results of operations and liquidity.

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Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation historically had paid the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. On November 19, 2013, the D.C. Circuit Court ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On May 9, 2014, the DOE notified Generation that the SNF disposal fee remained in effect through May 15, 2014, after which time the fee was set to zero. For the year ended December 31, 2014, and for the year ended December 31, 2013, Generation incurred expense of $49 million and $136 million, respectively, in SNF disposal fees, recorded in Purchased power and fuel expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, including Exelon's share of Salem and net of co-owner reimbursements (not including such fees incurred by CENG). Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance has been, and is expected to be, delayed significantly.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama administration devised a new strategy for long-term SNF management. A Blue Ribbon Commission (BRC) on America's Nuclear Future, appointed by the U.S. Energy Secretary, released a report on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's spent nuclear fuel and high-level radioactive waste.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that is planned to be operational in 2025.

Generation uses the 2025 date as the assumed date for when the DOE will begin accepting SNF for purposes of determining nuclear decommissioning asset retirement obligations. The extended delay in SNF acceptance by the DOE has led to Generation's adoption of dry cask storage at its Dresden, Clinton, Limerick, Oyster Creek, Peach Bottom, Byron, Braidwood, LaSalle, Quad Cities, Ginna, Nine Mile Point, and Calvert Cliffs stations.

In August 2004, Generation and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation, subject to certain damage limitations based on the extent of the government's breach, for costs associated with storage of SNF at Generation's nuclear stations pending the DOE's fulfillment of its obligations. Settlement agreements pertaining to Calvert Cliffs and Ginna were executed during 2011, and Nine Mile Point during 2012, (the "DOE Settlement Agreements"), as amended in 2014 for Calvert Cliffs and Nine Mile Point, under which the government has agreed to reimburse the costs associated with SNF storage expended or to be expended through 2016 as a result of the DOE delays. The DOE Settlement Agreement is expected to be amended for Ginna in a similar manner as needed. Generation, including CENG, submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

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Under the settlement agreement, Generation has received cumulative cash reimbursements for costs incurred as follows:

	Total	Net [a]
Cumulative cash reimbursements [b]	$836	$702

(a) Total after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek.
(b) Includes $33 million and $30 million, respectively, for amounts received since April 1, 2014, for costs incurred under the CENG DOE Settlement Agreements prior to the consolidation of CENG.

As of December 31, 2014, and 2013, the amount of SNF storage costs for which reimbursement has been or will be requested from the DOE under the DOE settlement agreements is as follows:

	December 31, 2014	December 31, 2013
DOE receivable—current [a]	$ 82	$ 71
DOE receivable—noncurrent [b]	7	—
Amounts owed to co-owners [a][c]	(5)	(18)

(a) Recorded in Accounts receivable, other.
(b) Recorded in Deferred debits and other assets, other
(c) Non-CENG amounts owed to co-owners are recorded in Accounts receivable, other. CENG amounts owed to co-owners are recorded in Accounts payable. Represents amounts owed to the co-owners of Peach Bottom, Quad Cities, and Nine Mile Point Unit 2 generating facilities.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. As of December 31, 2014, the unfunded SNF liability for the one-time fee with interest was $1,021 million. Interest accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2014, was 0.020%. The liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of Exelon's 2001 corporate restructuring. The outstanding one-time fee obligations for the Nine Mile Point, Ginna, Oyster Creek and TMI units remain with the former owners. The Clinton and Calvert Cliffs units have no outstanding obligation. See Note 11—Fair Value of Financial Assets and Liabilities for additional information.

Energy Commitments

Generation's customer facing activities include the physical delivery and marketing of power obtained through its generation capacity, and long-, intermediate- and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. Generation has also contracted for access to additional generation through bilateral long-term PPAs. These agreements are firm commitments related to power generation of specific generation plants and/or are dispatchable in nature. Several of Generation's long-term PPAs, which have been determined to be operating leases, have significant contingent rental payments that are dependent on the future operating characteristics of the associated plants, such as plant availability. Generation recognizes contingent rental expense when it becomes probable of payment. Generation enters into PPAs with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to its customers. Generation has also purchased firm transmission rights to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs. The primary intent and business objective for the use of its capital assets and

contracts is to provide Generation with physical power supply to enable it to deliver energy to meet customer needs. In addition to physical contracts, Generation uses financial contracts for economic hedging purposes and, to a lesser extent, as part of proprietary trading activities.

Generation has entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives and retail load aggregators. Generation also enters into contractual obligations to deliver energy to market participants who primarily focus on the resale of energy products for delivery. Generation provides for delivery of its energy to these customers through firm transmission.

At December 31, 2014, Generation's short- and long-term commitments, relating to the purchases from unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following tables:

	Net Capacity Purchases [a]	REC Purchases [b]	Transmission Rights Purchases [c]	Total
2015	$ 418	$ 152	$ 20	$ 590
2016	283	228	15	526
2017	222	121	15	358
2018	112	29	16	157
2019	117	5	16	138
Thereafter	279	1	35	315
Total	$ 1,431	$ 536	$ 117	$2,084

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2014, net of fixed capacity payments expected to be received ("capacity offsets") by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. As of December 31, 2014, capacity offsets were $132 million, $133 million, $136 million, $137 million, $138 million, and $591 million for years 2015, 2016, 2017, 2018, 2019, and thereafter, respectively. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.
(b) The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

ComEd purchases its expected energy requirements through an ICC approved competitive bidding process administered by the IPA and spot market purchases. See Note 3—Regulatory Matters for further information.

PECO has entered into contracts through a competitive procurement process in order to meet a portion of its default service customers' electric supply requirements through 2016. See Note 3—Regulatory Matters for further information regarding the DSP Programs.

ComEd is subject to requirements established by the Illinois legislation and the Energy Infrastructure Modernization Act related to the use of alternative energy resources. PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. BGE is subject to requirements established by the Public Utilities Article in Maryland related to the use of alternative energy resources; however, the wholesale suppliers that supply power to BGE through SOS procurement auctions have the obligation, by contract with BGE, to meet the RPS requirement. See Note 3—Regulatory Matters for additional information relating to electric generation procurement, alternative energy resources and energy efficiency programs.

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ComEd's, PECO's and BGE's electric supply procurement, curtailment services, REC and AEC purchase commitments as of December 31, 2014 are as follows:

		Expiration within					
	Total	2015	2016	2017	2018	2019	2020 and beyond
ComEd							
Electric supply procurement [a]	$ 620	$329	$151	$140	$—	$—	$ —
Renewable energy and RECs [b]	1,517	75	76	77	78	84	1,127
PECO							
Electric supply procurement [c]	609	527	82	—	—	—	—
AECs [d]	13	2	2	2	2	2	3
BGE							
Electric supply procurement [e]	1,315	779	448	88	—	—	—
Curtailment services [f]	115	40	34	29	12	—	—

(a) ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. As of December 31, 2014, ComEd has completed the ICC-approved procurement process for a portion of its energy requirements through the periods ending May 31, 2015, 2016 and 2017.
(b) Primarily related to ComEd 20-year contracts for renewable energy and RECs that began in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms.
(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2015 and 2016. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 3—Regulatory Matters for additional information.
(d) PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. See Note 3—Regulatory Matters for additional information.
(e) BGE entered into various contracts for the procurement of electricity beginning 2015 through 2017. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 3—Regulatory Matters for additional information.
(f) BGE has entered into various contracts with curtailment services providers related to transactions in PJM's capacity market. See Note 3—Regulatory Matters for additional information.

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation. Beginning with the second quarter of 2014, 100% of CENG's nuclear fuel commitments are disclosed within the Generation line below, since CENG is now fully consolidated by Generation. PECO and BGE have commitments to purchase natural gas related to transportation, storage capacity and services to serve customers in their gas distribution service territory. As of December 31, 2014, these commitments were as follows:

		Expiration within					
	Total	2015	2016	2017	2018	2019	2020 and beyond
Generation	$8,981	$1,404	$1,119	$1,124	$1,001	$888	$ 3,445
PECO	428	146	103	60	34	14	71
BGE	611	111	82	67	57	54	240

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Other Purchase Obligations

The Registrants' other purchase obligations as of December 31, 2014, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	2015	2016	2017	2018	2019	2020 and beyond
Exelon	$894	$336	$258	$150	$ 36	$ 30	$ 84
Generation [a][b]	396	163	67	42	30	24	70
ComEd [c]	148	63	77	1	1	1	5
PECO [c]	7	3	4	—	—	—	—
BGE [c]	343	107	110	107	5	5	9

(a) Purchase obligations do not include commitments related to construction contracts. See Construction Commitments section below for additional information.
(b) Purchase obligations include commitments related to assets-held-for-sale. See Note 4—Mergers, Acquisitions, and Dispositions for additional information.
(c) Purchase obligations include commitments related to smart meter installation. See Note 3—Regulatory Matters for additional information.

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Commercial Commitments

Exelon's commercial commitments as of December 31, 2014, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2015	2016	2017	2018	2019	2020 and beyond
Letters of credit (non-debt) [a]	$1,233	$1,151	$ 77	$ 5	$—	$—	$ —
Surety bonds [b]	596	545	10	4	1	2	34
Performance guarantees [c]	1,239	472	20	20	20	20	687
Energy marketing contract guarantees [d]	3,220	3,220	—	—	—	—	—
Lease guarantees [e]	40	—	—	—	—	—	40
Nuclear insurance premiums [f]	3,014	—	—	—	—	—	3,014
Underwriters discount [g]	60	60	—	—	—	—	—
Total commercial commitments	$9,402	$5,448	$107	$ 29	$ 21	$ 22	$ 3,775

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Guarantees issued to ensure performance under specific contracts. Additionally includes $200 million of Trust Preferred Securities of ComEd Financing III, $178 million of Trust Preferred Securities of PECO Trust III and IV and $250 million of Trust Preferred Securities of BGE Capital Trust II.
(d) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $3.2 billion of guarantees previously issued by Constellation on behalf of its Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Exelon's estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $0.6 billion at December 31, 2014, which represents the total amount Exelon could be required to fund based on December 31, 2014 market prices.
(e) Lease guarantees—Guarantees issued to ensure payments on building leases.
(f) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.
(g) Represents the underwriters discount for Exelon's forward equity transaction. See Note 19—Common Stock for further details of the equity securities offering.

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Generation's commercial commitments as of December 31, 2014, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2015	2016	2017	2018	2019	2020 and beyond
Letters of credit (non-debt) [a]	$1,187	$1,106	$ 76	$ 5	$—	$—	$ —
Surety bonds	481	468	3	—	—	—	10
Performance guarantees [b]	458	319	20	20	20	20	59
Energy marketing contract guarantees [c]	1,244	1,244	—	—	—	—	—
Nuclear insurance premiums [d]	3,014	—	—	—	—	—	3,014
Total commercial commitments	$6,384	$3,137	$ 99	$ 25	$ 20	$ 20	$ 3,083

(a) Letters of credit (non-debt)—Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.
(b) Performance guarantees—Guarantees issued to ensure performance under specific contracts.
(c) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $1.2 billion of guarantees previously issued by Constellation on behalf of its Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Generation's estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $0.4 billion at December 31, 2014, which represents the total amount Generation could be required to fund based on December 31, 2014 market prices.
(d) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site, including CENG sites, under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

ComEd's commercial commitments as of December 31, 2014, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2015	2016	2017	2018	2019	2020 and beyond
Letters of credit (non-debt) [a]	$ 17	$ 17	$—	$—	$—	$—	$ —
Surety bonds [b]	5	3	—	—	—	—	2
Performance guarantees [c]	200	—	—	—	—	—	200
Total commercial commitments	$222	$ 20	$—	$—	$—	$—	$ 202

(a) Letters of credit (non-debt)—ComEd maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Reflects full and unconditional guarantee of Trust Preferred Securities of ComEd Financing III which is a 100% owned finance subsidiary of ComEd.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PECO's commercial commitments as of December 31, 2014, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2015	2016	2017	2018	2019	2020 and beyond
Letters of credit (non-debt) [a]	$ 22	$ 22	$—	$—	$—	$—	$ —
Surety bonds [b]	18	18	—	—	—	—	—
Performance guarantees [c]	178	—	—	—	—	—	178
Total commercial commitments	$218	$ 40	$—	$—	$—	$—	$ 178

(a) Letters of credit (non-debt)—PECO maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Reflects full and unconditional guarantee of Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.

BGE's commercial commitments as of December 31, 2014, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2015	2016	2017	2018	2019	2020 and beyond
Letters of credit (non-debt) [a]	$ 1	$ 1	$—	$—	$—	$—	$ —
Surety bonds [b]	11	11	—	—	—	—	—
Performance guarantees [c]	253	3	—	—	—	—	250
Total commercial commitments	$265	$15	$—	$—	$—	$—	$ 250

(a) Letters of credit (non-debt)—BGE maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bond—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantee—Reflects full and unconditional guarantee of Trust Preferred Securities of BGE Capital Trust which is an unconsolidated VIE of BGE.

Construction Commitments

Generation's ongoing investments in renewables development and new natural gas construction illustrates Generation's growth strategy to provide for diversification opportunities while leveraging its expertise and strengths.

Generation completed the construction of the Antelope Valley solar PV facility in Los Angeles County, California, which became fully operational in the first half of 2014. Generation has no further remaining construction commitments for the project.

On July 3, 2013, Generation executed a turbine supply agreement to expand its Beebe wind project in Michigan. The remaining commitment is approximately $2 million under the contract and achievement of commercial operations was attained 2014.

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On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland generation site with at least 120MW of new natural gas-fired generation. The remaining commitment is approximately $39 million under the contract and achievement of commercial operation is expected in 2015. This project will satisfy a portion of Exelon's commitment to Maryland. See Note 4—Mergers, Acquisitions, and Dispositions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Constellation merger.

On December 27, 2013, Generated executed a turbine supply agreement for construction of the 40MW Fourmile Wind project in western Maryland. The remaining commitment is approximately $2 million under the contract and achievement of commercial operations was attained in 2014. This project will satisfy a portion of Exelon's 125 MW Tier I land-based renewables commitment made to Maryland. See Note 4—Mergers, Acquisitions, and Dispositions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Constellation merger.

During the third and fourth quarter of 2014, Generation executed contracts associated with the construction of new combined-cycle gas turbine units in Texas. The remaining commitment is approximately $1.0 billion under these contracts and achievement of commercial operations is expected in 2017.

During the fourth quarter of 2014 Generation executed contracts associated with the construction of the 30 MW Fair Wind project in western Maryland. The remaining commitment is approximately $19 million under these contracts and achievement of commercial operations is expected in 2015. This project will satisfy a portion of Exelon's 125 MW Tier I land-based renewables commitment made to Maryland. See Note 4—Mergers, Acquisitions, and Dispositions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Constellation merger.

During the fourth quarter of 2014 Generation executed contracts associated with the construction of the 78 MW Sendero Wind project in southern Texas. The remaining commitment is approximately $56 million under these contracts and achievement of commercial operations is expected in 2015.

Refer to Note 3—Regulatory Matters for information on investment programs associated with regulatory mandates, such as ComEd's Infrastructure Investment Plan under EIMA, PECO's Smart Meter Procurement and Installation Plan, and BGE's comprehensive smart grid initiative.

Combined Notes to Consolidated Financial Statements—(Continued)
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Equity Investment Commitments

As part of Generation's recent investments in technology development, Generation has entered into equity purchase agreements which include commitments to purchase additional equity through incremental payments. The additional equity is provided by the agreements to fund the anticipated needs of the planned operations of the associated companies. The commitment includes approximately $20 million of in-kind services. As of December 31, 2014, Generation's estimated commitment relating to its equity purchase agreements, including the in-kind services contributions, is anticipated to be as follows:

	Total
2015	$ 98
2016	38
2017	20
2018	11
Total	$167

Leases

Minimum future operating lease payments, including lease payments for vehicles, real estate, computers, rail cars, operating equipment and office equipment, as of December 31, 2014 were:

	Exelon	Generation (b)	ComEd (c)	PECO (c)	BGE (c)(d)
2015	$ 99	$ 51	$ 14	$ 3	$ 13
2016	102	57	13	3	11
2017	102	63	8	3	10
2018	86	57	4	3	9
2019	70	43	4	2	7
Remaining years	699	628	2	—	27
Total minimum future lease payments	$1,158[a]	$ 899[a]	$ 45	$ 14	$ 77

(a) Excludes Generation's PPAs and tolling arrangements that are accounted for as contingent operating lease payments, since these expected cash outflows are already disclosed in the Net Capacity Purchases table under the Energy Commitment.
(b) The Generation column above now includes minimum future lease payments associated with a 20-year lease agreement for the Baltimore headquarters that became effective during the second quarter of 2014. Generation's total commitments under the lease agreement are $0 in 2015, and $5 million, $12 million, $13 million, $13 million, and $285 million related to years 2016, 2017, 2018, 2019, and thereafter, respectively, for a total of $328 million .
(c) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, ComEd, PECO and BGE have excluded these payments from the remaining years, as such amounts would not be meaningful. ComEd's, PECO's, and BGE's annual obligation for these arrangements, included in each of the years 2015—2019, was $2 million, $3 million, and $2 million respectively.
(d) Includes all future lease payments on a 99 year real estate lease that expires in 2106.

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The following table presents the Registrants' rental expense under operating leases for the years ended December 31, 2014, 2013 and 2012:

For the Year Ended December 31,	Exelon	Generation [(a)]	ComEd	PECO	BGE
2014	$ 865	$ 806	$ 15	$ 14	$12
2013	806	744	15	21	11
2012	930	872	18	27	12

(a) Includes Generation's PPAs and other capacity contracts that are accounted for as operating leases and are reflected as net capacity purchases in the Energy Commitments table above. These agreements are considered contingent operating lease payments and are not included in the minimum future operating lease payments table above. Payments made under Generation's PPAs and other capacity contracts totaled $755 million, $694 million and $801 million during 2014, 2013 and 2012, respectively.

For information regarding capital lease obligations, see Note 13—Debt and Credit Agreements.

Indemnifications Related to Sale of Sithe (Exelon and Generation)

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. Specifically, subsidiaries of Generation consummated the acquisition of Reservoir Capital Group's 50% interest in Sithe and subsequently sold 100% of Sithe to Dynegy Inc. (Dynegy).

The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at December 31, 2013. The guarantee expired January 31, 2014. Generation was not required to make payments under the guarantee, and, therefore, has no further obligation related to this guarantee.

Environmental Matters

General. The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has identified 42 sites, 17 of which the remediation has been completed and approved by the Illinois EPA or the U.S. EPA and 25 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2019.
- PECO has identified 26 sites, 16 of which have been remediated in accordance with applicable PA DEP regulatory requirements. The remaining 10 sites are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2021.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE. At this time, BGE is unable to estimate the results of this investigation.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. BGE is authorized to recover, and is currently recovering, environmental costs for the remediation of former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. ComEd, PECO and BGE have recorded regulatory assets for the recovery of these costs. See Note 3—Regulatory Matters for additional information regarding the associated regulatory assets.

As of December 31, 2014 and 2013, the Registrants have accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

December 31, 2014	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 347	$ 277
Generation	63	—
ComEd	238	235
PECO	45	42
BGE	1	—

December 31, 2013	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 338	$ 273
Generation	56	—
ComEd	234	229
PECO	47	44
BGE	1	—

The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs based on probabilistic and deterministic modeling using all available information at the time of each study and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

During the third quarter of 2014, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. The results of these studies indicated that additional remediation would be required at certain sites. Accordingly, ComEd and PECO increased their environmental liabilities and related regulatory assets by $26 million and $4 million, respectively, primarily reflecting refined assumptions regarding clean-up techniques and scopes based on additional experience and analysis as site clean-up and investigation activities progress.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE has established a reserve for the active sites that is not material. Given that the former gas purification site is in the early stages of investigation and the extent of contamination is not currently known, BGE is unable to estimate actual remediation costs, which may be material to BGE's results of operations, cash flows, and financial position.

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water Quality

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. As of December 31, 2014 and 2013, Generation's remaining groundwater contamination reserve was $13 million and $14 million. respectively.

Midwest Generation Bankruptcy. In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

Under a supplemental agreement reached in 2003, Midwest Generation agreed to reimburse ComEd and Generation for 50% of the specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement.

On December 17, 2012 (Petition Date), EME and certain of its subsidiaries, including Midwest Generation, filed for protection under Chapter 11 of the U.S. Bankruptcy Code.

In 2012, the Bankruptcy Court approved the rejection of an agency agreement related to a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations incurred under the coal rail car lease. The rejection left Generation as the party responsible for making all remaining payments under the lease and performing all other obligations thereunder. In January 2013, Generation made the final $10 million payment due under the lease agreement which had been accrued at December 31, 2012.

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On March 11, 2014, the Bankruptcy Court for the Northern District of Illinois entered its Order Confirming Debtors' Joint Chapter 11 Plan of Reorganization. On April 1, 2014 (Effective Date), NRG Energy purchased EME's portfolio of generation, including Midwest Generation and the Joint Chapter 11 Plan of Reorganization (Plan) became effective. As part of the Plan, the sale agreement, including the environmental indemnity, and the asbestos cost-sharing agreement were rejected. Creditors were provided 30 days from the Effective Date to file rejection damages claims associated with contracts rejected under the Plan.

During the second quarter of 2013, Exelon filed proofs of claim for approximately $21 million with the Bankruptcy Court for amounts owed by EME and Midwest Generation related to the coal rail car lease. Further, Exelon filed an environmental claim with an unspecified amount that listed the indemnifications that were in place pre-Petition Date and other factors associated with the remediation and a claim under the asbestos cost-sharing agreement with an unspecified amount. A settlement was approved on January 22, 2015, to resolve the claims related to the coal rail car lease for $14 million. Exelon received the funds and recorded the corresponding gain January 2015.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in Exelon's 2001 corporate restructuring to assume ComEd's rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions at the stations requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors. ComEd and Generation have reviewed available public information as to potential environmental exposures regarding the Midwest Generation station sites. Midwest Generation publicly disclosed in its March 31, 2014 Form 10-Q, its last public filing prior to its deregistration, that (i) it has accrued a probable amount of approximately $9 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at two Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Crawford, Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted. For these reasons, ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations and as a result no liability has been recorded as of December 31, 2014. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Generation increased its reserve for asbestos-related bodily injury claims at December 31, 2013 by $25 million, as a result of Midwest Generation listing such agreement in the January 2014 plan supplement as an agreement to be rejected in connection with the Plan. As discussed above, the rejection became effective as part of the Plan. Subsequently, Generation increased its reserve by $15 million pursuant to the second quarter 2014 actuarial study of such claims, of which an estimated $6 million pertains to Midwest Generation's share. Midwest Generation publicly disclosed in its March 31, 2014 Form 10-Q, its last public filing prior to its deregistration, that it had $53 million recorded related to asbestos bodily injury claims under the contractual indemnity with ComEd. Exelon and Generation may be entitled to damages associated with the rejection of the agreement. These amounts are considered to be contingent gains and would not be recognized until realized.

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Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the supplemental feasibility study, and subsequently requested additional analysis sampling and modeling that will be conducted throughout 2015. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment, but will likely be sometime in 2016 at the earliest. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote. The current estimated cost of the landfill cover remediation for the site is approximately $50 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability.

On April 11, 2014, a class action complaint was filed in the U.S. District Court for the Eastern District of Missouri against Cotter and six additional defendants. The complaint alleges that individuals living in the North St. Louis area within a three-mile radius of the West Lake Landfill suffered damage to property or loss of use of property due to the defendants' negligent handling of radioactive materials. On August 22, 2014, the plaintiffs voluntarily dismissed the case without prejudice.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2015 so that settlement discussions could proceed. Based on Generation's preliminary review, it appears probable that Generation has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the Exelon defendants) and Cotter. The suits allege that individuals living in the North St.

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Louis area developed some form of cancer due to the Exelon defendants' negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which were subsequently granted. Since May 30, 2012, several related lawsuits have been filed in the same court on behalf of various plaintiffs against Cotter and other defendants, but not Exelon. The allegations in these related lawsuits mirror the initially filed lawsuits. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price-Anderson Act. On July 8, 2013, the plaintiffs filed amended complaints under the Price-Anderson Act. Cotter moved to dismiss the amended complaints and has motions currently pending before the court. At this stage of the litigation, Exelon, Generation, and ComEd cannot estimate a range of loss, if any.

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The PRPs submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. On September 30, 2013, U.S. EPA issued the Record of Decision identifying its preferred remedial alternative for the site. The estimated cost for the alternative chosen by U.S. EPA is consistent with the PRPs estimated range of costs noted above. Based on Generation's preliminary review, it appears probable that Generation has liability and has established an appropriate accrual for its share of the estimated clean-up costs. A wholly owned subsidiary of Generation has agreed to indemnify BGE for most of the costs related to this settlement and clean-up of the site.

Rossville Ash Site. The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC (CPSG). In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately $10 million, which has been fully reserved as of December 31, 2014.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRP's signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which

requires the PRP's to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

Coal Combustion Residuals. On December 19, 2014, the U.S. EPA issued the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants, including the classification of CCR as non-hazardous waste under RCRA. The EPA ruling is effective 180 days after publication in the Federal Register, which is anticipated in early 2015. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded reserves consistent with state regulation for its owned coal ash sites, and as such, the regulation is not expected to impact Exelon's and Generation's financial results. Generation is evaluating what, if any, incremental costs will be incurred for coal ash disposal sites formerly owned by Generation that have not yet been closed by their current owners. At this time, however, Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted for these former sites under the new federal regulations. For these reasons, Generation is unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations, and as a result no new liability has been recorded as of December 31, 2014.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon, Generation, PECO and BGE).

Exelon and Generation. Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2014 and 2013, Generation had reserved approximately $100 million and $90 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2014, approximately $22 million of this amount related to 255 open claims presented to Generation, while the remaining $78 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary. During the second quarter of 2014, Generation increased its reserve by approximately $15 million, primarily due to increased actual and projected number and severity of claims.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee's disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee's last employment-based exposure, and that therefore the exclusivity provision of the Act does not apply to preclude such employee from suing his or her employer in court. The Supreme Court's ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was

not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee's last employment-based exposure to asbestos. Currently, Exelon, Generation and PECO are unable to predict whether and to what extent they may experience additional claims in the future as a result of this ruling; as such no increase to the asbestos-related bodily injury liability has been recorded as of December 31, 2014. Increased claims activity resulting from this ruling could have a material adverse impact on Exelon, Generation's and PECO's future results of operations and cash flows.

Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

Approximately 486 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.

Discovery begins in these cases after they are placed on the trial docket. At present, only two of the pending cases are set for trial. Given the limited discovery in these cases, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

- the identity of the facilities at which the plaintiffs allegedly worked as contractors;
- the names of the plaintiffs' employers;
- the dates on which and the places where the exposure allegedly occurred; and
- the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

Federal Energy Regulatory Commission Investigation (Exelon and Generation).

On January 30, 2012, FERC published a notice on its website regarding a non-public investigation of certain of Constellation's power trading activities in and around the ISO-NY from September 2007 through December 2008. Prior to the Constellation merger, Constellation announced on March 9, 2012, that it had resolved the FERC investigation. Under the settlement, Constellation agreed to pay, and has paid, a $135 million civil penalty and $110 million in disgorgement.

During the year ended December 31, 2012, Generation recorded expense of $195 million in Operating and maintenance expense within its Statement of Operations and Comprehensive Income with the remaining $50 million recorded as a Constellation pre-acquisition contingency within its Consolidated Balance Sheets. See Note 4—Mergers, Acquisitions, and Dispositions for additional information on the Constellation merger.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Continuous Power Interruption (ComEd)

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd's service territory, as well as for five other storm systems that affected ComEd's customers during June and July 2011 (Summer 2011 Storm Docket). In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket).

On June 5, 2013, the ICC approved a complete waiver of liability for five of the six summer storms and the February 2011 blizzard. The ICC held that for the July 11, 2011 storm, 34,559 interruptions were preventable and therefore no waiver should apply. As required by the ICC's Order, ComEd notified relevant customers that they may be entitled to seek reimbursement of incurred costs in accordance with a claims procedure established under ICC rules and regulations. In addition, the ICC found that ComEd did not systematically fail in its duty to provide adequate, reliable and safe service. As a result, the ICC rejected the Illinois Attorney General's request for the ICC to open an investigation into ComEd's infrastructure and storm hardening investments.

Following the ICC's June 26, 2013 denial of ComEd's request for rehearing, on June 27, 2013 ComEd filed an appeal of both the summer and winter storm dockets with the Illinois Appellate Court regarding the ICC's interpretation of Section 16-125 of the Illinois Public Utilities Act. On July 31, 2014, the Illinois Appellate Court reaffirmed the ICC's decision in the appeal of the Summer 2011 Storm Docket and dismissed the appeal of the February 2011 Blizzard Docket. The Illinois Appellate Court's opinion has no accounting impact as ComEd previously established a liability in connection with the June 5, 2013 ICC ruling discussed below. ComEd has asked the Illinois Supreme Court to hear the matter. There is no set time in which the Court must decide whether it will take the case.

As a result of the ICC's June 5, 2013 ruling, ComEd established a liability, which was not material, for potential reimbursements for actual damages incurred by the 34,559 customers covered by the ICC's June 5, 2013 Order. The liability recorded represents the low end of a range of potential losses given that no amount within the range represents a better estimate. ComEd's ultimate liability will be based on actual claims eligible for reimbursement as well as the outcome of the appeal. Although reimbursements for actual damages will differ from the estimated accrual recorded, at this time ComEd does not expect the difference to be material to ComEd's results of operations or cash flows.

ComEd has not recorded an accrual for reimbursement of local governmental emergency and contingency expenses as a range of loss, if any, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Telephone Consumer Protection Act Lawsuit (ComEd)

On November 19, 2013, a class action complaint was filed in the Northern District of Illinois on behalf of a single individual and a presumptive class that would include all customers that ComEd enrolled in its Outage Alert text message program. The complaint alleges that ComEd violated the Telephone Consumer Protection Act ("TCPA") by sending approximately 1.2 million text messages to customers without first obtaining their consent to receive such messages. The complaint seeks certification of a class along with statutory damages, attorneys' fees, and an order prohibiting ComEd from sending additional text messages. Such statutory damages could range from $ 500 to $ 1,500 per text. ComEd intends to contest the allegations of this suit. In February 2014, ComEd filed a motion to dismiss this class action complaint, which was denied in June 2014. As of December 31, 2014, ComEd has a reserve, which is not material, representing its best estimate of probable loss associated with this class action complaint. As ComEd is unable to predict the ultimate outcome of this proceeding, actual damages may differ from the estimated amount recorded, which may be material to ComEd's results of operations, cash flows, and financial position.

Fund Transfer Restrictions (Exelon, Generation, ComEd, PECO and BGE)

Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as: (1) the source of the dividends is clearly disclosed; (2) the dividend is not excessive; and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. On May 1, 2013, PECO redeemed all outstanding preferred securities. As a result, the above ratio calculation is no longer applicable. Additionally, PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

BGE pays dividends on its common stock after its board of directors declares them. However, BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

Baltimore City Franchise Taxes (BGE)

The City of Baltimore claims that BGE has maintained electric facilities in the City's public right-of-ways for over one hundred years without the proper franchise rights from the City. BGE is currently reviewing the merits of this claim. BGE has not recorded an accrual for payment of franchise fees for past periods as a range of loss, if any, cannot be reasonably estimated at this time. Franchise fees assessed in future periods may be material to BGE's results of operations and cash flows.

General (Exelon, Generation, ComEd, PECO and BGE).

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Income Taxes

See Note 14—Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

23. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2014, 2013 and 2012.

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$ 456	$ 89	$ 238	$128	$ 86
Property	396	240	25	15	114
Payroll	200	118	28	14	18
Other	102	18	2	2	3
Total taxes other than income	$1,154	$ 465	293	$159	$221

For the year ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$ 449	$ 79	$ 241	$129	$ 82
Property	302	205	24	14	112
Payroll	159	89	27	13	15
Other	185	16	7	2	4
Total taxes other than income	$1,095	$ 389	$ 299	$158	$213

For the year ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility [(a)]	$ 463	$ 82	$ 239	$141	$ 75
Property	227	189	22	13	111
Payroll	131	78	26	12	18
Other	198	20	8	(4)	4
Total taxes other than income	$1,019	$ 369	$ 295	$162	$208

(a) Generation's utility tax represents gross receipts tax related to its retail operations and ComEd's, PECO's and BGE's utility taxes represent municipal and state utility taxes and gross receipts taxes related to their operating revenues, respectively. The offsetting collection of utility taxes from customers is recorded in revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a] —					
Regulatory agreement units	$ 216	$ 216	$ —	$—	$—
Non-regulatory agreement units	159	159	—	—	—
Net unrealized gains on decommissioning trust funds—					
Regulatory agreement units	180	180	—	—	—
Non-regulatory agreement units	134	134	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	29	29	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(358)	(358)	—	—	—
Total decommissioning-related activities	360	360	—	—	—
Investment income	1	1	—	(1)	7[c]
Long-term lease income	24	—	—	—	—
Interest income related to uncertain income tax positions	40	54	—	—	—
AFUDC—Equity	21	—	3	6	12
Other	9	(9)	14	2	(1)
Other, net	$ 455	$ 406	$ 17	$ 7	$ 18

For the year ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a] —					
Regulatory agreement units	$ 256	$ 256	$ —	$—	$—
Non-regulatory agreement units	77	77	—	—	—
Net unrealized gains on decommissioning trust funds—					
Regulatory agreement units	406	406	—	—	—
Non-regulatory agreement units	146	146	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	7	7	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(546)	(546)	—	—	—
Total decommissioning-related activities	346	346	—	—	—
Investment income	8	(1)	—	(1)	9[c]
Long-term lease income	28	—	—	—	—
Interest income related to uncertain income tax positions	24	4	—	—	—
AFUDC—Equity	22	—	11	4	7
Other	32	6	15	3	1
Other, net	$ 460	$ 355	$ 26	$ 6	$ 17

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [(a)] —					
Regulatory agreement units	$ 189	$ 189	$ —	$—	$—
Non-regulatory agreement units	102	102	—	—	—
Net unrealized losses on decommissioning trust funds—					
Regulatory agreement units	386	386	—	—	—
Non-regulatory agreement units	105	105	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	73	73	—	—	—
Regulatory offset to decommissioning trust fund-related activities [(b)]	(530)	(530)	—	—	—
Total decommissioning-related activities	325	325	—	—	—
Investment income	20	3	1	2	11[(c)]
Long-term lease income	29	—	—	—	—
Interest income related to uncertain income tax positions	15	2	20	—	—
AFUDC—Equity	17	—	6	4	10
Credit Facility termination fees	(85)	(85)	—	—	—
Other	32	1	12	2	2
Other, net	$ 353	$ 246	$ 39	$ 8	$ 23

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE's rate stabilization deferral. See Note 3—Regulatory Matters for additional information regarding the rate stabilization deferral.

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012.

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$2,080	$ 922	$ 588	$227	$288
Regulatory assets	191	—	99	9	83
Amortization of intangible assets, net	44	44	—	—	—
Amortization of energy contract assets and liabilities [(a)]	135	135	—	—	—
Nuclear fuel [(b)]	1,073	1,073	—	—	—
ARO accretion [(c)]	345	345	—	—	—
Total depreciation, amortization, accretion and depletion	$3,868	$ 2,519	$ 687	$236	$371

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,893	$ 813	$ 545	$219	$264
Regulatory assets	212	—	119	9	84
Amortization of intangible assets, net	48	43	5	—	—
Amortization of energy contract assets and liabilities [(a)]	430	507	—	—	—
Nuclear fuel [(b)]	921	921	—	—	—
ARO accretion [(c)]	275	275	—	—	—
Total depreciation, amortization, accretion and depletion	$3,779	$ 2,559	$ 669	$228	$348

For the year ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,712	$ 733	$ 525	$207	$245
Regulatory assets	129	—	80	10	53
Amortization of intangible assets, net	40	35	5	—	—
Amortization of energy contract assets and liabilities [(a)]	1,110	1,110	—	—	—
Nuclear fuel [(b)]	848	848	—	—	—
ARO accretion [(c)]	240	240	—	—	—
Total depreciation, amortization and accretion	$4,079	$ 2,966	$ 610	$217	$298

(a) Included in Operating revenues or Purchased power and fuel on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(c) Included in Operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 940	$ 322	$ 292	$ 94	$ 111
Income taxes (net of refunds)	$ 314	227	(6)	85	(21)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 560	$ 249	162	$ 36	$ 64
Loss from equity method investments	22	20	—	—	—
Provision for uncollectible accounts	156	14	26	52	64
Provision for excess and obsolete inventory	5	5	—	—	—
Stock-based compensation costs	91	—	—	—	—
Other decommissioning-related activity [(a)]	(132)	(132)	—	—	—
Energy-related options [(b)]	122	122	—	—	—
Amortization of regulatory asset related to debt costs	11	—	8	3	—
Amortization of rate stabilization deferral	65	—	—	—	65
Amortization of debt fair value adjustment	(23)	(23)	—	—	—
Merger-related commitments	44	44	—	—	—
Amortization of debt costs	53	12	4	2	2
Discrete impacts from EIMA [(c)]	53	—	53	—	—
Lower of cost or market inventory adjustment	29	29	—	—	—
Other	(2)	6	2	(1)	(15)
Total other non-cash operating activities	$ 1,054	$ 346	$ 255	$ 92	$ 180
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 47	$ —	$ 36	$—	$ 11
Other regulatory assets and liabilities	(167)	—	(13)	(16)	(121)
Cash deposits [(d)]	(241)	(241)	—	—	—
Other current assets	7	81	(10)	(2)	(44)
Other noncurrent assets and liabilities	(204)	(89)	32	1	(9)
Total changes in other assets and liabilities	$ (558)	$ (249)	$ 45	$(17)	$(163)
Non-cash investing and financing activities:					
Change in ARC	$ 72	$ 72	$ —	$—	$ —
Change in capital expenditures not paid	220	(61) [(e)]	78	—	25
Fair value of net assets recorded upon CENG consolidation [(f)]	(3,400)	(3,400)	—	—	—
Issuance of equity units [(g)]	131	—	—	—	—
Nuclear fuel procurement [(h)]	70	70	—	—	—
Indemnification of like-kind exchange position [(i)]	—	—	5	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 3—Regulatory Matters for more information.
(d) Relates primarily to cash deposits made to ISO's/RTO's.
(e) Includes $170 million of changes in capital expenditures not paid between December 31, 2014 and 2013 related to Antelope Valley.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(f) See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.
(g) Relates to the present value of the contract payments for the equity units issued by Exelon. See Note 19—Common Stock for additional information.
(h) Relates to the nuclear fuel procurement contracts for the purchase of fixed quantities of uranium, which was delivered to Generation on June 30, 2014 and September 24, 2014. Generation is required to make payments starting June 30, 2016, with the final payment being due no later than June 30, 2018.
(i) See Note 14—Income Taxes for discussion of the like-kind exchange tax position.

For the year ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 866	$ 291	$ 283	$ 95	$130
Income taxes (net of refunds)	112	(18)	33	70	42
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 825	$ 345	$ 308	$ 43	$ 56
Gain from equity method investments	(10)	(10)	—	—	—
Provision for uncollectible accounts	101	10	(15)	61	44
Provision for excess and obsolete inventory	9	9	—	—	—
Stock-based compensation costs	120	—	—	—	—
Other decommissioning-related activity [(a)]	(169)	(169)	—	—	—
Energy-related options [(b)]	104	104	—	—	—
Amortization of regulatory asset related to debt costs	12	—	9	3	—
Amortization of rate stabilization deferral	66	—	—	—	66
Amortization of debt fair value adjustment	(34)	(34)	—	—	—
Discrete impacts from EIMA [(c)]	(271)	—	(271)	—	—
Amortization of debt costs	18	10	1	2	2
Other	(53)	5	(4)	(1)	(15)
Total other non-cash operating activities	$ 718	$ 270	$ 28	$108	$153
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 12	$ —	$ (35)	$ 9	$ 38
Other regulatory assets and liabilities	(64)	—	(43)	(16)	(71)
Other current assets	(165)	(151)	51	13	(8)
Other noncurrent assets and liabilities	322	15	268 [(d)]	(12)	(23)
Total changes in other assets and liabilities	$ 105	$ (136)	$ 241	$ (6)	$ (64)
Non-cash investing and financing activities:					
Change in ARC	$(128)	$ (128)	$ —	$—	$ 4
Change in capital expenditures not paid	(38)	(107) [(e)]	(8)	13	(48)
Consolidated VIE dividend to noncontrolling interest	63	63	—	—	—
Indemnification of like-kind exchange position [(f)]	—	—	176	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 3—Regulatory Matters for more information.
(d) Relates primarily to interest payable related to like-kind exchange tax position. See Note 14—Income Taxes for discussion of the like-kind exchange tax position.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(e) Includes $55 million of changes in capital expenditures not paid between December 31, 2013 and 2012 related to Antelope Valley.
(f) See Note 14—Income Taxes for discussion of the like-kind exchanged tax position.

For the year ended December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 761	$ 286	$ 288	$113	$ 136
Income taxes (net of refunds)	(171)	175	(42)	(64)	(112)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 820	$ 341	$ 282	$ 50	$ 57
Earnings from equity method investments	91	91	—	—	—
Provision for uncollectible accounts	164	22	42	60	44
Provision for excess and obsolete inventory	6	6	1	—	—
Stock-based compensation costs	94	—	—	—	—
Other decommissioning-related activity [(a)]	(145)	(145)	—	—	—
Energy-related options [(b)]	160	160	—	—	—
Amortization of regulatory asset related to debt costs	18	—	13	3	2
Amortization of rate stabilization deferral	57	—	—	—	67
Amortization of debt fair value adjustment	(34)	(34)	—	—	—
Merger-related commitments [(c)]	141	32	—	—	27
Severance costs	99	34	—	—	—
Discrete impacts from EIMA [(d)]	(96)	—	(96)	—	—
Amortization of debt costs	19	11	5	3	2
Other	(30)	—	5	9	(6)
Total other non-cash operating activities	$1,364	$ 518	$ 252	$125	$ 193
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 71	$ —	$ 28	$ 20	$ 26
Other regulatory assets and liabilities	(404)	$ —	(68)	18	(112)
Other current assets	213	(30)	33	(12)	(7)
Other noncurrent assets and liabilities	(248)	(98)	(95)	(10)	8
Total changes in other assets and liabilities	$ (368)	$ (128)	$(102)	$ 16	$ (85)
Non-cash investing and financing activities:					
Change in ARC	$ 781	$ 781	$ 2	$—	$ —
Change in capital expenditures not paid	160	103[(e)]	15	26	(4)
Consolidated VIE dividend to noncontrolling interest	7,365	5,264	—	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Relates to the integration costs to achieve distribution synergies related to the Constellation merger transaction. See Note 4—Mergers, Acquisitions, and Dispositions for more information on Constellation merger-related commitments.
(d) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through pre-established performance-based formula rate tariff. See Note 3—Regulatory Matters.
(e) Includes $127 million of changes in capital expenditures not paid between December 31, 2012 and 2011 related to Antelope Valley.

DOE Smart Grid Investment Grant (Exelon, PECO and BGE) . For the year ended December 31, 2014, PECO has included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $2 million and reimbursements of $5 million related to PECO's DOE SGIG programs.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2013, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $74 million, $27 million and $47 million, and reimbursements of $95 million, $37 million and $58 million, related to PECO's and BGE's DOE SGIG programs. See Note 3—Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants at December 31, 2014 and 2013.

December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Investments					
Equity method investments:					
Financing trusts [(a)]	$ 22	$ —	$ 6	$ 8	$ 8
Bloom Energy	13	13	—	—	—
Net Power	9	9	—	—	—
Sunnyside	5	5	—	—	—
Other equity method investments	1	1	—	—	—
Total equity method investments	50	28	6	8	8
Other investments:					
Net investment in leases	367	7	—	—	—
Employee benefit trusts and investments [(b)]	85	27	—	23	4
Other investments [(c)]	42	42	—	—	—
Total investments	$ 544	$ 104	$ 6	$ 31	$ 12

December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Investments					
Equity method investments:					
Financing trusts [(a)]	$ 22	$ —	$ 6	$ 8	$ 8
Keystone Fuels, LLC	32	32	—	—	—
Conemaugh Fuels, LLC	21	21	—	—	—
CENG	1,925	1,925	—	—	—
Safe Harbor	285	285	—	—	—
Malacha	8	8	—	—	—
Other equity method investments	2	2	—	—	—
Total equity method investments	2,295	2,273	6	8	8
Other investments:					
Net investment in leases	705	7	—	—	—
Employee benefit trusts and investments [(b)]	90	23	5	23	5
Other investments [(c)]	22	22	—	—	—
Total investments	$3,112	$ 2,325	$ 11	$ 31	$ 13

(a) Includes investments in affiliated financing trusts, which were not consolidated within the financial statements of Exelon and are shown as investments on the Consolidated Balance Sheets. See Note 1—Significant Accounting Policies for additional information.
(b) The Registrants' investments in these marketable securities are recorded at fair market value.
(c) Includes cost method and available-for-sale investments.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables provide additional information about liabilities of the Registrants at December 31, 2014 and 2013.

December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Accrued expenses					
Compensation-related accruals [(a)]	$ 832	$ 447	$ 153	$ 50	$ 58
Taxes accrued	305	248	59	3	42
Interest accrued	240	66	102	33	29
Severance accrued	49	33	2	1	2
Other accrued expenses	113[(b)]	92[(b)]	15	4	0
Total accrued expenses	$1,539	$ 886	$ 331	$ 91	$131

December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Accrued expenses					
Compensation-related accruals [(a)]	$ 683	$ 337	$ 135	$ 47	$ 55
Taxes accrued	315	212	62	24	16
Interest accrued	234	72	95	32	29
Severance accrued	66	31	3	1	4
Other accrued expenses	335[(b)]	324[(b)]	12	2	7
Total accrued expenses	$1,633	$ 976	$ 307	$106	$111

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.
(b) Includes $19 million and $228 million for amounts accrued related to Antelope Valley as of December 31, 2014 and December 31, 2013, respectively.

24. Segment Information (Exelon, Generation, ComEd, PECO and BGE)

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants.

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation's six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other regions not considered individually significant referred to collectively as "Other Regions"; including the South, West and Canada. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon's CODM evaluates the performance of and allocates resources to ComEd, PECO and BGE based on net income and return on equity.

The CODMs for ComEd, PECO, and BGE evaluate performance and allocate resources for their respective companies based on net income and return on equity for ComEd, PECO, and BGE each as single integrated businesses.

The foundation of Generation's six reportable segments is based on the geographic location of its assets, and is largely representative of the footprints of an ISO / RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The CODMs for Exelon and Generation evaluate the performance of Generation's power marketing activities and allocate resources based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and sales to its affiliates, ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's own generation and fuel costs associated with tolling agreements. Generation's other business activities, including retail and wholesale gas, investments in gas and oil exploration and production activities, proprietary trading, distributed generation, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, and investments in energy-related proprietary technology are not allocated to regions. Further, Generation's compensation under the reliability-must-run rate schedule, results of operations from the Brandon Shores, Wagner, and C.P. Crane Maryland generating stations, and other miscellaneous revenues, unrealized mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value are also not allocated to a region. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the years ended December 31, 2014, 2013, and 2012 is as follows:

	Generation [a]	ComEd	PECO	BGE [b]	Other [c]	Intersegment Eliminations	Exelon
Operating revenues [d]:							
2014	$ 17,393	$ 4,564	$3,094	$3,165	$1,285	$ (2,072)	$27,429
2013	15,630	4,464	3,100	3,065	1,241	(2,612)	24,888
2012	14,437	5,443	3,186	2,091	1,396	(3,064)	23,489
Intersegment revenues [e]:							
2014	$ 762	$ 4	$ 2	$ 25	$1,280	$ (2,067)	$ 6
2013	1,367	3	1	13	1,237	(2,607)	14
2012	1,660	2	3	9	1,381	(3,049)	6
Depreciation and amortization							
2014	$ 967	$ 687	$ 236	$ 371	$ 53	$ —	$ 2,314
2013	856	669	228	348	52	—	2,153
2012	768	610	217	238	48	—	1,881
Operating expenses [d]:							
2014	$ 16,923	$ 3,586	$2,522	$2,726	$1,353	$ (2,071)	$25,039
2013	13,976	3,510	2,434	2,616	1,324	(2,618)	21,242
2012	13,226	4,557	2,563	2,053	1,662	(3,043)	21,018
Equity in earnings (losses) of unconsolidated affiliates							
2014	$ (20)	$ —	$ —	$ —	$ —	$ —	$ (20)
2013	10	—	—	—	—	—	10
2012	(91)	—	—	—	—	—	(91)
Interest expense, net:							
2014	$ 356	$ 321	$ 113	$ 106	$ 169	$ —	$ 1,065
2013	357	579	115	122	183	—	1,356
2012	301	307	123	111	86	—	928
Income (loss) before income taxes:							
2014	$ 1,226	$ 676	$ 466	$ 351	$ (227)	$ (6)	$ 2,486
2013	1,675	401	557	344	(191)	(13)	2,773
2012	1,058	618	508	(54)	(325)	(7)	1,798
Income taxes:							
2014	$ 207	$ 268	$ 114	$ 140	$ (63)	$ —	$ 666
2013	615	152	162	134	(20)	1	1,044
2012	500	239	127	(23)	(215)	(1)	627
Net income (loss):							
2014	$ 1,019	$ 408	$ 352	$ 211	$ (164)	$ (6)	$ 1,820
2013	1,060	249	395	210	(171)	(14)	1,729
2012	558	379	381	(31)	(110)	(6)	1,171
Capital expenditures:							
2014	$ 3,012	$ 1,689	$ 661	$ 620	$ 95	$ —	$ 6,077
2013	2,752	1,433	537	587	86	—	5,395
2012	3,554	1,246	422	500	67	—	5,789
Total assets:							
2014	$ 45,348	$25,392	$9,943	$8,078	$9,794	$ (11,741)	$86,814
2013	41,232	24,118	9,617	7,861	8,317	(11,221)	79,924

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. For the year ended December 31, 2014, intersegment revenues for Generation include revenue from sales to PECO of $198 million and sales to BGE of $387 million in the Mid-Atlantic region, and sales to ComEd of $176 million in the Midwest region, which eliminate upon consolidation. For the year ended December 31, 2013, intersegment revenues for Generation include revenue from sales to PECO of $405 million and sales to BGE of $455 million in the Mid-Atlantic region, and sales to ComEd of $506 million in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the year ended December 31, 2012, intersegment revenues for Generation include revenue from sales to PECO of $543 million and sales to BGE of $322 million in the Mid-Atlantic region, and sales to ComEd of $795 million in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation.
(b) Amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through December 31, 2014.
(c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(d) For the years ended December 31, 2014, 2013 and 2012, utility taxes of $89 million, $79 million and $82 million, respectively, are included in revenues and expenses for Generation. For the years ended December 31, 2014, 2013 and 2012, utility taxes of $238 million, $241 million and $239 million, respectively, are included in revenues and expenses for ComEd. For the years ended December 31, 2014, 2013 and 2012, utility taxes of $128 million, $129 million and $141 million, respectively, are included in revenues and expenses for PECO. For the years ended December 31, 2014, December 31, 2013 and for the period of March 12, 2012 through December 31, 2012, utility taxes of $86 million, $82 million and $59 million are included in revenues and expenses for BGE, respectively.
(e) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

Generation total revenues:

As of April 1, 2014, Generation total revenues and Generation total revenues net of purchased power and fuel expense includes 100% of the activity from CENG.

	2014			2013			2012		
	Revenues from external customers [a]	Intersegment revenues	Total Revenues	Revenues from external customers [a]	Intersegment revenues	Total Revenues	Revenues from external customers [a]	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 5,265	$ (6)	$ 5,259	$ 5,182	$ 22	$ 5,204	$ 5,082	$ (44)	$ 5,038
Midwest	4,467	8	4,475	4,280	(10)	4,270	4,824	24	4,848
New England	1,417	5	1,422	1,245	(8)	1,237	1,048	45	1,093
New York	843	—	843	735	(21)	714	582	(25)	557
ERCOT	938	(3)	935	1,222	(6)	1,216	1,365	2	1,367
Other Regions [b]	1,319	(10)	1,309	946	22	968	755	78	833
Total Revenues for Reportable Segments	$ 14,249	$ (6)	$14,243	$ 13,610	$ (1)	$13,609	$ 13,656	$ 80	$13,736
Other [c]	3,144	6	3,150	2,020	1	2,021	781	(80)	701
Total Generation Consolidated Operating Revenues	$ 17,393	$ —	$17,393	$ 15,630	$ —	$15,630	$ 14,437	$ —	$14,437

(a) Includes all electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of $289 million, $767 million, and $1,505 million for the years ended December 31, 2014, 2013, and 2012, respectively, and elimination of intersegment revenues.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation total revenues net of purchased power and fuel expense:

	2014			2013			2012		
	RNF from external customers [a]	Intersegment RNF	Total RNF	RNF from external customers [a]	Intersegment RNF	Total RNF	RNF from external customers [a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 3,466	$ (49)	$3,417	$ 3,273	$ (3)	$3,270	$ 3,477	$ (44)	$3,433
Midwest	2,580	14	2,594	2,585	1	2,586	2,974	24	2,998
New England	432	(81)	351	217	(32)	185	151	45	196
New York	457	26	483	14	(18)	(4)	101	(25)	76
ERCOT	573	(256)	317	604	(168)	436	403	2	405
Other Regions [b]	611	(284)	327	334	(133)	201	53	78	131
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 8,119	$ (630)	$7,489	$ 7,027	$ (353)	$6,674	$ 7,159	$ 80	$7,239
Other [c]	(651)	630	(21)	406	353	759	217	(80)	137
Total Generation Revenues net of purchased power and fuel expense	$ 7,468	$ —	$7,468	$ 7,433	$ —	$7,433	$ 7,376	$ —	$7,376

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of $124 million, $488 million, and $1,098 million, for the years ended December 31, 2014, 2013, and 2012, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

25. Related Party Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The financial statements of Exelon include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2014	2013	2012
Operating revenues from affiliates:			
PECO [a]	$ 1	$ 10	$ 6
CENG [b]	17	56	42
BGE [a]	5	4	—
Total operating revenues from affiliates	$ 23	$ 70	$ 48
Purchase power and fuel from affiliates:			
CENG [c]	$282	$ 992	$ 793
Keystone Fuels, LLC [d]	138	144	119
Conemaugh Fuels, LLC [d]	99	98	101
Safe Harbor Water Power Corp [d]	12	22	23
Total purchase power and fuel from affiliates	$531	$1,256	$1,036
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
BGE Capital Trust II [f]	16	16	12
Total interest expense to affiliates, net	$ 41	$ 41	$ 37
Earnings (losses) in equity method investments:			
CENG [e]	$ (19)	$ 9	$ (99)
Qualifying facilities and domestic power projects	(1)	1	8
Total earnings (losses) in equity method investments	$ (20)	$ 10	$ (91)

	December 31,	
	2014	2013
Receivables from affiliates (current):		
CENG [b]	$—	$ 3
Payables to affiliates (current):		
CENG [c]	$—	$ 85
ComEd Financing III	4	4
PECO Trust III	1	1
BGE Capital Trust II	3	4
Keystone Fuels, LLC [d]	—	12
Conemaugh Fuels, LLC [d]	—	9
Other	—	1
Total payables to affiliates (current)	$ 8	$116
Long-term debt due to financing trusts:		
ComEd Financing III	$206	$206
PECO Trust III	81	81
PECO Trust IV	103	103
BGE Capital Trust II	258	258
Total long-term debt due to financing trusts	$648	$648

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) The intersegment profit associated with the sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statement of Operations. See Note 3—Regulatory Matters for additional information.

(b) Beginning in 2012, Generation entered into a power services agency agreement (PSAA) with the CENG plants, which as of April 1, 2014, was amended and extended until the permanent cessation of power generation by the CENG generation plants. The PSAA is an agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services. On April 1, 2014, Generation and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were part of the Generation nuclear fleet. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(c) CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Beginning in 2012, Generation had a PPA under which it purchased 85% of the nuclear plant output owned by CENG that was not sold to third parties under pre-existing unit-contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit-contingent basis 50.01% of the nuclear plant output owned by CENG and a subsidiary of EDF will purchase on a unit-contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA). Beginning April 1, 2014, sales to Generation are eliminated in consolidation. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(d) During 2014, Generation closed the sale of Safe Harbor Water Power Corporation, Keystone Fuels, LLC, and Conemaugh Fuels LLC. Generation recorded purchase power and fuel costs from affiliates related to these generating assets during the time these assets were still partially owned by Generation. See Note 4—Mergers, Acquisitions, and Dispositions for more information.

(e) Prior to April 1, 2014, Generation's total gain (loss) in equity method investments includes equity investment income (loss) and amortization of the basis difference established as a result of purchase accounting applied upon Constellation merger in 2012. CENG was fully consolidated on April 1, 2014. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(f) The BGE Capital Trust II portion of Exelon's interest expense to affiliates, net, for December 31, 2012 excludes $4 million of expense incurred in 2012 prior to the closing of Exelon's merger with Constellation on March 12, 2012.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Transactions involving Generation, ComEd, PECO and BGE are further described in the tables below.

Generation

The financial statements of Generation include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2014	2013	2012
Operating revenues from affiliates:			
ComEd [a]	$176	$ 506	$ 795
PECO [b]	198	405	543
BGE [c]	387	455	322
CENG [d]	17	56	42
BSC	1	1	—
Total operating revenues from affiliates	$779	$1,423	$1,702
Purchase power and fuel from affiliates:			
ComEd	$ 1	$ 1	$ —
BGE	25	13	8
CENG [e]	282	992	793
Keystone Fuels, LLC [i]	138	144	119
Conemaugh Fuels, LLC [i]	99	98	101
Safe Harbor Water Power Corporation [i]	12	22	23
Total purchase power and fuel from affiliates	$557	$1,270	$1,044
Operating and maintenance from affiliates:			
ComEd [f]	$ 3	$ 2	$ 2
PECO [f]	2	1	3
BSC [g]	618	571	625
Total operating and maintenance from affiliates	$623	$ 574	$ 630
Interest expense to affiliates, net:			
Exelon Corporate	$ 53	$ 59	$ 75
Earnings (losses) in equity method investments			
CENG [h]	$ (19)	$ 9	$ (99)
Qualifying facilities and domestic power projects	(1)	1	8
Total earnings (losses) in equity method investments	$ (20)	$ 10	$ (91)
Capitalized costs			
BSC	$ 91	$ 93	$ 80
Cash distribution paid to member	$645	$ 625	$1,626
Contribution from member	$ 53	$ 26	$ 48

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2014	December 31, 2013
Receivables from affiliates (current):		
CENG [d]	$ —	$ 3
ComEd [a]	43	38
PECO [b]	29	38
BGE [c]	40	27
Other	1	2
Total receivables from affiliates (current)	$ 113	$ 108
Long-term debt due to affiliates (current):		
Exelon Corporate [l]	556	—
Payables to affiliates (current):		
CENG [e]	$ —	$ 85
Exelon Corporate [j]	12	7
BSC [g]	83	66
ComEd	12	—
Keystone Fuels, LLC [i]	—	12
Conemaugh Fuels, LLC [i]	—	9
Other	—	2
Total payables to affiliates (current)	$ 107	$ 181
Long-term debt due to affiliates (noncurrent):		
Exelon Corporate [l]	943	1,523
Payables to affiliates (noncurrent):		
BSC [g]	$ 1	$ —
ComEd [k]	2,389	2,293
PECO [k]	490	447
Total payables to affiliates (noncurrent)	$2,880	$2,740

(a) Generation has an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. Generation also sells RECs to ComEd. In addition, Generation had revenue from ComEd associated with the settled portion of the financial swap contract established as part of the Illinois Settlement. See Note 3—Regulatory Matters for additional information.

(b) Generation provides electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, Generation has five-year and ten-year agreements with PECO to sell non-solar and solar AECs, respectively. See Note 3—Regulatory Matters for additional information.

(c) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.

(d) Beginning in 2012, Generation entered into a power services agency agreement (PSAA) with the CENG plants, which as of April 1, 2014, was amended and extended until the permanent cessation of power generation by the CENG generation plants. The PSAA is an agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services. On April 1, 2014, Generation and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were part of the Generation nuclear fleet. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(e) CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Beginning in 2012, Generation had a PPA under which it purchased 85% of the nuclear plant output owned by CENG that was not sold to third parties under pre-existing unit-contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit-contingent basis 50.01% of the nuclear plant output owned by CENG and a subsidiary of EDF will purchase on a unit-contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA). Beginning April 1, 2014, sales to Generation are eliminated in consolidation. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(f) Generation requires electricity for its own use at its generating stations. Generation purchases electricity and distribution and transmission services from PECO and only distribution and transmission services from ComEd for the delivery of electricity to its generating stations.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(g) Generation receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(h) Prior to April 1, 2014, Generation's total gain (loss) in equity method investments includes equity income (loss) and amortization of the basis difference established as a result of purchase accounting applied upon Constellation merger in 2012. CENG was fully consolidated on April 1, 2014. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.
(i) During 2014, Generation closed the sale of Safe Harbor Water Power Corporation, Keystone Fuels, LLC, and Conemaugh Fuels LLC. Generation recorded purchase power and fuel costs from affiliates related to these generating assets during the time these assets were still partially owned by Generation. See Note 4—Mergers, Acquisitions, and Dispositions for more information.
(j) The balance consists of interest owed to Exelon Corporation related to the senior unsecured notes, as well as, expense related to certain invoices Exelon Corporation processed on behalf of Generation.
(k) Generation has long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 15—Asset Retirement Obligations.
(l) In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-term Debt to affiliate on Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd

The financial statements of ComEd include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2014	2013	2012
Operating revenues from affiliates			
Generation	$ 4	$ 3	$ 2
Purchased power from affiliate			
Generation [a]	$176	$512	$789
Operating and maintenance from affiliate			
BSC [b]	$166	$157	$163
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
Capitalized costs			
BSC [b]	$ 77	$ 69	$ 92
Cash dividends paid to parent	$307	$220	$105
Contribution from parent	$273	$—	$ 11

	December 31,	
	2014	2013
Prepaid voluntary employee beneficiary association trust [c]	$ 13	$ 13
Receivable from affiliates (current):		
Voluntary employee beneficiary association trust	$ 2	$ 3
Generation	12	—
Total receivable from affiliates (current)	$ 14	$ 3
Receivable from affiliates (noncurrent):		
Generation [d]	$2,389	$2,293
Exelon Corporate [e]	182	176
Total receivable from affiliates (noncurrent)	$2,571	$2,469
Payables to affiliates (current):		
Generation [a]	$ 43	$ 38
BSC [b]	32	30
ComEd Financing III	4	4
PECO	2	—
Exelon Corporate	3	9
Other	—	2
Total payables to affiliates (current)	$ 84	$ 83
Long-term debt to ComEd financing trust		
ComEd Financing III	$ 206	$ 206

(a) ComEd procures a portion of its electricity supply requirements from Generation under an ICC-approved RFP contract. ComEd also purchases RECs from Generation. In addition, purchased power expense includes the settled portion of the financial swap contract with Generation, which expired in 2013. See Note 3—Regulatory Matters and Note 12—Derivative Financial Instruments for additional information.

(b) ComEd receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(c) The voluntary employee benefit association trusts covering active employees are included in corporate operations and are funded by the Registrants. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for ComEd's contributions to the plans, being higher than actual claim expense incurred by the plans over time. The prepayment is included in other current assets.
(d) ComEd has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct for generating facilities previously owned by ComEd. To the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to ComEd for payment to ComEd's customers.
(e) Represents indemnification from Exelon Corporate related to the like-kind exchange transaction.

PECO

The financial statements of PECO include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2014	2013	2012
Operating revenues from affiliates:			
Generation [a]	$ 2	$ 1	$ 3
Purchased power from affiliate			
Generation [b]	$194	$392	$533
Operating and maintenance from affiliates:			
BSC [c]	$ 96	$ 98	$107
Generation	3	3	4
Total operating and maintenance from affiliates	$ 99	$101	$111
Interest expense to affiliates, net:			
PECO Trust III	$ 6	$ 6	$ 6
PECO Trust IV	6	6	6
Total interest expense to affiliates, net	$ 12	$ 12	$ 12
Capitalized costs			
BSC [c]	$ 39	$ 46	$ 54
Cash dividends paid to parent	$320	$332	$343
Contribution from parent	$ 24	$ 27	$ 9

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2014	December 31, 2013
Prepaid voluntary employee beneficiary association trust [d]	$ 3	$ 3
Receivable from affiliate (current):		
ComEd	$ 2	$—
BGE	1	3
Total receivable from affiliates (current)	$ 3	$ 3
Receivable from affiliate (noncurrent):		
Generation [e]	$490	$447
Payables to affiliates (current):		
Generation [b]	$ 29	$ 38
BSC [c]	20	17
Exelon Corporate	2	2
PECO Trust III	1	1
Total payables to affiliates (current)	$ 52	$ 58
Long-term debt to financing trusts:		
PECO Trust III	$ 81	$ 81
PECO Trust IV	103	103
Total long-term debt to financing trusts	$184	$184

(a) PECO provides energy to Generation for Generation's own use.
(b) PECO purchases electric supply from Generation under contracts executed through its competitive procurement process. In addition, PECO has five-year and ten-year agreements with Generation to purchase non-solar and solar AECs, respectively. See Note 3—Regulatory Matters for additional information on AECs.
(c) PECO receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) The voluntary employee beneficiary association trusts covering active employees are included in corporate operations and are funded by the Registrants. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for PECO's contributions to the plans, being higher than actual claim expense incurred by the plans over time.
(e) PECO has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct, whereby, to the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to PECO for payment to PECO's customers.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

The financial statements of BGE include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2014	2013	2012
Operating revenues from affiliates:			
Generation [a]	$ 25	$ 13	$ 10
Purchased power from affiliate			
Generation [b]	$382	$452	$396
Operating and maintenance from affiliates:			
BSC [c]	$103	$ 83	$106
Interest expense to affiliates, net:			
BGE Capital Trust II	$ 16	$ 16	$ 16
Capitalized costs			
BSC [c]	$ 19	$ 15	$ 21
Contribution from parent	$—	$—	$ 66

	December 31,	
	2014	2013
Prepaid voluntary employee beneficiary association trust [d]	$ 1	$ 1
Payables to affiliates (current):		
Generation [b]	$ 40	$ 27
BSC [c]	17	20
Exelon Corporate	5	1
PECO	1	3
BGE Capital Trust II	3	4
Total payables to affiliates (current)	$ 66	$ 55
Long-term debt to BGE financing trust		
BGE Capital Trust II	$258	$258

(a) BGE provides energy to Generation for Generation's own use.
(b) BGE procures a portion of its electricity and gas supply requirements from Generation under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.
(c) BGE receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) The voluntary employee benefit association trusts covering active employees are included in corporate operations and are funded by the Registrants. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for BGE's contributions to the plans, being higher than actual claim expense incurred by the plans over time. The prepayment is included in other current assets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

26. Quarterly Data (Unaudited) (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The data shown below, which may not equal the total for the year due to the effects of rounding and dilution, includes all adjustments that Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net (Loss) Income on Common Stock	
	2014	2013	2014	2013	2014	2013
Quarter ended:						
March 31	$ 7,237	$ 6,082	$ 168[a]	$ 513[b]	$ 90	$ (4) [c]
June 30	6,024	6,141	842[a]	1,005	522	490
September 30	6,912	6,502	1,739[a]	1,262[b]	993	738
December 31	7,255	6,163	348	889	18[d]	495

(a) In the first, second, and third quarter of 2014, Exelon reclassified $5 million, $13 million, and $339 million, respectively, to Operating income for presentation purposes in Exelon's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect Exelon's Net (Loss) Income on Common Stock.
(b) In the first and third quarter of 2013, Exelon reclassified $5 million and $8 million, respectively, to Operating income for presentation purposes in Exelon's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect Exelon's Net (Loss) Income on Common Stock.
(c) Includes $265 million of interest expense related to the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Includes charges to earnings related to the impairments of certain generating assets which were held for sale and certain Upstream exploration assets. See Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

	Average Basic Shares Outstanding (in millions)		Net (Loss) Income per Basic Share	
	2014	2013	2014	2013
Quarter ended:				
March 31	858	855	$ 0.10	$ (0.01)
June 30	860	856	0.61	0.57
September 30	861	857	1.15	0.86
December 31	861	856	0.02	0.60

	Average Diluted Shares Outstanding (in millions)		Net (Loss) Income per Diluted Share	
	2014	2013	2014	2013
Quarter ended:				
March 31	861	855	$ 0.10	$ (0.01)
June 30	864	860	0.60	0.57
September 30	863	860	1.15	0.86
December 31	868	860	0.02	0.59

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2014				2013			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$38.93	$36.26	$37.73	$33.94	$30.59	$32.42	$37.80	$34.56
Low price	33.07	30.66	33.11	26.45	26.64	29.42	29.84	29.10
Close	37.08	34.09	36.48	33.56	27.39	29.64	30.88	34.48
Dividends	0.310	0.310	0.310	0.310	0.310	0.310	0.310	0.525

Generation

The data shown below includes all adjustments that Generation considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating (Loss) Income		Net (Loss) Income on Membership Interest	
	2014	2013	2014 [(a)]	2013	2014	2013
Quarter ended:						
March 31	$ 4,390	$ 3,533	$ (384) [(a)]	$ (59) [(b)]	$ (185)	$ (18)
June 30	3,789	4,070	441[(a)]	603	340	330
September 30	4,412	4,255	1,225[(a)]	729[(b)]	771	490
December 31	4,802	3,772	(105)	405	(91)	269

(a) In the first, second, and third quarter of 2014, Generation reclassified $5 million, $12 million, and $338 million, respectively, to Operating (loss) income for presentation purposes in Generation's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect Generation's Net (Loss) Income on Membership Interest.
(b) In the first and third quarter of 2013, Generation reclassified $5 million and $8 million, respectively, to Operating (loss) income for presentation purposes in Generation's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect Generation's Net (Loss) Income on Membership Interest.

ComEd

The data shown below includes all adjustments that ComEd considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net (Loss) Income	
	2014	2013	2014	2013	2014	2013
Quarter ended:						
March 31	$ 1,134	$ 1,160	$ 238	$ 209	$ 98	$ (81)
June 30	1,128	1,080	259[(a)]	232	111	96
September 30	1,222	1,156	288[(a)]	278	126	126
December 31	1,079	1,068	196	236	73	109

(a) In both the second and third quarter of 2014, ComEd reclassified $1 million to Operating income for presentation purposes in ComEd's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect ComEd's Net (Loss) Income.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PECO

The data shown below includes all adjustments that PECO considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income on Common Stock	
	2014	2013	2014	2013	2014	2013
Quarter ended:						
March 31	$ 993	$ 895	$ 149	$ 203	$ 89	$ 121
June 30	656	672	134	138	84	72
September 30	693	728	133	155	81	92
December 31	750	805	156	168	98	102

BGE

The data shown below includes all adjustments that BGE considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income attributable to Common Shareholders	
	2014	2013	2014	2013	2014	2013
Quarter ended:						
March 31	$ 1,054	$ 880	$ 169	$ 163	$ 85	$ 77
June 30	653	653	55	69	16	22
September 30	697	737	102	114	46	50
December 31	761	794	113	101	52	47

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 9A. CONTROLS AND PROCEDURES

E x e lo n, Generation, ComEd, PECO and BGE—Disclosure Controls and Procedures

During the fourth quarter of 2014, each registrant's management, including its principal executive officer and principal financial officer, evaluated the effectiveness of that registrant's disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in that registrant's periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by each registrant to ensure that (a) information relating to that registrant, including its consolidated subsidiaries, that is required to be included in filings under the Securities Exchange Act of 1934, is accumulated and made known to that registrant's management, including its principal executive officer and principal financial officer, by other employees of that registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Consistent with guidance issued by the Securities and Exchange Commission that an assessment of internal controls over financial reporting of a recently acquired business may be omitted from management's evaluation of disclosure controls and procedures, management is excluding an assessment of such internal controls of Integrys, which we acquired on November 1, 2014, from its evaluation of the effectiveness of Exelon's and Generation's disclosure controls and procedures. The total assets related to Integrys are approximately 0.74% and 1.42%, respectively, and total revenues related to Integrys are 1.41% and 2.22%, respectively, of Exelon's and Generation's related consolidated financial statement amounts as of and for the year ended December 31, 2014.

Accordingly, as of December 31, 2014, the principal executive officer and principal financial officer of each registrant concluded that such registrant's disclosure controls and procedures were effective to accomplish their objectives.

Exelon, Generation, ComEd, PECO and BGE—Changes in Internal Control Over Financial Reporting

Each registrant continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. However, there have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2014 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's and BGE's internal control over financial reporting.

Exelon, Generation, ComEd, PECO and BGE—Internal Control Over Financial Reporting

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2014. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2014 and, therefore, concluded that each registrant's internal control over financial reporting was effective. Management's Report on Internal Control Over Financial Reporting is included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

ITEM 9B. OTHER INFORMATION

Exelon, Generation and ComEd

None.

PECO and BGE

None.

PART III

Exelon Generation Company, LLC, Baltimore Gas and Electric Company, and PECO Energy Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section relating to Generation, BGE, and PECO are not presented.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants at February 13, 2015.

Directors, Director Nomination Process, and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at the annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)), the audit committee (Item 407(d)(4) and (d)(5)) and the beneficial reporting compliance (Sec. 16(a)) is incorporated herein by reference to information to be contained in Exelon's definitive 2015 proxy statement (2015 Exelon Proxy Statement) and the ComEd information statement (2015 ComEd Information Statement) to be filed with the SEC before April 30, 2015 pursuant to Regulation 14A or 14C, as applicable, under the Securities Exchange Act of 1934.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to Exelon's and ComEd's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. The Code of Business Conduct is filed as Exhibit 14 to this report and is available on Exelon's website at *www.exeloncorp.com* . The Code of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Bruce G. Wilson, Senior Vice President, Deputy General Counsel, and Corporate Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

If any substantive amendments to the Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Code of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or Corporate Controller, Exelon will disclose the nature of such amendment or waiver on Exelon's website, *www.exeloncorp.com* , or in a report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under *Executive Compensation Data* and *Report of the Compensation Committee* in the 2015 Exelon Proxy Statement or the ComEd 2015 Information Statement and incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The additional information required by this item will be set forth under *Ownership of Exelon Stock* in the 2015 Exelon Proxy Statement or the ComEd 2015 Information Statement and incorporated herein by reference.

Securities Authorized for Issuance under Exelon Equity Compensation Plans

[A] Plan Category	[B] Number of securities to be issued upon exercise of outstanding Options, warrants and rights (Note 1)	[C] Weighted-average price of outstanding Options, warrants and rights (Note 2)	[D] Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column [B]) (Note 3)
Equity compensation plans approved by security holders	31,538,000	$ 36.67	32,278,000

(1) Balance includes stock options, unvested performance shares, and unvested restricted shares that were granted under the Exelon LTIP or predecessor company plans and shares awarded under those plans and deferred into the stock deferral plan, as well as deferred stock units granted to directors as part of their compensation. For performance shares and performance share transition awards granted in 2013 and 2014, the total includes the maximum number of shares that could be granted, if performance, total shareholder return modifier, and individual performance multipliers were all at maximum, a total of 7,138,000 shares. At target, the number of securities to be issued for such awards is 3,753,000. The deferred stock units granted to directors includes 284,000 shares to be issued upon the conversion of deferred stock units awarded to members of the Exelon board of directors, and 98,000 shares to be issued upon the conversion of stock units held by members of the Exelon board of directors that were earned under a legacy Constellation Energy Group plan. Conversion of stock units to shares will occur after the director terminates service to the Exelon board or the board of any of its subsidiary companies. See Note 19—Common Stock of the Combined Notes to Consolidated Financial Statements for additional information about the material features of the plans.

(2) Includes outstanding restricted stock units and performance shares that can be exercised for no consideration. Without such instruments, the weighted-average price of outstanding options, warrants and rights shown in column [C] would be $46.81.

(3) Includes 23,460,000 shares available for issuance from the company's employee stock purchase plan.

No ComEd securities are authorized for issuance under equity compensation plans.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The additional information required by this item will be set forth under *Related Persons Transactions* and *Director Independence* in the 2015 Exelon Proxy Statement or the ComEd 2015 Information Statement and incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under *The Ratification of PricewaterhouseCoopers LLP as Exelon's Independent Accountant for 2015* in the 2015 Proxy Statement and the 2015 ComEd Information Statement and incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

Exelon

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2015 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2014, 2013 and 2012

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012

   Consolidated Balance Sheets at December 31, 2014 and 2013

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2014, 2013 and 2012

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule I—Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2014 and 2013 and for the Years Ended December 31, 2014, 2013 and 2012

   Schedule II—Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Statements of Operations and Other Comprehensive Income

(In millions)	For the Years Ended December 31, 2014	2013	2012
Operating expenses			
Operating and maintenance	$ 9	$ 9	$ 201
Operating and maintenance from affiliates	38	34	72
Other	3	12	6
Total operating expenses	50	55	279
Operating loss	(50)	(55)	(279)
Other income and (deductions)			
Interest expense, net	(237)	(116)	(153)
Equity in earnings of investments	1,779	1,903	1,278
Interest income from affiliates, net	53	36	75
Other, net	(2)	(78)	7
Total other income	1,593	1,745	1,207
Income before income taxes	1,543	1,690	928
Income taxes (benefit)	(80)	(29)	(232)
Net income	$1,623	$1,719	$1,160
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service cost (benefit) reclassified to periodic costs	$ (30)	$ —	$ 1
Actuarial loss reclassified to periodic cost	147	208	168
Transition obligation reclassified to periodic cost	—	—	2
Pension and non-pension postretirement benefit plan valuation adjustment	(497)	669	(371)
Unrealized loss on cash flow hedges	(148)	(248)	(120)
Unrealized gain on marketable securities	1	2	2
Unrealized gain on equity investments	8	106	1
Unrealized loss on foreign currency translation	(9)	(10)	—
Reversal of CENG equity method AOCI	(116)	—	—
Other comprehensive income (loss)	(644)	727	(317)
Comprehensive income	$ 979	$2,446	$ 843

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2014	2013	2012
Net cash flows provided by operating activities	$ 806	$ 1,053	$ 2,131
Cash flows from investing activities			
Return on investment of direct financing lease termination	335	—	—
Changes in Exelon intercompany money pool	(83)	(60)	—
Note receivable from affiliates	—	484	—
Capital expenditures	1	—	(30)
Cash and restricted cash acquired from Constellation	—	—	679
Change in restricted cash	—	38	(38)
Investment in affiliates	(70)	(38)	(67)
Other investing activities	(126)	15	—
Net cash flows provided by (used in) investing activities	57	439	544
Cash flows from financing activities			
Cash receipts from intercompany money pool	—	—	(703)
Changes in short-term borrowings	—	10	(161)
Issuance of long-term debt	1,150	—	—
Retirement of long-term debt	(23)	(450)	(77)
Dividends paid on common stock	(1,065)	(1,249)	(1,716)
Proceeds from employee stock plans	35	47	73
Other financing activities	(84)	(6)	30
Net cash flows provided by (used in) financing activities	13	(1,648)	(2,554)
Increase (decrease) in cash and cash equivalents	876	(156)	121
Cash and cash equivalents at beginning of period	3	159	38
Cash and cash equivalents at end of period	$ 879	$ 3	$ 159

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

(In millions)	December 31, 2014	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 879	$ 3
Accounts receivable, net		
Other accounts receivable	209	72
Accounts receivable from affiliates	24	22
Deferred income taxes	20	27
Notes receivable from affiliates	818	179
Regulatory assets	254	233
Other	22	1
Total current assets	2,226	537
Property, plant and equipment, net	54	57
Deferred debits and other assets		
Regulatory assets	3,186	3,005
Investments in affiliates	26,670	26,390
Deferred income taxes	2,187	1,890
Notes receivable from affiliates	943	1,522
Other	172	17
Total deferred debits and other assets	33,158	32,824
Total assets	$35,438	$33,418

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

(In millions)	December 31, 2014	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 1,409	$ 10
Accounts payable	2	43
Unamortized energy contract liabilities	—	12
Accrued expenses	25	106
Deferred income taxes	60	26
Regulatory liabilities	51	2
Other	75	54
Total current liabilities	1,622	253
Long-term debt	2,841	3,033
Long-term debt to affiliate	182	176
Deferred credits and other liabilities		
Regulatory liabilities	37	43
Pension obligations	7,638	6,444
Non-pension postretirement benefit obligations	16	393
Deferred income taxes	93	70
Other	398	271
Total deferred credits and other liabilities	8,182	7,221
Total liabilities	12,827	10,683
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 860 and 857 shares outstanding at December 31, 2014 and 2013, respectively)	16,709	16,741
Treasury stock, at cost (35 shares held at December 31, 2014 and 2013, respectively)	(2,327)	(2,327)
Retained earnings	10,910	10,358
Accumulated other comprehensive loss, net	(2,684)	(2,040)
Total shareholders' equity	22,608	22,732
BGE preference stock not subject to mandatory redemption	3	3
Total liabilities and shareholders' equity	$35,438	$33,418

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

1. Basis of Presentation

Exelon Corporate is a holding company that conducts substantially all of its business operations through its subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of Exelon Corporation.

Exelon Corporate owns 100% of all of its significant subsidiaries, either directly or indirectly, except for Commonwealth Edison Company (ComEd), of which Exelon Corporate owns more than 99%, and BGE, of which Exelon owns 100% of the common stock but none of BGE's preferred stock. Exelon owned none of PECO's preference securities, which PECO redeemed in 2013.

2. Mergers

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Exelon and PHI continue to expect to complete the merger in the second or third quarter of 2015. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the Merger Agreement with PHI.

On March 12, 2012, Exelon Corporation completed the merger contemplated by the Merger Agreement, among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including the customer supply and generation businesses that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

For BGE's debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE's assets acquired and liabilities assumed is recorded as a regulatory asset at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the merger with Constellation. Also see Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information on BGE's push-down accounting treatment.

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

3. Debt and Credit Agreements

Short-Term Borrowings

Exelon Corporate meets its short-term liquidity requirements primarily through the issuance of commercial paper. Exelon Corporate had no commercial paper borrowings at both December 31, 2014 and December 31, 2013.

Credit Agreements

On May 30, 2014, Exelon Corporate amended and extended its unsecured syndicated revolving credit facility with aggregate bank commitments of $500 million through May 2019. As of December 31, 2014, Exelon Corporation had available capacity under those commitments of $494 million. See Note 13—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon Corporation's credit agreement.

Long-Term Debt

The following tables present the outstanding long-term debt for Exelon Corporate as of December 31, 2014 and December 31, 2013:

	Rates	Maturity Date	December 31, 2014	December 31, 2013
Long-term debt				
Junior subordinated notes	6.5%	2017	$ 1,150	$ —
Senior unsecured notes [(a)]	4.9% – 7.6%	2015-2035	2,658	2,658
Total long-term debt			3,808	2,658
Unamortized debt discount and premium, net			1	2
Fair value adjustment			441	383
Long-term debt due within one year			(1,409)	(10)
Long-term debt			$ 2,841	$3,033

(a) Senior unsecured notes include mirror debt that is held on both Generation and Exelon Corporation's balance sheets.

The debt maturities for Exelon Corporate for the periods 2015, 2016, 2017, 2018, 2019 and thereafter are as follows:

2015	$1,350
2016	—
2017	1,150
2018	—
2019	—
Remaining years	1,308
Total long-term debt	$3,808

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

4. Commitments and Contingencies

See Note 22—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's commitments and contingencies related to environmental matters and fund transfer restrictions.

5. Related Party Transactions

The financial statements of Exelon Corporate include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
(In millions)	2014	2013	2012
Operating and maintenance from affiliates:			
Business Services Company, LLC [a]	$ 38	$ 34	$ 72
Interest income from affiliates, net:			
Exelon Generation Consolidated	$ 53	$ 36	$ 75
Equity in earnings of investments:			
Exelon Energy Delivery Company, LLC [b]	$ 958	$ 834	$ 713
Exelon Ventures Company, LLC [c]	926	1,076	564
UII, LLC	(6)	(2)	25
Exelon Transmission Company, LLC	(7)	(5)	(3)
Exelon Enterprise	(1)	—	—
Exelon Generation Consolidated	(91)	—	—
Exelon Consolidations [d]	—	—	(21)
Total equity in earnings of investments	$1,779	$1,903	$1,278
Cash contributions received from affiliates	$1,370	$1,175	$2,074

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

(in millions)	December 31, 2014	2013
Accounts receivable from affiliates (current):		
Business Services Company, LLC [a]	$ 2	$ 3
Generation	12	7
ComEd	3	9
PECO	2	2
BGE	5	1
Total accounts receivable from affiliates (current)	$ 24	$ 22
Notes receivable from affiliates (current):		
Business Services Company, LLC [a]	$ 262	$ 179
Exelon Generation Consolidated [e]	$ 556	$ —
Total receivable from affiliates (current):	$ 818	$ 179
Investments in affiliates:		
Business Services Company, LLC [a]	$ 193	$ 201
Exelon Energy Delivery Company, LLC [b]	13,590	12,956
Exelon Ventures Company, LLC [c]	—	12,750
UII, LLC	130	470
Exelon Transmission Company, LLC	1	3
VEBA	9	10
Exelon Enterprises	23	—
Exelon Generation Consolidated	12,720	—
Exelon Consolidations	4	—
Total investments in affiliates	$26,670	$26,390
Notes receivable from affiliates (non-current):		
Generation [e]	$ 943	$ 1,522
Long-term debt to affiliates (non-current):		
ComEd	$ 182	$ 176

(a) Exelon Corporate receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead.
(b) Exelon Energy Delivery Company, LLC consists of ComEd, PECO and BGE.
(c) Exelon Ventures Company, LLC primarily consisted of Generation and was fully dissolved as of December 31, 2014. Exelon Enterprises, Exelon Generation Consolidated, and Exelon Consolidations are now directly owned Exelon Corporate investments as of December 31, 2014.
(d) Equity in earnings of investments for Exelon Consolidations represents the intercompany income component that offsets the corresponding intercompany expense at Generation for upgrades in transmission assets owned by ComEd, which are reflected as assets at Exelon Corporate.
(e) In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-Term Debt to affiliate on Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets.

Exelon Corporation and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
		(in millions)			
For the year ended December 31, 2014					
Allowance for uncollectible accounts [a]	$ 272	$ 175	$ 69[c]	$ 205[d]	$ 311
Deferred tax valuation allowance	13	—	37	—	50
Reserve for obsolete materials	58	5	34	2	95
For the year ended December 31, 2013					
Allowance for uncollectible accounts [a]	$ 293	$ 121	$ 37[c]	$ 179[d]	$ 272
Deferred tax valuation allowance	36	1	—	24	13
Reserve for obsolete materials	53	17	—	12	58
For the year ended December 31, 2012					
Allowance for uncollectible accounts [a]	$ 199	$ 144	$ 136[b][c]	$ 186[d]	$ 293
Deferred tax valuation allowance	10	18	18[b]	10	36
Reserve for obsolete materials	60	2	2[b]	11	53

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $8 million, $9 million, and $8 million for the years ended December 31, 2014, 2013, and 2012, respectively.
(b) Primarily represents the addition of Constellation's and BGE's results as of March 12, 2012, the date of the merger.
(c) Includes charges for late payments and non-service receivables.
(d) Write-off of individual accounts receivable.

Exelon Generation Company, LLC and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Generation

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2015 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2014, 2013 and 2012

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012

   Consolidated Balance Sheets at December 31, 2014 and 2013

   Consolidated Statements of Changes in Member's Equity for the Years Ended December 31, 2014, 2013 and 2012

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Exelon Generation Company, LLC and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 57	$ 14	$ 8	$ 19	$ 60
Deferred tax valuation allowance	11	—	37	—	48
Reserve for obsolete materials	55	5	32	(1)	93
For the year ended December 31, 2013					
Allowance for uncollectible accounts	$ 84	$ (16)	$ —	$ 11	$ 57
Deferred tax valuation allowance	35	1	—	25	11
Reserve for obsolete materials	50	16	—	11	55
For the year ended December 31, 2012					
Allowance for uncollectible accounts	$ 29	$ —	$ 66[(a)]	$ 11	$ 84
Deferred tax valuation allowance	—	17	18[(a)]	—	35
Reserve for obsolete materials	59	—	2[(a)]	11	50

(a) Represents the addition of Constellation's results as of March 12, 2012, the date of the merger.

Commonwealth Edison Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

ComEd

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2015 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2014, 2013 and 2012

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012

   Consolidated Balance Sheets at December 31, 2014 and 2013

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2014, 2013 and 2012

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

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Commonwealth Edison Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 62	$ 45	$ 33[a]	$ 56[b]	$ 84
Reserve for obsolete materials	2	—	2	2	2
For the year ended December 31, 2013					
Allowance for uncollectible accounts	$ 70	$ 33	$ 29[a]	$ 70[b]	$ 62
Reserve for obsolete materials	2	1	—	1	2
For the year ended December 31, 2012					
Allowance for uncollectible accounts	$ 78	$ 42	$ 26[a]	$ 76[b]	$ 70
Reserve for obsolete materials	1	1	—	—	2

(a) Primarily charges for late payments and non-service receivables.
(b) Write-off of individual accounts receivable.

PECO Energy Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

PECO

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2015 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2014, 2013 and 2012

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012

   Consolidated Balance Sheets at December 31, 2014 and 2013

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2014, 2013 and 2012

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

PECO Energy Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the year ended December 31, 2014					
Allowance for uncollectible accounts [(a)]	$ 107	$ 52	$ 11[(b)]	$ 70[(c)]	$ 100
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2013					
Allowance for uncollectible accounts [(a)]	$ 99	$ 61	$ 7[(b)]	$ 60[(c)]	$ 107
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2012					
Allowance for uncollectible accounts [(a)]	$ 92	$ 60	$ 8[(b)]	$ 61[(c)]	$ 99
Reserve for obsolete materials	1	—	—	—	1

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $8 million, $9 million, and $8 million for the years ended December 31, 2014, 2013, and 2012, respectively.
(b) Primarily charges for late payments.
(c) Write-off of individual accounts receivable.

Baltimore Gas and Electric Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

BGE

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2015 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2014, 2013 and 2012

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012

   Consolidated Balance Sheets at December 31, 2014 and 2013

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2014, 2013 and 2012

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Baltimore Gas and Electric Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 46	$ 64	$ 17[b]	$ 60[a]	$ 67
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	1	—	—	1	—
For the year ended December 31, 2013					
Allowance for uncollectible accounts	$ 40	$ 43	$ 1	$ 38[a]	$ 46
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2012					
Allowance for uncollectible accounts	$ 38	$ 45	$ —	$ 43[a]	$ 40
Deferred tax valuation allowance	—	1	—	—	1
Reserve for obsolete materials	—	1	—	—	1

(a) Write-off of individual accounts receivable.
(b) Primarily charges for late payments.

Exhibits required by Item 601 of Regulation S-K:

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
2-1	Agreement and Plan of Merger dated as of April 28, 2011 by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc. (File No. 001-16169, Form 8-K dated April 28, 2011, Exhibit No. 2-1).
2-2	Distribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Constellation Energy Group, Inc. and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-3).
2-3	Contribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Energy Delivery Company, LLC and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-4).
2-4	Contribution Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Ventures Company, LLC and Exelon Generation Company, LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-5).
2-5	Purchase Agreement dated as of August 8, 2012 by and between Constellation Power Source Generation, Inc. and Raven Power Holdings, LLC. (File No. 333-85496, Form 10-Q for the quarter ended September 30, 2012, Exhibit 2-1).
2-6	Master Agreement, dated as of October 26, 2010, by and between Electricite de France, S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 1, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
2-7	Put Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., Constellation Nuclear, LLC, and Constellation Energy Nuclear Group, LLC. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 8, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
2-8	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., Baltimore Gas and Electric Company and RF HoldCo LLC. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
2-9	Purchase Agreement, dated as of February 4, 2010, by and between RF HoldCo LLC and GSS Holdings (Baltimore Gas and Electric Company Utility), Inc. (Designated as Exhibit No. 99.3 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
2-10-1	Agreement and Plan of Merger, dated as of April 29, 2014, by and among Exelon Corporation, Pepco Holdings, Inc. and Purple Acquisition Corp. (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit 2.1).

Exhibit No.	Description
2-10-2	Amended and Restated Agreement and Plan of Merger, dated as of July 18, 2014, among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp. (File No. 001-16169, Form 8-K dated July 21, 2014, Exhibit 2.1).
2-10-3	Subscription Agreement for Series A Non-Voting Non-Convertible Preferred Stock, dated as of April 29, 2014, by and between Pepco Holdings, Inc. and Exelon Corporation (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit 2.2).
3-1	Amended and Restated Articles of Incorporation of Exelon Corporation, as amended May 8, 2007 (File No. 001-16169, Form 10-Q for the quarter ended September 30, 2008, Exhibit 3-1-2).
3-2	Exelon Corporation Amended and Restated Bylaws, effective as of March 12, 2012 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit 3-1).
3-3	Certificate of Formation of Exelon Generation Company, LLC (Registration Statement No. 333-85496, Form S-4, Exhibit 3-1).
3-4	First Amended and Restated Operating Agreement of Exelon Generation Company, LLC executed as of January 1, 2001 (File No. 333-85496, 2003 Form 10-K, Exhibit 3-8).
3-5	Restated Articles of Incorporation of Commonwealth Edison Company Effective February 20, 1985, including Statements of Resolution Establishing Series, relating to the establishment of three new series of Commonwealth Edison Company preference stock known as the “$9.00 Cumulative Preference Stock,” the “$6.875 Cumulative Preference Stock” and the “$2.425 Cumulative Preference Stock” (File No. 1-1839, 1994 Form 10-K, Exhibit 3-2).
3-6	Commonwealth Edison Company Amended and Restated By-Laws, Effective January 23, 2006 As Further Amended January 28, 2008 and July 27, 2009. (File No. 001-1839, Form 8-K dated July 27, 2009, Exhibit 3.1).
3-7	Amended and Restated Articles of Incorporation of PECO Energy Company (File No. 1-01401, 2000 Form 10-K, Exhibit 3-3).
3-8	PECO Energy Company Amended Bylaws (File 000-16844, Form 8-K dated May 6, 2009, Exhibit 99.1).
3-9	Articles of Amendment to the Charter of Baltimore Gas and Electric Company as of February 2, 2010. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File No. 1-1910).
3-10	Articles of Restatement to the Charter of Baltimore Gas and Electric Company, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, filed by Baltimore Gas and Electric Company, File No. 1-1910).
3-11	Bylaws of Baltimore Gas and Electric Company, as amended and restated as of May 10, 2012. (File No. 1-16169, 2013 Form 10-K, Exhibit 3-11).
3-12	Operating Agreement, dated as of February 4, 2010, by and among RF HoldCo LLC, Constellation Energy Group, Inc. and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File Nos. 1-12869 and 1-1910).
4-1	First and Refunding Mortgage dated May 1, 1923 between The Counties Gas and Electric Company (predecessor to PECO Energy Company) and Fidelity Trust Company, Trustee (U.S. Bank National Association, as current successor trustee), (Registration No. 2-2281, Exhibit B-1).

Exhibit No.	Description		
4-1-2	Reserved.		
4-1-3	Supplemental Indentures to PECO Energy Company's First and Refunding Mortgage:		
	Dated as of	**File Reference**	**Exhibit No.**
	May 1, 1927	2-2881	B-1(c)
	March 1, 1937	2-2881	B-1(g)
	December 1, 1941	2-4863	B-1(h)
	November 1, 1944	2-5472	B-1(i)
	December 1, 1946	2-6821	7-1(j)
	September 1, 1957	2-13562	2(b)-17
	May 1, 1958	2-14020	2(b)-18
	March 1, 1968	2-34051	2(b)-24
	March 1, 1981	2-72802	4-46
	March 1, 1981	2-72802	4-47
	December 1, 1984	1-01401, 1984 Form 10-K	4-2(b)
	March 1, 1993	1-01401, 1992 Form 10-K	4(e)-86
	May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-88
	May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-89
	April 15, 2004	0-6844, September 30, 2004 Form 10-Q	4-1-1
	September 15, 2006	000-16844, Form 8-K dated September 25, 2006	4.1
	March 1, 2007	000-16844, Form 8-K dated March 19, 2007	4.1
	March 15, 2009	000-16844, Form 8-K dated March 26, 2009	4.1
	September 1, 2012	000-16844, Form 8-K dated September 17, 2012	4.1
	September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1
	September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1
	September 1, 2014	000-16169, Form 8-K dated September 15, 2014	4.1
4-2	Exelon Corporation Direct Stock Purchase Plan (Registration Statement No. 333-183751, Form S-3, Prospectus).		

Exhibit No.	Description
4-3	Mortgage of Commonwealth Edison Company to Illinois Merchants Trust Company, Trustee (BNY Mellon Trust Company of Illinois, as current successor Trustee), dated July 1, 1923, as supplemented and amended by Supplemental Indenture thereto dated August 1, 1944. (Registration No. 2-60201, Form S-7, Exhibit 2-1).
4-3-1	Supplemental Indentures to Commonwealth Edison Company Mortgage.

Dated as of	File Reference	Exhibit No.
August 1, 1946	2-60201, Form S-7	2-1
April 1, 1953	2-60201, Form S-7	2-1
March 31, 1967	2-60201, Form S-7	2-1
April 1, 1967	2-60201, Form S-7	2-1
February 28, 1969	2-60201, Form S-7	2-1
May 29, 1970	2-60201, Form S-7	2-1
June 1, 1971	2-60201, Form S-7	2-1
April 1, 1972	2-60201, Form S-7	2-1
May 31, 1972	2-60201, Form S-7	2-1
June 15, 1973	2-60201, Form S-7	2-1
May 31, 1974	2-60201, Form S-7	2-1
June 13, 1975	2-60201, Form S-7	2-1
May 28, 1976	2-60201, Form S-7	2-1
June 3, 1977	2-60201, Form S-7	2-1
May 17, 1978	2-99665, Form S-3	4-3
August 31, 1978	2-99665, Form S-3	4-3
June 18, 1979	2-99665, Form S-3	4-3
June 20, 1980	2-99665, Form S-3	4-3
April 16, 1981	2-99665, Form S-3	4-3
April 30, 1982	2-99665, Form S-3	4-3
April 15, 1983	2-99665, Form S-3	4-3
April 13, 1984	2-99665, Form S-3	4-3
April 15, 1985	2-99665, Form S-3	4-3
April 15, 1986	33-6879, Form S-3	4-9
January 15, 1994	1-1839, 1993 Form 10-K	4-15
January 13, 2003	1-1839, Form 8-K dated January 22, 2003	4-4
March 14, 2003	1-1839, Form 8-K dated April 7, 2003	4-4
February 22, 2006	1-1839, Form 8-K dated March 6, 2006	4.1
August 1, 2006	1-1839, Form 8-K dated August 28, 2006	4.1

Exhibit No.	Description		
	Dated as of	File Reference	Exhibit No.
	September 15, 2006	1-1839, Form 8-K dated October 2, 2006	4.1
	March 1, 2007	1-1839, Form 8-K dated March 23, 2007	4.1
	August 30, 2007	1-1839, Form 8-K dated September 10, 2007	4.1
	December 20, 2007	1-1839, Form 8-K dated January 16, 2008	4.1
	March 10, 2008	1-1839, Form 8-K dated March 27, 2008	4.1
	July 12, 2010	001-01839, Form 8-K dated August 2, 2010	4.1
	January 4, 2011	001-01839, Form 8-K dated January 18, 2011	4.1
	August 22, 2011	001-01839, Form 8-K dated September 7, 2011	4.1
	September 17, 2012	001-01839, Form 8-K dated October 1, 2012	4.1
	August 1, 2013	001-01839, Form 8-K dated August 19, 2013	4.1
	January 2, 2014	001-01839, Form 8-K dated January 10, 2014	4.1
	October 28, 2014	001-1839, Form 8-K dated November 10, 2014	4.1

4-3-2	Instrument of Resignation, Appointment and Acceptance dated as of February 20, 2002, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923, and Indentures Supplemental thereto, regarding corporate trustee (File No. 1-1839, 2001 Form 10-K, Exhibit 4-4-2).
4-3-3	Instrument dated as of January 31, 1996, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923 and Indentures Supplemental thereto, regarding individual trustee (File No. 1-1839, 1995 Form 10-K, Exhibit 4-29).
4-4	Indenture dated as of September 1, 1987 between Commonwealth Edison Company and Citibank, N.A. (U.S. Bank National Association, as current successor trustee), Trustee relating to Notes (Registration No. 33-20619, Form S-3, Exhibit 4-13).
4-5	Indenture dated December 19, 2003 between Exelon Generation Company, LLC and U.S. Bank National Association (File No. 333-85496, 2003 Form 10-K, Exhibit 4-6).
4-6	Indenture to Subordinated Debt Securities dated as of June 24, 2003 between PECO Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.1).
4-7	Form of 4.25% Senior Note due 2022 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.1).
4-8	Form of 5.60% Senior Note due 2042 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.2).

Exhibit No.	Description
4-9	Form of 2.80% Senior Note due 2022 issued by Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated August 17, 2012, Exhibit 4.1).
4-10	Form of 3.35% Senior Note due 2023 Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated June 17, 2013, Exhibit 4.1).
4-11	Form of 6.000% Senior Secured Notes due 2033 issued by Exelon Generation Company, LLC (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.2).
4-12	Preferred Securities Guarantee Agreement between PECO Energy Company, as Guarantor, and U.S. Bank National Association, as Trustee, dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.2).
4-13	PECO Energy Capital Trust IV Amended and Restated Declaration of Trust among PECO Energy Company, as Sponsor, U.S. Bank Trust National Association, as Delaware Trustee and Property Trustee, and J. Barry Mitchell, George R. Shicora and Charles S. Walls as Administrative Trustees dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.3).
4-14	Indenture dated May 1, 2001 between Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 1-16169, June 30, 2005 Form 10-Q, Exhibit 4-10).
4-15	Form of $800,000,000 4.90% senior notes due 2015 dated June 9, 2005 issued by Exelon Corporation (File No. 1-16169, Form 8-K dated June 9, 2005, Exhibit 99.2).
4-16	Form of $500,000,000 5.625% senior notes due 2035 dated June 9, 2005 issued by Exelon Corporation (File No. 1-16169, Form 8-K dated June 9, 2005, Exhibit 99.3).
4-17	Indenture dated as of September 28, 2007 from Exelon Generation Company, LLC to U.S. Bank National Association, as trustee (File 333-85496, Form 8-K dated September 28, 2007, Exhibit 4.1).
4-18	Form of 5.20% Exelon Generation Company, LLC Senior Note due 2019 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.1).
4-19	Form of 6.25% Exelon Generation Company, LLC Senior Note due 2039 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.2).
4-20	Form of 4.00% Exelon Generation Company, LLC Senior Note due 2020 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.1).
4-21	Form of 5.75% Exelon Generation Company, LLC Senior Note due 2041 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.2).
4-22	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, filed by Constellation Energy Group, Inc., File No. 333-75217.)
4-23	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, filed by Constellation Energy Group, Inc., File No. 333-102723).
4-24	Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991).

Exhibit No.	Description
4-25	First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (Designated as Exhibit 4(a) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869).
4-26	Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
4-27	Indenture, dated as of September 30, 2013, among Continental Wind, LLC, the guarantors party thereto and Wilmington Trust, National Association, as trustee (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.1).
4-28	Indenture dated July 1, 1985, between Baltimore Gas and Electric Company and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, filed by Baltimore Gas and Electric Company, File No. 1-1910).
4-29	Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee (including form of Baltimore Gas and Electric Company Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibit Nos. 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01).
4-30	Indenture dated as of July 24, 2006 between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(b) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991).
4-31	Supplemental Indenture No. 1, dated as of October 1, 2009, to the Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
4-32	Baltimore Gas and Electric Company Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit No. 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01).
4-33	Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (Designated as Exhibit 4.1 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).
4-34	Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (Designated as Exhibit No. 4(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Baltimore Gas and Electric Company, File No. 1 1910).

Exhibit No.	Description
4-35	Replacement Capital Covenant dated June 27, 2008. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869).
4-36	Amendment to Replacement Capital Covenant, dated as of March 12, 2012, amending the Replacement Capital Covenant, dated as of June 27, 2008 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 99.4).
4-37	Officers' Certificate, dated December 14, 2010, establishing the 5.15% Notes due December 1, 2020 of Constellation Energy Group, Inc., with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated December 14, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
4-38	Officers' Certificate, November 16, 2011, establishing the 3.50% Notes due November 15, 2021 of Baltimore Gas and Electric Company, with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated November 16, 2011, filed by Baltimore Gas and Electric Company, File No. 1-1910).
4-39-1	Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee. (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.1).
4-39-2	First Supplemental Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee.(File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.2).
4-39-3	Form of 2.50% Notes due 2024 (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.1).
4-39-4	Purchase Contract and Pledge Agreement, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary. (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.4).
4-39-5	Form of Remarketing Agreement (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.5).
4-39-6	Form of Corporate Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.6).
4-39-7	Form of Treasury Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.7).
10-1	Facility Credit Agreement, dated as of February 6, 2014, among ExGen Renewables I Holding, LLC and Barclays Bank PLC (File No. 333-85496, Form 8-K dated February 12, 2014, Exhibit 10.1).
10-1-1	Credit Agreement, dated as of September 18, 2014, among ExGen Texas Power, LLC, ExGen Texas Power Holdings, LLC, Wolf Hollow I Power, LLC, Colorado Bend I Power, LLC, Laporte Power, LLC, Handley Power, LLC and Mountain Creek Power, LLC, the lenders party thereto from time to time, Bank of America, N.A., as administrative agent and collateral agent, and Wilmington Trust, National Association, as depositary agent. (File No. 1-16169, Form 8-K dated September 18, 2014, Exhibit 10.1).
10-2	Exelon Corporation Non-Employee Directors' Deferred Stock Unit Plan (As Amended and Restated Effective January 1, 2011). * (File No. 001-16169, 2010 Form 10-K, Exhibit 10.1).
10-3	Form of Exelon Corporation Unfunded Deferred Compensation Plan for Directors (as amended and restated Effective March 12, 2012). *
10-4	Reserved.

Exhibit No.	Description
10-5	Form of Restricted Stock Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-1).
10-6	Forms of Transferable Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-2).
10-7	Forms of Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-3).
10-8	Unicom Corporation Deferred Compensation Unit Plan, as amended *(File Nos. 1-11375 and 1-1839, 1995 Form 10-K, Exhibit 10-12).
10-9	Amendment Number One to the Unicom Corporation Deferred Compensation Unit Plan, as amended January 1, 2008 * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.16).
10-10	Unicom Corporation Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-12).
10-11	Commonwealth Edison Company Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-13).
10-12	Exelon Corporation Supplemental Management Retirement Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.19).
10-13	PECO Energy Company Supplemental Pension Benefit Plan (As Amended and Restated Effective January 1, 2009) (File No. 000-16844, 2008 Form 10-K, Exhibit 10.20).
10-14	Exelon Corporation Annual Incentive Plan for Senior Executives (As Amended Effective January 1, 2014 * (File No. 1-16169, Exelon Proxy Statement dated April 1, 2014, Appendix A).
10-15	Form of change in control employment agreement for senior executives effective January 1, 2009 * (File No. 001-16169. 2008 Form 10-K, Exhibit 10.23).
10-16	Form of change in control employment agreement (amended and restated as of January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.24).
10-17	Exelon Corporation Employee Stock Purchase Plan, as amended and restated effective July 1, 2013. (File No. 1-16169, Schedule 14A dated March 14, 2013 Appendix A).
10-18	Exelon Corporation 2006 Long-Term Incentive Plan (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex H).
10-19	Form of Stock Option Grant Instrument under the Exelon Corporation 2006 Long-Term Incentive Plan (File No. 1-16169, Form 8-K filed January 27, 2006, Exhibit 99.2).
10-20	Exelon Corporation Employee Stock Purchase Plan for Unincorporated Subsidiaries (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex I).
10-21	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective April 1, 2013).* (File No. 001-16169, 2013 Form 10-K, Exhibit 10.21).
10-22	Form of Separation Agreement under Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.30).
10-23	Facility Credit Agreement, dated as of November 4, 2010, among Exelon Generation Company, LLC and UBS AG, Stamford Branch (File No. 333-85496, Form 8-K dated February 22, 2011, Exhibit No. 10-1).

Exhibit No.	Description
10-24	Exelon Corporation Executive Death Benefits Plan dated as of January 1, 2003 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-52).
10-25	First Amendment to Exelon Corporation Executive Death Benefits Plan, Effective January 1, 2006 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-53).
10-26	Amendment Number One to the Exelon Corporation 2006 Long-Term Incentive Plan, Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-54).
10-27	Amendment Number Two to the Exelon Corporation 2006 Long-Term Incentive Plan (As Amended and Restated Effective January 28, 2002), Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-55).
10-28	Exelon Corporation Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-56).
10-29	Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-57).
10-30	Commonwealth Edison Company Long-Term Incentive Plan, Effective January 1, 2007 (File No. 1-16169, March 31, 2007 Form 10-Q, Exhibit 10-1).
10-31	Amendment Number One to the Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, June 30, 2007 Form 10-Q, Exhibit 10-3).
10-32	Restricted stock unit award agreement (File 1-16169, Form 8-K dated August 31, 2007, Exhibit 99.1).
10-33	Reserved.
10-34	Form of Exelon Corporation 2011 Long-Term Incentive Plan, as amended effective December 18, 2014.
10-34-1	Form of Exelon Corporation Long-Term Incentive Program, as amended and restated as of January 1, 2014.
10-35	Form of Change in Control Employment Agreement Effective February 10, 2011. * (File 1-16169, 2011 Form 10-K, Exhibit 10-44).
10-36	Credit Agreement for $500,000,000 dated as of March 23, 2011 between Exelon Corporation and Various Financial Institutions (File No. 001-16169, Form 8-K dated March 23, 2011, Exhibit No. 10-2).
10-37	Credit Agreement for $5,300,000,000 dated as of March 23, 2011 between Exelon Generation Company, LLC and Various Financial Institutions (File No. 333-85496, Form 8-K dated March 23, 2011, Exhibit No. 10-3).
10-38	Credit Agreement for $600,000,000 dated as of March 23, 2011 between PECO Energy Company and Various Financial Institutions (File No. 000-16844, Form 8-K dated March 23, 2011, Exhibit No. 10-4).
10-39	Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, Various Financial Institutions, as Lenders, and JP Morgan Chase Bank, N.A., as Administrative Agent (File No. 001-01839, Form 8-K dated March 28, 2012, Exhibit No. 99-1).
10-40	Amendment No. 3 to Credit Agreement dated as of March 23, 2011 among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated August 10, 2013, Exhibit No. 99-1).

Exhibit No.	Description
10-41	Amendment No. 1 to Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, as Borrower, the various financial institutions named therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-1839, Form 8-K dated August 10, 2013, Exhibit No. 99-2).
10-42	Amendment No. 1 to Credit Agreement, dated as of December 21, 2011, to the Credit Agreement dated as of March 23, 2011, among Exelon Generation Company, LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 4-6).
10-43	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-44	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. * (Designated as Exhibit No. 10(c) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-45	Constellation Energy Group, Inc. Benefits Restoration Plan, amended and restated effective June 1, 2010. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-46	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. * (Designated as Exhibit No. 10 (e) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-47	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. * (Designated as Exhibit No. 10(f) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-48	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. * (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-49	Constellation Energy Group, Inc. Executive Supplemental Benefits Plan, as amended and restated. * (Designated as Exhibit No. 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-50	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-51	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-52	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).

Exhibit No.	Description
10-53	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(d) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-54	Constellation Energy Group, Inc. Amended and Restated 2007 Long-Term Incentive Plan. * (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated June 4, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-55	Form of Grant Agreement for Stock Units with Sales Restriction. * (Designated as Exhibit No. 10(x) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-56	Rate Stabilization Property Servicing Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as servicer (Designated as Exhibit 10.2 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).
10-57	Administration Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as administrator (Designated as Exhibit 10.3 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).
10-58	Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 12, 2009, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-59	Amendment No. 1 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(s) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-60	Amendment No. 2 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(t) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-61	Amendment No. 3 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-62	Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).

Exhibit No.	Description
10-63	Settlement Agreement between EDF Inc., Exelon Corporation, Exelon Energy Delivery Company, LLC, Constellation Energy Group, Inc. and Baltimore Gas and Electric Company dated January 16, 2012. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated January 19, 2012, File Nos. 1-12869 and 1-1910).
10-64 - 10-70	Reserved.
10-71-1	Commitment Letter for $7.221 Billion Senior Unsecured Bridge Facility, dated April 29, 2014 (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit No. 10.1).
10-71-2	364-Day Bridge Term Loan Agreement, dated as of May 30, 2014, among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and Barclays Bank PLC, as Administrative Agent (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit No. 10.1).
10-71-3	Amendment No. 4 to Credit Agreement, dated May 30, 2014, among Exelon Corporation, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.2).
10-71-4	Amendment No. 4 to Credit Agreement, dated May 30, 2014, among Exelon Generation Company, LLC, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.3).
10-71-5	Amendment No. 3 to Credit Agreement, dated May 30, 2014, among PECO Energy Company, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.4).
10-71-6	Amendment No. 2 to Credit Agreement, dated as of May 30, 2014, among Baltimore Gas and Electric Company, as Borrower, the financial institutions signatory therein, as Lenders and The Royal Bank of Scotland plc, as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.6).
10-72-1	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Barclays Capital, Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.1).
10-72-2	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.2).
10-72-3	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Barclays Capital, Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.3).
10-72-4	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.4).
12-1	Exelon Corporation Computation of Ratio of Earnings to Fixed Charges.
12-2	Exelon Generation Company, LLC Computation of Ratio of Earnings to Fixed Charges.
12-3	Commonwealth Edison Company Computation of Ratio of Earnings to Fixed Charges.
12-4	PECO Energy Company Computation of Ratio of Earnings to Fixed Charges.
12-5	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preference Stock Dividends.

Exhibit No.	Description
14	Exelon Code of Conduct, as amended March 12, 2012 (File No. 1-16169, Form 8-K dated March 14, 2012, Exhibit No. 14-1).
	Subsidiaries
21-1	Exelon Corporation
21-2	Exelon Generation Company, LLC
21-3	Commonwealth Edison Company
21-4	PECO Energy Company
21-5	Baltimore Gas and Electric Company
	Consent of Independent Registered Public Accountants
23-1	Exelon Corporation
23-2	Exelon Generation Company, LLC
23-3	Commonwealth Edison Company
23-4	PECO Energy Company
23-5	Baltimore Gas and Electric Company
	Power of Attorney (Exelon Corporation)
24-1	Anthony K. Anderson
24-2	Ann C. Berzin
24-3	John A. Canning, Jr.
24-4	Christopher M. Crane
24-5	Yves C. de Balmann
24-6	Nicholas DeBenedictis
24-7	Paul L. Joskow
24-8	Reserved.
24-9	Robert J. Lawless
24-10	Richard W. Mies
24-11	William C. Richardson
24-12	John W. Rogers, Jr.
24-13	Mayo A. Shattuck III
24-14	Stephen D. Steinour
	Power of Attorney (Commonwealth Edison Company)
24-15	James W. Compton
24-16	Christopher M. Crane
24-17	A. Steven Crown
24-18	Nicholas DeBenedictis
24-19	Peter V. Fazio, Jr.
24-20	Michael Moskow
24-21	Denis O'Brien
24-22	Anne R. Pramaggiore
24-23	Reserved.

Exhibit No.	Description
	Power of Attorney (PECO Energy Company)
24-24	Craig L. Adams
24-25	Christopher M. Crane
24-26	M. Walter D'Alessio
24-27	Nicholas DeBenedictis
24-28	Reserved.
24-29	Reserved.
24-30	Denis O'Brien
24-31	Ronald Rubin
	Power of Attorney (Baltimore Gas and Electric Company)
24-32	Ann C. Berzin
24-33	Christopher M. Crane
24-34	Michael E. Cryor
24-35	James R. Curtiss
24-36	Calvin G. Butler, Jr.
24-37	Joseph Haskins, Jr.
24-38	Carla D. Hayden
24-39	Denis O'Brien
24-40	Michael D. Sullivan
	Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Annual Report on Form 10-K for the year ended December 31, 2013 filed by the following officers for the following registrants:
31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Jonathan W. Thayer for Exelon Corporation
31-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	Filed by Craig L. Adams for PECO Energy Company
31-8	Filed by Phillip S. Barnett for PECO Energy Company
31-9	Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
31-10	Filed by David M. Vahos Baltimore Gas and Electric Company
	Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Annual Report on Form 10-K for the year ended December 31, 2013 filed by the following officers for the following registrants:
32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Jonathan W. Thayer for Exelon Corporation
32-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
32-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC

Exhibit No.	Description
32-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	Filed by Craig L. Adams for PECO Energy Company
32-8	Filed by Phillip S. Barnett for PECO Energy Company
32-9	Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
32-10	Filed by David M. Vahos Baltimore Gas and Electric Company
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

* Compensatory plan or arrangements in which directors or officers of the applicable registrant participate and which are not available to all employees.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2014.

EXELON CORPORATION

By: /s/ Christopher M. Crane
Name: **Christopher M. Crane**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2015.

Signature	Title
/s/ Christopher M. Crane **Christopher M. Crane**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ Jonathan W. Thayer **Jonathan W. Thayer**	Senior Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Duane M. DesParte **Duane M. DesParte**	Senior Vice President and Corporate Controller (Principal Accounting Officer)

This annual report has also been signed below by Darryl M. Bradford, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Anthony K. Anderson
Ann C. Berzin
John A. Canning, Jr.
Yves C. de Balmann
Nicholas DeBenedictis
Paul L. Joskow
Robert J. Lawless
Richard W. Mies
William C. Richardson
John W. Rogers, Jr.
Mayo A. Shattuck III
Stephen D. Steinour

By: /s/ Darryl M. Bradford
Name: **Darryl M. Bradford**

February 13, 2015

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2015.

EXELON GENERATION COMPANY, LLC

By: /s/ Kenneth W. Cornew
Name: **Kenneth W. Cornew**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2015.

Signature	Title
/s/ Kenneth W. Cornew **Kenneth W. Cornew**	President and Chief Executive Officer (Principal Executive Officer)
/s/ Bryan P. Wright **Bryan P. Wright**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Robert M. Aiken **Robert M. Aiken**	Chief Accounting Officer (Principal Accounting Officer)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2015.

COMMONWEALTH EDISON COMPANY

By: /s/ Anne R. Pramaggiore
Name: **Anne R. Pramaggiore**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2015.

Signature	Title
/s/ Anne R. Pramaggiore **Anne R. Pramaggiore**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ Joseph R. Trpik Jr. **Joseph R. Trpik, Jr.**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Gerald J. Kozel **Gerald J. Kozel**	Vice President and Controller (Principal Accounting Officer)
/s/ Christopher M. Crane **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Anne R. Pramaggiore, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

James W. Compton
A. Steven Crown
Nicholas DeBenedictis
Peter V. Fazio, Jr.
Michael Moskow
Denis P. O'Brien

By: /s/ Anne R. Pramaggiore
Name: **Anne R. Pramaggiore**

February 13, 2015

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2015.

PECO ENERGY COMPANY

By: /s/ Craig L. Adams
Name: **Craig L. Adams**
Title: **Chief Executive Officer and President**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2015.

Signature	Title
/s/ Craig L. Adams **Craig L. Adams**	Chief Executive Officer and President (Principal Executive Officer) and Director
/s/ Phillip S. Barnett **Phillip S. Barnett**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Scott A. Bailey **Scott A. Bailey**	Vice President and Controller (Principal Accounting Officer)
/s/ Christopher M. Crane **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Craig L. Adams, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

M. Walter D'Alessio **Denis P. O'Brien**
Nicholas DeBenedictis **Ronald Rubin**

By: /s/ Craig L. Adams
Name: **Craig L. Adams**

February 13, 2015

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2015.

BALTIMORE GAS AND ELECTRIC COMPANY

By: /s/ Calvin G. Butler, Jr.
Name: **Calvin G. Butler, Jr.**
Title: **Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2015.

Signature	Title
/s/ Calvin G. Butler, Jr. **Calvin G. Butler, Jr.**	Chief Executive Officer (Principal Executive Officer)
/s/ David M. Vahos **David M. Vahos**	Vice President, Chief Financial Officer, and Treasurer (Principal Financial Officer)
/s/ Matthew N. Bauer **Matthew N. Bauer**	Vice President and Controller (Principal Accounting Officer)
/s/ Christopher M. Crane **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Calvin G. Butler, Jr., Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Ann C. Berzin
Michael E. Cryor
James R. Curtiss
Michael D. Sullivan
Joseph Haskins, Jr.
Carla D. Hayden
Denis O'Brien

By: /s/ Calvin G. Butler, Jr.
Name: **Calvin G. Butler, Jr.**

February 13, 2015

Exelon Corporation
Unfunded Deferred Compensation Plan for Directors
(Amended and Restated Effective March 12, 2012)

The purpose of this Unfunded Deferred Compensation Plan for Directors (the "Plan") is to permit Directors of Exelon Corporation ("Exelon") to elect to defer receipt of directors' fees. The Plan as set forth herein is an amendment and restatement of the Plan as originally adopted effective October 20, 2000 and previously amended and restated as of January 1, 2009 and January 1, 2011, and is a successor to the PECO Energy Company Unfunded Deferred Compensation Plan for Directors (the "Prior Plan").

1. Administration . The Plan shall be administered by the Corporate Secretary of Exelon or his or her designee (the "Secretary"), or such other individual or individuals as designated by the Board of Directors of Exelon (the "Exelon Board"). The Secretary shall interpret the Plan and establish such rules and regulations of plan administration that he or she deems appropriate. The cost of plan administration shall be paid by Exelon and its participating subsidiaries, and shall not be charged against the deferred accounts of Plan participants.

2. Eligibility . All Directors of Exelon (other than full-time employees of Exelon or its subsidiaries) shall be eligible to participate in the Plan. Effective as of January 1, 2011, all Directors of Commonwealth Edison Company ("ComEd") and PECO Energy Company ("PECO") who are not full-time employees of Exelon or its subsidiaries shall also be eligible to participate in the Plan. In addition, effective as of March 12, 2012, all Directors of Baltimore Gas and Electric Company ("BGE") who are not full-time employees of Exelon or its subsidiaries shall also be eligible to participate in the Plan.

3. Deferrals . (a) Prior to the first day of each calendar year, each eligible Director may elect in writing to defer the receipt of all or a portion of his or her directors' fees earned with respect to his or her service on the board of directors of Exelon, ComEd, PECO and/or BGE (each such board of directors, a "Board") for such calendar year, by filing a written Director's deferral agreement form with the Secretary with respect to each such Board on which the Director serves. A Director who first becomes eligible to participate in the Plan after the first day of any calendar year shall be permitted to make the election described in this Section 3 not later than 30 days after becoming eligible to participate in the Plan, and such election shall apply only to directors' fees earned during the remainder of such calendar year. In all events, each deferral election made under this Plan shall apply only to fees earned after the date of such election. Deferred amounts under the Plan, together with deferred amounts and attributable earnings under the Prior Plan, shall be credited to a deferral account in the participant's name ("Deferral Account") for later distribution. Each participant's Deferral Account shall be a bookkeeping entry only, and none of Exelon, ComEd, PECO or BGE shall be required to fund the Deferral Account. Any assets that may be held to fund a Deferral Account shall at all times remain unrestricted assets of Exelon, ComEd, PECO or BGE in its corporate capacity and not as a fiduciary, and shall be subject to the claims of its general creditors. Pending distribution, each participant's Deferral Account shall be credited with earnings or interest as provided in Section 3(b).

(b) (1) For purposes of measuring the earnings or losses credited to a participant's Deferral Account, the participant may select, from among the investment funds available from time to time under the Exelon Corporation Employee Savings Plan (the "Savings Plan"), the investment funds in which all or part of his or her Deferral Account shall be deemed to be invested.

(2) The participant shall make an investment designation in the form and manner prescribed by the Secretary, which shall remain effective until another valid designation has been made by the participant as herein provided. The Secretary may, but need not, permit separate investment designations with respect to amounts attributable to fees earned with respect to service on each Board. The participant may amend his or her investment designation at such times and in such manner as prescribed by the Secretary. A timely change to the participant's investment designation shall become effective as soon as administratively practicable after such designation is submitted.

(3) The investment funds deemed to be made available to the participant, and any limitation on the maximum or minimum percentages of the participant's Deferral Account that may be deemed to be invested in any particular fund, shall be the same as available or in effect from time to time under the Savings Plan.

(4) Except as provided below, the participant's Deferral Account shall be deemed to be invested in accordance with his or her investment designations, and the Deferral Account shall be credited with earnings (or losses) as if invested as directed by the participant.

To the extent that the participant does not furnish complete investment instructions, then the Deferral Account shall be deemed invested in the default investment fund then in effect under the Savings Plan. The Deferral Accounts maintained pursuant to the Plan are for bookkeeping purposes only and Exelon is under no obligation to invest such amounts.

Exelon shall provide a statement to each participant not less frequently than annually showing such information as is appropriate, including the aggregate amount in his or her Deferral Account, as of a reasonably current date.

4. Distributions . (a) The amount credited to a participant's Deferral Account with respect to his or her participation on each Board shall be distributed to the participant in, or beginning in, April of the first year beginning after the occurrence of one of the following

distribution events, as the participant shall direct in his or her Benefit Distribution Election Form: (i) the participant's separation from service, within the meaning of Section 409A of the Internal Revenue Code of 1986, as amended (the "Code"), as a Director of Exelon, ComEd, PECO, BGE and their affiliates, (ii) the participant's 65th birthday or (iii) the participant's 72 nd birthday. Distributions shall be paid in a lump sum payment or in annual installments over a period of up to 10 years, as the participant shall direct in his or her Benefit Distribution Election Form. Each installment payment shall be determined by multiplying the balance remaining to the credit of the Deferral Account as of March 31 of such year (including earnings or interest credited under Section 3) by a fraction, the numerator of which is "1" and the denominator of which is the number of years (including the current year) for which payments are yet to be made. Any unpaid balance in the Deferral Account shall be credited with earnings or interest as provided in Section 3. In the event a Director who has elected a distribution event based on his or her 65 th or 72 nd birthday continues to serve as a Director after the date such distributions commence, then in the year prior to the year in which such distributions commence such Director shall file a new Benefit Distribution Election Form governing any amounts credited to his or her Deferral Account after the date such distributions commence. If the Director does not file such new Benefit Distribution Election Form, then the Director shall be deemed to have elected to receive a lump sum distribution of any such amounts upon the Director's separation from service.

(b) Except as permitted under Section 4(c) or 4(d), each Director must submit a Benefit Distribution Election Form for amounts attributable to fees earned with respect to service on a Board at the time such Director makes his or her initial deferral election under the Plan with respect to his or her service on such Board (provided that a Director who participated in the Plan prior to January 1, 2009 and had not commenced distributions must have submitted such form not later than December 31, 2008). If a Director does not submit a Benefit Distribution Election Form

during this period, then such Director shall be deemed to have elected to receive the portion of his or her Account attributable to fees earned for service on such Board in the form of installments payments over a period of ten years upon the Director's separation from service.

(c) Notwithstanding Sections 4(a) and 4(b), each participant who had not commenced and was not scheduled to commence the receipt of distributions under the Plan on or before December 31, 2007 was permitted to submit a Benefit Distribution Election Form on or before June 30, 2007 which provided for the payment of such participant's Deferral Account (i) at any of the times and in any of the forms permitted under Section 4(a) of the Plan or (ii) in a lump sum payment in the first quarter of 2008; provided that such election did not cause any payment to be made in 2007 and did not apply to any payment that otherwise would be paid in 2007. This special election right was intended to comply with the transition rule set forth in IRS Notice 2005-1, Q&A-19(c), and extended in the preamble to regulations proposed under Section 409A of the Code and IRS Notice 2006-79, which permits participants in deferred compensation plans to change the date on which deferred compensation is payable.

(d) A Director may elect to change the time and/or method of his or her distributions payable under the Plan in accordance with procedures prescribed by the Secretary; provided that, in accordance with Section 409A of the Code, any such change in a distribution election (i) shall not be effective until 12 months after it is submitted to the Secretary, (ii) must be submitted to the Secretary at least 12 months prior to the date on which such distributions were previously scheduled to commence and (iii) must provide for distributions to commence at least five years after the date on which such distributions were previously scheduled to commence. No more than one such election change shall be permissible with respect to the portion of a Director's account attributable to service with any Board.

5. Death Benefits . Each participant shall designate a beneficiary or beneficiaries to receive any remaining amounts payable from his or her Deferral Account after the participant's death. The beneficiaries, and any priority or allocation between them, shall be designated in the manner specified by the Secretary. If a participant dies before the entire balance in his or her Deferral Account has been paid out, the remaining balance shall be paid to the beneficiary in a lump sum upon the participant's death. If the participant is not survived by a designated beneficiary, the participant's beneficiary shall be the participant's spouse, if living, or otherwise, the participant's estate. If a beneficiary survives the participant but dies before the entire balance payable to him or her has been distributed, any remaining balance shall be paid to the beneficiary's estate in a lump sum. In the absence of contrary proof, the participant shall be deemed to have survived any designated beneficiary. A participant may change his or her beneficiary designation under this Section at any time until his or her death by filing a written beneficiary designation with the Secretary, in the manner specified by the Secretary.

6. Unforeseeable Financial Emergency . The Secretary may, in his or her discretion, direct that a participant be paid an amount in cash (not in excess of the balance of his or her Deferral Account) sufficient to meet an unforeseeable emergency. An "unforeseeable emergency" means (i) a severe financial hardship to a Director resulting from an illness or accident of the Director, or the spouse or a dependent (as defined in Section 152(a) of the Code) of the Director, (ii) the loss of a Director's property due to casualty or (iii) such other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Director, within the meaning of Section 409A of the Code. A Director's written request for such a payment shall describe the circumstances which the Director believes justify the payment and an estimate of the amount necessary to eliminate the unforeseeable emergency. An immediate payment to satisfy an unforeseeable emergency will be made only to the extent necessary to satisfy the emergency need,

plus an amount necessary to pay any taxes reasonably anticipated as a result of such payment, and will not be made to the extent the need is or may be relieved through reimbursement or compensation, by insurance or otherwise or by liquidation of the Director's assets (to the extent such liquidation itself would not cause severe financial hardship). Any payment from a Director's Deferral Account on account of an unforeseeable emergency shall be deemed to cancel any Deferral Election of the Director then in effect and the Director shall not be permitted to participate in the Plan until the next following calendar year.

7. No Assignment or Alienation of Benefits . Except as hereinafter provided with respect to a domestic relations order, a participant's Deferral Account may not be voluntarily or involuntarily assigned or alienated. In cases of marital dispute, Exelon will observe the terms of the Plan unless and until ordered to do otherwise pursuant to a domestic relations order, as defined in Section 414(p)(1)(B) of the Code. As a condition of participation, a participant agrees to hold Exelon harmless from any claim that arises out of Exelon's obeying the terms of a domestic relations order, whether such order effects a judgment of such court or is issued to enforce a judgment or order of another court.

8. Amendment or Termination . The Plan may be altered, amended, suspended, or terminated at any time by the Exelon Board, provided that, except as otherwise provided herein or as permitted under Section 409A of the Code, no such action shall result in the distribution of amounts credited to the Deferral Accounts of any participant in any manner other than is provided in the Plan, nor shall such action reduce the availability of amounts previously deferred. To the extent permitted by Section 409A, the Exelon Board may, in its discretion, terminate the Plan with respect to Exelon, ComEd, PECO and/or BGE and accelerate the payment of all Deferral Accounts to the extent related to service on the Board for which the Plan is terminated:

(a) within 12 months of a corporate dissolution taxed under Section 331 of the Code, or with the approval of a bankruptcy court pursuant to 11 U.S.C. §503(b)(1)(A), provided that the payments with respect to each such Deferral Account are included in the Director's gross income in the later of (i) the calendar year in which the Plan termination occurs or (ii) the first calendar year in which the payments are administratively practicable;

(b) in connection with a "change in control event," as defined in, and to the extent permitted under, Treasury regulations promulgated under Section 409A of the Code or

(c) upon any other termination event permitted under Section 409A of the Code.

9. Compliance With Section 409A of the Code . The Plan is intended to comply with the provisions of Section 409A of the Code, and shall be interpreted and construed accordingly. Exelon shall have the discretion and authority to amend the Plan at any time to satisfy any requirements of Section 409A of the Code or guidance provided by the U.S. Treasury Department to the extent applicable to the Plan.

10. Governing Law . The Plan shall be governed by the law of the Commonwealth of Pennsylvania to the extent not preempted by applicable federal law.

EXELON CORPORATION

_____

Executive Vice President

EXELON CORPORATION

2011 LONG-TERM INCENTIVE PLAN

(As Amended Effective December 18, 2014)

I. INTRODUCTION

1.1 Purposes . The purposes of the Exelon Corporation 2011 Long-Term Incentive Plan (this " Plan ") are (i) to align the interests of the Company's stockholders and the recipients of awards under this Plan by increasing the proprietary interest of such recipients in the Company's growth and success, (ii) to advance the interests of the Company by attracting and retaining officers and other key management employees and (iii) to motivate such persons to act in the long-term best interests of the Company and its stockholders.

1.2 Certain Definitions .

" Affiliate " shall mean any Person (including a Subsidiary) that directly or indirectly controls, is controlled by, or is under common control with, the Company. For purposes of this definition the term "control" with respect to any Person means the power to direct or cause the direction of management or policies of such Person, directly or indirectly, whether through the ownership of Voting Securities, by contract or otherwise.

" Agreement " shall mean the written agreement evidencing an award hereunder between the Company and the recipient of such award.

" Beneficial Owner " shall mean such term as defined in Rule 13d-3 under the Exchange Act.

" Board " shall mean the Board of Directors of the Company.

" Cause " shall mean (a) with respect to an employee whose entitlement to severance benefits upon termination of employment is governed by an individual change in control agreement, the meaning of such term specified in such agreement, (b) with respect to an employee whose entitlement to severance benefits upon termination of employment is governed by the Exelon Corporation Senior Management Severance Plan or any other executive severance plan, as in effect from time to time, the meaning of such term specified in such plan, or (c) with respect to any other employee, the meaning of such term specified in the Exelon Corporation Severance Benefit Plan, as amended from time to time, or any successor plan thereto, regardless of whether such employee is eligible to participate in such plan.

" Change in Control " shall have the meaning set forth in Section 5.8.

" Code " shall mean the Internal Revenue Code of 1986, as amended.

" Committee " shall mean the Committee designated by the Board, consisting of two or more members of the Board, each of whom may be (i) a "Non-Employee Director" within the meaning of Rule 16b-3 under the Exchange Act, (ii) an "outside director" within the meaning of Section 162(m) of the Code and (iii) "independent" within the meaning of the rules of the New York Stock Exchange or, if the Common Stock is not listed on the New York Stock Exchange, within the meaning of the rules of the principal national stock exchange on which the Common Stock is then traded.

" Common Stock " shall mean the common stock, without par value, of the Company.

" Company " shall mean Exelon Corporation, a Pennsylvania corporation, or any successor thereto.

" Company Plan " shall have the meaning set forth in Section 5.8(b)(i).

" Corporate Transaction " shall have the meaning set forth in Section 5.8(a).

" Disability " shall have the meaning specified in any long term disability plan maintained by the Company in which the participant is eligible to participate; provided that a Disability shall not be deemed to have occurred until the Company has terminated such participant's employment in connection with such disability and the participant has commenced the receipt of long-term disability benefits under such plan. If an participant is not eligible to participate in a long-term disability plan maintained by the Company, then Disability shall mean a termination of such participant's employment by the Company due to the inability of such participant to perform the essential functions such participant's position, with or without reasonable accommodation, for a continuous period of at least twelve months, as determined solely by the Committee.

" Exchange Act " shall mean the Securities Exchange Act of 1934, as amended.

" Fair Market Value " shall mean the closing transaction price of a share of Common Stock as reported on the New York Stock Exchange on the date as of which such value is being determined or, if the Common Stock is not listed on the New York Stock Exchange, the closing transaction price of a share of Common Stock on the principal national stock exchange on which the Common Stock is traded on the date as of which such value is being determined or, if there shall be no reported transactions for such date, on the next preceding date for which transactions were reported; provided , however , that if the Common Stock is not listed on a national stock exchange or if Fair Market Value for any date cannot be so determined, Fair Market Value shall be determined by the Committee by whatever means or method as the Committee, in the good faith exercise of its discretion, shall at such time deem appropriate and in accordance with Section 409A of the Code.

" Free-Standing SAR " shall mean an SAR which is not granted in tandem with, or by reference to, an option, which entitles the holder thereof to receive, upon exercise, shares of Common Stock (which may be Restricted Stock), cash or a combination thereof with an aggregate value equal to the excess of the Fair Market Value of one share of Common Stock on the date of exercise over the base price of such SAR, multiplied by the number of such SARs which are exercised.

" Good Reason " shall mean (i) with respect to an employee whose entitlement to severance benefits upon termination of employment is governed by an individual change in control agreement, the meaning of such term specified in such agreement, or (ii) with respect to a employee whose entitlement to severance benefits upon termination of employment is governed by the Exelon Corporation Senior Management Severance Plan or any other executive severance plan, as in effect from time to time, the meaning of such term specified in such plan.

" Incentive Stock Option " shall mean an option to purchase shares of Common Stock that meets the requirements of Section 422 of the Code, or any successor provision, which is intended by the Committee to constitute an Incentive Stock Option.

" Incumbent Board " shall have the meaning set forth in Section 5.8(b)(ii).

" Nonqualified Stock Option " shall mean an option to purchase shares of Common Stock which is not an Incentive Stock Option.

" Performance Measures " shall mean the criteria and objectives, established by the Committee, which shall be satisfied or met (i) as a condition to the grant or exercisability of all or a portion of an option or SAR or (ii) during the applicable Restriction Period or Performance Period as a condition to the vesting of the holder's interest, in the case of a Restricted Stock Award, of the shares of Common Stock subject to such award, or, in the case of a Restricted Stock Unit Award or Performance Unit Award, to the holder's receipt of the shares of Common Stock subject to such award or of payment with respect to such award. To the extent necessary for an award to be qualified performance-based compensation under Section 162(m) of the Code and the regulations thereunder, such criteria and objectives shall include one or more of the following measures, each of which may be based on absolute standards or peer industry group comparatives and may be applied at various organizational levels (e.g., corporate, business unit, division):
(1) cumulative shareholder value added (SVA), (2) customer satisfaction, (3) revenue, (4) primary or fully-diluted earnings per share of Common Stock, (5) net income, (6) total shareholder return, (7) earnings before interest taxes (EBIT), (8) cash flow, including operating cash flows, free cash flow, discounted cash flow return on investment and cash flow in excess of cost of capital, or any combination thereof, (9) economic value added, (10) return on equity, (11) return on capital, (12) return on assets, (13) net operating profits after taxes, (14) stock price increase, (15) return on sales, (16) debt to equity ratio, (17) payout ratio, (18) asset turnover, (19) ratio of share price to book value of shares, (20) price/earnings ratio, (21) employee satisfaction, (22) diversity, (23) market share, (24) operating income, (25) pre-tax income, (26) safety, (27) diversification of business opportunities, (28) expense ratios, (29) total expenditures, (30) completion of key projects, (31) dividend payout as percentage of net income, (32) earnings before interest, taxes, depreciation and amortization (EBITDA), or (33) any individual performance objective which is measured solely in terms of quantitative targets related to the

Company, any Subsidiary or the Company's or Subsidiary's business. Such individual performance measures related to the Company, a Subsidiary or the Company's or Subsidiary's business may include: (A) production-related factors such as generating capacity factor, performance against the INPO index, generating equivalent availability, heat rates and production cost, (B) transmission and distribution-related factors such as customer satisfaction, reliability (based on outage frequency and duration), and cost, (C) customer service-related factors such as customer satisfaction, service levels and responsiveness and bad debt collections or losses, and (D) relative performance against other similar companies in targeted areas. The measures may be weighted differently for holders of awards based on their management level and the extent to which their responsibilities are primarily corporate or business unit-related, and may be based in whole or in part on the performance of the Company, a Subsidiary, division and/or other operational unit under one or more of such measures. In the sole discretion of the Committee, but subject to Section 162(m) of the Code, the Committee may amend or adjust the Performance Measures or other terms and conditions of an outstanding award in recognition of unusual or nonrecurring events affecting the Company or its financial statements or changes in law or accounting principles.

" Performance Option " shall mean an Incentive Stock Option or Nonqualified Stock Option, the grant of which or the exercisability of all or a portion of which is contingent upon the attainment of specified Performance Measures within a specified Performance Period.

" Performance Period " shall mean any period designated by the Committee during which (i) the Performance Measures applicable to an award shall be measured and (ii) the conditions to vesting applicable to an award shall remain in effect.

" Performance Share Award " shall mean a Restricted Stock Award or Restricted Stock Unit Award, the vesting of which is subject to the attainment of specified Performance Measures within a specified Performance Period.

" Performance Unit " shall mean a right to receive, contingent upon the attainment of specified Performance Measures within a specified Performance Period and the expiration of any applicable Restriction Period, a specified cash amount or, in lieu thereof, shares of Common Stock having a Fair Market Value equal to such cash amount.

" Performance Unit Award " shall mean an award of Performance Units under this Plan.

" Person " shall mean any individual, sole proprietorship, partnership, joint venture, limited liability company, trust, unincorporated organization, association, corporation, institution, public benefit corporation, entity or government instrumentality, division, agency, body or department.

" Plan " shall have the meaning set forth in Section 1.1.

" Prior Plan " shall mean the Exelon Corporation 2006 Long-Term Incentive Plan, as amended.

“ Restricted Stock ” shall mean shares of Common Stock which are subject to a Restriction Period and which may, in addition thereto, be subject to the attainment of specified Performance Measures within a specified Performance Period.

“ Restricted Stock Award ” shall mean an award of Restricted Stock under this Plan.

“ Restricted Stock Unit ” shall mean a right to receive one share of Common Stock or, in lieu thereof, the Fair Market Value of such share of Common Stock in cash, which shall be contingent upon the expiration of a specified Restriction Period and which may, in addition thereto, be contingent upon the attainment of specified Performance Measures within a specified Performance Period.

“ Restricted Stock Unit Award ” shall mean an award of Restricted Stock Units under this Plan.

“ Restriction Period ” shall mean any period designated by the Committee during which (i) the Common Stock subject to a Restricted Stock Award may not be sold, transferred, assigned, pledged, hypothecated or otherwise encumbered or disposed of, except as provided in this Plan or the Agreement relating to such award, or (ii) the conditions to vesting applicable to a Restricted Stock Unit Award shall remain in effect.

“ Restrictive Covenant ” shall have the meaning set forth in Section 2.3(g).

“ Retirement ” shall mean the retirement of a holder of an award from employment with the Company on or after attaining the minimum age specified for early or normal retirement in any then effective qualified defined benefit retirement plan of the Company in which such holder is a participant, provided that such holder has also attained age 50 and completed at least ten years of service with the Company and the Subsidiaries. For purposes of this definition, the holder’s age and service shall be determined taking into account any deemed age or service awarded to the holder for benefit accrual purposes under any nonqualified defined benefit retirement plan of the Company in which the holder is a participant.

“ SAR ” shall mean a stock appreciation right, which may be a Free-Standing SAR or a Tandem SAR.

“ SEC Person ” shall mean any person (as such term is used in Rule 13d-5 under the Exchange Act) or group (as such term is defined in Sections 3(a)(9) and 13(d)(3) of the Exchange Act), other than (i) the Company or an Affiliate, or (ii) any employee benefit plan (or any related trust) of the Company or any of its Affiliates.

“ Stock Award ” shall mean a Restricted Stock Award or a Restricted Stock Unit Award, including any such award which is granted as a Performance Share Award.

“ Subsidiary ” shall mean any corporation, limited liability company, partnership, joint venture or similar entity in which the Company owns, directly or indirectly, an equity interest possessing more than 50% of the combined voting power of the total outstanding equity interests of such entity.

“ Tandem SAR ” shall mean an SAR which is granted in tandem with, or by reference to, an option (including a Nonqualified Stock Option granted prior to the date of grant of the SAR), which entitles the holder thereof to receive, upon exercise of such SAR and surrender for cancellation of all or a portion of such option, shares of Common Stock (which may be Restricted Stock), cash or a combination thereof with an aggregate value equal to the excess of the Fair Market Value of one share of Common Stock on the date of exercise over the base price of such SAR, multiplied by the number of shares of Common Stock subject to such option, or portion thereof, which is surrendered.

“ Tax Date ” shall have the meaning set forth in Section 5.5.

“ Ten Percent Holder ” shall have the meaning set forth in Section 2.1(a).

“ 20% Owner ” shall have the meaning set forth in Section 5.8(b)(i).

“ Voting Securities ” shall mean with respect to a corporation, securities of such corporation that are entitled to vote generally in the election of directors of such corporation.

1.3 Administration . This Plan shall be administered by the Committee. Any one or a combination of the following awards may be made under this Plan to eligible persons: (i) options to purchase shares of Common Stock in the form of Incentive Stock Options or Nonqualified Stock Options (which may include Performance Options), (ii) SARs in the form of Tandem SARs or Free-Standing SARs, (iii) Stock Awards in the form of Restricted Stock or Restricted Stock Units (which may include Performance Share Awards) and (iv) Performance Units. The Committee shall, subject to the terms of this Plan, select eligible persons for participation in this Plan and determine the form, amount and timing of each award to such persons and, if applicable, the number of shares of Common Stock, the number of SARs, the number of Restricted Stock Units and the number of Performance Units subject to such an award, the exercise price or base price associated with the award, the time and conditions of exercise or settlement of the award and all other terms and conditions of the award, including, without limitation, the form of the Agreement evidencing the award. The Committee may, in its sole discretion and for any reason at any time, subject to the requirements of Section 162(m) of the Code and regulations thereunder in the case of an award intended to be qualified performance-based compensation, take action such that (i) any or all outstanding options and SARs shall become exercisable in part or in full, (ii) all or a portion of the Restriction Period applicable to any outstanding Restricted Stock or Restricted Stock Units shall lapse, (iii) all or a portion of the Performance Period applicable to any outstanding Performance Share Award or Performance Units shall lapse and (iv) the Performance Measures (if any) applicable to any outstanding award shall be deemed to be satisfied at the target or any other level not exceeding the maximum allowable under its terms. The Committee shall, subject to the terms of this Plan, interpret this Plan and the application thereof, establish rules and regulations it deems necessary or desirable for the administration of this Plan and may impose, incidental to the grant of an award, conditions with respect to the award, such as limiting competitive employment or other activities. All such interpretations, rules, regulations and conditions shall be conclusive and binding on all parties.

The Committee may delegate some or all of its power and authority hereunder to the Board or, subject to applicable law, to the Chief Executive Officer or other officer of the Company as the Committee deems appropriate; provided , however , that (i) the Committee may not delegate its power and authority to the Board or the Chief Executive Officer or other officer of the Company with regard to the grant of an award to any person who is a "covered employee" within the meaning of Section 162(m) of the Code or who, in the Committee's judgment, is likely to be a covered employee at the time during the period an award hereunder to such employee would be outstanding, (ii) the Committee may not delegate its power and authority to the Chief Executive Officer or other officer of the Company with regard to the selection for participation in this Plan of an officer or other person subject to Section 16 of the Exchange Act or whose title with the Company is "executive vice president" or higher, or decisions concerning the timing, pricing or amount of an award to such an officer or other person and (iii) the awards granted by the Chief Executive Officer pursuant to such delegation shall not exceed the limits set forth in Section 1.6(c) and 1.6(d).

No member of the Board or Committee, and neither the Chief Executive Officer nor any other officer to whom the Committee delegates any of its power and authority hereunder, shall be liable for any act, omission, interpretation, construction or determination made in connection with this Plan in good faith, and the members of the Board and the Committee and the Chief Executive Officer or other officer shall be entitled to indemnification and reimbursement by the Company in respect of any claim, loss, damage or expense (including attorneys' fees) arising therefrom to the full extent permitted by law (except as otherwise may be provided in the Company's Articles of Incorporation and/or By-laws) and under any directors' and officers' liability insurance that may be in effect from time to time.

A majority of the Committee shall constitute a quorum. The acts of the Committee shall be either (i) acts of a majority of the members of the Committee present at any meeting at which a quorum is present or (ii) acts approved in writing by all of the members of the Committee without a meeting.

1.4 Eligibility . Participants in this Plan shall consist of such officers and other key management employees, and persons expected to become officers and other key management employees, of the Company and its Subsidiaries as the Committee in its sole discretion may select from time to time. The Committee's selection of a person to participate in this Plan at any time shall not require the Committee to select such person to participate in this Plan at any other time. For purposes of this Plan, references to employment by the Company shall also mean employment by a Subsidiary.

1.5 Shares Available . Subject to adjustment as provided in Section 5.7, the aggregate number of shares of Common Stock available for awards granted under the Plan in the form of options, SARs, Stock Awards or Performance Units shall be the sum of (i) five million

(5,000,000), plus (ii) the number of shares of Common Stock which as of the effective date of this Plan remain available for future awards pursuant to Section 1.5 of the Prior Plan, and reduced by the sum of the aggregate number of shares of Common Stock which become subject to outstanding options, outstanding Free-Standing SARs and outstanding Stock Awards granted under the Plan and shares of Common Stock delivered upon the settlement of Performance Units granted under the Plan. To the extent that shares of Common Stock subject to an outstanding option, SAR or stock award granted under the Plan or any predecessor plan are not issued or delivered by reason of the expiration, termination, cancellation or forfeiture of such award (excluding shares subject to an option cancelled upon settlement in shares of a related tandem SAR or shares subject to a tandem SAR cancelled upon exercise of a related option), then such shares of Common Stock shall again be available under this Plan. Shares of Common Stock to be delivered under this Plan shall be made available from authorized and unissued shares of Common Stock, or authorized and issued shares of Common Stock reacquired and held as treasury shares or otherwise or a combination thereof.

1.6 Award Limits .

(a) Subject to adjustment as provided in Section 5.7, no individual may be granted awards under the Plan during any calendar year that, in the aggregate, may be settled by delivery of more than two million (2,000,000) shares of Common Stock. In addition, with respect to awards the value of which is based on the Fair Market Value of Common Stock and that may be settled in cash (in whole or in part), no individual may be paid during any calendar year cash amounts relating to such awards that exceed the greater of the Fair Market Value of the number of shares of Common Stock set forth in the preceding sentence either at the date of grant or at the date of settlement. This Section 1.6(a) sets forth two separate limitations, so that awards that may be settled solely by delivery of Common Stock will not operate to reduce the amount or value of cash-only awards, and vice versa; nevertheless, awards that may be settled in Common Stock or cash must not exceed either limitation.

(b) With respect to awards, the value of which is not based on the Fair Market Value of Common Stock, no individual may receive during any calendar year cash or shares of Common Stock with a Fair Market Value at the date of settlement that, in the aggregate, exceeds five million dollars ($5,000,000).

(c) Subject to adjustment as provided in Section 5.7, the number of shares of Common Stock subject to options and SARs granted in any single year by the Chief Executive Officer, pursuant to a delegation by the Committee in accordance with Section 1.3 of this Plan, shall not exceed 1,200,000 in the aggregate or 40,000 with respect to any individual employee.

(d) Subject to adjustment as provided in Section 5.7, the number of shares of Common Stock subject to Stock Awards and Performance Units granted in any single year by the Chief Executive Officer, pursuant to a delegation by the Committee in accordance with Section 1.3 of this Plan, shall not exceed 600,000 in the aggregate or 20,000 with respect to any individual employee.

II. STOCK OPTIONS AND STOCK APPRECIATION RIGHTS

2.1 Stock Options. The Committee may, in its discretion, grant options to purchase shares of Common Stock to such eligible persons as may be selected by the Committee. Each option, or portion thereof, that is not an Incentive Stock Option, shall be a Nonqualified Stock Option. Each option shall be granted within 10 years after the date on which this Plan is approved by the Board. To the extent that the aggregate Fair Market Value (determined as of the date of grant) of shares of Common Stock with respect to which options designated as Incentive Stock Options are exercisable for the first time by a participant during any calendar year (under this Plan or any other plan of the Company, or any parent or Subsidiary) exceeds the amount (currently $100,000) established by the Code, such options shall constitute Nonqualified Stock Options.

Options shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable:

(a) Number of Shares and Purchase Price. The number of shares of Common Stock subject to an option and the purchase price per share of Common Stock purchasable upon exercise of the option shall be determined by the Committee; provided, however, that the purchase price per share of Common Stock purchasable upon exercise of a Nonqualified Stock Option or an Incentive Stock Option shall not be less than 100% of the Fair Market Value of a share of Common Stock on the date of grant of such option; provided further, that if an Incentive Stock Option shall be granted to any person who, at the time such option is granted, owns capital stock possessing more than 10 percent of the total combined voting power of all classes of capital stock of the Company (or of any parent or Subsidiary) (a "Ten Percent Holder"), the purchase price per share of Common Stock shall not be less than the price (currently 110% of Fair Market Value) required by the Code in order to constitute an Incentive Stock Option.

(b) Option Period and Exercisability. The period during which an option may be exercised shall be determined by the Committee; provided, however, that no option shall be exercised later than 10 years after its date of grant; provided further, that if an Incentive Stock Option shall be granted to a Ten Percent Holder, such option shall not be exercised later than five years after its date of grant. The Committee may, in its discretion, determine that an option is to be granted as a Performance Option and may establish an applicable Performance Period and Performance Measures which shall be satisfied or met as a condition to the grant of such option or to the exercisability of all or a portion of such option. The Committee shall determine whether an option shall become exercisable in cumulative or non-cumulative installments and in part or in full at any time. An exercisable option, or portion thereof, may be exercised only with respect to whole shares of Common Stock.

(c) Method of Exercise. An option may be exercised (i) by giving written notice to the Company specifying the number of whole shares of Common Stock to be purchased and accompanying such notice with payment therefor in full, and without any extension of credit, either (A) in cash, (B) by delivery (either actual delivery or by attestation procedures established by the Company) to the Company of previously owned whole shares of Common Stock having a

Fair Market Value, determined as of the date of exercise, equal to the aggregate purchase price payable by reason of such exercise, (C) authorizing the Company to withhold whole shares of Common Stock which would otherwise be delivered having an aggregate Fair Market Value, determined as of the date of exercise, equal to the amount necessary to satisfy such obligation, provided that the Committee determines that such withholding of shares does not cause the Company to recognize an increased compensation expense under applicable accounting principles, (D) except as may be prohibited by applicable law, in cash by a broker-dealer acceptable to the Company to whom the optionee has submitted an irrevocable notice of exercise or (E) a combination of (A), (B) and (C), in each case to the extent set forth in the Agreement relating to the option, (ii) if applicable, by surrendering to the Company any Tandem SARs which are cancelled by reason of the exercise of the option and (iii) by executing such documents as the Company may reasonably request. Any fraction of a share of Common Stock which would be required to pay such purchase price shall be disregarded and the remaining amount due shall be paid in cash by the optionee. No shares of Common Stock shall be issued and no certificate representing Common Stock shall be delivered until the full purchase price therefor and any withholding taxes thereon, as described in Section 5.5, have been paid.

2.2 Stock Appreciation Rights . The Committee may, in its discretion, grant SARs to such eligible persons as may be selected by the Committee. The Agreement relating to an SAR shall specify whether the SAR is a Tandem SAR or a Free-Standing SAR.

SARs shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable:

(a) Number of SARs and Base Price . The number of SARs subject to an award shall be determined by the Committee. Any Tandem SAR related to an Incentive Stock Option shall be granted at the same time that such Incentive Stock Option is granted. The base price of a Tandem SAR shall be the purchase price per share of Common Stock of the related option. The base price of a Free-Standing SAR shall be determined by the Committee; provided , however , that such base price shall not be less than 100% of the Fair Market Value of a share of Common Stock on the date of grant of such SAR.

(b) Exercise Period and Exercisability . The Agreement relating to an award of SARs shall specify whether such award may be settled in shares of Common Stock (including shares of Restricted Stock) or cash or a combination thereof. The period for the exercise of an SAR shall be determined by the Committee; provided , however , that no SAR shall be exercised later than 10 years after its date of grant; and provided , further , that no Tandem SAR shall be exercised later than the expiration, cancellation, forfeiture or other termination of the related option. The Committee may, in its discretion, establish Performance Measures which shall be satisfied or met as a condition to the grant of an SAR or to the exercisability of all or a portion of an SAR. The Committee shall determine whether an SAR may be exercised in cumulative or non-cumulative installments and in part or in full at any time. An exercisable SAR, or portion thereof, may be exercised, in the case of a Tandem SAR, only with respect to whole shares of Common Stock and, in the case of a Free-Standing SAR, only with respect to a whole number of SARs. If an

SAR is exercised for shares of Restricted Stock, a certificate or certificates representing such Restricted Stock shall be issued in accordance with Section 3.2(c), or such shares shall be transferred to the holder in book entry form with restrictions on the Shares duly noted, and the holder of such Restricted Stock shall have such rights of a stockholder of the Company as determined pursuant to Section 3.2(d). Prior to the exercise of an SAR for shares of Common Stock, including Restricted Stock, the holder of such SAR shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such SAR.

(c) Method of Exercise . A Tandem SAR may be exercised (i) by giving written notice to the Company specifying the number of whole SARs which are being exercised, (ii) by surrendering to the Company any options which are cancelled by reason of the exercise of the Tandem SAR and (iii) by executing such documents as the Company may reasonably request. A Free-Standing SAR may be exercised (A) by giving written notice to the Company specifying the whole number of SARs which are being exercised and (B) by executing such documents as the Company may reasonably request.

2.3 Termination of Employment .

(a) Retirement or Disability . Subject to Sections 2.3(e) and 2.3(g) below, and unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the Company ceases to employ the holder of an option or SAR by reason of such holder's Retirement or Disability, each option and SAR held by such holder shall be fully exercisable, and may thereafter be exercised by such holder (or such holder's legal representative or similar person) until and including the earlier to occur of (i) the date which is five years after the effective date of such holder's termination of employment and (ii) the expiration date of the term of such option or SAR.

(b) Death . Unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the Company ceases to employ the holder of an option or SAR by reason of such holder's death, each option and SAR held by such holder shall be fully exercisable, and may thereafter be exercised by such holder's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the date which is three years after the date of death and (ii) the expiration date of the term of such option or SAR.

(c) Cause . If the Company ceases to employ the holder of an option or SAR due to a termination of employment by the Company for Cause, each option and SAR held by such holder shall be cancelled and cease to be exercisable as of the earlier to occur of (i) the effective date of such termination of employment and (ii) the date on which the holder first engaged in conduct giving rise to a termination for Cause, and the Company thereafter may require the repayment of any amounts received by such holder in connection with an exercise of such option or SAR following such cancellation date.

(d) Other Termination . Subject to Sections 2.3(e), 2.3(f) and 2.3(g) below and unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the Company ceases to employ the holder of an option or SAR for any reason other than as

described in Section 2.3(a) through Section 2.3(c), then each option and SAR held by such holder shall be exercisable only to the extent that such option or SAR is exercisable on the effective date of such holder's termination of employment, and may thereafter be exercised by such holder (or such holder's legal representative or similar person) until and including the earlier to occur of (i) the date which is 90 days after the effective date of such holder's termination of employment and (ii) the expiration date of the term of such option or SAR.

(e) Death Following Termination of Employment . Unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the holder of an option or SAR dies during the applicable post-termination exercise period described in Section 2.3(d), each option and SAR held by such holder shall be exercisable only to the extent that such option or SAR, as the case may be, is exercisable on the date of such holder's death and may thereafter be exercised by the holder's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the date which is one year after the date of death and (ii) the expiration date of the term of such option or SAR.

(f) Breach of Restrictive Covenant . Notwithstanding Sections 2.3(a) through (e), if the holder of an option or SAR breaches his or her obligations to the Company or any of its affiliates under a noncompetition, nonsolicitation, confidentiality, intellectual property or other restrictive covenant (a " Restrictive Covenant "), each option and SAR held by such holder shall be cancelled and cease to be exercisable as of the date on which the holder first breached such Restrictive Covenant, and the Company thereafter may require the repayment of any amounts received by such holder in connection with an exercise of such option or SAR following such cancellation date.

(g) Certain Terminations After Change in Control . Unless otherwise specified in, and subject to all conditions set forth in, the Agreement relating to an option or SAR, as the case may be, or any individual change in control agreement or severance plan, and notwithstanding any other provision of this Section 2.3, if within 24 months following a Change in Control, the Company ceases to employ the holder of an option or SAR due to a termination of employment (i) by the Company other than for Cause, or (ii) with respect to a holder whose position is at least salary band E09 (or its equivalent), by the holder for Good Reason, such holder's outstanding options shall immediately become fully exercisable and may thereafter be exercised by such holder (or such holder's legal representative or similar person) until and including the earlier to occur of (A) the date which is five years after the effective date of such holder's termination of employment and (B) the expiration date of the term of such option or SAR.

2.4 No Repricing . The Committee shall not without the approval of the stockholders of the Company, (i) reduce the purchase price or base price of any previously granted option or SAR, (ii) cancel any previously granted option or SAR in exchange for another option or SAR with a lower purchase price or base price or (iii) cancel any previously granted option or SAR in exchange for cash or another award if the purchase price of such option or the base price of such SAR exceeds the Fair Market Value of a share of Common Stock on the date of such cancellation, in each case, other than in connection with a Change in Control or the adjustment provisions set forth in Section 5.7.

III. STOCK AWARDS

3.1 Stock Awards. The Committee may, in its discretion, grant Stock Awards to such eligible persons as may be selected by the Committee. The Agreement relating to a Stock Award shall specify whether the Stock Award is a Restricted Stock Award or a Restricted Stock Unit Award. The Committee may, in its discretion, determine that a Restricted Stock Award or Restricted Stock Unit Award is to be granted as a Performance Share Award and may establish an applicable Performance Period and Performance Measures which shall be satisfied or met as a condition to the grant or vesting of all or a portion of such award.

3.2 Terms of Restricted Stock Awards. Restricted Stock Awards shall be subject to the following terms and conditions and shall be subject to such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable.

(a) Number of Shares and Other Terms. The number of shares of Common Stock subject to a Restricted Stock Award and the Restriction Period and Performance Measures (if any) applicable to a Restricted Stock Award shall be determined by the Committee.

(b) Vesting and Forfeiture. The Agreement relating to a Restricted Stock Award shall provide, in the manner determined by the Committee, in its discretion, and subject to the provisions of this Plan, for the vesting of the shares of Common Stock subject to such award (i) if the holder of such award remains continuously in the employment of the Company during the specified Restriction Period and (ii) in the case of a Performance Share Award, if specified Performance Measures are satisfied or met during a specified Performance Period, and for the forfeiture of the shares of Common Stock subject to such award (x) if the holder of such award does not remain continuously in the employment of the Company during the specified Restriction Period or (y) in the case of a Performance Share Award, if specified Performance Measures are not satisfied or met during a specified Performance Period. The restrictions applicable to each Performance Share Award shall lapse no earlier than one year after the applicable grant date, except to the extent an award Agreement provides otherwise in the case of a Change in Control or a participant's death, Disability or termination of employment.

(c) Stock Issuance. During the Restriction Period, the shares of Restricted Stock shall be held by a custodian in book entry form with restrictions on such shares duly noted or, alternatively, a certificate or certificates representing a Restricted Stock Award shall be registered in the holder's name and may bear a legend, in addition to any legend which may be required pursuant to Section 5.6, indicating that the ownership of the shares of Common Stock represented by such certificate is subject to the restrictions, terms and conditions of this Plan and the Agreement relating to the Restricted Stock Award. All such certificates shall be deposited with the Company, together with stock powers or other instruments of assignment (including a power of attorney), each endorsed in blank with a guarantee of signature if deemed necessary or appropriate, which would permit transfer to the Company of all or a portion of the shares of Common Stock subject to the Restricted Stock Award in the event such award is forfeited in whole or in part. Upon termination of any applicable Restriction Period (and the satisfaction or attainment of applicable Performance Measures), subject to the Company's right to require

payment of any taxes in accordance with Section 5.5, the restrictions shall be removed from the requisite number of any shares of Common Stock that are held in book entry form, and all certificates evidencing ownership of the requisite number of shares of Common Stock shall be delivered to the holder of such award.

(d) Rights with Respect to Restricted Stock Awards . Unless otherwise set forth in the Agreement relating to a Restricted Stock Award, and subject to the terms and conditions of a Restricted Stock Award, the holder of such award shall have all rights as a stockholder of the Company, including, but not limited to, voting rights, the right to receive dividends and the right to participate in any capital adjustment applicable to all holders of Common Stock; provided , however , that (i) a distribution with respect to shares of Common Stock, other than a regular cash dividend, and (ii) a regular cash dividend with respect to shares of Common Stock that are subject to performance-based vesting conditions, in each case shall be deposited with the Company and shall be subject to the same restrictions as the shares of Common Stock with respect to which such distribution was made.

3.3 Terms of Restricted Stock Unit Awards . Restricted Stock Unit Awards shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable.

(a) Number of Shares and Other Terms . The number of shares of Common Stock subject to a Restricted Stock Unit Award and the Restriction Period and Performance Measures (if any) applicable to a Restricted Stock Unit Award shall be determined by the Committee.

(b) Vesting and Forfeiture . The Agreement relating to a Restricted Stock Unit Award shall provide, in the manner determined by the Committee, in its discretion, and subject to the provisions of this Plan, for the vesting of such Restricted Stock Unit Award (i) if the holder of such award remains continuously in the employment of the Company during the specified Restriction Period and (ii) in the case of a Performance Share Award, if specified Performance Measures are satisfied or met during a specified Performance Period, and for the forfeiture of the shares of Common Stock subject to such award (x) if the holder of such award does not remain continuously in the employment of the Company during the specified Restriction Period or (y) in the case of a Performance Share Award, if specified Performance Measures are not satisfied or met during a specified Performance Period. Each Performance Share Award shall become vested no earlier than one year after the applicable grant date, except to the extent an award Agreement provides otherwise in the case of a Change in Control or a participant's death, Disability or termination of employment.

(c) Settlement of Vested Restricted Stock Unit Awards . The Agreement relating to a Restricted Stock Unit Award shall specify (i) whether such award may be settled in shares of Common Stock, including Restricted Stock, or cash or a combination thereof and (ii) whether the holder thereof shall be entitled to receive, on a current or deferred basis, dividend equivalents and, if determined by the Committee, interest on, or the deemed reinvestment of, any deferred dividend equivalents, with respect to the number of shares of Common Stock subject to such award. Prior to the settlement of a Restricted Stock Unit Award, the holder of such award shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such award.

3.4 Termination of Employment . All of the terms relating to the satisfaction of Performance Measures and the termination of the Restriction Period or Performance Period relating to a Stock Award, or any forfeiture and cancellation of such award upon a termination of employment with the Company of the holder of such award, whether by reason of Disability, Retirement, death or any other reason, shall be determined by the Committee and set forth in the applicable award Agreement.

IV. PERFORMANCE UNIT AWARDS

4.1 Performance Unit Awards . The Committee may, in its discretion, grant Performance Unit Awards to such eligible persons as may be selected by the Committee.

4.2 Terms of Performance Unit Awards . Performance Unit Awards shall be subject to the following terms and conditions and shall be subject to such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable.

(a) Number of Performance Units and Performance Measures . The number of Performance Units subject to a Performance Unit Award and the Performance Measures and Performance Period applicable to a Performance Unit Award shall be determined by the Committee.

(b) Vesting and Forfeiture . The Agreement relating to a Performance Unit Award shall provide, in the manner determined by the Committee, in its discretion, and subject to the provisions of this Plan, for the vesting of such Performance Unit Award if the specified Performance Measures are satisfied or met during the specified Performance Period and for the forfeiture of such award if the specified Performance Measures are not satisfied or met during the specified Performance Period.

(c) Settlement of Vested Performance Unit Awards . The Agreement relating to a Performance Unit Award shall specify whether such award may be settled in shares of Common Stock (including shares of Restricted Stock) or cash or a combination thereof. If a Performance Unit Award is settled in shares of Restricted Stock, such shares of Restricted Stock shall be issued to the holder in book entry form or a certificate or certificates representing such Restricted Stock shall be issued in accordance with Section 3.2(c) and the holder of such Restricted Stock shall have such rights as a stockholder of the Company as determined pursuant to Section 3.2(d). Prior to the settlement of a Performance Unit Award in shares of Common Stock, including Restricted Stock, the holder of such award shall have no rights as a stockholder of the Company.

4.3 Termination of Employment . All of the terms relating to the satisfaction of Performance Measures and the termination of the Performance Period relating to a Performance Unit Award, or any forfeiture and cancellation of such award upon a termination of employment with the Company of the holder of such award, whether by reason of Disability, Retirement, death or any other reason, shall be determined by the Committee and set forth in the applicable award Agreement.

V. GENERAL

5.1 Effective Date and Term of Plan . This Plan shall be submitted to the stockholders of the Company for approval at the Company's 2010 annual meeting of stockholders and, if approved by the affirmative vote of a majority of the shares of Common Stock present in person or represented by proxy at such annual meeting of stockholders, shall become effective as of January 1, 2011. This Plan shall terminate ten (10) years after its effective date, unless terminated earlier by the Committee. Termination of this Plan shall not affect the terms or conditions of any award granted prior to termination.

Awards hereunder may be made at any time prior to the termination of this Plan, provided that, subject to Section 2.1, no award may be made later than ten (10) years after the effective date of this Plan. In the event that this Plan is not approved by the stockholders of the Company, this Plan and any awards hereunder shall be void and of no force or effect.

5.2 Amendments . The Committee may amend this Plan as it shall deem advisable, subject to any requirement of stockholder approval required by applicable law, rule or regulation, including Section 162(m) of the Code and any rule of the New York Stock Exchange, or, if the Common Stock is not listed on the New York Stock Exchange, any rule of the principal national stock exchange on which the Common Stock is then traded; provided , however , that no amendment may impair the rights of a holder of an outstanding award without the consent of such holder.

5.3 Agreement . Each award under this Plan shall be evidenced by an Agreement setting forth the terms and conditions applicable to such award. No award shall be valid until an Agreement is executed by the Company and the recipient of such award and, upon execution by each party and delivery of the Agreement to the Company within the time period specified by the Company, such award shall be effective as of the effective date set forth in the Agreement.

5.4 Non-Transferability. No award shall be transferable other than by will, the laws of descent and distribution or pursuant to beneficiary designation procedures approved by the Company or, to the extent expressly permitted in the Agreement relating to such award, to the holder's family members, a trust or entity established by the holder for estate planning purposes or a charitable organization designated by the holder. Except to the extent permitted by the foregoing sentence or the Agreement relating to an award, each award may be exercised or settled during the holder's lifetime only by the holder or the holder's legal representative or similar person. Except as permitted by the second preceding sentence, no award may be sold, transferred, assigned, pledged, hypothecated, encumbered or otherwise disposed of (whether by operation of law or otherwise) or be subject to execution, attachment or similar process. Upon any attempt to so sell, transfer, assign, pledge, hypothecate, encumber or otherwise dispose of any award, such award and all rights thereunder shall immediately become null and void.

5.5 Tax Withholding . The Company shall have the right to require, prior to the issuance or delivery of any shares of Common Stock or the payment of any cash pursuant to an award made hereunder, or upon the vesting of any award that is considered deferred compensation, payment by the holder of such award of any federal, state, local or other taxes which may be required to be withheld or paid in connection with such award. An Agreement may provide that (i) the Company shall withhold whole shares of Common Stock which would otherwise be delivered to a holder, having an aggregate Fair Market Value determined as of the date the obligation to withhold or pay taxes arises in connection with an award (the " Tax Date "), or withhold an amount of cash which would otherwise be payable to a holder, in the amount necessary to satisfy any such obligation or (ii) the holder may satisfy any such obligation by any of the following means: (A) a cash payment to the Company, (B) authorizing the Company to withhold whole shares of Common Stock which would otherwise be delivered having an aggregate Fair Market Value, determined as of the Tax Date, or withhold an amount of cash which would otherwise be payable to a holder, equal to the amount necessary to satisfy any such obligation, (C) in the case of the exercise of an option and except as may be prohibited by applicable law, a cash payment by a broker-dealer acceptable to the Company to whom the optionee has submitted an irrevocable notice of exercise or (D) any combination of (A) and (B), in each case to the extent set forth in the Agreement relating to the award. Shares of Common Stock to be delivered or withheld may not have an aggregate Fair Market Value in excess of the amount determined by applying the minimum statutory withholding rate. Any fraction of a share of Common Stock which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by the holder.

5.6 Restrictions on Shares . Each award made hereunder shall be subject to the requirement that if at any time the Company determines that the listing, registration or qualification of the shares of Common Stock subject to such award upon any securities exchange or under any law, or the consent or approval of any governmental body, or the taking of any other action is necessary or desirable as a condition of, or in connection with, the delivery of shares thereunder, such shares shall not be delivered unless such listing, registration, qualification, consent, approval or other action shall have been effected or obtained, free of any conditions not acceptable to the Company. The Company may require that certificates evidencing shares of Common Stock delivered pursuant to any award made hereunder bear a legend indicating that the sale, transfer or other disposition thereof by the holder is prohibited except in compliance with the Securities Act of 1933, as amended, and the rules and regulations thereunder.

5.7 Adjustment . In the event any stock split, stock dividend, recapitalization, reorganization, merger, consolidation, combination, exchange of shares, liquidation, spin-off or other similar change in capitalization or event, or any distribution to holders of Common Stock (other than a regular cash dividend) occurs on or after the date this Plan is approved by the stockholders of the Company, the number and class of securities available for all awards under this Plan, the maximum number of securities with respect to which awards may be granted during any year to any one person, the maximum number of shares subject to awards granted during any year by the Chief Executive Officer, the number and class of securities subject to each outstanding option and the purchase price per security, and the terms of each outstanding SAR, Restricted Stock Award, Restricted Stock Unit Award, Performance Share Award and

Performance Unit Award, including the number and class of securities subject thereto, shall be appropriately adjusted by the Committee, such adjustments to be made in the case of outstanding options and SARs without an increase in the aggregate purchase price or base price. The decision of the Committee regarding any such adjustment shall be final, binding and conclusive. If any such adjustment would result in a fractional security being (a) available under this Plan, such fractional security shall be disregarded, or (b) subject to an award under this Plan, the Company shall pay the holder of such award, in connection with the first vesting, exercise or settlement of such award, in whole or in part, occurring after such adjustment, an amount in cash determined by multiplying (i) the fraction of such security (rounded to the nearest hundredth) by (ii) the excess, if any, of (A) the Fair Market Value on the vesting, exercise or settlement date over (B) the exercise or base price, if any, of such award.

5.8 Corporate Transactions; Change in Control .

(a) If the Company shall be a party to a reorganization, merger, or consolidation or sale or other disposition of more than 50% of the operating assets of the Company (determined on a consolidated basis), other than in connection with a sale-leaseback or other arrangement resulting in the continued utilization of such assets (or the operating products of such assets) (a " Corporate Transaction "), the Board (as constituted prior to any Change in Control resulting from such Corporate Transaction) may, in its discretion:

(i) require that (A) some or all outstanding options and SARs shall immediately become exercisable in full or in part, (B) the Restriction Period applicable to some or all outstanding Restricted Stock Awards and Restricted Stock Unit Awards shall lapse in full or in part, (C) the Performance Period applicable to some or all outstanding Performance Share Awards and Performance Unit Awards shall lapse in full or in part, and (D) the Performance Measures applicable to some or all outstanding awards shall be deemed to be satisfied at the target or any other level not exceeding the maximum levels allowable under their respective terms;

(ii) require that shares of capital stock of the corporation resulting from such Corporate Transaction, or a parent corporation thereof, be substituted for some or all of the shares of Common Stock subject to an outstanding award, with an appropriate and equitable adjustment to such award as determined by the Board in accordance with Section 5.7; and/or

(iii) require outstanding awards, in whole or in part, to be surrendered to the Company by the holder, and to be immediately cancelled by the Company, and to provide for the holder to receive (A) a cash payment in an amount equal to (1) in the case of an option or an SAR, the number of shares of Common Stock then subject to the portion of such option or SAR surrendered, to the extent such option or SAR is then exercisable or becomes exercisable pursuant to clause (i), multiplied by the excess, if any, of the Fair Market Value of a share of Common Stock as of the date of the Corporate Transaction, over the purchase price or base

price per share of Common Stock subject to such option or SAR, (2) in the case of a Stock Award, the number of shares of Common Stock then subject to the portion of such award surrendered, to the extent the Restriction Period and Performance Period, if any, on such Stock Award have lapsed or will lapse pursuant to clause (i) and to the extent that the Performance Measures, if any, have been satisfied or are deemed satisfied pursuant to clause (i), multiplied by the Fair Market Value of a share of Common Stock as of the date of the Corporate Transaction, and (3) in the case of a Performance Unit Award, the value of the Performance Units then subject to the portion of such award surrendered, to the extent the Performance Period applicable so such award has lapsed or will lapse pursuant to clause (i) and to the extent the Performance Measures applicable to such award have been satisfied or are deemed satisfied pursuant to clause (i); (B) shares of capital stock of the corporation resulting from such Corporate Transaction, or a parent corporation thereof, having a fair market value not less than the amount determined under clause (A) above; or (C) a combination of the payment of cash pursuant to clause (A) above and the issuance of shares pursuant to clause (B) above.

(b) For purposes of Sections 2.3(f) and 5.8(a), "Change in Control" shall mean, except as otherwise provided below, the first to occur of any of the following events:

(i) any SEC Person becomes the Beneficial Owner of 20% or more of the then outstanding common stock of the Company or of Voting Securities representing 20% or more of the combined voting power of all the then outstanding Voting Securities of the Company (such an SEC Person, a " 20% Owner "); provided, however, that for purposes of this subsection (i), the following acquisitions shall not constitute a Change in Control: (1) any acquisition directly from the Company (excluding any acquisition resulting from the exercise of an exercise, conversion or exchange privilege unless the security being so exercised, converted or exchanged was acquired directly from the Company), (2) any acquisition by the Company, (3) any acquisition by an employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company (a " Company Plan "), or (4) any acquisition by any corporation pursuant to a transaction which complies with paragraphs (A), (B) and (C) of subsection (iii) of this definition; provided further, that for purposes of clause (2), if any 20% Owner of the Company other than the Company or any Company Plan becomes a 20% Owner by reason of an acquisition by the Company, and such 20% Owner of the Company shall, after such acquisition by the Company, become the Beneficial Owner of any additional outstanding common shares of the Company or any additional outstanding Voting Securities of the Company (other than pursuant to any dividend reinvestment plan or arrangement maintained by the Company) and such beneficial ownership is publicly announced, such additional beneficial ownership shall constitute a Change in Control; or

(ii) Individuals who, as of the effective date hereof, constitute the Board (the " Incumbent Board ") cease for any reason to constitute at least a majority of the Incumbent Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by the Company's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest (as such terms are used in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(iii) Consummation of a Corporate Transaction by the Company; excluding, however, a Corporate Transaction pursuant to which:

(A) all or substantially all of the individuals and entities who are the Beneficial Owners, respectively, of the outstanding common stock of Company and outstanding Voting Securities of the Company immediately prior to such Corporate Transaction beneficially own, directly or indirectly, more than 60% of, respectively, the then-outstanding shares of common stock and the combined voting power of the then-outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Corporate Transaction (including, without limitation, a corporation which, as a result of such transaction, owns the Company or all or substantially all of the assets of the Company either directly or through one or more subsidiaries) in substantially the same proportions as their ownership immediately prior to such Corporate Transaction of the outstanding common stock of Company and outstanding Voting Securities of the Company, as the case may be;

(B) no SEC Person (other than the corporation resulting from such Corporate Transaction, and any Person which beneficially owned, immediately prior to such corporate Transaction, directly or indirectly, 20% or more of the outstanding common stock of the Company or the outstanding Voting Securities of the Company, as the case may be) becomes a 20% Owner, directly or indirectly, of the then-outstanding common stock of the corporation resulting from such Corporate Transaction or the combined voting power of the outstanding voting securities of such corporation; and

(C) individuals who were members of the Incumbent Board will constitute at least a majority of the members of the board of directors of the corporation resulting from such Corporate Transaction; or

(iv) Approval by the Company's shareholders of a plan of complete liquidation or dissolution of the Company, other than a plan of liquidation or dissolution which results in the acquisition of all or substantially all of the assets of the Company by an affiliated company.

Notwithstanding the occurrence of any of the foregoing events, a Change in Control shall not occur with respect to an award if, in advance of such event, the holder of such award agrees in writing that such event shall not constitute a Change in Control.

5.9 Deferrals . The Committee may determine that the delivery of shares of Common Stock or the payment of cash, or a combination thereof, upon the exercise or settlement of all or a portion of any award made hereunder shall be deferred, or the Committee may, in its sole discretion, approve deferral elections made by holders of awards. Deferrals shall be for such periods and upon such terms as shall be set forth in a deferral plan or program established by the Committee in its sole discretion in accordance with Section 409A of the Code.

5.10 No Right of Participation or Employment . Unless otherwise set forth in an employment agreement, no person shall have any right to participate in this Plan. Neither this Plan nor any award made hereunder shall confer upon any person any right to continued employment with the Company, any Subsidiary or any affiliate of the Company or affect in any manner the right of the Company, any Subsidiary or any affiliate of the Company to terminate the employment of any person at any time without liability hereunder.

5.11 Rights as Stockholder . No person shall have any right as a stockholder of the Company with respect to any shares of Common Stock or other equity security of the Company which is subject to an award hereunder unless and until such person becomes a stockholder of record with respect to such shares of Common Stock or equity security.

5.12 Designation of Beneficiary . A holder of an award may file with the Committee a written designation of one or more persons as such holder's beneficiary or beneficiaries (both primary and contingent) in the event of the holder's death or incapacity. To the extent an outstanding option or SAR granted hereunder is exercisable, such beneficiary or beneficiaries shall be entitled to exercise such option or SAR pursuant to procedures prescribed by the Committee.

Each beneficiary designation shall become effective only when filed in writing with the Committee during the holder's lifetime on a form prescribed by the Committee. The spouse of a married holder domiciled in a community property jurisdiction shall join in any designation of a beneficiary other than such spouse. The filing with the Committee of a new beneficiary designation shall cancel all previously filed beneficiary designations.

If a holder fails to designate a beneficiary, or if all designated beneficiaries of a holder predecease the holder, then each outstanding option and SAR hereunder held by such holder, to the extent exercisable, may be exercised by such holder's executor, administrator, legal representative or similar person.

5.13 Governing Law . This Plan, each award hereunder and the related Agreement, and all determinations made and actions taken pursuant thereto, to the extent not otherwise governed by the Code or the laws of the United States, shall be governed by the laws of the Commonwealth of Pennsylvania and construed in accordance therewith without giving effect to principles of conflicts of laws.

5.14 Foreign Employees . Without amending this Plan, the Committee may grant awards to eligible persons who are foreign nationals on such terms and conditions different from those specified in this Plan as may in the judgment of the Committee be necessary or desirable to foster and promote achievement of the purposes of this Plan and, in furtherance of such purposes the Committee may make such modifications, amendments, procedures, subplans and the like as may be necessary or advisable to comply with provisions of laws in other countries or jurisdictions in which the Company or its Subsidiaries operates or has employees.

EXELON CORPORATION
LONG-TERM INCENTIVE PROGRAM

(As amended and restated as of January 1, 2014)

1. Purpose . The purpose of this Exelon Corporation Long-Term Incentive Program (the " Program ") is to set forth certain provisions which shall be deemed a part of, and govern, equity compensation awards granted by Exelon Corporation, a Pennsylvania corporation (the " Company "), on or after January 1, 2011 to executives, key managers and other select management employees pursuant to the Exelon Corporation 2011 Long-Term Incentive Plan, as amended (the " Plan ").

2. Certain Definitions .

Except as otherwise set forth herein, the defined terms used in this Program shall have the meanings set forth below or in the Plan.

(a) "Administrator" shall have the meaning set forth in Section 14 below.

(b) "Award" shall mean an award granted under this Program.

(c) "Award Notice" shall mean a notice of a Participant's Award, issued by the Company in written or electronic form, which shall set forth the type of the Award, the number of shares (or target share opportunity that, together with the Program summary, sets forth the number of shares) of Common Stock subject to such Award and any other terms of the Award not set forth in the Plan, this Program or the Program summary.

(d) "Board" shall mean the board of directors of the Company.

(e) "Transition Award" shall mean a Performance Share Unit Award granted on a one-time basis in 2013 (or 2014, in certain cases such as new hires, promotions or transfers) in order to transition from a one-year Performance Cycle to a three-year Performance Cycle.

(f) "Committee" shall mean the compensation committee of the Board.

(g) "Dividend Payment Date" shall mean each date on which the Company pays a regular cash dividend to record owners of shares of Common Stock.

(h) "Earned Shares" shall mean shares of Common Stock (or cash representing shares, as applicable) subject to a Performance Share Unit Award that are earned based on the achievement of the performance goals for the applicable Performance Cycle (or portion thereof, in the case of Transition Awards).

(i) "Effective Date" shall mean January 1, 2011.

(j) “First Tranche” shall mean one-third of the Performance Share Units granted under a Transition Award.

(k) “Grant Date” shall mean the date on which an Award is granted, as set forth in the applicable Award Notice.

(l) “Option” shall mean a nonqualified option to purchase shares of Common Stock upon and subject to the satisfaction of the vesting conditions set forth in Section 5 of this Program.

(m) “Participant” shall mean the recipient of an Award granted under this Program.

(n) “Performance Cycle” shall mean (A) for Performance Share Unit Awards granted prior to January 1, 2013, the one-year period beginning on January 1 of the year in which the Award is granted (and any applicable look-back period), (B) for the Transition Awards, the two-year period beginning on January 1, 2013 and (C) for Performance Share Unit Awards granted on or after January 1, 2013 (other than Transition Awards) and Performance Cash Awards granted on or after January 1, 2014, the three-year period beginning on January 1of the year in which the Performance Share Unit Award is granted.

(o) “Performance Cash Unit” shall mean a right granted to a Participant employed in a Utility Company to receive an amount of cash subject to the achievement of the applicable performance goals and the satisfaction of the vesting conditions set forth in Section 3 of this Program.

(p) “Performance Share Unit” shall mean a right to receive shares of Common Stock or a cash equivalent (as applicable) subject to the achievement of the applicable performance goals and the satisfaction of the vesting conditions set forth in Section 3 of this Program.

(q) “Restricted Stock Unit” shall mean a right to receive shares of Common Stock upon and subject to the satisfaction of the vesting conditions set forth in Section 4 of this Program.

(r) “Restrictive Covenants” shall mean any noncompetition, nonsolicitation, confidentiality, intellectual property or other restrictive covenants to which a Participant is subject, required as a condition to receipt of an Award, or which is contained in any other agreement between the Participant and the Company or any of its affiliates.

(s) “Retirement” shall mean a Participant’s termination of employment (other than a termination upon death, disability or involuntary termination for cause) on or after the date as of which the Participant has attained age 50 (age 55 with respect to Awards granted on or after January 1, 2013) and completed at least ten years of service with the Company and the Subsidiaries. For purposes of this definition, the holder’s age and service shall be determined taking into account any deemed age or service awarded to the holder for benefit accrual purposes under any nonqualified defined benefit retirement plan of the Company in which the holder is a participant.

(t) “Second Tranche” shall mean two-thirds of the Performance Share Units granted under a Transition Award

(u) “Utility Company” shall mean Baltimore Gas & Electric Company, Commonwealth Edison Company, PECO Energy Company and the Exelon Utility Group within Exelon Business Services Company, LLC.

3. Long Term Performance Share Award and Performance Cash Award Program .

(a) Granting of Awards . Within the first 90 days of each Performance Cycle beginning on or after the Effective Date, the Committee may grant Performance Share Unit Awards to employees who are employed in a Vice President or more senior position, including without limitation Nuclear Plant Managers, as selected by the Committee in its sole discretion. Effective January 1, 2014, the Committee may grant Performance Cash Units in lieu of Performance Share Unit Awards to such designated employees who are employed in a Utility Company. Performance Share Unit Awards and Performance Cash Units shall be subject to the respective applicable terms and conditions set forth in this Section 3, and shall contain such additional terms and conditions, not inconsistent with the terms of this Program, as the Committee shall deem advisable and set forth in the applicable Program summary or Award Notice.

(b) Number of Shares and Other Terms . The number of shares of Common Stock represented by a Performance Share Unit Award (“ Earned Shares ”) for any Performance Cycle shall be determined based on the achievement of performance goals established by the Committee and set forth in the Program summary for such Performance Cycle and the administrative guidelines approved by the Committee. Each performance goal shall be assigned a weighting and scored at the end of each calendar year within the Performance Cycle. For Performance Cycles beginning on or after January 1, 2013, at the end of the Performance Cycle, the number of Earned Shares is determined based on the average of the annual performance results, subject to adjustment as set forth in the Program summary and/or administrative guidelines. Notwithstanding the foregoing, the maximum number of shares of Common Stock that may become subject to Performance Share Unit Awards granted in any calendar year to Participants the Company has determined as of the Grant Date may be “covered employees” (within the meaning of Section 162(m)(3) of the Code) for such year or for any subsequent year in which such Award may be outstanding, shall be equal to the lesser of (i) the number determined by (A) multiplying 1.5% of the Company’s Operating Income for such year by the allocation percentage approved by Committee for such Participant within the first 90 days of the applicable Performance Cycle and (B) dividing such dollar amount by the closing price of a share of Common Stock on the last trading day of such year and (ii) the per person limit set forth in Section 1.6 of the Plan. For purposes of this Section 3(b), the “Operating Income” of the Company for such year shall be as reported in the Company’s financial statements for such year according to generally accepted accounting principles and as reviewed or accepted, as the case may be,

by the Company's independent public accountants, and certified by the Committee in accordance with section 162(m) of the Code. The Committee reserves the right in its sole discretion to determine that the number of Earned Shares for any Performance Cycle shall be zero in the event of materially adverse business or financial circumstances as determined by the Committee.

(c) Vesting and Forfeiture .

(i) Awards Granted prior to January 1, 2013. Except as provided in Section 3(f)(i) of the Program, Earned Shares granted prior to January 1, 2013 shall become vested (i) on the date of the first regular meeting of the Committee held in the calendar year following the calendar year in which the Grant Date occurs with respect to one-third of the number of Earned Shares, (ii) on the date of the first regular meeting of the Committee held in the second calendar year following the calendar in which the Grant Date occurs with respect to an additional one-third of the number of Earned Shares, and (iii) on the date of the first regular meeting of the Committee held in the third calendar year following the calendar year in which the Grant Date occurs with respect to the remaining Earned Shares (but, with respect to each such year, not later than March 15), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(ii) Transition Awards . Except as provided in Section 3(f)(ii) of the Program, Performance Share Units subject to a Transition Award shall be earned and become vested (i) with respect to the First Tranche, on the date of the first regular meeting of the Committee held in 2014 and (ii) with respect to the Second Tranche, on the date of the first regular meeting of the Committee held in 2015 (but, with respect to each such year, not later than March 15), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(iii) Awards Granted on or after January 1, 2013 (Other than Transition Awards). Except as provided in Section 3(f)(ii) of the Program, Performance Share Units and Performance Cash Units subject to an Award (other than a Transition Award) and granted on or after January 1, 2013 shall be earned and become fully vested on the date of the first regular meeting of the Committee held in the third calendar year following the calendar year in which the Grant Date occurs (but, with respect to each such Performance Cycle, not later than March 15 of such year), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(d) Dividend Equivalents . As of each Dividend Payment Date, the Company shall pay to the Participant a cash payment in an amount equal to the dollar amount of the cash dividend paid per share of Common Stock multiplied by the number of Earned Shares that are subject to a Performance Share Unit Award immediately prior to the record date for such Dividend Payment Date, but that have not been issued pursuant to Section 3(e) as of such record date.

(e) Settlement of Vested Awards . Subject to the withholding of taxes pursuant to Section 8 of the Program, within 30 days after the vesting of a Performance Share Unit Award, in whole or in part (or at such later time as may be required pursuant to this Section 3(e)), the Company shall issue or transfer to the Participant the number of Earned Shares that have become vested. The Company may effect such transfer either by the delivery of one or more certificates of Common Stock to the Participant or by an appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company, and in either case by issuing such shares in the Participant's name or in such other name as is acceptable to the Company and designated in writing by the Participant. All such Awards payable for 2012 or thereafter shall be paid 50% in Common Stock and 50% in cash; provided, however, that effective for Awards granted on or after January 1, 2013 (including Transition Awards), a Participant whose title is Executive Vice President or above and who has achieved 200% or more of his or her stock ownership target by September 30 of the calendar year prior to payout of the Award shall be paid in cash. The Company shall pay all original issue or transfer taxes and all fees and expenses incident to such delivery, except as otherwise provided in Section 8 of the Program. Prior to the settlement of a Performance Share Unit Award, the holder of such Award shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such Award. Performance Cash Awards shall be paid in cash upon vesting. Notwithstanding the foregoing, if a Participant is a "Specified Employee," within the meaning of section 409A of the Code, and such Participant is or will become eligible for Retirement prior to the calendar year in which the Performance Share Unit Award is scheduled to become fully vested, then any Earned Shares subject to the Award or payment under a Performance Cash Unit which become vested upon the Participant's termination of employment in accordance with Section 3(f) of this Program shall be issued to the Participant as of the earlier to occur of the six-month anniversary of such Participant's separation from service or the date of the Participant's death.

(f) Termination of Employment . Except as otherwise provided in this Program or the Plan:

(i) Retirement, Disability, Death or Involuntary Termination Without Cause – Awards Granted prior to January 1, 2013 . If a Participant's employment with the Company terminates by reason of Retirement, Disability, death or an involuntary termination of employment by the Company for a reason other than Cause, and such Participant has not breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, then all Earned Shares subject to such Participant's Performance Share Unit Award and earned cash subject to a Performance Cash Unit shall become fully vested as of the effective date of the Participant's termination of employment or date of death, as the case may be. To the extent the Award has not been earned as of the date of the Participant's termination of employment or death (i.e. as to which the current Performance Cycle has not elapsed), the Participant shall become

vested in a pro-rated Award based on the number of elapsed days in the current Performance Cycle as of the termination date (or fully vested with respect to such an Award for 2012 upon an involuntary termination without Cause) and the extent to which the Company performance goals established under the Program for such Performance Cycle are attained as of the last day of the year in which the termination date occurs (and assuming a 100% individual performance multiplier), and such Award shall be payable as of the date the first third of the Awards for such Performance Cycle are payable to Participants who remain actively employed with the Company.

(ii) Retirement, Disability, Death or Involuntary Termination Without Cause – Awards Granted on or after January 1, 2013 (Including Transition Awards) . If a Participant's employment with the Company terminates by reason of Retirement, Disability, death or an involuntary termination of employment by the Company for a reason other than Cause, and such Participant has not breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, then (A) if such event occurs within the first 12 months of the Performance Cycle, then the Participant shall earn and become vested in a pro-rated Award (both First and Second Tranches, in the case of Bridge Awards) based on the number of elapsed days in such 12-month period as of the termination date (pro-ration determined by dividing the number of elapsed days by 365) and the extent to which the performance goals established under the Program for such Performance Cycle (or portion thereof, in the case of the Transition Awards) are attained, and (B) if such event occurs after the first 12 months of the Performance Cycle, then the Participant shall become fully vested in all Earned Shares (the number determined in accordance with Section 3(b) above) or earned cash, as applicable. In either event, the Earned Shares or cash shall be payable on the next payout date applicable to Participants who remain actively employed with the Company (either the payout date for the First Tranche or Second Tranche, as applicable, in the case of Transition Awards).

(iii) Termination for Other Reasons . If a Participant's employment with the Company terminates for any reason other than as described in clause (i) or (ii) of this Section 3(f) or if the Participant has breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, the unvested portion of such Participant's Award shall be forfeited and terminate as of the date of such termination of employment.

(g) Restriction on Sale of Shares by Senior Officers . Shares of Common Stock issued under an Award pursuant to Section 3(e) to a Participant who is employed as of the Grant Date in a position of, or more senior than, Senior Vice President may not be sold or transferred by such Participant until the earlier to occur of (i) the date as of which the final third of such Award is scheduled to become vested pursuant to Section 3(c) (even if such Award actually vests earlier pursuant to Section 3(f)) or (ii) the date of the Participant's death, regardless of when such shares are issued or transferred to such Participant. Effective January 1, 2013, this provision shall no longer be effective.

(h) Awards Granted to Employees of Commonwealth Edison Company Prior to 2014 . If Performance Share Unit Awards are granted to Participants who are employed by Commonwealth Edison Company, an Illinois corporation and subsidiary of the Company (" ComEd "), then unless the Committee determines otherwise, (i) the number of such Participant's Earned Shares shall be determined based on the achievement of performance criteria established by the Board of Directors of ComEd and ratified by the Committee, subject to the maximum number of Earned Shares that may be subject to a Performance Share Unit Award, as set forth in Section 3(b), and (ii) such Performance Share Unit Awards for 2011 shall be settled (subject to the vesting and other conditions herein) in a cash payment made by ComEd to the Participant in an amount equal to the Fair Market Value of the number of such Participant's Earned Shares, determined as of the applicable vesting date.

4. Restricted Stock Unit Award Program .

(a) Granting of Awards . The Committee may grant Restricted Stock Unit Awards to employees who are employed (i) in a Vice President or other executive position (including without limitation Nuclear Plant Managers) below the Senior Vice President level, and (ii) key managers and other select management employees, in each case as selected by the Committee in its sole discretion.

(b) Terms of Awards . Awards shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Program, as the Committee shall deem advisable and set forth in the applicable Award Notice.

(c) Number of Shares and Other Terms . The number of shares of Common Stock subject to a Restricted Stock Unit Award shall be determined by the Committee and set forth in the applicable Award Notice.

(d) Vesting and Forfeiture . Except to the extent a Restricted Stock Unit Award becomes immediately vested upon a termination of the Participant's employment pursuant to Section 4(g) of the Program, the shares subject to a Restricted Stock Unit Award shall become vested (i) on the date of the first regular meeting of the Committee in the calendar year following the calendar year in which the Grant Date occurs with respect to one-third of the number of shares of Common Stock subject to the Award on the Grant Date, (ii) on the date of the first regular meeting of the Committee in the second calendar year following the calendar year in which the Grant Date occurs with respect to an additional one-third of the number of shares of Common Stock subject to the Award on the Grant Date, and (iii) on the date of the first regular meeting of the Committee in the third calendar year following the calendar year in which the Grant Date occurs with respect to the remaining shares of Common Stock subject to the Award on the Grant Date (but, with respect to each such year, not later than March 15), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(e) Dividend Equivalents . As of each Dividend Payment Date, the number of shares of Common Stock that are subject to a Restricted Stock Unit Award shall be increased by (i) the product of the total number of shares of Common Stock that are subject to such Restricted Stock Unit Award immediately prior to the record date for such Dividend Payment Date, but that have not been issued pursuant to Section 4(f) as of such record date, multiplied by the dollar amount of the cash dividend paid per share of Common Stock, divided by (ii) the Fair Market Value of a share of Common Stock on such Dividend Payment Date. Such additional Restricted Stock Units shall be subject to all of the terms and conditions of the Award, including the vesting conditions set forth in Section 4(d).

(f) Settlement of Vested Awards . Subject to the withholding of taxes pursuant to Section 8 of the Program, within 30 days after the vesting of a Restricted Stock Unit Award, in whole or in part (or at such later time as may be required pursuant to this Section 4(f)), the Company shall issue or transfer to the Participant the number of shares of Common Stock that have become vested. The Company may effect such transfer either by the delivery of one or more certificates of Common Stock to the Participant or by an appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company, and in either case by issuing such shares in the Participant's name or in such other name as is acceptable to the Company and designated in writing by the Participant. The Company shall pay all original issue or transfer taxes and all fees and expenses incident to such delivery, except as otherwise provided in Section 8 of the Program. Prior to the settlement of a Restricted Stock Unit Award, the holder of such Award shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such Award. Notwithstanding the foregoing, if a Participant is a "Specified Employee," within the meaning of section 409A of the Code, and such Participant is or will become eligible for Retirement prior to the calendar year in which the Restricted Stock Unit Award is scheduled to become fully vested, then any shares of Common Stock subject to the Award which become vested upon the Participant's termination of employment in accordance with Section 4(g) of this Program shall be issued to the Participant as of the earlier to occur of the six-month anniversary of such Participant's separation from service or the date of the Participant's death.

(g) Termination of Employment . Except as otherwise provided in this Program or the Plan:

(i) Retirement, Disability or Death . If a Participant's employment with the Company terminates by reason of Retirement, Disability or death, and such Participant has not breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, then all shares of Common Stock subject to such Participant's Restricted Stock Unit Award shall become fully vested as of the effective date of the Participant's termination of employment or date of death, as the case may be.

(ii) Termination for Other Reasons . If a Participant's employment with the Company terminates for any reason other than as described in clause (i) of this Section 4(g) or if the Participant has breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, the

unvested portion of such Participant's Restricted Stock Unit Award shall be forfeited and terminate as of the date of such termination of employment; provided however, that such an Award granted on or after January 1, 2012 shall become fully vested upon an involuntary termination without Cause.

5. Stock Option Award Program .

(a) Granting of Awards . The Committee may grant Option Awards to employees who are employed in a Senior Vice President or more senior position, as selected by the Committee in its sole discretion or, to the extent permitted by the Plan, the Chief Executive Officer of the Company.

(b) Terms of Awards . Awards shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Program, as the Committee shall deem advisable and set forth in the applicable Award Notice.

(c) Number of Shares . The number of shares of Common Stock subject to an Option Award shall be determined by the Committee and set forth in the applicable Award Notice.

(d) Term of Option . Except to the extent earlier terminated or exercised, each Option shall expire on, and in no event may any portion of such Option be exercised after, the tenth anniversary of the Grant Date (the " Expiration Date ").

(e) Vesting and Forfeiture . Except to the extent the Award becomes immediately vested upon a termination of the Participant's employment pursuant to Section 5(g) of the Program, the Option shall become vested and exercisable (i) on the first anniversary of the Grant Date with respect to one-fourth of the number of shares of Common Stock subject to the Award on the Grant Date, (ii) on the second anniversary of the Grant Date with respect to an additional one-fourth of the number of shares of Common Stock subject to the Award on the Grant Date (iii) on the third anniversary of the Grant Date with respect to an additional one-fourth of the number of shares of Common Stock subject to the Award on the Grant Date, and (iv) on the fourth anniversary of the Grant Date with respect to the remaining shares of Common Stock subject to the award on the Grant Date, in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(f) Method of Exercise . To the extent permitted by the Administrator, a Participant may exercise an Option (i) by giving written notice to the Company (or its designated agent) specifying the number of whole shares of Common Stock to be purchased and accompanying such notice with payment therefor in full, and without any extension of credit, either (A) in cash, (B) by delivery (either actual delivery or by attestation procedures established by the Company) to the Company of previously owned whole shares of Common Stock having a Fair Market Value, determined as of the date of exercise, equal to the aggregate purchase price payable by reason of such exercise, (C) authorizing the Company to withhold whole shares of Common Stock which

would otherwise be delivered having an aggregate Fair Market Value, determined as of the date of exercise, equal to the amount necessary to satisfy such obligation, provided that the Committee determines that such withholding of shares does not cause the Company to recognize an increased compensation expense under applicable accounting principles, (D) except as may be prohibited by applicable law, in cash by a broker-dealer acceptable to the Company to whom the Participant has submitted an irrevocable notice of exercise or (E) a combination of (A), (B) and (C) and (ii) by executing such documents as the Company may reasonably request. Any fraction of a share of Common Stock which would be required to pay such purchase price shall be disregarded and the remaining amount due shall be paid in cash by the Participant. No shares of Common Stock shall be issued and no certificate representing Common Stock shall be delivered until the full purchase price therefor and any withholding taxes thereon, as described in Section 8, have been paid.

(g) Termination of Employment .

(i) Retirement or Disability . If the Company ceases to employ a Participant by reason of such Participant's Retirement or Disability, each Option held by such Participant shall be fully exercisable, and may thereafter be exercised by such Participant (or such Participant's legal representative or similar person) until and including the earlier to occur of (i) the fifth anniversary of the effective date of such Participant's termination of employment and (ii) the Expiration Date.

(ii) Death . If the Company ceases to employ a Participant by reason of such Participant's death, each Option held by such Participant shall be fully exercisable, and may thereafter be exercised by such Participant's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the third anniversary of the date of death and (ii) the Expiration Date.

(iii) Cause . If the Company ceases to employ a Participant due to a termination of employment by the Company for Cause, each Option held by such Participant shall be cancelled and cease to be exercisable as of the earlier to occur of (i) the effective date of such termination of employment and (ii) the date on which the Participant first engaged in conduct giving rise to a termination for Cause, and the Company thereafter may require the repayment of any amounts received by such Participant in connection with an exercise of such Option following such cancellation date.

(iv) Other Termination . Subject to clauses (v), (vi) and (vii) below, if the Company ceases to employ a Participant for any reason other than as described in clause (i), (ii) or (iii) above, then each Option held by such Participant shall be exercisable only to the extent that such Option is exercisable on the effective date of such Participant's termination of employment, and may thereafter be exercised by such Participant (or such Participant's legal representative or similar person) until and including the earlier to occur of (i) the date which is 90 days after the effective date of such Participant's termination of employment and (ii) the Expiration Date.

(v) Death Following Termination of Employment . If a Participant dies during the applicable post-termination exercise period described in clause (iv), each Option held by such Participant shall be exercisable only to the extent that such Option is exercisable on the date of such Participant's death and may thereafter be exercised by the Participant's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the first anniversary of the date of death and (ii) the expiration date of the term of such Option.

(vi) Breach of Restrictive Covenant . Notwithstanding clauses (i) through (v), if a Participant breaches his or her obligations to the Company or any of its affiliates under a Restrictive Covenant, each Option held by such Participant shall be cancelled and cease to be exercisable as of the date on which the Participant first breached such Restrictive Covenant, and the Company thereafter may require the repayment of any amounts received by such Participant in connection with an exercise of such Option following such cancellation date.

(vii) Certain Terminations After Change in Control . Unless otherwise specified in, and subject to all conditions set forth in, any individual change in control agreement or severance plan, and notwithstanding any other provision of this Section 5(g), if within 24 months following a Change in Control, the Company ceases to employ a Participant due to a termination of employment (i) by the Company other than for Cause, or (ii) with respect to a Participant whose position is at grade level E09 (or its equivalent), by the Participant for Good Reason, such Participant's outstanding Options shall immediately become fully exercisable and may thereafter be exercised by such Participant (or such Participant's legal representative or similar person) until and including the earlier to occur of (A) the fifth anniversary of the effective date of such Participant's termination of employment and (B) the Expiration Date.

(h) Termination of Option . In no event may an Option be exercised after it terminates as set forth in this Section 5(h). An Option shall terminate, to the extent not earlier exercised or terminated pursuant to Section 5(g), on the Expiration Date. Upon the termination of the Option, the Option and all rights thereunder shall immediately become null and void.

6. Employment . For purposes of this Program, references to employment with the Company shall include (i) employment with an Affiliate of the Company and (ii) any period during which the Participant is on a leave of absence approved by the Company.

7. Limited Transferability of Awards . Except as may otherwise be expressly provided in an Award Notice, an Award may be transferred by the Participant only (1) by will, (2) the laws of descent and distribution or (3) pursuant to beneficiary designation procedures approved by the Company. Except to the extent permitted by the foregoing, an Award may not be sold, transferred, assigned, pledged, hypothecated, encumbered or otherwise disposed of (whether by operation of law or otherwise) or be subject to execution, attachment or similar process or domestic relations order. Upon any attempt so to sell, transfer, assign, pledge, hypothecate, encumber or otherwise dispose of an Award, such Award and all rights thereunder shall immediately become null and void.

8. Withholding Taxes . The Company shall have the right to require, prior to the issuance or delivery of any shares of Common Stock or the payment of any cash pursuant to an Award, or upon the vesting of any Award that is considered deferred compensation, payment by the Participant of any federal, state, local or other taxes which may be required to be withheld or paid in connection with such Award. The Company may withhold whole shares of Common Stock which would otherwise be delivered to a Participant, having an aggregate Fair Market Value determined as of the Tax Date, or withhold an amount of cash which would otherwise be payable to a Participant, in the amount necessary to satisfy any such obligation. The Participant may elect to satisfy any such obligation by any of the following means, to the extent permitted by the Administrator: (A) a cash payment to the Company, (B) authorizing the Company to withhold whole shares of Common Stock which would otherwise be delivered having an aggregate Fair Market Value, determined as of the Tax Date, or withhold an amount of cash which would otherwise be payable to the Participant, equal to the amount necessary to satisfy any such obligation, (C) in the case of the exercise of an Option and except as may be prohibited by applicable law, a cash payment by a broker-dealer acceptable to the Company to whom the Participant has submitted an irrevocable notice of exercise or (D) any combination of (A) and (B). Shares of Common Stock to be delivered or withheld may not have an aggregate Fair Market Value in excess of the amount determined by applying the minimum statutory withholding rate. Any fraction of a share of Common Stock which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by the Participant.

9. Adjustment . The number and class of securities subject to an Award shall be subject to adjustment as provided in Section 5.7 of the Plan. The decision of the Committee regarding any such adjustment shall be final, binding and conclusive.

10. Compliance with Applicable Law . Each Award is subject to the condition that if the listing, registration or qualification of the shares subject to such Award upon any securities exchange or under any law, or the consent or approval of any governmental body, or the taking of any other action is necessary or desirable as a condition of, or in connection with, the delivery of shares hereunder, such Award may not be settled, in whole or in part, unless such listing, registration, qualification, consent or approval shall have been effected or obtained, free of any conditions not acceptable to the Company.

11. Award Subject to the Plan and Claw-back Policy . Each Award is subject to the provisions of the Plan, and each Award and this Program shall be interpreted in accordance therewith. Notwithstanding any provision of the Program to the contrary, each Award shall be subject to a clawback pursuant to the Exelon Executive Officer Compensation Recoupment Policy contained in the Exelon Corporation Board of Directors Corporate Governance Principles, as in effect from time to time, including any amendments thereto or new clawback policies required under the Dodd-Frank Wall Street Reform and Consumer Protection Act and implementing applicable stock exchange listing standards or rules and regulations thereunder, or as otherwise required by law or regulation.

12. Investment Representation . By accepting an Award, the Participant represents and covenants that (a) any share of Common Stock acquired upon the vesting of the Award will be acquired for investment and not with a view to the distribution thereof within the meaning of the Securities Act of 1933, as amended (the " Securities Act "), unless such acquisition has been registered under the Securities Act and any applicable state securities law; (b) any subsequent sale of any such shares shall be made either pursuant to an effective registration statement under the Securities Act and any applicable state securities laws, or pursuant to an exemption from registration under the Securities Act and such state securities laws; and (c) if requested by the Company, the Participant shall submit a written statement, in form satisfactory to the Company, to the effect that such representation (x) is true and correct as of the date of acquisition of any shares hereunder or (y) is true and correct as of the date of any sale of any such shares, as applicable. As a further condition precedent to the delivery to the Participant of any shares subject to the Award, the Participant shall comply with all regulations and requirements of any regulatory authority having control of or supervision over the issuance of the shares and, in connection therewith, shall execute any documents which the Company shall in its sole discretion deem necessary or advisable.

13. Award Confers No Rights to Continued Employment . In no event shall the granting of an Award or its acceptance by a Participant give or be deemed to give the Participant any right to continued employment by the Company.

14. Administrator . This Program shall be administered by the Company's Vice President, Corporate Compensation (the "Administrator"). Except for authority reserved to the Board or the Committee, the Administrator shall have the right to interpret the Program, make any determinations hereunder, and take any necessary or appropriate actions with respect to the administration of the Program or in connection with each Award. Any such interpretation, determination or other action made or taken by the regarding this Program or an Award shall be final, binding and conclusive.

15. Miscellaneous Provisions .

(a) Successors . This Program and each Award shall be binding upon and inure to the benefit of any successor or successors of the Company and any person or persons who shall, upon the death of a Participant, acquire any rights under such Award in accordance with this Program or the Plan.

(b) Notices . All notices, requests or other communications provided for in this Program (other than the exercise of a stock option) shall be made, if to the Company, to Exelon Corporation, 10 South Dearborn Street, Chicago, Illinois 60603, Attention: Vice President, Corporate Compensation, and if to the Participant, to his or her then current work location. All notices, requests or other communications provided for in this Program shall be made in writing either (a) by personal delivery to the party entitled thereto, (b) by facsimile with confirmation of receipt, (c) by mailing in the United States mails to the last known address of the party entitled thereto or (d) by express courier service. The notice, request or other communication shall be deemed to be received upon personal delivery, upon confirmation of receipt of facsimile transmission, or upon receipt by the party entitled thereto if by United States mail or express courier service; provided, however, that if a notice, request or other communication is not received during regular business hours, it shall be deemed to be received on the next succeeding business day of the Company.

(c) Section 409A . This Program and the Awards granted hereunder are intended to comply with the requirements of section 409A of the Code and shall be interpreted and construed consistently with such intent. Awards granted pursuant to this Program are also intended to be exempt from Section 409A of the Code to the maximum extent possible as short-term deferrals pursuant to Treasury regulation §1.409A-1(b)(4), and for this purpose each payment shall be considered a separate payment. In the event the terms of an Award would subject a Participant to taxes or penalties under Section 409A of the Code (" 409A Penalties "), the Company may modify the terms of such Award to avoid such 409A Penalties, to the extent possible; provided that in no event shall the Company be responsible for any 409A Penalties that arise in connection with any Award. To the extent the timing of payment under an Award is determined by reference to a Participant's "termination of employment," such term shall be deemed to refer to the Participant's "separation from service," within the meaning of section 409A of the Code. Notwithstanding any other provision in this Program, if a Participant is a "specified employee," as defined in Section 409A of the Code, as of the date of such Participant's separation from service, then to the extent any amount payable to the Participant (i) constitutes the payment of nonqualified deferred compensation, within the meaning of Section 409A of the Code, (ii) is payable upon the Participant's separation from service and (iii) under the terms of this Program would be payable prior to the six-month anniversary of the Participant's separation from service, such payment shall be delayed until the earlier to occur of (A) the six-month anniversary of the separation from service and (B) the date of the Participant's death.

(d) Amendment . The terms of this Program may be amended by the Committee or the Board (or their respective delegates), provided that the Chief Human Resources Officer or the Vice President, Corporate Compensation, of the Company may amend the Program to comply with applicable law, to make administrative changes or to carry out directives of the Board or the Committee.

(e) Governing Law . This Program and each Award granted thereunder, and all determinations made and actions taken pursuant thereto, to the extent not governed by the laws of the United States, shall be governed by the laws of the Commonwealth of Pennsylvania and construed in accordance therewith without giving effect to principles of conflicts of laws.

IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its Senior Vice President & Chief Human Resources Officer, effective as of January 1, 2014.

EXELON CORPORATION

By: _____
Senior Vice President &
Chief Human Resources Officer

Exelon Corporation
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2010	2011	2012	2013	2014
Pre-tax income from continuing operations	4,221	3,952	1,798	2,773	2,486
Plus: Loss from equity investees	—	1	91	(10)	20
Less: Capitalized interest	(43)	(57)	(75)	(67)	(79)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	4,178	3,896	1,814	2,696	2,427
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	836	761	1,021	1,436	1,110
Interest component of rental expense (a)	241	237	310	269	288
Total fixed charges	1,077	998	1,331	1,705	1,398
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	5,255	4,894	3,145	4,401	3,825
Ratio of earnings to fixed charges	4.9	4.9	2.4	2.6	2.7

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exelon Corporation
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
	2010	2011	2012	2013	2014
Pre-tax income from continuing operations	4,221	3,952	1,798	2,773	2,486
Plus: Loss from equity investees	—	1	91	(10)	20
Less: Capitalized interest	(43)	(57)	(75)	(67)	(79)
Preference security dividend requirements	(7)	(6)	(26)	(32)	(18)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	4,171	3,890	1,788	2,664	2,409
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	836	761	1,021	1,436	1,110
Interest component of rental expense (a)	241	237	310	269	288
Preference security dividend requirements of consolidated subsidiaries	7	6	26	32	18
Total fixed charges	1,084	1,004	1,357	1,737	1,416
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	5,255	4,894	3,145	4,401	3,825
Ratio of earnings to fixed charges and preferred stock dividends	4.8	4.9	2.3	2.5	2.7

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exelon Generation Company, LLC
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2010	2011	2012	2013	2014
Pre-tax income from continuing operations	3,150	2,827	1,058	1,675	1,226
Plus: (Income) or loss from equity investees	—	1	91	(10)	20
Less: Capitalized interest	(38)	(49)	(67)	(54)	(63)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	3,112	2,779	1,082	1,611	1,183
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	191	219	402	445	396
Interest component of rental expense (a)	222	220	291	248	269
Total fixed charges	413	439	693	693	665
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	3,525	3,218	1,775	2,304	1,848
Ratio of earnings to combined fixed charges	8.5	7.3	2.6	3.3	2.8

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exhibit 12.3

Commonwealth Edison Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2010	2011	2012	2013	2014
Pre-tax income from continuing operations	693	666	618	401	676
Plus: Loss from equity investees	—	—	—	—	—
Less:Capitalized interest	(2)	(4)	(3)	(5)	(2)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	691	662	615	396	674
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	368	330	297	575	311
Interest component of rental expense (a)	6	6	6	5	5
Total fixed charges	374	336	303	580	316
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest plus fixed charges	1,065	998	918	976	990
Ratio of earnings to fixed charges	2.8	3.0	3.0	1.7	3.1

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

PECO Energy Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2010	2011	2012	2013	2014
Pre-tax income from continuing operations	476	535	508	557	466
Plus: Loss from equity investees	—	—	—	—	—
Less: Capitalized interest	(4)	(4)	(2)	(2)	(2)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	472	531	506	555	464
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	193	135	122	114	112
Interest component of rental expense (a)	10	9	9	7	5
Total fixed charges	203	144	131	121	117
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	675	675	637	676	581
Ratio of earnings to combined fixed charges	3.3	4.7	4.9	5.6	5.0

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

PECO Energy Company
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
	2010	2011	2012	2013	2014
Pre-tax income from continuing operations	476	535	508	557	466
Plus: Loss from equity investees	—	—	—	—	—
Less: Capitalized interest	(4)	(4)	(2)	(2)	(2)
Preference security dividend requirements	(6)	(6)	(5)	(10)	—
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	466	525	501	545	464
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	193	135	122	114	112
Interest component of rental expense (a)	10	9	9	7	5
Preference security dividend requirements	6	6	5	10	—
Total fixed charges	209	150	136	131	117
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	675	675	637	676	581
Ratio of earnings to fixed charges and preferred stock dividends	3.2	4.5	4.6	5.2	5

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

BGE
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2010	2011	2012	2013	2014
Pre-tax income from continuing operations	244	211	11	344	351
Less: Capitalized interest	(6)	(7)	(5)	(6)	(12)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	238	204	6	338	339
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	137	136	149	127	118
Interest component of rental expense (a)	4	5	4	4	4
Total fixed charges	141	141	153	131	122
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	379	345	159	469	461
Ratio of earnings to fixed charges	2.7	2.4	1.0	3.6	3.8

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

BGE
Ratio of Earnings to Fixed Charges and Preference Stock Dividends

	Years Ended December 31,				
	2010	2011	2012	2013	2014
Pre-tax income from continuing operations	244	211	11	344	351
Less: Capitalized interest	(6)	(7)	(5)	(6)	(12)
Preference security dividend requirements	(20)	(20)	(20)	(21)	(22)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	218	184	(14)	317	317
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	137	136	149	127	118
Interest component of rental expense (a)	4	5	4	4	4
Preference security dividend requirements	20	20	20	21	22
Total fixed charges	161	161	173	152	144
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	379	345	159	469	461
Ratio of earnings to fixed charges and preferred stock dividends	2.4	2.1	0.9[(b)]	3.1	3.2

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.
(b) The ratio coverage was less than 1:1. The registrant must generate additional earnings of $14 million to achieve a coverage ratio of 1:1.

Exelon Corporation

Name	Jurisdiction
2014 ESA HoldCo, LLC	Delaware
2014 ESA Project Company, LLC	Delaware
A/C Fuels Company	Pennsylvania
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Albany Green Energy, LLC	Georgia
Annova LNG Common Infrastructure, LLC	Delaware
Annova LNG, LLC	Delaware
Annova LNG, LLC, Series A Units	Delaware
Annova LNG, LLC, Series Z Units	Delaware
APS Constellation, LLC	Delaware
Aquion Energy, Inc.	Delaware
ATNP Finance Company	Delaware
AV Solar Ranch 1, LLC	Delaware
Baltimore Gas and Electric Company	Maryland
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
BGE Capital Trust II	Delaware
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Breezy Bucks-I LLC	Minnesota
Breezy Bucks-II LLC	Minnesota
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
C3, Inc.	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Central Wayne Energy Recovery Limited Partnership	Maryland
CE Colver I, Inc.	Maryland
CE Colver II, LLC	Delaware
CE Colver III, Inc.	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Nuclear, LLC	Delaware
CE Wayne I, Inc.	Maryland
CE Wayne II, Inc.	Maryland
CECG International Holdings, Inc.	Delaware
Central Wayne Energy Recovery Limited Partnership	Maryland
CER Generation, LLC	Delaware
CER-Quail Run Energy LLC	Delaware
CER-Quail Run Energy Partners LP	Delaware
CEU Arkoma West, LLC	Delaware
CEU CHC, LLC	Delaware

CEU CoLa, LLC	Delaware
CEU Development, LLC	Delaware
CEU Eagle Ford, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Offshore I, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU Trenton, LLC	Delaware
CEU W&D, LLC	Delaware
ChargePoint Inc.	Delaware
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton NQF, LLC	Nevada
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
Cogenex Corporation	Massachusetts
CoLa Resources LLC	Delaware
Colorado Bend I Power, LLC	Delaware
Colorado Bend II Power, LLC	Delaware
Colorado Bend Services, LLC	Delaware
ComEd Financing III	Delaware
Commonwealth Edison Company	Illinois
Commonwealth Edison Company of Indiana, Inc.	Indiana
Compass Energy Gas Services, LLC	Virginia
Compass Energy Services, Inc.	Virginia
Constellation Alliance II, LP	Texas
Constellation Alliance, LLC	Delaware
Constellation Bulk Energy Holdings, Inc.	Marshall Islands
Constellation DCO Albany Power Holdings, LLC	Delaware
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Limited	United Kingdom
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Gas Choice, Inc.	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Partners Holdings, LLC	Delaware
Constellation Energy Power Choice, Inc.	Delaware
Constellation Energy Projects & Services Group Advisors, LLC	Delaware
Constellation Energy Projects and Services Canada, Inc.	Federal
Constellation Energy Resources, LLC	Delaware
Constellation Energy Upstream Holdings, Inc.	Delaware
Constellation Holdings, LLC	Maryland
Constellation International Holdings, Inc.	Marshall Islands
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy - Gas Division, LLC	Kentucky

Constellation NewEnergy Canada Inc.	Ontario
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Operating Services	California
Constellation Power Source Generation, LLC	Maryland
Constellation Power, Inc.	Maryland
Constellation Sacramento Holding, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Georgia, LLC	Georgia
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland MC, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
Cool Planet Energy Systems, Inc.	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
COSI Ultra II, Inc.	Maryland
COSI Ultra, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CPower Holdings, LLC	Delaware
CR Clearing, LLC	Missouri
Criterion Power Partners, LLC	Delaware
DAJAW Transmission LLC	Minnesota
Denver Airport Solar, LLC	Delaware
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
eCurv Inc.	Delaware
Energy Performance Services, Inc.	Pennsylvania
Essess Inc.	Delaware
ETT Canada, Inc.	New Brunswick
Ewington Energy Systems LLC	Minnesota
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Business Services Company, LLC	Delaware
Exelon Capital Trust I	Delaware
Exelon Capital Trust II	Delaware
Exelon Capital Trust III	Delaware
Exelon Corporation	Pennsylvania
Exelon Energy Delivery Company, LLC	Delaware
Exelon Enterprises Company, LLC	Pennsylvania

Exelon Framingham, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, Inc.	Pennsylvania
Exelon Generation Limited	United Kingdom
Exelon Mechanical, LLC	Delaware
Exelon Microgrid, LLC	Delaware
Exelon New Boston, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon Peaker Development Limited, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon Solar Chicago LLC	Delaware
Exelon Transmission Company, LLC	Delaware
Exelon West Medway II, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
Ex-FM, Inc.	New York
Ex-FME, Inc.	Delaware
ExGen Renewables I Holding, LLC	Delaware
ExGen Renewables I, LLC	Delaware
ExGen Texas II Power Holdings, LLC	Delaware
ExGen Texas II Power, LLC	Delaware
ExGen Texas Power Holdings, LLC	Delaware
ExGen Texas Power Services, LLC	Delaware
ExGen Texas Power, LLC	Delaware
ExGen Ventures International Holdings II Limited	United Kingdom
ExGen Ventures International Holdings Limited	United Kingdom
ExTel Corporation, LLC	Delaware
F & M Holdings Company, L.L.C.	Delaware
Fair Wind Power Partners, LLC	Delaware
FloDesign	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
G-Flow Wind, LLC	Minnesota
Grande Prairie Generation, Inc.	Alberta
Green Acres Breeze, LLC	Minnesota
Greensburg Wind Farm, LLC	Delaware
Handley Power, LLC	Delaware
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan

High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho
Integrys Energy Services - Electric, LLC	Delaware
Integrys Energy Services - Natural Gas, LLC	Delaware
Integrys Energy Services of New York, Inc.	New York
Integrys Energy Services, Inc.	Wisconsin
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
LaPorte Power, LLC	Delaware
Las Vegas District Energy, LLC	Delaware
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Luz Solar Partners Ltd., IV	California
Luz Solar Partners Ltd., V	California
Luz Solar Partners Ltd., VI	California
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Minnesota Breeze, LLC	Minnesota
Mohave Sunrise Solar I, LLC	Arizona
Mountain Creek Power, LLC	Delaware
Mountain Top Wind Power, LLC	Maryland
MXENERGY (CANADA) LTD.	Nova Scotia
MxEnergy Holdings Inc.	Delaware
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Northwind Thermal Technologies Canada Inc.	New Brunswick
Ogin Inc.	Delaware
OMF 11520, LLC	Delaware
Oregon Trail Windfarm, LLC	Oregon
Outback Solar, LLC	Oregon
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital Trust V	Delaware
PECO Energy Capital Trust VI	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Company	Pennsylvania
PECO Wireless, LLC	Delaware
Pegasus Power Company, Inc.	California

Pegasus Power Partners, a California Limited Partnership	California
Pinedale Energy, LLC	Colorado
Poseidon Interconnect, LLC	Delaware
Powerhouse Dynamics Inc.	Delaware
Prairie Wind Power LLC	Minnesota
Proterra Inc.	Delaware
Purple Acquisition Corp.	Delaware
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Residential Solar Holding, LLC	Delaware
Residential Solar II, LLC	Delaware
RF HoldCo LLC	Delaware
RITELine Illinois, LLC	Illinois
RITELine Indiana, LLC	Indiana
RITELine Transmission Development, LLC	Delaware
Roadrunner-I LLC	Minnesota
RSB BondCo LLC	Delaware
Sacramento PV Energy, LLC	Delaware
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Salty Dog-I LLC	Minnesota
Salty Dog-II LLC	Minnesota
Sand Ranch Windfarm, LLC	Oregon
Scherer Holdings 1, LLC	Delaware
Scherer Holdings 2, LLC	Delaware
Scherer Holdings 3, LLC	Delaware
Sendero Wind Energy, LLC	Delaware
Shane's Wind Machine LLC	Minnesota
Shooting Star Wind Project, LLC	Delaware
Simmons & Eastern, LLC	Delaware
Solarbridge Technologies Inc.	Delaware
Star Electricity, Inc.	Texas
Sunnyside Cogeneration Associates	Utah
Sunnyside Generation, LLC	Delaware
Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Sunnyside Properties, LLC	Utah
Sunset Breeze, LLC	Minnesota
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware
TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
UII, LLC	Illinois
W&D Gas Partners, LLC	Delaware
Wagon Trail, LLC	Oregon
Wally's Wind Farm LLC	Minnesota
Wansley Holdings 1, LLC	Delaware
Wansley Holdings 2, LLC	Delaware
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Windy Dog-1 LLC	Minnesota
Wolf Hollow I Power, LLC	Delaware
Wolf Hollow II Power, LLC	Delaware
Wolf Hollow Services, LLC	Delaware

Wolf Wind Enterprises, LLC	Minnesota
Wolf Wind Transmission, LLC	Minnesota
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Exelon Generation Company, LLC

Name	Jurisdiction
2014 ESA HoldCo, LLC	Delaware
2014 ESA Project Company, LLC	Delaware
A/C Fuels Company	Pennsylvania
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Albany Green Energy, LLC	Georgia
Annova LNG Common Infrastructure, LLC	Delaware
Annova LNG, LLC	Delaware
Annova LNG, LLC, Series A Units	Delaware
Annova LNG, LLC, Series Z Units	Delaware
APS Constellation, LLC	Delaware
Aquion Energy, Inc.	Delaware
AV Solar Ranch 1, LLC	Delaware
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Breezy Bucks-I LLC	Minnesota
Breezy Bucks-II LLC	Minnesota
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
C3, Inc.	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Central Wayne Energy Recovery Limited Partnership	Maryland
CE Colver I, Inc.	Maryland
CE Colver II, LLC	Delaware
CE Colver III, Inc.	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Nuclear, LLC	Delaware
CE Wayne I, Inc.	Maryland
CE Wayne II, Inc.	Maryland
CECG International Holdings, Inc.	Delaware
Central Wayne Energy Recovery Limited Partnership	Maryland
CER Generation, LLC	Delaware
CER-Quail Run Energy LLC	Delaware
CER-Quail Run Energy Partners LP	Delaware
CEU Arkoma West, LLC	Delaware
CEU CHC, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU Development, LLC	Delaware
CEU Eagle Ford, LLC	Delaware

CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Offshore I, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU Trenton, LLC	Delaware
CEU W&D, LLC	Delaware
ChargePoint Inc.	Delaware
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton NQF, LLC	Nevada
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
Cogenex Corporation	Massachusetts
CoLa Resources LLC	Delaware
Colorado Bend I Power, LLC	Delaware
Colorado Bend II Power, LLC	Delaware
Colorado Bend Services, LLC	Delaware
Compass Energy Gas Services, LLC	Virginia
Compass Energy Services, Inc.	Virginia
Constellation Alliance II, LP	Texas
Constellation Alliance, LLC	Delaware
Constellation Bulk Energy Holdings, Inc.	Marshall Islands
Constellation DCO Albany Power Holdings, LLC	Delaware
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Limited	United Kingdom
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Gas Choice, Inc.	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Partners Holdings, LLC	Delaware
Constellation Energy Power Choice, Inc.	Delaware
Constellation Energy Projects & Services Group Advisors, LLC	Delaware
Constellation Energy Projects and Services Canada, Inc.	Federal
Constellation Energy Resources, LLC	Delaware
Constellation Energy Upstream Holdings, Inc.	Delaware
Constellation Holdings, LLC	Maryland
Constellation International Holdings, Inc.	Marshall Islands
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy - Gas Division, LLC	Kentucky
Constellation NewEnergy Canada Inc.	Ontario
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Operating Services	California
Constellation Power Source Generation, LLC	Maryland

Constellation Power, Inc.	Maryland
Constellation Sacramento Holding, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Georgia, LLC	Georgia
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland MC, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
Cool Planet Energy Systems, Inc.	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
COSI Ultra II, Inc.	Maryland
COSI Ultra, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CPower Holdings, LLC	Delaware
CR Clearing, LLC	Missouri
Criterion Power Partners, LLC	Delaware
DAJAW Transmission LLC	Minnesota
Denver Airport Solar, LLC	Delaware
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
eCurv Inc.	Delaware
Energy Performance Services, Inc.	Pennsylvania
Essess Inc.	Delaware
Ewington Energy Systems LLC	Minnesota
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, Inc.	Pennsylvania
Exelon Generation Limited	United Kingdom
Exelon New Boston, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon Peaker Development Limited, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon Solar Chicago LLC	Delaware

Exelon West Medway II, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
ExGen Renewables I Holding, LLC	Delaware
ExGen Renewables I, LLC	Delaware
ExGen Texas II Power Holdings, LLC	Delaware
ExGen Texas II Power, LLC	Delaware
ExGen Texas Power Holdings, LLC	Delaware
ExGen Texas Power Services, LLC	Delaware
ExGen Texas Power, LLC	Delaware
ExGen Ventures International Holdings II Limited	United Kingdom
ExGen Ventures International Holdings Limited	United Kingdom
Fair Wind Power Partners, LLC	Delaware
FloDesign	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
G-Flow Wind, LLC	Minnesota
Grande Prairie Generation, Inc.	Alberta
Green Acres Breeze, LLC	Minnesota
Greensburg Wind Farm, LLC	Delaware
Handley Power, LLC	Delaware
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho
Integrys Energy Services - Electric, LLC	Delaware
Integrys Energy Services - Natural Gas, LLC	Delaware
Integrys Energy Services of New York, Inc.	New York
Integrys Energy Services, Inc.	Wisconsin
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
LaPorte Power, LLC	Delaware
Las Vegas District Energy, LLC	Delaware
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Luz Solar Partners Ltd., IV	California
Luz Solar Partners Ltd., V	California
Luz Solar Partners Ltd., VI	California
Marshall Wind 1, LLC	Minnesota

Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Minnesota Breeze, LLC	Minnesota
Mohave Sunrise Solar I, LLC	Arizona
Mountain Creek Power, LLC	Delaware
Mountain Top Wind Power, LLC	Maryland
MXENERGY (CANADA) LTD.	Nova Scotia
MxEnergy Holdings Inc.	Delaware
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Ogin Inc.	Delaware
Oregon Trail Windfarm, LLC	Oregon
Outback Solar, LLC	Oregon
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada
Pegasus Power Company, Inc.	California
Pegasus Power Partners, a California Limited Partnership	California
Pinedale Energy, LLC	Colorado
Poseidon Interconnect, LLC	Delaware
Powerhouse Dynamics Inc.	Delaware
Prairie Wind Power LLC	Minnesota
Proterra Inc.	Delaware
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Residential Solar Holding, LLC	Delaware
Residential Solar II, LLC	Delaware
Roadrunner-I LLC	Minnesota
Sacramento PV Energy, LLC	Delaware
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Salty Dog-I LLC	Minnesota
Salty Dog-II LLC	Minnesota
Sand Ranch Windfarm, LLC	Oregon
Sendero Wind Energy, LLC	Delaware
Shane’s Wind Machine LLC	Minnesota
Shooting Star Wind Project, LLC	Delaware
Simmons & Eastern, LLC	Delaware
Solarbridge Technologies Inc.	Delaware
Star Electricity, Inc.	Texas
Sunnyside Cogeneration Associates	Utah
Sunnyside Generation, LLC	Delaware
Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Sunnyside Properties, LLC	Utah
Sunset Breeze, LLC	Minnesota
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware

TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
W&D Gas Partners, LLC	Delaware
Wagon Trail, LLC	Oregon
Wally's Wind Farm LLC	Minnesota
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Windy Dog-1 LLC	Minnesota
Wolf Hollow I Power, LLC	Delaware
Wolf Hollow II Power, LLC	Delaware
Wolf Hollow Services, LLC	Delaware
Wolf Wind Enterprises, LLC	Minnesota
Wolf Wind Transmission, LLC	Minnesota
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Commonwealth Edison Company

Subsidiary	Jurisdiction
ComEd Financing III	Delaware
Commonwealth Edison Company of Indiana, Inc.	Indiana
RITELine Illinois, LLC	Illinois

PECO Energy Company

Subsidiary	Jurisdiction
ATNP Finance Company	Delaware
ExTel Corporation, LLC	Delaware
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital Trust V	Delaware
PECO Energy Capital Trust VI	Delaware
PECO Wireless, LLC	Delaware

Baltimore Gas and Electric Company

Subsidiary	Jurisdiction
BGE Capital Trust II	Delaware
RSB BondCo LLC	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. No.333-196220) and on Form S-8 (No.333-189849, No.333-175162, No.333-127377, No.333-37082 and No.333-49780) of Exelon Corporation of our report dated February 13, 2015 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting of Exelon Corporation, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2015

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-196220-04) and Form S-4 (No. 333-184712) of Exelon Generation Company, LLC of our report dated February 13, 2015 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Exelon Generation Company, LLC, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2015

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-196220-03) of Commonwealth Edison Company of our report dated February 13, 2015 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Commonwealth Edison Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2015

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-196220-02) of PECO Energy Company of our report dated February 13, 2015 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of PECO Energy Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 13, 2015

Exhibit 23.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-196220-01) of Baltimore Gas and Electric Company of our report dated February 13, 2015 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Baltimore Gas and Electric Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anthony K. Anderson** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Anthony K. Anderson
Anthony K. Anderson

DATE: February 9, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ann C. Berzin
Ann C. Berzin

DATE: February 6, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John A. Canning, Jr.** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John A. Canning, Jr.
John A. Canning, Jr.

DATE: February 11, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Darryl M. Bradford attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 8, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Yves C. de Balmann** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Yves C. de Balmann
Yves C. de Balmann

DATE: February 4, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis
Nicholas DeBenedictis

DATE: February 8, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Paul Joskow** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Paul L. Joskow
Paul L. Joskow

DATE: February 4, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Robert J. Lawless** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Robert J. Lawless
Robert J. Lawless

DATE: February 4, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Richard W. Mies** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Richard W. Mies
Richard W. Mies

DATE: February 8, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **William C. Richardson** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ William C. Richardson
William C. Richardson

DATE: February 6, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John W. Rogers, Jr.** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John W. Rogers, Jr.
John W. Rogers, Jr.

DATE: February 4, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Mayo A. Shattuck III** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Mayo A. Shattuck III
Mayo A. Shattuck III

DATE: February 4, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Stephen D. Steinour** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Stephen D. Steinour
Stephen D. Steinour

DATE: February 6, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James W. Compton** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ James W. Compton
James W. Compton

DATE: February 6, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 8, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **A. Steven Crown** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ A. Steven Crown
A. Steven Crown

DATE: February 3, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis
Nicholas DeBenedictis

DATE: February 8, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Peter V. Fazio, Jr.** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Peter V. Fazio, Jr.
Peter V. Fazio, Jr.

DATE: February 5, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael H. Moskow** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael H. Moskow
Michael H. Moskow

DATE: February 6, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien
Denis P. O'Brien

DATE: February 3, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anne R. Pramaggiore** , do hereby appoint Thomas S. O'Neill attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Anne R. Pramaggiore
Anne R. Pramaggiore

DATE: February 10, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Craig L. Adams** , do hereby appoint Romulo L. Diaz, Jr. attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Craig L. Adams
Craig L. Adams

DATE: February 3, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 8, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **M. Walter D'Alessio** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ M. Walter D'Alessio
M. Walter D'Alessio

DATE: February 4, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis
Nicholas DeBenedictis

DATE: February 8, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien
Denis P. O'Brien

DATE: February 3, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ronald Rubin** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ronald Rubin
Ronald Rubin

DATE: February 3, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ann C. Berzin
Ann C. Berzin

DATE: February 6, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane
Christopher M. Crane

DATE: February 8, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael E. Cryor** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael E. Cryor
Michael E. Cryor

DATE: February 4, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James R. Curtiss** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ James R. Curtiss
James R. Curtiss

DATE: February 6, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Calvin G. Butler, Jr.,** do hereby appoint Daniel P. Gahagan attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Calvin G. Butler, Jr.
Calvin G. Butler, Jr.

DATE: February 6, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Joseph Haskins, Jr.** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Joseph Haskins, Jr.
Joseph Haskins, Jr.

DATE: February 4, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Carla D. Hayden** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Carla D. Hayden
Carla D. Hayden

DATE: February 3, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien
Denis P. O'Brien

DATE: February 3, 2015

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael D. Sullivan** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2014 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael D. Sullivan
Michael D. Sullivan

DATE: February 4, 2015

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2015

/s/ CHRISTOPHER M. CRANE
President and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2015

/s/ Jonathan W. Thayer

Senior Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2015

/s/ Kenneth W. Cornew
President and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2015

/s/ B RYAN P. W RIGHT
Chief Financial Officer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2015

/s/ Anne R. Pramaggiore
President and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2015

/s/ J OSEPH R. T RPIK , J R .

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2015

/s/ C RAIG L. A DAMS
President and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2015

/s/ P HILLIP S. B ARNETT

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Calvin G. Butler, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2015

/s/ C ALVIN G. B UTLER
Chief Executive Officer
(Principal Executive Officer)

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Vahos, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2015

/s/ David M. Vahos

Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

Date: February 13, 2015

/s/ C HRISTOPHER M. C RANE

Christopher M. Crane
President and Chief Executive Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

Date: February 13, 2015

/s/ J ONATHAN W. T HAYER

Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15 (d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

Date: February 13, 2015

/s/ KENNETH W. CORNEW

Kenneth W. Cornew
President and Chief Executive Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15 (d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

Date: February 13, 2015

/s/ B RYAN P. W RIGHT

Bryan P. Wright
Chief Financial Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15 (d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

Date: February 13, 2015

/s/ Anne R. Pramaggiore
Anne R. Pramaggiore
President and Chief Executive Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15 (d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

Date: February 13, 2015

/s/ J OSEPH R. T RPIK , J R .

Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

Date: February 13, 2015

/s/ C RAIG L. A DAMS

Craig L. Adams
President and Chief Executive Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

Date: February 13, 2015

/s/ P HILLIP S. B ARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

Date: February 13, 2015

/s/ C ALVIN G. B UTLER , J R .
Calvin G. Butler, Jr.
Chief Executive Officer

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

Date: February 13, 2015

/s/ David M. Vahos

David M. Vahos
Vice President, Chief Financial Officer and Treasurer

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2015

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number	Exact Name of Registrant as Specified in its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
EXELON CORPORATION:	
Common Stock, without par value	New York and Chicago
Series A Junior Subordinated Debentures	New York
Corporate Units	New York
PECO ENERGY COMPANY:	
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York
BALTIMORE GAS AND ELECTRIC COMPANY:	
6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, by Baltimore Gas and Electric Company	New York

Securities registered pursuant to Section 12(g) of the Act:

COMMONWEALTH EDISON COMPANY:
Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes ☒	No ☐
Exelon Generation Company, LLC	Yes ☒	No ☐
Commonwealth Edison Company	Yes ☒	No ☐
PECO Energy Company	Yes ☒	No ☐
Baltimore Gas and Electric Company	Yes ☒	No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

	Large Accelerated	Accelerated	Non-Accelerated	Smaller Reporting Company
Exelon Corporation	✓			
Exelon Generation Company, LLC			✓	
Commonwealth Edison Company			✓	
PECO Energy Company			✓	
Baltimore Gas and Electric Company			✓	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2015 was as follows:

Exelon Corporation Common Stock, without par value	$ 27,049,825,290
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None
Baltimore Gas and Electric Company, without par value	None

The number of shares outstanding of each registrant's common stock as of January 31, 2016 was as follows:

Exelon Corporation Common Stock, without par value	919,924,742
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,973
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company, without par value	1,000

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2016 Annual Meeting of Shareholders and the Commonwealth Edison Company 2016 information statement are incorporated by reference in Part III.

S1-SSA-0009 - 14722

Exelon Generation Company, LLC, PECO Energy Company and Baltimore Gas and Electric Company meet the conditions set forth in General

Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form in the reduced disclosure format.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon's holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Antelope Valley, AVSR	Antelope Valley Solar Ranch One
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
ComEd Financing III	ComEd Financing III
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Energy Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
BGE Trust II	BGE Capital Trust II
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively

Other Terms and Abbreviations

1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CAP	Customer Assistance Program

Other Terms and Abbreviations

CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA and its subsidiaries
EE&C	Energy Efficiency and Conservation/Demand Response
EGR	ExGen Renewables I, LLC
EGS	Electric Generation Supplier
EGTP	ExGen Texas Power, LLC
EIMA	Illinois Energy Infrastructure Modernization Act
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt Hour
HAP	Hazardous Air Pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
Integrys	Integrys Energy Services, Inc.
IPA	Illinois Power Agency
IRC	Internal Revenue Code

Other Terms and Abbreviations

IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste
LTIP	Long-Term Incentive Plan
MATS	Mercury and Air Toxics Standard Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting including Calvert Cliffs, Nine Mile Point, Ginna, Clinton, Oyster Creek, Three Mile Island, Zion (a former ComEd unit), and portions of Peach Bottom (a former PECO unit)
NOSA	Nuclear Operating Services Agreement
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PHI	Pepco Holdings, Inc.

Other Terms and Abbreviations

PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
PPL	PPL Holtwood, LLC
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting including the former ComEd units (Braidwood, Byron, Dresden, LaSalle, Quad Cities) and the former PECO units (Limerick, Peach Bottom, Salem)
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
ROE	Return on Common Equity
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOA	Society of Actuaries
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
Upstream	Natural gas and oil exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by the Registrants. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

This Report contains certain forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a Registrants include those factors discussed herein, including those factors discussed with respect to such Registrant discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23; and (d) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants' websites at www.exeloncorp.com. Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I

ITEM 1. BUSINESS

General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through Generation, in the energy generation and power marketing business, and through ComEd, PECO and BGE, in the energy delivery businesses discussed below. Exelon's principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603, and its telephone number is 800-483-3220.

Generation

Generation's integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream). Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

Generation was formed in 2000 as a Pennsylvania limited liability company. Generation began operations as a result of a corporate restructuring, effective January 1, 2001, in which Exelon separated its generation and other competitive businesses from its regulated energy delivery businesses at ComEd and PECO.

Generation's principal executive offices are located at 300 Exelon Way, Kennett Square, Pennsylvania 19348, and its telephone number is 610-765-5959.

ComEd

ComEd's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in northern Illinois, including the City of Chicago.

ComEd was organized in the State of Illinois in 1913 as a result of the merger of Cosmopolitan Electric Company into the original corporation named Commonwealth Edison Company, which was incorporated in 1907. ComEd's principal executive offices are located at 440 South LaSalle Street, Chicago, Illinois 60605, and its telephone number is 312-394-4321.

PECO

PECO's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia.

PECO was incorporated in Pennsylvania in 1929. PECO's principal executive offices are located at 2301 Market Street, Philadelphia, Pennsylvania 19103, and its telephone number is 215-841-4000.

BGE

BGE's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in central Maryland, including the City of Baltimore.

BGE was incorporated in Maryland in 1906. BGE's principal executive offices are located at 110 West Fayette Street, Baltimore, Maryland 21201, and its telephone number is 410-234-5000.

Operating Segments

See Note 25—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's operating segments.

Pending Merger with Pepco Holdings, Inc.

On April 29, 2014, Exelon and PHI signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. The merger is expected to be completed in the first quarter of 2016. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the pending transaction.

Generation

Generation, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Constellation sells electricity and natural gas, including renewable energy, to both wholesale and retail customers. The retail sales include commercial, industrial and residential customers. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Generation's fleet, including its nuclear plants which consistently operate at high capacity factors, also provides geographic and supply source diversity. These factors help Generation mitigate the challenging conditions emanating from competitive energy markets. Generation's customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation also engages in natural gas and oil exploration and production activities (Upstream).

Generation is a public utility under the Federal Power Act and is subject to FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. FERC's jurisdiction over ratemaking also includes the authority to suspend the market-based rates of utilities and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate

reorganizations; and certain holding company acquisitions of public utility and holding company securities. Additionally, ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. Specific operations of Generation are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including the NRC and Federal and state environmental protection agencies. Additionally, Generation is subject to mandatory reliability standards promulgated by the NERC, with the approval of FERC.

RTOs and ISOs exist in a number of regions to provide transmission service across multiple transmission systems. PJM, MISO, ISO-NE and SPP, have been approved by FERC as RTOs, and CAISO and ISO-NY have been approved as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems.

Constellation Energy Nuclear Group, Inc.

Generation owns a 50.01% interest in CENG, a joint venture with EDF. CENG is governed by a board of ten directors, five of which are appointed by Generation and five by EDF. CENG owns a total of five nuclear generating facilities on three sites, Calvert Cliffs, R.E. Ginna and Nine Mile Point. CENG's ownership share in the total capacity of these units is 4,007 MW. See ITEM 2. PROPERTIES for additional information on these sites.

Generation and EDF also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDF has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interest in CENG at fair value on a fully consolidated basis in Exelon's and Generation's Consolidated Balance Sheets. Refer to Note 5— Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for further information regarding the integration transaction.

Significant Acquisitions

Integrys Energy Services, Inc. On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (Integrys) for a purchase price of $332 million, including net working capital. The generation and solar asset businesses of Integrys were excluded from the transaction. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the above acquisition.

Merger with Constellation Energy Group, Inc. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger. Since the merger transaction, Generation includes the former Constellation generation and customer supply operations.

Antelope Valley Solar Ranch One. On September 30, 2011, Exelon completed the acquisition of all of the interests in Antelope Valley, a 242-MW solar project under development in northern Los Angeles County, California, from First Solar, Inc. The facility became fully operational in 2014. The project has a 25-year PPA with Pacific Gas & Electric Company for the full output of the plant, which has been approved by the CPUC. Total capitalized costs for the facility incurred through completion of the project were approximately $1.1 billion.

Wolf Hollow Generating Station. On August 24, 2011, Generation completed the acquisition of all of the equity interests of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, for a purchase price of $311 million which increased Generation's owned capacity within the ERCOT power market by 704 MWs.

Significant Dispositions

Asset Divestitures. As of December 31, 2015, Generation has sold certain generating assets with total pre-tax proceeds of $1.8 billion (after-tax proceeds of approximately $1.4 billion). The proceeds are expected to be used primarily to finance a portion of the acquisition of PHI.

Maryland Clean Coal Stations. On November 30, 2012, a subsidiary of Generation sold the Brandon Shores generating station and H.A. Wagner generating station in Anne Arundel County, Maryland, and the C.P. Crane generating station in Baltimore County, Maryland to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC to comply with certain of the regulatory approvals required by the merger with Constellation Energy Group, Inc. for net proceeds of approximately $371 million, which resulted in a pre-tax impairment charge of $272 million.

See Note 4—Mergers, Acquisitions, and Dispositions and Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Generating Resources

At December 31, 2015, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [a][b]	
Nuclear	19,460
Fossil (primarily natural gas)	9,682
Renewable [c]	3,599
Owned generation assets	32,741
Long-term power purchase contracts	7,419
Total generating resources	40,160

(a) See "Fuel" for sources of fuels used in electric generation.
(b) Net generation capacity is stated at proportionate ownership share. See ITEM 2. PROPERTIES—Generation for additional information.
(c) Includes hydroelectric, wind, and solar generating assets.

Generation has six reportable segments, the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions, representing the different geographical areas in which Generation's customer-facing activities are conducted and where Generation's generating resources are located.

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina (approximately 36% of capacity).

- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee; and the United States footprint of MISO (excluding MISO's Southern Region), which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, and the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM; and parts of Montana, Missouri and Kentucky (approximately 37% of capacity).
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 7% of capacity).
- New York represents the operations within ISO-NY, which covers the state of New York in its entirety (approximately 3% of capacity).
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas (approximately 11% of capacity).
- Other Power Regions is an aggregate of regions not considered individually significant (approximately 6% of capacity).

See Note 25—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers and revenues net of purchased power and fuel expense for each of Generation's reportable segments.

Nuclear Facilities

Generation has ownership interests in fourteen nuclear generating stations currently in service, consisting of 24 units with an aggregate of 19,460 MW of capacity. Generation wholly owns all of its nuclear generating stations, except for Quad Cities Generating Station (75% ownership), Peach Bottom Generating Station (50% ownership), and Salem Generating Station (Salem) (42.59% ownership), which are consolidated on Exelon's and Generation's financial statements relative to its proportionate ownership interest in each unit. In addition, Generation owns a 50.01% interest, collectively, in the CENG generating stations (Calvert Cliffs, Nine Mile Point [excluding LIPA's 18% ownership interest in Nine Mile Point Unit 2] and R.E. Ginna) which are 100% consolidated on Exelon and Generation's financial statements as of April 1, 2014. See Note 5—Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's nuclear generating stations are all operated by Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. In 2015, 2014 and 2013 electric supply (in GWh) generated from the nuclear generating facilities was 68%, 67% and 57%, respectively, of Generation's total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation's electric supply sources.

Nuclear Operations. Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on Generation's results of operations. As the largest generator of nuclear power in the United States, Generation can negotiate favorable terms for the materials and services that its business requires. Generation's operations from its nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

During 2015, 2014 and 2013, the nuclear generating facilities operated by Generation achieved capacity factors of 93.7%, 94.3% and 94.1%, respectively. The capacity factors reflect ownership percentage of stations operated by Generation and include CENG as of April 1, 2014. Generation manages its scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for Generation's wholesale and retail marketing and trading activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations.

In addition to the maintenance and equipment upgrades performed by Generation during scheduled refueling outages, Generation has extensive operating and security procedures in place to ensure the safe operation of the nuclear units. Generation has extensive safety systems in place to protect the plant, personnel and surrounding area in the unlikely event of an accident or other incident.

Regulation of Nuclear Power Generation. Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of January 6, 2016, the NRC categorized Clinton and Dresden unit 2 in the Regulatory Response Column, which is the second highest of five performance bands. All other units operated by Generation are categorized in the Licensee Response Column as of December 31, 2015, which is the highest performance band. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. For additional information on the NRC actions related to the Japan Earthquake and Tsunami and the industry's response, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Executive Overview.

Licenses . Generation has 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals for Peach Bottom Units 2 and 3, Dresden Units 2 and 3, Quad Cities Units 1 and 2, Oyster Creek Unit 1, Calvert Cliffs Units 1 and 2, Nine Mile Point Units 1 and 2, R.E. Ginna Unit 1, Three Mile Island Unit 1, Limerick Units 1 and 2, Byron Units 1 and 2 and Braidwood Units 1 and 2. Additionally, PSEG has 40-year operating licenses from the NRC and has received 20-year operating license renewals for Salem Units 1 and 2. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. The following table summarizes the current operating license expiration dates for Generation's nuclear facilities in service:

Station	Unit	In-Service Date [a]	Current License Expiration
Braidwood [c]	1	1988	2046
	2	1988	2047
Byron [c]	1	1985	2044
	2	1987	2046
Calvert Cliffs [c]	1	1975	2034
	2	1977	2036
Clinton [d]	1	1987	2026
Dresden [c]	2	1970	2029
	3	1971	2031
LaSalle [b]	1	1984	2022
	2	1984	2023
Limerick [c]	1	1986	2044
	2	1990	2049
Nine Mile Point [c]	1	1969	2029
	2	1988	2046
Oyster Creek [c][e]	1	1969	2029
Peach Bottom [c]	2	1974	2033
	3	1974	2034
Quad Cities [c]	1	1973	2032
	2	1973	2032
R.E. Ginna [c]	1	1970	2029
Salem [c]	1	1977	2036
	2	1981	2040
Three Mile Island [c]	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) In December 2014, Generation submitted applications to the NRC to extend the operating licenses of LaSalle Units 1 and 2 by 20 years.
(c) Stations for which the NRC has issued renewed operating licenses.
(d) Although timing has been delayed, Generation currently plans to seek license renewal for Clinton and has advised the NRC that any license renewal application would not be filed until the first quarter of 2021.
(e) In December 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

Generation currently has a license renewal application pending for LaSalle Units 1 and 2. Generation has advised the NRC that any license renewal application for Clinton would not be filed until the first quarter of 2021. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC's review. The NRC review process takes approximately two years from the docketing of an application. Each requested license renewal is expected to be for 20 years beyond the original operating license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual and assumed renewal of operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek.

In August 2012, Generation entered into an operating services agreement with the Omaha Public Power District (OPPD) to provide operational and managerial support services for the Fort Calhoun Station and a licensing agreement for use of the Exelon Nuclear Management Model. The terms for both agreements are 20 years. OPPD will continue to own the plant and remain the NRC licensee.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Once all projects are completed in 2016, Generation will have placed in-service 538 MWs of new nuclear generation.

As of December 31, 2015, under the nuclear uprate program, Generation has placed into service projects representing 536 MWs of new nuclear generation at a cost of $1,436 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's Consolidated Balance Sheets.

Nuclear Waste Storage and Disposal. There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by its nuclear generating facilities in on-site storage pools or in dry cask storage facilities. Since Generation's SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, Generation has developed dry cask storage facilities to support operations.

As of December 31, 2015, Generation had approximately 75,800 SNF assemblies (18,800 tons) stored on site in SNF pools or dry cask storage (this includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party; see Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for Clinton and Three Mile Island, in which on-site dry cask storage will be in operation at Clinton in 2016 and is projected to be in operation at Three Mile Island in 2023. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites through the end of the license renewal periods and through decommissioning.

For a discussion of matters associated with Generation's contracts with the DOE for the disposal of SNF, see Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into such an agreement, although neither state currently has an operational site and none is anticipated to be operational until after 2020.

Generation ships its Class A LLRW, which represents 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Oyster Creek and Salem), and Connecticut.

Generation utilizes on-site storage capacity at all its stations to stage for shipping campaigns and store, as needed, Class B and Class C LLRW. Generation has a contract through 2032 to ship Class B

and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all current Class B and Class C LLRW currently stored at each station as well as the Class B and Class C LLRW generated during the term of the agreement. However, because the production of LLRW from Generation's nuclear fleet will exceed the capacity at the Texas site (3.9 million curies for 15 years beginning in 2012), Generation will still be required to utilize on-site storage at its stations for Class B and Class C LLRW. Generation currently has enough storage capacity to store all Class B and C LLRW for the life of all stations in Generation's nuclear fleet. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize cost impacts and on-site storage.

Nuclear Insurance. Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See "Nuclear Insurance" within Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. PROPERTIES—Generation. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and results of operations.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview; ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates, Nuclear Decommissioning, Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Note 3—Regulatory Matters, Note 12—Fair Value of Financial Assets and Liabilities and Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation's NDT funds and its decommissioning obligations.

Zion Station Decommissioning. On December 11, 2007, Generation entered into an Asset Sale Agreement (ASA) with EnergySolutions, Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, LLC (ZionSolutions) under which ZionSolutions assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998.

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request reimbursement; specifically, if certain milestones as defined in the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. See Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning and see Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for a discussion of variable interest entity considerations related to ZionSolutions.

Fossil and Renewable Facilities (including Hydroelectric)

Generation has ownership interests in 13,281 MW of capacity in fossil and renewable generating facilities currently in service. Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Wyman; (2) an ownership interest through an equity method investment in Sunnyside; (3) certain wind project entities with minority interest owners; and (4) an ownership interest in the Albany Green Energy, LLC project entity, see Note 2— Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information on these wind project entities. Generation's fossil and renewable generating stations are all operated by Generation, with the exception of LaPorte, Sunnyside and Wyman, which are operated by third parties. In 2015, 2014 and 2013, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 8%, 13% and 15%, respectively, of Generation's total electric supply. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. For additional information regarding Generation's electric generating facilities, see ITEM 2. PROPERTIES—Exelon Generation Company, LLC and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS— Exelon Corporation, Executive Overview for additional information on Generation Renewable Development.

Licenses. Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid. On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively. On December 22, 2015, FERC issued a new 40-year license for Muddy Run. The license term expires on December 1, 2055. Based on the FERC procedural schedule, the FERC licensing process was not completed prior to the expiration of Conowingo's license on September 1, 2014. FERC is required to issue an annual license for a facility until the new license is issued. On September 10, 2014, FERC issued an annual license for Conowingo, effective as of the expiration of the previous license. If FERC does not issue a new license prior to the expiration of annual license, the annual license will renew automatically. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. Refer to Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Insurance. Generation maintains business interruption insurance for its renewable and fossil projects, and delay in start-up insurance for its renewable and fossil projects currently under construction. Generation does not purchase business interruption insurance for its wholly owned fossil and hydroelectric operations, unless required by financing agreements; see Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on financing agreements. Generation maintains both property damage and liability insurance. For property damage and liability claims for these operations, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon's and Generation's financial condition and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. PROPERTIES—Exelon Generation Company, LLC.

Long-Term Power Purchase Contracts

In addition to energy produced by owned generation assets, Generation sources electricity and other related output from plants it does not own under long-term contracts. The following tables summarize Generation's long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2015:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	16	2016 - 2032	805
Midwest	7	2016 - 2022	1,536
New England	8	2016 - 2017	650
ERCOT	5	2020 - 2031	1,501
Other Power Regions	12	2016 - 2030	2,927
Total	48		7,419

	2016	2017	2018	2019	2020
Capacity Expiring (MW)	586	1,761	101	627	980

Fuel

The following table shows sources of electric supply in GWh for 2015 and 2014:

	Source of Electric Supply	
	2015	2014
Nuclear [(a)]	175,474	166,454
Purchases—non-trading portfolio [(b)]	61,592	48,200
Fossil (primarily natural gas)	14,937	26,324
Renewable [(c)]	5,982	6,429
Total supply	257,985	247,407

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g., CENG). Nuclear generation for 2015 and 2014 includes physical volumes of 33,415 GWh and 25,053 GWh, respectively, for CENG.
(b) Purchased power for 2015 and 2014 includes physical volumes of 0 GWh and 5,346 GWh, respectively, as a result of the PPA with CENG. On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, 100% of CENG volumes are included in nuclear generation after April 1, 2014.
(c) Includes hydroelectric, wind, and solar generating assets.

The fuel costs per MWh for nuclear generation are less than those for fossil-fuel generation. Consequently, nuclear generation is generally the most cost-effective way for Generation to meet its wholesale and retail load servicing requirements.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has uranium concentrate inventory and supply contracts sufficient to meet all of its uranium concentrate requirements through 2018. Generation's contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2018. All of Generation's enrichment requirements have been contracted through 2020. Contracts for fuel fabrication have been obtained through 2022. Generation does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures. Generation also hedges forward price risk, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation's integrated business operations include the physical delivery and marketing of power obtained through its generation capacity and through long-term, intermediate-term and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. Generation has also contracted for access to additional generation through bilateral long-term PPAs. PPAs, including tolling agreements, are commitments related to power generation of specific generation plants and/or are dispatchable in nature similar to asset ownership depending on the type of underlying asset. Generation secures contracted generation as part of its overall strategic plan, with objectives such as obtaining low-cost energy supply sources to meet its physical delivery obligations to both wholesale and retail customers and assisting customers to meet renewable portfolio standards. Generation may also buy power in the market to meet the energy demand of its customers. Generation sells electricity, natural gas, and related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets. Generation's customer facing operations combine a unified sales force with a customer-centric model that leverages technology to broaden the range of products and solutions offered, which Generation believes promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which provides a platform that is scalable and able to capitalize on opportunities for future growth.

Generation may purchase more than the energy demanded by its customers. Generation then sells this open position, along with capacity not used to meet customer demand, in the wholesale electricity markets. Where necessary, Generation also purchases transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs in markets without an organized RTO. Generation also incorporates contingencies into its planning for extreme weather conditions, including potentially reserving capacity to meet summer loads at levels representative of warmer-than-normal weather conditions. Additionally, Generation is involved in the development, exploration, and harvesting of oil, natural gas and natural gas liquids properties (Upstream).

Price Supply Risk Management

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation also enters into transactions that are outside of this ratable sales plan. Generation is exposed to commodity price risk in 2016 and beyond for portions of its electricity portfolio that are unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. As of December 31, 2015, the percentage of expected generation hedged for the major reportable segments was 90%-93%, 60%-63% and 28%-31% for 2016, 2017, and 2018, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation.

Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including sales to ComEd, PECO and BGE to serve their retail load. A portion of Generation's hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. The corporate risk management group and Exelon's RMC monitor the financial risks of the wholesale and retail power marketing activities. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation's efforts. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop-loss and value-at-risk limits, to manage exposure to market risk. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

At December 31, 2015, Generation's short and long-term commitments relating to the purchase of energy and capacity from and to unaffiliated utilities and others were as follows:

(in millions)	Net Capacity Purchases [a]	REC Purchases [b]	Transmission Rights Purchases [c]	Total
2016	$ 262	$ 229	$ 15	$ 506
2017	197	269	21	487
2018	92	115	23	230
2019	97	34	24	155
2020	40	1	16	57
Thereafter	221	1	35	257
Total	$ 909	$ 649	$ 134	$ 1,692

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2015, net of fixed capacity payments expected to be received ("Capacity offsets") by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. As of December 31, 2015, capacity offsets were $146 million, $149 million, $150 million, $151 million, $142 million, and $462 million for years 2016, 2017, 2018, 2019, 2020, and thereafter, respectively. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.
(b) The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

Capital Expenditures

Generation's business is capital intensive and requires significant investments in nuclear fuel and energy generation assets and in other internal infrastructure projects. Generation's estimated capital expenditures for 2016 are as follows:

(in millions)	
Nuclear fuel [a][b]	$ 1,150
Growth	1,350
Production plant [b]	950
Renewable energy projects	25
Other	125
Total	$ 3,600

(a) Includes Generation's share of the investment in nuclear fuel for the co-owned Salem plant.
(b) Includes the CENG units on a fully consolidated basis.

ComEd

ComEd is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in northern Illinois. ComEd is a public utility under the Illinois Public Utilities Act subject to regulation by the ICC related to distribution rates and service, the issuance of securities and certain other aspects of ComEd's business. ComEd is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of ComEd's business. Specific operations of ComEd are also subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, ComEd is subject to NERC mandatory reliability standards.

ComEd's franchises are sufficient to permit it to engage in the business it now conducts. ComEd's franchise rights are generally nonexclusive rights documented in agreements and, in some cases, certificates of public convenience issued by the ICC. With few exceptions, the franchise rights have stated expiration dates ranging from 2016 to 2066. ComEd anticipates working with the appropriate governmental bodies to extend or replace the franchise agreements prior to expiration.

PECO

PECO is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia. PECO is a public utility under the Pennsylvania Public Utility Code subject to regulation by the PAPUC related to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of PECO's business. PECO is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of PECO's business and by the U.S. Department of Transportation related to pipeline safety and other areas of gas operations. Specific operations of PECO are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, PECO is also subject to NERC mandatory reliability standards.

PECO has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities or territories in which it now supplies such services. PECO's authorizations consist of charter rights and certificates of public convenience issued by the PAPUC and/or "grandfathered rights," with all of such rights generally unlimited as to time and generally exclusive from competition from other electric and natural gas utilities. In a few defined municipalities, PECO's natural gas service territory authorizations overlap with that of another natural gas utility; however, PECO does not consider those situations as posing a material competitive or financial threat.

BGE

BGE is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in central Maryland, including the City of Baltimore. BGE is a public utility under the Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC related to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of BGE's business. BGE is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of BGE's business and by the U.S. Department of Transportation related to pipeline safety and other areas of gas operations. Specific operations of BGE are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, BGE is also subject to NERC mandatory reliability standards.

BGE has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities and territories in which it now supplies such services. With respect to electric distribution service, BGE's authorizations consist of charter rights, a state-wide franchise grant and a franchise grant from the City of Baltimore. The franchise rights are nonexclusive and are perpetual. With respect to natural gas distribution service, BGE's authorizations consist of charter rights, a perpetual state-wide franchise grant and franchises granted by all the municipalities and/or governmental bodies in which BGE now supplies services. The franchise grants are not exclusive; some are perpetual and some are for a limited duration, which BGE anticipates being able to extend or replace prior to expiration.

ComEd, PECO and BGE

Utility Operations

Service Territories. The following table presents the size of retail service territories, populations of each retail service territory and the number of retail customers within each retail service territory for ComEd, PECO and BGE as of December 31, 2015:

	Retail Service Territories (in square miles)			Retail Service Territory Population (in millions)			Number of Retail Customers (in millions)		
	Total	Electric	Natural gas	Total	Electric	Natural gas	Total	Electric	Natural gas
ComEd	11,400	11,400	n/a	9.0[a]	9.0	n/a	3.8	3.8	n/a
PECO	2,100	1,900	1,900	4.6[b]	4.0	3.1	2.1	1.6	0.5
BGE	2,300	2,300	800	3.0[c]	3.0	1.7	1.3	1.3	0.7

(a) Includes approximately 2.8 million in the city of Chicago.
(b) Includes approximately 1.6 million in the city of Philadelphia.
(c) Includes approximately 0.6 million in the city of Baltimore.

Peak Deliveries. ComEd, PECO and BGE electric sales and peak load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. For PECO and BGE, natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating.

The following table summarizes peak deliveries for ComEd, PECO and BGE for electric and gas deliveries during peak demand months as of December 31, 2015:

	Electric Peak Deliveries (in GW)				Natural Gas Peak Deliveries (in mmcfs)	
	Summer peak date	Summer deliveries	Winter peak date	Winter deliveries	Winter peak date	Winter deliveries
ComEd	7/20/2011	23.75	1/6/2014	16.51	n/a	n/a
PECO	7/22/2011	8.98	1/7/2014	7.17	2/15/2015	777
BGE	7/21/2011	7.23	2/20/2015	6.71	2/19/2015	777

Electric and Natural Gas Distribution Services. ComEd, PECO and BGE are allowed to recover reasonable costs and fair and prudent capital expenditures associated with electric and natural gas distribution services and earn a return on those capital expenditures, subject to commission approval. ComEd recovers costs through a performance-based rate formula, pursuant to EIMA. ComEd is required to file an update to the performance-based rate formula on an annual basis. PECO's and BGE's electric and gas distribution costs are recovered through traditional rate case proceedings. In certain instances, ComEd, PECO and BGE use specific recovery mechanisms as approved by the ICC, PAPUC, and MDPSC, respectively.

Through the ICC, ComEd is obligated to deliver electricity to customers in their respective service territories and also retain significant default service obligations (referred to as POLR) to provide electricity to certain groups of customers in their respective service areas who do not choose a competitive electric generation supplier. Through the PAPUC and MDPSC, PECO and BGE, respectively, are obligated to deliver electricity and natural gas to customers in their respective service territories and also retain significant default service obligations (referred to as DSP and SOS for electric and PGC and MBR for natural gas, respectively) to provide electricity or natural gas to certain groups of customers in their respective service areas who do not choose a competitive electric generation supplier or a competitive natural gas supplier. ComEd is permitted to recover electric costs, and PECO and BGE are permitted to recover electric and natural gas procurement costs from retail customers. Therefore, fluctuations in electric and natural gas procurement costs have no impact on electric and natural gas revenue net of purchased power and fuel expense.

ComEd customers have the choice to purchase electricity, and PECO and BGE customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenues collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenue net of purchased power and fuel expense. For those customers that choose a competitive electric generation or natural gas supplier, ComEd, PECO and BGE may act as the billing agent but do not record revenues or purchased power and fuel expense related to the electric and natural gas procurement costs. ComEd, PECO and BGE remain the distribution service providers for all customers in their respective service territories and charge a regulated rate for distribution service.

Retail customers participating in customer choice programs, and retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of GWh and mmcf sales, respectively) for ComEd, PECO and BGE consisted of the following at December 31, 2015, 2014 and 2013:

	December 31, 2015					
	Number of retail customers		% of total retail customers		Deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd [(a)]	1,655,400	n/a	42%	n/a	76%	n/a
PECO	563,400	81,100	35%	16%	70%	25%
BGE	343,000	154,000	27%	23%	61%	56%

	December 31, 2014					
	Number of retail customers		% of total retail customers		Deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd	2,426,900	n/a	63%	n/a	80%	n/a
PECO	546,900	78,400	34%	16%	70%	22%
BGE	364,000	161,000	29%	25%	60%	53%

	December 31, 2013					
	Number of retail customers		% of total retail customers		Deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd	2,630,200	n/a	68%	n/a	81%	n/a
PECO	531,500	66,400	34%	13%	68%	19%
BGE	399,000	172,000	32%	26%	61%	54%

(a) In September 2015, the City of Chicago discontinued its participation in the customer choice program and began purchasing its electricity from ComEd. Approximately 670,000 customers were impacted by the City of Chicago's decision which resulted in the reduction in the number of customers participating in customer choice programs in 2015.

Procurement-Related Proceedings. ComEd's, PECO's and BGE's electric supply for its customers is primarily procured through contracts as required by the ICC, PAPUC and MDPSC, respectively. ComEd, PECO and BGE procure electricity supply from various approved bidders, including Generation. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on ComEd's, PECO's and BGE's Statement of Operations and Comprehensive Income.

PECO's and BGE's natural gas supplies are purchased from a number of suppliers for terms of up to three years. PECO and BGE have annual firm supply from transportation contracts of 132,000 mmcf and 128,000 mmcf, respectively. In addition, to supplement gas supply at times of heavy winter demands and in the event of temporary emergencies, PECO and BGE have available storage capacity from the following sources:

	Peak Natural Gas Sources (in mmcf)		
	Liquefied Natural Gas Facility	Propane-Air Plant	Underground Storage Service Agreements [a]
PECO	1,200	150	18,000
BGE	1,055	546	22,000

(a) Natural gas from underground storage represents approximately 28% and 31% of PECO and BGE's 2015-2016 heating season planned supplies, respectively.

PECO and BGE have long-term interstate pipeline contracts and also participate in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between the utilities and customers. PECO and BGE make these sales as part of a program to balance its supply and cost of natural gas.

Energy Efficiency Programs. ComEd, PECO and BGE are also allowed to recover costs associated with energy efficiency and demand response programs. Each commission approved program seeks to meet mandated electric consumption reduction targets and implement demand response measures to reduce peak demand. The programs are designed to meet standards required by each respective regulatory agency.

Capital Investment. ComEd's, PECO's and BGE's businesses are capital intensive and requires significant investments, primarily in electric transmission and distribution and natural gas transportation and distribution facilities, to ensure the adequate capacity, reliability and efficiency of its system. ComEd's, PECO's and BGE's most recent estimates of capital expenditures for plant additions and improvements for 2016 are $2,425 million, $675 million and $825 million, respectively.

ComEd, PECO and BGE each have ICC, PAPUC and MDPSC, respectively, approved smart meter and smart grid deployment programs to enhance their distribution systems. The following table summarizes ComEd's smart meter and PECO's and BGE's smart meter and smart grid technology spending and meter installations as of December 31, 2015:

	December 31, 2015					
	Total Spend from Inception to Date		Total Meters to be Installed (in millions)		Meters Installed to Date	
	Projected	Actual	Electric	Natural gas	Electric	Natural gas
ComEd [a]	$ 2,615	$1,526	4.0	n/a	2.0	n/a
PECO [b]	818	803	1.7	0.5	1.7	0.5
BGE [c]	527	512	1.3	0.7	1.2	0.6

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(a) ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology. These amounts represent capital expenditures associated with ComEd's commitment.
(b) PECO will seek recovery of costs associated with PECO's gas AMI through the traditional rate case process.
(c) BGE is seeking recovery of its smart grid initiative costs as part of its 2015 electric and gas distribution rate case. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Services. ComEd, PECO and BGE provide unbundled transmission service under rates approved by FERC. FERC has used its regulation of transmission to encourage competition for wholesale generation services and the development of regional structures to facilitate regional wholesale markets. Under FERC's open access transmission policy promulgated in Order No. 888, ComEd, PECO and BGE, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. ComEd, PECO and BGE are required to comply with FERC's Standards of Conduct regulation governing the communication of non-public information between the transmission owner's employees and wholesale merchant employees.

PJM is the ISO and the FERC-approved RTO for the Mid-Atlantic and Midwest regions. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM Tariff). PJM operates the PJM energy, capacity and other markets, and, through central dispatch, controls the day-to-day operations of the bulk power system for the PJM region. ComEd, PECO and BGE are members of PJM and provide regional transmission service pursuant to the PJM Tariff. ComEd, PECO, BGE and the other transmission owners in PJM have turned over control of their transmission facilities to PJM, and their transmission systems are currently under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM members at rates based on the costs of transmission service.

ComEd 's and BGE's transmission rates are established based on a formula that was approved by FERC in January 2008 and April 2006, respectively. FERC's order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

PECO's customers are charged for PECO's PJM retail transmission services on a full and current basis through a Transmission Service Charge (applicable to default service only) and through a Non-Bypassable Transmission Charge (applicable to all distribution customers) in accordance with PECO's approved distribution rates.

See Note 3 — Regulatory Matters, Note 25—Segment Information of the Combined Notes to Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

Employees

As of December 31, 2015, Exelon and its subsidiaries had 29,762 employees in the following companies, of which 9,649 or 32% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 [(a)]	IBEW Local 614 [(b)]	Other CBAs [(c)]	Total Employees Covered by CBAs	Total Employees
Generation	1,688	102	2,424	4,214	14,512
ComEd	3,996	—	—	3,996	6,765
PECO	—	1,327	—	1,327	2,641
BGE	—	—	—	—	3,293
Other [(d)]	69	—	43	112	2,551
Total	5,753	1,429	2,467	9,649	29,762

(a) A separate CBA between ComEd and IBEW Local 15 covers approximately 61 employees in ComEd's System Services Group and was extended to April 1, 2016. Generation's and ComEd's separate CBAs with IBEW Local 15 expires in 2019.
(b) 1,327 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614, both expiring in 2021. Additionally, Exelon Power, an operating unit of Generation, has an agreement with IBEW Local 614, which expires in 2016 and covers 102 employees.
(c) During 2015, Generation finalized its CBA with Clinton Local 51 which will expire in 2020; its two CBAs with Local 369 at Mystic 7 and Mystic 8/9, both expiring in 2020; and four Security Officer unions at Braidwood, Byron, Clinton and TMI, all expiring between 2018 and 2021, respectively. During 2014, Generation finalized CBAs with TMI Local 777 and Oyster Creek Local 1289, expiring in 2019 and 2021, respectively and CENG finalized its CBA with Nine Mile Point which will expire in 2020. Additionally, during 2014, Generation finalized CBAs with the Security Officer unions at Dresden, LaSalle, Limerick and Quad Cities, which expire between 2017 and 2018. Lastly, during 2014, an agreement was negotiated with Las Vegas District Energy and IUOE Local 501, which will expire in 2018. During 2013, Generation finalized its CBA with the Security Officer union at Oyster Creek, expiring in 2016; as well as two other 3-year agreements: New England ENEH, UWUA Local 369, which will expire in 2017; and New Energy IUOE Local 95-95A, which will expire in 2016.
(d) Other includes shared services employees at BSC.

Environmental Regulation

General

Exelon, Generation, ComEd, PECO and BGE are subject to comprehensive and complex legislation regarding environmental matters by the federal government and various state and local jurisdictions in which they operate their facilities. The Registrants are also subject to regulations administered by the EPA and various state and local environmental protection agencies. Federal, state and local regulation includes the authority to regulate air, water, and solid and hazardous waste disposal.

The Exelon Board of Directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President, Corporate Strategy and Chief Sustainability Officer; the Corporate Environmental Strategy Director and the Environmental Regulatory Strategy Director, as well as senior management of Generation, ComEd, PECO and BGE. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. The Exelon Board of Directors has delegated to its corporate governance committee the authority to oversee Exelon's compliance with laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including Exelon's climate change and sustainability policies and programs, as discussed in further detail below. The Exelon Board of Directors has also delegated to its Generation Oversight Committee the authority to oversee environmental, health and safety issues relating to Generation. The respective Boards of ComEd, PECO and BGE, which each include directors who also serve on the Exelon Board of Directors, oversee environmental, health and safety issues related to ComEd, PECO and BGE.

Air Quality

Air quality regulations promulgated by the EPA and the various state and local environmental agencies in Illinois, Maryland, Massachusetts, New York, Pennsylvania and Texas in accordance with the Federal Clean Air Act impose restrictions on emission of particulates, sulfur dioxide (SO2), nitrogen oxides (NOx), mercury and other pollutants and require permits for operation of emissions sources. Such permits have been obtained by Exelon's subsidiaries and must be renewed periodically. The Clean Air Act establishes a comprehensive and complex national program to substantially reduce air pollution from power plants.

See ITEM 7.—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding clean air regulation in the forms of the CSAPR, the regulation of hazardous air pollutants from coal- and oil-fired electric generating facilities under MATS, and regulation of GHG emissions.

Water Quality

Under the Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the EPA or from the state environmental agency to which the permit program has been delegated and must be renewed periodically. Certain of Generation's power generation facilities discharge industrial wastewater into waterways and are therefore subject to these regulations and operate under NPDES permits or pending applications for renewals of such permits after being granted an administrative extension. Generation is also subject to the jurisdiction of certain other state and regional agencies and compacts, including the Delaware River Basin Commission and the Susquehanna River Basin Commission.

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, Ginna, Gould Street, Handley, Mountain Creek, Mystic 7, Nine Mile Point Unit 1, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill.

On October 14, 2014, the EPA's final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed to determine the best technology available to minimize adverse impacts on aquatic life, followed by an implementation period for the selected technology. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, Generation cannot estimate the effect that compliance with the rule will have on the operation of its generating facilities and its future results of operations, cash flows, and financial position. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility's economic viability would be called into question. However, the potential impact of the rule has been significantly reduced since the final rule does not mandate cooling towers as a national standard and sets forth technologies that are presumptively compliant, and the state permitting director is required to apply a cost-benefit test and can take into consideration site-specific factors.

New York Facilities . In July 2011, the New York Department of Environmental Conservation (DEC) issued a policy regarding the best available technology for cooling water intake structures. Through its policy, the DEC established closed-cycle cooling or its equivalent as the performance goal for all existing facilities, but also provided that the DEC will select a feasible technology whose costs are not wholly disproportionate to the environmental benefits to be gained and allows for a site-specific determination where the entrainment performance goal cannot be achieved. The Ginna and Nine Mile Point Unit 1 power generation facilities received renewals of their state water discharge permits in 2014.

Salem. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water system. In February 2006, PSEG filed a renewal application with the NJDEP allowing Salem to continue operating under its existing NPDES permit until a new permit was issued. On June 30, 2015, NJDEP issued a draft NPDES permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The draft permit was subject to a public notice and comment period and the NJDEP may make revisions before issuing the final permit expected during the first half of 2016.

Solid and Hazardous Waste

CERCLA provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at sites, most of which are listed by the EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight prior to listing on the NPL. Various states, including Illinois, Maryland and Pennsylvania, have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Generation, ComEd, PECO and BGE and their subsidiaries are, or are likely to become, parties to proceedings initiated by the EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party.

See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding solid and hazardous waste regulation and legislation.

Environmental Remediation

ComEd's, PECO's and BGE's environmental liabilities primarily arise from contamination at former MGP sites. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover environmental remediation costs of the MGP sites through a provision within customer rates. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The amount to be expended in 2016 at Exelon for compliance with environmental remediation related to contamination at former MGP sites and other gas purification sites is expected to total $38 million, consisting of $32 million and $6 million respectively, at ComEd and PECO.

Generation's environmental liabilities primarily arise from contamination at current and former generation and waste storage facilities. As of December 31, 2015, Generation has established an appropriate liability to comply with environmental remediation requirements including contamination attributable to low level radioactive residues at a storage and reprocessing facility named Latty Avenue, and at a disposal facility named West Lake Landfill, both near St. Louis, Missouri related to operations conducted by Cotter Corporation, a former ComEd subsidiary.

In addition, Generation, ComEd, PECO and BGE may be required to make significant additional expenditures not presently determinable for other environmental remediation costs.

See Notes 3—Regulatory Matters and 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' environmental remediation efforts and related impacts to the Registrants' results of operations, cash flows and financial positions.

Global Climate Change

Exelon believes the evidence of global climate change is compelling and that the energy industry, though not alone, is a significant contributor to the human-caused emissions of GHGs that many in the scientific community believe contribute to global climate change, and as reported by the Intergovernmental Panel on Climate Change in their Fifth Assessment Report Summary for Policy Makers issued in September 2013. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, hydroelectric, wind and solar photovoltaic), has a relatively small GHG emission profile, or carbon footprint, compared to other domestic generators of electricity. By virtue of its significant investment in low-carbon intensity assets, Generation's emission intensity, or rate of carbon dioxide equivalent (CO2e) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its natural gas-fired generating plants; CO2, methane and nitrous oxide are all emitted in this process, with CO2 representing the largest portion of these GHG emissions. GHG emissions from combustion of fossil fuels represent the majority of Exelon's direct GHG emissions in 2015, although only a small portion of Exelon's electric supply is from fossil generating plants. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF6) leakage in its electric transmission and distribution operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and fossil fuel generation of electricity used to power its facilities. Despite its focus on low-carbon generation, Exelon believes its operations could be significantly affected by the possible physical risks of climate change and by mandatory programs to reduce GHG emissions. See ITEM 1A. RISK FACTORS for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

Climate Change Regulation. Exelon is, or may become, subject to climate change regulation or legislation at the Federal, regional and state levels.

International Climate Change Regulation. At the international level, the United States is a Party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21 st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015. The Paris Agreement defines the UNFCCC's objective of limiting the global temperature increase to 1.5°C above pre-industrial levels. All Parties are required to develop their own national emission reductions and to update those reductions at least every five years. The Developed Country Parties, including the United States, are required to take the lead by undertaking economy-wide absolute emission reduction targets. The United States had previously submitted its national emission reductions to achieve a 2020 target of reducing net emissions in the range of 17% below the 2005 level and to achieve net greenhouse gas emission reductions of 26%—28% below the 2005 level by 2025. The United States has indicated that it intends to achieve these reductions through a variety of mechanisms, including regulations to cut carbon pollution from new and existing power plants. The Paris Agreement will enter into force on the thirtieth day after the date on which at least 55 Parties accounting for at least an estimated 55% of total global greenhouse gas emissions have ratified the Agreement.

Federal Climate Change Legislation and Regulation. It is highly uncertain that Federal legislation to reduce GHG emissions will be enacted. If such legislation is adopted, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits. In June 2013, the White House released the President's Climate Action Plan which consists of a wide variety of executive actions targeting GHG reductions, preparing for the impacts of climate change and showing leadership internationally; but the plan did not directly trigger any new requirements or legislative action.

The EPA is addressing the issue of carbon dioxide (CO_2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under

Section 111 of the Clean Air Act. Pursuant to the Climate Action Plan, President Obama directed the EPA to regulate new and modified fossil fired generating units under Section 111(b) of the Clean Air Act. The EPA finalized the rule in August 2015, and the final rule has been challenged in the U.S. Court of Appeals for the District of Columbia.

Under the President's memorandum, the EPA was also required to finalize a rule to establish CO_2 emission reduction requirements for existing fossil-fuel generating stations under Section 111(d) of the Clean Air Act. The final rule, known as the Clean Power Plan, became effective on December 22, 2015. The rule sets GHG emission reduction targets for each state, with reductions beginning in 2022, and the target achieved by 2030. States must submit an implementation plan to the EPA by September 2016, unless granted an extension of up to two years. States are granted latitude to select from a number of compliance options, which are designed to achieve the reductions in the most cost-effective manner. The final rule has been challenged in the U.S. Court of Appeals for the District of Columbia. On February 9, 2015, the U.S. Supreme Court issued a stay of the Clean Power Plan until the disposition of the petitions challenging the rule now before the Court of Appeals, and, if such petitions are filed in the future, before the U.S. Supreme Court. While the ultimate impact of the Clean Power Plan rule is expected to be favorable, Exelon and Generation cannot at this time predict to what extent the states' actions to comply with the Clean Power Plan's emission reduction targets will impact their future financial position, results of operations and cash flows.

Regional and State Climate Change Legislation and Regulation. After a two-year program review, the nine northeast and mid-Atlantic states currently participating in the Regional Greenhouse Gas Reduction Initiative (RGGI) released an updated RGGI Model Rule and Program Review Recommendations Summary on February 7, 2013. Under the updated RGGI program the regional RGGI CO_2 budget was reduced, starting in 2014, from its previous 165 million ton level to 91 million tons, with a 25 percent reduction in the cap level each year from 2015 through 2020. Included in the program are provisions for cost containment reserve (CCR) allowances, which will become available if the total demand for allowances, above the CCR trigger price, exceeds the number of CO_2 allowances available for purchase at auction. (CCR trigger prices are $6 in 2015, $8 in 2016 and $10 in 2017; after 2017 the CCR price increases by 2.5 percent each year). Such an outcome could put modest upward pressure on wholesale power prices; however, the specifics are currently uncertain.

At the state level, the Illinois Climate Change Advisory Group, created by Executive Order 2006-11 on October 5, 2006, made its final recommendations on September 6, 2007 to meet the Governor's GHG reduction goals. At this time, the only requirements imposed by the state of Illinois are the energy efficiency and renewable portfolio standards in the Illinois Power Act that apply to ComEd.

On December 18, 2009, Pennsylvania issued the state's final Climate Change Action Plan. The plan sets as a target a 30 percent reduction in GHG emissions by 2020. The Climate Change Advisory Committee continues to meet quarterly to review Climate Action Work Plans for the residential, commercial and industrial sectors. The Climate Change Action Plan does not impose any requirements on Generation or PECO at this time.

The Maryland Commission on Climate Change was chartered in 2007 and released a greenhouse gas reduction strategy with 42 recommendations on August 27, 2008. The plan's primary policy recommendation to formally adopt science-based regulatory goals to reduce Maryland's GHG emissions was realized with the passage of the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA) which requires Maryland to reduce its GHG emissions by 25 percent below 2006 levels by 2020. It also directed the Maryland Department of Environment to prepare and implement an action plan which was published in October of 2013. Maryland's electricity consumption reduction goals, required under the "EmPOWER Maryland" program, and mandatory State participation in RGGI Program, are listed as the energy sector's contribution in the plan. The plan also advocated raising the renewable portfolio standard requirement from 20% by 2022 to 25% by 2022. The Department of Environment was required to submit a December 2015 report to the Governor and General Assembly

on progress towards the 25% mandate; its costs and benefits; the need for target adjustments; and the status of federal programs. In 2016, the Legislature will review the progress report, its economic impacts on manufacturing sector and other information and determine whether to continue, adjust or eliminate the requirement to achieve a 25% reduction by 2020.

Exelon's Voluntary Climate Change Efforts . In a world increasingly concerned about global climate change and regulatory action to reduce GHG, Exelon's low-carbon generating fleet is seen by management as a competitive advantage. Exelon remains one of the largest, lowest carbon electric generators in the United States: nuclear for base load, natural gas for marginal and peak demand, hydro and pumped storage, and supplemental wind and solar renewables. As further legislation and regulation imposing requirements on emissions of GHG and air pollutants are promulgated, Exelon's low-carbon, low-emission generation fleet will position the company to benefit from its comparative advantage over other generation fleets.

Renewable and Alternative Energy Portfolio Standards

Thirty-nine states and the District of Columbia have adopted some form of RPS requirement. Illinois, Pennsylvania and Maryland have laws specifically addressing energy efficiency and renewable energy initiatives. In addition to state level activity, RPS legislation has been considered and may be considered again in the future by the United States Congress. Also, states that currently do not have RPS requirements may adopt such legislation in the future.

Illinois utilities are required to procure cost-effective renewable energy resources in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers. ComEd is also required to acquire amounts of renewable energy resources to cumulatively increase this percentage to at least 10% by June 1, 2015 and an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth by Illinois legislation. As of December 31, 2015, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois legislation. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates.

The AEPS Act became effective for PECO on January 1, 2011. During 2015, PECO was required to supply approximately 5.0% of electric energy generated from Tier I alternative energy resources (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania), as measured in AECs, through May 31, 2015 and subsequently 5.5% beginning June 1, 2015 and continuing through May 31, 2016. PECO was also required to supply 6.2% of electric energy generated from Tier II alternative energy resources (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing wood and by-products of the pulping process and wood, distributed generation systems and integrated combined coal gasification technology), as measured in AECs, through May 31, 2015 and subsequently 8.2% beginning June 1, 2015 and continuing through May 31, 2016. The compliance requirements will incrementally escalate to 8.0% for Tier I and 10.0% for Tier II by 2021. In order to comply with these requirements, PECO entered into agreements with varying terms with accepted bidders, including Generation, to purchase non-solar Tier I, solar Tier 1 and Tier II AECs. PECO also purchases AECs through its DSP Program full requirement contracts.

Section 7-703 of the Public Utilities Article in Maryland sets forth the RPS requirement, which applies to all retail electricity sales in Maryland by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, biomass, methane, geothermal, ocean, fuel cell, small hydroelectric, and poultry litter) and Tier 2

sources (hydroelectric, other than pump storage generation, and waste-to-energy). The RPS requirement began in 2006, requiring that suppliers procure 1.0% and 2.5% from Tier 1 and Tier 2 sources, respectively, escalating in 2022 to 22.0% from Tier 1 sources, including at least 2.0% from solar energy, and a phase out of Tier 2 resource options by 2022. In 2015, 10.5% was required from Tier 1 renewable sources, including at least 0.5% derived from solar energy and 2.5% from Tier 2 renewable sources. BGE is subject to requirements established by the Public Utilities Article in Maryland related to the use of alternative energy resources; however, the wholesale suppliers that supply power to BGE through SOS procurement auctions have the obligation, by contract with BGE, to meet the RPS requirements.

Similar to ComEd, PECO and BGE, Generation's retail electric business must source a portion of the electric load it serves in many of the states in which it does business from renewable resources or approved equivalents such as RECs. Potential regulation and legislation regarding renewable and alternative energy resources could increase the pace of development of wind and other renewable/alternative energy resources, which could put downward pressure on wholesale market prices for electricity in some markets where Exelon operates generation assets. At the same time, such developments may present some opportunities for sales of Generation's renewable power, including from wind, solar, hydroelectric and landfill gas.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Executive Officers of the Registrants as of February 10, 2016

Exelon

Name	Age	Position	Period
Crane, Christopher M.	57	Chief Executive Officer, Exelon;	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
		Chief Operating Officer, Exelon	2008 - 2012
		Chief Operating Officer, Generation	2007 - 2010
Cornew, Kenneth W.	50	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
O'Brien, Denis P.	55	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Vice Chairman, ComEd, PECO, BGE	2012 - Present
		Chief Executive Officer, PECO; Executive Vice President, Exelon	2007 - 2012
		President and Director, PECO	2003 - 2012
Pramaggiore, Anne R.	57	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012

Name	Age	Position	Period
Adams, Craig L.	63	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Butler, Calvin G.	46	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
		Senior Vice President, Human Resources, Exelon	2010 - 2011
		Senior Vice President, Corporate Affairs, ComEd	2009 - 2010
Von Hoene Jr., William A.	62	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
Thayer, Jonathan W.	44	Senior Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012
Aliabadi, Paymon	53	Executive Vice President and Chief Enterprise Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
		Principal and Managing Director, Gunvor International	2009 - 2011
DesParte, Duane M.	52	Senior Vice President and Corporate Controller, Exelon	2008 - Present

Generation

Name	Age	Position	Period
Cornew, Kenneth W.	50	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
Nigro, Joseph	51	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - Present
		Senior Vice President, Portfolio Management and Strategy	2012 - 2013
		Vice President, Structuring and Portfolio Management, Exelon Power Team	2010 - 2012
Pacilio, Michael J.	55	Executive Vice President and Chief Operating Officer, Exelon Generation	2015 - Present
		President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - 2015
		Chief Operating Officer, Exelon Nuclear	2007 - 2010

Name	Age	Position	Period
Hanson, Bryan C.	50	President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Exelon Generation	2015 - Present
		Chief Operating Officer, Exelon Nuclear	2014 - 2015
		Senior Vice President of Operations, Generation	2010 - 2013
		Vice President of Operations, Generation	2009 - 2010
DeGregorio, Ronald	53	Senior Vice President, Generation; President, Exelon Power	2012 - Present
		Chief Integration Officer, Exelon	2011 - 2012
		Chief Operating Officer, Exelon Transmission Company	2010 - 2011
		Senior Vice President, Mid- Atlantic Operations, Exelon Nuclear	2007 - 2010
Wright, Bryan P.	49	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
		Chief Accounting Officer, Constellation Energy	2009 - 2012
		Vice President and Controller, Constellation Energy	2008 - 2012
Aiken, Robert	49	Vice President and Controller, Generation	2012 - Present
		Executive Director and Assistant Controller, Constellation	2011 - 2012
		Executive Director of Operational Accounting, Constellation Energy Commodities Group	2009 - 2011

ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	57	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Donnelly, Terence R.	55	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
Trpik Jr., Joseph R.	46	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
Jensen, Val	59	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
O'Neill, Thomas S.	53	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2010 - Present
		Senior Vice President, Exelon	2009 - 2010
Marquez Jr., Fidel	54	Senior Vice President, Governmental and External Affairs, ComEd	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012

Name	Age	Position	Period
Brookins, Kevin B.	54	Senior Vice President, Strategy & Administration, ComEd	2012 - Present
		Vice President, Operational Strategy and Business Intelligence, ComEd	2010 - 2012
		Vice President, Distribution System Operations, ComEd	2008 - 2010
Anthony, J. Tyler	51	Senior Vice President, Distribution Operations, ComEd	2010 - Present
		Vice President, Transmission and Substations, ComEd	2007 - 2010
Kozel, Gerald J.	43	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013
		Director of Financial Reporting and Analysis, Exelon	2009 - 2012

PECO

Name	Age	Position	Period
Adams, Craig L.	63	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	52	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	50	Senior Vice President and Chief Operations Officer, PECO	2012 - Present
		Vice President, Distribution System Operations and Smart Grid/Smart Meter, PECO	2010 - 2012
		Vice President, Distribution System Operations	2007 - 2010
Webster Jr., Richard G.	54	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	56	Vice President, Governmental and External Affairs, PECO	2012 - Present
		Director, Governmental & External Affairs, PECO	2007 - 2012
Jiruska, Frank J.	55	Vice President, Customer Operations, PECO	2013 - Present
		Director of Energy and Marketing Services, PECO	2010 - 2013
Diaz Jr., Romulo L.	69	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
Bailey, Scott A.	39	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012
		Director of Accounting, Power Team	2007 - 2011

BGE

Name	Age	Position	Period
Butler, Calvin G.	46	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
		Senior Vice President, Human Resources, Exelon	2010 - 2011
		Senior Vice President, Corporate Affairs, ComEd	2009 - 2010
Woerner, Stephen J.	48	President, BGE	2014 - Present
		Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - 2014
		Vice President and Chief Integration Officer, Constellation Energy	2011 - 2012
		Vice President and Chief Information Officer, Constellation Energy	2010 - 2011
		Vice President, Transformation, Constellation Energy	2009 - 2010
Vahos, David M.	43	Chief Financial Officer and Treasurer	2014 - Present
		Vice President and Controller, BGE	2012 - 2014
		Executive Director, Audit, Constellation	2010 - 2012
		Director, Finance, BGE	2006 - 2010
Case, Mark D.	54	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Biagiotti, Robert D.	45	Vice President, Customer Operations and Chief Customer Officer, BGE	2015 - Present
		Vice President, Gas Distribution, BGE	2011 - 2015
		Director, Gas and Electric Field Services, BGE	2008 - 2011
Gahagan, Daniel P.	62	Vice President and General Counsel, BGE	2007 - Present
Bauer, Matthew N.	39	Vice President and Controller, BGE	2014 - Present
		Vice President of Power Finance, Exelon Power	2012 - 2014
		Director, FP&A and Retail, Constellation	2012 - 2012
		Executive Director, Corporate Development, Constellation	2009 - 2012
Núñez, Alexander G.	44	Vice President, Governmental and External Affairs, BGE	2013 - Present
		Director, State Affairs, BGE	2012 - 2013
		Director, State Affairs, Constellation Energy	2006 - 2012

ITEM 1A. RISK FACTORS

Each of the Registrants operates in a market and regulatory environment that poses significant risks, many of which are beyond that Registrant's control. Management of each Registrant regularly meets with the Chief Enterprise Risk Officer and the RMC, which comprises officers of the Registrants, to identify and evaluate the most significant risks of the Registrants' businesses, and the appropriate steps to manage and mitigate those risks. The Chief Enterprise Risk Officer and senior executives of the Registrants discuss those risks with the finance and risk committee and audit committee of the Exelon board of directors and the ComEd, PECO and BGE boards of directors. In addition, the

generation oversight committee of the Exelon board of directors evaluates risks related to the generation business. The risk factors discussed below could adversely affect one or more of the Registrants' results of operations or cash flows and the market prices of their publicly traded securities. Each of the Registrants has disclosed the known material risks that affect its business at this time. However, there may be further risks and uncertainties that are not presently known or that are not currently believed by a Registrant to be material that could adversely affect its performance or financial condition in the future.

Exelon's financial conditions and results of operations are affected to a significant degree by: (1) Generation's position as a predominantly nuclear generator selling power into competitive energy markets with a concentration in select regions, and (2) the role of ComEd, PECO and BGE as operators of electric transmission and distribution systems in three of the largest metropolitan areas in the United States. Factors that affect the financial condition and results of operations of the Registrants fall primarily under the following categories, all of which are discussed in further detail below:

- ***Market and Financial Factors.*** Exelon's and Generation's results of operations are affected by price fluctuations in the energy markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular the price of natural gas, which affects the prices that Generation can obtain for the output of its power plants, (2) the presence of other generation resources in the markets in which Generation's output is sold, (3) the demand for electricity in the markets where the Registrants conduct their business, and (4) the impacts of on-going competition in the retail channel.
- ***Regulatory and Legislative Factors.*** The regulatory and legislative factors that affect the Registrants include changes to the laws and regulations that govern competitive markets and utility cost recovery, and that drive environmental policy. In particular, Exelon's and Generation's financial performance could be affected by changes in the design of competitive wholesale power markets or Generation's ability to sell power in those markets. In addition, potential regulation and legislation, including legislation or regulation regarding climate change and renewable portfolio standards, could have significant effects on the Registrants. Also, returns for ComEd, PECO and BGE are influenced significantly by state regulation and regulatory proceedings.
- ***Operational Factors.*** The Registrants' operational performance is subject to those factors inherent in running the nation's largest fleet of nuclear power reactors and large electric and gas distribution systems. The safe and effective operation of the nuclear facilities and the ability to effectively manage the associated decommissioning obligations as well as the ability to maintain the availability, reliability and safety of its energy delivery systems are fundamental to Exelon's ability to protect and grow shareholder value. Additionally, the operating costs of ComEd, PECO and BGE, and the opinions of their customers and regulators, are affected by those companies' ability to maintain the reliability and safety of their energy delivery systems.
- ***Risks Related to the Pending Merger with PHI.*** There are various risks and uncertainties associated with the merger agreement announced with PHI on April 29, 2014.

A discussion of each of these risk categories and other risk factors is included below.

Market and Financial Factors

Generation is exposed to depressed prices in the wholesale and retail power markets, which could negatively affect its results of operations or cash flows. (Exelon and Generation)

Generation is exposed to commodity price risk for the unhedged portion of its electricity generation supply portfolio. Generation's earnings and cash flows are therefore subject to variability as spot and forward market prices in the markets in which it operates rise and fall.

Price of Fuels : The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit. Often, the next unit of electricity will be supplied from generating stations fueled by fossil fuels. Consequently, changes in the market price of fossil fuels often result in comparable changes to the market price of power. For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing downward pressure on natural gas prices and, therefore, on power prices. The continued addition of supply from new alternative generation resources, such as wind and solar, whether mandated through RPS or otherwise subsidized or encouraged through climate legislation or regulation, may displace a higher marginal cost plant, further reducing power prices. In addition, further delay or elimination of EPA air quality regulations could prolong the duration for which the cost of pollution from fossil fuel generation is not factored into market prices.

Demand and Supply: The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs could each depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on electricity market prices. The tepid economic environment in recent years and growing energy efficiency and demand response initiatives have limited the demand for electricity in Generation's markets. In addition, in some markets, the supply of electricity through wind or solar generation, when combined with other base-load generation such as nuclear, could often exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants. Increased supply in excess of demand is furthered by the continuation of RPS mandates and subsidies for renewable energy.

Retail Competition: Generation's retail operations compete for customers in a competitive environment, which affects the margins that Generation can earn and the volumes that it is able to serve. In periods of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including Generation) use their retail operations to hedge generation output. Increased or more aggressive competition could adversely affect overall gross margins and profitability in Generation's retail operations.

Sustained low market prices or depressed demand and over-supply could adversely affect Exelon's and Generation's results of operations or cash flows, and such impacts could be emphasized given Generation's concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect Exelon's and Generation's ability to fund other discretionary uses of cash such as growth projects or to pay dividends. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Exelon's and Generation's result of operations through accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, accelerated amortization of plant specific nuclear fuel costs, severance costs, accelerated asset retirement obligation expense relate to future decommissioning activities, and additional funding of decommissioning costs, which can be offset in whole or in part by reduced operating and maintenance expenses. A slow recovery in market conditions could result in a prolonged depression of or further decline in commodity prices, including low forward natural gas and power prices and low market volatility, which could also adversely affect Exelon's and Generation's results of operations, cash flows or financial positions. See Note 9—Implications of Potential Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

In addition to price fluctuations, Generation is exposed to other risks in the power markets that are beyond its control and could negatively affect its results of operations. (Exelon and Generation)

Credit Risk. In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money, or are obligated to purchase energy or fuel from Generation, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, Generation could be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. In the spot markets, Generation is exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs, the purpose of which is to spread such risk across all market participants. Generation is also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, Generation's retail sales subject it to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that could be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Market Designs. The wholesale markets remain evolving markets that vary from region to region and are still developing rules, practices and procedures. Changes in these market rules, problems with rule implementation, or failure of any of these markets could adversely affect Generation's business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry, including technologies related to energy generation, distribution and consumption. (Exelon, Generation, ComEd, PECO and BGE)

Some of these technologies include, but are not limited to further shale gas development or sources, cost-effective renewable energy technologies, broad consumer adoption of electric vehicles, distributed generation and energy storage devices. Such developments could affect the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could materially affect the Registrants' results of operations, cash flows or financial positions through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors could decrease the value of NDT funds and employee benefit plan assets and could increase the related employee benefit plan obligations, which then could require significant additional funding. (Exelon, Generation, ComEd, PECO and BGE)

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy could adversely affect the value of the investments held within Generation's NDTs and Exelon's employee benefit plan trusts. The Registrants have significant obligations in these areas and Exelon and Generation hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which could fall below the Registrants' projected return rates. A decline in the market value of the NDT fund investments could increase Generation's funding requirements to decommission its nuclear plants. A decline in the

market value of the pension and OPEB plan assets will increase the funding requirements associated with Exelon's pension and OPEB plan obligations. Additionally, Exelon's pension and OPEB plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements could also increase the costs and funding requirements of the obligations related to the pension and OPEB plans. If future increases in pension and other postretirement costs as a result of reduced plan assets or other factors cannot be recovered, or cannot be recovered in a timely manner, from ComEd, PECO and BGE customers, the results of operations and financial positions of ComEd, PECO and BGE could be negatively affected. Ultimately, if the Registrants are unable to manage the investments within the NDT funds and benefit plan assets, and are unable to manage the related benefit plan liabilities, their results of operations, cash flows or financial positions could be negatively impacted.

Unstable capital and credit markets and increased volatility in commodity markets could adversely affect the Registrants' businesses in several ways, including the availability and cost of short-term funds for liquidity requirements, the Registrants' ability to meet long-term commitments, Generation's ability to hedge effectively its generation portfolio, and the competitiveness and liquidity of energy markets; each could negatively impact the Registrants' results of operations, cash flows or financial positions. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity needs if internal funds are not available from the Registrants' respective operations. Disruptions in the capital and credit markets in the United States or abroad could adversely affect the Registrants' ability to access the capital markets or draw on their respective bank revolving credit facilities. The Registrants' access to funds under their credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from the Registrants and other borrowers within a short period of time. The inability to access capital markets or credit facilities, and longer term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, changes to Generation's hedging strategy in order to reduce collateral-posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

In addition, the Registrants have exposure to worldwide financial markets, including Europe. Disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2015, approximately 25%, or $2.1 billion of the Registrants' available credit facilities were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.9 billion was available as of December 31, 2015. There were no borrowings under the Registrants' credit facilities as of December 31, 2015. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in energy markets depend heavily on active participation by multiple trading parties, which could be adversely affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that may affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to the respective businesses of the Registrants. Perceived weaknesses in the competitive strength of

the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on Exelon's and Generation's results of operations or cash flows.

If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its trading counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs. (Exelon, Generation, ComEd, PECO and BGE)

Generation's business is subject to credit quality standards that could require market participants to post collateral for their obligations. If Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating) or otherwise fail to satisfy the credit standards of trading counterparties, it would be required under its hedging arrangements to provide collateral in the form of letters of credit or cash, which may have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time is dependent on a variety of factors, including (1) the notional amount of the applicable hedge, (2) the nature of counterparty and related agreements, and (3) changes in power or other commodity prices. In addition, if Generation were downgraded, it could experience higher borrowing costs as a result of the downgrade. Generation could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the power generation industry in general, or Generation in particular, has deteriorated. Changes in ratings methodologies by the credit rating agencies could also have a negative impact on the ratings of Generation. Generation has project-specific financing arrangements and must meet the requirements of various agreements relating to those financings. Failure to meet those arrangements could give rise to a project-specific financing default which, if not cured or waived, could result in the specific project being required to repay the associated debt or other borrowings earlier than otherwise anticipated, and if such repayment were not made, the lenders or security holders would generally have rights to foreclose against the project assets and related collateral.

ComEd's, PECO's and BGE's operating agreements with PJM and PECO's and BGE's natural gas procurement contracts contain collateral provisions that are affected by their credit rating and market prices. If certain wholesale market conditions were to exist and ComEd, PECO and BGE were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the forms of letters of credit or cash, which could have a material adverse effect upon their liquidity. Collateral posting requirements will generally increase as market prices rise and decrease as market prices fall. Collateral posting requirements for PECO and BGE, with respect to their natural gas supply contracts, will generally increase as forward market prices fall and decrease as forward market prices rise. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if ComEd, PECO and BGE were downgraded, they could experience higher borrowing costs as a result of the downgrade.

ComEd, PECO or BGE could experience a downgrade in its ratings if any of the credit rating agencies conclude that the level of business or financial risk and overall creditworthiness of the utility industry in general, or ComEd, PECO, or BGE in particular, has deteriorated. ComEd, PECO or BGE could experience a downgrade if the current regulatory environments in Illinois, Pennsylvania or Maryland, respectively, become less predictable by materially lowering returns for utilities in the applicable state or adopting other measures to limit electricity prices. Additionally, the ratings for ComEd, PECO or BGE could be downgraded if their financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage their capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of ComEd, PECO or BGE.

ComEd, PECO and BGE conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that ComEd, PECO and BGE are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate ComEd, PECO and BGE from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as "ring-fencing") may help avoid or limit a downgrade in the credit ratings of ComEd, PECO and BGE in the event of a reduction in the credit rating of Exelon. Despite these ring-fencing measures, the credit ratings of ComEd, PECO or BGE could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of ComEd, PECO or BGE, or all three. A reduction in the credit rating of ComEd, PECO or BGE could have a material adverse effect on ComEd, PECO or BGE, respectively.

See Liquidity and Capital Resources—Recent Market Conditions and Security Ratings for further information regarding the potential impacts of credit downgrades on the Registrants' cash flows.

Generation's financial performance could be negatively affected by price volatility, availability and other risk factors associated with the procurement of nuclear and fossil fuel. (Exelon and Generation)

Generation depends on nuclear fuel and fossil fuels to operate its generating facilities. Nuclear fuel is obtained predominantly through long-term uranium supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. Natural gas and oil are procured for generating plants through annual, short-term and spot-market purchases. The supply markets for nuclear fuel, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default that could negatively affect the results of operations or cash flows for Generation.

Generation's risk management policies cannot fully eliminate the risk associated with its commodity trading activities. (Exelon and Generation)

Generation's asset-based power position as well as its power marketing, fuel procurement and other commodity trading activities expose Generation to risks of commodity price movements. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations could be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, Generation cannot predict the impact that its commodity trading activities and risk management decisions could have on its business, operating results, cash flows or financial positions.

Generation buys and sells energy and other products and enters into financial contracts to manage risk and hedge various positions in Generation's power generation portfolio. The proportion of hedged positions in its power generation portfolio could expose Generation to volatility in future results of operations.

Financial performance and load requirements could be adversely affected if Generation is unable to effectively manage its power portfolio. (Exelon and Generation)

A significant portion of Generation's power portfolio is used to provide power under procurement contracts with ComEd, PECO, BGE and other customers. To the extent portions of the power portfolio

are not needed for that purpose, Generation's output is sold in the wholesale power markets. To the extent its power portfolio is not sufficient to meet the requirements of its customers under the related agreements, Generation must purchase power in the wholesale power markets. Generation's financial results could be negatively affected if it is unable to cost-effectively meet the load requirements of its customers, manage its power portfolio and effectively address the changes in the wholesale power markets.

Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could negatively impact the Registrants' results of operations or cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Corporate Tax Reform. There exists the potential for comprehensive tax reform in the United States that may significantly change the tax rules applicable to U.S. domiciled corporations. Exelon cannot assess what the overall effect of such potential legislation could be on its results of operations or cash flows.

1999 sale of fossil generating assets. The IRS has challenged Exelon's 1999 tax position on its like-kind exchange transaction. Exelon and the IRS failed to reach a settlement on the like-kind exchange position and Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court and the trial took place in August 2015. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the like-kind exchange position. The litigation could take three to five years including appeals, if necessary.

As of December 31, 2015, if the IRS is successful in its challenge to the like-kind exchange position, Exelon's potential cash outflow, including tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $760 million, of which approximately $280 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless. In addition to attempting to impose tax on the like-kind exchange position, the IRS has asserted approximately $90 million of penalties for a substantial understatement of tax. The timing effects of the final resolution of the like-kind exchange matter are unknown. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Tax reserves. The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeals issues related to these tax matters. These judgments include reserves for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities. See Notes 1—Significant Accounting Policies and Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Increases in customer rates and the impact of economic downturns could lead to greater expense for uncollectible customer balances. Additionally, increased rates could lead to decreased volumes delivered. Both of these factors could decrease Generation's, ComEd's, PECO's and BGE's results from operations or cash flows. (Exelon, Generation, ComEd, PECO and BGE)

ComEd's, PECO's and BGE's current procurement plans include purchasing power through contracted suppliers and in the spot market. ComEd's and PECO's costs of purchased power are charged to customers without a return or profit component. BGE's SOS rates charged to customers recover BGE's wholesale power supply costs and include a return component. For PECO, purchased natural gas costs are charged to customers with no return or profit component. For BGE, purchased natural gas costs are charged to customers using a MBR mechanism that compares the actual cost of gas to a market index. The difference between the actual cost and the market index is shared equally

between shareholders and customers. Purchased power and natural gas prices fluctuate based on their relevant supply and demand. Significantly higher rates related to purchased power and natural gas could result in declines in customer usage, lower revenues and potentially additional uncollectible accounts expense for ComEd, PECO and BGE. In addition, any challenges by the regulators or ComEd, PECO and BGE as to the recoverability of these costs could have a material effect on the Registrants' results of operations or cash flows. Also, ComEd's, PECO's and BGE's cash flows could be affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

Further, the impacts of economic downturns on ComEd, PECO and BGE customers and purchased natural gas costs for PECO and BGE customers, such as unemployment for residential customers and less demand for products and services provided by commercial and industrial customers, and the related regulatory limitations on residential service terminations, could result in an increase in the number of uncollectible customer balances, which would negatively impact ComEd's, PECO's and BGE's results of operations or cash flows. Generation's customer-facing energy delivery activities face economic downturn risks similar to Exelon's utility businesses, such as lower volumes sold and increased expense for uncollectible customer balances. As Generation increases its customer-facing energy delivery activities, economic downturn impacts could negatively affect Generation's results of operations or cash flows. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants' credit risk.

The effects of weather could impact the Registrants' results of operations or cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Moderate temperatures adversely affect the usage of energy and resulting revenues at ComEd and PECO. Due to revenue decoupling, BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period, and is not affected by actual weather with the exception of major storms. Extreme weather conditions or damage resulting from storms could stress ComEd's, PECO's and BGE's transmission and distribution systems, communication systems and technology, resulting in increased maintenance and capital costs and limiting each company's ability to meet peak customer demand. These extreme conditions could have detrimental effects on ComEd's, PECO's and BGE's results of operations or cash flows. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and could make period comparisons less relevant.

Generation's operations are also affected by weather, which affects demand for electricity as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation could require greater resources to meet its contractual commitments. Extreme weather conditions or storms could affect the availability of generation and its transmission, limiting Generation's ability to source or send power to where it is sold. In addition, drought-like conditions limiting water usage could impact Generation's ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, could have an adverse effect by causing Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Certain long-lived assets and other assets recorded on the Registrants' statements of financial position could become impaired, which would result in write-offs of the impaired amounts. (Exelon, Generation, ComEd, PECO and BGE)

Long-lived assets represent the single largest asset class on the Registrants' statement of financial positions. Specifically, long-lived assets account for 60%, 56%, 66%, 69% and 80% of total assets for Exelon, Generation, ComEd, PECO and BGE, respectively, as of December 31, 2015. In addition, Exelon and Generation have significant balances related to unamortized energy contracts. See Note 11—Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's unamortized energy contracts. The Registrants evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered when evaluating long-lived assets for potential impairment. An impairment would require the Registrants to reduce the carrying value of the long-lived asset through a non-cash charge to expense by the amount of the impairment, and such an impairment could have a material adverse impact on the Registrants' results of operations.

Exelon holds investments in coal-fired plants in Georgia that are subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual value of the leased assets at the end of the lease term. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records a non-cash impairment charge to expense if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Such an impairment could have a material adverse impact on Exelon's results of operations.

Exelon and ComEd had approximately $2.7 billion of goodwill recorded at December 31, 2015 in connection with the merger between PECO and Unicom Corporation, the former parent company of ComEd. Under GAAP, goodwill remains at its recorded amount unless it is determined to be impaired, which is generally based upon an annual analysis that compares the implied fair value of the goodwill to its carrying value. If an impairment occurs, the amount of the impaired goodwill will be written-off to expense, which will also reduce equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. A successful IRS challenge to Exelon's and ComEd's like-kind exchange income tax position, adverse regulatory actions such as early termination of EIMA, or changes in significant assumptions used in estimating ComEd's fair value (e.g., discount and growth rates, utility sector market performance and transactions, operating and capital expenditure requirements and the fair value of debt) could result in an impairment. Such an impairment would result in a non-cash charge to expense, which could have a material adverse impact on Exelon's and ComEd's results of operations.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Critical Accounting Policies and Estimates and Note 7—Property, Plant and Equipment, Note 8—Impairment of Long Lived Assets and Note 11—Intangible Assets of the Combined Notes to the Consolidated Financial Statements for additional discussion on long-lived asset and goodwill impairments.

The Registrants' businesses are capital intensive, and their assets could require significant expenditures to maintain and are subject to operational failure, which could result in potential liability. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants' businesses are capital intensive and require significant investments by Generation in electric generating facilities and by ComEd, PECO and BGE in transmission and

distribution infrastructure projects. These operational systems and infrastructure have been in service for many years. Equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Registrants' control, and could require significant expenditures to operate efficiently. The Registrants' results of operations, financial conditions, or cash flows could be adversely affected if they were unable to effectively manage their capital projects or raise the necessary capital. Furthermore, operational failure of electric or gas systems or infrastructure could result in potential liability if such failure results in damage to property or injury to individuals. See ITEM 1. BUSINESS for further information regarding the Registrants' potential future capital expenditures.

Exelon and its subsidiaries have guaranteed the performance of third parties, which could result in substantial costs in the event of non-performance by third parties. In addition, the Registrants have rights under agreements which obligate third parties to indemnify the Registrants for various obligations, and the Registrants could incur substantial costs in the event that the applicable Registrant is unable to enforce those agreements or the applicable third-party is otherwise unable to perform. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have issued guarantees of the performance of third parties, which obligate one or more of the Registrants or their subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, the Registrants could incur substantial cost to fulfill their obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial conditions, or cash flows of the Registrants.

The Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected Registrant could be held responsible for the obligations, which could impact that Registrant's results of operations, cash flows or financial positions. In connection with Exelon's 2001 corporate restructuring, Generation assumed certain of ComEd's and PECO's rights and obligations with respect to their former generation businesses. Further, ComEd and PECO could have entered into agreements with third parties under which the third-party agreed to indemnify ComEd or PECO for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the restructuring. If the third-party or Generation experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, ComEd or PECO could be liable for any existing or future claims, which could impact ComEd's or PECO's results of operations, cash flows or financial positions.

Regulatory and Legislative Factors

The Registrants' generation and energy delivery businesses are highly regulated and could be subject to regulatory and legislative actions that adversely affect their operations or financial results. Fundamental changes in regulation or legislation or violation of tariffs or market rules and anti-manipulation laws, could disrupt the Registrants' business plans and adversely affect their operations or financial results. (Exelon, Generation, ComEd, PECO and BGE)

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation. Further, Exelon's and Generation's operating results and cash flows are heavily dependent upon the ability of Generation to sell power at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon's, ComEd's, PECO's and BGE's operating results and cash flows are heavily dependent on the ability of ComEd, PECO and BGE to recover their costs for the retail purchase and distribution of power to their customers.

Similarly, there is risk that financial market regulations could increase the Registrants' compliance costs and limit their ability to engage in certain transactions. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, exchanges, ratemaking agencies and taxing authorities. Additionally, the Registrants need to be cognizant and understand rule changes or Registrant actions that could result in potential violation of tariffs, market rules and anti-manipulation laws. Fundamental changes in regulations or other adverse legislative actions affecting the Registrants' businesses would require changes in their business planning models and operations and could negatively impact their results of operations, cash flows or financial positions.

Regulatory and legislative developments related to climate change and RPS could also significantly affect Exelon's and Generation's results of operations, cash flows or financial positions. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, may sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. However, national regulation or legislation addressing climate change through an RPS could also increase the pace of development of wind energy facilities in the Midwest, which could put downward pressure on wholesale market prices for electricity from Generation's Midwest nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation's nuclear assets under a carbon constrained regulatory regime that might exist in the future. Similarly, final regulations under Section 111(d) of the Clean Air Act may not provide sufficient incentives for states to utilize carbon-free nuclear power as a means of meeting greenhouse gas emission reduction requirements, while continuing a policy of favoring renewable energy sources. Current state level climate change and renewable regulation is already providing incentives for regional wind development. The Registrants cannot predict when or whether any of these various legislative and regulatory proposals may become law or what their effect will be on the Registrants.

Generation could be negatively affected by possible Federal or state legislative or regulatory actions that could affect the scope and functioning of the wholesale markets. (Exelon and Generation)

Federal and state legislative and regulatory bodies are facing pressures to address consumer concerns, or are themselves raising concerns, that energy prices in wholesale markets are too high or insufficient generation is being built because the competitive model is not working, and, therefore, are considering some form of re-regulation or some other means of reducing wholesale market prices or subsidizing new generation. Generation is dependent on robust and competitive wholesale energy markets to achieve its business objectives.

Approximately 65% of Generation's generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Generation's future results of operations will depend on (1) FERC's continued adherence to and support for, policies that favor the preservation of competitive wholesale power markets, such as PJM's, and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competitiveness. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize new generation, such as the subsequently dismissed New Jersey Capacity Legislation and the MDPSC's RFP for new gas-fired generation in Maryland. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details related to the New Jersey Capacity Legislation and the Maryland new electric generation requirements.

In addition, FERC's application of its Order 697 and its subsequent revisions could pose a risk that Generation will have difficulty satisfying FERC's tests for market-based rates. Since Order 697 became final in June 2007, Generation has obtained orders affirming Generation's authority to sell at market-based rates and none denying that authority.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted in July 2010. The part of the Act that applies to Exelon is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires the creation of a new regulatory regime for over-the-counter swaps (swaps), including mandatory clearing for certain categories of Swaps, incentives to shift swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. For non security-based swaps including commodity swaps, Dodd-Frank empowers the Commodity Futures Trading Commission (CFTC) to promulgate regulations implementing the law's objectives. The primary aim of Dodd-Frank is to regulate the key intermediaries in the swaps market, which entities are either swap dealers (SDs), major swap participants (MSPs), and certain other financial entities, but the law also applies to a lesser degree to end-users of swaps. On January 12, 2015, President Obama signed into law a bill that exempts from margin requirements swaps used by end-users to hedge or mitigate commercial risk. Moreover, the CFTC's Dodd-Frank regulations preserve the ability of end users in the energy industry to hedge their risks using swaps without being subject to mandatory clearing, and accepts or exempts end-users from many of the other substantive regulations. Accordingly, as an end-user, Generation is conducting its commercial business in a manner that does not require registration with the CFTC as an SD or MSP. Generation does not anticipate transacting in the future in a manner in which it would become a SD or MSP.

There are, however, some rulemakings that have not yet been finalized, including the capital and margin rules for (non-cleared) swaps. Generation does not expect these rules to directly impact its collateral requirements. However, depending on the substance of these final rules in addition to certain international regulatory requirements still under development and that are similar to Dodd-Frank, Generation's swap counterparties could be subject to additional and potentially significant capitalization requirements. These regulations could motivate the SDs and MSPs to increase collateral requirements or cash postings from their counterparties, including Generation.

Generation continues to monitor the rulemaking proceedings with respect to the capital and margin rules, but cannot predict to what extent, if any, further refinements to Dodd-Frank requirements may impact its cash flows or financial position, but such impacts could be material.

ComEd, PECO and BGE could also be subject to some Dodd-Frank requirements to the extent they were to enter into swaps. However, at this time, management of ComEd, PECO and BGE continue to expect that their companies will not be materially affected by Dodd-Frank.

Generation's affiliation with ComEd, PECO and BGE, together with the presence of a substantial percentage of Generation's physical asset base within the ComEd, PECO and BGE service territories, could increase Generation's cost of doing business to the extent future complaints or challenges regarding ComEd, PECO and/or BGE retail rates result in settlements or legislative or regulatory requirements funded in part by Generation. (Exelon and Generation)

Generation has significant generating resources within the service areas of ComEd, PECO and BGE and makes significant sales to each of them. Those facts tend to cause Generation to be directly affected by developments in those markets. Government officials, legislators and advocacy groups are aware of Generation's affiliation with ComEd, PECO and BGE and its sales to each of them. In periods of rising utility rates, particularly when driven by increased costs of energy production and supply, those officials and advocacy groups may question or challenge costs and transactions incurred by

ComEd, PECO, or BGE, with Generation, irrespective of any previous regulatory processes or approvals underlying those transactions. The prospect of such challenges may increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges may subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators could seek ways to force Generation to contribute to efforts to mitigate potential or actual rate increases, through measures such as generation-based taxes and contributions to rate-relief packages.

The Registrants could incur substantial costs to fulfill their obligations related to environmental and other matters. (Exelon, Generation, ComEd, PECO and BGE)

The businesses which the Registrants operate are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the manner in which the Registrants conduct their operations and make capital expenditures including how they handle air and water emissions and solid waste disposal. Violations of these emission and disposal requirements could subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties' claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generate. The Registrants have incurred and expect to incur significant costs related to environmental compliance, site remediation and clean-up. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

If application of Section 316(b) of the Clean Water Act, which establishes a national requirement for reducing the adverse impacts to aquatic organisms at existing generating stations, requires the retrofitting of cooling water intake structures at Salem or other Exelon power plants, this development could result in material costs of compliance. Pursuant to discussions with the NJDEP regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029. On June 30, 2015, NJDEP issued a draft NPDES permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The draft permit is subject to a public notice and comment period after which the NJDEP may make revisions before issuing the final permit expected during the first half of 2016.

Additionally, Generation is subject to exposure for asbestos-related personal injury liability alleged at certain current and formerly owned generation facilities. Future legislative action could require Generation to make a material contribution to a fund to settle lawsuits for alleged asbestos-related disease and exposure.

In some cases, a third-party who has acquired assets from a Registrant has assumed the liability the Registrant could otherwise have for environmental matters related to the transferred property. If the transferee is unable, or fails, to discharge the assumed liability, a regulatory authority or injured person could attempt to hold the Registrant responsible, and the Registrant's remedies against the transferee may be limited by the financial resources of the transferee. See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in ComEd's, PECO's and BGE's respective terms and conditions of service, including their respective rates, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy and subject to appeal, which lead to uncertainty as to the ultimate result and which could introduce time delays in effectuating rate changes. (Exelon, ComEd, PECO and BGE)

ComEd, PECO and BGE are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for ComEd, PECO or BGE to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates could be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, bad debt, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs.

In certain instances, ComEd, PECO and BGE may agree to negotiated settlements related to various rate matters, customer initiatives or franchise agreements. These settlements are subject to regulatory approval.

ComEd, PECO and BGE cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania, Maryland or Federal regulators in establishing rates, including the extent, if any, to which certain costs such as significant capital projects will be recovered or what rates of return will be allowed. Nevertheless, the expectation is that ComEd, PECO and BGE will continue to be obligated to deliver electricity to customers in their respective service territories and will also retain significant default service obligations, referred to as POLR, DSP and SOS for ComEd, PECO and BGE, respectively, to provide electricity and natural gas to certain groups of customers in their respective service areas who do not choose an alternative supplier. The ultimate outcome and timing of regulatory rate proceedings have a significant effect on the ability of ComEd, PECO and BGE, as applicable, to recover their costs and could have a material adverse effect on ComEd's, PECO's and BGE's results of operations, cash flows and financial position. See Note 3—Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for information regarding rate proceedings.

Federal or additional state RPS and/or energy conservation legislation, along with energy conservation by customers, could negatively affect the results of operations or cash flows of Generation, ComEd, PECO and BGE. (Exelon, Generation, ComEd, PECO and BGE)

Changes to current state legislation or the development of Federal legislation that requires the use of renewable and alternate fuel sources, such as wind, solar, biomass and geothermal, could significantly impact Generation, ComEd, PECO and BGE, especially if timely cost recovery is not allowed. The impact could include increased costs for RECs and purchased power and increased rates for customers.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, have increased capital expenditures and could significantly impact ComEd, PECO and BGE, if timely cost recovery is not allowed. Furthermore, regulated energy consumption reduction targets and declines in customer energy consumption resulting from the implementation of new energy conservation technologies could

lead to a decline in the revenues of Exelon, ComEd, and PECO. For additional information, see ITEM 1. BUSINESS “Environmental Regulation-Renewable and Alternative Energy Portfolio Standards.”

The impact of not meeting the criteria of the FASB guidance for accounting for the effects of certain types of regulation could be material to Exelon, ComEd, PECO and BGE. (Exelon, ComEd, PECO and BGE)

As of December 31, 2015, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria of the authoritative guidance for accounting for the effects of certain types of regulation. If it is concluded in a future period that a separable portion of their businesses no longer meets the criteria, Exelon, ComEd, PECO and BGE would be required to eliminate the financial statement effects of regulation for that part of their business. That action would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets and the recognition of a one-time charge in their Consolidated Statements of Operations and Comprehensive Income. The impact of not meeting the criteria of the authoritative guidance could be material to the financial statements of Exelon, ComEd, PECO and BGE. At December 31, 2015, the gain (loss) could have been as much as $(2.5) billion, $978 million and $559 million (before taxes) as a result of the elimination of ComEd’s, PECO’s and BGE’s regulatory assets and liabilities, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to $2.5 billion and $634 million for ComEd and BGE, respectively, related to Exelon’s net regulatory assets associated with its defined benefit postretirement plans. Exelon also has a net regulatory liability of $47 million (before taxes) associated with PECO’s defined benefit postretirement plans that would result in an increase in OCI if reversed. The impacts and resolution of the above items could lead to an additional impairment of ComEd’s goodwill, which could be significant and at least partially offset the gain at ComEd discussed above. A significant decrease in equity as a result of any changes could limit the ability of ComEd, PECO and BGE to pay dividends under Federal and state law and no longer meeting the regulatory accounting criteria could cause significant volatility in future results of operations. See Notes 1—Significant Accounting Policies, 3—Regulatory Matters and 11—Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd’s goodwill, respectively.

Exelon and Generation could incur material costs of compliance if Federal and/or state regulation or legislation is adopted to address climate change. (Exelon and Generation)

Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. In 2009, select Northeast and Mid-Atlantic states implemented a model rule, developed via the RGGI, to regulate CO2 emissions from fossil-fired generation. RGGI states are working on updated programs to further limit emissions and the EPA has introduced regulation to address greenhouse gases from new fossil plants that could potentially impact existing plants. If carbon reduction regulation or legislation becomes effective, Exelon and Generation may incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. For example, more stringent permitting requirements may preclude the construction of lower-carbon nuclear and gas-fired power plants. Similarly, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS “Global Climate Change” and Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of ComEd, PECO, and BGE to the results of PJM's RTEP and NERC compliance requirements. (Exelon, Generation, ComEd, PECO and BGE)

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation, ComEd, PECO and BGE, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. As operators of natural gas distribution systems, PECO and BGE are also subject to mandatory reliability standards of the U.S. Department of Transportation. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards could subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC and MDPSC impose certain distribution reliability standards on ComEd, PECO and BGE, respectively. If the Registrants were found not to be in compliance with the mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

ComEd, PECO and BGE as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require ComEd, PECO and BGE to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards.

See Note 3—Regulatory Matters and Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants cannot predict the outcome of the legal proceedings relating to their business activities. An adverse determination could negatively impact their results of operations, cash flows or financial positions. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are involved in legal proceedings, claims and litigation arising out of their business operations, the most significant of which are summarized in Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on the Registrants' results of operations.

Generation could be negatively affected by possible Nuclear Regulatory Commission actions that could affect the operations and profitability of its nuclear generating fleet. (Exelon and Generation)

Regulatory risk . A change in the Atomic Energy Act or the applicable regulations or licenses could require a substantial increase in capital expenditures or could result in increased operating or decommissioning costs and significantly affect Generation's results of operations or financial positions. Events at nuclear plants owned by others, as well as those owned by Generation, could cause the NRC to initiate such actions.

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF, such as the one previously considered at Yucca Mountain, Nevada, and the timing of such facility opening, will significantly affect the costs associated with storage of SNF, and the ultimate amounts received from the DOE to reimburse Generation for these costs. The NRC's temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants. In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive

environmental review to support the rule. On September 19, 2014, the NRC issued a revised rule codifying the NRC's generic determinations regarding the environmental impacts of continued storage of spent nuclear fuel beyond a reactor's licensed operating life. The Continued Storage Rule became effective on October 20, 2014.

Any regulatory action relating to the timing and availability of a repository for SNF could adversely affect Generation's ability to decommission fully its nuclear units. Through May 15, 2014, in accordance with the NWPA and Generation's contract with the DOE, Generation paid the DOE a fee per kWh of net nuclear generation for the cost of SNF disposal. On November 19, 2013, the United States Court of Appeals for the District of Columbia Circuit ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On January 3, 2014, the DOE filed a petition for rehearing which was denied by the D.C. Circuit Court on March 18, 2014. Also, on January 3, 2014, the DOE submitted a proposal to Congress to reduce the current SNF disposal fee to zero. On May 9, 2014, the DOE notified Generation that the SNF disposal fee was set to zero, effective May 16, 2014. Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. Generation currently estimates 2025 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the spent nuclear fuel obligation. Generation cannot predict what, if any, fee will be established in the future for SNF disposal. However, such a fee could be material to Generation's results of operations or cash flows.

License renewals. Generation cannot assure that economics will support the continued operation of the facilities for all or any portion of any renewed license period. If the NRC does not renew the operating licenses for Generation's nuclear stations or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates, impairment charges and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. In addition, Generation could lose revenue and incur increased fuel and purchased power expense to meet supply commitments.

Operational Factors

The Registrants' employees, contractors, customers and the general public could be exposed to a risk of injury due to the nature of the energy industry. (Exelon, Generation, ComEd, PECO and BGE)

Employees and contractors throughout the organization work in, and customers and the general public could be exposed to, potentially dangerous environments near their operations. As a result, employees, contractors, customers and the general public are at risk for serious injury, including loss of life. Significant risks include nuclear accidents, dam failure, gas explosions, pole strikes and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events could negatively impact the Registrants' results of operations, its ability to raise capital and its future growth. (Exelon, Generation, ComEd, PECO and BGE)

Generation's fleet of power plants and ComEd's, PECO's and BGE's distribution and transmission infrastructures could be affected by natural disasters, such as seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural

disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Registrants' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. An example of such an event was the February 5, 2014 ice storm, which interrupted electric service delivery to customers in PECO's service territory and resulted in significant restoration costs.

Another example of such an event includes the 9.0 magnitude earthquake and ensuing tsunami experienced by Japan on March 11, 2011, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. Natural disasters and other significant events increase the risk to Generation that the NRC or other regulatory or legislative bodies may change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological aspects. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for Generation's continued operation, particularly the cooling of generating units. Additionally, natural disasters and other events that have an adverse effect on the economy in general may adversely affect the Registrants' operations and their ability to raise capital.

Exelon does not know the impact that potential terrorist attacks could have on the industry in general and on Exelon in particular. As owner-operators of infrastructure facilities, such as nuclear, fossil and hydroelectric generation facilities and electric and gas transmission and distribution facilities, the Registrants face a risk that their operations would be direct targets or indirect casualties of, an act of terror. Any retaliatory military strikes or sustained military campaign could affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cyber security of Exelon's facilities, which could adversely affect Exelon's ability to manage its business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also may result in a decline in energy consumption, which may adversely affect the Registrants' results of operations and its ability to raise capital. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants would be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate its generating and transmission and distribution assets could be affected, resulting in decreased service levels and increased costs.

In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property and casualty losses subject to unforeseen occurrences or catastrophic events that could damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

Generation's financial performance could be negatively affected by matters arising from its ownership and operation of nuclear facilities. (Exelon and Generation)

Nuclear capacity factors. Capacity factors for generating units, particularly capacity factors for nuclear generating units, significantly affect Generation's results of operations. Nuclear plant operations involve substantial fixed operating costs but produce electricity at low variable costs due to nuclear fuel costs typically being lower than fossil fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear facilities at high capacity factors. Lower capacity

factors increase Generation's operating costs by requiring Generation to produce additional energy from primarily its fossil facilities or purchase additional energy in the spot or forward markets in order to satisfy Generation's obligations to committed third-party sales, including ComEd, PECO and BGE. These sources generally have higher costs than Generation incurs to produce energy from its nuclear stations.

Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, could have a significant impact on Generation's results of operations. When refueling outages last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales.

Nuclear fuel quality . The quality of nuclear fuel utilized by Generation could affect the efficiency and costs of Generation's operations. Certain of Generation's nuclear units have previously had a limited number of fuel performance issues. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

Operational risk . Operations at any of Generation's nuclear generation plants could degrade to the point where Generation has to shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes could require significant time and expense. Generation could choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation could lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, Generation may not achieve the anticipated results under its series of planned power uprates across its nuclear fleet. For plants operated but not wholly owned by Generation, Generation could also incur liability to the co-owners. For plants not operated and not wholly owned by Generation, from which Generation receives a portion of the plants' output, Generation's results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by Generation could result in increased regulation and reduced public support for nuclear-fueled energy, which could significantly affect Generation's results of operations or financial positions. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident could be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by Generation or owned by others, could exceed Generation's resources, including insurance coverage. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by Generation and could have a material adverse effect on Generation's results of operations or financial positions. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, owned by others or Generation, could result in increased regulation and reduced public support for nuclear-fueled energy and significantly affect Generation's results of operations or financial positions.

Nuclear insurance. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance. The required amount of nuclear liability insurance is $375 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.5 billion limit for a single incident.

Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation's nuclear operations. In previous years, NEIL has made distributions to its members but Generation cannot predict the level of future distributions or if they will occur at all. See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired and units that are within five years of retirement) addressing Generation's ability to meet the NRC-estimated funding levels including scheduled contributions to and earnings on the decommissioning trust funds. The NRC funding levels are based upon the assumption that decommissioning will commence after the end of the current licensed life of each unit.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results may differ significantly from current estimates. The performance of capital markets also could significantly affect the value of the trust funds. Currently, Generation is making contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation, through PECO, has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from utility customers for any of its other nuclear units if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that Generation would be unable to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if Generation no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units could be negatively affected and Exelon's and Generation's results of operations or financial positions could be significantly affected. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Ultimately, if the investments held by Generation's NDTs are not sufficient to fund the decommissioning of Generation's nuclear units, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met. As a result, Generation's cash flows or financial positions could be significantly adversely affected. Additionally, if the pledged assets are not sufficient to fund the Zion station decommissioning activities under the Asset Sale Agreement (ASA), Generation could have to seek remedies available under the ASA to reduce the risk of default by ZionSolutions and its parent. See Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's financial performance could be negatively affected by risks arising from its ownership and operation of hydroelectric facilities. (Exelon and Generation)

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. The license for the Conowingo Hydroelectric Project expires September 1, 2016, and the license for the Muddy Run Pumped Storage Project expires on December 1, 2055. FERC is required to issue annual licenses for the facilities until a final determination is made on the license renewal. Generation cannot predict whether it will receive all the regulatory approvals for the renewed licenses of its hydroelectric facilities. If FERC does not issue new operating licenses for Generation's hydroelectric facilities or a station cannot be operated through the end of its operating license, Generation's results of operations could

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be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. Generation could also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions could be imposed as part of the license renewal process that could adversely affect operations, could require a substantial increase in capital expenditures or could result in increased operating costs and significantly affect Generation's results of operations or financial positions. Similar effects could result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by Generation.

ComEd's, PECO's and BGE's operating costs, and customers' and regulators' opinions of ComEd, PECO and BGE, respectively, are affected by their ability to maintain the availability and reliability of their delivery and operational systems. (Exelon, ComEd, PECO and BGE)

Failures of the equipment or facilities, including information systems, used in ComEd's, PECO's and BGE's delivery systems could interrupt the electric transmission and electric and natural gas delivery, which could negatively impact related revenues, and increase maintenance and capital expenditures. Equipment or facilities failures can be due to a number of factors, including weather or information systems failure. Specifically, if the implementation of advanced metering infrastructure, smart grid or other technologies in ComEd's, PECO's or BGE's service territory fail to perform as intended or are not successfully integrated with billing and other information systems, ComEd's, PECO's and BGE's results of operations, cash flows or financial conditions could be negatively impacted. Furthermore, if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, ComEd's, PECO's or BGE's financial results could be negatively impacted. If an employee causes the operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating the operational systems, ComEd's, PECO's or BGE's financial results could also be negatively impacted. In addition, dependence upon automated systems may further increase the risk that operational system flaws or employee tampering or manipulation of those systems will result in losses that are difficult to detect.

The aforementioned failures or those of other utilities, including prolonged or repeated failures, could affect customer satisfaction and the level of regulatory oversight and ComEd's, PECO's and BGE's maintenance and capital expenditures. Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd could be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, and those damages could be material to ComEd's results of operations or cash flows. See Note 23 —Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding proceedings related to storm-related outages in ComEd's service territory.

ComEd's, PECO's and BGE's respective ability to deliver electricity, their operating costs and their capital expenditures could be negatively impacted by transmission congestion. (Exelon, ComEd, PECO and BGE)

Demand for electricity within ComEd's, PECO's and BGE's service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage with consequent effects on operating costs, revenues and results of operations. Also, insufficient availability of electric supply to meet customer demand could jeopardize ComEd's, PECO's and BGE's ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring ComEd, PECO and BGE to upgrade or expand their respective transmission systems through additional capital expenditures.

The Registrants are subject to physical security and cybersecurity risks. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants face physical security and cybersecurity risks as the owner-operators of generation, transmission and distribution facilities and as a participant in commodities trading. Threat sources continue to seek to exploit potential vulnerabilities in the electric and natural gas utility industry associated with protection of sensitive and confidential information, grid infrastructure and other energy infrastructures, and such attacks and disruptions, both physical and cyber, are becoming increasingly sophisticated and dynamic. Continued implementation of advanced digital technologies increase the potentially unfavorable impacts of such attacks. A security breach of the physical assets or information systems of the Registrants, their competitors, interconnected entities in RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject the Registrants to financial harm associated with theft or inappropriate release of certain types of information, including sensitive customer, vendor, employee, trading or other confidential data. The risk of these system-related events and security breaches occurring continues to intensify, and while we have been, and will likely continue to be, subjected to physical and cyber-attacks, to date we have not experienced a material breach or disruption to our network or information systems or our service operations. However, as such attacks continue to increase in sophistication and frequency, we may be unable to prevent all such attacks in the future. If a significant breach occurred, the reputation of Exelon and its customer supply activities may be adversely affected, customer confidence in the Registrants or others in the industry may be diminished, or Exelon and its subsidiaries may be subject to legal claims, any of which may contribute to the loss of customers and have a negative impact on the business and/or results of operations. Moreover, the amount and scope of insurance we maintain against losses resulting from any such events or security breaches may not be sufficient to cover our losses or otherwise adequately compensate us for any disruptions to our business that may result. ComEd's, PECO's and BGE's deployment of smart meters throughout their service territories may increase the risk of damage from an intentional disruption of the system by third parties. In addition, new or updated security regulations or unforeseen threat sources could require changes in current measures taken by the Registrants or their business operations and could adversely affect their results of operations, cash flows and financial position.

Failure to attract and retain an appropriately qualified workforce could negatively impact the Registrants' results of operations. (Exelon, Generation, ComEd, PECO and BGE)

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, could lead to operating challenges and increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, could arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission and distribution operations. If the Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations could be negatively impacted.

The Registrants could make investments in new business initiatives, including initiatives mandated by regulators, and markets that may not be successful, and acquisitions could not achieve the intended financial results. (Exelon, Generation, ComEd, PECO and BGE)

Generation continues to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain. Generation is pursuing investment opportunities in renewables, development of natural gas generation, distributed generation, potential expansion of the existing natural gas and oil Upstream and wholesale gas businesses, and entry into

liquefied natural gas. Such initiatives could involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market. As these markets mature, there could be new market entrants or expansion by established competitors that increase competition for customers and resources. Additionally, it is possible that FERC, state public utility commissions or others could impose certain other restrictions on such transactions. All of these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment.

ComEd, PECO and BGE face risks associated with their regulatory-mandated Smart Grid initiatives. These risks include, but are not limited to, cost recovery, regulatory concerns, cybersecurity and obsolescence of technology. Due to these risks, no assurance can be given that such initiatives will be successful and will not have a material adverse effect on ComEd's, PECO's or BGE's financial results.

Risks Related to the Pending Merger with PHI

Exelon and PHI could encounter difficulties in satisfying the conditions for the completion of the Merger and the Merger could not be completed within the expected time frame or at all.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (1) the receipt of regulatory approvals required to consummate the Merger, (2) the expiration or termination of the applicable waiting period under the HSR Act and (3) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement. In addition, the obligation of Exelon to consummate the Merger is subject to the required regulatory approvals not, individually or in the aggregate, imposing terms, conditions, obligations or commitments that constitute a burdensome condition (as defined in the Merger Agreement).

In addition, the Merger Agreement provides that either Exelon or PHI could terminate the Merger Agreement if the merger is not completed by October 28, 2015. Exelon and PHI have agreed, among other things, that they will not exercise their rights to terminate the Merger Agreement before March 4, 2016, except under limited circumstances.

See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information regarding the status of the Merger.

The Merger is subject to the receipt of consent or approval from governmental entities that could delay the completion of the Merger or impose conditions that could cause abandonment of the Merger.

Completion of the Merger is conditioned upon the receipt of consents, orders, approvals or clearances, to the extent required, from various regulatory authorities, including the DCPSC and the public utility commissions or similar entities in certain states in which the companies operate. The Merger has been approved by the Delaware Public Service Commission (DPSC), the Maryland Public Service Commission (MDPSC), the New Jersey Board of Public Utilities (NJBPU) and the Virginia State Corporation Commission. Approval of the Merger by the MDPSC is subject to appeals by the Maryland Office of People's Counsel, the Sierra Club/Chesapeake Climate Action Network and Public Citizen, Inc. in the Circuit Court of Queen Anne's County, and the approval by the NJBPU expires on June 30, 2016. The HSR Act waiting period applicable to the Merger expired on December 2, 2015. The Merger remains subject to approval by the DCPSC. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information regarding the status of regulatory approvals.

Exelon and PHI have proposed conditions for approval in the filings that have been made with the DCPSC and other regulatory commissions. The conditions of approval of the Merger by the DCPSC will trigger the “most favored nation” provisions in the approvals of the Merger by the DPSC, MDPSC, and the NJBPU.

Exelon cannot provide assurance that all required regulatory consents or approvals will be obtained or that these consents or approvals will not contain terms, conditions or restrictions that would be unacceptable. The Merger Agreement generally permits Exelon to terminate the Merger Agreement if the final terms of any of the required regulatory consents or approvals include burdensome conditions (as defined in the Merger Agreement).

Failure to obtain regulatory approval could result in Exelon’s payment of a reverse termination fee.

If the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals, the failure to obtain regulatory approvals without burdensome conditions, or the breach by Exelon of its obligations in respect of obtaining regulatory approvals, Exelon will be required to pay PHI a reverse termination fee of $180 million, which would occur by means of PHI’s election to redeem the outstanding nonvoting preferred securities purchased by Exelon in connection with the execution of the Merger Agreement for no consideration other than the nominal par value of the stock. In these circumstances, Exelon will also be required to reimburse PHI for up to $40 million of its documented out-of-pocket expenses for the Merger.

Failure to complete the Merger could negatively impact the share price and the future business and financial results of Exelon.

If the Merger is not completed, the ongoing businesses of Exelon could be negatively impacted and Exelon will be subject to several risks, including:

- having to pay certain significant costs relating to the Merger without receiving the benefits of the Merger, including a termination fee of up to $180 million payable by Exelon to PHI under certain circumstances; and
- the share price of Exelon could decline if and to the extent that the current market prices reflect an assumption by the market that the Merger will be completed.

Exelon and PHI have incurred and will incur significant transaction and Merger-related costs in connection with the Merger.

Exelon and PHI have incurred and expect to incur non-recurring costs associated with combining the operations of the two companies. Most of these costs will be transaction costs, including fees paid to financial and legal advisors related to the Merger and related financing arrangements, and employment-related costs, including change-in- control related payments made to certain PHI executives. In addition, until the closing of the Merger, Exelon will be required to pay financing costs without having realized any benefits from the Merger during the period of delay. Exelon will also incur transition costs related to formulating integration plans. Exelon expects that the elimination of costs, as well as the realization of other efficiencies related to the integration of the businesses, will exceed incremental transaction and Merger-related costs over time.

Exelon may not realize all the expected benefits of the Merger because of integration difficulties.

The success of the PHI acquisition will depend, in part, on Exelon's ability to realize all or some of the anticipated benefits from integrating PHI's business with Exelon's existing businesses. The integration process could be complex, costly and time-consuming. The challenges associated with integrating the operations of PHI's business include, among others:

- delay in implementation of our business plan for the combined business;
- unanticipated issues or costs in integrating financial, information technology, communications and other systems;
- possible inconsistencies in standards, controls, procedures and policies, and compensation structures between PHI' s structure and our structure; and
- difficulties in retention of key employees.

Exelon and PHI will be subject to various uncertainties while the Merger is pending that could negatively impact their ability to attract and retain key employees, and potentially impact the company's financial results.

Uncertainty about the effect of the Merger on employees, suppliers and customers could have a negative impact on Exelon and/or PHI. These uncertainties could impair Exelon's and/or PHI's ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter, as employees and prospective employees could experience uncertainty about their future roles with the combined company. In addition, current and prospective Exelon and PHI employees could determine that they do not desire to work for the combined company for a variety of possible reasons. Moreover, the pendency of Merger regulatory-review proceedings has caused PHI to delay filing base rate cases on behalf of its utilities Pepco, ACE and Delmarva which have had a material impact to their results of operations and cash flows.

The Merger could divert attention of management at Exelon and PHI, which could detract from efforts to meet business goals.

The pursuit of the Merger and the preparation for the integration could place a burden on management and internal resources. Any significant diversion of management attention away from ongoing business concerns and any difficulties encountered in the transition and integration process could affect Exelon's and/or PHI's financial results.

Exelon is obligated to complete the Merger whether or not it has obtained the required financing.

Exelon intended to fund the cash consideration in the Merger using a combination of debt, cash from asset sales, the issuance of equity (including mandatory convertible securities). See Note 4—Mergers, Acquisitions, and Dispositions and Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information regarding the merger financing. Although Exelon had sufficient cash to fund the cash consideration in the Merger as of September 30, 2015, a $2.75 billion portion of the debt incurred to finance the cash consideration was subject to mandatory special redemption on December 31, 2015. On December 2, 2015, the holders of $1.9 billion of that debt exchanged those debt securities for new notes that extend the mandatory special redemption date from December 31, 2015 to June 30, 2016 (or later under some circumstances), and on December 2, 2015, Exelon redeemed $868 million of the debt. Exelon could be required to raise additional cash to fund the cash consideration in the Merger.

The combined company's assets, liabilities or results of operations could be negatively impacted by unknown or unexpected events, conditions or actions that might occur at PHI prior to the closing of the Merger.

The PHI assets, liabilities, business, financial condition, cash flows, operating results and prospects to be acquired or assumed by Exelon by reason of the Merger could be negatively impacted before or after the Merger closing as a result of previously unknown events or conditions occurring or existing before the Merger closing. Adverse changes in PHI's business or operations could occur or arise as a result of actions by PHI, legal or regulatory developments including the emergence or unfavorable resolution of pre-acquisition loss contingencies, deteriorating general business, market, industry or economic conditions, and other factors both within and beyond the control of PHI. A significant decline in the value of PHI assets to be acquired by Exelon or a significant increase in PHI liabilities to be assumed by Exelon could negatively impact the combined company's future business, operating results, cash flows, financial conditions or prospects.

Exelon could record goodwill that could become impaired and adversely affect its operating results.

In accordance with GAAP, the Merger will be accounted for as an acquisition of PHI common stock by Exelon and will follow the acquisition method of accounting for business combinations. The assets and liabilities of PHI will be consolidated with those of Exelon. The excess of the purchase price over the fair values of PHI's assets and liabilities, if any, will be recorded as goodwill.

The amount of goodwill, which could be material, will be allocated to the appropriate reporting units of the combined company. Exelon is required to assess goodwill for impairment at least annually by comparing the fair value of reporting units to the carrying value of those reporting units. To the extent the carrying value of any of those reporting units is greater than the fair value, a second step comparing the implied fair value of goodwill to the carrying amount would be required to determine if the goodwill is impaired. Such a potential impairment could result in a material non-cash charge that would have a material impact on Exelon's future operating results or financial positions.

Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could delay or prevent the completion of the Merger.

One of the conditions to the closing of the Merger is that no judgment (whether preliminary, temporary or permanent) or other order by any court or other governmental entity shall be in effect that restrains, enjoins or otherwise prohibits or makes illegal the consummation of the Merger.

PHI and its directors have been named as defendants in purported class action lawsuits filed on behalf of named plaintiffs and other public stockholders challenging the proposed Merger and seeking, among other things, to enjoin the defendants from consummating the Merger on the agreed-upon terms. Exelon has been named as a defendant in these lawsuits. Exelon has also been named in a federal court case with similar claims. In September 2014, the parties reached a proposed settlement which is subject to court approval. Final court approval of the proposed settlement is not expected to occur until approximately 90 days after the Merger closing date.

If a plaintiff in these or any other litigation claims that may be filed in the future is successful in obtaining an injunction prohibiting the parties from completing the Merger on the terms contemplated by the Merger Agreement, the injunction could prevent the completion of the Merger in the expected time frame or altogether. If completion of the Merger is prevented or delayed, it could result in substantial costs to Exelon. In addition, Exelon could incur significant costs in connection with the lawsuits, including costs associated with the indemnification of PHI's directors and officers.

The Merger could be completed on terms different from those contained in the Merger Agreement.

Prior to the completion of the Merger, Exelon and PHI could, by their mutual agreement, amend or alter the terms of the Merger Agreement, including with respect to, among other things, the Merger consideration to be received by PHI stockholders or any covenants or agreements with respect to the parties' respective operations pending completion of the Merger. In addition, Exelon could choose to waive requirements of the Merger Agreement, including some conditions to closing of the Merger.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 2. PROPERTIES

Generation

The following table describes Generation's interests in net electric generating capacity by station at December 31, 2015:

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,389
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,347
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,320
Dresden	Midwest	Morris, IL	2		Uranium	Base-load	1,845
Quad Cities	Midwest	Cordova, IL	2	75	Uranium	Base-load	1,403[f]
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,069
Michigan Wind 2	Midwest	Sanilac Co., MI	50		Wind	Base-load	90
Beebe	Midwest	Gratiot Co., MI	34		Wind	Base-load	82
Michigan Wind 1	Midwest	Huron Co., MI	46		Wind	Base-load	69
Harvest 2	Midwest	Huron Co., MI	33		Wind	Base-load	59
Harvest	Midwest	Huron Co., MI	32		Wind	Base-load	53
Beebe 1B	Midwest	Gratiot Co., MI	21		Wind	Base-load	50
Ewington	Midwest	Jackson Co., MN	10	99	Wind	Base-load	20[f]
Marshall	Midwest	Lyon Co., MN	9	99	Wind	Base-load	19[f]
Norgaard	Midwest	Lincoln Co., MN	7	99	Wind	Base-load	9[f]
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	9
AgriWind	Midwest	Bureau Co., IL	4	99	Wind	Base-load	8[f]
Cisco	Midwest	Jackson Co., MN	4	99	Wind	Base-load	8[f]
Wolf	Midwest	Nobles Co., MN	5	99	Wind	Base-load	6[f]
CP Windfarm	Midwest	Faribault Co., MN	2		Wind	Base-load	4
Blue Breezes	Midwest	Faribault Co., MN	2		Wind	Base-load	3
Solar Ohio	Midwest	Toledo, OH	3		Solar	Base-load	3
Cowell	Midwest	Pipestone Co., MN	1	99	Wind	Base-load	2[f]
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296
Total Midwest							12,163
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,317
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,299[f]
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,005[f]
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	878[f][g]
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837
Oyster Creek	Mid-Atlantic	Forked River, NJ	1		Uranium	Base-load	625[e]
Conowingo	Mid-Atlantic	Darlington, MD	11		Hydroelectric	Base-load	572
Criterion	Mid-Atlantic	Oakland, MD	28		Wind	Base-load	70
Fourmile	Mid-Atlantic	Garrett County, MD	16		Wind	Base-load	40
Fair Wind	Mid-Atlantic	Garrett County, MD	12		Wind	Base-load	30
Solar Maryland MC	Mid-Atlantic	Various, MD	15		Solar	Base-load	27
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1		Solar	Base-load	14
Solar New Jersey 2	Mid-Atlantic	Various, NJ	2		Solar	Base-load	9
Solar New Jersey 1	Mid-Atlantic	Various, NJ	4		Solar	Base-load	8
Solar Maryland	Mid-Atlantic	Various, MD	10		Solar	Base-load	7
Solar Maryland 2	Mid-Atlantic	Various, MD	3		Solar	Base-load	7
Solar Federal	Mid-Atlantic	Trenton, NJ	1		Solar	Base-load	4
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5		Solar	Base-load	1
Muddy Run	Mid-Atlantic	Drumore, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Mid-Atlantic	Eddystone, PA	2		Oil/Gas	Intermediate	760
Perryman	Mid-Atlantic	Aberdeen, MD	6		Oil/Gas	Peaking	463[h]
Croydon	Mid-Atlantic	West Bristol, PA	8		Oil	Peaking	391
Handsome Lake	Mid-Atlantic	Kennerdell, PA	5		Gas	Peaking	268
Notch Cliff	Mid-Atlantic	Baltimore, MD	8		Gas	Peaking	118
Westport	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	116
Riverside	Mid-Atlantic	Baltimore, MD	3		Oil/Gas	Peaking	113[h]
Richmond	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	98

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Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Gould Street	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	97
Philadelphia Road	Mid-Atlantic	Baltimore, MD	4		Oil	Peaking	61
Eddystone	Mid-Atlantic	Eddystone, PA	4		Oil	Peaking	60
Fairless Hills	Mid-Atlantic	Fairless Hills, PA	2		Landfill Gas	Peaking	60
Delaware	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	52
Falls	Mid-Atlantic	Morrisville, PA	3		Oil	Peaking	51
Moser	Mid-Atlantic	Lower PottsgroveTwp., PA	3		Oil	Peaking	51
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39
Schuylkill	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	30
Salem	Mid-Atlantic	Lower Alloways Creek Twp, NJ	1	42.59	Oil	Peaking	16 [f]
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	5
Total Mid-Atlantic							11,725
Whitetail	ERCOT	Webb County, TX	57		Wind	Base-load	91
Sendero	ERCOT	Jim Hogg and Zapata County, TX	39		Wind	Base-load	78
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3		Gas	Intermediate	704
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	565
Colorado Bend	ERCOT	Wharton, TX	6		Gas	Intermediate	498
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870
Mountain Creek 6, 7	ERCOT	Dallas, TX	2		Gas	Peaking	240
LaPorte	ERCOT	Laporte, TX	4		Gas	Peaking	152
Total ERCOT							3,593
Solar Massachusetts	New England	Various, MA	18		Solar	Base-load	8
Holyoke Solar	New England	Various, MA	2		Solar	Base-load	4
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2
Solar Connecticut	New England	Various, CT	2		Solar	Base-load	1
Mystic 8, 9	New England	Charlestown, MA	6		Gas	Intermediate	1,418
Mystic 7	New England	Charlestown, MA	1		Oil/Gas	Intermediate	575
Wyman	New England	Yarmouth, ME	1	5.9	Oil	Intermediate	36 [f]
West Medway	New England	West Medway, MA	3		Oil/Gas	Peaking	117
Framingham	New England	Framingham, MA	3		Oil	Peaking	33
New Boston	New England	South Boston, MA	1		Oil	Peaking	16
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9
Total New England							2,219
Nine Mile Point	New York	Scriba, NY	2	50.01	Uranium	Base-load	838 [f][g]
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288 [f][g]
Solar New York	New York	Bethlehem, NY	1		Solar	Base-load	2
Total New York							1,128
AVSR	Other	Lancaster, CA	1		Solar	Base-load	242
Shooting Star	Other	Kiowa County, KS	65		Wind	Base-load	104
Exelon Wind 4	Other	Gruver, TX	38		Wind	Base-load	80
Bluegrass Ridge	Other	King City, MO	27		Wind	Base-load	57
Conception	Other	Barnard, MO	24		Wind	Base-load	50
Cow Branch	Other	Rock Port, MO	24		Wind	Base-load	50
Mountain Home	Other	Glenns Ferry, ID	20		Wind	Base-load	42
High Mesa	Other	Elmore Co., ID	19		Wind	Base-load	40
Echo 1	Other	Echo, OR	21	99	Wind	Base-load	34 [f]
Solar Arizona	Other	Various, AZ	55		Solar	Base-load	33
Cassia	Other	Buhl, ID	14		Wind	Base-load	29
Wildcat	Other	Lovington, NM	13		Wind	Base-load	27
Sacramento PV Energy	Other	Sacramento, CA	4		Solar	Base-load	26
Sunnyside	Other	Sunnyside, UT	1	50	Waste Coal	Base-load	26 [f]
Echo 2	Other	Echo, OR	10		Wind	Base-load	20
Tuana Springs	Other	Hagerman, ID	8		Wind	Base-load	17
California PV Energy	Other	Various, CA	37		Solar	Base-load	16
Greensburg	Other	Greensburg, KS	10		Wind	Base-load	13

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Solar Georgia	Other	Various, GA	14		Solar	Base-load	12
Echo 3	Other	Echo, OR	6	99	Wind	Base-load	10[f]
Exelon Wind 1	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 2	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 3	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 5	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 6	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 7	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 8	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 9	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 10	Other	Dumas, TX	8		Wind	Base-load	10
Exelon Wind 11	Other	Dumas, TX	8		Wind	Base-load	10
High Plains	Other	Panhandle, TX	8	99.5	Wind	Base-load	10[f]
Three Mile Canyon	Other	Boardman, OR	6		Wind	Base-load	10
Solar California	Other	Various, CA	25		Solar	Base-load	10
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	5
Loess Hills	Other	Rock Port, MO	4		Wind	Base-load	5
Mohave Sunrise Solar	Other	Fort Mohave, AZ	1		Solar	Base-load	5
Denver Airport Solar	Other	Denver, CO	1		Solar	Base-load	4
Hillabee	Other	Alexander City, AL	3		Gas	Intermediate	722
Grande Prairie	Other	Alberta, Canada	1		Gas	Peaking	105
SEGS 4, 5, 6	Other	Boron, CA	3	4.2-12.2	Solar	Peaking	9[f]
Total Other							1,913
Total							32,741

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, Salem and Three Mile Island, which are pressurized water reactors.
(b) 100%, unless otherwise indicated.
(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations reflect a summer rating. Wind and solar facilities reflect name plate capacity.
(e) Generation has agreed to permanently cease generation operation at Oyster Creek by December 31, 2019.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Reflects Generation's 50.01% interest in CENG, a joint venture with EDF. For Nine Mile Point, the co-owner owns 18% of Unit 2. Thus Exelon's ownership is 50.01% of 82% of Nine Mile Point Unit 2. Generation also had a unit-contingent PPA with CENG under which it purchased 85% of the nuclear plant output owned by CENG that was not sold to third parties under the pre-existing PPAs through 2014.
(h) Generation has agreed to retire and cease generation operations at the Perryman 2 (51 MWs) and Riverside 4 (74 MWs) units effective February 1, 2016 and May 31, 2016, respectively.

The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies or generating units being temporarily out of service for inspection, maintenance, refueling, repairs or modifications required by regulatory authorities.

In addition to the electric generating stations, Generation has working interests in 9 natural gas and oil exploration and production properties (Upstream) across the United States. Production volumes will vary from year to year due to the timing of individual project start-ups, operational outages, reservoir performance, regulatory changes, asset sales, weather events, price effects and other factors.

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see ITEM 1. BUSINESS—Exelon Generation Company, LLC. For its insured losses, Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on Generation's consolidated financial condition or results of operations.

ComEd

ComEd's electric substations and a portion of its transmission rights of way are located on property that ComEd owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ComEd believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements, licenses and franchise rights; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ComEd's higher voltage electric transmission lines owned and in service at December 31, 2015 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,656
138,000	2,306

ComEd's electric distribution system includes 35,419 circuit miles of overhead lines and 31,040 circuit miles of underground lines.

First Mortgage and Insurance

The principal properties of ComEd are subject to the lien of ComEd's Mortgage dated July 1, 1923, as amended and supplemented, under which ComEd's First Mortgage Bonds are issued.

ComEd maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ComEd is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ComEd.

PECO

PECO's electric substations and a significant portion of its transmission lines are located on property that PECO owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. PECO believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

PECO's high voltage electric transmission lines owned and in service at December 31, 2015 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188 (a)
230,000	548
138,000	156
69,000	200

(a) In addition, PECO has a 22.00% ownership interest in 127 miles of 500 kV lines located in Pennsylvania and a 42.55% ownership interest in 131 miles of 500 kV lines located in Delaware and New Jersey.

PECO's electric distribution system includes 12,960 circuit miles of overhead lines and 9,218 circuit miles of underground lines.

Gas

The following table sets forth PECO's natural gas pipeline miles at December 31, 2015:

	Pipeline Miles
Transmission	30
Distribution	6,826
Service piping	6,220
Total	13,076

PECO has an LNG facility located in West Conshohocken, Pennsylvania that has a storage capacity of 1,200 mmcf and a send-out capacity of 157 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 150 mmcf and a peaking capability of 25 mmcf/day. In addition, PECO owns 31 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

The principal properties of PECO are subject to the lien of PECO's Mortgage dated May 1, 1923, as amended and supplemented, under which PECO's first and refunding mortgage bonds are issued.

PECO maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, PECO is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of PECO.

BGE

BGE's electric substations and a significant portion of its transmission lines are located on property that BGE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. BGE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

BGE's high voltage electric transmission lines owned and in service at December 31, 2015 were as follows:

Voltage (Volts)	Circuit Miles
500,000	218
230,000	322
138,000	55
115,000	703

BGE's electric distribution system includes 9,190 circuit miles of overhead lines and 16,841 circuit miles of underground lines.

Gas

The following table sets forth BGE's natural gas pipeline miles at December 31, 2015:

	Pipeline Miles
Transmission	161
Distribution	7,173
Service piping	6,225
Total	13,559

BGE has an LNG facility located in Baltimore, Maryland that has a storage capacity of 1,055 mmcf and a send-out capacity of 332 mmcf/day, an LNG facility located in Westminster, Maryland that has a storage capacity of 6 mmcf and a send-out capacity of 6 mmcf/day, and a propane-air plant located in Baltimore, Maryland, with a storage capacity of 546 mmcf and a send-out capacity of 85 mmcf/day. In addition, BGE owns 12 natural gas city gate stations and 20 direct pipeline customer delivery points at various locations throughout its gas service territory.

Property Insurance

BGE owns its principal headquarters building located in downtown Baltimore. BGE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, BGE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of BGE.

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long-term design changes and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country's energy systems.

ITEM 3. LEGAL PROCEEDINGS

Exelon, Generation, ComEd, PECO and BGE

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Note 3—Regulatory Matters and Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

Exelon, Generation, ComEd, PECO and BGE

Not Applicable to the Registrants.

PART II

(Dollars in millions except per share data, unless otherwise noted)

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Exelon

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2016, there were 919,924,742 shares of common stock outstanding and approximately 118,487 record holders of common stock.

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2015				2014			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 31.37	$ 34.44	$ 34.98	$ 38.25	$ 38.93	$ 36.26	$ 37.73	$ 33.94
Low price	25.09	28.41	31.28	31.71	33.07	30.66	33.11	26.45
Close	27.77	29.70	31.42	33.61	37.08	34.09	36.48	33.56
Dividends	0.310	0.310	0.310	0.310	0.310	0.310	0.310	0.310

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index, for the period 2011 through 2015.

This performance chart assumes:

- $100 invested on December 31, 2010 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.

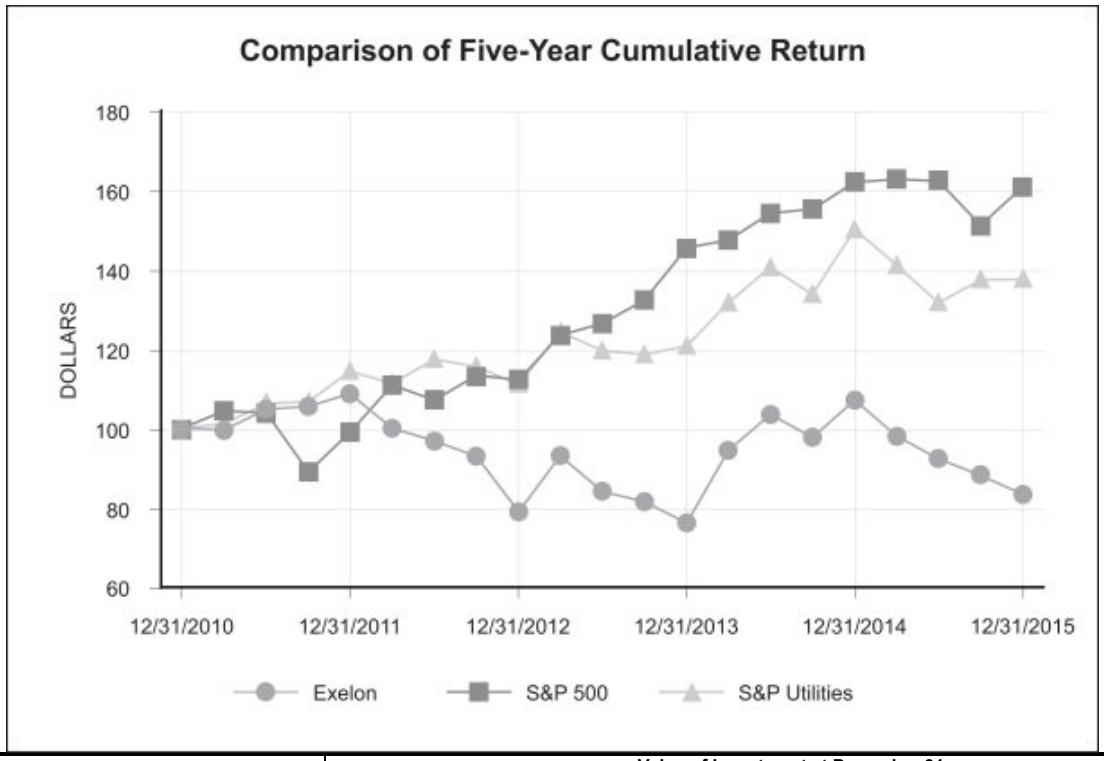

	Value of Investment at December 31,					
	2010	2011	2012	2013	2014	2015
Exelon Corporation	$100	$108.67	$78.93	$76.16	$107.03	$83.31
S&P 500	$100	$98.88	$112.13	$145.33	$161.88	$160.70
S&P Utilities	$100	$114.25	$110.93	$120.64	$149.94	$137.36

Generation

As of January 31, 2016, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2016, there were 127,016,973 outstanding shares of common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. At January 31, 2016, in addition to Exelon, there were 299 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2016, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2016, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

Exelon, Generation, ComEd, PECO and BGE

Dividends

Under applicable Federal law, Generation, ComEd, PECO and BGE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO or BGE may limit the dividends that these companies can distribute to Exelon.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with a financing arranged through ComEd Financing III that ComEd will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to certain dividend restrictions established by the MDPSC. First, in connection with the Constellation merger, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid and notify the

MDPSC that BGE's equity ratio is at least 48% within five business days after dividend payment. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

Exelon's Board of Directors approved a revised dividend policy. The approved policy would raise our dividend 2.5% each year for the next three years, beginning with the June 2016 dividend. The Board will take formal action to declare the next dividend in the second quarter.

At December 31, 2015, Exelon had retained earnings of $12,068 million, including Generation's undistributed earnings of $2,701 million, ComEd's retained earnings of $978 million consisting of retained earnings appropriated for future dividends of $2,617 million, partially offset by $(1,639) million of unappropriated retained deficits, PECO's retained earnings of $780 million, and BGE's retained earnings of $1,320 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2015 and 2014:

	2015				2014			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310

The following table sets forth Generation's quarterly distributions and ComEd's and PECO's quarterly common dividend payments:

	2015				2014			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 106	$ 106	$ 906	$ 1,356	$ 205	$ 205	$ 205	$ 31
ComEd	75	75	75	75	77	77	77	76
PECO	70	70	70	70	80	80	80	80

First Quarter 2016 Dividend. On January 26, 2016, the Exelon Board of Directors declared a first quarter 2016 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2016, to shareholders of record of Exelon at the end of the day on February 12, 2016.

ITEM 6. SELECTED FINANCIAL DATA

Exelon

The selected financial data presented below has been derived from the audited consolidated financial statements of Exelon. This data is qualified in its entirety by reference to and should be read in conjunction with Exelon's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions, except per share data)	2015	2014 [a]	2013	2012 [b]	2011
Statement of Operations data:					
Operating revenues	$29,447	$27,429	$24,888	$23,489	$19,063
Operating income	4,409	3,096	3,669	2,373	4,479
Income from continuing operations	2,250	1,820	1,729	1,171	2,499
Net income	2,250	1,820	1,729	1,171	2,499
Net income attributable to common shareholders	2,269	1,623	1,719	1,160	2,495
Earnings per average common share (diluted):					
Income from continuing operations	$ 2.54	$ 1.88	$ 2.00	$ 1.42	$ 3.75
Net income	$ 2.54	$ 1.88	$ 2.00	$ 1.42	$ 3.75
Dividends per common share	$ 1.24	$ 1.24	$ 1.46	$ 2.10	$ 2.10
Average shares of common stock outstanding—diluted	893	864	860	819	665

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis.
(b) 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

	December 31,				
(In millions)	2015	2014	2013	2012	2011
Balance Sheet data:					
Current assets	$15,334	$11,853	$ 9,562	$10,009	$ 5,713
Property, plant and equipment, net	57,439	52,170	47,330	45,186	32,570
Noncurrent regulatory assets	6,065	6,076	5,910	6,497	4,518
Goodwill	2,672	2,672	2,625	2,625	2,625
Other deferred debits and other assets	13,874	13,645	13,816	14,033	9,498
Total assets	$95,384	$86,416	$79,243	$78,350	$54,924
Current liabilities	$ 9,118	$ 8,762	$ 7,686	$ 7,734	$ 5,134
Long-term debt, including long-term debt to financing trusts	24,286	19,853	18,165	18,266	12,118
Noncurrent regulatory liabilities	4,201	4,550	4,388	3,981	3,627
Other deferred credits and other liabilities	30,457	29,118	26,064	26,552	19,570
Contingently redeemable noncontrolling interest [a]	28	—	—	—	—
Preferred securities of subsidiary	—	—	—	87	87
Noncontrolling interest	1,308	1,332	15	106	3
BGE preference stock not subject to mandatory redemption	193	193	193	193	—
Shareholders' equity	25,793	22,608	22,732	21,431	14,385
Total liabilities and shareholders' equity	$95,384	$86,416	$79,243	$78,350	$54,924

(a) Represents mezzanine equity related to contingently redeemable equity contributions made by a noncontrolling interest holder of one of Generation's subsidiaries. See Note 18—Contingently Redeemable Noncontrolling Interest for further information.

Generation

The selected financial data presented below has been derived from the audited consolidated financial statements of Generation. This data is qualified in its entirety by reference to and should be read in conjunction with Generation's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions)	2015	2014 [a]	2013	2012 [b]	2011
Statement of Operations data:					
Operating revenues	$19,135	$17,393	$15,630	$14,437	$10,447
Operating income	2,275	1,176	1,677	1,113	2,875
Net income	1,340	1,019	1,060	558	1,771
Net income attributable to membership interest	1,372	835	1,070	562	1,771

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis.
(b) 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

	December 31,				
(In millions)	2015	2014	2013	2012	2011
Balance Sheet data:					
Current assets	$ 6,342	$ 7,311	$ 5,964	$ 6,211	$ 3,217
Property, plant and equipment, net	25,843	23,028	20,111	19,531	13,475
Other deferred debits and other assets	14,344	14,612	14,625	14,906	10,714
Total assets	$46,529	$44,951	$40,700	$40,648	$27,406
Current liabilities	$ 4,933	$ 4,459	$ 3,842	$ 3,969	$ 1,899
Long-term debt	8,869	7,582	7,111	7,422	3,647
Other deferred credits and other liabilities	19,757	18,859	17,005	16,592	13,152
Contingently redeemable noncontrolling interest [a]	28	—	—	—	—
Noncontrolling interest	1,307	1,333	17	108	5
Member's equity	11,635	12,718	12,725	12,557	8,703
Total liabilities and member's equity	$46,529	$44,951	$40,700	$40,648	$27,406

(a) Represents mezzanine equity related to contingently redeemable equity contributions made by a noncontrolling interest holder of one of Generation's subsidiaries. See Note 18—Contingently Redeemable Noncontrolling Interest for further information.

ComEd

The selected financial data presented below has been derived from the audited consolidated financial statements of ComEd. This data is qualified in its entirety by reference to and should be read in conjunction with ComEd's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions)	2015	2014	2013	2012	2011
Statement of Operations data:					
Operating revenues	$4,905	$4,564	$4,464	$5,443	$6,056
Operating income	1,017	980	954	886	982
Net income	426	408	249	379	416

	December 31,				
(In millions)	2015	2014	2013	2012	2011
Balance Sheet data:					
Current assets	$ 1,518	$ 1,723	$ 1,540	$ 1,692	$ 2,127
Property, plant and equipment, net	17,502	15,793	14,666	13,826	13,121
Goodwill	2,625	2,625	2,625	2,625	2,625
Noncurrent regulatory assets	895	852	933	666	699
Other deferred debits and other assets	3,992	4,365	4,325	3,984	3,975
Total assets	$26,532	$25,358	$24,089	$22,793	$22,547
Current liabilities	$ 2,766	$ 1,923	$ 2,032	$ 1,655	$ 2,071
Long-term debt, including long-term debt to financing trusts	6,049	5,870	5,235	5,492	5,391
Noncurrent regulatory liabilities	3,459	3,655	3,512	3,229	3,042
Other deferred credits and other liabilities	6,015	6,003	5,782	5,094	5,006
Shareholders' equity	8,243	7,907	7,528	7,323	7,037
Total liabilities and shareholders' equity	$26,532	$25,358	$24,089	$22,793	$22,547

PECO

The selected financial data presented below has been derived from the audited consolidated financial statements of PECO. This data is qualified in its entirety by reference to and should be read in conjunction with PECO's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions)	2015	2014	2013	2012	2011
Statement of Operations data:					
Operating revenues	$3,032	$3,094	$3,100	$3,186	$3,720
Operating income	630	572	666	623	655
Net income	378	352	395	381	389
Net income attributable to common shareholder	378	352	388	377	385

(In millions)	December 31, 2015	2014	2013	2012	2011
Balance Sheet data:					
Current assets	$ 842	$ 645	$ 821	$1,054	$1,218
Property, plant and equipment, net	7,141	6,801	6,384	6,078	5,874
Noncurrent regulatory assets	1,583	1,529	1,448	1,378	1,216
Other deferred debits and other assets	801	885	868	793	814
Total assets	$10,367	$9,860	$9,521	$9,303	$9,122
Current liabilities	$ 944	$ 653	$ 889	$1,158	$1,145
Long-term debt, including long-term debt to financing trusts	2,464	2,416	2,120	1,821	1,772
Noncurrent regulatory liabilities	527	657	629	538	585
Other deferred credits and other liabilities	3,196	3,013	2,818	2,717	2,595
Preferred securities	—	—	—	87	87
Shareholders' equity	3,236	3,121	3,065	2,982	2,938
Total liabilities and shareholders' equity	$10,367	$9,860	$9,521	$9,303	$9,122

BGE

The selected financial data presented below has been derived from the audited consolidated financial statements of BGE. This data is qualified in its entirety by reference to and should be read in conjunction with BGE's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	For the Years Ended December 31, 2015	2014	2013	2012	2011
Statement of Operations data:					
Operating revenues	$3,135	$3,165	$3,065	$2,735	$3,068
Operating income	558	439	449	132	314
Net income	288	211	210	4	136
Net income (loss) attributable to common shareholder	275	198	197	(9)	123

(In millions)	December 31, 2015	2014	2013	2012 (a)	2011 (a)
Balance Sheet data:					
Current assets	$ 845	$ 951	$1,009	$ 979	$ 969
Property, plant and equipment, net	6,597	6,204	5,864	5,498	5,132
Noncurrent regulatory assets	514	510	524	522	551
Other deferred debits and other assets	339	391	442	486	531
Total assets	$8,295	$8,056	$7,839	$7,485	$7,183
Current liabilities	$1,134	$ 794	$ 800	$ 980	$ 675
Long-term debt, including long-term debt to financing trusts and variable interest entities	1,732	2,109	2,179	1,949	2,166
Noncurrent regulatory liabilities	184	200	204	214	201
Other deferred credits and other liabilities	2,368	2,200	2,101	1,984	1,840
Preference stock not subject to mandatory redemption	190	190	190	190	190
Shareholders' equity	2,687	2,563	2,365	2,168	2,111
Total liabilities and shareholders' equity	$8,295	$8,056	$7,839	$7,485	$7,183

(a) BGE retrospectively reclassified certain regulatory assets and regulatory liabilities to conform to the current year presentation.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Exelon

Executive Overview

Exelon, a utility services holding company, operates through the following principal subsidiaries:

- *Generation,* whose integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services.
  - As a result of the Constellation merger, Generation owns a 50.01% interest in CENG. During 2014, Generation assumed the operating licenses and corresponding operational control of CENG's nuclear fleet. As a result, Exelon and Generation fully consolidated CENG's financial position and results of operations into their financial statements since April 1, 2014.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in northern Illinois, including the City of Chicago.
- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE,* whose business consists of the purchase and regulated retail sale of electricity and natural gas and the provision of electricity distribution and transmission and gas distribution services in central Maryland, including the City of Baltimore.

Exelon has nine reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions in Generation), ComEd, PECO and BGE. See Note 25—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

Exelon's consolidated financial information includes the results of its four separate operating subsidiary registrants, Generation, ComEd, PECO and BGE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO and BGE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Financial Results. The following consolidated financial results reflect the results of Exelon for the year ended December 31, 2015 compared to the same period in 2014. The 2014 financial results only include the operations of CENG on a fully consolidated basis from the date Generation assumed

operational control, April 1, 2014, through December 31, 2014. All amounts presented below are before the impact of income taxes, except as noted.

	The Years Ended December 31,							
	2015						2014	Favorable (Unfavorable) Variance
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon (a)	
Operating revenues	$ 19,135	$4,905	$3,032	$3,135	$(760)	$29,447	$27,429	$ 2,018
Purchased power and fuel expense	10,021	1,319	1,190	1,305	(751)	13,084	13,003	(81)
Revenue net of purchased power and fuel expense (b)	9,114	3,586	1,842	1,830	(9)	16,363	14,426	1,937
Other operating expenses								
Operating and maintenance	5,308	1,567	794	683	(30)	8,322	8,568	246
Depreciation and amortization	1,054	707	260	366	63	2,450	2,314	(136)
Taxes other than income	489	296	160	224	31	1,200	1,154	(46)
Total other operating expenses	6,851	2,570	1,214	1,273	64	11,972	12,036	64
Equity in losses of unconsolidated affiliates	—	—	—	—	—	—	(20)	20
Gain on sales of assets	12	1	2	1	2	18	437	(419)
Gain on consolidation and acquisition of businesses	—	—	—	—	—	—	289	(289)
Operating income (loss)	2,275	1,017	630	558	(71)	4,409	3,096	1,313
Other income and (deductions)								
Interest expense, net	(365)	(332)	(114)	(99)	(123)	(1,033)	(1,065)	32
Other, net	(60)	21	5	18	(30)	(46)	455	(501)
Total other income and (deductions)	(425)	(311)	(109)	(81)	(153)	(1,079)	(610)	(469)
Income (loss) before income taxes	1,850	706	521	477	(224)	3,330	2,486	844
Income taxes	502	280	143	189	(41)	1,073	666	(407)
Equity in (losses) earnings of unconsolidated affiliates	(8)	—	—	—	1	(7)	—	(7)
Net income (loss)	1,340	426	378	288	(182)	2,250	1,820	430
Net income (loss) attributable to noncontrolling interests and preference stock dividends	(32)	—	—	13	—	(19)	197	(216)
Net income (loss) attributable to common shareholders	$ 1,372	$ 426	$ 378	$ 275	$(182)	$ 2,269	$ 1,623	$ 646

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.

(b) The Registrants' evaluate operating performance using the measure of revenue net of purchased power and fuel expense. The Registrants' believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Exelon's net income attributable to common shareholders was $2,269 million for the year ended December 31, 2015 as compared to $1,623 million for the year ended December 31, 2014, and diluted earnings per average common share were $2.54 for the year ended December 31, 2015 as compared to $1.88 for the year ended December 31, 2014.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $1,937 million as compared to 2014. The year-over-year increase was primarily due to the following favorable factors:

- Increase of $666 million at Generation primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015, benefit of lower cost to serve load (including the absence of higher procurement costs for replacement power in 2014), the cancellation of the DOE spent

nuclear fuel disposal fee, increased capacity prices, the inclusion of Integrys' results in 2015, favorability from portfolio management optimization activities in the Mid-Atlantic and Midwest regions, and increased load served, partially offset by lower margins resulting from the 2014 sales of generating assets, lower realized energy prices, and the absence of the 2014 fuel optimization opportunities in the South region due to extreme cold weather;

- Increase of $848 million at Generation due to mark-to-market gains of $257 million in 2015 from economic hedging activities as compared to losses of $591 million in 2014;
- Increase of $132 million at Generation related to amortization of contracts recorded at fair value associated with prior acquisitions;
- Increase of $228 million at ComEd primarily due to increased electric distribution and transmission formula rate revenues (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE);
- Increase of $9 million at PECO primarily due to favorable weather and volume; and
- Increase of $82 million at BGE primarily due to increased distribution revenue pursuant to increased rates effective December 2014 as a result of the electric and natural gas distribution rate case order issued by the Maryland PSC and increased transmission revenue.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

- Decrease of $38 million at ComEd due to unfavorable weather and volume.

Operating and maintenance expense decreased by $246 million as compared to 2014 primarily due to the following favorable factors:

- Long-lived asset impairments at Generation of $12 million in 2015 compared to $663 million in 2014.
- Decrease of $44 million resulting from the absence of 2014 expenses recorded for a Constellation merger commitment at Generation;
- Decreased storm costs at PECO and BGE of $78 million and $21 million, respectively;
- Decreased uncollectible accounts expense at BGE of $49 million.

The year-over-year decrease in operating and maintenance expense was partially offset by the following unfavorable factors:

- Increase in Generation's labor, contracting and materials costs of $323 million primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015 and increased contracting spend related to energy efficiency projects;
- Increase of $64 million as a result of an increase in the number of nuclear refueling outage days at Generation, including Salem, primarily related to the inclusion of CENG's plants on a fully consolidated basis in 2015;
- Increase in labor, contracting and materials costs of $31 million related to preventative maintenance and other projects at ComEd;
- Increased storm costs at ComEd of $27 million;
- Increased costs associated with ComEd's uncollectible accounts expense of $27 million; and
- An increase in pension and non-pension postretirement benefits expense of $47 million primarily at Exelon, Generation, and ComEd, resulting from the unfavorable impact of lower assumed pension and OPEB discount rates for 2015 and an increase in the life expectancy assumption for plan participants in 2015, partially offset by cost savings from plan design changes for certain OPEB plans effective April 2014 and forward.

Depreciation and amortization expense increased by $136 million primarily as a result of the inclusion of CENG's results on a fully consolidated basis in 2015, increased nuclear decommissioning amortization at Generation, and increased depreciation expense across the operating companies for ongoing capital expenditures.

Taxes other than income increased $46 million primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015 and increased sales and use tax at Corporate.

Gain on sales of assets decreased $419 million as a result of the absence of 2014 gains recorded on the sales of ownership interest in certain generating stations.

Gain on consolidation and acquisition of businesses decreased by $289 million due to a $261 million gain upon consolidation of CENG in 2014 resulting from the difference in fair value of CENG's net assets as of April 1, 2014, and the equity method investment previously recorded on Generation's and Exelon's books and the settlement of pre-existing transactions between Generation and CENG, and a $28 million bargain-purchase gain in 2014 related to the Integrys acquisition.

Interest expense decreased by $32 million primarily as a result of mark-to market gains in 2015 as compared to mark-to-market losses in 2014 associated with an interest rate swap terminated in June 2015, partially offset by higher debt in 2015 related to financing activities associated with the pending PHI merger.

Other, net decreased by $501 million primarily at Generation as a result of the change in realized and unrealized gains and losses on NDT funds.

Exelon's effective income tax rates for the years ended December 31, 2015 and 2014 were 32.2% and 26.8%, respectively. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the years ended December 31, 2015 and 2014, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings

Exelon's adjusted (non-GAAP) operating earnings for the year ended December 31, 2015 were $2,227 million, or $2.49 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,068 million, or $2.39 per diluted share, for the same period in 2014. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2015 as compared to 2014:

	For the years ended December 31,			
	2015		2014	
(All amounts after tax; in millions, except per share amounts)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$2,269	$ 2.54	$1,623	$ 1.88
Mark-to-Market Impact of Economic Hedging Activities (a)	(158)	(0.18)	363	0.42
Unrealized Losses (Gains) Related to NDT Fund Investments (b)	115	0.13	(86)	(0.10)
Plant Retirements and Divestitures (c)	—	—	(245)	(0.28)
Asset Retirement Obligation (d)	(6)	(0.01)	(13)	(0.02)
Merger and Integration Costs (e)	58	0.07	124	0.14
Amortization of Commodity Contract Intangibles (f)	(5)	—	64	0.07
Reassessment of State Deferred Income Taxes (g)	41	0.05	(27)	(0.03)
Long-Lived Asset Impairments (h)	21	0.02	435	0.50
Bargain-Purchase Gain on Integrys Acquisition (i)	—	—	(28)	(0.03)
Gain on CENG Integration (j)	—	—	(159)	(0.18)
Tax Settlements (k)	(52)	(0.06)	(106)	(0.12)
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps (l)	(21)	(0.02)	61	0.07
PHI Merger Related Redeemable Debt Exchange (m)	13	0.01	—	—
Reduction in State Income Tax Reserve (n)	(10)	(0.01)	—	—
Midwest Generation Bankruptcy Recoveries (o)	(6)	(0.01)	—	—
CENG Non-Controlling Interest (p)	(32)	(0.04)	62	0.07
Adjusted (non-GAAP) Operating Earnings	$2,227	$ 2.49	$2,068	$ 2.39

(a) Reflects the impact of (gains) losses for the years ended December 31, 2015 and 2014 (net of taxes of $99 million and $232 million, respectively) on Generation's economic hedging activities. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized losses (gains) for the years ended December 31, 2015 and 2014 (net of taxes of $148 million and $77 million, respectively) on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Reflects the impacts associated with the sales of Generation's ownership interests in generating stations for the year ended December 31, 2014 (net of taxes of $163 million, respectively).

(d) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the Non-Regulatory Agreement Units for the years ended December 31, 2015 and 2014 (net of taxes of $4 million).

(e) Reflects certain costs associated with mergers and acquisitions incurred for the years ended December 31, 2015 and 2014 (net of taxes of $38 million and $45 million, respectively) including professional fees, employee-related expenses, integration activities, upfront credit facilities fees, merger commitments, and certain pre-acquisition contingencies related to the Constellation merger, CENG integration and the Integrys and pending PHI acquisitions.

(f) Reflects the non-cash impact for the years ended December 31, 2015 and 2014 (net of taxes of $3 million and $68 million, respectively) of the amortization of commodity contracts recorded at fair value associated with prior acquisitions, if and when applicable.

(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment.

(h) In 2015, reflects charges to earnings primarily related to the impairments of investments in long-term leases and Upstream assets (net of taxes of $13 million). In 2014, reflects charges to earnings related to the impairments of certain generating assets held for sale, investment in long-term leases, Upstream assets, and wind generating assets (net of taxes of $250 million).

(i) Reflects the excess of the fair value of assets and liabilities acquired over the purchase price of Integrys (net of taxes of $16 million).

(j) Reflects the non-cash gain recorded upon consolidation of CENG in accordance with the execution of the NOSA on April 1, 2014 (net of taxes of $102 million).
(k) Reflects a benefit related to the favorable settlement in 2015 and 2014 of certain income tax positions on Constellation's pre-acquisition tax returns.
(l) Reflects the impact of mark-to-market activity on forward-starting interest rate swaps held at Exelon Corporate related to financing for the pending PHI acquisition for the years ended December 31, 2015 and 2014 (net of taxes of $14 million and $39 million, respectively).
(m) Reflects the costs associated with the exchange and redemption in December 2015 of certain mandatorily redeemable debt issued to finance the PHI merger (net of taxes of $8 million).
(n) Reflects the reduction of a previously recorded state income tax reserve associated with the 2014 sales of Keystone and Conemaugh for the year ended December 31, 2015.
(o) Reflects a benefit for the favorable settlement of a long-term railcar lease agreement pursuant to the Midwest Generation bankruptcy for the year ended December 31, 2015 (net of taxes of $4 million).
(p) Represents Generation's non-controlling interest related to CENG exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments and mark-to-market activity in 2015, and in 2014 the impact of unrealized gains and losses on NDT fund investments, costs incurred associated with the integration, non-cash amortization of intangible assets, net, related to commodity contracts, mark-to-market activity, and changes in asset retirement obligations.

Merger and Acquisition Costs

As presented in the table above, Exelon has incurred and will continue to incur costs associated with the Integrys and PHI acquisitions including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses), financing costs, integration initiatives, and certain pre-acquisition contingencies.

For the years ended December 31, 2015 and 2014, expense has been recognized for costs incurred to achieve the Constellation merger, CENG integration, Integrys acquisition and pending PHI acquisition as follows:

	Pre-tax Expense				
	Twelve Months Ended December 31, 2015				
Merger Integration and Acquisition Expense:	Generation	ComEd	PECO	BGE	Exelon
Financing [a]	$ —	$ —	$ —	$ —	$ 21
Transaction [b]	—	—	—	—	23
Other [c]	32	9	4	5	51
Total	$ 32	$ 9	$ 4	$ 5	$ 95

	Pre-tax Expense				
	Twelve Months Ended December 31, 2014				
Merger Integration and Acquisition Expense:	Generation	ComEd	PECO	BGE	Exelon
Financing [a]	$ —	$ —	$ —	$ —	$ 31
Transaction [b]	—	—	—	—	26
Regulatory commitments [d]	44	—	—	—	44
Employee-related [e]	5	—	—	—	5
Other [c]	56	4	2	2	65
Total	$ 105	$ 4	$ 2	$ 2	$ 171

(a) Reflects costs incurred at Exelon related to the financing of the PHI acquisition, including upfront credit facility fees. Excludes mark-to-market activity on forward-starting swaps and costs associated with the exchange and redemption of mandatorily redeemable debt.
(b) External, third party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of transactions.
(c) Costs to integrate CENG, Constellation and Integrys processes and systems into Exelon and to terminate certain Constellation debt agreements. Also includes professional fees primarily related to integration for the pending PHI acquisition.

(d) Reflects costs incurred at Generation for a Constellation merger commitment for the year ended December 31, 2014.
(e) Costs primarily for employee severance, pension and OPEB expense and retention bonuses.

As of December 31, 2015, Exelon projects incurring total PHI acquisition and integration related costs of approximately $700 million, excluding the amounts Exelon and PHI are committed, if approved, to provide to the PHI utility's respective customers. Of this amount, including 2014 and through December 31, 2015, Exelon has incurred approximately $300 million of costs associated with the proposed merger. Included in this amount are costs to fund the merger of which $76 million has been expensed, $56 million has been paid and recorded as deferred debt issuance costs and $60 million has been incurred and charged to common stock. The remaining costs will be primarily within Operating and maintenance expense within Exelon's Consolidated Statements of Operations and Comprehensive Income and will also include approximately $60 million for integration costs expected to be capitalized to Property, plant and equipment. The increase from the previous estimate of $635 million is due to higher transaction costs primarily driven by the merger delay. This increase in transaction costs is partially offset by lower integration costs.

Pursuant to the conditions set forth by the MDPSC in its approval of the Constellation merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion. The direct investment estimate includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a twenty year lease agreement for office space that was contingent upon the developer obtaining all required approvals, permits and financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. Construction began late in the second quarter of 2014 and the building is expected to be ready for occupancy by the end of 2016. See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information related to the lease commitments.

Exelon's Strategy and Outlook for 2016 and Beyond

Exelon's value proposition and competitive advantage come from its scope and its core strengths of operational excellence and financial discipline. Exelon leverages its integrated business model to create value. Exelon's regulated and competitive businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- Exelon's utilities provide a foundation for stable earnings, which translates to a stable currency in our stock.
- Generation's competitive businesses provide free cash flow to invest primarily into the utilities and in long-term, contracted assets.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The Exelon utilities only invest in rate base where it provides a net benefit to customers and the community by improving reliability and the service experience or otherwise meeting customer needs. The Exelon utilities make these investments prudently and at the lowest reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results. Additionally,

ComEd, PECO and BGE anticipate making significant future investments in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Generation's competitive businesses create value for customers by providing innovative solutions and reliable, clean and affordable energy. Generation's electricity generation strategy is to pursue opportunities that provide generation to load matching to reduce earnings volatility. Generation leverages its energy generation portfolio to deliver energy to both wholesale and retail customers. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon's financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, to maintain optimal capital structure and to return value to Exelon's shareholders with an attractive dividend throughout the energy commodity market cycle and through stable earnings growth. Exelon's Board of Directors approved a revised dividend policy. The approved policy would raise our dividend 2.5% each year for the next three years, beginning with the June 2016 dividend. The Board will take formal action to declare the next dividend in the second quarter.

Various market, financial, and other factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS for additional information regarding market and financial factors.

Continually optimizing the cost structure is a key component of Exelon's financial strategy. Through a recent focused cost management program the company has committed to reducing operation and maintenance expenses and capital costs by $350 million, of which approximately 35% of run-rate savings are expected to be achieved by the end of 2016 and fully realized in 2018. Savings will be allocated approximately 75%, 14%, 6% and 6% to Generation, ComEd, PECO and BGE, respectively. Exelon anticipates the earnings per share savings impact on EPS will be within $0.13 to $0.18 from 2018 forward.

Proposed Merger with Pepco Holdings, Inc. (Exelon)

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name. Under the Merger Agreement, PHI's shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. Based on the outstanding shares of PHI's common stock as of December 31, 2015, PHI shareholders would receive $6.9 billion in total cash. In addition, in connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $180 million of a class of nonvoting, nonconvertible and nontransferable preferred securities of PHI. The preferred securities are included in Other non-current assets on Exelon's Consolidated Balance Sheet. PHI has the right to redeem the preferred securities at its option for the purchase price paid plus accrued dividends, if any.

On November 2, 2015, Exelon and PHI each filed a new Notification and Report Form with the DOJ under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act) due to the expiration of the original filing. The HSR Act waiting period expired on December 2, 2015, and the HSR Act no longer precludes completion of the merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU), the Delaware Public Service Commission (DPSC), the Maryland Public Service Commission (MDPSC) and the FERC have approved the merger of PHI and Exelon. The Federal Communications Commission has also approved the transfer of certain PHI communications licenses.

On February 11, 2015, the NJBPU approved the proposed merger and the previously filed settlement signed and filed by Exelon, PHI, Atlantic City Electric (ACE), NJBPU staff, and the Independent Energy Coalition. The settlement provides a package of benefits to ACE customers and the state of New Jersey. This package of benefits includes the establishment of customer rate credit programs, with an aggregate value of $62 million for ACE customers and energy efficiency programs that will provide savings for ACE customers of $15 million. The March 6, 2015, order by the NJBPU approving the merger required that the consummation of the merger must take place no later than November 1, 2015 unless otherwise extended by the Board. On October 15, 2015, the NJBPU extended the November 1, 2015 date to June 30, 2016.

On February 13, 2015, Exelon and PHI announced that they had reached a settlement agreement in the proceeding before the DPSC to review the proposed merger. The settlement, which was amended on April 7, 2015, was signed and filed by Exelon, PHI, Delmarva Power & Light Company (DPL), the DPSC Staff, the Delaware Public Advocate, the Delaware Department of Natural Resources and Environmental Control, the Delaware Sustainable Energy Utility, the Mid-Atlantic Renewable Energy Coalition and the Clean Air Council. As part of this settlement, Exelon and PHI proposed a package of benefits to DPL customers and the state of Delaware including the establishment of customer rate credits of $40 million for DPL customers in Delaware, $2 million of funding for energy efficiency programs for DPL low income customers, and $2 million of funding for workforce development. On June 2, 2015, the DPSC issued an order accepting the settlement and approving the merger between Exelon and PHI.

On March 17, 2015, Exelon and PHI announced that they had reached settlements with multiple parties in the Maryland proceeding to review the proposed merger after filing a Request for Adoption of Settlements with the MDPSC. The settlements were signed and filed by Exelon, PHI, Montgomery County, Prince George's County, the National Consumer Law Center, National Housing Trust, the Maryland Affordable Housing Coalition, the Housing Association of Nonprofit Developers, and a consortium of recreational trail advocacy organizations led by the Mid-Atlantic Off-Road Enthusiasts. Exelon and PHI also announced a settlement with The Alliance for Solar Choice. On May 15, 2015, the MDPSC approved the merger after modifying a number of the conditions in the settlements, resulting in total rate credits of $66 million, funding for energy efficiency programs of $43.2 million, a Green Sustainability Fund of $14.4 million, 20 MWs of renewable generation development and increased penalties related to reliability commitments. On May 18, 2015, Exelon and PHI accepted and committed to fulfill the conditions.

On June 11, 2015, the Maryland Office of People's Counsel (OPC), the Sierra Club, and the Chesapeake Climate Action Network filed Petitions for Judicial Review of the MDPSC's approval of the merger with the Circuit Court for Queen Anne's County. On June 23, 2015, Public Citizen, Inc. filed its Petition for Judicial Review with the Circuit Court for Queen Anne's County. On July 10, 2015, Exelon and PHI filed a response in opposition to the Petitions for Review.

On July 21, 2015, the OPC filed a motion to stay the MDPSC order approving the merger and to set a schedule for discovery and presentation of new evidence. On July 29, 2015, Public Citizen, Inc. filed a response supporting OPC's motion to stay, and on July 31, 2015 the Sierra Club and the Chesapeake Climate Action Network filed a joint motion to stay. In July and August, Exelon, PHI, the MDPSC, Prince George's County and Montgomery County filed responses opposing the motions to stay. The judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC's order approving the merger and denied the petitions for

judicial review filed by the OPC, the Sierra Club, the Chesapeake Climate Action Network (CCAN) and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special appeals, and on January 21, Sierra Club and CCAN filed a notice of appeal. In the ordinary course this appeal would be resolved no earlier than third quarter 2016.

On August 27, 2015, the District of Columbia Public Service Commission (DCPSC) issued an Opinion and Order denying approval of the merger, concluding that the merger as presented was not in the public interest. Exelon and PHI filed an Application for Reconsideration with the DCPSC on September 28, 2015. On October 6, 2015, Exelon, PHI, the District of Columbia Government, the Office of Peoples Counsel, the District of Columbia Water and Sewer Authority, the National Consumer Law Center, National Housing Trust and National Housing Trust—Enterprise Preservation Corporation, and the Apartment and Office Building Association of Metropolitan Washington (collectively, Settling Parties) entered into a Nonunanimous Full Settlement Agreement and Stipulation (Settlement Agreement) with respect to the merger. Exelon and PHI subsequently filed a motion of joint applicants requesting the DCPSC to reopen the approval application to allow for consideration of the Settlement Agreement and granting additional requested relief. The new package of benefits totals $78 million and includes commitments to provide relief of residential customer base rate increases of $26 million, one-time direct bill credits of $14 million, low-income energy assistance of $16 million, improved reliability, a cleaner and greener D.C. through funding energy efficiency programs and development of renewable energy, and investment in local jobs and the local economy through workforce development of $5 million. It also guarantees charitable contributions totaling $19 million over 10 years.

On October 28, 2015, the DCPSC agreed to reopen the approval application to allow for consideration of the Settlement Agreement. Since then, parties supporting and opposing the Settlement filed testimony, participated in formal hearings and, on December 23, 2015, submitted final briefs to the DCPSC. The parties now await a formal decision from the DCPSC. The Merger Agreement provides that either Exelon or PHI may terminate the Merger Agreement if the merger is not completed by October 28, 2015. Pursuant to a Letter Agreement related to the Settlement Agreement, Exelon and PHI have agreed, among other things, that they will not exercise their rights to terminate the Merger Agreement before March 4, 2016, except under limited circumstances. If the DCPSC does not approve the Settlement Agreement by March 4, 2016, either Exelon or PHI may terminate the Settlement Agreement.

The settlements reached and commission orders received to date in Delaware, Maryland and New Jersey include a “most favored nation” provision which, generally speaking, requires allocation of merger benefits proportionately across all the jurisdictions. When applying the most favored nation provision to the settlement terms and other conditions established in the merger approvals received to date, and as proposed in the Settlement Agreement filed with the DCPSC, Exelon and PHI currently estimate direct benefits of $430 million or more on a net present value basis (excluding charitable contributions and renewable generation commitments) will be provided, including rate credits, funding for energy efficiency programs and other required commitments. Exelon and PHI anticipate substantially all of such amounts will be charged to earnings at the time of merger close and will be paid by the end of 2017. An additional $53 million will be charged to earnings for charitable contributions, which are required to be paid over a period of 10 years. Commitments to develop renewable generation, which are expected to be primarily capital in nature, will be recognized as incurred. Upon completion of the merger, the actual nature, amount, timing and financial reporting treatment for these commitments may be materially different from the current projection.

Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors’ breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. Exelon was also named in a federal court suit making similar claims. In September 2014, the parties reached a proposed settlement that would resolve all claims, which is

subject to court approval. Final court approval of the proposed settlement is not anticipated until approximately 90 days after merger close. Exelon does not believe these suits will impact the completion of the transaction, and they are not expected to have a material impact on Exelon's results of operations.

Including 2014 and through December 31, 2015, Exelon has incurred approximately $259 million of expense associated with the proposed merger. Of the total costs incurred, $121 million is primarily related to acquisition and integration costs and $138 million are for costs incurred to finance the transaction. The financing costs include $22 million of costs associated with the private exchange offer and redemption of certain Senior Unsecured Notes (see Note 14—Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information on the exchange), as well as, a net loss of $64 million related to the settlement of forward-starting interest-rate swaps. These swaps were terminated in connection with the $4.2 billion issuance of debt; refer to Note 13—Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for more information. The financing costs exclude costs to issue equity and the initial debt offering which we recorded to Exelon's Consolidated Balance Sheets.

Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the Merger Agreement is terminated due to a failure to obtain a required regulatory approval, Exelon may be required to pay PHI a termination fee equal to $180 million through the redemption by PHI of the outstanding nonvoting preferred securities described above for no consideration other than the nominal par value of the stock, plus reimbursement of PHI's documented out-of-pocket expenses up to a maximum of $40 million.

Merger Financing

Exelon has raised cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments, through the issuance of $4.2 billion of debt (of which $3.3 billion remains after execution of the exchange offer, see Note 14—Debt and Credit Agreements for further information on the exchange), $1.15 billion of junior subordinated notes in the form of 23 million equity units, the issuance of $1.9 billion of common stock, cash proceeds of $1.8 billion from asset sales primarily at Generation (after-tax proceeds of approximately $1.4 billion) and the remaining balance from cash on hand and/or short-term borrowings available to Exelon. Exelon will have sufficient cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments. See Note 14—Debt and Credit Agreements and Note 19—Shareholder's Equity of the Combined Notes to the Consolidated Financial Statements for further information on the debt and equity issuances.

Exelon has listed various potential risks relating to the pending merger with PHI (see ITEM 1A. RISK FACTORS), including difficulties that may be encountered in satisfying the conditions to completion of the merger and the potential for developments that might have an adverse effect on Exelon and the ability to realize the expected benefits of the merger. Exelon is taking steps to manage these risks and expects that the merger can be completed on a basis favorable to the company's shareholders and customers. Refer to Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the merger transaction.

Implications of Potential Early Plant Retirements

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation's nuclear plants. Factors that will continue to affect the economic value of Generation's nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative solutions in New York and Illinois such as the proposed Low Carbon Portfolio Standard (LCPS) legislation, the impact of final rules from the EPA requiring reduction of carbon and other emissions and the efforts of the states to implement those final rules, and the outcome of the Ginna RSSA hearing and settlement procedures and the resulting contractual terms and conditions.

On September 10, 2015, after considering the results of the recent PJM capacity auctions, Exelon and Generation decided to defer decisions about the future operations of its Quad Cities and Byron nuclear plants and will offer both plants in the 2019/2020 auction in May 2016. As a result of clearing the other PJM capacity auction in September 2015 for the 2017/2018 transitional capacity auction, Exelon and Generation will continue to operate its Quad Cities nuclear power plant through at least May 2018. The Byron plant is already obligated to operate through May 2019. On October 29, 2015, Exelon and Generation announced the deferral of any decision about the future operations of its Clinton nuclear plant and plans to bid the plant into the MISO capacity auction for the 2016-2017 planning year April 2016. This decision was driven by MISO's acknowledgment of the need for market design changes to ensure long-term power system reliability in southern Illinois, the desire to provide Illinois policy makers with additional time to consider needed reforms as well as the potential long-term impact of EPA's Clean Power Plan. Exelon and Generation previously committed to cease operation of the Oyster Creek nuclear plant by the end of 2019. Exelon and Generation have not made any decisions regarding potential nuclear plant closures at other sites at this time.

As a result of a decision to early retire one or more other nuclear plants, certain changes in accounting treatment would be triggered and Exelon's and Generation's results of operations and cash flows could be materially affected by a number of items including, among other items: accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, accelerated amortization of plant specific nuclear fuel costs, employee-related costs (i.e. severance, relocation, retention, etc.), accelerated asset retirement obligation expense related to future decommissioning activities, and additional funding of nuclear decommissioning trust funds. In addition, any early plant retirement would also result in reduced operating costs, lower fuel expense, and lower capital expenditures in the periods beyond shutdown. While there are a number of Generation's nuclear plants that are at risk of early retirement, the following table provides the balance sheet amounts as of December 31, 2015 for significant assets and liabilities associated with the three nuclear plants currently considered by management to be at the greatest risk of early retirement due to their current economic valuations and other factors:

(in millions)	Quad Cities	Clinton	Ginna	Total
Asset Balances				
Materials and supplies inventory	$ 50	$ 57	$ 29	$ 136
Nuclear fuel inventory, net	218	107	60	385
Completed plant, net	1,030	579	127	1,736
Construction work in progress	11	9	11	31
Liability Balances				
Asset retirement obligation	(698)	(401)	(644)	(1,743)
NRC License Renewal Term	2032	2046[a]	2029	

(a) Assumes Clinton seeks and receives a 20-year operating license renewal extension.

In the event a decision is made to retire early one or more nuclear plants, the precise timing of the retirement date, and resulting financial statement impact, is uncertain and would be influenced by a number of factors such as the results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity obligations and just prior to its next scheduled nuclear refueling outage date in that year.

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC

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minimum funding test, then Generation would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDTF to ensure sufficient funds are available.

As of December 31, 2015, all three of Generation's plants at the highest risk of early retirement (Quad Cities, Clinton, and Ginna) pass the NRC minimum funding test based on their current license lives. See Note 16—Asset Retirement Obligations for additional information on NRC minimum funding requirements. However, in the event of an early retirement just before their next individual refueling outages, it is estimated that Clinton and Ginna would no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDTF investments could appreciate in value. Quad Cities would also be at risk. However, the size of the guarantees are ultimately dependent on the decommissioning approach adopted at each site (i.e., DECON, Delayed DECON and SAFSTOR), the associated level of costs, and the decommissioning trust fund investment performance going forward. Considering the three alternative decommissioning approaches available to Generation for each site, parental guarantees of up to $315 million, $260 million, and $65 million for Clinton, Ginna, and Quad Cities, respectively, could be required in order for each site to access its NDTF for radiological decommissioning costs.

In addition, upon issuance of any required financial guarantees, while all three sites would be able to utilize their respective decommissioning trust funds for radiological decommissioning costs, the NRC must approve an additional exemption in order for Generation to utilize the NDTF funds to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by Generation. Accordingly, based on current projections, it is expected that some portion of the spent fuel management and/or site restoration costs would need to be funded through supplemental cash from Generation. While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under DOE reimbursement agreements or future litigation, across the three alternative decommissioning approaches available to Generation, for the next 10 years, Clinton and Ginna could incur spent fuel management and site restoration costs of up to $165 million and $115 million, net of taxes, respectively. The costs associated with Ginna would be shared by the plant co-owners at their respective ownership percentages. If Quad Cities fails the exemption test, at its ownership percentage Generation could be required to pay for spent fuel management costs of up to $180 million, net of taxes, but Quad Cities is better positioned to pass the test than the other two plants.

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Capacity Market Changes in PJM. In the wake of the January 2014 Polar Vortex that blanketed much of the Eastern and Midwestern United States, it became clear that while a major outage event was narrowly avoided, resources in PJM were not providing the level of reliability expected by customers. As a result, on December 12, 2014, PJM filed at FERC a proposal to make significant changes to its current capacity market construct, the Reliability Pricing Model (RPM). PJM's proposed changes generally sought to improve resource performance and reliability largely by limiting the excuses for non-performance and by increasing the penalties for performance failures. The proposal permits suppliers to include in capacity market offers additional costs and risk so they can meet these higher performance requirements. While offers are expected to put upward pressure on capacity clearing prices, operational improvements made as a result of PJM's proposal are expected to improve

reliability, to reduce energy production costs as a result of more efficient operations and to reduce the need for out of market energy payments to suppliers. Generation participated actively in PJM's stakeholder process through which PJM developed the proposal and also actively participated in the FERC proceeding including filing comments. On June 9, 2015, FERC approved PJM's filing largely as proposed by PJM, including transitional auction rules for delivery years 2016/2017 through 2017/2018. As a result of this and several related orders, PJM hosted its 2018/2019 Base Residual Auction (results posted on August 21, 2015) and its transitional auction for delivery year 2016/2017 (results posted on August 31, 2015) and its transitional auction for delivery years 2017/2018 (results posted on September 9, 2015).

MISO Capacity Market Results. On April 14, 2015, the Midcontinent Independent System Operator (MISO) released the results of its capacity auction covering the June 2015 through May 2016 delivery year. As a result of the auction, capacity prices for the zone 4 region in downstate Illinois increased to $150 per MW per day beginning in June 2015, an increase from the prior pricing of $16.75 per MW per day that was in effect from June 2014 to May 2015. Generation had an offer that was selected in the auction. However, due to Generation's ratable hedging strategy, the results of the capacity auction have not had a material impact on Exelon's and Generation's consolidated results of operations and cash flows.

Additionally, in late May and June 2015, separate complaints were filed at the FERC by each of the State of Illinois, the Southwest Electric Cooperative, Public Citizens, Inc., and the Illinois Industrial Energy Consumers challenging the results of this MISO capacity auction for the 2015/2016 delivery in MISO delivery zone 4. The complaints allege generally that 1) the results of the capacity auction for zone 4 are not just and reasonable, 2) the results should be suspended, set for hearing and replaced with a new just and reasonable rate, 3) a refund date should be established and that 4) certain alleged behavior by one of the market participants other than Exelon or Generation, be investigated.

On October 1, 2015, the FERC announced that it was conducting a non-public investigation (that does not involve Exelon or Generation) into whether market manipulation or other potential violations occurred related to the auction. On December 31, 2015, the FERC issued a decision that certain of the rules governing the establishment of capacity prices in downstate Illinois are "not just and reasonable" on a prospective basis. The FERC ordered that certain rules must be changed for the next auction scheduled for April 2016 that will set capacity prices beginning June 1, 2016. In response to this order, MISO must file certain rule changes with the FERC within 30 days and certain other changes within 90 days. The FERC continues to conduct its non-public investigation to determine if the April 2015 auction results were manipulated and, if so, whether refunds are appropriate. The FERC did establish May 28, 2015, the day the first complaint was filed, as the date from which refunds (if ordered) would be calculated, and it also made clear that the findings in the December 31, 2015 order do not prejudge the investigation or related proceedings. Generation cannot predict the impact the FERC order may ultimately have on future auction results, capacity pricing or decisions related to the potential early retirement of the Clinton nuclear plant, however, such impacts could be material to Generation's future results of operations and cash flows. See Note 9—Implications of Potential Early Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement.

MISO has acknowledged the need for capacity market design changes in the zone 4 region and stated that reforms to its capacity market process may be required to drive future investment and that it plans to engage stakeholders to consider such reforms. The FERC has also encouraged such efforts.

Subsidized Generation. The rate of expansion of subsidized generation, including low-carbon generation such as wind and solar energy, in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have attempted to implement or propose legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices. For example, the New Jersey legislature enacted into law in January 2011, the Long Term Capacity Pilot Program Act (LCAPP). LCAPP provides eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market. Under LCAPP, the local utilities in New Jersey are required to pay (or receive) the difference between the price eligible generators receive in the capacity market and the price guaranteed under the 15-year contract. New Jersey ultimately selected three proposals to participate in LCAPP and build new generation in the state. In addition, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected would be in commercial operation by June 1, 2015. CPV subsequently sought to extend that date. The CfD mandated that utilities (including BGE) pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Exelon and others challenged the constitutionality and other aspects of the New Jersey legislation in federal court. The actions taken by the MDPSC were also challenged in federal court in an action to which Exelon was not a party. The federal trial courts in both the New Jersey and Maryland actions effectively invalidated the actions taken by the New Jersey legislature and the MDPSC, respectively. Each of those decisions was upheld by the U.S. Court of Appeals for the Third Circuit and the U.S. Court of Appeals for the Fourth Circuit, respectively. However, the U.S. Supreme Court has agreed to review the matter, and there is risk the Supreme Court will overrule the lower courts.

As required under their contracts, generator developers who were selected in the New Jersey and Maryland programs (including CPV) offered and cleared in PJM's capacity market auctions. To the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon's market driven position. While the court decisions in New Jersey and Maryland are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR) for future capacity auctions, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon's market driven position and could have a significant effect on Exelon's financial results of operations, financial position and cash flows.

One such state is Ohio, where state-regulated utility companies FirstEnergy Ohio (FE) and AEP Ohio (AEP) have initiated actions at the Public Utilities Commission of Ohio (PUCO) to obtain approval for Riders that would effectively allow these two companies to pass through to all customers in their service territories the differences between their costs and market revenues on PPAs entered into between the utility and its merchant generation affiliate. Collectively more than 6,000MW of primarily coal-fired generation owned by FE and AEP's affiliates seek ratepayer guaranteed subsidies via the proposed Riders. Thus, the Riders are similar to the CfDs described above (except that the PPA Riders in Ohio would apply to certain existing generation facilities whereas the CfDs applied to new generation facilities). While AEP and FE initially filed for these Riders in 2013 and 2014, respectively, it was not until late 2015 that the proposals obtained meaningful traction when PUCO staff entered into a settlement and stipulation with the Ohio utilities supporting the proposals and recommending that the PUCO approve the Riders. Exelon is a participant in these proceedings. Although the matter is still in hearing and a decision by the PUCO is not expected until late February/early March 2016, it is increasingly likely that these subsidies may be approved by the PUCO. Litigation around these approvals is also likely.

Exelon opposes the proposals in Ohio, continues to monitor developments in Maryland and New Jersey, and participates in stakeholder and other processes to ensure that similar state subsidies are

not developed. Exelon remains active in advocating for competitive markets, while opposing policies that require taxpayers and/ or consumers to subsidize or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid.

Energy Demand. Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for BGE and PECO; and a decrease in projected load for electricity for ComEd. BGE, PECO and ComEd are projecting load volumes to increase (decrease) by 1.5%, 0.4% and (0.3)%, respectively, in 2016 compared 2015.

Retail Competition. Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. The market experienced high price volatility in the first quarter of 2014 which contributed to bankruptcies and consolidations within the industry during the year. However, forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

Strategic Policy Alignment

Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's board of directors declared first, second, third and fourth quarter 2015 and first quarter 2016 dividends of $0.31 per share each on Exelon's common stock. The dividends for the first, second, third and fourth quarter 2015 were paid on March 10, 2015, June 10, 2015, September 10, 2015 and December 10, 2015. The first quarter 2016 dividend is payable on March 10, 2016.

All future quarterly dividends require approval by Exelon's board of directors. Exelon's Board of Directors approved a revised dividend policy. The approved policy would raise our dividend 2.5% each year for the next three years, beginning with the June 2016 dividend. The Board will take formal action to declare the next dividend in the second quarter.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2015 and 2016. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of December 31, 2015, the percentage of expected generation hedged for the major reportable segments was 90%-93%, 60%-63% and 28%-31% for 2016, 2017, and 2018 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel,

load following products, and options. Equivalent sales represent all hedging products, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 50% of Generation's uranium concentrate requirements from 2016 through 2020 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position.

ComEd, PECO and BGE mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

Management continually evaluates growth opportunities aligned with Exelon's businesses, assets and markets, leveraging Exelon's expertise in those areas and offering sustainable returns.

Regulated Energy Businesses

The proposed merger with PHI provides an opportunity to accelerate Exelon's regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, ComEd, PECO and BGE anticipate investing approximately $18 billion over the next five years in electric and natural gas infrastructure improvements and modernization projects, including smart meter and smart grid initiatives, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $8 billion by the end of 2020. ComEd, PECO and BGE invest in rate base where beneficial to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made prudently and at the lowest reasonable cost to customers.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives and infrastructure development and enhancement programs.

Competitive Energy Businesses

Generation continually assesses the optimal structure and composition of our generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation's long-term growth strategy is to prioritize investments in long-term contracted generation across multiple technologies and identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, while identifying emerging technologies where strategic investments provide the option for significant future growth or influence in market development. As of December 31, 2015, Generation has currently approved plans to invest a total of approximately $2 billion in 2016 through 2018 on capital growth projects (primarily new plant construction and distributed generation).

Liquidity

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and OPEB obligations and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.4 billion. See Liquidity and Capital Resources—Credit Matters—Exelon Credit Facilities below.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets including European banks. Disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2015, approximately 25%, or $2.1 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.9 billion was available as of December 31, 2015, due to outstanding letters of credit. There were no borrowings under the Registrants' credit facilities as of December 31, 2015. See Note 14—Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon is actively involved in the EPA's development and implementation of environmental regulations for the electric industry, in pursuit of its business strategy to provide reliable, clean, affordable and innovative energy products. These efforts have most frequently involved air, water and waste controls for electric generating units, as set forth in the discussion below. These regulations have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Retirements of coal-fired power plants will continue as additional EPA regulations take effect, and as air quality standards are updated and further restrict emissions. Due to its low emission generation portfolio, Generation will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the EPA's rulemaking efforts, and it is uncertain whether any of these bills will become law.

Air Quality. In recent years, the EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act applicable to electric generating units. These regulations have resulted in more stringent emissions limits on fossil-fuel electric generating stations as states implement their compliance plans.

National Ambient Air Quality Standards (NAAQS). The EPA continues to review and update its NAAQS for conventional air pollutants relating to ground-level ozone and emissions of particulate

matter, SO2 and NOx. Following five years of litigation, the EPA is finalizing the Cross State Air Pollution Rule that requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states.

Mercury and Air Toxics Standard Rule (MATS). On December 16, 2011, the EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals, and to make capital investments in pollution control equipment and incur higher operating expenses. The initial compliance deadline to meet the new standards was April 16, 2015; however, facilities may have been granted an additional one or two year extension in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. In April 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety. On appeal, the U.S. Supreme Court decided in June 2015 that the EPA unreasonably refused to consider costs in determining whether it is appropriate and necessary to regulate hazardous air pollutants emitted by electric utilities. The U.S. Supreme Court, however, did not vacate the rule; rather, it was remanded to the D.C. Circuit Court to take further action consistent with the U.S. Supreme Court's opinion on this single issue. As such, the MATS rule remains in effect. Exelon will continue to participate in the remanded proceedings before the D.C. Circuit Court as an intervenor in support of the rule.

Climate Change. Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. In the absence of Federal legislation, the EPA is moving forward with the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change ("UNFCCC" of "Convention"). See ITEM 1.—BUSINESS,"Global Climate Change" for further discussion.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. Those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, Ginna, Gould Street, Handley, Mountain Creek, Mystic 7, Nine Mile Point Unit 1, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. See ITEM 1.—BUSINESS ,"Water Quality" for further discussion.

Solid and Hazardous Waste. In October 2015, the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants became effective. The rule classifies CCR as non-hazardous waste under RCRA. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded reserves consistent with state regulation for its owned coal ash sites, and as such, the regulation is not expected to impact Exelon's and Generation's financial results. Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted under the new federal regulations for coal ash disposal sites formerly owned by Generation. For these reasons, Generation is unable to predict whether and to what extent it may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations.

See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

NRC Task Force Insights from the Fukushima Daiichi Accident (Exelon and Generation). In July 2011, an NRC Task Force formed in the aftermath of the March 11, 2011, 9.0 magnitude earthquake and ensuing tsunami, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, issued a report of its review of the accident, including tiered recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for Generation, net of expected co-owner reimbursements, for the period from 2016 through 2019 is expected to be between approximately $175 million and $200 million of capital (which includes approximately $25 million for the CENG plants) and $25 million of operating expense (which includes approximately $5 million for the CENG plants). Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See ITEM 1A. RISK FACTORS for additional information.

Financial Reform Legislation (Exelon, Generation, ComEd, PECO, and BGE). The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted in July 2010. The part of the Act that applies to Exelon is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires the creation of a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing for certain categories of Swaps, incentives to shift Swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. For non security-based Swaps including commodity Swaps, Dodd-Frank empowers the Commodity Futures Trading Commission (CFTC) to promulgate regulations implementing the law's objectives. The primary aim of Dodd-Frank is to regulate the key intermediaries in the Swaps market, which entities are either swap dealers (SDs), major swap participants (MSPs), and certain other financial entities, but the law also applies to a lesser degree to end-users of Swaps. On January 12, 2015, President Obama signed into law a bill that exempts from margin requirements Swaps used by end-users to hedge or mitigate commercial risk. Moreover, the CFTC's Dodd-Frank regulations preserve the ability of end users in the energy industry to hedge their risks using Swaps without being subject to mandatory clearing, and excepts or exempts end-users from many of the other substantive regulations. Accordingly, as an end-user, Generation is conducting its commercial business in a manner that does not require registration with the CFTC as an SD or MSP. Generation does not anticipate transacting in the future in a manner in which it would become a SD or MSP.

There are, however, some rules, including the capital and margin rules for (non-cleared) Swaps that do not impact Generation's collateral requirements directly, but may have an indirect impact.

These rules, in addition to certain international regulatory requirements still under development and that are similar to Dodd-Frank, could subject Generation's SD or MSP counterparties to additional and potentially significant capitalization requirements and could motivate the SDs and MSPs to increase collateral requirements or cash postings from their counterparties, including Generation.

Generation cannot predict to what extent, if any, further refinements to Dodd-Frank and international regulatory requirements relating to Swaps may impact its cash flows or financial position, but such impacts could be material.

ComEd, PECO and BGE could also be subject to some Dodd-Frank requirements to the extent they were to enter into Swaps. However, at this time, management of ComEd, PECO and BGE continue to expect that their companies will not be materially affected by Dodd-Frank.

Market-Based Rates (Exelon, Generation, ComEd, PECO and BGE). Generation, ComEd, PECO and BGE are public utilities for purposes of the Federal Power Act and are required to obtain FERC's acceptance of rate schedules for wholesale electricity sales. Currently, Generation, ComEd, PECO and BGE have authority to execute wholesale electricity sales at market-based rates. As is customary with market-based rate schedules, FERC has reserved the right to suspend market-based rate authority on a retroactive basis if it subsequently determines that Generation, ComEd, PECO or BGE has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds in certain instances if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

As required by FERC's regulations, as promulgated in the Order No. 697 series, Generation, ComEd, PECO and BGE file market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd, PECO and BGE qualify for market-based rates in the regions where they are selling energy, capacity, and ancillary services under market-based rate tariffs. On December 30, 2013, Generation, ComEd, PECO and BGE filed its updated analysis for the Northeast Region, based on 2012 historic test period data which the FERC accepted on August 5, 2014. On December 23, 2014, Generation filed its updated market power analysis for the Southeast Region which the FERC accepted on July 16, 2015. On December 23, 2014, Generation filed its updated market power analysis for the Central Region which the FERC accepted on November 25, 2015. On December 29, 2015, Generation filed its updated market power analysis for the SPP Region, and the FERC has not yet acted on the filing.

Illinois Low Carbon Portfolio Standard (Exelon, Generation and ComEd). In March 2015, the Low Carbon Portfolio Standard (LCPS) was introduced in the Illinois General Assembly. The legislation would require ComEd and Ameren to purchase low carbon energy credits to match 70 percent of the electricity used on the distribution system. The LCPS is a technology-neutral solution, so all generators of zero or low carbon energy would be able to compete in the procurement process, including wind, solar, hydro, clean coal and nuclear. Costs associated with purchasing the low carbon energy credits would be collected from customers. The LCPS proposal includes consumer protection such as a price cap that would limit the impact to a 2.015% increase based off 2009 monthly bills, or about $2 per month for the average residential electricity customer. The legislation also includes a separate customer rebate provision that would provide a direct bill credit to customers in the event wholesale prices exceed a specified level. The proposed legislation is pending and Exelon and Generation continue to work with stakeholders.

Legislation to Maximize Smart Grid Investments and to Promote a Cleaner and Greener Illinois (Exelon and ComEd). In March 2015, legislation was introduced in the Illinois General Assembly that would (1) build on ComEd's investment in the Smart Grid to reinforce the resiliency and security of the electrical grid to withstand unexpected challenges, (2) expand energy efficiency

programs to reduce energy waste and increase customer savings, (3) further integrate clean renewable energy onto the power system, and (4) introduce a new demand-based rate design for residential customers that would allow for a more equitable sharing of smart grid costs among customers. The legislation also provides for additional funding for customer assistance programs for low-income customers. The proposed legislation is pending and ComEd continues to work with stakeholders.

Distribution Formula Rate Update Filing (Exelon and ComEd). On April 15, 2015, ComEd filed its annual distribution formula rate to request a total decrease to the revenue requirement of $50 million. On December 9, 2015, the ICC issued its final order which decreased the revenue requirement by $67 million, reflecting an increase of $85 million for the initial revenue requirement for 2015 and a decrease of $152 million related to the annual reconciliation for 2014. The rates took effect in January 2016. Intervenors requested a rehearing on specific issues. See Note 3 —Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to distribution formula updates.

2015 Pennsylvania Electric Distribution Rate Case (Exelon and PECO). On March 27, 2015, PECO filed a petition with the PAPUC requesting an increase of $190 million to its annual service revenues for electric delivery, which requested an ROE of 10.95%. On September 10, 2015, PECO and interested parties filed with the PAPUC a petition for joint settlement for an increase of $127 million in annual distribution service revenue. No overall ROE was specified in the settlement. On December 17, 2015, the PAPUC approved the settlement of PECO's electric distribution rate case. The approved electric delivery rates became effective on January 1, 2016.

The settlement includes approval of the In-Program Arrearage Forgiveness ("IPAF") Program, which provides for forgiveness of a portion of the eligible arrearage balance of its low-income Customer Assistance Program (CAP) accounts receivable that will be determined as of program inception in October 2016. The forgiveness will be granted to the extent CAP customers remain current with payments. The Settlement guarantees PECO's recovery of two-thirds of the arrearage balance through a combination of customer payments and rate recovery, including through future rates cases if necessary. The remaining one-third of the arrearage balance will be absorbed by PECO, of which a portion has already been expensed as bad debt for CAP customer's accounts receivable balances.

Although the actual arrearage balance is not defined until program inception, PECO believes that it can reasonably estimate certain CAP customer accounts receivable balances as of December 31, 2015 that will remain outstanding at program inception. Management determined its best estimate based on historical collectability information. As a result, a regulatory asset of $7 million, representing the previously incurred bad debt expense associated with the estimated eligible accounts receivable balances, was recorded on Exelon's and PECO's Consolidated Balance Sheets as of December 31, 2015. This estimate will be revisited on a quarterly basis through program inception.

PECO Gas Main Extension Program (Exelon and PECO). On November 6, 2014, PECO filed a plan with the PAPUC requesting approval of three initiatives to provide more incentives to customers interested in switching to natural gas service. On October 1, 2015, the PAPUC approved the PECO Gas Main Extension Program, without modification. This approval allows local customers to pay significantly less initially to have natural gas installed at their homes and businesses.

2015 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On November 6, 2015, and as amended on January 5, 2016, BGE filed for electric and gas base rate increases with the MDPSC, ultimately requesting an increase of $121 million and $79 million, respectively, of which $103 million and $37 million, respectively, is related to recovery of smart grid initiative costs. BGE requested a ROE for the electric and gas distribution rate case of 10.6% and 10.5%, respectively. The new

electric and gas base rates are expected to take effect in June 2016. BGE is also proposing to recover an annual increase of approximately $30 million for Baltimore City conduit lease fees through a surcharge. BGE cannot predict how much of the requested increase the MDPSC will approve or if it will approve BGE's request for a conduit fee surcharge.

Transmission Formula Rate Update Filing (Exelon, ComEd and BGE). On April 15, 2015 (and revised on May 19), ComEd filed its annual 2015 transmission formula rate update with the FERC, reflecting an increased revenue requirement of $86 million, including an increase of $68 million for the initial revenue requirement and an increase of $18 million related to the annual reconciliation. The filing establishes the revenue requirement used to set rates that took effect in June 2015, subject to review by the FERC and other parties. The time period for any challenges to ComEd's annual update expired in October 2015. No challenges were submitted. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to transmission formula update.

In April 2015, BGE filed its annual transmission formula rate update with the FERC, reflecting an increased revenue requirement of $10 million, including an increase of $13 million for the initial revenue requirement, inclusive of dedicated facilities charge revenues, and a decrease of $3 million related to the annual reconciliation for 2014. The filing establishes the revenue requirement used to set rates that took effect in June 2015. The time period for any challenges to BGE's annual update expired in October 2015. No challenges were submitted. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to the transmission formula update.

Grand Prairie Gateway Transmission Line (Exelon and ComEd). On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. The costs incurred for the project prior to May 21, 2014 were immaterial. ComEd has acquired numerous easements across the project route through voluntary transactions. ComEd will seek to acquire the property rights on the remaining 28 parcels through condemnation proceedings in the circuit courts. ComEd began construction of the line during the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

FERC Ameren Order (Exelon and ComEd). In July 2012, FERC issued an order to Ameren Corporation (Ameren) finding that Ameren had improperly included acquisition premiums/goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. Ameren filed for rehearing of the July 2012 order, which was denied in June 2014. On July 20, 2015, FERC approved a settlement between Ameren and its customers to resolve the matter. ComEd believes that the FERC settlement authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

FERC Order No. 1000 Compliance (ComEd, PECO and BGE). In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission

projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements of a right of first refusal to build certain new transmission facilities. On October 25, 2012, certain of the PJM transmission owners, including ComEd, PECO and BGE (collectively, the PJM Transmission Owners), submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC's " *Mobile-Sierra* " standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order that, among other things, rejected the arguments of the PJM Transmission Owners that changes to the PJM governing documents were entitled to review under the *Mobile-Sierra* standard. The FERC's March 22, 2013 order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd PECO and BGE's financial return on new investments in energy transmission facilities.

Numerous parties sought rehearing of the FERC's March 22, 2013 order, including the PJM Transmission Owners. On May 15, 2014, FERC denied the PJM Transmission Owners rehearing request. Several parties filed an appeal of the FERC's May 15, 2014, Order which upheld PJM's right of first refusal language in the D.C. Circuit. The ultimate outcome of this proceeding cannot be predicted at this time, however, it could be material to Exelon, ComEd, PECO and BGE's results of operations and cash flows.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the PHI companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) and a 50 basis point incentive for participating in PJM (and certain additional incentive basis points on certain projects). The parties sought a reduction in the base return on equity to 8.7% and changes to the formula rate process. Under FERC rules, any revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE could be adjusted and refunds required is the date of the complaint.

On August 21, 2014, FERC issued an order in the BGE and PHI companies' proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013.

On December 8, 2014, various state agencies in Delaware, Maryland, New Jersey, and D.C. filed a second complaint against BGE regarding the base ROE of the transmission business seeking a reduction from 10.8% to 8.8%. The filing of the second complaint created a second refund window. By order issued on February 9, 2015, FERC established a hearing on the second complaint with the complainants' requested refund effective date of December 8, 2014. On February 20, 2015, the Chief Judge issued an order consolidating the two complaint proceedings and established an Initial Decision issuance deadline of February 29, 2016.

On November 6, 2015, BGE and the PHI companies and the complainants filed a settlement with FERC covering the issues raised in the complaints. The settlement provides for a 10% base ROE, effective March 8, 2016, which will be augmented by the PJM incentive adder of 50 basis points, and refunds to BGE customers of $13.7 million. The settlement also provides a moratorium on any change in the ROE until June 1, 2018. On December 16, 2015, the Presiding Administrative Law Judge submitted a Certification of the Uncontested Settlement to the FERC Commissioners. The settlement remains subject to FERC approval. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In 2013, legislation intended to accelerate gas infrastructure replacements in Maryland was signed into law. The law established a mechanism, separate from base rate proceedings, for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects incurred after June 1, 2013. The monthly surcharge and infrastructure replacement costs must be approved by the MDPSC and are subject to a cap and require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation.

On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On November 16, 2015, BGE filed a surcharge update to be effective January 1, 2016, including a true-up of cost estimates included in the 2015 surcharge, along with its 2016 project list and projected capital estimates of $113 million to be included in the 2016 surcharge calculation. The MDPSC subsequently approved BGE's 2016 project list and the proposed surcharge for 2016, which included the 2015 surcharge true-up. As of December 31, 2015, BGE recorded a regulatory asset of less than $1 million, representing the difference between the surcharge revenues and program costs.

In 2014, the residential consumer advocate in Maryland appealed MDPSC's decision on BGE's infrastructure replacement plan and associated surcharge with the Baltimore City Circuit Court, who affirmed the MDPSC's decision. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court. During the third quarter of 2015, the residential consumer advocate, MDPSC, and BGE filed briefs. Oral argument in this matter was held before the Court of Special Appeals on November 3, 2015. On January 28, 2016, the Maryland Court of Special Appeals issued a decision affirming the MDPSC's decision. See Note 3 —Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

PJM Minimum Offer Price Rule (Exelon and Generation). PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The FERC orders approving the MOPR were upheld by the United States Court of Appeals for the Third Circuit in February 2014.

Exelon continues to work with PJM stakeholders and through the FERC process to implement several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts and capacity market speculators) cannot inappropriately affect capacity auction prices in PJM.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions with its accounting and disclosure governance committee on a regular basis and provides periodic updates on management decisions to the audit committee of the Exelon board of directors. Management believes that the accounting policies described below require significant judgment in their application, or estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation's ARO associated with decommissioning its nuclear units was $8.2 billion at December 31, 2015. The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple decommissioning outcome scenarios.

As a result of recent nuclear plant retirements in the industry, nuclear operators and third-party service providers are obtaining more information about costs associated with decommissioning activities. At the same time, regulators are gaining more information about decommissioning activities which could result in changes to existing decommissioning requirements. In addition, as more nuclear plants are retired, it is possible that technological advances will be identified that could create efficiencies and lead to a reduction in decommissioning costs. These factors could result in material changes to Generation's current estimates as more information becomes available and could change the timing and probability assigned to the decommissioning outcome scenarios.

The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing and/or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the methodologies and significant estimates and assumptions described as follows:

Decommissioning Cost Studies. Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the costs and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within its industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years, unless circumstances warrant more frequent updates (such as a change in assumed operating life for a nuclear plant). As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle.

Cost Escalation Factors. Generation uses cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors, and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal and other costs. All of the nuclear AROs are adjusted each year for the updated cost escalation factors.

Probabilistic Cash Flow Models. Generation's probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning cost levels, decommissioning approaches, and timing of plant shutdown on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. Probabilities are also assigned to three different decommissioning approaches as follows:

1. DECON—a method of decommissioning shortly after the cessation of operation in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a LLRW landfill or decontaminated to a level that permits property to be released for unrestricted use,
2. Delayed DECON—similar to the DECON scenario but with a delay to allow for spent fuel to be removed from the site prior to onset of decommissioning activities, or

3. SAFSTOR—a method of decommissioning in which the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated to levels that permit release for unrestricted use generally within 60 years after cessation of operations.

The actual decommissioning approach selected once a nuclear facility is shutdown will be determined by Generation at the time of shutdown and may be influenced by multiple factors including the funding status of the nuclear decommissioning trust fund at the time of shutdown.

The assumed plant shutdown timing scenarios have historically included the following two alternatives: (1) the probability of operating through the original 40-year nuclear license term, and (2) the probability of operating through an extended 60-year nuclear license term (regardless of whether such 20-year license extension had been received for each unit). During 2015, due to changing market conditions and regulatory environments, Generation began to consider and incorporate assumptions regarding plant shutdown timing scenarios for certain plants other than just the two scenarios historically considered. In addition to potential early shutdown scenarios, Generation also began in 2015 to incorporate into its ARO estimates some probability of a second, 20-year license renewal for some nuclear units. The successful operation of nuclear plants in the U.S. beyond the initial 40-year license terms has prompted the NRC to consider regulatory and technical requirements for potential plant operations for an 80-year nuclear operating term. As power market and regulatory environment developments occur, Generation evaluates and incorporates, as necessary, the impacts of such developments into its nuclear ARO assumptions and estimates.

Generation's probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal. Generation currently assumes DOE will begin accepting SNF in 2025. The SNF acceptance date assumption was based on management's estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

License Renewals. Generation has received, has applied for, or plans to seek, 20-year license renewals for all of its nuclear units. Generation has successfully secured 20-year operating license renewal extensions (i.e., extending the total license term to 60 years) for twenty-one of its nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG and Braidwood Units 1 and 2 for which the NRC approved the renewed license on January 27, 2016). None of Generation's previous applications for an operating license extension has been denied. The 20-year license renewal for Oyster Creek nuclear unit was obtained in 2009, however, operations will cease by the end of 2019. For its remaining three operating units, Generation is in various stages of the process of pursuing similar extensions and has filed license renewal applications for two operating nuclear units and has until 2021 to seek license renewal for one remaining operating nuclear unit. Generation's assumptions regarding successful license extension for the remaining three operating units for ARO determination purposes is based in part on the good current physical condition and high performance of these nuclear units, the favorable status of the ongoing license renewal proceedings with the NRC, and the successful renewals for twenty-one units to date.

Generation estimates that the failure to obtain initial license renewals to extend the operating life from 40 years to 60 years at any of its remaining nuclear units (assuming all other assumptions remain constant) would increase its ARO on average approximately $300 million per unit as of December 31, 2015. The size of the increase to the ARO for a particular nuclear unit is dependent upon the current stage in its original license term and its specific decommissioning cost estimates. If Generation does not receive license renewal on a particular unit, the increase to the ARO may be mitigated by Generation's ability to delay ultimate decommissioning activities under a SAFSTOR method of decommissioning.

Discount Rates. The probability-weighted estimated future cash flows using these various scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. The accounting guidance required Generation to establish an ARO at fair value at the time of the initial adoption of the current accounting standard. Subsequent to the initial adoption, the ARO is adjusted for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions, as described above. Increases in the ARO as a result of upward revisions in estimated undiscounted cash flows are considered new obligations and are measured using a current CARFR as the increase creates a new cost layer within the ARO. Any decrease in the estimated undiscounted future cash flows relating to the ARO are treated as a modification of an existing ARO and, therefore, are measured using the average historical CARFR rates used in creating the initial ARO cost layers.

Under the current accounting framework, the ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. This differs from the accounting requirements for other long-dated obligations, such as pension and other post-employment benefits that are required to be re-measured as and when corresponding discount rates change. If Generation's future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFRs, the obligation would increase from approximately $8.2 billion to approximately $8.5 billion. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon's and Generation's Consolidated Balance Sheets at December 31, 2015 at fair value of approximately $10.3 billion and have an estimated targeted annual pre-tax return of 6.1% to 6.3%.

To illustrate the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO: i) had Generation used the 2014 CARFRs rather than the 2015 CARFRs in performing its third quarter 2015 ARO update, Generation would have increased the ARO by approximately $940 million as compared to the actual increase to the ARO of $831 million; and ii) if the CARFR used in performing the third quarter 2015 ARO update (which also reflected increases in the amounts and changes to the timing of projected cash flows) was increased by 100 basis points or decreased by 50 basis points, the ARO would have increased by $100 million and $1.2 billion, respectively, as compared to the actual increase of $831 million.

ARO Sensitivities. Changes in the assumptions underlying the foregoing items could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions will change as well.

The following table illustrates the effects of changing certain ARO assumptions, discussed above, while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption	Increase (Decrease) to ARO at December 31, 2015
Cost escalation studies	
Uniform increase in escalation rates of 50 basis points	$ 1,600
Probabilistic cash flow models	
Increase the estimated costs to decommission the nuclear plants by 20 percent	$ 1,420
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$ 410
Increase the likelihood of the SAFSTOR scenario by 20 percentage points and decrease the likelihood of the Delayed DECON scenario by 20 percentage points [(a)]	$ (240)
Increase the likelihood of operating through current license lives by 10 percentage points and decrease the likelihood of operating through anticipated license renewals by 10 percentage points	$ 540
Extend the estimated date for DOE acceptance of SNF to 2030	$ (20)
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with an increase in discount rates of 100 basis points	$ (480)
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with a decrease in discount rates of 50 basis points	$ 270

(a) The Delayed DECON scenario is currently assumed to be the most likely decommissioning approach for a majority of Exelon's nuclear plants.

For more information regarding accounting for nuclear decommissioning obligations, see Note 1—Significant Accounting Policies, Note 9—Implications of Potential Early Plant Retirements and Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon and ComEd)

As of December 31, 2015, Exelon's and ComEd's carrying amount of goodwill was approximately $2.7 billion, relating to the acquisition of ComEd in 2000 as part of the PECO/Unicom Merger. Under the provisions of the authoritative guidance for goodwill, ComEd is required to perform an assessment for possible impairment of its goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Under the authoritative guidance, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and its operating results are regularly reviewed by segment management. ComEd has a single operating segment for its combined business. There is no level below this operating segment for which operating results are regularly reviewed by segment management. Therefore, ComEd's operating segment is considered its only reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors, and entity-specific events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the

qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's business and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit. See Note 1—Significant Accounting Policies, Note 11—Intangible Assets and Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon and Generation)

In accordance with the authoritative accounting guidance, the assets acquired and liabilities assumed in an acquired business are recorded at their estimated fair values on the date of acquisition. The difference between the purchase price amount and the net fair value of assets acquired and liabilities assumed is recognized as goodwill on the balance sheet if it exceeds the estimated fair value and as a bargain purchase gain on the income statement if it is below the estimated fair value. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, often utilizes independent valuation experts and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Assets and Liabilities (Exelon and Generation)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired. The initial amount recorded represents the fair value of the contract at the time of acquisition, and the balance is amortized over the life of the contract in relation to the expected realization of the underlying cash flows. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Refer to Note 4—Mergers, Acquisitions, and Dispositions and Note 11—Intangible Assets of the Combined Notes to Consolidated Financial Statements for further discussion.

Impairment of Long-lived Assets (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE regularly monitor and evaluate their long-lived assets and asset groups, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of potential impairment may include a deteriorating business climate, including decline in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life, among others.

The review of long-lived assets and asset groups for impairment utilizes significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power, costs of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could have a significant effect on the consolidated financial statements. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by the evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units as well as the associated intangible assets or liabilities recorded on the balance sheet. The cash flows from the generating units are generally evaluated at a regional portfolio level with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generating assets (typically contracted renewables).

On a quarterly basis, Generation assesses its asset groups for indicators of impairment. If indicators are present for a long-lived asset or asset group, a comparison of the undiscounted expected future cash flows to the carrying value is performed. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value less costs to sell. The fair value of the long-lived asset or asset group is dependent upon a market participant’s view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates. Events and circumstances often do not occur as expected and there will usually be differences between prospective financial information and actual results, and those differences may be material. Accordingly, to the extent that any of the information used in the fair value analysis requires judgment, the resulting fair market value would be different. As such, the determination of fair value is driven by both internal assumptions that include significant unobservable inputs (Level 3) such as revenue and generation forecasts, projected capital, and maintenance expenditures and discount rates, as well as information from various public, financial and industry sources. An impairment determination would require the affected Registrant to reduce the value of either the long-lived asset or asset group, including any associated intangible assets or liabilities, as well as reduce the current period earnings by the amount of the impairment.

Generation evaluates natural gas and oil upstream properties on a quarterly basis to determine if they are impaired. Impairment indicators for natural gas and oil upstream properties are present if there are no firm plans to continue drilling, lease expiration is at risk, historical experience indicates a decline in carrying value below fair value or the price of the underlying commodity significantly declines.

Generation evaluates its equity method investments and other investments in debt and equity securities to determine whether or not they are impaired based on whether the investment has experienced a decline in value that is not temporary in nature.

Exelon holds investments in coal-fired plants in Georgia subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual values of the leased assets at the end of the respective lease terms. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values

of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, that takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contracts associated with the plants given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

See Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Exelon.

Depreciable Lives of Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. Depreciation of these assets is generally provided over their estimated service lives on a straight-line basis using the composite method. The Registrants complete depreciation studies every five years, or more frequently if an event, regulatory action, or change in retirement patterns indicate an update is necessary. The estimation of service lives requires management judgment regarding the period of time that the assets will be in use. As circumstances warrant, the estimated service lives are reviewed to determine if any changes are needed. Depreciation rates incorporate assumptions on interim retirements based on actual historical retirement experience. To the extent interim retirement patterns change, this could have a significant impact on the amount of depreciation expense recorded in the income statement. Changes to depreciation estimates resulting from a change in the estimated end of service lives could have a significant impact on the amount of depreciation expense recorded in the income statement. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant and equipment of the Registrants.

The estimated service lives of the nuclear generating facilities are based on the estimated useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek. While Generation has received license renewals for certain facilities, and has applied for or expects to apply for and obtain approval of license renewals for the remaining facilities, circumstances may arise that would prevent Generation from obtaining additional license renewals. Generation also evaluates annually the estimated service lives of its generating facilities based on feasibility assessments as well as economic and capital requirements. The estimated service lives of hydroelectric facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the Conowingo and Muddy Run operating licenses. A change in depreciation estimates resulting from Generation's extension or reduction of the estimated service lives could have a significant effect on Generation's results of operations.

Generation completed a depreciation rate study during the first quarter of 2015, which resulted in the implementation of new depreciation rates effective January 1, 2015.

ComEd is required to file a depreciation rate study at least every five years with the ICC. ComEd completed a depreciation study and filed the updated depreciation rates with both FERC and the ICC in January 2014. This resulted in the implementation of new depreciation rates effective first quarter 2014.

PECO is required to file a depreciation rate study at least every five years with the PAPUC. In March 2015, PECO filed a depreciation rate study with the PAPUC for both its electric and gas assets, which resulted in the implementation of new depreciation rates effective January 1, 2015 for electric transmission assets, July 1, 2015 for gas distribution assets and January 1, 2016 for electric distribution assets.

The MDPSC does not mandate the frequency or timing of BGE's depreciation studies. In July 2014, BGE filed revised depreciation rates with the MDPSC for both its electric distribution and gas assets. Revisions to depreciation rates from this filing were finalized and effective December 15, 2014.

Defined Benefit Pension and Other Postretirement Employee Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement employee benefit plans for substantially all Generation, ComEd, PECO, BGE and BSC employees. See Note 17—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and other postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit pension and other postretirement benefit plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is affected by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, the anticipated rate of increase of health care costs, Exelon's expected level of contributions to the plans, the incidence of participant mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the long-term expected investment rate credited to employees of certain plans, among others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. Pension and other postretirement benefit costs attributed to the operating companies are labor costs and are ultimately allocated to projects within the operating companies, some of which are capitalized.

Pension and other postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 17—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification under the fair value hierarchy in accordance with authoritative guidance.

Expected Rate of Return on Plan Assets. The long-term EROA assumption used in calculating pension costs was 7.00%, 7.00% and 7.50% for 2015, 2014 and 2013, respectively. The weighted average EROA assumption used in calculating other postretirement benefit costs was 6.46%, 6.59% and 6.45% in 2015, 2014 and 2013, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. The current year EROA is based on asset allocations from the prior year end. In 2010, Exelon began implementation of a liability-driven investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. Over time, Exelon has decreased its equity investments and increased its investments in

fixed income securities and alternative investments within the pension asset portfolio in order to achieve a balanced portfolio of liability hedging and return-generating assets. See Note 17—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's asset allocations. Exelon used an EROA of 7.00% and 6.71% to estimate its 2016 pension and other postretirement benefit costs, respectively.

Exelon calculates the expected return on pension and other postretirement benefit plan assets by multiplying the EROA by the MRV of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments to be made during the year. In determining MRV, the authoritative guidance for pensions and postretirement benefits allows the use of either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. For the majority of pension plan assets, Exelon uses a calculated value that adjusts for 20% of the difference between fair value and expected MRV of plan assets. Use of this calculated value approach enables less volatile expected asset returns to be recognized as a component of pension cost from year to year. For other postretirement benefit plan assets and certain pension plan assets, Exelon uses fair value to calculate the MRV.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across the Registrants' pension and other postretirement benefit plans for the year ended December 31, 2015 were 0.29% and 0.80%, respectively, compared to an expected long-term return assumption of 7.00% and 6.46%, respectively.

Discount Rate. The discount rate used to determine the majority of pension and other postretirement benefit obligations was 4.29% at December 31, 2015. The discount rates at December 31, 2015 represent weighted-average rates for the majority of pension and other postretirement benefit plans. At December 31, 2015 and 2014, the discount rates were determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated distributions under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

The discount rate assumptions used to determine the obligation at year end are used to determine the cost for the following year. Exelon used discount rates ranging from 3.68% to 4.43% to estimate its 2016 pension and other postretirement benefit costs.

Health Care Reform Legislation. In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers, including a provision that imposes an excise tax on certain high-cost plans whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Additional legislation was passed in December 2015 that made some changes to the law, including moving the implementation date of the excise tax from 2018 to 2020. Although the excise tax does not go into effect until 2020, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Certain key assumptions are required to estimate the impact of the excise tax on Exelon's other postretirement benefit obligation, including projected inflation rates (based on the CPI). Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

Health Care Cost Trend Rate. Assumed health care cost trend rates impact the costs reported for Exelon's other postretirement benefit plans for participant populations with plan designs that do not

have a cap on cost growth. Accounting guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty. Exelon assumed an initial health care cost trend rate of 6.00% for 2015, decreasing to an ultimate health care cost trend rate of 5.00% in 2017.

Mortality. The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. Exelon uses a mortality base table for its accounting valuation that is consistent with the IRS required table for funding (referred to as RP-2000). Exelon has a substantial employee population that provides a credible basis for mortality evaluation. Exelon is utilizing the Scale BB 2-Dimensional improvement scale with long-term improvements of 0.75% for its mortality improvement assumption.

Sensitivity to Changes in Key Assumptions. The following tables illustrate the effects of changing certain of the actuarial assumptions discussed above, while holding all other assumptions constant (dollars in millions):

Actuarial Assumption	Change in Assumption	Pension	Other Postretirement Benefits	Total
Change in 2015 cost:				
Discount rate [a]	0.5%	$ (69)	$ (19)	$ (88)
	(0.5)%	83	30	113
EROA	0.5%	(73)	(11)	(84)
	(0.5)%	73	11	84
Health care cost trend rate [b]	1.00%	N/A	12	12
	(1.00)%	N/A	(9)	(9)
Change in benefit obligation at December 31, 2015:				
Discount rate [a]	0.5%	(1,042)	(249)	(1,291)
	(0.5)%	1,210	289	1,499
Health care cost trend rate [b]	1.00%	N/A	100	100
	(1.00)%	N/A	(89)	(89)

(a) In general, the discount rate will have a larger impact on the pension and other postretirement benefit cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon implemented a liability-driven investment strategy for a portion of its pension asset portfolio in 2010. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.
(b) Changes in the plan design of certain other postretirement benefit plans have resulted in reduced sensitivity to the health care cost trend rate.

Average Remaining Service Period. For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants' average remaining service periods. The average remaining service period of defined benefit pension plan participants was 11.9 years, 11.8 years and 11.8 years for the years ended December 31, 2015, 2014 and 2013, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants' average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants' average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan

participants related to benefit eligibility age was 10.8 years, 9.1 years and 8.7 years for the years ended December 31, 2015, 2014 and 2013, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.7 years, 10.1 years and 9.8 years for the years ended December 31, 2015, 2014 and 2013, respectively.

Regulatory Accounting (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE account for their regulated electric and gas operations in accordance with the authoritative guidance for accounting for certain types of regulations, which requires Exelon, ComEd, PECO and BGE to reflect the effects of cost-based rate regulation in their financial statements. This guidance is applicable to entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) a reasonable expectation that rates are set at levels that will recover the entities' costs from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2015, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of those operations no longer meets the criteria of this guidance, Exelon, ComEd, PECO and BGE would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and could be material. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon, ComEd, PECO and BGE.

For each regulatory jurisdiction in which they conduct business, Exelon, ComEd, PECO and BGE assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs in ComEd's, PECO's and BGE's jurisdictions, and factors such as changes in applicable regulatory and political environments. Furthermore, Exelon, ComEd, PECO and BGE make other judgments related to the financial statement impact of their regulatory environments, such as the types of adjustments to rate base that will be acceptable to regulatory bodies, if any, to which costs will be recoverable through rates. Refer to the revenue recognition discussion below for additional information on the annual revenue reconciliations associated with ComEd's distribution formula rate tariff, pursuant to EIMA, and FERC-approved transmission formula rate tariffs for ComEd and BGE. Additionally, estimates are made in accordance with the authoritative guidance for contingencies as to the amount of revenues billed under certain regulatory orders that may ultimately be refunded to customers upon finalization of applicable regulatory or judicial processes. These assessments are based, to the extent possible, on past relevant experience with regulatory bodies in ComEd's, PECO's and BGE's jurisdictions, known circumstances specific to a particular matter and hearings held with the applicable regulatory body. If the assessments and estimates made by Exelon, ComEd, PECO and BGE are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Accounting for Derivative Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants utilize derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy-related products marketed and purchased. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd had a financial swap contract with Generation that expired May 31, 2013 and currently holds floating-to-fixed energy swaps with several unaffiliated suppliers that extend into 2032. PECO and BGE have entered into derivative natural gas contracts to hedge their long-term price risk in the natural gas market. PECO has also entered into derivative contracts to procure electric supply through a competitive RFP process as outlined in its PAPUC-approved DSP Program. BGE has also entered into derivative contracts to procure electric supply through a competitive auction process as outlined in its MDPSC-approved SOS Program. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes. The Registrants' derivative activities are in accordance with Exelon's Risk Management Policy (RMP). See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether or not a contract qualifies as a derivative under this guidance requires that management exercise significant judgment, including assessing the market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. Further, interpretive guidance related to the authoritative literature continues to evolve, including how it applies to energy and energy-related products. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance related to derivatives, could result in previously excluded contracts being subject to the provisions of the authoritative derivative guidance. Generation has determined that contracts to purchase uranium, contracts to purchase and sell capacity in certain ISO's, certain emission products and RECs do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement and neither the uranium, certain capacity, emission nor the REC markets are sufficiently liquid to conclude that physical forward contracts are readily convertible to cash. If these markets do become sufficiently liquid in the future and Generation would be required to account for these contracts as derivative instruments, the fair value of these contracts would be accounted for consistent with Generation's other derivative instruments. In this case, if market prices differ from the underlying prices of the contracts, Generation would be required to record mark-to-market gains or losses, which may have a significant impact to Exelon's and Generation's financial positions and results of operations.

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, the normal purchases and normal sales exception. Further, derivatives that qualify and are designated for hedge accounting are classified as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For commodity transactions, effective with the date of the Constellation merger, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the Constellation merger. Because the underlying forecasted transactions remained probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred. None of

Constellation's designated cash flow hedges for commodity transactions prior to the Constellation merger were re-designated as cash flow hedges. The effect of this decision is that all economic hedges for commodities are recorded at fair value through earnings for the combined company. In addition, for energy-related derivatives entered into for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings each period. For economic hedges that are not designated for hedge accounting for ComEd, PECO and BGE, changes in the fair value each period are recorded as a regulatory asset or liability.

Normal Purchases and Normal Sales Exception. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated as normal purchases and normal sales and are thus not required to be recorded at fair value, but rather on an accrual basis of accounting. Determining whether a contract qualifies for the normal purchases and normal sales exception requires that management exercise judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and is not financially settled on a net basis. The contracts that ComEd has entered into with suppliers as part of ComEd's energy procurement process, PECO's full requirement contracts and block contracts under the PAPUC-approved DSP program, most of PECO's natural gas supply agreements and all of BGE's full requirement contracts and natural gas supply agreements that are derivatives qualify for the normal purchases and normal sales exception.

Commodity Contracts. Identification of a commodity contract as an economic hedge requires Generation to determine that the contract is in accordance with the RMP. Generation reassesses its economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

As a part of accounting for derivatives, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. In accordance with the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges are categorized in Level 2. These price quotations reflect the average of the bid-ask mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The Registrant's derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using models that take into account inputs such as contract terms, including maturity, and market parameters, and assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid

markets, such as generic forwards, swaps and options, the model inputs are generally observable. Such instruments are categorized in Level 2. For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of credit and nonperformance risk to date have generally not been material to the financial statements.

Interest Rate and Foreign Exchange Derivative Instruments. The Registrants may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve the targeted level of variable-rate debt as a percent of total debt. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings and floating to fixed swaps for project financing. In addition, Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the economic hedge and proprietary trading activity is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or change in market interest rates. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. The fair value of the agreements is calculated by discounting the future net cash flows to the present value based on the terms and conditions of the agreements and the forward interest rate and foreign exchange curves. As these inputs are based on observable data and valuations of similar instruments, the interest rate and foreign exchange derivatives are primarily categorized in Level 2 in the fair value hierarchy. Certain exchange based interest rate derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 12—Fair Value of Financial Assets and Liabilities and Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation (Exelon, Generation, ComEd, PECO and BGE)

Significant management judgment is required in determining the Registrants' provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of unrecognized tax benefits to be recorded in the Registrants' consolidated financial statements.

The Registrants evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and their intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. The Registrants also assess their ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. The Registrants record valuation allowances for deferred tax assets when the Registrants conclude it is more-likely-than-not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2015 and 2014 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Loss Contingencies (Exelon, Generation, ComEd, PECO and BGE)

In the preparation of their financial statements, the Registrants make judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amounts recorded may differ from the actual expense incurred when the uncertainty is resolved. The estimates that the Registrants make in accounting for loss contingencies and the actual results that they record upon the ultimate resolution of these uncertainties could have a significant effect on their consolidated financial statements.

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at ComEd, PECO and BGE to determine future remediation requirements and estimates are adjusted accordingly. In addition, periodic reviews are performed at Generation to assess the adequacy of its environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant effect on the Registrants' results of operations, financial position and cash flows. See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information.

Other, Including Personal Injury Claims. The Registrants are self-insured for general liability, automotive liability, workers' compensation, and personal injury claims to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. The Registrants have reserves for both open claims asserted and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible state and national legislative measures could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material effect on the Registrants' results of operations, financial position and cash flows.

Revenue Recognition (Exelon, Generation, ComEd, PECO and BGE)

Sources of Revenue and Determination of Accounting Treatment. The Registrants earn revenues from various business activities including: the sale of energy and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail) *;* the sale and delivery of electricity and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The appropriate accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable accounting standards. The Registrants primarily use accrual and mark-to-market accounting as discussed in more detail below.

Accrual Accounting. Under accrual accounting, the Registrants record revenues in the period when services are rendered or energy is delivered to customers. The Registrants generally use accrual accounting to recognize revenues for sales of electricity, natural gas and other commodities as part of their physical delivery activities. The Registrants enter into these sales transactions using a variety of instruments, including non-derivative agreements, derivatives that qualify for and are designated as normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to utility customers under regulated service tariffs and spot-market sales, including settlements with independent system operators.

Mark-to-Market Accounting. The Registrants record revenues and expenses using the mark-to-market method of accounting for transactions that meet the definition of a derivative for which they are not permitted, or have not elected, the NPNS exception. These mark-to-market transactions primarily relate to risk management activities and economic hedges of other accrual activities. Mark-to-market revenues and expenses include: inception gains or losses on new transactions where the fair value is observable and realized; and unrealized gains and losses from changes in the fair value of open contracts.

Use of Estimates. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliations can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Unbilled Revenues . The determination of Generation's, ComEd's, PECO's and BGE's retail energy sales to individual customers is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities' customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, revenues may fluctuate monthly as a result of customers electing to use an alternate supplier, since unbilled commodity receivables are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date would also have an effect on the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

See Note 6—Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

Regulated Transmission & Distribution Revenues **.** ComEd's EIMA distribution formula rate tariff provides for annual reconciliations to the distribution revenue requirement. As of the balance

sheet dates, ComEd has recorded its best estimates of the distribution revenue impact resulting from changes in rates that ComEd believes are probable of approval by the ICC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred, investments made, allowed ROE and actions by regulators or courts.

ComEd's and BGE's FERC transmission formula rate tariffs provide for annual reconciliations to the transmission revenue requirements. As of the balance sheet dates, ComEd and BGE have recorded the best estimate of their respective transmission revenue impact resulting from changes in rates that ComEd and BGE believe are probable of approval by FERC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd, PECO and BGE estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 6—Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2015, 2014 and 2013 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income Attributable to Common Shareholders by Registrant

	2015	2014	Favorable (unfavorable) 2015 vs. 2014 variance	2013	Favorable (unfavorable) 2014 vs. 2013 variance
Exelon	$2,269	$1,623	$ 646	$1,719	$ (96)
Generation	1,372	835	537	1,070	(235)
ComEd	426	408	18	249	159
PECO	378	352	26	388	(36)
BGE	275	198	77	197	1

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Results of Operations—Generation

	2015	2014 [a]	Favorable (unfavorable) 2015 vs. 2014 variance	2013	Favorable (unfavorable) 2014 vs. 2013 variance
Operating revenues	$19,135	$17,393	$ 1,742	$15,630	$ 1,763
Purchased power and fuel expense	10,021	9,925	(96)	8,197	(1,728)
Revenue net of purchased power and fuel expense [b]	9,114	7,468	1,646	7,433	35
Other operating expenses					
Operating and maintenance	5,308	5,566	258	4,534	(1,032)
Depreciation and amortization	1,054	967	(87)	856	(111)
Taxes other than income	489	465	(24)	389	(76)
Total other operating expenses	6,851	6,998	147	5,779	(1,219)
Equity in (losses) earnings of unconsolidated affiliates	—	(20)	20	10	(30)
Gain on sales of assets	12	437	(425)	13	424
Gain on consolidation and acquisition of businesses	—	289	(289)	—	289
Operating income	2,275	1,176	1,099	1,677	(501)
Other income and (deductions)					
Interest expense	(365)	(356)	(9)	(357)	1
Other, net	(60)	406	(466)	355	51
Total other income and (deductions)	(425)	50	(475)	(2)	52
Income before income taxes	1,850	1,226	624	1,675	(449)
Income taxes	502	207	(295)	615	408
Equity in losses of unconsolidated affiliates	(8)	—	8	—	—
Net income	1,340	1,019	321	1,060	(41)
Net income (loss) attributable to noncontrolling interest	(32)	184	(216)	(10)	194
Net income attributable to membership interest	$ 1,372	$ 835	$ 537	$ 1,070	$ (235)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, the financial results include CENG's results of operations on a fully consolidated basis.

(b) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Membership Interest

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. Generation's net income attributable to membership interest increased compared to the same period in 2014 primarily due to higher revenue net of purchase power and fuel expense and lower operating and maintenance expense; partially offset by the absence of the 2014 gains recorded on the sales of Generation's ownership interest in generating stations, the absence of the 2014 gain recorded upon the consolidation of CENG, decreased other income and increased income tax expense. The increase in

revenue, net of purchase power and fuel expense was primarily due to the inclusion of CENG's results on fully consolidated basis in 2015, the benefit of lower cost to serve load (including the absence of higher procurement costs for replacement power in 2014), the cancellation of the DOE spent nuclear fuel disposal fee, increased capacity prices, the inclusion of Integrys' results in 2015, favorability from portfolio management optimization activities, increased load served, and mark-to-market gains in 2015 compared to mark-to-market losses in 2014, partially offset by lower margins resulting from the 2014 sale of generating assets, lower realized energy prices, and the absence of the 2014 fuel optimization opportunities in the South region due to extreme cold weather. The decrease in operating and maintenance expense was largely due to the reduction of long-lived asset impairment charges in 2015 versus 2014, partially offset by increased labor, contracting and materials expense due to the inclusion of CENG's results on a fully consolidated basis in 2015 and increased energy efficiency projects. The decrease in other income is primarily the result of the change in realized and unrealized gains and losses on NDT fund investments in 2015 as compared to 2014.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Generation's net income attributable to membership interest decreased compared to the same period in 2013 primarily due to higher operating and maintenance expense and higher depreciation expense; partially offset by higher revenue, net of purchase power and fuel expense, higher other income, the gains recorded on the sale of Generation's ownership interest in generating stations, the bargain-purchase gain recorded related to the Integrys acquisition, and the gain recorded upon consolidation of CENG. The increase in operating and maintenance expense was largely due to increased labor contracting and materials expense due to the inclusion of CENG's results on a fully consolidated basis beginning April 1, 2014 and impairment charges related to 1) generating assets held-for-sale, 2) certain Upstream assets, and 3) wind generating assets. The increase in revenue, net of purchased power and fuel expense was primarily due to the inclusion of CENG's results beginning April 1, 2014, a decrease in fuel costs related to the cancellation of DOE spent nuclear fuel disposal fees, an increase in capacity prices, and favorable portfolio management activities in the New England and South regions, partially offset by lower realized energy prices related to executing Exelon's ratable hedging strategy, higher procurement costs for replacement power due to extreme cold weather in the first quarter of 2014, and unrealized mark-to-market losses in 2014. The increase in other income is primarily the result of increased realized and unrealized gains on NDT fund investments.

Revenue Net of Purchased Power and Fuel Expense

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned with these same geographic regions. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions :
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in the table below in Other: unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense, which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for owned generation and fuel costs associated with tolling agreements.

For the years ended December 31, 2015 compared to 2014 and December 31, 2014 compared to 2013, Generation's revenue net of purchased power and fuel expense by region were as follows:

			2015 vs. 2014			2014 vs. 2013	
	2015	2014	Variance	% Change	2013	Variance	% Change
Mid-Atlantic (a)(b)(e)	$3,571	$3,431	$ 140	4.1%	$3,270	$ 161	4.9%
Midwest (c)	2,892	2,599	293	11.3%	2,586	13	0.5%
New England	461	351	110	31.3%	185	166	89.7%
New York (a)(e)	634	483	151	31.3%	(4)	487	n.m.
ERCOT	293	317	(24)	(7.6)%	436	(119)	(27.3)%
Other Power Regions	250	327	(77)	(23.5)%	201	126	62.7%
Total electric revenue net of purchased power and fuel expense	8,101	7,508	593	7.9%	6,674	834	12.5%
Proprietary Trading	1	42	(41)	(97.6)%	(8)	50	n.m.
Mark-to-market gains (losses)	257	(591)	848	n.m.	504	(1,095)	n.m.
Other (d)	755	509	246	48.3%	263	246	93.5%
Total revenue net of purchased power and fuel expense	$9,114	$7,468	$1,646	22.0%	$7,433	$ 35	0.5%

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning April 1, 2014, the financial results include CENG's results on a fully consolidated basis.
(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes an $8 million increase to RNF, a $124 million decrease to RNF, and a $488 million decrease to RNF for the amortization of intangible assets related to energy contracts for the years ended December 31, 2015, 2014, and 2013, respectively.
(e) Includes $113 million and $169 million of purchased power from CENG prior to its consolidation on April 1, 2014 in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2014. Includes $542 million and $450 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2013. See Note 26—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's supply sources by region are summarized below:

			2015 vs. 2014			2014 vs. 2013	
Supply Source (GWh)	2015	2014	Variance	% Change	2013	Variance	% Change
Nuclear Generation (a)							
Mid-Atlantic	63,283	58,809	4,474	7.6%	48,881	9,928	20.3%
Midwest	93,422	94,000	(578)	(0.6)%	93,245	755	0.8%
New York	18,769	13,645	5,124	37.6%	—	13,645	n.m.
Total Nuclear Generation	175,474	166,454	9,020	5.4%	142,126	24,328	17.1%
Fossil and Renewables (a)							
Mid-Atlantic	2,774	11,025	(8,251)	(74.8)%	11,714	(689)	(5.9)%
Midwest	1,547	1,372	175	12.8%	1,478	(106)	(7.2)%
New England	2,983	5,233	(2,250)	(43.0)%	10,896	(5,663)	(52.0)%
New York	3	4	(1)	(25.0)%	—	4	n.m.
ERCOT	5,763	7,164	(1,401)	(19.6)%	6,453	711	11.0%
Other Power Regions	7,848	7,955	(107)	(1.3)%	6,664	1,291	19.4%
Total Fossil and Renewables	20,918	32,753	(11,835)	(36.1)%	37,205	(4,452)	(12.0)%
Purchased Power							
Mid-Atlantic (b)	8,160	6,082	2,078	34.2%	14,092	(8,010)	(56.8)%
Midwest	2,325	2,004	321	16.0%	4,408	(2,404)	(54.5)%
New England	24,309	12,354	11,955	96.8%	7,655	4,699	61.4%
New York (b)	—	2,857	(2,857)	(100.0)%	13,642	(10,785)	(79.1)%
ERCOT	10,070	8,651	1,419	16.4%	13,459	(4,808)	(35.7)%
Other Power Regions	16,728	14,795	1,933	13.1%	14,931	(136)	(0.9)%
Total Purchased Power	61,592	46,743	14,849	31.8%	68,187	(21,444)	(31.4)%
Total Supply/Sales by Region (c)							
Mid-Atlantic (d)	74,217	75,916	(1,699)	(2.2)%	74,687	1,229	1.6%
Midwest (d)	97,294	97,376	(82)	(0.1)%	99,131	(1,755)	(1.8)%
New England	27,292	17,587	9,705	55.2%	18,551	(964)	(5.2)%
New York	18,772	16,506	2,266	13.7%	13,642	2,864	21.0%
ERCOT	15,833	15,815	18	0.1%	19,912	(4,097)	(20.6)%
Other Power Regions	24,576	22,750	1,826	8.0%	21,595	1,155	5.3%
Total Supply/Sales by Region	257,984	245,950	12,034	4.9%	247,518	(1,568)	(0.6)%

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG). Nuclear generation for the year ended December 31, 2015 includes physical volumes of 14,646 GWh in Mid-Atlantic and 18,769 GWh in New York for CENG and for the year ended December 31, 2014 includes physical volumes of 11,409 GWh in Mid-Atlantic and 13,645 GWh in New York for CENG. Prior to the integration date of April 1, 2014, CENG volumes were included in purchased power.

(b) Purchased power includes physical volumes of 2,489 GWh and 12,067 GWh in the Mid-Atlantic and 2,857 GWh and 12,165 GWh in New York as a result of the PPA with CENG for the years ended December 31, 2014 and 2013, respectively. Since the integration date of April 1, 2014, CENG volumes are included in nuclear generation.
(c) Excludes physical proprietary trading volumes of 7,310 GWh, 10,571 GWh, and 8,762 GWh for the years ended December 31, 2015, 2014, and 2013, respectively.
(d) Includes affiliate sales to PECO and BGE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.

Mid-Atlantic

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $140 million was primarily due to the inclusion of CENG's results on a fully consolidated basis for the full year in 2015, the benefit of lower cost to serve load (which includes the absence of higher procurement costs for replacement power due to extreme cold weather in the first quarter of 2014), increased load volumes served, higher nuclear volumes, the cancellation of the DOE spent nuclear fuel disposal fee, and favorability from portfolio management optimization activities, partially offset by lower capacity revenues, and lower generation volumes due to the sale of generating assets.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $161 million was primarily due to the consolidation of CENG, the cancellation of the DOE spent nuclear fuel disposal fees in 2014, and favorable portfolio management optimization activities, partially offset by higher procurement costs for replacement power, lower nuclear volumes (excluding CENG), lower capacity revenues, and lower realized energy prices related to executing Generation's ratable hedging strategy.

Midwest

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The increase in revenue net of purchased power and fuel expense in the Midwest of $293 million was primarily due to higher capacity revenues, increased load volumes served, the inclusion of Integrys' results in 2015, the cancellation of the DOE spent nuclear fuel disposal fee in 2014, and favorability from portfolio management optimization activities, partially offset by lower nuclear volumes.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase in revenue net of purchased power and fuel expense in the Midwest of $13 million was primarily due to higher capacity prices, higher nuclear volumes, and the cancellation of the DOE spent nuclear fuel disposal fee, partially offset by lower realized energy prices related to executing Generation's ratable hedging strategy.

New England

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The increase in revenue net of purchased power and fuel expense in New England of $110 million was primarily due to the benefit of lower cost to serve load, increased load volumes served, the inclusion of Integrys' results in 2015, and favorability from portfolio management optimization activities, partially offset by lower generation volumes due to the sale of a generating asset.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase in revenue net of purchased power and fuel expense in New England of $166 million was primarily due to higher realized energy prices and favorable impacts from the restructuring of a fuel supply contract, partially offset by lower generation volume.

New York

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $151 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the

inclusion of CENG's results on a fully consolidated basis for the full year in 2015, increased nuclear volumes and the inclusion of Integrys' results in 2015, partially offset by lower realized energy prices and decreased capacity revenues.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The $487 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the consolidation of CENG.

ERCOT

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $24 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices and a decrease in generation volumes due to the sale of a generating asset, partially offset by the absence of higher procurement costs for replacement power in 2014 and decreased fuel costs.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $119 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to higher procurement costs for replacement power in the second quarter of 2014 and the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013. The decreases were partially offset by higher generation volume in the first quarter of 2014.

Other Power Regions

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in revenue net of purchased power and fuel expense in Other Power Regions of $77 million was primarily due to the amortization of contracts recorded at fair value associated with prior acquisitions, lower realized energy prices, the absence of the 2014 fuel optimization opportunities, partially offset by increased generation from power purchase agreements, and decreased fuel costs.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $126 million increase in revenue net of purchased power and fuel expense in Other Power Regions was primarily due to higher generation volumes and higher realized energy prices.

Proprietary Trading

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $41 million decrease in revenue net of purchased power and fuel expense in Proprietary trading was primarily due to the absence of gains on congestion trading products.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $50 million increase in revenue net of purchased power and fuel expense in Proprietary trading was primarily due to gains on congestion trading products.

Mark-to-market

Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. See Note 12—Fair Value of Financial

Assets and Liabilities and Note 13—Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . Mark-to-market gains on economic hedging activities were $257 million in 2015 compared to losses of $591 million in 2014.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . Mark-to-market losses on economic hedging activities were $591 million in 2014 compared to gains of $504 million in 2013.

Other

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $246 million increase in other revenue net of purchased power and fuel was primarily due to the amortization of energy contracts recorded at fair value associated with prior acquisitions, the inclusion of Integrys' gas results in 2015, and an increase in distributed generation and energy efficiency activity. See Note 11—Intangible Assets of the Combined Notes to Consolidated Financial Statements for information regarding energy contract intangibles.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. The $246 million increase in other revenue net of purchased power and fuel was primarily due to the amortization of energy contracts recorded at fair value associated with prior acquisitions, partially offset by a loss on gas inventory from lower of cost or market adjustments in 2014. See Note 11—Intangible Assets of the Combined Notes to Consolidated Financial Statements for information regarding energy contract intangibles.

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for 2015, as compared to 2014 and 2013, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Generation considers capacity factor useful measure to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	2015	2014	2013
Nuclear fleet capacity factor [(a)]	93.7%	94.3%	94.1%

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. As of April 1, 2014, CENG is included at ownership.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The nuclear fleet capacity factor, which excludes Salem, decreased in 2015 compared to 2014 primarily due to a higher number of refueling outage days and non-outage energy losses, partially offset by a lower number of unplanned outage days. For 2015 and 2014, planned refueling outage days totaled 290 and 275, respectively, and non-refueling outage days totaled 82 and 92, respectively

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The nuclear fleet capacity factor, which excludes Salem, increased in 2014 compared to 2013. While total days offline

were greater in 2014 as compared to 2013, the larger capacity units were online for more days in 2014. Additionally, with the addition of the CENG nuclear facilities there were more days offline in 2014 associated with units where Exelon's ownership percentage diminishes the impact on capacity factor. For 2014 and 2013, planned refueling outage days totaled 275 and 233, respectively, and non-refueling outage days totaled 92 and 75, respectively.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2015 compared to 2014, consisted of the following:

	Increase (Decrease) [a]
Impairment and related charges of certain generating assets [b]	$ (651)
Maryland merger commitments	(44)
Merger and integration costs	(28)
Midwest Generation bankruptcy charges	(14)
Decrease in asbestos bodily injury reserve	(12)
ARO update	8
Regulatory fees and assessments	10
Pension and non-pension postretirement benefits expense	15
Corporate allocations [c]	16
Accretion expense	18
Nuclear refueling outage costs, including the co-owned Salem plant [d]	64
Labor, other benefits, contracting and materials [e]	323
Other	37
Decrease in operating and maintenance expense	$ (258)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the operating results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014 and for the entire year in 2015.
(b) Primarily relates to impairments of certain generating assets held-for-sale, Upstream assets, and wind generating assets during 2014 that did not reoccur in 2015.
(c) Reflects an increased share of corporate allocated costs primarily due to the inclusion of CENG beginning April 1, 2014.
(d) Reflects the unfavorable impacts of increased nuclear outages in 2015.
(e) Reflects an increase of labor, other benefits, contracting and materials costs primarily due to the inclusion of CENG on a fully consolidated basis in 2015. Also includes cost of sales of our other business activities that are not allocated to a region.

The changes in operating and maintenance expense for 2014 compared to 2013, consisted of the following:

	Increase (Decrease) [a]
Impairment and related charges of certain generating assets [b]	$ 506
Labor, other benefits, contracting and materials [c]	361
Accretion expense	78
Corporate allocations [d]	69
Regulatory fees and assessments	51
Maryland merger commitments	44
Nuclear refueling outage costs, including the co-owned Salem plant [e]	54
Increase in asbestos bodily injury reserve	16
Midwest Generation bankruptcy charges	(26)
ARO update	(29)
Merger and integration costs	(29)
Pension and non-pension postretirement benefits expense	(81)
Other	18
Increase in operating and maintenance expense	$ 1,032

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 operating results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.
(b) Reflects the operating and maintenance expense associated with the impairment of certain generating assets held-for-sale, Upstream assets, and wind generating assets during 2014.
(c) Reflects an increase of labor, other benefits, contracting and materials costs primarily due to the inclusion of CENG beginning April 1, 2014. Also includes cost of sales of our other business activities that are not allocated to a region.
(d) Reflects an increased share of corporate allocated costs primarily due to the inclusion of CENG beginning April 1, 2014.
(e) Reflects the impact of increased nuclear outage days primarily due to the inclusion of CENG beginning April 1, 2014.

Depreciation and Amortization

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The increase in depreciation and amortization expense was primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015, increased nuclear decommissioning amortization, and an increase in ongoing capital expenditures.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase in depreciation and amortization expense was primarily due to the inclusion of CENG's results on a fully consolidated basis beginning April 1, 2014 and an increase in ongoing capital expenditures.

Taxes Other Than Income

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The increase in taxes other than income was primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase in taxes other than income was primarily due to the inclusion of CENG's results on a fully consolidated basis beginning April 1, 2014.

Equity in Earnings (Losses) of Unconsolidated Affiliates

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The year-over-year change in Equity in earnings (losses) of unconsolidated affiliates is primarily the result of the consolidation of CENG's results of operations beginning April 1, 2014, which were previously accounted for under the equity method of accounting.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The year-over-year change in Equity in earnings (losses) of unconsolidated affiliates is primarily the result of the consolidation of CENG's results of operations beginning April 1, 2014, which were previously accounted for under the equity method of accounting.

Gain (Loss) on Sales of Assets

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The decrease in gain (loss) on sales of assets in primarily related to the absence of $411 million of gains recorded on the sale of Generation's ownership interests in Safe Harbor Water Power Corporation, Fore River and West Valley generating stations in 2014. Refer to Note 4—Mergers, Acquisitions and Dispositions in the Combined Notes to Consolidated Financial Statements for additional information.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase in gain (loss) on sales of assets is primarily related to $411 million of gains recorded on the sale of

Generation's ownership interests in Safe Harbor Water Power Corporation, Fore River and West Valley generating stations in 2014. Refer to Note 4 —Mergers, Acquisitions and Dispositions in the Combined Notes to Consolidated Financial Statements for additional information.

Gain on Consolidation and Acquisition of Businesses

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The decrease in gain on consolidation and acquisition of businesses reflects the absence of a $261 million gain upon consolidation of CENG resulting from the difference in fair value of CENG's net assets as of April 1, 2014 and the equity method investment previously recorded on Generation's and Exelon's books and the settlement of pre-existing transactions between Generation and CENG recorded in 2014, and the absence of a $28 million bargain-purchase gain related to the Integrys acquisition recorded in 2014.

Interest Expense

The changes in interest expense for 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Interest expense on long-term debt	$ 53	$ 33
Interest expense on interest rate swaps	22	4
Interest expense on tax settlements	(37)	(21)
Other interest expense	(29)	(17)
Increase (decrease) in interest expense, net	$ 9	$ (1)

Other, Net

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The decrease in Other, net primarily reflects the net decrease in realized and unrealized gains related to the NDT fund investments of Generation's Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $(22) million and $67 million for the year ended December 31, 2015 and 2014, respectively, related to the contractual elimination of income tax expense associated with the NDT fund investments of the Regulatory Agreement Units. Refer to Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT fund investments.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 . The increase in Other, net primarily reflects $31 million of favorable tax settlements related to Constellation's pre-acquisition tax returns and the increased net realized and unrealized gains related to the NDT fund investments of Generation's Non-Regulatory Agreement Units compared to net realized and unrealized gains in 2013, as described in the table below. Other, net also reflects $67 million and $122 million for the year ended December 31, 2014 and 2013, respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT fund investments of the Regulatory Agreement Units. Refer to Note 15—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT fund investments.

The following table provides unrealized and realized gains (losses) on the NDT fund investments of the Non-Regulatory Agreement Units recognized in Other, net for 2015, 2014 and 2013:

	2015	2014	2013
Net unrealized (losses) gains on decommissioning trust funds	$(197)	$134	$146
Net realized gains on sale of decommissioning trust funds	$ 66	$ 77	$ 24

Effective Income Tax Rate.

Generation's effective income tax rates for the years ended December 31, 2015, 2014 and 2013 were 27.1%, 16.9% and 36.7%, respectively. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—ComEd

	2015	2014	Favorable (Unfavorable) 2015 vs. 2014 Variance	2013	Favorable (Unfavorable) 2014 vs. 2013 Variance
Operating revenue	$4,905	$4,564	$ 341	$4,464	$ 100
Purchased power expense	1,319	1,177	(142)	1,174	(3)
Revenue net of purchased power expense [a][b]	3,586	3,387	199	3,290	97
Other operating expenses					
Operating and maintenance	1,567	1,429	(138)	1,368	(61)
Depreciation and amortization	707	687	(20)	669	(18)
Taxes other than income	296	293	(3)	299	6
Total other operating expenses	2,570	2,409	(161)	2,336	(73)
Gain on sales of assets	1	2	(1)	—	2
Operating income	1,017	980	37	954	26
Other income and (deductions)					
Interest expense, net	(332)	(321)	(11)	(579)	258
Other, net	21	17	4	26	(9)
Total other income and (deductions)	(311)	(304)	(7)	(553)	249
Income before income taxes	706	676	30	401	275
Income taxes	280	268	(12)	152	(116)
Net income	$ 426	$ 408	$ 18	$ 249	$ 159

(a) ComEd evaluates its operating performance using the measure of Revenue net of purchased power expense. ComEd believes that Revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of Revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b) For regulatory recovery mechanisms, including ComEd's electric distribution and transmission formula rates, and riders, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).

Net Income

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. ComEd's Net income for the year ended December 31, 2015 was higher than the same period in 2014 primarily due to increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE), partially offset by unfavorable weather and volume.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. ComEd's Net income for the year ended December 31, 2014 was higher than the same period in 2013 primarily due to the 2013 remeasurement of Exelon's like-kind exchange tax position and increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment), partially offset by unfavorable weather.

Operating Revenue Net of Purchased Power Expense

There are certain drivers of Operating revenue that are fully offset by their impact on Purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on Revenue net of purchased power expense. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries, but do affect ComEd's Operating revenue related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2015, 2014 and 2013, consisted of the following:

	For the Years Ended December 31,		
	2015	2014	2013
Electric	76%	80%	81%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2015, 2014 and 2013 consisted of the following:

	December 31, 2015		December 31, 2014		December 31, 2013	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	1,655,400	42%	2,426,900	63%	2,630,200	68%

Under an Illinois law allowing municipalities to arrange the purchase of electricity for their participating residents, the City of Chicago previously participated in ComEd's customer choice program and arranged the purchase of electricity from Constellation (formerly Integrys), for those participating residents. In September 2015, the City of Chicago discontinued its participation in the customer choice program and many of those participating residents resumed their purchase of electricity from ComEd. ComEd's Operating revenue has increased as a result of the City of Chicago switching, but that increase is fully offset in Purchased power expense.

The changes in ComEd's Revenue net of purchased power expense for the year ended December 31, 2015 compared to the same period in 2014, and for the year ended December 31, 2014 compared to the same period in 2013, consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Weather	$ (16)	$ (16)
Volume	(22)	—
Electric distribution revenue	180	(2)
Transmission revenue	48	30
Regulatory required programs	(1)	52
Uncollectible accounts recovery, net	27	41
Pricing and customer mix	(4)	5
Revenue subject to refund	9	(9)
Other	(22)	(4)
Increase in revenue net of purchased power	$ 199	$ 97

Weather. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the years ended December 31, 2015 and 2014, unfavorable weather conditions reduced Operating revenue net of purchased power expense when compared to the prior years.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2015, 2014 and 2013 consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2015	2014	Normal	2015 vs. 2014	2015 vs. Normal
Heating Degree-Days	6,091	7,027	6,341	(13.3)%	(3.9)%
Cooling Degree-Days	806	799	842	0.9%	(4.3)%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2014	2013	Normal	2014 vs. 2013	2014 vs. Normal
Heating Degree-Days	7,027	6,603	6,341	6.4%	10.8%
Cooling Degree-Days	799	933	842	(14.4)%	(5.1)%

Volume. Revenue net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the year ended December 31, 2015, reflecting decreased average usage per residential customer and the impacts of energy efficiency programs, as compared to the same period in 2014. For the year ended December 31, 2014, Revenue net of purchased power expense remained relatively consistent, as compared to the same period in 2013.

Electric Distribution Revenue. EIMA provides for a performance-based formula rate tariff, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under EIMA, electric distribution

revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, allowed ROE, and other billing determinants. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points, subject to a collar of plus or minus 50 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on revenue. During the year ended December 31, 2015, electric distribution revenue increased $180 million, primarily due to higher Operating and maintenance expense and increased capital investment, partially offset by lower allowed ROE due to decreased treasury rates. During the year ended December 31, 2014, electric distribution revenue decreased $2 million, primarily due to lower Operating and maintenance expense resulting from certain OPEB plan design changes, partially offset by increased capital investment. See Operating and Maintenance Expense below and Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. During the years ended December 31, 2015 and 2014, ComEd recorded increased transmission revenue primarily due to higher Operating and maintenance expense and increased capital investment. See Operating and Maintenance Expense below and Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenue collected under approved riders to recover costs incurred for regulatory programs such as ComEd's energy efficiency and demand response and purchased power administrative costs. The riders are designed to provide full and current cost recovery. An equal and offsetting amount has been included in Operating and maintenance expense. See Operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Uncollectible accounts recovery, net, represents recoveries under ComEd's uncollectible accounts tariff. See Operating and maintenance expense discussion below for additional information on this tariff.

Pricing and Customer Mix. For the year ended December 31, 2015, the decrease in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to lower overall effective rates due to increased usage across all major customer classes and change in customer mix. For the year ended December 31, 2014, the increase in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes and change in customer mix.

Revenue Subject to Refund. ComEd records revenue subject to refund based upon its best estimate of customer collections that may be required to be refunded. Revenue net of purchase power expense was higher for the year ended December 31, 2015, due to the one-time revenue refund recorded in 2014 associated with the 2007 Rate Case.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental costs associated with MGP sites, and recoveries of energy procurement costs.

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease) 2015 vs. 2014	Year Ended December 31,		Increase (Decrease) 2014 vs. 2013
	2015	2014		2014	2013	
Operating and maintenance expense—baseline	$1,353	$1,214	$ 139	$1,214	$1,205	$ 9
Operating and maintenance expense—regulatory required programs [(a)]	214	215	(1)	215	163	52
Total operating and maintenance expense	$1,567	$1,429	$ 138	$1,429	$1,368	$ 61

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenue.

The changes in Operating and maintenance expense for year ended December 31, 2015, compared to the same period in 2014, and for the year ended December 31, 2014, compared to the same period in 2013, consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Baseline		
Labor, other benefits, contracting and materials [(a)]	$ 31	$ 56
Pension and non-pension postretirement benefits expense [(b)]	19	(85)
Storm-related costs	27	(11)
Uncollectible accounts expense—provision [(c)]	(7)	12
Uncollectible accounts expense—recovery, net [(c)]	34	29
Other [(d)]	35	8
	139	9
Regulatory required programs		
Energy efficiency and demand response programs	(1)	52
Increase in operating and maintenance expense	$ 138	$ 61

(a) Primarily reflects increased contracting costs related to preventative maintenance and other projects for the year ended December 31, 2015, and increased contracting costs resulting from new projects associated with EIMA for the year ended December 31, 2014. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding EIMA.

(b) The increase from 2014 to 2015 primarily reflects the unfavorable impact of lower assumed pension and OPEB discount rates and an increase in the life expectancy assumption for plan participants, partially offset by cost savings from plan design changes for certain OPEB plans effective April 2014 and forward. The decrease from 2013 to 2014 primarily reflects the cost savings from plan design changes for certain OPEB plans effective April 2014 and forward. See Note 16—Retirement Benefits of the Exelon 2014 Form 10-K for additional information regarding plan changes.

(c) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. In 2015 and 2014, ComEd recorded a net increase in Operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting amount has been recognized in Operating revenue for the periods presented.

(d) Primarily reflects increased information technology support services from BSC during 2015.

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Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2015 compared to 2014, and 2014 compared to 2013, consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Depreciation expense [a]	$ 43	$ 46
Amortization regulatory assets [b]	(28)	(21)
Other	5	(7)
Increase in depreciation and amortization expense	$ 20	$ 18

(a) Depreciation expense increased due to ongoing capital expenditure during the years ended December 31, 2015 and 2014.
(b) For the years ended December 31, 2015 and 2014, primarily relates to a decrease in MGP regulatory asset amortization and ComEd's severance regulatory assets fully amortizing during 2014.

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014, and for the year ended December 31, 2014, compared to the same period in 2013.

Interest Expense, Net

The changes in Interest expense, net, for the year ended 2015 compared to the same period in 2014, and for the year ended 2014 compared to the same period in 2013, consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Interest expense related to uncertain tax positions	$ 2	$ (275) [a]
Interest expense on debt (including financing trusts) [b]	13	16
Other	(4)	1
Increase (decrease) in interest expense, net	$ 11	$ (258)

(a) The reduction in interest expense in 2014 from 2013 is primarily attributable to the remeasurement of Exelon's like-kind exchange tax position recorded in the first quarter of 2013. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Primarily reflects an increase in interest expense due to the issuance of First Mortgage Bonds for the years ended December 31, 2015 and 2014. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's debt obligations.

Effective Income Tax Rate

ComEd's effective income tax rates for the years ended December 31, 2015, 2014 and 2013, were 39.7%, 39.6% and 37.9%, respectively. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2015	2014	% Change 2015 vs 2014	Weather-Normal % Change	2013	% Change 2014 vs 2013	Weather-Normal % Change
Retail Deliveries (a)							
Residential	26,496	27,230	(2.7)%	(1.5)%	27,800	(2.1)%	0.3%
Small commercial & industrial	31,717	32,146	(1.3)%	(0.9)%	32,305	(0.5)%	(0.3)%
Large commercial & industrial	27,210	27,847	(2.3)%	(2.0)%	27,684	0.6%	0.7%
Public authorities & electric railroads	1,309	1,358	(3.6)%	(2.6)%	1,355	0.2%	(0.7)%
Total retail deliveries	86,732	88,581	(2.1)%	(1.4)%	89,144	(0.6)%	0.2%

Number of Electric Customers	As of December 31, 2015	2014	2013
Residential	3,550,239	3,502,386	3,480,398
Small commercial & industrial	370,932	369,053	367,569
Large commercial & industrial	1,976	1,998	1,984
Public authorities & electric railroads	4,820	4,815	4,853
Total	3,927,967	3,878,252	3,854,804

Electric Revenue	2015	2014	% Change 2015 vs 2014	2013	% Change 2014 vs 2013
Retail Sales (a)					
Residential	$2,360	$2,074	13.8%	$2,073	— %
Small commercial & industrial	1,337	1,335	0.1%	1,250	6.8%
Large commercial & industrial	443	434	2.1%	427	1.6%
Public authorities & electric railroads	42	46	(8.7)%	48	(4.2)%
Total retail	4,182	3,889	7.5%	3,798	2.4%
Other revenue (b)	723	675	7.1%	666	1.4%
Total electric revenue	$4,905	$4,564	7.5%	$4,464	2.2%

(a) Reflects delivery revenue and volume from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other revenue also includes rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of remediation costs associated with MGP sites.

Results of Operations—PECO

	2015	2014	Favorable (unfavorable) 2015 vs. 2014 variance	2013	Favorable (unfavorable) 2014 vs. 2013 variance
Operating revenue	$3,032	$3,094	$ (62)	$3,100	$ (6)
Purchased power and fuel	1,190	1,261	71	1,300	39
Revenue net of purchased power and fuel expense (a)	1,842	1,833	9	1,800	33
Other operating expenses					
Operating and maintenance	794	866	72	748	(118)
Depreciation and amortization	260	236	(24)	228	(8)
Taxes other than income	160	159	(1)	158	(1)
Total other operating expenses	1,214	1,261	47	1,134	(127)
Gain on sale of assets	2	—	2	—	—
Operating income	630	572	58	666	(94)
Other income and (deductions)					
Interest expense, net	(114)	(113)	(1)	(115)	2
Other, net	5	7	(2)	6	1
Total other income and (deductions)	(109)	(106)	(3)	(109)	3
Income before income taxes	521	466	55	557	(91)
Income taxes	143	114	(29)	162	48
Net income	378	352	26	395	(43)
Preferred security dividends and redemption	—	—	—	7	7
Net income attributable to common shareholder	$ 378	$ 352	$ 26	$ 388	$ (36)

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. PECO's net income attributable to common shareholder for the year ended December 31, 2015 was higher than the same period in 2014, primarily due to a decrease in Operating and maintenance expense due to a decrease in storm costs.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. PECO's net income attributable to common shareholder for the year ended December 31, 2014 was lower than the same period in 2013, primarily due to an increase in Operating and maintenance expense due to an increase in storm costs partially offset by an increase in Operating revenue net of purchase power and fuel expense and a decrease in Income tax expense.

Operating Revenue Net of Purchased Power and Fuel Expense

Electric and natural gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments as specified in the PAPUC-approved tariffs that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with PECO's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and natural gas revenue net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer Choice Program activity has no impact on electric and natural gas revenue net of purchase power and fuel expense.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the years ended December 31, 2015, 2014, and 2013 consisted of the following:

	For the Years Ended December 31,		
	2015	2014	2013
Electric	70%	70%	68%
Natural Gas	25%	22%	19%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2015, 2014, and 2013 consisted of the following:

	December 31, 2015		December 31, 2014		December 31, 2013	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	563,400	35%	546,900	34%	531,500	34%
Natural Gas	81,100	16%	78,400	16%	66,400	13%

The changes in PECO's Operating revenue net of purchased power and fuel expense for the years ended December 31, 2015 and December 31, 2014 compared to the same periods in 2014 and 2013, respectively, consisted of the following:

	2015 vs. 2014 Increase (Decrease)			2014 vs. 2013 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ 28	$ (19)	$ 9	$ (15)	$ 13	$ (2)
Volume	4	7	11	2	5	7
Pricing	4	2	6	(1)	(3)	(4)
Regulatory required programs	(6)	—	(6)	33	—	33
Other	(12)	1	(11)	(1)	—	(1)
Total increase (decrease)	$ 18	$ (9)	$ 9	$ 18	$ 15	$ 33

Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric

and natural gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. Operating revenue net of purchased power and fuel expense for the year ended December 31, 2015 was higher primarily due to the impact of favorable 2015 summer and first quarter winter weather conditions, partially offset by the impact of unfavorable fourth quarter 2015 winter weather conditions in PECO’s service territory.

Operating revenue net of purchased power and fuel expense for the year ended December 31, 2014, was lower due to the impact of unfavorable 2014 summer and fourth quarter weather conditions, partially offset by the impact of favorable first quarter 2014 winter weather conditions in PECO’s service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO’s service territory. The changes in heating and cooling degree days in PECO’s service territory for the years ended December 31, 2015 and December 31, 2014 compared to the same periods in 2014 and 2013, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2015	2014	Normal	2015 vs. 2014	2015 vs. Normal
Heating Degree-Days	4,245	4,749	4,613	(10.6)%	(8.0)%
Cooling Degree-Days	1,720	1,311	1,301	31.2%	32.2%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2014	2013	Normal	2014 vs. 2013	2014 vs. Normal
Heating Degree-Days	4,749	4,474	4,603	6.1%	3.2%
Cooling Degree-Days	1,311	1,411	1,301	(7.1)%	0.8%

Volume. The increase in Operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2015, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for gas and residential and small commercial and industrial electric classes. Additionally, the increase represents a shift in the volume profile across classes from large commercial and industrial classes to residential and small commercial and industrial classes for electric.

The increase in Operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2014, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for gas and residential electric and a shift in the volume profile across classes from commercial and industrial classes to residential classes for electric.

Pricing. The increase in electric operating revenue net of purchased power expense as a result of pricing for the year ended December 31, 2015 is primarily attributable to increased monthly customer demand in the commercial and industrial classes. The increase in natural gas operating revenue net of fuel expense as a result of pricing for the year ended December 31, 2015, is primarily attributable to higher overall effective rates due to decreased retail gas usage.

The decrease in natural gas operating revenue net of fuel expense as a result of pricing for the year ended December 31, 2014, is primarily attributable to lower overall effective rates due to increased retail gas usage.

Regulatory Required Programs. This represents the change in operating revenue collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

Other. The decrease in other electric revenue net of purchased power expense for the year ended December 31, 2015 reflects the impact of lower wholesale transmission revenue, which is impacted by the previous year's peak demand, which was lower in 2014 than in 2013.

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2015	2014	2015 vs. 2014	2014	2013	2014 vs. 2013
Operating and maintenance expense—baseline	$ 685	$ 761	$ (76)	$ 761	$ 668	$ 93
Operating and maintenance expense—regulatory required programs [a]	109	105	$ 4	105	80	$ 25
Total operating and maintenance expense	$ 794	$ 866	$ (72)	$ 866	$ 748	$ 118

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenue.

The changes in Operating and maintenance expense for 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Baseline		
Labor, other benefits, contracting and materials	$ 1	$ 12
Storm-related costs	(78) [a]	100[b]
Pension and non-pension postretirement benefits expense	3	(5)
Merger integration costs	2	(7)
Corporate allocation	9	5
Uncollectible accounts expense	(22)	(9)
Other	9	(3)
	(76)	93
Regulatory required programs		
Smart meter	(3)	7
Energy efficiency	8	17
Other	(1)	1
	4	25
Increase (decrease) in operating and maintenance expense	$ (72)	$ 118

(a) Reflects a reduction of $67 million in incremental storm costs, primarily as a result of the February 5, 2014 ice storm.
(b) Reflects an increase of $85 million in incremental storm costs, including the February 5, 2014 ice storm and the significant July 2014 storms.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2015 compared to 2014 and 2014 compared to 2013, consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Depreciation expense	$ 13	$ 8
Regulatory asset amortization	11	—
Increase in depreciation and amortization expense	$ 24	$ 8

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014, and the year ended December 31, 2014, compared to the same period in 2013.

Interest Expense, Net

Interest expense, net remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014, and the year ended December 31, 2014, compared to the same period in 2013.

Other, Net

Other, net remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014, and the year ended December 31, 2014, compared to the same period in 2013.

Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2015, 2014 and 2013 were 27.4%, 24.5% and 29.1%, respectively. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2015	2014	% Change 2015 vs. 2014	Weather-Normal % Change	2013	% Change 2014 vs. 2013	Weather-Normal % Change
Retail Deliveries [a]							
Residential	13,630	13,222	3.1%	0.3%	13,341	(0.9)%	0.5%
Small commercial & industrial	8,118	8,025	1.2%	0.6%	8,101	(0.9)%	— %
Large commercial & industrial	15,365	15,310	0.4%	(0.5)%	15,379	(0.4)%	(0.1)%
Public authorities & electric railroads	881	937	(6.0)%	(6.0)%	930	0.8%	0.8%
Total electric retail deliveries	37,994	37,494	1.3%	(0.1)%	37,751	(0.7)%	0.1%

Number of Electric Customers	As of December 31, 2015	2014	2013
Residential	1,444,338	1,434,011	1,423,068
Small commercial & industrial	149,200	149,149	149,117
Large commercial & industrial	3,091	3,103	3,105
Public authorities & electric railroads	9,805	9,734	9,668
Total	1,606,434	1,595,997	1,584,958

Electric Revenue	2015	2014	% Change 2015 vs. 2014	2013	% Change 2014 vs. 2013
Retail Sales (a)					
Residential	$1,599	$1,555	2.8%	$1,592	(2.3)%
Small commercial & industrial	428	423	1.2%	433	(2.3)%
Large commercial & industrial	221	217	1.8%	224	(3.1)%
Public authorities & electric railroads	31	32	(3.1)%	30	6.7%
Total retail	2,279	2,227	2.3%	2,279	(2.3)%
Other revenue (b)	207	221	(6.3)%	221	— %
Total electric operating revenue	$2,486	$2,448	1.6%	$2,500	(2.1)%

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenue.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2015	2014	% Change 2015 vs. 2014	Weather-Normal % Change	2013	% Change 2014 vs. 2013	Weather-Normal % Change
Retail Deliveries (a)							
Retail sales	59,003	62,734	(5.9)%	3.3%	57,613	8.9%	2.2%
Transportation and other	27,879	27,208	2.5%	1.2%	28,089	(3.1)%	(1.0)%
Total natural gas deliveries	86,882	89,942	(3.4)%	2.6%	85,702	4.9%	1.2%

Number of Gas Customers	As of December 31, 2015	2014	2013
Residential	467,263	462,663	458,356
Commercial & industrial	43,160	42,686	42,174
Total retail	510,423	505,349	500,530
Transportation	827	855	909
Total	511,250	506,204	501,439

Gas revenue	2015	2014	% Change 2015 vs. 2014	2013	% Change 2014 vs. 2013
Retail Sales (a)					
Retail sales	$511	$608	(16.0)%	$562	8.2%
Transportation and other	35	38	(7.9)%	38	— %
Total natural gas operating revenue	$546	$646	(15.5)%	$600	7.7%

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(a) Reflects delivery volumes and revenue from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

Results of Operations—BGE

	2015	2014	Favorable (unfavorable) 2015 vs. 2014 variance	2013	Favorable (unfavorable) 2014 vs. 2013 variance
Operating revenue	$3,135	$3,165	$ (30)	$3,065	$ 100
Purchased power and fuel expense	1,305	1,417	112	1,421	4
Revenue net of purchased power and fuel expense (a)	1,830	1,748	82	1,644	104
Other operating expenses					
Operating and maintenance	683	717	34	634	(83)
Depreciation and amortization	366	371	5	348	(23)
Taxes other than income	224	221	(3)	213	(8)
Total other operating expenses	1,273	1,309	36	1,195	(114)
Gain on sales of assets	1	—	1	—	—
Operating income	558	439	119	449	(10)
Other income and (deductions)					
Interest expense, net	(99)	(106)	7	(122)	16
Other, net	18	18	—	17	1
Total other income and (deductions)	(81)	(88)	7	(105)	17
Income before income taxes	477	351	126	344	7
Income taxes	189	140	(49)	134	(6)
Net income	288	211	77	210	1
Preference stock dividends	13	13	—	13	—
Net income attributable to common shareholder	$ 275	$ 198	$ 77	$ 197	$ 1

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenue net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. Net income attributable to common shareholder was higher primarily due to an increase in Revenue net of purchased power and fuel expense as a result of the December 2014 electric and gas distribution rate order issued by the MDPSC, an increase in transmission formula rate revenues and a reduction in Operating and maintenance expense as a result of a decrease in bad debt expense and storm costs in the BGE service territory.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013. Net income attributable to common shareholder remained relatively consistent primarily due to an increase in

Revenue net of purchased power and fuel expense as a result of the December 2013 and 2014 electric and gas distribution rate orders issued by the MDPSC offset by increases in Operating and maintenance expense and Depreciation expense.

Operating Revenue Net of Purchased Power and Fuel Expense

There are certain drivers to Operating revenue that are offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenue and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

BGE is obligated to provide market-based SOS to all of its electric customers. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes a shareholder return component, which for residential SOS customers is being returned to residential distribution customers through December 31, 2016, and an incremental cost component. Bidding to supply BGE's market-based SOS occurs through a competitive bidding process approved by the MDPSC. Successful bidders, which may include Generation, will execute contracts with BGE for terms of three months or two years. BGE is obligated by the MDPSC to provide several variations of SOS to commercial and industrial customers depending on customer load. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on BGE's Statement of Operations and Comprehensive Income.

The number of customers electing to select a competitive electric generation supplier affects electric SOS revenue and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenue and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric generation supplier and/or natural gas from a competitive natural gas supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) at December 31, 2015, 2014 and 2013 consisted of the following:

	For the Years Ended December 31,		
	2015	2014	2013
Electric	61%	60%	61%
Natural Gas	56%	53%	54%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2015, 2014 and 2013 consisted of the following:

	December 31, 2015		December 31, 2014		December 31, 2013	
	Number of Customers	% of total retail customers	Number of Customers	% of total retail customers	Number of Customers	% of total retail customers
Electric	343,000	27%	364,000	29%	399,000	32%
Natural Gas	154,000	23%	161,000	25%	172,000	26%

The changes in BGE's Operating revenue net of purchased power and fuel expense for the year ended December 31, 2015 compared to the same period in 2014 and for the year ended December 31, 2014 compared to the same period in 2013, respectively, consisted of the following:

	2015 Increase (Decrease)			2014 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	$ 20	$ 35	$ 55	$ 57	$ 28	$ 85
Regulatory required programs	4	2	6	13	(1)	12
Transmission revenue	11	—	11	10	—	10
Other	10	—	10	(13)	10	(3)
Total increase	$ 45	$ 37	$ 82	$ 67	$ 37	$ 104

Revenue Decoupling. The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of changes in consumption levels. This allows BGE to recognize revenue at MDPSC-approved levels per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while this revenue is affected by customer growth, it will not be affected by actual weather or usage conditions. BGE bills or credits impacted customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating and cooling degree days in BGE's service territory for the year ended December 31, 2015 compared to the same period in 2014 and for the year ended December 31, 2014 compared to the same period in 2013, respectively, and normal weather consisted of the following:

	For the Year Ended December 31,			% Change	
Heating and Cooling Degree-Days	2015	2014	Normal	2015 vs. 2014	From Normal
Heating Degree-Days	4,666	5,091	4,663	(8.3)%	0.1%
Cooling Degree-Days	924	732	875	26.2%	5.6%

	For the Year Ended December 31,			% Change	
Heating and Cooling Degree-Days	2014	2013	Normal	2014 vs. 2013	From Normal
Heating Degree-Days	5,091	4,744	4,662	7.3%	9.2%
Cooling Degree-Days	732	869	876	(15.8)%	(16.4)%

Distribution Rate Increase . The increase in distribution revenue for the year ended December 31, 2015 was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in December 2014 in accordance with the MDPSC approved electric and natural gas distribution rate case order.

The increase in distribution revenue for the year ended December 31, 2014 was primarily due to the impact of new electric and natural gas distribution rates charged to customers that became

effective in December 2013 and 2014, in accordance with the MDPSC approved electric and natural gas distribution rate case orders. See Note 3—Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs. This represents the change in revenue collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in BGE's Consolidated Statements of Operations and Comprehensive Income.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. During the years ended December 31, 2015 and 2014, the increase in transmission revenue was primarily due to higher Operating and maintenance expense and increased capital investment. See Operating and Maintenance Expense below and Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other . Other revenue, which can vary from period to period, includes miscellaneous revenue such as service application and late payment fees.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Baseline		
Labor, other benefits, contracting and materials	$ 12	$ 22
Pension and non-pension postretirement benefits expense	(1)	8
Storm-related costs [a]	(21)	21
Uncollectible accounts expense [b]	(49)	17
Merger integration costs	3	5
Other	22	10
(Decrease) increase in operating and maintenance expense	$ (34)	$ 83

(a) Storm-related costs decreased due to lack of major storms for the year ended December 31, 2015 compared to the same period in 2014.
(b) Uncollectible accounts expense decreased primarily due to improved customer behavior and favorable weather for the year ended December 31, 2015 compared to the same period in 2014.

Conduit Lease with City of Baltimore

On September 23, 2015, the Baltimore City Board of Estimates approved an increase in rental fees for access to the Baltimore City conduit system effective November 1, 2015, which is expected to result in an increase to operating and maintenance expense of approximately $24 million in 2016 subject to an annual increase based on the Consumer Price Index. On October 16, 2015, BGE filed a lawsuit against the City in the Circuit Court for Baltimore City to protect its customers from any improper use by the City of the conduit fee revenues and to place constraints on the City's ability to set the conduit fee in the future.

Among the relief sought by BGE was a preliminary injunction preventing the City from enforcing its substantial increase in the conduit fee rate during the course of the litigation. A hearing was held in the Circuit Court for Baltimore County on December 15, 2015. While BGE's motion for preliminary injunction was denied, the Court's decision was premised upon several important concessions or acknowledgments made by the City in its written papers and at the hearing. Most importantly, the City conceded that it can charge BGE only for the actual costs of conduit maintenance and that a true-up process is required to the extent that the City fails to spend the amount collected for conduit maintenance.

As part of its electric and gas distribution rate case filed on November 6, 2015, and as amended on January 5, 2016, BGE is proposing to recover the annual increase in conduit fees, effective November 1, 2015 of approximately $30 million through a surcharge. BGE cannot predict if the MDPSC will approve BGE's request for a conduit fee surcharge.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Depreciation expense [a]	$ 2	$ 25
Regulatory asset amortization [b]	(6)	(1)
Other	(1)	(1)
(Decrease) increase in depreciation and amortization expense	$ (5)	$ 23

(a) Depreciation expense increased due to ongoing capital expenditures during the year ended December 31, 2015 compared to 2014 and 2014 compared 2013. The increase for the year ended December 31, 2015 compared to 2014 was offset by the effect of revised depreciation rates established in accordance with the MDPSC approved December 2014 electric and natural gas distribution rate case order.

(b) Regulatory asset amortization decreased for the year ended December 31, 2015 compared to the same period in 2014 due to a reduction in regulatory asset amortization related to demand response programs and revised recovery periods for certain regulatory assets in accordance with the MDPSC approved December 2014 electric and natural gas distribution rate case order.

Taxes Other Than Income

The change in taxes other than income for 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Property tax	$ 3	$ 2
Franchise tax	1	4
Other	(1)	2
Increase in taxes other than income	$ 3	$ 8

Interest Expense, Net

The decrease in Interest expense, net for 2015 compared to 2014 and 2014 compared to 2013 consisted of the following:

	Increase (Decrease) 2015 vs. 2014	Increase (Decrease) 2014 vs. 2013
Interest expense on debt (including financing trusts)	$ (4)	$ (10)
Interest expense related to capitalization of interest / AFUDC	(2)	(6)
Interest expense related to uncertain tax positions	(1)	—
Decrease in interest expense, net	$ (7)	$ (16)

Effective Income Tax Rate

BGE's effective income tax rates for the years ended December 31, 2015, 2014 and 2013 were 39.6%, 39.9% and 39.0%, respectively. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2015	2014	% Change 2015 vs. 2014	Weather-Normal % Change	2013	% Change 2014 vs. 2013	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	12,598	12,974	(2.9)%	n.m.	13,077	(0.8)%	n.m.
Small commercial & industrial	3,119	3,086	1.1%	n.m.	3,035	1.7%	n.m.
Large commercial & industrial	14,293	14,191	0.7%	n.m.	14,339	(1.0)%	n.m.
Public authorities & electric railroads	294	311	(5.5)%	n.m.	317	(1.9)%	n.m.
Total electric deliveries	30,304	30,562	(0.8)%	n.m.	30,768	(0.7)%	n.m.

	As of December 31,		
Number of Electric Customers	2015	2014	2013
Residential	1,137,934	1,125,369	1,120,431
Small commercial & industrial	113,138	112,972	112,850
Large commercial & industrial	11,906	11,730	11,652
Public authorities & electric railroads	285	290	292
Total	1,263,263	1,250,361	1,245,225

Electric Revenue	2015	2014	% Change 2015 vs. 2014	2013	% Change 2014 vs. 2013
Retail Sales [a]					
Residential	$1,449	$1,404	3.2%	$1,404	— %
Small commercial & industrial	273	271	0.7%	257	5.4%
Large commercial & industrial	469	491	(4.5)%	439	11.8%
Public authorities & electric railroads	32	32	— %	31	3.2%
Total retail	2,223	2,198	1.1%	2,131	3.1%
Other revenue	267	262	1.9%	274	(4.4)%
Total electric operating revenue	$2,490	$2,460	1.2%	$2,405	2.3%

(a) Reflects delivery revenue and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2015	2014	% Change 2015 vs. 2014	Weather-Normal % Change	2013	% Change 2014 vs. 2013	Weather-Normal % Change
Retail Deliveries [a]							
Retail sales	96,618	99,194	(2.6)%	n.m.	94,020	5.5%	n.m.
Transportation and other [b][c]	6,238	9,242	(32.5)%	n.m.	12,210	(24.3)%	n.m.
Total natural gas deliveries	102,856	108,436	(5.1)%	n.m.	106,230	2.1%	n.m.

Number of Gas Customers	As of December 31, 2015	2014	2013
Residential	616,994	609,626	611,532
Commercial & industrial	44,119	44,200	44,162
Total	661,113	653,826	655,694

Gas revenue	2015	2014	% Change 2015 vs. 2014	2013	% Change 2014 vs. 2013
Retail Sales [a]					
Retail sales	$607	$622	(2.4)%	$592	5.1%
Transportation and other [b][c]	38	83	(54.2)%	68	22.1%
Total natural gas operating revenue	$645	$705	(8.5)%	$660	6.8%

(a) Reflects delivery revenue and volumes from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.
(b) Transportation and other gas revenue includes off-system revenue of 6,238 mmcfs ($35 million), 9,242 mmcfs ($72 million), and 12,210 mmcfs ($55 million) for the years ended 2015, 2014 and 2013, respectively.
(c) Other revenue includes operating revenue with affiliates.

Liquidity and Capital Resources

Exelon's and Generation's prior year activity presented below includes the activity of CENG, from the integration date effective April 1, 2014. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1 billion, $0.6 billion and $0.6 billion, respectively. Exelon Corporate, Generation, ComEd, PECO and BGE's syndicated revolving credit facilities expire in 2018 and 2019. In addition, Generation has $0.4 billion in bilateral facilities with banks which have various expirations between March 2016 and January 2019. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time.

See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

PHI Merger Financing

Exelon has raised cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments, through the issuance of $4.2 billion of debt (of which $3.3 billion remains after execution of the exchange offer, see Note 14—Debt and Credit Agreements for further information on the exchange), $1.15 billion of junior subordinated notes in the form of 23 million equity units, the issuance of $1.9 billion of common stock, cash proceeds of $1.8 billion from asset sales primarily at Generation (after-tax proceeds of approximately $1.4 billion) and the remaining balance from cash on hand and/or short-term borrowings available to Exelon. Exelon will have sufficient cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments. See Note 14—Debt and Credit Agreements and Note 19—Shareholder's Equity for further information on the debt and equity issuances. In the event the PHI merger is terminated, the Board of Directors could direct Exelon to use its existing cash on hand to retire debt, to return capital to shareholders or for other general corporate purposes.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating

activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

ComEd's, PECO's and BGE's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd's, PECO's and BGE's distribution services are provided to an established and diverse base of retail customers. ComEd's, PECO's and BGE's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3—Regulatory Matters and 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while others took effect in 2013. On August 8, 2014, this funding relief was extended for five years. On November 2, 2015 the funding relief was extended for an additional three years and premiums pension plans pay to the Pension Benefit Guaranty Corporation were further increased. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to make qualified pension plan contributions of $250 million to its qualified pension plans in 2016, of which Generation, ComEd, PECO and BGE expect to contribute $134 million, $30 million, $28 million and $31 million, respectively. Exelon's and Generation's expected qualified pension plan contributions above include $25 million related to the legacy CENG plans that will be funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG. Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $21 million in 2016, of which Generation, ComEd, PECO and BGE will make payments of $9 million, $2 million, $1 million and $1 million respectively. See Note 17—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants' 2015 and 2014 pension contributions.

To the extent interest rates decline significantly or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase. Additionally, the contributions above could change if Exelon changes its pension funding strategy.

Unlike qualified pension plans, other postretirement benefit plans are not subject to statutory minimum contribution requirements and certain plans are not funded. Exelon's management has historically considered several factors in determining the level of contributions to its funded other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $35 million in 2016, of which Generation, ComEd, PECO, and BGE

expect to contribute $13 million, $3 million, $1 million, and $18 million, respectively. See Note 17— Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants' 2015 and 2014 other postretirement benefit contributions.

See the "Contractual Obligations" section for management's estimated future pension and other postretirement benefits contributions.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, Exelon would be required to either post a bond or pay the tax and interest for the tax years before the court to appeal the decision. If an adverse decision is reached in 2016, the potential tax and after-tax interest, exclusive of penalties, that could become payable may be as much as $860 million, of which approximately $300 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity, and the balance at Exelon. It is expected that Exelon's remaining tax years affected by the litigation will be settled following a final appellate decision which could take several years.
- Exelon, Generation, and ComEd expect to receive tax refunds of approximately $430 million, $190 million, and $260 million, respectively, in 2016. PECO expects to make tax payments of approximately $7 million related to IRS positions settling in 2016.
- State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes or the imposition, extension or permanence of temporary tax levies.
- On December 18, 2015, President Obama signed H.R. 2029, the Protecting Americans from Tax Hikes (PATH) Act. The Act included an extension of 50% bonus depreciation for 2015—2017. It also includes provisions for 40% and 30% bonus depreciation allowance for qualified property placed in service in 2018 and 2019, respectively. As a result of the 50% bonus depreciation extension for 2015, Exelon, Generation, ComEd, PECO, and BGE are estimated to generate incremental cash in 2016 of approximately $690 million, $350 million, $220 million, $70 million, and $50 million, respectively. Furthermore, the extension of 50% bonus depreciation resulted in a decrease to Generation's Domestic Production Activities Deduction, reducing cash tax benefits and increasing income tax expense by approximately $65 million in 2015. Due to the extension of bonus depreciation, ComEd's 2015 revenue requirement decreased by approximately $10 million (after-tax).

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2015, 2014 and 2013:

	2015 [c]	2014	2015 vs. 2014 Variance	2013	2014 vs. 2013 Variance
Net income	$2,250	$ 1,820	$ 430	1,729	$ 91
Add (subtract):					
Non-cash operating activities [a]	5,630	5,884	(254)	4,159	1,725
Pension and non-pension postretirement benefit contributions	(502)	(617)	115	(422)	(195)
Income taxes	97	(143)	240	883	(1,026)
Changes in working capital and other noncurrent assets and liabilities [b]	(264)	(806)	542	(185)	(621)
Option premiums received (paid), net	58	38	20	(36)	74
Collateral received (posted), net	347	(1,719)	2,066	215	(1,934)
Net cash flows provided by operations	$7,616	$ 4,457	$ 3,159	$6,343	$ (1,886)

(a) Represents depreciation, amortization, depletion and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, and other non-cash charges. See note 24 —Supplemental Financial Information for further detail on non-cash operating activity.
(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.
(c) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

Cash flows provided by operations for the year ended December 31, 2015, 2014 and 2013 by Registrant were as follows:

	2015	2014	2013
Exelon [a]	$7,616	$4,457	$6,343
Generation [a]	4,199	1,826	3,887
ComEd	1,896	1,326	1,218
PECO	770	712	747
BGE	782	740	561

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for 2015, 2014 and 2013 were as follows:

Generation

- Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the OTC markets. During 2015, 2014 and 2013, Generation had net collections/(payments) of counterparty cash collateral of $407 million, $(1,748) million and $162 million, respectively, primarily due to market conditions that resulted in changes to

Generation's net mark-to-market position, as well as Exelon's decision to post more cash collateral in 2014 compared to using letters of credit in 2015 to support the PHI merger financing.

- During 2015, 2014 and 2013, Generation had net collections/(payments) of approximately $58 million, $38 million and $(36) million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During 2015, 2014 and 2013, ComEd's payables for Generation energy purchases increased/(decreased) by $(28) million, $5 million and $(16) million, respectively, and payables to other energy suppliers for energy purchases increased by $2 million, $27 million and $35 million, respectively.
- During 2015, ComEd posted $31 million of cash collateral to PJM. During 2014, ComEd posted no cash collateral to PJM. ComEd's collateral posted with PJM has increased year over year primarily due to higher RPM credit requirements and higher PJM billings resulting from increased load being served by ComEd as a result of City of Chicago customers switching back to ComEd.

PECO

- During 2015, 2014 and 2013, PECO's payables to Generation for energy purchases increased/(decreased) by $7 million, $(9) million and $(17) million, respectively, and payables to other energy suppliers for energy purchases increased/(decreased) by $(38) million, $10 million and $39 million, respectively.

BGE

- During 2015, 2014 and 2013, BGE's payables to Generation for energy purchases increased/(decreased) by $(9) million, $13 million and $(4) million, respectively, and payables to other energy suppliers for energy purchases decreased by $(25) million, $(7) million and $(12) million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for the year ended December 31, 2015, 2014, and 2013 by Registrant were as follows:

	2015	2014	2013
Exelon [(a)]	$(7,822)	$(4,599)	$(5,394)
Generation [(a)]	(4,069)	(1,767)	(2,916)
ComEd	(2,362)	(1,655)	(1,387)
PECO	(588)	(649)	(531)
BGE	(675)	(622)	(571)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.

Generation

Generation has entered into several agreements to acquire equity interests in privately held development stage entities which develop energy-related technology. The agreements contain a series of scheduled investment commitments, including in-kind services contributions. There are approximately $327 million of anticipated expenditures remaining through 2018 to fund anticipated planned capital and operating needs of the associated companies, of which up to $172 million will be contributed by a non-controlling interest holder. See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further details of Generation's equity interests.

Capital expenditures by Registrant for the year ended December 31, 2015, 2014, and 2013 and projected amounts for 2016 are as follows:

	Projected 2016 [a]	2015	2014	2013
Exelon [b]	$ 7,600	$7,624	$6,077	$5,395
Generation [b][e]	3,600	3,841	3,012	2,752
ComEd [c]	2,425	2,398	1,689	1,433
PECO	675	601	661	537
BGE	825	719	620	587
Other [d]	75	65	95	86

(a) Total projected capital expenditures do not include adjustments for non-cash activity.
(b) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(c) The capital expenditures and 2016 projections include $610 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology.
(d) Other primarily consists of corporate operations and BSC.
(e) Generation's capital expenditures for the projected full year 2016 includes nuclear fuel of $1.1 billion and growth expenditures of $1.4 billion.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

In 2014, Exelon and its affiliates initiated a comprehensive project to ensure corporate-wide compliance with Version 5 of the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection Standards (CIP V.5) which will become effective on April 1, 2016. Generation, ComEd, PECO and BGE will be incurring incremental capital expenditures through 2016 associated with the CIP V.5 compliance implementation project, which are included in projected capital expenditures above.

Generation

Approximately 32% and 15% of the projected 2016 capital expenditures at Generation are for the acquisition of nuclear fuel and the construction of new natural gas plants, respectively, with the remaining amounts reflecting investment in renewable energy and additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

ComEd, PECO and BGE

Approximately 86%, 98% and 97% of the projected 2016 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and ComEd's, PECO's and BGE's construction commitments under PJM's RTEP. In addition to the capital expenditure for continuing projects, ComEd's total expenditures include smart grid/smart meter technology required under EIMA and for PECO and BGE, total capital expenditures related to their respective smart meter program.

In 2010, NERC provided guidance to transmission owners that recommends ComEd, PECO, and BGE perform assessments of their transmission lines. In compliance with this guidance, ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE have been incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2016 capital expenditures above reflect capital spending for remediation to be completed in 2017.

ComEd, PECO and BGE anticipate that they will fund capital expenditures with a combination of internally generated funds and borrowings and additional capital contributions from parent, including ComEd's capital expenditures associated with EIMA as further discussed in Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the year ended December 31, 2015, 2014, and 2013 by Registrant were as follows:

	2015	2014	2013
Exelon [(a)]	$4,830	$ 411	$(826)
Generation [(a)]	(479)	(537)	(384)
ComEd	467	359	61
PECO	83	(250)	(361)
BGE	(162)	(85)	(48)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 activity includes CENG on a fully consolidated basis.

Debt .

See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements. Debt activity for 2015, 2014 and 2013 by Registrant was as follows:

During the year ended December 31, 2015, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes [a]	1.55%	June 9, 2017	$ 550	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes [a]	2.85%	June 15, 2020	900	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes [a][b]	3.95%	June 15, 2025	1,250	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes [a][b]	4.95%	June 15, 2035	500	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes [a][b]	5.10%	June 15, 2045	1,000	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	111	Procurement of software licenses
Generation	Senior Unsecured Notes [c]	2.95%	January 15, 2020	750	Fund the optional redemption of Exelon's $550 million, 4.550% Senior Notes and for general corporate purposes

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	AVSR DOE Nonrecourse Debt (d)	2.29 - 2.96%	January 5, 2037	39	Antelope Valley solar development
Generation	Energy Efficiency Project Financing (e)	3.71%	July 31, 2017	42	Funding to install energy conservation measures in Coleman, Florida
Generation	Energy Efficiency Project Financing (e)	3.55%	November 15, 2016	19	Funding to install energy conservation measures in Frederick, Maryland
Generation	Tax Exempt Pollution Control Revenue Bonds (f)	2.50 - 2.70%	2019 - 2020	435	General corporate purposes
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	100	Albany Green Energy biomass generation development
Generation	Nuclear Fuel Procurement Contract	3.15%	September 30, 2020	57	Procurement of nuclear fuel
ComEd	First Mortgage Bonds, Series 118	3.70%	March 1, 2045	400	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes
ComEd	First Mortgage Bonds, Series 119	4.35%	November 15, 2045	450	Repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.15%	October 15, 2025	350	General corporate purposes

(a) See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the merger financing.
(b) In connection with the issuance of PHI merger financing, Exelon terminated its floating-to-fixed interest rate swaps that had been designated as cash flow hedges. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for further information.
(c) In connection with the issuance of Senior Unsecured Notes, Exelon terminated floating-to-fixed interest rate swaps that had been designated as cash flow hedges. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for further information on the swap termination.
(d) See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.
(e) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.
(f) The Tax Exempt pollution Control Revenue Bonds have a mandatory put date that ranges from March 1, 2019—September 1, 2020.

During the year ended December 31, 2014, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Junior Subordinated Notes	2.50%	June 1, 2024	$ 1,150	Finance a portion of the pending merger with PHI and for general corporate purposes
Generation	Nuclear Fuel Purchase Contract	3.25 - 3.35%	June 30, 2018	70	Procurement of uranium
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	300	General corporate purposes
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	675	General corporate purposes
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	12	Funding to install energy conservation measures in Washington, DC
Generation	AVSR DOE Nonrecourse Debt	3.06 - 3.14%	January 5, 2037	126	Antelope Valley solar development
ComEd	First Mortgage Bonds, Series 115	2.15%	January 15, 2019	300	Refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds, Series 116	4.70%	January 15, 2044	350	Refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds, Series 117	3.10%	November 1, 2024	250	Repay commercial paper obligations and general corporate purposes
PECO	First and Refunding Mortgage Bonds	4.15%	October 1, 2044	300	Refinance existing mortgage bonds and general corporate purposes

During the year ended December 31, 2013, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	CEU Upstream Nonrecourse Debt	2.21 - 2.44%	July 22, 2016	$ 5	Fund Upstream gas activities
Generation	AVSR DOE Nonrecourse Debt	2.53 - 3.35%	January 5, 2037	227	Antelope Valley solar development
Generation	Social Security Administration Project Financing	2.93%	February 18, 2015	1	Funding to install conservation measures for the Social Security Administration Headquarters facility in Maryland
Generation	Energy Efficiency Project Financing	4.40%	August 31, 2014	9	Funding to install energy conservation measures in Beckley, West Virginia
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	613	General corporate purposes
ComEd	First Mortgage Bonds, Series 114	4.60%	August 15, 2043	350	Repay commercial paper obligations and for general corporate purposes
PECO	First and Refunding Mortgage Bonds	1.20%	October 15, 2016	300	Pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
PECO	First and Refunding Mortgage Bonds	4.80%	October 15, 2043	250	Pay at maturity first and refunding mortgage bonds due October 15, 2013 and other general corporate purposes
BGE	Notes	3.35%	July 1, 2023	300	Partially refinance Notes due July 1, 2013 and for general corporate purposes

During the year ended December 31, 2015, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate [a]	Senior Unsecured Notes	4.55%	June 15, 2015	$ 550
Exelon Corporate	Senior Notes	4.90%	June 15, 2015	800
Exelon Corporate	Senior Unsecured Notes [b]	3.95%	June 15, 2025	443
Exelon Corporate	Senior Unsecured Notes [b]	4.95%	June 15, 2035	167
Exelon Corporate	Senior Unsecured Notes [b]	5.10%	June 15, 2045	259
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	1
Generation [a]	Senior Unsecured Notes	4.55%	June 15, 2015	550
Generation	CEU Upstream Nonrecourse Debt [c]	LIBOR + 2.25%	January 14, 2019	9
Generation	AVSR DOE Nonrecourse Debt [c]	2.29% - 3.56%	January 5, 2037	23
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	3
Generation	Continental Wind Nonrecourse Debt [c]	6.00%	February 28, 2033	20
Generation	ExGen Texas Power Nonrecourse Debt [c]	LIBOR + 4.75%	September 8, 2021	5
Generation	ExGen Renewables I Nonrecourse Debt [c]	LIBOR + 4.25%	February 6, 2021	24
Generation	Constellation Solar Horizons Nonrecourse Debt [c]	2.56%	September 7, 2030	2
Generation	Sacramento PV Energy Nonrecourse Debt [c]	2.58%	December 31, 2030	2
Generation	Energy Efficiency Project	3.55%	November 15, 2016	19
ComEd	First Mortgage Bonds, Series 101	4.70%	April 15, 2015	260
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	75

(a) As part of the 2012 Constellation merger, Exelon and subsidiaries of Generation assumed intercompany loan agreements that mirrored the terms and amounts of external obligations held by Exelon, resulting in intercompany notes payable at Generation and Exelon Corporate.
(b) See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the redemption of the Senior Unsecured Notes.
(c) See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.

On January 5, 2016, Generation paid down $5 million of principal of its 3.56% AVSR DOE Nonrecourse debt.

During the year ended December 31, 2014, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	Senior Unsecured Notes	5.35%	January 15, 2014	$ 500
Generation	Pollution Control Notes	4.10%	July 1, 2014	20
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	20
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	3
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	18
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	2
Generation	AVSR DOE Nonrecourse Debt	2.33% - 3.55%	January 5, 2037	15
Generation	Clean Horizons Solar Nonrecourse Debt	2.56%	September 7, 2030	2
Generation	Sacramento Solar Nonrecourse Debt	2.56%	December 31, 2030	2
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	12
ComEd	First Mortgage Bonds, Series 110	1.63%	January 15, 2014	600
ComEd	Pollution Control Series 1994C	5.85%	January 15, 2014	17
PECO	First and Refunding Mortgage Bonds	5.00%	October 1, 2014	250
BGE	Rate Stabilization Bonds	5.72%	April 1, 2017	35
BGE	Rate Stabilization Bonds	5.72%	October 1, 2014	35

During the year ended December 31, 2013, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	Kennett Square Capital Lease	7.83%	September 1, 2020	3
Generation	Solar Revolver Nonrecourse Debt	Variable Rate	July 7, 2014	113
Generation	Constellation Solar Horizons Nonrecourse Debt	2.56%	September 7, 2030	2
Generation	Sacramento Energy Nonrecourse Debt	2.68%	December 31, 2030	2
Generation [(a)]	Series A Junior Subordinated Debentures	8.63%	June 15, 2063	450
Generation	Energy Efficiency Project Financing	4.40%	August 31, 2014	9
ComEd	First Mortgage Bonds, Series 92	7.63%	April 15, 2013	125
ComEd	First Mortgage Bonds, Series 94	7.50%	July 1, 2013	127
PECO	First and Refunding Mortgage Bonds	5.60%	October 15, 2013	300
BGE	Rate Stabilization Bonds	5.72%	April 1, 2017	67
BGE	Notes	6.13%	July 1, 2013	400

(a) Represents debt obligations assumed by Exelon as part of the Constellation merger on March 12, 2012 that became callable at face value on June 15, 2013. Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets. The debentures were redeemed and the intercompany loan agreements repaid on June 15, 2013.

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective balance sheets.

Dividends.

Cash dividend payments and distributions for the year ended December 31, 2015, 2014 and 2013 by Registrant were as follows:

	2015	2014	2013
Exelon [a]	$1,105	$1,486	1,249
Generation [a]	2,474	1,066	625
ComEd	299	307	220
PECO	279	320	333
BGE [b]	171	13	13

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) Includes dividends paid on BGE's preference stock.

Quarterly dividends declared by the Exelon Board of Directors during the year ended December 31, 2015 and for the first quarter of 2016 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share
First Quarter 2015	January 27, 2015	February 13, 2015	March 10, 2015	$ 0.31
Second Quarter 2015	April 28, 2015	May 15, 2015	June 10, 2015	$ 0.31
Third Quarter 2015	July 28, 2015	August 14, 2015	September 10, 2015	$ 0.31
Fourth Quarter 2015	October 27, 2015	November 13, 2015	December 10, 2015	$ 0.31
First Quarter 2016 [a]	January 26, 2016	February 12, 2016	March 10, 2016	$ 0.31

(a) Exelon's Board of Directors approved a revised dividend policy. The approved policy would raise our dividend 2.5% each year for the next three years, beginning with the June 2016 dividend. The Board will take formal action to declare the next dividend in the second quarter.

Short-Term Borrowings. Short-term borrowings incurred (repaid) during 2015, 2014 and 2013 by Registrant were as follows:

	2015	2014	2013
Generation [a]	$—	$ 17	$ 13
ComEd	(10)	120	184
BGE	90	(15)	135
Other [b]	—	—	—
Exelon [a]	$ 80	$122	$332

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 activity includes CENG on a fully consolidated basis.
(b) Other primarily consists of corporate operations and BSC.

Retirement of Long-Term Debt to Financing Affiliates. There were no retirements of long-term debt to financing affiliates during 2015, 2014 and 2013 by the Registrants.

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2015, 2014 and 2013 by Registrant were as follows:

	2015	2014	2013
Generation	$ 47	$ 53	$ 26
ComEd [(a)]	209	278	176
PECO	16	24	27
BGE	7	—	—

(a) Additional contributions from parent or external debt financing may be required as a result of increased capital investment in infrastructure improvements and modernization pursuant to EIMA, transmission upgrades and expansions and Exelon's agreement to indemnify ComEd for any unfavorable after-tax impacts associated with ComEd's LKE tax matter.

Other. For the year ended December 31, 2015, other financing activities primarily consists of debt issuance costs. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements' for additional information.

Credit Matters

Market Conditions

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $8.4 billion in aggregate total commitments of which $6.9 billion was available as of December 31, 2015, and of which no financial institution has more than 7% of the aggregate commitments for Exelon, Generation, ComEd, PECO and BGE. The Registrants had access to the commercial paper market during 2015 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of December 31, 2015, it would have been required to provide incremental collateral of $2.0 billion to meet collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.3 billion. If ComEd lost its investment grade credit ratings as of December 31, 2015, it would have been required to provide collateral of $31 million pursuant to PJM's credit policy and could have been required to provide incremental collateral of $19 million which is well within its current available credit facility capacity of $998 million. If PECO lost its investment grade credit rating as of December 31, 2015 it would have been required to provide collateral of $2 million pursuant to PJM's credit policy and could have been required to provide collateral of $25 million related to its natural gas procurement contracts, which, in the aggregate, are well within PECO's current available credit facility capacity of $599 million. If BGE lost its investment grade credit rating as of December 31, 2015 it would have been required to

provide collateral of $6 million pursuant to PJM's credit policy and could have been required to provide collateral of $35 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of $600 million.

Exelon Credit Facilities

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure . At December 31, 2015, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE
Long-term debt	47%	37%	43%	43%	34%
Long-term debt to affiliates [(a)]	1%	4%	1%	3%	5%
Common equity	51%	—	54%	54%	53%
Member's equity	—	59%	—	—	—
Preference Stock	—	—	—	—	4%
Commercial paper and notes payable	1%	—	2%	—	4%

(a) Includes approximately $641 million, $205 million, $184 million and $252 million owed to unconsolidated affiliates of Exelon, ComEd, PECO and BGE respectively. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd, PECO and BGE. See Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

Intercompany Money Pool. To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participants during the year ended December 31, 2015, in addition to the net contribution or borrowing as of December 31, 2015, are presented in the following table:

	Maximum Contributed	Maximum Borrowed	December 31, 2015 Contributed (Borrowed)
Generation	$ 3	$ 1,709	$ (1,252)
PECO	—	100	—
BSC	—	413	(226)
Exelon Corporate	2,008	—	1,478

Investments in Nuclear Decommissioning Trust Funds. Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's and CENG's investment policies establish limits on the concentration of holdings in any one company and also in any one

industry. See Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements. The Registrants have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in May 2017. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations. As of December 31, 2015, ComEd had $442 million available in long-term debt refinancing authority and $353 million available in new money long-term debt financing authority from the ICC. In November 2015, the PAPUC approved PECO's application for long-term financing for $2.5 billion, which is effective through December 31, 2018. As of December 31, 2015, PECO had $1.9 billion available in long-term debt financing authority from the PAPUC. As of December 31, 2015, BGE had $1.4 billion available in long-term financing authority from MDPSC.

As of December 31, 2015, ComEd, PECO and BGE had short-term financing authority from FERC, which expires on December 31, 2017, of $2.5 billion, $1.5 billion and $700 million, respectively. Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon's ability to pay dividends on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid. At December 31, 2015, Exelon had retained earnings of $12,068 million, including Generation's undistributed earnings of $2,701 million, ComEd's retained earnings of $978 million consisting of retained earnings appropriated for future dividends of $2,617 million partially offset by $1,639 million of unappropriated retained deficit, PECO's retained earnings of $780 million and BGE's retained earnings $1,320 million. See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Contractual Obligations

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2015 under existing contractual obligations, including payments due by period. See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within				
	Total	2016	2017-2018	2019-2020	Due 2021 and beyond	All Other
Long-term debt [a]	$25,732	$ 1,483	$ 3,226	$ 4,275	$ 16,748	$ —
Interest payments on long-term debt [b]	14,459	1,146	2,122	1,863	9,328	—
Liability and interest for uncertain tax positions [c]	860	860	—	—	—	—
Capital leases	29	4	8	9	8	—
Operating leases [d]	1,174	133	195	144	702	—
Purchase power obligations [e]	1,692	506	717	212	257	—
Fuel purchase agreements [f]	9,382	1,448	2,460	1,919	3,555	—
Electric supply procurement [f]	1,563	993	570	—	—	—
AEC purchase commitments [f]	6	1	2	3	—	—
Curtailment services commitments [f]	99	37	55	7	—	—
Long-term renewable energy and REC commitments [g]	1,443	76	155	165	1,047	—
Other purchase obligations [h]	4,578	2,420	940	421	797	—
Construction commitments [i]	1,272	821	451	—	—	
PJM regional transmission expansion commitments [j]	737	375	293	69	—	—
Spent nuclear fuel obligation [k]	1,021	—	—	—	1,021	—
Pension minimum funding requirement [l]	1,412	250	500	500	162	—
Total contractual obligations	$65,459	$ 10,553	$ 11,694	$ 9,587	$ 33,625	$ —

(a) Includes $648 million due after 2021 to ComEd, PECO and BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2015 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2015. Includes estimated interest payments due to ComEd, PECO and BGE financing trusts.
(c) In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, Exelon would be required to either post a bond or pay the tax and interest for the tax years before the court to appeal the decision. If an adverse decision is reached in 2016, the potential tax and after-tax interest, exclusive of penalties, that could become payable may be as much as $860 million, of which approximately $300 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity, and the balance at Exelon. It is expected that Exelon's remaining tax years affected by the litigation will be settled following a final appellate decision which could take several years.
(d) Excludes Generation's contingent operating lease payments associated with contracted generation agreements. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO's meter reading operating lease.
(e) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2015, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. These obligations do not include ComEd's SFCs as these contracts do not require purchases of fixed or minimum quantities. See Notes 3—Regulatory Matters

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(f) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services.
(g) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(h) Represents the future estimated value at December 31, 2015 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(i) Represents commitments for Generation's ongoing investments in renewables development, new natural gas and biomass generation construction. Amount includes $421 million of remaining commitments related to the construction of new combined-cycle gas turbine units in Texas. Achievement of commercial operations related to this project is expected in 2017.
(j) Under their operating agreements with PJM, ComEd, PECO and BGE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's, PECO's and BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(k) See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding spent nuclear fuel obligations.
(l) These amounts represent Exelon's expected contributions to its qualified pension plans. The projected contributions reflect a funding strategy of contributing the greater of $250 million until the qualified plans are fully funded on an accumulated benefit obligation basis, and the minimum amounts under ERISA to avoid benefit restrictions and at-risk status thereafter. The remaining qualified pension plans' contributions are generally based on the estimated minimum pension contributions required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2021 are not included. See Note 17—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

		Payment due within				
	Total	2016	2017-2018	2019-2020	Due 2021 and beyond	All Other
Long-term debt	$ 8,898	$ 87	$ 849	$2,575	$ 5,387	$ —
Interest payments on long-term debt [a]	5,452	424	792	684	3,552	—
Capital leases	21	4	8	9	—	—
Operating leases [c]	956	86	126	89	655	—
Purchase power obligations [d]	1,692	506	717	212	257	—
Fuel purchase agreements [e]	8,450	1,211	2,167	1,777	3,295	—
Other purchase obligations [f]	2,193	928	392	225	648	—
Construction commitments [g]	1,272	821	451	—	—	
Spent nuclear fuel obligation [b]	1,021	—	—	—	1,021	—
Total contractual obligations	$29,955	$4,067	$5,502	$5,571	$ 14,815	$ —

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2015 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2015.
(b) See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding spent nuclear fuel obligations.
(c) Excludes Generation's contingent operating lease payments associated with contracted generation agreements.
(d) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2015. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature.
(e) Represents commitments to purchase fuel supplies for nuclear and fossil generation.

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(f) Represents the future estimated value at December 31, 2015 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(g) Represents commitments for Generation's ongoing investments in renewables development, new natural gas and biomass generation construction. Amount includes $421 million of remaining commitments related to the construction of new combined-cycle gas turbine units in Texas. Achievement of commercial operations related to this project is expected in 2017.

ComEd

		Payment due within				
	Total	2016	2017-2018	2019-2020	Due 2021 and beyond	All Other
Long-term debt [a]	$ 6,765	$ 665	$1,265	$ 800	$ 4,035	$—
Interest payments on long-term debt [b]	4,597	297	523	420	3,357	—
Liability and interest for uncertain tax positions [c]	300	300	—	—	—	—
Capital leases	8	—	—	—	8	—
Operating leases	37	14	14	8	1	—
Electric supply procurement	739	453	286	—	—	—
Long-term renewable energy and associated REC commitments [d]	1,444	76	156	165	1,047	—
Other purchase obligations [e]	699	565	94	39	1	—
PJM regional transmission expansion commitments [f]	297	204	87	6	—	—
Total contractual obligations	$14,886	$2,574	$2,425	$1,438	$ 8,449	$—

(a) Includes $206 million due after 2021 to a ComEd financing trust.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2015 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2015. Includes estimated interest payments due to the ComEd financing trust.

(c) In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, Exelon would be required to either post a bond or pay the tax and interest for the tax years before the court to appeal the decision. If an adverse decision is reached in 2016, the potential tax and after-tax interest, exclusive of penalties, that could become payable may be as much as $860 million, of which approximately $300 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity, and the balance at Exelon. It is expected that Exelon's remaining tax years affected by the litigation will be settled following a final appellate decision which could take several years.

(d) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(e) Represents the future estimated value at December 31, 2015 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(f) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

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PECO

	Total	Payment due within 2016	2017-2018	2019-2020	Due 2021 and beyond	All Other
Long-term debt [a]	$2,784	$ 300	$ 500	$ —	$ 1,984	$ —
Interest payments on long-term debt [b]	1,771	115	207	176	1,273	—
Operating leases	12	3	5	4	—	—
Fuel purchase agreements [c]	357	125	137	35	60	—
Electric supply procurement [c]	622	516	106	—	—	—
AEC purchase commitments [c]	9	2	4	3	—	—
Other purchase obligations [d]	215	174	18	22	1	—
PJM regional transmission expansion commitments [e]	67	31	32	4	—	—
Total contractual obligations	$5,837	$1,266	$1,009	$244	$ 3,318	$ —

(a) Includes $184 million due after 2021 to PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2014 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs.
(d) Represents the future estimated value at December 31, 2015 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(e) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

BGE

	Total	Payment due within 2016	2017-2018	2019-2020	Due 2021 and beyond	All Other
Long-term debt [a]	$2,128	$ 378	$ 42	$ —	$ 1,708	$ —
Interest payments on long-term debt [b]	1,353	82	159	159	953	—
Operating leases	65	12	19	15	19	—
Fuel purchase agreements [d]	575	112	156	107	200	—
Electric supply procurement [d]	1,427	860	567	—	—	—
Curtailment services commitments [d]	99	37	55	7	—	—
Other purchase obligations [e]	635	408	208	17	2	—
PJM regional transmission expansion commitments [c]	373	140	174	59	—	—
Total contractual obligations	$6,655	$2,029	$1,380	$364	$ 2,882	$ —

(a) Includes $258 million due after 2021 to the BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2015 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.
(d) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services.
(e) Represents the future estimated value at December 31, 2015 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

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See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- operating leases and rate relief commitments, see Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 16—Asset Retirement Obligations and 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.
- variable interest entities, see Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- new accounting pronouncements, see Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2016 through 2018.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Exelon's hedging program involves the hedging of commodity risk for Exelon's expected generation, typically on a ratable basis over a three year period. As of December 31, 2015, the proportion of expected generation hedged is 90%-93%, 60%-63% and 28%-31% for 2016, 2017 and 2018, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation's sales to ComEd, PECO and BGE to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-proprietary trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on December 31, 2015, market conditions and hedged position would be a decrease in pre-tax net income of approximately $50 million, $400 million and $725 million, respectively, for 2016, 2017 and 2018. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 7,310 GWh, 10,571 GWh, and 8,762 GWh for the years ended December 31, 2015, 2014 and 2013 respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Proprietary trading portfolio activity for the year ended December 31, 2015, resulted in pre-tax gains of $1 million due to net mark-to-market losses of $8 million and realized gains of $9 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $0.2 million of exposure during the year. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to

Generation's total Revenue net of purchase power and fuel expense from continuing operations for the year ended December 31, 2015 of $9,114 million.

Fuel Procurement . Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrates supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 50% of Generation's uranium concentrate requirements from 2016 through 2020 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial positions. See ITEM 7.—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding uranium and coal supply agreement matters.

ComEd

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd would be entitled to receive full cost recovery in rates. The change in fair value each period was recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expired on May 31, 2013. All realized impacts have been included in Generation's and ComEd's results of operations.

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014. See Note 3—Regulatory Matters and Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3—Regulatory Matters of the Combined Notes to the Consolidated Financial Statements. PECO has certain full requirements contracts and block contracts, which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance and as a result, are accounted for on an accrual basis of accounting. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities

The following detailed presentation of Exelon's, Generation's and ComEd's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, and ComEd's commodity mark-to-market net asset or liability balance sheet position from January 1, 2014 to December 31, 2015. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings, as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in Accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2015 and December 31, 2014.

	Generation	ComEd	Exelon
Total mark-to-market energy contract net assets (liabilities) at January 1, 2014 [a]	$ 1,047	$ (193)	$ 854
Contracts acquired at merger date [c]	128	—	128
Total change in fair value during 2014 of contracts recorded in result of operations	(608)	—	(608)
Reclassification to realized at settlement of contracts recorded in results of operations	(21)	—	(21)
Reclassification to realized at settlement from accumulated OCI	(195)	—	(195)
Changes in fair value—energy derivatives [b]	—	(14)	(14)
Changes in allocated collateral	1,503		1,503
Changes in net option premium paid/(received)	(38)	—	(38)
Option premium amortization	(122)	—	(122)
Other balance sheet reclassifications [d]	18	—	18
Total mark-to-market energy contract net assets (liabilities) at December 31, 2014 [a]	1,712	(207)	1,505
Total change in fair value during 2015 of contracts recorded in result of operations	412	—	412
Reclassification to realized at settlement of contracts recorded in results of operations	(168)	—	(168)
Reclassification to realized at settlement from accumulated OCI	(2)	—	(2)
Changes in fair value—energy derivatives [b]	—	(40)	(40)
Changes in allocated collateral	(172)	—	(172)
Changes in net option premium paid/(received)	(58)	—	(58)
Option premium amortization	(21)	—	(21)
Other balance sheet reclassifications [d]	50	—	50
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015 [a]	$ 1,753	$ (247)	$ 1,506

(a) Amounts are shown net of cash collateral paid to and received from counterparties.
(b) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2015 and 2014, ComEd recorded a regulatory liability of $247 million and $207 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. Includes $55 million of decreases in fair value and an increase for realized losses due to settlements off $(15) million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2015. Includes $13 million of decreases in fair value and a reduction for realized gains due to settlements of $1 million for the year ended December 31, 2014.
(c) Includes $81 million of fair value from contracts acquired and $47 million of cash collateral as a result of the Integrys acquisition.
(d) Other balance sheet reclassifications include derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities) net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 12—Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						Total Fair Value
	2016	2017	2018	2019	2020	2021 and Beyond	
Normal Operations, Commodity derivative contracts [a][b]:							
Actively quoted prices (Level 1)	$ 37	$ 27	$(19)	$(19)	$ (7)	$ —	$ 19
Prices provided by external sources (Level 2)	540	165	(8)	(8)	(6)	—	683
Prices based on model or other valuation methods (Level 3) [c]	572	255	95	(26)	(23)	(69)	804
Total	$1,149	$447	$ 68	$(53)	$(36)	$ (69)	$1,506

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $1,234 million at December 31, 2015.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						Total Fair Value
	2016	2017	2018	2019	2020	2021 and Beyond	
Normal Operations, Commodity derivative contracts [a][b]:							
Actively quoted prices (Level 1)	$ 37	$ 27	$ (19)	$(19)	$ (7)	$ —	$ 19
Prices provided by external sources (Level 2)	540	165	(8)	(8)	(6)	—	683
Prices based on model or other valuation methods (Level 3)	595	276	116	(5)	(1)	70	1,051
Total	$1,172	$468	$ 89	$(32)	$(14)	$ 70	$1,753

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $1,234 million at December 31, 2015.

ComEd

	Maturities Within						
	2016	2017	2018	2019	2020	2021 and Beyond	Fair Value
Prices based on model or other valuation methods (Level 3) [a]	$(23)	$(21)	$(21)	$(21)	$(22)	$ (139)	$(247)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2015. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of $15 million, $36 million and $31 million, respectively. See Note 26—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Rating as of December 31, 2015	Total Exposure Before Credit Collateral	Credit Collateral [a]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,397	$ 50	$ 1,347	1	$ 432
Non-investment grade	67	25	42	—	—
No external ratings					
Internally rated—investment grade	521	—	521	—	—
Internally rated—non-investment grade	77	7	70	—	—
Total	$ 2,062	$ 82	$ 1,980	1	$ 432

Rating as of December 31, 2015	Maturity of Credit Risk Exposure: Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,036	$343	$ 18	$ 1,397
Non-investment grade	40	19	8	67
No external ratings				
Internally rated—investment grade	452	46	23	521
Internally rated—non-investment grade	71	6	—	77
Total	$ 1,599	$414	$ 49	$ 2,062

Net Credit Exposure by Type of Counterparty	As of December 31, 2015
Financial institutions	$ 187
Investor-owned utilities, marketers, power producers	886
Energy cooperatives and municipalities	872
Other	35
Total	$ 1,980

(a) As of December 31, 2015, credit collateral held from counterparties where Generation had credit exposure included $13 million of cash and $69 million of letters of credit.

ComEd

Credit risk for ComEd is managed by credit and collection policies, which are consistent with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. The Illinois Settlement Legislation prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 1 of the following year. ComEd's ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2015. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. ComEd's counterparty credit risk is mitigated by its ability to

recover realized energy costs through customer rates. As of December 31, 2015, ComEd's credit exposure to energy suppliers was immaterial.

PECO

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2015.

PECO's supplier master agreements that govern the terms of its DSP Program contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2015, PECO had no net credit exposure with suppliers.

PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2015, PECO's credit exposure under its natural gas supply and asset management agreements with investment grade suppliers was immaterial.

BGE

Credit risk for BGE is managed by credit and collection policies, which are consistent with state regulatory requirements. BGE is currently obligated to provide service to all electric customers within its franchised territory. BGE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. BGE will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for uncollectible accounts policy. MDPSC regulations prohibit BGE from terminating service to residential customers due to nonpayment from November 1 through March 31 if the forecasted temperature is 32 degrees or below for the subsequent 72 hour period. BGE is also prohibited by the Public Utilities Article of the Annotated Code of Maryland and MDPSC regulations from terminating service to residential customers due to nonpayment if the forecasted temperature is 95 degrees or above for the subsequent 72 hour period. BGE did not have any customers representing over 10% of its revenues as of December 31, 2015.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day

a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The seller's credit exposure is calculated each business day. As of December 31, 2015, BGE had no net credit exposure with suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2015, BGE had credit exposure of $4 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Collateral (Exelon, Generation, ComEd, PECO and BGE)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, natural gas and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2015, Generation had cash collateral of $1,267 million posted and cash collateral held of $21 million for external counterparties with derivative positions, of which $1,234 million and $9 million in net cash collateral deposits were offset against energy derivatives and interest rate and foreign exchange derivatives related to underlying energy contracts, respectively. As of December 31, 2015, $3 million of cash collateral deposits was not offset against net derivative positions because it was not associated with energy-related derivatives or as of the balance sheet date there were no positions to offset. As of December 31, 2014, Generation had cash collateral posted of $1,497 million and cash collateral held of $77 million for external counterparties with derivative positions, of which $1,406 million and $6 million in net cash collateral deposits were offset against

energy derivatives and interest rate and foreign exchange derivatives related to underlying energy contracts, respectively. As of December 31, 2014, $8 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives or as the balance sheet date there were no positions to offset. See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 31, 2015, ComEd held no collateral from suppliers in association with standard block energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for renewable energy contracts. See Note 3—Regulatory Matters and Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

PECO

As of December 31, 2015, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of December 31, 2015, BGE was not required to post collateral under its natural gas procurement contracts nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon and Generation)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's Consolidated Balance Sheet, as of December 31, 2015, included a $352 million net investment in coal-fired plants in Georgia subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $639 million, less unearned income of $287 million. As of December 31, 2014, Exelon's Consolidated Balance Sheet included a $361 million net investment in coal-fired plants in Georgia subject to long-term leases, which represented the estimated residual value of leased assets at the end of the respective lease terms of $685 million, less unearned income of $324 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessee does not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessee to arrange for a third-party to bid on a service contract for a period following the lease term. Exelon will be subject to residual value risk if the lessee does not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and, if the review indicates a fair value below the carrying value and the decline is determined to be other than temporary, must record an impairment charge in the period the estimate changed. Based on the annual review performed in the second quarters of 2015 and 2014, the estimated residual value of Exelon's direct financing leases for the Georgia generating stations experienced other than temporary declines given increases in estimated long-term operating and maintenance costs in the 2015 annual review and reduced long-term energy and capacity price expectations in the 2014 annual review. As a result, Exelon recorded a $24 million pre-tax impairment charge in 2015 and 2014 for these stations. See Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for further information.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2015, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $738 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $6 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2015. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of December 31, 2015, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $454 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Generation

General

Generation's integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. These segments are discussed in further detail in "ITEM 1. BUSINESS—Exelon Generation Company, LLC" of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation's executive overview is set forth under "ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2015 Compared To Year Ended December 31, 2014 and Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

A discussion of Generation's results of operations for 2015 compared to 2014 and 2014 compared to 2013 is set forth under "Results of Operations—Generation" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.7 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 14 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Generation's capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon's pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE—Critical Accounting Policies and Estimates above for a discussion of Generation's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in "ITEM 1. BUSINESS—ComEd" of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 and Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

A discussion of ComEd's results of operations for 2015 compared to 2014 and for 2014 compared to 2013 is set forth under "Results of Operations—ComEd" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2015, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 14 of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ComEd's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE—Critical Accounting Policies and Estimates above for a discussion of ComEd's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in "ITEM 1. BUSINESS—PECO" of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 and Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

A discussion of PECO's results of operations for 2015 compared to 2014 and for 2014 compared to 2013 is set forth under "Results of Operations—PECO" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2015, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund PECO's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE—Critical Accounting Policies and Estimates above for a discussion of PECO's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BGE

General

BGE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in "ITEM 1. BUSINESS—BGE" of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 and Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

A discussion of BGE's results of operations for 2015 compared to 2014 and for 2014 compared to 2013 is set forth under "Results of Operations—BGE" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

BGE's business is capital intensive and requires considerable capital resources. BGE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2015, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund BGE's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to BGE's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to BGE's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd, PECO and BGE—Critical Accounting Policies and Estimates above for a discussion of BGE's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2015, Exelon's internal control over financial reporting was effective.

The effectiveness of Exelon's internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 10, 2016

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Generation's management conducted an assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation's management concluded that, as of December 31, 2015, Generation's internal control over financial reporting was effective.

The effectiveness of Generation's internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 10, 2016

Management's Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd's management concluded that, as of December 31, 2015, ComEd's internal control over financial reporting was effective.

The effectiveness of ComEd's internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 10, 2016

Management's Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO's management concluded that, as of December 31, 2015, PECO's internal control over financial reporting was effective.

The effectiveness of PECO's internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 10, 2016

Management's Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

BGE's management conducted an assessment of the effectiveness of BGE's internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE's management concluded that, as of December 31, 2015, BGE's internal control over financial reporting was effective.

The effectiveness of BGE's internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 10, 2016

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Corporation (the "Company") and its subsidiaries at December 31, 2015 and 2014 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 10, 2016

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Generation Company, LLC (the "Company") and its subsidiaries at December 31, 2015 and 2014 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 10, 2016

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Commonwealth Edison Company (the "Company") and its subsidiaries at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 10, 2016

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PECO Energy Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of PECO Energy Company (the "Company") and its subsidiaries at December 31, 2015 and 2014 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 10, 2016

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Baltimore Gas and Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company (the "Company") and its subsidiaries at December 31, 2015 and 2014 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 10, 2016

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Exelon Corporation and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2015	2014	2013
Operating revenues			
Competitive businesses revenues	$18,395	$16,637	$14,277
Rate-regulated utility revenues	11,052	10,792	10,611
Total operating revenues	29,447	27,429	24,888
Operating expenses			
Competitive businesses purchased power and fuel	10,007	9,369	6,928
Rate-regulated utility purchased power and fuel	3,077	3,103	2,540
Purchased power and fuel from affiliates	—	531	1,256
Operating and maintenance	8,322	8,568	7,270
Depreciation and amortization	2,450	2,314	2,153
Taxes other than income	1,200	1,154	1,095
Total operating expenses	25,056	25,039	21,242
Equity in (losses) earnings of unconsolidated affiliates	—	(20)	10
Gain on sales of assets	18	437	13
Gain on consolidation and acquisition of businesses	—	289	—
Operating income	4,409	3,096	3,669
Other income and (deductions)			
Interest expense, net	(992)	(1,024)	(1,315)
Interest expense to affiliates, net	(41)	(41)	(41)
Other, net	(46)	455	460
Total other income and (deductions)	(1,079)	(610)	(896)
Income before income taxes	3,330	2,486	2,773
Income taxes	1,073	666	1,044
Equity in losses of unconsolidated affiliates	(7)	—	—
Net income	2,250	1,820	1,729
Net income (loss) attributable to noncontrolling interest and preference stock dividends	(19)	197	10
Net income attributable to common shareholders	$ 2,269	$ 1,623	$ 1,719
Comprehensive income, net of income taxes			
Net income	$ 2,250	$ 1,820	$ 1,729
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	(46)	(30)	—
Actuarial loss reclassified to periodic benefit cost	220	147	208
Pension and non-pension postretirement benefit plan valuation adjustment	(99)	(497)	669
Unrealized gain (loss) on cash flow hedges	9	(148)	(248)
Unrealized gain on marketable securities	—	1	2
Unrealized gain (loss) on equity investments	(3)	8	106
Unrealized loss on foreign currency translation	(21)	(9)	(10)
Reversal of CENG equity method AOCI	—	(116)	—
Other comprehensive income (loss)	60	(644)	727
Comprehensive income	$ 2,310	$ 1,176	$ 2,456
Average shares of common stock outstanding:			
Basic	890	860	856
Diluted	893	864	860
Earnings per average common share:			
Basic	$ 2.55	$ 1.89	$ 2.01
Diluted	$ 2.54	$ 1.88	$ 2.00
Dividends per common share	$ 1.24	$ 1.24	$ 1.46

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2015	2014	2013
Cash flows from operating activities			
Net income	$ 2,250	$ 1,820	$ 1,729
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	3,987	3,868	3,779
Impairment of long-lived assets	36	687	171
Gain on consolidation and acquisition of businesses	—	(296)	—
Gain on sales of assets	(18)	(437)	(13)
Deferred income taxes and amortization of investment tax credits	752	502	119
Net fair value changes related to derivatives	(367)	716	(445)
Net realized and unrealized losses (gains) on nuclear decommissioning trust fund investments	131	(210)	(170)
Other non-cash operating activities	1,109	1,054	718
Changes in assets and liabilities:			
Accounts receivable	240	(318)	(97)
Inventories	4	(380)	(100)
Accounts payable and accrued expenses	(121)	49	(116)
Option premiums received (paid), net	58	38	(36)
Collateral received (posted), net	347	(1,719)	215
Income taxes	97	(143)	883
Pension and non-pension postretirement benefit contributions	(502)	(617)	(422)
Other assets and liabilities	(387)	(157)	128
Net cash flows provided by operating activities	7,616	4,457	6,343
Cash flows from investing activities			
Capital expenditures	(7,624)	(6,077)	(5,395)
Proceeds from termination of direct financing lease investment	—	335	—
Proceeds from nuclear decommissioning trust fund sales	6,895	7,396	4,217
Investment in nuclear decommissioning trust funds	(7,147)	(7,551)	(4,450)
Cash and restricted cash acquired from consolidations and acquisitions	—	140	—
Acquisitions of businesses	(40)	(386)	—
Proceeds from sales of long-lived assets	147	1,719	32
Proceeds from sales of investments	—	7	22
Purchases of investments	—	(3)	(4)
Change in restricted cash	66	(104)	(43)
Distribution from CENG	—	13	115
Other investing activities	(119)	(88)	112
Net cash flows used in investing activities	(7,822)	(4,599)	(5,394)
Cash flows from financing activities			
Payment of accounts receivable agreement	—	—	(210)
Changes in short-term borrowings	80	122	332
Issuance of long-term debt	6,709	3,463	2,055
Retirement of long-term debt	(2,687)	(1,545)	(1,589)
Issuance of common stock	1,868	—	—
Redemption of preferred securities	—	—	(93)
Distributions to noncontrolling interest of consolidated VIE	—	(421)	—
Dividends paid on common stock	(1,105)	(1,065)	(1,249)
Proceeds from employee stock plans	32	35	47
Other financing activities	(67)	(178)	(119)
Net cash flows provided by (used in) financing activities	4,830	411	(826)
Increase in cash and cash equivalents	4,624	269	123
Cash and cash equivalents at beginning of period	1,878	1,609	1,486
Cash and cash equivalents at end of period	$ 6,502	$ 1,878	$ 1,609

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2015	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 6,502	$ 1,878
Restricted cash and cash equivalents	205	271
Accounts receivable, net		
Customer	3,187	3,482
Other	912	1,227
Mark-to-market derivative assets	1,365	1,279
Unamortized energy contract assets	86	254
Inventories, net		
Fossil fuel	462	579
Materials and supplies	1,104	1,024
Regulatory assets	759	847
Assets held for sale	4	147
Other	748	865
Total current assets	15,334	11,853
Property, plant and equipment, net	57,439	52,170
Deferred debits and other assets		
Regulatory assets	6,065	6,076
Nuclear decommissioning trust funds	10,342	10,537
Investments	639	544
Goodwill	2,672	2,672
Mark-to-market derivative assets	758	773
Unamortized energy contract assets	484	549
Pledged assets for Zion Station decommissioning	206	319
Other	1,445	923
Total deferred debits and other assets	22,611	22,393
Total assets [(a)]	$95,384	$86,416

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2015	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 533	$ 460
Long-term debt due within one year	1,500	1,802
Accounts payable	2,883	3,048
Accrued expenses	2,376	1,539
Payables to affiliates	8	8
Regulatory liabilities	369	310
Mark-to-market derivative liabilities	205	234
Unamortized energy contract liabilities	100	238
Renewable energy credit obligation	302	192
Other	842	931
Total current liabilities	9,118	8,762
Long-term debt	23,645	19,212
Long-term debt to financing trusts	641	641
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,776	12,778
Asset retirement obligations	8,585	7,295
Pension obligations	3,385	3,366
Non-pension postretirement benefit obligations	1,618	1,742
Spent nuclear fuel obligation	1,021	1,021
Regulatory liabilities	4,201	4,550
Mark-to-market derivative liabilities	374	403
Unamortized energy contract liabilities	117	211
Payable for Zion Station decommissioning	90	155
Other	1,491	2,147
Total deferred credits and other liabilities	34,658	33,668
Total liabilities (a)	68,062	62,283
Commitments and contingencies		
Contingently redeemable noncontrolling interest	28	—
Shareholders' equity		
Common stock (No par value, 2000 shares authorized, 920 shares and 860 shares outstanding at December 31, 2015 and 2014, respectively)	18,676	16,709
Treasury stock, at cost (35 shares at December 31, 2015 and 2014, respectively)	(2,327)	(2,327)
Retained earnings	12,068	10,910
Accumulated other comprehensive loss, net	(2,624)	(2,684)
Total shareholders' equity	25,793	22,608
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	1,308	1,332
Total equity	27,294	24,133
Total liabilities and shareholders' equity	$95,384	$86,416

(a) Exelon's consolidated assets include $8,268 million and $8,159 million at December 31, 2015 and December 31, 2014, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $3,264 million and $2,728 million at December 31, 2015 and December 31, 2014, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 2–Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Non-controlling Interest	Preferred and Preference Stock	Total Shareholders' Equity
Balance, December 31, 2012	889,525	$ 16,632	$ (2,327)	$ 9,893	$ (2,767)	$ 106	$ 193	$ 21,730
Net income (loss)	—	—	—	1,719	—	(10)	20	1,729
Long-term incentive plan activity	1,445	81	—	—	—	—	—	81
Employee stock purchase plan issuances	1,064	28	—	—	—	—	—	28
Common stock dividends	—	—	—	(1,254)	—	—	—	(1,254)
Consolidated VIE dividend to noncontrolling interest	—	—	—	—	—	(63)	—	(63)
Deconsolidation of VIE	—	—	—	—	—	(18)	—	(18)
Redemption of preferred securities	—	—	—	—	—	—	(6)	(6)
Preferred and preference stock dividends	—	—	—	—	—	—	(14)	(14)
Other comprehensive income, net of income taxes	—	—	—	—	727	—	—	727
Balance, December 31, 2013	892,034	$ 16,741	$ (2,327)	$ 10,358	$ (2,040)	$ 15	$ 193	$ 22,940
Net income	—	—	—	1,623	—	184	13	1,820
Long-term incentive plan activity	1,574	72	—	—	—	—	—	72
Employee stock purchase plan issuances	960	35	—	—	—	—	—	35
Tax benefit on stock compensation	—	(8)	—	—	—	—	—	(8)
Acquisition of noncontrolling interest	—	(2)	—	—	—	6	—	4
Common stock dividends	—	—	—	(1,071)	—	—	—	(1,071)
Preferred and preference stock dividends	—	—	—	—	—	—	(13)	(13)
Fair value of financing contract payments	—	(131)	—	—	—	—	—	(131)
Noncontrolling interest established upon consolidation of CENG	—	—	—	—	—	1,548	—	1,548
Transfer of CENG pension and non-pension postretirement benefit obligations	—	2	—	—	—	—	—	2
Consolidated VIE dividend to noncontrolling interest	—	—	—	—	—	(421)	—	(421)
Reversal of CENG equity method AOCI, net of income taxes	—	—	—	—	(116)	—	—	(116)
Other comprehensive loss, net of income taxes	—	—	—	—	(528)	—	—	(528)
Balance, December 31, 2014	894,568	$ 16,709	$ (2,327)	$ 10,910	$ (2,684)	$ 1,332	$ 193	$ 24,133
Net income (loss)	—	—	—	2,269	—	(32)	13	2,250
Long-term incentive plan activity	1,430	70	—	—	—	—	—	70
Employee stock purchase plan issuances	1,170	32	—	—	—	—	—	32
Issuance of common stock	57,500	1,868	—	—	—	—	—	1,868
Tax benefit on stock compensation	—	(3)	—	—	—	—	—	(3)
Acquisition of noncontrolling interest	—	—	—	—	—	4	—	4
Adjustment of contingently redeemable noncontrolling interest due to release of contingency	—	—	—	—	—	4	—	4
Common stock dividends	—	—	—	(1,111)	—	—	—	(1,111)
Preferred and preference stock dividends	—	—	—	—	—	—	(13)	(13)
Other comprehensive loss, net of income taxes	—	—	—	—	60	—	—	60
Balance, December 31, 2015	954,668	$ 18,676	$ (2,327)	$ 12,068	$ (2,624)	$ 1,308	$ 193	$ 27,294

See the Combined Notes to Consolidated Financial Statements

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Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2015	2014	2013
Operating revenues			
Operating revenues	$18,386	$16,614	$14,207
Operating revenues from affiliates	749	779	1,423
Total operating revenues	19,135	17,393	15,630
Operating expenses			
Purchased power and fuel	10,007	9,368	6,927
Purchased power and fuel from affiliates	14	557	1,270
Operating and maintenance	4,688	4,943	3,960
Operating and maintenance from affiliates	620	623	574
Depreciation and amortization	1,054	967	856
Taxes other than income	489	465	389
Total operating expenses	16,872	16,923	13,976
Equity in (losses) earnings of unconsolidated affiliates	—	(20)	10
Gain on sales of assets	12	437	13
Gain on consolidation and acquisition of businesses	—	289	—
Operating income	2,275	1,176	1,677
Other income and (deductions)			
Interest expense	(322)	(303)	(298)
Interest expense to affiliates, net	(43)	(53)	(59)
Other, net	(60)	406	355
Total other income and (deductions)	(425)	50	(2)
Income before income taxes	1,850	1,226	1,675
Income taxes	502	207	615
Equity in losses of unconsolidated affiliates	(8)	—	—
Net income	1,340	1,019	1,060
Net income (loss) attributable to noncontrolling interests	(32)	184	(10)
Net income attributable to membership interest	$ 1,372	$ 835	$ 1,070
Comprehensive income, net of income taxes			
Net income	$ 1,340	$ 1,019	$ 1,060
Other comprehensive income (loss), net of income taxes			
Unrealized loss on cash flow hedges	(3)	(132)	(398)
Unrealized (loss) gain on equity investments	(3)	8	107
Unrealized loss on foreign currency translation	(21)	(9)	(10)
Unrealized (loss) gain on marketable securities	—	(1)	2
Reversal of CENG equity method AOCI	—	(116)	—
Other comprehensive loss	(27)	(250)	(299)
Comprehensive income	$ 1,313	$ 769	$ 761

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2015	2014	2013
Cash flows from operating activities			
Net income	$ 1,340	$ 1,019	$ 1,060
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,589	2,519	2,559
Impairment of long-lived assets	12	663	157
Gain on consolidation and acquisition of businesses	—	(296)	—
Gain on sales of assets	(12)	(437)	(13)
Deferred income taxes and amortization of investment tax credits	49	(198)	315
Net fair value changes related to derivatives	(249)	635	(448)
Net realized and unrealized losses (gains) on nuclear decommissioning trust fund investments	131	(210)	(170)
Other non-cash operating activities	268	346	270
Changes in assets and liabilities:			
Accounts receivable	194	(215)	109
Receivables from and payables to affiliates, net	15	15	2
Inventories	16	(359)	(88)
Accounts payable and accrued expenses	(149)	29	(160)
Option premiums received (paid), net	58	38	(36)
Collateral received (posted), net	407	(1,748)	162
Income taxes	(18)	265	402
Pension and non-pension postretirement benefit contributions	(245)	(297)	(149)
Other assets and liabilities	(207)	57	(85)
Net cash flows provided by operating activities	4,199	1,826	3,887
Cash flows from investing activities			
Capital expenditures	(3,841)	(3,012)	(2,752)
Proceeds from nuclear decommissioning trust fund sales	6,895	7,396	4,217
Investment in nuclear decommissioning trust funds	(7,147)	(7,551)	(4,450)
Cash and restricted cash acquired from consolidations and acquisitions	—	140	—
Proceeds from sales of long-lived assets	147	1,719	32
Acquisitions of businesses	(40)	(386)	—
Change in restricted cash	35	(87)	(64)
Changes in Exelon intercompany money pool	—	44	(44)
Distribution from CENG	—	13	115
Other investing activities	(118)	(43)	30
Net cash flows used in investing activities	(4,069)	(1,767)	(2,916)
Cash flows from financing activities			
Change in short-term borrowings	—	17	13
Issuance of long-term debt	1,309	1,112	854
Retirement of long-term debt	(89)	(586)	(570)
Retirement of long-term debt to affiliate	(550)	—	—
Changes in Exelon intercompany money pool	1,252	—	—
Distribution to member	(2,474)	(645)	(625)
Distribution to noncontrolling interest of consolidated VIE	—	(421)	—
Contribution from member	47	53	26
Other financing activities	26	(67)	(82)
Net cash flows used in financing activities	(479)	(537)	(384)
Increase (decrease) in cash and cash equivalents	(349)	(478)	587
Cash and cash equivalents at beginning of period	780	1,258	671
Cash and cash equivalents at end of period	$ 431	$ 780	$ 1,258

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2015	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 431	$ 780
Restricted cash and cash equivalents	123	158
Accounts receivable, net		
Customer	2,095	2,295
Other	360	318
Mark-to-market derivative assets	1,365	1,276
Receivables from affiliates	83	113
Unamortized energy contract assets	86	254
Inventories, net		
Fossil fuel	384	465
Materials and supplies	880	847
Assets held for sale	4	147
Other	531	658
Total current assets	6,342	7,311
Property, plant and equipment, net	25,843	23,028
Deferred debits and other assets		
Nuclear decommissioning trust funds	10,342	10,537
Investments	210	104
Goodwill	47	47
Mark-to-market derivative assets	733	771
Prepaid pension asset	1,689	1,704
Pledged assets for Zion Station decommissioning	206	319
Unamortized energy contract assets	484	549
Deferred income taxes	6	3
Other	627	578
Total deferred debits and other assets	14,344	14,612
Total assets [(a)]	$46,529	$44,951

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 29	$ 36
Long-term debt due within one year	90	58
Long-term debt to affiliates due within one year	—	556
Accounts payable	1,583	1,759
Accrued expenses	935	886
Payables to affiliates	104	107
Borrowings from Exelon intercompany money pool	1,252	—
Mark-to-market derivative liabilities	182	214
Unamortized energy contract liabilities	100	238
Renewable energy credit obligation	302	192
Other	356	413
Total current liabilities	4,933	4,459
Long-term debt	7,936	6,639
Long-term debt to affiliate	933	943
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,845	5,707
Asset retirement obligations	8,431	7,146
Non-pension postretirement benefit obligations	924	915
Spent nuclear fuel obligation	1,021	1,021
Payables to affiliates	2,577	2,880
Mark-to-market derivative liabilities	150	105
Unamortized energy contract liabilities	117	211
Payable for Zion Station decommissioning	90	155
Other	602	719
Total deferred credits and other liabilities	19,757	18,859
Total liabilities (a)	33,559	30,900
Commitments and contingencies		
Contingently redeemable noncontrolling interests	28	—
Equity		
Member's equity		
Membership interest	8,997	8,951
Undistributed earnings	2,701	3,803
Accumulated other comprehensive income (loss), net	(63)	(36)
Total member's equity	11,635	12,718
Noncontrolling interest	1,307	1,333
Total equity	12,942	14,051
Total liabilities and equity	$46,529	$44,951

(a) Generation's consolidated assets include $8,235 million and $8,118 million at December 31, 2015 and 2014, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $3,135 million and $2,512 million at December 31, 2015 and 2014, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 2–Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Changes in Member's Equity

(In millions)	Member's Equity			Noncontrolling Interest	Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income (Loss)		
Balance, December 31, 2012	$ 8,876	$ 3,168	$ 513	$ 108	$ 12,665
Net income (loss)	—	1,070	—	(10)	1,060
Distribution to member	—	(625)	—	—	(625)
Allocation of tax benefit from member	26	—	—	—	26
Consolidated VIE dividend to noncontrolling interest	—	—	—	(63)	(63)
Deconsolidation of VIE	(1)	—	—	(18)	(19)
Noncontrolling interest acquired	(3)	—	—	—	(3)
Other comprehensive loss, net of income taxes	—	—	(299)	—	(299)
Balance, December 31, 2013	$ 8,898	$ 3,613	$ 214	$ 17	$ 12,742
Net income	—	835	—	184	1,019
Acquisition of noncontrolling interest	—	—	—	5	5
Allocation of tax benefit from member	53	—	—	—	53
Distribution to member	—	(645)	—	—	(645)
Noncontrolling interest established upon consolidation of CENG	—	—	—	1,548	1,548
Consolidated VIE dividend to noncontrolling interest	—	—	—	(421)	(421)
Reversal of CENG equity method AOCI, net of income taxes	—	—	(116)	—	(116)
Other comprehensive loss, net of income taxes	—	—	(134)	—	(134)
Balance, December 31, 2014	$ 8,951	$ 3,803	$ (36)	$ 1,333	$ 14,051
Net income (loss)	—	1,372	—	(32)	1,340
Acquisition of non-controlling interest	(1)	—	—	2	1
Adjustment of contingently redeemable noncontrolling interest due to release of contingency	—	—	—	4	4
Allocation of tax benefit from member	47	—	—	—	47
Distribution to member	—	(2,474)	—	—	(2,474)
Other comprehensive loss, net of income taxes	—	—	(27)	—	(27)
Balance, December 31, 2015	$ 8,997	$ 2,701	$ (63)	$ 1,307	$ 12,942

See the Combined Notes to Consolidated Financial Statements

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Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(in millions)	For the Years Ended December 31, 2015	2014	2013
Operating revenues			
Electric operating revenues	$4,901	$4,560	$4,461
Operating revenues from affiliates	4	4	3
Total operating revenues	4,905	4,564	4,464
Operating expenses			
Purchased power	1,301	1,001	662
Purchased power from affiliate	18	176	512
Operating and maintenance	1,372	1,263	1,211
Operating and maintenance from affiliate	195	166	157
Depreciation and amortization	707	687	669
Taxes other than income	296	293	299
Total operating expenses	3,889	3,586	3,510
Gain on sales of assets	1	2	—
Operating income	1,017	980	954
Other income and (deductions)			
Interest expense	(319)	(308)	(566)
Interest expense to affiliates, net	(13)	(13)	(13)
Other, net	21	17	26
Total other income and (deductions)	(311)	(304)	(553)
Income before income taxes	706	676	401
Income taxes	280	268	152
Net income	$ 426	$ 408	$ 249
Comprehensive income	$ 426	$ 408	$ 249

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended 2015	2014	2013
Cash flows from operating activities			
Net income	$ 426	$ 408	$ 249
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	707	687	669
Deferred income taxes and amortization of investment tax credits	353	433	(57)
Other non-cash operating activities	416	255	28
Changes in assets and liabilities:			
Accounts receivable	(93)	(121)	(12)
Receivables from and payables to affiliates, net	(19)	(11)	(12)
Inventories	(40)	(16)	(18)
Accounts payable and accrued expenses	68	95	91
Counterparty collateral received (posted), net and cash deposits	(33)	2	53
Income taxes	192	(159)	178
Pension and non-pension postretirement benefit contributions	(150)	(248)	(122)
Other assets and liabilities	69	1	171
Net cash flows provided by operating activities	1,896	1,326	1,218
Cash flows from investing activities			
Capital expenditures	(2,398)	(1,689)	(1,433)
Proceeds from sales of investments	—	7	7
Purchases of investments	—	(3)	(4)
Change in restricted cash	2	(2)	(2)
Other investing activities	34	32	45
Net cash flows used in investing activities	(2,362)	(1,655)	(1,387)
Cash flows from financing activities			
Changes in short-term borrowings	(10)	120	184
Issuance of long-term debt	850	900	350
Retirement of long-term debt	(260)	(617)	(252)
Contributions from parent	202	273	—
Dividends paid on common stock	(299)	(307)	(220)
Other financing activities	(16)	(10)	(1)
Net cash flows provided by financing activities	467	359	61
Increase (decrease) in cash and cash equivalents	1	30	(108)
Cash and cash equivalents at beginning of period	66	36	144
Cash and cash equivalents at end of period	$ 67	$ 66	$ 36

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheet

(In millions)	December 31, 2015	2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 67	$ 66
Restricted cash	2	4
Accounts receivable, net		
Customer	533	477
Other	272	648
Receivables from affiliates	199	14
Inventories, net	164	125
Regulatory assets	218	349
Other	63	40
Total current assets	1,518	1,723
Property, plant and equipment, net	17,502	15,793
Deferred debits and other assets		
Regulatory assets	895	852
Investments	6	6
Goodwill	2,625	2,625
Receivable from affiliates	2,172	2,571
Prepaid pension asset	1,490	1,551
Other	324	237
Total deferred debits and other assets	7,512	7,842
Total assets	$26,532	$25,358

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 294	$ 304
Long-term debt due within one year	665	260
Accounts payable	660	598
Accrued expenses	706	331
Payables to affiliates	62	84
Customer deposits	131	128
Regulatory liabilities	155	125
Mark-to-market derivative liability	23	20
Other	70	73
Total current liabilities	2,766	1,923
Long-term debt	5,844	5,665
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,914	4,561
Asset retirement obligations	111	103
Non-pension postretirement benefits obligations	259	263
Regulatory liabilities	3,459	3,655
Mark-to-market derivative liability	224	187
Other	507	889
Total deferred credits and other liabilities	9,474	9,658
Total liabilities	18,289	17,451
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,677	5,468
Retained earnings	978	851
Total shareholders' equity	8,243	7,907
Total liabilities and shareholders' equity	$26,532	$25,358

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2012	$ 1,588	$5,014	$ (1,639)	$ 2,360	$ 7,323
Net income	—	—	249	—	249
Common stock dividends	—	—	—	(220)	(220)
Parent tax matter indemnification	—	176	—	—	176
Appropriation of retained earnings for future dividends	—	—	(249)	249	—
Balance, Balance at December 31, 2013	$ 1,588	$5,190	$ (1,639)	$ 2,389	$ 7,528
Net income	—	—	408	—	$ 408
Common stock dividends	—	—	—	(307)	(307)
Contribution from parent	—	273	—	—	273
Parent tax matter indemnification	—	5	—	—	5
Appropriation of retained earnings for future dividends	—	—	(408)	408	—
Balance, December 31, 2014	$ 1,588	$5,468	$ (1,639)	$ 2,490	$ 7,907
Net income	—	—	426	—	426
Common stock dividends	—	—	—	(299)	(299)
Contribution from parent	—	202	—	—	202
Parent tax matter indemnification	—	7	—	—	7
Appropriation of retained earnings for future dividends	—	—	(426)	426	—
Balance, December 31, 2015	$ 1,588	$5,677	$ (1,639)	$ 2,617	$ 8,243

See the Combined Notes to Consolidated Financial Statements

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PECO Energy Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2015	2014	2013
Operating revenues			
Electric operating revenues	$2,485	$2,446	$2,499
Natural gas operating revenues	545	646	600
Operating revenues from affiliates	2	2	1
Total operating revenues	3,032	3,094	3,100
Operating expenses			
Purchased power	735	740	612
Purchased fuel	235	327	296
Purchased power from affiliate	220	194	392
Operating and maintenance	684	767	647
Operating and maintenance from affiliates	110	99	101
Depreciation and amortization	260	236	228
Taxes other than income	160	159	158
Total operating expenses	2,404	2,522	2,434
Gain on sales of assets	2	—	—
Operating income	630	572	666
Other income and (deductions)			
Interest expense	(102)	(101)	(103)
Interest expense to affiliates, net	(12)	(12)	(12)
Other, net	5	7	6
Total other income and (deductions)	(109)	(106)	(109)
Income before income taxes	521	466	557
Income taxes	143	114	162
Net income	378	352	395
Preferred security dividends and redemption	—	—	7
Net income attributable to common shareholder	$ 378	$ 352	$ 388
Comprehensive income	$ 378	$ 352	$ 395

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2015	2014	2013
Cash flows from operating activities			
Net income	$ 378	$ 352	$ 395
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	260	236	228
Deferred income taxes and amortization of investment tax credits	90	88	20
Other non-cash operating activities	70	92	108
Changes in assets and liabilities:			
Accounts receivable	37	(16)	(79)
Receivables from and payables to affiliates, net	3	(6)	(18)
Inventories	10	2	2
Accounts payable and accrued expenses	(25)	58	31
Income taxes	(9)	(57)	87
Pension and non-pension postretirement benefit contributions	(40)	(16)	(31)
Other assets and liabilities	(4)	(21)	4
Net cash flows provided by operating activities	770	712	747
Cash flows from investing activities			
Capital expenditures	(601)	(661)	(537)
Change in restricted cash	(1)	—	(2)
Other investing activities	14	12	8
Net cash flows used in investing activities	(588)	(649)	(531)
Cash flows from financing activities			
Payment of accounts receivable agreement	—	—	(210)
Issuance of long-term debt	350	300	550
Retirement of long-term debt	—	(250)	(300)
Contributions from parent	16	24	27
Dividends paid on common stock	(279)	(320)	(332)
Dividends paid on preferred securities	—	—	(1)
Redemption of preferred securities	—	—	(93)
Other financing activities	(4)	(4)	(2)
Net cash flows provided by (used in) financing activities	83	(250)	(361)
Increase (decrease) in cash and cash equivalents	265	(187)	(145)
Cash and cash equivalents at beginning of period	30	217	362
Cash and cash equivalents at end of period	$ 295	$ 30	$ 217

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2015	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 295	$ 30
Restricted cash and cash equivalents	3	2
Accounts receivable, net		
Customer	258	320
Other	146	141
Receivables from affiliates	2	3
Inventories, net		
Fossil fuel	43	57
Materials and supplies	26	22
Prepaid utility taxes	11	10
Regulatory assets	34	29
Other	24	31
Total current assets	842	645
Property, plant and equipment, net	7,141	6,801
Deferred debits and other assets		
Regulatory assets	1,583	1,529
Investments	28	31
Receivable from affiliates	405	490
Prepaid pension asset	347	344
Other	21	20
Total deferred debits and other assets	2,384	2,414
Total assets	$10,367	$9,860

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 300	$ —
Accounts payable	281	337
Accrued expenses	109	91
Payables to affiliates	55	52
Customer deposits	58	52
Regulatory liabilities	112	90
Other	29	31
Total current liabilities	944	653
Long-term debt	2,280	2,232
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,792	2,602
Asset retirement obligations	27	29
Non-pension postretirement benefits obligations	287	287
Regulatory liabilities	527	657
Other	90	95
Total deferred credits and other liabilities	3,723	3,670
Total liabilities	7,131	6,739
Commitments and contingencies		
Shareholder's equity		
Common stock	2,455	2,439
Retained earnings	780	681
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,236	3,121
Total liabilities and shareholder's equity	$10,367	$9,860

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholder's Equity
Balance, December 31, 2012	$ 2,388	$ 593	$ 1	$ 2,982
Net income	—	395	—	395
Common stock dividends	—	(332)	—	(332)
Preferred security dividends	—	(1)	—	(1)
Redemption of preferred dividends	—	(6)	—	(6)
Allocation of tax benefit from parent	27	—	—	27
Balance, December 31, 2013	$ 2,415	$ 649	$ 1	$ 3,065
Net income	—	352	—	352
Common stock dividends	—	(320)	—	(320)
Allocation of tax benefit from parent	24	—	—	24
Balance, December 31, 2014	$ 2,439	$ 681	$ 1	$ 3,121
Net income	—	378	—	378
Common stock dividends	—	(279)	—	(279)
Allocation of tax benefit from parent	16	—	—	16
Balance, December 31, 2015	$ 2,455	$ 780	$ 1	$ 3,236

See the Combined Notes to Consolidated Financial Statements

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Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2015	2014	2013
Operating revenues			
Electric operating revenues	$2,490	$2,460	$2,405
Natural gas operating revenues	631	680	647
Operating revenues from affiliates	14	25	13
Total operating revenues	3,135	3,165	3,065
Operating expenses			
Purchased power	602	733	676
Purchased fuel	205	302	293
Purchased power from affiliate	498	382	452
Operating and maintenance	565	614	551
Operating and maintenance from affiliates	118	103	83
Depreciation and amortization	366	371	348
Taxes other than income	224	221	213
Total operating expenses	2,578	2,726	2,616
Gain on sales of assets	1	—	—
Operating income	558	439	449
Other income and (deductions)			
Interest expense	(83)	(90)	(106)
Interest expense to affiliates, net	(16)	(16)	(16)
Other, net	18	18	17
Total other income and (deductions)	(81)	(88)	(105)
Income before income taxes	477	351	344
Income taxes	189	140	134
Net income	288	211	210
Preference stock dividends	13	13	13
Net income attributable to common shareholder	$ 275	$ 198	$ 197
Comprehensive income	$ 288	$ 211	$ 210

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2015	2014	2013
Cash flows from operating activities			
Net income	$ 288	$ 211	$ 210
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	366	371	348
Deferred income taxes and amortization of investment tax credits	165	116	125
Other non-cash operating activities	137	180	153
Changes in assets and liabilities:			
Accounts receivable	84	46	(127)
Receivables from and payables to affiliates, net	(2)	(1)	(14)
Inventories	18	(6)	1
Accounts payable, accrued expenses	(3)	(75)	(6)
Collateral received (posted), net	(27)	27	—
Income taxes	(54)	45	(33)
Pension and non-pension postretirement benefit contributions	(17)	(16)	(24)
Other assets and liabilities	(173)	(158)	(72)
Net cash flows provided by operating activities	782	740	561
Cash flows from investing activities			
Capital expenditures	(719)	(620)	(587)
Change in restricted cash	26	(22)	2
Other investing activities	18	20	14
Net cash flows used in investing activities	(675)	(622)	(571)
Cash flows from financing activities			
Changes in short-term borrowings	90	(15)	135
Issuance of long-term debt	—	—	300
Retirement of long-term debt	(75)	(70)	(467)
Dividends paid on common stock	(158)	—	—
Dividends paid on preference stock	(13)	(13)	(13)
Allocations of tax benefit from parent	7	—	—
Other financing activities	(13)	13	(3)
Net cash flows used in financing activities	(162)	(85)	(48)
Increase (decrease) in cash and cash equivalents	(55)	33	(58)
Cash and cash equivalents at beginning of period	64	31	89
Cash and cash equivalents at end of period	$ 9	$ 64	$ 31

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 9	$ 64
Restricted cash and cash equivalents	24	50
Accounts receivable, net		
Customer	300	390
Other	112	82
Inventories, net		
Gas held in storage	36	57
Materials and supplies	33	30
Prepaid utility taxes	61	59
Regulatory assets	267	214
Other	3	5
Total current assets	845	951
Property, plant and equipment, net	6,597	6,204
Deferred debits and other assets		
Regulatory assets	514	510
Investments	12	12
Prepaid pension asset	319	370
Other	8	9
Total deferred debits and other assets	853	901
Total assets [(a)]	$8,295	$8,056

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2015	2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 210	$ 120
Long-term debt due within one year	378	75
Accounts payable	209	215
Accrued expenses	110	131
Payables to affiliates	52	66
Customer deposits	102	92
Regulatory liabilities	38	44
Other	35	51
Total current liabilities	1,134	794
Long-term debt	1,480	1,857
Long-term debt to financing trust	252	252
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,081	1,911
Asset retirement obligations	17	17
Non-pension postretirement benefits obligations	209	212
Regulatory liabilities	184	200
Other	61	60
Total deferred credits and other liabilities	2,552	2,400
Total liabilities [(a)]	5,418	5,303
Commitments and contingencies		
Shareholders' equity		
Common stock	1,367	1,360
Retained earnings	1,320	1,203
Total shareholders' equity	2,687	2,563
Preference stock not subject to mandatory redemption	190	190
Total equity	2,877	2,753
Total liabilities and shareholders' equity	$8,295	$8,056

(a) BGE's consolidated assets include $26 million and $24 million at December 31, 2015 and December 31, 2014, respectively, of BGE's consolidated VIE that can only be used to settle the liabilities of the VIE. BGE's consolidated liabilities include $122 million and $197 million at December 31, 2015 and December 31, 2014, respectively, of BGE's consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note 2—Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statement of Changes in Shareholders' Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$2,358
Net income	—	210	210	—	210
Preference stock dividends	—	(13)	(13)	—	(13)
Balance, December 31, 2013	$ 1,360	$ 1,005	$ 2,365	$ 190	$2,555
Net income	—	211	211	—	211
Preference stock dividends	—	(13)	(13)	—	(13)
Balance, December 31, 2014	$ 1,360	$ 1,203	$ 2,563	$ 190	$2,753
Net income	—	288	288	—	288
Preference stock dividends	—	(13)	(13)	—	(13)
Common stock dividends	—	(158)	(158)	—	(158)
Contribution from parent	7	—	7	—	7
Balance, December 31, 2015	$ 1,367	$ 1,320	$ 2,687	$ 190	$2,877

See the Combined Notes to Consolidated Financial Statements

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)

Index to Combined Notes to Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the registrants to which the footnotes apply:

Applicable Notes

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
Exelon Corporation	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Exelon Generation Company, LLC	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•		•		•	•	•	•	•	•
Commonwealth Edison Company	•	•	•			•	•				•	•	•	•	•	•	•		•	•			•	•	•	•	•
PECO Energy Company	•	•	•			•	•			•	•	•	•	•	•	•	•		•	•		•	•	•	•	•	•
Baltimore Gas And Electric Company	•	•	•			•	•			•		•	•	•	•	•	•		•	•			•	•	•	•	•

1. Significant Accounting Policies (Exelon, Generation, ComEd, PECO and BGE)

Description of Business (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy delivery businesses. On April 1, 2014, Generation assumed the operating licenses and corresponding operational control of CENG's nuclear fleet. As a result, Exelon and Generation consolidated CENG's financial position and results of operations into their businesses. Prior to April 1, 2014, Exelon and Generation accounted for CENG as an equity method investment. Refer to Note 5—Investment in Constellation Energy Nuclear Group, LLC for further information regarding the integration transaction.

The energy generation business includes:

- *Generation* : Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

The energy delivery businesses include:

- *ComEd* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

This is a combined annual report of Exelon, Generation, ComEd, PECO and BGE. The Notes to the Consolidated Financial Statements apply to Exelon, Generation, ComEd, PECO and BGE as

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

indicated above in the Index to Combined Notes to Consolidated Financial Statements and parenthetically next to each corresponding disclosure. When appropriate, Exelon, Generation, ComEd, PECO and BGE are named specifically for their related activities and disclosures.

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated. As a result of the Registrants' 2014 divestiture of certain unconsolidated affiliates considered integral to their operations and the consolidation of CENG during 2014, all Equity in earnings (losses) from unconsolidated affiliates have been presented below Income taxes in the Registrants' Consolidated Statements of Operations and Comprehensive Income starting in the first quarter of 2015.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC, including support services, are directly charged or allocated to the applicable subsidiaries using a cost-causative allocation method. Corporate governance-type costs that cannot be directly assigned are allocated based on a Modified Massachusetts Formula, which is a method that utilizes a combination of gross revenues, total assets and direct labor costs for the allocation base. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

Exelon owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%, and BGE, of which Exelon owns 100% of the common stock but none of BGE's preference stock. Exelon owned none of PECO's preferred securities, which PECO redeemed in 2013. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2015 and December 31, 2014, as equity, PECO's preferred securities as preferred securities of subsidiary through their redemption in 2013, and BGE's preference stock as BGE preference stock not subject to mandatory redemption in its consolidated financial statements. BGE is subject to some ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for certain Exelon Wind projects, of which Generation holds a majority interest of 99% for certain periods of time, and CENG, of which Generation holds a 50.01% interest. The remaining interests are included in noncontrolling interest on Exelon's and Generation's Consolidated Balance Sheets. See Note 2—Variable Interest Entities for further discussion of Exelon's and Generation's VIEs and the reversionary interests of the noncontrolling members for these certain subsidiaries.

ComEd owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for RITELine Illinois, LLC, of which ComEd owns 75% and an additional 12.5% is indirectly owned by Exelon. Exelon and ComEd have reflected the third-party interests of 12.5% and 25%, respectively, in RITELine Illinois, LLC, which both totaled less than $1 million at December 31, 2015 and December 31, 2014, as equity.

Exelon consolidates the accounts of entities in which Exelon has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which Exelon can exercise control over the operations and

policies of the investee, or the results of a model that identifies Exelon or one of its subsidiaries as the primary beneficiary of a VIE. Where Exelon does not have a controlling financial interest in an entity, it applies proportionate consolidation, equity method accounting or cost method accounting. Exelon applies proportionate consolidation when it has an undivided interest in an asset and is proportionately liable for its share of each liability associated with the asset. Exelon proportionately consolidates its undivided ownership interests in jointly owned electric plants and transmission facilities, as well as its undivided ownership interests in Upstream natural gas exploration and production activities. Under proportionate consolidation, Exelon separately records its proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. Exelon applies equity method accounting when it has significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. Exelon applies equity method accounting to certain investments and joint ventures, including certain financing trusts of ComEd, PECO, and BGE. Under the equity method, Exelon reports its interest in the entity as an investment and Exelon's percentage share of the earnings from the entity as single line items in its financial statements. Exelon uses the cost method if it holds less than 20% of the common stock of an entity. Under the cost method, Exelon reports its investment at cost and recognizes income only to the extent Exelon receives dividends or distributions.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (Exelon, Generation, ComEd, PECO and BGE)

The preparation of financial statements of each of the Registrants in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other AROs, pension and other postretirement benefits, the application of purchase accounting, inventory reserves, allowance for uncollectible accounts, goodwill and asset impairments, derivative instruments, unamortized energy contracts, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Reclassifications (Exelon, Generation, ComEd, PECO and BGE)

Certain prior year amounts in the registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows have been reclassified between line items for comparative purposes. The reclassifications did not affect any of the Registrants' net income, financial positions, or cash flows from operating activities.

Exelon revised the presentation on the Statements of Operations and Comprehensive Income for PECO and BGE to reflect separately operating revenues from the sale of electricity and operating revenues from the sale of natural gas, as well as, purchased power expense and purchased fuel expense within the operating expenses section of the Statement of Operations and Comprehensive Income. Further, Exelon revised the presentation from total operating revenues to "Rate-regulated utility revenues" and "Competitive businesses revenues" on the face of Exelon's consolidated Statement of Operations and Comprehensive Income for all periods presented. Similarly, Exelon will separately present rate-regulated purchased power and fuel expense and non-rate regulated

purchased power and fuel expense on the face of Exelon's consolidated Statement of Operations and Comprehensive Income for all periods presented. The reclassifications described herein were made for presentation purposes and did not affect any of the Registrants' total revenues or net income.

Accounting for the Effects of Regulation (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulation, which requires ComEd, PECO and BGE to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria: 1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation that rates are set at levels that will recover the entities' costs from customers. Exelon, ComEd, PECO and BGE account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, the PAPUC, and the MDPSC, in the cases of ComEd, PECO and BGE, respectively, under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the Consolidated Statements of Operations consistent with the recovery or refund included in customer rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. However, Exelon, ComEd, PECO and BGE continue to evaluate their respective abilities to apply the authoritative guidance for accounting for certain types of regulation, including consideration of current events in their respective regulatory and political environments. If a separable portion of ComEd's, PECO's or BGE's business was no longer able to meet the criteria discussed above, the affected entities would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which could have a material impact on their results of operations and financial positions. See Note 3—Regulatory Matters for additional information.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Revenues (Exelon, Generation, ComEd, PECO and BGE)

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimates of the distribution and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE records its best estimate of the transmission revenue impact resulting from changes in rates that BGE believes are probable of approval by FERC in accordance with its formula rate mechanism. See Note 3—Regulatory Matters and Note 6—Accounts Receivable for further information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations and Comprehensive Income, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Company in the different RTOs and ISOs.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. As ComEd receives full cost recovery for energy procurement and related costs from retail customers, ComEd records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. Refer to Note 3—Regulatory Matters and Note 13—Derivative Financial Instruments for further information.

Proprietary Trading Activities. Exelon and Generation account for Generation's trading activities under the provisions of the authoritative guidance for accounting for contracts involved in energy trading and risk management activities, which require energy revenues and costs related to energy trading contracts to be presented on a net basis in the income statement. Commodity derivatives used for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues. Refer to Note 13—Derivative Financial Instruments for further information.

Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

Deferred Federal and state income taxes are provided on all significant temporary differences between the book basis and the tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred on the Registrants' Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion; and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Registrants recognize accrued interest related to unrecognized tax benefits in Interest expense or Other income and deductions (interest income) on their Consolidated Statements of Operations and Comprehensive Income.

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 15—Income Taxes for further information.

Taxes Directly Imposed on Revenue-Producing Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, such as gross receipts taxes or other surcharges or fees, they are

reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 24—Supplemental Financial Information for Generation's, ComEd's, PECO's and BGE's utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE)

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE)

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2015 and 2014, Exelon Corporate's restricted cash and cash equivalents primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Additionally, as of December 31, 2015 and 2014, Generation's restricted cash and cash equivalents primarily included cash at Antelope Valley required for debt service and construction and cash at Continental Wind and ExGen Texas Power, which is required for debt service and financing of operation and maintenance of the underlying entities. As of December 31, 2015 and 2014, ComEd's restricted cash primarily represented cash collateral held from suppliers associated with ComEd's energy and REC procurement contracts. As of December 31, 2015 and 2014, PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's mortgage indenture. As of December 31, 2015 and 2014, BGE's restricted cash primarily represented funds restricted at its consolidated variable interest entity for repayment of rate stabilization bonds and cash collateral held from suppliers.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2015 and 2014, Exelon's and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2015, Exelon, Generation, ComEd, PECO and BGE had investments in Rabbi trusts classified as noncurrent assets.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging, historical experience and other currently available information. ComEd, PECO and BGE estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 3—Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and
- requires the entity that consolidates a VIE (the primary beneficiary) to disclose (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

Based on the above accounting guidance, Exelon has adopted the following policies related to variable interest entities:

- Exelon has disclosed, to the extent material, the assets of its consolidated VIEs that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of Exelon's consolidated VIEs for which creditors do not have recourse to Exelon's general credit.
- Exelon has qualitatively assessed whether the equity holders of the entity have the power to direct matters that most significantly impact the entity.

See Note 2—Variable Interest Entities for additional information.

Inventories (Exelon, Generation, ComEd, PECO and BGE)

Inventory is recorded at the lower of weighted average cost or market. Provisions are recorded for excess and obsolete inventory.

Fossil Fuel. Fossil fuel inventory includes the weighted average costs of stored natural gas, propane and oil. The costs of natural gas, propane and oil are generally included in inventory when purchased and charged to fuel expense when used or sold.

Materials and Supplies. Materials and supplies inventory generally includes the weighted average costs of transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and expensed or capitalized to property, plant and equipment, as appropriate, when installed or used.

Emission Allowances. Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) and are carried at the lower of weighted average cost or market and charged to fuel expense as they are used in operations.

Marketable Securities (Exelon, Generation, ComEd, PECO and BGE)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds are classified as trading securities and all other securities are classified as available-for-sale securities.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the Regulatory Agreement Units are included in regulatory liabilities at Exelon, ComEd and PECO and in noncurrent payables to affiliates at Generation and in noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the Non-Regulatory Agreement Units are included in earnings at Exelon and Generation. Unrealized gains and losses, net of tax, for Exelon's available-for-sale securities are reported in OCI. Any decline in the fair value of Exelon's available-for-sale securities below the cost basis is reviewed to determine if such decline is other-than-temporary. If the decline is determined to be other-than-temporary, the cost basis of the available-for-sale securities is written down to fair value as a new cost basis and the amount of the write-down is included in earnings. See Note 16—Asset Retirement Obligations for information regarding marketable securities held by NDT funds and Note 24—Supplemental Financial Information for additional information regarding ComEd's and PECO's regulatory assets and liabilities.

Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

Property, plant and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. ComEd, PECO and BGE also include indirect construction costs including labor and related costs of departments associated with supporting construction activities. When appropriate, original cost also includes capitalized interest for Generation and Exelon Corporate and AFUDC for regulated property at ComEd, PECO and BGE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred.

Third parties reimburse ComEd, PECO and BGE for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, Plant and Equipment. DOE SGIG funds reimbursed to PECO and BGE have been accounted for as CIAC.

For Generation, upon retirement, the cost of property is charged to accumulated depreciation in accordance with the composite method of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to operating and maintenance expense as incurred.

For ComEd, PECO and BGE, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. ComEd's and BGE's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. ComEd's and BGE's actual incurred removal costs are applied against a related regulatory liability. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method.

Generation's oil and gas exploration and production activities consist of working interests in gas producing fields. Generation accounts for these activities under the successful efforts method of accounting. Acquisition, development and exploration costs are capitalized. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

See Note 7—Property, Plant and Equipment, Note 10—Jointly Owned Electric Utility Plant and Note 24—Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within property, plant and equipment and charged to fuel expense using the unit-of-production method. Prior to May 16, 2014, the estimated disposal cost of SNF was established per the Standard Waste Contract with the DOE and was expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. Effective May 16, 2014, the SNF disposal fee was set to zero by the DOE and Exelon and Generation are not accruing any further costs related to SNF disposal fees until a new fee structure goes into effect. On-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 23—Commitments and Contingencies for additional information regarding the SNF disposal fee.

Nuclear Outage Costs (Exelon and Generation)

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to operating and maintenance expense or capitalized to property, plant and equipment (based on the nature of the activities) in the period incurred.

New Site Development Costs (Exelon and Generation)

New site development costs represent the costs incurred in the assessment and design of new power generating facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management's determination that the project is economically and operationally feasible, management and/or the Exelon board of directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. Capitalized development costs are charged to Operating and maintenance expense when project completion is no longer probable. New site development costs incurred prior to a project's completion being deemed probable are expensed as incurred. Approximately $22 million, $13 million and $10 million of costs were expensed by Exelon and Generation for the years ended December 31, 2015, 2014, and 2013, respectively. These costs are related to the possible development of new power generating facilities.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Capitalized Software Costs (Exelon, Generation, ComEd, PECO and BGE)

Costs incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized within property, plant, and equipment. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

Net unamortized software costs	Exelon	Generation	ComEd	PECO	BGE
December 31, 2015	$ 633	$ 180	$ 172	$ 86	$178
December 31, 2014	596	193	133	84	163

Amortization of capitalized software costs	Exelon	Generation	ComEd	PECO	BGE
2015	$ 208	$ 73	$ 47	$ 33	$ 46
2014	186	59	45	28	43
2013	198	67	52	33	36

Depreciation, Depletion and Amortization (Exelon, Generation, ComEd, PECO and BGE)

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method. ComEd's and BGE's depreciation includes a provision for estimated removal costs as authorized by the respective regulators. The estimated service lives for ComEd, PECO and BGE are primarily based on the average service lives from the most recent depreciation study for each respective company. The estimated service lives of the nuclear-fuel generating facilities are based on the remaining useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses (to the extent that such renewal has not yet been granted) for all of Generation's operating nuclear generating stations except for Oyster Creek. The estimated service lives of the hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the operating licenses. The estimated service lives of the fossil fuel and other renewable generating facilities are based on the remaining useful lives of the stations, which Generation periodically evaluates based on feasibility assessments taking into account economic and capital requirement considerations.

See Note 7—Property, Plant and Equipment for further information regarding depreciation.

Depletion of oil and gas exploration and production activities is recorded using the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for oil and gas reserves are based on internal calculations.

Amortization of regulatory assets and liabilities are recorded over the recovery or refund period specified in the related legislation or regulatory agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost or income would have originally been recorded in the Registrants' Consolidated Statements of Operations and Comprehensive Income. Amortization of ComEd's distribution formula rate regulatory asset and ComEd's and BGE's transmission formula rate regulatory assets is recorded to Operating revenues.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Amortization of income tax related regulatory assets and liabilities is generally recorded to Income tax expense. With the exception of the regulatory assets and liabilities discussed above, when the recovery period is more than one year, the amortization is generally recorded to Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

See Note 3—Regulatory Matters and Note 24—Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of ComEd's, PECO's and BGE's regulatory assets.

Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years unless circumstances warrant more frequent updates (such as a change in assumed operating life for a nuclear plant). As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle. The liabilities associated with Exelon's non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years. Changes to the recorded value of an ARO result from the passage of new laws and regulations, revisions to either the timing or amount of estimates of undiscounted cash flows, and estimates of cost escalation factors. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through a charge to Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income or, in the case of the majority of ComEd's, PECO's, and BGE's accretion, through an increase to regulatory assets. See Note 16—Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (Exelon, Generation, ComEd, PECO and BGE)

During construction, Exelon and Generation capitalize the costs of debt funds used to finance non-regulated construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense.

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to AFUDC that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

Combined Notes to Consolidated Financial Statements—(Continued)
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The following table summarizes total incurred interest, capitalized interest and credits to AFUDC by year:

		Exelon (a)	Generation (a)	ComEd	PECO	BGE
2015	Total incurred interest (b)	$1,170	$ 445	$ 336	$116	$113
	Capitalized interest	79	79	—	—	—
	Credits to AFUDC debt and equity	44	—	9	7	28
2014	Total incurred interest (b)	$1,144	$ 419	$ 323	$115	$118
	Capitalized interest	63	63	—	—	—
	Credits to AFUDC debt and equity	37	—	5	8	24
2013	Total incurred interest (b)	$1,423	$ 411	$ 584	$117	$129
	Capitalized interest	54	54	—	—	—
	Credits to AFUDC debt and equity	35	—	16	6	13

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's financial position and results of operations beginning April 1, 2014.
(b) Includes interest expense to affiliates.

Guarantees (Exelon, Generation, ComEd, PECO and BGE)

The Registrants recognize, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken by issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 23—Commitments and Contingencies for additional information.

Asset Impairments (Exelon, Generation, ComEd, PECO and BGE)

Long-Lived Assets. The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. The Registrants determine if long-lived assets and asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value less costs to sell.

Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generating units are generally evaluated at a regional portfolio level along with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets

may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables). See Note 8—Impairment of Long-Lived Assets for additional information.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 11—Intangible Assets for additional information regarding Exelon's, Generation's and ComEd's goodwill.

Equity Method Investments. Exelon and Generation regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature. Additionally, if the project in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other-than-temporary decline in value.

Debt and Equity Security Investments. Exelon and Generation regularly monitor and evaluate debt and equity investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature.

Direct Financing Lease Investments. Direct financing lease investments represent the estimated residual values of leased coal-fired plants in Georgia. Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other-than-temporary decline in the fair value of the residual values below their carrying values. See Note 8—Impairment of Long-Lived Assets for additional information.

Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For derivative contracts intended to serve as economic hedges and that are not designated or do not qualify for hedge accounting or the normal purchases and normal sales exception, changes in the fair value of the derivatives are recognized in earnings each period. Amounts classified in earnings are included in revenue, purchased power and fuel, interest expense or other, net on the Consolidated Statement of Operations based on the activity the transaction is economically hedging. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon's Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. All amounts classified in earnings related to proprietary trading are included in revenue on the Consolidated Statement of Operations. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For commodity derivative contracts Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the Constellation merger. Because the underlying forecasted transactions remained probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred through March 31, 2015. The effect of this decision is that all derivatives executed to hedge economic risk related to commodities are recorded at fair value with changes in fair value recognized through earnings for the combined company.

As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See Note 13—Derivative Financial Instruments for additional information.

Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 17—Retirement Benefits for additional discussion of Exelon's accounting for retirement benefits.

Equity Investment Earnings (Losses) of Unconsolidated Affiliates (Exelon and Generation)

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities, power projects and joint ventures, in equity in earnings (losses) of unconsolidated affiliates within their Consolidated Statements of Operations and Comprehensive Income. Equity in earnings (losses) of unconsolidated affiliates also includes any adjustments to amortize the difference, if any, except for goodwill and land, between their cost in an equity method investment and the underlying equity in net assets of the investee at the date of investment.

Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such investment experiences an other-than-temporary decline in value.

New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

Exelon has identified the following new accounting standards that have been recently adopted that management believes may significantly affect the Registrants.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued authoritative guidance that requires deferred tax assets and deferred tax liabilities to be classified as noncurrent in a classified statement of financial position. The guidance is effective for periods beginning after December 15, 2016, with early adoption permitted. The guidance can be applied either prospectively or retrospectively. The Registrants early adopted the standard retrospectively in the fourth quarter of 2015, resulting in the following impacts as of December 31, 2014 in the Consolidated Balance Sheets of the Registrants:

For the year ended December 31, 2014 Increase (Decrease)	Exelon	Generation	ComEd	PECO	BGE
Current assets—Deferred income taxes	$(244)	$ (327)	$ —	$ (69)	$ (6)
Deferred debits and other assets—Other	3	—	—	—	—
Current liabilities—Deferred income taxes	—	—	(63)	—	(52)
Deferred credits and other liabilities—Deferred income taxes	(241)	(327)	63	(69)	46

The adoption of this guidance had no impact on the Registrants' Consolidated Statements of Operations and Comprehensive Income and Consolidated Statements of Cash Flows.

Simplifying the Accounting for Measurement-Period Adjustments

In September 2015, the FASB issued authoritative guidance that requires an acquirer in a business combination to recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined and to record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. Under current guidance, such effects would be retrospectively recorded in prior periods. The guidance is effective for periods beginning after December 15, 2015. The guidance is required to be applied prospectively to adjustments to provisional amounts that occur after the effective date with earlier application permitted for financial statements that have not been issued. The Registrants early adopted the standard in the fourth quarter of 2015. The adoption of this guidance had no impact on the Registrants' Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

Application of Normal Purchases Normal Sales Exception to Power Contracts in Nodal Energy Markets

In August 2015, the FASB issued authoritative guidance addressing the ability of entities to elect the normal purchase normal sales (NPNS) scope exception when the contract for the purchase or sale of electricity on a forward basis is delivered to a nodal energy market or transmitted through a nodal energy market. The NPNS scope exception allows entities to treat certain contracts that qualify as derivatives as contracts that do not require recognition at fair value. The guidance specifies that the use of locational marginal pricing by an independent system operator in such transactions does not constitute net settlement of a contract for the purchase or sale of electricity, even in scenarios in which legal title to the associated electricity is conveyed to the independent system operator during transmission. Consequently, the use of locational marginal pricing by the independent system operator does not cause that contract to fail to meet the physical delivery criterion of the NPNS scope exception. Consistent with the Registrants' current practice, if the physical delivery criterion is met, along with all of the other criteria of the NPNS scope exception, an entity may elect to designate that contract as

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NPNS. The guidance is effective upon issuance and should be applied prospectively. The adoption of this guidance had no impact on the Registrants' Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

Simplifying the Presentation of Debt Issuance Costs

In April 2015, the FASB issued authoritative guidance that changes the presentation of debt issuance costs in financial statements. The new guidance requires entities to present such costs in the balance sheet as a direct reduction to the related debt liability rather than as a deferred cost (i.e., an asset) as required by current guidance. The new guidance does not change the recognition or measurement of debt issuance costs. The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015. Early adoption is permitted for financial statements that have not been previously issued. The guidance is required to be applied retrospectively to all prior periods presented. The Registrants early adopted the standard retrospectively in the fourth quarter of 2015. The adoption of this guidance resulted in a reclassification of $157 million, $70 million, $34 million, $14 million, and $16 million as of December 31, 2014, from Other long-term assets to Long-term debt, including Long-term debt to financing trusts, in the Consolidated Balance Sheets of Exelon, Generation, ComEd, PECO and BGE, respectively. The standard did not impact the Consolidated Statements of Operations and Comprehensive Income and Consolidated Statements of Cash Flows of the Registrants.

In August 2015, the FASB issued clarifying authoritative guidance for debt issuance costs incurred in connection with line-of-credit arrangements. The guidance states that an entity should defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement. The adoption of this guidance had no impact on the Registrants' Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

The following recently issued accounting standards are not yet required to be reflected in the combined financial statements of the Registrants.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued authoritative guidance which (i) requires all investments in equity securities, including other ownership interests such as partnerships, unincorporated joint ventures and limited liability companies, to be carried at fair value through net income, (ii) requires an incremental recognition and disclosure requirement related to the presentation of fair value changes of financial liabilities for which the fair value option has been elected, (iii) amends several disclosure requirements, including the methods and significant assumptions used to estimate fair value or a description of the changes in the methods and assumptions used to estimate fair value, and (iv) requires disclosure of the fair value of financial assets and liabilities measured at amortized cost at the amount that would be received to sell the asset or paid to transfer the liability. The standard is effective for fiscal years beginning after December 15, 2017 with early adoption permitted. The guidance is required to be applied retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures as well as the potential to early adopt the guidance.

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Simplifying the Measurement of Inventory

In July 2015, the FASB issued authoritative guidance that requires inventory to be measured at the lower of cost or net realizable value. The new guidance defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This definition is consistent with existing authoritative guidance. Current guidance requires inventory to be measured at the lower of cost or market where market could be replacement cost, net realizable value or net realizable value less an approximately normal profit margin. The guidance is effective for periods beginning after December 15, 2016 with early adoption permitted. The guidance is required to be applied prospectively. The Registrants do not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The Registrants are currently assessing the potential to early adopt the guidance.

Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share

In May 2015, FASB issued authoritative guidance that removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. Investments measured at net asset value per share using the practical expedient will be presented as a reconciling item between the fair value hierarchy disclosure and the investment line item on the statement of financial position. The guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient. Rather, those disclosures are limited to investments for which the entity has elected to measure the fair value using the practical expedient. The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015 with early adoption permitted. The guidance is required to be applied retrospectively to all prior periods presented. The Registrants are currently assessing the impacts this guidance may have on their disclosures. There will be no impact to the Registrants' Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income and Consolidated Statements of Cash Flows.

Customer's Accounting for Fees Paid in a Cloud Computing Arrangement

In April 2015, the FASB issued authoritative guidance that clarifies the circumstances under which a cloud computing customer would account for the arrangement as a license of internal-use software. A cloud computing arrangement would include a software license if (1) the customer has a contractual right to take possession of the software at any time during the hosting period without significant penalty and (2) it is feasible for the customer to either run the software on its own hardware or contract with another party unrelated to the vendor to host the software. If the arrangement does not contain a software license, it would be accounted for as a service contract. Beginning January 1, 2016, the Registrants will apply the standard prospectively and do not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

Amendments to the Consolidation Analysis

In February 2015, the FASB issued authoritative guidance that amends the consolidation analysis for variable interest entities (VIEs) as well as voting interest entities. The new guidance primarily (1) changes the assessment of limited partnerships as VIEs, (2) amends the effect that fees paid to a decision maker or service provider have on the VIE analysis, (3) amends how variable interests held by

a reporting entity's related parties and de facto agents impact its consolidation conclusion, (4) clarifies how to determine whether equity holders (as a group) have power over an entity, and (5) provides a scope exception for registered and similar unregistered money market funds. The guidance is effective for the Registrants for the first interim period beginning on or after December 15, 2015. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption (modified retrospective method). The Registrants are in the process of evaluating the standard and have not identified any changes to consolidation conclusions as a result of the new guidance and therefore have not elected an adoption method. Based on the analysis completed to date, a limited number of additional entities will be considered variable interest entities when the guidance is adopted, and required disclosures will be included in the Variable Interest Entities footnote.

Revenue from Contracts with Customers

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing and uncertainty of revenue and the related cash flows. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures as well as the transition method that they will use to adopt the guidance. Exelon is considering the impacts of the new guidance on our ability to recognize revenue for certain contracts where collectability is in question, our accounting for contributions in aid of construction, bundled sales contracts and contracts with pricing provisions that may require us to recognize revenue at prices other than the contract price (e.g., straight line or forward curve). In addition, the Registrants will be required to capitalize costs to acquire new contracts, whereas Exelon currently expenses those costs as incurred. In August 2015, the FASB issued an amendment to provide a one year deferral of the effective date to annual reporting periods beginning on or after December 15, 2017, as well as an option to early adopt the standard for annual periods beginning on or after December 15, 2016. The Registrants do not plan to early adopt the standard.

2. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

A VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly affect the entity's economic performance.

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At December 31, 2015 and 2014, Exelon, Generation, and BGE collectively consolidated seven and six VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary (*see Consolidated Variable Interest Entities below)* . As of December 31, 2015 and 2014, the Registrants had significant interests in eight and six other VIEs, respectively, for which the Registrants do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary (*see Unconsolidated Variable Interest Entities below)* .

Consolidated Variable Interest Entities

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the Registrants' consolidated financial statements at December 31, 2015 and 2014 are as follows:

	December 31, 2015			December 31, 2014 [a]		
	Exelon [b]	Generation	BGE	Exelon [b]	Generation	BGE
Current assets	$ 909	$ 881	$ 23	$ 1,275	$ 1,247	$ 21
Noncurrent assets	8,009	8,004	3	7,573	7,560	3
Total assets	$ 8,918	$ 8,885	$ 26	$ 8,848	$ 8,807	$ 24
Current liabilities	$ 473	$ 387	$ 81	$ 611	$ 526	$ 77
Noncurrent liabilities	2,927	2,884	41	2,728	2,597	120
Total liabilities	$ 3,400	$ 3,271	$122	$ 3,339	$ 3,123	$197

(a) Certain December 31, 2014 balances have been adjusted for the adoption of accounting guidance related to classification of deferred taxes and simplifying the presentation of debt costs. See Note 1—Significant Accounting Policies for additional information.
(b) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the table can only be settled using VIE resources.

Exelon's, Generation's and BGE's consolidated VIEs consist of:

RSB BondCo LLC. In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. BGE has determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE consolidates BondCo.

BondCo's assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2015, 2014, and 2013, BGE remitted $86 million, $85 million, and $83 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2015. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

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Retail Gas Group. During 2009, Constellation formed two new entities, which now are part of Generation, and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third-party gas supplier. While Generation owns 100% of these entities, it has been determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group's activities without the additional credit support that is provided in the form of a parental guarantee. Generation is the primary beneficiary of the retail gas entity group; accordingly, Generation consolidates the retail gas entity group as a VIE.

The third-party gas supply arrangement is collateralized as follows:

- the assets of the retail gas entity group must be used to settle obligations under the third-party gas supply agreement before it can make any distributions to Generation,
- the third-party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- Generation provides a $75 million parental guarantee to the third-party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee, Exelon or Generation do not have any contractual or other obligations to provide additional financial support under the collateralized third-party gas supply agreement. The third-party gas supply creditors do not have any recourse to Exelon's or Generation's general credit other than the parental guarantee.

Solar Project Entity Group. In 2011, Generation acquired all of the equity interests in Antelope Valley Solar Ranch One (Antelope Valley) from First Solar, Inc., a 242-MW solar PV project in northern Los Angeles County, California. In addition, Generation owns a number of limited liability companies that build, own, and operate solar power facilities. While Generation owns 100% of these entities, it has been determined that certain of the individual solar project entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the solar project entities that qualify as VIEs because Generation controls the design, construction, and operation of the solar power facilities. Generation provides operating and capital funding to the solar entities for ongoing construction, operations and maintenance of the solar power facilities and provides limited recourse related to the Antelope Valley project. In addition, these solar VIE entities have an aggregate amount of outstanding debt with third parties of $655 million, as of December 31, 2015, for which the creditors have no recourse to Generation. For additional information on these project-specific financing arrangements refer to Note 14—Debt and Credit Agreements.

Retail Power and Gas Companies. In March 2014, Generation began consolidating retail power and gas VIEs for which Generation is the primary beneficiary as a result of energy supply contracts that give Generation the power to direct the activities that most significantly affect the economic performance of the entities. Generation does not have an equity ownership interest in these entities, but provides approximately $12 million in credit support for the retail power and gas companies. These entities are included in Generation's consolidated financial statements, and the consolidation of the VIEs do not have a material impact on Generation's financial results or financial condition.

Wind Project Entity Group . Generation owns and operates a number of wind project limited liability entities, the majority of which were acquired during 2010 with the acquisition of all of the equity

interests of John Deere Renewables, LLC (now known as Exelon Wind). Generation has evaluated the significant agreements and ownership structures and the risks of each of its wind projects and underlying entities, and determined that certain of the entities are VIEs because either the projects have noncontrolling equity interest holders that absorb variability from the wind projects, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the wind project entities that qualify as VIEs because Generation controls the design, construction, and operation of the wind generation facilities. While Generation owns 100% of the majority of the wind project entities, nine of the projects have noncontrolling equity interests of 1% held by third parties. Generation's current economic interests in eight of these projects is significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the noncontrolling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the noncontrolling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the noncontrolling interests state that Generation is to provide financial support to the projects in proportion to its current 99% economic interests in the projects. However, no additional support to these projects beyond what was contractually required has been provided during 2015. As of December 31, 2015, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of the wind VIE entities primarily relates to the wind generating assets, PPA intangible assets and working capital amounts.

Other Generating Facilities. During the second quarter of 2015, Generation formed a limited liability company to build, own, and operate a backup generator. While Generation owns 100% of the backup generator company, it was determined that the entity is a VIE because the customer absorbs price variability from the entity through the fixed price backup generator agreement. Generation provides operating and capital funding to the backup generator company. Generation also owns 90% of a biomass fueled, combined heat and power company. In the second quarter of 2015, the entity was deemed to be a VIE because the entity requires additional subordinated financial support in the form of a parental guarantee provided by Generation for up to $275 million in support of the payment obligations related to the Engineering, Procurement and Construction contract for the facility (see Note 14—Debt and Credit Agreements for additional details on Albany Green Energy, LLC). In addition to the parental guarantee, Generation provides operating and capital funding to the biomass fueled, combined heat and power company. Generation is the primary beneficiary of both entities since Generation has the power to direct the activities that most significantly affect the economic performance of the entities.

CENG. Through March 31, 2014, CENG was operated as a joint venture with EDF and was governed by a board of ten directors, five of which were appointed by Generation and five by EDF. CENG was designed to operate under joint and equal control of Generation and EDF through the Board of Directors, subject to the Chairman of the Board's final decision making authority on certain special matters; therefore, CENG was not subject to VIE guidance. Accordingly, Generation's 50.01% interest in CENG was accounted for as an equity method investment. On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the Nuclear Operating Services Agreement (NOSA) pursuant to which Generation now conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF. As a result of executing the NOSA, CENG now qualifies as a VIE due to the disproportionate relationship between Generation's 50.01% equity ownership interest and its role in conducting the operational activities of CENG and the CENG fleet conveyed through the NOSA.

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Further, since Generation is conducting the operational activities of CENG and the CENG fleet, Generation qualifies as the primary beneficiary of CENG and, therefore, is required to consolidate the financial position and results of operations of CENG. On April 1, 2014, Exelon and Generation derecognized Generation's equity method investment in CENG and reflected all assets, liabilities, and the EDF noncontrolling interest in CENG at fair value on the consolidated balance sheets of Exelon and Generation, resulting in the recognition of a $261 million gain in their respective Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2014. For additional information on this transaction refer to Note 5—Investment in Constellation Energy Nuclear Group, LLC.

Generation and Exelon, where indicated, provide the following support to CENG (See Note 5—Investment in Constellation Energy Nuclear Group, LLC and Note 26—Related Party Transactions for additional information regarding Generation and Exelon's transactions with CENG):

- under the NOSA, Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life and decommissioning of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF,
- under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management, and billing services to the CENG fleet for the remaining operating life of the CENG nuclear plants,
- under power purchase agreements with CENG, Generation purchased or will purchase 50.01% of the available output generated by the CENG nuclear plants not subject to other contractual agreements from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs have been suspended during the term of the expected Reliability Support Services Agreement (RSSA). (see Note 3—Regulatory Matters for additional details),
- Generation provided a $400 million loan to CENG. As of December 31, 2015, the remaining obligation is $300 million including accrued interest, which reflects the principal payment made in January 2015 (see Note 5—Investment in Constellation Energy Nuclear Group, LLC for more details),
- Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. (See Note 23—Commitments and Contingencies for more details),
- in connection with CENG's severance obligations, Generation has agreed to reimburse CENG for a total of approximately $6 million of the severance benefits paid or to be paid in 2014 through 2016. As of December 31, 2015, the remaining obligation is approximately $1 million,
- Generation and EDF share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance (See Note 23—Commitments and Contingencies for more details),
- Generation provides a guarantee of approximately $7 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDF executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,

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- Generation and EDF are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (see Note 23—Commitments and Contingencies for more details), and
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

For each of the consolidated VIEs, except as otherwise noted:

- the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;
- Exelon, Generation and BGE did not provide any additional material financial support to the VIEs;
- Exelon, Generation and BGE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and
- the creditors of the VIEs did not have recourse to Exelon's, Generation's or BGE's general credit.

As of December 31, 2015 and 2014, ComEd and PECO did not have any material consolidated VIEs.

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Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of December 31, 2015 and 2014, these assets and liabilities primarily consisted of the following:

	December 31, 2015			December 31, 2014 [a]		
	Exelon	Generation	BGE	Exelon	Generation	BGE
Cash and cash equivalents	$ 164	$ 164	$ —	$ 392	$ 392	$ —
Restricted cash	100	77	23	117	96	21
Accounts receivable, net						
Customer	219	219	—	297	297	—
Other	43	43	—	57	57	—
Mark-to-market derivatives assets	140	140	—	171	171	—
Inventory						
Materials and supplies	181	181	—	172	172	—
Other current assets	35	30	—	37	30	—
Total current assets	882	854	23	1,243	1,215	21
Property, plant and equipment, net	5,160	5,160	—	4,638	4,638	—
Nuclear decommissioning trust funds	2,036	2,036	—	2,097	2,097	—
Goodwill	47	47	—	47	47	—
Mark-to-market derivatives assets	53	53	—	44	44	—
Other noncurrent assets	90	85	3	90	77	3
Total noncurrent assets	7,386	7,381	3	6,916	6,903	3
Total assets	$8,268	$ 8,235	$ 26	$8,159	$ 8,118	$ 24
Long-term debt due within one year	$ 111	$ 27	$ 79	$ 87	$ 5	$ 75
Accounts payable	216	216	—	292	292	—
Accrued expenses	115	113	2	111	108	2
Mark-to-market derivative liabilities	5	5	—	24	24	—
Unamortized energy contract liabilities	12	12	—	22	22	—
Other current liabilities	13	13	—	25	25	—
Total current liabilities	472	386	81	561	476	77
Long-term debt	666	623	41	212	81	120
Asset retirement obligations	1,999	1,999	—	1,763	1,763	—
Pension obligation [b]	9	9	—	9	9	—
Unamortized energy contract liabilities	39	39	—	51	51	—
Other noncurrent liabilities	79	79	—	132	132	—
Noncurrent liabilities	2,792	2,749	41	2,167	2,036	120
Total liabilities	$3,264	$ 3,135	$122	$2,728	$ 2,512	$197

(a) Certain December 31, 2014 balances have been adjusted for the adoption of accounting guidance related to classification of deferred taxes and simplifying the presentation of debt costs. See Note 1- Significant Accounting Policies for additional information.
(b) Includes the CNEG retail gas pension obligation, which is presented as a net asset balance within the Prepaid pension asset line item on Generation's balance sheet. See Note 17—Retirement Benefits for additional details.

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Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected on Exelon's and Generation's Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of December 31, 2015 and 2014, Exelon and Generation had significant unconsolidated variable interests in eight and six VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity method investments and certain commercial agreements. The increase in the number of unconsolidated VIEs is due to the execution of an energy purchase and sale agreement with a new unconsolidated VIE and an equity investment in a new unconsolidated VIE.

The following tables present summary information about Exelon and Generation's significant unconsolidated VIE entities:

December 31, 2015	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 263	$ 164	$427
Total liabilities [a]	22	125	147
Exelon's ownership interest in VIE [a]	—	11	11
Other ownership interests in VIE [a]	241	28	269
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	21	21
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning [b]	17	—	17

December 31, 2014	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 114	$ 91	$205
Total liabilities [a]	3	49	52
Exelon's ownership interest in VIE [a]	—	9	9
Other ownership interests in VIE [a]	111	33	144
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	13	13
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning [b]	27	—	27

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs. Exelon corrected an error in the December 31, 2014 balances within Commercial Agreement VIEs for an overstatement of Total assets, Total liabilities and Other ownership interests in VIE of $392 million, $234 million and $158 million, respectively. The error is not considered material to any prior period.

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(b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $206 million and $319 million as of December 31, 2015 and December 31, 2014, respectively; offset by payables to ZionSolutions LLC of $189 million and $292 million as of December 31, 2015 and December 31, 2014, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

For each unconsolidated VIE, Exelon and Generation assessed the risk of a loss equal to their maximum exposure to be remote and, accordingly Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would materially affect the fair value or risk of their variable interests in these variable interest entities.

Energy Purchase and Sale Agreements. Generation has several energy purchase and sale agreements with generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each entity, and determined that certain of the entities are VIEs because the entity absorbs risk through the sale of fixed price power and renewable energy credits. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

ZionSolutions . Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 16—Asset Retirement Obligations. Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning activities under the asset sale agreement are complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required. Other than the asset sale agreement, Exelon and Generation do not have any contractual or other obligations to provide additional financial support and ZionSolutions' creditors do not have any recourse to Exelon's or Generation's general credit.

Investment in Energy Development Projects, Distributed Energy Companies, and Energy Generating Facilities. Generation has several equity investments in energy development projects and energy generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each of its equity investments, and determined that certain of the entities are VIEs because the entity has an insufficient amount of equity at risk to finance its activities, Generation guarantees the debt of the entity, provides equity support, or provides operating services to the entity. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the entities that qualify as VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

In July 2014, Generation entered into an arrangement to purchase a 90% equity interest and 90% of the tax attributes of a distributed energy company. Generation's total equity commitment in this arrangement was $91 million and is paid incrementally over an approximate two year period (see Note 23—Commitments and Contingencies for additional details). This arrangement did not meet the definition of a VIE and is recorded as an equity method investment.

In June 2015, 2015 ESA Investco, LLC, then a wholly owned subsidiary of Generation, entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of another distributed energy company. Separate from the equity investment, Generation provided $27 million in cash to the other (10%) equity holder in the distributed energy company in exchange for a convertible

promissory note. In November 2015, Generation sold 69% of its equity interest in 2015 ESA Investco, LLC to a tax equity investor. Generation and the tax equity investor will contribute $250 million of equity incrementally through December 2016 in proportion to their ownership interests, which equates to approximately $172 million for the tax equity investor and $78 million for Generation (see Note 23—Commitments and Contingencies for additional details). Generation and the tax equity investor provide a parental guarantee of up to $275 million in proportion to their ownership interests in support of 2015 ESA Investco, LLC's obligation to make equity contributions to the distributed energy company. The investment in the distributed energy company was evaluated and it was determined to be a VIE for which Generation is not the primary beneficiary. Generation continues to consolidate 2015 ESA Investco, LLC under the voting interest model.

Both distributed energy companies from the 2014 and 2015 arrangements are considered related parties.

ComEd, PECO and BGE

The financing trust of ComEd, ComEd Financing III, the financing trusts of PECO, PECO Trust III and PECO Trust IV, and the financing trust of BGE, BGE Capital Trust II are not consolidated in Exelon's, ComEd's, PECO's or BGE's financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd, PECO, and BGE have concluded that they do not have a significant variable interest in ComEd Financing III, PECO Trust III, PECO Trust IV or BGE Capital Trust II as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk. See Note 14—Debt and Credit Agreements for additional information.

3. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

The following matters below discuss the current status of material regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd).

Background

Since 2011, ComEd's electric distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities to modernize Illinois' electric utility infrastructure. EIMA was scheduled to sunset, ending ComEd's performance based rate formula and investment commitment, at December 31, 2017, unless approved to continue through 2022 by the Illinois General Assembly. On April 3, 2015, the Governor signed legislation extending the EIMA sunset from 2017 to 2019.

Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions (initial revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred for that year (annual reconciliation). See *Annual Electric Distribution Filings* below for further details. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to

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Operating revenue for any differences between the revenue requirement in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. As of December 31, 2015, and December 31, 2014, ComEd had a regulatory asset associated with the electric distribution formula rate of $189 million and $371 million, respectively. The regulatory asset associated with electric distribution true-up is amortized to Operating revenue in ComEd's Consolidated Statement of Operations and Comprehensive Income as the associated amounts are recovered through rates.

Participating utilities are also required to file an annual update on their AMI implementation progress. On April 1, 2015, ComEd filed an annual progress report on its AMI Implementation Plan with the ICC, which allows for the installation of more than four million smart meters throughout ComEd's service territory by 2018. To date, approximately two million smart meters have been installed in the Chicago area.

Pursuant to EIMA, ComEd annually contributes $4 million for customer education for as long as the AMI Deployment Plan remains in effect. Additionally, ComEd contributes $10 million annually through 2016 to fund customer assistance programs for low-income customers, which will not be recoverable through rates.

Annual Electric Distribution Filings

For each of the following years, the ICC approved the following total increases/(decreases) in ComEd's electric distributions formula rate filings:

Annual Distribution Filings	2015	2014	2013
ComEd's requested total revenue requirement (decrease) increase	$ (50)	$ 269	$ 353
Final ICC Order			
Initial revenue requirement increase	$ 85	$ 160	$ 160
Annual reconciliation (decrease) increase	(152)	72	181
Total revenue requirement (decrease) increase	$ (67)	$ 232	$ 341
Allowed Return on Rate Base:			
Initial revenue requirement	7.05%	7.06%	6.94%
Annual reconciliation	7.02%	7.04%	6.94%
Allowed ROE:			
Initial revenue requirement	9.14% (a)	9.25% (a)	8.72%
Annual reconciliation	9.09% (a)	9.20% (a)	8.72%
Effective date of rates	January 2016	January 2015	January 2014

(a) Includes a reduction of 5 basis points for a reliability performance metric penalty.

Formula Rate Structure Investigation

In October 2013, the ICC opened an investigation (the Investigation), in response to a complaint filed by the Illinois Attorney General, to change the formula rate structure by requesting three changes: the elimination of the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance, the netting of associated accumulated deferred income

taxes against the annual reconciliation balance in calculating interest, and the use of average rather than year-end rate base for determining any ROE collar adjustment. On November 26, 2013, the ICC issued its final order in the Investigation, rejecting two of the proposed changes but accepting the proposed change to eliminate the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance. The accepted change became effective in January 2014, and reduced ComEd's 2014 revenue by approximately $8 million. This change had no financial statement impact on ComEd in 2013. ComEd and intervenors requested rehearing, however all rehearing requests were denied by the ICC. ComEd and intervenors filed appeals with the Illinois Appellate Court. ComEd subsequently withdrew its appeal, but the Illinois Attorney General and the Citizens Utility Board continued to argue that the ICC had wrongly approved ComEd's treatment of accumulated deferred income taxes (ADIT) relating to the annual reconciliation. On July 29, 2015, the Illinois Appellate Court rejected that appeal and affirmed the ICC's decision and its acceptance of ComEd's treatment of ADIT. The period in which to file requests for further review has expired and that decision is final.

Appeal of Initial Formula Rate Tariff

On March 26, 2014, the Illinois Appellate Court issued an opinion with respect to ComEd's appeal of the ICC's order relating to ComEd's initial formula rate tariff. The most significant financial issues under appeal related to ICC findings that were counter to the formula rate legislation and were clarified by subsequent legislation (Senate Bill 9). Therefore, only a subset of the issues originally appealed remained. The Court found against ComEd on each of the remaining issues: compensation related adjustments, billing determinants and the use of certain allocators. The Court's opinion has no accounting impact as ComEd recorded the distribution formula regulatory asset consistent with the ICC's final Order. On September 14, 2014, the Illinois Supreme Court declined to hear that appeal. ComEd elected not to seek review by the United States Supreme Court on the Federal law issues. Accordingly, the decision of the Illinois Appellate Court is considered final.

Grand Prairie Gateway Transmission Line (ComEd). On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. The costs incurred for the project prior to May 21, 2014 were immaterial. ComEd has acquired numerous easements across the project route through voluntary transactions. ComEd will seek to acquire the property rights on the remaining 28 parcels through condemnation proceedings in the circuit courts. ComEd began construction of the line during the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. As of December 31, 2015, ComEd has completed the ICC-approved procurement process for a portion of its energy requirements through 2021.

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ComEd is required to purchase an increasing percentage of the electricity for customer deliveries from renewable energy resources. Purchases by customers of electricity from competitive electric generation suppliers, whether as a result of the customers' own actions or as a result of municipal aggregation, are not included in this calculation and have the effect of reducing ComEd's purchase obligation. ComEd entered into several 20-year contracts with unaffiliated suppliers in December 2010 regarding the procurement of long-term renewable energy and associated RECs in order to meet its obligations under the Illinois' RPS. All associated costs are recoverable from customers.

FutureGen Industrial Alliance, Inc (Exelon and ComEd). During 2013, the ICC approved, and directed ComEd and Ameren (the Utilities) to enter into 20-year sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The sourcing agreement provides that ComEd and Ameren will pay FutureGen's contract prices, which are set annually pursuant to a formula rate. The contract prices are based on the difference between the costs of the facility and the revenues FutureGen receives from selling capacity and energy from the unit into the MISO or other markets, as well as any other revenue FutureGen receives from the operation of the facility. The order also directs ComEd and Ameren to recover these costs from their electric distribution customers through the use of a tariff, regardless of whether they purchase electricity from ComEd or Ameren, or from competitive electric generation suppliers.

In February 2013, ComEd filed an appeal with the Illinois Appellate Court questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers. On July 22, 2014, the Illinois Appellate Court issued its ruling re-affirming the ICC's order requiring ComEd to enter into the sourcing agreement with FutureGen and allowing the use of a tariff to recover its costs. ComEd decided not to appeal the Illinois Appellate Court's decision to the Illinois Supreme Court. However, the competitive electric generation suppliers and several large consumers petitioned for leave to appeal the Illinois Appellate Court's decision. On November 26, 2014, the Illinois Supreme Court granted the petition. ComEd executed the sourcing agreement with FutureGen in accordance with the ICC's order. In addition, ComEd filed a petition with the ICC seeking approval of the tariff allowing for the recovery of its costs associated with the FutureGen contract from all of its electric distribution customers, which was approved by the ICC on September 30, 2014.

A significant portion of the cost of the development of FutureGen was being funded by the DOE under the American Recovery and Reinvestment Act of 2009. In early February 2015, the DOE suspended funding for the project until further clarity could be obtained on certain significant hurdles facing the project, including the outcome of the litigation described above. Whether or not the DOE funding will be reinstated at some later date is unknown at this time.

On January 13, 2016, FutureGen informed the Illinois Supreme Court that it had ceased all development efforts on the FutureGen project and would soon be seeking to terminate the FutureGen supply agreements. Accordingly, FutureGen requested that the court dismiss the proceeding as moot. A decision from the Illinois Supreme Court dismissing the matter is expected in early 2016. In February 2016, FutureGen terminated its sourcing agreement with ComEd. As a result, ComEd is under no further obligation under this agreement.

Energy Efficiency and Renewable Energy Resources (Exelon and ComEd). Electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an

incremental annual program energy savings requirement of 2% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten-year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In January 2014, the ICC approved ComEd's third three-year Energy Efficiency and Demand Response Plan covering the period June 2014 through May 2017. The plans are designed to meet Illinois' energy efficiency and demand response goals through May 2017, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

EIMA provides for additional energy efficiency in Illinois. Starting in the June 2013 through May 2014 period and occurring annually thereafter, as part of the IPA procurement plan, ComEd is to include cost-effective expansion of current energy efficiency programs, and additional new cost-effective and/or third-party energy efficiency programs that are identified through a request for proposal process. All cost-effective energy efficiency programs are included in the IPA procurement plan for consideration of implementation. While these programs are monitored separately from the Energy Efficiency Portfolio Standard (EEPS), funds for both the EEPS portfolio and IPA energy efficiency programs are collected under the same rider.

Illinois utilities are required to procure cost-effective renewable energy resources in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers. ComEd is also required to acquire amounts of renewable energy resources that will cumulatively increase this percentage to at least 10% by June 1, 2015, with an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth by Illinois legislation. As of December 31, 2015, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois legislation. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates.

Pennsylvania Regulatory Matters

2015 Pennsylvania Electric Distribution Rate Case (Exelon and PECO). On March 27, 2015, PECO filed a petition with the PAPUC requesting an increase of $190 million to its annual service revenues for electric delivery, which requested an ROE of 10.95%. On September 10, 2015, PECO and interested parties filed with the PAPUC a petition for joint settlement for an increase of $127 million in annual distribution service revenue. No overall ROE was specified in the settlement. On December 17, 2015, the PAPUC approved the settlement of PECO's electric distribution rate case. The approved electric delivery rates became effective on January 1, 2016.

The settlement includes approval of the In-Program Arrearage Forgiveness ("IPAF") Program, which provides for forgiveness of a portion of the eligible arrearage balance of its low-income Customer Assistance Program (CAP) accounts receivable that will be determined as of program inception in October 2016. The forgiveness will be granted to the extent CAP customers remain current with payments. The Settlement guarantees PECO's recovery of two-thirds of the arrearage balance through a combination of customer payments and rate recovery, including through future rates cases if necessary. The remaining one-third of the arrearage balance will be absorbed by PECO, of which a portion has already been expensed as bad debt for CAP customer's accounts receivable balances.

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Although the actual arrearage balance is not defined until program inception, PECO believes that it can reasonably estimate certain CAP customer accounts receivable balances as of December 31, 2015 that will remain outstanding at program inception. Management determined its best estimate based on historical collectability information. As a result, a regulatory asset of $7 million, representing the previously incurred bad debt expense associated with the estimated eligible accounts receivable balances, was recorded on Exelon's and PECO's Consolidated Balance Sheets as of December 31, 2015. This estimate will be revisited on a quarterly basis through program inception.

2010 Pennsylvania Electric and Natural Gas Distribution Rate Cases (Exelon and PECO). On December 16, 2010, the PAPUC approved the settlement of PECO's electric and natural gas distribution rate cases, which were filed in March 2010, providing increases in annual service revenue of $225 million and $20 million, respectively.

The settlements included a stipulation regarding how tax benefits related to the application of any new IRS guidance on repairs deduction methodology are to be handled from a rate-making perspective. The settlements required that the expected cash benefit from the application of any new guidance to tax years prior to 2011 be refunded to customers over a seven-year period. On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for electric transmission and distribution property. PECO adopted the safe harbor and elected a method change for the 2010 tax year. The total refund to customers for the tax cash benefit from the application of the safe harbor to costs incurred prior to 2010 was $171 million. On October 4, 2011, PECO filed a supplement to its electric distribution tariff to execute the refund to customers of the tax cash benefit related to the IRC Section 481(a) "catch-up" adjustment claimed on the 2010 income tax return, which is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2012.

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The expected total refund to customers for the tax cash benefit from the application of the new method to costs incurred prior to 2011 is $54 million. This amount is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2013. PECO is awaiting IRS guidance that will provide a safe harbor method of accounting for gas transmission and distribution property.

The prospective tax benefits claimed as a result of the new methodology will be reflected in tax expense in the year in which they are claimed on the tax return. As agreed to in the 2010 distribution rate case settlements, these benefits were reflected in the determination of revenue requirements in the 2015 electric distribution rate case discussed above and will be reflected in the next natural gas distribution rate case. See Note 15—Income Taxes for additional information.

The 2010 electric and natural gas distribution rate case settlements did not specify the rate of return upon which the settlement rates are based, but rather provided for an increase in annual revenue. PECO has not filed a transmission rate case since rates have been unbundled.

Pennsylvania Procurement Proceedings (Exelon and PECO). Through PECO's first two PAPUC approved DSP Programs, PECO procured electric supply for its default electric customers through PAPUC approved competitive procurements. DSP I and DSP II expired on May 31, 2013 and May 31, 2015, respectively.

The second DSP Program included a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed

to submit a plan to allow its low-income CAP customers to purchase their generation supply from EGSs beginning in April 2014. In May 2013, PECO filed its CAP Shopping Plan with the PAPUC. By an Order entered on January 24, 2014, the PAPUC approved PECO's plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, the Office of Consumer Advocate (OCA) and low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court, claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On July 14, 2015, the Court issued opinions on the OCA and low-income advocacy group appeal. Specifically, the Court remanded the issue to the PAPUC with instructions that it approve a rule revision to the PECO CAP Shopping Plan that would prohibit CAP customers from entering into contracts with an EGS that would impose early cancellation/termination fees. The PAPUC has appealed the Court's decision. PECO does not have information at this time as to what action it may be required to take following remand to the PAPUC.

On December 4, 2014, the PAPUC approved PECO's third DSP Program. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. Under the program, PECO is procuring electric supply through four competitive procurements for fixed price full requirements contracts of two years or less for the residential classes and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. Beginning in June 2016, the medium commercial class (101-500 kW) will move to spot market pricing. As of December 31, 2015, PECO entered into contracts with PAPUC-approved bidders, including Generation, resulting from the first two of its four scheduled procurements. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Consolidated Statement of Operations and Comprehensive Income.

On March 12, 2015, PECO settled the CAP Design with the Office of Consumer Advocates (OCA) and Low Income Advocates, and filed the proposed plan with the PAPUC on March 20, 2015. The program design changes the rate structure of PECO's CAP to make the bills more affordable to customers enrolled in the assistance program. The CAP discounts continue to be recovered through PECO's universal service fund cost. On July 8, 2015, the CAP Design was approved by the PAPUC. PECO plans to implement the program changes in October 2016.

Smart Meter and Smart Grid Investments (Exelon and PECO). In April 2010, pursuant to Act 129 and the follow-on Implementation Order of 2009, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million electric smart meters and an AMI communication network by 2020. PECO is currently in the second phase of the SMPIP and has deployed substantially all remaining smart meters as of December 31, 2015, for a total of 1.7 million smart meters. In total, PECO currently expects to spend up to $589 million, excluding the cost of the original meters, on its smart meter infrastructure and approximately $155 million on smart grid investments through final deployment of which $200 million has been funded by SGIG. As of December 31, 2015, PECO has spent $578 million and $155 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received. Recovery of smart meter costs will be reflected in base rates effective January 1, 2016.

Energy Efficiency Programs (Exelon and PECO). PECO's PAPUC-approved Phase I EE&C Plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I plan set forth how PECO would meet the required reduction targets established by Act 129's EE&C provisions. On November 15, 2013, PECO filed its final compliance report with the PAPUC communicating PECO had met all Phase I reduction targets.

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The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provided energy consumption reduction requirements for the second phase of Act 129's EE&C program, which went into effect on June 1, 2013. Pursuant to the Phase II implementation order, PECO filed its three-year EE&C Phase II Plan with the PAPUC on November 1, 2012. The plan set forth how PECO would reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016, adjusted for weather and extraordinary loads. The implementation order permitted PECO to apply any excess savings achieved during Phase I against its Phase II consumption reduction targets, with no reduction to its Phase II budget. In accordance with the Act 129 Phase II implementation order, at least 10% and 4.5% of the total consumption reductions had to be through programs directed toward PECO's public and low income sectors, respectively. If PECO failed to achieve the required reductions in consumption, it would have been subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers. Act 129 mandates that the total cost of the plan may not exceed 2% of the electric company's total annual revenue as of December 31, 2006.

On March 15, 2013 and February 28, 2014, PECO filed Petitions for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers through May 31, 2014 and May 31, 2016, respectively. PECO proposed to fund the estimated $10 million annual costs of the plan by modifying incentive levels for other Phase II programs. The costs of the DLC program will be recovered through PECO's Energy Efficiency Plan surcharge along with other Phase II Plan costs. The PAPUC granted PECO's Petitions on May 5, 2013 and April 23, 2014, respectively.

The PAPUC issued its Phase III EE&C implementation order on June 19, 2015, that provides energy consumption reduction requirements for the third phase of Act 129's EE&C program with a five-year term from June 1, 2016 through May 31, 2021. The order tentatively established PECO's five-year cumulative consumption reduction target at 2,080,553 MWh.

Pursuant to the Phase III implementation order, PECO filed its five-year EE&C Phase III Plan with the PAPUC on November 30, 2015. The Plan sets forth how PECO will reduce electric consumption by at least 1,962,659 MWh, with a goal of 2,100,875 MWh in its service territory for the period June 1, 2016 through May 31, 2021. PECO expects a final decision from the PAPUC on PECO's EE&C Phase III Plan during the first quarter of 2016.

Alternative Energy Portfolio Standards (Exelon and PECO). In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of PECO's rate cap transition period, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources ranges from approximately 3.5% to 8%, and the requirement for Tier II alternative energy resources ranges from 6.2% to 10%. The required compliance percentages incrementally increase each annual compliance period, which is from June 1 through May 31, until May 31, 2021. These Tier I and Tier II alternative energy resources include acceptable energy sources as set forth in Act 129 and the AEPS Act.

PECO continues to procure alternative energy credits through full requirements contracts and its existing long-term solar contracts to meet the annual AEPS compliance requirements. All AEPS compliance costs are being recovered on a full and current basis from default service customers through the GSA.

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Pennsylvania Retail Electricity and Gas Markets (Exelon and PECO). Beginning in 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania's retail electricity market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. Through various orders, the PAPUC issued default electric service pricing for customers in PECO's service territory. See Pennsylvania procurement proceedings discussed above for additional details.

In early 2014, the extreme weather in PECO's service territory resulted in increased electricity commodity costs causing certain shopping customers to receive unexpectedly high utility bills. In response to a significant number of customer complaints throughout Pennsylvania, on April 3, 2014, the PAPUC unanimously voted to adopt two rulemaking orders to address the issue. The first rulemaking order requires electric generation suppliers to provide more consumer education regarding their contract. The second rulemaking order requires electric distribution companies to enable customers to switch suppliers within three business days (known as accelerated switching). The improved customer education and accelerated switching were to be in place within 30 days and six months of approval of the orders, respectively. The orders became final on June 14, 2014. On December 4, 2014, the PAPUC approved PECO's implementation plan (known as Bill on Supplier Switch), allowing PECO to implement accelerated switching by the December 15, 2014 deadline.

On September 12, 2013, the PAPUC issued an Order that initiated an investigation into Pennsylvania's natural gas retail market, including the role of the existing default service model and opportunities for market enhancements. On December 18, 2014, the PAPUC issued a Final Order directing the Office of Competitive Market Oversight (OCMO) to continue its investigation, confirming that natural gas distribution companies should remain with the default service model for the time being and directing establishment of a working group to examine other competitive issues. The OCMO has established a working group to review operation of the natural gas retail market and to consider potential recommendations on competitive issues.

Pennsylvania Act 11 of 2012 (Exelon and PECO). In February 2012, Act 11 was signed into law, which provided the PAPUC authority to approve the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems in Pennsylvania. Prior to recovering costs pursuant to a DSIC, the PAPUC's implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) approved by the Commission, which outlines how the utility is planning to increase its investment for repairing, improving or replacing aging infrastructure.

On May 7, 2015, the PAPUC approved PECO's modified natural gas LTIIP. In accordance with the approved LTIIP, PECO plans to spend $534 million through 2022 to further accelerate the replacement of existing gas mains and to relocate meters from indoors to outside in accordance with recent PAPUC rulemaking. In addition, on March 20, 2015, PECO filed a petition with the PAPUC for approval of its gas DSIC mechanism for recovery of gas LTIIP expenditures. On September 11, 2015, the PAPUC entered its Opinion and Order approving PECO's petition for a gas DSIC.

On March 27, 2015, PECO filed a petition with the PAPUC for approval of its proposed electric DSIC and LTIIP. In accordance with the LTIIP (System 2020 plan), PECO plans to spend $275 million over the next five years to modernize and storm-harden its electric distribution system, making it more

weather resistant and less vulnerable to damage. The DSIC will allow PECO the opportunity to recover the costs, subject to certain criteria, incurred to repair, improve or replace its electric distribution property between rate cases. On October 22, 2015, the PAPUC entered its Opinion and Order approving PECO's proposed petition for its electric LTIIP and DSIC.

Maryland Regulatory Matters

2015 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On November 6, 2015, and as amended on January 5, 2016, BGE filed for electric and gas base rate increases with the MDPSC, ultimately requesting an increase of $121 million and $79 million, respectively, of which $103 million and $37 million, respectively, is related to recovery of smart grid initiative costs. BGE requested a ROE for the electric and gas distribution rate case of 10.6% and 10.5%, respectively. The new electric and gas base rates are expected to take effect in June 2016. BGE is also proposing to recover an annual increase of approximately $30 million for Baltimore City conduit lease fees through a surcharge. BGE cannot predict how much of the requested increase the MDPSC will approve or if it will approve BGE's request for a conduit fee surcharge.

2014 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 2, 2014, and as amended on September 15, 2014, BGE filed for electric and gas base increases with the MDPSC, ultimately requesting increases of $99 million and $68 million, respectively.

On October 17, 2014, BGE filed with the MDPSC a unanimous settlement agreement (the Settlement Agreement) reached with all parties to the case under which it would receive an increase of $22 million in electric base rates and an increase of $38 million in gas base rates. The Settlement Agreement establishes new depreciation rates which have the effect of decreasing annual depreciation expense by approximately $20 million, primarily for electric. On December 4, 2014, the Public Utility Law Judge issued a proposed order approving the Settlement Agreement without modification, which became a final order on December 12, 2014. The approved distribution rate order authorizing BGE to increase electric and gas distribution rates became effective for services rendered on or after December 15, 2014.

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, and as amended on August 23, 2013, BGE filed for electric and gas base increases with the MDPSC, ultimately requesting increases of $83 million and $24 million, respectively. In addition to these requested rate increases, BGE's application includes a request for recovery of incremental capital expenditures and operating costs associated with BGE's proposed short-term reliability improvement plan (the "ERI initiative") in response to a MDPSC order through a surcharge separate from base rates.

On December 13, 2013, the MDPSC issued an order in BGE's 2013 electric and natural gas distribution rate case for increases in annual distribution service revenue of $34 million and $12 million, respectively, and an allowed return on equity of 9.75% and 9.60%, respectively. Rates became effective for services rendered on or after December 13, 2013. The MDPSC also authorized BGE to recover through a surcharge mechanism costs associated with five ERI initiative programs designed to accelerate electric reliability improvements premised upon the condition that the MDPSC approve specific projects in advance of cost recovery. On March 31, 2014, after reviewing comments filed by the parties and conducting a hearing on the matter, the MDPSC approved all but one project proposed for completion in 2014 as part of the ERI initiative. The ERI initiative surcharge became effective June 1, 2014. On November 2, 2015, BGE filed a surcharge update including a true-up of cost estimates included in the 2015 surcharge, along with its work plan and cost estimates for 2016, to be included in the 2016 surcharge. The MDPSC subsequently approved BGE's 2016 work plan and the 2016 surcharge.

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In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE's 2013 electric and gas distribution rate cases. The residential consumer advocate filed its related legal memorandum on August 22, 2014, challenging the MDPSC's approval of the ERI initiative surcharge. BGE submitted a response to the appeal on October 15, 2014, and a hearing was held on November 17, 2014. On October 26, 2015, the Circuit Court for Baltimore City issued an order affirming the MDPSC's decision. However, on November 30, 2015, the residential consumer advocate filed an appeal of the Circuit Court's decision with the Maryland Court of Special Appeals. BGE cannot predict the outcome of this appeal. If the residential consumer advocate's appeal is successful, BGE could recover ERI expenditures through other regulatory mechanisms.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million of which $200 million was funded by SGIG. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of December 31, 2015 and December 31, 2014, BGE recorded a regulatory asset of $196 million and $128 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. As part of the settlement in BGE's 2014 electric and gas distribution rate case, the cost of the retired non-AMI meters will be amortized over 10 years.

On February 26, 2014, the MDPSC issued an order authorizing BGE to impose a $75 upfront fee and an $11 recurring fee to customers electing to opt-out of BGE's smart meter installation program, effective the later of the first full billing cycle following July 1, 2014, or the AMI installation date in a customer's community. The fees authorized by the order will be reviewed after an initial 12 to 18 month period. On November 25, 2014, the MDPSC issued a decision approving BGE's proposal to automatically enroll unresponsive customers into the opt-out program and to charge those customers opt-out fees after BGE has exhausted attempts to schedule a meter installation. On November 5, 2015, the MDPSC held a hearing to evaluate the $11 recurring monthly fee paid by opt-out customers. Effective with January 2016 bills, the monthly recurring fee was reduced to $5.50.

As part of the 2015 electric and gas distribution rate case filed on November 6, 2015, BGE is seeking recovery of its smart grid initiative costs. Of BGE's requested $200 million, $140 million relates to the smart grid initiative. In support of its recovery of smart grid initiative costs, BGE provided evidence demonstrating that the benefits exceed the costs by a ratio of 2.3 to 1.0, on a nominal basis.

New Electric Generation (Exelon and BGE). On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that CPV projected will be in commercial operation by June 1, 2015. CPV subsequently sought to extend that date. The initial term of the proposed contract is 20 years. The CfD mandates that BGE and the other utilities pay (or receive) the difference between CPV's contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The MDPSC's order requires the three Maryland utilities to enter into a CfD in amounts proportionate to their relative SOS load. On April 16, 2013, the MDPSC issued an order that required BGE to execute a specific form of contract with CPV, and the parties executed the contract as of June 6, 2013.

On April 27, 2012, a civil complaint was filed in the U.S. District Court for the District of Maryland by certain unaffiliated parties that challenged the actions taken by the MDPSC on Federal law grounds. On

October 24, 2013, the U.S. District Court issued a judgment order finding that the MDPSC's Order directing BGE and the two other Maryland utilities to enter into a CfD, which assures that CPV receives a guaranteed fixed price regardless of the price set by the federally regulated wholesale market, violates the Supremacy Clause of the United States Constitution. On November 22, 2013, the MDPSC and CPV appealed the District Court's ruling to the United States Court of Appeals for the Fourth Circuit. The Fourth Circuit affirmed the District Court ruling in an opinion issued June 2, 2014. The MDPSC and CPV filed petitions for certiorari, seeking review of the case by the U.S. Supreme Court. On October 29, 2015, the U.S. Supreme Court granted the petition to review the Fourth Circuit decision, and that appeal is now pending in the Supreme Court with oral argument scheduled for February 24, 2016.

On February 9, 2011, a civil complaint was filed by Exelon and other unaffiliated parties in the United States District Court for the District of New Jersey, challenging a 2011 New Jersey law, the Long Term Capacity Pilot Program Act (LCAPP). LCAPP provides eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market. On October 25, 2013, the U.S. District Court issued a judgment order finding that LCAPP violates the Supremacy Clause of the United States Constitution. CPV and New Jersey appealed the District Court's ruling to the United States Court of Appeals for the Third Circuit. On September 11, 2014, the Third Circuit affirmed the District Court's ruling finding LCAPP unconstitutional. On November 26, 2014, CPV and New Jersey sought Supreme Court review of the Third Circuit decision. On October 29, 2015, the Supreme Court stayed the petition to review the Third Circuit case pending their review of the Fourth Circuit Maryland case described above.

On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order under state law. That petition was subsequently transferred to the Circuit Court for Baltimore City and consolidated with similar appeals that have been filed by other interested parties. On October 1, 2013, the Circuit Court Judge issued a Memorandum Opinion and Order finding the decisions of the MDPSC were within its statutory authority under Maryland law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD is unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands. On October 29, 2013, BGE and the two other Maryland utilities appealed the Circuit Court's ruling to the Maryland Court of Special Appeals. That appeal has been stayed pending decision by the U.S. Supreme Court in the federal action described above.

Depending on the ultimate outcome of the pending state and federal litigation, on the eventual market conditions, and on the manner of cost recovery as of the effective date of the agreement, the CfD could have a material impact on Exelon and BGE's results of operations, cash flows and financial positions.

Exelon believes that this and other states' projects may have artificially suppressed capacity prices in PJM and may continue to do so in future auctions to the detriment of Exelon's market driven position. In addition to this litigation, Exelon is working with other market participants to implement market rules that will appropriately limit the market suppressing effect of such state activities.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 requiring BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improve reliability and grid resiliency that were due at various times before August 30, 2013.

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On September 3, 2013, BGE filed a comprehensive long term assessment examining potential alternatives for improving the resiliency of the electric grid and a staffing analysis reviewing historical staffing levels as well as forecasting staffing levels necessary under various storm scenarios. During the summer of 2014, an evaluation of the reports filed by BGE and other Maryland utilities was undertaken by consultants on behalf of the MDPSC and MDPSC Staff. The MDPSC Staff also proposed standards for reliability during major events and estimated times of restoration as well as undertaking an evaluation of performance-based ratemaking principles and methodologies that would more directly and transparently align reliable service with the utilities' distribution rates and that reduce returns or otherwise penalize sub-standard performance. The MDPSC held hearings in September 2014. BGE currently cannot predict the outcome of these proceedings, which may result in increased capital expenditures and operating costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In 2013, legislation intended to accelerate gas infrastructure replacements in Maryland was signed into law. The law established a mechanism, separate from base rate proceedings, for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects incurred after June 1, 2013. The monthly surcharge and infrastructure replacement costs must be approved by the MDPSC and are subject to a cap and require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation.

On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On November 16, 2015, BGE filed a surcharge update to be effective January 1, 2016, including a true-up of cost estimates included in the 2015 surcharge, along with its 2016 project list and projected capital estimates of $113 million to be included in the 2016 surcharge calculation. The MDPSC subsequently approved BGE's 2016 project list and the proposed surcharge for 2016, which included the 2015 surcharge true-up. As of December 31, 2015, BGE recorded a regulatory asset of less than $1 million, representing the difference between the surcharge revenues and program costs.

In 2014, the residential consumer advocate in Maryland appealed MDPSC's decision on BGE's infrastructure replacement plan and associated surcharge with the Baltimore City Circuit Court, who affirmed the MDPSC's decision. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court. During the third quarter of 2015, the residential consumer advocate, MDPSC and BGE filed briefs. Oral argument in this matter was held before the Court of Special Appeals on November 3, 2015. On January 28, 2016, the Maryland Court of Special Appeals issued a decision affirming the MDPSC's decision.

New York Regulatory Matters

Ginna Nuclear Power Plant Reliability Support Services Agreement (Exelon and Generation). Ginna Nuclear Power Plant's (Ginna) prior period fixed-price PPA contract with Rochester Gas & Electric Company (RG&E) expired in June 2014. In light of the expiration of the PPA and prevailing market conditions, in January 2014, Ginna advised the New York Public Service Commission (NYPSC) and the ISO-NY that, in the absence of a reliability need, Ginna management

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would make a recommendation, subject to approval by the CENG board, that the Ginna plant be retired as soon as practicable. A formal study conducted by the ISO-NY and RG&E dated as of May 12, 2014 concluded that Ginna needs to remain in operation to maintain the reliability of the transmission grid in the Rochester region through September 2018 when planned transmission system upgrades undertaken by RG&E are expected to be completed.

In November 2014, in response to a petition filed by Ginna, the NYPSC directed Ginna and RG&E to negotiate a Reliability Support Services Agreement (RSSA). In February 2015, regulatory filings, including RSSA terms negotiated between Ginna and RG&E, to support the continued operation of Ginna for reliability purposes were made with the NYPSC and with the FERC for their approval. Although the RSSA contract is still subject to such regulatory approvals, on April 1, 2015, Ginna began delivering the power and capacity from the Ginna plant into the ISO-NY consistent with the technical provisions of the proposed RSSA contract.

In April 2015, the FERC issued an order which directed Ginna to make a compliance filing to ensure that the RSSA does not allow Ginna to receive revenues above its full cost of service and which rejected any extension of the RSSA beyond its initial term; rather the order required that any extension be subject to the rules currently being developed by the ISO-NY. The FERC order also set the RSSA for hearing and settlement procedures. In response to the FERC's April 2015 order, in May 2015, Ginna submitted a compliance filing to the FERC containing proposed revisions to the RSSA addressing the FERC's requirements and maintaining the April 1, 2015 proposed effective date. In July 2015, the FERC accepted Ginna's compliance filing effective April 1, 2015. The FERC accepted Ginna's proposal for market revenue sharing subject to a cap effective April 1, 2015, and rejected requests for rehearing by intervenors on a number of matters related to jurisdiction, the reliability need, the RSSA term, and possible price suppression.

In August 2015, Ginna reached a settlement in principle with intervenors modifying certain terms and conditions in the originally negotiated agreement. The proposed RSSA under the settlement preserves the value of the contract originally negotiated with RG&E, but shortens the term from 3.5 to 2 years, expiring March 31, 2017 and required RG&E to complete a new transmission reliability study to determine whether an interim reliability solution is required beyond March 31, 2017. That reliability study was completed in October 2015, and it identified certain RG&E projects that are needed to solve reliability problems that would be caused by an early retirement of Ginna. Under the settlement agreement, Ginna was required by December 29, 2015 to submit a bid to provide reliability services beginning April 1, 2017 until the necessary RG&E transmission upgrades are in service, which RG&E expects will be no later than October 31, 2017. Ginna submitted such a bid in December 2015. RG&E has the right until June 30, 2016 to select Ginna as an ongoing reliability solution. If such a need exists, and if Ginna is selected, Ginna and RG&E could enter into an additional RSSA commencing April 1, 2017 on the rates, terms and conditions set forth in Ginna's bid, or as might be otherwise agreed by Ginna and RG&E.

If RG&E seeks a reliability solution with Ginna, but RG&E and Ginna do not reach an agreement on rates, terms, and conditions of a new RSSA by March 31, 2016 (or by June 30, 2016 if RG&E elects to defer the decision date), the settlement agreement requires Ginna to file an unexecuted additional RSSA with the FERC for adjudication. If Ginna is not selected for continued reliability service and does not plan to retire shortly after the expiration of the RSSA, Ginna is required to file a notice to that effect with the NYPSC no later than September 30, 2016. Under the terms of the proposed RSSA, if RG&E does not select Ginna to provide reliability service after March 31, 2017, and Ginna continues to operate after June 14, 2017, Ginna would be required to make certain refund payments related to capital expenditures to RG&E.

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The August 2015 settlement was filed at the NYPSC and at the FERC in October 2015 and remains subject to review and approval by both agencies; such reviews are not expected to be completed until the first quarter of 2016.

Until final regulatory approvals are received, Generation is recognizing revenue based on market prices for energy and capacity delivered by Ginna into the ISO-NY. Upon receiving regulatory approvals, under the RSSA contract terms, Generation would then recognize revenue based on the final approved pricing contained in the contract retroactively from the April 1, 2015 effective date. While the RSSA is expected to receive regulatory approvals and, therefore, permit Ginna to continue operating through the RSSA term, there is still a risk that, for economic reasons, including the possibility that the FERC or the NYPSC may condition the approval of the RSSA on a modification of the rates set forth in the RSSA, Ginna could be retired before 2029, which is the end of its operating license period. In the event the plant were to be retired before the current license term ends in 2029, Exelon's and Generation's results of operations could be adversely affected by accelerated future decommissioning costs, severance costs, increased depreciation rates, and impairment charges, among other items. However, it is not expected that such impacts would be material to Exelon's or Generation's results of operations.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd's and BGE's transmission rates are each established based on a FERC-approved formula. ComEd and BGE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd and BGE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd's and BGE's best estimate of the revenue requirement expected to be filed with the FERC for that year's reconciliation. As of December 31, 2015, and 2014, ComEd had a regulatory asset associated with the transmission formula rate of $31 million and $21 million, respectively. As of December 31, 2015, and 2014, BGE had a net regulatory asset associated with the transmission formula rate of $12 million and $1 million, respectively. The regulatory asset associated with transmission true-up is amortized to Operating revenues within their Consolidated Statements of Operations of Comprehensive Income as the associated amounts are recovered through rates.

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For each of the following years, the following total increases/(decreases) were included in ComEd's and BGE's electric transmission formula rate filings:

Annual Transmission Filings	ComEd			BGE		
	2015	2014	2013	2015	2014	2013
Initial revenue requirement increase [a]	$ 68	$ 36	$ 38	$ —	$ 9	$ 2
Annual reconciliation (decrease) increase	18	(14)	30	(3)	5	(3)
Total revenue requirement increase	$ 86	$ 22	$ 68	$ (3)	$ 14	$ (1)
Allowed return on rate base [b]	8.61%	8.62%	8.7%	8.46%	8.53%	8.35%
Allowed ROE	11.5%	11.5%	11.5%	11.3%	11.3%	11.3%
Effective date of rates [c]	June 2015	June 2014	June 2013	June 2015	June 2014	June 2013

(a) For BGE, this excludes the increase in revenue requirement associated with dedicated facilities charges. The increases for dedicated facilities were $13 million and $3 million for 2015 and 2014, respectively. There were no dedicated facilities charges in 2013 for BGE.
(b) Refers to the weighted average debt and equity return on transmission rate bases for ComEd and BGE. As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of BGE's 2005 transmission rate case, the rate of return on common equity is 11.30%, inclusive of a 50 basis point incentive for participating in PJM.
(c) The time period for any challenges to the annual transmission formula rate update filings expired with no challenges submitted.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the PHI companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) and a 50 basis point incentive for participating in PJM (and certain additional incentive basis points on certain projects). The parties sought a reduction in the base return on equity to 8.7% and changes to the formula rate process. Under FERC rules, any revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE could be adjusted and refunds required is the date of the complaint.

On August 21, 2014, FERC issued an order in the BGE and PHI companies' proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013.

On December 8, 2014, various state agencies in Delaware, Maryland, New Jersey, and D.C. filed a second complaint against BGE regarding the base ROE of the transmission business seeking a reduction from 10.8% to 8.8%. The filing of the second complaint created a second refund window. By order issued on February 9, 2015, FERC established a hearing on the second complaint with the complainants' requested refund effective date of December 8, 2014. On February 20, 2015, the Chief Judge issued an order consolidating the two complaint proceedings and established an Initial Decision issuance deadline of February 29, 2016.

On November 6, 2015, BGE and the PHI companies and the complainants filed a settlement with FERC covering the issues raised in the complaints. The settlement provides for a 10% base ROE, effective March 8, 2016, which will be augmented by the PJM incentive adder of 50 basis points, and refunds to BGE customers of $13.7 million. The settlement also provides a moratorium on any change in the ROE until June 1, 2018. On December 16, 2015, the Presiding Administrative Law Judge submitted a Certification of the Uncontested Settlement to the FERC Commissioners. The settlement remains subject to FERC approval.

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PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. A number of parties appealed to the U.S. Court of Appeals for the Seventh Circuit for review of the decision.

In August 2009, the court issued its decision affirming the FERC's order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above (Cost Allocation Issue) for further consideration by the FERC. On remand, FERC reaffirmed its earlier decision to socialize the costs of new facilities 500 kV and above. A number of parties filed appeals of these orders. In June 2014, the court again remanded the Cost Allocation Issue to FERC. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the Cost Allocation Issue. The hearing only concerns new facilities approved by the PJM Board prior to February 1, 2013. As of December 31, 2015, settlement discussions are continuing.

Because a new cost allocation had been adopted for projects approved by the PJM Board on or after February 1, 2013, this latest remand only involves the cost allocation for facilities 500 kV and above approved prior to that date. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent any rate design changes are retroactive to periods prior to January 1, 2011, there may be an impact on PECO's results of operations. BGE anticipates that all impacts of any rate design changes effective after the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE's results of operations, cash flows or financial position.

ComEd, PECO and BGE are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd, PECO and BGE will work with PJM to continue to evaluate the scope and timing of any required construction projects. ComEd, PECO and BGE's estimated commitments are as follows:

	Total	2016	2017	2018	2019	2020
ComEd	$297	$204	$ 61	$26	$ 6	$—
PECO	67	31	24	8	4	—
BGE	373	140	112	62	46	13

Demand Response Resource Order (Exelon, Generation, ComEd, PECO, BGE). On May 23, 2014, the D.C. Circuit Court issued an opinion vacating the FERC Order No. 745 (D.C. Circuit Decision). Order No. 745 established uniform compensation levels for demand response resources

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that participate in the day ahead and real-time wholesale energy markets. Under Order No. 745, buyers in ISO and RTO markets were required to pay demand response resources the full Locational Marginal Price when the demand response replaced a generation resource and was cost-effective. On January 25, 2016, the U.S. Supreme Court reversed the D.C. Circuit Court decision and remanded the matter to the D.C. Circuit Court. While we cannot predict exactly how the D.C. Circuit Court will handle the matter on remand, we do not expect there will be any significant change in how demand response resources have or will participate in and be paid by wholesale energy markets. Thus, we do not anticipate that there will be any impact to the Registrants' results of operations or cash flows based on these proceedings.

New England Capacity Market Results (Exelon and Generation). Each year, ISO New England, Inc. (ISO-NE) files the results of its annual capacity auction at the FERC which is required to include documentation regarding the competitiveness of the auction. Consistent with this requirement, on February 27, 2015, ISO-NE filed the results of its ninth capacity auction (covering the June 1, 2018 through May 31, 2019 delivery period). On June 18, 2015, the FERC accepted the results of the ninth capacity auction. On July 20, 2015, a union representing utility workers sought rehearing of that decision which the FERC denied on December 30, 2015. It is not clear whether the FERC's order will be appealed.

On February 28, 2014, ISO-NE filed the results of its eighth capacity auction (covering the June 1, 2017 through May 31, 2018 delivery period). On June 27, 2014, the FERC issued a letter to ISO-NE noting that ISO-NE's February 28, 2014 filing was deficient and that ISO-NE must file additional information before the FERC can process the filing. ISO-NE filed the information on July 17, 2014, and the ISO-NE's filings became effective by operation of law pursuant to a notice issued by the secretary of FERC on September 16, 2014. Several parties sought rehearing of the secretary's notice which was effectively denied in October 2014 and have since appealed the matter to the D.C. Circuit Court. On April 7, 2015 the D.C. Circuit Court issued an order referring the matter to a merits panel where issues raised by parties challenging the FERC decision will be heard as well as FERC's Motion to Dismiss the challenges. It is not clear whether the court will decide ultimately on the merits of the case or whether it will dismiss the case as FERC urges based on the fact that there is no action by the FERC to be considered. Nonetheless, while any change in the auction results is thought to be unlikely, Exelon and Generation cannot predict with certainty what further action the court may take concerning the results of that auction, but any court action could be material to Exelon's and Generation's expected revenues from the capacity auction.

License Renewals (Exelon and Generation). Generation has 40-year operating licenses from the NRC for each of its nuclear units. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC's review.

On May 29, 2013, Generation submitted applications to the NRC to extend the current operating licenses of Byron Units 1 and 2 and Braidwood Units 1 and 2 by 20 years. On November 19, 2015, the NRC approved Generation's request to extend the operating licenses of Byron Unit 1 and 2 by 20 years to 2044 and 2046, respectively. On January 27, 2016 the NRC approved Generation's request to extend the operating licenses of Braidwood Unit 1 and 2 by 20 years to 2046 and 2047, respectively.

On December 09, 2014, Generation submitted an application to the NRC to extend the current operating licenses of LaSalle Units 1 and 2, which were set to expire in 2022 and 2023, respectively.

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy

Run Pumped Storage Project (Muddy Run), respectively. On December 22, 2015, FERC issued a new 40-year license for Muddy Run. The license term expires on December 1, 2055. The financial impact associated with Muddy Run license commitments is estimated to be in the range of an incremental $25 million to $35 million, and includes both capital expenditures and operating expenses, primarily relating to fish passage and habitat improvement projects. At December 31, 2015, $22 million of direct costs associated with the licensing effort have been capitalized.

Generation is working with stakeholders to resolve water quality licensing issues with the MDE for Conowingo, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On January 30, 2014, Generation filed a water quality certification application pursuant to Section 401 of the CWA with MDE for Conowingo, addressing these and other issues, although Generation cannot currently predict the conditions that ultimately may be imposed. MDE indicated that it believed it did not have sufficient information to process Generation's application. As a result, Generation entered into an agreement with MDE to work with state agencies in Maryland, the U.S. Army Corps of Engineers, the U.S. Geological Survey, the University of Maryland Center for Environmental Science and the U.S. Environmental Protection Agency Chesapeake Bay Program to design, conduct and fund an additional multi-year sediment study. Generation has agreed to contribute up to $3.5 million to fund the additional study. Because states must act on applications under Section 401 of the CWA within one year and the sediment study would not be completed prior to January 31, 2015, Exelon withdrew its application for a water quality certification on December 4, 2014. FERC policy requires that an applicant resubmit its request for a water quality certification within 90 days of the date of withdrawal. Accordingly, on March 3, 2015, Generation refiled its application for a water quality certification. Exelon has agreed with MDE to withdraw and refile its application for a water quality certification as necessary pending completion of the sediment study. On August 7, 2015, US Fish and Wildlife Service (USFWS) submitted its modified fishway prescription to FERC in the Conowingo licensing proceedings. On September 11, 2015, Exelon filed a request for an administrative hearing and proposed an alternative prescription to challenge USFWS's preliminary prescription. Resolution of these issues relating to Conowingo may have a material effect on Exelon's and Generation's results of operations and financial position through an increase in capital expenditures and operating costs.

The FERC license for Conowingo expired on September 1, 2014. Under the Federal Power Act, FERC is required to issue an annual license for a facility until the new license is issued. On September 10, 2014, FERC issued an annual license for Conowingo, effective as of the expiration of the previous license. If FERC does not issue a new license prior to the expiration of an annual license, the annual license will renew automatically. On March 11, 2015, FERC issued the final Environmental Impact Statement for Conowingo. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. As of December 31, 2015, $23 million of direct costs associated with licensing efforts have been capitalized.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of December 31, 2015 and 2014.

December 31, 2015	Exelon	ComEd	PECO	BGE
Regulatory assets				
Pension and other postretirement benefits	$3,156	$ —	$ —	$ —
Deferred income taxes	1,616	64	1,473	79
AMI programs	399	140	63	196
Under-recovered distribution service costs	189	189	—	—
Debt costs	47	46	1	8
Fair value of BGE long-term debt	162	—	—	—
Severance	9	—	—	9
Asset retirement obligations	108	67	22	19
MGP remediation costs	286	255	30	1
Under-recovered uncollectible accounts	52	52	—	—
Renewable energy	247	247	—	—
Energy and transmission programs	84	43	1	40
Deferred storm costs	2	—	—	2
Electric generation-related regulatory asset	20	—	—	20
Rate stabilization deferral	87	—	—	87
Energy efficiency and demand response programs	279	—	1	278
Merger integration costs	6	—	—	6
Conservation voltage reduction	3	—	—	3
Under-recovered revenue decoupling	30	—	—	30
CAP arrearage	7	—	7	—
Other	35	10	19	3
Total regulatory assets	6,824	1,113	1,617	781
Less: current portion	759	218	34	267
Total noncurrent regulatory assets	$6,065	$ 895	$1,583	$514

December 31, 2015	Exelon	ComEd	PECO	BGE
Regulatory liabilities				
Other postretirement benefits	$ 94	$ —	$ —	$ —
Nuclear decommissioning	2,577	2,172	405	—
Removal costs	1,527	1,332	—	195
Energy efficiency and demand response programs	92	52	40	—
DLC program costs	9	—	9	—
Electric distribution tax repairs	95	—	95	—
Gas distribution tax repairs	28	—	28	—
Energy and transmission programs	131	53	60	18
Over-recovered revenue decoupling	1	—	—	1
Other	16	5	2	8
Total regulatory liabilities	4,570	3,614	639	222
Less: current portion	369	155	112	38
Total noncurrent regulatory liabilities	$4,201	$3,459	$527	$184

Combined Notes to Consolidated Financial Statements—(Continued)
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December 31, 2014	Exelon	ComEd	PECO	BGE
Regulatory assets				
Pension and other postretirement benefits	$3,256	$ —	$ —	$ —
Deferred income taxes	1,542	64	1,400	78
AMI programs	296	91	77	128
Under-recovered distribution service costs	371	371	—	—
Debt costs	57	53	4	9
Fair value of BGE long-term debt	190	—	—	—
Severance	12	—	—	12
Asset retirement obligations	116	74	26	16
MGP remediation costs	257	219	37	1
Under-recovered uncollectible accounts	67	67	—	—
Renewable energy	207	207	—	—
Energy and transmission programs	48	33	—	15
Deferred storm costs	3	—	—	3
Electric generation-related regulatory asset	30	—	—	30
Rate stabilization deferral	160	—	—	160
Energy efficiency and demand response programs	248	—	—	248
Merger integration costs	8	—	—	8
Conservation voltage reduction	2	—	—	2
Under-recovered revenue decoupling	7	—	—	7
Other	46	22	14	7
Total regulatory assets	6,923	1,201	1,558	724
Less: current portion	847	349	29	214
Total noncurrent regulatory assets	$6,076	$ 852	$1,529	$510

December 31, 2014	Exelon	ComEd	PECO	BGE
Regulatory liabilities				
Other postretirement benefits	$ 88	$ —	$ —	$ —
Nuclear decommissioning	2,879	2,389	490	—
Removal costs	1,566	1,343	—	223
Energy efficiency and demand response programs	59	25	34	—
DLC program costs	10	—	10	—
Electric distribution tax repairs	102	—	102	—
Gas distribution tax repairs	49	—	49	—
Energy and transmission programs	84	19	58	7
Revenue subject to refund	3	3	—	—
Over-recovered revenue decoupling	12	—	—	12
Other	8	1	4	2
Total regulatory liabilities	4,860	3,780	747	244
Less: current portion	310	125	90	44
Total noncurrent regulatory liabilities	$4,550	$3,655	$657	$200

Pension and other postretirement benefits. As of December 31, 2015, Exelon had regulatory assets of $3,156 million and regulatory liabilities of $94 million related to ComEd's and BGE's portion of deferred costs associated with Exelon's pension plans and ComEd's, PECO's and BGE's portion of

deferred costs associated with Exelon's other postretirement benefit plans. PECO's pension regulatory recovery is based on cash contributions and is not included in the regulatory asset (liability) balances. The regulatory asset (liability) is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses (gains) attributable to Exelon's pension and other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd, PECO and BGE will recover these costs through base rates as allowed in their most recently approved regulated rate orders. The pension and other postretirement benefit regulatory asset balance includes a regulatory asset established at the date of the Constellation merger related to BGE's portion of the deferred costs associated with legacy Constellation's pension and other postretirement benefit plans. The BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the Constellation merger. See Note 17—Retirement Benefits for additional detail. No return is earned on Exelon's regulatory asset.

Deferred income taxes. These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded under GAAP. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with the authoritative guidance for accounting for certain types of regulation and income taxes, include the deferred tax effects associated principally with accelerated depreciation accounted for in accordance with the ratemaking policies of the ICC, PAPUC and MDPSC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For BGE, this amount includes the impacts of a reduction in the deductibility, for Federal income tax purposes, of certain retiree health care costs pursuant to the March 2010 Health Care Reform Acts. For BGE, these additional income taxes are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. For PECO, this amount includes the impacts of electric and gas distribution repairs in the deductibility pursuant to PUC's 2010 and 2015 rate case settlement agreements. See Note 15—Income Taxes and Note 17—Retirement Benefits for additional information. ComEd, PECO and BGE are not earning a return on the regulatory asset in base rates.

AMI programs. For ComEd, this amount represents meter costs associated with ComEd's AMI pilot program approved in ComEd's 2010 rate case. The recovery periods for the meter costs are through January 1, 2020. As of December 31, 2015 and December 31, 2014, ComEd had regulatory assets of $137 million and $88 million, respectively, related to accelerated depreciation costs resulting from the early retirements of non-AMI meters, which will be amortized over an average ten year period pursuant to the ICC approved AMI Deployment plan. ComEd is earning a return on the regulatory asset. For PECO, this amount represents accelerated depreciation and filing and implementation costs relating to the PAPUC-approved Smart Meter Procurement and Installation Plan as well as the return on the un-depreciated investment, taxes, and operating and maintenance expenses. The approved plan allows for recovery of filing and implementation costs incurred through December 31, 2012. In addition, the approved plan provides for recovery of program costs, which includes depreciation on new equipment placed in service, beginning in January 2011 on full and current basis, which includes interest income or expense on the under or over recovery. The approved plan also provides for recovery of accelerated depreciation on PECO's non-AMI meter assets over a 10-year period ending December 31, 2020. Recovery of smart meter costs will be reflected in base rates effective January 1, 2016. For BGE, this amount represents smart grid pilot program costs as well as the incremental costs associated with implementing full deployment of a smart grid program. Pursuant to a MDPSC order, pilot program costs of $11 million were deferred in a regulatory asset, and, beginning with the MDPSC's March 2011 rate order, is earning BGE's most current authorized rate of return. In August

2010, the MDPSC approved a comprehensive smart grid initiative for BGE, authorizing BGE to establish a separate regulatory asset for incremental costs incurred to implement the initiative, including the net depreciation and amortization costs associated with the meters, and an appropriate rate of return on these costs, a portion of which is not recognized under GAAP until cost recovery begins. Additionally, the MDPSC requires that BGE prove the cost-effectiveness of the entire smart grid initiative prior to seeking recovery of the costs deferred in these regulatory assets. As part of the 2015 electric and gas distribution rate case filed on November 6, 2015 and amended on January 5, 2016, BGE is seeking recovery of its smart grid initiative costs. Of BGE's requested $200 million, $140 million relates to the smart grid initiative. In support of its recovery of smart grid initiative costs, BGE provided evidence demonstrating that the benefits exceed the costs by a ratio of 2.3 to 1.0, on a nominal basis. If approved by the MDPSC, the amortization of these deferred costs would begin in June 2016. BGE's AMI regulatory asset excludes costs for non-AMI meters being replaced by AMI meters, as recovery of those costs commenced with the new rates approved and implemented with the MDPSC order in BGE's 2014 electric and gas distribution case.

Under-recovered distribution services costs. These amounts represent under (over) recoveries related to electric distribution services costs recoverable (refundable) through EIMA's performance based formula rate tariff. Under (over) recoveries for the annual reconciliations are recoverable (refundable) over a one-year period and costs for certain one-time events, such as large storms, are recoverable over a five-year period. ComEd earns and pays a return on under and over recovered costs, respectively. As of December 31, 2015, the regulatory asset was comprised of $142 million for the 2014 and 2015 annual reconciliations and $47 million related to significant one-time events, including $36 million in deferred storm costs and $11 million of Constellation merger and integration related costs. As of December 31, 2014, the regulatory asset was comprised of $286 million for the 2013 and 2014 annual reconciliations and $85 million related to significant one-time events, including $66 million in deferred storm costs and $19 million of Constellation merger and integration related costs. See *Energy Infrastructure Modernization Act* above for further details.

Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd's, PECO's and BGE's recoverable losses on reacquired long-term debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding or the life of the original issuance retired. These debt costs are used in the determination of the weighted cost of capital applied to rate base in the rate-making process. ComEd and BGE are not earning a return on the recovery of these costs, while PECO is earning a return on the premium of the cost of the reacquired debt through base rates.

Fair value of BGE long-term debt. These amounts represent the regulatory asset recorded at Exelon for the difference in the fair value of the long-term debt of BGE as of the Constellation merger date based on the MDPSC practice to allow BGE to recover its debt costs through rates. Exelon is amortizing the regulatory asset and the associated fair value over the life of the underlying debt and is not earning a return on the recovery of these costs.

Severance. For BGE, these costs represent deferred severance costs associated with a 2010 workforce reduction that were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. Additionally, costs associated with the 2012 BGE voluntary workforce reduction were deferred in 2012 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period that began in July 2012. BGE is earning a regulated return on the regulatory asset included in base rates.

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Asset retirement obligations. These costs represent future legally required removal costs associated with existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd and BGE will recover these costs through future depreciation rates and will earn a return on these costs once the removal activities have been performed. See Note 16—Asset Retirement Obligations for additional information.

MGP remediation costs . ComEd is allowed recovery of these costs under ICC approved rates. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures. ComEd and PECO are not earning a return on the recovery of these costs. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. BGE is earning a return on this regulatory asset and these costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. The recovery period for the 10-year period that began January 2006 was extended for an additional 24 months, in accordance with the MDPSC approved 2014 electric and natural gas distribution rate case order. See Note 23—Commitments and Contingencies for additional information.

Under recovered uncollectible accounts. These amounts represent the difference between ComEd's annual uncollectible accounts expense and revenues collected in rates through an ICC-approved rider. The difference between net uncollectible account charge-offs and revenues collected through the rider each calendar year is recovered or refunded over a twelve-month period beginning in June of the following calendar year. ComEd does not earn a return on these under recoveries.

Renewable energy. In December 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy. Delivery under the contracts began in June 2012. Since the swap contracts were deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy at the market price and the contracted price.

Energy and transmission programs. These amounts represent under (over) recoveries related to energy and transmission costs recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. Under (over) recoveries are recoverable (refundable) over a one-year period or less. ComEd earns a return or interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2015, ComEd's regulatory asset of $43 million included $5 million related to under-recovered energy costs, $31 million associated with transmission costs recoverable through its FERC-approved formula rate tariff, and $7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2015, ComEd's regulatory liability of $53 million included $29 million related to over-recovered energy costs and $24 million associated with revenues received for renewable energy requirements. As of December 31, 2014, ComEd's regulatory asset of $33 million included $4 million related to under-recovered energy costs, $22 million associated with transmission costs recoverable through its FERC-approved formula rate tariff, and $7 million of

Combined Notes to Consolidated Financial Statements—(Continued)
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Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2014, ComEd's regulatory liability of $19 million included $3 million related to over-recovered energy costs and $16 million associated with revenues received for renewable energy requirements. See *Transmission Formula Rate* above for further details.

The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO's GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. In addition, the DSP Program costs are presented on a net basis with PECO's GSA under (over)-recovered energy costs. See additional discussion below. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2015, PECO had a regulatory liability that included $35 million related to the DSP program, $22 million related to over-recovered natural gas supply costs under the PGC and $3 million related to over-recovered electric transmission costs. As of December 31, 2014, PECO had a regulatory liability that included $39 million related to the DSP program, $3 million related the over-recovered electric transmission costs and $16 million related to over-recovered natural gas supply costs under the PGC.

DSP Program Costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO's PAPUC-approved DSP programs for the procurement of electric supply. The filings and procurements of these DSP Programs are recoverable through the GSA over each respective term. The original DSP Program had a 29-month term that began January 1, 2011. DSP II and DSP III each have a 24-month term that began June 1, 2013 and June 1, 2015, respectively. The independent evaluator costs associated with conducting procurements are recoverable over a 12-month period after the PAPUC approves the results of the procurements. PECO is not earning a return on these costs. Certain costs included in PECO's original DSP program related to information technology improvements were recovered over a 5-year period that began January 1, 2011. PECO earns a return on the recovery of information technology costs. These costs are included within the energy and transmission programs line item.

The BGE energy costs represent the electric supply, gas supply, and transmission related costs recoverable (refundable) from (to) customers under BGE's market-based SOS program, MBR program, and FERC approved transmission rates, respectively. BGE does not earn or pay interest on under- or over-recovered costs to customers. As of December 31, 2015, BGE's regulatory asset of $40 million included $12 million associated with transmission costs recoverable through its FERC approved formula rate and $28 million related to under-recovered electric energy costs. As of December 31, 2015, BGE's regulatory liability of $18 million related to $5 million of over-recovered natural gas costs $14 million of over-recovered transmission costs, offset by $1 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2014, BGE's regulatory asset of $15 million included $10 million related to under-recovered electric energy costs, $4 million of Constellation merger and integration costs and $1 million of transmission costs recoverable through its FERC approved formula rate. As of December 31, 2014, BGE's regulatory liability of $7 million related to over-recovered natural gas supply costs.

Deferred storm costs. In the MDPSC's March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. BGE earns a return on this regulatory asset and the recovery period was extended for an additional 25 months, in accordance with the MDPSC approved 2014 electric and natural gas distribution rate case order.

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Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. The portion of this regulatory asset that does not earn a regulated rate of return was $19 million as of December 31, 2015, and $28 million as of December 31, 2014. BGE will continue to amortize this amount through 2017.

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006 to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007 to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2015 and 2014, BGE recovered $73 million and $65 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007.

Energy efficiency and demand response programs. For ComEd, these amounts represent over recoveries related to ComEd's ICC-approved Energy Efficiency and Demand Response Plan. ComEd refunds these over recoveries through a rider over a twelve-month period. ComEd earns a return on the capital investment incurred under the program, but does not earn or pay interest on under or over recoveries, respectively. For PECO, these amounts represent over recoveries of program costs related to both Phase I and Phase II of its PAPUC-approved EE&C Plan. PECO began recovering the costs of its Phase I and Phase II EE&C Plans through a surcharge in January 2010 and June 2013, respectively, based on projected spending under the programs. Phase I recovery continued over the life of the program, which expired on May 31, 2013 and excess funds collected began being refunded in June 2013. Phase II of the program began on June 1, 2013, and will continue over the life of the program, which will expire on May 31, 2016. Excess funds collected are required to be refunded beginning in June 2016. PECO earned a return on the capital investment incurred under Phase I of the program. PECO does not earn (pay) interest on under (over) collections. For BGE, these amounts represent under (over) recoveries related to BGE's Smart Energy Savers Program ®, which includes both MDPSC-approved demand response and energy efficiency programs. For the BGE Peak Rewards SM demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Also included in the demand response program are customer bill credits related to BGE's Smart Energy Rewards program which began in July 2013 and are being recovered through the surcharge. Actual costs incurred in the energy efficiency program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

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Merger integration costs. These amounts represent integration costs to achieve distribution synergies related to the Constellation merger transaction. As a result of the MDPSC's February 2013 rate order, BGE deferred $8 million related to non-severance merger integration costs incurred during 2012 and the first quarter of 2013. Of these costs, $4 million was authorized to be amortized over a 5-year period that began in March 2013. The recovery of the remaining $4 million was deferred. In the MDPSC's December 2013 rate order, BGE was authorized to recover the remaining $4 million and an additional $4 million of non-severance merger integration costs incurred during 2013. These costs are being amortized over a 5-year period that began in December 2013. BGE is earning a return on this regulatory asset included in base rates.

Under (Over)-recovered electric and gas revenue decoupling. These amounts represent the electric and gas distribution costs recoverable from or (refundable) to customers under BGE's decoupling mechanism, which does not earn a rate of return. As of December 31, 2015, BGE had a regulatory asset of $30 million related to under-recovered electric revenue decoupling and a regulatory liability of $1 million related to over-recovered natural gas revenue decoupling. As of December 31, 2014, BGE had a regulatory asset of $7 million related to under-recovered electric revenue decoupling and a regulatory liability of $12 million related to over-recovered natural gas revenue decoupling.

CAP arrearage. These amounts represent the guaranteed recovery of previously incurred bad debt expense associated with the estimated eligible CAP accounts receivable balances under the IPAF Program as provided by the 2015 electric distribution rate case settlement. These costs are amortized as recovery is received through a combination of customer payments and rate recovery, including through future rate cases if necessary. PECO is not earning a return on this regulatory asset.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs for the Regulatory Agreement Units that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will be sufficient to fund the associated future decommissioning costs at the time of decommissioning. Exelon is not accruing interest on these costs. See Note 16—Asset Retirement Obligations for additional information.

Removal costs. These amounts represent funds ComEd and BGE have received from customers through depreciation rates to cover the future non-legally required cost of removal of property, plant and equipment which reduces rate base for ratemaking purposes. This liability is reduced as costs are incurred.

DLC program costs. The DLC program costs include equipment, installation, and information technology costs necessary to implement the DLC Program under PECO's EE&C Phase I Plans. PECO received full cost recovery through Phase I collections and will amortize the costs as a credit to the income statement to offset the related depreciation expense during the same period through September 2025, which is the remaining useful life of the assets. PECO is not paying interest on these over-recovered costs.

Electric distribution tax repairs. PECO's 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits began being reflected in customer bills on January 1, 2012. PECO's 2015 electric distribution rate case settlement requires PECO to pay interest on the unamortized balance of the tax-effected catch-up deduction beginning January 1, 2016.

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Gas distribution tax repairs. PECO's 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits began being reflected in customer bills on January 1, 2013. No interest will be paid to customers.

Revenue subject to refund. These amounts represent refunds and associated interest ComEd owes to customers primarily related to the treatment of the post-test year accumulated depreciation issue in the 2007 Rate Case. As of December 31, 2015, and December 31, 2014, ComEd owed $0 million and $3 million, respectively.

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities' consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd and BGE purchase receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO, and BGE do not record unbilled commodity receivables under their POR programs. Purchased billed receivables are classified in other accounts receivable, net on Exelon's, ComEd's, PECO's and BGE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of December 31, 2015 and 2014.

As of December 31, 2015	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 229	$ 103	$ 67	$59
Allowance for uncollectible accounts [b]	(31)	(16)	(7)	(8)
Purchased receivables, net	$ 198	$ 87	$ 60	$51

As of December 31, 2014	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 290	$ 139	$ 76	$ 75
Allowance for uncollectible accounts [b]	(42)	(21)	(8)	(13)
Purchased receivables, net	$ 248	$ 118	$ 68	$ 62

(a) PECO's gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. The implementation costs were fully recovered and the 1% discount was reset to 0%, effective July 2015.
(b) For ComEd and BGE, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing (PORCB) tariff.

4. Mergers, Acquisitions, and Dispositions (Exelon and Generation)

Proposed Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to

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combine the two companies in an all cash transaction. The resulting company will retain the Exelon name. Under the Merger Agreement, PHI's shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. Based on the outstanding shares of PHI's common stock as of December 31, 2015, PHI shareholders would receive $6.9 billion in total cash. In addition, in connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $180 million of a class of nonvoting, nonconvertible and nontransferable preferred securities of PHI. The preferred securities are included in Other non-current assets on Exelon's Consolidated Balance Sheet. PHI has the right to redeem the preferred securities at its option for the purchase price paid plus accrued dividends, if any.

On November 2, 2015, Exelon and PHI each filed a new Notification and Report Form with the DOJ under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act) due to the expiration of the original filing. The HSR Act waiting period expired on December 2, 2015, and the HSR Act no longer precludes completion of the merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU), the Delaware Public Service Commission (DPSC), the Maryland Public Service Commission (MDPSC) and the FERC have approved the merger of PHI and Exelon. The Federal Communications Commission has also approved the transfer of certain PHI communications licenses.

On February 11, 2015, the NJBPU approved the proposed merger and the previously filed settlement signed and filed by Exelon, PHI, Atlantic City Electric (ACE), NJBPU staff, and the Independent Energy Coalition. The settlement provides a package of benefits to ACE customers and the state of New Jersey. This package of benefits includes the establishment of customer rate credit programs, with an aggregate value of $62 million for ACE customers and energy efficiency programs that will provide savings for ACE customers of $15 million. The March 6, 2015, order by the NJBPU approving the merger required that the consummation of the merger must take place no later than November 1, 2015 unless otherwise extended by the Board. On October 15, 2015, the NJBPU extended the November 1, 2015 date to June 30, 2016.

On February 13, 2015, Exelon and PHI announced that they had reached a settlement agreement in the proceeding before the DPSC to review the proposed merger. The settlement, which was amended on April 7, 2015, was signed and filed by Exelon, PHI, Delmarva Power & Light Company (DPL), the DPSC Staff, the Delaware Public Advocate, the Delaware Department of Natural Resources and Environmental Control, the Delaware Sustainable Energy Utility, the Mid-Atlantic Renewable Energy Coalition and the Clean Air Council. As part of this settlement, Exelon and PHI proposed a package of benefits to DPL customers and the state of Delaware including the establishment of customer rate credits of $40 million for DPL customers in Delaware, $2 million of funding for energy efficiency programs for DPL low income customers, and $2 million of funding for workforce development. On June 2, 2015, the DPSC issued an order accepting the settlement and approving the merger between Exelon and PHI.

On March 17, 2015, Exelon and PHI announced that they had reached settlements with multiple parties in the Maryland proceeding to review the proposed merger after filing a Request for Adoption of Settlements with the MDPSC. The settlements were signed and filed by Exelon, PHI, Montgomery County, Prince George's County, the National Consumer Law Center, National Housing Trust, the Maryland Affordable Housing Coalition, the Housing Association of Nonprofit Developers, and a consortium of recreational trail advocacy organizations led by the Mid-Atlantic Off-Road Enthusiasts.

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Exelon and PHI also announced a settlement with The Alliance for Solar Choice. On May 15, 2015, the MDPSC approved the merger after modifying a number of the conditions in the settlements, resulting in total rate credits of $66 million, funding for energy efficiency programs of $43.2 million, a Green Sustainability Fund of $14.4 million, 20 MWs of renewable generation development and increased penalties related to reliability commitments. On May 18, 2015, Exelon and PHI accepted and committed to fulfill the conditions.

On June 11, 2015, the Maryland Office of People's Counsel (OPC), the Sierra Club, and the Chesapeake Climate Action Network filed Petitions for Judicial Review of the MDPSC's approval of the merger with the Circuit Court for Queen Anne's County. On June 23, 2015, Public Citizen, Inc. filed its Petition for Judicial Review with the Circuit Court for Queen Anne's County. On July 10, 2015, Exelon and PHI filed a response in opposition to the Petitions for Review.

On July 21, 2015, the OPC filed a motion to stay the MDPSC order approving the merger and to set a schedule for discovery and presentation of new evidence. On July 29, 2015, Public Citizen, Inc. filed a response supporting OPC's motion to stay, and on July 31, 2015 the Sierra Club and the Chesapeake Climate Action Network filed a joint motion to stay. In July and August, Exelon, PHI, the MDPSC, Prince George's County and Montgomery County filed responses opposing the motions to stay. The judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC's order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, the Chesapeake Climate Action Network (CCAN) and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special appeals, and on January 21, Sierra Club and CCAN filed a notice of appeal. In the ordinary course this appeal would be resolved no earlier than third quarter 2016.

On August 27, 2015, the District of Columbia Public Service Commission (DCPSC) issued an Opinion and Order denying approval of the merger, concluding that the merger as presented was not in the public interest. Exelon and PHI filed an Application for Reconsideration with the DCPSC on September 28, 2015. On October 6, 2015, Exelon, PHI, the District of Columbia Government, the Office of Peoples Counsel, the District of Columbia Water and Sewer Authority, the National Consumer Law Center, National Housing Trust and National Housing Trust—Enterprise Preservation Corporation, and the Apartment and Office Building Association of Metropolitan Washington (collectively, Settling Parties) entered into a Nonunanimous Full Settlement Agreement and Stipulation (Settlement Agreement) with respect to the merger. Exelon and PHI subsequently filed a motion of joint applicants requesting the DCPSC to reopen the approval application to allow for consideration of the Settlement Agreement and granting additional requested relief. The new package of benefits totals $78 million and includes commitments to provide relief of residential customer base rate increases of $26 million, one-time direct bill credits of $14 million, low-income energy assistance of $16 million, improved reliability, a cleaner and greener D.C. through funding energy efficiency programs and development of renewable energy, and investment in local jobs and the local economy through workforce development of $5 million. It also guarantees charitable contributions totaling $19 million over 10 years.

On October 28, 2015, the DCPSC agreed to reopen the approval application to allow for consideration of the Settlement Agreement. Since then, parties supporting and opposing the Settlement filed testimony, participated in formal hearings and, on December 23, 2015, submitted final briefs to the DCPSC. The parties now await a formal decision from the DCPSC. The Merger Agreement provides that either Exelon or PHI may terminate the Merger Agreement if the merger is not completed by October 28, 2015. Pursuant to a Letter Agreement related to the Settlement Agreement, Exelon and PHI have agreed, among other things, that they will not exercise their rights to terminate

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the Merger Agreement before March 4, 2016, except under limited circumstances. If the DCPSC does not approve the Settlement Agreement by March 4, 2016, either Exelon or PHI may terminate the Settlement Agreement.

The settlements reached and commission orders received to date in Delaware, Maryland and New Jersey include a "most favored nation" provision which, generally speaking, requires allocation of merger benefits proportionately across all the jurisdictions. When applying the most favored nation provision to the settlement terms and other conditions established in the merger approvals received to date, and as proposed in the Settlement Agreement filed with the DCPSC, Exelon and PHI currently estimate direct benefits of $430 million or more on a net present value basis (excluding charitable contributions and renewable generation commitments) will be provided, including rate credits, funding for energy efficiency programs and other required commitments. Exelon and PHI anticipate substantially all of such amounts will be charged to earnings at the time of merger close and will be paid by the end of 2017. An additional $53 million will be charged to earnings at the time of the merger close for charitable contributions, which are then required to be paid over a period of 10 years. Commitments to develop renewable generation, which are expected to be primarily capital in nature, will be recognized as incurred. Upon completion of the merger, the actual nature, amount, timing and financial reporting treatment for these commitments may be materially different from the current projection.

Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. Exelon was also named in a federal court suit making similar claims. In September 2014, the parties reached a proposed settlement that would resolve all claims, which is subject to court approval. Final court approval of the proposed settlement is not anticipated until approximately 90 days after merger close. Exelon does not believe these suits will impact the completion of the transaction, and they are not expected to have a material impact on Exelon's results of operations.

Including 2014 and through December 31, 2015, Exelon has incurred approximately $259 million of expense associated with the proposed merger. Of the total costs incurred, $121 million is primarily related to acquisition and integration costs and $138 million are for costs incurred to finance the transaction. The financing costs include $22 million of costs associated with the private exchange offer and redemption of certain Senior Unsecured Notes (see Note 14—Debt and Credit Agreements for further information on the exchange), as well as, a net loss of $64 million related to the settlement of forward-starting interest-rate swaps. These swaps were terminated in connection with the $4.2 billion issuance of debt; refer to Note 13—Derivative Financial Instruments for more information. The financing costs exclude costs to issue equity and the initial debt offering which we recorded to Exelon's Consolidated Balance Sheets.

Acquisition, Integration and Financing Costs [a]	For the year ended, 2015	2014
Exelon	$ 80	$ 179
Generation	25	11
ComEd	10	4
PECO	5	2
BGE	5	2

(a) The costs incurred are classified primarily within Operating and maintenance expense in the Registrants' respective Consolidated Statement of Operations and Comprehensive Income, with the exception of the financing costs, which are included within Interest expense.

Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the Merger Agreement is terminated due to a failure to obtain a required regulatory approval, Exelon may be required to pay PHI a termination fee equal to $180 million through the redemption by PHI of the outstanding nonvoting preferred securities described above for no consideration other than the nominal par value of the stock, plus reimbursement of PHI's documented out-of-pocket expenses up to a maximum of $40 million.

Merger Financing

Exelon has raised cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments, through the issuance of $4.2 billion of debt (of which $3.3 billion remains after execution of the exchange offer, see Note 14—Debt and Credit Agreements for further information on the exchange), $1.15 billion of junior subordinated notes in the form of 23 million equity units, the issuance of $1.9 billion of common stock, cash proceeds of $1.8 billion from asset sales primarily at Generation (after-tax proceeds of approximately $1.4 billion) and the remaining balance from cash on hand and/or short-term borrowings available to Exelon. Exelon will have sufficient cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments. See Note 14—Debt and Credit Agreements and Note 19—Shareholder's Equity for further information on the debt and equity issuances.

Acquisitions (Exelon and Generation)

Acquisition of Integrys Energy Services, Inc. (Exelon and Generation)

On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (IES) for a purchase price of $332 million, including net working capital. Generation has elected to account for the transaction as an asset acquisition for federal income tax purposes. The generation and solar asset businesses of Integrys are excluded from the transaction. The Purchase Agreement also includes various representations, warranties, covenants, indemnification and other provisions customary for a transaction of this nature.

Consistent with the applicable accounting guidance, the fair value of the assets acquired and liabilities assumed was determined as of the acquisition date through the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including the amount and timing); discount rates reflecting the risk inherent in the future cash flows; and future power and fuel market prices.

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The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the Integrys acquisition by Generation:

Total consideration transferred	$ 332
Identifiable assets acquired and liabilities assumed	
Working capital assets	$ 390
Mark-to-market derivative assets	184
Unamortized energy contract assets	115
Customer relationships	50
Working capital liabilities	(196)
Mark-to-market derivative liabilities	(57)
Unamortized energy contract liabilities	(110)
Deferred tax liability	(16)
Total net identifiable assets, at fair value	$ 360
Bargain purchase gain (after-tax)	$ 28

The after-tax bargain purchase gain of $28 million is primarily the result of IES executing additional contract volumes between the date the acquisition agreement was signed and the closing of the transaction resulting in an increase in the fair value of the net assets acquired as of the acquisition date. The after-tax gain is included within Gain on consolidation and acquisition of businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

IES's operating revenues and net loss included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the period from November 1, 2014 to December 31, 2014 were $386 million and $(42) million, respectively. The net loss for the period from November 1, 2014 to December 31, 2014 includes pre-tax unrealized losses on derivative contracts of $108 million and the bargain purchase gain of $28 million. It is impracticable to determine the overall financial statement impact of IES for 2015 due to the integration of the business into ongoing operations. For the years ended December 31, 2015 and 2014, Exelon and Generation incurred $5 million and $7 million, respectively, of merger and integration related costs which are included within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

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Asset Divestitures (Exelon and Generation)

Including the Quail Run generating facility that was sold on January 21, 2015, Generation has sold certain generating assets with a total net book value of approximately $1.8 billion prior to consideration of asset impairments (See Note 8—Impairment of Long-Lived Assets for further information), for total pre-tax proceeds of approximately $1.8 billion (after-tax proceeds of approximately $1.4 billion), which resulted in cumulative pre-tax gains on sale of approximately $412 million, which are included in Gain (loss) on sales of assets on Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income for the year ended December 31, 2014. The proceeds are expected to be used primarily to finance a portion of the merger with PHI.

Station	Net Generation Capacity	Location	Operating Segment	Percent Owned
Fore River	726 MW	North Weymouth, MA	New England	100%
West Valley	185 MW	Salt Lake City, UT	Other	100%
Keystone	714 MW	Shelocta, PA	Mid-Atlantic	41.98%
Conemaugh	532 MW	New Florence, PA	Mid-Atlantic	31.28%
Safe Harbor	278 MW	Conestoga, PA	Mid-Atlantic	66.7%
Quail Run	488 MW	Odessa, TX	ERCOT	100%

At December 31, 2014, the assets and liabilities of the Quail Run generating facility were reported as Assets held for sale and within Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets. The table below presents the major classes of assets and liabilities held for sale at December 31, 2014. Assets held for sale at December 31, 2015 are not material.

	December 31, 2014
Assets	
Property, plant and equipment, net [(a)]	$ 143
Inventory	4
Total assets held for sale	$ 147
Liabilities	
Accrued expenses	$ 1
Asset retirement obligations	4
Total liabilities held for sale [(b)]	$ 5

(a) The total aggregate book value of property, plant and equipment is net of a $50 million pre-tax impairment loss recorded within Operating and maintenance expense on Exelon's and Generation's Statements of Operations and Comprehensive Income for the year ended December 31, 2014. See Note 8—Impairment of Long-Lived Assets for further information.
(b) Included within Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

5. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation has historically had various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements, see Note 26—Related Party Transactions.

On April 1, 2014, Generation and subsidiaries of Generation and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for

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the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDF's rights as a member of CENG (the Integration Transaction). CENG will reimburse Generation for its direct and allocated costs for such services. As part of the arrangement, Nine Mile Point Nuclear Station, LLC, a subsidiary of CENG, also assigned to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with Long Island Power Authority, the Unit 2 co-owner. In addition, on April 1, 2014, the Power Services Agency Agreement (PSAA) was amended and extended until the permanent cessation of power generation by the CENG generation plants.

In addition, on April 1, 2014, Generation made a $400 million loan to CENG, bearing interest at 5.25% per annum and payable out of specified available cash flows of CENG or payable upon the maturity date of April 1, 2034. Immediately following receipt of the proceeds of such loan, CENG made a $400 million special distribution to EDF. Unpaid principal and accrued interest on the loan was $300 million as of December 31, 2015.

Exelon, Generation, and subsidiaries of Generation, EDF and CENG also executed a Fourth Amended and Restated Operating Agreement for CENG on April 1, 2014, pursuant to which, among other things, CENG committed to make preferred distributions to Generation (after repayment of the $400 million loan and associated interest) quarterly out of specified available cash flows until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from April 1, 2014 (Preferred Distribution Rights).

Generation and EDF also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDF has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. Under limited circumstances, the period for exercise of the put option may be extended for 18 months. In order to exercise its option, EDF must give 60 days advance written notice to Generation stating that it is exercising its option. As of the date these financial statements were issued, EDF has not given notice to Generation that it is exercising its option.

On April 1, 2014, Generation also executed an Indemnity Agreement pursuant to which Generation indemnified EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity.

In addition, on April 1, 2014, Generation, EDF, CENG and Nine Mile Point Nuclear Station, LLC entered into an Employee Matters Agreement (EMA) that provides for the transfer of CENG employees to Exelon or one of its affiliates and Exelon's assumption of the sponsorship of the employee benefit plans (including certain incentive, health and welfare, and postemployment benefit plans, among others) and their related trusts by Exelon as the plan sponsor as of July 14, 2014. The EMA also generally requires CENG to fund the obligation related to pre-transfer service of employees, including the underfunded balance of the pension and other postretirement welfare benefit plans measured as of July 14, 2014 by making periodic payments to Generation. These payments will be made on an agreed

payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG. However, in the event that EDF exercises its rights under the Put Option, all payments not made as of the put closing date shall accelerate to be paid immediately prior to such closing date.

As a condition to obtaining regulatory approval for the NOSA and related transactions from the NRC, Exelon executed a support agreement pursuant to which Exelon may be required under specified circumstances to provide up to $245 million of financial support to CENG (Exelon Support Agreement). The Exelon Support Agreement supersedes a previous support agreement under which Generation had agreed to provide up to $205 million of financial support for CENG. In addition, Exelon executed a Guarantee pursuant to which Exelon may be required under specified circumstances to provide up to $165 million in additional financial support for CENG. A previous support agreement executed by an affiliate of EDF remains in effect under which the EDF affiliate may be required to provide up to approximately $145 million of financial support for CENG under specified circumstances. The agreements were executed on April 1, 2014 when the NRC licenses were transferred to Generation. No liability has been recognized by Exelon for the guarantees.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. From January 1, 2014, through March 31, 2014, Generation recorded $19 million of equity in losses of unconsolidated affiliates related to its investment in CENG and recorded $17 million of revenues from CENG. For the twelve months ended December 31, 2013, Generation recorded $9 million of equity in losses of unconsolidated affiliates related to its investment in CENG and $56 million of revenues from CENG. The book value of Generation's investment in CENG prior to the consolidation was $1.9 billion, and the book value of the AOCI related to CENG prior to consolidation was $116 million, net of taxes of $77 million.

As a result of the consolidation of CENG on April 1, 2014, there are several additional transactions included in Exelon's and Generation's Consolidated Financial Statements between CENG and Exelon's affiliates that are considered related party transactions to Generation. As further described in Note 26—Related Party Transactions, EDF and Generation had a PPA with CENG under which they purchased 15% and 85%, respectively, of the nuclear output owned by CENG that was not sold to third parties under pre-existing PPAs through December 31, 2014. Beginning January 1, 2015 and continuing through the life of the respective plants, EDF and Generation purchase 49.99% and 50.01%, respectively, of the nuclear output owned by CENG not subject to other contractual agreements. Beginning April 1, 2014, CENG's sales to Generation have been eliminated in consolidation. For the years ended December 31, 2015 and 2014, Generation had sales to EDF of $488 million and $137 million, respectively. See discussion above and Note 2—Variable Interest Entities for additional information regarding other transactions between CENG and EDF included within Exelon and Generation's consolidated financial statements and for additional information about the Registrants VIE's.

Accounting for the Consolidation of CENG

The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interest in CENG at fair value on Exelon's and Generation's Consolidated Balance Sheets. As a result of the consolidation, Exelon and Generation recorded a net gain of $261 million within their respective Consolidated Statements of Operations and Comprehensive Income. This gain consists of approximately $136 million related to the step up to fair value basis of

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Generation's ownership interest in CENG, and approximately $132 million related to the settlement of pre-existing transactions between CENG and Generation. The net gain on the consolidation of CENG of $261 million is net of a $7 million payment to EDF.

The fair value of CENG's assets and liabilities recorded in consolidation was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The valuations necessary to assess the fair values of certain assets and liabilities were considered preliminary as a result of the short time period between the execution of the NOSA and the end of the second quarter of 2014. The estimates of the fair value of assets and liabilities could be modified for up to one year from April 1, 2014, as more information was obtained about the fair value of assets and liabilities. The principal items that have been revised include the asset retirement obligation liabilities and related asset retirement costs. These items have been updated with inputs from a third party engineering firm with corresponding adjustments recorded in 2014 and the first quarter of 2015. See Note 16—Asset Retirement Obligations for discussion of the impacts of adjustments recorded during 2014 and 2015 related to updated estimates of the CENG asset retirement obligation liabilities. In the period of such revisions, these and any other material changes to the fair value assessments have resulted in adjustments to the amounts recorded upon consolidation. In addition, the asset or liability adjustments impacting depreciation and/or accretion expense recorded after the consolidation date have impacted Generation's post-consolidation results of operations.

Generation recorded the assets and liabilities of CENG at fair value as of April 1, 2014. The following assets and liabilities of CENG were recorded within Generation's Consolidated Balance Sheets as of the date of integration, adjusted for the modifications discussed above:

Fair Values	Exelon and Generation
Current assets	$ 499
Nuclear decommissioning trust fund	1,955
Property, plant and equipment	3,073
Nuclear fuel	482
Other assets	10
Total assets	6,019
Current liabilities	237
Asset retirement obligation	1,816
Pension and other employee benefit obligations	281
Unamortized energy contract liabilities	171
Other liabilities	114
Total liabilities	2,619
Total net assets	$ 3,400

Generation also recorded the fair value of the noncontrolling interest on its Consolidated Balance Sheets of approximately $1.5 billion, net of the fair value of $152 million for certain specified additional distribution rights under the Operating Agreement. In addition, the noncontrolling interest was further reduced by the $400 million special cash distribution to EDF.

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Due to the Preferred Distribution Rights that Generation has on CENG's available cash, the earnings attributable to the noncontrolling interest on the Statements of Operations and Comprehensive Income as well as the corresponding adjustment to Noncontrolling interest on the Consolidated Balance Sheets will not be in proportion to Generation's and EDF's equity ownership interests. Rather, the attribution will consider Generation's Preferred Distribution Rights and allocate net income based on each owner's rights to CENG's net assets. For the years ended December 31, 2015 and 2014, Generation reduced by $18 million and $13 million, respectively, the amount of Net income attributable to noncontrolling interests on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. As a result of the consolidation, Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income includes CENG's incremental operating revenues of $509 million and $218 million and CENG's net income (loss), prior to any intercompany eliminations and any adjustments for noncontrolling interest, of $(11) million and $407 million during the years ended December 31, 2015 and 2014, respectively.

Exelon and Generation incurred integration-related costs of $2 million and $26 million for the year ended December 31, 2015 and 2014, respectively. The costs incurred are classified primarily within Operating and maintenance expense in Exelon's and Generation's respective Consolidated Statements of Operations and Comprehensive Income.

6. Accounts Receivable (Exelon, Generation, ComEd, PECO and BGE)

Accounts receivable at December 31, 2015 and 2014 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

2015	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$1,203	$ 732[a]	$ 218	$105	$148
Allowance for uncollectible accounts [b]	(284)	(77)	(75)	(83) [c]	(49)

2014	Exelon	Generation	ComEd	PECO	BGE
Unbilled customer revenues	$1,381	$ 823[a]	$ 204	$ 140	$214
Allowance for uncollectible accounts [b]	(311)	(60)	(84)	(100) [c]	(67) [d]

(a) Represents unbilled portion of retail receivables estimated under Exelon's unbilled critical accounting policy.
(b) Includes the allowance for uncollectible accounts on customer and other accounts receivable.
(c) Excludes the non-current allowance for uncollectible accounts of $8 million at both December 31, 2015 and 2014, related to PECO's current installment plan receivables described below.
(d) At December 31, 2014, as explained in Note 1—Significant Accounting Policies, BGE estimated the allowance for uncollectible accounts on customer receivables by applying loss rates to the outstanding receivable balance by risk segment. The change in estimate resulted in a $19 million pre-tax charge to BGE's provision for uncollectible accounts expense for the year ended December 31, 2014, which is included in Operating and maintenance expense on BGE's Consolidated Statements of Operations and Comprehensive Income.

PECO Installment Plan Receivables (Exelon and PECO). PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $15 million at both

December 31, 2015 and 2014. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1—Significant Accounting Policies. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2015 and December 31, 2014 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of December 31, 2015 and 2014 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1—Significant Accounting Policies.

7. Property, Plant and Equipment (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2015 and 2014:

Asset Category	Average Service Life (years)	2015	2014
Electric—transmission and distribution	5-90	$32,546	$30,157
Electric—generation	1-56	25,615	22,911
Gas—transportation and distribution	5-90	3,864	3,505
Common—electric and gas	5-50	1,149	1,169
Nuclear fuel [a]	1-8	6,384	5,947
Construction work in progress	N/A	3,075	2,167
Other property, plant and equipment [b]	5-50	1,181	1,056
Total property, plant and equipment		73,814	66,912
Less: accumulated depreciation [c]		16,375	14,742
Property, plant and equipment, net		$57,439	$52,170

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,266 million and $1,003 million at December 31, 2015 and 2014, respectively.
(b) Includes Generation's buildings under capital lease with a net carrying value of $13 million and $15 million at December 31, 2015 and 2014, respectively. The original cost basis of the buildings was $52 million, and total accumulated amortization was $39 million and $37 million, as of December 31, 2015 and 2014, respectively. Also includes ComEd's buildings under capital lease with a net carrying value at December 31, 2015 and 2014, of $7 million and $8 million, respectively. The original cost basis of the buildings was $8 million and total accumulated amortization was $1 million and $0.3 million as of December 31, 2015 and 2014, respectively. Includes land held for future use and non utility property at ComEd, PECO, and BGE of $57 million, $21 million, and $32 million, respectively. These balances also include capitalized acquisition, development and exploration costs of $266 million and $242 million related to oil and gas production activities at Generation at December 31, 2015 and 2014, respectively. Includes the original cost and progress payments associated with Generation's turbine equipment held for future use with a carrying value of $146 million and $83 million at December 31, 2015 and 2014, respectively.
(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $2,861 million and $2,673 million as of December 31, 2015 and 2014, respectively.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2015	2014	2013
Electric—transmission and distribution	2.83%	2.93%	2.91%
Electric—generation	3.47%	3.50%	3.35%
Gas	2.17%	2.13%	2.06%
Common—electric and gas	7.79%	7.32%	7.53%

Generation

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2015 and 2014:

	Average Service Life (years)	2015	2014
Asset Category			
Electric—generation	1-56	$25,615	$22,911
Nuclear fuel [a]	1-8	6,384	5,947
Construction work in progress	N/A	2,017	1,404
Other property, plant and equipment [b]	5-31	466	378
Total property, plant and equipment		34,482	30,640
Less: accumulated depreciation [c]		8,639	7,612
Property, plant and equipment, net		$25,843	$23,028

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,266 million and $1,003 million at December 31, 2015 and 2014, respectively.
(b) Includes buildings under capital lease with a net carrying value of $13 million and $15 million at December 31, 2015 and 2014, respectively. The original cost basis of the buildings was $52 million, and total accumulated amortization was $39 million and $37 million, as of December 31, 2015 and 2014, respectively. These balances also include capitalized acquisition, development and exploration costs of $266 million and $242 million related to oil and gas production activities at Generation at December 31, 2015 and 2014, respectively. Includes the original cost and progress payments associated with Generation's turbine equipment held for future use with a carrying value of $146 million and $83 million at December 31, 2015 and 2014, respectively.
(c) Includes accumulated amortization of nuclear fuel in the reactor core of $2,861 million and $2,673 million as of December 31, 2015 and 2014, respectively.

The annual depreciation provisions as a percentage of average service life for electric generation assets were 3.47%, 3.50% and 3.35% for the years ended December 31, 2015, 2014 and 2013, respectively.

License Renewals. Generation's depreciation provisions are based on the estimated useful lives of its generating stations, which assume the renewal of the licenses for all nuclear generating stations (except for Oyster Creek) and the hydroelectric generating stations. As a result, the receipt of license renewals has no material impact on the Consolidated Statements of Operations and Comprehensive Income. See Note 3—Regulatory Matters for additional information regarding license renewals.

Combined Notes to Consolidated Financial Statements—(Continued)
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ComEd

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2015 and 2014:

	Average Service Life (years)	2015	2014
Asset Category			
Electric—transmission and distribution	5-80	$20,576	$18,884
Construction work in progress	N/A	572	276
Other property, plant and equipment [a], [b]	38-50	64	65
Total property, plant and equipment		21,212	19,225
Less: accumulated depreciation		3,710	3,432
Property, plant and equipment, net		$17,502	$15,793

(a) Includes buildings under capital lease with a net carrying value at December 31, 2015 and 2014 of $7 million and $8 million, respectively. The original cost basis of the buildings was $8 million and total accumulated amortization was $1 million and $0.3 million as of December 31, 2015 and 2014, respectively.
(b) Includes land held for future use and non-utility property.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 3.03%, 3.05% and 2.97% for the years ended December 31, 2015, 2014 and 2013, respectively.

PECO

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2015 and 2014:

	Average Service Life (years)	2015	2014
Asset Category			
Electric—transmission and distribution	5-65	$ 7,230	$6,886
Gas—transportation and distribution	5-70	2,206	2,039
Common—electric and gas	5-50	631	618
Construction work in progress	N/A	154	154
Other property, plant and equipment [a]	50	21	21
Total property, plant and equipment		10,242	9,718
Less: accumulated depreciation		3,101	2,917
Property, plant and equipment, net		$ 7,141	$6,801

(a) Represents land held for future use and non-utility property.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2015	2014	2013
Electric—transmission and distribution	2.39%	2.55%	2.73%
Gas	1.87%	1.84%	1.79%
Common—electric and gas	5.16%	5.16%	6.65%

Combined Notes to Consolidated Financial Statements—(Continued)
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BGE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2015 and 2014:

	Average Service Life (years)	2015	2014
Asset Category			
Electric—transmission and distribution	5-90	$6,663	$6,339
Gas—distribution	5-90	1,951	1,761
Common—electric and gas	5-40	655	623
Construction work in progress	N/A	312	317
Other property, plant and equipment [(a)]	20	32	32
Total property, plant and equipment		9,613	9,072
Less: accumulated depreciation		3,016	2,868
Property, plant and equipment, net		$6,597	$6,204

(a) Represents land held for future use and non-utility property.

Average Service Life Percentage by Asset Category	2015	2014	2013
Electric—transmission and distribution	2.62%	2.96%	2.91%
Gas	2.50%	2.47%	2.36%
Common—electric and gas	10.35%	9.49%	8.45%

See Note 1—Significant Accounting Policies for further information regarding property, plant and equipment policies and accounting for capitalized software costs for Exelon, Generation, ComEd, PECO and BGE. See Note 14—Debt and Credit Agreements for further information regarding Exelon's, ComEd's, and PECO's property, plant and equipment subject to mortgage liens.

8. Impairment of Long-Lived Assets (Exelon and Generation)

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the second quarter of each year, Generation updates the long-term fundamental energy prices, which includes a thorough evaluation of key assumptions including gas prices, load growth, environmental policy, plant retirements and renewable growth.

In 2015, the year over year change in fundamentals did not indicate any impairments. In 2014, the year over year change in fundamentals suggested that the carrying value of certain merchant wind assets may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of twelve wind projects, primarily located in West Texas, were less than their respective carrying values at May 31, 2014. As a result, long-lived assets held and used with a carrying amount of approximately $151 million were written down to their fair value of $65 million and a pre-tax impairment charge of $86 million was recorded within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

In 2013, lower projected wind production and a decline in power prices suggested that the carrying value of certain wind projects with market price exposure for either all or a portion of the life of the

asset may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of eleven wind projects, primarily located in West Texas and Minnesota, were less than their respective carrying values at September 30, 2013. As a result, long-lived assets held and used with a carrying amount of approximately $75 million were written down to their fair value of $32 million and a pre-tax impairment charge of $43 million, net of the impairment amount attributable to noncontrolling interests for certain of the projects, was recorded within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During 2015 and 2014, significant declines in oil and gas prices suggested that the carrying value of certain Upstream assets may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of various Upstream properties, primarily located in Oklahoma and Texas, were less than their respective carrying values at December 31, 2015 and 2014. As a result, pre-tax impairment charges of $5 million and $124 million were recorded for the years ended December 31, 2015 and 2014, respectively, within Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. After reflecting the impairment charges, Generation has $187 million of Upstream assets remaining on its Consolidated Balance Sheets at December 31, 2015. Further declines in commodity prices could potentially result in future impairments of the Upstream assets.

The fair value analysis used in the above impairments was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue, generation and production forecasts, projected capital and maintenance expenditures and discount rates. Changes in the assumptions described above could potentially result in future impairments of Exelon's long-lived assets, which could be material.

In 2014, certain non-nuclear generating assets were identified as assets held for sale on Exelon's and Generation's Consolidated Balance Sheets. When long-lived assets are held for sale, an impairment loss is recognized to the extent that the asset's carrying value exceeds its estimated fair value less costs to sell. Long-lived assets with a carrying amount of approximately $1 billion were written down to their fair value of $556 million and a pre-tax impairment charge of $450 million was recorded within Operating and maintenance expense on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. See Note 4—Mergers, Acquisitions, and Dispositions for further information on asset sales.

Nuclear Uprate Program (Exelon and Generation)

Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture (MUR) uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Exelon and Generation recorded a pre-tax charge to Operating and maintenance expense and Interest expense within their Statements of Operations and Comprehensive Income of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

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Like-Kind Exchange Transaction (Exelon)

Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in coal-fired generating station leases located in Georgia and Texas with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. See Note 15—Income Taxes for further information. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessees to arrange for a third-party to bid on a service contract for a period following the lease term. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. In 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases.

On February 26, 2014, UII and the City Public Service Board of San Antonio, Texas (CPS) finalized an agreement to terminate the leases on the generating station located in Texas, as described above, prior to its expiration dates. As a result of the lease termination, UII received a net early termination amount of $335 million from CPS and wrote down the net investment in the CPS long-term lease of $336 million in Investments in Exelon's Consolidated Balance Sheets in 2014; resulting in a pre-tax loss of $1 million being reflected in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income in 2014.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

Based on the annual reviews performed in the second quarters of 2015 and 2014, the estimated residual value of Exelon's direct financing leases for the Georgia generating stations experienced other than temporary declines given increases in estimated long-term operating and maintenance costs in the 2015 annual review and reduced long-term energy and capacity price expectations in the 2014 annual review. As a result, Exelon recorded $24 million pre-tax impairment charges in both 2015 and

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2014 for these stations. These impairment charges were recorded within Investments and Operating and maintenance expense in Exelon's Consolidated Balance Sheets and the Consolidated Statements of Operations and Comprehensive Income, respectively. Changes in the assumptions described above could potentially result in future impairments of Exelon's direct financing lease investments, which could be material. Through December 31, 2015, no events have occurred that would require Exelon to review the estimated residual values of its direct financing lease investments subsequent to the review performed in the second quarter of 2015.

At December 31, 2015 and 2014, the components of the net investment in long-term leases were as follows:

	December 31, 2015	December 31, 2014
Estimated residual value of leased assets	$ 639	$ 685
Less: unearned income	287	324
Net investment in long-term leases	$ 352	$ 361

9. Implications of Potential Early Plant Retirements (Exelon and Generation)

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation's nuclear plants. Factors that will continue to affect the economic value of Generation's nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative solutions in New York and Illinois such as the proposed Low Carbon Portfolio Standard (LCPS) legislation, the impact of final rules from the EPA requiring reduction of carbon and other emissions and the efforts of the states to implement those final rules, and the outcome of the Ginna RSSA hearing and settlement procedures and the resulting contractual terms and conditions. On September 10, 2015, after considering the results of the recent PJM capacity auctions, Exelon and Generation decided to defer decisions about the future operations of its Quad Cities and Byron nuclear plants and will offer both plants in the 2019/2020 auction in May 2016. As a result of clearing the other PJM capacity auction in September 2015 for the 2017/2018 transitional capacity auction, Exelon and Generation will continue to operate its Quad Cities nuclear power plant through at least May 2018. The Byron plant is already obligated to operate through May 2019. On October 29, 2015, Exelon and Generation announced the deferral of any decision about the future operations of its Clinton nuclear plant and plans to bid the plant into the MISO capacity auction for the 2016-2017 planning year in April 2016. This decision was driven by MISO's acknowledgment of the need for market design changes to ensure long-term power system reliability in southern Illinois, the desire to provide Illinois policy makers with additional time to consider needed reforms as well as the potential long-term impact of EPA's Clean Power Plan. Exelon and Generation previously committed to cease operation of the Oyster Creek nuclear plant by the end of 2019. Exelon and Generation have not made any decisions regarding potential nuclear plant closures at other sites at this time.

As a result of a decision to early retire one or more other nuclear plants, certain changes in accounting treatment would be triggered and Exelon's and Generation's results of operations and cash flows could be materially affected by a number of items including, among other items: accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, accelerated amortization of plant specific nuclear fuel costs, employee-related costs (i.e. severance, relocation, retention, etc.), accelerated asset retirement obligation expense related to future decommissioning activities, and additional funding of nuclear decommissioning trust funds. In addition, any early plant retirement would also result in reduced

operating costs, lower fuel expense, and lower capital expenditures in the periods beyond shutdown. While there are a number of Generation's nuclear plants that are at risk of early retirement, the following table provides the balance sheet amounts as of December 31, 2015 for significant assets and liabilities associated with the three nuclear plants currently considered by management to be at the greatest risk of early retirement due to their current economic valuations and other factors:

(in millions)	Quad Cities	Clinton	Ginna	Total
Asset Balances				
Materials and supplies inventory	$ 50	$ 57	$ 29	$ 136
Nuclear fuel inventory, net	218	107	60	385
Completed plant, net	1,030	579	127	1,736
Construction work in progress	11	9	11	31
Liability Balances				
Asset retirement obligation	(698)	(401)	(644)	(1,743)
NRC License Renewal Term	2032	2046(a)	2029	

(a) Assumes Clinton seeks and receives a 20-year operating license renewal extension.

In the event a decision is made to retire early one or more nuclear plants, the precise timing of the retirement date, and resulting financial statement impact, is uncertain and would be influenced by a number of factors such as the results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity obligations and just prior to its next scheduled nuclear refueling outage date in that year.

10. Jointly Owned Electric Utility Plant (Exelon, Generation, PECO and BGE)

Exelon, Generation, PECO and BGE's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2015 and 2014 were as follows:

	Nuclear Generation				Fossil Fuel Generation	Transmission		Other
	Quad Cities	Peach Bottom	Salem (a)	Nine Mile Point Unit 2 (f)	Wyman	PA (b)	DE/NJ (c)	Other (d)
Operator	Generation	Generation	PSEG Nuclear	Generation	FP&L	First Energy	PSEG	
Ownership interest	75.00%	50.00%	42.59%	82.00%	5.89%	Various	42.55%	44.24%
Exelon's share at December 31, 2015:								
Plant (e)	$ 1,035	$ 1,345	$ 566	$ 756	$ 3	$ 15	$ 65	$ 1
Accumulated depreciation (e)	309	368	167	42	3	7	35	1
Construction work in progress	11	18	40	56	—	—	—	—
Exelon's share at December 31, 2014:								
Plant (e)	$ 995	$ 1,095	$ 531	$ 676	$ 3	$ 14	$ 64	$ 2
Accumulated depreciation (e)	266	343	150	14	3	7	34	1
Construction work in progress	15	133	29	48	—	—	—	—

(a) Generation also owns a proportionate share in the fossil fuel combustion turbine at Salem, which is fully depreciated. The gross book value was $3 million at December 31, 2015 and 2014.

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(b) PECO and BGE own a 22% and 7% share, respectively, in 127 miles of 500kV lines located in Pennsylvania; PECO and BGE also own a 20.7% and 10.56% share, respectively, of a 500kV substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500kV lines including, but not limited to, the lines noted above.
(c) PECO owns a 42.55% share in 131 miles of 500kV lines located in Delaware and New Jersey as well as a 42.55% share in a 500kV substation immediately outside of the Salem nuclear generating station in New Jersey which supplies power to the 500kV lines including, but not limited to, the lines noted above.
(d) Generation has a 44.24% ownership interest in assets located at Merrill Creek Reservoir located in New Jersey.
(e) Excludes asset retirement costs.
(f) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet, and as of that date, CENG's operations are consolidated into Generation's financial statements. As of December 31, 2013, Generation's ownership interest in CENG, including Nine Mile Point, was treated as an equity method investment, and thus did not represent an undivided Interest. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.

Exelon's, Generation's, PECO's and BGE's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly-owned facilities. Exelon's, Generation's, PECO's and BGE's share of direct expenses of the jointly owned plants are included in Purchased power and fuel and Operating and maintenance expenses on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and in Operating and maintenance expenses on PECO's and BGE's Consolidated Statements of Operations and Comprehensive Income.

11. Intangible Assets (Exelon, Generation, ComEd and PECO)

Goodwill

Exelon's, Generation's and ComEd's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2015 and 2014 were as follows:

	ComEd			Generation		Exelon		
	Gross Amount [(a)]	Accumulated Impairment Losses	Carrying Amount	Gross Amount	Carrying Amount	Gross Amount	Accumulated Impairment Losses	Carrying Amount
Balance, January 1, 2014	$ 4,608	$ 1,983	$ 2,625	$ —	$ —	$4,608	$ 1,983	$ 2,625
Goodwill from business combination	—	—	—	47	47	47	—	47
Balance, December 31, 2014	4,608	1,983	2,625	47	47	4,655	1,983	2,672
Impairment losses	—	—	—	—	—	—	—	—
Balance, December 31, 2015	$ 4,608	$ 1,983	$ 2,625	$ 47	$ 47	$4,655	$ 1,983	$ 2,672

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom (predecessor parent company of ComEd) merger net of amortization, resolution of tax matters and other non-impairment-related changes as allowed under previous authoritative guidance.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Under the authoritative guidance for goodwill, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial

information is available and its operating results are regularly reviewed by segment management. ComEd has a single operating segment for its combined business. There is no level below this operating segment for which operating results are regularly reviewed by segment management. Therefore, ComEd's operating segment is considered its only reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step one of the two-step fair value based impairment test). If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step fair value based impairment test is required. Otherwise, no further testing is required.

If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Any goodwill impairment charge at ComEd will affect Exelon's consolidated results of operations.

ComEd's valuation approach is based on a market participant view, pursuant to authoritative guidance for fair value measurement, and utilizes a weighted combination of a discounted cash flow analysis and a market multiples analysis. The discounted cash flow analysis relies on a single scenario reflecting "base case" or "best estimate" projected cash flows for ComEd's business and includes an estimate of ComEd's terminal value based on these expected cash flows using the generally accepted Gordon Dividend Growth formula, which derives a valuation using an assumed perpetual annuity based on the entity's residual cash flows. The discount rate is based on the generally accepted Capital Asset Pricing Model and represents the weighted average cost of capital of comparable companies. The market multiples analysis utilizes multiples of business enterprise value to earnings, before interest, taxes, depreciation and amortization (EBITDA) of comparable companies in estimating fair value. Significant assumptions used in estimating the fair value include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd's business and the fair value of debt. Management performs a reconciliation of the sum of the estimated fair value of all Exelon reporting units to Exelon's enterprise value based on its trading price to corroborate the results of the discounted cash flow analysis and the market multiple analysis.

2015 and 2014 Goodwill Impairment Assessment. Pursuant to authoritative guidance, ComEd is required to test its goodwill for impairment annually and more frequently if an event occurs or circumstances change that suggest an impairment is more likely than not. ComEd performs its assessment as of November 1, of each year. For its 2015 and 2014 annual goodwill impairment assessments, ComEd qualitatively determined that its fair value was not more likely than not less than its carrying value. Therefore, ComEd did not perform quantitative assessments. As part of its qualitative assessments, ComEd evaluated, among other things, management's best estimate of projected operating and capital cash flows for ComEd's business, as well as, changes in certain market conditions, including the discount rate and regulated utility peer company EBITDA multiples, while also considering the passing margin from its last quantitative assessment performed as of November 1, 2013.

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Other Intangible Assets

Exelon's, Generation's and ComEd's other intangible assets and liabilities, included in Unamortized energy contract assets and liabilities and Other deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2015:

	Weighted Average Amortization Years (k)	Gross	Accumulated Amortization	Net	Estimated amortization expense				
					2016	2017	2018	2019	2020
Exelon									
Software License Agreement (a)	10.0	$ 95	$ (6)	$ 89	$ 10	$ 10	$ 10	$ 10	$ 10
Generation									
Unamortized Energy Contracts (b)									
Exelon Wind (c)	18.0	224	(69)	155	14	14	14	14	10
Antelope Valley (d)	25.0	190	(20)	170	8	8	8	8	8
Constellation (e)	1.5	1,499	(1,473)	26	(33)	(21)	11	8	10
CENG (f)	1.7	(97)	48	(49)	(11)	(15)	(18)	(15)	(8)
Integrys (g)	2.4	5	2	7	5	1	1	—	—
Customer Relationships (h)									
Constellation (e)	12.4	214	(76)	138	18	18	18	17	17
Integrys (g)	10.0	50	(6)	44	5	5	5	5	5
Trade Names									
Constellation (e)	10.0	243	(103)	140	23	23	23	23	23
ComEd									
Chicago settlement—1999 agreement (i)	21.8	100	(83)	17	3	3	3	4	4
Chicago settlement—2003 agreement (j)	17.9	62	(44)	18	4	4	4	3	3
Total intangible assets		$2,585	$ (1,830)	$755	$ 46	$ 50	$ 79	$ 77	$ 82

(a) On May 31, 2015, Exelon entered into a long-term software license agreement. Exelon is required to make payments starting August 2015 through May 2024. The intangible asset recognized as a result of these payments is being amortized on a straight-line basis over the contract term.
(b) Includes unamortized energy contract assets and liabilities on Exelon's and Generation's Consolidated Balance Sheets. Excludes $44 million of other miscellaneous unamortized energy contracts that have been acquired at various points in time. The estimated amortization for these miscellaneous unamortized energy contracts is $3 million, $0 million, $2 million, $3 million and $4 million for 2016, 2017, 2018, 2019 and 2020, respectively.
(c) In December 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (later named Exelon Wind), adding 735MWs of installed, operating wind capacity located in eight states.
(d) In September 2011, Generation acquired all of the interest in Antelope Valley Solar Ranch One, a 242 MW solar project under development in northern Los Angeles County, CA from First Solar, Inc.
(e) On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger. Since the merger transaction, Generation includes the former Constellation generation and customer supply operations.
(f) See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.
(g) See Note 4—Mergers, Acquisitions, and Dispositions for additional information.
(h) Excludes $12 million of other miscellaneous customer relationships that have been acquired. The estimated amortization for these miscellaneous customer relationships is $1 million in each of the years from 2016 to 2020.
(i) In March 1999, ComEd entered into a settlement agreement with the City of Chicago associated with ComEd's franchise agreement. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago each year from

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1999 to 2002. The intangible asset recognized as a result of these payments is being amortized ratably over the remaining term of the franchise agreement, which ends in 2020.

(j) In February 2003, ComEd entered into separate agreements with the City of Chicago and with Midwest Generation, LLC (Midwest Generation). Under the terms of the settlement agreement with the City of Chicago, ComEd agreed to pay the City of Chicago a total of $60 million over a ten-year period, beginning in 2003. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement, which ends in 2020. As required by the settlement, ComEd also made a payment of $2 million to a third-party on the City of Chicago's behalf. Under the terms of the agreement with Midwest Generation, ComEd received payments of $32 million from Midwest Generation to relieve Midwest Generation's obligation under the 1999 fossil sale agreement with ComEd to build the generation facility in the City of Chicago. The payments received by ComEd, which have been recorded in Other deferred credits and other liabilities, and other long-term liabilities on Exelon's and ComEd's Consolidated Balance Sheets are being recognized ratably (approximately $2 million annually) as an offset to amortization expense over the remaining term of the franchise agreement.

(k) Weighted-average amortization period was calculated at the date of a) acquisition for acquired assets or b) settlement agreement.

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2015, 2014 and 2013:

For the Year Ended December 31,	Exelon (a)	Generation (a)	ComEd
2015	$ 76	$ 69	$ 7
2014	179	179	7
2013	478	550	7

(a) At Exelon, amortization of unamortized energy contracts totaling $22 million, $135 million and $430 million for the years ended December 31, 2015, 2014 and 2013, respectively, was recorded in Operating revenues or Purchase power and fuel expense within Exelon's Consolidated Statement of Operations and Comprehensive Income. At Generation, amortization of unamortized energy contracts totaling $22 million, $135 million and $507 million for the years ended December 31, 2015, 2014 and 2013, respectively, was recorded in Operating revenues or Purchase power and fuel expense within Generation's Consolidated Statement of Operations and Comprehensive Income

Acquired Intangible Assets

Accounting guidance for business combinations requires the acquirer to separately recognize identifiable intangible assets in the application of purchase accounting.

Unamortized Energy Contracts. Unamortized energy contract assets and liabilities represent the remaining unamortized fair value of non-derivative energy contracts that Generation has acquired. The valuation of unamortized energy contracts was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise, the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. The Exelon Wind unamortized energy contracts are amortized on a straight line basis over the period in which the associated contract revenues are recognized as a decrease in Operating revenue within Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income. In the case of Antelope Valley, Constellation, CENG and Integrys, the fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the acquisition dates through either Operating revenues or Purchase power and fuel expense within Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

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Customer Relationships. The customer relationship intangible was determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The accounting guidance requires that customer-based intangibles be amortized over the period expected to be benefited using the pattern of economic benefit. The amortization of the customer relationships is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Trade Name. The Constellation trade name intangible was determined based on the relief from royalty method of income approach whereby fair value is determined to be the present value of the license fees avoided by owning the assets. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. The Constellation trade name intangible is amortized on a straight-line basis over a period of 10 years. The amortization of the trade name is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Renewable Energy Credits and Alternative Energy Credits (Exelon, Generation, ComEd and PECO).

Exelon's, Generation's, ComEd's and PECO's other intangible assets, included in Other current assets and Other deferred debits and other assets on the Consolidated Balance Sheets, include RECs (Exelon, Generation and ComEd) and AECs (Exelon and PECO). Purchased RECs are recorded at cost on the date they are purchased. The cost of RECs purchased on a stand-alone basis is based on the transaction price, while the cost of RECs acquired through PPAs represents the difference between the total contract price and the market price of energy at contract inception. Revenue for RECs that are part of a bundled power sale is recognized when the power is produced and delivered to the customer. As of December 31, 2015, and 2014, PECO had current AECs of $2 million and $13 million, respectively. PECO had no noncurrent AECs as of December 31, 2015 and 2014. As of December 31, 2015, and 2014, Generation had current RECs of $251 million and $191 million, respectively, and $56 million and $44 million of noncurrent REC's, respectively. As of December 31, 2015 and 2014, ComEd had current RECs of $5 million and $4 million, respectively. ComEd had no noncurrent RECs as of December 31, 2015 and 2014. See Note 3—Regulatory Matters and Note 23—Commitments and Contingencies for additional information on RECs and AECs.

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12. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of December 31, 2015 and 2014:

Exelon

	December 31, 2015					December 31, 2014	
	Carrying Amount	Fair Value				Carrying Amount	Fair Value
		Level 1	Level 2	Level 3	Total		
Short-term liabilities	$ 536	$ 3	$ 533	$ —	$ 536	$ 463	$ 463
Long-term debt (including amounts due within one year) [a]	25,145	931	23,644	1,349	25,924	21,014	22,936
Long-term debt to financing trusts [b]	641	—	—	673	673	641	648
SNF obligation	1,021	—	818	—	818	1,021	833

Generation

	December 31, 2015					December 31, 2014	
	Carrying Amount	Fair Value				Carrying Amount	Fair Value
		Level 1	Level 2	Level 3	Total		
Short-term liabilities	$ 29	$ —	$ 29	$ —	$ 29	$ 36	$ 36
Long-term debt (including amounts due within one year) [a]	8,959	—	7,767	1,349	9,116	8,196	8,822
SNF obligation	1,021	—	818	—	818	1,021	833

ComEd

	December 31, 2015					December 31, 2014	
	Carrying Amount	Fair Value				Carrying Amount	Fair Value
		Level 1	Level 2	Level 3	Total		
Short-term liabilities	$ 294	$ —	$ 294	$ —	$ 294	$ 304	$ 304
Long-term debt (including amounts due within one year) [a]	6,509	—	7,069	—	7,069	5,925	6,788
Long-term debt to financing trusts [b]	205	—	—	213	213	205	213

PECO

	December 31, 2015					December 31, 2014	
	Carrying Amount	Fair Value				Carrying Amount	Fair Value
		Level 1	Level 2	Level 3	Total		
Long-term debt (including amounts due within one year) [a]	$ 2,580	$ —	$2,786	$ —	$2,786	$ 2,232	$2,537
Long-term debt to financing trusts	184	—	—	195	195	184	199

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BGE

	December 31, 2015					December 31, 2014	
	Carrying Amount	Fair Value				Carrying Amount	Fair Value
		Level 1	Level 2	Level 3	Total		
Short-term liabilities	$ 213	$ 3	$ 210	$ —	$ 213	$ 123	$ 123
Long-term debt (including amounts due within one year) [(a)]	1,858	—	2,044	—	2,044	1,932	2,178
Long-term debt to financing trusts [(b)]	252	—	—	264	264	252	236

(a) Includes unamortized debt issuance costs of $180 million, $70 million, $38 million, $15 million and $9 million for Exelon, Generation, ComEd, PECO and BGE, respectively, at December 31, 2015 and $150 million, $70 million, $33 million, $14 million and $10 million at December 31, 2014.
(b) Includes unamortized debt issuance costs of $7 million, $1 million and $6 million for Exelon, ComEd and BGE, respectively, at both December 31, 2015 and 2014.

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of dividends payable (included in other current liabilities) (Level 1), short-term borrowings (Level 2) and third party financing (Level 3). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. The fair value of Exelon's equity units (Level 1) are valued based on publicly traded securities issued by Exelon.

The fair value of Generation's non-government-backed fixed rate nonrecourse debt (Level 3) is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles. Given the low trading volume in the nonrecourse debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-backed fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value (Level 2). Generation also has tax-exempt debt (Level 2). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (e.g., conduit issuer political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above.

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SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

Long-Term Debt to Financing Trusts. Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1—quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to liquidate as of the reporting date.
- Level 2—inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3—unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts. There were no transfers between Level 1 and Level 2 during the year ended December 31, 2015 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations.

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Generation and Exelon

The following tables present assets and liabilities measured and recorded at fair value on Exelon's and Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2015 and 2014:

	Generation				Exelon			
As of December 31, 2015	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents [a]	$ 104	$ —	$ —	$ 104	$ 5,766	$ —	$ —	$ 5,766
Nuclear decommissioning trust fund investments								
Cash equivalents [b]	219	92	—	311	219	92	—	311
Equities	3,008	1,894	—	4,902	3,008	1,894	—	4,902
Fixed income								
Corporate debt	—	1,824	242	2,066	—	1,824	242	2,066
U.S. Treasury and agencies	1,323	15	—	1,338	1,323	15	—	1,338
Foreign governments	—	61	—	61	—	61	—	61
State and municipal debt	—	326	—	326	—	326	—	326
Other [c]	—	537	—	537	—	537	—	537
Fixed income subtotal	1,323	2,763	242	4,328	1,323	2,763	242	4,328
Middle market lending	—	—	428	428	—	—	428	428
Private equity	—	—	125	125	—	—	125	125
Real estate	—	—	35	35	—	—	35	35
Other	—	216	—	216	—	216	—	216
Nuclear decommissioning trust fund investments subtotal [d]	4,550	4,965	830	10,345	4,550	4,965	830	10,345
Pledged assets for Zion Station decommissioning								
Cash equivalents	—	17	—	17	—	17	—	17
Equities	1	5	—	6	1	5	—	6
Fixed income								
U.S. Treasury and agencies	6	2	—	8	6	2	—	8
Corporate debt	—	46	—	46	—	46	—	46
Other	—	1	—	1	—	1	—	1
Fixed income subtotal	6	49	—	55	6	49	—	55
Middle market lending	—	—	127	127	—	—	127	127
Pledged assets for Zion Station decommissioning subtotal [e]	7	71	127	205	7	71	127	205
Rabbi trust investments in mutual funds [f]	17	—	—	17	48	—	—	48
Commodity derivative assets								
Economic hedges	1,922	3,467	1,707	7,096	1,922	3,467	1,707	7,096
Proprietary trading	36	64	30	130	36	64	30	130
Effect of netting and allocation of collateral [g]	(1,964)	(2,629)	(564)	(5,157)	(1,964)	(2,629)	(564)	(5,157)
Commodity derivative assets subtotal	(6)	902	1,173	2,069	(6)	902	1,173	2,069
Interest rate and foreign currency derivative assets								
Derivatives designated as hedging instruments	—	—	—	—	—	25	—	25
Economic hedges	—	20	—	20	—	20	—	20
Proprietary trading	10	5	—	15	10	5	—	15
Effect of netting and allocation of collateral	(3)	(3)	—	(6)	(3)	(3)	—	(6)
Interest rate and foreign currency derivative assets subtotal	7	22	—	29	7	47	—	54
Other investments	—	—	33	33	—	—	33	33
Total assets	4,679	5,960	2,163	12,802	10,372	5,985	2,163	18,520
Liabilities								
Commodity derivative liabilities								
Economic hedges	(2,382)	(3,348)	(850)	(6,580)	(2,382)	(3,348)	(1,097)	(6,827)
Proprietary trading	(33)	(57)	(37)	(127)	(33)	(57)	(37)	(127)
Effect of netting and allocation of collateral [g]	2,440	3,186	765	6,391	2,440	3,186	765	6,391
Commodity derivative liabilities subtotal	25	(219)	(122)	(316)	25	(219)	(369)	(563)
Interest rate and foreign currency derivative liabilities				—				—
Derivatives designated as hedging instruments	—	(16)	—	(16)	—	(16)	—	(16)
Economic hedges	—	(3)	—	(3)	—	(3)	—	(3)
Proprietary trading	(12)	—	—	(12)	(12)	—	—	(12)
Effect of netting and allocation of collateral	12	3	—	15	12	3	—	15
Interest rate and foreign currency derivative liabilities subtotal	—	(16)	—	(16)	—	(16)	—	(16)
Deferred compensation obligation	—	(30)	—	(30)	—	(99)	—	(99)
Total liabilities	25	(265)	(122)	(362)	25	(334)	(369)	(678)
Total net assets	$ 4,704	$ 5,695	$ 2,041	$12,440	$10,397	$ 5,651	$ 1,794	$17,842

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As of December 31, 2014	Generation				Exelon			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents [a]	$ 405	$ —	$ —	$ 405	$ 1,119	$ —	$ —	$ 1,119
Nuclear decommissioning trust fund investments								
Cash equivalents [b]	208	37	—	245	208	37	—	245
Equities	3,035	2,207	—	5,242	3,035	2,207	—	5,242
Fixed income								
Corporate debt	—	2,023	239	2,262	—	2,023	239	2,262
U.S. Treasury and agencies	996	—	—	996	996	—	—	996
Foreign governments	—	95	—	95	—	95	—	95
State and municipal debt	—	438	—	438	—	438	—	438
Other	—	511	—	511	—	511	—	511
Fixed income subtotal	996	3,067	239	4,302	996	3,067	239	4,302
Middle market lending	—	—	366	366	—	—	366	366
Private equity	—	—	83	83	—	—	83	83
Real estate	—	—	3	3	—	—	3	3
Other [c]	—	301	—	301	—	301	—	301
Nuclear decommissioning trust fund investments subtotal [d]	4,239	5,612	691	10,542	4,239	5,612	691	10,542
Pledged assets for Zion Station decommissioning								
Cash equivalents	—	15	—	15	—	15	—	15
Equities	6	1	—	7	6	1	—	7
Fixed income								
U.S. Treasury and agencies	5	3	—	8	5	3	—	8
Corporate debt	—	89	—	89	—	89	—	89
State and municipal debt	—	10	—	10	—	10	—	10
Other	—	3	—	3	—	3	—	3
Fixed income subtotal	5	105	—	110	5	105	—	110
Middle market lending	—	—	184	184	—	—	184	184
Pledged assets for Zion Station decommissioning subtotal [e]	11	121	184	316	11	121	184	316
Rabbi trust investments [f]								
Cash equivalents	—	—	—	—	1	—	—	1
Mutual funds	16	—	—	16	46	—	—	46
Rabbi trust investments subtotal	16	—	—	16	47	—	—	47
Commodity derivative assets				—				—
Economic hedges	1,667	3,465	1,681	6,813	1,667	3,465	1,681	6,813
Proprietary trading	201	284	27	512	201	284	27	512
Effect of netting and allocation of collateral [g]	(1,982)	(2,757)	(557)	(5,296)	(1,982)	(2,757)	(557)	(5,296)
Commodity derivative assets subtotal	(114)	992	1,151	2,029	(114)	992	1,151	2,029
Interest rate and foreign currency derivative assets				—				—
Derivatives designated as hedging instruments	—	8	—	8	—	31	—	31
Economic hedges	—	12	—	12	—	13	—	13
Proprietary trading	18	9	—	27	18	9	—	27
Effect of netting and allocation of collateral	(17)	(12)	—	(29)	(17)	(31)	—	(48)
Interest rate and foreign currency derivative assets subtotal	1	17	—	18	1	22	—	23
Other investments	—	—	3	3	2	—	3	5
Total assets	4,558	6,742	2,029	13,329	5,305	6,747	2,029	14,081
Liabilities								
Commodity derivative liabilities								
Economic hedges	(2,241)	(3,458)	(788)	(6,487)	(2,241)	(3,458)	(995)	(6,694)
Proprietary trading	(195)	(295)	(42)	(532)	(195)	(295)	(42)	(532)
Effect of netting and allocation of collateral [g]	2,416	3,557	729	6,702	2,416	3,557	729	6,702
Commodity derivative liabilities subtotal	(20)	(196)	(101)	(317)	(20)	(196)	(308)	(524)
Interest rate and foreign currency derivative liabilities				—				—
Derivatives designated as hedging instruments	—	(12)	—	(12)	—	(41)	—	(41)
Economic hedges	—	(2)	—	(2)	—	(103)	—	(103)
Proprietary trading	(14)	(9)	—	(23)	(14)	(9)	—	(23)
Effect of netting and allocation of collateral	25	10	—	35	25	29	—	54
Interest rate and foreign currency derivative liabilities subtotal	11	(13)	—	(2)	11	(124)	—	(113)
Deferred compensation obligation	—	(31)	—	(31)	—	(107)	—	(107)
Total liabilities	(9)	(240)	(101)	(350)	(9)	(427)	(308)	(744)
Total net assets	$ 4,549	$ 6,502	$ 1,928	$12,979	$ 5,296	$ 6,320	$ 1,721	$13,337

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(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Includes $52 million and $43 million of cash received from outstanding repurchase agreements at December 31, 2015 and 2014, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.
(c) Includes derivative instruments of $(8) million and $(10) million, which have a total notional amount of $1,236 million and $794 million at December 31, 2015 and 2014, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.
(d) Excludes net liabilities of $(3) million and $(5) million at December 31, 2015 and 2014, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.
(e) Excludes net assets of $1 million and $3 million at December 31, 2015 and 2014, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(f) Excludes $36 million and $35 million of cash surrender value of life insurance investment at December 31, 2015 and 2014, respectively, at Exelon Consolidated. Excludes $13 million and $11 million of cash surrender value of life insurance investment at December 31, 2015 and 2014, respectively, at Generation.
(g) Collateral posted to/(received from) counterparties totaled $476 million, $557 million and $201 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2015. Collateral posted to/(received from) counterparties totaled $434 million, $800 million and $172 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2014.

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on the utility Registrants' Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2015 and 2014:

	ComEd				PECO				BGE			
As of December 31, 2015	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents	$ 29	$ —	$ —	$ 29	$ 271	$ —	$ —	$271	$ 25	$ —	$ —	$ 25
Rabbi trust investments in mutual funds (a)	—	—	—	—	8	—	—	8	4	—	—	4
Total assets	29	—	—	29	279	—	—	279	29	—	—	29
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(12)	—	(12)	—	(4)	—	(4)
Mark-to-market derivative liabilities (b)	—	—	(247)	(247)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(247)	(255)	—	(12)	—	(12)	—	(4)	—	(4)
Total net assets (liabilities)	$ 29	$ (8)	$(247)	$(226)	$ 279	$ (12)	$ —	$267	$ 29	$ (4)	$ —	$ 25

Combined Notes to Consolidated Financial Statements—(Continued)
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	ComEd				PECO				BGE			
As of December 31, 2014	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents	$ 25	$ —	$ —	$ 25	$ 12	$ —	$ —	$ 12	$ 103	$ —	$ —	$ 103
Rabbi trust investments in mutual funds [(a)]	—	—	—	—	9	—	—	9	5	—	—	5
Total assets	25	—	—	25	21	—	—	21	108	—	—	108
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(15)	—	(15)	—	(5)	—	(5)
Mark-to-market derivative liabilities [(b)]	—	—	(207)	(207)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(207)	(215)	—	(15)	—	(15)	—	(5)	—	(5)
Total net assets (liabilities)	$ 25	$ (8)	$ (207)	$ (190)	$ 21	$ (15)	$ —	$ 6	$ 108	$ (5)	$ —	$ 103

(a) At PECO, excludes $12 million and $14 million of the cash surrender value of life insurance investments at December 31, 2015 and 2014, respectively.
(b) The Level 3 balance includes the current and noncurrent liability of $23 million and $224 million, respectively, at December 31, 2015, and $20 million and $187 million, respectively, at December 31, 2014, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the year ended December 31, 2015 and 2014:

	Generation					ComEd		Exelon
For The Year Ended December 31, 2015	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives [b]	Eliminated in Consolidation	Total
Balance as of January 1, 2015	$ 691	$ 184	$ 1,050	$ 3	$ 1,928	$ (207)	$ —	$ 1,721
Total realized / unrealized gains (losses)								
Included in net income	4	—	22[a]	1	27	—	—	27
Included in noncurrent payables to affiliates	23	—	—	—	23	—	(23)	—
Included in payable for Zion Station decommissioning	—	(2)	—	—	(2)	—	—	(2)
Included in regulatory assets/liabilities	—	—	—	—	—	(40)	23	(17)
Change in collateral	—	—	29	—	29	—	—	29
Purchases, sales, issuances and settlements								
Purchases	226	20	144	30	420	—	—	420
Sales	(8)	(75)	(25)	—	(108)	—	—	(108)
Settlements	(106)	—	—	—	(106)	—	—	(106)
Transfers into Level 3	4	—	80	—	84	—	—	84
Transfers out of Level 3	(4)	—	(249)	(1)	(254)	—	—	(254)
Balance as of December 31, 2015	$ 830	$ 127	$ 1,051	$ 33	$ 2,041	$ (247)	$ —	$ 1,794
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2015	$ 4	$ —	$ 856	$ —	$ 860	$ —	$ —	$ 860

Combined Notes to Consolidated Financial Statements—(Continued)
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	Generation					ComEd		Exelon
For The Year Ended December 31, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives (d)	Other Investments	Total Generation	Mark-to-Market Derivatives (b)	Eliminated in Consolidation	Total
Balance as of January 1, 2014	$ 350	$ 112	$ 465	$ 15	$ 942	$ (193)	$ —	$ 749
Total realized / unrealized gains (losses)								
Included in net income	6	—	526 (a)	—	532	—	—	532
Included in other comprehensive income	—	—	—	—	—	—	—	—
Included in noncurrent payables to affiliates	14	—	—	—	14	—	(14)	—
Included in payable for Zion Station decommissioning	—	2	—	—	2	—	—	2
Included in regulatory assets/liabilities	—	—	—	—	—	(14)	14	—
Change in collateral	—	—	198	—	198	—	—	198
Purchases, sales, issuances and settlements								
Purchases	400	120	76 (c)	2	598	—	—	598
Sales	(15)	(50)	(7)	(8)	(80)	—	—	(80)
Settlements	(64)	—	—	—	(64)	—	—	(64)
Transfers into Level 3	—	—	(7)	—	(7)	—	—	(7)
Transfers out of Level 3	—	—	(201)	(6)	(207)	—	—	(207)
Balance as of December 31, 2014	$ 691	$ 184	$ 1,050	$ 3	$ 1,928	$ (207)	$ —	$ 1,721
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2014	$ 4	$ —	$ 640	$ —	$ 644	$ —	$ —	$ 644

(a) Includes a reduction for the reclassification of $834 million and $114 million of realized gains due to the settlement of derivative contracts for the years ended December 31, 2015 and 2014, respectively.
(b) Includes $55 million of decreases in fair value and an increase for realized losses due to settlements of $(15) million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2015. Includes $13 million of decreases in fair value and a reduction for realized gains due to settlements of $1 million for the year ended December 31, 2014.
(c) Includes $34 million of fair value from contracts acquired as a result of the Integrys acquisition.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2015 and 2014:

	Generation			Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net (a)	Operating Revenues	Purchased Power and Fuel	Other, net (a)
Total gains (losses) included in net income for the year ended December 31, 2015	$ 67	$ (45)	$ 4	$ 67	$ (45)	$ 4
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2015	$ 858	$ (2)	$ 4	$ 858	$ (2)	$ 4

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation			Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net [a]	Operating Revenues	Purchased Power and Fuel	Other, net [a]
Total gains (losses) included in net income for the year ended December 31, 2014	$ 614	$ (88)	$ 6	$ 614	$ (88)	$ 6
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2014	$ 663	$ (23)	$ 4	$ 663	$ (23)	$ 4

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE). The Registrants' cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in Equities, Fixed Income and Other. Generation's and CENG's NDT fund investments policies outline investment guidelines for the trusts and limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are

Combined Notes to Consolidated Financial Statements—(Continued)
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derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The fair values of private placement fixed income securities, which are included in Corporate debt, are determined using a third party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity, balanced and fixed income commingled funds and mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives such as holding short term fixed income securities or tracking the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For commingled funds and mutual funds, which are not publicly quoted, the fund administrators value the funds using NAV as a practical expedient for fair value, which is primarily derived from the quoted prices in active markets on the underlying securities. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions, and, as a result are categorized as Level 2.

Derivative instruments consisting primarily of interest rate swaps to manage risk are recorded at fair value. Derivative instruments are valued based on external price data of comparable securities and have been categorized as Level 2.

Middle market lending are investments in loans or managed funds which lend to private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in middle market lending are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as,leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. The fair value of private equity and real estate investments is determined using NAV or its equivalent as a practical expedient. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date. Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. Since these valuation inputs are not highly observable, private equity and real estate investments have been categorized as Level 3.

As of December 31, 2015, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, private equity investments, and real estate investments of approximately $266 million. These commitments will be funded by Generation’s existing nuclear decommissioning trust funds.

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Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of December 31, 2015. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2015, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation's NDT assets.

See Note 16—Asset Retirement Obligations for further discussion on the NDT fund investments.

Rabbi Trust Investments (Exelon, Generation, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The Rabbi trusts assets are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of mutual funds and life insurance policies. The mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The life insurance policies are valued using the cash surrender value of the policies, which is provided by a third party. The cash surrender value inputs are not observable.

Mark-to-Market Derivatives (Exelon, Generation, and ComEd) . Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' derivatives are predominately at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 13—Derivative Financial Instruments for further discussion on mark-to-market derivatives.

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Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO and BGE). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds, and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd)

Mark-to-Market Derivatives (Exelon, Generation, ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases and certain transmission congestion contracts. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by

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commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $2.91 and $0.27 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 7A.—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrant's mark-to-market derivative assets and liabilities.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 13—Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at December 31, 2015	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic hedges (Generation) [a][c]	$ 857	Discounted Cash Flow	Forward power price	$11 - $88[d]
			Forward gas price	$1.18 - $8.95[d]
		Option Model	Volatility percentage	5% - 152%
Mark-to-market derivatives—Proprietary trading (Generation) [a][c]	$ (7)	Discounted Cash Flow	Forward power price	$13 - $78[d]
Mark-to-market derivatives (ComEd)	$ (247)	Discounted Cash Flow	Forward heat rate [b]	9x - 10x
			Marketability reserve	3.5% - 7%
			Renewable factor	87% - 128%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

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(c) The fair values do not include cash collateral posted on level three positions of $201 million as of December 31, 2015.
(d) Unlike the previous year, the New England region was not a significant driver for the upper end of the ranges for power and gas as of December 31, 2015.

Type of trade	Fair Value at December 31, 2014	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic hedges (Generation) [a][c]	$ 893	Discounted Cash Flow	Forward power price	$15 - $120[d]
			Forward gas price	$1.52 - $14.02[d]
		Option Model	Volatility percentage	8% - 257%
Mark-to-market derivatives— Proprietary trading (Generation) [a][c]	$ (15)	Discounted Cash Flow	Forward power price	$15 - $117[d]
Mark-to-market derivatives (ComEd)	$ (207)	Discounted Cash Flow	Forward heat rate [b]	8x - 9x
			Marketability reserve	3.5% - 8%
			Renewable factor	86% - 126%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
(c) The fair values do not include cash collateral posted on level three positions of $172 million as of December 31, 2014
(d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas would be approximately $97 and $8.14, respectively and would be approximately $76 for power proprietary trading.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending, certain corporate debt securities, real estate and private equity investments the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected

financial results, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations. For a sample of its Level 3 investments, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

13. Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use derivative instruments to manage commodity price risk, foreign currency exchange rate risk, and interest rate risk related to ongoing business operations.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

To the extent the amount of energy Generation produces differs from the amount of energy it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. Each of the Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, Generation no longer utilizes the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the Constellation merger. Because the underlying forecasted transactions remained probable, the fair value of the effective portion of these cash flow hedges was frozen in Accumulated OCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred. The effect of this decision is that all derivative economic hedges related to commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 23—Commitments and Contingencies. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall energy marketing activities.

Combined Notes to Consolidated Financial Statements—(Continued)
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Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and gas and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of December 31, 2015, the proportion of expected generation hedged for the major reportable segments was 90%-93%, 60%-63% and 28%-31% for 2016, 2017, and 2018, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including Generation's sales to ComEd, PECO and BGE to serve their retail load.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts for energy and associated RECs were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reductions was approved in March 2014. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3—Regulatory Matters for additional information.

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PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3—Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts and block contracts. PECO has certain full requirements contracts and block contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2015 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2015 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE's price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. All of BGE's natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The

proprietary trading activities, which included settled physical sales volumes of 7,310 GWh, 10,571 GWh and 8,762 GWh for the years ended December 31, 2015, 2014 and 2013, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2015, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $738 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximately $6 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2015. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign exchange hedge balances as of December 31, 2015:

	Generation					Other				Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Economic Hedges	Collateral and Netting [b]	Subtotal	Total
Mark-to-market derivative assets (current assets)	$ —	$ 10	$ 10	$ (5)	$ 15	$ —	$ —	$ —	$ —	$ 15
Mark-to-market derivative assets (noncurrent assets)	—	10	5	(1)	14	25	—	—	25	39
Total mark-to-market derivative assets	—	20	15	(6)	29	25	—	—	25	54
Mark-to-market derivative liabilities (current liabilities)	(8)	(2)	(9)	11	(8)	—	—	—	—	(8)
Mark-to-market derivative liabilities (noncurrent liabilities)	(8)	(1)	(3)	4	(8)	—	—	—	—	(8)
Total mark-to-market derivative liabilities	(16)	(3)	(12)	15	(16)	—	—	—	—	(16)
Total mark-to-market derivative net assets (liabilities)	$ (16)	$ 17	$ 3	$ 9	$ 13	$ 25	$ —	$ —	$ 25	$ 38

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

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The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2014:

	Generation					Other				Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Economic Hedges	Collateral and Netting [b]	Subtotal	Total
Mark-to-market derivative assets (current assets)	$ 7	$ 7	$ 20	$ (22)	$ 12	$ 3	$ —	$ —	$ 3	$ 15
Mark-to-market derivative assets (noncurrent assets)	1	5	7	(7)	6	20	1	(19)	$ 2	$ 8
Total mark-to-market derivative assets	8	12	27	(29)	18	23	1	(19)	5	23
Mark-to-market derivative liabilities (current liabilities)	(8)	(2)	(14)	25	1	—	—	—	—	1
Mark-to-market derivative liabilities (noncurrent liabilities)	(4)	—	(9)	10	(3)	(29)	(101)	19	(111)	(114)
Total mark-to-market derivative liabilities	(12)	(2)	(23)	35	(2)	(29)	(101)	19	(111)	(113)
Total mark-to-market derivative net assets (liabilities)	$ (4)	$ 10	$ 4	$ 6	$ 16	$ (6)	$ (100)	$ —	$ (106)	$ (90)

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

Fair Value Hedges . For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

		Year Ended December 31,					
		2015	2014	2013	2015	2014	2013
	Income Statement Location	Gain (Loss) on Swaps			Gain (Loss) on Borrowings		
Generation	Interest expense [a]	$ (1)	$ (16)	$ (15)	$ —	$ 2	$ (6)
Exelon	Interest expense	$ 2	$ 3	$ (24)	$ (9)	$ 15	$ (3)

(a) For the years ended December 31, 2015 and 2014, the loss on Generation swaps included $(1) million and $(17) million realized in earnings, respectively, with an immaterial amount and $4 million excluded from hedge effectiveness testing, respectively.

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At December 31, 2015, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $25 million. At December 31, 2014, Exelon and Generation had outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,450 million and $550 million, with a derivative asset of $29 million and $7 million, respectively. During the years ended December 31, 2015 and 2014, the impact on the results of operations, as a result of the ineffectiveness from fair value hedges, was a $17 million gain and $18 million gain, respectively.

Cash Flow Hedges . During 2014, Exelon entered into $400 million of floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with the anticipated refinancing of existing debt. The swaps are designated as cash flow hedges. In January 2015, in connection with Generation's $750 million issuance of five-year Senior Unsecured Notes, Exelon terminated these swaps. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments are probable not to occur. As a result, $26 million of anticipated payments were reclassified from Accumulated OCI to Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income.

During the third quarter of 2014, ExGen Texas Power, LLC, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowing. See Note 14—Debt and Credit Agreements for additional information regarding the financing. The swaps have a notional amount of $500 million as of December 31, 2015 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. At December 31, 2015, the subsidiary had a $12 million derivative liability related to the swap.

During the first quarter of 2014, ExGen Renewables I, LLC, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14—Debt and Credit Agreements for additional information regarding the financing. The swaps have a notional amount of $189 million as of December 31, 2015 and expire in 2020. The swaps are designated as cash flow hedges. At December 31, 2015, the subsidiary had a $2 million derivative liability related to the swaps.

During the years ended December 31, 2015 and 2014, the impact on the results of operations as a result of ineffectiveness from cash flow hedges in continuing designated hedge relationships were immaterial.

Economic Hedges. During the third quarter of 2011, Sacramento PV Energy, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14—Debt and Credit Agreements for additional information regarding the financing. The swaps have a total notional amount of $25 million as of December 31, 2015 and expire in 2027. After the closing of the Constellation merger, the swaps were re-designated as cash flow hedges. During the first quarter of 2015, the swaps were de-designated as the forecasted transaction was no longer probable of occurring. All future changes in fair value are reflected in Interest expense. At December 31, 2015, the subsidiary had a $2 million derivative liability related to these swaps, which included an immaterial amount that was amortized to Interest expense after de-designation.

During the third quarter of 2012, Constellation Solar Horizons, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14—Debt and Credit Agreements for additional information

regarding the financing. The swap has a notional amount of $24 million as of December 31, 2015, and expires in 2030. This swap was designated as a cash flow hedge. During the first quarter of 2015, the swaps were de-designated as the forecasted transaction was no longer probable of occurring. All future changes in fair value are reflected in Interest expense. At December 31, 2015, the derivative asset related to the swap was immaterial.

During the second quarter 2015, upon the issuance of debt, Exelon terminated $2,400 million of floating-to-fixed forward starting interest rate swaps. As a result of the termination of the swaps, Exelon realized a $64 million loss during the second quarter of 2015.

At December 31, 2015, Generation had immaterial notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $30 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon Generation, ComEd, PECO and BGE)

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation's use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e. to BB+ or Ba1). In the table below, Generation's energy related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral including initial margin on exchange positions, is aggregated in the collateral and netting column. As of December 31, 2015 and 2014, $3 million and $8 million of cash collateral posted, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e. to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in a non affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2015:

	Generation				ComEd	Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting [a]	Subtotal [b]	Economic Hedges [c]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 5,236	$ 108	$ (3,994)	$ 1,350	$ —	$ 1,350
Mark-to-market derivative assets (noncurrent assets)	1,860	22	(1,163)	719	—	719
Total mark-to-market derivative assets	7,096	130	(5,157)	2,069	—	2,069
Mark-to-market derivative liabilities (current liabilities)	(4,907)	(94)	4,827	(174)	(23)	(197)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,673)	(33)	1,564	(142)	(224)	(366)
Total mark-to-market derivative liabilities	(6,580)	(127)	6,391	(316)	(247)	(563)
Total mark-to-market derivative net assets (liabilities)	$ 516	$ 3	$ 1,234	$ 1,753	$ (247)	$ 1,506

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $352 million and $180 million, respectively, and current and noncurrent liabilities are shown net of collateral of $480 million and $222 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $1,234 million at December 31, 2015.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2014:

	Generation				ComEd	Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting (a)	Subtotal (b)	Economic Hedges (c)	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 4,992	$ 456	$ (4,184)	$ 1,264	$ —	$ 1,264
Mark-to-market derivative assets (noncurrent assets)	1,821	56	(1,112)	765	—	765
Total mark-to-market derivative assets	6,813	512	(5,296)	2,029	—	2,029
Mark-to-market derivative liabilities (current liabilities)	(4,947)	(468)	5,200	(215)	(20)	(235)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,540)	(64)	1,502	(102)	(187)	(289)
Total mark-to-market derivative liabilities	(6,487)	(532)	6,702	(317)	(207)	(524)
Total mark-to-market derivative net assets (liabilities)	$ 326	$ (20)	$ 1,406	$ 1,712	$ (207)	$ 1,505

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $416 million and $171 million, respectively, and current and noncurrent liabilities are shown net of collateral of $599 million and $220 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $1,406 million at December 31, 2014.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon, Generation and ComEd). As discussed previously, effective prior to the Constellation merger, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably probable, the fair value of the effective portion of these cash flow hedges was frozen in Accumulated OCI and is reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective changes in the fair value of these instruments through current earnings from the date of de-designation. As of December 31, 2015, no unrealized balance remains in accumulated OCI to be reclassified by Generation.

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The tables below provide the activity of Accumulated OCI related to cash flow hedges for the years ended December 31, 2015 and 2014, containing information about the changes in the fair value of cash flow hedges and the reclassification from Accumulated OCI into results of operations. The amounts reclassified from Accumulated OCI, when combined with the impacts of the hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at January 1, 2014		$ 114	$ 120
Effective portion of changes in fair value		(15)	(31)
Reclassifications from accumulated OCI to net income	Operating revenues	(117) (a)	(117) (a)
Accumulated OCI derivative gain at December 31, 2014		(18)	(28)
Effective portion of changes in fair value		(8)	(12)
Reclassifications from accumulated OCI to net income	Other, net	—	16(b)
Reclassifications from accumulated OCI to net income	Interest expense	7(c)	7(c)
Reclassifications from accumulated OCI to net income	Operating revenues	(2)	(2)
Accumulated OCI derivative gain at December 31, 2015		$ (21)	$ (19)

(a) Amount is net of related income tax expense of $78 million for the year ended December 31, 2014.
(b) Amount is net of related income tax benefit of $10 million for the year ended December 31, 2015.
(c) Amount is net of related income tax expense of $4 million for the year ended December 31, 2015.

During the years ended December 31, 2015, 2014, and 2013, Generation's former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from Accumulated OCI to earnings was a $2 million, $195 million and $683 million pre-tax gain, respectively. In addition, the effect of Exelon's former energy-related cash flow hedge activity impact on pre-tax earnings based on the reclassification adjustment from Accumulated OCI to earnings was a $2 million, $195 million and $464 million pre-tax gain for the years ended December 31, 2015, 2014 and 2013, respectively. Given that the cash flow hedges had primarily consisted of forward power sales and power swaps and did not include power and gas options or sales, neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods relating to energy-related hedge positions as all were de-designated prior to the merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps ("treasury") to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other

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than U.S. Dollars. Exelon entered into floating-to-fixed forward starting interest rate swaps to manage interest rate risks associated with anticipated future debt issuance related to the proposed PHI merger. For the years ended December 31, 2015, 2014 and 2013, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in Operating revenues or Purchased power and fuel expense, or Interest expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Generation				Intercompany Eliminations	Exelon Corporate	Exelon
Year Ended December 31, 2015	Operating Revenues	Purchased Power and Fuel	Interest Expense	Total	Operating Revenues [a]	Interest Expense	Total
Change in fair value of commodity positions	$ 759	$ (355)	$ —	$ 404	$ —	$ —	$ 404
Reclassification to realized at settlement of commodity positions	(563)	409	—	(154)	—	—	(154)
Net commodity mark-to-market gains (losses)	196	54	—	250	—	—	250
Change in fair value of treasury positions	13	—	—	13	—	36	49
Reclassification to realized at settlement of treasury positions	(6)	—	—	(6)	—	64	58
Net treasury mark-to market gains (losses)	7	—	—	7	—	100	107
Net mark-to market gains (losses)	$ 203	$ 54	$ —	$ 257	$ —	$ 100	$ 357

	Generation				Intercompany Eliminations	Exelon Corporate	Exelon
Year Ended December 31, 2014	Operating Revenues	Purchased Power and Fuel	Interest Expense	Total	Operating Revenues [a]	Interest Expense	Total
Change in fair value of commodity positions	$ (413)	$ (194)	$ —	$ (607)	$ —	$ —	$ (607)
Reclassification to realized at settlement of commodity positions	231	(223)	—	8	—	—	8
Net commodity mark-to-market gains (losses)	(182)	(417)	—	(599)	—	—	(599)
Change in fair value of treasury positions	10	—	(2)	8	—	(100)	(92)
Reclassification to realized at settlement of treasury positions	(2)	—	—	(2)	—	—	(2)
Net treasury mark-to market gains (losses)	8	—	(2)	6	—	(100)	(94)
Net mark-to market gains (losses)	$ (174)	$ (417)	$ (2)	$ (593)	$ —	$ (100)	$ (693)

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Year Ended December 31, 2013	Generation				Intercompany Eliminations	Exelon Corporate	Exelon
	Operating Revenues	Purchased Power and Fuel	Interest Expense	Total	Operating Revenues [a]	Interest Expense	Total
Change in fair value of commodity positions	$ 286	$ 180	$ —	$ 466	$ (6)	$ —	$ 460
Reclassification to realized at settlement of commodity positions	(64)	104	—	40	13	—	53
Net commodity mark-to-market gains (losses)	222	284	—	506	7	—	513
Change in fair value of treasury positions	(1)	—	(4)	(5)	—	—	(5)
Reclassification to realized at settlement of treasury positions	(1)	—	—	(1)	—	—	(1)
Net treasury mark-to market gains (losses)	(2)	—	(4)	(6)	—	—	(6)
Net mark-to market gains (losses)	$ 220	$ 284	$ (4)	$ 500	$ 7	$ —	$ 507

(a) Prior to the Constellation merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value were recorded to operating revenues and eliminated in consolidation.

Proprietary Trading Activities (Exelon and Generation). For the years ended December 31, 2015, 2014, and 2013 Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on commodity derivative instruments entered into for proprietary trading purposes and interest rate derivative contracts to hedge risk associated with the interest rate component of underlying commodity positions. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	For the Years Ended December 31,		
		2015	2014	2013
Change in fair value of commodity positions	Operating Revenues	$ 8	$ (1)	$ (22)
Reclassification to realized at settlement of commodity positions	Operating Revenues	(14)	(29)	(15)
Net commodity mark-to-market gains (losses)	Operating Revenues	(6)	(30)	(37)
Change in fair value of treasury positions	Operating Revenues	8	1	1
Reclassification to realized at settlement of treasury positions	Operating Revenues	(10)	3	(3)
Net treasury mark-to market gains (losses)	Operating Revenues	(2)	4	(2)
Net mark-to market gains (losses)	Operating Revenues	$ (8)	$ (26)	$ (39)

Credit Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its

Combined Notes to Consolidated Financial Statements—(Continued)
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counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2015. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below exclude credit risk exposure from individual retail counterparties, Nuclear fuel procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 7A.—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of $15 million, $36 million and $31 million, respectively.

Rating as of December 31, 2015	Total Exposure Before Credit Collateral	Credit Collateral [(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,397	$ 50	$ 1,347	1	$ 432
Non-investment grade	67	25	42	—	—
No external ratings					
Internally rated—investment grade	521	—	521	—	—
Internally rated—non-investment grade	77	7	70	—	—
Total	$ 2,062	$ 82	$ 1,980	1	$ 432

Net Credit Exposure by Type of Counterparty	December 31, 2015
Financial institutions	$ 187
Investor-owned utilities, marketers, power producers	886
Energy cooperatives and municipalities	872
Other	35
Total	$ 1,980

(a) As of December 31, 2015, credit collateral held from counterparties where Generation had credit exposure included $13 million of cash and $69 million of letters of credit.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The

benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of December 31, 2015, ComEd's net credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents PECO's net credit exposure. As of December 31, 2015, PECO had no net credit exposure to suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2015, PECO's credit exposure under its natural gas supply and asset management agreements with investment grade suppliers was immaterial.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents BGE's net credit exposure. The seller's credit exposure is calculated each business day. As of December 31, 2015, BGE had no net credit exposure to suppliers.

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BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2015, BGE had credit exposure of $4 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e. NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

	For the Years Ended December 31,	
Credit-Risk Related Contingent Feature	**2015**	**2014**
Gross Fair Value of Derivative Contracts Containing this Feature [(a)]	$ (932)	$ (1,433)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements [(b)]	684	1,140
Net Fair Value of Derivative Contracts Containing This Feature [(c)]	$ (248)	$ (293)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features ignoring the effects of master netting agreements.
(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

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Generation had cash collateral posted of $1,267 million and letters of credit posted of $497 million, and cash collateral held of $21 million and letters of credit held of $78 million as of December 31, 2015 for external counterparties with derivative positions. Generation had cash collateral posted of $1,497 million and letters of credit posted of $672 million and cash collateral held of $77 million and letters of credit held of $24 million at December 31, 2014 for external counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e. to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of $2.0 billion and $2.4 billion as of December 31, 2015 and 2014, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2015, Generation's and Exelon's swaps were in an asset position, with a fair value of $13 million and $38 million, respectively.

See Note 25—Segment Information for further information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2015, ComEd held no collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2015, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 3—Regulatory Matters for additional information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2015, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2015, PECO could have been required to post approximately $25 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

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BGE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2015, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2015, BGE could have been required to post approximately $35 million of collateral to its counterparties.

14. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool.

Exelon, Generation, ComEd, PECO and BGE had the following amounts of commercial paper borrowings at December 31, 2015 and 2014:

Commercial Paper Issuer	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
	2015 [a][b]	2014 [a][b]	2015	2014	2015	2014
Exelon Corporate	$ 500	$ 500	$ —	$ —	n.a.	n.a.
Generation	5,450	5,600	—	—	0.49%	0.32%
ComEd	1,000	1,000	294	304	0.53%	0.33%
PECO	600	600	—	—	n.a.	n.a.
BGE	600	600	210	120	0.48%	0.29%
Total	$8,150	$8,300	$504	$424		

(a) Reflects aggregate bank commitments under the revolving and bilateral credit agreements (with the exception of $275 million and $200 million bilateral agreements for Generation as of December 31, 2015 and 2014, respectively) that backstop the commercial paper program. See discussion and Credit Facilities table below for items affecting effective program size.

(b) Excludes additional credit facilities for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. The agreements for these facilities expired on October 16, 2015 and were renewed at the same amount through October 14, 2016. These facilities are solely utilized to issue letters of credit. As of December 31, 2015, letters of credit issued under these facilities totaled $7 million, $14 million, $21 million and $2 million for Generation, ComEd, PECO and BGE, respectively.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have revolving credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of outstanding commercial paper does not reduce available capacity under a Registrant's credit facility, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility.

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At December 31, 2015, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

Borrower	Aggregate Bank Commitment [a]	Facility Draws	Outstanding Letters of Credit [c]	Available Capacity at December 31, 2015	
				Actual	To Support Additional Commercial Paper [b]
Exelon Corporate	$ 500	$ —	$ 26	$ 474	$ 474
Generation	5,725	—	1,449	4,276	4,174
ComEd	1,000	—	2	998	704
PECO	600	—	1	599	599
BGE	600	—	—	600	390
Total	$ 8,425	$ —	$ 1,478	$6,947	$ 6,341

(a) Excludes additional credit facilities for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. The agreements for these facilities expired on October 16, 2015 and were renewed at the same amount through October 14, 2016. These facilities are solely utilized to issue letters of credit. As of December 31, 2015, letters of credit issued under these facilities totaled $7 million, $14 million, $21 million and $2 million for Generation, ComEd, PECO and BGE, respectively.
(b) Excludes $275 million bilateral credit facilities that do not back Generation's commercial paper program.
(c) Excludes nonrecourse debt letters of credit, see discussion below on Continental Wind.

As of December 31, 2015, there were no borrowings under the Registrants' credit facilities.

The following tables present the short-term borrowings activity for Exelon, Generation, ComEd, and BGE during 2015, 2014 and 2013. PECO did not have any short-term borrowings during 2015, 2014 or 2013.

Exelon

	2015	2014	2013
Average borrowings	$ 499	$ 571	$ 254
Maximum borrowings outstanding	739	1,164	682
Average interest rates, computed on a daily basis	0.53%	0.32%	0.37%
Average interest rates, at December 31	0.88%	0.53%	0.35%

Generation

	2015	2014	2013
Average borrowings	$ 1	$ 93	$ 42
Maximum borrowings outstanding	50	552	291
Average interest rates, computed on a daily basis	0.49%	0.32%	0.32%
Average interest rates, at December 31	n.a.	n.a.	n.a.

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ComEd

	2015	2014	2013
Average borrowings	$ 461	$ 415	$ 203
Maximum borrowings outstanding	684	597	446
Average interest rates, computed on a daily basis	0.53%	0.33%	0.40%
Average interest rates, at December 31	0.89%	0.50%	0.37%

BGE

	2015	2014	2013
Average borrowings	$ 37	$ 64	$ 35
Maximum borrowings outstanding	210	180	135
Average interest rates, computed on a daily basis	0.48%	0.29%	0.31%
Average interest rates, computed at December 31	0.87%	0.61%	0.31%

Credit Agreements

On October 23, 2015, the credit agreement for CENG's $100 million bilateral credit facility was amended and extended for an additional two years. This facility has been utilized by CENG to fund working capital and capital projects. This facility does not back Generation's commercial paper program.

On January 5, 2016, Generation entered into a credit agreement establishing a $150 million bilateral credit facility, scheduled to mature in January of 2019. This facility does not back Generation's commercial paper program.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's revolving credit facilities bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular registrant's credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 7.5, 0.0 and 0.0 basis points for prime based borrowings and 127.5, 127.5, 107.5, 90.0 and 100.0 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

An event of default under any of the Registrants' credit agreements would not constitute an event of default under any of the other Registrants' credit agreements, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit agreement would constitute an event of default under the Exelon Corporation credit agreement.

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Each credit agreement requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and, in the case of Exelon and Generation, interest on the debt of its project subsidiaries. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2015:

	Exelon	Generation	ComEd	PECO	BGE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2015, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	9.77	12.31	7.25	8.94	10.66

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(Dollars in millions, except per share data unless otherwise noted)

Long-Term Debt

The following tables present the outstanding long-term debt at Exelon, Generation, ComEd, PECO and BGE as of December 31, 2015 and 2014:

Exelon

	Rates	Maturity Date	December 31, 2015	December 31, 2014
Long-term debt				
Rate stabilization bonds	5.72% — 5.82%	2017	$ 120	$ 195
First mortgage bonds (a)	1.20% — 6.45%	2016-2045	9,019	8,079
Senior unsecured notes	1.55% — 7.60%	2017-2045	9,803	7,071
Unsecured bonds	2.80% — 6.35%	2016-2036	1,750	1,750
Pollution control notes	2.50% — 2.70%	2025-2036	435	—
Nuclear fuel procurement contracts	3.15% — 3.35%	2018-2020	127	70
Notes payable and other (b)(c)	1.43% — 7.83%	2016-2053	314	174
Junior subordinated notes	6.50%	2024	1,150	1,150
Contract payment - junior subordinated notes	2.50%	2017	64	108
Long-term software licensing agreement	3.95%	2024	111	—
Nonrecourse debt:				
Fixed rates	2.29% — 6.00%	2031-2037	1,162	1,166
Variable rates	2.42% — 5.00%	2017-2030	1,058	1,101
Total long-term debt			25,113	20,864
Unamortized debt discount and premium, net			(63)	(37)
Unamortized debt issuance costs (d)			(180)	(150)
Fair value adjustment			275	333
Fair value hedge carrying value adjustment, net			—	4
Long-term debt due within one year			(1,500)	(1,802)
Long-term debt			$ 23,645	$ 19,212
Long-term debt to financing trusts (e)				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III	7.38%	2028	81	81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Subordinated debentures to BGE Trust	6.20%	2043	258	258
Total long-term debt to financing trusts			648	648
Unamortized debt issuance costs (d)			(7)	(7)
Long-term debt to financing trusts			$ 641	$ 641

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's assets are subject to the liens of their respective mortgage indentures.
(b) Includes capital lease obligations of $29 million and $32 million at December 31, 2015 and 2014, respectively. Lease payments of $4 million, $4 million, $4 million, $5 million, $4 million, and $8 million will be made in 2016, 2017, 2018, 2019, 2020 and thereafter, respectively.
(c) Includes financing related to Albany Green Energy, LLC (AGE), which is a consolidated variable interest entity (see Note 2—Variable Interest Entities for additional information). The agreement is scheduled to expire on November 17, 2017, at a variable rate equal to LIBOR plus 1.25%. As of December 31, 2015, $100 million was outstanding.
(d) Certain December 31, 2014 balances have been adjusted for the adoption of accounting guidance related to simplifying the presentation of debt costs. See Note 1—Significant Accounting Policies for additional information.

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(e) Amounts owed to these financing trusts are recorded as Long-term debt to financing trusts within Exelon's Consolidated Balance Sheets.

Generation

	Rates	Maturity Date	December 31, 2015	December 31, 2014
Long-term debt				
Senior unsecured notes	2.00% — 7.60%	2017-2042	$5,971	$5,771
Pollution control notes	2.50% — 2.70%	2025-2036	435	—
Nuclear fuel procurement contracts	3.15% — 3.35%	2018-2020	127	70
Notes payable and other (a)(b)	1.43% — 7.83%	2016-2035	166	26
Nonrecourse debt:				
Fixed rates	2.29% — 6.00%	2031-2037	1,162	1,166
Variable rates	2.42% — 5.00%	2017-2030	1,058	1,101
Total long-term debt			8,919	8,134
Fair value adjustment			127	146
Unamortized debt discount and premium, net			(17)	(14)
Unamortized debt issuance costs (c)			(70)	(70)
Long-term debt due within one year			(90)	(614)
Long-term debt			$8,869	$7,582

(a) Includes Generation's capital lease obligations of $21 million and $24 million at December 31, 2015 and 2014, respectively. Generation will make lease payments of $4 million, $4 million, $4 million, $5 million and $4 million in 2016, 2017, 2018, 2019, 2020, respectively. The capital lease matures in 2020.
(b) Includes financing related to Albany Green Energy, LLC (AGE), which is a consolidated variable interest entity (see Note 2 - Variable Interest Entities for additional information). The agreement is scheduled to expire on November 17, 2017, at a variable rate equal to LIBOR plus 1.25%. As of December 31, 2015, $100 million was outstanding.
(c) Certain December 31, 2014 balances have been adjusted for the adoption of accounting guidance related to simplifying the presentation of debt costs. See Note 1 - Significant Accounting Policies for additional information.

ComEd

	Rates	Maturity Date	December 31, 2015	December 31, 2014
Long-term debt				
First mortgage bonds (a)	1.95% — 6.45%	2016-2045	$6,419	$5,829
Notes payable and other (b)	6.95% — 7.49%	2016-2053	148	148
Total long-term debt			6,567	5,977
Unamortized debt discount and premium, net			(20)	(19)
Unamortized debt issuance costs (c)			(38)	(33)
Long-term debt due within one year			(665)	(260)
Long-term debt			$5,844	$5,665
Long-term debt to financing trust (d)				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206
Total long-term debt to financing trusts			206	206
Unamortized debt issuance costs (c)			(1)	(1)
Long-term debt to financing trusts			$ 205	$ 205

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Substantially all of ComEd's assets other than expressly excepted property are subject to the lien of its mortgage indenture.
(b) Includes ComEd's capital lease obligations of $8 million at both December 31, 2015 and 2014, respectively. Lease payments of less than $1 million will be made from 2016 through expiration at 2053.
(c) Certain December 31, 2014 balances have been adjusted for the adoption of accounting guidance related to simplifying the presentation of debt costs. See Note 1—Significant Accounting Policies for additional information.
(d) Amount owed to this financing trust is recorded as Long-term debt to financing trust within ComEd's Consolidated Balance Sheets.

PECO

	Rates	Maturity Date	December 31, 2015	December 31, 2014
Long-term debt				
First mortgage bonds (a)	1.20% — 5.95%	2016-2044	$2,600	$2,250
Total long-term debt			2,600	2,250
Unamortized debt discount and premium, net			(5)	(4)
Unamortized debt issuance costs (b)			(15)	(14)
Long-term debt due within one year			(300)	—
Long-term debt			$2,280	$2,232
Long-term debt to financing trusts (c)				
Subordinated debentures to PECO Trust III	7.38%	2028	$ 81	$ 81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Long-term debt to financing trusts			$ 184	$ 184

(a) Substantially all of PECO's assets are subject to the lien of its mortgage indenture.
(b) Certain December 31, 2014 balances have been adjusted for the adoption of accounting guidance related to simplifying the presentation of debt costs. See Note 1—Significant Accounting Policies for additional information.
(c) Amounts owed to this financing trust are recorded as Long-term debt to financing trusts within PECO's Consolidated Balance Sheets.

BGE

	Rates	Maturity Date	December 31, 2015	December 31, 2014
Long-term debt				
Rate stabilization bonds	5.72% — 5.82%	2017	$ 120	$ 195
Senior unsecured notes	2.80% — 6.35%	2016-2036	1,750	1,750
Total long-term debt			1,870	1,945
Unamortized debt discount and premium, net			(3)	(3)
Unamortized debt issuance costs (a)			(9)	(10)
Long-term debt due within one year			(378)	(75)
Long-term debt			$1,480	$1,857
Long-term debt to financing trusts (b)				
Subordinated debentures to BGE Capital Trust II	6.20%	2043	$ 258	$ 258
Total long-term debt to financing trusts			258	258
Unamortized debt issuance costs (a)			(6)	(6)
Long-term debt to financing trusts			$ 252	$ 252

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Certain December 31, 2014 balances have been adjusted for the adoption of accounting guidance related to simplifying the presentation of debt costs. See Note 1—Significant Accounting Policies for additional information.
(b) Amount owed to this financing trust is recorded as Long-term debt to financing trust within BGE's Consolidated Balance Sheets.

Long-term debt maturities at Exelon, Generation, ComEd, PECO and BGE in the periods 2016 through 2020 and thereafter are as follows:

Year	Exelon	Generation	ComEd	PECO	BGE
2016	$ 1,487	$ 90	$ 665	$ 300	$ 378
2017	1,841	805	425	—	42
2018	1,393	53	840	500	—
2019	973	673	300	—	—
2020	3,311	1,911	500	—	—
Thereafter	16,756[a]	5,387	4,043[b]	1,984[c]	1,708[d]
Total	$25,761	$ 8,919	$6,773	$2,784	$2,128

(a) Includes $648 million due to ComEd, PECO and BGE financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.
(d) Includes $258 million due to BGE financing trust.

PHI Merger Financing

In May 2014, concurrently and in connection with entering into the agreement to acquire PHI, Exelon entered into a credit facility to which the lenders committed to provide Exelon a 364-day senior unsecured bridge credit facility of $7.2 billion to support the contemplated transaction and provide flexibility for timing of permanent financing. In June 2015, the remaining $3.2 billion bridge credit facility was terminated as a result of Exelon's issuance of $4.2 billion of long-term debt to fund a portion of the purchase price and related costs and expenses for the pending PHI merger and for general corporate purposes.

In connection with the $4.2 billion issuance of Senior Unsecured Notes in 2015, the tranches due in 2025, 2035, and 2045 had to be redeemed at the principal amount plus a 1% premium of principal on December 31, 2015, if the PHI merger was not consummated or terminated prior to such date ("Special Mandatory Redemption"). Exelon also had the option to redeem those notes earlier at a 1% premium of principal, if Exelon determined that the merger would not be completed before December 31, 2015.

On October 29, 2015, Exelon commenced a private exchange offer (Exchange Offer) to certain eligible holders whereby, for those that took part, the outstanding Senior Unsecured Notes in the 2025, 2035 and 2045 tranches were exchanged for new Senior Unsecured Notes. The new Senior Unsecured Notes have substantially the same terms as the outstanding Senior Unsecured Notes, except the outside date with regard to the special redemption provisions is June 30, 2016, (or the date the PHI merger is terminated if earlier), rather than December 31, 2015, and under certain circumstances, can be further extended to August 31, 2016.

On December 2, 2015, Exelon exchanged $1.9 billion of the Senior Unsecured Notes and paid a consent fee of approximately $5 million, which has been deferred on Exelon's Consolidated Balance

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Sheet and $4 million of third-party debt issuance costs, which were charged to earnings within Other, net on Exelon's Consolidated Statement of Operations and Comprehensive Income. On December 2, 2015, Exelon also redeemed $0.9 billion of Senior Unsecured Notes not exchanged in the Exchange Offer resulting in the payment of $9 million of redemption premium and the acceleration of the unamortized original issuance discount and deferred financing costs associated with the redeemed debt of $9 million, which were charged to earnings within Other, net on Exelon's Consolidated Statement of Operations and Comprehensive Income.

Junior Subordinated Notes

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Net proceeds from the issuance were $1.11 billion, net of a $35 million underwriter fee. The net proceeds are expected to be used to finance a portion of the merger and related costs and expenses for the pending PHI merger and for general corporate purposes. Each equity unit represents an undivided beneficial ownership interest in Exelon's 2.50% junior subordinated notes due in 2024 and a forward equity purchase contract which settles in 2017. The junior subordinated notes are expected to be remarketed in 2017.

At the time of issuance, Exelon determined that the forward equity purchase contract had no value and therefore the entire $1.15 billion of junior subordinated notes were allocated to debt and recorded within Long-term debt on Exelon's Consolidated Balance Sheet. Additionally, at the time of issuance, the present value of the contract payments of $131 million ("Contract Payment Obligation") were recorded to Long-term debt, representing the obligation to make contract payments, with an offsetting reduction to Common stock. The obligation for the contract payments is accreted to interest expense over the 3 year period ending in 2017 in Exelon's Consolidated Statement of Operations and Comprehensive Income. During 2015, contract payments of $44 million related to the Contract Payment Obligation were included within Retirements of long-term debt in Exelon's Consolidated Statements of Cash Flows. During 2014, the Contract Payment Obligation was considered a non-cash financing transaction that was excluded from Exelon's Consolidated Statements of Cash Flows. Until settlement of the equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method.

Nonrecourse Debt

Exelon and Generation have issued nonrecourse debt financing, in which approximately $2.4 billion of generating assets and $0.2 billion of Upstream gas properties have been pledged as collateral at December 31, 2015. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default.

Denver Airport. In June 2011, Generation entered into a 20-year, $7 million solar loan agreement to finance a solar construction project in Denver, Colorado. The agreement is scheduled to mature on June 30, 2031. The agreement bears interest at a fixed rate of 5.50% annually with interest payable annually. As of December 31, 2015, $7 million was outstanding.

CEU Upstream. In July 2011, Generation entered into a 5-year asset-based lending agreement associated with certain Upstream gas properties that it owns. The borrowing base committed under the facility is $85 million as of December 31, 2015. The commitment level can be decreased if the assets no longer support the current borrowing base, which would result in repayment of a portion or all of the outstanding balance. The commitment can be increased up to $500 million if the assets support a

higher borrowing base and Generation is able to obtain additional commitments from lenders. Calculations of the borrowing base are impacted by projected production and commodity prices. The facility was amended and extended through January 2019. The agreement bears interest at a variable rate equal to LIBOR plus 2.50% and is payable monthly. As of December 31, 2015, $68 million was outstanding under the facility.

Sacramento PV Energy. In July 2011, a subsidiary of Generation entered into a 19-year, $41 million nonrecourse note to finance a 30MW solar facility in Sacramento, California. The note is scheduled to mature on December 31, 2030. The note bears interest at a variable rate equal to LIBOR plus 2.25% and is payable quarterly. As of December 31, 2015, $33 million was outstanding. The subsidiary also executed interest rate swaps with an initial notional value of $30 million at an interest rate of 3.57% in order to convert the variable interest payments to fixed payments on 75% of the $41 million facility amount, as required by the debt covenants. See Note 13—Derivative Financial Instruments for additional information regarding interest rate swaps.

Holyoke Solar Cooperative. In October 2011, Generation entered into a 20-year, $11 million solar loan agreement related to a solar construction project in Holyoke, Massachusetts. The agreement is scheduled to mature on December 2031. The agreement bears interest at a fixed rate of 5.25% annually with interest payable monthly. As of December 31, 2015, $10 million was outstanding.

Antelope Valley Solar Ranch One. In December 2011, the DOE Loan Programs Office issued a guarantee for up to $646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational in the first half of 2014. The loan will mature on January 5, 2037. Interest rates on the loan were fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity. The advances were completed as of December 31, 2015 and the outstanding loan balance will bear interest at an average blended interest rate of 2.82%. As of December 31, 2015, $574 million was outstanding. In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2015, Generation had $69 million in letters of credit outstanding related to the project.

Constellation Solar Horizons. In September 2012, a subsidiary of Generation entered into an 18-year $38 million nonrecourse note to recover capital used to build a 16MW solar facility in Emmitsburg, Maryland. The note is scheduled to mature on September 7, 2030. The note bears interest at a variable rate equal to LIBOR plus 2.25% with interest payable quarterly. As of December 31, 2015, $32 million was outstanding. The subsidiary also executed interest rate swaps for an initial notional amount of $29 million at an interest rate of 2.03% in order to convert the variable interest payments to fixed payments on 75% of the $38 million facility amount, as required by the debt covenants. See Note 13—Derivative Financial Instruments for additional information regarding interest rate swaps.

Continental Wind. In September 2013, Continental Wind, LLC (Continental Wind), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million senior secured notes. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667MW. The net proceeds were distributed to Generation for its general business purposes. The notes are scheduled to mature on February 28, 2033. The notes bear interest at a fixed rate of 6.00% with interest payable semi-annually. As of December 31, 2015, $572 million was outstanding.

In addition, Continental Wind entered into a $131 million letter of credit facility and $10 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2015, the Continental Wind letter of credit facility had $99 million in letters of credit outstanding related to the project.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

ExGen Renewables I. In February 2014, ExGen Renewables I, LLC (EGR), an indirect subsidiary of Exelon and Generation, borrowed $300 million aggregate principal amount pursuant to a nonrecourse senior secured loan. The proceeds were distributed to Generation for its general business purposes. The loan is scheduled to mature on February 6, 2021. The loan bears interest at a variable rate equal to LIBOR plus 4.25%, subject to a 1% LIBOR floor with interest payable quarterly. EGR indirectly owns Continental Wind. As of December 31, 2015, $258 million was outstanding. In addition to the financing, EGR entered into interest rate swaps with an initial notional amount of $240 million at an interest rate of 2.03% to manage a portion of the interest rate exposure in connection with the financing. See Note 13—Derivative Financial Instruments for additional information regarding interest rate swaps.

ExGen Texas Power. In September 2014, ExGen Texas Power, LLC (EGTP), an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. The net proceeds were distributed to Generation for general business purposes. The loan is scheduled to mature on September 18, 2021. The term loan bears interest at a variable rate equal to LIBOR plus 4.75%, subject to a 1% LIBOR floor with interest payable quarterly. As of December 31, 2015, $666 million was outstanding. As part of the agreement, a revolving credit facility was established for the amount of $20 million available through, and scheduled to mature on September 18, 2019. In addition to the financing, EGTP entered into interest rate swaps with an initial notional amount of approximately $505 million at an interest rate of 2.34% to hedge a portion of the interest rate exposure in connection with this financing, as required by the debt covenants. See Note 13—Derivative Financial Instruments for additional information regarding interest rate swaps.

15. Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

Income tax expense (benefit) from continuing operations is comprised of the following components:

For the Year Ended December 31, 2015	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 407	$ 546	$ (80)	$ 64	$ 25
Deferred	566	16	310	69	126
Investment tax credit amortization	(22)	(19)	(2)	—	(1)
State					
Current	(86)	(90)	7	(10)	—
Deferred	208	49	45	20	39
Total	$1,073	$ 502	$ 280	$143	$189

For the Year Ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 121	$ 360	$(171)	$ 28	$ 24
Deferred	576	(35)	395	87	90
Investment tax credit amortization	(20)	(16)	(2)	—	(1)
State					
Current	42	35	7	(2)	—
Deferred	(53)	(137)	39	1	27
Total	$ 666	$ 207	$ 268	$114	$140

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Included in operations:					
Federal					
Current	$ 744	$ 250	$ 160	$126	$ 9
Deferred	140	360	(27)	23	100
Investment tax credit amortization	(15)	(11)	(2)	(1)	(1)
State					
Current	181	50	50	16	—
Deferred	(6)	(34)	(29)	(2)	26
Total	$1,044	$ 615	$ 152	$162	$134

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

For the Year Ended December 31, 2015	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	3.7	1.0	4.9	1.0	5.3
Qualified nuclear decommissioning trust fund loss	(0.4)	(0.8)	—	—	—
Domestic production activities deduction	(0.7)	(1.3)	—	—	—
Health care reform legislation	—	—	—	—	0.1
Amortization of investment tax credit, including deferred taxes on basis difference	(0.9)	(1.5)	(0.3)	(0.1)	(0.1)
Plant basis differences	(1.5)	—	(0.1)	(8.7)	(0.7)
Production tax credits and other credits	(1.9)	(3.4)	—	—	—
Non-controlling interest	0.3	0.5	—	—	—
Statute of limitations expiration	(1.4)	(2.4)	—	—	—
Other	—	—	0.2	0.2	—
Effective income tax rate	32.2%	27.1%	39.7%	27.4%	39.6%

For the Year Ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	1.3	(1.9)	4.5	(0.1)	5.0
Qualified nuclear decommissioning trust fund income	2.4	4.8	—	—	—
Domestic production activities deduction	(2.0)	(4.1)	—	—	—
Health care reform legislation	0.1	—	0.2	—	0.2
Amortization of investment tax credit, including deferred taxes on basis difference	(1.1)	(2.0)	(0.3)	(0.1)	(0.3)
Plant basis differences	(1.9)	—	(0.1)	(10.4)	0.2
Production tax credits and other credits	(2.4)	(4.8)	—	—	—
Non-controlling interest	(1.8)	(3.7)			
Statute of limitations expiration	(2.6)	(5.3)	—	—	—
Other	(0.2)	(1.1)	0.3	0.1	(0.2)
Effective income tax rate	26.8%	16.9%	39.6%	24.5%	39.9%

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	4.8	1.8	3.4	1.6	4.9
Qualified nuclear decommissioning trust fund income	3.7	6.1	—	—	—
Domestic production activities deduction	—	—	—	—	—
Health care reform legislation	0.1	—	0.7	—	0.2
Amortization of investment tax credit, including deferred taxes on basis difference	(1.9)	(3.0)	(0.6)	(0.1)	—
Plant basis differences	(1.6)	—	(0.8)	(7.1)	(0.2)
Production tax credits and other credits	(2.1)	(3.4)	(0.1)	—	—
Statute of limitations expiration	(0.1)	(0.2)	—	—	—
Other	(0.3)	0.4	0.3	(0.3)	(0.9)
Effective income tax rate	37.6%	36.7%	37.9%	29.1%	39.0%

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2015 and 2014 are presented below:

For the Year Ended December 31, 2015	Exelon	Generation	ComEd	PECO	BGE
Plant basis differences	$(13,393)	$ (4,269)	$(4,424)	$(2,901)	$(1,821)
Accrual based contracts	(136)	(136)	—	—	—
Derivatives and other financial instruments	(203)	(181)	(4)	—	—
Deferred pension and postretirement obligation	1,801	(371)	(505)	(9)	(47)
Nuclear decommissioning activities	(592)	(592)	—	—	—
Deferred debt refinancing costs	133	48	(15)	(1)	(4)
Regulatory assets and liabilities	(1,706)	—	(219)	16	(264)
Tax loss carryforward	103	56	—	—	33
Tax credit carryforward	327	374	—	—	—
Investment in CENG	(595)	(595)	—	—	—
Other, net	1,112	425	270	105	27
Deferred income tax liabilities (net)	$(13,149)	$ (5,241)	$(4,897)	$(2,790)	$(2,076)
Unamortized investment tax credits	(622)	(598)	(17)	(2)	(5)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(13,771)	$ (5,839)	$(4,914)	$(2,792)	$(2,081)

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Plant basis differences	$(12,143)	$ (3,834)	$(3,945)	$(2,749)	$(1,660)
Accrual based contracts	(178)	(178)	—	—	—
Derivatives and other financial instruments	(46)	(79)	(4)	—	—
Deferred pension and postretirement obligation	1,914	(390)	(543)	2	(53)
Nuclear decommissioning activities	(726)	(726)	—	—	—
Deferred debt refinancing costs	112	57	(18)	(2)	(4)
Regulatory assets and liabilities	(1,824)	—	(286)	27	(258)
Tax loss carryforward	111	48	—	11	39
Tax credit carryforward	97	143	—	—	—
Investment in CENG	(563)	(563)	—	—	—
Other, net	1,029	346	255	111	30
Deferred income tax liabilities (net)	$(12,217)	$ (5,176)	$(4,541)	$(2,600)	$(1,906)
Unamortized investment tax credits	(555)	(528)	(20)	(2)	(5)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(12,772)	$ (5,704)	$(4,561)	$(2,602)	$(1,911)

The following table provides the Registrants' carryforwards and any corresponding valuation allowances as of December 31, 2015.

	Exelon	Generation	ComEd	PECO	BGE
Federal					
Federal general business credits carryforward	416[a]	415	—	—	—
State					
State net operating losses and other credit carryforwards	2,086[b]	1,259[b]	—	—	618[c]
Deferred taxes on state tax attributes (net)	117	66	—	—	34
Valuation allowance on state tax attributes	13	11	—	—	1

(a) Exelon's federal general business credit carryforwards will expire beginning in 2032.
(b) Exelon's and Generation's state net operating losses and other carryforwards, which are presented on a post-apportioned basis, will expire beginning in 2016.
(c) BGE's state net operating losses will expire beginning in 2026.

Tabular reconciliation of unrecognized tax benefits

The following table provides a reconciliation of the Registrants' unrecognized tax benefits as of December 31, 2015, 2014 and 2013:

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2015	$1,829	$ 1,357	$ 149	$ 44	$—
Increases based on tax positions related to 2015	108	—	—	—	106
Change to positions that only affect timing	(705)	(659)	(7)	(44)	—
Increases based on tax positions prior to 2015	79	65	—	—	14
Decreases based on tax positions prior to 2015	(116)	(112)	—	—	—
Decrease from settlements with taxing authorities	(31)	(31)	—	—	—
Decreases from expiration of statute of limitations	(86)	(86)	—	—	—
Unrecognized tax benefits at December 31, 2015	$1,078	$ 534	$ 142	$—	$120

Combined Notes to Consolidated Financial Statements—(Continued)
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	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2014	$2,175	$ 1,415	$ 324	$ 44	$—
Increases based on tax positions related to 2014	15	15	—	—	—
Change to positions that only affect timing	(255)	33	(175)	—	—
Increases based on tax positions prior to 2014	18	18	—	—	—
Decreases based on tax positions prior to 2014	(1)	(2)	—	—	—
Decrease from settlements with taxing authorities	(35)	(34)	—	—	—
Decreases from expiration of statute of limitations	(88)	(88)	—	—	—
Unrecognized tax benefits at December 31, 2014	$1,829	$ 1,357	$ 149	$ 44	$—

	Exelon	Generation	ComEd	PECO	BGE
Unrecognized tax benefits at January 1, 2013	$1,024	$ 876	$ 67	$ 44	$—
Increases based on tax positions related to 2013	19	19	—	—	—
Change to positions that only affect timing	649	36	257	—	—
Increases based on tax positions prior to 2013	493	493	—	—	—
Decreases based on tax positions prior to 2013	(6)	(5)	—	—	—
Decreases from expiration of statute of limitations	(4)	(4)	—	—	—
Unrecognized tax benefits at December 31, 2013	$2,175	$ 1,415	$ 324	$ 44	$—

Included in Exelon's unrecognized tax benefits balance at December 31, 2015 and 2014 are approximately $540 million and $1,129 million, respectively, of tax positions for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits. The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to, or defer the receipt of the cash tax benefit from, the taxing authority to an earlier or later period respectively.

Nuclear Decommissioning Liabilities (Exelon and Generation)

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and disallowed AmerGen's claims. In early 2009, Generation filed a complaint in the United States Court of Federal Claims to contest this determination. On September 17, 2013, the Court granted the government's motion denying AmerGen's claims for refund. In the first quarter of 2014, Exelon filed an appeal of the decision to the United States Court of Appeals for the Federal Circuit. On March 11, 2015, the Federal Circuit affirmed the lower court's decision to deny AmerGen's claims for refund. Exelon will not be pursuing further appeals with respect to this issue and, as a result, reduced Generation and PECO's unrecognized tax benefits by a total of $661 million and $43 million, respectively, in the first quarter of 2015. This change in unrecognized tax benefits had no impact on Exelon, Generation, or PECO's effective tax rate.

Unrecognized tax benefits that if recognized would affect the effective tax rate

Exelon and Generation have $538 million and $509 million, respectively, of unrecognized tax benefits at December 31, 2015 that, if recognized, would decrease the effective tax rate. BGE has

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$120 million of unrecognized tax benefits at December 31, 2015 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate. Exelon and Generation had $701 million and $672 million, respectively, of unrecognized tax benefits at December 31, 2014 that, if recognized, would decrease the effective tax rate. In 2015, the unrecognized tax benefits decreased at Exelon and Generation due to settlements with state tax authorities and the expiration of statues of limitations for certain state jurisdictions.

Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Like-Kind Exchange

As of December 31, 2015, Exelon and ComEd have approximately $397 million and $142 million of unrecognized tax benefits that could significantly decrease within the 12 months after the reporting date as a result of a decision in the like-kind exchange litigation described below. Exelon and ComEd have unrecognized tax benefits that, if recognized, would decrease Exelon's effective tax rate by $69 million and increase ComEd's effective tax rate by $11 million.

Settlement of Income Tax Audits and Litigation

As of December 31, 2015, Exelon, Generation, and BGE have approximately $174 million, $54 million, and $120 million of unrecognized state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits, potential settlements, and expected statute of limitation expirations. Of the above unrecognized tax benefits, Exelon and Generation have $54 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefit related to BGE, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Total amounts of interest and penalties recognized

The following table represents the net interest receivable (payable), including interest related to tax positions reflected in the Registrants' Consolidated Balance Sheets.

Net interest receivable (payable) as of	Exelon	Generation	ComEd	PECO	BGE
December 31, 2015	$(288)	$ 80	$(210)	$ 3	$ (1)
December 31, 2014	(310)	40	(203)	3	(1)

The following table sets forth the net interest expense, including interest related to tax positions, recognized in interest expense (income) in other income and deductions in the Registrants' Consolidated Statements of Operations and Comprehensive Income. The Registrants have not accrued any material penalties with respect to uncertain tax positions.

Net interest expense (income) for the years ended	Exelon	Generation	ComEd	PECO	BGE
December 31, 2015	$ (13)	$ (31)	$ 7	$—	$—
December 31, 2014	(36)	(50)	6	—	1
December 31, 2013	391	17	281	(1)	—

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Description of tax years that remain open to assessment by major jurisdiction

Taxpayer	Open Years
Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns	1999, 2001-2014
Exelon and subsidiaries Illinois unitary income tax returns	2007-2014
Constellation combined New York corporate income tax returns	2010-March 2012
Various separate company Pennsylvania corporate net income tax returns	2010-2014
BGE Maryland corporate net income tax returns	2011-2014
Various Exelon Maryland corporate net income tax returns	2012-2014
Various Constellation (Non-BGE) Maryland corporate net income tax returns	2011-2014

Other Tax Matters

Like-Kind Exchange

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $1.2 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with this position and asserted that the entire gain of approximately $1.2 billion was taxable in 1999.

Exelon has been unable to reach agreement with the IRS regarding the dispute over the like-kind exchange position. The IRS has asserted that Exelon's purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately $90 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like-kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison's deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon's current determination that settlement is unlikely, Exelon has concluded that

subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013, Exelon recorded a non-cash charge to earnings of approximately $265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $172 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the unpaid tax liabilities related to the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition, ComEd will continue to record non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. Exelon continues to believe that it is unlikely that the IRS's assertion of penalties will ultimately be sustained and therefore no liability for the penalty has been recorded.

On September 30, 2013, the IRS issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court and the trial took place in August of 2015. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue. While the Tax Court could reach its decision as early as 2016, the litigation could take three to five years if an appeal is necessary. Decisions in the Tax Court are not controlled by the Federal Circuit's decision in Consolidated Edison.

In the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of $335 million. In connection with the termination, Exelon deposited $65 million with the IRS, including $35 million by ComEd. The deposit can be redesignated to any tax year, if necessary, and may be used to satisfy any amounts owed as a result of the litigation.

In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, net of the deposit discussed above and exclusive of penalties, that could become currently payable as of December 31, 2015 may be as much as $760 million, of which approximately $280 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless. Interest will continue to accrue until such time as payment is made. An appeal of an adverse decision in the Tax Court would necessitate either the posting of a bond or the payment of the tax and interest for the tax years before the court. A final appellate decision could take several years.

Accounting for Generation Repairs (Exelon and Generation)

On April 30, 2013, the IRS issued Revenue Procedure 2013-24 providing guidance for determining the appropriate tax treatment of costs incurred to repair electric generation assets. Generation changed its method of accounting for deducting repairs in accordance with this guidance beginning in the 2014 tax year. The adoption of the new method resulted in Generation recording a cash tax detriment of approximately $120 million in 2014.

Long-Term State Tax Apportionment (Exelon and Generation)

The long-term state tax apportionment was revised in the fourth quarter of 2015 pursuant to Exelon's long-term state tax apportionment policy, resulting in the recording of a deferred state tax

expense for Exelon and Generation of $41 million (net of Federal taxes) and $11 million (net of Federal taxes), respectively. In 2014, in accordance with the policy, Exelon and Generation recorded a deferred state tax benefit of $28 million (net of Federal taxes) and $40 million (net of Federal taxes), respectively. The amounts recorded for 2013 in accordance with the policy were immaterial.

Allocation of Tax Benefits (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2015, Generation, PECO, and BGE recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $57 million, $16 million, and $7 million respectively. ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss.

During 2014, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $55 million and $25 million, respectively. ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of tax net operating losses.

During 2013, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $26 million and $27 million, respectively. During 2013, ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd's and BGE's tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010.

16. Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

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The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets, from January 1, 2014 to December 31, 2015:

	Exelon and Generation
Nuclear decommissioning ARO at January 1, 2014	$ 4,855
Consolidation of CENG [a]	1,760
Accretion expense	334
Net increase due to changes in, and timing of, estimated future cash flows	19
Costs incurred to decommission retired plants	(7)
Nuclear decommissioning ARO at December 31, 2014 [b]	6,961
Accretion expense	387
Net increase due to changes in, and timing of, estimated future cash flows	901
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at December 31, 2015 [b]	$ 8,246

(a) Represents the fair value of the CENG ARO liability as of April 1, 2014, the date of consolidation. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.
(b) Includes $7 million and $8 million as the current portion of the ARO at December 31, 2015 and 2014, respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During 2015, Generation's total nuclear ARO increased by approximately $1.3 billion, reflecting impacts of ARO updates completed during 2015 to reflect changes in amounts and timing of estimated decommissioning cash flows and impacts of year-to-date accretion of the ARO liability due to the passage of time.

The increase in the ARO during 2015 was primarily driven by an increase of approximately $630 million for costs expected to be incurred for required site security during the decommissioning periods in which SNF remains on-site and until major reactor components and buildings have been dismantled and removed. This projected increase is based on emerging industry experience at nuclear sites in the planning or early stage of decommissioning indicating greater than originally expected numbers of security personnel required to be on site during these decommissioning periods. Generation will continue to monitor emerging security cost trends, including potential strategies to limit such costs by, for example, optimizing the transfer of SNF when DOE starts taking possession of SNF or increasing the use of dry SNF storage, and will adjust the ARO liability accordingly. The 2015 increase in the ARO includes an increase of approximately $285 million for the impacts of a change implemented in the 2015 annual assessment of Generation's SNF storage and disposal cost estimation methodology to better align the projected timing of SNF transfers to the DOE with assumed plant shutdown dates as well as higher assumed probabilities of early retirements of certain economically challenged nuclear plants (See Note 9—Implications of Potential Early Plant Retirements for additional information) and further accretion of the obligation. These increases were partially offset by reductions in estimated cost escalation rates, primarily for labor and energy costs.

The financial statement impact related to the increase in the ARO due to the changes in, and timing of, estimated cash flows primarily resulted in a corresponding increase in Property, plant and equipment on Exelon's and Generation's Consolidated Balance Sheets. Approximately $8 million of the 2015 adjustment resulted in a credit to income, which is included in Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

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During 2014, Generation's ARO increased by approximately $2.1 billion. The increase is largely driven by the recording of an ARO on Exelon's and Generation's Consolidated Balance Sheets at fair value, including subsequent purchase accounting adjustments, upon consolidation of CENG (see Note 5—Investment in Constellation Energy Nuclear Group, LLC). The change in the ARO was also driven by an increase for accretion of the obligation and an increase in the estimated costs to decommission Byron, Braidwood, and LaSalle nuclear units resulting from the completion of updated decommissioning costs studies received during 2014 as part of the annual assessment. These increases in the ARO were partially offset by decreases in the ARO due to a reduction in estimated escalation rates, primarily for labor and energy costs. The increase in the ARO due to the changes in, and timing of, estimated cash flows was offset within Property, plant and equipment on Exelon's and Generation's Consolidated Balance Sheets, aside from an approximate $16 million credit to income, which is included in Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with Generation's nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of approximately $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. Aside from the former PECO units, Generation does not currently collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from utility customers. Apart from the contributions made to the NDT funds from amounts previously collected from ComEd and currently collected from PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third-party (see Zion Station Decommissioning below) and the CENG units, where any shortfall is required to be funded by both Generation and EDF. Generation, through PECO, has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise Generation will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds compared to decommissioning costs, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from utility customers for any of Generation's other nuclear units. With respect to

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the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to Generation's other nuclear units, Generation retains any funds remaining after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to nuclear decommissioning trust funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. Generation expects to comply with applicable regulations and timely commence and complete all required decommissioning activities.

At December 31, 2015, and 2014, Exelon and Generation had NDT fund investments totaling $10,342 million and $10,537 million, respectively. For additional information related to the NDT fund investments, refer to Note 12—Fair Value of Financial Assets and Liabilities.

The following table provides unrealized gains on NDT funds for 2015, 2014 and 2013:

	Exelon and Generation		
	For the Years Ended December 31,		
	2015	2014	2013
Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units [a]	$ (282)	$ 180	$ 406
Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units [b][c]	(197)	134	146

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $7 million, $29 million and $7 million of net unrealized gains related to the Zion Station pledged assets in 2015, 2014 and 2013, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.
(c) Net unrealized gains (losses) related to Generation's NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Accounting Implications of the Regulatory Agreements with ComEd and PECO . Based on the regulatory agreement with the ICC that dictates Generation's obligations related to the shortfall or

excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the NDT funds are expected to exceed the total estimated decommissioning obligation, decommissioning-related activities, including realized and unrealized gains and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial position could be material. As of December 31, 2015, the NDT funds of each of the former ComEd units, except for Zion (see Zion Station Decommissioning below), are expected to exceed the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is different, as described below, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

Based on the regulatory agreement supported by the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the former PECO units, regardless of whether the funds held in the NDT funds are expected to exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial position could be material.

The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Refer to Note 3—Regulatory Matters and Note 26—Related Party Transactions for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion

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Station, which is located in Zion, Illinois and ceased operation in 1998. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF and decommission the SNF dry storage facility, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to its decommissioning efforts at Zion Station. During 2013, EnergySolutions entered a definitive acquisition agreement and was acquired by another Company. Generation reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to Pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a Payable for Zion Station decommissioning in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the Payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately $84 million, which is included within the nuclear decommissioning ARO at December 31, 2015. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2015 and 2014:

	Exelon and Generation	
	2015	2014
Carrying value of Zion Station pledged assets	$ 206	$ 319
Payable to Zion Solutions [a]	189	292
Current portion of payable to Zion Solutions [b]	99	137
Cumulative withdrawals by Zion Solutions to pay decommissioning costs [c]	786	666

(a) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.
(c) Includes project expenses to decommission Zion Station and estimated tax payments on Zion Station NDT fund earnings.

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required

decommissioning work according to an established schedule and constructed a dry cask storage facility on the land and has loaded the SNF from the SNF pools onto the dry cask storage facility at Zion Station. Rent payable under the Lease Agreement is $1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with Zion Station and penalty rents may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by ZionSolutions, EnergySolutions provided a $200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. EnergySolutions and its parent company have also provided a performance guarantee and EnergySolutions has entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in the type of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2015 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2019 for Oyster Creek); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2015 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning activities are completed under three possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the assumption plants cease operating at the end of an extended license life (assuming 20-year license renewal extensions, except Oyster Creek with an assumed end-of-operations date of 2019); (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 6.1% to 6.3% (as compared to a historical 5-year annual average pre-tax return of approximately 7%).

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Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial position may be significantly adversely affected.

On March 31, 2014, Generation submitted its NRC required annual decommissioning funding report as of December 31, 2013 for reactors that have been shut down except for Zion Station which is included on a separate report to the NRC submitted by EnergySolutions (see Zion Station Decommissioning above). This submittal also included the required updated financial tests for the Limerick Unit 1 parent guarantee that had been established in 2013. There was no change to the amount of the parent guarantee, or the funding status of these reactors. Adequate decommissioning funding assurance was in place for all reactors owned by Generation. During 2014, the operating license for Limerick Unit 1 was extended by 20 years. As a result of this extension, and the subsequent funding assurance calculation performed by the NRC, it was found that the parent company guarantee was no longer required and thus the parent guarantee for Limerick Unit 1 has been cancelled effective March 13, 2015. See Note 3—Regulatory Matters for additional information regarding the operating license extension for Limerick Unit 1.

Generation filed its biennial decommissioning funding status report with the NRC on March 31, 2015. This report reflects the status of decommissioning funding assurance as of December 31, 2014. Due to increased cost estimates received in the second half of 2014, Braidwood Unit 1, Braidwood Unit 2, and Byron Unit 2 did not meet the NRC's minimum funding assurance criteria as of December 31, 2014. NRC guidance provides licensees with two years or by the time of submitting the next biennial report (on or before March 31, 2017) to resolve funding assurance shortfalls. During this period, Generation will monitor funding assurance and new developments, including the impact of a 20-year license renewal for Braidwood and Byron, to assess the status of funding assurance and to take steps, if necessary, to address any funding shortfall on these funds on or before March 31, 2017. On February 4, 2016, Generation submitted an updated decommissioning funding status report with the NRC for Braidwood Units 1 and 2, and Byron Unit 2. This report reflected the recently approved license renewals for these units, and showed that they have adequate decommissioning funding assurance, and that the shortfall identified in the March 31, 2015 report has now been resolved. The increased security costs discussed above will be taken into consideration, as appropriate and in accordance with the regulatory requirements, in Generation's future decommissioning funding status reports submitted to the NRC. Generation does not expect the increased costs to change Generation's NRC minimum funding assurance status.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO units, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Non-Nuclear Asset Retirement Obligations (Exelon, Generation, ComEd, PECO and BGE)

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the

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condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. ComEd, PECO and BGE have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected on the Registrants' Consolidated Balance Sheets from January 1, 2014 to December 31, 2015:

	Exelon	Generation	ComEd	PECO	BGE
Non-nuclear AROs at January 1, 2014	$ 351	$ 201	$ 101	$ 30	$ 19
Net increase (decrease) due to changes in, and timing of, estimated future cash flows [a]	(1)	(2)	2	—	(1)
Development projects [b]	11	11	—	—	—
Accretion expense [c]	15	11	3	1	—
Liabilities held for sale [d]	(4)	(4)	—	—	—
Sale of generating assets [e]	(20)	(20)	—	—	—
Payments	(6)	(3)	(2)	(1)	—
Non-nuclear AROs at December 31, 2014 [f]	346	194	104	30	18
Net increase (decrease) due to changes in, and timing of, estimated future cash flows [a]	(10)	(12)	6	(4)	—
Development projects [b]	10	10	—	—	—
Accretion expense [c]	16	10	5	1	—
Sale of generating assets [e]	(2)	(2)	—	—	—
Payments	(5)	(3)	(2)	—	—
Non-nuclear AROs at December 31, 2015 [f]	$ 355	$ 197	$ 113	$ 27	$ 18

(a) During the year ended December 31, 2015, Generation recorded a decrease of $(2) million in Operating and maintenance expense. ComEd, PECO, and BGE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2015. During the year ended December 31, 2014, Generation recorded a decrease of $(2) million and ComEd recorded an increase of $1 million in Operating and maintenance expense. PECO and BGE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2014.
(b) Relates to new AROs recorded due to the construction of solar, wind and other non-nuclear generating sites.
(c) For ComEd, PECO, and BGE, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.
(d) Represents AROs related to generating stations classified as held for sale. See Note 4—Mergers, Acquisitions, and Dispositions for further information.
(e) Reflects a reduction to the ARO resulting primarily from the sales of Schuylkill generating station in 2015 and Keystone and Conemaugh generating stations in 2014. See Note 4—Mergers, Acquisitions, and Dispositions for further information.
(f) Excludes $5 million, $2 million, $0 million and $1 million as the current portion of the ARO at December 31, 2015 for Generation, ComEd, PECO and BGE, respectively. Excludes $1 million, $1 million, $1 million and $1 million as the current portion of the ARO at December 31, 2014 for Generation, ComEd, PECO and BGE, respectively. This is included in Other current liabilities on the Registrants' respective Consolidated Balance Sheets.

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17. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

As of December 31, 2015, Exelon sponsored defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. The table below shows the pension and other postretirement benefit plans in which employees of each operating company participated at December 31, 2015.

	Operating Company (d)				
Name of Plan:	Generation	ComEd	PECO	BGE	BSC
Qualified Pension Plans:					
Exelon Corporation Retirement Program (a)	X	X	X	X	X
Exelon Corporation Cash Balance Pension Plan (a)	X	X	X	X	X
Exelon Corporation Pension Plan for Bargaining Unit Employees (a)	X	X			X
Exelon New England Union Employees Pension Plan (a)	X				
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek (a)	X	X	X		X
Pension Plan of Constellation Energy Group, Inc. (b)	X	X	X	X	X
Pension Plan of Constellation Energy Nuclear Group, LLC (c)	X			X	X
Nine Mile Point Pension Plan (c)	X				X
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B (b)	X				
Non-Qualified Pension Plans:					
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan (a)	X	X	X		X
Exelon Corporation Supplemental Management Retirement Plan (a)	X	X	X	X	X
Constellation Energy Group, Inc. Senior Executive Supplemental Plan (b)	X			X	X
Constellation Energy Group, Inc. Supplemental Pension Plan (b)	X			X	X
Constellation Energy Group, Inc. Benefits Restoration Plan (b)	X	X		X	X
Constellation Nuclear Plan, LLC Executive Retirement Plan (c)	X				X
Constellation Energy Nuclear Plan, LLC Benefits Restoration Plan (c)	X				X
Baltimore Gas & Electric Company Executive Benefit Plan (b)	X			X	X
Baltimore Gas & Electric Company Manager Benefit Plan (b)	X	X		X	X
Other Postretirement Benefit Plans:					
PECO Energy Company Retiree Medical Plan (a)	X	X	X	X	X
Exelon Corporation Health Care Program (a)	X	X	X	X	X
Exelon Corporation Employees' Life Insurance Plan (a)	X	X	X	X	X
Constellation Energy Group, Inc. Retiree Medical Plan (b)	X	X	X	X	X
Constellation Energy Group, Inc. Retiree Dental Plan (b)	X			X	X
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan (b)	X	X	X	X	X
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan (b)	X				
Exelon New England Union Post-Employment Medical Savings Account Plan (a)	X				
Retiree Medical Plan of Constellation Energy Nuclear Group LLC (c)	X			X	X
Retiree Dental Plan of Constellation Energy Nuclear Group LLC (c)	X			X	X
Nine Mile Point Nuclear Station, LLC Medical Care and Prescription Drug Plan for Retired Employees (c)	X				X

(a) These plans are collectively referred to as the Legacy Exelon plans.
(b) These plans are collectively referred to as the Legacy Constellation Energy Group (CEG) Plans.
(c) These plans are collectively referred to as the Legacy CENG plans.
(d) Employees generally remain in their legacy benefit plans when transferring between operating companies.

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Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Exelon has elected that the trusts underlying these plans be treated under the IRC as qualified trusts. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets and Funded Status

Exelon recognizes the overfunded or underfunded status of defined benefit pension and OPEB plans as an asset or liability on its balance sheet, with offsetting entries to Accumulated OCI and regulatory assets (liabilities), in accordance with the applicable authoritative guidance. The measurement date for the plans is December 31.

During the first quarter of 2015, Exelon received an updated valuation of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2015. This valuation resulted in an increase to the pension obligation of $45 million and an increase to the other postretirement benefit obligation of $57 million. Additionally, Accumulated other comprehensive loss (AOCL) increased by approximately $27 million (after tax), regulatory assets increased by approximately $48 million, and regulatory liabilities decreased by approximately $11 million.

The following table provides a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
Change in benefit obligation:				
Net benefit obligation at beginning of year	$18,256	$15,459	$ 4,197	$ 4,451
Service cost	326	293	119	117
Interest cost	710	749	167	186
Plan participants' contributions	—	—	42	42
Actuarial (gain) loss	(582)	2,095	(341)	502
Plan amendments	—	—	(23)	(1,012)
Acquisitions/divestitures (a)	—	594	—	142
Curtailments	—	(8)	—	—
Settlements	(34)	(30)	—	—
Gross benefits paid	(923)	(896)	(223)	(231)
Net benefit obligation at end of year	$17,753	$18,256	$ 3,938	$ 4,197

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
Change in plan assets:				
Fair value of net plan assets at beginning of year	$14,874	$13,571	$ 2,430	$ 2,238
Actual return on plan assets	(32)	1,443	4	90
Employer contributions	462	332	40	291
Plan participants' contributions	—	—	42	42
Gross benefits paid	(923)	(896)	(223)	(231)
Acquisitions/divestitures (a)	—	454	—	—
Settlements	(34)	(30)	—	—
Fair value of net plan assets at end of year	$14,347	$14,874	$ 2,293	$ 2,430

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(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, Exelon became a sponsor of CENG's pension and OPEB plans effective July 14, 2014. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for further information.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
Other current liabilities	$ 21	$ 16	$ 27	$ 25
Pension obligations	3,385	3,366	—	—
Non-pension postretirement benefit obligations	—	—	1,618	1,742
Unfunded status (net benefit obligation less net plan assets)	$ 3,406	$ 3,382	$ 1,645	$ 1,767

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO), and fair value of plan assets for all pension plans with a PBO or ABO in excess of plan assets.

	PBO in excess of plan assets	
	2015	2014
Projected benefit obligation	$17,753	$18,256
Fair value of net plan assets	14,347	14,874

	ABO in excess of plan assets	
	2015	2014
Projected benefit obligation	$17,753	$18,256
Accumulated benefit obligation	16,792	17,191
Fair value of net plan assets	14,347	14,874

On a PBO basis, the plans were funded at 81% at December 31, 2015 compared to 81% at December 31, 2014. On an ABO basis, the plans were funded at 85% at December 31, 2015 compared to 87% at December 31, 2014. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

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Components of Net Periodic Benefit Costs

The majority of the 2015 pension benefit cost for Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 3.94%. The majority of the 2015 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.46% for funded plans and a discount rate of 3.92%. A portion of the net periodic benefit cost for all pension and OPEB plans are capitalized within each of the Registrant's Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to any capitalization, for the years ended December 31, 2015, 2014 and 2013.

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Components of net periodic benefit cost:						
Service cost	$ 326	$ 293	$ 317	$ 119	$ 117	$ 162
Interest cost	710	749	650	167	186	194
Expected return on assets	(1,026)	(994)	(1,015)	(151)	(154)	(132)
Amortization of:						
Prior service cost (credit)	13	14	14	(174)	(122)	(19)
Actuarial loss	571	420	562	80	50	83
Settlement charges	2	2	9	—	—	—
Net periodic benefit cost	$ 596	$ 484	$ 537	$ 41	$ 77	$ 288

Components of AOCI and Regulatory Assets

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets (liabilities) for the years ended December 31, 2015, 2014 and 2013 for all plans combined.

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial loss (gain)	$ 476	$1,639	$(1,169)	$(194)	$ 561	$(628)
Amortization of actuarial loss	(571)	(420)	(562)	(80)	(50)	(83)
Current year prior service (credit) cost	—	—	—	(23)	(1,012)	15
Amortization of prior service (cost) credit	(13)	(14)	(14)	174	122	19
Settlements	(2)	(2)	(8)	—	—	—
Total recognized in AOCI and regulatory assets (liabilities) [(a)]	$(110)	$1,203	$(1,753)	$(123)	$ (379)	$(677)

(a) Of the $110 million gain related to pension benefits, $64 million and $46 million were recognized in AOCI and regulatory assets, respectively, during 2015. Of the $123 million gain related to other postretirement benefits, $63 million and $60 million were recognized in AOCI and regulatory assets (liabilities), respectively, during 2015. Of the $1,203 million loss related to pension benefits, $788 million and $415 million were recognized in AOCI and regulatory assets, respectively, during 2014. Of the $379 million gain related to other postretirement benefits, $162 million and $217 million were recognized

in AOCI and regulatory assets (liabilities), respectively, during 2014. Of the $1,753 million gain related to pension benefits, $1,071 million and $682 million were recognized in AOCI and regulatory assets, respectively, during 2013. Of the $677 million gain related to other postretirement benefits, $352 million and $325 million were recognized in AOCI and regulatory assets, respectively, during 2013.

The following table provides the components of Exelon's gross accumulated other comprehensive loss and regulatory assets (liabilities) that have not been recognized as components of periodic benefit cost at December 31, 2015 and 2014, respectively, for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2015	2014	2015	2014
Prior service cost (credit)	$ 36	$ 49	$ (812)	$ (963)
Actuarial loss	7,310	7,407	711	985
Total [a]	$ 7,346	$ 7,456	$ (101)	$ 22

(a) Of the $7,346 million related to pension benefits, $4,246 million and $3,100 million are included in AOCI and regulatory assets, respectively, at December 31, 2015. Of the $(101) million related to other postretirement benefits, $(63) million and $(38) million are included in AOCI and regulatory assets (liabilities), respectively, at December 31, 2015. Of the $7,456 million related to pension benefits, $4,310 million and $3,146 million are included in AOCI and regulatory assets, respectively, at December 31, 2014. The $22 million related to other postretirement benefits is included in regulatory assets (liabilities) at December 31, 2014.

The following table provides the components of Exelon's AOCI and regulatory assets(liabilities) at December 31, 2015 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2016. These estimates are subject to the completion of an actuarial valuation of Exelon's pension and other postretirement benefit obligations, which will reflect actual census data as of January 1, 2016 and actual claims activity as of December 31, 2015. The valuation is expected to be completed in the first quarter of 2016 for the majority of the benefit plans.

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 13	$ (175)
Actuarial loss	501	50
Total [a]	$ 514	$ (125)

(a) Of the $514 million related to pension benefits at December 31, 2015, $290 million and $224 million are expected to be amortized from AOCI and regulatory assets in 2016, respectively. Of the $(125) million related to other postretirement benefits at December 31, 2015, $(64) million and $(61) million are expected to be amortized from AOCI and regulatory assets (liabilities) in 2016, respectively.

Assumptions

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term EROA, Exelon's expected level of contributions to the plans, the long-term expected investment rate credited to employees participating in cash balance plans and the anticipated rate of increase of health care costs. Additionally, assumptions related to plan participants include the incidence of mortality, the expected remaining service period, the level of compensation and rate of compensation increases, employee age and length of service, among other factors.

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Expected Rate of Return. In selecting the EROA, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

Mortality. For the December 31, 2014 actuarial valuation, Exelon changed its assumption of mortality to reflect more recent expectations of future improvements in life expectancy. The change was supported through completion of an experience study and supplemental analyses performed by its actuaries. The change in assumption resulted in increases of $361 million and $117 million in the pension and other postretirement benefits obligations as of December 31, 2014, respectively. There were no changes to the mortality assumption in 2015.

The following assumptions were used to determine the benefit obligations for the plans at December 31, 2015, 2014 and 2013. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Discount rate	4.29%	3.94%	4.80%	4.29%	3.92%	4.90%
Rate of compensation increase	(a)	(a)	(b)	(a)	(a)	(b)
Mortality table	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table with Scale AA improvements	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table with Scale AA improvements
Health care cost trend on covered charges	N/A	N/A	N/A	5.50% decreasing to ultimate trend of 5.00% in 2017	6.00% decreasing to ultimate trend of 5.00% in 2017	6.00% decreasing to ultimate trend of 5.00% in 2017

(a) 3.25% through 2019 and 3.75% thereafter.
(b) 3.25% through 2018 and 3.75% thereafter.

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The following assumptions were used to determine the net periodic benefit costs for all the plans for the years ended December 31, 2015, 2014 and 2013:

	Pension Benefits			Other Postretirement Benefits		
	2015	2014	2013	2015	2014	2013
Discount rate	3.94% (a)	4.80% (b)	3.92% (c)	3.92% (a)	4.90% (b)	4.00% (c)
Expected return on plan assets	7.00% (d)	7.00% (d)	7.50% (d)	6.50% (d)	6.59% (d)	6.45% (d)
Rate of compensation increase	(e)	(f)	(g)	(e)	(f)	(g)
Mortality table	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table with Scale AA improvements	RP-2000 table with Scale AA improvements	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table with Scale AA improvements	RP-2000 table with Scale AA improvements
Health care cost trend on covered charges	N/A	N/A	N/A	6.00% decreasing to ultimate trend of 5.00% in 2017	6.00% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017

(a) The discount rates above represent the initial discount rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2015. Discount rates for CENG's legacy pension and OPEB plans ranged from 3.68%-4.14% and 4.32%-4.43%, respectively.
(b) The discount rates above represent the initial discount rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2014. Certain of the other postretirement benefit plans were remeasured as of April 30, 2014 using an expected long-term rate of return on plan assets of 6.59% and a discount rate of 4.30%. Costs of the year ended December 31, 2014 reflect the impact of this remeasurement. On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, Exelon became the sponsor of CENG's legacy pension and OPEB plans effective July 14, 2014; discount rates for those plans, impacting 2014 costs, ranged from 3.60%-4.30% and 4.09%-4.55%, respectively. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for further information.
(c) The discount rates above represent the initial discounts rates used to establish Exelon's pension and other postretirement benefits costs for the year ended December 31, 2013. Certain of the benefit plans were remeasured during the year using discount rates of 4.21% and 4.66% for pension and other postretirement benefits, respectively. Costs for the year ended December 31, 2013 reflect the impact of these remeasurements.
(d) Not applicable to pension and other postretirement benefit plans that do not have plan assets.
(e) 3.25% through 2019 and 3.75% thereafter.
(f) 3.25% through 2018 and 3.75% thereafter.
(g) 3.25% through 2017 and 3.75% thereafter.

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Assumed health care cost trend rates impact the other postretirement benefit plan costs reported for Exelon's participant populations with plan designs that do not have a cap on cost growth. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend:	
on 2015 total service and interest cost components	$ 12
on postretirement benefit obligation at December 31, 2015	100
Effect of a one percentage point decrease in assumed health care cost trend:	
on 2015 total service and interest cost components	(9)
on postretirement benefit obligation at December 31, 2015	(89)

Health Care Reform Legislation

In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers, including a provision that imposes an excise tax on certain high-cost plans whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Additional legislation was passed in December 2015 that made some changes to the law, including moving the implementation date of the excise tax from 2018 to 2020. Although the excise tax does not go into effect until 2020, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Certain key assumptions are required to estimate the impact of the excise tax on Exelon's other postretirement benefit obligation, including projected inflation rates (based on the CPI). Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

Contributions

The following table provides contributions made by Generation, ComEd, PECO, BGE and BSC to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2015 [a]	2014 [a]	2013	2015	2014	2013
Generation	$ 231	$ 173	$ 119	$ 14	$ 124	$ 30
ComEd	143	122	118	7	125	4
PECO	40	11	11	—	5	20
BGE	1	—	—	16	17	24
BSC [b]	47	26	91	3	20	5
Exelon	$ 462	$ 332	$ 339	$ 40	$ 291	$ 83

(a) Exelon's and Generation's pension contributions include $36 million and $43 million related to the legacy CENG plans that was funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG for the years ended December 31, 2015 and 2014, respectively.
(b) Includes $5 million, $9 million, and $72 million of pension contributions funded by Exelon Corporate, for the years ended December 31, 2015, 2014, and 2013, respectively.

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of

certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). Additionally, the projected contribution reflects a funding strategy of contributing the greater of $250 million until the qualified plans are fully funded on an ABO basis, and the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions.

Exelon plans to contribute $250 million to its qualified pension plans in 2016, of which Generation, ComEd, PECO, and BGE will contribute $134 million, $30 million, $28 million, and $31 million, respectively. Exelon's and Generation's expected qualified pension plan contributions above include $25 million related to the legacy CENG plans that will be funded by CENG as provided in an EMA between Exelon and CENG.

Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon plans to make non-qualified pension plan benefit payments of $21 million in 2016, of which Generation, ComEd, PECO, and BGE will make payments of $9 million, $2 million, $1 million and $1 million, respectively.

Unlike the qualified pension plans, other postretirement plans are not subject to statutory minimum contribution requirements. Exelon's management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). In 2016, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $35 million in 2016, of which Generation, ComEd, PECO, and BGE expect to contribute $13 million, $3 million, $1 million, and $18 million, respectively.

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2015 were:

	Pension Benefits	Other Postretirement Benefits
2016	$ 1,153	$ 217
2017	997	223
2018	1,009	228
2019	1,036	235
2020	1,071	244
2021 through 2025	5,923	1,341
Total estimated future benefit payments through 2025	$11,189	$ 2,488

Allocation to Exelon Subsidiaries

Generation, ComEd, PECO, and BGE account for their participation in Exelon's pension and other postretirement benefit plans by applying multi-employer accounting. Employee-related assets and

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liabilities, including both pension and postretirement liabilities, for the legacy Exelon plans were allocated by Exelon to its subsidiaries based on the number of active employees as of January 1, 2001 as part of Exelon's corporate restructuring. The obligation for Generation, ComEd and PECO reflects the initial allocation and the cumulative costs incurred and contributions made since January 1, 2001. Historically, Exelon has allocated the components of pension and other postretirement costs to the subsidiaries in the legacy Exelon plans based upon several factors, including the measures of active employee participation in each participating unit. Pension and other postretirement benefit contributions were allocated to legacy Exelon subsidiaries in proportion to active service costs recognized and total costs recognized, respectively. Beginning in 2015, Exelon began allocating costs related to its legacy Exelon pension and other postretirement benefit plans to its subsidiaries based on both active and retired employee participation and contributions are allocated based on accounting cost. The impact of this allocation methodology change is not material to any Registrant. For legacy CEG and legacy CENG plans, components of pension and other postretirement benefit costs and contributions have been, and will continue to be, allocated to the subsidiaries based on employee participation (both active and retired).

The amounts below were included in capital expenditures and Operating and maintenance expense for the years ended December 31, 2015, 2014 and 2013, respectively, for Generation's, ComEd's, PECO's, BSC's and BGE's allocated portion of the pension and other postretirement benefit plan costs. These amounts include the recognized contractual termination benefit charges, curtailment gains, and settlement charges:

For the Year Ended December 31,	Generation	ComEd	PECO	BSC (a)	BGE	Exelon
2015	$ 269	$ 206	$ 39	$57	$66	637
2014	250	162	36	46	67	561
2013	347	309	43	71	55	825

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above.

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Exelon used an EROA of 7.00% and 6.71% to estimate its 2016 pension and other postretirement benefit costs, respectively.

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Exelon's pension and other postretirement benefit plan target asset allocations at December 31, 2015 and 2014 asset allocations were as follows:

Pension Plans

Asset Category	Target Allocation	Percentage of Plan Assets at December 31, 2015	Percentage of Plan Assets at December 31, 2014
Equity securities	32%	35%	33%
Fixed income securities	37%	34	37
Alternative investments [(a)]	31%	31	30
Total		100%	100%

Other Postretirement Benefit Plans

Asset Category	Target Allocation	Percentage of Plan Assets at December 31, 2015	Percentage of Plan Assets at December 31, 2014
Equity securities	39%	43%	42%
Fixed income securities	26%	27	34
Alternative investments [(a)]	35%	30	24
Total		100%	100%

(a) Alternative investments include private equity, hedge funds, real estate, and private credit.

Concentrations of Credit Risk. Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2015. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2015, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

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Fair Value Measurements

The following table presents Exelon's pension and other postretirement benefit plan assets measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2015 and 2014:

At December 31, 2015 [a]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 210	$ —	$ —	$ 210
Equities [b]	3,571	1,462	2	5,035
Fixed income:				
U.S. Treasury and agencies	1,001	79	—	1,080
State and municipal debt	—	61	—	61
Corporate debt	—	2,901	165	3,066
Other [b]	—	395	203	598
Fixed income subtotal	1,001	3,436	368	4,805
Private equity	—	—	924	924
Hedge funds	—	1,129	795	1,924
Real estate	—	—	725	725
Private credit	—	—	699	699
Pension plan assets subtotal	4,782	6,027	3,513	14,322

At December 31, 2015 [a]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	15	—	—	15
Equities	510	482	—	992
Fixed income:				
U.S. Treasury and agencies	11	53	—	64
State and municipal debt	—	131	—	131
Corporate debt	—	44	—	44
Other	155	205	—	360
Fixed income subtotal	166	433	—	599
Hedge funds	—	312	139	451
Real estate	—	—	131	131
Private credit	—	—	103	103
Other postretirement benefit plan assets subtotal	691	1,227	373	2,291
Total pension and other postretirement benefit plan assets [c]	$5,473	$7,254	$3,886	$16,613

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At December 31, 2014 [a]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 1	$ —	$ —	$ 1
Equities [b]	3,261	1,449	2	4,712
Fixed income:				
U.S. Treasury and agencies	1,051	88	—	1,139
State and municipal debt	—	80	—	80
Corporate debt	—	3,125	120	3,245
Other [b]	—	930	152	1,082
Fixed income subtotal	1,051	4,223	272	5,546
Private equity	—	—	900	900
Hedge funds	—	1,355	785	2,140
Real estate	243	—	685	928
Private credit	—	—	607	607
Pension plan assets subtotal	4,556	7,027	3,251	14,834

At December 31, 2014 [a]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	11	—	—	11
Equities	480	525	—	1,005
Fixed income:				
U.S. Treasury and agencies	15	59	—	74
State and municipal debt	—	197	—	197
Corporate debt	—	42	—	42
Other	253	272	—	525
Fixed income subtotal	268	570	—	838
Hedge funds	—	339	—	339
Real estate	8	—	116	124
Private credit	—	—	110	110
Other postretirement benefit plan assets subtotal	767	1,434	226	2,427
Total pension and other postretirement benefit plan assets [c]	$5,323	$8,461	$3,477	$17,261

(a) See Note 12—Fair Value of Financial Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Includes derivative instruments of $5 million and $(3) million, which have a total notional amount of $1,774 million and $1,491 million at December 31, 2015 and 2014, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.
(c) Excludes net assets of $27 million and $42 million at December 31, 2015 and 2014, respectively, which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables related to pending securities sales, interest and dividends receivable, and payables related to pending securities purchases.

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The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2015 and 2014:

	Hedge funds	Private equity	Real estate	Fixed income	Equities	Private Credit	Total
Pension Assets							
Balance as of January 1, 2015	$ 785	$ 900	$ 685	$ 272	$ 2	$ 607	$ 3,251
Actual return on plan assets:							
Relating to assets still held at the reporting date	(39)	60	76	(14)	—	(19)	64
Relating to assets sold during the period	4	—	9	—	—	—	13
Purchases, sales and settlements:							
Purchases	104	186	116	125	—	200	731
Sales	(57)	—	(54)	(7)	—	(5)	(123)
Settlements [a]	(2)	(222)	(107)	(8)	—	(84)	(423)
Balance as of December 31, 2015	$ 795	$ 924	$ 725	$ 368	$ 2	$ 699	$ 3,513
Other Postretirement Benefits							
Balance as of January 1, 2015	$ —	$ —	$ 116	$ —	$ —	$ 110	$ 226
Actual return on plan assets:							
Relating to assets still held at the reporting date	1	—	15	—	—	(7)	9
Purchases, sales and settlements:							
Purchases	138	—	62	—	—	—	200
Settlements [a]	—	—	(62)	—	—	—	(62)
Balance as of December 31, 2015	$ 139	$ —	$ 131	$ —	$ —	$ 103	$ 373

	Hedge funds	Private equity	Real estate	Fixed income	Equities	Private credit	Total
Pension Assets							
Balance as of January 1, 2014	$ 706	$ 806	$ 544	$ 41	$ 2	$ 371	$ 2,470
Actual return on plan assets:							
Relating to assets still held at the reporting date	59	112	81	7	—	20	279
Relating to assets sold during the period	2	—	—	—	—	1	3
Purchases, sales and settlements:							
Purchases	74	169	112	227	—	265	847
Sales	(25)	—	(19)	(3)	—	(13)	(60)
Settlements [a]	(1)	(203)	(60)	—	—	(37)	(301)
Transfers into (out of) Level 3 [b][c]	(30)	16	27	—	—	—	13
Balance as of December 31, 2014	$ 785	$ 900	$ 685	$ 272	$ 2	$ 607	$ 3,251
Other Postretirement Benefits							
Balance as of January 1, 2014	$ —	$ 2	$ 109	$ —	$ —	$ 4	$ 115
Actual return on plan assets:							
Relating to assets still held at the reporting date	—	—	13	—	—	1	14
Purchases, sales and settlements:							
Purchases	—	1	1	—	—	109	111
Sales	—	(2)	(7)	—	—	(4)	(13)
Settlements [a]	—	(1)	—	—	—	—	(1)
Balance as of December 31, 2014	$ —	$ —	$ 116	$ —	$ —	$ 110	$ 226

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(a) Represents cash settlements only.
(b) In connection with the Employee Matters Agreement between EDF and Exelon, Exelon assumed the pension plan assets of Nine Mile Point Nuclear Station, LLC and Constellation Energy Nuclear Group, LLC resulting in transfers into Level 3 of $56 million.
(c) As of January 1, 2015 and January 1, 2014, hedge fund investments that contained redemption restrictions limiting Exelon's ability to redeem the investments within a reasonable period of time were classified as Level 3 investments. As of December 31, 2014, restrictions for certain investments no longer applied, therefore allowing redemption within a reasonable period of time from the measurement date at NAV. As such, these hedge fund investments are reflected as transfers out of Level 3 to Level 2 of $43 million in 2014.

There were no transfers between Level 1 and Level 2 during the twelve months ended December 31, 2015 for the pension and other postretirement benefit plan assets.

Valuation Techniques Used to Determine Fair Value

Cash equivalents . Investments with maturities of three months or less when purchased, including certain short-term fixed income securities and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

Equities . Equities consist of individually held equity securities, equity mutual funds and equity commingled funds in domestic and foreign markets. With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity securities held individually, including real estate investment trusts, rights and warrants, are primarily traded on exchanges that contain only actively traded securities due to the volume trading requirements imposed by these exchanges. Equity securities are valued based on quoted prices in active markets and are categorized as Level 1. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies that hold certain investments in accordance with a stated set of fund objectives, which are consistent with the plans' overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

Fixed income . For fixed income securities, which consist primarily of corporate debt securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other

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market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The remaining fixed income securities, including certain other fixed income investments, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2

Other fixed income investments primarily consist of fixed income commingled funds and mutual funds, which are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Certain fixed income commingled funds are valued using the NAV per fund share, which is based on the valuation of the underlying investments and include significant unobservable inputs. These funds have been categorized as Level 3.

Derivative instruments consisting primarily of interest rate swaps to manage risk are recorded at fair value. Derivative instruments are valued based on external price data of comparable securities and have been categorized as Level 2.

Private equity . Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments and investments in natural resources. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows and market based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3.

Hedge funds . Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or ownership interest of the investments. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate. For Exelon's investments that have terms that allow redemption within a reasonable period of time from the measurement date, the hedge fund investments are categorized as Level 2. For investments that have restrictions that may limit Exelon's ability to redeem the investments at the measurement date or within a reasonable period of time, the hedge fund investments are categorized as Level 3.

Real estate . Real estate funds are funds with a direct investment in pools of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. Since these valuation inputs are not highly observable, these real estate funds have been categorized as Level 3.

Private credit. Private credit investments primarily consist of limited partnerships that invest in private debt strategies. These investments are generally less liquid assets with an underlying term of 3

to 5 years and are intended to be held to maturity. The fair value of these investments is determined by the fund manager or administrator and include unobservable inputs such as cost, operating results, and discounted cash flows. Since the valuation inputs are not highly observable, private credit investments have been categorized as Level 3.

Defined Contribution Savings Plan (Exelon, Generation, ComEd, PECO and BGE)

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2015, 2014 and 2013:

For the Year Ended December 31,	Exelon (a)	Generation (a)	ComEd	PECO	BGE	BSC (b)
2015	$ 148	$ 80	$ 32	$ 11	$ 14	$ 11
2014	103	51	26	8	8	10
2013	85	40	22	8	8	7

(a) Includes $9 million and $5 million related to CENG for the year ended December 31, 2015, and for the period from April 1, 2014 to December 31, 2014, respectively.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, or BGE amounts above.

18. Contingently Redeemable Noncontrolling Interest (Exelon, Generation)

In November 2015, 2015 ESA Investco, LLC, a wholly owned subsidiary of Generation, entered into an arrangement to sell a portion of its equity to a tax equity investor. Pursuant to the operating agreement, in certain situations the equity contributions made by the noncontrolling interest holder could be contingently redeemable. These situations are outside of the control of Generation and the noncontrolling interest holder resulting in a portion of the noncontrolling interest being considered contingently redeemable and thus presented in mezzanine equity in the consolidated balance sheet.

The following table summarizes the changes in the contingently redeemable noncontrolling interest for the year ended December 31, 2015:

	Year Ended December 31, 2015
Beginning Balance	$ —
Cash received from noncontrolling interest	32
Release of contingency	(4)
Ending Balance	$ 28

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19. Shareholder's Equity (Exelon, ComEd, PECO and BGE)

The following table presents common stock authorized and outstanding as of December 31, 2015 and 2014:

	Par Value	Shares Authorized	December 31, 2015 Shares Outstanding	December 31, 2014 Shares Outstanding
Common Stock				
Exelon	no par value	2,000,000,000	919,924,742	859,833,343
ComEd	$12.50	250,000,000	127,016,973	127,016,947
PECO	no par value	500,000,000	170,478,507	170,478,507
BGE	no par value	175,000,000	1,000	1,000

ComEd had 73,434 and 73,533 warrants outstanding to purchase ComEd common stock at December 31, 2015 and 2014, respectively. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants. At December 31, 2015 and 2014, 24,478 and 24,511 shares of common stock, respectively, were reserved for the conversion of warrants.

Equity Securities Offering

In June 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share. In connection with such offering, Exelon entered into forward sale agreements with two counterparties. In July 2015, Exelon settled the forward sale agreement by the issuance of 57.5 million shares of Exelon common stock. Exelon received net cash proceeds of $1.87 billion, which was calculated based on a forward price of $32.48 per share as specified in the forward sale agreements. Use of net proceeds will be to fund the pending merger with PHI and related costs and expenses, and for general corporate purposes. The forward sale agreements are classified as equity transactions. As a result, no amounts were recorded in the consolidated financial statements until the July 2015 settlement of the forward sale agreements. However, prior to the July 2015 settlement, incremental shares, if any, were included within the calculation of diluted EPS using the treasury stock method.

Concurrent with the forward equity transaction, Exelon also issued $1.15 billion of junior subordinated notes in the form of 23 million equity units. See Note 14—Debt and Credit Agreements for further information on the equity units.

Share Repurchases

Share Repurchase Programs . There currently is no Exelon Board of Director authority to repurchase shares. Any previous shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon's management. Under the previous share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion at December 31, 2015. During 2015, 2014 and 2013, Exelon had no common stock repurchases.

Preferred and Preference Securities of Subsidiaries

At December 31, 2015 and 2014, Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

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At December 31, 2015 and 2014, ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

At December 31, 2015 and 2014, BGE cumulative preference stock, $100 par value, consisted of 6,500,000 shares authorized of which 1,900,000 are outstanding as set forth in the table below. Shares of BGE preference stock have no voting power except for the following:

- The preference stock has one vote per share on any charter amendment that i) with regards to either dividends or distribution of assets, would create or authorize any shares of stock ranking prior to or on a parity with the preference stock or ii) substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock. Each such amendment would require the affirmative vote of two-thirds of all the shares of preference stock outstanding; and
- Whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

		December 31,			
		2015	2014	2015	2014
	Redemption Price [(a)]	Shares Outstanding		Dollar Amount	
Series (without mandatory redemption)					
7.125%, 1993 Series	$ 100.00	400,000	400,000	$ 40	$ 40
6.97%, 1993 Series	100.00	500,000	500,000	50	50
6.70%, 1993 Series	100.00	400,000	400,000	40	40
6.99%, 1995 Series	100.00	600,000	600,000	60	60
Total preference stock		1,900,000	1,900,000	$190	$190

(a) Redeemable, at the option of BGE, at the indicated dollar amounts per share, plus accrued and unpaid dividends.

20. Stock-Based Compensation Plans (Exelon, Generation, ComEd, PECO and BGE)

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At December 31, 2015, there were approximately 16 million shares authorized for issuance under the LTIP. For the years ended December 31, 2015, 2014 and 2013, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

The Compensation Committee of Exelon's Board of Directors changed the mix of awards granted under the LTIP in 2013 by eliminating stock options in favor of the use of full value shares, consisting of 67% performance shares and 33% restricted stock units. The performance share awards granted in 2013 will cliff vest at the end of a three-year performance period. The performance share awards granted in 2012 and earlier had a one-year performance period and vested ratably over three years. To address the reduction in annual award opportunity resulting from the transition to a three-year cliff vesting performance period, the Compensation Committee also approved a one-time grant of

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performance share transition awards in 2013, which vested one-third after one year, with the remaining balance vesting over a two-year performance period. These one-time 2013 performance share transition awards will be settled 50% in common stock and 50% in cash, except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain Exelon stock ownership requirements are satisfied. In addition to this change, in 2013 ComEd and in 2014 PECO and BGE transitioned from Exelon stock-based awards to cash award programs with payouts based on the performance of each respective utility. The following tables do not include expense related to these plans as they are not considered stock-based compensation plans under the applicable accounting guidance.

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
Components of Stock-Based Compensation Expense	2015	2014	2013
Performance share awards	$ 41	$ 59	$ 48
Restricted stock units	71	61	61
Stock options	1	2	3
Other stock-based awards	6	5	6
Total stock-based compensation expense included in operating and maintenance expense	119	127	118
Income tax benefit	(46)	(47)	(44)
Total after-tax stock-based compensation expense	$ 73	$ 80	$ 74

The following table presents stock-based compensation expense (pre-tax) for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
Subsidiaries	2015	2014	2013
Generation	$ 64	$ 52	$ 48
ComEd	6	7	9
PECO	3	3	5
BGE	3	5	6
BSC [(a)]	43	60	50
Total	$119	$127	$118

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO and BGE amounts above.

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2015, 2014 and 2013.

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Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and the distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon recognizes the tax benefit related to compensation costs. The following table presents information regarding Exelon's tax benefits for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
Realized tax benefit when exercised/distributed:			
Restricted stock units	$ 30	$ 17	$ 11
Performance share awards	18	11	11
Stock deferral plan	—	—	1

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock were granted under the LTIP through 2012. Due to changes in the LTIP, there were no stock options granted in 2013, 2014 or 2015. For all stock options granted through 2012, the exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. The vesting period of stock options is generally four years. All stock options expire ten years from the date of grant.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years. However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

The fair value of each option is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The following table presents the weighted average assumptions used in the pricing model for grants and the resulting weighted average grant date fair value of stock options granted for the year ended 2012:

	Year ended December 31, 2012
Dividend yield	5.28%
Expected volatility	23.20%
Risk-free interest rate	1.30%
Expected life (years)	6.25
Weighted average grant date fair value (per share)	4.18

The assumptions above relate to Exelon stock options granted in 2012 and therefore do not include stock options that were converted in connection with the merger with Constellation during the year ended 2012.

The dividend yield is based on several factors, including Exelon's most recent dividend payment at the grant date and the average stock price over the previous year. Expected volatility is based on implied volatilities of traded stock options in Exelon's common stock and historical volatility over the estimated expected life of the stock options. The risk-free interest rate for a security with a term equal

to the expected life is based on a yield curve constructed from U.S. Treasury strips at the time of grant. For each year presented, the expected life represents the period of time the stock options are expected to be outstanding and is based on the simplified method. Exelon believes that the simplified method is appropriate due to several factors that result in historical exercise data not being sufficient to determine a reasonable estimate of expected term. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table presents information with respect to stock option activity for the year ended December 31, 2015:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2014	18,830,967	$ 46.85		
Options exercised	(7,133)	21.25		
Options forfeited	(5,250)	39.81		
Options expired	(3,245,827)	47.75		
Balance of shares outstanding at December 31, 2015	15,572,757	$ 46.68	3.85	$ 9
Exercisable at December 31, 2015 [a]	15,490,507	$ 46.72	3.84	$ 9

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
	2015	2014	2013
Intrinsic value [a]	$—	$ 3	$ 4
Cash received for exercise price	—	7	19

(a) The difference between the market value on the date of exercise and the option exercise price.

The following table summarizes Exelon's nonvested stock option activity for the year ended December 31, 2015:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2014 [a]	432,035	$ 39.91
Vested	(344,535)	39.93
Forfeited	(5,250)	39.81
Nonvested at December 31, 2015 [a]	82,250	$ 39.81

(a) Excludes 279,000 and 746,140 of stock options issued to retirement-eligible employees as of December 31, 2015 and 2014, respectively, as they are fully vested.

At December 31, 2015, $0.1 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of less than a year.

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Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table summarizes Exelon's nonvested restricted stock unit activity for the year ended December 31, 2015:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2014 [a]	3,758,218	$ 31.27
Granted	2,132,856	36.55
Vested	(1,597,255)	32.88
Forfeited	(76,232)	33.06
Undistributed vested awards [b]	(654,333)	35.35
Nonvested at December 31, 2015 [a]	3,563,254	$ 32.92

(a) Excludes 1,097,630 and 975,116 of restricted stock units issued to retirement-eligible employees as of December 31, 2015 and 2014, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2015.

The weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2015, 2014 and 2013 was $36.55, $28.71 and $31.06, respectively. At December 31, 2015 and 2014, Exelon had obligations related to outstanding restricted stock units not yet settled of $97 million and $85 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. For the years ended December 31, 2015, 2014 and 2013, Exelon settled restricted stock units with fair value totaling $75 million, $43 million and $28 million, respectively. At December 31, 2015, $56 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2 years.

Performance Share Awards

Performance share awards are granted under the LTIP. The 2015 and 2014 performance share awards are being settled 50% in common stock and 50% in cash at the end of the three-year performance period except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. The performance shares granted prior to 2012 generally vest and settle over a three-year period with the holders receiving shares of common stock and/or cash annually during the vesting period.

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The common stock portion of the performance share and one-time 2013 performance share transition awards is considered an equity award and is valued based on Exelon's stock price on the grant date. The cash portion of the awards is considered a liability award which is remeasured each reporting period based on Exelon's current stock price. As the value of the common stock and cash portions of the awards are based on Exelon's stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share and one-time performance share transition awards granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period, which is the year of grant.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2015:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2014 [a]	2,696,097	$ 30.62
Granted	1,556,273	35.88
Change in performance	(118,398)	35.88
Vested	(704,141)	32.80
Forfeited	(52,167)	32.25
Undistributed vested awards [b]	(820,505)	33.95
Nonvested at December 31, 2015 [a]	2,557,159	$ 31.88

(a) Excludes 1,817,883 and 1,535,791 of performance share awards issued to retirement-eligible employees as of December 31, 2015 and 2014, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2015.

The weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2015, 2014 and 2013 was $35.88, $28.75, and $31.55, respectively. During the years ended December 31, 2015, 2014 and 2013, Exelon settled performance shares with a fair value totaling $46 million, $27 million and $26 million, respectively, of which $29 million, $13 million and $12 million was paid in cash, respectively. As of December 31, 2015, $27 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.4 years.

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31, 2015	December 31, 2014
Current liabilities [a]	$ 28	$ 28
Deferred credits and other liabilities [b]	32	36
Common stock	35	33
Total	$ 95	$ 97

(a) Represents the current liability related to performance share awards expected to be settled in cash.
(b) Represents the long-term liability related to performance share awards expected to be settled in cash.

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21. Earnings Per Share (Exelon)

Diluted earnings per share is calculated by dividing Net income attributable to common shareholders by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of the stock options, performance share awards and restricted stock on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Year Ended December 31,		
	2015	2014	2013
Net income attributable to common shareholders	$2,269	$1,623	$1,719
Weighted average common shares outstanding—basic	890	860	856
Assumed exercise and/or distributions of stock-based awards	3	4	4
Weighted average common shares outstanding—diluted	893	864	860

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 16 million in 2015, 17 million in 2014, and 20 million in 2013. The number of equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect was 3 million for the year ended December 2015 and less than 1 million for the year ended December 31, 2014. Additionally, there were no forward units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the years ended December 31, 2015 and 2014. Refer to Note 19—Shareholder's Equity for further information regarding the equity units and equity forward units.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of December 31, 2015. In 2008, Exelon management decided to defer indefinitely any share repurchases.

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22. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, and PECO)

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the years ended December 31, 2015 and 2014:

For the Year Ended December 31, 2015	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon [a]						
Beginning balance	$ (28)	$ 3	$ (2,640)	$ (19)	$ —	$(2,684)
OCI before reclassifications	(12)	—	(100)	(21)	(3)	(136)
Amounts reclassified from AOCI [b]	21	—	175	—	—	196
Net current-period OCI	9	—	75	(21)	(3)	60
Ending balance	$ (19)	$ 3	$ (2,565)	$ (40)	$ (3)	$(2,624)
Generation [a]						
Beginning balance	$ (18)	$ 1	$ —	$ (19)	$ —	$ (36)
OCI before reclassifications	(8)	—	—	(21)	(3)	(32)
Amounts reclassified from AOCI [b]	5	—	—	—	—	5
Net current-period OCI	(3)	—	—	(21)	(3)	(27)
Ending balance	$ (21)	$ 1	$ —	$ (40)	$ (3)	$ (63)
PECO [a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI [b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

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For the Year Ended December 31, 2014	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon [a]						
Beginning balance	$ 120	$ 2	$ (2,260)	$ (10)	$ 108	$(2,040)
OCI before reclassifications	(31)	(1)	(498)	(9)	11	(528)
Amounts reclassified from AOCI [b]	(117)	2	118	—	(119)	(116)
Net current-period OCI	(148)	1	(380)	(9)	(108)	(644)
Ending balance	$ (28)	$ 3	$ (2,640)	$ (19)	$ —	$(2,684)
Generation [a]						
Beginning balance	$ 114	$ 2	$ —	$ (10)	$ 108	214
OCI before reclassifications	(15)	(1)	—	(9)	11	(14)
Amounts reclassified from AOCI [b]	(117)	—	—	—	(119)	(236)
Net current-period OCI	(132)	(1)	—	(9)	(108)	(250)
Ending balance	$ (18)	$ 1	$ —	$ (19)	$ —	$ (36)
PECO [a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI [b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See next tables for details about these reclassifications.

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ComEd, PECO, and BGE did not have any reclassifications out of AOCI to Net income during the years ended December 31, 2015 and 2014. The following tables present amounts reclassified out of AOCI to Net income for Exelon and Generation during the years ended December 31, 2015 and 2014:

For the Year Ended December 31, 2015

Details about AOCI components	Items reclassified out of AOCI [a]		Affected line item in the Statements of Operations and Comprehensive Income
	Exelon	Generation	
Gains and (losses) on cash flow hedges			
Terminated interest rate swaps	$ (26)	$ —	Other, net
Energy related hedges	2	2	Operating revenues
Other cash flow hedges	(11)	(11)	Interest expense
Total before tax	(35)	(9)	
Tax benefit	14	4	
Net of tax	$ (21)	$ (5)	Comprehensive income
Amortization of pension and other postretirement benefit plan items			
Prior service costs [b]	$ 74	$ —	
Actuarial losses [b]	(361)	—	
Total before tax	(287)	—	
Tax benefit	112	—	
Net of tax	$ (175)	$ —	
Total Reclassifications	$ (196)	$ (5)	Comprehensive income

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For the Year Ended December 31, 2014

Details about AOCI components	Items reclassified out of AOCI [a]		Affected line item in the Statements of Operations and Comprehensive Income
	Exelon	Generation	
Gains and (losses) on cash flow hedges			
Energy related hedges	$ 195	$ 195	Operating revenues
Total before tax	195	195	
Tax expense	(78)	(78)	
Net of tax	$ 117	$ 117	Comprehensive income
Gains and (losses) on available for sale securities			
Other available securities for sale	$ (2)	$ —	Other Income and Deductions
Total before tax	(2)	—	
Net of tax	$ (2)	$ —	Comprehensive income
Amortization of pension and other postretirement benefit plan items			
Prior service costs [b]	$ 46	$ —	
Actuarial losses [b]	(239)	—	
Total before tax	(193)	—	
Tax benefit	75	—	
Net of tax	$ (118)	$ —	Comprehensive income
Equity investments			
Sale of equity method investment	$ 5	$ 5	Equity in losses of unconsolidated affiliates
Reversal of CENG equity method AOCI	193	193	Gain on Consolidation of CENG
Total before tax	198	198	
Tax expense	(79)	(79)	
Net of tax	$ 119	$ 119	
Total Reclassifications	$ 116	$ 236	Comprehensive income

(a) Amounts in parenthesis represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see Note 17—Retirement Benefits for additional details).
(c) Amortization of the deferred compensation unit plan is allocated to capital and operating and maintenance expense.

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The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the years ended December 31, 2015 and 2014:

	For the Years Ended December 31,		
	2015	2014	2013
Exelon			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	$ 30	$ 19	$ —
Actuarial loss reclassified to periodic cost	(140)	(93)	(133)
Pension and non-pension postretirement benefit plan valuation adjustment	62	317	(430)
Change in unrealized (gain) loss on cash flow hedges	(6)	96	166
Change in unrealized (gain) loss on equity investments	1	73	(71)
Total	$ (53)	$412	$(468)
Generation			
Change in unrealized loss on cash flow hedges	$ 2	$ 84	$ 262
Change in unrealized (gain) loss on equity investments	1	73	(72)
Total	$ 3	$157	$ 190

23. Commitments and Contingencies (Exelon, Generation, ComEd, PECO and BGE)

Commitments

Constellation Merger Commitments

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion. The direct investment estimate includes $95 million to $120 million relating to the construction of a headquarters building in Baltimore for Generation's competitive energy businesses.

The direct investment commitment also includes $500 million to $600 million relating to Exelon and Generation's development or assistance in the development of 275—300 MWs of new generation in Maryland, which is expected to be completed within a period of 10 years. Exelon and Generation have incurred $393 million towards satisfying the commitment for new generation development in the state of Maryland, with approximately 220 MW of the new generation commencing with commercial operations to date. The MDPSC order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed or certain specified provisions are elected, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. However, during the third quarter of 2014, the conditions associated with one of the generation development commitments changed such that Exelon and Generation now believe that the most likely outcome will involve making subsidy payments and/or liquidated damages payments rather than constructing the specified generating plant. As a result, Exelon and Generation recorded a pre-tax $44 million loss contingency related to this generation development commitment which is included in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and

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Comprehensive Income for the year ended December 31, 2014. While this $44 million loss contingency represents Generation's best estimate of the future obligation, it is reasonably possible that Exelon and Generation could ultimately be required to make cumulative subsidy payments of up to a maximum of approximately $105 million over a 20-year period dependent on actual generating output from a successfully constructed generating plant.

Equity Investment Commitments

As part of Generation's recent investments in technology development, Generation enters into equity purchase agreements that include commitments to invest additional equity through incremental payments to fund the anticipated needs of the planned operations of the associated companies. The commitment includes approximately $20 million of in-kind services and 100% of 2015 ESA Investco, LLC's equity commitment since 2015 ESA Investco, LLC is consolidated by Generation (see Note 2—Variable Interest Entities for additional details). As of December 31, 2015, Generation's estimated commitment relating to its equity purchase agreements, including in-kind services contributions, is anticipated to be as follows:

	Total
2016 [a]	$299
2017	21
2018	7
2019	—
Total	$327

(a) The noncontrolling interest holder of 2015 ESA Investco, LLC will contribute up to $172 million in support of a portion of this equity commitment.

Commercial Commitments

Exelon's commercial commitments as of December 31, 2015, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2016	2017	2018	2019	2020	2021 and beyond
Letters of credit (non-debt) [a]	$1,583	$1,565	$ 5	$—	$—	$ 13	$ —
Surety bonds [b]	809	733	49	3	2	16	6
Financing trust guarantees [c]	628	—	—	—	—	—	628
Energy marketing contract guarantees [d]	3,126	3,126	—	—	—	—	—
Nuclear insurance premiums [e]	3,060	—	—	—	—	—	3,060
Total commercial commitments	$9,206	$5,424	$ 54	$ 3	$ 2	$ 29	$ 3,694

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Includes $200 million of Trust Preferred Securities of ComEd Financing III, $178 million of Trust Preferred Securities of PECO Trust III and IV and $250 million of Trust Preferred Securities of BGE Capital Trust II.
(d) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $3.1 billion of guarantees issued by Exelon and Generation on behalf of its Constellation businesses to allow it the flexibility needed to conduct business with counterparties without having to post other forms of

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collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Exelon's estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $0.5 billion at December 31, 2015, which represents the total amount Exelon could be required to fund based on December 31, 2015 market prices.

(e) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

Generation's commercial commitments as of December 31, 2015, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2016	2017	2018	2019	2020	2021 and beyond
Letters of credit (non-debt) (a)	$1,503	$1,485	$ 5	$—	$—	$ 13	$ —
Surety bonds	737	692	45	—	—	—	—
Energy marketing contract guarantees (b)	1,532	1,532	—	—	—	—	—
Nuclear insurance premiums (c)	3,060	—	—	—	—	—	3,060
Total commercial commitments	$6,832	$3,709	$ 50	$—	$—	$ 13	$ 3,060

(a) Letters of credit (non-debt)—Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.

(b) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $1.5 billion of guarantees issued by Generation on behalf of its Constellation businesses to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Generation's estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $0.3 billion at December 31, 2015, which represents the total amount Generation could be required to fund based on December 31, 2015 market prices.

(c) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site, including CENG sites, under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

ComEd's commercial commitments as of December 31, 2015, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2016	2017	2018	2019	2020	2021 and beyond
Letters of credit (non-debt) (a)	$ 16	$ 16	$—	$—	$—	$—	$ —
Surety bonds (b)	8	6	—	2	—	—	—
Financing trust guarantees (c)	200	—	—	—	—	—	200
Total commercial commitments	$224	$ 22	$—	$ 2	$—	$—	$ 200

(a) Letters of credit (non-debt)—ComEd maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.

(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

(c) Performance guarantees—Reflects full and unconditional guarantee of Trust Preferred Securities of ComEd Financing III which is a 100% owned finance subsidiary of ComEd.

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PECO's commercial commitments as of December 31, 2015, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2016	2017	2018	2019	2020	2021 and beyond
Letters of credit (non-debt) [a]	$ 22	$ 22	$—	$—	$—	$—	$ —
Surety bonds [b]	9	9	—	—	—	—	—
Financing trust guarantees [c]	178	—	—	—	—	—	178
Total commercial commitments	$209	$ 31	$—	$—	$—	$—	$ 178

(a) Letters of credit (non-debt)—PECO maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantees—Reflects full and unconditional guarantee of Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.

BGE's commercial commitments as of December 31, 2015, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2016	2017	2018	2019	2020	2021 and beyond
Letters of credit (non-debt) [a]	$ 2	$ 2	$—	$—	$—	$—	$ —
Surety bonds [b]	10	10	—	—	—	—	—
Financing trust guarantees [c]	250	—	—	—	—	—	250
Total commercial commitments	$262	$ 12	$—	$—	$—	$—	$ 250

(a) Letters of credit (non-debt)—BGE maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Performance guarantee—Reflects full and unconditional guarantee of Trust Preferred Securities of BGE Capital Trust which is an unconsolidated VIE of BGE.

Leases

Minimum future operating lease payments, including lease payments for contracted generation, vehicles, real estate, computers, rail cars, operating equipment and office equipment, as of December 31, 2015 were:

	Exelon [a]	Generation [a][b]	ComEd [c]	PECO [c]	BGE [c][d]
2016	$ 133	$ 86	$ 14	$ 3	$ 12
2017	109	69	9	3	10
2018	86	57	5	2	9
2019	74	45	5	2	8
2020	70	44	3	2	7
Remaining years	702	655	1	—	19
Total minimum future lease payments	$1,174	$ 956	$ 37	$ 12	$ 65

(a) Excludes Generation's contingent operating lease payments associated with contracted generation agreements.
(b) The Generation column above includes minimum future lease payments associated with a 20-year lease agreement for the Baltimore headquarters that became effective during the second quarter of 2015. Generation's total commitments under the

lease agreement are $4 million, $10 million, $11 million, $13 million, $14 million, and $271 million related to years 2016, 2017, 2018, 2019, 2020 and thereafter, respectively.

(c) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, ComEd, PECO and BGE have excluded these payments from the remaining years, as such amounts would not be meaningful. ComEd's, PECO's, and BGE's annual obligation for these arrangements, included in each of the years 2016—2020, was $2 million, $3 million, and $1 million respectively.

(d) Includes all future lease payments on a 99 year real estate lease that expires in 2106.

The following table presents the Registrants' rental expense under operating leases for the years ended December 31, 2015, 2014 and 2013:

For the Year Ended December 31,	Exelon	Generation [a]	ComEd	PECO	BGE
2015	$ 922	$ 851	$ 12	$ 9	$ 32
2014	865	806	15	14	12
2013	806	744	15	21	11

(a) Includes contingent operating lease payments associated with contracted generation agreements that are not included in the minimum future operating lease payments table above. Payments made under Generation's contracted generation lease agreements totaled $798 million, $755 million and $694 million during 2015, 2014 and 2013, respectively. Excludes contract amortization associated with purchase accounting and contract acquisitions.

For information regarding capital lease obligations, see Note 14—Debt and Credit Agreements.

Nuclear Insurance

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has mitigated its financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2015, the current liability limit per incident is $13.5 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of December 31, 2015, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 103 reactors) resulting in an additional $13.1 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $127.3 million, payable at no more than $19 million per reactor per incident per year. Exelon's maximum liability per incident is approximately $2.7 billion, including CENG's related liability.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.5 billion limit for a single incident.

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As part of the execution of the NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information on Generation's operations relating to CENG.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. Generation's portion of the distribution declared by NEIL is estimated to be $20.7 million for 2015, and was $18.3 million for 2014 and $18.5 million for 2013. The distributions were recorded as a reduction to Operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income. Premiums paid to NEIL by its members are subject to assessment for adverse loss experience (the retrospective premium obligation). NEIL has never exercised this assessment since its formation in 1973, and while Generation cannot predict the level of future assessments, or if they will be imposed at all, as of December 31, 2015, the current maximum aggregate annual retrospective premium obligation for Generation is approximately $365 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery for all losses by all insureds will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon's and Generation's financial condition, results of operations and liquidity.

Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to

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contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation historically had paid the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. On November 19, 2013, the D.C. Circuit Court ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On May 9, 2014, the DOE notified Generation that the SNF disposal fee remained in effect through May 15, 2014, after which time the fee was set to zero. As a result, for the year ended December 31, 2015, Generation did not incur any expense in SNF disposal fees. For the year ended December 31, 2014 and 2013, Generation incurred expense of $49 million and $136 million, respectively, in SNF disposal fees recorded in Purchased power and fuel expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, including Exelon's share of Salem and net of co-owner reimbursements (not including such fees incurred by CENG). Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance has been, and is expected to be, delayed significantly.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama administration devised a new strategy for long-term SNF management. A Blue Ribbon Commission (BRC) on America's Nuclear Future, appointed by the U.S. Energy Secretary, released a report on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's spent nuclear fuel and high-level radioactive waste.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that is planned to be operational in 2025.

Generation uses the 2025 date as the assumed date for when the DOE will begin accepting SNF for purposes of determining nuclear decommissioning asset retirement obligations.

In August 2004, Generation and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation, subject to certain damage limitations based on the extent of the government's breach, for costs associated with storage of SNF at Generation's nuclear stations pending the DOE's fulfillment of its obligations. Settlement agreements pertaining to Calvert Cliffs and Ginna were executed during 2011, and Nine Mile Point during 2012, (the "DOE Settlement Agreements"), as amended in 2014 for Calvert Cliffs and Nine Mile Point, under which the government has agreed to reimburse the costs associated with SNF storage expended or to be expended through 2016 as a result of the DOE delays. The DOE Settlement Agreement is expected to be amended for Ginna in a similar manner as needed. Generation, including CENG, submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

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Under the settlement agreement, Generation has received cumulative cash reimbursements for costs incurred as follows:

	Total	Net [a]
Cumulative cash reimbursements [b]	$945	$804

(a) Total after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek.
(b) Includes $53 million and $49 million, respectively, for amounts received since April 1, 2014, for costs incurred under the CENG DOE Settlement Agreements prior to the consolidation of CENG.

As of December 31, 2015, and 2014, the amount of SNF storage costs for which reimbursement has been or will be requested from the DOE under the DOE settlement agreements is as follows:

	December 31, 2015	December 31, 2014
DOE receivable—current [a]	$ 76	$ 82
DOE receivable—noncurrent [b]	14	7
Amounts owed to co-owners [a][c]	(5)	(5)

(a) Recorded in Accounts receivable, other.
(b) Recorded in Deferred debits and other assets, other
(c) Non-CENG amounts owed to co-owners are recorded in Accounts receivable, other. CENG amounts owed to co-owners are recorded in Accounts payable. Represents amounts owed to the co-owners of Peach Bottom, Quad Cities, and Nine Mile Point Unit 2 generating facilities.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. As of December 31, 2015, the unfunded SNF liability for the one-time fee with interest was $1,021 million. Interest accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2015, was 0.112%. The liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of Exelon's 2001 corporate restructuring. The outstanding one-time fee obligations for the Nine Mile Point, Ginna, Oyster Creek and TMI units remain with the former owners. The Clinton and Calvert Cliffs units have no outstanding obligation. See Note 12—Fair Value of Financial Assets and Liabilities for additional information.

Environmental Matters

General. The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

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ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has identified 42 sites, 17 of which have been remediated and approved by the Illinois EPA or the U.S. EPA and 25 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2020.
- PECO has identified 26 sites, 16 of which have been remediated in accordance with applicable PA DEP regulatory requirements. The remaining 10 sites are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2021.
- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. An investigation of an additional gas purification site was completed during the first quarter of 2015 at the direction of the MDE. For more information, see the discussion of the Riverside site below.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. See Note 3—Regulatory Matters for additional information regarding the associated regulatory assets. BGE is authorized to recover, and is currently recovering, environmental costs for the remediation of the former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. ComEd, PECO and BGE have recorded regulatory assets for the recovery of these costs.

As of December 31, 2015 and 2014, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

December 31, 2015	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation [(a)]
Exelon	$ 369	$ 301
Generation	63	—
ComEd	266	264
PECO	37	35
BGE [(a)]	3	2

December 31, 2014	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 347	$ 277
Generation	63	—
ComEd	238	235
PECO	45	42
BGE	1	—

(a) For BGE, includes reserve for Riverside, a gas purification site. See discussion below for additional information.

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The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, including probabilistic and deterministic modeling for ComEd and PECO, and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

During the third quarter of 2015, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. For ComEd, the results of the study resulted in a $50 million increase to ComEd's environmental liabilities and related regulatory assets. The increase at ComEd was primarily driven by refined assumptions and scopes based on further experience and analysis, including one site where a new option is being considered for a facility under which contamination exists and certain sites where another PRP leads the remediation efforts and ComEd shares responsibility. For PECO, the results of the study resulted in a $1 million decrease to PECO's environmental liabilities and related regulatory assets.

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water Quality

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. As of December 31, 2015 and 2014, Generation's remaining groundwater contamination reserve was $12 million and $13 million respectively.

Air Quality

Notices and Finding of Violations and Midwest Generation Bankruptcy. In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

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Under a supplemental agreement reached in 2003, Midwest Generation agreed to reimburse ComEd and Generation for 50% of the specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement.

On December 17, 2012 (Petition Date), EME and certain of its subsidiaries, including Midwest Generation, filed for protection under Chapter 11 of the U.S. Bankruptcy Code.

In 2012, the Bankruptcy Court approved the rejection of an agency agreement related to a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations incurred under the coal rail car lease. The rejection left Generation as the party responsible for making all remaining payments under the lease and performing all other obligations thereunder. A settlement was reached in January 2015, to resolve the claims related to the coal rail car lease for approximately $14 million and Exelon recorded a gain upon receipt of the funds, within Operating and maintenance expense in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income. No further action is expected related to the rail car lease.

On March 11, 2014, the Bankruptcy Court for the Northern District of Illinois entered its Order Confirming Debtors' Joint Chapter 11 Plan of Reorganization. On April 1, 2014 (Effective Date), NRG Energy purchased EME's portfolio of generation, including Midwest Generation and the Joint Chapter 11 Plan of Reorganization (Plan) became effective. As part of the Plan, the sale agreement, including the environmental indemnity, and the asbestos cost-sharing agreement were rejected.

Generation increased its reserve for asbestos-related bodily injury claims pertaining to Midwest Generations' share of liability as a result of the rejection of the asbestos cost sharing agreement in the bankruptcy proceedings. Exelon and Generation may be entitled to damages associated with the rejection of the agreement and a claim has been filed by Exelon for such damages. These amounts are considered to be contingent gains and would not be recognized until realized.

As a prior owner of the generating stations, ComEd (and Generation, through its agreement in Exelon's 2001 corporate restructuring to assume ComEd's rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions at the stations requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors. ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations and as a result no liability has been recorded as of December 31, 2015. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required

additional landfill cover. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. Since, June 2012, the U.S. EPA has requested that the PRPs perform a series of additional analyses and groundwater and soil sampling as part of the supplemental feasibility study, that are now scheduled to be completed in mid-2016 to enable the EPA to propose a remedy for public comment by the end of 2016. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote. The U.S. EPA is also reviewing a partial excavation remedy; however, until the current sampling is concluded there is no basis to determine the likelihood and estimate of a partial excavation remedy. The current estimated cost of the landfill cover remediation for the site is approximately $60 million, which will be allocated among all PRPs. Recent investigation has identified a number of other parties who may be PRPs and could be liable to contribute to the final remedy. Further investigation is underway. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability.

During December 2015, the U.S. EPA took two actions related to the West Lake Landfill designed to abate what it termed as imminent and dangerous conditions at the landfill. The first involved installation of a non-combustible interim surface cover to protect against surface fires in areas where radiological materials are believed to have been disposed. Generation has accrued what it believes to be an adequate amount to cover its anticipated liability for this interim action. The second action involved EPA's public statement that it will require the PRPs to construct a barrier wall in an adjacent landfill to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, EPA has not provided sufficient details related to the basis for and the requirements and design of a barrier wall to enable Generation to determine the likelihood such a remedy will ultimately be implemented, assess the degree to which Generation may have liability as a potentially responsible party, or develop a reasonable estimate of the potential incremental costs. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Generation's and Exelon's future results of operations and cash flows. Finally, one of the other PRPs, the landfill owner and operator of the adjacent landfill, has indicated that it will be making a contribution claim against Cotter for costs that it has incurred to prevent the subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Generation and Exelon do not possess sufficient information to assess this claim and are therefore unable to determine the impact on their future results of operations and cash flows.

On February 2, 2015, the U.S. Senate passed a bill to transfer remediation authority over the West Lake landfill from the U.S. EPA to the U.S. Army Corps of Engineers, under the Formerly Utilized Sites Remedial Action Program (FUSRAP). Such legislation would become final upon passage in the U.S. House of Representatives and the signature of the President, and be subject to annual funding appropriations in the U.S. Budget. Remediation under FUSRAP would not alter the liability of the PRPs, but could delay the determination of a final remedy and its implementation.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale

of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2016 so that settlement discussions could proceed. Based on Generation's preliminary review, it appears probable that Generation has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

Commencing in February 2012, 37 lawsuits have been filed in the U.S. District Court for the Eastern District of Missouri. Among the defendants were Exelon, Generation and ComEd, all of which were subsequently dismissed from the case, and Cotter, which remains a defendant. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to Cotter's negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. The court has dismissed the lawsuits filed by 30 of the plaintiffs. Pre-trial motions and discovery are proceeding in the remaining cases and a proposed pre-trial scheduling order has been filed with the court. At this stage of the litigation, Generation and ComEd cannot estimate a range of loss, if any.

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The PRPs submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. On September 30, 2013, U.S. EPA issued the Record of Decision identifying its preferred remedial alternative for the site. The estimated cost for the alternative chosen by U.S. EPA is consistent with the PRPs' estimated range of costs noted above. Based on Generation's preliminary review, it appears probable that Generation has liability and has established an appropriate accrual for its share of the estimated clean-up costs. A wholly owned subsidiary of Generation has agreed to indemnify BGE for most of the costs related to this settlement and clean-up of the site.

Rossville Ash Site. The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC (CPSG), a wholly-owned subsidiary of Generation. In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently

going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately $9 million, which has been fully reserved as of December 31, 2015.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRPs signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRPs to conduct a remedial investigation and feasibility study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

Riverside . In 2013, the Maryland Department of the Environment (MDE), at the request of U.S. EPA, conducted a site inspection and limited environmental sampling of certain portions of the 170 acre Riverside property owned by BGE. The site consists of several different parcels with different current and historical uses. The sampling included soil and groundwater samples for a number of potential environmental contaminants. The sampling confirmed the existence of contaminants consistent with the known historical uses of the various portions of the site. In March 2014, the MDE requested that BGE conduct an investigation of three specific areas of the site, and a site-wide investigation of soils, sediment, groundwater, and surface water to complement the MDE sampling. The field investigation was completed in January 2015, and a final report was provided to MDE on June 2, 2015. On November 3, 2015, MDE provided BGE with its comments and recommendations on the report which require BGE to conduct further investigation and sampling at the site to better delineate the nature and extent of historic contamination, including off-site sediment and soil sampling. MDE did not request any interim remediation at this time. Upon completion of the investigation the MDE will determine if the site requires further action and/or remediation. Based upon the investigation to date, BGE has established what it believes is an appropriate reserve. As the investigation and potential remediation proceed, it is possible that additional reserves could be established, in amounts that could be material to BGE.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon, Generation, PECO and BGE).

Exelon and Generation. Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2015 and 2014, Generation had reserved approximately $95 million and $100 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2015, approximately $21 million of this amount related to 228 open claims presented to Generation, while the remaining $74 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee's disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee's last employment-based exposure, and that therefore the exclusivity provision of the Act does not preclude such employee from suing his or her employer in court. The Supreme Court's ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee's last employment-based exposure to asbestos. Since the Pennsylvania Supreme Court's ruling in November 2013, Exelon, Generation, and PECO have experienced an increase in asbestos-related personal injury claims brought by former PECO employees, all of which have been reserved against on a claim by claim basis. Those additional claims are taken into account in projecting estimated future asbestos-related bodily injury claims.

On November 4, 2015, the Illinois Supreme Court found that the provisions of the Illinois' Workers' Compensation Act and the Workers' Occupational Diseases Act barred an employee from bringing a direct civil action against an employer for latent diseases, including asbestos-related diseases that fall outside the 25-year limit of the statute of repose. The Illinois Supreme Court's ruling reversed previous rulings by the Illinois Court of Appeals, which initially ruled that the Illinois Worker's Compensation law should not apply in cases where the diagnosis of an asbestos related disease occurred after the 25-year maximum time period for filing a Worker's Compensation claim. As a result of this ruling, Exelon, Generation, and ComEd have not recorded an increase to the asbestos-related bodily injury liability as of December 31, 2015.

There is a reasonable possibility that Exelon may have additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued and the increases could have a material adverse effect on Exelon's, Generation's and PECO's future results of operations and cash flows.

BGE. Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

Approximately 454 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.

Discovery begins in these cases after they are placed on the trial docket. At present, only two of the pending cases are set for trial. Given the limited discovery in these cases, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

- the identity of the facilities at which the plaintiffs allegedly worked as contractors;
- the names of the plaintiffs' employers;

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

- the dates on which and the places where the exposure allegedly occurred; and
- the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

Continuous Power Interruption (ComEd)

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. As of December 31, 2015 and 2014, ComEd did not have any material liabilities recorded for these storm events.

Telephone Consumer Protection Act Lawsuit (ComEd)

On November 19, 2013, a class action complaint was filed in the Northern District of Illinois on behalf of a single individual and a presumptive class that would include all customers that ComEd enrolled in its Outage Alert text message program. The complaint alleged that ComEd violated the Telephone Consumer Protection Act (TCPA) by sending text messages to customers without first obtaining their consent to receive such messages. The complaint sought certification of a class along with statutory damages, attorneys' fees, and an order prohibiting ComEd from sending additional text messages. ComEd and the plaintiff agreed in principle to settle the suit for $5 million, with payments to the class commencing in the fourth quarter 2015.

Fund Transfer Restrictions (Exelon, Generation, ComEd, PECO and BGE)

Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as: (1) the source of the dividends is clearly disclosed; (2) the dividend is not excessive; and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. On May 1, 2013, PECO redeemed all outstanding preferred securities. As a result, the above ratio calculation is no longer applicable. Additionally, PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid.

Baltimore City Franchise Taxes (BGE)

The City of Baltimore claims that BGE has maintained electric facilities in the City's public right-of-ways for over one hundred years without the proper franchise rights from the City. BGE has reviewed the City's claim and believes that it lacks merit. BGE has not recorded an accrual for payment of franchise fees for past periods as a range of loss, if any, cannot be reasonably estimated at this time. Franchise fees assessed in future periods may be material to BGE's results of operations and cash flows.

General (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or

unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Income Taxes *(Exelon, Generation, ComEd, PECO and BGE)*

See Note 15—Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

24. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2015, 2014 and 2013.

For the year ended December 31, 2015	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility (a)	$ 474	$ 105	$ 236	$133	$ 85
Property	407	250	27	11	119
Payroll	201	118	28	14	16
Other	118	16	5	2	4
Total taxes other than income	$1,200	$ 489	296	$160	$224

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility (a)	$ 456	$ 89	$ 238	$128	$ 86
Property	396	240	25	15	114
Payroll	200	118	28	14	18
Other	102	18	2	2	3
Total taxes other than income	$1,154	$ 465	$ 293	$159	$221

For the year ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Taxes other than income					
Utility (a)	$ 449	$ 79	$ 241	$129	$ 82
Property	302	205	24	14	112
Payroll	159	89	27	13	15
Other	185	16	7	2	4
Total taxes other than income	$1,095	$ 389	$ 299	$158	$213

(a) Generation's utility tax represents gross receipts tax related to its retail operations and ComEd's, PECO's and BGE's utility taxes represent municipal and state utility taxes and gross receipts taxes related to their operating revenues. The offsetting collection of utility taxes from customers is recorded in revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2015	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a] —					
Regulatory agreement units	$ 232	$ 232	$ —	$ —	$ —
Non-regulatory agreement units	156	156	—	—	—
Net unrealized losses on decommissioning trust funds—					
Regulatory agreement units	(282)	(282)	—	—	—
Non-regulatory agreement units	(197)	(197)	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	7	7	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	21	21	—	—	—
Total decommissioning-related activities	(63)	(63)	—	—	—
Investment income (loss)	8	3	—	(2)	4 [c]
Long-term lease income	15	—	—	—	—
Interest income related to uncertain income tax positions	1	1	—	—	—
AFUDC—Equity	24	—	5	5	14
Terminated interest rate swaps [d]	(26)	—	—	—	—
PHI merger related debt exchange [e]	(22)	—	—	—	—
Other	17	(1)	16	2	—
Other, net	$ (46)	$ (60)	$ 21	$ 5	$ 18

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a] —					
Regulatory agreement units	$ 216	$ 216	$ —	$ —	$ —
Non-regulatory agreement units	159	159	—	—	—
Net unrealized gains on decommissioning trust funds—					
Regulatory agreement units	180	180	—	—	—
Non-regulatory agreement units	134	134	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	29	29	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(358)	(358)	—		
Total decommissioning-related activities	360	360	—	—	—
Investment income	1	1	—	(1)	7 [c]
Long-term lease income	24	—	—	—	—
Interest income related to uncertain income tax positions	40	54	—	—	—
AFUDC—Equity	21	—	3	6	12
Other	9	(9)	14	2	(1)
Other, net	$ 455	$ 406	$ 17	$ 7	$ 18

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a] —					
Regulatory agreement units	$ 256	$ 256	$ —	$ —	$ —
Non-regulatory agreement units	77	77	—	—	—
Net unrealized gains on decommissioning trust funds—					
Regulatory agreement units	406	406	—	—	—
Non-regulatory agreement units	146	146	—	—	—
Net unrealized gains on pledged assets—					
Zion Station decommissioning	7	7	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(546)	(546)	—		—
Total decommissioning-related activities	346	346	—	—	—
Investment income	8	(1)	—	(1)	9[c]
Long-term lease income	28	—	—	—	—
Interest income related to uncertain income tax positions	24	4	—	—	—
AFUDC—Equity	22	—	11	4	7
Other	32	6	15	3	1
Other, net	$ 460	$ 355	$ 26	$ 6	$ 17

(a) Includes investment income and realized gains and losses on sales of investments within the nuclear decommissioning trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 16—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE's rate stabilization deferral. See Note 3—Regulatory Matters for additional information regarding the rate stabilization deferral.
(d) In January 2015, in connection with Generation's $750 million issuance of five-year Senior Unsecured Notes, Exelon terminated certain floating-to-fixed interest rate swaps. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments are probable not to occur. As a result, $26 million of anticipated payments were reclassified from Accumulated OCI to Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income.
(e) See Note 14—Debt and Credit Agreements and 4—Mergers, Acquisitions, and Dispositions for additional information on the PHI merger related debt exchange.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013.

For the year ended December 31, 2015	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$2,227	$ 1,007	$ 635	$240	$289
Regulatory assets	170	—	72	20	77
Amortization of intangible assets, net	54	47	—	—	—
Amortization of energy contract assets and liabilities (a)	22	22	—	—	—
Nuclear fuel (b)	1,116	1,116	—	—	—
ARO accretion (c)	398	397	—	—	—
Total depreciation, amortization, accretion and depletion	$3,987	$ 2,589	$ 707	$260	$366

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$2,080	$ 922	$ 588	$227	$288
Regulatory assets	191	—	99	9	83
Amortization of intangible assets, net	44	44	—	—	—
Amortization of energy contract assets and liabilities (a)	135	135	—	—	—
Nuclear fuel (b)	1,073	1,073	—	—	—
ARO accretion (c)	345	345	—	—	—
Total depreciation, amortization, accretion and depletion	$3,868	$ 2,519	$ 687	$236	$371

For the year ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,893	$ 813	$ 545	$219	$264
Regulatory assets	212	—	119	9	84
Amortization of intangible assets, net	48	43	5	—	—
Amortization of energy contract assets and liabilities (a)	430	507	—	—	—
Nuclear fuel (b)	921	921	—	—	—
ARO accretion (c)	275	275	—	—	—
Total depreciation, amortization and accretion	$3,779	$ 2,559	$ 669	$228	$348

(a) Included in Operating revenues or Purchased power and fuel on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(c) Included in Operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2015	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 930	$ 348	$ 308	$ 94	$120
Income taxes (net of refunds)	342	476	(265)	64	73
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 637	$ 269	$ 206	$ 39	$ 65
Loss from equity method investments	7	8	—	—	—
Provision for uncollectible accounts	120	22	53	30	15
Provision for excess and obsolete inventory	10	9	1	—	—
Stock-based compensation costs	97	—	—	—	—
Other decommissioning-related activity (a)	(82)	(82)	—	—	—
Energy-related options (b)	21	21	—	—	—
Amortization of regulatory asset related to debt costs	7	—	5	2	—
Amortization of rate stabilization deferral	73	—	—	—	73
Amortization of debt fair value adjustment	(17)	(17)	—	—	—
Amortization of debt costs	58	15	4	2	2
Discrete impacts from EIMA (c)	144	—	144	—	—
Lower of cost or market inventory adjustment	23	23	—	—	—
Other	11	—	3	(3)	(18)
Total other non-cash operating activities	$1,109	$ 268	$ 416	$ 70	$137
Non-cash investing and financing activities:					
Change in PPE related to ARO update	$ 885	$ 885	$ —	$—	$—
Change in capital expenditures not paid	96	82	34	(13)	(9)
Non-cash financing of capital projects	77	77	—	—	—
Nuclear fuel procurement (d)	57	57	—	—	—
Indemnification of like-kind exchange position (e)	—	—	7	—	—
Long-term software licensing agreement (f)	95	—	—	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 16—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 3—Regulatory Matters for more information.
(d) Relates to the nuclear fuel procurement contract for the purchase of fixed quantities of converted uranium, which was delivered to Generation in 2015. Generation is required to make payments starting September 28, 2018, with the final payment being due no later than September 30, 2020.
(e) See Note 15—Income Taxes for discussion of the like-kind exchange tax position.
(f) Relates to a long-term software license agreement entered into on May 30, 2015. Exelon is required to make payments starting August of 2015 through May of 2024. See Note 14—Debt and Credit Agreements for additional information.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 940	$ 322	$ 292	$ 94	$ 111
Income taxes (net of refunds)	314	227	(6)	85	(21)
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 560	$ 249	$ 162	$ 36	$ 64
Loss from equity method investments	22	20	—	—	—
Provision for uncollectible accounts	156	14	26	52	64
Provision for excess and obsolete inventory	5	5	—	—	—
Stock-based compensation costs	91	—	—	—	—
Other decommissioning-related activity [a]	(132)	(132)	—	—	—
Energy-related options [b]	122	122	—	—	—
Amortization of regulatory asset related to debt costs	11	—	8	3	—
Amortization of rate stabilization deferral	65	—	—	—	65
Amortization of debt fair value adjustment	(23)	(23)	—	—	—
Merger-related commitments	44	44	—	—	—
Amortization of debt costs	53	12	4	2	2
Discrete impacts from EIMA [c]	53	—	53	—	—
Lower of cost or market inventory adjustment	29	29	—	—	—
Other	(2)	6	2	(1)	(15)
Total other non-cash operating activities	$ 1,054	$ 346	$ 255	$ 92	$ 180
Non-cash investing and financing activities:					
Change in PPE related to ARO update	$ 72	$ 72	$ —	$ —	$ —
Change in capital expenditures not paid	220	(61) [d]	78	—	25
Fair value of net assets recorded upon CENG consolidation [e]	3,400	3,400	—	—	—
Issuance of equity units [f]	131	—	—	—	—
Nuclear fuel procurement [g]	70	70	—	—	—
Indemnification of like-kind exchange position [h]	—	—	5	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 16—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 3—Regulatory Matters for more information.
(d) Includes $170 million of changes in capital expenditures not paid between December 31, 2014 and 2013 related to Antelope Valley.
(e) See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.
(f) Relates to the present value of the contract payments for the equity units issued by Exelon. See Note 20—Stock-Based Compensation Plans for additional information.
(g) Relates to the nuclear fuel procurement contracts for the purchase of fixed quantities of uranium, which was delivered to Generation in 2014. Generation is required to make payments starting June 30, 2016, with the final payment being due no later than June 30, 2018.
(h) See Note 15—Income Taxes for discussion of the like-kind exchange tax position.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Cash paid (refunded) during the year:					
Interest (net of amount capitalized)	$ 866	$ 291	$ 283	$ 95	$130
Income taxes (net of refunds)	112	(18)	33	70	42
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 825	$ 345	$ 308	$ 43	$ 56
Gain from equity method investments	(10)	(10)	—	—	—
Provision for uncollectible accounts	101	10	(15)	61	44
Provision for excess and obsolete inventory	9	9	—	—	—
Stock-based compensation costs	120	—	—	—	—
Other decommissioning-related activity (a)	(169)	(169)	—	—	—
Energy-related options (b)	104	104	—	—	—
Amortization of regulatory asset related to debt costs	12	—	9	3	—
Amortization of rate stabilization deferral	66	—	—	—	66
Amortization of debt fair value adjustment	(34)	(34)	—	—	—
Discrete impacts from EIMA (c)	(271)	—	(271)	—	—
Amortization of debt costs	18	10	1	2	2
Other	(53)	5	(4)	(1)	(15)
Total other non-cash operating activities	$ 718	$ 270	$ 28	$108	$153
Non-cash investing and financing activities:					
Change in PPE related to ARO update	$(128)	$ (128)	$ —	$—	$ 4
Change in capital expenditures not paid	(38)	(107) (d)	(8)	13	(48)
Consolidated VIE dividend to noncontrolling interest	63	63	—	—	—
Indemnification of like-kind exchange position (e)	—	—	176	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 16—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through pre-established performance-based formula rate tariff. See Note 3—Regulatory Matters.
(d) Includes $55 million of changes in capital expenditures not paid between December 31, 2013 and 2012 related to Antelope Valley.
(e) See Note 15—Income Taxes for discussion of the like-kind exchanged tax position.

DOE Smart Grid Investment Grant (Exelon, PECO and BGE). For the year ended December 31, 2014, PECO has included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $2 million and reimbursements of $5 million related to PECO's DOE SGIG programs. For the year ended December 31, 2015, PECO had no capital expenditures or reimbursements, as the DOE SGIG program was completed during 2014. For the year ended December 31, 2013, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $74 million, $27 million and $47 million, and reimbursements of $95 million, $37 million and $58 million, related to PECO's and BGE's DOE SGIG programs. See Note 3—Regulatory Matters for additional information regarding the DOE SGIG.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants at December 31, 2015 and 2014.

December 31, 2015	Exelon	Generation	ComEd	PECO	BGE
Investments					
Equity method investments:					
Financing trusts [a]	$ 22	$ —	$ 6	$ 8	$ 8
Bloom	63	63	—	—	—
Net Power	23	23	—	—	—
Other equity method investments	4	3	—	—	—
Total equity method investments	112	89	6	8	8
Other investments:					
Net investment in leases [b]	358	6	—	—	—
Employee benefit trusts and investments [c]	85	31	—	20	4
Other cost method investments	55	55	—	—	—
Other available for sale investments	29	29	—	—	—
Total investments	$ 639	$ 210	$ 6	$ 28	$ 12

December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Investments					
Equity method investments:					
Financing trusts [a]	$ 22	$ —	$ 6	$ 8	$ 8
Bloom	13	13	—	—	—
Net Power	9	9	—	—	—
Sunnyside	5	5	—	—	—
Other equity method investments	1	1	—	—	—
Total equity method investments	50	28	6	8	8
Other investments:					
Net investment in leases [b]	367	7	—	—	—
Employee benefit trusts and investments [c]	85	27	—	23	4
Other cost method investments	37	37	—	—	—
Other available for sale investments	5	5	—	—	—
Total investments	$ 544	$ 104	$ 6	$ 31	$ 12

(a) Includes investments in affiliated financing trusts, which were not consolidated within the financial statements of Exelon and are shown as investments on the Consolidated Balance Sheets. See Note 1—Significant Accounting Policies for additional information.
(b) Represents direct financing lease investments. See Note 8—Impairment of Long-Lived Assets for additional information.
(c) The Registrants' investments in these marketable securities are recorded at fair market value.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables provide additional information about liabilities of the Registrants at December 31, 2015 and 2014.

December 31, 2015	Exelon	Generation	ComEd	PECO	BGE
Accrued expenses					
Compensation-related accruals (a)	$1,014	$ 547	$ 183	$ 66	$ 57
Taxes accrued	293	186	63	4	23
Interest accrued	915	77	443	35	27
Severance accrued	21	11	3	—	1
Other accrued expenses	133	114	14	4	2
Total accrued expenses	$2,376	$ 935	$ 706	$109	$110

December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Accrued expenses					
Compensation-related accruals (a)	$ 832	$ 447	$ 153	$ 50	$ 58
Taxes accrued	305	248	59	3	42
Interest accrued	240	66	102	33	29
Severance accrued	49	33	2	1	2
Other accrued expenses	113(b)	92(b)	15	4	—
Total accrued expenses	$1,539	$ 886	$ 331	$ 91	$131

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.
(b) Includes $19 million for amounts accrued related to Antelope Valley as of December 31, 2014.

25. Segment Information (Exelon, Generation, ComEd, PECO and BGE)

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants.

Exelon has nine reportable segments, which include ComEd, PECO, BGE and Generation's six power marketing reportable segments, consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as "Other Power Regions", which includes activities in the South, West and Canada. ComEd, PECO and BGE each represent a single reportable segment, and as such, no separate segment information is provided for these Registrants. Exelon, ComEd, PECO and BGE's CODMs evaluate the performance of and allocate resources to ComEd, PECO and BGE based on net income and return on equity.

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions :
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

The CODMs for Exelon and Generation evaluate the performance of Generation's power marketing activities and allocate resources based on revenue net of purchased power and fuel expense (RNF). Generation believes that RNF is a useful measurement of operational performance. RNF is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO, and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's owned generation and fuel costs associated with tolling agreements. The results of Generation's other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, Generation's unrealized mark-to-market gains and losses on economic hedging activities and its amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also not included in the regional reportable segment amounts. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the years ended December 31, 2015, 2014, and 2013 is as follows:

	Generation [a]	ComEd	PECO	BGE	Other [b]	Intersegment Eliminations	Exelon
Operating revenues [c]:							
2015							
Competitive businesses electric revenues	$ 15,944	$ —	$ —	$ —	$ —	$ (744)	$ 15,200
Competitive businesses natural gas revenues	2,433	—	—	—	—	—	2,433
Competitive businesses other revenues	758	—	—	—	—	(1)	757
Rate-regulated electric revenues	—	4,905	2,486	2,490	—	(5)	9,876
Rate-regulated natural gas revenues	—	—	546	645	—	(15)	1,176
Shared service and other revenues	—	—	—	—	1,372	(1,367)	5
2014							
Competitive businesses electric revenues	$ 14,533	$ —	$ —	$ —	$ —	$ (760)	$ 13,773
Competitive businesses natural gas revenues	2,705	—	—	—	—	(1)	2,704
Competitive businesses other revenues	155	—	—	—	—	(1)	154
Rate-regulated electric revenues	—	4,564	2,448	2,460	—	(5)	9,467
Rate-regulated natural gas revenues	—	—	646	705	—	(26)	1,325
Shared service and other revenues	—	—	—	—	1,285	(1,279)	6
2013							
Competitive businesses electric revenues	$ 13,862	$ —	$ —	$ —	$ —	$ (1,366)	$ 12,496
Competitive businesses natural gas revenues	1,721	—	—	—	—	—	1,721
Competitive businesses other revenues	47	—	—	—	—	(1)	46
Rate-regulated electric revenues	—	4,464	2,500	2,405	—	(4)	9,365
Rate-regulated natural gas revenues	—	—	600	660	—	(14)	1,246
Shared service and other revenues	—	—	—	—	1,241	(1,227)	14
Intersegment revenues [d]:							
2015	$ 745	$ 4	$ 2	$ 14	$ 1,367	$ (2,127)	$ 5
2014	762	4	2	25	1,280	(2,067)	6
2013	1,367	3	1	13	1,237	(2,607)	14
Depreciation and amortization							
2015	$ 1,054	$ 707	$ 260	$ 366	$ 63	$ —	$ 2,450
2014	967	687	236	371	53	—	2,314
2013	856	669	228	348	52	—	2,153
Operating expenses [c]:							
2015	$ 16,872	$ 3,889	$ 2,404	$ 2,578	$ 1,444	$ (2,131)	$ 25,056
2014	16,923	3,586	2,522	2,726	1,353	(2,071)	25,039
2013	13,976	3,510	2,434	2,616	1,324	(2,618)	21,242
Equity in earnings (losses) of unconsolidated affiliates							
2015	$ (8)	$ —	$ —	$ —	$ 1	$ —	$ (7)
2014	(20)	—	—	—	—	—	(20)
2013	10	—	—	—	—	—	10
Interest expense, net:							
2015	$ 365	$ 332	$ 114	$ 99	$ 123	$ —	$ 1,033
2014	356	321	113	106	169	—	1,065
2013	357	579	115	122	183	—	1,356
Income (loss) before income taxes:							
2015	$ 1,850	$ 706	$ 521	$ 477	$ (219)	$ (5)	$ 3,330
2014	1,226	676	466	351	(227)	(6)	2,486
2013	1,675	401	557	344	(191)	(13)	2,773
Income taxes:							
2015	$ 502	$ 280	$ 143	$ 189	$ (41)	$ —	$ 1,073
2014	207	268	114	140	(63)	—	666
2013	615	152	162	134	(20)	1	1,044
Net income (loss):							
2015	$ 1,340	$ 426	$ 378	$ 288	$ (177)	$ (5)	$ 2,250
2014	1,019	408	352	211	(164)	(6)	1,820
2013	1,060	249	395	210	(171)	(14)	1,729
Capital expenditures:							
2015	$ 3,841	$ 2,398	$ 601	$ 719	$ 65	$ —	7,624
2014	3,012	1,689	661	620	95	—	6,077
2013	2,752	1,433	537	587	86	—	5,395
Total assets:							
2015	$ 46,529	$ 26,532	$ 10,367	$ 8,295	$ 15,389	$ (11,728)	$ 95,384
2014	44,951	25,358	9,860	8,056	9,711	(11,520)	86,416

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. For the year ended December 31, 2015, intersegment revenues for Generation include revenue from sales to PECO of $224 million and sales to BGE of $502 million in the Mid-Atlantic region, and sales to ComEd of $18 million in the Midwest region, which eliminate upon consolidation. For the year ended December 31, 2014, intersegment revenues for Generation include revenue from sales to PECO of $198 million and sales to BGE of $387 million in the Mid-Atlantic region, and sales to ComEd of $176 million in the Midwest region, which eliminate upon consolidation. For the year ended December 31, 2013, intersegment revenues for Generation include revenue from sales to PECO of $405 million and sales to BGE of $455 million in the Mid-Atlantic region, and sales to ComEd of $506 million in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation.
(b) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(c) For the years ended December 31, 2015, 2014 and 2013, utility taxes of $105 million, $89 million and $79 million, respectively, are included in revenues and expenses for Generation. For the years ended December 31, 2015, 2014 and 2013, utility taxes of $236 million, $238 million and $241 million, respectively, are included in revenues and expenses for ComEd. For the years ended December 31, 2015, 2014 and 2013, utility taxes of $133 million, $128 million and $129 million, respectively, are included in revenues and expenses for PECO. For the years ended December 31, 2015, 2014 and 2013, utility taxes of $85 million, $86 million and $82 million are included in revenues and expenses for BGE, respectively.
(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

Generation total revenues:

	2015			2014			2013		
	Revenues from external customers (b)	Intersegment revenues	Total revenues	Revenues from external customers (b)(d)	Intersegment revenues (d)	Total revenues	Revenues from external customers (b)(d)	Intersegment revenues (d)	Total revenues
Mid-Atlantic (a)	$ 5,974	$ (74)	$ 5,900	$ 5,414	$ (155)	$ 5,259	$ 5,261	$ (57)	$ 5,204
Midwest	4,712	(2)	4,710	4,488	(13)	4,475	4,298	(28)	4,270
New England	2,217	(5)	2,212	1,468	(46)	1,422	1,279	(42)	1,237
New York	996	(11)	985	846	(3)	843	717	(3)	714
ERCOT	863	(6)	857	938	(3)	935	1,223	(7)	1,216
Other Power Regions	1,182	(80)	1,102	1,379	(70)	1,309	1,084	(116)	968
Total Revenues for Reportable Segments	$ 15,944	$ (178)	$15,766	$ 14,533	$ (290)	$14,243	$ 13,862	$ (253)	$13,609
Other (c)	3,191	178	3,369	2,860	290	3,150	1,768	253	2,021
Total Generation Consolidated Operating Revenues	$ 19,135	$ —	$19,135	$ 17,393	$ —	$17,393	$ 15,630	$ —	$15,630

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, CENG's revenues are included on a fully consolidated basis.
(b) Includes all wholesale and retail electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a $7 million increase to revenues, a $289 million decrease to revenues, and a $767 million decrease to revenues for the amortization of intangible assets related to commodity contracts recorded at fair value for the years ended December 31, 2015, 2014, and 2013, respectively, unrealized mark-to-market gains of $203 million, losses of $174 million, and gains of $220 million for the years ended December 31, 2015, 2014, and 2013, respectively, and elimination of intersegment revenues.
(d) Exelon corrected an error in the December 31, 2014 and December 31, 2013 balances within Intersegment revenues and Revenues from external customers for an overstatement of Intersegment revenues for Reportable Segments of $284 million and

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

$252 million for the years ended December 31, 2014 and 2013, respectively, an understatement of Revenues from external customers for Reportable Segments of $284 million and $252 million for the years ended December 31, 2014 and 2013, respectively, an understatement of Intersegment revenues for Other of $284 million and $252 million for the years ended December 31, 2014 and 2013, respectively, and an overstatement of Revenues from external customers for Other of $284 million and $252 million for the years ended December 31, 2014 and 2013, respectively. The error is not considered material to any prior period, and there is no net impact to Total Revenues.

Generation total revenues net of purchased power and fuel expense:

	2015			2014			2013		
	RNF from external customers [b]	Intersegment RNF	Total RNF	RNF from external customers [b][d]	Intersegment RNF [d]	Total RNF	RNF from external customers [b][d]	Intersegment RNF [d]	Total RNF
Mid-Atlantic [a]	$ 3,556	$ 15	$3,571	$ 3,544	$ (113)	$3,431	$ 3,287	$ (17)	$3,270
Midwest	2,912	(20)	2,892	2,607	(8)	2,599	2,606	(20)	2,586
New England	519	(58)	461	450	(99)	351	299	(114)	185
New York	584	50	634	439	44	483	(55)	51	(4)
ERCOT	425	(132)	293	573	(256)	317	627	(191)	436
Other Power Regions	440	(190)	250	517	(190)	327	397	(196)	201
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 8,436	$ (335)	$8,101	$ 8,130	$ (622)	$7,508	$ 7,161	$ (487)	$6,674
Other [c]	678	335	1,013	(662)	622	(40)	272	487	759
Total Generation Revenues net of purchased power and fuel expense	$ 9,114	$ —	$9,114	$ 7,468	$ —	$7,468	$ 7,433	$ —	$7,433

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, CENG's revenue net of purchased power and fuel expense are included on a fully consolidated basis.
(b) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a $8 million increase in RNF, a $124 million decrease in RNF, and a $488 million decrease in RNF for the amortization of intangible assets related to commodity contracts recorded at fair value for the years ended December 31, 2015, 2014, and 2013, respectively, unrealized mark-to-market gains of $257 million, losses of $591 million, and gains of $504 million for the years ended December 31, 2015, 2014, and 2013, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.
(d) Exelon corrected an error in the December 31, 2014 and December 31, 2013 balances within Intersegment RNF and RNF from external customers for an understatement of $8 million and an overstatement of $134 million of Intersegment RNF for Reportable Segments for the years ended December 31, 2014 and 2013, respectively, an understatement of RNF from external customers for Reportable Segments of $11 million and $134 million for the years ended December 31, 2014 and 2013, respectively, an overstatement of $8 million and an understatement $134 million of Intersegment RNF for Other for the years ended December 31, 2014 and 2013, respectively, and an overstatement of RNF from external customers for Other of $11 million and $134 million for the years ended December 31, 2014 and 2013, respectively. This also included an understatement of total RNF for Reportable Segments and an overstatement of total RNF for Other of $19 million for the year ended December 31, 2014. The error is not considered material to any prior period, and there is no net impact to Generation Total RNF for 2013 or 2014.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

26. Related Party Transactions (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The financial statements of Exelon include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2015	2014	2013
Operating revenues from affiliates:			
PECO [a]	$ 1	$ 1	$ 10
CENG [b]	—	17	56
BGE [a]	4	5	4
Other	4	—	—
Total operating revenues from affiliates	$ 9	$ 23	$ 70
Purchase power and fuel from affiliates:			
CENG [c]	$—	$282	$ 992
Keystone Fuels, LLC [d]	—	138	144
Conemaugh Fuels, LLC [d]	—	99	98
Safe Harbor Water Power Corp [d]	—	12	22
Total purchase power and fuel from affiliates	$—	$531	$1,256
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
BGE Capital Trust II	16	16	16
Total interest expense to affiliates, net	$ 41	$ 41	$ 41
Earnings (losses) in equity method investments:			
CENG [e]	$—	$ (19)	$ 9
Qualifying facilities and domestic power projects	(8)	(1)	1
Other	$ 1	$—	$ —
Total earnings (losses) in equity method investments	$ (7)	$ (20)	$ 10

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2015	December 31, 2014
Payables to affiliates (current):		
ComEd Financing III	$ 4	$ 4
PECO Trust III	1	1
BGE Capital Trust II	3	3
Total payables to affiliates (current)	$ 8	$ 8
Long-term debt due to financing trusts:		
ComEd Financing III	$205	$205
PECO Trust III	81	81
PECO Trust IV	103	103
BGE Capital Trust II	252	252
Total long-term debt due to financing trusts	$641	$641

(a) The intersegment profit associated with the sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statement of Operations. See Note 3—Regulatory Matters for additional information.

(b) Beginning in 2012, Generation entered into a power services agency agreement (PSAA) with the CENG plants, which as of April 1, 2014, was amended and extended until the permanent cessation of power generation by the CENG generation plants. The PSAA is an agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services. On April 1, 2014, Generation and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were part of the Generation nuclear fleet. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(c) CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Beginning in 2012, Generation had a PPA under which it purchased 85% of the nuclear plant output owned by CENG that was not sold to third parties under pre-existing unit-contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit-contingent basis 50.01% of the nuclear plant output owned by CENG and a subsidiary of EDF will purchase on a unit-contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA) not sold to third parties. Beginning April 1, 2014, sales to Generation are eliminated in consolidation. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(d) During 2014, Generation closed the sale of Safe Harbor Water Power Corporation, Keystone Fuels, LLC, and Conemaugh Fuels LLC. Generation recorded purchase power and fuel costs from affiliates related to these generating assets during the time these assets were still partially owned by Generation. See Note 4—Mergers, Acquisitions, and Dispositions for more information.

(e) Prior to April 1, 2014, Generation's total gain (loss) in equity method investments includes equity investment income (loss) and amortization of the basis difference established as a result of purchase accounting applied upon Constellation merger in 2012. CENG was fully consolidated on April 1, 2014. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Transactions involving Generation, ComEd, PECO and BGE are further described in the tables below.

Generation

The financial statements of Generation include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2015	2014	2013
Operating revenues from affiliates:			
ComEd (a)	$ 18	$176	$ 506
PECO (b)	224	198	405
BGE (c)	502	387	455
CENG (d)	—	17	56
BSC	1	1	1
Other	4	—	—
Total operating revenues from affiliates	$ 749	$779	$1,423
Purchase power and fuel from affiliates:			
ComEd	$ —	$ 1	$ 1
BGE	14	25	13
CENG (e)	—	282	992
Keystone Fuels, LLC (i)	—	138	144
Conemaugh Fuels, LLC (i)	—	99	98
Safe Harbor Water Power Corporation (i)	—	12	22
Total purchase power and fuel from affiliates	$ 14	$557	$1,270
Operating and maintenance from affiliates:			
ComEd (f)	$ 4	$ 3	$ 2
PECO (f)	2	2	1
BSC (g)	614	618	571
Total operating and maintenance from affiliates	$ 620	$623	$ 574
Interest expense to affiliates, net:			
Exelon Corporate (j)	$ 43	$ 53	$ 59
Earnings (losses) in equity method investments			
CENG (h)	$ —	$ (19)	$ 9
Qualifying facilities and domestic power projects	(8)	(1)	1
Total earnings (losses) in equity method investments	$ (8)	$ (20)	$ 10
Capitalized costs			
BSC (g)	$ 76	$ 91	$ 93
Cash distribution paid to member	$2,474	$645	$ 625
Contribution from member	$ 47	$ 53	$ 26

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2015	December 31, 2014
Receivables from affiliates (current):		
ComEd [a]	$ 15	$ 43
PECO [b]	36	29
BGE [c]	31	40
Other	1	1
Total receivables from affiliates (current)	$ 83	$ 113
Intercompany money pool (current):		
Exelon Corporate	$1,252	$ —
Long-term debt due to affiliates (current):		
Exelon Corporate [l]	$ —	$ 556
Payables to affiliates (current):		
Exelon Corporate [j]	$ 16	$ 12
BSC [g]	78	83
ComEd	9	12
Other	1	—
Total payables to affiliates (current)	$ 104	$ 107
Long-term debt due to affiliates (noncurrent):		
Exelon Corporate [l]	$ 933	$ 943
Payables to affiliates (noncurrent):		
BSC [g]	$ —	$ 1
ComEd [k]	2,172	2,389
PECO [k]	405	490
Total payables to affiliates (noncurrent)	$2,577	$2,880

(a) Generation has an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. Generation also sells RECs to ComEd. In addition, Generation had revenue from ComEd associated with the settled portion of the financial swap contract established as part of the Illinois Settlement. See Note 3—Regulatory Matters for additional information.

(b) Generation provides electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, Generation has five-year and ten-year agreements with PECO to sell non-solar and solar AECs, respectively. See Note 3—Regulatory Matters for additional information.

(c) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.

(d) Beginning in 2012, Generation entered into a power services agency agreement (PSAA) with the CENG plants, which as of April 1, 2014, was amended and extended until the permanent cessation of power generation by the CENG generation plants. The PSAA is an agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services. On April 1, 2014, Generation and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were part of the Generation nuclear fleet. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(e) CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Beginning in 2012, Generation had a PPA under which it purchased 85% of the nuclear plant output owned by CENG that was not sold to third parties under pre-existing unit-contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit-contingent basis 50.01% of the nuclear plant output owned by CENG and a subsidiary of EDF will purchase on a unit-contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA) not sold to third parties. Beginning April 1, 2014, sales to Generation are eliminated in consolidation. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(f) Generation requires electricity for its own use at its generating stations. Generation purchases electricity and distribution and transmission services from PECO and only distribution and transmission services from ComEd for the delivery of electricity to its generating stations.
(g) Generation receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(h) Prior to April 1, 2014, Generation's total gain (loss) in equity method investments includes equity income (loss) and amortization of the basis difference established as a result of purchase accounting applied upon Constellation merger in 2012. CENG was fully consolidated on April 1, 2014. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.
(i) During 2014, Generation closed the sale of Safe Harbor Water Power Corporation, Keystone Fuels, LLC, and Conemaugh Fuels LLC. Generation recorded purchase power and fuel costs from affiliates related to these generating assets during the time these assets were still partially owned by Generation. See Note 4—Mergers, Acquisitions, and Dispositions for more information.
(j) The balance consists of interest owed to Exelon Corporation related to the senior unsecured notes, as well as, expense related to certain invoices Exelon Corporation processed on behalf of Generation.
(k) Generation has long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 16—Asset Retirement Obligations.
(l) In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-term Debt to affiliate on Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets.

ComEd

The financial statements of ComEd include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2015	2014	2013
Operating revenues from affiliates			
Generation	$ 4	$ 4	$ 3
Purchased power from affiliate			
Generation [(a)]	$ 18	$176	$512
Operating and maintenance from affiliate			
BSC [(b)]	$195	$166	$157
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
Capitalized costs			
BSC [(b)]	$103	$ 77	$ 69
Cash dividends paid to parent	$299	$307	$220
Contribution from parent	$202	$273	$—

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2015	December 31, 2014
Prepaid voluntary employee beneficiary association trust [c]	$ 11	$ 13
Receivable from affiliates (current):		
Voluntary employee beneficiary association trust	$ 2	$ 2
Generation	9	12
Exelon Corporate [e]	188	—
Total receivable from affiliates (current)	$ 199	$ 14
Receivable from affiliates (noncurrent):		
Generation [d]	$2,172	$2,389
Exelon Corporate [e]	—	182
Total receivable from affiliates (noncurrent)	$2,172	$2,571
Payables to affiliates (current):		
Generation [a]	$ 15	$ 43
BSC [b]	39	32
ComEd Financing III	4	4
PECO	2	2
Exelon Corporate	2	3
Total payables to affiliates (current)	$ 62	$ 84
Long-term debt to ComEd financing trust		
ComEd Financing III	$ 205	$ 205

(a) ComEd procures a portion of its electricity supply requirements from Generation under an ICC-approved RFP contract. ComEd also purchases RECs from Generation. In addition, purchased power expense includes the settled portion of the financial swap contract with Generation, which expired in 2013. See Note 3—Regulatory Matters and Note 13—Derivative Financial Instruments for additional information.

(b) ComEd receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

(c) The voluntary employee benefit association trusts covering active employees are included in corporate operations and are funded by the Registrants. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for ComEd's contributions to the plans, being higher than actual claim expense incurred by the plans over time. The prepayment is included in other current assets.

(d) ComEd has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct for generating facilities previously owned by ComEd. To the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to ComEd for payment to ComEd's customers.

(e) Represents indemnification from Exelon Corporate related to the like-kind exchange transaction.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PECO

The financial statements of PECO include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2015	2014	2013
Operating revenues from affiliates:			
Generation (a)	$ 2	$ 2	$ 1
Purchased power from affiliate			
Generation (b)	$220	$194	$392
Operating and maintenance from affiliates:			
BSC (c)	$107	$ 96	$ 98
Generation	3	3	3
Total operating and maintenance from affiliates	$110	$ 99	$101
Interest expense to affiliates, net:			
PECO Trust III	$ 6	$ 6	$ 6
PECO Trust IV	6	6	6
Total interest expense to affiliates, net	$ 12	$ 12	$ 12
Capitalized costs			
BSC (c)	$ 40	$ 39	$ 46
Cash dividends paid to parent	$279	$320	$332
Contribution from parent	$ 16	$ 24	$ 27

	December 31,	
	2015	2014
Prepaid voluntary employee beneficiary association trust (d)	$ 2	$ 3
Receivable from affiliate (current):		
ComEd	$ 2	$ 2
BGE	—	1
Total receivable from affiliates (current)	$ 2	$ 3
Receivable from affiliate (noncurrent):		
Generation (e)	$405	$490
Payables to affiliates (current):		
Generation (b)	$ 36	$ 29
BSC (c)	17	20
Exelon Corporate	1	2
PECO Trust III	1	1
Total payables to affiliates (current)	$ 55	$ 52
Long-term debt to financing trusts:		
PECO Trust III	$ 81	$ 81
PECO Trust IV	103	103
Total long-term debt to financing trusts	$184	$184

(a) PECO provides energy to Generation for Generation's own use.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(b) PECO purchases electric supply from Generation under contracts executed through its competitive procurement process. In addition, PECO has five-year and ten-year agreements with Generation to purchase non-solar and solar AECs, respectively. See Note 3—Regulatory Matters for additional information on AECs.
(c) PECO receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) The voluntary employee beneficiary association trusts covering active employees are included in corporate operations and are funded by the Registrants. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for PECO's contributions to the plans, being higher than actual claim expense incurred by the plans over time.
(e) PECO has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct, whereby, to the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to PECO for payment to PECO's customers.

BGE

The financial statements of BGE include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2015	2014	2013
Operating revenues from affiliates:			
Generation [a]	$ 14	$ 25	$ 13
Purchased power from affiliate			
Generation [b]	$498	$382	$452
Operating and maintenance from affiliates:			
BSC [c]	$118	$103	$ 83
Interest expense to affiliates, net:			
BGE Capital Trust II	$ 16	$ 16	$ 16
Capitalized costs			
BSC [c]	$ 28	$ 19	$ 15
Cash dividends paid to parent	$158	$—	$—
Contribution from parent	$ 7	$—	$—

	December 31,	
	2015	2014
Prepaid voluntary employee beneficiary association trust [d]	$—	$ 1
Payables to affiliates (current):		
Generation [b]	$ 31	$ 40
BSC [c]	17	17
Exelon Corporate	1	5
PECO	—	1
BGE Capital Trust II	3	3
Total payables to affiliates (current)	$ 52	$ 66
Long-term debt to BGE financing trust		
BGE Capital Trust II	$252	$252

(a) BGE provides energy to Generation for Generation's own use.
(b) BGE procures a portion of its electricity and gas supply requirements from Generation under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(c) BGE receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) The voluntary employee benefit association trusts covering active employees are included in corporate operations and are funded by the Registrants. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for BGE's contributions to the plans, being higher than actual claim expense incurred by the plans over time. The prepayment is included in other current assets.

27. Quarterly Data (Unaudited) (Exelon, Generation, ComEd, PECO and BGE)

Exelon

The data shown below, which may not equal the total for the year due to the effects of rounding and dilution, includes all adjustments that Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income on Common Stock	
	2015	2014	2015	2014	2015	2014
Quarter ended:						
March 31	$ 8,830	$ 7,237	$1,366[a]	$ 168[b]	$693	$ 90
June 30	6,514	6,024	1,134[a]	842[b]	638	522
September 30	7,401	6,912	1,200[a]	1,738[b]	629	993
December 31	6,702	7,255	707	348	309	18[c]

(a) In the first, second, and third quarter of 2015, Exelon reclassified $(1) million, $7 million, and $2 million, respectively, to Operating income for presentation purposes in Exelon's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect Exelon's Net (Loss) Income on Common Stock.
(b) In the first, second, and third quarter of 2014, Exelon reclassified $5 million, $13 million, and $339 million, respectively, to Operating income for presentation purposes in Exelon's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect Exelon's Net (Loss) Income on Common Stock.
(c) Includes charges to earnings related to the impairments of certain generating assets which were held for sale and certain Upstream exploration assets. See Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

	Average Basic Shares Outstanding (in millions)		Net Income per Basic Share	
	2015	2014	2015	2014
Quarter ended:				
March 31	862	858	$0.80	$0.10
June 30	863	860	0.74	0.61
September 30	913	861	0.69	1.15
December 31	921	861	0.34	0.02

	Average Diluted Shares Outstanding (in millions)		Net Income per Diluted Share	
	2015	2014	2015	2014
Quarter ended:				
March 31	867	861	$ 0.80	$ 0.10
June 30	866	864	0.74	0.60
September 30	915	863	0.69	1.15
December 31	924	868	0.33	0.02

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2015				2014			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 31.37	$ 34.44	$ 34.98	$ 38.25	$ 38.93	$ 36.26	$ 37.73	$ 33.94
Low price	25.09	28.41	31.28	31.71	33.07	30.66	33.11	26.45
Close	27.77	29.70	31.42	33.61	37.08	34.09	36.48	33.56
Dividends	0.310	0.310	0.310	0.310	0.310	0.310	0.310	0.310

Generation

The data shown below includes all adjustments that Generation considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating (Loss) Income		Net (Loss) Income on Membership Interest	
	2015	2014	2015 [a]	2014	2015	2014
Quarter ended:						
March 31	$ 5,840	$ 4,390	$ 719 [a]	$ (384) [b]	$ 443	$ (185)
June 30	4,232	3,789	703 [a]	441 [b]	398	340
September 30	4,768	4,412	622 [a]	1,225 [b]	377	771
December 31	4,294	4,802	230	(105)	154	(91)

(a) In the first, second, and third quarter of 2015, Generation reclassified $(1) million, $7 million, and $1 million, respectively, to Operating (loss) income for presentation purposes in Generation's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect Generation's Net (Loss) Income on Membership Interest.
(b) In the first, second, and third quarter of 2014, Generation reclassified $5 million, $12 million, and $338 million, respectively, to Operating (loss) income for presentation purposes in Generation's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect Generation's Net (Loss) Income on Membership Interest.

ComEd

The data shown below includes all adjustments that ComEd considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income	
	2015	2014	2015	2014	2015	2014
Quarter ended:						
March 31	$ 1,185	$ 1,134	$ 230	$ 238	$ 90	$ 98
June 30	1,148	1,128	243	258 [a]	99	111
September 30	1,376	1,222	327	287 [a]	149	126
December 31	1,196	1,079	217	196	87	73

(a) In both the second and third quarter of 2014, ComEd reclassified $1 million to Operating income for presentation purposes in ComEd's Consolidated Statements of Operations and Comprehensive Income. The reclassifications did not affect ComEd's Net (Loss) Income.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PECO

The data shown below includes all adjustments that PECO considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income on Common Stock	
	2015	2014	2015	2014	2015	2014
Quarter ended:						
March 31	$ 985	$ 993	$ 223	$ 149	$ 139	$ 89
June 30	661	656	124	134	70	84
September 30	740	693	154	133	90	81
December 31	645	750	128	156	79	98

BGE

The data shown below includes all adjustments that BGE considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income attributable to Common Shareholders	
	2015	2014	2015	2014	2015	2014
Quarter ended:						
March 31	$ 1,036	$ 1,054	$ 204	$ 169	$ 106	$ 85
June 30	628	653	99	55	44	16
September 30	725	697	110	102	51	46
December 31	746	761	144	113	74	52

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Exelon, Generation, ComEd, PECO and BGE—Disclosure Controls and Procedures

During the fourth quarter of 2015, each registrant's management, including its principal executive officer and principal financial officer, evaluated the effectiveness of that registrant's disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in that registrant's periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by each registrant to ensure that (a) information relating to that registrant, including its consolidated subsidiaries, that is required to be included in filings under the Securities Exchange Act of 1934, is accumulated and made known to that registrant's management, including its principal executive officer and principal financial officer, by other employees of that registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of December 31, 2015, the principal executive officer and principal financial officer of each registrant concluded that such registrant's disclosure controls and procedures were effective to accomplish their objectives.

Exelon, Generation, ComEd, PECO and BGE—Changes in Internal Control Over Financial Reporting

Each registrant continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. However, there have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2015 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's and BGE's internal control over financial reporting.

During 2015 management included an assessment of internal controls over financial reporting of Integrys, a business acquired on November 1, 2014, that was excluded from management's prior year evaluation consistent with guidance issued by the Securities and Exchange Commission that an assessment of internal controls of a recently acquired business may be omitted. The total revenues related to the Integrys business are 7.45% and 11.46%, respectively, and total assets related to Integrys are approximately 0.53% and 1.08%, respectively, of Exelon's and Generation's related consolidated financial statement amounts as of and for the year ended December 31, 2015.

Exelon, Generation, ComEd, PECO and BGE—Internal Control Over Financial Reporting

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2015. As a result of that assessment, management determined

that there were no material weaknesses as of December 31, 2015 and, therefore, concluded that each registrant's internal control over financial reporting was effective. Management's Report on Internal Control Over Financial Reporting is included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

ITEM 9B. OTHER INFORMATION

Exelon, Generation, ComEd, PECO and BGE

None.

PART III

Exelon Generation Company, LLC, Baltimore Gas and Electric Company, and PECO Energy Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section relating to Generation, BGE, and PECO are not presented.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants at February 10, 2016.

Directors, Director Nomination Process, and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at the annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)), the audit committee (Item 407(d)(4) and (d)(5)) and the beneficial reporting compliance (Sec. 16(a)) is incorporated herein by reference to information to be contained in Exelon's definitive 2016 proxy statement (2016 Exelon Proxy Statement) and the ComEd information statement (2016 ComEd Information Statement) to be filed with the SEC before April 29, 2016 pursuant to Regulation 14A or 14C, as applicable, under the Securities Exchange Act of 1934.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to Exelon's and ComEd's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. The Code of Business Conduct is filed as Exhibit 14 to this report and is available on Exelon's website at *www.exeloncorp.com* . The Code of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Bruce G. Wilson, Senior Vice President, Deputy General Counsel, and Corporate Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

If any substantive amendments to the Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Code of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or Corporate Controller, Exelon will disclose the nature of such amendment or waiver on Exelon's website, *www.exeloncorp.com* , or in a report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under *Executive Compensation Data* and *Report of the Compensation Committee* in the 2016 Exelon Proxy Statement or the ComEd 2016 Information Statement and incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The additional information required by this item will be set forth under *Ownership of Exelon Stock* in the 2016 Exelon Proxy Statement or the ComEd 2016 Information Statement and incorporated herein by reference.

Securities Authorized for Issuance under Exelon Equity Compensation Plans

[A] Plan Category	[B] Number of securities to be issued upon exercise of outstanding Options, warrants and rights (Note 1)	[C] Weighted-average price of outstanding Options, warrants and rights (Note 2)	[D] Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column [B]) (Note 3)
Equity compensation plans approved by security holders	29,694,000	$ 35.67	30,102,000

(1) Balance includes stock options, unvested performance shares, and unvested restricted shares that were granted under the Exelon LTIP or predecessor company plans and shares awarded under those plans and deferred into the stock deferral plan, as well as deferred stock units granted to directors as part of their compensation. For performance shares granted in 2013, 2014 and 2015, the total includes the maximum number of shares that could be granted, if performance, total shareholder return modifier, and individual performance multipliers were all at maximum, a total of 9,016,000 shares. At target, the number of securities to be issued for such awards is 4,508,000. The deferred stock units granted to directors includes 338,000 shares to be issued upon the conversion of deferred stock units awarded to members of the Exelon board of directors, and 102,000 shares to be issued upon the conversion of stock units held by members of the Exelon board of directors that were earned under a legacy Constellation Energy Group plan. Conversion of stock units to shares will occur after the director terminates service to the Exelon board or the board of any of its subsidiary companies. See Note 20—Common Stock of the Combined Notes to Consolidated Financial Statements for additional information about the material features of the plans.

(2) Includes outstanding restricted stock units and performance shares that can be exercised for no consideration. Without such instruments, the weighted-average price of outstanding options, warrants and rights shown in column [C] would be $46.68.

(3) Includes 22,289,000 shares available for issuance from the company's employee stock purchase plan.

No ComEd securities are authorized for issuance under equity compensation plans.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The additional information required by this item will be set forth under *Related Persons Transactions* and *Director Independence* in the 2016 Exelon Proxy Statement or the ComEd 2016 Information Statement and incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under *The Ratification of PricewaterhouseCoopers LLP as Exelon's Independent Accountant for 2016* in the 2016 Proxy Statement and the 2016 ComEd Information Statement and incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

Exelon

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 10, 2016 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2015, 2014 and 2013

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2015, 2014 and 2013

   Consolidated Balance Sheets at December 31, 2015 and 2014

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2015, 2014 and 2013

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule I—Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2015 and 2014 and for the Years Ended December 31, 2015, 2014 and 2013

   Schedule II—Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Operations and Other Comprehensive Income

(In millions)	For the Years Ended December 31, 2015	2014	2013
Operating expenses			
Operating and maintenance	$ —	$ 9	$ 9
Operating and maintenance from affiliates	43	38	34
Other	4	3	12
Total operating expenses	47	50	55
Operating loss	(47)	(50)	(55)
Other income and (deductions)			
Interest expense, net	(168)	(237)	(116)
Equity in earnings of investments	2,461	1,779	1,903
Interest income from affiliates, net	43	53	36
Other, net	(43)	(2)	(78)
Total other income	2,293	1,593	1,745
Income before income taxes	2,246	1,543	1,690
Income taxes	(23)	(80)	(29)
Net income	$2,269	$1,623	$1,719
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service cost (benefit) reclassified to periodic costs	$ (46)	$ (30)	$ —
Actuarial loss reclassified to periodic cost	220	147	208
Transition obligation reclassified to periodic cost	—	—	—
Pension and non-pension postretirement benefit plan valuation adjustment	(99)	(497)	669
Unrealized loss on cash flow hedges	9	(148)	(248)
Unrealized gain on marketable securities	—	1	2
Unrealized gain on equity investments	(3)	8	106
Unrealized loss on foreign currency translation	(21)	(9)	(10)
Reversal of CENG equity method AOCI	—	(116)	—
Other comprehensive income (loss)	60	(644)	727
Comprehensive income	$2,329	$ 979	$2,446

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2015	2014	2013
Net cash flows provided by operating activities	$ 3,071	$ 806	$ 1,053
Cash flows from investing activities			
Return on investment of direct financing lease termination	—	335	—
Changes in Exelon intercompany money pool	(1,217)	(83)	(60)
Note receivable from affiliates	550	—	484
Capital expenditures	—	1	—
Change in restricted cash	—	—	38
Investment in affiliates	(212)	(70)	(38)
Other investing activities	(55)	(126)	15
Net cash flows provided by (used in) investing activities	(934)	57	439
Cash flows from financing activities			
Changes in short-term borrowings	—	—	10
Issuance of long-term debt	4,200	1,150	—
Retirement of long-term debt	(2,263)	(23)	(450)
Issuance of common stock	1,868	—	—
Dividends paid on common stock	(1,105)	(1,065)	(1,249)
Proceeds from employee stock plans	32	35	47
Other financing activities	(58)	(84)	(6)
Net cash flows provided by (used in) financing activities	2,674	13	(1,648)
Increase (decrease) in cash and cash equivalents	4,811	876	(156)
Cash and cash equivalents at beginning of period	879	3	159
Cash and cash equivalents at end of period	$ 5,690	$ 879	$ 3

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Balance Sheets

(In millions)	December 31, 2015	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 5,690	$ 879
Accounts receivable, net		
Other accounts receivable	272	209
Accounts receivable from affiliates	20	24
Notes receivable from affiliates	1,478	818
Regulatory assets	241	254
Other	5	22
Total current assets	7,706	2,206
Property, plant and equipment, net	53	54
Deferred debits and other assets		
Regulatory assets	3,072	3,186
Investments in affiliates	26,119	26,670
Deferred income taxes	2,036	2,147
Non-pension postretirement benefit asset	108	—
Notes receivable from affiliates	933	943
Other	404	149
Total deferred debits and other assets	32,672	33,095
Total assets	$40,431	$35,355

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Balance Sheets

(In millions)	December 31, 2015	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 188	$ —
Long-term debt due within one year	60	1,409
Accounts payable	5	2
Accrued expenses	440	25
Regulatory liabilities	63	51
Pension obligations	52	45
Other	1	30
Total current liabilities	809	1,562
Long-term debt	6,017	2,818
Long-term debt to affiliate	—	182
Deferred credits and other liabilities		
Regulatory liabilities	31	37
Pension obligations	7,520	7,638
Non-pension postretirement benefit obligations	—	16
Deferred income taxes	134	93
Other	122	398
Total deferred credits and other liabilities	7,807	8,182
Total liabilities	14,633	12,744
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2000 shares authorized, 920 shares and 860 shares outstanding at December 31, 2015 and 2014, respectively)	18,678	16,709
Treasury stock, at cost (35 shares at December 31, 2015 and 2014, respectively)	(2,327)	(2,327)
Retained earnings	12,068	10,910
Accumulated other comprehensive loss, net	(2,624)	(2,684)
Total shareholders' equity	25,795	22,608
BGE preference stock not subject to mandatory redemption	3	3
Total liabilities and shareholders' equity	$40,431	$35,355

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

1. Basis of Presentation

Exelon Corporate is a holding company that conducts substantially all of its business operations through its subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of Exelon Corporation.

Exelon Corporate owns 100% of all of its significant subsidiaries, either directly or indirectly, except for Commonwealth Edison Company (ComEd), of which Exelon Corporate owns more than 99%, and BGE, of which Exelon owns 100% of the common stock but none of BGE's preferred stock. Exelon owned none of PECO's preference securities, which PECO redeemed in 2013.

2. Mergers

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the Merger Agreement with PHI.

For BGE's debt, the difference between fair value and book value of BGE's assets acquired and liabilities assumed is recorded as a regulatory asset at Exelon Corporate as Exelon did not apply push-down accounting to BGE as part of the 2012 Constellation Merger. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the fair value of BGE long-term debt regulatory asset.

3. Debt and Credit Agreements

Short-Term Borrowings

Exelon Corporate meets its short-term liquidity requirements primarily through the issuance of commercial paper. Exelon Corporate had no commercial paper borrowings at both December 31, 2015 and December 31, 2014.

Credit Agreements

On May 30, 2014, Exelon Corporate amended and extended its unsecured syndicated revolving credit facility with aggregate bank commitments of $500 million through May 2019. As of December 31, 2015, Exelon Corporation had available capacity under those commitments of $474 million. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon Corporation's credit agreement.

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

Long-Term Debt

The following tables present the outstanding long-term debt for Exelon Corporate as of December 31, 2015 and December 31, 2014:

	Rates	Maturity Date	December 31, 2015	December 31, 2014
Long-term debt				
Junior subordinated notes	6.5%	2024	$1,150	$ 1,150
Contract payment—junior subordinated notes	2.5%	2017	64	108
Senior unsecured notes [(a)]	1.6% – 7.6%	2017-2045	4,639	2,658
Total long-term debt			5,853	3,916
Unamortized debt discount and premium, net			(4)	1
Unamortized debt issuance costs			(47)	(23)
Fair value adjustment of consolidated subsidiary			275	333
Long-term debt due within one year			(60)	(1,409)
Long-term debt			$6,017	$ 2,818

(a) Senior unsecured notes include mirror debt that is held on both Generation and Exelon Corporation's balance sheets.

The debt maturities for Exelon Corporate for the periods 2016, 2017, 2018, 2019, 2020 and thereafter are as follows:

2016	$ 45
2017	569
2018	—
2019	—
2020	1,450
Remaining years	3,789
Total long-term debt	$5,853

4. Commitments and Contingencies

See Note 23—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's commitments and contingencies related to environmental matters and fund transfer restrictions.

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

5. Related Party Transactions

The financial statements of Exelon Corporate include related party transactions as presented in the tables below:

(In millions)	For the Years Ended December 31, 2015	2014	2013
Operating and maintenance from affiliates:			
BSC [a]	$ 43	$ 38	$ 34
Interest income from affiliates, net:			
Generation	$ 43	$ 53	$ 36
Equity in earnings of investments:			
Exelon Energy Delivery Company, LLC [b]	$1,079	$ 958	$ 834
Exelon Ventures Company, LLC [c]	—	926	1,076
UII, LLC	20	(6)	(2)
Exelon Transmission Company, LLC	(8)	(7)	(5)
Exelon Enterprise	(1)	(1)	—
Generation	1,371	(91)	—
Total equity in earnings of investments	$2,461	$1,779	$1,903
Cash contributions received from affiliates	$3,209	$1,370	$1,175

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

(in millions)	December 31, 2015	December 31, 2014
Accounts receivable from affiliates (current):		
BSC [a]	$ —	$ 2
Generation	16	12
ComEd	2	3
PECO	1	2
BGE	1	5
Total accounts receivable from affiliates (current)	$ 20	$ 24
Notes receivable from affiliates (current):		
BSC [a]	$ 226	$ 262
Generation [d]	1,252	556
Total receivable from affiliates (current):	$ 1,478	$ 818
Investments in affiliates:		
BSC [a]	$ 191	$ 193
Exelon Energy Delivery Company, LLC [b]	14,163	13,590
UII, LLC	102	130
Exelon Transmission Company, LLC	3	1
Voluntary Employee Beneficiary Association trust	7	9
Exelon Enterprises	22	23
Generation	11,637	12,720
Other	(6)	4
Total investments in affiliates	$26,119	$26,670
Notes receivable from affiliates (non-current):		
Generation [d]	$ 933	$ 943
Notes payable to affiliates (current):		
ComEd	$ 188	$ —
Long-term debt to affiliates (non-current):		
ComEd	$ —	$ 182

(a) Exelon Corporate receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead.
(b) Exelon Energy Delivery Company, LLC consists of ComEd, PECO and BGE.
(c) Exelon Ventures Company, LLC primarily consisted of Generation and was fully dissolved as of December 31, 2014. Exelon Enterprises, Exelon Generation Company, LLC, and Exelon Consolidations are now directly owned Exelon Corporate investments as of December 31, 2014.
(d) In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-Term Debt to affiliate on Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets.

Exelon Corporation and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2015					
Allowance for uncollectible accounts [a]	$ 311	$ 113	$ 27[b]	$ 167[c]	$ 284
Deferred tax valuation allowance	50	—	(27)	10	13
Reserve for obsolete materials	95	10	2	2	105
For the year ended December 31, 2014					
Allowance for uncollectible accounts [a]	$ 272	$ 175	$ 69[b]	$ 205[c]	$ 311
Deferred tax valuation allowance	13	—	37	—	50
Reserve for obsolete materials	58	5	34	2	95
For the year ended December 31, 2013					
Allowance for uncollectible accounts [a]	$ 293	$ 121	$ 37[b]	$ 179[c]	$ 272
Deferred tax valuation allowance	36	1	—	24	13
Reserve for obsolete materials	53	17	—	12	58

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $8 million, $8 million, and $9 million for the years ended December 31, 2015, 2014, and 2013, respectively.
(b) Includes charges for late payments and non-service receivables.
(c) Write-off of individual accounts receivable.

Exelon Generation Company, LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Generation

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 10, 2016 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2015, 2014 and 2013

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2015, 2014 and 2013

   Consolidated Balance Sheets at December 31, 2015 and 2014

   Consolidated Statements of Changes in Member's Equity for the Years Ended December 31, 2015, 2014 and 2013

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Exelon Generation Company, LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 60	$ 22	$ —	$ 5	$ 77
Deferred tax valuation allowance	48	—	(27)	10	11
Reserve for obsolete materials	93	9	—	—	102
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 57	$ 14	$ 8	$ 19	$ 60
Deferred tax valuation allowance	11	—	37	—	48
Reserve for obsolete materials	55	5	32	(1)	93
For the year ended December 31, 2013					
Allowance for uncollectible accounts	$ 84	$ (16)	$ —	$ 11	$ 57
Deferred tax valuation allowance	35	1	—	25	11
Reserve for obsolete materials	50	16	—	11	55

Commonwealth Edison Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

ComEd

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 10, 2016 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2015, 2014 and 2013

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2015, 2014 and 2013

   Consolidated Balance Sheets at December 31, 2015 and 2014

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2015, 2014 and 2013

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Commonwealth Edison Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 84	$ 39	$ 18[a]	$ 66[b]	$ 75
Reserve for obsolete materials	2	1	2	2	3
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 62	$ 45	$ 33[a]	$ 56[b]	$ 84
Reserve for obsolete materials	2	—	2	2	2
For the year ended December 31, 2013					
Allowance for uncollectible accounts	$ 70	$ 33	$ 29[a]	$ 70[b]	$ 62
Reserve for obsolete materials	2	1	—	1	2

(a) Primarily charges for late payments and non-service receivables.
(b) Write-off of individual accounts receivable.

PECO Energy Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

PECO

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 10, 2016 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2015, 2014 and 2013

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2015, 2014 and 2013

   Consolidated Balance Sheets at December 31, 2015 and 2014

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2015, 2014 and 2013

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

PECO Energy Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2015					
Allowance for uncollectible accounts [a]	$ 100	$ 37	$ 9[b]	$ 63[c]	$ 83
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2014					
Allowance for uncollectible accounts [a]	$ 107	$ 52	$ 11[b]	$ 70[c]	$ 100
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2013					
Allowance for uncollectible accounts [a]	$ 99	$ 61	$ 7[b]	$ 60[c]	$ 107
Reserve for obsolete materials	1	—	—	—	1

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $8 million, $8 million, and $9 million for the years ended December 31, 2015, 2014, and 2013, respectively.
(b) Primarily charges for late payments.
(c) Write-off of individual accounts receivable.

Baltimore Gas and Electric Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

BGE

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 10, 2016 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2015, 2014 and 2013

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2015, 2014 and 2013

   Consolidated Balance Sheets at December 31, 2015 and 2014

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2015, 2014 and 2013

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Baltimore Gas and Electric Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 67	$ 15	$ — (b)	$ 33(a)	$ 49
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	—	—	—	—	—
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 46	$ 64	$ 17(b)	$ 60(a)	$ 67
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	1	—	—	1	—
For the year ended December 31, 2013					
Allowance for uncollectible accounts	$ 40	$ 43	$ 1	$ 38(a)	$ 46
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	1	—	—	—	1

(a) Write-off of individual accounts receivable.
(b) Primarily charges for late payments.

Exhibits required by Item 601 of Regulation S-K:

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
2-1	Agreement and Plan of Merger dated as of April 28, 2011 by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc. (File No. 001-16169, Form 8-K dated April 28, 2011, Exhibit No. 2-1).
2-2	Distribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Constellation Energy Group, Inc. and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-3).
2-3	Contribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Energy Delivery Company, LLC and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-4).
2-4	Contribution Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Ventures Company, LLC and Exelon Generation Company, LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-5).
2-5	Purchase Agreement dated as of August 8, 2012 by and between Constellation Power Source Generation, Inc. and Raven Power Holdings, LLC. (File No. 333-85496, Form 10-Q for the quarter ended September 30, 2012, Exhibit 2-1).
2-6	Master Agreement, dated as of October 26, 2010, by and between Electricite de France, S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 1, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
2-7	Put Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., Constellation Nuclear, LLC, and Constellation Energy Nuclear Group, LLC. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 8, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
2-8	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., Baltimore Gas and Electric Company and RF HoldCo LLC. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
2-9	Purchase Agreement, dated as of February 4, 2010, by and between RF HoldCo LLC and GSS Holdings (Baltimore Gas and Electric Company Utility), Inc. (Designated as Exhibit No. 99.3 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
2-10-1	Agreement and Plan of Merger, dated as of April 29, 2014, by and among Exelon Corporation, Pepco Holdings, Inc. and Purple Acquisition Corp. (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit 2.1).
2-10-2	Amended and Restated Agreement and Plan of Merger, dated as of July 18, 2014, among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp. (File No. 001-16169, Form 8-K dated July 21, 2014, Exhibit 2.1).

Exhibit No.	Description
2-10-3	Subscription Agreement for Series A Non-Voting Non-Convertible Preferred Stock, dated as of April 29, 2014, by and between Pepco Holdings, Inc. and Exelon Corporation (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit 2.2).
3-1	Amended and Restated Articles of Incorporation of Exelon Corporation, as amended May 8, 2007 (File No. 001-16169, Form 10-Q for the quarter ended September 30, 2008, Exhibit 3-1-2).
3-2	Exelon Corporation Amended and Restated Bylaws, effective as of March 12, 2012 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit 3-1).
3-3	Certificate of Formation of Exelon Generation Company, LLC (Registration Statement No. 333-85496, Form S-4, Exhibit 3-1).
3-4	First Amended and Restated Operating Agreement of Exelon Generation Company, LLC executed as of January 1, 2001 (File No. 333-85496, 2003 Form 10-K, Exhibit 3-8).
3-5	Restated Articles of Incorporation of Commonwealth Edison Company Effective February 20, 1985, including Statements of Resolution Establishing Series, relating to the establishment of three new series of Commonwealth Edison Company preference stock known as the “$9.00 Cumulative Preference Stock,” the “$6.875 Cumulative Preference Stock” and the “$2.425 Cumulative Preference Stock” (File No. 1-1839, 1994 Form 10-K, Exhibit 3-2).
3-6	Commonwealth Edison Company Amended and Restated By-Laws, Effective January 23, 2006 As Further Amended January 28, 2008 and July 27, 2009. (File No. 001-1839, Form 8-K dated July 27, 2009, Exhibit 3.1).
3-7	Amended and Restated Articles of Incorporation of PECO Energy Company (File No. 1-01401, 2000 Form 10-K, Exhibit 3-3).
3-8	PECO Energy Company Amended Bylaws (File 000-16844, Form 8-K dated May 6, 2009, Exhibit 99.1).
3-9	Articles of Amendment to the Charter of Baltimore Gas and Electric Company as of February 2, 2010. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File No. 1-1910).
3-10	Articles of Restatement to the Charter of Baltimore Gas and Electric Company, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, filed by Baltimore Gas and Electric Company, File No. 1-1910).
3-11	Bylaws of Baltimore Gas and Electric Company, as amended and restated as of May 10, 2012. (File No. 1-16169, 2013 Form 10-K, Exhibit 3-11).
3-12	Operating Agreement, dated as of February 4, 2010, by and among RF HoldCo LLC, Constellation Energy Group, Inc. and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File Nos. 1-12869 and 1-1910).
4-1	First and Refunding Mortgage dated May 1, 1923 between The Counties Gas and Electric Company (predecessor to PECO Energy Company) and Fidelity Trust Company, Trustee (U.S. Bank National Association, as current successor trustee), (Registration No. 2-2281, Exhibit B-1).
4-1-2	Reserved.

Exhibit No.	Description
4-1-3	Supplemental Indentures to PECO Energy Company's First and Refunding Mortgage:

Dated as of	File Reference	Exhibit No.
May 1, 1927	2-2881	B-1(c)
March 1, 1937	2-2881	B-1(g)
December 1, 1941	2-4863	B-1(h)
November 1, 1944	2-5472	B-1(i)
December 1, 1946	2-6821	7-1(j)
September 1, 1957	2-13562	2(b)-17
May 1, 1958	2-14020	2(b)-18
March 1, 1968	2-34051	2(b)-24
March 1, 1981	2-72802	4-46
March 1, 1981	2-72802	4-47
December 1, 1984	1-01401, 1984 Form 10-K	4-2(b)
March 1, 1993	1-01401, 1992 Form 10-K	4(e)-86
May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-88
May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-89
April 15, 2004	0-6844, September 30, 2004 Form 10-Q	4-1-1
September 15, 2006	000-16844, Form 8-K dated September 25, 2006	4.1
March 1, 2007	000-16844, Form 8-K dated March 19, 2007	4.1
March 15, 2009	000-16844, Form 8-K dated March 26, 2009	4.1
September 1, 2012	000-16844, Form 8-K dated September 17, 2012	4.1
September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1
September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1
September 1, 2014	000-16169, Form 8-K dated September 15, 2014	4.1
September 15, 2015	000-16844, Form 8-K dated October 5, 2015	4.1

4-2	Exelon Corporation Direct Stock Purchase Plan (Registration Statement No. 333-206474, Form S-3, Prospectus).
4-3	Mortgage of Commonwealth Edison Company to Illinois Merchants Trust Company, Trustee (BNY Mellon Trust Company of Illinois, as current successor Trustee), dated July 1, 1923, as supplemented and amended by Supplemental Indenture thereto dated August 1, 1944. (Registration No. 2-60201, Form S-7, Exhibit 2-1).

Exhibit No.	Description
4-3-1	Supplemental Indentures to Commonwealth Edison Company Mortgage.

Dated as of	File Reference	Exhibit No.
August 1, 1946	2-60201, Form S-7	2-1
April 1, 1953	2-60201, Form S-7	2-1
March 31, 1967	2-60201, Form S-7	2-1
April 1, 1967	2-60201, Form S-7	2-1
February 28, 1969	2-60201, Form S-7	2-1
May 29, 1970	2-60201, Form S-7	2-1
June 1, 1971	2-60201, Form S-7	2-1
April 1, 1972	2-60201, Form S-7	2-1
May 31, 1972	2-60201, Form S-7	2-1
June 15, 1973	2-60201, Form S-7	2-1
May 31, 1974	2-60201, Form S-7	2-1
June 13, 1975	2-60201, Form S-7	2-1
May 28, 1976	2-60201, Form S-7	2-1
June 3, 1977	2-60201, Form S-7	2-1
May 17, 1978	2-99665, Form S-3	4-3
August 31, 1978	2-99665, Form S-3	4-3
June 18, 1979	2-99665, Form S-3	4-3
June 20, 1980	2-99665, Form S-3	4-3
April 16, 1981	2-99665, Form S-3	4-3
April 30, 1982	2-99665, Form S-3	4-3
April 15, 1983	2-99665, Form S-3	4-3
April 13, 1984	2-99665, Form S-3	4-3
April 15, 1985	2-99665, Form S-3	4-3
April 15, 1986	33-6879, Form S-3	4-9
January 13, 2003	001-01839, Form 8-K dated January 22, 2003	4-4
February 22, 2006	001-01839, Form 8-K dated March 6, 2006	4.1
August 1, 2006	001-01839, Form 8-K dated August 28, 2006	4.1
September 15, 2006	001-01839, Form 8-K dated October 2, 2006	4.1
March 1, 2007	001-01839, Form 8-K dated March 23, 2007	4.1
August 30, 2007	001-01839, Form 8-K dated September 10, 2007	4.1
December 20, 2007	001-01839, Form 8-K dated January 16, 2008	4.1

Dated as of	File Reference	Exhibit No.
March 10, 2008	001-01839, Form 8-K dated March 27, 2008	4.1
July 12, 2010	001-01839, Form 8-K dated August 2, 2010	4.1
August 22, 2011	001-01839, Form 8-K dated September 7, 2011	4.1
September 17, 2012	001-01839, Form 8-K dated October 1, 2012	4.1
August 1, 2013	001-01839, Form 8-K dated August 19, 2013	4.1
January 2, 2014	001-01839, Form 8-K dated January 10, 2014	4.1
October 28, 2014	001-01839, Form 8-K dated November 10, 2014	4.1
February 18, 2015	001-01839, Form 8-K dated March 2, 2015	4.1
November 4, 2015	001-01839, Form 8-K dated November 19, 2015	4.1

Exhibit No.	Description
4-3-2	Instrument of Resignation, Appointment and Acceptance dated as of February 20, 2002, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923, and Indentures Supplemental thereto, regarding corporate trustee (File No. 1-1839, 2001 Form 10-K, Exhibit 4-4-2).
4-3-3	Instrument dated as of January 31, 1996, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923 and Indentures Supplemental thereto, regarding individual trustee (File No. 1-1839, 1995 Form 10-K, Exhibit 4-29).
4-4	Indenture dated as of September 1, 1987 between Commonwealth Edison Company and Citibank, N.A. (U.S. Bank National Association, as current successor trustee), Trustee relating to Notes (Registration No. 33-20619, Form S-3, Exhibit 4-13).
4-5	Indenture dated December 19, 2003 between Exelon Generation Company, LLC and U.S. Bank National Association (File No. 333-85496, 2003 Form 10-K, Exhibit 4-6).
4-6	Indenture to Subordinated Debt Securities dated as of June 24, 2003 between PECO Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.1).
4-7	Form of 4.25% Senior Note due 2022 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.1).
4-8	Form of 5.60% Senior Note due 2042 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.2).
4-9	Form of 2.80% Senior Note due 2022 issued by Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated August 17, 2012, Exhibit 4.1).
4-10	Form of 3.35% Senior Note due 2023 Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated June 17, 2013, Exhibit 4.1).
4-11	Form of 6.000% Senior Secured Notes due 2033 issued by Exelon Generation Company, LLC (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.2).

Exhibit No.	Description
4-12	Preferred Securities Guarantee Agreement between PECO Energy Company, as Guarantor, and U.S. Bank National Association, as Trustee, dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.2).
4-13	PECO Energy Capital Trust IV Amended and Restated Declaration of Trust among PECO Energy Company, as Sponsor, U.S. Bank Trust National Association, as Delaware Trustee and Property Trustee, and J. Barry Mitchell, George R. Shicora and Charles S. Walls as Administrative Trustees dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.3).
4-14	Indenture dated May 1, 2001 between Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 1-16169, June 30, 2005 Form 10-Q, Exhibit 4-10).
4-15	Form of $500,000,000 5.625% senior notes due 2035 dated June 9, 2005 issued by Exelon Corporation (File No. 1-16169, Form 8-K dated June 9, 2005, Exhibit 99.3).
4-16	Indenture dated as of September 28, 2007 from Exelon Generation Company, LLC to U.S. Bank National Association, as trustee (File 333-85496, Form 8-K dated September 28, 2007, Exhibit 4.1).
4-17	Form of 5.20% Exelon Generation Company, LLC Senior Note due 2019 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.1).
4-18	Form of 6.25% Exelon Generation Company, LLC Senior Note due 2039 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.2).
4-19	Form of 4.00% Exelon Generation Company, LLC Senior Note due 2020 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.1).
4-20	Form of 5.75% Exelon Generation Company, LLC Senior Note due 2041 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.2).
4-21	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, filed by Constellation Energy Group, Inc., File No. 333-75217.)
4-22	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, filed by Constellation Energy Group, Inc., File No. 333-102723).
4-23	Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991).
4-24	First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (Designated as Exhibit 4(a) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869).
4-25	Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
4-26	Indenture, dated as of September 30, 2013, among Continental Wind, LLC, the guarantors party thereto and Wilmington Trust, National Association, as trustee (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.1).

Exhibit No.	Description
4-27	Indenture dated July 1, 1985, between Baltimore Gas and Electric Company and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, filed by Baltimore Gas and Electric Company, File No. 1-1910).
4-28	Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee (including form of Baltimore Gas and Electric Company Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibit Nos. 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01).
4-29	Indenture dated as of July 24, 2006 between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(b) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991).
4-30	Supplemental Indenture No. 1, dated as of October 1, 2009, to the Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
4-31	Baltimore Gas and Electric Company Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit No. 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01).
4-32	Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (Designated as Exhibit 4.1 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).
4-33	Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (Designated as Exhibit No. 4(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Baltimore Gas and Electric Company, File No. 1 1910).
4-34	Replacement Capital Covenant dated June 27, 2008. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869).
4-35	Amendment to Replacement Capital Covenant, dated as of March 12, 2012, amending the Replacement Capital Covenant, dated as of June 27, 2008 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 99.4).
4-36	Officers' Certificate, dated December 14, 2010, establishing the 5.15% Notes due December 1, 2020 of Constellation Energy Group, Inc., with the form of Notes attached thereto. (Designated as Exhibit No. 4 (b) to the Current Report on Form 8-K dated December 14, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).

Exhibit No.	Description
4-37	Officers' Certificate, November 16, 2011, establishing the 3.50% Notes due November 15, 2021 of Baltimore Gas and Electric Company, with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated November 16, 2011, filed by Baltimore Gas and Electric Company, File No. 1-1910).
4-38-1	Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee. (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.1).
4-38-2	First Supplemental Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee.(File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.2).
4-38-3	Form of 2.50% Notes due 2024 (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.1).
4-38-4	Purchase Contract and Pledge Agreement, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary. (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.4).
4-38-5	Form of Remarketing Agreement (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.5).
4-38-6	Form of Corporate Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.6).
4-38-7	Form of Treasury Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.7).
4-39-1	Indenture, dated as of June 11, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Exelon Corporation's Current Report on Form 8-K, filed on June 11, 2015).
4-39-2	First Supplemental Indenture, dated as of June 11, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to Exelon Corporation's Current Report on Form 8-K, filed on June 11, 2015).
4-39-3	Second Supplemental Indenture, dated as of December 2, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Exelon Corporation's Current Report on Form 8-K, filed on December 2, 2015).
4-39-4	Registration Rights Agreement, dated as of December 2, 2015, among Exelon Corporation, Barclays Capital Inc. and Goldman, Sachs & Co. (incorporated herein by reference to Exhibit 1.1 to Exelon Corporation's Current Report on Form 8-K, filed on December 2, 2015).
10-1	Facility Credit Agreement, dated as of February 6, 2014, among ExGen Renewables I Holding, LLC and Barclays Bank PLC (File No. 333-85496, Form 8-K dated February 12, 2014, Exhibit 10.1).
10-1-1	Credit Agreement, dated as of September 18, 2014, among ExGen Texas Power, LLC, ExGen Texas Power Holdings, LLC, Wolf Hollow I Power, LLC, Colorado Bend I Power, LLC, Laporte Power, LLC, Handley Power, LLC and Mountain Creek Power, LLC, the lenders party thereto from time to time, Bank of America, N.A., as administrative agent and collateral agent, and Wilmington Trust, National Association, as depositary agent. (File No. 1-16169, Form 8-K dated September 18, 2014, Exhibit 10.1).
10-2	Exelon Corporation Non-Employee Directors' Deferred Stock Unit Plan (As Amended and Restated Effective January 1, 2011). * (File No. 001-16169, 2010 Form 10-K, Exhibit 10.1).

Exhibit No.	Description
10-3	Form of Exelon Corporation Unfunded Deferred Compensation Plan for Directors (as amended and restated Effective March 12, 2012). *
10-4	Reserved.
10-5	Form of Restricted Stock Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-1).
10-6	Forms of Transferable Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-2).
10-7	Forms of Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-3).
10-8	Unicom Corporation Deferred Compensation Unit Plan, as amended *(File Nos. 1-11375 and 1-1839, 1995 Form 10-K, Exhibit 10-12).
10-9	Amendment Number One to the Unicom Corporation Deferred Compensation Unit Plan, as amended January 1, 2008 * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.16).
10-10	Unicom Corporation Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-12).
10-11	Commonwealth Edison Company Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-13).
10-12	Exelon Corporation Supplemental Management Retirement Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.19).
10-13	PECO Energy Company Supplemental Pension Benefit Plan (As Amended and Restated Effective January 1, 2009) (File No. 000-16844, 2008 Form 10-K, Exhibit 10.20).
10-14	Exelon Corporation Annual Incentive Plan for Senior Executives (As Amended Effective January 1, 2014 * (File No. 1-16169, Exelon Proxy Statement dated April 1, 2014, Appendix A).
10-15	Form of change in control employment agreement for senior executives effective January 1, 2009 * (File No. 001-16169. 2008 Form 10-K, Exhibit 10.23).
10-16	Form of change in control employment agreement (amended and restated as of January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.24).
10-17	Exelon Corporation Employee Stock Purchase Plan, as amended and restated effective July 1, 2013. (File No. 1-16169, Schedule 14A dated March 14, 2013 Appendix A).
10-18	Exelon Corporation 2006 Long-Term Incentive Plan (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex H).
10-19	Form of Stock Option Grant Instrument under the Exelon Corporation 2006 Long-Term Incentive Plan (File No. 1-16169, Form 8-K filed January 27, 2006, Exhibit 99.2).
10-20	Exelon Corporation Employee Stock Purchase Plan for Unincorporated Subsidiaries (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex I).
10-21	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective April 1, 2013).* (File No. 001-16169, 2013 Form 10-K, Exhibit 10.21).
10-21-1	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective November 1, 2015)

Exhibit No.	Description
10-22	Form of Separation Agreement under Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.30).
10-23	Facility Credit Agreement, dated as of November 4, 2010, among Exelon Generation Company, LLC and UBS AG, Stamford Branch (File No. 333-85496, Form 8-K dated February 22, 2011, Exhibit No. 10-1).
10-24	Exelon Corporation Executive Death Benefits Plan dated as of January 1, 2003 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-52).
10-25	First Amendment to Exelon Corporation Executive Death Benefits Plan, Effective January 1, 2006 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-53).
10-26	Amendment Number One to the Exelon Corporation 2006 Long-Term Incentive Plan, Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-54).
10-27	Amendment Number Two to the Exelon Corporation 2006 Long-Term Incentive Plan (As Amended and Restated Effective January 28, 2002), Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-55).
10-28	Exelon Corporation Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-56).
10-29	Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-57).
10-30	Commonwealth Edison Company Long-Term Incentive Plan, Effective January 1, 2007 (File No. 1-16169, March 31, 2007 Form 10-Q, Exhibit 10-1).
10-31	Amendment Number One to the Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, June 30, 2007 Form 10-Q, Exhibit 10-3).
10-32	Restricted stock unit award agreement (File 1-16169, Form 8-K dated August 31, 2007, Exhibit 99.1).
10-33	Reserved.
10-34	Form of Exelon Corporation 2011 Long-Term Incentive Plan, as amended effective December 18, 2014.
10-34-1	Form of Exelon Corporation Long-Term Incentive Program, as amended and restated as of January 1, 2014.
10-34-2	Form of Exelon Corporation Long-Term Incentive Program, as amended and restated as of January 1, 2015.
10-34-3	Amendment Number Two to the Exelon Corporation 2011 Long-Term Incentive Plan (As Amended and Restated Effective January 21, 2014), Effective October 26, 2015.
10-35	Form of Change in Control Employment Agreement Effective February 10, 2011. * (File 1-16169, 2011 Form 10-K, Exhibit 10-44).
10-36	Credit Agreement for $500,000,000 dated as of March 23, 2011 between Exelon Corporation and Various Financial Institutions (File No. 001-16169, Form 8-K dated March 23, 2011, Exhibit No. 10-2).
10-37	Credit Agreement for $5,300,000,000 dated as of March 23, 2011 between Exelon Generation Company, LLC and Various Financial Institutions (File No. 333-85496, Form 8-K dated March 23, 2011, Exhibit No. 10-3).
10-38	Credit Agreement for $600,000,000 dated as of March 23, 2011 between PECO Energy Company and Various Financial Institutions (File No. 000-16844, Form 8-K dated March 23, 2011, Exhibit No. 10-4).

Exhibit No.	Description
10-39	Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, Various Financial Institutions, as Lenders, and JP Morgan Chase Bank, N.A., as Administrative Agent (File No. 001-01839, Form 8-K dated March 28, 2012, Exhibit No. 99-1).
10-40	Amendment No. 3 to Credit Agreement dated as of March 23, 2011 among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated August 10, 2013, Exhibit No. 99-1).
10-41	Amendment No. 1 to Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, as Borrower, the various financial institutions named therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-1839, Form 8-K dated August 10, 2013, Exhibit No. 99-2).
10-42	Amendment No. 1 to Credit Agreement, dated as of December 21, 2011, to the Credit Agreement dated as of March 23, 2011, among Exelon Generation Company, LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 4-6).
10-43	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-44	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. * (Designated as Exhibit No. 10(c) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-45	Constellation Energy Group, Inc. Benefits Restoration Plan, amended and restated effective June 1, 2010. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-46	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. * (Designated as Exhibit No. 10(e) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-47	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. * (Designated as Exhibit No. 10(f) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-48	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. * (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-49	Constellation Energy Group, Inc. Executive Supplemental Benefits Plan, as amended and restated. * (Designated as Exhibit No. 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-50	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).

Exhibit No.	Description
10-51	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-52	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-53	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(d) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-54	Constellation Energy Group, Inc. Amended and Restated 2007 Long-Term Incentive Plan. * (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated June 4, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-55	Form of Grant Agreement for Stock Units with Sales Restriction. * (Designated as Exhibit No. 10(x) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-56	Rate Stabilization Property Servicing Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as servicer (Designated as Exhibit 10.2 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).
10-57	Administration Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as administrator (Designated as Exhibit 10.3 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).
10-58	Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 12, 2009, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-59	Amendment No. 1 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(s) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-60	Amendment No. 2 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(t) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-61	Amendment No. 3 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).

Exhibit No.	Description
10-62	Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-63	Settlement Agreement between EDF Inc., Exelon Corporation, Exelon Energy Delivery Company, LLC, Constellation Energy Group, Inc. and Baltimore Gas and Electric Company dated January 16, 2012. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated January 19, 2012, File Nos. 1-12869 and 1-1910).
10-64-10-70	Reserved.
10-71-1	Commitment Letter for $7.221 Billion Senior Unsecured Bridge Facility, dated April 29, 2014 (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit No. 10.1).
10-71-2	364-Day Bridge Term Loan Agreement, dated as of May 30, 2014, among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and Barclays Bank PLC, as Administrative Agent (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit No. 10.1).
10-71-3	Amendment No. 4 to Credit Agreement, dated May 30, 2014, among Exelon Corporation, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.2).
10-71-4	Amendment No. 4 to Credit Agreement, dated May 30, 2014, among Exelon Generation Company, LLC, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.3).
10-71-5	Amendment No. 3 to Credit Agreement, dated May 30, 2014, among PECO Energy Company, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.4).
10-71-6	Amendment No. 2 to Credit Agreement, dated as of May 30, 2014, among Baltimore Gas and Electric Company, as Borrower, the financial institutions signatory therein, as Lenders and The Royal Bank of Scotland plc, as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.6).
10-72-1	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Barclays Capital, Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.1).
10-72-2	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.2).
10-72-3	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Barclays Capital, Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.3).
10-72-4	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.4).
12-1	Exelon Corporation Computation of Ratio of Earnings to Fixed Charges.
12-2	Exelon Generation Company, LLC Computation of Ratio of Earnings to Fixed Charges.
12-3	Commonwealth Edison Company Computation of Ratio of Earnings to Fixed Charges.

Exhibit No.	Description
12-4	PECO Energy Company Computation of Ratio of Earnings to Fixed Charges.
12-5	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preference Stock Dividends.
14	Exelon Code of Conduct, as amended March 12, 2012 (File No. 1-16169, Form 8-K dated March 14, 2012, Exhibit No. 14-1).
	Subsidiaries
21-1	Exelon Corporation
21-2	Exelon Generation Company, LLC
21-3	Commonwealth Edison Company
21-4	PECO Energy Company
21-5	Baltimore Gas and Electric Company
	Consent of Independent Registered Public Accountants
23-1	Exelon Corporation
23-2	Exelon Generation Company, LLC
23-3	Commonwealth Edison Company
23-4	PECO Energy Company
23-5	Baltimore Gas and Electric Company
	Power of Attorney (Exelon Corporation)
24-1	Anthony K. Anderson
24-2	Ann C. Berzin
24-3	John A. Canning, Jr.
24-4	Christopher M. Crane
24-5	Yves C. de Balmann
24-6	Nicholas DeBenedictis
24-7	Paul L. Joskow
24-8	Linda P. Jojo
24-9	Robert J. Lawless
24-10	Richard W. Mies
24-11	John W. Rogers, Jr.
24-12	Mayo A. Shattuck III
24-13	Stephen D. Steinour
	Power of Attorney (Commonwealth Edison Company)
24-14	James W. Compton
24-15	Christopher M. Crane
24-16	A. Steven Crown
24-17	Nicholas DeBenedictis
24-18	Peter V. Fazio, Jr.
24-19	Michael Moskow
24-20	Denis P. O'Brien

Exhibit No.	Description
24-21	Anne R. Pramaggiore
24-22	Reserved.
	Power of Attorney (PECO Energy Company)
24-23	Craig L. Adams
24-24	Christopher M. Crane
24-25	M. Walter D'Alessio
24-26	Nicholas DeBenedictis
24-27	Nelson A. Diaz
24-28	Rosemarie B. Greco
24-29	Charisse R. Lillie
24-30	Denis P. O'Brien
24-31	Ronald Rubin
	Power of Attorney (Baltimore Gas and Electric Company)
24-32	Ann C. Berzin
24-33	Christopher M. Crane
24-34	Michael E. Cryor
24-35	James R. Curtiss
24-36	Calvin G. Butler, Jr.
24-37	Joseph Haskins, Jr.
24-38	Carla D. Hayden
24-39	Denis P. O'Brien
24-40	Michael D. Sullivan
	Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Annual Report on Form 10-K for the year ended December 31, 2013 filed by the following officers for the following registrants:
31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Jonathan W. Thayer for Exelon Corporation
31-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	Filed by Craig L. Adams for PECO Energy Company
31-8	Filed by Phillip S. Barnett for PECO Energy Company
31-9	Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
31-10	Filed by David M. Vahos Baltimore Gas and Electric Company
	Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Annual Report on Form 10-K for the year ended December 31, 2013 filed by the following officers for the following registrants:
32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Jonathan W. Thayer for Exelon Corporation
32-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC

Exhibit No.	Description
32-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	Filed by Craig L. Adams for PECO Energy Company
32-8	Filed by Phillip S. Barnett for PECO Energy Company
32-9	Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
32-10	Filed by David M. Vahos Baltimore Gas and Electric Company
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

* Compensatory plan or arrangements in which directors or officers of the applicable registrant participate and which are not available to all employees.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 10th day of February, 2016.

EXELON CORPORATION

By: /S/ CHRISTOPHER M. CRANE
Name: **Christopher M. Crane**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 10th day of February, 2016.

Signature	Title
/S/ CHRISTOPHER M. CRANE **Christopher M. Crane**	President and Chief Executive Officer (Principal Executive Officer) and Director
/S/ JOHNATHAN W. THAYER **Jonathan W. Thayer**	Senior Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/S/ DUANE M. DESPARTE **Duane M. DesParte**	Senior Vice President and Corporate Controller (Principal Accounting Officer)

This annual report has also been signed below by Darryl M. Bradford, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Anthony K. Anderson
Ann C. Berzin
John A. Canning, Jr.
Yves C. de Balmann
Nicholas DeBenedictis
Paul L. Joskow
Linda P. Jojo
Robert J. Lawless
Richard W. Mies
John W. Rogers, Jr.
Mayo A. Shattuck III
Stephen D. Steinour

By: /S/ DARRYL M. BRADFORD
Name: **Darryl M. Bradford**

February 10, 2016

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 10th day of February, 2016.

EXELON GENERATION COMPANY, LLC

By: /S/ KENNETH W. CORNEW
Name: **Kenneth W. Cornew**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 10th day of February, 2016.

Signature	Title
/S/ KENNETH W. CORNEW **Kenneth W. Cornew**	President and Chief Executive Officer (Principal Executive Officer)
/S/ BRYAN P. WRIGHT **Bryan P. Wright**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/S/ ROBERT M. AIKEN **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 10th day of February, 2016.

COMMONWEALTH EDISON COMPANY

By: /s/ A NNE R. P RAMAGGIORE
Name: **Anne R. Pramaggiore**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 10th day of February, 2016.

Signature	Title
/s/ A NNE R. P RAMAGGIORE **Anne R. Pramaggiore**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ J OSEPH R. T RPIK J R . **Joseph R. Trpik, Jr.**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ G ERALD J. K OZEL **Gerald J. Kozel**	Vice President and Controller (Principal Accounting Officer)
/s/ C HRISTOPHER M. C RANE **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Anne R. Pramaggiore, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

James W. Compton
A. Steven Crown
Nicholas DeBenedictis
Peter V. Fazio, Jr.
Michael Moskow
Denis P. O'Brien

By: /s/ A NNE R. P RAMAGGIORE
Name: **Anne R. Pramaggiore**

February 10, 2016

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 10th day of February, 2016.

PECO ENERGY COMPANY

By: /s/ C RAIG L. A DAMS
Name: **Craig L. Adams**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 10th day of February, 2016.

Signature	Title
/s/ C RAIG L. A DAMS **Craig L. Adams**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ P HILLIP S. B ARNETT **Phillip S. Barnett**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ S COTT A. B AILEY **Scott A. Bailey**	Vice President and Controller (Principal Accounting Officer)
/s/ C HRISTOPHER M. C RANE **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Craig L. Adams, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

M. Walter D'Alessio
Nicholas DeBenedictis
Nelson A. Diaz
Rosemarie B. Greco
Charisse R. Lillie
Denis P. O'Brien
Ronald Rubin

By: /s/ C RAIG L. A DAMS
Name: **Craig L. Adams**

February 10, 2016

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 10th day of February, 2016.

BALTIMORE GAS AND ELECTRIC COMPANY

By: /s/ C ALVIN G. B UTLER , J R .
Name: **Calvin G. Butler, Jr.**
Title: **Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 10th day of February, 2016.

Signature	Title
/s/ C ALVIN G. B UTLER , J R . **Calvin G. Butler, Jr.**	Chief Executive Officer (Principal Executive Officer)
/s/ D AVID M. V AHOS **David M. Vahos**	Vice President, Chief Financial Officer, and Treasurer (Principal Financial Officer)
/s/ M ATTHEW N. B AUER **Matthew N. Bauer**	Vice President and Controller (Principal Accounting Officer)
/s/ C HRISTOPHER M. C RANE **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Calvin G. Butler, Jr., Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Ann C. Berzin
Michael E. Cryor
James R. Curtiss
Michael D. Sullivan
Joseph Haskins, Jr.
Carla D. Hayden
Denis O'Brien

By: /s/ C ALVIN G. B UTLER , J R .
Name: **Calvin G. Butler, Jr.**

February 10, 2016

Exelon Corporation
Unfunded Deferred Compensation Plan for Directors
(Amended and Restated Effective March 12, 2012)

The purpose of this Unfunded Deferred Compensation Plan for Directors (the "Plan") is to permit Directors of Exelon Corporation ("Exelon") to elect to defer receipt of directors' fees. The Plan as set forth herein is an amendment and restatement of the Plan as originally adopted effective October 20, 2000 and previously amended and restated as of January 1, 2009 and January 1, 2011, and is a successor to the PECO Energy Company Unfunded Deferred Compensation Plan for Directors (the "Prior Plan").

1. Administration. The Plan shall be administered by the Corporate Secretary of Exelon or his or her designee (the "Secretary"), or such other individual or individuals as designated by the Board of Directors of Exelon (the "Exelon Board"). The Secretary shall interpret the Plan and establish such rules and regulations of plan administration that he or she deems appropriate. The cost of plan administration shall be paid by Exelon and its participating subsidiaries, and shall not be charged against the deferred accounts of Plan participants.

2. Eligibility. All Directors of Exelon (other than full-time employees of Exelon or its subsidiaries) shall be eligible to participate in the Plan. Effective as of January 1, 2011, all Directors of Commonwealth Edison Company ("ComEd") and PECO Energy Company ("PECO") who are not full-time employees of Exelon or its subsidiaries shall also be eligible to participate in the Plan. In addition, effective as of March 12, 2012, all Directors of Baltimore Gas and Electric Company ("BGE") who are not full-time employees of Exelon or its subsidiaries shall also be eligible to participate in the Plan.

3. Deferrals. (a) Prior to the first day of each calendar year, each eligible Director may elect in writing to defer the receipt of all or a portion of his or her directors' fees

earned with respect to his or her service on the board of directors of Exelon, ComEd, PECO and/or BGE (each such board of directors, a "Board") for such calendar year, by filing a written Director's deferral agreement form with the Secretary with respect to each such Board on which the Director serves. A Director who first becomes eligible to participate in the Plan after the first day of any calendar year shall be permitted to make the election described in this Section 3 not later than 30 days after becoming eligible to participate in the Plan, and such election shall apply only to directors' fees earned during the remainder of such calendar year. In all events, each deferral election made under this Plan shall apply only to fees earned after the date of such election. Deferred amounts under the Plan, together with deferred amounts and attributable earnings under the Prior Plan, shall be credited to a deferral account in the participant's name ("Deferral Account") for later distribution. Each participant's Deferral Account shall be a bookkeeping entry only, and none of Exelon, ComEd, PECO or BGE shall be required to fund the Deferral Account. Any assets that may be held to fund a Deferral Account shall at all times remain unrestricted assets of Exelon, ComEd, PECO or BGE in its corporate capacity and not as a fiduciary, and shall be subject to the claims of its general creditors. Pending distribution, each participant's Deferral Account shall be credited with earnings or interest as provided in Section 3(b).

(b) (1) For purposes of measuring the earnings or losses credited to a participant's Deferral Account, the participant may select, from among the investment funds available from time to time under the Exelon Corporation Employee Savings Plan (the "Savings Plan"), the investment funds in which all or part of his or her Deferral Account shall be deemed to be invested.

(2) The participant shall make an investment designation in the form and manner prescribed by the Secretary, which shall remain effective until another valid

designation has been made by the participant as herein provided. The Secretary may, but need not, permit separate investment designations with respect to amounts attributable to fees earned with respect to service on each Board. The participant may amend his or her investment designation at such times and in such manner as prescribed by the Secretary. A timely change to the participant's investment designation shall become effective as soon as administratively practicable after such designation is submitted.

(3) The investment funds deemed to be made available to the participant, and any limitation on the maximum or minimum percentages of the participant's Deferral Account that may be deemed to be invested in any particular fund, shall be the same as available or in effect from time to time under the Savings Plan.

(4) Except as provided below, the participant's Deferral Account shall be deemed to be invested in accordance with his or her investment designations, and the Deferral Account shall be credited with earnings (or losses) as if invested as directed by the participant.

To the extent that the participant does not furnish complete investment instructions, then the Deferral Account shall be deemed invested in the default investment fund then in effect under the Savings Plan. The Deferral Accounts maintained pursuant to the Plan are for bookkeeping purposes only and Exelon is under no obligation to invest such amounts.

Exelon shall provide a statement to each participant not less frequently than annually showing such information as is appropriate, including the aggregate amount in his or her Deferral Account, as of a reasonably current date.

4. Distributions . (a) The amount credited to a participant's Deferral Account with respect to his or her participation on each Board shall be distributed to the participant in, or beginning in, April of the first year beginning after the occurrence of one of the following

distribution events, as the participant shall direct in his or her Benefit Distribution Election Form: (i) the participant's separation from service, within the meaning of Section 409A of the Internal Revenue Code of 1986, as amended (the "Code"), as a Director of Exelon, ComEd, PECO, BGE and their affiliates, (ii) the participant's 65th birthday or (iii) the participant's 72 nd birthday. Distributions shall be paid in a lump sum payment or in annual installments over a period of up to 10 years, as the participant shall direct in his or her Benefit Distribution Election Form. Each installment payment shall be determined by multiplying the balance remaining to the credit of the Deferral Account as of March 31 of such year (including earnings or interest credited under Section 3) by a fraction, the numerator of which is "1" and the denominator of which is the number of years (including the current year) for which payments are yet to be made. Any unpaid balance in the Deferral Account shall be credited with earnings or interest as provided in Section 3. In the event a Director who has elected a distribution event based on his or her 65 th or 72 nd birthday continues to serve as a Director after the date such distributions commence, then in the year prior to the year in which such distributions commence such Director shall file a new Benefit Distribution Election Form governing any amounts credited to his or her Deferral Account after the date such distributions commence. If the Director does not file such new Benefit Distribution Election Form, then the Director shall be deemed to have elected to receive a lump sum distribution of any such amounts upon the Director's separation from service.

(b) Except as permitted under Section 4(c) or 4(d), each Director must submit a Benefit Distribution Election Form for amounts attributable to fees earned with respect to service on a Board at the time such Director makes his or her initial deferral election under the Plan with respect to his or her service on such Board (provided that a Director who participated in the Plan prior to January 1, 2009 and had not commenced distributions must have submitted such form not later than December 31, 2008). If a Director does not submit a Benefit Distribution Election Form

during this period, then such Director shall be deemed to have elected to receive the portion of his or her Account attributable to fees earned for service on such Board in the form of installments payments over a period of ten years upon the Director's separation from service.

(c) Notwithstanding Sections 4(a) and 4(b), each participant who had not commenced and was not scheduled to commence the receipt of distributions under the Plan on or before December 31, 2007 was permitted to submit a Benefit Distribution Election Form on or before June 30, 2007 which provided for the payment of such participant's Deferral Account (i) at any of the times and in any of the forms permitted under Section 4(a) of the Plan or (ii) in a lump sum payment in the first quarter of 2008; provided that such election did not cause any payment to be made in 2007 and did not apply to any payment that otherwise would be paid in 2007. This special election right was intended to comply with the transition rule set forth in IRS Notice 2005-1, Q&A-19(c), and extended in the preamble to regulations proposed under Section 409A of the Code and IRS Notice 2006-79, which permits participants in deferred compensation plans to change the date on which deferred compensation is payable.

(d) A Director may elect to change the time and/or method of his or her distributions payable under the Plan in accordance with procedures prescribed by the Secretary; provided that, in accordance with Section 409A of the Code, any such change in a distribution election (i) shall not be effective until 12 months after it is submitted to the Secretary, (ii) must be submitted to the Secretary at least 12 months prior to the date on which such distributions were previously scheduled to commence and (iii) must provide for distributions to commence at least five years after the date on which such distributions were previously scheduled to commence. No more than one such election change shall be permissible with respect to the portion of a Director's account attributable to service with any Board.

5. Death Benefits . Each participant shall designate a beneficiary or beneficiaries to receive any remaining amounts payable from his or her Deferral Account after the participant's death. The beneficiaries, and any priority or allocation between them, shall be designated in the manner specified by the Secretary. If a participant dies before the entire balance in his or her Deferral Account has been paid out, the remaining balance shall be paid to the beneficiary in a lump sum upon the participant's death. If the participant is not survived by a designated beneficiary, the participant's beneficiary shall be the participant's spouse, if living, or otherwise, the participant's estate. If a beneficiary survives the participant but dies before the entire balance payable to him or her has been distributed, any remaining balance shall be paid to the beneficiary's estate in a lump sum. In the absence of contrary proof, the participant shall be deemed to have survived any designated beneficiary. A participant may change his or her beneficiary designation under this Section at any time until his or her death by filing a written beneficiary designation with the Secretary, in the manner specified by the Secretary.

6. Unforeseeable Financial Emergency . The Secretary may, in his or her discretion, direct that a participant be paid an amount in cash (not in excess of the balance of his or her Deferral Account) sufficient to meet an unforeseeable emergency. An "unforeseeable emergency" means (i) a severe financial hardship to a Director resulting from an illness or accident of the Director, or the spouse or a dependent (as defined in Section 152(a) of the Code) of the Director, (ii) the loss of a Director's property due to casualty or (iii) such other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Director, within the meaning of Section 409A of the Code. A Director's written request for such a payment shall describe the circumstances which the Director believes justify the payment and an estimate of the amount necessary to eliminate the unforeseeable emergency. An immediate payment to satisfy an unforeseeable emergency will be made only to the extent necessary to satisfy the emergency need,

plus an amount necessary to pay any taxes reasonably anticipated as a result of such payment, and will not be made to the extent the need is or may be relieved through reimbursement or compensation, by insurance or otherwise or by liquidation of the Director's assets (to the extent such liquidation itself would not cause severe financial hardship). Any payment from a Director's Deferral Account on account of an unforeseeable emergency shall be deemed to cancel any Deferral Election of the Director then in effect and the Director shall not be permitted to participate in the Plan until the next following calendar year.

7. No Assignment or Alienation of Benefits . Except as hereinafter provided with respect to a domestic relations order, a participant's Deferral Account may not be voluntarily or involuntarily assigned or alienated. In cases of marital dispute, Exelon will observe the terms of the Plan unless and until ordered to do otherwise pursuant to a domestic relations order, as defined in Section 414(p)(1)(B) of the Code. As a condition of participation, a participant agrees to hold Exelon harmless from any claim that arises out of Exelon's obeying the terms of a domestic relations order, whether such order effects a judgment of such court or is issued to enforce a judgment or order of another court.

8. Amendment or Termination . The Plan may be altered, amended, suspended, or terminated at any time by the Exelon Board, provided that, except as otherwise provided herein or as permitted under Section 409A of the Code, no such action shall result in the distribution of amounts credited to the Deferral Accounts of any participant in any manner other than is provided in the Plan, nor shall such action reduce the availability of amounts previously deferred. To the extent permitted by Section 409A, the Exelon Board may, in its discretion, terminate the Plan with respect to Exelon, ComEd, PECO and/or BGE and accelerate the payment of all Deferral Accounts to the extent related to service on the Board for which the Plan is terminated:

(a) within 12 months of a corporate dissolution taxed under Section 331 of the Code, or with the approval of a bankruptcy court pursuant to 11 U.S.C. §503(b)(1)(A), provided that the payments with respect to each such Deferral Account are included in the Director's gross income in the later of (i) the calendar year in which the Plan termination occurs or (ii) the first calendar year in which the payments are administratively practicable;

(b) in connection with a "change in control event," as defined in, and to the extent permitted under, Treasury regulations promulgated under Section 409A of the Code or

(c) upon any other termination event permitted under Section 409A of the Code.

9. Compliance With Section 409A of the Code . The Plan is intended to comply with the provisions of Section 409A of the Code, and shall be interpreted and construed accordingly. Exelon shall have the discretion and authority to amend the Plan at any time to satisfy any requirements of Section 409A of the Code or guidance provided by the U.S. Treasury Department to the extent applicable to the Plan.

10. Governing Law . The Plan shall be governed by the law of the Commonwealth of Pennsylvania to the extent not preempted by applicable federal law.

EXELON CORPORATION

Executive Vice President

EXELON CORPORATION
SENIOR MANAGEMENT
SEVERANCE PLAN
(As Amended and Restated)

EXELON CORPORATION
SENIOR MANAGEMENT SEVERANCE PLAN
(As Amended and Restated)

1. PURPOSE OF THE PLAN

The Exelon Corporation Senior Management Severance Plan, as amended and restated herein (the " Plan "), is effective as of November 1, 2015 (the " Effective Date ") except as otherwise specifically provided herein, and supersedes in its entirety all prior versions of the Plan with respect to terminations of employment occurring any time on or after the Effective Date (or such other date as set forth herein). The Plan provides severance benefits to eligible executives of Exelon Corporation (" Exelon ") and its subsidiaries of which Exelon owns at least 80% of the outstanding voting power that are designated by the Plan Administrator as participating employers in the Plan (Exelon and such subsidiaries jointly and severally referred to as the " Company ") who submit a Notice of Termination or who are notified of their termination of employment on or after the Effective Date (or such other date as set forth herein), and to provide additional protection in the event of a Change in Control of Exelon or an Imminent Control Change of Exelon.

2. ELIGIBILITY

2.1. Eligibility in General . Subject to the remaining provisions of this Section 2.1, eligibility to participate in the Plan is limited to each employee of the Company whose position is in Salary Band E09 (or equivalent executive grade) or above (an " Executive ") who executes and returns to the Company by the later of 90 days after becoming an Executive, or 90 days after delivery thereof to the Executive, non-competition, non-solicitation, confidential information and intellectual property covenants (" Restrictive Covenants ") which are acceptable to Exelon and are either substantially in the form attached hereto and made a part hereof as Exhibit I (as may be modified from time to time by Exelon in its sole discretion) or set forth in another agreement between the Company and the Executive. Notwithstanding any provision of the Plan to the contrary, eligibility for benefits under the Plan shall be subject to the provisions of any agreement (including but not limited to an offer of employment or grant instrument) between an Executive and the Company providing that that such Executive would be ineligible for (or waives) all or a portion of the benefits under the Plan or "change in control" benefits in the event of a termination of employment, or under which the Executive had agreed, prior to the Applicable Trigger Date, to terminate his or her employment.

2.2. Eligibility Under Section 4 . Subject to Section 2.1, each Executive shall be eligible for the benefits provided under Section 4 hereof in the event such Executive has a Termination of Employment; provided, however, that any Executive whose Termination of Employment is covered under Section 5 hereof or a change in control agreement entered into between such Executive and the Company (an " Individual Change in Control Agreement "), or who is an interim employee separating under the change in control provisions of another severance

plan, shall not be eligible for benefits under Section 4, except as expressly provided in Section 5 or such Individual Change in Control Agreement (which expressly refers to the benefits under Section 4 of this Plan).

2.3. Eligibility Under Section 5. Eligibility for the benefits provided under Section 5 hereof due to a Termination of Employment during a Post-Change Period or an Imminent Control Change Period shall be subject to Section 2.1, and shall be limited to persons who are Executives immediately prior to the Applicable Trigger Date and who are not subject to Individual Change in Control Agreements.

3. PARTICIPATION

Each eligible Executive shall become a participant in the Plan (" Participant ") upon his or her execution of a separation agreement with the Company in such form as the Company, in its sole discretion, shall require or permit (the " Severance Agreement "), provided such Severance Agreement is executed not later than 45 days after the Executive's Termination Date. Notwithstanding anything herein to the contrary, each Executive shall also be required to execute, not later than 45 days after the Executive's Termination Date, a waiver and release of claims against the Company (" Waiver and Release ") which is substantially in the form attached hereto and made a part hereof as Exhibit II, as may from time to time be modified by the Company in its sole discretion. An Executive's right to the payments and benefits under this Plan shall be contingent upon (a) Executive having timely executed and delivered to the Company the Severance Agreement, Waiver and Release and Restrictive Covenants, (b) Executive not revoking the Waiver and Release and (c) Executive not violating any of Executive's on-going obligations under the Plan, the Waiver and Release and the Restrictive Covenants. To the extent that the Company makes payments and provides benefits to an Executive prior to receipt of the Waiver and Release and/or the expiration of the revocation period and the Executive either does not timely execute and deliver the Waiver and Release to the Company or revokes the Waiver and Release in accordance with its terms, Executive shall pay to the Company within 10 days following the expiration of the 45-day consideration period or the date such release was revoked, a lump sum payment of all payments and the value of all benefits received by Executive to date hereunder.

4. BENEFITS

A Participant described in Section 2.2 shall be entitled to all Accrued Obligations and, subject to Section 6, benefits pursuant to this Section 4 upon the Participant's Termination of Employment.

4.1. Severance Pay.

(a) In General. Each Participant other than a Participant described in Section 4.1(b) shall receive severance pay at a monthly rate equal to 1/12 of the sum of (a) the Participant's annual base salary in effect as of the date of Termination of Employment, plus, if the Executive is a participant in the Annual Incentive Award Plan with respect to the year in which the Termination Date occurs, (b) the Severance Incentive. Subject to Section 13.13 below, payment shall be made in regular payroll installments for the

duration of the applicable Salary Continuation Period, as indicated below, commencing no later than the second paydate which occurs after the Participant's Termination Date. Payment will be made in accordance with the Company's normal payroll practices, net of applicable taxes and other deductions.

Participant Level	Salary Continuation Period
Senior Executive Management	24 months
Senior Vice Presidents of Exelon	18 months
Other Executives	15 months

(b) Participants Employed for Less Than Two Years . Each Participant who has been continuously employed by the Company for less than twenty-four months as of the Participant's Termination Date shall receive severance pay at a monthly rate equal to 1/12 of the Participant's annual base salary in effect as of the Termination Date. Subject to Section 13.13 below, payment shall be made in regular payroll installments for the duration of the applicable Salary Continuation Period, as indicated below, commencing no later than the second paydate which occurs after the Participant's Termination Date. Payment will be made in accordance with the Company's normal payroll practices, net of applicable taxes and other deductions.

Participant Level	Salary Continuation Period
Senior Executive Management	18 months (12 months if employed < 12 months)
Other Executives	12 months (6 months if employed < 12 months)

4.2. Annual Incentive Awards . Each Participant who is a participant in the Annual Incentive Award Plan for the year in which the Termination Date occurs shall receive an Annual Incentive which shall be prorated by multiplying the amount of such Annual Incentive by a fraction the numerator of which is the number of days elapsed during such year as of the Participant's Termination Date and the number of days in the year in which Termination Date occurs. Payment of Annual Incentives under this Section 4.2 shall be made in a lump sum net of applicable taxes and other deductions at the time awards under the Annual Incentive Award Plan are paid to active employees for such performance period (but not later than March 15 of the year following the last day of such performance period), and

shall be considered a "short-term deferral" within the meaning of Section 409A of the Code. A Participant who is not a participant in the Annual Incentive Award Plan for the year in which the Termination Date occurs shall not be entitled to an Annual Incentive, and the amount (if any) payable under any other Incentive Plan for such year shall be determined by the Company in its sole discretion.

4.3. Stock Options . No Participant shall be entitled to participate in any new grants of Stock Options (as defined in Section 5.1(b)) made after such Participant's notification of his or her Termination of Employment. Except as provided below, any Stock Options previously granted to the Participant shall be exercisable only to the extent such Stock Options are exercisable as of the date of such Participant's Termination Date and shall thereafter be exercised in accordance with the provisions of the LTIP. Stock Options which remain unexercisable as of the Participant's Termination Date shall be forfeited. Notwithstanding the preceding, if, as of the last day of the Salary Continuation Period, such Participant has attained at least age 50 (age 55 with respect to Stock Options granted on or after January 1, 2013) and completed at least 10 years of service as defined under the tax-qualified defined benefit plan maintained by Exelon in which the Executive is a participant (the " Pension Plan ") or SERP, then any Stock Options granted to such Participant which have not become exercisable prior to the Participant's Termination Date shall (i) become fully vested, and (ii) remain exercisable until the fifth anniversary of the Termination Date or, if earlier, the option expiration date, provided that this Section 4.3 shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

4.4. Other Awards . Awards of Performance Shares, Restricted Stock (as defined in Sections 5.1(c) and 5.1(d), respectively) and/or Cash Performance Awards, as applicable, shall be payable to a Participant solely to the extent provided under the terms of such awards and the applicable plan under which such awards are granted; provided, however, that to the extent the Company determines that a Participant is a Specified Employee and that any such payment is deferred compensation, each within the meaning of Section 409A of the Code, such payment shall not be made prior to the earlier to occur of (i) the six-month anniversary of the Termination Date or (ii) the date of the Participant's death.

4.5. Health Care Coverage . During the Salary Continuation Period, a Participant (and his or her dependents) shall be eligible to participate in the health care plans under which they were covered immediately prior to his or her Termination of Employment, in accordance with and subject to the terms and conditions of such plans as in effect from time to time. The Participant's out of pocket costs (including premiums, deductibles and co-payments) for such coverage shall be the same as that in effect from time to time for active peer employees during such period. Coverage under this Paragraph 4.5 shall be provided for the duration of the Salary Continuation Period in lieu of continuation coverage under Section 4980B of the Code and Section 601 to 609 of ERISA (" COBRA ") for the same period. At the end of the Salary Continuation Period, COBRA continuation coverage may be elected for the remaining balance of the statutory coverage

period, if any; provided, however that a Participant who, as of the last day of the Salary Continuation Period, has attained at least age 50 and completed at least 10 years of service (or who has completed such other age and service requirement then in effect under the Exelon Corporation Severance Benefit Plan or any successor plan as of the relevant time set forth in such plan) under the terms of the Pension Plan (or who, pursuant to the terms of an offer of employment or employment agreement or under any provision of the Pension Plan or SERP, is credited with a number of additional years of age and/or service that would enable such Participant to satisfy the above eligibility requirements) shall be entitled to elect such Company group health care programs for retirees as are in effect as of the Termination Date and are applicable to such Participant by the programs' eligibility terms and conditions as though such Participant had attained such programs' age and service requirements. The eligibility for coverage and availability of programs or plans, the amounts charged for coverage, and the other terms, conditions and limitations under the Company's group health care programs or plans shall remain subject to the Company's right to amend, change or terminate such programs or plans at any time.

4.6. SERP / Other Deferred Compensation . For purposes of the Participant's SERP benefit, the Salary Continuation Period shall be taken into account as service solely for purposes of determining whether the Participant is vested (i.e., 3 or 5 years of service) and, to the extent relevant under the Pension Plan covering the Participant, the amount of the Participant's regular accrued benefit, but not for purposes of determining eligibility for early retirement benefits (including any social security supplement) or any other purpose. In determining the amount of the Participant's vested benefit, if any, the severance payments made under Section 4.1 shall be taken into account as if such payments were normal base salary and incentive payments. Payment shall be made in accordance with the SERP and the Participant's distribution election in effect thereunder as of the Termination Date (or, if no affirmative election is in effect as of such date, the default election applicable to the Participant). All amounts previously deferred by, or accrued to the benefit of, such Participant under the Exelon Corporation Deferred Compensation Plan, the Exelon Corporation Stock Deferral Plan or the Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan shall, to the extent vested, be paid in accordance with the Participant's distribution election in effect thereunder as of the Termination Date (or, if no affirmative election is in effect as of such date, the default election applicable to the Participant).

4.7. Life Insurance and Disability Coverage . A Participant shall be eligible for continued coverage under the applicable basic life insurance and long term disability plans sponsored by the Company (or other equivalent coverage or benefits) shall be extended to each Participant through the last day of the Salary Continuation Period applicable to such Participant on the same terms and subject to the same terms and conditions as are applicable to active peer employees (including, without limitation, submission of proof by an Executive who seeks long term disability benefits that such Executive would have satisfied the conditions for such benefits had the Executive been an employee during the Salary Continuation Period and terminated employment on or before the last day of such period).

4.8. Executive Perquisites . Executive perquisites shall terminate effective as of the Participant's Termination Date, and any Company-owned property shall be required to be returned to the Company no later than such date.

4.9. Outplacement and Financial Counseling Services . Each Participant shall be entitled to outplacement services at the expense of the Company for the twelve month period following the Termination Date, and subject to such terms and conditions as the Plan Administrator, in its sole discretion, determines are appropriate. No cash shall be paid in lieu of such fees and costs.

4.10. Restrictions on In-Kind Benefits . The in-kind benefits provided under each of Sections 4.5, 4.7 and 4.8 during any calendar year shall not affect the benefits to be provided under such section in any subsequent calendar year. The right to such benefits shall not be subject to liquidation or exchange for any other benefit

4.11. Other Coverage . Notwithstanding the foregoing, if such Participant is eligible to obtain a specific type of coverage under welfare plan(s) sponsored by another employer of such Participant (e.g. medical, prescription, vision, dental, disability, individual life insurance benefits, group life insurance benefits, but excluding for the purposes of this sentence retiree benefits if such Participant is so eligible), then the Company shall not be obligated to provide any such specific type of coverage. The Participant shall promptly notify the Plan Administrator of any such coverage.

5. CHANGE IN CONTROL BENEFITS

A Participant described in Section 2.3 shall be entitled to all Accrued Obligations and, subject to Section 6, benefits pursuant to this Section 5 if such a Participant has a Termination of Employment during a Post-Change Period or Imminent Control Change Period, and such Participant shall not be eligible for benefits under Section 4 unless so expressly provided in this Section 5.

5.1. Termination During a Post-Change Period . If, during a Post-Change Period, an eligible Executive has a Termination of Employment and becomes a Participant, the Company's sole obligations under Section 4 and Sections 5.1 and 5.2 shall be as set forth in this Section 5.1 (subject to Sections 5.3, 5.5, 5.6 and 6.0.

(a) Severance Payments . The Company shall pay or provide (or cause to be provided) to such Participant, according to the payment terms set forth in Section 5.3 below, the following:

(i) Annual Incentive for Year of Termination . An amount equal to the Annual Incentive applicable to such Participant under the Incentive Plan for the performance period in which the Termination Date occurs;

(ii) Deferred Compensation and Non-Qualified Defined Contribution Plans . All amounts previously deferred by, or accrued to the benefit of, such Participant under the Exelon Corporation Deferred Compensation Plan, the Exelon Corporation Stock Deferral Plan or the Constellation Energy Group Inc. Deferred Compensation Plan, any successor plan, or under any other non-qualified defined contribution or deferred compensation plan of the Company, whether vested or non-vested, together with any accrued earnings thereon, to the extent that such amounts and earnings have not been previously paid by the Company and are not provided under the terms of any such non-qualified plan;

(iii) SERP Enhancement . An amount payable under the SERP equal to the positive difference, if any, between:

(1) the lump sum value of such Participant's benefit, if any, under the SERP, calculated as if such Participant had:

(a) become fully vested in all Pension Plan and SERP benefits,

(b) to the extent age is relevant under the Pension Plan covering the Participant, attained as of the Termination Date an age that is two years greater than such Participant's actual age and that includes the number of years of age credited to such Participant pursuant to any other agreement between the Company and such Participant,

(c) to the extent service is relevant under the Pension Plan covering the Participant, accrued a number of years of service (for purposes of determining the amount of such benefits, entitlement to - but not commencement of - early retirement benefits, and all other purposes of the Pension Plan and SERP) that is two years greater than the number of years of service actually accrued by such Participant as of the Termination Date and that includes the number of years of service credited to such Participant pursuant to any other agreement between the Company and such Participant, and

(d) received the severance benefits specified in Sections 5.1(a)(i) and 5.1(a)(v) as covered compensation in regular installments during the Severance Period, minus

(2) the aggregate amounts paid or payable to such Participant under the SERP;

(iv) Non-vested Benefits Under Pension Plan . An amount equal to the actuarial equivalent present value of any non-vested portion of such Participant's accrued benefit under the Pension Plan as of the Termination Date and forfeited by such Participant by reason of the Termination of Employment; and

(v) Multiple of Salary and Severance Incentive . An amount equal to two (2) times the sum of (x) the Participant's Base Salary plus, if the Participant is a participant in the Annual Incentive Award Plan for the year in which the Termination Date occurs, (y) the Severance Incentive, net of applicable taxes and other deductions.

(b) Stock Options . Each of such Participant's stock options granted under the LTIP (" Stock Options ") shall (i) become fully vested, and (ii) remain exercisable until the fifth anniversary of the Termination Date or, if earlier, the expiration date of any such Stock Option, provided that this Section 5.1(b) shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

(c) Performance Share Vesting . On the Termination Date, all of the long term performance share or performance cash units granted to such Participant under the LTIP (" Performance Shares ") prior to January 1, 2013 to the extent earned by and awarded to such Participant (i.e. as to which the applicable performance cycle has elapsed) as of the Termination Date, shall become fully vested at the actual level earned and awarded, and, to the extent not yet earned by and awarded to such Participant (i.e. as to which the current performance cycle has not elapsed) as of the Termination Date, shall become fully vested at the earned level determined as of the last day of the applicable performance cycle. With respect to all Performance Shares granted on or after January 1, 2013, such Performance Shares shall become vested and earned as set forth in the LTIP, as if the Executive had been involuntarily terminated without cause.

(d) Other Awards . All forfeiture conditions that as of the Termination Date are applicable to any shares of restricted stock or restricted stock units awarded to such Participant by Exelon other than under the Exelon Long Term Performance Share Award Program under the LTIP (" Restricted Stock ") shall (except as expressly provided to the contrary in the applicable awards) lapse immediately and all such awards will become fully vested. All Cash Performance Awards shall become fully vested in accordance with their terms.

(e) Continuation of Welfare Benefits . During the Severance Period, the Executive and the Executive's dependents shall be eligible for participation in the Company's welfare plans, including medical, prescription, dental, disability, employee life, group life and accidental death benefits but excluding any severance pay (" Welfare Plans ") that

covered the Participant or such Participant's dependents as of the Termination Date, in accordance with the terms and conditions of such plans and applicable law. Such provision of welfare benefits shall be subject to the following:

(i) In determining benefits applicable under such Welfare Plans, such Participant's annual compensation attributable to base salary and incentives for any plan year or calendar year, as applicable, shall be deemed to be not less than such Participant's Base Salary and annual incentive for the year in which the Termination Date occurs.

(ii) The cost of such welfare benefits to such Participant and dependents under this Section 5.1(e) shall not exceed the cost of such benefits to peer executives who are actively employed during the Severance Period.

(iii) Health care coverage under this Section 5.1(e) shall be provided for the duration of the Severance Period in lieu of continuation coverage under Section 4980B of the Code and Section 601 to 609 of ERISA (" COBRA ") for the same period. At the end of the Severance Period, COBRA continuation coverage may be elected for the remaining balance of the statutory coverage period, if any, at the Participant's sole expense.

(iv) If such Participant has, as of the last day of the Severance Period, attained age 50 and completed at least 10 years of service with the Company, such Participant shall be entitled to elect coverage under such Company group health care programs for retirees as are in effect as of the Termination Date and are applicable to such Participant by the programs' eligibility terms and conditions as though such Participant had attained such programs' age and service requirements ; provided, however, that for purposes hereof, any years of age and/or credited service granted to such Participant in any other plan or agreement between such Participant and the Company shall be taken into account. For purposes of determining eligibility for (but not the time of commencement of) such retiree benefits, such Participant shall also be considered (1) to have remained employed until the last day of the Severance Period and to have retired on the last day of such period, and (2) to have attained at least the age such Participant would have attained on the last day of the Severance Period. The eligibility for coverage and availability of programs or plans, the amounts charged for coverage, and the other terms, conditions and limitations under the Company's group health care programs or plans shall remain subject to the Company's right to amend, change or terminate such programs or plans at any time.

Notwithstanding the foregoing, if such Participant is eligible to obtain a specific type of coverage under welfare plan(s) sponsored by another employer of such Participant (e.g. medical, prescription, vision, dental, disability, individual life insurance benefits, group life insurance benefits, but excluding for the purposes of this sentence retiree benefits if such Participant is so eligible), then the Company shall not be obligated to provide any such specific type of coverage. The Participant shall promptly notify the Plan Administrator of any such coverage.

(f) Outplacement . To the extent actually incurred by such Participant, the Company shall pay or cause to be paid on behalf of such Participant, as incurred, all reasonable fees and costs charged by a nationally recognized outplacement firm selected by such Participant for outplacement services provided for up to 12 months after the Termination Date. No cash shall be paid in lieu of such fees and costs.

(g) Indemnification . Such Participant shall be indemnified and held harmless by the Company to the greatest extent permitted under applicable law and the Company's by-laws if such Participant was, is, or is threatened to be, made a party to any pending, completed or threatened action, suit, arbitration, alternate dispute resolution mechanism, investigation, administrative hearing or any other proceeding brought by a third party (and not by or on behalf of the Company or its shareholders) whether civil, criminal, administrative or investigative, and whether formal or informal, by reason of the fact that such Participant is or was, or had agreed to become, a director, officer, employee, agent, or fiduciary of the Company or any other entity which such Participant is or was serving at the request of the Company (" Proceeding "), against all expenses (including all reasonable attorneys' fees) and all claims, damages, liabilities and losses incurred or suffered by such Participant or to which such Participant may become subject for any reason; provided, that the Participant provides the Company written notice of any such Proceeding promptly after receipt and such that the Company's ability to defend shall not be prejudiced in any fashion and the Company shall have the right to direct the defense, approve any settlement and shall not be required to indemnify the Participant in connection with any proceeding initiated by the Participant, including a counterclaim or crossclaim, unless such proceeding was authorized by the Company, and that the Participant fully cooperates in the investigation and defense of such Proceeding.

(h) Directors' and Officers' Liability Insurance . For a period of six years after the Termination Date, the Company shall provide such Participant with coverage under a directors' and officers' liability insurance policy in an amount no less than, and on terms no less favorable than, those provided to peer executives of the Company from time to time.

5.2. Termination During an Imminent Control Change Period . If, during an Imminent Control Change Period, a Participant has a Termination of Employment, then

such Participant shall receive benefits at the time and in the manner provided in Section 4 and the Company's sole obligations to such Participant under Sections 5.1 and 5.2 shall be as set forth in this Section 5.2 (and subject to Sections 5.3, 5.5, 5.6 and 6). The Company's obligations to such Participant under this Section 5.2 shall in all events be reduced by any amounts or benefits paid or provided pursuant to Section 4.

(a) Cash Severance Payments . If the Imminent Control Change Period culminates in a Change Date, the Company shall pay (or cause to be paid) to such Participant the amounts described in Section 5.1(a)(i) through (v). Such amounts shall be paid to such Participant as described in Section 5.3, provided that amounts that would have been paid prior to the Change Date shall be paid in a lump sum (without interest) within 30 business days after the Change Date.

(b) Vested Stock Options . Such Participant's Stock Options, to the extent vested on the Termination Date,

(i) will not expire (unless such Stock Options would have expired had such Participant remained an employee of the Company) during the Imminent Control Change Period; and

(ii) will continue to be exercisable after the Termination Date to the extent provided in the applicable grant agreement or the LTIP, and thereafter such Stock Options shall not be exercisable during the Imminent Control Change Period.

If the Imminent Control Change Period lapses without a Change Date, then such Participant's Stock Options, to the extent vested on the Termination Date, may be exercised, in whole or in part, during the 30-day period following the lapse of the Imminent Control Change Period, or, if longer, the period during which such Participant's vested Stock Options could otherwise be exercised under the terms of the applicable grant agreement or the LTIP (but in no case shall any Stock Options remain exercisable after the date on which such Stock Options would have expired if such Participant had remained an employee of the Company).

If the Imminent Control Change Period culminates in a Change Date, then effective upon the Change Date, such Participant's Stock Options, to the extent vested on the Termination Date, may be exercised in whole or in part by such Participant at any time until the earlier of the fifth anniversary of the Change Date or the option expiration date for such Stock Options, provided that this Section 5.2(b) shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

(c) Non-vested Stock Options . Such Participant's Stock Options that are not vested on the Termination Date:

(i) will not expire (unless such Stock Options would have expired had such Participant remained an employee of the Company) during the Imminent Control Change Period; and

(ii) will not continue to vest and will not be exercisable during the Imminent Control Change Period.

If the Imminent Control Change lapses without a Change Date, such non-vested Stock Options will thereupon expire.

If the Imminent Control Change culminates in a Change Date, then immediately prior to the Change Date, such non-vested Stock Options shall become fully vested, and may thereupon be exercised in whole or in part by such Participant at any time until the earlier of the fifth anniversary of the Change Date, or the option expiration date for such Stock Options, provided that this Section 5.2(c) shall not limit the right of the Company to cancel the Stock Options in connection with a corporate transaction pursuant to the terms of the LTIP.

(d) Performance Shares . Such Participant's Performance Shares granted under the Exelon Long Term Performance Share Award Program under the LTIP will not be forfeited during the Imminent Control Change Period, and will not continue to vest during the Imminent Control Change Period. If the Imminent Control Change lapses without a Change Date, such Performance Shares shall be governed according to the terms of Section 4. If the Imminent Control Change Period culminates in a Change Date:

(i) All Performance Shares granted to such Participant under the Exelon Long Term Performance Share Award Program under the LTIP prior to January 1, 2013, which, as of the Termination Date, have been earned by and awarded to such Participant, shall become fully vested at the actual earned level on the Change Date, and

(ii) All of the Performance Shares granted to such Participant under the Exelon Long Term Performance Share Award Program under the LTIP prior to January 1, 2013 which, as of the Termination Date, have not been earned by and awarded to such Participant shall become fully vested on the Change Date at the actual earned level as of the last day of the applicable performance cycle, and

(iii) With respect to all Performance Shares granted on or after January 1, 2013, such Performance Shares shall become vested and earned as set forth in the LTIP, as if the Executive had been involuntarily terminated without cause.

(e) Restricted Stock . Such Participant's non-vested Restricted Stock will:

(i) not be forfeited during the Imminent Control Change Period; and

(ii) not continue to vest during the Imminent Control Change Period.

If the Imminent Control Change Period lapses without a Change Date, such non-vested Restricted Stock shall thereupon be forfeited.

If the Imminent Control Change Period culminates in a Change Date, then immediately prior to the Change Date, such Participant's Restricted Stock shall (except as expressly provided to the contrary in the award) become fully vested, and within ten business days after the Change Date, the Company shall deliver to such Participant all of such shares theretofore held by or on behalf of the Company, which will be subject to the same terms which other stockholders of the Company receive in the transaction.

(f) Cash Performance Awards . All Cash Performance Awards shall become fully vested in accordance with the terms of the underlying award documents.

(g) Continuation of Welfare Benefits . The Participant and the Participant's dependents shall be eligible for welfare benefits (other than any severance pay that may be considered a welfare benefit) in accordance with the terms and conditions of the applicable plans during the Imminent Control Change Period, to the same extent as if such Participant had remained employed during such period, subject to the following:

(i) in determining benefits applicable under such Welfare Plans, such Participant's annual compensation attributable to base salary and incentives for any plan year or calendar year, as applicable, shall be deemed to be not less than such Participant's Base Salary and annual incentive for the year in which the Termination Date occurs;

(ii) the cost of such welfare benefits to such Participant and dependents under this Section 5.2(g) shall not exceed the cost of such benefits to peer executives who are actively employed by the Company during the Imminent Control Change Period; and

(iii) Health care coverage under this Section 5.2(g) shall be provided for the duration of the Severance Period in lieu of continuation coverage under Section 4980B of the Code and Section 601 to 609 of ERISA (" COBRA ") for the same period. At the end of the Severance Period, COBRA continuation coverage may be elected for the remaining balance of the statutory coverage period, if any.

If the Imminent Control Change Period lapses without a Change Date, welfare benefit plan coverage under this Section 5.2(g) shall thereupon cease, subject to such Participant's rights, if any, to continued coverage under a Welfare Plan, Section 4, or applicable law. If the Imminent Control Change Period culminates in a Change Date, then for the remainder of the Severance Period, the Participant and his or her dependents shall continue to be eligible for welfare benefits as described in, and subject to the limitations of Section 5.1(e).

Notwithstanding the foregoing, if such Participant obtains a specific type of coverage under welfare plan(s) sponsored by another employer of such Participant (e.g. medical, prescription, vision, dental, disability, individual life insurance benefits, group life insurance benefits, but excluding for the purposes of this sentence retiree benefits if such Participant is so eligible), then the Company shall not be obligated to provide any such specific type of coverage. The Participant shall immediately notify the Plan Administrator of any such coverage.

(h) Indemnification . Such Participant shall be indemnified and held harmless by the Company to the same extent as provided in Section 5.1(g), but only during the Imminent Control Change Period (or greater period provided under the Company's by-laws) if the Imminent Control Change Period lapses without a Change Date.

(i) Termination During an Imminent Control Change Period: Directors' and Officers' Liability Insurance . The Company shall provide the same level of directors' and officers' liability insurance for such Participant as provided in Section 5.1(h), but only during the Imminent Control Change Period (or greater period provided under the Company's by-laws) if the Imminent Control Change Period lapses without a Change Date.

5.3. Timing of Severance Payments . Unless otherwise specified herein, the Accrued Obligations and the amount described in Section 5.1(a)(i) shall be paid within 30 business days of the Termination Date, and such amounts shall be considered "short-term deferrals" within the meaning of Section 409A of the Code. The amounts described in Sections 5.1(a)(ii), (iii) and (iv) shall be paid in accordance with the applicable deferred compensation plan or the SERP and the Participant's distribution election thereunder as of the Termination Date (or, if no affirmative election is in effect as of such date, the default election in effect with respect to the Participant as of such date). Subject to Section 13.13, the severance payments described in Section 5.1(a)(v) shall be paid during the Severance Period, beginning no later than the second paydate which occurs after the Termination Date, in periodic payments to a Participant according to the Company's normal payroll practices at a monthly rate equal to 1/12 of the sum of (i) such Participant's Base Salary plus (ii) the Severance Incentive (if any). The in-kind benefits and reimbursements provided under each of Sections 5.1(e), 5.1(h), 5.2(g) and 5.2(i) during any calendar year shall not affect the benefits or reimbursements to be provided under such section in any subsequent calendar year. The right to such benefits and reimbursements shall not be subject to liquidation or exchange for any other benefit.

5.4. Other Terminations of Employment by the Company or a Participant .

(a) Obligations . If, during a Post-Change Period or an Imminent Control Change Period, (i) the Company terminates an eligible Executive's employment for Cause (or causes a Participant to be terminated for Cause) (" Cause Termination ") or disability (as determined by the Plan Administrator in good faith), (ii) an Executive elects to retire or otherwise terminate employment other than for Good Reason, disability or death, or (iii) an eligible Executive's employment terminates on account of death, the Company shall have no obligations to such Executive under Section 5. The remaining applicable provisions of this Plan (including the Restrictive Covenants) shall continue to apply.

(b) Procedural Requirements . The Company shall strictly observe or cause to be strictly observed each of the following procedures in connection with any Cause Termination during a Post-Change Period or an Imminent Control Change Period: an eligible Executive's termination of employment shall not be deemed to be for Cause under this Section 5.4 unless and until there shall have been delivered to such Executive a written notice of the determination of the Chief Executive Officer of the Executive's employer (" CEO ") (after reasonable written notice of such consideration by the CEO of acts or omissions alleged to constitute Cause is provided to such Executive and such Executive is given an opportunity to present a written response to the CEO regarding such allegations), finding that, in his or her good faith opinion, such Executive's acts, or failure to act, constitutes Cause and specifying the particulars thereof in detail.

5.5. Sole and Exclusive Obligations . The obligations of the Company under this Plan with respect to any Termination of Employment occurring during a Post-Change Period or Imminent Control Change Period shall supersede any severance obligations of the Company in any other plan of the Company or agreement between such Participant and the Company, including, without limitation, Section 4, any offer of employment or employment contract of the Company which provides for severance benefits, except as explicitly provided in Section 5.2 or to the extent such Participant is ineligible for such benefits or such benefits are waived pursuant to Section 2.1.

5.6. Payment Capped . If at any time or from time to time, it shall be determined by the Company's independent auditors that any payment or other benefit to a Participant pursuant to Section 4 or 5 of this Plan or otherwise (" Potential Parachute Payment ") is or will become subject to the excise tax imposed by Section 4999 of the Code or any similar tax payable under any United States federal, state, local, foreign or other law (" Excise Taxes "), then the Potential Parachute Payments payable to such Participant shall be reduced to the largest amount which would both (a) not cause any Excise Tax to be payable by such Participant and (b) not cause any Potential Parachute Payments to become nondeductible by the Company by reason of Section 280G of the Code (or any successor provision).

6. **TERMINATION OF PARTICIPATION; CESSATION OF BENEFITS**

A Participant's benefits under Section 4 of the Plan shall terminate on the last day of the Participant's Salary Continuation Period; provided that a Participant's right to benefits shall terminate immediately on such date as the Company discovers that the Participant has breached any of the Restrictive Covenants or the Waiver and Release, or if at any time the Company determines that in the course of his or her employment the Executive engaged in conduct described in Section 7.11(b), (c), (d) or (e) or the Executive fails to comply with Section 13.2, in which case the Company may require the repayment of amounts paid pursuant to Section 4.1 prior to such breach or other conduct, and shall discontinue the payment of any additional amounts under Section 4 of the Plan.

A Participant's benefits under Section 5 of the Plan shall terminate on the later of the last day of the Participant's Severance Period or the date all benefits to which the Participant is entitled to have been paid from the Plan; provided that a Participant's right to benefits shall terminate immediately on the date the Company discovers that the Participant has breached any of the Restrictive Covenants or the Waiver and Release, or if at any time the Company determines, in accordance with the procedural requirements set forth in Section 5.4(b) that in the course of his or her employment the Executive engaged in conduct described in Section 7.11(b), (c), (d) or (e) or the Executive fails to comply with Section 13.2, in which case the Company may require the repayment of amounts paid pursuant to Section 5 prior to such breach or other conduct, and shall discontinue the payment of any additional amounts under Section 5 of the Plan.

Benefits paid or payable to a Participant under Section 4 and Section 5 of the Plan shall be subject to any executive or officer incentive compensation recoupment policy of the Board of Directors as in effect as of the Termination Date.

7. **DEFINITIONS**

In addition to terms previously defined, when used in the Plan, the following capitalized terms shall have the following meanings unless the context clearly indicates otherwise:

7.1. " Accrued Annual Incentive " means the amount of any annual incentive earned but not yet paid with respect to the Company's latest fiscal year ended prior to the Termination Date.

7.2. " Accrued Base Salary " means the amount of a Participant's Base Salary that is accrued but not yet paid as of the Termination Date.

7.3. " Accrued Obligations " means, as of any date, the sum of a Participant's Accrued Base Salary, Accrued Annual Incentive and any accrued but unpaid paid time off

7.4. " Annual Incentive " as of a certain date means an amount to which a Participant would have been entitled under the Annual Incentive Award Plan (or, with respect to a termination pursuant to Section 5, such other Incentive Plan applicable to such Participant) for the applicable performance period based on the actual achievement performance goals established pursuant to such plan as of the end of the applicable performance period had the Participant remained employed through

the last day of such period; provided, however, that any reduction in a Participant's Base Salary or annual incentive that would qualify as Good Reason shall be disregarded for purposes of this definition

7.5. " Annual Incentive Award Plan ", means the Exelon Corporation Annual Incentive Award Plan (but not any other short-term incentive plan of a Company), or any successor plan thereto (including but not limited to any annual incentive plan of a successor to Exelon pursuant to a Change in Control).

7.6. " Applicable Trigger Date " means

(a) the Change Date, with respect to a Post-Change Period; or

(b) the date of an Imminent Control Change, with respect to the Imminent Control Change Period.

7.7. " Base Salary " for purposes of Section 5, means not less than 12 times the highest monthly base salary paid or payable to a Participant by the Company in respect of the 12-month period immediately before the Applicable Trigger Date.

7.8. " Beneficial Owner " means such term as defined in Rule 13d-3 of the SEC under the Exchange Act.

7.9. " Board " means the Board of Directors of Exelon or, from and after the effective date of a Corporate Transaction (as defined in the definition of Change in Control), the Board of Directors of the corporation resulting from a Corporate Transaction or, if securities representing at least 50% of the aggregate voting power of such resulting corporation are directly or indirectly owned by another corporation, such other corporation.

7.10. "Cash Performance Award" means any cash performance award granted to a Participant in lieu of an award of Performance Shares or Restricted Stock under the LTIP.

7.11. " Cause " means, with respect to any Executive:

(a) the refusal to perform or habitual neglect in the performance of the Executive's duties or responsibilities, or of specific directives of the officer or other executive of Exelon or any of its affiliates to whom the Executive reports which are not materially inconsistent with the scope and nature of the Executive's employment duties and responsibilities;

(b) an Executive's willful or reckless commission of act(s) or omission(s) which have resulted in or are likely to result in, a material loss to, or material damage to the reputation of, Exelon or any of its affiliates, or that compromise the safety of any employee or other person;

(c) the Executive's commission of a felony or any crime involving dishonesty or moral turpitude;

(d) an Executive's material violation of Exelon's or any of its affiliate's Code of Business Conduct (including the corporate policies referenced therein), or of any statutory or common law duty of loyalty to Exelon or any of its affiliates; or

(e) any breach by the Executive of any one or more of the Restrictive Covenants.

7.12. "Change Date" means each date on which a Change in Control occurs after the Effective Date.

7.13. "Change in Control" means:

(a) any SEC Person becomes the Beneficial Owner of 20% or more of the then outstanding common stock of Exelon or of Voting Securities representing 20% or more of the combined voting power of all the then outstanding Voting Securities of Exelon (such an SEC Person, a "20% Owner"); provided, however, that for purposes of this subsection (a), the following acquisitions shall not constitute a Change in Control: (1) any acquisition directly from Exelon (excluding any acquisition resulting from the exercise of an exercise, conversion or exchange privilege unless the security being so exercised, converted or exchanged was acquired directly from Exelon), (2) any acquisition by Exelon, (3) any acquisition by an employee benefit plan (or related trust) sponsored or maintained by Exelon or any corporation controlled by Exelon (a "Company Plan"), or (4) any acquisition by any corporation pursuant to a transaction which complies with clauses (i), (ii) and (iii) of subsection (c) of this definition; provided further, that for purposes of clause (2), if any 20% Owner of Exelon other than Exelon or any Company Plan becomes a 20% Owner by reason of an acquisition by Exelon, and such 20% Owner of Exelon shall, after such acquisition by Exelon, become the beneficial owner of any additional outstanding common shares of Exelon or any additional outstanding Voting Securities of Exelon (other than pursuant to any dividend reinvestment plan or arrangement maintained by Exelon) and such beneficial ownership is publicly announced, such additional beneficial ownership shall constitute a Change in Control; or

(b) Individuals who, as of the date hereof, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Incumbent Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by Exelon's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest (as such terms are used in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(c) Consummation of a reorganization, merger or consolidation (" Merger "), or the sale or other disposition of more than 50% of the operating assets of Exelon (determined on a consolidated basis), other than in connection with a sale-leaseback or other arrangement resulting in the continued utilization of such assets (or the operating products of such assets) by Exelon (such reorganization, merger, consolidation, sale or other disposition, a " Corporate Transaction "); excluding, however, a Corporate Transaction pursuant to which:

(i) all or substantially all of the individuals and entities who are the Beneficial Owners, respectively, of the outstanding common stock of Exelon and outstanding Voting Securities of Exelon immediately prior to such Corporate Transaction beneficially own, directly or indirectly, more than 60% of, respectively, the then-outstanding shares of common stock and the combined voting power of the then-outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Corporate Transaction (including, without limitation, a corporation which, as a result of such transaction, owns Exelon or all or substantially all of the assets of Exelon either directly or through one or more subsidiaries) in substantially the same proportions as their ownership immediately prior to such Corporate Transaction of the outstanding common stock of Company and outstanding Voting Securities of Exelon, as the case may be;

(ii) no SEC Person (other than the corporation resulting from such Corporate Transaction, and any Person which beneficially owned, immediately prior to such corporate Transaction, directly or indirectly, 20% or more of the outstanding common stock of Exelon or the outstanding Voting Securities of Exelon, as the case may be) becomes a 20% Owner, directly or indirectly, of the then-outstanding common stock of the corporation resulting from such Corporate Transaction or the combined voting power of the outstanding voting securities of such corporation; and

(iii) individuals who were members of the Incumbent Board will constitute at least a majority of the members of the board of directors of the corporation resulting from such Corporate Transaction; or

(d) Approval by Exelon's shareholders of a plan of complete liquidation or dissolution of Exelon, other than a plan of liquidation or dissolution which results in the acquisition of all or substantially all of the assets of Exelon by an affiliated company.

Notwithstanding the occurrence of any of the foregoing events, a Change in Control shall not occur with respect to a Participant if, in advance of such event, such Participant agrees in writing that such event shall not constitute a Change in Control.

7.14. " Code " means the Internal Revenue Code of 1986, as amended.

7.15. "ComEd Key Manager Plan" means the ComEd Key Manager Long-Term Performance Plan, or any successor thereto.

7.16. " ERISA " means the Employee Retirement Income Security Act of 1974, as amended.

7.17. " Exchange Act " means the Securities Exchange Act of 1934, as amended.

7.18. " Good Reason " means:

(a) for purposes of Section 4 hereof,

(i) a material reduction of an Executive's salary unless such reduction is part of a policy, program or arrangement applicable to peer executives of the Company or of the Executive's business unit; and

(ii) with respect to an Executive whose title with respect to a Company is Senior Vice President or above, a material adverse reduction in the Executive's position or duties that is not applicable to peer executives of the Company or of the Executive's business unit, but excluding any change (A) resulting from a reorganization or realignment of all or a significant portion of the business, operations or senior management of the Company or of the business unit that employs the Executive or (B) that generally places the Executive in substantially the same level of responsibility. Notwithstanding the foregoing, no change in the position or level of officer to whom an Executive reports shall constitute grounds for Good Reason.

(b) for purposes of Section 5 hereof, the occurrence of any one or more of the following actions or omissions that occurs during a Post-Change Period or an Imminent Control Change Period:

(i) a material reduction of an Executive's salary, incentive compensation opportunity or aggregate benefits unless such reduction is part of a policy, program or arrangement applicable to peer executives (including peer executives of any successor to Exelon);

(ii) a material adverse reduction in the Executive's position, duties or responsibilities (excluding a change in the position or level of officer to whom the Executive reports), unless such reduction is part of a policy, program or arrangement applicable to peer executives (including peer executives of any successor to Exelon);

(iii) a relocation by more than 50 miles of (A) the Executive's primary workplace, or (B) the principal offices of Exelon or its successor (if such offices are such Executive's workplace), in each case without the Executive's consent; provided, however, in both cases of (A) and (B) of this subsection (b)(iv), such new location is farther from the Executive's residence than the prior location; or

(iv) a material breach of this Plan by Exelon or its successor.

(c) Application of "Good Reason" Definition During the Imminent Control Change Period . During the Imminent Control Change Period, "Good Reason" shall not include the events or conditions described in subsection (b)(i), (b)(ii) or (b)(iv) above unless the Imminent Control Change Period culminates in a Change Date.

(d) Limitations on Good Reason . Notwithstanding the foregoing provisions of this Section, no act or omission shall constitute a material breach of this Plan by Exelon, nor grounds for "Good Reason":

(i) unless the Executive gives the Plan Administrator a Notice of Termination at least 30 days prior to the Executive's Termination Date, and the Company fails to cure such act or omission within the 30-day period;

(ii) if the Executive first acquired knowledge of such act or omission more than 90 days before such Participant gives the Plan Administrator such Notice or Termination; or

(iii) if the Executive has consented in writing to such act or omission.

7.19. " Imminent Control Change " means, as of any date on or after the Effective Date and prior to the Change Date, the occurrence of any one or more of the following:

(a) Exelon enters into an agreement the consummation of which would constitute a Change in Control;

(b) Any SEC Person commences a "tender offer" (as such term is used in Section 14(d) of the Exchange Act) or exchange offer, which, if consummated, would result in a Change in Control; or

(c) Any SEC Person files with the SEC a preliminary or definitive proxy solicitation or election contest to elect or remove one or more members of the Board, which, if consummated or effected, would result in a Change in Control;

provided, however, that an Imminent Control Change will lapse and cease to qualify as an Imminent Control Change:

(i) With respect to an Imminent Control Change described in clause (a) of this definition, the date such agreement is terminated, cancelled or expires without a Change Date occurring;

(ii) With respect to an Imminent Control Change described in clause (b) of this definition, the date such tender offer or exchange offer is withdrawn or terminates without a Change Date occurring;

(iii) With respect to an Imminent Control Change described in clause (c) of this definition, (1) the date the validity of such proxy solicitation or election contest expires under relevant state corporate law, or (2) the date such proxy solicitation or election contest culminates in a shareholder vote, in either case without a Change Date occurring; or

(iv) The date a majority of the members of the Incumbent Board make a good faith determination that any event or condition described in clause (a), (b), or (c) of this definition no longer constitutes an Imminent Control Change, provided that such determination may not be made prior to the first anniversary of the occurrence of such event.

7.20. " Imminent Control Change Period " means the period commencing on the date of an Imminent Control Change, and ending on the first to occur thereafter of

(a) a Change Date, provided

(i) such date occurs no later than the first anniversary of the Termination Date, and

(ii) either the Imminent Control Change has not lapsed, or the Imminent Control Change in effect upon such Change Date is the last Imminent Control Change in a series of Imminent Control Changes unbroken by any period of time between the lapse of an Imminent Control Change and the occurrence of a new Imminent Control Change;

(b) the date an Imminent Control Changes lapses without the prior or concurrent occurrence of a new Imminent Control Change; or

(c) the first anniversary of the Termination Date.

7.21. " Incentive Plan " means the Exelon Corporation Annual Incentive Award Plan, or such other annual cash bonus arrangement of the Company in which the Executive is a participant in lieu of the Annual Incentive Award Plan, but excluding any supplemental incentive plans.

7.22. " including " means including without limitation.

7.23. " Incumbent Board " - see definition of Change in Control.

7.24. " LTIP " means the Exelon Corporation Long-Term Incentive Plan, as amended from time to time, or any successor thereto.

7.25. " LTIP Performance Period " means the performance period applicable to an LTIP award, as designated in accordance with the LTIP.

7.26. " LTIP Target Level " means, in respect of any grant of Performance Shares under the Exelon Long Term Performance Share Award Program under the LTIP, the number of Performance Shares which a Participant would have been awarded (prior to the Termination Date) for the LTIP Performance Period corresponding to such grant if the business and personal performance goals related to such grant were achieved at the 100% (target) level as of the end of the LTIP Performance Period.

7.27. " Merger " - see definition of Change in Control.

7.28. " Notice of Termination " means a written notice given by an Executive in accordance with Sections 7.18(d)(i) and 13.10 which sets forth in reasonable detail the specific facts and circumstances claimed to provide a basis for a Termination of Employment for Good Reason.

7.29. " Performance Shares " - see Section 5.1(c).

7.30. " Person " means any individual, sole proprietorship, partnership, joint venture, limited liability company, trust, unincorporated organization, association, corporation, institution, public benefit corporation, entity or government instrumentality, division, agency, body or department.

7.31. " Plan Administrator " – See Section 9.

7.32. " Post-Change Period " means the period commencing on a Change Date and ending on the earlier of (a) the Termination Date or (b) the second anniversary of such Change Date; provided that no duplicate benefits shall be paid with respect to simultaneous or overlapping Post-Change Periods.

7.33. " Restricted Stock " — see Section 5.1(d).

7.34. " Retiree " means a Participant who, as of his or her Termination Date, is eligible for "retirement" as defined in the LTIP.

7.35. " Salary Continuation Period " means the applicable period designated in Section 4.1 during which severance is payable.

7.36. " SEC " means the United States Securities and Exchange Commission.

7.37. " SEC Person " means any person (as such term is used in Rule 13d-5 of the SEC under the Exchange Act) or group (as such term is defined in Sections 3(a)(9) and 13(d)(3) of the Exchange Act), other than (a) Exelon or any Person that directly or indirectly controls, is controlled by, or is under common control with, Exelon (an " Affiliate "). For purposes of this definition the term "control" with respect to any Person means the power to direct or cause the direction of management or policies of such Person, directly or indirectly, whether through the ownership of Voting Securities, by contract or otherwise, or (b) any employee benefit plan (or any related trust) of Exelon or any of its Affiliates.

7.38. " Section " means, unless the context otherwise requires, a section of this Plan.

7.39. " Senior Executive Management " means (a) an Executive whose title with respect to Exelon is Executive Vice President or above, (b) an Executive whose title is President or Chief Executive Officer with respect to Baltimore Gas & Electric Company, Commonwealth Edison Company, Exelon Generation Company, LLC, PECO Energy Company or such other Company as may be designated by Exelon's Chief Human Resources Officer, and (c) such other Executive who was described in subparagraph (a) or (b) and has been grandfathered by the Plan Administrator.

7.40. " SERP " means the Constellation Energy Group, Inc. Benefit Restoration Plan, the PECO Energy Company Supplemental Retirement Plan or the Exelon Corporation Supplemental Executive Retirement Plan, whichever is applicable to a Participant, or any successor thereto.

7.41. " Severance Incentive " means the Target Incentive for the performance period in which the Termination Date occurs; provided, however, that for purposes of Section 5, " Severance Incentive " shall mean the greater of (a) the Target Incentive for the performance period in which the Termination Date occurs, or (b) the average of the actual Annual Incentives paid (or payable, to the extent not previously paid) to a Participant under the Annual Incentive Award Plan for each of the two calendar years preceding the calendar year in which the Termination Date occurs.

7.42. " Severance Period " means the period beginning on a Participant's Termination Date, provided such Participant's Termination of Employment entitles such Participant to benefits under Section 5.1 or 5.2, and ending on the second anniversary thereof.

7.43. " Specified Employee " means a "specified employee" within the meaning of Section 409A of the Code.

7.44. " Stock Options " — see Section 5.1(b).

7.45. " Target Incentive " as of a certain date means an amount equal to the product of Base Salary determined as of such date multiplied by the percentage of such Base Salary (if any) to which a Participant would have been entitled immediately prior to such date under the Annual Incentive Award Plan for the applicable

performance period if the performance goals established pursuant to such plan were achieved at the 100% (target) level as of the end of the applicable performance period; provided, however, that any reduction in a Participant's Base Salary or annual incentive that would qualify as Good Reason shall be disregarded for purposes of this definition.

7.46. " Taxes " means the incremental federal, state, local and foreign income, employment, excise and other taxes payable by a Participant with respect to any applicable item of income.

7.47. " Termination Date " means the effective date of an eligible Executive's Termination of Employment with the Company for any or no reason, which shall be the date on which such Executive has a "separation from service," within the meaning of Section 409A of the Code; provided, however, that if the Executive terminates his or her employment for Good Reason, the Termination Date shall not be earlier than the thirtieth day following the Company's receipt of such Executive's Notice of Termination, unless the Exelon consents in writing to an earlier Termination Date.

7.48. " Termination of Employment " means:

(a) a termination of an eligible Executive's employment by the Company for reasons other than for Cause; or

(b) a resignation by an eligible Executive for Good Reason.

The following shall not constitute a Termination of Employment for purposes of the Plan: (i) a termination of employment for Cause, (ii) an Executive's resignation for any reason other than for Good Reason, (iii) the cessation of an Executive's employment with the Company or any Affiliate due to death or disability (as determined by the Plan Administrator in good faith), or (iv) the cessation of an Executive's employment with the Company or any subsidiary thereof as the result of the sale, spin-off or other divestiture of a plant, division, business unit or subsidiary or a merger or other business combination followed by employment or reemployment with the purchaser or successor in interest to the Executive's employer with regard to such plant, division, business unit or subsidiary, or an offer of employment by such purchaser or successor in interest on terms and conditions comparable in the aggregate (as determined by the Plan Administrator in its sole discretion) to the terms and conditions of the Executive's employment with the Company or its subsidiary immediately prior to such transaction.

7.49. " 20% Owner " — see paragraph (a) of the definition of "Change in Control."

7.50. " Voting Securities " means with respect to a corporation, securities of such corporation that are entitled to vote generally in the election of directors of such corporation.

8. **FUNDING**

The Plan is an unfunded employee welfare benefit plan maintained for the purpose of providing severance benefits to a select group of management or highly compensated employees. Nothing in the Plan shall be interpreted as requiring the Company to set aside any of its assets for the purpose of funding its obligations under the Plan. No person entitled to benefits under the Plan shall have any right, title or claim in or to any specific assets of the Company, but shall have the right only as a general creditor to receive benefits from the Company on the terms and conditions provided in the Plan.

9. **ADMINISTRATION OF THE PLAN**

The Plan shall be administered on a day-to-day basis by the Vice President, Corporate Compensation of Exelon (the " Plan Administrator "). The Plan Administrator has the sole and absolute power and authority to interpret and apply the provisions of this Plan to a particular circumstance, make all factual and legal determinations, construe uncertain or disputed terms and make eligibility and benefit determinations in such manner and to such extent as the Plan Administrator, in his or her sole discretion may determine. Benefits under the Plan will be paid only if the Plan Administrator, in his or her discretion, determines that an individual is entitled to them; provided, however, that any dispute after the claims procedure under Section 10 has been exhausted regarding whether an Executive's termination of employment for purposes of Section 5 is based on either Good Reason or Cause may, at the election of the Executive, be submitted to binding arbitration pursuant to Section 11.

The Plan Administrator may promulgate any rules and regulations it deems necessary to carry out the purposes of the Plan or to interpret the terms and conditions of the Plan; provided, however, that no rule, regulation or interpretation shall be contrary to the provisions of the Plan. The rules, regulations and interpretations made by the Plan Administrator shall, where appropriate, be applied on a consistent basis with respect to similarly situated Executives, and shall be final and binding on any Executive or former Executive and any successor in interest.

The Plan Administrator may delegate any administrative duties, including, without limitation, duties with respect to the processing, review, investigation, approval and payment of severance pay and provision of severance benefits, to designated individuals or committees. The Plan Administrator may amend any Participant's Severance Agreement to the extent the Plan Administrator determines it is reasonably necessary or appropriate to do so to comply with section 409A of the Code.

10. **CLAIMS PROCEDURE**

The Plan Administrator shall determine the status of an individual as an Executive and the eligibility and rights of any Executive or former Executive as a Participant to any severance pay or benefits hereunder. Any Executive or former Executive who believes that he or she is entitled to receive severance pay or benefits under the Plan, including severance pay or benefits other than those initially determined by the Plan Administrator, may file a claim in writing with the Plan Administrator. Within 90 days after the receipt of the claim the Plan Administrator shall either allow or deny the claim in writing, unless special circumstances require an extension of time for processing, in which case a decision shall be rendered as soon as practicable, but not later than 180 days after receipt of a request for review.

A claimant whose claim is denied (or his or her duly authorized representative) may, within 60 days after receipt of the denial of his or her claim, request a review upon written application to Exelon's Chief Human Resources Officer or other officer designated by Exelon and specified in the claim denial; review (without charge) relevant documents; and submit written comments, documents, records and other information relating to the claim.

The Chief Human Resources Officer or other designated officer shall notify the claimant of his or her decision on review within 60 days after receipt of a request for review unless special circumstances require an extension of time for processing, in which case a decision shall be rendered as soon as possible, but not later than 120 days after receipt of a request for review. Notice of the decision on review shall be in writing. The officer's decision on review shall be final and binding on any claimant or any successor in interest.

In reviewing a claim or an appeal of a claim denial, the Plan Administrator and the Chief Human Resources Officer or other designated by Exelon shall have all of the powers and authority granted to the Plan Administrator pursuant to Section 9.

11. **ARBITRATION**

Any dispute, controversy or claim between the parties hereto concerning whether an Executive's termination of employment for purposes of Section 5 is based on either Good Reason or Cause may, after the claims procedure under Section 10 has been exhausted and at the election of the Executive, be settled by binding arbitration in Chicago, Illinois, before an impartial arbitrator pursuant to the rules and regulations of the American Arbitration Association (" AAA ") pertaining to the arbitration of employee benefit plan disputes. The costs and fees of the arbitrator shall be borne equally by the parties, regardless of the result of the arbitration. No arbitration shall be commenced after the date when institution of legal or equitable proceedings based upon such subject matter would be barred by the applicable statutes of limitations. Notwithstanding anything to the contrary contained in this Section or elsewhere in this Plan, any party may seek relief in the form of specific performance, injunctive or other equitable relief in order to enforce the decision of the arbitrator, and the Company may seek injunctive relief to enforce the above-referenced statutes of limitations.

12. **AMENDMENT OR TERMINATION OF PLAN**

Exelon's Chief Human Resources Officer or another designated officer of the Company may amend, modify or terminate the Plan at any time by written instrument; provided, however,

that no amendment, modification or termination shall deprive any Participant of any payment or benefit that the Plan Administrator previously has determined is payable under the Plan. Notwithstanding the foregoing, no amendment or termination that reduces the severance payments or materially adversely affects any Participant's other benefits under Section 5 shall become effective as to such Participant during: (a) the 24-month period following a Change Date or (b) during an Imminent Control Change Period (unless such Participant consents to such termination or amendment). Any purported Plan termination or amendment in violation of this Section 12 shall be void and of no effect.

13. **MISCELLANEOUS**

13.1. Limitation on Rights . Participation in the Plan is limited to the individuals described in Sections 2 and 3, and the benefits under the Plan shall not be payable with respect to any voluntary or involuntary termination of employment that is not a Termination of Employment.

13.2. Cooperation By Participants . During the Salary Continuation Period or Severance Period, as applicable, the Executive shall (a) be reasonably available to the Company to respond to requests by them for information pertaining to or relating to matters which may be within the knowledge of the Executive and (b) cooperate with the Company in connection with any existing or future litigation or other proceedings brought by or against the Company, its subsidiaries or affiliates, to the extent the Company deems the Executive's cooperation reasonably necessary.

13.3. No Set-off by Company . This Section shall apply solely with respect to a Termination of Employment during a Post-Change Period or an Imminent Control Change Period that culminates in a Change Date. Except as provided in Section 6, a Participant's right to receive when due the payments and other benefits provided for under Section 5 of this Plan is absolute, unconditional and subject to no setoff, counterclaim or legal or equitable defense.

13.4. No Mitigation . A Participant shall not have any duty to mitigate the amounts payable by the Company under this Plan by seeking new employment following termination. Except as specifically otherwise provided in this Plan, all amounts payable pursuant to this Plan shall be paid without reduction regardless of any amounts of salary, compensation or other amounts which may be paid or payable to the Executive as the result of the Executive's employment by another, unaffiliated employer.

13.5. Headings . Headings of sections in this document are for convenience only, and do not constitute any part of the Plan.

13.6. Severability . If any one or more Sections, subsections or other portions of this Plan are declared by any court or governmental authority to be unlawful or invalid, such unlawfulness or invalidity shall not serve to invalidate any Section, subsection or other portion not so declared to be unlawful or invalid. Any Section, subsection or other portion so declared to be unlawful or invalid shall be construed so as to effectuate the terms of such Section, subsection or other portion

to the fullest extent possible while remaining lawful and valid. Notwithstanding the foregoing, in the event a determination is made that the Restrictive Covenants are invalid or unenforceable in whole or in part, then the Severance Agreement with respect to the Participant subject to such determination shall be void and the Company shall have no obligation to provide benefits under this Plan to such Participant.

13.7. Governing Law . The Plan shall be construed and enforced in accordance with the applicable provisions of ERISA and Section 409A of the Code.

13.8. No Right to Continued Employment . Nothing in this Plan shall guarantee the right of a Participant to continue in employment, and the Company retains the right to terminate a Participant's employment at any time for any reason or for no reason.

13.9. Successors and Assigns . This Plan shall be binding upon and inure to the benefit of Exelon and its successors and assigns and shall be binding upon and inure to the benefit of a Participant and his or her legal representatives, heirs and legatees. Exelon shall cause any successor to assume the Plan. No rights, obligations or liabilities of a Participant hereunder shall be assignable without the prior written consent of Exelon Corporation. In the event of the death of a Participant prior to receipt of severance pay or benefits to which he or she is entitled hereunder (and, with respect to benefits under Section 4 or Section 5, after he or she has signed the Waiver and Release), the severance pay described in Sections 4.1, 5.1, or 5.2, as applicable, shall be paid to his or her estate, and the Participant's dependents who are covered under any health care plans maintained by the Company shall be entitled to continued rights under Section 4.5 or Section 5.1(e) or Section 5.2(g), as applicable; provided that the estate or other successor of the Participant has not revoked such Waiver and Release.

13.10. Notices . All notices and other communications under this Plan shall be in writing and delivered by hand, by nationally-recognized delivery service that promises overnight delivery, or by first-class registered or certified mail, return receipt requested, postage prepaid, addressed as follows:

If to a Participant, to such Participant at his most recent home address on file with the Company.

If to the Company: to the Plan Administrator.

or to such other address as either party shall have furnished to the other in writing. Notice and communications shall be effective when actually received by the addressee.

13.11. Number and Gender . Wherever appropriate, the singular shall include the plural, the plural shall include the singular, and the masculine shall include the feminine.

13.12. Tax Withholding . The Company may withhold from any amounts payable under this Plan or otherwise payable to a Participant or beneficiary any Taxes the

Company determines to be appropriate under applicable law and may report all such amounts payable to such authority in accordance with any applicable law or regulation.

13.13. Section 409A . This Plan shall be interpreted and construed in a manner that avoids the imposition of additional taxes and penalties under Section 409A of the Code ("409A Penalties"). In the event the terms of this Plan would subject a Participant to 409A Penalties, the Company may amend the terms of the Plan to avoid such 409A Penalties, to the extent possible. The payments to a Participant pursuant to this Plan are intended to be exempt from Section 409A of the Code to the maximum extent possible, under either the separation pay exemption pursuant to Treasury regulation §1.409A-1(b)(9)(iii) or as a short-term deferral pursuant to Treasury regulation §1.409A-1(b)(4), and for purposes of the separation pay exemption, each installment paid to a Participant shall be considered a separate payment. Notwithstanding any other provision in this Plan, if on the date of a Participant's Termination Date the Participant is a Specified Employee, then to the extent any amount payable under this Plan constitutes the payment of nonqualified deferred compensation, within the meaning of Section 409A of the Code, that under the terms of this Plan would be payable prior to the six-month anniversary of the Termination Date, such payment shall be delayed until the earlier to occur of (A) the six-month anniversary of the Termination Date or (B) the date of the Participant's death. Any reimbursement (including any advancement) payable to a Participant pursuant to this Plan shall be conditioned on the submission by the Participant of all expense reports reasonably required by the Company under any applicable expense reimbursement policy, and shall be paid to the Participant within 30 days following receipt of such expense reports (or invoices), but in no event later than the last day of the calendar year following the calendar year in which the Participant incurred the reimbursable expense. Any amount of expenses eligible for reimbursement during a calendar year shall not affect the expenses eligibility for reimbursement during any other calendar year. The right to reimbursement pursuant to this Plan shall not be subject to liquidation or exchange for any other benefit.

EXELON CORPORATION

By: /s/ Amy E. Best
Amy E. Best
Senior Vice President and
Chief Human Resources Officer

EXELON CORPORATION

2011 LONG-TERM INCENTIVE PLAN

(As Amended Effective December 18, 2014)

I. INTRODUCTION

1.1 Purposes. The purposes of the Exelon Corporation 2011 Long-Term Incentive Plan (this " Plan ") are (i) to align the interests of the Company's stockholders and the recipients of awards under this Plan by increasing the proprietary interest of such recipients in the Company's growth and success, (ii) to advance the interests of the Company by attracting and retaining officers and other key management employees and (iii) to motivate such persons to act in the long-term best interests of the Company and its stockholders.

1.2 Certain Definitions .

" Affiliate " shall mean any Person (including a Subsidiary) that directly or indirectly controls, is controlled by, or is under common control with, the Company. For purposes of this definition the term "control" with respect to any Person means the power to direct or cause the direction of management or policies of such Person, directly or indirectly, whether through the ownership of Voting Securities, by contract or otherwise.

" Agreement " shall mean the written agreement evidencing an award hereunder between the Company and the recipient of such award.

" Beneficial Owner " shall mean such term as defined in Rule 13d-3 under the Exchange Act.

" Board " shall mean the Board of Directors of the Company.

" Cause " shall mean (a) with respect to an employee whose entitlement to severance benefits upon termination of employment is governed by an individual change in control agreement, the meaning of such term specified in such agreement, (b) with respect to an employee whose entitlement to severance benefits upon termination of employment is governed by the Exelon Corporation Senior Management Severance Plan or any other executive severance plan, as in effect from time to time, the meaning of such term specified in such plan, or (c) with respect to any other employee, the meaning of such term specified in the Exelon Corporation Severance Benefit Plan, as amended from time to time, or any successor plan thereto, regardless of whether such employee is eligible to participate in such plan.

" Change in Control " shall have the meaning set forth in Section 5.8.

" Code " shall mean the Internal Revenue Code of 1986, as amended.

" Committee " shall mean the Committee designated by the Board, consisting of two or more members of the Board, each of whom may be (i) a "Non-Employee Director" within the meaning of Rule 16b-3 under the Exchange Act, (ii) an "outside director" within the meaning of Section 162(m) of the Code and (iii) "independent" within the meaning of the rules of the New York Stock Exchange or, if the Common Stock is not listed on the New York Stock Exchange, within the meaning of the rules of the principal national stock exchange on which the Common Stock is then traded.

" Common Stock " shall mean the common stock, without par value, of the Company.

" Company " shall mean Exelon Corporation, a Pennsylvania corporation, or any successor thereto.

" Company Plan " shall have the meaning set forth in Section 5.8(b)(i).

" Corporate Transaction " shall have the meaning set forth in Section 5.8(a).

" Disability " shall have the meaning specified in any long term disability plan maintained by the Company in which the participant is eligible to participate; provided that a Disability shall not be deemed to have occurred until the Company has terminated such participant's employment in connection with such disability and the participant has commenced the receipt of long-term disability benefits under such plan. If an participant is not eligible to participate in a long-term disability plan maintained by the Company, then Disability shall mean a termination of such participant's employment by the Company due to the inability of such participant to perform the essential functions such participant's position, with or without reasonable accommodation, for a continuous period of at least twelve months, as determined solely by the Committee.

" Exchange Act " shall mean the Securities Exchange Act of 1934, as amended.

" Fair Market Value " shall mean the closing transaction price of a share of Common Stock as reported on the New York Stock Exchange on the date as of which such value is being determined or, if the Common Stock is not listed on the New York Stock Exchange, the closing transaction price of a share of Common Stock on the principal national stock exchange on which the Common Stock is traded on the date as of which such value is being determined or, if there shall be no reported transactions for such date, on the next preceding date for which transactions were reported; provided , however , that if the Common Stock is not listed on a national stock exchange or if Fair Market Value for any date cannot be so determined, Fair Market Value shall be determined by the Committee by whatever means or method as the Committee, in the good faith exercise of its discretion, shall at such time deem appropriate and in accordance with Section 409A of the Code.

" Free-Standing SAR " shall mean an SAR which is not granted in tandem with, or by reference to, an option, which entitles the holder thereof to receive, upon exercise, shares of

Common Stock (which may be Restricted Stock), cash or a combination thereof with an aggregate value equal to the excess of the Fair Market Value of one share of Common Stock on the date of exercise over the base price of such SAR, multiplied by the number of such SARs which are exercised.

" Good Reason " shall mean (i) with respect to an employee whose entitlement to severance benefits upon termination of employment is governed by an individual change in control agreement, the meaning of such term specified in such agreement, or (ii) with respect to a employee whose entitlement to severance benefits upon termination of employment is governed by the Exelon Corporation Senior Management Severance Plan or any other executive severance plan, as in effect from time to time, the meaning of such term specified in such plan.

" Incentive Stock Option " shall mean an option to purchase shares of Common Stock that meets the requirements of Section 422 of the Code, or any successor provision, which is intended by the Committee to constitute an Incentive Stock Option.

" Incumbent Board " shall have the meaning set forth in Section 5.8(b)(ii).

" Nonqualified Stock Option " shall mean an option to purchase shares of Common Stock which is not an Incentive Stock Option.

" Performance Measures " shall mean the criteria and objectives, established by the Committee, which shall be satisfied or met (i) as a condition to the grant or exercisability of all or a portion of an option or SAR or (ii) during the applicable Restriction Period or Performance Period as a condition to the vesting of the holder's interest, in the case of a Restricted Stock Award, of the shares of Common Stock subject to such award, or, in the case of a Restricted Stock Unit Award or Performance Unit Award, to the holder's receipt of the shares of Common Stock subject to such award or of payment with respect to such award. To the extent necessary for an award to be qualified performance-based compensation under Section 162(m) of the Code and the regulations thereunder, such criteria and objectives shall include one or more of the following measures, each of which may be based on absolute standards or peer industry group comparatives and may be applied at various organizational levels (e.g., corporate, business unit, division): (1) cumulative shareholder value added (SVA), (2) customer satisfaction, (3) revenue, (4) primary or fully-diluted earnings per share of Common Stock, (5) net income, (6) total shareholder return, (7) earnings before interest taxes (EBIT), (8) cash flow, including operating cash flows, free cash flow, discounted cash flow return on investment and cash flow in excess of cost of capital, or any combination thereof, (9) economic value added, (10) return on equity, (11) return on capital, (12) return on assets, (13) net operating profits after taxes, (14) stock price increase, (15) return on sales, (16) debt to equity ratio, (17) payout ratio, (18) asset turnover, (19) ratio of share price to book value of shares, (20) price/earnings ratio, (21) employee satisfaction, (22) diversity, (23) market share, (24) operating income, (25) pre-tax income, (26) safety, (27) diversification of business opportunities, (28) expense ratios, (29) total expenditures, (30) completion of key projects, (31) dividend payout as percentage of net income, (32) earnings before interest, taxes, depreciation and amortization (EBITDA), or (33) any individual performance objective which is measured solely in terms of quantitative targets related to the

Company, any Subsidiary or the Company's or Subsidiary's business. Such individual performance measures related to the Company, a Subsidiary or the Company's or Subsidiary's business may include: (A) production-related factors such as generating capacity factor, performance against the INPO index, generating equivalent availability, heat rates and production cost, (B) transmission and distribution-related factors such as customer satisfaction, reliability (based on outage frequency and duration), and cost, (C) customer service-related factors such as customer satisfaction, service levels and responsiveness and bad debt collections or losses, and (D) relative performance against other similar companies in targeted areas. The measures may be weighted differently for holders of awards based on their management level and the extent to which their responsibilities are primarily corporate or business unit-related, and may be based in whole or in part on the performance of the Company, a Subsidiary, division and/or other operational unit under one or more of such measures. In the sole discretion of the Committee, but subject to Section 162(m) of the Code, the Committee may amend or adjust the Performance Measures or other terms and conditions of an outstanding award in recognition of unusual or nonrecurring events affecting the Company or its financial statements or changes in law or accounting principles.

" Performance Option " shall mean an Incentive Stock Option or Nonqualified Stock Option, the grant of which or the exercisability of all or a portion of which is contingent upon the attainment of specified Performance Measures within a specified Performance Period.

" Performance Period " shall mean any period designated by the Committee during which (i) the Performance Measures applicable to an award shall be measured and (ii) the conditions to vesting applicable to an award shall remain in effect.

" Performance Share Award " shall mean a Restricted Stock Award or Restricted Stock Unit Award, the vesting of which is subject to the attainment of specified Performance Measures within a specified Performance Period.

" Performance Unit " shall mean a right to receive, contingent upon the attainment of specified Performance Measures within a specified Performance Period and the expiration of any applicable Restriction Period, a specified cash amount or, in lieu thereof, shares of Common Stock having a Fair Market Value equal to such cash amount.

" Performance Unit Award " shall mean an award of Performance Units under this Plan.

" Person " shall mean any individual, sole proprietorship, partnership, joint venture, limited liability company, trust, unincorporated organization, association, corporation, institution, public benefit corporation, entity or government instrumentality, division, agency, body or department.

" Plan " shall have the meaning set forth in Section 1.1.

" Prior Plan " shall mean the Exelon Corporation 2006 Long-Term Incentive Plan, as amended.

“ Restricted Stock ” shall mean shares of Common Stock which are subject to a Restriction Period and which may, in addition thereto, be subject to the attainment of specified Performance Measures within a specified Performance Period.

“ Restricted Stock Award ” shall mean an award of Restricted Stock under this Plan.

“ Restricted Stock Unit ” shall mean a right to receive one share of Common Stock or, in lieu thereof, the Fair Market Value of such share of Common Stock in cash, which shall be contingent upon the expiration of a specified Restriction Period and which may, in addition thereto, be contingent upon the attainment of specified Performance Measures within a specified Performance Period.

“ Restricted Stock Unit Award ” shall mean an award of Restricted Stock Units under this Plan.

“ Restriction Period ” shall mean any period designated by the Committee during which (i) the Common Stock subject to a Restricted Stock Award may not be sold, transferred, assigned, pledged, hypothecated or otherwise encumbered or disposed of, except as provided in this Plan or the Agreement relating to such award, or (ii) the conditions to vesting applicable to a Restricted Stock Unit Award shall remain in effect.

“ Restrictive Covenant ” shall have the meaning set forth in Section 2.3(g).

“ Retirement ” shall mean the retirement of a holder of an award from employment with the Company on or after attaining the minimum age specified for early or normal retirement in any then effective qualified defined benefit retirement plan of the Company in which such holder is a participant, provided that such holder has also attained age 50 and completed at least ten years of service with the Company and the Subsidiaries. For purposes of this definition, the holder’s age and service shall be determined taking into account any deemed age or service awarded to the holder for benefit accrual purposes under any nonqualified defined benefit retirement plan of the Company in which the holder is a participant.

“ SAR ” shall mean a stock appreciation right, which may be a Free-Standing SAR or a Tandem SAR.

“ SEC Person ” shall mean any person (as such term is used in Rule 13d-5 under the Exchange Act) or group (as such term is defined in Sections 3(a)(9) and 13(d)(3) of the Exchange Act), other than (i) the Company or an Affiliate, or (ii) any employee benefit plan (or any related trust) of the Company or any of its Affiliates.

“ Stock Award ” shall mean a Restricted Stock Award or a Restricted Stock Unit Award, including any such award which is granted as a Performance Share Award.

“ Subsidiary ” shall mean any corporation, limited liability company, partnership, joint venture or similar entity in which the Company owns, directly or indirectly, an equity interest possessing more than 50% of the combined voting power of the total outstanding equity interests of such entity.

" Tandem SAR " shall mean an SAR which is granted in tandem with, or by reference to, an option (including a Nonqualified Stock Option granted prior to the date of grant of the SAR), which entitles the holder thereof to receive, upon exercise of such SAR and surrender for cancellation of all or a portion of such option, shares of Common Stock (which may be Restricted Stock), cash or a combination thereof with an aggregate value equal to the excess of the Fair Market Value of one share of Common Stock on the date of exercise over the base price of such SAR, multiplied by the number of shares of Common Stock subject to such option, or portion thereof, which is surrendered.

" Tax Date " shall have the meaning set forth in Section 5.5.

" Ten Percent Holder " shall have the meaning set forth in Section 2.1(a).

" 20% Owner " shall have the meaning set forth in Section 5.8(b)(i).

" Voting Securities " shall mean with respect to a corporation, securities of such corporation that are entitled to vote generally in the election of directors of such corporation.

1.3 Administration . This Plan shall be administered by the Committee. Any one or a combination of the following awards may be made under this Plan to eligible persons: (i) options to purchase shares of Common Stock in the form of Incentive Stock Options or Nonqualified Stock Options (which may include Performance Options), (ii) SARs in the form of Tandem SARs or Free-Standing SARs, (iii) Stock Awards in the form of Restricted Stock or Restricted Stock Units (which may include Performance Share Awards) and (iv) Performance Units. The Committee shall, subject to the terms of this Plan, select eligible persons for participation in this Plan and determine the form, amount and timing of each award to such persons and, if applicable, the number of shares of Common Stock, the number of SARs, the number of Restricted Stock Units and the number of Performance Units subject to such an award, the exercise price or base price associated with the award, the time and conditions of exercise or settlement of the award and all other terms and conditions of the award, including, without limitation, the form of the Agreement evidencing the award. The Committee may, in its sole discretion and for any reason at any time, subject to the requirements of Section 162(m) of the Code and regulations thereunder in the case of an award intended to be qualified performance-based compensation, take action such that (i) any or all outstanding options and SARs shall become exercisable in part or in full, (ii) all or a portion of the Restriction Period applicable to any outstanding Restricted Stock or Restricted Stock Units shall lapse, (iii) all or a portion of the Performance Period applicable to any outstanding Performance Share Award or Performance Units shall lapse and (iv) the Performance Measures (if any) applicable to any outstanding award shall be deemed to be satisfied at the target or any other level not exceeding the maximum allowable under its terms. The Committee shall, subject to the terms of this Plan, interpret this Plan and the application thereof, establish rules and regulations it deems necessary or desirable for the administration of this Plan and may impose, incidental to the grant of an award,

conditions with respect to the award, such as limiting competitive employment or other activities. All such interpretations, rules, regulations and conditions shall be conclusive and binding on all parties.

The Committee may delegate some or all of its power and authority hereunder to the Board or, subject to applicable law, to the Chief Executive Officer or other officer of the Company as the Committee deems appropriate; provided , however , that (i) the Committee may not delegate its power and authority to the Board or the Chief Executive Officer or other officer of the Company with regard to the grant of an award to any person who is a "covered employee" within the meaning of Section 162(m) of the Code or who, in the Committee's judgment, is likely to be a covered employee at the time during the period an award hereunder to such employee would be outstanding, (ii) the Committee may not delegate its power and authority to the Chief Executive Officer or other officer of the Company with regard to the selection for participation in this Plan of an officer or other person subject to Section 16 of the Exchange Act or whose title with the Company is "executive vice president" or higher, or decisions concerning the timing, pricing or amount of an award to such an officer or other person and (iii) the awards granted by the Chief Executive Officer pursuant to such delegation shall not exceed the limits set forth in Section 1.6(c) and 1.6(d).

No member of the Board or Committee, and neither the Chief Executive Officer nor any other officer to whom the Committee delegates any of its power and authority hereunder, shall be liable for any act, omission, interpretation, construction or determination made in connection with this Plan in good faith, and the members of the Board and the Committee and the Chief Executive Officer or other officer shall be entitled to indemnification and reimbursement by the Company in respect of any claim, loss, damage or expense (including attorneys' fees) arising therefrom to the full extent permitted by law (except as otherwise may be provided in the Company's Articles of Incorporation and/or By-laws) and under any directors' and officers' liability insurance that may be in effect from time to time.

A majority of the Committee shall constitute a quorum. The acts of the Committee shall be either (i) acts of a majority of the members of the Committee present at any meeting at which a quorum is present or (ii) acts approved in writing by all of the members of the Committee without a meeting.

1.4 Eligibility . Participants in this Plan shall consist of such officers and other key management employees, and persons expected to become officers and other key management employees, of the Company and its Subsidiaries as the Committee in its sole discretion may select from time to time. The Committee's selection of a person to participate in this Plan at any time shall not require the Committee to select such person to participate in this Plan at any other time. For purposes of this Plan, references to employment by the Company shall also mean employment by a Subsidiary.

1.5 Shares Available . Subject to adjustment as provided in Section 5.7, the aggregate number of shares of Common Stock available for awards granted under the Plan in the form of options, SARs, Stock Awards or Performance Units shall be the sum of (i) five million

(5,000,000), plus (ii) the number of shares of Common Stock which as of the effective date of this Plan remain available for future awards pursuant to Section 1.5 of the Prior Plan, and reduced by the sum of the aggregate number of shares of Common Stock which become subject to outstanding options, outstanding Free-Standing SARs and outstanding Stock Awards granted under the Plan and shares of Common Stock delivered upon the settlement of Performance Units granted under the Plan. To the extent that shares of Common Stock subject to an outstanding option, SAR or stock award granted under the Plan or any predecessor plan are not issued or delivered by reason of the expiration, termination, cancellation or forfeiture of such award (excluding shares subject to an option cancelled upon settlement in shares of a related tandem SAR or shares subject to a tandem SAR cancelled upon exercise of a related option), then such shares of Common Stock shall again be available under this Plan. Shares of Common Stock to be delivered under this Plan shall be made available from authorized and unissued shares of Common Stock, or authorized and issued shares of Common Stock reacquired and held as treasury shares or otherwise or a combination thereof.

1.6 Award Limits .

(a) Subject to adjustment as provided in Section 5.7, no individual may be granted awards under the Plan during any calendar year that, in the aggregate, may be settled by delivery of more than two million (2,000,000) shares of Common Stock. In addition, with respect to awards the value of which is based on the Fair Market Value of Common Stock and that may be settled in cash (in whole or in part), no individual may be paid during any calendar year cash amounts relating to such awards that exceed the greater of the Fair Market Value of the number of shares of Common Stock set forth in the preceding sentence either at the date of grant or at the date of settlement. This Section 1.6(a) sets forth two separate limitations, so that awards that may be settled solely by delivery of Common Stock will not operate to reduce the amount or value of cash-only awards, and vice versa; nevertheless, awards that may be settled in Common Stock or cash must not exceed either limitation.

(b) With respect to awards, the value of which is not based on the Fair Market Value of Common Stock, no individual may receive during any calendar year cash or shares of Common Stock with a Fair Market Value at the date of settlement that, in the aggregate, exceeds five million dollars ($5,000,000).

(c) Subject to adjustment as provided in Section 5.7, the number of shares of Common Stock subject to options and SARs granted in any single year by the Chief Executive Officer, pursuant to a delegation by the Committee in accordance with Section 1.3 of this Plan, shall not exceed 1,200,000 in the aggregate or 40,000 with respect to any individual employee.

(d) Subject to adjustment as provided in Section 5.7, the number of shares of Common Stock subject to Stock Awards and Performance Units granted in any single year by the Chief Executive Officer, pursuant to a delegation by the Committee in accordance with Section 1.3 of this Plan, shall not exceed 600,000 in the aggregate or 20,000 with respect to any individual employee.

II. STOCK OPTIONS AND STOCK APPRECIATION RIGHTS

2.1 Stock Options . The Committee may, in its discretion, grant options to purchase shares of Common Stock to such eligible persons as may be selected by the Committee. Each option, or portion thereof, that is not an Incentive Stock Option, shall be a Nonqualified Stock Option. Each option shall be granted within 10 years after the date on which this Plan is approved by the Board. To the extent that the aggregate Fair Market Value (determined as of the date of grant) of shares of Common Stock with respect to which options designated as Incentive Stock Options are exercisable for the first time by a participant during any calendar year (under this Plan or any other plan of the Company, or any parent or Subsidiary) exceeds the amount (currently $100,000) established by the Code, such options shall constitute Nonqualified Stock Options.

Options shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable:

(a) Number of Shares and Purchase Price . The number of shares of Common Stock subject to an option and the purchase price per share of Common Stock purchasable upon exercise of the option shall be determined by the Committee; provided , however , that the purchase price per share of Common Stock purchasable upon exercise of a Nonqualified Stock Option or an Incentive Stock Option shall not be less than 100% of the Fair Market Value of a share of Common Stock on the date of grant of such option; provided further , that if an Incentive Stock Option shall be granted to any person who, at the time such option is granted, owns capital stock possessing more than 10 percent of the total combined voting power of all classes of capital stock of the Company (or of any parent or Subsidiary) (a " Ten Percent Holder "), the purchase price per share of Common Stock shall not be less than the price (currently 110% of Fair Market Value) required by the Code in order to constitute an Incentive Stock Option.

(b) Option Period and Exercisability . The period during which an option may be exercised shall be determined by the Committee; provided , however , that no option shall be exercised later than 10 years after its date of grant; provided further , that if an Incentive Stock Option shall be granted to a Ten Percent Holder, such option shall not be exercised later than five years after its date of grant. The Committee may, in its discretion, determine that an option is to be granted as a Performance Option and may establish an applicable Performance Period and Performance Measures which shall be satisfied or met as a condition to the grant of such option or to the exercisability of all or a portion of such option. The Committee shall determine whether an option shall become exercisable in cumulative or non-cumulative installments and in part or in full at any time. An exercisable option, or portion thereof, may be exercised only with respect to whole shares of Common Stock.

(c) Method of Exercise . An option may be exercised (i) by giving written notice to the Company specifying the number of whole shares of Common Stock to be purchased and accompanying such notice with payment therefor in full, and without any extension of credit, either (A) in cash, (B) by delivery (either actual delivery or by attestation procedures established by the Company) to the Company of previously owned whole shares of Common Stock having a

Fair Market Value, determined as of the date of exercise, equal to the aggregate purchase price payable by reason of such exercise, (C) authorizing the Company to withhold whole shares of Common Stock which would otherwise be delivered having an aggregate Fair Market Value, determined as of the date of exercise, equal to the amount necessary to satisfy such obligation, provided that the Committee determines that such withholding of shares does not cause the Company to recognize an increased compensation expense under applicable accounting principles, (D) except as may be prohibited by applicable law, in cash by a broker-dealer acceptable to the Company to whom the optionee has submitted an irrevocable notice of exercise or (E) a combination of (A), (B) and (C), in each case to the extent set forth in the Agreement relating to the option, (ii) if applicable, by surrendering to the Company any Tandem SARs which are cancelled by reason of the exercise of the option and (iii) by executing such documents as the Company may reasonably request. Any fraction of a share of Common Stock which would be required to pay such purchase price shall be disregarded and the remaining amount due shall be paid in cash by the optionee. No shares of Common Stock shall be issued and no certificate representing Common Stock shall be delivered until the full purchase price therefor and any withholding taxes thereon, as described in Section 5.5, have been paid.

2.2 Stock Appreciation Rights . The Committee may, in its discretion, grant SARs to such eligible persons as may be selected by the Committee. The Agreement relating to an SAR shall specify whether the SAR is a Tandem SAR or a Free-Standing SAR.

SARs shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable:

(a) Number of SARs and Base Price . The number of SARs subject to an award shall be determined by the Committee. Any Tandem SAR related to an Incentive Stock Option shall be granted at the same time that such Incentive Stock Option is granted. The base price of a Tandem SAR shall be the purchase price per share of Common Stock of the related option. The base price of a Free-Standing SAR shall be determined by the Committee; provided , however , that such base price shall not be less than 100% of the Fair Market Value of a share of Common Stock on the date of grant of such SAR.

(b) Exercise Period and Exercisability . The Agreement relating to an award of SARs shall specify whether such award may be settled in shares of Common Stock (including shares of Restricted Stock) or cash or a combination thereof. The period for the exercise of an SAR shall be determined by the Committee; provided , however , that no SAR shall be exercised later than 10 years after its date of grant; and provided , further , that no Tandem SAR shall be exercised later than the expiration, cancellation, forfeiture or other termination of the related option. The Committee may, in its discretion, establish Performance Measures which shall be satisfied or met as a condition to the grant of an SAR or to the exercisability of all or a portion of an SAR. The Committee shall determine whether an SAR may be exercised in cumulative or non-cumulative installments and in part or in full at any time. An exercisable SAR, or portion thereof, may be exercised, in the case of a Tandem SAR, only with respect to whole shares of Common Stock and, in the case of a Free-Standing SAR, only with respect to a whole number of SARs. If an

SAR is exercised for shares of Restricted Stock, a certificate or certificates representing such Restricted Stock shall be issued in accordance with Section 3.2(c), or such shares shall be transferred to the holder in book entry form with restrictions on the Shares duly noted, and the holder of such Restricted Stock shall have such rights of a stockholder of the Company as determined pursuant to Section 3.2(d). Prior to the exercise of an SAR for shares of Common Stock, including Restricted Stock, the holder of such SAR shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such SAR.

(c) Method of Exercise . A Tandem SAR may be exercised (i) by giving written notice to the Company specifying the number of whole SARs which are being exercised, (ii) by surrendering to the Company any options which are cancelled by reason of the exercise of the Tandem SAR and (iii) by executing such documents as the Company may reasonably request. A Free-Standing SAR may be exercised (A) by giving written notice to the Company specifying the whole number of SARs which are being exercised and (B) by executing such documents as the Company may reasonably request.

2.3 Termination of Employment .

(a) Retirement or Disability . Subject to Sections 2.3(e) and 2.3(g) below, and unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the Company ceases to employ the holder of an option or SAR by reason of such holder's Retirement or Disability, each option and SAR held by such holder shall be fully exercisable, and may thereafter be exercised by such holder (or such holder's legal representative or similar person) until and including the earlier to occur of (i) the date which is five years after the effective date of such holder's termination of employment and (ii) the expiration date of the term of such option or SAR.

(b) Death . Unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the Company ceases to employ the holder of an option or SAR by reason of such holder's death, each option and SAR held by such holder shall be fully exercisable, and may thereafter be exercised by such holder's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the date which is three years after the date of death and (ii) the expiration date of the term of such option or SAR.

(c) Cause . If the Company ceases to employ the holder of an option or SAR due to a termination of employment by the Company for Cause, each option and SAR held by such holder shall be cancelled and cease to be exercisable as of the earlier to occur of (i) the effective date of such termination of employment and (ii) the date on which the holder first engaged in conduct giving rise to a termination for Cause, and the Company thereafter may require the repayment of any amounts received by such holder in connection with an exercise of such option or SAR following such cancellation date.

(d) Other Termination . Subject to Sections 2.3(e), 2.3(f) and 2.3(g) below and unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the Company ceases to employ the holder of an option or SAR for any reason other than as

described in Section 2.3(a) through Section 2.3(c), then each option and SAR held by such holder shall be exercisable only to the extent that such option or SAR is exercisable on the effective date of such holder's termination of employment, and may thereafter be exercised by such holder (or such holder's legal representative or similar person) until and including the earlier to occur of (i) the date which is 90 days after the effective date of such holder's termination of employment and (ii) the expiration date of the term of such option or SAR.

(e) Death Following Termination of Employment . Unless otherwise specified in the Agreement relating to an option or SAR, as the case may be, if the holder of an option or SAR dies during the applicable post-termination exercise period described in Section 2.3(d), each option and SAR held by such holder shall be exercisable only to the extent that such option or SAR, as the case may be, is exercisable on the date of such holder's death and may thereafter be exercised by the holder's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the date which is one year after the date of death and (ii) the expiration date of the term of such option or SAR.

(f) Breach of Restrictive Covenant . Notwithstanding Sections 2.3(a) through (e), if the holder of an option or SAR breaches his or her obligations to the Company or any of its affiliates under a noncompetition, nonsolicitation, confidentiality, intellectual property or other restrictive covenant (a " Restrictive Covenant "), each option and SAR held by such holder shall be cancelled and cease to be exercisable as of the date on which the holder first breached such Restrictive Covenant, and the Company thereafter may require the repayment of any amounts received by such holder in connection with an exercise of such option or SAR following such cancellation date.

(g) Certain Terminations After Change in Control . Unless otherwise specified in, and subject to all conditions set forth in, the Agreement relating to an option or SAR, as the case may be, or any individual change in control agreement or severance plan, and notwithstanding any other provision of this Section 2.3, if within 24 months following a Change in Control, the Company ceases to employ the holder of an option or SAR due to a termination of employment (i) by the Company other than for Cause, or (ii) with respect to a holder whose position is at least salary band E09 (or its equivalent), by the holder for Good Reason, such holder's outstanding options shall immediately become fully exercisable and may thereafter be exercised by such holder (or such holder's legal representative or similar person) until and including the earlier to occur of (A) the date which is five years after the effective date of such holder's termination of employment and (B) the expiration date of the term of such option or SAR.

2.4 No Repricing . The Committee shall not without the approval of the stockholders of the Company, (i) reduce the purchase price or base price of any previously granted option or SAR, (ii) cancel any previously granted option or SAR in exchange for another option or SAR with a lower purchase price or base price or (iii) cancel any previously granted option or SAR in exchange for cash or another award if the purchase price of such option or the base price of such SAR exceeds the Fair Market Value of a share of Common Stock on the date of such cancellation, in each case, other than in connection with a Change in Control or the adjustment provisions set forth in Section 5.7.

III. STOCK AWARDS

3.1 Stock Awards. The Committee may, in its discretion, grant Stock Awards to such eligible persons as may be selected by the Committee. The Agreement relating to a Stock Award shall specify whether the Stock Award is a Restricted Stock Award or a Restricted Stock Unit Award. The Committee may, in its discretion, determine that a Restricted Stock Award or Restricted Stock Unit Award is to be granted as a Performance Share Award and may establish an applicable Performance Period and Performance Measures which shall be satisfied or met as a condition to the grant or vesting of all or a portion of such award.

3.2 Terms of Restricted Stock Awards. Restricted Stock Awards shall be subject to the following terms and conditions and shall be subject to such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable.

(a) Number of Shares and Other Terms. The number of shares of Common Stock subject to a Restricted Stock Award and the Restriction Period and Performance Measures (if any) applicable to a Restricted Stock Award shall be determined by the Committee.

(b) Vesting and Forfeiture. The Agreement relating to a Restricted Stock Award shall provide, in the manner determined by the Committee, in its discretion, and subject to the provisions of this Plan, for the vesting of the shares of Common Stock subject to such award (i) if the holder of such award remains continuously in the employment of the Company during the specified Restriction Period and (ii) in the case of a Performance Share Award, if specified Performance Measures are satisfied or met during a specified Performance Period, and for the forfeiture of the shares of Common Stock subject to such award (x) if the holder of such award does not remain continuously in the employment of the Company during the specified Restriction Period or (y) in the case of a Performance Share Award, if specified Performance Measures are not satisfied or met during a specified Performance Period. The restrictions applicable to each Performance Share Award shall lapse no earlier than one year after the applicable grant date, except to the extent an award Agreement provides otherwise in the case of a Change in Control or a participant's death, Disability or termination of employment.

(c) Stock Issuance. During the Restriction Period, the shares of Restricted Stock shall be held by a custodian in book entry form with restrictions on such shares duly noted or, alternatively, a certificate or certificates representing a Restricted Stock Award shall be registered in the holder's name and may bear a legend, in addition to any legend which may be required pursuant to Section 5.6, indicating that the ownership of the shares of Common Stock represented by such certificate is subject to the restrictions, terms and conditions of this Plan and the Agreement relating to the Restricted Stock Award. All such certificates shall be deposited with the Company, together with stock powers or other instruments of assignment (including a power of attorney), each endorsed in blank with a guarantee of signature if deemed necessary or appropriate, which would permit transfer to the Company of all or a portion of the shares of Common Stock subject to the Restricted Stock Award in the event such award is forfeited in whole or in part. Upon termination of any applicable Restriction Period (and the satisfaction or attainment of applicable Performance Measures), subject to the Company's right to require

payment of any taxes in accordance with Section 5.5, the restrictions shall be removed from the requisite number of any shares of Common Stock that are held in book entry form, and all certificates evidencing ownership of the requisite number of shares of Common Stock shall be delivered to the holder of such award.

(d) Rights with Respect to Restricted Stock Awards . Unless otherwise set forth in the Agreement relating to a Restricted Stock Award, and subject to the terms and conditions of a Restricted Stock Award, the holder of such award shall have all rights as a stockholder of the Company, including, but not limited to, voting rights, the right to receive dividends and the right to participate in any capital adjustment applicable to all holders of Common Stock; provided , however , that (i) a distribution with respect to shares of Common Stock, other than a regular cash dividend, and (ii) a regular cash dividend with respect to shares of Common Stock that are subject to performance-based vesting conditions, in each case shall be deposited with the Company and shall be subject to the same restrictions as the shares of Common Stock with respect to which such distribution was made.

3.3 Terms of Restricted Stock Unit Awards . Restricted Stock Unit Awards shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable.

(a) Number of Shares and Other Terms . The number of shares of Common Stock subject to a Restricted Stock Unit Award and the Restriction Period and Performance Measures (if any) applicable to a Restricted Stock Unit Award shall be determined by the Committee.

(b) Vesting and Forfeiture . The Agreement relating to a Restricted Stock Unit Award shall provide, in the manner determined by the Committee, in its discretion, and subject to the provisions of this Plan, for the vesting of such Restricted Stock Unit Award (i) if the holder of such award remains continuously in the employment of the Company during the specified Restriction Period and (ii) in the case of a Performance Share Award, if specified Performance Measures are satisfied or met during a specified Performance Period, and for the forfeiture of the shares of Common Stock subject to such award (x) if the holder of such award does not remain continuously in the employment of the Company during the specified Restriction Period or (y) in the case of a Performance Share Award, if specified Performance Measures are not satisfied or met during a specified Performance Period. Each Performance Share Award shall become vested no earlier than one year after the applicable grant date, except to the extent an award Agreement provides otherwise in the case of a Change in Control or a participant's death, Disability or termination of employment.

(c) Settlement of Vested Restricted Stock Unit Awards . The Agreement relating to a Restricted Stock Unit Award shall specify (i) whether such award may be settled in shares of Common Stock, including Restricted Stock, or cash or a combination thereof and (ii) whether the holder thereof shall be entitled to receive, on a current or deferred basis, dividend equivalents and, if determined by the Committee, interest on, or the deemed reinvestment of, any deferred dividend equivalents, with respect to the number of shares of Common Stock subject to such award. Prior to the settlement of a Restricted Stock Unit Award, the holder of such award shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such award.

3.4 Termination of Employment . All of the terms relating to the satisfaction of Performance Measures and the termination of the Restriction Period or Performance Period relating to a Stock Award, or any forfeiture and cancellation of such award upon a termination of employment with the Company of the holder of such award, whether by reason of Disability, Retirement, death or any other reason, shall be determined by the Committee and set forth in the applicable award Agreement.

IV. PERFORMANCE UNIT AWARDS

4.1 Performance Unit Awards . The Committee may, in its discretion, grant Performance Unit Awards to such eligible persons as may be selected by the Committee.

4.2 Terms of Performance Unit Awards . Performance Unit Awards shall be subject to the following terms and conditions and shall be subject to such additional terms and conditions, not inconsistent with the terms of this Plan, as the Committee shall deem advisable.

(a) Number of Performance Units and Performance Measures . The number of Performance Units subject to a Performance Unit Award and the Performance Measures and Performance Period applicable to a Performance Unit Award shall be determined by the Committee.

(b) Vesting and Forfeiture . The Agreement relating to a Performance Unit Award shall provide, in the manner determined by the Committee, in its discretion, and subject to the provisions of this Plan, for the vesting of such Performance Unit Award if the specified Performance Measures are satisfied or met during the specified Performance Period and for the forfeiture of such award if the specified Performance Measures are not satisfied or met during the specified Performance Period.

(c) Settlement of Vested Performance Unit Awards . The Agreement relating to a Performance Unit Award shall specify whether such award may be settled in shares of Common Stock (including shares of Restricted Stock) or cash or a combination thereof. If a Performance Unit Award is settled in shares of Restricted Stock, such shares of Restricted Stock shall be issued to the holder in book entry form or a certificate or certificates representing such Restricted Stock shall be issued in accordance with Section 3.2(c) and the holder of such Restricted Stock shall have such rights as a stockholder of the Company as determined pursuant to Section 3.2(d). Prior to the settlement of a Performance Unit Award in shares of Common Stock, including Restricted Stock, the holder of such award shall have no rights as a stockholder of the Company.

4.3 Termination of Employment . All of the terms relating to the satisfaction of Performance Measures and the termination of the Performance Period relating to a Performance Unit Award, or any forfeiture and cancellation of such award upon a termination of employment with the Company of the holder of such award, whether by reason of Disability, Retirement, death or any other reason, shall be determined by the Committee and set forth in the applicable award Agreement.

V. GENERAL

5.1 Effective Date and Term of Plan . This Plan shall be submitted to the stockholders of the Company for approval at the Company's 2010 annual meeting of stockholders and, if approved by the affirmative vote of a majority of the shares of Common Stock present in person or represented by proxy at such annual meeting of stockholders, shall become effective as of January 1, 2011. This Plan shall terminate ten (10) years after its effective date, unless terminated earlier by the Committee. Termination of this Plan shall not affect the terms or conditions of any award granted prior to termination.

Awards hereunder may be made at any time prior to the termination of this Plan, provided that, subject to Section 2.1, no award may be made later than ten (10) years after the effective date of this Plan. In the event that this Plan is not approved by the stockholders of the Company, this Plan and any awards hereunder shall be void and of no force or effect.

5.2 Amendments . The Committee may amend this Plan as it shall deem advisable, subject to any requirement of stockholder approval required by applicable law, rule or regulation, including Section 162(m) of the Code and any rule of the New York Stock Exchange, or, if the Common Stock is not listed on the New York Stock Exchange, any rule of the principal national stock exchange on which the Common Stock is then traded; provided , however , that no amendment may impair the rights of a holder of an outstanding award without the consent of such holder.

5.3 Agreement . Each award under this Plan shall be evidenced by an Agreement setting forth the terms and conditions applicable to such award. No award shall be valid until an Agreement is executed by the Company and the recipient of such award and, upon execution by each party and delivery of the Agreement to the Company within the time period specified by the Company, such award shall be effective as of the effective date set forth in the Agreement.

5.4 Non-Transferability. No award shall be transferable other than by will, the laws of descent and distribution or pursuant to beneficiary designation procedures approved by the Company or, to the extent expressly permitted in the Agreement relating to such award, to the holder's family members, a trust or entity established by the holder for estate planning purposes or a charitable organization designated by the holder. Except to the extent permitted by the foregoing sentence or the Agreement relating to an award, each award may be exercised or settled during the holder's lifetime only by the holder or the holder's legal representative or similar person. Except as permitted by the second preceding sentence, no award may be sold, transferred, assigned, pledged, hypothecated, encumbered or otherwise disposed of (whether by operation of law or otherwise) or be subject to execution, attachment or similar process. Upon any attempt to so sell, transfer, assign, pledge, hypothecate, encumber or otherwise dispose of any award, such award and all rights thereunder shall immediately become null and void.

5.5 Tax Withholding . The Company shall have the right to require, prior to the issuance or delivery of any shares of Common Stock or the payment of any cash pursuant to an award made hereunder, or upon the vesting of any award that is considered deferred compensation, payment by the holder of such award of any federal, state, local or other taxes which may be required to be withheld or paid in connection with such award. An Agreement may provide that (i) the Company shall withhold whole shares of Common Stock which would otherwise be delivered to a holder, having an aggregate Fair Market Value determined as of the date the obligation to withhold or pay taxes arises in connection with an award (the " Tax Date "), or withhold an amount of cash which would otherwise be payable to a holder, in the amount necessary to satisfy any such obligation or (ii) the holder may satisfy any such obligation by any of the following means: (A) a cash payment to the Company, (B) authorizing the Company to withhold whole shares of Common Stock which would otherwise be delivered having an aggregate Fair Market Value, determined as of the Tax Date, or withhold an amount of cash which would otherwise be payable to a holder, equal to the amount necessary to satisfy any such obligation, (C) in the case of the exercise of an option and except as may be prohibited by applicable law, a cash payment by a broker-dealer acceptable to the Company to whom the optionee has submitted an irrevocable notice of exercise or (D) any combination of (A) and (B), in each case to the extent set forth in the Agreement relating to the award. Shares of Common Stock to be delivered or withheld may not have an aggregate Fair Market Value in excess of the amount determined by applying the minimum statutory withholding rate. Any fraction of a share of Common Stock which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by the holder.

5.6 Restrictions on Shares . Each award made hereunder shall be subject to the requirement that if at any time the Company determines that the listing, registration or qualification of the shares of Common Stock subject to such award upon any securities exchange or under any law, or the consent or approval of any governmental body, or the taking of any other action is necessary or desirable as a condition of, or in connection with, the delivery of shares thereunder, such shares shall not be delivered unless such listing, registration, qualification, consent, approval or other action shall have been effected or obtained, free of any conditions not acceptable to the Company. The Company may require that certificates evidencing shares of Common Stock delivered pursuant to any award made hereunder bear a legend indicating that the sale, transfer or other disposition thereof by the holder is prohibited except in compliance with the Securities Act of 1933, as amended, and the rules and regulations thereunder.

5.7 Adjustment . In the event any stock split, stock dividend, recapitalization, reorganization, merger, consolidation, combination, exchange of shares, liquidation, spin-off or other similar change in capitalization or event, or any distribution to holders of Common Stock (other than a regular cash dividend) occurs on or after the date this Plan is approved by the stockholders of the Company, the number and class of securities available for all awards under this Plan, the maximum number of securities with respect to which awards may be granted during any year to any one person, the maximum number of shares subject to awards granted during any year by the Chief Executive Officer, the number and class of securities subject to each outstanding option and the purchase price per security, and the terms of each outstanding SAR, Restricted Stock Award, Restricted Stock Unit Award, Performance Share Award and

Performance Unit Award, including the number and class of securities subject thereto, shall be appropriately adjusted by the Committee, such adjustments to be made in the case of outstanding options and SARs without an increase in the aggregate purchase price or base price. The decision of the Committee regarding any such adjustment shall be final, binding and conclusive. If any such adjustment would result in a fractional security being (a) available under this Plan, such fractional security shall be disregarded, or (b) subject to an award under this Plan, the Company shall pay the holder of such award, in connection with the first vesting, exercise or settlement of such award, in whole or in part, occurring after such adjustment, an amount in cash determined by multiplying (i) the fraction of such security (rounded to the nearest hundredth) by (ii) the excess, if any, of (A) the Fair Market Value on the vesting, exercise or settlement date over (B) the exercise or base price, if any, of such award.

5.8 Corporate Transactions; Change in Control .

(a) If the Company shall be a party to a reorganization, merger, or consolidation or sale or other disposition of more than 50% of the operating assets of the Company (determined on a consolidated basis), other than in connection with a sale-leaseback or other arrangement resulting in the continued utilization of such assets (or the operating products of such assets) (a " Corporate Transaction "), the Board (as constituted prior to any Change in Control resulting from such Corporate Transaction) may, in its discretion:

(i) require that (A) some or all outstanding options and SARs shall immediately become exercisable in full or in part, (B) the Restriction Period applicable to some or all outstanding Restricted Stock Awards and Restricted Stock Unit Awards shall lapse in full or in part, (C) the Performance Period applicable to some or all outstanding Performance Share Awards and Performance Unit Awards shall lapse in full or in part, and (D) the Performance Measures applicable to some or all outstanding awards shall be deemed to be satisfied at the target or any other level not exceeding the maximum levels allowable under their respective terms;

(ii) require that shares of capital stock of the corporation resulting from such Corporate Transaction, or a parent corporation thereof, be substituted for some or all of the shares of Common Stock subject to an outstanding award, with an appropriate and equitable adjustment to such award as determined by the Board in accordance with Section 5.7; and/or

(iii) require outstanding awards, in whole or in part, to be surrendered to the Company by the holder, and to be immediately cancelled by the Company, and to provide for the holder to receive (A) a cash payment in an amount equal to (1) in the case of an option or an SAR, the number of shares of Common Stock then subject to the portion of such option or SAR surrendered, to the extent such option or SAR is then exercisable or becomes exercisable pursuant to clause (i), multiplied by the excess, if any, of the Fair Market Value of a share of Common Stock as of the date of the Corporate Transaction, over the purchase price or base

price per share of Common Stock subject to such option or SAR, (2) in the case of a Stock Award, the number of shares of Common Stock then subject to the portion of such award surrendered, to the extent the Restriction Period and Performance Period, if any, on such Stock Award have lapsed or will lapse pursuant to clause (i) and to the extent that the Performance Measures, if any, have been satisfied or are deemed satisfied pursuant to clause (i), multiplied by the Fair Market Value of a share of Common Stock as of the date of the Corporate Transaction, and (3) in the case of a Performance Unit Award, the value of the Performance Units then subject to the portion of such award surrendered, to the extent the Performance Period applicable so such award has lapsed or will lapse pursuant to clause (i) and to the extent the Performance Measures applicable to such award have been satisfied or are deemed satisfied pursuant to clause (i); (B) shares of capital stock of the corporation resulting from such Corporate Transaction, or a parent corporation thereof, having a fair market value not less than the amount determined under clause (A) above; or (C) a combination of the payment of cash pursuant to clause (A) above and the issuance of shares pursuant to clause (B) above.

(b) For purposes of Sections 2.3(f) and 5.8(a), "Change in Control" shall mean, except as otherwise provided below, the first to occur of any of the following events:

(i) any SEC Person becomes the Beneficial Owner of 20% or more of the then outstanding common stock of the Company or of Voting Securities representing 20% or more of the combined voting power of all the then outstanding Voting Securities of the Company (such an SEC Person, a " 20% Owner "); provided, however, that for purposes of this subsection (i), the following acquisitions shall not constitute a Change in Control: (1) any acquisition directly from the Company (excluding any acquisition resulting from the exercise of an exercise, conversion or exchange privilege unless the security being so exercised, converted or exchanged was acquired directly from the Company), (2) any acquisition by the Company, (3) any acquisition by an employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation controlled by the Company (a " Company Plan "), or (4) any acquisition by any corporation pursuant to a transaction which complies with paragraphs (A), (B) and (C) of subsection (iii) of this definition; provided further, that for purposes of clause (2), if any 20% Owner of the Company other than the Company or any Company Plan becomes a 20% Owner by reason of an acquisition by the Company, and such 20% Owner of the Company shall, after such acquisition by the Company, become the Beneficial Owner of any additional outstanding common shares of the Company or any additional outstanding Voting Securities of the Company (other than pursuant to any dividend reinvestment plan or arrangement maintained by the Company) and such beneficial ownership is publicly announced, such additional beneficial ownership shall constitute a Change in Control; or

(ii) Individuals who, as of the effective date hereof, constitute the Board (the " Incumbent Board ") cease for any reason to constitute at least a majority of the Incumbent Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by the Company's shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest (as such terms are used in Rule 14a-11 promulgated under the Exchange Act) or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(iii) Consummation of a Corporate Transaction by the Company; excluding, however, a Corporate Transaction pursuant to which:

(A) all or substantially all of the individuals and entities who are the Beneficial Owners, respectively, of the outstanding common stock of Company and outstanding Voting Securities of the Company immediately prior to such Corporate Transaction beneficially own, directly or indirectly, more than 60% of, respectively, the then-outstanding shares of common stock and the combined voting power of the then-outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Corporate Transaction (including, without limitation, a corporation which, as a result of such transaction, owns the Company or all or substantially all of the assets of the Company either directly or through one or more subsidiaries) in substantially the same proportions as their ownership immediately prior to such Corporate Transaction of the outstanding common stock of Company and outstanding Voting Securities of the Company, as the case may be;

(B) no SEC Person (other than the corporation resulting from such Corporate Transaction, and any Person which beneficially owned, immediately prior to such corporate Transaction, directly or indirectly, 20% or more of the outstanding common stock of the Company or the outstanding Voting Securities of the Company, as the case may be) becomes a 20% Owner, directly or indirectly, of the then-outstanding common stock of the corporation resulting from such Corporate Transaction or the combined voting power of the outstanding voting securities of such corporation; and

(C) individuals who were members of the Incumbent Board will constitute at least a majority of the members of the board of directors of the corporation resulting from such Corporate Transaction; or

(iv) Approval by the Company's shareholders of a plan of complete liquidation or dissolution of the Company, other than a plan of liquidation or dissolution which results in the acquisition of all or substantially all of the assets of the Company by an affiliated company.

Notwithstanding the occurrence of any of the foregoing events, a Change in Control shall not occur with respect to an award if, in advance of such event, the holder of such award agrees in writing that such event shall not constitute a Change in Control.

5.9 Deferrals . The Committee may determine that the delivery of shares of Common Stock or the payment of cash, or a combination thereof, upon the exercise or settlement of all or a portion of any award made hereunder shall be deferred, or the Committee may, in its sole discretion, approve deferral elections made by holders of awards. Deferrals shall be for such periods and upon such terms as shall be set forth in a deferral plan or program established by the Committee in its sole discretion in accordance with Section 409A of the Code.

5.10 No Right of Participation or Employment . Unless otherwise set forth in an employment agreement, no person shall have any right to participate in this Plan. Neither this Plan nor any award made hereunder shall confer upon any person any right to continued employment with the Company, any Subsidiary or any affiliate of the Company or affect in any manner the right of the Company, any Subsidiary or any affiliate of the Company to terminate the employment of any person at any time without liability hereunder.

5.11 Rights as Stockholder . No person shall have any right as a stockholder of the Company with respect to any shares of Common Stock or other equity security of the Company which is subject to an award hereunder unless and until such person becomes a stockholder of record with respect to such shares of Common Stock or equity security.

5.12 Designation of Beneficiary . A holder of an award may file with the Committee a written designation of one or more persons as such holder's beneficiary or beneficiaries (both primary and contingent) in the event of the holder's death or incapacity. To the extent an outstanding option or SAR granted hereunder is exercisable, such beneficiary or beneficiaries shall be entitled to exercise such option or SAR pursuant to procedures prescribed by the Committee.

Each beneficiary designation shall become effective only when filed in writing with the Committee during the holder's lifetime on a form prescribed by the Committee. The spouse of a married holder domiciled in a community property jurisdiction shall join in any designation of a beneficiary other than such spouse. The filing with the Committee of a new beneficiary designation shall cancel all previously filed beneficiary designations.

If a holder fails to designate a beneficiary, or if all designated beneficiaries of a holder predecease the holder, then each outstanding option and SAR hereunder held by such holder, to the extent exercisable, may be exercised by such holder's executor, administrator, legal representative or similar person.

5.13 Governing Law . This Plan, each award hereunder and the related Agreement, and all determinations made and actions taken pursuant thereto, to the extent not otherwise governed by the Code or the laws of the United States, shall be governed by the laws of the Commonwealth of Pennsylvania and construed in accordance therewith without giving effect to principles of conflicts of laws.

5.14 Foreign Employees . Without amending this Plan, the Committee may grant awards to eligible persons who are foreign nationals on such terms and conditions different from those specified in this Plan as may in the judgment of the Committee be necessary or desirable to foster and promote achievement of the purposes of this Plan and, in furtherance of such purposes the Committee may make such modifications, amendments, procedures, subplans and the like as may be necessary or advisable to comply with provisions of laws in other countries or jurisdictions in which the Company or its Subsidiaries operates or has employees.

EXELON CORPORATION
LONG-TERM INCENTIVE PROGRAM

(As amended and restated as of January 1, 2014)

1. Purpose. The purpose of this Exelon Corporation Long-Term Incentive Program (the "Program") is to set forth certain provisions which shall be deemed a part of, and govern, equity compensation awards granted by Exelon Corporation, a Pennsylvania corporation (the "Company"), on or after January 1, 2011 to executives, key managers and other select management employees pursuant to the Exelon Corporation 2011 Long-Term Incentive Plan, as amended (the "Plan").

2. Certain Definitions.

Except as otherwise set forth herein, the defined terms used in this Program shall have the meanings set forth below or in the Plan.

(a) "Administrator" shall have the meaning set forth in Section 14 below.

(b) "Award" shall mean an award granted under this Program.

(c) "Award Notice" shall mean a notice of a Participant's Award, issued by the Company in written or electronic form, which shall set forth the type of the Award, the number of shares (or target share opportunity that, together with the Program summary, sets forth the number of shares) of Common Stock subject to such Award and any other terms of the Award not set forth in the Plan, this Program or the Program summary.

(d) "Board" shall mean the board of directors of the Company.

(e) "Transition Award" shall mean a Performance Share Unit Award granted on a one-time basis in 2013 (or 2014, in certain cases such as new hires, promotions or transfers) in order to transition from a one-year Performance Cycle to a three-year Performance Cycle.

(f) "Committee" shall mean the compensation committee of the Board.

(g) "Dividend Payment Date" shall mean each date on which the Company pays a regular cash dividend to record owners of shares of Common Stock.

(h) "Earned Shares" shall mean shares of Common Stock (or cash representing shares, as applicable) subject to a Performance Share Unit Award that are earned based on the achievement of the performance goals for the applicable Performance Cycle (or portion thereof, in the case of Transition Awards).

(i) "Effective Date" shall mean January 1, 2011.

(j) “First Tranche” shall mean one-third of the Performance Share Units granted under a Transition Award.

(k) “Grant Date” shall mean the date on which an Award is granted, as set forth in the applicable Award Notice.

(l) “Option” shall mean a nonqualified option to purchase shares of Common Stock upon and subject to the satisfaction of the vesting conditions set forth in Section 5 of this Program.

(m) “Participant” shall mean the recipient of an Award granted under this Program.

(n) “Performance Cycle” shall mean (A) for Performance Share Unit Awards granted prior to January 1, 2013, the one-year period beginning on January 1 of the year in which the Award is granted (and any applicable look-back period), (B) for the Transition Awards, the two-year period beginning on January 1, 2013 and (C) for Performance Share Unit Awards granted on or after January 1, 2013 (other than Transition Awards) and Performance Cash Awards granted on or after January 1, 2014, the three-year period beginning on January 1of the year in which the Performance Share Unit Award is granted.

(o) “Performance Cash Unit” shall mean a right granted to a Participant employed in a Utility Company to receive an amount of cash subject to the achievement of the applicable performance goals and the satisfaction of the vesting conditions set forth in Section 3 of this Program.

(p) “Performance Share Unit” shall mean a right to receive shares of Common Stock or a cash equivalent (as applicable) subject to the achievement of the applicable performance goals and the satisfaction of the vesting conditions set forth in Section 3 of this Program.

(q) “Restricted Stock Unit” shall mean a right to receive shares of Common Stock upon and subject to the satisfaction of the vesting conditions set forth in Section 4 of this Program.

(r) “Restrictive Covenants” shall mean any noncompetition, nonsolicitation, confidentiality, intellectual property or other restrictive covenants to which a Participant is subject, required as a condition to receipt of an Award, or which is contained in any other agreement between the Participant and the Company or any of its affiliates.

(s) “Retirement” shall mean a Participant’s termination of employment (other than a termination upon death, disability or involuntary termination for cause) on or after the date as of which the Participant has attained age 50 (age 55 with respect to Awards granted on or after January 1, 2013) and completed at least ten years of service with the Company and the Subsidiaries. For purposes of this definition, the holder’s age and service shall be determined taking into account any deemed age or service awarded to the holder for benefit accrual purposes under any nonqualified defined benefit retirement plan of the Company in which the holder is a participant.

(t) “Second Tranche” shall mean two-thirds of the Performance Share Units granted under a Transition Award

(u) “Utility Company” shall mean Baltimore Gas & Electric Company, Commonwealth Edison Company, PECO Energy Company and the Exelon Utility Group within Exelon Business Services Company, LLC.

3. Long Term Performance Share Award and Performance Cash Award Program .

(a) Granting of Awards . Within the first 90 days of each Performance Cycle beginning on or after the Effective Date, the Committee may grant Performance Share Unit Awards to employees who are employed in a Vice President or more senior position, including without limitation Nuclear Plant Managers, as selected by the Committee in its sole discretion. Effective January 1, 2014, the Committee may grant Performance Cash Units in lieu of Performance Share Unit Awards to such designated employees who are employed in a Utility Company. Performance Share Unit Awards and Performance Cash Units shall be subject to the respective applicable terms and conditions set forth in this Section 3, and shall contain such additional terms and conditions, not inconsistent with the terms of this Program, as the Committee shall deem advisable and set forth in the applicable Program summary or Award Notice.

(b) Number of Shares and Other Terms . The number of shares of Common Stock represented by a Performance Share Unit Award (“ Earned Shares ”) for any Performance Cycle shall be determined based on the achievement of performance goals established by the Committee and set forth in the Program summary for such Performance Cycle and the administrative guidelines approved by the Committee. Each performance goal shall be assigned a weighting and scored at the end of each calendar year within the Performance Cycle. For Performance Cycles beginning on or after January 1, 2013, at the end of the Performance Cycle, the number of Earned Shares is determined based on the average of the annual performance results, subject to adjustment as set forth in the Program summary and/or administrative guidelines. Notwithstanding the foregoing, the maximum number of shares of Common Stock that may become subject to Performance Share Unit Awards granted in any calendar year to Participants the Company has determined as of the Grant Date may be “covered employees” (within the meaning of Section 162(m)(3) of the Code) for such year or for any subsequent year in which such Award may be outstanding, shall be equal to the lesser of (i) the number determined by (A) multiplying 1.5% of the Company’s Operating Income for such year by the allocation percentage approved by Committee for such Participant within the first 90 days of the applicable Performance Cycle and (B) dividing such dollar amount by the closing price of a share of Common Stock on the last trading day of such year and (ii) the per person limit set forth in Section 1.6 of the Plan. For purposes of this Section 3(b), the “Operating Income” of the Company for such year shall be as reported in the Company’s financial statements for such year according to generally accepted accounting principles and as reviewed or accepted, as the case may be,

by the Company's independent public accountants, and certified by the Committee in accordance with section 162(m) of the Code. The Committee reserves the right in its sole discretion to determine that the number of Earned Shares for any Performance Cycle shall be zero in the event of materially adverse business or financial circumstances as determined by the Committee.

(c) Vesting and Forfeiture .

(i) Awards Granted prior to January 1, 2013. Except as provided in Section 3(f)(i) of the Program, Earned Shares granted prior to January 1, 2013 shall become vested (i) on the date of the first regular meeting of the Committee held in the calendar year following the calendar year in which the Grant Date occurs with respect to one-third of the number of Earned Shares, (ii) on the date of the first regular meeting of the Committee held in the second calendar year following the calendar in which the Grant Date occurs with respect to an additional one-third of the number of Earned Shares, and (iii) on the date of the first regular meeting of the Committee held in the third calendar year following the calendar year in which the Grant Date occurs with respect to the remaining Earned Shares (but, with respect to each such year, not later than March 15), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(ii) Transition Awards . Except as provided in Section 3(f)(ii) of the Program, Performance Share Units subject to a Transition Award shall be earned and become vested (i) with respect to the First Tranche, on the date of the first regular meeting of the Committee held in 2014 and (ii) with respect to the Second Tranche, on the date of the first regular meeting of the Committee held in 2015 (but, with respect to each such year, not later than March 15), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(iii) Awards Granted on or after January 1, 2013 (Other than Transition Awards). Except as provided in Section 3(f)(ii) of the Program, Performance Share Units and Performance Cash Units subject to an Award (other than a Transition Award) and granted on or after January 1, 2013 shall be earned and become fully vested on the date of the first regular meeting of the Committee held in the third calendar year following the calendar year in which the Grant Date occurs (but, with respect to each such Performance Cycle, not later than March 15 of such year), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(d) Dividend Equivalents . As of each Dividend Payment Date, the Company shall pay to the Participant a cash payment in an amount equal to the dollar amount of the cash dividend paid per share of Common Stock multiplied by the number of Earned Shares that are subject to a Performance Share Unit Award immediately prior to the record date for such Dividend Payment Date, but that have not been issued pursuant to Section 3(e) as of such record date.

(e) Settlement of Vested Awards . Subject to the withholding of taxes pursuant to Section 8 of the Program, within 30 days after the vesting of a Performance Share Unit Award, in whole or in part (or at such later time as may be required pursuant to this Section 3(e)), the Company shall issue or transfer to the Participant the number of Earned Shares that have become vested. The Company may effect such transfer either by the delivery of one or more certificates of Common Stock to the Participant or by an appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company, and in either case by issuing such shares in the Participant's name or in such other name as is acceptable to the Company and designated in writing by the Participant. All such Awards payable for 2012 or thereafter shall be paid 50% in Common Stock and 50% in cash; provided, however, that effective for Awards granted on or after January 1, 2013 (including Transition Awards), a Participant whose title is Executive Vice President or above and who has achieved 200% or more of his or her stock ownership target by September 30 of the calendar year prior to payout of the Award shall be paid in cash. The Company shall pay all original issue or transfer taxes and all fees and expenses incident to such delivery, except as otherwise provided in Section 8 of the Program. Prior to the settlement of a Performance Share Unit Award, the holder of such Award shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such Award. Performance Cash Awards shall be paid in cash upon vesting. Notwithstanding the foregoing, if a Participant is a "Specified Employee," within the meaning of section 409A of the Code, and such Participant is or will become eligible for Retirement prior to the calendar year in which the Performance Share Unit Award is scheduled to become fully vested, then any Earned Shares subject to the Award or payment under a Performance Cash Unit which become vested upon the Participant's termination of employment in accordance with Section 3(f) of this Program shall be issued to the Participant as of the earlier to occur of the six-month anniversary of such Participant's separation from service or the date of the Participant's death.

(f) Termination of Employment . Except as otherwise provided in this Program or the Plan:

(i) Retirement, Disability, Death or Involuntary Termination Without Cause – Awards Granted prior to January 1, 2013 . If a Participant's employment with the Company terminates by reason of Retirement, Disability, death or an involuntary termination of employment by the Company for a reason other than Cause, and such Participant has not breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, then all Earned Shares subject to such Participant's Performance Share Unit Award and earned cash subject to a Performance Cash Unit shall become fully vested as of the effective date of the Participant's termination of employment or date of death, as the case may be. To the extent the Award has not been earned as of the date of the Participant's termination of employment or death (i.e. as to which the current Performance Cycle has not elapsed), the Participant shall become

vested in a pro-rated Award based on the number of elapsed days in the current Performance Cycle as of the termination date (or fully vested with respect to such an Award for 2012 upon an involuntary termination without Cause) and the extent to which the Company performance goals established under the Program for such Performance Cycle are attained as of the last day of the year in which the termination date occurs (and assuming a 100% individual performance multiplier), and such Award shall be payable as of the date the first third of the Awards for such Performance Cycle are payable to Participants who remain actively employed with the Company.

(ii) Retirement, Disability, Death or Involuntary Termination Without Cause – Awards Granted on or after January 1, 2013 (Including Transition Awards) . If a Participant's employment with the Company terminates by reason of Retirement, Disability, death or an involuntary termination of employment by the Company for a reason other than Cause, and such Participant has not breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, then (A) if such event occurs within the first 12 months of the Performance Cycle, then the Participant shall earn and become vested in a pro-rated Award (both First and Second Tranches, in the case of Bridge Awards) based on the number of elapsed days in such 12-month period as of the termination date (pro-ration determined by dividing the number of elapsed days by 365) and the extent to which the performance goals established under the Program for such Performance Cycle (or portion thereof, in the case of the Transition Awards) are attained, and (B) if such event occurs after the first 12 months of the Performance Cycle, then the Participant shall become fully vested in all Earned Shares (the number determined in accordance with Section 3(b) above) or earned cash, as applicable. In either event, the Earned Shares or cash shall be payable on the next payout date applicable to Participants who remain actively employed with the Company (either the payout date for the First Tranche or Second Tranche, as applicable, in the case of Transition Awards).

(iii) Termination for Other Reasons . If a Participant's employment with the Company terminates for any reason other than as described in clause (i) or (ii) of this Section 3(f) or if the Participant has breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, the unvested portion of such Participant's Award shall be forfeited and terminate as of the date of such termination of employment.

(g) Restriction on Sale of Shares by Senior Officers . Shares of Common Stock issued under an Award pursuant to Section 3(e) to a Participant who is employed as of the Grant Date in a position of, or more senior than, Senior Vice President may not be sold or transferred by such Participant until the earlier to occur of (i) the date as of which the final third of such Award is scheduled to become vested pursuant to Section 3(c) (even if such Award actually vests earlier pursuant to Section 3(f)) or (ii) the date of the Participant's death, regardless of when such shares are issued or transferred to such Participant. Effective January 1, 2013, this provision shall no longer be effective.

(h) Awards Granted to Employees of Commonwealth Edison Company Prior to 2014 . If Performance Share Unit Awards are granted to Participants who are employed by Commonwealth Edison Company, an Illinois corporation and subsidiary of the Company (" ComEd "), then unless the Committee determines otherwise, (i) the number of such Participant's Earned Shares shall be determined based on the achievement of performance criteria established by the Board of Directors of ComEd and ratified by the Committee, subject to the maximum number of Earned Shares that may be subject to a Performance Share Unit Award, as set forth in Section 3(b), and (ii) such Performance Share Unit Awards for 2011 shall be settled (subject to the vesting and other conditions herein) in a cash payment made by ComEd to the Participant in an amount equal to the Fair Market Value of the number of such Participant's Earned Shares, determined as of the applicable vesting date.

4. Restricted Stock Unit Award Program .

(a) Granting of Awards . The Committee may grant Restricted Stock Unit Awards to employees who are employed (i) in a Vice President or other executive position (including without limitation Nuclear Plant Managers) below the Senior Vice President level, and (ii) key managers and other select management employees, in each case as selected by the Committee in its sole discretion.

(b) Terms of Awards . Awards shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Program, as the Committee shall deem advisable and set forth in the applicable Award Notice.

(c) Number of Shares and Other Terms . The number of shares of Common Stock subject to a Restricted Stock Unit Award shall be determined by the Committee and set forth in the applicable Award Notice.

(d) Vesting and Forfeiture . Except to the extent a Restricted Stock Unit Award becomes immediately vested upon a termination of the Participant's employment pursuant to Section 4(g) of the Program, the shares subject to a Restricted Stock Unit Award shall become vested (i) on the date of the first regular meeting of the Committee in the calendar year following the calendar year in which the Grant Date occurs with respect to one-third of the number of shares of Common Stock subject to the Award on the Grant Date, (ii) on the date of the first regular meeting of the Committee in the second calendar year following the calendar year in which the Grant Date occurs with respect to an additional one-third of the number of shares of Common Stock subject to the Award on the Grant Date, and (iii) on the date of the first regular meeting of the Committee in the third calendar year following the calendar year in which the Grant Date occurs with respect to the remaining shares of Common Stock subject to the Award on the Grant Date (but, with respect to each such year, not later than March 15), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(e) Dividend Equivalents . As of each Dividend Payment Date, the number of shares of Common Stock that are subject to a Restricted Stock Unit Award shall be increased by (i) the product of the total number of shares of Common Stock that are subject to such Restricted Stock Unit Award immediately prior to the record date for such Dividend Payment Date, but that have not been issued pursuant to Section 4(f) as of such record date, multiplied by the dollar amount of the cash dividend paid per share of Common Stock, divided by (ii) the Fair Market Value of a share of Common Stock on such Dividend Payment Date. Such additional Restricted Stock Units shall be subject to all of the terms and conditions of the Award, including the vesting conditions set forth in Section 4(d).

(f) Settlement of Vested Awards . Subject to the withholding of taxes pursuant to Section 8 of the Program, within 30 days after the vesting of a Restricted Stock Unit Award, in whole or in part (or at such later time as may be required pursuant to this Section 4(f)), the Company shall issue or transfer to the Participant the number of shares of Common Stock that have become vested. The Company may effect such transfer either by the delivery of one or more certificates of Common Stock to the Participant or by an appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company, and in either case by issuing such shares in the Participant's name or in such other name as is acceptable to the Company and designated in writing by the Participant. The Company shall pay all original issue or transfer taxes and all fees and expenses incident to such delivery, except as otherwise provided in Section 8 of the Program. Prior to the settlement of a Restricted Stock Unit Award, the holder of such Award shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such Award. Notwithstanding the foregoing, if a Participant is a "Specified Employee," within the meaning of section 409A of the Code, and such Participant is or will become eligible for Retirement prior to the calendar year in which the Restricted Stock Unit Award is scheduled to become fully vested, then any shares of Common Stock subject to the Award which become vested upon the Participant's termination of employment in accordance with Section 4(g) of this Program shall be issued to the Participant as of the earlier to occur of the six-month anniversary of such Participant's separation from service or the date of the Participant's death.

(g) Termination of Employment . Except as otherwise provided in this Program or the Plan:

(i) Retirement, Disability or Death . If a Participant's employment with the Company terminates by reason of Retirement, Disability or death, and such Participant has not breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, then all shares of Common Stock subject to such Participant's Restricted Stock Unit Award shall become fully vested as of the effective date of the Participant's termination of employment or date of death, as the case may be.

(ii) Termination for Other Reasons . If a Participant's employment with the Company terminates for any reason other than as described in clause (i) of this Section 4(g) or if the Participant has breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, the

unvested portion of such Participant's Restricted Stock Unit Award shall be forfeited and terminate as of the date of such termination of employment; provided however, that such an Award granted on or after January 1, 2012 shall become fully vested upon an involuntary termination without Cause.

5. Stock Option Award Program .

(a) Granting of Awards . The Committee may grant Option Awards to employees who are employed in a Senior Vice President or more senior position, as selected by the Committee in its sole discretion or, to the extent permitted by the Plan, the Chief Executive Officer of the Company.

(b) Terms of Awards . Awards shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Program, as the Committee shall deem advisable and set forth in the applicable Award Notice.

(c) Number of Shares . The number of shares of Common Stock subject to an Option Award shall be determined by the Committee and set forth in the applicable Award Notice.

(d) Term of Option . Except to the extent earlier terminated or exercised, each Option shall expire on, and in no event may any portion of such Option be exercised after, the tenth anniversary of the Grant Date (the " Expiration Date ").

(e) Vesting and Forfeiture . Except to the extent the Award becomes immediately vested upon a termination of the Participant's employment pursuant to Section 5(g) of the Program, the Option shall become vested and exercisable (i) on the first anniversary of the Grant Date with respect to one-fourth of the number of shares of Common Stock subject to the Award on the Grant Date, (ii) on the second anniversary of the Grant Date with respect to an additional one-fourth of the number of shares of Common Stock subject to the Award on the Grant Date (iii) on the third anniversary of the Grant Date with respect to an additional one-fourth of the number of shares of Common Stock subject to the Award on the Grant Date, and (iv) on the fourth anniversary of the Grant Date with respect to the remaining shares of Common Stock subject to the award on the Grant Date, in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(f) Method of Exercise . To the extent permitted by the Administrator, a Participant may exercise an Option (i) by giving written notice to the Company (or its designated agent) specifying the number of whole shares of Common Stock to be purchased and accompanying such notice with payment therefor in full, and without any extension of credit, either (A) in cash, (B) by delivery (either actual delivery or by attestation procedures established by the Company) to the Company of previously owned whole shares of Common Stock having a Fair Market Value, determined as of the date of exercise, equal to the aggregate purchase price payable by reason of such exercise, (C) authorizing the Company to withhold whole shares of Common Stock which

would otherwise be delivered having an aggregate Fair Market Value, determined as of the date of exercise, equal to the amount necessary to satisfy such obligation, provided that the Committee determines that such withholding of shares does not cause the Company to recognize an increased compensation expense under applicable accounting principles, (D) except as may be prohibited by applicable law, in cash by a broker-dealer acceptable to the Company to whom the Participant has submitted an irrevocable notice of exercise or (E) a combination of (A), (B) and (C) and (ii) by executing such documents as the Company may reasonably request. Any fraction of a share of Common Stock which would be required to pay such purchase price shall be disregarded and the remaining amount due shall be paid in cash by the Participant. No shares of Common Stock shall be issued and no certificate representing Common Stock shall be delivered until the full purchase price therefor and any withholding taxes thereon, as described in Section 8, have been paid.

(g) Termination of Employment .

(i) Retirement or Disability . If the Company ceases to employ a Participant by reason of such Participant's Retirement or Disability, each Option held by such Participant shall be fully exercisable, and may thereafter be exercised by such Participant (or such Participant's legal representative or similar person) until and including the earlier to occur of (i) the fifth anniversary of the effective date of such Participant's termination of employment and (ii) the Expiration Date.

(ii) Death . If the Company ceases to employ a Participant by reason of such Participant's death, each Option held by such Participant shall be fully exercisable, and may thereafter be exercised by such Participant's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the third anniversary of the date of death and (ii) the Expiration Date.

(iii) Cause . If the Company ceases to employ a Participant due to a termination of employment by the Company for Cause, each Option held by such Participant shall be cancelled and cease to be exercisable as of the earlier to occur of (i) the effective date of such termination of employment and (ii) the date on which the Participant first engaged in conduct giving rise to a termination for Cause, and the Company thereafter may require the repayment of any amounts received by such Participant in connection with an exercise of such Option following such cancellation date.

(iv) Other Termination . Subject to clauses (v), (vi) and (vii) below, if the Company ceases to employ a Participant for any reason other than as described in clause (i), (ii) or (iii) above, then each Option held by such Participant shall be exercisable only to the extent that such Option is exercisable on the effective date of such Participant's termination of employment, and may thereafter be exercised by such Participant (or such Participant's legal representative or similar person) until and including the earlier to occur of (i) the date which is 90 days after the effective date of such Participant's termination of employment and (ii) the Expiration Date.

(v) Death Following Termination of Employment . If a Participant dies during the applicable post-termination exercise period described in clause (iv), each Option held by such Participant shall be exercisable only to the extent that such Option is exercisable on the date of such Participant's death and may thereafter be exercised by the Participant's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the first anniversary of the date of death and (ii) the expiration date of the term of such Option.

(vi) Breach of Restrictive Covenant . Notwithstanding clauses (i) through (v), if a Participant breaches his or her obligations to the Company or any of its affiliates under a Restrictive Covenant, each Option held by such Participant shall be cancelled and cease to be exercisable as of the date on which the Participant first breached such Restrictive Covenant, and the Company thereafter may require the repayment of any amounts received by such Participant in connection with an exercise of such Option following such cancellation date.

(vii) Certain Terminations After Change in Control . Unless otherwise specified in, and subject to all conditions set forth in, any individual change in control agreement or severance plan, and notwithstanding any other provision of this Section 5(g), if within 24 months following a Change in Control, the Company ceases to employ a Participant due to a termination of employment (i) by the Company other than for Cause, or (ii) with respect to a Participant whose position is at grade level E09 (or its equivalent), by the Participant for Good Reason, such Participant's outstanding Options shall immediately become fully exercisable and may thereafter be exercised by such Participant (or such Participant's legal representative or similar person) until and including the earlier to occur of (A) the fifth anniversary of the effective date of such Participant's termination of employment and (B) the Expiration Date.

(h) Termination of Option . In no event may an Option be exercised after it terminates as set forth in this Section 5(h). An Option shall terminate, to the extent not earlier exercised or terminated pursuant to Section 5(g), on the Expiration Date. Upon the termination of the Option, the Option and all rights thereunder shall immediately become null and void.

6. Employment . For purposes of this Program, references to employment with the Company shall include (i) employment with an Affiliate of the Company and (ii) any period during which the Participant is on a leave of absence approved by the Company.

7. Limited Transferability of Awards . Except as may otherwise be expressly provided in an Award Notice, an Award may be transferred by the Participant only (1) by will, (2) the laws of descent and distribution or (3) pursuant to beneficiary designation procedures approved by the Company. Except to the extent permitted by the foregoing, an Award may not be sold, transferred, assigned, pledged, hypothecated, encumbered or otherwise disposed of (whether by operation of law or otherwise) or be subject to execution, attachment or similar

process or domestic relations order. Upon any attempt so to sell, transfer, assign, pledge, hypothecate, encumber or otherwise dispose of an Award, such Award and all rights thereunder shall immediately become null and void.

8. Withholding Taxes . The Company shall have the right to require, prior to the issuance or delivery of any shares of Common Stock or the payment of any cash pursuant to an Award, or upon the vesting of any Award that is considered deferred compensation, payment by the Participant of any federal, state, local or other taxes which may be required to be withheld or paid in connection with such Award. The Company may withhold whole shares of Common Stock which would otherwise be delivered to a Participant, having an aggregate Fair Market Value determined as of the Tax Date, or withhold an amount of cash which would otherwise be payable to a Participant, in the amount necessary to satisfy any such obligation. The Participant may elect to satisfy any such obligation by any of the following means, to the extent permitted by the Administrator: (A) a cash payment to the Company, (B) authorizing the Company to withhold whole shares of Common Stock which would otherwise be delivered having an aggregate Fair Market Value, determined as of the Tax Date, or withhold an amount of cash which would otherwise be payable to the Participant, equal to the amount necessary to satisfy any such obligation, (C) in the case of the exercise of an Option and except as may be prohibited by applicable law, a cash payment by a broker-dealer acceptable to the Company to whom the Participant has submitted an irrevocable notice of exercise or (D) any combination of (A) and (B). Shares of Common Stock to be delivered or withheld may not have an aggregate Fair Market Value in excess of the amount determined by applying the minimum statutory withholding rate. Any fraction of a share of Common Stock which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by the Participant.

9. Adjustment . The number and class of securities subject to an Award shall be subject to adjustment as provided in Section 5.7 of the Plan. The decision of the Committee regarding any such adjustment shall be final, binding and conclusive.

10. Compliance with Applicable Law . Each Award is subject to the condition that if the listing, registration or qualification of the shares subject to such Award upon any securities exchange or under any law, or the consent or approval of any governmental body, or the taking of any other action is necessary or desirable as a condition of, or in connection with, the delivery of shares hereunder, such Award may not be settled, in whole or in part, unless such listing, registration, qualification, consent or approval shall have been effected or obtained, free of any conditions not acceptable to the Company.

11. Award Subject to the Plan and Claw-back Policy . Each Award is subject to the provisions of the Plan, and each Award and this Program shall be interpreted in accordance therewith. Notwithstanding any provision of the Program to the contrary, each Award shall be subject to a clawback pursuant to the Exelon Executive Officer Compensation Recoupment Policy contained in the Exelon Corporation Board of Directors Corporate Governance Principles, as in effect from time to time, including any amendments thereto or new clawback policies required under the Dodd-Frank Wall Street Reform and Consumer Protection Act and implementing applicable stock exchange listing standards or rules and regulations thereunder, or as otherwise required by law or regulation.

12. Investment Representation . By accepting an Award, the Participant represents and covenants that (a) any share of Common Stock acquired upon the vesting of the Award will be acquired for investment and not with a view to the distribution thereof within the meaning of the Securities Act of 1933, as amended (the " Securities Act "), unless such acquisition has been registered under the Securities Act and any applicable state securities law; (b) any subsequent sale of any such shares shall be made either pursuant to an effective registration statement under the Securities Act and any applicable state securities laws, or pursuant to an exemption from registration under the Securities Act and such state securities laws; and (c) if requested by the Company, the Participant shall submit a written statement, in form satisfactory to the Company, to the effect that such representation (x) is true and correct as of the date of acquisition of any shares hereunder or (y) is true and correct as of the date of any sale of any such shares, as applicable. As a further condition precedent to the delivery to the Participant of any shares subject to the Award, the Participant shall comply with all regulations and requirements of any regulatory authority having control of or supervision over the issuance of the shares and, in connection therewith, shall execute any documents which the Company shall in its sole discretion deem necessary or advisable.

13. Award Confers No Rights to Continued Employment . In no event shall the granting of an Award or its acceptance by a Participant give or be deemed to give the Participant any right to continued employment by the Company.

14. Administrator . This Program shall be administered by the Company's Vice President, Corporate Compensation (the "Administrator"). Except for authority reserved to the Board or the Committee, the Administrator shall have the right to interpret the Program, make any determinations hereunder, and take any necessary or appropriate actions with respect to the administration of the Program or in connection with each Award. Any such interpretation, determination or other action made or taken by the regarding this Program or an Award shall be final, binding and conclusive.

15. Miscellaneous Provisions .

(a) Successors . This Program and each Award shall be binding upon and inure to the benefit of any successor or successors of the Company and any person or persons who shall, upon the death of a Participant, acquire any rights under such Award in accordance with this Program or the Plan.

(b) Notices . All notices, requests or other communications provided for in this Program (other than the exercise of a stock option) shall be made, if to the Company, to Exelon Corporation, 10 South Dearborn Street, Chicago, Illinois 60603, Attention: Vice President, Corporate Compensation, and if to the Participant, to his or her then current work location. All notices, requests or other communications provided for in this Program shall be made in writing either (a) by personal delivery to the party entitled thereto, (b) by facsimile with confirmation of receipt, (c) by mailing in the United States mails to the last known address of the party entitled thereto or (d) by express courier service. The notice, request or other communication shall be deemed to be received upon personal delivery, upon confirmation of receipt of facsimile transmission, or upon receipt by the party entitled thereto if by United States mail or express courier service; provided, however, that if a notice, request or other communication is not received during regular business hours, it shall be deemed to be received on the next succeeding business day of the Company.

(c) Section 409A . This Program and the Awards granted hereunder are intended to comply with the requirements of section 409A of the Code and shall be interpreted and construed consistently with such intent. Awards granted pursuant to this Program are also intended to be exempt from Section 409A of the Code to the maximum extent possible as short-term deferrals pursuant to Treasury regulation §1.409A-1(b)(4), and for this purpose each payment shall be considered a separate payment. In the event the terms of an Award would subject a Participant to taxes or penalties under Section 409A of the Code (" 409A Penalties "), the Company may modify the terms of such Award to avoid such 409A Penalties, to the extent possible; provided that in no event shall the Company be responsible for any 409A Penalties that arise in connection with any Award. To the extent the timing of payment under an Award is determined by reference to a Participant's "termination of employment," such term shall be deemed to refer to the Participant's "separation from service," within the meaning of section 409A of the Code. Notwithstanding any other provision in this Program, if a Participant is a "specified employee," as defined in Section 409A of the Code, as of the date of such Participant's separation from service, then to the extent any amount payable to the Participant (i) constitutes the payment of nonqualified deferred compensation, within the meaning of Section 409A of the Code, (ii) is payable upon the Participant's separation from service and (iii) under the terms of this Program would be payable prior to the six-month anniversary of the Participant's separation from service, such payment shall be delayed until the earlier to occur of (A) the six-month anniversary of the separation from service and (B) the date of the Participant's death.

(d) Amendment . The terms of this Program may be amended by the Committee or the Board (or their respective delegates), provided that the Chief Human Resources Officer or the Vice President, Corporate Compensation, of the Company may amend the Program to comply with applicable law, to make administrative changes or to carry out directives of the Board or the Committee.

(e) Governing Law . This Program and each Award granted thereunder, and all determinations made and actions taken pursuant thereto, to the extent not governed by the laws of the United States, shall be governed by the laws of the Commonwealth of Pennsylvania and construed in accordance therewith without giving effect to principles of conflicts of laws.

IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its Senior Vice President & Chief Human Resources Officer, effective as of January 1, 2014.

EXELON CORPORATION

By: _____

Senior Vice President & Chief Human Resources Officer

E XELON C ORPORATION
L ONG -T ERM I NCENTIVE P ROGRAM

(As amended and restated as of January 1, 2015)

1. Purpose. The purpose of this Exelon Corporation Long-Term Incentive Program (the "Program") is to set forth certain provisions which shall be deemed a part of, and govern, equity compensation awards granted by Exelon Corporation, a Pennsylvania corporation (the "Company"), on or after January 1, 2011 to executives, key managers and other select management employees pursuant to the Exelon Corporation 2011 Long-Term Incentive Plan, as amended (the "Plan").

2. Certain Definitions.

Except as otherwise set forth herein, the defined terms used in this Program shall have the meanings set forth below or in the Plan.

(a) "Administrator" shall have the meaning set forth in Section 14 below.

(b) "Award" shall mean an award granted under this Program.

(c) "Award Notice" shall mean a notice of a Participant's Award, issued by the Company in written or electronic form, which shall set forth the type of the Award, the number of shares (or target share opportunity that, together with the Program summary, sets forth the number of shares) of Common Stock subject to such Award and any other terms of the Award not set forth in the Plan, this Program or the Program summary.

(d) "Board" shall mean the board of directors of the Company.

(e) "Transition Award" shall mean a Performance Share Unit Award granted on a one-time basis in 2013 (or 2014, in certain cases such as new hires, promotions or transfers) in order to transition from a one-year Performance Cycle to a three-year Performance Cycle.

(f) "Committee" shall mean the compensation committee of the Board.

(g) "Dividend Payment Date" shall mean each date on which the Company pays a regular cash dividend to record owners of shares of Common Stock.

(h) "Earned Cash" shall be the dollar amount of cash subject to a Performance Cash Unit Award that have been earned based on the achievement of the performance goals for the applicable Performance Cycle).

(i) "Earned Shares" shall mean shares of Common Stock (or cash representing shares, as applicable) subject to a Performance Share Unit Award that have been earned based on the achievement of the performance goals for the applicable Performance Cycle (or portion thereof, in the case of Transition Awards).

(j) “Effective Date” shall mean January 1, 2011.

(k) “First Tranche” shall mean one-third of the Performance Share Units granted under a Transition Award.

(l) “Grant Date” shall mean the date on which an Award is granted, as set forth in the applicable Award Notice.

(m) “Option” shall mean a nonqualified option to purchase shares of Common Stock upon and subject to the satisfaction of the vesting conditions set forth in Section 5 of this Program.

(n) “Participant” shall mean the recipient of an Award granted under this Program.

(o) “Performance Cycle” shall mean (A) for Performance Share Unit Awards granted prior to January 1, 2013, the one-year period beginning on January 1 of the year in which the Award is granted (and any applicable look-back period), (B) for the Transition Awards, the two-year period beginning on January 1, 2013 and (C) for Performance Share Unit Awards granted on or after January 1, 2013 (other than Transition Awards) and Performance Cash Awards granted on or after January 1, 2014, the three-year period beginning on January 1of the year in which the Performance Share Unit Award is granted.

(p) “Performance Cash Unit” shall mean a right granted to a Participant employed in a Utility Company to receive an amount of cash subject to the achievement of the applicable performance goals and the satisfaction of the vesting conditions set forth in Section 3 of this Program.

(q) “Performance Share Unit” shall mean a right to receive shares of Common Stock or a cash equivalent (as applicable) subject to the achievement of the applicable performance goals and the satisfaction of the vesting conditions set forth in Section 3 of this Program.

(r) “Restricted Stock Unit” shall mean a right to receive shares of Common Stock upon and subject to the satisfaction of the vesting conditions set forth in Section 4 of this Program.

(s) “Restrictive Covenants” shall mean any noncompetition, nonsolicitation, confidentiality, intellectual property or other restrictive covenants to which a Participant is subject, required as a condition to receipt of an Award, or which is contained in any other agreement between the Participant and the Company or any of its affiliates.

(t) “Retirement” shall mean a Participant’s termination of employment (other than a termination upon death, disability or involuntary termination for cause) on or

after the date as of which the Participant has attained age 55 (age 50 with respect to Awards granted prior to January 1, 2013) and completed at least ten years of service with the Company and the Subsidiaries. For purposes of this definition, the holder's age and service shall be determined taking into account any deemed age or service awarded to the holder for benefit accrual purposes under any nonqualified defined benefit retirement plan of the Company in which the holder is a participant.

(u) "Second Tranche" shall mean two-thirds of the Performance Share Units granted under a Transition Award

(v) "Utility Company" shall mean Baltimore Gas & Electric Company, Commonwealth Edison Company, PECO Energy Company and the Exelon Utility Group within Exelon Business Services Company, LLC.

3. Long Term Performance Share Award and Performance Cash Award Program .

(a) Granting of Awards . Within the first 90 days (or later, with respect to a new hire or promotion) of each Performance Cycle beginning on or after the Effective Date, the Committee may grant Performance Share Unit Awards to employees who are employed in a Vice President or more senior position, including without limitation Nuclear Plant Managers, as selected by the Committee in its sole discretion. Effective January 1, 2014, the Committee may grant Performance Cash Units in lieu of Performance Share Unit Awards to such designated employees who are employed in a Utility Company. Performance Share Unit Awards and Performance Cash Unit Awards shall be subject to the respective applicable terms and conditions set forth in this Section 3, and shall contain such additional terms and conditions, not inconsistent with the terms of this Program, as the Committee shall deem advisable and set forth in the applicable Program summary or Award Notice.

(b) Number of Shares (or Amount of Cash) and Other Terms . The number of shares of Common Stock represented by a Performance Share Unit Award, and the amount of cash represented by a Performance Cash Award, for any Performance Cycle shall be determined based on the achievement of performance goals established by the Committee and set forth in the Program summary for such Performance Cycle and the administrative guidelines approved by the Committee. Each performance goal shall be assigned a weighting and scored at the end of each calendar year within the Performance Cycle. For Performance Cycles beginning on or after January 1, 2013, at the end of the Performance Cycle, the number of Earned Shares (or the amount of Earned Cash) is determined based on the average of the annual performance results, subject to adjustment as set forth in the Program summary and/or administrative guidelines. Notwithstanding the foregoing, the maximum number of shares of Common Stock that may become subject to Performance Share Unit Awards and Performance Cash Awards granted in any calendar year to Participants the Company has determined as of the Grant Date may be "covered employees" (within the meaning of Section 162(m)(3) of the Code) for such year or for any subsequent year in which such Award may be outstanding, shall be equal to the lesser of (i) the number determined by (A) multiplying 1.5% of the Company's Operating Income for such year by

the allocation percentage approved by Committee for such Participant within the first 90 days of the applicable Performance Cycle and (B) dividing such dollar amount by the closing price of a share of Common Stock on the last trading day of such year and (ii) the per person limit set forth in Section 1.6 of the Plan. For purposes of this Section 3(b), the "Operating Income" of the Company for such year shall be as reported in the Company's financial statements for such year according to generally accepted accounting principles and as reviewed or accepted, as the case may be, by the Company's independent public accountants, and certified by the Committee in accordance with section 162(m) of the Code. The Committee reserves the right in its sole discretion to determine that the number of Earned Shares for any Performance Cycle shall be zero in the event of materially adverse business or financial circumstances as determined by the Committee.

(c) Vesting and Forfeiture .

(i) Awards Granted prior to January 1, 2013. Except as provided in Section 3(f)(i) of the Program, Earned Shares granted prior to January 1, 2013 shall become vested (i) on the date of the first regular meeting of the Committee held in the calendar year following the calendar year in which the Grant Date occurs with respect to one-third of the number of Earned Shares, (ii) on the date of the first regular meeting of the Committee held in the second calendar year following the calendar in which the Grant Date occurs with respect to an additional one-third of the number of Earned Shares, and (iii) on the date of the first regular meeting of the Committee held in the third calendar year following the calendar year in which the Grant Date occurs with respect to the remaining Earned Shares (but, with respect to each such year, not later than March 15), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(ii) Transition Awards . Except as provided in Section 3(f)(ii) of the Program, Performance Share Units subject to a Transition Award shall be earned and become vested (i) with respect to the First Tranche, on the date of the first regular meeting of the Committee held in 2014 and (ii) with respect to the Second Tranche, on the date of the first regular meeting of the Committee held in 2015 (but, with respect to each such year, not later than March 15), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(iii) Awards Granted on or after January 1, 2013 (Other than Transition Awards). Except as provided in Section 3(f)(ii) of the Program, Performance Share Units and Performance Cash Units subject to an Award (other than a Transition Award) and granted on or after January 1, 2013 shall be earned and become fully vested on the date of the first regular meeting of the Committee held in the third calendar year following the calendar year in which the Grant Date occurs (but, with respect to each such Performance Cycle, not later than March 15 of such year), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(d) Dividend Equivalents . As of each Dividend Payment Date, the Company shall pay to the Participant a cash payment in an amount equal to the dollar amount of the cash dividend paid per share of Common Stock multiplied by the number of Earned Shares (if any) that are subject to a Performance Share Unit Award immediately prior to the record date for such Dividend Payment Date, but that have not been issued pursuant to Section 3(e) as of such record date.

(e) Settlement of Vested Awards . Subject to the withholding of taxes pursuant to Section 8 of the Program, within 30 days after the vesting of a Performance Share Unit Award, in whole or in part (or at such later time as may be required pursuant to this Section 3(e)), the Company shall issue or transfer to the Participant the number of Earned Shares that have become vested. The Company may effect such transfer either by the delivery of one or more certificates of Common Stock to the Participant or by an appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company, and in either case by issuing such shares in the Participant's name or in such other name as is acceptable to the Company and designated in writing by the Participant. All such Awards payable for 2012 or thereafter shall be paid 50% in Common Stock and 50% in cash; provided, however, that effective for Awards granted on or after January 1, 2013 (including Transition Awards), a Participant whose title is Executive Vice President or above and who has achieved 200% or more of his or her stock ownership target by September 30 of the calendar year prior to payout of the Award shall be paid in cash. The Company shall pay all original issue or transfer taxes and all fees and expenses incident to such delivery, except as otherwise provided in Section 8 of the Program. Prior to the settlement of a Performance Share Unit Award, the holder of such Award shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such Award. Performance Cash Unit Awards shall be paid in cash upon vesting. Notwithstanding the foregoing, if a Participant is a "Specified Employee," within the meaning of section 409A of the Code, and such Participant is or will become eligible for Retirement prior to the calendar year in which the Performance Share Unit Award is scheduled to become fully vested, then any Earned Shares subject to the Award or payment under a Performance Cash Unit which become vested upon the Participant's termination of employment in accordance with Section 3(f) of this Program shall be issued to the Participant as of the earlier to occur of the six-month anniversary of such Participant's separation from service or the date of the Participant's death.

(f) Termination of Employment . Except as otherwise provided in this Program or the Plan:

(i) Retirement, Disability, Death or Involuntary Termination Without Cause – Awards Granted prior to January 1, 2013 . If a Participant's employment with the Company terminates by reason of Retirement, Disability, death or an involuntary termination of employment by the Company for a reason other than Cause, and such Participant has not breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, then all Earned Shares subject to such Participant's

Performance Share Unit Award and earned cash subject to a Performance Cash Unit shall become fully vested as of the effective date of the Participant's termination of employment or date of death, as the case may be. To the extent the Award has not been earned as of the date of the Participant's termination of employment or death (i.e. as to which the current Performance Cycle has not elapsed), the Participant shall become vested in a pro-rated Award based on the number of elapsed days in the current Performance Cycle as of the termination date (or fully vested with respect to such an Award for 2012 upon an involuntary termination without Cause) and the extent to which the Company performance goals established under the Program for such Performance Cycle are attained as of the last day of the year in which the termination date occurs (and assuming a 100% individual performance multiplier), and such Award shall be payable as of the date the first third of the Awards for such Performance Cycle are payable to Participants who remain actively employed with the Company.

(ii) Retirement, Disability, Death or Involuntary Termination Without Cause – Awards Granted on or after January 1, 2013 (Including Transition Awards) . If a Participant's employment with the Company terminates by reason of Retirement, Disability, death or an involuntary termination of employment by the Company for a reason other than Cause, and such Participant has not breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, then (A) if such event occurs within the first 12 months of the Performance Cycle, then the Participant shall earn and become vested in a pro-rated Award (both First and Second Tranches, in the case of Bridge Awards) based on the number of elapsed days in such 12-month period as of the termination date (pro-ration determined by dividing the number of elapsed days by 365) and the extent to which the performance goals established under the Program for such Performance Cycle (or portion thereof, in the case of the Transition Awards) are attained, and (B) if such event occurs after the first 12 months of the Performance Cycle, then the Participant shall become fully vested in all Earned Shares (the number determined in accordance with Section 3(b) above) or earned cash, as applicable. In either event, the Earned Shares or cash shall be payable on the next payout date applicable to Participants who remain actively employed with the Company (either the payout date for the First Tranche or Second Tranche, as applicable, in the case of Transition Awards).

(iii) Termination for Other Reasons . If a Participant's employment with the Company terminates for any reason other than as described in clause (i) or (ii) of this Section 3(f) or if the Participant has breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, the unvested portion of such Participant's Award shall be forfeited and terminate as of the date of such termination of employment.

(g) Restriction on Sale of Shares by Senior Officers . Shares of Common Stock issued under an Award pursuant to Section 3(e) to a Participant who is employed as of the Grant Date in a position of, or more senior than, Senior Vice President may not be sold or transferred by such Participant until the earlier to occur of (i) the date as of which the final third of such Award is scheduled to become vested pursuant to Section 3(c) (even if such Award actually vests earlier pursuant to Section 3(f)) or (ii) the date of the Participant's death, regardless of when such shares are issued or transferred to such Participant. Effective January 1, 2013, this provision shall no longer be effective.

(h) Awards Granted to Employees of Commonwealth Edison Company Prior to 2014 . If Performance Share Unit Awards are granted to Participants who are employed by Commonwealth Edison Company, an Illinois corporation and subsidiary of the Company (" ComEd "), then unless the Committee determines otherwise, (i) the number of such Participant's Earned Shares shall be determined based on the achievement of performance criteria established by the Board of Directors of ComEd and ratified by the Committee, subject to the maximum number of Earned Shares that may be subject to a Performance Share Unit Award, as set forth in Section 3(b), and (ii) such Performance Share Unit Awards for 2011 shall be settled (subject to the vesting and other conditions herein) in a cash payment made by ComEd to the Participant in an amount equal to the Fair Market Value of the number of such Participant's Earned Shares, determined as of the applicable vesting date.

4. Restricted Stock Unit Award Program, and Constellation Short-Term Incentives and Commissions Payable as Restricted Stock Units .

(a) Granting of Awards . The Committee may grant Restricted Stock Unit Awards to employees who are employed (i) in a Vice President or other executive position (including without limitation Nuclear Plant Managers) below the Senior Vice President level, and (ii) key managers and other select management employees, in each case as selected by the Committee in its sole discretion.

(b) Terms of Awards . Awards shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Program, as the Committee shall deem advisable and set forth in the applicable Award Notice.

(c) Number of Shares and Other Terms . The number of shares of Common Stock subject to a Restricted Stock Unit Award shall be determined by the Committee and set forth in the applicable Program summary or Award Notice (which may reference a number of shares or cash value).

(d) Vesting and Forfeiture . Except to the extent a Restricted Stock Unit Award becomes immediately vested upon a termination of the Participant's employment pursuant to Section 4(g) of the Program, the shares subject to a Restricted Stock Unit Award shall become vested (i) on the date of the first regular meeting of the Committee in the calendar year following the calendar year in which the Grant Date occurs with respect to one-third of the number of shares of Common Stock subject to the Award on the Grant

Date, (ii) on the date of the first regular meeting of the Committee in the second calendar year following the calendar year in which the Grant Date occurs with respect to an additional one-third of the number of shares of Common Stock subject to the Award on the Grant Date, and (iii) on the date of the first regular meeting of the Committee in the third calendar year following the calendar year in which the Grant Date occurs with respect to the remaining shares of Common Stock subject to the Award on the Grant Date (but, with respect to each such year, not later than March 15), in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(e) Dividend Equivalents . As of each Dividend Payment Date, the number of shares of Common Stock that are subject to a Restricted Stock Unit Award shall be increased by (i) the product of the total number of shares of Common Stock that are subject to such Restricted Stock Unit Award immediately prior to the record date for such Dividend Payment Date, but that have not been issued pursuant to Section 4(f) as of such record date, multiplied by the dollar amount of the cash dividend paid per share of Common Stock, divided by (ii) the Fair Market Value of a share of Common Stock on such Dividend Payment Date. Such additional Restricted Stock Units shall be subject to all of the terms and conditions of the Award, including the vesting conditions set forth in Section 4(d).

(f) Settlement of Vested Awards . Subject to the withholding of taxes pursuant to Section 8 of the Program, within 30 days after the vesting of a Restricted Stock Unit Award, in whole or in part (or at such later time as may be required pursuant to this Section 4(f)), the Company shall issue or transfer to the Participant the number of shares of Common Stock that have become vested. The Company may effect such transfer either by the delivery of one or more certificates of Common Stock to the Participant or by an appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company, and in either case by issuing such shares in the Participant's name or in such other name as is acceptable to the Company and designated in writing by the Participant. The Company shall pay all original issue or transfer taxes and all fees and expenses incident to such delivery, except as otherwise provided in Section 8 of the Program. Prior to the settlement of a Restricted Stock Unit Award, the holder of such Award shall have no rights as a stockholder of the Company with respect to the shares of Common Stock subject to such Award. Notwithstanding the foregoing, if a Participant is a "Specified Employee," within the meaning of section 409A of the Code, and such Participant is or will become eligible for Retirement prior to the calendar year in which the Restricted Stock Unit Award is scheduled to become fully vested, then any shares of Common Stock subject to the Award which become vested upon the Participant's termination of employment in accordance with Section 4(g) of this Program shall be issued to the Participant as of the earlier to occur of the six-month anniversary of such Participant's separation from service or the date of the Participant's death.

(g) Termination of Employment . Except as otherwise provided in this Program or the Plan:

(i) Retirement, Disability or Death . If a Participant's employment with the Company terminates by reason of Retirement, Disability or death, and such Participant has not breached his or her obligations to the Company or

any of its affiliates under any Restrictive Covenant, then all shares of Common Stock subject to such Participant's Restricted Stock Unit Award shall become fully vested as of the effective date of the Participant's termination of employment or date of death, as the case may be.

(ii) Termination for Other Reasons . If a Participant's employment with the Company terminates for any reason other than as described in clause (i) of this Section 4(g) or if the Participant has breached his or her obligations to the Company or any of its affiliates under any Restrictive Covenant, the unvested portion of such Participant's Restricted Stock Unit Award shall be forfeited and terminate as of the date of such termination of employment; provided however, that such an Award granted on or after January 1, 2012 shall become fully vested upon an involuntary termination without Cause.

5. Stock Option Award Program .

(a) Granting of Awards . The Committee may grant Option Awards to employees who are employed in a Senior Vice President or more senior position, as selected by the Committee in its sole discretion or, to the extent permitted by the Plan, the Chief Executive Officer of the Company.

(b) Terms of Awards . Awards shall be subject to the following terms and conditions and shall contain such additional terms and conditions, not inconsistent with the terms of this Program, as the Committee shall deem advisable and set forth in the applicable Award Notice.

(c) Number of Shares . The number of shares of Common Stock subject to an Option Award shall be determined by the Committee and set forth in the applicable Award Notice.

(d) Term of Option . Except to the extent earlier terminated or exercised, each Option shall expire on, and in no event may any portion of such Option be exercised after, the tenth anniversary of the Grant Date (the " Expiration Date ").

(e) Vesting and Forfeiture . Except to the extent the Award becomes immediately vested upon a termination of the Participant's employment pursuant to Section 5(g) of the Program, the Option shall become vested and exercisable (i) on the first anniversary of the Grant Date with respect to one-fourth of the number of shares of Common Stock subject to the Award on the Grant Date, (ii) on the second anniversary of the Grant Date with respect to an additional one-fourth of the number of shares of Common Stock subject to the Award on the Grant Date (iii) on the third anniversary of the Grant Date with respect to an additional one-fourth of the number of shares of Common Stock subject to the Award on the Grant Date, and (iv) on the fourth anniversary of the Grant Date with respect to the remaining shares of Common Stock subject to the award on the Grant Date, in each case subject to the Participant's continuous employment with the Company through the applicable vesting date.

(f) Method of Exercise . To the extent permitted by the Administrator, a Participant may exercise an Option (i) by giving written notice to the Company (or its designated agent) specifying the number of whole shares of Common Stock to be purchased and accompanying such notice with payment therefor in full, and without any extension of credit, either (A) in cash, (B) by delivery (either actual delivery or by attestation procedures established by the Company) to the Company of previously owned whole shares of Common Stock having a Fair Market Value, determined as of the date of exercise, equal to the aggregate purchase price payable by reason of such exercise, (C) authorizing the Company to withhold whole shares of Common Stock which would otherwise be delivered having an aggregate Fair Market Value, determined as of the date of exercise, equal to the amount necessary to satisfy such obligation, provided that the Committee determines that such withholding of shares does not cause the Company to recognize an increased compensation expense under applicable accounting principles, (D) except as may be prohibited by applicable law, in cash by a broker-dealer acceptable to the Company to whom the Participant has submitted an irrevocable notice of exercise or (E) a combination of (A), (B) and (C) and (ii) by executing such documents as the Company may reasonably request. Any fraction of a share of Common Stock which would be required to pay such purchase price shall be disregarded and the remaining amount due shall be paid in cash by the Participant. No shares of Common Stock shall be issued and no certificate representing Common Stock shall be delivered until the full purchase price therefor and any withholding taxes thereon, as described in Section 8, have been paid.

(g) Termination of Employment .

(i) Retirement or Disability . If the Company ceases to employ a Participant by reason of such Participant's Retirement or Disability, each Option held by such Participant shall be fully exercisable, and may thereafter be exercised by such Participant (or such Participant's legal representative or similar person) until and including the earlier to occur of (i) the fifth anniversary of the effective date of such Participant's termination of employment and (ii) the Expiration Date.

(ii) Death . If the Company ceases to employ a Participant by reason of such Participant's death, each Option held by such Participant shall be fully exercisable, and may thereafter be exercised by such Participant's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the third anniversary of the date of death and (ii) the Expiration Date.

(iii) Cause . If the Company ceases to employ a Participant due to a termination of employment by the Company for Cause, each Option held by such Participant shall be cancelled and cease to be exercisable as of the earlier to occur of (i) the effective date of such termination of employment and (ii) the date on which the Participant first engaged in conduct giving rise to a termination for Cause, and the Company thereafter may require the repayment of any amounts received by such Participant in connection with an exercise of such Option following such cancellation date.

(iv) Other Termination . Subject to clauses (v), (vi) and (vii) below, if the Company ceases to employ a Participant for any reason other than as described in clause (i), (ii) or (iii) above, then each Option held by such Participant shall be exercisable only to the extent that such Option is exercisable on the effective date of such Participant's termination of employment, and may thereafter be exercised by such Participant (or such Participant's legal representative or similar person) until and including the earlier to occur of (i) the date which is 90 days after the effective date of such Participant's termination of employment and (ii) the Expiration Date.

(v) Death Following Termination of Employment . If a Participant dies during the applicable post-termination exercise period described in clause (iv), each Option held by such Participant shall be exercisable only to the extent that such Option is exercisable on the date of such Participant's death and may thereafter be exercised by the Participant's executor, administrator, legal representative, beneficiary or similar person until and including the earlier to occur of (i) the first anniversary of the date of death and (ii) the expiration date of the term of such Option.

(vi) Breach of Restrictive Covenant . Notwithstanding clauses (i) through (v), if a Participant breaches his or her obligations to the Company or any of its affiliates under a Restrictive Covenant, each Option held by such Participant shall be cancelled and cease to be exercisable as of the date on which the Participant first breached such Restrictive Covenant, and the Company thereafter may require the repayment of any amounts received by such Participant in connection with an exercise of such Option following such cancellation date.

(h) Termination of Option . In no event may an Option be exercised after it terminates as set forth in this Section 5(h). An Option shall terminate, to the extent not earlier exercised or terminated pursuant to Section 5(g), on the Expiration Date. Upon the termination of the Option, the Option and all rights thereunder shall immediately become null and void.

6. Employment . For purposes of this Program, references to employment with the Company shall include (i) employment with an Affiliate of the Company and (ii) any period during which the Participant is on a leave of absence approved by the Company.

7. Limited Transferability of Awards . Except as may otherwise be expressly provided in an Award Notice, an Award may be transferred by the Participant only (1) by will, (2) the laws of descent and distribution or (3) pursuant to beneficiary designation procedures approved by the Company. Except to the extent permitted by the foregoing, an Award may not be sold, transferred, assigned, pledged, hypothecated, encumbered or otherwise disposed of (whether by operation of law or otherwise) or be subject to execution, attachment or similar process or domestic relations order. Upon any attempt so to sell, transfer, assign, pledge, hypothecate, encumber or otherwise dispose of an Award, such Award and all rights thereunder shall immediately become null and void.

8. Withholding Taxes . The Company shall have the right to require, prior to the issuance or delivery of any shares of Common Stock or the payment of any cash pursuant to an Award, or upon the vesting of any Award that is considered deferred compensation, payment by the Participant of any federal, state, local or other taxes which may be required to be withheld or paid in connection with such Award. The Company may withhold whole shares of Common Stock which would otherwise be delivered to a Participant, having an aggregate Fair Market Value determined as of the Tax Date, or withhold an amount of cash which would otherwise be payable to a Participant, in the amount necessary to satisfy any such obligation. The Participant may elect to satisfy any such obligation by any of the following means, to the extent permitted by the Administrator: (A) a cash payment to the Company, (B) authorizing the Company to withhold whole shares of Common Stock which would otherwise be delivered having an aggregate Fair Market Value, determined as of the Tax Date, or withhold an amount of cash which would otherwise be payable to the Participant, equal to the amount necessary to satisfy any such obligation, (C) in the case of the exercise of an Option and except as may be prohibited by applicable law, a cash payment by a broker-dealer acceptable to the Company to whom the Participant has submitted an irrevocable notice of exercise or (D) any combination of (A) and (B). Shares of Common Stock to be delivered or withheld may not have an aggregate Fair Market Value in excess of the amount determined by applying the minimum statutory withholding rate. Any fraction of a share of Common Stock which would be required to satisfy such an obligation shall be disregarded and the remaining amount due shall be paid in cash by the Participant.

9. Adjustment; Change in Control or Corporate Transaction . The number and class of securities subject to an Award shall be subject to adjustment as provided in Section 5.7 of the Plan. In the event of a Change in Control or Corporate Transaction, Awards shall be subject to the terms of Section 5.8 of the Plan, as determined by the Committee. The decision of the Committee regarding any such adjustment, Change in Control and/or Corporate Transaction shall be final, binding and conclusive.

10. Compliance with Applicable Law . Each Award is subject to the condition that if the listing, registration or qualification of the shares subject to such Award upon any securities exchange or under any law, or the consent or approval of any governmental body, or the taking of any other action is necessary or desirable as a condition of, or in connection with, the delivery of shares hereunder, such Award may not be settled, in whole or in part, unless such listing, registration, qualification, consent or approval shall have been effected or obtained, free of any conditions not acceptable to the Company.

11. Award Subject to the Plan and Claw-back Policy . Each Award is subject to the provisions of the Plan, and each Award and this Program shall be interpreted in accordance therewith. Notwithstanding any provision of the Program to the contrary, each Award shall be subject to a clawback pursuant to the Exelon Executive Officer Compensation Recoupment Policy contained in the Exelon Corporation Board of Directors Corporate Governance Principles, as in effect from time to time, including any amendments thereto or new clawback policies required under the Dodd-Frank Wall Street Reform and Consumer Protection Act and implementing applicable stock exchange listing standards or rules and regulations thereunder, or as otherwise required by law or regulation.

12. Investment Representation . By accepting an Award, the Participant represents and covenants that (a) any share of Common Stock acquired upon the vesting of the Award will be acquired for investment and not with a view to the distribution thereof within the meaning of the Securities Act of 1933, as amended (the " Securities Act "), unless such acquisition has been registered under the Securities Act and any applicable state securities law; (b) any subsequent sale of any such shares shall be made either pursuant to an effective registration statement under the Securities Act and any applicable state securities laws, or pursuant to an exemption from registration under the Securities Act and such state securities laws; and (c) if requested by the Company, the Participant shall submit a written statement, in form satisfactory to the Company, to the effect that such representation (x) is true and correct as of the date of acquisition of any shares hereunder or (y) is true and correct as of the date of any sale of any such shares, as applicable. As a further condition precedent to the delivery to the Participant of any shares subject to the Award, the Participant shall comply with all regulations and requirements of any regulatory authority having control of or supervision over the issuance of the shares and, in connection therewith, shall execute any documents which the Company shall in its sole discretion deem necessary or advisable.

13. Award Confers No Rights to Continued Employment . In no event shall the granting of an Award or its acceptance by a Participant give or be deemed to give the Participant any right to continued employment by the Company.

14. Administrator . This Program shall be administered by the Company's Vice President, Corporate Compensation (the "Administrator"). Except for authority reserved to the Board or the Committee, the Administrator shall have the right to interpret the Program, make any determinations hereunder, and take any necessary or appropriate actions with respect to the administration of the Program or in connection with each Award. Any such interpretation, determination or other action made or taken by the regarding this Program or an Award shall be final, binding and conclusive. The Administrator may adopt such rules and procedures as it deems appropriate for the administration of the Plan, including but not limited to rules and procedures governing the administration and treatment (e.g., pro-ration, vesting, etc.) of Awards to Participants in situations involving transfers between business units and eligible and ineligible positions, which may be set forth in the applicable Program summary or Award Notice.

15. Miscellaneous Provisions .

(a) Successors . This Program and each Award shall be binding upon and inure to the benefit of any successor or successors of the Company and any person or persons who shall, upon the death of a Participant, acquire any rights under such Award in accordance with this Program or the Plan.

(b) Notices . All notices, requests or other communications provided for in this Program (other than the exercise of a stock option) shall be made, if to the Company, to Exelon Corporation, 10 South Dearborn Street, Chicago, Illinois 60603, Attention: Vice President, Corporate Compensation, and if to the Participant, to his or her then current work location. All notices, requests or other communications provided for in this Program shall be made in writing either (a) by personal delivery to the party entitled thereto, (b) by facsimile with confirmation of receipt, (c) by mailing in the United States mails to the last

known address of the party entitled thereto or (d) by express courier service. The notice, request or other communication shall be deemed to be received upon personal delivery, upon confirmation of receipt of facsimile transmission, or upon receipt by the party entitled thereto if by United States mail or express courier service; provided, however, that if a notice, request or other communication is not received during regular business hours, it shall be deemed to be received on the next succeeding business day of the Company.

(c) Section 409A . This Program and the Awards granted hereunder are intended to comply with the requirements of section 409A of the Code and shall be interpreted and construed consistently with such intent. Awards granted pursuant to this Program are also intended to be exempt from Section 409A of the Code to the maximum extent possible as short-term deferrals pursuant to Treasury regulation §1.409A-1(b)(4), and for this purpose each payment shall be considered a separate payment. In the event the terms of an Award would subject a Participant to taxes or penalties under Section 409A of the Code (" 409A Penalties "), the Company may modify the terms of such Award to avoid such 409A Penalties, to the extent possible; provided that in no event shall the Company be responsible for any 409A Penalties that arise in connection with any Award. To the extent the timing of payment under an Award is determined by reference to a Participant's "termination of employment," such term shall be deemed to refer to the Participant's "separation from service," within the meaning of section 409A of the Code. Notwithstanding any other provision in this Program, if a Participant is a "specified employee," as defined in Section 409A of the Code, as of the date of such Participant's separation from service, then to the extent any amount payable to the Participant (i) constitutes the payment of nonqualified deferred compensation, within the meaning of Section 409A of the Code, (ii) is payable upon the Participant's separation from service and (iii) under the terms of this Program would be payable prior to the six-month anniversary of the Participant's separation from service, such payment shall be delayed until the earlier to occur of (A) the six-month anniversary of the separation from service and (B) the date of the Participant's death.

(d) Amendment . The terms of this Program may be amended by the Committee or the Board (or their respective delegates), provided that the Chief Human Resources Officer or the Vice President, Corporate Compensation, of the Company may amend the Program to comply with applicable law, to make administrative changes or to carry out directives of the Board or the Committee.

(e) Governing Law . This Program and each Award granted thereunder, and all determinations made and actions taken pursuant thereto, to the extent not governed by the laws of the United States, shall be governed by the laws of the Commonwealth of Pennsylvania and construed in accordance therewith without giving effect to principles of conflicts of laws.

IN WITNESS WHEREOF, Exelon Corporation has caused this instrument to be executed by its Senior Vice President & Chief Human Resources Officer, effective as of January 1, 2015.

EXELON CORPORATION

By: _____

Senior Vice President & Chief Human Resources Officer

AMENDMENT NUMBER TWO
TO THE EXELON CORPORATION
2011 LONG-TERM INCENTIVE PLAN

WHEREAS, Exelon Corporation (the "Company") maintains the Exelon Corporation 2011 Long-Term Incentive Plan, effective January 1, 2011, as amended (the "Plan");

WHEREAS, pursuant to Section 5.2 of the Plan, the Compensation Committee of the Board of Directors of the Company (the "Committee") is authorized to amend the Plan to the extent that the Committee deems such amendment advisable, subject to certain requirements; and

WHEREAS, the Committee has approved the adoption of this amendment, in order to allow flexibility with respect to the approval of permitted awards to executives who are not officers subject to Section 16 of the Securities Exchange Act of 1934, as amended.

NOW, THEREFORE, the Plan is amended for all outstanding and future awards under the Plan, effective October 26, 2015, as follows:

1. The second paragraph of Section 1.3 of the Plan is amended by deleting the phrase "or whose title with the Company is 'executive vice president' or higher" therein.

IN WITNESS WHEREOF, the Company has caused this amendment to be executed this 18 th day of December, 2015.

Exelon Corporation

By: /s/ Amy Best
Amy Best
Senior Vice President &
Chief Human Resources Officer

Exelon Corporation
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2011	2012	2013	2014	2015
Pre-tax income from continuing operations	3,952	1,798	2,773	2,486	3,330
Plus: Loss from equity investees	1	91	(10)	20	—
Less: Capitalized interest	(57)	(75)	(67)	(79)	(99)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	3,896	1,814	2,696	2,427	3,231
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	761	1,021	1,436	1,110	1,107
Interest component of rental expense (a)	237	310	269	288	300
Total fixed charges	998	1,331	1,705	1,398	1,407
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	4,894	3,145	4,401	3,825	4,638
Ratio of earnings to fixed charges	4.9	2.4	2.6	2.7	3.3

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exelon Corporation
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
	2011	2012	2013	2014	2015
Pre-tax income from continuing operations	3,952	1,798	2,773	2,486	3,330
Plus: Loss from equity investees	1	91	(10)	20	—
Less: Capitalized interest	(57)	(75)	(67)	(79)	(99)
Preference security dividend requirements	(6)	(26)	(32)	(18)	(19)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	3,890	1,788	2,664	2,409	3,212
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	761	1,021	1,436	1,110	1,107
Interest component of rental expense (a)	237	310	269	288	300
Preference security dividend requirements of consolidated subsidiaries	6	26	32	18	19
Total fixed charges	1,004	1,357	1,737	1,416	1,426
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	4,894	3,145	4,401	3,825	4,638
Ratio of earnings to fixed charges and preferred stock dividends	4.9	2.3	2.5	2.7	3.3

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exelon Generation Company, LLC
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2011	2012	2013	2014	2015
Pre-tax income from continuing operations	2,827	1,058	1,675	1,226	1,850
Plus: (Income) or loss from equity investees	1	91	(10)	20	—
Less: Capitalized interest	(49)	(67)	(54)	(63)	(79)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	2,779	1,082	1,611	1,183	1,771
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	219	402	445	396	427
Interest component of rental expense (a)	220	291	248	269	284
Total fixed charges	439	693	693	665	711
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	3,218	1,775	2,304	1,848	2,482
Ratio of earnings to combined fixed charges	7.3	2.6	3.3	2.8	3.5

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Commonwealth Edison Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2011	2012	2013	2014	2015
Pre-tax income from continuing operations	666	618	401	676	706
Plus: Loss from equity investees	—	—	—	—	
Less:Capitalized interest	(4)	(3)	(5)	(2)	(4)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	662	615	396	674	702
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	330	297	575	311	331
Interest component of rental expense (a)	6	6	5	5	4
Total fixed charges	336	303	580	316	335
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest plus fixed charges	998	918	976	990	1,037
Ratio of earnings to fixed charges	3.0	3.0	1.7	3.1	3.1

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

PECO Energy Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2011	2012	2013	2014	2015
Pre-tax income from continuing operations	535	508	557	466	521
Plus: Loss from equity investees	—	—	—	—	—
Less: Capitalized interest	(4)	(2)	(2)	(2)	(2)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	531	506	555	464	519
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	135	122	114	112	114
Interest component of rental expense (a)	9	9	7	5	3
Total fixed charges	144	131	121	117	117
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	675	637	676	581	636
Ratio of earnings to combined fixed charges	4.7	4.9	5.6	5.0	5.4

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

PECO Energy Company
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
	2011	2012	2013	2014	2015
Pre-tax income from continuing operations	535	508	557	466	521
Plus: Loss from equity investees	—	—	—	—	—
Less: Capitalized interest	(4)	(2)	(2)	(2)	(2)
Preference security dividend requirements	(6)	(5)	(10)	—	—
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	525	501	545	464	519
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	135	122	114	112	114
Interest component of rental expense (a)	9	9	7	5	3
Preference security dividend requirements	6	5	10	—	—
Total fixed charges	150	136	131	117	117
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	675	637	676	581	636
Ratio of earnings to fixed charges and preferred stock dividends	4.5	4.7	5.2	5.0	5.4

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

BGE
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2011	2012	2013	2014	2015
Pre-tax income from continuing operations	211	11	344	351	477
Less: Capitalized interest	(7)	(5)	(6)	(12)	(14)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	204	6	338	339	463
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	136	149	127	118	113
Interest component of rental expense (a)	5	4	4	4	11
Total fixed charges	141	153	131	122	124
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	345	159	469	461	587
Ratio of earnings to fixed charges	2.4	1.0	3.6	3.8	4.7

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

BGE
Ratio of Earnings to Fixed Charges and Preference Stock Dividends

	Years Ended December 31,				
	2011	2012	2013	2014	2015
Pre-tax income from continuing operations	211	11	344	351	477
Less: Capitalized interest	(7)	(5)	(6)	(12)	(14)
Preference security dividend requirements	(20)	(20)	(21)	(22)	(22)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	184	(14)	317	317	441
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	136	149	127	118	113
Interest component of rental expense (a)	5	4	4	4	11
Preference security dividend requirements	20	20	21	22	22
Total fixed charges	161	173	152	144	146
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	345	159	469	461	587
Ratio of earnings to fixed charges and preferred stock dividends	2.1	0.9 (b)	3.1	3.2	4.0

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.
(b) The ratio coverage was less than 1:1. The registrant must generate additional earnings of $14 million to achieve a coverage ratio of 1:1.

Exelon Corporation
12/31/2015

Name	Jurisdiction
2014 ESA HoldCo, LLC	Delaware
2014 ESA Project Company, LLC	Delaware
2015 ESA Holdco, LLC	Delaware
2015 ESA Investco, LLC	Delaware
2015 ESA Project Company, LLC	Delaware
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Albany Green Energy, LLC	Georgia
Annova LNG Brownsville A, LLC	Delaware
Annova LNG Brownsville B, LLC	Delaware
Annova LNG Brownsville C, LLC	Delaware
Annova LNG Common Infrastructure, LLC	Delaware
Annova LNG, LLC	Delaware
Annova LNG, LLC, Series A Units	Delaware
Annova LNG, LLC, Series B Units	Delaware
Annova LNG, LLC, Series C Units	Delaware
Annova LNG, LLC, Series Z Units	Delaware
ATNP Finance Company	Delaware
AV Solar Ranch 1, LLC	Delaware
Baltimore Gas and Electric Company	Maryland
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
BGE Capital Trust II	Delaware
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Bluestem Wind Energy, LLC	Delaware
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Breezy Bucks-I LLC	Minnesota
Breezy Bucks-II LLC	Minnesota
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
California PV Energy 2, LLC	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Colver I, Inc.	Maryland
CE Colver III, Inc.	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Nuclear, LLC	Delaware
CECG International Holdings, Inc.	Delaware
CER Generation, LLC	Delaware
CEU Arkoma West, LLC	Delaware
CEU CHC, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU Development, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware

CEU Offshore I, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU Trenton, LLC	Delaware
CEU W&D, LLC	Delaware
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton NQF, LLC	Nevada
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
Cogenex Corporation	Massachusetts
CoLa Resources LLC	Delaware
Colorado Bend I Power, LLC	Delaware
Colorado Bend II Power, LLC	Delaware
Colorado Bend Services, LLC	Delaware
ComEd Financing III	Delaware
Commonwealth Edison Company	Illinois
Commonwealth Edison Company of Indiana, Inc.	Indiana
Compass Energy Gas Services, LLC	Virginia
Compass Energy Services, Inc.	Virginia
Constellation Bulk Energy Holdings, Inc.	Marshall Islands
Constellation CNG, LLC	Delaware
Constellation DCO Albany Power Holdings, LLC	Delaware
Constellation EG, LLC	Delaware
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Limited	United Kingdom
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Gas Choice, Inc.	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Partners Holdings, LLC	Delaware
Constellation Energy Power Choice, Inc.	Delaware
Constellation Energy Projects & Services Group Advisors, LLC	Delaware
Constellation Energy Projects and Services Canada, Inc.	Federal
Constellation Energy Resources, LLC	Delaware
Constellation Energy Services - Natural Gas, LLC	Delaware
Constellation Energy Services of New York, Inc.	New York
Constellation Energy Services, Inc.	Wisconsin
Constellation Energy Upstream Holdings, Inc.	Delaware
Constellation Holdings, LLC	Maryland
Constellation International Holdings, Inc.	Marshall Islands
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy - Gas Division, LLC	Kentucky
Constellation NewEnergy Canada Inc.	Ontario
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Operating Services	California

Constellation Power Source Generation, LLC	Maryland
Constellation Power, Inc.	Maryland
Constellation Sacramento Holding, LLC	Delaware
Constellation Solar Arizona 2, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Georgia, LLC	Georgia
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland MC, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
COSI Ultra II, Inc.	Maryland
COSI Ultra, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CR Clearing, LLC	Missouri
Criterion Power Partners, LLC	Delaware
DAJAW Transmission LLC	Minnesota
Denver Airport Solar, LLC	Delaware
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
Energy Performance Services, Inc.	Pennsylvania
ETT Canada, Inc.	New Brunswick
Ewington Energy Systems LLC	Minnesota
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Business Services Company, LLC	Delaware
Exelon Corporation	Pennsylvania
Exelon Energy Delivery Company, LLC	Delaware
Exelon Enterprises Company, LLC	Pennsylvania
Exelon Framingham, LLC	Delaware
Exelon Fulton, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, Inc.	Pennsylvania
Exelon Generation Limited	United Kingdom
Exelon Mechanical, LLC	Delaware
Exelon Microgrid, LLC	Delaware
Exelon New Boston, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon Peaker Development Limited, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon Solar Chicago LLC	Delaware

Exelon Transmission Company, LLC	Delaware
Exelon West Medway II, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
Ex-FM, Inc.	New York
Ex-FME, Inc.	Delaware
ExGen Renewables Holdings II, LLC	Delaware
ExGen Renewables I Holding, LLC	Delaware
ExGen Renewables I, LLC	Delaware
ExGen Renewables II, LLC	Delaware
ExGen Texas II Power Holdings, LLC	Delaware
ExGen Texas II Power, LLC	Delaware
ExGen Texas Power Holdings, LLC	Delaware
ExGen Texas Power Services, LLC	Delaware
ExGen Texas Power, LLC	Delaware
ExGen Ventures International Holdings II Limited	United Kingdom
ExGen Ventures International Holdings Limited	United Kingdom
ExTel Corporation, LLC	Delaware
F & M Holdings Company, L.L.C.	Delaware
Fair Wind Power Partners, LLC	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
G-Flow Wind, LLC	Minnesota
Grande Prairie Generation, Inc.	Alberta
Green Acres Breeze, LLC	Minnesota
Greensburg Wind Farm, LLC	Delaware
Handley Power, LLC	Delaware
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
Lake Houston Power, LLC	Delaware
LaPorte Power, LLC	Delaware
Las Vegas District Energy, LLC	Delaware
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware

Minergy LLC	Wisconsin
Minnesota Breeze, LLC	Minnesota
Mohave Sunrise Solar I, LLC	Arizona
Mountain Creek Power, LLC	Delaware
Mountain Top Wind Power, LLC	Maryland
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Northwind Thermal Technologies Canada Inc.	New Brunswick
OMF 11520, LLC	Delaware
Oregon Trail Windfarm, LLC	Oregon
Outback Solar, LLC	Oregon
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Company	Pennsylvania
PECO Wireless, LLC	Delaware
Pegasus Power Company, Inc.	California
PH Holdco LLC	Delaware
Pinedale Energy, LLC	Colorado
Prairie Wind Power LLC	Minnesota
Purple Acquisition Corp.	Delaware
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Renewable Power Generation Holdings, LLC	Delaware
Renewable Power Generation, LLC	Delaware
Residential Solar Holding, LLC	Delaware
Residential Solar II, LLC	Delaware
RF HoldCo LLC	Delaware
RITELine Illinois, LLC	Illinois
RITELine Indiana, LLC	Indiana
RITELine Transmission Development, LLC	Delaware
Roadrunner-I LLC	Minnesota
RSB BondCo LLC	Delaware
Sacramento PV Energy, LLC	Delaware
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Salty Dog-I LLC	Minnesota
Salty Dog-II LLC	Minnesota
Sand Ranch Windfarm, LLC	Oregon
Scherer Holdings 1, LLC	Delaware
Scherer Holdings 2, LLC	Delaware
Scherer Holdings 3, LLC	Delaware
Sendero Wind Energy, LLC	Delaware
Shane’s Wind Machine LLC	Minnesota
Shooting Star Wind Project, LLC	Delaware
Sky Valley, LLC	Delaware
Star Electricity, Inc.	Texas
Sugar Beet Wind, LLC	Delaware
Sunnyside Cogeneration Associates	Utah
Sunnyside Generation, LLC	Delaware
Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Sunnyside Properties, LLC	Utah
Sunset Breeze, LLC	Minnesota
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware

TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
UII, LLC	Illinois
W&D Gas Partners, LLC	Delaware
Wagon Trail, LLC	Oregon
Wally's Wind Farm LLC	Minnesota
Wansley Holdings 1, LLC	Delaware
Wansley Holdings 2, LLC	Delaware
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Western Path Development, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wibaux Wind, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Windy Dog-1 LLC	Minnesota
Wolf Hollow I Power, LLC	Delaware
Wolf Hollow II Power, LLC	Delaware
Wolf Hollow Services, LLC	Delaware
Wolf Wind Enterprises, LLC	Minnesota
Wolf Wind Transmission, LLC	Minnesota
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Exelon Generation Company, LLC
12/31/2015

Name	Jurisdiction
2014 ESA HoldCo, LLC	Delaware
2014 ESA Project Company, LLC	Delaware
2015 ESA Holdco, LLC	Delaware
2015 ESA Investco, LLC	Delaware
2015 ESA Project Company, LLC	Delaware
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Albany Green Energy, LLC	Georgia
Annova LNG Brownsville A, LLC	Delaware
Annova LNG Brownsville B, LLC	Delaware
Annova LNG Brownsville C, LLC	Delaware
Annova LNG Common Infrastructure, LLC	Delaware
Annova LNG, LLC	Delaware
Annova LNG, LLC, Series A Units	Delaware
Annova LNG, LLC, Series B Units	Delaware
Annova LNG, LLC, Series C Units	Delaware
Annova LNG, LLC, Series Z Units	Delaware
AV Solar Ranch 1, LLC	Delaware
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Bluestem Wind Energy, LLC	Delaware
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Breezy Bucks-I LLC	Minnesota
Breezy Bucks-II LLC	Minnesota
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
California PV Energy 2, LLC	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Colver I, Inc.	Maryland
CE Colver III, Inc.	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Nuclear, LLC	Delaware
CECG International Holdings, Inc.	Delaware
CER Generation, LLC	Delaware
CEU Arkoma West, LLC	Delaware
CEU CHC, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU Development, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Niobrara, LLC	Delaware
CEU Offshore I, LLC	Delaware
CEU Ohio Shale, LLC	Delaware

CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU Trenton, LLC	Delaware
CEU W&D, LLC	Delaware
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton NQF, LLC	Nevada
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
Cogenex Corporation	Massachusetts
CoLa Resources LLC	Delaware
Colorado Bend I Power, LLC	Delaware
Colorado Bend II Power, LLC	Delaware
Colorado Bend Services, LLC	Delaware
Compass Energy Gas Services, LLC	Virginia
Compass Energy Services, Inc.	Virginia
Constellation Bulk Energy Holdings, Inc.	Marshall Islands
Constellation CNG, LLC	Delaware
Constellation DCO Albany Power Holdings, LLC	Delaware
Constellation EG, LLC	Delaware
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Limited	United Kingdom
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Gas Choice, Inc.	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Partners Holdings, LLC	Delaware
Constellation Energy Power Choice, Inc.	Delaware
Constellation Energy Projects & Services Group Advisors, LLC	Delaware
Constellation Energy Projects and Services Canada, Inc.	Federal
Constellation Energy Resources, LLC	Delaware
Constellation Energy Services - Natural Gas, LLC	Delaware
Constellation Energy Services of New York, Inc.	New York
Constellation Energy Services, Inc.	Wisconsin
Constellation Energy Upstream Holdings, Inc.	Delaware
Constellation Holdings, LLC	Maryland
Constellation International Holdings, Inc.	Marshall Islands
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy - Gas Division, LLC	Kentucky
Constellation NewEnergy Canada Inc.	Ontario
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Operating Services	California
Constellation Power Source Generation, LLC	Maryland
Constellation Power, Inc.	Maryland
Constellation Sacramento Holding, LLC	Delaware
Constellation Solar Arizona 2, LLC	Delaware

Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Georgia, LLC	Georgia
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland MC, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
COSI Ultra II, Inc.	Maryland
COSI Ultra, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CR Clearing, LLC	Missouri
Criterion Power Partners, LLC	Delaware
DAJAW Transmission LLC	Minnesota
Denver Airport Solar, LLC	Delaware
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
Energy Performance Services, Inc.	Pennsylvania
Ewington Energy Systems LLC	Minnesota
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Fulton, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, Inc.	Pennsylvania
Exelon Generation Limited	United Kingdom
Exelon New Boston, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon Peaker Development Limited, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon Solar Chicago LLC	Delaware
Exelon West Medway II, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas

Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
ExGen Renewables Holdings II, LLC	Delaware
ExGen Renewables I Holding, LLC	Delaware
ExGen Renewables I, LLC	Delaware
ExGen Renewables II, LLC	Delaware
ExGen Texas II Power Holdings, LLC	Delaware
ExGen Texas II Power, LLC	Delaware
ExGen Texas Power Holdings, LLC	Delaware
ExGen Texas Power Services, LLC	Delaware
ExGen Texas Power, LLC	Delaware
ExGen Ventures International Holdings II Limited	United Kingdom
ExGen Ventures International Holdings Limited	United Kingdom
Fair Wind Power Partners, LLC	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
G-Flow Wind, LLC	Minnesota
Grande Prairie Generation, Inc.	Alberta
Green Acres Breeze, LLC	Minnesota
Greensburg Wind Farm, LLC	Delaware
Handley Power, LLC	Delaware
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
Lake Houston Power, LLC	Delaware
LaPorte Power, LLC	Delaware
Las Vegas District Energy, LLC	Delaware
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Minergy LLC	Wisconsin
Minnesota Breeze, LLC	Minnesota
Mohave Sunrise Solar I, LLC	Arizona
Mountain Creek Power, LLC	Delaware
Mountain Top Wind Power, LLC	Maryland
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Oregon Trail Windfarm, LLC	Oregon
Outback Solar, LLC	Oregon
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada

Peach Bottom 3 NQF, LLC	Nevada
Pegasus Power Company, Inc.	California
Pinedale Energy, LLC	Colorado
Prairie Wind Power LLC	Minnesota
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Renewable Power Generation Holdings, LLC	Delaware
Renewable Power Generation, LLC	Delaware
Residential Solar Holding, LLC	Delaware
Residential Solar II, LLC	Delaware
Roadrunner-I LLC	Minnesota
Sacramento PV Energy, LLC	Delaware
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Salty Dog-I LLC	Minnesota
Salty Dog-II LLC	Minnesota
Sand Ranch Windfarm, LLC	Oregon
Sendero Wind Energy, LLC	Delaware
Shane's Wind Machine LLC	Minnesota
Shooting Star Wind Project, LLC	Delaware
Sky Valley, LLC	Delaware
Star Electricity, Inc.	Texas
Sugar Beet Wind, LLC	Delaware
Sunnyside Cogeneration Associates	Utah
Sunnyside Generation, LLC	Delaware
Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Sunnyside Properties, LLC	Utah
Sunset Breeze, LLC	Minnesota
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware
TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
W&D Gas Partners, LLC	Delaware
Wagon Trail, LLC	Oregon
Wally's Wind Farm LLC	Minnesota
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wibaux Wind, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Windy Dog-1 LLC	Minnesota
Wolf Hollow I Power, LLC	Delaware
Wolf Hollow II Power, LLC	Delaware
Wolf Hollow Services, LLC	Delaware
Wolf Wind Enterprises, LLC	Minnesota
Wolf Wind Transmission, LLC	Minnesota
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Commonwealth Edison Company

Subsidiary	Jurisdiction
ComEd Financing III	Delaware
Commonwealth Edison Company of Indiana, Inc.	Indiana
RITELine Illinois, LLC	Illinois

PECO Energy Company
12/31/2015

Subsidiary	Jurisdiction
ATNP Finance Company	Delaware
ExTel Corporation, LLC	Delaware
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Wireless, LLC	Delaware

Baltimore Gas and Electric Company

Subsidiary	Jurisdiction
BGE Capital Trust II	Delaware
RSB BondCo LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-196220 and No. 333-206474), Form S-4 (No. 333-209209) and on Form S-8 (No.333-189849, No.333-175162, No.333-127377, No.333-37082, No.333-49780 and No. 333-61390) of Exelon Corporation of our report dated February 10, 2016 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting of Exelon Corporation, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 10, 2016

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-196220-04) and Form S-4 (No. 333-184712) of Exelon Generation Company, LLC of our report dated February 10, 2016 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Exelon Generation Company, LLC, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 10, 2016

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-196220-03) of Commonwealth Edison Company of our report dated February 10, 2016 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Commonwealth Edison Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 10, 2016

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-196220-02) of PECO Energy Company of our report dated February 10, 2016 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of PECO Energy Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 10, 2016

Exhibit 23.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-196220-01) of Baltimore Gas and Electric Company of our report dated February 10, 2016 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Baltimore Gas and Electric Company, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 10, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anthony K. Anderson** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Anthony K. Anderson

Anthony K. Anderson

DATE: February 8, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ann C. Berzin

Ann C. Berzin

DATE: February 8, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John A. Canning, Jr.** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John A. Canning, Jr.

John A. Canning, Jr.

DATE: February 4, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Darryl M. Bradford attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane

Christopher M. Crane

DATE: February 2, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Yves C. de Balmann** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Yves C. de Balmann

Yves C. de Balmann

DATE: February 2, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis

Nicholas DeBenedictis

DATE: February 4, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Paul Joskow** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Paul Joskow

Paul Joskow

DATE: February 2, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Linda P. Jojo** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Linda P. Jojo

Linda P. Jojo

DATE: February 3, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Robert J. Lawless** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Robert J. Lawless

Robert J. Lawless

DATE: February 3, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Richard W. Mies** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Richard W. Mies

Richard W. Mies

DATE: February 9, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John W. Rogers, Jr.** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John W. Rogers, Jr.

John W. Rogers, Jr.

DATE: February 3, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Mayo A. Shattuck III** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Mayo A. Shattuck III

Mayo A. Shattuck III

DATE: February 2, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Stephen D. Steinour** , do hereby appoint Christopher M. Crane and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Stephen D. Steinour

Stephen D. Steinour

DATE: February 2, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James W. Compton** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ James W. Compton

James W. Compton

DATE: February 4, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane

Christopher M. Crane

DATE: February 2, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **A. Steven Crown** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ A. Steven Crown

A. Steven Crown

DATE: February 4, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis

Nicholas DeBenedictis

DATE: February 4, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Peter V. Fazio, Jr.** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Peter V. Fazio, Jr.

Peter V. Fazio, Jr.

DATE: February 3, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael H. Moskow** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael H. Moskow

Michael H. Moskow

DATE: February 3, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Anne R. Pramaggiore and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien

Denis P. O'Brien

DATE: February 3, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anne R. Pramaggiore** , do hereby appoint Thomas S. O'Neill attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Anne R. Pramaggiore

Anne R. Pramaggiore

DATE: February 2, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Craig L. Adams** , do hereby appoint Romulo L. Diaz, Jr. attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Craig L. Adams

Craig L. Adams

DATE: February 4, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane

Christopher M. Crane

DATE: February 2, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **M. Walter D'Alessio** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ M. Walter D'Alessio

M. Walter D'Alessio

DATE: February 2, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis

Nicholas DeBenedictis

DATE: February 4, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nelson A. Diaz** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nelson A. Diaz
Nelson A. Diaz

DATE: February 8, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Rosemarie B. Greco** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Rosemarie B. Greco

Rosemarie B. Greco

DATE: February 6, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Charisse R. Lillie** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Charisse R. Lillie

Charisse R. Lillie

DATE: February 2, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien

Denis P. O'Brien

DATE: February 3, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ronald Rubin** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ronald Rubin

Ronald Rubin

DATE: February 3, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ann C. Berzin

Ann C. Berzin

DATE: February 8, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Christopher M. Crane

Christopher M. Crane

DATE: February 2, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael E. Cryor** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael E. Cryor

Michael E. Cryor

DATE: February 4, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James R. Curtiss** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ James R. Curtiss

James R. Curtiss

DATE: February 5, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Calvin G. Butler, Jr.,** do hereby appoint Daniel P. Gahagan attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Calvin G. Butler, Jr.

Calvin G. Butler, Jr.

DATE: February 9, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Joseph Haskins, Jr.** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Joseph Haskins, Jr.

Joseph Haskins, Jr.

DATE: February 4, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Carla D. Hayden** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Carla D. Hayden

Carla D. Hayden

DATE: February 3, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Denis P. O'Brien

Denis P. O'Brien

DATE: February 3, 2016

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael D. Sullivan** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2015 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael D. Sullivan

Michael D. Sullivan

DATE: February 3, 2016

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / C HRISTOPHER M. C RANE
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 10, 2016

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / J ONATHAN W. T HAYER
Senior Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: February 10, 2016

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / K ENNETH W. C ORNEW
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 10, 2016

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / B RYAN P. W RIGHT
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: February 10, 2016

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / A NNE R. P RAMAGGIORE
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 10, 2016

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / J OSEPH R. T RPIK , J R .
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 10, 2016

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / C RAIG L. A DAMS
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 10, 2016

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / P HILLIP S. B ARNETT
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 10, 2016

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Calvin G. Butler, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / C ALVIN G. B UTLER
Chief Executive Officer
(Principal Executive Officer)

Date: February 10, 2016

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Vahos, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / D AVID M. V AHOS
Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 10, 2016

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/ S / C HRISTOPHER M. C RANE
Christopher M. Crane
President and Chief Executive Officer

Date: February 10, 2016

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/ S / J ONATHAN W. T HAYER
Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer

Date: February 10, 2016

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/ S / K ENNETH W. C ORNEW
Kenneth W. Cornew
President and Chief Executive Officer

Date: February 10, 2016

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/ S / B RYAN P. W RIGHT
Bryan P. Wright
Senior Vice President and Chief Financial Officer

Date: February 10, 2016

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/ S / A NNE R. P RAMAGGIORE
Anne R. Pramaggiore
President and Chief Executive Officer

Date: February 10, 2016

Exhibit 32-6

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/ S / J OSEPH R. T RPIK , J R .
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Date: February 10, 2016

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/ S / C RAIG L. A DAMS
Craig L. Adams
President and Chief Executive Officer

Date: February 10, 2016

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/ S / P HILLIP S. B ARNETT
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Date: February 10, 2016

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/ S / C ALVIN G. B UTLER , J R .
Calvin G. Butler, Jr.
Chief Executive Officer

Date: February 10, 2016

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/ S / D AVID M. V AHOS
David M. Vahos
Vice President, Chief Financial Officer and Treasurer

Date: February 10, 2016

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2016

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210
001-31403	**PEPCO HOLDINGS LLC** **(a Delaware limited liability company)** 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	52-2297449
001-01072	**POTOMAC ELECTRIC POWER COMPANY** **(a District of Columbia and Virginia corporation)** 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	53-0127880
001-01405	**DELMARVA POWER & LIGHT COMPANY** **(a Delaware and Virginia corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
001-03559	**ATLANTIC CITY ELECTRIC COMPANY** **(a New Jersey corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	21-0398280

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
EXELON CORPORATION:	
Common Stock, without par value	New York and Chicago
Series A Junior Subordinated Debentures	New York
Corporate Units	New York
PECO ENERGY COMPANY:	
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York
BALTIMORE GAS AND ELECTRIC COMPANY:	
6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, by Baltimore Gas and Electric Company	New York

Securities registered pursuant to Section 12(g) of the Act:

Title of Each Class
COMMONWEALTH EDISON COMPANY:
Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants
POTOMAC ELECTRIC POWER COMPANY:
Common Stock, $.01 par value
DELMARVA POWER & LIGHT COMPANY:
Common Stock, $2.25 par value
ATLANTIC CITY ELECTRIC COMPANY:
Common Stock, $3.00 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes ☒	No ☐
Exelon Generation Company, LLC	Yes ☒	No ☐
Commonwealth Edison Company	Yes ☒	No ☐
PECO Energy Company	Yes ☒	No ☐
Baltimore Gas and Electric Company	Yes ☒	No ☐
Pepco Holdings LLC	Yes ☒	No ☐
Potomac Electric Power Company	Yes ☐	No ☒
Delmarva Power & Light Company	Yes ☐	No ☒
Atlantic City Electric Company	Yes ☐	No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒
Pepco Holdings LLC	Yes ☐	No ☒
Potomac Electric Power Company	Yes ☐	No ☒
Delmarva Power & Light Company	Yes ☐	No ☒
Atlantic City Electric Company	Yes ☐	No ☒

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

S1-SSA-0009 - 15385

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, non-accelerated filer, or a smaller reporting company. See definition of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
Exelon Corporation	☒			
Exelon Generation Company, LLC			☒	
Commonwealth Edison Company			☒	
PECO Energy Company			☒	
Baltimore Gas and Electric Company			☒	
Pepco Holdings LLC			☒	
Potomac Electric Power Company			☒	
Delmarva Power & Light Company			☒	
Atlantic City Electric Company			☒	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2016 was as follows:

Exelon Corporation Common Stock, without par value	$33,527,039,724
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None
Baltimore Gas and Electric Company, without par value	None
Pepco Holdings LLC	Not applicable
Potomac Electric Power Company	None
Delmarva Power & Light Company	None
Atlantic City Electric Company	None

The number of shares outstanding of each registrant’s common stock as of January 31, 2017 was as follows:

Exelon Corporation Common Stock, without par value	926,589,614
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,017,157
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company, without par value	1,000
Pepco Holdings LLC	not applicable
Potomac Electric Power Company Common Stock, $.01 par value	100
Delmarva Power & Light Company Common Stock, $2.25 par value	1,000
Atlantic City Electric Company Common Stock, $3.00 par value	8,546,017

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2017 Annual Meeting of Shareholders and the Commonwealth Edison Company 2017 Information Statement are incorporated by reference in Part III.

Exelon Generation Company, LLC, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form in the reduced disclosure format.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PCI	Potomac Capital Investment Corporation and its subsidiaries
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
BSC	Exelon Business Services Company, LLC
PHISCO	PHI Service Company
Exelon Corporate	Exelon in its corporate capacity as a holding company
PHI Corporate	PHI in its corporate capacity as a holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Antelope Valley	Antelope Valley Solar Ranch One
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
EGTP	ExGen Texas Power, LLC
EGR	ExGen Renewables I, LLC
AmerGen	AmerGen Energy Company, LLC
RPG	Renewable Power Generation
SolGen	SolGen, LLC
BondCo	RSB BondCo LLC
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
Registrants	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL and ACE, collectively
Legacy PHI	PHI, Pepco, DPL and ACE, collectively
ConEdison Solutions	The competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc., a subsidiary of Consolidated Edison, Inc
UII	Unicom Investments, Inc.

Other Terms and Abbreviations

1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source

Other Terms and Abbreviations

AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
AOCI	Accumulated Other Comprehensive Income
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
ASC	Accounting Standards Codification
BGS	Basic Generation Service
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CES	Clean Energy Standard
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE
Conectiv Energy	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
Contract EDCs	Pepco, DPL and BGE, the Maryland utilities required by the MDPSC to enter into a contract for new generation
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTA	Consolidated tax adjustment
CTC	Competitive Transition Charge
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DCPSC	District of Columbia Public Service Commission
DC PLUG	District of Columbia Power Line Undergrounding
Default Electricity Supply	The supply of electricity by PHI's electric utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive supplier, and which, depending on the jurisdiction, is also known as Standard Offer Service or BGS
Default Electricity Supply Revenue	Revenue primarily from Default Electricity Supply
DOE	United States Department of Energy
DOJ	United States Department of Justice

Other Terms and Abbreviations

DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDCs	Electric distribution companies
EDF	Electricite de France SA and its subsidiaries
EE&C	Energy Efficiency and Conservation/Demand Response
EGS	Electric Generation Supplier
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
HSR Act	The Hart-Scott-Rodino Antitrust Improvements Act of 1976
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
Integrys	Integrys Energy Services, Inc.
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out

Other Terms and Abbreviations

LLRW	Low-Level Radioactive Waste
LT Plan	Long-term renewable resources procurement plan
LTIP	Long-Term Incentive Plan
MAPP	Mid-Atlantic Power Pathway
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJBPU	New Jersey Board of Public Utilities
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOSA	Nuclear Operating Services Agreement
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NUGs	Non-utility generators
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPC	Office of People's Counsel
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PHI Retirement Plan	PHI's noncontributory retirement plan
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
Preferred Stock	Originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share

Other Terms and Abbreviations

PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
ROE	Return on equity
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RSSA	Reliability Support Services Agreement
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant from DOE
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOCAs	Standard Offer Capacity Agreements required to be entered into by ACE pursuant to a New Jersey law enacted to promote the construction of qualified electric generation facilities in New Jersey
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
Transition Bond Charge	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees
Transition Bonds	Transition Bonds issued by ACE Funding
Upstream	Natural gas and oil exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit
ZES	Zero Emission Standard

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants). Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a Registrants include those factors discussed herein, including those factors discussed with respect to such Registrant discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 24; and (d) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants' websites at www.exeloncorp.com. Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I

ITEM 1. BUSINESS

General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through Generation, in the energy generation business, and through ComEd, PECO, BGE, PHI, Pepco, DPL and ACE in the energy delivery businesses discussed below. Exelon's principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603, and its telephone number is 800-483-3220.

Generation

Generation's integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

Generation was formed in 2000 as a Pennsylvania limited liability company. Generation began operations as a result of a corporate restructuring, effective January 1, 2001, in which Exelon separated its generation and other competitive businesses from its regulated energy delivery businesses at ComEd and PECO.

Generation's principal executive offices are located at 300 Exelon Way, Kennett Square, Pennsylvania 19348, and its telephone number is 610-765-5959.

ComEd

ComEd's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in northern Illinois, including the City of Chicago.

ComEd was organized in the State of Illinois in 1913 as a result of the merger of Cosmopolitan Electric Company into the original corporation named Commonwealth Edison Company, which was incorporated in 1907. ComEd's principal executive offices are located at 440 South LaSalle Street, Chicago, Illinois 60605, and its telephone number is 312-394-4321.

PECO

PECO's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia.

PECO was incorporated in Pennsylvania in 1929. PECO's principal executive offices are located at 2301 Market Street, Philadelphia, Pennsylvania 19103, and its telephone number is 215-841-4000.

BGE

BGE's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in central Maryland, including the City of Baltimore.

BGE was incorporated in Maryland in 1906. BGE's principal executive offices are located at 110 West Fayette Street, Baltimore, Maryland 21201, and its telephone number is 410-234-5000.

PHI

PHI is a utility services holding company engaged, through its reportable segments Pepco, DPL and ACE, in the energy delivery businesses discussed below. On March 23, 2016, Pepco Holdings, Inc., converted from a Delaware corporation to a Delaware limited liability company, Pepco Holdings LLC. PHI's principal executive offices are located at 701 Ninth Street, N.W., Washington, D.C. 20068, and its telephone number is 202-872-2000.

Pepco

Pepco's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in the District of Columbia and major portions of Montgomery County and Prince George's County in Maryland.

Pepco was incorporated in the District of Columbia in 1896 and Virginia in 1949. Pepco's principal executive offices are located at 701 Ninth Street, N.W., Washington, D.C. 20068, and its telephone number is 202-872-2000.

DPL

DPL's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in portions of Delaware and Maryland, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in portions of New Castle County in Delaware.

DPL was incorporated in Delaware in 1909 and Virginia in 1979. DPL's principal executive offices are located at 500 North Wakefield Drive, Newark, Delaware 19702, and its telephone number is 202-872-2000.

ACE

ACE's energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in portions of southern New Jersey.

ACE was incorporated in New Jersey in 1924. ACE's principal executive offices are located at 500 North Wakefield Drive, Newark, Delaware 19702, and its telephone number is 202-872-2000.

Business Services

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

PHI Service Company, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHI Service Company and the participating operating subsidiaries.

Operating Segments

See Note 26—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's operating segments.

Merger with Pepco Holdings, Inc. (Exelon)

On March 23, 2016, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Purple Acquisition Corp., a wholly owned subsidiary of Exelon (Merger Sub) and Pepco Holdings, Inc. (PHI). As a result of that merger, Merger Sub was merged into PHI (the PHI Merger) with PHI surviving as a wholly owned subsidiary of Exelon and Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon which also owns Exelon's interests in ComEd, PECO and BGE (through a special purpose subsidiary in the case of BGE). Following the completion of the

PHI Merger, Exelon and PHI completed a series of internal corporate organization restructuring transactions resulting in the transfer of PHI's unregulated business interests to Exelon and Generation and the transfer of PHI, Pepco, DPL and ACE to a special purpose subsidiary of EEDC. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the PHI transaction.

Generation

Generation, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Constellation sells electricity and natural gas, including renewable energy, in competitive energy markets to both wholesale and retail customers. The retail sales include commercial, industrial and residential customers. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Generation's fleet also provides geographic and supply source diversity. Generation's customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers.

Generation is a public utility under the Federal Power Act and is subject to FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. FERC's jurisdiction over ratemaking also includes the authority to suspend the market-based rates of utilities and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities. Additionally, ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. Specific operations of Generation are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including the NRC and Federal and state environmental protection agencies. Additionally, Generation is subject to mandatory reliability standards promulgated by the NERC, with the approval of FERC.

RTOs and ISOs exist in a number of regions to provide transmission service across multiple transmission systems. PJM, MISO, ISO-NE and SPP, have been approved by FERC as RTOs, and CAISO and ISO-NY have been approved as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems.

Constellation Energy Nuclear Group, Inc.

Generation owns a 50.01% interest in CENG, a joint venture with EDF. CENG is governed by a board of ten directors, five of which are appointed by Generation and five by EDF. CENG owns a total of five nuclear generating facilities on three sites, Calvert Cliffs, R.E. Ginna and Nine Mile Point. CENG's ownership share in the total capacity of these units is 4,007 MW. See ITEM 2. PROPERTIES for additional information on these sites.

Generation and EDF also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDF has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interests in CENG at fair value on a fully consolidated basis in Exelon's and Generation's Consolidated Balance Sheets. Refer to Note 5—Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for further information regarding the integration transaction.

Acquisitions

ConEdison Solutions. On September 1, 2016, Generation acquired the competitive retail electric and natural gas business activities of ConEdison Solutions, a subsidiary of Consolidated Edison, Inc., for a purchase price of $257 million including net working capital of $204 million. The renewable energy, sustainable services and energy efficiency businesses of ConEdison were excluded from the transaction.

Integrys Energy Services, Inc. On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (Integrys) for a purchase price of $332 million, including net working capital. The generation and solar asset businesses of Integrys were excluded from the transaction.

Merger with Constellation Energy Group, Inc. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger. Since the merger transaction, Generation includes the former Constellation generation and customer supply operations.

Dispositions

Upstream Disposition. On June 16, 2016, Generation initiated the sales process of its Upstream business. See Note 14—Debt and Credit Agreements for more information. In December 2016, Generation sold substantially all of the Upstream assets for $37 million which resulted in a pre-tax loss on sale of $10 million which is included in Gain(loss) on sales of assets on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016.

Asset Divestitures. During 2014 and 2015, Generation sold certain generating assets with total pre-tax proceeds of $1.8 billion (after-tax proceeds of approximately $1.4 billion). Proceeds were used primarily to finance a portion of the acquisition of PHI.

Maryland Clean Coal Stations. On November 30, 2012, a subsidiary of Generation sold the Brandon Shores generating station and H.A. Wagner generating station in Anne Arundel County, Maryland, and the C.P. Crane generating station in Baltimore County, Maryland to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC to comply with certain of the regulatory approvals required by the merger with Constellation Energy Group, Inc. for net proceeds of approximately $371 million, which resulted in a pre-tax impairment charge of $272 million.

See Note 4—Mergers, Acquisitions, and Dispositions and Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Generating Resources

At December 31, 2016, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [a][b]	
Nuclear	19,457
Fossil (primarily natural gas and oil)	9,548
Renewable [c]	3,715
Owned generation assets	32,720
Long-term power purchase contracts [d]	6,879
Total generating resources	39,599

(a) See “Fuel” for sources of fuels used in electric generation.
(b) Net generation capacity is stated at proportionate ownership share. See ITEM 2. PROPERTIES—Generation for additional information.
(c) Includes wind, hydroelectric, and solar generating assets.
(d) Electric supply procured under site specific agreements.

Generation has six reportable segments, the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions, representing the different geographical areas in which Generation’s customer-facing activities are conducted and where Generation’s generating resources are located.

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina (approximately 36% of capacity).
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee; and the United States footprint of MISO (excluding MISO’s Southern Region), which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, and the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM; and parts of Montana, Missouri and Kentucky (approximately 37% of capacity).
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 7% of capacity).
- New York represents the operations within ISO-NY, which covers the state of New York in its entirety (approximately 3% of capacity).
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas (approximately 11% of capacity).
- Other Power Regions is an aggregate of regions not considered individually significant (approximately 6% of capacity).

See Note 26—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers and revenues net of purchased power and fuel expense for each of Generation's reportable segments.

Nuclear Facilities

Generation has ownership interests in fourteen nuclear generating stations currently in service, consisting of 24 units with an aggregate of 19,457 MW of capacity. Generation wholly owns all of its nuclear generating stations, except for Quad Cities Generating Station (75% ownership), Peach Bottom Generating Station (50% ownership), and Salem Generating Station (Salem) (42.59% ownership), which are consolidated on Exelon's and Generation's financial statements relative to its proportionate ownership interest in each unit. In addition, Generation owns a 50.01% interest, collectively, in the CENG generating stations (Calvert Cliffs, Nine Mile Point [excluding LIPA's 18% ownership interest in Nine Mile Point Unit 2] and R.E. Ginna) which are 100% consolidated on Exelon and Generation's financial statements as of April 1, 2014. See Note 5—Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for additional information. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the impact of the Future Energy Jobs Bill and New York CES on certain nuclear plants.

Generation's nuclear generating stations are all operated by Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. In 2016, 2015 and 2014 electric supply (in GWh) generated from the nuclear generating facilities was 67%, 68% and 67%, respectively, of Generation's total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation's electric supply sources.

On August 8, 2016, Generation executed a series of agreements with Entergy Nuclear FitzPatrick LLC (Entergy) to acquire the 838MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York. Closing of the transaction is currently anticipated to occur in the first half of 2017 and requires regulatory approval by FERC, NRC and the New York Public Service Commission (NYPSC). The transaction is also subject to the notification and reporting requirements of the HSR Act (which has been completed) and other customary closing conditions. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail on the proposed acquisition of the FitzPatrick nuclear generating station.

Nuclear Operations. Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on Generation's results of operations. As the largest generator of nuclear power in the United States, Generation can negotiate favorable terms for the materials and services that its business requires. Generation's operations from its nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

During 2016, 2015 and 2014, the nuclear generating facilities operated by Generation achieved capacity factors of 94.6%, 93.7% and 94.3%, respectively. The capacity factors reflect ownership percentage of stations operated by Generation and include CENG as of April 1, 2014. Generation manages its scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for Generation's wholesale and retail

marketing and trading activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations.

In addition to the maintenance and equipment upgrades performed by Generation during scheduled refueling outages, Generation has extensive operating and security procedures in place to ensure the safe operation of the nuclear units. Generation has extensive safety systems in place to protect the plant, personnel and surrounding area in the unlikely event of an accident or other incident.

Regulation of Nuclear Power Generation. Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of January 30, 2017, the NRC categorized Ginna in the Regulatory Response Column, which is the second highest of five performance bands. All other units operated by Generation are categorized in the Licensee Response Column, which is the highest performance band. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

For information on the NRC actions related to the Japan Earthquake and Tsunami and the industry's response, see ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Executive Overview.

Licenses . Generation has original 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals from the NRC for all its nuclear units except Clinton. Additionally, PSEG has received 20-year operating license renewals for Salem Units 1 and 2. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

The following table summarizes the current operating license expiration dates for Generation's nuclear facilities in service:

Station	Unit	In-Service Date [a]	Current License Expiration
Braidwood	1	1988	2046
	2	1988	2047
Byron	1	1985	2044
	2	1987	2046
Calvert Cliffs	1	1975	2034
	2	1977	2036
Clinton [b]	1	1987	2026
Dresden	2	1970	2029
	3	1971	2031
LaSalle	1	1984	2042
	2	1984	2043
Limerick	1	1986	2044
	2	1990	2049
Nine Mile Point	1	1969	2029
	2	1988	2046
Oyster Creek [c]	1	1969	2029
Peach Bottom [d]	2	1974	2033
	3	1974	2034
Quad Cities	1	1973	2032
	2	1973	2032
R.E. Ginna	1	1970	2029
Salem	1	1977	2036
	2	1981	2040
Three Mile Island	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) Although timing has been delayed, Generation currently plans to seek license renewal for Clinton and has advised the NRC that any license renewal application would not be filed until the first quarter of 2021.
(c) In December 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. In 2016, Exelon notified the NRC that it will cease operations at Oyster Creek on November 30, 2019.
(d) On June 7, 2016, Generation announced that it will submit a second 20 year license renewal application to NRC for Peach Bottom Units 2 and 3 in 2018.

The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC's review. The NRC review process takes approximately two years from the docketing of an application. To date, each granted license renewal has been for 20 years beyond the original operating license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual renewal of operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek and Clinton. Oyster Creek depreciation provisions are based on the 2019 expected shutdown date. Clinton depreciation provisions are based on 2027 which is the last year of the Illinois Zero Emissions Standard. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional detail on the new Illinois legislation and Note 9—Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional detail on the reversal of the decision to early retire Clinton.

In August 2012, Generation entered into an operating services agreement with the Omaha Public Power District (OPPD) to provide operational and managerial support services for the Fort Calhoun Station and a licensing agreement for use of the Exelon Nuclear Management Model. On

December 16, 2016, Generation was notified by OPPD of the termination of the operating services agreement for Fort Calhoun Station effective June 14, 2017. OPPD has the option to continue to use the Exelon Nuclear Management Model for payment of a fee.

Nuclear Waste Storage and Disposal. There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by its nuclear generating facilities on-site in storage pools or in dry cask storage facilities. Since Generation's SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, Generation has developed dry cask storage facilities to support operations.

As of December 31, 2016, Generation had approximately 77,900 SNF assemblies (19,200 tons) stored on site in SNF pools or dry cask storage (this includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party; see Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for Three Mile Island, where such storage is projected to be in operation in 2023. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites through the end of the license renewal periods and through decommissioning.

For a discussion of matters associated with Generation's contracts with the DOE for the disposal of SNF, see Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into such an agreement, although neither state currently has an operational site and none is anticipated to be operational until after 2020.

Generation ships its Class A LLRW, which represents 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Oyster Creek and Salem), and Connecticut.

Generation utilizes on-site storage capacity at all its stations to store and stage for shipping Class B and Class C LLRW. Generation has a contract through 2032 to ship Class B and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all current Class B and Class C LLRW currently stored at each station as well as the Class B and Class C LLRW generated during the term of the agreement. However, because the production of LLRW from Generation's nuclear fleet will exceed the capacity at the Texas site (3.9 million curies for 15 years beginning in 2012), Generation will still be required to utilize on-site storage at its stations for Class B and Class C LLRW. Generation currently has enough storage capacity to store all Class B and C LLRW for the life of all stations in Generation's nuclear fleet. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize cost impacts and on-site storage.

Nuclear Insurance. Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has

reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See “Nuclear Insurance” within Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. PROPERTIES—Generation. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon’s and Generation’s future financial conditions and results of operations and cash flows.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. See ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview; ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates, Nuclear Decommissioning, Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Note 3—Regulatory Matters, Note 12—Fair Value of Financial Assets and Liabilities and Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation’s NDT funds and its decommissioning obligations. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon’s and Generation’s Consolidated Balance Sheets at December 31, 2016 at fair value of approximately $11.1 billion and have an estimated targeted annual pre-tax return of 5.3% to 5.9%.

Zion Station Decommissioning. On December 11, 2007, Generation entered into an Asset Sale Agreement (ASA) with EnergySolutions, Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, LLC (ZionSolutions) under which ZionSolutions assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998.

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation’s transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request reimbursement; specifically, if certain milestones as defined in the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. See Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning and see Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for a discussion of variable interest entity considerations related to ZionSolutions.

Fossil and Renewable Facilities (including Hydroelectric)

At December 31, 2016, Generation had ownership interests in 13,263 MW of capacity in generating facilities currently in service, consisting of 9,522 MW of natural gas and oil, 3,715 MW of renewables (wind, hydroelectric, and solar) and 26 MW of waste coal. Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Wyman; (2) certain wind project entities with minority interest owners; and (3) an ownership interest in the Albany Green Energy, LLC project entity, see Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding certain of these entities which are VIEs. Generation’s fossil and renewable generating stations are all operated by Generation, with the exception of LaPorte

and Wyman, which are operated by third parties. In 2016, 2015 and 2014, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 10%, 8% and 13%, respectively, of Generation's total electric supply. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. For additional information regarding Generation's electric generating facilities, see ITEM 2. PROPERTIES—Exelon Generation Company, LLC and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview for additional information on Generation Renewable Development.

Licenses. Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid. On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively. On December 22, 2015, FERC issued a new 40-year license for Muddy Run. The license term expires on December 1, 2055. Based on the FERC procedural schedule, the FERC licensing process was not completed prior to the expiration of Conowingo's license on September 1, 2014. FERC is required to issue an annual license for the facility until the new license is issued. On September 10, 2014, FERC issued an annual license for Conowingo, effective as of the expiration of the previous license. If FERC does not issue a new license prior to the expiration of annual license, the annual license will renew automatically. The stations are currently being depreciated over their estimated useful lives, which includes actual and anticipated license renewal periods. Refer to Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Insurance. Generation maintains business interruption insurance for its renewable and fossil projects, and delay in start-up insurance for its renewable and fossil projects currently under construction. Generation does not purchase business interruption insurance for its wholly owned fossil and hydroelectric operations, unless required by financing agreements; see Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on financing agreements. Generation maintains both property damage and liability insurance. For property damage and liability claims for these operations, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon's and Generation's future financial conditions and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. PROPERTIES—Exelon Generation Company, LLC.

Long-Term Power Purchase Contracts

In addition to energy produced by owned generation assets, Generation sources electricity and other related output from plants it does not own under long-term contracts. The following tables summarize Generation's long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2016:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	16	2017 - 2032	800
Midwest	6	2017 - 2026	1,236
New England	8	2017	650
ERCOT	5	2020 - 2031	1,501
Other Power Regions	11	2017 - 2030	2,692
Total	46		6,879

	2017	2018	2019	2020	2021
Capacity Expiring (MW)	1,790	101	644	980	815

Fuel

The following table shows sources of electric supply in GWh for 2016 and 2015:

	Source of Electric Supply	
	2016	2015
Nuclear [a]	176,799	175,474
Purchases—non-trading portfolio	59,987	63,637
Fossil (primarily natural gas and oil)	19,830	14,936
Renewable [b]	6,324	5,982
Total supply	262,940	260,029

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g., CENG). Nuclear generation for 2016 and 2015 includes physical volumes of 33,444 GWh and 33,415 GWh, respectively, for CENG.
(b) Includes wind, hydroelectric, and solar generating assets.

The fuel costs per MWh for nuclear generation are less than those for fossil-fuel generation. Consequently, nuclear generation is generally the most cost-effective way for Generation to meet its wholesale and retail load servicing requirements.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has uranium concentrate inventory and supply contracts sufficient to meet all of its uranium concentrate requirements through 2018. Generation's contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2017. All of Generation's enrichment requirements have been contracted through 2020. Contracts for fuel fabrication have been obtained through 2022. Generation does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are

available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures. Generation also hedges forward price risk, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation's integrated business operations include the physical delivery and marketing of power obtained through its generation capacity and through long-term, intermediate-term and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. Generation has also contracted for access to additional generation through bilateral long-term PPAs. PPAs, including tolling agreements, are commitments related to power generation of specific generation plants and/or are dispatchable in nature similar to asset ownership depending on the type of underlying asset. Generation secures contracted generation as part of its overall strategic plan, with objectives such as obtaining low-cost energy supply sources to meet its physical delivery obligations to both wholesale and retail customers and assisting customers to meet renewable portfolio standards. Generation sells electricity, natural gas, and other energy related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets. Generation's customer facing operations combine a unified sales force with a customer-centric model that leverages technology to broaden the range of products and solutions offered, which Generation believes promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which provides a platform that is scalable and able to capitalize on opportunities for future growth.

Generation may purchase more than the energy demanded by its customers. Generation then sells this open position, along with capacity not used to meet customer demand, in the wholesale electricity markets. Where necessary, Generation also purchases transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs in markets without an organized RTO. Generation also incorporates contingencies into its planning for extreme weather conditions, including potentially reserving capacity to meet summer loads at levels representative of warmer-than-normal weather conditions.

Price Supply Risk Management

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation also enters into transactions that are outside of this ratable sales plan. Generation is exposed to commodity price risk in 2017 and beyond for portions of its electricity portfolio that are unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. As of December 31, 2016, the percentage of expected generation hedged for the major reportable segments was 91%-94%, 56%-59% and 28%-31% for 2017, 2018, and 2019, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that

makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including sales to ComEd, PECO, BGE, Pepco, DPL, and ACE to serve their retail load. A portion of Generation's hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. The corporate risk management group and Exelon's RMC monitor the financial risks of the wholesale and retail power marketing activities. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation's efforts. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop-loss and value-at-risk limits, to manage exposure to market risk. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

Capital Expenditures

Generation's business is capital intensive and requires significant investments in nuclear fuel and energy generation assets and in other internal infrastructure projects. Generation's estimated capital expenditures for 2017 are as follows:

(in millions)	
Nuclear fuel (a)	$ 925
Growth	600
Production plant	1,125
Total	$2,650

(a) Includes Generation's share of the investment in nuclear fuel for the co-owned Salem plant.

ComEd

ComEd is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in northern Illinois. ComEd is a public utility under the Illinois Public Utilities Act subject to regulation by the ICC related to distribution rates and service, the issuance of securities and certain other aspects of ComEd's business. ComEd is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of ComEd's business. Specific operations of ComEd are also subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, ComEd is subject to NERC mandatory reliability standards.

ComEd's franchises are sufficient to permit it to engage in the business it now conducts. ComEd's franchise rights are generally nonexclusive rights documented in agreements and, in some cases, certificates of public convenience issued by the ICC. With few exceptions, the franchise rights have stated expiration dates ranging from 2017 to 2066. ComEd anticipates working with the appropriate governmental bodies to extend or replace the franchise agreements prior to expiration.

PECO

PECO is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia. PECO is a public utility under the Pennsylvania Public

Utility Code subject to regulation by the PAPUC related to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of PECO's business. PECO is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of PECO's business and by the U.S. Department of Transportation related to pipeline safety and other areas of gas operations. Specific operations of PECO are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, PECO is also subject to NERC mandatory reliability standards.

PECO has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities or territories in which it now supplies such services. PECO's authorizations consist of charter rights and certificates of public convenience issued by the PAPUC and/or "grandfathered rights," with all of such rights generally unlimited as to time and generally exclusive from competition from other electric and natural gas utilities. In a few defined municipalities, PECO's natural gas service territory authorizations overlap with that of another natural gas utility; however, PECO does not consider those situations as posing a material competitive or financial threat.

BGE

BGE is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in central Maryland, including the City of Baltimore. BGE is a public utility under the Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC related to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of BGE's business. BGE is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of BGE's business and by the U.S. Department of Transportation related to pipeline safety and other areas of gas operations. Specific operations of BGE are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, BGE is also subject to NERC mandatory reliability standards.

BGE has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities and territories in which it now supplies such services. With respect to electric distribution service, BGE's authorizations consist of charter rights, a state-wide franchise grant and a franchise grant from the City of Baltimore. The franchise rights are nonexclusive and are perpetual. Pursuant to statute, public service companies in Maryland may exercise a franchise to the extent authorized by the MDPSC. The service territory for BGE, as well as for other electric utilities in the state, was precisely delineated in 1966 by the MDPSC and has been modified in minor ways over the years. With respect to natural gas distribution service, BGE's authorizations consist of charter rights, a perpetual state-wide franchise grant and franchises granted by all the municipalities and/or governmental bodies in which BGE now supplies services. The franchise grants are not exclusive; some are perpetual and some are for a limited duration, which BGE anticipates being able to extend or replace prior to expiration.

PHI

PHI was incorporated in Delaware in 2001. Through its reportable segments Pepco, DPL and ACE, PHI is engaged primarily in the transmission, distribution and default supply of electricity, and, to a lesser extent, the distribution and supply of natural gas. On March 23, 2016, Pepco Holdings, Inc., converted from a Delaware corporation to a Delaware limited liability company, Pepco Holdings LLC. PHI Service Company, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries.

Pepco

Pepco is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in the District of Columbia and major portions of Prince George's County and Montgomery County in Maryland. Pepco is a public utility under the Code of the District of Columbia and subject to regulation by the DCPSC related to distribution rates and service, the issuance of securities and certain other aspects of Pepco's business in the District of Columbia. Pepco is also an electric company under the Maryland Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC related to distribution rates and service, the issuance of securities and certain other aspects of Pepco's business in Maryland. Pepco is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of Pepco's business. Additionally, Pepco is subject to NERC mandatory reliability standards.

Pepco's right to occupy public space for utility purposes is by permit from the District of Columbia and the federal government. Pepco is the only public utility that distributes electricity for sale to the public in the District of Columbia. In Maryland, Pepco operates pursuant to state-wide franchises granted by Maryland's General Assembly that are unlimited in duration. Pursuant to statute, public service companies in Maryland may exercise a franchise to the extent authorized by the MDPSC. The service territories for Pepco, as well as for other electric utilities in the state, were precisely delineated in 1966 by the MDPSC and have been modified in minor ways over the years.

DPL

DPL is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in portions of Maryland and Delaware, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in New Castle County, Delaware. DPL is a public utility under the Delaware Code and subject to regulation by the DPSC related to electric and gas distribution rates and service, the issuance of certain securities and certain other aspects of DPL's business in Delaware. In Maryland, DPL is an electric company under the Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC related to electric rates and service, the issuances of certain securities and certain other aspects of DPL's business in Maryland. DPL is a public utility under the Federal Power Act and is subject to regulation by FERC related to transmission rates and certain other aspects of DPL's business and by the U.S. Department of Transportation related to pipeline safety and other areas of gas operations. Additionally, DPL is also subject to NERC mandatory reliability standards.

DPL has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities and territories in which it now supplies such services. In Maryland, DPL operates pursuant to state-wide franchises that are substantially similar in nature to those described above with respect to Pepco's Maryland operations. DPL's exclusive and continuing authority to distribute electricity and natural gas in its non-municipal service territories in Delaware is derived from legislation, through which the DPSC has established exclusive service territories. With respect to municipalities that it serves, DPL provides service under various franchises granted to DPL and predecessor companies, which franchises are generally either unlimited as to time or renew automatically.

ACE

ACE is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in portions of southern New

Jersey. ACE is a public utility under the New Jersey Public Utilities Act subject to regulation by the NJBPU related to distribution rates and service, the issuance of securities and certain other aspects of ACE's business. ACE is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of ACE's business. Additionally, ACE is subject to NERC mandatory reliability standards.

ACE's franchises are sufficient to permit it to engage in the business it now conducts. ACE operates under non-exclusive franchises that have been granted by the NJBPU and under certain non-exclusive consents from municipalities in which ACE provides service. While most of the municipal consents were granted in perpetuity, two of the municipal consents require renewal on a periodic basis in accordance with their terms with respect to ACE's continued right to erect and maintain wires and poles in, upon, over and under the public streets, streets and alleys, and are subject to the ultimate review and approval of the NJBPU. All of the franchises and consents are currently in full force and effect.

ComEd, PECO, BGE, Pepco, DPL and ACE

Utility Operations

Service Territories. The following table presents the size of retail service territories, populations of each retail service territory and the number of retail customers within each retail service territory for the Utility Registrants as of December 31, 2016:

	Retail Service Territories (in square miles)			Retail Service Territory Population (in millions)			Number of Retail Customers (in millions)		
	Total	Electric	Natural gas	Total	Electric	Natural gas	Total	Electric	Natural gas
ComEd	11,400	11,400	n/a	9.4[a]	9.4	n/a	4.0	4.0	n/a
PECO	2,100	1,900	1,900	4.6[b]	4.0	3.1	2.1	1.6	0.5
BGE	2,300	2,300	800	3.0[c]	3.0	2.9	1.3	1.3	0.7
Pepco	640	640	n/a	2.4[d]	2.4	n/a	0.9	0.9	n/a
DPL	5,675	5,400	275	2.0[e]	1.4	0.6	0.6	0.5	0.1
ACE	2,800	2,800	n/a	1.1[f]	1.1	n/a	0.5	0.5	n/a

(a) Includes approximately 2.7 million in the city of Chicago.
(b) Includes approximately 1.6 million in the city of Philadelphia.
(c) Includes approximately 0.6 million in the city of Baltimore.
(d) Includes approximately 0.7 million in the District of Columbia.
(e) Includes approximately 0.1 million in the city of Wilmington.
(f) Includes approximately 0.1 million in the city of Atlantic City.

Peak Deliveries. The Utility Registrants electric sales and peak load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. For PECO, BGE and DPL natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating.

The following table summarizes historic peak deliveries for the Utility Registrants for electric and gas deliveries during peak demand months through December 31, 2016:

	Electric Peak Deliveries (in GW)				Natural Gas Peak Deliveries (in mmcfs)	
	Summer peak date	Summer deliveries	Winter peak date	Winter deliveries	Winter peak date	Winter deliveries
ComEd	7/20/2011	23.75	1/6/2014	16.51	n/a	n/a
PECO	7/22/2011	8.98	1/7/2014	7.17	2/15/2015	777
BGE	7/21/2011	7.23	2/20/2015	6.71	2/19/2015	777
Pepco	7/22/2011	7.02	2/20/2015	6.07	n/a	n/a
DPL	7/22/2011	4.14	2/20/2015	4.11	2/15/2015	186
ACE	7/22/2011	2.96	1/7/2014	1.8	n/a	n/a

Electric and Natural Gas Distribution Services. The Utility Registrants are allowed to recover reasonable costs and fair and prudent capital expenditures associated with electric and natural gas distribution services and earn a return on those capital expenditures, subject to commission approval. ComEd recovers costs through a performance-based rate formula, pursuant to EIMA. ComEd is required to file an update to the performance-based rate formula on an annual basis. PECO's, BGE's and DPL's electric and gas distribution costs and Pepco's and ACE's electric distribution costs are recovered through traditional rate case proceedings. In certain instances, the Utility Registrants use specific recovery mechanisms as approved by their respective regulatory agencies.

ComEd, Pepco, and ACE customers have the choice to purchase electricity, and PECO, BGE, and DPL customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. The Utility Registrants remain the distribution service providers for all customers and are obligated to deliver electricity and natural gas to customers in their respective service territories while charging a regulated rate for distribution service. In addition, the Utility Registrants also retain significant default service obligations to provide electricity to certain groups of customers in their respective service areas who do not choose a competitive electric generation supplier. PECO and BGE also retain significant default service obligations to provide natural gas to certain groups of customers in their respective service areas who do not choose a competitive natural gas supplier. For natural gas, DPL does not retain default service obligations. For those customers that choose a competitive electric generation or natural gas supplier, the Utility Registrants may act as the billing agent but do not record revenues or purchased power and fuel expense related to the electricity and/or natural gas. For those customers that choose one of the Utility Registrants as their electric generation or natural gas supplier, the Utility Registrants are permitted to recover electric and natural gas procurement costs from retail customers. Therefore, fluctuations in electric and natural gas procurement costs have no impact on electric and natural gas revenues net of purchased power and fuel expense.

The following table outlines the state regulatory agencies and default service obligations for each of the Utility Registrants:

	Regulatory Agency	Default Service Obligation-Electricity	Default Service Obligation-Natural Gas
ComEd	ICC	POLR	n/a
PECO	PAPUC	DSP	PGC
BGE	MDPSC	SOS	MBR
Pepco	DCPSC/MDPSC	SOS	n/a
DPL	DPSC/MDPSC	SOS	n/a
ACE	NJBPU	BGS	n/a

Retail customers participating in customer choice programs, and retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of GWh and mmcf sales, respectively) for the Utility Registrants consisted of the following at December 31, 2016, 2015 and 2014:

	December 31, 2016					
	Number of retail customers in customer choice programs		% of total retail customers		Customer choice program deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd	1,502,900	n/a	38%	n/a	72%	n/a
PECO	587,200	81,300	36%	16%	70%	26%
BGE	337,000	151,000	27%	23%	59%	57%
Pepco	176,372	n/a	21%	n/a	65%	n/a
DPL	78,994	156	15%	0.1%	51%	28%
ACE	94,562	n/a	17%	n/a	47%	n/a

	December 31, 2015					
	Number of retail customers in customer choice programs		% of total retail customers		Customer choice program deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd (a)	1,655,400	n/a	42%	n/a	76%	n/a
PECO	563,400	81,100	35%	16%	70%	25%
BGE	343,000	154,000	27%	23%	61%	56%
Pepco	173,222	n/a	21%	n/a	65%	n/a
DPL	77,603	159	15%	0.1%	51%	31%
ACE	78,299	n/a	14%	n/a	45%	n/a

	December 31, 2014					
	Number of retail customers in customer choice programs		% of total retail customers		Customer choice program deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd	2,426,900	n/a	63%	n/a	80%	n/a
PECO	546,900	78,400	34%	16%	70%	22%
BGE	364,000	161,000	29%	25%	60%	53%
Pepco	179,524	n/a	22%	n/a	65%	n/a
DPL	78,153	157	15%	0.1%	53%	31%
ACE	86,780	n/a	16%	n/a	51%	n/a

(a) In September 2015, the City of Chicago discontinued its participation in the customer choice program and began purchasing its electricity from ComEd. Approximately 670,000 customers were impacted by the City of Chicago's decision which resulted in the reduction in the number of customers participating in customer choice programs in 2015.

Procurement-Related Proceedings. The Utility Registrants' electric supply for its customers is primarily procured through contracts as required by the ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU. The Utility Registrants procure electricity supply from various approved bidders, including Generation. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on the Utility Registrants' Statements of Operations and Comprehensive Income.

PECO's, BGE's and DPL's natural gas supplies are purchased from a number of suppliers for terms of up to three years. PECO, BGE and DPL have annual firm supply and transportation contracts of 132,000 mmcf, 128,000 mmcf and 58,000 mmcf, respectively. In addition, to supplement gas supply at times of heavy winter demands and in the event of temporary emergencies, PECO, BGE and DPL have available storage capacity from the following sources:

	Peak Natural Gas Sources (in mmcf)		
	Liquefied Natural Gas Facility	Propane-Air Plant	Underground Storage Service Agreements (a)
PECO	1,200	150	18,000
BGE	1,056	550	22,000
DPL	257	n/a	3,800

(a) Natural gas from underground storage represents approximately 28%, 46% and 34% of PECO's, BGE's and DPL's 2016-2017 heating season planned supplies, respectively.

PECO, BGE and DPL have long-term interstate pipeline contracts and also participate in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between the utilities and customers. PECO, BGE and DPL make these sales as part of a program to balance its supply and cost of natural gas.

Energy Efficiency Programs. The Utility Registrants are also allowed to recover costs associated with energy efficiency and demand response programs. Each commission approved program seeks to meet mandated electric consumption reduction targets and implement demand response measures to reduce peak demand. The programs are designed to meet standards required by each respective regulatory agency.

Capital Investment. The Utility Registrants' businesses are capital intensive and require significant investments, primarily in electric transmission and distribution and natural gas transportation and distribution facilities, to ensure the adequate capacity, reliability and efficiency of their systems. ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's most recent estimates of capital expenditures for plant additions and improvements for 2017 are $2,200 million, $775 million, $925 million, $625 million, $375 million and $300 million, respectively.

ComEd, PECO, BGE, Pepco and DPL have AMI smart meter and smart grid deployment programs within their respective service territories to enhance their distribution systems. PECO, BGE, Pepco and DPL have completed the installation and activation of smart meters in their respective service territories. ACE has yet to receive approval from the NJBPU to proceed with the installation of AMI smart meters.

Transmission Services. The Utility Registrants provide unbundled transmission service under rates approved by FERC. Under FERC's open access transmission policy promulgated in Order No. 888, the Utility Registrants, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. The Utility Registrants and their affiliates are required to comply with FERC's Standards of Conduct regulation governing the communication of non-public transmission information between the transmission owner's employees and wholesale merchant employees.

PJM is the regional grid operator and operates pursuant to FERC-approved tariffs. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM Tariff). PJM operates the PJM energy, capacity and other markets, and, through central dispatch, controls the day-to-day operations of the bulk power system for the PJM region. The Utility Registrants

are members of PJM and provide regional transmission service pursuant to the PJM Tariff. The Utility Registrants and the other transmission owners in PJM have turned over control of their transmission facilities to PJM, and their transmission systems are under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM transmission owners at rates based on the costs of transmission service.

ComEd's transmission rates are established based on a formula that was approved by FERC in January 2008. BGE's, Pepco's, DPL's and ACE's transmission rates are established based on a formula that was approved by FERC in April 2006. FERC's orders establish the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

PECO's customers are charged for PECO's PJM retail transmission services on a full and current basis through a Transmission Service Charge (applicable to default service only) and through a Non-Bypassable Transmission Charge (applicable to all distribution customers) in accordance with PECO's approved distribution rates.

See Note 3 — Regulatory Matters, Note 26—Segment Information of the Combined Notes to Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for additional information regarding transmission services.

Employees

As of December 31, 2016, Exelon and its subsidiaries had 34,396 employees in the following companies, of which 11,984 or 35% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 (a)	IBEW Local 614 (b)	Other CBAs	Total Employees Covered by CBAs	Total Employees
Generation (c)	1,640	99	2,635	4,374	14,717
ComEd	3,777	—	—	3,777	6,574
PECO	—	1,310	—	1,310	2,651
BGE (d)	—	—	—	—	3,097
PHI (e)	—	—	331	331	1,670
Pepco (e)	—	—	1,056	1,056	1,466
DPL (e)	—	—	631	631	871
ACE (e)	—	—	399	399	595
Other (f)	65	—	41	106	2,755
Total	5,482	1,409	5,093	11,984	34,396

(a) A separate CBA between ComEd and IBEW Local 15 covers approximately 62 employees in ComEd's System Services Group and was renewed in 2016. Generation's and ComEd's separate CBAs with IBEW Local 15 will expire in 2022.

(b) 1,310 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614, both expiring in 2021. Additionally, Exelon Power, an operating unit of Generation, has an agreement covering 99 employees, which was renewed in 2016 and expiring in 2019.

(c) During 2016, Generation finalized its CBA with the Security Officer union at Oyster Creek, expiring in 2022 and New Energy IUOE Local 95-95A, which will expire in 2021. Also during 2016, Pepco Energy Services was allocated to Generation with a total of 358 employees broken down as follows: 229 employees covered by CBAs and 129 non-represented employees. During 2015, Generation finalized its CBA with Clinton Local 51 which will expire in 2020; its two CBAs with Local 369 at Mystic 7 and Mystic 8/9, both expiring in 2020; and four Security Officer unions at Braidwood, Byron, Clinton and TMI, all expiring between 2018 and 2021, respectively. During 2014, Generation finalized CBAs with TMI Local 777 and Oyster Creek Local 1289, expiring in 2019 and 2021, respectively and CENG finalized its CBA with Nine Mile Point which will expire in 2020. Additionally, during 2014, Generation finalized CBAs with the Security Officer unions at Dresden, LaSalle, Limerick and Quad Cities, which expire between 2017 and 2018. Lastly, during 2014, an agreement was negotiated with Las Vegas District Energy and IUOE Local 501, which will expire in 2018. During 2013, Generation finalized two 3-year agreements: New England ENEH, UWUA Local 369, which will expire in 2017.

(d) In January 2017, an election was held at BGE which resulted in union representation for approximately 1,400 employees. BGE and IBEW Local 410 will begin negotiations for an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. No agreement has been finalized to date and management cannot predict the outcome of such negotiations.
(e) PHI's utility subsidiaries are parties to five collective bargaining agreements with four local unions. Collective bargaining agreements are generally renegotiated every three to five years. All of these collective bargaining agreements were renegotiated in 2014 and were extended through various dates ranging from October 2018 through June 2020
(f) Other includes shared services employees at BSC.

Environmental Regulation

General

The Registrants are subject to comprehensive and complex legislation regarding environmental matters by the federal government and various state and local jurisdictions in which they operate their facilities. The Registrants are also subject to regulations administered by the EPA and various state and local environmental protection agencies. Federal, state and local regulation includes the authority to regulate air, water, and solid and hazardous waste disposal.

The Exelon Board of Directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President, Corporate Strategy and Chief Sustainability Officer; the Corporate Environmental Strategy Director and the Environmental Regulatory Strategy Director, as well as senior management of Generation, ComEd, PECO, BGE, Pepco, DPL and ACE. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. The Exelon Board of Directors has delegated to its Corporate Governance Committee the authority to oversee Exelon's compliance with laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including Exelon's climate change and sustainability policies and programs, as discussed in further detail below. The Exelon Board of Directors has also delegated to its Generation Oversight Committee the authority to oversee environmental, health and safety issues relating to Generation. The respective Boards of ComEd, PECO, BGE, Pepco, DPL and ACE oversee environmental, health and safety issues related to these companies.

Air Quality

Air quality regulations promulgated by the EPA and the various state and local environmental agencies in Illinois, Maryland, Massachusetts, New York, Pennsylvania and Texas in accordance with the Federal Clean Air Act impose restrictions on emission of particulates, sulfur dioxide (SO2), nitrogen oxides (NOx), mercury and other pollutants and require permits for operation of emissions sources. Such permits have been obtained by Exelon's subsidiaries and must be renewed periodically. The Clean Air Act establishes a comprehensive and complex national program to substantially reduce air pollution from power plants.

See ITEM 7.—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding clean air regulation in the forms of the CSAPR, the regulation of hazardous air pollutants from coal- and oil-fired electric generating facilities under MATS, and regulation of GHG emissions.

Water Quality

Under the Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the EPA or from the state environmental agency to which the permit program has been delegated and must be renewed periodically. Certain of Generation's power generation facilities

discharge industrial wastewater into waterways and are therefore subject to these regulations and operate under NPDES permits or pending applications for renewals of such permits after being granted an administrative extension. Generation is also subject to the jurisdiction of certain other state and regional agencies and compacts, including the Delaware River Basin Commission and the Susquehanna River Basin Commission.

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by any changes to the existing regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, Ginna, Gould Street, Handley, Mountain Creek, Mystic 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities, Riverside and Salem.

On October 14, 2014, the EPA's final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed to determine the best technology available to minimize adverse impacts on aquatic life, followed by an implementation period for the selected technology. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, Generation cannot estimate the effect that compliance with the rule will have on the operation of its generating facilities and its future results of operations, cash flows, and financial position. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility's economic viability could be called into question. However, the potential impact of the rule has been significantly reduced since the final rule does not mandate cooling towers as a national standard and sets forth technologies that are presumptively compliant, and the state permitting director is required to apply a cost-benefit test and can take into consideration site-specific factors.

Pursuant to discussions with the NJDEP in 2010 regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029. The agreement only applies to Oyster Creek based on its unique circumstances and does not set any precedent for the ultimate compliance requirements for Section 316(b) at Exelon's other plants.

New York Facilities . In July 2011, the New York Department of Environmental Conservation (DEC) issued a policy regarding the best available technology for cooling water intake structures. Through its policy, the DEC established closed-cycle cooling or its equivalent as the performance goal for all existing facilities, but also provided that the DEC will select a feasible technology whose costs are not wholly disproportionate to the environmental benefits to be gained and allows for a site-specific determination where the entrainment performance goal cannot be achieved. The Ginna and Nine Mile Point Unit 1 power generation facilities received renewals of their state water discharge permits in 2014.

Salem. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water system. In February 2006, PSEG filed a renewal application with the NJDEP allowing Salem to continue operating under its existing NPDES permit until a new permit is issued. On June 30, 2015, NJDEP issued a draft NPDES permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to

continue to operate utilizing the existing once-through cooling water system with certain required system modifications. On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance.

Solid and Hazardous Waste

CERCLA provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at sites, most of which are listed by the EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight prior to listing on the NPL. Various states, including Delaware, District of Colombia, Illinois, Maryland, New Jersey and Pennsylvania, have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Generation, ComEd, PECO, BGE, Pepco, DPL and ACE and their subsidiaries are, or are likely to become, parties to proceedings initiated by the EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party.

See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding solid and hazardous waste regulation and legislation.

Environmental Remediation

ComEd's, PECO's and BGE's environmental liabilities primarily arise from contamination at former MGP sites. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover environmental remediation costs of the MGP sites through a provision within customer rates. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The amount to be expended in 2017 at Exelon for compliance with environmental remediation related to contamination at former MGP sites and other gas purification sites is expected to total $41 million, consisting of $35 million and $6 million respectively, at ComEd and PECO.

Generation's environmental liabilities primarily arise from contamination at current and former generation and waste storage facilities. As of December 31, 2016, Generation has established appropriate contingent liabilities for potential environmental remediation requirements including contamination attributable to low level radioactive residues at a storage and reprocessing facility named Latty Avenue, and at a disposal facility named West Lake Landfill, both near St. Louis, Missouri related to operations conducted by Cotter Corporation, a former ComEd subsidiary.

The Utility Registrants also have environmental liabilities for remediation considerations. As of December 31, 2016, Generation has established appropriate contingent liabilities for potential environmental remediation requirements.

In addition, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE may be required to make significant additional expenditures not presently determinable for other environmental remediation costs.

See Notes 3—Regulatory Matters and 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' environmental remediation efforts and related impacts to the Registrants' results of operations, cash flows and financial positions.

Global Climate Change

Exelon has utility and generation assets, and customers, that are subject to the effects of climate change as described in the Intergovernmental Panel on Climate Change (IPCC) 5th Assessment Report, published in 2014, Accordingly the company is engaged in a variety of initiatives to better understand and develop responses to these issues, including investments in resiliency, partnering with federal, state and local governments and advocating for science-based public policy. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, hydroelectric, wind and solar photovoltaic), has a relatively small greenhouse gas (GHG) emission profile, or carbon footprint, compared to other domestic generators of electricity. By virtue of its significant investment in low-carbon intensity assets, Generation's emission intensity, or rate of carbon dioxide equivalent (CO_2e) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its fossil fuel-fired generating plants (primarily natural gas); CO_2, methane and nitrous oxide are all emitted in this process, with CO_2 representing the largest portion of these GHG emissions. GHG emissions from combustion of fossil fuels represented the majority of Exelon's direct GHG emissions in 2016, although less than 30 percent of its owned generating capacity utilizes fossil fuels with less than 10 percent of owned generation MWh actually produced by fossil fuels as Exelon's fossil-fired generation is primarily intermediate and peaking in nature. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF_6) leakage in its electric transmission and distribution operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and fossil fuel generation of electricity used to power its facilities. Despite its focus on low-carbon generation, Exelon believes its operations could be significantly affected by the possible physical risks of climate change and by mandatory programs to reduce GHG emissions. See ITEM 1A. RISK FACTORS for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

Climate Change Regulation. Exelon is or may become subject to climate change regulation or legislation at the Federal, regional and state levels.

International Climate Change Regulation. At the international level, the United States is a Party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21 st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015. The Paris Agreement defines the UNFCCC's objective of limiting the global temperature increase to 1.5°C above pre-industrial levels. All Parties are required to develop their own national emission reductions and to update those reductions at least every five years. The Developed Country Parties, including the United States, are required to take the lead by undertaking economy-wide absolute emission reduction targets. The United States had previously submitted its national emission reductions to achieve a 2020 target of reducing net emissions to 17% below the 2005 level and to achieve net greenhouse gas emission reductions of 26%—28% below the 2005 level by 2025. The United States has indicated that it intends to achieve these reductions through a variety of mechanisms, including regulations to cut carbon pollution from new and existing power plants. The Paris Agreement entered into force on November 4, 2016 the thirtieth day after the date on which at

least 55 Parties accounting for at least an estimated 55% of total global greenhouse gas emissions ratified the Agreement. The Agreement has not been ratified by the US Senate and it is uncertain whether or not or to what extent the new Trump Administration will pursue the established target.

Federal Climate Change Legislation and Regulation. It is highly uncertain that Federal legislation to reduce GHG emissions will be enacted. If such legislation is adopted, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits.

Under the Obama Administration, the EPA proposed and finalized regulations for new and modified fossil-fuel power plants under Section 111(b) of the Clean Air Act and Section 111(d) for existing fossil-fuel power plants. These regulations are currently being litigated. The 111(d) regulations, referred to as the Clean Power Plan, are currently subject to a stay by the Supreme Court, pending conclusion of all litigation at both the D.C. Circuit and Supreme Court levels. The D.C. Circuit heard *en banc* oral argument in late September 2016, but has not yet issued its decision. Prior to the stay, the Clean Power Plan had established GHG emission reduction targets for each state, with emission reductions slated to begin in 2022. State requirements to submit plans to EPA in September 2016 (or within two years if an extension was requested) were placed in abeyance pending results of litigation.

President Trump's election platform called for eliminating a number of EPA regulations, including the Clean Power Plan. Due to the need to appoint and confirm key EPA officials as the Trump Administration begins to govern, the specific details of the Trump Administration's plans to address the Clean Power Plan are not known. In the interim, the D.C. Circuit continues its review of the regulation under existing litigation and is expected to issue its decision in the first half of 2017.

Due to current litigation and the need for the new Administration to develop its approach to dealing with the Clean Power plan, Exelon and Generation cannot at this time predict the future of the Clean Power Plan or individual state responses to Clean Power Plan developments or how developments will impact their future financial positions, results of operations and cash flows.

Regional and State Climate Change Legislation and Regulation. After a two-year program review, the nine northeast and mid-Atlantic states currently participating in the Regional Greenhouse Gas Reduction Initiative (RGGI) released an updated RGGI Model Rule and Program Review Recommendations Summary on February 7, 2013. Under the updated RGGI program the regional RGGI CO_2 budget was reduced, starting in 2014, from its previous 165 million ton level to 91 million tons, with a 25 percent reduction in the cap level each year from 2015 through 2020. Included in the program are provisions for cost containment reserve (CCR) allowances, which will become available if the total demand for allowances, above the CCR trigger price, exceeds the number of CO_2 allowances available for purchase at auction. (CCR trigger prices are $6 in 2015, $8 in 2016 and $10 in 2017; after 2017 the CCR price increases by 2.5 percent each year). Allowance prices in 2016 remained below the applicable CCR trigger price, indicating program costs remained within the boundaries of costs acceptable to participating states. During 2016, RGGI began its quadrennial review process to determine what, if any, program design amendments should be pursued for the regional program. A series of stakeholder calls occurred in 2016, which included discussion around potential linkage issues with the federal Clean Power Plan, linkages to state GHG emission reduction goals/programs, functioning of cost containment mechanisms, and consideration of whether future cap levels should be adjusted for the post-2020 period. RGGI intends to complete its program review in early 2017.

On December 18, 2009, Pennsylvania issued the state's final Climate Change Action Plan. The plan sets as a target a 30 percent reduction in GHG emissions by 2020. The Climate Change Advisory Committee continues to meet quarterly to review Climate Action Work Plans for the residential, commercial and industrial sectors. The Climate Change Action Plan does not impose any requirements on Generation or PECO at this time.

The Maryland Commission on Climate Change was chartered in 2007 and released a greenhouse gas reduction strategy with 42 recommendations on August 27, 2008. The plan's primary policy recommendation to formally adopt science-based regulatory goals to reduce Maryland's green house gas emissions (GHG) was realized with the passage of the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA) which required Maryland to reduce its GHG emissions by 25 percent below 2006 levels by 2020. It also directed the Maryland Department of Environment to prepare and implement an action plan which listed Maryland's electricity consumption reduction goals, required under the "EmPOWER Maryland" program, and mandatory State participation in RGGI Program, as the energy sector's contribution to the plan. In April 2016, the Governor of Maryland signed the GGRA of 2016 into law, which updated the state's Climate Commission charter. It expanded membership to include more non-governmental members and established an enhanced statewide GHG emissions reduction target of 40 percent from 2006 levels by 2030, maintaining the caveats from the 2007 legislation that the implementation have a net positive impact on both jobs and the economy. MDE is currently working on plans to meet the 2016 GGRA requirements. In February of this year (2017) , the Maryland General Assembly overrode Maryland Governor Hogan's veto of legislation that requires the current Renewable Portfolio Standard (RPS) to be accelerated and enhanced. The law requires the RPS, previously set at 20% renewables by 2022, with a 2% solar carve out, to move to 25% renewables by 2020 with a 2.5% solar carve out.

Exelon's Voluntary Climate Change Efforts . In a world increasingly concerned about global climate change and regulatory action to reduce GHG, Exelon's low-carbon generating fleet is seen by management as a competitive advantage. Exelon remains one of the largest, lowest carbon electric generators in the United States: nuclear for base load, natural gas for marginal and peak demand, hydro and pumped storage, and supplemental wind and solar renewables. As further legislation and regulation imposing requirements on emissions of GHG and air pollutants are promulgated, Exelon's low-carbon, low-emission generation fleet will position the company to benefit from its comparative advantage over other generation fleets.

Renewable and Alternative Energy Portfolio Standards

Thirty-nine states and the District of Columbia have adopted some form of RPS requirement. Illinois, Pennsylvania, Maryland, the District of Columbia, Delaware and New Jersey have laws specifically addressing energy efficiency and renewable energy initiatives. In addition to state level activity, RPS legislation has been considered and may be considered again in the future by the United States Congress. Also, states that currently do not have RPS requirements may adopt such legislation in the future.

In Illinois, in accordance with legislation in effect on December 31, 2016, the IPA's Procurement Plans include the procurement of cost-effective renewable energy resources in amounts that equal or exceed a minimum target percentage of the total electricity that each electric utility supplies to its eligible retail customers. The June 1, 2016 target renewable energy resources obligation for the utilities was at least 11.5%. This obligation increases by at least 1.5% each year thereafter to an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth by Illinois legislation. As of December 31, 2016, ComEd had purchased renewable energy resources or equivalents, such as RECs, in accordance with the IPA Procurement Plan. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates.

In accordance with FEJA that takes effect on June 1, 2017, beginning with the plan or plans to be implemented in the 2017 delivery year, the IPA shall develop a long term renewable resources procurement plan (LT Plan). The RPS target percentages for the overall service territory have not changed through June 1, 2025 (11.5% of retail load by June 1 2016 growing to 25% by June 1 2025) although FEJA extended the 25% RPS target to delivery years after 2025. Currently, each Retail

Electric Supplier and each utility is responsible for the renewable resource obligation for the customers to which it supplies power. Over time, this will change and the utility will procure renewable resources based on the retail load of substantially all customers in its service territory. For the delivery year beginning June 1, 2017, the LT Plan shall include cost effective renewable energy resources procured by the utility for the retail load the utility supplies and for 50% of the retail customer load supplied by Retail Electric Suppliers in the utility service territory on February 28, 2017. Utility procurement for RES supplied retail customer load will increase to 75% June 1, 2018 and to 100% beginning June 1, 2019.

Originally passed November 30, 2004 the AEPS Act became effective for PECO on January 1, 2011. During 2016, PECO was required to supply approximately 5.5% of electric energy generated from Tier I alternative energy resources (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania), as measured in AECs, through May 31, 2016 and subsequently 6.0% beginning June 1, 2016 and continuing through May 31, 2017. PECO is also required to supply 8.2% of electric energy generated from Tier II alternative energy resources (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing wood and by-products of the pulping process and wood, distributed generation systems and integrated combined coal gasification technology), as measured in AECs, effective June 1, 2015 and continuing through May 31, 2020. The compliance requirements will incrementally escalate to 8.0% for Tier I and 10.0% for Tier II by 2021. In order to comply with these requirements, PECO purchases its AECs through its DSP Program full requirement contracts with various counterparties, including Generation. PECO also obtains AECs of Solar Tier I annually from long term agreements with various counterparties, including Generation, and balancing amounts of Tier 1 non-solar and Tier II through broker purchases.

Section 7-703 of the Public Utilities Article in Maryland sets forth the RPS requirement, which applies to all retail electricity sales in Maryland by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, biomass, methane, geothermal, ocean, fuel cell, small hydroelectric, and poultry litter) and Tier 2 sources (hydroelectric, other than pump storage generation, and waste-to-energy). The RPS requirement began in 2006, requiring that suppliers procure 1.0% and 2.5% from Tier 1 and Tier 2 sources, respectively, escalating in 2022 to 22.0% from Tier 1 sources, including at least 2.0% from solar energy, and a phase out of Tier 2 resource options by 2022. In 2015, 10.5% was required from Tier 1 renewable sources, including at least 0.5% derived from solar energy and 2.5% from Tier 2 renewable sources. BGE, Pepco and DPL are subject to requirements established by the Public Utilities Article in Maryland related to the use of alternative energy resources. In addition, the wholesale suppliers that supply power to BGE, Pepco and DPL through SOS procurement auctions have the obligation, by contract with BGE, Pepco and DPL, to meet the RPS requirements.

Section 34-1432 of the D.C. Code sets forth the RPS requirement, which applies to all retail electricity sales in the District of Columbia by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, certain qualifying biomass, methane from anaerobia decomposition of organic materials in landfill or wastewater treatment plant, geothermal, ocean, and fuel cell) and Tier 2 sources (hydroelectric (other than pumped storage generation), certain qualifying biomass and waste-to-energy). The RPS requirement began in 2007, with standards increasing annually. For 2017, the RPS requires that suppliers procure 13.1% and 2.5% from Tier 1 and Tier 2 sources, respectively, with not less than 0.95% solar, and escalating in 2023 to 20.0% from Tier 1 sources, including at least 2.5% from solar energy, and a phase out of Tier 2 resource options. In 2015 the law was amended to extend the RPS requirements to 2032, at which time not less than 50% is required from Tier 1 renewable sources, including at least 5.0% derived from solar energy. Tier 2 renewable sources remain phased out. The wholesale suppliers that supply power to Pepco through SOS procurement auctions have the obligation, by contract with Pepco, to meet the RPS requirements.

Title 26 of the Delaware Code sets forth the RPS requirement, which applies to retail electricity sales in Delaware by electricity suppliers. The RPS requirement requires that DPL obtain a specified percentage of the electricity it delivers to its eligible customers from eligible energy resources (solar electric, wind, ocean tidal, ocean thermal, fuel cells powered by renewable fuels, hydroelectric facilities with a maximum capacity of 30 MW, sustainable biomass, anaerobic digestion and landfill gas). The RPS requirement, beginning in 2007, required that suppliers procure 2.0% from eligible energy resources, with not less than 0.011% from solar, and escalating annually through 2025, at which time suppliers must procure 25.0% from eligible energy resources, including at least 3.5% from solar. As of December 31, 2016, DPL is a party to three land-based wind power purchase agreements in the aggregate amount of 128 MWs (nameplate capacity). DPL has contracted for approximately 48 MW of Solar Renewable Energy Credits (SRECs) through a combination of long term SREC purchase agreements with solar facilities, SREC Purchase agreements with the Delaware Sustainable Energy Utility and the DE SREC Procurement Program. On October 18, 2011, the DPSC approved a tariff submitted by DPL in accordance with the requirements of the RPS specific to a fuel cell facility totaling 30 MWs to be constructed by a qualified fuel cell provider. The tariff and the RPS establish that DPL acts solely as an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MWh of energy produced by the fuel cell facilities through 2033. The qualified fuel cell provider output reduces the non-solar and/or solar requirements needed to satisfy the Delaware RPS obligations.

The Electric Discount and Energy Competition Act, (“EDECA”), was signed into law in 1999, and includes the requirement for compliance with New Jersey’s RPS by electric power suppliers and providers of BGS. The RPS requires that electric power suppliers obtain a specified percentage of the electricity they sell from Class I sources (solar, wind, wave/tidal action, geothermal, methane captured from landfills, fuel cells with certain types of power sources, and biomass) and Class II sources (hydroelectric facilities with a combined design capacity of less than 30 MW, and certain resource recovery facilities). In 2010, the Solar Energy Advancement and Fair Competition Act, (“SEAFCA”), was signed into law. SEAFCA amended several provisions of EDECA, among them the manner in which suppliers were to comply with the solar portion of the RPS. SEAFCA, beginning in energy year 2011, set out a specific requirement for solar energy generation. The Solar Act of 2012 made further changes effective for energy year 2014 and beyond. The RPS requirement has changed over time. For energy year 2005, suppliers were required to procure 0.74% and 2.5% from Class I and Class II sources, respectively. For the most recently completed energy year 2016, 9.649% was required from Class I renewable sources, 2.5% from Class II renewable sources, and 2.75% from solar energy. As noted above, the RPS applies to each supplier or provider that sells electricity to retail customers in New Jersey. Pursuant to Section 14:4-1.2 of the New Jersey Administrative Code, electric public utilities, such as ACE, that provide electric generation services only for the purpose of providing BGS are not electric power suppliers and so are not subject to the RPS procurement requirements.

Similar to ComEd, PECO, BGE, Pepco, DPL and ACE, Generation’s retail electric business must source a portion of the electric load it serves in many of the states in which it does business from renewable resources or approved equivalents such as RECs. Potential regulation and legislation regarding renewable and alternative energy resources could increase the pace of development of wind and other renewable/alternative energy resources, which could put downward pressure on wholesale market prices for electricity in some markets where Exelon operates generation assets. At the same time, such developments may present some opportunities for sales of Generation’s renewable power, including from wind, solar, hydroelectric and landfill gas.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on renewable portfolio standards.

Executive Officers of the Registrants as of February 13, 2017

Exelon

Name	Age	Position	Period
Crane, Christopher M.	58	Chief Executive Officer, Exelon	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		Chairman, PHI	2016 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
		Chief Operating Officer, Exelon	2008 - 2012
Cornew, Kenneth W.	51	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
O'Brien, Denis P.	56	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Vice Chairman, ComEd, PECO, BGE	2012 - Present
		Vice Chairman, PHI	2016 - Present
		Chief Executive Officer, PECO; Executive Vice President, Exelon	2007 - 2012
		President and Director, PECO	2003 - 2012
Pramaggiore, Anne R.	58	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Adams, Craig L.	64	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Butler, Calvin G.	47	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
Velazquez, David M.	57	President and Chief Executive Officer, PHI	2016 - Present
		President and Chief Executive Officer, Pepco, DPL and ACE	2009 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009 - 2016
Von Hoene Jr., William A.	63	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
Thayer, Jonathan W.	45	Senior Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012
Aliabadi, Paymon	54	Executive Vice President and Chief Enterprise Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
DesParte, Duane M.	53	Senior Vice President and Corporate Controller, Exelon	2008 - Present

Generation

Name	Age	Position	Period
Cornew, Kenneth W.	51	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
Pacilio, Michael J.	56	Executive Vice President and Chief Operating Officer, Exelon Generation	2015 - Present
		President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - 2015
		Chief Operating Officer, Exelon Nuclear	
Hanson, Bryan C.	51	President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Exelon Generation	2015 - Present
Nigro, Joseph	52	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - Present
		Senior Vice President, Portfolio Management and Strategy	2012 - 2013
		Vice President, Structuring and Portfolio Management, Exelon Power Team	2010 - 2012
DeGregorio, Ronald	54	Senior Vice President, Generation; President, Exelon Power	2012 - Present
		Chief Integration Officer, Exelon	2011 - 2012
Wright, Bryan P.	50	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
		Chief Accounting Officer, Constellation Energy	2009 - 2012
		Vice President and Controller, Constellation Energy	2008 - 2012
Bauer, Matthew N.	40	Vice President and Controller, Generation	2016 - Present
		Vice President and Controller, BGE	2014 - 2016
		Vice President of Power Finance, Exelon Power	2012 - 2014
		Director, FP&A and Retail, Constellation	2012 - 2012
		Executive Director, Corporate Development, Constellation	2009 - 2012

ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	58	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Donnelly, Terence R.	56	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
Trpik Jr., Joseph R.	47	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
Jensen, Val	61	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
Gomez, Veronica	47	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2017 - Present
		Vice President and Deputy General Counsel, Litigation, Exelon	2012 - 2017
Marquez Jr., Fidel	55	Senior Vice President, Governmental and External Affairs, ComEd	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012
Brookins, Kevin B.	55	Senior Vice President, Strategy & Administration, ComEd	2012 - Present
		Vice President, Operational Strategy and Business Intelligence, ComEd	2010 - 2012
McGuire, Timothy M.	58	Senior Vice President, Distribution Operations, ComEd	2016 - Present
		Vice President, Transmission and Substations, ComEd	2010 - 2016
Kozel, Gerald J.	44	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013
		Director of Financial Reporting and Analysis, Exelon	2009 - 2012

PECO

Name	Age	Position	Period
Adams, Craig L.	64	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	53	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	51	Senior Vice President and Chief Operations Officer, PECO	2012 - Present
		Vice President, Distribution System Operations and Smart Grid/Smart Meter, PECO	2010 - 2012
Webster Jr., Richard G.	55	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	57	Senior Vice President, Governmental and External Affairs, PECO	2016 - Present
		Vice President, Governmental and External Affairs, PECO	2012 - 2016
		Director, Governmental & External Affairs, PECO	2007 - 2012
Jiruska, Frank J.	56	Vice President, Customer Operations, PECO	2013 - Present
Diaz Jr., Romulo L.	70	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
Bailey, Scott A.	40	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012

BGE

Name	Age	Position	Period
Butler, Calvin G.	47	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
Woerner, Stephen J.	49	President, BGE	2014 - Present
		Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - 2014
		Vice President and Chief Integration Officer, Constellation Energy	2011 - 2012
Case, Mark D.	55	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Biagiotti, Robert D.	47	Vice President, Customer Operations and Chief Customer Officer, BGE	2015 - Present
		Vice President, Gas Distribution, BGE	2011 - 2015
Gahagan, Daniel P.	63	Vice President and General Counsel, BGE	2007 - Present
Vahos, David M.	44	Senior Vice President, Chief Financial Officer and Treasurer, BGE	2016 - Present
		Vice President, Chief Financial Officer and Treasurer, BGE	2014 - 2016
		Vice President and Controller, BGE	2012 - 2014
		Executive Director, Audit, Constellation	2010 - 2012
Holmes, Andrew W.	48	Vice President and Controller, BGE	2016 - Present
		Director, Generation Accounting, Exelon	2013 - 2016
		Director, Derivatives and Technical Accounting, Exelon	2008 - 2013
Núñez, Alexander G.	45	Senior Vice President, Regulatory and External Affairs, BGE	2016 - Present
		Vice President, Governmental and External Affairs, BGE	2013 - 2016
		Director, State Affairs, BGE	2012 - 2013

PHI, Pepco, DPL and ACE

Name	Age	Position	Period
Velazquez, David M.	57	President and Chief Executive Officer, PHI	2016 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009 - 2016
		President and Chief Executive Officer, Pepco, DPL and ACE	2009 - Present
Anthony, J. Tyler	52	Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL and ACE	2016 - Present
		Senior Vice President, Distribution Operations, ComEd	2010 - 2016
Kinzel, Donna J.	49	Senior Vice President and Chief Financial Officer, PHI, Pepco, DPL and ACE	2016 - Present
		Vice President, Treasurer and Chief Risk Officer, Pepco Holdings	2012 - Present
Bonney, Paul R.	58	Senior Vice President, Legal and Regulatory Strategy, PHI, Pepco, DPL and ACE	2016 - Present
		Senior Vice President and General Counsel, Constellation Energy	2012 - 2016
Parker, Kenneth J.	54	Senior Vice President, Governmental and External Affairs, PHI, Pepco, DPL and ACE	2016 - Present
		Senior Vice President, Government Affairs and Corporate Citizenship, Pepco Holdings, Inc.	2012 - 2016
Stark, Wendy E.	44	Vice President and General Counsel, PHI, Pepco DPL and ACE	2016 - Present
		Deputy General Counsel, Pepco Holdings, Inc.	2012 - Present
McGowan, Kevin M.	55	Vice President, Regulatory Policy and Strategy	2016 - Present
		Vice President, Regulatory Affairs, Pepco Holdings, Inc.	2012 - 2016
Aiken, Robert M.	50	Vice President and Controller, PHI, Pepco, DPL and ACE	2016 - Present
		Vice President and Controller, Generation	2012 - 2016
		Executive Director and Assistant Controller, Constellation	2011 - 2012

ITEM 1A. RISK FACTORS

Each of the Registrants operates in a market and regulatory environment that poses significant risks, many of which are beyond that Registrant's control. Management of each Registrant regularly meets with the Chief Enterprise Risk Officer and the RMC, which comprises officers of the Registrants, to identify and evaluate the most significant risks of the Registrants' businesses and the appropriate steps to manage and mitigate those risks. The Chief Enterprise Risk Officer and senior executives of the Registrants discuss those risks with the Finance and Risk Committee and Audit Committee of the Exelon Board of Directors and the ComEd, PECO, BGE, and PHI boards of directors. In addition, the generation oversight committee of the Exelon board of directors evaluates risks related to the generation business. The risk factors discussed below could adversely affect one or more of the Registrants' results of operations or cash flows and the market prices of their publicly traded securities. Each of the Registrants has disclosed the known material risks that affect its business at this time. However, there may be further risks and uncertainties that are not presently known or that are not currently believed by a Registrant to be material that could adversely affect its performance or financial condition in the future.

Exelon's financial condition and results of operations are affected to a significant degree by: (1) Generation's position as a predominantly nuclear generator selling power into competitive energy markets with a concentration in select regions, and (2) the role of the Utility Registrants as operators of electric transmission and distribution systems in six of the largest metropolitan areas in the United States. Factors that affect the financial condition and results of operations of the Registrants fall primarily under the following categories, all of which are discussed in further detail below:

- ***Market and Financial Factors.*** Exelon's and Generation's results of operations are affected by price fluctuations in the energy markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular the price of natural gas, which affects the prices that Generation can obtain for the output of its power plants, (2) the presence of other generation resources in the markets in which Generation's output is sold, (3) the demand for electricity in the markets where the Registrants conduct their business, and (4) the impacts of on-going competition in the retail channel.
- ***Regulatory and Legislative Factors.*** The regulatory and legislative factors that affect the Registrants include changes to the laws and regulations that govern competitive markets and utility cost recovery and environmental policy. In particular, Exelon's and Generation's financial performance could be affected by changes in the design of competitive wholesale power markets or Generation's ability to sell power in those markets. In addition, potential regulation and legislation, including regulation or legislation regarding climate change and renewable portfolio standards, could have significant effects on the Registrants. Also, returns for the Utility Registrants are influenced significantly by state regulation and regulatory proceedings.
- ***Operational Factors.*** The Registrants' operational performance is subject to those factors inherent in running the nation's largest fleet of nuclear power reactors and large electric and gas distribution systems. The safe and effective operation of the nuclear facilities and the ability to effectively manage the associated decommissioning obligations as well as the ability to maintain the availability, reliability and safety of its energy delivery systems are fundamental to Exelon's ability to protect and grow shareholder value. Additionally, the operating costs of the Utility Registrants and the opinions of their customers and regulators, are affected by those companies' ability to maintain the reliability and safety of their energy delivery systems.
- **Risks Related to the PHI Merger.** Exelon is subject to additional risks related to the merger with PHI that closed on March 23, 2016.

A discussion of each of these risk categories and other risk factors is included below.

Market and Financial Factors

Generation is exposed to depressed prices in the wholesale and retail power markets, which could negatively affect its results of operations or cash flows. (Exelon and Generation)

Generation is exposed to commodity price risk for the unhedged portion of its electricity generation supply portfolio. Generation's earnings and cash flows are therefore subject to variability of spot and forward market prices in the markets in which it operates rise and fall.

Price of Fuels : The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit. Often, the next unit of electricity will be supplied from generating stations fueled by fossil fuels. Consequently, changes in the market price of fossil fuels often result in comparable changes to the market price of power. For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing downward pressure on natural gas

prices and, therefore, on power prices. The continued addition of supply from new alternative generation resources, such as wind and solar, whether mandated through RPS or otherwise subsidized or encouraged through climate legislation or regulation, could displace a higher marginal cost plant, further reducing power prices. In addition, further delay or elimination of EPA air quality regulations could prolong the duration for which the cost of pollution from fossil fuel generation is not factored into market prices.

Demand and Supply: The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs could each depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on electricity market prices. The tepid economic environment in recent years and growing energy efficiency and demand response initiatives have limited the demand for electricity in Generation's markets. In addition, in some markets, the supply of electricity through wind or solar generation, when combined with other base-load generation such as nuclear, could often exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants. Increased supply in excess of demand is furthered by the continuation of RPS mandates and subsidies for renewable energy.

Retail Competition: Generation's retail operations compete for customers in a competitive environment, which affects the margins that Generation can earn and the volumes that it is able to serve. In periods of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including Generation) use their retail operations to hedge generation output. Increased or more aggressive competition could adversely affect overall gross margins and profitability in Generation's retail operations.

Sustained low market prices or depressed demand and over-supply could adversely affect Exelon's and Generation's results of operations or cash flows, and such impacts could be emphasized given Generation's concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect Exelon's and Generation's ability to fund other discretionary uses of cash such as growth projects or to pay dividends. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Exelon's and Generation's result of operations through accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, accelerated amortization of plant specific nuclear fuel costs, severance costs, accelerated asset retirement obligation expense related to future decommissioning activities, and additional funding of decommissioning costs, which can be offset in whole or in part by reduced operating and maintenance expenses. A slow recovery in market conditions could result in a prolonged depression of or further decline in commodity prices, including low forward natural gas and power prices and low market volatility, which could also adversely affect Exelon's and Generation's results of operations, cash flows or financial position. See Note 9—Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

In addition to price fluctuations, Generation is exposed to other risks in the power markets that are beyond its control and could negatively affect its results of operations. (Exelon and Generation)

Credit Risk. In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money, or are obligated to purchase energy or fuel from Generation, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these

arrangements fail to perform, Generation could be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. In the spot markets, Generation is exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs, the purpose of which is to spread such risk across all market participants. Generation is also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, Generation's retail sales subject it to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that could be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Market Designs. The wholesale markets vary from region to region with distinct rules, practices and procedures. Changes in these market rules, problems with rule implementation, or failure of any of these markets could adversely affect Generation's business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry, including technologies related to energy generation, distribution and consumption. (All Registrants)

Some of these technologies include, but are not limited, to further shale gas development or sources, cost-effective renewable energy technologies, broad consumer adoption of electric vehicles, distributed generation and energy storage devices. Such developments could affect the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could materially affect the Registrants' results of operations, cash flows or financial position through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors could decrease the value of NDT funds and employee benefit plan assets and could increase the related employee benefit plan obligations, which then could require significant additional funding. (All Registrants)

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy could adversely affect the value of the investments held within Generation's NDTs and Exelon's employee benefit plan trusts. The Registrants have significant obligations in these areas and Exelon and Generation hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which could fall below the Registrants' projected return rates. A decline in the market value of the NDT fund investments could increase Generation's funding requirements to decommission its nuclear plants. A decline in the market value of the pension and OPEB plan assets will increase the funding requirements associated with Exelon's pension and OPEB plan obligations. Additionally, Exelon's pension and OPEB plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements could also increase the costs and funding requirements of

the obligations related to the pension and OPEB plans. If future increases in pension and other postretirement costs as a result of reduced plan assets or other factors cannot be recovered, or cannot be recovered in a timely manner, from the Utility Registrants' customers, the results of operations and financial position of the Utility Registrants could be negatively affected. Ultimately, if the Registrants are unable to manage the investments within the NDT funds and benefit plan assets, and are unable to manage the related benefit plan liabilities, their results of operations, cash flows or financial position could be negatively impacted.

Unstable capital and credit markets and increased volatility in commodity markets could adversely affect the Registrants' businesses in several ways, including the availability and cost of short-term funds for liquidity requirements, the Registrants' ability to meet long-term commitments, Generation's ability to hedge effectively its generation portfolio, and the competitiveness and liquidity of energy markets; each could negatively impact the Registrants' results of operations, cash flows or financial position. (All Registrants)

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity needs if internal funds are not available from the Registrants' respective operations. Disruptions in the capital and credit markets in the United States or abroad could adversely affect the Registrants' ability to access the capital markets or draw on their respective bank revolving credit facilities. The Registrants' access to funds under their credit facilities depends on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from the Registrants and other borrowers within a short period of time. The inability to access capital markets or credit facilities, and longer term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, changes to Generation's hedging strategy in order to reduce collateral-posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

In addition, the Registrants have exposure to worldwide financial markets, including Europe. Disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2016, approximately 23%, or $2.2 billion of the Registrants' available credit facilities were with European banks. The credit facilities include $9.5 billion in aggregate total commitments of which $7.9 billion was available as of December 31, 2016. As of December 31, 2016, there was $75 million of borrowings under Generation's bilateral credit facilities. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in energy markets depend heavily on active participation by multiple trading parties, which could be adversely affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that could affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to the respective businesses of the Registrants. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on Exelon's and Generation's results of operations or cash flows.

If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs. (All Registrants)

Generation's business is subject to credit quality standards that could require market participants to post collateral for their obligations. If Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating) or otherwise fail to satisfy the credit standards of trading counterparties, it would be required under its hedging arrangements to provide collateral in the form of letters of credit or cash, which could have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time depends on a variety of factors, including (1) the notional amount of the applicable hedge, (2) the nature of counterparty and related agreements, and (3) changes in power or other commodity prices. In addition, if Generation were downgraded, it could experience higher borrowing costs as a result of the downgrade. Generation could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the power generation industry in general, or Generation in particular, has deteriorated. Changes in ratings methodologies by the credit rating agencies could also have a negative impact on the ratings of Generation. Generation has project-specific financing arrangements and must meet the requirements of various agreements relating to those financings. Failure to meet those arrangements could give rise to a project-specific financing default which, if not cured or waived, could result in the specific project being required to repay the associated debt or other borrowings earlier than otherwise anticipated, and if such repayment were not made, the lenders or security holders would generally have rights to foreclose against the project assets and related collateral.

The Utility Registrants' operating agreements with PJM and PECO's, BGE's and DPL's natural gas procurement contracts contain collateral provisions that are affected by their credit rating and market prices. If certain wholesale market conditions were to exist and the Utility Registrants were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the forms of letters of credit or cash, which could have a material adverse effect upon their liquidity. Collateral posting requirements will generally increase as market prices rise and decrease as market prices fall. Collateral posting requirements for PECO, BGE and DPL, with respect to their natural gas supply contracts, will generally increase as forward market prices fall and decrease as forward market prices rise. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if the Utility Registrants were downgraded, they could experience higher borrowing costs as a result of the downgrade.

A Utility Registrant could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the utility industry in general, or a Utility Registrant in particular, has deteriorated. A Utility Registrant could experience a downgrade if its current regulatory environment becomes less predictable by materially lowering returns for the Utility Registrant or adopting other measures to limit utility rates. Additionally, the ratings for a Utility Registrant could be downgraded if its financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage its capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of the Utility Registrants.

The Utility Registrants conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that the Utility Registrants are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate the Utility Registrants from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as "ring-

fencing") could help avoid or limit a downgrade in the credit ratings of the Utility Registrants in the event of a reduction in the credit rating of Exelon. Despite these ring-fencing measures, the credit ratings of the Utility Registrants could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of some or all of the Utility Registrants. A reduction in the credit rating of a Utility Registrant could have a material adverse effect on the Utility Registrant.

See Liquidity and Capital Resources—Recent Market Conditions and Security Ratings for further information regarding the potential impacts of credit downgrades on the Registrants' cash flows.

Generation's financial performance could be negatively affected by price volatility, availability and other risk factors associated with the procurement of nuclear and fossil fuel. (Exelon and Generation)

Generation depends on nuclear fuel and fossil fuels to operate most of its generating facilities. Nuclear fuel is obtained predominantly through long-term uranium supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. Natural gas and oil are procured for generating plants through annual, short-term and spot-market purchases. The supply markets for nuclear fuel, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default that could negatively affect the results of operations or cash flows for Generation.

Generation's risk management policies cannot fully eliminate the risk associated with its commodity trading activities. (Exelon and Generation)

Generation's asset-based power position as well as its power marketing, fuel procurement and other commodity trading activities expose Generation to risks of commodity price movements. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations could be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, Generation cannot predict the impact that its commodity trading activities and risk management decisions could have on its business, operating results, cash flows or financial position.

Generation buys and sells energy and other products and enters into financial contracts to manage risk and hedge various positions in Generation's power generation portfolio. Generation is exposed to volatility in financial results for unhedged positions.

Financial performance and load requirements could be adversely affected if Generation is unable to effectively manage its power portfolio. (Exelon and Generation)

A significant portion of Generation's power portfolio is used to provide power under procurement contracts with the Utility Registrants and other customers. To the extent portions of the power portfolio are not needed for that purpose, Generation's output is sold in the wholesale power markets. To the extent its power portfolio is not sufficient to meet the requirements of its customers under the related agreements, Generation must purchase power in the wholesale power markets. Generation's financial results could be negatively affected if it is unable to cost-effectively meet the load requirements of its customers, manage its power portfolio and effectively address the changes in the wholesale power markets.

Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could negatively impact the Registrants' results of operations or cash flows. (All Registrants)

Potential Corporate Tax Reform. The results of the November 2016 U.S. elections have introduced greater uncertainty with respect to federal tax policies. President Trump has stated that one of his top priorities is comprehensive tax reform and House Republicans plan to advance their tax reform "blueprint". Tax reform proposals call for a reduction in the corporate federal income tax rate from the current 35% to as low as 15%. Other proposals provide, among other items, for the immediate deduction of capital investment expenditures and full or partial elimination of debt interest expense deductions. It is uncertain whether, to what extent or when these or any other changes in federal tax policies will be enacted or the transition time frame for such changes. Further, for the Utility Registrants, regulators may impose rate reductions to provide the benefit of any income tax expense reductions to customers and refund "excess" deferred income taxes previously collected through rates. The amounts and timing of any such rate changes would be subject to the discretion of the rate regulator in each specific jurisdiction. For these reasons, the Registrants cannot predict the impact any potential changes may have on their future results of operations, cash flows or financial position, and such changes could be material.

Tax reserves. The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeals issues related to these tax matters. These judgments include reserves established for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities. See Notes 1—Significant Accounting Policies and Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Increases in customer rates and the impact of economic downturns could lead to greater expense for uncollectible customer balances. Additionally, increased rates could lead to decreased volumes delivered. Both of these factors could decrease Generation's and the Utility Registrants' results from operations or cash flows. (All Registrants)

The Utility Registrants' current procurement plans include purchasing power through contracted suppliers and in the spot market. ComEd's, PECO's and ACE's costs of purchased power are charged to customers without a return or profit component. BGE's, Pepco's and DPL's SOS rates charged to customers recover their wholesale power supply costs and include a return component. For PECO, purchased natural gas costs are charged to customers with no return or profit component. For BGE, purchased natural gas costs are charged to customers using a MBR mechanism that compares the actual cost of gas to a market index. The difference between the actual cost and the market index is shared equally between shareholders and customers. For DPL, purchased natural gas costs are charged to customers using a GCR mechanism that compares the actual cost of gas to a forecasted amount. The difference between the actual cost and the forecast is fully recoverable and carried forward as a recovery balance in the next GCR filing. Purchased power and natural gas prices fluctuate based on their relevant supply and demand. Significantly higher rates related to purchased power and natural gas could result in declines in customer usage, lower revenues and potentially additional uncollectible accounts expense for the Utility Registrants. In addition, any challenges by the regulators or the Utility Registrants as to the recoverability of these costs could have a material effect on the Registrants' results of operations or cash flows. Also, the Utility Registrants' cash flows could be affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

Further, the impacts of economic downturns on the Utility Registrants' customers, such as unemployment for residential customers and less demand for products and services provided by

commercial and industrial customers, and the related regulatory limitations on residential service terminations, could result in an increase in the number of uncollectible customer balances', which would negatively impact the Utility Registrants' results of operations or cash flows. Generation's customer-facing energy delivery activities face similar economic downturn risks, such as lower volumes sold and increased expense for uncollectible customer balances which could negatively affect Generation's results of operations or cash flows. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants' credit risk.

The effects of weather could impact the Registrants' results of operations or cash flows. (All Registrants)

Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Moderate temperatures adversely affect the usage of energy and resulting revenues at ComEd, PECO, DPL and ACE. Due to revenue decoupling, BGE, Pepco and DPL recognize revenues at MDPSC and DCPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period, and are not affected by actual weather with the exception of major storms. Pursuant to the Illinois FEJA signed into law on December 2016 and effective in 2017, ComEd can eliminate the favorable or unfavorable impacts of weather or load on its electric distribution revenues by either (1) revising its electric distribution formula rate to eliminate the ROE collar beginning with the reconciliation performed for the 2017 calendar year or (2) implementing a decoupling tariff if the electric distribution formula rate were to be terminated at anytime.

Extreme weather conditions or damage resulting from storms could stress the Utility Registrants' transmission and distribution systems, communication systems and technology, resulting in increased maintenance and capital costs and limiting each company's ability to meet peak customer demand. These extreme conditions could have detrimental effects on the Utility Registrants' results of operations or cash flows. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and could make period comparisons less relevant.

Generation's operations are also affected by weather, which affects demand for electricity as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation could require greater resources to meet its contractual commitments. Extreme weather conditions or storms could affect the availability of generation and its transmission, limiting Generation's ability to source or send power to where it is sold. In addition, drought-like conditions limiting water usage could impact Generation's ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, could have an adverse effect by causing Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Certain long-lived assets and other assets recorded on the Registrants' statements of financial position could become impaired, which would result in write-offs of the impaired amounts. (All Registrants)

Long-lived assets represent the single largest asset class on the Registrants' statements of financial position. Specifically, long-lived assets account for 62%, 54%, 68%, 70%, 81%, 76%, 79% and 73% of total assets for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE, respectively, as of December 31, 2016. In addition, Exelon and Generation have significant balances related to unamortized energy contracts, as further disclosed in Note 11—Intangible Assets of the Combined Notes to Consolidated Financial Statements. The Registrants evaluate the recoverability of

the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered when evaluating long-lived assets for potential impairment. An impairment would require the Registrants to reduce the carrying value of the long-lived asset to fair value through a non-cash charge to expense by the amount of the impairment, and such an impairment could have a material adverse impact on the Registrants' results of operations.

As of December 31, 2016, Exelon's $6.7 billion carrying amount of goodwill primarily consists of $2.6 billion at ComEd relating to the acquisition of ComEd in 2000 upon the formation of Exelon and $4.0 billion at PHI primarily resulting from Exelon's acquisition of PHI in the first quarter of 2016. Under GAAP, goodwill remains at its recorded amount unless it is determined to be impaired, which is generally based upon an annual analysis that compares the implied fair value of the goodwill to its carrying value. If an impairment occurs, the amount of the impaired goodwill will be written-off to expense, which will also reduce equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. Such an impairment would result in a non-cash charge to expense, which could have a material adverse impact on Exelon's, ComEd's, and PHI's results of operations.

Regulatory actions or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's, Pepco's, DPL's, and ACE's business, and the fair value of debt, could potentially result in future impairments of Exelon's, PHI's, and ComEd's goodwill, which could be material.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Critical Accounting Policies and Estimates and Note 7—Property, Plant and Equipment, Note 8—Impairment of Long Lived Assets and Note 11—Intangible Assets of the Combined Notes to the Consolidated Financial Statements for additional discussion on long-lived asset and goodwill impairments.

Exelon and its subsidiaries at times guarantee the performance of third parties, which could result in substantial costs in the event of non-performance by such third parties. In addition, the Registrants could have rights under agreements which obligate third parties to indemnify the Registrants for various obligations, and the Registrants could incur substantial costs in the event that the applicable Registrant is unable to enforce those agreements or the applicable third-party is otherwise unable to perform. The Registrants could also incur substantial costs in the event that third parties are entitled to indemnification related to environmental or other risks in connection with the acquisition and divestiture of assets. (All Registrants)

Some of the Registrants have issued guarantees of the performance of third parties, which obligate the Registrant or its subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, a Registrant could incur substantial cost to fulfill its obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial condition, or cash flows of the Registrant. Some of the Registrants have issued indemnities to third parties regarding environmental or other matters in connection with purchases and sales of asset and a Registrant could incur substantial costs to fulfill its obligations under these indemnities.

Some of the Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected

Registrant could be held responsible for the obligations, which could impact that Registrant's results of operations, cash flows or financial position. In connection with Exelon's 2001 corporate restructuring, Generation assumed certain of ComEd's and PECO's rights and obligations with respect to their former generation businesses. Further, ComEd and PECO may have entered into agreements with third parties under which the third-party agreed to indemnify ComEd or PECO for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the restructuring. If the third-party or Generation experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, ComEd or PECO could be liable for any existing or future claims, which could impact ComEd's or PECO's results of operations, cash flows or financial position.

Regulatory and Legislative Factors

The Registrants' generation and energy delivery businesses are highly regulated and could be subject to regulatory and legislative actions that adversely affect their operations or financial results. Fundamental changes in regulation or legislation or violation of tariffs or market rules and anti-manipulation laws, could disrupt the Registrants' business plans and adversely affect their operations or financial results. (All Registrants)

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation. Further, Exelon's and Generation's operating results and cash flows are significantly affected by Generation's sale of power at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon's and the Utility Registrants' operating results and cash flows are heavily dependent on the ability of the Utility Registrants to recover their costs for the retail purchase and distribution of power to their customers. Similarly, there is risk that financial market regulations could increase the Registrants' compliance costs and limit their ability to engage in certain transactions. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, exchanges, ratemaking agencies and taxing authorities. Additionally, the Registrants need to be cognizant and understand rule changes or Registrant actions that could result in potential violation of tariffs, market rules and anti-manipulation laws. Fundamental changes in regulations or other adverse legislative actions affecting the Registrants' businesses would require changes in their business planning models and operations and could negatively impact their respective results of operations, cash flows or financial position.

Regulatory and legislative developments related to climate change and RPS could also significantly affect Exelon's and Generation's results of operations, cash flows or financial position. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, could sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. However, national regulation or legislation addressing climate change through an RPS could also increase the pace of development of wind energy facilities in the Midwest, which could put downward pressure on wholesale market prices for electricity from Generation's Midwest nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation's nuclear assets under a carbon constrained regulatory regime that might exist in the future. Similarly, final regulations under Section 111(d) of the Clean Air Act may not provide sufficient incentives for states to utilize carbon-free nuclear power as a means of meeting greenhouse gas emission reduction requirements, while continuing a policy of favoring renewable energy sources. Current state level climate change and renewable regulation is already providing incentives for regional wind development. The Registrants cannot predict when or whether any of these various legislative and regulatory proposals could become law or what their effect will be on the Registrants.

Generation could be negatively affected by possible Federal or state legislative or regulatory actions that could affect the scope and functioning of the wholesale markets. (Exelon and Generation)

Federal and state legislative and regulatory bodies are facing pressures to address consumer concerns, or are themselves raising concerns, that energy prices in wholesale markets are too high or insufficient generation is being built because the competitive model is not working and, therefore, are considering some form of re-regulation or some other means of reducing wholesale market prices or subsidizing new generation. Generation is dependent on robust and competitive wholesale energy markets to achieve its business objectives.

Approximately 65% of Generation's generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Generation's future results of operations will depend on (1) FERC's continued adherence to and support for, policies that favor the preservation of competitive wholesale power markets, such as PJM's, and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competitiveness. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize new generation, such as the subsequently dismissed New Jersey Capacity Legislation and the MDPSC's RFP for new gas-fired generation in Maryland. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details related to the New Jersey Capacity Legislation and the Maryland new electric generation requirements.

In addition, FERC's application of its Order 697 and its subsequent revisions could pose a risk that Generation will have difficulty satisfying FERC's tests for market-based rates. Since Order 697 became final in June 2007, Generation has obtained orders affirming Generation's authority to sell at market-based rates and none denying that authority.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted in July 2010. The part of the Act that applies to Exelon is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires the creation of a new regulatory regime for over-the-counter swaps (swaps), including mandatory clearing for certain categories of swaps, incentives to shift swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. For non security-based swaps including commodity swaps, Dodd-Frank empowers the Commodity Futures Trading Commission (CFTC) to promulgate regulations implementing the law's objectives. The primary aim of Dodd-Frank is to regulate the key intermediaries in the swaps market, which entities are either swap dealers (SDs), major swap participants (MSPs), and certain other financial entities, but the law also applies to a lesser degree to end-users of swaps. On January 12, 2015, President Obama signed into law a bill that exempts from margin requirements swaps used by end-users to hedge or mitigate commercial risk. Moreover, the CFTC's Dodd-Frank regulations preserve the ability of end users in the energy industry to hedge their risks using swaps without being subject to mandatory clearing, and accepts or exempts end-users from many of the other substantive regulations. Accordingly, as an end-user, Generation is conducting its commercial business in a manner that does not require registration with the CFTC as an SD or MSP. Generation does not anticipate transacting in the future in a manner in which it would become a SD or MSP.

There are, however, some rulemaking proceedings that have not yet been finalized, including the capital and margin rules for (non-cleared) swaps. Generation does not expect these rules to directly impact its collateral requirements. However, depending on the substance of these final rules in addition to certain international regulatory requirements still under development and that are similar to Dodd-Frank, Generation's swap counterparties could be subject to additional and potentially significant

capitalization requirements. These regulations could motivate the SDs and MSPs to increase collateral requirements or cash postings from their counterparties, including Generation.

Generation continues to monitor the rulemaking proceedings with respect to the capital and margin rules, but cannot predict to what extent, if any, further refinements to Dodd-Frank requirements could impact its cash flows or financial position, but such impacts could be material.

The Utility Registrants could also be subject to some Dodd-Frank requirements to the extent they were to enter into swaps. However, at this time, management of the Utility Registrants continue to expect that their companies will not be materially affected by Dodd-Frank.

Generation's affiliation with the Utility Registrants, together with the presence of a substantial percentage of Generation's physical asset base within the Utility Registrants' service territories, could increase Generation's cost of doing business to the extent future complaints or challenges regarding the Utility Registrants' retail rates result in settlements or legislative or regulatory requirements funded in part by Generation. (Exelon and Generation)

Generation has significant generating resources within the service areas of the Utility Registrants and makes significant sales to each of them. Those facts tend to cause Generation to be directly affected by developments in those markets. Government officials, legislators and advocacy groups are aware of Generation's affiliation with the Utility Registrants and its sales to each of them. In periods of rising utility rates, particularly when driven by increased costs of energy production and supply, those officials and advocacy groups could question or challenge costs and transactions incurred by the Utility Registrants with Generation, irrespective of any previous regulatory processes or approvals underlying those transactions. The prospect of such challenges could increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges could subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators could seek ways to force Generation to contribute to efforts to mitigate potential or actual rate increases, through measures such as generation-based taxes and contributions to rate-relief packages.

The Registrants could incur substantial costs to fulfill their obligations related to environmental and other matters. (All Registrants)

The businesses which the Registrants operate are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the manner in which the Registrants conduct their operations and make capital expenditures including how they handle air and water emissions and solid waste disposal. Violations of these emission and disposal requirements could subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties' claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generate. The Registrants have incurred and expect to incur significant costs related to environmental compliance, site remediation and clean-up. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and could be subject to additional proceedings in the future.

If application of Section 316(b) of the Clean Water Act, which establishes a national requirement for reducing the adverse impacts to aquatic organisms at existing generating stations, requires the

retrofitting of cooling water intake structures at Salem or other Exelon power plants, this development could result in material costs of compliance. Pursuant to discussions with the NJDEP regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029. On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance.

Additionally, Generation is subject to exposure for asbestos-related personal injury liability alleged at certain current and formerly owned generation facilities. Future legislative action could require Generation to make a material contribution to a fund to settle lawsuits for alleged asbestos-related disease and exposure.

In some cases, a third-party who has acquired assets from a Registrant has assumed the liability the Registrant could otherwise have for environmental matters related to the transferred property. If the transferee is unable, or fails, to discharge the assumed liability, a regulatory authority or injured person could attempt to hold the Registrant responsible, and the Registrant's remedies against the transferee could be limited by the financial resources of the transferee. See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in the Utility Registrants' respective terms and conditions of service, including their respective rates, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy and subject to appeal, which lead to uncertainty as to the ultimate result and which could introduce time delays in effectuating rate changes. (Exelon and the Utility Registrants)

The Utility Registrants are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for a Utility Registrant to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates could be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, bad debt, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs.

In certain instances, the Utility Registrants could agree to negotiated settlements related to various rate matters, customer initiatives or franchise agreements. These settlements are subject to regulatory approval.

The Utility Registrants cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania, Maryland, the District of Columbia, Delaware, New Jersey or Federal regulators in establishing rates, including the extent, if any, to which certain costs such as significant capital projects will be recovered or what rates of return will be allowed. Nevertheless, the expectation is that the Utility Registrants will continue to be obligated to deliver electricity to customers in their respective service territories and will also retain significant default service obligations, referred to as POLR, DSP, SOS, and BGS, to provide electricity and natural gas to certain groups of customers in their respective service areas who do not choose an alternative supplier. The ultimate outcome and timing of regulatory

rate proceedings have a significant effect on the ability of the Utility Registrants, as applicable, to recover their costs and could have a material adverse effect on the Utility Registrants' results of operations, cash flows and financial position. See Note 3—Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for information regarding rate proceedings.

Federal or additional state RPS and/or energy conservation legislation, along with energy conservation by customers, could negatively affect the results of operations or cash flows of Generation and the Utility Registrants. (All Registrants)

Changes to current state legislation or the development of Federal legislation that requires the use of renewable and alternate fuel sources, such as wind, solar, biomass and geothermal, could significantly impact Generation and the Utility Registrants, especially if timely cost recovery is not allowed for Utility Registrants. The impact could include increased costs for RECs and purchased power and increased rates for customers.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, have increased capital expenditures and could significantly impact the Utility Registrants if timely cost recovery is not allowed. Furthermore, regulated energy consumption reduction targets and declines in customer energy consumption resulting from the implementation of new energy conservation technologies could lead to a decline in the revenues of Exelon, Generation and the Utility Registrants. For additional information, see ITEM 1. BUSINESS "Environmental Regulation-Renewable and Alternative Energy Portfolio Standards."

The impact of not meeting the criteria of the FASB guidance for accounting for the effects of certain types of regulation could be material to Exelon and the Utility Registrants. (Exelon and the Utility Registrants)

As of December 31, 2016, Exelon and the Utility Registrants have concluded that the operations of the Utility Registrants meet the criteria of the authoritative guidance for accounting for the effects of certain types of regulation. If it is concluded in a future period that a separable portion of their businesses no longer meets the criteria, Exelon, and the Utility Registrants would be required to eliminate the financial statement effects of regulation for that part of their business. That action would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets and the recognition of a one-time charge in their Consolidated Statements of Operations and Comprehensive Income. The impact of not meeting the criteria of the authoritative guidance could be material to the financial statements of Exelon and the Utility Registrants. At December 31, 2016, the gain (loss) could have been as much as $2.5 billion, $(1.1) billion, $(552) million, $(821) million, $(208) million and $(476) million (before taxes) as a result of the elimination of regulatory assets and liabilities of ComEd, PECO, BGE, Pepco, DPL and ACE, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to $2.6 billion, $614 million, $424 million, $243 million, and $84 million for ComEd, BGE, Pepco, DPL and ACE respectively, related to Exelon's net regulatory assets associated with its defined benefit postretirement plans. Exelon also has a net regulatory liability of $47 million (before taxes) associated with PECO's defined benefit postretirement plans that would result in an increase in OCI if reversed. The impacts and resolution of the above items could lead to an impairment of ComEd's or PHI's goodwill, which could be significant and at least partially offset the gains at ComEd discussed above. A significant decrease in equity as a result of any changes could limit the ability of the Utility Registrants to pay dividends under Federal and state law and no longer meeting the regulatory accounting criteria could cause significant volatility in future results of operations. See Notes 1—Significant Accounting Policies, 3—Regulatory Matters and 11—Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd's and PHI's goodwill, respectively.

Exelon and Generation could incur material costs of compliance if Federal and/or state regulation or legislation is adopted to address climate change. (Exelon and Generation)

Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. In 2009, select Northeast and Mid-Atlantic states implemented a model rule, developed via the RGGI, to regulate CO2 emissions from fossil-fired generation. RGGI states are working on updated programs to further limit emissions, and the EPA has introduced regulation to address greenhouse gases from new fossil plants that could potentially impact existing plants. If carbon reduction regulation or legislation becomes effective, Exelon and Generation could incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. For example, more stringent permitting requirements could preclude the construction of lower-carbon nuclear and gas-fired power plants. Similarly, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS “Global Climate Change” and Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of the Utility Registrants to the results of PJM’s RTEP and NERC compliance requirements. (All Registrants)

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation and the Utility Registrants, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. As operators of natural gas distribution systems, PECO, BGE, and DPL are also subject to mandatory reliability standards of the U.S. Department of Transportation. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards could subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU impose certain distribution reliability standards on the Utility Registrants. If the Registrants were found not to be in compliance with the mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards.

See Note 3—Regulatory Matters and Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants could be subject to adverse publicity and reputational risks, which make them vulnerable to negative customer perception and could lead to increased regulatory oversight or other consequences. (All Registrants)

The Registrants have large consumer customer bases and as a result could be the subject of public criticism focused on the operability of their assets and infrastructure and quality of their service. Adverse publicity of this nature could render legislatures and other governing bodies, public service commissions and other regulatory authorities, and government officials less likely to view energy companies such as Exelon and its subsidiaries in a favorable light, and could cause Exelon and its

subsidiaries to be susceptible to less favorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent regulatory requirements. Unfavorable regulatory outcomes can include the enactment of more stringent laws and regulations governing Exelon's operations, as well as fines, penalties or other sanctions or requirements. The imposition of any of the foregoing could have a material negative impact on the Registrants' business, results of operations, cash flows and financial positions.

The Registrants cannot predict the outcome of the legal proceedings relating to their business activities. An adverse determination could negatively impact their results of operations, cash flows or financial position. (All Registrants)

The Registrants are involved in legal proceedings, claims and litigation arising out of their business operations, the most significant of which are summarized in Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on the Registrants' results of operations.

Generation could be negatively affected by possible Nuclear Regulatory Commission actions that could affect the operations and profitability of its nuclear generating fleet. (Exelon and Generation)

Regulatory risk **.** A change in the Atomic Energy Act or the applicable regulations or licenses could require a substantial increase in capital expenditures or could result in increased operating or decommissioning costs and significantly affect Generation's results of operations or financial position. Events at nuclear plants owned by others, as well as those owned by Generation, could cause the NRC to initiate such actions.

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF, such as the one previously considered at Yucca Mountain, Nevada, and the timing of such facility opening, will significantly affect the costs associated with storage of SNF, and the ultimate amounts received from the DOE to reimburse Generation for these costs. The NRC's temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store SNF at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants.

Any regulatory action relating to the timing and availability of a repository for SNF could adversely affect Generation's ability to decommission fully its nuclear units. Through May 15, 2014, in accordance with the NWPA and Generation's contract with the DOE, Generation paid the DOE a fee per kWh of net nuclear generation for the cost of SNF disposal. This fee was discontinued effective May 16, 2014. Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. Generation currently estimates 2030 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the SNF obligation. Generation cannot predict what, if any, fee will be established in the future for SNF disposal. However, such a fee could be material to Generation's results of operations or cash flows.

Operational Factors

The Registrants' employees, contractors, customers and the general public could be exposed to a risk of injury due to the nature of the energy industry. (All Registrants)

Employees and contractors throughout the organization work in, and customers and the general public could be exposed to, potentially dangerous environments near their operations. As a result, employees, contractors, customers and the general public are at some risk for serious injury, including loss of life. These risks include nuclear accidents, dam failure, gas explosions, pole strikes and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events could negatively impact the Registrants' results of operations, their ability to raise capital and their future growth. (All Registrants)

Generation's fleet of power plants and the Utility Registrants' distribution and transmission infrastructures could be affected by natural disasters, such as seismic activity, extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Registrants' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment.

Natural disasters and other significant events increase the risk to Generation that the NRC or other regulatory or legislative bodies could change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological matters. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for Generation's continued operation, particularly the cooling of generating units. Additionally, natural disasters and other events that have an adverse effect on the economy in general could adversely affect the Registrants' operations and their ability to raise capital.

The impact that potential terrorist attacks could have on the industry in general and on Exelon in particular is uncertain. As owner-operators of infrastructure facilities, such as nuclear, fossil and hydroelectric generation facilities and electric and gas transmission and distribution facilities, the Registrants face a risk that their operations would be direct targets or indirect casualties of an act of terror. Any retaliatory military strikes or sustained military campaign could affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cyber security of Exelon's facilities, which could adversely affect Exelon's ability to manage its business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also could result in a decline in energy consumption, which could adversely affect the Registrants' results of operations and its ability to raise capital. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants could be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate Exelon's generating and transmission and distribution assets could be affected, resulting in decreased service levels and increased costs.

In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property and casualty losses subject to unforeseen occurrences or catastrophic events that could damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

Generation's financial performance could be negatively affected by matters arising from its ownership and operation of nuclear facilities. (Exelon and Generation)

Nuclear capacity factors. Capacity factors for generating units, particularly capacity factors for nuclear generating units, significantly affect Generation's results of operations. Nuclear plant operations involve substantial fixed operating costs but produce electricity at low variable costs due to nuclear fuel costs typically being lower than fossil fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear facilities at high capacity factors. Lower capacity factors increase Generation's operating costs by requiring Generation to produce additional energy from primarily its fossil facilities or purchase additional energy in the spot or forward markets in order to satisfy Generation's obligations to committed third-party sales, including the Utility Registrants. These sources generally have higher costs than Generation incurs to produce energy from its nuclear stations.

Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, could have a significant impact on Generation's results of operations. When refueling outages last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales.

Nuclear fuel quality . The quality of nuclear fuel utilized by Generation could affect the efficiency and costs of Generation's operations. Certain of Generation's nuclear units have previously had a limited number of fuel performance issues. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

Operational risk . Operations at any of Generation's nuclear generation plants could degrade to the point where Generation has to shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes could require significant time and expense. Generation could choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation could lose revenue and incur increased fuel and purchased power expense to meet supply commitments. For plants operated but not wholly owned by Generation, Generation could also incur liability to the co-owners. For plants not operated and not wholly owned by Generation, from which Generation receives a portion of the plants' output, Generation's results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by Generation could result in increased regulation and reduced public support for nuclear-fueled energy, which could significantly affect Generation's results of operations or financial position. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident could be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by Generation or owned by others, could exceed Generation's resources, including insurance coverage. Uninsured losses and other expenses, to the extent not recovered from insurers or the

nuclear industry, could be borne by Generation and could have a material adverse effect on Generation's results of operations or financial position. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, whether owned Generation or others, could result in increased regulation and reduced public support for nuclear-fueled energy and significantly affect Generation's results of operations or financial position.

Nuclear insurance. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance. The required amount of nuclear liability insurance is $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.4 billion limit for a single incident.

Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation's nuclear operations. In previous years, NEIL has made distributions to its members but Generation cannot predict the level of future distributions or if they will occur at all. See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired and units that are within five years of retirement) addressing Generation's ability to meet the NRC-estimated funding levels including scheduled contributions to and earnings on the decommissioning trust funds. The NRC funding levels are based upon the assumption that decommissioning will commence after the end of the current licensed life of each unit.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. The performance of capital markets also could significantly affect the value of the trust funds. Currently, Generation is making contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation, through PECO, has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from utility customers for any of its other nuclear units if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that Generation would be unable to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if Generation no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units could be negatively affected and Exelon's and Generation's results of operations or financial position could be significantly affected. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Ultimately, if the investments held by Generation's NDTs are not sufficient to fund the decommissioning of Generation's nuclear units, Generation could be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met. As a result, Generation's cash flows or financial position could be significantly adversely affected. Additionally, if the pledged assets are not sufficient to fund the Zion station decommissioning activities under the Asset Sale Agreement (ASA), Generation could have to seek remedies available under the ASA to reduce the risk of default by ZionSolutions and its parent. See Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

For nuclear units that are subject to regulatory agreements with either the ICC or the PAPUC, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd and PECO have recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability.

In the case of the nuclear units subject to the regulatory agreements with the ICC, if the funds held in the NDT funds for any former ComEd unit are expected to not exceed the total decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial position could be material. Additionally, any remaining balances in noncurrent payables to affiliates at Generation and ComEd's noncurrent affiliate receivable from Generation and corresponding regulatory liability may need to be reversed and could have a material impact on Generation's Consolidated Statement of Operations and Comprehensive Income.

In the case of the nuclear units subject to the regulatory agreements with the PAPUC, any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial position could be material. Additionally, any remaining balances in noncurrent payables to affiliates at Generation and PECO's noncurrent affiliate receivable from Generation and corresponding regulatory liability may need to be reversed and could have a material impact on Generation's Consolidated Statement of Operations and Comprehensive Income.

Generation's financial performance could be negatively affected by risks arising from its ownership and operation of hydroelectric facilities. (Exelon and Generation)

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. The license for the Muddy Run Pumped Storage Project expires on December 1, 2055. The license for the Conowingo Hydroelectric Project expired September 1, 2014. FERC issued an annual license, effective as of the expiration of the previous license. If FERC does not issue a license prior to the expiration of the annual license, the annual license will renew automatically. Generation cannot predict whether it will receive all the regulatory approvals for the renewed licenses of its hydroelectric facilities. If FERC does not issue new operating licenses for Generation's hydroelectric facilities or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. Generation could also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions could be imposed as part of the license renewal process that could adversely affect operations, could require a substantial increase in capital expenditures or could result in increased operating costs and significantly affect Generation's results of operations or financial position. Similar effects could result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by Generation.

The Registrants' businesses are capital intensive, and their assets could require significant expenditures to maintain and are subject to operational failure, which could result in potential liability. (All Registrants)

The Registrants' businesses are capital intensive and require significant investments by Generation in electric generating facilities and by the Utility Registrants in transmission and distribution infrastructure projects. These operational systems and infrastructure have been in service for many years. Equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Registrants' control, and could require significant expenditures to operate efficiently. The Registrants' respective results of operations, financial condition, or cash flows could be adversely affected if they were unable to effectively manage their capital projects or raise the necessary capital. Furthermore, operational failure of electric or gas systems or infrastructure could result in potential liability if such failure results in damage to property or injury to individuals. See ITEM 1. BUSINESS for further information regarding the Registrants' potential future capital expenditures.

The Utility Registrants' operating costs, and customers' and regulators' opinions of the Utility Registrants are affected by their ability to maintain the availability and reliability of their delivery and operational systems. (Exelon and the Utility Registrants)

Failures of the equipment or facilities, including information systems, used in the Utility Registrants' delivery systems could interrupt the electric transmission and electric and natural gas delivery, which could negatively impact related revenues, and increase maintenance and capital expenditures. Equipment or facilities failures can be due to a number of factors, including weather or information systems failure. Specifically, if the implementation of advanced metering infrastructure, smart grid or other technologies in the Utility Registrants' service territory fail to perform as intended or are not successfully integrated with billing and other information systems, the Utility Registrants' results of operations, cash flows or financial condition could be negatively impacted. Furthermore, if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, the Utility Registrants' financial results could be negatively impacted. If an employee causes the operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating the operational systems, the Utility Registrants' financial results could also be negatively impacted. In addition, dependence upon automated systems could further increase the risk that operational system flaws or employee tampering or manipulation of those systems will result in losses that are difficult to detect.

The aforementioned failures or those of other utilities, including prolonged or repeated failures, could affect customer satisfaction and the level of regulatory oversight and the Utility Registrants' maintenance and capital expenditures. Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd could be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, and those damages could be material to ComEd's results of operations or cash flows. See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding proceedings related to storm-related outages in ComEd's service territory.

The Utility Registrants' respective ability to deliver electricity, their operating costs and their capital expenditures could be negatively impacted by transmission congestion and failures of neighboring transmission systems. (All Registrants)

Demand for electricity within the Utility Registrants' service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage with consequent

effects on operating costs, revenues and results of operations. Also, insufficient availability of electric supply to meet customer demand could jeopardize the Utility Registrants' ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring the Utility Registrant's to upgrade or expand their respective transmission systems through additional capital expenditures.

The electricity transmission facilities of the Utility Registrants are interconnected with the transmission facilities of neighboring utilities and are part of the interstate power transmission grid that is operated by PJM RTO. Although PJM's systems and operations are designed to ensure the reliable operation of the transmission grid and prevent the operations of one utility from having an adverse impact on the operations of the other utilities, there can be no assurance that service interruptions at other utilities will not cause interruptions in the Utility Registrants' service areas. If the Utility Registrants were to suffer such a service interruption, it could have a negative impact on their and Exelon's results of operations, cash flows and financial position.

The Registrants are subject to physical security and cybersecurity risks. (All Registrants)

The Registrants face physical security and cybersecurity risks as the owner-operators of generation, transmission and distribution facilities and as participants in commodities trading. Threat sources continue to seek to exploit potential vulnerabilities in the electric and natural gas utility industry associated with protection of sensitive and confidential information, grid infrastructure and other energy infrastructures, and such attacks and disruptions, both physical and cyber, are becoming increasingly sophisticated and dynamic. Continued implementation of advanced digital technologies increase the potentially unfavorable impacts of such attacks. A security breach of the physical assets or information systems of the Registrants, their competitors, interconnected entities in RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject the Registrants to financial harm associated with theft or inappropriate release of certain types of information, including critical infrastructure information, sensitive customer, vendor and employee data, trading or other confidential data. The risk of these system-related events and security breaches occurring continues to intensify, and while we have been, and will likely continue to be, subjected to physical and cyber-attacks, to date we have not experienced a material breach or disruption to our network or information systems or our service operations. However, as such attacks continue to increase in sophistication and frequency, the Registrants may be unable to prevent all such attacks in the future. If a significant breach were to occur, the reputation of Exelon and its customer supply activities could be adversely affected, customer confidence in the Registrants or others in the industry could be diminished, or Exelon and its subsidiaries could be subject to legal claims, any of which could contribute to the loss of customers and have a negative impact on the business and/or results of operations. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result. The Utility Registrants' deployment of smart meters throughout their service territories could increase the risk of damage from an intentional disruption of the system by third parties. In addition, new or updated security regulations or unforeseen threat sources could require changes in current measures taken by the Registrants or their business operations and could adversely affect their results of operations, cash flows and financial position.

Failure to attract and retain an appropriately qualified workforce could negatively impact the Registrants' results of operations. (All Registrants)

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, could lead to operating challenges and

increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, could arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission and distribution operations. If the Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations could be negatively impacted.

The Registrants could make investments in new business initiatives, including initiatives mandated by regulators, and markets that may not be successful, and acquisitions could not achieve the intended financial results. (All Registrants)

Generation could continue to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain. This could include investment opportunities in renewables, development of natural gas generation, distributed generation, potential expansion of the existing wholesale gas businesses and entry into liquefied natural gas. Such initiatives could involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market. As these markets mature, there could be new market entrants or expansion by established competitors that increase competition for customers and resources. Additionally, it is possible that FERC, state public utility commissions or others could impose certain other restrictions on such transactions. All of these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment.

The Utility Registrants face risks associated with their regulatory-mandated Smart Grid initiatives. These risks include, but are not limited to, cost recovery, regulatory concerns, cybersecurity and obsolescence of technology. Due to these risks, no assurance can be given that such initiatives will be successful and will not have a material adverse effect on the Utility Registrants' financial results.

Risks Related to the PHI Merger

The merger may not achieve its anticipated results, and Exelon could be unable to integrate the operations of PHI in the manner expected. (Exelon)

Exelon and PHI entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and PHI can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Exelon's businesses, processes and systems or inconsistencies in standards, controls, procedures, practices and policies, any of which could adversely affect the combined company's ability to achieve the anticipated benefits of the merger as and when expected. Exelon could have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs and could adversely affect Exelon's future business, financial condition, operating results and prospects.

The merger may not be accretive to earnings and could cause dilution to Exelon's earnings per share, which could negatively affect the market price of Exelon's common stock. (Exelon)

The timing and amount of accretion expected could be significantly adversely affected by a number of uncertainties, including market conditions, risks related to Exelon's businesses and whether

the business of PHI is integrated in an efficient and effective manner. Exelon also could encounter additional transaction and integration-related costs, could fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates. Any of these factors could cause a decrease in Exelon's adjusted earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Exelon's common stock.

Exelon could incur unexpected transaction fees and merger-related costs in connection with the merger. (Exelon, PHI, Pepco, DPL and ACE)

Exelon is incurring costs to combine the operations of Exelon, PHI and its subsidiaries. Exelon and PHI could incur additional unanticipated costs in the integration of the businesses of the two companies. Although Exelon and PHI expect that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger-related costs over time, the combined company may not achieve this net benefit in the near term, or at all.

Exelon could encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the PHI Merger. (Exelon, PHI, Pepco, DPL and ACE)

As a result of the process to obtain regulatory approvals required for the PHI Merger, Exelon is committed to various programs, contributions and investments in several settlement agreements and regulatory approval orders, one of which may remain subject to the "most favored nation" reconciliation process. It is possible that Exelon could encounter delays, unexpected difficulties, or additional costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon's, PHI's, Pepco's, DPL's and ACE's financial position and operating results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

All Registrants

None.

ITEM 2. PROPERTIES

Generation

The following table describes Generation's interests in net electric generating capacity by station at December 31, 2016:

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,383
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,347
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,320
Dresden	Midwest	Morris, IL	2		Uranium	Base-load	1,845
Quad Cities	Midwest	Cordova, IL	2	75	Uranium	Base-load	1,403[f]
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,069
Michigan Wind 2	Midwest	Sanilac Co., MI	50		Wind	Base-load	90
Beebe	Midwest	Gratiot Co., MI	34		Wind	Base-load	82
Michigan Wind 1	Midwest	Huron Co., MI	46		Wind	Base-load	69
Harvest 2	Midwest	Huron Co., MI	33		Wind	Base-load	59
Harvest	Midwest	Huron Co., MI	32		Wind	Base-load	53
Beebe 1B	Midwest	Gratiot Co., MI	21		Wind	Base-load	50
Ewington	Midwest	Jackson Co., MN	10	99	Wind	Base-load	20[f]
Marshall	Midwest	Lyon Co., MN	9	99	Wind	Base-load	19[f]
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	9
AgriWind	Midwest	Bureau Co., IL	4	99	Wind	Base-load	8[f]
Cisco	Midwest	Jackson Co., MN	4	99	Wind	Base-load	8[f]
CP Windfarm	Midwest	Faribault Co., MN	2		Wind	Base-load	4
Blue Breezes	Midwest	Faribault Co., MN	2		Wind	Base-load	3
Solar Ohio	Midwest	Toledo, OH	3		Solar	Base-load	3
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296
Clinton Battery Storage	Midwest	Blanchester, OH	1		Energy Storage	Peaking	10
Total Midwest							12,150
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,317
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,301[f]
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,005[f]
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	879[f][g]
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837
Oyster Creek	Mid-Atlantic	Forked River, NJ	1		Uranium	Base-load	625[e]
Conowingo	Mid-Atlantic	Darlington, MD	11		Hydroelectric	Base-load	572
Criterion	Mid-Atlantic	Oakland, MD	28		Wind	Base-load	70
Fourmile	Mid-Atlantic	Garrett County, MD	16		Wind	Base-load	40
Fair Wind	Mid-Atlantic	Garrett County, MD	12		Wind	Base-load	30
Solar Maryland MC	Mid-Atlantic	Various, MD	16		Solar	Base-load	28
Solar New Jersey 1	Mid-Atlantic	Various, NJ	6		Solar	Base-load	18
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1		Solar	Base-load	16
Solar New Jersey 2	Mid-Atlantic	Various, NJ	2		Solar	Base-load	11
Solar Maryland	Mid-Atlantic	Various, MD	10		Solar	Base-load	9
Solar Maryland 2	Mid-Atlantic	Various, MD	3		Solar	Base-load	8
Solar Federal	Mid-Atlantic	Trenton, NJ	1		Solar	Base-load	5
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5		Solar	Base-load	2
Solar DC	Mid-Atlantic	District of Columbia	1		Solar	Base-load	1
Muddy Run	Mid-Atlantic	Drumore, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Mid-Atlantic	Eddystone, PA	2		Oil/Gas	Intermediate	760
Perryman	Mid-Atlantic	Aberdeen, MD	5		Oil/Gas	Peaking	412
Croydon	Mid-Atlantic	West Bristol, PA	8		Oil	Peaking	391
Handsome Lake	Mid-Atlantic	Kennerdell, PA	5		Gas	Peaking	268
Notch Cliff	Mid-Atlantic	Baltimore, MD	8		Gas	Peaking	117
Westport	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	116
Richmond	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	98
Gould Street	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	97

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Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Philadelphia Road	Mid-Atlantic	Baltimore, MD	4		Oil	Peaking	61
Eddystone	Mid-Atlantic	Eddystone, PA	4		Oil	Peaking	60
Fairless Hills	Mid-Atlantic	Fairless Hills, PA	2		Landfill Gas	Peaking	60
Delaware	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	52
Falls	Mid-Atlantic	Morrisville, PA	3		Oil	Peaking	51
Moser	Mid-Atlantic	Lower PottsgroveTwp., PA	3		Oil	Peaking	51
Riverside	Mid-Atlantic	Baltimore, MD	2		Oil/Gas	Peaking	39
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39
Schuylkill	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	30
Salem	Mid-Atlantic	Lower Alloways Creek Twp, NJ	1	42.59	Oil	Peaking	16[f]
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	6
Total Mid-Atlantic							11,624
Whitetail	ERCOT	Webb County, TX	57		Wind	Base-load	91
Sendero	ERCOT	Jim Hogg and Zapata County, TX	39		Wind	Base-load	78
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3		Gas	Intermediate	705
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	568
Colorado Bend	ERCOT	Wharton, TX	6		Gas	Intermediate	468
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870
Mountain Creek 6, 7	ERCOT	Dallas, TX	2		Gas	Peaking	240
LaPorte	ERCOT	Laporte, TX	4		Gas	Peaking	152
Total ERCOT							3,567
Solar Massachusetts	New England	Various, MA	11		Solar	Base-load	5
Holyoke Solar	New England	Various, MA	2		Solar	Base-load	5
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2
Solar Connecticut	New England	Various, CT	3		Solar	Base-load	2
Mystic 8, 9	New England	Charlestown, MA	6		Gas	Intermediate	1,415
Mystic 7	New England	Charlestown, MA	1		Oil/Gas	Intermediate	575
Wyman	New England	Yarmouth, ME	1	5.9	Oil	Intermediate	36[f]
West Medway	New England	West Medway, MA	3		Oil/Gas	Peaking	124
Framingham	New England	Framingham, MA	3		Oil	Peaking	31
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9
Total New England							2,204
Nine Mile Point	New York	Scriba, NY	2	50.01	Uranium	Base-load	838[f][g]
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288[f][g]
Solar New York	New York	Bethlehem, NY	1		Solar	Base-load	3
Total New York							1,129
AVSR	Other	Lancaster, CA	1		Solar	Base-load	242
Shooting Star	Other	Kiowa County, KS	65		Wind	Base-load	104
Exelon Wind 4	Other	Gruver, TX	38		Wind	Base-load	80
Bluestem	Other	Beaver County, OK	60	29	Wind	Base-load	57
Bluegrass Ridge	Other	King City, MO	27		Wind	Base-load	57
Conception	Other	Barnard, MO	24		Wind	Base-load	50
Cow Branch	Other	Rock Port, MO	24		Wind	Base-load	50
Solar Arizona	Other	Various, AZ	127		Solar	Base-load	46
Mountain Home	Other	Glenns Ferry, ID	20		Wind	Base-load	42
High Mesa	Other	Elmore Co., ID	19		Wind	Base-load	40
Echo 1	Other	Echo, OR	21	99	Wind	Base-load	34[f]
Sacramento PV Energy	Other	Sacramento, CA	4		Solar	Base-load	30
Cassia	Other	Buhl, ID	14		Wind	Base-load	29
Wildcat	Other	Lovington, NM	13		Wind	Base-load	27
Sunnyside	Other	Sunnyside, UT	1	50	Waste Coal	Base-load	26[f][h]
Solar Arizona 2	Other	Various, AZ	25		Solar	Base-load	23

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
California PV Energy	Other	Various, CA	53		Solar	Base-load	21
Echo 2	Other	Echo, OR	10		Wind	Base-load	20
Tuana Springs	Other	Hagerman, ID	8		Wind	Base-load	17
Greensburg	Other	Greensburg, KS	10		Wind	Base-load	13
Echo 3	Other	Echo, OR	6	99	Wind	Base-load	10[f]
Exelon Wind 1	Other	Gruver, TX	8		Wind	Base-load	10[i]
Exelon Wind 2	Other	Gruver, TX	8		Wind	Base-load	10[i]
Exelon Wind 3	Other	Gruver, TX	8		Wind	Base-load	10[i]
Exelon Wind 5	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 6	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 7	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 8	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 9	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 10	Other	Dumas, TX	8		Wind	Base-load	10
Exelon Wind 11	Other	Dumas, TX	8		Wind	Base-load	10
High Plains	Other	Panhandle, TX	8	99.5	Wind	Base-load	10[f]
Three Mile Canyon	Other	Boardman, OR	6		Wind	Base-load	10
California PV Energy 2	Other	Various, CA	31		Solar	Base-load	9
Solar Georgia	Other	Various, GA	10		Solar	Base-load	8
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	6
Loess Hills	Other	Rock Port, MO	4		Wind	Base-load	5
Mohave Sunrise Solar	Other	Fort Mohave, AZ	1		Solar	Base-load	5
Denver Airport Solar	Other	Denver, CO	1		Solar	Base-load	4
Solar California	Other	Various, CA	4		Solar	Base-load	3
Solar Georgia 2	Other	Various, GA	1		Solar	Base-load	1
Hillabee	Other	Alexander City, AL	3		Gas	Intermediate	753
Grande Prairie	Other	Alberta, Canada	1		Gas	Peaking	105
SEGS 4, 5, 6	Other	Boron, CA	3	4.2-12.2	Solar	Peaking	9[f]
Total Other							2,046
Total							32,720

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, Salem and Three Mile Island, which are pressurized water reactors.
(b) 100%, unless otherwise indicated.
(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations reflect a summer rating. Wind and solar facilities reflect name plate capacity.
(e) Generation has agreed to permanently cease generation operation at Oyster Creek by November 30, 2019.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Reflects Generation's 50.01% interest in CENG, a joint venture with EDF. For Nine Mile Point, the co-owner owns 18% of Unit 2. Thus Exelon's ownership is 50.01% of 82% of Nine Mile Point Unit 2.
(h) Generation sold its 50% interest in Sunnyside effective February 3, 2017
(i) Generation plans to retire and cease generation operations at the Exelon Wind 1, Exelon Wind 2 and Exelon Wind 3 units effective June 1, 2017.

The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies or generating units being temporarily out of service for inspection, maintenance, refueling, repairs or modifications required by regulatory authorities.

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see ITEM 1. BUSINESS—Exelon Generation Company, LLC. For its insured losses, Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on Generation's consolidated financial condition or results of operations.

ComEd

ComEd's electric substations and a portion of its transmission rights of way are located on property that ComEd owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ComEd believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements, licenses and franchise rights; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ComEd's higher voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,658
138,000	2,208

ComEd's electric distribution system includes 35,397 circuit miles of overhead lines and 31,049 circuit miles of underground lines.

First Mortgage and Insurance

The principal properties of ComEd are subject to the lien of ComEd's Mortgage dated July 1, 1923, as amended and supplemented, under which ComEd's First Mortgage Bonds are issued.

ComEd maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ComEd is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ComEd.

PECO

PECO's electric substations and a significant portion of its transmission lines are located on property that PECO owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. PECO believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

PECO's high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188 (a)
230,000	549
138,000	156
69,000	200

(a) In addition, PECO has a 22.00% ownership interest in 127 miles of 500 kV lines located in Pennsylvania and a 42.55% ownership interest in 131 miles of 500 kV lines located in Delaware and New Jersey.

PECO's electric distribution system includes 12,963 circuit miles of overhead lines and 9,290 circuit miles of underground lines.

Gas

The following table sets forth PECO's natural gas pipeline miles at December 31, 2016:

	Pipeline Miles
Transmission	30
Distribution	6,871
Service piping	6,273
Total	13,174

PECO has an LNG facility located in West Conshohocken, Pennsylvania that has a storage capacity of 1,200 mmcf and a send-out capacity of 157 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 150 mmcf and a peaking capability of 25 mmcf/day. In addition, PECO owns 31 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

The principal properties of PECO are subject to the lien of PECO's Mortgage dated May 1, 1923, as amended and supplemented, under which PECO's first and refunding mortgage bonds are issued.

PECO maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, PECO is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of PECO.

BGE

BGE's electric substations and a significant portion of its transmission lines are located on property that BGE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. BGE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

BGE's high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	218
230,000	331
138,000	55
115,000	709

BGE's electric distribution system includes 9,443 circuit miles of overhead lines and 17,306 circuit miles of underground lines.

Gas

The following table sets forth BGE's natural gas pipeline miles at December 31, 2016:

	Pipeline Miles
Transmission	161
Distribution	7,239
Service piping	6,230
Total	13,630

BGE has an LNG facility located in Baltimore, Maryland that has a storage capacity of 1,056 mmcf and a send-out capacity of 332 mmcf/day and a propane-air plant located in Baltimore, Maryland, with a storage capacity of 550 mmcf and a send-out capacity of 85 mmcf/day. In addition, BGE owns 12 natural gas city gate stations and 20 direct pipeline customer delivery points at various locations throughout its gas service territory.

Property Insurance

BGE owns its principal headquarters building located in downtown Baltimore. BGE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, BGE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of BGE.

Pepco

Pepco's electric substations and a significant portion of its transmission lines are located on property that Pepco owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. Pepco believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

Pepco's high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	142
230,000	774
138,000	60
115,000	38

Pepco's electric distribution system includes approximately 4,100 circuit miles of overhead lines and 6,800 circuit miles of underground lines. Pepco also operates a distribution system control center in Bethesda, Maryland. The computer equipment and systems contained in Pepco's control center are financed through a sale and leaseback transaction.

First Mortgage and Insurance

The principal properties of Pepco are subject to the lien of Pepco's mortgage dated July 1, 1935, as amended and supplemented, under which Pepco First Mortgage Bonds are issued.

Pepco maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, Pepco is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of Pepco.

DPL

DPL's electric substations and a significant portion of its transmission lines are located on property that DPL owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. DPL believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

DPL's high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	16
230,000	470
138,000	557
69,000	576

DPL's electric distribution system includes approximately 6,100 circuit miles of overhead lines and 6,100 circuit miles of underground lines. DPL also owns and operates a distribution system control center in New Castle, Delaware.

Gas

The following table sets forth DPL's natural gas pipeline miles at December 31, 2016 :

	Pipeline Miles
Transmission (a)	7
Distribution	2,036
Service Piping	1,385
Total	3,428

(a) DPL has a 10% undivided interest in approximately 7 miles of natural gas transmission mains located in Delaware which are used by DPL for its natural gas operations and by 90% owner for distribution of natural gas to its electric generating facilities.

DPL owns a liquefied natural gas facility located in Wilmington, Delaware, with a storage capacity of approximately 3,045 mmcf and an emergency sendout capability of 36,000 Mcf per day. DPL owns 4 natural gas city gate stations at various locations in New Castle County, Delaware. These stations have a total primary delivery point contractual entitlement of 158,485 Mcf per day.

First Mortgage and Insurance

The principal properties of PDL are subject to the lien of DPL's mortgage dated October 1, 1947, as amended and supplemented, under which DPL First Mortgage Bonds are issued.

DPL maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, DPL is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of DPL.

ACE

ACE's electric substations and a significant portion of its transmission lines are located on property that ACE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ACE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ACE's high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	281
230,000	234
138,000	268
69,000	652

ACE's electric distribution system includes approximately 7,400 circuit miles of overhead lines and 2,900 circuit miles of underground lines. ACE also owns and operates a distribution system control center in Mays Landing, New Jersey.

First Mortgage and Insurance

The principal properties of ACE are subject to the lien of ACE's mortgage dated January 15, 1937, as amended and supplemented, under which ACE First Mortgage Bonds are issued.

ACE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ACE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ACE.

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long-term design changes and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country's energy systems.

ITEM 3. LEGAL PROCEEDINGS

All Registrants

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Note 3—Regulatory Matters and Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

All Registrants

Not Applicable to the Registrants.

PART II

(Dollars in millions except per share data, unless otherwise noted)

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Exelon

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2017, there were 926,589,614 shares of common stock outstanding and approximately 113,308 record holders of common stock.

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2016				2015			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 36.36	$ 37.70	$ 36.37	$ 35.95	$ 31.37	$ 34.44	$ 34.98	$ 38.25
Low price	29.82	32.86	33.18	26.26	25.09	28.41	31.28	31.71
Close	35.49	33.29	36.36	35.86	27.77	29.70	31.42	33.61
Dividends	0.318	0.318	0.318	0.310	0.310	0.310	0.310	0.310

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index, for the period 2012 through 2016.

This performance chart assumes:

- $100 invested on December 31, 2011 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.

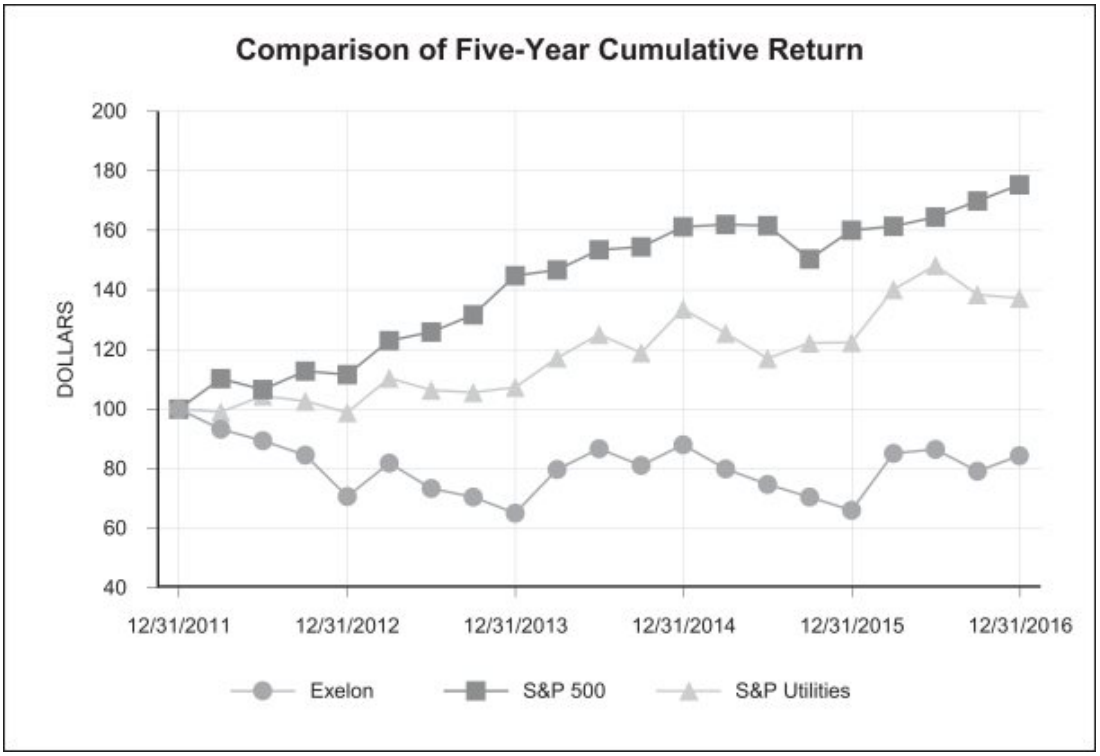

	Value of Investment at December 31,					
	2011	2012	2013	2014	2015	2016
Exelon Corporation	$100	$70.69	$65.11	$88.14	$66.01	$84.36
S&P 500	$100	$111.68	$144.74	$161.22	$160.05	$175.31
S&P Utilities	$100	$98.78	$107.43	$133.52	$122.32	$137.24

Generation

As of January 31, 2017, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2017, there were 127,017,157 outstanding shares of common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. At January 31, 2017, in

addition to Exelon, there were 299 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2017, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2017, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

PHI

As of January 31, 2017, Exelon indirectly held the entire membership interest in PHI.

Pepco

As of January 31, 2017, there were 100 outstanding shares of common stock, $0.01 par value, of Pepco, all of which were indirectly held by Exelon.

DPL

As of January 31, 2017, there were 1,000 outstanding shares of common stock, $2.25 par value, of DPL, all of which were indirectly held by Exelon.

ACE

As of January 31, 2017, there were 8,546,017 outstanding shares of common stock, $3.00 par value, of ACE, all of which were indirectly held by Exelon.

All Registrants

Dividends

Under applicable Federal law, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO, BGE, PHI, Pepco, DPL or ACE may limit the dividends that these companies can distribute to Exelon.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility “to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account.” What constitutes “funds properly included in capital account” is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon’s actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, “[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves,” or unless it has specific authorization from the ICC. ComEd has also agreed in connection with a financing arranged through ComEd Financing III that ComEd will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend

the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to certain dividend restrictions established by the MDPSC. First, in connection with the Constellation merger, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid and notify the MDPSC that BGE's equity ratio is at least 48% within five business days after dividend payment. There are no other limitations on BGE paying common stock dividends unless BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid.

Pepco is subject to certain dividend restrictions limits imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends, and (ii) the prior rights of holders of future preferred stock, if any, and existing and future mortgage bonds and other long-term debt issued by Pepco and any other restrictions imposed in connection with the incurrence of liabilities.

DPL is subject to certain dividend restrictions imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends, and (ii) the prior rights of holders of existing and future preferred stock, mortgage bonds and other long-term debt issued by DPL and any other restrictions imposed in connection with the incurrence of liabilities.

ACE is subject to dividend restrictions imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends and the regulatory requirement that ACE obtain the prior approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%; (ii) the prior rights of holders of existing and future preferred stock, mortgage bonds and other long-term debt issued by ACE and any other restrictions imposed in connection with the incurrence of liabilities; and (iii) certain provisions of the charter of ACE which impose restrictions on payment of common stock dividends for the benefit of preferred stockholders. Currently, the restriction in the ACE charter does not limit its ability to pay common stock dividends.

Exelon's Board of Directors has approved a dividend policy providing a raise of 2.5% each year for three years, beginning with the June 2016 dividend.

At December 31, 2016, Exelon had retained earnings of $12,030 million, including Generation's undistributed earnings of $2,275 million, ComEd's retained earnings of $987 million consisting of retained earnings appropriated for future dividends of $2,626 million, partially offset by $(1,639) million of unappropriated accumulated deficits, PECO's retained earnings of $941 million, BGE's retained earnings of $1,427 million, and PHI's undistributed earnings of $(61) million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2016 and 2015:

	2016				2015			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$ 0.318	$ 0.318	$ 0.318	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310

The following table sets forth Generation's and PHI's quarterly distributions and ComEd's, PECO's, Pepco's, DPL's and ACE's quarterly common dividend payments:

	2016				2015			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 755	$ 56	$ 56	$ 55	$ 106	$ 106	$ 906	$ 1,356
ComEd	94	92	92	91	73	76	75	75
PECO	69	69	70	69	70	70	69	70
BGE	45	44	45	45	42	39	41	36
PHI	99	50	16	108	69	69	69	68
Pepco	44	37	16	39	55	60	31	—
DPL	15	1	—	38	12	18	—	62
ACE	39	13	—	11	—	—	—	12

First Quarter 2017 Dividend. On January 31, 2017, the Exelon Board of Directors declared a first quarter 2017 regular quarterly dividend of $0.3275 per share on Exelon's common stock payable on March 10, 2017, to shareholders of record of Exelon at the end of the day on February 15, 2017.

ITEM 6. SELECTED FINANCIAL DATA

Exelon

The selected financial data presented below has been derived from the audited consolidated financial statements of Exelon. This data is qualified in its entirety by reference to and should be read in conjunction with Exelon's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions, except per share data)	2016 [a]	2015	2014 [b]	2013	2012 [c]
Statement of Operations data:					
Operating revenues	$31,360	$29,447	$27,429	$24,888	$23,489
Operating income	3,112	4,409	3,096	3,669	2,373
Net income	1,204	2,250	1,820	1,729	1,171
Net income attributable to common shareholders	1,134	2,269	1,623	1,719	1,160
Earnings per average common share (diluted):					
Net income	$ 1.22	$ 2.54	$ 1.88	$ 2.00	$ 1.42
Dividends per common share	$ 1.26	$ 1.24	$ 1.24	$ 1.46	$ 2.10

(a) The 2016 financial results include the activity of PHI from the merger effective date of March 24, 2016 through December 31, 2016.
(b) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis.
(c) The 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

	December 31,				
(In millions)	2016	2015	2014	2013	2012
Balance Sheet data:					
Current assets	$ 12,412	$15,334	$11,853	$ 9,562	$10,009
Property, plant and equipment, net	71,555	57,439	52,170	47,330	45,186
Total assets	114,904	95,384	86,416	79,243	78,350
Current liabilities	13,457	9,118	8,762	7,686	7,734
Long-term debt, including long-term debt to financing trusts	32,216	24,286	19,853	18,165	18,266
Preferred securities of subsidiary	—	—	—	—	87
Shareholders' equity	25,837	25,793	22,608	22,732	21,431

Generation

The selected financial data presented below has been derived from the audited consolidated financial statements of Generation. This data is qualified in its entirety by reference to and should be read in conjunction with Generation's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions)	2016	2015	2014 [a]	2013	2012 [b]
Statement of Operations data:					
Operating revenues	$17,751	$19,135	$17,393	$15,630	$14,437
Operating income	836	2,275	1,176	1,677	1,113
Net income	558	1,340	1,019	1,060	558

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis.
(b) The 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

(In millions)	December 31, 2016	2015	2014	2013	2012
Balance Sheet data:					
Current assets	$ 6,528	$ 6,342	$ 7,311	$ 5,964	$ 6,211
Property, plant and equipment, net	25,585	25,843	23,028	20,111	19,531
Total assets	46,974	46,529	44,951	40,700	40,648
Current liabilities	5,683	4,933	4,459	3,842	3,969
Long-term debt, including long-term debt to affiliate	8,124	8,869	7,582	7,111	7,422
Member's equity	11,482	11,635	12,718	12,725	12,557

ComEd

The selected financial data presented below has been derived from the audited consolidated financial statements of ComEd. This data is qualified in its entirety by reference to and should be read in conjunction with ComEd's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	For the Years Ended December 31, 2016	2015	2014	2013	2012
Statement of Operations data:					
Operating revenues	$5,254	$4,905	$4,564	$4,464	$5,443
Operating income	1,205	1,017	980	954	886
Net income	378	426	408	249	379

(In millions)	December 31, 2016	2015	2014	2013	2012
Balance Sheet data:					
Current assets	$ 1,554	$ 1,518	$ 1,723	$ 1,540	$ 1,692
Property, plant and equipment, net	19,335	17,502	15,793	14,666	13,826
Total assets	28,335	26,532	25,358	24,089	22,793
Current liabilities	2,938	2,766	1,923	2,032	1,655
Long-term debt, including long-term debt to financing trusts	6,813	6,049	5,870	5,235	5,492
Shareholders' equity	8,725	8,243	7,907	7,528	7,323

PECO

The selected financial data presented below has been derived from the audited consolidated financial statements of PECO. This data is qualified in its entirety by reference to and should be read in conjunction with PECO's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	For the Years Ended December 31, 2016	2015	2014	2013	2012
Statement of Operations data:					
Operating revenues	$2,994	$3,032	$3,094	$3,100	$3,186
Operating income	702	630	572	666	623
Net income	438	378	352	395	381

(In millions)	December 31, 2016	2015	2014	2013	2012
Balance Sheet data:					
Current assets	$ 757	$ 842	$ 645	$ 821	$1,054
Property, plant and equipment, net	7,565	7,141	6,801	6,384	6,078
Total assets	10,831	10,367	9,860	9,521	9,303
Current liabilities	727	944	653	889	1,158
Long-term debt, including long-term debt to financing trusts	2,764	2,464	2,416	2,120	1,821
Preferred securities	—	—	—	—	87
Shareholders' equity	3,415	3,236	3,121	3,065	2,982

BGE

The selected financial data presented below has been derived from the audited consolidated financial statements of BGE. This data is qualified in its entirety by reference to and should be read in conjunction with BGE's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	For the Years Ended December 31, 2016	2015	2014	2013	2012
Statement of Operations data:					
Operating revenues	$3,233	$3,135	$3,165	$3,065	$2,735
Operating income	550	558	439	449	132
Net income	294	288	211	210	4

(In millions)	December 31, 2016	2015	2014	2013	2012
Balance Sheet data:					
Current assets	$ 842	$ 845	$ 951	$1,009	$ 979
Property, plant and equipment, net	7,040	6,597	6,204	5,864	5,498
Total assets	8,704	8,295	8,056	7,839	7,485
Current liabilities	707	1,134	794	800	980
Long-term debt, including long-term debt to financing trusts and variable interest entities	2,533	1,732	2,109	2,179	1,949
Shareholders' equity	2,848	2,687	2,563	2,365	2,168

PHI

The selected financial data presented below has been derived from the audited consolidated financial statements of PHI. This data is qualified in its entirety by reference to and should be read in conjunction with PHI's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	Successor	*Predecessor*		
			For the Years Ended December 31,	
(In millions)	March 24 - December 31 2016	January 1 - March 23 2016	2015	2014
Statement of Operations data [a] :				
Operating revenues	$ 3,643	$ 1,153	$ 4,935	$ 4,808
Operating income	93	105	673	605
Net (loss) income from continuing operations	(61)	19	318	242
Net (loss) income	(61)	19	327	242

(In millions)	Successor December 31, 2016	Predecessor December 31, 2015
Balance Sheet data (a) :		
Current assets	$ 1,838	$ 1,474
Property, plant and equipment, net	11,598	10,864
Total assets	21,025	16,188
Current liabilities	2,284	2,327
Long-term debt	5,645	4,823
Preferred Stock	—	183
Member's equity/Shareholders' equity	8,016	4,413

(a) As a result of the PHI Merger in 2016, Exelon has elected to present PHI's selected financial data for the periods reflected above.

Pepco

The selected financial data presented below has been derived from the audited consolidated financial statements of Pepco. This data is qualified in its entirety by reference to and should be read in conjunction with Pepco's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	For the Years Ended December 31, 2016	2015	2014
Statement of Operations data (a) :			
Operating revenues	$ 2,186	$ 2,129	$ 2,055
Operating income	174	385	349
Net (loss) income	42	187	171

(In millions)	December 31, 2016	2015
Balance Sheet data (a) :		
Current assets	$ 684	$ 726
Property, plant and equipment, net	5,571	5,162
Total assets	7,335	6,908
Current liabilities	596	455
Long-term debt	2,333	2,340
Shareholders' equity	2,300	2,240

(a) As a result of the PHI Merger in 2016, Exelon has elected to present Pepco's selected financial data for the periods reflected above.

DPL

The selected financial data presented below has been derived from the audited consolidated financial statements of DPL. This data is qualified in its entirety by reference to and should be read in conjunction with DPL's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	For the Years Ended December 31, 2016	2015	2014
Statement of Operations data (a) :			
Operating revenues	$ 1,277	$ 1,302	$ 1,282
Operating income	50	165	207
Net (loss) income	(9)	76	104

(In millions)	December 31, 2016	2015
Balance Sheet data [a] :		
Current assets	$ 370	$ 388
Property, plant and equipment, net	3,273	3,070
Total assets	4,153	3,969
Current liabilities	381	564
Long-term debt	1,221	1,061
Shareholders' equity	1,326	1,237

(a) As a result of the PHI Merger in 2016, Exelon has elected to present DPL's selected financial data for the periods reflected above.

ACE

The selected financial data presented below has been derived from the audited consolidated financial statements of ACE. This data is qualified in its entirety by reference to and should be read in conjunction with ACE's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	For the Years Ended December 31, 2016	2015	2014
Statement of Operations data [a] :			
Operating revenues	$ 1,257	$ 1,295	$ 1,210
Operating income	7	134	137
Net (loss) income	(42)	40	46

(In millions)	December 31, 2016	2015
Balance Sheet data [a] :		
Current assets	$ 399	$ 546
Property, plant and equipment, net	2,521	2,322
Total assets	3,457	3,387
Current liabilities	320	297
Long-term debt	1,120	1,153
Shareholders' equity	1,034	1,000

(a) As a result of the PHI Merger in 2016, Exelon has elected to present ACE's selected financial data for the periods reflected above.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Exelon

Executive Overview

Exelon, a utility services holding company, operates through the following principal subsidiaries:

- *Generation,* whose integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in northern Illinois, including the City of Chicago.
- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE,* whose business consists of the purchase and regulated retail sale of electricity and natural gas and the provision of electricity distribution and transmission and gas distribution services in central Maryland, including the City of Baltimore.
- *Pepco,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission in the District of Columbia and major portions of Prince George's County and Montgomery County in Maryland.
- *DPL,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.
- *ACE,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in southern New Jersey.

Pepco, DPL and ACE are operating companies of PHI, which is a utility services holding company and a wholly owned subsidiary of Exelon.

Exelon has twelve reportable segments consisting of Generation's six reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions in Generation), ComEd, PECO, BGE and PHI's three utility reportable segments (Pepco, DPL and ACE). See Note 26—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

PHI Service Company, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHI Service Company and the participating operating subsidiaries.

Exelon's consolidated financial information includes the results of its eight separate operating subsidiary registrants, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Financial Results of Operations

GAAP Results of Operations

The following tables set forth Exelon's GAAP consolidated results of operations for the year ended December 31, 2016 compared to the same period in 2015. 2016 amounts include the operations of PHI, Pepco, DPL and ACE from March 24, 2016 through December 31, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	For the Years Ended December 31,								Favorable (Unfavorable) Variance
	2016							2015	
	Generation	ComEd	PECO	BGE	PHI [b]	Other	Exelon	Exelon	
Operating revenues	$ 17,751	$ 5,254	$ 2,994	$ 3,233	$ 3,643	$ (1,515)	$ 31,360	$ 29,447	$ 1,913
Purchased power and fuel expense	8,830	1,458	1,047	1,294	1,447	(1,436)	12,640	13,084	444
Revenue net of purchased power and fuel expense [a]	8,921	3,796	1,947	1,939	2,196	(79)	18,720	16,363	2,357
Other operating expenses									
Operating and maintenance	5,641	1,530	811	737	1,233	96	10,048	8,322	(1,726)
Depreciation and amortization	1,879	775	270	423	515	74	3,936	2,450	(1,486)
Taxes other than income	506	293	164	229	354	30	1,576	1,200	(376)
Total other operating expenses	8,026	2,598	1,245	1,389	2,102	200	15,560	11,972	(3,588)
Gain (Loss) on sales of assets	(59)	7	—	—	(1)	5	(48)	18	(66)
Operating income (loss)	836	1,205	702	550	93	(274)	3,112	4,409	(1,297)
Other income and (deductions)									
Interest expense, net	(364)	(461)	(123)	(103)	(195)	(290)	(1,536)	(1,033)	(503)
Other, net	401	(65)	8	21	44	4	413	(46)	459
Total other income and (deductions)	37	(526)	(115)	(82)	(151)	(286)	(1,123)	(1,079)	(44)
Income (loss) before income taxes	873	679	587	468	(58)	(560)	1,989	3,330	(1,341)
Income taxes	290	301	149	174	3	(156)	761	1,073	312
Equity in (losses) earnings of unconsolidated affiliates	(25)	—	—	—	—	1	(24)	(7)	(17)
Net income (loss)	558	378	438	294	(61)	(403)	1,204	2,250	(1,046)
Net income (loss) attributable to noncontrolling interests and preference stock dividends	62	—	—	8	—	—	70	(19)	89
Net income (loss) attributable to common shareholders	$ 496	$ 378	$ 438	$ 286	$ (61)	$ (403)	$ 1,134	$ 2,269	$ (1,135)

(a) The Registrants' evaluate operating performance using the measure of revenues net of purchased power and fuel expense. The Registrants' believe that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenues net of purchased power and fuel

expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b) As a result of the PHI Merger, PHI includes the consolidated results of PHI, Pepco, DPL and ACE from March 24, 2016 through December 31, 2016.

Exelon's net income attributable to common shareholders was $1,134 million for the year ended December 31, 2016 as compared to $2,269 million for the year ended December 31, 2015, and diluted earnings per average common share were $1.22 for the year ended December 31, 2016 as compared to $2.54 for the year ended December 31, 2015.

Operating revenues net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $2,357 million as compared to 2015. The year-over-year increase was primarily due to the following favorable factors:

- Increase of $2,196 million in revenue net of purchased power and fuel due to the inclusion of PHI's results for the period of March 24, 2016 to December 31, 2016;
- Increase of $210 million at ComEd primarily due to increased distribution and transmission formula rate revenue resulting from increased capital investment, as well as, favorable weather;
- Increase of $109 million at BGE primarily due to increased transmission revenue as a result of increased capital investments and operating and maintenance expense recoveries and increased distribution revenue pursuant to increased rates as a result of the distribution rate orders issued by the MDPSC in June 2016 and July 2016;
- Increase of $105 million at Generation primarily due to the impact of the Ginna Reliability Support Services Agreement and a decrease in nuclear outage days at higher capacity units despite an increase in overall outage days, partially offset by lower realized energy prices; and
- Increase of $105 million at PECO primarily due to increased electric distribution revenue pursuant to a rate increase effective January 1, 2016.

The year-over-year increase in operating revenues net of purchased power and fuel expense described above was partially offset by a decrease of $298 million at Generation due to mark-to-market losses of $41 million in 2016 from economic hedging activities as compared to gains of $257 million in 2015.

Operating and maintenance expense increased by $1,726 million as compared to 2015. The year-over-year increase was primarily due to the following unfavorable factors:

- Increase of $910 million, exclusive of merger commitment costs discussed above, due to the inclusion of PHI's results for the period March 24, 2016 to December 31, 2016;
- Approval of the merger across all regulatory jurisdictions was conditioned on Exelon and PHI agreeing to certain commitments pursuant to which, upon acquisition close, Exelon recorded $513 million of costs;
- Increase in Generation's labor, contracting and materials cost of $185 million related to the inclusion of Pepco Energy Services results in 2016 and increased contracting costs related to energy efficiency projects;
- Long-lived asset impairments of $171 million at Generation in 2016 compared to $10 million in 2015;
- Increase of $54 million at BGE primarily as a result of one-time charges associated with the reduction of regulatory assets and other long-lived assets stemming from certain cost disallowances contained within the distribution rate orders issued by the MDPSC in June and July 2016; and

- Increase of $28 million at Generation for the recognition of one-time charges associated with Generation's 2016 decision to early retire the Clinton and Quad Cities nuclear generating facilities.

The year-over-year increase in operating and maintenance expense was partially offset by the following favorable factors:

- Decrease of $79 million at Generation as a result of the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units in 2016 versus 2015;
- Decrease of $79 million at Generation as a result of a decrease in nuclear outage days in 2016, excluding Salem; and
- Decrease of $77 million in pension and non-pension post-retirement benefit costs resulting from the favorable impact of higher pension and OPEB discount rates in 2016.

Depreciation and amortization expense increased by $1,486 million primarily as a result of accelerated depreciation and amortization expense related to Generation's previous decision to early retire the Clinton and Quad Cities nuclear generating facilities, increased nuclear decommissioning amortization at Generation, increased depreciation expense due to ongoing capital expenditures across all operating companies and the inclusion of PHI's results for the period of March 24, 2016 to December 31, 2016.

Taxes other than income increased $376 million primarily due to increased property and utility taxes as a result of the inclusion of PHI's results for the period March 24, 2016 to December 31, 2016.

Gain (Loss) on sales of assets decreased $66 million primarily due to certain Generation projects and contracts being terminated or renegotiated in 2016, partially offset by a gain associated with Generation's sale of the retired New Boston generating site in 2016.

Interest expense, net increased by $503 million primarily due to the recognition of the interest due on the asserted penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position, higher outstanding debt to fund the PHI acquisition and general corporate purposes and the absence of the forward-starting interest rate swaps in 2016.

Other, net increased by $459 million primarily due to the change in realized and unrealized gains and losses on NDT funds at Generation, partially offset by the recognition of the penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position.

Exelon's effective income tax rates for the years ended December 31, 2016 and 2015 were 38.3% and 32.2%, respectively. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. Exelon recorded an after-tax charge of $98 million for the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state PHI, Pepco, DPL and ACE uncertain tax positions.

For further detail regarding the financial results for the years ended December 31, 2016 and 2015, including explanation of the non-GAAP measure revenues net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings

Exelon's adjusted (non-GAAP) operating earnings for the year ended December 31, 2016 were $2,488 million, or $2.68 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,227 million, or $2.49 per diluted share, for the same period in 2015. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2016 as compared to 2015:

	For the years ended December 31,			
	2016		2015	
(All amounts after tax; in millions, except per share amounts)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$1,134	$ 1.22	$2,269	$ 2.54
Mark-to-Market Impact of Economic Hedging Activities (a)	24	0.03	(158)	(0.18)
Unrealized (Gains) Losses Related to NDT Fund Investments (b)	(118)	(0.13)	115	0.13
Plant Retirements and Divestitures (c)	432	0.47	—	—
Asset Retirement Obligation (d)	(75)	(0.08)	(6)	(0.01)
Merger and Integration Costs (e)	114	0.12	58	0.07
Amortization of Commodity Contract Intangibles (f)	35	0.04	(5)	—
Reassessment of State Deferred Income Taxes (g)	10	0.01	41	0.05
Long-Lived Asset Impairments (h)	103	0.11	21	0.02
Tax Settlements (i)	—	—	(52)	(0.06)
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps (j)	—	—	(21)	(0.02)
PHI Merger Related Redeemable Debt Exchange (k)	—	—	13	0.01
Reduction in State Income Tax Reserve (l)	—	—	(10)	(0.01)
Midwest Generation Bankruptcy Recoveries (m)	—	—	(6)	(0.01)
Merger Commitments (n)	437	0.47	—	—
Curtailment of Generation Growth and Development Activities (o)	57	0.06	—	—
Cost Management Program (p)	34	0.04	—	—
Like-Kind Exchange Tax Position (q)	199	0.21	—	—
CENG Noncontrolling Interests (r)	102	0.11	(32)	(0.04)
Adjusted (non-GAAP) Operating Earnings	$2,488	$ 2.68	$2,227	$ 2.49

(a) Reflects the impact of (gains) losses for the years ended December 31, 2016 and 2015 (net of taxes of $18 million and $99 million, respectively) on Generation's economic hedging activities. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized (gains) losses for the years ended December 31, 2016 and 2015 (net of taxes of $112 million and $148 million, respectively) on Generation's NDT fund investments for Non-Regulatory Agreement Units.

See Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Primarily reflects incremental accelerated depreciation and amortization expenses from June 2, 2016 through December 6, 2016 and construction work in progress impairments pursuant to the second quarter decision to early retire the Clinton and Quad Cities nuclear generating facilities, which decision was reversed in December 2016 (net of taxes of $285 million), partially offset by a gain associated with Generation's 2016 sale of the New Boston generating site (net of taxes of $12 million).

(d) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the Non-Regulatory Agreement Units for the years ended December 31, 2016 and 2015 (net of taxes of $13 million and $4 million, respectively).

(e) Reflects certain costs associated with mergers and acquisitions incurred for the years ended December 31, 2016 and 2015 (net of taxes of $50 million and $38 million, respectively) including professional fees, employee-related expenses, integration activities and upfront credit facilities fees related to the PHI acquisition and pending Fitzpatrick acquisition, partially offset in 2016 at ComEd, BGE and PHI by the anticipated recovery of previously incurred PHI acquisition costs.

(f) Reflects the non-cash impact for the years ended December 31, 2016 and 2015 (net of taxes of $22 million and $3 million, respectively) of the amortization of commodity contracts recorded at fair value associated with prior acquisitions, if and when applicable.

(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment.

(h) Reflects impairment of upstream assets and certain wind projects in 2016 (net of taxes of $68 million) and the impairment of investment in long-term leases at Corporate in 2015 (net of taxes of $13 million).

(i) Reflects a benefit related to the favorable settlement in 2015 of certain income tax positions on Constellation's pre-acquisition tax returns.

(j) Reflects the impact of mark-to-market activity on forward-starting interest rate swaps held at Exelon Corporate related to financing for the PHI acquisition for the year ended December 31, 2015 (net of taxes of $14 million).

(k) Reflects the costs associated with the exchange and redemption in December 2015 of certain mandatorily redeemable debt issued to finance the PHI merger (net of taxes of $8 million in 2015).

(l) Reflects the reduction of a previously recorded state income tax reserve associated with the 2014 sales of Keystone and Conemaugh for the year ended December 31, 2015.

(m) Reflects a benefit for the favorable settlement of a long-term railcar lease agreement pursuant to the Midwest Generation bankruptcy for the year ended December 31, 2015 (net of taxes of $4 million).

(n) Represents adjustments to costs incurred as part of the settlement orders approving the PHI acquisition and a charge related to a 2012 CEG merger commitment for the year ended December 31, 2016 (net of taxes of $126 million).

(o) Reflects the one-time recognition for a loss on sale of assets and asset impairment charges pursuant to Generation's strategic decision to narrow the scope and scale of its growth and development activities for the year ended December 31, 2016 (net of taxes of $35 million).

(p) Represents 2016 severance expense and reorganization costs related to a cost management program (net of taxes of $21 million).

(q) Represents the recognition of a penalty and associated interest expense in the third quarter of 2016, as a result of a tax court decision on Exelon's like-kind exchange tax position (net of taxes of $61 million).

(r) Represents elimination from Generation's results of the noncontrolling interests related to CENG exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments and changes in asset retirement obligations in 2016, and in 2015 the impact of unrealized gains and losses on NDT fund investments and mark-to-market activity.

Merger and Acquisition Costs

On March 23, 2016, the Exelon and PHI Merger was completed. On the merger date, PHI shareholders received $27.25 of cash in exchange for each share of PHI common stock. The resulting company retained the Exelon name and is headquartered in Chicago.

As a result of the PHI Merger, Exelon has incurred costs associated with evaluating, structuring and executing the PHI Merger transaction itself, and will continue to incur cost associated with meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former PHI businesses into Exelon.

The table below presents the one-time pre-tax charges recognized for the PHI Merger included in the Registrant's respective Consolidated Statements of Operations and Comprehensive Income.

	For the Year Ended December 31, 2016					Successor March 24, 2016 to December 31, 2016
	Exelon	Generation	Pepco	DPL	ACE	PHI
Merger commitments	$ 513	$ 3	$ 126	$ 86	$111	$ 323
Changes in accounting and tax related policies and estimates	—	—	25	15	5	—
Total	$ 513	$ 3	$ 151	$101	$116	$ 323

In addition to the one-time PHI Merger charges discussed above, for the years ended December 31, 2016 and 2015, expense has been recognized for the PHI Merger, Constellation acquisition and the pending FitzPatrick acquisition as follows:

	Pre-tax Expense For the Year Ended December 31, 2016								
Merger Integration and Acquisition Expense:	Exelon (a)	Generation (a)	ComEd	PECO	BGE	PHI (a)	Pepco (a)	DPL (a)	ACE (a)
Transaction (c)	34	2	—	—	—	—	—	—	—
Employee-related (d)	77	10	2	1	1	64	30	18	15
Other (e)	52	44	(8)	4	(2)	5	(2)	2	4
Total	$ 163	$ 56	$ (6)	$ 5	$ (1)	$ 69	$ 28	$ 20	$ 19

	Pre-tax Expense For the Year Ended December 31, 2015				
Merger Integration and Acquisition Expense:	Exelon	Generation	ComEd	PECO	BGE
Financing (b)	$ 21	$ —	$ —	$ —	$—
Transaction (c)	23	—	—	—	—
Other (e)	51	32	9	4	5
Total	$ 95	$ 32	$ 9	$ 4	$ 5

(a) For Exelon, Generation, PHI, Pepco, DPL, and ACE, includes the operations of the acquired businesses beginning on March 24, 2016.
(b) Reflects costs incurred at Exelon related to the financing of the PHI Merger, including upfront credit facility fees and mark-to-market activity on forward-starting interest rate swaps and costs associated with the exchange and redemption of mandatorily redeemable debt.
(c) External, third party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of transactions.
(d) Costs primarily for employee severance, pension and OPEB expense and retention bonuses.
(e) For the year ended December 31, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million, $6 million, $11 million, $4 million and $16 million incurred at ComEd, BGE, Pepco, DPL and PHI, respectively, that has been deferred and recorded as a regulatory asset for anticipated recovery. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for more information. For the year ended December 31, 2015, includes costs to integrate CENG, Constellation and Integrys systems into Exelon and terminate certain Constellation debt agreements. Also includes professional fees primarily related to integration for the PHI acquisition.

As of December 31, 2016, Exelon expects to incur total PHI acquisition and integration related costs of approximately $700 million, excluding merger commitments. Of this amount, including costs incurred from 2014 through December 31, 2016, Exelon and PHI have incurred approximately $610 million. Included in this amount are costs to fund the merger of which $76 million has been

expensed, $56 million has been paid and recorded as deferred debt issuance costs and $60 million has been incurred and charged to common stock. The remaining costs will be primarily within Operating and maintenance expense within Exelon's Consolidated Statements of Operations and Comprehensive Income and will also include approximately $30 million for integration costs expected to be capitalized to Property, plant and equipment.

Significant 2016 Transactions and Developments

PHI Acquisition

On March 23, 2016, Exelon completed its acquisition of PHI for a total cash purchase price of $7.1 billion, significantly expanding its regulated utility business and resulting in a total of over 10 million utility customers. In accounting for the acquisition as a business combination, Exelon and PHI recorded $4.0 billion in goodwill. Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments including customer rate credits, funding for energy efficiency and delivery system modernization programs, and other various requirements, for which Exelon recorded $513 million of Operating and maintenance expense for the year ended December 31, 2016. The Registrants have also incurred costs for evaluating, structuring and executing the transaction, as well as integrating the former PHI businesses into Exelon. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information regarding the PHI acquisition and related costs.

Illinois Future Energy Jobs Act

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA is effective June 1, 2017, and includes, among other provisions, (1) a ZES providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd's electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd's customer rates exceeds specified limits, (6) revisions to the existing net metering statute to (i) mandate net metering for community generation projects, and establish billing procedures for subscribers to those projects, (ii) provide immediately for netting at the energy-only rate for nonresidential customers, and (iii) transition from netting at the full retail rate to the energy-only rate for certain residential net metering customers once the net meter customer load equals 5% of total peak demand supplied in the previous year and (7) support for low income rooftop and community solar programs. FEJA establishes new or adjusts existing rate recovery mechanisms for ComEd to recover costs associated with the new or expanded energy efficiency and RPS requirements. Regulatory or legal challenges over the validity of FEJA are possible. See Note 3—Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information regarding FEJA. See Note 9—Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for the impacts of ZES on Generation's Consolidated Balance Sheets and Consolidated Statements of Operations and Comprehensive Income.

New York Clean Energy Standard

On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the CES, a component of a Tier 3 ZEC program targeted at preserving the environmental attributes of qualifying zero-emissions nuclear-powered generating facilities, including CENG's Ginna, and Nine Mile Point and Entergy Nuclear Fitzpatrick LLC's (Entergy) 838 MW single unit James A. FitzPatrick facilities. On November 18, 2016, required contracts with the New York State Energy Research and Development Authority (NYSERDA) were executed for each of these three plants.

Regulatory and legal challenges over the validity the New York CES have been made, the outcomes of which remain uncertain. Also in August 2016, Generation executed a series of agreements with Entergy to acquire the Fitzpatrick nuclear generating station, subject to various regulatory approvals. The transaction is anticipated to close in the first or second quarter of 2017. See Note 3—Regulatory Matters Matters of the Combined Notes to the Consolidated Financial Statements for regulatory updates related to the New York CES, Note 9—Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information relative to Ginna and Nine Mile Point, and Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information on Generation's proposed acquisition of FitzPatrick.

Potential Early Nuclear Plant Retirements

Exelon and Generation continually evaluate the current and expected economic value of each of Generation's nuclear plants. Factors that will continue to affect the economic value of Generation's nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure nuclear plants are fairly compensated for their carbon-free emissions, and the impact of final rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. In 2015 and 2016, Generation identified the Clinton, Quad Cities, Ginna, Nine Mile Point, and Three Mile Island nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. On June 2, 2016, Generation announced its decision to shut down the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively; thereby resulting in accelerated depreciation for these plant assets thereafter. With the passage of the Illinois ZES on December 7, 2016, Generation reversed its original decision, and revised the expected economic useful lives for both facilities to 2027 for Clinton and to 2032 for Quad Cities. Furthermore, assuming the successful implementation of the Illinois ZES and the New York CES for their entire terms, Generation no longer considers Clinton, Quad Cities, Ginna or Nine Mile Point to be at heightened risk of early retirement. Generation currently considers Three Mile Island to be at the greatest risk of early retirement due to current economic valuations and other factors. See Note 9—Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information.

Like-Kind Exchange

On September 19, 2016, the United States Tax Court rejected Exelon's position on its 1999 income tax return to defer under the like-kind exchange provisions of the IRC $1.2 billion of tax gain on the sale of ComEd's fossil generating assets. In addition, contrary to Exelon's evaluation that any penalty was unwarranted, the Tax Court ruled that Exelon is liable for the penalty and interest thereon asserted by the IRS, pursuant to which Exelon and ComEd recorded charges to earnings in 2016 of $106 million and $86 million, respectively. Exelon expects to timely appeal this decision to the U.S. Court of Appeals for the Seventh Circuit. While awaiting a final calculation from the IRS, Exelon estimates an approximate $1.4 billion payment will be due, including $300 million form ComEd, in the second quarter of 2017 at the time it expects to file its appeal. Of this amount, Exelon deposited with the IRS $1.25 billion in October 2016, with the remainder to be paid at the time the appeal is filed. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for further information related to the like-kind exchange tax matter, including Exelon's agreement to hold ComEd harmless from any unfavorable impacts of after-tax interest or penalty amounts on ComEd's equity.

BGE 2015 Electric and Natural Gas Distribution Base Rates

On November 6, 2015, and as amended through the course of the proceeding, BGE filed for electric and natural gas base rate increases with the MDPSC, which included recovery of electric and

natural gas smart grid initiative costs. On June 3, 2016, the MDPSC issued an order in which the MDPSC found compelling evidence to conclude that BGE's smart grid initiative overall was cost beneficial to customers. However, the June 3 order contained several cost disallowances and adjustments, which BGE filed a petition for rehearing on and certain of which were reversed by the MDPSC in an order issued on July 29, 2016. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

Pepco Maryland 2016 Electric Distribution Base Rates

On November 15, 2016, the MDPSC approved an increase in electric distribution base rates of $53 million based on a ROE of 9.55%. The new rates became effective for services rendered on or after November 15, 2016. MDPSC also approved Pepco's recovery of substantially all of its capital investment and regulatory assets associated with its AMI program as part of the newly effective rates as well as recovery over a five-year period of transition costs related to a new billing system implemented in 2015. As a result, during the fourth quarter of 2016, Exelon, PHI and Pepco established a regulatory asset of $13 million, wrote off $3 million in disallowed AMI costs and recorded a pre-tax credit to net income for $10 million. Additionally, the MDPSC denied Pepco's request to extend its Grid Resiliency Program surcharge for new system reliability and safety improvement projects, with costs for such programs to be recovered going forward through base rates. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

DPL Delaware 2016 Electric and Natural Gas Distribution Base Rates

The DPSC approved provisional increases in annual electric and natural gas distribution base rates of $2.5 million effective May 17, 2016, and an additional $30 million effective December 17, 2016, for electric and of $2.5 million effective May 17, 2016, and an additional $10 million effective December 17, 2016, for gas. These increases are subject to refund based on the final DPSC orders. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

DPL filed an application with the DPSC to increase its annual electric and natural gas distribution base rates by $63 million and $22 million, respectively, based on a requested ROE of 10.6%. While the DPSC is not required to issue a decision on the application within a specified period of time, Delaware law allowed DPL to put into effect $2.5 million of each of the rate increases two months after filing the applications which were effective July 16, 2016. On December 1, 2016, the DPSC approved that an additional $30 million in electric distribution base rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order, and an additional $10 million in gas base rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

ACE 2016 Electric Distribution Base Rates

On August 24, 2016, the NJBPU issued an order approving a stipulation of settlement among ACE, the New Jersey Division of Rate Counsel, NJBPU Staff and Unimin Corporation, and an increase of $45 million (before New Jersey sales and use tax) to its electric distribution base rates, with the new rates effective immediately. The stipulation of settlement provided that a determination on PowerAhead would be separated into a phase II of the rate proceeding and decided at a later date, most likely in the first quarter of 2017. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

Exelon's Strategy and Outlook for 2017 and Beyond

Exelon's value proposition and competitive advantage come from its scope and its core strengths of operational excellence and financial discipline. Exelon leverages its integrated business model to create value. Exelon's regulated and competitive businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- Exelon's utilities provide a foundation for stable earnings, which translates to a stable currency in our stock.
- Generation's competitive businesses provide free cash flow to invest primarily into the utilities and in long-term, contracted assets and to reduce debt.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The Exelon utilities only invest in rate base where it provides a benefit to customers and the community by improving reliability and the service experience or otherwise meeting customer needs. The Exelon utilities make these investments at the lowest reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of resources and best practices to achieve improved operational and financial results. Additionally, ComEd, PECO and BGE anticipate making significant future investments in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Generation's competitive businesses create value for customers by providing innovative solutions and reliable, clean and affordable energy. Generation's electricity generation strategy is to pursue opportunities that provide stable revenues and generation to load matching to reduce earnings volatility. Generation leverages its energy generation portfolio to deliver energy to both wholesale and retail customers. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon's financial priorities are to maintain investment grade credit metrics at each of the Registrants, to maintain optimal capital structure and to return value to Exelon's shareholders with an attractive dividend throughout the energy commodity market cycle and through stable earnings growth. Exelon's Board of Directors has approved a dividend policy providing a raise of 2.5% each year for three years, beginning with the June 2016 dividend.

Various market, financial, regulatory, legislative and operational factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS for additional information.

Continually optimizing the cost structure is a key component of Exelon's financial strategy. Through a recent focused cost management program, the company has committed to reducing operation and maintenance expenses and capital costs by approximately $350 million and $50 million,

respectively, of which approximately 35% of run-rate savings was achieved by the end of 2016. Approximately 60% of run-rate savings are expected to be achieved by the end of 2017 and fully realized in 2018. At least 75% of the savings are expected to be allocated to Generation, with the remaining amount allocated to the Utility Registrants.

Growth Opportunities

Management continually evaluates growth opportunities aligned with Exelon's businesses, assets and markets, leveraging Exelon's expertise in those areas and offering sustainable returns.

Regulated Energy Businesses . The PHI merger provides an opportunity to accelerate Exelon's regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, the Utility Registrants anticipate investing approximately $25 billion over the next five years in electric and natural gas infrastructure improvements and modernization projects, including smart meter and smart grid initiatives, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $9 billion by the end of 2021. The Utility Registrants invest in rate base where beneficial to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made at the lowest reasonable cost to customers.

See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives and infrastructure development and enhancement programs.

Competitive Energy Businesses . Generation continually assesses the optimal structure and composition of our generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation's long-term growth strategy is to prioritize investments in long-term contracted generation across multiple technologies and identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, while identifying emerging technologies where strategic investments provide the option for significant future growth or influence in market development. As of December 31, 2016, Generation has currently approved plans to invest a total of approximately $1 billion in 2017 through 2019 on capital growth projects (primarily new plant construction and distributed generation).

Liquidity Considerations

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and OPEB obligations and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.6 billion, $5.3 billion, $1.0 billion, $0.6 billion, $0.6 billion, $0.5 billion, $0.5 billion and $0.4 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.5 billion. See Liquidity and Capital Resources—Credit Matters—Exelon Credit Facilities below.

Project Financing

Generation utilizes individual project financings as a means to finance the construction of various generating asset projects. Project financing is based upon a nonrecourse financial structure, in which project debt and equity used to finance the project are paid back from the cash generated by the newly constructed asset once operational. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific nonrecourse debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful life. See Note 14—Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on nonrecourse debt.

ExGen Texas Power

In September 2014, ExGen Texas Power, LLC (EGTP), an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. The net proceeds were distributed to Generation for general business purposes. EGTP's operating cash flows have been negatively impacted by certain market conditions including, but not limited to: low power prices, higher fuel prices and the seasonality of its cash flows . Despite the declining operating cash flows, EGTP remains in compliance with its covenants related to the project specific financing. Management continues to monitor the project entity's short term liquidity needs. See Note 14—Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the EGTP.

Other Key Business Drivers and Management Strategies

Utility Rates and Rate Proceedings

The Utility Registrants file rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants' current and future results of operations, cash flows and financial position. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details on these regulatory proceedings.

Power Markets

Price of Fuels

The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Capacity Market Changes in PJM

In the wake of the January 2014 Polar Vortex that blanketed much of the Eastern and Midwestern United States, it became clear that while a major outage event was narrowly avoided, resources in PJM were not providing the level of reliability expected by customers. As a result, on December 12,

2014, PJM filed at FERC a proposal to make significant changes to its current capacity market construct, the Reliability Pricing Model (RPM). PJM's proposed changes generally sought to improve resource performance and reliability largely by limiting the excuses for non-performance and by increasing the penalties for performance failures. The proposal permits suppliers to include in capacity market offers additional costs and risk so they can meet these higher performance requirements. While offers are expected to put upward pressure on capacity clearing prices, operational improvements made as a result of PJM's proposal are expected to improve reliability, to reduce energy production costs as a result of more efficient operations and to reduce the need for out of market energy payments to suppliers. Generation participated actively in PJM's stakeholder process through which PJM developed the proposal and also actively participated in the FERC proceeding including filing comments. On June 9, 2015, FERC approved PJM's filing largely as proposed by PJM, including transitional auction rules for delivery years 2016/2017 through 2017/2018. As a result of this and several related orders, PJM hosted its 2018/2019 Base Residual Auction (results posted on August 21, 2015) and its transitional auction for delivery year 2016/2017 (results posted on August 31, 2015) and its transitional auction for delivery years 2017/2018 (results posted on September 9, 2015). On May 10, 2016, FERC largely denied rehearing, and a number of parties appealed to the U.S. Court of Appeals for the DC Circuit for review of the decision. It is too early in the process to predict the appeal outcome.

MISO Capacity Market Results

On April 14, 2015, the Midcontinent Independent System Operator (MISO) released the results of its capacity auction covering the June 2015 through May 2016 delivery year. As a result of the auction, capacity prices for the zone 4 region in downstate Illinois increased to $150 per MW per day beginning in June 2015, an increase from the prior pricing of $16.75 per MW per day that was in effect from June 2014 to May 2015. Generation had an offer that was selected in the auction. However, due to Generation's ratable hedging strategy, the results of the capacity auction have not had a material impact on Exelon's and Generation's consolidated results of operations and cash flows.

Additionally, in late May and June 2015, separate complaints were filed at the FERC by each of the State of Illinois, the Southwest Electric Cooperative, Public Citizens, Inc., and the Illinois Industrial Energy Consumers challenging the results of this MISO capacity auction for the 2015/2016 delivery in MISO delivery zone 4. The complaints allege generally that 1) the results of the capacity auction for zone 4 are not just and reasonable, 2) the results should be suspended, set for hearing and replaced with a new just and reasonable rate, 3) a refund date should be established and that 4) certain alleged behavior by one of the market participants other than Exelon or Generation, be investigated.

On October 1, 2015, the FERC announced that it was conducting a non-public investigation (that does not involve Exelon or Generation) into whether market manipulation or other potential violations occurred related to the auction. On December 31, 2015, the FERC issued a decision that certain of the rules governing the establishment of capacity prices in downstate Illinois are "not just and reasonable" on a prospective basis. The FERC ordered that certain rules be changed prior to the April 2016 auction which set capacity prices for the 2016/2017 planning year. In response to this order, MISO filed certain rule changes with the FERC. On March 18, 2016, FERC largely denied rehearing of its December 31, 2015 order. FERC continues to conduct its non-public investigation to determine if the April 2015 auction results were manipulated and, if so, whether refunds are appropriate. The FERC did establish May 28, 2015, the day the first complaint was filed, as the date from which refunds (if ordered) would be calculated, and it also made clear that the findings in the December 31, 2015 order do not prejudge the investigation or related proceedings. Generation cannot predict the impact the FERC order may ultimately have on future auction results, capacity pricing or decisions related to the potential early retirement of the Clinton nuclear plant, however, such impacts could be material to Generation's future results of operations and cash flows. See Note 9—Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement.

MISO has acknowledged the need for capacity market design changes in the zone 4 regions, and on November 1, 2016 filed a comprehensive capacity market proposal for the zone 4 region (as well as another zone). It is too early to predict the outcome of that filing. Exelon is generally supportive of such changes. However, several fossil generators have requested that FERC impose an expanded minimum offer price rule (MOPR) that could affect capacity offers from the Clinton nuclear plant. See Note 9—Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement. Exelon is actively participating in this aspect of the proceeding, seeking to avoid the implementation of such a MOPR mechanism. However, it is too early in the proceeding to predict.

Subsidized Generation

The rate of expansion of subsidized generation, in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have attempted to implement or propose legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices. For example, the New Jersey legislature enacted into law in January 2011, the Long Term Capacity Pilot Program Act (LCAPP). LCAPP provides eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market. Under LCAPP, the local utilities in New Jersey are required to pay (or receive) the difference between the price eligible generators receive in the capacity market and the price guaranteed under the 15-year contract. New Jersey ultimately selected three proposals to participate in LCAPP and build new generation in the state. In addition, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV was required to construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland. The CfD mandated that utilities (including BGE, Pepco and DPL) pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Exelon and others challenged the constitutionality and other aspects of the New Jersey legislation in federal court. The actions taken by the MDPSC were also challenged in federal court in an action to which Exelon was not a party. The federal trial courts in both the New Jersey and Maryland actions effectively invalidated the actions taken by the New Jersey legislature and the MDPSC, respectively. Each of those decisions was upheld by the U.S. Court of Appeals for the Third Circuit and the U.S. Court of Appeals for the Fourth Circuit, respectively. On April 19, 2016, the U.S. Supreme Court affirmed the decision of the U.S. Court of Appeals for the Fourth Circuit, and subsequently denied certiorari with respect to the appeal from the U.S. Court of Appeals for the Third Circuit, leaving in place that court's decision. The matter is now considered closed.

As required under their contracts, generator developers who were selected in the New Jersey and Maryland programs (including CPV) offered and cleared in PJM's capacity market auctions. To the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon. While the court decisions are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR) for future capacity auctions, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon's position and could have a significant effect on Exelon's financial results of operations, financial position and cash flows.

One such state is Ohio, where state-regulated utility companies FirstEnergy Ohio (FE) and AEP Ohio (AEP) initiated actions at the Public Utilities Commission of Ohio (PUCO) to obtain approval for Riders that would effectively allow these two companies to pass through to all customers in their service territories the differences between their costs and market revenues on PPAs entered into

between the utility and its merchant generation affiliate for what was collectively more than 6,000MW of primarily coal-fired generation. Thus, the Riders were similar to the CfDs described above (except that the PPA Riders in Ohio would apply to existing generation facilities whereas the CfDs applied to new generation facilities). While FERC orders on April 27, 2016 largely alleviated the concerns related to the Riders by holding that the PPAs ran afoul of affiliate restrictions on FE and AEP, we continue to closely monitor developments in Ohio.

In addition, Exelon continues to monitor developments in Maryland, New Jersey, and other states and participates in stakeholder and other processes to ensure that similar state subsidies are not developed. Exelon remains active in advocating for competitive markets, while opposing policies that require taxpayers and/ or consumers to subsidize or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid.

Complaints at FERC Seeking to Mitigate Illinois and New York Programs Providing ZECs

PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to remove the revenues it receives through a federal, state or other government-provided financial support program—resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new resources. Exelon has generally opposed policies that required subsidies or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid. Thus, Exelon has supported a MOPR as a means of minimizing the detrimental impact of certain subsidized resources could have on capacity markets (such as the New Jersey (LCAPP) and Maryland (CfD) programs. However, in Exelon's view, MOPRs should not be applied to resources that receive compensation for providing superior reliability or environmental benefits.

On January 9, 2017, the Electric Power Supply Association (EPSA) filed two requests with FERC: one seeking to amend a prior complaint against PJM and another seeking expedited action on a pending NYISO compliance filing in an existing proceeding. Both filings allege that the relevant MOPR should be expanded to also apply to existing resources receiving ZEC compensation under the New York CES and Illinois ZES programs. Exelon has filed protests at FERC in response to each filing, arguing generally that ZEC payments provide compensation for an environmental attribute that is distinct from the energy and capacity sold in the FERC-jurisdictional markets, and therefore, are no different than other renewable support programs like the PTC and RPS that have generally not been subject to a MOPR. However, if successful, an expanded MOPR could result in mitigation of Generation's Quad Cities, Ginna, and Nine Mile Point facilities, which are expected to receive ZEC compensation, such that they would have an increased risk of not clearing in future capacity auctions and thus no longer receiving capacity revenues during the respective ZEC programs. This would also impact the FitzPatrick facility that Generation is currently in the process of acquiring from Entergy. Any mitigation of these generating resources could have a material effect on Exelon's and Generation's future cash flows and results of operations. The timing of FERC's decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

Energy Demand

Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for Pepco, a decrease in projected load for electricity for BGE, DPL and ACE, and an essentially flat projected load for electricity for ComEd and PECO. ComEd, PECO, BGE, Pepco, DPL and ACE are projecting load volumes to increase (decrease) by (0.3)%, 0.6%, (1.4)%, (1.7)%, 0.8% and (0.7)%, respectively, in 2017 compared 2016.

Retail Competition

Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. The market experienced high price volatility in the first quarter of 2014 which contributed to bankruptcies and consolidations within the industry during the year. However, forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

Strategic Policy Alignment

As part of its strategic business planning process, Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's board of directors declared first quarter 2016 dividends of $0.31 per share each on Exelon's common stock. The second, third and fourth quarter 2016 dividends declared was $0.318 on Exelon's common stock, and the first quarter 2017 dividends declared was $0.328 per share. The dividends for the first, second, third and fourth quarter 2016 were paid on March 10, 2016, June 10, 2016, September 9, 2016 and December 9, 2016, respectively. The first quarter 2017 dividend is payable on March 10, 2017.

Exelon's Board of Directors has approved a dividend policy providing a raise of 2.5% each year for three years, beginning with the June 2016 dividend.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2017 and 2018. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of December 31, 2016, the percentage of expected generation hedged for the major reportable segments was 91%-94%, 56%-59% and 28%-31% for 2017, 2018, and 2019 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability

restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 39% of Generation's uranium concentrate requirements from 2017 through 2021 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position.

The Utility Registrants mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Tax Matters

Potential Corporate Tax Reform

The results of the November 2016 U.S. elections have introduced greater uncertainty with respect to federal tax policies. President Trump has stated that one of his top priorities is comprehensive tax reform and House Republicans plan to advance their tax reform "blueprint". Tax reform proposals call for a reduction in the corporate federal income tax rate from the current 35% to as low as 15%. Other proposals provide, among other items, for the immediate deduction of capital investment expenditures and full or partial elimination of debt interest expense deductions. It is uncertain whether, to what extent or when these or any other changes in federal tax policies will be enacted or the transition time frame for such changes. Further, for the Utility Registrants, regulators may impose rate reductions to provide the benefit of any income tax expense reductions to customers and refund "excess" deferred income taxes previously collected through rates. The amounts and timing of any such rate changes would be subject to the discretion of the rate regulator in each specific jurisdiction. For these reasons, the Registrants cannot predict the impact any potential changes may have on their future results of operations, cash flows or financial position, and such changes could be material.

See Note 15—Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information

Environmental Legislative and Regulatory Developments

Exelon is actively involved in the EPA's development and implementation of environmental regulations for the electric industry, in pursuit of its business strategy to provide reliable, clean, affordable and innovative energy products. These efforts have most frequently involved air, water and waste controls for electric generating units, as set forth in the discussion below. These regulations have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Retirements of coal-fired power plants will continue as additional EPA regulations take effect, and as air quality standards are updated and further restrict emissions. Due to its low emission generation portfolio, Generation will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the EPA's rulemaking efforts, and it is uncertain whether any of these bills will become law.

Air Quality

In recent years, the EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act applicable to electric generating units. These regulations have resulted in more stringent emissions limits on fossil-fuel electric generating stations as states implement their compliance plans.

National Ambient Air Quality Standards (NAAQS). The EPA continues to review and update its NAAQS for conventional air pollutants relating to ground-level ozone and emissions of particulate matter, SO2 and NOx. Following five years of litigation, the EPA is implementing the Cross State Air Pollution Rule that requires upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states, and otherwise contributes to non-attainment status of downwind states with the various NAAQS requirements.

Mercury and Air Toxics Standard Rule (MATS). On December 16, 2011, the EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals, and to make capital investments in pollution control equipment and incur higher operating expenses. The initial compliance deadline to meet the new standards was April 16, 2015; however, facilities may have been granted an additional one or two year extension in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. In April 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety. On appeal, the U.S. Supreme Court decided in June 2015 that the EPA unreasonably refused to consider costs in determining whether it is appropriate and necessary to regulate hazardous air pollutants emitted by electric utilities. The U.S. Supreme Court, however, did not vacate the rule; rather, it was remanded to the D.C. Circuit Court to take further action consistent with the U.S. Supreme Court's opinion on this single issue. As such, the MATS rule remains in effect. Exelon will continue to participate in the remanded proceedings before the D.C. Circuit Court as an intervenor in support of the rule.

Climate Change. Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. In the absence of Federal legislation, the EPA is moving forward with the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change ("UNFCCC" of "Convention"). See ITEM 1.—BUSINESS,"Global Climate Change" for further discussion.

Water Quality

Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. Those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, Ginna, Gould Street, Handley, Mountain Creek, Mystic 7, Nine Mile Point Unit 1, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. See ITEM 1.—BUSINESS ,"Water Quality" for further discussion.

Solid and Hazardous Waste

In October 2015, the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants became effective. The rule classifies CCR as non-hazardous waste under RCRA. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded reserves consistent with state regulation for its owned coal ash sites, and as such, the regulation is not expected to impact Exelon's and Generation's financial results. Generation does not have sufficient information to reasonably assess the potential

likelihood or magnitude of any remediation requirements that may be asserted under the new federal regulations for coal ash disposal sites formerly owned by Generation. For these reasons, Generation is unable to predict whether and to what extent it may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations.

See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Legislative and Regulatory Developments

NRC Task Force on Fukishima

In July 2011, an NRC Task Force formed in the aftermath of the March 11, 2011, 9.0 magnitude earthquake and ensuing tsunami, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, issued a report of its review of the accident, including tiered recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for Generation, net of expected co-owner reimbursements, for the period from 2017 through 2019 is expected to be between approximately $75 million and $100 million of capital and $15 million of operating expense. Generation's current assessments are specific to the Tier 1 recommendations. The NRC has not finalized actions with respect to the Tier 2 and Tier 3 recommendations and is expected to do so in 2017. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input.

Employees

During 2016, Exelon BSC and ComEd extended the collective bargaining agreement (CBA) with IBEW Local 15 by three years; with an expiration date of September 30, 2022. Exelon Generation extended its CBA with both the IBEW Local 15 (covering the five (5) Midwest nuclear plants) and IBEW Local 51 (Clinton) by three years; with expiration dates of April 30, 2022 and December 15, 2023, respectively. Additionally, Exelon Nuclear Security successfully ratified its CBA with the UGSOA Local 17 at Oyster Creek to an extension of five (5) years, and Exelon Power successfully ratified its CBA with the IBEW Local 614 to a three (3) extension. In January 2017, an election was held at BGE which resulted in union representation for approximately 1,400 employees. BGE and IBEW Local 410 will begin negotiations for an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. No agreement has been finalized to date and management cannot predict the outcome of such negotiations.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the

amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions with its Accounting and Disclosure Governance Committee on a regular basis and provides periodic updates on management decisions to the Audit Committee of the Exelon Board of Directors. Management believes that the accounting policies described below require significant judgment in their application, or incorporate estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation's ARO associated with decommissioning its nuclear units was $8.7 billion at December 31, 2016. The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple decommissioning outcome scenarios.

As a result of recent nuclear plant retirements in the industry, nuclear operators and third-party service providers are obtaining more information about costs associated with decommissioning activities. At the same time, regulators are gaining more information about decommissioning activities which could result in changes to existing decommissioning requirements. In addition, as more nuclear plants are retired, it is possible that technological advances will be identified that could create efficiencies and lead to a reduction in decommissioning costs. The availability of decommissioning trust funds could impact the timing of the decommissioning activities. Additionally, certain factors such as changes in regulatory requirements during plant operations or the profitability of a nuclear plant could impact the timing of plant retirements. These factors could result in material changes to Generation's current estimates as more information becomes available and could change the timing of plant retirements and the probability assigned to the decommissioning outcome scenarios.

The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing and/or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the methodologies and significant estimates and assumptions described as follows:

Decommissioning Cost Studies

Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the expected costs (in current year dollars) and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within the industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years, unless circumstances warrant more frequent updates (such as a change in assumed operating life for a nuclear plant). As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle.

Cost Escalation Factors

Generation uses cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors, and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal and other costs. All of the nuclear AROs are adjusted each year for the updated cost escalation factors.

Probabilistic Cash Flow Models

Generation's probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning cost levels, decommissioning approaches, and timing of plant shutdown on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. Probabilities are also assigned to four different decommissioning approaches. In response to expected increased security costs for spent fuel stored in the spent fuel pool (wet storage), in 2016 Generation has evaluated an alternative approach for managing spent fuel between the date of a plant's cessation of operations and the fuel's acceptance for disposal by the DOE. This new approach, the Shortened SAFSTOR approach, provides for increased usage of dry cask storage for the spent fuel, and is now considered as one of the decommissioning approaches in determining the ARO as follows:

1. DECON—a method of decommissioning shortly after the cessation of operation in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a LLRW landfill or decontaminated to a level that permits property to be released for unrestricted use. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.
2. Delayed DECON—similar to the DECON scenario but with a delay to allow for spent fuel to be removed from the site prior to onset of decommissioning activities. Spent fuel is retained in existing location (either wet or dry storage) until DOE acceptance for disposal.
3. Shortened SAFSTOR—similar to the DECON scenario but with generally a 30 year delay prior to onset of decommissioning activities. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.
4. SAFSTOR—a method of decommissioning in which the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated to levels that permit release for unrestricted use generally within 60 years after cessation of operations. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

The actual decommissioning approach selected once a nuclear facility is shutdown will be determined by Generation at the time of shutdown and may be influenced by multiple factors including the funding status of the nuclear decommissioning trust fund at the time of shutdown.

The assumed plant shutdown timing scenarios include the following four alternatives: (1) the probability of operating through the original 40-year nuclear license term, (2) the probability of operating through an extended 60-year nuclear license term (regardless of whether such 20-year license extension has been received for each unit), (3) the probability of a second, 20-year license renewal for some nuclear units, and (4) the probability of early plant retirement for certain sites due to changing market conditions and regulatory environments. The successful operation of nuclear plants in the U.S. beyond the initial 40-year license terms has prompted the NRC to consider regulatory and technical requirements for potential plant operations for an 80-year nuclear operating term. As power market and regulatory environment developments occur, Generation evaluates and incorporates, as necessary, the impacts of such developments into its nuclear ARO assumptions and estimates.

Generation's probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal. Generation currently assumes DOE will begin accepting SNF in 2030. The SNF acceptance date assumption is based on management's estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

License Renewals

Except for its Clinton unit, Generation has successfully obtained initial 20-year operating license renewal extensions (i.e. extending the total license term to 60 years) for all of its operating nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG). Generation intends to apply for an initial 20-year renewal for the Clinton unit. No prior Generation license extension application has been denied.

Discount Rates

The probability-weighted estimated future cash flows for the various assumed scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. The accounting guidance required Generation to establish an ARO at fair value at the time of the initial adoption of the current accounting standard. Subsequent to the initial adoption, the ARO is adjusted for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions, as described above. Increases in the ARO as a result of upward revisions in estimated undiscounted cash flows are considered new obligations and are measured using a current CARFR as the increase creates a new cost layer within the ARO. Any decrease in the estimated undiscounted future cash flows relating to the ARO are treated as a modification of an existing ARO cost layer and, therefore, is measured using the average historical CARFR rates used in creating the initial ARO cost layers.

Under the current accounting framework, the ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. This differs from the accounting requirements for other long-dated obligations, such as pension and other post-employment benefits that are required to be re-measured as and when corresponding discount rates change. If Generation's future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFRs, the obligation would increase from approximately $8.7 billion to approximately $9.7 billion.

To illustrate the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO: i) had Generation used the 2015 CARFRs rather than the 2016 CARFRs in performing its annual 2016 ARO update, Generation would have decreased the ARO by an additional $45 million; and ii) if the CARFR used in performing the annual 2016 ARO update was increased by 100 basis points or decreased by 50 basis points, the ARO would have decreased by $1.2 billion and increased by $150 million, respectively, as compared to the actual decrease of $385 million.

ARO Sensitivities

Changes in the assumptions underlying the ARO could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions may correspondingly change.

The following table illustrates the effects of changing certain ARO assumptions while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption	Increase (Decrease) to ARO at December 31, 2016
Cost escalation studies	
Uniform increase in escalation rates of 50 basis points	$ 1,730
Probabilistic cash flow models	
Increase the estimated costs to decommission the nuclear plants by 20 percent	1,610
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	470
Shorten each unit's probability weighted operating life assumption by 2 years	840
Extend the estimated date for DOE acceptance of SNF to 2035	140

For more information regarding accounting for nuclear decommissioning obligations, see Note 1—Significant Accounting Policies, Note 9—Early Nuclear Plant Retirements and Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon, Generation, ComEd, PHI and DPL)

As of December 31, 2016, Exelon's $6.7 billion carrying amount of goodwill primarily consists of $2.6 billion at ComEd relating to the acquisition of ComEd in 2000 as part of the formation of Exelon and $4 billion at PHI pursuant to Exelon's acquisition of PHI in the first quarter of 2016. DPL has $8 million of goodwill as of December 31, 2016, related to its 1995 acquisition of the Conowingo Power Company. Generation also has goodwill of $47 million as of December 31, 2016. Under the provisions of the authoritative guidance for goodwill, these entities are required to perform an assessment for possible impairment of their goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting units below their carrying amount. Under the authoritative guidance, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and its operating results are regularly reviewed by segment management. ComEd has a single operating segment, and PHI's operating segments are Pepco, DPL and ACE. See Note 26—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information. There is no level below these operating segments for which operating results are regularly reviewed by segment management. Therefore, the ComEd, Pepco, DPL and ACE operating segments are also considered reporting units for goodwill impairment testing purposes. Exelon's and ComEd's $2.6 billion of goodwill has been assigned entirely to the ComEd reporting unit, while Exelon's and PHI's $4 billion of goodwill has been assigned to the Pepco, DPL and ACE reporting units in the amounts of $1.7 billion, $1.1 billion and $1.2 billion, respectively. DPL's $8 million of goodwill is assigned entirely to the DPL reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors, and entity-specific conditions and events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the qualitative assessment, or performs the qualitative assessment but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed.

Exelon's, ComEd's and PHI's accounting policy is to perform a quantitative test of goodwill at least once every three years, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount. The first step in the quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's, Pepco's, DPL's and ACE's businesses and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

Exelon, ComEd, PHI and DPL performed quantitative tests as of November 1, 2016, for their 2016 annual goodwill impairment assessments. The first step of the tests comparing the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units to their carrying values, including goodwill, indicated no impairments of goodwill; therefore, no second steps were required.

While the annual assessments indicated no impairments, certain assumptions used to estimate reporting unit fair values are highly sensitive to changes. Adverse regulatory actions or changes in significant assumptions could potentially result in future impairments of Exelon's, ComEd's, PHI's or DPL's goodwill, which could be material. Based on the results of the annual goodwill tests performed as of November 1, 2016, the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units would have needed to decrease by more than 30%, 10%, 10% and 10%, respectively, for Exelon, ComEd and PHI to have failed the first step of their respective impairment tests. For the $8 million of goodwill recorded at DPL related to DPL's 1995 acquisition of the Conowingo Power Company, the fair value of the DPL reporting unit would have needed to decrease by more than 50% for DPL to fail the first step of the impairment test.

See Note 1—Significant Accounting Policies, Note 11—Intangible Assets and Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon, Generation and PHI)

In accordance with the authoritative accounting guidance, the assets acquired and liabilities assumed in an acquired business are recorded at their estimated fair values on the date of acquisition. The difference between the purchase price amount and the net fair value of assets acquired and liabilities assumed is recognized as goodwill on the balance sheet if it exceeds the estimated net fair value and as a bargain purchase gain on the income statement if it is below the estimated net fair value. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, often utilizes independent valuation experts and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the merger as more information is obtained about the fair

value of assets acquired and liabilities assumed. See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Contract Assets and Liabilities (Exelon, Generation, PHI, Pepco, DPL and ACE)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired and the electricity and gas energy supply contracts Exelon has acquired as part of the PHI acquisition. The initial amount recorded represents the fair value of the contracts at the time of acquisition. At PHI, offsetting regulatory assets or liabilities were also recorded. The unamortized energy contract assets and liabilities and any corresponding regulatory assets or liabilities, respectively, are amortized over the life of the contract in relation to the expected realization of the underlying cash flows. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues, respectively. Refer to Note 3—Regulatory Matters, Note 4—Mergers, Acquisitions, and Dispositions and Note 11—Intangible Assets of the Combined Notes to Consolidated Financial Statements for further discussion.

Impairment of Long-lived Assets (All Registrants)

All Registrants regularly monitor and evaluate their long-lived assets and asset groups, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of potential impairment may include a deteriorating business climate, including declines in energy prices, condition of the asset, specific regulatory disallowance, advances in technology, or plans to dispose of a long-lived asset significantly before the end of its useful life, among others.

The review of long-lived assets and asset groups for impairment utilizes significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power, costs of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could have a significant effect on the consolidated financial statements. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by the evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units as well as the associated intangible assets or liabilities recorded on the balance sheet. The cash flows from the generating units are generally evaluated at a regional portfolio level with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generating assets (typically contracted renewables).

On a quarterly basis, Generation assesses its asset groups for indicators of impairment. If indicators are present for a long-lived asset or asset group, a comparison of the undiscounted expected future cash flows to the carrying value is performed. When the undiscounted cash flow analysis indicates the carrying value of a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value less costs to sell. The fair value of the long-lived asset or asset group is dependent upon a market participant’s view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates. Events and circumstances often do not occur as expected and there will usually be differences between prospective financial information and actual results, and those differences may be material. The determination of fair

value is driven by both internal assumptions that include significant unobservable inputs (Level 3) such as revenue and generation forecasts, projected capital, and maintenance expenditures and discount rates, as well as information from various public, financial and industry sources.

Generation evaluates its equity method investments and other investments in debt and equity securities to determine whether or not they are impaired based on whether the investment has experienced a decline in value that is not temporary in nature.

See Note 8—Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Exelon.

Depreciable Lives of Property, Plant and Equipment (All Registrants)

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. These assets are generally depreciated on a straight-line basis, using the composite method in which depreciation is calculated using the average estimated useful life of assets within an asset group. The estimation of asset useful lives requires management judgment, supported by formal depreciation studies of historical asset retirement experience. Depreciation studies are completed every five years, or more frequently if required by a rate regulator or if an event, regulatory action, or change in retirement patterns indicate an update is necessary.

For the Utility Registrants, depreciation studies generally serve as the basis for amounts allowed in customer rates for recovery of depreciation costs. Generally, the Utility Registrants adjust their depreciation rates for financial reporting purposes concurrent with adjustments to depreciation rates reflected in rates, unless the depreciation rates reflected in rates do not align with management's judgment as to an appropriate estimated useful life or have not been updated on a timely basis. Consistent with each utility's regulatory recovery method, the Utility Registrant's depreciation expense for each asset group includes an amount for the estimated cost of dismantling and removing plant from service spread straight line over the asset group's average remaining useful life. Estimates for such removal costs are also evaluated in the periodic depreciation studies.

At Generation, along with depreciation study results, management considers expected future energy market conditions and generation plant operating costs and capital investment requirements in determining the estimated service lives of its generating facilities. See Note 9—Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on expected and potential early nuclear plant retirements.

Generation completed a depreciation rate study during the first quarter of 2015, which resulted in revised depreciation rates effective January 1, 2015.

ComEd is required to file an electric distribution depreciation rate study at least every five years with the ICC. ComEd completed an electric distribution and transmission depreciation study and filed the updated depreciation rates with both the ICC and FERC in January 2014, resulting in new depreciation rates effective first quarter 2014.

PECO is required to file electric distribution and gas depreciation rate studies at least every five years with the PAPUC. In March 2015, PECO filed a depreciation rate study with the PAPUC for both its electric distribution and gas assets, resulting in new depreciation rates for electric transmission assets effective January 1, 2015, for gas distribution assets effective July 1, 2015, and for electric distribution assets January 1, 2016.

The MDPSC does not mandate the frequency or timing of BGE's electric distribution or gas depreciation studies. In July 2014, BGE filed revised depreciation rates with the MDPSC for both its electric distribution and gas assets, which became effective December 15, 2014.

The MDPSC does not mandate the frequency or timing of Pepco's electric distribution depreciation studies, while the DCPSC directs Pepco as to when it should file an electric distribution depreciation study. In 2016 and 2013, Pepco filed revised electric distribution depreciation rates with the MDPSC and DCPSC, respectively, with the new rates effective November 15, 2016 and April 16, 2014, respectively.

Neither the DPSC nor the MDPSC mandates the frequency or timing of DPL's electric distribution or gas depreciation studies. DPL filed revised depreciation rates for gas assets in 2006, with the new rates effective April 1, 2007. In 2013, DPL filed revised electric distribution depreciation rates with the MDPSC, with the new rates effective July 20, 2013. On July 20, 2016, DPL filed revised electric depreciation rates with the MDPSC as part of the electric distribution base rate filing. Any adjustments to the depreciation rates approved by the MDPSC are expected to take effect in the first quarter of 2017. On May 17, 2016, DPL filed revised electric and natural gas depreciation rates with the DPSC as part of the electric and natural gas base rate case filing. The DPSC is not required to issue a decision on the application within a specific period of time and adjustments to the depreciation rates will be made based on the outcome of the final orders, when received.

The NJBPU does not mandate the frequency or timing of ACE's electric distribution depreciation studies. In 2012, ACE filed revised electric distribution depreciation rates with the NJBPU, with the new rates effective July 1, 2013.

FERC does not mandate the frequency or timing of electric transmission depreciation studies.

Changes in estimated useful lives of electric generation assets and of electric and natural gas transmission and distribution assets could have a significant impact on the Registrants' future results of operations. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant and equipment of the Registrants.

Defined Benefit Pension and Other Postretirement Employee Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement employee benefit plans for substantially all employees. See Note 17—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and other postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits involves various factors, including the development of valuation assumptions and inputs and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is affected by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, the anticipated rate of increase of health care costs, Exelon's expected level of contributions to the plans, the incidence of participant mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the long-term expected investment rate credited to employees of certain plans, among others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. Exelon amortizes actuarial gains or losses in excess of a corridor of 10% of the greater of the projected benefit obligation or the market-related value (MRV) of plan assets over the expected average remaining service period of plan participants. Pension and other postretirement benefit costs attributed to the operating companies are labor costs and are ultimately allocated to projects within the operating companies, some of which are capitalized.

Pension and other postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 17—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification under the fair value hierarchy in accordance with authoritative guidance.

Expected Rate of Return on Plan Assets

The long-term EROA assumption used in calculating pension costs for Exelon plans was 7.00% for each of 2016, 2015 and 2014. For the predecessor periods of 2016, 2015 and 2014, the long-term EROA assumption used in calculating pension costs for the PHI plans was 6.50%, 6.50% and 7.00%, respectively. The weighted after-tax average EROA assumption used in calculating other postretirement benefit costs for Exelon plans was 6.71%, 6.50% and 6.59% in 2016, 2015 and 2014, respectively. For the predecessor periods of 2016, 2015 and 2014, the EROA assumption used in calculating other postretirement benefit costs for PHI plans was 6.75%, 6.75% and 7.25%, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. In 2010, Exelon began implementation of a liability-driven investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. Over time, Exelon has decreased its equity investments and increased its investments in fixed income securities and alternative investments within the pension asset portfolio in order to achieve a balanced portfolio of liability hedging and return-generating assets. See Note 17—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's asset allocations. Exelon used an EROA of 7.00% and 6.60% to estimate its 2017 pension and other postretirement benefit costs, respectively.

Exelon calculates the amount of expected return on pension and other postretirement benefit plan assets by multiplying the EROA by the MRV of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments to be made during the year. In determining MRV, the authoritative guidance for pensions and postretirement benefits allows the use of either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. For the majority of pension plan assets, Exelon uses a calculated value that adjusts for 20% of the difference between fair value and expected MRV of plan assets. Use of this calculated value approach enables less volatile expected asset returns to be recognized as a component of pension cost from year to year. For other postretirement benefit plan assets and certain pension plan assets, Exelon uses fair value to calculate the MRV.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across the Registrants' pension and other postretirement benefit plans for the year ended December 31, 2016 were 7.30% and 6.02%, respectively, compared to an expected long-term return assumption of 7.00% and 6.71%, respectively.

Discount Rate

The discount rate used to determine the majority of the December 31, 2016 pension and other postretirement benefit obligations was 4.04%, representing a weighted-average of the rate for the majority of pension and other postretirement benefit plans. At December 31, 2016 and 2015, for both Exelon and PHI, the discount rates were determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated future benefit distribution amounts under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

The discount rate assumptions used to determine the obligation valuation at year end are also used to determine the cost for the following year. Exelon used discount rates ranging from 3.66% to 4.17% to estimate its 2017 pension and other postretirement benefit costs.

Health Care Cost Trend Rate

Assumed health care cost trend rates impact the costs reported for Exelon's other postretirement benefit plans for participant populations with plan designs that do not have a cap on cost growth. Accounting guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty. Exelon assumed an initial health care cost trend rate of 5.50% for 2016, decreasing to an ultimate health care cost trend rate of 5.00% in 2017 for the majority of its plans.

Mortality

The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. Exelon uses a mortality base table for its accounting valuation that is consistent with the IRS-required table for determining plan funding requirements pursuant to ERISA (referred to as RP-2000). Exelon is utilizing the Scale BB 2-Dimensional improvement scale with long-term improvements of 0.75% for its mortality improvement assumption. The mortality assumption is supported by an actuarial experience study on Exelon's plan participants performed in 2014.

Sensitivity to Changes in Key Assumptions

The following tables illustrate the effects of changing certain of the actuarial assumptions discussed above, while holding all other assumptions constant (dollars in millions):

Actuarial Assumption	Change in Assumption	Pension	Other Postretirement Benefits	Total
Change in 2016 cost:				
Discount rate [a]	0.5%	$ (65)	$ (16)	$ (81)
	(0.5)%	78	20	98
EROA	0.5%	(82)	(12)	(94)
	(0.5)%	82	12	94
Health care cost trend rate	1.00%	N/A	9	9
	(1.00)%	N/A	(8)	(8)
Change in benefit obligation at December 31, 2016:				
Discount rate [a]	0.5%	(1,119)	(250)	(1,369)
	(0.5)%	1,298	290	1,588
Health care cost trend rate	1.00%	N/A	105	105
	(1.00)%	N/A	(95)	(95)

(a) In general, the discount rate will have a larger impact on the pension and other postretirement benefit cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon implemented a liability-driven investment strategy for a portion of its pension asset portfolio in 2010. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

Average Remaining Service Period

For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants' average remaining service periods. The average remaining service period of Exelon's defined benefit pension plan participants was 11.9 years, 11.9 years and 11.8 years for the years ended December 31, 2016, 2015 and 2014, respectively. For the predecessor periods, the average remaining service period of PHI's defined benefit plans was approximately 11 years for both 2015 and 2014.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants' average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants' average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 9.0 years, 10.8 years and 9.1 years for the years ended December 31, 2016, 2015 and 2014, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.7 years, 9.7 years and 10.1 years for the years ended December 31, 2016, 2015 and 2014, respectively. For the predecessor periods, the average remaining service period of PHI's other postretirement benefit plans was approximately 11 years for both 2015 and 2014.

Regulatory Accounting (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

Exelon and the Utility Registrants account for their regulated electric and gas operations in accordance with the authoritative guidance, which requires Exelon and the Utility Registrants to reflect the effects of cost-based rate regulation in their financial statements. This guidance is applicable to entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) a reasonable expectation that rates are set at levels that will recover the entities' costs from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2016, Exelon and the Utility Registrants have concluded that the operations of each such Registrant meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of operations no longer meets the criteria of this guidance, Exelon and the Utility Registrants would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and Comprehensive Income and could be material. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon and the Utility Registrants.

For each regulatory jurisdiction in which they conduct business, Exelon and the Utility Registrants assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs in each Registrant's jurisdictions, and factors such as changes in applicable regulatory and political environments. Furthermore, each Registrant makes other judgments related to the financial statement impact of their regulatory environments, such as the types of adjustments to rate base that will be acceptable to regulatory bodies, if any, for which costs will be recoverable through rates. Refer to the revenue recognition discussion below for additional information on the annual revenue reconciliations associated with ComEd's distribution formula rate, pursuant to EIMA, and FERC-approved

transmission formula rate tariffs for ComEd, BGE, Pepco, DPL and ACE. Additionally, estimates are made in accordance with the authoritative guidance for contingencies as to the amount of revenues billed under certain regulatory orders that may ultimately be refunded to customers upon finalization of applicable regulatory or judicial processes. These assessments are based, to the extent possible, on past relevant experience with regulatory bodies in each Registrant's jurisdictions, known circumstances specific to a particular matter and hearings held with the applicable regulatory body. If the assessments and estimates made by Exelon and the Utility Registrants for regulatory assets and regulatory liabilities are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

ACE has a recovery mechanism for purchased power costs associated with BGS. ACE records a deferred energy supply costs regulatory asset or regulatory liability for under or over-recovered costs that are expected to be recovered from or refunded to ACE customers, respectively. In the first quarter of 2016, ACE changed its method of accounting for determining under or over-recovered costs in this recovery mechanism to include unbilled revenues in the determination of under or over-recovered costs. ACE believes this change is preferable as it better reflects the economic impacts of dollar-for-dollar cost recovery mechanisms. ACE applied the change retrospectively. The impact of the change was a $12 million reduction to ACE's opening Retained earnings as of January 1, 2014 with a corresponding reduction to Regulatory assets. The impact of the change on Net income attributable to common shareholder was an increase of $2 million and $1 million for the years ended December 31, 2015 and December 31, 2014, respectively.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Accounting for Derivative Instruments (All Registrants)

The Registrants utilize derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy-related products marketed and purchased. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd currently holds floating-to-fixed energy swaps with several unaffiliated suppliers that extend into 2032. PECO and BGE have entered into derivative natural gas contracts to hedge their long-term price risk in the natural gas market. PECO has also entered into derivative contracts to procure electric supply through a competitive RFP process as outlined in its PAPUC-approved DSP Program. BGE has also entered into derivative contracts to procure electric supply through a competitive auction process as outlined in its MDPSC-approved SOS Program. Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. DPL also uses derivatives to reduce natural gas commodity volatility and to limit its customers' exposure to natural gas price fluctuations under a hedging program approved by the DPSC. ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. ComEd, PECO, BGE, Pepco, DPL and ACE do not enter into derivatives for proprietary trading purposes. The Registrants' derivative activities are in accordance with Exelon's Risk Management Policy (RMP). See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether or not a contract qualifies as a derivative under this guidance requires that management exercise significant judgment, including assessing market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance related to derivatives, could result in previously excluded contracts being subject to the provisions of the authoritative derivative guidance. Generation has determined that contracts to purchase uranium, contracts to purchase and sell capacity in certain ISO's, certain emission products and RECs do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement and neither the uranium, certain capacity, emission nor the REC markets are sufficiently liquid to conclude that physical forward contracts are readily convertible to cash. If these markets do become sufficiently liquid in the future and Generation would be required to account for these contracts as derivative instruments, the fair value of these contracts would be accounted for consistent with Generation's other derivative instruments. In this case, if market prices differ from the underlying prices of the contracts, Generation would be required to record mark-to-market gains or losses, which may have a significant impact to Exelon's and Generation's financial positions and results of operations.

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, the normal purchases and normal sales exception. Further, derivatives that qualify and are designated for hedge accounting are classified as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. Generally, hedge accounting is not elected for commodity transactions. Economic hedges for commodities are recorded at fair value through earnings. In addition, for energy-related derivatives entered into for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings each period. For economic hedges that are not designated for hedge accounting for the Utility Registrants, changes in the fair value each period are recorded with a corresponding offsetting regulatory asset or liability if there is an ability to recover the associated costs.

Normal Purchases and Normal Sales Exception

As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated as normal purchases and normal sales and are thus not required to be recorded at fair value, but rather on an accrual basis of accounting. Determining whether a contract qualifies for the normal purchases and normal sales exception requires that management exercise judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and is not financially settled on a net basis. The contracts that ComEd has entered into with suppliers as part of ComEd's energy procurement process, PECO's full requirement contracts under the PAPUC-approved DSP

program, most of PECO's natural gas supply agreements, all of BGE's full requirement contracts and natural gas supply agreements that are derivatives and certain Pepco, DPL and ACE full requirement contracts qualify for and are accounted for under the normal purchases and normal sales exception.

Commodity Contracts

Identification of a commodity contract as an economic hedge requires Generation to determine that the contract is in accordance with the RMP. Generation reassesses its economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

As a part of accounting for derivatives, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. In accordance with the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges are categorized in Level 2. These price quotations reflect the average of the bid-ask mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The Registrant's derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using models that take into account inputs such as contract terms, including maturity, and market parameters, and assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, the model inputs are generally observable. Such instruments are categorized in Level 2. For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of credit and nonperformance risk to date have generally not been material to the financial statements.

Interest Rate and Foreign Exchange Derivative Instruments

The Registrants may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve the targeted level of variable-rate debt as a percent of total debt. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings and floating to fixed swaps for project financing. In addition, Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the economic hedge and proprietary trading activity is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates. To manage foreign exchange rate exposure

associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. The fair value of the agreements is calculated by discounting the future net cash flows to the present value based on the terms and conditions of the agreements and the forward interest rate and foreign exchange curves. As these inputs are based on observable data and valuations of similar instruments, the interest rate and foreign exchange derivatives are primarily categorized in Level 2 in the fair value hierarchy. Certain exchange based interest rate derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 12—Fair Value of Financial Assets and Liabilities and Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation (All Registrants)

Significant management judgment is required in determining the Registrants' provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of tax benefits to be recorded in the Registrants' consolidated financial statements.

In the first quarter of 2016, PHI, Pepco, DPL and ACE changed their accounting principle for classification of interest on uncertain tax positions. PHI, Pepco, DPL and ACE have reclassified interest on uncertain tax positions as interest expense from income tax expense in the Consolidated Statements of Operations and Comprehensive Income. GAAP does not address the preferability of one acceptable method of accounting over the other for the classification of interest on uncertain tax positions. However, PHI, Pepco, DPL and ACE believe this change is preferable for comparability of their financial statements with the financial statements of the other Registrants in the combined filing, for consistency with FERC classification and for a more appropriate representation of the effective tax rate as they manage the settlement of uncertain tax positions and interest expense separately. PHI, Pepco, DPL and ACE applied the change retrospectively. The reclassification in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2015 is $34 million and $4 million for PHI and Pepco, respectively, and for the year ended December 31, 2014 is $1 million for both Pepco and ACE. The impact on all other PHI Registrants for years ended December 31, 2015 and December 31, 2014 is less than $1 million.

The Registrants evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and their intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. The Registrants also evaluate for negative evidence that could indicate the Registrant's inability to realize its deferred tax assets, such as historical operating loss or tax credit carryforward expiration. Based on the combined assessment, the Registrants record valuation allowances for deferred tax assets when they conclude it is more-likely-than-not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including future changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2016 and 2015 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Loss Contingencies (All Registrants)

In the preparation of their financial statements, the Registrants make judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amounts recorded may differ from the actual expense incurred when the uncertainty is resolved. The estimates that the Registrants make in accounting for loss contingencies and the actual results that they record upon the ultimate resolution of these uncertainties could have a significant effect on their consolidated financial statements.

Environmental Costs

Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work and changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at ComEd, PECO, BGE, Pepco, DPL and ACE to determine future remediation requirements and estimates are adjusted accordingly. In addition, periodic reviews are performed at Generation to assess the adequacy of its environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant effect on the Registrants' results of operations, financial position and cash flows. See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information.

Other, Including Personal Injury Claims

The Registrants are self-insured for general liability, automotive liability, workers' compensation, and personal injury claims to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. The Registrants have reserves for both open claims asserted and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible state and national legislative measures could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material effect on the Registrants' results of operations, financial position and cash flows.

Revenue Recognition (All Registrants)

Sources of Revenue and Determination of Accounting Treatment

The Registrants earn revenues from various business activities including: the sale of energy and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail) *;* the sale and delivery of electricity and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The appropriate accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable accounting standards. The Registrants primarily use accrual and mark-to-market accounting as discussed in more detail below.

Accrual Accounting

Under accrual accounting, the Registrants record revenues in the period when services are rendered or energy is delivered to customers. The Registrants generally use accrual accounting to recognize revenues for sales of electricity, natural gas and other commodities as part of their physical delivery activities. The Registrants enter into these sales transactions using a variety of instruments, including non-derivative agreements, derivatives that qualify for and are designated as normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to utility customers under regulated service tariffs and spot-market sales, including settlements with independent system operators.

Mark-to-Market Accounting

The Registrants record revenues and expenses using the mark-to-market method of accounting for transactions that meet the definition of a derivative for which they are not permitted, or have not elected, the NPNS exception. These mark-to-market transactions primarily relate to commodity price risk management activities. Mark-to-market revenues and expenses include: inception gains or losses on new transactions where the fair value is observable and realized; and unrealized gains and losses from changes in the fair value of open contracts.

Unbilled Revenues

The determination of Generation's and the Utility Registrants' retail energy sales to individual customers is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities' customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, revenues may fluctuate monthly as a result of customers electing to use an alternate supplier, since unbilled commodity receivables are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date would also have an effect on the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

See Note 6—Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

Regulated Distribution & Transmission Revenues

ComEd's EIMA distribution formula rate provides for annual reconciliations to the distribution revenue requirement. As of the balance sheet dates, ComEd has recorded its best estimates of the distribution revenue impact resulting from changes in rates that ComEd believes are probable of approval by the ICC in accordance with the formula rate mechanism.

ComEd's, BGE's, Pepco's, DPL's and ACE's FERC transmission formula rate tariffs provide for annual reconciliations to the transmission revenue requirements. As of the balance sheet dates,

ComEd, BGE, Pepco, DPL and ACE have recorded the best estimate of their respective transmission revenue impact resulting from changes in rates that each Registrant believes are probable of approval by FERC in accordance with the formula rate mechanism.

Distribution and transmission formula rates require significant estimates. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred, investments made, allowed ROE, and actions by regulators or courts.

See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for more information on the potential impacts of the new revenue accounting standard effective for annual reporting periods beginning on or after December 15, 2017.

Allowance for Uncollectible Accounts (All Registrants)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd, PECO and BGE estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. At December 31, 2015, Pepco, DPL and ACE estimated the allowance for uncollectible accounts based on specific identification of material amounts at risk by customer and maintained a reserve based on their historical collection experience. At December 31, 2016, Pepco, DPL and ACE aligned the estimation of their allowance for uncollectible accounts to be consistent with ComEd, PECO and BGE, as described above. Risk segments represent a group of customers with similar credit quality indicators that are comprised based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. The Utility Registrant customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. Utility Registrants' customer accounts are written off consistent with approved regulatory requirements. Utility Registrants' allowances for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU regulations. See Note 6—Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2016, 2015 and 2014 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) Attributable to Common Shareholders by Registrant

	For the Years Ended December 31, 2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	For the Year Ended December 31, 2014	Favorable (unfavorable) 2015 vs. 2014 variance
Exelon	$1,134	$2,269	$ (1,135)	$ 1,623	$ 646
Generation	496	1,372	(876)	835	537
ComEd	378	426	(48)	408	18
PECO	438	378	60	352	26
BGE	286	275	11	198	77
Pepco	42	187	(145)	171	16
DPL	(9)	76	(85)	104	(28)
ACE	(42)	40	(82)	46	(6)

	Successor	*Predecessor*			
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014	Favorable (unfavorable) 2015 vs. 2014 variance
PHI	$ (61)	$ 19	$ 327	$ 242	$ 85

Results of Operations—Generation

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014 [a]	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$17,751	$19,135	$ (1,384)	$17,393	$ 1,742
Purchased power and fuel expense	8,830	10,021	1,191	9,925	(96)
Revenues net of purchased power and fuel expense [b]	8,921	9,114	(193)	7,468	1,646
Other operating expenses					
Operating and maintenance	5,641	5,308	(333)	5,566	258
Depreciation and amortization	1,879	1,054	(825)	967	(87)
Taxes other than income	506	489	(17)	465	(24)
Total other operating expenses	8,026	6,851	(1,175)	6,998	147
Equity in losses of unconsolidated affiliates	—	—	—	(20)	20
Gain (Loss) on sales of assets	(59)	12	(71)	437	(425)
Gain on consolidation and acquisition of businesses	—	—	—	289	(289)
Operating income	836	2,275	(1,439)	1,176	1,099
Other income and (deductions)					
Interest expense	(364)	(365)	1	(356)	(9)
Other, net	401	(60)	461	406	(466)
Total other income and (deductions)	37	(425)	462	50	(475)
Income before income taxes	873	1,850	(977)	1,226	624
Income taxes	290	502	212	207	(295)
Equity in losses of unconsolidated affiliates	(25)	(8)	(17)	—	(8)
Net income	558	1,340	(782)	1,019	321
Net income (loss) attributable to noncontrolling interests	62	(32)	94	184	(216)
Net income attributable to membership interest	$ 496	$ 1,372	$ (876)	$ 835	$ 537

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, the financial results include CENG's results of operations on a fully consolidated basis.
(b) Generation evaluates its operating performance using the measure of revenues net of purchased power and fuel expense. Generation believes that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenues net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Membership Interest

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. Generation's net income attributable to membership interest decreased compared to the same period in 2015, primarily due to lower revenues net of purchased power and fuel expense, higher operating and maintenance expense, higher depreciation and amortization expense, and losses on sales of assets in 2016, partially offset by increased other income and decreased income tax expense. The decrease in revenues net of purchased power and fuel expense primarily relates to lower mark-to-market results in 2016 compared to 2015 and lower realized energy prices, partially offset by the Ginna Reliability Support Services Agreement and a decrease in outage days at higher capacity units despite an increase in overall outage days. The increase in operating and maintenance expense is primarily related to the impairment of Upstream assets and certain wind projects, and increased costs related to the implementation of the cost management program. The increase in depreciation and amortization expense is primarily related to accelerated depreciation and amortization expense related to the previous decision to early retire the Clinton and Quad Cities nuclear generating facilities, increased nuclear decommissioning amortization and increased depreciation expense due to ongoing capital expenditures. The increase in losses on sales of assets is primarily due to Generation's strategic decision to narrow the scope and scale of its growth and development activities. The increase in other income is primarily due to the change in realized and unrealized gains and losses on NDT funds.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. Generation's net income attributable to membership interest increased compared to the same period in 2014 primarily due to higher revenue net of purchase power and fuel expense and lower operating and maintenance expense; partially offset by the absence of the 2014 gains recorded on the sales of Generation's ownership interest in generating stations, the absence of the 2014 gain recorded upon the consolidation of CENG, decreased other income and increased income tax expense. The increase in revenue, net of purchase power and fuel expense was primarily due to the inclusion of CENG's results on fully consolidated basis in 2015, the benefit of lower cost to serve load (including the absence of higher procurement costs for replacement power in 2014), the cancellation of the DOE SNF disposal fee, increased capacity prices, the inclusion of Integrys' results in 2015, favorability from portfolio management optimization activities, increased load served, and mark-to-market gains in 2015 compared to mark-to-market losses in 2014, partially offset by lower margins resulting from the 2014 sale of generating assets, lower realized energy prices, and the absence of the 2014 fuel optimization opportunities in the South region due to extreme cold weather. The decrease in operating and maintenance expense was largely due to the reduction of long-lived asset impairment charges in 2015 versus 2014, partially offset by increased labor, contracting and materials expense due to the inclusion of CENG's results on a fully consolidated basis in 2015 and increased energy efficiency projects. The decrease in other income is primarily the result of the change in realized and unrealized gains and losses on NDT fund investments in 2015 as compared to 2014.

Revenues Net of Purchased Power and Fuel Expense

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of

ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned with these same geographic regions. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions :
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in Other: amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; accelerated nuclear fuel amortization associated with the initial early retirement decision for Clinton and Quad Cities; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities using the measure of revenues net of purchased power and fuel expense, which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for owned generation and fuel costs associated with tolling agreements.

For the years ended December 31, 2016 compared to 2015 and December 31, 2015 compared to 2014, Generation's revenues net of purchased power and fuel expense by region were as follows:

			2016 vs. 2015			2015 vs. 2014	
	2016	2015	Variance	% Change	2014	Variance	% Change
Mid-Atlantic [a][b][e]	$3,317	$3,571	$ (254)	(7.1)%	$3,431	$ 140	4.1%
Midwest [c]	2,971	2,892	79	2.7%	2,599	293	11.3%
New England	438	461	(23)	(5.0)%	351	110	31.3%
New York [a][e]	742	634	108	17.0%	483	151	31.3%
ERCOT	281	293	(12)	(4.1)%	317	(24)	(7.6)%
Other Power Regions	336	250	86	34.4%	327	(77)	(23.5)%
Total electric revenues net of purchased power and fuel expense	8,085	8,101	(16)	(0.2)%	7,508	593	7.9%
Proprietary Trading	15	1	14	n.m.	42	(41)	(97.6)%
Mark-to-market gains (losses)	(41)	257	(298)	(116.0)%	(591)	848	n.m.
Other [d]	862	755	107	14.2%	509	246	48.3%
Total revenue net of purchased power and fuel expense	$8,921	$9,114	$ (193)	(2.1)%	$7,468	$ 1,646	22.0%

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning April 1, 2014, the financial results include CENG's results on a fully consolidated basis.
(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region. Results of transactions with Pepco, DPL, and ACE are included in the Mid-Atlantic region for the successor period of March 24, 2016 to December 31, 2016.
(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $57 million decrease to RNF, an $8 million increase to RNF, and a $124 million decrease to RNF for the amortization of intangible assets related to commodity contracts recorded at fair value for the years ended December 31, 2016, 2015, and 2014, respectively, and accelerated nuclear fuel amortization associated with the initial early retirement of Clinton and Quad Cities as discussed in Note 9—Early Nuclear Plant Retirements of the Combined Notes to the Financial Statements of $60 million for the year ended December 31, 2016.
(e) Includes $113 million and $169 million of purchased power from CENG prior to its consolidation on April 1, 2014 in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2014. See Note 27—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's supply sources by region are summarized below:

Supply Source (GWh)	2016	2015	2016 vs. 2015 Variance	2016 vs. 2015 % Change	2014	2015 vs. 2014 Variance	2015 vs. 2014 % Change
Nuclear Generation [a]							
Mid-Atlantic	63,447	63,283	164	0.3%	58,809	4,474	7.6%
Midwest	94,668	93,422	1,246	1.3%	94,000	(578)	(0.6)%
New York	18,684	18,769	(85)	(0.5)%	13,645	5,124	37.6%
Total Nuclear Generation	176,799	175,474	1,325	0.8%	166,454	9,020	5.4%
Fossil and Renewables							
Mid-Atlantic	2,731	2,774	(43)	(1.6)%	11,025	(8,251)	(74.8)%
Midwest	1,488	1,547	(59)	(3.8)%	1,372	175	12.8%
New England	6,968	2,983	3,985	133.6%	5,233	(2,250)	(43.0)%
New York	3	3	—	— %	4	(1)	(25.0)%
ERCOT	6,785	5,763	1,022	17.7%	7,164	(1,401)	(19.6)%
Other Power Regions	8,179	7,848	331	4.2%	7,955	(107)	(1.3)%
Total Fossil and Renewables	26,154	20,918	5,236	25.0%	32,753	(11,835)	(36.1)%
Purchased Power							
Mid-Atlantic	16,874	8,160	8,714	106.8%	6,082	2,078	34.2%
Midwest	2,255	2,325	(70)	(3.0)%	2,004	321	16.0%
New England	16,632	24,309	(7,677)	(31.6)%	12,354	11,955	96.8%
New York	—	—	—	— %	2,857	(2,857)	(100.0)%
ERCOT	10,637	10,070	567	5.6%	8,651	1,419	16.4%
Other Power Regions	13,589	18,773	(5,184)	(27.6)%	14,795	3,978	26.9%
Total Purchased Power	59,987	63,637	(3,650)	(5.7)%	46,743	16,894	36.1%
Total Supply/Sales by Region [b]							
Mid-Atlantic [c]	83,052	74,217	8,835	11.9%	75,916	(1,699)	(2.2)%
Midwest [c]	98,411	97,294	1,117	1.1%	97,376	(82)	(0.1)%
New England	23,600	27,292	(3,692)	(13.5)%	17,587	9,705	55.2%
New York	18,687	18,772	(85)	(0.5)%	16,506	2,266	13.7%
ERCOT	17,422	15,833	1,589	10.0%	15,815	18	0.1%
Other Power Regions	21,768	26,621	(4,853)	(18.2)%	22,750	3,871	17.0%
Total Supply/Sales by Region	262,940	260,029	2,911	1.1%	245,950	14,079	5.7%

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG).
(b) Excludes physical proprietary trading volumes of 6,179 GWh, 7,310 GWh, and 10,571 GWh for the years ended December 31, 2016, 2015, and 2014, respectively.
(c) Includes affiliate sales to PECO and BGE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region. As a result of the PHI Merger, includes affiliate sales to Pepco, DPL, and ACE in the Mid-Atlantic region for the successor period of March 24, 2016 to December 31, 2016.

Mid-Atlantic. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The $254 million decrease in revenues net of purchased power and fuel expense in the Mid-Atlantic was primarily due to lower realized energy prices, decreased capacity prices and higher oil inventory write-downs in 2016, partially offset by increased load volumes served.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The $140 million increase in revenues net of purchased power and fuel expense in the Mid-Atlantic was primarily due to the inclusion of CENG's results on a fully consolidated basis for the full year in 2015, the benefit of lower cost to serve load (which includes the absence of higher procurement costs for replacement power due to extreme cold weather in the first quarter of 2014), increased load volumes served, higher

nuclear volumes, the cancellation of the DOE SNF disposal fee, and favorability from portfolio management optimization activities, partially offset by lower capacity revenues, and lower generation volumes due to the sale of generating assets.

Midwest. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The $79 million increase in revenues net of purchased power and fuel expense in the Midwest was primarily due to decreased nuclear outage days and decreased nuclear fuel prices.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The $293 million increase in revenues net of purchased power and fuel expense in the Midwest was primarily due to higher capacity revenues, increased load volumes served, the inclusion of Integrys' results in 2015, the cancellation of the DOE SNF disposal fee in 2014, and favorability from portfolio management optimization activities, partially offset by lower nuclear volumes.

New England. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The $23 million decrease in revenues net of purchased power and fuel expense in New England was primarily due to lower realized energy prices and higher oil inventory write-downs in 2016, partially offset by increased capacity prices.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The $110 million increase in revenues net of purchased power and fuel expense in New England was primarily due to the benefit of lower cost to serve load, increased load volumes served, the inclusion of Integrys' results in 2015, and favorability from portfolio management optimization activities, partially offset by lower generation volumes due to the sale of a generating asset.

New York. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $108 million increase in revenues net of purchased power and fuel expense in New York was primarily due to the impact of the Ginna Reliability Support Service Agreement, partially offset by lower realized energy prices.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The $151 million increase in revenues net of purchased power and fuel expense in New York was primarily due to the inclusion of CENG's results on a fully consolidated basis for the full year in 2015, increased nuclear volumes and the inclusion of Integrys' results in 2015, partially offset by lower realized energy prices and decreased capacity revenues.

ERCOT. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $12 million decrease in revenues net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices, partially offset by increased output from renewable assets.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $24 million decrease in revenues net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices and a decrease in generation volumes due to the sale of a generating asset, partially offset by the absence of higher procurement costs for replacement power in 2014 and decreased fuel costs.

Other Power Regions. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $86 million increase in revenues net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $77 million decrease in revenues net of purchased power and fuel expense in Other Power Regions was primarily

due to the amortization of contracts recorded at fair value associated with prior acquisitions, lower realized energy prices, the absence of the 2014 fuel optimization opportunities, partially offset by increased generation from power purchase agreements, and decreased fuel costs.

Proprietary Trading. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $14 million increase in revenues net of purchased power and fuel expense in Proprietary trading was primarily due to congestion activity.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $41 million decrease in revenues net of purchased power and fuel expense in Proprietary trading was primarily due to the absence of gains on congestion trading products.

Mark-to-market. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. See Note 12—Fair Value of Financial Assets and Liabilities and Note 13—Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . Mark-to-market losses on economic hedging activities were $41 million in 2016 compared to gains of $257 million in 2015.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . Mark-to-market gains on economic hedging activities were $257 million in 2015 compared to losses of $591 million in 2014.

Other. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $107 million increase in other revenue net of purchased power and fuel was primarily due to revenue related to the inclusion of Pepco Energy Services results in 2016 and revenue related to energy efficiency projects, partially offset by the amortization of energy contracts recorded at fair value associated with prior acquisitions, and accelerated nuclear fuel amortization associated with the initial early retirement decision for Clinton and Quad Cities as discussed in Note 9—Early Nuclear Plant Retirements of the Combined Notes to the Financial Statements.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $246 million increase in other revenue net of purchased power and fuel was primarily due to the amortization of energy contracts recorded at fair value associated with prior acquisitions, the inclusion of Integrys' gas results in 2015, and an increase in distributed generation and energy efficiency activity. See Note 11—Intangible Assets of the Combined Notes to Consolidated Financial Statements for information regarding energy contract intangibles.

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for 2016, as compared to 2015 and 2014, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Generation considers capacity factor a useful measure to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	2016	2015	2014
Nuclear fleet capacity factor (a)	94.6%	93.7%	94.3%

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. As of April 1, 2014, CENG is included at ownership.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The nuclear fleet capacity factor, which excludes Salem, increased in 2016 compared to 2015 primarily due to fewer refueling and non-refueling outage days. For 2016 and 2015, planned refueling outage days totaled 245 and 290, respectively, and non-refueling outage days totaled 63 and 82, respectively.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The nuclear fleet capacity factor, which excludes Salem, decreased in 2015 compared to 2014 primarily due to a higher number of refueling outage days and non-outage energy losses, partially offset by a lower number of unplanned outage days. For 2015 and 2014, planned refueling outage days totaled 290 and 275, respectively, and non-refueling outage days totaled 82 and 92, respectively.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2016 compared to 2015, consisted of the following:

	Increase (Decrease)
Impairment and related charges of certain generating assets (a)	$ 161
Merger and integration costs	27
Midwest Generation bankruptcy charges	10
ARO update (b)	(79)
Pension and non-pension postretirement benefits expense (c)	(42)
Corporate allocations (d)	(12)
Plant retirements and divestitures (e)	(50)
Accretion expense	(21)
Nuclear refueling outage costs, including the co-owned Salem plant (f)	(61)
Merger commitments	53
Labor, other benefits, contracting and materials (g)	185
Cost management program (h)	43
Curtailment of Generation growth and development activities (i)	24
Other	95
Increase in operating and maintenance expense	$ 333

(a) Reflects increased impairments in 2016 compared to 2015, primarily related to the impairments of certain Upstream assets and wind generating assets in 2016.
(b) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units.
(c) Reflects the favorable impact of higher pension and OPEB discount rates.
(d) Reflects a decreased share of corporate allocated costs.
(e) Reflects the impact of the Generation's previous decision to early retire the Clinton and Quad cities nuclear facilities.
(f) Reflects the favorable impacts of decreased nuclear outages in 2016.
(g) Reflects an increase of labor, other benefits, contracting and materials costs primarily due to increased contracting costs related to energy efficiency projects and the inclusion of Pepco Energy Services results in 2016. Also includes cost of sales of our other business activities that are not allocated to a region.
(h) Represents the 2016 severance expense and reorganization costs related to a cost management program.
(i) Reflects the one-time recognition for asset impairment charges pursuant to Generation's strategic decision in the fourth quarter of 2016 to narrow the scope and scale of its growth and development activities.

The changes in operating and maintenance expense for 2015 compared to 2014, consisted of the following:

	Increase (Decrease) [a]
Impairment and related charges of certain generating assets [b]	$ (651)
Maryland merger commitments	(44)
Merger and integration costs	(28)
Midwest Generation bankruptcy charges	(14)
Decrease in asbestos bodily injury reserve	(12)
ARO update	8
Regulatory fees and assessments	10
Pension and non-pension postretirement benefits expense	15
Corporate allocations [c]	16
Accretion expense	18
Nuclear refueling outage costs, including the co-owned Salem plant [d]	64
Labor, other benefits, contracting and materials [e]	323
Other	37
Decrease in operating and maintenance expense	$ (258)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 operating results include CENG's results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.
(b) Primarily relates to impairments of certain generating assets held-for-sale, Upstream assets, and wind generating assets during 2014 that did not reoccur in 2015.
(c) Reflects an increased share of corporate allocated costs primarily due to the inclusion of CENG beginning April 1, 2014.
(d) Reflects the unfavorable impacts of increased nuclear outages in 2015.
(e) Reflects an increase of labor, other benefits, contracting and materials costs primarily due to the inclusion of CENG on a fully consolidated basis in 2015. Also includes cost of sales of our other business activities that are not allocated to a region.

Depreciation and Amortization

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . Depreciation and amortization expense increased primarily due to accelerated depreciation and increased nuclear decommissioning amortization related to the previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016, and increased depreciation expense due to ongoing capital expenditures.

Excluding the impacts of future capital additions, Generation expects total annual depreciation for Clinton and Quad Cities in 2017 and future years will be consistent with the annual depreciation recognized prior to the June 2016 early retirement decision, with the impact on prospective depreciation of the reduction in the plants' book values as a result of the accelerated depreciation recorded from June 2, 2016 to December 6, 2016, being essentially offset by the impact of shortening Clinton's expected economic useful life from the original 2046 date to the now expected 2027 date.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The increase in depreciation and amortization expense was primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015, increased nuclear decommissioning amortization, and an increase in ongoing capital expenditures.

Taxes Other Than Income

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The increase in taxes other than income was primarily due to an increase in gross receipts tax.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The increase in taxes other than income was primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015.

Equity in Losses of Unconsolidated Affiliates

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The year-over-year change in Equity in losses of unconsolidated affiliates is primarily the result of increased losses on equity investments.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The year-over-year change in Equity in losses of unconsolidated affiliates is primarily the result of the consolidation of CENG's results of operations beginning April 1, 2014, which were previously accounted for under the equity method of accounting.

Gain (Loss) on Sales of Assets

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The decrease in gain (loss) on sales of assets is primarily related to the one-time recognition for a loss on sale of assets pursuant to Generation's strategic decision in the fourth quarter of 2016 to narrow the scope and scale of its growth and development activities, partially offset by a gain associated with Generation's sale of the retired New Boston generating site in 2016.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The decrease in gain (loss) on sales of assets is primarily related to the absence of $411 million of gains recorded on the sale of Generation's ownership interests in Safe Harbor Water Power Corporation, Fore River and West Valley generating stations in 2014. Refer to Note 4—Mergers, Acquisitions, and Dispositions in the Combined Notes to Consolidated Financial Statements for additional information.

Gain on Consolidation and Acquisition of Businesses

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The decrease in gain on consolidation and acquisition of businesses reflects the absence of a $261 million gain upon consolidation of CENG resulting from the difference in fair value of CENG's net assets as of April 1, 2014 and the equity method investment previously recorded on Generation's and Exelon's books and the settlement of pre-existing transactions between Generation and CENG recorded in 2014, and the absence of a $28 million bargain-purchase gain related to the Integrys acquisition recorded in 2014.

Interest Expense

The changes in interest expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Interest expense on long-term debt	$ 8	$ 53
Interest expense on interest rate swaps	1	22
Interest expense on tax settlements	16	(37)
Other interest expense	(26)	(29)
(Decrease) increase in interest expense, net	$ (1)	$ 9

Other, Net

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The increase in Other, net primarily reflects the net increase in realized and unrealized gains related to the NDT fund investments of Generation's Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $80 million and $(22) million for the years ended December 31, 2016 and 2015,

respectively, related to the contractual elimination of income tax expense associated with the NDT fund investments of the Regulatory Agreement Units. Refer to Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT fund investments.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014 . The decrease in Other, net primarily reflects the net decrease in realized and unrealized gains related to the NDT fund investments of Generation's Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $(22) million and $67 million for the years ended December 31, 2015 and 2014, respectively, related to the contractual elimination of income tax expense associated with the NDT fund investments of the Regulatory Agreement Units. Refer to Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT fund investments.

The following table provides unrealized and realized gains (losses) on the NDT fund investments of the Non-Regulatory Agreement Units recognized in Other, net for 2016, 2015 and 2014:

	2016	2015	2014
Net unrealized gains (losses) on decommissioning trust funds	$194	$(197)	$134
Net realized gains on sale of decommissioning trust funds	35	66	77

Effective Income Tax Rate.

Generation's effective income tax rates for the years ended December 31, 2016, 2015 and 2014 were 33.2%, 27.1% and 16.9%, respectively. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—ComEd

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$5,254	$4,905	$ 349	$4,564	$ 341
Purchased power expense	1,458	1,319	(139)	1,177	(142)
Revenues net of purchased power expense [a][b]	3,796	3,586	210	3,387	199
Other operating expenses					
Operating and maintenance	1,530	1,567	37	1,429	(138)
Depreciation and amortization	775	707	(68)	687	(20)
Taxes other than income	293	296	3	293	(3)
Total other operating expenses	2,598	2,570	(28)	2,409	(161)
Gain on sales of assets	7	1	6	2	(1)
Operating income	1,205	1,017	188	980	37
Other income and (deductions)					
Interest expense, net	(461)	(332)	(129)	(321)	(11)
Other, net	(65)	21	(86)	17	4
Total other income and (deductions)	(526)	(311)	(215)	(304)	(7)
Income before income taxes	679	706	(27)	676	30
Income taxes	301	280	(21)	268	(12)
Net income	$ 378	$ 426	$ (48)	$ 408	$ 18

(a) ComEd evaluates its operating performance using the measure of Revenue net of purchased power expense. ComEd believes that Revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of Revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.
(b) For regulatory recovery mechanisms, including ComEd's electric distribution and transmission formula rates, and riders, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).

Net Income

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. ComEd's Net income for the year ended December 31, 2016 was lower than the same period in 2015 primarily due to the recognition of the penalty and the after-tax interest related to the Tax Court's decision on Exelon's like-kind exchange tax position, partially offset by increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE) and favorable weather.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. ComEd's Net income for the year ended December 31, 2015 was higher than the same period in 2014 primarily due to increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE), partially offset by unfavorable weather and volume.

Revenues Net of Purchased Power Expense

There are certain drivers of Operating revenues that are fully offset by their impact on Purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on Revenue net of purchased power expense. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries, but do affect ComEd's Operating revenues related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2016, 2015 and 2014, consisted of the following:

	For the Years Ended December 31,		
	2016	2015	2014
Electric	72%	76%	80%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2016, 2015 and 2014 consisted of the following:

	December 31, 2016		December 31, 2015		December 31, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
	1,502,900	38%	1,655,400	42%	2,426,900	63%

Under an Illinois law allowing municipalities to arrange the purchase of electricity for their participating residents, the City of Chicago previously participated in ComEd's customer choice program and arranged the purchase of electricity from Constellation (formerly Integrys), for those participating residents. In September 2015, the City of Chicago discontinued its participation in the customer choice program and many of those participating residents resumed their purchase of electricity from ComEd. ComEd's Operating revenues has increased as a result of the City of Chicago switching, but that increase is fully offset in Purchased power expense.

The changes in ComEd's Revenue net of purchased power expense for the year ended December 31, 2016 compared to the same period in 2015, and for the year ended December 31, 2015 compared to the same period in 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Weather	$ 54	$ (16)
Volume	(2)	(22)
Electric distribution revenue	69	180
Transmission revenue	97	48
Regulatory required programs	(31)	(1)
Uncollectible accounts recovery, net	(13)	27
Pricing and customer mix	14	(4)
Revenue subject to refund	—	9
Other	22	(22)
Increase in revenue net of purchased power	$ 210	$ 199

Weather. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the year ended December 31, 2016, favorable weather conditions increased Operating revenues net of purchased power expense when compared to the prior years. For the year ended December 31, 2015, unfavorable weather conditions reduced Operating revenues net of purchased power expense when compared to the prior years.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2016, 2015 and 2014 consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	5,715	6,091	6,341	(6.2)%	(9.9)%
Cooling Degree-Days	1,157	806	842	43.5%	37.4%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2015	2014	Normal	2015 vs. 2014	2015 vs. Normal
Heating Degree-Days	6,091	7,027	6,341	(13.3)%	(3.9)%
Cooling Degree-Days	806	799	842	0.9%	(4.3)%

Volume. Revenue net of purchased power expense remained relatively consistent as a result of delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016, reflecting a consistent average usage per residential customer as compared to the same period in 2015. For the year ended December 31, 2015, Revenue net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential customer and the impacts of energy efficiency programs, as compared to the same period in 2014.

Electric Distribution Revenue. EIMA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under EIMA, electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and allowed ROE. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points, subject to a collar of plus or minus 50 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on revenue. In addition, ComEd's allowed ROE is subject to reduction if ComEd does not deliver the reliability and customer service benefits to which it has committed over the ten-year life of the investment program. During the year ended December 31, 2016, electric distribution revenue increased $69 million, primarily due to increased capital investment and depreciation expense, partially offset by lower allowed ROE due to a decrease in treasury rates. During the year ended December 31, 2015, electric distribution revenue increased $180 million, primarily due to higher Operating and maintenance expense and increased capital investment, partially offset by lower allowed ROE due to decreased treasury rates. See Operating and Maintenance Expense below and Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. For the years ended December 31, 2016 and 2015, ComEd recorded increased transmission revenue due to increased capital investment, higher depreciation expense and increased highest daily peak load. See Operating and Maintenance Expense below and Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved riders to recover costs incurred for regulatory programs such as ComEd's energy efficiency and demand response and purchased power administrative costs. The riders are designed to provide full and current cost recovery. An equal and offsetting amount has been included in Operating and maintenance expense. See Operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Uncollectible accounts recovery, net, represents recoveries under ComEd's uncollectible accounts tariff. See Operating and maintenance expense discussion below for additional information on this tariff.

Pricing and Customer Mix. For the year ended December 31, 2016, the increase in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes and change in customer mix. For the year ended December 31, 2015, the decrease in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to lower overall effective rates due to increased usage across all major customer classes and change in customer mix.

Revenue Subject to Refund. ComEd records revenue subject to refund based upon its best estimate of customer collections that may be required to be refunded. Revenue net of purchase power expense was higher for the year ended December 31, 2015, due to the one-time revenue refund recorded in 2014 associated with the 2007 Rate Case.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental costs associated with MGP sites, and recoveries of energy procurement costs.

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2016	2015	2016 vs. 2015	2015	2014	2015 vs. 2014
Operating and maintenance expense—baseline	$ 1,347	$ 1,353	$ (6)	$ 1,353	$ 1,214	$ 139
Operating and maintenance expense—regulatory required programs (a)	183	214	(31)	214	215	(1)
Total operating and maintenance expense	$ 1,530	$ 1,567	$ (37)	$ 1,567	$ 1,429	$ 138

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for year ended December 31, 2016, compared to the same period in 2015, and for the year ended December 31, 2015, compared to the same period in 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Labor, other benefits, contracting and materials (a)	$ 12	$ 31
Pension and non-pension postretirement benefits expense (b)	(24)	19
Storm-related costs	(9)	27
Uncollectible accounts expense—provision (c)	5	(7)
Uncollectible accounts expense—recovery, net (c)	(18)	34
BSC costs (d)	29	30
Other	(1)	5
	(6)	139
Regulatory required programs		
Energy efficiency and demand response programs	(31)	(1)
Increase in operating and maintenance expense	$ (37)	$ 138

(a) Primarily reflects increased contracting costs related to preventative maintenance and other projects for the year ended December 31, 2015.
(b) Primarily reflects the favorable impact of higher assumed pension and OPEB discount rates for the year ended December 31, 2016 and the unfavorable impact of lower assumed pension and OPEB discount rates for the year ended December 31, 2015.

(c) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. ComEd recorded a net decrease and increase in 2016 and 2015, respectively, in Operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting amount has been recognized in Operating revenues for the periods presented.
(d) Primarily reflects increased information technology support services from BSC during 2016 and 2015.

Depreciation and Amortization Expense

The increases in Depreciation and amortization expense for 2016 compared to 2015, and 2015 compared to 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense (a)	$ 58	$ 43
Regulatory asset amortization (b)	(5)	(28)
Other	15	5
Total increase	$ 68	$ 20

(a) Primarily reflects ongoing capital expenditures for the years ended December 31, 2016 and 2015.
(b) Primarily reflects a decrease in MGP regulatory asset amortization for the year ended December 31, 2015,

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income taxes remained relatively consistent for the year ended December 31, 2016 compared to the same period in 2015, and for the year ended December 31, 2015 compared to the same period in 2014.

Gain on Sale of Assets

Gain on sale of assets increased primarily due to the sale of land during the year ended December 31, 2016, compared to the same period in 2015. Gain on sale of assets remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014.

Interest Expense, Net

The increases in Interest expense, net, for the year ended 2016 compared to the same period in 2015, and for the year ended 2015 compared to the same period in 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Interest expense related to uncertain tax positions (a)	$ 109	$ 2
Interest expense on debt (including financing trusts) (b)	24	13
Other	(4)	(4)
Increase (decrease) in interest expense, net	$ 129	$ 11

(a) Primarily reflects the recognition of after-tax interest related to the Tax Court's decision on Exelon's like-kind exchange tax position in the third quarter of 2016. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Primarily reflects an increase in interest expense due to the issuance of First Mortgage Bonds for the years ended December 31, 2016 and 2015. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's debt obligations.

Other, Net

The increase (decrease) in other, net, for the year ended 2016 compared to the same period in 2015, and for the year ended 2015 compared to the same period in 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Other income and deductions, net [a]	$ (94)	$ 2
AFUDC equity	9	2
Other	(1)	—
Increase (decrease) in other, net	$ (86)	$ 4

(a) Primarily reflects the recognition of the penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position in the third quarter of 2016. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Effective Income Tax Rate

ComEd's effective income tax rates for the years ended December 31, 2016, 2015 and 2014, were 44.3%, 39.7% and 39.6%, respectively. The increase in the effective income tax rate for the year ended December 31, 2016 compared to the same period in 2015 is primarily due to the recognition of a non-deductible penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position in the third quarter of 2016. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [a]							
Residential	27,790	26,496	4.9%	(0.6)%	27,230	(2.7)%	(1.5)%
Small commercial & industrial	31,975	31,717	0.8%	(0.3)%	32,146	(1.3)%	(0.9)%
Large commercial & industrial	27,842	27,210	2.3%	1.5%	27,847	(2.3)%	(2.0)%
Public authorities & electric railroads	1,298	1,309	(0.8)%	(0.8)%	1,358	(3.6)%	(2.6)%
Total retail deliveries	88,905	86,732	2.5%	0.2%	88,581	(2.1)%	(1.4)%

	As of December 31,		
Number of Electric Customers	2016	2015	2014
Residential	3,595,376	3,550,239	3,502,386
Small commercial & industrial	374,644	370,932	369,053
Large commercial & industrial	2,007	1,976	1,998
Public authorities & electric railroads	4,750	4,820	4,815
Total	3,976,777	3,927,967	3,878,252

Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [a]					
Residential	$2,597	$2,360	10.0%	$2,074	13.8%
Small commercial & industrial	1,316	1,337	(1.6)%	1,335	0.1%
Large commercial & industrial	462	443	4.3%	434	2.1%
Public authorities & electric railroads	45	42	7.1%	46	(8.7)%
Total retail	4,420	4,182	5.7%	3,889	7.5%
Other revenue [b]	834	723	15.4%	675	7.1%
Total electric revenue [c]	$5,254	$4,905	7.1%	$4,564	7.5%

(a) Reflects delivery revenue and volume from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.
(b) Other revenue primarily includes transmission revenue from PJM. Other revenue also includes rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of remediation costs associated with MGP sites.
(c) Includes operating revenues from affiliates totaling $15 million, $4 million, and $4 million for the years ended December 31, 2016, 2015, and 2014, respectively.

Results of Operations—PECO

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$2,994	$3,032	$ (38)	$3,094	$ (62)
Purchased power and fuel	1,047	1,190	143	1,261	71
Revenues net of purchased power and fuel expense [a]	1,947	1,842	105	1,833	9
Other operating expenses					
Operating and maintenance	811	794	(17)	866	72
Depreciation and amortization	270	260	(10)	236	(24)
Taxes other than income	164	160	(4)	159	(1)
Total other operating expenses	1,245	1,214	(31)	1,261	47
Gain on sales of assets	—	2	(2)	—	2
Operating income	702	630	72	572	58
Other income and (deductions)					
Interest expense, net	(123)	(114)	(9)	(113)	(1)
Other, net	8	5	3	7	(2)
Total other income and (deductions)	(115)	(109)	(6)	(106)	(3)
Income before income taxes	587	521	66	466	55
Income taxes	149	143	(6)	114	(29)
Net income attributable to common shareholder	$ 438	$ 378	$ 60	$ 352	$ 26

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to

evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. PECO's net income attributable to common shareholder for the year ended December 31, 2016 was higher than the same period in 2015, primarily due to an increase in Revenues net of purchased power and fuel expense as a result of increased electric distribution revenue pursuant to the 2015 PAPUC authorized electric distribution rate increase effective January 1, 2016.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. PECO's net income attributable to common shareholder for the year ended December 31, 2015 was higher than the same period in 2014, primarily due to a decrease in Operating and maintenance expense due to a decrease in storm costs.

Revenues Net of Purchased Power and Fuel Expense

Electric and natural gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments as specified in the PAPUC-approved tariffs that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with PECO's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and natural gas revenues net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer Choice Program activity has no impact on electric and natural gas revenue net of purchase power and fuel expense.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the years ended December 31, 2016, 2015, and 2014 consisted of the following:

	For the Years Ended December 31,		
	2016	2015	2014
Electric	70%	70%	70%
Natural Gas	26%	25%	22%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2016, 2015, and 2014 consisted of the following:

	December 31, 2016		December 31, 2015		December 31, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	587,200	36%	563,400	35%	546,900	34%
Natural Gas	81,300	16%	81,100	16%	78,400	16%

The changes in PECO's Operating revenues net of purchased power and fuel expense for the years ended December 31, 2016 and December 31, 2015 compared to the same periods in 2015 and 2014, respectively, consisted of the following:

	2016 vs. 2015 Increase (Decrease)			2015 vs. 2014 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ 1	$ (12)	$ (11)	$ 28	$ (19)	$ 9
Volume	6	4	10	4	7	11
Pricing	160	(1)	159	4	2	6
Regulatory required programs	(46)	—	(46)	(6)	—	(6)
Other	(7)	—	(7)	(12)	1	(11)
Total increase (decrease)	$ 114	$ (9)	$ 105	$ 18	$ (9)	$ 9

Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. Operating revenues net of purchased power and fuel expense for the year ended December 31, 2016 was reduced by the impact of unfavorable weather conditions in PECO's service territory.

Operating revenues net of purchased power and fuel expense for the year ended December 31, 2015, was higher primarily due to the impact of favorable 2015 summer and first quarter winter weather conditions, partially offset by the impact of unfavorable fourth quarter 2015 winter weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the years ended December 31, 2016 and December 31, 2015 compared to the same periods in 2015 and 2014, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	4,041	4,245	4,613	(4.8)%	(12.4)%
Cooling Degree-Days	1,726	1,720	1,301	0.3%	32.7%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2015	2014	Normal	2015 vs. 2014	2015 vs. Normal
Heating Degree-Days	4,245	4,749	4,613	(10.6)%	(8.0)%
Cooling Degree-Days	1,720	1,311	1,301	31.2%	32.2%

Volume. The increase in Operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 and 2015, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for gas and residential and small commercial and industrial electric classes. Additionally, the increase represents a shift in the volume profile across classes from large commercial and industrial classes to residential and small commercial and industrial classes for electric.

Pricing. The increase in electric operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2016 reflects an increase in electric distribution rates charged to customers. The increase in electric distribution rates was effective January 1, 2016 in accordance with the 2015 PAPUC approved electric distribution rate case settlement. See Note 3—Regulatory Matters for further information.

The increase in electric operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2015 is primarily attributable to increased monthly customer demand in the commercial and industrial classes. The increase in natural gas operating revenues net of fuel expense as a result of pricing for the year ended December 31, 2015, is primarily attributable to higher overall effective rates due to decreased retail gas usage.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

Other. Other revenue, which can vary period to period, primarily includes wholesale transmission revenue, rental revenue, revenue related to late payment charges and assistance provided to other utilities through mutual assistance programs.

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2016	2015	2016 vs. 2015	2015	2014	2015 vs. 2014
Operating and maintenance expense—baseline	$ 740	$ 685	$ 55	$ 685	$ 761	$ (76)
Operating and maintenance expense—regulatory required programs [a]	71	109	$ (38)	109	105	$ 4
Total operating and maintenance expense	$ 811	$ 794	$ 17	$ 794	$ 866	$ (72)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in Operating and maintenance expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Labor, other benefits, contracting and materials	$ 22	$ 1
Storm-related costs	(9)	(78) [b]
Pension and non-pension postretirement benefits expense	(4)	3
PHI merger integration costs	6	2
BSC costs [a]	36	9
Uncollectible accounts expense	1	(22)
Other	3	9
	55	(76)
Regulatory required programs		
Smart meter	(28)	(3)
Energy efficiency	(7)	8
GSA	(2)	—
Other	(1)	(1)
	(38)	4
Increase (decrease) in operating and maintenance expense	$ 17	$ (72)

(a) Primarily reflects increased information technology support services from BSC during 2016.
(b) Reflects a reduction of $67 million in incremental storm costs, primarily as a result of the February 5, 2014 ice storm.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2016 compared to 2015 and 2015 compared to 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense	$ 5	$ 13
Regulatory asset amortization	5	11
Increase in depreciation and amortization expense	$ 10	$ 24

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income increased for the year ended December 31, 2016, compared to the same period in 2015 primarily due to an increase in gross receipts tax driven by increases in electric revenue, which was impacted primarily by the new distribution rates that went into effect in January 2016 .

Taxes other than income remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014.

Interest Expense, Net

The increase in Interest expense, net for the year ended December 31, 2016, compared to the same period in 2015, primarily reflects an increase in interest expense due to the issuance of First and Refunding Mortgage Bonds in October 2015.

Interest expense, net remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014.

Other, Net

Other, net remained relatively consistent for the year ended December 31, 2016, compared to the same period in 2015, and the year ended December 31, 2015, compared to the same period in 2014.

Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2016, 2015 and 2014 were 25.4%, 27.4% and 24.5%, respectively. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries (a)							
Residential	13,664	13,630	0.2%	0.4%	13,222	3.1%	0.3%
Small commercial & industrial	8,099	8,118	(0.2)%	0.5%	8,025	1.2%	0.6%
Large commercial & industrial	15,263	15,365	(0.7)%	(1.4)%	15,310	0.4%	(0.5)%
Public authorities & electric railroads	890	881	1.0%	1.0%	937	(6.0)%	(6.0)%
Total electric retail deliveries	37,916	37,994	(0.2)%	(0.3)%	37,494	1.3%	(0.1)%

	As of December 31,		
Number of Electric Customers	2016	2015	2014
Residential	1,456,585	1,444,338	1,434,011
Small commercial & industrial	150,142	149,200	149,149
Large commercial & industrial	3,096	3,091	3,103
Public authorities & electric railroads	9,823	9,805	9,734
Total	1,619,646	1,606,434	1,595,997

Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales (a)					
Residential	$1,631	$1,599	2.0%	$1,555	2.8%
Small commercial & industrial	430	428	0.5%	423	1.2%
Large commercial & industrial	234	221	5.9%	217	1.8%
Public authorities & electric railroads	32	31	3.2%	32	(3.1)%
Total retail	2,327	2,279	2.1%	2,227	2.3%
Other revenue (b)	204	207	(1.4)%	221	(6.3)%
Total electric operating revenues (c)	$2,531	$2,486	1.8%	$2,448	1.6%

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenue.
(c) Total electric revenue includes operating revenues from affiliates totaling $7 million, $1 million and $1 million for the years ended December 31, 2016, 2015, and 2014, respectively.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries (a)							
Retail sales	56,447	59,003	(4.3)%	1.5%	62,734	(5.9)%	3.3%
Transportation and other	27,630	27,879	(0.9)%	(0.1)%	27,208	2.5%	1.2%
Total natural gas deliveries	84,077	86,882	(3.2)%	1.0%	89,942	(3.4)%	2.6%

Number of Gas Customers	As of December 31, 2016	2015	2014
Residential	472,606	467,263	462,663
Commercial & industrial	43,668	43,160	42,686
Total retail	516,274	510,423	505,349
Transportation	790	827	855
Total	517,064	511,250	506,204

Gas revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales (a)					
Retail sales	$430	$511	(15.9)%	$608	(16.0)%
Transportation and other	33	35	(5.7)%	38	(7.9)%
Total natural gas operating revenues (b)	$463	$546	(15.2)%	$646	(15.5)%

(a) Reflects delivery volumes and revenue from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.
(b) Total natural gas revenues includes operating revenues from affiliates totaling $1 million for the years ended December 31, 2016, 2015 and 2014.

Results of Operations—BGE

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$3,233	$3,135	$ 98	$3,165	$ (30)
Purchased power and fuel expense	1,294	1,305	11	1,417	112
Revenues net of purchased power and fuel expense [a]	1,939	1,830	109	1,748	82
Other operating expenses					
Operating and maintenance	737	683	(54)	717	34
Depreciation and amortization	423	366	(57)	371	5
Taxes other than income	229	224	(5)	221	(3)
Total other operating expenses	1,389	1,273	(116)	1,309	36
Gain on sales of assets	—	1	(1)	—	1
Operating income	550	558	(8)	439	119
Other income and (deductions)					
Interest expense, net	(103)	(99)	(4)	(106)	7
Other, net	21	18	3	18	—
Total other income and (deductions)	(82)	(81)	(1)	(88)	7
Income before income taxes	468	477	(9)	351	126
Income taxes	174	189	15	140	(49)
Net income	294	288	6	211	77
Preference stock dividends	8	13	5	13	—
Net income attributable to common shareholder	$ 286	$ 275	$ 11	$ 198	$ 77

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenues net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. Net income attributable to common shareholder was higher primarily due to lower income tax expense and decreased preference stock dividends partially offset by slightly lower operating income. The lower income tax expense was driven by a one-time adjustment associated with transmission-related regulatory assets. The slight decrease in operating income was driven by an increase in Operating and maintenance expense as a result of cost disallowances which reduced certain regulatory assets and other long-lived assets stemming from the distribution rate orders issued by the MDPSC in June 2016 and July 2016 and increased storm costs. This increase in Operating and maintenance expense was offset by an increase in Revenues net of purchased power and fuel expense, primarily as a result of an increase in transmission formula rate revenues and higher electric and natural gas revenues as a result of the distribution rate orders issued by the MDPSC in June 2016 and July 2016.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. Net income attributable to common shareholder was higher primarily due to an increase in Revenues net of purchased power and fuel expense as a result of the December 2014 electric and natural gas distribution rate order issued by the MDPSC, an increase in transmission formula rate revenues and a reduction in Operating and maintenance expense as a result of a decrease in bad debt expense and storm costs in the BGE service territory.

Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to Operating revenues that are offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Operating revenues and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in the number of customers electing to use a competitive electric generation or natural gas supplier. All BGE customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. This customers' choice of suppliers does not impact the volume of deliveries, but does affect revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) at December 31, 2016, 2015 and 2014 consisted of the following:

	For the Years Ended December 31,		
	2016	2015	2014
Electric	59%	61%	60%
Natural Gas	57%	56%	53%

The number of retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2016, 2015 and 2014 consisted of the following:

	December 31, 2016		December 31, 2015		December 31, 2014	
	Number of Customers	% of total retail customers	Number of Customers	% of total retail customers	Number of Customers	% of total retail customers
Electric	337,000	27%	343,000	27%	364,000	29%
Natural Gas	151,000	23%	154,000	23%	161,000	25%

The changes in BGE's Operating revenues net of purchased power and fuel expense for the year ended December 31, 2016 compared to the same period in 2015 and for the year ended December 31, 2015 compared to the same period in 2014, respectively, consisted of the following:

	2016 Increase (Decrease)			2015 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	$ 24	$ 22	$ 46	$ 20	$ 35	$ 55
Regulatory required programs	15	2	17	4	2	6
Transmission revenue	30	—	30	11	—	11
Other, net	19	(3)	16	10	—	10
Total increase	$ 88	$ 21	$109	$ 45	$ 37	$ 82

Distribution Rate Increase. The increase in distribution revenues for the year ended December 31, 2016 was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in June 2016 in accordance with the MDPSC approved electric and natural gas distribution rate case orders in June 2016 and July 2016. The increase in distribution revenue for the year ended December 31, 2015 was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in December 2014 in accordance with the MDPSC approved electric and natural gas distribution rate case order. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and usage conditions. The MDPSC allows BGE to record a monthly adjustment to its electric and natural gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service natural gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and natural gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of changes in actual consumption levels. This allows BGE to recognize revenue at MDPSC-approved levels per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while this revenue is affected by customer growth (i.e., increase in the number of customers), it will not be affected by actual weather or usage conditions (i.e., changes in consumption per customer). BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating and cooling degree days in BGE's service territory for the year ended December 31, 2016 compared to the same period in 2015 and for the year ended December 31, 2015 compared to the same period in 2014, respectively, and normal weather consisted of the following:

	For the Year Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	4,427	4,666	4,684	(5.1)%	(5.5)%
Cooling Degree-Days	998	924	876	8.0%	13.9%

	For the Year Ended December 31,			% Change	
Heating and Cooling Degree-Days	2015	2014	Normal	2015 vs. 2014	2015 vs. Normal
Heating Degree-Days	4,666	5,091	4,663	(8.3)%	0.1%
Cooling Degree-Days	924	732	875	26.2%	5.6%

Regulatory Required Programs. This represents the change in revenue collected under approved riders to recover costs incurred for the energy efficiency and demand response programs. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in BGE's Consolidated Statements of Operations and Comprehensive Income.

Transmission Revenue. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. During the years ended December 31, 2016 and 2015, the increase in transmission revenue was primarily due to increases in rates to reflect capital investment and operating and maintenance expense recoveries. See Operating and Maintenance Expense below and Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net. Other net revenue, which can vary from period to period, includes commodity electric and gas revenue and other miscellaneous revenue such as service application and late payment fees; partially offset by commodity electric and gas purchased fuel and energy.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Impairment on long-lived assets and losses on regulatory assets [a]	$ 52	$ —
Labor, other benefits, contracting and materials	7	12
Storm-related costs	18	(21)
Uncollectible accounts expense [b]	(14)	(49)
BSC costs [c]	11	13
Conduit lease settlement	(15)	—
Other	(5)	11
Increase (Decrease) in operating and maintenance expense	$ 54	$ (34)

(a) See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Uncollectible accounts expense decreased primarily due to improved customer behavior and milder weather for the years ended December 31, 2016 and 2015.
(c) Primarily reflects increased information technology support services and other services from BSC for the year ended December 31, 2016 and increased information technology support services for the year ended 2015.

On September 23, 2015, the Baltimore City Board of Estimates approved an increase in annual rental fees for access to the Baltimore City underground conduit system effective November 1, 2015, from $12 million to $42 million, subject to an annual increase thereafter based on the Consumer Price Index. BGE subsequently entered into litigation with the City regarding the amount of and basis for establishing the conduit fee. On November 30, 2016, the Baltimore City Board of Estimates approved a settlement agreement entered into between BGE and the City to resolve the disputes and pending litigation related to BGE's use of and payment for the underground conduit system. As a result of the settlement, the parties have entered into a six-year lease that reduces the annual expense to $25 million in the first three years and caps the annual expense in the last three years to not more than $29 million. BGE recorded a credit to Operating and maintenance expense in the fourth quarter of

approximately $28 million for the reversal of the previously higher fees accrued in the current year as well as the settlement of prior year disputed fee true-up amounts. See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the financial impacts of the newly agreed upon six-year lease.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense (a)	$ 10	$ 2
Regulatory asset amortization (b)	47	(6)
Other	—	(1)
Increase (Decrease) in depreciation and amortization expense	$ 57	$ (5)

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to an increase in regulatory asset amortization related to energy efficiency programs and the initiation of cost recovery of the AMI programs under the final electric and natural gas distribution rate case order issued by the MDPSC in June 2016. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Taxes Other Than Income

The change in taxes other than income for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Property tax	$ 6	$ 3
Franchise tax	—	1
Other	—	(1)
Increase in taxes other than income	$ 6	$ 3

Interest Expense, Net

The decrease in Interest expense, net for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Interest expense on debt (including financing trusts)	$ 5	$ (4)
Interest expense related to capitalization of interest / AFUDC	3	(2)
Interest expense related to uncertain tax positions	—	(1)
Interest Expense related to repayment of the rate stabilization bonds	(4)	—
Increase (Decrease) in interest expense, net	$ 4	$ (7)

Effective Income Tax Rate

BGE's effective income tax rates for the years ended December 31, 2016, 2015 and 2014 were 37.2%, 39.6% and 39.9%, respectively. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [a]							
Residential	12,740	12,598	1.1%	n.m.	12,974	(2.9)%	n.m.
Small commercial & industrial	3,040	3,119	(2.5)%	n.m.	3,086	1.1%	n.m.
Large commercial & industrial	13,957	14,293	(2.4)%	n.m.	14,191	0.7%	n.m.
Public authorities & electric railroads	283	294	(3.7)%	n.m.	311	(5.5)%	n.m.
Total electric deliveries	30,020	30,304	(0.9)%	n.m.	30,562	(0.8)%	n.m.

Number of Electric Customers	As of December 31, 2016	2015	2014
Residential	1,150,096	1,137,934	1,125,369
Small commercial & industrial	113,230	113,138	112,972
Large commercial & industrial	12,053	11,906	11,730
Public authorities & electric railroads	280	285	290
Total	1,275,659	1,263,263	1,250,361

Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [a]					
Residential	$1,554	$1,449	7.2%	$1,404	3.2%
Small commercial & industrial	277	273	1.5%	271	0.7%
Large commercial & industrial	449	469	(4.3)%	491	(4.5)%
Public authorities & electric railroads	35	32	9.4%	32	— %
Total retail	2,315	2,223	4.1%	2,198	1.1%
Other revenue [b]	294	267	10.1%	262	1.9%
Total electric operating revenues	$2,609	$2,490	4.8%	$2,460	1.2%

(a) Reflects delivery revenue and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.

(b) Includes operating revenues from affiliates totaling $7 million for the year ended December 31, 2016 and less than $1 million in the years ended December 31, 2015 and 2014, respectively.

BGE Natural Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries (a)							
Retail sales	96,808	96,618	0.2%	n.m.	99,194	(2.6)%	n.m.
Transportation and other (b)	5,977	6,238	(4.2)%	n.m.	9,242	(32.5)%	n.m.
Total natural gas deliveries	102,785	102,856	(0.1)%	n.m.	108,436	(5.1)%	n.m.

	As of December 31,		
Number of Gas Customers	2016	2015	2014
Residential	623,647	616,994	609,626
Commercial & industrial	44,255	44,119	44,200
Total	667,902	661,113	653,826

Natural Gas revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales (a)					
Retail sales	$593	$607	(2.3)%	$622	(2.4)%
Transportation and other (b)	31	38	(18.4)%	83	(54.2)%
Total natural gas revenues (c)	$624	$645	(3.3)%	$705	(8.5)%

(a) Reflects delivery volumes and revenue from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.
(b) Transportation and other gas revenue includes off-system revenue of 5,977 mmcfs ($23 million), 6,238 mmcfs ($35 million), and 9,242 mmcfs ($72 million) for the years ended 2016, 2015 and 2014, respectively.
(c) Includes operating revenues from affiliates totaling $14 million, $14 million, and $25 million for the years ended 2016, 2015 and 2014, respectively.

Results of Operations—PHI

PHI's results of operations include the results of its three reportable segments, Pepco, DPL and ACE for all periods presented below. For "Predecessor" reporting periods, PHI's results of operations also include the results of PES and PCI. See Note 26—Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding PHI's reportable segments. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for Pepco, DPL and ACE is presented elsewhere in this report.

As a result of the PHI Merger, the following consolidated financial results present two separate reporting periods for 2016. The "Predecessor" reporting periods represent PHI's results of operations for the period of January 1, 2016 to March 23, 2016 and the years ended December 31, 2015 and 2014. The "Successor" reporting period represents PHI's results of operations for the period of March 24, 2016 to December 31, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	Successor	*Predecessor*		
	March 24 to December 31, 2016	**January 1 to March 23, 2016**	**For the Years Ended December 31, 2015**	**2014**
Operating revenues	$ 3,643	$ 1,153	$ 4,935	$ 4,808
Purchased power and fuel	1,447	497	2,073	2,057
Revenues net of purchased power and fuel expense (a)	2,196	656	2,862	2,751
Other operating expenses				
Operating and maintenance	1,233	294	1,156	1,183
Depreciation, amortization and accretion	515	152	624	526
Taxes other than income	354	105	455	437
Total other operating expenses	2,102	551	2,235	2,146
(Loss) gain on sales of assets	(1)	—	46	—
Operating income	93	105	673	605
Other income and (deductions)				
Interest expense, net	(195)	(65)	(280)	(269)
Other, net	44	(4)	88	44
Total other income and (deductions)	(151)	(69)	(192)	(225)
(Loss) Income before income taxes	(58)	36	481	380
Income taxes	3	17	163	138
Net (loss) income from continuing operations	(61)	19	318	242
Net income from discontinued operations	—	—	9	—
Net (loss) income attributable to membership interest/common shareholders	$ (61)	$ 19	$ 327	$ 242

(a) PHI evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. PHI believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. PHI has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Successor Period of March 24, 2016 to December 31, 2016

PHI's net loss attributable to membership interest for the Successor period of March 24, 2016 to December 31, 2016 was $61 million. There were no significant changes in the underlying trends affecting PHI's results of operations during the Successor period March 24, 2016 to December 31,

2016 except for the pre-tax recording of $392 million of non-recurring merger-related costs including merger integration and merger commitments within Operating and maintenance expense. For more information on 2016 versus 2015 results please refer to Results of Operations for Pepco, DPL and ACE.

PHI's effective income tax rate for the period of March 24, 2016 to December 31, 2016 was (5.2)%. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Predecessor Period of January 1, 2016 to March 23, 2016

PHI's net income attributable to membership interest for the Predecessor period of January 1, 2016 to March 23, 2016 was $19 million. There were no significant changes in the underlying trends affecting PHI's results of operations during the Predecessor period of January 1, 2016 to March 23, 2016 except for the pre-tax recording of $29 million of non-recurring merger-related costs within Operating and maintenance expense and $18 million of preferred stock derivative expense within Other, net.

PHI's effective income tax rate for the period of January 1, 2016 to March 23, 2016 was 47.2%. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Predecessor Period Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

PHI's net income attributable to common shareholders was $327 million for the year ended December 31, 2015 as compared to $242 million for the year ended December 31, 2014.

Revenues Net of Purchased Power and Fuel Expense

Operating revenues net of purchased power and fuel expense, which is a non-GAAP measure discussed above, increased by $111 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. The increase is attributable to the following factors:

- Increase of $90 million at Pepco primarily related to electric distribution revenue increases totaling $46 million due to electric distribution base rate increases in the District of Columbia effective April 2014 and in Maryland effective July 2014 and customer growth, $34 million in required regulatory programs primarily due to EmPower Maryland rate increases effective February 2015 and 2014, and $10 million higher transmission revenue due to higher rates effective June 1, 2015 and June 1, 2014.
- Increase of $26 million at DPL primarily related to electric distribution revenue increases totaling $7 million due to higher weather-related sales and customer growth, $17 million in required regulatory programs primarily due to EmPower Maryland rate increases effective February 2015 and 2014, and $7 million higher transmission revenue due to higher rates effective June 1, 2015 and June 1, 2014, partially offset by lower natural gas distribution revenues totaling $5 million due to milder weather.
- Increase of $41 million at ACE primarily related to electric distribution revenue increases totaling $26 million due to an electric distribution rate increase effective September 2014 and higher weather-related sales and $15 million in required regulatory programs.
- Decrease of $47 million at PES primarily related to lower energy efficiency construction activity in 2015.

Operating and Maintenance Expense

Operating and maintenance expense decreased by $27 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. The decrease is attributable to the following factors:

- Increase of $107 million at Pepco, DPL and ACE primarily due to higher labor, contracting and material costs related to the implementation of a new customer information system in 2015, increased bad debt expense, higher tree-trimming and system maintenance costs, higher customer service costs, and higher environmental remediation costs.
- Decrease of $118 million at PES primarily due to 2014 impairment losses associated with its combined heat and power thermal generating facilities and operations in Atlantic City.
- Decrease of $15 million at Corporate due primarily to lower Merger-related transaction and integration costs.

Depreciation, Amortization and Accretion Expense

Depreciation, amortization and accretion expense increased by $98 million primarily due to an increase of $48 million associated with EmPower Maryland surcharge rate increases effective February 2015 and February 2014, higher depreciation of $23 million due to on-going capital expenditures at Pepco, DPL, and ACE, an increase of $15 million in the amortization of stranded costs, primarily as the result of higher revenue due to a rate increase effective October 2014 for the ACE Market Transition Tax and an increase of $10 million in amortization of software, primarily related to the implementation of a new customer information system.

Taxes Other Than Income

Taxes other than income increased by $18 million primarily due to higher property taxes related to an increase in assets.

(Loss) gain on Sale of Assets

(Loss) gain on sale of assets increased by $46 million due to 2015 gains recorded at Pepco associated with the sale of unimproved land, held as non-utility property.

Interest Expense, Net

Interest expense increased by $11 million due to higher long-term and short-term debt.

Other, Net

Other, net increased by $44 million due to $33 million of interest income on uncertain tax positions from the PHI Global Tax Settlement and an increase in income of $15 million due to an increase in the fair value of the derivative related to preferred stock.

Effective Income Tax Rate

PHI's effective income tax rates for the years ended December 31, 2015 and December 31, 2014 were 33.9% and 36.3%, respectively. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—Pepco

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$2,186	$2,129	$ 57	$2,055	$ 74
Purchased power expense	706	719	13	735	16
Revenues net of purchased power expense [(a)]	1,480	1,410	70	1,320	90
Other operating expenses					
Operating and maintenance	642	439	(203)	390	(49)
Depreciation and amortization	295	256	(39)	212	(44)
Taxes other than income	377	376	(1)	369	(7)
Total other operating expenses	1,314	1,071	(243)	971	(100)
Gain on sales of assets	8	46	(38)	—	46
Operating income	174	385	(211)	349	36
Other income and (deductions)					
Interest expense, net	(127)	(124)	(3)	(115)	(9)
Other, net	36	28	8	30	(2)
Total other income and (deductions)	(91)	(96)	5	(85)	(11)
Income before income taxes	83	289	(206)	264	25
Income taxes	41	102	61	93	(9)
Net income attributable to common shareholder	$ 42	$ 187	$ (145)	$ 171	$ 16

(a) Pepco evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. Pepco believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Pepco has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. Pepco's net income attributable to common shareholder for the year ended December 31, 2016, was lower than the same period in 2015, primarily due to an increase in Operating and maintenance expense due to merger-related costs.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The increase in net income attributable to common shareholder was driven primarily by an increase in gains recorded from the sale of certain Pepco properties in 2015 and higher Operating revenues net of purchased power expense resulting from customer growth and electric distribution base rate increases in 2014 in the District of Columbia and Maryland, partially offset by an increase in Operating and maintenance expense primarily due to the implementation of a new customer information system and higher maintenance expense.

Revenues Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to Pepco's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that Pepco receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All Pepco customers have the choice to purchase electricity from competitive electric generation suppliers. The customers' choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2016, 2015, and 2014 respectively , consisted of the following:

	For the Years Ended December 31,		
	2016	2015	2014
Electric	65%	65%	65%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2016, 2015, and 2014 consisted of the following:

	December 31, 2016		December 31, 2015		December 31, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	176,372	21%	173,222	21%	179,524	22%

Retail deliveries purchased from competitive electric generation suppliers represented 73% of Pepco's retail kWh sales to the District of Columbia customers and 59% of Pepco's retail kWh sales to Maryland customers for the year ended December 31, 2016 ; 71% of Pepco's retail kWh sales to the District of Columbia customers and 60% of Pepco's retail kWh sales to Maryland customers for the year ended December 31, 2015; and 73% of Pepco's retail kWh sales to the District of Columbia customers and 59% of Pepco's retail kWh sales to Maryland customers for year ended December 31, 2014.

The costs related to default electricity supply are included in Purchased power expense. Operating revenues also include transmission enhancement credits that Pepco receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Purchased power expense consists of the cost of electricity purchased by Pepco to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders.

The changes in Pepco's operating revenues net of purchased power expense for the years ended December 31, 2016 and 2015 compared to the same periods in 2015 and 2014, respectively, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Volume	$ 15	$ 24
Pricing—distribution revenues	5	20
Regulatory required programs	48	34
Transmission revenues	(1)	10
Other	3	2
Total increase	$ 70	$ 90

Revenue Decoupling. Pepco's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco in Maryland and in the District of Columbia, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

In accounting for the BSA in Maryland and the District of Columbia, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from Maryland and the District of Columbia retail distribution sales falls short of the revenue that Pepco is entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that Pepco is entitled to earn based on the approved distribution charge per customer.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in Pepco's service territory. The changes in heating and cooling degree days in Pepco's service territory for the years ended December 31, 2016 and December 31, 2015 compared to same periods in 2015 and 2014, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	3,624	3,657	3,887	(0.9)%	(6.8)%
Cooling Degree-Days	1,936	1,936	1,626	— %	19.1%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2015	2014	Normal	2015 vs. 2014	2015 vs. Normal
Heating Degree-Days	3,657	4,017	3,914	(9.0)%	(6.6)%
Cooling Degree-Days	1,936	1,662	1,614	16.5%	20.0%

Volume. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015 primarily reflects the impact of moderate economic and customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2015 compared to the same period in 2014 primarily reflects the impact of moderate economic and customer growth.

Pricing—Distribution Revenues. The increase in electric operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution rates charged to customers in Maryland that became effective in November 2016. The increase in distribution revenue for the year ended December 31, 2015 compared to the same period in 2014 was primarily due to the impact of the new electric distribution rates charged to customers in the District of Columbia effective April 2014 and in Maryland effective July 2014. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Transmission Revenues . Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. Transmission revenue decreased for the year ended December 31, 2016 compared to the same period in 2015 due to lower revenue related to the MAPP abandonment recovery period that ended in March 2016, partially offset by higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses. Transmission revenue increased for the year ended December 31, 2015 compared to the same period in 2014 due to higher rates effective June 1, 2015 and June 1, 2014 related to increases in transmission plant investment and operating expenses, partially offset by the establishment of a reserve related to the FERC ROE challenges in 2015.

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2016	2015	2016 vs. 2015	2015	2014	2015 vs. 2014
Operating and maintenance expense—baseline	$631	$427	$ 204	$427	$379	$ 48
Operating and maintenance expense—regulatory required programs [a]	11	12	(1)	12	11	1
Total operating and maintenance expense	$642	$439	$ 203	$439	$390	$ 49

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in operating and maintenance expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Labor, other benefits, contracting and materials	$ 7	$ 26
Storm-related costs	6	(3)
Pension and non-pension postretirement benefits expense	—	4
Remeasurement of AMI—related regulatory asset	7	—
Deferral of billing system transition costs to regulatory asset	(7)	—
Deferral of merger-related costs to regulatory asset	(11)	—
Uncollectible accounts expense—provision	8	4
BSC and PHISCO allocations (a)	53	15
Merger commitments (b)	126	—
Write-off of construction work in progress (c)	13	—
Other	2	2
	204	48
Regulatory required programs		
Purchased power administrative costs	(1)	1
	(1)	1
Total increase	$ 203	$ 49

(a) Primarily related to merger severance and compensation costs for the year ended December 31, 2016 compared to the same period in 2015.
(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.
(c) Primarily resulting from a review of capital projects during the fourth quarter of 2016.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense (a)	$ 11	$ 10
Regulatory asset amortization (b)	28	34
Total increase	$ 39	$ 44

(a) Depreciation expense increased primarily due to ongoing capital expenditures.
(b) Regulatory asset amortization increased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to an EmPower Maryland surcharge rate increase effective February 2016, partially offset by lower amortization of MAPP abandonment costs and for the year ended December 31, 2015 compared to the same period in 2014 due to an EmPower Maryland surcharge rate increase effective February 2015.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher utility taxes that are collected and passed through by Pepco, partially offset by lower property taxes in Maryland. Taxes other than income for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to higher property taxes in Maryland.

Gain on Sales of Assets

Gain on Sale of Assets for the year ended December 31, 2016 compared to the same period in 2015 decreased primarily due to higher gains recorded in 2015 at Pepco associated with the sale of land held as non-utility property. Gain on sale of assets for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to 2015 gains recorded at Pepco associated with the sale of land.

Interest Expense, Net

Interest expense, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to the recording of interest expense for an uncertain tax position in 2016, partially offset by an increase in capitalized AFUDC debt. Interest expense, net for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to higher long-term debt interest expense.

Other, Net

Other, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC equity. Other, net for the year ended December 31, 2015 compared to the same period in 2014 decreased primarily due to gains recorded in 2014 associated with condemnation awards for certain transmission property, partially offset by higher income from AFUDC equity.

Effective Income Tax Rate

Pepco's effective income tax rates for the years ended December 31, 2016, 2015, and 2014 were 49.4%, 35.3%, and 35.2%, respectively. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates. As a result of the merger, Pepco recorded an after-tax charge of $31 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

Pepco Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [a]							
Residential	8,372	8,452	(0.9)%	1.6%	7,854	7.6%	2.2%
Small commercial & industrial	1,459	1,471	(0.8)%	0.8%	1,747	(15.8)%	1.4%
Large commercial & industrial	15,559	15,351	1.4%	1.0%	15,410	(0.4)%	1.2%
Public authorities & electric railroads	724	714	1.4%	— %	740	(3.5)%	— %
Total retail deliveries	26,114	25,988	0.5%	1.1%	25,751	0.9%	1.5%

	As of December 31,		
Number of Electric Customers	2016	2015	2014
Residential	780,652	767,392	740,102
Small commercial & industrial	53,529	53,838	54,176
Large commercial & industrial	21,391	20,976	20,649
Public authorities & electric railroads	130	129	124
Total	855,702	842,335	815,051

Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales (a)					
Residential	$1,000	$ 970	3.1%	$ 889	9.1%
Small commercial & industrial	150	153	(2)%	174	(12.1)%
Large commercial & industrial	803	777	3.3%	766	1.4%
Public authorities & electric railroads	32	30	6.7%	30	— %
Total retail	1,985	1,930	2.8%	1,859	3.8%
Other revenue (b)	201	199	1.0%	196	1.5%
Total electric revenue (c)	$2,186	$2,129	2.7%	$2,055	3.6%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from Pepco and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from Pepco, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.
(c) Includes operating revenues from affiliates totaling $5 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Results of Operations—DPL

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$1,277	$1,302	$ (25)	$1,282	$ 20
Purchased power and fuel	583	634	51	640	6
Revenues net of purchased power and fuel expense (a)	694	668	26	642	26
Other operating expenses					
Operating and maintenance	441	304	(137)	267	(37)
Depreciation, amortization and accretion	157	148	(9)	122	(26)
Taxes other than income	55	51	(4)	46	(5)
Total other operating expenses	653	503	(150)	435	(68)
Gain on sales of assets	9	—	9	—	—
Operating income	50	165	(115)	207	(42)
Other income and (deductions)					
Interest expense, net	(50)	(50)	—	(48)	(2)
Other, net	13	10	3	10	—
Total other income and (deductions)	(37)	(40)	3	(38)	(2)
Income before income taxes	13	125	(112)	169	(44)
Income taxes	22	49	27	65	16
Net (loss) income attributable to common shareholder	$ (9)	$ 76	$ (85)	$ 104	$ (28)

(a) DPL evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. DPL believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements because they provide information that can be used to evaluate its operational performance. DPL has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense and Revenue net of fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The decrease in net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense primarily due to merger-related costs.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense primarily due to the implementation of a new customer information system, higher bad debt expense and higher tree trimming and system maintenance costs, partially offset by higher Operating revenues net of purchased power expense resulting from customer growth and higher transmission revenue.

Revenues Net of Purchased Power and Fuel Expense

Operating revenues include revenue from the distribution and supply of electricity to DPL's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that DPL receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All DPL customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customers' choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the years ended December 31, 2016, 2015, and 2014, consisted of the following:

	For the Years Ended December 31,		
	2016	2015	2014
Electric	51%	51%	53%
Natural Gas	28%	31%	31%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2016, 2015, and 2014 consisted of the following:

	December 31, 2016		December 31, 2015		December 31, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	78,994	15.2%	77,603	15.1%	78,153	15.3%
Natural Gas	156	0.1%	159	0.1%	157	0.1%

Retail deliveries purchased from competitive electric generation suppliers represented 53% of DPL's retail kWh sales to Delaware customers and 48% of DPL retail kWh sales to Maryland customers for the year ended December 31, 2016; 53% of DPL's retail kWh sales to Delaware customers and 47% of DPL's retail kWh sales to Maryland customers for the year ended December 31, 2015; and 56% of DPL's retail kWh sales to Delaware customers and 49% of DPL's retail kWh sales to Maryland customers for the year ended December 31, 2014.

The costs related to default electricity supply are included in Purchased power and fuel. Operating revenues also include transmission enhancement credits that DPL receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Natural Gas operating revenues includes sources that are subject to price regulation (Regulated Gas Revenue) and those that generally are not subject to price regulation (Other Gas Revenue). Regulated gas revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates. Other gas revenue consists of off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Purchased power consists of the cost of electricity purchased by DPL to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased fuel consists of the cost of gas purchased by DPL to fulfill its obligation to regulated gas customers and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of gas purchased for off-system sales.

The changes in DPL's operating revenues net of purchased power and fuel expense for the years ended December 31, 2016 and 2015 compared to the same periods in 2015 and 2014, respectively, consisted of the following:

	2016 vs. 2015 Increase (Decrease)			2015 vs. 2014 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ —	$—	$—	$ 3	$ (5)	$ (2)
Volume	2	2	4	3	—	3
Pricing—distribution revenues	2	1	3	—	—	—
Regulatory required programs	12	—	12	17	—	17
Transmission revenues	8	—	8	7	—	7
Other	(1)	—	(1)	1	—	1
Increase (Decrease) in revenue net of purchased power expense	$ 23	$ 3	$ 26	$ 31	$ (5)	$ 26

Revenue Decoupling. DPL's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of DPL in Maryland, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. A modified fixed variable rate design, which would provide for a charge not tied to a customer's volumetric consumption of electricity or natural gas, has been proposed for DPL electricity and natural gas customers in Delaware. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

In accounting for the BSA in Maryland, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from Maryland retail

distribution sales falls short of the revenue that DPL is entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that DPL is entitled to earn based on the approved distribution charge per customer.

Weather. The demand for electricity and gas in areas not subject to the BSA is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. During the year ended December 31, 2016 compared to the same period in 2015, weather was not a significant impact. During the year ended December 31, 2015 compared to the same period in 2014, operating revenues net of purchased power and fuel expense was higher due to the impact of favorable spring and summer weather conditions in DPL's Delaware electric service territory and lower due to the impact of warmer weather during the fourth quarter of 2015, as compared to 2014, in DPL's natural gas service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in DPL's electric service territory and a 30-year period in DPL's gas service territory. The changes in heating and cooling degree days in DPL's service territory for the years ended December 31, 2016 and December 31, 2015 compared to same periods in 2015 and 2014, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	4,319	4,421	4,572	(2.3)%	(5.5)%
Cooling Degree-Days	1,453	1,328	1,188	9.4%	22.3%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2015	2014	Normal	2015 vs. 2014	2015 vs. Normal
Heating Degree-Days	4,421	4,724	4,592	(6.4)%	(3.7)%
Cooling Degree-Days	1,328	1,139	1,184	16.6%	12.2%

Volume. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015, primarily reflects the impact of moderate economic and customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2015 compared to the same period in 2014, primarily reflects the impact of moderate economic and customer growth.

Pricing—Distribution Revenues. The increase in electric operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution and natural gas rates charged to customers that became effective in July 2016. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Transmission Revenues. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. Transmission revenue increased for the year ended December 31, 2016 compared to the same period in 2015 due to higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by lower revenue related to the MAPP abandonment recovery period that ended in March 2016. Transmission revenue increased for the year ended December 31, 2015 compared to the same period in 2014 due to higher rates effective June 1, 2015 and June 1, 2014 related to increases in transmission plant investment and operating expenses, partially offset by the establishment of a reserve related to the FERC ROE challenges in 2015.

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2016	2015		2015	2014	
Operating and maintenance expense—baseline	$425	$289	$ 136	$289	$256	$ 33
Operating and maintenance expense—regulatory required programs (a)	16	15	1	15	11	4
Total operating and maintenance expense	$441	$304	$ 137	$304	$267	$ 37

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in operating and maintenance expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Labor, other benefits, contracting and materials	$ 1	$ 5
Pension and non-pension postretirement benefits expense	1	3
Storm-related costs	5	1
Remeasurement of AMI-related regulatory asset	1	—
Deferral of billing system transition costs to regulatory asset	(2)	—
Deferral of merger-related costs to regulatory asset	(4)	—
Uncollectible accounts expense—provision	3	6
BSC and PHISCO allocations (a)	34	13
Merger commitments (b)	86	—
Write-off of construction work in progress	4	2
Other	7	3
	136	33
Regulatory required programs		
Purchased power administrative costs	1	4
Total increase	$ 137	$ 37

(a) Primarily related to merger severance and compensation costs for the year ended December 31, 2016 compared to the same period in 2015.
(b) Primarily related to merger-related commitments for energy efficiency programs, customer rate credits and charitable contributions.

Depreciation, Amortization and Accretion Expense

The changes in depreciation, amortization and accretion expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense (a)	$ 7	$ 9
Regulatory asset amortization (b)	3	14
Delaware renewable energy portfolio standards deferral	(1)	3
Total increase	$ 9	$ 26

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to an EmPower Maryland surcharge rate increase effective February 2016, partially offset by lower amortization of MAPP abandonment costs and for the year ended December 31, 2015 compared to the same period in 2014 due to an EmPower Maryland surcharge rate increase effective February 2015.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher property taxes in Maryland related to higher property assessments and rate increases. Taxes other than income for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to higher property taxes related to an increase in assets.

Gain on Sales of Assets

Gain on Sale of Assets for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to gains recorded in 2016 at DPL associated with the sale of land held as non-utility property.

Interest Expense, Net

Interest expense, net for the year ended December 31, 2016 compared to the same period in 2015 remained constant. Interest expense, net for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to higher long-term debt interest expense.

Other, Net

Other, net for the year ended December 31, 2016, compared to the same period in 2015 increased primarily due to higher income from AFUDC equity. Other, net for the year ended December 31, 2015, compared to the same period in 2014 remained constant.

Effective Income Tax Rate

DPL's effective income tax rates for the years ended December 31, 2016, 2015, and 2014 were 169.2%, 39.2%, and 38.5%, respectively. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates As a result of the merger, DPL recorded an after-tax charge of $23 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

DPL Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [a]							
Residential	5,181	5,337	(2.9)%	1.0%	5,188	2.9%	0.9%
Small commercial & industrial	2,290	2,311	(0.9)%	0.7%	2,147	7.6%	0.5%
Large commercial & industrial	4,623	4,781	(3.3)%	1.0%	5,030	(5.0)%	0.5%
Public authorities & electric railroads	46	45	2.2%	— %	47	(4.3)%	— %
Total retail deliveries	12,140	12,474	(2.7)%	0.9%	12,412	0.5%	0.7%

Number of Electric Customers	As of December 31, 2016	2015	2014
Residential	456,181	453,145	448,615
Small commercial & industrial	60,173	59,714	39,246
Large commercial & industrial	1,411	1,410	21,388
Public authorities & electric railroads	643	643	642
Total	518,408	514,912	509,891

Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [a]					
Residential	$ 668	$ 681	(1.9)%	$ 653	4.3%
Small commercial & industrial	187	192	(2.6)%	160	20.0%
Large commercial & industrial	98	101	(3.0)%	108	(6.5)%
Public authorities & electric railroads	13	12	8.3%	12	— %
Total retail	966	986	(2.0)%	933	5.7%
Other revenue [b]	163	152	7.2%	155	(1.9)%
Total electric revenue [c]	$1,129	$1,138	(0.8)%	$1,088	4.6%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from DPL, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.
(c) Includes operating revenues from affiliates totaling $7 million, $6 million and $7 million for the years ended December 31, 2016, 2015 and 2014, respectively.

DPL Gas Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in mmcf)	2016	2015	% Change 2016 vs. 2015	Weather Normal % change	2014	% Change 2015 vs. 2014	Weather Normal % change
Retail Deliveries							
Residential	14,087	13,816	2.0%	(5.0)%	14,613	(5.5)%	(2.4)%
Transportation & other	5,455	6,193	(11.9)%	(1.4)%	6,418	(3.5)%	— %
Total gas deliveries	19,542	20,009	(2.3)%	(4.1)%	21,031	(4.9)%	(1.6)%

Number of Gas Customers	As of December 31, 2016	2015	2014
Residential	120,951	119,771	117,880
Commercial & industrial	9,801	9,712	9,615
Transportation & other	156	159	157
Total	130,908	129,642	127,652

Gas Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales (a)					
Retail sales	$127	$143	(11.2)%	$165	(13.3)%
Transportation & other (b)	21	21	— %	29	(27.6)%
Total gas revenues	$148	$164	(9.8)%	$194	(15.5)%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from DPL and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from DPL, revenue also reflects the cost of natural gas.
(b) Transportation and other revenue includes off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers.

Results of Operations—ACE

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$1,257	$1,295	$ (38)	$1,210	$ 85
Purchased power expense	651	708	57	664	(44)
Revenues net of purchased power expense (a)	606	587	19	546	41
Other operating expenses					
Operating and maintenance	428	271	(157)	250	(21)
Depreciation, amortization and accretion	165	175	10	155	(20)
Taxes other than income	7	7	—	4	(3)
Total other operating expenses	600	453	(147)	409	(44)
Gain on sales of assets	1	—	1	—	—
Operating income	7	134	(127)	137	(3)
Other income and (deductions)					
Interest expense, net	(62)	(64)	2	(64)	—
Other, net	9	3	6	3	—
Total other income and (deductions)	(53)	(61)	8	(61)	—
(Loss) income before income taxes	(46)	73	(119)	76	(3)
Income taxes	(4)	33	37	30	(3)
Net (loss) income attributable to common shareholder	$ (42)	$ 40	$ (82)	$ 46	$ (6)

(a) ACE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. ACE believes Revenue net of purchased power expense is a useful measurement of its performance because it provides

information that can be used to evaluate its operational performance. ACE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The decrease in net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense primarily due to merger-related costs.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense primarily due to the implementation of a new customer information system and higher storm restoration costs, partially offset by higher Operating revenues net of purchased power expense resulting from an electric distribution base rate increase in 2014 in New Jersey.

Revenues Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to ACE's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that ACE receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All ACE customers have the choice to purchase electricity from competitive electric generation suppliers. The customer's choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2016, 2015, and 2014, consisted of the following:

	For the Years Ended December 31,		
	2016	2015	2014
Electric	47%	45%	51%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2016, 2015, and 2014 consisted of the following:

	December 31, 2016		December 31, 2015		December 31, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	94,562	17%	78,299	14%	86,780	16%

The costs related to default electricity supply are included in Purchased power expense. Operating revenues also include revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, revenue from the resale in the PJM RTO market of energy and capacity purchased under contacts with unaffiliated NUGs, and revenue from transmission enhancement credits.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Purchased power expense consists of the cost of electricity purchased by ACE to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders.

The changes in ACE's operating revenues net of purchased power expense for the years ended December 31, 2016 and 2015 compared to the same periods in 2015 and 2014, respectively, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Weather	$ (3)	$ 9
Volume	1	2
Pricing—distribution revenues	14	18
Regulatory required programs	(15)	15
Transmission revenues	23	—
Other	(1)	(3)
Increase in revenue net of purchased power expense	$ 19	$ 41

Weather. The demand for electricity is affected by weather conditions. With respect to the electric business, very warm weather in summer months and very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity. Conversely, mild weather reduces demand. During the year ended December 31, 2016 compared to the same period in 2015, operating revenues net of purchased power and fuel expense was lower due to the impact of unfavorable winter weather conditions in ACE's service territory. During the year ended December 31, 2015 compared to the same period in 2014, operating revenues net of purchased power and fuel expense was higher due to the impact of favorable spring and summer weather conditions in ACE's service territory.

For retail customers of ACE, distribution revenues are not decoupled for the distribution of electricity by ACE, and thus are subject to variability due to changes in customer consumption. Therefore, changes in customer usage (due to weather conditions, energy prices, energy savings programs or other reasons) from period to period have a direct impact on reported distribution revenue for customers in ACE's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in ACE's service territory. The changes in heating and cooling degree days in ACE's service territory for the years ended December 31, 2016 and December 31, 2015 compared to same periods in 2015 and 2014, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	4,487	4,671	4,768	(3.9)%	(5.9)%
Cooling Degree-Days	1,303	1,259	1,093	3.5%	19.2%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2015	2014	Normal	2015 vs. 2014	2015 vs. Normal
Heating Degree-Days	4,671	5,192	4,795	(10.0)%	(2.6)%
Cooling Degree-Days	1,259	819	1,076	53.7%	17.0%

Volume. The decrease in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015, primarily reflects lower average customer usage, partially offset by the impact of moderate economic and customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2015 compared to the same period in 2014, primarily reflects the impact of moderate economic and customer growth.

Pricing—Distribution Revenues. The increase in electric operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution rates charged to customers that became effective in August 2016. The increase in distribution revenue for the year ended December 31, 2015 compared to the same period in 2014 was primarily due to the impact of the new electric distribution rates charged to customers that became effective September 2014. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the depreciation and amortization expense discussion below for additional information on included programs.

Transmission Revenues. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. Transmission revenue increased for the year ended December 31, 2016 compared to the same period in 2015 due to higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses. Transmission revenue remained constant for the year ended December 31, 2015 compared to the same period in 2014 due to higher rates effective June 1, 2015 and June 1, 2014 related to increases in transmission plant investment and operating expenses, offset by the establishment of a reserve related to the FERC ROE challenges in 2015.

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2016	2015	2016 vs. 2015	2015	2014	2015 vs. 2014
Operating and maintenance expense—baseline	$424	$267	$ 157	$267	$243	$ 24
Operating and maintenance expense—regulatory required programs [(a)]	4	4	—	4	7	(3)
Total operating and maintenance expense	$428	$271	$ 157	$271	$250	$ 21

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in operating and maintenance expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Labor, other benefits, contracting and materials	$ 6	$ 5
Pension and non-pension postretirement benefits expense	—	1
Storm-related costs	1	6
BSC and PHISCO allocations (a)	26	17
Uncollectible accounts expense	2	—
Merger commitments (b)	111	—
Other	11	(5)
	157	24
Regulatory required programs		
Purchased power administrative costs	—	(3)
	—	(3)
Total increase	$ 157	$ 21

(a) Primarily related to merger severance and compensation costs for the year ended December 31, 2016 compared to the same period in 2015.
(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.

Depreciation, Amortization and Accretion Expense

The changes in depreciation, amortization and accretion expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense (a)	$ 6	$ 4
Regulatory asset amortization (b)	(16)	16
Total (decrease) increase	$ (10)	$ 20

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization decreased for the year ended December 31, 2016 compared to the same period in 2015 primarily as a result of lower revenue due to a rate decrease effective October 2015 for the ACE Market Transition charge tax. Regulatory asset amortization increased for the year ended December 31, 2015 compared to the same period in 2014 as a result of higher revenue due to a rate increase effective October 2014 for the ACE Market Transition charge tax.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015, remained constant. Taxes other than income for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to an increase in the New Jersey use tax.

Interest Expense, Net

Interest expense, net remained relatively consistent for the year ended December 31, 2016, compared to the same period in 2015, and the year ended December 31, 2015, compared to the same period in 2014.

Gain on Sales of Assets

Gain on Sale of Assets for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to gains recorded in 2016 at ACE associated with the sale of property.

Other, Net

Other, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC equity. Other, net for the year ended December 31, 2015 compared to the same period in 2014 remained relatively consistent.

Effective Income Tax Rate

ACE's effective income tax rates for the years ended December 31, 2016, 2015, and 2014 were 8.7%, 45.2%, and 39.5%, respectively. See Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates As a result of the merger, ACE recorded an after-tax charge of $22 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

ACE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [a]							
Residential	4,153	4,322	(3.9)%	1.1%	4,087	5.7%	2.7%
Small commercial & industrial	1,455	1,288	13.0%	0.5%	1,217	5.8%	1.4%
Large commercial & industrial	3,402	3,594	(5.3)%	0.7%	3,699	(2.8)%	1.4%
Public authorities & electric railroads	49	45	8.9%	— %	48	(6.3)%	— %
Total retail deliveries	9,059	9,249	(2.1)%	0.8%	9,051	2.2%	2.0%

	As of December 31,		
Number of Electric Customers	2016	2015	2014
Residential	484,240	482,000	479,140
Small commercial & industrial	61,008	60,745	61,734
Large commercial & industrial	3,763	3,871	3,877
Public authorities & electric railroads	610	529	526
Total	549,621	547,145	545,277

Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [a]					
Residential	$ 664	$ 690	(3.8)%	$ 582	18.6%
Small commercial & industrial	183	175	4.6%	152	15.1%
Large commercial & industrial	201	213	(5.6)%	190	12.1%
Public authorities & electric railroads	13	12	8.3%	12	— %
Total retail	1,061	1,090	(2.7)%	936	16.5%
Other revenue [b]	196	205	(4.4)%	274	(25.2)%
Total electric revenue [c]	$1,257	$1,295	(2.9)%	$1,210	7.0%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from ACE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from ACE, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.
(c) Includes operating revenues from affiliates totaling $3 million, $4 million and $4 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Liquidity and Capital Resources

Exelon activity presented below includes the activity of PHI, Pepco, DPL and ACE, from the PHI Merger effective date of March 24, 2016 through December 31, 2016. Exelon prior year activity is unadjusted for the effects of the PHI Merger. Due to the application of push-down accounting to the PHI entity, PHI's activity is presented in two separate reporting periods, the legacy PHI activity through March 23, 2016 (Predecessor), and PHI activity for the remainder of the period after the PHI merger date (Successor). For each of Pepco, DPL and ACE the activity presented below include its activity for the years ended December 31, 2016, 2015 and 2014. Exelon's and Generation's activity presented below includes the activity of CENG, from the integration date effective April 1, 2014. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to unsecured revolving credit facilities with aggregate bank commitments of $9 billion. In addition, Generation has $500 million in bilateral facilities with banks which have various expirations between January 2017 and January 2019. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO, BGE, Pepco, DPL and ACE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant's owners or parent companies would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or

making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 16—Asset Retirement Obligations to the Combined Notes to Consolidated Financial Statements for additional information on the NRC minimum funding requirements.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT fund investments could appreciate in value. A shortfall could require Exelon to post parental guarantees for Generation's share of the obligations. However, the amount of any required guarantees will ultimately depend on the decommissioning approach adopted at each site, the associated level of costs, and the decommissioning trust fund investment performance going forward. Within two years after shutting down a plant, Generation must submit a post-shutdown decommissioning activities report (PSDAR) to the NRC that includes the planned option for decommissioning the site. When Generation files its biennial decommissioning funding status report with the NRC on March 31, 2017, as compared to previous estimates prior to the reversal of the early retirement decision, it is currently estimated that given the later commencement of decommissioning activities and a longer time period over which the NDT fund investments can appreciate in value, Quad Cities will meet the NRC minimum funding requirements. It is currently estimated that Clinton will fall below the NRC minimum funding requirements by only a small amount. As of December 31, 2016, TMI passes the NRC minimum funding test based on its current license life. However, in the event of an early retirement of TMI, the most costly estimates could require parental guarantees of up to $60 million.

Upon issuance of any required financial guarantees, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, the NRC must approve an additional exemption in order for the plant's owner(s) to utilize the NDT fund to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by the owner(s). While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under the United States Department of Energy reimbursement agreements or future litigation, across the three alternative decommissioning approaches available, if an early retirement decision is made and TMI were to fail the exemption test, Generation could incur spent fuel management and site restoration costs over the next ten years of up to $145 million, net of taxes.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

The Utility Registrants' cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, BGE, and DPL, gas distribution services. The Utility Registrants' distribution services are provided to an established and diverse base of retail customers. The Utility Registrants' future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3—Regulatory Matters and 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2016, 2015 and 2014:

	2016	2015	2016 vs. 2015 Variance	2014 (c)	2015 vs. 2014 Variance
Net income	$1,204	$2,250	$ (1,046)	1,820	$ 430
Add (subtract):					
Non-cash operating activities (a)	7,722	5,630	2,092	5,884	(254)
Pension and non-pension postretirement benefit contributions	(397)	(502)	105	(617)	115
Income taxes	(674)	97	(771)	(143)	240
Changes in working capital and other noncurrent assets and liabilities (b)	(275)	(264)	(11)	(806)	542
Option premiums received (paid), net	(66)	58	(124)	38	20
Collateral received (posted), net	931	347	584	(1,719)	2,066
Net cash flows provided by operations	$8,445	$7,616	$ 829	$ 4,457	$ 3,159

(a) Represents depreciation, amortization, depletion and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, and other non-cash charges. See Note 25—Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for further detail on non-cash operating activity.
(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.
(c) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, CENG's revenues net of purchased power and fuel expenses are included on a fully consolidated basis.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. On August 8, 2014, this funding relief was extended for five years. On November 2, 2015 the funding relief was extended for an additional three years and premiums pension plans pay to the Pension Benefit Guaranty Corporation were further increased. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to make qualified pension plan contributions of $310 million to its qualified pension plans in 2017, of which Generation, ComEd, PECO, BGE and Pepco expect to contribute $127 million, $33 million, $23 million, $38 million and $60 million, respectively. Exelon's and Generation's expected qualified pension plan contributions above include $21 million related to the legacy CENG plans that will be funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG. Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $23 million in 2017, of which Generation, ComEd, PECO, BGE and Pepco will make payments of $6 million, $1 million, $1 million, $2 million and $1 million, respectively. See Note 17—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants' 2016 and 2015 pension contributions.

To the extent interest rates decline significantly or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

Unlike qualified pension plans, other postretirement benefit plans are not subject to statutory minimum contribution requirements and certain plans are not funded. OPEB funding generally follows accounting cost; however, Exelon's management has historically considered several factors in determining the level of contributions to its funded other postretirement benefit plans, including liabilities management, levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $44 million in 2017, of which Generation, ComEd, BGE and Pepco expect to contribute $12 million, $2 million, $16 million and $10 million, respectively. See Note 17—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants' 2016 and 2015 other postretirement benefit contributions.

See the "Contractual Obligations" section for management's estimated future pension and other postretirement benefits contributions.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- In order to appeal the Tax Court's like-kind exchange decision, Exelon is required to pay the tax, penalty and interest at the time Exelon files its appeal (expected in the second quarter of 2017). While the final calculation of tax, penalty and interest has not yet been finalized by the IRS, Exelon estimates that a payment of approximately $1.4 billion related to the like-kind exchange will be due, including $300 million from ComEd, in the second quarter of 2017. While Exelon will receive a tax benefit of approximately $400 million associated with the deduction for the interest, Exelon currently expects to have a net operating loss carryforward and thus does not expect to realize the cash benefit until 2018. Exelon's total estimated cash outflow for the like-kind exchange is $1.0 billion, of which approximately $300 million would be attributable to ComEd after giving consideration to Exelon's agreement to hold ComEd harmless from any unfavorable impacts of the after-tax interest and penalty amounts on ComEd's equity. ComEd will fund the $300 million with a combination of debt and equity in a manner to maintain its current capital structure. Upon a final appellate decision, which could take up to several years, Exelon expects to receive $80 million related to final interest computations.

  Of the above amounts payable, Exelon deposited with the IRS approximately $1.25 billion in October of 2016. The remaining amount will be paid in the second quarter of 2017 at the time Exelon files its appeal of the Tax Court decision. Exelon funded the $1.25 billion deposit with a combination of cash on hand and short-term borrowings. The deposit is reflected as a current asset and the related liabilities for the tax, penalty, and interest are included on Exelon's balance sheet as current obligations.
- In April of 2016, Exelon received tax refunds of approximately $460 million related to IRS positions settled in prior tax years. Of this amount, approximately $195 million of the refund is attributable to Generation and the remaining $265 million is attributable to ComEd.
- State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes or the imposition, extension or permanence of temporary tax levies.

Cash flows provided by operations for the year ended December 31, 2016, 2015 and 2014 by Registrant were as follows:

	2016	2015	2014
Exelon (a)	$8,445	$7,616	$4,457
Generation (a)	4,444	4,199	1,826
ComEd	2,505	1,896	1,326
PECO	829	770	712
BGE	945	782	740
Pepco	651	373	386
DPL	310	266	268
ACE	385	256	259

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
PHI	$ 888	$ 264	$ 939	$ 854

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, CENG's revenues net of purchased power and fuel expenses are included on a fully consolidated basis.

Changes in Registrants' cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for 2016, 2015 and 2014 were as follows:

Generation

- Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the OTC markets. During 2016, 2015 and 2014, Generation had net collections/(payments) of counterparty cash collateral of $923 million, $407 million and $(1,748) million, respectively, primarily due to market conditions that resulted in changes to Generation's net mark-to-market position, as well as Exelon's decision to post more cash collateral in 2014 compared to using letters of credit in 2015 to support the PHI merger financing.
- During 2016, 2015 and 2014, Generation had net (payments)/collections of approximately $(66) million, $58 million, and $38 million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During 2016 and 2015, ComEd received a return of approximately $7 million of cash collateral from PJM and posted $31 million of cash collateral to PJM, respectively. During 2014, ComEd posted no cash collateral to PJM. During 2016, ComEd's collateral posted with PJM has decreased due to lower PJM billings. During 2015 ComEd's collateral posted with PJM has increased primarily due to higher RPM credit requirements and higher PJM billings resulting from increased load being served by ComEd as a result of City of Chicago customers switching back to ComEd.

For further discussion regarding changes in non-cash operating activities, please refer to Note 25—Supplemental Financial Information of the Combined Notes to the Financial Statements.

Cash Flows from Investing Activities

Cash flows used in investing activities for the year ended December 31, 2016, 2015, and 2014 by Registrant were as follows:

	2016	2015	2014
Exelon (a)	$(15,503)	$(7,822)	$(4,599)
Generation (a)	(3,851)	(4,069)	(1,767)
ComEd	(2,685)	(2,362)	(1,655)
PECO	(798)	(588)	(649)
BGE	(910)	(675)	(622)
Pepco	(647)	(477)	(560)
DPL	(336)	(345)	(358)
ACE	(309)	(306)	(224)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, CENG's revenues net of purchased power and fuel expenses are included on a fully consolidated basis.

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
PHI	$ (1,030)	$ (343)	$ (1,161)	$ (1,226)

Significant investing cash flow impacts for the Registrants for 2016, 2015 and 2014 were as follows:

Exelon

- During 2016, Exelon had expenditures of $6.6 billion, $235 million and $58 million relating to the acquisitions of PHI, ConEdison Solutions and the pending acquisition of the FitzPatrick facility, respectively.
- During 2016 and 2014, Exelon had proceeds of $360 million and $335 million as a result of early termination of direct financing leases.
- During 2014, Exelon had proceeds of $1.7 billion from the sale of certain long lived assets in order to finance a portion of the merger with PHI.

Generation

- During 2016, Generation had expenditures of, $235 million and $58 million relating to the acquisitions of ConEdison Solutions and the pending acquisition of the FitzPatrick facility, respectively.
- During 2014, Generation had proceeds of $1.7 billion from the sale of certain long lived assets in order to finance a portion of the merger with PHI.

Capital Expenditure Spending

Generation

Generation has entered into several agreements to acquire equity interests in privately held development stage entities which develop energy-related technology. The agreements contain a series of scheduled investment commitments, including in-kind services contributions. There are approximately $39 million of anticipated expenditures remaining through 2018 to fund anticipated planned capital and operating needs of the associated companies. See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further details of Generation's equity interests.

Capital expenditures by Registrant for the year ended December 31, 2016, 2015, and 2014 and projected amounts for 2017 are as follows:

	Projected 2017 [a]	2016	2015	2014
Exelon [b][d]	$ 8,250	$8,553	$7,624	$6,077
Generation [b]	2,650	3,078	3,841	3,012
ComEd [c]	2,200	2,734	2,398	1,689
PECO	775	686	601	661
BGE	925	934	719	620
Pepco	625	586	544	567
DPL	375	349	352	352
ACE	300	311	300	225

		Successor	*Predecessor*		
	Projected 2017 [a]	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
PHI [e]	$ 1,375	$ 1,008	$ 273	$ 1,230	$ 1,223

(a) Total projected capital expenditures do not include adjustments for non-cash activity.
(b) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, CENG's revenues net of purchased power and fuel expenses are included on a fully consolidated basis.
(c) The capital expenditures and 2017 projections include $281 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology.
(d) Includes corporate operations, BSC, and PHISCO rounded to the nearest $25 million.
(e) Includes PHISCO rounded to the nearest $25 million.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 35% and 23% of the projected 2017 capital expenditures at Generation are for the acquisition of nuclear fuel and the construction of new natural gas plants, respectively, with the remaining amounts reflecting investment in renewable energy and additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

ComEd, PECO, BGE, Pepco, DPL and ACE

Approximately 89% of the projected 2017 capital expenditures at ComEd and 100% of the projected 2017 capital expenditures at PECO, BGE, Pepco, DPL, and ACE are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and the Utility Registrants' construction commitments under PJM's RTEP. In addition to the capital expenditure for continuing projects, ComEd's total expenditures include smart grid/smart meter technology required under EIMA.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. In

2010, NERC provided guidance to transmission owners that recommended the Utility Registrants perform assessments of their transmission lines. ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2017 capital expenditures above reflect capital spending for remediation to be completed through 2018. Pepco, DPL and ACE have substantially completed their assessments and thus do not expect significant capital expenditures related to this guidance in 2017.

The Utility Registrants anticipate that they will fund their capital expenditures with a combination of internally generated funds and borrowings and additional capital contributions from parent, including ComEd's capital expenditures associated with EIMA as further discussed in Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the year ended December 31, 2016, 2015, and 2014 by Registrant were as follows:

	2016	2015	2014
Exelon [a]	$1,191	$4,830	$ 411
Generation [a]	(734)	(479)	(537)
ComEd	169	467	359
PECO	(263)	83	(250)
BGE	(21)	(162)	(85)
Pepco	—	103	171
DPL	67	80	92
ACE	22	51	(36)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, CENG's revenues net of purchased power and fuel expenses are included on a fully consolidated basis.

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
PHI	$ (7)	$ 372	$ 233	$ 363

Debt

See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements. Debt activity for 2016, 2015 and 2014 by Registrant was as follows:

During the year ended December 31, 2016, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes	2.45%	April 15, 2021	$ 300	Repay commercial paper issued by PHI and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	3.40%	April 15, 2026	$ 750	Repay commercial paper issued by PHI and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	4.45%	April 15, 2046	$ 750	Repay commercial paper issued by PHI and for general corporate purposes
Generation	Renewable Power Generation Nonrecourse Debt (a)	4.11%	March 31, 2035	$ 150	Paydown long term debt obligations at Sacramento PV Energy and Constellation Solar Horizons and for general corporate purposes
Generation	Albany Green Energy Project Financing (b)	LIBOR + 1.25%	November 17, 2017	$ 98	Albany Green Energy biomass generation development
Generation	Energy Efficiency Project Financing (b)	3.17%	December 31, 2017	$ 16	Funding to install energy conservation measures in Brooklyn, NY
Generation	Energy Efficiency Project Financing (b)	3.90%	January 31, 2018	$ 19	Funding to install energy conservation measures for the Naval Station Great Lakes project
Generation	Energy Efficiency Project Financing (b)	3.52%	April 30, 2018	$ 14	Funding to install energy conservation measures for the Smithsonian Zoo project
Generation	SolGen Nonrecourse Debt (a)	3.93%	September 30, 2036	$ 150	General corporate purposes
Generation	Energy Efficiency Project Financing (b)	3.46%	October 1, 2018	$ 36	Funding to install energy conservation measures or the Marine Corps Logistics Base project

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing (b)	2.61%	September 30, 2018	$ 4	Funding to install energy conservation measures for the Pensacola project
ComEd	First Mortgage Bonds, Series 120	2.55%	June 15, 2026	$ 500	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes
ComEd	First Mortgage Bonds, Series 121	3.65%	June 15, 2046	$ 700	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes
PECO	First Mortgage Bonds	1.70%	September 15, 2021	$ 300	Refinance maturing mortgage bonds
BGE	Notes	2.40%	August 15, 2026	$ 350	Redeem the $190M of outstanding preference shares and for general corporate purposes
BGE	Notes	3.50%	August 15, 2046	$ 500	Redeem the $190M of outstanding preference shares and for general corporate purposes
Pepco	Energy Efficiency Project Financing (b)	3.30%	December 15, 2017	$ 4	Funding to install energy conservation measures for the DOE Germantown project
DPL	First Mortgage Bonds	4.15%	May 15, 2045	$ 175	Refinance maturing mortgage bonds, repay commercial paper and general corporate purposes

(a) See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.
(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

During the year ended December 31, 2015, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes	1.55%	June 9, 2017	$ 550	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	2.85%	June 15, 2020	$ 900	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	3.95%	June 15, 2025	$ 1,250	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	4.95%	June 15, 2035	$ 500	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	5.10%	June 15, 2045	$ 1,000	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	$ 111	Procurement of software licenses
Generation	Senior Unsecured Notes	2.95%	January 15, 2020	$ 750	Fund the optional redemption of Exelon's $550 million, 4.550% Senior Notes and for general corporate purposes
Generation	AVSR DOE Nonrecourse Debt	2.29 - 2.96%	January 5, 2037	$ 39	Antelope Valley solar development
Generation	Energy Efficiency Project Financing	3.71%	July 31, 2017	$ 42	Funding to install energy conservation measures in Coleman, Florida

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing	3.55%	November 15, 2016	$ 19	Funding to install energy conservation measures in Frederick, Maryland
Generation	Tax Exempt Pollution Control Revenue Bonds	2.50 - 2.70%	2019 - 2020	$ 435	General corporate purposes
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	$ 100	Albany Green Energy biomass generation development
Generation	Nuclear Fuel Purchase Contract	3.15%	September 30, 2020	$ 57	Procurement of uranium
ComEd	First Mortgage Bonds, Series 118	3.70%	March 1, 2045	$ 400	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes
ComEd	First Mortgage Bonds, Series 119	4.35%	November 15, 2045	$ 450	Repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes
PECO	First and Refunding Mortgage Bonds	3.15%	October 15, 2025	$ 350	General corporate purposes
Pepco	First Mortgage Bonds	4.15%	March 15, 2043	$ 200	Repay outstanding commercial paper obligations and general corporate purposes
DPL	First Mortgage Bonds	4.15%	May 15, 2045	$ 200	Repay outstanding commercial paper obligations and general corporate purposes
ACE	First Mortgage Bonds	3.50%	December 1, 2025	$ 150	Repay outstanding commercial paper obligations and general corporate purposes

During the year ended December 31, 2014, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Junior Subordinated Notes	2.50%	June 1, 2024	$ 1,150	Finance a portion of the pending merger with PHI and for general corporate purposes
Generation	Nuclear Fuel Purchase Contract	3.25 - 3.35%	June 30, 2018	$ 70	Procurement of uranium
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 300	General corporate purposes
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	$ 675	General corporate purposes
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	$ 12	Funding to install energy conservation measures in Washington, DC
Generation	AVSR DOE Nonrecourse Debt	3.06 - 3.14%	January 5, 2037	$ 126	Antelope Valley solar development
ComEd	First Mortgage Bonds, Series 115	2.15%	January 15, 2019	$ 300	Refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds, Series 116	4.70%	January 15, 2044	$ 350	Refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds, Series 117	3.10%	November 1, 2024	$ 250	Repay commercial paper obligations and general corporate purposes
PECO	First and Refunding Mortgage Bonds	4.15%	October 1, 2044	$ 300	Refinance existing mortgage bonds and general corporate purposes
PHI (a)	Energy Efficiency Project Financing	4.68%	February 10, 2015	$ 6	Funding to install energy conservation measures for the Natick Project
Pepco	First Mortgage Bonds	3.60%	March 15, 2024	$ 400	Repay $175M of 4.65% Senior Notes, repay outstanding commercial paper obligations, and general corporate purposes

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Pepco	Energy Efficiency Project Financing	3.12%	February 20, 2015	$ 12	Funding to install energy conservation measures for the State Department project
DPL	First Mortgage Bonds	3.50%	November 15, 2023	$ 200	Repay outstanding commercial paper obligations and general corporate purposes
ACE	First Mortgage Bonds	3.375%	September 1, 2024	$ 150	Repay $7M of 7.63% medium term notes, repay commercial paper issued to repay $100M term loan, and general commercial purposes

(a) Represents Pepco Energy Services energy efficiency project financing. As of the date of the merger, PES financing was included with Generation.

During the year ended December 31, 2016, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	$ 8
Exelon Corporate	Senior Notes	4.95%	June 15, 2035	$ 1
Generation	AVSR DOE Nonrecourse Debt (a)	2.29% - 3.56%	January 5, 2037	$ 22
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 4
Generation	Continental Wind Nonrecourse Debt (a)	6.00%	February 28, 2033	$ 29
Generation	CEU Upstream Nonrecourse Debt (a)	1mL + 2.25%	January 14, 2019	$ 46
Generation	ExGen Texas Power Nonrecourse Debt (a)	5.00%	September 18, 2021	$ 7
Generation	Sacramento Solar Nonrecourse Debt (a)	1mL + 2.25%	December 31, 2030	$ 33
Generation	Clean Horizons Nonrecourse Debt (a)	1mL + 2.25%	September 7, 2030	$ 32
Generation	ExGen Renewables Nonrecourse Debt (a)	3mL + 4.25%	February 6, 2021	$ 24
Generation	PES—PGOV Notes Payable	6.70 - 7.46%	2017 - 2018	$ 1
Generation	NUKEM	3.35%	June 30, 2018	$ 12
Generation	NUKEM	3.25%	July 1, 2018	$ 10
Generation	Renewable Power Generation Nonrecourse Debt (a)	4.11%	March 31, 2035	$ 9

Company	Type	Interest Rate	Maturity	Amount
Generation	SolGen Nonrecourse Debt [(a)]	3.93%	September 30, 2036	$ 2
ComEd	First Mortgage Bonds, Series 104	5.95%	August 15, 2016	$ 415
ComEd	First Mortgage Bonds, Series 111	1.95%	August 1, 2016	$ 250
PECO	First and Refunding Mortgage Bonds	1.20%	October 15, 2016	$ 300
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	$ 1
BGE	Rate Stabilization Bonds	5.82%	April 1, 2017	$ 38
BGE	Notes	5.90%	October 1, 2016	$ 300
BGE	Securitization Bonds	5.82%	April 1, 2017	$ 40
PHI	Senior Unsecured Notes	5.90%	December 12, 2016	$ 190
DPL	First Mortgage Bonds	5.22%	December 30, 2016	$ 100
ACE	Transition Bonds	5.05%	October 20, 2020	$ 12
ACE	Transition Bonds	5.55%	October 20, 2023	$ 34
ACE	First Mortgage Bonds	7.68%	August 23, 2016	$ 2

(a) See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.

During the year ended December 31, 2015, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate	Senior Unsecured Notes	4.55%	June 15, 2015	$ 550
Exelon Corporate	Senior Notes	4.90%	June 15, 2015	$ 800
Exelon Corporate	Senior Unsecured Notes	3.95%	June 15, 2025	$ 443
Exelon Corporate	Senior Unsecured Notes	4.95%	June 15, 2035	$ 167
Exelon Corporate	Senior Unsecured Notes	5.10%	June 15, 2045	$ 259
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	$ 1
Generation	Senior Unsecured Notes	4.55%	June 15, 2015	$ 550
Generation	CEU Upstream Nonrecourse Debt	LIBOR + 2.25%	January 14, 2019	$ 9
Generation	AVSR DOE Nonrecourse Debt	2.29% - 3.56%	January 5, 2037	$ 23
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 3
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	$ 20
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 8, 2021	$ 5
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 24
Generation	Constellation Solar Horizons Nonrecourse Debt	2.56%	September 7, 2030	$ 2

Company	Type	Interest Rate	Maturity	Amount
Generation	Sacramento PV Energy Nonrecourse Debt	2.58%	December 31, 2030	$ 2
Generation	Energy Efficiency Project	3.55%	November 15, 2016	$ 19
ComEd	First Mortgage Bonds, Series 101	4.70%	April 15, 2015	$ 260
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	$ 75
PHI	Senior Unsecured Notes	2.70%	October 1, 2015	$ 250
PHI (a)	Energy Efficiency Project Financing	4.68%	February 10, 2015	$ 7
PHI (a)	Energy Efficiency Project Financing	8.87%	June 1, 2021	$ 5
PHI (a)	Energy Efficiency Project Financing	7.61%	August 1, 2015	$ 1
PHI (a)	PES-PGOV Notes Payable	6.70 - 7.46%	2017-2018	$ 1
Pepco	Energy Efficiency Project Financing	3.12%	February 20, 2015	$ 12
DPL	Senior Unsecured Notes	5.00%	June 1, 2015	$ 100
ACE	Secured Medium-Term Notes Series C	7.68%	August 24, 2015	$ 15
ACE	Transition Bonds	5.05%	October 20, 2020	$ 12
ACE	Transition Bonds	5.55%	October 20, 2023	$ 32

(a) Represents Pepco Energy Services energy efficiency project financing. As of the date of the merger, PES financing was included with Generation.

During the year ended December 31, 2014, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	Senior Unsecured Notes	5.35%	January 15, 2014	$ 500
Generation	Pollution Control Notes	4.10%	July 1, 2014	$ 20
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	$ 20
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 3
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 18
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	$ 2
Generation	AVSR DOE Nonrecourse Debt	2.33% - 3.55%	January 5, 2037	$ 15
Generation	Clean Horizons Solar Nonrecourse Debt	2.56%	September 7, 2030	$ 2
Generation	Sacramento Solar Nonrecourse Debt	2.56%	December 31, 2030	$ 2
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	$ 12
ComEd	First Mortgage Bonds, Series 110	1.63%	January 15, 2014	$ 600
ComEd	Pollution Control Series 1994C	5.85%	January 15, 2014	$ 17
PECO	First and Refunding Mortgage Bonds	5.00%	October 1, 2014	$ 250

Company	Type	Interest Rate	Maturity	Amount
BGE	Rate Stabilization Bonds	5.72%	April 1, 2017	$ 35
BGE	Rate Stabilization Bonds	5.72%	October 1, 2014	$ 35
PHI (a)	PES-PGOV Notes Payable	6.70 - 7.46%	2017-2018	$ 1
Pepco	Senior Notes	4.65%	April 15, 2014	$ 175
DPL	Senior Unsecured Notes	5.00%	June 1, 2015	$ 100
ACE	Term Loan	LIBOR + 0.75%	November 10, 2014	$ 100
ACE	Variable Rate Demand Bonds	variable	April 15, 2014	$ 18
ACE	Transition Bonds	5.05%	October 20, 2020	$ 11
ACE	Transition Bonds	5.55%	October 20, 2023	$ 30
ACE	Secured Medium-Term Notes	7.63%	August 29, 2014	$ 7

(a) Represents Pepco Energy Services energy efficiency project financing. As of the date of the merger, PES debt was included with Generation.

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective balance sheets.

Dividends

Cash dividend payments and distributions for the year ended December 31, 2016, 2015 and 2014 by Registrant were as follows:

	2016	2015	2014
Exelon (a)	$1,166	$1,105	$1,486
Generation (a)	922	2,474	1,066
ComEd	369	299	307
PECO	277	279	320
BGE (b)	187	171	13
Pepco	136	146	86
DPL	54	92	100
ACE	63	12	26

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
PHI	$ 273	$ —	$ 275	$ 272

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2016, 2015, and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) Includes dividends paid on BGE's preference stock.

Quarterly dividends declared by the Exelon Board of Directors during the year ended December 31, 2016 and for the first quarter of 2017 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share [a]
First Quarter 2016	January 26, 2016	February 12, 2016	March 10, 2016	$ 0.310
Second Quarter 2016	April 26, 2016	May 13, 2016	June 10, 2016	$ 0.318
Third Quarter 2016	July 26, 2016	August 15, 2016	September 9, 2016	$ 0.318
Fourth Quarter 2016	October 25, 2016	November 15, 2016	December 9, 2016	$ 0.318
First Quarter 2017	January 31, 2017	February 15, 2017	March 10, 2017	$ 0.3275

(a) Exelon's Board of Directors has approved a dividend policy providing a raise of 2.5% each year for three years, beginning with the June 2016 dividend.

Short-Term Borrowings

Short-term borrowings incurred (repaid) during 2016, 2015 and 2014 by Registrant were as follows:

	2016	2015	2014
Exelon [a]	$(353)	$ 80	$122
Generation [a]	620	—	17
ComEd	(294)	(10)	120
BGE	(165)	90	(15)
Pepco	(41)	(40)	(47)
DPL	(105)	(1)	(41)
ACE	(5)	(122)	7

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
PHI	$ (515)	$ (121)	$ 34	$ 183

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, CENG's revenues net of purchased power and fuel expenses are included on a fully consolidated basis.

Retirement of Long-Term Debt to Financing Affiliates

There were no retirements of long-term debt to financing affiliates during 2016, 2015 and 2014 by the Registrants.

Contributions from Parent/Member.

Contributions from Parent/Member (Exelon) during 2016, 2015 and 2014 by Registrant were as follows:

	2016	2015	2014
Generation	$142	$ 47	$ 53
ComEd (a)(b)	473	209	278
PECO (b)	18	16	24
BGE (b)	61	7	—
Pepco (c)	187	112	80
DPL (c)	152	75	130
ACE (c)	139	95	—

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**	**For the Year Ended December 31, 2014**
PHI (b)	$ 1,251	$ —	$ —	$ —

(a) Additional contributions from parent or external debt financing may be required as a result of increased capital investment in infrastructure improvements and modernization pursuant to EIMA, transmission upgrades and expansions and Exelon's agreement to indemnify ComEd for any unfavorable after-tax impacts associated with ComEd's LKE tax matter.
(b) Contribution paid by Exelon.
(c) Contribution paid by PHI.

Pursuant to the orders approving the merger, Exelon made equity contributions of $73 million, $46 million and $49 million to Pepco, DPL and ACE, respectively, in the second quarter of 2016 to fund the after-tax amount of the customer bill credit and the customer base rate credit.

Redemptions of Preference Stock. BGE had $190 million of cumulative preference stock that was redeemable at its option at any time after October 1, 2015 for the redemption price of $100 per share, plus accrued and unpaid dividends. On July 3, 2016, BGE redeemed all 400,000 shares of its outstanding 7.125% Cumulative Preference Stock, 1993 Series and all 600,000 shares of its outstanding 6.990% Cumulative Preference Stock, 1995 Series for $100 million, plus accrued and unpaid dividends. On September 18, 2016, BGE redeemed the remaining 500,000 shares of its outstanding 6.970% Cumulative Preference Stock, 1993 Series and the remaining 400,000 shares of its outstanding 6.700% Cumulative Preference Stock, 1993 Series for $90 million, plus accrued and unpaid dividends. As of December 31, 2016, BGE no longer has any preferred stock outstanding. See Note 22—Earnings Per Share of the Combined Notes to Consolidated Financial Statements for further details.

Other

For the year ended December 31, 2016, other financing activities primarily consists of debt issuance costs. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements' for additional information.

Credit Matters

Market Conditions

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $9.5 billion in aggregate total commitments of which $7.9 billion was available as of December 31, 2016, and of which no financial institution has more than 7% of the aggregate commitments for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE. The Registrants had access to the commercial paper market during 2016 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of December 31, 2016, it would have been required to provide incremental collateral of $1.9 billion to meet collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.2 billion.

The following table presents the incremental collateral that each Utility Registrant would have been required to provide in the event each utility registrant lost its investment grade credit rating at December 31, 2016 and available credit facility capacity prior to any incremental collateral at December 31, 2016:

	PJM Credit Policy Collateral	Other Incremental Collateral Required [a]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 19	$ —	$ 998
PECO	2	31	598
BGE	2	62	600
Pepco	—	—	300
DPL	3	10	300
ACE	—	—	299

(a) Represents incremental collateral related to natural gas procurement contracts.

Exelon Credit Facilities

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. PHI meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure . At December 31, 2016, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Long-term debt	54%	36%	44%	42%	42%	41%	50%	50%	53%
Long-term debt to affiliates [(a)]	1%	4%	1%	3%	5%	— %	— %	— %	— %
Common equity	43%	— %	55%	55%	52%	—	50%	50%	47%
Member's equity	— %	57%	— %	— %	— %	55%	—	—	—
Preference Stock	— %	— %	— %	— %	—	— %	— %	— %	— %
Commercial paper and notes payable	2%	3%	—	— %	1%	4%	— %	— %	— %

(a) Includes approximately $641 million, $205 million, $184 million and $252 million owed to unconsolidated affiliates of Exelon, ComEd, PECO and BGE respectively. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd, PECO and BGE. See Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of December 31, 2016, are presented in the following tables:

Exelon Intercompany Money Pool	For the Year Ended December 31, 2016		As of December 31, 2016
Contributed (borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Corporate	$ 1,534	$ —	$ 88
Generation	—	1,292	(55)
PECO	395	—	131
BSC	—	387	(219)
PHI Corporate [a]	—	53	—
PCI [a]	63	—	55

(a) As a result of the merger, PHI Corporate and PCI began to participate in the Exelon Intercompany Money Pool effective March 24, 2016.

PHI Intercompany Money Pool	For the Year Ended December 31, 2016		As of December 31, 2016
Contributed (borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
PHI Corporate	$ 152	$ —	$ —
Pepco	—	—	—
DPL	—	—	—
ACE	—	—	—
PHISCO	26	152	—

Investments in Nuclear Decommissioning Trust Funds. Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's and CENG's investment policies establish limits on the concentration of holdings in any one company and also in any one industry. See Note 16—Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements. Exelon, Generation, ComEd, PECO, BGE, Pepco and DPL have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2019. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations. Generation, ComEd, PECO, BGE, Pepco, DPL and ACE are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	Short-term Financing Authority [a]			Long-term Financing Authority		
	Commission	Expiration Date	Amount (in millions)	Commission	Expiration Date	Amount (in millions)
ComEd [b]	FERC	December 31, 2017	$ 2,500	ICC	2019	$ 2,383
PECO	FERC	December 31, 2017	1,500	PAPUC	December 31, 2018	1,600
BGE [c]	FERC	December 31, 2017	700	MDPSC	N/A	—
Pepco	FERC	June 30, 2018	500	MDPSC / DCPSC	September 25, 2017	550
DPL	FERC	June 30, 2018	500	MDPSC / DPSC	December 31, 2017	125
ACE	NJBPU	January 1, 2018	350	NJBPU	December 31, 2017	300

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.
(b) ComEd had $1,565 million available in long-term debt refinancing authority and $818 million available in new money long term debt financing authority from the ICC as of December 31, 2016 and has an expiration date of June 1, 2019 and March 1, 2019, respectively.
(c) In December 2016, BGE filed an application for $1 billion of long term financing authority with the MDPSC.

Exelon's ability to pay dividends on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid. Pepco, DPL and ACE are subject to certain dividend restrictions established by settlements approved in NJ, DE, MD and the DC. Pepco, DPL and ACE are prohibited from paying a dividend on their common shares if (a) after the dividend payment, Pepco's, DPL's or ACE's equity ratio would be below 48% as equity levels are calculated under the ratemaking precedents of the Commissions and the Board or (b) Pepco's, DPL's or ACE's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. At December 31, 2016, Exelon had retained earnings of $12,030 million, including Generation's undistributed earnings of $2,275 million, ComEd's retained earnings of $987 million consisting of retained earnings appropriated for future dividends of $2,626 million partially offset by $1,639 million of unappropriated retained deficit, PECO's retained earnings of $941 million and BGE's retained earnings $1,427 million. At December 31, 2016, Pepco had retained earnings of $991 million, DPL had retained earnings of $562 million and ACE had retained earnings of $122 million. See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Contractual Obligations

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2016 under existing contractual obligations, including payments due by period. See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within			
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt (a)	$33,959	$ 2,430	$ 2,751	$ 5,705	$ 23,073
Interest payments on long-term debt (b)	16,368	1,432	2,680	2,361	9,895
Liability and interest for uncertain tax positions (c)	150	150	—	—	—
Capital leases	69	17	38	6	8
Operating leases (d)	1,726	183	302	273	968
Purchase power obligations (e)	1,502	508	626	148	220
Fuel purchase agreements (f)	7,693	1,297	2,165	1,501	2,730
Electric supply procurement (f)	3,632	2,261	1,357	14	—
AEC purchase commitments (f)	6	1	3	2	—
Curtailment services commitments (f)	148	61	80	7	—
Long-term renewable energy and REC commitments (g)	1,517	107	213	225	972
Other purchase obligations (h)	7,739	5,426	1,292	517	504
Construction commitments (i)	317	276	41	—	—
PJM regional transmission expansion commitments (j)	617	280	301	36	—
SNF obligation (k)	1,024	—	—	—	1,024
Pension minimum funding requirement (l)	3,899	596	1,073	899	1,331
Total contractual obligations	$80,366	$15,025	$12,922	$11,694	$ 40,725

(a) Includes $648 million due after 2022 to ComEd, PECO and BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2016. Includes estimated interest payments due to ComEd, PECO, BGE, PHI, Pepco, DPL and ACE financing trusts.
(c) While the final calculation of tax, penalties and interest has not yet been finalized by the IRS, Exelon estimates that a payment of approximately $1.4 billion related to the like-kind exchange will be due in the second quarter of 2017. Exelon deposited with the IRS approximately $1.25 billion in October of 2016 and expects that the approximately $150 million remaining will be paid in the second quarter of 2017.
(d) Excludes Generation's contingent operating lease payments associated with contracted generation agreements. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO's meter reading operating lease.
(e) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2016, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature.
(f) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services.
(g) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(h) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(i) Represents commitments for Generation's ongoing investments in new natural gas and biomass generation construction. Amount includes $139 million of remaining commitments related to the construction of new combined-cycle gas turbine units in Texas. Achievement of commercial operations related to this project is expected in 2017.
(j) Under their operating agreements with PJM, ComEd, PECO, BGE, Pepco, DPL and ACE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd, PECO, BGE, Pepco, DPL and ACE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(k) See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding SNF obligations.
(l) These amounts represent Exelon's expected contributions to its qualified pension plans. The projected contributions reflect a funding strategy for the legacy Exelon, CEG and CENG plans of contributing the greater of $250 million until the qualified plans are fully funded on an accumulated benefit obligation basis, and the minimum amounts under ERISA to avoid benefit restrictions and at-risk status thereafter. The remaining qualified pension plans' contributions are generally based on the estimated minimum pension contributions required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2022 are not included. See Note 17—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

		Payment due within			
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt	$ 9,208	$1,117	$ 710	$2,800	$ 4,581
Interest payments on long-term debt (a)	5,086	383	752	574	3,377
Capital leases	22	5	11	6	—
Operating leases (b)	914	70	105	95	644
Purchase power obligations (c)	1,502	508	626	148	220
Fuel purchase agreements (d)	6,510	1,057	1,825	1,296	2,332
Other purchase obligations (e)	1,828	1,111	296	115	306
Construction commitments (f)	317	276	41	—	—
SNF obligation (g)	1,024	—	—	—	1,024
Total contractual obligations	$26,411	$4,527	$4,366	$5,034	$ 12,484

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2016.
(b) Excludes Generation's contingent operating lease payments associated with contracted generation agreements. These amounts are included within purchase power obligations.
(c) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2016, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature.
(d) Represents commitments to purchase fuel supplies for nuclear and fossil generation.
(e) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(f) Represents commitments for Generation's ongoing investments in new natural gas and biomass generation construction. Amount includes $139 million of remaining commitments related to the construction of new combined-cycle gas turbine units in Texas. Achievement of commercial operations related to this project is expected in 2017.
(g) See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding SNF obligations.

ComEd

	Total	Payment due within 2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt [a]	$ 7,307	$ 425	$1,140	$ 850	$ 4,892
Interest payments on long-term debt [b]	4,400	283	473	421	3,223
Liability and interest for uncertain tax positions [c]	300	300	—	—	—
Capital leases	8	—	—	—	8
Operating leases	29	11	12	6	—
Electric supply procurement	733	461	272	—	—
Long-term renewable energy and REC commitments [d]	1,375	80	156	167	972
Other purchase obligations [e]	830	692	102	32	4
PJM regional transmission expansion commitments [f]	97	64	33	—	—
Total contractual obligations	$15,079	$2,316	$2,188	$1,476	$ 9,099

(a) Includes $206 million due after 2022 to a ComEd financing trust.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2016. Includes estimated interest payments due to the ComEd financing trust.
(c) While the final calculation of tax, penalties and interest has not yet been finalized by the IRS, Exelon estimates that a payment of approximately $1.4 billion related to the like-kind exchange will be due, including $300 million from ComEd, in the second quarter of 2017.
(d) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(e) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(f) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

PECO

	Total	Payment due within 2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt [a]	$2,784	$—	$ 500	$ 300	$ 1,984
Interest payments on long-term debt [b]	1,679	120	190	185	1,184
Operating leases [c]	18	3	7	8	—
Fuel purchase agreements [d]	327	99	144	37	47
Electric supply procurement [d]	481	397	84	—	—
AEC purchase commitments [d]	8	2	4	2	—
Other purchase obligations [e]	418	216	126	73	3
PJM regional transmission expansion commitments [f]	34	14	17	3	—
Total contractual obligations	$5,749	$851	$1,072	$ 608	$ 3,218

(a) Includes $184 million due after 2022 to PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Includes estimated cash payments for service fees related to PECO's meter reading operating lease.

(d) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs.
(e) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(f) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

BGE

		Payment due within			
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt (a)	$2,599	$ 41	$ —	$ 300	$ 2,258
Interest payments on long-term debt (b)	2,247	118	235	234	1,660
Operating leases	199	32	68	66	33
Fuel purchase agreements (c)	599	114	139	110	236
Electric supply procurement (c)	1,228	758	470	—	—
Curtailment services commitments (c)	63	30	31	2	—
Other purchase obligations (d)	851	633	132	85	1
PJM regional transmission expansion commitments (e)	226	113	99	14	—
Total contractual obligations	$8,012	$1,839	$1,174	$ 811	$ 4,188

(a) Includes $258 million due after 2022 to the BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services.
(d) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(e) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

PHI

		Payment due within			
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt	$ 5,157	$ 251	$ 403	$255	$ 4,248
Interest payments on long-term debt (a)	1,329	244	461	424	200
Capital leases	39	12	27	—	—
Operating leases	418	50	85	72	211
Fuel purchase agreements (b)	257	27	57	58	115
Long-term renewable energy and REC commitments (b)	143	28	57	58	—
Electric supply procurement (b)	2,017	1,171	832	14	—
Curtailment services commitments (b)	85	31	49	5	—
Other purchase obligations (c)	3,017	2,394	441	84	98
PJM regional transmission expansion commitments (d)	260	89	152	19	—
Total contractual obligations	$12,722	$4,297	$2,564	$989	$ 4,872

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services.
(c) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(d) Under its operating agreement with PJM, PHI is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PHI's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Pepco

		Payment due within			
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt	$2,381	$ 16	$ 137	$ 2	$ 2,226
Interest payments on long-term debt (a)	695	121	237	228	109
Capital leases	39	12	27	—	—
Operating leases	32	7	11	7	7
Electric supply procurement (b)	838	510	328	—	—
Curtailment services commitments (b)	36	19	17	—	—
Other purchase obligations (c)	1,345	1,165	164	8	8
PJM regional transmission expansion commitments (d)	104	6	79	19	—
Total contractual obligations	$5,470	$1,856	$1,000	$264	$ 2,350

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Represents commitments to purchase procure electric supply and curtailment services.
(c) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(d) Under its operating agreement with PJM, Pepco is committed to the construction of transmission facilities to maintain system reliability. These amounts represent Pepco's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

DPL

		Payment due within			
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt	$1,348	$ 119	$ 16	$ —	$ 1,213
Interest payments on long-term debt (a)	291	49	98	96	48
Operating leases	110	13	24	19	54
Fuel purchase agreements (b)	257	27	57	58	115
Long-term renewable energy and associated REC commitments (b)	143	28	57	58	—
Electric supply procurement (b)	627	334	279	14	—
Curtailment services commitments (b)	40	10	26	4	—
Other purchase obligations (c)	897	568	175	69	85
PJM regional transmission expansion commitments (d)	63	47	16	—	—
Total contractual obligations	$3,776	$1,195	$748	$318	$ 1,515

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric renewable energy and RECs, procure electric supply, and curtailment services.
(c) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(d) Under its operating agreement with PJM, DPL is committed to the construction of transmission facilities to maintain system reliability. These amounts represent DPL's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

ACE

		Payment due within			
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt	$1,162	$ 35	$250	$253	$ 624
Interest payments on long-term debt (a)	259	60	98	72	29
Operating leases	54	8	15	11	20
Electric supply procurement (b)	552	327	225	—	—
Curtailment services commitments (b)	9	2	6	1	—
Other purchase obligations (c)	514	432	76	3	3
PJM regional transmission expansion commitments (d)	93	36	57	—	—
Total contractual obligations	$2,643	$900	$727	$340	$ 676

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Represents commitments to procure electric supply and curtailment services.
(c) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(d) Under its operating agreement with PJM, ACE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ACE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 15—Income Taxes of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- operating leases and rate relief commitments, see Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

- the nuclear decommissioning and SNF obligations, see Notes 16—Asset Retirement Obligations and 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements.
- variable interest entities, see Note 2—Variable Interest Entities of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- new accounting pronouncements, see Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities.

Commodity Price Risk (All Registrants)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of the Utility Registrants' retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2017 through 2019.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Exelon's hedging program involves the hedging of commodity risk for Exelon's expected generation, typically on a ratable basis over a three-year period. As of December 31, 2016, the proportion of expected generation hedged is 91%-94%, 56%-59% and 28%-31% for 2017, 2018 and 2019, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents

our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation's sales to the Utility Registrants to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-proprietary trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on December 31, 2016 market conditions and hedged position would be decreases in pre-tax net income of approximately $65 million, $410 million and $685 million, respectively, for 2017, 2018 and 2019. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 6,179 GWh, 7,310 GWh, and 10,571 GWh for the years ended December 31, 2016, 2015 and 2014 respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Proprietary trading portfolio activity for the year ended December 31, 2016, resulted in pre-tax gains of $15 million due to net mark-to-market gains of $1 million and realized gains of $14 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, and one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $0.2 million of exposure during the year. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total Revenue net of purchase power and fuel expense for the year ended December 31, 2016 of $8,921 million.

Fuel Procurement . Generation procures natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 39% of Generation's uranium concentrate requirements from 2017 through 2021 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial positions.

ComEd

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014. See Note 3—Regulatory Matters and Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives. ComEd does not enter into derivatives for speculative or proprietary trading purposes.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements. PECO has certain full requirements contracts, which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result, are accounted for on an accrual basis of accounting. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Pepco

Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. The SOS rates charged recover Pepco's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for residential and commercial rate classes. Pepco's price risk related to electric supply procurement is limited. Pepco locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of Pepco's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other Pepco full requirements contracts are not derivatives.

Pepco does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

DPL

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. The SOS rates charged recover DPL's wholesale power supply costs. In Delaware, DPL is also entitled to recover a Reasonable Allowance for Retail Margin (RARM). The RARM includes a fixed annual margin of approximately $2.75 million, plus an incremental cost component and a cash working capital allowance. In Maryland, DPL charges an administrative fee intended to allow it to recover its administrative costs. DPL locks in fixed prices for all of its SOS requirements through full requirements contracts. DPL's price risk related to electric supply procurement is limited. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

DPL provides natural gas to its customers under a GCR mechanism approved by the DPSC. The demand portion of the GCR is based upon DPL's firm transportation and storage contracts. DPL has firm deliverability of swing and seasonal storage; a liquefied natural gas facility and firm transportation capacity to meet customer demand and provide a reserve margin. The commodity portion of the GCR includes a commission approved hedging program which is intended to reduce gas commodity price volatility while limiting the firm natural gas customers' exposure to adverse changes in the market price of natural gas.

DPL does not enter into derivatives for speculative or proprietary trading purposes. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

ACE

ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. The BGS rates charged recover ACE's wholesale power supply costs. ACE does not make any profit or incur any loss on the supply component of the BGS it supplies to customers. ACE's price risk related to electric supply procurement is limited. ACE locks in fixed prices for all of its BGS requirements through full requirements contracts. ACE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other ACE full requirements contracts are not derivatives.

ACE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities

The following detailed presentation of Exelon's, Generation's, ComEd's, PHI's and DPL's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, ComEd's, PHI's and DPL's commodity mark-to-market net asset or liability balance sheet position from January 1, 2015 to December 31, 2016. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2016 and December 31, 2015.

					Predecessor
	Exelon	**Generation**	**ComEd**	**DPL**	**PHI**
Total mark-to-market energy contract net assets (liabilities) at January 1, 2015 (a)	$1,505	$ 1,712	$ (207)	$—	$ —
Total change in fair value during 2015 of contracts recorded in result of operations	412	412	—	—	—
Reclassification to realized at settlement of contracts recorded in results of operations	(168)	(168)	—	—	—
Reclassification to realized at settlement from accumulated OCI	(2)	(2)	—	—	—
Changes in fair value—recorded through regulatory assets and liabilities (b)	(40)	—	(40)	2	2
Changes in allocated collateral	(172)	(172)	—	(2)	(2)
Changes in net option premium paid/(received)	(58)	(58)	—	—	—
Option premium amortization	(21)	(21)	—	—	—
Upfront payments and amortizations (c)	50	50	—	—	—
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015 (a)	$1,506	$ 1,753	$ (247)	$—	$ —

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2015, ComEd recorded a regulatory liability of $247 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. ComEd recorded $55 million of decreases in fair value and an increase for realized losses due to settlements of $(15) million in purchased power expense associated with floating-to-fixed energy swap suppliers for the year ended December 31, 2015.
(c) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

	Exelon	Generation	ComEd	DPL	Successor March 24 to December 31, PHI	Predecessor January 1 to March 23, PHI
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015 (a)	$1,506	$ 1,753	$ (247)	$—	$ —	$ —
Total change in fair value during 2016 of contracts recorded in result of operations	236	236	—	—	—	—
Reclassification to realized at settlement of contracts recorded in results of operations	(265)	(265)	—	—	—	—
Contracts received at acquisition date (b)	(59)	(59)	—	—	—	—
Changes in fair value—recorded through regulatory assets and liabilities (c)	(8)	—	(11)	4	3	1
Changes in allocated collateral	(908)	(905)	—	(4)	(3)	(1)
Changes in net option premium paid/(received)	66	66	—	—	—	—
Option premium amortization	11	11	—	—	—	—
Upfront payments and amortizations (d)	140	140	—	—	—	—
Total mark-to-market energy contract net assets (liabilities) at December 31, 2016 (a)	$ 719	$ 977	$ (258)	$—	$ —	$ —

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Includes fair value from contracts received at acquisition of ConEdison Solutions of $(59) million.
(c) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2016 ComEd recorded a regulatory liability of $258 million, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. For the year ended December 31, 2016, ComEd also recorded $29 million of decreases in fair value and realized losses due to settlements of $18 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2016.
(d) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities) net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 12—Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2017	2018	2019	2020	2021	2022 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts (a)(b) :							
Actively quoted prices (Level 1)	$205	$ 8	$(38)	$(14)	$ (1)	$ —	$ 160
Prices provided by external sources (Level 2)	273	49	2	—	—	—	324
Prices based on model or other valuation methods (Level 3) (c)	162	123	49	8	(21)	(86)	235
Total	$640	$180	$ 13	$ (6)	$(22)	$ (86)	$ 719

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $329 million at December 31, 2016.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2017	2018	2019	2020	2021	2022 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts (a)(b) :							
Actively quoted prices (Level 1)	$205	$ 8	$(38)	$(14)	$ (1)	$ —	$ 160
Prices provided by external sources (Level 2)	273	49	2	—	—	—	324
Prices based on model or other valuation methods (Level 3)	181	142	69	28	(1)	74	493
Total	$659	$199	$ 33	$ 14	$ (2)	$ 74	$ 977

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $329 million at December 31, 2016.

ComEd

	Maturities Within						
	2017	2018	2019	2020	2021	2022 and Beyond	Fair Value
Prices based on model or other valuation methods (Level 3) (a)	$(19)	$(19)	$(20)	$(20)	$(20)	$ (160)	$(258)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features (All Registrants)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before

collateral, is represented by the fair value of contracts at the reporting date. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2016. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $14 million, $33 million, $26 million, $44 million, $16 million and $9 million respectively. See Note 27—Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Rating as of December 31, 2016	Total Exposure Before Credit Collateral	Credit Collateral [a]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 995	$ —	$ 995	1	$ 328
Non-investment grade	118	16	102	—	—
No external ratings					
Internally rated—investment grade	352	1	351	—	—
Internally rated—non-investment grade	72	8	64	—	—
Total	$ 1,537	$ 25	$ 1,512	1	$ 328

	Maturity of Credit Risk Exposure			
Rating as of December 31, 2016	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 782	$207	$ 6	$ 995
Non-investment grade	73	45	—	118
No external ratings				
Internally rated—investment grade	292	39	21	352
Internally rated—non-investment grade	53	19	—	72
Total	$ 1,200	$310	$ 27	$ 1,537

Net Credit Exposure by Type of Counterparty	As of December 31, 2016
Financial institutions	$ 116
Investor-owned utilities, marketers, power producers	689
Energy cooperatives and municipalities	636
Other	71
Total	$ 1,512

(a) As of December 31, 2016, credit collateral held from counterparties where Generation had credit exposure included $9 million of cash and $16 million of letters of credit.

ComEd

Credit risk for ComEd is governed by credit and collection policies, which are aligned with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. The Illinois Public Utilities Act prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 31 of the following year. ComEd's ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2016. See Note 3—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. As of December 31, 2016, ComEd's credit exposure to energy suppliers was approximately $1 million.

PECO

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2016.

PECO's supplier master agreements that govern the terms of its DSP Program contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2016, PECO had no net credit exposure with suppliers.

PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2016, PECO's credit exposure under its natural gas supply and asset management agreements with investment grade suppliers was immaterial.

BGE

Credit risk for BGE is managed by credit and collection policies, which are consistent with state regulatory requirements. BGE is currently obligated to provide service to all electric customers within its franchised territory. BGE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. BGE will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for uncollectible accounts policy. MDPSC regulations prohibit BGE from terminating service to residential customers due to nonpayment from November 1 through March 31 if the forecasted temperature is 32 degrees or below for the subsequent 72 hour period. BGE is also prohibited by the Public Utilities Article of the Annotated Code of Maryland and MDPSC regulations from terminating service to residential customers due to nonpayment if the forecasted temperature is 95 degrees or above for the subsequent 72 hour period. BGE did not have any customers representing over 10% of its revenues as of December 31, 2016.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents BGE's net credit exposure. The seller's credit exposure is calculated each business day. As of December 31, 2016, BGE had no net credit exposure with suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2016, BGE had credit exposure of $8 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Pepco

Credit risk for Pepco is managed by credit and collection policies, which are consistent with state regulatory requirements. Pepco is currently obligated to provide service to all retail electric customers within its franchised territory. Pepco records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with MDPSC and DCPSC regulations, applicable weather regulatory provisions are in effect January through December, the utility will not terminate service to any residential customer when weather conditions prohibit termination. Additional MDPSC cold weather requirements are in effect after November 1 and before April 1. Pepco's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in MDPSC and DCPSC regulations. Pepco did not have any customers representing over 10% of its revenues as of December 31, 2016.

Pepco's full requirement wholesale electric power agreements in Maryland and the District of Columbia, that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured cap. The credit position is based on the initial market price, which is the forward price of energy on the day. A similar agreement in the District of Columbia requires a supplier to meet its credit requirements with a specified amount equal to fifteen percent (15%) of the total purchase amount. As of December 31, 2016, Pepco had no net credit exposure with suppliers.

DPL

Credit risk for DPL is managed by credit and collection policies, which are consistent with state regulatory requirements. DPL is currently obligated to provide service to all retail electric customers within its franchised territory. DPL records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with DPSC and MDPSC regulations, applicable weather regulatory provisions are in effect January through December, the utility will not terminate service to any residential customer when weather conditions prohibit termination. Additional cold weather regulatory requirements are in effect after November 1 and before April 1. DPL's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in DPSC and MDPSC regulations. DPL did not have any customers representing over 10% of its revenues as of December 31, 2016.

DPL's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day. As of December 31, 2016, DPL had no net credit exposure with suppliers.

DPL conducts margining under it natural gas supply contracts. As of December 31, 2016, DPL's credit exposure under its natural gas supply and asset management agreements was immaterial.

ACE

Credit risk for ACE is managed by credit and collection policies, which are consistent with state regulatory requirements. ACE is currently obligated to provide service to all retail electric customers within its franchised territory. ACE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with NJBPU regulations, applicable weather regulatory provisions are in effect January through December, the utility will not terminate service to any residential customer when weather conditions prohibit termination. Additional cold weather regulatory requirements are in effect after November 15 and through March 15. ACE's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in NJBPU regulations. ACE did not have any customers representing over 10% of its revenues as of December 31, 2016.

ACE's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's creditworthiness requirements, require a supplier to partially meet its credit requirements with an independent credit requirement in an amount equal to $2.4 million per

tranche and allow a supplier to meet its additional credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day. As of December 31, 2016, ACE had no net credit exposure with suppliers.

Collateral (All Registrants)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, natural gas and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See ITEM 7.—Liquidity and Capital Resources—Credit Matters—Exelon Credit Facilities for additional information.

As of December 31, 2016, Generation had cash collateral of $347 million posted and cash collateral held of $24 million for external counterparties with derivative positions, of which $329 million and $2 million in net cash collateral deposits were offset against energy derivative and interest rate and foreign exchange derivative related to underlying energy contracts, respectively. As of December 31, 2016, $8 million of cash collateral held was not offset against net derivative positions because it was not associated with energy-related derivatives or as of the balance sheet date there were no positions to offset. As of December 31, 2015, Generation had cash collateral posted of $1,267 million and cash collateral held of $21 million for external counterparties with derivative positions, of which $1,234 million and $9 million in net cash collateral deposits were offset against energy derivatives and interest rate and foreign exchange derivatives related to underlying energy contracts, respectively. As of December 31, 2015, $3 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives or as the balance sheet date there were no positions to offset. See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 31, 2016, ComEd held $3 million in collateral from suppliers in association with standard block energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for renewable energy contracts. See Note 3—Regulatory Matters and Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

PECO

As of December 31, 2016, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of December 31, 2016, BGE was not required to post collateral under its natural gas procurement contracts, nor was it holding collateral under its electric supply contracts, but was holding $1 million in collateral under its natural gas procurement contracts. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Pepco

Pepco is not required to post collateral under its energy procurement contracts. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

DPL

DPL is not required to post collateral under its energy procurement contracts. As of December 31, 2016, DPL was not required to post collateral under its natural gas procurement contracts. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

ACE

ACE is not required to post collateral under its energy procurement contracts. See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (All Registrants)

Generation, ComEd, PECO, BGE, Pepco, DPL and ACE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon, Generation, PHI and DPL)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. DPL enters into commodity transactions on ICE. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Interest Rate and Foreign Exchange Risk (All Registrants)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2016, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $659 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $7 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2016. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of December 31, 2016, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $535 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Generation

General

Generation's integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. These segments are discussed in further detail in "ITEM 1. BUSINESS—Exelon Generation Company, LLC" of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation's executive overview is set forth under "ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared To Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of Generation's results of operations for 2016 compared to 2015 and 2015 compared to 2014 is set forth under "Results of Operations—Generation" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.8 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See "EXELON CORPORATION—Liquidity and Capital Resources" and Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Generation's capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon's pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants—Critical Accounting Policies and Estimates above for a discussion of Generation's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in "ITEM 1. BUSINESS—ComEd" of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of ComEd's results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under "Results of Operations—ComEd" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2016, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion.

See "EXELON CORPORATION—Liquidity and Capital Resources" and Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ComEd's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants—Critical Accounting Policies and Estimates above for a discussion of ComEd's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in "ITEM 1. BUSINESS—PECO" of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of PECO's results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under "Results of Operations—PECO" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2016, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million.

See "EXELON CORPORATION—Liquidity and Capital Resources" and Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund PECO's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants—Critical Accounting Policies and Estimates above for a discussion of PECO's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BGE

General

BGE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in "ITEM 1. BUSINESS—BGE" of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of BGE's results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under "Results of Operations—BGE" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

BGE's business is capital intensive and requires considerable capital resources. BGE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2016, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million.

See "EXELON CORPORATION—Liquidity and Capital Resources" and Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund BGE's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to BGE's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to BGE's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants—Critical Accounting Policies and Estimates above for a discussion of BGE's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PHI

General

PHI has three reportable segments Pepco, DPL, and ACE. Its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services, and to a lesser extent, the purchase and regulated retail sale and supply of natural gas in Delaware. This segment is discussed in further detail in "ITEM 1. BUSINESS—PHI" of this Form 10-K.

Executive Overview

A discussion of items pertinent to PHI's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Successor Period of March 24, 2016 to December 31, 2016, Predecessor Period of January 1, 2016 to March 23, 2016, and Predecessor Period Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of PHI's results of operations for March 24, 2016 to December 31, 2016 and January 1, 2016 to March 23, 2016 and 2015 compared to 2014 is set forth under "Results of Operations—PHI" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

PHI's business is capital intensive and requires considerable capital resources. PHI's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper, borrowings from the Exelon money pool or capital contributions from Exelon. PHI's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general.

See "EXELON CORPORATION—Liquidity and Capital Resources" and Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund PHI's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PHI operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PHI's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PHI's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PHI's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PHI is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PHI's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants—Critical Accounting Policies and Estimates above for a discussion of PHI's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PHI

PHI is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pepco

General

Pepco operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in District of Columbia and major portions of Prince George's County and Montgomery County in Maryland. This segment is discussed in further detail in "ITEM 1. BUSINESS—Pepco" of this Form 10-K.

Executive Overview

A discussion of items pertinent to Pepco's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of Pepco's results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under "Results of Operations—Pepco" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

Pepco's business is capital intensive and requires considerable capital resources. Pepco's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. Pepco's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2016, Pepco had access to a revolving credit facility with aggregate bank commitments of $300 million.

See "EXELON CORPORATION—Liquidity and Capital Resources" and Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Pepco's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, Pepco operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to Pepco's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Pepco's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Pepco's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Pepco is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Pepco's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants—Critical Accounting Policies and Estimates above for a discussion of Pepco's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Pepco

Pepco is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

DPL

General

DPL operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale and supply of natural gas in New Castle County, Delaware. This segment is discussed in further detail in "ITEM 1. BUSINESS—DPL" of this Form 10-K.

Executive Overview

A discussion of items pertinent to DPL's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of DPL's results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under "Results of Operations—DPL" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

DPL's business is capital intensive and requires considerable capital resources. DPL's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. DPL's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where DPL no longer has access to the capital markets at reasonable terms, DPL has access to a revolving credit facility. At December 31, 2016, DPL had access to a revolving credit facility with aggregate bank commitments of $300 million.

See "EXELON CORPORATION—Liquidity and Capital Resources" and Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund DPL's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, DPL operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to DPL's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to DPL's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to DPL's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to DPL is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of DPL's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants—Critical Accounting Policies and Estimates above for a discussion of DPL's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

DPL

DPL is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ACE

General

ACE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in portions of southern New Jersey. This segment is discussed in further detail in "ITEM 1. BUSINESS—ACE" of this Form 10-K.

Executive Overview

A discussion of items pertinent to ACE's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of ACE's results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under "Results of Operations—ACE" in "EXELON CORPORATION—Results of Operations" of this Form 10-K.

Liquidity and Capital Resources

ACE's business is capital intensive and requires considerable capital resources. ACE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ACE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2016, ACE had access to a revolving credit facility with aggregate bank commitments of $300 million.

See "EXELON CORPORATION—Liquidity and Capital Resources" and Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ACE's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ACE operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ACE's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ACE's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ACE's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ACE is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ACE's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under "Contractual Obligations and Off-Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants—Critical Accounting Policies and Estimates above for a discussion of ACE's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1—Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ACE

ACE is exposed to market risks associated with credit and interest rates. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2016, Exelon's internal control over financial reporting was effective.

We excluded ConEdison Solutions from our assessment of internal control over financial reporting as of December 31, 2016 because it was acquired by the Company in a purchase business combination on September 1, 2016. The total assets and total operating revenues related to ConEdison Solutions, a wholly-owned subsidiary, represent less than 1% and 1%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2016.

The effectiveness of Exelon's internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2017

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Generation's management conducted an assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation's management concluded that, as of December 31, 2016, Generation's internal control over financial reporting was effective.

We excluded ConEdison Solutions from our assessment of internal control over financial reporting as of December 31, 2016 because it was acquired by the Company in a purchase business combination on September 1, 2016. The total assets and total operating revenues related to ConEdison Solutions, a wholly-owned subsidiary, represent less than 1% and 2%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2016.

The effectiveness of Generation's internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2017

Management's Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd's management concluded that, as of December 31, 2016, ComEd's internal control over financial reporting was effective.

The effectiveness of ComEd's internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2017

Management's Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO's management concluded that, as of December 31, 2016, PECO's internal control over financial reporting was effective.

The effectiveness of PECO's internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2017

Management's Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

BGE's management conducted an assessment of the effectiveness of BGE's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE's management concluded that, as of December 31, 2016, BGE's internal control over financial reporting was effective.

The effectiveness of BGE's internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2017

Management's Report on Internal Control Over Financial Reporting

The management of Pepco Holdings LLC (PHI) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PHI's management conducted an assessment of the effectiveness of PHI's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PHI's management concluded that, as of December 31, 2016, PHI's internal control over financial reporting was effective.

The effectiveness of PHI's internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 13, 2017

Management's Report on Internal Control Over Financial Reporting

The management of Potomac Electric Power Company (Pepco) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Pepco's management conducted an assessment of the effectiveness of Pepco's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Pepco's management concluded that, as of December 31, 2016, Pepco's internal control over financial reporting was effective.

February 13, 2017

Management's Report on Internal Control Over Financial Reporting

The management of Delmarva Power & Light Company (DPL) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

DPL's management conducted an assessment of the effectiveness of DPL's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, DPL's management concluded that, as of December 31, 2016, DPL's internal control over financial reporting was effective.

February 13, 2017

Management's Report on Internal Control Over Financial Reporting

The management of Atlantic City Electric Company (ACE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ACE's management conducted an assessment of the effectiveness of ACE's internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ACE's management concluded that, as of December 31, 2016, ACE's internal control over financial reporting was effective.

February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Corporation and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control Over Financial Reporting, management has excluded Consolidated Edison Solutions, Inc. from its assessment of internal control over financial reporting as of December 31, 2016 because it was acquired by the Company in a purchase business combination on September 1, 2016. We have also excluded Consolidated Edison Solutions, Inc. from our audit of internal control over financial reporting. Consolidated Edison Solutions, Inc. is a wholly-owned subsidiary whose total assets and total operating revenues represent less than 1% and 1%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2016.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Generation Company, LLC (the "Company") and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control Over Financial Reporting, management has excluded Consolidated Edison Solutions, Inc. from its assessment of internal control over financial reporting as of December 31, 2016 because it was acquired by the Company in a purchase business combination on September 1, 2016. We have also excluded Consolidated Edison Solutions, Inc. from our audit of internal control over financial reporting. Consolidated Edison Solutions, Inc. is a wholly-owned subsidiary whose total assets and total operating revenues represent less than 1% and 2%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2016.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Commonwealth Edison Company and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PECO Energy Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of PECO Energy Company and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Baltimore Gas and Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Pepco Holdings LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Pepco Holdings LLC and its subsidiaries (Successor) at December 31, 2016, and the results of their operations and their cash flows for the period from March 24, 2016 to December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Pepco Holdings LLC:

In our opinion, the financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Pepco Holdings LLC and its subsidiaries (formerly Pepco Holdings, Inc.) (Predecessor) at December 31, 2015, and the results of their operations and their cash flows for the period January 1, 2016 to March 23, 2016 and for each of the two years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the financial statements, the Company changed the manner in which it accounts for interest on uncertain tax positions in 2016.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Potomac Electric Power Company:

In our opinion, the financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Potomac Electric Power Company at December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Delmarva Power & Light Company:

In our opinion, the financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Delmarva Power & Light Company at December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Atlantic City Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Atlantic City Electric Company and its subsidiary at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for its regulatory recovery mechanism for purchased power costs associated with Basic Generation Service in 2016.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 13, 2017

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Exelon Corporation and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Competitive businesses revenues	$16,324	$18,395	$16,637
Rate-regulated utility revenues	15,036	11,052	10,792
Total operating revenues	31,360	29,447	27,429
Operating expenses			
Competitive businesses purchased power and fuel	8,817	10,007	9,369
Rate-regulated utility purchased power and fuel	3,823	3,077	3,103
Purchased power and fuel from affiliates	—	—	531
Operating and maintenance	10,048	8,322	8,568
Depreciation and amortization	3,936	2,450	2,314
Taxes other than income	1,576	1,200	1,154
Total operating expenses	28,200	25,056	25,039
Equity in losses of unconsolidated affiliates	—	—	(20)
Gain (Loss) on sales of assets	(48)	18	437
Gain on consolidation and acquisition of businesses	—	—	289
Operating income	3,112	4,409	3,096
Other income and (deductions)			
Interest expense, net	(1,495)	(992)	(1,024)
Interest expense to affiliates	(41)	(41)	(41)
Other, net	413	(46)	455
Total other income and (deductions)	(1,123)	(1,079)	(610)
Income before income taxes	1,989	3,330	2,486
Income taxes	761	1,073	666
Equity in losses of unconsolidated affiliates	(24)	(7)	—
Net income	1,204	2,250	1,820
Net income (loss) attributable to noncontrolling interests and preference stock dividends	70	(19)	197
Net income attributable to common shareholders	$ 1,134	$ 2,269	$ 1,623
Comprehensive income, net of income taxes			
Net income	$ 1,204	$ 2,250	$ 1,820
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	(48)	(46)	(30)
Actuarial loss reclassified to periodic benefit cost	184	220	147
Pension and non-pension postretirement benefit plan valuation adjustment	(181)	(99)	(497)
Unrealized gain (loss) on cash flow hedges	2	9	(148)
Unrealized gain on marketable securities	1	—	1
Unrealized (loss) gain on equity investments	(4)	(3)	8
Unrealized gain (loss) on foreign currency translation	10	(21)	(9)
Reversal of CENG equity method AOCI	—	—	(116)
Other comprehensive (loss) income	(36)	60	(644)
Comprehensive income	1,168	2,310	1,176
Comprehensive income (loss) attributable to noncontrolling interests and preference stock dividends	70	(19)	197
Comprehensive income attributable to common shareholders	$ 1,098	$ 2,329	$ 979
Average shares of common stock outstanding:			
Basic	924	890	860
Diluted	927	893	864
Earnings per average common share:			
Basic	$ 1.23	$ 2.55	$ 1.89
Diluted	$ 1.22	$ 2.54	$ 1.88
Dividends per common share	$ 1.26	$ 1.24	$ 1.24

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income	$ 1,204	$ 2,250	$ 1,820
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	5,576	3,987	3,868
Impairments of long-lived assets	306	36	687
Gain on consolidation and acquisition of businesses	—	—	(296)
(Gain) Loss on sales of assets	48	(18)	(437)
Deferred income taxes and amortization of investment tax credits	664	752	502
Net fair value changes related to derivatives	24	(367)	716
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(229)	131	(210)
Other non-cash operating activities	1,333	1,109	1,054
Changes in assets and liabilities:			
Accounts receivable	(432)	240	(318)
Inventories	7	4	(380)
Accounts payable and accrued expenses	771	(121)	49
Option premiums (paid) received, net	(66)	58	38
Collateral received (posted), net	931	347	(1,719)
Income taxes	576	97	(143)
Pension and non-pension postretirement benefit contributions	(397)	(502)	(617)
Deposit with IRS	(1,250)	—	—
Other assets and liabilities	(621)	(387)	(157)
Net cash flows provided by operating activities	8,445	7,616	4,457
Cash flows from investing activities			
Capital expenditures	(8,553)	(7,624)	(6,077)
Proceeds from termination of direct financing lease investment	360	—	335
Proceeds from nuclear decommissioning trust fund sales	9,496	6,895	7,396
Investment in nuclear decommissioning trust funds	(9,738)	(7,147)	(7,551)
Cash and restricted cash acquired from consolidations and acquisitions	—	—	140
Acquisitions of businesses, net	(6,934)	(40)	(386)
Proceeds from sales of long-lived assets	61	147	1,719
Proceeds from sales of investments	—	—	7
Purchases of investments	—	—	(3)
Change in restricted cash	(42)	66	(104)
Distribution from CENG	—	—	13
Other investing activities	(153)	(119)	(88)
Net cash flows used in investing activities	(15,503)	(7,822)	(4,599)
Cash flows from financing activities			
Changes in short-term borrowings	(353)	80	122
Proceeds from short-term borrowings with maturities greater than 90 days	240	—	—
Repayments on short-term borrowings with maturities greater than 90 days	(462)	—	—
Issuance of long-term debt	4,716	6,709	3,463
Retirement of long-term debt	(1,936)	(2,687)	(1,545)
Issuance of common stock	—	1,868	—
Redemption of preference stock	(190)	—	—
Distributions to noncontrolling interests of consolidated VIE	—	—	(421)
Dividends paid on common stock	(1,166)	(1,105)	(1,065)
Proceeds from employee stock plans	55	32	35
Sale of noncontrolling interests	372	32	—
Other financing activities	(85)	(99)	(178)
Net cash flows provided by financing activities	1,191	4,830	411
(Decrease) Increase in cash and cash equivalents	(5,867)	4,624	269
Cash and cash equivalents at beginning of period	6,502	1,878	1,609
Cash and cash equivalents at end of period	$ 635	$ 6,502	$ 1,878

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 635	$ 6,502
Restricted cash and cash equivalents	253	205
Deposit with IRS	1,250	—
Accounts receivable, net		
Customer	4,158	3,187
Other	1,201	912
Mark-to-market derivative assets	917	1,365
Unamortized energy contract assets	88	86
Inventories, net		
Fossil fuel	364	462
Materials and supplies	1,274	1,104
Regulatory assets	1,342	759
Other	930	752
Total current assets	12,412	15,334
Property, plant and equipment, net	71,555	57,439
Deferred debits and other assets		
Regulatory assets	10,046	6,065
Nuclear decommissioning trust funds	11,061	10,342
Investments	629	639
Goodwill	6,677	2,672
Mark-to-market derivative assets	492	758
Unamortized energy contract assets	447	484
Pledged assets for Zion Station decommissioning	113	206
Other	1,472	1,445
Total deferred debits and other assets	30,937	22,611
Total assets [a]	$114,904	$95,384

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 1,267	$ 533
Long-term debt due within one year	2,430	1,500
Accounts payable	3,441	2,883
Accrued expenses	3,460	2,376
Payables to affiliates	8	8
Regulatory liabilities	602	369
Mark-to-market derivative liabilities	282	205
Unamortized energy contract liabilities	407	100
Renewable energy credit obligation	428	302
PHI Merger related obligation	151	—
Other	981	842
Total current liabilities	13,457	9,118
Long-term debt	31,575	23,645
Long-term debt to financing trusts	641	641
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	18,138	13,776
Asset retirement obligations	9,111	8,585
Pension obligations	4,248	3,385
Non-pension postretirement benefit obligations	1,848	1,618
Spent nuclear fuel obligation	1,024	1,021
Regulatory liabilities	4,187	4,201
Mark-to-market derivative liabilities	392	374
Unamortized energy contract liabilities	830	117
Payable for Zion Station decommissioning	14	90
Other	1,827	1,491
Total deferred credits and other liabilities	41,619	34,658
Total liabilities [a]	87,292	68,062
Commitments and contingencies		
Contingently redeemable noncontrolling interests	—	28
Shareholders' equity		
Common stock (No par value, 2000 shares authorized, 924 shares and 920 shares outstanding at December 31, 2016 and 2015, respectively)	18,794	18,676
Treasury stock, at cost (35 shares at December 31, 2016 and 2015, respectively)	(2,327)	(2,327)
Retained earnings	12,030	12,068
Accumulated other comprehensive loss, net	(2,660)	(2,624)
Total shareholders' equity	25,837	25,793
BGE preference stock not subject to mandatory redemption	—	193
Noncontrolling interests	1,775	1,308
Total equity	27,612	27,294
Total liabilities and shareholders' equity	$114,904	$95,384

(a) Exelon's consolidated assets include $8,893 million and $8,268 million at December 31, 2016 and December 31, 2015, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $3,356 million and $3,264 million at December 31, 2016 and December 31, 2015, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 2—Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Preference Stock	Total Shareholders' Equity
Balance, December 31, 2013	892,034	$ 16,741	$ (2,327)	$ 10,358	$ (2,040)	$ 15	$ 193	$ 22,940
Net income	—	—	—	1,623	—	184	13	1,820
Long-term incentive plan activity	1,574	72	—	—	—	—	—	72
Employee stock purchase plan issuances	960	35	—	—	—	—	—	35
Tax benefit on stock compensation	—	(8)	—	—	—	—	—	(8)
Acquisition of noncontrolling interests	—	(2)	—	—	—	6	—	4
Common stock dividends	—	—	—	(1,071)	—	—	—	(1,071)
Preference stock dividends	—	—	—	—	—	—	(13)	(13)
Fair value of financing contract payments	—	(131)	—	—	—	—	—	(131)
Noncontrolling interests established upon consolidation of CENG	—	—	—	—	—	1,548	—	1,548
Transfer of CENG pension and non-pension postretirement benefit obligations	—	2	—	—	—	—	—	2
Consolidated VIE dividend to noncontrolling interests	—	—	—	—	—	(421)	—	(421)
Reversal of CENG equity method AOCI, net of income taxes	—	—	—	—	(116)	—	—	(116)
Other comprehensive loss, net of income taxes	—	—	—	—	(528)	—	—	(528)
Balance, December 31, 2014	894,568	$ 16,709	$ (2,327)	$ 10,910	$ (2,684)	$ 1,332	$ 193	$ 24,133
Net income (loss)	—	—	—	2,269	—	(32)	13	2,250
Long-term incentive plan activity	1,430	70	—	—	—	—	—	70
Employee stock purchase plan issuances	1,170	32	—	—	—	—	—	32
Issuance of common stock	57,500	1,868	—	—	—	—	—	1,868
Tax benefit on stock compensation	—	(3)	—	—	—	—	—	(3)
Acquisition of noncontrolling interests	—	—	—	—	—	4	—	4
Adjustment of contingently redeemable noncontrolling interests due to release of contingency	—	—	—	—	—	4	—	4
Common stock dividends	—	—	—	(1,111)	—	—	—	(1,111)
Preference stock dividends	—	—	—	—	—	—	(13)	(13)
Other comprehensive income, net of income taxes	—	—	—	—	60	—	—	60
Balance, December 31, 2015	954,668	$ 18,676	$ (2,327)	$ 12,068	$ (2,624)	$ 1,308	$ 193	$ 27,294
Net income	—	—	—	1,134	—	62	8	1,204
Long-term incentive plan activity	2,868	85	—	—	—	—	—	85
Employee stock purchase plan issuances	1,242	55	—	—	—	—	—	55
Tax benefit on stock compensation	—	(18)	—	—	—	—	—	(18)
Changes in equity of noncontrolling interests	—	—	—	—	—	5	—	5
Sale of noncontrolling interests	—	(4)	—	—	—	400	—	396
Common stock dividends	—	—	—	(1,172)	—	—	—	(1,172)
Redemption of preference stock	—	—	—	—	—	—	(193)	(193)
Preference stock dividends	—	—	—	—	—	—	(8)	(8)
Other comprehensive loss, net of income taxes	—	—	—	—	(36)	—	—	(36)
Balance, December 31, 2016	958,778	$ 18,794	$ (2,327)	$ 12,030	$ (2,660)	$ 1,775	$ —	$ 27,612

See the Combined Notes to Consolidated Financial Statements

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Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Operating revenues	$16,312	$18,386	$16,614
Operating revenues from affiliates	1,439	749	779
Total operating revenues	17,751	19,135	17,393
Operating expenses			
Purchased power and fuel	8,818	10,007	9,368
Purchased power and fuel from affiliates	12	14	557
Operating and maintenance	4,978	4,688	4,943
Operating and maintenance from affiliates	663	620	623
Depreciation and amortization	1,879	1,054	967
Taxes other than income	506	489	465
Total operating expenses	16,856	16,872	16,923
Equity in losses of unconsolidated affiliates	—	—	(20)
Gain (Loss) on sales of assets	(59)	12	437
Gain on consolidation and acquisition of businesses	—	—	289
Operating income	836	2,275	1,176
Other income and (deductions)			
Interest expense, net	(325)	(322)	(303)
Interest expense to affiliates	(39)	(43)	(53)
Other, net	401	(60)	406
Total other income and (deductions)	37	(425)	50
Income before income taxes	873	1,850	1,226
Income taxes	290	502	207
Equity in losses of unconsolidated affiliates	(25)	(8)	—
Net income	558	1,340	1,019
Net income (loss) attributable to noncontrolling interests	62	(32)	184
Net income attributable to membership interest	$ 496	$ 1,372	$ 835
Comprehensive income, net of income taxes			
Net income	$ 558	$ 1,340	$ 1,019
Other comprehensive income (loss), net of income taxes			
Unrealized gain (loss) on cash flow hedges	2	(3)	(132)
Unrealized (loss) gain on equity investments	(4)	(3)	8
Unrealized gain (loss) on foreign currency translation	10	(21)	(9)
Unrealized loss on marketable securities	1	—	(1)
Reversal of CENG equity method AOCI	—	—	(116)
Other comprehensive income (loss)	9	(27)	(250)
Comprehensive income	$ 567	$ 1,313	$ 769
Comprehensive income (loss) attributable to noncontrolling interests	62	(32)	184
Comprehensive income attributable to membership interest	$ 505	$ 1,345	$ 585

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income	$ 558	$ 1,340	$ 1,019
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	3,519	2,589	2,519
Impairment of long-lived assets	243	12	663
Gain on consolidation and acquisition of businesses	—	—	(296)
(Gain) Loss on sales of assets	59	(12)	(437)
Deferred income taxes and amortization of investment tax credits	(269)	49	(198)
Net fair value changes related to derivatives	40	(249)	635
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(229)	131	(210)
Other non-cash operating activities	15	268	346
Changes in assets and liabilities:			
Accounts receivable	(152)	194	(215)
Receivables from and payables to affiliates, net	(21)	15	15
Inventories	(4)	16	(359)
Accounts payable and accrued expenses	29	(149)	29
Option premiums (paid) received, net	(66)	58	38
Collateral received (posted), net	923	407	(1,748)
Income taxes	182	(18)	265
Pension and non-pension postretirement benefit contributions	(152)	(245)	(297)
Other assets and liabilities	(231)	(207)	57
Net cash flows provided by operating activities	4,444	4,199	1,826
Cash flows from investing activities			
Capital expenditures	(3,078)	(3,841)	(3,012)
Proceeds from nuclear decommissioning trust fund sales	9,496	6,895	7,396
Investment in nuclear decommissioning trust funds	(9,738)	(7,147)	(7,551)
Cash and restricted cash acquired from consolidations and acquisitions	—	—	140
Proceeds from sales of long-lived assets	37	147	1,719
Acquisitions of businesses, net	(293)	(40)	(386)
Change in restricted cash	(35)	35	(87)
Changes in Exelon intercompany money pool	—	—	44
Distribution from CENG	—	—	13
Other investing activities	(240)	(118)	(43)
Net cash flows used in investing activities	(3,851)	(4,069)	(1,767)
Cash flows from financing activities			
Change in short-term borrowings	620	—	17
Proceeds from short-term borrowings with maturities greater than 90 days	240	—	—
Repayments of short-term borrowings with maturities greater than 90 days	(162)	—	—
Issuance of long-term debt	388	1,309	1,112
Retirement of long-term debt	(202)	(89)	(586)
Retirement of long-term debt to affiliate	—	(550)	—
Changes in Exelon intercompany money pool	(1,191)	1,252	—
Distribution to member	(922)	(2,474)	(645)
Distribution to noncontrolling interests of consolidated VIE	—	—	(421)
Contribution from member	142	47	53
Sale of noncontrolling interests	372	32	—
Other financing activities	(19)	(6)	(67)
Net cash flows used in financing activities	(734)	(479)	(537)
Decrease in cash and cash equivalents	(141)	(349)	(478)
Cash and cash equivalents at beginning of period	431	780	1,258
Cash and cash equivalents at end of period	$ 290	$ 431	$ 780

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 290	$ 431
Restricted cash and cash equivalents	158	123
Accounts receivable, net		
Customer	2,433	2,095
Other	558	360
Mark-to-market derivative assets	917	1,365
Receivables from affiliates	156	83
Unamortized energy contract assets	88	86
Inventories, net		
Fossil fuel	292	384
Materials and supplies	935	880
Other	701	535
Total current assets	6,528	6,342
Property, plant and equipment, net	25,585	25,843
Deferred debits and other assets		
Nuclear decommissioning trust funds	11,061	10,342
Investments	418	210
Goodwill	47	47
Mark-to-market derivative assets	476	733
Prepaid pension asset	1,595	1,689
Pledged assets for Zion Station decommissioning	113	206
Unamortized energy contract assets	447	484
Deferred income taxes	16	6
Other	688	627
Total deferred debits and other assets	14,861	14,344
Total assets (a)	$46,974	$46,529

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 699	$ 29
Long-term debt due within one year	1,117	90
Accounts payable	1,610	1,583
Accrued expenses	989	935
Payables to affiliates	137	104
Borrowings from Exelon intercompany money pool	55	1,252
Mark-to-market derivative liabilities	263	182
Unamortized energy contract liabilities	72	100
Renewable energy credit obligation	428	302
Other	313	356
Total current liabilities	5,683	4,933
Long-term debt	7,202	7,936
Long-term debt to affiliate	922	933
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,585	5,845
Asset retirement obligations	8,922	8,431
Non-pension postretirement benefit obligations	930	924
Spent nuclear fuel obligation	1,024	1,021
Payables to affiliates	2,608	2,577
Mark-to-market derivative liabilities	153	150
Unamortized energy contract liabilities	80	117
Payable for Zion Station decommissioning	14	90
Other	595	602
Total deferred credits and other liabilities	19,911	19,757
Total liabilities (a)	33,718	33,559
Commitments and contingencies		
Contingently redeemable noncontrolling interests	—	28
Equity		
Member's equity		
Membership interest	9,261	8,997
Undistributed earnings	2,275	2,701
Accumulated other comprehensive loss, net	(54)	(63)
Total member's equity	11,482	11,635
Noncontrolling interests	1,774	1,307
Total equity	13,256	12,942
Total liabilities and equity	$46,974	$46,529

(a) Generation's consolidated assets include $8,817 million and $8,235 million at December 31, 2016 and 2015, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $3,170 million and $3,135 million at December 31, 2016 and 2015, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 2—Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Changes in Equity

(In millions)	Member's Equity			Noncontrolling Interests	Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income (Loss)		
Balance, December 31, 2013	$ 8,898	$ 3,613	$ 214	$ 17	$ 12,742
Net income	—	835	—	184	1,019
Acquisition of noncontrolling interests	—	—		5	5
Allocation of tax benefit from member	53	—	—	—	53
Distribution to member	—	(645)	—	—	(645)
Noncontrolling interests established upon consolidation of CENG	—	—	—	1,548	1,548
Consolidated VIE dividend to noncontrolling interests	—	—	—	(421)	(421)
Reversal of CENG equity method AOCI, net of income taxes	—	—	(116)	—	(116)
Other comprehensive loss, net of income taxes	—	—	(134)	—	(134)
Balance, December 31, 2014	$ 8,951	$ 3,803	$ (36)	$ 1,333	$ 14,051
Net income (loss)	—	1,372	—	(32)	1,340
Acquisition of noncontrolling interests	(1)	—	—	2	1
Adjustment of contingently redeemable noncontrolling interests due to release of contingency	—	—	—	4	4
Allocation of tax benefit from member	47	—	—	—	47
Distribution to member	—	(2,474)	—	—	(2,474)
Other comprehensive loss, net of income taxes	—	—	(27)	—	(27)
Balance, December 31, 2015	$ 8,997	$ 2,701	$ (63)	$ 1,307	$ 12,942
Net income	—	496	—	62	558
Sale of noncontrolling interests	(4)	—	—	400	396
Changes in equity of noncontrolling interests	—	—	—	5	5
Allocation of tax benefit from member	98	—	—	—	98
Contribution from member	170	—	—	—	170
Distribution to member	—	(922)	—	—	(922)
Other comprehensive income, net of income taxes	—	—	9	—	9
Balance, December 31, 2016	$ 9,261	$ 2,275	$ (54)	$ 1,774	$ 13,256

See the Combined Notes to Consolidated Financial Statements

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Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(in millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Electric operating revenues	$5,239	$4,901	$4,560
Operating revenues from affiliates	15	4	4
Total operating revenues	5,254	4,905	4,564
Operating expenses			
Purchased power	1,411	1,301	1,001
Purchased power from affiliate	47	18	176
Operating and maintenance	1,303	1,372	1,263
Operating and maintenance from affiliate	227	195	166
Depreciation and amortization	775	707	687
Taxes other than income	293	296	293
Total operating expenses	4,056	3,889	3,586
Gain on sales of assets	7	1	2
Operating income	1,205	1,017	980
Other income and (deductions)			
Interest expense, net	(448)	(319)	(308)
Interest expense to affiliates	(13)	(13)	(13)
Other, net	(65)	21	17
Total other income and (deductions)	(526)	(311)	(304)
Income before income taxes	679	706	676
Income taxes	301	280	268
Net income	$ 378	$ 426	$ 408
Comprehensive income	$ 378	$ 426	$ 408

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income	$ 378	$ 426	$ 408
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	775	707	687
Deferred income taxes and amortization of investment tax credits	439	353	433
Other non-cash operating activities	215	416	255
Changes in assets and liabilities:			
Accounts receivable	(25)	(93)	(121)
Receivables from and payables to affiliates, net	3	(19)	(11)
Inventories	1	(40)	(16)
Accounts payable and accrued expenses	339	68	95
Counterparty collateral received (posted), net and cash deposits	7	(33)	2
Income taxes	306	192	(159)
Pension and non-pension postretirement benefit contributions	(38)	(150)	(248)
Other assets and liabilities	105	69	1
Net cash flows provided by operating activities	2,505	1,896	1,326
Cash flows from investing activities			
Capital expenditures	(2,734)	(2,398)	(1,689)
Proceeds from sales of investments	—	—	7
Purchases of investments	—	—	(3)
Change in restricted cash	—	2	(2)
Other investing activities	49	34	32
Net cash flows used in investing activities	(2,685)	(2,362)	(1,655)
Cash flows from financing activities			
Changes in short-term borrowings	(294)	(10)	120
Issuance of long-term debt	1,200	850	900
Retirement of long-term debt	(665)	(260)	(617)
Contributions from parent	315	202	273
Dividends paid on common stock	(369)	(299)	(307)
Other financing activities	(18)	(16)	(10)
Net cash flows provided by financing activities	169	467	359
(Decrease) increase in cash and cash equivalents	(11)	1	30
Cash and cash equivalents at beginning of period	67	66	36
Cash and cash equivalents at end of period	$ 56	$ 67	$ 66

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 56	$ 67
Restricted cash	2	2
Accounts receivable, net		
Customer	528	533
Other	218	272
Receivables from affiliates	356	199
Inventories, net	159	164
Regulatory assets	190	218
Other	45	63
Total current assets	1,554	1,518
Property, plant and equipment, net	19,335	17,502
Deferred debits and other assets		
Regulatory assets	977	895
Investments	6	6
Goodwill	2,625	2,625
Receivable from affiliates	2,170	2,172
Prepaid pension asset	1,343	1,490
Other	325	324
Total deferred debits and other assets	7,446	7,512
Total assets	$28,335	$26,532

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	2015
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 294
Long-term debt due within one year	425	665
Accounts payable	645	660
Accrued expenses	1,250	706
Payables to affiliates	65	62
Customer deposits	121	131
Regulatory liabilities	329	155
Mark-to-market derivative liability	19	23
Other	84	70
Total current liabilities	2,938	2,766
Long-term debt	6,608	5,844
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,364	4,914
Asset retirement obligations	119	111
Non-pension postretirement benefits obligations	239	259
Regulatory liabilities	3,369	3,459
Mark-to-market derivative liability	239	224
Other	529	507
Total deferred credits and other liabilities	9,859	9,474
Total liabilities	19,610	18,289
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	6,150	5,677
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	2,626	2,617
Total shareholders' equity	8,725	8,243
Total liabilities and shareholders' equity	$28,335	$26,532

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2013	$ 1,588	$5,190	$ (1,639)	$ 2,389	$ 7,528
Net income	—	—	408	—	408
Common stock dividends	—	—	—	(307)	(307)
Contribution from parent	—	273			273
Parent tax matter indemnification	—	5	—	—	5
Appropriation of retained earnings for future dividends	—	—	(408)	408	—
Balance, Balance at December 31, 2014	$ 1,588	$5,468	$ (1,639)	$ 2,490	$ 7,907
Net income	—	—	426	—	426
Common stock dividends	—	—	—	(299)	(299)
Contribution from parent	—	202	—	—	202
Parent tax matter indemnification	—	7	—	—	7
Appropriation of retained earnings for future dividends	—	—	(426)	426	—
Balance, December 31, 2015	$ 1,588	$5,677	$ (1,639)	$ 2,617	$ 8,243
Net income	—	—	378	—	378
Common stock dividends	—	—	—	(369)	(369)
Contribution from parent	—	315	—	—	315
Parent tax matter indemnification	—	158	—	—	158
Appropriation of retained earnings for future dividends	—	—	(378)	378	—
Balance, December 31, 2016	$ 1,588	$6,150	$ (1,639)	$ 2,626	$ 8,725

See the Combined Notes to Consolidated Financial Statements

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PECO Energy Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Electric operating revenues	$2,524	$2,485	$2,446
Natural gas operating revenues	462	545	646
Operating revenues from affiliates	8	2	2
Total operating revenues	2,994	3,032	3,094
Operating expenses			
Purchased power	598	735	740
Purchased fuel	162	235	327
Purchased power from affiliate	287	220	194
Operating and maintenance	665	684	767
Operating and maintenance from affiliates	146	110	99
Depreciation and amortization	270	260	236
Taxes other than income	164	160	159
Total operating expenses	2,292	2,404	2,522
Gain on sales of assets	—	2	—
Operating income	702	630	572
Other income and (deductions)			
Interest expense, net	(111)	(102)	(101)
Interest expense to affiliates	(12)	(12)	(12)
Other, net	8	5	7
Total other income and (deductions)	(115)	(109)	(106)
Income before income taxes	587	521	466
Income taxes	149	143	114
Net income	438	378	352
Net income attributable to common shareholder	$ 438	$ 378	$ 352
Comprehensive income	$ 438	$ 378	$ 352

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income	$ 438	$ 378	$ 352
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	270	260	236
Deferred income taxes and amortization of investment tax credits	78	90	88
Other non-cash operating activities	65	70	92
Changes in assets and liabilities:			
Accounts receivable	(71)	37	(16)
Receivables from and payables to affiliates, net	6	3	(6)
Inventories	6	10	2
Accounts payable and accrued expenses	67	(25)	58
Income taxes	8	(9)	(57)
Pension and non-pension postretirement benefit contributions	(30)	(40)	(16)
Other assets and liabilities	(8)	(4)	(21)
Net cash flows provided by operating activities	829	770	712
Cash flows from investing activities			
Capital expenditures	(686)	(601)	(661)
Changes in intercompany money pool	(131)	—	—
Change in restricted cash	(1)	(1)	—
Other investing activities	20	14	12
Net cash flows used in investing activities	(798)	(588)	(649)
Cash flows from financing activities			
Issuance of long-term debt	300	350	300
Retirement of long-term debt	(300)	—	(250)
Contributions from parent	18	16	24
Dividends paid on common stock	(277)	(279)	(320)
Other financing activities	(4)	(4)	(4)
Net cash flows provided by (used in) financing activities	(263)	83	(250)
(Decrease) Increase in cash and cash equivalents	(232)	265	(187)
Cash and cash equivalents at beginning of period	295	30	217
Cash and cash equivalents at end of period	$ 63	$ 295	$ 30

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 63	$ 295
Restricted cash and cash equivalents	4	3
Accounts receivable, net		
Customer	306	258
Other	131	146
Receivables from affiliates	4	2
Receivable from Exelon intercompany pool	131	—
Inventories, net		
Fossil fuel	35	43
Materials and supplies	27	26
Prepaid utility taxes	9	11
Regulatory assets	29	34
Other	18	24
Total current assets	757	842
Property, plant and equipment, net	7,565	7,141
Deferred debits and other assets		
Regulatory assets	1,681	1,583
Investments	25	28
Receivable from affiliates	438	405
Prepaid pension asset	345	347
Other	20	21
Total deferred debits and other assets	2,509	2,384
Total assets	$10,831	$10,367

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	$ —	$ 300
Accounts payable	342	281
Accrued expenses	104	109
Payables to affiliates	63	55
Customer deposits	61	58
Regulatory liabilities	127	112
Other	30	29
Total current liabilities	727	944
Long-term debt	2,580	2,280
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,006	2,792
Asset retirement obligations	28	27
Non-pension postretirement benefits obligations	289	287
Regulatory liabilities	517	527
Other	85	90
Total deferred credits and other liabilities	3,925	3,723
Total liabilities	7,416	7,131
Commitments and contingencies		
Shareholder's equity		
Common stock	2,473	2,455
Retained earnings	941	780
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,415	3,236
Total liabilities and shareholder's equity	$10,831	$10,367

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholder's Equity
Balance, December 31, 2013	$ 2,415	$ 649	$ 1	$ 3,065
Net income	—	352	—	352
Common stock dividends	—	(320)	—	(320)
Allocation of tax benefit from parent	24	—	—	24
Balance, December 31, 2014	$ 2,439	$ 681	$ 1	$ 3,121
Net income	—	378	—	378
Common stock dividends	—	(279)	—	(279)
Allocation of tax benefit from parent	16	—	—	16
Balance, December 31, 2015	$ 2,455	$ 780	$ 1	$ 3,236
Net income	—	438	—	438
Common stock dividends	—	(277)	—	(277)
Allocation of tax benefit from parent	18	—	—	18
Balance, December 31, 2016	$ 2,473	$ 941	$ 1	$ 3,415

See the Combined Notes to Consolidated Financial Statements

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Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Electric operating revenues	$2,603	$2,490	$2,460
Natural gas operating revenues	609	631	680
Operating revenues from affiliates	21	14	25
Total operating revenues	3,233	3,135	3,165
Operating expenses			
Purchased power	528	602	733
Purchased fuel	162	205	302
Purchased power from affiliate	604	498	382
Operating and maintenance	605	565	614
Operating and maintenance from affiliates	132	118	103
Depreciation and amortization	423	366	371
Taxes other than income	229	224	221
Total operating expenses	2,683	2,578	2,726
Gain on sales of assets	—	1	—
Operating income	550	558	439
Other income and (deductions)			
Interest expense, net	(87)	(83)	(90)
Interest expense to affiliates	(16)	(16)	(16)
Other, net	21	18	18
Total other income and (deductions)	(82)	(81)	(88)
Income before income taxes	468	477	351
Income taxes	174	189	140
Net income	294	288	211
Preference stock dividends	8	13	13
Net income attributable to common shareholder	$ 286	$ 275	$ 198
Comprehensive income	$ 294	$ 288	$ 211
Comprehensive income attributable to preference stock dividends	8	13	13
Comprehensive income attributable to common shareholder	$ 286	$ 275	$ 198

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income	$ 294	$ 288	$ 211
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	423	366	371
Impairment of long-lived assets and losses on regulatory assets	52	—	—
Deferred income taxes and amortization of investment tax credits	118	165	116
Other non-cash operating activities	88	137	180
Changes in assets and liabilities:			
Accounts receivable	(98)	84	46
Receivables from and payables to affiliates, net	3	(2)	(1)
Inventories	1	18	(6)
Accounts payable and accrued expenses	138	(3)	(75)
Collateral received (posted), net	—	(27)	27
Income taxes	18	(54)	45
Pension and non-pension postretirement benefit contributions	(49)	(17)	(16)
Other assets and liabilities	(43)	(173)	(158)
Net cash flows provided by operating activities	945	782	740
Cash flows from investing activities			
Capital expenditures	(934)	(719)	(620)
Change in restricted cash	—	26	(22)
Other investing activities	24	18	20
Net cash flows used in investing activities	(910)	(675)	(622)
Cash flows from financing activities			
Changes in short-term borrowings	(165)	90	(15)
Issuance of long-term debt	850	—	—
Retirement of long-term debt	(379)	(75)	(70)
Redemption of preference stock	(190)	—	—
Dividends paid on common stock	(179)	(158)	—
Dividends paid on preference stock	(8)	(13)	(13)
Contributions from parent	61	7	—
Other financing activities	(11)	(13)	13
Net cash flows used in financing activities	(21)	(162)	(85)
Increase (Decrease) in cash and cash equivalents	14	(55)	33
Cash and cash equivalents at beginning of period	9	64	31
Cash and cash equivalents at end of period	$ 23	$ 9	$ 64

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 23	$ 9
Restricted cash and cash equivalents	24	24
Accounts receivable, net		
Customer	395	300
Other	102	112
Inventories, net		
Gas held in storage	30	36
Materials and supplies	38	33
Prepaid utility taxes	15	61
Regulatory assets	208	267
Other	7	3
Total current assets	842	845
Property, plant and equipment, net	7,040	6,597
Deferred debits and other assets		
Regulatory assets	504	514
Investments	12	12
Prepaid pension asset	297	319
Other	9	8
Total deferred debits and other assets	822	853
Total assets [a]	$8,704	$8,295

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 45	$ 210
Long-term debt due within one year	41	378
Accounts payable	205	209
Accrued expenses	175	110
Payables to affiliates	55	52
Customer deposits	110	102
Regulatory liabilities	50	38
Other	26	35
Total current liabilities	707	1,134
Long-term debt	2,281	1,480
Long-term debt to financing trust	252	252
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,219	2,081
Asset retirement obligations	21	17
Non-pension postretirement benefits obligations	205	209
Regulatory liabilities	110	184
Other	61	61
Total deferred credits and other liabilities	2,616	2,552
Total liabilities [(a)]	5,856	5,418
Commitments and contingencies		
Shareholders' equity		
Common stock	1,421	1,367
Retained earnings	1,427	1,320
Total shareholders' equity	2,848	2,687
Preference stock not subject to mandatory redemption	—	190
Total equity	2,848	2,877
Total liabilities and shareholders' equity	$8,704	$8,295

(a) BGE's consolidated assets include $26 million and $26 million at December 31, 2016 and December 31, 2015, respectively, of BGE's consolidated VIE that can only be used to settle the liabilities of the VIE. BGE's consolidated liabilities include $42 million and $122 million at December 31, 2016 and December 31, 2015, respectively, of BGE's consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note 2—Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2013	$ 1,360	$ 1,005	$ 2,365	$ 190	$2,555
Net income	—	211	211	—	211
Preference stock dividends	—	(13)	(13)	—	(13)
Balance, December 31, 2014	$ 1,360	$ 1,203	$ 2,563	$ 190	$2,753
Net income	—	288	288	—	288
Preference stock dividends	—	(13)	(13)	—	(13)
Common stock dividends	—	(158)	(158)	—	(158)
Contribution from parent	7	—	7	—	7
Balance, December 31, 2015	$ 1,367	$ 1,320	$ 2,687	$ 190	$2,877
Net income	—	294	294	—	294
Preference stock dividends	—	(8)	(8)	—	(8)
Common stock dividends	—	(179)	(179)	—	(179)
Distribution to parent	(7)	—	(7)	—	(7)
Contribution from parent	61	—	61	—	61
Redemption of preference stock	—	—	—	(190)	(190)
Balance, December 31, 2016	$ 1,421	$ 1,427	$ 2,848	$ —	$2,848

See the Combined Notes to Consolidated Financial Statements

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Pepco Holdings LLC and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	Successor	Predecessor		
	March 24 to December 31, 2016	January 1 to March 23, 2016	For the Years Ended December 31, 2015	2014
Operating revenues				
Electric operating revenues	$ 3,506	$ 1,096	$ 4,770	$ 4,614
Natural gas operating revenues	92	57	165	194
Operating revenues from affiliates	45	—	—	—
Total operating revenues	3,643	1,153	4,935	4,808
Operating expenses				
Purchased power	925	471	1,986	1,940
Purchased fuel	36	26	87	117
Purchased power and fuel from affiliates	486	—	—	—
Operating and maintenance	1,144	294	1,156	1,183
Operating and maintenance from affiliates	89	—	—	—
Depreciation, amortization and accretion	515	152	624	526
Taxes other than income	354	105	455	437
Total operating expenses	3,549	1,048	4,308	4,203
(Loss) gain on sales of assets	(1)	—	46	—
Operating income	93	105	673	605
Other income and (deductions)				
Interest expense, net	(195)	(65)	(280)	(269)
Other, net	44	(4)	88	44
Total other income and (deductions)	(151)	(69)	(192)	(225)
(Loss) income before income taxes	(58)	36	481	380
Income taxes	3	17	163	138
Net (loss) income from continuing operations	(61)	19	318	242
Net income from discontinued operations	—	—	9	—
Net (loss) income attributable to membership interest/common shareholders	$ (61)	$ 19	$ 327	$ 242
Comprehensive income (loss), net of income taxes				
Net (loss) income	$ (61)	$ 19	$ 327	$ 242
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Actuarial loss (gain) reclassified to periodic cost	—	1	9	(12)
Unrealized loss on cash flow hedges	—	—	1	—
Other comprehensive income (loss)	—	1	10	(12)
Comprehensive (loss) income	$ (61)	$ 20	$ 337	$ 230

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	Successor March 24 to December 31, 2016	Predecessor January 1 to March 23, 2016	Predecessor For the Years Ended December 31, 2015	Predecessor For the Years Ended December 31, 2014
Cash flows from operating activities				
Net (loss) income	$ (61)	$ 19	$ 327	$ 242
Income from discontinued operations, net of income taxes	—	—	(9)	—
Adjustments to reconcile net (loss) income to net cash from operating activities:				
Depreciation, amortization and accretion	515	152	624	526
Impairment of long-lived assets	—	—	—	81
Loss (Gain) on sales of assets	1	—	(46)	—
Deferred income taxes and amortization of investment tax credits	295	19	134	303
Net fair value changes related to derivatives	—	18	—	—
Other non-cash operating activities	514	46	167	127
Changes in assets and liabilities:				
Accounts receivable	(21)	(28)	(105)	(2)
Receivables from and payables to affiliates, net	42	—	—	—
Inventories	3	(4)	—	8
Accounts payable and accrued expenses	19	42	(41)	(31)
Collateral received, net	—	1	—	1
Income taxes	(22)	12	8	(197)
Pension and non-pension postretirement benefit contributions	(86)	(4)	(21)	(18)
Other assets and liabilities	(311)	(9)	(99)	(186)
Net cash flows provided by operating activities	888	264	939	854
Cash flows from investing activities				
Capital expenditures	(1,008)	(273)	(1,230)	(1,223)
Proceeds from sales of land	24	—	54	—
Changes in restricted cash	(37)	3	6	(12)
Purchases of investments	—	(68)	—	—
Other investing activities	(9)	(5)	9	9
Net cash flows used in investing activities	(1,030)	(343)	(1,161)	(1,226)
Cash flows from financing activities				
Changes in short-term borrowings	(515)	(121)	34	183
Proceeds from short-term borrowings with maturities greater than 90 days	—	500	300	—
Repayments of short-term borrowings with maturities greater than 90 days	(300)	—	—	—
Issuance of long-term debt	179	—	558	766
Retirement of long-term debt	(338)	(11)	(430)	(462)
Issuance of preferred stock	—	—	54	126
Dividends paid on common stock	—	—	(275)	(272)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation	—	2	18	33
Distribution to member	(273)	—	—	—
Contribution from member	1,251	—	—	—
Change in Exelon intercompany money pool	(6)	—	—	—
Other financing activities	(5)	2	(26)	(11)
Net cash flows (used in) provided by financing activities	(7)	372	233	363
(Decrease) Increase in cash and cash equivalents	(149)	293	11	(9)
Cash and cash equivalents at beginning of period	319	26	15	24
Cash and cash equivalents at end of period	$ 170	$ 319	$ 26	$ 15

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	*Successor* December 31, 2016	*Predecessor* December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 170	$ 26
Restricted cash and cash equivalents	43	14
Accounts receivable, net		
Customer	496	581
Other	283	319
Mark-to-market derivative asset	—	18
Inventories, net		
Gas held in storage	6	9
Materials and supplies	116	122
Regulatory assets	653	305
Other	71	80
Total current assets	1,838	1,474
Property, plant and equipment, net	11,598	10,864
Deferred debits and other assets		
Regulatory assets	2,851	2,277
Investments	133	80
Goodwill	4,005	1,406
Long-term note receivable	4	4
Prepaid pension asset	509	—
Deferred income taxes	6	14
Other	81	69
Total deferred debits and other assets	7,589	3,850
Total assets (a)	$ 21,025	$ 16,188

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	*Successor* December 31, 2016	*Predecessor* December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 522	$ 958
Long-term debt due within one year	253	456
Accounts payable	458	404
Accrued expenses	272	266
Payables to affiliates	94	—
Unamortized energy contract liabilities	335	—
Customer deposits	123	107
Merger related obligation	101	—
Regulatory liabilities	79	66
Other	47	70
Total current liabilities	2,284	2,327
Long-term debt	5,645	4,823
Deferred credits and other liabilities		
Regulatory liabilities	158	147
Deferred income taxes and unamortized investment tax credits	3,775	3,406
Asset retirement obligations	14	8
Pension obligations	—	466
Non-pension postretirement benefit obligations	134	215
Unamortized energy contract liabilities	750	—
Other	249	200
Total deferred credits and other liabilities	5,080	4,442
Total liabilities (a)	13,009	11,592
Commitments and contingencies		
Preferred stock (b)	—	183
Member's equity/Shareholders' equity		
Membership interest/Common stock (c)	8,077	3,832
Undistributed (losses)/Retained earnings	(61)	617
Accumulated other comprehensive loss, net	—	(36)
Total member's equity/shareholders' equity	8,016	4,413
Total liabilities and member's equity/shareholders' equity	$ 21,025	$ 16,188

(a) PHI's consolidated total assets include $49 million and $30 million at December 31, 2016 and 2015, respectively, of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI's consolidated total liabilities include $143 million and $172 million at December 31, 2016 and 2015, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 2—Variable Interest Entities.

(b) At December 31, 2015, PHI had 18,000 shares of Series A preferred stock authorized and outstanding, par value $0.01 per share.

(c) At December 31, 2015, PHI's (predecessor) shareholders' equity included $3,829 million of other paid-in capital and $3 million of common stock. At December 31, 2015, PHI had 400,000,000 shares of common stock authorized and 254,289,261 shares of common stock outstanding, par value $0.01 per share.

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies

Consolidated Statements of Changes in Equity

(In millions, except share data) *Predecessor*	Common Stock [a]	Retained Earnings	Accumulated Other Comprehensive Loss, net	Total Shareholders' Equity
Balance, December 31, 2013	$ 3,754	$ 595	$ (34)	$ 4,315
Net income	—	242	—	242
Common stock dividends	—	(272)	—	(272)
Original issue shares, net	14	—	—	14
DRP original issue shares	28	—	—	28
Net activity related to stock-based awards	7	—	—	7
Other comprehensive loss, net of income taxes	—	—	(12)	(12)
Balance, December 31, 2014	$ 3,803	$ 565	$ (46)	$ 4,322
Net income	—	327	—	327
Common stock dividends	—	(275)	—	(275)
Original issue shares, net	15	—	—	15
DRP original issue shares	11	—	—	11
Net activity related to stock-based awards	3	—	—	3
Other comprehensive income, net of income taxes	—	—	10	10
Balance, December 31, 2015	$ 3,832	$ 617	$ (36)	$ 4,413
Net income	—	19	—	19
Original issue shares, net	3	—	—	3
Net activity related to stock-based awards	3	—	—	3
Other comprehensive income, net of income taxes	—	—	1	1
Balance, March 23, 2016	$ 3,838	$ 636	$ (35)	$ 4,439

Successor	Membership Interest	Undistributed Losses	Accumulated Other Comprehensive Loss, net	Member's Equity
Balance, March 24, 2016 [b]	$ 7,200	$ —	$ —	$ 7,200
Net loss	—	(61)	—	(61)
Distribution to member [c]	(400)	—	—	(400)
Contribution from member	1,251	—	—	1,251
Measurement period adjustment of Exelon's deferred tax liabilities to reflect unitary state income tax consequences of the merger	35	—	—	35
Distribution of net retirement benefit obligation to member	53	—	—	53
Assumption of member liabilities [d]	(62)	—	—	(62)
Balance, December 31, 2016	$ 8,077	$ (61)	$ —	$ 8,016

(a) At March 23, 2016 and December 31, 2015, PHI's (predecessor) shareholders' equity included $3,835 million and $3,829 million of other paid-in capital, and $3 million and $3 million of common stock, respectively.

(b) The March 24, 2016, beginning balance differs from the PHI Merger total purchase price by $59 million related to an acquisition accounting adjustment recorded at Exelon Corporate to reflect unitary state income tax consequences of the merger.

(c) Distribution to member includes $235 million of net assets associated with PHI's unregulated business interests and $165 million of cash, each of which were distributed by PHI to Exelon.

(d) The liabilities assumed include $29 million for PHI stock-based compensation awards and $33 million for a merger related obligation, each assumed by PHI from Exelon. See Note 4—Mergers, Acquisitions, and Dispositions.

See the Combined Notes to Consolidated Financial Statements

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Potomac Electric Power Company

Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Electric operating revenues	$2,181	$2,124	$2,050
Operating revenues from affiliates	5	5	5
Total operating revenues	2,186	2,129	2,055
Operating expenses			
Purchased power	411	719	735
Purchased power from affiliates	295	—	—
Operating and maintenance	607	435	386
Operating and maintenance from affiliates	35	4	4
Depreciation and amortization	295	256	212
Taxes other than income	377	376	369
Total operating expenses	2,020	1,790	1,706
Gain on sales of assets	8	46	—
Operating income	174	385	349
Other income and (deductions)			
Interest expense, net	(127)	(124)	(115)
Other, net	36	28	30
Total other income and (deductions)	(91)	(96)	(85)
Income before income taxes	83	289	264
Income taxes	41	102	93
Net income attributable to common shareholder	$ 42	$ 187	$ 171
Comprehensive income	$ 42	$ 187	$ 171

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company

Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income	$ 42	$ 187	$ 171
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:			
Depreciation and amortization	295	256	212
Gain on sales of assets	(8)	(46)	—
Deferred income taxes and amortization of investment tax credits	153	150	175
Other non-cash operating activities	183	54	37
Changes in assets and liabilities:			
Accounts receivable	(41)	(43)	7
Receivables from and payables to affiliates, net	44	—	(2)
Inventories	1	(5)	5
Accounts payable and accrued expenses	32	(21)	(37)
Income taxes	110	(46)	(14)
Pension and non-pension postretirement benefit contributions	(32)	(14)	(11)
Other assets and liabilities	(128)	(99)	(157)
Net cash flows provided by operating activities	651	373	386
Cash flows from investing activities			
Capital expenditures	(586)	(544)	(567)
Proceeds from sale of long-lived asset	12	54	9
Purchases of investments	(30)	—	—
Changes in restricted cash	(31)	3	(3)
Other investing activities	(12)	10	1
Net cash flows used in investing activities	(647)	(477)	(560)
Cash flows from financing activities			
Changes in short-term borrowings	(41)	(40)	(47)
Issuance of long-term debt	4	208	412
Retirement of long-term debt	(11)	(22)	(184)
Dividends paid on common stock	(136)	(146)	(86)
Contribution from parent	187	112	80
Other financing activities	(3)	(9)	(4)
Net cash flows provided by financing activities	—	103	171
Increase (decrease) in cash and cash equivalents	4	(1)	(3)
Cash and cash equivalents at beginning of period	5	6	9
Cash and cash equivalents at end of period	$ 9	$ 5	$ 6

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company

Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 9	$ 5
Restricted cash and cash equivalents	33	2
Accounts receivable, net		
Customer	235	230
Other	150	261
Inventories, net	63	67
Regulatory assets	162	140
Other	32	21
Total current assets	684	726
Property, plant and equipment, net	5,571	5,162
Deferred debits and other assets		
Regulatory assets	690	661
Investments	102	68
Prepaid pension asset	282	287
Other	6	4
Total deferred debits and other assets	1,080	1,020
Total assets	$7,335	$6,908

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company

Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 23	$ 64
Long-term debt due within one year	16	11
Accounts payable	209	145
Accrued expenses	113	119
Payables to affiliates	74	30
Customer deposits	53	46
Regulatory liabilities	11	15
Merger related obligation	68	—
Other	29	25
Total current liabilities	596	455
Long-term debt	2,333	2,340
Deferred credits and other liabilities		
Regulatory liabilities	20	29
Deferred income taxes and unamortized investment tax credits	1,910	1,723
Non-pension postretirement benefit obligations	43	49
Other	133	72
Total deferred credits and other liabilities	2,106	1,873
Total liabilities	5,035	4,668
Commitments and contingencies		
Shareholder's equity		
Common stock	1,309	1,122
Retained earnings	991	1,118
Total shareholder's equity	2,300	2,240
Total liabilities and shareholder's equity	$7,335	$6,908

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company

Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2013	$ 930	$ 992	$ 1,922
Net income	—	171	171
Common stock dividends	—	(86)	(86)
Contribution from Parent	80	—	80
Balance, December 31, 2014	$ 1,010	$ 1,077	$ 2,087
Net income	—	187	187
Common stock dividends	—	(146)	(146)
Contribution from Parent	112	—	112
Balance, December 31, 2015	$ 1,122	$ 1,118	$ 2,240
Net income	—	42	42
Common stock dividends	—	(169)	(169)
Contribution from Parent	187	—	187
Balance, December 31, 2016	$ 1,309	$ 991	$ 2,300

See the Combined Notes to Consolidated Financial Statements

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Delmarva Power & Light Company

Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Electric operating revenues	$1,122	$1,132	$1,081
Natural gas operating revenues	148	164	194
Operating revenues from affiliates	7	6	7
Total operating revenues	1,277	1,302	1,282
Operating expenses			
Purchased power	369	555	536
Purchased fuel	60	79	104
Purchased power from affiliate	154	—	—
Operating and maintenance	422	303	266
Operating and maintenance from affiliates	19	1	1
Depreciation, amortization and accretion	157	148	122
Taxes other than income	55	51	46
Total operating expenses	1,236	1,137	1,075
Gain on sales of assets	9	—	—
Operating income	50	165	207
Other income and (deductions)			
Interest expense, net	(50)	(50)	(48)
Other, net	13	10	10
Total other income and (deductions)	(37)	(40)	(38)
Income before income taxes	13	125	169
Income taxes	22	49	65
Net (loss) income attributable to common shareholder	$ (9)	$ 76	$ 104
Comprehensive (loss) income	$ (9)	$ 76	$ 104

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company

Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net (loss) income	$ (9)	$ 76	$ 104
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion	157	148	122
Deferred income taxes and amortization of investment tax credits	109	73	110
Other non-cash operating activities	114	33	22
Changes in assets and liabilities:			
Accounts receivable	(5)	(24)	1
Receivables from and payables to affiliates, net	13	3	(6)
Inventories	—	6	(2)
Accounts payable and accrued expenses	(4)	(8)	—
Collateral (paid) received, net	1	(1)	—
Income taxes	28	(26)	(1)
Pension and non-pension postretirement benefit contributions	(22)	—	—
Other assets and liabilities	(72)	(14)	(82)
Net cash flows provided by operating activities	310	266	268
Cash flows from investing activities			
Capital expenditures	(349)	(352)	(352)
Proceeds from sales of long-lived assets	9	—	—
Change in restricted cash	—	5	(5)
Other investing activities	4	2	(1)
Net cash flows used in investing activities	(336)	(345)	(358)
Cash flows from financing activities			
Change in short-term borrowings	(105)	(1)	(41)
Issuance of long-term debt	175	200	204
Retirement of long-term debt	(100)	(100)	(100)
Dividends paid on common stock	(54)	(92)	(100)
Contribution from parent	152	75	130
Other financing activities	(1)	(2)	(1)
Net cash flows provided by financing activities	67	80	92
Increase in cash and cash equivalents	41	1	2
Cash and cash equivalents at beginning of period	5	4	2
Cash and cash equivalents at end of period	$ 46	$ 5	$ 4

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company

Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 46	$ 5
Accounts receivable, net		
Customer	136	154
Other	63	96
Receivables from affiliates	3	—
Inventories, net		
Gas held in storage	7	8
Materials and supplies	32	32
Regulatory assets	59	72
Other	24	21
Total current assets	370	388
Property, plant and equipment, net	3,273	3,070
Deferred debits and other assets		
Regulatory assets	289	299
Goodwill	8	8
Prepaid pension asset	206	202
Other	7	2
Total deferred debits and other assets	510	511
Total assets	$4,153	$3,969

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company

Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 105
Long-term debt due within one year	119	204
Accounts payable	88	109
Accrued expenses	36	31
Payables to affiliates	38	20
Customer deposits	36	31
Regulatory liabilities	43	49
Merger related obligation	13	—
Other	8	15
Total current liabilities	381	564
Long-term debt	1,221	1,061
Deferred credits and other liabilities		
Regulatory liabilities	97	111
Deferred income taxes and unamortized investment tax credits	1,056	945
Non-pension postretirement benefit obligations	19	19
Other	53	32
Total deferred credits and other liabilities	1,225	1,107
Total liabilities	2,827	2,732
Commitments and contingencies		
Shareholder's equity		
Common stock	764	612
Retained earnings	562	625
Total shareholder's equity	1,326	1,237
Total liabilities and shareholder's equity	$4,153	$3,969

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company

Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2013	$ 407	$ 637	$ 1,044
Net income	—	104	104
Common stock dividends	—	(100)	(100)
Contribution from parent	130	—	130
Balance, December 31, 2014	$ 537	$ 641	$ 1,178
Net income	—	76	76
Common stock dividends	—	(92)	(92)
Contribution from parent	75	—	75
Balance, December 31, 2015	$ 612	$ 625	$ 1,237
Net loss	—	(9)	(9)
Common stock dividends	—	(54)	(54)
Contribution from parent	152	—	152
Balance, December 31, 2016	$ 764	$ 562	$ 1,326

See the Combined Notes to Consolidated Financial Statements

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Atlantic City Electric Company and Subsidiary Company

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Electric operating revenues	$1,254	$1,291	$1,206
Operating revenues from affiliates	3	4	4
Total operating revenues	1,257	1,295	1,210
Operating expenses			
Purchased power	614	708	664
Purchased power from affiliates	37	—	—
Operating and maintenance	410	268	247
Operating and maintenance from affiliates	18	3	3
Depreciation, amortization and accretion	165	175	155
Taxes other than income	7	7	4
Total operating expenses	1,251	1,161	1,073
Gain on sale of assets	1	—	—
Operating income	7	134	137
Other income and (deductions)			
Interest expense, net	(62)	(64)	(64)
Other, net	9	3	3
Total other income and (deductions)	(53)	(61)	(61)
(Loss) income before income taxes	(46)	73	76
Income taxes	(4)	33	30
Net (loss) income attributable to common shareholder	$ (42)	$ 40	$ 46
Comprehensive (loss) income	$ (42)	$ 40	$ 46

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net (loss) income	$ (42)	$ 40	$ 46
Adjustments to reconcile net (loss) income to net cash from operating activities:			
Depreciation, amortization and accretion	165	175	155
Deferred income taxes and amortization of investment tax credits	22	31	38
Other non-cash operating activities	155	37	26
Changes in assets and liabilities:			
Accounts receivable	(8)	(67)	6
Receivables from and payables to affiliates, net	13	1	—
Inventories	(1)	(1)	4
Accounts payable, accrued expenses and other current liabilities	9	9	(17)
Income taxes	174	(34)	(20)
Pension and non-pension postretirement benefit contributions	(17)	(2)	(3)
Other assets and liabilities	(85)	67	24
Net cash flows provided by operating activities	385	256	259
Cash flows from investing activities			
Capital expenditures	(311)	(300)	(225)
Proceeds from sale of long-lived assets	2	—	—
Changes in restricted cash	(2)	(6)	—
Other investing activities	2	—	1
Net cash flows used in investing activities	(309)	(306)	(224)
Cash flows from financing activities			
Change in short-term borrowings	(5)	(122)	7
Issuance of long-term debt	—	150	150
Retirement of long-term debt	(48)	(58)	(66)
Repayment of term loan	—	—	(100)
Dividends paid on common stock	(63)	(12)	(26)
Contributions from parent	139	95	—
Other financing activities	(1)	(2)	(1)
Net cash flows provided by (used in) financing activities	22	51	(36)
Increase (decrease) in cash and cash equivalents	98	1	(1)
Cash and cash equivalents at beginning of period	3	2	3
Cash and cash equivalents at end of period	$ 101	$ 3	$ 2

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 101	$ 3
Restricted cash and cash equivalents	9	12
Accounts receivable, net		
Customer	125	156
Other	44	242
Inventories, net	22	23
Regulatory assets	96	98
Other	2	12
Total current assets	399	546
Property, plant and equipment, net	2,521	2,322
Deferred debits and other assets		
Regulatory assets	405	414
Long-term note receivable	4	4
Prepaid pension asset	84	82
Other	44	19
Total deferred debits and other assets	537	519
Total assets (a)	$3,457	$3,387

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31, 2016	2015
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 5
Long-term debt due within one year	35	48
Accounts payable	132	96
Accrued expenses	38	70
Payables to affiliates	29	16
Customer deposits	33	30
Regulatory liabilities	25	18
Merger related obligation	20	—
Other	8	14
Total current liabilities	320	297
Long-term debt	1,120	1,153
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	917	885
Non-pension postretirement benefit obligations	34	33
Regulatory liabilities	—	7
Other	32	12
Total deferred credits and other liabilities	983	937
Total liabilities [(a)]	2,423	2,387
Commitments and contingencies		
Shareholder's equity		
Common stock	912	773
Retained earnings	122	227
Total shareholder's equity	1,034	1,000
Total liabilities and shareholder's equity	$3,457	$3,387

(a) ACE's consolidated assets include $32 million and $30 million at December 31, 2016 and 2015, respectively, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE's consolidated liabilities include $126 million and $172 million at December 31, 2016 and 2015, respectively, of ACE's consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 2—Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company

Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2013	$ 678	$ 179	$ 857
Net income	—	46	46
Common stock dividends	—	(26)	(26)
Balance, December 31, 2014	$ 678	$ 199	$ 877
Net income	—	40	40
Common stock dividends	—	(12)	(12)
Contribution from parent	95	—	95
Balance, December 31, 2015	$ 773	$ 227	$ 1,000
Net loss	—	(42)	(42)
Common stock dividends	—	(63)	(63)
Contribution from parent	139	—	139
Balance, December 31, 2016	$ 912	$ 122	$ 1,034

See the Combined Notes to Consolidated Financial Statements

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)

Index to Combined Notes to Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the registrants to which the footnotes apply:

Applicable Notes

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Exelon Corporation	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Exelon Generation Company, LLC	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•		•		•	•	•	•	•	•
Commonwealth Edison Company	•	•	•			•	•				•	•	•	•	•	•	•	•		•	•			•	•	•	•	•
PECO Energy Company	•	•	•			•	•			•	•	•	•	•	•	•	•	•		•	•		•	•	•	•	•	•
Baltimore Gas and Electric Company	•	•	•			•	•			•		•	•	•	•	•	•	•		•	•			•	•	•	•	•
Pepco Holdings LLC	•	•	•	•		•	•			•	•	•	•	•	•	•	•	•	•	•	•		•	•	•	•	•	•
Potomac Electric Power Company	•	•	•	•		•	•			•	•	•	•	•	•	•	•	•		•	•			•	•	•	•	•
Delmarva Power & Light Company	•	•	•	•		•	•			•	•	•	•	•	•	•	•	•		•	•			•	•	•	•	•
Atlantic City Electric Company	•	•	•			•	•			•	•	•	•	•	•	•	•	•		•	•			•	•	•	•	•

1. Significant Accounting Policies (All Registrants)

Description of Business (All Registrants)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution and transmission businesses. Prior to March 23, 2016, Exelon's principal, wholly owned subsidiaries included Generation, ComEd, PECO and BGE. On March 23, 2016, in conjunction with the Amended and Restated Agreement and Plan of Merger (the PHI Merger Agreement), Purple Acquisition Corp, a wholly owned subsidiary of Exelon, merged with and into PHI, with PHI continuing as the surviving entity as a wholly owned subsidiary of Exelon. PHI is a utility services holding company engaged through its principal wholly owned subsidiaries, Pepco, DPL and ACE, in the energy distribution and transmission businesses. Refer to Note 4—Mergers, Acquisitions, and Dispositions for further information regarding the merger transaction.

The energy generation business includes:

- *Generation* : Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation. Generation also sells renewable energy and other energy-related products and services. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

The energy delivery businesses include:

- *ComEd* : Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO* : Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE* : Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in central Maryland, including the City of Baltimore.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

- *Pepco* : Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in the District of Columbia and major portions of Prince George's County and Montgomery County in Maryland.
- *DPL* : Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.
- *ACE* : Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in southern New Jersey.

Basis of Presentation (All Registrants)

This is a combined annual report of all registrants. The Notes to the Consolidated Financial Statements apply to the registrants as indicated above in the Index to Combined Notes to Consolidated Financial Statements and parenthetically next to each corresponding disclosure. When appropriate, the registrants are named specifically for their related activities and disclosures.

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated. All Equity in earnings (losses) from unconsolidated affiliates have been presented below Income taxes in the Registrants' Consolidated Statements of Operations and Comprehensive Income starting in the first quarter of 2015.

Pursuant to the acquisition of PHI, Exelon's financial reporting reflects PHI's consolidated financial results subsequent to the March 23, 2016, acquisition date. Exelon has accounted for the merger transaction applying the acquisition method of accounting, which requires the assets acquired and liabilities assumed by Exelon to be reported in Exelon's financial statements at fair value, with any excess of the purchase price over the fair value of net assets acquired reported as goodwill. Exelon has pushed-down the application of the acquisition method of accounting to the consolidated financial statements of PHI such that the assets and liabilities of PHI are similarly recorded at their respective fair values, and goodwill has been established as of the acquisition date. Accordingly, the consolidated financial statements of PHI for periods before and after the March 23, 2016, acquisition date reflect different bases of accounting, and the financial positions and the results of operations of the predecessor and successor periods are not comparable. The acquisition method of accounting has not been pushed down to PHI's wholly-owned subsidiary utility registrants, Pepco, DPL and ACE.

For financial statement purposes, beginning on March 24, 2016, disclosures that had solely related to PHI, Pepco, DPL or ACE activities now also apply to Exelon, unless otherwise noted.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC, including support services, are directly charged or allocated to the applicable subsidiaries using a cost-causative allocation method. Corporate governance-type costs that cannot be directly assigned are allocated based on a Modified Massachusetts Formula, which is a method that utilizes a combination of gross revenues, total assets and direct labor costs for the allocation base. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHISCO, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHI Service Company and the participating operating subsidiaries.

Exelon owns 100% of all of its significant consolidated subsidiaries, including PHI, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%. As of December 31, 2016, Exelon owned none of BGE's preferred securities, which BGE redeemed in 2016. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2016 and December 31, 2015, as equity, and BGE's preference stock as BGE preference stock not subject to mandatory redemption in its consolidated financial statements. BGE is subject to some ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters. PHI is subject to some ring-fencing measures established by orders of the DCPSC, DPSC, MDPSC and NJBPU, pursuant to which all of the membership interest in PHI is held directly by PH Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (PH Utility), Inc., an unrelated party, holds a nominal non-economic interest in PH Holdco LLC with limited voting rights on specified matters. PHI owns 100% of its subsidiaries including Pepco, DPL and ACE.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for certain variable interest entities, including CENG, of which Generation holds a 50.01% interest. The remaining interests are included in noncontrolling interests on Exelon's and Generation's Consolidated Balance Sheets. See Note 2—Variable Interest Entities for further discussion of Exelon's and Generation's consolidated VIEs.

The Registrants consolidate the accounts of entities in which a Registrant has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which the Registrant can exercise control over the operations and policies of the investee, or the results of a model that identifies the Registrant or one of its subsidiaries as the primary beneficiary of a VIE. Where the Registrants do not have a controlling financial interest in an entity, proportionate consolidation, equity method accounting or cost method accounting is applied. The Registrants apply proportionate consolidation when they have an undivided interest in an asset and are proportionately liable for their share of each liability associated with the asset. The Registrants proportionately consolidate their undivided ownership interests in jointly owned electric plants and transmission facilities. Under proportionate consolidation, the Registrants separately record their proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. The Registrants apply equity method accounting when they have significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. The Registrants apply equity method accounting to certain investments and joint ventures, including certain financing trusts of ComEd, PECO and BGE. Under the equity method, the Registrants report their interest in the entity as an investment and the Registrants' percentage share of the earnings from the entity as single line items in their financial statements. The Registrants use the cost method if they lack significant influence, which generally results when they hold less than 20% of the common stock of an entity. Under the cost method, the Registrants report their investments at cost and recognize income only to the extent dividends or distributions are received.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (All Registrants)

The preparation of financial statements of each of the Registrants in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other AROs, pension and other postretirement benefits, the application of purchase accounting, inventory reserves, allowance for uncollectible accounts, goodwill and asset impairments, derivative instruments, unamortized energy contracts, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Reclassifications (All Registrants)

Certain prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows have been reclassified between line items for comparative purposes. The reclassifications did not affect any of the Registrants' net income, financial positions, or cash flows from operating activities.

Certain prior year amounts in the Consolidated Statements of Operations and Comprehensive Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows of PHI, Pepco, DPL and ACE have been reclassified to conform the presentation of these amounts to the current period presentation in Exelon's financial statements. Most significantly for PHI, Pepco, DPL and ACE, current regulatory assets and liabilities have been presented separately from the non-current portions in each respective Consolidated Balance Sheet where recovery or refund is expected within the next 12 months. Additionally, for PHI, Pepco, DPL and ACE, the removal cost within Accumulated depreciation was reclassified to the Regulatory liability or Regulatory asset account to align with Exelon's presentation. The reclassifications were not considered errors in the prior financial statements.

Accounting for the Effects of Regulation (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

The Registrants apply the authoritative guidance for accounting for certain types of regulation, which requires them to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria: 1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation that rates are set at levels that will recover the entities' costs from customers. Exelon and the Utility Registrants account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, the PAPUC, the MDPSC, the DCPSC, the DPSC and the NJBPU, under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the Consolidated Statements of Operations consistent with the recovery or refund included in customer rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. Exelon and the Utility Registrants continue to

evaluate their respective abilities to continue to apply the authoritative guidance for accounting for certain types of regulation, including consideration of current events in their respective regulatory and political environments. If a separable portion of the Registrants' business was no longer able to meet the criteria discussed above, the affected entities would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which could have a material impact on their results of operations and financial positions. See Note 3—Regulatory Matters for additional information.

ACE has a recovery mechanism for purchased power costs associated with BGS. ACE records a deferred energy supply costs regulatory asset or regulatory liability for under or over-recovered costs that are expected to be recovered from or refunded to ACE customers, respectively. In the first quarter of 2016, ACE changed its method of accounting for determining under or over-recovered costs in this recovery mechanism to include unbilled revenues in the determination of under or over-recovered costs. ACE believes this change is preferable as it better reflects the economic impacts of dollar-for-dollar cost recovery mechanisms. ACE applied the change retrospectively. The impact of the change was a $12 million reduction to ACE's opening Retained earnings as of January 1, 2014 with a corresponding reduction to Regulatory assets. The impact of the change on Net income attributable to common shareholder was an increase of $2 million and $1 million for the years ended December 31, 2015 and December 31, 2014, respectively.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Revenues (All Registrants)

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimates of the distribution and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE, Pepco, DPL and ACE record their best estimate of the transmission revenue impacts resulting from changes in rates that they each believe are probable of approval by FERC in accordance with their formula rate mechanisms. See Note 3—Regulatory Matters and Note 6—Accounts Receivable for further information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations and Comprehensive Income, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Company in the different RTOs and ISOs.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. To the

extent a Utility Registrant receives full cost recovery for energy procurement and related costs from retail customers, it records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. Refer to Note 3—Regulatory Matters and Note 13—Derivative Financial Instruments for further information.

Proprietary Trading Activities. Exelon and Generation account for Generation's trading activities under the provisions of the authoritative guidance for accounting for contracts involved in energy trading and risk management activities, which require energy revenues and costs related to energy trading contracts to be presented on a net basis in the Consolidated Statements of Operations and Comprehensive Income. Commodity derivatives used for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues. Refer to Note 13—Derivative Financial Instruments for further information.

Income Taxes (All Registrants)

Deferred Federal and state income taxes are provided on all significant temporary differences between the book basis and the tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred on the Registrants' Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion; and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Registrants recognize accrued interest related to unrecognized tax benefits in Interest expense or Other income and deductions (interest income) and recognize penalties related to unrecognized tax benefits in Other, net on their Consolidated Statements of Operations and Comprehensive Income.

In the first quarter of 2016, PHI, Pepco, DPL and ACE changed their accounting for classification of interest on uncertain tax positions. PHI, Pepco, DPL and ACE have reclassified interest on uncertain tax positions as Interest expense from Income tax expense in the Consolidated Statements of Operations and Comprehensive Income. GAAP does not address the preferability of one acceptable method of accounting over the other for the classification of interest on uncertain tax positions. However, PHI, Pepco, DPL and ACE believe this change is preferable for comparability of their financial statements with the financial statements of the other Registrants in the combined filing, for consistency with FERC classification and for a more appropriate representation of the effective tax rate as they manage the settlement of uncertain tax positions and interest expense separately. PHI, Pepco, DPL and ACE applied the change retrospectively. The reclassification in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2015 is $34 million and $4 million for PHI and Pepco, respectively, and for the year ended December 31, 2014 is $1 million for both Pepco and ACE. The impact on all other PHI Registrants for years ended December 31, 2015 and December 31, 2014 is less than $1 million.

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 15—Income Taxes for further information.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Taxes Directly Imposed on Revenue-Producing Transactions (All Registrants)

The Registrants collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, such as gross receipts taxes or other surcharges or fees, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 25—Supplemental Financial Information for Generation's, ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (All Registrants)

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents (All Registrants)

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2016 and 2015, Exelon Corporate's restricted cash and cash equivalents primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Generation's restricted cash and cash equivalents primarily included cash at various project-specific non-recourse financing structures for debt service and financing of operations of the underlying entities, see Note 14—Debt and Credit Agreements for additional information on Generation's project- specific financing structures. ComEd's restricted cash primarily represented cash collateral held from suppliers associated with ComEd's energy and REC procurement contracts. PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's mortgage indenture. BGE's restricted cash primarily represented funds restricted at its consolidated variable interest entity for repayment of rate stabilization bonds and cash collateral held from suppliers. PHI Corporate's restricted cash and cash equivalents primarily represented funds restricted for the payment of merger commitments and cash collateral held from its utility suppliers. Pepco's restricted cash and cash equivalents primarily represented funds restricted for the payment of merger commitments and collateral held from its utility suppliers. DPL's restricted cash and cash equivalents primarily represented cash collateral held from suppliers associated with procurement contracts. ACE's restricted cash and cash equivalents primarily represented funds restricted at its consolidated variable interest entity for repayment of transition bonds and cash collateral held from suppliers.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2016 and 2015, Exelon's and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2016, Exelon, Generation, ComEd, PECO, BGE, PHI and Pepco had investments in Rabbi trusts classified as noncurrent assets.

Allowance for Uncollectible Accounts (All Registrants)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging

historical experience and other currently available information. ComEd, PECO and BGE estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. At December 31, 2015, Pepco, DPL and ACE estimated the allowance for uncollectible accounts based on specific identification of material amounts at risk by customer and maintained a reserve based on their historical collection experience. At December 31, 2016, Pepco, DPL and ACE aligned the estimation of their allowance for uncollectible accounts to be consistent with ComEd, PECO and BGE, as described above. Risk segments represent a group of customers with similar credit quality indicators that are comprised based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. Utility Registrants customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. Utility Registrants' customer accounts are written off consistent with approved regulatory requirements. Utility Registrants' allowances for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU regulations. See Note 3—Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Variable Interest Entities (All Registrants)

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity has a controlling financial interest, meaning (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and
- requires the entity that consolidates a VIE (the primary beneficiary) to disclose (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

See Note 2—Variable Interest Entities for additional information.

Inventories (All Registrants)

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory.

Fossil Fuel. Fossil fuel inventory includes natural gas held in storage, propane and oil. The costs of natural gas, propane and oil are generally included in inventory when purchased and charged to purchased power and fuel expense at weighted average cost when used or sold.

Materials and Supplies. Materials and supplies inventory generally includes transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and expensed or capitalized to property, plant and equipment, as appropriate, at weighted average cost when installed or used.

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Emission Allowances. Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) and charged to purchased power and fuel expense at weighted average cost as they are used in operations.

Marketable Securities (All Registrants)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds are classified as trading securities, and all other securities are classified as available-for-sale securities. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the Regulatory Agreement Units are included in regulatory liabilities at Exelon, ComEd and PECO and in Noncurrent payables to affiliates at Generation and in Noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the Non-Regulatory Agreement Units are included in earnings at Exelon and Generation. Unrealized gains and losses, net of tax, for Exelon's available-for-sale securities are reported in OCI. Any decline in the fair value of Exelon's available-for-sale securities below the cost basis is reviewed to determine if such decline is other-than-temporary. If the decline is determined to be other-than-temporary, the cost basis of the available-for-sale securities is written down to fair value as a new cost basis and the amount of the write-down is included in earnings. See Note 3—Regulatory Matters for additional information regarding ComEd's and PECO's regulatory assets and liabilities and Note 12—Fair Value of Financial Assets and Liabilities and Note 16—Asset Retirement Obligations for information regarding marketable securities held by NDT funds.

Property, Plant and Equipment (All Registrants)

Property, plant and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. The Utility Registrants also include indirect construction costs including labor and related costs of departments associated with supporting construction activities. When appropriate, original cost also includes capitalized interest for Generation and Exelon Corporate and AFUDC for regulated property at ComEd, PECO, BGE, Pepco, DPL and ACE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred.

Third parties reimburse the Utility Registrants for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, plant and equipment. DOE SGIG funds reimbursed to PECO, BGE, Pepco and ACE have been accounted for as CIAC.

For Generation, upon retirement, the cost of property is generally charged to accumulated depreciation in accordance with the composite method of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to Operating and maintenance expense as incurred.

For the Utility Registrants, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. The Utility Registrants' depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. The Utility

Registrants' actual incurred removal costs are applied against a related regulatory liability. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method.

See Note 7—Property, Plant and Equipment, Note 10—Jointly Owned Electric Utility Plant and Note 25—Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within Property, plant and equipment and charged to fuel expense using the unit-of-production method. Prior to May 16, 2014, the estimated disposal cost of SNF was established per the Standard Waste Contract with the DOE and was expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. Effective May 16, 2014, the SNF disposal fee was set to zero by the DOE and Exelon and Generation are not accruing any further costs related to SNF disposal fees until a new fee structure goes into effect. Certain on-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 24—Commitments and Contingencies for additional information regarding the SNF disposal fee.

Nuclear Outage Costs (Exelon and Generation)

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to operating and maintenance expense or capitalized to property, plant and equipment (based on the nature of the activities) in the period incurred.

New Site Development Costs (Exelon and Generation)

New site development costs represent the costs incurred in the assessment and design of new power generating facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management's determination that the project is economically and operationally feasible, management and/or the Exelon board of directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. As of December 31, 2016 and 2015, Generation has capitalized $1.7 billion and $1.3 billion, respectively, to Property, plant and equipment, net on its Consolidated Balance Sheets. Capitalized development costs are charged to Operating and maintenance expense when project completion is no longer probable. New site development costs incurred prior to a project's completion being deemed probable are expensed as incurred. Approximately $30 million, $22 million and $13 million of costs were expensed by Exelon and Generation for the years ended December 31, 2016, 2015, and 2014, respectively. These costs are primarily related to the possible development of new power generating facilities with the exception of approximately $13 million of costs expensed in 2016 which relate to projects for which completion is no longer probable.

Capitalized Software Costs (All Registrants)

Costs incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized within property, plant, and equipment. Such

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capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

Net unamortized software costs	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
December 31, 2016	$ 808	$ 173	$ 213	$ 91	$ 164	$ 1	$ 1	$ 1
December 31, 2015	633	180	172	86	178	—	1	1

Amortization of capitalized software costs	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
2016	$ 255	$ 72	$ 62	$ 33	$ 44	$ —	$ —	$ —
2015	208	73	47	33	46	(2)	—	—
2014	186	59	45	28	43	2	—	—

PHI	Successor December 31, 2016	Predecessor December 31, 2015
Net unamortized software costs	$ 153	$ 172

PHI	Successor March 24, 2016 to December 31, 2016	Predecessor January 1, 2016 to March 23, 2016	Predecessor For the Year Ended December 31, 2015	Predecessor For the Year Ended December 31, 2014
Amortization of capitalized software costs	$ 29	$ 8	$ 36	$ 30

Depreciation, Depletion and Amortization (All Registrants)

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method in which depreciation is calculated using the average estimated service life of assets within a group. The Utility Registrants' depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. The estimated service lives for the Utility Registrants are primarily based on each company's most recent depreciation studies of historical asset retirement and removal cost experience. At Generation, along with depreciation study results, management considers expected future energy market conditions and generation plant operating costs and capital investment requirements in determining the estimated service lives of its generating facilities. For its nuclear generating facilities, except for Oyster Creek and Clinton, Generation estimates each unit will operate through the full term of its initial 20-year operating license renewal period. See Note 9—Early Nuclear Plant Retirements for additional information on the impacts of expected and potential early plant retirements. The estimated service lives of Generation's hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of 40 years.

See Note 7—Property, Plant and Equipment for further information regarding depreciation.

Amortization of regulatory assets and liabilities are recorded over the recovery or refund period specified in the related legislation or regulatory order or agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost or income would have originally been recorded in the Registrants' Consolidated Statements of Operations

and Comprehensive Income. Amortization of ComEd's distribution formula rate regulatory asset and ComEd's, BGE's, Pepco's, DPL's and ACE's transmission formula rate regulatory assets is recorded to Operating revenues.

Amortization of income tax related regulatory assets and liabilities are generally recorded to Income tax expense. With the exception of the regulatory assets and liabilities discussed above, when the recovery period is more than one year, the amortization is generally recorded to Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

See Note 3—Regulatory Matters and Note 25—Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of the Utility Registrants' regulatory assets.

Asset Retirement Obligations (All Registrants)

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic future cash flow models and discount rates. Generation generally updates its ARO annually, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various decommissioning scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years unless circumstances warrant more frequent updates (such as a change in assumed operating life for a nuclear plant). As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle. The liabilities associated with Exelon's non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years unless circumstances warrant more frequent updates. Changes to the recorded value of an ARO result from the passage of new laws and regulations, revisions to either the timing or amount of estimated undiscounted cash flows, and estimates of cost escalation factors. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through a charge to Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income or, in the case of the Utility Registrants' accretion, through an increase to regulatory assets. See Note 16—Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (All Registrants)

During construction, Exelon and Generation capitalize the costs of debt funds used to finance non-regulated construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense.

Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations.

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AFUDC is recorded to construction work in progress and as a non-cash credit to AFUDC that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

The following table summarizes total incurred interest, capitalized interest and credits to AFUDC by year:

		Exelon [a]	Generation [a]	ComEd	PECO	BGE	Pepco	DPL	ACE
2016	Total incurred interest [b]	$ 1,678	$ 472	$ 469	$ 127	$ 114	$ 137	$ 52	$ 65
	Capitalized interest	108	107	—	—	—	—	—	—
	Credits to AFUDC debt and equity	98	—	22	11	30	29	7	9
2015	Total incurred interest [b]	$ 1,170	$ 445	$ 336	$ 116	$ 113	$ 131	$ 51	$ 65
	Capitalized interest	79	79	—	—	—	—	—	—
	Credits to AFUDC debt and equity	44	—	9	7	28	19	2	2
2014	Total incurred interest [b]	$ 1,144	$ 419	$ 323	$ 115	$ 118	$ 121	$ 49	$ 65
	Capitalized interest	63	63	—	—	—	—	—	—
	Credits to AFUDC debt and equity	37	—	5	8	24	16	3	2

	Successor	Predecessor		
PHI	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
Total incurred interest [b]	$ 207	$ 68	$ 289	$ 277
Credits to AFUDC debt and equity	35	10	23	21

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's financial position and results of operations beginning April 1, 2014.
(b) Includes interest expense to affiliates.

Guarantees (All Registrants)

The Registrants recognize, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken by issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 24—Commitments and Contingencies for additional information.

Asset Impairments (All Registrants)

Long-Lived Assets. The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may

not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. The Registrants determine if long-lived assets and asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value less costs to sell.

Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generating units are generally evaluated at a regional portfolio level along with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables). See Note 8—Impairment of Long-Lived Assets for additional information.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 11—Intangible Assets for additional information regarding Exelon's, Generation's, ComEd's and PHI's goodwill.

Equity Method Investments. Exelon and Generation regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature. Additionally, if the project in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other-than-temporary decline in value.

Debt and Equity Security Investments. Exelon and Generation regularly monitor and evaluate debt and equity investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature.

Derivative Financial Instruments (All Registrants)

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For derivative contracts intended to serve as economic hedges and that are not

designated or do not qualify for hedge accounting or the normal purchases and normal sales exception, changes in the fair value of the derivatives are recognized in earnings each period, except for the Utility Registrants where changes in fair value may be recorded as a regulatory asset or liability if there is an ability to recover or return the associated costs. See Note 3—Regulatory Matters and Note 13—Derivative Financial Instruments for additional information. Amounts classified in earnings are included in revenue, purchased power and fuel, interest expense or other, net on the Consolidated Statements of Operations and Comprehensive Income based on the activity the transaction is economically hedging. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon's Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. All amounts classified in earnings related to proprietary trading are included in revenue on the Consolidated Statements of Operations and Comprehensive Income. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

For commodity derivative contracts Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the March 2012 merger of Exelon and Constellation. Because the underlying forecasted transactions at that time remained probable, the fair value of the effective portion of these cash flow hedges was frozen in AOCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred through March 31, 2015. Accordingly, all derivatives executed to hedge economic risk related to commodities are recorded at fair value with changes in fair value recognized through earnings for the combined company.

As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See Note 13—Derivative Financial Instruments for additional information.

Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all employees.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and inputs and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the Consolidated Statements of Operations and Comprehensive Income. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 17—Retirement Benefits for additional information.

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Equity Investment Earnings (Losses) of Unconsolidated Affiliates (Exelon and Generation)

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities, power projects and joint ventures, in equity in earnings (losses) of unconsolidated affiliates within their Consolidated Statements of Operations and Comprehensive Income. Equity in earnings (losses) of unconsolidated affiliates also includes any adjustments to amortize the difference, if any, except for goodwill and land, between the cost in an equity method investment and the underlying equity in net assets of the investee at the date of investment.

New Accounting Standards (All Registrants)

New Accounting Standards Adopted: in 2016 the Registrants have adopted the following new authoritative accounting guidance issued by the FASB. Unless otherwise indicated, adoption of the guidance in each instance had no or insignificant impacts on the Registrants' Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income or Consolidated Statements of Cash Flows and disclosures.

Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (Issued May 2015; Adopted first quarter 2016 retrospectively to all prior periods presented): Removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient, and instead provides for such investments to be disclosed as a reconciling item between the fair value hierarchy disclosure and the investment line item on the Balance Sheet. The guidance also simplified the disclosure requirements for investments valued using the practical expedient. See Note 12—Fair Value of Financial Assets and Liabilities for the disclosure impacts.

Customer ' s Accounting for Fees Paid in a Cloud Computing Arrangement (Issued April 2015; Adopted first quarter 2016 prospectively): Clarifies the circumstances under which a cloud computing customer would account for the arrangement as a license of internal-use software. A cloud computing arrangement would include a software license if (1) the customer has a contractual right to take possession of the software at any time during the hosting period without significant penalty and (2) it is feasible for the customer to either operate the software on its own hardware or contract with another party unrelated to the vendor to host the software. If the arrangement does not contain a software license, it would be accounted for as a service contract.

Amendments to the Consolidation Analysis (Issued February 2015; Adopted January 1, 2016): Amends the consolidation analysis for variable interest entities (VIEs) and voting interest entities. The new guidance primarily (1) changes the VIE assessment of limited partnerships, (2) amends the effect that fees paid to a decision maker or service provider have on the VIE analysis, (3) amends how variable interests held by a reporting entity's related parties and de facto agents impact its consolidation conclusion, (4) clarifies how to determine whether equity holders (as a group) have power over an entity, and (5) provides a scope exception for registered and similar unregistered money market funds. The Registrants did not revise any consolidation conclusions as a result of the guidance, but did identify additional entities that are now considered VIEs. See Note 2—Variable Interest Entities for the associated disclosures.

Simplifying the Transition to the Equity Method of Accounting (Issued March 2016; Early adopted fourth quarter 2016): Eliminates the requirement to retroactively adopt the equity method of accounting as a result of an increase in the level ownership or degree of influence of an existing investment.

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Instead, an investor now adds the cost of acquiring the additional interest in the investee to the current basis of the investor's previously held interest and adopts the equity method of accounting as of the date the investment qualifies for such treatment.

Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships (Issued March 2016; Early adopted fourth quarter 2016 prospectively): Clarifies that a change in the counterparty of a derivative contract does not, in and of itself, require dedesignation of that hedge accounting relationship as long as all of the other hedge accounting criteria are met.

Simplifying the Measurement of Inventory (Issued July 2015; Early adopted fourth quarter 2016 prospectively): Requires inventory to be measured at the lower of cost or net realizable value, with net realizable value defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This definition is consistent with existing authoritative guidance. Current guidance requires inventory to be measured at the lower of cost or market where market could be replacement cost, net realizable value or net realizable value less an approximately normal profit margin.

Contingent Put and Call Options in Debt Instruments (Issued March 2016; Adopted January 1, 2017 on a modified retrospective basis): Simplifies the embedded derivative analysis for debt instruments containing contingent call or put options by removing the requirement to assess whether a contingent event is related to interest rates or credit risks. The guidance clarifies that a contingent put or call option embedded in a debt instrument would be evaluated for possible separate accounting as a derivative instrument without regard to the nature of the exercise contingency. The guidance is required to be applied on a modified retrospective basis to all existing and future debt instruments.

Interests Held through Related Parties that are Under Common Control (Issued October 2016; Adopted January 1, 2017 on a retrospective basis to January 1, 2016): Requires consideration of indirect interests held through related parties under common control proportionately when determining whether an entity is the primary beneficiary of a variable interest entity.

Improvements to Employee Share-Based Payment Accounting (Issued March 2016; Adopted January 1, 2017 using either the prospective, modified retrospective, or retrospective method as prescribed by the standard): Simplifies various aspects of how share-based payment awards to employees are accounted for and presented in the financial statements. The new guidance eliminates additional paid-in capital pools and requires excess tax benefits and tax deficiencies to be recorded in the Statement of Operations and Comprehensive Income.

New Accounting Standards Issued and Not Yet Adopted: The following new authoritative accounting guidance issued by the FASB has not yet been adopted and reflected by the Registrants in their consolidated financial statements. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures, as well as the potential to early adopt where applicable. The Registrants have assessed other FASB issuances of new standards which are not listed below given the current expectation such standards will not significantly impact the Registrants' financial reporting.

Revenue from Contracts with Customers (Issued May 2014 and subsequently amended to address implementation questions): Changes the criteria for recognizing revenue from a contract with a

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customer. The new revenue recognition guidance, including subsequent amendments, is effective for annual reporting periods beginning on or after December 15, 2017, with the option to early adopt the standard for annual periods beginning on or after December 15, 2016. The Registrants do not plan to early adopt the standard.

The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries, and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. In addition, the Registrants will be required to capitalize costs to acquire new contracts, and amortize such costs in a manner consistent with the transfer to the customer of the associated goods or services. Exelon currently expenses those costs as incurred. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method).

The Registrants continue to assess the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. In performing this assessment, the Registrants have utilized a project implementation team comprised of both internal and external resources to conduct the following key activities:

- Actively participate in the AICPA Power and Utilities Industry Task Force (Industry Task Force) process to identify implementation issues and support the development of related implementation guidance;
- Evaluate existing contracts and revenue streams for potential changes in the amounts and timing of recognizing revenues under the new guidance;
- Evaluate and select the transition method; and
- Develop and implement the approach and process for complying with the new revenue recognition disclosure requirements.

While there continues to be some ongoing activities in all of these areas, the Registrants have substantially completed the evaluation of their collective contracts and revenue streams, as well as the evaluation of the transition method. Based on the work completed thus far, the Registrants have reached the following preliminary conclusions:

- The Registrants expect to apply the new guidance using the full retrospective method, however this conclusion could change based on the outcome of open implementation issues discussed below;
- The Registrants currently anticipate that the implementation of the new guidance will not have a material impact on the amount and timing of revenue recognition; and
- The Registrants expect the new guidance will result in more detailed disclosures of revenue compared to current guidance.

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Notwithstanding the preliminary conclusions noted above, certain implementation issues continue to be debated and worked through the Industry Task Force process that could result in amendments to the standard or implementation guidance that could have a material impact on the Registrants' Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The open implementation issues that could be most impactful to the Registrants include: (1) the ability of the Utility Registrants to recognize revenue for certain contracts where collectability is in question, (2) the accounting by the Utility Registrants for contributions in aid of construction (CIAC) and whether CIAC arrangements are within the scope of the revenue guidance and (3) primarily at Generation, bundled sales contracts and contracts with pricing provisions that may require recognition of revenue at prices other than the contract price (e.g., straight line or estimated future market prices). As part of the overall implementation project, the Registrants are developing alternative adoption plans that would be implemented in the event the ultimate resolution of the open implementation issues result in significant changes from current revenue recognition practices.

Leases (Issued February 2016): Increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The guidance requires lessees to recognize both the right-of-use assets and lease liabilities in the balance sheet for most leases, whereas today only financing type lease liabilities (capital leases) are recognized in the balance sheet. This is expected to require significant changes to systems, processes and procedures in order to recognize and measure leases recorded on the balance sheet that are currently classified as operating leases. In addition, the definition of a lease has been revised in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement which may result in changes to the classification of an arrangement as a lease. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from current GAAP. The accounting applied by a lessor is largely unchanged from that applied under current GAAP. The standard is effective for fiscal years beginning after December 15, 2018. Early adoption is permitted, however the Registrants do not expect to early adopt the standard. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. Refer to Note 24—Commitments and Contingencies for additional information regarding operating leases.

Impairment of Financial Instruments (Issued June 2016): Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects the entity's current estimate of credit losses expected to be incurred over the life of the financial instrument. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard will be effective January 1, 2020 and, for most debt instruments, requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption.

Goodwill Impairment (issued January 2017): Simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two step impairment test). Entities will continue to have the option to perform a

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qualitative assessment to determine if a quantitative impairment test is necessary. Exelon, ComEd, Generation, and DPL have goodwill as of December 31, 2016. This updated guidance is not currently expected to impact the Registrants' financial reporting. The standard is effective January 1, 2020, with early adoption permitted, and must be adopted on a prospective basis.

Clarifying the Definition of a Business (issued January 2017): Clarifies the definition of a business with the objective of addressing whether acquisitions should be accounted for as acquisitions of assets or as acquisitions of businesses. If substantially all the fair value of the assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets, the set of transferred assets and activities is not a business. If the fair value of the assets acquired is not concentrated in a single identifiable asset or a group of similar identifiable assets, then an entity must evaluate whether an input and a substantive process exist, which together significantly contribute to the ability to produce outputs. The standard also revises the definition of outputs to focus on goods and services to customers. The standard could result in more acquisitions being accounted for as asset acquisitions. The standard will be effective January 1, 2018 and will be applied prospectively.

Intra-Entity Transfers of Assets Other Than Inventory (Issued October 2016): Requires entities to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs (compared to current GAAP which prohibits the recognition of current and deferred income taxes for an intra-entity asset transfer until the asset has been sold to an outside party). The standard is effective for fiscal years beginning after December 15, 2017 with early adoption permitted. The guidance is required to be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments (Issued August 2016) and Restricted Cash (Issued November 2016): In 2016, the FASB issued two standards impacting the Statement of Cash Flows. The first adds or clarifies guidance on the classification of certain cash receipts and payments on the statement of cash flows as follows: debt prepayment or extinguishment costs, settlement of zero-coupon bonds, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies and bank-owned life insurance policies, distributions received from equity method investees, beneficial interest in securitization transactions, and the application of the predominance principle to separately identifiable cash flows. The second states that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows (instead of being presented as cash flow activities). Exelon will adopt both standards on January 1, 2018 on a retrospective basis. Adoption of the second standard will result in a change in presentation of restricted cash on the face of the Statement of Cash Flows; otherwise the Registrants expect that adoption of the guidance will have insignificant impacts on the Registrants' Consolidated Statements of Cash Flows and disclosures.

Recognition and Measurement of Financial Assets and Financial Liabilities (Issued January 2016): (i) requires all investments in equity securities, including other ownership interests such as partnerships, unincorporated joint ventures and limited liability companies, to be carried at fair value through net income, (ii) requires an incremental recognition and disclosure requirement related to the presentation of fair value changes of financial liabilities for which the fair value option has been elected, (iii) amends several disclosure requirements, including the methods and significant assumptions used to estimate fair value or a description of the changes in the methods and assumptions used to estimate fair value, and (iv) requires disclosure of the fair value of financial assets and liabilities measured at

amortized cost at the amount that would be received to sell the asset or paid to transfer the liability. The standard is effective for fiscal years beginning after December 15, 2017 with early adoption permitted. The guidance is required to be applied retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption (modified retrospective method).

2. Variable Interest Entities (All Registrants)

A VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly affect the entity's economic performance.

At December 31, 2016, Exelon, Generation, BGE, PHI, and ACE collectively consolidated nine VIEs or VIE groups, for which the applicable Registrant was the primary beneficiary. At December 31, 2015, Exelon, Generation and BGE collectively had seven consolidated VIEs or VIE groups and PHI and ACE had one consolidated VIE (*see Consolidated Variable Interest Entities below)* . As of December 31, 2016 and December 31, 2015, Exelon and Generation collectively had significant interests in eight other VIEs for which the applicable Registrant does not have the power to direct the entities' activities and, accordingly, was not the primary beneficiary (*see Unconsolidated Variable Interest Entities below)* .

Consolidated Variable Interest Entities

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the Registrants' consolidated financial statements at December 31, 2016 and December 31, 2015 are as follows:

	December 31, 2016					December 31, 2015				
				Successor					Predecessor	
	Exelon [a][b]	Generation	BGE	PHI [b]	ACE	Exelon [a]	Generation	BGE	PHI	ACE
Current assets	$ 954	$ 916	$ 23	$ 14	9	$ 909	$ 881	$ 23	$ 12	$ 12
Noncurrent assets	8,563	8,525	3	35	23	8,009	8,004	3	18	18
Total assets	$ 9,517	$ 9,441	$ 26	$ 49	$ 32	$8,918	$ 8,885	$ 26	$ 30	$ 30
Current liabilities	$ 885	$ 802	$ 42	$ 42	37	$ 473	$ 387	$ 81	$ 48	$ 48
Noncurrent liabilities	2,713	2,612	—	101	89	2,927	2,884	41	124	124
Total liabilities	$ 3,598	$ 3,414	$ 42	$ 143	$126	$3,400	$ 3,271	$122	$ 172	$172

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the table can only be settled using VIE resources.

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Exelon's, Generation's, BGE's, PHI's and ACE's consolidated VIEs consist of:

RSB BondCo LLC. In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. BGE has determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE consolidates BondCo.

BondCo's assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2016, 2015 and 2014, BGE remitted $86 million, $86 million and $85 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2016. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

ACE Transition Funding . A special purpose entity formed by ACE for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of transition bonds. Proceeds from the sale of each series of transition bonds by ATF were transferred to ACE in exchange for the transfer by ACE to ATF of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on transition bonds and related taxes, expenses and fees. During the three years ended December 31, 2016, 2015 and 2014, ACE transferred $60 million, $61 million and $55 million to ATF, respectively.

Retail Gas Group. During 2009, Constellation formed two new entities, which now are part of Generation, and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third-party gas supplier. While Generation owns 100% of these entities, it has been determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group's activities without the additional credit support that is provided in the form of a parental guarantee. Generation is the primary beneficiary of the retail gas entity group; accordingly, Generation consolidates the retail gas entity group as a VIE.

The third-party gas supply arrangement is collateralized as follows:

- the assets of the retail gas entity group must be used to settle obligations under the third-party gas supply agreement before it can make any distributions to Generation,
- the third-party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- Generation provides a $75 million parental guarantee to the third-party gas supplier and provides limited recourse to other third-party suppliers and customers in support of the retail gas group.

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Other than credit support provided by the parental guarantee, Exelon or Generation do not have any contractual or other obligations to provide additional financial support under the collateralized third-party gas supply agreement. The third-party gas supply creditors do not have any recourse to Exelon's or Generation's general credit other than the parental guarantee.

Solar Project Entity Group. In 2011, Generation acquired all of the equity interests in Antelope Valley Solar Ranch One (Antelope Valley) from First Solar, Inc., a 242-MW solar PV project in northern Los Angeles County, California. In addition, Generation owns a number of limited liability companies that build, own, and operate solar power facilities. While Generation owns 100% of these entities, it has been determined that certain of the individual solar project entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the solar project entities that qualify as VIEs because Generation controls the design, construction, and operation of the solar power facilities. Generation provides operating and capital funding to the solar entities for ongoing construction, operations and maintenance of the solar power facilities and there is limited recourse related to Generation related to certain solar entities. In addition, these solar VIE entities have an aggregate amount of outstanding debt with third parties of $568 million, as of December 31, 2016, for which the creditors have no recourse to Generation. For additional information on these project-specific financing arrangements refer to Note 14—Debt and Credit Agreements.

Retail Power and Gas Companies. In March 2014, Generation began consolidating retail power and gas VIEs for which Generation is the primary beneficiary as a result of energy supply contracts that give Generation the power to direct the activities that most significantly affect the economic performance of the entities. Generation does not have an equity ownership interest in these entities, but provides approximately $21 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy. These entities are included in Generation's consolidated financial statements, and the consolidation of the VIEs do not have a material impact on Generation's financial results or financial condition.

Wind Project Entity Group . Generation owns and operates a number of wind project limited liability entities, the majority of which were acquired during 2010 with the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind). Generation has evaluated the significant agreements and ownership structures and the risks of each of its wind projects and underlying entities, and determined that certain of the entities are VIEs because either the projects have noncontrolling equity interest holders that absorb variability from the wind projects, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the wind project entities that qualify as VIEs because Generation controls the design, construction, and operation of the wind generation facilities.

In December 2016, Generation sold approximately 71% of its equity interest in one of its wind projects that was previously consolidated under the voting interest model to a tax equity investor. The wind project was evaluated and it was determined to be a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick-out rights with respect to the general partner. While Generation is the minority interest holder, Generation is the primary beneficiary, because Generation manages the day-to-day activities of the entity. Therefore, the entity continues to be consolidated by Generation.

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While Generation owns 100% of the majority of the wind project entities, six of the projects have noncontrolling equity interests of 1% held by third parties and one of the projects has noncontrolling equity interests of approximately 71%. Regarding the projects with noncontrolling equity interests of 1% held by third parties, Generation's current economic interests in five of these projects is significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the noncontrolling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the noncontrolling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the noncontrolling interests state that Generation is to provide financial support to the projects in proportion to its current 99% economic interests in the projects. Generation provides operating and capital funding to the wind project entities for ongoing construction, operations and maintenance of the wind power and there is limited recourse to Generation related to certain wind project entities. However, no additional support to these projects beyond what was contractually required has been provided during 2016. As of December 31, 2016, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of the wind VIE entities primarily relates to the wind generating assets, PPA intangible assets and working capital amounts.

Other Generating Facilities. During the second quarter of 2015, Generation formed a limited liability company to build, own, and operate a backup generator. While Generation owns 100% of the backup generator company, it was determined that the entity is a VIE because the customer absorbs price variability from the entity through the fixed price backup generator agreement. Generation provides operating and capital funding to the backup generator company. Generation also owns 90% of a biomass fueled, combined heat and power company. In the second quarter of 2015, the entity was deemed to be a VIE because the entity requires additional subordinated financial support in the form of a parental guarantee provided by Generation for up to $275 million in support of the payment obligations related to the Engineering, Procurement and Construction contract for the facility in support of one of its other generating facilities (see Note 14—Debt and Credit Agreements for additional details on Albany Green Energy, LLC). In addition to the parental guarantee, Generation provides operating and capital funding to the biomass fueled, combined heat and power company. Generation is the primary beneficiary of both entities since Generation has the power to direct the activities that most significantly affect the economic performance of the entities.

CENG. Through March 31, 2014, CENG was operated as a joint venture with EDF and was governed by a board of ten directors, five of which were appointed by Generation and five by EDF. CENG was designed to operate under joint and equal control of Generation and EDF through the Board of Directors, subject to the Chairman of the Board's final decision making authority on certain special matters; therefore, CENG was not subject to VIE guidance. Accordingly, Generation's 50.01% interest in CENG was accounted for as an equity method investment. On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the Nuclear Operating Services Agreement (NOSA) pursuant to which Generation now conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF. As a result of executing the NOSA, CENG now qualifies as a VIE due to the disproportionate relationship between Generation's 50.01% equity ownership interest and its role in conducting the operational activities of CENG and the CENG fleet conveyed through the NOSA. Further, since Generation is conducting the operational activities of CENG and the CENG fleet, Generation qualifies as the primary beneficiary of CENG and, therefore, is required to consolidate the financial position and results of operations of CENG. On April 1, 2014, Exelon and Generation

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derecognized Generation's equity method investment in CENG and reflected all assets, liabilities, and the EDF noncontrolling interests in CENG at fair value on the consolidated balance sheets of Exelon and Generation, resulting in the recognition of a $261 million gain in their respective Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2014.

Generation and Exelon, where indicated, provide the following support to CENG (see Note 5—Investment in Constellation Energy Nuclear Group, LLC and Note 27—Related Party Transactions for additional information regarding Generation's and Exelon's transactions with CENG):

- under the NOSA, Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life and decommissioning of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF,
- under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management, and billing services to the CENG fleet for the remaining operating life of the CENG nuclear plants,
- under power purchase agreements with CENG, Generation purchased or will purchase 50.01% of the available output generated by the CENG nuclear plants not subject to other contractual agreements from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs have been suspended during the term of the Reliability Support Services Agreement (RSSA) (see Note 3—Regulatory Matters for additional details),
- Generation provided a $400 million loan to CENG. As of December 31, 2016, the remaining obligation is $316 million, including accrued interest, which reflects the principal payment made in January 2015,
- Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. (See Note 24—Commitments and Contingencies for more details),
- in connection with CENG's severance obligations, Generation reimbursed CENG for a total of approximately $6 million of the severance benefits paid from 2014 through 2016. The final reimbursement was made in 2016, and there was no remaining obligation as of December 31, 2016.
- Generation and EDF share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance,
- Generation provides a guarantee of approximately $7 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDF executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,
- Generation and EDF are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (See Note 24—Commitments and Contingencies for more details), and

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- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

2015 ESA Investco, LLC. In June 2015, 2015 ESA Investco, LLC, then a wholly owned subsidiary of Generation, entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of another distributed energy company. In November 2015, Generation sold 69% of its equity interest in 2015 ESA Investco, LLC to a tax equity investor. Generation and the tax equity investor will contribute up to a total of $250 million of equity incrementally from inception through the first quarter of 2017 in proportion to their ownership interests, which is up to $172 million for the tax equity investor and up to $78 million for Generation (see Note 24—Commitments and Contingencies for more details). The investment in the distributed energy company was evaluated, and it was determined to be a VIE for which Generation is not the primary beneficiary (see additional details in the Unconsolidated Variable Interest Entities section below). As of December 31, 2015, Generation consolidated 2015 ESA Investco, LLC under the voting interest model. Pursuant to the new consolidation guidance effective January 1, 2016, 2015 ESA Investco, LLC meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick-out rights with respect to the general partner. Under VIE guidance, Generation is the primary beneficiary; therefore, the entity continues to be consolidated.

For each of the consolidated VIEs, except as otherwise noted:

- the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;
- Exelon, Generation, BGE, PHI and ACE did not provide any additional material financial support to the VIEs;
- Exelon, Generation, BGE, PHI and ACE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and
- the creditors of the VIEs did not have recourse to Exelon's, Generation's, BGE's, PHI's or ACE's general credit.

As of December 31, 2016 and December 31, 2015, ComEd, PECO, Pepco and DPL do not have any material consolidated VIEs.

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Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of December 31, 2016 and December 31, 2015, these assets and liabilities primarily consisted of the following:

	December 31, 2016					December 31, 2015				
				Successor					*Predecessor*	
	Exelon [a][b]	Generation	BGE	PHI [b]	ACE	Exelon [a]	Generation	BGE	PHI	ACE
Cash and cash equivalents	$ 150	$ 150	$ —	$ —	$ —	$ 164	$ 164	$ —	$ —	$ —
Restricted cash	59	27	23	9	9	100	77	23	12	12
Accounts receivable, net										
Customer	371	371	—	—	—	219	219	—	—	—
Other	48	48	—	—	—	43	43	—	—	—
Mark-to-market derivatives assets	31	31	—	—	—	140	140	—	—	—
Inventory										
Materials and supplies	199	199	—	—	—	181	181	—	—	—
Other current assets	50	44	—	5	—	35	30	—	—	—
Total current assets	908	870	23	14	9	882	854	23	12	12
Property, plant and equipment, net	5,415	5,415	—	—	—	5,160	5,160	—	—	—
Nuclear decommissioning trust funds	2,185	2,185	—	—	—	2,036	2,036	—	—	—
Goodwill	47	47	—	—	—	47	47	—	—	—
Mark-to-market derivatives assets	23	23	—	—	—	53	53	—	—	—
Other noncurrent assets	315	277	3	35	23	90	85	3	18	18
Total noncurrent assets	7,985	7,947	3	35	23	7,386	7,381	3	18	18
Total assets	$ 8,893	$ 8,817	$ 26	$ 49	$ 32	$ 8,268	$ 8,235	$ 26	$ 30	$ 30
Long-term debt due within one year	$ 181	$ 99	$ 41	$ 40	$ 35	$ 111	$ 27	$ 79	$ 46	$ 46
Accounts payable	269	269	—	—	—	216	216	—	—	—
Accrued expenses	119	116	1	2	2	115	113	2	2	2
Mark-to-market derivative liabilities	60	60	—	—	—	5	5	—	—	—
Unamortized energy contract liabilities	15	15	—	—	—	12	12	—	—	—
Other current liabilities	30	30	—	—	—	13	13	—	—	—
Total current liabilities	674	589	42	42	37	472	386	81	48	48
Long-term debt	641	540	—	101	89	666	623	41	124	124
Asset retirement obligations	1,904	1,904	—	—	—	1,999	1,999	—	—	—
Pension obligation [c]	9	9	—	—	—	9	9	—	—	—
Unamortized energy contract liabilities	22	22	—	—	—	39	39	—	—	—
Other noncurrent liabilities	106	106	—	—	—	79	79	—	—	—
Noncurrent liabilities	2,682	2,581	—	101	89	2,792	2,749	41	124	124
Total liabilities	$ 3,356	$ 3,170	$ 42	$ 143	$ 126	$ 3,264	$ 3,135	$ 122	$ 172	$ 172

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.

(c) Includes the CNEG retail gas pension obligation, which is presented as a net asset balance within the Prepaid pension asset line item on Generation's balance sheet. See Note 17—Retirement Benefits for additional details.

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected on Exelon's and Generation's Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of December 31, 2016 and 2015, Exelon and Generation had significant unconsolidated variable interests in eight VIEs for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity method investments and certain commercial agreements. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Generation has several individually immaterial VIEs that in aggregate represent a total investment of $18 million. These immaterial VIEs are equity and debt securities in energy development companies. The maximum exposure to loss related to these securities is limited to the $18 million included in Investments on Exelon's and Generation's Consolidated Balance Sheets.

The following tables present summary information about Exelon and Generation's significant unconsolidated VIE entities:

December 31, 2016	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets (a)	$ 638	$ 567	$ 1,205
Total liabilities (a)	215	287	502
Exelon's ownership interest in VIE (a)	—	248	248
Other ownership interests in VIE (a)	423	32	455
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	264	264
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning (b)	9	—	9

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December 31, 2015	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets (a)	$ 263	$ 164	$427
Total liabilities (a)	22	125	147
Exelon's ownership interest in VIE (a)	—	11	11
Other ownership interests in VIE (a)	241	28	269
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	21	21
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning (b)	17	—	17

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.
(b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $113 million and $206 million as of December 31, 2016 and December 31, 2015, respectively; offset by payables to ZionSolutions LLC of $104 million and $189 million as of December 31, 2016 and December 31, 2015, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

For each unconsolidated VIE, Exelon and Generation assessed the risk of a loss equal to their maximum exposure to be remote and, accordingly Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would materially affect the fair value or risk of their variable interests in these variable interest entities.

The Registrants' unconsolidated VIEs consist of:

Energy Purchase and Sale Agreements. Generation has several energy purchase and sale agreements with generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each entity, and determined that certain of the entities are VIEs because the entity absorbs risk through the sale of fixed price power and renewable energy credits. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

ZionSolutions . Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 16—Asset Retirement Obligations. Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning activities under the asset sale agreement are complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required. Other than the asset sale agreement, Exelon and Generation do not have any contractual or other obligations to provide additional financial support and ZionSolutions' creditors do not have any recourse to Exelon's or Generation's general credit.

Investment in Energy Development Projects, Distributed Energy Companies, and Energy Generating Facilities. Generation has several equity investments in energy development projects and energy generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each of its equity investments, and determined that certain of the entities are

VIEs because the entity has an insufficient amount of equity at risk to finance its activities, Generation guarantees the debt of the entity, provides equity support, or provides operating services to the entity. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the entities that qualify as VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

In July 2014, Generation entered into an arrangement to purchase a 90% equity interest and 90% of the tax attributes of a distributed energy company. Generation's total equity commitment in this arrangement was $85 million and was paid incrementally over an approximate two year period (see Note 24—Commitments and Contingencies for additional details). This arrangement did not meet the definition of a VIE and was recorded as an equity method investment. However, pursuant to the new consolidation guidance effective as of January 1, 2016 for the Registrants, the distributed energy company meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick-out rights of the general partner. (For additional details related to the new consolidation guidance, see Note 1—Significant Accounting Policies.) Generation is not the primary beneficiary; therefore, the investment continues to be recorded using the equity method.

In June 2015, 2015 ESA Investco, LLC, then a wholly owned subsidiary of Generation, entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of another distributed energy company. Separate from the equity investment, Generation provided $27 million in cash to the other (10%) equity holder in the distributed energy company in exchange for a convertible promissory note. In November 2015, Generation sold 69% of its equity interest in 2015 ESA Investco, LLC to a tax equity investor. Generation and the tax equity investor will contribute up to a total of $250 million of equity incrementally through the first quarter of 2017 in proportion to their ownership interests, which is up to $172 million for the tax equity investor and up to $78 million for Generation (see Note 24—Commitments and Contingencies for additional details). Generation and the tax equity investor provide a parental guarantee of up to $275 million in proportion to their ownership interests in support of 2015 ESA Investco, LLC's obligation to make equity contributions to the distributed energy company. The investment in the distributed energy company was evaluated and it was determined to be a VIE for which Generation is not the primary beneficiary. See additional details in the Consolidated Variable Interest Entities section above.

Both distributed energy companies from the 2015 and 2014 arrangements are considered related parties.

ComEd, PECO and BGE

The financing trust of ComEd, ComEd Financing III, the financing trusts of PECO, PECO Trust III and PECO Trust IV, and the financing trust of BGE, BGE Capital Trust II, are not consolidated in Exelon's, ComEd's, PECO's or BGE's financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd, PECO, and BGE have concluded that they do not have a significant variable interest in ComEd Financing III, PECO Trust III, PECO Trust IV or BGE Capital Trust II as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk. See Note 14—Debt and Credit Agreements for additional information.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

3. Regulatory Matters (All Registrants)

The following matters below discuss the current status of material regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd).

Background

Since 2011, ComEd's electric distribution rates are established through a performance-based formula rate, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities to modernize Illinois' electric utility infrastructure.

Participating utilities are required to file an annual update to the performance-based formula rate on or before May 1, with resulting rates effective in January of the following year. This annual electric distribution formula rate update is based on prior year actual costs and current year projected capital additions (initial revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred for that year (annual reconciliation). See *Annual Electric Distribution Filings* below for further details. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to Operating revenues for any differences between the revenue requirement in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. As of December 31, 2016, and December 31, 2015, ComEd had a regulatory asset associated with the electric distribution formula rate of $188 million and $189 million, respectively. The regulatory asset associated with electric distribution formula rate is amortized to Operating revenues in ComEd's Consolidated Statement of Operations and Comprehensive Income as the associated amounts are recovered through rates.

Participating utilities are also required to file an annual update on their AMI implementation progress. On April 1, 2016, ComEd filed an annual progress report on its AMI Implementation Plan with the ICC, which allows for the installation of more than four million smart meters throughout ComEd's service territory through 2018. To date, approximately three million smart meters have been installed in the Chicago area.

Pursuant to EIMA, ComEd annually contributes $4 million for customer education for as long as the AMI Deployment Plan remains in effect. Additionally, ComEd contributed $10 million annually through 2016 to fund customer assistance programs for low-income customers, which are not recoverable through rates.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Annual Electric Distribution Filings

For each of the following years, the ICC approved the following total increases/(decreases) in ComEd's electric distributions formula rate filings:

Annual Electric Distribution Filings	2016	2015	2014
ComEd's requested total revenue requirement increase (decrease)	$ 138	$ (50)	$ 269
Final ICC Order			
Initial revenue requirement increase	$ 134	$ 85	$ 160
Annual reconciliation (decrease) increase	(7)	(152)	72
Total revenue requirement increase (decrease)	$ 127[a]	$ (67)	$ 232
Allowed Return on Rate Base:			
Initial revenue requirement	6.71%	7.05%	7.06%
Annual reconciliation	6.69%	7.02%	7.04%
Allowed ROE:			
Initial revenue requirement	8.64%	9.14%	9.25%
Annual reconciliation	8.59% [b]	9.09% [b]	9.20% [b]
Effective date of rates	January 2017	January 2016	January 2015

(a) On December 20, 2016, the ICC granted ComEd's and other parties' joint application for rehearing on the impact that changing ComEd's OSHA recordable rate for 2014 and 2015 has on the revenue requirement approved in this order. ComEd has proposed that the 2016 total electric distribution revenue requirement be reduced by $18 million which would be refunded to customers in 2017.
(b) Includes a reduction of 5 basis points for a reliability performance metric penalty.

Illinois Future Energy Jobs Act (Exelon, Generation, and ComEd).

Background

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA is effective June 1, 2017, and includes, among other provisions, (1) a ZES providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd's electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd's customer rates exceeds specified limits, (6) revisions to the existing net metering statute to (i) mandate net metering for community generation projects, and establish billing procedures for subscribers to those projects, (ii) provide immediately for netting at the energy-only rate for nonresidential customers, and (iii) transition from netting at the full retail rate to the energy-only rate for certain residential net metering customers once the net meter customer load equals 5% of total peak demand supplied in the previous year and (7) support for low income rooftop and community solar programs.

Zero Emission Standard

FEJA includes a ZES that provides compensation through the procurement of ZECs targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet specific eligibility criteria. ZES will have a 10-year duration extending through May 31, 2027.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Eligible generators may participate in a procurement event overseen by the Illinois Power Agency and selected generators will directly contract with Illinois utilities for the procurement of the ZECs based upon the number of MWh produced by the eligible facilities, subject to specified annual caps. The ZEC price will be based upon the current social cost of carbon as determined by the federal government and is initially established at $16.50 per MWh of production, subject to future adjustments based on specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices.

Illinois utilities, including ComEd, will be required to purchase from eligible nuclear facilities an amount of ZECs equivalent to 16% of the actual amount of electricity delivered in 2014. ComEd will recover all costs associated with purchasing ZECs through a new rate rider, which will provide for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase ZECs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods.

See Note 9—Early Nuclear Plant Retirements for the impacts of the provisions above on Generation's Consolidated Balance Sheets and Consolidated Statements of Operations and Comprehensive Income. The provisions do not impact ComEd's Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income or Consolidated Statements of Cash Flows until 2017.

ComEd Electric Distribution Rates

FEJA extends the sunset date for ComEd's performance-based electric distribution formula rate from 2019 to the end of 2022, allows ComEd to revise the electric distribution formula rate to eliminate the ROE collar, and allows ComEd to implement a decoupling tariff if the electric distribution formula rate is terminated at any time. ComEd will revise its electric distribution formula rate to eliminate the ROE collar, which will eliminate any unfavorable or favorable impacts of weather or load from ComEd's electric distribution formula rate revenues beginning with the reconciliation filed in 2018 for the 2017 calendar year. ComEd will begin reflecting the impacts of this change in its electric distribution services costs regulatory asset or liability beginning in 2017.

FEJA requires ComEd to make non-recoverable contributions to low income energy assistance programs of $10 million per year for 5 years as long as the electric distribution formula rate remains in effect. With the exception of these contributions, ComEd will recover from customers, subject to certain caps explained below, the costs it incurs pursuant to FEJA either through its electric distribution formula rate or other recovery mechanisms.

Energy Efficiency

Existing Illinois law requires ComEd to implement cost-effective energy efficiency measures and, for a 10-year period ending May 31, 2018, cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers.

Beginning January 1, 2018, FEJA provides for new cumulative annual energy efficiency MWh savings goals for ComEd, which are designed to achieve 21.5% of cumulative persisting annual MWh savings by 2030, as compared to the deemed baseline of 88 million MWhs of electric power and energy sales. FEJA, deems the cumulative persisting annual MWh savings to be 6.6% from 2012 through the end of 2017. ComEd expects to spend approximately $250 million to $400 million annually from 2017 through 2030 to achieve these energy efficiency MWh savings goals. In addition, FEJA extends the peak demand reduction requirement from 2018 to 2026. Because the new requirements

apply beginning in 2018, FEJA extends the existing energy efficiency plans, which were due to end on May 31, 2017, through December 31, 2017. FEJA also exempts customers with demands over 10 MW from energy efficiency plans and requirements beginning June 1, 2017.

FEJA allows ComEd to cancel its existing energy efficiency rate rider and replace it with an energy efficiency formula rate, and to defer energy efficiency costs (except for any voltage optimization costs which will be recovered through the electric distribution formula rate) as a separate regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life, as approved by the ICC, of the related energy efficiency measures. ComEd will earn a return on the energy efficiency regulatory asset at a rate equal to its weighted average cost of capital, which is based on a year-end capital structure and calculated using the same methodology applicable to ComEd's electric distribution formula rate. Through December 31, 2030, the return on equity that ComEd earns on its energy efficiency regulatory asset is subject to a maximum downward or upward adjustment of 200 basis points if ComEd's cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual incremental savings goal. ComEd will be required to file an update to its energy efficiency formula rate on or before June 1 each year, with resulting rates effective in January of the following year. The annual update will be based on projected current year energy efficiency costs and the related projected year-end regulatory asset balance less any related deferred taxes. The update will also include a reconciliation of any differences between the revenue requirement in effect for the prior year and the revenue requirement based on actual prior year costs and year-end energy efficiency regulatory asset balances less any related deferred taxes.

ComEd expects to cancel its existing energy efficiency rider, at which time it must perform a reconciliation of revenues and costs incurred through the cancellation date and issue a one-time credit on retail customers' bills for any over-recoveries. As of December 31, 2016, ComEd's over-recoveries associated with its existing energy efficiency rider of $141 million were reflected in Current regulatory liabilities on Exelon's and ComEd's Consolidated Balance Sheets. As a result, ComEd expects to provide credits to customers in 2017 to address this over-recovery.

Renewable Portfolio Standard

Existing Illinois law requires ComEd to purchase each year an increasing percentage of renewable energy resources for the customers for which it supplies electricity. This obligation is satisfied through the procurement of renewable energy credits (RECs). FEJA revises the Illinois RPS to require ComEd to procure RECs for all retail customers by June 2019, regardless of the customers' electricity supplier, and provides support for low-income rooftop and community solar programs, which will be funded by the existing Renewable Energy Resources Fund and ongoing RPS collections. ComEd will recover all costs associated with purchasing RECs through rate riders, which will provide for a reconciliation and true-up to actual costs, with any difference between revenues and expenses to be credited to or collected from ComEd's retail customers in subsequent periods. The first reconciliation and true-up for RECs will cover revenues and costs for the four year period beginning June 1, 2017 through May 31, 2021. Subsequently, the RPS rate rider will provide for an annual reconciliation and true-up.

Customer Rate Increase Limitations

FEJA includes provisions intended to limit the average impact on ComEd customer rates for recovery of costs incurred under FEJA as follows: (1) for a typical ComEd residential customer, the average impact must be less than $0.25 cents per month, (2) for nonresidential customers with a peak demand less than 10 MW, the average annual impact must be less than 1.3% of the average amount

paid per kWh for electric service by Illinois commercial retail customers during 2015, and (3) for nonresidential customers with a peak demand greater than 10 MW, the average annual impact must be less than 1.3% of the average amount paid per kWh for electric service by Illinois industrial retail customers during 2015.

By June 30, 2017, ComEd must submit a 10-year projection to the ICC of customer rate impacts for residential customers and nonresidential customers with a peak demand less than 10 MW. Thereafter, beginning in 2018, ComEd must submit a report to the ICC for residential customers and nonresidential customers with a peak demand less than 10 MW by February 15th and June 30th of each year, respectively. For nonresidential customers with a peak demand greater than 10 MW, ComEd must submit a report to the ICC by May 1 of each year if a rate reduction will be necessary in the following year. For residential customers, the reports will include the actual costs incurred under FEJA during the preceding year and a rolling 10-year customer rate impact projection. The reports for nonresidential customers with a peak demand less than 10 MW will also include the actual costs incurred under FEJA during the preceding year, as well as the average annual rate increase from January 1, 2017 through the end of the preceding year and the average annual rate increase projected for the remainder of the 10-year period.

If the projected residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations during the first four years, ComEd is required to decrease costs associated with FEJA investments, including reductions to ZEC contract quantities. If the projected residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations during the last six years, ComEd is required to demonstrate how it will reduce FEJA investments to ensure compliance. If the actual residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations for any one year, ComEd is required to submit a corrective action plan to decrease future year costs to reduce customer rates to ensure future compliance. If the actual residential customer or nonresidential customer rate exceeds the limitations for two consecutive years, ComEd can offer to credit customers for amounts billed in excess of the limitations or ComEd can terminate FEJA investments. If ComEd chooses to terminate FEJA investments, the ICC shall order termination of ZEC contracts and further initiate proceedings to reduce energy efficiency savings goals and terminate support for low-income rooftop and community solar programs. ComEd is allowed to fully recover all costs incurred as of and up to the date of the programs' termination.

For the energy efficiency formula, ComEd will record a regulatory asset or liability and corresponding increase or decrease to Operating revenues for any differences between the revenue requirement in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. For the other rate riders to be established under FEJA, ComEd will record a regulatory asset or liability for any differences between revenues and incurred expenses. FEJA did not have any impacts on ComEd's Consolidated Statements of Operations and Comprehensive Income or Consolidated Statements of Cash Flows in 2016.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. As of December 31, 2016, ComEd has completed all required ICC-approved procurements as called for by the IPA Procurement Plan's timeline.

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Energy Efficiency and Renewable Energy Resources (Exelon and ComEd).

In accordance with legislation in effect on December 31, 2016, the IPA's Procurement Plans include the procurement of cost-effective renewable energy resources in amounts that equal or exceed a minimum target percentage of the total electricity that each electric utility supplies to its eligible retail customers. The June 1, 2016 target renewable energy resources obligation for the utilities was at least 11.5%. This obligation increases by at least 1.5% each year thereafter to an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth by Illinois legislation. As of December 31, 2016, ComEd had purchased renewable energy resources or equivalents, such as RECs, in accordance with the IPA Procurement Plan. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates.

In accordance with FEJA that takes effect on June 1, 2017, beginning with the plan or plans to be implemented in the 2017 delivery year, the IPA shall develop a long term renewable resources procurement plan (LT Plan). The RPS target percentages for the overall service territory have not changed through June 1, 2025 although FEJA extended the 25% RPS target to delivery years after 2025. Currently, each RES and each utility is responsible for the renewable resource obligation of the customers it supplies power for. Over time, this will change and the utility will procure renewable resources based on the retail load of substantially all customers in its service territory. For the delivery year beginning June 1, 2017, the LT Plan shall include cost effective renewable energy resources procured by the utility for the retail load the utility supplies and for 50% of the retail customer load supplied by Retail Electric Suppliers in the utility service territory on February 28, 2017. Utility procurement for RES supplied retail customer load will increase to 75% June 1, 2018 and to 100% beginning June 1, 2019.

Grand Prairie Gateway Transmission Line (Exelon and ComEd). On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On October 22, 2014, the ICC issued an Order approving ComEd's request. The City of Elgin and certain other parties each filed an appeal of the ICC Order in the Illinois Appellate Court for the Second District. ComEd then reached a settlement of the appeal filed by all parties except Elgin. On March 31, 2016, the Illinois Appellate Court issued its opinion affirming the ICC's grant of a certificate to ComEd to construct and operate the line. Elgin did not seek further review of the Illinois Appellate Court decision. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. The costs incurred for the project prior to May 21, 2014 were immaterial. ComEd has acquired the necessary land rights across the project route through voluntary transactions. ComEd began construction of the line during 2015 with an expected in-service date of June 2017.

FutureGen Industrial Alliance, Inc (Exelon and ComEd). During 2013, the ICC approved, and directed ComEd and Ameren (the Utilities) to enter into 20-year sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. ComEd executed the sourcing agreement with FutureGen in accordance with the ICC's order. The order also directed ComEd and Ameren to recover these costs from their electric distribution customers through the use of a tariff, regardless of whether they purchase electricity from ComEd or Ameren, or from competitive electric generation suppliers.

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In February 2015, the DOE suspended funding for the cost development of FutureGen. On January 13, 2016, FutureGen informed the Illinois Supreme Court that it had ceased all development efforts on the FutureGen project. In February 2016, FutureGen terminated its sourcing agreement with ComEd. On May 19, 2016, the Illinois Supreme Court dismissed the matter as moot. As a result, ComEd is under no further obligation under this agreement.

Pennsylvania Regulatory Matters

2015 Pennsylvania Electric Distribution Rate Case (Exelon and PECO). On March 27, 2015, PECO filed a petition with the PAPUC requesting an increase of $190 million to its annual service revenues for electric delivery, which requested an ROE of 10.95%. On September 10, 2015, PECO and interested parties filed with the PAPUC a petition for joint settlement for an increase of $127 million in annual distribution service revenue. No overall ROE was specified in the settlement. On December 17, 2015, the PAPUC approved the settlement of PECO's electric distribution rate case, which included the approval of the In-Program Arrearage Forgiveness ("IPAF") Program. The approved electric delivery rates became effective on January 1, 2016.

The IPAF Program provides for forgiveness of a portion of the eligible arrearage balance of its low-income Customer Assistance Program (CAP) accounts receivable at program inception. The forgiveness will be granted to the extent CAP customers remain current over the duration of the five-year payment agreement term. The Settlement guarantees PECO's recovery of two-thirds of the arrearage balance through a combination of customer payments and rate recovery, including through future rates cases if necessary. The remaining one-third of the arrearage balance has been absorbed by PECO through bad debt expense on its Consolidated Statements of Operations. In October 2016, the IPAF was fully implemented. A regulatory asset of $11 million representing previously incurred bad debt expense associated with the eligible accounts receivable balances was recorded as of December 31, 2016.

Pennsylvania Procurement Proceedings (Exelon and PECO). Through PECO's first two PAPUC approved DSP Programs, PECO procured electric supply for its default electric customers through PAPUC approved competitive procurements. DSP I and DSP II expired on May 31, 2013 and May 31, 2015, respectively.

The second DSP Program included a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to submit a plan to allow its low-income CAP customers to purchase their generation supply from EGSs beginning in April 2014. In May 2013, PECO filed its CAP Shopping Plan with the PAPUC. By an Order entered on January 24, 2014, the PAPUC approved PECO's plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, the Office of Consumer Advocate (OCA) and low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court, claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On July 14, 2015, the Court issued opinions on the OCA and low-income advocacy group appeal. Specifically, the Court remanded the issue to the PAPUC with instructions that it approve a rule revision to the PECO CAP Shopping Plan that would prohibit CAP customers from entering into contracts with an EGS that would impose early cancellation/termination fees. The PAPUC, as well as the low-income advocates and the Office of Consumer Advocate, appealed the Court's decision. On April 5, 2016, the Pennsylvania Supreme Court declined to accept the appeals. On May 11, 2016, the PAPUC issued a Secretarial Letter requiring PECO to propose a rule revision to the PECO CAP Shopping Plan consistent with the Court's decision. On July 19, 2016, PECO filed a letter stating its intent to revise its Plan by September 1, 2016 to incorporate the rule revision. On September 1, 2016, PECO filed its proposed rule revision that is consistent with the Court's opinion with a proposed effective date of April 14, 2017.

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On December 4, 2014, the PAPUC approved PECO's third DSP Program. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. Under the program, PECO procured electric supply through four competitive procurements for fixed price full requirements contracts of two years or less for the residential classes and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. Beginning in June 2016, the medium commercial class (101-500 kW) moved to spot market pricing. In September 2016, PECO entered into contracts with PAPUC-approved bidders, including Generation, resulting from the final of its four scheduled procurements. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Consolidated Statement of Operations and Comprehensive Income.

On March 12, 2015, PECO settled the CAP Design with the Office of Consumer Advocates (OCA) and Low Income Advocates, and filed the proposed plan with the PAPUC on March 20, 2015. The program design changes the rate structure of PECO's CAP to make the bills more affordable to customers enrolled in the assistance program. The CAP discounts continue to be recovered through PECO's universal service fund cost. On July 8, 2015, the CAP Design was approved by the PAPUC, and subsequently implemented in October 2016 as planned.

On March 17, 2016, PECO filed its fourth DSP Program with the PAPUC proposing a 24-month term from June 1, 2017 through May 31, 2019, in compliance with electric generation procurement guidelines set forth in Act 129. On October 4, 2016, the Administrative Law Judge recommended that PECO's previously filed partial settlement be approved without modification. The settlement would extend the program period through May 2021 and consolidate the Medium Commercial and Large Commercial classes of default service customers into a Consolidated Large Commercial Class proposed by the Company. The issue of PECO's implementation of CAP Shopping was reserved for briefing, and the Administrative Law Judge determined that issue was not a part of the DSP IV case. On December 8, 2016, the PAPUC approved the fourth DSP Program for a 48-month term and deferred CAP Shopping to another proceeding. OCA and Low Income Advocates subsequently filed a Petition for Reconsideration and Clarification, which is pending before the PAPUC.

Smart Meter and Smart Grid Investments (Exelon and PECO). In April 2010, pursuant to Act 129 and the follow-on Implementation Order of 2009, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million electric smart meters and an AMI communication network by 2020. As approved by the PAPUC, PECO accelerated its installation and deployed substantially all smart meters by December 31, 2015, for a total of 1.7 million smart meters. PECO spent $578 million and $155 million on smart meter and smart grid infrastructure, respectively, of which $200 million has been funded by SGIG. Recovery of smart meter costs are reflected in base rates effective January 1, 2016.

Energy Efficiency Programs (Exelon and PECO). The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provided energy consumption reduction requirements for the second phase of Act 129's EE&C program, which went into effect on June 1, 2013. Pursuant to the Phase II implementation order, PECO filed its three-year EE&C Phase II Plan with the PAPUC on November 1, 2012. The plan set forth how PECO would reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016, adjusted for weather and extraordinary loads. The implementation order permitted PECO to apply any excess savings achieved during Phase I against its Phase II consumption reduction targets, with no reduction to its Phase II budget. In accordance with the Act 129 Phase II implementation order, at least 10% and 4.5% of the total consumption reductions had to be through programs directed toward PECO's public

and low income sectors, respectively. Act 129 mandates that the total cost of the plan may not exceed 2% of the electric company's total annual revenue as of December 31, 2006.

On March 15, 2013 and February 28, 2014, PECO filed Petitions for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers through May 31, 2014 and May 31, 2016, respectively. PECO proposed to fund the estimated $10 million annual costs of the plan by modifying incentive levels for other Phase II programs. The costs of the DLC program were recovered through PECO's Energy Efficiency Plan surcharge along with other Phase II Plan costs. The PAPUC granted PECO's Petitions on May 5, 2013 and April 23, 2014, respectively. On November 15 2016, PECO reported to the PAPUC that as of the conclusion of the EE&C Phase II Plan, all plan requirements have been met. A final Phase II compliance determination is expected to be issued in the first half of 2017.

On June 19, 2015, the PAPUC issued its Phase III EE&C implementation order that provides energy consumption reduction requirements for the third phase of Act 129's EE&C program with a five-year term from June 1, 2016 through May 31, 2021.

Pursuant to the Phase III implementation order, PECO filed its five-year EE&C Phase III Plan with the PAPUC on November 30, 2015. The Plan sets forth how PECO will reduce electric consumption by at least 1,962,659 MWh, with a goal of 2,100,875 MWh in its service territory for the period June 1, 2016 through May 31, 2021. The PAPUC approved PECO's EE&C Phase III Plan, with requested clarifications, on May 19, 2016.

Alternative Energy Portfolio Standards (Exelon and PECO). In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of PECO's rate cap transition period, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources ranges from approximately 3.5% to 8%, and the requirement for Tier II alternative energy resources ranges from 6.2% to 10%. The required compliance percentages incrementally increase each annual compliance period, which is from June 1 through May 31, until May 31, 2021. These Tier I and Tier II alternative energy resources include acceptable energy sources as set forth in Act 129 and the AEPS Act.

PECO continues to procure alternative energy credits through full requirements contracts and its existing long-term solar contracts to meet the annual AEPS compliance requirements. All AEPS compliance costs are being recovered on a full and current basis from default service customers through the GSA.

Pennsylvania Retail Electricity and Gas Markets (Exelon and PECO). Beginning in 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania's retail electricity market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. Through various orders, the PAPUC issued default electric service pricing for customers in PECO's service territory. See Pennsylvania procurement proceedings discussed above for additional details.

In early 2014, the extreme weather in PECO's service territory resulted in increased electricity commodity costs causing certain shopping customers to receive unexpectedly high utility bills. In response to a significant number of customer complaints throughout Pennsylvania, on April 3, 2014,

the PAPUC unanimously voted to adopt two rulemaking orders to address the issue. The first rulemaking order requires electric generation suppliers to provide more consumer education regarding their contract. The second rulemaking order requires electric distribution companies to enable customers to switch suppliers within three business days (known as accelerated switching). The improved customer education and accelerated switching were to be in place within 30 days and six months of approval of the orders, respectively. The orders became final on June 14, 2014. On December 4, 2014, the PAPUC approved PECO's implementation plan (known as Bill on Supplier Switch), allowing PECO to implement accelerated switching by the December 15, 2014 deadline.

On September 12, 2013, the PAPUC issued an Order that initiated an investigation into Pennsylvania's natural gas retail market, including the role of the existing default service model and opportunities for market enhancements. On December 18, 2014, the PAPUC issued a Final Order directing the Office of Competitive Market Oversight (OCMO) to continue its investigation, confirming that natural gas distribution companies should remain with the default service model for the time being and directing establishment of a working group to examine other competitive issues. The OCMO has established a working group to review operation of the natural gas retail market and to consider potential recommendations on competitive issues.

Pennsylvania Act 11 of 2012 (Exelon and PECO). In February 2012, Act 11 was signed into law, which provided the PAPUC authority to approve the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems in Pennsylvania. Prior to recovering costs pursuant to a DSIC, the PAPUC's implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) approved by the Commission, which outlines how the utility is planning to increase its investment for repairing, improving or replacing aging infrastructure.

On May 7, 2015, the PAPUC approved PECO's modified natural gas LTIIP. In accordance with the approved LTIIP, PECO plans to spend $534 million through 2022 to further accelerate the replacement of existing gas mains and to relocate meters from indoors to outside in accordance with recent PAPUC rulemaking. In addition, on March 20, 2015, PECO filed a petition with the PAPUC for approval of its gas DSIC mechanism for recovery of gas LTIIP expenditures. On September 11, 2015, the PAPUC entered its Opinion and Order approving PECO's petition for a gas DSIC.

On March 27, 2015, PECO filed a petition with the PAPUC for approval of its proposed electric DSIC and LTIIP. In accordance with the LTIIP (System 2020 plan), PECO plans to spend $275 million over the next five years to modernize and storm-harden its electric distribution system, making it more weather resistant and less vulnerable to damage. The DSIC will allow PECO the opportunity to recover the costs, subject to certain criteria, incurred to repair, improve or replace its electric distribution property between rate cases. On October 22, 2015, the PAPUC entered its Opinion and Order approving PECO's proposed petition for its electric LTIIP and DSIC.

Maryland Regulatory Matters

2016 Maryland Electric Distribution Base Rates (Exelon, PHI and Pepco). On November 15, 2016, the MDPSC approved an increase in electric distribution base rates of $53 million based on a ROE of 9.55%. The new rates became effective for services rendered on or after November 15, 2016. MDPSC also approved Pepco's recovery of substantially all of its capital investment and regulatory assets associated with its AMI program as part of the newly effective rates as well as a recovery over a five-year period of transition costs related to a new billing system implemented in 2015. As a result,

during the fourth quarter of 2016, Exelon, PHI and Pepco established a regulatory asset of $13 million, wrote-off $3 million in disallowed AMI costs and recorded a pre-tax credit to net income for $10 million. Additionally, the MDPSC denied Pepco's request to extend its Grid Resiliency Program surcharge for new system reliability and safety improvement projects, with costs for such programs to be recovered going forward through base rates.

2016 Maryland Electric Distribution Base Rates (Exelon, PHI and DPL). On July 20, 2016, DPL filed an application with the MDPSC requesting an increase of $66 million to its electric distribution base rates, which was later updated to $57 million, based on a requested ROE of 10.6%. The application is inclusive of a request seeking recovery of DPL's regulatory assets associated with its AMI program over a five year period, which was later modified to 10 years, supported by evidence demonstrating that the benefits of the AMI program exceed the costs on a present value basis. Any adjustments to rates approved by the MDPSC are expected to take effect in February 2017. DPL cannot predict how much of the requested increase the MDPSC will approve. In addition to the proposed rate increase, DPL is proposing to continue its Grid Resiliency Program initially approved in September 2013 in connection with DPL's electric distribution rate case filed in February 2013. Under the Grid Resiliency Program, DPL is authorized to receive recovery of specific investments as the assets are placed in service through the Grid Resiliency Charge. In connection with the Grid Resiliency Program, DPL proposes to accelerate improvement to priority feeders and install single-phase reclosing fuse technology by investing $4.6 million a year for two years for a total of $9.2 million. DPL cannot predict whether the MDPSC will approve a continuation of DPL's Grid Resiliency Program proposal.

2015 Maryland Electric and Natural Gas Distribution Base Rates (Exelon and BGE). On November 6, 2015, and as amended through the course of the proceeding, BGE filed for electric and natural gas base rate increases with the MDPSC, ultimately requesting annual increases of $116 million and $78 million, respectively, of which $104 million and $37 million were related to recovery of electric and natural gas smart grid initiative costs, respectively. BGE also proposed to recover an annual increase of approximately $30 million for Baltimore City underground conduit fees through a surcharge.

On June 3, 2016, the MDPSC issued an order in which the MDPSC found compelling evidence to conclude that BGE's smart grid initiative overall was cost beneficial to customers. However, the June 3 order contained several cost disallowances and adjustments, including not allowing BGE to defer or recover through a surcharge the $30 million increase in annual Baltimore City underground conduit fees. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions including the decision associated with the Baltimore City underground conduit fees. OPC also subsequently filed for a petition for rehearing of the June 3 order.

On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative. Through the combination of the orders, the MDPSC authorized electric and natural gas rate increases of $44 million and $48 million, respectively, and an allowed ROE for the electric and natural gas distribution businesses of 9.75% and 9.65%, respectively. The new electric and natural gas base rates took effect for service rendered on or after June 4, 2016. However, MDPSC's July 29 order on the petition on rehearing still did not allow BGE to defer or recover through a surcharge the increase in Baltimore City underground conduit fees.

On August 26, 2016, BGE filed an appeal of the MDPSC's orders with the Circuit Court for Baltimore County. On August 29, 2016, the residential consumer advocate also filed an appeal of the

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MDPSC's order but with the Circuit Court for Baltimore City. On November 15, 2016, Baltimore County Circuit Court issued an order deciding that the cases should be consolidated and should proceed in Baltimore County Circuit Court. However, on January 9, 2017, BGE filed to withdraw its appeal of the MDPSC's orders and on January 10, 2017, the residential consumer advocate filed to withdraw its appeal as well. Refer to the Smart Meter and Smart Grid Investment disclosure below for further details on the impact of the ultimate disallowances contained in the orders to BGE.

Cash Working Capital Order (Exelon and BGE). On November 17, 2016, the MDPSC rendered a decision in the proceeding to review BGE's request to recover its cash working capital (CWC) requirement for its Provider of Last Resort service, also known as Standard Offer Service (SOS), as well as other components that make up the Administrative Charge, the mechanism that enables BGE to recover all of its SOS-related costs. The Administrative Charge is now comprised of five components: CWC, uncollectibles, incremental costs, return, and an administrative adjustment, which is an adder to the utility's SOS rate to act as a proxy for retail suppliers' costs. The Commission accepted BGE positions on recovery of CWC and pass-through recovery of BGE's actual uncollectibles and incremental costs. The order also grants BGE a modest return on the SOS. The Commission ruled that the level of the administrative adjustment will be determined in BGE's next rate case. On December 16, 2016, MDPSC Staff requested clarification concerning the amount of return on the SOS awarded to BGE and on December 19, 2016, the residential consumer advocate sought rehearing of the return awarded. On January 24, 2017, the MDPSC issued an order denying the MDPSC Staff request for clarification and the residential consumer advocate request for rehearing.

2014 Maryland Electric and Gas Distribution Base Rates (Exelon and BGE). On July 2, 2014, and as amended on September 15, 2014, BGE filed for electric and gas base increases with the MDPSC, ultimately requesting increases of $99 million and $68 million, respectively.

On October 17, 2014, BGE filed with the MDPSC a unanimous settlement agreement (the Settlement Agreement) reached with all parties to the case under which it would receive an increase of $22 million in electric base rates and an increase of $38 million in gas base rates. The Settlement Agreement establishes new depreciation rates which have the effect of decreasing annual depreciation expense by approximately $20 million, primarily for electric. On December 4, 2014, the Public Utility Law Judge issued a proposed order approving the Settlement Agreement without modification, which became a final order on December 12, 2014. The approved distribution rate order authorizing BGE to increase electric and gas distribution rates became effective for services rendered on or after December 15, 2014.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and natural gas smart meters at an expected total cost of $480 million of which $200 million was funded by SGIG. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. Refer to AMI programs in the Regulatory Assets and Liabilities section below for further details.

As part of the 2015 electric and natural gas distribution rate case filed on November 6, 2015, BGE sought recovery of its smart grid initiative costs, supported by evidence demonstrating that BGE had, in fact, implemented a cost-beneficial advanced metering system. On June 3, 2016, the MDPSC issued an order concluding that the smart grid initiative overall is cost beneficial to its customers. However, the June 3 order contained several cost disallowances and adjustments including disallowances of certain program and meter installation costs and denial of recovery of any return on unrecovered costs for

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non-AMI meters replaced under the program. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions and change certain of the cost disallowances and adjustments to enable BGE to defer those costs for recovery through future electric and natural gas rates. The residential consumer advocate also subsequently filed for a petition for rehearing of the June 3 order. On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative. On August 26, 2016, BGE filed an appeal of the MDPSC's orders with the Circuit Court for Baltimore County. On August 29, 2016, the residential consumer advocate also filed an appeal of the MDPSC's order but with the Circuit Court for Baltimore City. On November 15, 2016, Baltimore County Circuit Court issued an order deciding that the cases should be consolidated and should proceed in Baltimore County Circuit Court. However, on January 9, 2017, BGE filed to withdraw its appeal of the MDPSC's orders and on January 10, 2017, the residential consumer advocate filed to withdraw its appeal as well.

As a combined result of the MDPSC orders, BGE recorded a $52 million charge to Operating and maintenance expense in Exelon's and BGE's Consolidated Statements of Operations and Comprehensive Income reducing certain regulatory assets and other long-lived assets. Pursuant to the combined MDPSC orders, BGE also reclassified $54 million of non-AMI plant costs from Property, plant and equipment, net to Regulatory assets on Exelon's and BGE's Consolidated Balance Sheets as of December 31, 2016.

2013 Maryland Electric and Gas Distribution Base Rates (Exelon and BGE). On May 17, 2013, and as amended on August 23, 2013, BGE filed for electric and natural gas base increases with the MDPSC. In addition to these requested rate increases, BGE's application also included a request for recovery of incremental capital expenditures and operating costs associated with BGE's proposed short-term reliability improvement plan (the ERI initiative) in response to a MDPSC order through a surcharge separate from base rates.

On December 13, 2013, the MDPSC issued an order authorizing BGE to recover through a surcharge mechanism costs associated with five ERI initiative programs designed to accelerate electric reliability improvements premised upon the condition that the MDPSC approve specific projects in advance of cost recovery. As of December 31, 2016, BGE has received approval of its updated surcharge filings three times for rates to be effective in 2014, 2015 and 2016.

In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE's 2013 electric and natural gas distribution rate cases. The residential consumer advocate filed its related legal memorandum on August 22, 2014, challenging the MDPSC's approval of the ERI initiative surcharge. BGE submitted a response to the appeal on October 15, 2014, and a hearing was held on November 17, 2014. On October 26, 2015, the Circuit Court for Baltimore City issued an order affirming the MDPSC decision. However, on November 30, 2015, the residential consumer advocate filed an appeal of the Circuit Court's decision with the Maryland Court of Special Appeals. On March 7, 2016, the consumer advocate withdrew its appeal and no further action is expected.

MDPSC New Generation Contract Requirement (Exelon, Generation, BGE, PHI, Pepco and DPL). On April 12, 2012, the MDPSC issued an order that requires BGE, Pepco and DPL (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process to build one new power plant in the range of 650 to 700 MWs beginning in 2015, in amounts proportional to their relative SOS loads. Under the terms of the order, the winning bidder was to construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an

expected commercial operation date of June 1, 2015, and each of the Contract EDCs was to recover its costs associated with the contract through surcharges on its respective SOS customers.

In response to a complaint filed by a group of generating companies in the PJM region, on September 30, 2013, the U.S. District Court for the District of Maryland issued a ruling that the MDPSC's April 2012 order violated the Supremacy Clause of the U.S. Constitution by attempting to regulate wholesale prices. In contrast, on October 1, 2013, in response to appeals filed by the Contract EDCs and other parties, the Maryland Circuit Court for Baltimore City upheld the MDPSC's orders requiring the Contract EDCs to enter into the contracts.

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. In November 2013 both the winning bidder and the MDPSC appealed the Federal district court decision to the U.S. Court of Appeals for the Fourth Circuit, which affirmed the lower Federal court ruling. On November 26, 2014, both the winning bidder and the MDPSC petitioned the U.S. Supreme Court to consider hearing an appeal of the Fourth Circuit decision. On October 19, 2015, the U.S. Supreme Court agreed to review the decision. On April 19, 2016, the U.S. Supreme Court unanimously affirmed the Fourth Circuit's ruling upholding the Federal district court's decision.

The decision of the Maryland Circuit Court was appealed to the Maryland Court of Special Appeals and was stayed pending decision by the U.S. Supreme Court. On August 1, 2016, the Contract EDCs submitted a filing requesting that the MDPSC take notice of the U.S. Supreme Court's decision, and notifying the MDPSC that the Contract EDCs will dismiss their appeal pending at the Maryland Court of Special Appeals. On September 14, 2016, the Maryland Court of Special Appeals dismissed the pending appeal and the matter is considered closed.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 requiring BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improve reliability and grid resiliency that were due at various times before August 30, 2013.

On September 3, 2013, BGE filed a comprehensive long term assessment examining potential alternatives for improving the resiliency of the electric grid and a staffing analysis reviewing historical staffing levels as well as forecasting staffing levels necessary under various storm scenarios. During the summer of 2014, an evaluation of the reports filed by BGE and other Maryland utilities was undertaken by consultants on behalf of the MDPSC and MDPSC Staff. The MDPSC Staff also proposed standards for reliability during major events and estimated times of restoration as well as undertaking an evaluation of performance-based ratemaking principles and methodologies that would more directly and transparently align reliable service with the utilities' distribution rates and that reduce returns or otherwise penalize sub-standard performance. The MDPSC held hearings in September 2014. BGE currently cannot predict the outcome of these proceedings, which may result in increased capital expenditures and operating costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In 2013, legislation intended to accelerate gas infrastructure replacements in Maryland was signed into law. The law established a mechanism, separate from base rate proceedings, for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects incurred after June 1, 2013. The monthly surcharge and infrastructure replacement costs must be approved by the MDPSC and are subject to a cap and require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in

a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation.

On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On July 1, 2016, BGE filed an amendment to its infrastructure replacement plan, which the MDPSC conditionally approved in an order dated November 23, 2016. The revised surcharge reflecting the costs of the amendment became effective January 1, 2017. On December 2, 2016, BGE filed a surcharge update to be effective February 1, 2017, including a true-up of cost estimates included in the 2016 surcharge, along with its 2017 project list and projected capital estimates of $131 million to be included in the 2017 surcharge calculation. The MDPSC subsequently approved BGE's 2017 project list and the proposed surcharge for 2017, which included the 2016 surcharge true-up. As of December 31, 2016, BGE recorded a regulatory liability of $2 million, representing the difference between the surcharge revenues and program costs.

In 2014, the residential consumer advocate in Maryland appealed MDPSC's decision on BGE's infrastructure replacement plan and associated surcharge with the Baltimore City Circuit Court, who affirmed the MDPSC's decision. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court. During the third quarter of 2015, the residential consumer advocate, MDPSC and BGE filed briefs. Oral argument in this matter was held before the Court of Special Appeals on November 3, 2015. On January 28, 2016, the Maryland Court of Special Appeals issued a decision affirming the MDPSC's decision. As the residential consumer advocate did not appeal the decision of the Court of Special Appeals, the matter is now closed.

Delaware Regulatory Matters

Gas Cost Rates. (Exelon, PHI and DPL) DPL makes an annual GCR filing with the DPSC for the purpose of allowing DPL to recover natural gas procurement costs through customer rates. In August 2016, DPL made its 2016-2017 GCR filing. The rates proposed in the 2016-2017 GCR filing would result in a GCR increase of approximately 14%. On September 20, 2016, the DPSC issued an order allowing DPL to place the new rates into effect on November 1, 2016, subject to refund and pending final DPSC approval.

2016 Delaware Electric and Natural Gas Distribution Base Rates (Exelon, PHI and DPL). On May 17, 2016, DPL filed an application with the DPSC to increase its annual electric and natural gas distribution base rates by $63 million and $22 million, respectively, based on a requested ROE of 10.6%. While the DPSC is not required to issue a decision on the application within a specified period of time, Delaware law allowed DPL to put into effect $2.5 million of each of the rate increases two months after filing the applications which were effective July 16, 2016. On December 1, 2016, the DPSC approved that an additional $30 million in electric distribution base rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order, and an additional $10 million in gas base rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order.

2013 Delaware Electric Distribution Base Rates (Exelon, PHI and DPL). In March 2013, and as amended on September 20, 2013, DPL filed for an electric distribution base rate increase with the DPSC, ultimately requesting an annual increase of $39 million.

In August 2014, the DPSC issued a final order in DPL's 2013 electric distribution rate case for an annual increase of $15 million and an ROE of 9.7%. Rates became effective on May 1, 2014.

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In September 2014, DPL filed an appeal with the Delaware Superior Court of the DPSC's August 2014 order in this proceeding, seeking the court's review of the DPSC's decision relating to the recovery of costs associated with one component of employee compensation, certain retirement benefits and credit facility expenses. The Division of the Public Advocate filed a cross-appeal in September 2014, pertaining to the treatment of a prepaid pension expense and other postretirement benefit obligations in base rates. Under the Settlement Agreement related to the Merger, the parties agreed to suspend the appeal and, upon consummation of the Merger, to the withdrawal of the appeal and the cross-appeal with prejudice. In accordance with the settlement, on April 13, 2016, the parties filed a Stipulation of Dismissal with the court to dismiss the appeal and the cross-appeal, at which time the matter was closed.

District of Columbia Regulatory Matters

2016 District of Columbia Electric Distribution Base Rates (Exelon, PHI and Pepco). On June 30, 2016, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $86 million, which was updated to $82 million on October 14, 2016, and further updated to approximately $77 million on February 1, 2017, based on a requested ROE of 10.6%. The DCPSC has issued a procedural schedule indicating a final decision will be issued by July 25, 2017. Any adjustments to its rates approved by the DCPSC are expected to take effect soon thereafter. Pepco cannot predict how much of the requested increase the DCPSC will approve.

On April 18, 2016, a party to a separate DCPSC proceeding filed a motion to suspend Pepco's bill stabilization adjustment (BSA), which decouples distribution revenues from utility customers from the amount of electricity delivered. On September 9, 2016, the DCPSC denied the party's motion and determined that the appropriate forum in which to determine whether the BSA continues to be just and reasonable is in Pepco's rate case proceeding. In addition, the DCPSC stated that it was putting Pepco on notice that all funds collected for the BSA from January 2015 to the issuance of a decision in the rate case proceeding are subject to refund should the DCPSC determine that such funds were not justly or reasonably collected. On November 22, 2016, following Pepco's October 7, 2016 request for reconsideration of the order, the DCPSC issued an order stating that its September 9, 2016 order was not final and confirming that issues related to the BSA, including potential remedial actions, would be addressed in Pepco's rate case. Pepco cannot predict the outcome of this matter or the impact of a refund if ordered by the DCPSC.

District of Columbia Power Line Undergrounding Initiative (Exelon, PHI and Pepco). In May 2014, the Council of the District of Columbia enacted the Electric Company Infrastructure Improvement Financing Act of 2014 (the Improvement Financing Act), which provided enabling legislation for the District of Columbia Power Line Undergrounding (DC PLUG) initiative which would selectively place underground some of the District of Columbia's most outage-prone power lines.

The Improvement Financing Act provides that: (i) Pepco is to fund approximately $500 million of the estimated cost to complete the DC PLUG initiative, recovering those costs through a volumetric surcharge on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the DC PLUG initiative cost is to be financed by the District of Columbia's issuance of securitized bonds, which bonds will be repaid through a volumetric surcharge (the DDOT surcharge) on the electric bills of Pepco District of Columbia customers that Pepco will remit to the District of Columbia; and (iii) the remaining costs up to $125 million are to be covered by the existing capital projects program of the District of Columbia Department of Transportation (DDOT). Pepco will not earn a return on or a return of the cost of the assets funded with the proceeds of the securitized bonds or assets that are constructed by DDOT under its capital projects program, but ownership and responsibility for the operation and maintenance of such assets will be transferred to Pepco for a nominal amount.

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In June 2014, Pepco and DDOT filed a Triennial Plan related to the construction of selected underground feeders in the District of Columbia. In August 2014, Pepco filed an application for the issuance of a financing order to provide for the issuance of the District's bonds. In March 2016, the DCPSC's orders approving the Triennial Plan and the application for financing were upheld upon the resolution of appeals that had been filed with the District of Columbia Court of Appeals. In compliance with the Improvement Financing Act, on September 30, 2016, Pepco and DDOT filed a Second Triennial Plan. Recognizing the delays to the First Triennial Plan, Pepco and DDOT requested that the DCPSC hold the Second Triennial Plan in abeyance, and the DCPSC granted this request by order dated October 27, 2016.

In June 2015, an agency of the federal government served by Pepco asserted that the DDOT surcharge constitutes a tax on end users from which the federal government is immune. PHI is currently evaluating the assertion and the resolution of this matter will likely further delay implementation of the DC PLUG initiative.

New Jersey Regulatory Matters

2016 New Jersey Electric Distribution Base Rates (Exelon, PHI and ACE). On August 24, 2016, the NJBPU issued an order approving a stipulation of settlement among ACE, the New Jersey Division of Rate Counsel, NJBPU Staff and Unimin Corporation, and an increase of $45 million (before New Jersey sales and use tax) to its electric distribution base rates, with the new rates effective immediately. The stipulation of settlement provided that a determination on PowerAhead would be separated into a phase II of the rate proceeding and decided at a later date and the parties would seek to resolve the matter by the end of 2016, although resolution will most likely occur in the first quarter of 2017. PowerAhead includes capital investments to advance modernization of the electric grid through energy efficiency, increased distributed generation, and resiliency, focused on improving the distribution system's ability to withstand major storm events. ACE cannot predict if the NJBPU will approve the PowerAhead initiative.

Update and Reconciliation of Certain Under-Recovered Balances (Exelon, PHI and ACE). *O* n February 1, 2016, ACE submitted its 2016 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the non-utility generators and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE's uncollectible accounts.

As filed, the net impact of adjusting the charges as proposed would have been an overall annual rate increase of $9 million (revised to $19 million in April 2016, based upon an update for actuals through March 2016), including New Jersey sales and use tax.

On November 30, 2016, the NJBPU approved a stipulation of settlement entered into by the parties providing for an overall annual rate increase of $1 million effective January 1, 2017. This settlement included a credit of approximately $10 million to the Non-Utility Generation charge deferral balance and a credit of approximately $7 million to the Uncollectible deferral balance. These credits were directed to be applied to the deferral balances in an NJBPU order dated October 31, 2016. That order approved the Joint Recommendation for Settlement of the Most Favored Nation Provision, which was a condition of the merger between Exelon Corporation and Pepco Holdings, Inc. This rate increase will have no effect on ACE's operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism.

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On February 1, 2017, ACE submitted its 2017 annual petition with the NJBPU seeking to reconcile and update the same categories of charges and costs as set forth in its 2016 annual petition discussed above. The net impact of adjusting the charges as proposed is an overall annual rate decrease of approximately $29 million, including New Jersey Sales and Use Tax. The matter is pending at the NJBPU and will be updated for January through March 2017 actual data. ACE has requested that the NJBPU place the new rates into effect by June 1, 2017. There is no assurance that NJBPU will put final rates in effect by the requested date.

New York Regulatory Matters

New York Clean Energy Standard (Exelon, Generation). On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the CES, a component of a Tier 3 ZEC program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity as determined by the NYPSC. The New York State Energy Research and Development Authority (NYSERDA) will centrally procure the ZECs from eligible plants through a 12-year contract, to be administered in six two-year tranches, extending from April 1, 2017 through March 31, 2029. ZEC payments will be made to the eligible resources based upon the number of MWh produced, subject to specified caps and minimum performance requirements. The price to be paid for the ZECs under each tranche will be administratively determined using a formula based on the social cost of carbon as determined in 2016 by the federal government, subject to pricing adjustments designed to lower the ZEC price based on increase in underlying energy and capacity prices. The ZEC price for the first tranche has been set at $17.48 per MWh of production. Following the first tranche, the price will be updated bi-annually. Each Load Serving Entity (LSE) shall be required to purchase an amount of ZECs equivalent to its load ratio share of the total electric energy in the New York Control Area. Cost recovery from ratepayers shall be incorporated into the commodity charges on customer bills.

The NYPSC initially identified the three plants eligible for the ZEC program to include, for now, the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. As issued, the order also provided that the duration of the program beyond the first tranche was conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018. On November 18, 2016, the required contracts with NYSERDA were executed for Ginna and Nine Mile Point, in addition to Entergy's execution of the required contract for the FitzPatrick facility.

Several parties filed with the NYPSC requests for rehearing or reconsideration of the CES. Generation and CENG also filed a request for clarification, or in the alternative limited rehearing, that the condition limiting the duration of the program beyond the first tranche be limited to the eligibility of the FitzPatrick plant only and have no bearing on Ginna or Nine Mile Point's eligibility for the full 12-year duration. On December 15, 2016, the NYPSC approved Exelon's petition to clarify this condition and denied all petitions for rehearing of the CES. Parties have until mid-April to appeal to New York State court the denials of the requests for rehearing. In addition, one Petition seeking to invalidate the ZEC program was filed in New York State court on November 30, 2016, and amended on January 13, 2017, arguing that the NYPSC violated certain technical provisions of the State Administrative Procedures Act (SAPA) when adopting the ZEC program.

On October 19, 2016, a coalition of fossil generation companies filed a complaint in federal district court against the NYPSC alleging that the ZEC program violates certain provisions of the U.S. Constitution; specifically that the ZEC program interferes with FERC's jurisdiction over wholesale rates

and that it discriminates against out of state competitors. On December 9, 2016, Generation and CENG filed a motion to intervene in the case and to dismiss the lawsuit. The motion to intervene has been granted and the motion to dismiss is pending.

Other legal challenges remain possible, the outcomes of which remain uncertain. See Note 9—Early Nuclear Plant Retirements for additional information relative to Ginna and Nine Mile Point, and Note 4—Mergers, Acquisitions, and Dispositions for additional information on Generation's proposed acquisition of FitzPatrick.

Ginna Nuclear Power Plant Reliability Support Services Agreement (Exelon and Generation). In November 2014, in response to a petition filed by Ginna Nuclear Power Plant (Ginna) regarding the possible retirement of Ginna, the NYPSC directed Ginna and Rochester Gas & Electric Company (RG&E) to negotiate a Reliability Support Services Agreement (RSSA) to support the continued operation of Ginna to maintain the reliability of the RG&E transmission grid for a specified period of time. During 2015 and 2016, Ginna and RG&E made filings with the NYPSC and FERC for their approval of the proposed RSSA. Although the RSSA was still subject to regulatory approvals, on April 1, 2015, Ginna began delivering the power and capacity from the Ginna plant into the ISO-NY consistent with the technical provisions of the RSSA.

On March 22, 2016, Ginna submitted a compliance filing with FERC with revisions to the RSSA requested by FERC. On April 8, 2016, FERC accepted the compliance filing and on April 20, 2016, the NYPSC accepted the revised RSSA. Because all regulatory approvals for the RSSA have now been received, Generation began recognizing revenue based on the final approved pricing contained in the RSSA. Generation also recognized a one-time revenue adjustment in April 2016 of approximately $101 million representing the net cumulative previously unrecognized amount of revenue retroactive from the April 1, 2015 effective date through March 31, 2016. A 49.99% portion of the one-time adjustment will be removed from Generation's results of operations as a result of the noncontrolling interests in CENG.

The RSSA approved by the regulatory authorities has a term expiring on March 31, 2017, subject to possible extension in the event that RG&E needs additional time to complete transmission upgrades to address reliability concerns. In March 2016, RG&E notified Ginna that RG&E expects to complete the transmission upgrades prior to the RSSA expiration in March 2017 and will not need Ginna as an ongoing reliability solution after that date.

The approved RSSA requires Ginna to continue operating through the RSSA term. If Ginna did not plan to retire shortly after the expiration of the RSSA, Ginna was required to file a notice to that effect with the NYPSC no later than September 30, 2016. Under the terms of the RSSA, if Ginna continues to operate after June 14, 2017, Ginna would be required to make certain refund payments up to a maximum of $20 million to RG&E related to capital expenditures. On September 30, 2016, Ginna filed the required notice with the NYPSC of its intent to continue operating beyond the March 31, 2017 expiry of the RSSA, conditioned upon successful execution of an agreement between Ginna and NYSERDA for the sale of ZECs under the CES. As stated previously, on November 18, 2016 the required contract with NYSERDA was executed by Generation and CENG for Ginna. Subject to prevailing over any administrative or legal challenges, it is expected the CES will allow Ginna to continue to operate through the end of its current operating license in 2029. See Note 9—Early Nuclear Plant Retirements for additional discussion of Ginna.

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(Dollars in millions, except per share data unless otherwise noted)

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE). ComEd's, BGE's, Pepco's, DPL's and ACE's transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL, and ACE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd, BGE, Pepco, DPL, and ACE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd's, BGE's, Pepco's, DPL's and ACE's best estimate of the revenue requirement expected to be filed with the FERC for that year's reconciliation. The regulatory asset associated with transmission true-up is amortized to Operating revenues within their Consolidated Statements of Operations of Comprehensive Income as the associated amounts are recovered through rates. On December 13, 2016, BGE filed with the FERC to modify its FERC-approved formula to recover its existing regulatory asset and any future changes to its regulatory asset concerning various tax issues including certain deferred income taxes.

For each of the following years, the following total increases/(decreases) were included in ComEd's, BGE's, Pepco's, DPL's and ACE's electric transmission formula rate filings:

Annual Transmission Filings	ComEd			BGE		
	2016	2015	2014	2016	2015	2014
Initial revenue requirement increase	$ 90	$ 68	$ 36	$ 12	$ —	$ 9
Annual reconciliation increase (decrease)	4	18	(14)	3	(3)	5
Dedicated facilities increase [a]	—	—	—	13	13	3
Total revenue requirement increase	$ 94	$ 86	$ 22	$ 28	$ 10	$ 17
Allowed return on rate base [c]	8.47%	8.61%	8.62%	8.09%	8.46%	8.53%
Allowed ROE [d]	11.50%	11.50%	11.50%	10.50%	11.30%	11.30%
Effective date of rates	June 2016	June 2015	June 2014	June 2016	June 2015	June 2014

Annual Transmission Filings	Pepco			DPL			ACE		
	2016	2015	2014	2016	2015	2014	2016	2015	2014
Initial revenue requirement increase (decrease)	$ 2	$ 10	$ (9)	$ 8	$ 15	$ 4	$ 8	$ 10	$ 4
Annual reconciliation (decrease) increase	(10)	(3)	(1)	(10)	(1)	6	(14)	2	3
MAPP abandonment recovery (decrease) increase [b]	(15)	(2)	17	(12)	(2)	15	—	—	—
Total revenue requirement (decrease) increase	$ (23)	$ 5	$ 7	$ (14)	$ 12	$ 25	$ (6)	$ 12	$ 7
Allowed return on rate base [c]	7.88%	8.36%	8.60%	7.21%	7.80%	8.05%	7.83%	8.51%	8.66%
Allowed ROE [d]	10.50%	11.30%	11.30%	10.50%	11.30%	11.30%	10.50%	11.30%	11.30%
Effective date of rates [e]	June 2016	June 2015	June 2014	June 2016	June 2015	June 2014	June 2016	June 2015	June 2014

(a) BGE's transmission revenues include a FERC approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE.
(b) In 2012, PJM terminated the MAPP transmission line construction project planned for the Pepco and DPL service territories. Pursuant to a FERC approved settlement agreement, the abandonment costs associated with MAPP were being recovered in transmission rates over a three-year period that ended in May 2016.
(c) Represents to the weighted average debt and equity return on transmission rate bases.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(d) As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.5%, inclusive of a 50 basis point incentive adder for being a member of a regional transmission organization.
(e) The time period for any challenges to the annual transmission formula rate update flings expired with no challenges submitted.

PJM Transmission Rate Design and Operating Agreements (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO, BGE, Pepco, DPL and ACE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. A number of parties appealed to the U.S. Court of Appeals for the Seventh Circuit for review of the decision.

In August 2009, the court issued its decision affirming the FERC's order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above (Cost Allocation Issue) for further consideration by the FERC. On remand, FERC reaffirmed its earlier decision to socialize the costs of new facilities 500 kV and above. A number of parties filed appeals of these orders. In June 2014, the court again remanded the Cost Allocation Issue to FERC. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the Cost Allocation Issue. On June 15, 2016, a number of parties, including Exelon and the Utility Registrants filed an Offer of Settlement with FERC. Each state that is a party in this proceeding either signed, or will not oppose, the settlement. If the Settlement is approved, effective January 1, 2016, for the costs of the 500 kV facilities approved by the PJM Board on or after February 1, 2013, 50% will be socialized across PJM and 50% will be allocated according to an engineering formula that calculates the flows on the transmission facilities. The Settlement includes provisions for monthly credits or charges that are expected to be mostly refunded or recovered through customer rates over a 10-year period based on negotiated numbers for charges prior to January 1, 2016.

Exelon expects that the Settlement will not have a material impact on the results of operations, cash flows and financial position of Generation, ComEd, PECO, BGE, Pepco, DPL or ACE. The Settlement is subject to approval by FERC.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The Utility Registrants are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. The Utility Registrants will work with PJM to continue to evaluate the scope and timing of any required construction projects. The Utility Registrant's estimated commitments are as follows:

	Total	2017	2018	2019	2020	2021
ComEd	$ 97	$ 64	$ 28	$ 5	$—	$—
PECO	34	14	10	7	2	1
BGE	226	113	55	44	14	—
Pepco	104	6	39	40	19	—
DPL	63	47	16	—	—	—
ACE	93	36	39	18	—	—

Complaints at FERC Seeking to Mitigate Illinois and New York Programs Providing ZECs (Exelon and Generation). PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to remove the revenues it receives through a federal, state or other government-provided financial support program, resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new resources. Exelon has generally opposed policies that require subsidies or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid. Thus, Exelon has supported a MOPR as a means of minimizing the detrimental impact certain subsidized resources could have on capacity markets (such as the New Jersey (LCAPP) and Maryland (CfD) programs). However, in Exelon's view, MOPRs should not be applied to resources that receive compensation for providing superior reliability or environmental benefits.

On January 9, 2017, the Electric Power Supply Association (EPSA) filed two requests with FERC: one seeking to amend a prior complaint against PJM and another seeking expedited action on a pending NYISO compliance filing in an existing proceeding. Both filings allege that the relevant MOPR should be expanded to also apply to existing resources receiving ZEC compensation under the New York CES and Illinois ZES programs. Exelon has filed protests at FERC in response to each filing, arguing generally that ZEC payments provide compensation for an environmental attribute that is distinct from the energy and capacity sold in the FERC-jurisdictional markets, and therefore, are no different than other renewable support programs like the PTC and RPS that have generally not been subject to a MOPR. However, if successful, an expanded MOPR could result in mitigation of Generation's Quad Cities, Ginna, and Nine Mile Point facilities, which are expected to receive ZEC compensation, such that they would have an increased risk of not clearing in future capacity auctions and thus of no longer receiving capacity revenues during the respective ZEC programs. This would also impact the FitzPatrick facility that Generation is currently in the process of acquiring from Entergy. Any mitigation of these generating resources could have a material effect on Exelon's and Generation's future cash flows and results of operations. The timing of FERC's decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

Demand Response Resource Order (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). On May 23, 2014, the D.C. Circuit Court issued an opinion vacating the FERC Order No. 745 (D.C. Circuit Decision). Order No. 745 established uniform compensation levels for demand response resources that participate in the day ahead and real-time wholesale energy markets. Under Order No. 745, buyers in ISO and RTO markets were required to pay demand response resources the full Locational Marginal Price when the demand response replaced a generation resource and was

cost-effective. On January 25, 2016, the U.S. Supreme Court reversed the D.C. Circuit Court decision and remanded the matter to the D.C. Circuit Court. While Exelon cannot predict exactly how the D.C. Circuit Court will handle the matter on remand, Exelon does not expect there will be any significant change in how demand response resources have or will participate in and be paid by wholesale energy markets. Thus, Exelon does not anticipate that there will be any impact to the Registrants' results of operations or cash flows based on these proceedings.

New England Capacity Market Results (Exelon and Generation). On February 28, 2014, ISO-NE filed the results of its eighth capacity auction (covering the June 1, 2017 through May 31, 2018 delivery period). On June 27, 2014, the FERC issued a letter to ISO-NE noting that ISO-NE's February 28, 2014 filing was deficient and that ISO-NE must file additional information before the FERC can process the filing. ISO-NE filed the information on July 17, 2014, and the ISO-NE's filings became effective by operation of law pursuant to a notice issued by the secretary of FERC on September 16, 2014. Several parties sought rehearing of the secretary's notice which was effectively denied in October 2014 and have since appealed the matter to the D.C. Circuit Court. On October 25, 2016, the D.C. Circuit Court dismissed the appeal.

Operating License Renewals (Exelon and Generation). Generation has 40-year operating license from the NRC for each of its nuclear units. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC's review.

On December 9, 2014, Generation submitted an application to the NRC to extend the current operating licenses of LaSalle Units 1 and 2 by 20 years. On October 19, 2016, the NRC approved Generation's request to extend the operating licenses of LaSalle units 1 and 2 by 20 years to 2042 and 2043, respectively.

On August 29, 2012, Generation submitted a hydroelectric license application to FERC for a 46-year license for the Conowingo Hydroelectric Project (Conowingo). In connection with Generation's efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act with Maryland Department of the Environment (MDE) for Conowingo, Generation continues to work with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment. In addition, Generation continues to work with MDE and other Federal and Maryland state agencies to conduct and fund an additional sediment and nutrient monitoring study.

On August 7, 2015, US Fish and Wildlife Service of the US Department of the Interior (Interior) submitted its modified fishway prescription to FERC in the Conowingo licensing proceedings. On September 11, 2015, Exelon filed a request for an administrative hearing and proposed an alternative prescription to challenge Interior's preliminary prescription. On April 21, 2016, Exelon and Interior executed a Settlement Agreement resolving all fish passage issues between the parties. Accordingly, on April 22, 2016, Exelon withdrew its Request for a Trial-Type Hearing and Alternative Prescription. The financial impact of the Settlement Agreement is estimated to be $3 million to $7 million per year, on average, over the 46-year life of the new license, including both capital and operating costs. The actual timing and amount of these costs are not currently fixed and may vary significantly from year to year throughout the life of the new license. Resolution of the remaining issues relating to Conowingo involving various stakeholders may have a material effect on Exelon's and Generation's results of operations and financial position through an increase in capital expenditures and operating costs. As of December 31, 2016, $28 million of direct costs associated with Conowingo licensing efforts have been capitalized-to-date.

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Regulatory Assets and Liabilities (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE each prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

As a result of applying the acquisition method of accounting and pushing it down to the consolidated financial statements of PHI, certain regulatory assets and liabilities were established at Exelon and PHI to offset the impacts of fair valuing the acquired assets and liabilities assumed which are subject to regulatory recovery. In total, Exelon and PHI recorded a net $2.4 billion regulatory asset reflecting adjustments recorded as a result of the acquisition method of accounting. See Note 4—Mergers, Acquisitions and Dispositions for additional information.

Combined Notes to Consolidated Financial Statements—(Continued)
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The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE as of December 31, 2016 and December 31, 2015:

December 31, 2016	Exelon	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits	$ 4,162	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	2,016	75	1,583	98	260	171	38	51
AMI programs	701	164	49	230	258	174	84	—
Under-recovered distribution service costs	188	188	—	—	—	—	—	—
Debt costs	124	42	1	7	81	17	9	6
Fair value of long-term debt	812	—	—	—	671	—	—	—
Fair value of PHI's unamortized energy contracts	1,085	—	—	—	1,085	—	—	—
Severance	5	—	—	5	—	—	—	—
Asset retirement obligations	111	76	23	12	—	—	—	—
MGP remediation costs	305	278	26	1	—	—	—	—
Under-recovered uncollectible accounts	56	56	—	—	—	—	—	—
Renewable energy	260	258	—	—	2	—	—	2
Energy and transmission programs	89	23	—	38	28	6	5	17
Deferred storm costs	36	—	—	1	35	12	5	18
Electric generation-related regulatory asset	10	—	—	10	—	—	—	—
Rate stabilization deferral	7	—	—	7	—	—	—	—
Energy efficiency and demand response programs	621	—	1	285	335	250	85	—
Merger integration costs	25	—	—	10	15	11	4	—
Under-recovered revenue decoupling	27	—	—	3	24	21	3	—
COPCO acquisition adjustment	8	—	—	—	8	—	8	—
Recoverable workers compensation and long-term disability costs	34	—	—	—	34	34	—	—
Vacation accrual	31	—	7	—	24	—	14	10
Securitized stranded costs	138	—	—	—	138	—	—	138
CAP arrearage	11	—	11	—	—	—	—	—
Removal costs	477	—	—	—	477	134	88	255
Other	49	7	9	5	29	22	5	4
Total regulatory assets	11,388	1,167	1,710	712	3,504	852	348	501
Less: current portion	1,342	190	29	208	653	162	59	96
Total noncurrent regulatory assets	$10,046	$ 977	$1,681	$504	$ 2,851	$ 690	$289	$405

Combined Notes to Consolidated Financial Statements—(Continued)
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December 31, 2016	Exelon	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$ 47	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	2,607	2,169	438	—	—	—	—	—
Removal costs	1,601	1,324	—	141	136	18	118	—
Deferred rent	39	—	—	—	39	—	—	—
Energy efficiency and demand response programs	185	141	41	—	3	3	—	—
DLC program costs	8	—	8	—	—	—	—	—
Electric distribution tax repairs	76	—	76	—	—	—	—	—
Gas distribution tax repairs	20	—	20	—	—	—	—	—
Energy and transmission programs	134	60	56	—	18	8	5	5
Other	72	4	5	19	41	2	17	20
Total regulatory liabilities	4,789	3,698	644	160	237	31	140	25
Less: current portion	602	329	127	50	79	11	43	25
Total noncurrent regulatory liabilities	$4,187	$3,369	$ 517	$110	$ 158	$ 20	$ 97	$ —

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

December 31, 2015	Exelon	ComEd	PECO	BGE	*Predecessor* PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits	$3,156	$ —	$ —	$ —	$ 910	$ —	$ —	$ —
Deferred income taxes	1,616	64	1,473	79	214	137	36	41
AMI programs	399	140	63	196	267	180	87	—
Under-recovered distribution service costs	189	189	—	—	—	—	—	—
Debt costs	47	46	1	8	36	19	10	7
Fair value of long-term debt	162	—	—	—	—	—	—	—
Severance	9	—	—	9	—	—	—	—
Asset retirement obligations	108	67	22	19	1	1	—	—
MGP remediation costs	286	255	30	1	—	—	—	—
Under-recovered uncollectible accounts	52	52	—	—	—	—	—	—
Renewable energy	247	247	—	—	6	—	1	5
Energy and transmission programs	84	43	1	40	33	9	11	13
Deferred storm costs	2	—	—	2	43	19	6	18
Electric generation-related regulatory asset	20	—	—	20	—	—	—	—
Rate stabilization deferral	87	—	—	87	—	—	—	—
Energy efficiency and demand response programs	279	—	1	278	401	289	111	1
Merger integration costs	6	—	—	6	—	—	—	—
Conservation voltage reduction	3	—	—	3	—	—	—	—
Under-recovered revenue decoupling	30	—	—	30	14	10	4	—
COPCO acquisition adjustment	—	—	—	—	—	—	13	—
Workers compensation and long-term disability costs	—	—	—	—	31	31	—	—
Vacation accrual	6	—	6	—	23	—	14	9
Securitized stranded costs	—	—	—	—	202	—	—	202
CAP arrearage	7	—	7	—	—	—	—	—
Removal costs	—	—	—	—	369	92	69	208
Other	29	10	13	3	32	14	9	8
Total regulatory assets	6,824	1,113	1,617	781	2,582	801	371	512
Less: current portion	759	218	34	267	305	140	72	98
Total noncurrent regulatory assets	$6,065	$ 895	$1,583	$514	$ 2,277	$ 661	$299	$414

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

December 31, 2015	Exelon	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$ 94	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	2,577	2,172	405	—	—	—	—	—
Removal costs	1,527	1,332	—	195	150	21	129	—
Energy efficiency and demand response programs	92	52	40	—	1	—	—	1
DLC program costs	9	—	9	—	—	—	—	—
Electric distribution tax repairs	95	—	95	—	—	—	—	—
Gas distribution tax repairs	28	—	28	—	—	—	—	—
Energy and transmission programs	131	53	60	18	27	16	19	8
Over-recovered revenue decoupling	1	—	—	1	—	—	—	—
Other	16	5	2	8	35	7	12	16
Total regulatory liabilities	4,570	3,614	639	222	213	44	160	25
Less: current portion	369	155	112	38	66	15	49	18
Total noncurrent regulatory liabilities	$4,201	$3,459	$ 527	$184	$ 147	$ 29	$111	$ 7

Pension and other postretirement benefits. As of December 31, 2016, Exelon had regulatory assets of $3,075 and regulatory liabilities of $47 million related to ComEd's and BGE's portion of deferred costs associated with Exelon's pension plans and ComEd's, PECO's and BGE's portion of deferred costs associated with Exelon's other postretirement benefit plans. PECO's pension regulatory recovery is based on cash contributions and is not included in the regulatory asset (liability) balances. The regulatory asset (liability) is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses (gains) attributable to Exelon's pension and other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd, PECO and BGE will recover these costs through base rates as allowed in their most recently approved regulated rate orders. The pension and other postretirement benefit regulatory asset balance includes a regulatory asset established at the date of the Constellation merger related to BGE's portion of the deferred costs associated with legacy Constellation's pension and other postretirement benefit plans. The BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the Constellation merger. As of December 31, 2016, the pension and other postretirement benefits regulatory asset at Exelon includes regulatory assets of $1,087 million established at the date of the PHI Merger related to unrecognized costs that are probable of regulatory recovery. The regulatory assets are amortized and recovered over periods from 3 to 15 years, depending on the underlying component. Pepco, DPL and ACE are currently recovering these costs through base rates. Pepco, DPL and ACE are not earning a return on the recovery of these costs in base rates. See Note 17—Retirement Benefits for additional detail. No return is earned on Exelon's regulatory asset.

Deferred income taxes. These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded under GAAP. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with the authoritative guidance for accounting for certain types of regulation and income taxes, include the deferred tax effects associated principally with accelerated depreciation accounted for in accordance with the ratemaking policies of the ICC, PAPUC and MDPSC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For BGE, this amount includes the impacts of a reduction in the deductibility, for Federal income

tax purposes, of certain retiree health care costs pursuant to the March 2010 Health Care Reform Acts. For BGE, these additional income taxes are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. For PECO, this amount includes the impacts of electric and gas distribution repairs in the deductibility pursuant to PUC's 2010 and 2015 rate case settlement agreements. As of December 31, 2016, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of $22 million, $38 million, $31 million, $20 million and $19 million for ComEd, BGE, Pepco, DPL and ACE, respectively. As of December 31, 2015, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of $15 million, $16 million, $26 million, $18 million and $15 million for ComEd, BGE, Pepco, DPL and ACE, respectively. See Note 15—Income Taxes, Note 17—Retirement Benefits, and the Transmission Formula Rate section above for additional information. ComEd, PECO, BGE, Pepco, DPL and ACE are not earning a return on the regulatory asset in rates. The recovery period is over the life of the associated assets.

AMI programs. For ComEd, this amount represents meter costs associated with ComEd's AMI pilot program approved in ComEd's 2010 rate case. The recovery periods for these meter costs are through January 2020. As of December 31, 2016 and December 31, 2015, ComEd had regulatory assets of $162 million and $137 million, respectively, related to accelerated depreciation costs resulting from the early retirements of non-AMI meters, which will be amortized over an average ten year period pursuant to the ICC approved AMI Deployment plan. ComEd is earning a return on the regulatory asset. For PECO, this amount primarily represents accelerated depreciation on PECO's non-AMI meter assets over a 10-year period ending December 31, 2020. Recovery of smart meter costs are reflected in base rates effective January 1, 2016. For BGE, this amount represents AMI costs associated with the installation of smart meters and the early retirement of legacy meters. The incremental costs associated with the installation, along with depreciation, amortization, and an appropriate return, had been building in a regulatory asset since the MDPSC approved the comprehensive smart grid initiative for BGE in August 2010 through approval of the program in BGE's rate order issued June, 2016. As of December 31, 2016, the balance of BGE's regulatory asset was $230 million, which consists of three major components, including $144 million of unamortized incremental deployment costs of the AMI program, $54 million of unamortized costs of the non-AMI meters replaced under the program, and $32 million related to post-test year incremental program deployment costs incurred prior to when approval became effective June 2016. The incremental deployment costs for the AMI program and the non-AMI meter components of the regulatory asset are being amortized and recovered through rates over a 10-year period, which began in June, 2016. A return on the $144 million incremental deployment costs for the AMI program portion of the regulatory asset is included in rates. The $54 million portion of the regulatory asset related to the unamortized cost of the retired non-AMI meters is not earning a return in rates. The $32 million portion related to post-test year incremental program deployment costs have not yet been approved for recovery by the MDPSC and are not currently earning a return for financial reporting purposes. For PHI, this amount represents AMI costs associated with the installation of smart meters and the early retirement of legacy meters throughout the service territories for Pepco and DPL. An AMI program has not been approved by the NJBPU for ACE in New Jersey. Pepco has received approval for recovery of deferred AMI program costs from the DCPSC and the MDPSC in its DC and Maryland service territories. Pepco does earn a return on the AMI deployment costs, but not on the early retirement of legacy meters. DPL has received approval for recovery of deferred AMI program costs from the DPSC in its Delaware service territory and has received a proposed order from the MDPSC approving recovery of deferred AMI program costs in its Maryland service territory. As of December 31, 2016, the DPL deferred AMI program costs pending finalization of the proposed order from the MDPSC are $41 million, of which $14 million relates to retired legacy meters which are not earning a return.

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Under-recovered distribution services costs. These amounts represent under recoveries related to electric distribution services costs recoverable through EIMA's performance based formula rate. Under (over) recoveries for the annual reconciliations are recoverable (refundable) over a one-year period and costs for certain one-time events, such as large storms, are recoverable over a five-year period. ComEd earns and pays a return on under and over-recovered costs, respectively. As of December 31, 2016, the regulatory asset was comprised of $134 million for the 2015 to 2016 annual reconciliations and $54 million related to significant one-time events, including $20 million in deferred storm costs and $11 million of Constellation and PHI merger and integration related costs, and $23 million of smart meter related costs. ComEd's 2015 annual reconciliation regulatory asset includes a reduction of $8 million related to a ComEd-proposed refund to customers for the impact of changing its OSHA recordable rate for 2014 and 2015. As of December 31, 2015, the regulatory asset was comprised of $142 million for the 2014 and 2015 annual reconciliations and $47 million related to significant one-time events, including $36 million in deferred storm costs and $11 million of Constellation merger and integration related costs.

Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's recoverable losses on reacquired long-term debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding or the life of the original issuance retired. These debt costs are used in the determination of the weighted cost of capital applied to rate base in the rate-making process. ComEd and BGE are not earning a return on these costs. Recovery of these costs will continue through 2038 for ComEd and BGE. PECO, Pepco, DPL and ACE are earning a return on the premium of the cost of the reacquired debt through base rates. The regulatory asset for Pepco, DPL and ACE was eliminated at Exelon and PHI as part of acquisition accounting.

Fair value of long-term debt. These amounts represent the unamortized regulatory assets recorded at Exelon for the difference between the carrying value and fair value of the long-term debt of BGE as of the Constellation merger date based on the MDPSC practice to allow BGE to recover its debt costs through rates and at Exelon and PHI for the difference between carrying value and fair value of long-term debt of Pepco, DPL and ACE as of the PHI Merger date. Exelon is amortizing the regulatory asset and the associated fair value over the life of the underlying debt and is not earning a return on the recovery of these costs.

Fair value of PHI's unamortized energy contracts. These amounts represent the regulatory asset recorded at Exelon and PHI offsetting the fair value adjustments related to Pepco's, DPL's and ACE's electricity and natural gas energy supply contracts recorded at PHI as of the PHI Merger date. Pepco, DPL and ACE are allowed full recovery of the costs of these contracts through their respective rate making processes.

Severance. For BGE, these costs represent deferred severance costs associated with a 2010 workforce reduction that were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. Additionally, costs associated with the 2012 BGE voluntary workforce reduction were deferred in 2012 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period that began in July 2012. BGE is earning a regulated return on the regulatory asset included in base rates.

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Asset retirement obligations. These costs represent future legally required removal costs associated with existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd and BGE will recover these costs through future depreciation rates and will earn a return on these costs once the removal activities have been performed. The recovery period will be over the expected life of the related assets. See Note 16—Asset Retirement Obligations for additional information.

MGP remediation costs . ComEd is allowed recovery of these costs under ICC approved rates. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures, currently estimated to be completed in 2022 for both ComEd and PECO. ComEd and PECO are not earning a return on the recovery of these costs. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. BGE is earning a return on this regulatory asset and these costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. The recovery period for the 10-year period that began January 2006 was extended for an additional 24 months, in accordance with the MDPSC approved 2014 electric and natural gas distribution rate case order. See Note 24—Commitments and Contingencies for additional information.

Under recovered uncollectible accounts. These amounts represent the difference between ComEd's annual uncollectible accounts expense and revenues collected in rates through an ICC-approved rider. The difference between net uncollectible account charge-offs and revenues collected through the rider each calendar year is recovered or refunded over a twelve-month period beginning in June of the following calendar year. ComEd does not earn a return on these under recoveries.

Renewable energy. In December 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs through 2032 in order to meet a portion of its obligations under the Illinois RPS. Delivery under the contracts began in June 2012. Since the swap contracts were deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). Recovery of these costs will continue through 2032. The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy at the market price and the contracted price.

Energy and transmission programs. These amounts represent under (over) recoveries related to energy and transmission costs recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. Under (over) recoveries are recoverable (refundable) over a one-year period or less. ComEd earns a return or interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2016, ComEd's regulatory asset of $23 million included $15 million associated with transmission costs recoverable through its FERC approved formula rate and $8 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2016, ComEd's regulatory liability of $60 million included $30 million related to over-recovered energy costs and $30 million associated with revenues received for renewable energy requirements. As of December 31, 2015, ComEd's regulatory asset of $43 million included $5 million

related to under-recovered energy costs, $31 million associated with transmission costs recoverable through its FERC-approved formula rate tariff, and $7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2015, ComEd's regulatory liability of $53 million included $29 million related to over-recovered energy costs and $24 million associated with revenues received for renewable energy requirements. See *Transmission Formula Rate* above for further details.

The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO's GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. In addition, the DSP Program costs are presented on a net basis with PECO's GSA under (over)-recovered energy costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO's PAPUC-approved DSP programs for the procurement of electric supply. The filings and procurements of these DSP Programs are recoverable through the GSA over each respective term. DSP II and DSP III each have a 24-month term that began June 1, 2013 and June 1, 2015, respectively. The independent evaluator costs associated with conducting procurements are recoverable over a 12-month period after the PAPUC approves the results of the procurements. PECO is not earning a return on these costs. Certain costs included in PECO's original DSP program related to information technology improvements were recovered over a 5-year period that began January 1, 2011. PECO earns a return on the recovery of information technology costs. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2016, PECO's regulatory liability of $56 million included $34 million related to over-recovered costs under the DSP program, $10 million related to over-recovered non-bypassable transmission service charges, $8 million related to the over-recovered natural gas costs under the PGC and $4 million related to over-recovered electric transmission costs. As of December 31, 2015, PECO's regulatory asset of $1 million related to under-recovered non-bypassable transmission service charges. As of December 31, 2015, PECO's regulatory liability of $60 million included $35 million related to over-recovered costs under the DSP program, $22 million related to the over-recovered natural gas costs under the PGC and $3 million related to the over-recovered electric transmission costs.

The BGE energy costs represent the electric supply, gas supply, and transmission related costs recoverable (refundable) from (to) customers under BGE's market-based SOS program, MBR program, and FERC approved transmission rates, respectively. BGE earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. BGE does not earn or pay interest to customers on under-recovered or over-recovered SOS and MBR costs. The recovery or refund period is a twelve-month period beginning in June of the following calendar year. As of December 31, 2016, BGE's regulatory asset of $38 million included $4 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $28 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval, and $3 million related to under-recovered natural gas costs. As of December 31, 2015, BGE's regulatory asset of $40 million included $12 million of costs associated with transmission costs recoverable through its FERC approved formula rate and $28 million related to under-recovered electric energy costs. As of December 31, 2015, BGE's regulatory liability of $18 million related to $14 million of over-recovered transmission costs and $5 million of over-recovered natural gas costs, offset by $1 million of abandonment costs to be recovered upon FERC approval.

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The Pepco energy costs represent the electric supply and transmission related costs recoverable (refundable) from (to) customers under Pepco's market-based SOS program and FERC approved transmission rates. Pepco earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. Pepco does not earn or pay interest to customers on under- or over-recovered SOS costs. The asset is being amortized and recovered over the life of the associated assets. As of December 31, 2016, Pepco's regulatory asset of $6 million related to under-recovered electric energy costs. As of December 31, 2016, Pepco's regulatory liability of $8 million included $5 million of over-recovered transmission costs and $3 million of over-recovered electric energy costs. As of December 31, 2015, Pepco's regulatory asset of $9 million included $5 million of transmission costs recoverable through its FERC approved formula rate and $4 million of recoverable abandonment costs. As of December 31, 2015, Pepco's regulatory liability of $16 million included $14 million of over-recovered transmission costs and $2 million of over-recovered electric energy costs.

The DPL energy costs represent the electric supply, gas supply, and transmission related costs recoverable (refundable) from (to) customers under DPL's market-based SOS program, GCR and FERC approved transmission rates. DPL earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. In Delaware, DPL earns interest on under-recovered costs and pays interest to customers on over-recovered SOS an GCR costs. In Maryland, DPL does not earn or pay interest to customers on under- or over-recovered SOS costs. The asset is being amortized and recovered over the life of the associated assets. As of December 31, 2016, DPL's regulatory asset of $5 million included $1 million of transmission costs recoverable through its FERC approved formula rate and $4 million of under-recovered electric energy costs. As of December 31, 2016, DPL's regulatory liability of $5 million included $2 million of over-recovered electric energy costs and $3 million of over-recovered transmission costs. As of December 31, 2015, DPL's regulatory asset of $11 million included $7 million of transmission costs recoverable through its FERC approved formula rate, $3 million of recoverable abandonment costs, and $1 million of under-recovered electric energy costs. As of December 31, 2015, DPL's regulatory liability of $19 million included $4 million related to the over-recovered natural gas costs under the GCR mechanism, $4 million of over-recovered electric energy costs, and $11 million of over-recovered transmission costs.

The ACE energy costs represent the electric supply and transmission related costs recoverable (refundable) from (to) customers under ACE's market-based BGS program and FERC approved transmission rates. ACE earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. ACE earns interest on under-recovered and pays interest to customers on over-recovered BGS costs. As of December 31, 2016, ACE's regulatory asset of $17 million included $6 million of transmission costs recoverable through its FERC approved formula rate and $11 million of under-recovered electric energy costs. As of December 31, 2016, ACE's regulatory liability of $5 million included $4 million of over-recovered transmission costs and $1 million of over-recovered electric energy costs. As of December 31, 2015, ACE's regulatory asset of $13 million included $2 million of transmission costs recoverable through its FERC approved formula rate and $11 million of under-recovered electric energy costs. As of December 31, 2015, ACE's regulatory liability of $8 million related to over-recovered transmission costs.

Deferred storm costs. In the MDPSC's March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. BGE earns a return on this regulatory asset and the original recovery period of five years was extended for an additional 25 months, in accordance with the MDPSC 2014 electric and natural gas distribution rate case order.

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For Pepco, DPL and ACE, amounts represent total incremental storm restoration costs incurred for repair work due to major storm events in 2016, 2015, 2012 and 2011, including the January 2016 winter storm Jonas for Pepco, June 2015 storm (for DPL and ACE), Hurricane Sandy, the June 2012 derecho, Hurricane Irene and the 2011 severe winter storm (for Pepco), that are recoverable from customers in the Maryland and New Jersey jurisdictions. Pepco's and DPL's costs related to Hurricane Sandy, the June 2012 derecho, Hurricane Irene and Pepco's costs related to the 2011 severe winter storm are being amortized and recovered from customers, each over a five-year period. However, in the November 2016 Pepco Maryland Case No. 9418 order, the Commission ruled that the remaining amortization for the Pepco Maryland February 2010 storm, the January 2011 storm and Hurricane Irene be extended for an additional three years. The reason for the extension was that since these assets would be fully amortized in 2017, Pepco would over-recover these costs if the rates in this case remained in effect beyond July 2017. The January 2017 PULJ report for DPL Maryland Case No. 9424 also recommended that amortization period for Hurricane Irene (DPL MD) be extended an additional three years as well. ACE's costs related to Hurricane Sandy, the June 2012 derecho and Hurricane Irene are being amortized and recovered from customers, each over a three-year period. PHI does not earn a return on these ACE regulatory assets.

Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. The portion of this regulatory asset that does not earn a regulated rate of return was $9 million as of December 31, 2016, and $19 million as of December 31, 2015. BGE will continue to amortize this amount through 2017.

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006 to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007 to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2016 and 2015, BGE recovered $81 million and $73 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007.

Energy efficiency and demand response programs. For ComEd, these amounts represent over recoveries related to ComEd's ICC-approved Energy Efficiency and Demand Response Plan. ComEd expects to refund these over recoveries in 2017. ComEd earns a return on the capital investment incurred under the program, but does not earn or pay a return or interest on under or over recoveries, respectively. For PECO, these amounts represent over recoveries of program costs related to both Phase II and Phase III of its PAPUC-approved EE&C Plan. PECO began recovering the costs of its Phase II and Phase III EE&C Plans through a surcharge in June 2013 and June 2016, respectively,

based on projected spending under the programs. Phase II of the program began on June 1, 2013 and expired on May 31, 2016. Phase III of the program began on June 1, 2016 and will expire on May 31, 2021. PECO does not earn (pay) interest on under (over) collections. For BGE, these amounts represent under (over) recoveries related to BGE's Smart Energy Savers Program ®, which includes both MDPSC-approved demand response and energy efficiency programs. For the BGE Peak Rewards SM demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Also included in the demand response program are customer bill credits related to BGE's Smart Energy Rewards program which began in July 2013 and are being recovered through the surcharge. Actual costs incurred in the energy efficiency program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

For Pepco, DPL and ACE, amounts represent recoverable costs associated with customer direct load control and energy efficiency and conservation programs in all jurisdictions that are being recovered from customers. These programs are designed to reduce customers' energy consumption. PHI earns a return on these regulatory assets.

Merger integration costs. These amounts include integration costs to achieve distribution synergies related to the Constellation merger transaction. As a result of the MDPSC's February 2013 rate order, BGE deferred $8 million related to non-severance merger integration costs incurred during 2012 and the first quarter of 2013. Of these costs, $4 million was authorized to be amortized over a 5-year period that began in March 2013. The recovery of the remaining $4 million was deferred. In the MDPSC's December 2013 rate order, BGE was authorized to recover the remaining $4 million and an additional $4 million of non-severance merger integration costs incurred during 2013. These costs are being amortized over a 5-year period that began in December 2013. BGE is earning a return on this regulatory asset included in base rates.

These amounts also include integration costs to achieve distribution synergies related to the PHI acquisition. As of December 31, 2016, BGE's regulatory asset of $10 million included $6 million of previously incurred PHI acquisition costs as authorized by the June 2016 rate case order. As of December 31, 2016, PHI's regulatory asset of $15 million represents previously incurred PHI acquisition costs expected to earn a return and be recovered in distribution rates in the Maryland service territories of Pepco and DPL.

Under (Over)-recovered electric and gas revenue decoupling. For BGE, these amounts represent the electric and gas distribution costs recoverable from or (refundable) to customers under BGE's decoupling mechanisms, which does not earn a rate of return and is being recovered over the life of the associated assets. As of December 31, 2016, BGE had a regulatory asset of $2 million related to under-recovered natural gas revenue decoupling and $1 million related to under-recovered electric revenue decoupling. As of December 31, 2015, BGE had a regulatory asset of $30 million related to under-recovered electric revenue decoupling and a regulatory liability of $1 million related to over-recovered natural gas revenue decoupling.

For Pepco and DPL, these amounts represents the electric distribution costs recoverable from customers under Pepco's Maryland and District of Columbia decoupling mechanisms and DPL's Maryland decoupling mechanism. Pepco and DPL earn a return on these regulatory assets.

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COPCO acquisition adjustment. On July 19, 2007, the MDPSC issued an order which provided for the recovery of a portion of DPL's goodwill. As a result of this order, $41 million in DPL goodwill was transferred to a regulatory asset. This item is being amortized from August 2007 through August 2018. DPL earns a return of 12.95% on these regulatory assets.

Recoverable workers compensation and long-term disability costs. These amounts represent accrued workers' compensation and long-term disability costs for Pepco, which are recoverable from customers when actual claims are paid to employees. Pepco is not earning a return on the recovery of these costs and the recovery period is over the life of the associated assets.

Vacation accrual. These amounts represent accrued vacation costs for PECO, DPL and ACE. PECO, DPL and ACE do not earn a return on these regulatory assets and the costs are recoverable from customers when actual payments are made to employees or when vacation is taken.

Securitized stranded costs. These amounts represent certain contract termination payments under a contract between ACE and an unaffiliated non-utility generator and costs associated with the regulated operations of ACE's electricity generation business that are no longer recoverable through customer rates (collectively referred to as "stranded costs"). The stranded costs are amortized over the life of Transition Bonds issued by Atlantic City Electric Transition Funding LLC (ACE Funding) to securitize the recoverability of these stranded costs. These bonds mature between 2017 and 2023. A customer surcharge is collected by ACE to fund principal and interest payments on the Transition Bonds. PHI earns a return on these regulatory assets.

CAP arrearage. These amounts represent the guaranteed recovery of PECO's previously incurred bad debt expense associated with the eligible CAP accounts receivable balances under the IPAF Program as provided by the 2015 electric distribution rate case settlement. These costs are amortized as recovery is received through a combination of customer payments over the duration of the five-year payment agreement term and rate recovery, including through future rate cases if necessary. PECO is not earning a return on this regulatory asset.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs for the Regulatory Agreement Units that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will be sufficient to fund the associated future decommissioning costs at the time of decommissioning. Exelon is not accruing interest on these costs. See Note 16—Asset Retirement Obligations for additional information.

Removal costs. These amounts represent funds ComEd, BGE, PHI, Pepco, DPL and ACE have received from customers through depreciation rates to cover the future non-legally required cost of removal of property, plant and equipment which reduces rate base for ratemaking purposes. This liability is reduced as costs are incurred. PHI, Pepco, DPL, and ACE have a regulatory asset which represents removal costs incurred in excess of amounts received from customers through depreciation rates recoverable from ratepayers. Pepco, DPL and ACE do not earn a return on these regulatory assets and the recovery period is over the life of the associated assets.

Deferred rent. Represents the regulatory liability recorded at Exelon and PHI for deferred rent related to a lease. The costs of the lease are recoverable through the ratemaking process at Pepco, DPL and ACE.

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DLC program costs. The DLC program costs include equipment, installation, and information technology costs necessary to implement the DLC Program under PECO's EE&C Phase I Plans. PECO received full cost recovery through Phase I collections and will amortize the costs as a credit to the income statement to offset the related depreciation expense during the same period through September 2025, which is the remaining useful life of the assets. PECO is not paying interest on these over-recovered costs.

Electric distribution tax repairs. PECO's 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits began being reflected in customer bills on January 1, 2012. PECO's 2015 electric distribution rate case settlement requires PECO to pay interest on the unamortized balance of the tax-effected catch-up deduction beginning January 1, 2016.

Gas distribution tax repairs. PECO's 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits began being reflected in customer bills on January 1, 2013. No interest will be paid to customers.

Capitalized Ratemaking Amounts Not Recognized (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

The following table illustrates our authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment that are not recognized for financial reporting purposes on our Consolidated Balance Sheets. These amounts will be recognized as revenues in our Consolidated Statements of Operations and Comprehensive Income in the periods they are billable to our customers.

					Successor			
	Exelon	ComEd (a)	PECO	BGE (b)	PHI	Pepco (b)	DPL (b)	ACE
December 31, 2016	$ 72	$ 5	$ —	$ 57	$ 10	$ 6	$ 4	$—

					Predecessor			
	Exelon	ComEd (a)	PECO	BGE (b)	PHI	Pepco (b)	DPL (b)	ACE
December 31, 2015	$ 55	$ 6	$ —	$ 49	$ 4	$ 1	$ 3	$—

(a) Reflects ComEd's unrecognized equity returns earned for ratemaking purposes on its under-recovered distribution services costs regulatory assets.
(b) BGE's, Pepco's and DPL's authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment on their respective AMI Programs.

Purchase of Receivables Programs (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

ComEd, PECO, BGE, Pepco, DPL and ACE are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia and New Jersey, to purchase certain receivables from retail electric and natural gas suppliers that participate in the utilities' consolidated billing. ComEd, BGE, Pepco and DPL purchase receivables at a discount primarily to recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables

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(Dollars in millions, except per share data unless otherwise noted)

at face value and is permitted to recover uncollectible accounts expense, including those from Third Party Suppliers, from customers through distribution rates. ACE purchases receivables at face value. ACE recovers all uncollectible accounts expense, including those from Third Party Suppliers, through the Societal Benefits Charge (SBC) rider, which includes uncollectible accounts expense as a component. The SBC is filed annually with the NJBPU. Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of those companies as of December 31, 2016 and December 31, 2015.

					Successor			
As of December 31, 2016	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Purchased receivables (c)	$ 313	$ 87	$ 72	$ 59	$ 95	$ 63	$ 10	$ 22
Allowance for uncollectible accounts (a)	(37)	(14)	(6)	(4)	(13)	(7)	(2)	(4)
Purchased receivables, net	$ 276	$ 73	$ 66	$ 55	$ 82	$ 56	$ 8	$ 18

					Predecessor			
As of December 31, 2015	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Purchased receivables (b)(c)	$ 229	$ 103	$ 67	$ 59	$ 100	$ 70	$ 11	$ 19
Allowance for uncollectible accounts (a)	(31)	(16)	(7)	(8)	(6)	(4)	—	(2)
Purchased receivables, net	$ 198	$ 87	$ 60	$ 51	$ 94	$ 66	$ 11	$ 17

(a) For ComEd, BGE, Pepco and DPL, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing tariff.
(b) PECO's natural gas POR program became effective on January 1, 2012 and included a 1% discount on purchased receivables in order to recover the implementation costs of the program. The implementation costs were fully recovered and the 1% discount was reset to 0%, effective July 2015.
(c) Pepco's electric POR program in Maryland included a discount on purchased receivables ranging from 0% to 2% depending on customer class, and Pepco's electric POR program in the District of Columbia included a discount on purchased receivables ranging from 0% to 6% depending on customer class. DPL's electric POR program in Maryland included a discount on purchased receivables ranging from 0% to 1% depending on customer class.

4. Mergers, Acquisitions, and Dispositions (Exelon, Generation, PHI, DPL and Pepco)

Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

On March 23, 2016, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Purple Acquisition Corp., a wholly owned subsidiary of Exelon (Merger Sub) and Pepco Holdings, Inc. (PHI). As a result of that merger, Merger Sub was merged into PHI (the PHI Merger) with PHI surviving as a wholly owned subsidiary of Exelon and Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon which also owns Exelon's interests in ComEd, PECO and BGE (through a special purpose subsidiary in the case of BGE). Following the completion of the PHI Merger, Exelon and PHI completed a series of internal corporate organization restructuring transactions resulting in the transfer of PHI's unregulated business interests to Exelon and Generation and the transfer of PHI, Pepco, DPL and ACE to a special purpose subsidiary of EEDC.

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Regulatory Matters

Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments including where applicable: customer rate credits, funding for energy efficiency and delivery system modernization programs, a green sustainability fund, workforce development initiatives, charitable contributions, renewable generation and other required commitments. In addition, the orders approving the merger in Delaware, New Jersey, and Maryland include a "most favored nation" provision which, generally speaking, requires allocation of merger benefits proportionally across all the jurisdictions.

During the third and fourth quarters of 2016, Exelon and PHI filed proposals in Delaware, New Jersey and Maryland for amounts and allocations reflecting the application of the most favored nation provision, resulting in a total nominal cost of commitments of $513 million excluding renewable generation commitments (approximately $444 million on a net present value basis, excluding renewable generation commitments and charitable contributions). These filings, which reflect agreements reached with certain parties to the merger proceedings in the jurisdictions, were subject to regulatory review and approval in each jurisdiction. The DPSC and NJBPU approved the amounts and allocations during the third and fourth quarters of 2016. An order from the MDPSC is expected in the first quarter of 2017. No changes in commitment cost levels are required in the District of Columbia.

During the fourth quarter of 2016, the MDPSC approved a change in the application of $9 million in funding for energy-efficiency program support in the DPL MD service territory. This resulted in an adjustment to the merger commitment costs recorded at Exelon Corporate and DPL. Exelon Corporate recorded a decrease and DPL recorded an increase of $9 million in Operating and maintenance expense.

The following amounts were recognized as total commitment costs in Operating and maintenance expense in Exelon's, PHI's, Pepco's, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016 and PHI's successor period:

Description	Expected Payment Period	Pepco (a)	DPL (a)	ACE (a)	Successor PHI (a)	Exelon (a)
Rate credits	2016 - 2017	$ 91	$ 67	$ 101	$ 259	$ 259
Energy efficiency	2016 - 2021	—	—	—	—	111
Charitable contributions	2016 - 2026	28	12	10	50	50
Delivery system modernization	Q2 2016	—	—	—	—	22
Green sustainability fund	Q2 2016	—	—	—	—	14
Workforce development	2016 - 2020	—	—	—	—	24
Other		7	7	—	14	33
Total		$ 126	$ 86	$ 111	$ 323	$ 513

(a) Included within the individual line items is the most favored nation provision estimate of $6 million, $5 million $38 million, $49 million and $134 million at Pepco, DPL, ACE, PHI and Exelon, respectively.

Pursuant to the orders approving the merger, Exelon made $73 million, $46 million and $49 million of equity contributions to Pepco, DPL and ACE, respectively, in the second quarter of 2016 to fund the after-tax amounts of the customer bill credit and the customer base rate credit commitments.

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In addition, Exelon is committed to develop or to assist in the commercial development of 37 MWs of new generation in Maryland, District of Columbia, and Delaware, 27 MWs of which are to be completed by 2018. These investments are expected to total approximately $137 million, are expected to be primarily capital in nature, and will generate future earnings at Exelon and Generation. Investment costs will be recognized as incurred and recorded on Exelon's and Generation's financial statements. Exelon has also committed to purchase 100 MWs of wind energy in PJM, to procure 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards, and to maintain and promote energy efficiency and demand response programs in the PHI jurisdictions.

Pursuant to the various jurisdictions' merger approval conditions, over specified periods Pepco, DPL and ACE are not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process and have made other commitments regarding hiring and relocation of positions.

Exelon was previously named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the merger transaction and that Exelon aided and abetted the individual directors' breaches. The suits sought rescission of the merger and unspecified damages and costs. On June 1, 2016, the parties executed a settlement to resolve all claims, subject to the approval of the Delaware Court. A hearing had been scheduled for September 8, 2016 in the Delaware Court to consider whether to approve the settlement. However, on August 19, 2016, the plaintiffs advised Exelon that they had determined to dismiss the case in its entirety and with prejudice. On August 24, 2016, the Delaware Court issued an order approving the dismissal.

In July 2015, the OPC, Public Citizen, Inc., the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed motions to stay the MDPSC order approving the merger and in July and August, Exelon, PHI, the MDPSC, Prince George's County and Montgomery County filed responses opposing the motions to stay. The judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC's order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, CCAN and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special Appeals, and on January 21, 2016, the Sierra Club and CCAN filed a notice of appeal. On January 27, 2017, the Maryland Court of Special Appeals affirmed the Circuit Court's judgment. The OPC and Sierra Club have until the later of (i) 30 days from the date of the Court's order or (ii) 15 days from the date the Court enters its mandate, to file their petition for further review in the Court of Appeals. Exelon cannot predict if the petition will be filed.

Between March 25, 2016 and April 22, 2016, various parties filed motions with the DCPSC to reconsider its March 23, 2016 order approving the merger. On June 17, 2016, the DCPSC denied all motions. In August 2016, the District of Columbia Office of People's Counsel, the District of Columbia Government, and Public Citizen jointly with DC Sun each filed petitions for judicial review of the DCPSC's March 23, 2016 order with the District of Columbia Court of Appeals. On September 9, 2016, the Court consolidated the appeals. The Court has issued a scheduling order, and a decision is expected in the second or third quarter of 2017. Exelon believes the matters are without merit.

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Accounting for the Merger Transaction

The total purchase price consideration of approximately $7.1 billion for the PHI Merger consisted of cash paid to PHI shareholders, cash paid for PHI preferred securities and cash paid for PHI stock-based compensation equity awards as follows:

(In millions of dollars, except per share data)	Total Consideration
Cash paid to PHI shareholders at $27.25 per share (254 million shares outstanding at March 23, 2016)	$ 6,933
Cash paid for PHI preferred stock [a]	180
Cash paid for PHI stock-based compensation equity awards [b]	29
Total purchase price	$ 7,142

(a) As of December 31, 2015, the preferred stock was included in Other non-current assets on Exelon's Consolidated Balance Sheets.
(b) PHI's unvested time-based restricted stock units and performance-based restricted stock units issued prior to April 29, 2014 were immediately vested and paid in cash upon the close of the merger. PHI's remaining unvested time-based restricted stock units as of the close of the merger were cancelled. There were no remaining unvested performance-based restricted stock units as of the close of the merger.

PHI shareholders received $27.25 of cash in exchange for each share of PHI common stock outstanding as of the effective date of the merger. In connection with the Merger Agreement, Exelon entered into a Subscription Agreement under which it purchased $180 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI prior to December 31, 2015. On March 23, 2016, the preferred securities were cancelled for no consideration to Exelon, and accordingly, the $180 million cash consideration previously paid to acquire the preferred securities was treated as purchase price consideration.

The valuations performed in the first quarter of 2016 to assess the fair value of certain assets acquired and liabilities assumed were considered preliminary as a result of the short time period between the closing of the merger and the end of the first quarter of 2016. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the merger as more information is obtained about the fair value of assets acquired and liabilities assumed. Exelon expects to finalize these amounts in the first quarter of 2017. During the second, third and fourth quarters of 2016, certain modifications were made to preliminary valuation amounts for acquired property, plant and equipment, unamortized energy contracts, current liabilities, long-term debt, deferred income taxes and pension and OPEB liabilities resulting in an $11 million net decrease to goodwill. The preliminary amounts recognized are subject to further revision to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. Any changes to the fair value assessments may affect the purchase price allocation and could potentially impact goodwill.

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Exelon applied push-down accounting to PHI, and accordingly, the PHI assets acquired and liabilities assumed were recorded at their estimated fair values on Exelon's and PHI's Consolidated Balance Sheets as of March 23, 2016, as follows:

Preliminary Purchase Price Allocation	
Current assets	$ 1,441
Property, plant and equipment	11,088
Regulatory assets	5,015
Other assets	248
Goodwill	4,005
Total assets	$21,797
Current liabilities	$ 2,752
Unamortized energy contracts	1,515
Regulatory liabilities	297
Long-term debt, including current maturities	5,636
Deferred income taxes	3,447
Pension and OPEB liabilities	821
Other liabilities	187
Total liabilities	$14,655
Total purchase price	$ 7,142

On its successor financial statements, PHI has recorded, beginning March 24, 2016, Membership interest equity of $7.2 billion, which is greater than the total $7.1 billion purchase price, reflecting the impact of a $59 million deferred tax liability recorded only at Exelon Corporate to reflect unitary state income tax consequences of the merger.

The excess of the purchase price over the estimated fair value of the assets acquired and the liabilities assumed totaled $4.0 billion, which was recognized as goodwill by PHI and Exelon at the acquisition date, reflecting the value associated with enhancing Exelon's regulated utility portfolio of businesses, including the ability to leverage experience and best practices across the utilities and the opportunities for synergies. For purposes of future required impairment assessments, the goodwill has been preliminarily assigned to PHI's reportable units Pepco, DPL and ACE in the amounts of $1.7 billion, $1.1 billion and $1.2 billion, respectively. None of this goodwill is tax deductible.

Immediately following closing of the merger, $235 million of net assets included in the table above associated with PHI's unregulated business interests were distributed by PHI to Exelon. Exelon contributed $163 million of such net assets to Generation.

The fair values of PHI's assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows, future market prices and impacts of utility rate regulation. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired.

Through its wholly-owned rate regulated utility subsidiaries, most of PHI's assets and liabilities are subject to cost-of-service rate regulation. Under such regulation, rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate

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base, generally measured at historical cost. In applying the acquisition method of accounting, for regulated assets and liabilities included in rate base or otherwise earning a return (primarily property, plant and equipment and regulatory assets earning a return), no fair value adjustments were recorded as historical cost is viewed as a reasonable proxy for fair value.

Fair value adjustments were applied to the historical cost bases of other assets and liabilities subject to rate regulation but not earning a return (including debt instruments and pension and OPEB obligations). In these instances, a corresponding offsetting regulatory asset or liability was also established, as the underlying utility asset and liability amounts are recoverable from or refundable to customers at historical cost (and not at fair value) through the rate setting process. Similar treatment was applied for fair value adjustments to record intangible assets and liabilities, such as for electricity and gas energy supply contracts as further described below. Regulatory assets and liabilities established to offset fair value adjustments are amortized in amounts and over time frames consistent with the realization or settlement of the fair value adjustments, with no impact on reported net income. See Note 3—Regulatory Matters for additional information regarding the fair value of regulatory assets and liabilities established by Exelon and PHI.

Fair value adjustments were recorded at Exelon and PHI for the difference between the contract price and the market price of electricity and gas energy supply contracts of PHI's wholly-owned rate regulated utility subsidiaries. These adjustments are intangible assets and liabilities classified as unamortized energy contracts on Exelon's and PHI's Consolidated Balance Sheets as of December 31, 2016. The difference between the contract price and the market price at the acquisition date of the Merger was recognized for each contract as either an intangible asset or liability. In total, Exelon and PHI recorded a net $1.5 billion liability reflecting out-of-the-money contracts. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. In certain instances, the valuations were based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power prices and the discount rate. The unamortized energy contract fair value adjustment amounts and the corresponding offsetting regulatory asset and liability amounts are amortized through Purchase power and fuel expense or Operating revenues, as applicable, over the life of the applicable contract in relation to the present value of the underlying cash flows as of the merger date.

As mentioned, under cost-of-service rate regulation, rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate base, generally measured at historical cost. Historical cost information therefore is the most relevant presentation for the financial statements of PHI's rate regulated utility subsidiary registrants, Pepco, DPL and ACE. As such, Exelon and PHI did not push-down the application of acquisition accounting to PHI's utility registrants, and therefore the financial statements of Pepco, DPL and ACE do not reflect the revaluation of any assets and liabilities.

The current impact of PHI, including its unregulated businesses, on Exelon's Consolidated Statements of Operations and Comprehensive Income includes Operating revenues of $3,785 million and Net loss of $(66) million during the year ended December 31, 2016.

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For the periods ended December 31, 2016 and 2015, Exelon and PHI have recognized expense to achieve the PHI acquisition as follows:

Acquisition, Integration and Financing Costs [a]	For the Year Ended December 31, 2016	2015
Exelon [b]	$ 143	$ 87
Generation	37	24
ComEd [c]	(6)	9
PECO	5	4
BGE [c]	(1)	5
Pepco [c]	28	3
DPL [c]	20	2
ACE	19	1

Acquisition, Integration and Financing Costs [a]	*Successor* March 24, 2016 to December 31, 2016	*Predecessor* January 1, 2016 to March 23, 2016	*Predecessor* For the Year Ended December 31, 2015
PHI [c]	$ 69	$ 29	$ 19

(a) The costs incurred are classified primarily within Operating and maintenance expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the financing costs, which are included within Interest expense. Costs do not include merger commitments discussed above.
(b) Reflects costs (benefits) recorded at Exelon related to financing, including mark-to-market activity on forward-starting interest rate swaps.
(c) For the year ended December 31, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million, $6 million, $11 million, $4 million, and $16 million incurred at ComEd, BGE, Pepco, DPL and PHI, respectively, that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 3—Regulatory Matters for more information.

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon as if the merger with PHI had taken place on January 1, 2015. The unaudited pro forma information was calculated after applying Exelon's accounting policies and adjusting PHI's results to reflect purchase accounting adjustments.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Year Ended December 31, 2016 [a]	2015 [b]
Total operating revenues	$32,342	$33,823
Net income attributable to common shareholders	1,562	2,618
Basic earnings per share	$ 1.69	$ 2.85
Diluted earnings per share	1.69	2.84

(a) The amounts above exclude non-recurring costs directly related to the merger of $680 million and intercompany revenue of $171 million for year ended December 31, 2016.

(b) The amounts above exclude non-recurring costs directly related to the merger of $92 million and intercompany revenue of $559 million for the year ended December 31, 2015.

Acquisition of ConEdison Solutions (Exelon and Generation)

On September 1, 2016, Generation acquired the competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc. (ConEdison Solutions), a subsidiary of Consolidated Edison, Inc. for a purchase price of $257 million including net working capital of $204 million. The renewable energy, sustainable services and energy efficiency businesses of ConEdison Solutions are excluded from the transaction. As of December 31, 2016, Generation had remitted $235 million to ConEdison Solutions and the remaining balance of $22 million, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets, will be paid during the first quarter of 2017.

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the ConEdison Solutions acquisition by Generation as of September 1, 2016:

Total consideration transferred	$257
Identifiable assets acquired and liabilities assumed	
Working capital assets	$204
Property, plant and equipment	2
Mark-to-market derivative assets	6
Unamortized energy contract assets	100
Customer relationships	9
Other assets	1
Total assets	$322
Mark-to-market derivative liabilities	$ (65)
Total liabilities	$ (65)
Total net identifiable assets, at fair value	$257

The purchase price equaled the estimated fair value of the net assets acquired and the liabilities assumed and, therefore, no goodwill or bargain purchase was recorded as of December 31, 2016. The purchase accounting is preliminary, and, although not expected, may be further adjusted from what is shown above. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the acquisition as more information is obtained about the fair value of assets acquired and liabilities assumed; however, Generation expects to finalize these amounts by the first quarter of 2017.

The fair values of ConEdison Solutions' assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows and future power and fuel market prices.

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Proposed Acquisition of James A. FitzPatrick Nuclear Generating Station (Exelon and Generation)

On August 8, 2016, Generation executed a series of agreements with Entergy Nuclear FitzPatrick LLC (Entergy) to acquire the 838 MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York for a cash purchase price of $110 million. As part of the transaction, Generation would receive the FitzPatrick NDT fund assets and assume the obligation to decommission FitzPatrick. The NRC license for FitzPatrick expires in 2034. In November 2015, Entergy had announced plans to early retire FitzPatrick at the end of the current fuel cycle in January 2017. Under the terms of the agreements, Generation will reimburse Entergy for approximately $200 million to $250 million of incremental costs to prepare for and conduct the plant refueling outage as well as to operate and maintain the plant after the refueling outage, scheduled to end in February 2017, through the closing date. These are costs which otherwise would have been avoided by FitzPatrick's planned permanent shutdown in January 2017. Generation will be entitled to all revenues from FitzPatrick's electricity and capacity sales for the period commencing upon completion of the refueling outage through the acquisition closing date. The agreements provide for certain termination rights, including the right of either party to terminate if the transaction has not been consummated within 12 months due to failure to obtain the required regulatory approvals.

Closing of the transaction is currently anticipated to occur in the first half of 2017 and requires regulatory approval by FERC, NRC, and the New York Public Service Commission (NYPSC). The transaction is also subject to the notification and reporting requirements of the HSR Act (which had been completed) and other customary closing conditions. On November 17, 2016 the NYPSC issued an order approving the transaction. On October 11, 2016, Public Citizen, Inc. filed a protest with FERC challenging Generation and Entergy's application to FERC for the transfer of ownership of FitzPatrick. No other party to the FERC proceeding filed any protests or comments. On December 7, 2016 FERC approved Generation's acquisition of the FitzPatrick facility and dismissed the Public Citizen protest. Public Citizen filed a request for rehearing on January 6, 2017. NRC is the final regulatory approval required to close the transaction and is anticipated during the first half of 2017.

The transaction is expected to be accounted for as a business combination. For accounting and financial reporting purposes, the costs for which Generation reimburses Entergy as well as the revenue received from FitzPatrick prior to the closing of the transaction will be treated as part of the purchase price consideration. Generation will record the fair value of the assets acquired and liabilities assumed as of the acquisition date. To the extent the purchase price is greater than the fair value of the net assets acquired, goodwill will be recorded. To the extent the fair value of the net assets acquired is greater than the purchase price, a bargain purchase gain will be recorded.

As of December 31, 2016, Generation has recorded $127 million of purchase price consideration in Other noncurrent assets on Exelon's and Generation's Consolidated Balance Sheets. The cash outflows associated with these amounts are reflected within Acquisition of businesses on Exelon's and Generation's Consolidated Statements of Cash Flows. In the event the acquisition does not close, these amounts would be subject to potential write-off to Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. For the year ended December 31, 2016, Exelon and Generation incurred $19 million of merger and integration related costs which are included within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

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Acquisition of Integrys Energy Services, Inc. (Exelon and Generation)

On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (IES) for a purchase price of $332 million including net working capital. Generation has elected to account for the transaction as an asset acquisition for federal income tax purposes. The generation and solar asset businesses of Integrys are excluded from the transaction. The Purchase Agreement also includes various representations, warranties, covenants, indemnification and other provisions customary for a transaction of this nature.

Consistent with the applicable accounting guidance, the fair value of the assets acquired and liabilities assumed was determined as of the acquisition date through the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including the amount and timing); discount rates reflecting the risk inherent in the future cash flows; and future power and fuel market prices.

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the Integrys acquisition by Generation:

Total consideration transferred	$ 332
Identifiable assets acquired and liabilities assumed	
Working capital assets	$ 390
Mark-to-market derivative assets	184
Unamortized energy contract assets	115
Customer relationships	50
Working capital liabilities	(196)
Mark-to-market derivative liabilities	(57)
Unamortized energy contract liabilities	(110)
Deferred tax liability	(16)
Total net identifiable assets, at fair value	$ 360
Bargain purchase gain (after-tax)	$ 28

The after-tax bargain purchase gain of $28 million is primarily the result of IES executing additional contract volumes between the date the acquisition agreement was signed and the closing of the transaction resulting in an increase in the fair value of the net assets acquired as of the acquisition date. The after-tax gain is included within Gain on consolidation and acquisition of businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

IES's operating revenues and net loss included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the period from November 1, 2014 to December 31, 2014 were $386 million and $(42) million, respectively. The net loss for the period from November 1, 2014 to December 31, 2014 includes pre-tax unrealized losses on derivative contracts of $108 million and the bargain purchase gain of $28 million. It is impracticable to determine the overall financial statement impact of IES for 2015 and 2016 due to the integration of the business into ongoing operations. For the years ended December 31, 2015, and 2014, Exelon and Generation incurred $5 million and $7 million, respectively, of merger and integration related costs which are included within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

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Asset Divestitures (Exelon, Generation, PHI, Pepco and DPL)

On November 10, 2015, Pepco completed the sale of a 3.5 acre parcel of unimproved land (held as non-utility property) in the Buzzard Point area of southeast Washington, D.C., resulting in a pre-tax gain of $37 million.

On December 31, 2015, Pepco completed the sale of a 3.8 acre parcel of unimproved land (held as non-utility property) in the NoMa area of northeast Washington, D.C., resulting in a pre-tax gain of $9 million. The purchase and sale agreement also provided the third party with a 90-day option to purchase the remaining 1.8 acre land parcel.

On April 21, 2016, Generation completed the sale of the retired New Boston generating site, located in Boston, Massachusetts, resulting in a pre-tax gain of approximately $32 million.

On May 2, 2016, Pepco completed the sale of the remaining 1.8 acre land parcel noted above, located in the NoMa area of northeast Washington, D.C., resulting in a pre-tax gain of approximately $8 million at Pepco. Due to the fair value adjustments recorded at Exelon and PHI as part of purchase accounting, no gain was recorded in Exelon's and PHI's Consolidated Statements of Operations and Comprehensive Income.

On June 16, 2016, Generation initiated the sales process of its Upstream business by executing a forbearance agreement with the lenders of the nonrecourse debt. See Note 14—Debt and Credit Agreements for more information. In December 2016, Generation sold substantially all of the Upstream assets for $37 million which resulted in a pre-tax loss on sale of $10 million which is included in Gain (loss) on sales of assets on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016.

In July 2016, DPL completed the sale of a 9 acre land parcel located on South Madison Street in Wilmington, DE, resulting in a pre-tax gain of approximately $4 million. In December 2016, DPL completed the sale of a 48 acre land parcel located in Middletown, DE, resulting in a pre-tax gain of approximately $5 million. Due to the fair value adjustments recorded at Exelon and PHI as part of purchase accounting, no gain was recorded in Exelon's and PHI's Consolidated Statements of Operations and Comprehensive Income.

During the fourth quarter, as part of its continual assessment of growth and development opportunities, Generation has reevaluated and in certain instances terminated or renegotiated certain projects and contracts. As a result a pre-tax loss of $69 million was recorded within Loss on sale of assets and pre-tax impairment charges of $23 million were recorded within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

5. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation has historically had various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements, see Note 27—Related Party Transactions.

On April 1, 2014, Generation and subsidiaries of Generation and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear

generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDF's rights as a member of CENG (the Integration Transaction). CENG will reimburse Generation for its direct and allocated costs for such services. As part of the arrangement, Nine Mile Point Nuclear Station, LLC, a subsidiary of CENG, also assigned to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with Long Island Power Authority, the Unit 2 co-owner. In addition, on April 1, 2014, the Power Services Agency Agreement (PSAA) was amended and extended until the permanent cessation of power generation by the CENG generation plants.

In addition, on April 1, 2014, Generation made a $400 million loan to CENG, bearing interest at 5.25% per annum and payable out of specified available cash flows of CENG or payable upon the maturity date of April 1, 2034. Immediately following receipt of the proceeds of such loan, CENG made a $400 million special distribution to EDF. Unpaid principal and accrued interest on the loan was $316 million as of December 31, 2016.

Exelon, Generation, and subsidiaries of Generation, EDF and CENG also executed a Fourth Amended and Restated Operating Agreement for CENG on April 1, 2014, pursuant to which, among other things, CENG committed to make preferred distributions to Generation (after repayment of the $400 million loan and associated interest) quarterly out of specified available cash flows until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from April 1, 2014 (Preferred Distribution Rights).

Generation and EDF also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDF has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. Under limited circumstances, the period for exercise of the put option may be extended for 18 months. In order to exercise its option, EDF must give 60 days advance written notice to Generation stating that it is exercising its option. As of the date these financial statements were issued, EDF has not given notice to Generation that it is exercising its option.

On April 1, 2014, Generation also executed an Indemnity Agreement pursuant to which Generation indemnified EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity.

In addition, on April 1, 2014, Generation, EDF, CENG and Nine Mile Point Nuclear Station, LLC entered into an Employee Matters Agreement (EMA) that provides for the transfer of CENG employees to Exelon or one of its affiliates and Exelon's assumption of the sponsorship of the employee benefit plans (including certain incentive, health and welfare, and postemployment benefit plans, among others) and their related trusts by Exelon as the plan sponsor as of July 14, 2014. The EMA also generally requires CENG to fund the obligation related to pre-transfer service of employees, including the underfunded balance of the pension and other postretirement welfare benefit plans measured as of July 14, 2014 by making periodic payments to Generation. These payments will be made on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a

majority of its interest in CENG. However, in the event that EDF exercises its rights under the Put Option, all payments not made as of the put closing date shall accelerate to be paid immediately prior to such closing date.

As a condition to obtaining regulatory approval for the NOSA and related transactions from the NRC, Exelon executed a support agreement pursuant to which Exelon may be required under specified circumstances to provide up to $245 million of financial support to CENG (Exelon Support Agreement). The Exelon Support Agreement supersedes a previous support agreement under which Generation had agreed to provide up to $205 million of financial support for CENG. In addition, Exelon executed a Guarantee pursuant to which Exelon may be required under specified circumstances to provide up to $165 million in additional financial support for CENG. A previous support agreement executed by an affiliate of EDF remains in effect under which the EDF affiliate may be required to provide up to approximately $145 million of financial support for CENG under specified circumstances. The agreements were executed on April 1, 2014 when the NRC licenses were transferred to Generation. No liability has been recognized by Exelon for the guarantees.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. From January 1, 2014, through March 31, 2014, Generation recorded $19 million of equity in losses of unconsolidated affiliates related to its investment in CENG and recorded $17 million of revenues from CENG. The book value of Generation's investment in CENG prior to the consolidation was $1.9 billion, and the book value of the AOCI related to CENG prior to consolidation was $116 million, net of taxes of $77 million.

As a result of the consolidation of CENG on April 1, 2014, there are several additional transactions included in Exelon's and Generation's Consolidated Financial Statements between CENG and Exelon's affiliates that are considered related party transactions to Generation. As further described in Note 27—Related Party Transactions, EDF and Generation had a PPA with CENG under which they purchased 15% and 85%, respectively, of the nuclear output owned by CENG that was not sold to third parties under pre-existing PPAs through December 31, 2014. Beginning January 1, 2015 and continuing through the life of the respective plants, EDF and Generation purchase 49.99% and 50.01%, respectively, of the nuclear output owned by CENG not subject to other contractual agreements. Beginning April 1, 2014, CENG's sales to Generation have been eliminated in consolidation. For the years ended December 31, 2016, 2015, and 2014 Generation had sales to EDF of $376 million, $488 million, and $137 million respectively. See discussion above and Note 2—Variable Interest Entities for additional information regarding other transactions between CENG and EDF included within Exelon and Generation's consolidated financial statements and for additional information about the Registrants VIE's.

Accounting for the Consolidation of CENG

The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interests in CENG at fair value on Exelon's and Generation's Consolidated Balance Sheets. As a result of the consolidation, Exelon and Generation recorded a net gain of $261 million within their respective Consolidated Statements of Operations and Comprehensive Income. This gain consists of approximately $136 million related to the step up to fair value basis of Generation's ownership interest in CENG, and approximately $132 million related to the settlement of pre-existing transactions between CENG and Generation. The net gain on the consolidation of CENG of $261 million is net of a $7 million payment to EDF.

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(Dollars in millions, except per share data unless otherwise noted)

The fair value of CENG's assets and liabilities recorded in consolidation was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The valuations necessary to assess the fair values of certain assets and liabilities were considered preliminary as a result of the short time period between the execution of the NOSA and the end of the second quarter of 2014. The estimates of the fair value of assets and liabilities could be modified for up to one year from April 1, 2014, as more information was obtained about the fair value of assets and liabilities. The principal items that have been revised include the asset retirement obligation liabilities and related asset retirement costs. These items have been updated with inputs from a third party engineering firm with corresponding adjustments recorded in 2014 and the first quarter of 2015. See Note 16—Asset Retirement Obligations for discussion of the impacts of adjustments recorded during 2014 and 2015 related to updated estimates of the CENG asset retirement obligation liabilities. In the period of such revisions, these and any other material changes to the fair value assessments have resulted in adjustments to the amounts recorded upon consolidation. In addition, the asset or liability adjustments impacting depreciation and/or accretion expense recorded after the consolidation date have impacted Generation's post-consolidation results of operations.

Generation recorded the assets and liabilities of CENG at fair value as of April 1, 2014. The following assets and liabilities of CENG were recorded within Generation's Consolidated Balance Sheets as of the date of integration, adjusted for the modifications discussed above:

Fair Values	Exelon and Generation
Current assets	$ 499
Nuclear decommissioning trust fund	1,955
Property, plant and equipment	3,073
Nuclear fuel	482
Other assets	10
Total assets	6,019
Current liabilities	237
Asset retirement obligation	1,816
Pension and other employee benefit obligations	281
Unamortized energy contract liabilities	171
Other liabilities	114
Total liabilities	2,619
Total net assets	$ 3,400

Generation also recorded the fair value of the noncontrolling interests on its Consolidated Balance Sheets of approximately $1.5 billion, net of the fair value of $152 million for certain specified additional distribution rights under the Operating Agreement. In addition, the noncontrolling interests was further reduced by the $400 million special cash distribution to EDF.

Due to the Preferred Distribution Rights that Generation has on CENG's available cash, the earnings attributable to the noncontrolling interests on the Statements of Operations and Comprehensive Income as well as the corresponding adjustment to Noncontrolling interests on the

Combined Notes to Consolidated Financial Statements—(Continued)
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Consolidated Balance Sheets will not be in proportion to Generation's and EDF's equity ownership interests. Rather, the attribution will consider Generation's Preferred Distribution Rights and allocate net income based on each owner's rights to CENG's net assets. For the years ended December 31, 2016 and 2015, Generation reduced by $20 million and $18 million, respectively, the amount of Net income attributable to noncontrolling interests on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. As a result of the consolidation, Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income includes CENG's incremental operating revenues of $548 million and $509 million and CENG's net income (loss), prior to any intercompany eliminations and any adjustments for noncontrolling interests, of $201 million and $(11) million during the years ended December 31, 2016 and 2015, respectively.

Exelon and Generation incurred no merger integration-related costs in 2016. However, in 2015 Exelon and Generation incurred $2 million of merger related integration costs. The costs incurred are classified primarily within Operating and maintenance expense in Exelon's and Generation's respective Consolidated Statements of Operations and Comprehensive Income.

6. Accounts Receivable (All Registrants)

Accounts receivable at December 31, 2016 and 2015 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

						Successor			
2016	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Unbilled customer revenues	$1,673	$ 910[a]	$ 219	$ 140	$182	$ 222	$ 123	$ 58	$ 41
Allowance for uncollectible accounts [b]	(334)	(91)	(70)	(61) [c]	(32)	(80) [d]	(29) [d]	(24) [d]	(27) [d]

						Predecessor			
2015	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Unbilled customer revenues	$1,203	$ 732[a]	$ 218	$ 105	$148	$ 177	$ 93	$ 45	$ 39
Allowance for uncollectible accounts [b]	(284)	(77)	(75)	(83) [c]	(49)	(56)	(17)	(17)	(17)

(a) Represents unbilled portion of retail receivables estimated under Exelon's unbilled critical accounting policy.
(b) Includes the allowance for uncollectible accounts on customer and other accounts receivable.
(c) Excludes the non-current allowance for uncollectible accounts of $23 million and $8 million at December 31, 2016 and 2015, respectively, related to PECO's current installment plan receivables described below.
(d) At December 31, 2016, as explained in Note 1—Significant Accounting Policies, PHI, Pepco, DPL and ACE estimated the allowance for uncollectible accounts on customer receivables by applying loss rates to the outstanding receivable balance by risk segment. The change in estimate resulted in an overall increase of $30 million, $14 million, $8 million, and $8 million in the allowance for uncollectible accounts with $20 million, $8 million, $4 million, and $8 million deferred as a regulatory asset on PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets at December 31, 2016, respectively. This also resulted in a $10 million, $6 million, and $4 million pre-tax charge to provision for uncollectible accounts expense for the year ended December 31, 2016, which is included in Operating and maintenance expense on PHI's, Pepco's, and DPL's Consolidated Statements of Operations and Comprehensive Income, respectively.

PECO Installment Plan Receivables (Exelon and PECO). PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than

one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $9 million and $15 million at December 31, 2016 and 2015, respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1—Significant Accounting Policies. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2016 of $13 million consists of $1 million, $3 million and $9 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2015 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of December 31, 2016 and 2015 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1—Significant Accounting Policies.

7. Property, Plant and Equipment (All Registrants)

Exelon

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

Asset Category	Average Service Life (years)	2016	2015
Electric—transmission and distribution	5-90	$45,698	$32,546
Electric—generation	3-56	27,193	25,615
Gas—transportation and distribution	5-90	4,642	3,864
Common—electric and gas	4-50	1,312	1,149
Nuclear fuel [a]	1-8	6,546	6,384
Construction work in progress	N/A	4,306	3,075
Other property, plant and equipment [b]	3-50	1,027	1,181
Total property, plant and equipment		90,724	73,814
Less: accumulated depreciation [c]		19,169	16,375
Property, plant and equipment, net		$71,555	$57,439

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,326 million and $1,266 million at December 31, 2016 and 2015, respectively.
(b) Includes Generation's buildings under capital lease with a net carrying value of $10 million and $13 million at December 31, 2016 and 2015, respectively. The original cost basis of the buildings was $52 million, and total accumulated amortization was $42 million and $39 million, as of December 31, 2016 and 2015, respectively. Also includes ComEd's buildings under capital lease with a net carrying value at both December 31, 2016 and 2015, of $7 million. The original cost basis of the buildings was $8 million and total accumulated amortization was $1 million as of both December 31, 2016 and 2015. Includes land held for future use and non utility property at ComEd, PECO, BGE, Pepco, DPL, and ACE of $60 million, $21 million, $32 million, $66 million, $16 million, and $27 million, respectively, at December 31, 2016. At December 31, 2015

these balances also include capitalized acquisition, development and exploration costs of $266 million related to oil and gas production activities at Generation, see Note 4—Mergers, Acquisitions, and Dispositions for additional information regarding the sale of upstream assets. Includes the original cost and progress payments associated with Generation's turbine equipment held for future use with a carrying value of $17 million and $146 million at December 31, 2016 and 2015, respectively. See Note 8—Impairment of Long-Lived Assets for additional information on the impairment of Generations turbine equipment.

(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $3,186 million and $2,861 million as of December 31, 2016 and 2015, respectively.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2016	2015	2014
Electric—transmission and distribution	2.73%	2.83%	2.93%
Electric—generation	5.94% (a)	3.47%	3.50%
Gas	2.17%	2.17%	2.13%
Common—electric and gas	7.41%	7.79%	7.32%

(a) See Note 9—Early Nuclear Plant Retirements for additional information on the accelerated net depreciation and amortization of Clinton and Quad Cities.

Generation

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	2016	2015
Asset Category			
Electric—generation	3-56	$27,193	$25,615
Nuclear fuel (a)	1-8	6,546	6,384
Construction work in progress	N/A	2,332	2,017
Other property, plant and equipment (b)	4	76	466
Total property, plant and equipment		36,147	34,482
Less: accumulated depreciation (c)		10,562	8,639
Property, plant and equipment, net		$25,585	$25,843

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,326 million and $1,266 million at December 31, 2016 and 2015, respectively.

(b) Includes buildings under capital lease with a net carrying value of $10 million and $13 million at December 31, 2016 and 2015, respectively. The original cost basis of the buildings was $52 million, and total accumulated amortization was $42 million and $39 million, as of December 31, 2016 and 2015, respectively. At December 31, 2015 these balances also include capitalized acquisition, development and exploration costs of $266 million related to oil and gas production activities at Generation, see Note 4—Mergers, Acquisitions, and Dispositions for additional information regarding the sale of upstream assets. Includes the original cost and progress payments associated with Generation's turbine equipment held for future use with a carrying value of $17 million and $146 million at December 31, 2016 and 2015, respectively. See Note 8—Impairment of Long-Lived Assets for additional information on the impairment of Generations turbine equipment.

(c) Includes accumulated amortization of nuclear fuel in the reactor core of $3,186 million and $2,861 million as of December 31, 2016 and 2015, respectively.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The annual depreciation provisions as a percentage of average service life for electric generation assets were 5.94%, 3.47% and 3.50% for the years ended December 31, 2016, 2015 and 2014, respectively. See Note 9—Early Nuclear Plant Retirements for additional information on the accelerated net depreciation and amortization of Clinton and Quad Cities.

License Renewals. Generation's depreciation provisions are based on the estimated useful lives of its generating stations, which assume the renewal of the licenses for all nuclear generating stations (except for Oyster Creek and Clinton) and the hydroelectric generating stations. As a result, the receipt of license renewals has no material impact on the Consolidated Statements of Operations and Comprehensive Income. Oyster Creek depreciation provisions are based on the 2019 expected shutdown date. Clinton depreciation provisions are based on 2027 which is the last year of the Illinois ZECs. See Note 3—Regulatory Matters for additional information regarding license renewals and the Illinois ZECs. See Note 9—Early Nuclear Plant Retirements for additional information on the impacts of expected and potential early plant retirement.

ComEd

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	2016	2015
Asset Category			
Electric—transmission and distribution	5-80	$22,636	$20,576
Construction work in progress	N/A	569	572
Other property, plant and equipment [a], [b]	37-50	67	64
Total property, plant and equipment		23,272	21,212
Less: accumulated depreciation		3,937	3,710
Property, plant and equipment, net		$19,335	$17,502

(a) Includes buildings under capital lease with a net carrying value at both December 31, 2016 and 2015 of $7 million. The original cost basis of the buildings was $8 million and total accumulated amortization was $1 million as of both December 31, 2016 and 2015.
(b) Includes land held for future use and non-utility property.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 3.03%, 3.03% and 3.05% for the years ended December 31, 2016, 2015 and 2014, respectively.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PECO

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	2016	2015
Asset Category			
Electric—transmission and distribution	5-65	$ 7,591	$ 7,230
Gas—transportation and distribution	5-70	2,348	2,206
Common—electric and gas	5-50	670	631
Construction work in progress	N/A	188	154
Other property, plant and equipment [a]	50	21	21
Total property, plant and equipment		10,818	10,242
Less: accumulated depreciation		3,253	3,101
Property, plant and equipment, net		$ 7,565	$ 7,141

(a) Represents land held for future use and non-utility property.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2016	2015	2014
Electric—transmission and distribution	2.32%	2.39%	2.55%
Gas	1.82%	1.87%	1.84%
Common—electric and gas	5.11%	5.16%	5.16%

BGE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	2016	2015
Asset Category			
Electric—transmission and distribution	5-90	$ 7,067	$6,663
Gas—distribution	5-90	2,170	1,951
Common—electric and gas	5-40	707	655
Construction work in progress	N/A	318	312
Other property, plant and equipment [a]	20	32	32
Total property, plant and equipment		10,294	9,613
Less: accumulated depreciation		3,254	3,016
Property, plant and equipment, net		$ 7,040	$6,597

(a) Represents land held for future use and non-utility property.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2016	2015	2014
Electric—transmission and distribution	2.56%	2.62%	2.96%
Gas	2.45%	2.50%	2.47%
Common—electric and gas	9.45%	10.35%	9.49%

PHI

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	*Successor* 2016	*Predecessor* 2015
Asset Category			
Electric—transmission and distribution	5-86	$ 10,315	$ 14,563
Gas—distribution	5-75	414	547
Common—electric and gas	4-40	65	164
Construction work in progress	N/A	892	591
Other property, plant and equipment (a)	3-43	107	339
Total property, plant and equipment		11,793	16,204
Less: accumulated depreciation		195	5,340
Property, plant and equipment, net		$ 11,598	$ 10,864

(a) Represents plant held for future use and non-utility property. Utility plant is generally subject to a first mortgage lien.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2016	2015	2014
Electric—transmission and distribution	2.52%	2.48%	2.42%
Gas	2.57%	2.55%	2.48%
Common—electric and gas	8.12%	5.19%	4.55%

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Pepco

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	2016	2015
Asset Category			
Electric—transmission and distribution	5-86	$8,018	$7,682
Construction work in progress	N/A	537	318
Other property, plant and equipment [a]	10-33	66	91
Total property, plant and equipment		8,621	8,091
Less: accumulated depreciation		3,050	2,929
Property, plant and equipment, net		$5,571	$5,162

(a) Represents plant held for future use and non-utility property. Utility plant is generally subject to a first mortgage lien.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 2.17%, 2.13% and 2.10% for the years ended December 31, 2016, 2015 and 2014, respectively.

DPL

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service life	2016	2015
Asset Category			
Electric—transmission and distribution	5-68	$3,574	$3,431
Gas—distribution	5-75	580	547
Common—electric and gas	4-40	115	108
Construction work in progress	N/A	163	107
Other property, plant and equipment [a]	10-43	16	16
Total property, plant and equipment		4,448	4,209
Less: accumulated depreciation		1,175	1,139
Property, plant and equipment, net		$3,273	$3,070

(a) Represents plant held for future use and non-utility property. Utility plant is generally subject to a first mortgage lien.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2016	2015	2014
Electric—transmission and distribution	2.49%	2.44%	2.41%
Gas	2.57%	2.55%	2.48%
Common—electric and gas	4.99%	4.24%	4.08%

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

ACE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	2016	2015
Asset Category			
Electric—transmission and distribution	5-55	$3,341	$3,105
Construction work in progress	N/A	169	158
Other property, plant and equipment [a]	13-15	27	28
Total property, plant and equipment		3,537	3,291
Less: accumulated depreciation		1,016	969
Property, plant and equipment, net		$2,521	$2,322

(a) Represents plant held for future use and non-utility property. Utility plant is generally subject to a first mortgage lien.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 2.45%, 2.46% and 2.48% for the years ended December 31, 2016, 2015 and 2014, respectively.

See Note 1—Significant Accounting Policies for further information regarding property, plant and equipment policies and accounting for capitalized software costs for the Registrants. See Note 14—Debt and Credit Agreements for further information regarding Exelon's, ComEd's, and PECO's property, plant and equipment subject to mortgage liens.

8. Impairment of Long-Lived Assets (Exelon and Generation)

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets or asset groups for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the second quarter of 2016, updates to the Company's long-term view of energy and capacity prices suggested that the carrying value of a group of merchant wind assets, located in West Texas, may be impaired. Upon review, the estimated undiscounted future cash flows and fair value of the group were less than their carrying value. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result of the fair value analysis, long-lived merchant wind assets held and used with a carrying amount of approximately $60 million were written down to their fair value of $24 million and a pre-tax impairment charge of $36 million was recorded during the second quarter of 2016 in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Also in the second quarter of 2016, updates to the Company's long-term view, as described above, in conjunction with the retirement announcements of the Quad Cities and Clinton nuclear plants in Illinois suggested that the carrying value of our Midwest asset group may be impaired. Generation completed a comprehensive review of the estimated undiscounted future cash flows of the Midwest asset group and no impairment charge was required.

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In 2015, the year over year change in fundamentals did not indicate any impairments. In 2014, the year over year change in fundamentals suggested that the carrying value of certain merchant wind assets may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of twelve wind projects, primarily located in West Texas, were less than their respective carrying values at May 31, 2014. As a result, long-lived assets held and used with a carrying amount of approximately $151 million were written down to their fair value of $65 million and a pre-tax impairment charge of $86 million was recorded within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During the first quarter of 2016, significant changes in Generation's intended use of the Upstream oil and gas assets, developments with nonrecourse debt held by its upstream subsidiary CEU Holdings, LLC (as described in Note 14—Debt and Credit Agreements) and continued declines in both production volumes and commodity prices suggested that the carrying value may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of its Upstream properties were less than their carrying values. As a result, a pre-tax impairment charge of $119 million was recorded in March 2016 within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. On June 16, 2016, Generation initiated the sales process of its Upstream natural gas and oil exploration and production business by executing a forbearance agreement with the lenders of the nonrecourse debt, see Note 14—Debt and Credit Agreements for additional information. An additional pre-tax impairment charge of $15 million was recorded in September 2016 within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income due to further declines in fair value. In December 2016, Generation sold substantially all of the Upstream Assets. See Note 4—Mergers, Acquisitions, and Dispositions for additional information.

During 2015 and 2014, significant declines in oil and gas prices suggested that the carrying value of certain Upstream assets may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of various Upstream properties, primarily located in Oklahoma and Texas, were less than their respective carrying values at December 31, 2015 and 2014. As a result, pre-tax impairment charges of $5 million and $124 million were recorded for the years ended December 31, 2015 and 2014, respectively, within Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

The fair value analysis used in the above impairments was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue, generation and production forecasts, projected capital and maintenance expenditures and discount rates. Changes in the assumptions described above could potentially result in future impairments of Exelon's long-lived assets, which could be material.

In 2014, certain non-nuclear generating assets were identified as assets held for sale on Exelon's and Generation's Consolidated Balance Sheets. When long-lived assets are held for sale, an impairment loss is recognized to the extent that the asset's carrying value exceeds its estimated fair value less costs to sell. Long-lived assets with a carrying amount of approximately $1 billion were written down to their fair value of $556 million and a pre-tax impairment charge of $450 million was recorded within Operating and maintenance expense and is included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2014. See Note 4—Mergers, Acquisitions, and Dispositions for further information on asset sales.

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Like-Kind Exchange Transaction (Exelon)

In June 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon Corporation, entered into transactions pursuant to which UII invested in coal-fired generating station leases (Headleases) with the Municipal Electric Authority of Georgia (MEAG). The generating stations were leased back to MEAG as part of the transactions (Leases).

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

Based on the annual reviews performed in the second quarters of 2015 and 2014, the estimated residual value of Exelon's direct financing leases for the Georgia generating stations experienced other than temporary declines given increases in estimated long-term operating and maintenance costs in the 2015 annual review and reduced long-term energy and capacity price expectations in the 2014 annual review. As a result, Exelon recorded $24 million pre-tax impairment charges in both 2015 and 2014 for these stations. These impairment charges were recorded within Investments and Operating and maintenance expense in Exelon's Consolidated Balance Sheets and the Consolidated Statements of Operations and Comprehensive Income, respectively. All the Headleases were terminated by the second quarter of 2016, and no events occurred prior to the termination that required Exelon to review the estimated residual values of the direct financing lease investments in 2016.

On February 26, 2014, UII and the City Public Service Board of San Antonio, Texas (CPS) finalized an agreement to terminate the leases on the generating station located in Texas, as described above, prior to its expiration dates. As a result of the lease termination, UII received a net early termination amount of $335 million from CPS and wrote down the net investment in the CPS long-term lease of $336 million in Investments in Exelon's Consolidated Balance Sheets in 2014; resulting in a pre-tax loss of $1 million being reflected in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income in 2014.

On March 31, 2016, UII and MEAG finalized an agreement to terminate the MEAG Headleases, the MEAG Leases, and other related agreements prior to their expiration dates. As a result of the lease termination, UII received an early termination payment of $360 million from MEAG and wrote-off the $356 million net investment in the MEAG Headleases and the Leases. The transaction resulted in a pre-tax gain of $4 million which is reflected in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income. See Note 15—Income Taxes for additional information.

As of December 31, 2016, all the long-term leases had been terminated and no residual and net investment value was outstanding. At December 31, 2015, the components of the net investment in the

long-term leases consisted of estimated residual value of $639 million, unearned income of $287 million and a resulting net investment of $352 million.

9. Early Nuclear Plant Retirements (Exelon and Generation)

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation's nuclear plants. Factors that will continue to affect the economic value of Generation's nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure nuclear plants are fairly compensated for their carbon-free emissions, and the impact of final rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules.

In 2015, Generation identified the Quad Cities, Clinton and Ginna nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. At that time, Exelon and Generation deferred retirement decisions on Clinton and Quad Cities until 2016 in order to participate in the 2016-2017 MISO primary reliability auction and the 2019-2020 PJM capacity auctions held in April and May 2016, respectively, as well as to provide Illinois policy makers with additional time to consider needed reforms and for MISO to consider market design changes to ensure long-term power system reliability in southern Illinois.

In April 2016, Clinton cleared the MISO primary reliability auction as a price taker for the 2016-2017 planning year. The resulting capacity price was insufficient to cover cash operating costs and a risk-adjusted rate of return to shareholders. In May 2016, Quad Cities did not clear in the PJM capacity auction for the 2019-2020 planning year and will not receive capacity revenue for that period.

Based on these capacity auction results, and given the lack of progress on Illinois energy legislation and MISO market reforms, on June 2, 2016 Generation announced it would move forward to shut down the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively. The current Nuclear Regulatory Commission (NRC) licenses for Clinton and Quad Cities expire in 2026 and 2032, respectively.

In June 2016, as a result of the retirement decision for Clinton and Quad Cities, Exelon and Generation recognized one-time charges in Operating and maintenance expense of $146 million related to materials and supplies inventory reserve adjustments, employee-related costs and construction work-in-progress (CWIP) impairments, among other items. In addition to these one-time charges, Exelon and Generation began recognizing incremental non-cash charges to earnings stemming from shortening the expected economic useful life of Clinton and Quad Cities, including accelerated depreciation of plant assets (along with any asset retirement costs (ARC)), accelerated amortization of nuclear fuel, and additional asset retirement obligation (ARO) accretion expense associated with the changes in decommissioning timing and cost assumptions.

On December 7, 2016, Illinois FEJA was signed into law by the Governor of Illinois and included a ZES that provides compensation through the procurement of ZECs targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet specific eligibility criteria, much like the solution implemented with the New York CES. The Illinois ZES will have a 10-year duration extending from June 1, 2017 through May 31, 2027. See Note 3—Regulatory Matters for additional discussion on the Illinois FEJA and the ZES.

With the passage of the Illinois ZES, and subject to prevailing over any related potential administrative or legal challenges, in December 2016 Generation reversed its June 2016 decision to

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permanently cease generation operations at the Clinton and Quad Cities nuclear generating plants. Accordingly, in December 2016 Exelon and Generation reversed approximately $120 million of the one-time charges initially recorded in June 2016 associated with the early retirements primarily for employee-related costs and a materials and supplies inventory reserve adjustment. In addition, Generation updated the expected economic useful life for both facilities, to 2027 for Clinton, commensurate with the end of the Illinois ZES, and to 2032 for Quad Cities, the end of its current operating license. Depreciation was therefore adjusted beginning December 7, 2016, to reflect these extended useful life estimates. See Note 16—Asset Retirement Obligations for additional detail on changes to the Nuclear decommissioning ARO balances resulting from the initial decision and subsequent reversal of the decision to early retire Clinton and Quad Cities.

Through December 31, 2016, Exelon's and Generation's results include a net incremental $688 million of pre-tax expense associated with the initial early retirement decision for Clinton and Quad Cities, as summarized in the table below.

Income statement expense (pre-tax)	2016
Depreciation and Amortization	
Accelerated depreciation [a]	$712
Accelerated nuclear fuel amortization	60
Operating and Maintenance	
Increase ARO accretion, net of contractual offset [b]	2
Contractual offset for ARC depreciation [b]	(86)
Total	$688

(a) Reflects incremental accelerated depreciation of plant assets, including any ARC, for the period June 2, 2016, through December 6, 2016.
(b) For Quad Cities based on the regulatory agreement with the Illinois Commerce Commission, decommissioning-related activities are offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability.

In New York, the Ginna and Nine Mile Point nuclear plants continue to face significant economic challenges and risk of retirement before the end of each unit's respective operating license period (2029 for Ginna and Nine Mile Point Unit 1, and 2046 for Nine Mile Point Unit 2). On August 1, 2016, the NYPSC issued an order adopting the CES, which would provide payments to Ginna and Nine Mile Point for the environmental attributes of their production. On November 18, 2016 Ginna and Nine Mile Point executed the necessary contracts with NYSERDA, as required under the CES. Subject to prevailing over any administrative or legal challenges, the CES will allow Ginna and Nine Mile Point to continue to operate at least through the life of the program (March 31, 2029). The assumed useful life for depreciation purposes is through the end of their current operating licenses. The approved RSSA currently requires Ginna to continue operating through the RSSA term expiring on March 31, 2017 and required notification to the NYPSC if Ginna did not plan to retire shortly after the expiration of the RSSA. On September 30, 2016, Ginna filed the required notice with the NYPSC of its intent to continue operating beyond the expiry of the RSSA. Refer to Note 3—Regulatory Matters for additional discussion on the Ginna RSSA and the New York CES.

Assuming the successful implementation of the Illinois ZES and the New York CES and the continued effectiveness of these programs, Generation and CENG, through its ownership of Ginna and

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Nine Mile Point, no longer consider Clinton, Quad Cities, Ginna or Nine Mile Point to be at heightened risk for early retirement. However, to the extent either the Illinois ZES or the New York CES programs do not operate as expected over their full terms, each of these plants could again be at heightened risk for early retirement, which could have a material impact on Exelon's and Generation's future results of operations, cash flows and financial position.

The Three Mile Island (TMI) nuclear plant also did not clear in the May 2016 PJM capacity auction for the 2019-2020 planning year and will not receive capacity revenue for that period. This is the second consecutive year that TMI failed to clear the capacity auction. Although the plant is committed to operate through May 2019, the plant faces continued economic challenges and Exelon and Generation are exploring all options to return it to profitability. While a portion of the Byron nuclear plant's capacity did not clear the PJM 2019-2020 planning year capacity auction, the plant is committed to run through May 2020. The Company's other nuclear plants in PJM cleared in the auction, except Oyster Creek, which did not participate in the auction given Exelon's and Generation's previous commitment to cease operation of the Oyster Creek nuclear plant by the end of 2019.

The following table provides the balance sheet amounts as of December 31, 2016 for significant assets and liabilities associated with TMI currently considered by management to be at the greatest risk of early retirement due to current economic valuations and other factors.

(in millions)	TMI
Asset Balances	
Materials and supplies inventory	$ 39
Nuclear fuel inventory, net	83
Completed plant, net	1,015
Construction work in progress	37
Liability Balances	
Asset retirement obligation	(565)
NRC License Renewal Term	2034

The precise timing of an early retirement date for any nuclear plant, and the resulting financial statement impacts, may be affected by a number of factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, where applicable, and just prior to its next scheduled nuclear refueling outage.

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10. Jointly Owned Electric Utility Plant (Exelon, Generation, PECO, BGE, PHI, Pepco, DPL and ACE)

Exelon's, Generation's, PECO's, BGE's, PHI's and ACE's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2016 and 2015 were as follows:

	Nuclear Generation				Fossil Fuel Generation	Transmission		Other
	Quad Cities	Peach Bottom	Salem [a]	Nine Mile Point Unit 2	Wyman	PA [b]	NJ/DE [c]	Other [d]
Operator	Generation	Generation	PSEG Nuclear	Generation	FP&L	First Energy	PSEG/ DPL	various
Ownership interest	75.00%	50.00%	42.59%	82.00%	5.89%	various	various	various
Exelon's share at December 31, 2016:								
Plant [e]	$ 1,054	$ 1,384	$ 596	$ 830	$ 3	$ 27	$ 97	$ 15
Accumulated depreciation [e]	515	407	186	68	3	15	52	13
Construction work in progress	—	16	41	37	—	—	—	—
Exelon's share at December 31, 2015:								
Plant [e]	$ 1,035	$ 1,345	$ 566	$ 756	$ 3	$ 27	$ 93	$ 15
Accumulated depreciation [e]	309	368	167	42	3	15	52	13
Construction work in progress	11	18	40	56	—	—	—	—

(a) Generation also owns a proportionate share in the fossil fuel combustion turbine at Salem, which is fully depreciated. The gross book value was $3 million at December 31, 2016 and 2015.
(b) PECO, BGE, Pepco, DPL and ACE own a 22%, 7%, 27%, 9% and 8% share, respectively, in 127 miles of 500kV lines located in Pennsylvania as well as a 20.72%, 10.56%, 9.72%, 3.72% and 3.83% share, respectively, of a 500kV substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500kV lines including, but not limited to, the lines noted above.
(c) PECO, DPL and ACE own a 42.55%, 1% and 13.9% share, respectively in 151.3 miles of 500kV lines located in New Jersey and Delaware Station. PECO, DPL and ACE also own a 42.55%, 7.45% and 7.45% share, respectively, in 2.5 miles of 500kV line located over the Delaware River. ACE also has a 21.78% share in a 500kV New Freedom Switching
(d) Generation, DPL and ACE own a 44.24%, 4.83% and 11.91% share, respectively in assets located at Merrill Creek Reservoir located in New Jersey. Pepco, DPL and ACE own a 11.9%, 7.4% and 6.6% share, respectively, in Valley Forge Corporate Center.
(e) Excludes asset retirement costs.

Exelon's, Generation's, PECO's, BGE's, Pepco's, DPL's and ACE's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly-owned facilities. Exelon's, Generation's, PECO's, BGE's, Pepco's, DPL's and ACE's share of direct expenses of the jointly owned plants are included in Purchased power and fuel and Operating and maintenance expenses on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and in Operating and maintenance expenses on PECO's, BGE's, Pepco, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income.

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11. Intangible Assets (Exelon, Generation, ComEd, PECO, PHI, Pepco, DPL and ACE)

Goodwill

Exelon's, Generation's, ComEd's, PHI's, and DPL's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2016 and 2015 were as follows:

	Balance at January 1, 2015	Impairment losses	Balance at December 31, 2015	Goodwill from business combination	Impairment losses	Measurement period adjustments (b)	Balance at December 31, 2016
Exelon							
Gross amount	$ 4,655	$ —	$ 4,655	$ 4,016	$ —	$ (11)	$ 8,660
Accumulated impairment loss	1,983	—	1,983	—	—	—	1,983
Carrying amount	2,672	—	2,672	4,016	—	(11)	6,677
Generation							
Gross amount	47	—	47	—	—	—	47
Carrying amount	47	—	47	—	—	—	47
ComEd (a)							
Gross amount	4,608	—	4,608	—	—	—	4,608
Accumulated impairment loss	1,983	—	1,983	—	—	—	1,983
Carrying amount	2,625	—	2,625	—	—	—	2,625
DPL							
Gross amount	8	—	8	—	—	—	8
Carrying amount	8	—	8	—	—	—	8

March 24, 2016 to December 31, 2016	Beginning Balance	Goodwill from business combination	Impairment losses	Measurement period adjustments (b)	Ending Balance
PHI— *Successor*					
Gross amount	$ —	$ 4,016	$ —	$ (11)	$ 4,005
Accumulated impairment loss	—	—	—	—	—
Carrying amount	—	4,016	—	(11)	4,005
January 1, 2016 to March 23, 2016					
PHI— *Predecessor*					
Gross amount	1,418	—	—	—	1,418
Accumulated impairment loss	12	—	—	—	12
Carrying amount	1,406	—	—	—	1,406
For the Year Ended December 31, 2015					
PHI— *Predecessor*					
Gross amount	1,425	—	(7)	—	1,418
Accumulated impairment loss	18	—	(6)	—	12
Carrying amount	1,407	—	(1)	—	1,406

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom (predecessor parent company of ComEd) merger net of amortization, resolution of tax matters and other non-impairment-related changes as allowed under previous authoritative guidance.
(b) Represents various measurement period adjustments to the valuation of the fair value of the PHI assets acquired and liabilities assumed as a result of the merger.

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Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the Exelon, Generation, ComEd, PHI and DPL reporting unit below its carrying amount. Under the authoritative guidance for goodwill, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and its operating results are regularly reviewed by segment management. Generation's operating segments are Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as "Other Power Regions", PHI's operating segments are Pepco, DPL and ACE, and ComEd and DPL have a single operating segment. See Note 26—Segment Information for additional information. There is no level below these operating segments for which operating results are regularly reviewed by segment management. Therefore, the ComEd, Pepco, DPL and ACE operating segments are also considered reporting units for goodwill impairment testing purposes. Exelon's and ComEd's $2.6 billion of goodwill has been assigned entirely to the ComEd reporting unit, while Exelon's and PHI's $4 billion of goodwill has been assigned to the Pepco, DPL and ACE reporting units in the amounts of $1.7 billion, $1.1 billion and $1.2 billion, respectively. DPL's $8 million of goodwill is assigned entirely to the DPL reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors and entity-specific events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required.

If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed. Exelon's, Generation's, ComEd's, PHI's and DPL's accounting policy is to perform a quantitative test of goodwill at least once every three years. The first step in the quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for Generation's, ComEd's, Pepco's, DPL's and ACE's businesses and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

2016 and 2015 Goodwill Impairment Assessment. Generation performed a qualitative test as of November 1, 2016, for its 2016 annual goodwill impairment assessment. Generation previously completed its last quantitative assessment in the first quarter of 2015, and updated its qualitative assessment as of November 1, 2015. Based on the qualitative factors above, Generation concluded that the fair value of the reporting unit is more likely than not greater than the carrying amount, and no further testing was required.

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Exelon, ComEd, PHI, and DPL performed quantitative tests as of November 1, 2016, for their 2016 annual goodwill impairment assessments. The first step of the tests comparing the estimated fair values of the ComEd, Pepco, DPL, and ACE reporting units to their carrying values, including goodwill, indicated no impairments of goodwill; therefore, no second steps were required.

While the annual assessments indicated no impairments, certain assumptions used to estimate reporting unit fair values are highly sensitive to changes. Adverse regulatory actions or changes in significant assumptions could potentially result in future impairments of Exelon's, ComEd's, PHI's or DPL's goodwill, which could be material. Based on the results of the annual goodwill test performed as of November 1, 2016, the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units would have needed to decrease by more than 30%, 10%, 10% and 10%, respectively, for Exelon, ComEd and PHI to fail the first step of their respective impairment tests. The $8 million of goodwill recorded at DPL is related to DPL's 1995 acquisition of the Conowingo Power Company and the fair value of the DPL reporting unit would have needed to decrease by more than 50% for DPL to fail the first step of the impairment test.

As of November 1, 2015, Exelon, ComEd, and PHI qualitatively determined that the fair value of their reporting units was not more likely than not less than their carrying value and, therefore, did not perform quantitative assessments. As part of their qualitative assessments, Exelon, ComEd and PHI evaluated, among other things, management's best estimate of projected operating and capital cash flows for their respective business, as well as, changes in certain market conditions, including the discount rate and regulated utility peer company EBITDA multiples, while also considering, the passing margin from their last quantitative assessments.

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Other Intangible Assets and Liabilities

Exelon's, Generation's, ComEd's and PHI's other intangible assets and liabilities, included in Unamortized energy contract assets and liabilities and Other deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2016:

	Weighted Average Amortization Years (l)	Gross	Accumulated Amortization	Net	Estimated amortization expense				
					2017	2018	2019	2020	2021
Exelon									
Software License Agreement (a)	10.0	$ 95	$ (15)	$ 80	$ 10	$ 10	$ 10	$ 10	$ 10
Generation									
Unamortized Energy Contracts (b)									
Exelon Wind (c)	18.0	224	(83)	141	14	14	14	10	10
Antelope Valley (d)	25	190	(28)	162	8	8	8	8	8
Constellation (e)	1.5	1,499	(1,440)	59	(21)	11	8	10	10
CENG (f)	1.7	(97)	59	(38)	(15)	(18)	(15)	(8)	(4)
Integrys (g)	2.4	5	(3)	2	1	1	—	—	—
ConEdison (h)	1.5	100	(53)	47	37	7	2	1	—
Service Contract Backlog									
PES (h)	1.0	9	(7)	2	2	—	—	—	—
Customer Relationships (i)									
Constellation (e)	12.4	214	(94)	120	18	18	17	17	17
Integrys (g)	10.0	50	(11)	39	5	5	5	5	5
PES (h)	15.0	12	(1)	11	1	1	1	1	1
ConEdison (h)	10.0	9	—	9	1	1	1	1	1
Trade Names									
Constellation (e)	10.0	243	(125)	118	23	23	23	23	23
ComEd									
Chicago settlement—1999 agreement (j)	21.8	100	(86)	14	3	3	3	3	—
Chicago settlement—2003 agreement (k)	17.9	62	(47)	15	4	4	4	4	—
PHI									
Unamortized Energy Contracts (h)	6.8	(1,515)	430	(1,085)	(335)	(189)	(119)	(115)	(92)
Pepco									
DC Sponsorship Agreement (m)	0	25	—	25	—	—	—	—	—
Total		$ 1,225	$ (1,504)	$ (279)	$(244)	$(101)	$ (38)	$ (30)	$ (11)

(a) On May 31, 2015, Exelon entered into a long-term software license agreement. Exelon is required to make payments starting August 2015 through May 2024. The intangible asset recognized as a result of these payments is being amortized on a straight-line basis over the contract term.

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(Dollars in millions, except per share data unless otherwise noted)

(b) Includes unamortized energy contract assets and liabilities on Exelon's and Generation's Consolidated Balance Sheets. Excludes $10 million of other miscellaneous unamortized energy contracts that have been acquired at various points in time. The estimated amortization for these miscellaneous unamortized energy contracts is $(9) million, $(7) million, $(6) million, $(2) million and $4 million for 2017, 2018, 2019, 2020 and 2021, respectively.
(c) In December 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (later named Exelon Wind), adding 735 MWs of installed, operating wind capacity located in eight states.
(d) In September 2011, Generation acquired all of the interest in Antelope Valley Solar Ranch One, a 242 MW solar project in northern Los Angeles County, CA from First Solar, Inc.
(e) On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger. Since the merger transaction, Generation includes the former Constellation generation and customer supply operations.
(f) See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.
(g) On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc.
(h) See Note 4—Mergers, Acquisitions, and Dispositions for additional information.
(i) Excludes $11 million of other miscellaneous customer relationships that have been acquired. The estimated amortization for these miscellaneous customer relationships is $1 million in each of the years from 2017 to 2021.
(j) In March 1999, ComEd entered into a settlement agreement with the City of Chicago associated with ComEd's franchise agreement. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago each year from 1999 to 2002. The intangible asset recognized as a result of these payments is being amortized ratably over the remaining term of the franchise agreement, which ends in 2020.
(k) In February 2003, ComEd entered into separate agreements with the City of Chicago and with Midwest Generation, LLC (Midwest Generation). Under the terms of the settlement agreement with the City of Chicago, ComEd agreed to pay the City of Chicago a total of $60 million over a ten-year period, beginning in 2003. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement, which ends in 2020. As required by the settlement, ComEd also made a payment of $2 million to a third-party on the City of Chicago's behalf. Under the terms of the agreement with Midwest Generation, ComEd received payments of $32 million from Midwest Generation to relieve Midwest Generation's obligation under the 1999 fossil sale agreement with ComEd to build the generation facility in the City of Chicago. The payments received by ComEd, which have been recorded in Other deferred credits and other liabilities, and other long-term liabilities on Exelon's and ComEd's Consolidated Balance Sheets are being recognized ratably (approximately $2 million annually) as an offset to amortization expense over the remaining term of the franchise agreement.
(l) Weighted-average amortization period was calculated at the date of a) acquisition for acquired assets or b) settlement agreement.
(m) In the third quarter of 2015, Pepco entered into a sponsorship agreement with the District of Columbia for future naming rights associated with public property within the District of Columbia to be determined over time through future negotiations. Amortization of the intangible asset will begin once the terms of the naming rights are defined.

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2016, 2015 and 2014:

For the Year Ended December 31,	Exelon (a)	Generation (a)	ComEd
2016	$ 87	$ 79	$ 7
2015	76	69	7
2014	179	179	7

(a) At Exelon, amortization of unamortized energy contracts totaling $35 million, $22 million and $135 million for the years ended December 31, 2016, 2015 and 2014, respectively, was recorded in Operating revenues or Purchase power and fuel expense within Exelon's Consolidated Statements of Operations and Comprehensive Income. At Generation, amortization of unamortized energy contracts totaling $35 million, $22 million and $135 million for the years ended December 31, 2016, 2015 and 2014, respectively, was recorded in Operating revenues or Purchase power and fuel expense within Generation's Consolidated Statements of Operations and Comprehensive Income

Combined Notes to Consolidated Financial Statements—(Continued)
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Acquired Intangible Assets and Liabilities

Accounting guidance for business combinations requires the acquirer to separately recognize identifiable intangible assets in the application of purchase accounting.

Unamortized Energy Contracts. Unamortized energy contract assets and liabilities represent the remaining unamortized fair value of non-derivative energy contracts that Exelon and Generation have acquired. The valuation of unamortized energy contracts was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise, the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. The Exelon Wind unamortized energy contracts are amortized on a straight line basis over the period in which the associated contract revenues are recognized as a decrease in Operating revenues within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. In the case of Antelope Valley, Constellation, CENG, Integrys and ConEdison, the fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the acquisition dates through either Operating revenues or Purchase power and fuel expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. At PHI, offsetting regulatory assets or liabilities were also recorded. The unamortized energy contract assets and liabilities and any corresponding regulatory assets or liabilities, respectively, are amortized over the life of the contract in relation to the expected realization of the underlying cash flows.

Customer Relationships. The customer relationship intangibles were determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The accounting guidance requires that customer-based intangibles be amortized over the period expected to be benefited using the pattern of economic benefit. The amortization of the customer relationships recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Service Contract Backlog. The service contract backlog intangibles were determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the contracts. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include estimated revenues and expenses to complete the contracts as well as the discount rate. The accounting guidance requires that customer-based intangibles be amortized over the period expected to be benefited using the pattern of economic benefit. The amortization of the service contract backlog is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Trade Name. The Constellation trade name intangible was determined based on the relief from royalty method of income approach whereby fair value is determined to be the present value of the

license fees avoided by owning the assets. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. The Constellation trade name intangible is amortized on a straight-line basis over a period of 10 years. The amortization of the trade name is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Renewable Energy Credits and Alternative Energy Credits (Exelon, Generation, ComEd, PECO, DPL and ACE)

Exelon's, Generation's, ComEd's, PECO's, DPL's and ACE's other intangible assets, included in Other current assets and Other deferred debits and other assets on the Consolidated Balance Sheets, include RECs (Exelon, Generation, ComEd, DPL and ACE) and AECs (Exelon and PECO). Purchased RECs are recorded at cost on the date they are purchased. The cost of RECs purchased on a stand-alone basis is based on the transaction price, while the cost of RECs acquired through PPAs represents the difference between the total contract price and the market price of energy at contract inception. Generally, revenue for RECs that are part of a bundled power sale is recognized when the power is produced and delivered to the customer, otherwise, the revenue is recognized upon physical transfer of the REC. As of December 31, 2016, and 2015, PECO had current AECs of $1 million and $2 million, respectively. PECO had no noncurrent AECs as of December 31, 2016 and 2015. As of December 31, 2016, and 2015, Generation had current RECs of $317 million and $251 million, respectively, and $29 million and $56 million of noncurrent REC's, respectively. ComEd had no current RECs as of December 31, 2016 and $5 million as of December 31, 2015. ComEd had no noncurrent RECs as of December 31, 2016 and 2015. As of December 31, 2016 and 2015, DPL had current RECs of $11 million and $9 million, respectively. DPL had no noncurrent RECs as of December 31, 2016 and 2015. As of December 31, 2016 and 2015, ACE had current RECs of $1 million. ACE had no noncurrent RECs as of December 31, 2016 and 2015. See Note 3—Regulatory Matters and Note 24—Commitments and Contingencies for additional information on RECs and AECs.

12. Fair Value of Financial Assets and Liabilities (All Registrants)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of December 31, 2016 and 2015:

Exelon

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 1,267	$ —	$ 1,267	$ —	$ 1,267
Long-term debt (including amounts due within one year) (a)	34,005	1,113	31,741	1,959	34,813
Long-term debt to financing trusts (b)	641	—	—	667	667
SNF obligation	1,024	—	732	—	732

Combined Notes to Consolidated Financial Statements—(Continued)
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	December 31, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 536	$ 3	$ 533	$ —	$ 536
Long-term debt (including amounts due within one year) [a]	25,145	931	23,644	1,349	25,924
Long-term debt to financing trusts [b]	641	—	—	673	673
SNF obligation	1,021	—	818	—	818

Generation

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 699	$ —	$ 699	$ —	$ 699
Long-term debt (including amounts due within one year) [a]	9,241	—	7,482	1,670	9,152
SNF obligation	1,024	—	732	—	732

	December 31, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 29	$ —	$ 29	$ —	$ 29
Long-term debt (including amounts due within one year) [a]	8,959	—	7,767	1,349	9,116
SNF obligation	1,021	—	818	—	818

ComEd

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year) [a]	$ 7,033	$ —	$7,585	$ —	$7,585
Long-term debt to financing trusts [b]	205	—	—	215	215

	December 31, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 294	$ —	$ 294	$ —	$ 294
Long-term debt (including amounts due within one year) [a]	6,509	—	7,069	—	7,069
Long-term debt to financing trusts [b]	205	—	—	213	213

PECO

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year) [a]	$ 2,580	$ —	$2,794	$ —	$2,794
Long-term debt to financing trusts	184	—	—	192	192

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year) [a]	$ 2,580	$ —	$2,786	$ —	$2,786
Long-term debt to financing trusts	184	—	—	195	195

BGE

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 45	$ —	$ 45	$ —	$ 45
Long-term debt (including amounts due within one year) [a]	2,322	—	2,467	—	2,467
Long-term debt to financing trusts [b]	252	—	—	260	260

	December 31, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 213	$ 3	$ 210	$ —	$ 213
Long-term debt (including amounts due within one year) [a]	1,858	—	2,044	—	2,044
Long-term debt to financing trusts [b]	252	—	—	264	264

PHI

	December 31, 2016				
Successor	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 522	$ —	$ 522	$ —	$ 522
Long-term debt (including amounts due within one year) [a]	5,898	—	5,520	289	5,809

	December 31, 2015				
Predecessor	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 958	$ —	$ 958	$ —	$ 958
Long-term debt (including amounts due within one year) [a]	5,279	—	5,231	586	5,817
Preferred stock	183	—	—	183	183

Pepco

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 23	$ —	$ 23	$ —	$ 23
Long-term debt (including amounts due within one year) [a]	2,349	—	2,788	8	2,796

	December 31, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 64	$ —	$ 64	$ —	$ 64
Long-term debt (including amounts due within one year) [a]	2,351	—	2,673	—	2,673

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

DPL

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year) (a)	$ 1,340	$ —	$ 1,383	$ —	$ 1,383

	December 31, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 105	$ —	$ 105	$ —	$ 105
Long-term debt (including amounts due within one year) (a)	1,265	—	1,185	103	1,288

ACE

	December 31, 2016				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year) (a)	$ 1,155	$ —	$ 1,007	$ 280	$ 1,287

	December 31, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 5	$ —	$ 5	$ —	$ 5
Long-term debt (including amounts due within one year) (a)	1,201	—	1,044	280	1,324

(a) Includes unamortized debt issuance costs, which are not fair valued, of $200 million, $64 million, $46 million, $15 million, $15 million, $2 million, $30 million, $11 million, and $6 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE respectively, as of December 31, 2016. Includes unamortized debt issuance costs, which are not fair valued, of $180 million, $70 million, $38 million, $15 million, $9 million, $49 million, $31 million, $10 million, and $6 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE respectively, as of December 31, 2015.
(b) Includes unamortized debt issuance costs which are not fair valued of $7 million, $1 million and $6 million for Exelon, ComEd and BGE, respectively, as of December 31, 2016 and December 31, 2015.

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of dividends payable (included in other current liabilities) (Level 1) and short-term borrowings (Level 2). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) and private placement taxable debt securities (Level 3) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. Due to low trading volume of private placement debt,

qualitative factors such as market conditions, low volume of investors and investor demand, this debt is classified as Level 3. The fair value of Exelon's equity units (Level 1) are valued based on publicly traded securities issued by Exelon.

The fair value of Generation's, Pepco's and PHI's non-government-backed fixed rate nonrecourse debt (Level 3) is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles. Given the low trading volume in the nonrecourse debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-backed fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a monthly or quarterly basis and the carrying value approximates fair value (Level 2). When trading data is available on variable rate project financing debt, the fair value is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles (Level 2). Generation, Pepco, DPL and ACE also have tax-exempt debt (Level 2). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (e.g., conduit issuer political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above. Variable rate tax-exempt debt (Level 2) resets on a regular basis and the carrying value approximates fair value.

SNF Obligation . The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2030 and 2025 as of December 31, 2016 and 2015, respectively. See Note 24—Commitments and Contingencies for additional information regarding the change in estimated settlement date.

Long-Term Debt to Financing Trusts . Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Preferred Stock . The fair value of these securities is determined based on the carrying value of the shares per the Subscription Agreement between PHI and Exelon. See Note 19—Mezzanine Equity for further details.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1—quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to liquidate as of the reporting date.

Combined Notes to Consolidated Financial Statements—(Continued)
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- Level 2—inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3—unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Additionally, there were no significant transfers between Level 1 and Level 2 during the year ended December 31, 2016 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations. For derivative contracts, transfers into Level 2 from Level 3 generally occur when the contract tenor becomes more observable and due to changes in market liquidity or assumptions for certain commodity contracts.

Generation and Exelon

In accordance with the applicable guidance on fair value measurement, certain investments that are measured at fair value using the NAV per share as a practical expedient are no longer classified within the fair value hierarchy and are included under “Not subject to leveling” in the table below. See Note 1—Significant Accounting Policies for additional information.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables present assets and liabilities measured and recorded at fair value on Exelon's and Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2016 and 2015:

	Generation					Exelon				
As of December 31, 2016	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Assets										
Cash equivalents [a]	$ 39	$ —	$ —	$ —	$ 39	$ 373	$ —	$ —	$ —	$ 373
NDT fund investments										
Cash equivalents [b]	110	19	—	—	129	110	19	—	—	129
Equities	3,551	452	—	2,011	6,014	3,551	452	—	2,011	6,014
Fixed income										
Corporate debt	—	1,554	250	—	1,804	—	1,554	250	—	1,804
U.S. Treasury and agencies	1,291	29	—	—	1,320	1,291	29	—	—	1,320
Foreign governments	—	37	—	—	37	—	37	—	—	37
State and municipal debt	—	264	—	—	264	—	264	—	—	264
Other [c]	—	59	—	493	552	—	59	—	493	552
Fixed income subtotal	1,291	1,943	250	493	3,977	1,291	1,943	250	493	3,977
Middle market lending	—	—	427	71	498	—	—	427	71	498
Private equity	—	—	—	148	148	—	—	—	148	148
Real estate	—	—	—	326	326	—	—	—	326	326
NDT fund investments subtotal [d]	4,952	2,414	677	3,049	11,092	4,952	2,414	677	3,049	11,092
Pledged assets for Zion Station decommissioning										
Cash equivalents	11	—	—	—	11	11	—	—	—	11
Equities	—	2	—	—	2	—	2	—	—	2
Fixed Income—U.S. Treasury and agencies	16	1	—	—	17	16	1	—	—	17
Middle market lending	—	—	19	64	83	—	—	19	64	83
Pledged assets for Zion Station decommissioning subtotal [e]	27	3	19	64	113	27	3	19	64	113
Rabbi trust investments										
Cash equivalents	2	—	—	—	2	74	—	—	—	74
Mutual funds	19	—	—	—	19	50	—	—	—	50
Fixed income	—	—	—	—	—	—	16	—	—	16
Life insurance contracts	—	18	—	—	18	—	64	20	—	84
Rabbi trust investments subtotal	21	18	—	—	39	124	80	20	—	224
Commodity derivative assets										
Economic hedges	1,356	2,505	1,229	—	5,090	1,358	2,505	1,229	—	5,092
Proprietary trading	3	50	23	—	76	3	50	23	—	76
Effect of netting and allocation of collateral [f]	(1,162)	(2,142)	(481)	—	(3,785)	(1,164)	(2,142)	(481)	—	(3,787)
Commodity derivative assets subtotal	197	413	771	—	1,381	197	413	771	—	1,381
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	—	—	—	—	—	16	—	—	16
Economic hedges	—	28	—	—	28	—	28	—	—	28
Proprietary trading	3	2	—	—	5	3	2	—	—	5
Effect of netting and allocation of collateral	(2)	(19)	—	—	(21)	(2)	(19)	—	—	(21)
Interest rate and foreign currency derivative assets subtotal	1	11	—	—	12	1	27	—	—	28
Other investments	—	—	42	—	42	—	—	42	—	42
Total assets	5,237	2,859	1,509	3,113	12,718	5,674	2,937	1,529	3,113	13,253

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					Exelon				
As of December 31, 2016	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Liabilities										
Commodity derivative liabilities										
Economic hedges	(1,267)	(2,378)	(794)	—	(4,439)	(1,267)	(2,378)	(1,052)	—	(4,697)
Proprietary trading	(3)	(50)	(26)	—	(79)	(3)	(50)	(26)	—	(79)
Effect of netting and allocation of collateral [f]	1,233	2,339	542	—	4,114	1,233	2,339	542	—	4,114
Commodity derivative liabilities subtotal	(37)	(89)	(278)	—	(404)	(37)	(89)	(536)	—	(662)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	(10)	—	—	(10)	—	(10)	—	—	(10)
Economic hedges	—	(21)	—	—	(21)	—	(21)	—	—	(21)
Proprietary trading	(4)	—	—	—	(4)	(4)	—	—	—	(4)
Effect of netting and allocation of collateral	4	19	—	—	23	4	19	—	—	23
Interest rate and foreign currency derivative liabilities subtotal	—	(12)	—	—	(12)	—	(12)	—	—	(12)
Deferred compensation obligation	—	(34)	—	—	(34)	—	(136)	—		(136)
Total liabilities	(37)	(135)	(278)	—	(450)	(37)	(237)	(536)	—	(810)
Total net assets	$ 5,200	$ 2,724	$ 1,231	$ 3,113	$12,268	$ 5,637	$ 2,700	$ 993	$ 3,113	$12,443

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					Exelon				
As of December 31, 2015	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Assets										
Cash equivalents [a]	$ 104	$ —	$ —	$ —	$ 104	$ 5,766	$ —	$ —	$ —	$ 5,766
NDT fund investments										
Cash equivalents [b]	219	92	—	—	311	219	92	—	—	311
Equities	3,008	—	—	1,894	4,902	3,008	—	—	1,894	4,902
Fixed income										
Corporate debt	—	1,824	242	—	2,066	—	1,824	242	—	2,066
U.S. Treasury and agencies	1,323	15	—	—	1,338	1,323	15	—	—	1,338
Foreign governments	—	61	—	—	61	—	61	—	—	61
State and municipal debt	—	326	—	—	326	—	326	—	—	326
Other [c]	—	147	—	390	537	—	147	—	390	537
Fixed income subtotal	1,323	2,373	242	390	4,328	1,323	2,373	242	390	4,328
Middle market lending	—	—	428	—	428	—	—	428	—	428
Private equity	—	—	—	125	125	—	—	—	125	125
Real estate	—	—	—	35	35	—	—	—	35	35
Other	—	—	—	216	216	—	—	—	216	216
Nuclear decommissioning trust fund investments subtotal [d]	4,550	2,465	670	2,660	10,345	4,550	2,465	670	2,660	10,345
Pledged assets for Zion Station decommissioning										
Cash equivalents	—	17	—	—	17	—	17	—	—	17
Equities	1	5	—	—	6	1	5	—	—	6
Fixed income										
U.S. Treasury and agencies	6	2	—	—	8	6	2	—	—	8
Corporate debt	—	46	—	—	46	—	46	—	—	46
Other	—	1	—	—	1	—	1	—	—	1
Fixed income subtotal	6	49	—	—	55	6	49	—	—	55
Middle market lending	—	—	22	105	127	—	—	22	105	127
Pledged assets for Zion Station decommissioning subtotal [e]	7	71	22	105	205	7	71	22	105	205
Rabbi trust investments										
Mutual funds	17	—	—	—	17	48	—	—	—	48
Life insurance contracts	—	13	—	—	13	—	36	—	—	36
Rabbi trust investments subtotal	17	13	—	—	30	48	36	—	—	84
Commodity derivative assets										
Economic hedges	1,922	3,467	1,707	—	7,096	1,922	3,467	1,707	—	7,096
Proprietary trading	36	64	30	—	130	36	64	30	—	130
Effect of netting and allocation of collateral [f]	(1,964)	(2,629)	(564)	—	(5,157)	(1,964)	(2,629)	(564)	—	(5,157)
Commodity derivative assets subtotal	(6)	902	1,173	—	2,069	(6)	902	1,173	—	2,069
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	—	—	—	—	—	25	—	—	25
Economic hedges	—	20	—	—	20	—	20	—	—	20
Proprietary trading	10	5	—	—	15	10	5	—	—	15
Effect of netting and allocation of collateral	(3)	(3)	—	—	(6)	(3)	(3)	—	—	(6)
Interest rate and foreign currency derivative assets subtotal	7	22	—	—	29	7	47	—	—	54
Other investments	—	—	33	—	33	—	—	33	—	33
Total assets	4,679	3,473	1,898	2,765	12,815	10,372	3,521	1,898	2,765	18,556

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					Exelon				
As of December 31, 2015	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Liabilities										
Commodity derivative liabilities										
Economic hedges	(2,382)	(3,348)	(850)	—	(6,580)	(2,382)	(3,348)	(1,097)	—	(6,827)
Proprietary trading	(33)	(57)	(37)	—	(127)	(33)	(57)	(37)	—	(127)
Effect of netting and allocation of collateral [f]	2,440	3,186	765	—	6,391	2,440	3,186	765	—	6,391
Commodity derivative liabilities subtotal	25	(219)	(122)	—	(316)	25	(219)	(369)	—	(563)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	(16)	—	—	(16)	—	(16)	—	—	(16)
Economic hedges	—	(3)	—	—	(3)	—	(3)	—	—	(3)
Proprietary trading	(12)	—	—	—	(12)	(12)	—	—	—	(12)
Effect of netting and allocation of collateral	12	3	—	—	15	12	3	—	—	15
Interest rate and foreign currency derivative liabilities subtotal	—	(16)	—	—	(16)	—	(16)	—	—	(16)
Deferred compensation obligation	—	(30)	—	—	(30)	—	(99)	—	—	(99)
Total liabilities	25	(265)	(122)	—	(362)	25	(334)	(369)	—	(678)
Total net assets	$ 4,704	$ 3,208	$ 1,776	$ 2,765	$12,453	$10,397	$ 3,187	$ 1,529	$ 2,765	$17,878

(a) Generation excludes cash of $252 million and $329 million at December 31, 2016 and 2015 and restricted cash of $157 million and $121 million at December 31, 2016 and 2015. Exelon excludes cash of $360 million and $763 million at December 31, 2016 and 2015 and restricted cash of $180 million and $178 million at December 31, 2016 and 2015 and includes long term restricted cash of $25 million at December 31, 2016, which is reported in other deferred debits on the balance sheet.

(b) Includes $29 million and $52 million of cash received from outstanding repurchase agreements at December 31, 2016 and 2015, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.

(c) Includes derivative instruments of $(2) million and $(8) million, which have a total notional amount of $933 million and $1,236 million at December 31, 2016 and 2015, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.

(d) Excludes net liabilities of $(31) million and $(3) million at December 31, 2016 and 2015, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.

(e) Excludes net assets of less than $1 million and $1 million at December 31, 2016 and 2015, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(f) Collateral posted to/(received from) counterparties totaled $71 million, $197 million and $61 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2016. Collateral posted to/(received from) counterparties totaled $476 million, $557 million and $201 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2015.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on ComEd's, PECO's and BGE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2016 and 2015:

	ComEd				PECO				BGE			
As of December 31, 2016	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents [a]	$ 20	$ —	$ —	$ 20	$ 45	$ —	$ —	$ 45	$ 36	$ —	$ —	$ 36
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	4	—	—	4
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	7	10	—	17	4	—	—	4
Total assets	20	—	—	20	52	10	—	62	40	—	—	40
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(11)	—	(11)	—	(4)	—	(4)
Mark-to-market derivative liabilities [b]	—	—	(258)	(258)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(258)	(266)	—	(11)	—	(11)	—	(4)	—	(4)
Total net assets (liabilities)	$ 20	$ (8)	$ (258)	$ (246)	$ 52	$ (1)	$ —	$ 51	$ 40	$ (4)	$ —	$ 36

	ComEd				PECO				BGE			
As of December 31, 2015	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents [a]	$ 29	$ —	$ —	$ 29	$ 271	$ —	$ —	$ 271	$ 25	$ —	$ —	$ 25
Rabbi trust investments												
Mutual funds	—	—	—	—	8	—	—	8	4	—	—	4
Life insurance contracts	—	—	—	—	—	12	—	12	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	8	12	—	20	4	—	—	4
Total assets	29	—	—	29	279	12	—	291	29	—	—	29
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(12)	—	(12)	—	(4)	—	(4)
Mark-to-market derivative liabilities [b]	—	—	(247)	(247)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(247)	(255)	—	(12)	—	(12)	—	(4)	—	(4)
Total net assets (liabilities)	$ 29	$ (8)	$ (247)	$ (226)	$ 279	$ —	$ —	$ 279	$ 29	$ (4)	$ —	$ 25

(a) ComEd excludes cash of $36 million and $38 million at December 31, 2016 and 2015 and restricted cash of $2 million and $2 million at December 31, 2016 and 2015. PECO excludes cash of $22 million and $27 million at December 31, 2016 and 2015. BGE excludes cash of $13 million and $6 million at December 31, 2016 and 2015 and restricted cash of less than $1 million and $2 million at December 31, 2016 and 2015 and includes long term restricted cash of $2 million at December 31, 2016, which is reported in other deferred debits on the balance sheet.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(b) The Level 3 balance consists of the current and noncurrent liability of $19 million and $239 million, respectively, at December 31, 2016, and $23 million and $224 million, respectively, at December 31, 2015, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

PHI, Pepco, DPL and ACE

The following tables present assets and liabilities measured and recorded at fair value on PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2016 and December 31, 2015:

	Successor				*Predecessor*			
	As of December 31, 2016				As of December 31, 2015			
PHI	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents (a)	$ 217	$ —	$ —	$217	$ 42	$ —	$ —	$ 42
Mark-to-market derivative assets (b)(c)	2	—	—	2	—	—	18	18
Effect of netting and allocation of collateral	(2)	—	—	(2)	—	—	—	—
Mark-to-market derivative assets subtotal	—	—	—	—	—	—	18	18
Rabbi trust investments								
Cash equivalents	73	—	—	73	12	—	—	12
Fixed income	—	16	—	16	—	15	—	15
Life insurance contracts	—	22	20	42	—	27	19	46
Rabbi trust investments subtotal	73	38	20	131	12	42	19	73
Total assets	290	38	20	348	54	42	37	133
Liabilities								
Deferred compensation obligation	—	(28)	—	(28)	—	(30)	—	(30)
Mark-to-market derivative liabilities (b)	—	—	—	—	(2)	—	—	(2)
Effect of netting and allocation of collateral	—	—	—	—	2	—	—	2
Mark-to-market derivative liabilities subtotal	—	—	—	—	—	—	—	—
Total liabilities	—	(28)	—	(28)	—	(30)	—	(30)
Total net assets	$ 290	$ 10	$ 20	$320	$ 54	$ 12	$ 37	$103

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

As of December 31, 2016	Pepco				DPL				ACE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents [a]	$ 33	$ —	$ —	$ 33	$ 42	$ —	$ —	$ 42	$ 130	$ —	$ —	$ 130
Mark-to-market derivative assets [b]	—	—	—	—	2	—	—	2	—	—	—	—
Effect of netting and allocation of collateral	—	—	—	—	(2)	—	—	(2)	—	—	—	—
Mark-to-market derivative assets subtotal	—	—	—	—	—	—	—	—	—	—	—	—
Rabbi trust investments												
Cash equivalents	43	—	—	43	—	—	—	—	—	—	—	—
Fixed income	—	16	—	16	—	—	—	—	—	—	—	—
Life insurance contracts	—	22	19	41	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	43	38	19	100	—	—	—	—	—	—	—	—
Total assets	76	38	19	133	42	—	—	42	130	—	—	130
Liabilities												
Deferred compensation obligation	—	(5)	—	(5)	—	(1)	—	(1)	—	—	—	—
Total liabilities	—	(5)	—	(5)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$ 76	$ 33	$ 19	$ 128	$ 42	$ (1)	$ —	$ 41	$ 130	$ —	$ —	$ 130

As of December 31, 2015	Pepco				DPL				ACE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents [a]	$ 2	$ —	$ —	$ 2	$ —	$ —	$ —	$ —	$ 30	$ —	$ —	$ 30
Rabbi trust investments												
Cash equivalents	11	—	—	11	—	—	—	—	—	—	—	—
Fixed income	—	15	—	15	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	19	42	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	11	38	19	68	—	—	—	—	—	—	—	—
Total assets	13	38	19	70	—	—	—	—	30	—	—	30
Liabilities												
Deferred compensation obligation	—	(6)	—	(6)	—	(1)	—	(1)	—	—	—	—
Mark-to-market derivative liabilities [b]	—	—	—	—	(2)	—	—	(2)	—	—	—	—
Effect of netting and allocation of collateral	—	—	—	—	2	—	—	2	—	—	—	—
Mark-to-market derivative liabilities subtotal	—	—	—	—	—	—	—	—	—	—	—	—
Total liabilities	—	(6)	—	(6)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$ 13	$ 32	$ 19	$ 64	$ —	$ (1)	$ —	$ (1)	$ 30	$ —	$ —	$ 30

(a) PHI excludes cash of $19 million and $16 million at December 31, 2016 and 2015 and includes long term restricted cash of $23 million and $18 million at December 31, 2016 and 2015 which is reported in other deferred debits on the balance sheet. Pepco excludes cash of $9 million and $5 million at December 31, 2016 and 2015. DPL excludes cash of $4 million and

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

$5 million at December 31, 2016 and 2015. ACE excludes cash of $3 million and $3 million at December 31, 2016 and 2015 and includes long term restricted cash of $23 million and $18 million at December 31, 2016 and 2015 which is reported in other deferred debits on the balance sheet.

(b) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

(c) Prior to the PHI Merger, PHI recorded derivative assets for the embedded call and redemption features on the shares of Preferred Stock outstanding as of December 31, 2015. See Note 19—Mezzanine Equity for additional information. As a result of the PHI Merger, the PHI preferred stock derivative was reduced to zero as of March 23, 2016.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the year ended December 31, 2016 and 2015:

	Generation					ComEd	*Successor* PHI (c)		Exelon
For the year ended December 31, 2016	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives (a)	Life Insurance Contracts	Eliminated in Consolidation	Total
Balance as of January 1, 2016	$ 670	$ 22	$ 1,051	$ 33	$ 1,776	$ (247)	$ —	$ —	$ 1,529
Included due to merger	—	—	—	—	—	—	20	—	20
Total realized / unrealized gains (losses)									
Included in net income	7	—	(568) (b)	1	(560)	—	3	—	(557)
Included in noncurrent payables to affiliates	16	—	—	—	16	—	—	(16)	—
Included in regulatory assets/liabilities	—	—	—	—	—	(11)	—	16	5
Change in collateral	—	—	(141)	—	(141)	—	—	—	(141)
Purchases, sales, issuances and settlements							—		
Purchases	143	2	342(d)	7	494	—	—	—	494
Sales	(1)	(5)	(9)	—	(15)	—	—	—	(15)
Issuances	—	—	—	—	—	—	(3)	—	(3)
Settlements	(144)	—	—	—	(144)	—	—	—	(144)
Transfers into Level 3	—	—	1	1	2	—	—	—	2
Transfers out of Level 3	(14)	—	(183)	—	(197)	—	—	—	(197)
Balance as of December 31, 2016	$ 677	$ 19	$ 493	$ 42	$ 1,231	$ (258)	$ 20	$ —	$ 993
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2016	$ 5	$ —	$ 109	$ —	$ 114	$ —	$ 2	$ —	$ 116

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					ComEd		Exelon
For the year ended December 31, 2015	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives (d)	Other Investments	Total Generation	Mark-to-Market Derivatives (a)	Eliminated in Consolidation	Total
Balance as of January 1, 2015	$ 605	$ 50	$ 1,050	$ 3	$ 1,708	$ (207)	$ —	$ 1,501
Total realized / unrealized gains (losses)								
Included in net income	4	—	22(b)	1	27	—	—	27
Included in noncurrent payables to affiliates	18	—	—	—	18	—	(18)	—
Included in payable for Zion Station decommissioning	—	(2)	—	—	(2)	—	—	(2)
Included in regulatory assets/liabilities	—	—	—	—	—	(40)	18	(22)
Change in collateral	—	—	29	—	29	—	—	29
Purchases, sales, issuances and settlements								
Purchases	146	2	144	30	322	—	—	322
Sales	(8)	(28)	(25)	—	(61)	—	—	(61)
Settlements	(95)	—	—	—	(95)	—	—	(95)
Transfers into Level 3	4	—	80	—	84	—	—	84
Transfers out of Level 3	(4)	—	(249)	(1)	(254)	—	—	(254)
Balance as of December 31, 2015	$ 670	$ 22	$ 1,051	$ 33	$ 1,776	$ (247)	$ —	$ 1,529
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2015	$ 2	$ —	$ 856	$ —	$ 858	$ —	$ —	$ 858

(a) Includes $29 million of decreases in fair value and an increase for realized losses due to settlements of $18 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2016. Includes $55 million of decreases in fair value and a reduction for realized losses due to settlements of $(15) million for the year ended December 31, 2015.

(b) Includes a reduction for the reclassification of $677 million and $834 million of realized gains due to the settlement of derivative contracts for the years ended December 31, 2016 and 2015, respectively.

(c) Successor period represents activity from March 24, 2016 to December 31, 2016. See tables below for PHI's predecessor periods, as well as activity for Pepco and DPL for the year ended December 31, 2016.

(d) Includes $168 million of fair value from contracts acquired as a result of portfolio acquisitions.

	Successor	*Predecessor*			
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016		December 31, 2015	
PHI	Life Insurance Contracts	Preferred Stock	Life Insurance Contracts	Preferred Stock	Life Insurance Contracts
Beginning Balance	$ 20	$ 18	$ 19	$ 3	$ 19
Total realized / unrealized gains (losses)					
Included in net income	3	(18)	1	15	5
Purchases, sales, issuances and settlements					
Issuances	(3)	—	—	—	(3)
Settlements	—	—	—	—	(2)
Ending Balance	$ 20	$ —	$ 20	$ 18	$ 19
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$ 2	$ —	$ 1	$ 15	$ 3

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2016		December 31, 2015	
	Pepco	DPL	Pepco	DPL
	Life Insurance Contracts	Life Insurance Contracts	Life Insurance Contracts	Life Insurance Contracts
Balance as of December 31	$ 19	$ —	$ 18	$ 1
Total realized / unrealized gains (losses)				
Included in net income	3	—	5	—
Purchases, sales, issuances and settlements				
Issuances	(3)	—	(3)	—
Settlements	—	—	(1)	(1)
Balance as of December 31	$ 19	$ —	$ 19	$ —
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities for the period	$ 3	$ —	$ 3	$ —

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2016 and 2015:

	Generation			Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net [a]	Operating Revenues	Purchased Power and Fuel	Other, net [a]
Total gains (losses) included in net income for the year ended December 31, 2016	$ (477)	$ (91)	$ 7	$ (477)	$ (91)	$ 10
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2016	$ 154	$ (45)	$ 5	$ 154	$ (45)	$ 7

	Generation			Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net [a]	Operating Revenues	Purchased Power and Fuel	Other, net [a]
Total gains (losses) included in net income for the year ended December 31, 2015	$ 67	$ (45)	$ 4	$ 67	$ (45)	$ 4
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2015	$ 858	$ (2)	$ 2	$ 858	$ (2)	$ 2

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Successor	Predecessor			
	PHI	PHI		Pepco	
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	December 31, 2015	December 31, 2016	December 31, 2015
	Other, net	Other, net		Other, net	
Total (losses) gains included in net income	$ 3	$ (17)	$ 20	$ 3	$ 5
Change in the unrealized gains (losses) relating to assets and liabilities held	2	1	18	3	3

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation and the life insurance contracts held by Pepco.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). The Registrants' cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Preferred Stock Derivative (PHI). In connection with entering into the PHI Merger Agreement, as further described in Note 19—Mezzanine Equity, PHI entered into a Subscription Agreement with Exelon dated April 29, 2014, pursuant to which PHI issued to Exelon shares of Preferred stock. The Preferred stock contained embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding Preferred stock could be called and redeemed at a nominal par value upon a termination of the merger agreement under certain circumstances due to the failure to obtain required regulatory approvals. The embedded call and redemption features on the shares of the Preferred stock in the event of such a termination were separately accounted for as derivatives. These Preferred stock derivatives were valued quarterly using quantitative and qualitative factors, including management's assessment of the likelihood of a Regulatory Termination and therefore, were categorized in Level 3 in the fair value hierarchy. As a result of the PHI Merger, the PHI Preferred stock derivative was reduced to zero as of March 23, 2016. The write-off was charged to Other, net on the PHI Consolidated Statement of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in Equities, Fixed Income and Other. Generation's and CENG's NDT fund investments policies outline investment guidelines for the trusts and limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are

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considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds which are based on quoted prices in active markets are categorized in Level 1. Certain equity securities have been categorized as Level 2 because they are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The fair values of private placement fixed income securities, which are included in Corporate debt, are determined using a third party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity and fixed income commingled funds and mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives such as holding short term fixed income securities or tracking the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For commingled funds and mutual funds, which are not publicly quoted, the funds are valued using NAV as a practical expedient for fair value, which is primarily derived from the quoted prices in active markets on the underlying securities, and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Derivative instruments consisting primarily of futures and interest rate swaps to manage risk are recorded at fair value. Over the counter derivatives are valued daily based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over the counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Middle market lending are investments in loans or managed funds which lend to private companies. Generation elected the fair value option for its investments in certain limited partnerships

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that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in loans are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Managed funds are valued using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. The fair value of private equity and real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date. Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are not highly observable.

As of December 31, 2016, Generation has outstanding commitments to invest in middle market lending, private equity investments and real estate investments of approximately $284 million, $65 million, and $205 million, respectively. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of December 31, 2016. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2016, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation's NDT assets.

See Note 16—Asset Retirement Obligations for further discussion on the NDT fund investments.

Rabbi Trust Investments (Exelon, Generation, PECO, BGE, PHI, Pepco, DPL and ACE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The Rabbi trusts assets are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of money market funds, mutual funds, fixed income securities and life insurance policies. The mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Money market funds and mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The fair values of fixed income securities are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The life insurance policies are valued using the cash surrender value of the policies, net of loans against those policies, which is provided by a third-party. Certain life insurance policies, which consist primarily of mutual funds that are priced based on observable market data, have been categorized as Level 2 because the life insurance policies can be liquidated at the reporting date for the value of the underlying assets. Life insurance policies that are valued using unobservable inputs have been categorized as Level 3.

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Mark-to-Market Derivatives (Exelon, Generation, ComEd, PHI and DPL) . Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' derivatives are predominately at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 13—Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds, and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

The value of certain employment agreement obligations (which are included with the Deferred Compensation Obligation in the tables above) are based on a known and certain stream of payments to be made over time and are categorized as Level 2 within the fair value hierarchy.

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Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd, PHI, Pepco and DPL)

Mark-to-Market Derivatives (Exelon, Generation and ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas and certain transmission congestion contracts. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid

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market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $2.65 and $0.34 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 13—Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at December 31, 2016	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic hedges (Exelon and Generation) [a][c]	$ 435	Discounted Cash Flow	Forward power price	$11 - $130
			Forward gas price	$1.72 - $9.20
		Option Model	Volatility percentage	8% - 173%
Mark-to-market derivatives—Proprietary trading (Exelon and Generation) [a][c]	$ (3)	Discounted Cash Flow	Forward power price	$19 - $79
Mark-to-market derivatives (Exelon and ComEd)	$ (258)	Discounted Cash Flow	Forward heat rate [b]	8x - 9x
			Marketability reserve	3% - 8%
			Renewable factor	89% - 121%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
(c) The fair values do not include cash collateral posted on level three positions of $61 million as of December 31, 2016.

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Type of trade	Fair Value at December 31, 2015	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic hedges (Exelon and Generation) [a][c]	$ 857	Discounted Cash Flow	Forward power price	$11 - $88
			Forward gas price	$1.18 - $8.95
		Option Model	Volatility percentage	5% - 152%
Mark-to-market derivatives—Proprietary trading (Exelon and Generation) [a][c]	$ (7)	Discounted Cash Flow	Forward power price	$13 - $78
Mark-to-market derivatives (Exelon and ComEd)	$ (247)	Discounted Cash Flow	Forward heat rate [b]	9x - 10x
			Marketability reserve	3.5% - 7%
			Renewable factor	87% - 128%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
(c) The fair values do not include cash collateral posted on level three positions of $201 million as of December 31, 2015

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending and certain corporate debt securities investments, the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on discounting the forecasted cash flows, market-based comparable data, credit and liquidity factors, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations.

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Rabbi Trust Investments—Life insurance contracts (Exelon, PHI, Pepco, DPL and ACE) For life insurance policies categorized as Level 3, the fair value is determined based on the cash surrender value of the policy, which contains unobservable inputs and assumptions. Because Exelon relies on its third-party insurance provider to develop the inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Exelon. Exelon gains an understanding of the types of inputs and assumptions used in preparing the valuations and performs procedures to assess the reasonableness of the valuations.

13. Derivative Financial Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk, foreign currency exchange risk and interest rate risk related to ongoing business operations.

Commodity Price Risk (All Registrants)

To the extent the amount of energy Generation produces differs from the amount of energy it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. Each of the Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge. For Generation, all derivative economic hedges related to commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Generation has also entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives and retail load aggregators, as well as contractual obligations to deliver energy to market participants who primarily focus on the resale of energy products for delivery. These non-derivative contracts are accounted for primarily under the accrual method of accounting. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation

facilities, including power and gas sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and gas and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of December 31, 2016, the proportion of expected generation hedged for the major reportable segments was 91%-94%, 56%-59% and 28%-31% for 2017, 2018, and 2019, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including Generation's sales to ComEd, PECO and BGE to serve their retail load.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3—Regulatory Matters for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3—Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts. PECO has certain full requirements contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply

reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2016 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2016 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 25% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE's price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e. non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. All of BGE's natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. The SOS rates charged recover Pepco's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for residential and commercial rate classes. Pepco's price risk related to electric supply procurement is limited. Pepco locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of Pepco's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other Pepco full requirements contracts are not derivatives.

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. The SOS rates charged recover DPL's wholesale power supply costs. In Delaware, DPL is also entitled to recover a Reasonable Allowance for Retail Margin (RARM). The RARM includes a fixed annual margin of approximately $2.75 million, plus an incremental cost component and a cash working capital allowance. In Maryland, DPL charges an administrative fee intended to allow it to recover its administrative costs. DPL locks in fixed prices

for all of its SOS requirements through full requirements contracts. DPL's price risk related to electric supply procurement is limited. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

DPL provides natural gas to its customers under an Annual GCR mechanism approved by the DPSC. Under this mechanism, DPL's Annual GCR Filing establishes a future GCR for firm bundled sales customers by using a forecast of demand and commodity costs. The actual costs are trued up versus the forecast on a monthly basis and any shortfall or excess is carried forward as a recovery balance in the next GCR filing. The demand portion of the GCR is based upon DPL's firm transportation and storage contracts. DPL has firm deliverability of swing and seasonal storage; a liquefied natural gas facility and firm transportation capacity to meet customer demand and provide a reserve margin. The commodity portion of the GCR includes a commission approved hedging program which is intended to reduce gas commodity price volatility while limiting the firm natural gas customers' exposure to adverse changes in the market price of natural gas. The hedge program requires that DPL hedge, on a non-discretionary basis, an amount equal to fifty percent (50%) of estimated purchase requirements for each month, including estimated monthly purchases for storage injections. The fifty percent (50%) hedge monthly target is achieved by hedging 1/12th of the 50% target each month beginning 12-months prior to the month in which the physical gas is to be purchased. Currently, DPL uses only exchange traded futures for its Gas Hedging Program, which are considered derivatives, however, it retains the capability to employ other physical and financial hedges if needed. DPL has not elected hedge accounting for these derivative financial instruments. Because of the DPSC-approved fuel adjustment clause for DPL's derivatives, the change in fair value of the derivatives each period, in addition to all premiums paid and other transaction costs incurred as part of the Gas Hedging Program, are fully recoverable and are recorded by DPL as regulatory assets or liabilities. DPL's physical gas purchases are currently all daily, monthly or intra-month transactions. From time to time, DPL will enter into seasonal purchase or sale arrangements, however, there are none currently in the portfolio. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. The BGS rates charged recover ACE's wholesale power supply costs. ACE does not make any profit or incur any loss on the supply component of the BGS it supplies to customers. ACE's price risk related to electric supply procurement is limited. ACE locks in fixed prices for all of its BGS requirements through full requirements contracts. Certain of ACE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other ACE full requirements contracts are not derivatives.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 6,179 GWh, 7,310 GWh and 10,571 GWh for the years ended December 31, 2016, 2015 and 2014, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not enter into derivatives for proprietary trading purposes.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO, BGE and PHI)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2016, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $659 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximately $7 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2016. To manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign exchange hedge balances as of December 31, 2016:

	Generation					Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$ —	$ 17	$ 4	$ (13)	$ 8	$ —	$ 8
Mark-to-market derivative assets (noncurrent assets)	—	11	1	(8)	4	16	20
Total mark-to-market derivative assets	—	28	5	(21)	12	16	28
Mark-to-market derivative liabilities (current liabilities)	(7)	(13)	(2)	14	(8)	—	(8)
Mark-to-market derivative liabilities (noncurrent liabilities)	(3)	(8)	(2)	9	(4)	—	(4)
Total mark-to-market derivative liabilities	(10)	(21)	(4)	23	(12)	—	(12)
Total mark-to-market derivative net assets (liabilities)	$ (10)	$ 7	$ 1	$ 2	$ —	$ 16	$ 16

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

Combined Notes to Consolidated Financial Statements—(Continued)
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The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2015:

	Generation					Other		Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Subtotal	Total
Mark-to-market derivative assets (current assets)	$ —	$ 10	$ 10	$ (5)	$ 15	$ —	$ —	$ 15
Mark-to-market derivative assets (noncurrent assets)	—	10	5	(1)	14	25	$ 25	$ 39
Total mark-to-market derivative assets	—	20	15	(6)	29	25	25	54
Mark-to-market derivative liabilities (current liabilities)	(8)	(2)	(9)	11	(8)	—	—	(8)
Mark-to-market derivative liabilities (noncurrent liabilities)	(8)	(1)	(3)	4	(8)	—	—	(8)
Total mark-to-market derivative liabilities	(16)	(3)	(12)	15	(16)	—	—	(16)
Total mark-to-market derivative net assets (liabilities)	$ (16)	$ 17	$ 3	$ 9	$ 13	$ 25	$ 25	$ 38

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

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Fair Value Hedges . For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

	Income Statement Location	Year Ended December 31,					
		2016	2015	2014	2016	2015	2014
		Gain (Loss) on Swaps			Gain (Loss) on Borrowings		
Generation	Interest expense [a]	$ —	$ (1)	$ (16)	$ —	$ —	$ 2
Exelon	Interest expense	$ (9)	$ 3	$ 14	$ 23	$ 14	$ (1)

(a) For the years ended December 31, 2015 and 2014, the loss on Generation swaps included $(1) million and $(17) million realized in earnings, respectively, with an immaterial amount and $4 million excluded from hedge effectiveness testing, respectively.

At December 31, 2016, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $16 million. At December 31, 2015, Exelon had outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $25 million. During the years ended December 31, 2016 and 2015, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $14 million gain and $17 million gain, respectively.

Cash Flow Hedges . During the second quarter of 2016, Exelon entered into $90 million of floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with an anticipated debt issuance. The swaps were designated as cash flow hedges. Exelon terminated the swaps during the third quarter of 2016 upon issuance of the debt. Exelon did not recognize a gain or loss as a result of the termination.

During the first and second quarter of 2016, Exelon entered into $600 million and $100 million of floating-to-fixed forward starting interest rate swaps, respectively, to manage a portion of the interest rate exposure associated with an anticipated debt issuance. The swaps were designated as cash flow hedges. Exelon terminated the swaps during the second quarter of 2016 upon issuance of the debt. Exelon recognized a loss of $3 million related to the swaps and $3 million of AOCI will be amortized into Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income over the term of the debt. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

During the first quarter of 2016, Exelon entered into a $100 million floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with an anticipated debt issuance. The swap was designated as a cash flow hedge. Exelon terminated the swap during the first quarter of 2016 upon issuance of the debt. Exelon did not recognize a gain or loss as a result of the termination of the swap and an immaterial amount of AOCI will be amortized into Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income over the term of the debt.

During the third quarter of 2014, EGTP, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowing. See Note 14—Debt and Credit Agreements for additional information regarding the financing. The swaps have a notional amount of $495 million as of December 31, 2016 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. At December 31, 2016, the subsidiary had a $9 million derivative liability related to the swap.

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During the first quarter of 2014, EGR, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14—Debt and Credit Agreements for additional information regarding the financing. The swaps have a notional amount of $164 million as of December 31, 2016 and expire in 2020. The swaps are designated as cash flow hedges. At December 31, 2016, the subsidiary had a $1 million derivative liability related to the swaps.

During the second quarter of 2002, PHI entered into treasury rate lock transactions in anticipation of the issuance of several series of fixed-rate debt commencing in August 2002 to manage a portion of its interest rate exposure. Upon issuance of the fixed-rate debt in August 2002, the treasury rate locks were terminated at a loss and the loss was deferred in AOCI. As a result of the PHI Merger, the remaining unamortized deferred loss recorded in AOCI was adjusted to zero through application of purchase accounting.

During the years ended December 31, 2016 and 2015, the impact on the results of operations as a result of ineffectiveness from cash flow hedges in continuing designated hedge relationships was immaterial.

Economic Hedges. During the third quarter of 2011, Sacramento PV Energy, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14—Debt and Credit Agreements for additional information regarding the financing. During the first quarter of 2016, upon the termination of debt, Generation terminated the swaps. The total notional amount of the swaps were $25 million. No gain or loss was recognized as a result of the termination of the swaps.

During the third quarter of 2012, Constellation Solar Horizons, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14—Debt and Credit Agreements for additional information regarding the financing. During the first quarter of 2016, upon the termination of debt, Generation terminated the swap. The total notional amount of the swap was $24 million. No gain or loss was recognized as a result of the termination of the swap.

During the second quarter 2015, upon the issuance of debt, Exelon terminated $2,400 million of floating-to-fixed forward starting interest rate swaps. As a result of the termination of the swaps, Exelon realized a $64 million loss during the second quarter of 2015.

At December 31, 2016, Generation had no notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $85 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon Generation, ComEd, PECO, BGE, PHI and DPL)

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master

Combined Notes to Consolidated Financial Statements—(Continued)
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netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation's use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e. to BB+ or Ba1). In the table below, Generation's energy related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral including initial margin on exchange positions, is aggregated in the collateral and netting column. As of December 31, 2016 and 2015, $8 million of cash collateral held and $3 million of cash collateral posted, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e. to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in a non affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

In the table below, DPL's economic hedges are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, is aggregated in the collateral and netting column.

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2016:

	Generation				ComEd	DPL			*Successor* PHI	Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting [a]	Subtotal [b]	Economic Hedges [c]	Economic Hedges [d]	Collateral and Netting [a]	Subtotal	Subtotal	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 3,623	$ 55	$ (2,769)	$ 909	$ —	$ 2	$ (2)	$ —	$ —	$ 909
Mark-to-market derivative assets (noncurrent assets)	1,467	21	(1,016)	472	—	—	—	—	—	472
Total mark-to-market derivative assets	5,090	76	(3,785)	1,381	—	2	(2)	—	—	1,381
Mark-to-market derivative liabilities (current liabilities)	(3,165)	(54)	2,964	(255)	(19)	—	—	—	—	(274)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,274)	(25)	1,150	(149)	(239)	—	—	—	—	(388)
Total mark-to-market derivative liabilities	(4,439)	(79)	4,114	(404)	(258)	—	—	—	—	(662)
Total mark-to-market derivative net assets (liabilities)	$ 651	$ (3)	$ 329	$ 977	$ (258)	$ 2	$ (2)	$ —	$ —	$ 719

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $100 million and $72 million, respectively, and current and noncurrent liabilities are shown net of collateral of $95 million and $62 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $329 million at December 31, 2016.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(d) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2015:

	Generation				ComEd	Exelon	DPL			PHI Corporate	*Predecessor* PHI
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting (a)	Subtotal (b)	Economic Hedges (c)	Total Derivatives	Economic Hedges (e)	Collateral and Netting (a)	Subtotal	Other (d)	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 5,236	$ 108	$ (3,994)	$ 1,350	$ —	$ 1,350	$ —	$ —	$ —	$ 18	$ 18
Mark-to-market derivative assets (noncurrent assets)	1,860	22	(1,163)	719	—	719	—	—	—	—	—
Total mark-to-market derivative assets	7,096	130	(5,157)	2,069	—	2,069	—	—	—	18	18
Mark-to-market derivative liabilities (current liabilities)	(4,907)	(94)	4,827	(174)	(23)	(197)	(2)	2	—	—	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,673)	(33)	1,564	(142)	(224)	(366)	—	—	—	—	—
Total mark-to-market derivative liabilities	(6,580)	(127)	6,391	(316)	(247)	(563)	(2)	2	—	—	—
Total mark-to-market derivative net assets (liabilities)	$ 516	$ 3	$ 1,234	$ 1,753	$ (247)	$ 1,506	$ (2)	$ 2	$ —	$ 18	$ 18

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $352 million and $180 million, respectively, and current and noncurrent liabilities are shown net of collateral of $480 million and $222 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $1,234 million at December 31, 2015.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(d) Prior to the PHI Merger, PHI recorded derivative assets for the embedded call and redemption features on the shares of Preferred Stock outstanding as of December 31, 2015. See Note 19—Mezzanine Equity for additional information. As a result of the PHI Merger, the PHI preferred stock derivative was reduced to zero as of March 23, 2016.

(e) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

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Cash Flow Hedges (Exelon and Generation). The tables below provide the activity of OCI related to cash flow hedges for the years ended December 31, 2016 and 2015, containing information about the changes in the fair value of cash flow hedges and the reclassification from Accumulated OCI into results of operations. The amounts reclassified from OCI, when combined with the impacts of the hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
For the Year Ended December 31, 2016	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
AOCI derivative loss at December 31, 2015		$ (21)	$ (19)
Effective portion of changes in fair value		(6)	(6)
Reclassifications from AOCI to net income	Interest expense	8(a)	8(a)
AOCI derivative loss at December 31, 2016		$ (19)	$ (17)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
For the Year Ended December 31, 2015	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
Accumulated OCI derivative loss at December 31, 2014		$ (18)	$ (28)
Effective portion of changes in fair value		(8)	(12)
Reclassifications from AOCI to net income	Other, net	—	16 (b)
Reclassifications from AOCI to net income	Interest Expense	7(c)	7(c)
Reclassifications from AOCI to net income	Operating Revenues	(2)	(2)
Accumulated OCI derivative loss at December 31, 2015		$ (21)	$ (19)

(a) Amount is net of related income tax expense of $5 million for the year ended December 31, 2016.
(b) Amount is net of related income tax expense of $10 million for the year ended December 31, 2015.
(c) Amount is net of related income tax expense of $4 million for the year ended December 31, 2015,

During the years ended December 31, 2015 and 2014, the effect of Exelon's and Generation's former energy-related cash flow hedge activity on pre-tax earnings based on the reclassification adjustment from OCI to earnings was a $2 million and $195 million pre-tax gain, respectively. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods relating to energy-related hedges positions as all were de-designated prior to the Constellation merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps ("treasury") to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars. For the years ended December 31, 2016, 2015 and 2014, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in Operating

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revenues or Purchased power and fuel expense, or Interest expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Generation			Exelon
Year Ended December 31, 2016	Operating Revenues	Purchased Power and Fuel	Total	Total
Change in fair value of commodity positions	$ 5	$ 208	$ 213	$ 213
Reclassification to realized at settlement of commodity positions	(495)	251	(244)	(244)
Net commodity mark-to-market gains (losses)	(490)	459	(31)	(31)
Change in fair value of treasury positions	(2)	—	(2)	(2)
Reclassification to realized at settlement of treasury positions	(8)	—	(8)	(8)
Net treasury mark-to-market gains (losses)	(10)	—	(10)	(10)
Net mark-to-market gains (losses)	$ (500)	$ 459	$ (41)	$ (41)

	Generation			Exelon Corporate	Exelon
Year Ended December 31, 2015	Operating Revenues	Purchased Power and Fuel	Total	Interest Expense	Total
Change in fair value of commodity positions	$ 759	$ (355)	$ 404	$ —	$ 404
Reclassification to realized at settlement of commodity positions	(563)	409	(154)	—	(154)
Net commodity mark-to-market gains (losses)	196	54	250	—	250
Change in fair value of treasury positions	13	—	13	36	49
Reclassification to realized at settlement of treasury positions	(6)	—	(6)	64	58
Net treasury mark-to-market gains (losses)	7	—	7	100	107
Net mark-to-market gains (losses)	$ 203	$ 54	$ 257	$ 100	$ 357

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Year Ended December 31, 2014	Generation				Exelon Corporate	Exelon
	Operating Revenues	Purchased Power and Fuel	Interest Expense	Total	Interest Expense	Total
Change in fair value of commodity positions	$ (413)	$ (194)	$ —	$(607)	$ —	$ (607)
Reclassification to realized at settlement of commodity positions	231	(223)	—	8	—	8
Net commodity mark-to-market gains (losses)	(182)	(417)	—	(599)	—	(599)
Change in fair value of treasury positions	10	—	(2)	8	(100)	(92)
Reclassification to realized at settlement of treasury positions	(2)	—	—	(2)	—	(2)
Net treasury mark-to-market gains (losses)	8	—	(2)	6	(100)	(94)
Net mark-to-market gains (losses)	$ (174)	$ (417)	$ (2)	$(593)	$ (100)	$ (693)

Proprietary Trading Activities (Exelon and Generation). For the years ended December 31, 2016, 2015, and 2014 Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses), before income taxes, relating to mark-to-market activity on commodity derivative instruments entered into for proprietary trading purposes and interest rate and foreign exchange derivative contracts to hedge risk associated with the interest rate and foreign exchange components of underlying commodity positions. Gains and losses associated with proprietary trading are reported as operating revenues in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	For the Years Ended December 31,		
	2016	2015	2014
Change in fair value of commodity positions	$ 23	$ 8	$ (1)
Reclassification to realized at settlement of commodity positions	(21)	(14)	(29)
Net commodity mark-to-market gains (losses)	2	(6)	(30)
Change in fair value of treasury positions	(1)	8	1
Reclassification to realized at settlement of treasury positions	—	(10)	3
Net treasury mark-to market gains (losses)	(1)	(2)	4
Net mark-to market gains (losses)	$ 1	$ (8)	$(26)

Credit Risk (All Registrants)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before

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collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2016. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below exclude credit risk exposure from individual retail counterparties, Nuclear fuel procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $14 million, $33 million $26 million, $44 million, $16 million and $9 million as of December 31, 2016, respectively.

Rating as of December 31, 2016	Total Exposure Before Credit Collateral	Credit Collateral (a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 995	$ —	$ 995	1	$ 328
Non-investment grade	118	16	102	—	—
No external ratings					
Internally rated—investment grade	352	1	351	—	—
Internally rated—non-investment grade	72	8	64	—	—
Total	$ 1,537	$ 25	$ 1,512	1	$ 328

Net Credit Exposure by Type of Counterparty	December 31, 2016
Financial institutions	$ 116
Investor-owned utilities, marketers, power producers	689
Energy cooperatives and municipalities	636
Other	71
Total	$ 1,512

(a) As of December 31, 2016, credit collateral held from counterparties where Generation had credit exposure included $9 million of cash and $16 million of letters of credit. The credit collateral does not include non-liquid collateral.

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ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of December 31, 2016, ComEd's net credit exposure to suppliers was approximately $1 million.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents PECO's net credit exposure. As of December 31, 2016, PECO had no net credit exposure to suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2016, PECO had no material credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The

unsecured credit used by the suppliers represents BGE's net credit exposure. The seller's credit exposure is calculated each business day. As of December 31, 2016, BGE had no net credit exposure to suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2016, BGE had credit exposure of $8 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Pepco's, DPL's and ACE's power procurement contracts provide suppliers with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents Pepco's, DPL's and ACE's net credit exposure. As of December 31, 2016, Pepco's, DPL's and ACE's net credit exposures to suppliers were immaterial.

Pepco is permitted to recover its costs of procuring energy through the MDPSC-approved and DCPSC-approved procurement tariffs. DPL is permitted to recover its costs of procuring energy through the MDPSC-approved and DPSC-approved procurement tariffs. ACE is permitted to recover its costs of procuring energy through the NJBPU-approved procurement tariffs. Pepco's, DPL's and ACE's counterparty credit risks are mitigated by their ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for additional information.

DPL's natural gas procurement plan is reviewed and approved annually on a prospective basis by the DPSC. DPL's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the GCR, which allows DPL to adjust rates annually to reflect realized natural gas prices. To the extent that the fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder. As of December 31, 2016, DPL had no credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

Collateral and Contingent-Related Features (All Registrants)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e. NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if

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Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

	For the Years Ended December 31,	
Credit-Risk Related Contingent Feature	**2016**	**2015**
Gross Fair Value of Derivative Contracts Containing this Feature (a)	$ (960)	$ (932)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements (b)	627	684
Net Fair Value of Derivative Contracts Containing This Feature (c)	$ (333)	$ (248)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features ignoring the effects of master netting agreements.
(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of $347 million and letters of credit posted of $284 million, and cash collateral held of $24 million and letters of credit held of $28 million as of December 31, 2016 for external counterparties with derivative positions. Generation had cash collateral posted of $1,267 million and letters of credit posted of $497 million and cash collateral held of $21 million and letters of credit held of $78 million at December 31, 2015 for external counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e. to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of $1.9 billion and $2.0 billion as of December 31, 2016 and 2015, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2016, Generation's swaps had an immaterial fair value and Exelon's swaps were in an asset position with a fair value of $16 million.

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See Note 26—Segment Information for further information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2016, ComEd held approximately $3 million in collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2016, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. If ComEd lost its investment grade credit rating as of December 31, 2016, it would have been required to post approximately $19 million of collateral to its counterparties. See Note 3—Regulatory Matters for additional information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2016, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2016, PECO could have been required to post approximately $31 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2016, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2016, BGE could have been required to post approximately $62 million of collateral to its counterparties.

Pepco's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require Pepco to post collateral.

DPL's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require DPL to post collateral.

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DPL's natural gas procurement contracts contain provisions that could require DPL to post collateral. To the extent that the fair value of the natural gas derivative transaction in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The DPL obligations are standalone, without the guaranty of PHI. If DPL lost its investment grade credit rating as of December 31, 2016, DPL could have been required to post an additional amount of approximately $10 million of collateral to its natural gas counterparties.

ACE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require ACE to post collateral.

14. Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

Exelon, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. PHI meets its short-term liquidity requirement primarily through the issuance of short-term notes and the Exelon intercompany money pool. Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at December 31, 2016 and December 31, 2015:

	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
Commercial Paper Issuer	2016 (a)(b)	2015 (a) (b)	2016	2015	2016	2015
Exelon Corporate	$ 600	$ 500	$ —	$ —	0.70%	n.a.
Generation	5,300	5,450	620	—	0.94%	0.49%
ComEd	1,000	1,000	—	294	0.77%	0.53%
PECO	600	600	—	—	n.a	n.a.
BGE	600	600	45	210	0.77%	0.48%
PHI Corporate	—	875	—	484	1.03%	0.80%
Pepco	500	500	23	64	0.71%	0.44%
DPL	500	500	—	105	0.68%	0.47%
ACE	350	350	—	5	0.65%	0.46%
Total	$9,450	$10,375	$688	$1,162		

(a) Excludes $500 million and $275 million in bilateral credit facilities that do not back Generation's commercial paper program at December 31, 2016 and 2015, respectively.
(b) Excludes additional credit facility agreements for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $50 million, $34 million, $34 million, $5 million, $2 million, $2 million and $2 million, respectively, arranged with minority and community banks located primarily within utilities' service territories. These facilities expire on October 13, 2017. These facilities are solely utilized to issue letters of credit. As of December 31, 2016, letters of credit issued under these facilities totaled $7 million, $12 million, $21 million and $2 million for Generation, ComEd, PECO and BGE, respectively.

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In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of outstanding commercial paper does not reduce available capacity under a Registrant's credit facility, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility.

At December 31, 2016, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

Borrower	Facility Type	Aggregate Bank Commitment [a][b]	Facility Draws	Outstanding Letters of Credit [c]	Available Capacity at December 31, 2016	
					Actual	To Support Additional Commercial Paper [d]
Exelon Corporate	Syndicated Revolver	$ 600	$ —	$ 29	$ 571	$ 571
Generation	Syndicated Revolver	5,300	—	1,170	4,130	3,510
Generation	Bilaterals	500	75	306	119	—
ComEd	Syndicated Revolver	1,000	—	2	998	998
PECO	Syndicated Revolver	600	—	2	598	598
BGE	Syndicated Revolver	600	—	—	600	555
Pepco	Syndicated Revolver	300	—	—	300	277
DPL	Syndicated Revolver	300	—	—	300	300
ACE	Syndicated Revolver	300	—	1	299	299
Total		$ 9,500	$ 75	$ 1,510	$7,915	$ 7,108

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $50 million, $34 million, $34 million ,$5 million, $2 million, $2 million and $2 million, respectively, arranged with minority and community banks located primarily within utilities' service territories. These facilities expire on October 13, 2017. These facilities are solely utilized to issue letters of credit. As of December 31, 2016, letters of credit issued under these facilities totaled $7 million, $12 million, $21 million and $2 million for Generation, ComEd, PECO and BGE, respectively.
(b) Pepco, DPL and ACE's revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL or ACE may not exceed $900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility.
(c) Excludes nonrecourse debt letters of credit, see discussion below on Continental Wind.
(d) Excludes $500 million in bilateral credit facilities that do not back Generation's commercial paper program.

As of December 31, 2016, there was $75 million of borrowings under Generation's bilateral credit facilities.

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The following tables present the short-term borrowings activity for Exelon, Generation, ComEd, BGE, PHI, Pepco, DPL and ACE during 2016, 2015 and 2014. PECO did not have any short-term borrowings during 2016, 2015 or 2014.

Exelon

	2016	2015	2014
Average borrowings	$1,125	$ 499	$ 571
Maximum borrowings outstanding	3,076	739	1,164
Average interest rates, computed on a daily basis	0.88%	0.53%	0.32%
Average interest rates, at December 31	1.12%	0.88%	0.53%

Generation

	2016	2015	2014
Average borrowings	$ 536	$ 1	$ 93
Maximum borrowings outstanding	1,735	50	552
Average interest rates, computed on a daily basis	0.94%	0.49%	0.32%
Average interest rates, at December 31	1.14%	n.a.	n.a.

ComEd

	2016	2015	2014
Average borrowings	$ 256	$ 461	$ 415
Maximum borrowings outstanding	755	684	597
Average interest rates, computed on a daily basis	0.77%	0.53%	0.33%
Average interest rates, at December 31	n.a.	0.89%	0.50%

BGE

	2016	2015	2014
Average borrowings	$ 143	$ 37	$ 64
Maximum borrowings outstanding	369	210	180
Average interest rates, computed on a daily basis	0.77%	0.48%	0.29%
Average interest rates, computed at December 31	0.95%	0.87%	0.61%

PHI

	Successor	*Predecessor*	
	2016	2015	2014
Average borrowings	$ 153	$ 444	$ 153
Maximum borrowings outstanding	559	784	369
Average interest rates, computed on a daily basis	1.03%	0.90%	0.56%
Average interest rates, computed at December 31	n.a.	1.22%	0.78%

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Pepco

	2016	2015	2014
Average borrowings	$ 4	$ 34	$ 37
Maximum borrowings outstanding	73	190	209
Average interest rates, computed on a daily basis	0.71%	0.44%	0.28%
Average interest rates, computed at December 31	0.90%	0.68%	0.46%

DPL

	2016	2015	2014
Average borrowings	$ 33	$ 81	$ 69
Maximum borrowings outstanding	116	179	177
Average interest rates, computed on a daily basis	0.68%	0.47%	0.26%
Average interest rates, computed at December 31	n.a.	0.79%	0.42%

ACE

	2016	2015	2014
Average borrowings	$ —	$ 175	$ 112
Maximum borrowings outstanding	5	253	259
Average interest rates, computed on a daily basis	0.65%	0.46%	0.27%
Average interest rates, computed at December 31	n.a.	0.65%	0.52%

Short-Term Loan Agreements

On July 30, 2015, PHI entered into a $300 million term loan agreement. The net proceeds of the loan were used to repay PHI's outstanding commercial paper and for general corporate purposes. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.95%, and all indebtedness thereunder is unsecured. On April 4, 2016, PHI repaid $300 million of its term loan in full.

On January 13, 2016, PHI entered into a $500 million term loan agreement, which was amended on March 28, 2016. The net proceeds of the loan were used to repay PHI's outstanding commercial paper, and for general corporate purposes. Pursuant to the loan agreement, as amended, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1%, and all indebtedness thereunder is unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the Loan Agreement, must be repaid in full on or before March 27, 2017. The loan agreement is reflected in Exelon's and PHI's Consolidated Balance Sheets within Short-term borrowings.

On February 22, 2016, Generation and EDF entered into separate member revolving promissory notes with CENG to finance short-term working capital needs. The notes are scheduled to mature on January 31, 2017 and bear interest at a variable rate equal to LIBOR plus 1.75%. On July 25, 2016, CENG paid off the outstanding balances under each note.

Credit Agreements

On January 5, 2016, Generation entered into a credit agreement establishing a $150 million bilateral credit facility, scheduled to mature in January of 2019. This facility will solely be utilized by Generation to issue lines of credit. This facility does not back Generation's commercial paper program.

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On April 1, 2016, the credit agreement for CENG's $100 million bilateral credit facility was amended to increase the overall facility size to $200 million. This facility is utilized by CENG to fund working capital and capital projects. The facility does not back Generation's commercial paper program.

On May 26, 2016, Exelon Corporate, Generation, ComEd, PECO and BGE entered into amendments to each of their respective syndicated revolving credit facilities, which extended the maturity of each of the facilities to May 26, 2021. Exelon Corporate also increased the size of its facility from $500 million to $600 million. On May 26, 2016, PHI, Pepco, DPL and ACE entered into an amendment to their Second Amended and Restated Credit Agreement dated as of August 1, 2011, which (i) extended the maturity date of the facility to May 26, 2021, (ii) removed PHI as a borrower under the facility, (iii) decreased the size of the facility from $1.5 billion to $900 million and (iv) aligned its financial covenant from debt to capitalization leverage ratio to interest coverage ratio.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's, BGE's, Pepco's, DPL's, and ACE's revolving credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant's credit rating. The adders for the prime based borrowings and LIBOR-based borrowings are presented in the following table:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Prime based borrowings	27.5	27.5	7.5	0.0	0.0	7.5	7.5	7.5
LIBOR-based borrowings	127.5	127.5	107.5	90.0	100.0	107.5	107.5	107.5

The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 90 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

An event of default under any of the Registrants' credit agreements would not constitute an event of default under any of the other Registrants' credit agreements, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit agreement would constitute an event of default under the Exelon Corporation credit agreement.

Each credit agreement requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and, in the case of Exelon and Generation, interest on the debt of its project subsidiaries. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2016:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2016, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Interest coverage ratio	7.03	11.81	6.89	8.77	10.47	6.24	8.42	5.84

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Through May 26, 2016, when Pepco, DPL and ACE entered into a new restated credit agreement, as mentioned above, PHI, Pepco, DPL and ACE had maintained an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. The termination date of this credit facility was August 1, 2018.

The aggregate borrowing limit under the amended and restated credit facility was $1.5 billion, all or any portion of which could have been used to obtain loans and up to $500 million of which could have been used to obtain letters of credit. The facility also included a swingline loan sub-facility, pursuant to which each company could have made same day borrowings in an aggregate amount not to exceed 10% of the total amount of the facility. Any swingline loan had to be repaid by the borrower within fourteen days of receipt. The credit sublimit was $750 million for PHI and $250 million for each of Pepco, DPL and ACE. The sublimits could have been increased or decreased by the individual borrower during the term of the facility, except that (i) the sum of all of the borrower sublimits following any such increase or decrease had to equal the total amount of the facility and (ii) the aggregate amount of credit used at any given time by (a) PHI could not exceed $1.25 billion and (b) each of Pepco, DPL or ACE could not exceed the lesser of $500 million and the maximum amount of short-term debt the company was permitted to have outstanding by its regulatory authorities. The total number of the sublimit reallocations could not exceed eight per year during the term of the facility.

The interest rate payable by each company on utilized funds was, at the borrowing company's election, (i) the greater of the prevailing prime rate, the federal funds effective rate plus 0.5% and the one-month London Interbank Offered Rate (LIBOR) plus 1.0%, or (ii) the prevailing Eurodollar rate, plus a margin that varies according to the credit rating of the borrower.

In order for a borrower to use the facility, certain representations and warranties had to be true and correct, and the borrower had to be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excluded from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contained certain covenants and other customary agreements and requirements that, if not complied with, resulted in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder.

The absence of a material adverse change in PHI's business, property, results of operations or financial condition was not a condition to the availability of credit under the credit agreement. The credit agreement did not include any rating triggers.

Variable Rate Demand Bonds

DPL has outstanding obligations in respect of Variable Rate Demand Bonds (VRDB). VRDBs are subject to repayment on the demand of the holders and, for this reason, are accounted for as short-term debt in accordance with GAAP. However, bonds submitted for purchase are remarketed by a remarketing agent on a best efforts basis. PHI expects that any bonds submitted for purchase will be remarketed successfully due to the creditworthiness of the issuer and, as applicable, the credit support, and because the remarketing resets the interest rate to the then-current market rate. The bonds may

be converted to a fixed-rate, fixed-term option to establish a maturity which corresponds to the date of final maturity of the bonds. On this basis, PHI views VRDBs as a source of long-term financing. As of December 31, 2016 and December 31, 2015, $105 million in variable rate demand bonds issued by DPL were outstanding and are included in the Long-term debt due within one year on Exelon's, PHI's and DPL's Consolidated Balance Sheet.

Long-Term Debt

The following tables present the outstanding long-term debt at the Registrants as of December 31, 2016 and 2015:

Exelon

	Rates	Maturity Date	December 31, 2016	December 31, 2015
Long-term debt				
Rate stabilization bonds	5.82% — 5.82%	2017	$ 41	$ 120
First mortgage bonds (a)	1.70% — 7.90%	2017-2046	14,123	9,019
Senior unsecured notes	1.55% — 7.60%	2017-2046	11,868	9,803
Unsecured bonds	2.40% — 6.35%	2021-2046	2,300	1,750
Pollution control notes	2.50% — 2.70%	2025-2036	435	435
Nuclear fuel procurement contracts	3.15% — 3.35%	2018-2020	105	127
Notes payable and other (b)(c)	1.43% — 7.83%	2017-2053	576	314
Junior subordinated notes	6.50%	2024	1,150	1,150
Contract payment - junior subordinated notes	2.50%	2017	19	64
Long-term software licensing agreement	3.95%	2024	103	111
Unsecured Tax-Exempt Bonds	5.40%	2031	112	—
Medium-Terms Notes (unsecured)	6.81% — 7.72%	2017-2027	40	—
Transition bonds	5.05% — 5.55%	2020-2023	124	—
Nonrecourse debt:				
Fixed rates	2.29% — 6.00%	2031-2037	1,400	1,162
Variable rates	3.18% — 5.00%	2019-2021	915	1,058
Total long-term debt			33,311	25,113
Unamortized debt discount and premium, net			(68)	(63)
Unamortized debt issuance costs			(200)	(180)
Fair value adjustment			962	275
Long-term debt due within one year			(2,430)	(1,500)
Long-term debt			$31,575	$23,645
Long-term debt to financing trusts (d)				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III	7.38%	2028	81	81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Subordinated debentures to BGE Capital Trust II	6.20%	2043	258	258
Total long-term debt to financing trusts			648	648
Unamortized debt issuance costs			(7)	(7)
Long-term debt to financing trusts			$ 641	$ 641

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's, Pepco's, DPL's and ACE's assets are subject to the liens of their respective mortgage indentures.
(b) Includes capital lease obligations of $69 million and $29 million at December 31, 2016 and 2015, respectively. Lease payments of $17 million, $18 million, $20 million, $5 million, $1 million, and $8 million will be made in 2017, 2018, 2019, 2020, 2021 and thereafter, respectively.
(c) Includes financing related to Albany Green Energy, LLC (AGE), which is a consolidated variable interest entity (see Note 2—Variable Interest Entities for additional information). The agreement is scheduled to expire on November 17, 2017, at a variable rate equal to LIBOR plus 1.25%. As of December 31, 2016, $198 million was outstanding.
(d) Amounts owed to these financing trusts are recorded as Long-term debt to financing trusts within Exelon's Consolidated Balance Sheets.

Generation

	Rates	Maturity Date	December 31, 2016	December 31, 2015
Long-term debt				
Senior unsecured notes	2.00% — 7.60%	2017-2042	$ 5,971	$5,971
Pollution control notes	2.50% — 2.70%	2025-2036	435	435
Nuclear fuel procurement contracts	3.15% — 3.35%	2018-2020	105	127
Notes payable and other [a][b]	1.43% — 7.83%	2017-2035	382	166
Nonrecourse debt:				
Fixed rates	2.29% — 6.00%	2031-2037	1,400	1,162
Variable rates	3.18% — 5.00%	2019-2021	915	1,058
Total long-term debt			9,208	8,919
Fair value adjustment			115	127
Unamortized debt discount and premium, net			(17)	(17)
Unamortized debt issuance costs			(65)	(70)
Long-term debt due within one year			(1,117)	(90)
Long-term debt			$ 8,124	$8,869

(a) Includes Generation's capital lease obligations of $22 million and $21 million at December 31, 2016 and 2015, respectively. Generation will make lease payments of $5 million, $5 million, $6 million and $5 million and $1 million in 2017, 2018, 2019, 2020 and 2021 respectively. The capital lease matures in 2020.
(b) Includes financing related to Albany Green Energy, LLC (AGE), which is a consolidated variable interest entity (see Note 2—Variable Interest Entities for additional information). The agreement is scheduled to expire on November 17, 2017, at a variable rate equal to LIBOR plus 1.25%. As of December 31, 2016, $198 million was outstanding.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd

	Rates	Maturity Date	December 31, 2016	December 31, 2015
Long-term debt				
First mortgage bonds (a)	2.15% — 6.45%	2017-2046	$6,954	$6,419
Notes payable and other (b)	6.95% — 7.49%	2018-2053	147	148
Total long-term debt			7,101	6,567
Unamortized debt discount and premium, net			(22)	(20)
Unamortized debt issuance costs			(46)	(38)
Long-term debt due within one year			(425)	(665)
Long-term debt			$6,608	$5,844
Long-term debt to financing trust (c)				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206
Total long-term debt to financing trusts			206	206
Unamortized debt issuance costs			(1)	(1)
Long-term debt to financing trusts			$ 205	$ 205

(a) Substantially all of ComEd's assets other than expressly excepted property are subject to the lien of its mortgage indenture.
(b) Includes ComEd's capital lease obligations of $8 million at both December 31, 2016 and 2015, respectively. Lease payments of less than $1 million will be made from 2017 through expiration at 2053.
(c) Amount owed to this financing trust is recorded as Long-term debt to financing trust within ComEd's Consolidated Balance Sheets.

PECO

	Rates	Maturity Date	December 31, 2016	December 31, 2015
Long-term debt				
First mortgage bonds (a)	1.70% — 5.95%	2018-2044	$2,600	$2,600
Total long-term debt			2,600	2,600
Unamortized debt discount and premium, net			(5)	(5)
Unamortized debt issuance costs			(15)	(15)
Long-term debt due within one year			—	(300)
Long-term debt			$2,580	$2,280
Long-term debt to financing trusts (b)				
Subordinated debentures to PECO Trust III	7.38%	2028	$ 81	$ 81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Long-term debt to financing trusts			$ 184	$ 184

(a) Substantially all of PECO's assets are subject to the lien of its mortgage indenture.
(b) Amounts owed to this financing trust are recorded as Long-term debt to financing trusts within PECO's Consolidated Balance Sheets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

	Rates	Maturity Date	December 31, 2016	December 31, 2015
Long-term debt				
Rate stabilization bonds	5.82% — 5.82%	2017	$ 41	$ 120
Senior unsecured notes	2.40% — 6.35%	2021-2046	2,300	1,750
Total long-term debt			2,341	1,870
Unamortized debt discount and premium, net			(4)	(3)
Unamortized debt issuance costs			(15)	(9)
Long-term debt due within one year			(41)	(378)
Long-term debt			$ 2,281	$ 1,480
Long-term debt to financing trusts [a]				
Subordinated debentures to BGE Capital Trust II	6.20%	2043	$ 258	$ 258
Total long-term debt to financing trusts			258	258
Unamortized debt issuance costs			(6)	(6)
Long-term debt to financing trusts			$ 252	$ 252

(a) Amount owed to this financing trust is recorded as Long-term debt to financing trust within BGE's Consolidated Balance Sheets.

PHI

	Rates	Maturity Date	Successor December 31, 2016	Predecessor December 31, 2015
Long-term debt				
Notes (unsecured)	6.13% — 7.45%	2017-2032	$ 266	$ 456
First mortgage bonds	3.05% — 7.90%	2018-2045	4,569	4,495
Unsecured Tax-Exempt Bonds	5.40%	2031	112	112
Medium-Terms Notes (unsecured)	6.81% — 7.72%	2017-2027	40	40
Transition bonds [a]	5.05% — 5.55%	2020-2023	124	171
Notes payable and other [b]	6.20% — 8.88%	2019-2021	46	57
Total long-term debt			5,157	5,331
Unamortized debt discount and premium, net			1	(2)
Unamortized debt issuance costs			(2)	(50)
Fair value adjustment			742	—
Long-term debt due within one year			(253)	(456)
Long-term debt			$ 5,645	$ 4,823

(a) Transition bonds are recorded as part of Long-term debt within ACE's Consolidated Balance Sheets.
(b) Includes Pepco's capital lease obligations of $39 million and $50 million at December 31, 2016 and 2015, respectively.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Pepco

	Rates	Maturity Date	December 31, 2016	December 31, 2015
Long-term debt				
First mortgage bonds (a)	3.05% — 7.90%	2022-2043	$ 2,335	$ 2,335
Notes payable and other (b)	6.20% — 8.88%	2019-2021	46	50
Total long-term debt			2,381	2,385
Unamortized debt discount and premium, net			(2)	(3)
Unamortized debt issuance costs			(30)	(31)
Long-term debt due within one year			(16)	(11)
Long-term debt			$ 2,333	$ 2,340

(a) Substantially all of Pepco's assets are subject to the lien of its respective mortgage indenture.
(b) Includes capital lease obligations of $39 million and $50 million at December 31, 2016 and 2015, respectively. Lease payments of $12 million, $13 million and $14 million will be made in 2017, 2018 and 2019, respectively.

DPL

	Rates	Maturity Date	December 31, 2016	December 31, 2015
Long-term debt				
First mortgage bonds (a)	3.50% — 4.15%	2023-2045	$ 1,196	$ 1,121
Unsecured Tax-Exempt Bonds	5.40%	2031	112	112
Medium-Terms Notes (unsecured)	6.81% — 7.72%	2017-2027	40	40
Total long-term debt			1,348	1,273
Unamortized debt discount and premium, net			2	2
Unamortized debt issuance costs			(10)	(10)
Long-term debt due within one year			(119)	(204)
Long-term debt			$ 1,221	$ 1,061

(a) Substantially all of DPL's assets are subject to the lien of its respective mortgage indenture.

ACE

	Rates	Maturity Date	December 31, 2016	December 31, 2015
Long-term debt				
First mortgage bonds (a)	3.38% — 7.75%	2018-2036	$1,038	$1,039
Transition bonds (b)	5.05% — 5.55%	2020-2023	124	171
Total long-term debt			1,162	1,210
Unamortized debt discount and premium, net			(1)	(1)
Unamortized debt issuance costs			(6)	(8)
Long-term debt due within one year			(35)	(48)
Long-term debt			$1,120	$1,153

(a) Substantially all of ACE's assets are subject to the lien of its respective mortgage indenture.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(b) Maturities of ACE's Transition Bonds outstanding at December 31, 2016 are $35 million in 2017, $31 million in 2018, $18 million in 2019, $19 million in 2020 and $21 million in 2021.

Long-term debt maturities at Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE in the periods 2017 through 2021 and thereafter are as follows:

Year	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2017	$ 2,430	$ 1,117	$ 425	$ —	$ 41	253	16	119	35
2018	1,742	104	840	500	—	298	13	4	281
2019	1,060	606	300	—	—	154	124	12	18
2020	3,331	1,912	500	—	—	19	—	—	19
2021	2,400	888	350	300	300	262	2	—	260
Thereafter	22,996(a)	4,581	4,892(b)	1,984(c)	2,258(d)	4,171	2,226	1,213	549
Total	$33,959	$ 9,208	$7,307	$2,784	$2,599	5,157	$2,381	$1,348	$1,162

(a) Includes $648 million due to ComEd, PECO and BGE financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.
(d) Includes $258 million due to BGE financing trust.

PHI Merger Financing

In May 2014, concurrently and in connection with entering into the agreement to acquire PHI, Exelon entered into a credit facility to which the lenders committed to provide Exelon a 364-day senior unsecured bridge credit facility of $7.2 billion to support the contemplated transaction and provide flexibility for timing of permanent financing. In June 2015, the remaining $3.2 billion bridge credit facility was terminated as a result of Exelon's issuance of $4.2 billion of long-term debt to fund a portion of the purchase price and related costs and expenses for the pending PHI merger and for general corporate purposes.

In connection with the $4.2 billion issuance of Senior Unsecured Notes in 2015, the tranches due in 2025, 2035, and 2045 had to be redeemed at the principal amount plus a 1% premium of principal on December 31, 2015, if the PHI merger was not consummated or terminated prior to such date ("Special Mandatory Redemption"). Exelon also had the option to redeem those notes earlier at a 1% premium of principal, if Exelon determined that the merger would not be completed before December 31, 2015.

On October 29, 2015, Exelon commenced a private exchange offer (Exchange Offer) to certain eligible holders whereby, for those that took part, the outstanding Senior Unsecured Notes in the 2025, 2035 and 2045 tranches were exchanged for new Senior Unsecured Notes.

On December 2, 2015, Exelon exchanged $1.9 billion of the Senior Unsecured Notes and paid a consent fee of approximately $5 million, which has been deferred on Exelon's Consolidated Balance Sheet and $4 million of third-party debt issuance costs, which were charged to earnings within Other, net on Exelon's Consolidated Statement of Operations and Comprehensive Income. On December 2, 2015, Exelon also redeemed $0.9 billion of Senior Unsecured Notes not exchanged in the Exchange Offer resulting in the payment of $9 million of redemption premium and the acceleration of the unamortized original issuance discount and deferred financing costs associated with the redeemed debt of $9 million, which were charged to earnings within Other, net on Exelon's Consolidated Statement of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Junior Subordinated Notes

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Net proceeds from the issuance were $1.11 billion, net of a $35 million underwriter fee. The net proceeds were used to finance a portion of the merger and related costs and expenses for the pending PHI merger and for general corporate purposes. Each equity unit represents an undivided beneficial ownership interest in Exelon's 2.50% junior subordinated notes due in 2024 and a forward equity purchase contract which settles in 2017. The junior subordinated notes are expected to be remarketed in 2017.

At the time of issuance, Exelon determined that the forward equity purchase contract had no value and therefore the entire $1.15 billion of junior subordinated notes were allocated to debt and recorded within Long-term debt on Exelon's Consolidated Balance Sheet. Additionally, at the time of issuance, the present value of the contract payments of $131 million ("Contract Payment Obligation") were recorded to Long-term debt, representing the obligation to make contract payments, with an offsetting reduction to Common stock. The obligation for the contract payments is accreted to interest expense over the 3 year period ending in 2017 in Exelon's Consolidated Statement of Operations and Comprehensive Income. During 2016, contract payments of $45 million related to the Contract Payment Obligation were included within Retirements of long-term debt in Exelon's Consolidated Statements of Cash Flows. During 2015, contract payments of $44 million related to the Contract Payment Obligation were included within Retirements of long-term debt in Exelon's Consolidated Statements of Cash Flows. During 2014, the Contract Payment Obligation was considered a non-cash financing transaction that was excluded from Exelon's Consolidated Statements of Cash Flows. Until settlement of the equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method.

Nonrecourse Debt

Exelon and Generation have issued nonrecourse debt financing, in which approximately $2.8 billion of generating assets have been pledged as collateral at December 31, 2016. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific nonrecourse debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives.

Denver Airport. In June 2011, Generation entered into a 20-year, $7 million solar loan agreement to finance a solar construction project in Denver, Colorado. The agreement is scheduled to mature on June 30, 2031. The agreement bears interest at a fixed rate of 5.50% annually with interest payable annually. As of December 31, 2016, $6 million was outstanding.

CEU Upstream. In July 2011, CEU Holdings, LLC, a wholly owned subsidiary of Generation, entered into a 5-year reserve based lending agreement (RBL) associated with certain Upstream oil and gas properties. The lenders do not have recourse against Exelon or Generation in the event of default pursuant to the RBL. Borrowings under this arrangement are secured by the assets and equity of CEU

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Holdings. The commitment level can be decreased if the assets no longer support the current borrowing base, which may result in repayment of a portion or all of the outstanding balance, or potential foreclosure of the assets. The commitment can be increased up to $500 million million if the assets support a higher borrowing base and CEU Holdings is able to obtain additional commitments from lenders. Calculations of the borrowing base are impacted by projected production and commodity prices. The facility was amended and extended on January 14, 2014 through January 2019. As of December 31, 2015, $68 million was outstanding under the facility with interest payable monthly at a variable rate equal to LIBOR plus 2.50% and the borrowing base committed under the facility was $85 million. The outstanding balance was classified as Long-term debt on Exelon's and Generation's Consolidated Balance Sheets.

In February 2016, as part of their semi-annual borrowing base re-determination testing, the RBL lenders notified CEU Holdings that the RBL borrowing base was decreased to $45 million, resulting in a "borrowing base deficiency" under the RBL of $23 million. Given the decline in value of the Upstream assets resulting from lower commodity prices, CEU Holdings chose not to provide the lenders with a formal plan for curing the borrowing base deficiency by March 31, 2016, as was required by the RBL. The lenders sent CEU Holdings a notice of event of default and demand for cure.

On June 16, 2016, CEU Holdings executed a forbearance agreement with the lenders which included terms stipulating roles and responsibilities governing a sales process, approval of the sale of the assets to be at the discretion of the lenders, and a sales timetable.

In December 2016, substantially all of the Upstream natural gas and oil exploration and production assets were sold for $37 million. The proceeds were used to reduce the debt balance by $31 million. The remaining proceeds of $6 million are being held in escrow and will be released at final settlement. In addition, during 2016, $15 million of the debt was repaid using CEU Holding's cash, resulting in an outstanding debt balance of $22 million with interest payable monthly at a variable rate equal to LIBOR plus 2.75%. Upon disposition of all of the assets and the satisfaction of certain other conditions, CEU Holdings will be released of its obligations regardless of the amount of asset sale proceeds received. The ultimate resolution of this matter has no direct effect on any Exelon or Generation credit facilities or other debt of an Exelon entity. At December 31, 2016, the outstanding debt balance of $22 million was classified within Long term debt due within one year on Exelon's and Generation's Consolidated Balance Sheets. See Note 4—Mergers, Acquisitions, and Dispositions and Note 8—Impairment of Long-Lived Assets for additional information.

Holyoke Solar Cooperative. In October 2011, Generation entered into a 20-year, $11 million solar loan agreement related to a solar construction project in Holyoke, Massachusetts. The agreement is scheduled to mature on December 2031. The agreement bears interest at a fixed rate of 5.25% annually with interest payable monthly. As of December 31, 2016, $9 million was outstanding.

Antelope Valley Solar Ranch One. In December 2011, the DOE Loan Programs Office issued a guarantee for up to $646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational in the first half of 2014. The loan will mature on January 5, 2037. Interest rates on the loan were fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity. The advances were completed as of December 31, 2015 and the outstanding loan balance will bear interest at an average blended interest rate of 2.82%. As of December 31, 2016, $552 million was outstanding. In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2016, Generation had $106 million in letters of credit outstanding related to the project.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Continental Wind. In September 2013, Continental Wind, LLC (Continental Wind), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million senior secured notes. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667MW. The net proceeds were distributed to Generation for its general business purposes. The notes are scheduled to mature on February 28, 2033. The notes bear interest at a fixed rate of 6.00% with interest payable semi-annually. As of December 31, 2016, $543 million was outstanding.

In addition, Continental Wind entered into a $131 million letter of credit facility and $10 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2016, the Continental Wind letter of credit facility had $108 million in letters of credit outstanding related to the project.

ExGen Renewables I. In February 2014, EGR, an indirect subsidiary of Exelon and Generation, borrowed $300 million aggregate principal amount pursuant to a nonrecourse senior secured loan. The proceeds were distributed to Generation for its general business purposes. The loan is scheduled to mature on February 6, 2021. The loan bears interest at a variable rate equal to LIBOR plus 4.25%, subject to a 1% LIBOR floor with interest payable quarterly. EGR indirectly owns Continental Wind. As of December 31, 2016, $234 million was outstanding. In addition to the financing, EGR entered into interest rate swaps with an initial notional amount of $240 million at an interest rate of 2.03% to manage a portion of the interest rate exposure in connection with the financing. See Note 13—Derivative Financial Instruments for additional information regarding interest rate swaps.

ExGen Texas Power. In September 2014, EGTP, an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. The net proceeds were distributed to Generation for general business purposes. The loan is scheduled to mature on September 18, 2021. The term loan bears interest at a variable rate equal to LIBOR plus 4.75%, subject to a 1% LIBOR floor with interest payable quarterly. As of December 31, 2016, $660 million was outstanding. As part of the agreement, a revolving credit facility was established for the amount of $20 million available through, and scheduled to mature on September 18, 2019. In addition to the financing, EGTP entered into various interest rate swaps with an initial notional amount of approximately $505 million at an interest rate of 2.34% to hedge a portion of the interest rate exposure in connection with this financing, as required by the debt covenants. See Note 13—Derivative Financial Instruments for additional information regarding interest rate swaps.

EGTP's operating cash flows have been negatively impacted by certain market conditions including, but not limited to: low power prices, higher fuel prices and the seasonality of its cash flows. Despite the declining operating cash flows, EGTP remains in compliance with its covenants related to the project specific financing. Management continues to monitor the project entity's short term liquidity needs.

Renewable Power Generation. In March 2016, RPG, an indirect subsidiary of Exelon and Generation, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to Generation for paydown of long term debt obligations at Sacramento PV Energy and Constellation Solar Horizons and for general business purposes. The loan is scheduled to mature on March 31, 2035. The term loan bears interest at a fixed rate of 4.11% payable semi-annually. As of December 31, 2016, $141 million was outstanding.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

SolGen. In September 2016, SolGen, LLC (SolGen), an indirect subsidiary of Exelon and Generation, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to Generation for general business purposes. The loan is scheduled to mature on September 30, 2036. The term loan bears interest at a fixed rate of 3.93% payable semi-annually. As of December 31, 2016, $148 million was outstanding.

15. Income Taxes (All Registrants)

Income tax expense (benefit) from continuing operations is comprised of the following components:

	For the Year Ended December 31, 2016								Successor	Predecessor
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	March 24, 2016 to December 31, 2016 PHI	January 1, 2016 to March 23, 2016 PHI
Included in operations:										
Federal										
Current	$ 60	$ 513	$ (135)	$ 63	$ 51	$ (118)	$ (88)	$ (26)	$ (281)	$ —
Deferred	607	(247)	379	72	88	136	97	22	283	10
Investment tax credit amortization	(24)	(20)	(2)	—	(1)	—	—	—	(1)	—
State										
Current	39	45	(4)	9	5	7	1	—	(11)	—
Deferred	79	(1)	63	5	31	16	12	—	13	7
Total	$ 761	$ 290	$ 301	$ 149	$ 174	$ 41	$ 22	$ (4)	$ 3	$ 17

	For the Year Ended December 31, 2015								Predecessor
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI
Included in operations:									
Federal									
Current	$ 407	$ 546	$ (80)	$ 64	$ 25	$ (54)	$ (27)	$ (2)	$ 12
Deferred	566	16	310	69	126	126	73	27	103
Investment tax credit amortization	(22)	(19)	(2)	—	(1)	—	—	—	(1)
State									
Current	(86)	(90)	7	(10)	—	6	2	3	17
Deferred	208	49	45	20	39	24	1	5	32
Total	$ 1,073	$ 502	$ 280	$ 143	$ 189	$ 102	$ 49	$ 33	$ 163

	For the Year Ended December 31, 2014								Predecessor
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI
Included in operations:									
Federal									
Current	$ 121	$ 360	$ (171)	$ 28	$ 24	$ (79)	$ (45)	$ (6)	$ (153)
Deferred	576	(35)	395	87	90	150	98	31	261
Investment tax credit amortization	(20)	(16)	(2)	—	(1)	—	(1)	(1)	(1)
State									
Current	42	35	7	(2)	—	(2)	—	(1)	(10)
Deferred	(53)	(137)	39	1	27	24	13	7	41
Total	$ 666	$ 207	$ 268	$ 114	$ 140	$ 93	$ 65	$ 30	$ 138

Combined Notes to Consolidated Financial Statements—(Continued)
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The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

	For the Year Ended December 31, 2016								Successor March 24, 2016 to December 31, 2016	Predecessor January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL (a)	ACE (a)	PHI (a)	PHI
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:										
State income taxes, net of Federal income tax benefit (b)	3.3	3.3	5.6	1.3	5.0	15.7	52.7	6.2	5.8	11.9
Qualified nuclear decommissioning trust fund loss	3.4	7.8	—	—	—	—	—	—	—	—
Domestic production activities deduction	—	—	—	—	—	—	—	—	—	—
Health care reform legislation	—	—	—	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.2)	(2.3)	(0.3)	(0.1)	(0.1)	(0.2)	(3.7)	0.8	1.4	(0.9)
Plant basis differences	(4.8)	—	(0.6)	(9.6)	(2.7)	(22.8)	(25.5)	10.3	39.0	(13.5)
Production tax credits and other credits	(3.6)	(8.2)	—	—	—	—	—	—	—	—
Noncontrolling interests	(0.2)	(0.3)	—	—	—	—	—	—	—	—
Statute of limitations expiration	(0.4)	(1.7)	—	—	—	—	—	—	—	—
Penalties	1.9	—	4.5	—	—	—	—	—	(0.7)	—
Merger Expenses	5.5	1.1	—	—	—	23.5	112.9	(44.9)	(89.0)	11.1
Other (c)	(0.6)	(1.5)	0.1	(1.2)	—	(1.8)	(2.2)	1.3	3.3	3.6
Effective income tax rate	38.3%	33.2%	44.3%	25.4%	37.2%	49.4%	169.2%	8.7%	(5.2)%	47.2%

	For the Year Ended December 31, 2015								
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	Predecessor PHI
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	3.7	1.0	4.9	1.0	5.3	6.7	1.7	5.7	6.6
Qualified nuclear decommissioning trust fund income	(0.4)	(0.8)	—	—	—	—	—	—	—
Domestic production activities deduction	(0.7)	(1.3)	—	—	—	—	—	—	—
Health care reform legislation	—	—	—	—	0.1	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.9)	(1.5)	(0.3)	(0.1)	(0.1)	(0.1)	(0.4)	(0.6)	(0.2)
Plant basis differences	(1.5)	—	(0.1)	(8.7)	(0.7)	(5.8)	(2.3)	(1.3)	(4.3)
Production tax credits and other credits	(1.9)	(3.4)	—	—	—	—	—	—	—
Noncontrolling interests	0.3	0.5	—	—	—	—	—	—	—
Statute of limitations expiration	(1.4)	(2.4)	—	—	—	—	—	—	—
Other (d)	—	—	0.2	0.2	—	(0.5)	5.2	6.4	(3.2)
Effective income tax rate	32.2%	27.1%	39.7%	27.4%	39.6%	35.3%	39.2%	45.2%	33.9%

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the Year Ended December 31, 2014								
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	*Predecessor* PHI
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	1.3	(1.9)	4.5	(0.1)	5.0	5.4	4.8	5.8	5.3
Qualified nuclear decommissioning trust fund income	2.4	4.8	—	—	—	—	—	—	—
Domestic production activities deduction	(2.0)	(4.1)	—	—	—	—	—	—	—
Health care reform legislation	0.1	—	0.2	—	0.2	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.1)	(2.0)	(0.3)	(0.1)	(0.3)	(0.1)	(0.3)	(0.6)	(0.3)
Plant basis differences	(1.9)	—	(0.1)	(10.4)	0.2	(4.9)	(2.4)	(0.5)	(4.5)
Production tax credits and other credits	(2.4)	(4.8)	—	—	—	—	—	—	—
Noncontrolling interests	(1.8)	(3.7)	—	—	—	—	—	—	—
Statute of limitations expiration	(2.6)	(5.3)	—	—	—	—	—	—	—
Other	(0.2)	(1.1)	0.3	0.1	(0.2)	(0.2)	1.4	(0.2)	0.8
Effective income tax rate	26.8%	16.9%	39.6%	24.5%	39.9%	35.2%	38.5%	39.5%	36.3%

(a) DPL and ACE recognized a loss before income taxes for the year ended December 31, 2016, and PHI recognized a loss before income taxes for the period of March 24, 2016, through December 31, 2016. As a result, positive percentages represent an income tax benefit for the periods presented.
(b) Includes a remeasurement of uncertain state income tax positions for Pepco and DPL.
(c) At PECO, includes a cumulative adjustment related to an anticipated gas repairs tax return accounting method change.
(d) Includes impacts of the PHI Global Settlement for Pepco, DPL, ACE, and PHI

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2016 and 2015 are presented below:

	As of December 31, 2016								
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	*Successor* PHI
Plant basis differences	$ (17,966)	$ (4,192)	$ (5,034)	$ (3,095)	$ (1,977)	$ (1,678)	$ (973)	$ (869)	$ (3,586)
Accrual based contracts	434	(115)	—	—	—	—	—	—	548
Derivatives and other financial instruments	(179)	(162)	(3)	—	—	—	—	—	(1)
Deferred pension and postretirement obligation	2,287	(316)	(453)	(18)	(43)	(122)	(74)	(21)	(111)
Nuclear decommissioning activities	(509)	(509)	—	—	—	—	—	—	—
Deferred debt refinancing costs	325	44	(13)	(1)	(3)	(7)	(4)	(2)	293
Regulatory assets and liabilities	(3,319)	—	(226)	10	(240)	(194)	(75)	(69)	(1,205)
Tax loss carryforward	189	61	29	—	22	27	39	14	77
Tax credit carryforward	446	493	—	—	—	—	—	—	—
Investment in CENG	(650)	(650)	—	—	—	—	—	—	—
Other, net	1,485	403	351	99	27	66	34	34	225
Deferred income tax liabilities (net)	$ (17,457)	$ (4,943)	$ (5,349)	$ (3,005)	$ (2,214)	$ (1,908)	$ (1,053)	$ (913)	$ (3,760)
Unamortized investment tax credits	(658)	(626)	(15)	(1)	(5)	(2)	(3)	(4)	(9)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (18,115)	$ (5,569)	$ (5,364)	$ (3,006)	$ (2,219)	$ (1,910)	$ (1,056)	$ (917)	$ (3,769)

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	As of December 31, 2015								
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	*Predecessor* PHI
Plant basis differences	$ (13,393)	$ (4,269)	$ (4,424)	$ (2,901)	$ (1,821)	$ (1,599)	$ (915)	$ (791)	$ (3,342)
Accrual based contracts	(136)	(136)	—	—	—	—	—	—	—
Derivatives and other financial instruments	(203)	(181)	(4)	—	—	—	—	—	(1)
Deferred pension and postretirement obligation	1,801	(371)	(505)	(9)	(47)	(95)	(82)	(20)	(92)
Nuclear decommissioning activities	(592)	(592)	—	—	—	—	—	—	—
Deferred debt refinancing costs	133	48	(15)	(1)	(4)	(8)	(4)	(3)	(15)
Regulatory assets and liabilities	(1,706)	—	(219)	16	(264)	(202)	(91)	(93)	(414)
Tax loss carryforward	103	56	—	—	33	141	122	8	378
Tax credit carryforward	327	374	—	—	—	—	—	—	6
Investment in CENG	(595)	(595)	—	—	—	—	—	—	—
Other, net	1,112	425	270	105	27	42	29	18	103
Deferred income tax liabilities (net)	$ (13,149)	$ (5,241)	$ (4,897)	$ (2,790)	$ (2,076)	$ (1,721)	$ (941)	$ (881)	$ (3,377)
Unamortized investment tax credits	(622)	(598)	(17)	(2)	(5)	(2)	(4)	(4)	(15)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (13,771)	$ (5,839)	$ (4,914)	$ (2,792)	$ (2,081)	$ (1,723)	$ (945)	$ (885)	$ (3,392)

The following table provides the Registrants' carryforwards and any corresponding valuation allowances as of December 31, 2016.

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	*Successor* PHI
Federal									
Federal net operating loss	$ 282[a]	$ 11	$ 82	$ —	$ —	$ 44	$ 38	$ 18	$ 121
Deferred taxes on Federal net operating loss	99	4	29	—	—	15	13	6	42
Federal general business credits carryforwards	511[b]	509	1	—	1	—	—	—	—
State									
State net operating losses and credit carryforwards	3,501[c]	1,245[c]	—	—	425[d]	360[e]	639[f]	272[g]	1,522[h]
Deferred taxes on state tax attributes (net)	186	65	—	—	23	20	36	16	86
Valuation allowance on state tax attributes	20	9	—	—	1	—	—	—	10

(a) Exelon's federal net operating loss will begin expiring in 2032.
(b) Exelon's federal general business credit carryforwards will begin expiring in 2033.
(c) Exelon's and Generation's state net operating losses and credit carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2017.
(d) BGE's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2026.
(e) Pepco's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2028.
(f) DPL's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2023.
(g) ACE's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2032.
(h) PHI's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2023.

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Tabular reconciliation of unrecognized tax benefits

The following tables provide a reconciliation of the Registrants' unrecognized tax benefits as of December 31, 2016, 2015 and 2014:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	Successor PHI
Unrecognized tax benefits at January 1, 2016	$1,078	$ 534	$ 142	$ —	$120	$ 8	$ 3	$—	$ 22
Merger balance transfer	22	5	—	—	—	—	—	—	(5)
Increases based on tax positions related to 2016	108	10	—	—	—	21	16	22	59
Change to positions that only affect timing	(332)	(12)	(154)	—	—	—	—	—	—
Increases based on tax positions prior to 2016	88	—	—	—	—	51	18	—	96
Decreases based on tax positions prior to 2016	(21)	(20)	—	—	—	—	—	—	—
Decrease from settlements with taxing authorities	(27)	(27)	—	—	—	—	—	—	—
Decreases from expiration of statute of limitations	—	—	—	—	—	—	—	—	—
Unrecognized tax benefits at December 31, 2016	$ 916	$ 490	$ (12)	$ —	$120	$ 80	$ 37	$ 22	$ 172

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	Predecessor PHI
Unrecognized tax benefits at January 1, 2015	$1,829	$ 1,357	$ 149	$ 44	$ —	$ —	$—	$—	$ 702
Increases based on tax positions related to 2015	108	—	—	—	106	—	—	—	—
Change to positions that only affect timing	(705)	(659)	(7)	(44)	—	—	—	—	(688)
Increases based on tax positions prior to 2015	79	65	—	—	14	8	3	—	11
Decreases based on tax positions prior to 2015	(116)	(112)	—	—	—	—	—	—	—
Decrease from settlements with taxing authorities	(31)	(31)	—	—	—	—	—	—	—
Decreases from expiration of statute of limitations	(86)	(86)	—	—	—	—	—	—	(3)
Unrecognized tax benefits at December 31, 2015	$1,078	$ 534	$ 142	$ —	$120	$ 8	$ 3	$—	$ 22

Combined Notes to Consolidated Financial Statements—(Continued)
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	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	Predecessor PHI
Unrecognized tax benefits at January 1, 2014	$2,175	$ 1,415	$ 324	$ 44	$—	$ 45	$ 3	$ 3	$ 743
Increases based on tax positions related to 2014	15	15	—	—	—	—	—	—	—
Change to positions that only affect timing	(255)	33	(175)	—	—	(45)	(3)	(3)	(41)
Increases based on tax positions prior to 2014	18	18	—	—	—	—	—	—	—
Decreases based on tax positions prior to 2014	(1)	(2)	—	—	—	—	—	—	—
Decreases from settlements with taxing authorities	(35)	(34)	—	—	—	—	—	—	—
Decreases from expiration of statute of limitations	(88)	(88)	—	—	—	—	—	—	—
Unrecognized tax benefits at December 31, 2014	$1,829	$ 1,357	$ 149	$ 44	$—	$ —	$—	$—	$ 702

Exelon, Generation, and ComEd have $83 million, $7 million, and $(12) million of unrecognized tax benefits balance at December 31, 2016 for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits.

Exelon, Generation, and ComEd had $415 million, $20 million, and $142 million of unrecognized tax benefits at December 31, 2015 for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits

Exelon, Generation, ComEd, PECO, and PHI had $1,122 million, $680 million, $149 million, $43 million, and $686 million of unrecognized tax benefits at December 31, 2014 for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits

The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to, or defer the receipt of the cash tax benefit from, the taxing authority to an earlier or later period respectively.

Unrecognized tax benefits that if recognized would affect the effective tax rate

Exelon, Generation, PHI, Pepco, ACE, and DPL have $633 million, $483 million, $93 million, $21 million, $22 million, and $16 million, respectively, of unrecognized tax benefits at December 31, 2016 that, if recognized, would decrease the effective tax rate. BGE, PHI, Pepco, and DPL have $120 million, $80 million, $59 million, and $21 million of unrecognized tax benefits at December 31, 2016 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Exelon, Generation, and PHI had $538 million, $509 million, and $11 million, respectively, of unrecognized tax benefits at December 31, 2015 that, if recognized, would decrease the effective tax rate. BGE, PHI, Pepco, and DPL had $120 million, $11 million, $8 million, and $3 million of unrecognized tax benefits at December 31, 2015 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Combined Notes to Consolidated Financial Statements—(Continued)
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Exelon, Generation, and PHI had $701 million, $672 million, and $15 million, respectively, of unrecognized tax benefits at December 31, 2014 that, if recognized, would decrease the effective tax rate.

Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Settlement of Income Tax Audits and Litigation

As of December 31, 2016, Exelon, Generation, PHI, Pepco, ACE and DPL have approximately $146 million, $19 million, $59 million, $21 million, $22 million and $16 million, respectively, of unrecognized federal and state tax benefits that will decrease in the first quarter of 2017 due to the receipt in January of favorable IRS guidance as to whether certain business expenses should be capitalized or deducted. The recognition of these unrecognized tax benefits will decrease the effective tax rate in the first quarter of 2017.

As of December 31, 2016, Exelon, Generation, BGE, PHI, Pepco, and DPL have approximately $244 million, $44 million, $120 million, $80 million, $59 million, and $21 million, respectively, of unrecognized state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits, potential settlements, and expected statute of limitation expirations. Of the above unrecognized tax benefits, Exelon and Generation have $44 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefit related to BGE, Pepco, and DPL if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Total amounts of interest and penalties recognized

The following tables represent the net interest and penalties receivable (payable), including interest and penalties related to tax positions reflected in the Registrants' Consolidated Balance Sheets.

Net interest receivable (payable) as of	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
December 31, 2016	$ (507)	$ 46	$ (384)	$ 8	$ (1)	$ 1	$—	$ 1
December 31, 2015	(288)	80	(210)	3	(1)	20	3	24

Net penalties receivable (payable) as of	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
December 31, 2016	$ (106)	$ —	$ (86)	$ —	$—	$ —	$—	$—
December 31, 2015	—	—	—	—	—	—	—	—

PHI	*Successor* December 31, 2016	*Predecessor* December 31, 2015
Net interest receivable (payable)	$ 2	$ (34)
Net penalties receivable (payable)	—	—

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The following tables set forth the net interest and penalty expense, including interest and penalties related to tax positions, recognized in Interest expense, net and Other, net in Other income and deductions in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Net interest expense (income) for the years ended	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
December 31, 2016	$ 165	$ (13)	$ 117	$ —	$—	$ 6	$—	$ (1)
December 31, 2015	(13)	(31)	7	—	—	(4)	—	—
December 31, 2014	(36)	(50)	6	—	1	(1)	—	(1)

Net penalty expense (income) for the years ended	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
December 31, 2016	$ 106	$ —	$ 86	$ —	$—	$ —	$—	$—
December 31, 2015	—	—	—	—	—	—	—	—
December 31, 2014	—	—	—	—	—	—	—	—

	Successor	*Predecessor*		
PHI	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	December 31, 2015	December 31, 2014
Net interest expense (income)	$ (2)	$ —	$ (34)	$ —
Net penalty expense (income)	—	—	—	—

Description of tax years that remain open to assessment by major jurisdiction

Taxpayer	Open Years
Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns	1999, 2001-2015
PHI Holdings and subsidiaries consolidated Federal income tax returns	2013-2015
Exelon and subsidiaries Illinois unitary income tax returns	2010-2015
Constellation combined New York corporate income tax returns	2010-March 2012
Exelon combined New York corporate income tax returns	2011-2015
Various separate company (excluding PECO) Pennsylvania corporate net income tax returns	2011-2015
PECO Pennsylvania separate company returns	2010-2015
DPL Delaware separate company returns	Same as Federal
ACE New Jersey separate company returns	2012-2015
Various separate company Maryland corporate net income tax returns	Same as Federal
Washington D.C. corporate income tax returns	2013-2015

Other Tax Matters

Like-Kind Exchange

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $1.2 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities.

The IRS disagreed with this position and asserted that the entire gain of approximately $1.2 billion was taxable in 1999. Exelon was unable to reach agreement with the IRS regarding the dispute over

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

the like-kind exchange position. The IRS asserted that the Exelon purchase and leaseback transaction was substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities did not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS also asserted a penalty of approximately $90 million for a substantial understatement of tax.

In accordance with applicable accounting standards, Exelon was required to assess whether it was more-likely-than-not that to prevail in litigation. In light of the outcome of another case involving a listed transaction and Exelon's determination that settlement was unlikely, Exelon concluded that subsequent to December 31, 2012, it was no longer more-likely-than-not that its position would be sustained. As a result, in the first quarter of 2013 Exelon recorded a non-cash charge to earnings of approximately $265 million, which represented the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013, that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $172 million was recorded at ComEd. Exelon has agreed to hold ComEd harmless from any unfavorable impacts on ComEd's equity of the after-tax interest or penalty amounts. As a result, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Based on applicable case law and the facts of the transaction, Exelon did not believe it was likely a penalty would be assessed. Accordingly, no charge was recorded for the penalty asserted nor for after-tax interest that could be due on the asserted penalty.

On September 30, 2013, the IRS issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court and the trial took place in August of 2015. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue.

On September 19, 2016, the Tax Court rejected Exelon's position in the case and ruled that Exelon was not entitled to defer gain on the transaction. In addition, contrary to Exelon's evaluation that the penalty was unwarranted, the Tax Court ruled that Exelon is liable for the penalty and interest due on the asserted penalty. In the second quarter of 2017, Exelon expects to timely appeal this decision to the U.S. Court of Appeals for the Seventh Circuit.

While it has strong arguments on appeal with respect to both the merits and the penalty, Exelon has determined that, pursuant to accounting standards, it is no longer more-likely-than-not to avoid the penalty. As a result, in the third quarter of 2016, Exelon and ComEd recorded a charge to earnings of approximately $106 million and $86 million, respectively, of penalty and approximately $94 million and $64 million, respectively, of after-tax interest. Exelon and ComEd recorded the penalty and pre-tax interest due on the asserted penalty to Other, net and Interest expense, net, respectively, on their Consolidated Statements of Operations. Consistent with Exelon's agreement to continue to hold ComEd harmless from any unfavorable impact on its equity, ComEd recorded on its Consolidated Balance Sheets as of September 30, 2016, a $150 million receivable and non-cash equity contributions from Exelon.

In order to appeal the decision, Exelon is required to pay the tax, penalty and interest at the time Exelon files its appeal (expected in the second quarter of 2017). While the final calculation of tax, penalty and interest has not yet been finalized by the IRS, Exelon estimates that a payment of

approximately $1.4 billion related to the like-kind exchange will be due, including $300 million from ComEd, in the second quarter of 2017. While Exelon will receive a tax benefit of $400 million associated with the deduction for the interest, Exelon expects to have a net operating loss carryforward and thus does not expect to realize the cash benefit until 2018. After taking into account these interest deduction tax benefits, the total estimated net cash outflow for the like-kind exchange is $1 billion, of which approximately $300 million is attributable to ComEd after giving consideration to Exelon's agreement to hold ComEd harmless from any unfavorable impacts of after-tax interest or penalty amounts on ComEd's equity. Upon a final appellate decision, which could take up to several years, Exelon expects to receive $80 million related to final interest computations.

Of the above amounts payable, Exelon deposited with the IRS approximately $1.25 billion in October of 2016. The remaining amount will be paid in the second quarter of 2017 at the time Exelon files its appeal of the Tax Court decision. Exelon funded the $1.25 billion deposit with a combination of cash on hand and short-term borrowings. The deposit is reflected as a current asset and the related liabilities for the tax, penalty, and interest are included on Exelon's balance sheet as current obligations.

As of December 31, 2016, ComEd has a total receivable from Exelon pursuant to the hold harmless agreement of $345 million, which is included in Current Receivables from Affiliates on ComEd's Consolidated Balance Sheet. Under the agreement, Exelon will settle this receivable with ComEd no later than the time that the payments related to the like-kind exchange are due to the IRS, currently anticipated in the second quarter of 2017. Exelon will not seek recovery from ComEd customers for any interest or penalty amounts associated with the like-kind exchange tax position.

As previously disclosed, in the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of $335 million. On March 31, 2016, Exelon entered into an agreement to terminate its interests in the remaining two municipal-owned electric generation properties in exchange for $360 million.

PHI Global Tax Settlement

On November 18, 2015, PHI entered into a settlement with the IRS and the DOJ (the Global Tax Settlement) to primarily provide for the resolution of the uncertain tax treatment of its previously held cross-border energy lease investments involving public utility assets located outside of the United States structured as sale-in, lease-out, or SILO, transactions.

As a result of the Global Tax Settlement in the fourth quarter of 2015, PHI re-measured uncertain tax positions resulting in the recognition of a tax benefit of $35 million, including $26 million related to continuing operations and $9 million related to discontinued operations. PHI also recorded an interest benefit, net of tax, of $21 million. Pepco recorded a tax benefit of $6 million and interest benefit, net of tax, of $3 million. ACE and DPL recorded a tax expense of $3 million and $3 million, respectively.

Long-Term State Tax Apportionment (Exelon, Generation and PHI)

Exelon, Generation and PHI periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of their respective deferred state income taxes. Events that may require Exelon, Generation and PHI to update their long-term state tax apportionment include significant changes in tax law and/or significant operational changes, such as

the merger with PHI. As a result of the merger, Exelon and Generation reevaluated their long-term state tax apportionment for all states where they have state income tax obligations, which include Delaware, Illinois, Maryland, New Jersey, Pennsylvania, and Washington D.C., as well as other states. The total effect of revising the long-term state tax apportionment resulted in the recording of deferred state tax benefit in the amount of $1 million and $6 million, net of tax, for Exelon and Generation, respectively. Further, Exelon and PHI recorded deferred state tax liabilities of $59 million and $8 million, net of tax, respectively, as part of purchase accounting during the first quarter of 2016. The long-term state tax apportionment was revised in the fourth quarter of 2016 pursuant to Exelon's long-term state tax apportionment policy, resulting in the recording of a deferred state tax expense for Exelon and Generation of $8 million and $14 million, net of tax.

Allocation of Tax Benefits (All Registrants)

Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2016, Generation, PECO, and BGE recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $94 million, $18 million, and $8 million respectively. ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss. PHI, Pepco, DPL, and ACE did not record an allocation of Federal tax benefits from Exelon as they were not a part of Exelon's 2015 consolidated tax return.

During 2015, Generation, PECO, and BGE recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $57 million, $16 million, and $7 million respectively. ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss.

During 2014, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $55 million and $25 million, respectively. ComEd and BGE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of tax net operating losses.

16. Asset Retirement Obligations (All Registrants)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation updates its ARO annually unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

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The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets, from January 1, 2015 to December 31, 2016:

	Exelon and Generation
Nuclear decommissioning ARO at January 1, 2015	$ 6,961
Accretion expense	387
Net increase for changes in and timing of estimated future cash flows	901
Costs incurred related to decommissioning plants	(3)
Nuclear decommissioning ARO at December 31, 2015 (a)	8,246
Accretion expense	436
Net increase for changes in and timing of estimated future cash flows	61
Costs incurred related to decommissioning plants	(9)
Nuclear decommissioning ARO at December 31, 2016 (a)	$ 8,734

(a) Includes $10 million and $7 million as the current portion of the ARO at December 31, 2016 and 2015, respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During 2016, Generation's total nuclear ARO increased by approximately $488 million, primarily reflecting year-to-date accretion of the ARO liability of approximately $436 million due to the passage of time and impacts of ARO updates completed during 2016 to reflect changes in amounts and timing of estimated decommissioning cash flows.

The $61 million increase in the ARO during 2016 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year, some with offsetting impacts. These adjustments include increases of $288 million resulting from the change in the assumed DOE spent fuel acceptance date for disposal from 2025 to 2030 as well as increases resulting from updates to the cost studies of Oyster Creek, Zion, Calvert Cliffs, R.E. Ginna and Nine Mile Point. These increases were partially offset by a decrease of $165 million resulting from changes to the decommissioning scenarios and their probabilities as well as reductions in estimated cost escalation rates, primarily for labor, energy and waste burial costs. Most of the increase to the ARO resulting from the June 2, 2016, announcement to early retire Clinton and Quad Cities was reversed pursuant to the December 7, 2016, enactment of the Illinois FEJA. See Note 9—Early Nuclear Plant Retirements for additional information.

The financial statement impact related to changes in the ARO, on an individual unit basis, due to the changes in, and timing of, estimated cash flows primarily resulted in a corresponding change in the unit's ARC within Property, plant and equipment on Exelon's and Generation's Consolidated Balance Sheets. If the ARO decreases for a unit that does not have any remaining ARC, the corresponding change is recorded as a credit to income in Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Approximately $89 million of the 2016 adjustment resulted in a credit to income, which is included in Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During 2015, Generation's ARO increased by approximately $1.3 billion. The increase was primarily driven by an increase of approximately $630 million for costs expected to be incurred for required site security during the decommissioning periods in which SNF remains on-site and until major reactor components and buildings have been dismantled and removed. This projected increase was based on emerging industry experience at nuclear sites in the planning or early stage of decommissioning indicating greater than originally expected numbers of security personnel required to

be on site during these decommissioning periods. Generation will continue to monitor emerging security cost trends, including potential strategies to limit such costs by, for example, optimizing the transfer of SNF when DOE starts taking possession of SNF or increasing the use of dry SNF storage, and will adjust the ARO liability accordingly. The 2015 increase in the ARO included an increase of approximately $285 million for the impacts of a change implemented in the 2015 annual assessment of Generation's SNF storage and disposal cost estimation methodology to better align the projected timing of SNF transfers to the DOE with assumed plant shutdown dates as well as higher assumed probabilities of early retirements of certain economically challenged nuclear plants (See Note 9—Early Nuclear Plant Retirements for additional information) and further accretion of the obligation. These increases were partially offset by reductions in estimated cost escalation rates, primarily for labor and energy costs.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with Generation's nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of approximately $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. Aside from the former PECO units, Generation does not currently collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from utility customers. Apart from the contributions made to the NDT funds from amounts previously collected from ComEd and currently collected from PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third-party (see Zion Station Decommissioning below) and the CENG units, where any shortfall is required to be funded by both Generation and EDF. Generation, through PECO, has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise Generation will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds compared to decommissioning costs, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from utility customers for any of Generation's other nuclear units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With

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respect to Generation's other nuclear units, Generation retains any funds remaining after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to nuclear decommissioning trust funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. Generation expects to comply with applicable regulations and timely commence and complete all required decommissioning activities.

At December 31, 2016, and 2015, Exelon and Generation had NDT fund investments totaling $11,061 million and $10,342 million, respectively. For additional information related to the NDT fund investments, refer to Note 12—Fair Value of Financial Assets and Liabilities.

The following table provides unrealized gains on NDT funds for 2016, 2015 and 2014:

	Exelon and Generation		
	For the Years Ended December 31,		
	2016	2015	2014
Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units (a)	$ 216	$ (282)	$ 180
Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units (b)(c)	194	(197)	134

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $(1) million, $7 million and $29 million of net unrealized gains (losses) related to the Zion Station pledged assets in 2016, 2015 and 2014, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.
(c) Net unrealized gains (losses) related to Generation's NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Accounting Implications of the Regulatory Agreements with ComEd and PECO . Based on the regulatory agreement with the ICC that dictates Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the NDT funds are expected to exceed the total estimated decommissioning obligation, decommissioning-related activities, including realized and unrealized gains and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's

and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial position could be material. As of December 31, 2016, the NDT funds of each of the former ComEd units, except for Zion (see Zion Station Decommissioning below), are expected to exceed the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is different, as described below, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

Based on the regulatory agreement supported by the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the former PECO units, regardless of whether the funds held in the NDT funds are expected to exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial position could be material.

The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Refer to Note 3—Regulatory Matters and Note 27—Related Party Transactions for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to

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dispose of SNF and decommission the SNF dry storage facility, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to its decommissioning efforts at Zion Station. During 2013, EnergySolutions entered a definitive acquisition agreement and was acquired by another Company. Generation reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to Pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a Payable for Zion Station decommissioning in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the Payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately $111 million, which is included within the nuclear decommissioning ARO at December 31, 2016. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2016 and 2015:

	Exelon and Generation	
	2016	2015
Carrying value of Zion Station pledged assets	$ 113	$ 206
Payable to Zion Solutions [a]	104	189
Current portion of payable to Zion Solutions [b]	90	99
Cumulative withdrawals by Zion Solutions to pay decommissioning costs [c]	878	786

(a) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.
(c) Includes project expenses to decommission Zion Station and estimated tax payments on Zion Station NDT fund earnings.

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required decommissioning work according to an established schedule and constructed a dry cask storage facility on the land and has loaded the SNF from the SNF pools onto the dry cask storage facility at Zion Station. Rent payable under the Lease Agreement is $1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with Zion Station and penalty rents

may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by ZionSolutions, EnergySolutions provided a $200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. In accordance with the terms of the ASA, the letter of credit was reduced to $173 million in November 2016 due to the completion of key decommissioning milestones. EnergySolutions and its parent company have also provided a performance guarantee and EnergySolutions has entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in the type of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2016 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2019 for Oyster Creek); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2016 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning and site restoration activities, as applicable, are completed under four possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the consideration of multiple end of life scenarios; (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 5.3% to 5.9% (as compared to a historical 5-year annual average pre-tax return of approximately 8%).

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Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial position may be significantly adversely affected.

Generation filed its biennial decommissioning funding status report with the NRC on March 31, 2015. This report reflects the status of decommissioning funding assurance for all units as of December 31, 2014. Due to increased cost estimates received in the second half of 2014, Braidwood Unit 1, Braidwood Unit 2, and Byron Unit 2 did not meet the NRC's minimum funding assurance criteria as of December 31, 2014. NRC guidance provides licensees with two years or by the time of submitting the next biennial report (on or before March 31, 2017) to resolve funding assurance shortfalls. On February 4, 2016, Generation submitted an updated decommissioning funding status report with the NRC for Braidwood Units 1 and 2, and Byron Unit 2. This report reflected the approved license renewals for these units, and showed adequate decommissioning funding assurance for each of the three units.

On March 31, 2016, Generation submitted its NRC required annual decommissioning funding status report as of December 31, 2015 for reactors that have been shut down or are within five years of shut down (Dresden Unit 1, Oyster Creek, Zion and Peach Bottom Unit 1), except for Zion Station which is included in a separate report to the NRC submitted by EnergySolutions (see Zion Station Decommissioning above). The status report demonstrated adequate decommissioning funding assurance for all these units except for Peach Bottom Unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom Unit 1 is provided by the NDT fund in addition to collections from PECO ratepayers. As discussed under Nuclear Decommissioning Trust Fund Investments above, the amount collected from PECO ratepayers will be adjusted in the next filing to the PAPUC with new rates effective January 1, 2018.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2017. This report will reflect the status of decommissioning funding assurance as of December 31, 2016.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO units, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Non-Nuclear Asset Retirement Obligations (All Registrants)

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. PHI and the Utility Registrants have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides a rollforward of the non-nuclear AROs reflected on the Registrants' Consolidated Balance Sheets from January 1, 2015 to December 31, 2016:

	Exelon	Generation	ComEd	PECO	BGE	Successor PHI [f]	Pepco	DPL	ACE
Non-nuclear AROs at January 1, 2015	$ 346	$ 194	$ 104	$ 30	$ 18	$ —	$ —	$ —	$ —
Net (decrease) increase due to changes in, and timing of, estimated future cash flows [a]	(10)	(12)	6	(4)	—	—	—	—	—
Development projects [b]	10	10	—	—	—	—	—	—	—
Accretion expense [c]	16	10	5	1	—	—	—	—	—
Sale of generating assets [d]	(2)	(2)	—	—	—	—	—	—	—
Payments	(5)	(3)	(2)	—	—	—	—	—	—
Non-nuclear AROs at December 31, 2015 [e]	355	197	113	27	18	—	—	—	—
Merger with PHI [g]	8	1	—	—	—	—	—	—	—
Net increase (decrease) due to changes in, and timing of, estimated future cash flows [a]	34	8	4	1	7	14	2	9	3
Development projects [b]	11	11	—	—	—	—	—	—	—
Accretion expense [c]	18	10	7	1	—	—	—	—	—
Sale of generating assets [d]	(22)	(22)	—	—	—	—	—	—	—
Payments	(11)	(6)	(3)	(1)	(1)	—	—	—	—
Non-nuclear AROs at December 31, 2016 [e]	$ 393	$ 199	$ 121	$ 28	$ 24	$ 14	$ 2	$ 9	$ 3

	Predecessor PHI [f]
Non-nuclear AROs at January 1, 2015	$ 7
Accretion expense [c]	1
Non-nuclear AROs at December 31, 2015	$ 8
Non-nuclear AROs at March 23, 2016	$ 8

(a) During the year ended December 31, 2016, Generation recorded an increase of $1 million in Operating and maintenance expense. ComEd, PECO and BGE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2016. During the year ended December 31, 2015, Generation recorded a decrease of $(2) million in Operating and maintenance expense. ComEd, PECO and BGE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2015.
(b) Relates to new AROs recorded due to the construction of solar, wind and other non-nuclear generating sites.
(c) For ComEd, PECO, and BGE, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.
(d) Reflects a reduction to the ARO resulting primarily from the sales of the New Boston generating site and Upstream business in 2016 and Schuylkill generating station in 2015. See Note 4—Mergers, Acquisitions, and Dispositions for further information.
(e) Excludes $1 million, $2 million and $3 million as the current portion of the ARO at December 31, 2016 for Generation, ComEd and BGE, respectively. Excludes $5 million, $2 million and $1 million as the current portion of the ARO at December 31, 2015 for Generation, ComEd and BGE, respectively. This is included in Other current liabilities on the Registrants' respective Consolidated Balance Sheets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(f) For PHI, the successor period includes activity for the period of March 24, 2016 through December 31, 2016. The PHI predecessor periods include activity for the year ended December 31, 2015 and the period January 1, 2016 through March 23, 2016.
(g) Following the completion of the PHI merger on March 23, 2016, PHI's AROs related to its unregulated business interests were transferred to Exelon and Generation.

17. Retirement Benefits (All Registrants)

As of December 31, 2016, Exelon sponsored defined benefit pension plans and other postretirement benefit plans for essentially all employees.

Effective March 23, 2016, Exelon became the sponsor of all of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets. As a result, PHI's benefit plan net obligation and related regulatory assets were transferred to Exelon and remeasured at the merger date using current assumptions, including discount rates.

The table below shows the pension and other postretirement benefit plans in which employees of each operating company participated at December 31, 2016.

	Operating Company [e]								
Name of Plan:	**Generation**	**ComEd**	**PECO**	**BGE**	**BSC**	**PHI**	**Pepco**	**DPL**	**ACE**
Qualified Pension Plans:									
Exelon Corporation Retirement Program [a]	X	X	X	X	X				
Exelon Corporation Cash Balance Pension Plan [a]	X	X	X	X	X				
Exelon Corporation Pension Plan for Bargaining Unit Employees [a]	X	X			X				
Exelon New England Union Employees Pension Plan [a]	X								
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek [a]	X	X	X		X				
Pension Plan of Constellation Energy Group, Inc. [b]	X	X	X	X	X				
Pension Plan of Constellation Energy Nuclear Group, LLC [c]	X			X	X				
Nine Mile Point Pension Plan [c]	X				X				
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B [b]	X								
Pepco Holdings LLC Retirement Plan [d]	X					X	X	X	X
Non-Qualified Pension Plans:									
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan [a]	X	X	X		X				
Exelon Corporation Supplemental Management Retirement Plan [a]	X	X	X	X	X				
Constellation Energy Group, Inc. Senior Executive Supplemental Plan [b]	X			X	X				
Constellation Energy Group, Inc. Supplemental Pension Plan [b]	X			X	X				
Constellation Energy Group, Inc. Benefits Restoration Plan [b]	X	X		X	X				

Combined Notes to Consolidated Financial Statements—(Continued)
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	Operating Company (e)								
Name of Plan:	**Generation**	**ComEd**	**PECO**	**BGE**	**BSC**	**PHI**	**Pepco**	**DPL**	**ACE**
Constellation Energy Nuclear Plan, LLC Executive Retirement Plan (c)	X				X				
Constellation Energy Nuclear Plan, LLC Benefits Restoration Plan (c)	X				X				
Baltimore Gas & Electric Company Executive Benefit Plan (b)	X			X	X				
Baltimore Gas & Electric Company Manager Benefit Plan (b)	X	X		X	X				
Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan (d)	X					X	X	X	X
Conectiv Supplemental Executive Retirement Plan (d)	X					X		X	X
Pepco Holdings LLC Combined Executive Retirement Plan (d)	X					X	X		
Atlantic City Electric Director Retirement Plan (d)									X
Other Postretirement Benefit Plans:									
PECO Energy Company Retiree Medical Plan (a)	X	X	X	X	X				
Exelon Corporation Health Care Program (a)	X	X	X	X	X				
Exelon Corporation Employees' Life Insurance Plan (a)	X	X	X	X	X				
Exelon Corporation Health Reimbursement Arrangement Plan (a)	X	X	X	X	X				
Constellation Energy Group, Inc. Retiree Medical Plan (b)	X	X	X	X	X				
Constellation Energy Group, Inc. Retiree Dental Plan (b)	X			X	X				
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan (b)	X	X	X	X	X				
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan (b)	X								
Exelon New England Union Post-Employment Medical Savings Account Plan (a)	X								
Retiree Medical Plan of Constellation Energy Nuclear Group LLC (c)	X			X	X				
Retiree Dental Plan of Constellation Energy Nuclear Group LLC (c)	X			X	X				
Nine Mile Point Nuclear Station, LLC Medical Care and Prescription Drug Plan for Retired Employees (c)	X				X				
Pepco Holdings LLC Welfare Plan for Retirees (d)	X					X	X	X	X

(a) These plans are collectively referred to as the legacy Exelon plans.
(b) These plans are collectively referred to as the legacy Constellation Energy Group (CEG) Plans.
(c) These plans are collectively referred to as the legacy CENG plans.
(d) These plans are collectively referred to as the legacy PHI plans.
(e) Employees generally remain in their legacy benefit plans when transferring between operating companies.

Combined Notes to Consolidated Financial Statements—(Continued)
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Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Exelon has elected that the trusts underlying these plans be treated as qualified trusts under the IRC. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets and Funded Status

Exelon recognizes the overfunded or underfunded status of defined benefit pension and OPEB plans as an asset or liability on its balance sheet, with offsetting entries to AOCI and regulatory assets (liabilities), in accordance with the applicable authoritative guidance. The measurement date for the plans is December 31.

During the first quarter of 2016, Exelon received an updated valuation of its legacy Exelon, CEG and CENG pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2016. This valuation resulted in an increase to the pension obligation of $35 million and a decrease to the other postretirement benefit obligation of $8 million. Additionally, accumulated other comprehensive loss increased by approximately $2 million (after tax), regulatory assets increased by approximately $27 million, and regulatory liabilities increased by approximately $3 million.

The legacy PHI pension and other postretirement benefit plans were initially remeasured on February 29, 2016 as a result of the short time between the merger close and the end of the first quarter of 2016, using current assumptions, including the discount rate. Exelon updated these amounts in the second quarter of 2016 to reflect assumptions at March 31, 2016 resulting in a $25 million reduction in the net obligation.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables provide a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

Exelon	Pension Benefits		Other Postretirement Benefits	
	2016(b)	2015	2016(b)	2015
Change in benefit obligation:				
Net benefit obligation at beginning of year	$17,753	$18,256	$ 3,938	$ 4,197
Service cost	354	326	107	119
Interest cost	830	710	185	167
Plan participants' contributions	—	—	54	42
Actuarial (gain) loss	567	(582)	(136)	(341)
Plan amendments	(60)	—	—	(23)
Acquisitions/divestitures [a]	2,667	—	589	—
Settlements	—	(34)	—	—
Gross benefits paid	(1,051)	(923)	(280)	(223)
Net benefit obligation at end of year	$21,060	$17,753	$ 4,457	$ 3,938

Exelon	Pension Benefits		Other Postretirement Benefits	
	2016(b)	2015	2016(b)	2015
Change in plan assets:				
Fair value of net plan assets at beginning of year	$14,347	$14,874	$ 2,293	$ 2,430
Actual return on plan assets	1,061	(32)	128	4
Employer contributions	347	462	50	40
Plan participants' contributions	—	—	54	42
Gross benefits paid	(1,051)	(923)	(280)	(223)
Acquisitions/divestitures [a]	2,087	—	333	—
Settlements	—	(34)	—	—
Fair value of net plan assets at end of year	$16,791	$14,347	$ 2,578	$ 2,293

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI	Predecessor Pension Benefits January 1, 2016 to March 23, 2016	Pension Benefits 2015	Predecessor Other Postretirement Benefits January 1, 2016 to March 23, 2016	Other Postretirement Benefits 2015
Change in benefit obligation:				
Net benefit obligation at beginning of the period	$ 2,490	$2,638	$ 563	$ 632
Service cost	12	57	1	7
Interest cost	26	109	6	24
Actuarial (gain) loss	(30)	(151)	(5)	(61)
Gross benefits paid	(2)	(163)	(1)	(39)
Net benefit obligation at end of the period	$ 2,496	$2,490	$ 564	$ 563

PHI	Predecessor Pension Benefits January 1, 2016 to March 23, 2016	Pension Benefits 2015	Predecessor Other Postretirement Benefits January 1, 2016 to March 23, 2016	Other Postretirement Benefits 2015
Change in plan assets:				
Fair value of net plan assets at beginning of the period	$ 2,018	$ 2,236	$ 348	$ 367
Actual return on plan assets	—	(61)	—	1
Employer and plan participant contributions	4	6	1	5
Gross benefits paid by plan	(2)	(163)	(1)	(25)
Fair value of net plan assets at end of the period	$ 2,020	$ 2,018	$ 348	$ 348

(a) Effective March 23, 2016, Exelon became the sponsor of PHI's defined benefit pension and other postretirement benefit plans.
(b) 2016 amounts include PHI for the period of March 24, 2016 through December 31, 2016.

Exelon and PHI present their benefit obligations and plan assets net on their balance sheet within the following line items:

Exelon	Pension Benefits 2016(a)	Pension Benefits 2015	Other Postretirement Benefits 2016(a)	Other Postretirement Benefits 2015
Other current liabilities	$ 21	$ 21	$ 31	$ 27
Pension obligations	4,248	3,385	—	—
Non-pension postretirement benefit obligations	—	—	1,848	1,618
Unfunded status (net benefit obligation less plan assets)	$4,269	$ 3,406	$ 1,879	$ 1,645

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI	Pension Benefits *Predecessor* 2015	Other Postretirement Benefits *Predecessor* 2015
Other current liabilities	$ 6	$ —
Pension obligations	466	—
Non-pension postretirement benefit obligations	—	215
Unfunded status (net benefit obligation less plan assets)	$ 472	$ 215

(a) Effective March 23, 2016, Exelon became the sponsor of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets.

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO), and fair value of plan assets for all pension plans with a PBO or ABO in excess of plan assets.

PBO in excess of plan assets

	Exelon		*Predecessor* PHI
	2016	2015	2015
Projected benefit obligation	$21,060	$17,753	$ 2,490
Fair value of net plan assets	16,791	14,347	2,018

ABO in excess of plan assets

	Exelon		*Predecessor* PHI
	2016	2015	2015
Projected benefit obligation	$21,060	$17,753	$ 2,490
Accumulated benefit obligation	19,930	16,792	2,275
Fair value of net plan assets	16,791	14,347	2,018

On a PBO basis, the Exelon plans were funded at 80% and 81% at December 31, 2016 and December 31, 2015, respectively, and the PHI plans were funded at 81% at December 31, 2015. On an ABO basis, the Exelon plans were funded at 84% and 85% at December 31, 2016 and December 31, 2015, respectively, and the PHI plans were funded at 89% at December 31, 2015. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The majority of the 2016 pension benefit cost for the legacy Exelon, CEG and CENG plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 4.29%. The majority of the 2016 other postretirement benefit cost for the legacy Exelon, CEG and CENG plans is calculated using an expected long-term rate of return on plan assets of 6.71% for funded plans and a discount rate of 4.29%. The majority of the 2016 pension benefit cost of the legacy PHI plans is calculated using an expected long-term rate of return on plan assets of 6.50% and a discount rate of 3.96%. The 2016 other postretirement benefit cost for the legacy PHI plan is calculated using an expected long-term rate of return on plan assets of 6.75% and a discount rate of 3.80%.

Combined Notes to Consolidated Financial Statements—(Continued)
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A portion of the net periodic benefit cost for all pension and OPEB plans is capitalized within each of the Registrants' Consolidated Balance Sheets. The following tables present the components of Exelon's net periodic benefit costs, prior to any capitalization, for the years ended December 31, 2016, 2015 and 2014 and the components of PHI's predecessor net periodic benefit costs, prior to any capitalization, for the years ended December 31, 2015 and 2014, and the period January 1, 2016 to March 23, 2016.

	Pension Benefits			Other Postretirement Benefits		
Exelon	**2016 (a)**	**2015**	**2014**	**2016 (a)**	**2015**	**2014**
Components of net periodic benefit cost:						
Service cost	$ 354	$ 326	$ 293	$ 107	$ 119	$ 117
Interest cost	830	710	749	185	167	186
Expected return on assets	(1,141)	(1,026)	(994)	(162)	(151)	(154)
Amortization of:						
Prior service cost (credit)	14	13	14	(185)	(174)	(122)
Actuarial loss	554	571	420	63	80	50
Settlement and other charges (b)	2	2	2	—	—	—
Net periodic benefit cost	$ 613	$ 596	$ 484	$ 8	$ 41	$ 77

(a) 2016 amounts include PHI for the period of March 24, 2016 through December 31, 2016.
(b) 2016 amount includes an additional termination benefit for PHI.

		Predecessor				
	Pension Benefits			Other Postretirement Benefits		
PHI	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**	**For the Year Ended December 31, 2014**	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**	**For the Year Ended December 31, 2014**
Components of net periodic benefit cost:						
Service cost	$ 12	$ 57	$ 44	$ 1	$ 7	$ 7
Interest cost	26	109	109	6	24	26
Expected return on assets	(30)	(140)	(141)	(5)	(22)	(24)
Amortization of:						
Prior service cost (credit)	—	2	2	(3)	(13)	(13)
Actuarial loss	14	65	45	2	8	3
Net periodic benefit cost	$ 22	$ 93	$ 59	$ 1	$ 4	$ (1)

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Components of AOCI and Regulatory Assets

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets (liabilities) for the years ended December 31, 2016, 2015 and 2014 for all plans combined and the components of PHI's predecessor AOCI and regulatory assets (liabilities) for the years ended December 31, 2015 and 2014, and the period January 1, 2016 to March 23, 2016.

	Pension Benefits			Other Postretirement Benefits		
Exelon	**2016 [a]**	**2015**	**2014**	**2016 [a]**	**2015**	**2014**
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial loss (gain)	$ 644	$ 476	$ 1,639	$ (101)	$ (194)	$ 561
Amortization of actuarial loss	(554)	(571)	(420)	(63)	(80)	(50)
Current year prior service (credit) cost	(60)	—	—	—	(23)	(1,012)
Amortization of prior service (cost) credit	(14)	(13)	(14)	185	174	122
Settlements	—	(2)	(2)	—	—	—
Acquisitions	994	—	—	94	—	—
Total recognized in AOCI and regulatory assets (liabilities)	$ 1,010	$ (110)	$ 1,203	$ 115	$ (123)	$ (379)
Total recognized in AOCI	$ 51	$ (64)	$ 788	$ 20	$ (63)	$ (162)
Total recognized in regulatory assets (liabilities)	$ 959	$ (46)	$ 415	$ 95	$ (60)	$ (217)

		Predecessor				
	Pension Benefits			Other Postretirement Benefits		
PHI	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**	**For the Year Ended December 31, 2014**	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**	**For the Year Ended December 31, 2014**
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial loss (gain)	$ —	$ 50	$ 276	$ —	$ (39)	$ 62
Amortization of actuarial loss	(14)	(65)	(45)	(2)	(8)	(3)
Amortization of prior service (cost) credit	—	(2)	(2)	3	13	13
Total recognized in AOCI and regulatory assets (liabilities)	$ (14)	$ (17)	$ 229	$ 1	$ (34)	$ 72
Total recognized in AOCI	$ (1)	$ (11)	$ 17	$ —	$ —	$ —
Total recognized in regulatory assets (liabilities)	$ (13)	$ (6)	$ 212	$ 1	$ (34)	$ 72

(a) 2016 amounts include PHI for the period of March 24, 2016 through December 31, 2016.

The following table provides the components of gross accumulated other comprehensive loss and regulatory assets (liabilities) that have not been recognized as components of periodic benefit cost at December 31, 2016 and 2015, respectively, for all plans combined:

	Exelon		*Predecessor* PHI	Exelon		*Predecessor* PHI
	Pension Benefits			Other Postretirement Benefits		
	2016 (a)	2015	2015	2016 (a)	2015	2015
Prior service cost (credit)	$ (31)	$ 36	$ 6	$ (710)	$(812)	$ (88)
Actuarial loss	8,387	7,310	910	724	711	128
Total (a)	$8,356	$7,346	$ 916	$ 14	$(101)	$ 40
Total included in AOCI	$4,297	$4,246	$ 46	$ (42)	$ (63)	$ —
Total included in regulatory assets (liabilities)	$4,059	$3,100	$ 870	$ 56	$ (38)	$ 40

(a) Effective March 23, 2016, Exelon became the sponsor of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets.

The following table provides the impact to Exelon's AOCI and regulatory assets (liabilities) at December 31, 2016 as a result of the components of periodic benefit costs that are expected to be amortized in 2017. These estimates are subject to the completion of an actuarial valuation of Exelon's pension and other postretirement benefit obligations, which will reflect actual census data as of January 1, 2017 and actual claims activity as of December 31, 2016. The valuation is expected to be completed in the first quarter of 2017 for the majority of the benefit plans.

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 1	$ (188)
Actuarial loss	605	55
Total (a)	$ 606	$ (133)

(a) Of the $606 million related to pension benefits at December 31, 2016, $297 million and $309 million are expected to be amortized from AOCI and regulatory assets in 2017, respectively. Of the $(133) million related to other postretirement benefits at December 31, 2016, $(70) million and $(63) million are expected to be amortized from AOCI and regulatory assets (liabilities) in 2017, respectively.

Assumptions

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and inputs and accounting policy elections. The measurement of benefit obligations and costs is impacted by several assumptions and inputs, including the discount rate applied to benefit obligations, the long-term EROA, Exelon's expected level of contributions to the plans, the long-term expected investment rate credited to employees participating in cash balance plans and the anticipated rate of increase of health care costs. Additionally, assumptions related to plan participants include the incidence of mortality, the expected remaining service period, the level of compensation and rate of compensation increases, employee age and length of service, among other factors. When developing the required assumptions, Exelon considers historical information as well as future expectations.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Expected Rate of Return. In selecting the EROA, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

Mortality. For the December 31, 2014 actuarial valuation, Exelon changed its assumption of mortality to reflect more recent expectations of future improvements in life expectancy. The change was supported through completion of an experience study and supplemental analyses performed by Exelon's actuaries. The change in assumption resulted in increases of $361 million and $117 million in the pension and other postretirement benefits obligations as of December 31, 2014, respectively. There were no changes to the mortality assumption in 2015 or 2016.

The following assumptions were used to determine the benefit obligations for the plans at December 31, 2016, 2015 and 2014. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits			Other Postretirement Benefits		
Exelon	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Discount rate	4.04% (a)	4.29% (b)	3.94% (c)	4.04% (a)	4.29% (b)	3.92% (c)
Rate of compensation increase	(d)	(d)	(d)	(d)	(d)	(d)
Mortality table	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)
Health care cost trend on covered charges	N/A	N/A	N/A	5.50% with ultimate trend of 5.00% in 2017	5.50% decreasing to ultimate trend of 5.00% in 2017	6.00% decreasing to ultimate trend of 5.00% in 2017

Combined Notes to Consolidated Financial Statements—(Continued)
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PHI	Predecessor Pension Benefits January 1, 2016 to March 23, 2016 (e)	Pension Benefits 2015	Pension Benefits 2014	Predecessor Other Postretirement Benefits January 1, 2016 to March 23, 2016 (e)	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014
Discount rate		4.65% / 4.55% (f)	4.20%		4.55%	4.15%
Rate of compensation increase		5.00%	5.00%		5.00%	5.00%
Mortality table		RP-2014 table with improvement scale MP-2015	RP-2014 table with improvement scale MP-2014		RP-2014 table with improvement scale MP-2015	RP-2014 table with improvement scale MP-2014
Health care cost trend on covered charges		N/A	N/A		6.33% pre-65 and 5.40% post-65 decreasing to ultimate trend of 5.00% in 2020	6.67% pre-65 and 5.50% post-65 decreasing to ultimate trend of 5.00% in 2020

(a) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2016. Certain benefit plans used individual rates ranging from 3.66% - 4.11% and 4.00% - 4.17% for pension and other postretirement plans, respectively.
(b) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2015. Certain benefit plans used individual rates ranging from 3.68% - 4.14% and 4.32% - 4.43% for pension and other postretirement plans, respectively.
(c) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2014. Certain benefit plans used individual rates ranging from 3.29% - 3.82% and 3.99% - 4.06% for pension and other postretirement plans, respectively.
(d) The legacy Exelon, CEG and CENG pension and other postretirement plans used a rate of compensation increase of 3.25% through 2019 and 3.75% thereafter, while the legacy PHI pension and other postretirement plans used a weighted-average rate of compensation increase of 5% for all periods.
(e) Obligation was not remeasured during this period.
(f) The discount rate for the qualified and nonqualified pension plans was 4.65% and 4.55%, respectively.

The following assumptions were used to determine the net periodic benefit costs for the plans for the years ended December 31, 2016, 2015 and 2014, as well as for the PHI predecessor period January 1, 2016 to March 23, 2016:

Exelon	Pension Benefits 2016	Pension Benefits 2015	Pension Benefits 2014	Other Postretirement Benefits 2016	Other Postretirement Benefits 2015	Other Postretirement Benefits 2014
Discount rate	4.29% (a)	3.94% (b)	4.80% (c)	4.29% (a)	3.92% (b)	4.90% (c)
Expected return on plan assets	7.00% (d)	7.00% (d)	7.00% (d)	6.71% (d)	6.50% (d)	6.59% (d)
Rate of compensation increase	(e)	(e)	(f)	(e)	(e)	(f)
Mortality table	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table with Scale AA improvements	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table with Scale AA improvements
Health care cost trend on covered charges	N/A	N/A	N/A	5.50% decreasing to ultimate trend of 5.00% in 2017	6.00% decreasing to ultimate trend of 5.00% in 2017	6.00% decreasing to ultimate trend of 5.00% in 2017

Combined Notes to Consolidated Financial Statements—(Continued)
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PHI	*Predecessor* Pension Benefits			*Predecessor* Other Postretirement Benefits		
	January 1, 2016 to March 23, 2016	2015	2014	January 1, 2016 to March 23, 2016	2015	2014
Discount rate	4.65% / 4.55% (h)	4.20%	5.05%	4.55%	4.15%	5.00%
Expected return on plan assets (g)	6.50%	6.50%	7.00%	6.75%	6.75%	7.25%
Rate of compensation increase	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Mortality table	RP-2014 table with improvement scale MP-2015	RP-2014 table with improvement scale MP-2014	2014 Mortality tables prescribed by the Pension Protection Act of 2006	RP-2014 table with improvement scale MP-2015	RP-2014 table with improvement scale MP-2014	2014 Mortality tables prescribed by the Pension Protection Act of 2006
Health care cost trend on covered charges				6.33% pre-65 and 5.40% post-65 decreasing to ultimate trend of 5.00% in 2020	6.67% pre-65 and 5.50% post-65 decreasing to ultimate trend of 5.00% in 2020	7.00% pre-65 and 5.60% post-65 decreasing to ultimate trend of 5.00% in 2020
	N/A	N/A	N/A			

(a) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2016. Certain benefit plans used individual rates ranging from 3.68%-4.14% and 4.32%-4.43% for pension and other postretirement plans, respectively.
(b) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2015. Certain benefit plans used individual rates ranging from 3.29%-3.82% and 3.99%-4.06% for pension and other postretirement plans, respectively.
(c) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2014. Certain of the other postretirement benefit plans were remeasured as of April 30, 2014 using an expected long-term rate of return on plan assets of 6.59% and a discount rate of 4.30%. Costs for the year ended December 31, 2014 reflect the impact of this remeasurement. On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, Exelon became the sponsor of CENG's legacy pension and OPEB plans effective July 14, 2014; discount rates for those plans, impacting 2014 costs, ranged from 3.60%-4.30% and 4.09%-4.55%, respectively. See Note 5 - Investment in Constellation Energy Nuclear Group, LLC for further information.
(d) Not applicable to pension and other postretirement benefit plans that do not have plan assets.
(e) 3.25% through 2019 and 3.75% thereafter.
(f) 3.25% through 2018 and 3.75% thereafter.
(g) Expected return on other postretirement benefit plan assets is pre-tax.
(h) The discount rate for the qualified and nonqualified pension plans was 4.65% and 4.55%, respectively.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Assumed health care cost trend rates impact the other postretirement benefit plan costs reported for Exelon's participant populations with plan designs that do not have a cap on cost growth. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend:	
on 2016 total service and interest cost components	$ 9
on postretirement benefit obligation at December 31, 2016	105
Effect of a one percentage point decrease in assumed health care cost trend:	
on 2016 total service and interest cost components	(8)
on postretirement benefit obligation at December 31, 2016	(95)

Contributions

The following tables provide contributions to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2016 (a)	2015 (a)	2014 (a)	2016	2015	2014
Exelon	$ 347	$ 462	$ 332	$ 50	$ 40	$ 291
Generation	140	231	173	12	14	124
ComEd	33	143	122	5	7	125
PECO	30	40	11	—	—	5
BGE	31	1	—	18	16	17
BSC (b)	39	47	26	3	3	20
Pepco	24	—	—	8	2	1
DPL	22	—	—	—	—	—
ACE	15	—	—	2	3	3
PHISCO (c)	17	—	—	2	—	—

	Pension Benefits				Other Postretirement Benefits			
	Successor	*Predecessor*			*Successor*	*Predecessor*		
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
PHI	$ 74	$ 4	$ —	$ —	$ 12	$ —	$ 5	$ 4

(a) Exelon's and Generation's pension contributions include $25 million, $36 million and $43 million related to the legacy CENG plans that was funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG for the years ended December 31, 2016, 2015 and 2014, respectively.
(b) Includes $6 million, $5 million, and $9 million of pension contributions funded by Exelon Corporate, for the years ended December 31, 2016, 2015, and 2014, respectively.
(c) PHISCO's pension contributions for the year ended December 31, 2016 include $4 million of contributions made prior to the closing of Exelon's merger with PHI on March 23, 2016.

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). Additionally, the projected contribution reflects a funding strategy for the

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legacy Exelon, CEG and CENG plans of contributing the greater of $250 million until the qualified plans are fully funded on an ABO basis, and the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. Contributions to the PHI qualified pension plan are $60 million.

The following table provides all registrants' planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to other postretirement plans in 2017:

	Qualified Pension Plans (a)	Non-Qualified Pension Plans (b)	Other Postretirement Benefits (c)
Exelon	$ 310	$ 23	$ 44
Generation	127	6	12
ComEd	33	1	2
PECO	23	1	—
BGE	38	2	16
PHI	60	8	12
Pepco	60	1	10
DPL	—	—	—
ACE	—	—	—

(a) Exelon's and Generation's expected qualified pension plan contributions above include $21 million related to the legacy CENG plans that will be funded by CENG as provided in an EMA between Exelon and CENG.
(b) Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded.
(c) Unlike the qualified pension plans, other postretirement plans are not subject to statutory minimum contribution requirements. OPEB funding generally follows accounting costs however, Exelon's management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including liabilities management, levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). These amounts include benefit payments related to unfunded plans.

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2016 were:

	Pension Benefits	Other Postretirement Benefits
2017	$ 1,360	$ 244
2018	1,170	250
2019	1,191	256
2020	1,223	263
2021	1,275	272
2022 through 2026	6,791	1,456
Total estimated future benefit payments through 2026	$13,010	$ 2,741

Allocation to Exelon Subsidiaries

All registrants account for their participation in Exelon's pension and other postretirement benefit plans by applying multi-employer accounting. Employee-related assets and liabilities, including both

pension and postretirement liabilities, for the legacy Exelon plans were allocated by Exelon to its subsidiaries based on the number of active employees as of January 1, 2001 as part of Exelon's corporate restructuring. The obligation for Generation, ComEd and PECO reflects the initial allocation and the cumulative costs incurred and contributions made since January 1, 2001. Historically, Exelon has allocated the components of pension and other postretirement costs to the subsidiaries in the legacy Exelon plans based upon several factors, including the measures of active employee participation in each plan. Pension and other postretirement benefit contributions were allocated to legacy Exelon subsidiaries in proportion to active service costs recognized and total costs recognized, respectively. Beginning in 2015, Exelon began allocating costs related to its legacy Exelon pension and other postretirement benefit plans to its subsidiaries based on both active and retired employee participation and contributions are allocated based on accounting cost. The impact of this allocation methodology change was not material to any Registrant. For legacy CEG, legacy CENG, and legacy PHI plans, components of pension and other postretirement benefit costs and contributions have been, and will continue to be, allocated to the subsidiaries based on employee participation (both active and retired).

The amounts below were included in capital expenditures and operating and maintenance expense for the years ended December 31, 2016, 2015 and 2014, respectively, for each of the entities allocated portion of the pension and other postretirement benefit plan costs. These amounts include the recognized contractual termination benefit charges, curtailment gains, and settlement charges:

For the Year Ended December 31,	Exelon	Generation	ComEd	PECO	BGE	BSC (a)	Pepco	DPL	ACE	PHISCO (a)
2016 (b)	$ 621	$ 218	$ 166	$ 33	$ 68	$ 48	$ 31	$ 18	$ 15	$ 47
2015	637	269	206	39	66	57	30	15	15	37
2014	561	250	162	36	67	46	22	7	13	16

	Successor	Predecessor		
PHI	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
Pension and Other Postretirement Benefit Costs	$ 88	$ 23	$ 97	$ 58

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE, Pepco, DPL or ACE amounts above.
(b) Pepco's, DPL's, ACE's and PHISCO's pension and postretirement benefit costs for the year ended December 31, 2016 include $7 million, $4 million, $3 million and $9 million, respectively, of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016.

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses.

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(Dollars in millions, except per share data unless otherwise noted)

Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Exelon used an EROA of 7.00% and 6.60% to estimate its 2017 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations at December 31, 2016 and 2015 asset allocations were as follows:

Pension Plans

		Exelon		*Predecessor* PHI
		Percentage of Plan Assets at December 31,		
Asset Category	Target Allocation	2016	2015	2015
Equity securities	33%	33%	35%	28%
Fixed income securities	39%	39	34	66
Alternative investments [a]	28%	28	31	6
Total		100%	100%	100%

Other Postretirement Benefit Plans

		Exelon		*Predecessor* PHI
		Percentage of Plan Assets at December 31,		
Asset Category	Target Allocation	2016	2015	2015
Equity securities	43%	47%	43%	63%
Fixed income securities	28%	29	27	34
Alternative investments [a]	29%	24	30	3
Total		100%	100%	100%

(a) Alternative investments include private equity, hedge funds, real estate, and private credit.

Concentrations of Credit Risk. Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2016. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2016, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Fair Value Measurements

The following tables present pension and other postretirement benefit plan assets measured and recorded at fair value on the Registrants' Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2016 and 2015:

Exelon

At December 31, 2016 [a][d]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Pension plan assets					
Cash equivalents	$ 325	$ —	$ —	$ —	$ 325
Equities [b]	3,144	—	2	2,535	5,681
Fixed income:					
U.S. Treasury and agencies	1,008	192	—	—	1,200
State and municipal debt	—	64	—	—	64
Corporate debt	—	3,641	206	—	3,847
Other [b]	—	340	—	748	1,088
Fixed income subtotal	1,008	4,237	206	748	6,199
Private equity	—	—	—	991	991
Hedge funds	—	—	—	1,962	1,962
Real estate	—	—	—	828	828
Private credit	—	—	—	833	833
Pension plan assets subtotal	$4,477	$4,237	$ 208	$ 7,897	$16,819

At December 31, 2016 [a][d]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Other postretirement benefit plan assets					
Cash equivalents	$ 24	$ —	$ —	$ —	$ 24
Equities	547	2	—	644	1,193
Fixed income:					
U.S. Treasury and agencies	9	59	—	—	68
State and municipal debt	—	134	—	—	134
Corporate debt	—	43	—	—	43
Other	256	60	—	131	447
Fixed income subtotal	265	296	—	131	692
Hedge funds	—	—	—	445	445
Real estate	—	—	—	117	117
Private credit	—	—	—	107	107
Other postretirement benefit plan assets subtotal	$ 836	$ 298	$ —	$ 1,444	$ 2,578
Total pension and other postretirement benefit plan assets [c]	$5,313	$4,535	$ 208	$ 9,341	$19,397

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2015 [a]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Pension plan assets					
Cash equivalents	$ 210	$ —	$ —	$ —	$ 210
Equities [b]	3,571	—	2	1,462	5,035
Fixed income:					
U.S. Treasury and agencies	1,001	79	—	—	1,080
State and municipal debt	—	61	—	—	61
Corporate debt	—	2,901	165	—	3,066
Other [b]	—	146	—	452	598
Fixed income subtotal	1,001	3,187	165	452	4,805
Private equity	—	—	—	924	924
Hedge funds	—	—	—	1,924	1,924
Real estate	—	—	—	725	725
Private credit	—	—	—	699	699
Pension plan assets subtotal	$4,782	$3,187	$ 167	$ 6,186	$14,322

At December 31, 2015 [a]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Other postretirement benefit plan assets					
Cash equivalents	$ 15	$ —	$ —	$ —	$ 15
Equities	510	2	—	480	992
Fixed income:					
U.S. Treasury and agencies	11	53	—	—	64
State and municipal debt	—	131	—	—	131
Corporate debt	—	44	—	—	44
Other	155	59	—	146	360
Fixed income subtotal	166	287	—	146	599
Hedge funds	—	—	—	451	451
Real estate	—	—	—	131	131
Private credit	—	—	—	103	103
Other postretirement benefit plan assets subtotal	$ 691	$ 289	$ —	$ 1,311	$ 2,291
Total pension and other postretirement benefit plan assets [c]	$5,473	$3,476	$ 167	$ 7,497	$16,613

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI	Predecessor December 31, 2015 (a) Level 1	Level 2	Level 3	Not subject to leveling	Total
Pension plan assets					
Cash equivalents	$ 50	$ —	$ —	$ —	$ 50
Equities	335	—	—	224	559
Fixed income:					
U.S. Treasury and agencies	114	15	—	—	129
State and municipal debt	—	18	—	—	18
Corporate debt securities	—	625	—	—	625
Other	—	40	—	504	544
Fixed income subtotal	114	698	—	504	1,316
Private equity	—	—	—	38	38
Real estate	—	—	—	46	46
Pension plan assets subtotal	$ 499	$ 698	$ —	$ 812	$2,009

PHI	Predecessor December 31, 2015 (a) Level 1	Level 2	Level 3	Not subject to leveling	Total
Other postretirement benefit plan assets					
Cash equivalents	$ 8	$ —	$ —	$ —	$ 8
Equities	197	—	—	22	219
Fixed income—other	121	—	—	—	121
Other postretirement benefit plan assets subtotal	$ 326	$ —	$ —	$ 22	$ 348
Total pension and other postretirement benefit plan assets (e)	$ 825	$ 698	$ —	$ 834	$2,357

(a) See Note 12—Fair Value of Financial Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Includes derivative instruments of $1 million and $5 million, which have a total notional amount of $2,918 million and $1,774 million at December 31, 2016 and 2015, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.
(c) Excludes net liabilities of $28 million and net assets of $27 million at December 31, 2016 and 2015, respectively, which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables related to pending securities sales, interest and dividends receivable, and payables related to pending securities purchases.
(d) Effective March 23, 2016, Exelon became sponsor of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets.
(e) Excludes net assets of $9 million at December 31, 2015, which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables related to pending securities sales, interest and dividends receivable, and payables related to pending securities purchased.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2016 and 2015:

Exelon

	Fixed income	Equities	Total
Pension Assets			
Balance as of January 1, 2016	$ 165	$ 2	$167
Actual return on plan assets:			
Relating to assets still held at the reporting date	(2)	—	(2)
Purchases, sales and settlements:			
Purchases	69	—	69
Sales	(14)	—	(14)
Settlements [a]	(12)	—	(12)
Balance as of December 31, 2016	$ 206	$ 2	$208

	Fixed income	Equities	Total
Pension Assets			
Balance as of January 1, 2015	$ 120	$ 2	$122
Actual return on plan assets:			
Relating to assets still held at the reporting date	(8)	—	(8)
Purchases, sales and settlements:			
Purchases	61	—	61
Settlements [a]	(8)	—	(8)
Balance as of December 31, 2015	$ 165	$ 2	$167

(a) Represents cash settlements only.

There were no significant transfers between Level 1 and Level 2 during the year ended December 31, 2016 for the pension and other postretirement benefit plan assets.

Valuation Techniques Used to Determine Fair Value

Cash equivalents . Investments with maturities of three months or less when purchased, including certain short-term fixed income securities and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

Equities . Equities consist of individually held equity securities, equity mutual funds and equity commingled funds in domestic and foreign markets. With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity securities held individually, including real estate investment trusts, rights and warrants, are primarily traded on exchanges that contain only actively traded securities due to the volume trading requirements imposed

by these exchanges. Equity securities are valued based on quoted prices in active markets and are categorized as Level 1. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies that hold certain investments in accordance with a stated set of fund objectives, which are consistent with the plans' overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Fixed income . For fixed income securities, which consist primarily of corporate debt securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The remaining fixed income securities, including certain other fixed income investments, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Other fixed income investments primarily consist of fixed income commingled funds and mutual funds, which are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Derivative instruments consisting primarily of futures and interest rate swaps to manage risk are recorded at fair value. Over the counter derivatives are valued daily based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over the counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

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Private equity . Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments and investments in natural resources. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include unobservable inputs such as cost, operating results, discounted future cash flows and market based comparable data. The fair value of private equity investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Hedge funds . Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or its equivalent as a practical expedient, and therefore, hedge funds are not classified within the fair value hierarchy. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate.

Real estate . Real estate funds are funds with a direct investment in pools of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. These valuation inputs are not highly observable. The fair value of real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Private credit. Private credit investments primarily consist of limited partnerships that invest in private debt strategies. These investments are generally less liquid assets with an underlying term of 3 to 5 years and are intended to be held to maturity. The fair value of these investments is determined by the fund manager or administrator and include unobservable inputs such as cost, operating results, and discounted cash flows. The fair value of private credit investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Defined Contribution Savings Plan (All Registrants)

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2016, 2015 and 2014:

For the Year Ended December 31,	Exelon [a]	Generation [a]	ComEd	PECO	BGE	BSC [b]	Pepco [c]	DPL [c]	ACE	PHISCO [c]
2016	$ 164	$ 79	$ 34	$ 10	$ 12	$ 19	$ 3	$ 2	$ 2	$ 6
2015	148	80	32	11	14	11	3	2	2	6
2014	103	51	26	8	8	10	3	2	1	6

	Successor	*Predecessor*		
PHI	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
Saving Plan Matching Contributions	$ 10	$ 3	$ 14	$ 13

(a) Includes $13 million, $9 million and $5 million related to CENG for the years ended December 31, 2016, December 31, 2015 and for the period from April 1, 2014 to December 31, 2014, respectively.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, or BGE amounts above.
(c) Pepco's, DPL's and PHISCO's matching contributions include $1 million, $1 million and $1 million, respectively, of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016, which is not included in Exelon's matching contributions at December 31, 2016.

18. Severance (All Registrants)

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

Ongoing Severance Plans

The Registrants provide severance and health and welfare benefits under Exelon's ongoing severance benefit plans to terminated employees in the normal course of business. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the years ended December 31, 2016 and 2015, the Registrants recorded the following severance costs associated with ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

	Exelon	Generation (a)	ComEd (a)	PECO (a)	BGE (a)
Year ended December 31,					
2016	$ 19	$ 13	$ 3	$ 1	$ 1
2015	18	15	2	—	1

	Successor	*Predecessor*	
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI (a)			
Severance Benefits	$ 1	$ —	$ —

(a) The amounts above for Generation, ComEd, PECO, BGE and PHI include immaterial amounts billed by BSC for the years ended December 31, 2016 and 2015.

Early Plant Retirement-Related Severance

On December 7, 2016 the Future Energy Jobs Bill was signed into law by the Governor of Illinois and included a ZES. With the passage of the IL ZES, Generation reversed its decision to permanently cease generation operations at the Clinton and Quad Cities nuclear generating plants and expects the

plants to continue operation for at least another 10 years. As a result, Exelon and Generation reversed the associated severance benefit costs of $44 million in December 2016 which were previously recorded for expected employee severances.

Cost Management Program-Related Severance

In August 2015, Exelon announced a cost management program focused on cost savings at BSC and Generation, including the elimination of approximately 500 positions. These actions are in response to the continuing economic challenges confronting all parts of Exelon's business and industry, necessitating continued focus on cost management through enhanced efficiency and productivity. Exelon expects that approximately 250 corporate support positions in BSC and approximately 250 positions located throughout Generation will be eliminated. The final amount of the severance charges related to the cost management program will ultimately depend on the specific employees severed.

For the year ended December 31, 2016, the Registrants recorded the following severance costs related to the cost management program within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	Exelon	Generation	ComEd	PECO	BGE
Severance benefits (a)	$ 23	$ 18	$ 3	$ 1	$ 1

(a) The amounts above for Generation, ComEd, PECO and BGE include $7 million, $3 million, $1 million, and $1 million, respectively, for amounts billed by BSC through intercompany allocations for the year ended December 31, 2016.

Severance Costs Related to the PHI Merger

Upon closing the PHI Merger, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. Cash payments under the plan began in May 2016 and will continue through 2020.

For the year ended December 31, 2016, the Registrants recorded the following severance costs associated with the identified job reductions within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco (b)	DPL (c)	ACE
Severance benefits (a)	$ 57	$ 9	$ 2	$ 1	$ 1	$ 44	$ 21	$ 13	$ 10

(a) The amounts above for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE include $8 million, $2 million, $1 million, $1 million, $20 million, $12 million and $10 million, respectively, for amounts billed by BSC and/or PHISCO through intercompany allocations for the year ended December 31, 2016.
(b) Pepco established a regulatory asset of $11 million as of December 31, 2016, primarily for severance benefit costs related to the PHI merger.
(c) DPL established a regulatory asset of $4 million as of December 31, 2016, primarily for severance benefit costs related to the PHI merger.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Severance Liability

Amounts included in the table below represent the severance liability recorded for employees of each Registrant and exclude amounts included at Exelon and billed through intercompany allocations:

						Successor			
Severance Liability	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI (b)**	**Pepco**	**DPL**	**ACE**
Balance at December 31, 2014	$ 50	$ 34	$ 2	$ —	$ 2	$ —	$ 1	$—	$—
Severance charges	16	10	2	—	—	—	—	—	—
Payments	(31)	(21)	(1)	—	(1)	—	(1)	—	—
Balance at December 31, 2015	$ 35	$ 23	$ 3	$ —	$ 1	$ —	$ —	$—	$—
Severance charges (a)	99	22	2	—	—	56	1	1	—
Payments	(46)	(9)	(2)	—	(1)	(27)	(1)	(1)	—
Balance at December 31, 2016	$ 88	$ 36	$ 3	$ —	$—	$ 29	$ —	$—	$—

	Predecessor
Severance Liability	**PHI (b)**
Balance at December 31, 2014	$ 3
Severance charges	—
Payments	(3)
Balance at December 31, 2015	$ —

(a) Includes salary continuance and health and welfare severance benefits. Amounts primarily represent benefits provided for the PHI post-merger integration and the cost management program.
(b) For PHI, the successor period includes activity for the period from March 24, 2016 through December 31, 2016. The PHI predecessor periods include activity for the year ended December 31, 2015 and the period January 1, 2016 through March 23, 2016. There was no activity in the 2016 PHI predecessor period.

19. Mezzanine Equity (Exelon, Generation and PHI)

Contingently Redeemable Noncontrolling Interests (Exelon and Generation)

In November 2015, 2015 ESA Investco, LLC, a wholly owned subsidiary of Generation, entered into an arrangement to sell a portion of its equity to a tax equity investor. Pursuant to the operating agreement, in certain circumstances the equity contributed by the noncontrolling interests holder could be contingently redeemable. These circumstances are outside of the control of Generation and the noncontrolling interests holder resulting in a portion of the noncontrolling interests being considered contingently redeemable and thus presented in mezzanine equity on the consolidated balance sheet.

The following table summarizes the changes in the contingently redeemable noncontrolling interests for the years ended December 31, 2016 and 2015:

	Contingently Redeemable NCI
Balance at December 31, 2014	$ —
Cash received from noncontrolling interests	32
Release of contingency	(4)
Balance at December 31, 2015	$ 28
Cash received from noncontrolling interests	129
Release of contingency	(157)
Balance at December 31, 2016	$ —

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Preferred Stock (PHI)

In connection with the PHI Merger Agreement, Exelon purchased 18,000 originally issued shares of PHI preferred stock for a purchase price of $180 million. PHI excluded the preferred stock from equity at December 31, 2015 since the preferred stock contained conditions for redemption that were not solely within the control of PHI. Management determined that the preferred stock contained embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding preferred stock could be called and redeemed at a nominal par value upon a termination of the merger agreement under certain circumstances due to the failure to obtain required regulatory approvals. The embedded call and redemption features on the shares of the preferred stock in the event of such a termination were separately accounted for as derivatives. As of December 31, 2015, the fair value of the derivative related to the preferred stock was estimated to be $18 million based on PHI's updated assessment and was included in current assets with a corresponding increase in preferred stock on the Consolidated Balance Sheet. Immediately prior to the merger date, PHI updated its assessment of the fair value of the derivative and reduced the fair value to zero, recording the $18 million decrease in fair value as a reduction of Other, within PHI's predecessor period, January 1, 2016 to March 23, 2016, Statements of Operations and Comprehensive Income.

On March 23, 2016, the preferred stock was cancelled and the $180 million cash consideration previously received by PHI to issue the preferred stock was treated as additional merger purchase price consideration.

20. Shareholders' Equity (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

The following table presents common stock authorized and outstanding as of December 31, 2016 and 2015:

			December 31,	
			2016	2015
	Par Value	Shares Authorized	Shares Outstanding	
Common Stock				
Exelon	no par value	2,000,000,000	924,035,059	919,924,742
ComEd	$12.50	250,000,000	127,017,157	127,016,973
PECO	no par value	500,000,000	170,478,507	170,478,507
BGE	no par value	175,000,000	1,000	1,000
PHI *Predecessor*	$ 0.01	400,000,000	n/a	254,289,261
Pepco	$ 0.01	200,000,000	100	100
DPL	$ 2.25	1,000	1,000	1,000
ACE	$ 3.00	25,000,000	8,546,017	8,546,017

ComEd had 72,859 and 73,434 warrants outstanding to purchase ComEd common stock at December 31, 2016 and 2015, respectively. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants. At December 31, 2016 and 2015, 24,286 and 24,478 shares of common stock, respectively, were reserved for the conversion of warrants.

Equity Securities Offering

In June 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share. In connection with such offering, Exelon entered into forward

sale agreements with two counterparties. In July 2015, Exelon settled the forward sale agreement by the issuance of 57.5 million shares of Exelon common stock. Exelon received net cash proceeds of $1.87 billion, which was calculated based on a forward price of $32.48 per share as specified in the forward sale agreements. The net proceeds were used to fund the merger with PHI and related costs and expenses, and for general corporate purposes. The forward sale agreements are classified as equity transactions. As a result, no amounts were recorded in the consolidated financial statements until the July 2015 settlement of the forward sale agreements. However, prior to the July 2015 settlement, incremental shares, if any, were included within the calculation of diluted EPS using the treasury stock method.

Concurrent with the forward equity transaction, Exelon also issued $1.15 billion of junior subordinated notes in the form of 23 million equity units. See Note 14—Debt and Credit Agreements for further information on the equity units.

Share Repurchases

Share Repurchase Programs . There currently is no Exelon Board of Director authority to repurchase shares. Any previous shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon's management. Under the previous share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion at December 31, 2016. During 2016, 2015 and 2014, Exelon had no common stock repurchases.

Preferred and Preference Securities of Subsidiaries

At December 31, 2016 and 2015, Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

At December 31, 2016 and 2015, ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

On July 3, 2016, BGE redeemed all 400,000 shares of its outstanding 7.125% Cumulative Preference Stock, 1993 Series and all 600,000 shares of its outstanding 6.990% Cumulative Preference Stock, 1995 Series for $100 million, plus accrued and unpaid dividends. On September 18, 2016, BGE redeemed the remaining 500,000 shares of its outstanding 6.970% Cumulative Preference Stock, 1993 Series and the remaining 400,000 shares of its outstanding 6.700% Cumulative Preference Stock, 1993 Series for $90 million, plus accrued and unpaid dividends. At December 31, 2016 and 2015, BGE cumulative preference stock, $100 par value, consisted of 6,500,000 shares authorized and the outstanding amounts set forth in the table below. Shares of BGE preference stock have no voting power except for the following:

- The preference stock has one vote per share on any charter amendment that i) with regards to either dividends or distribution of assets, would create or authorize any shares of stock ranking prior to or on a parity with the preference stock or ii) substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock. Each such amendment would require the affirmative vote of two-thirds of all the shares of preference stock outstanding; and
- Whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and

unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

	Redemption Price [a]	December 31, 2016 Shares Outstanding	December 31, 2015 Shares Outstanding	December 31, 2016 Dollar Amount	December 31, 2015 Dollar Amount
Series (without mandatory redemption)					
7.125%, 1993 Series	$ 100.00	—	400,000	$—	$ 40
6.97%, 1993 Series	100.00	—	500,000	—	50
6.70%, 1993 Series	100.00	—	400,000	—	40
6.99%, 1995 Series	100.00	—	600,000	—	60
Total preference stock		—	1,900,000	$—	$190

(a) Redeemable, at the option of BGE, at the indicated dollar amounts per share, plus accrued and unpaid dividends.

21. Stock-Based Compensation Plans (All Registrants)

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At December 31, 2016, there were approximately 14 million shares authorized for issuance under the LTIP. For the years ended December 31, 2016, 2015 and 2014, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

Beginning in 2014, ComEd, PECO and BGE grant cash awards. The following tables do not include expense related to these plans as they are not considered stock-based compensation plans under the applicable accounting guidance.

In connection with the acquisition of PHI in March 2016, PHI's unvested time-based restricted stock units and performance-based restricted stock units issued prior to April 29, 2014 were immediately vested and paid in cash upon the close of the merger. PHI's remaining unvested time-based restricted stock units as of the close of the merger were cancelled. There were no remaining unvested performance-based restricted stock units as of the close of the merger.

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(Dollars in millions, except per share data unless otherwise noted)

The following tables present the stock-based compensation expense included in Exelon's and PHI's Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2016, 2015 and 2014, as well as for the PHI predecessor period January 1, 2016 to March 23, 2016:

Exelon

	Year Ended December 31,		
Components of Stock-Based Compensation Expense	2016 (a)	2015	2014
Performance share awards	$ 93	$ 41	$ 59
Restricted stock units	75	71	61
Stock options	—	1	2
Other stock-based awards	7	6	5
Total stock-based compensation expense included in operating and maintenance expense	175	119	127
Income tax benefit	(68)	(46)	(47)
Total after-tax stock-based compensation expense	$107	$ 73	$ 80

(a) 2016 amounts include expense related to stock-based compensation granted to eligible PHI employees since the merger date of March 23, 2016.

PHI

	Predecessor		
	January 1 to March 23,	Years Ended December 31,	
Components of Stock-Based Compensation Expense	2016	2015	2014
Time-based restricted stock units	$ 2	$ 7	$ 5
Performance-based restricted stock units	1	5	8
Time-based restricted stock awards	—	1	5
Total stock-based compensation expense included in operating and maintenance expense	3	13	18
Income tax benefit	(1)	(5)	(7)
Total after-tax stock-based compensation expense	$ 2	$ 8	$ 11

The following tables present the Registrants' stock-based compensation expense (pre-tax) for the years ended December 31, 2016, 2015 and 2014, as well as for the PHI predecessor period January 1, 2016 to March 23, 2016:

	Years Ended December 31,		
Subsidiaries	2016	2015	2014
Exelon	$175	$119	$127
Generation	78	64	52
ComEd	8	6	7
PECO	3	3	3
BGE	1	3	5
BSC (a)	81	43	60
PHI (a)(b)	7	13	18

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Successor	Predecessor		
	March 24 to December 31, 2016	January 1 to March 23, 2016	Years Ended December 31, 2015	2014
PHI	$ 4	$ 3	$ 13	$ 18

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE or PHI amounts above.
(b) Pepco's, DPL's and ACE's stock-based compensation expense for the year ended December 31, 2016 and for the period January 1, 2016 through March 23, 2016 was not material. PHI's stock-based compensation expense for the year ended December 31, 2016 includes $3 million of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016.

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2016, 2015 and 2014 for Exelon or PHI, or for PHI during the predecessor period January 1, 2016 to March 23, 2016.

Exelon and PHI receive a tax deduction based on the intrinsic value of the award on the exercise date for stock options and the distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon and PHI recognize the tax benefit related to compensation costs. The following tables present information regarding Exelon's and PHI's tax benefits for the years ended December 31, 2016, 2015 and 2014 and PHI's predecessor period January 1, 2016 to March 23, 2016:

Exelon

	Years Ended December 31,		
	2016	2015	2014
Realized tax benefit when exercised/distributed:			
Restricted stock units	$ 27	$ 30	$ 17
Performance share awards	18	18	11

PHI

	Predecessor		
	January 1 to March 23, 2016	Years Ended December 31, 2015	2014
Realized tax benefit when exercised/distributed:			
Time-based restricted stock units	$ —	$ 2	$ 3
Performance-based restricted stock units	—	5	4
Time-based restricted stock awards	—	—	1

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock were granted under the LTIP through 2012. Due to changes in the LTIP, there were no stock options granted in 2014, 2015 or 2016. For all stock options granted through 2012, the exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. The vesting period of stock options is generally four years. As of December 31, 2016 all stock options are fully vested. All stock options expire ten years from the date of grant.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years.

Combined Notes to Consolidated Financial Statements—(Continued)
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However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

The following table presents information with respect to stock option activity for the year ended December 31, 2016:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2015	15,572,757	$ 46.68		
Options exercised	(840,672)	22.12		
Options forfeited	—	—		
Options expired	(2,200,494)	58.60		
Balance of shares outstanding at December 31, 2016	12,531,591	$ 46.23	3.50	$ 13
Exercisable at December 31, 2016 (a)	12,531,591	$ 46.23	3.50	$ 13

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2016, 2015 and 2014:

	Years Ended December 31,		
	2016	2015	2014
Intrinsic value (a)	$ 11	$—	$ 3
Cash received for exercise price	19	—	7

(a) The difference between the market value on the date of exercise and the option exercise price.

The following table summarizes Exelon's nonvested stock option activity for the year ended December 31, 2016:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2015 (a)	82,250	$ 39.81
Vested	(82,250)	39.81
Nonvested at December 31, 2016 (a)	—	$ —

(a) Excludes 279,000 of stock options issued to retirement-eligible employees as of December 31, 2015 as they are fully vested. As of December 31, 2016, all stock options are fully vested.

At December 31, 2016, there was no unrecognized compensation costs related to nonvested stock options.

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(Dollars in millions, except per share data unless otherwise noted)

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following tables summarize Exelon's and PHI's nonvested restricted stock unit activity for the year ended December 31, 2016 and PHI's for the predecessor period January 1, 2016 to March 23, 2016:

Exelon

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2015 (a)	3,563,254	$ 32.92
Granted	3,042,184	28.14
Vested	(1,797,536)	32.44
Forfeited	(85,940)	30.08
Undistributed vested awards (b)	(897,546)	28.35
Nonvested at December 31, 2016 (a)(c)	3,824,416	$ 30.49

PHI

	Time-based Shares	Weighted Average Grant Date Fair Value (per share)	Performance-based Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2015	628,514	$ 24.71	$ 408,638	$ 18.56
Granted	152,928	26.01	305,856	25.41
Vested	—	—	(4,950)	26.08
Forfeited	—	—	(1,238)	26.08
Nonvested at March 23, 2016	781,442	$ 24.96	$ 708,306	$ 21.45

(a) Excludes 1,319,372 and 975,116 of restricted stock units issued to retirement-eligible employees as of December 31, 2016 and 2015, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2016.
(c) 2016 amounts include activity related to stock-based compensation granted to eligible PHI employees since the merger date of March 23, 2016.

For Exelon, the weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2016, 2015 and 2014 was $28.14, $36.55 and $28.71, respectively.

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At December 31, 2016 and 2015, Exelon had obligations related to outstanding restricted stock units not yet settled of $101 million and $97 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. For the years ended December 31, 2016, 2015 and 2014, Exelon settled restricted stock units with fair value totaling $68 million, $75 million and $43 million, respectively. At December 31, 2016, $58 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2 years.

For PHI, the weighted average grant date fair value (per share) of time-based restricted stock units granted for the years ended December 31, 2015 and 2014 was $27.40 and $19.77, respectively, and for performance-based restricted stock units was $26.08 and $18.53 for the same periods, respectively. At December 31, 2015 PHI had obligations related to outstanding time-based and performance-based restricted stock units not yet settled of $1 million each, which are included in common stock in PHI's Consolidated Balance Sheet. For the years ended December 31, 2015 and 2014, PHI settled time-based restricted stock units with fair value totaling $6 million and $8 million, respectively, and settled performance-based restricted stock units with fair value totaling $15 million and $9 million, for the same periods, respectively. There were no settled restricted stock units for the predecessor period January 1, 2016 to March 23, 2016.

Performance Share Awards

Performance share awards are granted under the LTIP. The performance share awards are being settled 50% in common stock and 50% in cash at the end of the three-year performance period, except for awards granted to vice presidents and higher officers that may be settled 100% in common stock, 100% in cash or 50%in common stock and 50% in cash if certain ownership requirements are satisfied.

The common stock portion of the performance share is considered an equity award and is valued based on Exelon's stock price on the grant date. The cash portion of the awards is considered a liability award which is remeasured each reporting period based on Exelon's current stock price. As the value of the common stock and cash portions of the awards are based on Exelon's stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share awards granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period, which is the year of grant.

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The following tables summarize Exelon's and PHI's nonvested performance share awards activity for the year ended December 31, 2016 and PHI's for the predecessor period January 1, 2016 to March 23, 2016:

Exelon

	Shares [c]	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2015 [a]	2,557,159	$ 31.88
Granted	2,319,407	28.85
Change in performance	627,303	30.04
Vested	(949,315)	31.31
Forfeited	(70,876)	30.90
Undistributed vested awards [b]	(1,367,417)	28.33
Nonvested at December 31, 2016 [a]	3,116,261	$ 30.77

PHI

	Time-based Shares	Weighted Average Grant Date Fair Value (per share)	Performance-based Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2015	54,165	$ 26.80	24,717	$ 26.10
Vested	—	—	(24,717)	26.10
Nonvested at March 23, 2016	54,165	$ 26.80	—	$ —

(a) Excludes 2,443,409 and 1,817,883 of performance share awards issued to retirement-eligible employees as of December 31, 2016 and 2015, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2016.
(c) 2016 amounts include PHI for the period of March 24, 2016 through December 31, 2016.

For Exelon, the weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2016, 2015 and 2014 was $28.85, $35.88, and $28.75, respectively. During the years ended December 31, 2016, 2015 and 2014, Exelon settled performance shares with a fair value totaling $45 million, $46 million and $27 million, respectively, of which $28 million, $29 million and $13 million was paid in cash, respectively. As of December 31, 2016, $51 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 2 years.

For PHI, the weighted average grant date fair value (per share) of time-based restricted stock awards granted for the year ended December 31, 2014 was $26.80 and for performance-based restricted stock awards was $26.10 and $27.01 for the years ended December 31, 2015 and 2014, respectively. There were no time-based restricted stock awards granted for the year ended December 31, 2015. At December 31, 2015 PHI had no obligations related to vested time-based and performance-based restricted stock awards not yet settled. For the year ended December 31, 2014 PHI settled time-based shares with a fair value totaling $3 million. There were no time-based share settlements for the year-ended December 31, 2015 or the predecessor period January 1, 2016 to March 23, 2016 or performance-based share settlements for the predecessor period January 1, 2016 to March 23, 2016 and the years ended December 31, 2015 and 2014.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31,	
	2016	2015 (c)
Current liabilities (a)	$ 49	$ 28
Deferred credits and other liabilities (b)	52	32
Common stock	40	35
Total	$141	$ 95

(a) Represents the current liability related to performance share awards expected to be settled in cash.
(b) Represents the long-term liability related to performance share awards expected to be settled in cash.
(c) Excludes $8 million of common stock for PHI at December 31, 2015.

22. Earnings Per Share (Exelon)

Diluted earnings per share is calculated by dividing Net income attributable to common shareholders by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of the stock options, performance share awards and restricted stock on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Years Ended December 31,		
	2016	2015	2014
Net income attributable to common shareholders	$1,134	$2,269	$1,623
Weighted average common shares outstanding—basic	924	890	860
Assumed exercise and/or distributions of stock-based awards	3	3	4
Weighted average common shares outstanding—diluted	927	893	864

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 12 million in 2016, 16 million in 2015, and 17 million in 2014. There were no equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the year ended December 31, 2016. The number of equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect were 3 million and less than 1 million for the years ended December 31, 2015 and 2014. Refer to Note 20—Shareholders' Equity for further information regarding the equity units and equity forward units.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of December 31, 2016. In 2008, Exelon management decided to defer indefinitely any share repurchases.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

23. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, PECO and PHI)

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the years ended December 31, 2016 and 2015:

For the Year Ended December 31, 2016	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Gains and (Losses) on Foreign Currency Items	AOCI of Equity Investments	Total
Exelon (a)						
Beginning balance	$ (19)	$ 3	$ (2,565)	$ (40)	$ (3)	$(2,624)
OCI before reclassifications	(6)	1	(182)	5	(4)	(186)
Amounts reclassified from AOCI (b)	8	—	137	5	—	150
Net current-period OCI	2	1	(45)	10	(4)	(36)
Ending balance	$ (17)	$ 4	$ (2,610)	$ (30)	$ (7)	$(2,660)
Generation (a)						
Beginning balance	$ (21)	$ 1	$ —	$ (40)	$ (3)	$ (63)
OCI before reclassifications	(6)	1	—	5	(4)	(4)
Amounts reclassified from AOCI (b)	8	—	—	5	—	13
Net current-period OCI	2	1	—	10	(4)	9
Ending balance	$ (19)	$ 2	$ —	$ (30)	$ (7)	$ (54)
PECO (a)						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI (b)	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1
PHI Predecessor (a)						
Beginning balance January 1, 2016	$ (8)	$ —	$ (28)	$ —	$ —	$ (36)
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI (b)	—	—	1	—	—	1
Net current-period OCI	—	—	1	—	—	1
Ending balance March 23, 2016 (c)	$ (8)	$ —	$ (27)	$ —	$ —	$ (35)

Combined Notes to Consolidated Financial Statements—(Continued)
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For the Year Ended December 31, 2015	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Gains and (Losses) on Foreign Currency Items	AOCI of Equity Investments	Total
Exelon (a)						
Beginning balance	$ (28)	$ 3	$ (2,640)	$ (19)	$ —	$(2,684)
OCI before reclassifications	(12)	—	(100)	(21)	(3)	(136)
Amounts reclassified from AOCI (b)	21	—	175	—	—	196
Net current-period OCI	9	—	75	(21)	(3)	60
Ending balance	$ (19)	$ 3	$ (2,565)	$ (40)	$ (3)	$(2,624)
Generation (a)						
Beginning balance	$ (18)	$ 1	$ —	$ (19)	$ —	(36)
OCI before reclassifications	(8)	—	—	(21)	(3)	(32)
Amounts reclassified from AOCI (b)	5	—	—	—	—	5
Net current-period OCI	(3)	—	—	(21)	(3)	(27)
Ending balance	$ (21)	$ 1	$ —	$ (40)	$ (3)	$ (63)
PECO (a)						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI (b)	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1
PHI Predecessor (a)						
Beginning balance	$ (9)	$ —	$ (37)	$ —	$ —	$ (46)
OCI before reclassifications	—	—	5	—	—	5
Amounts reclassified from AOCI (b)	1	—	4	—	—	5
Net current-period OCI	1	—	9	—	—	10
Ending balance	$ (8)	$ —	$ (28)	$ —	$ —	$ (36)

(a) All amounts are net of tax and noncontrolling interests. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See next tables for details about these reclassifications.
(c) As a result of the PHI Merger, the PHI predecessor balances at March 23, 2016 were reduced to zero on March 24, 2016 due to purchase accounting adjustments applied to PHI.

Combined Notes to Consolidated Financial Statements—(Continued)
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ComEd, PECO, BGE, Pepco, DPL and ACE did not have any reclassifications out of AOCI to Net income during the years ended December 31, 2016 and 2015. The following tables present amounts reclassified out of AOCI to Net income for Exelon, Generation and PHI during the years ended December 31, 2016 and 2015:

For the Year Ended December 31, 2016

Details about AOCI components	Items reclassified out of AOCI [a]			Affected line item in the Statements of Operations and Comprehensive Income
	Exelon	Generation	*Predecessor* January 1, 2016 to March 23, 2016 PHI	
Gains and (losses) on cash flow hedges				
Other cash flow hedges	$ (13)	$ (13)	$ —	Interest expense
Total before tax	(13)	(13)	—	
Tax benefit	5	5	—	
Net of tax	$ (8)	$ (8)	$ —	Comprehensive income
Amortization of pension and other postretirement benefit plan items				
Prior service costs [b]	$ 78	$ —	$ —	
Actuarial losses [b]	(302)	—	(1)	
Total before tax	(224)	—	(1)	
Tax benefit	87	—	—	
Net of tax	$ (137)	$ —	$ (1)	
Gains and (losses) of FX				
Gains	$ (5)	$ (5)	$ —	
Other	—	—	—	
Total before tax	(5)	(5)	—	
Tax benefit	—	—	—	
Net of tax	$ (5)	$ (5)	$ —	
Total Reclassifications	$ (150)	$ (13)	$ (1)	Comprehensive income

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For the Year Ended December 31, 2015

Details about AOCI components	Items reclassified out of AOCI [a]			Affected line item in the Statements of Operations and Comprehensive Income
	Exelon	Generation	*Predecessor* PHI	
Gains and (losses) on cash flow hedges				
Terminated interest rate swaps	$ (26)	$ —	$ —	Other, net
Energy related hedges	2	2	—	Operating revenues
Other cash flow hedges	(11)	(11)	(1)	Interest expense
Total before tax	(35)	(9)	(1)	
Tax benefit	14	4	—	
Net of tax	$ (21)	$ (5)	$ (1)	Comprehensive income
Amortization of pension and other postretirement benefit plan items				
Prior service costs [b]	$ 74	$ —	$ —	
Actuarial losses [b]	(361)	—	(6)	
Total before tax	(287)	—	(6)	
Tax benefit	112	—	2	
Net of tax	$ (175)	$ —	$ (4)	
Total Reclassifications	$ (196)	$ (5)	$ (5)	Comprehensive income

(a) Amounts in parenthesis represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see Note 17—Retirement Benefits for additional details).
(c) Amortization of the deferred compensation unit plan is allocated to capital and operating and maintenance expense.

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the years ended December 31, 2016 and 2015:

	For the Years Ended December 31,		
	2016	2015	2014
Exelon			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	$ 30	$ 30	$ 19
Actuarial loss reclassified to periodic cost	(118)	(140)	(93)
Pension and non-pension postretirement benefit plan valuation adjustment	115	62	317
Change in unrealized (gain) loss on cash flow hedges	—	(6)	96
Change in unrealized (gain) loss on equity investments	3	1	73
Total	$ 30	$ (53)	$412
Generation			
Change in unrealized loss on cash flow hedges	$ (2)	$ 2	$ 84
Change in unrealized (gain) loss on equity investments	3	1	73
Total	$ 1	$ 3	$157

Combined Notes to Consolidated Financial Statements—(Continued)
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	Predecessor		
	January 1 to March 23, 2016	For the Years Ended December 31, 2015	2014
PHI			
Pension and non-pension postretirement benefit plans:			
Actuarial loss reclassified to periodic cost	$ —	$ 6	$ 5

24. Commitments and Contingencies (All Registrants)

Commitments

Constellation Merger Commitments

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion. The direct investment estimate includes $95 million to $120 million relating to the construction of a headquarters building in Baltimore for Generation's competitive energy businesses.

The direct investment commitment also includes $450 million to $500 million relating to Exelon and Generation's development or assistance in the development of 285—300 MWs of new generation in Maryland, which is expected to be completed within a period of 10 years. The MDPSC order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed or certain specified provisions are elected, making liquidated damages payments. Exelon and Generation have incurred $454 million towards satisfying the commitment for new generation development in the state of Maryland, with approximately 220 MW of the new generation commencing with commercial operations to date. During the third quarter of 2014, the conditions associated with one of the generation development commitments changed such that the most likely outcome would involve Exelon and Generation making subsidy payments and/or liquidated damages payments rather than constructing the specified generating plant. As a result, Exelon and Generation recorded a pre-tax $44 million loss contingency in Operating and maintenance expense related to this specific commitment that is included in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2014. On December 19, 2016, Generation paid $44 million to the Maryland Energy Administration in full satisfaction of this commitment. During the fourth quarter of 2016, given continued declines in projected energy and capacity prices, Generation terminated rights to certain development projects originally intended to meet its remaining 55 MW commitment amount. The commitment will now most likely be satisfied via payment of liquidated damages or execution of a third party PPA, rather than by Generation constructing renewable generating assets. As a result, Exelon and Generation recorded a pre-tax $50 million loss contingency in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016.

Equity Investment Commitments

As part of Generation's recent investments in technology development, Generation enters into equity purchase agreements that include commitments to invest additional equity through incremental payments to fund the anticipated needs of the planned operations of the associated companies. The commitment includes approximately $20 million of in-kind services and 100% of 2015 ESA Investco,

Combined Notes to Consolidated Financial Statements—(Continued)
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LLC's equity commitment since 2015 ESA Investco, LLC is consolidated by Generation (see Note 2—Variable Interest Entities for additional details). As of December 31, 2016, Generation's estimated commitment relating to its equity purchase agreements, including in-kind services contributions, is anticipated to be as follows:

	Total
2017	$ 34
2018	5
Total	$ 39

Commercial Commitments

Exelon's commercial commitments as of December 31, 2016, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2017	2018	2019	2020	2021	2022 and beyond
Letters of credit (non-debt) (a)	$1,614	$1,355	$246	$—	$ 13	$—	$ —
Surety bonds (b)	1,035	978	33	2	16	6	—
Financing trust guarantees (c)	628	—	—	—	—	—	628
Guaranteed lease residual values (d)	20	—	—	—	—	—	20
Total commercial commitments	$3,297	$2,333	$279	$ 2	$ 29	$ 6	$ 648

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Includes $200 million of Trust Preferred Securities of ComEd Financing III, $178 million of Trust Preferred Securities of PECO Trust III and IV and $250 million of Trust Preferred Securities of BGE Capital Trust II.
(d) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $50 million, $14 million of which is a guarantee by Pepco, $17 million by DPL and $13 million by ACE. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Generation's commercial commitments as of December 31, 2016, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2017	2018	2019	2020	2021	2022 and beyond
Letters of credit (non-debt) (a)	$1,546	$1,287	$246	$—	$ 13	$—	$ —
Surety bonds	945	918	27	—	—	—	—
Total commercial commitments	$2,491	$2,205	$273	$—	$ 13	$—	$ —

(a) Letters of credit (non-debt)—Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.

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ComEd's commercial commitments as of December 31, 2016, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2017	2018	2019	2020	2021	2022 and beyond
Letters of credit (non-debt) (a)	$ 14	$ 14	$—	$—	$—	$—	$ —
Surety bonds (b)	11	9	2		—	—	—
Financing trust guarantees	200	—	—	—	—	—	200
Total commercial commitments	$225	$ 23	$ 2	$—	$—	$—	$ 200

(a) Letters of credit (non-debt)—ComEd maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

PECO's commercial commitments as of December 31, 2016, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2017	2018	2019	2020	2021	2022 and beyond
Letters of credit (non-debt) (a)	$ 23	$ 23	$—	$—	$—	$—	$ —
Surety bonds (b)	9	9	—	—	—	—	—
Financing trust guarantees	178	—	—	—	—	—	178
Total commercial commitments	$210	$ 32	$—	$—	$—	$—	$ 178

(a) Letters of credit (non-debt)—PECO maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

BGE's commercial commitments as of December 31, 2016, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2017	2018	2019	2020	2021	2022 and beyond
Letters of credit (non-debt) (a)	$ 2	$ 2	$—	$—	$—	$—	$ —
Surety bonds (b)	11	10	1	—	—	—	—
Financing trust guarantees	250	—	—	—	—	—	250
Total commercial commitments	$263	$ 12	$ 1	$—	$—	$—	$ 250

(a) Letters of credit (non-debt)—BGE maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

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PHI commercial commitments (Successor) as of December 31, 2016, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2017	2018	2019	2020	2021	2022 and beyond
Letters of credit (non-debt) (a)	$ 1	$ 1	$—	$—	$—	$—	$ —
Surety bonds (b)	16	14	2	—	—	—	—
Guaranteed lease residual values (c)	20	—	—	—	—	—	20
Total commercial commitments	$ 37	$ 15	$ 2	$—	$—	$—	$ 20

(a) Letters of credit (non-debt)—PHI and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $50 million. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Pepco commercial commitments as of December 31, 2016, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2017	2018	2019	2020	2021	2022 and beyond
Surety bonds (a)	$ 9	$ 9	$—	$—	$—	$—	$ —
Guaranteed lease residual values (b)	6	—	—	—	—	—	6
Total commercial commitments	$ 15	$ 9	$—	$—	$—	$—	$ 6

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $14 million. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

DPL commercial commitments as of December 31, 2016, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2017	2018	2019	2020	2021	2022 and beyond
Surety bonds (a)	$ 4	$ 3	$ 1	$—	$—	$—	$ —
Guaranteed lease residual values (b)	7	—	—	—	—	—	7
Total commercial commitments	$ 11	$ 3	$ 1	$—	$—	$—	$ 7

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $17 million. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

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ACE commercial commitments as of December 31, 2016, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2017	2018	2019	2020	2021	2022 and beyond
Letters of credit (non-debt) (a)	$ 1	$ 1	$ —	$ —	$ —	$ —	$ —
Surety bonds (b)	3	2	1	—	—	—	—
Guaranteed lease residual values (c)	5	—	—	—	—	—	5
Total commercial commitments	$ 9	$ 3	$ 1	$ —	$ —	$ —	$ 5

(a) Letters of credit (non-debt)—ACE maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $13 million. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Leases

Minimum future operating lease payments, including lease payments for contracted generation, vehicles, real estate, computers, rail cars, operating equipment and office equipment, as of December 31, 2016 were:

	Exelon (a)	Generation (a)	ComEd (b)	PECO (b)	BGE (b)(c) (d)	PHI	Pepco	DPL (b)	ACE
2017	$ 183	$ 70	$ 11	$ 3	$ 32	$ 50	$ 7	$ 13	$ 8
2018	179	75	6	3	34	49	6	17	8
2019	123	30	6	4	34	36	5	7	7
2020	140	48	3	4	34	38	4	10	6
2021	133	47	3	4	32	34	3	9	5
Remaining years	968	644	—	—	33	211	7	54	20
Total minimum future lease payments	$ 1,726	$ 914	$ 29	$ 18	$ 199	$ 418	$ 32	$ 110	$ 54

(a) Excludes Generation's contingent operating lease payments associated with contracted generation agreements.
(b) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, ComEd, PECO, BGE and DPL have excluded these payments from the remaining years, as such amounts would not be meaningful. ComEd's, PECO's, BGE's and DPL's average annual obligation for these arrangements, included in each of the years 2017—2021, was $2 million, $4 million, $2 million and $2 million, respectively.
(c) Includes all future lease payments on a 99 year real estate lease that expires in 2106.
(d) The BGE column above includes minimum future lease payments associated with a 6-year lease for the Baltimore City conduit system that became effective during the fourth quarter of 2016. BGE's total commitments under the lease agreement are $21 million $25 million, $26 million , $27 million, $28 million, and $14 million related to years 2017, 2018, 2019, 2020, 2021 and thereafter, respectively.

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(Dollars in millions, except per share data unless otherwise noted)

The following table presents the Registrants' rental expense under operating leases for the years ended December 31, 2016, 2015 and 2014:

For the Year Ended December 31,	Exelon	Generation (a)	ComEd	PECO	BGE	Pepco	DPL	ACE
2016	$ 777	$ 667	$ 15	$ 7	$ 22	$ 8	$ 15	$ 13
2015	922	851	12	9	32	7	14	13
2014	865	806	15	14	12	8	14	12

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
PHI				
Rental expense under operating leases	$ 49	12	60	59

(a) Includes contingent operating lease payments associated with contracted generation agreements that are not included in the minimum future operating lease payments table above. Payments made under Generation's contracted generation lease agreements totaled $604 million, $798 million and $755 million during 2016, 2015 and 2014, respectively. Excludes contract amortization associated with purchase accounting and contract acquisitions.

For information regarding capital lease obligations, see Note 14—Debt and Credit Agreements.

Nuclear Insurance

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has mitigated its financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2016, the current liability limit per incident is $13.4 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors at least once every five years with the last adjustment effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. Effective January 1, 2017, the required amount of nuclear energy liability insurance purchased is $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool, as required by the Price Anderson-Act, which provides the additional $13.0 billion per incident in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Exelon's share of this secondary layer would be approximately $2.7 billion, including CENG's related liability, however any amounts payable under this secondary layer would be capped at $400 million per year.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.4 billion limit for a single incident.

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As part of the execution of the NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity. See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information on Generation's operations relating to CENG.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. Generation's portion of the distribution declared by NEIL is estimated to be $21 million for 2016, and was $21 million for 2015 and $18 million for 2014. The distributions were recorded as a reduction to Operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

Premiums paid to NEIL by its members are also subject to a potential assessment for adverse loss experience in the form of a retrospective premium obligation. NEIL has never assessed this retrospective premium since its formation in 1973, and Generation cannot predict the level of future assessments if any. The current maximum aggregate annual retrospective premium obligation for Generation is approximately $353 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery by Exelon will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon's and Generation's financial condition, results of operations and liquidity.

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Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation historically had paid the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. On November 19, 2013, the D.C. Circuit Court ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On May 9, 2014, the DOE notified Generation that the SNF disposal fee remained in effect through May 15, 2014, after which time the fee was set to zero. As a result, for the year ended December 31, 2016, and December 31, 2015, Generation did not incur any expense in SNF disposal fees. For the year ended December 31, 2014, Generation incurred expense of $49 million in SNF disposal fees recorded in Purchased power and fuel expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, including Exelon's share of Salem and net of co-owner reimbursements (not including such fees incurred by CENG). Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance has been, and is expected to be, delayed significantly.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama Administration devised a new strategy for long-term SNF management. A Blue Ribbon Commission (BRC) on America's Nuclear Future, appointed by the U.S. Energy Secretary, released a report on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's SNF and high-level radioactive waste.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that was planned to be operational in 2025. However, due to continued delays on the part of the DOE, Generation currently assumes the DOE will begin accepting SNF in 2030. The SNF acceptance date assumption is based on management's estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage.

Generation uses the 2030 date as the assumed date for when the DOE will begin accepting SNF for purposes of determining nuclear decommissioning asset retirement obligations.

In August 2004, Generation and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation, subject to certain damage limitations based on the extent of the government's breach, for costs associated with storage of SNF at Generation's nuclear stations pending the DOE's fulfillment of its obligations. A settlement agreement for Calvert Cliffs and Nine Mile Point was executed during 2011, pursuant to which the government agreed to reimburse the costs associated with SNF storage expended or to be expended during a term set by the agreement. The term was subsequently extended during 2014 to include SNF storage costs incurred at Calvert Cliffs and Nine Mile Point through December 31, 2016. A DOE settlement agreement for Ginna was also executed during 2011. During 2015, Ginna executed another DOE

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settlement agreement providing for the reimbursement of SNF storage costs incurred through December 31, 2016. Generation expects the terms for each of the settlement agreements to be extended during 2017 for another three years to cover SNF storage costs through December 31, 2019. Generation, including CENG, submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

Under the settlement agreement, Generation has received cumulative cash reimbursements for costs incurred as follows:

	Total	Net (a)
Cumulative cash reimbursements (b)	$1,038	$887

(a) Total after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek.
(b) Includes $53 million and $49 million, respectively, for amounts received since April 1, 2014, for costs incurred under the CENG DOE Settlement Agreements prior to the consolidation of CENG.

As of December 31, 2016, and 2015, the amount of SNF storage costs for which reimbursement has been or will be requested from the DOE under the DOE settlement agreements is as follows:

	December 31, 2016	December 31, 2015
DOE receivable—current (a)	$ 109	$ 76
DOE receivable—noncurrent (b)	15	14
Amounts owed to co-owners (a)(c)	(13)	(5)

(a) Recorded in Accounts receivable, other.
(b) Recorded in Deferred debits and other assets, other
(c) Non-CENG amounts owed to co-owners are recorded in Accounts receivable, other. CENG amounts owed to co-owners are recorded in Accounts payable. Represents amounts owed to the co-owners of Peach Bottom, Quad Cities, and Nine Mile Point Unit 2 generating facilities.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. As of December 31, 2016, the unfunded SNF liability for the one-time fee with interest was $1,024 million. Interest accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2016, was 0.355%. The liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of Exelon's 2001 corporate restructuring. The outstanding one-time fee obligations for the Nine Mile Point, Ginna, Oyster Creek and TMI units remain with the former owners. The Clinton and Calvert Cliffs units have no outstanding obligation. See Note 12—Fair Value of Financial Assets and Liabilities for additional information.

Environmental Remediation Matters

General. The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels,

including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd, PECO, BGE, and DPL have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has identified 42 sites, 18 of which have been remediated and approved by the Illinois EPA or the U.S. EPA and 24 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2021.
- PECO has identified 26 sites, 17 of which have been remediated in accordance with applicable PA DEP regulatory requirements. The remaining 9 sites are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2022.
- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these 2 sites are not considered material. An investigation of an additional gas purification site was completed during the first quarter of 2015 at the direction of the MDE. For more information, see the discussion of the Riverside site below.
- DPL has identified 2 sites, all of which the remediation has been completed and approved by the MDE or the Delaware Department of Natural Resources and Environmental Control.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. See Note 3—Regulatory Matters for additional information regarding the associated regulatory assets. BGE is authorized to recover, and is currently recovering, environmental costs for the remediation of the former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. DPL has historically received recovery of actual clean-up costs in distribution rates.

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As of December 31, 2016 and 2015, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

December 31, 2016	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation (a)
Exelon	$ 429	$ 325
Generation	72	—
ComEd	292	291
PECO	33	31
BGE (a)	2	2
PHI	30	1
Pepco	27	—
DPL	2	1
ACE	1	—

December 31, 2015	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 369	$ 301
Generation	63	—
ComEd	266	264
PECO	37	35
BGE	3	2
PHI (Predecessor)	33	1
Pepco	24	—
DPL	3	1
ACE	1	—

The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, including probabilistic and deterministic modeling for ComEd and PECO, and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

During the third quarter of 2016, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. The results of the study resulted in a $7 million and $2 million increase to environmental liabilities and related regulatory assets for ComEd and PECO, respectively.

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

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Water Quality

Benning Road Site NPDES Permit Limit Exceedances . Pepco holds an NPDES permit issued by EPA with a July 19, 2009 effective date, which authorizes discharges from the Benning Road service facility. The 2009 permit for the first time imposed numerical limits on the allowable concentration of certain metals in storm water discharged from the site into the Anacostia River. The permit contemplated that Pepco would meet these limits over time through the use of best management practices (BMPs). The BMPs were effective in reducing metal concentrations in storm water discharges, but were not sufficient to meet all of the numerical limits for all metals.

The 2009 permit remains in effect pending EPA's action on the Pepco renewal application, including resolution of the stormwater compliance issues. On October 30, 2015, EPA filed a Clean Water Act civil enforcement action against Pepco in federal district court, and in March 2016 the court granted a motion by the Anacostia Riverkeeper to intervene in this case as a plaintiff along with EPA. Since 2009 Pepco has installed runoff mitigation measures and implemented new operating procedures to comply with regulations. In January 2017, the parties agreed to a settlement in the form of a Consent Decree whereby Pepco will pay a civil penalty in the amount of $1.6 million, continue the BMPs to manage stormwater, construct a new stormwater treatment system, and make certain other capital improvements to the stormwater management system. The Consent Decree has been lodged with the Court and will be subject to a 30-day public comment period. It is expected that the Court will approve the Consent Decree in the first quarter of 2017. Pepco has established appropriate reserves for the liabilities under the Consent Agreement, which is included in the table above.

Solid and Hazardous Waste

Cotter Corporation. The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the landfill cover remediation for the site is approximately $90 million including escalation, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability, which is included in the table above. By letter dated January 11, 2010, the EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the supplemental feasibility study to the EPA for review. Since June 2012, the EPA has requested that the PRPs perform a series of additional analyses and groundwater and soil sampling as part of the supplemental feasibility study. The final supplemental feasibility study was completed in December of 2016 and will enable the EPA to propose a remedy for public comment. While the EPA has not yet formally announced a change in the schedule, the PRPs believe that the EPA announcement of the proposed remedy will take place in the third quarter of 2017 at the earliest. Thereafter, the EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. Recent investigation has identified a number of other parties who may be PRPs and could be liable to contribute to the final remedy. Further investigation is underway. Generation believes that a partial excavation remedy is reasonably possible, and the partial excavation costs, inclusive of a landfill cover, could range from approximately $225 million to$650 million; such costs would likely be shared by the final group of identified PRPs.

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Generation believes the likelihood that the EPA would require a complete excavation remedy is remote. The cost of a partial or complete excavation could have a material, unfavorable impact on Generation's and Exelon's future results of operations and cash flows.

During December 2015, the EPA took two actions related to the West Lake Landfill designed to abate what it termed as imminent and dangerous conditions at the landfill. The first involved installation by the PRPs of a non-combustible surface cover to protect against surface fires in areas where radiological materials are believed to have been disposed. Generation has accrued what it believes to be an adequate amount to cover its anticipated liability for this interim action. The second action involved EPA's public statement that it will require the PRPs to construct a barrier wall in an adjacent landfill to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, EPA has not provided sufficient details related to the basis for and the requirements and design of a barrier wall to enable Generation to determine the likelihood such a remedy will ultimately be implemented, assess the degree to which Generation may have liability as a potentially responsible party, or develop a reasonable estimate of the potential incremental costs. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Generation's and Exelon's future results of operations and cash flows. Finally, one of the other PRP's, the landfill owner and operator of the adjacent landfill, has indicated that it will be making a contribution claim against Cotter for costs that it has incurred to prevent the subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Generation and Exelon do not possess sufficient information to assess this claim and are therefore unable to determine the impact on their future results of operations and cash flows.

On February 2, 2016, the U.S. Senate passed a bill to transfer remediation authority over the West Lake Landfill from the EPA to the U.S. Army Corps of Engineers, under the Formerly Utilized Sites Remedial Action Program (FUSRAP). Such legislation would become final upon passage in the U.S. House of Representatives and the signature of the President, and be subject to annual funding appropriations in the U.S. Budget. The legislation has not passed in the House. Remediation under FUSRAP would not alter the liability of the PRPs, but could delay the determination of a final remedy and its implementation.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the FUSRAP. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2017 so that settlement discussions could proceed. Based on Generation's preliminary review, it appears probable that Generation has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability, which is included in the table above.

Commencing in February 2012, a number of lawsuits have been filed in the U.S. District Court for the Eastern District of Missouri. Among the defendants were Exelon, Generation and ComEd, all of

which were subsequently dismissed from the case, as well as Cotter, which remains a defendant. The suits allege that individuals living in the North St. Louis area developed some form of cancer or other serious illness due to Cotter's negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs are asserting public liability claims under the Price-Anderson Act. Their state law claims for negligence, strict liability, emotional distress, and medical monitoring have been dismissed. The complaints do not contain specific damage claims. In the event of a finding of liability against Cotter, it is reasonably possible that Exelon would be financially responsible due to its indemnification responsibilities of Cotter described above. The court has dismissed a number of lawsuits, and is expected to dismiss additional lawsuits based on a recent ruling. Pre-trial motions and discovery are proceeding in the remaining cases and a pre-trial scheduling order has been filed with the court. At this stage of the litigation, Generation and ComEd cannot estimate a range of loss, if any.

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In connection with BGE's 2000 corporate restructuring the responsibility for this liability was transferred to Constellation and as a result of the 2012 Exelon and CEG merger is now Generation's responsibility. In March 2004, the PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and the PRPs with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The PRPs submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. On September 30, 2013, U.S. EPA issued the Record of Decision identifying its preferred remedial alternative for the site. The estimated cost for the alternative chosen by U.S. EPA is consistent with the PRPs' estimated range of costs noted above. Based on Generation's preliminary review, it appears probable that Generation has liability and has established an appropriate accrual for its share of the estimated clean-up costs.

Rossville Ash Site. The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC (CPSG), a wholly-owned subsidiary of Generation. In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately $4 million, which has been fully reserved as of December 31, 2016 and is included in the table above.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRPs signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRPs to conduct a remedial investigation and feasibility study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup

remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined. It is possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and BGE's future results of operations and cash flows.

Riverside . In 2013, the MDE, at the request of EPA, conducted a site inspection and limited environmental sampling of certain portions of the 170 acre Riverside property owned by BGE. The site consists of several different parcels with different current and historical uses. The sampling included soil and groundwater samples for a number of potential environmental contaminants. The sampling confirmed the existence of contaminants consistent with the known historical uses of the various portions of the site. In March 2014, the MDE requested that BGE conduct an investigation which included a site-wide investigation of soils, sediment, groundwater, and surface water to complement the MDE sampling. The field investigation was completed in January 2015, and a final report was provided to MDE on June 2, 2015. On November 3, 2015, MDE provided BGE with its comments and recommendations on the report which require BGE to conduct further investigation and sampling at the site to better delineate the nature and extent of historic contamination, including off-site sediment and soil sampling. MDE did not request any interim remediation at this time and BGE anticipates completing the additional work requested by the end of the first quarter of 2017. BGE has established what it believes is an appropriate reserve based upon the investigation to date. The established reserve is included in the table above. As the investigation and potential remediation proceed, it is possible that resolution of this matter could have a material, unfavorable impact on Exelon's and BGE's future results of operations and cash flows.

Benning Road Site. In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility. That generating facility was deactivated in June 2012 and plant structure demolition was completed in July 2015. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a consent decree entered into by Pepco and Pepco Energy Services with the DOEE, which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15 acre portion of the adjacent Anacostia River. The RI/FS will form the basis for the remedial actions for the Benning Road site and for the Anacostia River sediment associated with the site. The consent decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DOEE will look to Pepco and Pepco Energy Services to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site.

The initial RI field work began in January 2013 and was completed in December 2014. In April 2015, Pepco and Pepco Energy Services submitted a draft RI Report to DOEE. After review, DOEE determined that additional field investigation and data analysis was required to complete the RI process (much of which was beyond the scope of the original DOEE-approved RI work plan). In the meantime, Pepco and Pepco Energy Services revised the draft RI Report to address DOEE's comments and DOEE released the draft RI Report for public review in February 2016. Once the additional RI work has been completed, Pepco and Pepco Energy Services will issue a draft "final" RI report for review and comment by DOEE and the public. Pepco and Pepco Energy Services will then proceed to develop an FS to evaluate possible remedial alternatives for submission to DOEE.

Upon DOEE's approval of the final remedial investigation and feasibility study Reports, Pepco and Pepco Energy Services will have satisfied their obligations under the consent decree. At that point,

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DOEE will prepare a Proposed Plan regarding further response actions. After considering public comment on the Proposed Plan, DOEE will issue a Record of Decision identifying any further response actions determined to be necessary.

PHI, Pepco and Pepco Energy Services have determined that a loss associated with this matter for PHI, Pepco and Pepco Energy Services is probable and an estimated liability for this issue has been accrued, which is included in the table above. As the remedial investigation proceeds and potential remedies are identified, it is possible that additional reserves could be established in amounts that could be material to PHI, Pepco and Pepco Energy Services. Pursuant to Exelon's March 2016 acquisition of PHI, Pepco Energy Services was transferred to Generation. The ultimate resolution of this matter is currently not expected to have any significant financial impact on Generation.

Anacostia River Tidal Reach . Contemporaneous with the Benning RI/FS being performed by Pepco and Pepco Energy Services, DOEE and certain federal agencies have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-D.C. boundary line to the confluence of the Anacostia and Potomac Rivers. In March 2016, DOEE released a draft of the river-wide RI Report for public review and comment. The river-wide RI incorporated the results of the river sampling performed by Pepco and Pepco Energy Services as part of the Benning RI/FS, as well as similar sampling efforts conducted by owners of other sites adjacent to this segment of the river and supplemental river sampling conducted by DOEE's contractor. DOEE asked Pepco, along with parties responsible for other sites along the river, to participate in a "Consultative Working Group" to provide input into the process for future remedial actions addressing the entire tidal reach of the river and to ensure proper coordination with the other river cleanup efforts currently underway, including cleanup of the river segment adjacent to the Benning Road site resulting from the Benning Road RI/FS. Pepco responded that it will participate in the Consultative Working Group but its participation is not an acceptance of any financial responsibility beyond the work that will be performed at the Benning Road site described above. DOEE has advised the Consultative Working Group that the federal and DOEE authorities are conducting phase 2 of a remedial investigation. DOEE has targeted June 2018 as the date for remedy selection for clean-up of sediments in this section of the river. The Consultative Working Group and the other possible PRPs have provided input into the proposed clean-up process and schedule. At this time, it is not possible to predict the extent of Pepco's participation in the river-wide RI/FS process, and Pepco cannot estimate the reasonably possible range of loss for response costs beyond those associated with the Benning RI/FS component of the river-wide initiative. It is possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Pepco's future results of operations and cash flows.

Conectiv Energy Wholesale Power Generation Sites. In July 2010, PHI sold the wholesale power generation business of Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries (Conectiv Energy) to Calpine Corporation (Calpine). Under New Jersey's Industrial Site Recovery Act (ISRA), the transfer of ownership triggered an obligation on the part of Conectiv Energy to remediate any environmental contamination at each of the nine Conectiv Energy generating facility sites located in New Jersey. Under the terms of the sale, Calpine has assumed responsibility for performing the ISRA-required remediation and for the payment of all related ISRA compliance costs up to $10 million. PHI is obligated to indemnify Calpine for any ISRA compliance remediation costs in excess of $10 million. According to PHI's estimates, the costs of ISRA-required remediation activities at the nine generating facility sites located in New Jersey are in the range of approximately $7 million to $18 million, and PHI has established an appropriate accrual for its share of the estimated clean-up costs, which is included in the table above. Pursuant to Exelon's March 2016 acquisition of PHI, Conectiv Energy was transferred to Generation, however, the responsibility to indemnify Calpine remained at PHI. The ultimate resolution of this matter is currently not expected to have any significant financial impact on PHI.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Rock Creek Mineral Oil Release. In late August 2015, a Pepco underground transmission line in the District of Columbia suffered a breach, resulting in the release of non-toxic mineral oil surrounding the transmission line into the surrounding soil, and a small amount reached Rock Creek through a storm drain. Pepco notified regulatory authorities, and Pepco and its spill response contractors placed booms in Rock Creek, blocked the storm drain to prevent the release of mineral oil into the creek and commenced remediation of soil around the transmission line and the Rock Creek shoreline. Pepco estimates that approximately 6,100 gallons of mineral oil were released and that its remediation efforts recovered approximately 80% of the amount released. Pepco's remediation efforts are ongoing under the direction of the DOEE, including the requirements of a February 29, 2016 compliance order which requires Pepco to prepare a full incident investigation report and prepare a removal action work plan to remove all impacted soils in the vicinity of the storm drain outfall, and in collaboration with the National Park Service, the Smithsonian Institution/National Zoo and EPA. Pepco's investigation presently indicates that the damage to Pepco's facilities occurred prior to the release of mineral oil when third-party excavators struck the Pepco underground transmission line while installing cable for another utility.

To the extent recovery is available against any party who contributed to this loss, PHI and Pepco will pursue such action. Exelon, PHI and Pepco continue to investigate the cause of the incident, the parties involved, and legal responsibility under District of Columbia law, but do not believe that the remediation costs to resolve this matter will have a material adverse effect on their respective financial condition, results of operations or cash flows.

Brandywine Fly Ash Disposal Site. In February 2013, Pepco received a letter from the MDE requesting that Pepco investigate the extent of waste on a Pepco right-of-way that traverses the Brandywine fly ash disposal site in Brandywine, Prince George's County, Maryland, owned by NRG Energy, Inc. (as successor to GenOn MD Ash Management, LLC) (NRG). In July 2013, while reserving its rights and related defenses under a 2000 agreement covering the sale of this site, Pepco indicated its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way. Pepco submitted a schedule for development of a closure plan to MDE on September 30, 2013 and, by letter dated October 18, 2013, MDE approved the schedule.

Exelon, PHI and Pepco have determined that a loss associated with this matter is probable and have estimated that the costs for implementation of a closure plan and cap on the site are in the range of approximately $3 million to $6 million, for which an appropriate reserve has been established and is included in the table above. Exelon, PHI and Pepco believe that the costs incurred in this matter will be recoverable from NRG under the 2000 sale agreement.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon, Generation, ComEd, PECO and BGE).

Exelon and Generation. Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2016 and 2015, Generation had reserved approximately $83 million and $95 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2016, approximately $22 million of this amount related to 230 open claims presented to Generation, while the

remaining $61 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee's disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee's last employment-based exposure, and that therefore the exclusivity provision of the Act does not preclude such employee from suing his or her employer in court. The Supreme Court's ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee's last employment-based exposure to asbestos. Since the Pennsylvania Supreme Court's ruling in November 2013, Exelon, Generation, and PECO have experienced an increase in asbestos-related personal injury claims brought by former PECO employees, all of which have been reserved against on a claim by claim basis. Those additional claims are taken into account in projecting estimated future asbestos-related bodily injury claims.

On November 4, 2015, the Illinois Supreme Court found that the provisions of the Illinois' Workers' Compensation Act and the Workers' Occupational Diseases Act barred an employee from bringing a direct civil action against an employer for latent diseases, including asbestos-related diseases that fall outside the 25-year limit of the statute of repose. The Illinois Supreme Court's ruling reversed previous rulings by the Illinois Court of Appeals, which initially ruled that the Illinois Worker's Compensation law should not apply in cases where the diagnosis of an asbestos related disease occurred after the 25-year maximum time period for filing a Worker's Compensation claim. As a result of this ruling, Exelon, Generation, and ComEd have not recorded an increase to the asbestos-related bodily injury liability as of December 31, 2016.

There is a reasonable possibility that Exelon may have additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued and the increases could have a material adverse effect on Exelon's, Generation's and PECO's future results of operations and cash flows.

BGE. Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

To date, most asbestos claims which have been resolved relating to BGE and certain Constellation subsidiaries have been dismissed or resolved without any payment and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results. Presently, there are an immaterial number of asbestos cases pending against BGE and certain Constellation subsidiaries.

Continuous Power Interruption (Exelon and ComEd)

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's

case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. As of December 31, 2016 and 2015, ComEd did not have any material liabilities recorded for these storm events.

Fund Transfer Restrictions (Exelon, Generation, ComEd, PECO, BGE, PEPCO, DPL and ACE)

Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as: (1) the source of the dividends is clearly disclosed; (2) the dividend is not excessive; and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. On May 1, 2013, PECO redeemed all outstanding preferred securities. As a result, the above ratio calculation is no longer applicable. Additionally, PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity

ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid.

PEPCO is subject to certain dividend restrictions established by settlements approved in Maryland and the District of Columbia. PEPCO is prohibited from paying a dividend on its common shares if (a) after the dividend payment, PEPCO's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the commissions and the Board or (b) Pepco's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade.

DPL is subject to certain dividend restrictions established by settlements approved in Delaware and Maryland. DPL is prohibited from paying a dividend on its common shares if (a) after the dividend payment, DPL's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the commissions and the Board or (b) DPL's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade.

ACE is subject to certain dividend restrictions established by settlements approved in New Jersey. ACE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, ACE's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the commissions and the Board or (b) ACE's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade.

Baltimore City Franchise Taxes (BGE)

The City of Baltimore claims that BGE has maintained electric facilities in the City's public right-of-ways for over one hundred years without the proper franchise rights from the City. BGE has reviewed the City's claim and believes that it lacks merit. BGE has not recorded an accrual for payment of franchise fees for past periods as a range of loss, if any, cannot be reasonably estimated at this time. Franchise fees assessed in future periods may be material to BGE's results of operations and cash flows.

Conduit Lease with City of Baltimore (Exelon and BGE)

On September 23, 2015, the Baltimore City Board of Estimates approved an increase in annual rental fees for access to the Baltimore City underground conduit system effective November 1, 2015, from $12 million to $42 million, subject to an annual increase thereafter based on the Consumer Price Index. BGE subsequently entered into litigation with the City regarding the amount of and basis for establishing the conduit fee. On November 30, 2016, the Baltimore City Board of Estimates approved a settlement agreement entered into between BGE and the City to resolve the disputes and pending litigation related to BGE's use of and payment for the underground conduit system. As a result of the settlement, the parties have entered into a six-year lease that reduces the annual expense to $25 million in the first three years and caps the annual expense in the last three years to not more than $29 million. BGE recorded a credit to Operating and maintenance expense in the fourth quarter of approximately $28 million for the reversal of the previously higher fees accrued in the current year as well as the settlement of prior year disputed fee true-up amounts.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Deere Wind Energy Assets (Exelon and Generation)

In 2013, Deere & Company ("Deere") filed a lawsuit against Generation in the Delaware Superior Court relating to Generation's acquisition of the Deere wind energy assets. Under the purchase agreement, Deere was entitled to receive earn-out payments if certain specific wind projects already under development in Michigan met certain development and construction milestones following the sale. In the complaint, Deere seeks to recover a $14 million earn-out payment associated with one such project, which was never completed. Generation has filed counterclaims against Deere for breach of contract, with a right of recoupment and set off. On June 2, 2016, the Delaware Superior Court entered summary judgment in favor of Deere. On January 17, 2017, Generation filed an appeal with the Supreme Court of Delaware. Generation has accrued an amount to cover its potential liability.

General (All Registrants)

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

See Note 15—Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

25. Supplemental Financial Information (All Registrants)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2016, 2015 and 2014.

For the year ended December 31, 2016	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	Successor PHI (March 24, 2016 to December 31, 2016)	Predecessor PHI (January 1, 2016 to March 23, 2016)
Taxes other than income										
Utility [a]	$ 753	$ 122	$ 242	$ 136	$ 85	$ 312	$ 18	$ —	$ 253	$ 78
Property	483	246	27	13	123	53	31	3	73	18
Payroll	226	117	28	15	17	8	5	3	23	8
Other	114	21	(4)	—	4	4	1	1	5	1
Total taxes other than income	$ 1,576	$ 506	$ 293	$ 164	$ 229	$ 377	$ 55	$ 7	$ 354	$ 105

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2015	Exelon	Generation	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
Taxes other than income									
Utility [a]	$ 474	$ 105	$ 236	$ 133	$ 85	$ 326	$ 308	$ 18	$ —
Property	407	250	27	11	119	94	57	28	3
Payroll	201	118	28	14	16	27	6	4	2
Other	118	16	5	2	4	8	5	1	2
Total taxes other than income	$ 1,200	$ 489	$ 296	$ 160	$ 224	$ 455	$ 376	$ 51	$ 7

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
Taxes other than income									
Utility [a]	$ 456	$ 89	$ 238	$ 128	$ 86	$ 324	$ 307	$ 17	$ —
Property	396	240	25	15	114	85	51	24	3
Payroll	200	118	28	14	18	23	6	4	2
Other	102	18	2	2	3	5	5	1	(1)
Total taxes other than income	$ 1,154	$ 465	$ 293	$ 159	$ 221	$ 437	$ 369	$ 46	$ 4

(a) Generation's utility tax represents gross receipts tax related to its retail operations and ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's utility taxes represent municipal and state utility taxes and gross receipts taxes related to their operating revenues. The offsetting collection of utility taxes from customers is recorded in revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2016	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	Successor March 24, 2016 to December 31, 2016 PHI	Predecessor January 1, 2016 to March 23, 2016 PHI
Other, Net										
Decommissioning-related activities:										
Net realized income on decommissioning trust funds [a]										
Regulatory agreement units	$ 237	$ 237	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	126	126	—	—	—	—	—	—	—	—
Net unrealized gains on decommissioning trust funds										
Regulatory agreement units	216	216	—	—	—	—	—	—	—	—
Non-regulatory agreement units	194	194	—	—	—	—	—	—	—	—
Net unrealized losses on pledged assets										
Zion Station decommissioning	(1)	(1)	—	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(372)	(372)	—	—	—	—	—	—	—	—
Total decommissioning-related activities	400	400	—	—	—	—	—	—	—	—
Investment income (loss)	17	8	—	(1)	2[f]	1	—	1	1	—
Long-term lease income	4	—	—	—	—	—	—	—	—	—
Interest income related to uncertain income tax positions	13	—	—	—	—	1	—	—	(1)	—
Penalty related to uncertain income tax positions [c]	(106)	—	(86)	—	—	—	—	—	—	—
AFUDC—Equity	64	—	14	8	19	19	5	6	23	7
Loss on debt extinguishment	(3)	(2)	—	—	—	—	—	—	—	—
Other	24	(5)	7	1	—	15	8	2	21	(11)
Other, net	$ 413	$ 401	$ (65)	$ 8	$ 21	$ 36	$ 13	$ 9	$ 44	$ (4)

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2015	Exelon	Generation	ComEd	PECO	BGE	*Predecessor* PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds [a]									
Regulatory agreement units	$ 232	$ 232	$ —	$ —	$—	$ —	$ —	$—	$—
Non-regulatory agreement units	156	156	—	—	—	—	—	—	—
Net unrealized losses on decommissioning trust funds—									
Regulatory agreement units	(282)	(282)	—	—	—	—	—	—	—
Non-regulatory agreement units	(197)	(197)	—	—	—	—	—	—	—
Net unrealized gains on pledged assets									
Zion Station decommissioning	7	7	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	21	21	—	—	—	—	—	—	—
Total decommissioning-related activities	(63)	(63)	—	—	—	—	—	—	—
Investment income (loss)	8	3	—	(2)	4[f]	—	—	—	—
Long-term lease income	15	—	—	—	—	—	—	—	—
Interest income related to uncertain income tax positions	1	1	—	—	—	34	5	—	—
AFUDC—Equity	24	—	5	5	14	14	12	1	1
Terminated interest rate swaps [d]	(26)	—	—	—	—	—	—	—	—
PHI merger related debt exchange [e]	(22)	—	—	—	—	—	—	—	—
Other	17	(1)	16	2	—	40	11	9	2
Other, net	$ (46)	$ (60)	$ 21	$ 5	$ 18	$ 88	$ 28	$ 10	$ 3

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds [a]									
Regulatory agreement units	$ 216	$ 216	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	159	159	—	—	—	—	—	—	—
Net unrealized gains on decommissioning trust funds									
Regulatory agreement units	180	180	—	—	—				
Non-regulatory agreement units	134	134	—	—	—	—	—	—	—
Net unrealized gains on pledged assets									
Zion Station decommissioning	29	29	—	—	—	—			
Regulatory offset to decommissioning trust fund-related activities [b]	(358)	(358)	—		—	—	—	—	—
Total decommissioning-related activities	360	360	—	—	—	—	—	—	—
Investment income (loss)	1	1	—	(1)	7[f]	1	—	—	—
Long-term lease income	24	—	—	—	—	—	—	—	—
Interest income related to uncertain income tax positions	40	54	—	—	—	—	1	—	1
AFUDC—Equity	21	—	3	6	12	13	10	2	1
Other	9	(9)	14	2	(1)	30	19	8	1
Other, net	$ 455	$ 406	$ 17	$ 7	$ 18	$ 44	$ 30	$ 10	$ 3

(a) Includes investment income and realized gains and losses on sales of investments within the nuclear decommissioning trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 16—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(c) See Note 15—Income Taxes for discussion of the penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position.
(d) In January 2015, in connection with Generation's $750 million issuance of five-year Senior Unsecured Notes, Exelon terminated certain floating-to-fixed interest rate swaps. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments are probable not to occur. As a result, $26 million of anticipated payments were reclassified from AOCI to Other, net in Exelon's Consolidated Statements of Operations and Comprehensive Income.
(e) See Note 14—Debt and Credit Agreements and Note 4—Mergers, Acquisitions, and Dispositions for additional information on the PHI merger related debt exchange.
(f) Relates to the cash return on BGE's rate stabilization deferral. See Note 3—Regulatory Matters for additional information regarding the rate stabilization deferral.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the years ended December 31, 2016, 2015 and 2014.

For the year ended December 31, 2016	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	Successor PHI (March 24, 2016 to December 31, 2016)	Predecessor PHI (January 1, 2016 to March 23, 2016)
Depreciation, amortization and accretion										
Property, plant and equipment	$ 3,477	$ 1,835	$ 708	$ 244	$ 299	$ 175	$ 110	$ 82	$ 325	$ 94
Regulatory assets	407	—	67	26	124	120	47	83	190	58
Amortization of intangible assets, net	52	44	—	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities [a]	35	35	—	—	—	—	—	—	—	—
Nuclear fuel [b]	1,159	1,159	—	—	—	—	—	—	—	—
ARO accretion [c]	446	446	—	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$ 5,576	$ 3,519	$ 775	$ 270	$ 423	$ 295	$ 157	$ 165	$ 515	$ 152

For the year ended December 31, 2015	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	Predecessor PHI
Depreciation, amortization and accretion									
Property, plant and equipment	$ 2,227	$ 1,007	$ 635	$ 240	$ 289	$ 164	$ 103	$ 76	$ 392
Regulatory assets	170	—	72	20	77	92	45	99	232
Amortization of intangible assets, net	54	47	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities [a]	22	22	—	—	—	—	—	—	—
Nuclear fuel [b]	1,116	1,116	—	—	—	—	—	—	—
ARO accretion [c]	398	397	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$ 3,987	$ 2,589	$ 707	$ 260	$ 366	$ 256	$ 148	$ 175	$ 624

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	Predecessor PHI
Depreciation, amortization and accretion									
Property, plant and equipment	$ 2,080	$ 922	$ 588	$ 227	$ 288	$ 155	$ 94	$ 72	$ 363
Regulatory assets	191	—	99	9	83	57	28	83	163
Amortization of intangible assets, net	44	44	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities [a]	135	135	—	—	—	—	—	—	—
Nuclear fuel [b]	1,073	1,073	—	—	—	—	—	—	—
ARO accretion [c]	345	345	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$ 3,868	$ 2,519	$ 687	$ 236	$ 371	$ 212	$ 122	$ 155	$ 526

(a) Included in Operating revenues or Purchased power and fuel on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(c) Included in Operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the year ended December 31, 2016	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	Successor PHI (March 24, 2016 to December 31, 2016)	Predecessor PHI (January 1, 2016 to March 23, 2016)
Cash paid (refunded) during the year:										
Interest (net of amount capitalized)	$ 1,340	$ 339	$ 298	$ 104	$ 92	$ 118	$ 47	$ 62	$ 209	$ 43
Income taxes (net of refunds)	(441)	435	(444)	64	31	216	115	200	258	11
Other non-cash operating activities:										
Pension and non-pension postretirement benefit costs	$ 619	$ 218	$ 166	$ 33	$ 67	$ 31	$ 18	$ 15	$ 86	$ 23
Loss from equity method investments	24	25	—	—	—	—	—	—	—	—
Provision for uncollectible accounts	155	19	41	30	1	29	23	32	65	16
Provision for excess and obsolete inventory	12	6	4	—	—	3	1	1	1	1
Stock-based compensation costs	111	—	—	—	—	—	—	—	—	3
Other decommissioning-related activity [a]	(384)	(384)	—	—	—	—	—	—	—	—
Energy-related options [b]	(11)	(11)	—	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	9	—	4	1	—	2	1	1	3	1
Amortization of rate stabilization deferral	76	—	—	—	81	(12)	2	—	(5)	5
Amortization of debt fair value adjustment	(11)	(11)	—	—	—	—	—	—	—	—
Merger-related commitments [c][d]	558	53	—	—	—	125	82	110	317	—
Severance costs	99	22	—	—	—	—	—	—	56	—
Asset retirement costs	2	—	—	—	—	—	1	2	2	—
Amortization of debt costs	35	17	4	3	1	—	—	—	1	—
Discrete impacts from EIMA [e]	8	—	8	—	—	—	—	—	—	—
Lower of cost or market inventory adjustment	37	36	—	1	—	—	—	—	—	—
Baltimore City Conduit Lease Settlement	(28)	—	—	—	(28)	—	—	—	—	—
Cash Working Capital Order	(13)	—	—	—	(13)	—	—	—	—	—
Other	35	25	(12)	(3)	(21)	5	(14)	(6)	(12)	(3)
Total other non-cash operating activities	$ 1,333	$ 15	$ 215	$ 65	$ 88	$ 183	$ 114	$ 155	$ 514	$ 46
Non-cash investing and financing activities:										
Change in capital expenditures not paid	$ (128)	$ 50	$ (91)	$ (11)	$ (86)	$ 27	$ (12)	$ 11	$ 21	$ 11
Fair value of net assets contributed to Generation in connection with the PHI Merger, net of cash	—	119	—	—	—	—	—	—	—	—
Fair value of net assets distributed to Exelon in connection with the PHI Merger, net of cash [c][f]	—	—	—	—	—	—	—	—	127	—
Fair value of pension obligation transferred in connection with the PHI Merger [c][f]	—	—	—	—	—	—	—	—	53	—
Assumption of member purchase liability	—	—	—	—	—	—	—	—	29	—
Assumption of merger commitment liability	—	—	—	—	—	33	—	—	33	—
Change in PPE related to ARO update	191	191	—	—	—	—	—	—	—	—
Non-cash financing of capital projects	95	95	—	—	—	—	—	—	—	—
Indemnification of like-kind exchange position [h]	—	—	158	—	—	—	—	—	—	—
Sale of Upstream assets [c]	37	37	—	—	—	—	—	—	—	—
Pending FitzPatrick Acquisition [i]	(54)	(54)	—	—	—	—	—	—	—	—

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 16—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) See Note 4—Mergers, Acquisitions, and Dispositions for more information.
(d) Excludes $5 million of forgiveness of Accounts receivable related to merger commitments recorded in connection with the PHI Merger, the balance is included within Provision for uncollectible accounts.
(e) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate. See Note 3—Regulatory Matters for more information.
(f) Immediately following closing of the PHI Merger, the net assets associated with PHI's unregulated business interests were distributed by PHI to Exelon. Exelon contributed a portion of such net assets to Generation.
(g) Relates to the nuclear fuel procurement contract for the purchase of fixed quantities of converted uranium, which was delivered to Generation in 2015. Generation is required to make payments starting September 28, 2018, with the final payment being due no later than September 30, 2020.
(h) See Note 15—Income Taxes for discussion of the like-kind exchange tax position.
(i) Reflects the transfer of nuclear fuel to Entergy under the cost reimbursement provisions of the FitzPatrick acquisition agreements. See Note 4—Mergers, Acquisitions, and Dispositions for more information.

For the year ended December 31, 2015	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	*Predecessor* PHI
Cash paid (refunded) during the year:									
Interest (net of amount capitalized)	$ 930	$ 348	$ 308	$ 94	$ 120	$ 116	$ 47	$ 63	$ 268
Income taxes (net of refunds)	342	476	(265)	64	73	(6)	(5)	—	(13)
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$ 637	$ 269	$ 206	$ 39	$ 65	$ 30	$ 15	$ 15	$ 97
Loss from equity method investments	7	8	—	—	—	—	—	—	—
Provision for uncollectible accounts	120	22	53	30	15	21	20	20	61
Stock-based compensation costs	97	—	—	—	—	—	—	—	13
Other decommissioning-related activity (a)	(82)	(82)	—	—	—	—	—	—	—
Energy-related options (b)	21	21	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	7	—	5	2	—	2	1	1	5
Amortization of rate stabilization deferral	73	—	—	—	73	1	(3)	—	(2)
Amortization of debt fair value adjustment	(17)	(17)	—	—	—	—	—	—	—
Discrete impacts from EIMA (c)	144	—	144	—	—	—	—	—	—
Amortization of debt costs	58	15	4	2	2	—	—	—	2
Provision for excess and obsolete inventory	10	9	1	—	—	—	—	—	1
Lower of cost or market inventory adjustment	23	23	—	—	—	—	—	—	—
Other	11	—	3	(3)	(18)	—	—	1	(10)
Total other non-cash operating activities	$ 1,109	$ 268	$ 416	$ 70	$ 137	$ 54	$ 33	$ 37	$ 167
Non-cash investing and financing activities:									
Change in capital expenditures not paid	$ 96	$ 82	$ 34	$ (13)	$ (9)	$ (1)	$ 3	$ 3	$ 6
Nuclear fuel procurement (d)	57	57	—	—	—	—	—	—	—
Change in PPE related to ARO update	885	885	—	—	—	—	—	—	—
Indemnification of like-kind exchange position (e)	—	—	7	—	—	—	—	—	—
Non-cash financing of capital projects	77	77	—	—	—	—	—	—	—
Long-term software licensing agreement (f)	95	—	—	—	—	—	—	—	—

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 16—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate. See Note 3—Regulatory Matters for more information.
(d) Relates to the nuclear fuel procurement contract for the purchase of fixed quantities of converted uranium, which was delivered to Generation in 2015. Generation is required to make payments starting September 28, 2018, with the final payment being due no later than September 30, 2020.
(e) See Note 15—Income Taxes for discussion of the like-kind exchange tax position.
(f) Relates to a long-term software license agreement entered into on May 30, 2015. Exelon is required to make payments starting August of 2015 through May of 2024. See Note 14—Debt and Credit Agreements for additional information.

For the year ended December 31, 2014	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	*Predecessor* PHI
Cash paid (refunded) during the year:									
Interest (net of amount capitalized)	$ 940	$ 322	$ 292	$ 94	$ 111	$ 111	$ 45	$ 61	$ 257
Income taxes (net of refunds)	314	227	(6)	85	(21)	(58)	(43)	(3)	(2)
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$ 560	$ 249	$ 162	$ 36	$ 64	$ 22	$ 7	$ 13	$ 58
Loss from equity method investments	22	20	—	—	—	—	—	—	—
Provision for uncollectible accounts	156	14	26	52	64	17	14	13	49
Provision for excess and obsolete inventory	5	5	—	—	—	—	—	—	—
Stock-based compensation costs	91	—	—	—	—	—	—	—	18
Other decommissioning-related activity (a)	(132)	(132)	—	—	—	—	—	—	—
Energy-related options (b)	122	122	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	11	—	8	3	—	3	2	—	5
Amortization of rate stabilization deferral	65	—	—	—	65	3	(1)	—	2
Amortization of debt fair value adjustment	(23)	(23)	—	—	—	—	—	—	—
Merger-related commitments	44	44	—	—	—	—	—	—	—
Discrete impacts from EIMA (c)	53	—	53	—	—	—	—	—	—
Amortization of debt costs	53	12	4	2	2	—	—	—	1
Lower of cost or market inventory adjustment	29	29	—	—	—	—	—	—	—
Other	(2)	6	2	(1)	(15)	(8)	—	—	(6)
Total other non-cash operating activities	$ 1,054	$ 346	$ 255	$ 92	$ 180	$ 37	$ 22	$ 26	$ 127
Non-cash investing and financing activities:									
Change in PPE related to ARO update	$ 72	$ 72	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Change in capital expenditures not paid	220	(61) (d)	78	—	25	10	8	9	28
Fair value of net assets recorded upon CENG consolidation (e)	3,400	3,400	—	—	—	—	—	—	—
Issuance of equity units (f)	131	—	—	—	—	—	—	—	—
Nuclear fuel procurement (g)	70	70	—	—	—	—	—	—	—
Indemnification of like-kind exchange position (h)	—	—	5	—	—	—	—	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 16—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

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Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate. See Note 3—Regulatory Matters for more information.
(d) Includes $170 million of changes in capital expenditures not paid between December 31, 2014 and 2013 related to Antelope Valley.
(e) See Note 5—Investment in Constellation Energy Nuclear Group, LLC for additional information.
(f) Relates to the present value of the contract payments for the equity units issued by Exelon. See Note 21—Stock-Based Compensation Plans for additional information.
(g) Relates to the nuclear fuel procurement contracts for the purchase of fixed quantities of uranium, which was delivered to Generation in 2014. Generation is required to make payments starting June 30, 2016, with the final payment being due no later than June 30, 2018.
(h) See Note 15—Income Taxes for discussion of the like-kind exchange tax position.

DOE Smart Grid Investment Grant (Exelon, PECO and BGE). For the year ended December 31, 2014, PECO has included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $2 million and reimbursements of $5 million related to PECO's DOE SGIG programs. For the years ended December 31, 2016 and 2015, PECO had no capital expenditures or reimbursements, as the DOE SGIG program was completed during 2014. See Note 3—Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants at December 31, 2016 and 2015.

December 31, 2016	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Investments									
Equity method investments:									
Financing trusts (a)	$ 22	$ —	$ 6	$ 8	$ 8	$ —	$ —	$ —	$ —
Bloom	216	216	—	—	—	—	—	—	—
Net Power	57	57	—	—	—	—	—	—	—
Other equity method investments	16	15	—	—	—	—	—	—	—
Total equity method investments	311	288	6	8	8	—	—	—	—
Other investments:									
Employee benefit trusts and investments (c)	232	44	—	17	4	133	102	—	—
Other cost method investments	52	52	—	—	—	—	—	—	—
Other available for sale investments	34	34	—	—	—	—	—	—	—
Total investments	$ 629	$ 418	$ 6	$ 25	$ 12	$ 133	$ 102	$ —	$ —

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

December 31, 2015	Exelon	Generation	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
Investments									
Equity method investments:									
Financing trusts (a)	$ 22	$ —	$ 6	$ 8	$ 8	$ —	$ —	$—	$—
Bloom	63	63	—	—	—	—	—	—	—
Net Power	23	23	—	—	—	—	—	—	—
Other equity method investments	4	3	—	—	—	—	—	—	—
Total equity method investments	112	89	6	8	8	—	—	—	—
Other investments:									
Net investment in leases (b)	358	6	—	—	—	—	—	—	—
Employee benefit trusts and investments (c)	85	31	—	20	4	80	68	—	—
Other cost method investments	55	55	—	—	—	—	—	—	—
Other available for sale investments	29	29	—	—	—	—	—	—	—
Total investments	$ 639	$ 210	$ 6	$ 28	$ 12	$ 80	$ 68	$—	$—

(a) Includes investments in affiliated financing trusts, which were not consolidated within the financial statements of Exelon and are shown as investments on the Consolidated Balance Sheets. See Note 1—Significant Accounting Policies for additional information.
(b) Represents direct financing lease investments. See Note 8—Impairment of Long-Lived Assets for additional information.
(c) The Registrants' investments in these marketable securities are recorded at fair market value.

The following tables provide additional information about liabilities of the Registrants at December 31, 2016 and 2015.

December 31, 2016	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Accrued expenses									
Compensation-related accruals (a)	$1,199	$ 557	$ 199	$ 67	$ 64	$ 112	$ 30	$ 17	$ 11
Taxes accrued	723	239	330	4	78	65	48	4	9
Interest accrued	1,234	82	609	30	31	49	21	8	12
Severance accrued	44	15	2	—	—	19	—	—	—
Other accrued expenses	260	96	110	3	2	27	14	7	6
Total accrued expenses	$3,460	$ 989	$1,250	$ 104	$175	$ 272	$ 113	$ 36	$ 38

December 31, 2015	Exelon	Generation	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
Accrued expenses									
Compensation-related accruals (a)	$1,014	$ 547	$ 183	$ 66	$ 57	$ 88	$ 26	$ 14	$ 8
Taxes accrued	293	186	63	4	23	77	56	3	23
Interest accrued	915	77	443	35	27	54	23	8	13
Severance accrued	21	11	3	—	1	—	—	—	—
Other accrued expenses	133	114	14	4	2	47	14	6	26
Total accrued expenses	$2,376	$ 935	$ 706	$ 109	$110	$ 266	$ 119	$ 31	$ 70

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

26. Segment Information (All Registrants)

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants.

In the first quarter of 2016, following the consummation of the PHI Merger, three new reportable segments were added: Pepco, DPL and ACE. As a result, Exelon has twelve reportable segments, which include ComEd, PECO, BGE, PHI's three reportable segments consisting of Pepco, DPL, and ACE, and Generation's six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as "Other Power Regions", which includes activities in the South, West and Canada. ComEd, PECO, BGE, Pepco, DPL and ACE each represent a single reportable segment, and as such, no separate segment information is provided for these Registrants. Exelon, ComEd, PECO, BGE, Pepco, DPL and ACE's CODMs evaluate the performance of and allocate resources to ComEd, PECO, BGE, Pepco, DPL and ACE based on net income and return on equity.

Effective with the consummation of the PHI Merger, PHI's reportable segments have changed based on the information used by the CODM to evaluate performance and allocate resources. PHI's reportable segments consist of Pepco, DPL and ACE. PHI's Predecessor periods' segment information has been recast to conform to the current presentation. The reclassification of the segment information did not impact PHI's reported consolidated revenues or net income. PHI's CODM evaluates the performance of and allocates resources to Pepco, DPL and ACE based on net income and return on equity.

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

- Other Power Regions :
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

The CODMs for Exelon and Generation evaluate the performance of Generation's electric business activities and allocate resources based on revenues net of purchased power and fuel expense (RNF). Generation believes that RNF is a useful measurement of operational performance. RNF is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's owned generation and fuel costs associated with tolling agreements. The results of Generation's other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, Generation's unrealized mark-to-market gains and losses on economic hedging activities and its amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the years ended December 31, 2016, 2015, and 2014 is as follows:

					Successor			
	Generation (a)	ComEd	PECO	BGE	PHI (e)	Other (b)	Intersegment Eliminations	Exelon
Operating revenues (c) :								
2016								
Competitive businesses electric revenues	$ 15,390	$ —	$ —	$ —	$ —	$ —	$ (1,430)	$ 13,960
Competitive businesses natural gas revenues	2,146	—	—	—	—	—	—	2,146
Competitive businesses other revenues	215	—	—	—	—	—	(4)	211
Rate-regulated electric revenues	—	5,254	2,531	2,609	3,506	—	(31)	13,869
Rate-regulated natural gas revenues	—	—	463	624	92	—	(13)	1,166
Shared service and other revenues	—	—	—	—	45	1,648	(1,686)	7
2015								
Competitive businesses electric revenues	$ 15,944	$ —	$ —	$ —	$ —	$ —	$ (744)	$ 15,200
Competitive businesses natural gas revenues	2,433	—	—	—	—	—	—	2,433
Competitive businesses other revenues	758	—	—	—	—	—	(1)	757
Rate-regulated electric revenues	—	4,905	2,486	2,490	—	—	(5)	9,876
Rate-regulated natural gas revenues	—	—	546	645	—	—	(15)	1,176
Shared service and other revenues	—	—	—	—	—	1,372	(1,367)	5
2014								
Competitive businesses electric revenues	$ 14,533	$ —	$ —	$ —	$ —	$ —	$ (760)	$ 13,773
Competitive businesses natural gas revenues	2,705	—	—	—	—	—	(1)	2,704
Competitive businesses other revenues	155	—	—	—	—	—	(1)	154
Rate-regulated electric revenues	—	4,564	2,448	2,460	—	—	(5)	9,467
Rate-regulated natural gas revenues	—	—	646	705	—	—	(26)	1,325
Shared service and other revenues	—	—	—	—	—	1,285	(1,279)	6
Intersegment revenues (d) :								
2016	$ 1,428	$ 15	$ 8	$ 21	$ 45	$ 1,647	$ (3,159)	$ 5
2015	745	4	2	14	—	1,367	(2,127)	5
2014	762	4	2	25	—	1,280	(2,067)	6
Depreciation and amortization:								
2016	$ 1,879	$ 775	$ 270	$ 423	$ 515	$ 74	$ —	$ 3,936
2015	1,054	707	260	366	—	63	—	2,450
2014	967	687	236	371	—	53	—	2,314
Operating expenses (c) :								
2016	$ 16,856	$ 4,056	$ 2,292	$ 2,683	$ 3,549	$ 1,928	$ (3,164)	$ 28,200
2015	16,872	3,889	2,404	2,578	—	1,444	(2,131)	25,056
2014	16,923	3,586	2,522	2,726	—	1,353	(2,071)	25,039
Equity in earnings (losses) of unconsolidated affiliates:								
2016	$ (25)	$ —	$ —	$ —	$ —	$ 1	$ —	$ (24)
2015	(8)	—	—	—	—	1	—	(7)
2014	(20)	—	—	—	—	—	—	(20)
Interest expense, net:								
2016	$ 364	$ 461	$ 123	$ 103	$ 195	$ 290	$ —	$ 1,536
2015	365	332	114	99	—	123	—	1,033
2014	356	321	113	106	—	169	—	1,065

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation (a)	ComEd	PECO	BGE	Successor PHI (e)	Other (b)	Intersegment Eliminations	Exelon
Income (loss) before income taxes:								
2016	$ 873	$ 679	$ 587	$ 468	$ (58)	$ (555)	$ (5)	$ 1,989
2015	1,850	706	521	477	—	(219)	(5)	3,330
2014	1,226	676	466	351	—	(227)	(6)	2,486
Income taxes:								
2016	$ 290	$ 301	$ 149	$ 174	$ 3	$ (156)	$ —	$ 761
2015	502	280	143	189	—	(41)	—	1,073
2014	207	268	114	140	—	(63)	—	666
Net income (loss):								
2016	$ 558	$ 378	$ 438	$ 294	$ (61)	$ (398)	$ (5)	$ 1,204
2015	1,340	426	378	288	—	(177)	(5)	2,250
2014	1,019	408	352	211	—	(164)	(6)	1,820
Capital expenditures:								
2016	$ 3,078	$ 2,734	$ 686	$ 934	$ 1,008	$ 113	$ —	$ 8,553
2015	3,841	2,398	601	719	—	65	—	7,624
2014	3,012	1,689	661	620	—	95	—	6,077
Total assets:								
2016	$ 46,974	$ 28,335	$ 10,831	$ 8,704	$ 21,025	$ 10,369	$ (11,334)	$ 114,904
2015	46,529	26,532	10,367	8,295	—	15,389	(11,728)	95,384

(a) Generation includes the six reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. For the year ended December 31, 2016, intersegment revenues for Generation include revenue from sales to PECO of $290 million, sales to BGE of $608 million, sales to Pepco of $295 million, sales to DPL of $154 million and sales to ACE of $37 million in the Mid-Atlantic region, and sales to ComEd of $47 million in the Midwest region, which eliminate upon consolidation. For the year ended December 31, 2015, intersegment revenues for Generation include revenue from sales to PECO of $224 million and sales to BGE of $502 million in the Mid-Atlantic region, and sales to ComEd of $18 million in the Midwest region, which eliminate upon consolidation. For the year ended December 31, 2014, intersegment revenues for Generation include revenue from sales to PECO of $198 million and sales to BGE of $387 million in the Mid-Atlantic region, and sales to ComEd of $176 million in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation.

(b) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.

(c) For the years ended December 31, 2016, 2015 and 2014, utility taxes of $122 million, $105 million and $89 million, respectively, are included in revenues and expenses for Generation. For the years ended December 31, 2016, 2015 and 2014, utility taxes of $242 million, $236 million and $238 million, respectively, are included in revenues and expenses for ComEd. For the years ended December 31, 2016, 2015 and 2014, utility taxes of $136 million, $133 million and $128 million, respectively, are included in revenues and expenses for PECO. For the years ended December 31, 2016, 2015 and 2014, utility taxes of $85 million, $85 million and $86 million are included in revenues and expenses for BGE, respectively.

(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

(e) Amounts included represent activity for PHI's successor period, March 24, 2016 through December 31, 2016. PHI includes the three reportable segments: Pepco, DPL and ACE. See tables below for PHI's predecessor periods, including Pepco, DPL and ACE, for January 1, 2016 to March 23, 2016 and for the years ended December 31, 2015 and December 31, 2014.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Successor and Predecessor PHI:

	Pepco	DPL	ACE	Other (b)	Intersegment Eliminations	PHI
Operating revenues (a):						
March 24, 2016 to December 31, 2016—Successor						
Rate-regulated electric revenues	$1,675	$ 850	$ 989	$ 5	$ (13)	$ 3,506
Rate-regulated natural gas revenues	—	92	—	—	—	92
Shared service and other revenues	—	—	—	45	—	45
January 1, 2016 to March 23, 2016—Predecessor						
Rate-regulated electric revenues	$ 511	$ 279	$ 268	$ 42	$ (4)	$ 1,096
Rate-regulated natural gas revenues	—	56	—	1	—	57
Shared service and other revenues	—	—	—	—	—	—
December 31, 2015—Predecessor						
Rate-regulated electric revenues	$2,129	$1,138	$1,295	$ 210	$ (2)	$ 4,770
Rate-regulated natural gas revenues	—	164	—	1	—	165
Shared service and other revenues	—	—	—	—	—	—
December 31, 2014—Predecessor						
Rate-regulated electric revenues	$2,055	$1,088	$1,210	$ 264	$ (3)	$ 4,614
Rate-regulated natural gas revenues	—	194	—	—	—	194
Shared service and other revenues	—	—	—	—	—	—
Intersegment revenues:						
March 24, 2016 to December 31, 2016—Successor	$ 4	$ 5	$ 2	$ 47	$ (13)	$ 45
January 1, 2016 to March 23, 2016—Predecessor	1	2	1	—	(4)	—
December 31, 2015—Predecessor	5	6	4	—	(15)	—
December 31, 2014—Predecessor	5	7	4	—	(16)	—
Depreciation and amortization:						
March 24, 2016 to December 31, 2016—Successor	$ 224	$ 120	$ 128	$ 43	$ —	$ 515
January 1, 2016 to March 23, 2016—Predecessor	71	37	37	11	(4)	152
December 31, 2015—Predecessor	256	148	175	45	—	624
December 31, 2014—Predecessor	212	122	155	38	(1)	526
Operating expenses:						
March 24, 2016 to December 31, 2016—Successor	$1,577	$ 952	$1,000	$ 33	$ (13)	$ 3,549
January 1, 2016 to March 23, 2016—Predecessor	443	284	251	73	(3)	1,048
December 31, 2015—Predecessor	1,790	1,137	1,161	220	—	4,308
December 31, 2014—Predecessor	1,706	1,075	1,073	350	(1)	4,203
Interest expense, net:						
March 24, 2016 to December 31, 2016—Successor	$ 98	$ 38	$ 47	$ 12	$ —	$ 195
January 1, 2016 to March 23, 2016—Predecessor	29	12	15	11	(2)	65
December 31, 2015—Predecessor	124	50	64	43	(1)	280
December 31, 2014—Predecessor	115	48	64	42	—	269
Income (loss) before income taxes:						
March 24, 2016 to December 31, 2016—Successor	$ 36	$ (30)	$ (51)	$ (84)	$ 71	$ (58)
January 1, 2016 to March 23, 2016—Predecessor	47	43	5	59	(118)	36
December 31, 2015—Predecessor	289	125	73	23	(29)	481
December 31, 2014—Predecessor	264	169	76	306	(435)	380
Income taxes:						
March 24, 2016 to December 31, 2016—Successor	$ 26	$ 5	$ (5)	$ (23)	$ —	$ 3
January 1, 2016 to March 23, 2016—Predecessor	15	17	1	(16)	—	17
December 31, 2015—Predecessor	102	49	33	(48)	27	163
December 31, 2014—Predecessor	93	65	30	(228)	178	138
Net income (loss):						
March 24, 2016 to December 31, 2016—Successor	$ 10	$ (35)	$ (47)	$ (34)	$ 45	$ (61)
January 1, 2016 to March 23, 2016—Predecessor	32	26	5	(44)	—	19
December 31, 2015—Predecessor	187	76	40	25	(1)	327
December 31, 2014—Predecessor	171	104	46	(78)	(1)	242
Capital Expenditures:						
March 24, 2016 to December 31, 2016—Successor	$ 489	$ 277	$ 218	$ 24	$ —	$ 1,008
January 1, 2016 to March 23, 2016—Predecessor	97	72	93	11	—	273
December 31, 2015—Predecessor	544	352	300	34	—	1,230
December 31, 2014—Predecessor	567	352	225	79	—	1,223
Total assets:						
December 31, 2016—Successor	$7,335	$4,153	$3,457	$10,804	$ (4,724)	$21,025
December 31, 2015—Predecessor	6,908	3,969	3,387	7,162	(5,238)	16,188

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 25—Supplemental Financial Information for total utility taxes for the year ended December 31, 2016 and 2015
(b) Other primarily includes PHI's corporate operations, shared service entities and other financing and investment activities. For the predecessor periods presented, Other includes the activity of PHI's unregulated businesses which were distributed to Exelon and Generation as a result of the PHI Merger.

Generation total revenues:

	2016			2015			2014		
	Revenues from external customers (b)	Intersegment revenues	Total revenues	Revenues from external customers (b)	Intersegment revenues	Total revenues	Revenues from external customers (b)(d)	Intersegment revenues (d)	Total revenues
Mid-Atlantic (a)	$ 6,212	$ (33)	$ 6,179	$ 5,974	$ (74)	$ 5,900	$ 5,414	$ (155)	$ 5,259
Midwest	4,402	10	4,412	4,712	(2)	4,710	4,488	(13)	4,475
New England	1,778	(9)	1,769	2,217	(5)	2,212	1,468	(46)	1,422
New York (a)	1,198	(42)	1,156	996	(11)	985	846	(3)	843
ERCOT	831	6	837	863	(6)	857	938	(3)	935
Other Power Regions	969	(62)	907	1,182	(80)	1,102	1,379	(70)	1,309
Total Revenues for Reportable Segments	$15,390	$ (130)	$15,260	$15,944	$ (178)	$15,766	$14,533	$ (290)	$14,243
Other (c)	2,361	130	2,491	3,191	178	3,369	2,860	290	3,150
Total Generation Consolidated Operating Revenues	$17,751	$ —	$17,751	$19,135	$ —	$19,135	$17,393	$ —	$17,393

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, CENG's revenues are included on a fully consolidated basis.
(b) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a $52 million decrease to revenues, a $7 million increase to revenues, and a $289 million decrease to revenues for the amortization of intangible assets related to commodity contracts recorded at fair value for the years ended December 31, 2016, 2015, and 2014, respectively, unrealized mark-to-market losses of $500 million, gains of $203 million, and losses of $174 million for the years ended December 31, 2016, 2015, and 2014, respectively, and elimination of intersegment revenues.
(d) Exelon corrected an error in the December 31, 2014 balances within Intersegment revenues and Revenues from external customers for an overstatement of Intersegment revenues for Reportable Segments of $284 million for the year ended December 31, 2014, an understatement of Revenues from external customers for Reportable Segments of $284 million for the year ended December 31, 2014, an understatement of Intersegment revenues for Other of $284 million for the year ended December 31, 2014, and an overstatement of Revenues from external customers for Other of $284 million for the year ended December 31, 2014. The error is not considered material to any prior period, and there is no net impact to Total Revenues.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation total revenues net of purchased power and fuel expense:

	2016			2015			2014		
	RNF from external customers (b)	Intersegment RNF	Total RNF	RNF from external customers (b)	Intersegment RNF	Total RNF	RNF from external customers (b)(d)	Intersegment RNF (d)	Total RNF
Mid-Atlantic (a)	$ 3,282	$ 35	$3,317	$ 3,556	$ 15	$3,571	$ 3,544	$ (113)	$3,431
Midwest	2,969	2	2,971	2,912	(20)	2,892	2,607	(8)	2,599
New England	467	(29)	438	519	(58)	461	450	(99)	351
New York (a)	761	(19)	742	584	50	634	439	44	483
ERCOT	412	(131)	281	425	(132)	293	573	(256)	317
Other Power Regions	483	(147)	336	440	(190)	250	517	(190)	327
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 8,374	$ (289)	$8,085	$ 8,436	$ (335)	$8,101	$ 8,130	$ (622)	$7,508
Other (c)	547	289	836	678	335	1,013	(662)	622	(40)
Total Generation Revenues net of purchased power and fuel expense	$ 8,921	$ —	$8,921	$ 9,114	$ —	$9,114	$ 7,468	$ —	$7,468

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, CENG's revenues net of purchased power and fuel expense are included on a fully consolidated basis.
(b) Includes purchases and sales from third parties and affiliated sales to the Utility Registrants.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a $57 million decrease in RNF, a $8 million increase in RNF, and a $124 million decrease in RNF for the amortization of intangible assets related to commodity contracts recorded at fair value for the years ended December 31, 2016, 2015, and 2014, respectively, unrealized mark-to-market losses of $41 million, gains of $257 million, and losses of $591 million for the years ended December 31, 2016, 2015, and 2014, respectively, accelerated nuclear fuel amortization associated with the initial early retirement decision for Clinton and Quad Cities as discussed in Note 9—Early Nuclear Plant Retirements of $60 million for the year ended December 31, 2016, and the elimination of intersegment revenues net of purchased power and fuel expense.
(d) Exelon corrected an error in the December 31, 2014 balances within Intersegment RNF and RNF from external customers for an understatement of $8 million of Intersegment RNF for Reportable Segments for the year ended December 31, 2014, an understatement of RNF from external customers for Reportable Segments of $11 million for the year ended December 31, 2014, an overstatement of $8 million of Intersegment RNF for Other for the year ended December 31, 2014, and an overstatement of RNF from external customers for Other of $11 million for the year ended December 31, 2014. This also included an understatement of total RNF for Reportable Segments and an overstatement of total RNF for Other of $19 million for the year ended December 31, 2014. The error is not considered material to any prior period, and there is no net impact to Generation Total RNF for 2014.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

27. Related Party Transactions (All Registrants)

Exelon

The financial statements of Exelon include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2016	2015	2014
Operating revenues from affiliates:			
PECO [a]	$ 1	$ 1	$ 1
CENG [b]	—	—	17
BGE [a]	4	4	5
Other	5	4	—
Total operating revenues from affiliates	$ 10	$ 9	$ 23
Purchase power and fuel from affiliates:			
CENG [c]	$—	$—	$282
Keystone Fuels, LLC [d]	—	—	138
Conemaugh Fuels, LLC [d]	—	—	99
Safe Harbor Water Power Corp [d]	—	—	12
Total purchase power and fuel from affiliates	$—	$—	$531
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
BGE Capital Trust II	16	16	16
Total interest expense to affiliates, net	$ 41	$ 41	$ 41
Earnings (losses) in equity method investments:			
CENG [e]	$—	$—	$ (19)
Qualifying facilities and domestic power projects	(25)	(8)	(1)
Other	1	1	—
Total losses in equity method investments	$ (24)	$ (7)	$ (20)

	December 31,	
	2016	2015
Payables to affiliates (current):		
ComEd Financing III	$ 4	$ 4
PECO Trust III	1	1
BGE Capital Trust II	3	3
Total payables to affiliates (current)	$ 8	$ 8
Long-term debt due to financing trusts:		
ComEd Financing III	$205	$205
PECO Trust III	81	81
PECO Trust IV	103	103
BGE Capital Trust II	252	252
Total long-term debt due to financing trusts	$641	$641

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) The intersegment profit associated with the sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations. See Note 3—Regulatory Matters for additional information.

(b) Beginning in 2012, Generation entered into a power services agency agreement (PSAA) with the CENG plants, which as of April 1, 2014, was amended and extended until the permanent cessation of power generation by the CENG generation plants. The PSAA is an agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services. On April 1, 2014, Generation and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were part of the Generation nuclear fleet. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(c) CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Beginning in 2012, Generation had a PPA under which it purchased 85% of the nuclear plant output owned by CENG that was not sold to third parties under pre-existing unit-contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit-contingent basis 50.01% of the nuclear plant output owned by CENG and a subsidiary of EDF will purchase on a unit-contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA) not sold to third parties. Beginning April 1, 2014, sales to Generation are eliminated in consolidation. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(d) During 2014, Generation closed the sale of Safe Harbor Water Power Corporation, Keystone Fuels, LLC, and Conemaugh Fuels LLC. Generation recorded purchase power and fuel costs from affiliates related to these generating assets during the time these assets were still partially owned by Generation. See Note 4—Mergers, Acquisitions, and Dispositions for more information.

(e) Prior to April 1, 2014, Generation's total gain (loss) in equity method investments includes equity investment income (loss) and amortization of the basis difference established as a result of purchase accounting applied upon Constellation merger in 2012. CENG was fully consolidated on April 1, 2014. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Transactions involving Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE are further described in the tables below.

Generation

The financial statements of Generation include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2016	2015	2014
Operating revenues from affiliates:			
ComEd (a)	$ 47	$ 18	$176
PECO (b)	290	224	198
BGE (c)	608	502	387
Pepco (d)	295	—	—
DPL (e)	154	—	—
ACE (f)	37	—	—
CENG (g)	—	—	17
BSC	2	1	1
Other	6	4	—
Total operating revenues from affiliates	$1,439	$ 749	$779
Purchase power and fuel from affiliates:			
ComEd	$ —	$ —	$ 1
BGE	12	14	25
CENG (h)	—	—	282
Keystone Fuels, LLC (l)	—	—	138
Conemaugh Fuels, LLC (l)	—	—	99
Safe Harbor Water Power Corporation (l)	—	—	12
Total purchase power and fuel from affiliates	$ 12	$ 14	$557
Operating and maintenance from affiliates:			
ComEd (i)	$ 7	$ 4	$ 3
PECO (i)	3	2	2
BGE (i)	1	—	—
PHI	1	—	—
Pepco	1	—	—
BSC (j)	650	614	618
Total operating and maintenance from affiliates	$ 663	$ 620	$623
Interest expense to affiliates, net:			
Exelon Corporate (m)	$ 39	$ 43	$ 53
Earnings (losses) in equity method investments			
CENG (k)	$ —	$ —	$ (19)
Qualifying facilities and domestic power projects	(25)	(8)	(1)
Total losses in equity method investments	$ (25)	$ (8)	$ (20)
Capitalized costs			
BSC (j)	$ 98	$ 76	$ 91
Cash distribution paid to member	$ 922	$2,474	$645
Contribution from member	$ 142	$ 47	$ 53

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2016	December 31, 2015
Receivables from affiliates (current):		
ComEd (a)	$ 14	$ 15
PECO (b)	33	36
BGE (c)	26	31
Pepco (d)	44	—
DPL (e)	16	—
ACE (f)	9	—
PHISCO (j)	5	—
PCI	8	—
Other	1	1
Total receivables from affiliates (current)	$ 156	$ 83
Intercompany money pool (current):		
Exelon Corporate	$ —	$1,252
PCI	55	—
Total intercompany money pool (current)	$ 55	$1,252
Payables to affiliates (current):		
Exelon Corporate (m)	$ 22	$ 16
BSC (j)	99	78
ComEd	9	9
Other	7	1
Total payables to affiliates (current)	$ 137	$ 104
Long-term debt due to affiliates (noncurrent):		
Exelon Corporate (o)	$ 922	$ 933
Payables to affiliates (noncurrent):		
BSC (g)	$ 1	$ —
ComEd (n)	2,169	2,172
PECO (n)	438	405
Total payables to affiliates (noncurrent)	$2,608	$2,577

(a) Generation has an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. Generation also sells RECs to ComEd. In addition, Generation had revenue from ComEd associated with the settled portion of the financial swap contract established as part of the Illinois Settlement. See Note 3—Regulatory Matters for additional information.
(b) Generation provides electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, Generation has a ten-year agreement with PECO to sell solar AECs. See Note 3—Regulatory Matters for additional information.
(c) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.
(d) Generation provides electric supply to Pepco under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC. See Note 3—Regulatory Matters for additional information.
(e) Generation provides a portion of DPL's energy requirements under its MDPSC and DPSC approved market based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.
(f) Generation provides electric supply to ACE under contracts executed through ACE's competitive procurement process. See Note 3—Regulatory Matters for additional information.
(g) Beginning in 2012, Generation entered into a power services agency agreement (PSAA) with the CENG plants, which as of April 1, 2014, was amended and extended until the permanent cessation of power generation by the CENG generation plants. The PSAA is an agreement under which Generation provides scheduling, asset management and billing services to

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services. On April 1, 2014, Generation and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were part of the Generation nuclear fleet. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(h) CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Beginning in 2012, Generation had a PPA under which it purchased 85% of the nuclear plant output owned by CENG that was not sold to third parties under pre-existing unit-contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit-contingent basis 50.01% of the nuclear plant output owned by CENG and a subsidiary of EDF will purchase on a unit-contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA) not sold to third parties. Beginning April 1, 2014, sales to Generation are eliminated in consolidation. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(i) Generation requires electricity for its own use at its generating stations. Generation purchases electricity and distribution and transmission services from PECO and BGE and only distribution and transmission services from ComEd for the delivery of electricity to its generating stations.

(j) Generation receives a variety of corporate support services from BSC and PHISCO, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

(k) Prior to April 1, 2014, Generation's total gain (loss) in equity method investments includes equity income (loss) and amortization of the basis difference established as a result of purchase accounting applied upon Constellation merger in 2012. CENG was fully consolidated on April 1, 2014. For further information regarding the Investment in CENG, see Note 5—Investment in Constellation Energy Nuclear Group, LLC.

(l) During 2014, Generation closed the sale of Safe Harbor Water Power Corporation, Keystone Fuels, LLC, and Conemaugh Fuels LLC. Generation recorded purchase power and fuel costs from affiliates related to these generating assets during the time these assets were still partially owned by Generation. See Note 4—Mergers, Acquisitions, and Dispositions for more information.

(m) The balance consists of interest owed to Exelon Corporation related to the senior unsecured notes, as well as, expense related to certain invoices Exelon Corporation processed on behalf of Generation.

(n) Generation has long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 16—Asset Retirement Obligations.

(o) In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-term Debt to affiliate on Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd

The financial statements of ComEd include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2016	2015	2014
Operating revenues from affiliates			
Generation	$ 7	$ 4	$ 4
BSC	6	—	—
PECO	1	—	—
BGE	1	—	—
Total operating revenues from affiliates	$ 15	$ 4	$ 4
Purchased power from affiliate			
Generation [a]	$ 47	$ 18	$176
Operating and maintenance from affiliates			
BSC [b]	$225	$195	$166
PECO	1	—	—
BGE	1	—	—
Total operating and maintenance from affiliates	227	195	166
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
Capitalized costs			
BSC [b]	$112	$103	$ 77
Cash dividends paid to parent	$369	$299	$307
Contribution from parent	$315	$202	$273

	December 31,	
	2016	2015
Prepaid voluntary employee beneficiary association trust [c]	$ 5	$ 11
Receivable from affiliates (current):		
Voluntary employee beneficiary association trust	$ 2	$ 2
Generation	9	9
Exelon Corporate [e]	345	188
Total receivable from affiliates (current)	$ 356	$ 199
Receivable from affiliates (noncurrent):		
Generation [d]	$2,169	$2,172
Other	1	—
Total receivable from affiliates (noncurrent)	$2,170	$2,172
Payables to affiliates (current):		
Generation [a]	$ 14	$ 15
BSC [b]	42	39
ComEd Financing III	4	4
PECO	2	2
Exelon Corporate	3	2
Total payables to affiliates (current)	$ 65	$ 62
Long-term debt to ComEd financing trust		
ComEd Financing III	$ 205	$ 205

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) ComEd procures a portion of its electricity supply requirements from Generation under an ICC-approved RFP contract. ComEd also purchases RECs from Generation. In addition, purchased power expense includes the settled portion of the financial swap contract with Generation, which expired in 2013. See Note 3—Regulatory Matters and Note 13—Derivative Financial Instruments for additional information.
(b) ComEd receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(c) The voluntary employee benefit association trusts covering active employees are included in corporate operations and are funded by the Registrants. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for ComEd's contributions to the plans, being higher than actual claim expense incurred by the plans over time. The prepayment is included in other current assets.
(d) ComEd has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct for generating facilities previously owned by ComEd. To the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to ComEd for payment to ComEd's customers.
(e) Represents indemnification from Exelon Corporate related to the like-kind exchange.

PECO

The financial statements of PECO include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2016	2015	2014
Operating revenues from affiliates:			
Generation (a)	$ 3	$ 2	$ 2
BSC	3	—	—
ComEd	1	—	—
BGE	1	—	—
Total operating revenues from affiliates	$ 8	$ 2	$ 2
Purchased power from affiliate			
Generation (b)	$287	$220	$194
Operating and maintenance from affiliates:			
BSC (c)	$142	$107	$ 96
Generation	2	3	3
ComEd	1	—	—
BGE	1	—	—
Total operating and maintenance from affiliates	$146	$110	$ 99
Interest expense to affiliates, net:			
PECO Trust III	$ 6	$ 6	$ 6
PECO Trust IV	6	6	6
Total interest expense to affiliates, net	$ 12	$ 12	$ 12
Capitalized costs			
BSC (c)	$ 57	$ 40	$ 39
Cash dividends paid to parent	$277	$279	$320
Contribution from parent	$ 18	$ 16	$ 24

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2016	December 31, 2015
Prepaid voluntary employee beneficiary association trust (d)	$ 1	$ 2
Receivable from affiliate (current):		
ComEd	$ 2	$ 2
BGE	2	—
Total receivable from affiliates (current)	$ 4	$ 2
Receivable from affiliate (noncurrent):		
Generation (e)	$438	$405
Payables to affiliates (current):		
Generation (b)	$ 33	$ 36
BSC (c)	28	17
Exelon Corporate	1	1
PECO Trust III	1	1
Total payables to affiliates (current)	$ 63	$ 55
Long-term debt to financing trusts:		
PECO Trust III	$ 81	$ 81
PECO Trust IV	103	103
Total long-term debt to financing trusts	$184	$184

(a) PECO provides energy to Generation for Generation's own use.
(b) PECO purchases electric supply from Generation under contracts executed through its competitive procurement process. In addition, PECO has five-year and ten-year agreements with Generation to purchase non-solar and solar AECs, respectively. See Note 3—Regulatory Matters for additional information on AECs.
(c) PECO receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) The voluntary employee beneficiary association trusts covering active employees are included in corporate operations and are funded by the Registrants. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for PECO's contributions to the plans, being higher than actual claim expense incurred by the plans over time.
(e) PECO has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct, whereby, to the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to PECO for payment to PECO's customers.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

The financial statements of BGE include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2016	2015	2014
Operating revenues from affiliates:			
Generation [a]	$ 13	$ 14	$ 25
BSC	6	—	—
ComEd	1	—	—
PECO	1	—	—
Total operating revenues from affiliates	$ 21	$ 14	$ 25
Purchased power from affiliate			
Generation [b]	$604	$498	$382
Operating and maintenance from affiliates:			
BSC [c]	$130	$118	$103
ComEd	1	—	—
PECO	1	—	—
Total operating and maintenance from affiliates	$132	$118	$103
Interest expense to affiliates, net:			
BGE Capital Trust II	$ 16	$ 16	$ 16
Capitalized costs			
BSC [c]	$ 36	$ 28	$ 19
Cash dividends paid to parent	$179	$158	$—
Contribution from parent	$ 61	$ 7	$—

	December 31,	
	2016	2015
Payables to affiliates (current):		
Generation [b]	$ 26	$ 31
BSC [c]	22	17
Exelon Corporate	1	1
PECO	2	—
BGE Capital Trust II	3	3
Other	1	—
Total payables to affiliates (current)	$ 55	$ 52
Long-term debt to BGE financing trust		
BGE Capital Trust II	$252	$252

(a) BGE provides energy to Generation for Generation's own use.
(b) BGE procures a portion of its electricity and gas supply requirements from Generation under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.
(c) BGE receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI

The financial statements of PHI include related party transactions as presented in the tables below:

	Successor March 24, 2016 to December 31, 2016
Operating revenues from affiliates:	
BSC	$ 44
Generation	1
Total operating revenues from affiliates	$ 45
Purchased power from affiliate	
Generation	$ 486
Operating and maintenance from affiliates:	
BSC	$ 86
PCI	3
Total operating and maintenance from affiliates	$ 89
Cash dividends paid to parent	$ 273
Contribution from member	$ 1,251

	December 31, 2016 Successor
Payables to affiliates (current):	
Generation	$ 74
BSC	10
Exelon Corporate	6
PHI Corporate	4
Total payables to affiliates (current)	$ 94

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Pepco

The financial statements of Pepco include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2016	2015	2014
Operating revenues from affiliates:			
Generation [a]	$ 1	$ —	$ —
PHISCO	4	5	5
Total operating revenues from affiliates	$ 5	$ 5	$ 5
Purchased power from affiliate			
Generation [b]	$295	$ —	$ —
Operating and maintenance:			
PHISCO [c]	$263	$240	$220
PES [d]	39	26	30
Total operating and maintenance	$302	$266	$250
Operating and maintenance from affiliates:			
BSC [c]	$ 31	$ —	$ —
PHISCO [c]	4	4	4
Total operating and maintenance from affiliates	$ 35	$ 4	$ 4
Cash dividends paid to parent	$136	$146	$ 86
Contribution from parent	$187	$112	$ 80

	December 31,	
	2016	2015
Payables to affiliates (current):		
Generation [b]	$ 44	$ —
BSC [c]	4	—
DPL	1	—
PHISCO [c]	25	25
PES [e]	—	4
Other	—	1
Total payables to affiliates (current)	$ 74	$ 30

(a) Pepco provides energy to Generation for Generation's own use.
(b) Pepco procures a portion of its electricity and gas supply requirements from Generation under its MDPSC and DPSC approved market based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.
(c) Pepco receives a variety of corporate support services from BSC and PHISCO, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) PES performs underground transmission, distribution construction and maintenance services, including services that are treated as capital costs, for Pepco.
(e) Pepco bills customers on behalf of PES where PES has performed work for certain government agencies under a General Services Administration area-wide agreement on behalf of Pepco.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

DPL

The financial statements of DPL include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2016	2015	2014
Operating revenues from affiliates:			
PHISCO	$ 5	$ 5	$ 6
Other	2	1	1
Total operating revenues from affiliates	$ 7	$ 6	$ 7
Purchased power from affiliate			
Generation (a)	$154	$—	$—
Operating and maintenance:			
PHISCO (b)	$194	$179	$163
PES (c)	8	3	—
Total operating and maintenance	$202	$182	$163
Operating and maintenance from affiliates:			
BSC (b)	$ 18	$—	$—
Other	1	1	1
Total operating and maintenance from affiliates	$ 19	$ 1	$ 1
Cash dividends paid to parent	$ 54	$ 92	$100
Contribution from parent	$152	$ 75	$130

	December 31,	
	2016	2015
Receivables from affiliates (current):		
Pepco	$ 1	$—
ACE	2	—
Total receivable from affiliates (current)	$ 3	$—
Payables to affiliates (current):		
Generation (a)	$ 16	$—
BSC (b)	3	—
PHISCO (b)	19	19
Other	—	1
Total payables to affiliates (current)	$ 38	$ 20

(a) DPL procures a portion of its electricity and gas supply requirements from Generation under its MDPSC and DPSC approved market based SOS and gas commodity programs. See Note 3—Regulatory Matters for additional information.
(b) DPL receives a variety of corporate support services from BSC and PHISCO, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(c) PES performs underground transmission construction services, including services that are treated as capital costs, for DPL.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

ACE

The financial statements of ACE include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2016	2015	2014
Operating revenues from affiliates:			
PHISCO	$ 2	$ 2	$ 1
Other	1	2	3
Total operating revenues from affiliates	$ 3	$ 4	$ 4
Purchased power from affiliate			
Generation (a)	$ 37	$ —	$ —
Operating and maintenance:			
PHISCO (b)	$ 155	$ 143	$ 124
Operating and maintenance from affiliates:			
BSC (b)	$ 15	$ —	$ —
Other	3	3	3
Total operating and maintenance from affiliates	$ 18	$ 3	$ 3
Cash dividends paid to parent	$ 63	$ 12	$ 26
Contribution from parent	$ 139	$ 95	$ —

	December 31,	
	2016	2015
Payables to affiliates (current):		
Generation (a)	$ 9	$ —
BSC (b)	2	—
DPL	2	—
PHISCO (b)	16	15
Other	—	1
Total payables to affiliates (current)	$ 29	$ 16

(a) ACE purchases electric supply from Generation under contracts executed through its competitive procurement process. See Note 3—Regulatory Matters for additional information.
(b) ACE receives a variety of corporate support services from BSC and PHISCO, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

28. Quarterly Data (Unaudited) (All Registrants)

Exelon

The data shown below, which may not equal the total for the year due to the effects of rounding and dilution, includes all adjustments that Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income Attributable to Common Shareholders	
	2016	2015	2016	2015	2016	2015
Quarter ended:						
March 31	$ 7,573	$ 8,830	$ 483	$ 1,366	$ 173	$ 693
June 30	6,910	6,514	647	1,134	267	638
September 30	9,002	7,401	1,267	1,200	490	629
December 31	7,875	6,702	714	707	204	309

	Average Basic Shares Outstanding (in millions)		Net Income per Basic Share	
	2016	2015	2016	2015
Quarter ended:				
March 31	923	862	$ 0.19	$ 0.80
June 30	924	863	0.29	0.74
September 30	925	913	0.53	0.69
December 31	925	921	0.22	0.34

	Average Diluted Shares Outstanding (in millions)		Net Income per Diluted Share	
	2016	2015	2016	2015
Quarter ended:				
March 31	925	867	$ 0.19	$ 0.80
June 30	926	866	0.29	0.74
September 30	927	915	0.53	0.69
December 31	928	924	0.22	0.33

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2016				2015			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 36.36	$ 37.70	$ 36.37	$ 35.95	$ 31.37	$ 34.44	$ 34.98	$ 38.25
Low price	29.82	32.86	33.18	26.26	25.09	28.41	31.28	31.71
Close	35.49	33.29	36.36	35.86	27.77	29.70	31.42	33.61
Dividends	0.318	0.318	0.318	0.310	0.310	0.310	0.310	0.310

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation

The data shown below includes all adjustments that Generation considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating (Loss) Income		Net (Loss) Income Attributable to Membership Interest	
	2016	2015	2016	2015	2016	2015
Quarter ended:						
March 31	$ 4,739	$ 5,840	$ 415	$ 719	$ 310	$ 443
June 30	3,589	4,232	(13)	703	(8)	398
September 30	5,035	4,768	342	622	236	377
December 31	4,388	4,294	94	230	(41)	154

ComEd

The data shown below includes all adjustments that ComEd considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income	
	2016	2015	2016	2015	2016	2015
Quarter ended:						
March 31	$ 1,249	$ 1,185	$ 274	$ 230	$ 115	$ 90
June 30	1,286	1,148	324	243	145	99
September 30	1,497	1,376	389	327	37	149
December 31	1,223	1,196	217	217	80	87

PECO

The data shown below includes all adjustments that PECO considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income Attributable to Common Shareholders	
	2016	2015	2016	2015	2016	2015
Quarter ended:						
March 31	$ 841	$ 985	$ 196	$ 223	$ 124	$ 139
June 30	664	661	152	124	100	70
September 30	788	740	204	154	122	90
December 31	701	645	150	128	92	79

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

The data shown below includes all adjustments that BGE considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income Attributable to Common Shareholders	
	2016	2015	2016	2015	2016	2015
Quarter ended:						
March 31	$ 929	$ 1,036	$ 187	$ 204	$ 98	$ 106
June 30	680	628	59	99	31	44
September 30	812	725	115	110	54	51
December 31	812	746	190	144	103	74

PHI

The data shown below includes all adjustments that PHI considers necessary for a fair presentation of such amounts:

	Successor	*Predecessor*	*Successor*	*Predecessor*	*Successor*	*Predecessor*
	Operating Revenues		Operating (Loss) Income		Net (Loss) Income Attributable to Membership Interest	
	2016	2015	2016	2015	2016	2015
Quarter ended:						
March 31	$ 105 (a)	$ 1,354	$ (411) (a)	$ 142	$ (309) (a)	$ 53
June 30	1,066	1,119	136	139	52	53
September 30	1,394	1,336	279	184	166	91
December 31	1,078	1,126	90	208	30	130

	Predecessor		
	Operating Revenues	Operating Income	Net Income Attributable to Membership Interest
January 1, 2016—March 23, 2016	1,153	105	19

(a) Amounts for March 31, 2016 reflect the PHI Successor activity for the period March 24, 2016 to March 31, 2016.

Pepco

The data shown below includes all adjustments that Pepco considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating (Loss) Income		Net (Loss) Income Attributable to Common Shareholders	
	2016	2015	2016	2015	2016	2015
Quarter ended:						
March 31	$ 551	$ 545	$(105)	$ 63	$ (108)	$ 26
June 30	509	504	97	83	49	42
September 30	635	592	132	115	79	60
December 31	491	488	51	123	23	59

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

DPL

The data shown below includes all adjustments that DPL considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating (Loss) Income		Net (Loss) Income Attributable to Common Shareholders	
	2016	2015	2016	2015	2016	2015
Quarter ended:						
March 31	$ 362	$ 421	$ (72)	$ 63	$ (72)	$ 32
June 30	281	271	30	24	12	8
September 30	331	314	72	32	44	15
December 31	303	296	20	46	7	21

ACE

The data shown below includes all adjustments that ACE considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating (Loss) Income		Net (Loss) Income Attributable to Common Shareholders	
	2016	2015	2016	2015	2016	2015
Quarter ended:						
March 31	$ 291	$ 334	$ (121)	$ 29	$ (100)	$ 9
June 30	270	285	19	25	3	6
September 30	421	386	83	51	47	22
December 31	275	291	26	29	8	3

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

All Registrants

None.

ITEM 9A. CONTROLS AND PROCEDURES

All Registrants—Disclosure Controls and Procedures

During the fourth quarter of 2016, each registrant's management, including its principal executive officer and principal financial officer, evaluated the effectiveness of that registrant's disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in that registrant's periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by each registrant to ensure that (a) information relating to that registrant, including its consolidated subsidiaries, that is required to be included in filings under the Securities Exchange Act of 1934, is accumulated and made known to that registrant's management, including its principal executive officer and principal financial officer, by other employees of that registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of December 31, 2016, the principal executive officer and principal financial officer of each registrant concluded that such registrant's disclosure controls and procedures were effective to accomplish their objectives.

All Registrants—Changes in Internal Control Over Financial Reporting

Each registrant continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. However, there have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2016 that have materially affected, or are reasonably likely to materially affect, any of the registrant's internal control over financial reporting.

Consistent with guidance issued by the SEC that an assessment of internal control over financial reporting of a recently acquired business may be omitted from management's evaluation of disclosure controls and procedures, management is excluding an assessment of such internal controls of ConEdison Solutions, which was acquired on September 1, 2016, from its evaluation of the effectiveness of Exelon's and Generation's disclosure controls and procedures. The total assets related to ConEdison Solutions are approximately less than 1% and total operating revenues related to ConEdison Solutions are 1% and 2%, respectively, of Exelon's and Generation's related consolidated financial statement amounts as of and for the year ended December 31, 2016.

All Registrants—Internal Control Over Financial Reporting

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2016. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2016 and, therefore, concluded that each registrant's internal control over financial reporting was effective. Management's Report on Internal Control Over Financial Reporting is included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

ITEM 9B. OTHER INFORMATION

All Registrants

None.

PART III

Exelon Generation Company, LLC, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section relating to Generation, PECO, BGE, PHI, Pepco, DPL and ACE are not presented.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants at February 13, 2017.

Directors, Director Nomination Process, and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at the annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)), the audit committee (Item 407(d)(4) and (d)(5)) and the beneficial reporting compliance (Sec. 16(a)) is incorporated herein by reference to information to be contained in Exelon's definitive 2017 proxy statement (2017 Exelon Proxy Statement) and the ComEd information statement (2017 ComEd Information Statement) to be filed with the SEC before April 29, 2017 pursuant to Regulation 14A or 14C, as applicable, under the Securities Exchange Act of 1934.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to Exelon's and ComEd's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. The Code of Business Conduct is filed as Exhibit 14 to this report and is available on Exelon's website at *www.exeloncorp.com* . The Code of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Bruce G. Wilson, Senior Vice President, Deputy General Counsel, and Corporate Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

If any substantive amendments to the Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Code of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or Corporate Controller, Exelon will disclose the nature of such amendment or waiver on Exelon's website, *www.exeloncorp.com* , or in a report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under *Executive Compensation Data* and *Report of the Compensation Committee* in the Exelon Proxy Statement for the 2017 Annual Meeting of Shareholders or the ComEd 2017 Information Statement, which are incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The additional information required by this item will be set forth under *Ownership of Exelon Stock* in the Exelon Proxy Statement for the 2017 Annual Meeting of Shareholders or the ComEd 2017 Information Statement, which are incorporated herein by reference.

Securities Authorized for Issuance under Exelon Equity Compensation Plans

[A] Plan Category	[B] Number of securities to be issued upon exercise of outstanding Options, warrants and rights (Note 1)	[C] Weighted-average price of outstanding Options, warrants and rights (Note 2)	[D] Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column [B]) (Note 3)
Equity compensation plans approved by security holders	28,108,200	$ 32.47	26,042,500

(1) Balance includes stock options, unvested performance shares, and unvested restricted shares that were granted under the Exelon LTIP or predecessor company plans and shares awarded under those plans and deferred into the stock deferral plan, as well as deferred stock units granted to directors as part of their compensation. For performance shares granted in 2014, 2015 and 2016, the total includes the maximum number of shares that could be granted, if performance, total shareholder return modifier, and individual performance multipliers were all at maximum, a total of 9,800,400 shares. At target, the number of securities to be issued for such awards is 4,900,200. The deferred stock units granted to directors includes 357,700 shares to be issued upon the conversion of deferred stock units awarded to members of the Exelon board of directors, and 105,500 shares to be issued upon the conversion of stock units held by members of the Exelon board of directors that were earned under a legacy Constellation Energy Group plan. Conversion of stock units to shares will occur after the director terminates service to the Exelon board or the board of any of its subsidiary companies. See Note 21—Common Stock of the Combined Notes to Consolidated Financial Statements for additional information about the material features of the plans.

(2) Includes outstanding restricted stock units and performance shares that can be exercised for no consideration. Without such instruments, the weighted-average price of outstanding options, warrants and rights shown in column [C] would be $46.23.

(3) Includes 21,055,700 shares available for issuance from the company's employee stock purchase plan.

No ComEd securities are authorized for issuance under equity compensation plans.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The additional information required by this item will be set forth under *Related Persons Transactions* and *Director Independence* in the Exelon Proxy Statement for the 2017 Annual Meeting of Shareholders or the ComEd 2017 Information Statement, which are incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under *The Ratification of PricewaterhouseCoopers LLP as Exelon's Independent Accountant for 2017* in the Exelon Proxy Statement for the 2017 Annual Meeting of Shareholders and the ComEd 2017 Information Statement, which are incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

Exelon

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2017 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2016, 2015 and 2014

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014

   Consolidated Balance Sheets at December 31, 2016 and 2015

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2016, 2015 and 2014

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule I—Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2016 and 2015 and for the Years Ended December 31, 2016, 2015 and 2014

   Schedule II—Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Operations and Other Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating expenses			
Operating and maintenance	$ 221	$ —	$ 9
Operating and maintenance from affiliates	51	43	38
Other	4	4	3
Total operating expenses	276	47	50
Operating loss	(276)	(47)	(50)
Other income and (deductions)			
Interest expense, net	(312)	(168)	(237)
Equity in earnings of investments	1,521	2,461	1,779
Interest income from affiliates, net	39	43	53
Other, net	7	(43)	(2)
Total other income	1,255	2,293	1,593
Income before income taxes	979	2,246	1,543
Income taxes	(155)	(23)	(80)
Net income	$1,134	$2,269	$1,623
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic costs	$ (48)	$ (46)	$ (30)
Actuarial loss reclassified to periodic cost	184	220	147
Pension and non-pension postretirement benefit plan valuation adjustment	(181)	(99)	(497)
Unrealized gain (loss) on cash flow hedges	2	9	(148)
Unrealized gain on marketable securities	1	—	1
Unrealized (loss) gain on equity investments	(4)	(3)	8
Unrealized gain (loss) on foreign currency translation	10	(21)	(9)
Reversal of CENG equity method AOCI	—	—	(116)
Other comprehensive (loss) income	(36)	60	(644)
Comprehensive income	$1,098	$2,329	$ 979

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Net cash flows provided by operating activities	$ 1,029	$ 3,071	$ 806
Cash flows from investing activities			
Return on investment of direct financing lease termination	—	—	335
Changes in Exelon intercompany money pool	1,390	(1,217)	(83)
Note receivable from affiliates	—	550	—
Capital expenditures	—	—	1
Investment in affiliates	(1,757)	(212)	(70)
Acquisition of business	(6,962)	—	—
Other investing activities	5	(55)	(126)
Net cash flows (used in) provided by investing activities	(7,324)	(934)	57
Cash flows from financing activities			
Issuance of long-term debt	1,800	4,200	1,150
Retirement of long-term debt	(46)	(2,263)	(23)
Issuance of common stock	—	1,868	—
Dividends paid on common stock	(1,166)	(1,105)	(1,065)
Proceeds from employee stock plans	55	32	35
Other financing activities	(20)	(58)	(84)
Net cash flows provided by financing activities	623	2,674	13
(Decrease) Increase in cash and cash equivalents	(5,672)	4,811	876
Cash and cash equivalents at beginning of period	5,690	879	3
Cash and cash equivalents at end of period	$ 18	$ 5,690	$ 879

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Balance Sheets

(In millions)	December 31, 2016	2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 18	$ 5,690
Deposit with IRS	1,250	—
Accounts receivable, net		
Other accounts receivable	73	272
Accounts receivable from affiliates	48	20
Notes receivable from affiliates	88	1,478
Regulatory assets	263	241
Other	—	5
Total current assets	1,740	7,706
Property, plant and equipment, net	51	53
Deferred debits and other assets		
Regulatory assets	4,033	3,072
Investments in affiliates	34,869	26,119
Deferred income taxes	2,107	2,036
Non-pension postretirement benefit asset	—	108
Notes receivable from affiliates	922	933
Other	256	404
Total deferred debits and other assets	42,187	32,672
Total assets	$43,978	$40,431

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 188
Long-term debt due within one year	570	60
Accounts payable	2	5
Accrued expenses	489	440
Payables to affiliates	706	—
Regulatory liabilities	16	63
Pension obligations	58	52
Other	50	1
Total current liabilities	1,891	809
Long-term debt	7,193	6,017
Deferred credits and other liabilities		
Regulatory liabilities	31	31
Pension obligations	8,608	7,520
Non-pension postretirement benefit obligations	7	—
Deferred income taxes	226	134
Other	182	122
Total deferred credits and other liabilities	9,054	7,807
Total liabilities	18,138	14,633
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2000 shares authorized, 924 shares and 920 shares outstanding at December 31, 2016 and 2015, respectively)	18,797	18,678
Treasury stock, at cost (35 shares at December 31, 2016 and 2015, respectively)	(2,327)	(2,327)
Retained earnings	12,030	12,068
Accumulated other comprehensive loss, net	(2,660)	(2,624)
Total shareholders' equity	25,840	25,795
BGE preference stock not subject to mandatory redemption	—	3
Total liabilities and shareholders' equity	$43,978	$40,431

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

1. Basis of Presentation

Exelon Corporate is a holding company that conducts substantially all of its business operations through its subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of Exelon Corporation.

Exelon Corporate owns 100% of all of its significant subsidiaries, either directly or indirectly, except for Commonwealth Edison Company (ComEd), of which Exelon Corporate owns more than 99%, and BGE, of which Exelon owns 100% of the common stock but none of BGE's preferred stock. BGE redeemed all of its outstanding preferred stock in 2016.

2. Mergers

On March 23, 2016, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Purple Acquisition Corp., a wholly owned subsidiary of Exelon (Merger Sub) and Pepco Holdings, Inc. (PHI). As a result of that merger, Merger Sub was merged into PHI (the PHI Merger) with PHI surviving as a wholly owned subsidiary of Exelon and Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon which also owns Exelon's interests in ComEd, PECO and BGE (through a special purpose subsidiary in the case of BGE). See Note 4—Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the PHI Merger.

3. Debt and Credit Agreements

Short-Term Borrowings

Exelon Corporate meets its short-term liquidity requirements primarily through the issuance of commercial paper. Exelon Corporate had no commercial paper borrowings at both December 31, 2016 and December 31, 2015.

Credit Agreements

On May 30, 2014, Exelon Corporate amended and extended its unsecured syndicated revolving credit facility with aggregate bank commitments of $600 million through May 2019. As of December 31, 2016, Exelon Corporation had available capacity under those commitments of $571 million. See Note 14—Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon Corporation's credit agreement.

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

Long-Term Debt

The following tables present the outstanding long-term debt for Exelon Corporate as of December 31, 2016 and December 31, 2015:

	Rates		Maturity Date	December 31, 2016	December 31, 2015
Long-term debt					
Junior subordinated notes		6.5%	2024	$1,150	$1,150
Contract payment—junior subordinated notes		2.5%	2017	19	64
Senior unsecured notes (a)	1.6%	7.6%	2017-2046	6,439	4,639
Total long-term debt				7,608	5,853
Unamortized debt discount and premium, net				(8)	(4)
Unamortized debt issuance costs				(57)	(47)
Fair value adjustment of consolidated subsidiary				220	275
Long-term debt due within one year				(570)	(60)
Long-term debt				$7,193	$6,017

(a) Senior unsecured notes include mirror debt that is held on both Generation and Exelon Corporation's balance sheets.

The debt maturities for Exelon Corporate for the periods 2017, 2018, 2019, 2020, 2021 and thereafter are as follows:

2017	$ 570
2018	—
2019	—
2020	1,450
2021	300
Remaining years	5,288
Total long-term debt	$7,608

4. Commitments and Contingencies

See Note 24—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's commitments and contingencies related to environmental matters and fund transfer restrictions.

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

5. Related Party Transactions

The financial statements of Exelon Corporate include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
(In millions)	2016	2015	2014
Operating and maintenance from affiliates:			
BSC [a]	$ 51	$ 43	$ 38
Interest income from affiliates, net:			
Generation	$ 39	$ 43	$ 53
Equity in earnings (losses) of investments:			
Exelon Energy Delivery Company, LLC [b]	$1,041	$1,079	$ 958
PCI	6	—	—
BSC	1	—	—
Exelon Ventures Company, LLC [c]	—	—	926
UII, LLC	(9)	20	(6)
Exelon Transmission Company, LLC	(13)	(8)	(7)
Exelon Enterprise	(1)	(1)	(1)
Generation	496	1,371	(91)
Total equity in earnings of investments	$1,521	$2,461	$1,779
Cash contributions received from affiliates	$1,912	$3,209	$1,370

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Notes to Financial Statements

(in millions)	December 31, 2016	2015
Accounts receivable from affiliates (current):		
BSC (a)	$ 15	$ —
Generation	22	16
ComEd	3	2
PECO	1	1
BGE	1	1
PHISCO	6	—
Total accounts receivable from affiliates (current)	$ 48	$ 20
Notes receivable from affiliates (current):		
BSC (a)	$ 88	$ 226
Generation (d)	—	1,252
Total notes receivable from affiliates (current):	$ 88	$ 1,478
Investments in affiliates:		
BSC (a)	$ 194	$ 191
Exelon Energy Delivery Company, LLC (b)	23,003	14,163
PCI	77	—
UII, LLC	92	102
Exelon Transmission Company, LLC	5	3
Voluntary Employee Beneficiary Association trust	(5)	7
Exelon Enterprises	21	22
Generation	11,488	11,637
Other	(6)	(6)
Total investments in affiliates	$34,869	$26,119
Notes receivable from affiliates (non-current):		
Generation (d)	$ 922	$ 933
Notes payable to affiliates (current):		
ComEd	$ —	$ 188
Accounts payable to affiliates (current):		
ComEd	$ 345	$ —
UII, LLC	361	—
Total accounts payable to affiliates (current)	$ 706	$ —

(a) Exelon Corporate receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead.
(b) Exelon Energy Delivery Company, LLC consists of ComEd, PECO, BGE, PHI, Pepco, DPL and ACE.
(c) Exelon Ventures Company, LLC primarily consisted of Generation and was fully dissolved as of December 31, 2014. Exelon Enterprises, Exelon Generation Company, LLC, and Exelon Consolidations are now directly owned Exelon Corporate investments as of December 31, 2014.
(d) In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-Term Debt to affiliate on Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets.

Exelon Corporation and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2016					
Allowance for uncollectible accounts (a)	$ 284	$ 162	$ 99(b) (c)	$ 211(d)	$ 334
Deferred tax valuation allowance	13	—	10(b)	3	20
Reserve for obsolete materials	105	12	1(b)	5	113
For the year ended December 31, 2015					
Allowance for uncollectible accounts (a)	$ 311	$ 113	$ 27(c)	$ 167(d)	$ 284
Deferred tax valuation allowance	50	—	(27)	10	13
Reserve for obsolete materials	95	10	2	2	105
For the year ended December 31, 2014					
Allowance for uncollectible accounts (a)	$ 272	$ 175	$ 69(c)	$ 205(d)	$ 311
Deferred tax valuation allowance	13	—	37	—	50
Reserve for obsolete materials	58	5	34	2	95

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $23 million, $8 million, and $8 million for the years ended December 31, 2016, 2015, and 2014, respectively.
(b) Primarily represents the addition of PHI's results as of March 23, 2016, the date of the merger
(c) Includes charges for late payments and non-service receivables.
(d) Write-off of individual accounts receivable.

Exelon Generation Company, LLC and Subsidiary Companies

Generation

1. Financial Statements:

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   Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014

   Consolidated Balance Sheets at December 31, 2016 and 2015

   Consolidated Statements of Changes in Equity for the Years Ended December 31, 2016, 2015 and 2014

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II—Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Exelon Generation Company, LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 77	$ 19	$ 3	$ 8	$ 91
Deferred tax valuation allowance	11	—	—	2	9
Reserve for obsolete materials	102	6	—	2	106
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 60	$ 22	$ —	$ 5	$ 77
Deferred tax valuation allowance	48	—	(27)	10	11
Reserve for obsolete materials	93	9	—	—	102
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 57	$ 14	$ 8	$ 19	$ 60
Deferred tax valuation allowance	11	—	37	—	48
Reserve for obsolete materials	55	5	32	(1)	93

Commonwealth Edison Company and Subsidiary Companies

ComEd

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2017 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2016, 2015 and 2014

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014

   Consolidated Balance Sheets at December 31, 2016 and 2015

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2016, 2015 and 2014

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Commonwealth Edison Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 75	$ 45	$ 23(a)	$ 73(b)	$ 70
Reserve for obsolete materials	3	4	1	4	4
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 84	$ 39	$ 18(a)	$ 66(b)	$ 75
Reserve for obsolete materials	2	1	2	2	3
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 62	$ 45	$ 33(a)	$ 56(b)	$ 84
Reserve for obsolete materials	2	—	2	2	2

(a) Primarily charges for late payments and non-service receivables.
(b) Write-off of individual accounts receivable.

PECO Energy Company and Subsidiary Companies

PECO

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2017 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2016, 2015 and 2014

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014

   Consolidated Balance Sheets at December 31, 2016 and 2015

   Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2016, 2015 and 2014

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

PECO Energy Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2016					
Allowance for uncollectible accounts (a)	$ 83	$ 32	$ 7(b)	$ 61(c)	$ 61
Reserve for obsolete materials	1	1	—	—	2
For the year ended December 31, 2015					
Allowance for uncollectible accounts (a)	$ 100	$ 37	$ 9(b)	$ 63(c)	$ 83
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2014					
Allowance for uncollectible accounts (a)	$ 107	$ 52	$ 11(b)	$ 70(c)	$ 100
Reserve for obsolete materials	1	—	—	—	1

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $23 million, $8 million, and $8 million for the years ended December 31, 2016, 2015, and 2014, respectively.
(b) Primarily charges for late payments.
(c) Write-off of individual accounts receivable.

Baltimore Gas and Electric Company and Subsidiary Companies

BGE

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2017 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2016, 2015 and 2014

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014

   Consolidated Balance Sheets at December 31, 2016 and 2015

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2016, 2015 and 2014

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Baltimore Gas and Electric Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 49	$ 1	$ 9(b)	$ 27(a)	$ 32
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	—	—	—	—	—
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 67	$ 15	$ — (b)	$ 33(a)	$ 49
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	—	—	—	—	—
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 46	$ 64	$ 17(b)	$ 60(a)	$ 67
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	1	—	—	1	—

(a) Write-off of individual accounts receivable.
(b) Primarily charges for late payments.

Pepco Holdings LLC and Subsidiary Companies

PHI

1. *Successor Company Financial Statements:*

Report of Independent Registered Public Accounting Firm dated February 13, 2017 of PricewaterhouseCoopers LLP

Consolidated Statement of Operations and Comprehensive Income for the Periods March 24, 2016 to December 31, 2016

Consolidated Statement of Cash Flows for the Periods March 24, 2016 to December 31, 2016

Consolidated Balance Sheet at December 31, 2016

Consolidated Statement of Changes in Equity for the Periods March 24, 2016 to December 31, 2016

Notes to Consolidated Financial Statements

Predecessor Company Financial Statements:

Report of Independent Registered Public Accounting Firm date February 13, 2017 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Income for the Period January 1, 2016 to March 23, 2016 and the Years Ended December 31, 2015 and 2014

Consolidated Statements of Cash Flows for the Period January 1, 2016 to March 23, 2016 and for the Years Ended December 31, 2015 and 2014 (Predecessor)

Consolidated Balance Sheet at December 31, 2015

Consolidated Statements of Changes in Equity for the Period January 1, 2016 to March 23, 2016 and for the Years Ended December 31, 2015 and 2014

Notes to Consolidated Financial Statements

2. *Successor Financial Statement Schedules:*

Schedule II – Valuation and Qualifying Accounts—For the Period March 24, 2016 to December 31, 2016

Predecessor Financial Statement Schedules:

Schedule II – Valuation and Qualifying Accounts—For the Period January 1, 2016 to March 23, 2016 and For the Years Ended December 31, 2015 and 2014

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Pepco Holdings LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
March 24, 2016 to December 31, 2016 *(Successor)*					
Allowance for uncollectible accounts	$ 52	$ 65	$ 5(a)	$ 42(b)	$ 80
Deferred tax valuation allowance	63	—	(53)	—	10
Reserve for obsolete materials	—	1	—	(1)	2
January 1, 2016 to March 23, 2016 *(Predecessor)*					
Allowance for uncollectible accounts	$ 56	$ 16	$ 2(a)	$ 22(b)	$ 52
Deferred tax valuation allowance	63	—	—	—	63
Reserve for obsolete materials	—	—	—	—	—
For the Year Ended December 31, 2015 *(Predecessor)*					
Allowance for uncollectible accounts	$ 40	$ 59	$ 5(a)	$ 48(b)	$ 56
Deferred tax valuation allowance	61	—	2	—	63
Reserve for obsolete materials	—	—	—	—	—
For the Year Ended December 31, 2014 *(Predecessor)*					
Allowance for uncollectible accounts	$ 38	$ 46	$ 9(a)	$ 53(b)	$ 40
Deferred tax valuation allowance	21	—	40	—	61
Reserve for obsolete materials	—	—	—	—	—

(a) Primarily charges for late payments.
(b) Write-off of individual accounts receivable.

Potomac Electric Power Company

Pepco

1. Financial Statements:

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   Statements of Operations and Comprehensive Income for the Years Ended December 31, 2016, 2015 and 2014

   Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014

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   Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2016, 2015 and 2014

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Potomac Electric Power Company

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 17	$ 29	$ 3(a)	$ 20(b)	$ 29
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	3	—	2	1
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 16	$ 20	$ 1(a)	$ 20(b)	$ 17
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	—	—	—	—
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 16	$ 17	$ 2(a)	$ 19(b)	$ 16
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	—	—	—	—

(a) Primarily charges for late payments.
(b) Write-off of individual accounts receivable.

Delmarva Power & Light Company

DPL

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2017 of PricewaterhouseCoopers LLP

   Statements of Operations and Comprehensive Income for the Years Ended December 31, 2016, 2015 and 2014

   Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014

   Balance Sheets at December 31, 2016 and 2015

   Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2016, 2015 and 2014

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Delmarva Power & Light Company

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 17	$ 23	$ 2(a)	$ 18(b)	$ 24
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	1	—	1	—
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 11	$ 20	$ 2(a)	$ 16(b)	$ 17
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	—	—	—	—
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 12	$ 13	$ 4(a)	$ 18(b)	$ 11
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	—	—	—	—

(a) Primarily charges for late payments.
(b) Write-off of individual accounts receivable.

Atlantic City Electric Company and Subsidiary Company

ACE

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 13, 2017 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2016, 2015 and 2014

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014

   Consolidated Balance Sheets at December 31, 2016 and 2015

   Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2016, 2015 and 2014

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Atlantic City Electric Company and Subsidiary Company

Schedule II – Valuation and Qualifying Accounts

Column A Description	Column B Balance at Beginning of Period	Column C Additions and adjustments Charged to Costs and Expenses	Column C Additions and adjustments Charged to Other Accounts	Column D Deductions	Column E Balance at End of Period
			(in millions)		
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 17	$ 32	$ 2(a)	$ 24(b)	$ 27
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	1	—	—	1
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 9	$ 18	$ 2(a)	$ 12(b)	$ 17
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	—	—	—	—
For the year ended December 31, 2014					
Allowance for uncollectible accounts	$ 10	$ 12	$ 3(a)	$ 16(b)	$ 9
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	—	—	—	—

(a) Primarily charges for late payments.
(b) Write-off of individual accounts receivable.

Exhibits required by Item 601 of Regulation S-K:

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
2-1	Agreement and Plan of Merger dated as of April 28, 2011 by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc. (File No. 001-16169, Form 8-K dated April 28, 2011, Exhibit No. 2-1).
2-2	Distribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Constellation Energy Group, Inc. and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-3).
2-3	Contribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Energy Delivery Company, LLC and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-4).
2-4	Contribution Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Ventures Company, LLC and Exelon Generation Company, LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-5).
2-5	Purchase Agreement dated as of August 8, 2012 by and between Constellation Power Source Generation, Inc. and Raven Power Holdings, LLC. (File No. 333-85496, Form 10-Q for the quarter ended September 30, 2012, Exhibit 2-1).
2-6	Master Agreement, dated as of October 26, 2010, by and between Electricite de France, S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 1, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
2-7	Put Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., Constellation Nuclear, LLC, and Constellation Energy Nuclear Group, LLC. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 8, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
2-8	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., Baltimore Gas and Electric Company and RF HoldCo LLC. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
2-9	Purchase Agreement, dated as of February 4, 2010, by and between RF HoldCo LLC and GSS Holdings (Baltimore Gas and Electric Company Utility), Inc. (Designated as Exhibit No. 99.3 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
2-10-1	Agreement and Plan of Merger, dated as of April 29, 2014, by and among Exelon Corporation, Pepco Holdings, Inc. and Purple Acquisition Corp. (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit 2.1).
2-10-2	Amended and Restated Agreement and Plan of Merger, dated as of July 18, 2014, among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp. (File No. 001-16169, Form 8-K dated July 21, 2014, Exhibit 2.1).

Exhibit No.	Description
2-10-3	Subscription Agreement for Series A Non-Voting Non-Convertible Preferred Stock, dated as of April 29, 2014, by and between Pepco Holdings, Inc. and Exelon Corporation (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit 2.2).
2-10-4	Letter Agreement, dated March 7, 2016, among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp. (File No. 001-31403, Form 8-K dated March 7, 2016, Exhibit 2)
3-1	Amended and Restated Articles of Incorporation of Exelon Corporation, as amended May 8, 2007 (File No. 001-16169, Form 10-Q for the quarter ended September 30, 2008, Exhibit 3-1-2).
3-2	Exelon Corporation Amended and Restated Bylaws, as amended on April 26, 2016 (File No. 001-16169, Form 8-K dated April 29, 2016, Exhibit 4.1).
3-3	Certificate of Formation of Exelon Generation Company, LLC (Registration Statement No. 333-85496, Form S-4, Exhibit 3-1).
3-4	First Amended and Restated Operating Agreement of Exelon Generation Company, LLC executed as of January 1, 2001 (File No. 333-85496, 2003 Form 10-K, Exhibit 3-8).
3-5	Restated Articles of Incorporation of Commonwealth Edison Company Effective February 20, 1985, including Statements of Resolution Establishing Series, relating to the establishment of three new series of Commonwealth Edison Company preference stock known as the “$9.00 Cumulative Preference Stock,” the “$6.875 Cumulative Preference Stock” and the “$2.425 Cumulative Preference Stock” (File No. 1-1839, 1994 Form 10-K, Exhibit 3-2).
3-6	Commonwealth Edison Company Amended and Restated By-Laws, Effective January 23, 2006 As Further Amended January 28, 2008 and July 27, 2009. (File No. 001-1839, Form 8-K dated July 27, 2009, Exhibit 3.1).
3-7	Amended and Restated Articles of Incorporation of PECO Energy Company (File No. 1-01401, 2000 Form 10-K, Exhibit 3-3).
3-8	PECO Energy Company Amended Bylaws (File 000-16844, Form 8-K dated May 6, 2009, Exhibit 99.1).
3-9	Articles of Amendment to the Charter of Baltimore Gas and Electric Company as of February 2, 2010. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File No. 1-1910).
3-10	Articles of Restatement to the Charter of Baltimore Gas and Electric Company, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, filed by Baltimore Gas and Electric Company, File No. 1-1910).
3-11	Bylaws of Baltimore Gas and Electric Company, as amended and restated as of May 10, 2012. (File No. 1-16169, 2013 Form 10-K, Exhibit 3-11).
3-12	Operating Agreement, dated as of February 4, 2010, by and among RF HoldCo LLC, Constellation Energy Group, Inc. and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File Nos. 1-12869 and 1-1910).
3-13	Certificate of Conversion of Pepco Holdings LLC, dated March 23, 2016 (File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 3.1)
3-14	Certificate of Formation of Pepco Holdings LLC, dated March 23, 2016 (File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 3.2)

Exhibit No.	Description
3-15	Limited Liability Company Agreement of Pepco Holdings LLC, dated March 23, 2016 (File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 3.3)
3-16	Potomac Electric Power Company Restated Articles of Incorporation and Articles of Restatement of (as filed in the District of Columbia) (File No. 001-31403, Form 10-Q dated May 5, 2006, Exhibit 3.1)
3-17	Potomac Electric Power Company Restated Articles of Incorporation and Articles of Restatement of (as filed in Virginia) (File No. 001-01072, Form 10-Q dated November 4, 2011, Exhibit 3.3)
3-18	Delmarva Power & Light Company Articles of Restatement of Certificate and Articles of Incorporation (filed in Delaware and Virginia 02/22/07) (File No. 001-01405, Form 10-K dated March 1, 2007, Exhibit 3.3)
3-19	Atlantic City Electric Company Restated Certificate of Incorporation (filed in New Jersey on August 9, 2002) (File No. 001-03559, Amendment No. 1 to Form U5B dated February 13, 2003, Exhibit B.8.1)
3-20	Bylaws of Potomac Electric Power Company (File No. 001-01072, Form 10-Q dated May 5, 2006, Exhibit 3.2)
3-21	Bylaws of Delmarva Power & Light Company (File No. 001-01405, Form 10-Q dated May 9, 2005, Exhibit 3.2.1)
3-22	Bylaws of Atlantic City Electric Company (File No. 001-03559, Form 10-Q dated May 9, 2005, Exhibit 3.2.2)
4-1	First and Refunding Mortgage dated May 1, 1923 between The Counties Gas and Electric Company (predecessor to PECO Energy Company) and Fidelity Trust Company, Trustee (U.S. Bank National Association, as current successor trustee), (Registration No. 2-2281, Exhibit B-1).
4-1-2	Reserved.
4-1-3	Supplemental Indentures to PECO Energy Company's First and Refunding Mortgage:

Dated as of	File Reference	Exhibit No.
May 1, 1927	2-2881	B-1(c)
March 1, 1937	2-2881	B-1(g)
December 1, 1941	2-4863	B-1(h)
November 1, 1944	2-5472	B-1(i)
December 1, 1946	2-6821	7-1(j)
September 1, 1957	2-13562	2(b)-17
May 1, 1958	2-14020	2(b)-18
March 1, 1968	2-34051	2(b)-24
March 1, 1981	2-72802	4-46
March 1, 1981	2-72802	4-47
December 1, 1984	1-01401, 1984 Form 10-K	4-2(b)
March 1, 1993	1-01401, 1992 Form 10-K	4(e)-86
May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-88
May 1, 1993	1-01401, March 31, 1993 Form 10-Q	4(e)-89

Dated as of	File Reference	Exhibit No.
April 15, 2004	0-6844, September 30, 2004 Form 10-Q	4-1-1
September 15, 2006	000-16844, Form 8-K dated September 25, 2006	4.1
March 1, 2007	000-16844, Form 8-K dated March 19, 2007	4.1
March 15, 2009	000-16844, Form 8-K dated March 26, 2009	4.1
September 1, 2012	000-16844, Form 8-K dated September 17, 2012	4.1
September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1
September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1
September 1, 2014	000-16169, Form 8-K dated September 15, 2014	4.1
September 15, 2015	000-16844, Form 8-K dated October 5, 2015	4.1
September 1, 2016	000-16844, Form 8-K dated September 21, 2016	4.1

4-2 Exelon Corporation Direct Stock Purchase Plan (Registration Statement No. 333-206474, Form S-3, Prospectus).

4-3 Mortgage of Commonwealth Edison Company to Illinois Merchants Trust Company, Trustee (BNY Mellon Trust Company of Illinois, as current successor Trustee), dated July 1, 1923, as supplemented and amended by Supplemental Indenture thereto dated August 1, 1944. (Registration No. 2-60201, Form S-7, Exhibit 2-1).

4-3-1 Supplemental Indentures to Commonwealth Edison Company Mortgage.

Dated as of	File Reference	Exhibit No.
August 1, 1946	2-60201, Form S-7	2-1
April 1, 1953	2-60201, Form S-7	2-1
March 31, 1967	2-60201, Form S-7	2-1
April 1, 1967	2-60201, Form S-7	2-1
February 28, 1969	2-60201, Form S-7	2-1
May 29, 1970	2-60201, Form S-7	2-1
June 1, 1971	2-60201, Form S-7	2-1
April 1, 1972	2-60201, Form S-7	2-1
May 31, 1972	2-60201, Form S-7	2-1
June 15, 1973	2-60201, Form S-7	2-1
May 31, 1974	2-60201, Form S-7	2-1
June 13, 1975	2-60201, Form S-7	2-1
May 28, 1976	2-60201, Form S-7	2-1

Dated as of	File Reference	Exhibit No.
June 3, 1977	2-60201, Form S-7	2-1
May 17, 1978	2-99665, Form S-3	4-3
August 31, 1978	2-99665, Form S-3	4-3
June 18, 1979	2-99665, Form S-3	4-3
June 20, 1980	2-99665, Form S-3	4-3
April 16, 1981	2-99665, Form S-3	4-3
April 30, 1982	2-99665, Form S-3	4-3
April 15, 1983	2-99665, Form S-3	4-3
April 13, 1984	2-99665, Form S-3	4-3
April 15, 1985	2-99665, Form S-3	4-3
April 15, 1986	33-6879, Form S-3	4-9
January 13, 2003	001-01839, Form 8-K dated January 22, 2003	4-4
February 22, 2006	001-01839, Form 8-K dated March 6, 2006	4.1
August 1, 2006	001-01839, Form 8-K dated August 28, 2006	4.1
September 15, 2006	001-01839, Form 8-K dated October 2, 2006	4.1
March 1, 2007	001-01839, Form 8-K dated March 23, 2007	4.1
August 30, 2007	001-01839, Form 8-K dated September 10, 2007	4.1
December 20, 2007	001-01839, Form 8-K dated January 16, 2008	4.1
March 10, 2008	001-01839, Form 8-K dated March 27, 2008	4.1
July 12, 2010	001-01839, Form 8-K dated August 2, 2010	4.1
August 22, 2011	001-01839, Form 8-K dated September 7, 2011	4.1
September 17, 2012	001-01839, Form 8-K dated October 1, 2012	4.1
August 1, 2013	001-01839, Form 8-K dated August 19, 2013	4.1
January 2, 2014	001-01839, Form 8-K dated January 10, 2014	4.1
October 28, 2014	001-01839, Form 8-K dated November 10, 2014	4.1
February 18, 2015	001-01839, Form 8-K dated March 2, 2015	4.1
November 4, 2015	001-01839, Form 8-K dated November 19, 2015	4.1
June 15, 2016	001-01839, Form 8-K dated June 27, 2016	4.1

Exhibit No.	Description
4-3-2	Instrument of Resignation, Appointment and Acceptance dated as of February 20, 2002, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923, and Indentures Supplemental thereto, regarding corporate trustee (File No. 1-1839, 2001 Form 10-K, Exhibit 4-4-2).
4-3-3	Instrument dated as of January 31, 1996, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923 and Indentures Supplemental thereto, regarding individual trustee (File No. 1-1839, 1995 Form 10-K, Exhibit 4-29).
4-4	Indenture dated as of September 1, 1987 between Commonwealth Edison Company and Citibank, N.A. (U.S. Bank National Association, as current successor trustee), Trustee relating to Notes (Registration No. 33-20619, Form S-3, Exhibit 4-13).
4-5	Indenture dated December 19, 2003 between Exelon Generation Company, LLC and U.S. Bank National Association (File No. 333-85496, 2003 Form 10-K, Exhibit 4-6).
4-6	Indenture to Subordinated Debt Securities dated as of June 24, 2003 between PECO Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.1).
4-7	Form of 4.25% Senior Note due 2022 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.1).
4-8	Form of 5.60% Senior Note due 2042 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.2).
4-9	Form of 2.80% Senior Note due 2022 issued by Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated August 17, 2012, Exhibit 4.1).
4-10	Form of 3.35% Senior Note due 2023 Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated June 17, 2013, Exhibit 4.1).
4-11	Form of 6.000% Senior Secured Notes due 2033 issued by Exelon Generation Company, LLC (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.2).
4-12	Preferred Securities Guarantee Agreement between PECO Energy Company, as Guarantor, and U.S. Bank National Association, as Trustee, dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.2).
4-13	PECO Energy Capital Trust IV Amended and Restated Declaration of Trust among PECO Energy Company, as Sponsor, U.S. Bank Trust National Association, as Delaware Trustee and Property Trustee, and J. Barry Mitchell, George R. Shicora and Charles S. Walls as Administrative Trustees dated as of June 24, 2003 (File No. 0-16844, June 30, 2003 Form 10-Q, Exhibit 4.3).
4-14	Indenture dated May 1, 2001 between Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 1-16169, June 30, 2005 Form 10-Q, Exhibit 4-10).
4-15	Form of $500,000,000 5.625% senior notes due 2035 dated June 9, 2005 issued by Exelon Corporation (File No. 1-16169, Form 8-K dated June 9, 2005, Exhibit 99.3).
4-16	Indenture dated as of September 28, 2007 from Exelon Generation Company, LLC to U.S. Bank National Association, as trustee (File 333-85496, Form 8-K dated September 28, 2007, Exhibit 4.1).
4-17	Form of 5.20% Exelon Generation Company, LLC Senior Note due 2019 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.1).
4-18	Form of 6.25% Exelon Generation Company, LLC Senior Note due 2039 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.2).

Exhibit No.	Description
4-19	Form of 4.00% Exelon Generation Company, LLC Senior Note due 2020 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.1).
4-20	Form of 5.75% Exelon Generation Company, LLC Senior Note due 2041 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.2).
4-21	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, filed by Constellation Energy Group, Inc., File No. 333-75217.)
4-22	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, filed by Constellation Energy Group, Inc., File No. 333-102723).
4-23	Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991).
4-24	First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (Designated as Exhibit 4(a) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869).
4-25	Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
4-26	Indenture, dated as of September 30, 2013, among Continental Wind, LLC, the guarantors party thereto and Wilmington Trust, National Association, as trustee (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.1).
4-27	Indenture dated July 1, 1985, between Baltimore Gas and Electric Company and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, filed by Baltimore Gas and Electric Company, File No. 1-1910).
4-28	Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee (including form of Baltimore Gas and Electric Company Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibit Nos. 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01).
4-29	Indenture dated as of July 24, 2006 between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(b) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991).

Exhibit No.	Description
4-30	Supplemental Indenture No. 1, dated as of October 1, 2009, to the Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
4-31	Baltimore Gas and Electric Company Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit No. 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01).
4-32	Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (Designated as Exhibit 4.1 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).
4-33	Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (Designated as Exhibit No. 4(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Baltimore Gas and Electric Company, File No. 1 1910).
4-34	Replacement Capital Covenant dated June 27, 2008. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869).
4-35	Amendment to Replacement Capital Covenant, dated as of March 12, 2012, amending the Replacement Capital Covenant, dated as of June 27, 2008 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 99.4).
4-36	Officers' Certificate, dated December 14, 2010, establishing the 5.15% Notes due December 1, 2020 of Constellation Energy Group, Inc., with the form of Notes attached thereto. (Designated as Exhibit No. 4 (b) to the Current Report on Form 8-K dated December 14, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
4-37	Officers' Certificate, November 16, 2011, establishing the 3.50% Notes due November 15, 2021 of Baltimore Gas and Electric Company, with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated November 16, 2011, filed by Baltimore Gas and Electric Company, File No. 1-1910).
4-38	Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee. (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.1).
4-38-1	First Supplemental Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee.(File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.2).
4-38-2	Form of 2.50% Notes due 2024 (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.1).
4-38-3	Purchase Contract and Pledge Agreement, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary. (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.4).

Exhibit No.	Description
4-38-4	Form of Remarketing Agreement (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.5).
4-38-5	Form of Corporate Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.6).
4-38-6	Form of Treasury Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.7).
4-39	Indenture, dated as of June 11, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Exelon Corporation's Current Report on Form 8-K, filed on June 11, 2015).
4-39-1	First Supplemental Indenture, dated as of June 11, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to Exelon Corporation's Current Report on Form 8-K, filed on June 11, 2015).
4-39-2	Second Supplemental Indenture, dated as of December 2, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Exelon Corporation's Current Report on Form 8-K, filed on December 2, 2015).
4-39-3	Registration Rights Agreement, dated as of December 2, 2015, among Exelon Corporation, Barclays Capital Inc. and Goldman, Sachs & Co. (incorporated herein by reference to Exhibit 1.1 to Exelon Corporation's Current Report on Form 8-K, filed on December 2, 2015).
4-40	Form of Conversion Supplemental Indenture, dated March 23, 2016 (File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 4.1)
4-41	Third Supplemental Indenture, dated as of April 7, 2016, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee (File No. 001-16169, Form 8-K dated April 7, 2016, Exhibit 4.2)
4-42	Mortgage and Deed of Trust, dated July 1, 1936, of Potomac Electric Power Company to The Bank of New York Mellon as successor trustee, securing First Mortgage Bonds of Potomac Electric Power Company, and Supplemental Indenture dated July 1, 1936 (File No. 2-2232, Registration Statement dated June 19, 1936, Exhibit B-4)
4-42-1	Supplemental Indentures to Potomac Electric Power Company Mortgage.

Dated as of	File Reference	Exhibit No.
December 10, 1939	Form 8-K, 1/3/40	B
July 15, 1942	2-5032, Amendment No 2. To Registration Statement, 8/24/42	B-1
October 15, 1947	Form 8-K , 12/8/47	A
December 31, 1948	Form 10-K, 4/13/49	A-2
December 31, 1949	Form 8-K, 2/8/50	(a)-1
February 15, 1951	Form 8-K, 3/9/51	(a)
February 16, 1953	Form 8-K, 3/5/53	(a)-1
March 15, 1954 and March 15, 1955	2-11627, Registration Statement, 5/2/55	4-B
March 15, 1956	Form 10-K, 4/4/56	C

Dated as of	File Reference	Exhibit No.
April 1, 1957	2-13884, Registration Statement, 2/5/58	4-B
May 1, 1958	2-14518, Registration Statement, 11/10/58	2-B
May 1, 1959	2-15027, Amendment No. 1 to Registration Statement, 5/13/59	4-B
May 2, 1960	2-17286, Registration Statement, 11/9/60	2-B
April 3, 1961	Form 10-K, 4/24/61	A-1
May 1, 1962	2-21037, Registration Statement, 1/25/63	2-B
May 1, 1963	2-21961, Registration Statement, 12/19/63	4-B
April 23, 1964	2-22344, Registration Statement, 4/24/64	2-B
May 3, 1965	2-24655, Registration Statement, 3/16/66	2-B
June 1, 1966	Form 10-K, 4/11/67	1
April 28, 1967	2-26356, Post-Effective Amendment No. 1 to Registration Statement, 5/3/67	2-B
July 3, 1967	2-28080, Registration Statement, 1/25/68	2-B
May 1, 1968	2-31896, Registration Statement, 2/28/69	2-B
June 16, 1969	2-36094, Registration Statement, 1/27/70	2-B
May 15, 1970	2-38038, Registration Statement, 7/27/70	2-B
September 1, 1971	2-45591, Registration Statement, 9/1/72	2-C
June 17, 1981	Amendment No. 1 to Form 8-A, 6/18/81	2
November 1, 1985	Form 8-A, 11/1/85	2B
September 16, 1987	33-18229, Registration Statement, 10/30/87	4-B
May 1, 1989	33-29382, Registration Statement, 6/16/89	4-C
May 21, 1991	Form 10-K, 3/27/92	4
May 7, 1992	Form 10-K, 3/26/93	4

Dated as of	File Reference	Exhibit No.
September 1, 1992	Form 10-K, 3/26/93	4
November 1, 1992	Form 10-K, 3/26/93	4
July 1, 1993	33-49973, Registration Statement, 8/11/93	4.4
February 10, 1994	Form 10-K, 3/25/94	4
February 11, 1994	Form 10-K, 3/25/94	4
October 2, 1997	001-01072, Form 10-K, 3/26/98	4
November 17, 2003	001-01072, Form 10-K, 3/11/04	4.1
March 16, 2004	001-01072, Form 8-K, 3/23/04	4.3
May 24, 2005	001-01072, Form 8-K, 5/26/05	4.2
April 1, 2006	001-01072, Form 8-K, 4/17/06	4.1
November 13, 2007	001-01072, Form 8-K, 11/15/07	4.2
March 24, 2008	001-01072, Form 8-K, 3/28/08	4.1
December 3, 2008	001-01072, Form 8-K, 12/8/08	4.2
March 28, 2012	001-01072, Form 8-K, 3/29/12	4.2
March 11, 2013	001-01072, Form 8-K, 3/12/13	4.2
November 14, 2013	001-01072, Form 8-K, 11/15/13	4.2
March 11, 2014	001-01072, Form 8-K, 3/12/14	4.2
March 9, 2015	001-01072, Form 8-K, 3/10/15	4.3

Exhibit No.	Description
4-43	Indenture, dated as of July 28, 1989, between Potomac Electric Power Company and The Bank of New York Mellon, Trustee, with respect to Medium-Term Note Program (File No. 001-01072, Form 8-K dated June 21, 1990, Exhibit 4)
4-44	Senior Note Indenture, dated November 17, 2003 between Potomac Electric Power Company and The Bank of New York Mellon (File No. 001-01072, Form 8-K dated November 21, 2003, Exhibit 4.2)
4-44-1	Supplemental Indenture, dated March 3, 2008, to Senior Note Indenture between Potomac Electric Power Company and The Bank of New York Mellon (File No. 001-01072, Form 8-K dated March 2, 2009, Exhibit 4.3)

Exhibit No.	Description
4-45	Mortgage and Deed of Trust of Delaware Power & Light Company to The Bank of New York Mellon (ultimate successor to the New York Trust Company), as trustee, dated as of October 1, 1943, and copies of the First through Sixty-Eighth Supplemental Indentures thereto (File No. 33-1763, Registration Statement dated November 27, 1985, Exhibit 4-A)
4-45-1	Supplemental Indentures to Delmarva Power & Light Company Mortgage.

Dated as of	File Reference	Exhibit No.
January 1, 1986	33-39756, Registration Statement, 4/03/91	4-B
June 1, 1986	33-24955, Registration Statement, 10/13/88	4-B
January 1, 1987	33-24955, Registration Statement, 10/13/88	4-B
September 1, 1987	33-24955, Registration Statement, 10/13/88	4-B
October 1, 1987	33-24955, Registration Statement, 10/13/88	4-B
January 1, 1988	33-24955, Registration Statement, 10/13/88	4-B
December 1, 1988	33-39756, Registration Statement, 4/03/91	4-D
January 1, 1989	33-39756, Registration Statement, 4/03/91	4-E
March 1, 1990	33-39756, Registration Statement, 4/03/91	4-F
January 1, 1991	33-46892, Registration Statement, 4/1/92	4-E
July 1, 1991	33-46892, Registration Statement, 4/1/92	4-F
February 1, 1992	33-49750, Registration Statement, 7/17/92	4
May 1, 1992	33-57652, Registration Statement, 1/29/93	4-G
October 1, 1992	33-63582, Registration Statement, 5/28/93	4-H
January 1, 1993	33-50453, Registration Statement, 10/1/93	99
June 1, 1993	33-53855, Registration Statement, 1/30/95	4-J
July 1, 1993	33-53855, Registration Statement, 1/30/95	4-K
October 1, 1993	33-53855, Registration Statement, 1/30/95	4-L
January 1, 1994	33-53855, Registration Statement, 1/30/95	4-M

Dated as of	File Reference	Exhibit No.
October 1, 1994	33-53855, Registration Statement, 1/30/95	4-N
January 1, 1995	333-00505, Registration Statement, 1/29/96	4-K
June 1, 1995	333-00505, Registration Statement, 1/29/96	4-L
January 1, 1996	333-24059, Registration Statement, 3/27/97	4-L
January 1, 1997	001-01405, Form 10-K, 2/24/12	4.4
January 1, 1998	001-01405, Form 10-K, 2/24/12	4.4
January 1, 1999	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2000	333-145691-02, Post Effective Amendment No. 1 to Registration Statement, 11/18/08	4.24(k)
January 1, 2001	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2002	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2003	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2004	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2005	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2006	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2007	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2008	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2009	001-01405, Form 10-K, 2/24/12	4.4
September 22, 2009	001-01405, Form 8-K, 10/1/09	4.4
January 1, 2010	001-01405, Form 10-K, 2/25/11	4.4
January 1, 2011	001-01405, Form 10-Q, 8/3/11	4.2

Dated as of	File Reference	Exhibit No.
May 2, 2011	001-01405, Form 8-K, 6/3/11	4.2
January 1, 2012	001-01405, Form 10-Q, 8/7/12	4.3
June 19, 2012	001-01405, Form 8-K, 6/20/12	4.2
January 1, 2013	001-01405, Form 10-Q, 8/7/13	4.1
November 7, 2013	001-01405, Form 8-K, 11/8/13	4.2
January 1, 2014	001-01405, Form 10-K, 2/27/15	4.4
June 2, 2014	001-01405, Form 8-K, 6/3/14	4.3
January 1, 2015	001-01405, Form 10-K, 2/19/16	4.4
May 4, 2015	001-01405, Form 8-K, 5/5/15	4.2
January 1, 2016	Filed herewith.	
December 5, 2016	001-01405, Form 8-K, 12/12/16	4.2

Exhibit No.	Description
4-46	Indenture between Delmarva Power & Light Company and The Bank of New York Mellon Trust Company, N.A. (ultimate successor to Manufacturers Hanover Trust Company), as trustee, dated as of November 1, 1988 (File No. 33-46892, Registration Statement dated April 1, 1992, Exhibit 4-G)
4-47	Mortgage and Deed of Trust, dated January 15, 1937, between Atlantic City Electric Company and The Bank of New York Mellon (formerly Irving Trust Company), as trustee (File No. 2-66280, Registration Statement dated December 21, 1979, Exhibit 2(a))
4-47-1	Supplemental Indentures to Atlantic City Electric Company Mortgage.

Dated as of	File Reference	Exhibit No.
June 1, 1949	2-66280, Registration Statement, 12/21/79	2(b)
July 1, 1950	2-66280, Registration Statement, 12/21/79	2(b)
November 1, 1950	2-66280, Registration Statement, 12/21/79	2(b)
March 1, 1952	2-66280, Registration Statement, 12/21/79	2(b)
January 1, 1953	2-66280, Registration Statement, 12/21/79	2(b)
March 1, 1954	2-66280, Registration Statement, 12/21/79	2(b)

Dated as of	File Reference	Exhibit No.
March 1, 1955	2-66280, Registration Statement, 12/21/79	2(b)
January 1, 1957	2-66280, Registration Statement, 12/21/79	2(b)
April 1, 1958	2-66280, Registration Statement, 12/21/79	2(b)
April 1, 1959	2-66280, Registration Statement, 12/21/79	2(b)
March 1, 1961	2-66280, Registration Statement, 12/21/79	2(b)
July 1, 1962	2-66280, Registration Statement, 12/21/79	2(b)
March 1, 1963	2-66280, Registration Statement, 12/21/79	2(b)
February 1, 1966	2-66280, Registration Statement, 12/21/79	2(b)
April 1, 1970	2-66280, Registration Statement, 12/21/79	2(b)
September 1, 1970	2-66280, Registration Statement, 12/21/79	2(b)
May 1, 1971	2-66280, Registration Statement, 12/21/79	2(b)
April 1, 1972	2-66280, Registration Statement, 12/21/79	2(b)
June 1, 1973	2-66280, Registration Statement, 12/21/79	2(b)
January 1, 1975	2-66280, Registration Statement, 12/21/79	2(b)
May 1, 1975	2-66280, Registration Statement, 12/21/79	2(b)
December 1, 1976	2-66280, Registration Statement, 12/21/79	2(b)
January 1, 1980	Form 10-K, 3/25/81	4(e)
May 1, 1981	Form 10-Q, 8/10/81	4(a)
November 1, 1983	Form 10-K, 3/30/84	4(d)
April 15, 1984	Form 10-Q, 5/14/84	4(a)
July 15, 1984	Form 10-Q, 8/13/84	4(a)
October 1, 1985	Form 10-Q, 11/12/85	4
May 1, 1986	Form 10-Q, 5/12/86	4
July 15, 1987	Form 10-K, 3/28/88	4(d)
October 1, 1989	Form 10-Q for quarter ended 9/30/89	4(a)

Dated as of	File Reference	Exhibit No.
March 1, 1991	Form 10-K, 3/28/91	4(d)(1)
May 1, 1992	33-49279, Registration Statement, 1/6/93	4(b)
January 1, 1993	333-108861, Registration Statement, 9/17/03	4.05(hh)
August 1, 1993	Form 10-Q, 11/12/93	4(a)
September 1, 1993	Form 10-Q, 11/12/93	4(b)
November 1, 1993	Form 10-K, 3/29/94	4(c)(1)
June 1, 1994	Form 10-Q, 8/14/94	4(a)
October 1, 1994	Form 10-Q, 11/14/94	4(a)
November 1, 1994	Form 10-K, 3/21/95	4(c)(1)
March 1, 1997	001-03559, Form 8-K, 3/24/97	4(b)
April 1, 2004	001-03559, Form 8-K, 4/6/04	4.3
August 10, 2004	001-03559, Form 10-Q, 11/8/04	4
March 8, 2006	001-03559, Form 8-K, 3/17/06	4
November 6, 2008	001-03559, Form 8-K, 11/10/08	4.2
March 29, 2011	001-03559, Form 8-K, 4/1/11	4.2
August 18, 2014	001-03559, Form 8-K, 8/19/14	4.2
December 1, 2015	001-03559, Form 8-K, 12/2/15	4.2

Exhibit No.	Description
4-48	Indenture, dated as of March 1, 1997, between Atlantic City Electric Company and The Bank of New York Mellon, as trustee (File No. 001-03559, Form 8-K dated March 24, 1997, Exhibit 4.2)
4-49	Senior Note Indenture, dated as of April 1, 2004, between Atlantic City Electric Company and The Bank of New York Mellon, as trustee (File No. 001-03559, Form 8-K dated April 6, 2004, Exhibit 4.2)
4-50	Indenture, dated as of December 19, 2002 between Atlantic City Electric Transition Funding LLC and The Bank of New York Mellon, as trustee (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 4.1)
4-51	2002-1 Series Supplement, dated as of December 19, 2002 between Atlantic City Electric Transition Funding LLC and The Bank of New York Mellon, as trustee (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 4.2)
4-52	2003-1 Series Supplement, dated as of December 23, 2003 between Atlantic City Electric Transition Funding LLC and The Bank of New York Mellon, as trustee (File No. 333-59558, Form 8-K dated December 23, 2003, Exhibit 4.2)

Exhibit No.	Description
4-53	Indenture, dated September 6, 2002, between Pepco Holdings, Inc. and The Bank of New York Mellon, as trustee (File No. 333-100478, Registration Statement on Form S-3 dated October 10, 2002, Exhibit 4.03)
4-54	Corporate Commercial Paper Master Note (File No. 001-31403, Form 10-K dated February 24, 2012, Exhibit 4.13)
4-55	Pepco Holdings, Inc. Certificate of Series A Non-Voting Non-Convertible Preferred Stock (File No. 001-31403, Form 8-k dated April 30, 2014, Exhibit 4.1)
4-56	Form of 2.400% notes due 2026 (File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.1)
4-57	Form of 3.500% notes due 2046 (File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.2)
10-1	Facility Credit Agreement, dated as of February 6, 2014, among ExGen Renewables I Holding, LLC and Barclays Bank PLC (File No. 333-85496, Form 8-K dated February 12, 2014, Exhibit 10.1).
10-1-1	Credit Agreement, dated as of September 18, 2014, among ExGen Texas Power, LLC, ExGen Texas Power Holdings, LLC, Wolf Hollow I Power, LLC, Colorado Bend I Power, LLC, Laporte Power, LLC, Handley Power, LLC and Mountain Creek Power, LLC, the lenders party thereto from time to time, Bank of America, N.A., as administrative agent and collateral agent, and Wilmington Trust, National Association, as depositary agent. (File No. 1-16169, Form 8-K dated September 18, 2014, Exhibit 10.1).
10-2	Exelon Corporation Non-Employee Directors' Deferred Stock Unit Plan (As Amended and Restated Effective January 1, 2011). * (File No. 001-16169, 2010 Form 10-K, Exhibit 10.1).
10-3	Form of Exelon Corporation Unfunded Deferred Compensation Plan for Directors (as amended and restated Effective March 12, 2012). * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-3)
10-4	Reserved.
10-5	Form of Restricted Stock Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-1).
10-6	Forms of Transferable Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-2).
10-7	Forms of Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-3).
10-8	Unicom Corporation Deferred Compensation Unit Plan, as amended *(File Nos. 1-11375 and 1-1839, 1995 Form 10-K, Exhibit 10-12).
10-9	Amendment Number One to the Unicom Corporation Deferred Compensation Unit Plan, as amended January 1, 2008 * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.16).
10-10	Unicom Corporation Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-12).
10-11	Commonwealth Edison Company Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-13).
10-12	Exelon Corporation Supplemental Management Retirement Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.19).
10-13	PECO Energy Company Supplemental Pension Benefit Plan (As Amended and Restated Effective January 1, 2009) (File No. 000-16844, 2008 Form 10-K, Exhibit 10.20).

Exhibit No.	Description
10-14	Exelon Corporation Annual Incentive Plan for Senior Executives (As Amended Effective January 1, 2014 * (File No. 1-16169, Exelon Proxy Statement dated April 1, 2014, Appendix A).
10-15	Form of change in control employment agreement for senior executives effective January 1, 2009 * (File No. 001-16169. 2008 Form 10-K, Exhibit 10.23).
10-16	Form of change in control employment agreement (amended and restated as of January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.24).
10-17	Exelon Corporation Employee Stock Purchase Plan, as amended and restated effective July 1, 2013. (File No. 1-16169, Schedule 14A dated March 14, 2013 Appendix A).
10-18	Exelon Corporation 2006 Long-Term Incentive Plan (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex H).
10-19	Form of Stock Option Grant Instrument under the Exelon Corporation 2006 Long-Term Incentive Plan (File No. 1-16169, Form 8-K filed January 27, 2006, Exhibit 99.2).
10-20	Exelon Corporation Employee Stock Purchase Plan for Unincorporated Subsidiaries (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex I).
10-21	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective April 1, 2013).* (File No. 001-16169, 2013 Form 10-K, Exhibit 10.21).
10-21-1	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective November 1, 2015) * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-21-1)
10-22	Form of Separation Agreement under Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective November 1, 2015) * Filed herewith.
10-23	Facility Credit Agreement, dated as of November 4, 2010, among Exelon Generation Company, LLC and UBS AG, Stamford Branch (File No. 333-85496, Form 8-K dated February 22, 2011, Exhibit No. 10-1).
10-24	Exelon Corporation Executive Death Benefits Plan dated as of January 1, 2003 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-52).
10-25	First Amendment to Exelon Corporation Executive Death Benefits Plan, Effective January 1, 2006 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-53).
10-26	Amendment Number One to the Exelon Corporation 2006 Long-Term Incentive Plan, Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-54).
10-27	Amendment Number Two to the Exelon Corporation 2006 Long-Term Incentive Plan (As Amended and Restated Effective January 28, 2002), Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-55).
10-28	Exelon Corporation Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-56).
10-29	Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-57).
10-30	Commonwealth Edison Company Long-Term Incentive Plan, Effective January 1, 2007 (File No. 1-16169, March 31, 2007 Form 10-Q, Exhibit 10-1).
10-31	Amendment Number One to the Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, June 30, 2007 Form 10-Q, Exhibit 10-3).

Exhibit No.	Description
10-32	Restricted stock unit award agreement (File 1-16169, Form 8-K dated August 31, 2007, Exhibit 99.1).
10-33	Reserved.
10-34	Form of Exelon Corporation 2011 Long-Term Incentive Plan, as amended effective December 18, 2014. * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-34)
10-34-1	Form of Exelon Corporation Long-Term Incentive Program, as amended and restated as of January 1, 2014. * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-34-1)
10-34-2	Form of Exelon Corporation Long-Term Incentive Program, as amended and restated as of January 1, 2015. * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-34-2)
10-34-3	Amendment Number Two to the Exelon Corporation 2011 Long-Term Incentive Plan (As Amended and Restated Effective January 21, 2014), Effective October 26, 2015. * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-34-3)
10-35	Form of Change in Control Employment Agreement Effective February 10, 2011. * (File 1-16169, 2011 Form 10-K, Exhibit 10-44).
10-36	Credit Agreement for $500,000,000 dated as of March 23, 2011 between Exelon Corporation and Various Financial Institutions (File No. 001-16169, Form 8-K dated March 23, 2011, Exhibit No. 10-2).
10-37	Credit Agreement for $5,300,000,000 dated as of March 23, 2011 between Exelon Generation Company, LLC and Various Financial Institutions (File No. 333-85496, Form 8-K dated March 23, 2011, Exhibit No. 10-3).
10-38	Credit Agreement for $600,000,000 dated as of March 23, 2011 between PECO Energy Company and Various Financial Institutions (File No. 000-16844, Form 8-K dated March 23, 2011, Exhibit No. 10-4).
10-39	Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, Various Financial Institutions, as Lenders, and JP Morgan Chase Bank, N.A., as Administrative Agent (File No. 001-01839, Form 8-K dated March 28, 2012, Exhibit No. 99-1).
10-40	Amendment No. 3 to Credit Agreement dated as of March 23, 2011 among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated August 10, 2013, Exhibit No. 99-1).
10-41	Amendment No. 1 to Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, as Borrower, the various financial institutions named therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-1839, Form 8-K dated August 10, 2013, Exhibit No. 99-2).
10-42	Amendment No. 1 to Credit Agreement, dated as of December 21, 2011, to the Credit Agreement dated as of March 23, 2011, among Exelon Generation Company, LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 4-6).
10-43	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-44	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. * (Designated as Exhibit No. 10(c) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).

Exhibit No.	Description
10-45	Constellation Energy Group, Inc. Benefits Restoration Plan, amended and restated effective June 1, 2010. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-46	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. * (Designated as Exhibit No. 10(e) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-47	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. * (Designated as Exhibit No. 10(f) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-48	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. * (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-49	Constellation Energy Group, Inc. Executive Supplemental Benefits Plan, as amended and restated. * (Designated as Exhibit No. 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-50	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-51	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-52	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-53	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(d) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-54	Constellation Energy Group, Inc. Amended and Restated 2007 Long-Term Incentive Plan. * (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated June 4, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-55	Form of Grant Agreement for Stock Units with Sales Restriction. * (Designated as Exhibit No. 10(x) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-56	Rate Stabilization Property Servicing Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as servicer (Designated as Exhibit 10.2 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).

Exhibit No.	Description
10-57	Administration Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as administrator (Designated as Exhibit 10.3 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).
10-58	Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 12, 2009, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-59	Amendment No. 1 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(s) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-60	Amendment No. 2 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(t) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-61	Amendment No. 3 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-62	Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-63	Settlement Agreement between EDF Inc., Exelon Corporation, Exelon Energy Delivery Company, LLC, Constellation Energy Group, Inc. and Baltimore Gas and Electric Company dated January 16, 2012. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated January 19, 2012, File Nos. 1-12869 and 1-1910).
10-64 - 10-70	Reserved.
10-71	Commitment Letter for $7.221 Billion Senior Unsecured Bridge Facility, dated April 29, 2014 (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit No. 10.1).
10-71-1	364-Day Bridge Term Loan Agreement, dated as of May 30, 2014, among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and Barclays Bank PLC, as Administrative Agent (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit No. 10.1).
10-71-2	Amendment No. 4 to Credit Agreement, dated May 30, 2014, among Exelon Corporation, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.2).

Exhibit No.	Description
10-71-3	Amendment No. 4 to Credit Agreement, dated May 30, 2014, among Exelon Generation Company, LLC, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.3).
10-71-4	Amendment No. 3 to Credit Agreement, dated May 30, 2014, among PECO Energy Company, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.4).
10-71-5	Amendment No. 2 to Credit Agreement, dated as of May 30, 2014, among Baltimore Gas and Electric Company, as Borrower, the financial institutions signatory therein, as Lenders and The Royal Bank of Scotland plc, as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.6).
10-72-1	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Barclays Capital, Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.1).
10-72-2	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.2).
10-72-3	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Barclays Capital, Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.3).
10-72-4	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.4).
10-73	Bondable Transition Property Sale Agreement, dated as of December 19, 2002, between ACE Funding and ACE (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 10.1)
10-74	Bondable Transition Property Servicing Agreement, dated as of December 19, 2002, between ACE Funding and ACE (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 10.2)
10-75	Purchase Agreement, dated as of April 20, 2010, by and among Pepco Holdings, Inc., Conectiv, LLC, Conectiv Energy Holding Company, LLC and New Development Holdings, LLC (File No. 001-31403, Form 8-K dated July 8, 2010, Exhibit 2.1)
10-76	Purchase Agreement, dated March 9, 2015, among Potomac Electric Power Company and BNY Mellon Capital Markets, LLC, Morgan Stanley & Co. LLC, and RBS Securities Inc., as representatives of the several underwriters named therein (File No. 001-01072, Form 8-K dated March 10, 2015, Exhibit 1.1)
10-77	Purchase Agreement, May 4, 2015, among Delmarva Power & Light Company and J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, and Scotia Capital (USA) Inc., as representatives of the several underwriters named therein (File No. 001-01405, Form 8-K dated May 5, 2015, Exhibit 1.1)
10-78	Bond Purchase Agreement, dated December 1, 2015, among Atlantic City Electric Company and the purchasers signatory thereto (File No. 001-035559, Form 8-K dated December 2, 2015, Exhibit 1.1)
10-79	$300,000,000 Term Loan Agreement by and among PHI, The Bank of Nova Scotia, as Administrative Agent, and the lenders party thereto, dated July 30, 2015 (File No. 001-31403, Form 8-K dated July 30, 2015, Exhibit 10)

Exhibit No.	Description
10-80	First Amendment to Term Loan Agreement, dated as of October 29, 2015, by and among PHI, The Bank of Nova Scotia, as Administrative Agent, and the lenders party thereto (File No. 001-31403, Form 8-K dated October 29, 2015, Exhibit 10.2)
10-81	$500,000,000 Term Loan Agreement by and among PHI, The Bank of Nova Scotia, as Administrative Agent, and the lenders party thereto, dated January 13, 2016 (File No. 001-31403, Form 8-K dated January 14, 2016, Exhibit 10)
10-82	Second Amended and Restated Credit Agreement, dated as of August 1, 2011, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the lenders party thereto, Wells Fargo Bank, National Association, as agent, issuer and swingline lender, Bank of America, N.A., as syndication agent and issuer, The Royal Bank of Scotland plc and Citicorp USA, Inc., as co-documentation agents, Wells Fargo Securities, LLC and Merrill Lynch, Pierce, Fenner and Smith Incorporated, as active joint lead arrangers and joint book runners, and Citigroup Global Markets Inc. and RBS Securities, Inc. as passive joint lead arrangers and joint book runners (File No. 001-31403, Form 10-Q dated August 3, 2011, Exhibit 10.1)
10-82-1	First Amendment, dated as of August 2, 2012, to Second Amended and Restated Credit Agreement, dated as of August 1, 2011, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions party thereto, Wells Fargo Bank, National Association, as agent, issuer of letters of credit and swingline lender, Bank of America, N.A., as syndication agent and issuer of letters of credit, and The Royal Bank of Scotland plc and Citibank, N.A., as co-documentation agents (File No. 001-31403, Form 10-K dated March 1, 2013, Exhibit 10.25.1)
10-82-2	Amendment and Consent to Second Amended and Restated Credit Agreement, dated as of May 20, 2014, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions from time to time party thereto, Bank of America, N.A. and Wells Fargo Bank, National Association (File No. 001-31403, Form 8-K dated May 20, 2014, Exhibit 10.1)
10-82-3	Third Amendment to Second Amended and Restated Credit Agreement, dated as of May 1, 2015, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions from time to time party thereto, Bank of America, N.A. and Wells Fargo Bank, National Association (File No. 001-31403, Form 8-K dated May 1, 2015, Exhibit 10.1)
10-82-4	Consent, dated as of October 29, 2015, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions from time to time party thereto, Bank of America, N.A. and Wells Fargo Bank, National Association (File No. 001-31403, Form 8-K dated October 29, 2015, Exhibit 10.1)
10-83	Asset Purchase and Sale Agreement for Generating Plants and Related Assets, dated as of June 7, 2000, by and between Pepco and Southern Energy, Inc. (File No. 001-01072, Form 8-K dated June 13, 2000, Exhibit 10)
10-83-1	Amendment No. 1 to the Asset Purchase and Sale Agreement for Generating Plants and Related Assets, dated September 18, 2000, by and between Potomac Electric Power Company and Southern Energy, Inc. (File No. 001-01072, Form 8-K dated December 9, 2000, Exhibit 10.1)

Exhibit No.	Description
10-83-2	Amendment No. 1 to the Asset Purchase and Sale Agreement for Generating Plants and Related Assets, dated December 19, 2000, by and between Potomac Electric Power Company and Southern Energy, Inc. (File No. 001-01072, Form 8-K dated December 9, 2000, Exhibit 10.2)
10-84	First Amendment to Loan Agreement, by and between Pepco Holdings LLC and The Bank of Nova Scotia, as administrative agent and lender, dated March 28, 2016 (File No. 001-31403, Form 8-K dated March 28, 2016, Exhibit 2)
10-85	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated May 27, 2016, Exhibit 99.1)
10-86	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Generation Company, LLC, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 333-85496, Form 8-K dated May 27, 2016, Exhibit 99.2)
10-87	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Generation Company, LLC, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 333-85496, Form 8-K dated May 27, 2016, Exhibit 99.2)
10-88	Amendment No. 6 to Credit Agreement, dated as of March 23, 2011, among PECO Energy Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 000-16844, Form 8-K dated May 27, 2016, Exhibit 99.4)
10-89	Amendment No. 5 to Credit Agreement, dated as of March 23, 2011, among Baltimore Gas and Electric Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-01910, Form 8-K dated May 27, 2016, Exhibit 99.5)
10-90	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of August 1, 2011, among Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, as Borrowers, the various financial institutions named therein, as Lenders, and Wells Fargo Bank, National Association, as Administrative Agent (File No. 001-31403, Form 8-K dated May 27, 2016, Exhibit 99.6)
10-91	2016 Form of Exelon Corporation Change in Control Agreement (File No. 001-16169, Form 10-Q dated October 26, 2016, Exhibit 10.1)
10-92	Execution Version-ZEC Standard Contract by and between the NYSERDA and Nine Mile Point Nuclear Station, LLC dated Nov. 18, 2016 (File No. 001-16169, Form 8-K dated November 18, 2016, Exhibit 10.1)
10-93	Execution Version-ZEC Standard Contract by and between the NYSERDA and R. E. Ginna Nuclear Power Plant, LLC dated Nov. 18, 2016 (File No. 001-16169, Form 8-K dated November 18, 2016, Exhibit 10.2)
12-1	Exelon Corporation Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
12-2	Exelon Generation Company, LLC Computation of Ratio of Earnings to Fixed Charges.
12-3	Commonwealth Edison Company Computation of Ratio of Earnings to Fixed Charges.

Exhibit No.	Description
12-4	PECO Energy Company Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
12-5	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preference Stock Dividends.
12-6	Pepco Holdings LLC Computation of Ratio of Earnings to Fixed Charges.
12-7	Potomac Electric Power Company Computation of Ratio of Earnings.
12-8	Delmarva Power & Light Company Computation of Ratio of Earnings to Fixed Charges.
12-9	Atlantic City Electric Company Computation of Ratio of Earnings to Fixed Charges.
14	Exelon Code of Conduct, as amended March 12, 2012 (File No. 1-16169, Form 8-K dated March 14, 2012, Exhibit No. 14-1).
	Subsidiaries
21-1	Exelon Corporation
21-2	Exelon Generation Company, LLC
21-3	Commonwealth Edison Company
21-4	PECO Energy Company
21-5	Baltimore Gas and Electric Company
21-6	Pepco Holdings LLC
21-7	Potomac Electric Power Company
21-8	Delmarva Power & Light Company
21-9	Atlantic City Electric Company
	Consent of Independent Registered Public Accountants
23-1	Exelon Corporation
23-2	Exelon Generation Company, LLC
23-3	Commonwealth Edison Company
23-4	PECO Energy Company
23-5	Baltimore Gas and Electric Company
23-6	Potomac Electric Power Company
23-7	Delmarva Power & Light Company
	Power of Attorney (Exelon Corporation)
24-1	Anthony K. Anderson
24-2	Ann C. Berzin
24-3	Christopher M. Crane
24-4	Yves C. de Balmann
24-5	Nicholas DeBenedictis
24-6	Nancy L. Gioia
24-7	Linda P. Jojo
24-8	Paul Joskow
24-9	Robert J. Lawless
24-10	Richard W. Mies
24-11	Reserved.

Exhibit No.	Description
24-12	John W. Rogers, Jr.
24-13	Mayo A. Shattuck III
24-14	Stephen D. Steinour
	Power of Attorney (Commonwealth Edison Company)
24-15	James W. Compton
24-16	Christopher M. Crane
24-17	A. Steven Crown
24-18	Nicholas DeBenedictis
24-19	Peter V. Fazio, Jr.
24-20	Michael H. Moskow
24-21	Denis P. O'Brien
24-22	Anne R. Pramaggiore
24-23	Jesse H. Ruiz
24-24	Reserved.
	Power of Attorney (PECO Energy Company)
24-25	Craig L. Adams
24-26	Christopher M. Crane
24-27	M. Walter D'Alessio
24-28	Nicholas DeBenedictis
24-29	Nelson A. Diaz
24-30	Rosemarie B. Greco
24-31	Charisse R. Lillie
24-32	Denis P. O'Brien
24-33	Ronald Rubin
	Power of Attorney (Baltimore Gas and Electric Company)
24-34	Ann C. Berzin
24-35	Calvin G. Butler, Jr.
24-36	Christopher M. Crane
24-37	Michael E. Cryor
24-38	James R. Curtiss
24-39	Joseph Haskins, Jr.
24-40	Denis P. O'Brien
24-41	Michael D. Sullivan
24-42	Maria Harris Tildon
	Power of Attorney (Pepco Holdings LLC)
24-43	Christopher M. Crane
24-44	Linda Cropp
24-45	Michael E. Cryor
24-46	Ernest Dianastasis

Exhibit No.	Description
24-47	Debra DiLorenzo
24-48	Denis P. O'Brien
24-49	David M. Velazquez
	Power of Attorney (Potomac Electric Power Company)
24-50	J. Tyler Anthony
24-51	Christopher M. Crane
24-52	Donna J. Kinzel
24-53	Kevin M. McGowan
24-54	Denis P. O'Brien
24-55	Kenneth J. Parker
24-56	David M. Velazquez
	Power of Attorney (Delmarva Power & Light Company)
24-57	Denis P. O'Brien
24-58	David M. Velazquez
	Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Annual Report on Form 10-K for the year ended December 31, 2016 filed by the following officers for the following registrants:
31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Jonathan W. Thayer for Exelon Corporation
31-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	Filed by Craig L. Adams for PECO Energy Company
31-8	Filed by Phillip S. Barnett for PECO Energy Company
31-9	Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
31-10	Filed by David M. Vahos for Baltimore Gas and Electric Company
31-11	Filed by David M. Velazquez for Pepco Holdings LLC
31-12	Filed by Donna J. Kinzel for Pepco Holdings LLC
31-13	Filed by David M. Velazquez for Potomac Electric Power Company
31-14	Filed by Donna J. Kinzel for Potomac Electric Power Company
31-15	Filed by David M. Velazquez for Delmarva Power & Light Company
31-16	Filed by Donna J. Kinzel for Delmarva Power & Light Company
31-17	Filed by David M. Velazquez for Atlantic City Electric Company
31-18	Filed by Donna J. Kinzel for Atlantic City Electric Company
	Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Annual Report on Form 10-K for the year ended December 31, 2016 filed by the following officers for the following registrants:
32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Jonathan W. Thayer for Exelon Corporation

Exhibit No.	Description
32-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
32-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	Filed by Craig L. Adams for PECO Energy Company
32-8	Filed by Phillip S. Barnett for PECO Energy Company
32-9	Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
32-10	Filed by David M. Vahos for Baltimore Gas and Electric Company
32-11	Filed by David M. Velazquez for Pepco Holdings LLC
32-12	Filed by Donna J. Kinzel for Pepco Holdings LLC
32-13	Filed by David M. Velazquez for Potomac Electric Power Company
32-14	Filed by Donna J. Kinzel for Potomac Electric Power Company
32-15	Filed by David M. Velazquez for Delmarva Power & Light Company
32-16	Filed by Donna J. Kinzel for Delmarva Power & Light Company
32-17	Filed by David M. Velazquez for Atlantic City Electric Company
32-18	Filed by Donna J. Kinzel for Atlantic City Electric Company
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

* Compensatory plan or arrangements in which directors or officers of the applicable registrant participate and which are not available to all employees.

ITEM 16. FORM 10-K SUMMARY

All Registrants

Registrants may voluntarily include a summary of information required by Form 10-K under this Item 16. The Registrants have elected not to include such summary information.

S IGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2017.

EXELON CORPORATION

By: /S/ CHRISTOPHER M. CRANE
Name: **Christopher M. Crane**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2017.

Signature	Title
/S/ CHRISTOPHER M. CRANE **Christopher M. Crane**	President and Chief Executive Officer (Principal Executive Officer) and Director
/S/ JONATHAN W. THAYER **Jonathan W. Thayer**	Senior Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/S/ DUANE M. DESPARTE **Duane M. DesParte**	Senior Vice President and Corporate Controller (Principal Accounting Officer)

This annual report has also been signed below by Thomas S. O'Neil, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Anthony K. Anderson
Ann C. Berzin
Christopher M. Crane
Yves C. de Balmann
Nicholas DeBenedictis
Nancy L. Gioia
Linda P. Jojo
Paul Joskow
Robert J. Lawless
Richard W. Mies
John W. Rogers, Jr.
Mayo A. Shattuck III
Stephen D. Steinour

By: /S/ THOMAS S. O'NEILL
Name: **Thomas S. O'Neill**

February 13, 2017

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2017.

EXELON GENERATION COMPANY, LLC

By: /S/ KENNETH W. CORNEW
Name: **Kenneth W. Cornew**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2017.

Signature	Title
/S/ KENNETH W. CORNEW **Kenneth W. Cornew**	President and Chief Executive Officer (Principal Executive Officer)
/S/ BRYAN P. WRIGHT **Bryan P. Wright**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/S/ MATTHEW N. BAUER **Matthew N. Bauer**	Vice President and Controller (Principal Accounting Officer)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2017.

COMMONWEALTH EDISON COMPANY

By: /S/ ANNE R. PRAMAGGIORE
Name: **Anne R. Pramaggiore**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2017.

Signature	Title
/S/ ANNE R. PRAMAGGIORE **Anne R. Pramaggiore**	President and Chief Executive Officer (Principal Executive Officer) and Director
/S/ JOSEPH R. TRPIK, JR. **Joseph R. Trpik, Jr.**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/S/ GERALD J. KOZEL **Gerald J. Kozel**	Vice President and Controller (Principal Accounting Officer)
/S/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Anne R. Pramaggiore, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

James W. Compton
Christopher M. Crane
A. Steven Crown
Nicholas DeBenedictis
Peter V. Fazio, Jr.
Michael H. Moskow
Denis P. O'Brien
Jesse H. Ruiz

By: /S/ ANNE R. PRAMAGGIORE
Name: **Anne R. Pramaggiore**

February 13, 2017

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2017.

PECO ENERGY COMPANY

By: /S/ CRAIG L. ADAMS
Name: Craig L. Adams
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2017.

Signature	Title
/S/ CRAIG L. ADAMS **Craig L. Adams**	President and Chief Executive Officer (Principal Executive Officer) and Director
/S/ PHILLIP S. BARNETT **Phillip S. Barnett**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/S/ SCOTT A. BAILEY **Scott A. Bailey**	Vice President and Controller (Principal Accounting Officer)
/S/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Craig L. Adams, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Christopher M. Crane
M. Walter D'Alessio
Nicholas DeBenedictis
Nelson A. Diaz
Rosemarie B. Greco
Charisse R. Lillie
Denis P. O'Brien
Ronald Rubin

By: /S/ CRAIG L. ADAMS
Name: Craig L. Adams

February 13, 2017

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2017.

BALTIMORE GAS AND ELECTRIC COMPANY

By: /S/ CALVIN G. BUTLER, JR.
Name: Calvin G. Butler, Jr.
Title: Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2017.

Signature	Title
/S/ CALVIN G. BUTLER, JR. **Calvin G. Butler, Jr.**	Chief Executive Officer (Principal Executive Officer)
/S/ DAVID M. VAHOS **David M. Vahos**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/S/ ANDREW W. HOLMES **Andrew W. Holmes**	Vice President and Controller (Principal Accounting Officer)
/S/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Calvin G. Butler, Jr., Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Ann C. Berzin
Christopher M. Crane
Michael E. Cryor
James R. Curtiss
Joseph Haskins, Jr.
Denis P. O'Brien
Michael D. Sullivan
Maria Harris Tildon

By: /S/ CALVIN G. BUTLER, JR.
Name: Calvin G. Butler, Jr.

February 13, 2017

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2017.

PEPCO HOLDINGS LLC

By: /s/ David M. Velazquez
Name: **David M. Velazquez**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2017.

Signature	Title
/s/ David M. Velazquez **David M. Velazquez**	President and Chief Executive Officer (Principal Executive Officer)
/s/ Donna J. Kinzel **Donna J. Kinzel**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Robert M. Aiken **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)
/s/ Christopher M. Crane **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by David M. Velazquez, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Christopher M. Crane
Linda Cropp
Michael E. Cryor
Ernest Dianastasis
Debra P. DiLorenzo
Denis P. O'Brien

By: /s/ David M. Velazquez
Name: **David M. Velazquez**

February 13, 2017

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2017.

POTOMAC ELECTRIC POWER COMPANY

By: /S/ DAVID M. VELAZQUEZ
Name: David M. Velazquez
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2017.

Signature	Title
/S/ DAVID M. VELAZQUEZ **David M. Velazquez**	President and Chief Executive Officer (Principal Executive Officer)
/S/ DONNA J. KINZEL **Donna J. Kinzel**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/S/ ROBERT M. AIKEN **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)
/S/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman

This annual report has also been signed below by David M. Velazquez, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

J. Tyler Anthony
Christopher M. Crane
Donna J. Kinzel
Kevin M. McGowan
Denis P. O'Brien
Kenneth J. Parker

By: /S/ DAVID M. VELAZQUEZ
Name: David M. Velazquez

February 13, 2017

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2017.

DELMARVA POWER & LIGHT COMPANY

By: /S/ DAVID M. VELAZQUEZ
Name: **David M. Velazquez**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2017.

Signature	Title
/S/ DAVID M. VELAZQUEZ **David M. Velazquez**	President and Chief Executive Officer (Principal Executive Officer)
/S/ DONNA J. KINZEL **Donna J. Kinzel**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/S/ ROBERT M. AIKEN **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)
/S/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman

This annual report has also been signed below by David M. Velazquez, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Denis P. O'Brien

By: /S/ DAVID M. VELAZQUEZ
Name: **David M. Velazquez**

February 13, 2017

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 13th day of February, 2017.

ATLANTIC CITY ELECTRIC COMPANY

By: /S/ DAVID M. VELAZQUEZ
Name: David M. Velazquez
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 13th day of February, 2017.

Signature	Title
/S/ DAVID M. VELAZQUEZ **David M. Velazquez**	President and Chief Executive Officer (Principal Executive Officer)
/S/ DONNA J. KINZEL **Donna J. Kinzel**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/S/ ROBERT M. AIKEN **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)
/S/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman

This Instrument Prepared By:

/s/ Christie D. Cannon
Christie D. Cannon
Delmarva Power & Light Company
Mailstop 92DC42
500 N. Wakefield Drive
Newark, DE 19702-5440

DELMARVA POWER & LIGHT COMPANY

TO

THE BANK OF NEW YORK MELLON,
Trustee.

ONE HUNDRED AND SEVENTEENTH SUPPLEMENTAL INDENTURE

Dated as of January 1, 2016
(but executed on the dates shown on the execution page)

This **ONE HUNDRED AND SEVENTEENTH SUPPLEMENTAL INDENTURE** , dated as of the first day of January, 2016 (but executed on the dates hereinafter shown), made and entered into by and between DELMARVA POWER & LIGHT COMPANY, a corporation of the State of Delaware and the Commonwealth of Virginia, hereinafter called the Company and THE BANK OF NEW YORK MELLON, a New York banking corporation, hereinafter called the Trustee;

WITNESSETH:

WHEREAS, the Company heretofore executed and delivered its Indenture of Mortgage and Deed of Trust (hereinafter in this One Hundred and Seventeenth Supplemental Indenture called the "Original Indenture"), dated as of October 1, 1943, to The New York Trust Company, a corporation of the State of New York, as Trustee, to which The Bank of New York Mellon is successor Trustee, to secure the First Mortgage Bonds of the Company, unlimited in aggregate principal amount and issuable in series, from time to time, in the manner and subject to the conditions set forth in the Original Indenture granted and conveyed unto the Trustee, upon the trusts, uses and purposes specifically therein set forth, certain real estate, franchises and other property therein described, including property acquired after the date thereof, except as therein otherwise provided; and

WHEREAS, the Original Indenture has been supplemented by one hundred and sixteen supplemental indentures specifically subjecting to the lien of the Original Indenture as though included in the granting clause thereof certain property in said supplemental indentures specifically described and amending and modifying the provisions of the Original Indenture (the Original Indenture, as amended, modified and supplemented by all of the indentures supplemental thereto, including this One Hundred and Seventeenth Supplemental Indenture, is hereinafter in this One Hundred and Seventeenth Supplemental Indenture called the "Indenture"); and

WHEREAS, the execution and delivery of this One Hundred and Seventeenth Supplemental Indenture has been duly authorized by Unanimous Written Consent of the Board of Directors of the Company, and all conditions and requirements necessary to make this One Hundred and Seventeenth Supplemental Indenture a valid, binding and legal instrument in accordance with its terms, for the purposes herein expressed, and the execution and delivery hereof, have been in all respects duly authorized; and

WHEREAS, it is provided in and by the Original Indenture, inter alia, as follows:

> "IT IS HEREBY AGREED by the Company that all the property, rights and franchises acquired by the Company after the date hereof (except any hereinbefore or hereinafter expressly excepted) shall (subject to the provisions of Section 9.01 hereof and to the extent permitted by law) be as fully embraced within the lien hereof as if such property, rights and franchises were now owned by the Company and/or specifically described herein and conveyed hereby;"

and

WHEREAS, the Company has acquired certain other property, real, personal and mixed, which heretofore has not been specifically conveyed to the Trustee;

NOW, THEREFORE, this ONE HUNDRED AND SEVENTEENTH SUPPLEMENTAL INDENTURE WITNESSETH that for and in consideration of the premises and in pursuance of the provisions of the Indenture, the Company has granted, bargained, sold, released, conveyed, assigned, transferred, mortgaged, pledged, set over and confirmed, and by these presents does grant, bargain, sell, release, convey, assign, transfer, mortgage, pledge, set over and confirm unto the Trustee and to its successors in the trust in the Indenture created, to its and their assigns forever, all the following described properties of the Company, and does confirm that the Company will not cause or consent to a partition, either voluntary or through legal proceedings, of property, whether herein described or

heretofore or hereafter acquired, in which its ownership shall be as tenant in common, except as permitted by, and in conformity with, the provisions of the Indenture and particularly of Article IX thereof:

DELAWARE

Sussex County

Property Name	Instrument Date	Deed Records		Tax Map No.
		Liber	Folio	
Midway Substation	11/17/2015	4472	4	334-06.00-497.00

MARYLAND

Harford County

Property Name	Instrument Date	Deed Records		Tax Map No.
		Liber	Folio	
Prospect Road Land Purchase - DPL MD CAP H1 [Paul J. Madden & Brittany Madden]	12/29/2015	11602	414	TM 18, Parcel 304

MARYLAND

Wicomico County

Property Name	Instrument Date	Deed Records		Tax Map No.
		Liber	Folio	
Chesapeake Substation	12/29/2015	3945	465	Map 38 Parcel 103 & Map 38 Parcel 369 Lot 27

Together with all other property, real, personal and mixed, tangible and intangible (except such property as in said Indenture expressly excepted from the lien and operation thereof), acquired by the Company on or prior to December 31, 2015, and not heretofore specifically subjected to the lien of the Indenture.

Also without limitation of the generality of the foregoing, the easements and rights-of-way and other rights in or relating to real estate or the occupancy of the same owned by the Company, and whether used or not used in connection with the Company's operations, which are conveyed to the Company and recorded in the following Real Property Deed Records to which reference is made for a more particular description, to wit:

DELAWARE

New Castle County

Instrument Date	Instrument No.	Tax ID No.
01/30/2015	20150227-0009102	1401100072
02/17/2015	20150320-0012858	2602930254, 2602930261
02/25/2015	20150311-0011350	1502000074
03/24/2015	20150331-0014740	1102300025
03/26/2015	20150406-0015639	611500141
05/05/2015	20150611-0028549	1501100121
05/06/2015	20150527-0024976	1501000121
05/12/2015	20150528-0025500	1104100014
05/13/2015	20150528-0025501	804510252
07/14/2015	20150819-0042053	1301100047M001
07/14/2015	20150819-0042054	1301100009
08/03/2015	20150818-0041630	1301300148
08/05/2015	20150819-0042052	0901100065
08/05/2015	20150825-0043084	1401500262
08/11/2015	20150825-0043051	0611000003
09/14/2015	20151006-0051092	0804000019
09/15/2015	20151006-0051093	0702700119
09/16/2015	20160119-0002254	0804220028
09/29/2015	20160119-0002253	2602610035
10/01/2015	20151016-0053150	0611200012
10/02/2015	20151110-0058220	0604600159
10/09/2015	20151020-0053692	0605200247
10/09/2015	20151020-0053691	0613100019
10/09/2015	20151020-0053690	0605200248
10/13/2015	20160119-0002252	0902400030
10/15/2015	20151028-0055310	0605700142
10/15/2015	20160119-0002250	1003500022, 1003500025, 1003500026
10/19/2015	20151028-0055311	0901700076
10/19/2015	20151201-0061397	1300300001, 1300300002, 1300700020, 1300700021, 1300800001, 1300800002
10/30/2015	20151211-0063727	1101300015
11/10/2015	20151201-0061396	1301100165
11/23/2015	20160119-0002249	0803910138
11/25/2015	20151211-0063726	0615000306
12/15/2015	20160129-0004536	0801310209, 0801310210, 0801310234, 0801310282
01/04/2016	20160119-0002251	0702900036

Instrument Date	Instrument No.	Tax ID No.
01/05/2016	20160119-0002248	1103620042, 1103620073, 1103640073, 1103640188, 1103710037, 1103710040, 1103730220, 1103730226
01/07/2015	20150116-0002216	0607100248, 0607100249, 0607100250, 0607100255, 0607100256, 0607100257 0607100260, 0607100264, 0605800457
01/07/2015	20150016-0002217	0607100156, 0607100157, 0607100259, 0607100261
07/17/2014	20150116-0002439	0801700003
07/17/2014	20150116-0002440	0801700120
07/17/2014	20150116-0002441	0801700034
07/29/2014	20150116-0002442	0801710001
08/27/2014	20150116-0002443	0802340091
07/18/2014	20150116-0002438	0801100002
07/18/2014	20150116-0002437	0801700031
07/18/2014	20150116-0002436	0801700002
11/19/2014	20150116-0002444	2603540058
01/26/2015	20150127-0003924	1300900057
02/05/2015	20150219-0007706	0604600047
02/05/2015	20150219-0007707	0603500244
02/05/2015	20150219-0007708	0604600248
02/05/2015	20150219-0007709	0604600249
02/05/2015	20150219-0007710	0604600250
01/29/2015	20150219-0007967	1401100073
10/30/2014	20150211-0006654	1101300015

DELAWARE

Kent County

Instrument Date	Instrument Number	Tax ID No.
11/23/2014	2015-269001	6-00-15900-01-2809-00001
12/23/2014	2015-270213	6-00-17900-02-0100-00001
01/14/2015	2015-269325	6-00-14800-01-4100-00001
04/21/2015	2015-275053	5-00-17200-02-2000-00001
05/18/2015	2015-276538	3-00-04600-02-1504-00001
05/18/2015	2015-276539	3-00-04600-02-1504-00001
05/27/2015	2015-276540	4-03-0469.00-01-07.27000
06/09/2015	2015-277709	7-00-10200-02-2300-00001
07/21/2015	2015-279352	2-00-07500-01-1203-00001
07/21/2015	2015-279353	2-00-07500-01-1205-00001
09/23/2015	2015-284125	3-00-01600-01-1101-00001

DELAWARE

Sussex County

Instrument Date	Deed Records		Tax ID No.
	Book	Page	
06/11/2014	4345	159	334-10.00-30.26
			334-10.00-30.27
12/17/2014	4357	151	533-18.00-84.00
01/14/2015	4362	33	234-33.00-23.02
01/22/2015	4362	30	334-13.00-325.37
02/03/2015	4371	273	234-50.02-08
04/26/2015	4398	256	432-7.00-25.01
05/11/2015	4406	298	433-6.15-44.00-PARK
05/12/2015	4420	24	33450015204
05/18/2015	4420	22	533-11.00-18.02
05/23/2015	4406	296	134-23.12-62.00
06/11/2015	4420	26	334-60.06-609
			334-10.00-73.00
06/24/2015	4422	333	334-10.00-74.00
07/20/2015	4440	141	530-9.00-47.00
07/20/2015	4440	139	234-5.00-46.03
09/10/2015	4460	68	331-2.00-15.00
09/12/2015	4460	70	132-13.00-7.00
09/29/2015	4458	334	234-32.00-110.00
10/02/2015	4458	320	334-5.00-88.00
10/30/2015	4469	21	5-32-13.00-32.01
11/10/2015	4480	220	334-13.00-325.18
12/17/2015	4496	308	134-20.08-5500

MARYLAND

Caroline County

Instrument Date	Deed Records		Map	Parcel	Lot
	Book	Page			
02/16/2015	1151	233	53	84	2
07/08/2015	1165	180	23	105	1-24
08/24/2015	1172	464	14	47	2
10/10/2015	1177	461	100	1165	
09/28/2015	1177	459	59	82	

MARYLAND

Cecil County

Instrument Date	Deed Records		Map	Parcel	Lot
	Book	Page			
12/02/2014	3770	303	30	116	
12/02/2014	3770	309	30	3 &97	
03/27/2015	3727	191	25	719	
04/02/2015	3724	232	6	28	
04/10/2015	3724	234	38	13	
04/10/2015	3724	236	38	12	
04/10/2015	3724	240	38	192	
04/15/2015	3724	238	38	20	
04/15/2015	3724	242	38	208	
04/27/2015	3727	189	25	325	
05/02/2015	3770	307	38	9	
05/14/2015	3732	13	13	497	
08/12/2015	3770	301	38	379	
08/24/2015	3779	348	31	47	
08/29/2015	3783	249	14	462	
11/06/2015	3818	390	20	123	
11/06/2015	3818	393	18	432	
11/20/2015	3824	7	19	505	
12/04/2015	3832	404	19	159	
12/10/2015	3832	402	52	18	
12/22/2014	3674	475	42	73	
01/10/2015	3674	477	11	9	1
01/10/2015	3674	479	11	9	

MARYLAND

Dorchester County

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
09/14/2014	1248	364	31	135	
02/19/2015	1256	497	6	87	
06/01/2015	1309	188	32	76	
01/15/2015	1247	189	33	10	
09/08/2014	1247	193	31	135	
01/16/2015	1247	326	33	10	
01/20/2015	1249	32	400	589	
01/27/2015	1251	298	6	130	

MARYLAND

Harford County

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
05/09/2015	11276	482	17	268	
02/04/2015	11129	39	12	34	

MARYLAND

Kent County

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
11/12/2014	815	285	42	21	
11/30/2014	826	349	53	52	
12/05/2014	826	353	53	8	
12/05/2014	818	130	53	54	
12/08/2014	826	351	53	3	
12/12/2014	818	136	53	9	
12/20/2014	818	132	53	45	
12/23/2014	818	134	36	169	
01/06/2015	818	128	42	154	
01/29/2015	820	70	48	20	
01/29/2015	820	72	53	14	
01/29/2015	820	74	48	78	
03/06/2015	822	455	44	308	1
04/06/2015	826	343	53	20	
04/06/2015	826	340	53	14	
04/06/2015	826	346	53	78	
04/09/2015	834	478	53	3	
05/01/2015	829	200	44	231	
05/04/2015	834	493	53	29	
05/08/2015	834	496	53	53	
05/11/2015	834	481	53	6	
05/14/2015	829	436	201	399	
05/15/2015	829	433	4	173	
05/19/2015	834	490	53	24	
05/27/2015	834	484	53	9	
05/28/2015	834	487	53	18	
06/03/2015	835	426	53	48	
06/03/2015	835	429	53	31	
06/25/2015	835	423	48	54	
07/13/2015	837	27	47	83	
09/01/2015	818	339	53	2	
09/02/2015	841	314	55	55	3
09/02/2015	841	316	55	55	4

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
09/02/2015	841	318	55	55	5
09/02/2015	841	320	55	73	

MARYLAND

Queen Anne's County

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
09/24/2014	2366	474	58D	420	
12/17/2014	2361	54	58D	419	
12/17/2014	2361	51	58E	427	
12/19/2014	2366	471	58D	425	
01/14/2015	2368	298	64	60 & 31	
01/22/2015	2375	33	10	88	
01/24/2015	2375	29	10	13	
02/02/2015	2379	139	64	32	
02/11/2015	2377	257	45	46	
03/25/2015	2437	358	63	28	
03/25/2015	2437	362	63	27	3
03/25/2015	2437	366	63	27	4
03/26/2015	2393	180	48	42	
04/30/2015	2437	370	63	85	
05/18/2015	2413	109	65	30	
06/10/2015	2437	383	63	41	1
06/19/2015	2437	374	58H	201	
06/19/2015	2437	377	65	45	
06/19/2015	2437	380	65	46	
06/22/2015	2437	353	44	33	
06/24/2015	2437	78	68	1	
06/30/2015	2437	82	29	4	
08/11/2015	2449	7	51	29	1-5
08/19/2015	2458	399	73	12	
08/20/2015	2453	502	58D	73	
08/31/2015	2477	1	64	1	
09/18/2015	2466	84	36	62	
09/21/2015	2466	452	35	178	3
09/22/2015	2485	405	56	50	
09/25/2015	2466	449	17	58	2
10/12/2015	2487	395	44B	963	
11/02/2015	2485	402	058E	57	
11/17/2015	2487	391	581	369	
12/01/2015	2492	437	58E	57	
12/04/2015	2499	183	7	3	

MARYLAND

Somerset County

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
12/04/2014	893	157	65	34	
12/05/2014	893	155	57	604	
12/12/2014	903	403	41	46	
01/07/2015	890	551	7	209	
01/30/2015	892	575	101	340	
03/04/2015	895	32	79	20	
05/27/2015	901	69	58	64	
05/27/2015	901	67	58	13	
07/22/2015	907	311	19	332	
07/22/2015	907	316	19	345	
10/20/2015	912	161	200	16	

MARYLAND

Talbot County

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
03/04/2015	2250	219	53	119	9
03/04/2015	2251	1	53	166	2
03/26/2015	2250	223	59	125	
03/31/2015	2270	274	59	45	
03/31/2015	2270	282	59	61	
03/31/2015	2270	286	59	67	2
03/31/2015	2270	290	59	81	
04/08/2015	2270	262	59	41	
04/10/2015	2270	266	53	167	
04/21/2015	2270	270	59	20	
05/20/2015	2278	73	53	105	
05/21/2015	2268	307	59	40&43	
05/28/2015	2270	258	59	91	
06/01/2015	2270	278	59	107	
06/12/2015	2278	68	62	69	
06/12/2015	2278	63	62	82	
06/12/2015	2278	59	62	63	
06/13/2015	2278	55	62	77	
06/30/2015	2278	51	62	7	
06/30/2015	2287	111	53	119	
07/17/2015	2287	127	59	56	
07/21/2015	2287	131	62	8	
07/22/2015	2290	156	59	119	5
07/23/2015	2287	123	59	114	

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
07/24/2015	2290	152	59	119	1&2
07/27/2015	2290	160	59	6	
07/27/2015	2290	164	59	7	
07/27/2015	2290	168	59	111	
07/27/2015	2290	172	59	135	
07/29/2015	2290	176	62	06&28	
08/07/2015	2293	450	22	348	
08/10/2015	2287	115	59	23	
08/10/2015	2287	119	59	95	
08/10/2015	2290	180	11	289	
08/24/2015	2307	34	59	119	3
08/24/2015	2307	38	59	119	4
08/27/2015	2307	42	59	42	
09/18/2015	2299	69	59	17	
09/18/2015	2299	73	59	24	
09/18/2015	2299	77	59	104	
01/07/2016	2326	378	59	108	

MARYLAND

Wicomico County

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
01/14/2015	6533	1	27	632	
03/11/2015	3873	452	39	181	5
03/14/2015	6533	9	27	632	
03/17/2015	3832	195	37	116	
03/30/2015	3832	192	37	120	1&2
04/09/2015	3843	141	104	1344	
04/20/2015	3843	152	48	63	
04/20/2015	3843	155	48	317	
04/20/2015	3843	138	107	1088	
				1089	
				1090	
				1091	
				1092	
04/21/2015	3843	148	5	10	
04/22/2015	3843	145	70	16	
05/11/2015	3851	238	48	319	
05/13/2015	3873	458	33	50	
05/14/2015	3873	447	39	719	
05/18/2015	3861	0-20	106	1191	
05/18/2015	3861	0-15	111	1114	
05/19/2015	3873	465	31	107	

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
06/09/2015	3861	248	10	7	
06/09/2015	3873	461	10	7	
09/02/2015	841	322	773	804	
09/02/2015	3902	150	773	804	
09/02/2015	3902	153	103	371	
09/11/2015	3906	475	61	82	
09/23/2015	3909	316	600	315	
10/05/2015	3921	163	49	22	
10/09/2015	3913	30	30		
			301	1453	
10/12/2015	3923	1	113	1126	
10/19/2015	3923	6	63	532	
10/28/2015	3933	118	29	9	
10/28/2015	3933	121	29	338	
11/10/2015	3933	124	54	14	
12/10/2015	3942	171	101	5484	
				5485	
12/11/2015	3964	114	31	460	
12/15/2015	3950	286	48	729	
12/15/2015	3950	282	48	306	
12/15/2015	3950	278	48	321	
12/15/2015	3950	274	48	310	
12/19/2015	3950	270	30	105	
12/09/2014	3791	500	49	65	4,5,6,7
01/05/2015	3800	266	115	2937	
01/14/2015	3803	368	107	1887	
01/28/2015	3810	362	106	1306	7

MARYLAND

Worcester County

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
10/28/2014	6532	469	301	1707	
11/19/2014	6500	50			
12/29/2014	6500	391	115	1114A	
02/06/2015	6521	9			
02/23/2015	6524	375	15	131	
02/28/2015	6597	110	27	249	
03/25/2015	6561	279	56	83	
03/27/2015	6536	271	110	2797	
03/31/2015	6566	115	63	153	
04/03/2015	6560	172	115	9346	
05/17/2015	6569	29	9	165	

Instrument Date	Deed Records		Map	Parcel	Lot
	Liber	Folio			
05/20/2015	6577	227	111	5749	10
05/20/2015	6577	230	111	5754	
05/20/2015	6577	233	111	5755	4
05/20/2015	6577	236	111	5756	5
05/20/2015	6577	239	111	5757	6
05/21/2015	6572	17	9	386	
06/24/2015	6597	107	26	201	
07/03/2015	6609	429	Elliott Bayside Partnership – Deed of Easement and Release of Rights		
07/03/2015	6609	437	Elliott Bayside Partnership - Supplemental Use and Maintenance Agreement		
07/23/2015	6609	407	Seaside Village Commercial Land Condominium - Deed of Easement and Release of Rights		
07/23/2015	6609	426	Seaside Village Commercial Land Condominium - Declaration of Easement Use Limitations		
08/06/2015	6618	477	49	10	
08/06/2015	6623	188	49	10	
10/17/2015	6662	45		6837	
11/02/2015	6676	215	27	637	
11/17/2015	6684	267	79	215	
12/04/2015	6689	375	49	144	
12/08/2015	6689	378	27	466	
12/15/2015	6703	31	110	3894	
12/16/2015	6703	28	20	167	

The following is a schedule of bonds issued under the Eighty-Eighth Supplemental Indenture and Credit Line Deed of Trust, effective as of October 1, 1994, that can be designated as First Mortgage Bonds, Series I, which may also be designated as Secured Medium Term Notes, Series I; and First Mortgage Bonds, Pledged Series I.

First Mortgage Bonds, Series I/Secured Medium Term Notes, Series I

Issuance Date	Tranche	Maturity	Principal
06/19/95	7.71% Bonds	06/01/25	$100,000,000
06/19/95	6.95% Amortizing Bonds	06/01/08	$ 25,800,000
11/25/08	6.40% Bonds	12/01/13	$250,000,000

First Mortgage Bonds, Pledged Series I

Issuance Date	Tranche	Maturity	Principal
10/12/94	1994	10/01/29	$ 33,750,000
Total Bonds Issued:			$409,550,000

As supplemented and amended by this One Hundred and Seventeenth Supplemental Indenture, the Original Indenture and all indentures supplemental thereto are in all respects ratified and confirmed and the Original Indenture and the aforesaid supplemental indentures and this One Hundred and Seventeenth Supplemental Indenture shall be read, taken and construed as one and the same instrument.

This One Hundred and Seventeenth Supplemental Indenture shall be simultaneously executed in several counterparts, and all such counterparts executed and delivered, each as an original, shall constitute but one and the same instrument.

The recitals of fact contained herein shall be taken as the statements of the Company, and the Trustee assumes no responsibility for the correctness of the same.

The debtor and its mailing address are Delmarva Power & Light Company, Mailstop 92DC42, 500 N. Wakefield Drive, Newark, Delaware 19702-5440. The secured party and its address, from which information concerning the security interest hereunder may be obtained, is The Bank of New York Mellon, 500 Ross Street, 12 th Floor, Pittsburgh, Pennsylvania 15262, Attn: Corporate Trust Administration.

The Company acknowledges that it received a true and correct copy of this One Hundred and Seventeenth Supplemental Indenture.

This One Hundred and Seventeenth Supplemental Indenture is executed and delivered pursuant to the provisions of Section 5.11 and paragraph (a) of Section 17.01 of the Indenture for the purpose of conveying, transferring and assigning to the Trustee and of subjecting to the lien of the Indenture with the same force and effect as though included in the granting clause thereof the above described property so acquired by the Company on or prior to the date of execution, and not heretofore specifically subject to the lien of the Indenture; but nothing contained in this One Hundred and Seventeenth Supplemental Indenture shall be deemed in any manner to affect (except for such purposes) or to impair the provisions, terms and conditions of the Original Indenture, or of any indenture supplemental thereto and the provisions, terms and conditions thereof are hereby expressly confirmed.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, the Company has caused this instrument to be signed in its name and behalf by its President, and its corporate seal to be hereunto affixed and attested by its Assistant Secretary and the Trustee has caused this instrument to be signed in its name and behalf by a Vice President and its corporate seal to be hereunto affixed and attested by an authorized officer, effective as of the 1st day of January, 2016.

DELMARVA POWER & LIGHT COMPANY

Date of Execution

April 7, 2016

By /s/ David M. Velazquez
David M. Velazquez, President

Attest:

/s/ Jeffery E. Snyder [SEAL]
Jeffery E. Snyder, Assistant Secretary

STATE OF DELAWARE)
) SS
COUNTY OF NEW CASTLE)

BE IT REMEMBERED that as of the 7 th day of April, 2016, personally came before me, a notary public for the State of Delaware, David M. Velazquez, President of DELMARVA POWER & LIGHT COMPANY, a corporation of the State of Delaware and the Commonwealth of Virginia (the "Company"), party to the foregoing instrument, known to me personally to be such, and acknowledged the instrument to be his own act and deed and the act and deed of the Company; that his signature is in his own proper handwriting; that the seal affixed is the common or corporate seal of the Company; and that his act of signing, sealing, executing and delivering such instrument was duly authorized by resolution of the Board of Directors of the Company.

GIVEN under my hand and official seal the day and year aforesaid.

/s/ Julia P. Reilly [SEAL]
Notary Public, State of Delaware
My commission expires _____.

Julia P. Reilly
Notary Public
State of Delaware
My Commission Expires:
April 3, 2017

THE BANK OF NEW YORK MELLON,
as Trustee

Date of Execution

April 7, 2016

By /s/ Francine J. Kincaid
Francine J. Kincaid, Vice President

Attest:

/s/ Arsala Kidwai
Arsala Kidwai, Vice President

STATE OF NEW YORK)
) SS.
COUNTY OF NEW YORK)

BE IT REMEMBERED that on this 7 th day of April, 2016, personally came before me, a Notary Public for the State of New York, Francine J. Kincaid, Vice President of THE BANK OF NEW YORK MELLON, a New York banking corporation (the "Trustee"), party to the foregoing instrument, known to me personally to be such, and acknowledged the instrument to be her own act and deed and the act and deed of the Trustee; that his signature is her own proper handwriting; that the seal affixed is the common or corporate seal of the Trustee; and that her act of signing, sealing, executing and delivering said instrument was duly authorized by resolution of the Board of Directors of the Trustee.

GIVEN under my hand and official seal the day and year aforesaid.

/s/ Christopher J. Traina
Notary Public, State of New York
My commission expires _____.

Christopher J. Traina
Notary Public-State of New York
No. 01TR6297825
Qualified in Queen's County
Qualified in New York County
My Commission Expires March 03, 2018
[SEAL]

CERTIFICATE OF RESIDENCE

THE BANK OF NEW YORK MELLON, successor Trustee to the Trustee within named, hereby certifies that it has a residence at 101 Barclay Street, in the Borough of Manhattan, in The City of New York, in the State of New York.

THE BANK OF NEW YORK MELLON

By /s/ Francine J. Kincaid

Name: Francine J. Kincaid
Title: Vice President

Certification

This document was prepared under the supervision of an attorney admitted to practice before the Court of Appeals of Maryland, or by or on behalf of one of the parties named in the within instrument.

/s/ Christie D. Cannon

Christie D. Cannon

CONFIDENTIAL SEPARATION AGREEMENT

THIS CONFIDENTIAL SEPARATION AGREEMENT (this " *Agreement* ") is entered into as of _____ between Exelon Corporation ("Exelon"), _____ ("Subsidiary", and, collectively with Exelon, the " *Company* ") and _____ (the " *Executive* ").

W I T N E S S E T H:

WHEREAS, the Executive is separating from all positions with Exelon, Subsidiary and their respective affiliates.

NOW, THEREFORE, in consideration of the mutual promises and agreements contained herein, the adequacy and sufficiency of which are hereby acknowledged, the Company and the Executive agree as follows:

1. Resignation; Termination of Employment . The Executive's employment with Subsidiary will be terminated, and Executive hereby resigns, each effective as of the close of business on _____ (the " *Termination Date* "), as Vice President of Subsidiary and from all other positions as an officer or director of Exelon and its subsidiaries and affiliates.

2. Payment of Accrued Amounts . The Company shall pay to the Executive not later than the second payroll date after the Termination Date the following amounts:

(a) the portion of his or her annual salary that has accrued but is unpaid as of the Termination Date; and

(b) an additional amount representing the Executive's accrued but unused vacation days as of the Termination Date, if any.

3. Severance Payments . The Company shall pay to the Executive:

(a) cash severance payments in an aggregate amount equal to $ _____ which is equal to 1. ___ times the sum of (i) the Executive's base salary of $ _____ plus (ii) the Executive's 201_ target annual incentive award of $ _____. Payment shall commence not later than forty-five days following the Termination Date, in substantially equal regular payroll installments over a period of fifteen months; and

(b) Executive shall remain eligible to receive a pro-rated annual incentive award for 201_ based on actual performance results determined in a manner consistent with peer executives, payable at the time such awards (if any) are paid to active executives (but not later than March 15, 201_), and such payment shall be considered a short-term deferral for purposes of section 409A of the Code.

4. Tax Withholding . The Company shall deduct from the amounts payable to the Executive pursuant to this Agreement the amount of all required federal, state and local withholding taxes in accordance with the Executive's Form W-4 on file with the Company and

all applicable social security and Medicare taxes. The Company shall be entitled to withhold from any shares of common stock of the Company to be delivered to the Executive pursuant to Sections 6(a), (b) and (c) a number of shares of common stock of the Company having a value (based upon the closing price of a share of the Company's common stock as reported on the New York Stock Exchange on the applicable valuation date) equal to the minimum amount of all required federal, state and local withholding taxes and all applicable social security and Medicare taxes with respect to the lapse of forfeiture conditions applicable to the vesting of performance shares or the exercise of options.

5. Outplacement Assistance and Financial Counseling . During the twelve-month period following the Termination Date, the Company shall reimburse the Executive for reasonable fees incurred for services rendered to the Executive by a professional outplacement organization selected by the Executive and acceptable to the Company to provide individual outplacement services, and Executive also shall be eligible to receive financial counseling services consistent with the terms and conditions applicable to active peer executives under Exelon's executive perquisite policy.

6. Long Term Incentive Awards . Subject to Executive's timely execution of (and not revoking) the Waiver and Release,

(a) each of Executive's options to purchase common stock of Exelon granted pursuant to the Exelon Corporation Long-Term Incentive Plan shall (i) to the extent exercisable on the Termination Date, remain exercisable for ninety days following the Termination Date (or until the option expiration date, if earlier), and (ii) to the extent not exercisable as of the Termination Date, be forfeited as of the Termination Date;

(b) Executive shall remain eligible to receive (i) full long-term [performance share / cash] awards under Exelon's long-term incentive program for the 201_-201_ and 201_-201_ performance cycles, the respective amounts (if any) of which shall be determined based on actual performance results for such respective periods, and all such awards shall be payable at the time or times such respective awards are paid to active executives; and

(c) the non-vested portion of Executive's [restricted stock unit / cash unit] awards granted on January __, 201_, January __, 201_ and January __, 201_ under Exelon's long term incentive program shall become fully vested as of the Termination Date.

All such awards payable in shares shall be subject to the Company's applicable resale restrictions, if any.

7. Supplemental Executive Retirement Benefits . The Executive shall be eligible for a retirement benefit under the Exelon applicable supplemental management retirement plan in which Executive is a participant (the " *SERP* ") in accordance with the terms and conditions thereof, except that in determining such benefit, the Executive shall, subject to the Executive's timely execution of the Waiver and Release, be credited with months additional service calculated as though he or she received the severance benefits specified in Section 3(a) as regular salary incentive pay over such period (and limited in its application to the amounts of such payments that exceed the compensation limitations applicable to qualified pension plans under the Code). Such benefit shall be paid as provided in Section 8(b).

8. Employee and Other Benefits .

(a) During the period commencing on the Termination Date and ending _____ months after the Termination Date (the " *Severance Period* ") and in satisfaction of COBRA continuation coverage during such period with respect to healthcare benefits, (i) the Executive (and his or her participating dependents) shall be eligible to participate in, and shall receive benefits under Exelon's welfare benefit plans (including medical, dental, vision and hearing) in which the Executive (and his or her eligible dependents) were participating immediately prior to the Termination Date, and (ii) the Executive shall be eligible to participate in the life insurance programs in which he or she was a participant immediately prior to the Termination Date, in each case on the same basis as if the Executive had remained actively employed during the Severance Period.

(b) Following the Severance Period, the Executive (and his or her eligible dependents) shall be eligible for continued health care coverage at Executive's sole expense for any remaining period required by COBRA.

(c) The Company shall pay to the Executive, in the time and manner specified in the terms and conditions of such plans and any distribution elections by the Executive in effect thereunder, his or her account balances (if any) under Exelon's deferred compensation plans, as adjusted by all applicable earnings and losses on such account balances.

(d) The Executive shall be entitled to purchase the computer furnished by the Company for his or her use, subject to removal of data and programs as determined by the Company. The Executive shall be responsible for payment of expenses incurred after the Termination Date with respect to the Company-owned cellular phone furnished for his or her use.

(e) If the Executive is entitled to any benefit under any employee benefit plan of the Company that is accrued and vested on the Termination Date and that is not expressly referred to in this Agreement, such benefit shall be provided to the Executive in accordance with the terms of such employee benefit plan.

(f) Notwithstanding Section 8(e) or anything else contained in this Agreement to the contrary, the Executive acknowledges and agrees that he or she is not and shall not be entitled to benefits under any other severance or change in control plan, program, agreement or arrangement, and that the benefits provided under this Agreement shall be the sole and exclusive benefits to which the Executive may become entitled upon his or her termination of employment. In the event the Executive dies prior to executing the Waiver and Release (as described in Section 9 below) attached hereto, neither he or she, his or her estate, nor any other person shall be entitled to any further compensation or benefits under this Agreement, unless and until the executor of the Executive's estate (and/or such other heirs or representatives as may be requested by the Company) executes upon Company request and does not revoke such a Waiver and Release.

9. Waiver and Release . Notwithstanding anything herein to the contrary, Executive's right to the payments and benefits under this Agreement shall be contingent upon (a) Executive having executed and delivered to the Company a waiver and general release provided by the Company (the " *Waiver and Release* ") not earlier than the Termination Date and not later than the date set forth in the release (but in no event more than _____days after the Termination Date) (the "Consideration Period"), (b) Executive not revoking such release in accordance with the terms of the release and (c) Executive not violating any of Executive's on-going obligations under this Agreement; provided, however, that the Company has the discretion to pay such benefits prior to receipt of the Waiver and Release and/or the expiration of the revocation period; provided further that if Executive does not execute and deliver the Waiver and Release to the Company prior to the expiration of the Consideration Period or if the Executive revokes the Waiver and Release in accordance with its terms, Executive shall pay to the Company within 10 days following the expiration of the Consideration Period or the date such release was revoked, a lump sum payment of all payments received by Executive to date hereunder.

10. Restrictive Covenants . The Executive acknowledges and agrees that he or she is bound by, and subject to, the Restrictive Covenants and the Waiver and Release. The Executive shall comply with, and observe, the Restrictive Covenants including, without limitation, the confidential information, non-solicitation and intellectual property provisions and related covenants contained therein, all of which are hereby incorporated by reference. In the event the Company determines that Executive has breached any of the Restrictive Covenants or the Waiver and Release or has engaged in conduct during his or her employment with the Company that would constitute ground for termination for Cause, benefits under this Agreement shall terminate immediately, and Executive shall reimburse Exelon for any benefits received.

11. Certain Tax Matters .

(a) If it is determined by Exelon's independent auditors that any severance payment, benefit or enhancement that is provided to the Executive pursuant to the terms of the this Agreement is or will become subject to any excise tax under section 4999 of the Internal Revenue Code of 1986, as amended, or any similar tax payable under any United States federal, state, local, foreign or other law (" *Excise Taxes* "), then such payment, benefit or enhancement shall be reduced to the largest amount which would not cause any such Excise Tax to by payable by the Executive and not cause a loss of the related income tax deduction by the Company.

(b) The parties intend this Agreement to comply with section 409A of the Code. In the event the timing of any payment or benefit under this Agreement would result in any tax or penalty under section 409A of the Code, the Company may reasonably adjust the timing of such payment or benefit if doing so will eliminate or materially reduce such tax or penalty and amend this Agreement accordingly. Executive acknowledges that Executive has been advised to consult Executive's personal tax advisor concerning this Agreement, and has not relied on the Company or Subsidiary for tax advice.

12. Non-disparagement . The Executive shall not (a) make any written or oral statement that brings the Company or any of its affiliates or the employees, officers, directors or agents of the Company or any of its affiliates into disrepute, or tarnishes any of their images or

reputations or (b) publish, comment upon or disseminate any statements suggesting or accusing the Company or any of its affiliates, employees, officers, directors or agents of any misconduct or unlawful behavior. The provisions of this Section 12 shall not apply to truthful testimony as a witness, compliance with other legal obligations, assertion of or defense against any claim of breach of this Agreement, or any activity that otherwise may be required by the lawful order of a court or agency of competent jurisdiction, and shall not require the Executive to make false statements or disclosures.

13. Publicity . Executive shall not issue or cause the publication of any press release or other announcement with respect to the terms or provisions of this Agreement, nor disclose the contents hereof to any third party (other than to members of his or her immediate family or to tax, financial and legal advisors), without obtaining the consent of Exelon, except where such release, announcement or disclosure shall be required by applicable law or administrative regulation or agency or other legal process.

14. Other Employment; Other Plans . The Executive shall not be obligated to seek other employment or take any other action by way of mitigation of the amounts payable to the Executive under any provision of this Agreement. The amounts payable hereunder shall not be reduced by any payments received by the Executive from any other employer; *provided* , *however* , that any continued welfare benefits provided for by Section 8(a) shall not duplicate any benefits that are provided to the Executive and his or her family by such other employer and shall be secondary to any coverage provided by Medicare.

15. Cooperation by the Executive . During the Severance Period, the Executive shall (a) be reasonably available to the Company to respond to requests by them for information pertaining to or relating to matters which may be within the knowledge of the Executive and (b) cooperate with the Company in connection with any existing or future litigation or other proceedings brought by or against the Company, its subsidiaries or affiliates, to the extent Exelon reasonably deems the Executive's cooperation necessary, including truthful testimony in any related proceeding.

16. Successors; Binding Agreement . This Agreement shall inure to the benefit of and binding upon the Company and its successors, and by the Executive, his or her spouse, personal or legal representatives, executors, administrators and heirs. This Agreement, being personal, may not be assigned by Executive.

17. Governing Law; Validity . This Agreement shall be interpreted, construed and enforced in accordance with the terms of the Exelon Corporation Senior Management Severance Plan, and the applicable provisions of the Employee Retirement Income Security Act of 1974, as amended, and section 409A of the Code.

18. Entire Agreement . This Agreement and the Waiver and Release constitute the entire agreement and understanding between the parties with respect to the subject matter hereof and supersede and preempt any other understandings, agreements or representations by or between the parties, written or oral, which may have related in any manner to the subject matter hereof. Executive acknowledges that the Company has made no representations regarding the tax consequences of payments under this Agreement and has had the opportunity to consult Executive's tax advisor.

19. Counterparts . This Agreement may be executed in two counterparts, each of which shall be deemed to be an original and both of which together shall constitute one and the same instrument.

20. Miscellaneous . No provision of this Agreement may be modified or waived unless such modification or waiver is agreed to in writing and executed by the Executive and by a duly authorized officer of the Company. No waiver by either party hereto at any time of any breach by the other party hereto of, or compliance with, any condition or provision of this Agreement to be performed by such other party shall be deemed a waiver of similar or dissimilar provisions or conditions at the same or at any prior or subsequent time. Failure by the Executive or the Company to insist upon strict compliance with any provision of this Agreement or to assert any right which the Executive or the Company may have hereunder shall not be deemed to be a waiver of such provision or right or any other provision or right of this Agreement.

21. Beneficiary . If the Executive dies prior to receiving all of the amounts payable hereunder (other than amounts payable under any plan referenced in Section 8(d), which shall be governed by any beneficiary designation in effect thereunder) but after executing the Waiver and Release, such amounts shall be paid, except as may be otherwise expressly provided herein or in the applicable plans, to the beneficiary (" *Beneficiary* ") designated with respect to this Agreement by the Executive in writing to the Vice President, Corporate Compensation of the Company during his or her lifetime, which the Executive may change from time to time by new designation filed in like manner without the consent of any Beneficiary; or if no such Beneficiary is designated, to his or her surviving spouse, and if there be none, to his or her estate.

22. Nonalienation of Benefits . Benefits payable under this Agreement shall not be subject in any manner to anticipation, alienation, sale, transfer, assignment, pledge, encumbrance, charge, prior to actually being received by the Executive, and any such attempt to dispose of any right to benefits payable hereunder shall be void.

23. Severability . If all or any part of this Agreement is declared by any court or governmental authority to be unlawful or invalid, such unlawfulness or invalidity shall not serve to invalidate any portion of this Agreement not declared to be unlawful or invalid, except that in the event a determination is made that the Restrictive Covenants as applied to the Executive are invalid or unenforceable in whole or in part, then this Agreement shall be void and the Company shall have no obligation to provide benefits hereunder. Any paragraph or part of a paragraph so declared to be unlawful or invalid shall, if possible, be construed in a manner which will give effect to the terms of such paragraph or part of a paragraph to the fullest extent possible while remaining lawful and valid.

24. Communications . Nothing in this Agreement or the Waiver and Release shall be construed to prohibit or limit the Executive from filing a charge with, or reporting possible violations of law or regulation to any governmental agency or entity, including but not limited to the National Labor Relations Board, Nuclear Regulatory Commission, U.S. Equal Opportunity Commission, the Department of Labor, the Department of Justice, the Securities Exchange

Commission, the Congress, and any agency Inspector General, or making other disclosures that are protected under the whistleblower provisions of applicable law or regulation, or taking any other action protected under section 211 of the Energy Reorganization Act. The Executive does not need the prior authorization of the Company to make any such charges, reports or disclosures, and is not required to notify the Company that Executive has made such charges reports or disclosures, and no such report or disclosure shall be considered a violation of Section 12 of this Agreement or the Waiver and Release. In addition, neither this Agreement nor the Waiver and Release limits the Executive's ability to receive a monetary award from a government-administered whistleblower award program for providing any such reports or disclosures directly to a governmental agency. Executive acknowledges, however, that the Waiver and Release requires Executive to specifically waive all rights to recover any monetary damages from the Company, including but not limited to lost wages and benefits, lost pay, damages for emotional distress, punitive damages, reinstatement, and attorneys' fees and costs.

25. Sections . Except where otherwise indicated by the context, any reference to a "Section" shall be to a Section of this Agreement.

IN WITNESS WHEREOF, Exelon and Subsidiary have caused this Agreement to be executed by their duly authorized officers and the Executive has executed this Agreement as of the day and year first above written.

EXELON CORPORATION

By: _____
Vice President, Corporate Compensation

SUBSIDIARY

By: _____
Vice President, Human Resources

_____
EXECUTIVE

WAIVER AND RELEASE
UNDER
CONFIDENTIAL SEPARATION AGREEMENT

In consideration for the Executive's receiving severance benefits under the Separation Agreement (as defined below), _____(the "Executive") hereby agrees as follows:

1. Release. Except with respect to the Company's obligations under the Confidential Separation Agreement by and between Exelon Corporation, _____, (collectively, the " *Company* ") and the Executive dated as of _____(the " *Separation Agreement* "), the Executive, on behalf of Executive and his or her heirs, executors, assigns, agents, legal representatives and personal representatives, hereby releases, acquits and forever discharges the Company, its agents, subsidiaries, affiliates, and their respective officers, directors, agents, servants, employees, attorneys, shareholders, successors, assigns and affiliates, of and from any and all claims, liabilities, demands, causes of action, costs, expenses, attorneys fees, damages, indemnities and obligations of every kind and nature, in law, equity, or otherwise, known and unknown, foreseen or unforeseen, disclosed and undisclosed, suspected and unsuspected, arising out of or in any way related to agreements, events, acts or conduct at any time prior to the day of execution of this Waiver and Release, including but not limited to any and all such claims and demands directly or indirectly arising out of or in any way connected with the Executive's employment or other service with the Company, or any of its Subsidiaries or affiliates; the Executive's termination of employment and other service with the Company or any of its subsidiaries or affiliates; claims or demands related to salary, bonuses, commissions, stock, stock options, restricted stock or any other ownership interests in the Company or any of its subsidiaries and affiliates, vacation pay, fringe benefits, expense reimbursements, sabbatical benefits, severance, change in control or other separation benefits, or any other form of compensation or equity; and claims pursuant to any federal, state, local law, statute, ordinance, common law or other cause of action including but not limited to, the federal Civil Rights Act of 1964, as amended; the federal Age Discrimination in Employment Act of 1967, as amended; the federal Americans with Disabilities Act of 1990; the Employee Retirement Income Security Act of 1974, as amended, tort law; contract law; wrongful discharge; discrimination; fraud; defamation; harassment; emotional distress; or breach of the covenant of good faith and fair dealing. This Waiver and Release does not apply to the payment of any benefits to which the Executive may be entitled under a Company-sponsored tax qualified retirement or savings plan or Executives's entitlement to indemnification with respect to his service as an officer, director, employee or agent of the Company in accordance with Article VII of the Exelon Corporation Amended and Restated Bylaws.

2. No Inducement . The Executive agrees that no promise or inducement to enter into this Waiver or Release has been offered or made except as set forth in this Waiver and Release and the Separation Agreement, that the Executive is entering into this Waiver and Release without any threat or coercion and without reliance on any statement or representation made on behalf of the Company or any of its subsidiaries or affiliates, or by any person employed by or representing the Company or any of its subsidiaries or affiliates, except for the written provisions and promises contained in this Waiver and Release and the Separation Agreement.

3. **Advice of Counsel; Time to Consider; Revocation . The Executive acknowledges the following:**

(a) The Executive has read this Waiver and Release, and understands its legal and binding effect, including that by signing and not revoking this Waiver and Release the Executive waives and releases any and all claims under the Age Discrimination in Employment Act of 1967, as amended, including but not limited to the Older Workers Benefits Protection Act. The Executive is acting voluntarily and of the Executive's own free will in executing this Waiver and Release.

(b) The Executive has been advised to seek and has had the opportunity to seek legal counsel in connection with this Waiver and Release.

(c) The Executive was given at least twenty-one (21) days to consider the terms of this Waiver and Release before signing it.

(d) At the time Executive was given this Waiver and Release, Executive was informed that his or her termination was not part of a group separation.

The Executive understands that, if the Executive signs the Waiver and Release, the Executive may revoke it within seven (7) days after signing it, provided that Executive will not receive any severance benefits under the Separation Agreement. The Executive understands that this Waiver and Release will not be effective until after the seven-day period has expired and no consideration will be due the Executive.

4. Severability . If all or any part of this Waiver and Release is declared by any court or governmental authority to be unlawful or invalid, such unlawfulness or invalidity shall not invalidate any other portion of this Waiver and Release. Any Section or a part of a Section declared to be unlawful or invalid shall, if possible, be construed in a manner which will give effect to the terms of the Section to the fullest extent possible while remaining lawful and valid.

5. Amendment . This Waiver and Release shall not be altered, amended, or modified except by written instrument executed by the Company and the Executive. A waiver of any portion of this Waiver and Release shall not be deemed a waiver of any other portion of this Waiver and Release.

6. Applicable Law . The provisions of this Waiver and Release shall be interpreted and construed in accordance with the laws of the State of Illinois without regard to its choice of law principles.

IN WITNESS WHEREOF, the Executive has executed this Waiver and Release as of the date specified below.

EXECUTIVE

DATE: _____

Exelon Corporation
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2012	2013	2014	2015	2016
Pre-tax income from continuing operations	1,798	2,773	2,486	3,330	1,989
Plus: Loss (income) from equity investees	91	(10)	20	—	—
Less: Capitalized interest	(75)	(67)	(79)	(99)	(142)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	1,814	2,696	2,427	3,231	1,847
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	1,021	1,436	1,110	1,107	1,651
Interest component of rental expense (a)	310	269	288	300	259
Total fixed charges	1,331	1,705	1,398	1,407	1,910
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	3,145	4,401	3,825	4,638	3,757
Ratio of earnings to fixed charges	2.4	2.6	2.7	3.3	2.0

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exelon Corporation
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
	2012	2013	2014	2015	2016
Pre-tax income from continuing operations	1,798	2,773	2,486	3,330	1,989
Plus: Loss (income) from equity investees	91	(10)	20	—	—
Less: Capitalized interest	(75)	(67)	(79)	(99)	(142)
Preference security dividend requirements	(26)	(32)	(18)	(19)	(13)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	1,788	2,664	2,409	3,212	1,834
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	1,021	1,436	1,110	1,107	1,651
Interest component of rental expense (a)	310	269	288	300	259
Preference security dividend requirements of consolidated subsidiaries	26	32	18	19	13
Total fixed charges	1,357	1,737	1,416	1,426	1,923
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	3,145	4,401	3,825	4,638	3,757
Ratio of earnings to fixed charges and preferred stock dividends	2.3	2.5	2.7	3.3	2.0

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exelon Generation Company, LLC
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2012	2013	2014	2015	2016
Pre-tax income from continuing operations	1,058	1,675	1,226	1,850	873
Plus: Loss (income) from equity investees	91	(10)	20	—	—
Less: Capitalized interest	(67)	(54)	(63)	(79)	(107)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	1,082	1,611	1,183	1,771	766
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	402	445	396	427	454
Interest component of rental expense (a)	291	248	269	284	222
Total fixed charges	693	693	665	711	676
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	1,775	2,304	1,848	2,482	1,442
Ratio of earnings to combined fixed charges	2.6	3.3	2.8	3.5	2.1

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Commonwealth Edison Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2012	**2013**	**2014**	**2015**	**2016**
Pre-tax income from continuing operations	618	401	676	706	679
Less:Capitalized interest	(3)	(5)	(2)	(4)	(8)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	615	396	674	702	671
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	297	575	311	331	465
Interest component of rental expense (a)	6	5	5	4	5
Total fixed charges	303	580	316	335	470
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest plus fixed charges	918	976	990	1,037	1,141
Ratio of earnings to fixed charges	3.0	1.7	3.1	3.1	2.4

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

PECO Energy Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2012	2013	2014	2015	2016
Pre-tax income from continuing operations	508	557	466	521	587
Less: Capitalized interest	(2)	(2)	(2)	(2)	(3)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	506	555	464	519	584
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	122	114	112	114	125
Interest component of rental expense (a)	9	7	5	3	2
Total fixed charges	131	121	117	117	127
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	637	676	581	636	711
Ratio of earnings to combined fixed charges	4.9	5.6	5.0	5.4	5.6

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

PECO Energy Company
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
	2012	2013	2014	2015	2016
Pre-tax income from continuing operations	508	557	466	521	587
Less: Capitalized interest	(2)	(2)	(2)	(2)	(3)
Preference security dividend requirements	(5)	(10)	—	—	—
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	501	545	464	519	584
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	122	114	112	114	125
Interest component of rental expense (a)	9	7	5	3	2
Preference security dividend requirements	5	10	—	—	—
Total fixed charges	136	131	117	117	127
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	637	676	581	636	711
Ratio of earnings to fixed charges and preferred stock dividends	4.7	5.2	5.0	5.4	5.6

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

BGE
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2012	2013	2014	2015	2016
Pre-tax income from continuing operations	11	344	351	477	468
Less: Capitalized interest	(5)	(6)	(12)	(14)	(11)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	6	338	339	463	457
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	149	127	118	113	115
Interest component of rental expense (a)	4	4	4	11	7
Total fixed charges	153	131	122	124	122
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	159	469	461	587	579
Ratio of earnings to fixed charges	1.0	3.6	3.8	4.7	4.7

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

BGE
Ratio of Earnings to Fixed Charges and Preference Stock Dividends

	Years Ended December 31,				
	2012	2013	2014	2015	2016
Pre-tax income from continuing operations	11	344	351	477	468
Less: Capitalized interest	(5)	(6)	(12)	(14)	(11)
Preference security dividend requirements	(20)	(21)	(22)	(22)	(13)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	(14)	317	317	441	444
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	149	127	118	113	115
Interest component of rental expense (a)	4	4	4	11	7
Preference security dividend requirements	20	21	22	22	13
Total fixed charges	173	152	144	146	135
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	159	469	461	587	579
Ratio of earnings to fixed charges and preferred stock dividends	0.9(b)	3.1	3.2	4.0	4.3

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.
(b) The ratio coverage was less than 1:1. The registrant must generate additional earnings of $14 million to achieve a coverage ratio of 1:1.

Pepco Holdings LLC and Subsidiary Companies
Ratio of Earnings to Fixed Charges

	Predecessor					*Successor*
	Years Ended December 31,					
	2012	**2013**	**2014**	**2015**	**January 1, 2016 to March 23, 2016**	**March 24, 2016 to December 31, 2016**
Pre-tax income from continuing operations	344	304	380	481	36	(58)
Plus: (Income) loss from equity investees	(1)	(2)	—	—	—	—
Less: Capitalized interest	(3)	(2)	(3)	(2)	(3)	(12)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	340	300	377	479	33	(70)
Fixed Charges:						
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	265	279	276	288	69	210
Interest component of rental expense (a)	21	22	24	24	4	16
Total fixed charges	286	301	300	312	73	226
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	626	601	677	791	106	156
Ratio of earnings to fixed charges	2.2	2.0	2.3	2.5	1.5	0.7(b)

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.
(b) The ratio coverage was less than 1:1. The registrant must generate additional earnings of $70 million to achieve a coverage ratio of 1:1.

Potomac Electric Power Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2012	**2013**	**2014**	**2015**	**2016**
Pre-tax income from continuing operations	193	235	264	289	83
Less: Capitalized interest	(2)	(1)	(2)	(1)	(10)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	191	234	262	288	73
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	106	114	121	130	137
Interest component of rental expense (a)	7	7	7	7	3
Total fixed charges	113	121	128	137	140
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	304	355	390	425	213
Ratio of earnings to fixed charges	2.7	2.9	3.0	3.1	1.5

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Delmarva Power & Light Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2012	2013	2014	2015	2016
Pre-tax income from continuing operations	118	146	169	125	13
Less: Capitalized interest	—	—	—	—	(2)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	118	146	169	125	11
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	49	52	49	50	51
Interest component of rental expense (a)	3	3	4	4	5
Total fixed charges	52	55	53	54	56
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	170	201	222	179	67
Ratio of earnings to fixed charges	3.3	3.7	4.2	3.3	1.2

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Atlantic City Electric Company and Subsidiary Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2012	**2013**	**2014**	**2015**	**2016**
Pre-tax income from continuing operations	52	78	76	73	(46)
Less: Capitalized interest	—	—	—	—	(3)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	52	78	76	73	(49)
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	71	68	64	65	64
Interest component of rental expense (a)	4	4	4	4	4
Total fixed charges	75	72	68	69	68
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	127	150	144	142	19
Ratio of earnings to fixed charges	1.7	2.1	2.1	2.1	0.3(b)

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.
(b) The ratio coverage was less than 1:1. The registrant must generate additional earnings of $49 million to achieve a coverage ratio of 1:1.

Exelon Corporation (50% and Greater)
12/31/2016

Name	Jurisdiction
2014 ESA HoldCo, LLC	Delaware
2014 ESA Project Company, LLC	Delaware
2015 ESA Holdco, LLC	Delaware
2015 ESA Investco, LLC	Delaware
2015 ESA Project Company, LLC	Delaware
A/C Fuels Company	Pennsylvania
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Albany Green Energy, LLC	Georgia
American Energy Corporation	Delaware
AMP Funding, L.L.C.	Delaware
Annova LNG Brownsville A, LLC	Delaware
Annova LNG Brownsville B, LLC	Delaware
Annova LNG Brownsville C, LLC	Delaware
Annova LNG Common Infrastructure, LLC	Delaware
Annova LNG, LLC	Delaware
Annova LNG, LLC, Series A Units	Delaware
Annova LNG, LLC, Series B Units	Delaware
Annova LNG, LLC, Series C Units	Delaware
Annova LNG, LLC, Series Z Units	Delaware
APS Constellation, LLC	Delaware
ATE Investment, Inc.	Delaware
Atlantic City Electric Company	New Jersey
Atlantic City Electric Transition Funding LLC	Delaware
Atlantic Generation, Inc.	New Jersey
Atlantic Southern Properties, Inc.	New Jersey
ATNP Finance Company	Delaware
AV Solar Ranch 1, LLC	Delaware
Baltimore Gas and Electric Company	Maryland
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
Bethlehem Renewable Energy, LLC	Delaware
BGE Capital Trust II	Delaware
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Blue Ridge Renewable Energy, LLC	Delaware
Bluestem Wind Energy Holdings, LLC	Delaware
Bluestem Wind Energy Member Holdings, LLC	Delaware
Bluestem Wind Energy Member, LLC	Delaware
Bluestem Wind Energy, LLC	Delaware
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
California PV Energy 2, LLC	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CD Panther I, Inc.	Maryland

CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Nuclear, LLC	Delaware
CER Generation, LLC	Delaware
CEU Arkoma West, LLC	Delaware
CEU CHC, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU Development, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Niobrara, LLC	Delaware
CEU Offshore I, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU Trenton, LLC	Delaware
CEU W&D, LLC	Delaware
Chesapeake HVAC, Inc.	Delaware
Chester Transmission Construction Canada, Inc.	Canada
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton Battery Utility, LLC	Delaware
Clinton NQF, LLC	Nevada
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
CoLa Resources LLC	Delaware
Colorado Bend I Power, LLC	Delaware
Colorado Bend II Power, LLC	Delaware
Colorado Bend Services, LLC	Delaware
ComEd Financing III	Delaware
Commonwealth Edison Company	Illinois
Commonwealth Edison Company of Indiana, Inc.	Indiana
Compass Energy Gas Services, LLC	Virginia
Compass Energy Services, Inc.	Virginia
Conectiv Communications, Inc.	Delaware
Conectiv Energy Supply, Inc.	Delaware
Conectiv North East, LLC	Delaware
Conectiv Properties and Investments, Inc.	Delaware
Conectiv Services, Inc.	Delaware
Conectiv Solutions LLC	Delaware
Conectiv Thermal Systems, Inc.	Delaware

Conectiv, LLC	Delaware
Constellation DCO Albany Power Holdings, LLC	Delaware
Constellation EG, LLC	Delaware
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Gas Choice, LLC	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Partners Holdings, LLC	Delaware
Constellation Energy Power Choice, LLC	Delaware
Constellation Energy Projects & Services Group Advisors, LLC	Delaware
Constellation Energy Projects and Services Canada, Inc.	Alberta
Constellation Energy Resources, LLC	Delaware
Constellation Energy Services—Natural Gas, LLC	Delaware
Constellation Energy Services of New York, Inc.	New York
Constellation Energy Services, Inc.	Wisconsin
Constellation Energy Upstream Holdings, LLC	Delaware
Constellation ESCO, LLC	Delaware
Constellation Holdings, LLC	Maryland
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy—Gas Division, LLC	Kentucky
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Power Source Generation, LLC	Maryland
Constellation Power, Inc.	Maryland
Constellation Solar Arizona 2, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Georgia 2, LLC	Delaware
Constellation Solar Georgia, LLC	Georgia
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland MC, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CR Clearing, LLC	Missouri

Criterion Power Partners, LLC	Delaware
Delaware Operating Services Company, LLC	Delaware
Delmarva Power & Light Company	Delaware & Virginia
Denver Airport Solar, LLC	Delaware
Distributed Generation Partners, LLC	Delaware
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
Eastern Landfill Gas, LLC	Delaware
Energy Performance Services, Inc.	Pennsylvania
ETT Canada, Inc.	New Brunswick
Ewington Energy Systems LLC	Minnesota
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Business Services Company, LLC	Delaware
Exelon Energy Delivery Company, LLC	Delaware
Exelon Enterprises Company, LLC	Pennsylvania
Exelon Framingham, LLC	Delaware
Exelon Fulton, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, LLC	Pennsylvania
Exelon Generation Limited	United Kingdom
Exelon Mechanical, LLC	Delaware
Exelon Microgrid, LLC	Delaware
Exelon New Boston, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon Solar Chicago LLC	Delaware
Exelon Transmission Company, LLC	Delaware
Exelon West Medway II, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
Ex-FM, Inc.	New York
Ex-FME, Inc.	Delaware
ExGen Energy, S. de R.L. de C.V.	Mexico
ExGen Renewables Holdings II, LLC	Delaware
ExGen Renewables Holdings, LLC	Delaware
ExGen Renewables I Holding, LLC	Delaware
ExGen Renewables I, LLC	Delaware
ExGen Renewables II, LLC	Delaware
ExGen Renewables IV Holding, LLC	Delaware

ExGen Renewables IV, LLC	Delaware
ExGen Renewables Partners, LLC	Delaware
ExGen Texas II Power Holdings, LLC	Delaware
ExGen Texas II Power, LLC	Delaware
ExGen Texas Power Holdings, LLC	Delaware
ExGen Texas Power Services, LLC	Delaware
ExGen Texas Power, LLC	Delaware
ExGen Ventures International Holdings II Limited	United Kingdom
ExGen Ventures International Holdings Limited	United Kingdom
ExTel Corporation, LLC	Delaware
F & M Holdings Company, L.L.C.	Delaware
Fair Wind Power Partners, LLC	Delaware
Fauquier Landfill Gas, L.L.C.	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
Friendly Skies, Inc.	Virgin Islands, U.S.
Grande Prairie Generation, Inc.	Alberta
Greensburg Wind Farm, LLC	Delaware
Handley Power, LLC	Delaware
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
Lake Houston Power, LLC	Delaware
LaPorte Power, LLC	Delaware
Las Vegas District Energy, LLC	Delaware
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Millennium Account Services, LLC	Delaware
Minergy LLC	Wisconsin
Mohave Sunrise Solar I, LLC	Arizona
Mountain Creek Power, LLC	Delaware
Mountain Top Wind Power, LLC	Maryland
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Northwind Thermal Technologies Canada Inc.	New Brunswick
Oregon Trail Windfarm, LLC	Oregon
Outback Solar, LLC	Oregon
Oyster Creek NQF, LLC	Nevada

Pacific Canyon Windfarm, LLC	Oregon
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
PCI—BT Investing, L.L.C.	Delaware
PCI Air Management Corporation	Nevada
PCI Air Management Partners, L.L.C.	Delaware
PCI Energy Corporation	Delaware
PCI Engine Trading Ltd.	Bermuda
PCI Ever, Inc.	Delaware
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Company	Pennsylvania
PECO Wireless, LLC	Delaware
Pegasus Power Company, Inc.	California
Pepco Building Services Inc.	Delaware
Pepco Energy Cogeneration LLC	Delaware
Pepco Energy Services, Inc.	Delaware
Pepco Energy Solutions LLC	Delaware
Pepco Government Services LLC	Delaware
Pepco Holdings LLC	Delaware
PH Holdco LLC	Delaware
PHI Service Company	Delaware
Pinedale Energy, LLC	Colorado
POM Holdings, Inc.	Delaware
Potomac Capital Investment Corporation	Delaware
Potomac Delaware Leasing Corporation	Delaware
Potomac Electric Power Company	District of Columbia & Virginia
Potomac Leasing Associates, L.P.	Delaware
Potomac Power Resources, LLC	Delaware
Prairie Wind Power LLC	Minnesota
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Ramp Investments, L.L.C.	Delaware
Renewable Power Generation Holdings, LLC	Delaware
Renewable Power Generation, LLC	Delaware
Residential Solar Holding, LLC	Delaware
Residential Solar II, LLC	Delaware
RF HoldCo LLC	Delaware
RITELine Illinois, LLC	Illinois
RITELine Indiana, LLC	Indiana
RITELine Transmission Development, LLC	Delaware
Rolling Hills Landfill Gas, LLC	Delaware
RSB BondCo LLC	Delaware
Sacramento PV Energy, LLC	Delaware
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Sand Ranch Windfarm, LLC	Oregon
Scherer Holdings 1, LLC	Delaware
Scherer Holdings 2, LLC	Delaware
Scherer Holdings 3, LLC	Delaware
Sendero Wind Energy, LLC	Delaware
Severn Construction Services, L.L.C.	Delaware

Shooting Star Wind Project, LLC	Delaware
Sky Valley, LLC	Delaware
SolGen Holding, LLC	Delaware
SolGen, LLC	Delaware
Sugar Beet Wind, LLC	Delaware
Sunnyside Cogeneration Associates	Utah
Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Sunnyside Properties, LLC	Utah
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware
TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
UII, LLC	Illinois
Vineland Cogeneration Limited Partnership	Delaware
Vineland General, Inc.	Delaware
Vineland Ltd., Inc.	Delaware
Volta Energy Technologies, LLC	Delaware
W&D Gas Partners, LLC	Delaware
W.A. Chester Corporation	Delaware
W.A. Chester, L.L.C.	Delaware
Wagon Trail, LLC	Oregon
Wansley Holdings 1, LLC	Delaware
Wansley Holdings 2, LLC	Delaware
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Western Path Development, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wibaux Wind, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Wolf Hollow I Power, LLC	Delaware
Wolf Hollow II Power, LLC	Delaware
Wolf Hollow Services, LLC	Delaware
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Exelon Generation Company, LLC
(50% and greater)
12/31/2016

Name	Jurisdiction
2014 ESA HoldCo, LLC	Delaware
2014 ESA Project Company, LLC	Delaware
2015 ESA Holdco, LLC	Delaware
2015 ESA Investco, LLC	Delaware
2015 ESA Project Company, LLC	Delaware
A/C Fuels Company	Pennsylvania
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Albany Green Energy, LLC	Georgia
Annova LNG Brownsville A, LLC	Delaware
Annova LNG Brownsville B, LLC	Delaware
Annova LNG Brownsville C, LLC	Delaware
Annova LNG Common Infrastructure, LLC	Delaware
Annova LNG, LLC	Delaware
Annova LNG, LLC, Series A Units	Delaware
Annova LNG, LLC, Series B Units	Delaware
Annova LNG, LLC, Series C Units	Delaware
Annova LNG, LLC, Series Z Units	Delaware
APS Constellation, LLC	Delaware
ATE Investment, Inc.	Delaware
Atlantic Generation, Inc.	New Jersey
AV Solar Ranch 1, LLC	Delaware
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
Bethlehem Renewable Energy, LLC	Delaware
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Blue Ridge Renewable Energy, LLC	Delaware
Bluestem Wind Energy Holdings, LLC	Delaware
Bluestem Wind Energy Member Holdings, LLC	Delaware
Bluestem Wind Energy Member, LLC	Delaware
Bluestem Wind Energy, LLC	Delaware
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
California PV Energy 2, LLC	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Nuclear, LLC	Delaware

CER Generation, LLC	Delaware
CEU Arkoma West, LLC	Delaware
CEU CHC, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU Development, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Niobrara, LLC	Delaware
CEU Offshore I, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU Trenton, LLC	Delaware
CEU W&D, LLC	Delaware
Chesapeake HVAC, Inc.	Delaware
Chester Transmission Construction Canada, Inc.	Canada
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton Battery Utility, LLC	Delaware
Clinton NQF, LLC	Nevada
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
CoLa Resources LLC	Delaware
Colorado Bend I Power, LLC	Delaware
Colorado Bend II Power, LLC	Delaware
Colorado Bend Services, LLC	Delaware
Compass Energy Gas Services, LLC	Virginia
Compass Energy Services, Inc.	Virginia
Conectiv Energy Supply, Inc.	Delaware
Conectiv North East, LLC	Delaware
Conectiv Thermal Systems, Inc.	Delaware
Conectiv, LLC	Delaware
Constellation DCO Albany Power Holdings, LLC	Delaware
Constellation EG, LLC	Delaware
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Gas Choice, LLC	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Partners Holdings, LLC	Delaware
Constellation Energy Power Choice, LLC	Delaware
Constellation Energy Projects & Services Group Advisors, LLC	Delaware
Constellation Energy Projects and Services Canada, Inc.	Alberta
Constellation Energy Resources, LLC	Delaware

Constellation Energy Services—Natural Gas, LLC	Delaware
Constellation Energy Services of New York, Inc.	New York
Constellation Energy Services, Inc.	Wisconsin
Constellation Energy Upstream Holdings, LLC	Delaware
Constellation ESCO, LLC	Delaware
Constellation Holdings, LLC	Maryland
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy—Gas Division, LLC	Kentucky
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Power Source Generation, LLC	Maryland
Constellation Power, Inc.	Maryland
Constellation Solar Arizona 2, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Georgia 2, LLC	Delaware
Constellation Solar Georgia, LLC	Georgia
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland MC, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CR Clearing, LLC	Missouri
Criterion Power Partners, LLC	Delaware
Delaware Operating Services Company, LLC	Delaware
Denver Airport Solar, LLC	Delaware
Distributed Generation Partners, LLC	Delaware
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
Eastern Landfill Gas, LLC	Delaware
Energy Performance Services, Inc.	Pennsylvania
Ewington Energy Systems LLC	Minnesota
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Fulton, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania

Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, LLC	Pennsylvania
Exelon Generation Limited	United Kingdom
Exelon New Boston, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon Solar Chicago LLC	Delaware
Exelon West Medway II, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
ExGen Energy, S. de R.L. de C.V.	Mexico
ExGen Renewables Holdings II, LLC	Delaware
ExGen Renewables Holdings, LLC	Delaware
ExGen Renewables I Holding, LLC	Delaware
ExGen Renewables I, LLC	Delaware
ExGen Renewables II, LLC	Delaware
ExGen Renewables IV Holding, LLC	Delaware
ExGen Renewables IV, LLC	Delaware
ExGen Renewables Partners, LLC	Delaware
ExGen Texas II Power Holdings, LLC	Delaware
ExGen Texas II Power, LLC	Delaware
ExGen Texas Power Holdings, LLC	Delaware
ExGen Texas Power Services, LLC	Delaware
ExGen Texas Power, LLC	Delaware
ExGen Ventures International Holdings II Limited	United Kingdom
ExGen Ventures International Holdings Limited	United Kingdom
Fair Wind Power Partners, LLC	Delaware
Fauquier Landfill Gas, L.L.C.	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
Grande Prairie Generation, Inc.	Alberta
Greensburg Wind Farm, LLC	Delaware
Handley Power, LLC	Delaware
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho

K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
Lake Houston Power, LLC	Delaware
LaPorte Power, LLC	Delaware
Las Vegas District Energy, LLC	Delaware
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Minergy LLC	Wisconsin
Mohave Sunrise Solar I, LLC	Arizona
Mountain Creek Power, LLC	Delaware
Mountain Top Wind Power, LLC	Maryland
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Oregon Trail Windfarm, LLC	Oregon
Outback Solar, LLC	Oregon
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada
Pegasus Power Company, Inc.	California
Pepco Building Services Inc.	Delaware
Pepco Energy Cogeneration LLC	Delaware
Pepco Energy Services, Inc.	Delaware
Pepco Energy Solutions LLC	Delaware
Pepco Government Services LLC	Delaware
Pinedale Energy, LLC	Colorado
Potomac Capital Investment Corporation	Delaware
Potomac Power Resources, LLC	Delaware
Prairie Wind Power LLC	Minnesota
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Renewable Power Generation Holdings, LLC	Delaware
Renewable Power Generation, LLC	Delaware
Residential Solar Holding, LLC	Delaware
Residential Solar II, LLC	Delaware
Rolling Hills Landfill Gas, LLC	Delaware
Sacramento PV Energy, LLC	Delaware
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Sand Ranch Windfarm, LLC	Oregon
Sendero Wind Energy, LLC	Delaware
Severn Construction Services, L.L.C.	Delaware
Shooting Star Wind Project, LLC	Delaware

Sky Valley, LLC	Delaware
SolGen Holding, LLC	Delaware
SolGen, LLC	Delaware
Sugar Beet Wind, LLC	Delaware
Sunnyside Cogeneration Associates	Utah
Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Sunnyside Properties, LLC	Utah
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware
TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
Vineland Cogeneration Limited Partnership	Delaware
Vineland General, Inc.	Delaware
Vineland Ltd., Inc.	Delaware
Volta Energy Technologies, LLC	Delaware
W&D Gas Partners, LLC	Delaware
W.A. Chester Corporation	Delaware
W.A. Chester, L.L.C.	Delaware
Wagon Trail, LLC	Oregon
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wibaux Wind, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Wolf Hollow I Power, LLC	Delaware
Wolf Hollow II Power, LLC	Delaware
Wolf Hollow Services, LLC	Delaware
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Commonwealth Edison Company
12/31/2016

Subsidiary	**Jurisdiction**
ComEd Financing III	Delaware
Commonwealth Edison Company of Indiana, Inc.	Indiana
RITELine Illinois, LLC	Illinois

PECO Energy Company
12/31/2016

Subsidiary	**Jurisdiction**
ATNP Finance Company	Delaware
ExTel Corporation, LLC	Delaware
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Wireless, LLC	Delaware

Baltimore Gas and Electric Company
12/31/2016

Subsidiary	**Jurisdiction**
BGE Capital Trust II	Delaware
RSB BondCo LLC	Delaware

Pepco Holdings LLC
12/31/2016

Subsidiary	Jurisdiction
Atlantic City Electric Company	New Jersey
Atlantic City Electric Transition Funding LLC	Delaware
Delmarva Power & Light Company	Delaware & Virginia
Millennium Account Services, LLC	Delaware
PHI Service Company	Delaware
Potomac Electric Power Company	District of Columbia & Virginia
POM Holdings, Inc.	Delaware

Potomac Electric Power Company
12/31/2016

Subsidiary	**Jurisdiction**
POM Holdings, Inc.	Delaware

Delmarva Power & Light Company
12/31/2016

Subsidiary	**Jurisdiction**
N/A	

Atlantic City Electric Company
12/31/2016

Subsidiary	Jurisdiction
Atlantic City Electric Transition Funding LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-213383), Form S-4 (No. 333-209209) and on Form S-8 (No. 333-215114, No.333-189849, No.333-175162, No.333-127377, No.333-37082, No.333-49780 and No. 333-61390) of Exelon Corporation of our report dated February 13, 2017 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2017

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-213383-06) and Form S-4 (No. 333-184712) of Exelon Generation Company, LLC of our report dated February 13, 2017 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2017

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-213383-05) of Commonwealth Edison Company of our report dated February 13, 2017 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 13, 2017

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-213383-04) of PECO Energy Company of our report dated February 13, 2017 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 13, 2017

Exhibit 23.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-213383-03) of Baltimore Gas and Electric Company of our report dated February 13, 2017 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 13, 2017

Exhibit 23.6

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-213383-02) of Potomac Electric Power Company of our report dated February 13, 2017, relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 13, 2017

Exhibit 23.7

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-213383-01) of Delmarva Power & Light Company of our report dated February 13, 2017, relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 13, 2017

Exhibit 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anthony K. Anderson** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ANTHONY K. ANDERSON

Anthony K. Anderson

DATE: January 31, 2017

Exhibit 24.2

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ANN C. BERZIN

Ann C. Berzin

DATE: January 31, 2017

Exhibit 24.3

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Thomas S. O'Neill attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

DATE: January 31, 2017

Exhibit 24.4

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Yves C. de Balmann** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ YVES C. DE BALMANN

Yves C. de Balmann

DATE: January 31, 2017

Exhibit 24.5

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ NICHOLAS DEBENEDICTIS

Nicholas DeBenedictis

DATE: January 31, 2017

Exhibit 24.6

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nancy L. Gioia** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ NANCY L. GIOIA

Nancy L. Gioia

DATE: January 31, 2017

Exhibit 24.7

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Linda P. Jojo** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ LINDA P. JOJO

Linda P. Jojo

DATE: January 31, 2017

Exhibit 24.8

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Paul Joskow** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ PAUL JOSKOW
Paul Joskow

DATE: January 31, 2017

Exhibit 24.9

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Robert J. Lawless** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ROBERT J. LAWLESS

Robert J. Lawless

DATE: January 31, 2017

Exhibit 24.10

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Richard W. Mies** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ RICHARD W. MIES

Richard W. Mies

DATE: January 31, 2017

Exhibit 24.12

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John W. Rogers, Jr.** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ JOHN W. ROGERS, JR.
John W. Rogers, Jr.

DATE: January 31, 2017

Exhibit 24.13

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Mayo A. Shattuck III** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ MAYO A. SHATTUCK III

Mayo A. Shattuck III

DATE: January 31, 2017

Exhibit 24.14

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Stephen D. Steinour** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ STEPHEN D. STEINOUR

Stephen D. Steinour

DATE: January 31, 2017

Exhibit 24.15

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James W. Compton** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ JAMES W. COMPTON

James W. Compton

DATE: February 2, 2017

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE
Christopher M. Crane

DATE: January 31, 2017

Exhibit 24.17

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **A. Steven Crown** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ A. STEVEN CROWN

A. Steven Crown

DATE: February 6, 2017

Exhibit 24.18

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ NICHOLAS DEBENEDICTIS

Nicholas DeBenedictis

DATE: January 31, 2017

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Peter V. Fazio, Jr.** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ PETER V. FAZIO, JR.
Peter V. Fazio, Jr.

DATE: January 31, 2017

Exhibit 24.20

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael H. Moskow** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ MICHAEL H. MOSKOW

Michael H. Moskow

DATE: February 4, 2017

Exhibit 24.21

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

DATE: January 31, 2017

Exhibit 24.22

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anne R. Pramaggiore** , do hereby appoint Verónica Gómez attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ANNE R. PRAMAGGIORE

Anne R. Pramaggiore

DATE: February 1, 2017

Exhibit 24.23

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Jesse H. Ruiz** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ JESSE H. RUIZ

Jesse H. Ruiz

DATE: February 2, 2017

Exhibit 24.25

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Craig L. Adams** , do hereby appoint Romulo L. Diaz, Jr. attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CRAIG L. ADAMS

Craig L. Adams

DATE: January 31, 2017

Exhibit 24.26

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

DATE: January 31, 2017

Exhibit 24.27

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **M. Walter D'Alessio** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ M. WALTER D'ALESSIO
M. Walter D'Alessio

DATE: February 6, 2017

Exhibit 24.28

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ NICHOLAS DEBENEDICTIS

Nicholas DeBenedictis

DATE: January 31, 2017

Exhibit 24.29

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nelson A. Diaz** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ NELSON A. DIAZ
Nelson A. Diaz

DATE: February 6, 2017

Exhibit 24.30

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Rosemarie B. Greco** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ROSEMARIE B. GRECO

Rosemarie B. Greco

DATE: February 10, 2017

Exhibit 24.31

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Charisse R. Lillie** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHARISSE R. LILLIE

Charisse R. Lillie

DATE: February 8, 2017

Exhibit 24.32

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

DATE: January 31, 2017

Exhibit 24.33

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ronald Rubin** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ RONALD RUBIN

Ronald Rubin

DATE: February 6, 2017

Exhibit 24.34

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ANN C. BERZIN

Ann C. Berzin

DATE: January 31, 2017

Exhibit 24.35

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Calvin G. Butler, Jr.,** do hereby appoint Daniel P. Gahagan attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CALVIN G. BUTLER, JR.
Calvin G. Butler, Jr.

DATE: February 4, 2017

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

DATE: January 31, 2017

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael E. Cryor** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ MICHAEL E. CRYOR

Michael E. Cryor

DATE: February 3, 2017

Exhibit 24.38

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James R. Curtiss** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ JAMES R. CURTISS

James R. Curtiss

DATE: February 9, 2017

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Joseph Haskins, Jr.** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ JOSEPH HASKINS, JR.
Joseph Haskins, Jr.

DATE: February 8, 2017

Exhibit 24.40

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

DATE: January 31, 2017

Exhibit 24.41

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael D. Sullivan** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ MICHAEL D. SULLIVAN

Michael D. Sullivan

DATE: February 9, 2017

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Maria Harris Tildon** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ MARIA HARRIS TILDON

Maria Harris Tildon

DATE: February 10, 2017

Exhibit 24.43

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

Date: February 2, 2017

Exhibit 24.44

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Linda Cropp** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Linda Cropp
Linda Cropp

Date: February 8, 2017

Exhibit 24.45

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael E. Cryor** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael Cryor

Michael Cryor

Date: February 3, 2017

Exhibit 24.46

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ernest Dianastasis** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ERNEST DIANASTASIS

Ernest Dianastasis

Date: February 6, 2017

Exhibit 24.47

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Debra DiLorenzo** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Debra DiLorenzo

Debra DiLorenzo

Date: February 6, 2017

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

Date: February 2, 2017

Exhibit 24.49

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **David M. Velazquez** , do hereby appoint Wendy E. Stark as attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DAVID M. VELAZQUEZ
David M. Velazquez

DATE: February 8, 2017

Exhibit 24.50

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **J. Tyler Anthony** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ J. TYLER ANTHONY

J. Tyler Anthony

DATE: January 30, 2017

Exhibit 24.51

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

DATE: February 2, 2017

Exhibit 24.52

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Donna J. Kinzel** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/ S / DONNA J. KINZEL

Donna J. Kinzel

DATE: February 9, 2017

Exhibit 24.53

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Kevin M. McGowan** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ KEVIN M. MCGOWAN

Kevin M. McGowan

DATE: February 3, 2017

Exhibit 24.54

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

DATE: February 2, 2017

Exhibit 24.55

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Kenneth J. Parker** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ KENNETH J. PARKER

Kenneth J. Parker

DATE: February 9, 2017

Exhibit 24.56

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **David M. Velazquez** , do hereby appoint Wendy E. Stark, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DAVID M. VELAZQUEZ

David M. Velazquez

DATE: February 8, 2017

Exhibit 24.57

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Delmarva Power & Light Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

DATE: February 2, 2017

Exhibit 24.58

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **David M. Velazquez** , do hereby appoint Wendy E. Stark as attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2016 of Delmarva Power & Light Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DAVID M. VELAZQUEZ

David M. Velazquez

DATE: February 8, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / C HRISTOPHER M. C RANE
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / J ONATHAN W. T HAYER
Senior Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / K ENNETH W. C ORNEW
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / B RYAN P. W RIGHT
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / A NNE R. P RAMAGGIORE
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / J OSEPH R. T RPIK , J R .

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / C RAIG L. A DAMS
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / P HILLIP S. B ARNETT
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Calvin G. Butler, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/S/ CALVIN G. BUTLER, JR.
Chief Executive Officer
(Principal Executive Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Vahos, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / D AVID M. V AHOS

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this annual report on Form 10-K of Pepco Holdings LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / D AVID M. V ELAZQUEZ
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this annual report on Form 10-K of Pepco Holdings LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / D ONNA J. K INZEL
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this annual report on Form 10-K of Potomac Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / D AVID M. V ELAZQUEZ
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this annual report on Form 10-K of Potomac Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / D ONNA J. K INZEL
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this annual report on Form 10-K of Delmarva Power & Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / D AVID M. V ELAZQUEZ
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this annual report on Form 10-K of Delmarva Power & Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / D ONNA J. K INZEL
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this annual report on Form 10-K of Atlantic City Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / D AVID M. V ELAZQUEZ
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 13, 2017

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this annual report on Form 10-K of Atlantic City Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/ S / D ONNA J. K INZEL
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: February 13, 2017

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/ S / C HRISTOPHER M. C RANE

Christopher M. Crane
President and Chief Executive Officer

Date: February 13, 2017

Exhibit 32-2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/ S / J ONATHAN W. T HAYER
Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer

Date: February 13, 2017

Exhibit 32-3

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/ S / K ENNETH W. C ORNEW
Kenneth W. Cornew
President and Chief Executive Officer

Date: February 13, 2017

Exhibit 32-4

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/ S / B RYAN P. W RIGHT

Bryan P. Wright
Senior Vice President and Chief Financial Officer

Date: February 13, 2017

Exhibit 32-5

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/ S / A NNE R. P RAMAGGIORE
Anne R. Pramaggiore
President and Chief Executive Officer

Date: February 13, 2017

Exhibit 32-6

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/ S / J OSEPH R. T RPIK , J R .

Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Date: February 13, 2017

Exhibit 32-7

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/ S / C RAIG L. A DAMS
Craig L. Adams
President and Chief Executive Officer

Date: February 13, 2017

Exhibit 32-8

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/ S / P HILLIP S. B ARNETT
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Date: February 13, 2017

Exhibit 32-9

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/ S / C ALVIN G. B UTLER , J R .
Calvin G. Butler, Jr.
Chief Executive Officer

Date: February 13, 2017

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/ S / D AVID M. V AHOS
David M. Vahos
Senior Vice President, Chief Financial Officer and Treasurer

Date: February 13, 2017

Exhibit 32-11

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Pepco Holdings LLC for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Pepco Holdings LLC.

/ S / D AVID M. V ELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Date: February 13, 2017

Exhibit 32-12

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Pepco Holdings LLC for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Pepco Holdings LLC.

/ S / D ONNA J. K INZEL
Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer

Date: February 13, 2017

Exhibit 32-13

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Potomac Electric Power Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Potomac Electric Power Company.

/ S / D AVID M. V ELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Date: February 13, 2017

Exhibit 32-14

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Potomac Electric Power Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Potomac Electric Power Company.

/ S / D ONNA J. K INZEL
Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer

Date: February 13, 2017

Exhibit 32-15

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Delmarva Power & Light Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Delmarva Power & Light Company.

/ S / D AVID M. V ELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Date: February 13, 2017

Exhibit 32-16

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Delmarva Power & Light Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Delmarva Power & Light Company.

/ S / D ONNA J. K INZEL
Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer

Date: February 13, 2017

Exhibit 32-17

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Atlantic City Electric Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Atlantic City Electric Company.

/ S / D AVID M. V ELAZQUEZ
David M. Velazquez
President and Chief Executive Officer

Date: February 13, 2017

Exhibit 32-18

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Atlantic City Electric Company for the year ended December 31, 2016, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Atlantic City Electric Company.

/ S / D ONNA J. K INZEL
Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer

Date: February 13, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2017
or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210
001-31403	PEPCO HOLDINGS LLC (a Delaware limited liability company) 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	52-2297449
001-01072	POTOMAC ELECTRIC POWER COMPANY (a District of Columbia and Virginia corporation) 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	53-0127880
001-01405	DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation) 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
001-03559	ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation) 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	21-0398280

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
EXELON CORPORATION:	
Common Stock, without par value	New York and Chicago
Series A Junior Subordinated Debentures	New York
Corporate Units	New York
PECO ENERGY COMPANY:	
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York

Securities registered pursuant to Section 12(g) of the Act:

Title of Each Class
COMMONWEALTH EDISON COMPANY:
Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants
POTOMAC ELECTRIC POWER COMPANY:
Common Stock, $.01 par value
DELMARVA POWER & LIGHT COMPANY:
Common Stock, $2.25 par value
ATLANTIC CITY ELECTRIC COMPANY:
Common Stock, $3.00 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes ☒	No ☐
Exelon Generation Company, LLC	Yes ☒	No ☐
Commonwealth Edison Company	Yes ☒	No ☐
PECO Energy Company	Yes ☒	No ☐
Baltimore Gas and Electric Company	Yes ☒	No ☐
Pepco Holdings LLC	Yes ☒	No ☐
Potomac Electric Power Company	Yes ☐	No ☒
Delmarva Power & Light Company	Yes ☐	No ☒
Atlantic City Electric Company	Yes ☐	No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒
Pepco Holdings LLC	Yes ☐	No ☒
Potomac Electric Power Company	Yes ☐	No ☒
Delmarva Power & Light Company	Yes ☐	No ☒
Atlantic City Electric Company	Yes ☐	No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company	Emerging Growth Company
Exelon Corporation	☒				
Exelon Generation Company, LLC			☒		
Commonwealth Edison Company			☒		
PECO Energy Company			☒		
Baltimore Gas and Electric Company			☒		
Pepco Holdings LLC			☒		
Potomac Electric Power Company			☒		
Delmarva Power & Light Company			☒		
Atlantic City Electric Company			☒		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2017 was as follows:

Exelon Corporation Common Stock, without par value	$34,604,071,959
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None
Baltimore Gas and Electric Company, without par value	None
Pepco Holdings LLC	Not applicable
Potomac Electric Power Company	None
Delmarva Power & Light Company	None
Atlantic City Electric Company	None

The number of shares outstanding of each registrant's common stock as of January 31, 2018 was as follows:

Exelon Corporation Common Stock, without par value	965,029,399
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,256
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000
Pepco Holdings LLC	Not applicable
Potomac Electric Power Company Common Stock, $0.01 par value	100
Delmarva Power & Light Company Common Stock, $2.25 par value	1,000
Atlantic City Electric Company Common Stock, $3.00 par value	8,546,017

Documents Incorporated by Reference
Portions of the Exelon Proxy Statement for the 2018 Annual Meeting of Shareholders and the Commonwealth Edison Company 2018 Information Statement are incorporated by reference in Part III.

Exelon Generation Company, LLC, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form in the reduced disclosure format.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
Registrants	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL and ACE, collectively
Legacy PHI	PHI, Pepco, DPL, ACE, PES and PCI collectively
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
Antelope Valley	Antelope Valley Solar Ranch One
BondCo	RSB BondCo LLC
BSC	Exelon Business Services Company, LLC
CENG	Constellation Energy Nuclear Group, LLC
ConEdison Solutions	The competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc., a subsidiary of Consolidated Edison, Inc
Constellation	Constellation Energy Group, Inc.
EEDC	Exelon Energy Delivery Company, LLC
EGR IV	ExGen Renewables IV, LLC
EGTP	ExGen Texas Power, LLC
Entergy	Entergy Nuclear FitzPatrick, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
FitzPatrick	James A. FitzPatrick nuclear generating station
PCI	Potomac Capital Investment Corporation and its subsidiaries
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PHI Corporate	PHI in its corporate capacity as a holding company
PHISCO	PHI Service Company
RPG	Renewable Power Generation
SolGen	SolGen, LLC
TMI	Three Mile Island nuclear facility
UII	Unicom Investments, Inc.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
AGE	Albany Green Energy Project
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
AOCI	Accumulated Other Comprehensive Income
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
CAISO	California ISO
CAP	Customer Assistance Program
CCGTs	Combined-Cycle gas turbines
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CES	Clean Energy Standard
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE during the Predecessor periods
Conectiv Energy	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
CSAPR	Cross-State Air Pollution Rule
CTA	Consolidated tax adjustment
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DCPSC	District of Columbia Public Service Commission
Default Electricity Supply	The supply of electricity by PHI's electric utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive supplier, and which, depending on the jurisdiction, is also known as Standard Offer Service or BGS
DOE	United States Department of Energy
DOJ	United States Department of Justice
DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA and its subsidiaries
EE&C	Energy Efficiency and Conservation/Demand Response
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL
EPA	United States Environmental Protection Agency
EPSA	Electric Power Supply Association

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GHG	Greenhouse Gas
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
Integrys	Integrys Energy Services, Inc.
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LLRW	Low-Level Radioactive Waste
LT Plan	Long-Term renewable resources procurement plan
LTIP	Long-Term Incentive Plan
MAPP	Mid-Atlantic Power Pathway
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
MOPR	Minimum Offer Price Rule

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
n.m.	not meaningful
NAAQS	National Ambient Air Quality Standards
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJBPU	New Jersey Board of Public Utilities
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOSA	Nuclear Operating Services Agreement
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NUGs	Non-utility generators
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPC	Office of People's Counsel
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
Preferred Stock	Originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
ROE	Return on equity
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RSSA	Reliability Support Services Agreement
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SGIG	Smart Grid Investment Grant from DOE
SILO	Sale-In, Lease-Out
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPFPA	Security, Police and Fire Professionals of America
SPP	Southwest Power Pool
TCJA	Tax Cuts and Jobs Act
Transition Bond Charge	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees
Transition Bonds	Transition Bonds issued by ACE Funding
Upstream	Natural gas and oil exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit
ZES	Zero Emission Standard

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FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company (Registrants). Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, including those factors discussed with respect to the Registrants discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23 , Commitments and Contingencies; and (d) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants' website at www.exeloncorp.com. Information contained on the Registrants' website shall not be deemed incorporated into, or to be a part of, this Report.

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PART I

ITEM 1. BUSINESS

General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through Generation, in the energy generation business, and through ComEd, PECO, BGE, PHI, Pepco, DPL and ACE in the energy delivery businesses discussed below. Exelon's principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603.

Name of Registrant	State/Jurisdiction and Year of Incorporation	Business	Service Territories	Address of Principal Executive Offices
Exelon Generation Company, LLC	Pennsylvania (2000)	Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. Generation also sells natural gas, renewable energy and other energy-related products and services.	Six reportable segments: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions	300 Exelon Way, Kennett Square, Pennsylvania 19348
Commonwealth Edison Company	Illinois (1913)	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	Northern Illinois, including the City of Chicago	440 South LaSalle Street, Chicago, Illinois 60605
PECO Energy Company	Pennsylvania (1929)	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Southeastern Pennsylvania, including the City of Philadelphia (electricity) Pennsylvania counties surrounding the City of Philadelphia (natural gas)	2301 Market Street, Philadelphia, Pennsylvania 19103
Baltimore Gas and Electric Company	Maryland (1906)	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Central Maryland, including the City of Baltimore (electricity and natural gas)	110 West Fayette Street, Baltimore, Maryland 21201
Pepco Holdings LLC	Delaware (2016)	Utility services holding company engaged, through its reportable segments Pepco, DPL and ACE	Service Territories of Pepco, DPL and ACE	701 Ninth Street, N.W., Washington, D.C. 20068
Potomac Electric Power Company	District of Columbia (1896) Virginia (1949)	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	District of Columbia and Major portions of Montgomery and Prince George's Counties, Maryland	701 Ninth Street, N.W., Washington, D.C. 20068
Delmarva Power & Light Company	Delaware (1909) Virginia (1979)	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of Delaware and Maryland (electricity) Portions of New Castle County, Delaware (natural gas)	500 North Wakefield Drive, Newark, Delaware 19702
Atlantic City Electric Company	New Jersey (1924)	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	Portions of Southern New Jersey	500 North Wakefield Drive, Newark, Delaware 19702

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Business Services

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of corporate governance support services including corporate strategy and development, legal, human resources, information technology, finance, real estate, security, corporate communications and supply at cost. The costs of these services are directly charged or allocated to the applicable operating segments. The services are provided pursuant to service agreements. Additionally, the results of Exelon's corporate operations include interest costs and income from various investment and financing activities.

PHI Service Company (PHISCO), a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, finance, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHISCO and the participating operating subsidiaries.

Operating Segments

See Note 25 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's operating segments.

Merger with Pepco Holdings, Inc. (Exelon)

On March 23, 2016 , Exelon completed the merger contemplated by the Merger Agreement among Exelon, Purple Acquisition Corp., a wholly owned subsidiary of Exelon (Merger Sub) and Pepco Holdings, Inc. (PHI). As a result of that merger, Merger Sub was merged into PHI (the PHI Merger) with PHI surviving as a wholly owned subsidiary of Exelon and Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon which also owns Exelon's interests in ComEd, PECO and BGE (through a special purpose subsidiary in the case of BGE). Following the completion of the PHI Merger, Exelon and PHI completed a series of internal corporate organization restructuring transactions resulting in the transfer of PHI's unregulated business interests to Exelon and Generation and the transfer of PHI, Pepco, DPL and ACE to a special purpose subsidiary of EEDC. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the PHI transaction.

Generation

Generation, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Constellation sells electricity and natural gas, including renewable energy, in competitive energy markets to both wholesale and retail customers. The retail sales include commercial, industrial and residential customers. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Generation's fleet also provides geographic and supply source diversity. Generation's customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation's customer-facing activities foster development and delivery of other innovative energy-related products and services for its customers.

Generation is a public utility under the Federal Power Act and is subject to FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates

for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. FERC's jurisdiction over ratemaking includes the authority to suspend the market-based rates of utilities and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities.

RTOs and ISOs exist in a number of regions to provide transmission service across multiple transmission systems. FERC has approved PJM, MISO, ISO-NE and SPP as RTOs and CAISO and ISO-NY as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC.

Specific operations of Generation are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including the NRC and Federal and state environmental protection agencies. Additionally, Generation is subject to NERC mandatory reliability standards, which protect the nation's bulk power system against potential disruptions from cyber and physical security breaches.

Constellation Energy Nuclear Group, LLC

Generation owns a 50.01% interest in CENG, a joint venture with EDF. CENG is governed by a board of ten directors, five of which are appointed by Generation and five by EDF. CENG owns a total of five nuclear generating facilities on three sites, Calvert Cliffs, R.E. Ginna (Ginna) and Nine Mile Point. CENG's ownership share in the total capacity of these units is 4,026 MW. See ITEM 2. PROPERTIES for additional information on these sites.

Generation and EDF entered into a Put Option Agreement on April 1, 2014, pursuant to which EDF has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months. In order to exercise its option, EDF must give 60-days advance written notice to Generation stating that it is exercising its option. To date, EDF has not given notice to Generation that it is exercising its option.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interests in CENG at fair value on a fully consolidated basis in Exelon's and Generation's Consolidated Balance Sheets. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for further information regarding the CENG consolidation.

Acquisitions

James A. FitzPatrick Nuclear Generating Station

On March 31, 2017, Generation acquired the 838 MW single-unit James A. FitzPatrick nuclear generating station located in Scriba, New York from Entergy Nuclear FitzPatrick LLC (Entergy) for a total purchase price consideration of $289 million , resulting in an after-tax bargain purchase gain of $233 million in 2017.

ConEdison Solutions

On September 1, 2016, Generation acquired the competitive retail electric and natural gas business activities of ConEdison Solutions, a subsidiary of Consolidated Edison, Inc., for a purchase price of $257 million including net working capital of $204 million. The renewable energy, sustainable services and energy efficiency businesses of ConEdison were excluded from the transaction.

Integrys Energy Services, Inc.

On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (Integrys) for a purchase price of $ 332 million , including net working capital. The generation and solar asset businesses of Integrys were excluded from the transaction.

Dispositions

ExGen Texas Power, LLC.

On May 2, 2017, EGTP entered into a consent agreement with its lenders to permit EGTP to draw on its revolving credit facility and initiate an orderly sales process to sell the assets of its wholly owned subsidiaries, the proceeds from which will first be used to pay the administrative costs of the sale, the normal and ordinary costs of operating the plants and repayment of the secured debt of EGTP, including the revolving credit facility. As a result, Exelon and Generation classified certain EGTP assets and liabilities as held for sale at their respective fair values less costs to sell and recorded associated pre-tax impairment charges of $460 million . On November 7, 2017, EGTP and all of its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware. As a result of the bankruptcy filing, EGTP's assets and liabilities were deconsolidated from Exelon and Generation's consolidated financial statements. Exelon and Generation recorded a pre-tax gain upon deconsolidation of $213 million in the fourth quarter of 2017.

Asset Divestitures

During 2015 and 2014, Generation sold certain generating assets with total pre-tax proceeds of $ 1.8 billion (after-tax proceeds of approximately $1.4 billion). Proceeds were used primarily to finance a portion of the acquisition of PHI.

See Note 4 — Mergers, Acquisitions and Dispositions and Note 7 — Impairment of Long-Lived Assets and Intangibles of the Combined Notes to Consolidated Financial Statements for additional information on acquisitions and dispositions.

Generating Resources

At December 31, 2017 , the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [a][b]	
Nuclear	20,310
Fossil (primarily natural gas and oil)	11,723
Renewable [c]	3,135
Owned generation assets [e]	35,168
Long-term power purchase contracts [d]	5,285
Total generating resources	40,453

(a) See "Fuel" for sources of fuels used in electric generation.
(b) Net generation capacity is stated at proportionate ownership share. See ITEM 2. PROPERTIES —Generation for additional information.
(c) Includes wind, hydroelectric and solar generating assets.
(d) Electric supply procured under site specific agreements.
(e) Includes EGTP generating assets that were deconsolidated from Generation's consolidated financial statements. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Generation has six reportable segments, the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions, representing the different geographical areas in which Generation's generating resources are located and Generation's customer-facing activities are conducted.

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina (approximately 33% of capacity).
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee; and the United States footprint of MISO (excluding MISO's Southern Region), which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin and the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM; and parts of Montana, Missouri and Kentucky (approximately 34% of capacity).
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 6% of capacity).
- New York represents the operations within ISO-NY, which covers the state of New York in its entirety (approximately 6% of capacity).
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas (approximately 16% of capacity).
- Other Power Regions is an aggregate of regions not considered individually significant (approximately 5% of capacity).

See Note 25 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers and revenues net of purchased power and fuel expense for each of Generation's reportable segments.

Nuclear Facilities

Generation has ownership interests in fifteen nuclear generating stations currently in service, consisting of 25 units with an aggregate of 20,310 MW of capacity. Generation wholly owns all of its

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nuclear generating stations, except for undivided ownership interests in three jointly-owned nuclear stations: Quad Cities (75% ownership), Peach Bottom (50% ownership), and Salem (42.59% ownership), which are consolidated on Exelon's and Generation's financial statements relative to its proportionate ownership interest in each unit, and a 50.01% membership interest in CENG, which owns Calvert Cliffs, Nine Mile Point [excluding Long Island Power Authority's 18% undivided ownership interest in Nine Mile Point Unit 2] and Ginna nuclear stations. CENG is 100% consolidated on Exelon's and Generation's financial statements.

Generation's nuclear generating stations are all operated by Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. In 2017 , 2016 and 2015 electric supply (in GWh) generated from the nuclear generating facilities was 69% , 67% and 68% , respectively, of Generation's total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. Generation's wholesale and retail power marketing activities are, in part, supplied by the output from the nuclear generating stations. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation's electric supply sources.

Nuclear Operations

Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on Generation's results of operations. As the largest generator of nuclear power in the United States, Generation can negotiate favorable terms for the materials and services that its business requires. Generation's operations from its nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

During 2017 , 2016 and 2015 , the nuclear generating facilities operated by Generation achieved capacity factors of 94.1% , 94.6% and 93.7% , respectively. The capacity factors reflect ownership percentage of stations operated by Generation and include CENG. Generation manages its scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for Generation's wholesale and retail power marketing activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations.

In addition to the maintenance and equipment upgrades performed by Generation during scheduled refueling outages, Generation has extensive operating and security procedures in place to ensure the safe operation of the nuclear units. Generation also has extensive safety systems in place to protect the plant, personnel and surrounding area in the unlikely event of an accident or other incident.

Regulation of Nuclear Power Generation

Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. All nuclear generating stations operated by Generation, except for Clinton, are categorized by the NRC in the Licensee Response Column, which is the highest of five performance bands. As of February 1, 2018, the NRC categorized Clinton in the Regulatory Response Column, which is the second highest of five performance bands. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures and/or operating costs for nuclear generating facilities.

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Licenses

Generation has original 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals from the NRC for all its nuclear units except Clinton. Additionally, PSEG has received 20-year operating license renewals for Salem Units 1 and 2. On May 30, 2017, Exelon announced that Generation will permanently cease generation operations at TMI on or about September 30, 2019. On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018. In 2010, Generation had previously agreed to permanently cease generation operations at Oyster Creek by the end of 2019. See Note 8 — Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information regarding the early retirement of TMI. See Note 28 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information regarding the early retirement of Oyster Creek.

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The following table summarizes the current operating license expiration dates for Generation's nuclear facilities in service:

Station	Unit	In-Service Date [a]	Current License Expiration
Braidwood	1	1988	2046
	2	1988	2047
Byron	1	1985	2044
	2	1987	2046
Calvert Cliffs	1	1975	2034
	2	1977	2036
Clinton [b]	1	1987	2026
Dresden	2	1970	2029
	3	1971	2031
FitzPatrick	1	1974	2034
LaSalle	1	1984	2042
	2	1984	2043
Limerick	1	1986	2044
	2	1990	2049
Nine Mile Point	1	1969	2029
	2	1988	2046
Oyster Creek [c]	1	1969	2029
Peach Bottom [d]	2	1974	2033
	3	1974	2034
Quad Cities	1	1973	2032
	2	1973	2032
Ginna	1	1970	2029
Salem	1	1977	2036
	2	1981	2040
Three Mile Island [e]	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) Although timing has been delayed, Generation currently plans to seek license renewal for Clinton and has advised the NRC that any license renewal application would not be filed until the first quarter of 2021.
(c) Generation had previously announced and notified the NRC that it will permanently cease generation operations at Oyster Creek by the end of 2019. On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018.
(d) On June 7, 2016, Generation announced that it will submit a second 20-year license renewal application to NRC for Peach Bottom Units 2 and 3 in 2018.
(e) On May 30, 2017, Exelon announced that Generation will permanently cease generation operations at TMI on or about September 30, 2019 and has notified the NRC.

The operating license renewal process takes approximately four to five years from the commencement of the renewal process, which includes approximately two years for Generation to develop the application and approximately two years for the NRC to review the application. To date, each granted license renewal has been for 20 years beyond the original operating license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual renewal of operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek, TMI and Clinton. In 2017, Oyster Creek and TMI depreciation provisions were based on

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their 2019 expected shutdown dates. Beginning February 2018, Oyster Creek depreciation provisions will be based on its announced shutdown date of 2018. Clinton depreciation provisions are based on 2027 which is the last year of the Illinois Zero Emissions Standard. See Note 3 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional detail on the new Illinois legislation and Note 8 — Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional detail on early retirements.

Nuclear Waste Storage and Disposal

There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by its nuclear generating facilities on-site in storage pools or in dry cask storage facilities. Since Generation's SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, Generation has developed dry cask storage facilities to support operations.

As of December 31, 2017 , Generation had approximately 84,100 SNF assemblies (20,600 tons) stored on site in SNF pools or dry cask storage (this includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party; see Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for TMI, where such storage is projected to be in operation in 2021. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation's sites through the end of the license renewal periods and through decommissioning.

For a discussion of matters associated with Generation's contracts with the DOE for the disposal of SNF, see Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into such an agreement, although neither state currently has an operational site and none is anticipated to be operational until after 2020.

Generation ships its Class A LLRW, which represents 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina, which have enough storage capacity to store all Class A LLRW for the life of all stations in Generation's nuclear fleet. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Oyster Creek and Salem) and Connecticut.

Generation utilizes on-site storage capacity at all its stations to store and stage for shipping Class B and Class C LLRW. Generation has a contract through 2032 to ship Class B and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all current Class B and Class C LLRW currently stored at each station as well as the Class B and Class C LLRW generated during the term of the agreement. However, because the production of LLRW from Generation's nuclear fleet will exceed the capacity at the Texas site (3.9 million curies for 15 years beginning in 2012), Generation will still be required to utilize on-site storage at its stations for Class B and Class C LLRW. Generation currently has enough storage capacity to store all Class B and Class C LLRW for the life of all stations in Generation's nuclear fleet. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize on-site storage and cost impacts.

Nuclear Insurance

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See "Nuclear Insurance" within Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. PROPERTIES — Generation. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon's and Generation's future financial conditions and results of operations and cash flows.

Decommissioning

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon's and Generation's Consolidated Balance Sheets at December 31, 2017 at fair value of approximately $13.3 billion and have an estimated targeted annual pre-tax return of 4.8% to 6.4% , while the Nuclear AROs are recorded on Exelon's and Generation's Consolidated Balance Sheets at December 31, 2017 at approximately $9.7 billion and have an estimated annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Exelon Corporation , Executive Overview ; ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS , Critical Accounting Policies and Estimates , Nuclear Decommissioning, Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Note 3 — Regulatory Matters , Note 11 — Fair Value of Financial Assets and Liabilities and Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation's NDT funds and its decommissioning obligations.

Zion Station Decommissioning. On December 11, 2007, Generation entered into an Asset Sale Agreement (ASA) with EnergySolutions, Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, LLC (ZionSolutions) under which ZionSolutions assumed responsibility for decommissioning Zion Station, which is in Zion, Illinois, and ceased operation in 1998.

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request reimbursement; specifically, if certain milestones as defined in the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. See Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station decommissioning and see Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for a discussion of variable interest entity considerations related to ZionSolutions.

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Fossil and Renewable Facilities (including Hydroelectric)

At December 31, 2017 , Generation had ownership interests in 14,858 MW of capacity in generating facilities currently in service, consisting of 11,723 MW of natural gas and oil, and 3,135 MW of renewables (wind, hydroelectric and solar). Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) Wyman; (2) certain wind project entities and a biomass project entity with minority interest owners; and (3) ExGen Renewables Partners, LLC which is owned 49% by another owner. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding certain of these entities which are VIEs. Generation's fossil and renewable generating stations are all operated by Generation, with the exception of LaPorte and Wyman, which are operated by third parties. In 2017 , 2016 and 2015 , electric supply (in GWh) generated from owned fossil and renewable generating facilities was 12% , 10% and 8% , respectively, of Generation's total electric supply. The majority of this output was dispatched to support Generation's wholesale and retail power marketing activities. For additional information regarding Generation's electric generating facilities, see ITEM 2. PROPERTIES — Exelon Generation Company, LLC and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Exelon Corporation , Executive Overview for additional information on Generation Renewable Development.

Licenses

Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid, which include Generation's Conowingo Hydroelectric Project (Conowingo) and Muddy Run Pumped Storage Facility Project (Muddy Run). On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo and Muddy Run, respectively. On December 22, 2015, FERC issued a new 40-year license for Muddy Run. The license term expires on December 1, 2055. Based on the FERC procedural schedule, the FERC licensing process for Conowingo was not completed prior to the expiration of the plant's license on September 1, 2014. The FERC is required to issue annual licenses for Conowingo until the new long-term license is issued. On September 10, 2014, FERC issued an annual license for Conowingo, effective as of the expiration of the previous license. The annual license renews automatically absent any further FERC action. The stations are currently being depreciated over their estimated useful lives, which includes actual and anticipated license renewal periods. Refer to Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Insurance

Generation maintains business interruption insurance for its renewable projects, but not for its fossil and hydroelectric operations unless required by contract or financing agreements. Refer to Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on financing agreements. Generation maintains both property damage and liability insurance. For property damage and liability claims for these operations, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon's and Generation's future financial conditions and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. PROPERTIES — Exelon Generation Company, LLC .

Long-Term Power Purchase Contracts

In addition to energy produced by owned generation assets, Generation sources electricity from plants it does not own under long-term contracts. The following tables summarize Generation's long-

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term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2017 :

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	14	2019 - 2032	237
Midwest	4	2019 - 2026	834
New England	7	2018	40
ERCOT	5	2020 - 2031	1,524
Other Power Regions	12	2018 - 2030	2,650
Total	42		5,285

	2018	2019	2020	2021	2022	Thereafter	Total
Capacity Expiring (MW)	141	644	1,020	815	298	2,367	5,285

Fuel

The following table shows sources of electric supply in GWh for 2017 and 2016 :

	Source of Electric Supply	
	2017	2016
Nuclear [(a)]	182,843	176,799
Purchases — non-trading portfolio	51,595	59,987
Fossil (primarily natural gas and oil)	22,546	19,830
Renewable [(b)]	7,848	6,324
Total supply	264,832	262,940

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g., CENG). Nuclear generation for 2017 and 2016 includes physical volumes of 34,761 GWh and 33,444 GWh, respectively, for CENG.
(b) Includes wind, hydroelectric and solar generating assets.

The fuel costs per MWh for nuclear generation are less than those for fossil-fuel generation. Consequently, nuclear generation is generally the most cost-effective way for Generation to meet its wholesale and retail load servicing requirements.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has inventory in various forms and does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS , ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS , Critical Accounting Policies and Estimates and Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation's integrated business operations include physical delivery and marketing of power. Generation largely obtains physical power supply from its generating assets and power purchase agreements in multiple geographic regions. Power purchase agreements, including tolling arrangements, are commitments related to power generation of specific generation plants and/or dispatch similar to an owned asset depending on the type of underlying asset. The commodity risks associated with the output from generating assets and PPAs are managed using various commodity transactions including sales to customers. The main objective is to obtain low-cost energy supply to meet physical delivery obligations to both wholesale and retail customers. Generation sells electricity, natural gas and other energy related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental and residential customers in competitive markets. Where necessary, Generation may also purchase transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs.

Price and Supply Risk Management

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation may also enter into transactions that are outside of this ratable sales plan. Generation is exposed to commodity price risk in 2018 and beyond for portions of its electricity portfolio that are unhedged. As of December 31, 2017 , the percentage of expected generation hedged is 85% - 88% , 55% - 58% and 26% - 29% for 2018 , 2019 , and 2020 , respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including sales to ComEd, PECO, BGE, Pepco, DPL and ACE to serve their retail load. A portion of Generation's hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices. The risk management group and Exelon's RMC monitor the financial risks of the wholesale and retail power marketing activities. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation's efforts. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

Capital Expenditures

Generation's business is capital intensive and requires significant investments primarily in nuclear fuel and energy generation assets. Generation's estimated capital expenditures for 2018 are approximately $2.1 billion , which includes Generation's share of the investment in nuclear fuel for the co-owned Salem plant.

ComEd, PECO, BGE, Pepco, DPL and ACE

Utility Operations

Service Territories and Franchise Agreements

The following table presents the size of service territories, populations of each service territory and the number of customers within each service territory for the Utility Registrants as of December 31, 2017 :

	Service Territories (in square miles)			Service Territory Population (in millions)			Number of Customers (in millions)		
	Total	Electric	Natural gas	Total	Electric	Natural gas	Total	Electric	Natural gas
ComEd	11,400	11,400	n/a	9.4 [a]	9.4	n/a	4.0	4.0	n/a
PECO	2,100	1,900	1,900	4.0 [b]	4.0	2.4	1.6	1.6	0.5
BGE	3,250	2,300	3,050	3.1 [c]	3.0	2.9	1.3	1.3	0.7
Pepco	640	640	n/a	2.4 [d]	2.4	n/a	0.9	0.9	n/a
DPL	5,400	5,400	275	1.4 [e]	1.4	0.6	0.5	0.5	0.1
ACE	2,800	2,800	n/a	1.1 [f]	1.1	n/a	0.6	0.6	n/a

(a) Includes approximately 2.7 million in the city of Chicago.
(b) Includes approximately 1.6 million in the city of Philadelphia.
(c) Includes approximately 0.6 million in the city of Baltimore.
(d) Includes approximately 0.7 million in the District of Columbia.
(e) Includes approximately 0.1 million in the city of Wilmington.
(f) Includes approximately 0.1 million in the city of Atlantic City.

The Utility Registrants have the necessary authorizations to perform their current business of providing regulated electric and natural gas distribution services in the various municipalities and territories in which they now supply such services. These authorizations include charters, franchises, permits, and certificates of public convenience issued by local and state governments and state utility commissions. ComEd's, BGE's and ACE's rights are generally non-exclusive; while PECO's, Pepco's and DPL's rights are generally exclusive. Certain authorizations are perpetual while others have varying expiration dates. The Utility Registrants anticipate working with the appropriate governmental bodies to extend or replace the authorizations prior to their expirations.

Utility Regulations

State utility commissions regulate the Utility Registrants' electric and gas distribution rates and service, issuances of certain securities, and certain other aspects of the business. The following table outlines the state commissions responsible for utility oversight.

Registrant	Commission
ComEd	ICC
PECO	PAPUC
BGE	MDPSC
Pepco	DCPSC/MDPSC
DPL	DPSC/MDPSC
ACE	NJBPU

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The Utility Registrants are public utilities under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of the utilities' business. The U.S. Department of Transportation also regulates pipeline safety and other areas of gas operations for PECO, BGE and DPL. Additionally, the Utility Registrants are subject to NERC mandatory reliability standards, which protect the nation's bulk power system against potential disruptions from cyber and physical security breaches.

Seasonality Impacts on Delivery Volumes

The Utility Registrants' electric distribution volumes are generally higher during the summer and winter months when temperature extremes create demand for either summer cooling or winter heating. For PECO, BGE and DPL, natural gas distribution volumes are generally higher during the winter months when cold temperatures create demand for winter heating.

ComEd, BGE, Pepco and DPL Maryland have electric distribution decoupling mechanisms and BGE has a natural gas decoupling mechanism that eliminate the favorable and unfavorable impacts of weather and customer usage patterns on electric distribution and natural gas delivery volumes. As a result, ComEd's, BGE's, Pepco's and DPL's Maryland electric distribution revenues and BGE's natural gas revenues are not materially impacted by delivery volumes. PECO's and ACE's electric distribution revenues and DPL's Delaware electric distribution and natural gas revenues are impacted by delivery volumes.

Electric and Natural Gas Distribution Services

The Utility Registrants are allowed to recover reasonable costs and fair and prudent capital expenditures associated with electric and natural gas distribution services and earn a return on those capital expenditures, subject to commission approval. ComEd recovers costs through a performance-based rate formula. ComEd is required to file an update to the performance-based rate formula on an annual basis. PECO's, BGE's and DPL's electric and gas distribution costs and Pepco's and ACE's electric distribution costs are recovered through traditional rate case proceedings. In certain instances, the Utility Registrants use specific recovery mechanisms as approved by their respective regulatory agencies.

ComEd, Pepco and ACE customers have the choice to purchase electricity, and PECO, BGE and DPL customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. The Utility Registrants remain the distribution service providers for all customers and are obligated to deliver electricity and natural gas to customers in their respective service territories while charging a regulated rate for distribution service. In addition, the Utility Registrants also retain significant default service obligations to provide electricity to certain groups of customers in their respective service areas who do not choose a competitive electric generation supplier. PECO and BGE also retain significant default service obligations to provide natural gas to certain groups of customers in their respective service areas who do not choose a competitive natural gas supplier. For natural gas, DPL does not retain default service obligations.

For customers that choose to purchase electric generation or natural gas from competitive suppliers, the Utility Registrants act as the billing agent and therefore do not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. Refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS , Results of Operations for further information. For customers that choose to purchase electric generation or natural gas from a Utility Registrant, the Utility Registrants are permitted to recover the electricity and natural gas procurement costs without mark-up and therefore record equal and offsetting amounts of Operating revenues and Purchased power and fuel expense related to the electricity and/or natural gas. As a result, fluctuations in electricity or natural gas sales and procurement costs

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have no impact on the Utility Registrants' Revenues net of purchased power and fuel expense, which is a non-GAAP measure used to evaluate operational performance, or Net Income.

Procurement-Related Proceedings

The Utility Registrants' electric supply for its customers is primarily procured through contracts as required by the ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU. The Utility Registrants procure electricity supply from various approved bidders, including Generation. RTO spot market purchases and sales are utilized to balance the utility electric load and supply as required. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on the Utility Registrants' Statements of Operations and Comprehensive Income.

PECO's, BGE's and DPL's natural gas supplies are purchased from a number of suppliers for terms of up to three years. PECO, BGE and DPL have annual firm supply and transportation contracts of 132,000 mmcf, 128,000 mmcf and 58,000 mmcf, respectively. In addition, to supplement gas supply at times of heavy winter demands and in the event of temporary emergencies, PECO, BGE and DPL have available storage capacity from the following sources:

	Peak Natural Gas Sources (in mmcf)		
	Liquefied Natural Gas Facility	Propane-Air Plant	Underground Storage Service Agreements [a]
PECO	1,200	150	18,000
BGE	1,056	550	22,000
DPL	257	n/a	3,800

(a) Natural gas from underground storage represents approximately 28% , 46% and 34% of PECO's, BGE's and DPL's 2017 - 2018 heating season planned supplies, respectively.

PECO, BGE and DPL have long-term interstate pipeline contracts and also participate in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between the utilities and customers. PECO, BGE and DPL make these sales as part of a program to balance its supply and cost of natural gas. The off-system gas sales are not material to PECO, BGE and DPL.

Refer to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK , Commodity Price, for further information regarding Utility Registrants' contracts to procure electric supply and natural gas.

Energy Efficiency Programs

The Utility Registrants are allowed to recover costs associated with energy efficiency and demand response programs. Each commission approved program seeks to meet mandated electric consumption reduction targets and implement demand response measures to reduce peak demand. The programs are designed to meet standards required by each respective regulatory agency.

The Utility Registrants are allowed to earn a return on their energy efficiency costs. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

Capital Investment

The Utility Registrants' businesses are capital intensive and require significant investments, primarily in electric transmission and distribution and natural gas transportation and distribution facilities, to ensure the adequate capacity, reliability and efficiency of their systems. ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's most recent estimates of capital expenditures for plant additions and improvements for 2018 are as follows:

	Projected 2018 Capital Expenditure Spending			
(in millions)	Transmission	Distribution	Gas	Total
ComEd	$ 375	$ 1,750	N/A	$ 2,125
PECO	125	450	$ 225	800
BGE	175	425	400	1,000
Pepco	125	600	N/A	725
DPL	150	200	50	400
ACE	175	200	N/A	375

ComEd, PECO, BGE, Pepco and DPL have AMI smart meter and smart grid deployment programs within their respective service territories to enhance their distribution systems. PECO, BGE, Pepco and DPL have completed the installation and activation of smart meters and smart grid in their respective service territories. ComEd expects to complete its smart meter and smart grid deployment in 2018.

Transmission Services

Under FERC's open access transmission policy, the Utility Registrants, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates approved by FERC. The Utility Registrants and their affiliates are required to comply with FERC's Standards of Conduct regulation governing the communication of non-public transmission information between the transmission owner's employees and wholesale merchant employees.

PJM is the regional grid operator and operates pursuant to FERC-approved tariffs. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM Tariff). PJM operates the PJM energy, capacity and other markets, and, through central dispatch, controls the day-to-day operations of the bulk power system for the region. The Utility Registrants are members of PJM and provide regional transmission service pursuant to the PJM Tariff. The Utility Registrants and the other transmission owners in PJM have turned over control of their transmission facilities to PJM, and their transmission systems are under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM transmission owners at rates based on the costs of transmission service.

ComEd's transmission rates are established based on a formula that was approved by FERC in January 2008. BGE's, Pepco's, DPL's and ACE's transmission rates are established based on a formula that was approved by FERC in April 2006. FERC's orders establish the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO's transmission rate is determined from a fixed rate to a formula rate. The new formula was accepted by FERC effective as of December 1, 2017, subject to refund and set for hearing and settlement judge proceedings, which are currently ongoing. See Note 3

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— Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional detail regarding the transmission formula late.

See Note 3 — Regulatory Matters , Note 25 — Segment Information of the Combined Notes to Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS , Liquidity and Capital Resources for additional information regarding transmission services.

Employees

As of December 31, 2017 , Exelon and its subsidiaries had 34,621 employees in the following companies, of which 11,845 or 34% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 [a]	IBEW Local 614 [b]	Other CBAs	Total Employees Covered by CBAs	Total Employees
Generation [c]	1,660	97	2,729	4,486	15,011
ComEd	3,515	—	—	3,515	6,280
PECO	—	1,148	—	1,148	2,534
BGE [d]	—	—	—	—	3,022
PHI [e]	—	—	322	322	1,320
Pepco [e]	—	—	1,151	1,151	1,582
DPL [e]	—	—	688	688	944
ACE [e]	—	—	421	421	647
Other [f]	65	—	49	114	3,281
Total	5,240	1,245	5,360	11,845	34,621

(a) A separate CBA between ComEd and IBEW Local 15 covers approximately 65 employees in ComEd's System Services Group and was renewed in 2016. Generation's and ComEd's separate CBAs with IBEW Local 15 will expire in 2022.
(b) PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614, both expiring in 2021. Additionally, Exelon Power, an operating unit of Generation, has an agreement covering 97 employees, which was renewed in 2016 and expiring in 2019.
(c) During 2017, Generation finalized CBAs with the Security Officer unions at LaSalle, Limerick and Quad Cities, which all will expire in 2020 and Dresden expiring in 2021. Additionally, during 2017, Generation acquired and combined two CBAs at FitzPatrick into one CBA covering both craft and security employees, which will expire in 2023. During 2016, Generation finalized its CBA with the Security Officer union at Oyster Creek, expiring in 2022 and New Energy IUOE Local 95-95A, which will expire in 2021. Also, during 2016, Generation finalized a 5-year agreement with the New England ENEH, UWUA Local 369, which will expire in 2022. During 2015, Generation finalized its CBA with Clinton Local 51 which will expire in 2020; its two CBAs with Local 369 at Mystic 7 and Mystic 8/9, both expiring in 2020; and four Security Officer unions at Braidwood, Byron, Clinton and TMI, all expiring between 2018 and 2021, respectively. During 2014, Generation finalized CBAs with TMI Local 777 and Oyster Creek Local 1289, expiring in 2019 and 2021, respectively and CENG finalized its CBA with Nine Mile Point which will expire in 2020. Additionally, during 2014, an agreement was negotiated with Las Vegas District Energy and IUOE Local 501, which will expire in 2018.
(d) In January 2017, an election was held at BGE which resulted in union representation for 1,394 employees at the end of the year. BGE and IBEW Local 410 are negotiating an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. No agreement has been finalized to date and management cannot predict the outcome of such negotiations.
(e) PHI's utility subsidiaries are parties to five CBAs with four local unions. CBAs are generally renegotiated every three to five years. All of these CBAs were renegotiated in 2014 and were extended through various dates ranging from October 2018 through June 2020.
(f) Other includes shared services employees at BSC.

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Environmental Regulation

General

The Registrants are subject to comprehensive and complex legislation regarding environmental matters by the federal government and various state and local jurisdictions in which they operate their facilities. The Registrants are also subject to environmental regulations administered by the EPA and various state and local environmental protection agencies. Federal, state and local regulation includes the authority to regulate air, water, and solid and hazardous waste disposal.

The Exelon Board of Directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President, Corporate Strategy and Chief Sustainability Officer; the Senior Vice President, Competitive Market Policy; and the Director, Safety & Sustainability, as well as senior management of Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. The Exelon Board of Directors has delegated to its Generation Oversight Committee and the Corporate Governance Committee the authority to oversee Exelon's compliance with health, environmental and safety laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including Exelon's internal climate change and sustainability policies and programs, as discussed in further detail below. The respective Boards of ComEd, PECO, BGE, Pepco, DPL and ACE oversee environmental, health and safety issues related to these companies.

Air Quality

Air quality regulations promulgated by the EPA and the various state and local environmental agencies impose restrictions on emission of particulates, sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury and other air pollutants and require permits for operation of emitting sources. Such permits have been obtained as needed by Exelon's subsidiaries. However, due to its low emitting generation fleet comprised of nuclear, natural gas, hydroelectric, wind and solar, compliance with the Federal Clean Air Act does not have a material impact on Generation's operations.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding clean air regulation in the forms of the CSAPR, the regulation of hazardous air pollutants from coal- and oil-fired electric generating facilities under MATS, and regulation of GHG emissions.

Water Quality

Under the federal Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the EPA or from the state environmental agency to which the permit program has been delegated and must be renewed periodically. Certain of Exelon's facilities discharge stormwater and industrial wastewater into waterways and are therefore subject to these regulations and operate under NPDES permits or pending applications for renewals of such permits after being granted an administrative extension. Generation is also subject to the jurisdiction of the Delaware River Basin Commission and the Susquehanna River Basin Commission, regional agencies that primarily regulate water usage.

Section 316(b) of the Clean Water Act

Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers)

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are potentially most affected by recent changes to the regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, FitzPatrick, Ginna, Gould Street, Mountain Creek, Handley, Mystic 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities, Riverside and Salem.

On October 14, 2014, the EPA's Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed to determine the best technology available to minimize adverse impacts on aquatic life, followed by an implementation period for the selected technology. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, Generation cannot estimate the effect that compliance with the rule will have on the operation of its generating facilities and its future results of operations, cash flows, and financial position. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility's economic viability could be called into question. However, the potential impact of the rule has been significantly reduced since the final rule does not mandate cooling towers as a national standard and sets forth technologies that are presumptively compliant, and the state permitting director is required to apply a cost-benefit test and can take into consideration site-specific factors, such as those that would make cooling towers infeasible.

Pursuant to discussions with the NJDEP in 2010 regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029. The agreement only applies to Oyster Creek based on its unique circumstances and does not set any precedent for the ultimate compliance requirements for Section 316(b) at Exelon's other plants. On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018.

New York Facilities

In July 2011, the New York Department of Environmental Conservation (DEC) issued a policy regarding the best available technology for cooling water intake structures. Through its policy, the DEC established closed-cycle cooling or its equivalent as the performance goal for all existing facilities, but also provided that the DEC will select a feasible technology whose costs are not wholly disproportionate to the environmental benefits to be gained and allows for a site-specific determination where the entrainment performance goal cannot be achieved (i.e., the requirement most likely to support cooling towers). The R.E Ginna and Nine Mile Point Unit 1 power generation facilities received renewals of their state water discharge permits in 2014 and cooling towers were not required. These facilities are now engaged in the required analyses to enable the environmental agency to determine the best technology available in the next permit renewal cycles.

Salem

On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers and allows Salem to continue to operate utilizing the existing cooling water system with certain required system modifications. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

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Solid and Hazardous Waste

CERCLA provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances and authorizes the EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at sites, most of which are listed by the EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight prior to listing on the NPL. Various states, including Delaware, Illinois, Maryland, New Jersey and Pennsylvania and the District of Columbia have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Generation, ComEd, PECO, BGE, Pepco, DPL and ACE and their subsidiaries are, or could become in the future, parties to proceedings initiated by the EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party.

See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding solid and hazardous waste regulation and legislation.

Environmental Remediation

ComEd's and PECO's environmental liabilities primarily arise from contamination at former MGP sites. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover environmental remediation costs of the MGP sites through a provision within customer rates. BGE, ACE, Pepco and DPL do not have material contingent liabilities relating to MGP sites. The amount to be expended in 2018 for compliance with environmental remediation related to contamination at former MGP sites and other gas purification sites is expected to total $ 48 million , consisting of $ 42 million and $ 6 million at ComEd and PECO respectively. The Utility Registrants also have contingent liabilities for environmental remediation of non-MGP contaminants (e.g., PCBs). As of December 31, 2017 , the Utility Registrants have established appropriate contingent liabilities for environmental remediation requirements.

The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws.

In addition, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE may be required to make significant additional expenditures not presently determinable for other environmental remediation costs.

See Notes 3 — Regulatory Matters and 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' environmental remediation efforts and related impacts to the Registrants' results of operations, cash flows and financial positions.

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Global Climate Change

Exelon has utility and generation assets, and customers, that are and will be further subject to the impacts of climate change. Accordingly, Exelon is engaged in a variety of initiatives to understand and mitigate these impacts, including investments in resiliency, partnering with federal, state and local governments to minimize impacts, and, importantly, advocating for public policy that reduces emissions that cause climate change. Exelon, as a producer of electricity from predominantly low- and zero-carbon generating facilities (such as nuclear, hydroelectric, natural gas, wind and solar photovoltaic), has a relatively small greenhouse gas (GHG) emission profile, or carbon footprint, compared to other domestic generators of electricity (Exelon neither owns or operates any coal-fueled generating assets). Exelon's natural gas and biomass fired generating plants produce GHG emissions, most notably, CO_2. However, Generation's owned-asset emission intensity, or rate of carbon dioxide equivalent (CO_2e) emitted per unit of electricity generated, is among the lowest in the industry. In 2017, while fossil fuel powered approximately 33 percent of Exelon's owned generating capacity, fossil fuel-fired generation represents less than 12 percent of Exelon's overall generation on a MWh basis. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF_6) leakage from electric transmission and distribution operations, refrigerant leakage from chilling and cooling equipment, and fossil fuel combustion in motor vehicles. Exelon facilities and operations are subject to the global impacts of climate change and Exelon believes its operations could be significantly affected by the physical risks of climate change. See ITEM 1A. RISK FACTORS for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

Climate Change Regulation

Exelon is or may become subject to additional climate change regulation or legislation at the federal, regional and state levels.

International Climate Change Agreements. At the international level, the United States is a Party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21 st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015, and it became effective on November 4, 2016. Under the Paris Agreement, the Parties agreed to try to limit the global average temperature increase to 2°C (3.6°F) above pre-industrial levels. In doing so, Parties developed their own national reduction commitments. The United States submitted a non-binding target of 17% below 2005 emission levels by 2020 and 26% to 28% below 2005 levels by 2025. President Trump has stated his intention to withdraw the U.S. from the Paris Agreement, but no formal action has been initiated.

Federal Climate Change Legislation and Regulation. It is highly unlikely whether federal legislation to reduce GHG emissions will be enacted in the near-term. If such legislation is adopted, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits. More importantly, continued inaction could negatively impact the value of Exelon's low-carbon fleet.

Under the Obama Administration, the EPA proposed and finalized regulations for fossil fuel-fired power plants, referred to as the Clean Power Plan, which are currently being litigated. However, the Trump Administration has proposed a repeal of the Clean Power Plan, and is expected to seek broad public comment on whether and how to regulate GHGs at the federal level. Details are not yet known and are likely to be further informed by the public comment process.

Given this uncertainty, Exelon and Generation cannot at this time predict the future of the Clean Power Plan, or its repeal and/or replacement, or individual state responses to Clean Power Plan developments or how developments will impact their future results of operations, cash flows and financial positions.

Regional and State Climate Change Legislation and Regulation. A number of states in which Exelon operates have state and regional programs to reduce GHG emissions, including from the power sector. As the nation's largest generator of carbon-free electricity, our fleet supports these efforts to produce safe, reliable electricity with minimal GHGs. Notably, nine northeast and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont) currently participate in the Regional Greenhouse Gas Initiative (RGGI), which is in the process of strengthening its requirements. The program requires most fossil fuel-fired power plants in the region to hold allowances, purchased at auction, for each ton of CO_2 emissions. Non-emitting resources do not have to purchase or hold these allowances.

Many states in which Exelon subsidiaries operate also have state-specific programs to address GHGs, including from power plants. Most notable of these, besides RGGI, are through renewable and other portfolio standards. Additionally, in response to a court decision clarifying obligations under the Global Warming Solutions Act, the Massachusetts Department of Environmental Protection in 2017 finalized regulations establishing a statewide cap on CO_2 emissions from fossil fuel power plants (Massachusetts remains in RGGI as well). The effect of this new obligation and potential for market illiquidity in the early years represent a risk to Generation's Massachusetts fossil facilities, including Medway and Mystic. At the same time, the District of Columbia is considering a plan to incorporate the cost of carbon into electricity, via consumption, as well as directly into the cost of transportation and home heating fuels. Details remain to be developed, but the specifics could have implications for Pepco's operations.

Regardless of whether GHG regulation occurs at the local, state, or federal level, Exelon remains one of the largest, lowest-carbon electric generators in the United States, relying mainly on nuclear, natural gas, hydropower, wind, and solar. The extent that the low-carbon generating fleet will continue to be a competitive advantage for Exelon depends on what, if anything, replaces the Clean Power Plan at the federal level, new or expanded state action on greenhouse gas emissions or direct support of clean energy technologies, including nuclear, as well as potential market reforms that value our fleet's emission-free attributes.

Renewable and Alternative Energy Portfolio Standards

Thirty-nine states and the District of Columbia, incorporating the vast majority of Exelon operations as well as all utility operations, have adopted some form of RPS requirement. These standards impose varying levels of mandates for procurement of renewable or clean electricity (the definition of which varies by state) and/or energy efficiency. These are generally expressed as a percentage of annual electric load, often increasing by year. Exelon's utilities comply with these various requirements through purchasing qualifying renewables, implementing efficiency programs, acquiring sufficient credits (e.g., RECs), paying an alternative compliance payment, and/or a combination of these compliance alternatives. The Utility Registrants are permitted to recover from retail customers the costs of complying with their state RPS requirements, including the procurement of RECs or other alternative energy resources. New York and Illinois adopted standards targeted at preserving the zero-carbon attributes of certain Exelon's nuclear-powered generating facilities. Generation owns multiple facilities participating in these programs within both states. Other states in which Generation and our utilities operate are considering similar programs.

See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on renewable portfolio standards.

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Executive Officers of the Registrants as of February 9, 2018

Exelon

Name	Age	Position	Period
Crane, Christopher M.	59	Chief Executive Officer, Exelon	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		Chairman, PHI	2016 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
Cornew, Kenneth W.	52	Senior Executive Vice President and Chief Commercial Officer, Exelon	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
O'Brien, Denis P.	57	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Vice Chairman, ComEd, PECO & BGE	2012 - Present
		Vice Chairman, PHI	2016 - Present
Pramaggiore, Anne R.	59	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
Adams, Craig L.	65	President and Chief Executive Officer, PECO	2012 - Present
Butler, Calvin G.	48	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
David M. Velazquez	58	President and Chief Executive Officer, PHI	2016 - Present
		President and Chief Executive Officer, Pepco, DPL & ACE	2009 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009 - 2016
Von Hoene Jr., William A.	64	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
Thayer, Jonathan W.	46	Senior Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
Aliabadi, Paymon	55	Executive Vice President and Chief Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
DesParte, Duane M.	54	Senior Vice President and Corporate Controller, Exelon	2008 - Present

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Generation

Name	Age	Position	Period
Cornew, Kenneth W.	52	Senior Executive Vice President and Chief Commercial Officer, Exelon	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
Pacilio, Michael J.	57	Executive Vice President and Chief Operating Officer, Generation	2015 - Present
		President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - 2015
Hanson, Bryan C	52	President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Generation	2015 - Present
Nigro, Joseph	53	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - Present
		Senior Vice President, Portfolio Management and Strategy	2012 - 2013
DeGregorio, Ronald	55	Senior Vice President, Generation; President, Exelon Power	2012 - Present
Wright, Bryan P.	51	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
Bauer, Matthew N.	41	Vice President and Controller, Generation	2016 - Present
		Vice President and Controller, BGE	2014 - 2016
		Vice President of Power Finance, Exelon Power	2012 - 2014

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ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	59	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
Donnelly, Terence R.	57	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
Trpik Jr., Joseph R.	48	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
Jensen, Val	62	Senior Vice President, Customer Operations, ComEd	2012 - Present
Gomez, Veronica	48	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2017 - Present
		Vice President and Deputy General Counsel, Litigation, Exelon	2012 - 2017
Marquez Jr., Fidel	56	Senior Vice President, Governmental & External Affairs, Exelon	2012 - Present
McGuire, Timothy M.	59	Senior Vice President, Distribution Operations, ComEd	2016 - Present
		Vice President, Transmission and Substations, ComEd	2010 - 2016
Kozel, Gerald J.	45	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013

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PECO

Name	Age	Position	Period
Adams, Craig L.	65	President and Chief Executive Officer, PECO	2012 - Present
Barnett, Phillip S.	54	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	52	Senior Vice President and Chief Operations Officer, PECO	2012 - Present
Murphy, Elizabeth A.	58	Senior Vice President, Governmental & External Affairs, PECO	2016 - Present
		Vice President, Governmental & External Affairs, PECO	2012 - 2016
Webster Jr., Richard G.	56	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
Jiruska, Frank J.	57	Vice President, Customer Operations, PECO	2013 - Present
Diaz Jr., Romulo L.	71	Vice President and General Counsel, PECO	2012 - Present
Bailey, Scott A.	41	Vice President and Controller, PECO	2012 - Present

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BGE

Name	Age	Position	Period
Butler, Calvin G.	48	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
Woerner, Stephen J.	50	President, BGE	2014 - Present
		Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - 2014
Vahos, David M.	45	Senior Vice President, Chief Financial Officer and Treasurer, BGE	2016 - Present
		Vice President, Chief Financial Officer and Treasurer, BGE	2014 - 2016
		Vice President and Controller, BGE	2012 - 2014
Núñez, Alexander G.	46	Senior Vice President, Regulatory and External Affairs, BGE	2016 - Present
		Vice President, Governmental & External Affairs, BGE	2013 - 2016
		Director, State Affairs, BGE	2012 - 2013
Case, Mark D.	56	Vice President, Regulatory Policy and Strategy, BGE	2012 - Present
Biagiotti, Robert D.	48	Vice President, Customer Operations, BGE	2015 - Present
		Vice President, Gas Distribution, BGE	2011 - 2015
Gahagan, Daniel P.	64	Vice President and General Counsel, BGE	2007 - Present
Andrew W. Holmes	49	Vice President and Controller, BGE	2016 - Present
		Director, Generation Accounting, Exelon	2013 - 2016
		Director, Derivatives and Technical Accounting, Exelon	2008 - 2013

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PHI, Pepco, DPL and ACE

Name	Age	Position	Period
Velazquez, David M.	58	President and Chief Executive Officer, PHI	2016 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009-2016
		President and Chief Executive Officer, Pepco, DPL & ACE	2009 - Present
Anthony, J. Tyler	53	Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL & ACE	2016 - Present
		Senior Vice President, Distribution Operations, ComEd	2010 - 2016
Kinzel, Donna J.	50	Senior Vice President, Chief Financial Officer and Treasurer, PHI, Pepco, DPL & ACE	2016 - Present
		Vice President, Treasurer and Chief Risk Officer, Pepco Holdings	2012 - 2016
Bonney, Paul R.	59	Senior Vice President, Legal and Regulatory Strategy, PHI, Pepco, DPL & ACE	2016 - Present
		Senior Vice President and General Counsel, Constellation	2012 - 2016
Lavinson, Melissa A.	48	Senior Vice President, Governmental & External Affairs, PHI, Pepco, DPL & ACE	2018 - Present
		Vice President, Federal Affairs and Policy, and Chief Sustainability Officer, PG&E Corporation	2015 - 2018
		Vice President, Federal Affairs, PG&E Corporation	2012 - 2015
Stark, Wendy E.	45	Vice President and General Counsel, PHI, Pepco DPL & ACE	2016 - Present
		Deputy General Counsel, Pepco Holdings, Inc.	2012 - Present
McGowan, Kevin M.	56	Vice President, Regulatory Policy and Strategy, PHI, Pepco, DPL & ACE	2016 - Present
		Vice President, Regulatory Affairs, Pepco Holdings, Inc.	2012 - 2016
Aiken, Robert M.	51	Vice President and Controller, PHI, Pepco, DPL & ACE	2016 - Present
		Vice President and Controller, Generation	2012 - 2016

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ITEM 1A. RISK FACTORS

Each of the Registrants operates in a market and regulatory environment that poses significant risks, many of which are beyond that Registrant's control. Management of each Registrant regularly meets with the Chief Risk Officer and the Registrant's Risk Management Committee (RMC), which comprises officers of the Registrant, to identify and evaluate the most significant risks of the Registrant's business and the appropriate steps to manage and mitigate those risks. The Chief Risk Officer and senior executives of the Registrants discuss those risks with the Finance and Risk Committee and Audit Committee of the Exelon Board of Directors and the ComEd, PECO, BGE and PHI boards of directors. In addition, the Generation Oversight Committee of the Exelon Board of Directors evaluates risks related to the generation business. The risk factors discussed below could adversely affect one or more of the Registrants' results of operations, cash flows or financial positions and the market prices of their publicly traded securities. Each of the Registrants has disclosed the known material risks that affect its business at this time. However, there may be further risks and uncertainties that are not presently known or that are not currently believed by a Registrant to be material that could adversely affect its performance or financial condition in the future.

Exelon's results of operations, cash flows and financial position are affected to a significant degree by: (1) Generation's position as a predominantly nuclear generator selling power into competitive energy markets with a concentration in select regions and (2) the role of the Utility Registrants as operators of electric transmission and distribution systems in six of the largest metropolitan areas in the United States. Factors that affect the results of operations, cash flows or financial positions of the Registrants fall primarily under the following categories, all of which are discussed in further detail below:

- ***Market and Financial Factors.*** Exelon's and Generation's results of operations are affected by price fluctuations in the energy markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular the price of natural gas, which affects the prices that Generation can obtain for the output of its power plants, (2) the presence of other generation resources in the markets in which Generation's output is sold, (3) the demand for electricity in the markets where the Registrants conduct their business, (4) the impacts of on-going competition in the retail channel and (5) emerging technologies.

- ***Regulatory and Legislative Factors.*** The regulatory and legislative factors that affect the Registrants include changes to the laws and regulations that govern competitive markets and utility cost recovery, tax policy, zero emission credit programs and environmental policy. In particular, Exelon's and Generation's financial performance could be affected by changes in the design of competitive wholesale power markets or Generation's ability to sell power in those markets. In addition, potential regulation and legislation, including regulation or legislation regarding climate change and renewable portfolio standards (RPS), could have significant effects on the Registrants. Also, returns for the Utility Registrants are influenced significantly by state regulation and regulatory proceedings.

- ***Operational Factors.*** The Registrants' operational performance is subject to those factors inherent in running the nation's largest fleet of nuclear power reactors and large electric and gas distribution systems. The safe, secure and effective operation of the nuclear facilities and the ability to effectively manage the associated decommissioning obligations as well as the ability to maintain the availability, reliability, safety and security of its energy delivery systems are fundamental to Exelon's ability to achieve value-added growth for customers, communities and shareholders. Additionally, the operating costs of the Registrants and the opinions of their customers, regulators and shareholders are affected by those companies' ability to maintain the reliability, safety and efficiency of their energy delivery systems.

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- ***Risks Related to the PHI Merger.*** Exelon is subject to additional risks related to the merger with PHI, which closed on March 23, 2016.

A discussion of each of these risk categories and other risk factors is included below.

Market and Financial Factors

Generation is exposed to depressed prices in the wholesale and retail power markets, which could negatively affect its results of operations, cash flows or financial position (Exelon and Generation).

Generation is exposed to commodity price risk for the unhedged portion of its electricity generation supply portfolio. Generation's earnings and cash flows are therefore exposed to variability of spot and forward market prices in the markets in which it operates.

Price of Fuels

The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit. Often, the next unit of electricity will be supplied from generating stations fueled by fossil fuels. Consequently, changes in the market price of fossil fuels often result in comparable changes to the market price of power. For example, the use of technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing downward pressure on natural gas prices and, therefore, on power prices. The continued addition of supply from new alternative generation resources, such as wind and solar, whether mandated through RPS or otherwise subsidized or encouraged through climate legislation or regulation, could displace a higher marginal cost plant, further reducing power prices. In addition, further delay or elimination of EPA air quality regulations could prolong the duration for which the cost of pollution from fossil fuel generation is not factored into market prices.

Demand and Supply

The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs could each depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on electricity market prices. The tepid economic environment in recent years and growing energy efficiency and demand response initiatives have limited the demand for electricity in Generation's markets. In addition, in some markets, the supply of electricity through wind or solar generation, when combined with other base-load generation such as nuclear, could often exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants such as Exelon's nuclear plants. Increased supply in excess of demand is furthered by the continuation of RPS mandates and subsidies for renewable energy.

Retail Competition

Generation's retail operations compete for customers in a competitive environment, which affects the margins that Generation can earn and the volumes that it is able to serve. In periods of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including Generation) use their retail operations to hedge generation output. Increased or more aggressive competition could adversely affect overall gross margins and profitability in Generation's retail operations.

Sustained low market prices or depressed demand and over-supply could adversely affect Exelon's and Generation's results of operations, cash flows or financial positions and such impacts could be

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emphasized given Generation's concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect Exelon's and Generation's ability to fund regulated utility growth for the benefit of customers, reduce debt and provide attractive shareholder returns. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Exelon's and Generation's result of operations through accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, accelerated amortization of plant specific nuclear fuel costs, severance costs, accelerated asset retirement obligation expense related to future decommissioning activities, and additional funding of decommissioning costs, which can be offset in whole or in part by reduced operating and maintenance expenses. A slow recovery in market conditions could result in a prolonged depression of or further decline in commodity prices, including low forward natural gas and power prices and low market volatility, which could also adversely affect Exelon's and Generation's results of operations, cash flows or financial positions. See Note 8 — Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

In addition to price fluctuations, Generation is exposed to other risks in the power markets that are beyond its control and could negatively affect its results of operations (Exelon and Generation).

Credit Risk

In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money, or are obligated to purchase energy or fuel from Generation, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, Generation could be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. In the spot markets, Generation is exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs, the purpose of which is to spread such risk across all market participants. Generation is also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, Generation's retail sales subject it to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that could be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Market Designs

The wholesale markets vary from region to region with distinct rules, practices and procedures. Changes in these market rules, problems with rule implementation, or failure of any of these markets could adversely affect Generation's business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry, including technologies related to energy generation, distribution and consumption (All Registrants).

Some of these technologies include, but are not limited to, further development or applications of technologies related to shale gas production, cost-effective renewable energy technologies, energy efficiency, distributed generation and energy storage devices. Such developments could affect the price of energy, levels of customer-owned generation, customer expectations and current business models and make portions of our electric system power supply and transmission and/or distribution facilities

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obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could materially affect the Registrants' results of operations, cash flows or financial positions through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors could decrease the value of NDT funds and employee benefit plan assets and could increase the related employee benefit plan obligations, which then could require significant additional funding (All Registrants).

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy could adversely affect the value of the investments held within Generation's NDTs and Exelon's employee benefit plan trusts. The Registrants have significant obligations in these areas and Exelon and Generation hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which could fall below the Registrants' projected return rates. A decline in the market value of the NDT fund investments could increase Generation's funding requirements to decommission its nuclear plants. A decline in the market value of the pension and OPEB plan assets will increase the funding requirements associated with Exelon's pension and OPEB plan obligations. Additionally, Exelon's pension and OPEB plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements could also increase the costs and funding requirements of the obligations related to the pension and OPEB plans. If future increases in pension and other postretirement costs as a result of reduced plan assets or other factors cannot be recovered, or cannot be recovered in a timely manner, from the Utility Registrants' customers, the results of operations, cash flows or financial positions of the Utility Registrants could be negatively affected. Ultimately, if the Registrants are unable to manage the investments within the NDT funds and benefit plan assets, and are unable to manage the related benefit plan liabilities, their results of operations, cash flows or financial positions could be negatively impacted.

Unstable capital and credit markets and increased volatility in commodity markets could adversely affect the Registrants' businesses in several ways, including the availability and cost of short-term funds for liquidity requirements, the Registrants' ability to meet long-term commitments, Generation's ability to hedge effectively its generation portfolio, and the competitiveness and liquidity of energy markets; each could negatively impact the Registrants' results of operations, cash flows or financial positions (All Registrants).

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity needs if internal funds are not available from the Registrants' respective operations. Disruptions in the capital and credit markets in the United States or abroad could adversely affect the Registrants' ability to access the capital markets or draw on their respective bank revolving credit facilities. The Registrants' access to funds under their credit facilities depends on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from the Registrants and other borrowers within a short period of time. The inability to access capital markets or credit facilities, and longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital

expenditures, changes to Generation's hedging strategy in order to reduce collateral posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

In addition, the Registrants have exposure to worldwide financial markets, including Europe, Canada and Asia. Disruptions in these markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2017 , approximately 19% , or $1.8 billion , 19% , or $1.8 billion , and 17% , or $1.6 billion of the Registrants' available credit facilities were with European, Canadian and Asian banks, respectively. The credit facilities include $9.5 billion in aggregate total commitments of which $8.3 billion was available as of December 31, 2017 . As of December 31, 2017 , there were no borrowings under Generation's bilateral credit facilities. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in energy markets depend heavily on active participation by multiple trading parties, which could be adversely affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that could affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to the respective businesses of the Registrants. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on Exelon's and Generation's results of operations, cash flows or financial positions.

If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs (All Registrants).

Generation's business is subject to credit quality standards that could require market participants to post collateral for their obligations. If Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating) or otherwise fail to satisfy the credit standards of trading counterparties, it would be required under its hedging arrangements to provide collateral in the form of letters of credit or cash, which could have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time depends on a variety of factors, including (1) the notional amount of the applicable hedge, (2) the nature of counterparty and related agreements, and (3) changes in power or other commodity prices. In addition, if Generation were downgraded, it could experience higher borrowing costs as a result of the downgrade. Generation could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the power generation industry in general, or Generation in particular, has deteriorated. Changes in ratings methodologies by the credit rating agencies could also have a negative impact on the ratings of Generation. Generation has project-specific financing arrangements and must meet the requirements of various agreements relating to those financings. Failure to meet those arrangements could give rise to a project-specific financing default which, if not cured or waived, could result in the specific project being required to repay the associated debt or other borrowings earlier than otherwise anticipated, and if such repayment were not made, the lenders or security holders would generally have broad remedies, including rights to foreclose against the project assets and related collateral or to force the Exelon subsidiaries in the project-specific financings to enter into bankruptcy proceedings.

The Utility Registrants' operating agreements with PJM and PECO's, BGE's and DPL's natural gas procurement contracts contain collateral provisions that are affected by their credit rating and market

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prices. If certain wholesale market conditions were to exist and the Utility Registrants were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the forms of letters of credit or cash, which could have a material adverse effect upon their remaining sources of liquidity. PJM collateral posting requirements will generally increase as market prices rise and decrease as market prices fall. Collateral posting requirements for PECO, BGE and DPL, with respect to their natural gas supply contracts, will generally increase as forward market prices fall and decrease as forward market prices rise. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if the Utility Registrants were downgraded, they could experience higher borrowing costs as a result of the downgrade.

A Utility Registrant could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the utility industry in general, or a Utility Registrant in particular, has deteriorated. A Utility Registrant could experience a downgrade if its current regulatory environment becomes less predictable by materially lowering returns for the Utility Registrant or adopting other measures to limit utility rates. Additionally, the ratings for a Utility Registrant could be downgraded if its financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage its capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of the Utility Registrants.

The Utility Registrants conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that the Utility Registrants are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate the Utility Registrants from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as “ring-fencing”) could help avoid or limit a downgrade in the credit ratings of the Utility Registrants in the event of a reduction in the credit rating of Exelon. Despite these ring-fencing measures, the credit ratings of the Utility Registrants could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of some or all of the Utility Registrants. A reduction in the credit rating of a Utility Registrant could have a material adverse effect on the Utility Registrant.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources — Credit Matters — Market Conditions and Security Ratings for further information regarding the potential impacts of credit downgrades on the Registrants’ cash flows.

Generation’s financial performance could be negatively affected by price volatility, availability and other risk factors associated with the procurement of nuclear and fossil fuel (Exelon and Generation).

Generation depends on nuclear fuel and fossil fuels to operate most of its generating facilities. Nuclear fuel is obtained predominantly through long-term uranium supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. Natural gas and oil are procured for generating plants through annual, short-term and spot-market purchases. The supply markets for nuclear fuel, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default that could negatively affect the results of operations, cash flows or financial position for Generation.

Generation's risk management policies cannot fully eliminate the risk associated with its commodity trading activities (Exelon and Generation).

Generation's asset-based power position as well as its power marketing, fuel procurement and other commodity trading activities expose Generation to risks of commodity price movements. Generation buys and sells energy and other products and enters into financial contracts to manage risk and hedge various positions in Generation's power generation portfolio. Generation is exposed to volatility in financial results for unhedged positions as well as the risk of ineffective hedges. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations could be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, Generation cannot predict the impact that its commodity trading activities and risk management decisions could have on its business, results of operations, cash flows or financial position.

Financial performance and load requirements could be adversely affected if Generation is unable to effectively manage its power portfolio (Exelon and Generation).

A significant portion of Generation's power portfolio is used to provide power under procurement contracts with the Utility Registrants and other customers. To the extent portions of the power portfolio are not needed for that purpose, Generation's output is sold in the wholesale power markets. To the extent its power portfolio is not sufficient to meet the requirements of its customers under the related agreements, Generation must purchase power in the wholesale power markets. Generation's financial results could be negatively affected if it is unable to cost-effectively meet the load requirements of its customers, manage its power portfolio or effectively address the changes in the wholesale power markets.

Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could impact the Registrants' results of operations, cash flows or financial positions. (All Registrants).

Corporate Tax Reform

On December 22, 2017, President Trump signed into law the TCJA. See Note 14 - Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

While the Registrants' current tax accounting and future expectations are based on management's present understanding of the provisions under the TCJA, further interpretive guidance of the TCJA's provisions could result in further adjustments that could have a material impact to the Registrants' future results of operations, cash flows or financial positions.

In addition, as allowed under SEC Staff Accounting Bulletin No. 118 (SAB 118), the Registrants have recorded provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation for which the impacts could not be finalized upon issuance of the Registrants' financial statements, but reasonable estimates could be determined. However, the provisional amounts may change as the Registrants finalize their analysis and computations and such changes could be material to the Registrants' future results of operations, cash flows or financial positions.

The Utility Registrants have made their best estimate regarding the probability and timing of settlements of net regulatory liabilities established pursuant to the TCJA. However, the amount and timing of the settlements may change based on decisions and actions by the rate regulators, which could

have a material impact on the Utility Registrants' future results of operations, cash flows or financial positions.

Tax reserves

The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeal issues related to these tax matters. These judgments include reserves established for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities. See Note 1 — Significant Accounting Policies and Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Increases in customer rates, including increases in the cost of purchased power and increases in natural gas prices for the Utility Registrants, and the impact of economic downturns could lead to greater expense for uncollectible customer balances. Additionally, increased rates could lead to decreased volumes delivered. Both of these factors could decrease Generation's and the Utility Registrants' results from operations, cash flows or financial positions (All Registrants).

The impacts of economic downturns on the Utility Registrants' customers, such as unemployment for residential customers and less demand for products and services provided by commercial and industrial customers, and the related regulatory limitations on residential service terminations, could result in an increase in the number of uncollectible customer balances', which would negatively affect the Utility Registrants' results of operations, cash flows or financial positions. Generation's customer-facing energy delivery activities face similar economic downturn risks, such as lower volumes sold and increased expense for uncollectible customer balances which could negatively affect Generation's results of operations, cash flows or financial position. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants' credit risk.

The Utility Registrants' current procurement plans include purchasing power through contracted suppliers and in the spot market. ComEd's, PECO's and ACE's costs of purchased power are charged to customers without a return or profit component. BGE's, Pepco's and DPL's SOS rates charged to customers recover their wholesale power supply costs and include a return component. For PECO and DPL, purchased natural gas costs are charged to customers with no return or profit component. For BGE, purchased natural gas costs are charged to customers using a MBR mechanism that compares the actual cost of gas to a market index. The difference between the actual cost and the market index is shared equally between shareholders and customers. Purchased power and natural gas prices fluctuate based on their relevant supply and demand. Significantly higher rates related to purchased power and natural gas could result in declines in customer usage, lower revenues and potentially additional uncollectible accounts expense for the Utility Registrants. In addition, any challenges by the regulators or the Utility Registrants as to the recoverability of these costs could have a material adverse effect on the Registrants' results of operations, cash flows or financial positions. Also, the Utility Registrants' cash flows could be adversely affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

The effects of weather could impact the Registrants' results of operations, cash flows or financial positions (All Registrants).

Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Moderate temperatures adversely affect the usage of energy and resulting revenues at PECO, DPL and ACE. Due to revenue decoupling,

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BGE, Pepco and DPL Maryland recognize revenues at MDPSC and DCPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period, and are not affected by actual weather with the exception of major storms. Pursuant to the Future Energy Jobs Act (FEJA), beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution revenue.

Extreme weather conditions or damage resulting from storms could stress the Utility Registrants' transmission and distribution systems, communication systems and technology, resulting in increased maintenance and capital costs and limiting each company's ability to meet peak customer demand. These extreme conditions could have detrimental effects on the Utility Registrants' results of operations, cash flows or financial positions. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and could make period comparisons less relevant.

Generation's operations are also affected by weather, which affects demand for electricity as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation could require greater resources to meet its contractual commitments. Extreme weather conditions or storms could affect the availability of generation and its transmission, limiting Generation's ability to source or send power to where it is sold. In addition, drought-like conditions limiting water usage could impact Generation's ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, could have an adverse effect by causing Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Certain long-lived assets and other assets recorded on the Registrants' statements of financial position could become impaired, which would result in write-offs of the impaired amounts (All Registrants).

Long-lived assets represent the single largest asset class on the Registrants' statements of financial position. Specifically, long-lived assets account for 64% , 51% , 70% , 79% , 84% , 77% , 82% and 79% of total assets for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE, respectively, as of December 31, 2017 . In addition, Exelon and Generation have significant balances related to unamortized energy contracts, as further disclosed in Note 10 — Intangible Assets of the Combined Notes to Consolidated Financial Statements. The Registrants evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered when evaluating long-lived assets for potential impairment. An impairment would require the Registrants to reduce the carrying value of the long-lived asset to fair value through a non-cash charge to expense by the amount of the impairment, and such an impairment could have a material adverse impact on the Registrants' results of operations, cash flows or financial positions.

As of December 31, 2017 , Exelon's $6.7 billion carrying amount of goodwill primarily consists of $2.6 billion at ComEd relating to the acquisition of ComEd in 2000 upon the formation of Exelon and $4.0 billion at PHI primarily resulting from Exelon's acquisition of PHI in the first quarter of 2016. Under GAAP, goodwill remains at its recorded amount unless it is determined to be impaired, which is generally based upon an annual analysis that compares the implied fair value of the goodwill to its carrying value. If an impairment occurs, the amount of the impaired goodwill will be written-off to expense, which will also reduce equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. Such an impairment would result in a non-cash charge to expense, which could have a material adverse impact on Exelon's, ComEd's, and PHI's results of operations.

Regulatory actions or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's, Pepco's, DPL's, and ACE's business, and the fair value of debt, could potentially result in future impairments of Exelon's, PHI's, and ComEd's goodwill, which could be material.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates and Note 6 — Property, Plant and Equipment, Note 7 — Impairment of Long-Lived Assets and Intangibles and Note 10 — Intangible Assets of the Combined Notes to the Consolidated Financial Statements for additional discussion on long-lived asset and goodwill impairments.

Exelon and its subsidiaries at times guarantee the performance of third parties, which could result in substantial costs in the event of non-performance by such third parties. In addition, the Registrants could have rights under agreements which obligate third parties to indemnify the Registrants for various obligations, and the Registrants could incur substantial costs in the event that the applicable Registrant is unable to enforce those agreements or the applicable third-party is otherwise unable to perform. The Registrants could also incur substantial costs in the event that third parties are entitled to indemnification related to environmental or other risks in connection with the acquisition and divestiture of assets (All Registrants).

Some of the Registrants have issued guarantees of the performance of third parties, which obligate the Registrant or its subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, a Registrant could incur substantial cost to fulfill its obligations under these guarantees. Such performance guarantees could have a material impact on the results of operations, cash flows or financial position of the Registrant. Some of the Registrants have issued indemnities to third parties regarding environmental or other matters in connection with purchases and sales of assets and a Registrant could incur substantial costs to fulfill its obligations under these indemnities and such costs could adversely affect a Registrant's results of operations, cash flows or financial position.

Some of the Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected Registrant could be held responsible for the obligations, which could adversely impact that Registrant's results of operations, cash flows or financial position. Each of the Utility Registrants has transferred its former generation business to a third party and in each case the transferee may have agreed to assume certain obligations and to indemnify the applicable Utility Registrant for such obligations. In connection with the restructurings under which ComEd, PECO and BGE transferred their generating assets to Generation, Generation assumed certain of ComEd's, PECO's and BGE's rights and obligations with respect to their former generation businesses. Further, ComEd, PECO and BGE may have entered into agreements with third parties under which the third-party agreed to indemnify ComEd, PECO or BGE for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the restructuring. If the third-party, Generation or the transferee of Pepco's, DPL's or ACE's generation facilities experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, the applicable Utility Registrant could be liable for any existing or future claims, which could impact that Utility Registrant's results of operations, cash flows or financial position. In addition, the Utility Registrants may have residual liability under certain laws in connection with their former generation facilities. For example, under CERCLA, former owners of property may retain certain liability for environmental claims and remediation. The third parties to whom the Utility Registrants transferred their former generation facilities may have agreed to indemnify the Utility Registrants for all or a portion

of such liability but if such third parties fail or are unable to perform under the indemnity, the applicable Utility Registrant may be liable for certain remediation costs.

Regulatory and Legislative Factors

The Registrants' generation and energy delivery businesses are highly regulated and could be subject to regulatory and legislative actions that adversely affect their results of operations, cash flows or financial positions. Fundamental changes in regulation or legislation or violation of tariffs or market rules and anti-manipulation laws, could disrupt the Registrants' business plans and adversely affect their operations, cash flows or financial results (All Registrants).

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation. Further, Exelon's and Generation's results of operations, cash flows or financial positions are significantly affected by Generation's sales and purchases of commodities at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon's and the Utility Registrants' results of operations, cash flows or financial positions are heavily dependent on the ability of the Utility Registrants to recover their costs for the retail purchase and distribution of power and natural gas to their customers. Similarly, there is risk that financial market regulations could increase the Registrants' compliance costs and limit their ability to engage in certain transactions. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, exchanges, ratemaking agencies and taxing authorities. Additionally, the Registrants need to be cognizant and understand rule changes or Registrant actions that could result in potential violation of tariffs, market rules and anti-manipulation laws. Fundamental changes in regulations or other adverse legislative actions affecting the Registrants' businesses would require changes in their business planning models and operations and could negatively impact their respective results of operations, cash flows or financial positions.

State and federal regulatory and legislative developments related to emissions, climate change, tax reform, capacity market mitigation, energy price information, resilience, fuel diversity and RPS could also significantly affect Exelon's and Generation's results of operations, cash flows or financial positions. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, could sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. Conversely, existing or new regulations intended to reduce GHG emissions could be rolled back, allowing fossil fueled facilities which were otherwise scheduled to retire to continue to operate if economical. This could result in decreases in market prices thereby reducing Generation's revenues. However, national regulation or legislation addressing climate change through an RPS could also increase the pace of development of wind energy facilities in the Midwest, which could put downward pressure on wholesale market prices for electricity from Generation's Midwest nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation's nuclear assets under a carbon constrained regulatory regime that might exist in the future. Similarly, final regulations under Section 111(d) of the Clean Air Act may not provide sufficient incentives for states to utilize carbon-free nuclear power as a means of meeting GHG reduction requirements, while continuing a policy of favoring renewable energy sources. Current state level climate change and renewable regulation is already providing incentives for regional wind development. The Registrants cannot predict when or whether any of these various legislative and regulatory proposals could become law or what their effect will be on the Registrants.

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Legislative and regulatory efforts in Illinois and New York to preserve the environmental attributes and reliability benefits of zero-emission nuclear-powered generating facilities through zero emission credit programs are subject to legal challenges and, if overturned, could negatively impact Exelon's and Generation's results of operations, cash flows or financial positions and result in the early retirement of certain of Generation's nuclear plants.

Generation could be negatively affected by possible Federal or state legislative or regulatory actions that could affect the scope and functioning of the wholesale markets (Exelon and Generation).

Federal and state legislative and regulatory bodies are facing pressures to address consumer concerns, or are themselves raising concerns, that energy prices in wholesale markets are too high or insufficient generation is being built because the competitive model is not working and, therefore, are considering some form of re-regulation or some other means of reducing wholesale market prices or subsidizing new generation. Generation is dependent on robust and competitive wholesale energy markets to achieve its business objectives.

Approximately 61% of Generation's generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Generation's future results of operations will depend on (1) FERC's continued adherence to and support for, policies that favor the preservation of competitive wholesale power markets and recognize the value of zero-carbon electricity and resiliency and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competition. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize existing or new generation.

FERC's requirements for market-based rate authority, established in Order 697 and 816 and related subsequent orders, could pose a risk that Generation may no longer satisfy FERC's tests for market-based rates. Since Order 697 became final in June 2007, Generation has obtained orders affirming Generation's authority to sell at market-based rates and none denying that authority.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted in July 2010. The part of the Act that affects Exelon most significantly is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires a new regulatory regime for over-the-counter swaps (swaps), including mandatory clearing for certain categories of swaps, incentives to shift swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. The primary aim of Dodd-Frank is to regulate the key intermediaries in the swaps market, which entities are swap dealers (SDs), major swap participants (MSPs), or certain other financial entities, but the law also applies to a lesser degree to end-users of swaps. The CFTC's Dodd-Frank regulations generally preserved the ability of end users in the energy industry to hedge their risks using swaps without being subject to mandatory clearing, and many of the other substantive regulations that apply to SDs, MSPs, and other financial entities. Generation manages, and expects to be able to continue to manage, its commercial activity to ensure that it does not have to register as an SD or MSP or other type of covered financial entity.

There are some rulemaking proceedings that have not yet been finalized, in particular, proposed rules on position limits that would apply to both Exchange-traded futures contracts and economically-equivalent over-the-counter swaps. It is possible that those rules will be finalized by the end of 2018. Although the company would incur some costs associated with monitoring and compliance with such rules, it does not expect the rules to have a material impact on its business operations.

The Utility Registrants could also be subject to some Dodd-Frank requirements to the extent they were to enter into swaps. However, at this time, management of the Utility Registrants continue to expect that their companies will not be materially affected by Dodd-Frank.

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Generation's affiliation with the Utility Registrants, together with the presence of a substantial percentage of Generation's physical asset base within the Utility Registrants' service territories, could increase Generation's cost of doing business to the extent future complaints or challenges regarding the Utility Registrants' retail rates result in settlements or legislative or regulatory requirements funded in part by Generation (Exelon and Generation).

Generation has significant generating resources within the service areas of the Utility Registrants and makes significant sales to each of them. Those facts tend to cause Generation to be directly affected by developments in those markets. Government officials, legislators and advocacy groups are aware of Generation's affiliation with the Utility Registrants and its sales to each of them. In periods of rising utility rates, particularly when driven by increased costs of energy production and supply, those officials and advocacy groups could question or challenge costs and transactions incurred by the Utility Registrants with Generation, irrespective of any previous regulatory processes or approvals underlying those transactions. These challenges could increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges could subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators could seek ways to force Generation to contribute to efforts to mitigate potential or actual rate increases, through measures such as generation-based taxes and contributions to rate-relief packages.

The Registrants could incur substantial costs to fulfill their obligations related to environmental and other matters (All Registrants).

The businesses which the Registrants operate are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the manner in which the Registrants conduct their operations and make capital expenditures including how they handle air and water emissions and solid waste disposal. Violations of these emission and disposal requirements could subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties' claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generate. The Registrants have incurred and expect to incur significant costs related to environmental compliance, site remediation and clean-up. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and could be subject to additional proceedings in the future.

If application of Section 316(b) of the Clean Water Act, which establishes a national requirement for reducing the adverse impacts to aquatic organisms at existing generating stations, requires the retrofitting of cooling water intake structures at Salem or other Exelon power plants, this development could result in material costs of compliance. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Additionally, Generation is subject to exposure for asbestos-related personal injury liability alleged at certain current and formerly owned generation facilities. Future legislative action could require Generation to make a material contribution to a fund to settle lawsuits for alleged asbestos-related disease and exposure.

In some cases, a third-party who has acquired assets from a Registrant has assumed the liability the Registrant could otherwise have for environmental matters related to the transferred property. If the transferee is unable, or fails, to discharge the assumed liability, a regulatory authority or injured person

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could attempt to hold the Registrant responsible, and the Registrant's remedies against the transferee could be limited by the financial resources of the transferee. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in the Utility Registrants' respective terms and conditions of service, including their respective rates, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy and subject to appeal, which lead to uncertainty as to the ultimate result and which could introduce time delays in effectuating rate changes (Exelon and the Utility Registrants).

The Utility Registrants are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for a Utility Registrant to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates could be adjusted, subject to refund or disallowed, including recovery mechanisms for costs associated with the procurement of electricity or gas, bad debt, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs.

In certain instances, the Utility Registrants could agree to negotiated settlements related to various rate matters, customer initiatives or franchise agreements. These settlements are subject to regulatory approval.

The Utility Registrants cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania, Maryland, the District of Columbia, Delaware, New Jersey or Federal regulators in establishing rates, including the extent, if any, to which certain costs such as significant capital projects will be recovered or what rates of return will be allowed. Nevertheless, the expectation is that the Utility Registrants will continue to be obligated to deliver electricity to customers in their respective service territories and will also retain significant default service obligations, referred to as POLR, DSP, SOS and BGS, to provide electricity and natural gas to certain groups of customers in their respective service areas who do not choose an alternative supplier. The ultimate outcome and timing of regulatory rate proceedings have a significant effect on the ability of the Utility Registrants, as applicable, to recover their costs or earn an adequate return and could have a material adverse effect on the Utility Registrants' results of operations, cash flows or financial positions. See Note 3 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for information regarding rate proceedings.

Federal or additional state RPS and/or energy conservation legislation, along with energy conservation by customers, could negatively affect the results of operations, cash flows or financial positions of Generation and the Utility Registrants (All Registrants).

Changes to current state legislation or the development of Federal legislation that requires the use of renewable and alternate fuel sources, such as wind, solar, biomass and geothermal, could significantly impact Generation and the Utility Registrants, especially if timely cost recovery is not allowed for Utility Registrants. The impact could include increased costs for RECs and purchased power and increased rates for customers.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, have increased capital expenditures and could significantly impact the Utility Registrants if timely cost recovery is not allowed. Furthermore, regulated energy consumption reduction targets and declines in customer energy consumption resulting from the implementation of new energy conservation technologies could lead to a decline in the revenues of Exelon, Generation and the Utility Registrants. For additional information, see ITEM 1. BUSINESS — Environmental Regulation — Renewable and Alternative Energy Portfolio Standards.

The impact of not meeting the criteria of the FASB guidance for accounting for the effects of certain types of regulation could be material to Exelon and the Utility Registrants (Exelon and the Utility Registrants).

As of December 31, 2017 , Exelon and the Utility Registrants have concluded that the operations of the Utility Registrants meet the criteria of the authoritative guidance for accounting for the effects of certain types of regulation. If it is concluded in a future period that a separable portion of their businesses no longer meets the criteria, Exelon, and the Utility Registrants would be required to eliminate the financial statement effects of regulation for that part of their business. That action would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets and the recognition of a one-time charge in their Consolidated Statements of Operations and Comprehensive Income. The impact of not meeting the criteria of the authoritative guidance could be material to the financial statements of Exelon and the Utility Registrants. The impacts and resolution of the above items could lead to an impairment of ComEd's or PHI’s goodwill, which could be significant and at least partially offset the gains at ComEd discussed above. A significant decrease in equity as a result of any changes could limit the ability of the Utility Registrants to pay dividends under Federal and state law and no longer meeting the regulatory accounting criteria could cause significant volatility in future results of operations. See Notes 1 — Significant Accounting Policies , 3 — Regulatory Matters and 10 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd’s and PHI's goodwill, respectively.

Exelon and Generation could incur material costs of compliance if Federal and/or state regulation or legislation is adopted to address climate change (Exelon and Generation).

Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. If carbon reduction regulation or legislation becomes effective, Exelon and Generation could incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. For example, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS — Global Climate Change and Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of the Utility Registrants to the results of PJM’s RTEP and NERC compliance requirements (All Registrants).

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation and the Utility Registrants, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. As operators of natural gas distribution systems, PECO, BGE and DPL are also subject to mandatory reliability standards of the U.S. Department of Transportation. The standards are based on the functions that need to be performed to ensure the

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bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards could subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU impose certain distribution reliability standards on the Utility Registrants. If the Registrants were found not to be in compliance with the mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards.

See Note 3 — Regulatory Matters and Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants could be subject to adverse publicity and reputational risks, which make them vulnerable to negative customer perception and could lead to increased regulatory oversight or other consequences (All Registrants).

The Registrants have large consumer customer bases and as a result could be the subject of public criticism focused on the operability of their assets and infrastructure and quality of their service. Adverse publicity of this nature could render legislatures and other governing bodies, public service commissions and other regulatory authorities, and government officials less likely to view energy companies such as Exelon and its subsidiaries in a favorable light, and could cause Exelon and its subsidiaries to be susceptible to less favorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent legislative or regulatory requirements (e.g. disallowances of costs, lower ROEs). The imposition of any of the foregoing could have a material negative impact on the Registrants' business, results of operations, cash flows or financial positions.

The Registrants cannot predict the outcome of the legal proceedings relating to their business activities. An adverse determination could negatively impact their results of operations, cash flows or financial positions (All Registrants).

The Registrants are involved in legal proceedings, claims and litigation arising out of their business operations, the most significant of which are summarized in Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures , result in lost revenue or restrict existing business activities, any of which could have a material adverse effect on the Registrants' results of operations, cash flows or financial positions.

Generation could be negatively affected by possible Nuclear Regulatory Commission actions that could affect the operations and profitability of its nuclear generating fleet (Exelon and Generation).

Regulatory risk

A change in the Atomic Energy Act or the applicable regulations or licenses could require a substantial increase in capital expenditures or could result in increased operating or decommissioning costs and significantly affect Generation's results of operations, cash flows or financial position. Events at nuclear plants owned by others, as well as those owned by Generation, could cause the NRC to initiate such actions.

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Spent nuclear fuel storage

The approval of a national repository for the storage of SNF, such as the one previously considered at Yucca Mountain, Nevada, and the timing of such facility opening, will significantly affect the costs associated with storage of SNF, and the ultimate amounts received from the DOE to reimburse Generation for these costs. The NRC's temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store SNF at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants.

Any regulatory action relating to the timing and availability of a repository for SNF could adversely affect Generation's ability to decommission fully its nuclear units. Through May 15, 2014, in accordance with the NWPA and Generation's contract with the DOE, Generation paid the DOE a fee per kWh of net nuclear generation for the cost of SNF disposal. This fee was discontinued effective May 16, 2014. Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. Generation cannot predict what, if any, fee will be established in the future for SNF disposal. However, such a fee could be material to Generation's results of operations, cash flows or financial position. Generation currently estimates 2030 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the SNF obligation.

Operational Factors

The Registrants' employees, contractors, customers and the general public could be exposed to a risk of injury due to the nature of the energy industry (All Registrants).

Employees and contractors throughout the organization work in, and customers and the general public could be exposed to, potentially dangerous environments near their operations. As a result, employees, contractors, customers and the general public are at some risk for serious injury, including loss of life. These risks include nuclear accidents, dam failure, gas explosions, pole strikes and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events could negatively impact the Registrants' results of operations, their ability to raise capital and their future growth (All Registrants).

Generation's fleet of power plants and the Utility Registrants' distribution and transmission infrastructures could be affected by natural disasters, such as seismic activity, fires resulting from natural causes such as lightning, extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Registrants' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment.

Natural disasters and other significant events increase the risk to Generation that the NRC or other regulatory or legislative bodies could change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological matters. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for Generation's continued operation, particularly the cooling of generating units. Additionally, natural disasters and other events that have an adverse effect on the economy in general could adversely affect the Registrants' results of operations, cash flows or financial positions and their ability to raise capital.

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The impact that potential terrorist attacks could have on the industry and on Exelon is uncertain. As owner-operators of infrastructure facilities, such as nuclear, fossil and hydroelectric generation facilities and electric and gas transmission and distribution facilities, the Registrants face a risk that their operations would be direct targets or indirect casualties of an act of terror. Any retaliatory military strikes or sustained military campaign could affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cyber security of Exelon's facilities, which could adversely affect Exelon's ability to manage its business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also could result in a decline in energy consumption or interruption of fuel or the supply chain, which could adversely affect the Registrants' results of operations, cash flows or financial positions and their ability to raise capital. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants could be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate Exelon's generating and transmission and distribution assets could be affected, resulting in decreased service levels and increased costs.

In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property, casualty and cybersecurity losses subject to unforeseen occurrences or catastrophic events that could damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

Generation's financial performance could be negatively affected by matters arising from its ownership and operation of nuclear facilities (Exelon and Generation).

Nuclear capacity factors

Capacity factors for generating units, particularly capacity factors for nuclear generating units, significantly affect Generation's results of operations. Nuclear plant operations involve substantial fixed operating costs but produce electricity at low variable costs due to nuclear fuel costs typically being lower than fossil fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear facilities at high capacity factors. Lower capacity factors increase Generation's operating costs by requiring Generation to produce additional energy from primarily its fossil facilities or purchase additional energy in the spot or forward markets in order to satisfy Generation's obligations to committed third-party sales, including the Utility Registrants. These sources generally have higher costs than Generation incurs to produce energy from its nuclear stations.

Nuclear refueling outages

In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, could have a significant impact on Generation's results of operations. When refueling outages last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales and higher operating and maintenance costs.

Nuclear fuel quality

The quality of nuclear fuel utilized by Generation could affect the efficiency and costs of Generation's operations. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

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Operational risk

Operations at any of Generation's nuclear generation plants could degrade to the point where Generation has to shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes could require significant time and expense. Generation could choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation could lose revenue and incur increased fuel and purchased power expense to meet supply commitments. For plants operated but not wholly owned by Generation, Generation could also incur liability to the co-owners. For nuclear plants not operated and not wholly owned by Generation, from which Generation receives a portion of the plants' output, Generation's results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by Generation could result in increased regulation and reduced public support for nuclear-fueled energy, which could significantly affect Generation's results of operations, cash flows or financial position. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk

Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident could be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by Generation or owned by others, could exceed Generation's resources, including insurance coverage. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by Generation and could have a material adverse effect on Generation's results of operations, cash flows or financial position. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, whether owned Generation or others, could result in increased regulation and reduced public support for nuclear-fueled energy and significantly adversely affect Generation's results of operations, cash flows or financial position.

Nuclear insurance

As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance, $ 450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $ 13.4 billion limit for a single incident.

Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation's nuclear operations. In previous years, NEIL has made distributions to its members but Generation cannot predict the level of future distributions or if they will occur at all. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

Decommissioning obligation and funding

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired and units that are within five years of retirement) addressing Generation's ability to meet the NRC-estimated funding levels including scheduled contributions to and earnings on

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the decommissioning trust funds. The NRC funding levels are based upon the assumption that decommissioning will commence after the end of the current licensed life of each unit.

Generation recognizes as a liability the present value of the estimated future costs to decommission its nuclear facilities. The estimated liability is based on assumptions in the approach and timing of decommissioning the nuclear facilities, estimation of decommissioning costs and Federal and state regulatory requirements. No assurance can be given that the costs of such decommissioning will not substantially exceed such liability, as facts, circumstances or our estimates may change, including changes in the approach and timing of decommissioning activities, changes in decommissioning costs, changes in Federal or state regulatory requirements on the decommissioning of such facilities, other changes in our estimates or Generation's ability to effectively execute on its planned decommissioning activities.

The performance of capital markets could significantly affect the value of the trust funds. Currently, Generation is making contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation, through PECO, has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from utility customers for any of its other nuclear units if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that Generation would be unable to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if Generation no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units could be negatively affected and Exelon's and Generation's results of operations, cash flows or financial positions could be significantly affected. See Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. Ultimately, if the investments held by Generation's NDTs are not sufficient to fund the decommissioning of Generation's nuclear units, Generation could be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met. As a result, Generation's results of operations, cash flows or financial position could be significantly adversely affected. Additionally, if the pledged assets are not sufficient to fund the Zion Station decommissioning activities under the Asset Sale Agreement (ASA), Generation could have to seek remedies available under the ASA to reduce the risk of default by ZionSolutions and its parent. See Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

For nuclear units that are subject to regulatory agreements with either the ICC or the PAPUC, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statements of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd and PECO have recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability.

In the case of the nuclear units subject to the regulatory agreements with the ICC, if the funds held in the NDT funds for any former ComEd unit are expected to not exceed the total decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations

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and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations, cash flows or financial positions could be material. Additionally, any remaining balances in noncurrent payables to affiliates at Generation and ComEd's noncurrent affiliate receivable from Generation and corresponding regulatory liability may need to be reversed and could have a material impact on Generation's Consolidated Statements of Operations and Comprehensive Income.

In the case of the nuclear units subject to the regulatory agreements with the PAPUC, any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations, cash flows and financial positions could be material. Additionally, any remaining balances in noncurrent payables to affiliates at Generation and PECO's noncurrent affiliate receivable from Generation and corresponding regulatory liability may need to be reversed and could have a material impact on Generation's Consolidated Statement of Operations and Comprehensive Income.

Generation's financial performance could be negatively affected by risks arising from its ownership and operation of hydroelectric facilities (Exelon and Generation).

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. The license for the Muddy Run Pumped Storage Project expires on December 1, 2055. The license for the Conowingo Hydroelectric Project expired on September 1, 2014. FERC issued an annual license, effective as of the expiration of the previous license. If FERC does not issue a license prior to the expiration of the annual license, the annual license renews automatically. Generation cannot predict whether it will receive all the regulatory approvals for the renewed licenses of its hydroelectric facilities. If FERC does not issue new operating licenses for Generation's hydroelectric facilities or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. Generation could also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions could be imposed as part of the license renewal process that could adversely affect operations, could require a substantial increase in capital expenditures or could result in increased operating costs and significantly affect Generation's results of operations, cash flows or financial position. Similar effects could result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by Generation.

The Registrants' businesses are capital intensive, and their assets could require significant expenditures to maintain and are subject to operational failure, which could result in potential liability (All Registrants).

The Registrants' businesses are capital intensive and require significant investments by Generation in electric generating facilities and by the Utility Registrants in transmission and distribution infrastructure projects. These operational systems and infrastructure have been in service for many years. Equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Registrants' control, and could require significant expenditures to operate efficiently. The Registrants' respective results of operations, cash flows or financial positions could be adversely affected if they were unable to effectively manage their capital projects or raise the necessary capital. Furthermore, operational failure of electric or gas systems, generation facilities or infrastructure could result in potential liability if such failure results in damage to property or injury to individuals. See ITEM 1. BUSINESS for further information regarding the Registrants' potential future capital expenditures.

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The Utility Registrants' operating costs, and customers' and regulators' opinions of the Utility Registrants are affected by their ability to maintain the availability and reliability of their delivery and operational systems (Exelon and the Utility Registrants).

Failures of the equipment or facilities, including information systems, used in the Utility Registrants' delivery systems could interrupt the electric transmission and electric and natural gas delivery, which could negatively impact related revenues, and increase maintenance and capital expenditures. Equipment or facilities failures can be due to a number of factors, including natural causes such as weather or information systems failure. Specifically, if the implementation of advanced metering infrastructure, smart grid or other technologies in the Utility Registrants' service territory fail to perform as intended or are not successfully integrated with billing and other information systems, the Utility Registrants' results of operations, cash flows or financial positions could be negatively impacted. Furthermore, if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, the Utility Registrants' financial results could be negatively impacted. If an employee or third party causes the operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating the operational systems, the Utility Registrants' financial results could also be negatively impacted. In addition, dependence upon automated systems could further increase the risk that operational system flaws or internal and/or external tampering or manipulation of those systems will result in losses that are difficult to detect.

The aforementioned failures or those of other utilities, including prolonged or repeated failures, could affect customer satisfaction and the level of regulatory oversight and the Utility Registrants' maintenance and capital expenditures. Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd could be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, and those damages could be material to ComEd's results of operations, cash flows or financial position.

The Utility Registrants' respective ability to deliver electricity, their operating costs and their capital expenditures could be negatively impacted by transmission congestion and failures of neighboring transmission systems (Exelon and the Utility Registrants).

Demand for electricity within the Utility Registrants' service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage with consequent effects on operating costs, revenues and results of operations. Also, insufficient availability of electric supply to meet customer demand could jeopardize the Utility Registrants' ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring the Utility Registrants to upgrade or expand their respective transmission systems through additional capital expenditures.

The electricity transmission facilities of the Utility Registrants are interconnected with the transmission facilities of neighboring utilities and are part of the interstate power transmission grid that is operated by PJM RTO. Although PJM's systems and operations are designed to ensure the reliable operation of the transmission grid and prevent the operations of one utility from having an adverse impact on the operations of the other utilities, there can be no assurance that service interruptions at other utilities will not cause interruptions in the Utility Registrants' service areas. If the Utility Registrants were to suffer such a service interruption, it could have a negative impact on their and Exelon's results of operations, cash flows and financial positions.

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The Registrants are subject to physical security and cybersecurity risks (All Registrants).

The Registrants face physical security and cybersecurity risks as the owner-operators of generation, transmission and distribution facilities and as participants in commodities trading. Threat sources continue to seek to exploit potential vulnerabilities in the electric and natural gas utility industry associated with protection of sensitive and confidential information, grid infrastructure and other energy infrastructures, and such attacks and disruptions, both physical and cyber, are becoming increasingly sophisticated and dynamic. Continued implementation of advanced digital technologies increases the potentially unfavorable impacts of such attacks. A security breach of the physical assets or information systems of the Registrants, their competitors, vendors, business partners and interconnected entities in RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or result in the theft or inappropriate release of certain types of information, including critical infrastructure information, sensitive customer, vendor and employee data, trading or other confidential data. The risk of these system-related events and security breaches occurring continues to intensify, and while the Registrants have been, and will likely continue to be, subjected to physical and cyber-attacks, to date none has directly experienced a material breach or disruption to its network or information systems or our service operations. However, as such attacks continue to increase in sophistication and frequency, the Registrants may be unable to prevent all such attacks in the future. If a significant breach were to occur, the reputation of Exelon or another Registrant and its customer supply activities could be adversely affected, customer confidence in the Registrants or others in the industry could be diminished, or Exelon and its subsidiaries could be subject to legal claims, loss of revenues, increased costs, operations shutdown, etc., any of which could contribute to the loss of customers and have a negative impact on the business and/or results of operations, cash flows or financial positions. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result. The Utility Registrants' deployment of smart meters throughout their service territories could increase the risk of damage from an intentional disruption of the system by third parties. In addition, new or updated security regulations or unforeseen threat sources could require changes in current measures taken by the Registrants or their business operations and could adversely affect their results of operations, cash flows or financial positions.

Failure to attract and retain an appropriately qualified workforce could negatively impact the Registrants' results of operations, cash flows or financial positions (All Registrants).

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, could lead to operating challenges and increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, could arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission and distribution operations. If the Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations, cash flows or financial positions could be negatively impacted.

The Registrants could make investments in new business initiatives, including initiatives mandated by regulators, and markets that may not be successful, and acquisitions could not achieve the intended financial results (All Registrants).

Generation could continue to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain. This could include investment opportunities in renewables, development of natural gas generation, nuclear advisory or operating services for third

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parties, distributed generation, potential expansion of the existing wholesale gas businesses and entry into liquefied natural gas. Such initiatives could involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market. As these markets mature, there could be new market entrants or expansion by established competitors that increase competition for customers and resources. Additionally, it is possible that FERC, state public utility commissions or others could impose certain other restrictions on such transactions. All of these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment.

The Utility Registrants face risks associated with their regulatory-mandated Smart Grid and utility of the future initiatives and other non-regulatory mandated initiatives. These risks include, but are not limited to, cost recovery, regulatory concerns, cybersecurity and obsolescence of technology. Due to these risks, no assurance can be given that such initiatives will be successful and will not have a material adverse effect on the Utility Registrants' results of operations, cash flows or financial positions.

The Registrants may not realize or achieve the anticipated cost savings through the cost management efforts which could impact the Registrants' results of operations (All Registrants).

The Registrants' future financial performance and level of profitability is dependent, in part, on various cost reduction initiatives. The Registrants may encounter challenges in executing these cost reduction initiatives and not achieve the intended cost savings.

Risks Related to the PHI Merger

The merger may not achieve its anticipated results, and Exelon could be unable to integrate the operations of PHI in the manner expected (Exelon and PHI).

Exelon and PHI entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and PHI can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Exelon's businesses, processes and systems or inconsistencies in standards, controls, procedures, practices and policies, any of which could adversely affect the combined company's ability to achieve the anticipated benefits of the merger as and when expected. Exelon could have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs and could adversely affect Exelon's and PHI's future business, prospects, results of operations, cash flows or financial conditions.

The merger may not be accretive to earnings and could cause dilution to Exelon's earnings per share, which could negatively affect the market price of Exelon's common stock (Exelon).

The timing and amount of accretion expected could be significantly adversely affected by a number of uncertainties, including market conditions, risks related to Exelon's businesses and whether the business of PHI is integrated in an efficient and effective manner. Exelon also could encounter additional transaction and integration-related costs, could fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates. Any of these factors could cause a decrease

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in Exelon's adjusted earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Exelon's common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

All Registrants

None.

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ITEM 2. PROPERTIES

Generation

The following table describes Generation's interests in net electric generating capacity by station at December 31, 2017 :

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]	
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,381	
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,347	
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,320	
Dresden	Midwest	Morris, IL	2		Uranium	Base-load	1,845	
Quad Cities	Midwest	Cordova, IL	2	75	Uranium	Base-load	1,403	[f]
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,069	
Michigan Wind 2	Midwest	Sanilac Co., MI	50	51	Wind	Base-load	46	[f][h]
Beebe	Midwest	Gratiot Co., MI	34	51	Wind	Base-load	42	[f][h]
Michigan Wind 1	Midwest	Huron Co., MI	46	51	Wind	Base-load	35	[f][h]
Harvest 2	Midwest	Huron Co., MI	33	51	Wind	Base-load	30	[f][h]
Harvest	Midwest	Huron Co., MI	32	51	Wind	Base-load	27	[f][h]
Beebe 1B	Midwest	Gratiot Co., MI	21	51	Wind	Base-load	26	[f][h]
Ewington	Midwest	Jackson Co., MN	10	99	Wind	Base-load	20	[f]
Marshall	Midwest	Lyon Co., MN	9	99	Wind	Base-load	19	[f]
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	9	
AgriWind	Midwest	Bureau Co., IL	4	99	Wind	Base-load	8	[f]
Cisco	Midwest	Jackson Co., MN	4	99	Wind	Base-load	8	[f]
Solar Ohio	Midwest	Toledo, OH	2		Solar	Base-load	4	
Blue Breezes	Midwest	Faribault Co., MN	2		Wind	Base-load	3	
CP Windfarm	Midwest	Faribault Co., MN	2	51	Wind	Base-load	2	[f][h]
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296	
Clinton Battery Storage	Midwest	Blanchester, OH	1		Energy Storage	Peaking	10	
Total Midwest							11,950	
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,317	
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,303	[f]
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,007	[f]
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	888	[f][g]
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837	[k]
Oyster Creek	Mid-Atlantic	Forked River, NJ	1		Uranium	Base-load	625	[e]
Conowingo	Mid-Atlantic	Darlington, MD	11		Hydroelectric	Base-load	572	
Criterion	Mid-Atlantic	Oakland, MD	28	51	Wind	Base-load	36	[f][h]
Fair Wind	Mid-Atlantic	Garrett County, MD	12		Wind	Base-load	30	
Solar Maryland MC	Mid-Atlantic	Various, MD	17		Solar	Base-load	29	
Fourmile	Mid-Atlantic	Garrett County, MD	16	51	Wind	Base-load	20	[f][h]
Solar New Jersey 1	Mid-Atlantic	Various, NJ	5		Solar	Base-load	18	
Solar New Jersey 2	Mid-Atlantic	Various, NJ	2		Solar	Base-load	11	

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Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]	
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1	51	Solar	Base-load	8	[f],[h]
Solar Maryland	Mid-Atlantic	Various, MD	11		Solar	Base-load	8	
Solar Maryland 2	Mid-Atlantic	Various, MD	3		Solar	Base-load	8	
Solar Federal	Mid-Atlantic	Trenton, NJ	1		Solar	Base-load	5	
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5	51	Solar	Base-load	1	[f],[h]
Solar DC	Mid-Atlantic	District of Columbia	1		Solar	Base-load	1	
Muddy Run	Mid-Atlantic	Drumore, PA	8		Hydroelectric	Intermediate	1,070	
Eddystone 3, 4	Mid-Atlantic	Eddystone, PA	2		Oil/Gas	Intermediate	760	
Perryman	Mid-Atlantic	Aberdeen, MD	5		Oil/Gas	Peaking	404	
Croydon	Mid-Atlantic	West Bristol, PA	8		Oil	Peaking	391	
Handsome Lake	Mid-Atlantic	Kennerdell, PA	5		Gas	Peaking	268	
Notch Cliff	Mid-Atlantic	Baltimore, MD	8		Gas	Peaking	117	
Westport	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	116	
Richmond	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	98	
Gould Street	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	97	
Philadelphia Road	Mid-Atlantic	Baltimore, MD	4		Oil	Peaking	61	
Eddystone	Mid-Atlantic	Eddystone, PA	4		Oil	Peaking	60	
Fairless Hills	Mid-Atlantic	Fairless Hills, PA	2		Landfill Gas	Peaking	60	
Delaware	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	56	
Southwark	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	52	
Falls	Mid-Atlantic	Morrisville, PA	3		Oil	Peaking	51	
Moser	Mid-Atlantic	Lower PottsgroveTwp., PA	3		Oil	Peaking	51	
Riverside	Mid-Atlantic	Baltimore, MD	2		Oil/Gas	Peaking	39	
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39	
Schuylkill	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	30	
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	1	42.59	Oil	Peaking	16	[f]
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	6	
Total Mid-Atlantic							11,566	
Whitetail	ERCOT	Webb County, TX	57	51	Wind	Base-load	46	[f],[h]
Sendero	ERCOT	Jim Hogg and Zapata County, TX	39	51	Wind	Base-load	40	[f],[h]
Colorado Bend II	ERCOT	Wharton, TX	3		Gas	Intermediate	1,088	
Wolf Hollow II	ERCOT	Granbury, TX	3		Gas	Intermediate	1,064	
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3		Gas	Intermediate	705	[l]
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	568	[l]
Colorado Bend	ERCOT	Wharton, TX	6		Gas	Intermediate	468	[l]
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395	[l]
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870	[l]
Mountain Creek 6, 7	ERCOT	Dallas, TX	2		Gas	Peaking	240	[l]
LaPorte	ERCOT	Laporte, TX	4		Gas	Peaking	152	[l]
Total ERCOT							5,636	
Solar Massachusetts	New England	Various, MA	10		Solar	Base-load	7	
Holyoke Solar	New England	Various, MA	2		Solar	Base-load	5	

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]	
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2	
Solar Connecticut	New England	Various, CT	1		Solar	Base-load	1	
Mystic 8, 9	New England	Charlestown, MA	6		Gas	Intermediate	1,417	
Mystic 7	New England	Charlestown, MA	1		Oil/Gas	Intermediate	575	
Wyman	New England	Yarmouth, ME	1	5.9	Oil	Intermediate	36	[f]
West Medway	New England	West Medway, MA	3		Oil	Peaking	124	
Framingham	New England	Framingham, MA	3		Oil	Peaking	30	
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9	
Total New England							2,206	
Nine Mile Point	New York	Scriba, NY	2	50.01	Uranium	Base-load	838	[f][g]
FitzPatrick	New York	Scriba, NY	1		Uranium	Base-load	842	
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288	[f][g]
Solar New York	New York	Bethlehem, NY	1		Solar	Base-load	3	
Total New York							1,971	
AVSR	Other	Lancaster, CA	1		Solar	Base-load	242	
Bluestem	Other	Beaver County, OK	60	51	Wind	Base-load	101	[f][h][i]
Exelon Wind 4	Other	Gruver, TX	38		Wind	Base-load	80	
Shooting Star	Other	Kiowa County, KS	65	51	Wind	Base-load	53	[f][h]
Albany Green Energy	Other	Albany, GA	1	99	Biomass	Base-load	46	[j]
Solar Arizona	Other	Various, AZ	127		Solar	Base-load	46	
Bluegrass Ridge	Other	King City, MO	27	51	Wind	Base-load	29	[f][h]
California PV Energy 2	Other	Various, CA	89		Solar	Base-load	27	
Conception	Other	Barnard, MO	24	51	Wind	Base-load	26	[f][h]
Cow Branch	Other	Rock Port, MO	24	51	Wind	Base-load	26	[f][h]
Solar Arizona 2	Other	Various, AZ	25		Solar	Base-load	23	
California PV Energy	Other	Various, CA	53		Solar	Base-load	21	
Mountain Home	Other	Glenns Ferry, ID	20	51	Wind	Base-load	21	[f][h]
High Mesa	Other	Elmore Co., ID	19	51	Wind	Base-load	20	[f][h]
Echo 1	Other	Echo, OR	21	50.49	Wind	Base-load	17	[f][h]
Sacramento PV Energy	Other	Sacramento, CA	4	51	Solar	Base-load	15	[f][h]
Cassia	Other	Buhl, ID	14	51	Wind	Base-load	15	[f][h]
Wildcat	Other	Lovington, NM	13	51	Wind	Base-load	14	[f][h]
Echo 2	Other	Echo, OR	10	51	Wind	Base-load	10	[f][h]
Exelon Wind 5	Other	Texhoma, TX	8		Wind	Base-load	10	
Exelon Wind 6	Other	Texhoma, TX	8		Wind	Base-load	10	
Exelon Wind 7	Other	Sunray, TX	8		Wind	Base-load	10	
Exelon Wind 8	Other	Sunray, TX	8		Wind	Base-load	10	
Exelon Wind 9	Other	Sunray, TX	8		Wind	Base-load	10	
Exelon Wind 10	Other	Dumas, TX	8		Wind	Base-load	10	

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Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]	
Exelon Wind 11	Other	Dumas, TX	8		Wind	Base-load	10	
High Plains	Other	Panhandle, TX	8	99.5	Wind	Base-load	10	(f)
Tuana Springs	Other	Hagerman, ID	8	51	Wind	Base-load	9	(f)(h)
Solar Georgia	Other	Various, GA	10		Solar	Base-load	8	
Solar Georgia 2	Other	Various, GA	6		Solar	Base-load	8	
Greensburg	Other	Greensburg, KS	10	51	Wind	Base-load	7	(f)(h)
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	6	
Echo 3	Other	Echo, OR	6	50.49	Wind	Base-load	5	(f)(h)
Three Mile Canyon	Other	Boardman, OR	6	51	Wind	Base-load	5	(f)(h)
Loess Hills	Other	Rock Port, MO	4		Wind	Base-load	5	
Mohave Sunrise Solar	Other	Fort Mohave, AZ	1		Solar	Base-load	5	
Denver Airport Solar	Other	Denver, CO	1	51	Solar	Base-load	2	(f)(h)
Hillabee	Other	Alexander City, AL	3		Gas	Intermediate	753	
Grande Prairie	Other	Alberta, Canada	1		Gas	Peaking	105	
SEGS 4, 5, 6	Other	Boron, CA	3	4.2-12.2	Solar	Peaking	9	(f)
Total Other							1,839	
Total							35,168	

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, Salem and Three Mile Island, which are pressurized water reactors.
(b) 100%, unless otherwise indicated.
(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations reflect a summer rating. Wind and solar facilities reflect name plate capacity.
(e) Generation had previously agreed to permanently cease generation operations at Oyster Creek by the end of 2019. On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018. See Note 28 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for additional information regarding the early retirement of Oyster Creek.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Reflects Generation's 50.01% interest in CENG, a joint venture with EDF. For Nine Mile Point, the co-owner owns 18% of Unit 2. Thus, Exelon's ownership is 50.01% of 82% of Nine Mile Point Unit 2.
(h) Reflects the sale of 49% of ExGen Renewables Partners to a third party on July 6, 2017. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information.
(i) ExGen Renewables Partners owns 100% of the Class A membership interests and a tax equity investor owns 100% of the Class B membership interests of the entity that owns the Bluestem generating assets.
(j) Generation directly owns a 50% interest in the Albany Green Energy station and an additional 49% through the consolidation of a Variable Interest Entity.
(k) Generation has announced it will permanently cease generation operations at TMI on or about September 30, 2019. See Note 8 — Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information regarding the early retirement of TMI.
(l) As a result of the EGTP bankruptcy and deconsolidation on November 7, 2017, Generation deconsolidated EGTP's assets and liabilities from Generation's consolidated financial statements. As of December 31, 2017 , these assets were still under Generation's ownership and included in the table. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies or generating units being temporarily out of service for inspection, maintenance, refueling, repairs or modifications required by regulatory authorities.

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding

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nuclear insurance of generating facilities, see ITEM 1. BUSINESS — Exelon Generation Company, LLC . For its insured losses, Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on Generation's consolidated financial condition or results of operations.

ComEd

ComEd's electric substations and a portion of its transmission rights of way are located on property that ComEd owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ComEd believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements, licenses and franchise rights; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ComEd's high voltage electric transmission lines owned and in service at December 31, 2017 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,718
138,000	2,209

ComEd's electric distribution system includes 35,383 circuit miles of overhead lines and 31,798 circuit miles of underground lines.

First Mortgage and Insurance

The principal properties of ComEd are subject to the lien of ComEd's Mortgage dated July 1, 1923, as amended and supplemented, under which ComEd's First Mortgage Bonds are issued.

ComEd maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ComEd is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ComEd.

PECO

PECO's electric substations and a significant portion of its transmission lines are located on property that PECO owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. PECO believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

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Transmission and Distribution

PECO's high voltage electric transmission lines owned and in service at December 31, 2017 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188(a)
230,000	548
138,000	135
69,000	181

(a) In addition, PECO has a 22.00% ownership interest in 127 miles of 500 kV lines located in Pennsylvania and a 42.55% ownership interest in 131 miles of 500 kV lines located in Delaware and New Jersey.

PECO's electric distribution system includes 12,957 circuit miles of overhead lines and 9,322 circuit miles of underground lines.

Gas

The following table sets forth PECO's natural gas pipeline miles at December 31, 2017 :

	Pipeline Miles
Transmission	30
Distribution	6,889
Service piping	6,328
Total	13,247

PECO has an LNG facility located in West Conshohocken, Pennsylvania that has a storage capacity of 1,200 mmcf and a send-out capacity of 157 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 105 mmcf and a peaking capability of 25 mmcf/day. In addition, PECO owns 31 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

The principal properties of PECO are subject to the lien of PECO's Mortgage dated May 1, 1923, as amended and supplemented, under which PECO's first and refunding mortgage bonds are issued.

PECO maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, PECO is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of PECO.

BGE

BGE's electric substations and a significant portion of its transmission lines are located on property that BGE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. BGE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and

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licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

BGE's high voltage electric transmission lines owned and in service at December 31, 2017 were as follows:

Voltage (Volts)	Circuit Miles
500,000	218
230,000	352
138,000	55
115,000	713

BGE's electric distribution system includes 9,169 circuit miles of overhead lines and 17,209 circuit miles of underground lines.

Gas

The following table sets forth BGE's natural gas pipeline miles at December 31, 2017 :

	Pipeline Miles
Transmission	161
Distribution	7,306
Service piping	6,263
Total	13,730

BGE has an LNG facility located in Baltimore, Maryland that has a storage capacity of 1,056 mmcf and a send-out capacity of 332 mmcf/day and a propane-air plant located in Baltimore, Maryland, with a storage capacity of 550 mmcf and a send-out capacity of 85 mmcf/day. In addition, BGE owns 12 natural gas city gate stations and 20 direct pipeline customer delivery points at various locations throughout its gas service territory.

Property Insurance

BGE owns its principal headquarters building located in downtown Baltimore. BGE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, BGE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of BGE.

Pepco

Pepco's electric substations and a significant portion of its transmission lines are located on property that Pepco owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. Pepco believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

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Transmission and Distribution

Pepco's high voltage electric transmission lines owned and in service at December 31, 2017 were as follows:

Voltage (Volts)	Circuit Miles
500,000	142
230,000	767
138,000	61
115,000	38

Pepco's electric distribution system includes approximately 4,105 circuit miles of overhead lines and 6,844 circuit miles of underground lines. Pepco also operates a distribution system control center in Bethesda, Maryland. The computer equipment and systems contained in Pepco's control center are financed through a sale and leaseback transaction.

First Mortgage and Insurance

The principal properties of Pepco are subject to the lien of Pepco's mortgage dated July 1, 1935, as amended and supplemented, under which Pepco First Mortgage Bonds are issued.

Pepco maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, Pepco is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of Pepco.

DPL

DPL's electric substations and a significant portion of its transmission lines are located on property that DPL owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. DPL believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

DPL's high voltage electric transmission lines owned and in service at December 31, 2017 were as follows:

Voltage (Volts)	Circuit Miles
500,000	16
230,000	470
138,000	557
69,000	576

DPL's electric distribution system includes approximately 6,028 circuit miles of overhead lines and 6,103 circuit miles of underground lines. DPL also owns and operates a distribution system control center in New Castle, Delaware.

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Gas

The following table sets forth DPL's natural gas pipeline miles at December 31, 2017 :

	Pipeline Miles
Transmission [(a)]	8
Distribution	2,061
Service piping	1,393
Total	3,462

(a) DPL has a 10% undivided interest in approximately 8 miles of natural gas transmission mains located in Delaware which are used by DPL for its natural gas operations and by 90% owner for distribution of natural gas to its electric generating facilities.

DPL owns a liquefied natural gas facility located in Wilmington, Delaware, with a storage capacity of approximately 3,045 mmcf and an emergency sendout capability of 36,000 Mcf per day. DPL owns 4 natural gas city gate stations at various locations in New Castle County, Delaware. These stations have a total primary delivery point contractual entitlement of 158,485 Mcf per day.

First Mortgage and Insurance

The principal properties of DPL are subject to the lien of DPL's mortgage dated October 1, 1947, as amended and supplemented, under which DPL First Mortgage Bonds are issued.

DPL maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, DPL is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of DPL.

ACE

ACE's electric substations and a significant portion of its transmission lines are located on property that ACE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ACE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ACE's high voltage electric transmission lines owned and in service at December 31, 2017 were as follows:

Voltage (Volts)	Circuit Miles
500,000	281
230,000	237
138,000	268
69,000	652

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ACE's electric distribution system includes approximately 7,378 circuit miles of overhead lines and 2,900 circuit miles of underground lines. ACE also owns and operates a distribution system control center in Mays Landing, New Jersey.

First Mortgage and Insurance

The principal properties of ACE are subject to the lien of ACE's mortgage dated January 15, 1937, as amended and supplemented, under which ACE First Mortgage Bonds are issued.

ACE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ACE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ACE.

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long-term design changes and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country's energy systems.

ITEM 3. LEGAL PROCEEDINGS

All Registrants

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Note 3 — Regulatory Matters and Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

All Registrants

Not Applicable to the Registrants.

PART II

(Dollars in millions except per share data, unless otherwise noted)

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Exelon

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2018 , there were 965,029,399 shares of common stock outstanding and approximately 104,909 record holders of common stock.

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2017				2016			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 42.67	$ 38.78	$ 37.44	$ 37.19	$ 36.36	$ 37.70	$ 36.37	$ 35.95
Low price	37.55	35.37	33.30	34.47	29.82	32.86	33.18	26.26
Close	39.41	37.67	36.07	35.98	35.49	33.29	36.36	35.86
Dividends	0.328	0.328	0.328	0.328	0.318	0.318	0.318	0.310

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index, for the period 2013 through 2017 .

This performance chart assumes:

- $100 invested on December 31, 2012 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.

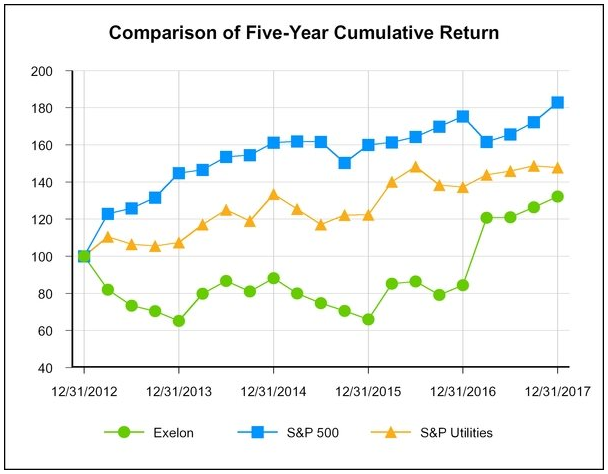

	Value of Investment at December 31,					
	2012	2013	2014	2015	2016	2017
Exelon Corporation	$100	$65.11	$88.14	$66.01	$84.36	$132.16
S&P 500	$100	$144.74	$161.22	$160.05	$175.31	$182.82
S&P Utilities	$100	$107.43	$133.52	$122.32	$137.24	$147.82

Generation

As of January 31, 2018 , Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2018 , there were 127,021,256 outstanding shares of common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. At January 31, 2018 , in addition to Exelon, there were 294 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2018 , there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2018 , there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

PHI

As of January 31, 2018 , Exelon indirectly held the entire membership interest in PHI.

Pepco

As of January 31, 2018 , there were 100 outstanding shares of common stock, $0.01 par value, of Pepco, all of which were indirectly held by Exelon.

DPL

As of January 31, 2018 , there were 1,000 outstanding shares of common stock, $2.25 par value, of DPL, all of which were indirectly held by Exelon.

ACE

As of January 31, 2018 , there were 8,546,017 outstanding shares of common stock, $3.00 par value, of ACE, all of which were indirectly held by Exelon.

All Registrants

Dividends

Under applicable Federal law, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO, BGE, PHI, Pepco, DPL or ACE may limit the dividends that these companies can distribute to Exelon.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with a financing arranged through ComEd Financing III that ComEd will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment

periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to certain dividend restrictions established by the MDPSC. First, in connection with the Constellation merger, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid and notify the MDPSC that BGE's equity ratio is at least 48% within five business days after dividend payment.

Pepco is subject to certain dividend restrictions limits imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends, and (ii) the prior rights of holders of future preferred stock, if any, and existing and future mortgage bonds and other long-term debt issued by Pepco and any other restrictions imposed in connection with the incurrence of liabilities.

DPL is subject to certain dividend restrictions imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends, and (ii) the prior rights of holders of existing and future preferred stock, mortgage bonds and other long-term debt issued by DPL and any other restrictions imposed in connection with the incurrence of liabilities.

ACE is subject to dividend restrictions imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends and the regulatory requirement that ACE obtain the prior approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%; (ii) the prior rights of holders of existing and future preferred stock, mortgage bonds and other long-term debt issued by ACE and any other restrictions imposed in connection with the incurrence of liabilities; and (iii) certain provisions of the charter of ACE which impose restrictions on payment of common stock dividends for the benefit of preferred stockholders. Currently, the restriction in the ACE charter does not limit its ability to pay common stock dividends.

Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

At December 31, 2017 , Exelon had retained earnings of $13,503 million , including Generation's undistributed earnings of $4,310 million , ComEd's retained earnings of $1,132 million consisting of retained earnings appropriated for future dividends of $2,771 million , partially offset by $1,639 million of unappropriated accumulated deficits, PECO's retained earnings of $1,087 million , BGE's retained earnings of $1,536 million , and PHI's undistributed earnings of $(10) million .

The following table sets forth Exelon's quarterly cash dividends per share paid during 2017 and 2016 :

	2017				2016			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$ 0.328	$ 0.328	$ 0.328	$ 0.328	$ 0.318	$ 0.318	$ 0.318	$ 0.310

The following table sets forth Generation's and PHI's quarterly distributions and ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's quarterly common dividend payments:

	2017				2016			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 165	$ 164	$ 166	$ 164	$ 755	$ 56	$ 56	$ 55
ComEd	106	105	106	105	94	92	92	91
PECO	72	72	72	72	69	69	70	69
BGE	50	49	50	49	45	44	45	45
PHI	44	136	62	69	99	50	16	108
Pepco	—	75	28	30	44	37	16	39
DPL	30	28	24	30	15	1	—	38
ACE	15	31	12	10	39	13	—	11

First Quarter 2018 Dividend

On January 30, 2018 , the Exelon Board of Directors declared a first quarter 2018 regular quarterly dividend of $0.3450 per share on Exelon's common stock payable on March 9, 2018 , to shareholders of record of Exelon at the end of the day on February 15, 2018 .

ITEM 6. SELECTED FINANCIAL DATA

Exelon

The selected financial data presented below has been derived from the audited consolidated financial statements of Exelon. This data is qualified in its entirety by reference to and should be read in conjunction with Exelon's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS .

	For the Years Ended December 31,				
(In millions, except per share data)	2017	2016 [a]	2015	2014 [b]	2013
Statement of Operations data:					
Operating revenues	$ 33,531	$ 31,360	$ 29,447	$ 27,429	$ 24,888
Operating income	4,260	3,112	4,409	3,096	3,669
Net income	3,849	1,204	2,250	1,820	1,729
Net income attributable to common shareholders	3,770	1,134	2,269	1,623	1,719
Earnings per average common share (diluted):					
Net income	$ 3.97	$ 1.22	$ 2.54	$ 1.88	$ 2.00
Dividends per common share	$ 1.31	$ 1.26	$ 1.24	$ 1.24	$ 1.46

(a) The 2016 financial results include the activity of PHI from the merger effective date of March 24, 2016 through December 31, 2016.
(b) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis.

	December 31,				
(In millions)	2017	2016	2015	2014	2013
Balance Sheet data:					
Current assets	$ 11,834	$ 12,412	$ 15,334	$ 11,853	$ 9,562
Property, plant and equipment, net	74,202	71,555	57,439	52,170	47,330
Total assets	116,700	114,904	95,384	86,416	79,243
Current liabilities	10,796	13,457	9,118	8,762	7,686
Long-term debt, including long-term debt to financing trusts	32,565	32,216	24,286	19,853	18,165
Shareholders' equity	29,857	25,837	25,793	22,608	22,732

Generation

The selected financial data presented below has been derived from the audited consolidated financial statements of Generation. This data is qualified in its entirety by reference to and should be read in conjunction with Generation's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS .

	For the Years Ended December 31,				
(In millions)	2017	2016	2015	2014 [a]	2013
Statement of Operations data:					
Operating revenues	$ 18,466	$ 17,751	$ 19,135	$ 17,393	$ 15,360
Operating income	921	836	2,275	1,176	1,677
Net income	2,771	558	1,340	1,019	1,060

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2014 financial results include CENG's results of operations on a fully consolidated basis.

	December 31,				
(In millions)	2017	2016	2015	2014	2013
Balance Sheet data:					
Current assets	$ 6,820	$ 6,528	$ 6,342	$ 7,311	$ 5,964
Property, plant and equipment, net	24,906	25,585	25,843	23,028	20,111
Total assets	48,387	46,974	46,529	44,951	40,700
Current liabilities	4,189	5,683	4,933	4,459	3,842
Long-term debt, including long-term debt to affiliate	8,644	8,124	8,869	7,582	7,111
Member's equity	13,630	11,482	11,635	12,718	12,725

ComEd

The selected financial data presented below has been derived from the audited consolidated financial statements of ComEd. This data is qualified in its entirety by reference to and should be read in conjunction with ComEd's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS .

	For the Years Ended December 31,				
(In millions)	2017	2016	2015	2014	2013
Statement of Operations data:					
Operating revenues	$ 5,536	$ 5,254	$ 4,905	$ 4,564	$ 4,464
Operating income	1,323	1,205	1,017	980	954
Net income	567	378	426	408	249

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	December 31,				
(In millions)	2017	2016	2015	2014	2013
Balance Sheet data:					
Current assets	$ 1,364	$ 1,554	$ 1,518	$ 1,723	$ 1,540
Property, plant and equipment, net	20,723	19,335	17,502	15,793	14,666
Total assets	29,726	28,335	26,532	25,358	24,089
Current liabilities	2,294	2,938	2,766	1,923	2,032
Long-term debt, including long-term debt to financing trusts	6,966	6,813	6,049	5,870	5,235
Shareholders' equity	9,542	8,725	8,243	7,907	7,528

PECO

The selected financial data presented below has been derived from the audited consolidated financial statements of PECO. This data is qualified in its entirety by reference to and should be read in conjunction with PECO's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS .

	For the Years Ended December 31,				
(In millions)	2017	2016	2015	2014	2013
Statement of Operations data:					
Operating revenues	$ 2,870	$ 2,994	$ 3,032	$ 3,094	$ 3,100
Operating income	655	702	630	572	666
Net income	434	438	378	352	395

	December 31,				
(In millions)	2017	2016	2015	2014	2013
Balance Sheet data:					
Current assets	$ 822	$ 757	$ 842	$ 645	$ 821
Property, plant and equipment, net	8,053	7,565	7,141	6,801	6,384
Total assets	10,170	10,831	10,367	9,860	9,521
Current liabilities	1,267	727	944	653	889
Long-term debt, including long-term debt to financing trusts	2,587	2,764	2,464	2,416	2,120
Shareholder's equity	3,577	3,415	3,236	3,121	3,065

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BGE

The selected financial data presented below has been derived from the audited consolidated financial statements of BGE. This data is qualified in its entirety by reference to and should be read in conjunction with BGE's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS .

	For the Years Ended December 31,				
(In millions)	2017	2016	2015	2014	2013
Statement of Operations data:					
Operating revenues	$ 3,176	$ 3,233	$ 3,135	$ 3,165	$ 3,065
Operating income	614	550	558	439	449
Net income	307	294	288	211	210

	December 31,				
(In millions)	2017	2016	2015	2014	2013
Balance Sheet data:					
Current assets	$ 811	$ 842	$ 845	$ 951	$ 1,009
Property, plant and equipment, net	7,602	7,040	6,597	6,204	5,864
Total assets	9,104	8,704	8,295	8,056	7,839
Current liabilities	760	707	1,134	794	800
Long-term debt, including long-term debt to financing trusts and variable interest entities	2,577	2,533	1,732	2,109	2,179
Shareholder's equity	3,141	2,848	2,687	2,563	2,365

PHI

The selected financial data presented below has been derived from the audited consolidated financial statements of PHI. This data is qualified in its entirety by reference to and should be read in conjunction with PHI's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS .

	Successor		*Predecessor*		
	For the Year Ended December 31,	March 24 to December 31	January 1 to March 23,	For the Years Ended December 31,	
(In millions)	2017	2016	2016	2015	2014
Statement of Operations data [a] :					
Operating revenues	$ 4,679	$ 3,643	$ 1,153	$ 4,935	$ 4,808
Operating income	769	93	105	673	605
Net income (loss) from continuing operations	362	(61)	19	318	242
Net income (loss)	362	(61)	19	327	242

(In millions)	Successor December 31, 2017	Successor December 31, 2016	Predecessor December 31, 2015
Balance Sheet data [a]:			
Current assets	$ 1,551	$ 1,838	$ 1,474
Property, plant and equipment, net	12,498	11,598	10,864
Total assets	21,247	21,025	16,188
Current liabilities	1,931	2,284	2,327
Long-term debt	5,478	5,645	4,823
Preferred Stock	—	—	183
Member's equity/Shareholders' equity	8,825	8,016	4,413

(a) As a result of the PHI Merger in 2016, Exelon has elected to present PHI's selected financial data for the periods reflected above.

Pepco

The selected financial data presented below has been derived from the audited consolidated financial statements of Pepco. This data is qualified in its entirety by reference to and should be read in conjunction with Pepco's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS .

(In millions)	For the Years Ended December 31, 2017	2016	2015	2014
Statement of Operations data [a]:				
Operating revenues	$ 2,158	$ 2,186	$ 2,129	$ 2,055
Operating income	399	174	385	349
Net income	205	42	187	171

(In millions)	December 31, 2017	2016	2015
Balance Sheet data [a]:			
Current assets	$ 710	$ 684	$ 726
Property, plant and equipment, net	6,001	5,571	5,162
Total assets	7,832	7,335	6,908
Current liabilities	550	596	455
Long-term debt	2,521	2,333	2,340
Shareholders' equity	2,533	2,300	2,240

(a) As a result of the PHI Merger in 2016, Exelon has elected to present Pepco's selected financial data for the periods reflected above.

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DPL

The selected financial data presented below has been derived from the audited consolidated financial statements of DPL. This data is qualified in its entirety by reference to and should be read in conjunction with DPL's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS .

	For the Years Ended December 31,			
(In millions)	2017	2016	2015	2014
Statement of Operations data [a] :				
Operating revenues	$ 1,300	$ 1,277	$ 1,302	$ 1,282
Operating income	229	50	165	207
Net income (loss)	121	(9)	76	104

	December 31,		
(In millions)	2017	2016	2015
Balance Sheet data [a] :			
Current assets	$ 325	$ 370	$ 388
Property, plant and equipment, net	3,579	3,273	3,070
Total assets	4,357	4,153	3,969
Current liabilities	547	381	564
Long-term debt	1,217	1,221	1,061
Shareholders' equity	1,335	1,326	1,237

(a) As a result of the PHI Merger in 2016, Exelon has elected to present DPL's selected financial data for the periods reflected above.

ACE

The selected financial data presented below has been derived from the audited consolidated financial statements of ACE. This data is qualified in its entirety by reference to and should be read in conjunction with ACE's Consolidated Financial Statements and ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS .

	For the Years Ended December 31,			
(In millions)	2017	2016	2015	2014
Statement of Operations data [a] :				
Operating revenues	$ 1,186	$ 1,257	$ 1,295	$ 1,210
Operating income	157	7	134	137
Net income (loss)	77	(42)	40	46

(In millions)	December 31, 2017	2016	2015
Balance Sheet data [a]:			
Current assets	$ 258	$ 399	$ 546
Property, plant and equipment, net	2,706	2,521	2,322
Total assets	3,445	3,457	3,387
Current liabilities	619	320	297
Long-term debt	840	1,120	1,153
Shareholders' equity	1,043	1,034	1,000

(a) As a result of the PHI Merger in 2016, Exelon has elected to present ACE's selected financial data for the periods reflected above.

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Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Exelon

Executive Overview

Exelon, a utility services holding company, operates through the following principal subsidiaries:

- *Generation,* whose integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in northern Illinois, including the City of Chicago.
- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE*, whose business consists of the purchase and regulated retail sale of electricity and natural gas and the provision of electricity distribution and transmission and gas distribution services in central Maryland, including the City of Baltimore.
- *Pepco,* whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission in the District of Columbia and major portions of Prince George's County and Montgomery County in Maryland.
- *DPL*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.
- *ACE*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in southern New Jersey.

Pepco, DPL and ACE are operating companies of PHI, which is a utility services holding company and a wholly owned subsidiary of Exelon.

Exelon has twelve reportable segments consisting of Generation's six reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions in Generation), ComEd, PECO, BGE and PHI's three utility reportable segments (Pepco, DPL and ACE). See Note 25 - Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of corporate governance support services including corporate strategy and development, legal, human resources, information technology, finance, real estate, security, corporate communications and supply at cost. The costs of these services are directly charged or allocated to the applicable operating segments. The services are provided pursuant to service agreements. Additionally, the results of Exelon's corporate operations include interest costs and income from various investment and financing activities.

PHISCO, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, finance, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHISCO and the participating operating subsidiaries.

Exelon's consolidated financial information includes the results of its eight separate operating subsidiary registrants, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

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Financial Results of Operations

GAAP Results of Operations

The following table sets forth Exelon's GAAP consolidated results of operations for the year ended December 31, 2017 compared to the same period in 2016 . 2016 amounts include the operations of PHI, Pepco, DPL and ACE from March 24, 2016 through December 31, 2016 . All amounts presented below are before the impact of income taxes, except as noted.

	For the Years Ended December 31,								
	2017							2016	Favorable (Unfavorable) Variance
	Generation	ComEd	PECO	BGE	PHI	Other	Exelon	Exelon [b]	
Operating revenues	$ 18,466	$ 5,536	$ 2,870	$ 3,176	$ 4,679	$ (1,196)	$ 33,531	$ 31,360	$ 2,171
Purchased power and fuel expense	9,690	1,641	969	1,133	1,716	(1,114)	14,035	12,640	(1,395)
Revenue net of purchased power and fuel expense [a]	8,776	3,895	1,901	2,043	2,963	(82)	19,496	18,720	776
Other operating expenses									
Operating and maintenance	6,291	1,427	806	716	1,068	(182)	10,126	10,048	(78)
Depreciation and amortization	1,457	850	286	473	675	87	3,828	3,936	108
Taxes other than income	555	296	154	240	452	34	1,731	1,576	(155)
Total other operating expenses	8,303	2,573	1,246	1,429	2,195	(61)	15,685	15,560	(125)
Gain (Loss) on sales of assets	2	1	—	—	1	(1)	3	(48)	51
Bargain purchase gain	233	—	—	—	—	—	233	—	233
Gain on deconsolidation of business	213	—	—	—	—	—	213	—	213
Operating income (loss)	921	1,323	655	614	769	(22)	4,260	3,112	1,148
Other income and (deductions)									
Interest expense, net	(440)	(361)	(126)	(105)	(245)	(283)	(1,560)	(1,536)	(24)
Other, net	948	22	9	16	54	7	1,056	413	643
Total other income and (deductions)	508	(339)	(117)	(89)	(191)	(276)	(504)	(1,123)	619
Income (loss) before income taxes	1,429	984	538	525	578	(298)	3,756	1,989	1,767
Income taxes	(1,375)	417	104	218	217	294	(125)	761	886
Equity in (losses) earnings of unconsolidated affiliates	(33)	—	—	—	1	—	(32)	(24)	(8)
Net income (loss)	2,771	567	434	307	362	(592)	3,849	1,204	2,645
Net income attributable to noncontrolling interests and preference stock dividends	77	—	—	—	—	2	79	70	(9)
Net income (loss) attributable to common shareholders	$ 2,694	$ 567	$ 434	$ 307	$ 362	$ (594)	$ 3,770	$ 1,134	$ 2,636

(a) The Registrants' evaluate operating performance using the measure of revenues net of purchased power and fuel expense. The Registrant's believe that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenues net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.
(b) As a result of the PHI Merger, Exelon includes the consolidated results of PHI, Pepco, DPL and ACE from March 24, 2016 through December 31, 2016.

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Exelon's Net income attributable to common shareholders was $3,770 million for the year ended December 31, 2017 as compared to $1,134 million for the year ended December 31, 2016 , and diluted earnings per average common share were $3.97 for the year ended December 31, 2017 as compared to $1.22 for the year ended December 31, 2016 .

Revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $776 million as compared to 2016 . The year-over-year increase was primarily due to the following favorable factors:

- Increase of $104 million at BGE primarily due to the impacts of the electric and natural gas distribution rate orders issued by the MDPSC in June 2016 and July 2016 and an increase in transmission formula rate revenues;
- Increase of $99 million at ComEd primarily due to increased electric distribution and transmission formula rate revenues (reflecting the impacts of increased capital investment and higher allowed electric distribution ROE), partially offset by lower revenues resulting from the change to defer and recover over time energy efficiency costs pursuant to FEJA and the impact of favorable weather conditions in 2016; and
- Increase of $767 million in Revenue net of purchased power and fuel due to the inclusion of PHI's results for the year ended December 31, 2017 compared to the period March 24, 2016 to December 31, 2016 , as well as distribution rate increases effective in 2016 and 2017.

The year-over-year increase in Revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

- Decrease of $134 million at Generation due to mark-to-market losses of $175 million in 2017 compared to mark-to-market losses of $41 million in 2016 ;
- Decrease of $46 million at PECO primarily due to unfavorable weather conditions; and
- Decrease of $11 million at Generation primarily due to lower realized energy prices, the impacts of lower load volumes delivered due to mild weather in the third quarter 2017, the conclusion of the Ginna Reliability Support Services Agreement and the impact of declining natural gas prices on Generation's natural gas portfolio, partially offset by the impact of the New York CES, increased nuclear volumes primarily as a result of the acquisition of FitzPatrick, higher capacity prices, the addition of two combined-cycle gas turbines in Texas and lower nuclear fuel prices.

Operating and maintenance expense increased by $78 million as compared to 2016 . The year-over-year increase was primarily due to the following unfavorable factors:

- Increase of $307 million at Generation due to higher asset impairment charges;
- Increase of $127 million at Generation primarily due to Generation's decision in 2017 to early retire the TMI nuclear facility compared to the previous decision in 2016 to early retire the Clinton and Quad Cities nuclear facilities;
- Increase of $104 million at Generation due to increased nuclear refueling outage costs;
- Increase of $84 million at Generation due to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units in 2017 versus 2016; and
- Increase of $253 million at PHI due to the inclusion of PHI's results for the year ended December 31, 2017 compared to the period March 24, 2016 to December 31, 2016 .

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The year-over-year increase in Operating and maintenance expense was partially offset by the following favorable factors:

- Decrease of $665 million at Exelon due to merger commitment and other merger-related costs of $73 million in 2017 compared to $738 million in 2016;
- Decrease of $85 million at ComEd due to the change to defer and recover over time energy efficiency costs pursuant to the Illinois Future Energy Jobs Act; and
- Decrease of $21 million at BGE primarily due to certain disallowances contained in the June and July 2016 rate orders, partially offset by the impact of the favorable 2016 settlement of the Baltimore City conduit fee dispute.

Depreciation and amortization expense decreased by $108 million primarily due to lower accelerated depreciation and amortization expense as a result of the 2017 decision to early retire the TMI nuclear facility compared to the previous decision in 2016 to early retire the Clinton and Quad Cities nuclear facilities, partially offset by increased depreciation expense as a result of ongoing capital expenditures across all operating companies and the inclusion of PHI's results for the year ended December 31, 2017 compared to the period March 24, 2016 to December 31, 2016 .

Taxes other than income increased by $155 million primarily due to increased real estate taxes and sales and use taxes at Generation, as well as the inclusion of PHI's results for the year ended December 31, 2017 compared to the period March 24, 2016 to December 31, 2016 .

Gain (Loss) on sales of assets increased by $51 million primarily due to certain Generation projects and contracts being terminated or renegotiated in 2016, partially offset by a gain associated with Generation’s sale of the retired New Boston generating site in 2016.

Bargain purchase gain increased by $233 million due to the gain associated with Generation's acquisition of FitzPatrick in 2017.

Gain on deconsolidation of business increased by $213 million due to the deconsolidation of EGTP's net liabilities, which included the previously impaired assets and related debt, as a result of the November 2017 bankruptcy filing.

Interest expense, net increased by $24 million primarily due to the inclusion of PHI's results for the year ended December 31, 2017 compared to the period March 24, 2016 to December 31, 2016 , partially offset by additional interest related to Exelon's like-kind exchange tax position recorded in 2016 compared to 2017.

Other, net increased by $643 million primarily due to higher net unrealized and realized gains on NDT funds at Generation for the year ended December 31, 2017 as compared to the same period in 2016 and the penalty recorded in 2016 related to Exelon's like-kind exchange tax position.

Exelon’s effective income tax rates for the years ended December 31, 2017 and 2016 were (3.3)% and 38.3% , respectively. Exelon's effective income tax rate for the year ended December 31, 2017 includes the impact of the Tax Cuts and Jobs Act. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the years ended December 31, 2017 and 2016 , including explanation of the non-GAAP measure revenues net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

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Adjusted (non-GAAP) Operating Earnings

Exelon's Adjusted (non-GAAP) operating earnings for the year ended December 31, 2017 were $2,471 million , or $2.60 per diluted share, compared with Adjusted (non-GAAP) operating earnings of $2,488 million , or $2.68 per diluted share, for the same period in 2016 . In addition to net income, Exelon evaluates its operating performance using the measure of Adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between Net income attributable to common shareholders as determined in accordance with GAAP and Adjusted (non-GAAP) operating earnings for the year ended December 31, 2017 as compared to 2016 :

	For the years ended December 31,			
	2017		2016	
(All amounts after tax; in millions, except per share amounts)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 3,770	$ 3.97	$ 1,134	$ 1.22
Mark-to-Market Impact of Economic Hedging Activities [a] (net of taxes of $68 and $18, respectively)	107	0.11	24	0.03
Unrealized Gains Related to NDT Fund Investments [b] (net of taxes of $204 and $77, respectively)	(318)	(0.34)	(118)	(0.13)
Amortization of Commodity Contract Intangibles [c] (net of taxes of $22 and $22, respectively)	34	0.04	35	0.04
Merger and Integration Costs [d] (net of taxes of $25 and $50, respectively)	40	0.04	114	0.12
Merger Commitments [e] (net of taxes of $137 and $126, respectively)	(137)	(0.14)	437	0.47
Long-Lived Asset Impairments [f] (net of taxes of $204 and $68, respectively)	321	0.34	103	0.11
Plant Retirements and Divestitures [g] (net of taxes of $134 and $273, respectively)	207	0.22	432	0.47
Reassessment of Deferred Income Taxes [h] (entire amount represents tax expense)	(1,299)	(1.37)	10	0.01
Cost Management Program [i] (net of taxes of $21 and $21, respectively)	34	0.04	34	0.04
Like-Kind Exchange Tax Position [j] (net of taxes of $66 and $61, respectively)	(26)	(0.03)	199	0.21
Asset Retirement Obligation [k] (net of taxes of $1 and $13, respectively)	(2)	—	(75)	(0.08)
Tax Settlements [l] (net of taxes of $1 and $0, respectively)	(5)	(0.01)	—	—
Bargain Purchase Gain [m] (net of taxes of $0 and $0, respectively)	(233)	(0.25)	—	—
Gain on Deconsolidation of Business [n] (net of taxes of $83 and $0, respectively)	(130)	(0.14)	—	—
Vacation Policy Change [o] (net of taxes of $21 and $0, respectively)	(33)	(0.03)	—	—
Curtailment of Generation Growth and Development Activities [p] (net of taxes of $0 and $35, respectively)	—	—	57	0.06
Change in Environmental Remediation Liabilities (net of taxes of $17 and $0, respectively)	27	0.03	—	—
Noncontrolling Interests [q] (net of taxes of $24 and $9, respectively)	114	0.12	102	0.11
Adjusted (non-GAAP) Operating Earnings	$ 2,471	$ 2.60	$ 2,488	$ 2.68

(a) Reflects the impact of net gains and losses on Generation's economic hedging activities. See Note 12 - Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.
(b) Reflects the impact of net unrealized gains on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 15 - Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Represents the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to, in 2017, the ConEdison Solutions and FitzPatrick acquisitions, and in 2016, the Integrys and ConEdison Solutions acquisitions.
(d) Primarily reflects certain costs incurred for the PHI acquisition in 2017 and 2016 and Generation's FitzPatrick acquisition in 2017, including professional fees, employee-related expenses and integration activities. See Note 4 - Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to merger and acquisition costs.
(e) Represents costs incurred as part of the settlement orders approving the PHI acquisition, and in 2017, a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions, and in 2016, a charge related to a 2012 CEG merger commitment. See Note 4 - Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to PHI Merger commitments.
(f) Primarily reflects charges to earnings in 2017 related to impairments of EGTP assets and the PHI District of Columbia sponsorship intangible asset, and in 2016, impairments of Upstream assets and certain wind projects at Generation.
(g) Primarily reflects in 2017 accelerated depreciation and amortization expenses, increases to materials and supplies inventory reserves, construction work in progress impairments and charges for severance reserves associated with Generation's decision to early retire the Three Mile Island nuclear facility. Primarily reflects in 2016 accelerated depreciation and amortization expenses through December 2016 and construction work in progress impairments associated with Generation's previous decision to early retire the Clinton and Quad Cities nuclear facilities, partially offset by a gain associated with Generation's sale of the New Boston generating site.
(h) Reflects in 2017 one-time non-cash impacts associated with remeasurements of deferred income taxes as a result of the Tax Cuts and Jobs Act (including impacts on pension obligations), changes in the Illinois and District of Columbia statutory tax rates and changes in forecasted apportionment, and in 2016, the non-cash impact of the remeasurement of deferred income taxes as a result of changes in forecasted apportionment related to the PHI acquisition.
(i) Represents severance and reorganization costs related to a cost management program.
(j) Represents in 2017 adjustments to income tax, penalties and interest expenses as a result of the finalization of the IRS tax computation related to Exelon's like-kind exchange tax position, and in 2016, the recognition of a penalty and associated interest expense as a result of a tax court decision on Exelon's like-kind exchange tax position.
(k) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units.
(l) Reflects benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI's unregulated business interests that were transferred to Generation.
(m) Represents the excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.
(n) Represents the gain recorded upon deconsolidation of EGTP's net liabilities, which included the previously impaired assets and related debt, as a result of the November 2017 bankruptcy filing.
(o) Represents the reversal of previously accrued vacation expenses as a result of a change in Exelon's vacation vesting policy.
(p) Reflects the the one-time recognition for a loss on sale of assets and asset impairment charges pursuant to Generation's strategic decision in the fourth quarter of 2016 to narrow the scope and scale of its growth and development activities.
(q) Represents elimination from Generation's results of the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.

Note:
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates ranged from 39 percent to 41 percent. Under IRS regulations, NDT fund investment returns are taxed at differing rates for investments in qualified vs. non-qualified funds. The tax rates applied to unrealized gains and losses related to NDT Fund investments were 47.4 percent and 48.7 percent for the years ended December 31, 2017 and 2016 , respectively.

Merger, Integration and Acquisition Costs

As a result of the PHI Merger that was completed on March 23, 2016, the Registrants have incurred costs associated with evaluating, structuring and executing the PHI Merger transaction itself, and will continue to incur cost associated with meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former PHI businesses into Exelon. In addition, as a result of the acquisition of the FitzPatrick nuclear generating station on March 31, 2017, Exelon and Generation incurred costs associated with evaluating, structuring and executing the transaction and integrating FitzPatrick into Exelon.

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The table below presents the one-time pre-tax charges recognized for the PHI Merger included in the Registrant's respective Consolidated Statements of Operations and Comprehensive Income.

	For the Year Ended December 31, 2016					Successor March 24, 2016 to December 31, 2016
	Exelon	Generation	Pepco	DPL	ACE	PHI
Merger commitments [a]	$ 513	$ 3	$ 126	$ 86	$ 111	$ 323
Changes in accounting and tax related policies and estimates	—	—	25	15	5	—
Total	$ 513	$ 3	$ 151	$ 101	$ 116	$ 323

(a) See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for more information.

In addition to the one-time PHI Merger charges discussed above, for the years ended December 31, 2017 and 2016 , expense has been recognized for the PHI Merger and Generation's FitzPatrick acquisition as follows:

	Pre-tax Expense For the Year Ended December 31, 2017								
Merger, Integration and Acquisition Expense:	Exelon [a]	Generation [a]	ComEd	PECO	BGE	PHI [a]	Pepco [a]	DPL [a]	ACE [a]
Transaction [b]	$ 6	$ 5	$ —	$ —	$ —	$ —	$ —	$ —	—
Other [c][d]	67	75	1	4	4	(18)	(6)	(7)	(6)
Total	$ 73	$ 80	$ 1	$ 4	$ 4	$ (18)	$ (6)	$ (7)	$ (6)

	Pre-tax Expense For the Year Ended December 31, 2016								
Merger Integration and Acquisition Expense:	Exelon [a]	Generation [a]	ComEd	PECO	BGE	PHI [a]	Pepco [a]	DPL [a]	ACE [a]
Transaction [b]	$ 34	$ 2	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Employee-related [e]	77	10	2	1	1	64	30	18	15
Other [c][d]	52	44	(8)	4	(2)	5	(2)	2	4
Total	$ 163	$ 56	$ (6)	$ 5	$ (1)	$ 69	$ 28	$ 20	$ 19

(a) For Exelon, Generation, PHI, Pepco, DPL and ACE, includes the operations of the acquired businesses beginning on March 24, 2016 .
(b) External, third party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of transactions.
(c) Costs to integrate PHI processes and systems into Exelon. For the year ended December 31, 2017 , also includes costs to integrate FitzPatrick processes and systems into Exelon.
(d) For the year ended December 31, 2017 , includes deferrals of previously incurred integration costs to achieve distribution synergies related to the PHI acquisition of $24 million , $8 million , $8 million , and $8 million incurred at PHI, Pepco, DPL, and ACE, respectively, that have been recorded as a regulatory asset for anticipated recovery. For the year ended December 31, 2016 , includes deferrals of previously incurred integration costs to achieve distribution synergies related to the PHI acquisition of $8 million , $6 million , $11 million , and $4 million incurred at ComEd, BGE, Pepco, and DPL, respectively, that have been recorded as a regulatory asset for anticipated recovery. For the Successor period March 24, 2016 to December 31, 2016 , includes deferrals of previously incurred integration costs to achieve distribution synergies related to the PHI acquisition of $16 million incurred at PHI that have been recorded as a regulatory asset for anticipated recovery. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for more information.
(e) Costs primarily for employee severance, pension and OPEB expense and retention bonuses.

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Significant 2017 Transactions and Recent Developments

Corporate Tax Reform

On December 22, 2017, President Trump signed the TCJA into law. The TCJA makes many significant changes to the Internal Revenue Code, including, but not limited to, (1) reducing the U.S. federal corporate tax rate from 35% to 21%; (2) creating a 30% limitation on deductible interest expense (not applicable to regulated utilities); (3) allowing 100% expensing for the cost of qualified property (not applicable to regulated utilities); (4) eliminating the domestic production activities deduction; (5) eliminating the corporate alternative minimum tax and changing how existing alternative minimum tax credits can be realized; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017.

The most significant change that impacts the Registrants is the reduction of the corporate federal income tax rate from 35% to 21% beginning January 1, 2018. Adjusted non-GAAP operating earnings per share for Exelon is expected to increase by approximately $0.10 on a run-rate basis in 2019 relative to Exelon's projections before the TCJA. For the Utility Registrants, the amount and timing of when certain income tax benefits resulting from the TCJA are provided to customers may vary from jurisdiction to jurisdiction.

Beginning in 2018, Generation will incur lower income tax expense, which will decrease its projected effective income tax rate, even with the elimination of the domestic production activities deduction, and increase its net income. Generation's operating cash inflows are also expected to increase beginning in 2018 reflecting the lower income tax rates and full expensing of capital investments. Generation's projected effective income tax rate in 2018, 2019, and 2020 is expected to be approximately 22%.

Beginning in 2018, the Utility Registrants will incur lower income tax expense, which will generally decrease their projected effective income tax rates. The TCJA is expected to lead to lower customer rates over time due to lower income tax expense recoveries and the settlement of deferred income tax net regulatory liabilities. The TCJA is expected to lead to an incremental increase in rate base of approximately $1.7 billion by 2020 relative to previous expectations across the Utility Registrants. The increased rate base will be funded consistent with each utility jurisdiction, using a combination of third party debt financings and equity funding from Exelon generally consistent with existing capitalization ratio structures. To fund any additional equity contributions to the Utility Registrants, Exelon would have available to it its typical sources, including, but not limited to, the increased operating cash flows at Generation referenced above, which over time are expected to exceed the incremental equity needs at the Utility Registrants. The TCJA is generally expected to result in lower operating cash inflows for the Utility Registrants as a result of the elimination of bonus depreciation and lower customer rates.

Exelon Corporate expects that the interest on its debt will continue to be fully tax deductible albeit at a lower tax rate.

The Utility Registrants continue to work with their state regulatory commissions to determine the amount and timing of the passing back of TCJA income tax savings benefits to customers; with filings either made, or expected to be made, at Pepco, DPL and ACE, and approved filings at ComEd and BGE. The amounts being passed back or proposed to be passed back to customers reflect the benefit of lower income tax expense beginning January 1, 2018 (Feb. 1, 2018 for DPL Delaware), and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. To date, neither the PAPUC nor FERC has yet issued guidance on how and when to reflect the impacts of the TCJA in customer rates. Refer to Note 3 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information on their filings.

Early Nuclear Plant Retirements

On May 30, 2017, Generation announced it will permanently cease generation operations at Three Mile Island Generating Station (TMI) on or about September 30, 2019. The TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020-2021 planning year and will not receive capacity revenue for that period, the third consecutive year that TMI failed to clear the PJM base residual capacity auction. The plant is currently committed to operate through May 2019. In 2017, as a result of the plant retirement decision of TMI, Exelon and Generation recognized one-time charges in Operating and maintenance expense of $77 million related to materials and supplies inventory reserve adjustments, employee-related costs and construction work-in-progress (CWIP) impairments, among other items. In addition to these one-time charges, there will be ongoing annual incremental non-cash charges to earnings stemming from shortening the expected economic useful life of TMI primarily related to accelerated depreciation of plant assets (including any asset retirement costs (ARC)), accelerated amortization of nuclear fuel, and additional asset retirement obligation (ARO) accretion expense associated with the changes in decommissioning timing and cost assumptions. During the year ended December 31, 2017 , both Exelon's and Generation's results include an incremental $262 million of pre-tax expense for these items.

The following table summarizes the estimated annual amount and timing of expected incremental non-cash expense items through 2019.

	Actual	Projected [a]	
Income statement expense (pre-tax)	2017	2018	2019
Depreciation and Amortization			
Accelerated depreciation [b]	$ 250	$ 440	$ 330
Accelerated nuclear fuel amortization	12	20	5
Total	$ 262	$ 460	$ 335

(a) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.
(b) Reflects incremental accelerated depreciation of plant assets, including any ARC.

On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018. In 2010, Generation announced that Oyster Creek would retire by the end of 2019 as part of an agreement with the State of New Jersey to avoid significant costs associated with the construction of cooling towers to meet the State's then new environmental regulations. Since then, like other nuclear sites, Oyster Creek has continued to face rising operating costs amid a historically low wholesale power price environment. The decision to retire Oyster Creek in 2018 at the end of its current operating cycle involved consideration of several factors, including economic and operating efficiencies, and avoids a refueling outage scheduled for the fall of 2018 that would have required advanced purchasing of fuel fabrication and materials beginning in late February 2018.

Because of the decision to retire Oyster Creek in 2018, Exelon and Generation will recognize certain one-time charges in the first quarter of 2018 ranging from an estimated $25 million to $35 million (pre-tax) related to a materials and supplies inventory reserve adjustment, employee-related costs, and construction work-in-progress impairment, among other items. Estimated cash expenditures related to the one-time charges primarily for employee-related costs are expected to range from $5 million to $10 million.

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In addition to these one-time charges, there will be financial impacts stemming from shortening the expected economic useful life of Oyster Creek primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions to reflect an earlier retirement date. The following table summarizes the estimated amount of expected incremental non-cash expense items expected to be incurred in 2018 because of the early retirement decision.

	Projected [b]
Income statement expense (pre-tax)	2018
Depreciation and Amortization	
Accelerated depreciation [a]	$110 to $140
Accelerated nuclear fuel amortization	$40
Operating and Maintenance	
Increased ARO accretion	Up to $5

(a) Includes the accelerated depreciation of plant assets including any ARC.
(b) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.

EGTP Consent Agreement and Bankruptcy

On May 2, 2017, EGTP, an indirect subsidiary of Exelon and Generation, entered into a consent agreement with its lenders to permit EGTP to draw on its revolving credit facility and initiate an orderly sales process to sell the assets of its wholly owned subsidiaries. As a result, Exelon and Generation classified certain EGTP assets and liabilities as held for sale at their respective fair values less costs to sell and recorded a $460 million pre-tax impairment loss during 2017. On November 7, 2017, EGTP and all of its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware. As a result, Exelon and Generation deconsolidated EGTP's assets and liabilities from their consolidated financial statements and recorded a $213 million pre-tax gain. See Note 4 — Mergers, Acquisitions and Dispositions , Note 7 — Impairment of Long-Lived Assets and Intangibles and Note 13 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information regarding EGTP and the associated nonrecourse debt.

Acquisition of James A. FitzPatrick Nuclear Generating Station

On March 31, 2017, Generation acquired the 842 MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station for a total purchase price of $289 million . In accounting for the acquisition as a business combination, Exelon and Generation recorded an after-tax bargain purchase gain of $233 million which is included within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information regarding the Generation's acquisition of FitzPatrick and related costs.

Illinois Future Energy Jobs Act

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA was effective on June 1, 2017, and includes, among other provisions, (1) a Zero Emission Standard (ZES) providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd’s electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd’s customer rates

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exceeds specified limits, (6) revisions to the existing net metering statute and (7) support for low income rooftop and community solar programs . FEJA establishes new or adjusts existing rate recovery mechanisms for ComEd to recover costs associated with the new or expanded energy efficiency and RPS requirements. Regulatory or legal challenges over the validity of FEJA are possible. See Note 3 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information regarding FEJA. See Note 8 — Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information regarding the economic challenges facing Generation's Clinton and Quad Cities nuclear plants and the expected benefits of the ZES.

Illinois ZEC Procurement

On January 25, 2018, the ICC announced that Generation's Clinton Unit 1, Quad Cities Unit 1 and Quad Cities Unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event. Generation executed the ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and will begin recognizing revenue. Winning bidders will be entitled to compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. In the first quarter of 2018, Generation will recognize approximately $150 million of revenue and ComEd will record an obligation to Generation and corresponding reduction to its regulatory liability of approximately $100 million related to ZECs generated from June 1, 2017 through December 31, 2017.

Dismissal of Litigation Challenging ZEC Programs

On July 14, 2017, the U.S. District Court for the Northern District of Illinois dismissed two lawsuits challenging the ZEC program contained in FEJA. On July 17, 2017, the plaintiffs appealed the court's decisions to the U.S. Court of Appeals for the Seventh Circuit. Briefs were fully submitted on December 12, 2017 and the Court heard oral argument on January 3, 2018. At the argument, the Court asked for supplemental briefing, which was filed on January 26, 2018.

Additionally, on July 25, 2017, the U.S. District Court for the Southern District of New York dismissed a lawsuit challenging the ZEC program contained in the New York CES. On August 24, 2017, the plaintiffs appealed the decision to the Second Circuit. Briefing in the appeal was completed in December 2017, and oral argument is expected to take place in March 2018.

In addition, on November 30, 2016, a group of parties, including certain environmental groups and individuals, filed a Petition in New York State court seeking to invalidate the ZEC program. The Petition, which was amended on January 13, 2017, argued that the NYPSC did not have authority to establish the program and that it violated certain technical provisions of the State Administrative Procedures Act (SAPA) when adopting the ZEC program. On February 15, 2017, Generation and CENG filed a motion to dismiss the state court action. The NYPSC also filed a motion to dismiss the state court action. On March 24, 2017, the plaintiffs filed a memorandum of law opposing the motions to dismiss, and Generation and CENG filed a reply brief on April 28, 2017. Oral argument was held on June 19, 2017. On January 22, 2018, the court denied the motions to dismiss without commenting on the merits of the case. The case will now proceed to summary judgment upon filing of the full record.

The court decisions to date have upheld the ZEC programs which support Illinois's and New York's efforts to advance clean energy and preserve affordable and reliable energy resources for customers. See Note 3 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information regarding FEJA and the New York CES.

Merger Commitment Unrecognized Tax Benefits

Exelon established a liability for an uncertain tax position associated with the tax deductibility of certain merger commitments incurred by Exelon in connection with the acquisitions of Constellation in 2012 and PHI in 2016. In the first quarter 2017, as a part of its examination of Exelon's return, the IRS

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National Office issued guidance concurring with Exelon's position that the merger commitments were deductible. As a result, Exelon, Generation, PHI, Pepco, DPL and ACE decreased their liability for unrecognized tax benefits by $146 million , $19 million , $59 million , $21 million , $16 million , and $22 million , respectively, as of December 31, 2017 , resulting in a benefit to Income taxes on Exelon's, Generation's, PHI's, Pepco's, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income and corresponding decreases in their effective tax rates.

Combined-Cycle Gas Turbine Projects

In June 2017, Generation commenced commercial operations of two new combined-cycle gas turbines (CCGTs) at the Colorado Bend II and Wolf Hollow II Generating Stations in Texas. The two new CCGTs have added nearly 2,200 MWs of capacity to Generation's fleet, enhancing Generation's strategy to match generation to customer load. Generation invested approximately $1.5 billion over the past three years to complete the new plant construction, which utilizes new General Electric technology to make them among the cleanest, most efficient CCGTs in the nation.

Utility Rates and Rate Proceedings

The Utility Registrants file rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants' current and future results of operations, cash flows and financial position.

The following tables show the Utility Registrants' completed and pending distribution rate case proceedings in 2017.

Completed Distribution Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase (in millions)	Approved Return on Equity	Completion Date	Rate Effective Date
ComEd	Illinois (Electric) [a]	$ 96 [b]	8.4% [c]	December 6, 2017	January 1, 2018
Pepco	District of Columbia (Electric)	$ 37	9.5%	July 25, 2017	August 15, 2017
Pepco	Maryland (Electric)	$ 32	9.5%	October 27, 2017	October 20, 2017
DPL	Maryland (Electric)	$ 38	9.6%	February 15, 2017	February 15, 2017
DPL	Delaware (Electric)	$ 31.5	9.7%	May 23, 2017	June 1, 2017
DPL	Delaware (Natural Gas)	$ 4.9	9.7%	June 6, 2017	July 1, 2017
ACE	New Jersey (Electric)	$ 43	9.6%	September 22, 2017	October 1, 2017

(a) Pursuant to EIMA, ComEd's electric distribution rates are established through a performance-based formula through which ComEd is required to file an annual update on or before May 1, with resulting rates effective in January of the following year. ComEd's annual electric distribution formula rate update is based on prior year actual costs and current year projected capital additions (initial year revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred for the year (annual reconciliation).
(b) Reflects an increase of $78 million for the initial revenue requirement for 2017 and an increase of $18 million related to the annual reconciliation.
(c) ComEd's allowed ROE under its electric distribution formula rate is the annual average rate on 30-year treasury notes plus 580 basis points and is subject to reduction if ComEd does not deliver certain reliability and customer service benefits. The initial revenue requirement for 2017 reflects an allowed ROE of 8.40%, while the annual reconciliation reflects an allowed ROE of 8.34%, which is inclusive of a 6-basis-point performance penalty.

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Pending Distribution Rate Case Proceedings

Company	Jurisdiction	Requested Revenue Requirement Increase (in millions)	Requested Return on Equity	Filing Date	Expected Completion Timing
Pepco	Maryland (Electric)	$ 11 [a]	10.1%	January 2, 2018 (Updated February 5, 2018)	Third quarter 2018
Pepco	District of Columbia (Electric)	$ 66 [b]	10.1%	December 19, 2017	Fourth quarter 2018
DPL	Maryland (Electric)	$ 19 [b][c]	10.1% [c]	July 14, 2017 (Updated on November 16, 2017)	First quarter 2018
DPL	Delaware (Electric)	$ 31 [b]	10.1%	August 17, 2017 (Updated on October 18, 2017)	Third quarter 2018
DPL	Delaware (Natural Gas)	$ 11 [b]	10.1%	August 17, 2017 (Updated on November 7, 2017)	Fourth quarter 2018

(a) On February 5, 2018, Pepco filed with the MDPSC an update to its current distribution rate case to reflect approximately $31 million in TCJA tax savings, thereby reducing the requested annual base rate increase to $11 million .
(b) By mid-February, Pepco and DPL will update their current distribution rate cases to reflect the TCJA impacts.
(c) On December 18, 2017, a settlement agreement was filed with the MDPSC wherein DPL will be granted a rate increase of $13 million , and a ROE of 9.5% solely for purposes of calculating AFUDC and regulatory asset carrying costs. On January 5, 2018, the MDPSC held a hearing on the settlement agreement. DPL expects a decision in the matter in the first quarter of 2018, but cannot predict whether the MDPSC will approve the settlement agreement as filed or how much of the requested increase will be approved.

Transmission Formula Rates

The following total increases/(decreases) were included in ComEd's, BGE's, Pepco's, DPL's and ACE's 2017 annual electric transmission formula rate filings:

	2017				
Annual Transmission Filings [a]	ComEd	BGE	Pepco	DPL	ACE
Initial revenue requirement increase	$ 44	$ 31	$ 5	$ 6	$ 20
Annual reconciliation increase (decrease)	(33)	3	15	8	22
Dedicated facilities decrease [b]	—	(8)	—	—	—
Total revenue requirement increase	$ 11	$ 26	$ 20	$ 14	$ 42
Allowed return on rate base [c]	8.43%	7.47%	7.92%	7.16%	8.02%
Allowed ROE [d]	11.50%	10.50%	10.50%	10.50%	10.50%

(a) All rates are effective June 2017.
(b) BGE's transmission revenues include a FERC approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE.
(c) Represents the weighted average debt and equity return on transmission rate bases.
(d) As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50% , inclusive of a 50-basis-point incentive adder for being a member of a RTO, and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55% . As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50% , inclusive of a 50-basis-point incentive adder for being a member of a RTO.

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PECO Transmission Formula Rate. On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO's transmission rate is determined from a fixed rate to a formula rate. The formula rate would be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO's annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50-basis-point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. PECO cannot predict the final outcome of the settlement or hearing proceedings, or the transmission formula FERC may approve.

See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details on these regulatory proceedings.

Westinghouse Electric Company LLC Bankruptcy

On March 29, 2017, Westinghouse Electric Company LLC (Westinghouse) and its affiliated debtors filed petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York. In the petitions and supporting documents, Westinghouse makes clear that its requests for relief center on one business area that is losing money - the construction of nuclear power plants in Georgia and South Carolina. On January 4, 2018, Westinghouse announced its agreement to be acquired by Brookfield Business Partners. The deal, which requires bankruptcy court and regulatory approvals, is expected to close in in the third quarter of 2018. Brookfield has informally indicated to Generation that it will assume all of Exelon's contracts with Westinghouse. Generation is monitoring the bankruptcy and pending sale proceedings to ensure that its rights are protected.

ExGen Renewables Holdings, LLC Transaction

On July 6, 2017, ExGen Renewables Holdings, LLC, a wholly owned subsidiary of Generation, completed the sale of a 49% interest of ExGen Renewables Partners, LLC, a newly formed owner and operator of approximately 1,439 megawatts of Generation's operating wind and solar electric generating facilities. ExGen Renewables Holdings will be the managing member of ExGen Renewables Partners, LLC, and have day-to-day control and management over its renewable generation portfolio. The closing of the transaction was subject to certain regulatory approvals, including the Federal Energy Regulatory Commission (FERC) and the Public Utility Commission of Texas (PUCT) which were received during the second quarter of 2017. The sale price was $400 million plus immaterial working capital and other customary post-closing adjustments. The net proceeds, after approximately $100 million of income taxes, will be used to pay down debt and for general corporate purposes. Generation will continue to consolidate ExGen Renewables Partners, LLC and will record a noncontrolling interest on its Consolidated Balance Sheet for the investor's equity share as well as earnings attributable to the noncontrolling interest in the Consolidated Statements of Operations and Comprehensive Income each period going forward.

Hurricanes Harvey, Irma and Maria Impacts

Although Exelon subsidiaries provided substantial assistance to recovery efforts following Hurricanes Harvey and Irma, Hurricanes Harvey, Irma and Maria are not expected to have a material impact on the Registrants' businesses or financial results given the limited operations in the areas affected by the storms.

Exelon's Strategy and Outlook for 2018 and Beyond

Exelon's value proposition and competitive advantage come from its scope and its core strengths of operational excellence and financial discipline. Exelon leverages its integrated business model to create value. Exelon's regulated and competitive businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- Exelon's utilities provide a foundation for steadily growing earnings, which translates to a stable currency in our stock.
- Generation's competitive businesses provide free cash flow to invest primarily in the utilities and in long-term, contracted assets and to reduce debt.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The Exelon utilities only invest in rate base where it provides a benefit to customers and the community by improving reliability and the service experience or otherwise meeting customer needs. The Exelon utilities make these investments at the lowest reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of resources and best practices to achieve improved operational and financial results. Additionally, the Utility Registrants anticipate making significant future investments in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Generation's competitive businesses create value for customers by providing innovative energy solutions and reliable, clean and affordable energy. Generation's electricity generation strategy is to pursue opportunities that provide stable revenues and generation to load matching to reduce earnings volatility. Generation leverages its energy generation portfolio to deliver energy to both wholesale and retail customers. Generation's customer-facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon's financial priorities are to maintain investment grade credit metrics at each of the Registrants, to maintain optimal capital structure and to return value to Exelon's shareholders with an attractive dividend throughout the energy commodity market cycle and through stable earnings growth. Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Various market, financial, regulatory, legislative and operational factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. One key issue is ensuring the ability to properly value nuclear generation assets in the market, solutions to which Exelon is actively pursuing in a variety of jurisdictions and venues. See ITEM 1A. RISK FACTORS for additional information regarding market and financial factors.

Continually optimizing the cost structure is a key component of Exelon's financial strategy. In August 2015, Exelon announced a cost management program focused on cost savings of approximately $400 million at BSC and Generation, of which approximately 60% of run-rate savings was achieved by the

end of 2017 with the remainder to be fully realized in 2018. At least 75% of the savings are expected to be related to Generation, with the remaining amount related to the Utility Registrants. Additionally, in November 2017, Exelon announced a new commitment for an additional $250 million of cost savings, primarily at Generation, to be achieved by 2020. These actions are in response to the continuing economic challenges confronting all parts of Exelon's business and industry, necessitating continued focus on cost management through enhanced efficiency and productivity.

Growth Opportunities

Management continually evaluates growth opportunities aligned with Exelon's businesses, assets and markets, leveraging Exelon's expertise in those areas and offering sustainable returns.

Regulated Energy Businesses. The PHI merger provides an opportunity to accelerate Exelon's regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, the Utility Registrants anticipate investing approximately $26 billion over the next five years in electric and natural gas infrastructure improvements and modernization projects, including smart meter and smart grid initiatives, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $15 billion by the end of 2022. The Utility Registrants invest in rate base where beneficial to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made at the lowest reasonable cost to customers.

See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives and infrastructure development and enhancement programs.

Competitive Energy Businesses. Generation continually assesses the optimal structure and composition of its generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation's long-term growth strategy is to ensure appropriate valuation of its generation assets, in part through public policy efforts, identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, and identify emerging technologies where strategic investments provide the option for significant future growth or influence in market development.

Liquidity Considerations

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and OPEB obligations and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.6 billion , $5.3 billion , $1.0 billion , $0.6 billion , $0.6 billion , $0.5 billion , $0.5 billion and $0.4 billion , respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.5 billion . See Liquidity and Capital Resources — Credit Matters — Exelon Credit Facilities below.

For further detail regarding the Registrants' liquidity for the year ended December 31, 2017 , see Liquidity and Capital Resources discussion below.

Project Financing

Generation utilizes individual project financings as a means to finance the construction of various generating asset projects. Project financing is based upon a nonrecourse financial structure, in which project debt and equity used to finance the project are paid back from the cash generated by the newly constructed asset once operational. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other project-related borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, or restructured, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives. See Note 13 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on nonrecourse debt.

Other Key Business Drivers and Management Strategies

Utility Rates and Rate Proceedings

The Utility Registrants file rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants' current and future results of operations, cash flows and financial positions. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details on these regulatory proceedings.

Power Markets

Price of Fuels

The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Capacity Market Changes in PJM

In the wake of the January 2014 Polar Vortex that blanketed much of the Eastern and Midwestern United States, it became clear that while a major outage event was narrowly avoided, resources in PJM were not providing the level of reliability expected by customers. As a result, on December 12, 2014, PJM filed at FERC a proposal to make significant changes to its current capacity market construct, the Reliability Pricing Model (RPM). PJM's proposed changes generally sought to improve resource performance and reliability largely by limiting the excuses for non-performance and by increasing the penalties for performance failures. The proposal permits suppliers to include in capacity market offers additional costs and risk so they can meet these higher performance requirements. While offers are expected to put upward pressure on capacity clearing prices, operational improvements made as a result of PJM's proposal are expected to improve reliability, to reduce energy production costs as a result of more efficient operations and to reduce the need for out of market energy payments to suppliers. Generation participated actively in PJM's stakeholder process through which PJM developed the proposal and also actively participated in the FERC proceeding including filing comments. On June 9,

2015, FERC approved PJM's filing largely as proposed by PJM, including transitional auction rules for delivery years 2016/2017 through 2017/2018. As a result of this and several related orders, PJM hosted its 2018/2019 Base Residual Auction (results posted on August 21, 2015) and its transitional auction for delivery year 2016/2017 (results posted on August 31, 2015) and its transitional auction for delivery years 2017/2018 (results posted on September 9, 2015). On May 10, 2016, FERC largely denied rehearing, and a number of parties appealed to the U.S. Court of Appeals for the DC Circuit for review of the decision. On June 20, 2017, the DC Circuit denied all the appeals.

MISO Capacity Market Results

On April 14, 2015, the MISO released the results of its capacity auction covering the June 2015 through May 2016 delivery year. As a result of the auction, capacity prices for the zone 4 region in downstate Illinois increased to $150 per MW per day beginning in June 2015, an increase from the prior pricing of $16.75 per MW per day that was in effect from June 2014 to May 2015. Generation had an offer that was selected in the auction. However, due to Generation's ratable hedging strategy, the results of the capacity auction have not had a material impact on Exelon's and Generation's consolidated results of operations and cash flows.

Additionally, in late May and June 2015, separate complaints were filed at the FERC by each of the State of Illinois, the Southwest Electric Cooperative, Public Citizens, Inc., and the Illinois Industrial Energy Consumers challenging the results of this MISO capacity auction for the 2015/2016 delivery in MISO delivery zone 4. The complaints allege generally that 1) the results of the capacity auction for zone 4 are not just and reasonable, 2) the results should be suspended, set for hearing and replaced with a new just and reasonable rate, 3) a refund date should be established and that 4) certain alleged behavior by one of the market participants other than Exelon or Generation, be investigated.

On October 1, 2015, FERC announced that it was conducting a non-public investigation (that does not involve Exelon or Generation) into whether market manipulation or other potential violations occurred related to the auction. On December 31, 2015, FERC issued a decision that certain of the rules governing the establishment of capacity prices in downstate Illinois are "not just and reasonable" on a prospective basis. FERC ordered that certain rules be changed prior to the April 2016 auction which set capacity prices for the 2016/2017 planning year. In response to this order, MISO filed certain rule changes with FERC. On March 18, 2016, FERC largely denied rehearing of its December 31, 2015 order. FERC continues to conduct its non-public investigation to determine if the April 2015 auction results were manipulated and, if so, whether refunds are appropriate. FERC did establish May 28, 2015, the day the first complaint was filed, as the date from which refunds (if ordered) would be calculated, and it also made clear that the findings in the December 31, 2015 order do not prejudge the investigation or related proceedings. Generation cannot predict the impact the FERC order may ultimately have on future auction results, capacity pricing or decisions related to the potential early retirement of the Clinton nuclear plant, however, such impacts could be material to Generation's future results of operations and cash flows . See Note 8 - Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement.

Complaints at FERC Seeking to Mitigate Illinois and New York Programs Providing ZECs

PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to remove the revenues it receives through a federal, state or other government-provided financial support program - resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new resources. Exelon has generally opposed policies that require subsidies or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid. Thus, Exelon has supported a MOPR as a means of minimizing the detrimental impact certain subsidized resources could have on capacity markets (such as the New

Jersey (LCAPP) and Maryland (CfD) programs). However, in Exelon's view, MOPRs should not be applied to resources that receive compensation for providing superior reliability or environmental benefits.

On January 9, 2017, the Electric Power Supply Association (EPSA) filed two requests with FERC: one seeking to amend a prior complaint against PJM and another seeking expedited action on a pending NYISO compliance filing in an existing proceeding. Both filings allege that the relevant MOPR should be expanded to also apply to existing resources receiving ZEC compensation under the New York CES and Illinois ZES programs. The EPSA parties have filed motions to expedite both proceedings. Exelon has filed protests at FERC in response to each filing, arguing generally that ZEC payments provide compensation for an environmental attribute that is distinct from the energy and capacity sold in the FERC-jurisdictional markets , and therefore, are no different than other renewable support programs like the PTC and RPS that have generally not been subject to a MOPR. However, if successful, for Generation's facilities in NYISO and PJM expected to receive ZEC compensation (Quad Cities, Ginna, Nine Mile Point and FitzPatrick), an expanded MOPR could require exclusion of ZEC compensation when bidding into future capacity auctions such that these facilities would have an increased risk of not clearing in those auctions and thus no longer receiving capacity revenues during the respective ZEC programs. Any such mitigation of these generating resources could have a material effect on Exelon's and Generation's future cash flows and results of operations. On August 30, 2017, EPSA filed motions to lodge the district court decisions dismissing the complaints and urging FERC to act expeditiously on its requests to expand the MOPR. On September 14, 2017, Exelon filed a response in each docket noting that it does not oppose the motions to lodge but arguing that the requests to expedite a decision on the requests to expand the MOPR have no merit. The timing of FERC's decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

DOE Notice of Proposed Rulemaking

On August 23, 2017, the DOE staff released its report on the reliability of the electric grid. One aspect of the wide-ranging report is the DOE's recognition that the electricity markets do not currently value the resiliency provided by baseload generation, such as nuclear plants. On September 28, 2017, the DOE issued a Notice of Proposed Rulemaking (NOPR) that would entitle certain eligible resilient generating units (i.e., those located in organized markets, with a 90-day supply of fuel on site, not already subject to state cost of service regulation and satisfying certain other requirements) to recover fully allocated costs and earn a fair return on equity on their investment. The DOE's NOPR recommended that the FERC take comments for 45 days after publication in the Federal Register and issue a final order 60 days after such publication. On January 8, 2018, the FERC issued an order terminating the rulemaking docket that was initiated to address the proposed rule in the DOE NOPR, concluding the proposed rule did not sufficiently demonstrate there is a resiliency issue and that it proposed a remedy that did not appear to be just, reasonable and nondiscriminatory as required under the Federal Power Act. At the same time, the FERC initiated a new proceeding to consider resiliency challenges to the bulk power system and evaluate whether additional FERC action to address resiliency would be appropriate. The FERC directed each RTO and ISO to respond within 60 days to 24 specific questions about how they assess and mitigate threats to resiliency. Interested parties may submit reply comments within 30 days after the due date of the RTO/ISO responses. Exelon has been and will continue to be an active participant in these proceedings, but cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.

Energy Demand

Modest economic growth partially offset by energy efficiency initiatives is resulting in flat to declining load growth in electricity for the utilities. There is decrease in projected load for electricity for ComEd, PECO, BGE, and DPL, and an increase in projected load for electricity for Pepco and ACE. ComEd, PECO, BGE, Pepco, DPL, and ACE are projecting load volumes to increase (decrease) by (0.5)% , (0.5)% , (0.6)% , 1.5% , (1.5)% and 1.5% , respectively, in 2018 compared to 2017 .

Retail Competition

Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. The market experienced high price volatility in the first quarter of 2014 which contributed to bankruptcies and consolidations within the industry during the year. However, forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

Strategic Policy Alignment

As part of its strategic business planning process, Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's Board of Directors declared first, second, third and fourth quarter 2017 dividends of $0.3275 per share each on Exelon's common stock, and the first quarter 2018 dividends declared was $0.3450 per share. The dividends for the first, second, third and fourth quarter 2017 were paid on March 10, 2017 , June 9, 2017 , September 8, 2017 and December 8, 2017 , respectively. The first quarter 2018 dividend is payable on March 9, 2018 .

Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2018 and 2019 . However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of December 31, 2017 , the percentage of expected generation hedged is 85% - 88% , 55% - 58% and 26% - 29% for 2018 , 2019 , and 2020 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the

contracted prices. Approximately 59% of Generation's uranium concentrate requirements from 2018 through 2022 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial positions.

The Utility Registrants mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Environmental Legislative and Regulatory Developments

Exelon was actively involved in the Obama Administration's development and implementation of environmental regulations for the electric industry, in pursuit of its business strategy to provide reliable, clean, affordable and innovative energy products. These efforts have most frequently involved air, water and waste controls for fossil-fueled electric generating units, as set forth in the discussion below. These regulations have had a disproportionate adverse impact on coal-fired power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Due to its low emission generation portfolio, Generation has not been significantly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil fuel plants.

Through the issuance of a series of Executive Orders (EO), President Trump has initiated review of a number of EPA and other regulations issued during the Obama Administration, with the expectation that the Administration will seek repeal or significant revision of these rules. Under these EOs, each executive agency is required to evaluate existing regulations and make recommendations regarding repeal, replacement, or modification. The Administration's actions are intended to result in less stringent compliance requirements under air, water, and waste regulations. The exact nature, extent, and timing of the regulatory changes are unknown, as well as the ultimate impact on Exelon's and its subsidiaries results of operations and cash flows.

In particular, the Administration has targeted existing EPA regulations for repeal, including notably the Clean Power Plan, as well as revoking many Executive Orders, reports, and guidance issued by the Obama Administration on the topic of climate change or the regulation of greenhouse gases. The Executive Order also disbanded the Interagency Working Group that developed the social cost of carbon used in rulemakings, and withdrew all technical support documents supporting the calculation. Other regulations that have been specifically identified for review are the Clean Water Act rule relating to jurisdictional waters of the U.S., the Steam Electric Effluent Guidelines relating to waste water discharges from coal-fired power plants, and the 2015 National Ambient Air Quality Standard (NAAQS) for ozone. The review of final rules could extend over several years as formal notice and comment rulemaking process proceeds.

Air Quality

Mercury and Air Toxics Standard Rule (MATS). On December 16, 2011, the EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals, and to make capital investments in pollution control equipment and incur higher operating expenses. The initial compliance deadline to meet the new standards was April 16, 2015; however, facilities may have been granted an additional one or two-year extension in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. In April 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety. On appeal, the U.S. Supreme Court decided in June 2015 that the EPA unreasonably refused to consider costs in determining whether it is appropriate and necessary to regulate

hazardous air pollutants emitted by electric utilities. The U.S. Supreme Court, however, did not vacate the rule; rather, it was remanded to the D.C. Circuit Court to take further action consistent with the U.S. Supreme Court's opinion on this single issue. On April 27, 2017, the D.C. Circuit granted EPA's motion to hold the litigation in abeyance, pending EPA's review of the MATS rule pursuant to President Trump's EO discussed above. Following EPA's review and determination of its course of action for the MATS rule, the parties will have 30 days to file motions on future proceedings. Notwithstanding the Court's order to hold the litigation in abeyance, the MATS rule remains in effect. Exelon will continue to participate in the remanded proceedings before the D.C. Circuit Court as an intervenor in support of the rule.

Clean Power Plan . On April 28, 2017, the D.C. Circuit Court issued orders in separate litigation related to the EPA's actions under the Clean Power Plan (CPP) to amend Clean Air Act Section 111(d) regulation of existing fossil-fired electric generating units and Section 111(b) regulation of new fossil-fired electric generating units. In both cases, the Court has determined to hold the litigation in abeyance pending a determination whether the rule should be remanded to the EPA. On October 10, 2017, EPA issued a proposed rule to repeal the CPP in its entirety, based on a proposed change in the Agency's legal interpretation of Clean Air Act Section 111(d) regarding actions that the Agency can consider when establishing the Best System of Emission Reduction ("BSER") for existing power plants. Under the proposed interpretation, the Agency exceeded its authority under the Clean Air Act by regulating beyond individual sources of GHG emissions. The EPA has also indicated its intent to issue an advance notice of proposed rulemaking to solicit information on systems of emission reduction that are in accord with the Agency's proposed revised legal interpretation; namely, only by regulating emission reductions that can be implemented at and to individual sources.

2015 Ozone National Ambient Air Quality Standards (NAAQS). On April 11, 2017, the D.C. Circuit ordered that the consolidated 2015 ozone NAAQS litigation be held in abeyance pending EPA's further review of the 2015 Rule. EPA did not meet the October 1, 2017 deadline to promulgate initial designations for areas in attainment or non-attainment of the standard. A number of states and environmental organizations have notified the EPA of their intent to file suit to compel EPA to issue the designations.

Climate Change. Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. In the absence of Federal legislation, the EPA is moving forward with the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change ("UNFCCC" or "Convention"). See ITEM 1. BUSINESS , "Global Climate Change" for further discussion.

Water Quality

Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by recent changes to the regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, FitzPatrick, Ginna, Gould Street, Mountain Creek, Handley, Mystic 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities, and Salem. See ITEM 1. BUSINESS , "Water Quality" for further discussion.

Solid and Hazardous Waste

In October 2015, the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants became effective. The rule classifies CCR as non-hazardous waste under RCRA. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the

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federal regulations. Generation has previously recorded accruals consistent with state regulation for its owned coal ash sites, and as such, the regulation is not expected to impact Exelon's and Generation's financial results. Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted under the new federal regulations for coal ash disposal sites formerly owned by Generation. For these reasons, Generation is unable to predict whether and to what extent it may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations.

See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Employees

In January 2017, an election was held at BGE which resulted in union representation for approximately 1,394 employees. BGE and IBEW Local 410 are negotiating an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. No agreement has been finalized to date and management cannot predict the outcome of such negotiations. In April 2017, Exelon Nuclear Security successfully ratified its CBA with the SPFPA Local 238 at Quad Cities to an extension of three years. In June 2017, Exelon Nuclear Security successfully ratified its CBA with the UGSOA Local 12 at Limerick to an extension of three years.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions with its Accounting and Disclosure Governance Committee on a regular basis and provides periodic updates on management decisions to the Audit Committee of the Exelon Board of Directors. Management believes that the accounting policies described below require significant judgment in their application, or incorporate estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation's ARO associated with decommissioning its nuclear units was $9.7 billion at December 31, 2017 . The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple decommissioning outcome scenarios.

As a result of recent nuclear plant retirements in the industry, nuclear operators and third-party service providers are obtaining more information about costs associated with decommissioning activities. At the same time, regulators are gaining more information about decommissioning activities which could result in changes to existing decommissioning requirements. In addition, as more nuclear plants are retired, it is possible that technological advances will be identified that could create efficiencies and lead to a reduction in decommissioning costs. The availability of decommissioning trust funds could impact the timing of the decommissioning activities. Additionally, certain factors such as changes in regulatory requirements during plant operations or the profitability of a nuclear plant could impact the timing of plant retirements. These factors could result in material changes to Generation's current estimates as more information becomes available and could change the timing of plant retirements and the probability assigned to the decommissioning outcome scenarios.

The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing and/or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the following methodologies and significant estimates and assumptions:

Decommissioning Cost Studies

Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the expected costs (in current year dollars) and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within the industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years, unless circumstances warrant more frequent updates (such as a change in assumed operating life for a nuclear plant). As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle.

Cost Escalation Factors

Generation uses cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors, and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal and other costs. All of the nuclear AROs are adjusted each year for the updated cost escalation factors.

Probabilistic Cash Flow Models

Generation's probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning cost levels, decommissioning approaches, and timing of plant shutdown on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. Probabilities are also assigned to four different decommissioning approaches.

1. DECON - a method of decommissioning shortly after the cessation of operation in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a LLRW landfill or decontaminated to a level that permits property to be released for unrestricted use. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

2. Delayed DECON - similar to the DECON scenario but with a delay to allow for spent fuel to be removed from the site prior to onset of decommissioning activities. Spent fuel is retained in existing location (either wet or dry storage) until DOE acceptance for disposal.

3. Shortened SAFSTOR - similar to the DECON scenario but with generally a 30-year delay prior to onset of decommissioning activities. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

4. SAFSTOR - a method of decommissioning in which the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated to levels that permit release for unrestricted use generally within 60 years after cessation of operations. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal .

The actual decommissioning approach selected once a nuclear facility is shutdown will be determined by Generation at the time of shutdown and may be influenced by multiple factors including the funding status of the nuclear decommissioning trust fund at the time of shutdown.

The assumed plant shutdown timing scenarios include the following four alternatives: (1) the probability of operating through the original 40-year nuclear license term, (2) the probability of operating through an extended 60-year nuclear license term (regardless of whether such 20-year license extension has been received for each unit), (3) the probability of a second, 20-year license renewal for some nuclear units, and (4) the probability of early plant retirement for certain sites due to changing market conditions and regulatory environments. The successful operation of nuclear plants in the U.S. beyond the initial 40-year license terms has prompted the NRC to consider regulatory and technical requirements for potential plant operations for an 80-year nuclear operating term. As power market and regulatory environment developments occur, Generation evaluates and incorporates, as necessary, the impacts of such developments into its nuclear ARO assumptions and estimates.

Generation's probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal. Generation currently assumes DOE will begin accepting SNF in 2030. The SNF acceptance date assumption is based on management's estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

License Renewals

Except for its Clinton unit, Generation has successfully obtained initial 20-year operating license renewal extensions (i.e., extending the total license term to 60 years) for all of its operating nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG). Generation intends to apply for an initial license renewal for the Clinton unit. Clinton depreciation provisions are based on 2027 which is the last year of the Illinois Zero Emissions Standard. No prior Generation initial license extension application has been denied. Generation intends to apply for a second 20-year renewal for the Peach Bottom Units 2 and 3.

Discount Rates

The probability-weighted estimated future cash flows for the various assumed scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. The authoritative guidance required Generation to establish an ARO at fair value at the time of the initial adoption. Subsequent to the initial adoption, the ARO is adjusted for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions, as described above. The ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. Increases in the ARO as a result of upward revisions in estimated undiscounted cash flows are considered new obligations and are measured using a current CARFR as the increase creates a new cost layer within the ARO. Any decrease in the estimated undiscounted future cash flows relating to the ARO are treated as a modification of an existing ARO cost layer and, therefore, is measured using the average historical CARFR rates used in creating the initial ARO cost layers. If Generation's future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFR, the obligation would increase from approximately $9.7 billion to approximately $10.3 billion .

To illustrate the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO: i) had Generation used the 2016 CARFR rather than the 2017 CARFR in performing its annual 2017 ARO update, Generation would have increased the ARO by an additional $10 million ; and ii) if the CARFR

used in performing the annual 2017 ARO update are increased by 50 basis points or decreased by 50 basis points, the ARO would have decreased by $170 million and increased by $30 million , respectively, as compared to the actual decrease of $69 million .

ARO Sensitivities

Changes in the assumptions underlying the ARO could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions may correspondingly change.

The following table illustrates the effects of changing certain ARO assumptions while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption	Increase (Decrease) to ARO at December 31, 2017
Cost escalation studies	
Uniform increase in escalation rates of 50 basis points	$ 1,690
Probabilistic cash flow models	
Increase the estimated costs to decommission the nuclear plants by 10 percent	700
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	500
Shorten each unit's probability weighted operating life assumption by 10% [(a)]	660
Extend the estimated date for DOE acceptance of SNF to 2035	130

(a) Timing sensitivity does not include any sites for which an early plant retirement has been announced.

For more information regarding accounting for nuclear decommissioning obligations, see Note 1 — Significant Accounting Policies , Note 8 — Early Nuclear Plant Retirements and Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements.

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Goodwill (Exelon, Generation, ComEd, PHI and DPL)

As of December 31, 2017 , Exelon's $6.7 billion carrying amount of goodwill primarily consists of $2.6 billion at ComEd relating to the acquisition of ComEd in 2000 as part of the formation of Exelon and $4 billion at PHI pursuant to Exelon's acquisition of PHI in the first quarter of 2016. DPL has $8 million of goodwill as of December 31, 2017 , related to its 1995 acquisition of the Conowingo Power Company. Generation also has goodwill of $47 million as of December 31, 2017 . Under the provisions of the authoritative guidance for goodwill, these entities are required to perform an assessment for possible impairment of their goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting units below their carrying amount. Under the authoritative guidance, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and its operating results are regularly reviewed by segment management. ComEd has a single operating segment, and PHI's operating segments are Pepco, DPL and ACE. See Note 25 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information. There is no level below these operating segments for which operating results are regularly reviewed by segment management. Therefore, the ComEd, Pepco, DPL and ACE operating segments are also considered reporting units for goodwill impairment testing purposes. Exelon's and ComEd's $2.6 billion of goodwill has been assigned entirely to the ComEd reporting unit, while Exelon's and PHI's $4 billion of goodwill has been assigned to the Pepco, DPL and ACE reporting units in the amounts of $1.7 billion , $1.1 billion and $1.2 billion , respectively. DPL's $8 million of goodwill is assigned entirely to the DPL reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations including regulatory and political developments, overall financial performance, cost factors, and entity-specific conditions and events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the qualitative assessment, or performs the qualitative assessment but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed.

Exelon's, ComEd's and PHI's accounting policy is to perform a quantitative test of goodwill at least once every three years, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount. The first step in the quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation authoritative guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. In January 2017, the FASB issued a new standard, effective January 1, 2020 with early adoption permitted, that simplifies the accounting for goodwill impairment by removing the second step of the test and, instead, measuring goodwill impairment at the amount by which a reporting unit's carrying value exceeds its fair value (currently the first step in the test). Exelon, Generation, ComEd, PHI and DPL have not determined whether to early adopt this standard.

Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates,

utility sector market performance and transactions, projected operating and capital cash flows for ComEd's, Pepco's, DPL's and ACE's businesses and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

For their 2017 annual goodwill impairment assessments, Exelon, ComEd, PHI and DPL each qualitatively determined that it was more likely than not that the fair value of their respective reporting unit exceeded their respective carrying value. Therefore, ComEd, PHI and DPL did not perform quantitative assessments. As part of their qualitative assessments, ComEd, PHI and DPL evaluated, among other things, management's best estimate of projected operating and capital cash flows for their businesses, outcomes of recent regulatory proceedings, changes in certain market conditions, including the discount rate and regulated utility peer EBITDA multiples, and the passing margin from their last quantitative assessments performed as of November 1, 2016.

ComEd, PHI and DPL performed quantitative tests as of November 1, 2016, for their 2016 annual goodwill impairment assessments. The first step of the tests comparing the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units to their carrying values, including goodwill, indicated no impairments of goodwill; therefore, no second steps were required.

While the annual assessments indicated no impairments, certain assumptions used to estimate reporting unit fair values are highly sensitive to changes. Adverse regulatory actions or changes in significant assumptions could potentially result in future impairments of Exelon's, ComEd's, PHI's or DPL's goodwill, which could be material. Based on the results of the annual goodwill tests performed as of November 1, 2016, the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units would have needed to decrease by more than 30% , 10% , 10% and 10% , respectively, for Exelon, ComEd and PHI to have failed the first step of their respective impairment tests. For the $8 million of goodwill recorded at DPL related to DPL's 1995 acquisition of the Conowingo Power Company, the fair value of the DPL reporting unit would have needed to decrease by more than 50% for DPL to fail the first step of the impairment test.

See Note 1 — Significant Accounting Policies , Note 10 — Intangible Assets and Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon, Generation and PHI)

In January 2017, the FASB issued a new standard, effective January 1, 2018 with early adoption permitted, that clarifies the definition of a business with the objective of addressing whether acquisitions/dispositions should be accounted for as acquisitions/dispositions of assets or as acquisitions/dispositions of businesses. The Registrants did not early adopt this new standard. See Note 1-Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for further information.

In accordance with authoritative guidance, the assets acquired and liabilities assumed in an acquired business are recorded at their estimated fair values on the date of acquisition. The difference between the purchase price amount and the net fair value of assets acquired and liabilities assumed is recognized as goodwill on the balance sheet if the purchase price exceeds the estimated net fair value or as a bargain purchase gain on the income statement if the purchase price is less than the estimated net fair value. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, often utilizes independent valuation experts and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, could significantly impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. Authoritative guidance provides that the allocation of the purchase price may be modified up to one year after the

acquisition date as more information is obtained about the fair value of assets acquired and liabilities assumed. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Contract Assets and Liabilities (Exelon, Generation and PHI)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired and the electricity contracts Exelon has acquired as part of the PHI acquisition. The initial amount recorded represents the fair value of the contracts at the time of acquisition. At PHI, offsetting regulatory assets or liabilities were also recorded. The unamortized energy contract assets and liabilities and any corresponding regulatory assets or liabilities, respectively, are amortized over the life of the contract in relation to the expected realization of the underlying cash flows. Amortization of the unamortized energy contract assets and liabilities is recorded through purchased power and fuel expense or operating revenues, depending on the nature of the underlying contract. Refer to Note 3 — Regulatory Matters , Note 4 — Mergers, Acquisitions and Dispositions and Note 10 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for further discussion.

Impairment of Long-lived Assets (All Registrants)

All Registrants regularly monitor and evaluate their long-lived assets and asset groups, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of potential impairment may include a deteriorating business climate, including declines in energy prices, condition of the asset, an asset remaining idle for more than a short period of time, specific regulatory disallowance, advances in technology or plans to dispose of a long-lived asset significantly before the end of its useful life, among others.

The review of long-lived assets and asset groups for impairment utilizes significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power and purchases of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could have a significant impact on the consolidated financial statements. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by the evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units as well as the associated intangible assets or liabilities recorded on the balance sheet. The cash flows from the generating units are generally evaluated at a regional portfolio level with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generating assets (typically contracted renewables).

On a quarterly basis, Generation assesses its long-lived assets or asset groups for indicators of impairment. If indicators are present for a long-lived asset or asset group, a comparison of the undiscounted expected future cash flows to the carrying value is performed. When the undiscounted cash flow analysis indicates the carrying value of a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value of the long-lived asset or asset group is dependent upon a market participant's view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates.

Events and circumstances often do not occur as expected and there will usually be differences between prospective financial information and actual results, and those differences may be material. The determination of fair value is driven by both internal assumptions that include significant unobservable inputs (Level 3) such as revenue and generation forecasts, projected capital, and maintenance expenditures and discount rates, as well as information from various public, financial and industry sources.

Generation evaluates its equity method investments and other investments in debt and equity securities to determine whether or not they are impaired based on whether the investment has experienced a decline in value that is not temporary in nature. Beginning January 1, 2018, the authoritative guidance eliminates the available-for-sale and cost method classifications for equity securities and requires that all equity investments (other than those accounted for using the equity method of accounting) be measured and recorded at fair value with any changes in fair value recorded through earnings. Investments in equity securities without readily determinable fair values must be qualitatively assessed for impairment each reporting period and fair value determined if any significant impairment indicators exist. If the fair value is less than the carrying value, the impairment is recorded through earnings immediately in the period in which it is identified without regard to whether the decline in value is temporary in nature. The new authoritative guidance does not impact the classification or measurement of investments in debt securities. See Note 1 - Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for further information.

See Note 7 — Impairment of Long-Lived Assets and Intangibles of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Exelon.

Depreciable Lives of Property, Plant and Equipment (All Registrants)

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. These assets are generally depreciated on a straight-line basis, using the group, composite or unitary methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for heterogeneous assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. The estimation of asset useful lives requires management judgment, supported by formal depreciation studies of historical asset retirement experience. Depreciation studies are generally completed every five years, or more frequently if required by a rate regulator or if an event, regulatory action, or change in retirement patterns indicate an update is necessary.

For the Utility Registrants, depreciation studies generally serve as the basis for amounts allowed in customer rates for recovery of depreciation costs. Generally, the Utility Registrants adjust their depreciation rates for financial reporting purposes concurrent with adjustments to depreciation rates reflected in customer rates, unless the depreciation rates reflected in customer rates do not align with management's judgment as to an appropriate estimated useful life or have not been updated on a timely basis. Depreciation expense for ComEd, BGE, Pepco, DPL and ACE includes an estimated cost of dismantling and removing plant from service upon retirement. Actual incurred removal costs are applied against a related regulatory liability or recorded to a regulatory asset if in excess of previously collected removal costs. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method. Estimates for such removal costs are also evaluated in the periodic depreciation studies.

At Generation, along with depreciation study results, management considers expected future energy market conditions and generation plant operating costs and capital investment requirements in determining the estimated service lives of its generating facilities. See Note 8 — Early Nuclear Plant

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Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on expected and potential early nuclear plant retirements.

Generation completed a depreciation rate study during the first quarter of 2015, which resulted in revised depreciation rates effective January 1, 2015.

ComEd is required to file an electric distribution depreciation rate study at least every five years with the ICC. ComEd completed an electric distribution and transmission depreciation study and filed the updated depreciation rates with both the ICC and FERC in January 2014, resulting in new depreciation rates effective first quarter 2014.

PECO is required to file electric distribution and gas depreciation rate studies at least every five years with the PAPUC. In March 2015, PECO filed a depreciation rate study with the PAPUC for both its electric distribution and gas assets, resulting in new depreciation rates for electric transmission assets effective January 1, 2015, for gas distribution assets effective July 1, 2015, and for electric distribution assets effective January 1, 2016.

The MDPSC does not mandate the frequency or timing of BGE's electric distribution or gas depreciation studies. In July 2014, BGE filed revised depreciation rates with the MDPSC for both its electric distribution and gas assets, which became effective December 15, 2014. In addition, BGE's electric transmission depreciation rates were updated effective April 1, 2015.

The MDPSC does not mandate the frequency or timing of Pepco's electric distribution depreciation studies, while the DCPSC directs Pepco as to when it should file an electric distribution depreciation study. In 2016 and 2013, Pepco filed revised electric distribution depreciation rates with the MDPSC and DCPSC, respectively, with the new rates effective November 15, 2016 and April 16, 2014, respectively. On December 19, 2017, Pepco filed an electric distribution rate application which included revised depreciation rates. Pepco expects a decision in the fourth quarter of 2018.

Neither the DPSC nor the MDPSC mandates the frequency or timing of DPL's electric distribution or gas depreciation studies. On July 20, 2016, DPL filed revised electric depreciation rates with the MDPSC as part of the electric distribution base rate filing, resulting in new depreciation rates effective on April 20, 2017. On May 17, 2016, DPL filed revised electric and natural gas depreciation rates with the DPSC as part of the electric and natural gas base rate case filing, resulting in new electric depreciation rates effective June 1, 2017 and new gas depreciation rates effective July 1, 2017.

The NJBPU does not mandate the frequency or timing of ACE's electric distribution depreciation studies. In 2012, ACE filed revised electric distribution depreciation rates with the NJBPU, with the new rates effective July 1, 2013. ACE expects to perform an electric distribution depreciation study in 2018.

While FERC does not mandate the frequency or timing of electric transmission depreciation studies, the Utility Registrants and Generation perform studies on all assets every 5 years. Pepco, DPL and ACE last performed transmission depreciation studies in 1988, 1990, and 2003, respectively, but are adopting Exelon's practice and are currently evaluating the timing of the next study.

Changes in estimated useful lives of electric generation assets and of electric and natural gas transmission and distribution assets could have a significant impact on the Registrants' future results of operations. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant and equipment of the Registrants.

Defined Benefit Pension and Other Postretirement Employee Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement employee benefit plans for substantially all current employees. See Note 16 — Retirement Benefits of the Combined Notes to

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Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and other postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits involves various factors, including the development of valuation assumptions and inputs and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is affected by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, the anticipated rate of increase of health care costs, Exelon's expected level of contributions to the plans, the incidence of participant mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the long-term expected investment rate credited to employees of certain plans, among others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. Exelon amortizes actuarial gains or losses in excess of a corridor of 10% of the greater of the projected benefit obligation or the market-related value (MRV) of plan assets over the expected average remaining service period of plan participants. Pension and other postretirement benefit costs attributed to the operating companies are labor costs and are ultimately allocated to projects within the operating companies, some of which are capitalized.

Pension and other postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 16 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification under the fair value hierarchy in accordance with authoritative guidance.

Expected Rate of Return on Plan Assets

In determining the EROA, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectation regarding future long-term capital market performance, weighted by Exelon's target asset class allocations. Exelon calculates the amount of expected return on pension and other postretirement benefit plan assets by multiplying the EROA by the MRV of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments to be made during the year. In determining MRV, the authoritative guidance for pensions and postretirement benefits allows the use of either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. For the majority of pension plan assets, Exelon uses a calculated value that adjusts for 20% of the difference between fair value and expected MRV of plan assets. Use of this calculated value approach enables less volatile expected asset returns to be recognized as a component of pension cost from year to year. For other postretirement benefit plan assets and certain pension plan assets, Exelon uses fair value to calculate the MRV. See Note 16 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon's EROA assumptions.

Discount Rate

At December 31, 2017 and 2016 , the discount rates were determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated future benefit distribution amounts under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates. See Note 16 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon's discount rate assumptions.

Health Care Cost Trend Rate

Assumed health care cost trend rates impact the costs reported for Exelon's other postretirement benefit plans for participant populations with plan designs that do not have a cap on cost growth. Authoritative guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty. Exelon assumes an ultimate health care cost trend rate of 5.00% has been reached in 2017 for its other postretirement benefit plans.

Mortality

The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. Exelon's mortality assumption is supported by an actuarial experience study of Exelon's plan participants and utilizes the IRS's RP-2000 base table and the Scale BB 2-Dimensional improvement scale with long-term improvements of 0.75% .

Sensitivity to Changes in Key Assumptions

The following tables illustrate the effects of changing certain of the actuarial assumptions discussed above, while holding all other assumptions constant (dollars in millions):

	Actual Assumption					
Actuarial Assumption	Pension	OPEB	Change in Assumption	Pension	OPEB	Total
Change in 2017 cost:						
Discount rate [a]	4.04%	4.04%	0.5%	$ (72)	$ (16)	$ (88)
	4.04%	4.04%	(0.5)%	89	19	108
EROA	7.00%	6.58%	0.5%	(85)	(12)	(97)
	7.00%	6.58%	(0.5)%	85	12	97
Health care cost trend rate	NA	5.00%	1.00%	N/A	9	9
	NA	5.00%	(1.00)%	N/A	(8)	(8)
Change in benefit obligation at December 31, 2017:						
Discount rate [a]	3.62%	3.61%	0.5%	(1,183)	(252)	(1,435)
	3.62%	3.61%	(0.5)%	1,371	291	1,662
Health care cost trend rate	NA	5.00%	1.00%	N/A	125	125
	NA	5.00%	(1.00)%	N/A	(113)	(113)

(a) In general, the discount rate will have a larger impact on the pension and other postretirement benefit cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon utilizes a liability-driven investment strategy for its pension asset portfolio. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

Regulatory Accounting (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

Exelon and the Utility Registrants account for their regulated electric and gas operations in accordance with the authoritative guidance, which requires Exelon and the Utility Registrants to reflect the effects of cost-based rate regulation in their financial statements. This authoritative guidance is

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applicable to entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) revenue or gains that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2017 , Exelon and the Utility Registrants have concluded that the operations of each such Registrant meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of operations no longer meets the criteria of this authoritative guidance, Exelon and the Utility Registrants would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and Comprehensive Income and could be material. At December 31, 2017 , the gain (loss) could have been as much as $1.1 billion , $5.3 billion , $280 million , $592 million , $(1.1) billion , $(59) million , $321 million and $(8) million (before taxes) as a result of the elimination of regulatory assets and liabilities of Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to $3.8 billion , $2.4 billion , $544 million , $177 million , $407 million , $202 million and $92 million related to Exelon's, ComEd's, BGE's, PHI's, Pepco's, DPL's and ACE's respective portions of the deferred costs associated with Exelon's pension and other postretirement benefit plans that are recorded as regulatory assets on Exelon's Consolidated Balance Sheets. Exelon also has a net regulatory liability of $(31) million (before taxes) related to PECO's portion of the deferred costs associated with Exelon's other postretirement benefit plans that would result in an increase in OCI if reversed. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon and the Utility Registrants.

For each regulatory jurisdiction in which they conduct business, Exelon and the Utility Registrants assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs in each Registrant's jurisdictions, and factors such as changes in applicable regulatory and political environments. Furthermore, each Registrant makes other judgments related to the financial statement impact of their regulatory environments, such as the types of adjustments to rate base that will be acceptable to regulatory bodies, if any, for which costs will be recoverable through rates. Refer to the revenue recognition discussion below for additional information on the annual revenue reconciliations associated with ICC-approved electric distribution and energy efficiency formula rates for ComEd, and FERC transmission formula rate tariffs for ComEd, PECO, BGE, Pepco, DPL and ACE. Additionally, estimates are made in accordance with the authoritative guidance for contingencies as to the amount of revenues billed under certain regulatory orders that may ultimately be refunded to customers upon finalization of applicable regulatory or judicial processes. These assessments are based, to the extent possible, on past relevant experience with regulatory bodies in each Registrant's jurisdictions, known circumstances specific to a particular matter and hearings held with the applicable regulatory body. If the assessments and estimates made by Exelon and the Utility Registrants for regulatory assets and regulatory liabilities are ultimately different than actual regulatory outcomes, the impact on their results of operations, cash flows and financial positions could be material.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Accounting for Derivative Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk, foreign currency exchange risk and interest rate risk related to ongoing business operations. The Registrants' derivative activities are in accordance with Exelon's Risk Management Policy (RMP). See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether a contract qualifies as a derivative requires that management exercise significant judgment, including assessing market liquidity as well as determining whether a contract has one or more underlyings and one or more notional quantities. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance, could result in previously excluded contracts becoming in scope to new authoritative guidance. Generation has determined that contracts to purchase uranium, contracts to purchase and sell capacity in certain ISO's, certain emission products, ZECs and RECs do not meet the definition of a derivative as they do not provide for net settlement and the uranium, certain capacity, emission and ZEC and REC markets are not sufficiently liquid to conclude that physical forward contracts are readily convertible to cash. If these markets become sufficiently liquid, then Generation would be required to account for these contracts as derivative instruments. In this case, if market prices differ from the underlying prices of the contracts, Generation would be required to record mark-to-market gains or losses, which could have a material impact to Exelon's and Generation's results of operations and financial positions.

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, the normal purchases and normal sales exception. Further, derivatives that qualify and are designated for hedge accounting are classified as either fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings immediately. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in AOCI and reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. The Registrants rarely elect hedge accounting for commodity transactions. Economic commodity hedges are recorded at fair value through earnings. In addition, for commodity derivatives executed for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings immediately. For economic hedges that are not designated for hedge accounting for the Utility Registrants, changes in the fair value each period are generally recorded with a corresponding offsetting regulatory asset or liability given likelihood of recovering the associated costs through customer rates.

Normal Purchases and Normal Sales Exception

As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated by Generation as normal purchases and normal sales transactions, which are thus not required to be recorded at fair value, but rather on an accrual basis of accounting. Determining whether a contract qualifies for the normal purchases and normal sales exception requires judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts that qualify for the normal purchases and normal sales exception

are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and the contract is not financially settled on a net basis. The contracts that ComEd has entered into with suppliers as part of ComEd's energy procurement process, PECO's full requirement contracts under the PAPUC-approved DSP program, most of PECO's natural gas supply agreements, all of BGE's full requirement contracts and natural gas supply agreements that are derivatives and certain Pepco, DPL and ACE full requirement contracts qualify for and are accounted for under the normal purchases and normal sales exception.

Commodity Contracts

Identification of a commodity contract as an economic hedge requires Generation to determine that the contract is in accordance with the RMP. Generation reassesses its economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

As a part of the authoritative guidance, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. Under the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value.

Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are generally categorized in Level 1 in the fair value hierarchy.

Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges. The price quotations reflect the average of the bid-ask mid-point from markets that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. The Registrant's derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using models that consider inputs such as contract terms, including maturity, and market parameters, and assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, the model inputs are generally observable. Such instruments are categorized in Level 2.

For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs and are categorized in Level 3.

The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of nonperformance and credit risk to date have generally not been material to the financial statements.

Interest Rate and Foreign Exchange Derivative Instruments

The Registrants may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, to achieve the targeted level of variable-rate debt as a percent of total debt. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels and floating to fixed swaps for project financing. In addition, Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the economic hedge and proprietary trading activity is driven by the corresponding characterization of the underlying

commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. The fair value of the agreements is calculated by discounting the future net cash flows to the present value based on observable inputs and are primarily categorized in Level 2 in the fair value hierarchy. Certain exchange based interest rate derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 11 — Fair Value of Financial Assets and Liabilities and Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation (All Registrants)

Significant management judgment is required in determining the Registrants' provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of tax benefits to be recorded in the Registrants' consolidated financial statements.

The Registrants evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and their intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. The Registrants also evaluate for negative evidence that could indicate the Registrant's inability to realize its deferred tax assets, such as historical operating loss or tax credit carryforward expiration. Based on the combined assessment, the Registrants record valuation allowances for deferred tax assets when they conclude it is more-likely-than-not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including future changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. The Registrants have recorded the provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation for which the impacts could not be finalized upon issuance of the Registrants' financial statements, but for which reasonable estimates could be determined. In accordance with SAB 118, additional remeasurement may occur based on technical corrections or other forms of guidance issued, which may result in material changes to previously finalized provisions. While the Registrants believe the resulting tax balances as of December 31, 2017 and 2016 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments that could be material to their consolidated financial statements. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Loss Contingencies (All Registrants)

In the preparation of their financial statements, the Registrants make judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amount recorded may differ from the actual expense incurred when the uncertainty is resolved. Such difference could have a significant impact on the Registrants' consolidated financial statements.

Environmental Costs

Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work and changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at the Utility Registrants to determine future remediation requirements for MGP sites and estimates are adjusted accordingly. In addition, periodic reviews are performed at each of the Registrants to assess the adequacy of other environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant impact on the Registrants' results of operations, cash flows and financial positions. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information.

Other, Including Personal Injury Claims

The Registrants are self-insured for general liability, automotive liability, workers' compensation, and personal injury claims to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. The Registrants have reserves for both open claims asserted and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible state and national legislative measures could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material impact on the Registrants' results of operations, cash flows and financial positions.

Revenue Recognition (All Registrants)

Sources of Revenue and Determination of Accounting Treatment

The Registrants earn revenues from various business activities including: the sale of energy and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail) *;* the sale and delivery of electricity and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable authoritative guidance. The Registrants primarily use accrual, mark-to-market, and Alternative Revenue Program (ARP) accounting as discussed in more detail below. Beginning on January 1, 2018, the Registrants will begin applying the Revenue from Contracts with Customers guidance to recognize revenue. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information.

Accrual Accounting

Under accrual accounting, the Registrants recognize revenues in the period when services are rendered or energy is delivered to customers. The Registrants generally use accrual accounting to recognize revenues for sales of electricity, natural gas and other commodities as part of their physical delivery activities. The Registrants enter into these sales transactions using a variety of instruments,

including non-derivative agreements, derivatives that qualify for and are designated as normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to utility customers under regulated service tariffs and spot-market sales, including settlements with independent system operators.

The determination of Generation's and the Utility Registrants' energy sales to individual customers is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by energy or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities' customers and favorable or unfavorable rate mix due to changes in usage patterns in customers classes in the period could be significant to the calculation of unbilled revenue. In addition, unbilled revenues may fluctuate monthly as a result of customers electing to use an alternate supplier, since unbilled commodity receivables are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date also impact the measurement of unbilled revenue, however, total operating revenues would remain materially unchanged. See Note 5 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information on unbilled revenue.

Mark-to-Market Accounting

The Registrants record revenues and expenses using the mark-to-market method of accounting for transactions that meet the definition of a derivative for which they are not permitted, or have not elected, the NPNS exception. These mark-to-market transactions primarily relate to commodity price risk management activities. Mark-to-market revenues and expenses include: inception gains or losses on new transactions where the fair value is observable and realized; and unrealized gains and losses from changes in the fair value of open contracts.

Alternative Revenue Program Accounting

Certain of the Utility Registrants' ratemaking mechanisms qualify as ARPs if they meet certain criteria. At each balance sheet date, the Utility Registrants with such mechanisms, including ComEd's electric distribution and energy efficiency formulas, and ComEd's, PECO's, BGE's, Pepco's, DPL's, and ACE's FERC transmission formula rates, record ARP revenues for any differences between the prior year revenue requirement in effect in rates and their best estimate of the current year revenue requirement that is probable of approval by the ICC or FERC. Estimates of the current year revenue requirement are based on actual and/or forecasted costs and investment in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. ComEd, BGE, Pepco, and DPL also have decoupling mechanisms which qualify as ARPs. The Utility Registrants recognize and record an offsetting regulatory asset or liability once the condition or event allowing for the automatic adjustment of future rates occurs.

The Utility Registrants’ ARP revenues include both: (i) the recognition of “originating” ARP revenues (when the regulator-specified condition or event allowing for additional billing or refund has occurred) and (ii) an equal and offsetting reversal of the “originating” ARP revenues as those amounts are reflected in the price of utility service

See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

Allowance for Uncollectible Accounts (All Registrants)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd, PECO, BGE, Pepco, DPL and ACE, estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. Risk segments represent a group of customers with similar credit quality indicators that are comprised based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on a historical average of charge-offs as a percentage of accounts receivable in each risk segment. The Utility Registrants' customer accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. Utility Registrants' customer accounts are written off consistent with approved regulatory requirements. Utility Registrants' allowances for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU regulations. See Note 5 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2017 , 2016 and 2015 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) Attributable to Common Shareholders by Registrant

	For the Years Ended December 31,				
	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	For the Year Ended December 31, 2015	Favorable (unfavorable) 2016 vs. 2015 variance
Exelon	$ 3,770	$ 1,134	$ 2,636	$ 2,269	$ (1,135)
Generation	2,694	496	2,198	1,372	(876)
ComEd	567	378	189	426	(48)
PECO	434	438	(4)	378	60
BGE	307	286	21	275	11
Pepco	205	42	163	187	(145)
DPL	121	(9)	130	76	(85)
ACE	77	(42)	119	40	(82)

	Successor		*Predecessor*	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	$ 362	$ (61)	$ 19	$ 327

Results of Operations—Generation

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	$ 18,466	$ 17,751	$ 715	$ 19,135	$ (1,384)
Purchased power and fuel expense	9,690	8,830	(860)	10,021	1,191
Revenues net of purchased power and fuel expense [(a)]	8,776	8,921	(145)	9,114	(193)
Other operating expenses					
Operating and maintenance	6,291	5,641	(650)	5,308	(333)
Depreciation and amortization	1,457	1,879	422	1,054	(825)
Taxes other than income	555	506	(49)	489	(17)
Total other operating expenses	8,303	8,026	(277)	6,851	(1,175)
Gain (Loss) on sales of assets	2	(59)	61	12	(71)
Bargain purchase gain	233	—	233	—	—
Gain on deconsolidation of business	213	—	213	—	—
Operating income	921	836	85	2,275	(1,439)
Other income and (deductions)					
Interest expense	(440)	(364)	(76)	(365)	1
Other, net	948	401	547	(60)	461
Total other income and (deductions)	508	37	471	(425)	462
Income before income taxes	1,429	873	556	1,850	(977)
Income taxes	(1,375)	290	1,665	502	212
Equity in losses of unconsolidated affiliates	(33)	(25)	(8)	(8)	(17)
Net income	2,771	558	2,213	1,340	(782)
Net income (loss) attributable to noncontrolling interests	77	62	15	(32)	94
Net income attributable to membership interest	$ 2,694	$ 496	$ 2,198	$ 1,372	$ (876)

(a) Generation evaluates its operating performance using the measure of revenues net of purchased power and fuel expense. Generation believes that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenues net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

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Net Income Attributable to Membership Interest

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . Generation's Net income attributable to membership interest increased compared to the same period in 2016 , primarily due to lower Depreciation and amortization, a Bargain purchase gain in 2017, a Gain on deconsolidation of business in 2017, higher Other income and decreased Income taxes, partially offset by lower Revenues net of purchased power and fuel expense and higher Operating and maintenance expense. The decrease in Depreciation and amortization expense is primarily due to lower accelerated depreciation and amortization as a result of the 2017 decision to early retire the TMI nuclear facility compared to the previous decision in 2016 to early retire Clinton and Quad Cities nuclear facilities. The Bargain purchase gain is due to the acquisition of the FitzPatrick nuclear facility. The Gain on deconsolidation of business in 2017 is due to the deconsolidation of EGTP's net liabilities, which included the previously impaired assets and related debt, as a result of the November 2017 bankruptcy filing. The increase in Other income is primarily due to higher realized NDT fund gains. The decrease in Income taxes primarily relates to the one-time non-cash impacts associated with the Tax Cuts and Jobs Act. The decrease in Revenues net of purchased power and fuel expense primarily reflects lower realized energy prices, the impacts of lower load volumes delivered due to mild weather in the third quarter 2017, the conclusion of the Ginna Reliability Support Services Agreement and the impact of declining natural gas prices on Generation’s natural gas portfolio, partially offset by the impact of the New York CES, higher capacity prices, the addition of two combined-cycle gas turbines in Texas and lower nuclear fuel prices. The increase in Operating and maintenance expense is primarily related to the impairment of EGTP in 2017.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . Generation's Net income attributable to membership interest decreased compared to the same period in 2015 , primarily due to lower Revenues net of purchased power and fuel expense, higher Operating and maintenance expense, higher Depreciation and amortization expense, and Losses on sales of assets in 2016 , partially offset by increased Other income and decreased Income tax expense. The decrease in Revenues net of purchased power and fuel expense primarily relates to lower mark-to-market results in 2016 compared to 2015 and lower realized energy prices, partially offset by the Ginna Reliability Support Services Agreement and a decrease in outage days at higher capacity units despite an increase in overall outage days. The increase in Operating and maintenance expense is primarily related to the impairment of Upstream assets and certain wind projects, and increased costs related to the implementation of the cost management program. The increase in Depreciation and amortization expense is primarily related to accelerated depreciation and amortization expense related to the previous decision to early retire the Clinton and Quad Cities nuclear generating facilities, increased nuclear decommissioning amortization and increased depreciation expense due to ongoing capital expenditures. The increase in Losses on sales of assets is primarily due to Generation's strategic decision to narrow the scope and scale of its growth and development activities. The increase in Other income is primarily due to the change in realized and unrealized gains and losses on NDT funds.

Revenues Net of Purchased Power and Fuel Expense

The basis for Generation’s reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned with these same geographic regions. Descriptions of each of Generation’s six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.

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- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.

- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

- New York represents operations within ISO-NY, which covers the state of New York in its entirety.

- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.

- Other Power Regions :

  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.

  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in Other: amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; accelerated nuclear fuel amortization associated with nuclear decommissioning; and other miscellaneous revenues.

Generation evaluates the operating performance of electric business activities using the measure of Revenue net of purchased power and fuel expense, which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for owned generation and fuel costs associated with tolling agreements.

For the years ended December 31, 2017 compared to 2016 and December 31, 2016 compared to 2015 , Generation's Revenue net of purchased power and fuel expense by region were as follows:

			2017 vs. 2016			2016 vs. 2015	
	2017	2016	Variance	% Change	2015	Variance	% Change
Mid-Atlantic [a]	$ 3,214	$ 3,317	$ (103)	(3.1)%	$ 3,571	$ (254)	(7.1)%
Midwest [b]	2,820	2,971	(151)	(5.1)%	2,892	79	2.7 %
New England	514	438	76	17.4 %	461	(23)	(5.0)%
New York [d]	976	742	234	31.5 %	634	108	17.0 %
ERCOT	332	281	51	18.1 %	293	(12)	(4.1)%
Other Power Regions	305	336	(31)	(9.2)%	250	86	34.4 %
Total electric revenues net of purchased power and fuel expense	8,161	8,085	76	0.9 %	8,101	(16)	(0.2)%
Proprietary Trading	18	15	3	n.m.	1	14	n.m.
Mark-to-market gains (losses)	(175)	(41)	(134)	326.8 %	257	(298)	(116.0)%
Other [c]	772	862	(90)	(10.4)%	755	107	14.2 %
Total revenue net of purchased power and fuel expense	$ 8,776	$ 8,921	$ (145)	(1.6)%	$ 9,114	$ (193)	(2.1)%

(a) Results of transactions with PECO and BGE are included in the Mid-Atlantic region. Results of transactions with Pepco, DPL, and ACE are included in the Mid-Atlantic region beginning on March 24, 2016, the day after the PHI merger was completed.
(b) Results of transactions with ComEd are included in the Midwest region.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes amortization of intangible assets related to commodity contracts recorded at fair value of a $54 million decrease to RNF, an $57 million decrease to RNF, and an $8 million increase to RNF for the years ended December 31, 2017 , 2016 , and 2015 , respectively, and accelerated nuclear fuel amortization associated with announced early plant retirements, as discussed in Note 8 - Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements, of $12 million and $60 million for the years ended December 31, 2017 and 2016 , respectively.
(d) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

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Generation's supply sources by region are summarized below:

			2017 vs. 2016			2016 vs. 2015	
Supply Source (GWh)	2017	2016	Variance	% Change	2015	Variance	% Change
Nuclear Generation [a]							
Mid-Atlantic	64,466	63,447	1,019	1.6 %	63,283	164	0.3 %
Midwest	93,344	94,668	(1,324)	(1.4)%	93,422	1,246	1.3 %
New York [c]	25,033	18,684	6,349	34.0 %	18,769	(85)	(0.5)%
Total Nuclear Generation	182,843	176,799	6,044	3.4 %	175,474	1,325	0.8 %
Fossil and Renewables							
Mid-Atlantic	2,789	2,731	58	2.1 %	2,774	(43)	(1.6)%
Midwest	1,482	1,488	(6)	(0.4)%	1,547	(59)	(3.8)%
New England	7,179	6,968	211	3.0 %	2,983	3,985	133.6 %
New York	3	3	—	— %	3	—	— %
ERCOT	12,072	6,785	5,287	77.9 %	5,763	1,022	17.7 %
Other Power Regions	6,869	8,179	(1,310)	(16.0)%	7,848	331	4.2 %
Total Fossil and Renewables	30,394	26,154	4,240	16.2 %	20,918	5,236	25.0 %
Purchased Power							
Mid-Atlantic	9,801	16,874	(7,073)	(41.9)%	8,160	8,714	106.8 %
Midwest	1,373	2,255	(882)	(39.1)%	2,325	(70)	(3.0)%
New England	18,517	16,632	1,885	11.3 %	24,309	(7,677)	(31.6)%
New York	28	—	28	— %	—	—	— %
ERCOT	7,346	10,637	(3,291)	(30.9)%	10,070	567	5.6 %
Other Power Regions	14,530	13,589	941	6.9 %	18,773	(5,184)	(27.6)%
Total Purchased Power	51,595	59,987	(8,392)	(14.0)%	63,637	(3,650)	(5.7)%
Total Supply/Sales by Region							
Mid-Atlantic [b]	77,056	83,052	(5,996)	(7.2)%	74,217	8,835	11.9 %
Midwest [b]	96,199	98,411	(2,212)	(2.2)%	97,294	1,117	1.1 %
New England	25,696	23,600	2,096	8.9 %	27,292	(3,692)	(13.5)%
New York	25,064	18,687	6,377	34.1 %	18,772	(85)	(0.5)%
ERCOT	19,418	17,422	1,996	11.5 %	15,833	1,589	10.0 %
Other Power Regions	21,399	21,768	(369)	(1.7)%	26,621	(4,853)	(18.2)%
Total Supply/Sales by Region	264,832	262,940	1,892	0.7 %	260,029	2,911	1.1 %

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG).
(b) Includes affiliate sales to PECO and BGE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region. As a result of the PHI Merger, includes affiliate sales to Pepco, DPL and ACE in the Mid-Atlantic region beginning on March 24, 2016.
(c) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

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Mid-Atlantic

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The $103 million decrease in revenues net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower load volumes, lower realized energy prices and decreased capacity prices, partially offset by the absence of oil inventory write-downs in 2017 and decreased nuclear outage days.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The $254 million decrease in revenues net of purchased power and fuel expense in the Mid-Atlantic was primarily due to lower realized energy prices, decreased capacity prices and higher oil inventory write-downs in 2016, partially offset by increased load volumes served.

Midwest

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The $151 million decrease in revenues net of purchased power and fuel expense in the Midwest primarily reflects lower realized energy prices and increased nuclear outage days, partially offset by decreased fuel prices.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The $79 million increase in revenues net of purchased power and fuel expense in the Midwest was primarily due to decreased nuclear outage days and decreased nuclear fuel prices.

New England

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The $76 million increase in revenues net of purchased power and fuel expense in New England was driven by increased capacity prices, partially offset by lower realized energy prices.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The $23 million decrease in revenues net of purchased power and fuel expense in New England was primarily due to lower realized energy prices and higher oil inventory write-downs in 2016, partially offset by increased capacity prices.

New York

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The $234 million increase in revenues net of purchased power and fuel expense in New York was primarily due to the impact of the New York CES and the acquisition of Fitzpatrick, partially offset by the conclusion of the Ginna Reliability Support Service Agreement and lower realized energy prices.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The $108 million increase in revenues net of purchased power and fuel expense in New York was primarily due to the impact of the Ginna Reliability Support Service Agreement, partially offset by lower realized energy prices.

ERCOT

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The $51 million increase in revenues net of purchased power and fuel expense in ERCOT was primarily due to the addition of two combined-cycle gas turbines in Texas, partially offset by lower realized energy prices.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The $12 million decrease in revenues net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices, partially offset by increased output from renewable assets.

Other Power Regions

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The $31 million decrease in revenues net of purchased power and fuel expense in Other Power Regions was primarily due to lower realized energy prices.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The $86 million increase in revenues net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

Proprietary Trading

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The $3 million increase in revenues net of purchased power and fuel expense in Proprietary trading was primarily due to congestion activity.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The $14 million increase in revenues net of purchased power and fuel expense in Proprietary trading was primarily due to congestion activity.

Mark-to-market

Generation is exposed to market risks associated with changes in commodity prices and executes economic hedges to mitigate exposure to these fluctuations. See Note 11 — Fair Value of Financial Assets and Liabilities and Note 12 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . Mark-to-market losses on economic hedging activities were $175 million in 2017 compared to losses of $41 million in 2016 .

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . Mark-to-market losses on economic hedging activities were $41 million in 2016 compared to gains of $257 million in 2015 .

Other

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The $90 million decrease in other revenue net of purchased power and fuel was primarily due to the impacts of declining natural gas prices on Generation's natural gas portfolio and the decline in revenues related to the distributed generation business, partially offset by a decrease in accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Nuclear Plant Retirements of the Combined Notes to the Financial Statements.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The $107 million increase in other revenue net of purchased power and fuel was primarily due to revenue related to the inclusion of Pepco Energy Services results in 2016 and revenue related to energy efficiency projects, partially offset by the amortization of energy contracts recorded at fair value associated with prior acquisitions, and accelerated nuclear fuel amortization associated with the initial early retirement decision for Clinton and Quad Cities as discussed in Note 8 — Early Nuclear Plant Retirements of the Combined Notes to the Financial Statements.

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for 2017 , as compared to 2016 and 2015 , for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Generation considers capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	2017	2016	2015
Nuclear fleet capacity factor [(a)]	94.1%	94.6%	93.7%
Refueling outage days [(a)]	293	245	290
Non-refueling outage days [(a)]	53	63	82

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The nuclear fleet capacity factor, which excludes Salem, decreased in 2017 compared to 2016 primarily due to increased refueling outage days, partially offset by fewer non-refueling outage days.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The nuclear fleet capacity factor, which excludes Salem, increased in 2016 compared to 2015 primarily due to fewer refueling and non-refueling outage days.

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Operating and Maintenance Expense

The changes in operating and maintenance expense for 2017 compared to 2016 , consisted of the following:

	Increase (Decrease) [a]
Impairment and related charges of certain generating assets [b]	$ 307
Merger and integration costs	13
ARO update [c]	84
Pension and non-pension postretirement benefits expense	10
Corporate allocations	23
Plant retirements and divestitures [d]	127
Accretion expense [e]	35
Nuclear refueling outage costs, including the co-owned Salem plant [f]	104
Merger commitments [g]	(53)
Labor, other benefits, contracting and materials [h]	52
Cost management program	(2)
Curtailment of Generation growth and development activities [i]	(24)
Vacation policy change [i]	(40)
Allowance for uncollectible accounts	33
Change in Environmental Remediation Liabilities	44
Other	(63)
Increase in operating and maintenance expense	$ 650

(a) The 2017 financial results include Generation's acquisition of the FitzPatrick nuclear generating station from March 31, 2017.
(b) Primarily reflects charges to earnings related to impairments as a result of the EGTP assets in 2017 and impairment of Upstream assets and certain wind projects in 2016.
(c) Primarily reflects the non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units in 2017 compared to 2016.
(d) Primarily represents the announcement of the early retirement of Generation's TMI nuclear facility in 2017 compared to the previous decision to early retire Generation's Clinton and Quad Cities nuclear facilities in 2016.
(e) Reflects the impact of increased accretion expenses primarily due to the acquisition of FitzPatrick on March 31, 2017.
(f) Primarily reflects an increase in the number of nuclear outage days during 2017 compared to 2016.
(g) Primarily represents costs incurred as part of the settlement orders approving the PHI acquisition during 2016.
(h) Reflects increased salaries, wages and contracting costs primarily related to the acquisition of the FitzPatrick nuclear facility beginning on March 31, 2017.
(i) Represents the reversal of previously accrued vacation expenses as a result of a change in Exelon's vacation vesting policy.
(j) Reflects the one-time recognition for a loss on sale of assets and asset impairment charges pursuant to Generation's strategic decision in the fourth quarter of 2016 to narrow the scope and scale of its growth and development activities.

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The changes in operating and maintenance expense for 2016 compared to 2015 , consisted of the following:

	Increase (Decrease)
Impairment and related charges of certain generating assets [a]	$ 161
Merger and integration costs	27
Midwest Generation bankruptcy charges	10
ARO update [b]	(79)
Pension and non-pension postretirement benefits expense [c]	(42)
Corporate allocations [d]	(12)
Plant retirements and divestitures [e]	(50)
Accretion expense	(21)
Nuclear refueling outage costs, including the co-owned Salem plant [f]	(61)
Merger commitments	53
Labor, other benefits, contracting and materials [g]	185
Cost management program [h]	43
Curtailment of Generation growth and development activities [i]	24
Other	95
Increase in operating and maintenance expense	$ 333

(a) Reflects increased impairments in 2016 compared to 2015, primarily related to the impairments of certain Upstream assets and wind generating assets in 2016.
(b) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units.
(c) Reflects the favorable impact of higher pension and OPEB discount rates.
(d) Reflects a decreased share of corporate allocated costs.
(e) Reflects the impact of the Generation's previous decision to early retire the Clinton and Quad Cities nuclear facilities.
(f) Reflects the favorable impacts of decreased nuclear outages in 2016.
(g) Reflects an increase of labor, other benefits, contracting and materials costs primarily due to increased contracting costs related to energy efficiency projects and the inclusion of Pepco Energy Services results in 2016. Also includes cost of sales of our other business activities that are not allocated to a region.
(h) Represents the 2016 severance expense and reorganization costs related to a cost management program.
(i) Reflects the one-time recognition for asset impairment charges pursuant to Generation's strategic decision in the fourth quarter of 2016 to narrow the scope and scale of its growth and development activities.

Depreciation and Amortization

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . Depreciation and amortization expense decreased primarily due to accelerated depreciation and increased nuclear decommissioning amortization related to the previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016 compared to the decision to early retire the Three Mile Island nuclear facility in 2017.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . Depreciation and amortization expense increased primarily due to accelerated depreciation and increased nuclear decommissioning amortization related to the previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016, and increased depreciation expense due to ongoing capital expenditures.

Taxes Other Than Income

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The increase in taxes other than income was primarily due to increased real estate taxes and sales and use taxes.

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Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The increase in taxes other than income was primarily due to an increase in gross receipts tax.

Gain (Loss) on Sales of Assets

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The increase in gain (loss) on sales of assets is primarily due to certain Generation projects and contracts being terminated or renegotiated in 2016, partially offset by a gain associated with Generation's sale of the retired New Boston generating site in 2016.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The decrease in gain (loss) on sales of assets is primarily related to the one-time recognition for a loss on sale of assets pursuant to Generation's strategic decision in the fourth quarter of 2016 to narrow the scope and scale of its growth and development activities, partially offset by a gain associated with Generation's sale of the retired New Boston generating site in 2016.

Bargain Purchase Gain

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The increase in the Bargain purchase gain is related to the result of the gain associated with the FitzPatrick acquisition. Refer to Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information.

Gain on Deconsolidation of Business

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The increase in the Gain on deconsolidation of business is related to the deconsolidation of EGTP's net liabilities, which included the previously impaired assets and related debt, as a result of the November 2017 bankruptcy filing. Refer to Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information.

Interest Expense

The changes in interest expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Interest expense on long-term debt	$ —	$ 8
Interest expense on interest rate swaps	(2)	1
Interest expense on tax settlements	12	16
Other interest expense	66	(26)
(Decrease) increase in interest expense, net	$ 76	$ (1)

Other, Net

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The increase in Other, net primarily reflects the net increase in realized and unrealized gains related to the NDT fund investments of Generation's Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $209 million and $80 million for the years ended December 31, 2017 and 2016 , respectively, related to the contractual elimination of income tax expense associated with the NDT fund investments of the Regulatory Agreement Units. Refer to Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT fund investments.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The increase in Other, net primarily reflects the net increase in realized and unrealized gains related to the NDT fund investments of Generation's Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $80 million and $(22) million for the years ended December 31, 2016 and 2015 , respectively, related to the contractual elimination of income tax expense associated with the NDT fund investments of the Regulatory Agreement Units. Refer to Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT fund investments.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for 2017 , 2016 and 2015 :

	2017	2016	2015
Net unrealized gains (losses) on decommissioning trust funds	$ 521	$ 194	$ (197)
Net realized gains on sale of decommissioning trust funds	95	35	66

Effective Income Tax Rate

Generation's effective income tax rates for the years ended December 31, 2017 , 2016 and 2015 were (96.2)% , 33.2% and 27.1% , respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

Results of Operations—ComEd

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	$ 5,536	$ 5,254	$ 282	$ 4,905	$ 349
Purchased power expense	1,641	1,458	(183)	1,319	(139)
Revenues net of purchased power expense [(a)(b)]	3,895	3,796	99	3,586	210
Other operating expenses					
Operating and maintenance	1,427	1,530	103	1,567	37
Depreciation and amortization	850	775	(75)	707	(68)
Taxes other than income	296	293	(3)	296	3
Total other operating expenses	2,573	2,598	25	2,570	(28)
Gain on sales of assets	1	7	(6)	1	6
Operating income	1,323	1,205	118	1,017	188
Other income and (deductions)					
Interest expense, net	(361)	(461)	100	(332)	(129)
Other, net	22	(65)	87	21	(86)
Total other income and (deductions)	(339)	(526)	187	(311)	(215)
Income before income taxes	984	679	305	706	(27)
Income taxes	417	301	(116)	280	(21)
Net income	$ 567	$ 378	$ 189	$ 426	$ (48)

(a) ComEd evaluates its operating performance using the measure of Revenue net of purchased power expense. ComEd believes that Revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of Revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b) For regulatory recovery mechanisms, including ComEd's electric distribution and transmission formula rates, and riders, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).

Net Income

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . ComEd's Net income for the year ended December 31, 2017 was higher than the same period in 2016 primarily due to the recognition of the penalty and the after-tax interest due on the asserted penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position in 2016 and increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment and higher allowed electric distribution ROE). The higher Net income was partially offset by the impact of weather conditions in 2016. See Revenue Decoupling discussion below for additional information on the impact of weather.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . ComEd's Net income for the year ended December 31, 2016 was lower than the same period in 2015 primarily due to the recognition of the penalty and the after-tax interest due on the asserted penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position, partially offset by increased electric

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distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE) and favorable weather.

Revenues Net of Purchased Power Expense

There are certain drivers of Operating revenues that are fully offset by their impact on Purchased power expense, such as commodity, REC and ZEC procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity, REC and ZEC procurement costs from retail customers without mark-up. Therefore, fluctuations in these costs have no impact on Revenue net of purchased power expense. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries, but do affect ComEd's Operating revenues related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2017 , 2016 and 2015 , consisted of the following:

	For the Years Ended December 31,		
	2017	2016	2015
Electric	70%	72%	76%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2017 , 2016 and 2015 consisted of the following:

	December 31, 2017		December 31, 2016		December 31, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	1,371,700	34%	1,502,900	38%	1,655,400	42%

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The changes in ComEd's Revenue net of purchased power expense for the year ended December 31, 2017 , compared to the same period in 2016 , and for the year ended December 31, 2016 , compared to the same period in 2015 , consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Weather [(a)]	$ (36)	$ 54
Volume [(a)]	(5)	(2)
Pricing and customer mix [(a)]	(18)	14
Electric distribution revenue	170	69
Transmission revenue	60	97
Energy efficiency revenue [(b)]	16	—
Regulatory required programs [(b)]	(85)	(31)
Uncollectible accounts recovery, net	(7)	(13)
Other	4	22
Total increase	$ 99	$ 210

(a) For the year ended December 31, 2017 , compared to the same period in 2016 , the changes reflect the 2016 impacts of weather, volume and pricing and customer mix. As further described below, pursuant to the revenue decoupling provision in FEJA, ComEd began recording an adjustment to revenue in the first quarter of 2017 to eliminate the favorable or unfavorable impacts associated with variations in delivery volumes associated with above or below normal weather, number of customers or usage per customer.
(b) Beginning on June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life of the related energy efficiency measures.

Revenue Decoupling. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand.

Under EIMA, ComEd's electric distribution formula rate provided for an adjustment to future billings if its earned ROE fell outside a 50-basis-point collar of its allowed ROE, which partially eliminated the impacts of weather and load on ComEd's revenue. As allowed under FEJA, ComEd will revise its electric distribution formula rate to eliminate the ROE collar beginning with the reconciliation filed in 2018 for the 2017 calendar year. Elimination of the ROE collar effectively offsets the favorable or unfavorable impacts to Operating revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer. ComEd began recognizing the impacts of this change beginning in the first quarter of 2017. For the year ended December 31, 2017 , ComEd recorded an increase to Electric distribution revenues of approximately $32 million to eliminate weather and load impacts.

For the year ended December 31, 2016 , favorable weather conditions increased Operating revenues net of purchased power expense when compared to the prior year.

For the year ended December 31, 2016 , the increase in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes and change in customer mix.

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Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2017 , 2016 and 2015 consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	5,435	5,715	6,198	(4.9)%	(12.3)%
Cooling Degree-Days	991	1,157	893	(14.3)%	11.0 %

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	5,715	6,091	6,198	(6.2)%	(7.8)%
Cooling Degree-Days	1,157	806	893	43.5 %	29.6 %

Electric Distribution Revenue. EIMA and FEJA provide for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and allowed ROE. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points. In addition, ComEd's allowed ROE is subject to reduction if ComEd does not deliver the reliability and customer service benefits to which it has committed over the ten-year life of the investment program. During the year ended December 31, 2017 , electric distribution revenue increased $170 million , primarily due to increased capital investment, increased Depreciation expense, higher allowed ROE due to an increase in treasury rates and revenue decoupling impacts (as described above). During the year ended December 31, 2016 , electric distribution revenue increased $69 million , primarily due to increased capital investment and Depreciation expense, partially offset by lower allowed ROE due to a decrease in treasury rates. See Operating and Maintenance Expense below and Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. For the years ended December 31, 2017 and 2016 , ComEd recorded increased transmission revenue due to increased capital investment, higher Depreciation expense and increased highest daily peak load. See Operating and Maintenance Expense below and Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Revenue. Beginning June 1, 2017, FEJA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under FEJA, energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points. Beginning January 1, 2018, ComEd's allowed ROE is subject to a maximum downward or upward adjustment of 200 basis points if ComEd's cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual

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incremental savings goal. See Depreciation and amortization expense discussions below and Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved rate riders to recover costs incurred for regulatory programs such as ComEd's purchased power administrative costs and energy efficiency and demand response through June 1, 2017 pursuant to FEJA. The riders are designed to provide full and current cost recovery. An equal and offsetting amount has been included in Operating and maintenance expense. See Operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Uncollectible accounts recovery, net, represents recoveries under ComEd's uncollectible accounts tariff. See Operating and maintenance expense discussion below for additional information on this tariff.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental costs associated with MGP sites, and recoveries of energy procurement costs.

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2017	2016	2017 vs. 2016	2016	2015	2016 vs. 2015
Operating and maintenance expense—baseline	$ 1,329	$ 1,347	$ (18)	$ 1,347	$ 1,353	$ (6)
Operating and maintenance expense—regulatory required programs [(a)]	98	183	(85)	183	214	(31)
Total operating and maintenance expense	$ 1,427	$ 1,530	$ (103)	$ 1,530	$ 1,567	$ (37)

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

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The changes in Operating and maintenance expense for year ended December 31, 2017 , compared to the same period in 2016 , and for the year ended December 31, 2016 , compared to the same period in 2015 , consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Baseline		
Labor, other benefits, contracting and materials	$ (41)	$ 12
Pension and non-pension postretirement benefits expense [a]	3	(24)
Storm-related costs	2	(9)
Uncollectible accounts expense—provision [b]	(6)	5
Uncollectible accounts expense—recovery, net [b]	(1)	(18)
BSC costs [c]	44	29
Other	(19)	(1)
	(18)	(6)
Regulatory required programs		
Energy efficiency and demand response programs [d]	(85)	(31)
Decrease in operating and maintenance expense	$ (103)	$ (37)

(a) Primarily reflects the favorable impact of higher assumed pension and OPEB discount rates for the year ended December 31, 2016.
(b) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. ComEd recorded a net decrease in 2017 and 2016 in Operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting amount has been recognized in Operating revenues for the periods presented.
(c) Primarily reflects increased information technology support services from BSC in 2017 and 2016. For the year ended December 31, 2017, includes the $8 million write-off of a regulatory asset related to Constellation merger and integration costs for which recovery is no longer expected.
(d) Beginning on June 1, 2017 ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency over the weighted average useful life of the related energy efficiency measures.

Depreciation and Amortization Expense

The increases in Depreciation and amortization expense for 2017 compared to 2016 , and 2016 compared to 2015 , consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Depreciation expense [a]	$ 60	$ 58
Regulatory asset amortization [b]	7	(5)
Other	8	15
Total increase	$ 75	$ 68

(a) Primarily reflects ongoing capital expenditures for the years ended December 31, 2017 and 2016 .
(b) Beginning in June 2017, includes amortization of ComEd's energy efficiency formula rate regulatory asset.

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income taxes remained relatively consistent for the year ended December 31, 2017 , compared to the same period in 2016 , and for the year ended December 31, 2016 , compared to the same period in 2015 .

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Gain on Sale of Assets

Gain on sale of assets decreased during the year ended December 31, 2017 , compared to the same period in 2016 , and increased during the year ended December 31, 2016 , compared to the same period in 2015 , primarily due to the sale of land during March 2016.

Interest Expense, Net

The increase (decrease) in Interest expense, net, for the year ended 2017 , compared to the same period in 2016 , and for the year ended 2016 , compared to the same period in 2015 , consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Interest expense related to uncertain tax positions [(a)]	$ (104)	$ 109
Interest expense on debt (including financing trusts) [(b)]	6	24
Other	(2)	(4)
Increase (decrease) in interest expense, net	$ (100)	$ 129

(a) Primarily reflects the recognition of after-tax interest related to the Tax Court's decision on Exelon's like-kind exchange tax position in the 2016. For the year ended December 31, 2017, the decrease was partially offset by additional interest recorded in 2017 related to Exelon's like-kind exchange tax position. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Primarily reflects an increase in interest expense due to the issuance of First Mortgage Bonds for the years ended December 31, 2016 . See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's debt obligations.

Other, Net

The increase (decrease) in Other, net, for the year ended 2017 compared to the same period in 2016 , and for the year ended 2016 compared to the same period in 2015 , consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Other income and deductions, net [(a)]	$ 88	$ (94)
AFUDC equity	(2)	9
Other	1	(1)
Increase (decrease) in Other, net	$ 87	$ (86)

(a) Primarily reflects the recognition of the penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position in 2016. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Effective Income Tax Rate

ComEd's effective income tax rates for the years ended December 31, 2017 , 2016 and 2015 , were 42.4% , 44.3% and 39.7% , respectively. The decrease in the effective income tax rate for the year ended December 31, 2017 compared to the same period in 2016 is primarily due to the recognition of a non-deductible penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position in the third quarter of 2016. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2017	2016	% Change 2017 vs. 2016	Weather-Normal % Change	2015	% Change 2016 vs. 2015	Weather-Normal % Change
Retail Deliveries [a]							
Residential	26,292	27,790	(5.4)%	(0.9)%	26,496	4.9 %	(0.6)%
Small commercial & industrial	31,332	31,975	(2.0)%	(0.7)%	31,717	0.8 %	(0.3)%
Large commercial & industrial	27,467	27,842	(1.3)%	(0.5)%	27,210	2.3 %	1.5 %
Public authorities & electric railroads	1,286	1,298	(0.9)%	(0.3)%	1,309	(0.8)%	(0.8)%
Total retail deliveries	86,377	88,905	(2.8)%	(0.7)%	86,732	2.5 %	0.2 %

	As of December 31,		
Number of Electric Customers	2017	2016	2015
Residential	3,624,372	3,595,376	3,550,239
Small commercial & industrial	378,345	374,644	370,932
Large commercial & industrial	1,959	2,007	1,976
Public authorities & electric railroads	4,775	4,750	4,820
Total	4,009,451	3,976,777	3,927,967

Electric Revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Retail Sales [a]					
Residential	$ 2,746	$ 2,597	5.7 %	$ 2,360	10.0 %
Small commercial & industrial	1,376	1,316	4.6 %	1,337	(1.6)%
Large commercial & industrial	461	462	(0.2)%	443	4.3 %
Public authorities & electric railroads	44	45	(2.2)%	42	7.1 %
Total retail	4,627	4,420	4.7 %	4,182	5.7 %
Other revenue [b]	909	834	9.0 %	723	15.4 %
Total electric revenue [c]	$ 5,536	$ 5,254	5.4 %	$ 4,905	7.1 %

(a) Reflects delivery revenue and volume from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.
(b) Other revenue primarily includes transmission revenue from PJM. Other revenue also includes rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of remediation costs associated with MGP sites.
(c) Includes operating revenues from affiliates totaling $15 million , $15 million , and $4 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively.

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Results of Operations—PECO

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	$ 2,870	$ 2,994	$ (124)	$ 3,032	$ (38)
Purchased power and fuel expense	969	1,047	78	1,190	143
Revenues net of purchased power and fuel expense [(a)]	1,901	1,947	(46)	1,842	105
Other operating expenses					
Operating and maintenance	806	811	5	794	(17)
Depreciation and amortization	286	270	(16)	260	(10)
Taxes other than income	154	164	10	160	(4)
Total other operating expenses	1,246	1,245	(1)	1,214	(31)
Gain on sales of assets	—	—	—	2	(2)
Operating income	655	702	(47)	630	72
Other income and (deductions)					
Interest expense, net	(126)	(123)	(3)	(114)	(9)
Other, net	9	8	1	5	3
Total other income and (deductions)	(117)	(115)	(2)	(109)	(6)
Income before income taxes	538	587	(49)	521	66
Income taxes	104	149	45	143	(6)
Net income	$ 434	$ 438	$ (4)	$ 378	$ 60

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . PECO's net income for the year ended December 31, 2017 was lower than the same period in 2016 , primarily due to a decrease in Revenues net of purchased power and fuel expense as a result of unfavorable weather in PECO's service territory, partially offset by the one-time non-cash impacts associated with the Tax Cuts and Jobs Act in 2017.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . PECO's net income for the year ended December 31, 2016 was higher than the same period in 2015 , primarily due to an increase in Revenues net of purchased power and fuel expense as a result of increased electric distribution revenue pursuant to the 2015 PAPUC authorized electric distribution rate increase effective January 1, 2016.

Revenues Net of Purchased Power and Fuel Expense

Electric and natural gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers

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are subject to adjustments as specified in the PAPUC-approved tariffs that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with PECO's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and natural gas revenues net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer Choice Program activity has no impact on electric and natural gas revenue net of purchase power and fuel expense.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the years ended December 31, 2017 , 2016 , and 2015 consisted of the following:

	For the Years Ended December 31,		
	2017	2016	2015
Electric	71%	70%	70%
Natural Gas	26%	26%	25%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2017 , 2016 , and 2015 consisted of the following:

	December 31, 2017		December 31, 2016		December 31, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	565,900	35%	587,200	36%	563,400	35%
Natural Gas	83,800	16%	81,300	16%	81,100	16%

The changes in PECO's Operating revenues net of purchased power and fuel expense for the years ended December 31, 2017 and December 31, 2016 compared to the same periods in 2016 and 2015 , respectively, consisted of the following:

	2017 vs. 2016			2016 vs. 2015		
	Increase (Decrease)			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ (28)	$ 4	$ (24)	$ 1	$ (12)	$ (11)
Volume	(18)	3	(15)	6	4	10
Pricing	8	2	10	160	(1)	159
Regulatory required programs	(31)	—	(31)	(46)	—	(46)
Other	14	—	14	(7)	—	(7)
Total increase (decrease)	$ (55)	$ 9	$ (46)	$ 114	$ (9)	$ 105

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Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. For the year ended December 31, 2017 compared to the same period in 2016 , and the year ended December 31, 2016 compared to the same period in 2015 Operating revenues net of purchased power and fuel expense was reduced by the impact of unfavorable weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the years ended December 31, 2017 and December 31, 2016 compared to the same periods in 2016 and 2015 , respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	3,949	4,041	4,603	(2.3)%	(14.2)%
Cooling Degree-Days	1,490	1,726	1,290	(13.7)%	15.5 %

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	4,041	4,245	4,603	(4.8)%	(12.2)%
Cooling Degree-Days	1,726	1,720	1,290	0.3 %	33.8 %

Volume. The decrease in Operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2017 compared to the same period in 2016 , was driven by electric and primarily reflects the impact of energy efficiency initiatives on customer usages for residential and small commercial and industrial electric classes, partially offset by solid customer growth. Additionally, the decrease represents a shift in the volume profile across classes from residential and small commercial and industrial to large commercial and industrial.

The increase in Operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for gas and residential and small commercial and industrial electric classes. Additionally, the increase represents a shift in the volume profile across classes from large commercial and industrial classes to residential and small commercial and industrial classes for electric.

Pricing. The increase in Operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2017 compared to the same period in 2016 reflects higher overall effective rates due to decreased usage in the residential and small commercial and industrial customer classes. Operating revenues net of fuel expense as a result of pricing remained relatively consistent.

The increase in Operating revenues net of purchased power and fuel expense as a result of pricing for the year ended December 31, 2016 compared to the same period in 2015 reflects an increase in

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electric distribution rates charged to customers. The increase in electric distribution rates was effective January 1, 2016 in accordance with the 2015 PAPUC approved electric distribution rate case settlement. See Note 3 — Regulatory Matters for further information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

Other. Other revenue, which can vary period to period, primarily includes wholesale transmission revenue, rental revenue, revenue related to late payment charges and assistance provided to other utilities through mutual assistance programs.

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2017	2016	2017 vs. 2016	2016	2015	2016 vs. 2015
Operating and maintenance expense—baseline	$ 746	$ 740	$ 6	$ 740	$ 685	$ 55
Operating and maintenance expense—regulatory required programs [(a)]	60	71	(11)	71	109	(38)
Total operating and maintenance expense	$ 806	$ 811	$ (5)	$ 811	$ 794	$ 17

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

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The changes in Operating and maintenance expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Baseline		
Labor, other benefits, contracting and materials	$ 17	$ 22
Storm-related costs	(7)	(9)
Pension and non-pension postretirement benefits expense	(3)	(4)
PHI merger integration costs	—	6
BSC costs	4	36 [(a)]
Uncollectible accounts expense	(5)	1
Other	—	3
	6	55
Regulatory required programs		
Smart meter	—	(28)
Energy efficiency	(10)	(7)
GSA	—	(2)
Other	(1)	(1)
	(11)	(38)
Increase (decrease) in operating and maintenance expense	$ (5)	$ 17

(a) Primarily reflects increased information technology support services from BSC during 2016.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2017 compared to 2016 and 2016 compared to 2015 , consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Depreciation expense	$ 17	$ 5
Regulatory asset amortization	(1)	5
Increase in depreciation and amortization expense	$ 16	$ 10

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income decreased for the year ended December 31, 2017 , compared to the same period in 2016 , primarily due to a decrease in gross receipts tax driven by decreases in electric revenue.

Taxes other than income increased for the year ended December 31, 2016 , compared to the same period in 2015 , primarily due to an increase in gross receipts tax driven by increases in electric revenue, which was impacted primarily by the new distribution rates that went into effect in January 2016.

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Interest Expense, Net

The increase in Interest expense, net for the year ended December 31, 2017 , compared to the same period in 2016 , primarily reflects an increase in interest expense due to the issuance of First and Refunding Mortgage Bonds in September 2017.

The increase in Interest expense, net for the year ended December 31, 2016 , compared to the same period in 2015 , primarily reflects an increase in interest expense due to the issuance of First and Refunding Mortgage Bonds in October 2015.

Other, Net

Other, net remained relatively consistent for the year ended December 31, 2017 , compared to the same period in 2016 , and the year ended December 31, 2016 , compared to the same period in 2015 .

Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2017 , 2016 and 2015 were 19.3% , 25.4% and 27.4% , respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2017	2016	% Change 2017 vs. 2016	Weather-Normal % Change	2015	% Change 2016 vs. 2015	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	13,024	13,664	(4.7)%	(1.8)%	13,630	0.2 %	0.4 %
Small commercial & industrial	7,968	8,099	(1.6)%	(1.1)%	8,118	(0.2)%	0.5 %
Large commercial & industrial	15,426	15,263	1.1 %	1.4 %	15,365	(0.7)%	(1.4)%
Public authorities & electric railroads	809	890	(9.1)%	(9.1)%	881	1.0 %	1.0 %
Total electric retail deliveries	37,227	37,916	(1.8)%	(0.5)%	37,994	(0.2)%	(0.3)%

	As of December 31,		
Number of Electric Customers	2017	2016	2015
Residential	1,469,916	1,456,585	1,444,338
Small commercial & industrial	151,552	150,142	149,200
Large commercial & industrial	3,112	3,096	3,091
Public authorities & electric railroads	9,569	9,823	9,805
Total	1,634,149	1,619,646	1,606,434

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Electric Revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Retail Sales [a]					
Residential	$ 1,505	$ 1,631	(7.7)%	$ 1,599	2.0 %
Small commercial & industrial	401	430	(6.7)%	428	0.5 %
Large commercial & industrial	223	234	(4.7)%	221	5.9 %
Public authorities & electric railroads	30	32	(6.3)%	31	3.2 %
Total retail	2,159	2,327	(7.2)%	2,279	2.1 %
Other revenue [b]	216	204	5.9 %	207	(1.4)%
Total electric operating revenues [c]	$ 2,375	$ 2,531	(6.2)%	$ 2,486	1.8 %

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenue.
(c) Total electric revenue includes operating revenues from affiliates totaling $6 million , $7 million and $1 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2017	2016	% Change 2017 vs. 2016	Weather-Normal % Change	2015	% Change 2016 vs. 2015	Weather-Normal % Change
Retail Deliveries [a]							
Retail sales	58,457	56,447	3.6 %	1.2 %	59,003	(4.3)%	1.5 %
Transportation and other	26,382	27,630	(4.5)%	(2.3)%	27,879	(0.9)%	(0.1)%
Total natural gas deliveries	84,839	84,077	0.9 %	0.1 %	86,882	(3.2)%	1.0 %

	As of December 31,		
Number of Gas Customers	2017	2016	2015
Residential	477,213	472,606	467,263
Commercial & industrial	43,892	43,668	43,160
Total retail	521,105	516,274	510,423
Transportation	771	790	827
Total	521,876	517,064	511,250

Gas revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Retail Sales [a]					
Retail sales	$ 462	$ 430	7.4%	$ 511	(15.9)%
Transportation and other	33	33	—%	35	(5.7)%
Total natural gas operating revenues [b]	$ 495	$ 463	6.9%	$ 546	(15.2)%

(a) Reflects delivery volumes and revenue from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.
(b) Total natural gas revenue includes operating revenues from affiliates totaling $1 million for the years ended December 31, 2017 , 2016 and 2015 .

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Results of Operations—BGE

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	$ 3,176	$ 3,233	$ (57)	$ 3,135	$ 98
Purchased power and fuel expense	1,133	1,294	161	1,305	11
Revenues net of purchased power and fuel expense [(a)]	2,043	1,939	104	1,830	109
Other operating expenses					
Operating and maintenance	716	737	21	683	(54)
Depreciation and amortization	473	423	(50)	366	(57)
Taxes other than income	240	229	(11)	224	(5)
Total other operating expenses	1,429	1,389	(40)	1,273	(116)
Gain on sales of assets	—	—	—	1	(1)
Operating income	614	550	64	558	(8)
Other income and (deductions)					
Interest expense, net	(105)	(103)	(2)	(99)	(4)
Other, net	16	21	(5)	18	3
Total other income and (deductions)	(89)	(82)	(7)	(81)	(1)
Income before income taxes	525	468	57	477	(9)
Income taxes	218	174	(44)	189	15
Net income	307	294	13	288	6
Preference stock dividends	—	8	8	13	5
Net income attributable to common shareholder	$ 307	$ 286	$ 21	$ 275	$ 11

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenues net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . Net income attributable to common shareholder was higher primarily due to an increase in Revenues net of purchased power and fuel expense and lower Operating and maintenance expense, partially offset by higher Depreciation and amortization expense and higher income tax expense. The increase in Revenues net of purchased power and fuel expense was primarily due to the impacts of the electric and natural gas distribution rate orders issued by the MDPSC in June 2016 and July 2016 and an increase in transmission formula rate revenues. The lower Operating and maintenance expense was primarily due to the absence of cost disallowances resulting from the 2016 distribution rate orders issued by the MDPSC and

decreased storm costs in 2017 partially offset by the favorable 2016 settlement of the Baltimore City conduit fee dispute. These items were partially offset by an increase in Depreciation and amortization expense primarily related to the initiation of cost recovery of the AMI programs under the distribution rate orders and the impacts of increased capital investment and higher income tax expense primarily resulting from higher taxable income as well as a 2016 favorable adjustment and 2017 impairment of certain transmission-related income tax regulatory assets.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . Net income attributable to common shareholder was higher primarily due to lower income tax expense and decreased preference stock dividends partially offset by slightly lower operating income. The lower income tax expense was driven by a one-time adjustment associated with transmission-related regulatory assets. The slight decrease in operating income was driven by an increase in Operating and maintenance expense as a result of cost disallowances which reduced certain regulatory assets and other long-lived assets stemming from the distribution rate orders issued by the MDPSC in June 2016 and July 2016 and increased storm costs. This increase in Operating and maintenance expense was offset by an increase in Revenues net of purchased power and fuel expense, primarily as a result of an increase in transmission formula rate revenues and higher electric and natural gas revenues as a result of the distribution rate orders issued by the MDPSC in June 2016 and July 2016.

Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to Operating revenues that are offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Operating revenues and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on Revenues net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in the number of customers electing to use a competitive supplier for electricity and/or natural gas. All BGE customers have the choice to purchase electricity and natural gas from competitive suppliers. The customers' choice of suppliers does not impact the volume of deliveries, but does affect revenue collected from customers related to supplied electricity and natural gas.

Retail deliveries purchased from competitive electricity and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the years ended December 31, 2017 , 2016 and 2015 consisted of the following:

	For the Years Ended December 31,		
	2017	2016	2015
Electric	60%	59%	61%
Natural Gas	55%	57%	56%

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The number of retail customers purchasing electricity and natural gas from competitive suppliers at December 31, 2017 , 2016 and 2015 consisted of the following:

	December 31, 2017		December 31, 2016		December 31, 2015	
	Number of Customers	% of total retail customers	Number of Customers	% of total retail customers	Number of Customers	% of total retail customers
Electric	341,000	27%	337,000	27%	343,000	27%
Natural Gas	151,000	22%	151,000	23%	154,000	23%

The changes in BGE's Operating revenues net of purchased power and fuel expense for the year ended December 31, 2017 compared to the same period in 2016 and for the year ended December 31, 2016 compared to the same period in 2015 , respectively, consisted of the following:

	2017 vs. 2016			2016 vs. 2015		
	Increase (Decrease)			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	$ 21	$ 29	$ 50	$ 24	$ 22	$ 46
Regulatory required programs	17	3	20	10	(5)	5
Transmission revenue	18	—	18	30	—	30
Other, net	5	11	16	24	4	28
Total increase	$ 61	$ 43	$ 104	$ 88	$ 21	$ 109

Distribution Rate Increase. During the years ended December 31, 2017 and December 31, 2016 , the increases in distribution revenues were primarily due to the impact of the electric and natural gas distribution rate changes that became effective in June 2016 in accordance with the electric and natural gas distribution rate case orders in June 2016 and July 2016. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and usage conditions. The MDPSC allows BGE to record a monthly adjustment to its electric and natural gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service natural gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and natural gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of fluctuations in actual consumption levels. This allows BGE to recognize revenue at MDPSC-approved distribution charges per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while this revenue is affected by customer growth (i.e., increase in the number of customers), it will not be affected by volatility in actual weather or usage conditions (i.e., changes in consumption per customer). BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

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Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating and cooling degree days in BGE's service territory for the year ended December 31, 2017 compared to the same period in 2016 and for the year ended December 31, 2016 compared to the same period in 2015 , respectively, and normal weather consisted of the following:

	For the Year Ended December 31,			% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	4,190	4,427	4,666	(5.4)%	(10.2)%
Cooling Degree-Days	940	998	875	(5.8)%	7.4 %

	For the Year Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	4,427	4,666	4,684	(5.1)%	(5.5)%
Cooling Degree-Days	998	924	876	8.0 %	13.9 %

Regulatory Required Programs. Revenue from regulatory required programs are billings for the costs of various legislative and/or regulatory programs that are recoverable from customers on a full and current basis. These programs are designed to provide full cost recovery, as well as a return in certain instances. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in BGE's Consolidated Statements of Operations and Comprehensive Income.

Transmission Revenue. Under a FERC approved formula, transmission revenue varies from year to year based upon rate adjustments to reflect fluctuations in the underlying costs, capital investments being recovered and other billing determinants. During the years ended December 31, 2017 and 2016 , the increase in transmission revenue was primarily due to increases in capital investment and operating and maintenance expense recoveries. See Operating and Maintenance Expense below and Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net. Other net revenue, which can vary from period to period, primarily includes late payment fees and other miscellaneous revenue such as service application fees, assistance provided to other utilities through BGE's mutual assistance program and recoveries of electric supply and natural gas procurement costs.

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Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2017	2016	2017 vs. 2016	2016	2015	2016 vs. 2015
Operating and maintenance expense—baseline	$ 672	$ 701	$ (29)	$ 701	$ 636	$ 65
Operating and maintenance expense—regulatory required programs [(a)]	44	36	8	36	47	(11)
Total operating and maintenance expense	$ 716	$ 737	$ (21)	$ 737	$ 683	$ 54

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for the year ended December 31, 2017 compared to the same period in 2016 and the year ended December 31, 2016 compared to the same period in 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Baseline		
Impairment on long-lived assets and losses on regulatory assets [(a)]	$ (50)	$ 52
Labor, other benefits, contracting and materials	(11)	7
Storm-related costs	(13)	18
Uncollectible accounts expense	7	(14)
BSC costs	16	11
Conduit lease settlement [(b)]	15	(15)
Other	7	6
	$ (29)	$ 65
Regulatory Required Programs		
Other	8	(11)
	8	(11)
Total (decrease) increase	$ (21)	$ 54

(a) See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.
(b) See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

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Depreciation and Amortization

The changes in Depreciation and amortization expense for the year ended December 31, 2017 compared to the same period in 2016 and December 31, 2016 compared to the same period in 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Depreciation expense [(a)]	$ 13	$ 10
Regulatory asset amortization [(b)]	25	31
Regulatory required programs [(c)]	12	16
Increase in depreciation and amortization expense	$ 50	$ 57

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased primarily due to an increase in regulatory asset amortization related to energy efficiency programs and the initiation of cost recovery of the AMI programs under the final electric and natural gas distribution rate case order issued by the MDPSC in June 2016. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.
(c) Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income taxes increased for the year ended December 31, 2017 compared to the same period in 2016 , and for the year ended December 31, 2016 compared to the same period in 2015 , primarily due to an increase in property taxes.

Interest Expense, Net

Interest expense, net remained relatively consistent for the year ended December 31, 2017 compared to the same period in 2016 , and for the year ended December 31, 2016 compared to the same period in 2015 .

Other, Net

Other, net remained relatively consistent for the year ended December 31, 2017 , compared to the same period in 2016 , and the year ended December 31, 2016 , compared to the same period in 2015 .

Effective Income Tax Rate

BGE's effective income tax rates for the years ended December 31, 2017 , 2016 and 2015 were 41.5% , 37.2% and 39.6% , respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2017	2016	% Change 2017 vs. 2016	Weather-Normal % Change	2015	% Change 2016 vs. 2015	Weather-Normal % Change
Retail Deliveries [a]							
Residential	12,094	12,740	(5.1)%	(2.8)%	12,598	1.1 %	(3.2)%
Small commercial & industrial	2,921	3,040	(3.9)%	(4.9)%	3,119	(2.5)%	2.7 %
Large commercial & industrial	13,688	13,957	(1.9)%	(2.4)%	14,293	(2.4)%	(1.6)%
Public authorities & electric railroads	268	283	(5.3)%	(3.0)%	294	(3.7)%	(8.9)%
Total electric deliveries	28,971	30,020	(3.5)%	(2.8)%	30,304	(0.9)%	(1.9)%

	As of December 31,		
Number of Electric Customers	2017	2016	2015
Residential	1,160,783	1,150,096	1,137,934
Small commercial & industrial	113,594	113,230	113,138
Large commercial & industrial	12,155	12,053	11,906
Public authorities & electric railroads	272	280	285
Total	1,286,804	1,275,659	1,263,263

Electric Revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Retail Sales [a]					
Residential	$ 1,428	$ 1,554	(8.1)%	$ 1,449	7.2 %
Small commercial & industrial	266	277	(4.0)%	273	1.5 %
Large commercial & industrial	450	449	0.2 %	469	(4.3)%
Public authorities & electric railroads	31	35	(11.4)%	32	9.4 %
Total retail	2,175	2,315	(6.0)%	2,223	4.1 %
Other revenue [b][c]	314	294	6.8 %	267	10.1 %
Total electric revenue	$ 2,489	$ 2,609	(4.6)%	$ 2,490	4.8 %

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.
(b) Other revenue primarily includes wholesale transmission revenue and late payment charges.
(c) Includes operating revenues from affiliates totaling $5 million , $7 million and less than $1 million for the years ended 2017 , 2016 and 2015 , respectively.

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BGE Natural Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2017	2016	% Change 2017 vs. 2016	Weather-Normal % Change	2015	% Change 2016 vs. 2015	Weather-Normal % Change
Retail Deliveries [a]							
Retail sales	89,337	96,808	(7.7)%	(4.2)%	96,618	0.2 %	3.5%
Transportation and other [b]	3,615	5,977	(39.5)%	n/a	6,238	(4.2)%	n/a
Total natural gas deliveries	92,952	102,785	(9.6)%	(4.2)%	102,856	(0.1)%	3.5%

	As of December 31,		
Number of Gas Customers	2017	2016	2015
Residential	629,690	623,647	616,994
Commercial & industrial	44,247	44,255	44,119
Total	673,937	667,902	661,113

Natural Gas revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Retail Sales [a]					
Retail sales	$ 655	$ 593	10.5%	$ 607	(2.3)%
Transportation and other [b]	32	31	3.2%	38	(18.4)%
Total natural gas revenues [c]	$ 687	$ 624	10.1%	$ 645	(3.3)%

(a) Reflects delivery volumes and revenue from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from BGE, revenue also reflects the cost of natural gas.
(b) Transportation and other natural gas revenue includes off-system revenue of 3,615 mmcfs ($21 million), 5,977 mmcfs ($23 million), and 6,238 mmcfs ($35 million) for the years ended 2017 , 2016 and 2015 , respectively.
(c) Includes operating revenues from affiliates totaling $11 million , $14 million , and $14 million for the years ended 2017 , 2016 and 2015 , respectively.

Results of Operations—PHI

PHI's results of operations include the results of its three reportable segments, Pepco, DPL and ACE for all periods presented below. For "Predecessor" reporting periods, PHI's results of operations also include the results of PES and PCI. See Note 25 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding PHI's reportable segments. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for Pepco, DPL and ACE is presented elsewhere in this report.

As a result of the PHI Merger, the following consolidated financial results present two separate reporting periods for 2016. The "Predecessor" reporting periods represent PHI's results of operations for the period of January 1, 2016 to March 23, 2016 and the year ended December 31, 2015 . The "Successor" reporting periods represents PHI's results of operations for the year ended December 31, 2017 and for the period of March 24, 2016 to December 31, 2016 . All amounts presented below are before the impact of income taxes, except as noted.

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	Successor		Predecessor	
	For the Year Ended December 31,	March 24 to December 31,	January 1 to March 23,	For the Year Ended December 31,
	2017	2016	2016	2015
Operating revenues	$ 4,679	$ 3,643	$ 1,153	$ 4,935
Purchased power and fuel	1,716	1,447	497	2,073
Revenues net of purchased power and fuel expense [(a)]	2,963	2,196	656	2,862
Other operating expenses				
Operating and maintenance	1,068	1,233	294	1,156
Depreciation and amortization	675	515	152	624
Taxes other than income	452	354	105	455
Total other operating expenses	2,195	2,102	551	2,235
Gain (loss) on sales of assets	1	(1)	—	46
Operating income	769	93	105	673
Other income and (deductions)				
Interest expense, net	(245)	(195)	(65)	(280)
Other, net	54	44	(4)	88
Total other income and (deductions)	(191)	(151)	(69)	(192)
Income (loss) before income taxes	578	(58)	36	481
Income taxes	217	3	17	163
Equity in earnings of unconsolidated affiliates	1	—	—	—
Net income (loss) from continuing operations	362	(61)	19	318
Net income from discontinued operations	—	—	—	9
Net income (loss) attributable to membership interest/common shareholders	$ 362	$ (61)	$ 19	$ 327

(a) PHI evaluates its operating performance using the measure of revenue net of purchased power and fuel expense for electric and natural gas sales. PHI believes revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. PHI has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Successor Year Ended December 31, 2017

PHI's Net income was $362 million for the year ended December 31, 2017 . There were no significant changes in the underlying trends affecting PHI's results of operations during the Successor year except for the impact of increases in electric distribution and natural gas rates within Revenue net of purchased power expense (Pepco electric distribution rates effective November 2016 and October 2017 in Maryland, Pepco electric distribution rates effective August 2017 in the District of Columbia, DPL electric distribution rates effective February 2017 in Maryland, DPL electric distribution and natural gas rates effective July 2016 and December 2016 in Delaware, and ACE electric distribution rates effective August 2016 and

October 2017 in New Jersey). Operating and maintenance expense incurred included the deferral of merger-related, rate case, and customer billing system costs to regulatory assets and lower uncollectible accounts expense, partially offset by a pre-tax impairment charge of $25 million. Income taxes expense incurred included unrecognized tax benefits of $59 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017, and was offset by a $27 million December 2017 impairment of certain transmission-related income tax regulatory assets and the one-time non-cash impacts of $35 million associated with the Tax Cuts and Jobs Act in 2017. For more information on 2017 results please refer to Results of Operations for Pepco, DPL, and ACE.

PHI's effective income tax rate for the year ended December 31, 2017 was 37.5% . See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of effective income tax rates.

Successor Period of March 24, 2016 to December 31, 2016

PHI's Net loss for the Successor period of March 24, 2016 to December 31, 2016 was $61 million . There were no significant changes in the underlying trends affecting PHI's results of operations during the Successor period March 24, 2016 to December 31, 2016 except for the pre-tax recording of $392 million of non-recurring merger-related costs including merger integration and merger commitments within Operating and maintenance expense. For more information on 2016 results please refer to Results of Operations for Pepco, DPL and ACE.

PHI's effective income tax rate for the period of March 24, 2016 to December 31, 2016 was (5.2)% . See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Predecessor Period of January 1, 2016 to March 23, 2016

PHI's Net income for the Predecessor period of January 1, 2016 to March 23, 2016 was $19 million . There were no significant changes in the underlying trends affecting PHI's results of operations during the Predecessor period of January 1, 2016 to March 23, 2016 except for the pre-tax recording of $29 million of non-recurring merger-related costs within Operating and maintenance expense and $18 million of preferred stock derivative expense within Other, net.

PHI's effective income tax rate for the period of January 1, 2016 to March 23, 2016 was 47.2% . See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Predecessor Period Year Ended December 31, 2015

PHI's Net income was $327 million for the year ended December 31, 2015 . There were no significant changes in the underlying trends affecting PHI's results of operations during the Predecessor year except for the impact of increases in electric distribution rates within Revenue net of purchased power expense (Pepco electric distribution rates effective April 2014 in the District of Columbia, Pepco electric distribution rates effective July 2014 in Maryland, and ACE electric distribution rates effective September 2014), partially offset by Operating and maintenance costs incurred due to the implementation of a new customer information system for Pepco, DPL, and ACE in 2015. Gain (loss) on sales of assets were $46 million , primarily due to 2015 gains recorded at Pepco associated with the sale of unimproved land, held as non-utility property.

PHI's effective income tax rate for the year ended December 31, 2015 was 33.9% . See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations — Pepco

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	$ 2,158	$ 2,186	$ (28)	$ 2,129	$ 57
Purchased power expense	614	706	92	719	13
Revenues net of purchased power expense [(a)]	1,544	1,480	64	1,410	70
Other operating expenses					
Operating and maintenance	454	642	188	439	(203)
Depreciation and amortization	321	295	(26)	256	(39)
Taxes other than income	371	377	6	376	(1)
Total other operating expenses	1,146	1,314	168	1,071	(243)
Gain on sales of assets	1	8	(7)	46	(38)
Operating income	399	174	225	385	(211)
Other income and (deductions)					
Interest expense, net	(121)	(127)	6	(124)	(3)
Other, net	32	36	(4)	28	8
Total other income and (deductions)	(89)	(91)	2	(96)	5
Income before income taxes	310	83	227	289	(206)
Income taxes	105	41	(64)	102	61
Net income	$ 205	$ 42	$ 163	$ 187	$ (145)

(a) Pepco evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. Pepco believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Pepco has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . Pepco's Net income for the year ended December 31, 2017 , was higher than the same period in 2016 , primarily due to a decrease in Operating and maintenance expense due to merger-related costs recognized in March 2016 and an increase in Revenue net of purchased power expense as a result of the distribution rate increases approved by the MDPSC effective November 2016 and October 2017 and an electric distribution rate increase approved by the DCPSC effective August 2017, partially offset by higher depreciation expense due to increased depreciation rates in Maryland effective November 2016. Income taxes expense incurred included unrecognized tax benefits of $21 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017. This decrease was offset by an increase in income taxes due to the $14 million December 2017 impairment of certain transmission-related income tax regulatory assets and the one-time non-cash impacts of $8 million associated with the Tax Cuts and Jobs Act in 2017.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . Pepco's Net income for the year ended December 31, 2016 , was lower than the same period in 2015 , primarily due to an increase in Operating and maintenance expense due to merger-related costs.

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Operating Revenue Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to Pepco's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that Pepco receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All Pepco customers have the choice to purchase electricity from competitive electric generation suppliers. The customers' choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2017 , 2016 and 2015 respectively, consisted of the following:

	For the Years Ended December 31,		
	2017	2016	2015
Electric	66%	65%	65%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2017 , 2016 and 2015 consisted of the following:

	December 31, 2017		December 31, 2016		December 31, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	179,184	21%	176,372	21%	173,222	21%

Retail deliveries purchased from competitive electric generation suppliers represented 73% of Pepco's retail kWh sales to the District of Columbia customers and 60% of Pepco's retail kWh sales to Maryland customers for the year ended December 31, 2017 ; 73% of Pepco's retail kWh sales to the District of Columbia customers and 59% of Pepco's retail kWh sales to Maryland customers for the year ended December 31, 2016 ; and 71% of Pepco's retail kWh sales to the District of Columbia customers and 60% of Pepco's retail kWh sales to Maryland customers for year ended December 31, 2015 .

Operating revenues include transmission enhancement credits that Pepco receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Purchased power expense consists of the cost of electricity purchased by Pepco to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders.

The changes in Pepco's Operating revenues net of purchased power expense for the years ended December 31, 2017 and 2016 compared to the same periods in 2016 and 2015 , respectively, consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Volume	$ 16	$ 15
Distribution rate increase	66	5
Regulatory required programs	(12)	38
Transmission revenues	9	(1)
Other	(15)	13
Total increase	$ 64	$ 70

Volume. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2017 compared to the same period in 2016 primarily reflects the impact of residential customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015 primarily reflects the impact of moderate economic and customer growth.

Distribution Rate Increase. The increase in electric operating revenues net of purchased power expense for the year ended December 31, 2017 compared to the same period in 2016 was primarily due to the impact of the higher electric distribution rates charged to customers in Maryland that became effective in November 2016 and October 2017 and higher electric distribution rates charged to customers in the District of Columbia that became effective August 2017. The increase in distribution revenue for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution rates charged to customers in Maryland that became effective in November 2016. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Revenue Decoupling. Pepco's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco in Maryland and in the District of Columbia, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in Pepco's service territory. The changes in heating and cooling degree days in Pepco's service territory for the years ended December 31, 2017 and December 31, 2016 compared to same periods in 2016 and 2015 , respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	3,312	3,624	3,869	(8.6)%	(14.4)%
Cooling Degree-Days	1,767	1,936	1,653	(8.7)%	6.9 %

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	3,624	3,657	3,887	(0.9)%	(6.8)%
Cooling Degree-Days	1,936	1,936	1,626	— %	19.1 %

Regulatory Required Programs. This represents the change in Operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in Pepco's Consolidated Statements of Operations and Comprehensive Income. Revenue from regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 primarily due to lower demand-side management program surcharge revenue due to a decrease in kWh sales and a rate decrease effective January 2017. Revenue from regulatory required programs increased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to higher demand-side management program surcharge revenue due to a rate increase effective February 2016. Refer to the Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs.

Transmission Revenues . Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and other billing adjustments. Transmission revenue increased for the year ended December 31, 2017 compared to the same period in 2016 due to higher rates effective June 1, 2017 and June 1, 2016 related to increases in transmission plant investment and operating expenses. Transmission revenue decreased for the year ended December 31, 2016 compared to the same period in 2015 due to lower revenue related to the MAPP abandonment recovery period that ended in March 2016, partially offset by higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses.

Other. The decrease in other operating revenue net of purchased power expense for the year ended December 31, 2017 compared to the same period in 2016 is primarily due to lower pass-through revenue (which is substantially offset in Taxes other than income) primarily the result of lower sales that resulted in a decrease in utility taxes that are collected by Pepco on behalf of the jurisdiction. The increase in other operating revenue net of purchased power expense for the year ended December 31, 2016 compared to the same period in 2015 is primarily due to higher pass-through revenue (which is substantially offset in Taxes other than income) primarily the result of higher sales that resulted in an increase in utility taxes that are collected by Pepco on behalf of the jurisdiction.

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Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2017	2016	2017 vs. 2016	2016	2015	2016 vs. 2015
Operating and maintenance expense - baseline	$ 449	$ 631	$ (182)	$ 631	$ 427	$ 204
Operating and maintenance expense - regulatory required programs [(a)]	5	11	(6)	11	12	(1)
Total operating and maintenance expense	$ 454	$ 642	$ (188)	$ 642	$ 439	$ 203

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Baseline		
Labor, other benefits, contracting and materials	$ 16	$ 7
Storm-related costs	(1)	6
Remeasurement of AMI-related regulatory asset [(a)]	(7)	7
Deferral of billing system transition costs to regulatory asset	—	(7)
Deferral of merger-related costs to regulatory asset	—	(11)
Uncollectible accounts expense - provision	(11)	8
BSC and PHISCO allocations [(b)]	(24)	53
Merger commitments [(c)]	(132)	126
Write-off of construction work in progress [(d)]	(14)	13
Other	(9)	2
	(182)	204
Regulatory required programs		
Purchased power administrative costs	(6)	(1)
Total (decrease) increase	$ (188)	$ 203

(a) Related to a remeasurement of a regulatory asset for legacy meters recognized in 2016 .
(b) Primarily related to merger severance and compensation costs recognized in 2016
(c) Primarily related to merger-related commitments for customer rate credits and charitable contributions recognized in 2016 .
(d) Primarily resulting from a review of capital projects during the fourth quarter of 2016 .

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Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Depreciation expense [(a)]	$ 28	$ 11
Regulatory asset amortization [(b)]	8	(11)
Regulatory required programs [(c)]	(10)	39
Total increase	$ 26	$ 39

(a) Depreciation expense increased primarily due to higher depreciation rates in Maryland effective November 2016 and ongoing capital expenditures.
(b) Regulatory asset amortization increased for the year ended December 31, 2017 compared to the same period in 2016 primarily due to higher amortization of AMI-related regulatory assets, partially offset by lower amortization of MAPP abandonment costs. Regulatory asset amortization decreased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to lower amortization of MAPP abandonment costs.
(c) Regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 primarily due to an EmPower Maryland surcharge rate decrease effective February 2016 and increased for the year ended December 31, 2016 compared to the same period in 2015 due to an EmPower Maryland surcharge rate increase effective February 2015. Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues and Operating and maintenance expense.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to lower utility taxes that are collected and passed through by Pepco (which is substantially offset in Operating revenues), partially offset by higher property taxes. Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher utility taxes that are collected and passed through by Pepco, partially offset by lower property taxes in Maryland.

Gain on Sales of Assets

Gain on sales of assets for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to higher gains recorded in 2016 at Pepco associated with the sale of land. Gain on sale of assets for the year ended December 31, 2016 compared to the same period in 2015 decreased primarily due to higher gains recorded in 2015 at Pepco associated with the sale of land held as non-utility property.

Interest Expense, Net

Interest expense, net for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to the recording of interest expense for an uncertain tax position in 2016, partially offset by higher interest expense associated with the issuance of long term debt in May 2017. Interest expense, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to the recording of interest expense for an uncertain tax position in 2016, partially offset by an increase in capitalized AFUDC debt.

Other, Net

Other, net for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to the September 2016 reversal of contributions in aid of construction tax gross-

up reserves due to the determination that there is no legal obligation to refund customers per contract term. Other, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC equity.

Effective Income Tax Rate

Pepco's effective income tax rates for the years ended December 31, 2017 , 2016 , and 2015 were 33.9% , 49.4% , and 35.3% , respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates. In the first quarter of 2017, Pepco decreased its liability for unrecognized tax benefits by $21 million resulting in a benefit to Income taxes and corresponding decrease to its effective tax rate. This decrease was offset by an increase in income taxes due to the $14 million December 2017 impairment of certain transmission-related income tax regulatory assets and the one-time non-cash impacts of $8 million associated with the Tax Cuts and Jobs Act in 2017.

As a result of the merger, Pepco recorded an after-tax charge of $31 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

Pepco Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2017	2016	% Change 2017 vs. 2016	Weather - Normal % Change	2015	% Change 2016 vs. 2015	Weather - Normal % Change
Retail Deliveries [a]							
Residential	7,831	8,372	(6.5)%	(2.5)%	8,452	(0.9)%	(0.3)%
Small commercial & industrial	1,303	1,459	(10.7)%	(9.0)%	1,471	(0.8)%	(0.6)%
Large commercial & industrial	14,988	15,559	(3.7)%	(2.5)%	15,351	1.4 %	1.6 %
Public authorities & electric railroads	734	724	1.4 %	1.4 %	714	1.4 %	1.7 %
Total retail deliveries	24,856	26,114	(4.8)%	(2.8)%	25,988	0.5 %	0.9 %

	As of December 31,		
Number of Electric Customers	2017	2016	2015
Residential	792,211	780,652	767,392
Small commercial & industrial	53,489	53,529	53,838
Large commercial & industrial	21,732	21,391	20,976
Public authorities & electric railroads	144	130	129
Total	867,576	855,702	842,335

Electric Revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Retail Sales [a]					
Residential	$ 956	$ 1,000	(4.4)%	$ 970	3.1 %
Small commercial & industrial	147	150	(2.0)%	153	(2.0)%
Large commercial & industrial	810	803	0.9 %	777	3.3 %
Public authorities & electric railroads	33	32	3.1 %	30	6.7 %
Total retail	1,946	1,985	(2.0)%	1,930	2.8 %
Other revenue [b]	212	201	5.5 %	199	1.0 %
Total electric revenue [c]	$ 2,158	$ 2,186	(1.3)%	$ 2,129	2.7 %

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from Pepco and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from Pepco, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.
(c) Includes operating revenues from affiliates totaling $6 million for the year ended December 31, 2017 and $5 million for the years ended December 31, 2016 and 2015 , respectively.

Results of Operations — DPL

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	$ 1,300	$ 1,277	$ 23	$ 1,302	$ (25)
Purchased power and fuel expense	532	583	51	634	51
Revenues net of purchased power and fuel expense [a]	768	694	74	668	26
Other operating expenses					
Operating and maintenance	315	441	126	304	(137)
Depreciation and amortization	167	157	(10)	148	(9)
Taxes other than income	57	55	(2)	51	(4)
Total other operating expenses	539	653	114	503	(150)
Gain on sales of assets	—	9	(9)	—	9
Operating income	229	50	179	165	(115)
Other income and (deductions)					
Interest expense, net	(51)	(50)	(1)	(50)	—
Other, net	14	13	1	10	3
Total other income and (deductions)	(37)	(37)	—	(40)	3
Income before income taxes	192	13	179	125	(112)
Income taxes	71	22	(49)	49	27
Net income (loss)	$ 121	$ (9)	$ 130	$ 76	$ (85)

(a) DPL evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. DPL believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements because they provide information that can be used to evaluate its operational performance. DPL has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense and Revenue net of fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

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Net Income (Loss)

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The increase in Net income was driven primarily by a decrease in Operating and maintenance expense primarily due to merger-related costs recognized in March 2016 and an increase in Revenues net of purchased power and fuel expense as a result of the distribution rate increases approved by the DPSC effective July and December 2016 and a distribution rate increase approved by the MDPSC effective February 2017, partially offset by higher depreciation expense due to increased depreciation rates in Maryland effective February 2017. Income taxes expense incurred included unrecognized tax benefits of $16 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017. This decrease was offset by an increase in income taxes due to the $6 million December 2017 impairment of certain transmission-related income tax regulatory assets and the one-time non-cash impacts of $5 million associated with the Tax Cuts and Jobs Act in 2017.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The decrease in Net income was driven primarily by an increase in Operating and maintenance expense primarily due to merger-related costs.

Operating Revenue Net of Purchased Power and Fuel Expense

Operating revenues include revenue from the distribution and supply of electricity and natural gas to DPL's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that DPL receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric and natural gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All DPL customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customers' choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the years ended December 31, 2017 , 2016 and 2015 , consisted of the following:

	For the Years Ended December 31,		
	2017	2016	2015
Electric	52%	51%	51%
Natural Gas	33%	28%	31%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2017 , 2016 and 2015 consisted of the following:

	December 31, 2017		December 31, 2016		December 31, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	77,790	14.9%	78,675	15.2%	77,603	15.1%
Natural Gas	154	0.1%	156	0.1%	159	0.1%

Retail deliveries purchased from competitive electric generation suppliers represented 54% of DPL's retail kWh sales to Delaware customers and 48% of DPL retail kWh sales to Maryland customers for

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the year ended December 31, 2017 ; 53% of DPL's retail kWh sales to Delaware customers and 48% of DPL's retail kWh sales to Maryland customers for the year ended December 31, 2016 ; and 53% of DPL's retail kWh sales to Delaware customers and 47% of DPL's retail kWh sales to Maryland customers for the year ended December 31, 2015 .

Operating revenues include transmission enhancement credits that DPL receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Natural gas operating revenues includes sources that are subject to price regulation (Regulated Gas Revenue) and those that generally are not subject to price regulation (Other Gas Revenue). Regulated gas revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates. Other gas revenue consists of off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Purchased power expense consists of the cost of electricity purchased by DPL to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased fuel expense consists of the cost of gas purchased by DPL to fulfill its obligation to regulated gas customers and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of gas purchased for off-system sales.

The changes in DPL's Operating revenues net of purchased power and fuel expense for the years ended December 31, 2017 and 2016 compared to the same periods in 2016 and 2015 , respectively, consisted of the following:

	2017 vs. 2016			2016 vs. 2015		
	Increase (Decrease)			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ (7)	$ (13)	$ (20)	$ —	$ —	$ —
Volume	2	11	13	2	2	4
Distribution rate increase	65	4	69	2	1	3
Regulatory required programs	(3)	—	(3)	10	—	10
Transmission revenues	10	—	10	8	—	8
Other	6	(1)	5	1	—	1
Increase in revenue net of purchased power expense	$ 73	$ 1	$ 74	$ 23	$ 3	$ 26

Revenue Decoupling. DPL's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of DPL in Maryland, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland to fluctuate from period to period are changes

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in the number of customers and changes in the approved distribution charge per customer. A modified fixed variable rate design, which would provide for a charge not tied to a customer's volumetric consumption of electricity or natural gas, has been proposed for DPL electricity and natural gas customers in Delaware. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

Weather. The demand for electricity and natural gas in areas not subject to the BSA is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the year ended December 31, 2017 compared to the same period in 2016 , operating revenues net of purchased power and fuel expenses was lower due to the impact of unfavorable weather conditions in DPL's service territory. During the year ended December 31, 2016 compared to the same period in 2015 , weather was not a significant impact.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in DPL's electric service territory and a 30-year period in DPL's natural gas service territory. The changes in heating and cooling degree days in DPL's service territory for the years ended December 31, 2017 and December 31, 2016 compared to same periods in 2016 and 2015 , respectively, and normal weather consisted of the following:

Electric Service Territory	**For the Years Ended December 31,**			**% Change**	
Heating and Cooling Degree-Days	**2017**	**2016**	**Normal**	**2017 vs. 2016**	**2017 vs. Normal**
Heating Degree-Days	4,077	4,319	4,519	(5.6)%	(9.8)%
Cooling Degree-Days	1,300	1,453	1,210	(10.5)%	7.4 %

	For the Years Ended December 31,			**% Change**	
Heating and Cooling Degree-Days	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	4,319	4,421	4,572	(2.3)%	(5.5)%
Cooling Degree-Days	1,453	1,328	1,188	9.4 %	22.3 %

Natural Gas Service Territory	**For the Years Ended December 31,**			**% Change**	
Heating and Cooling Degree-Days	**2017**	**2016**	**Normal**	**2017 vs. 2016**	**2017 vs. Normal**
Heating Degree-Days	4,203	4,454	4,739	(5.6)%	(11.3)%

	For the Years Ended December 31,			**% Change**	
Heating and Cooling Degree-Days	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	4,454	4,618	4,754	(3.6)%	(6.3)%

Volume . The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2017 compared to the same period in 2016 , primarily reflects the impact of customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects

of weather, for the year ended December 31, 2016 compared to the same period in 2015 , primarily reflects the impact of moderate economic and customer growth.

Distribution Rate Increase . The increase in electric operating revenues net of purchased power expense for the year ended December 31, 2017 compared to the same period in 2016 was primarily due to the impact of the higher electric distribution and natural gas rates charged to Delaware customers that became effective in July and December 2016 and the impact of higher electric distribution rates charged to Maryland customers that became effective in February 2017. The increase in electric operating revenues net of purchased power expense for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution rates charged to Delaware customers that became effective in July 2016. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in DPL's Consolidated Statements of Operations and Comprehensive Income. Revenue from regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 primarily due to lower demand-side management program surcharge revenue due to a decrease in kWh sales and a rate decrease effective January 2017. Revenue from regulatory required programs increased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to higher demand-side management program surcharge revenue due to a rate increase effective February 2016. Refer to the Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs.

Transmission Revenues . Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and other billing adjustments. Transmission revenue increased for the year ended December 31, 2017 compared to the same period in 2016 due to higher rates effective June 1, 2017 and June 1, 2016 related to increases in transmission plant investment and operating expenses. Transmission revenue increased for the year ended December 31, 2016 compared to the same period in 2015 due to higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by lower revenue related to the MAPP abandonment recovery period that ended in March 2016.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of other taxes.

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Operating and Maintenance Expense

	Year Ended December 31,			Year Ended December 31,		
	2017	2016	Increase (Decrease)	2016	2015	Increase (Decrease)
Operating and maintenance expense - baseline	$ 306	$ 425	$ (119)	$ 425	$ 289	$ 136
Operating and maintenance expense - regulatory required programs [(a)]	9	16	(7)	16	15	1
Total operating and maintenance expense	$ 315	$ 441	$ (126)	$ 441	$ 304	$ 137

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Baseline		
Labor, other benefits, contracting and materials	$ 4	$ 1
Storm-related costs	4	5
Deferral of billing system transition costs to regulatory asset	2	(2)
Deferral of merger-related costs to regulatory asset	(6)	(4)
Uncollectible accounts expense - provision	(10)	3
BSC and PHISCO allocations [(a)]	(15)	34
Merger commitments [(b)]	(88)	86
Write-off of construction work in progress [(c)]	(3)	4
Other	(7)	9
	(119)	136
Regulatory required programs		
Purchased power administrative costs	(7)	1
Total (decrease) increase	$ (126)	$ 137

(a) Primarily related to merger severance and compensation costs recognized in 2016 .
(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions recognized in 2016 .
(c) Primarily resulting from a review of capital projects during the fourth quarter of 2016 .

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Depreciation expense [(a)]	$ 14	$ 7
Regulatory asset amortization [(b)]	—	(7)
Regulatory required programs [(c)]	(4)	9
Total increase	$ 10	$ 9

(a) Depreciation expense increased due to higher depreciation rates in Maryland effective February 2017 and due to ongoing capital expenditures.
(b) Regulatory asset amortization decreased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to lower amortization of MAPP abandonment costs.
(c) Regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 primarily due to an EmPower Maryland surcharge rate decrease effective February 2016 and increased for the year ended December 31, 2016 compared to the same period in 2015 due to an EmPower Maryland surcharge rate increase effective February 2015. Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. A partially offsetting amount has been reflected in Operating revenues and Operating and maintenance expense.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2017 compared to the same period in 2016 remained relatively constant. Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher property taxes in Maryland related to higher property assessments and rate increases.

Gain on Sales of Assets

Gain on sales of assets for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to gains recorded in 2016 at DPL associated with the sale of land held as non-utility property. Gain on sales of assets for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to gains recorded in 2016 at DPL associated with the sale of land held as non-utility property.

Interest Expense, Net

Interest expense, net for the year ended December 31, 2017 compared to the same period in 2016 and for the year ended December 31, 2016 compared to the same period in 2015 remained relatively constant.

Other, Net

Other, net for the year ended December 31, 2017 compared to the same period in 2016 remained relatively constant. Other, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC equity.

Effective Income Tax Rate

DPL's effective income tax rates for the years ended December 31, 2017 , 2016 and 2015 were 37.0% , 169.2% and 39.2% , respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates. In the first quarter of 2017, DPL decreased its liability for unrecognized

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tax benefits by $16 million resulting in a benefit to Income taxes and corresponding decrease to its effective tax rate. This decrease was offset by an increase in income taxes due to the $6 million December 2017 impairment of certain transmission-related income tax regulatory assets and the one-time non-cash impacts of $5 million associated with the Tax Cuts and Jobs Act in 2017.

As a result of the merger, DPL recorded an after-tax charge of $23 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

DPL Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2017	2016	% Change 2017 vs. 2016	Weather - Normal % Change	2015	% Change 2016 vs. 2015	Weather - Normal % Change
Retail Deliveries [a]							
Residential	5,010	5,181	(3.3)%	(0.3)%	5,337	(2.9)%	(2.9)%
Small commercial & industrial	2,237	2,290	(2.3)%	(0.9)%	2,311	(0.9)%	(1.3)%
Large commercial & industrial	4,585	4,623	(0.8)%	0.3 %	4,781	(3.3)%	(3.9)%
Public authorities & electric railroads	44	46	(4.3)%	(8.3)%	45	2.2 %	6.7 %
Total retail deliveries	11,876	12,140	(2.2)%	(0.2)%	12,474	(2.7)%	(2.9)%

	As of December 31,		
Number of Electric Customers	2017	2016	2015
Residential	459,389	456,181	453,145
Small commercial & industrial	60,697	60,173	59,714
Large commercial & industrial	1,400	1,411	1,410
Public authorities & electric railroads	629	643	643
Total	522,115	518,408	514,912

Electric Revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Retail Sales [a]					
Residential	$ 660	$ 668	(1.2)%	$ 681	(1.9)%
Small commercial & industrial	185	187	(1.1)%	192	(2.6)%
Large commercial & industrial	102	98	4.1 %	101	(3.0)%
Public authorities & electric railroads	14	13	7.7 %	12	8.3 %
Total retail	961	966	(0.5)%	986	(2.0)%
Other revenue [b]	178	163	9.2 %	152	7.2 %
Total electric revenue [c]	$ 1,139	$ 1,129	0.9 %	$ 1,138	(0.8)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from DPL, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.
(c) Includes operating revenues from affiliates totaling $8 million , $7 million and $6 million for the years ended December 31, 2017 , 2016 and 2015 , respectively.

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DPL Gas Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in mmcf)	2017	2016	% Change 2017 vs. 2016	Weather Normal % change	2015	% Change 2016 vs. 2015	Weather Normal % change
Retail Deliveries							
Residential	13,107	13,341	(1.8)%	5.2%	13,816	(3.4)%	(0.4)%
Transportation & other	6,538	6,201	5.4 %	6.9%	6,193	0.1 %	1.4 %
Total gas deliveries	19,645	19,542	0.5 %	5.7%	20,009	(2.3)%	0.1 %

	As of December 31,		
Number of Gas Customers	2017	2016	2015
Residential	122,347	120,951	119,771
Commercial & industrial	9,853	9,801	9,712
Transportation & other	154	156	159
Total	132,354	130,908	129,642

Gas Revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Retail Sales [a]					
Retail sales	$ 136	$ 127	7.1%	$ 143	(11.2)%
Transportation & other [b]	25	21	19.0%	21	— %
Total gas revenues	$ 161	$ 148	8.8%	$ 164	(9.8)%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from DPL and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from DPL, revenue also reflects the cost of natural gas.
(b) Transportation and other revenue includes off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers.

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Results of Operations — ACE

	2017	2016	Favorable (unfavorable) 2017 vs. 2016 variance	2015	Favorable (unfavorable) 2016 vs. 2015 variance
Operating revenues	$ 1,186	$ 1,257	$ (71)	$ 1,295	$ (38)
Purchased power expense	570	651	81	708	57
Revenues net of purchased power expense [(a)]	616	606	10	587	19
Other operating expenses					
Operating and maintenance	307	428	121	271	(157)
Depreciation and amortization	146	165	19	175	10
Taxes other than income	6	7	1	7	—
Total other operating expenses	459	600	141	453	(147)
Gain on sales of assets	—	1	(1)	—	1
Operating income	157	7	150	134	(127)
Other income and (deductions)					
Interest expense, net	(61)	(62)	1	(64)	2
Other, net	7	9	(2)	3	6
Total other income and (deductions)	(54)	(53)	(1)	(61)	8
Income (loss) before income taxes	103	(46)	149	73	(119)
Income taxes	26	(4)	(30)	33	37
Net income (loss)	$ 77	$ (42)	$ 119	$ 40	$ (82)

(a) ACE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. ACE believes Revenue net of purchased power expense is a useful measurement of its performance because it provides information that can be used to evaluate its operational performance. ACE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income (Loss)

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 . The increase in Net income was primarily due to a decrease in Operating and maintenance expense primarily due to merger-related costs recognized in March 2016 and an increase in Revenues net of purchased power expense resulting from impact of distribution rate increases approved by the NJBPU effective August 2016 and October 2017 and an increase in transmission formula rate revenues, partially offset by lower customer usage. Income taxes expense incurred included unrecognized tax benefits of $22 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017. This decrease was offset by an increase in income taxes due to the December 2017 impairment of certain transmission-related income tax regulatory assets of $7 million and the one-time non-cash impacts of $2 million associated with the Tax Cuts and Jobs Act in 2017.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 . The decrease in Net income was driven primarily by an increase in Operating and maintenance expense primarily due to merger-related costs.

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Revenues Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to ACE's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that ACE receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All ACE customers have the choice to purchase electricity from competitive electric generation suppliers. The customer's choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2017 , 2016 and 2015 , consisted of the following:

	For the Years Ended December 31,		
	2017	2016	2015
Electric	48%	47%	45%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2017 , 2016 and 2015 consisted of the following:

	December 31, 2017		December 31, 2016		December 31, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	86,155	16%	94,562	17%	78,299	14%

Operating revenues include revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, revenue from the resale in the PJM wholesale markets for energy and capacity purchased under contracts with unaffiliated NUGs, and revenue from transmission enhancement credits.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Purchased power expense consists of the cost of electricity purchased by ACE to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders.

The changes in ACE's Operating revenues net of purchased power expense for the years ended December 31, 2017 and 2016 compared to the same periods in 2016 and 2015 , respectively, consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Weather	$ (3)	$ (3)
Volume	(20)	1
Distribution rate increase	40	14
Regulatory required programs	(24)	(14)
Transmission revenues	22	23
Other	(5)	(2)
Increase in revenue net of purchased power expense	$ 10	$ 19

Weather. The demand for electricity is affected by weather conditions. With respect to the electric business, very warm weather in summer months and very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity. Conversely, mild weather reduces demand. During the year ended December 31, 2017 compared to the same period in 2016 , operating revenues net of purchased power and fuel expense was lower due to the impact of unfavorable winter weather conditions in ACE's service territory. During the year ended December 31, 2016 compared to the same period in 2015 , operating revenues net of purchased power and fuel expense was lower due to the impact of unfavorable winter weather conditions in ACE's service territory.

For retail customers of ACE, distribution revenues are not decoupled for the distribution of electricity by ACE, and thus are subject to variability due to changes in customer consumption. Therefore, changes in customer usage (due to weather conditions, energy prices, energy savings programs or other reasons) from period to period have a direct impact on reported distribution revenue for customers in ACE's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in ACE's service territory. The changes in heating and cooling degree days in ACE's service territory for the years ended December 31, 2017 and December 31, 2016 compared to same periods in 2016 and 2015 , respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	4,206	4,487	4,713	(6.3)%	(10.8)%
Cooling Degree-Days	1,228	1,303	1,115	(5.8)%	10.1 %

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	4,487	4,671	4,768	(3.9)%	(5.9)%
Cooling Degree-Days	1,303	1,259	1,093	3.5 %	19.2 %

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Volume. The decrease in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2017 compared to the same period in 2016 , primarily reflects lower average customer usage, partially offset by the impact of customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015 , primarily reflects the impact of moderate economic and customer growth, partially offset by lower average customer usage.

Distribution Rate Increase. The increase in electric operating revenues net of purchased power expense for the year ended December 31, 2017 compared to the same period in 2016 was primarily due to the impact of the new electric distribution rates charged to customers that became effective in August 2016 and October 2017. The increase in electric operating revenues net of purchased power expense for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution rates charged to customers that became effective in August 2016. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in ACE's Consolidated Statements of Operations and Comprehensive Income. Revenue from regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 due to a rate decrease effective October 2016 for the ACE Transition Bond Charge and Market Transition Charge Tax. Revenue from required regulatory programs decreased for the year ended December 31, 2016 compared to the same period in 2015 due to rate decreases effective October 2016 and October 2015 for the ACE Market Transition charge tax. Refer to the Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs.

Transmission Revenues . Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered and other billing adjustments. Transmission revenue increased for the year ended December 31, 2017 compared to the same period in 2016 due to higher rates effective June 1, 2017 and June 1, 2016 related to increases in transmission plant investment and operating expenses. Transmission revenue increased for the year ended December 31, 2016 compared to the same period in 2015 due to higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses.

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Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease)	Year Ended December 31,		Increase (Decrease)
	2017	2016	2017 vs. 2016	2016	2015	2016 vs. 2015
Operating and maintenance expense - baseline	$ 303	$ 424	$ (121)	$ 424	$ 267	$ 157
Operating and maintenance expense - regulatory required programs [(a)]	4	4	—	4	4	—
Total operating and maintenance expense	$ 307	$ 428	$ (121)	$ 428	$ 271	$ 157

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Baseline		
Labor, other benefits, contracting and materials	$ 9	$ 6
BSC and PHISCO allocations [(a)]	(11)	26
Merger commitments [(b)]	(111)	111
Deferral of merger-related costs to regulatory asset	(9)	—
Other	1	14
Total (decrease) increase	$ (121)	$ 157

(a) Primarily related to merger severance and compensation costs recognized in 2016 .
(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions re cognized in 2016 .

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2017 compared to 2016 and 2016 compared to 2015 consisted of the following:

	Increase (Decrease) 2017 vs. 2016	Increase (Decrease) 2016 vs. 2015
Depreciation expense [(a)]	$ 6	$ 6
Regulatory asset amortization	(2)	(4)
Required regulatory programs [(b)]	(24)	(12)
Other	1	—
Total decrease	$ (19)	$ (10)

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory required programs decreased for the year ended December 31, 2017 compared to the same period in 2016 primarily as a result of lower revenue due to a rate decrease effective October 2016 for the ACE Transition Bond Charge and Market Transition Charge Tax. Required regulatory programs amortization decreased for the year ended December 31, 2016 compared to the same period in 2015 primarily as a result of lower revenue due to a rate decrease effective October 2015 for the ACE Market Transition charge tax. Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues and Operating and maintenance expense.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2017 compared to the same period in 2016 , remained constant. Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015 , remained constant.

Interest Expense, Net

Interest expense, net remained relatively consistent for the year ended December 31, 2017 , compared to the same period in 2016 , and the year ended December 31, 2016 , compared to the same period in 2015 .

Gain on Sales of Assets

Gain on sales of assets for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to gains recorded in 2016 at ACE associated with the sale of property. Gain on sales of assets for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to gains recorded in 2016 at ACE associated with the sale of property.

Other, Net

Other, net for the year ended December 31, 2017 compared to the same period in 2016 remained relatively constant. Other, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC equity.

Effective Income Tax Rate

ACE's effective income tax rates for the years ended December 31, 2017 , 2016 and 2015 were 25.2% , 8.7% , and 45.2% , respectively. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates. In the first quarter of 2017, ACE decreased its liability for unrecognized tax benefits by $22 million resulting in a benefit to Income taxes and corresponding decrease to its effective tax rate. This decrease was offset by an increase in income taxes due to the December 2017

impairment of certain transmission-related income tax regulatory assets of $7 million and the one-time non-cash impacts of $2 million associated with the Tax Cuts and Jobs Act in 2017.

As a result of the merger, ACE recorded an after-tax charge of $22 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

ACE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2017	2016	% Change 2017 vs. 2016	Weather - Normal % Change	2015	% Change 2016 vs. 2015	Weather - Normal % Change
Retail Deliveries [a]							
Residential	3,853	4,153	(7.2)%	(6.2)%	4,322	(3.9)%	(2.9)%
Small commercial & industrial	1,286	1,455	(11.6)%	(11.1)%	1,288	13.0 %	13.5 %
Large commercial & industrial	3,399	3,402	(0.1)%	0.4 %	3,594	(5.3)%	(5.2)%
Public authorities & electric railroads	47	49	(4.1)%	(4.1)%	45	8.9 %	8.9 %
Total retail deliveries	8,585	9,059	(5.2)%	(4.5)%	9,249	(2.1)%	(1.4)%

	As of December 31,		
Number of Electric Customers	2017	2016	2015
Residential	487,168	484,240	482,000
Small commercial & industrial	61,013	61,008	60,745
Large commercial & industrial	3,684	3,763	3,871
Public authorities & electric railroads	636	610	529
Total	552,501	549,621	547,145

Electric Revenue	2017	2016	% Change 2017 vs. 2016	2015	% Change 2016 vs. 2015
Retail Sales [a]					
Residential	$ 619	$ 664	(6.8)%	$ 690	(3.8)%
Small commercial & industrial	166	183	(9.3)%	175	4.6 %
Large commercial & industrial	189	201	(6.0)%	213	(5.6)%
Public authorities & electric railroads	13	13	— %	12	8.3 %
Total retail	987	1,061	(7.0)%	1,090	(2.7)%
Other revenue [b]	199	196	1.5 %	205	(4.4)%
Total electric revenue [c]	$ 1,186	$ 1,257	(5.6)%	$ 1,295	(2.9)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from ACE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from ACE, revenue also reflects the cost of energy and transmission.
(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.
(c) Includes operating revenues from affiliates totaling $2 million , $3 million and $4 million for the years ended December 31, 2017 , 2016 and 2015 , respectively.

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Liquidity and Capital Resources

Exelon activity presented below includes the activity of PHI, Pepco, DPL and ACE, from the PHI Merger effective date of March 24, 2016 through December 31, 2017 . Exelon prior year activity is unadjusted for the effects of the PHI Merger. Due to the application of push-down accounting to the PHI entity, PHI's activity is presented in two separate reporting periods, the legacy PHI activity through March 23, 2016 (Predecessor), and PHI activity for the remainder of the period after the PHI merger date (Successor). For each of Pepco, DPL and ACE the activity presented below include its activity for the years ended December 31, 2017 , 2016 and 2015 . All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to unsecured revolving credit facilities with aggregate bank commitments of $9 billion . In addition, Generation has $ 480 million in bilateral facilities with banks which have various expirations between January 2019 and December 2019. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO, BGE, Pepco, DPL and ACE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant's owners or parent companies would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 15 - Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information on the NRC minimum funding requirements.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT fund investments could appreciate in value. A shortfall could require Exelon to post parental guarantees for Generation's share of the obligations. However, the amount of any required guarantees will ultimately depend on the decommissioning approach adopted at each site, the associated level of costs, and the decommissioning trust fund investment performance going forward.

Within two years after shutting down a plant, Generation must submit a post-shutdown decommissioning activities report (PSDAR) to the NRC that includes the planned option for decommissioning the site. As discussed in Note 15 - Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements, Generation filed its biennial decommissioning funding status report with the NRC on March 31, 2017 and demonstrated adequate funding assurance for all nuclear units currently operating. As of December 31, 2017 , across the four alternative decommissioning approaches available, Generation estimates a parental guarantee of up to $90 million from Exelon could be required for TMI, dependent upon the ultimate decommissioning approach selected. For Oyster Creek, none of the alternative decommissioning approaches available would require Exelon to post a parental guarantee. In the event PSEG decides to early retire Salem, Generation estimates a parental guarantee of up to $45 million from Exelon could be required for Salem, dependent upon the ultimate decommissioning approach selected .

Upon issuance of any required financial guarantees, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, the NRC must approve an additional exemption in order for the plant's owner(s) to utilize the NDT fund to pay for non-radiological decommissioning costs (i.e., spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by the owner(s). While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under the United States Department of Energy reimbursement agreements or future litigation, across the four alternative decommissioning approaches available, if TMI or Oyster Creek were to fail to obtain the exemption, Generation estimates it could incur spent fuel management and site restoration costs over the next ten years of up to $225 million and $200 million net of taxes, respectively, dependent upon the ultimate decommissioning approach selected. In the event PSEG decides to early retire Salem and Salem were to fail to obtain the exemption, Generation estimates it could incur spent fuel management and site restoration costs over the next ten years of up to $80 million net of taxes.

Junior Subordinated Notes

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Each equity unit represented an undivided beneficial ownership interest in Exelon's $1.15 billion of 2.50% junior subordinated notes due in 2024 ("2024 notes") and a forward equity purchase contract. As contemplated in the June 2014 equity unit structure, in April 2017, Exelon completed the remarketing of the 2024 notes into $1.15 billion of 3.497% junior subordinated notes due in 2022 ("Remarketing"). Exelon conducted the Remarketing on behalf of the holders of equity units and did not directly receive any proceeds therefrom. Instead, the former holders of the 2024 notes used debt remarketing proceeds towards settling the forward equity purchase contract with Exelon on June 1, 2017. Exelon issued approximately 33 million shares of common stock from treasury stock and received $1.15 billion upon settlement of the forward equity purchase contract. When reissuing treasury stock Exelon uses the average price paid to repurchase shares to calculate a gain or loss on issuance and records gains or losses directly to retained earnings. A loss on reissuance of treasury shares of $1.05 billion was recorded to retained earnings as of December 31, 2017 . See Note 21 — Earnings Per Share of the Combined Notes to Consolidated Financial Statements for further information on the issuance of common stock.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

The Utility Registrants' cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, BGE and DPL, gas distribution services. The Utility Registrants' distribution services are provided to an established and diverse base of retail customers. The Utility Registrants' future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3 — Regulatory Matters and 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2017 , 2016 and 2015 :

	2017	2016	2017 vs. 2016 Variance	2015	2016 vs. 2015 Variance
Net income	$ 3,849	$ 1,204	$ 2,645	2,250	$ (1,046)
Add (subtract):					
Non-cash operating activities [a]	5,446	7,722	(2,276)	5,630	2,092
Pension and non-pension postretirement benefit contributions	(405)	(397)	(8)	(502)	105
Income taxes	299	(674)	973	97	(771)
Changes in working capital and other noncurrent assets and liabilities [b]	(1,579)	(275)	(1,304)	(264)	(11)
Option premiums received (paid), net	28	(66)	94	58	— (124)
Collateral received (posted), net	(158)	931	(1,089)	347	584
Net cash flows provided by operations	$ 7,480	$ 8,445	$ (965)	$ 7,616	$ 829

(a) Represents depreciation, amortization, depletion and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, and other non-cash charges. See Note 24 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for further detail on non-cash operating activity.
(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions below reflect a funding strategy of contributing the greater of (1) $300 million (updated for the inclusion of PHI) until the qualified plans are fully funded on an ABO basis, and (2) the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. Unlike

the qualified pension plans, Exelon's non-qualified pension plans are not funded given that they are not subject to statutory minimum contribution requirements.

While other postretirement plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon's management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including liabilities management, levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). The amounts below include benefit payments related to unfunded plans.

The following table provides all registrants' planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to other postretirement plans in 2018:

	Qualified Pension Plans	Non-Qualified Pension Plans	Other Postretirement Benefits
Exelon	$ 301	$ 30	$ 42
Generation	119	11	13
ComEd	38	2	3
PECO	17	1	—
BGE	41	1	16
BSC	36	7	1
PHI	50	8	9
Pepco	4	2	8
DPL	—	1	—
ACE	6	—	—
PHISCO	40	5	1

To the extent interest rates decline significantly or the pension and OPEB plans earn less than the expected asset returns, annual pension contribution requirements in future years could increase. Conversely, to the extent interest rates increase significantly or the pension and OPEB plans earn greater than the expected asset returns, annual pension and OPEB contribution requirements in future years could decrease. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

On October 3, 2017, the US Department of Treasury and IRS released final regulations updating the mortality tables to be used for defined benefit pension plan funding, as well as the valuation of lump sum and other accelerated distribution options, effective for plan years beginning in 2018. The new mortality tables reflect improved projected life expectancy as compared to the existing table, which is generally expected to increase minimum pension funding requirements, Pension Benefit Guaranty Corporation premiums and the value of lump sum distributions. The IRS permits plan sponsors the option of delaying use of the new mortality tables for determining minimum funding requirements until 2019, which Exelon intends to utilize. The one-year delay does not apply for use of the mortality tables to determine the present value of lump sum distributions. The estimated impact of the new mortality tables along with other current assumptions and market information are reflected in the estimated future pension contributions in the "Contractual Obligations" section below .

The EMA requires CENG to fund the obligation related to pre-transfer service of employees, including the underfunded balance of the pension and other postretirement welfare benefit plans

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measured as of July 14, 2014 by making periodic payments to Generation. These payments will be made on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG. However, in the event that EDF exercises its rights under the Put Option, all payments not made as of the put closing date shall accelerate to be paid immediately prior to such closing date. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the investment in CENG.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- Pursuant to the TCJA, beginning in 2018 Generation is expected to have higher operating cash flows in the range of approximately $1.2 billion to $1.6 billion for the period from 2018 to 2021, reflecting the reduction in the corporate federal income tax rate and full expensing of capital investments.

  The TCJA is generally expected to result in lower operating cash flows for the Utility Registrants as a result of the elimination of bonus depreciation and lower customer rates. Increased operating cash flows for the Utility Registrants from lower corporate federal income tax rates is expected to be more than offset over time by lower customer rates resulting from lower income tax expense recoveries and the settlement of deferred income tax net regulatory liabilities established pursuant to the TCJA. The amount and timing of settlement of the net regulatory liabilities will be determined by the Utility Registrants' respective rate regulators, subject to certain IRS "normalization" rules. The table below sets forth the Registrants' estimated categorization of their net regulatory liabilities as of December 31, 2017. The amounts in the table below are shown on an after-tax basis reflecting future net cash outflows after taking into consideration the income tax benefits associated with the ultimate settlement with customers.

					Successor			
	Exelon	ComEd	PECO (a)	BGE	PHI	PEPCO	DPL	ACE
Subject to IRS Normalization Rules	$ 3,040	$ 1,400	$ 533	$ 459	$ 648	$ 299	$ 195	$ 153
Subject to Rate Regulator Determination	1,694	573	43	324	754	391	194	170
Net Regulatory Liabilities	$ 4,734	$ 1,973	$ 576	$ 783	$ 1,402	$ 690	$ 389	$ 323

(a) Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO remains in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA. As a result, the amount of customer benefits resulting from the TCJA subject to the discretion of PECO's rate regulators are lower relative to the other Utility Registrants. Refer to Note 3 - Regulatory Matters for additional information.

Net regulatory liability amounts subject to normalization rules generally may not be passed back to customers any faster than over the remaining useful lives of the underlying assets giving rise to the associated deferred income taxes. Such deferred income taxes generally relate to property, plant and equipment with remaining useful lives ranging from 30 to 40 years across the Utility Registrants. For the remaining amounts, rate regulators could require the passing back of amounts to customers over shorter time frames, which could materially decrease operating cash outflows at each of the Utility Registrants in the near term.

The Utility Registrants expect to fund any such required incremental operating cash outflows using a combination of third party debt financings and equity funding from Exelon in combinations generally consistent with existing capitalization ratio structures. To fund any additional equity contributions to the Utility Registrants, Exelon would have available to it its typical sources, including, but not limited to, the increased operating cash flows at Generation

referenced above, which over time are expected to exceed the incremental equity needs at the Utility Registrants.

The Utility Registrants continue to work with their state regulatory commissions to determine the amount and timing of the passing back of TCJA income tax savings benefits to customers; with filings either made, or expected to be made, at Pepco, DPL and ACE, and approved filings at ComEd and BGE. The amounts being passed back or proposed to be passed back to customers reflect the benefit of lower income tax expense beginning January 1, 2018 (Feb. 1, 2018 for DPL Delaware), and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. To date, neither the PAPUC nor FERC has yet issued guidance on how and when to reflect the impacts of the TCJA in customer rates. Refer to Note 3 - Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information on their filings.

In general, most states use federal taxable income as the starting point for computing state corporate income tax. Now that the TCJA has been enacted, state governments are beginning to analyze the impact of the TCJA on their state revenues. Exelon is uncertain regarding what the state governments will do, and there is a possibility that state corporate income taxes could change due to the enactment of the TCJA. In 2018, Exelon will be closely monitoring the states' responses to the TCJA as these could have an impact on Exelon's future cash flows.

See Note 14 - Income Taxes of the Combined Notes to Consolidated Financial Information for further information on the amounts of the net regulatory liabilities subject to determinations by rate regulators.

- Exelon appealed the Tax Court's like-kind exchange decision in the third quarter of 2017. In the fourth quarter of 2017, the IRS assessed the tax, penalties and interest of approximately $ 1.3 billion related to the like-kind exchange, including $ 300 million attributable to ComEd. While Exelon will receive a tax benefit of approximately $ 350 million associated with the deduction for the interest, Exelon currently has a net operating loss carryforward and thus does not expect to realize the cash benefit until 2018. After taking into account these interest deduction tax benefits, the total estimated net cash outflow for the like-kind exchange is approximately $ 950 million , of which approximately $ 300 million is attributable to ComEd after giving consideration to Exelon's agreement to hold ComEd harmless from any unfavorable impacts on ComEd's equity from the like-kind exchange position.

  Of the above amounts payable, Exelon deposited with the IRS $ 1.25 billion in October of 2016. Exelon funded the $ 1.25 billion deposit with a combination of cash on hand and short-term borrowings. As a result of the IRS's assessment of the tax, penalties and interest in the fourth quarter of 2017, the deposit is no longer available to Exelon and thus was reclassified from a current asset and is now reflected as an offset to the related liabilities for the tax, penalties, and interest that are included on Exelon's balance sheet as current liabilities. The remaining amount due of approximately $ 20 million was paid in the fourth quarter of 2017. In the third quarter of 2017, the $ 300 million payable discussed above attributable to ComEd, net of ComEd's receivable pursuant to the hold harmless agreement, was settled with Exelon. See Note 14 - Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the like-kind exchange tax position.

- State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax, property taxes and other taxes or the imposition, extension or permanence of temporary tax increases. On July 6, 2017, Illinois enacted Senate Bill 9, which permanently increased Illinois' total corporate income tax rate from 7.75% to 9.50% effective July 1, 2017. The rate increase is not expected to have a material ongoing

impact to Exelon's, Generation's or ComEd's future cash taxes. See Note 14 - Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the Illinois tax rate change.

Cash flows provided by operations for the year ended December 31, 2017 , 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Exelon	$ 7,480	$ 8,445	$ 7,616
Generation	3,299	4,444	4,199
ComEd	1,527	2,505	1,896
PECO	755	829	770
BGE	821	945	782
Pepco	407	651	373
DPL	321	310	266
ACE	206	385	256

	Successor		*Predecessor*	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	$ 950	$ 888	$ 264	$ 939

Changes in Registrants' cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for 2017 , 2016 and 2015 were as follows:

Generation

- Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the OTC markets. During 2017 , 2016 and 2015 , Generation had net collections/(payments) of counterparty cash collateral of $(129) million , $923 million and $407 million , respectively, primarily due to market conditions that resulted in changes to Generation's net mark-to-market position.

- During 2017 , 2016 and 2015 , Generation had net collections/(payments) of approximately $28 million , $(66) million and $58 million , respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During 2017 , 2016 , and 2015 ComEd (posted)/received approximately $(27 million), $7 million , and $(31 million) of cash collateral with/from PJM, respectively. ComEd's collateral posted with PJM has increased from 2017 to 2016, primarily due to an increase in ComEd's RPM credit requirements and peak market activity with PJM. The collateral posted with PJM decreased from 2016 to 2015 due to lower PJM billings.

For further discussion regarding changes in non-cash operating activities, please refer to Note 24 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Investing Activities

Cash flows used in investing activities for the year ended December 31, 2017 , 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Exelon	$ (7,934)	$ (15,503)	$ (7,822)
Generation [(a)]	(2,592)	(3,851)	(4,069)
ComEd	(2,296)	(2,685)	(2,362)
PECO	(597)	(798)	(588)
BGE	(849)	(910)	(675)
Pepco	(630)	(647)	(477)
DPL	(429)	(336)	(345)
ACE	(310)	(309)	(306)

	Successor		*Predecessor*	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	$ (1,396)	$ (1,030)	$ (343)	$ (1,161)

Significant investing cash flow impacts for the Registrants for 2017 , 2016 and 2015 were as follows:

Exelon

- During 2017, Exelon had additional expenditures of $23 million and $178 million relating to the ConEdison Solutions and the acquisitions of the FitzPatrick nuclear generating station, respectively. During 2016, Exelon had expenditures of $6.6 billion , $235 million, and $58 million relating to the acquisitions of PHI, ConEdison Solutions and the acquisitions of the FitzPatrick nuclear generating station, respectively.
- During 2017, Exelon had proceeds of $219 million from sales of long-lived assets.
- During 2016, Exelon had proceeds of $360 million as a result of early termination of direct financing leases.

Generation

- During 2017, Generation had additional expenditures of $23 million and $178 million relating to the ConEdison Solutions and the acquisitions of the FitzPatrick nuclear generating station, respectively. During 2016, Generation had expenditures of $235 million, and $58 million relating to the acquisitions of ConEdison Solutions and the acquisitions of the FitzPatrick nuclear generating station, respectively.
- During 2017, Generation had proceeds of $218 million from sales of long-lived assets.

Capital Expenditure Spending

Generation

Generation has entered into several agreements to acquire equity interests in privately held development stage entities which develop energy-related technology. The agreements contain a series of scheduled investment commitments, including in-kind services contributions. There are anticipated expenditures to fund anticipated planned capital and operating needs of the associated companies.

Capital expenditures by Registrant for the year ended December 31, 2017 , 2016 and 2015 and projected amounts for 2018 are as follows:

	Projected 2018 [a]	2017	2016	2015
Exelon [b]	$ 7,825	$ 7,584	$ 8,553	$ 7,624
Generation	2,100	2,259	3,078	3,841
ComEd [c]	2,125	2,250	2,734	2,398
PECO	800	732	686	601
BGE	1,000	882	934	719
Pepco	725	628	586	544
DPL	400	428	349	352
ACE	375	312	311	300

		Successor		*Predecessor*	
	Projected 2018 [a]	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI [d]	$ 1,500	$ 1,396	$ 1,008	$ 273	$ 1,230

(a) Total projected capital expenditures do not include adjustments for non-cash activity.
(b) Includes corporate operations, BSC and PHISCO rounded to the nearest $25 million.
(c) The capital expenditures and 2018 projections include $86 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten-year period to modernize and storm-harden its distribution system and to implement smart grid technology.
(d) Includes PHISCO rounded to the nearest $25 million.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 40% and 10% of the projected 2018 capital expenditures at Generation are for the acquisition of nuclear fuel, and the construction of new natural gas plants and solar facilities, respectively, with the remaining amounts reflecting investment in renewable energy and additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

ComEd, PECO, BGE, Pepco, DPL and ACE

Projected 2018 capital expenditures at the Utility Registrants are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and the Utility Registrants' construction commitments under PJM's RTEP.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. In 2010, NERC provided guidance to transmission owners that recommended the Utility Registrants perform assessments of their transmission lines. ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and

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expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2018 capital expenditures above reflect capital spending for remediation to be completed through 2019. Pepco, DPL and ACE have substantially completed their assessments and thus do not expect significant capital expenditures related to this guidance in 2018 .

The Utility Registrants anticipate that they will fund their capital expenditures with a combination of internally generated funds and borrowings and additional capital contributions from parent.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the year ended December 31, 2017 , 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Exelon	$ 717	$ 1,191	$ 4,830
Generation	(581)	(734)	(479)
ComEd	789	169	467
PECO	50	(263)	83
BGE	22	(21)	(162)
Pepco	219	—	103
DPL	64	67	80
ACE	5	22	51

	Successor		*Predecessor*	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	$ 306	$ (7)	$ 372	$ 233

Debt

See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements. Debt activity for 2017 , 2016 and 2015 by Registrant was as follows:

During the year ended December 31, 2017 , the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Junior Subordinated Notes	3.50%	June 1, 2022	$ 1,150	Refinance Exelon's Junior Subordinated Notes issued in June 2014.
Generation	Albany Green Energy Project Financing [(a)]	LIBOR + 1.25%	November 17, 2017	$ 14	Albany Green Energy biomass generation development.
Generation	Energy Efficiency Project Financing [(a)]	3.90%	February 1, 2018	$ 19	Funding to install energy conservation measures for the Naval Station Great Lakes project.
Generation	Energy Efficiency Project Financing [(a)]	3.72%	May 1, 2018	$ 5	Funding to install energy conservation measures for the Smithsonian Zoo project.

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Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing [a]	2.61%	September 30, 2018	$ 13	Funding to install energy conservation measures for the Pensacola project.
Generation	Energy Efficiency Project Financing [a]	3.53%	April 1, 2019	$ 8	Funding to install energy conservation measures for the State Department project.
Generation	Senior Notes	2.95%	January 15, 2020	$ 250	Repay outstanding commercial paper obligations and for general corporate purposes.
Generation	Senior Notes	3.40%	March 15, 2022	$ 500	Repay outstanding commercial paper obligations and for general corporate purposes.
Generation	ExGen Texas Power Nonrecourse Debt [b][c]	LIBOR + 4.75%	September 18, 2021	$ 6	General corporate purposes.
Generation	ExGen Renewables IV, Nonrecourse Debt [b]	LIBOR + 3.00%	November 30, 2024	$ 850	General corporate purposes.
ComEd	First Mortgage Bonds, Series 122	2.95%	August 15, 2027	$ 350	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
ComEd	First Mortgage Bonds, Series 123	3.75%	August 15, 2047	$ 650	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.70%	September 15, 2047	$ 325	General corporate purposes.
BGE	Senior Notes	3.75%	August 15, 2047	$ 300	Redeem $250 million in principal amount of the 6.20% Deferrable Interest Subordinated Debentures due October 15, 2043 issued by BGE's affiliate BGE Capital Trust II, repay commercial paper obligations and for general corporate purposes.
Pepco	Energy Efficiency Project Financing [a]	3.30%	December 15, 2017	$ 2	Funding to install energy conservation measures for the DOE Germantown project.
Pepco	First Mortgage Bonds	4.15%	March 15, 2043	$ 200	Funding to repay outstanding commercial paper and for general corporate purposes.

(a) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.
(b) See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.
(c) As a result of the bankruptcy filing for EGTP on November 7, 2017, the nonrecourse debt was deconsolidated from Exelon's and Generation's consolidated financial statements. Refer to Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for further discussion.

During the year ended December 31, 2016 , the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes	2.45%	April 15, 2021	$ 300	Repay commercial paper issued by PHI and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	3.40%	April 15, 2026	$ 750	Repay commercial paper issued by PHI and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	4.45%	April 15, 2046	$ 750	Repay commercial paper issued by PHI and for general corporate purposes.
Generation	Renewable Power Generation Nonrecourse Debt [a]	4.11%	March 31, 2035	$ 150	Paydown long-term debt obligations at Sacramento PV Energy and Constellation Solar Horizons and for general corporate purposes.
Generation	Albany Green Energy Project Financing [b]	LIBOR + 1.25%	November 17, 2017	$ 98	Albany Green Energy biomass generation development
Generation	Energy Efficiency Project Financing [b]	3.17%	December 31, 2017	$ 16	Funding to install energy conservation measures in Brooklyn, NY.
Generation	Energy Efficiency Project Financing [b]	3.90%	January 31, 2018	$ 19	Funding to install energy conservation measures for the Naval Station Great Lakes project.
Generation	Energy Efficiency Project Financing [b]	3.52%	April 30, 2018	$ 14	Funding to install energy conservation measures for the Smithsonian Zoo project.
Generation	SolGen Nonrecourse Debt [a]	3.93%	September 30, 2036	$ 150	General corporate purposes.
Generation	Energy Efficiency Project Financing [b]	3.46%	October 1, 2018	$ 36	Funding to install energy conservation measures or the Marine Corps Logistics Base project.
Generation	Energy Efficiency Project Financing [b]	2.61%	September 30, 2018	$ 4	Funding to install energy conservation measures for the Pensacola project
ComEd	First Mortgage Bonds, Series 120	2.55%	June 15, 2026	$ 500	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
ComEd	First Mortgage Bonds, Series 121	3.65%	June 15, 2046	$ 700	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
PECO	First Mortgage Bonds	1.70%	September 15, 2021	$ 300	Refinance maturing mortgage bonds.
BGE	Notes	2.40%	August 15, 2026	$ 350	Redeem the $190M of outstanding preference shares and for general corporate purposes.

BGE	Notes	3.50%	August 15, 2046	$	500	Redeem the $190M of outstanding preference shares and for general corporate purposes.
Pepco	Energy Efficiency Project Financing [b]	3.30%	December 15, 2017	$	4	Funding to install energy conservation measures for the DOE Germantown project.
DPL	First Mortgage Bonds	4.15%	May 15, 2045	$	175	Refinance maturing mortgage bonds, repay commercial paper and for general corporate purposes.

(a) See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.
(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

During the year ended December 31, 2015 , the following long term-debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes	1.55%	June 9, 2017	$ 550	Finance a portion of the pending merger with PHI and related costs and expenses and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	2.85%	June 15, 2020	$ 900	Finance a portion of the pending merger with PHI and related costs and expenses and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	3.95%	June 15, 2025	$ 1,250	Finance a portion of the pending merger with PHI and related costs and expenses and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	4.95%	June 15, 2035	$ 500	Finance a portion of the pending merger with PHI and related costs and expenses and for general corporate purposes.
Exelon Corporate	Senior Unsecured Notes	5.10%	June 15, 2045	$ 1,000	Finance a portion of the pending merger with PHI and related costs and expenses and for general corporate purposes.
Exelon Corporate	Long-Term Software License Agreement	3.95%	May 1, 2024	$ 111	Procurement of software licenses.
Generation	Senior Unsecured Notes	2.95%	January 15, 2020	$ 750	Fund the optional redemption of Exelon's $550 million, 4.550% Senior Notes and for general corporate purposes.
Generation	AVSR DOE Nonrecourse Debt [a]	2.29 - 2.96%	January 5, 2037	$ 39	Antelope Valley solar development.
Generation	Energy Efficiency Project Financing [b]	3.71%	July 31, 2017	$ 42	Funding to install energy conservation measures in Coleman, Florida.

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Generation	Energy Efficiency Project Financing [b]	3.55%	November 15, 2016	$	19	Funding to install energy conservation measures in Frederick, Maryland.
Generation	Tax Exempt Pollution Control Revenue Bonds	2.50 - 2.70%	2019 - 2020	$	435	General corporate purposes.
Generation	Albany Green Energy Project Financing [b]	LIBOR + 1.25%	November 17, 2017	$	100	Albany Green Energy biomass generation development.
Generation	Nuclear Fuel Purchase Contract	3.15%	September 30, 2020	$	57	Procurement of uranium.
ComEd	First Mortgage Bonds, Series 118	3.70%	March 1, 2045	$	400	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
ComEd	First Mortgage Bonds, Series 119	4.35%	November 15, 2045	$	450	Repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.15%	October 15, 2025	$	350	General corporate purposes
Pepco	First Mortgage Bonds	4.15%	March 15, 2043	$	200	Repay outstanding commercial paper obligations and general corporate purposes
DPL	First Mortgage Bonds	4.15%	May 15, 2045	$	200	Repay outstanding commercial paper obligations and general corporate purposes
ACE	First Mortgage Bonds	3.50%	December 1, 2025	$	150	Repay outstanding commercial paper obligations and general corporate purposes

(a) See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.
(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

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During the year ended December 31, 2017 , the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate	Long-Term Software License Agreement	3.95%	May 1, 2024	$ 24
Exelon Corporate	Senior Notes	1.55%	June 9, 2017	$ 550
Generation	Senior Notes - Exelon Wind	2.00%	July 31, 2017	$ 1
Generation	CEU Upstream Nonrecourse Debt [a]	LIBOR + 2.25%	January 14, 2019	$ 6
Generation	SolGen Nonrecourse Debt [a]	3.93%	September 30, 2036	$ 2
Generation	AVSR DOE Nonrecourse Debt [a]	2.29% - 3.56%	January 5, 2037	$ 22
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 2
Generation	Continental Wind Nonrecourse Debt [a]	6.00%	February 28, 2033	$ 31
Generation	PES - PGOV Notes Payable	6.70-7.60%	2017 - 2018	$ 1
Generation	ExGen Texas Power Nonrecourse Debt [a][b]	LIBOR + 4.75%	September 18, 2021	$ 665
Generation	Renewable Power Generation Nonrecourse Debt [a]	4.11%	March 31, 2035	$ 14
Generation	NUKEM	3.25% - 3.35%	June 30, 2018	$ 23
Generation	ExGen Renewables I, Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 233
Generation	Senior Notes	6.20%	October 1, 2017	$ 700
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	$ 212
ComEd	First Mortgage Bonds	6.15%	September 15, 2017	$ 425
BGE	Rate Stabilization Bonds	5.82%	April 1, 2017	$ 41
BGE	Capital Trust Preferred Securities	6.20%	October 15, 2043	$ 258
PHI	Senior Notes	6.13%	June 1, 2017	$ 81
DPL	Medium Term Notes, Unsecured	7.56% - 7.58%	February 1, 2017	$ 14
DPL	Variable Rate Demand Bonds	Variable	October 1, 2017	$ 26
Pepco	Third Party Financing	6.97% - 7.99%	2018 - 2022	$ 1
ACE	Transition Bonds	5.05% - 5.55%	2020 - 2023	$ 35

(a) See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.
(b) As a result of the bankruptcy filing for EGTP on November 7, 2017, the nonrecourse debt was deconsolidated from Exelon's and Generation's consolidated financial statements. Refer to Note 4 — Mergers, Acquisitions and Dispositions for further discussion.

During the year ended December 31, 2016 , the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	$ 8
Exelon Corporate	Senior Notes	4.95%	June 15, 2035	$ 1
Generation	AVSR DOE Nonrecourse Debt [a]	2.29% - 3.56%	January 5, 2037	$ 22
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 4
Generation	Continental Wind Nonrecourse Debt [a]	6.00%	February 28, 2033	$ 29
Generation	CEU Upstream Nonrecourse Debt [a]	LIBOR + 2.25%	January 14, 2019	$ 46
Generation	ExGen Texas Power Nonrecourse Debt [a][b]	5.00%	September 18, 2021	$ 7
Generation	Sacramento Solar Nonrecourse Debt	LIBOR + 2.25%	December 31, 2030	$ 33
Generation	Clean Horizons Nonrecourse Debt	LIBOR + 2.25%	September 7, 2030	$ 32
Generation	ExGen Renewables I, Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 24
Generation	PES - PGOV Notes Payable	6.70% - 7.46%	2017-2018	$ 1
Generation	NUKEM	3.35%	June 30, 2018	$ 12
Generation	NUKEM	3.25%	July 1, 2018	$ 10
Generation	Renewable Power Generation Nonrecourse Debt [a]	4.11%	March 31, 2035	$ 9
Generation	SolGen Nonrecourse Debt [a]	3.93%	September 30, 2036	$ 2
ComEd	First Mortgage Bonds, Series 104	5.95%	August 15, 2016	$ 415
ComEd	First Mortgage Bonds, Series 111	1.95%	August 1, 2016	$ 250
PECO	First and Refunding Mortgage Bonds	1.20%	October 15, 2016	$ 300
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	$ 1
BGE	Rate Stabilization Bonds	5.82%	April 1, 2017	$ 38
BGE	Notes	5.90%	October 1, 2016	$ 300
BGE	Rate Stabilization Bonds	5.82%	April 1, 2017	$ 40
PHI	Senior Unsecured Notes	5.90%	December 12, 2016	$ 190
DPL	First Mortgage Bonds	5.22%	December 30, 2016	$ 100
ACE	Transition Bonds	5.05%	October 20, 2020	$ 12
ACE	Transition Bonds	5.55%	October 20, 2023	$ 34
ACE	First Mortgage Bonds	7.68%	August 23, 2016	$ 2

(a) See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.
(b) As a result of the bankruptcy filing for EGTP on November 7, 2017, the nonrecourse debt was deconsolidated from Exelon's and Generation's consolidated financial statements. Refer to Note 4 — Mergers, Acquisitions and Dispositions for further discussion.

During the year ended December 31, 2015 , the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate	Senior Unsecured Notes	4.55%	June 15, 2015	$ 550
Exelon Corporate	Senior Notes	4.90%	June 15, 2015	$ 800
Exelon Corporate	Senior Unsecured Notes	3.95%	June 15, 2025	$ 443
Exelon Corporate	Senior Unsecured Notes	4.95%	June 15, 2035	$ 167
Exelon Corporate	Senior Unsecured Notes	5.10%	June 15, 2045	$ 259
Exelon Corporate	Long-Term Software License Agreement	3.95%	May 1, 2024	$ 1
Generation	Senior Unsecured Notes	4.55%	June 15, 2015	$ 550
Generation	CEU Upstream Nonrecourse Debt [a]	LIBOR + 2.25%	January 14, 2019	$ 9
Generation	AVSR DOE Nonrecourse Debt [a]	2.29%-3.56%	January 5, 2037	$ 23
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 3
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	$ 20
Generation	ExGen Texas Power Nonrecourse Debt [a][b]	LIBOR + 4.75%	September 8, 2021	$ 5
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 24
Generation	Constellation Solar Horizons Nonrecourse Debt	2.56%	September 7, 2030	$ 2
Generation	Sacramento PV Energy Nonrecourse Debt	2.58%	December 31, 2030	$ 2
Generation	Energy Efficiency Project [b]	3.55%	November 15, 2016	$ 19
ComEd	First Mortgage Bonds, Series 101	4.70%	April 15, 2015	$ 260
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	$ 75
PHI	Senior Unsecured Notes	2.70%	October 1, 2015	$ 250
PHI [c]	Energy Efficiency Project Financing	4.68%	February 10, 2015	$ 7
PHI [c]	Energy Efficiency Project Financing	8.87%	June 1, 2021	$ 5
PHI [c]	Energy Efficiency Project Financing	7.61%	August 1, 2015	$ 1
PHI [c]	PES - PGOV Notes Payable	6.70%	2017-2018	$ 1
Pepco	Energy Efficiency Project Financing	3.12%	February 20, 2015	$ 12
DPL	Senior Unsecured Notes	5.00%	June 1, 2015	$ 100
ACE	Secured Medium-Term Notes Series C	7.68%	August 24, 2015	$ 15
ACE	Transition Bonds	5.05%	October 20, 2020	$ 12
ACE	Transition Bonds	5.55%	October 20, 2023	$ 32

(a) See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.
(b) As a result of the bankruptcy filing for EGTP on November 7, 2017, the nonrecourse debt was deconsolidated from Exelon's and Generation's consolidated financial statements. Refer to Note 4 — Mergers, Acquisitions and Dispositions for further discussion.
(c) Represents Pepco Energy Services energy efficiency project financing. As of the date of the merger, PES financing was included with Generation.

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective balance sheets.

Dividends

Cash dividend payments and distributions for the year ended December 31, 2017 , 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Exelon	$ 1,236	$ 1,166	$ 1,105
Generation	659	922	2,474
ComEd	422	369	299
PECO	288	277	279
BGE [(a)]	198	187	171
Pepco	133	136	146
DPL	112	54	92
ACE	68	63	12

	Successor		*Predecessor*	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	$ 311	$ 273	$ —	$ 275

(a) Includes dividends paid on BGE's preference stock during 2016 and 2015.

Quarterly dividends declared by the Exelon Board of Directors during the year ended December 31, 2017 and for the first quarter of 2018 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share
First Quarter 2017	January 31, 2017	February 15, 2017	March 10, 2017	$ 0.3275
Second Quarter 2017	April 25, 2017	May 15, 2017	June 9, 2017	$ 0.3275
Third Quarter 2017	July 25, 2017	August 15, 2017	September 8, 2017	$ 0.3275
Fourth Quarter 2017	September 25, 2017	November 15, 2017	December 8, 2017	$ 0.3275
First Quarter 2018 [(a)]	January 30, 2018	February 15, 2018	March 9, 2018	$ 0.3450

(a) Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Short-Term Borrowings

Short-term borrowings incurred (repaid) during 2017 , 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Exelon	$ (261)	$ (353)	$ 80
Generation	(620)	620	—
ComEd	—	(294)	(10)
BGE	32	(165)	90
Pepco	3	(41)	(40)
DPL	216	(105)	(1)
ACE	108	(5)	(122)

	Successor		*Predecessor*	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	$ 328	$ (515)	$ (121)	$ 34

Retirement of Long-Term Debt to Financing Affiliates

On August 28, 2017, BGE redeemed all of the outstanding shares of BGE Capital Trust II 6.20% Preferred Securities. See Note 13 — Debt and Credit Agreements for further discussion.

Contributions from Parent/Member

Contributions from Parent/Member (Exelon) during 2017 , 2016 and 2015 by Registrant were as follows:

	2017	2016	2015
Generation	$ 102	$ 142	$ 47
ComEd [(a)(b)]	672	473	209
PECO [(b)]	16	18	16
BGE [(b)]	184	61	7
Pepco [(c)]	161	187	112
DPL [(c)]	—	152	75
ACE [(c)]	—	139	95

	Successor		*Predecessor*	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI [(b)]	$ 758	$ 1,251	$ —	$ —

(a) Additional contributions from parent or external debt financing may be required as a result of increased capital investment in infrastructure improvements and modernization pursuant to EIMA, transmission upgrades and expansions and Exelon's agreement to indemnify ComEd for any unfavorable after-tax impacts associated with ComEd's LKE tax matter.
(b) Contribution paid by Exelon.
(c) Contribution paid by PHI.

Pursuant to the orders approving the merger, Exelon made equity contributions of $73 million , $46 million and $49 million to Pepco, DPL and ACE, respectively, in the second quarter of 2016 to fund the after-tax amount of the customer bill credit and the customer base rate credit.

Redemptions of Preference Stock. BGE had $190 million of cumulative preference stock that was redeemable at its option at any time after October 1, 2015 for the redemption price of $100 per share, plus accrued and unpaid dividends. On July 3, 2016, BGE redeemed all 400,000 shares of its outstanding 7.125% Cumulative Preference Stock, 1993 Series and all 600,000 shares of its outstanding 6.990% Cumulative Preference Stock, 1995 Series for $100 million , plus accrued and unpaid dividends. On September 18, 2016, BGE redeemed the remaining 500,000 shares of its outstanding 6.970% Cumulative Preference Stock, 1993 Series and the remaining 400,000 shares of its outstanding 6.700% Cumulative Preference Stock, 1993 Series for $90 million , plus accrued and unpaid dividends. As of December 31, 2017 , BGE no longer has any preferred stock outstanding. See Note 21 - Earnings Per Share of the Combined Notes to Consolidated Financial Statements for further details.

Other

For the year ended December 31, 2017 , other financing activities primarily consists of debt issuance costs. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements' for additional information.

Credit Matters

Market Conditions

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $9.5 billion in aggregate total commitments of which $8.3 billion was available as of December 31, 2017 , and of which no financial institution has more than 7% of the aggregate commitments for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE. The Registrants had access to the commercial paper market during 2017 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of December 31, 2017 , it would have been required to provide incremental collateral of $1.8 billion to meet collateral obligations for derivatives, non-derivatives, normal purchases and normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $ 4.7 billion .

The following table presents the incremental collateral that each Utility Registrant would have been required to provide in the event each Utility Registrant lost its investment grade credit rating at December 31, 2017 and available credit facility capacity prior to any incremental collateral at December 31, 2017 :

	PJM Credit Policy Collateral	Other Incremental Collateral Required [a]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 18	$ —	$ 998
PECO	3	34	599
BGE	3	66	600
Pepco	4	—	300
DPL	1	11	300
ACE	—	—	300

(a) Represents incremental collateral related to natural gas procurement contracts.

Exelon Credit Facilities

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. P HI meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure . At December 31, 2017 , the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Long-term debt	51%	32%	44%	44%	45%	39%	50%	46%	49%
Long-term debt to affiliates [a]	1%	4%	1%	3%	—%	—%	—%	—%	—%
Common equity	47%	—%	55%	53%	54%	—	49%	46%	46%
Member's equity	—%	64%	—%	—%	—%	59%	—	—	—
Commercial paper and notes payable	1%	—%	—	—%	1%	2%	1%	8%	5%

(a) Includes approximately $389 million , $205 million and $184 million owed to unconsolidated affiliates of Exelon, ComEd, and PECO respectively. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd and PECO. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

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Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of December 31, 2017 , are presented in the following tables:

Exelon Intercompany Money Pool	For the Year Ended December 31, 2017		As of December 31, 2017
Contributed (borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Corporate	$ 579	$ —	$ 217
Generation	20	(589)	(54)
PECO	336	(22)	—
BSC	—	(423)	(217)
PHI Corporate	—	(47)	—
PCI	55	—	54

PHI Intercompany Money Pool	For the Year Ended December 31, 2017		As of December 31, 2017
Contributed (borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
PHI Corporate	$ 9	$ (2)	$ 1
Pepco	—	—	—
DPL	—	—	—
ACE	—	—	—
PHISCO	3	(9)	—

Investments in Nuclear Decommissioning Trust Funds. Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with

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Generation's NDT fund investment policy. Generation's and CENG's investment policies establish limits on the concentration of holdings in any one company and also in any one industry. See Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements. Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2019. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations. ComEd, PECO, BGE, Pepco, DPL and ACE are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	Short-term Financing Authority [a]			Long-term Financing Authority [a]		
	Commission	Expiration Date	Amount	Commission	Expiration Date [c]	Amount
ComEd [b]	FERC	December 31, 2019	$ 2,500	ICC	2019	$ 1,383
PECO	FERC	December 31, 2019	1,500	PAPUC	December 31, 2018	1,275
BGE	FERC	December 31, 2019	700	MDPSC	N/A	700
Pepco	FERC	December 31, 2019	500	MDPSC	September 25, 2017	—
				DCPSC	December 31, 2020	600
DPL	FERC	December 31, 2019	500	MDPSC	December 31, 2017	—
				DPSC	December 31, 2020	350
ACE	NJBPU	December 31, 2019	350	NJBPU	December 31, 2019	350

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.
(b) ComEd had $1,140 million available in long-term debt refinancing authority and $243 million available in new money long term debt financing authority from the ICC as of December 31, 2017 and has an expiration date of June 1, 2019 and March 1, 2019, respectively.
(c) Pepco and DPL are currently in the process of renewing their long-term financing authority with the MDPSC.

Exelon's ability to pay dividends on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. Pepco, DPL and ACE are subject to certain dividend restrictions established by settlements approved in NJ, DE, MD and the DC. Pepco, DPL and ACE are prohibited from paying a dividend on their common shares if (a) after the dividend payment, Pepco's, DPL's or ACE's equity ratio would be below 48% as equity levels are calculated under the ratemaking precedents of the Commissions

and the Board or (b) Pepco's, DPL's or ACE's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. At December 31, 2017 , Exelon had retained earnings of $13,503 million , including Generation's undistributed earnings of $4,310 million , ComEd's retained earnings of $1,132 million consisting of retained earnings appropriated for future dividends of $2,771 million partially offset by $1,639 million of unappropriated retained deficit, PECO's retained earnings of $1,087 million and BGE's retained earnings $1,536 million . At December 31, 2017 , Pepco had retained earnings of $ 1,063 million , DPL had retained earnings of $ 571 million and ACE had retained earnings of $ 131 million . See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Contractual Obligations and Off-Balance Sheet Arrangements

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2017 under existing contractual obligations, including payments due by period. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within			
	Total	2018	2019 - 2020	2021 - 2022	Due 2023 and beyond
Long-term debt [a]	$ 33,994	$ 2,057	$ 4,459	$ 4,574	$ 22,904
Interest payments on long-term debt [b]	15,999	1,346	2,579	2,231	9,843
Capital leases	53	18	25	2	8
Operating leases [c]	1,512	188	276	261	787
Purchase power obligations [d]	1,153	358	498	103	194
Fuel purchase agreements [e]	7,270	1,229	2,241	1,385	2,415
Electric supply procurement [e]	3,417	2,213	1,204	—	—
AEC purchase commitments [e]	3	1	2	—	—
Curtailment services commitments [e]	119	52	54	13	—
Long-term renewable energy and REC commitments [f]	1,666	111	224	235	1,096
Other purchase obligations [g]	7,765	4,844	1,585	561	775
DC PLUG obligation [h]	188	28	60	60	40
Construction commitments [i]	57	56	1	—	—
PJM regional transmission expansion commitments [j]	569	179	270	120	—
SNF obligation [k]	1,147	—	—	—	1,147
Pension contributions [l]	1,393	301	493	386	213
Total contractual obligations	$ 76,305	$ 12,981	$ 13,971	$ 9,931	$ 39,422

(a) Includes $390 million due after 2023 to ComEd and PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2017 . Includes estimated interest payments due to ComEd, PECO, BGE, PHI, Pepco, DPL and ACE financing trusts.

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(c) Excludes Generation's contingent operating lease payments associated with contracted generation agreements. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO's meter reading operating lease.
(d) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2017 , including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. Contained within Purchase power obligations are Net Capacity Purchases of $106 million , $99 million , $40 million , $31 million , $19 million and $171 million for 2018 , 2019 , 2020 , 2021 , 2022 and thereafter, respectively.
(e) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric renewable energy and RECs, procure electric supply, and purchase AECs and curtailment services.
(f) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the earliest and maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(g) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(h) Related to DC PLUG project costs for assets funded by the District of Columbia for which the District of Columbia has assessed a charge on Pepco. Pepco will recover this charge from customers through a volumetric distribution rider. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(i) Represents commitments for Generation's ongoing investments in new natural gas and biomass generation construction.
(j) Under their operating agreements with PJM, ComEd, PECO, BGE, Pepco, DPL and ACE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd, PECO, BGE, Pepco, DPL and ACE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(k) See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding SNF obligations.
(l) These amounts represent Exelon's expected contributions to its qualified pension plans. The projected contributions reflect a funding strategy of contributing the greater of $300 million (which has been updated for the inclusion of PHI) until the qualified plans are fully funded on an accumulated benefit obligation basis, and the minimum amounts under ERISA to avoid benefit restrictions and at-risk status thereafter. The remaining qualified pension plans' contributions are generally based on the estimated minimum pension contributions required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. Qualified pension contributions for years after 2023 are not included. See Note 16 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

		Payment due within			
	Total	2018	2019 - 202 0	2021 - 202 2	Due 2023 and beyond
Long-term debt	$ 8,937	$ 341	$ 2,747	$ 1,023	$ 4,826
Interest payments on long-term debt [a]	4,808	391	705	530	3,182
Capital leases	18	5	11	2	—
Operating leases [b]	817	74	76	94	573
Purchase power obligations [c]	1,153	358	498	103	194
Fuel purchase agreements [d]	6,147	1,000	1,909	1,184	2,054
Other purchase obligations [e]	1,456	398	249	181	628
Construction commitments [f]	57	56	1	—	—
SNF obligation [g]	1,147	—	—	—	1,147
Total contractual obligations	$ 24,540	$ 2,623	$ 6,196	$ 3,117	$ 12,604

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2017 .
(b) Excludes Generation's contingent operating lease payments associated with contracted generation agreements. These amounts are included within purchase power obligations.
(c) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2017 . Expected

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payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. Contained within Purchase power obligations are Net Capacity Purchases of $106 million , $99 million , $40 million , $31 million , $19 million and $171 million for 2018 , 2019 , 2020 , 2021 , 2022 and thereafter, respectively.

(d) Represents commitments to purchase fuel supplies for nuclear and fossil generation, including those related to CENG.

(e) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(f) Represents commitments for Generation's ongoing investments in new natural gas generation construction. As of December 31, 2017, the commitments relate to the construction of a new dual fuel, natural peaking facility in Massachusetts. Achievement of commercial operation related to this project is expected in 2018.

(g) See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding SNF obligations.

ComEd

		Payment due within			
	Total	2018	2019 - 202 0	2021 - 202 2	Due 2023 and beyond
Long-term debt [a]	$ 7,874	$ 840	$ 800	$ 350	$ 5,884
Interest payments on long-term debt [b]	4,937	269	517	469	3,682
Capital leases	8	—	—	—	8
Operating leases [c]	23	7	10	6	—
Electric supply procurement	741	476	265	—	—
Long-term renewable energy and REC commitments [d]	1,321	82	166	177	896
Other purchase obligations [e]	1,035	927	82	16	10
PJM regional transmission expansion commitments [f]	164	36	104	24	—
Total contractual obligations	$ 16,103	$ 2,637	$ 1,944	$ 1,042	$ 10,480

(a) Includes $206 million due after 2023 to a ComEd financing trust.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2017 . Includes estimated interest payments due to the ComEd financing trust.

(c) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, ComEd, has excluded these payments from the remaining years as such amounts would not be meaningful. ComEd's average annual obligation for these arrangements, included in each of the years 2018-2022, was $2 million .

(d) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum and earliest settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(e) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(f) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

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In January 2018, ComEd entered into 10-year ZEC procurement contracts with Generation. The following table summarizes ComEd's future estimated cash payments under the executed contract. See Note 3 — Regulatory Matters and Note 28 — Subsequent Events of the Combined Notes to Consolidated Financial Statements for more information.

		Payment due within			
	Total	2018	2019 - 202 0	2021 - 202 2	Due 2023 and beyond
ZEC commitments [a]	$ 1,589	$ 271	$ 327	$ 314	$ 677

(a) Annual ZEC commitment amounts will be published by the IPA each May prior to the start of the subsequent planning year. Amounts presented in the table represent management's estimate of ComEd's obligation based on forward energy prices and load forecasts. ComEd is permitted to recover its ZEC costs from retail customers with no mark-up.

PECO

		Payment due within			
	Total	2018	2019 - 202 0	2021 - 202 2	Due 2023 and beyond
Long-term debt [a]	$ 3,109	$ 500	$ —	$ 650	$ 1,959
Interest payments on long-term debt [b]	1,916	105	210	202	1,399
Operating leases [c]	25	5	10	10	—
Fuel purchase agreements [d]	339	113	151	35	40
Electric supply procurement [d]	526	420	106	—	—
AEC purchase commitments [d]	6	2	4	—	—
Other purchase obligations [e]	465	257	157	46	5
PJM regional transmission expansion commitments [f]	53	16	29	8	—
Total contractual obligations	$ 6,439	$ 1,418	$ 667	$ 951	$ 3,403

(a) Includes $184 million due after 2023 to PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Includes estimated cash payments for service fees related to PECO's meter reading operating lease. Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, PECO has excluded these payments from the remaining years as such amounts would not be meaningful. PECO's average annual obligation for these arrangements, included in each of the years 2018-2022, was $5 million .
(d) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs.
(e) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(f) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

BGE

	Total	Payment due within 2018	2019 - 202 0	2021 - 202 2	Due 2023 and beyond
Long-term debt	$ 2,600	$ —	$ —	$ 550	$ 2,050
Interest payments on long-term debt [a]	1,689	101	201	186	1,201
Operating leases [b][c][d]	170	34	68	49	19
Fuel purchase agreements [e]	514	86	121	106	201
Electric supply procurement [e]	1,026	645	381	—	—
Curtailment services commitments [e]	50	22	21	7	—
Other purchase obligations [f]	453	394	50	4	5
PJM regional transmission expansion commitments [g]	118	35	70	13	—
Total contractual obligations	$ 6,620	$ 1,317	$ 912	$ 915	$ 3,476

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, BGE has excluded these payments from the remaining years as such amounts would not be meaningful. BGE's average annual obligation for these arrangements, included in each of the years 2018—2022, was $1 million , respectively.
(c) Includes all future lease payments on a 99 -year real estate lease that expires in 2106 .
(d) The BGE column above includes minimum future lease payments associated with a 6-year lease for the Baltimore City conduit system that became effective during the fourth quarter of 2016. BGE's total commitments under the lease agreement are $25 million , $26 million , $28 million , $28 million and $14 million related to years 2018, 2019, 2020, 2021and 2022, respectively.
(e) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services.
(f) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the BGE and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(g) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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PHI

	Total	Payment due within 2018	2019 - 202 0	2021 - 202 2	Due 2023 and beyond
Long-term debt	$ 5,162	$ 370	$ 12	$ 551	$ 4,229
Interest payments on long-term debt [a]	1,328	231	461	433	203
Capital leases	27	13	14	—	—
Operating leases	415	56	86	79	194
Fuel purchase agreements [b]	270	30	60	60	120
Long-term renewable energy and REC commitments [b]	345	29	58	58	200
Electric supply procurement [b]	1,720	1,060	660	—	—
Curtailment services commitments [b]	69	30	33	6	—
Other purchase obligations [c]	3,434	2,368	822	196	48
DC PLUG obligation [d]	188	28	60	60	40
PJM regional transmission expansion commitments [e]	234	92	67	75	—
Total contractual obligations	$ 13,192	$ 4,307	$ 2,333	$ 1,518	$ 5,034

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric renewable energy and RECs, procure electric supply, and curtailment services.
(c) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(d) Related to DC PLUG project costs for assets funded by the District of Columbia for which the District of Columbia has assessed a charge on Pepco. Pepco will recover this charge from customers through a volumetric distribution rider. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(e) Under its operating agreement with PJM, PHI is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PHI's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

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Pepco

	Total	Payment due within 2018	2019 - 202 0	2021 - 202 2	Due 2023 and beyond
Long-term debt	$ 2,543	$ 6	$ —	$ 312	$ 2,225
Interest payments on long-term debt [a]	755	129	259	251	116
Capital leases	27	13	14	—	—
Operating leases	38	8	13	9	8
Electric supply procurement [b]	675	433	242	—	—
Curtailment services commitments [b]	26	13	10	3	—
Other purchase obligations [c]	1,676	995	497	146	38
DC PLUG obligation [d]	188	28	60	60	40
PJM regional transmission expansion commitments [e]	86	5	38	43	—
Total contractual obligations	$ 6,014	$ 1,630	$ 1,133	$ 824	$ 2,427

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Represents commitments to purchase procure electric supply and curtailment services.
(c) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(d) Related to DC PLUG project costs for assets funded by the District of Columbia for which the District of Columbia has assessed a charge on Pepco. Pepco will recover this charge from customers through a volumetric distribution rider. See Note 3 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(e) Under its operating agreement with PJM, Pepco is committed to the construction of transmission facilities to maintain system reliability. These amounts represent Pepco's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

DPL

	Total	Payment due within 2018	2019 - 202 0	2021 - 202 2	Due 2023 and beyond
Long-term debt	$ 1,309	$ 83	$ 12	$ —	$ 1,214
Interest payments on long-term debt [a]	288	49	97	96	46
Operating leases [b]	121	20	23	24	54
Fuel purchase agreements [c]	270	30	60	60	120
Long-term renewable energy and associated REC commitments [c]	345	29	58	58	200
Electric supply procurement [c]	504	312	192	—	—
Curtailment services commitments [c]	36	14	19	3	—
Other purchase obligations [d]	963	776	152	32	3
PJM regional transmission expansion commitments [e]	27	19	3	5	—
Total contractual obligations	$ 3,863	$ 1,332	$ 616	$ 278	$ 1,637

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

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(b) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, DPL has excluded these payments from the remaining years as such amounts would not be meaningful. DPL's average annual obligation for these arrangements, included in each of the years 2018-2022, was $2 million .

(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric renewable energy and RECs, procure electric supply, and curtailment services.

(d) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(e) Under its operating agreement with PJM, DPL is committed to the construction of transmission facilities to maintain system reliability. These amounts represent DPL's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

ACE

		Payment due within			
	Total	2018	2019 - 202 0	2021 - 202 2	Due 2023 and beyond
Long-term debt	$ 1,127	$ 281	$ —	$ 239	$ 607
Interest payments on long-term debt [(a)]	201	39	77	58	27
Operating leases	57	9	16	13	19
Electric supply procurement [(b)]	541	315	226	—	—
Curtailment services commitments [(b)]	7	3	4	—	—
Other purchase obligations [(c)]	581	439	124	15	3
PJM regional transmission expansion commitments [(d)]	121	68	26	27	—
Total contractual obligations	$ 2,635	$ 1,154	$ 473	$ 352	$ 656

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2017 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

(b) Represents commitments to procure electric supply and curtailment services.

(c) Represents the future estimated value at December 31, 2017 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(d) Under its operating agreement with PJM, ACE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ACE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.

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- operating leases and rate relief commitments, see Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 15 — Asset Retirement Obligations and 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.
- variable interest entities, see Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- new accounting pronouncements, see Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities.

Commodity Price Risk (All Registrants)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies and other factors. To the extent the total amount of energy Exelon generates and purchases differs from the amount of energy it has contracted to sell, Exelon is exposed to market fluctuations in commodity prices. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel and other commodities.

Generation

Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of the Utility Registrants' retail load, is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards and options, with approved counterparties to hedge anticipated exposures. Generation uses derivative instruments as economic hedges to mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2018 through 2020 .

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Exelon's hedging program involves the hedging of commodity price risk for Exelon's expected generation, typically on a ratable basis over three-year periods. As of December 31, 2017 , the percentage of expected generation hedged is 85% - 88% , 55% - 58% and 26% - 29% for 2018 , 2019 and 2020 ,

respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including Generation's sales to ComEd, PECO and BGE to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire economic hedge portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on December 31, 2017 market conditions and hedged position would be decreases in pre-tax net income of approximately $110 million , $400 million and $630 million , respectively, for 2018 , 2019 and 2020 . Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation actively manages its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Proprietary Trading Activities

Proprietary trading portfolio activity for the year ended December 31, 2017 , resulted in pre-tax gains of $18 million due to net mark-to-market gains of $5 million and realized gains of $13 million . Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total Revenue net of purchased power and fuel expense. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Fuel Procurement

Generation procures natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 59% of Generation's uranium concentrate requirements from 2018 through 2022 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial positions.

ComEd

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction

of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014.

ComEd has block energy contracts to procure electric supply that are executed through a competitive procurement process, which is further discussed in Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. The block energy contracts are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. ComEd does not execute derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

PECO, BGE, Pepco, DPL and ACE

PECO, BGE, Pepco, DPL and ACE have contracts to procure electric supply that are executed through a competitive procurement process, which are further discussed in Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. PECO, BGE, Pepco, DPL and ACE have certain full requirements contracts, which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Other full requirements contracts are not derivatives.

PECO, BGE and DPL have also executed derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge their long-term price risk in the natural gas market. The hedging programs for natural gas procurement have no direct impact on their results of operations or financial position.

PECO, BGE, Pepco, DPL and ACE do not execute derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities

The following tables detail Exelon's, Generation's, ComEd's, PHI's and DPL's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, ComEd's, PHI's and DPL's commodity mark-to-market net asset or liability balance sheet position from December 31, 2015 to December 31, 2017 . It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all NPNS contracts and does not segregate proprietary trading activity. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2017 and 2016 .

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	Exelon	Generation	ComEd	DPL	Successor PHI March 24 to December 31,	Predecessor PHI January 1 to March 23,
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015 [a]	$ 1,506	$ 1,753	$ (247)	$ —	$ —	$ —
Total change in fair value during 2016 of contracts recorded in result of operations	236	236	—	—		—
Reclassification to be realized at settlement of contracts recorded in results of operations	(265)	(265)	—	—	—	—
Contracts received at acquisition date [b]	(59)	(59)	—	—	—	—
Changes in fair value—recorded through regulatory assets and liabilities [c]	(8)	—	(11)	4	3	1
Changes in allocated collateral	(908)	(905)	—	(4)	(3)	(1)
Changes in net option premium paid	66	66	—	—	—	—
Option premium amortization	11	11	—	—	—	—
Upfront payments and amortizations [d]	140	140	—	—		
Total mark-to-market energy contract net assets (liabilities) at December 31, 2016 [a]	$ 719	$ 977	$ (258)	$ —	$ —	$ —

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Includes fair value from contracts received at acquisition of ConEdison Solutions of $(59) million .
(c) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2016 , ComEd recorded a regulatory liability of $258 million , respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. ComEd recorded $29 million of decreases in fair value and an increase for realized losses due to settlements of $18 million in purchased power expense associated with floating-to-fixed energy swap suppliers for the year ended December 31, 2016 .
(d) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

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	Exelon	Generation	ComEd	DPL	Successor PHI
Total mark-to-market energy contract net assets (liabilities) at December 31, 2016 [a]	$ 719	$ 977	$ (258)	$ —	$ —
Total change in fair value during 2016 of contracts recorded in result of operations	110	110	—	—	—
Reclassification to be realized at settlement of contracts recorded in results of operations	(273)	(273)	—	—	—
Changes in fair value—recorded through regulatory assets and liabilities [c]	(1)	—	2	(3)	(3)
Changes in allocated collateral	140	137	—	3	3
Changes in net option premium received	(28)	(28)	—	—	—
Option premium amortization	(7)	(7)	—	—	—
Upfront payments and amortizations [b]	(24)	(24)	—	—	—
Other miscellaneous [d]	31	31	—	—	—
Total mark-to-market energy contract net assets (liabilities) at December 31, 2017 [a]	$ 667	$ 923	$ (256)	$ —	$ —

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.
(c) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2017 , ComEd recorded a regulatory liability of $256 million , related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. For the year ended December 31, 2017 , ComEd also recorded $18 million of decreases in fair value and realized losses due to settlements of $20 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2017 .
(d) As a result of the bankruptcy filing for EGTP on November 7, 2017, the net mark-to-market commodity contracts were deconsolidated from Exelon's and Generation consolidated financial statements.

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Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities) net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 11 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						Total Fair Value
	2018	2019	2020	2021	2022	2023 and Beyond	
Normal Operations, Commodity derivative contracts [(a)(b)]:							
Actively quoted prices (Level 1)	$ (32)	$ (43)	$ (15)	$ 2	$ (2)	$ —	$ (90)
Prices provided by external sources (Level 2)	462	(6)	(1)	6	—	—	461
Prices based on model or other valuation methods (Level 3) [(c)]	315	130	23	(27)	(58)	(87)	296
Total	$ 745	$ 81	$ 7	$ (19)	$ (60)	$ (87)	$ 667

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $466 million at December 31, 2017 .
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						Total Fair Value
	2018	2019	2020	2021	2022	2023 and Beyond	
Normal Operations, Commodity derivative contracts [(a)(b)]:							
Actively quoted prices (Level 1)	$ (32)	$ (43)	$ (15)	$ 2	$ (2)	$ —	$ (90)
Prices provided by external sources (Level 2)	462	(6)	(1)	6	—	—	461
Prices based on model or other valuation methods (Level 3) [(c)]	336	152	44	(6)	(37)	63	552
Total	$ 766	$ 103	$ 28	$ 2	$ (39)	$ 63	$ 923

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $466 million at December 31, 2017 .

ComEd

	Maturities Within						Fair Value
	2018	2019	2020	2021	2022	2023 and Beyond	
Prices based on model or other valuation methods (Level 3) [a]	$ (21)	$ (22)	$ (21)	$ (21)	$ (21)	$ (150)	$ (256)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral and Contingent Related Features (All Registrants)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that execute derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchases and normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2017 . The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs and commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $28 million , $22 million , $24 million , $36 million , $12 million and $6 million respectively. See Note 26 — Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Rating as of December 31, 2017	Total Exposure Before Credit Collateral	Credit Collateral [a]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 738	$ 4	$ 734	1	$ 244
Non-investment grade	90	12	78	—	—
No external ratings					
Internally rated—investment grade	253	—	253	—	—
Internally rated—non-investment grade	83	11	72	—	—
Total	$ 1,164	$ 27	$ 1,137	1	$ 244

Rating as of December 31, 2017	Maturity of Credit Risk Exposure: Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 657	$ 80	$ 1	$ 738
Non-investment grade	74	16	—	90
No external ratings				
Internally rated—investment grade	191	30	32	253
Internally rated—non-investment grade	79	4	—	83
Total	$ 1,001	$ 130	$ 33	$ 1,164

Net Credit Exposure by Type of Counterparty	As of December 31, 2017
Financial institutions	$ 41
Investor-owned utilities, marketers, power producers	558
Energy cooperatives and municipalities	452
Other	86
Total	$ 1,137

(a) As of December 31, 2017 , credit collateral held from counterparties where Generation had credit exposure included $8 million of cash and $ 19 million of letters of credit.

The Utility Registrants

Credit risk for the Utility Registrants is governed by credit and collection policies, which are aligned with state regulatory requirements. The Utility Registrants are currently obligated to provide service to all electric customers within their franchised territories. The Utility Registrants record a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. The Utility Registrants will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. The Utility Registrants did not have any customers representing over 10% of their revenues as of December 31, 2017 . See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2017 , ComEd's net credit exposure to suppliers was approximately $1 million . PECO and BGE had no net credit exposure to suppliers as of December 31, 2017 . As of December 31, 2017 Pepco, DPL and ACE's net credit exposures were immaterial. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Collateral (All Registrants)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, natural gas and other commodities. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation

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at the time of the demand. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements. See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. To post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See ITEM 7. Liquidity and Capital Resources — Credit Matters — Exelon Credit Facilities for additional information.

The Utility Registrants

As of December 31, 2017 , ComEd held $10 million in collateral from suppliers in association with energy procurement contracts, approximately $2 million in collateral from suppliers for REC contract obligations and approximately $ 19 million in collateral from suppliers for long-term renewable energy contracts. BGE is not required to post collateral under its electric supply contracts but was holding an immaterial amount of collateral under its electric supply procurement contracts. BGE was not required to post collateral under its natural gas procurement contracts, but was holding an immaterial amount of collateral under its natural gas procurement contracts. PECO, Pepco, DPL and ACE were not required to post collateral under their energy and/or natural gas procurement contracts. See Note 3 — Regulatory Matters and Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (All Registrants)

All Registrants participate in all, or some, of the established, wholesale spot energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot energy markets that are administered by the RTOs or ISOs, as applicable. In areas where there is no spot energy market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot energy market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon, Generation, PHI and DPL)

Generation enters into commodity transactions on NYMEX, ICE, NASDAQ, NGX and the Nodal exchange ("the Exchanges"). DPL enters into commodity transactions on ICE. The Exchange clearinghouses act as the counterparty to each trade. Transactions on the Exchanges must adhere to comprehensive collateral and margining requirements. As a result, transactions on Exchanges are significantly collateralized and have limited counterparty credit risk.

Interest Rate and Foreign Exchange Risk (All Registrants)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2017 , Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $636 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 basis point increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $6 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2017 . To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning its nuclear plants. As of December 31, 2017 , Generation’s decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation’s NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $662 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Generation

General

Generation's integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. These segments are discussed in further detail in ITEM 1. BUSINESS — Exelon Generation Company, LLC of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation's executive overview is set forth under ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Exelon Corporation — Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of Generation's results of operations for 2017 compared to 2016 and 2016 compared to 2015 is set forth under Results of Operations—Generation in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.8 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Generation's capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon's pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation's cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of Generation's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk — Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in ITEM 1. BUSINESS—ComEd of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd's executive overview is set forth under EXELON CORPORATION—Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of ComEd's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—ComEd in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2017 , ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion .

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ComEd's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd's cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of ComEd's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk— Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in ITEM 1. BUSINESS—PECO of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO's executive overview is set forth under EXELON CORPORATION—Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of PECO's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—PECO in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2017 , PECO had access to a revolving credit facility with aggregate bank commitments of $600 million .

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund PECO's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Investing Activities

A discussion of items pertinent to PECO's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO's cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under Credit Matters in "EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of PECO's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk—Exelon.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BGE

General

BGE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in ITEM 1. BUSINESS—BGE of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE's executive overview is set forth under EXELON CORPORATION — Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of BGE's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—BGE in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

BGE's business is capital intensive and requires considerable capital resources. BGE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2017 , BGE had access to a revolving credit facility with aggregate bank commitments of $600 million .

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund BGE's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Investing Activities

A discussion of items pertinent to BGE's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to BGE's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of BGE's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk—Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PHI

General

PHI has three reportable segments Pepco, DPL, and ACE. Its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services, and to a lesser extent, the purchase and regulated retail sale and supply of natural gas in Delaware. This segment is discussed in further detail in ITEM 1. BUSINESS — PHI of this Form 10-K.

Executive Overview

A discussion of items pertinent to PHI's executive overview is set forth under EXELON CORPORATION — Executive Overview of this Form 10-K.

Results of Operations

Successor Period Year Ended December 31, 2017 , Successor Period of March 24, 2016 to December 31, 2016 and Predecessor Period of January 1, 2016 to March 23, 2016, Predecessor Period Year Ended December 31, 2015

A discussion of PHI's results of operations for 2017 compared to 2016 , March 24, 2016 to December 31, 2016 and January 1, 2016 to March 23, 2016 , and the year ended December 31, 2015 is set forth under Results of Operations—PHI in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

PHI's business is capital intensive and requires considerable capital resources. PHI's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper, borrowings from the Exelon money pool or capital contributions from Exelon. PHI's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund PHI's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PHI operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PHI's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Investing Activities

A discussion of items pertinent to PHI's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PHI's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PHI is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PHI's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of PHI's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PHI

PHI is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk — Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pepco

General

Pepco operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in District of Columbia and major portions of Prince George's County and Montgomery County in Maryland. This segment is discussed in further detail in ITEM 1. BUSINESS — Pepco of this Form 10-K.

Executive Overview

A discussion of items pertinent to Pepco's executive overview is set forth under EXELON CORPORATION — Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of Pepco's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—Pepco in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

Pepco's business is capital intensive and requires considerable capital resources. Pepco's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. Pepco's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2017 , Pepco had access to a revolving credit facility with aggregate bank commitments of $300 million .

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Pepco's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, Pepco operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to Pepco's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Investing Activities

A discussion of items pertinent to Pepco's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Pepco's cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Pepco is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Pepco's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of Pepco's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Pepco

Pepco is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk— Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

DPL

General

DPL operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale and supply of natural gas in New Castle County, Delaware. This segment is discussed in further detail in ITEM 1. BUSINESS — DPL of this Form 10-K.

Executive Overview

A discussion of items pertinent to DPL's executive overview is set forth under EXELON CORPORATION — Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of DPL's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—DPL in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

DPL's business is capital intensive and requires considerable capital resources. DPL's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. DPL's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where DPL no longer has access to the capital markets at reasonable terms, DPL has access to a revolving credit facility. At December 31, 2017 , DPL had access to a revolving credit facility with aggregate bank commitments of $300 million .

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund DPL's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, DPL operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to DPL's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to DPL's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to DPL's cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to DPL is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of DPL's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of DPL's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

DPL

DPL is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk—Exelon.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ACE

General

ACE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in portions of southern New Jersey. This segment is discussed in further detail in ITEM 1. BUSINESS — ACE of this Form 10-K.

Executive Overview

A discussion of items pertinent to ACE's executive overview is set forth under EXELON CORPORATION — Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016 and Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

A discussion of ACE's results of operations for 2017 compared to 2016 and for 2016 compared to 2015 is set forth under Results of Operations—ACE in EXELON CORPORATION — Results of Operations of this Form 10-K.

Liquidity and Capital Resources

ACE's business is capital intensive and requires considerable capital resources. ACE's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ACE's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2017 , ACE had access to a revolving credit facility with aggregate bank commitments of $300 million .

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ACE's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ACE operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ACE's cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Investing Activities

A discussion of items pertinent to ACE's cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ACE's cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ACE is set forth under Credit Matters in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ACE's contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION — Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants — Critical Accounting Policies and Estimates above for a discussion of ACE's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ACE

ACE is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk— Exelon.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2017 . In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2017 , Exelon's internal control over financial reporting was effective.

The effectiveness of Exelon's internal control over financial reporting as of December 31, 2017 , has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2018

S1-SSA-0009 - 16444

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Generation's management conducted an assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2017 . In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation's management concluded that, as of December 31, 2017 , Generation's internal control over financial reporting was effective.

The effectiveness of Generation's internal control over financial reporting as of December 31, 2017 , has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2018

S1-SSA-0009 - 16445

Management's Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2017 . In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd's management concluded that, as of December 31, 2017 , ComEd's internal control over financial reporting was effective.

The effectiveness of ComEd's internal control over financial reporting as of December 31, 2017 , has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2018

S1-SSA-0009 - 16446

Management's Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2017 . In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO's management concluded that, as of December 31, 2017 , PECO's internal control over financial reporting was effective.

The effectiveness of PECO's internal control over financial reporting as of December 31, 2017 , has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2018

Management's Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

BGE's management conducted an assessment of the effectiveness of BGE's internal control over financial reporting as of December 31, 2017 . In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE's management concluded that, as of December 31, 2017 , BGE's internal control over financial reporting was effective.

The effectiveness of BGE's internal control over financial reporting as of December 31, 2017 , has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2018

S1-SSA-0009 - 16448

Management's Report on Internal Control Over Financial Reporting

The management of Pepco Holdings LLC (PHI) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PHI's management conducted an assessment of the effectiveness of PHI's internal control over financial reporting as of December 31, 2017 . In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PHI's management concluded that, as of December 31, 2017 , PHI's internal control over financial reporting was effective.

The effectiveness of PHI's internal control over financial reporting as of December 31, 2017 , has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2018

Management's Report on Internal Control Over Financial Reporting

The management of Potomac Electric Power Company (Pepco) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Pepco's management conducted an assessment of the effectiveness of Pepco's internal control over financial reporting as of December 31, 2017 . In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Pepco's management concluded that, as of December 31, 2017 , Pepco's internal control over financial reporting was effective.

February 9, 2018

S1-SSA-0009 - 16450

Management's Report on Internal Control Over Financial Reporting

The management of Delmarva Power & Light Company (DPL) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

DPL's management conducted an assessment of the effectiveness of DPL's internal control over financial reporting as of December 31, 2017 . In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, DPL's management concluded that, as of December 31, 2017 , DPL's internal control over financial reporting was effective.

February 9, 2018

S1-SSA-0009 - 16451

Management's Report on Internal Control Over Financial Reporting

The management of Atlantic City Electric Company (ACE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ACE's management conducted an assessment of the effectiveness of ACE's internal control over financial reporting as of December 31, 2017 . In making this assessment, management used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ACE's management concluded that, as of December 31, 2017 , ACE's internal control over financial reporting was effective.

February 9, 2018

S1-SSA-0009 - 16452

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedules listed in the index appearing under Item 15(a)(2), of Exelon Corporation and its subsidiaries (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2018

We have served as the Company's auditor since 2000.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Exelon Generation Company, LLC and its subsidiaries (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 **,** and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 9, 2018

We have served as the Company's auditor since 2001.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Commonwealth Edison Company and its subsidiaries (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 **,** and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2018

We have served as the Company's auditor since 2000.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of PECO Energy Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of PECO Energy Company and its subsidiaries (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 **,** and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 9, 2018

We have served as the Company's auditor since 1932.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Baltimore Gas and Electric Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Baltimore Gas and Electric Company and its subsidiaries (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 **,** and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 9, 2018

We have served as the Company's auditor since at least 1993. We have not determined the specific year we began serving as auditor of the Company.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Pepco Holdings LLC

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Pepco Holdings LLC and its subsidiaries (Successor) (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016 **,** and the results of their operations and their cash flows for the year ended December 31, 2017, for the period from March 24, 2016 to December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 9, 2018

We have served as the Company's auditor since 2001.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Pepco Holdings LLC

In our opinion, the financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the results of operations and the cash flows of Pepco Holdings LLC and its subsidiaries (formerly Pepco Holdings, Inc.) (Predecessor) for the period January 1, 2016 to March 23, 2016 and for the year ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the financial statements, the Company changed the manner in which it accounts for interest on uncertain tax positions in 2016.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Potomac Electric Power Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Potomac Electric Power Company (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 9, 2018

We have served as the Company's auditor since at least 1993. We have not determined the specific year we began serving as auditor of the Company.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Delmarva Power & Light Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Delmarva Power & Light Company (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 9, 2018

We have served as the Company's auditor since at least 1993. We have not determined the specific year we began serving as auditor of the Company.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Atlantic City Electric Company

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1), and the financial statement schedule listed in the index appearing under Item 15(a)(2), of Atlantic City Electric Company and its subsidiary (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 9, 2018

We have served as the Company's auditor since 1998.

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2017	2016	2015
Operating revenues			
Competitive businesses revenues	$ 17,360	$ 16,324	$ 18,395
Rate-regulated utility revenues	16,171	15,036	11,052
Total operating revenues	33,531	31,360	29,447
Operating expenses			
Competitive businesses purchased power and fuel	9,668	8,817	10,007
Rate-regulated utility purchased power and fuel	4,367	3,823	3,077
Operating and maintenance	10,126	10,048	8,322
Depreciation and amortization	3,828	3,936	2,450
Taxes other than income	1,731	1,576	1,200
Total operating expenses	29,720	28,200	25,056
Gain (Loss) on sales of assets	3	(48)	18
Bargain purchase gain	233	—	—
Gain on deconsolidation of business	213	—	—
Operating income	4,260	3,112	4,409
Other income and (deductions)			
Interest expense, net	(1,524)	(1,495)	(992)
Interest expense to affiliates	(36)	(41)	(41)
Other, net	1,056	413	(46)
Total other income and (deductions)	(504)	(1,123)	(1,079)
Income before income taxes	3,756	1,989	3,330
Income taxes	(125)	761	1,073
Equity in losses of unconsolidated affiliates	(32)	(24)	(7)
Net income	3,849	1,204	2,250
Net income (loss) attributable to noncontrolling interests and preference stock dividends	79	70	(19)
Net income attributable to common shareholders	$ 3,770	$ 1,134	$ 2,269
Comprehensive income, net of income taxes			
Net income	$ 3,849	$ 1,204	$ 2,250
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	(56)	(48)	(46)
Actuarial loss reclassified to periodic benefit cost	197	184	220
Pension and non-pension postretirement benefit plan valuation adjustment	10	(181)	(99)
Unrealized gain on cash flow hedges	3	2	9
Unrealized gain on marketable securities	6	1	—
Unrealized gain (loss) on equity investments	4	(4)	(3)
Unrealized gain (loss) on foreign currency translation	7	10	(21)
Other comprehensive income (loss)	171	(36)	60
Comprehensive income	4,020	1,168	2,310
Comprehensive income (loss) attributable to noncontrolling interests and preference stock dividends	77	70	(19)
Comprehensive income attributable to common shareholders	$ 3,943	$ 1,098	$ 2,329
Average shares of common stock outstanding:			
Basic	947	924	890
Diluted	949	927	893
Earnings per average common share:			
Basic	$ 3.98	$ 1.23	$ 2.55
Diluted	$ 3.97	$ 1.22	$ 2.54
Dividends per common share	$ 1.31	$ 1.26	$ 1.24

See the Combined Notes to Consolidated Financial Statements

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Exelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2017	2016	2015
Cash flows from operating activities			
Net income	$ 3,849	$ 1,204	$ 2,250
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	5,427	5,576	3,987
Impairment losses of long-lived assets, intangibles and regulatory assets	573	306	36
Gain on deconsolidation of business	(213)	—	—
(Gain) Loss on sales of assets	(3)	48	(18)
Bargain purchase gain	(233)	—	—
Deferred income taxes and amortization of investment tax credits	(361)	664	752
Net fair value changes related to derivatives	151	24	(367)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(616)	(229)	131
Other non-cash operating activities	721	1,333	1,109
Changes in assets and liabilities:			
Accounts receivable	(426)	(432)	240
Inventories	(72)	7	4
Accounts payable and accrued expenses	(390)	771	(121)
Option premiums received (paid), net	28	(66)	58
Collateral (posted) received, net	(158)	931	347
Income taxes	299	576	97
Pension and non-pension postretirement benefit contributions	(405)	(397)	(502)
Deposit with IRS	—	(1,250)	—
Other assets and liabilities	(691)	(621)	(387)
Net cash flows provided by operating activities	7,480	8,445	7,616
Cash flows from investing activities			
Capital expenditures	(7,584)	(8,553)	(7,624)
Proceeds from termination of direct financing lease investment	—	360	—
Proceeds from nuclear decommissioning trust fund sales	7,845	9,496	6,895
Investment in nuclear decommissioning trust funds	(8,113)	(9,738)	(7,147)
Acquisitions of businesses, net	(208)	(6,934)	(40)
Proceeds from sales of long-lived assets	219	61	147
Change in restricted cash	(50)	(42)	66
Other investing activities	(43)	(153)	(119)
Net cash flows used in investing activities	(7,934)	(15,503)	(7,822)
Cash flows from financing activities			
Changes in short-term borrowings	(261)	(353)	80
Proceeds from short-term borrowings with maturities greater than 90 days	621	240	—
Repayments on short-term borrowings with maturities greater than 90 days	(700)	(462)	—
Issuance of long-term debt	3,470	4,716	6,709
Retirement of long-term debt	(2,490)	(1,936)	(2,687)
Retirement of long-term debt to financing trust	(250)	—	—
Restricted proceeds from issuance of long-term debt	(50)	—	—
Issuance of common stock	—	—	1,868
Common stock issued from treasury stock	1,150	—	—
Redemption of preference stock	—	(190)	—
Dividends paid on common stock	(1,236)	(1,166)	(1,105)
Proceeds from employee stock plans	150	55	32
Sale of noncontrolling interests	396	372	32
Other financing activities	(83)	(85)	(99)
Net cash flows provided by financing activities	717	1,191	4,830
Increase (Decrease) in cash and cash equivalents	263	(5,867)	4,624
Cash and cash equivalents at beginning of period	635	6,502	1,878
Cash and cash equivalents at end of period	$ 898	$ 635	$ 6,502

See the Combined Notes to Consolidated Financial Statements

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Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 898	$ 635
Restricted cash and cash equivalents	207	253
Deposit with IRS	—	1,250
Accounts receivable, net		
Customer	4,401	4,158
Other	1,132	1,201
Mark-to-market derivative assets	976	917
Unamortized energy contract assets	60	88
Inventories, net		
Fossil fuel and emission allowances	340	364
Materials and supplies	1,311	1,274
Regulatory assets	1,267	1,342
Other	1,242	930
Total current assets	11,834	12,412
Property, plant and equipment, net	74,202	71,555
Deferred debits and other assets		
Regulatory assets	8,021	10,046
Nuclear decommissioning trust funds	13,272	11,061
Investments	640	629
Goodwill	6,677	6,677
Mark-to-market derivative assets	337	492
Unamortized energy contract assets	395	447
Pledged assets for Zion Station decommissioning	—	113
Other	1,322	1,472
Total deferred debits and other assets	30,664	30,937
Total assets [(a)]	$ 116,700	$ 114,904

See the Combined Notes to Consolidated Financial Statements

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Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 929	$ 1,267
Long-term debt due within one year	2,088	2,430
Accounts payable	3,532	3,441
Accrued expenses	1,835	3,460
Payables to affiliates	5	8
Regulatory liabilities	523	602
Mark-to-market derivative liabilities	232	282
Unamortized energy contract liabilities	231	407
Renewable energy credit obligation	352	428
PHI Merger related obligation	87	151
Other	982	981
Total current liabilities	10,796	13,457
Long-term debt	32,176	31,575
Long-term debt to financing trusts	389	641
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,222	18,138
Asset retirement obligations	10,029	9,111
Pension obligations	3,736	4,248
Non-pension postretirement benefit obligations	2,093	1,848
Spent nuclear fuel obligation	1,147	1,024
Regulatory liabilities	9,865	4,187
Mark-to-market derivative liabilities	409	392
Unamortized energy contract liabilities	609	830
Payable for Zion Station decommissioning	—	14
Other	2,097	1,827
Total deferred credits and other liabilities	41,207	41,619
Total liabilities [(a)]	84,568	87,292
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2000 shares authorized, 963 shares and 924 shares outstanding at December 31, 2017 and 2016, respectively)	18,964	18,794
Treasury stock, at cost (2 shares and 35 shares at December 31, 2017 and 2016, respectively)	(123)	(2,327)
Retained earnings	13,503	12,030
Accumulated other comprehensive loss, net	(2,487)	(2,660)
Total shareholders' equity	29,857	25,837
Noncontrolling interests	2,275	1,775
Total equity	32,132	27,612
Total liabilities and equity	$ 116,700	$ 114,904

(a) Exelon's consolidated assets include $9,565 million and $8,893 million at December 31, 2017 and December 31, 2016 , respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $3,612 million and $3,356 million at December 31, 2017 and December 31, 2016 , respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 2 – Variable Interest Entities .

See the Combined Notes to Consolidated Financial Statements

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Exelon Corporation and Subsidiary Companies
Consolidated Statements of Changes in Equity

(In millions, shares in thousands)	Shareholders' Equity							
	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Preference Stock	Total Equity
Balance, December 31, 2014	894,568	$ 16,709	$ (2,327)	$ 10,910	$ (2,684)	$ 1,332	$ 193	$ 24,133
Net income (loss)	—	—	—	2,269	—	(32)	13	2,250
Long-term incentive plan activity	1,430	70	—	—	—	—	—	70
Employee stock purchase plan issuances	1,170	32	—	—	—	—	—	32
Issuance of common stock	57,500	1,868	—	—	—	—	—	1,868
Tax benefit on stock compensation	—	(3)	—	—	—	—	—	(3)
Acquisition of noncontrolling interests	—	—	—	—	—	4	—	4
Adjustment of contingently redeemable noncontrolling interests due to release of contingency	—	—	—	—	—	4	—	4
Common stock dividends	—	—	—	(1,111)	—	—	—	(1,111)
Preference stock dividends	—	—	—	—	—	—	(13)	(13)
Other comprehensive income, net of income taxes	—	—	—	—	60	—	—	60
Balance, December 31, 2015	954,668	$ 18,676	$ (2,327)	$ 12,068	$ (2,624)	$ 1,308	$ 193	$ 27,294
Net income	—	—	—	1,134	—	62	8	1,204
Long-term incentive plan activity	2,868	85	—	—	—	—	—	85
Employee stock purchase plan issuances	1,242	55	—	—	—	—	—	55
Tax benefit on stock compensation	—	(18)	—	—	—	—	—	(18)
Changes in equity of noncontrolling interests	—	—	—	—	—	5	—	5
Sale of noncontrolling interest	—	(4)	—	—	—	243	—	239
Adjustment of contingently redeemable noncontrolling interests due to release of contingency	—	—	—	—	—	157	—	157
Common stock dividends	—	—	—	(1,172)	—	—	—	(1,172)
Redemption of preference stock	—	—	—	—	—	—	(193)	(193)
Preference stock dividends	—	—	—	—	—	—	(8)	(8)
Other comprehensive loss, net of income taxes	—	—	—	—	(36)	—	—	(36)
Balance, December 31, 2016	958,778	$ 18,794	$ (2,327)	$ 12,030	$ (2,660)	$ 1,775	$ —	$ 27,612
Net income	—	—	—	3,770	—	79	—	3,849
Long-term incentive plan activity	5,066	56	—	—	—	—	—	56
Employee stock purchase plan issuances	1,324	150	—	—	—	—	—	150
Common stock issued from treasury stock	—	—	2,204	(1,054)	—	—	—	1,150
Changes in equity of noncontrolling interests	—	—	—	—	—	(20)	—	(20)
Sale of noncontrolling interests	—	(36)	—	—	—	443	—	407
Common stock dividends	—	—	—	(1,243)	—	—	—	(1,243)
Other comprehensive income, net of income taxes	—	—	—	—	173	(2)	—	171
Balance, December 31, 2017	965,168	$ 18,964	$ (123)	$ 13,503	$ (2,487)	$ 2,275	$ —	$ 32,132

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2017	2016	2015
Operating revenues			
Operating revenues	$ 17,351	$ 16,312	$ 18,386
Operating revenues from affiliates	1,115	1,439	749
Total operating revenues	18,466	17,751	19,135
Operating expenses			
Purchased power and fuel	9,671	8,818	10,007
Purchased power and fuel from affiliates	19	12	14
Operating and maintenance	5,594	4,978	4,688
Operating and maintenance from affiliates	697	663	620
Depreciation and amortization	1,457	1,879	1,054
Taxes other than income	555	506	489
Total operating expenses	17,993	16,856	16,872
Gain (Loss) on sales of assets	2	(59)	12
Bargain purchase gain	233	—	—
Gain on deconsolidation of business	213	—	—
Operating income	921	836	2,275
Other income and (deductions)			
Interest expense, net	(401)	(325)	(322)
Interest expense to affiliates	(39)	(39)	(43)
Other, net	948	401	(60)
Total other income and (deductions)	508	37	(425)
Income before income taxes	1,429	873	1,850
Income taxes	(1,375)	290	502
Equity in losses of unconsolidated affiliates	(33)	(25)	(8)
Net income	2,771	558	1,340
Net income (loss) attributable to noncontrolling interests	77	62	(32)
Net income attributable to membership interest	$ 2,694	$ 496	$ 1,372
Comprehensive income, net of income taxes			
Net income	$ 2,771	$ 558	$ 1,340
Other comprehensive income (loss), net of income taxes			
Unrealized gain (loss) on cash flow hedges	3	2	(3)
Unrealized gain (loss) on equity investments	4	(4)	(3)
Unrealized gain (loss) on foreign currency translation	7	10	(21)
Unrealized gain on marketable securities	1	1	—
Other comprehensive income (loss)	15	9	(27)
Comprehensive income	$ 2,786	$ 567	$ 1,313
Comprehensive income (loss) attributable to noncontrolling interests	75	62	(32)
Comprehensive income attributable to membership interest	$ 2,711	$ 505	$ 1,345

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2017	2016	2015
Cash flows from operating activities			
Net income	$ 2,771	$ 558	$ 1,340
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	3,056	3,519	2,589
Impairment losses of long-lived assets	510	243	12
Gain on deconsolidation of business	(213)	—	—
(Gain) Loss on sales of assets	(2)	59	(12)
Bargain purchase gain	(233)	—	—
Deferred income taxes and amortization of investment tax credits	(2,022)	(269)	49
Net fair value changes related to derivatives	167	40	(249)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(616)	(229)	131
Other non-cash operating activities	112	15	268
Changes in assets and liabilities:			
Accounts receivable	(276)	(152)	194
Receivables from and payables to affiliates, net	(7)	(21)	15
Inventories	(29)	(4)	16
Accounts payable and accrued expenses	2	29	(149)
Option premiums received (paid), net	28	(66)	58
Collateral (posted) received, net	(129)	923	407
Income taxes	496	182	(18)
Pension and non-pension postretirement benefit contributions	(148)	(152)	(245)
Other assets and liabilities	(168)	(231)	(207)
Net cash flows provided by operating activities	3,299	4,444	4,199
Cash flows from investing activities			
Capital expenditures	(2,259)	(3,078)	(3,841)
Proceeds from nuclear decommissioning trust fund sales	7,845	9,496	6,895
Investment in nuclear decommissioning trust funds	(8,113)	(9,738)	(7,147)
Proceeds from sales of long-lived assets	218	37	147
Acquisitions of businesses, net	(208)	(293)	(40)
Change in restricted cash	(17)	(35)	35
Other investing activities	(58)	(240)	(118)
Net cash flows used in investing activities	(2,592)	(3,851)	(4,069)
Cash flows from financing activities			
Change in short-term borrowings	(620)	620	—
Proceeds from short-term borrowings with maturities greater than 90 days	121	240	—
Repayments of short-term borrowings with maturities greater than 90 days	(200)	(162)	—
Issuance of long-term debt	1,645	388	1,309
Retirement of long-term debt	(1,261)	(202)	(89)
Restricted proceeds from issuance of long-term debt	(50)	—	—
Retirement of long-term debt to affiliate	—	—	(550)
Changes in Exelon intercompany money pool	(1)	(1,191)	1,252
Distributions to member	(659)	(922)	(2,474)
Contributions from member	102	142	47
Sale of noncontrolling interests	396	372	32
Other financing activities	(54)	(19)	(6)
Net cash flows used in financing activities	(581)	(734)	(479)
Increase (Decrease) in cash and cash equivalents	126	(141)	(349)
Cash and cash equivalents at beginning of period	290	431	780
Cash and cash equivalents at end of period	$ 416	$ 290	$ 431

See the Combined Notes to Consolidated Financial Statements

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Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 416	$ 290
Restricted cash and cash equivalents	138	158
Accounts receivable, net		
Customer	2,653	2,433
Other	321	558
Mark-to-market derivative assets	976	917
Receivables from affiliates	140	156
Unamortized energy contract assets	60	88
Inventories, net		
Fossil fuel and emission allowances	264	292
Materials and supplies	937	935
Other	915	701
Total current assets	6,820	6,528
Property, plant and equipment, net	24,906	25,585
Deferred debits and other assets		
Nuclear decommissioning trust funds	13,272	11,061
Investments	433	418
Goodwill	47	47
Mark-to-market derivative assets	334	476
Prepaid pension asset	1,502	1,595
Pledged assets for Zion Station decommissioning	—	113
Unamortized energy contract assets	395	447
Deferred income taxes	16	16
Other	662	688
Total deferred debits and other assets	16,661	14,861
Total assets [(a)]	$ 48,387	$ 46,974

See the Combined Notes to Consolidated Financial Statements

S1-SSA-0009 - 16476

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 2	$ 699
Long-term debt due within one year	346	1,117
Accounts payable	1,773	1,610
Accrued expenses	1,020	989
Payables to affiliates	123	137
Borrowings from Exelon intercompany money pool	54	55
Mark-to-market derivative liabilities	211	263
Unamortized energy contract liabilities	43	72
Renewable energy credit obligation	352	428
Other	265	313
Total current liabilities	4,189	5,683
Long-term debt	7,734	7,202
Long-term debt to affiliate	910	922
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,798	5,585
Asset retirement obligations	9,844	8,922
Non-pension postretirement benefit obligations	916	930
Spent nuclear fuel obligation	1,147	1,024
Payables to affiliates	3,065	2,608
Mark-to-market derivative liabilities	174	153
Unamortized energy contract liabilities	48	80
Payable for Zion Station decommissioning	—	14
Other	658	595
Total deferred credits and other liabilities	19,650	19,911
Total liabilities [(a)]	32,483	33,718
Equity		
Member's equity		
Membership interest	9,357	9,261
Undistributed earnings	4,310	2,275
Accumulated other comprehensive loss, net	(37)	(54)
Total member's equity	13,630	11,482
Noncontrolling interests	2,274	1,774
Total equity	15,904	13,256
Total liabilities and equity	$ 48,387	$ 46,974

(a) Generation's consolidated assets include $9,524 million and $8,817 million at December 31, 2017 and 2016 , respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $3,510 million and $3,170 million at December 31, 2017 and 2016 , respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 2 – Variable Interest Entities .

See the Combined Notes to Consolidated Financial Statements

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Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Changes in Equity

(In millions)	Member's Equity			Noncontrolling Interests	Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net		
Balance, December 31, 2014	$ 8,951	$ 3,803	$ (36)	$ 1,333	$ 14,051
Net income (loss)	—	1,372	—	(32)	1,340
Acquisition of noncontrolling interests	(1)	—	—	2	1
Adjustment of contingently redeemable noncontrolling interests due to release of contingency	—	—	—	4	4
Allocation of tax benefit from member	47	—	—	—	47
Distribution to member	—	(2,474)	—	—	(2,474)
Other comprehensive loss, net of income taxes	—	—	(27)	—	(27)
Balance, December 31, 2015	$ 8,997	$ 2,701	$ (63)	$ 1,307	$ 12,942
Net income	—	496	—	62	558
Sale of noncontrolling interests	(4)	—	—	243	239
Adjustment of contingently redeemable noncontrolling interests due to release of contingency	—	—	—	157	157
Changes in equity of noncontrolling interests	—	—	—	5	5
Allocation of tax benefit from member	98	—	—	—	98
Contribution from member	170	—	—	—	170
Distribution to member	—	(922)	—	—	(922)
Other comprehensive income, net of income taxes	—	—	9	—	9
Balance, December 31, 2016	$ 9,261	$ 2,275	$ (54)	$ 1,774	$ 13,256
Net income	—	2,694	—	77	2,771
Sale of noncontrolling interests	(36)	—	—	443	407
Changes in equity of noncontrolling interests	—	—	—	(18)	(18)
Distribution of net retirement benefit obligation to member	33	—	—	—	33
Allocation of tax benefit from member	99	—	—	—	99
Distribution to member	—	(659)	—	—	(659)
Other comprehensive income, net of income taxes	—	—	17	(2)	15
Balance, December 31, 2017	$ 9,357	$ 4,310	$ (37)	$ 2,274	$ 15,904

See the Combined Notes to Consolidated Financial Statements

S1-SSA-0009 - 16478

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2017	2016	2015
Operating revenues			
Electric operating revenues	$ 5,521	$ 5,239	$ 4,901
Operating revenues from affiliates	15	15	4
Total operating revenues	5,536	5,254	4,905
Operating expenses			
Purchased power	1,533	1,411	1,301
Purchased power from affiliate	108	47	18
Operating and maintenance	1,157	1,303	1,372
Operating and maintenance from affiliate	270	227	195
Depreciation and amortization	850	775	707
Taxes other than income	296	293	296
Total operating expenses	4,214	4,056	3,889
Gain on sales of assets	1	7	1
Operating income	1,323	1,205	1,017
Other income and (deductions)			
Interest expense, net	(348)	(448)	(319)
Interest expense to affiliates	(13)	(13)	(13)
Other, net	22	(65)	21
Total other income and (deductions)	(339)	(526)	(311)
Income before income taxes	984	679	706
Income taxes	417	301	280
Net income	$ 567	$ 378	$ 426
Comprehensive income	$ 567	$ 378	$ 426

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2017	2016	2015
Cash flows from operating activities			
Net income	$ 567	$ 378	$ 426
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	850	775	707
Deferred income taxes and amortization of investment tax credits	659	439	353
Other non-cash operating activities	164	215	416
Changes in assets and liabilities:			
Accounts receivable	(59)	(25)	(93)
Receivables from and payables to affiliates, net	8	3	(19)
Inventories	4	1	(40)
Accounts payable and accrued expenses	(297)	339	68
Counterparty collateral received (posted), net and cash deposits	(26)	7	(33)
Income taxes	(308)	306	192
Pension and non-pension postretirement benefit contributions	(41)	(38)	(150)
Other assets and liabilities	6	105	69
Net cash flows provided by operating activities	1,527	2,505	1,896
Cash flows from investing activities			
Capital expenditures	(2,250)	(2,734)	(2,398)
Change in restricted cash	(66)	—	2
Other investing activities	20	49	34
Net cash flows used in investing activities	(2,296)	(2,685)	(2,362)
Cash flows from financing activities			
Changes in short-term borrowings	—	(294)	(10)
Issuance of long-term debt	1,000	1,200	850
Retirement of long-term debt	(425)	(665)	(260)
Contributions from parent	651	315	202
Dividends paid on common stock	(422)	(369)	(299)
Other financing activities	(15)	(18)	(16)
Net cash flows provided by financing activities	789	169	467
Increase (Decrease) in cash and cash equivalents	20	(11)	1
Cash and cash equivalents at beginning of period	56	67	66
Cash and cash equivalents at end of period	$ 76	$ 56	$ 67

See the Combined Notes to Consolidated Financial Statements

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Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 76	$ 56
Restricted cash	5	2
Accounts receivable, net		
Customer	559	528
Other	266	218
Receivables from affiliates	13	356
Inventories, net	152	159
Regulatory assets	225	190
Other	68	45
Total current assets	1,364	1,554
Property, plant and equipment, net	20,723	19,335
Deferred debits and other assets		
Regulatory assets	1,054	977
Investments	6	6
Goodwill	2,625	2,625
Receivable from affiliates	2,528	2,170
Prepaid pension asset	1,188	1,343
Other	238	325
Total deferred debits and other assets	7,639	7,446
Total assets	$ 29,726	$ 28,335

See the Combined Notes to Consolidated Financial Statements

S1-SSA-0009 - 16481

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 840	$ 425
Accounts payable	568	645
Accrued expenses	327	1,250
Payables to affiliates	74	65
Customer deposits	112	121
Regulatory liabilities	249	329
Mark-to-market derivative liability	21	19
Other	103	84
Total current liabilities	2,294	2,938
Long-term debt	6,761	6,608
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,469	5,364
Asset retirement obligations	111	119
Non-pension postretirement benefits obligations	219	239
Regulatory liabilities	6,328	3,369
Mark-to-market derivative liability	235	239
Other	562	529
Total deferred credits and other liabilities	10,924	9,859
Total liabilities	20,184	19,610
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	6,822	6,150
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	2,771	2,626
Total shareholders' equity	9,542	8,725
Total liabilities and shareholders' equity	$ 29,726	$ 28,335

See the Combined Notes to Consolidated Financial Statements

S1-SSA-0009 - 16482

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2014	$ 1,588	$ 5,468	$ (1,639)	$ 2,490	$ 7,907
Net income	—	—	426	—	426
Common stock dividends	—	—	—	(299)	(299)
Contribution from parent	—	202	—	—	202
Parent tax matter indemnification	—	7	—	—	7
Appropriation of retained earnings for future dividends	—	—	(426)	426	—
Balance, December 31, 2015	$ 1,588	$ 5,677	$ (1,639)	$ 2,617	$ 8,243
Net income	—	—	378	—	378
Common stock dividends	—	—	—	(369)	(369)
Contribution from parent	—	315	—	—	315
Parent tax matter indemnification	—	158	—	—	158
Appropriation of retained earnings for future dividends	—	—	(378)	378	—
Balance, December 31, 2016	$ 1,588	$ 6,150	$ (1,639)	$ 2,626	$ 8,725
Net income	—	—	567	—	567
Common stock dividends	—	—	—	(422)	(422)
Contribution from parent	—	651	—	—	651
Parent tax matter indemnification	—	21	—	—	21
Appropriation of retained earnings for future dividends	—	—	(567)	567	—
Balance, December 31, 2017	$ 1,588	$ 6,822	$ (1,639)	$ 2,771	$ 9,542

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2017	2016	2015
Operating revenues			
Electric operating revenues	$ 2,369	$ 2,524	$ 2,485
Natural gas operating revenues	494	462	545
Operating revenues from affiliates	7	8	2
Total operating revenues	2,870	2,994	3,032
Operating expenses			
Purchased power	648	598	735
Purchased fuel	186	162	235
Purchased power from affiliate	135	287	220
Operating and maintenance	657	665	684
Operating and maintenance from affiliates	149	146	110
Depreciation and amortization	286	270	260
Taxes other than income	154	164	160
Total operating expenses	2,215	2,292	2,404
Gain on sales of assets	—	—	2
Operating income	655	702	630
Other income and (deductions)			
Interest expense, net	(115)	(111)	(102)
Interest expense to affiliates, net	(11)	(12)	(12)
Other, net	9	8	5
Total other income and (deductions)	(117)	(115)	(109)
Income before income taxes	538	587	521
Income taxes	104	149	143
Net income	$ 434	$ 438	$ 378
Comprehensive income	$ 434	$ 438	$ 378

See the Combined Notes to Consolidated Financial Statements

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PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2017	2016	2015
Cash flows from operating activities			
Net income	$ 434	$ 438	$ 378
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	286	270	260
Deferred income taxes and amortization of investment tax credits	19	78	90
Other non-cash operating activities	54	65	70
Changes in assets and liabilities:			
Accounts receivable	(44)	(71)	37
Receivables from and payables to affiliates, net	(6)	6	3
Inventories	1	6	10
Accounts payable and accrued expenses	6	67	(25)
Income taxes	34	8	(9)
Pension and non-pension postretirement benefit contributions	(24)	(30)	(40)
Other assets and liabilities	(5)	(8)	(4)
Net cash flows provided by operating activities	755	829	770
Cash flows from investing activities			
Capital expenditures	(732)	(686)	(601)
Changes in intercompany money pool	131	(131)	—
Change in restricted cash	—	(1)	(1)
Other investing activities	4	20	14
Net cash flows used in investing activities	(597)	(798)	(588)
Cash flows from financing activities			
Issuance of long-term debt	325	300	350
Retirement of long-term debt	—	(300)	—
Contributions from parent	16	18	16
Dividends paid on common stock	(288)	(277)	(279)
Other financing activities	(3)	(4)	(4)
Net cash flows provided by (used in) financing activities	50	(263)	83
Increase (Decrease) in cash and cash equivalents	208	(232)	265
Cash and cash equivalents at beginning of period	63	295	30
Cash and cash equivalents at end of period	$ 271	$ 63	$ 295

See the Combined Notes to Consolidated Financial Statements

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PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 271	$ 63
Restricted cash and cash equivalents	4	4
Accounts receivable, net		
Customer	327	306
Other	105	131
Receivables from affiliates	—	4
Receivable from Exelon intercompany pool	—	131
Inventories, net		
Fossil fuel	31	35
Materials and supplies	30	27
Prepaid utility taxes	8	9
Regulatory assets	29	29
Other	17	18
Total current assets	822	757
Property, plant and equipment, net	8,053	7,565
Deferred debits and other assets		
Regulatory assets	381	1,681
Investments	25	25
Receivable from affiliates	537	438
Prepaid pension asset	340	345
Other	12	20
Total deferred debits and other assets	1,295	2,509
Total assets	$ 10,170	$ 10,831

See the Combined Notes to Consolidated Financial Statements

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PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 500	$ —
Accounts payable	370	342
Accrued expenses	114	104
Payables to affiliates	53	63
Customer deposits	66	61
Regulatory liabilities	141	127
Other	23	30
Total current liabilities	1,267	727
Long-term debt	2,403	2,580
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,789	3,006
Asset retirement obligations	27	28
Non-pension postretirement benefits obligations	288	289
Regulatory liabilities	549	517
Other	86	85
Total deferred credits and other liabilities	2,739	3,925
Total liabilities	6,593	7,416
Commitments and contingencies		
Shareholder's equity		
Common stock	2,489	2,473
Retained earnings	1,087	941
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,577	3,415
Total liabilities and shareholder's equity	$ 10,170	$ 10,831

See the Combined Notes to Consolidated Financial Statements

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PECO Energy Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholder's Equity
Balance, December 31, 2014	$ 2,439	$ 681	$ 1	$ 3,121
Net income	—	378	—	378
Common stock dividends	—	(279)	—	(279)
Allocation of tax benefit from parent	16	—	—	16
Balance, December 31, 2015	$ 2,455	$ 780	$ 1	$ 3,236
Net income	—	438	—	438
Common stock dividends	—	(277)	—	(277)
Allocation of tax benefit from parent	18	—	—	18
Balance, December 31, 2016	$ 2,473	$ 941	$ 1	$ 3,415
Net income	—	434	—	434
Common stock dividends	—	(288)	—	(288)
Allocation of tax benefit from parent	16	—	—	16
Balance, December 31, 2017	$ 2,489	$ 1,087	$ 1	$ 3,577

See the Combined Notes to Consolidated Financial Statements

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Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2017	2016	2015
Operating revenues			
Electric operating revenues	$ 2,484	$ 2,603	$ 2,490
Natural gas operating revenues	676	609	631
Operating revenues from affiliates	16	21	14
Total operating revenues	3,176	3,233	3,135
Operating expenses			
Purchased power	566	528	602
Purchased fuel	183	162	205
Purchased power from affiliate	384	604	498
Operating and maintenance	563	605	565
Operating and maintenance from affiliates	153	132	118
Depreciation and amortization	473	423	366
Taxes other than income	240	229	224
Total operating expenses	2,562	2,683	2,578
Gain on sales of assets	—	—	1
Operating income	614	550	558
Other income and (deductions)			
Interest expense, net	(95)	(87)	(83)
Interest expense to affiliates	(10)	(16)	(16)
Other, net	16	21	18
Total other income and (deductions)	(89)	(82)	(81)
Income before income taxes	525	468	477
Income taxes	218	174	189
Net income	307	294	288
Preference stock dividends	—	8	13
Net income attributable to common shareholder	$ 307	$ 286	$ 275
Comprehensive income	$ 307	$ 294	$ 288
Comprehensive income attributable to preference stock dividends	—	8	13
Comprehensive income attributable to common shareholder	$ 307	$ 286	$ 275

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2017	2016	2015
Cash flows from operating activities			
Net income	$ 307	$ 294	$ 288
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	473	423	366
Impairment losses on long-lived assets and regulatory assets	7	52	—
Deferred income taxes and amortization of investment tax credits	145	118	165
Other non-cash operating activities	65	88	137
Changes in assets and liabilities:			
Accounts receivable	(5)	(98)	84
Receivables from and payables to affiliates, net	(4)	3	(2)
Inventories	(9)	1	18
Accounts payable and accrued expenses	(15)	138	(3)
Collateral received (posted), net	—	—	(27)
Income taxes	60	18	(54)
Pension and non-pension postretirement benefit contributions	(53)	(49)	(17)
Other assets and liabilities	(150)	(43)	(173)
Net cash flows provided by operating activities	821	945	782
Cash flows from investing activities			
Capital expenditures	(882)	(934)	(719)
Change in restricted cash	26	—	26
Other investing activities	7	24	18
Net cash flows used in investing activities	(849)	(910)	(675)
Cash flows from financing activities			
Changes in short-term borrowings	32	(165)	90
Issuance of long-term debt	300	850	—
Retirement of long-term debt	(41)	(379)	(75)
Retirement of long-term debt to financing trust	(250)	—	—
Redemption of preference stock	—	(190)	—
Dividends paid on preference stock	—	(8)	(13)
Dividends paid on common stock	(198)	(179)	(158)
Contributions from parent	184	61	7
Other financing activities	(5)	(11)	(13)
Net cash flows provided by (used in) financing activities	22	(21)	(162)
(Decrease) Increase in cash and cash equivalents	(6)	14	(55)
Cash and cash equivalents at beginning of period	23	9	64
Cash and cash equivalents at end of period	$ 17	$ 23	$ 9

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 17	$ 23
Restricted cash and cash equivalents	1	24
Accounts receivable, net		
Customer	375	395
Other	94	102
Receivable from affiliates	1	—
Inventories, net		
Gas held in storage	37	30
Materials and supplies	40	38
Prepaid utility taxes	69	15
Regulatory assets	174	208
Other	3	7
Total current assets	811	842
Property, plant and equipment, net	7,602	7,040
Deferred debits and other assets		
Regulatory assets	397	504
Investments	5	12
Prepaid pension asset	285	297
Other	4	9
Total deferred debits and other assets	691	822
Total assets [a]	$ 9,104	$ 8,704

See the Combined Notes to Consolidated Financial Statements

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Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 77	$ 45
Long-term debt due within one year	—	41
Accounts payable	265	205
Accrued expenses	164	175
Payables to affiliates	52	55
Customer deposits	116	110
Regulatory liabilities	62	50
Other	24	26
Total current liabilities	760	707
Long-term debt	2,577	2,281
Long-term debt to financing trust	—	252
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,244	2,219
Asset retirement obligations	23	21
Non-pension postretirement benefits obligations	202	205
Regulatory liabilities	1,101	110
Other	56	61
Total deferred credits and other liabilities	2,626	2,616
Total liabilities [(a)]	5,963	5,856
Commitments and contingencies		
Shareholder's equity		
Common stock	1,605	1,421
Retained earnings	1,536	1,427
Total shareholder's equity	3,141	2,848
Total liabilities and shareholder's equity	$ 9,104	$ 8,704

(a) BGE's consolidated assets include $26 million at December 31, 2016 of BGE's consolidated VIE that can only be used to settle the liabilities of the VIE. BGE's consolidated liabilities include $42 million at December 31, 2016 of BGE's consolidated VIE for which the VIE creditors do not have recourse to BGE. BGE no longer has interests in any VIEs as of December 31, 2017 . See Note 2 - Variable Interest Entities .

See the Combined Notes to Consolidated Financial Statements

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Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2014	$ 1,360	$ 1,203	$ 2,563	$ 190	$ 2,753
Net income	—	288	288	—	288
Preference stock dividends	—	(13)	(13)	—	(13)
Common stock dividends	—	(158)	(158)	—	(158)
Contribution from parent	7	—	7	—	7
Balance, December 31, 2015	$ 1,367	$ 1,320	$ 2,687	$ 190	$ 2,877
Net income	—	294	294	—	294
Preference stock dividends	—	(8)	(8)	—	(8)
Common stock dividends	—	(179)	(179)	—	(179)
Distribution to parent	(7)	—	(7)	—	(7)
Contribution from parent	61	—	61	—	61
Redemption of preference stock	—	—	—	(190)	(190)
Balance, December 31, 2016	$ 1,421	$ 1,427	$ 2,848	$ —	$ 2,848
Net income	—	307	307	—	307
Common stock dividends	—	(198)	(198)	—	(198)
Contribution from parent	184	—	184	—	184
Balance, December 31, 2017	$ 1,605	$ 1,536	$ 3,141	$ —	$ 3,141

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income (Loss)

(In millions)	Successor		Predecessor	
	For the Year Ended December 31,	March 24 to December 31,	January 1 to March 23,	For the Year Ended December 31,
	2017	2016	2016	2015
Operating revenues				
Electric operating revenues	$ 4,468	$ 3,506	$ 1,096	$ 4,770
Natural gas operating revenues	161	92	57	165
Operating revenues from affiliates	50	45	—	—
Total operating revenues	4,679	3,643	1,153	4,935
Operating expenses				
Purchased power	1,182	925	471	1,986
Purchased fuel	71	36	26	87
Purchased power and fuel from affiliates	463	486	—	—
Operating and maintenance	918	1,144	294	1,156
Operating and maintenance from affiliates	150	89	—	—
Depreciation, amortization and accretion	675	515	152	624
Taxes other than income	452	354	105	455
Total operating expenses	3,911	3,549	1,048	4,308
Gain (loss) on sales of assets	1	(1)	—	46
Operating income	769	93	105	673
Other income and (deductions)				
Interest expense, net	(245)	(195)	(65)	(280)
Other, net	54	44	(4)	88
Total other income and (deductions)	(191)	(151)	(69)	(192)
Income (loss) before income taxes	578	(58)	36	481
Income taxes	217	3	17	163
Equity in earnings of unconsolidated affiliates	1	—	—	—
Net income (loss) from continuing operations	362	(61)	19	318
Net income from discontinued operations	—	—	—	9
Net income (loss) attributable to membership interest/common shareholders	$ 362	$ (61)	$ 19	$ 327
Comprehensive income (loss), net of income taxes				
Net income (loss)	$ 362	$ (61)	$ 19	$ 327
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Actuarial loss reclassified to periodic cost	—	—	1	9
Unrealized loss on cash flow hedges	—	—	—	1
Other comprehensive income	—	—	1	10
Comprehensive income (loss)	$ 362	$ (61)	$ 20	$ 337

See the Combined Notes to Consolidated Financial Statements

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Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

	Successor		Predecessor	
	For the Year Ended December 31,	March 24 to December 31,	January 1 to March 23,	For the Year Ended December 31,
(In millions)	2017	2016	2016	2015
Cash flows from operating activities				
Net income (loss)	$ 362	$ (61)	$ 19	$ 327
Income from discontinued operations, net of income taxes	—	—	—	(9)
Adjustments to reconcile net income (loss) to net cash from operating activities:				
Depreciation and amortization	675	515	152	624
Impairment losses on intangibles and regulatory assets	52	—	—	—
(Gain) loss on sales of assets	(1)	1	—	(46)
Deferred income taxes and amortization of investment tax credits	252	295	19	134
Net fair value changes related to derivatives	—	—	18	—
Other non-cash operating activities	59	514	46	167
Changes in assets and liabilities:				
Accounts receivable	(26)	(21)	(28)	(105)
Receivables from and payables to affiliates, net	(2)	42	—	—
Inventories	(37)	3	(4)	—
Accounts payable and accrued expenses	(106)	19	42	(41)
Income taxes	79	(22)	12	8
Pension and non-pension postretirement benefit contributions	(99)	(86)	(4)	(21)
Other assets and liabilities	(258)	(311)	(8)	(99)
Net cash flows provided by operating activities	950	888	264	939
Cash flows from investing activities				
Capital expenditures	(1,396)	(1,008)	(273)	(1,230)
Proceeds from sales of long-lived assets	1	24	—	54
Changes in restricted cash	1	(37)	3	6
Purchases of investments	—	—	(68)	—
Other investing activities	(2)	(9)	(5)	9
Net cash flows used in investing activities	(1,396)	(1,030)	(343)	(1,161)
Cash flows from financing activities				
Changes in short-term borrowings	328	(515)	(121)	34
Proceeds from short-term borrowings with maturities greater than 90 days	—	—	500	300
Repayments of short-term borrowings with maturities greater than 90 days	(500)	(300)	—	—
Issuance of long-term debt	202	179	—	558
Retirement of long-term debt	(169)	(338)	(11)	(430)
Issuance of preferred stock	—	—	—	54
Dividends paid on common stock	—	—	—	(275)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation	—	—	2	18
Distribution to member	(311)	(273)	—	—
Contributions from member	758	1,251	—	—
Change in Exelon intercompany money pool	—	(6)	—	—
Other financing activities	(2)	(5)	2	(26)
Net cash flows provided by (used in) financing activities	306	(7)	372	233
(Decrease) Increase in cash and cash equivalents	(140)	(149)	293	11
Cash and cash equivalents at beginning of period	170	319	26	15
Cash and cash equivalents at end of period	$ 30	$ 170	$ 319	$ 26

See the Combined Notes to Consolidated Financial Statements

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Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	Successor December 31, 2017	Successor December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 30	$ 170
Restricted cash and cash equivalents	42	43
Accounts receivable, net		
Customer	486	496
Other	206	283
Inventories, net		
Gas held in storage	7	6
Materials and supplies	151	116
Regulatory assets	554	653
Other	75	71
Total current assets	1,551	1,838
Property, plant and equipment, net	12,498	11,598
Deferred debits and other assets		
Regulatory assets	2,493	2,851
Investments	132	133
Goodwill	4,005	4,005
Long-term note receivable	4	4
Prepaid pension asset	490	509
Deferred income taxes	4	6
Other	70	81
Total deferred debits and other assets	7,198	7,589
Total assets [a]	$ 21,247	$ 21,025

See the Combined Notes to Consolidated Financial Statements

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Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	Successor December 31, 2017	Successor December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 350	$ 522
Long-term debt due within one year	396	253
Accounts payable	348	458
Accrued expenses	261	272
Payables to affiliates	90	94
Unamortized energy contract liabilities	188	335
Customer deposits	119	123
Merger related obligation	42	101
Regulatory liabilities	56	79
Other	81	47
Total current liabilities	1,931	2,284
Long-term debt	5,478	5,645
Deferred credits and other liabilities		
Regulatory liabilities	1,872	158
Deferred income taxes and unamortized investment tax credits	2,070	3,775
Asset retirement obligations	16	14
Non-pension postretirement benefit obligations	105	134
Unamortized energy contract liabilities	561	750
Other	389	249
Total deferred credits and other liabilities	5,013	5,080
Total liabilities [(a)]	12,422	13,009
Commitments and contingencies		
Member's equity		
Membership interest	8,835	8,077
Undistributed (losses)	(10)	(61)
Total member's equity	8,825	8,016
Total liabilities and member's equity	$ 21,247	$ 21,025

(a) PHI's consolidated total assets include $41 million and $49 million at December 31, 2017 and 2016, respectively, of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI's consolidated total liabilities include $102 million and $143 million at December 31, 2017 and 2016, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 2 - Variable Interest Entities .

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Changes in Equity

(In millions, except share data)	Common Stock [a]	Retained Earnings	Accumulated Other Comprehensive Loss, net	Total Shareholders' Equity
Predecessor				
Balance, December 31, 2014	$ 3,803	$ 565	$ (46)	$ 4,322
Net income	—	327	—	327
Common stock dividends	—	(275)	—	(275)
Original issue shares, net	15	—	—	15
DRP original issue shares	11	—	—	11
Net activity related to stock-based awards	3	—	—	3
Other comprehensive income, net of income taxes	—	—	10	10
Balance, December 31, 2015	$ 3,832	$ 617	$ (36)	$ 4,413
Net income	—	19	—	19
Original issue shares, net	3	—	—	3
Net activity related to stock-based awards	3	—	—	3
Other comprehensive income, net of income taxes	—	—	1	1
Balance, March 23, 2016	$ 3,838	$ 636	$ (35)	$ 4,439

Successor	Membership Interest	Undistributed Losses	Accumulated Other Comprehensive Loss, net	Total Member's Equity
Balance, March 24, 2016 [b]	$ 7,200	$ —	$ —	$ 7,200
Net loss	—	(61)	—	(61)
Distribution to member [c]	(400)	—	—	(400)
Contribution from member	1,251	—	—	1,251
Measurement period adjustment of Exelon's deferred tax liabilities to reflect unitary state income tax consequences of the merger	35	—	—	35
Distribution of net retirement benefit obligation to member	53	—	—	53
Assumption of member liabilities [d]	(62)	—	—	(62)
Balance, December 31, 2016	$ 8,077	$ (61)	$ —	$ 8,016
Net Income	—	362	—	362
Distribution to member	—	(311)	—	(311)
Contribution from member	751	—	—	751
Allocation of tax benefit from member	7	—	—	7
Balance, December 31, 2017	$ 8,835	$ (10)	$ —	$ 8,825

(a) At March 23, 2016 and December 31, 2015 , PHI's (predecessor) shareholders' equity included $3,835 million and $3,829 million of other paid-in capital, and $3 million and $3 million of common stock, respectively.
(b) The March 24, 2016 , beginning balance differs from the PHI Merger total purchase price by $59 million related to an acquisition accounting adjustment recorded at Exelon Corporate to reflect unitary state income tax consequences of the merger.
(c) Distribution to member includes $235 million of net assets associated with PHI's unregulated business interests and $165 million of cash, each of which were distributed by PHI to Exelon.
(d) The liabilities assumed include $29 million for PHI stock-based compensation awards and $33 million for a merger related obligation, each assumed by PHI from Exelon. See Note 4 — Mergers, Acquisitions and Dispositions .

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2017	2016	2015
Operating revenues			
Electric operating revenues	$ 2,152	$ 2,181	$ 2,124
Operating revenues from affiliates	6	5	5
Total operating revenues	2,158	2,186	2,129
Operating expenses			
Purchased power	359	411	719
Purchased power from affiliates	255	295	—
Operating and maintenance	396	607	435
Operating and maintenance from affiliates	58	35	4
Depreciation and amortization	321	295	256
Taxes other than income	371	377	376
Total operating expenses	1,760	2,020	1,790
Gain on sales of assets	1	8	46
Operating income	399	174	385
Other income and (deductions)			
Interest expense, net	(121)	(127)	(124)
Other, net	32	36	28
Total other income and (deductions)	(89)	(91)	(96)
Income before income taxes	310	83	289
Income taxes	105	41	102
Net income	$ 205	$ 42	$ 187
Comprehensive income	$ 205	$ 42	$ 187

See the Combined Notes to Consolidated Financial Statements

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Potomac Electric Power Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2017	2016	2015
Cash flows from operating activities			
Net income	$ 205	$ 42	$ 187
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	321	295	256
Impairment losses on regulatory assets	14	—	—
Gain on sales of assets	(1)	(8)	(46)
Deferred income taxes and amortization of investment tax credits	113	153	150
Other non-cash operating activities	(5)	183	54
Changes in assets and liabilities:			
Accounts receivable	(20)	(41)	(43)
Receivables from and payables to affiliates, net	—	44	—
Inventories	(24)	1	(5)
Accounts payable and accrued expenses	(63)	32	(21)
Income taxes	81	110	(46)
Pension and non-pension postretirement benefit contributions	(72)	(32)	(14)
Other assets and liabilities	(142)	(128)	(99)
Net cash flows provided by operating activities	407	651	373
Cash flows from investing activities			
Capital expenditures	(628)	(586)	(544)
Proceeds from sale of long-lived assets	1	12	54
Purchases of investments	—	(30)	—
Changes in restricted cash	(2)	(31)	3
Other investing activities	(1)	(12)	10
Net cash flows used in investing activities	(630)	(647)	(477)
Cash flows from financing activities			
Changes in short-term borrowings	3	(41)	(40)
Issuance of long-term debt	202	4	208
Retirement of long-term debt	(13)	(11)	(22)
Dividends paid on common stock	(133)	(136)	(146)
Contributions from parent	161	187	112
Other financing activities	(1)	(3)	(9)
Net cash flows provided by financing activities	219	—	103
(Decrease) Increase in cash and cash equivalents	(4)	4	(1)
Cash and cash equivalents at beginning of period	9	5	6
Cash and cash equivalents at end of period	$ 5	$ 9	$ 5

See the Combined Notes to Consolidated Financial Statements

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Potomac Electric Power Company
Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 5	$ 9
Restricted cash and cash equivalents	35	33
Accounts receivable, net		
Customer	250	235
Other	87	150
Inventories, net	87	63
Regulatory assets	213	162
Other	33	32
Total current assets	710	684
Property, plant and equipment, net	6,001	5,571
Deferred debits and other assets		
Regulatory assets	678	690
Investments	102	102
Prepaid pension asset	322	282
Other	19	6
Total deferred debits and other assets	1,121	1,080
Total assets	$ 7,832	$ 7,335

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 26	$ 23
Long-term debt due within one year	19	16
Accounts payable	139	209
Accrued expenses	137	113
Payables to affiliates	74	74
Customer deposits	54	53
Regulatory liabilities	3	11
Merger related obligation	42	68
Current portion of DC PLUG obligation	28	—
Other	28	29
Total current liabilities	550	596
Long-term debt	2,521	2,333
Deferred credits and other liabilities		
Regulatory liabilities	829	20
Deferred income taxes and unamortized investment tax credits	1,063	1,910
Non-pension postretirement benefit obligations	36	43
Other	300	133
Total deferred credits and other liabilities	2,228	2,106
Total liabilities	5,299	5,035
Commitments and contingencies		
Shareholder's equity		
Common stock	1,470	1,309
Retained earnings	1,063	991
Total shareholder's equity	2,533	2,300
Total liabilities and shareholder's equity	$ 7,832	$ 7,335

See the Combined Notes to Consolidated Financial Statements

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Potomac Electric Power Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2014	$ 1,010	$ 1,077	$ 2,087
Net income	—	187	187
Common stock dividends	—	(146)	(146)
Contribution from Parent	112	—	112
Balance, December 31, 2015	$ 1,122	$ 1,118	$ 2,240
Net income	—	42	42
Common stock dividends	—	(169)	(169)
Contribution from Parent	187	—	187
Balance, December 31, 2016	$ 1,309	$ 991	$ 2,300
Net income	—	205	205
Common stock dividends	—	(133)	(133)
Contribution from Parent	161	—	161
Balance, December 31, 2017	$ 1,470	$ 1,063	$ 2,533

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Statements of Operations and Comprehensive Income (Loss)

(In millions)	For the Years Ended December 31, 2017	2016	2015
Operating revenues			
Electric operating revenues	$ 1,131	$ 1,122	$ 1,132
Natural gas operating revenues	161	148	164
Operating revenues from affiliates	8	7	6
Total operating revenues	1,300	1,277	1,302
Operating expenses			
Purchased power	282	369	555
Purchased fuel	71	60	79
Purchased power from affiliate	179	154	—
Operating and maintenance	283	422	303
Operating and maintenance from affiliates	32	19	1
Depreciation and amortization	167	157	148
Taxes other than income	57	55	51
Total operating expenses	1,071	1,236	1,137
Gain on sales of assets	—	9	—
Operating income	229	50	165
Other income and (deductions)			
Interest expense, net	(51)	(50)	(50)
Other, net	14	13	10
Total other income and (deductions)	(37)	(37)	(40)
Income before income taxes	192	13	125
Income taxes	71	22	49
Net income (loss)	$ 121	$ (9)	$ 76
Comprehensive income (loss)	$ 121	$ (9)	$ 76

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2017	2016	2015
Cash flows from operating activities			
Net income (loss)	$ 121	$ (9)	$ 76
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation and amortization	167	157	148
Impairment losses on regulatory assets	6	—	—
Deferred income taxes and amortization of investment tax credits	89	109	73
Other non-cash operating activities	9	114	33
Changes in assets and liabilities:			
Accounts receivable	(22)	(5)	(24)
Receivables from and payables to affiliates, net	11	13	3
Inventories	(5)	—	6
Accounts payable and accrued expenses	(8)	(4)	(8)
Collateral (posted) received, net	—	1	(1)
Income taxes	26	28	(26)
Pension and non-pension postretirement benefit contributions	(2)	(22)	—
Other assets and liabilities	(71)	(72)	(14)
Net cash flows provided by operating activities	321	310	266
Cash flows from investing activities			
Capital expenditures	(428)	(349)	(352)
Proceeds from sales of long-lived assets	—	9	—
Change in restricted cash	—	—	5
Other investing activities	(1)	4	2
Net cash flows used in investing activities	(429)	(336)	(345)
Cash flows from financing activities			
Change in short-term borrowings	216	(105)	(1)
Issuance of long-term debt	—	175	200
Retirement of long-term debt	(40)	(100)	(100)
Dividends paid on common stock	(112)	(54)	(92)
Contributions from parent	—	152	75
Other financing activities	—	(1)	(2)
Net cash flows provided by financing activities	64	67	80
(Decrease) Increase in cash and cash equivalents	(44)	41	1
Cash and cash equivalents at beginning of period	46	5	4
Cash and cash equivalents at end of period	$ 2	$ 46	$ 5

See the Combined Notes to Consolidated Financial Statements

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Delmarva Power & Light Company
Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 2	$ 46
Accounts receivable, net		
Customer	146	136
Other	38	63
Receivables from affiliates	—	3
Inventories, net		
Gas held in storage	7	7
Materials and supplies	36	32
Regulatory assets	69	59
Other	27	24
Total current assets	325	370
Property, plant and equipment, net	3,579	3,273
Deferred debits and other assets		
Regulatory assets	245	289
Goodwill	8	8
Prepaid pension asset	193	206
Other	7	7
Total deferred debits and other assets	453	510
Total assets	$ 4,357	$ 4,153

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 216	$ —
Long-term debt due within one year	83	119
Accounts payable	82	88
Accrued expenses	35	36
Payables to affiliates	46	38
Customer deposits	35	36
Regulatory liabilities	42	43
Merger related obligation	—	13
Other	8	8
Total current liabilities	547	381
Long-term debt	1,217	1,221
Deferred credits and other liabilities		
Regulatory liabilities	593	97
Deferred income taxes and unamortized investment tax credits	603	1,056
Non-pension postretirement benefit obligations	14	19
Other	48	53
Total deferred credits and other liabilities	1,258	1,225
Total liabilities	3,022	2,827
Commitments and contingencies		
Shareholder's equity		
Common stock	764	764
Retained earnings	571	562
Total shareholder's equity	1,335	1,326
Total liabilities and shareholder's equity	$ 4,357	$ 4,153

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2014	$ 537	$ 641	$ 1,178
Net income	—	76	76
Common stock dividends	—	(92)	(92)
Contribution from parent	75	—	75
Balance, December 31, 2015	$ 612	$ 625	$ 1,237
Net loss	—	(9)	(9)
Common stock dividends	—	(54)	(54)
Contribution from parent	152	—	152
Balance, December 31, 2016	$ 764	$ 562	$ 1,326
Net income	—	121	121
Common stock dividends	—	(112)	(112)
Balance, December 31, 2017	$ 764	$ 571	$ 1,335

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Operations and Comprehensive Income (Loss)

(In millions)	For the Years Ended December 31, 2017	2016	2015
Operating revenues			
Electric operating revenues	$ 1,184	$ 1,254	$ 1,291
Operating revenues from affiliates	2	3	4
Total operating revenues	1,186	1,257	1,295
Operating expenses			
Purchased power	541	614	708
Purchased power from affiliates	29	37	—
Operating and maintenance	279	410	268
Operating and maintenance from affiliates	28	18	3
Depreciation and amortization	146	165	175
Taxes other than income	6	7	7
Total operating expenses	1,029	1,251	1,161
Gain on sale of assets	—	1	—
Operating income	157	7	134
Other income and (deductions)			
Interest expense, net	(61)	(62)	(64)
Other, net	7	9	3
Total other income and (deductions)	(54)	(53)	(61)
Income (loss) before income taxes	103	(46)	73
Income taxes	26	(4)	33
Net income (loss)	$ 77	$ (42)	$ 40
Comprehensive income (loss)	$ 77	$ (42)	$ 40

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2017	2016	2015
Cash flows from operating activities			
Net income (loss)	$ 77	$ (42)	$ 40
Adjustments to reconcile net income (loss) to net cash from operating activities:			
Depreciation and amortization	146	165	175
Impairment losses on regulatory assets	7	—	—
Deferred income taxes and amortization of investment tax credits	32	22	31
Other non-cash operating activities	17	155	37
Changes in assets and liabilities:			
Accounts receivable	14	(8)	(67)
Receivables from and payables to affiliates, net	—	13	1
Inventories	(7)	(1)	(1)
Accounts payable and accrued expenses	(2)	9	9
Income taxes	(11)	174	(34)
Pension and non-pension postretirement benefit contributions	(20)	(17)	(2)
Other assets and liabilities	(47)	(85)	67
Net cash flows provided by operating activities	206	385	256
Cash flows from investing activities			
Capital expenditures	(312)	(311)	(300)
Proceeds from sale of long-lived assets	—	2	—
Changes in restricted cash	3	(2)	(6)
Other investing activities	(1)	2	—
Net cash flows used in investing activities	(310)	(309)	(306)
Cash flows from financing activities			
Change in short-term borrowings	108	(5)	(122)
Issuance of long-term debt	—	—	150
Retirement of long-term debt	(35)	(48)	(58)
Dividends paid on common stock	(68)	(63)	(12)
Contributions from parent	—	139	95
Other financing activities	—	(1)	(2)
Net cash flows provided by financing activities	5	22	51
(Decrease) Increase in cash and cash equivalents	(99)	98	1
Cash and cash equivalents at beginning of period	101	3	2
Cash and cash equivalents at end of period	$ 2	$ 101	$ 3

See the Combined Notes to Consolidated Financial Statements

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Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 2	$ 101
Restricted cash and cash equivalents	6	9
Accounts receivable, net		
Customer	92	125
Other	56	44
Inventories, net	29	22
Regulatory assets	71	96
Other	2	2
Total current assets	258	399
Property, plant and equipment, net	2,706	2,521
Deferred debits and other assets		
Regulatory assets	359	405
Long-term note receivable	4	4
Prepaid pension asset	73	84
Other	45	44
Total deferred debits and other assets	481	537
Total assets [(a)]	$ 3,445	$ 3,457

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 108	$ —
Long-term debt due within one year	281	35
Accounts payable	118	132
Accrued expenses	33	38
Payables to affiliates	29	29
Customer deposits	31	33
Regulatory liabilities	11	25
Merger related obligation	—	20
Other	8	8
Total current liabilities	619	320
Long-term debt	840	1,120
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	493	917
Non-pension postretirement benefit obligations	14	34
Regulatory liabilities	411	—
Other	25	32
Total deferred credits and other liabilities	943	983
Total liabilities [(a)]	2,402	2,423
Commitments and contingencies		
Shareholder's equity		
Common stock	912	912
Retained earnings	131	122
Total shareholder's equity	1,043	1,034
Total liabilities and shareholder's equity	$ 3,445	$ 3,457

(a) ACE's consolidated assets include $29 million and $32 million at December 31, 2017 and 2016 , respectively, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE's consolidated liabilities include $90 million and $126 million at December 31, 2017 and 2016 , respectively, of ACE's consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 2 - Variable Interest Entities .

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2014	$ 678	$ 199	$ 877
Net income	—	40	40
Common stock dividends	—	(12)	(12)
Contribution from parent	95	—	95
Balance, December 31, 2015	$ 773	$ 227	$ 1,000
Net loss	—	(42)	(42)
Common stock dividends	—	(63)	(63)
Contribution from parent	139	—	139
Balance, December 31, 2016	$ 912	$ 122	$ 1,034
Net income	—	77	77
Common stock dividends	—	(68)	(68)
Balance, December 31, 2017	$ 912	$ 131	$ 1,043

See the Combined Notes to Consolidated Financial Statements

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)

Index to Combined Notes to Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the Registrants to which the footnotes apply:

Applicable Notes

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Exelon Corporation	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
Exelon Generation Company, LLC	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		.		.	.	.	.	.	.	.
Commonwealth Edison Company	.	.	.		.	.				.	.	.	.	.	.	.	.		.	.			.	.	.	.	.	.
PECO Energy Company	.	.	.		.	.			.	.	.	.	.	.	.	.	.		.	.		.	.	.	.	.	.	
Baltimore Gas and Electric Company	.	.	.		.	.			.		.	.	.	.	.	.	.		.	.			.	.	.	.	.	
Pepco Holdings LLC	.	.	.	.	.	.	.		.	.	.	.	.	.	.	.	.	.		.		.	.	.	.	.	.	
Potomac Electric Power Company	.	.	.	.	.	.			.	.	.	.	.	.	.	.	.		.	.			.	.	.	.	.	
Delmarva Power & Light Company	.	.	.	.	.	.			.	.	.	.	.	.	.	.	.		.	.			.	.	.	.	.	
Atlantic City Electric Company	.	.	.		.	.			.	.	.	.	.	.	.	.	.		.	.			.	.	.	.	.	

1 . Significant Accounting Policies (All Registrants)

Description of Business (All Registrants)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution and transmission businesses. Prior to March 23, 2016 , Exelon's principal, wholly owned subsidiaries included Generation, ComEd, PECO and BGE. On March 23, 2016 , in conjunction with the Amended and Restated Agreement and Plan of Merger (the PHI Merger Agreement), Purple Acquisition Corp, a wholly owned subsidiary of Exelon, merged with and into PHI, with PHI continuing as the surviving entity as a wholly owned subsidiary of Exelon. PHI is a utility services holding company engaged through its principal wholly owned subsidiaries, Pepco, DPL and ACE, in the energy distribution and transmission businesses. Refer to Note 4 — Mergers, Acquisitions and Dispositions for further information regarding the merger transaction.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Name of Registrant	Business	Service Territories
Exelon Generation Company, LLC	Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. Generation also sells natural gas, renewable energy and other energy-related products and services.	Six reportable segments: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions
Commonwealth Edison Company	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	Northern Illinois, including the City of Chicago
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Southeastern Pennsylvania, including the City of Philadelphia (electricity) Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Central Maryland, including the City of Baltimore (electricity and natural gas)
Pepco Holdings LLC	Utility services holding company engaged, through its reportable segments Pepco, DPL and ACE	Service Territories of Pepco, DPL and ACE
Potomac Electric Power Company	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	District of Columbia, and major portions of Montgomery and Prince George's Counties, Maryland.
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of Delaware and Maryland (electricity) Portions of New Castle County, Delaware (natural gas)
Atlantic City Electric Company	Purchase and regulated retail sale of electricity Transmission and distribution of electricity to retail customers	Portions of Southern New Jersey

Basis of Presentation (All Registrants)

This is a combined annual report of all Registrants. The Notes to the Consolidated Financial Statements apply to the Registrants as indicated above in the Index to Combined Notes to Consolidated Financial Statements and parenthetically next to each corresponding disclosure. When appropriate, the Registrants are named specifically for their related activities and disclosures. Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

As a result of the acquisition of PHI, Exelon's financial reporting reflects PHI's consolidated financial results subsequent to the March 23, 2016 , acquisition date. Exelon has accounted for the merger transaction applying the acquisition method of accounting, which requires the assets acquired and liabilities assumed by Exelon to be reported in Exelon's financial statements at fair value, with any excess of the purchase price over the fair value of net assets acquired reported as goodwill. Exelon has pushed-down the application of the acquisition method of accounting to the consolidated financial statements of PHI such that the assets and liabilities of PHI are similarly recorded at their respective fair values, and goodwill has been established as of the acquisition date. Accordingly, the consolidated financial statements of PHI for periods before and after the March 23, 2016 , acquisition date reflect different bases of accounting, and the results of operations and the financial positions of the predecessor and successor periods are not comparable. The acquisition method of accounting has not been pushed down to PHI's wholly owned subsidiary utility registrants, Pepco, DPL and ACE.

For financial statement purposes, beginning on March 24, 2016 , disclosures related to Exelon now also apply to PHI, Pepco, DPL and ACE, unless otherwise noted.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC, including support services, are directly charged or allocated to the applicable subsidiaries using a cost-causative allocation method. Corporate governance-type costs that cannot be directly assigned are allocated based on a Modified Massachusetts Formula, which is a method that utilizes a combination of gross revenues, total assets and direct labor costs for the allocation base. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

PHISCO, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHISCO and the participating operating subsidiaries.

Exelon owns 100% of its significant consolidated subsidiaries, including PHI, either directly or indirectly, except for ComEd, of which Exelon owns more than 99% . As of December 31, 2017 , Exelon owned none of BGE's preferred securities, which BGE redeemed in 2016. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2017 and December 31, 2016 , as equity, in its consolidated financial statements. BGE is subject to certain ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters. PHI is subject to some ring-fencing measures established by orders of the DCPSC, DPSC, MDPSC and NJBPU, pursuant to which all of the membership interest in PHI is held directly by PH Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (PH Utility), Inc., an unrelated party, holds a nominal non-economic interest in PH Holdco LLC with limited voting rights on specified matters. PHI owns 100% of its subsidiaries including Pepco, DPL and ACE.

Generation owns 100% of its significant consolidated subsidiaries, either directly or indirectly, except for certain consolidated VIEs, including CENG and ExGen Renewables Partners, LLC, of which Generation holds a 50.01% and 51% interest, respectively. The remaining interests in these consolidated VIEs are included in noncontrolling interests on Exelon's and Generation's Consolidated Balance Sheets. See Note 2 — Variable Interest Entities for further discussion of Exelon's and Generation's consolidated VIEs.

The Registrants consolidate the accounts of entities in which a Registrant has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which the Registrant can exercise control over the operations and policies of the investee, or the results of a model that identifies the Registrant or one of its subsidiaries as the primary beneficiary of a VIE. Where the Registrants do not have a controlling financial interest in an entity, proportionate consolidation, equity method accounting or cost method accounting is applied. The Registrants apply proportionate consolidation when they have an undivided interest in an asset and are proportionately liable for their share of each liability associated with the asset. The Registrants proportionately consolidate their undivided ownership interests in jointly owned electric plants and transmission facilities. Under proportionate consolidation, the Registrants separately record their proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. The Registrants apply equity method accounting when they have significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. The Registrants apply equity method accounting to certain investments and joint ventures, including certain financing trusts of ComEd, PECO and BGE. Under equity method accounting, the Registrants report their interest in the entity as an investment and the Registrants' percentage share of the earnings from the entity as single line items in their financial statements. The Registrants use cost

method accounting if they lack significant influence, which generally results when they hold less than 20% of the common stock of an entity. Under cost method accounting, the Registrants report their investments at cost and recognize income only to the extent dividends or distributions are received.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (All Registrants)

The preparation of financial statements of each of the Registrants in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other AROs, pension and other postretirement benefits, the application of purchase accounting, inventory reserves, allowance for uncollectible accounts, goodwill and asset impairments, derivative instruments, unamortized energy contracts, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Reclassifications (All Registrants)

Certain prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows, Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholders' Equity have been reclassified between line items for comparative purposes. The reclassifications did not affect any of the Registrants' net income, cash flows from operating activities or financial positions.

Accounting for the Effects of Regulation (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

The Registrants apply the authoritative guidance for accounting for certain types of regulation, which requires them to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria: 1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. Exelon and the Utility Registrants account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU, under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the Consolidated Statements of Operations consistent with the recovery or refund included in customer rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. Exelon and the Utility Registrants continue to evaluate their respective abilities to continue to apply the authoritative guidance for accounting for certain types of regulation, including consideration of current events in their respective regulatory and political environments. If a separable portion of the Registrants' business was no longer able to meet the criteria discussed above, the affected entities would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which could have a material impact on their results of operations and financial positions. See Note 3 — Regulatory Matters for additional information.

With the exception of income tax-related regulatory assets and liabilities, the Registrants classify regulatory assets and liabilities with a recovery or settlement period greater than one year as both current and non-current in their Consolidated Balance Sheets, with the current portion representing the amount expected to be recovered from or settled to customers over the next twelve-month period as of the balance sheet date. Income tax-related regulatory assets and liabilities are classified entirely as non-

current on the Registrants' Consolidated Balance Sheets to align with the classification of the related deferred income tax balances.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Revenues (All Registrants)

Operating Revenues

Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimate of its electric distribution, energy efficiency and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. PECO, BGE, Pepco, DPL and ACE record their best estimate of the transmission revenue impacts resulting from changes in rates that they each believe are probable of approval by FERC in accordance with their formula rate mechanisms. See Note 3 — Regulatory Matters and Note 5 — Accounts Receivable for further information.

RTOs and ISOs

In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations and Comprehensive Income, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of Exelon in the different RTOs and ISOs.

Option Contracts, Swaps and Commodity Derivatives

Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. To the extent a Utility Registrant receives full cost recovery for energy procurement and related costs from retail customers, it records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. Refer to Note 3 — Regulatory Matters and Note 12 — Derivative Financial Instruments for further information.

Income Taxes (All Registrants)

Deferred Federal and state income taxes are recorded on significant temporary differences between the book and tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred on the Registrants' Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion; and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Registrants recognize accrued interest related to unrecognized tax benefits in Interest expense or Other income and

deductions (interest income) and recognize penalties related to unrecognized tax benefits in Other, net on their Consolidated Statements of Operations and Comprehensive Income.

In the first quarter of 2016, PHI, Pepco, DPL and ACE changed their accounting for classification of interest on uncertain tax positions. PHI, Pepco, DPL and ACE have reclassified interest on uncertain tax positions as Interest expense from Income tax expense in the Consolidated Statements of Operations and Comprehensive Income. GAAP does not address the preferability of one acceptable method of accounting over the other for the classification of interest on uncertain tax positions. However, PHI, Pepco, DPL and ACE believe this change is preferable for comparability of their financial statements with the financial statements of the other Registrants in the combined filing, for consistency with FERC classification and for a more appropriate representation of the effective tax rate as they manage the settlement of uncertain tax positions and interest expense separately. PHI, Pepco, DPL and ACE applied the change retrospectively. The reclassification in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2015 was $34 million and $4 million for PHI and Pepco, respectively. The impact on all other PHI Registrants for the year ended December 31, 2015 was less than $1 million .

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 14 — Income Taxes for further information.

Taxes Directly Imposed on Revenue-Producing Transactions (All Registrants)

The Registrants collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, such as gross receipts taxes or other surcharges or fees, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 24 — Supplemental Financial Information for Generation’s, ComEd’s, PECO’s, BGE’s, Pepco's, DPL's and ACE’s utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (All Registrants)

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents (All Registrants)

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2017 and 2016 , Exelon Corporate’s restricted cash and cash equivalents primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Generation’s restricted cash and cash equivalents primarily included cash at various project-specific nonrecourse financing structures for debt service and financing of operations of the underlying entities, see Note 13 — Debt and Credit Agreements for additional information on Generation’s project- specific financing structures. ComEd’s restricted cash primarily represented cash collateral held from suppliers associated with ComEd’s energy and REC procurement contracts, any over-recovered RPS costs and alternative compliance payments received from RES pursuant to FEJA and certain funds set aside for the remediation of one of ComEd's MGP sites. PECO’s restricted cash primarily represented funds from the sales of assets that were subject to PECO’s mortgage indenture. BGE’s restricted cash primarily represented funds restricted for certain energy conservation incentive programs. PHI Corporate's restricted cash and cash equivalents primarily represented funds restricted for the payment

of merger commitments and cash collateral held from its utility suppliers. Pepco's restricted cash and cash equivalents primarily represented funds restricted for the payment of merger commitments and collateral held from its utility suppliers. DPL's restricted cash and cash equivalents primarily represented cash collateral held from suppliers associated with procurement contracts. ACE's restricted cash and cash equivalents primarily represented funds restricted at its consolidated variable interest entity for repayment of transition bonds and cash collateral held from suppliers.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets.

Allowance for Uncollectible Accounts (All Registrants)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the customers' accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd, PECO, BGE, Pepco, DPL and ACE estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. Risk segments represent a group of customers with similar credit quality indicators that are comprised based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on a historical average of charge-offs as a percentage of accounts receivable in each risk segment. Utility Registrants' customer accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. Utility Registrants' customer accounts are written off consistent with approved regulatory requirements. Utility Registrants' allowances for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU regulations. See Note 3 — Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd and ACE.

Variable Interest Entities (All Registrants)

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity has a controlling financial interest, meaning (1) has the power to direct the activities that most significantly impact the VIE's economic performance, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and
- requires the entity that consolidates a VIE (the primary beneficiary) to disclose (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

See Note 2 — Variable Interest Entities for additional information.

Inventories (All Registrants)

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory.

Fossil Fuel

Fossil fuel inventory includes natural gas held in storage, propane and oil. The costs of natural gas, propane and oil are generally included in inventory when purchased and charged to purchased power and fuel expense at weighted average cost when used or sold.

Materials and Supplies

Materials and supplies inventory generally includes transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and expensed or capitalized to property, plant and equipment, as appropriate, at weighted average cost when installed or used.

Emission Allowances

Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) and charged to purchased power and fuel expense at weighted average cost as they are used in operations.

Marketable Securities (All Registrants)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds are classified as trading securities, and all other securities are classified as available-for-sale securities. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the Regulatory Agreement Units are included in regulatory liabilities at Exelon, ComEd and PECO and in Noncurrent payables to affiliates at Generation and in Noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the Non-Regulatory Agreement Units are included in earnings at Exelon and Generation. Unrealized gains and losses, net of tax, for Exelon's available-for-sale securities are reported in OCI. Exelon's and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, are classified as either noncurrent or current assets, depending on the timing of the decommissioning activities and income taxes on trust earnings. Beginning January 1, 2018, the authoritative guidance eliminates the available-for-sale classification for equity securities and requires that all equity investments (other than those accounted for using the equity method of accounting) be measured and recorded at fair value with any changes in fair value recorded through earnings. The new authoritative guidance does not impact the classification or measurement of investments in debt securities. See Note 3 — Regulatory Matters for additional information regarding ComEd's and PECO's regulatory assets and liabilities and Note 11 — Fair Value of Financial Assets and Liabilities and Note 15 — Asset Retirement Obligations for information regarding marketable securities held by NDT funds.

Property, Plant and Equipment (All Registrants)

Property, plant and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. The Utility Registrants also include indirect construction costs including labor and related costs of departments associated with supporting construction activities. When appropriate, original cost also includes capitalized interest for Generation, Exelon Corporate and PHI and AFUDC for regulated property at ComEd, PECO, BGE, Pepco, DPL and ACE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to Operating and maintenance expense as incurred.

Third parties reimburse the Utility Registrants for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, plant and equipment. DOE SGIG and other funds reimbursed to the Utility Registrants have been accounted for as CIAC.

For Generation, upon retirement, the cost of property is generally charged to accumulated depreciation in accordance with the composite and group methods of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to Operating and maintenance expense as incurred.

For the Utility Registrants, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation consistent with the composite and group methods of depreciation. Depreciation expense at ComEd, BGE, Pepco, DPL and ACE includes the estimated cost of dismantling and removing plant from service upon retirement. Actual incurred removal costs are applied against a related regulatory liability or recorded to a regulatory asset if in excess of previously collected removal costs. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method.

See Note 6 — Property, Plant and Equipment , Note 9 — Jointly Owned Electric Utility Plant and Note 24 — Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within Property, plant and equipment and charged to fuel expense using the unit-of-production method. Prior to May 16, 2014, the estimated disposal cost of SNF was established per the Standard Waste Contract with the DOE and was expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. Effective May 16, 2014, the SNF disposal fee was set to zero by the DOE and Exelon and Generation are not accruing any further costs related to SNF disposal fees until a new fee structure goes into effect. Certain on-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 23 — Commitments and Contingencies for additional information regarding the SNF disposal fee.

Nuclear Outage Costs (Exelon and Generation)

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to Operating and maintenance expense or capitalized to Property, plant and equipment (based on the nature of the activities) in the period incurred.

New Site Development Costs (Exelon and Generation)

New site development costs represent the costs incurred in the assessment and design of new power generating facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management's determination that the project is economically and operationally feasible, management and/or the Exelon Board of Directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. As of December 31, 2017 and 2016 , Generation has capitalized $228 million and $1.7 billion , respectively, to Property, plant and equipment, net on its Consolidated Balance Sheets. Capitalized development costs are charged to Operating and maintenance expense when project completion is no longer probable. New site development costs incurred prior to a project's completion being deemed probable are expensed as incurred. Approximately $4 million , $30 million and $22 million of costs were expensed by Exelon and Generation for the years ended December 31, 2017 , 2016 and 2015 , respectively. These costs are primarily related to the possible development of new power generating facilities with the exception of

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approximately $13 million of costs expensed in 2016 which relate to projects for which completion is no longer probable.

Capitalized Software Costs (All Registrants)

Costs incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized within Property, plant and equipment. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

						Successor			
Net unamortized software costs	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
December 31, 2017	$ 834	$ 173	$ 227	$ 111	$ 179	$ 133	$ 2	$ 1	$ 1
December 31, 2016	808	173	213	91	164	153	1	1	1

Amortization of capitalized software costs	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**
2017	$ 270	$ 73	$ 73	$ 39	$ 46	$ —	$ —	$ —
2016	255	72	62	33	44	—	—	—
2015	208	73	47	33	46	(2)	—	—

	Successor		*Predecessor*	
PHI	**For the Year Ended December 31, 2017**	**March 24, 2016 to December 31, 2016**	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**
Amortization of capitalized software costs	$ 34	$ 29	$ 8	$ 36

Depreciation and Amortization (All Registrants)

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the group, composite or unitary methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for dissimilar assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. The Utility Registrants' depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. The estimated service lives for the Utility Registrants are primarily based on each company's most recent depreciation studies of historical asset retirement and removal cost experience. At Generation, along with depreciation study results, management considers expected future energy market conditions and generation plant operating costs and capital investment requirements in determining the estimated service lives of its generating facilities. For its nuclear generating facilities, except for Oyster Creek, Clinton and TMI, Generation estimates each unit will operate through the full term of its initial 20-year operating license renewal period. See Note 8 — Early Nuclear Plant Retirements for additional information on the impacts of expected and potential early plant retirements . The estimated service lives of Generation's hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of 40 years.

See Note 6 — Property, Plant and Equipment for further information regarding depreciation.

Amortization of regulatory assets and liabilities are recorded over the recovery or refund period specified in the related legislation or regulatory order or agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost or income would have originally been recorded in the Registrants' Consolidated Statements of Operations and Comprehensive Income. Amortization of ComEd's electric distribution and energy efficiency formula rate regulatory assets and ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's transmission formula rate regulatory assets is recorded to Operating revenues.

Amortization of income tax related regulatory assets and liabilities are generally recorded to Income tax expense. With the exception of the regulatory assets and liabilities discussed above, when the recovery period is more than one year, the amortization is generally recorded to Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

See Note 3 — Regulatory Matters and Note 24 — Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of the Utility Registrants' regulatory assets.

Asset Retirement Obligations (All Registrants)

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic future cash flow models and discount rates. Generation generally updates its ARO annually, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various decommissioning scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years unless circumstances warrant more frequent updates (such as a change in assumed operating life for a nuclear plant). As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle. The liabilities associated with Exelon's non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years unless circumstances warrant more frequent updates. Changes to the recorded value of an ARO result from the passage of new laws and regulations, revisions to either the timing or amount of estimated undiscounted cash flows, and estimates of cost escalation factors. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through a charge to Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income or, in the case of the Utility Registrants' accretion, through an increase to regulatory assets. See Note 15 — Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (All Registrants)

During construction, Exelon and Generation capitalize the costs of debt funds used to finance non-regulated construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense.

Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to AFUDC that is included

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in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

The following table summarizes total incurred interest, capitalized interest and credits to AFUDC by year:

		Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
2017	Total incurred interest [a]	$ 1,658	$ 502	$ 369	$ 130	$ 111	$ 133	$ 54	$ 64
	Capitalized interest	63	63	—	—	—	—	—	—
	Credits to AFUDC debt and equity	108	—	20	12	22	34	10	9
2016	Total incurred interest [a]	$ 1,678	$ 472	$ 469	$ 127	$ 114	$ 137	$ 52	$ 65
	Capitalized interest	108	107	—	—	—	—	—	—
	Credits to AFUDC debt and equity	98	—	22	11	30	29	7	9
2015	Total incurred interest [a]	$ 1,170	$ 445	$ 336	$ 116	$ 113	$ 131	$ 51	$ 65
	Capitalized interest	79	79	—	—	—	—	—	—
	Credits to AFUDC debt and equity	44	—	9	7	28	19	2	2

	Successor		*Predecessor*	
PHI	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
Total incurred interest [a]	$ 263	$ 207	$ 68	$ 289
Credits to AFUDC debt and equity	54	35	10	23

(a) Includes interest expense to affiliates.

Guarantees (All Registrants)

The Registrants recognize, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken by issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 23 — Commitments and Contingencies for additional information.

Asset Impairments (All Registrants)

Long-Lived Assets

The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. The Registrants determine if long-lived

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assets and asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value.

Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generating units are generally evaluated at a regional portfolio level along with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables). See Note 7 — Impairment of Long-Lived Assets and Intangibles for additional information.

Goodwill

Goodwill represents the excess of the purchase price paid over the estimated fair value of the net assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or in an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 10 — Intangible Assets for additional information regarding Exelon's, Generation's, ComEd's, PHI's and DPL's goodwill.

Equity Method Investments

Exelon and Generation regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature. Additionally, if the entity in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other-than-temporary decline in value.

Debt and Equity Security Investments

Declines in the fair value of Exelon's debt and equity investments below the cost basis are reviewed to determine if such decline is other-than-temporary. For available-for-sale securities and cost investments, if the decline is determined to be other-than-temporary, the cost basis is written down to fair value as a new cost basis. For equity securities and cost investments, the amount of the impairment loss is included in earnings. For debt securities, the amount of the impairment loss is included in earnings or separated between earnings and OCI depending on whether Exelon intends to sell the debt securities before recovery of its cost basis. Beginning January 1, 2018, the authoritative guidance eliminates the available-for-sale and cost method classifications for equity securities and requires that all equity investments (other than those accounted for using the equity method of accounting) be measured and recorded at fair value with any changes in fair value recorded through earnings. Investments in equity securities without readily determinable fair values must be qualitatively assessed for impairment each reporting period and fair value determined if any significant impairment indicators exist. If fair value is less than carrying value, the impairment is recorded through earnings immediately in the period in which it is identified without regard to whether the decline in value is temporary in nature. The new authoritative guidance does not impact the classification or measurement of investments in debt securities.

Derivative Financial Instruments (All Registrants)

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a

recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For derivative contracts intended to serve as economic hedges and that are not designated or do not qualify for hedge accounting or the normal purchases and normal sales exception, changes in the fair value of the derivatives are recognized in earnings each period, except for the Utility Registrants where changes in fair value may be recorded as a regulatory asset or liability if there is an ability to recover or return the associated costs. See Note 3 — Regulatory Matters and Note 12 — Derivative Financial Instruments for additional information. Amounts classified in earnings are included in revenue, purchased power and fuel, interest expense or other, net on the Consolidated Statements of Operations and Comprehensive Income based on the activity the transaction is economically hedging. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon's Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. All amounts classified in earnings related to proprietary trading are included in revenue on the Consolidated Statements of Operations and Comprehensive Income. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See Note 12 — Derivative Financial Instruments for additional information.

Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all employees.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and inputs and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the Consolidated Statements of Operations and Comprehensive Income. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 16 — Retirement Benefits for additional information.

Equity Investment Earnings (Losses) of Unconsolidated Affiliates (Exelon and Generation)

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities and power projects in Equity in earnings (losses) of unconsolidated affiliates within their Consolidated Statements of Operations and Comprehensive Income.

New Accounting Standards (All Registrants)

New Accounting Standards Issued and Adopted as of January 1, 2018: The following new authoritative accounting guidance issued by the FASB has been adopted as of January 1, 2018 and will be reflected by the Registrants in their consolidated financial statements beginning in the first quarter of 2018. Unless otherwise indicated, adoption of the new guidance in each instance will have no or insignificant impacts on the Registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows, Consolidated Balance Sheets and disclosures.

Revenue from Contracts with Customers (Issued May 2014 and subsequently amended to address implementation questions; Adopted January 1, 2018): Changes the criteria for recognizing revenue from a contract with a customer. The new revenue recognition guidance, including subsequent amendments, is effective for annual reporting periods beginning on or after December 15, 2017, with the option to early adopt the standard for annual periods beginning on or after December 15, 2016. The Registrants did not early adopt this standard.

The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five-step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries, and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants will apply the new guidance using the full retrospective method, which will not have a material impact on previously issued financial statements.

In coordination with the AICPA Power and Utilities Industry Task Force, the Registrants reached conclusions on the following key accounting issues:

- The Utility Registrants' tariff sale contracts, including those with lower credit quality customers, are generally deemed to be probable of collection under the guidance and, thus, the timing of revenue recognition will continue to be concurrent with the delivery of electricity or natural gas, consistent with current practice;
- Consistent with current industry practice, revenues recognized from sales of bundled energy commodities (i.e., contracts involving the delivery of multiple energy commodities such as electricity, capacity, ancillary services, etc.) are generally expected to be recognized upon delivery to the customer in an amount based on the invoice price given that it corresponds directly with the value of the commodities transferred to the customer; and
- Contributions in aid of construction are outside of the scope of the standard and, therefore, will continue to be accounted for as a reduction to Property, Plant, and Equipment.

In assessing the impacts of the new revenue guidance, the Registrants identified the following items that will be accounted for differently:

- Costs to acquire certain contracts (e.g., sales commissions associated with retail power contracts) will be deferred and amortized ratably over the term of the contract rather than being expensed as incurred; and

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- Variable consideration within certain contracts (e.g., performance bonuses) will be estimated and recognized as revenue over the term of the contract rather than being recognized when realized.

Based on an assessment of existing contracts and revenue streams, the new guidance, including the identified changes above, will not have a material impact on the amount and timing of the Registrants' revenue recognition.

One of the new disclosure requirements is to present disaggregated revenue into categories that show how economic factors affect the nature, amount, timing, and uncertainty of revenue and cash flows. In order to comply with this new disclosure requirement, Generation will disclose disaggregated revenue by operating segment and provide further differentiation by major products (i.e., electric power and gas) and the Utility Registrants will disclose disaggregated revenue by major customer class (i.e., residential and commercial and industrial) separately for electric and gas in the Combined Notes to Consolidated Financial Statements. In addition, pursuant to the requirements of the new standard, Exelon and the Utility Registrants will present alternative revenue program revenue separately from revenue from contracts with customers on the face of their Consolidated Statements of Operations and Comprehensive Income.

Recognition and Measurement of Financial Assets and Financial Liabilities (Issued January 2016; Adopted January 1, 2018): Eliminates the available-for-sale and cost method classification for equity securities and requires that all equity investments (other than those accounted for using the equity method of accounting) be measured and recorded at fair value with any changes in fair value recorded through earnings and, for equity investments without a readily determinable fair value, provides a measurement alternative of cost less impairment plus or minus adjustments for observable price changes in identical or similar assets. In addition, equity investments without readily determinable fair values must be qualitatively assessed for impairment each reporting period and fair value determined if any significant impairment indicators exist. If fair value is less than carrying value, the impairment is recorded through net income immediately in the period in which it is identified. The guidance does not impact the classification or measurement of investments in debt securities. The guidance also amends several disclosure requirements, including requiring i) financial assets and financial liabilities to be presented separately in the balance sheet or note, grouped by measurement category and form, ii) disclosure of the methods and significant assumptions used to estimate fair value or a description of the changes in the methods and assumptions used to estimate fair value, and iii) for financial assets and liabilities measured at amortized cost, disclosure of the fair value of the amount that would be received to sell the asset or paid to transfer the liability. The guidance is effective January 1, 2018 and must be applied using a modified retrospective transition approach with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption. The Registrants recorded an insignificant adjustment to opening retained earnings as of January 1, 2018 related to unrealized gains/losses on available for sale equity securities.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments (Issued August 2016; Adopted January 1, 2018) and Restricted Cash (Issued November 2016; Adopted January 1, 2018): In 2016, the FASB issued two standards impacting the Statement of Cash Flows. The first adds or clarifies guidance on the classification of certain cash receipts and payments on the statement of cash flows as follows: debt prepayment or extinguishment costs, settlement of zero-coupon bonds, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies and bank-owned life insurance policies, distributions received from equity method investees, beneficial interest in securitization transactions, and the application of the predominance principle to separately identifiable cash flows. The second states that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows (instead of being presented as

cash flow activities). The new standards are effective on January 1, 2018 and must be applied on a full retrospective basis. Adoption of the second standard will result in a change in presentation of restricted cash on the face of the Statement of Cash Flows; otherwise this guidance will not have a significant impact on the Registrants' Consolidated Statements of Cash Flows and disclosures.

Intra-Entity Transfers of Assets Other Than Inventory (Issued October 2016; Adopted January 1, 2018): Requires entities to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs (current GAAP prohibits the recognition of current and deferred income taxes for an intra-entity asset transfer until the asset has been sold to an outside party). The standard is effective January 1, 2018 with early adoption permitted. The guidance requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption.

Clarifying the Definition of a Business (Issued January 2017; Adopted January 1, 2018): Clarifies the definition of a business with the objective of addressing whether acquisitions (or dispositions) should be accounted for as acquisitions/dispositions of assets or as acquisitions/dispositions of businesses. If substantially all the fair value of the assets acquired/disposed of is concentrated in a single identifiable asset or a group of similar identifiable assets, the set of transferred assets and activities is not a business. If the fair value of the assets acquired/disposed of is not concentrated in a single identifiable asset or a group of similar identifiable assets, then an entity must evaluate whether an input and a substantive process exist, which together significantly contribute to the ability to produce outputs. The standard also revises the definition of outputs to focus on goods and services to customers. The standard will likely result in more acquisitions being accounted for as asset acquisitions. The standard is effective January 1, 2018, with early adoption permitted, and must be applied on a prospective basis. The Registrants did not early adopt the guidance.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (Issued March 2017; Adopted January 1, 2018): Changes the accounting and presentation of pension and OPEB costs at the plan sponsor (i.e., Exelon) level. The guidance requires plan sponsors to report the service cost and other non-service cost components of net periodic pension cost and net periodic OPEB cost (together, net benefit cost) separately. Under the new guidance, service cost is presented as part of income from operations and the other non-service cost components are classified outside of income from operations on the Consolidated Statements of Operations and Comprehensive Income. Additionally, service cost is the only component eligible for capitalization. Under prior GAAP, the total amount of net benefit cost was recorded as part of income from operations and all components were eligible for capitalization.

Generation, ComEd, PECO, BGE, BSC, PHI, Pepco, DPL, ACE and PHISCO participate in Exelon's single employer pension and OPEB plans and apply multi-employer accounting. Multi-employer accounting is not impacted by this standard; therefore, Exelon's subsidiary financial statements will not change upon its adoption. On Exelon's consolidated financial statements, non-service cost components of pension and OPEB cost capitalizable under a regulatory framework are prospectively reported as regulatory assets (currently, they are capitalizable under pension and OPEB accounting guidance and reported as PP&E). These regulatory assets are amortized outside of operating income.

The presentation of the service cost component and the other non-service cost components of net benefit cost will be applied retrospectively in the Exelon consolidated financial statements beginning in the first quarter of 2018. On Exelon's consolidated financial statements, service cost will continue to be reported in Operating and maintenance and Non-service cost will be reported outside of operating income. The prospective change in the capitalization eligibility is not expected to have a significant impact on Exelon's consolidated net income.

New Accounting Standards Issued and Not Yet Adopted as of December 31, 2017 : The following new authoritative accounting guidance issued by the FASB has not yet been adopted and

reflected by the Registrants in their consolidated financial statements as of December 31, 2017. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures, as well as the potential to early adopt where applicable. The Registrants have assessed other FASB issuances of new standards which are not listed below given the current expectation such standards will not significantly impact the Registrants' financial reporting.

Leases (Issued February 2016): Increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The standard is effective January 1, 2019. Early adoption is permitted, however the Registrants will not early adopt the standard. The issued guidance required a modified retrospective transition approach, which requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented (January 1, 2017). In January 2018, the FASB proposed amending the standard to give entities another option for transition. The proposed transition method would allow entities to initially apply the requirements of the standard in the period of adoption (January 1, 2019). The Registrants will assess this transition option when the FASB issues the standard.

The new guidance requires lessees to recognize both the right-of-use assets and lease liabilities in the balance sheet for most leases, whereas today only finance lease liabilities (referred to as capital leases) are recognized in the balance sheet. In addition, the definition of a lease has been revised when an arrangement conveys the right to control the use of the identified asset which may change the classification of an arrangement as a lease. Quantitative and qualitative disclosures related to the amount, timing and judgments of an entity's accounting for leases and the related cash flows are also expanded. Disclosure requirements apply to both lessees and lessors, whereas current disclosures relate only to lessees. Significant changes to lease systems, processes and procedures are required to implement the requirements of the new standard. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from current GAAP. Lessor accounting is also largely unchanged.

The standard provides a number of transition practical expedients that entities may elect. These include a "package of three" expedients that must be taken together and allow entities to (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases. In January 2018, the FASB issued additional guidance which provides another optional transition practical expedient. This practical expedient allows entities to not evaluate land easements under the new guidance at adoption if they were not previously accounted for as leases.

The Registrants have assessed the lease standard and are executing a detailed implementation plan in preparation for adoption on January 1, 2019. Key activities in the implementation plan include:

- Developing a complete lease inventory and abstracting the required data attributes into a lease accounting system that supports the Registrants' lease portfolios and integrates with existing systems.
- Evaluating the transition practical expedients available under the guidance.
- Identifying, assessing and documenting technical accounting issues, policy considerations and financial reporting implications. Includes completing a detailed contract assessment for a sample of transactions to determine whether they are leases under the new guidance.

- Identifying and implementing changes to processes and controls to ensure all impacts of the new guidance are effectively addressed.

Accounting and implementation issues continue to be identified and evaluated by the implementation team.

Impairment of Financial Instruments (Issued June 2016): Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects the entity's current estimate of credit losses expected to be incurred over the life of the financial instrument. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard will be effective January 1, 2020 (with early adoption as of January 1, 2019 permitted) and, for most debt instruments, requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption.

Goodwill Impairment (Issued January 2017): Simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two-step impairment test). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment test is necessary. Exelon, Generation, ComEd, PHI, and DPL have goodwill as of December 31, 2017 . This updated guidance is not currently expected to impact the Registrants' financial reporting. The standard is effective January 1, 2020, with early adoption permitted, and must be applied on a prospective basis.

Derivatives and Hedging (Issued September 2017): Allows more financial and nonfinancial hedging strategies to be eligible for hedge accounting. The amendments are intended to more closely align hedge accounting with companies' risk management strategies, simplify the application of hedge accounting, and increase transparency as to the scope and results of hedging programs. There are also amendments related to effectiveness testing and disclosure requirements. The guidance is effective January 1, 2019 and early adoption is permitted with a modified retrospective transition approach. The Registrants are currently assessing this standard but do not currently expect a significant impact given the limited activity for which the Registrants elect hedge accounting and because the Registrants do not anticipate increasing their use of hedge accounting as a result of this standard.

2 . Variable Interest Entities (All Registrants)

A VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly affect the entity's economic performance.

At December 31, 2017 , Exelon, Generation, PHI and ACE collectively consolidated five VIEs or VIE groups for which the applicable Registrant was the primary beneficiary. At December 31, 2016 , Exelon, Generation, BGE, PHI and ACE collectively consolidated nine VIEs or VIE groups for which the applicable Registrant was the primary beneficiary (*see Consolidated Variable Interest Entities below)* . As of December 31, 2017 and 2016 , Exelon and Generation collectively had significant interests in seven and eight other VIEs, respectively, for which the applicable Registrant does not have the power to direct

the entities' activities and, accordingly, was not the primary beneficiary (*see Unconsolidated Variable Interest Entities below)* .

Consolidated Variable Interest Entities

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the Registrants' consolidated financial statements at December 31, 2017 and 2016 are as follows:

	December 31, 2017			
		Successor		
	Exelon [a]	Generation	PHI [a]	ACE
Current assets	$ 630	$ 620	$ 10	6
Noncurrent assets	9,317	9,286	31	23
Total assets	$ 9,947	$ 9,906	$ 41	$ 29
Current liabilities	$ 306	$ 270	$ 36	32
Noncurrent liabilities	3,312	3,246	66	58
Total liabilities	$ 3,618	$ 3,516	$ 102	$ 90

	December 31, 2016				
				Successor	
	Exelon [a][b]	Generation	BGE	PHI [a]	ACE
Current assets	$ 954	$ 916	$ 23	$ 14	$ 9
Noncurrent assets	8,563	8,525	3	35	23
Total assets	$ 9,517	$ 9,441	$ 26	$ 49	$ 32
Current liabilities	$ 885	$ 802	$ 42	$ 42	$ 37
Noncurrent liabilities	2,713	2,612	—	101	89
Total liabilities	$ 3,598	$ 3,414	$ 42	$ 143	$ 126

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.
(b) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the table can only be settled using VIE resources.

As of December 31, 2017 , Exelon's and Generation's consolidated VIEs consist of:

Investments in Other Energy Related Companies

During 2015, Generation sold 69% of its equity interest in a company to a tax equity investor. The company holds an equity method investment in a distributed energy company that is an unconsolidated VIE (see unconsolidated VIE section for additional details). Generation and the tax equity investor contributed a total of $227 million of equity in proportion to their ownership interests to the company. The company meets the definition of a VIE because it has a similar structure to a limited partnership and the limited partners do not have kick-out rights with respect to the general partner. Generation is the primary beneficiary because Generation manages the day-to-day activities of the entity.

During 2015, Generation formed a limited liability company to build, own, and operate a backup generator. While Generation owns 100% of the backup generator company, it was determined that the entity is a VIE because the customer absorbs price variability from the entity through the fixed price

backup generator agreement. Generation provides operating and capital funding to the backup generator company.

During the fourth quarter of 2017 Generation acquired a controlling financial interest in an energy development company. The company is in the development stage and requires additional subordinated financial support from the equity holders to fund activities. Generation is the majority owner with a 62% equity interest and has the power to direct the activities that most significantly affect the economic performance of the company.

Renewable Energy Project Companies

In July 2017, Generation entered into an arrangement to sell a 49% interest in ExGen Renewable Partners, LLC (the Renewable JV) to an outside investor for $400 million of cash plus immaterial working capital and other customary post-closing adjustments. The Renewable JV meets the definition of a VIE because the Renewable JV has a similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner. Generation is the primarily beneficiary because Generation manages the day-to-day activities of the entity; therefore, Generation will continue to consolidate the Renewable JV. The Renewable JV is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by the Renewable JV. The details relating to these VIEs are discussed below.

Generation owns a number of limited liability companies that build, own, and operate solar and wind power facilities some of which are owned by the Renewable JV. While Generation or the Renewable JV owns 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that certain of the solar and wind entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of these solar and wind entities that qualify as VIEs because Generation controls the design, construction, and operation of the facilities. Generation provides operating and capital funding to the solar and wind entities for ongoing construction, operations and maintenance and there is limited recourse related to Generation related to certain solar and wind entities.

While Generation or the Renewable JV owns 100% of the majority of the wind entities, six of the projects have noncontrolling equity interests of 1% held by third parties and one of the projects has noncontrolling equity interests related to its Class B Membership Interest (see additional details below). The entities with noncontrolling equity interests of 1% held by third parties meet the definition of a VIE because the entities have noncontrolling equity interest holders that absorb variability from the wind projects. Generation's or the Renewable JV's current economic interests in five of these projects is significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the noncontrolling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the noncontrolling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the noncontrolling interests state that Generation or the Renewable JV are to provide financial support to the projects in proportion to its current 99% economic interests in the projects. Generation provides operating and capital funding to the wind project entities for ongoing construction, operations and maintenance and there is limited recourse to Generation related to certain wind project entities. However, no additional support to these projects beyond what was contractually required has been provided during 2017. Generation is the primary beneficiary of these wind entities because Generation controls the design, construction, and operation of the facilities.

In December 2016, Generation sold 100% of the Class B Membership Interests to a tax equity investor and retained 100% of the Class A Membership Interests of its equity interest in one of its wind

entities that was previously consolidated under the voting interest model. The wind entity meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick-out rights with respect to the general partner. While Generation is the minority interest holder, Generation is the primary beneficiary, because Generation manages the day-to-day activities of the entity. Therefore, the entity continues to be consolidated by Generation.

The renewable energy project companies VIE group was previously separated into two VIE groups for solar project limited liability companies and wind project companies as of December 31, 2016 .

Retail Power and Gas Companies

In March 2014, Generation began consolidating retail power and gas VIEs for which Generation is the primary beneficiary as a result of energy supply contracts that give Generation the power to direct the activities that most significantly affect the economic performance of the entities. Generation does not have an equity ownership interest in these entities, but provides approximately $30 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy. These entities are included in Generation's consolidated financial statements, and the consolidation of the VIEs do not have a material impact on Generation's financial results or financial condition.

CENG

CENG is a joint venture between Generation and EDF. On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the Nuclear Operating Services Agreement (NOSA) pursuant to which Generation now conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF. As a result of executing the NOSA, CENG qualifies as a VIE due to the disproportionate relationship between Generation's 50.01% equity ownership interest and its role in conducting the operational activities of CENG and the CENG fleet conveyed through the NOSA. Further, since Generation is conducting the operational activities of CENG and the CENG fleet, Generation qualifies as the primary beneficiary of CENG and, therefore, is required to consolidate the results of operations and financial position of CENG.

Exelon and Generation, where indicated, provide the following support to CENG (see Note 26 — Related Party Transactions for additional information regarding Generation's and Exelon's transactions with CENG):

- under power purchase agreements with CENG, Generation purchased or will purchase 50.01% of the available output generated by the CENG nuclear plants not subject to other contractual agreements from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs were suspended during the term of the Reliability Support Services Agreement (RSSA), through the end of March 31, 2017. With the expiration of the RSSA, the PPA was reinstated beginning April 1, 2017. (see Note 3 — Regulatory Matters for additional details),

- Generation provided a $400 million loan to CENG. As of December 31, 2017 , the remaining obligation is $333 million , including accrued interest, which reflects the principal payment made in January 2015,

- Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their

operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. (See Note 23 — Commitments and Contingencies for more details),

- Generation and EDF share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance, and
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

As of December 31, 2016 , Exelon and Generation had the following consolidated VIEs that are no longer VIEs as of December 31, 2017 :

Retail Gas Group

During 2009, Constellation formed a retail gas group to enter into a collateralized gas supply agreement with a third-party gas supplier. The retail gas group was determined to be a VIE because there was not sufficient equity to fund the group's activities without additional credit support and a $75 million parental guarantee provided by Generation. As the primary beneficiary, Generation consolidated the retail gas group. During the second quarter of 2017, the collateral structure was terminated with the third-party gas supplier except for the $75 million parental guarantee provided by Generation. Although the parental guarantee remains, this is considered customary and reasonable for the unsecured position Generation has with the third-party gas supplier. As a result of the termination, the retail gas group no longer met the definition of a VIE. However, the retail gas group continues to be consolidated by Generation under the voting interest model.

Other Generating Facilities

Prior to 2017, Generation owned 90% of a biomass fueled, combined heat and power company. In the second quarter of 2015, the entity was deemed to be a VIE because the entity required additional subordinated financial support in the form of a parental guarantee provided by Generation for up to $ 275 million in support of the payment obligations related to the Engineering, Procurement and Construction contract for the facility in support of one of its other generating facilities. During the third quarter of 2017, the ownership of the entity increased to 99% , all payment obligations related to the EPC contract were satisfied, and the parental guarantee provided by Generation was terminated. As a result, the entity is now sufficiently capitalized and no longer meets the definition of a VIE. However, the biomass facility continues to be consolidated by Generation under the voting interest model.

As of December 31, 2017 and 2016 , Exelon's and ACE's consolidated VIE consists of:

ACE Transition Funding

A special purpose entity formed by ACE for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of transition bonds. Proceeds from the sale of each series of transition bonds by ATF were transferred to ACE in exchange for the transfer by ACE to ATF of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on transition bonds and related taxes, expenses and fees. During the three years ended December 31, 2017 , 2016 and 2015 , ACE transferred $48 million , $60 million and $61 million to ATF, respectively.

As of December 31, 2016 , Exelon and BGE had the following consolidated VIE that is no longer a VIE as of December 31, 2017 :

RSB BondCo LLC.

In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges were assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. In the second quarter of 2017 the rate stabilization bonds were fully redeemed and BGE remitted its final payment to BondCo. Upon redemption of the bonds, BondCo no longer meets the definition of a variable interest entity.

BondCo's assets were restricted and could only be used to settle the obligations of BondCo. Further, BGE was required to remit all payments it received from customers for rate stabilization charges to BondCo. During 2017, 2016 and 2015, BGE remitted $22 million , $86 million and $86 million , respectively, to BondCo.

For each of the consolidated VIEs noted above, except as otherwise noted:

- the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;
- Exelon, Generation, BGE, PHI and ACE did not provide any additional material financial support to the VIEs;
- Exelon, Generation, BGE, PHI and ACE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and
- the creditors of the VIEs did not have recourse to Exelon's, Generation's, BGE's, PHI's or ACE's general credit.

As of December 31, 2017 and 2016 , ComEd, PECO, Pepco and DPL do not have any material consolidated VIEs.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of December 31, 2017 and 2016 , these assets and liabilities primarily consisted of the following:

	December 31, 2017			
			Successor	
	Exelon [a]	Generation	PHI [a]	ACE
Cash and cash equivalents	$ 126	$ 126	$ —	$ —
Restricted cash	64	58	6	6
Accounts receivable, net				
Customer	138	138	—	—
Other	25	25	—	—
Inventory				
Materials and supplies	205	205	—	—
Other current assets	45	41	4	—
Total current assets	603	593	10	6
Property, plant and equipment, net	6,186	6,186	—	—
Nuclear decommissioning trust funds	2,502	2,502	—	—
Other noncurrent assets	274	243	31	23
Total noncurrent assets	8,962	8,931	31	23
Total assets	$ 9,565	$ 9,524	$ 41	$ 29
Long-term debt due within one year	$ 102	$ 67	$ 35	$ 31
Accounts payable	114	114	—	—
Accrued expenses	65	64	1	1
Unamortized energy contract liabilities	18	18	—	—
Other current liabilities	7	7	—	—
Total current liabilities	306	270	36	32
Long-term debt	1,154	1,088	66	58
Asset retirement obligations	2,035	2,035	—	—
Unamortized energy contract liabilities	5	5	—	—
Other noncurrent liabilities	112	112	—	—
Noncurrent liabilities	3,306	3,240	66	58
Total liabilities	$ 3,612	$ 3,510	$ 102	$ 90

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2016				
				Successor	
	Exelon [a][b]	Generation	BGE	PHI [a]	ACE
Cash and cash equivalents	$ 150	$ 150	$ —	$ —	$ —
Restricted cash	59	27	23	9	9
Accounts receivable, net					
Customer	371	371	—	—	—
Other	48	48	—	—	—
Mark-to-market derivative assets	31	31	—	—	—
Inventory					
Materials and supplies	199	199	—	—	—
Other current assets	50	44	—	5	—
Total current assets	908	870	23	14	9
Property, plant and equipment, net	5,415	5,415	—	—	—
Nuclear decommissioning trust funds	2,185	2,185	—	—	—
Goodwill	47	47	—	—	—
Mark-to-market derivative assets	23	23	—	—	—
Other noncurrent assets	315	277	3	35	23
Total noncurrent assets	7,985	7,947	3	35	23
Total assets	$ 8,893	$ 8,817	$ 26	$ 49	$ 32
Long-term debt due within one year	$ 181	$ 99	$ 41	$ 40	$ 35
Accounts payable	269	269	—	—	—
Accrued expenses	119	116	1	2	2
Mark-to-market derivative liabilities	60	60	—	—	—
Unamortized energy contract liabilities	15	15	—	—	—
Other current liabilities	30	30	—	—	—
Total current liabilities	674	589	42	42	37
Long-term debt	641	540	—	101	89
Asset retirement obligations	1,904	1,904	—	—	—
Pension obligation [c]	9	9	—	—	—
Unamortized energy contract liabilities	22	22	—	—	—
Other noncurrent liabilities	106	106	—	—	—
Noncurrent liabilities	2,682	2,581	—	101	89
Total liabilities	$ 3,356	$ 3,170	$ 42	$ 143	$ 126

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.
(b) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(c) Includes the CNEG retail gas pension obligation, which is presented as a net asset balance within the Prepaid pension asset line item on Generation's balance sheet. See Note 16 - Retirement Benefits for additional details.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected on Exelon's and Generation's Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of December 31, 2017 and 2016 , Exelon and Generation had significant unconsolidated variable interests in seven and eight VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary. These interests include certain equity method investments and certain commercial agreements. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Generation has several individually immaterial VIEs that in aggregate represent a total investment of $ 8 million . These immaterial VIEs are equity and debt securities in energy development companies. The maximum exposure to loss related to these securities is limited to the $ 8 million included in Investments on Exelon's and Generation's Consolidated Balance Sheets .

The following tables present summary information about Exelon and Generation's significant unconsolidated VIE entities:

December 31, 2017	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 625	$ 509	$ 1,134
Total liabilities [a]	37	228	265
Exelon's ownership interest in VIE [a]	—	251	251
Other ownership interests in VIE [a]	588	30	618
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	251	251
Contract intangible asset	8	—	8
Debt and payment guarantees	—	—	—
Net assets pledged for Zion Station decommissioning [b]	2	—	2

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

December 31, 2016	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 638	$ 567	$ 1,205
Total liabilities [a]	215	287	502
Exelon's ownership interest in VIE [a]	—	248	248
Other ownership interests in VIE [a]	423	32	455
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	264	264
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning [b]	9	—	9

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.
(b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $39 million and $113 million as of December 31, 2017 and December 31, 2016 , respectively; offset by payables to ZionSolutions LLC of $37 million and $104 million as of December 31, 2017 and December 31, 2016 , respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

For each unconsolidated VIE, Exelon and Generation assessed the risk of a loss equal to their maximum exposure to be remote and accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would materially affect the fair value or risk of their variable interests in these variable interest entities.

As of December 31, 2017 , Exelon's and Generation's unconsolidated VIEs consist of:

Energy Purchase and Sale Agreements

Generation has several energy purchase and sale agreements with generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each entity, and determined that certain of the entities are VIEs because the entity absorbs risk through the sale of fixed price power and renewable energy credits. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

ZionSolutions

Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 15 — Asset Retirement Obligations . Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning activities under the asset sale agreement are complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required. Other than the asset sale agreement, Exelon and Generation do not have any contractual or other obligations to provide additional financial support and ZionSolutions' creditors do not have any recourse to Exelon's or Generation's general credit.

Investment in Distributed Energy Companies

In July 2014, Generation entered into an arrangement to purchase a 90% equity interest and 90% of the tax attributes of a distributed energy company. Generation contributed a total $ 85 million of equity. The distributed energy company meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick-out rights of the general partner. Generation is not the primary beneficiary; therefore, the investment continues to be recorded using the equity method.

During 2015, a company that is consolidated by Generation as a VIE entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of another distributed energy company (see additional details in the Consolidated Variable Interest Entities section above). The equity holders (of which Generation is one) contributed to the distributed energy company a total of $ 227 million of equity in proportion to their ownership interests. The equity holders provided a parental guarantee of up to $ 275 million in support of equity contributions to the distributed energy company. As all equity contributions were made as of the first quarter of 2017, there is no further payment obligation under the parental guarantee. The distributed energy company meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick-out rights of the general partner. Generation is not the primary beneficiary; therefore, the investment is recorded using the equity method.

Both distributed energy companies from the 2015 and 2014 arrangements are considered related parties to Generation.

As of December 31, 2016 , Exelon and Generation had the following unconsolidated VIE that is no longer a VIE as of December 31, 2017 :

Investment in Energy Generating Facility

As of December 31, 2016, Generation had an equity investment in an energy generating facility. The entity was a VIE because Generation guaranteed the debt of the entity, provided equity support, and provided operating services to the entity. Generation was not the primary beneficiary of the entity because Generation did not have the power to direct the activities that most significantly impacted the VIE's economic performance. During 2017, Generation sold its equity investment in the entity; therefore, the entity is no longer a VIE as of December 31, 2017.

ComEd, PECO and BGE

The financing trust of ComEd, ComEd Financing III, and the financing trusts of PECO, PECO Trust III and PECO Trust IV, are not consolidated in Exelon's, ComEd's, or PECO's financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd and PECO have concluded that they do not have a significant variable interest in ComEd Financing III, PECO Trust III, or PECO Trust IV as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk.

The financing trust of BGE, BGE Capital Trust II, was created for the purpose of issuing mandatorily redeemable trust preferred securities. In the third quarter of 2017, BGE redeemed the securities pursuant to the optional redemption provisions of the Indenture, under which the subordinated debt securities were issued, and dissolved BGE Capital Trust II. Prior to dissolution, the BGE Capital Trust II was not consolidated in Exelon's or BGE's financial statements. BGE concluded it did not have a significant variable interest in BGE Capital Trust II as BGE financed its equity interest in the financing trust through the issuance of subordinated debt and, therefore, had no equity at risk. See Note 13 — Debt and Credit Agreements for additional information.

3 . Regulatory Matters (All Registrants)

The following matters below discuss the status of material regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Tax Cuts and Jobs Act (Exelon and ComEd). On January 18, 2018, the ICC approved ComEd's petition filed on January 5, 2018 seeking approval to pass back to customers beginning February 1, 2018 $201 million in tax savings resulting from the enactment of the TCJA through a reduction in electric distribution rates. The amounts being passed back to customers reflect the benefit of lower income tax rates beginning January 1, 2018 and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. Refer to Note 14 - Income Taxes for more detail on Corporate Tax Reform.

Electric Distribution Formula Rate (Exelon and ComEd). ComEd's electric distribution rates are established through a performance-based formula rate. ComEd is required to file an annual update to the performance-based formula rate on or before May 1, with resulting rates effective in January of the following year. This annual electric distribution formula rate update is based on prior year actual costs and current year projected capital additions (initial revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred for that year (annual reconciliation). Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to Operating revenues for any differences between the revenue requirement in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. The regulatory asset associated with electric distribution formula rate is amortized to Operating revenues in ComEd's Consolidated Statement of Operations and Comprehensive Income as the associated amounts are recovered through rates. Changes to the distribution formula rate as a result of FEJA are discussed below.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

For each of the following years, the ICC approved the following total increases/(decreases) in ComEd's electric distributions formula rate filings:

Annual Electric Distribution Filings	2017	2016	2015
ComEd's requested total revenue requirement increase (decrease)	$ 96	$ 138	$ (50)
Final ICC Order			
Initial revenue requirement increase	$ 78	$ 134	$ 85
Annual reconciliation increase (decrease)	18	(7)	(152)
Total revenue requirement increase (decrease)	$ 96	$ 127 [a]	$ (67)
Allowed Return on Rate Base:			
Initial revenue requirement	6.47%	6.71%	7.05%
Annual reconciliation	6.45%	6.69%	7.02%
Allowed ROE:			
Initial revenue requirement	8.40%	8.64%	9.14%
Annual reconciliation	8.34% [b]	8.59% [b]	9.09% [b]
Effective date of rates	January 2018	January 2017	January 2016

(a) On March 22, 2017, the ICC issued an order approving ComEd's proposal to reduce the 2016 revenue requirement by $18 million , which was reflected in customer rates beginning in April 2017. This reduction is not reflected in the 2016 revenue requirement amounts above.
(b) Includes a reduction of 6 basis points in 2017 and 5 basis points in 2016 and 2015 for a reliability performance metric penalty.

Illinois Future Energy Jobs Act (Exelon, Generation and ComEd)

Background

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA went into effect on June 1, 2017, and includes, among other provisions, (1) a ZES providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd's electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd's customer rates exceeds specified limits, (6) revisions to the existing net metering statute to (i) mandate net metering for community generation projects, and establish billing procedures for subscribers to those projects, (ii) provide immediately for netting at the energy-only rate for nonresidential customers, and (iii) transition from netting at the full retail rate to the energy-only rate for certain residential net metering customers once the net meter customer load equals 5% of total peak demand supplied in the previous year and (7) support for low income rooftop and community solar programs .

Zero Emission Standard

FEJA includes a ZES that provides compensation through the procurement of ZECs targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet specific eligibility criteria.

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On September 11, 2017, the ICC approved the IPA's ZES Procurement Plan filed with the ICC on July 31, 2017. Bidders interested in participating in the procurement process had 14 days following the ICC's approval of the plan to submit the required eligibility information and become qualified bidders. Generation's Clinton and Quad Cities nuclear plants timely submitted the required eligibility information to the ICC and responded to follow up questions. Winning bidders will contract directly with Illinois utilities, including ComEd, for 10-year terms extending through May 31, 2027. The ZEC price will be based upon the current social cost of carbon as determined by the Federal government and is initially established at $16.50 per MWh of production, subject to annual future adjustments determined by the IPA for specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices. Illinois utilities will be required to purchase all ZECs delivered by the zero-emissions nuclear-powered generating facilities, subject to annual cost caps. For the initial delivery year, June 1, 2017 to May 31, 2018, the ZEC annual cost cap is set at $235 million (ComEd's share is approximately $170 million). For subsequent delivery years, the IPA-approved targeted ZEC procurement amounts will change based on forward energy and capacity prices. ZECs delivered to Illinois utilities in excess of the annual cost cap will be paid in subsequent years if the payments do not exceed the prescribed annual cost cap for that year.

ComEd recovers all costs associated with purchasing ZECs through a rate rider that provides for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase ZECs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods with interest. ComEd began billing its retail customers under its new ZEC rate rider on June 1, 2017.

On February 14, 2017, two lawsuits were filed in the Northern District of Illinois against the IPA alleging that the state's ZEC program violates certain provisions of the U.S. Constitution. One lawsuit was filed by customers of ComEd, led by the Village of Old Mill Creek, and the other was brought by the EPSA and three other electric suppliers. Both lawsuits argue that the Illinois ZEC program will distort PJM's FERC-approved energy and capacity market auction system of setting wholesale prices, and seek a permanent injunction preventing the implementation of the program. Exelon intervened and filed motions to dismiss in both lawsuits. In addition, on March 31, 2017, plaintiffs in both lawsuits filed motions for preliminary injunction with the court; the court stayed briefing on the motions for preliminary injunction until the resolution of the motions to dismiss. On July 14, 2017, the district court granted the motions to dismiss. On July 17, 2017, the plaintiffs appealed the decision to the Seventh Circuit. Briefs were fully submitted on December 12, 2017, the Court heard oral argument on January 3, 2018. At the argument, the Court asked for supplemental briefing, which was filed on January 26, 2018. Exelon cannot predict the outcome of these lawsuits. It is possible that resolution of these matters could have a material, unfavorable impact on Exelon's and Generation's results of operations, cash flows and financial positions.

See Note 8 — Early Nuclear Plant Retirements for additional information regarding the economic challenges facing Generation's Clinton and Quad Cities nuclear plants and the expected benefits of the ZES.

ComEd Electric Distribution Rates

FEJA extended the sunset date for ComEd's performance-based electric distribution formula rate from 2019 to the end of 2022, allowed ComEd to revise the electric distribution formula rate to eliminate the ROE collar, and allowed ComEd to implement a decoupling tariff if the electric distribution formula rate is terminated at any time. ComEd revised its electric distribution formula rate to eliminate the ROE collar, which eliminates any unfavorable or favorable impacts of weather or load from ComEd's electric distribution formula rate revenues beginning with the reconciliation filed in 2018 for the 2017 calendar year. Elimination of the ROE collar effectively offsets the favorable or unfavorable impacts to ComEd's electric distribution formula rate revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer. ComEd began reflecting the impacts of this change in its electric distribution services costs regulatory asset in the first quarter

2017. As of December 31, 2017 , ComEd recorded an increase to its electric distribution services costs regulatory asset of approximately $32 million for this change.

FEJA requires ComEd to make non-recoverable contributions to low income energy assistance programs of $10 million per year for 5 years as long as the electric distribution formula rate remains in effect. With the exception of these contributions, ComEd will recover from customers, subject to certain caps explained below, the costs it incurs pursuant to FEJA either through its electric distribution formula rate or other recovery mechanisms.

Energy Efficiency

Prior to FEJA, Illinois law required ComEd to implement cost-effective energy efficiency measures and, for a 10-year period ending May 31, 2018, cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers.

Beginning January 1, 2018, FEJA provides for new cumulative annual energy efficiency MWh savings goals for ComEd, which are designed to achieve 21.5% of cumulative persisting annual MWh savings by 2030, as compared to the deemed baseline of 88 million MWhs of electric power and energy sales. FEJA deems the cumulative persisting annual MWh savings to be 6.6% from 2012 through the end of 2017. ComEd expects to spend approximately $350 million to $400 million annually through 2030 to achieve these energy efficiency MWh savings goals. In addition, FEJA extends the peak demand reduction requirement from 2018 to 2026. Because the new requirements apply beginning in 2018, FEJA extends the existing energy efficiency plans, which were due to end on May 31, 2017, through December 31, 2017. FEJA also exempts customers with demands over 10 MW from energy efficiency plans and requirements beginning June 1, 2017. On September 11, 2017, the ICC approved ComEd's 2018-2021 energy efficiency plan with minor modifications filed by ComEd with the ICC on June 30, 2017.

As allowed by FEJA, ComEd cancelled its existing energy efficiency rate rider effective June 2, 2017. On August 1, 2017, ComEd filed with the ICC a reconciliation of revenues and costs incurred through the cancellation date. On August 30, 2017, the ICC approved ComEd's request, filed on August 1, 2017, to issue an $80 million credit on retail customers' bills in October 2017 for the majority of the over-recoveries with any final adjustment applicable to the over-recoveries to be billed or credited in the future. As of December 31, 2017 , ComEd's over-recoveries associated with its former energy efficiency rate rider were $4 million and are expected to be refunded to customers in future rates.

FEJA allows ComEd to defer energy efficiency costs (except for any voltage optimization costs which are recovered through the electric distribution formula rate) as a separate regulatory asset that is recovered through the energy efficiency formula rate over the weighted average useful life, as approved by the ICC, of the related energy efficiency measures. ComEd earns a return on the energy efficiency regulatory asset at a rate equal to its weighted average cost of capital, which is based on a year-end capital structure and calculated using the same methodology applicable to ComEd's electric distribution formula rate. Beginning January 1, 2018 through December 31, 2030, the return on equity that ComEd earns on its energy efficiency regulatory asset is subject to a maximum downward or upward adjustment of 200 basis points if ComEd's cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual incremental savings goal. ComEd is required to file an update to its energy efficiency formula rate on or before June 1 each year, with resulting rates effective in January of the following year. The annual update will be based on projected current year energy efficiency costs, PJM capacity revenues, and the projected year-end regulatory asset balance less any related deferred income taxes. The update will also include a reconciliation of any differences between the revenue requirement in effect for the prior year and the revenue requirement based on actual prior year costs and actual year-end energy efficiency regulatory asset balances less any related deferred income taxes. ComEd records a regulatory asset or liability and corresponding increase or decrease to

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Operating revenues for any differences between the revenue requirement in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation.

On August 15, 2017, the ICC approved ComEd's new initial energy efficiency formula rate filed pursuant to FEJA. The order establishes the formula under which energy efficiency rates will be calculated going forward and the revenue requirement used to set the initial rates for the period October 1, 2017 through December 31, 2017. The initial revenue requirement is based on projected costs and projected PJM capacity revenues for the period from June 1, 2017 through December 31, 2017, and projected year-end 2017 energy efficiency regulatory asset balances (less related deferred income taxes). The approved energy efficiency formula rate also provides for revenue decoupling to effectively offset the favorable or unfavorable impacts to ComEd's energy efficiency formula rate revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer.

On September 11, 2017, the ICC approved ComEd's annual energy efficiency formula rate. The order establishes the revenue requirement used to set rates that will take effect in January 2018. The revenue requirement for 2018 is based on projected 2018 energy efficiency costs and PJM capacity revenues, and year-end 2018 energy efficiency regulatory asset balances (less related deferred income taxes).

For each of the following years, the ICC approved the following total increases/(decreases) in ComEd's requested energy efficiency revenue requirement:

Annual Energy Efficiency Filings	Initial	2017
ComEd's requested total revenue requirement (decrease) increase	$ (7) [a]	$ 12
Allowed Return on Rate Base:		
Initial revenue requirement	6.47%	6.47%
Allowed ROE:		
Initial revenue requirement	8.40%	8.40%
Effective date of rates [b]	October 2017	January 2018

(a) Reflects higher projected PJM capacity revenues compared to projected energy efficiency costs.
(b) An ICC order on the annual reconciliation of any differences between the revenue requirement in effect and the revenue requirement based on actual costs for 2017 and 2018 is expected in December 2018 and December 2019, respectively.

Renewable Portfolio Standard

Existing Illinois law requires ComEd to purchase each year an increasing percentage of renewable energy resources for the customers for which it supplies electricity. This obligation is satisfied through the procurement of RECs. FEJA revises the Illinois RPS to require ComEd to procure RECs for all retail customers by June 2019, regardless of the customers' electricity supplier, and provides support for low-income rooftop and community solar programs, which will be funded by the existing Renewable Energy Resources Fund and ongoing RPS collections. FEJA also requires ComEd to use RPS collections to fund utility job training and workforce development programs in the amounts of $10 million in each of the years 2017, 2021, and 2025. ComEd recorded a $20 million noncurrent liability as of December 31, 2017 associated with this obligation. ComEd will recover all costs associated with purchasing RECs and funding utility job training and workforce development programs through a new RPS rate rider that provides for a reconciliation and true-up to actual costs, with any difference between revenues and expenses to be credited to or collected from ComEd's retail customers in subsequent periods with

interest. The first reconciliation and true-up for RECs will occur in 2021 and cover revenues and costs for the four-year period beginning June 1, 2017 through May 31, 2021. Subsequently, the RPS rate rider will provide for an annual reconciliation and true-up. ComEd began billing its retail customers under its new RPS rate rider on June 1, 2017 and recorded a related regulatory liability of $21 million as of December 31, 2017 . ComEd also recorded a regulatory liability of $41 million for alternative compliance payments received from RES to purchase RECs on behalf of the RES in the future.

As of December 31, 2017 , ComEd had received $62 million of over-recovered RPS costs and alternative compliance payments from RES, which are deposited into a separate interest-bearing bank account pursuant to FEJA. The current portion is classified as Restricted cash and the non-current portion is classified as other deferred debits on Exelon's and ComEd's Balance Sheets.

Customer Rate Increase Limitations

FEJA includes provisions intended to limit the average impact on ComEd customer rates for recovery of costs incurred under FEJA as follows: (1) for a typical ComEd residential customer, the average impact must be less than $0.25 cents per month, (2) for nonresidential customers with a peak demand less than 10 MW, the average annual impact must be less than 1.3% of the average amount paid per kWh for electric service by Illinois commercial retail customers during 2015, and (3) for nonresidential customers with a peak demand greater than 10 MW, the average annual impact must be less than 1.3% of the average amount paid per kWh for electric service by Illinois industrial retail customers during 2015.

On June 30, 2017, ComEd submitted a 10-year projection to the ICC of customer rate impacts for residential customers and nonresidential customers with a peak demand less than 10 MW . Such projections indicate that customer rate impacts will not exceed the limitations set by FEJA discussed below. Thereafter, beginning in 2018, ComEd must submit a report to the ICC for residential customers and nonresidential customers with a peak demand less than 10 MW by February 15th and June 30th of each year, respectively. For nonresidential customers with a peak demand greater than 10 MW, ComEd must submit a report to the ICC by May 1 of each year if a rate reduction will be necessary in the following year. For residential customers, the reports will include the actual costs incurred under FEJA during the preceding year and a rolling 10-year customer rate impact projection. The reports for nonresidential customers with a peak demand less than 10 MW will also include the actual costs incurred under FEJA during the preceding year, as well as the average annual rate increase from January 1, 2017 through the end of the preceding year and the average annual rate increase projected for the remainder of the 10-year period.

If the projected residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations during the first four years, ComEd is required to decrease costs associated with FEJA investments, including reductions to ZEC contract quantities. If the projected residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations during the last six years, ComEd is required to demonstrate how it will reduce FEJA investments to ensure compliance. If the actual residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations for any one year, ComEd is required to submit a corrective action plan to decrease future year costs to reduce customer rates to ensure future compliance. If the actual residential customer or nonresidential customer rate exceeds the limitations for two consecutive years, ComEd can offer to credit customers for amounts billed in excess of the limitations or ComEd can terminate FEJA investments. If ComEd chooses to terminate FEJA investments, the ICC shall order termination of ZEC contracts and further initiate proceedings to reduce energy efficiency savings goals and terminate support for low-income rooftop and community solar programs . ComEd is allowed to fully recover all costs incurred as of and up to the date of the programs' termination.

Renewable Energy Resources (Exelon and ComEd). In accordance with FEJA, beginning with the plan or plans to be implemented in the 2017 delivery year, the IPA filed its long term renewable

resource procurement plan (LT Plan) with the ICC on December 4, 2017. The LT Plan requires a certain percentage of electricity sales be met with a climbing percentage of REC procurement. The 2017 delivery year requirement was 13% , with the obligation increasing by at least 1.5% each year thereafter to at least 25% by the 2025 delivery year; and continuing at no less than 25% for each delivery year thereafter.

Each RES and each Illinois utility, which includes ComEd, is responsible for the renewable resource obligation for the customers to which it supplies power. Over time, this will change and ComEd will procure renewable resources based on the retail load of substantially all customers in its service territory. For the delivery year beginning June 1, 2017, the LT Plan shall include cost effective renewable energy resources procured by ComEd for the retail load it supplies and for 50% of the retail customer load supplied by RES in ComEd's service territory on February 28, 2017. ComEd's procurement for RES supplied retail customer load will increase to 75% June 1, 2018 and to 100% beginning June 1, 2019. All goals are subject to rate impact criteria set forth by Illinois legislation. As of December 31, 2017 , ComEd had purchased renewable energy resources or equivalents, such as RECs, in accordance with the IPA Plan. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates.

Pennsylvania Regulatory Matters

Tax Cuts and Jobs Act (Exelon and PECO). PECO is working with the PAPUC and stakeholders on behalf of its distribution customers to determine the proper regulatory mechanisms and timing to reflect the tax benefits from the TCJA.

2015 Pennsylvania Electric Distribution Rate Case (Exelon and PECO). On March 27, 2015, PECO filed a petition with the PAPUC requesting an increase of $190 million to its annual service revenues for electric delivery, which requested an ROE of 10.95% . On September 10, 2015, PECO and interested parties filed with the PAPUC a petition for joint settlement for an increase of $127 million in annual distribution service revenue. No overall ROE was specified in the settlement. On December 17, 2015, the PAPUC approved the settlement of PECO's electric distribution rate case, which included the approval of the In-Program Arrearage Forgiveness ("IPAF") Program. The approved electric delivery rates became effective on January 1, 2016.

The IPAF Program provides for forgiveness of a portion of the eligible arrearage balance of its low-income Customer Assistance Program (CAP) accounts receivable at program inception. The forgiveness will be granted to the extent CAP customers remain current over the duration of the five-year payment agreement term. The Settlement guarantees PECO's recovery of two-thirds of the arrearage balance through a combination of customer payments and rate recovery, including through future rates cases if necessary. The remaining one-third of the arrearage balance has been absorbed by PECO through bad debt expense on its Consolidated Statements of Operations. In October 2016, the IPAF was fully implemented. PECO recorded a regulatory asset representing previously incurred bad debt expense associated with the eligible accounts receivable balances, which is included in the Regulatory assets table below.

Maryland Regulatory Matters

Tax Cuts and Jobs Act (Exelon, BGE, PHI, Pepco and DPL). On January 12, 2018, the MDPSC issued an order that directed each of BGE, Pepco and DPL to track the impacts of the TCJA beginning January 1, 2018 and file by February 15, 2018 how and when they expect to pass through such impacts to their customers.

On January 31, 2018, the MDPSC approved BGE's petition to pass back to customers beginning February 1, 2018 $103 million in tax savings resulting from the enactment of the TCJA through a reduction in distribution rates, of which $72 million and $31 million were related to electric and natural gas, respectively. On February 5, 2018, Pepco filed with the MDPSC an update to its current distribution rate

case to reflect $31 million in TCJA tax savings. By mid-February 2018, DPL is planning to file with the MDPSC seeking approval to pass back to customers beginning in 2018 $13 million in TCJA tax savings through a reduction in electric distribution rates. The amounts being passed back or proposed to be passed back to customers reflect the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. Refer to Note 14 — Income Taxes for more detail on Corporate Tax Reform.

After the filings due by February 15, 2018, it is expected that the MDPSC will address the treatment of the TCJA tax savings tracked by BGE, Pepco and DPL for the period January 1, 2018 through the effective date of their respective $103 million , $31 million and $13 million customer rate adjustments described above.

2018 Maryland Electric Distribution Rates (Exelon, PHI and Pepco). On January 2, 2018, Pepco filed an application with the MDPSC to increase its annual electric distribution base rates by $41 million , reflecting a requested ROE of 10.1% . On February 5, 2018, Pepco filed with the MDPSC an update to its current distribution rate case to reflect $31 million in TCJA tax savings, thereby reducing the requested annual base rate increase to $11 million . Pepco expects a decision in the matter in the third quarter of 2018, but cannot predict how much of the requested increase the MDPSC will approve.

2017 Maryland Electric Distribution Rates (Exelon, PHI and Pepco). On March 24, 2017, Pepco filed an application with the MDPSC to increase its annual electric distribution base rates by $69 million , which was updated to $67 million on August 24, 2017, reflecting a requested ROE of 10.1% . The application included a request for an income tax adjustment to reflect full normalization of removal costs associated with pre-1981 property, which accounted for $18 million of the requested increase. On October 20, 2017, the MDPSC approved an increase in Pepco electric distribution rates of $34 million , reflecting a ROE of 9.5% . On October 27, 2017, the MDPSC issued an errata order revising the approved increase in Pepco electric distribution rates to $32 million . The errata order corrected a number of computational errors in the original order but did not alter any of the findings. The new rates became effective for services rendered on or after October 20, 2017. In its decision, the MDPSC denied Pepco's request regarding the income tax adjustment without prejudice to Pepco filing another similar proposal with additional information. On November 20, 2017, an interested party in the proceeding filed a request for rehearing. On December 4, 2017, Pepco filed its response in opposition to the request for rehearing. Pepco cannot predict the outcome of this matter or when it will be decided.

2016 Maryland Electric Distribution Base Rates (Exelon, PHI and Pepco). On November 15, 2016, the MDPSC approved an increase in electric distribution base rates of $53 million based on a ROE of 9.55% . The new rates became effective for services rendered on or after November 15, 2016. MDPSC also approved Pepco's recovery of substantially all of its capital investment and regulatory assets associated with its AMI program as part of the newly effective rates as well as a recovery over a five-year period of transition costs related to a new billing system implemented in 2015. As a result, during the fourth quarter of 2016, Exelon, PHI and Pepco established a regulatory asset of $13 million , wrote-off $3 million in disallowed AMI costs and recorded a pre-tax credit to net income for $10 million . Additionally, the MDPSC denied Pepco's request to extend its Grid Resiliency Program surcharge for new system reliability and safety improvement projects, with costs for such programs to be recovered going forward through base rates.

2017 Maryland Electric Distribution Rates (Exelon, PHI and DPL). On July 14, 2017, DPL filed an application with the MDPSC to increase its annual electric distribution base rates by $27 million , which was updated to $19 million on November 16, 2017, reflecting a requested ROE of 10.1% . On December 18, 2017, a settlement agreement was filed with the MDPSC wherein DPL will be granted a rate increase of $13 million , and a ROE of 9.5% solely for purposes of calculating AFUDC and regulatory asset carrying costs. On January 5, 2018, the MDPSC held a hearing on the settlement agreement.

DPL expects a decision in the matter in the first quarter of 2018, but cannot predict whether the MDPSC will approve the settlement agreement as filed or how much of the requested increase will be approved.

2016 Maryland Electric Distribution Base Rates (Exelon, PHI and DPL). On February 15, 2017, the MDPSC approved an increase in DPL electric distribution rates of $38 million reflecting a ROE of 9.6% . The new rates became effective for services rendered on or after February 15, 2017. The MDPSC also denied DPL's request to continue its Grid Resiliency Program, through which DPL proposed to invest $5 million a year for two years to improve priority feeders and install single-phase reclosing fuse technology. The final order did not result in the recognition of any incremental regulatory assets or liabilities.

2015 Maryland Electric and Natural Gas Distribution Base Rates (Exelon and BGE). On November 6, 2015, and as amended through the course of the proceeding, BGE filed for electric and natural gas distribution base rate increases with the MDPSC, ultimately requesting annual increases of $116 million and $78 million , respectively, of which $104 million and $37 million were related to recovery of electric and natural gas smart grid initiative costs, respectively. BGE also proposed to recover an annual increase of approximately $30 million for Baltimore City underground conduit fees through a surcharge.

On June 3, 2016, the MDPSC issued an order in which the MDPSC found compelling evidence to conclude that BGE's smart grid initiative overall was cost beneficial to customers. However, the June 3 order contained several cost disallowances and adjustments, including not allowing BGE to defer or recover through a surcharge the $30 million increase in annual Baltimore City underground conduit fees. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions including the decision associated with the Baltimore City underground conduit fees. OPC also subsequently filed for a petition for rehearing of the June 3 order.

On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative. Through the combination of the orders, the MDPSC authorized electric and natural gas rate increases of $44 million and $48 million , respectively, and an allowed ROE for the electric and natural gas distribution businesses of 9.75% and 9.65% , respectively. The new electric and natural gas base rates took effect for service rendered on or after June 4, 2016. However, MDPSC's July 29 order on the petition on rehearing still did not allow BGE to defer or recover through a surcharge the increase in Baltimore City underground conduit fees.

On August 26, 2016, BGE filed an appeal of the MDPSC's orders with the Circuit Court for Baltimore County. On August 29, 2016, the residential consumer advocate also filed an appeal of the MDPSC's order but with the Circuit Court for Baltimore City. On November 15, 2016, Baltimore County Circuit Court issued an order deciding that the cases should be consolidated and should proceed in Baltimore County Circuit Court. However, on January 9, 2017, BGE filed to withdraw its appeal of the MDPSC's orders and on January 10, 2017, the residential consumer advocate filed to withdraw its appeal as well. Refer to the Smart Meter and Smart Grid Investments disclosure below for further details on the impact of the ultimate disallowances contained in the orders to BGE. See Conduit Lease with City of Baltimore in Litigation and Regulatory Matters of Note 23 - Commitments and Contingencies for information about the settlement agreement related to BGE's use of the City-owned underground conduit system.

Cash Working Capital Order (Exelon and BGE). On November 17, 2016, the MDPSC rendered a decision in the proceeding to review BGE's request to recover its cash working capital (CWC) requirement for its Provider of Last Resort service, also known as Standard Offer Service (SOS), as well as other components that make up the Administrative Charge, the mechanism that enables BGE to recover all of its SOS-related costs. The Administrative Charge is now comprised of five components: CWC, uncollectibles, incremental costs, return, and an administrative adjustment, which is an adder to the utility's SOS rate to act as a proxy for retail suppliers' costs. The Commission accepted BGE's

positions on recovery of CWC and pass-through recovery of BGE's actual uncollectibles and incremental costs. The order also grants BGE a return on the SOS. The Commission ruled that the level of the administrative adjustment will be determined in BGE's next rate case. On December 16, 2016, MDPSC Staff requested clarification concerning the amount of return on the SOS awarded to BGE and on December 19, 2016, the residential consumer advocate sought rehearing of the return awarded. On January 24, 2017, the MDPSC issued an order denying the MDPSC Staff request for clarification and the residential consumer advocate request for rehearing. On February 22, 2017, the residential consumer advocate filed an appeal of the MDPSC's orders with the Circuit Court for Baltimore City. The residential consumer advocate filed its Memorandum on Appeal on June 5, 2017 and subsequent Reply Memoranda were filed by BGE and the MDPSC on July 7, 2017 and July 12, 2017, respectively. On August 7, 2017, following oral argument by the parties, a decision was issued from the Circuit Court affirming the decision of the MDPSC. On September 5, 2017, the residential consumer advocate filed an appeal of the Circuit Court's decision to the Maryland Court of Special Appeals. BGE cannot predict the outcome of this appeal.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and natural gas smart meters at an expected total cost of $480 million of which $200 million was funded by SGIG. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. Refer to AMI programs in the Regulatory Assets and Liabilities section below for further details.

As part of the 2015 electric and natural gas distribution rate case filed on November 6, 2015, BGE sought recovery of its smart grid initiative costs, supported by evidence demonstrating that BGE had, in fact, implemented a cost-beneficial advanced metering system. On June 3, 2016, the MDPSC issued an order concluding that the smart grid initiative overall is cost beneficial to its customers. However, the June 3 order contained several cost disallowances and adjustments including disallowances of certain program and meter installation costs and denial of recovery of any return on unrecovered costs for non-AMI meters replaced under the program. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions and change certain of the cost disallowances and adjustments to enable BGE to defer those costs for recovery through future electric and natural gas rates. The residential consumer advocate also subsequently filed for a petition for rehearing of the June 3 order. On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative.

As a combined result of the MDPSC orders in BGE's 2015 electric and natural gas distribution rate case, BGE recorded a $52 million charge in June 2016 to Operating and maintenance expense in Exelon's and BGE's Consolidated Statements of Operations and Comprehensive Income reducing certain regulatory assets and other long-lived assets and reclassified $56 million of non-AMI plant costs from Property, plant and equipment, net to Regulatory assets on Exelon's and BGE's Consolidated Balance Sheets.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In 2013, legislation intended to accelerate gas infrastructure replacements in Maryland was signed into law. The law established a mechanism, separate from base rate proceedings, for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects incurred after June 1, 2013. The monthly surcharge and infrastructure replacement costs must be approved by the MDPSC and are subject to a cap and require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled

into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation.

On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On July 1, 2016, BGE filed an amendment to its infrastructure replacement plan, which the MDPSC conditionally approved in an order dated November 23, 2016. The revised surcharge reflecting the costs of the amendment became effective January 1, 2017. On November 1, 2017, BGE filed a surcharge update to be effective January 1, 2018 along with its 2018 project list and projected capital estimates of $136 million to be included in the 2018 surcharge calculation. The MDPSC subsequently approved BGE's 2018 project list and the proposed surcharge for 2018. As of December 31, 2017 , BGE recorded a regulatory liability of less than $1 million , representing the difference between the surcharge revenues and program costs.

On December 1, 2017 (and as amended on January 22, 2018), BGE filed an application with the MDPSC seeking approval for a new infrastructure replacement plan and associated surcharge, effective for the five-year period from 2019 through 2023. BGE's new plan calls for capital expenditures over the 2019-2023 timeframe of $963 million , with an associated revenue requirement of $242 million . BGE expects a decision in the matter by May 31, 2018, but cannot predict whether the MDPSC will approve the plan as filed.

Delaware Regulatory Matters

Tax Cuts and Jobs Act (Exelon, PHI and DPL). On January 16, 2018, the DPSC opened a docket to examine the impacts of the TCJA on the cost of service and rates of all regulated public utilities in Delaware, which includes DPL. The DPSC also stated the TCJA benefits would be addressed in DPL's pending rate case.

In response, by mid-February 2018, DPL is planning to file with the DPSC updates to its electric and gas distribution rate cases described below to reflect approximately $26 million in tax savings resulting from the enactment of the TCJA, of which $19 million and $7 million are related to electric and natural gas, respectively. The updated requests for amounts being passed back to customers would reflect the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. Refer to Note 14 - Income Taxes for more detail on Corporate Tax Reform. DPL expects a decision in the matter in the third quarter of 2018 for the electric distribution proceeding and in the fourth quarter of 2018 for the gas distribution proceeding, but cannot predict how much of the requested increase the DPSC will approve. It is expected that the DPSC will address in a future rate proceeding DPL's treatment of the TCJA tax savings for the period February 1, 2018 through the effective date of any customer rate adjustments in the pending rate proceedings.

2017 Delaware Electric and Natural Gas Distribution Rates (Exelon, PHI and DPL). On August 17, 2017, DPL filed applications with the DPSC to increase its annual electric and natural gas distribution base rates by $24 million and $13 million respectively, reflecting a requested ROE of 10.1% . DPL filed updated testimony on October 18, 2017, to request a $31 million increase in electric distribution rates, and updated testimony on November 7, 2017, to request an $11 million increase in natural gas distribution rates. While the DPSC is not required to issue a decision on the applications within a specified period of time, Delaware law allows DPL to put into effect $2.5 million of the rate increases for both electric and natural gas two months after filing the application and the entire requested rate increases seven months after filing, subject to a cap and a refund obligation based on the final DPSC order. On October 24, 2017, the Staff of the DPSC and the Public Advocate filed a joint motion to dismiss DPL's electric distribution base rate application without prejudice to refiling, arguing that the amount of the requested increase to $31 million required additional time to review and additional public notice. In November 2017, the DPSC denied the joint motion to dismiss.

2016 Delaware Electric and Natural Gas Distribution Base Rates (Exelon, PHI and DPL). On May 17, 2016, DPL filed applications with the DPSC to increase its annual electric and natural gas distribution base rates by $63 million , which was updated to $60 million on March 8, 2017, and $22 million , respectively, reflecting a requested ROE of 10.6% . Delaware law allowed DPL to put into effect $2.5 million of each of the rate increases effective July 16, 2016. On December 17, 2016, the DPSC approved that an additional $30 million in electric distribution rates and an additional $10 million in gas distribution rates effective December 17, 2016, subject to refund based on the final DPSC orders.

On March 8, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate, Delaware Electric Users Group and the DPSC Staff in its electric distribution rate proceeding, which provides for an increase in DPL annual electric distribution base rates of $31.5 million reflecting a ROE of 9.7% compared to the $32 million increase previously put into effect. On May 23, 2017, the DPSC issued an order approving the settlement agreement, with the new rates effective June 1, 2017. Pursuant to the settlement agreement, no refund of the interim rates put into effect on July 16, 2016 and December 17, 2016 (as discussed above) is required.

On April 6, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate and the DPSC Staff in its natural gas distribution rate proceeding, which provides for an increase in DPL annual natural gas distribution base rates of $4.9 million reflecting a ROE of 9.7% . The settlement agreement also provides that DPL will refund amounts collected under the temporary rates effective July 16, 2016 and December 17, 2016 (as discussed above) in excess of the $4.9 million , and that the new rates will be effective within thirty days of DPSC approval of the settlement agreement. On June 6, 2017, the DPSC issued an order approving the settlement agreement, with the new rates effective July 1, 2017. Pursuant to the settlement agreement, a rate refund plus interest of approximately $5 million was issued to customers beginning in August 2017. This was a one-time refund and was included on customer bills from mid-August through mid-September.

District of Columbia Regulatory Matters

Tax Cuts and Jobs Act (Exelon, PHI and Pepco) . On January 23, 2018, the DCPSC opened a rate proceeding directing Pepco to track the impacts of the TCJA beginning January 1, 2018 and file its plan to reduce the current revenue requirement by customer class by February 12, 2018. The DCPSC stated it will address the impact of the TCJA on future rates within Pepco's pending electric distribution rate case discussed below and Pepco will accordingly update its current distribution rate case in February 2018.

Separately, on February 6, 2018, Pepco filed with the DCPSC seeking approval to pass back to customers beginning in 2018 $39 million in tax savings resulting from the enactment of the TCJA through a reduction in electric distribution rates. The amounts being passed back to customers would reflect the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. It is expected that the DCPSC will address in a future rate proceeding Pepco's treatment of the TCJA tax savings for the period January 1, 2018 through the effective date of any customer rate adjustments. Refer to Note 14 - Income Taxes for more detail on Corporate Tax Reform.

2017 District of Columbia Electric Distribution Base Rates (Exelon, PHI and Pepco). On December 19, 2017, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $66 million , reflecting a requested ROE of 10.1% . By mid-February, Pepco will update its current distribution rate case to reflect the TCJA impacts from January 1, 2018 through the effective date of the $39 million customer rate adjustment described above. Pepco expects a decision in the matter in the fourth quarter of 2018, but cannot predict how much of the requested increase the DCPSC will approve.

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2016 District of Columbia Electric Distribution Base Rates (Exelon, PHI and Pepco). On June 30, 2016, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $86 million , which was updated to $77 million on February 1, 2017, reflecting a requested ROE of 10.6% .

On July 25, 2017, the DCPSC approved an increase in Pepco electric distribution base rates of $37 million reflecting a ROE of 9.5% . The new rates became effective for services rendered on or after August 15, 2017. In its decision, the DCPSC ordered that the $26 million customer rate credit created as a result of the Exelon and PHI merger will be provided primarily to residential customers and some small commercial customers to offset the impact of this increase until that amount has been exhausted, which is expected to take approximately two years. Additionally, the Commission is holding approximately $6 million to $7 million of the customer rate credit for use toward a possible new class of customers for certain senior citizens and disabled persons. The DCPSC also held that Pepco's bill stabilization adjustment, which decouples distribution revenues from utility customers from the amount of electricity delivered, will continue to be in place and that no refund of previously collected funds is required. Several parties filed requests that the DCPSC reconsider the order on various issues, and on October 6, 2017, the Commission issued an order denying each of the requests.

District of Columbia Power Line Undergrounding Initiative (Exelon, PHI and Pepco). The District of Columbia government enacted on an emergency basis (effective May 17, 2017) and thereafter on a permanent basis (effective July 11, 2017) legislation to amend the Electric Company Infrastructure Improvement Financing Act of 2014 (as amended) (the Infrastructure Improvement Financing Act) to authorize the District of Columbia Power Line Undergrounding (DC PLUG) initiative, a projected six year, $500 million project to place underground some of the District of Columbia's most outage-prone power lines with $250 million of the project costs funded by Pepco and $250 million funded by the District of Columbia.

The $250 million of project costs funded by Pepco will be recovered through a volumetric surcharge on the electric bill of substantially all of Pepco's customers in the District of Columbia. Pepco will earn a return on these project costs.

The $250 million of project costs funded by the District of Columbia will come from two sources. Project costs of $187.5 million will be funded through a charge assessed on Pepco by the District of Columbia; Pepco will recover this charge from customers through a volumetric distribution rider. The remaining costs up to $62.5 million are to be funded by the existing capital projects program of the District Department of Transportation (DDOT). Ownership and responsibility for the operation and maintenance of all the assets funded by the District of Columbia will be transferred to Pepco for a nominal amount upon completion. Pepco will not recover or earn a return on the cost of the assets transferred to it by the District of Columbia.

In accordance with the Infrastructure Improvement Financing Act, Pepco filed an application for approval of the first two-year plan in the DC PLUG initiative (the First Biennial Plan) on July 3, 2017. After the initial application, Pepco will be required to make two additional applications. On November 9, 2017, the DCPSC issued an order approving the First Biennial Plan and the application for a financing order. Pursuant to that order, Pepco is obligated to pay $187.5 million to the District of Columbia over the six-year project term, of which it expects to pay $27.5 million in 2018. Pepco recorded an obligation and offsetting regulatory asset in November. On December 11, 2017, an interested party filed for reconsideration of the DCPSC's November 9 order and on January 18, 2018, the DCPSC denied the interested party's request. Rates for the DC PLUG initiative went into effect on February 7, 2018.

New Jersey Regulatory Matters

Tax Cuts and Jobs Act (Exelon, PHI and ACE) . On January 31, 2018, the NJBPU issued an order mandating that New Jersey utility companies, including ACE, pass any economic benefit from the

TCJA to rate payers. The order directed New Jersey utility companies to file by March 2, 2018 proposed tariff sheets reflecting TCJA benefits, with new rates to be implemented effective April 1, 2018. In addition, the NJBPU directed New Jersey utility companies to file by March 2, 2018 a Petition with the NJBPU outlining how they propose to refund any over-collection associated with revised rates not being in place from January 1, 2018 through March 31, 2018, with interest.

ACE estimates that approximately $23 million in TCJA savings will be passed back to ACE customers, reflecting the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. Refer to Note 14 - Income Taxes for more detail on Corporate Tax Reform.

New Jersey Consolidated Tax Adjustment (Exelon, PHI and ACE). The Consolidated Tax Adjustment (CTA) is a New Jersey ratemaking policy that requires utilities that are part of a consolidated tax group to share with customers the tax benefits that came from losses at unregulated affiliates through a reduction in rate base. In 2013, the NJBPU opened a generic proceeding to review the policy. In 2014, the NJBPU issued a decision which retained the CTA, but in a highly modified format that significantly reduced the impact of the CTA to ACE. On September 18, 2017, the Appellate Division of the Superior Court of New Jersey reversed the NJBPU's decision in adopting the revised CTA policy and held that NJBPU's actions related to the CTA constituted a rulemaking that should have been undertaken pursuant to the requirements of the Administrative Procedures Act. The Court did not address the merits of the CTA methodology itself. No party filed an appeal of the Court's decision, and the NJBPU has issued a proposed rule for comment, consistent with the requirements of the Administrative Procedures Act. The substance of the proposed rule is consistent with the NJBPU's decision in the generic proceeding. If the NJBPU were to apply the CTA in its unmodified form, it could have a material prospective impact to ACE through a reduction in rate base in future rate cases.

2017 New Jersey Electric Distribution Rates (Exelon, PHI and ACE). On March 30, 2017, ACE filed an application with the NJBPU to increase its annual electric distribution rates by $70 million (before New Jersey sales and use tax), which was updated to $73 million on July 14, 2017, reflecting a requested ROE of 10.1% . The application also requests approval of a rate surcharge mechanism called the "System Renewal Recovery Charge," which would permit more timely recovery of certain costs associated with reliability and system renewal-related capital investments.

On September 8, 2017, ACE entered into a settlement agreement with the NJBPU staff, the New Jersey Division of Rate Counsel and Wal-Mart Stores, Inc. in its electric distribution rate proceeding, which provides for an increase in ACE annual electric distribution base rates of $43 million (before New Jersey sales and use tax) reflecting a ROE of 9.6% . In addition, pursuant to the settlement agreement, ACE agreed to withdraw its request for approval of a System Renewal Recovery Charge without prejudice to its right to refile. On September 22, 2017, the NJBPU issued an order approving the settlement agreement, with the new rates effective on October 1, 2017.

2016 New Jersey Electric Distribution Base Rates (Exelon, PHI and ACE). On August 24, 2016, the NJBPU issued an order approving a stipulation of settlement among ACE, the New Jersey Division of Rate Counsel, NJBPU Staff and Unimin Corporation, which, among other things, provided that a determination on ACE's grid resiliency program, PowerAhead, would be separated into a phase II of the rate proceeding and decided at a later date. PowerAhead includes capital investments to enhance the resiliency of the system through improvements focused on improving the distribution system's ability to withstand major storm events. A stipulation of settlement with respect to the PowerAhead program (the PowerAhead Stipulation) was approved by the NJBPU on May 31, 2017. As adopted, the PowerAhead program includes an approved investment level of $79 million to be recovered through the cost recovery mechanism described in the PowerAhead Stipulation. The NJBPU order adopting the PowerAhead Stipulation was effective on June 10, 2017.

2017 Update and Reconciliation of Certain Under-Recovered Balances (Exelon, PHI and ACE). On February 1, 2017, ACE submitted its 2017 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the non-utility generators and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE's uncollectible accounts. As filed, the net impact of adjusting the charges as proposed would have been an overall annual rate decrease of approximately $29 million (revised to approximately $32 million in April 2017, based upon an update for actuals through March 2017), including New Jersey sales and use tax. On May 31, 2017, the NJBPU approved a stipulation of settlement entered into by the parties providing for an overall annual rate decrease of approximately $32 million , effective June 1, 2017. The rate decrease was placed into effect provisionally, subject to a review by NJBPU and the Division of Rate Counsel of the final underlying costs for reasonableness and prudence. This rate decrease will have no effect on ACE's operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism. On November 1, 2017, ACE entered into a Stipulation of Final Rates with the NJBPU staff and the New Jersey Division of Rate Counsel which was unchanged from the provisional rates. On November 21, 2017, the NJBPU issued an order approving the Stipulation of Final Rates as filed.

2016 Update and Reconciliation of Certain Under-Recovered Balances (Exelon, PHI and ACE). On February 1, 2016, ACE submitted its 2016 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the non-utility generators and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE's uncollectible accounts.

As filed, the net impact of adjusting the charges as proposed would have been an overall annual rate increase of $9 million (revised to $19 million in April 2016, based upon an update for actuals through March 2016), including New Jersey sales and use tax.

On November 30, 2016, the NJBPU approved a stipulation of settlement entered into by the parties providing for an overall annual rate increase of $1 million effective January 1, 2017. This settlement included a credit of approximately $10 million to the Non-Utility Generation charge deferral balance and a credit of approximately $7 million to the Uncollectible deferral balance. These credits were directed to be applied to the deferral balances in an NJBPU order dated October 31, 2016. That order approved the Joint Recommendation for Settlement of the Most Favored Nation Provision, which was a condition of the merger between Exelon Corporation and Pepco Holdings, Inc. This rate increase will have no effect on ACE's operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism.

New York Regulatory Matters

New York Clean Energy Standard (Exelon and Generation). On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the New York CES, a component of which is a Tier 3 ZEC program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity as determined by the NYPSC. The New York State Energy Research and Development Authority (NYSERDA) will centrally procure the ZECs from eligible plants through a 12-year contract, to be administered in six two-year tranches, extending from April 1, 2017 through March 31, 2029. ZEC payments will be made to the eligible resources based upon the number of MWh produced, subject to specified caps and minimum performance requirements. The price to be paid for the ZECs under each tranche will be administratively determined using a formula based on the social cost of carbon as determined in 2016 by the federal government, subject to pricing adjustments designed to lower the ZEC price based on increases in underlying energy and capacity prices. The ZEC price for the first tranche has been set at $17.48 per

MWh of production. Following the first tranche, the price will be updated bi-annually. Each Load Serving Entity (LSE) shall be required to purchase an amount of ZECs equivalent to its load ratio share of the total electric energy in the New York Control Area. Cost recovery from ratepayers shall be incorporated into the commodity charges on customer bills.

The NYPSC initially identified three plants eligible for the ZEC program: the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. As issued, the order also provided that the duration of the program beyond the first tranche was conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018. On November 18, 2016, the required contracts with NYSERDA were executed for Ginna and Nine Mile Point, in addition to Entergy's execution of the required contract for the FitzPatrick facility. On March 31, 2017, Generation closed on the acquisition of FitzPatrick. Generation is currently recognizing revenue for the sale of New York ZECs in the month following generation when the ZECs are transferred to NYSERDA. For the year ended December 31, 2017 , Generation has recognized $311 million of ZEC revenue.

Several parties filed with the NYPSC requests for rehearing or reconsideration of the New York CES. Generation and CENG also filed a request for clarification, or in the alternative limited rehearing, that the condition limiting the duration of the program beyond the first tranche be limited to the eligibility of the FitzPatrick plant only and have no bearing on Ginna or Nine Mile Point's eligibility for the full 12-year duration. On December 15, 2016, the NYPSC approved Exelon's petition to clarify this condition and denied all petitions for rehearing of the New York CES. Parties had until mid-April 2017 to appeal to New York State court the denials of the requests for rehearing.

On October 19, 2016, a coalition of fossil-generation companies filed a complaint in federal district court against the NYPSC alleging that the ZEC program violates certain provisions of the U.S. Constitution; specifically, that the ZEC program interferes with FERC's jurisdiction over wholesale rates and that it discriminates against out of state competitors. On December 9, 2016, Generation and CENG filed a motion to intervene in the case and to dismiss the lawsuit. The State also filed a motion to dismiss. On July 25, 2017, the court granted both motions to dismiss. On August 24, 2017, plaintiffs appealed the decision to the Second Circuit. Plaintiffs-Appellants' initial brief was filed on October 13, 2017. Briefing in the appeal was completed in December 2017, and oral argument is expected to take place in March 2018.

In addition, on November 30, 2016, a group of parties, including certain environmental groups and individuals, filed a Petition in New York State court seeking to invalidate the ZEC program. The Petition, which was amended on January 13, 2017, argued that the NYPSC did not have authority to establish the program and that it violated certain technical provisions of the State Administrative Procedures Act (SAPA) when adopting the ZEC program. On February 15, 2017, Generation and CENG filed a motion to dismiss the state court action. The NYPSC also filed a motion to dismiss the state court action. On March 24, 2017, the plaintiffs filed a memorandum of law opposing the motions to dismiss, and Generation and CENG filed a reply brief on April 28, 2017. Oral argument was held on June 19, 2017. On January 22, 2018, the court denied the motions to dismiss without commenting on the merits of the case. The case will now proceed to summary judgment upon filing of the full record.

Other legal challenges remain possible, the outcomes of which remain uncertain. See Note 8 - Early Nuclear Plant Retirements for additional information relative to Ginna and Nine Mile Point, and Note 4 - Mergers, Acquisitions and Dispositions for additional information on Generation's proposed acquisition of FitzPatrick.

Ginna Nuclear Power Plant Reliability Support Services Agreement (Exelon and Generation). In November 2014, in response to a petition filed by Ginna Nuclear Power Plant (Ginna) regarding the possible retirement of Ginna, the NYPSC directed Ginna and Rochester Gas & Electric Company (RG&E) to negotiate a Reliability Support Services Agreement (RSSA) to support the continued operation of Ginna to maintain the reliability of the RG&E transmission grid for a specified period of time. During 2015

and 2016, Ginna and RG&E made filings with the NYPSC and FERC for their approval of the proposed RSSA. Although the RSSA was still subject to regulatory approvals, on April 1, 2015, Ginna began delivering the power and capacity from the Ginna plant into the ISO-NY consistent with the technical provisions of the RSSA.

On March 22, 2016, Ginna submitted a compliance filing with FERC with revisions to the RSSA requested by FERC. On April 8, 2016, FERC accepted the compliance filing and on April 20, 2016, the NYPSC accepted the revised RSSA with a term expiring on March 31, 2017. In April 2016, Generation began recognizing revenue based on the final approved pricing contained in the RSSA and also recognized a one-time revenue adjustment of approximately $101 million representing the net cumulative previously unrecognized amount of revenue retroactive from the April 1, 2015 effective date through March 31, 2016. A 49.99% portion of the one-time adjustment was removed from Generation's results of operations as a result of the noncontrolling interests in CENG.

The RSSA required Ginna to continue operating through the RSSA term. On September 30, 2016, Ginna filed the required notice with the NYPSC of its intent to continue operating beyond the March 31, 2017 expiry of the RSSA, conditioned upon successful execution of an agreement between Ginna and NYSERDA for the sale of ZECs under the New York CES. As stated previously, on November 18, 2016 the required contract with NYSERDA was executed by Generation and CENG for Ginna. Upon the expiry of the RSSA on March 31, 2017, Ginna was required to make refund payments of $20 million to RG&E related to capital expenditures. Ginna paid RG&E the $20 million in June 2017. Additionally, the provisions of the RSSA provided for a one-time payment of $12 million to be paid from RG&E to Ginna at the end of the contract. This $12 million was recognized in revenue as of March 31, 2017. RG&E paid the $12 million to Ginna in May 2017. Subject to prevailing over any administrative or legal challenges, it is expected the New York CES will allow Ginna to continue to operate through the end of its current operating license in 2029. See Note 8 - Early Nuclear Plant Retirements for further information regarding the impacts of a decision to early retire one or more nuclear plants.

Federal Regulatory Matters

Tax Cuts and Jobs Act (All Registrants). To date, the FERC has not yet issued guidance to utilities on how and when to reflect the impacts of the TCJA in customer rates. However, pursuant to their respective transmission formula rates, ComEd, BGE, Pepco, DPL and ACE will begin passing back to customers on June 1, 2018, the benefit of lower income tax rates effective January 1, 2018. ComEd's, BGE's, Pepco's, DPL's and ACE's transmission formula rates currently do not provide for the pass back or recovery of income tax-related regulatory liabilities or assets. As discussed above, on December 13, 2016 (and as amended on March 13, 2017), BGE filed with FERC to begin recovering certain existing and future transmission-related income tax regulatory assets through its transmission formula rate. On November 16, 2017, FERC issued an order rejecting BGE's proposed revisions to its transmission formula rate and on December 18, 2017, BGE filed for clarification and rehearing of FERC's order. ComEd, Pepco, DPL and ACE also have similar transmission-related income tax regulatory assets and liabilities, for which FERC approval is required, separate from their transmission formula rate mechanisms, to pass back or recover those regulatory liabilities and assets through customer rates. PECO is currently in settlement discussions regarding its transmission formula rate and expects to pass back TCJA benefits to customers through its annual formula rate update.

Refer to Deferred income taxes in the Regulatory Assets and Liabilities section below for the balances of transmission-related income tax regulatory assets as of December 31, 2017 and 2016.

Transmission Formula Rate (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE). ComEd's, BGE's, Pepco's, DPL's and ACE's transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL and ACE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions. The

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update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd, BGE, Pepco, DPL, and ACE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd's, BGE's, Pepco's, DPL's and ACE's best estimate of the revenue requirement expected to be filed with the FERC for that year's reconciliation. The regulatory asset associated with transmission true-up is amortized to Operating revenues within their Consolidated Statements of Operations of Comprehensive Income as the associated amounts are recovered through rates.

For each of the following years, the following total increases/(decreases) were included in ComEd's, BGE's, Pepco's, DPL's and ACE's electric transmission formula rate filings:

	ComEd			BGE		
Annual Transmission Filings [a]	2017	2016	2015	2017	2016	2015
Initial revenue requirement increase	$ 44	$ 90	$ 68	$ 31	$ 12	$ —
Annual reconciliation increase (decrease)	(33)	4	18	3	3	(3)
Dedicated facilities (decrease) increase [b]	—	—	—	(8)	13	13
Total revenue requirement increase	$ 11	$ 94	$ 86	$ 26	$ 28	$ 10
Allowed return on rate base [d]	8.43%	8.47%	8.61%	7.47%	8.09%	8.46%
Allowed ROE [e]	11.50%	11.50%	11.50%	10.50%	10.50%	11.30%

	Pepco			DPL			ACE		
Annual Transmission Filings [a]	2017	2016	2015	2017	2016	2015	2017	2016	2015
Initial revenue requirement increase (decrease)	$ 5	$ 2	$ 10	$ 6	$ 8	$ 15	$ 20	$ 8	$ 10
Annual reconciliation (decrease) increase	15	(10)	(3)	8	(10)	(1)	22	(14)	2
MAPP abandonment recovery (decrease) increase [c]	—	(15)	(2)	—	(12)	(2)	—	—	—
Total revenue requirement (decrease) increase	$ 20	$ (23)	$ 5	$ 14	$ (14)	$ 12	$ 42	$ (6)	$ 12
Allowed return on rate base [d]	7.92%	7.88%	8.36%	7.16%	7.21%	7.80%	8.02%	7.83%	8.51%
Allowed ROE [e]	10.50%	10.50%	11.30%	10.50%	10.50%	11.30%	10.50%	10.50%	11.30%

(a) The time period for any challenges to the annual transmission formula rate update filings expired with no challenges submitted.
(b) BGE's transmission revenues include a FERC approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE.
(c) In 2012, PJM terminated the MAPP transmission line construction project planned for the Pepco and DPL service territories. Pursuant to a FERC approved settlement agreement, the abandonment costs associated with MAPP were being recovered in transmission rates over a three-year period that ended in May 2016.
(d) Represents to the weighted average debt and equity return on transmission rate bases.

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(e) As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50% , inclusive of a 50-basis-point incentive adder for being a member of a RTO, and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55% . As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50% , inclusive of a 50-basis-point incentive adder for being a member of a RTO.

Transmission Formula Rate (Exelon and PECO). On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO's transmission rate is determined from a fixed rate to a formula rate. The formula rate would be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO's annual transmission revenues and a requested rate of return on common equity of 11% , inclusive of a 50 basis point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. The parties currently are engaged in settlement discussions. PECO cannot predict the final outcome of the settlement or hearing proceedings, or the transmission formula FERC may approve.

Transmission-Related Income Tax Regulatory Assets (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE). On December 13, 2016 (and as amended on March 13, 2017), BGE filed with FERC to begin recovering certain existing and future transmission-related income tax regulatory assets through its transmission formula rate. BGE's existing regulatory assets included (1) amounts that, if BGE's transmission formula rate provided for recovery, would have been previously amortized and (2) amounts that would be amortized and recovered prospectively. On November 16, 2017, FERC issued an order rejecting BGE's proposed revisions to its transmission formula rate to recover these transmission-related income tax regulatory assets. On December 18, 2017, BGE filed for clarification and rehearing of FERC's order, still seeking full recovery of its existing transmission-related income tax regulatory asset amounts.

ComEd, Pepco, DPL and ACE have similar transmission-related income tax regulatory assets also requiring FERC approval separate from their transmission formula rate mechanisms. Similar regulatory assets at PECO are not subject to the same FERC transmission rate recovery formula and, thus, are not impacted by the November 16, 2017 FERC order.

Each of BGE, ComEd, Pepco, DPL and ACE believe there is sufficient basis to support full recovery of their existing transmission-related income tax regulatory assets, and each intends to further pursue such full recovery with FERC. However, upon further consideration of the November 16, 2017 FERC order, management of each company concluded that the portion of the total transmission-related income tax regulatory assets that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery was no longer probable of recovery. As a result, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE recorded the following charges to Income tax expense within their Consolidated Statements of Operations and Comprehensive Income in the fourth quarter 2017, reducing their associated transmission-related income tax regulatory assets.

	For the year ended December 31, 2017
Exelon [a]	$ 35
ComEd	3
BGE	5
PHI [a]	27
Pepco	14
DPL	6
ACE	7

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(a) Exelon reflects the consolidated regulatory asset impairments of ComEd, BGE, Pepco, DPL and ACE, and PHI reflects the consolidated regulatory asset impairments of Pepco, DPL and ACE.

To the extent any of the companies are ultimately successful with the FERC allowing future recovery of these amounts, the associated regulatory assets will be reestablished, with corresponding decreases to Income tax expense. To the extent all or a portion of the prospective amortization amounts were no longer considered probable of recovery, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE would record additional charges to Income tax expense, which could be up to approximately $81 million , $41 million , $22 million , $18 million , $8 million , $7 million and $3 million , respectively, as of December 31, 2017.

Refer to Deferred income taxes in the Regulatory Assets and Liabilities section below for the balances of these transmission-related income tax regulatory assets as of December 31, 2017 and 2016.

PJM Transmission Rate Design and Operating Agreements (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO, BGE, Pepco, DPL and ACE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. A number of parties appealed to the U.S. Court of Appeals for the Seventh Circuit for review of the decision.

In August 2009, the court issued its decision affirming the FERC's order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above (Cost Allocation Issue) for further consideration by the FERC. On remand, FERC reaffirmed its earlier decision to socialize the costs of new facilities 500 kV and above. A number of parties filed appeals of these orders. In June 2014, the court again remanded the Cost Allocation Issue to FERC. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the Cost Allocation Issue. On June 15, 2016, a number of parties, including Exelon and the Utility Registrants, filed a proposed Settlement with FERC. If the Settlement is approved, 50% of the costs of the 500 kV and above facilities approved by the PJM Board on or before February 1, 2013 will be socialized across PJM and 50% will be allocated according to a formula that calculates the flows on the transmission facilities. Each state that is a party in this proceeding either signed, or did not oppose, the settlement. The Settlement is opposed by a number of merchant transmission owners and New York load-serving entities. The Settlement includes provisions for monthly credits or charges that are expected to be mostly refunded or recovered through customer rates over a 10-year period based on negotiated numbers for charges prior to January 1, 2016.

Exelon expects that the Settlement will not have a material impact on the results of operations, cash flows and financial position of Generation, ComEd, PECO, BGE, Pepco, DPL or ACE. The Settlement is subject to approval by FERC. The FERC is not required to issue a decision on the matter within a specified period of time.

The Utility Registrants are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. The Utility Registrants will work with PJM to continue to evaluate the scope and timing of any required construction projects. The Utility Registrants' estimated commitments are as follows:

	Total	2018	2019	2020	2021	2022
ComEd	$ 164	$ 36	$ 60	$ 44	$ 24	$ —
PECO	53	16	19	10	5	3
BGE	118	35	35	35	13	—
Pepco	86	5	11	27	33	10
DPL	27	19	2	1	2	3
ACE	121	68	20	6	21	6

DOE Notice of Proposed Rulemaking (Exelon and Generation). On August 23, 2017, the DOE staff released its report on the reliability of the electric grid. One aspect of the wide-ranging report is the DOE's recognition that the electricity markets do not currently value the resiliency provided by baseload generation, such as nuclear plants. On September 28, 2017, the DOE issued a Notice of Proposed Rulemaking (NOPR) that would entitle certain eligible resilient generating units (i.e., those located in organized markets, with a 90-day supply of fuel on site, not already subject to state cost of service regulation and satisfying certain other requirements) to recover fully allocated costs and earn a fair return on equity on their investment. The DOE's NOPR recommended that the FERC take comments for 45 days after publication in the Federal Register and issue a final order 60 days after such publication. On January 8, 2018, the FERC issued an order terminating the rulemaking docket that was initiated to address the proposed rule in the DOE NOPR, concluding the proposed rule did not sufficiently demonstrate there is a resiliency issue and that it proposed a remedy that did not appear to be just, reasonable and nondiscriminatory as required under the Federal Power Act. At the same time, the FERC initiated a new proceeding to consider resiliency challenges to the bulk power system and evaluate whether additional FERC action to address resiliency would be appropriate. The FERC directed each RTO and ISO to respond within 60 days to 24 specific questions about how they assess and mitigate threats to resiliency. Interested parties may submit reply comments within 30 days after the due date of the RTO/ISO responses. Exelon has been and will continue to be an active participant in these proceedings, but cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.

Complaints at FERC Seeking to Mitigate Illinois and New York Programs Providing ZECs (Exelon and Generation). PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to remove the revenues it receives through a federal, state or other government-provided financial support program - resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new resources. Exelon has generally opposed policies that require subsidies or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid. Thus, Exelon has supported a MOPR as a means of minimizing the detrimental impact certain subsidized resources could have on capacity markets (such as the New Jersey (LCAPP) and Maryland (CfD) programs). However, in Exelon's view, MOPRs should not be applied to resources that receive compensation for providing superior reliability or environmental benefits.

On January 9, 2017, the Electric Power Supply Association (EPSA) filed two requests with FERC: one seeking to amend a prior complaint against PJM and another seeking expedited action on a pending NYISO compliance filing in an existing proceeding. Both filings allege that the relevant MOPR should be expanded to also apply to existing resources receiving ZEC compensation under the New York CES and Illinois ZES programs. The EPSA parties have filed motions to expedite both proceedings. Exelon has filed protests at FERC in response to each filing, arguing generally that ZEC payments provide compensation for an environmental attribute that is distinct from the energy and capacity sold in the FERC-jurisdictional markets , and therefore, are no different than other renewable support programs like

the PTC and RPS that have generally not been subject to a MOPR. However, if successful, for Generation's facilities in NYISO and PJM expected to receive ZEC compensation (Quad Cities, Ginna, Nine Mile Point and FitzPatrick), an expanded MOPR could require exclusion of ZEC compensation when bidding into future capacity auctions such that these facilities would have an increased risk of not clearing in those auctions and thus no longer receiving capacity revenues during the respective ZEC programs. Any such mitigation of these generating resources could have a material effect on Exelon's and Generation's future cash flows and results of operations. On August 30, 2017, EPSA filed motions to lodge the district court decisions dismissing the complaints and urging FERC to act expeditiously on its requests to expand the MOPR. On September 14, 2017, Exelon filed a response in each docket noting that it does not oppose the motions to lodge but arguing that the requests to expedite a decision on the requests to expand the MOPR have no merit. The timing of FERC's decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

Operating License Renewals (Exelon and Generation). On August 29, 2012, Generation submitted a hydroelectric license application to FERC for a 46 -year license for the Conowingo Hydroelectric Project (Conowingo). In connection with Generation's efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act with Maryland Department of the Environment (MDE) for Conowingo, Generation continues to work with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment.

On April 21, 2016, Exelon and the US Fish and Wildlife Service of the US Department of the Interior executed a Settlement Agreement resolving all fish passage issues between the parties. The financial impact of the Settlement Agreement is estimated to be $3 million to $7 million per year, on average, over the 46-year life of the new license, including both capital and operating costs. The actual timing and amount of these costs are not currently fixed and may vary significantly from year to year throughout the life of the new license.

Resolution of the remaining issues relating to Conowingo involving various stakeholders may have a material effect on Exelon's and Generation's results of operations and financial positions through an increase in capital expenditures and operating costs. As of December 31, 2017 , $31 million of direct costs associated with Conowingo licensing efforts have been capitalized.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE each prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

As a result of applying the acquisition method of accounting and pushing it down to the consolidated financial statements of PHI, certain regulatory assets and liabilities were established at Exelon and PHI to offset the impacts of fair valuing the acquired assets and liabilities assumed which are subject to regulatory recovery. In total, Exelon and PHI recorded a net $2.4 billion regulatory asset reflecting adjustments recorded as a result of the acquisition method of accounting. See Note 4 - Mergers, Acquisitions and Dispositions for additional information.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE as of December 31, 2017 and December 31, 2016 :

					Successor			
December 31, 2017	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Regulatory assets								
Pension and other postretirement benefits	$ 3,848	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	306	—	297	—	9	9	—	—
AMI programs	640	155	36	214	235	158	77	—
Electric distribution formula rate	244	244	—	—	—	—	—	—
Energy efficiency costs	166	166	—	—	—	—	—	—
Debt costs	116	37	1	11	73	15	8	5
Fair value of long-term debt	758	—	—	—	619	—	—	—
Fair value of PHI's unamortized energy contracts	750	—	—	—	750	—	—	—
Asset retirement obligations	109	73	22	14	—	—	—	—
MGP remediation costs	295	273	22	—	—	—	—	—
Under-recovered uncollectible accounts	61	61	—	—	—	—	—	—
Renewable energy	258	256	—	—	2	—	1	1
Energy and transmission programs	82	6	1	23	52	11	15	26
Deferred storm costs	27	—	—	—	27	7	5	15
Energy efficiency and demand response programs	596	—	1	285	310	229	81	—
Merger integration costs	45	—	—	6	39	20	10	9
Under-recovered revenue decoupling	55	—	—	14	41	38	3	—
COPCO acquisition adjustment	5	—	—	—	5	—	5	—
Workers compensation and long-term disability costs	35	—	—	—	35	35	—	—
Vacation accrual	19	—	6	—	13	—	8	5
Securitized stranded costs	79	—	—	—	79	—	—	79
CAP arrearage	8	—	8	—	—	—	—	—
Removal costs	529	—	—	—	529	150	93	286
DC PLUG charge	190	—	—	—	190	190	—	—
Other	67	8	16	4	39	29	8	4
Total regulatory assets	9,288	1,279	410	571	3,047	891	314	430
Less: current portion	1,267	225	29	174	554	213	69	71
Total noncurrent regulatory assets	$ 8,021	$ 1,054	$ 381	$ 397	$ 2,493	$ 678	$ 245	$ 359

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

					Successor			
December 31, 2017	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$ 30	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	5,241	2,479	—	1,032	$ 1,730	809	510	411
Nuclear decommissioning	3,064	2,528	536	—	—	—	—	—
Removal costs	1,573	1,338	—	105	130	20	110	—
Deferred rent	36	—	—	—	36	—	—	—
Energy efficiency and demand response programs	23	4	19	—	—	—	—	—
DLC program costs	7	—	7	—	—	—	—	—
Electric distribution tax repairs	35	—	35	—	—	—	—	—
Gas distribution tax repairs	9	—	9	—	—	—	—	—
Energy and transmission programs	111	47	60	—	4	—	1	3
Renewable portfolio standards costs	63	63	—	—	—	—	—	—
Zero emission credit costs	112	112	—	—	—	—	—	—
Over-recovered uncollectible accounts	2	—	—	—	2	—	—	2
Other	82	6	24	26	26	3	14	6
Total regulatory liabilities	10,388	6,577	690	1,163	1,928	832	635	422
Less: current portion	523	249	141	62	56	3	42	11
Total noncurrent regulatory liabilities	$ 9,865	$ 6,328	$ 549	$ 1,101	$ 1,872	$ 829	$ 593	$ 411

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

					Successor			
December 31, 2016	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits	$ 4,162	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	2,016	75	1,583	98	260	171	38	51
AMI programs	701	164	49	230	258	174	84	—
Electric distribution formula rate	188	188	—	—	—	—	—	—
Debt costs	124	42	1	7	81	17	9	6
Fair value of long-term debt	812	—	—	—	671	—	—	—
Fair value of PHI's unamortized energy contracts	1,085	—	—	—	1,085	—	—	—
Asset retirement obligations	111	76	23	12	—	—	—	—
MGP remediation costs	305	278	26	1	—	—	—	—
Under-recovered uncollectible accounts	56	56	—	—	—	—	—	—
Renewable energy	260	258	—	—	2	—	—	2
Energy and transmission programs	89	23	—	38	28	6	5	17
Deferred storm costs	36	—	—	1	35	12	5	18
Electric generation-related regulatory asset	10	—	—	10	—	—	—	—
Rate stabilization deferral	7	—	—	7	—	—	—	—
Energy efficiency and demand response programs	621	—	1	285	335	250	85	—
Merger integration costs	25	—	—	10	15	11	4	—
Under-recovered revenue decoupling	27	—	—	3	24	21	3	—
COPCO acquisition adjustment	8	—	—	—	8	—	8	—
Workers compensation and long-term disability costs	34	—	—	—	34	34	—	—
Vacation accrual	31	—	7	—	24	—	14	10
Securitized stranded costs	138	—	—	—	138	—	—	138
CAP arrearage	11	—	11	—	—	—	—	—
Removal costs	477	—	—	—	477	134	88	255
Other	54	7	9	10	29	22	5	4
Total regulatory assets	11,388	1,167	1,710	712	3,504	852	348	501
Less: current portion	1,342	190	29	208	653	162	59	96
Total noncurrent regulatory assets	$ 10,046	$ 977	$ 1,681	$ 504	$ 2,851	$ 690	$ 289	$ 405

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

					Successor			
December 31, 2016	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$ 47	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	2,607	2,169	438	—	—	—	—	—
Removal costs	1,601	1,324	—	141	136	18	118	—
Deferred rent	39	—	—	—	39	—	—	—
Energy efficiency and demand response programs	185	141	41	—	3	3	—	—
DLC program costs	8	—	8	—	—	—	—	—
Electric distribution tax repairs	76	—	76	—	—	—	—	—
Gas distribution tax repairs	20	—	20	—	—	—	—	—
Energy and transmission programs	134	60	56	—	18	8	5	5
Other	72	4	5	19	41	2	17	20
Total regulatory liabilities	4,789	3,698	644	160	237	31	140	25
Less: current portion	602	329	127	50	79	11	43	25
Total noncurrent regulatory liabilities	$ 4,187	$ 3,369	$ 517	$ 110	$ 158	$ 20	$ 97	$ —

Descriptions of the regulatory assets and liabilities included in the tables above are summarized below, including their recovery and amortization periods. Unless otherwise noted, the Utility Registrants are not earning or paying a return on these amounts.

Pension and other postretirement benefits. PECO's regulatory recovery for pension is based on cash contributions and, thus, is not included in the regulatory asset balances above. Otherwise, these amounts represent the Utility Registrants' portion of deferred costs associated with Exelon's pension and other postretirement benefit plans, which are recovered through customer rates. These amounts are generally amortized over the plan participants' average remaining service periods, subject to applicable cost recognition policies allowed under the authoritative guidance for pensions and postretirement benefits. See Note 16 - Retirement Benefits for additional information. These amounts also include regulatory assets established at the Constellation and PHI merger dates of $440 million and $953 million , respectively, as of December 31, 2017 and $492 million and $1,027 million , respectively, as of December 31, 2016 related to the rate regulated portions of the deferred costs associated with legacy Constellation's and PHI's pension and other postretirement benefit plans that are being amortized and recovered over approximately 12 years and 3 to 15 years, respectively (as established at the respective acquisition dates).

Deferred income taxes. These amounts represent deferred income taxes that are recoverable or refundable through customer rates, primarily associated with accelerated depreciation, the equity component of the allowance for funds used during construction, and the effects of income tax rate changes, including those resulting from the TCJA. These amounts are being amortized over the period in which the related deferred income taxes reverse, which is generally based on the expected life of the underlying assets, but may vary for certain deferred income taxes based on the determination of the rate regulators. These amounts include transmission-related regulatory liabilities that require FERC approval separate from the transmission formula rate of $484 million , $137 million , $147 million , $148 million and $147 million for ComEd, BGE, Pepco, DPL and ACE, respectively, as of December 31, 2017 . The December 31, 2017 balances reflect the impact of regulatory liabilities recorded in the fourth quarter, 2017 associated with the income tax rate reductions under the TCJA of $553 million , $174 million , $161 million , $160 million and $152 million for ComEd, BGE, Pepco, DPL and ACE, respectively, as well as the impact of impairment charges discussed above. As of December 31, 2016 the comparative amounts are a regulatory asset of $22 million , $38 million , $31 million , $20 million and $19 million for ComEd, BGE, Pepco, DPL and ACE, respectively. See Note 14 — Income Taxes and the Transmission-Related Income Tax Regulatory Assets section above for additional information.

AMI programs. For ComEd, this amount primarily represents accelerated depreciation costs resulting from the early retirements of non-AMI meters, which will be amortized over an average ten -year period pursuant to the ICC approved AMI Deployment plan. ComEd is earning a return on the regulatory asset.

For PECO, this amount primarily represents accelerated depreciation on PECO's non-AMI meter assets over a 10 -year period ending December 31, 2020. Recovery of smart meter costs are reflected in base rates effective January 1, 2016.

For BGE, this amount represents AMI costs associated with the installation of smart meters and the early retirement of legacy meters. The incremental costs associated with the installation, along with depreciation, amortization, and an appropriate return, had been building in a regulatory asset since the MDPSC approved the comprehensive smart grid initiative for BGE in August 2010 through approval of the program in BGE's rate order issued June 2016. As of December 31, 2017 , the balance of BGE's regulatory asset was $214 million , which consists of three major components, including $129 million of unamortized incremental deployment costs of the AMI program, $53 million of unamortized costs of the non-AMI meters replaced under the program, and $32 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. As of December 31, 2016 , the balance of BGE's regulatory asset was $230 million , which consists of three major components, including $144 million of unamortized incremental deployment costs of the AMI program, $54 million of unamortized costs of the non-AMI meters replaced under the program, and $32 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. The balances above reflect the impact of the cost allowances and adjustments in BGE's 2015 electric and natural gas distribution rate case. The incremental deployment costs for the AMI program and the non-AMI meter components of the regulatory asset are being amortized and recovered through rates over a 10-year period, which began in June 2016, while the post-test year incremental program deployment costs have not yet been approved for recovery by the MDPSC. A return on the regulatory asset is currently included in rates, except for the portion representing the unamortized cost of the retired non-AMI meters and the portion related to post-test year incremental program deployment costs.

For PHI, this amount represents AMI costs associated with the installation of smart meters and the early retirement of legacy meters throughout the service territories for Pepco and DPL. An AMI program has not been approved by the NJBPU for ACE in New Jersey. Pepco has received approval for recovery of deferred AMI program costs from the DCPSC and the MDPSC in its District of Columbia and Maryland service territories. Pepco does earn a return on the AMI deployment costs, but not on the early retirement of legacy meters. DPL has received approval for recovery of deferred AMI program costs from the DPSC and the MDPSC in its Delaware and Maryland service territories. DPL earns a return on the AMI deployment costs, but not on the early retirement of legacy meters.

Electric Distribution Formula Rate. These amounts represent under recoveries related to electric distribution services costs recoverable through ComEd's performance based formula rate. Under (over) recoveries for the annual reconciliations are recoverable (refundable) over a one-year period and costs for certain one-time events, such as large storms, are recoverable over a five-year period. ComEd earns and pays a return on under and over-recovered costs, respectively. As of December 31, 2017 , the regulatory asset was comprised of $186 million for the 2016 and 2017 annual reconciliations and $58 million related to significant one-time events. As of December 31, 2016 , the regulatory asset of $188 million was comprised of $134 million for the 2015 and 2016 annual reconciliations and $54 million related to significant one-time events.

Energy efficiency costs. These amounts represent deferred energy efficiency costs beginning June 1, 2017 that will be recovered through ComEd's energy efficiency formula rate tariff over the weighted average useful life of the related energy efficiency measures. The balance also includes the reconciliation of the difference of the revenue requirement in effect for the prior year and the revenue

requirement based on actual prior year costs. ComEd earns a return on the energy efficiency regulatory asset.

Debt costs. The Utility Registrants' debt costs are used in the determination of their weighted average cost of capital, which is applied to rate base for rate-making purposes. Consistent with the treatment for ratemaking purposes, ComEd's, PECO's, and Pepco's recoverable losses or refundable gains on reacquired long-term debt are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced, while BGE's, DPL's, and ACE's recoverable losses or refundable gains on reacquired long-term debt are deferred and amortized to interest expense over the life of the original debt issuance even if the debt was refinanced. The regulatory asset for Pepco, DPL and ACE as of March 23, 2016 was eliminated at Exelon and PHI as part of acquisition accounting.

Fair value of long-term debt. These amounts represent the unamortized regulatory assets recorded at Exelon for the difference between the carrying value and fair value of the long-term debt of BGE as of the Constellation merger date based on the MDPSC practice to allow BGE to recover its debt costs through rates and at Exelon and PHI for the difference between carrying value and fair value of long-term debt of Pepco, DPL and ACE as of the PHI Merger date. Exelon is amortizing the regulatory asset and the associated fair value over the life of the underlying debt.

Fair value of PHI's unamortized energy contracts. These amounts represent the regulatory asset recorded at Exelon and PHI offsetting the fair value adjustments related to Pepco's, DPL's and ACE's electricity and natural gas energy supply contracts recorded at PHI as of the PHI Merger date. Pepco, DPL and ACE are allowed full recovery of the costs of these contracts through their respective rate making processes.

Asset retirement obligations. These costs represent future legally required removal costs associated with existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd and BGE will recover these costs through future depreciation rates and will earn a return on these costs once the removal activities have been performed. The recovery period will be over the expected life of the related assets. See Note 15 — Asset Retirement Obligations for additional information.

MGP remediation costs . ComEd is allowed recovery of these costs under ICC approved rates. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures, currently estimated to be completed in 2022 for both ComEd and PECO. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. BGE is earning a return on this regulatory asset and these costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. The recovery period for the 10-year period that began January 2006 was extended for an additional 24 months, in accordance with the MDPSC approved 2014 electric and natural gas distribution rate case order. See Note 23 — Commitments and Contingencies for additional information.

Under-recovered uncollectible accounts. These amounts represent the difference between ComEd's annual uncollectible accounts expense and revenues collected in rates through an ICC-approved rider. The difference between net uncollectible account charge-offs and revenues collected through the rider each calendar year is recovered or refunded over a twelve-month period beginning in June of the following calendar year.

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(Dollars in millions, except per share data unless otherwise noted)

Renewable energy. In December 2010, ComEd entered into several 20 -year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs through 2032 in order to meet a portion of its obligations under the Illinois RPS. Delivery under the contracts began in June 2012. Since the swap contracts were deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). Recovery of these costs will continue through 2032. The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy at the market price and the contracted price.

Beginning with the 2012 compliance year the DPSC required DPL to be responsible for the RPS compliance obligation with respect to energy delivered to all end use customers, including RES supplied customers. This obligation has been met by DPL entering into long term contract(s) for the procurement of renewable energy. This energy is then sold into the market at current energy prices to offset the net cost to customers. An RPS surcharge is billed to customers to ensure recovery of the procurement costs with any variance recorded as an asset or liability. The balance at year end represents an under-recovery of the net procurement costs. These costs will be recovered over the life of the contracts, which range from 15 to 20 years.

In 2008 the NJBPU directed ACE to file a program for the purchase of Solar Renewable Energy Credits (SREC's). In 2009 the NJBPU approved ACE's SREC based contracting program and authorized ACE to enter into long-term contracts to purchase SREC's generated by solar generation projects. ACE is required to auction the purchased SREC's under Purchase and Sale Agreements (PSA) with the solar project developers. In 2015 the NJBPU authorized a "phase II" SREC program. A Regional Greenhouse Gas Initiative (RGGI) surcharge rider ensures recovery of the SREC costs. The balance at year end represents an under-recovery of the SREC costs. These costs will be recovered over the life of the contracts, which range from 15 to 20 years.

Energy and transmission programs. These amounts represent under (over) recoveries related to energy and transmission costs recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. Under (over) recoveries are recoverable (refundable) over a one-year period or less. ComEd earns a return or interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2017 , ComEd's regulatory asset of $6 million represents transmission costs recoverable through its FERC approved formula rate. As of December 31, 2017 , ComEd's regulatory liability of $47 million included $14 million related to over-recovered energy costs and $33 million associated with revenues received for renewable energy requirements. As of December 31, 2016 , ComEd's regulatory asset of $23 million included $15 million associated with transmission costs recoverable through its FERC-approved formula rate tariff and $8 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2016 , ComEd's regulatory liability of $60 million included $30 million related to over-recovered energy costs and $30 million associated with revenues received for renewable energy requirements. See *Transmission Formula Rate* above for further details.

The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO's GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. In addition, the DSP Program costs are presented on a net basis with PECO's GSA under (over)-recovered energy costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO's PAPUC-approved DSP programs for the procurement of electric supply. The filings and procurements of these DSP Programs are recoverable through the GSA over each respective term. DSP III has a 24 -month term that began June 1, 2015, and DSP IV has a 48-month term that began June 1, 2017. The independent evaluator costs associated with conducting procurements are recoverable over a 12 -month period after the PAPUC approves the results

of the procurements. PECO is not earning a return on these costs. Certain costs included in PECO's original DSP program related to information technology improvements were recovered over a 5 -year period that began January 1, 2011. PECO earns a return on the recovery of information technology costs. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2017 , PECO's regulatory liability of $60 million included $36 million related to over-recovered costs under the DSP program, $12 million related to over-recovered non-bypassable transmission service charges and $12 million related to the over-recovered natural gas costs under the PGC. As of December 31, 2016 , PECO's regulatory liability of $56 million included $34 million related to over-recovered costs under the DSP program, $10 million related to over-recovered non-bypassable transmission service charges, $8 million related to the over-recovered natural gas costs under the PGC and $4 million related to over-recovered electric transmission costs.

The BGE energy costs represent the electric supply, gas supply, and transmission related costs recoverable (refundable) from (to) customers under BGE's market-based SOS program, MBR program, and FERC approved transmission rates, respectively. BGE earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. BGE does not earn or pay interest to customers on under-recovered or over-recovered SOS and MBR costs. The recovery or refund period is a twelve-month period beginning in June of the following calendar year. As of December 31, 2017 , BGE's regulatory asset of $23 million included $7 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $5 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval, and $8 million related to under-recovered natural gas costs. As of December 31, 2016 , BGE's regulatory asset of $38 million included $4 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $28 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval and $3 million related to under-recovered natural gas costs.

The Pepco energy costs represent the electric supply and transmission related costs recoverable (refundable) from (to) customers under Pepco's market-based SOS program and FERC approved transmission rates. Pepco earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. Pepco does not earn or pay interest to customers on under- or over-recovered SOS costs. The asset is being amortized and recovered over the life of the associated assets. As of December 31, 2017 , Pepco's regulatory asset of $11 million included $3 million of transmission costs recoverable through its FERC approved formula rate and $8 million of under-recovered electric energy costs. As of December 31, 2017 , Pepco's regulatory liability was zero. As of December 31, 2016 , Pepco's regulatory asset of $6 million related to under-recovered electric energy costs. As of December 31, 2016 , Pepco's regulatory liability of $8 million included $5 million of over-recovered transmission costs and $3 million of over-recovered electric energy costs.

The DPL energy costs represent the electric supply, gas supply, and transmission related costs recoverable (refundable) from (to) customers under DPL's market-based SOS program, GCR and FERC approved transmission rates. DPL earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. In Delaware, DPL earns interest on under-recovered costs and pays interest to customers on over-recovered SOS and GCR costs. In Maryland, DPL does not earn or pay interest to customers on under- or over-recovered SOS costs. The asset is being amortized and recovered over the life of the associated assets. As of December 31, 2017 , DPL's regulatory asset of $15 million included $8 million of transmission costs recoverable through its FERC approved formula rate and $7 million of under-recovered electric energy costs. As of December 31, 2017 , DPL's regulatory liability of $1 million related to over-recovered electric energy costs. As of December 31, 2016 , DPL's regulatory asset of $5 million included $1 million of transmission costs recoverable through its FERC approved formula rate and $4 million of under-recovered electric energy

costs. As of December 31, 2016 , DPL's regulatory liability of $5 million included $2 million of over-recovered electric energy costs and $3 million of over-recovered transmission costs.

The ACE energy costs represent the electric supply and transmission related costs recoverable (refundable) from (to) customers under ACE's market-based BGS program and FERC approved transmission rates. ACE earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. ACE earns interest on under-recovered and pays interest to customers on over-recovered BGS costs. As of December 31, 2017 , ACE's regulatory asset of $26 million included $11 million of transmission costs recoverable through its FERC approved formula rate and $15 million of under-recovered electric energy costs. As of December 31, 2017 , ACE's regulatory liability of $3 million related to over-recovered electric energy costs. As of December 31, 2016 , ACE's regulatory asset of $17 million included $6 million of transmission costs recoverable through its FERC approved formula rate and $11 million of under-recovered electric energy costs. As of December 31, 2016 , ACE's regulatory liability of $5 million included $4 million of over-recovered transmission costs and $1 million of over-recovered electric energy costs.

Deferred storm costs. In the MDPSC's March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. BGE earns a return on this regulatory asset and the original recovery period of five years was extended for an additional 25 months, in accordance with the MDPSC 2014 electric and natural gas distribution rate case order. This regulatory asset has now been fully amortized as of December 31, 2017 .

For Pepco, DPL and ACE, amounts represent total incremental storm restoration costs incurred for repair work due to major storm events in 2017, 2016, 2015, 2012 and 2011 recoverable from customers in the Maryland and New Jersey jurisdictions. These incremental storm restoration costs are amortized over a three or five year period dependent on jurisdiction.

Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. The portion of this regulatory asset that does not earn a regulated rate of return was $9 million as of December 31, 2016 . This regulatory asset has now been fully amortized as of December 31, 2017 .

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006 to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007 to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2017 and 2016 , BGE recovered $7 million and $81 million , respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007. This regulatory asset has now been fully amortized as of December 31, 2017 .

Energy efficiency and demand response programs. For ComEd, these amounts represent over recoveries related to ComEd's ICC-approved Energy Efficiency and Demand Response Plan under

the energy efficiency rate rider cancelled on June 2, 2017. ComEd expects to refund these over recoveries in future rates. ComEd earns a return on the capital investment incurred under the program, but does not earn or pay a return or interest on under or over recoveries, respectively. For PECO, these amounts represent over recoveries of program costs related to both Phase II and Phase III of its PAPUC-approved EE&C Plan. PECO began recovering the costs of its Phase II and Phase III EE&C Plans through a surcharge in June 2013 and June 2016, respectively, based on projected spending under the programs. Phase II of the program began on June 1, 2013 and expired on May 31, 2016. Phase III of the program began on June 1, 2016 and will expire on May 31, 2021. PECO earns a return on the capital portion of the EE&C Plan. For BGE, these amounts represent under (over) recoveries related to BGE's Smart Energy Savers Program ®, which includes both MDPSC-approved demand response and energy efficiency programs. For the BGE Peak Rewards SM demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Also included in the demand response program are customer bill credits related to BGE's Smart Energy Rewards program which began in July 2013 and are being recovered through the surcharge. Actual costs incurred in the energy efficiency program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

For Pepco, DPL and ACE, amounts represent recoverable costs associated with customer direct load control and energy efficiency and conservation programs in all jurisdictions that are being recovered from customers. These programs are designed to reduce customers' energy consumption. Pepco Maryland and DPL Maryland energy efficiency program costs are recovered over 5 years and the direct load control program costs are recovered over 5 years and 15 years, depending on the type. ACE costs are recovered over 10 years. Pepco, DPL and ACE earn a return on these regulatory assets.

Merger integration costs. These amounts include integration costs to achieve distribution synergies related to the Constellation merger transaction. As a result of the MDPSC's February 2013 rate order, BGE deferred $8 million related to non-severance merger integration costs incurred during 2012 and the first quarter of 2013. Of these costs, $4 million was authorized to be amortized over a 5 -year period that began in March 2013. The recovery of the remaining $4 million was deferred. In the MDPSC's December 2013 rate order, BGE was authorized to recover the remaining $4 million and an additional $4 million of non-severance merger integration costs incurred during 2013. These costs are being amortized over a 5 -year period that began in December 2013. BGE is earning a return on this regulatory asset.

These amounts also include integration costs to achieve distribution synergies related to the PHI acquisition. As of December 31, 2017 and 2016 , BGE's regulatory asset of $6 million and $10 million , respectively, included $4 million and $6 million , respectively, of previously incurred PHI integration costs as authorized by the June 2016 rate case order. As of December 31, 2017 , Pepco's regulatory asset of $20 million represents previously incurred PHI integration costs, including $11 million authorized for recovery in Maryland and $9 million expected to be recovered in the District of Columbia service territory. As of December 31, 2016 , Pepco's regulatory asset of $11 million represents previously incurred PHI integration costs authorized for recovery in Maryland. As of December 31, 2017 , DPL's regulatory asset of $10 million represents previously incurred PHI integration costs, including $4 million authorized for recovery in Maryland, $5 million authorized for recovery in Delaware electric rates, and $1 million expected to be recovered in electric and gas rates in the Maryland and Delaware service territories. As of December 31, 2016 , DPL's regulatory asset of $4 million represents previously incurred PHI integration costs expected to be recovered in the Maryland service territory. As of December 31, 2017 , ACE's regulatory asset of $9 million represents previously incurred PHI integration costs expected to be recovered in the New Jersey service territory. Pepco and DPL are earning a return on the regulatory

assets being recovered in Maryland and these costs are being amortized over five years. DPL is earning a return on the regulatory asset being recovered in Delaware and the cost is being amortized over five years. Amounts deferred for Pepco in the District of Columbia and ACE in New Jersey do not earn a return.

Under (Over)-recovered electric and gas revenue decoupling. For BGE, these amounts represent the electric and gas distribution costs recoverable from or (refundable) to customers under BGE's decoupling mechanisms and are being recovered over the life of the associated assets. As of December 31, 2017 , BGE had a regulatory asset of $10 million related to under-recovered electric revenue decoupling and $4 million related to under-recovered natural gas revenue decoupling. As of December 31, 2016 , BGE had a regulatory asset of $2 million related to under-recovered natural gas revenue decoupling and $1 million related to under-recovered electric revenue decoupling.

For Pepco and DPL, these amounts represent the electric distribution costs recoverable from customers under Pepco's Maryland and District of Columbia decoupling mechanisms and DPL's Maryland decoupling mechanism. Pepco and DPL earn a return on these regulatory assets.

COPCO acquisition adjustment. On July 19, 2007, the MDPSC issued an order which provided for the recovery of a portion of DPL's goodwill. As a result of this order, $41 million in DPL goodwill was transferred to a regulatory asset. In February 2017 the MDPSC ruled that the remaining amortization be extended for an additional three years, and this item is now amortized from August 2007 through February 2020. DPL earns a return on these regulatory assets.

Workers compensation and long-term disability costs. These amounts represent accrued workers' compensation and long-term disability costs for Pepco, which are recoverable from customers when actual claims are paid to employees. The recovery period for these regulatory assets is over the life of the associated assets.

Vacation accrual. These amounts represent accrued vacation costs for PECO, DPL and ACE. PECO, DPL and ACE and the costs are recoverable from customers when actual payments are made to employees or when vacation is taken.

Securitized stranded costs. These amounts represent certain contract termination payments under a contract between ACE and an unaffiliated non-utility generator and costs associated with the regulated operations of ACE's electricity generation business that are no longer recoverable through customer rates (collectively referred to as "stranded costs"). The stranded costs are amortized over the life of Transition Bonds issued by Atlantic City Electric Transition Funding LLC (ACE Funding) to securitize the recoverability of these stranded costs. These bonds mature between 2018 and 2023. A customer surcharge is collected by ACE to fund principal and interest payments on the Transition Bonds. PHI earns a return on these regulatory assets.

CAP arrearage. These amounts represent the guaranteed recovery of PECO's previously incurred bad debt expense associated with the eligible CAP accounts receivable balances under the IPAF Program as provided by the 2015 electric distribution rate case settlement. These costs are amortized as recovery is received through a combination of customer payments over the duration of the five-year payment agreement term and rate recovery, including through future rate cases if necessary.

Removal costs. These amounts represent funds ComEd, BGE, PHI, Pepco, DPL and ACE have received from customers through depreciation rates to cover the future non-legally required cost of removal of property, plant and equipment which reduces rate base for ratemaking purposes. This liability is reduced as costs are incurred. PHI, Pepco, DPL, and ACE have a regulatory asset which represents removal costs incurred in excess of amounts received from customers through depreciation rates recoverable from ratepayers. The recovery period of these regulatory assets is over the life of the associated assets.

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(Dollars in millions, except per share data unless otherwise noted)

DC PLUG charge . On November 9, 2017, the DCPSC issued an order approving the First Biennial Plan and the application for a financing order. As a result, Pepco's obligation of $187 million will be recovered from customers and therefore, a $187 million regulatory asset was established. Pepco will recover $60 million over a two-year period and the remainder will be recovered based on future biennial plans filed with the DCPSC. In addition, $3 million of previously deferred costs from the first Triennial Plan were approved for recovery from customers over a one year recovery period.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs for the Regulatory Agreement Units that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will be sufficient to fund the associated future decommissioning costs at the time of decommissioning. See Note 15 — Asset Retirement Obligations for additional information.

Deferred rent. Represents the regulatory liability recorded at Exelon and PHI for deferred rent related to a lease. The costs of the lease are recoverable through the ratemaking process at Pepco, DPL and ACE.

DLC program costs. The DLC program costs include equipment, installation, and information technology costs necessary to implement the DLC Program under PECO's EE&C Phase I Plans. PECO received full cost recovery through Phase I collections and will amortize the costs as a credit to the income statement to offset the related depreciation expense during the same period through September 2025, which is the remaining useful life of the assets.

Electric distribution tax repairs. PECO's 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits began being reflected in customer bills on January 1, 2012. PECO's 2015 electric distribution rate case settlement requires PECO to pay interest on the unamortized balance of the tax-effected catch-up deduction beginning January 1, 2016.

Gas distribution tax repairs. PECO's 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits began being reflected in customer bills on January 1, 2013. No interest will be paid to customers.

Renewable portfolio standards costs. Beginning June 1, 2017, ComEd recovers all costs associated with purchasing renewable energy credits through a new tariff rate rider that provides for a reconciliation and true-up to actual costs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods with interest. In addition, this balance includes the over recovery of renewable energy credits associated with RPS alternative compliance payments recovered under supply base rates. These collections were required under the Illinois Public Utilities Act to be used for renewable energy purchases in accordance with ICC procurement orders. The amortization period is in accordance with the applicable ICC procurement orders.

Zero emission credit costs. Beginning June 1, 2017, ComEd recovers all costs associated with purchasing ZECs through a new tariff rate rider that provides for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase ZECs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods with interest.

Over-recovered uncollectible accounts. These amounts represent the difference between ACE's annual uncollectible accounts expense and revenues collected in rates through an NJBPU-approved

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rider. The difference between GAAP uncollectible expense and revenues collected through the rider each calendar year is recovered or refunded over a twelve-month period beginning in June of the following calendar year.

Capitalized Ratemaking Amounts Not Recognized (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

The following table illustrates our authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment that are not recognized for financial reporting purposes on our Consolidated Balance Sheets. These amounts will be recognized as revenues in our Consolidated Statements of Operations and Comprehensive Income in the periods they are billable to our customers.

					Successor			
	Exelon	**ComEd (a)**	**PECO**	**BGE (b)**	**PHI**	**Pepco (c)**	**DPL (c)**	**ACE**
December 31, 2017	$ 69	$ 6	$ —	$ 53	$ 10	$ 6	$ 4	$ —
December 31, 2016	$ 72	$ 5	$ —	$ 57	$ 10	$ 6	$ 4	$ —

(a) Reflects ComEd's unrecognized equity returns earned for ratemaking purposes on its under-recovered distribution services costs regulatory assets.
(b) BGE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholders' investment on its AMI programs
(c) Pepco's and DPL's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on their respective AMI Programs and Energy Efficiency and Demand Response Programs. The earnings on energy efficiency are on Pepco DC and DPL DE programs only.

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Purchase of Receivables Programs (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

ComEd, PECO, BGE, Pepco, DPL and ACE are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia and New Jersey, to purchase certain receivables from retail electric and natural gas suppliers that participate in the utilities' consolidated billing. ComEd, BGE, Pepco and DPL purchase receivables at a discount primarily to recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense, including those from Third Party Suppliers, from customers through distribution rates. ACE purchases receivables at face value. ACE recovers all uncollectible accounts expense, including those from Third Party Suppliers, through the Societal Benefits Charge (SBC) rider, which includes uncollectible accounts expense as a component. The SBC is filed annually with the NJBPU. Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of those companies as of December 31, 2017 and December 31, 2016 .

					Successor			
As of December 31, 2017	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Purchased receivables	$ 298	$ 87	$ 70	$ 58	$ 83	$ 56	$ 9	$ 18
Allowance for uncollectible accounts [(a)]	(31)	(14)	(5)	(3)	(9)	(5)	(1)	(3)
Purchased receivables, net	$ 267	$ 73	$ 65	$ 55	$ 74	$ 51	$ 8	$ 15

					Successor			
As of December 31, 2016	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Purchased receivables	$ 313	$ 87	$ 72	$ 59	$ 95	$ 63	$ 10	$ 22
Allowance for uncollectible accounts [(a)]	(37)	(14)	(6)	(4)	(13)	(7)	(2)	(4)
Purchased receivables, net	$ 276	$ 73	$ 66	$ 55	$ 82	$ 56	$ 8	$ 18

(a) For ComEd, BGE, Pepco and DPL, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing tariff.

4 . Mergers, Acquisitions and Dispositions (Exelon, Generation, PHI, Pepco and DPL)

Acquisition of James A. FitzPatrick Nuclear Generating Station (Exelon and Generation)

On March 31, 2017, Generation acquired the 842 MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York from Entergy Nuclear FitzPatrick LLC (Entergy) for a total purchase price of $289 million , which consisted of a cash purchase price of $110 million and a net cost reimbursement to and on behalf of Entergy of $179 million . As part of the acquisition agreements, Generation provided nuclear fuel and reimbursed Entergy for incremental costs to prepare for and conduct a plant refueling outage; and Generation reimbursed Entergy for incremental costs to operate and maintain the plant for the period after the refueling outage through the acquisition closing date. These reimbursements covered costs that Entergy otherwise would have avoided had it shut down the plant as originally intended in January 2017. The amounts reimbursed by Generation were offset by FitzPatrick's electricity and capacity sales revenues for this same post-outage period. As part of the transaction, Generation received the FitzPatrick NDT fund assets and assumed the obligation to decommission FitzPatrick. The NRC license for FitzPatrick expires in 2034. In 2017, the final purchase price consideration of $289 million (including $235 million of cash and $54 million of nuclear fuel) was remitted to and on behalf of Entergy.

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The fair values of FitzPatrick's assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows and future power and fuel market prices. The valuations performed in the first quarter of 2017 to determine the fair value of the FitzPatrick assets acquired and liabilities assumed were preliminary. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the acquisition to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date.

During the third quarter of 2017, certain modifications were made to the initial preliminary valuation amounts for acquired property, plant and equipment, the decommissioning ARO, pension and OPEB obligations and related deferred tax liabilities, resulting in a $3 million net increase in assets acquired and liabilities assumed. Additionally, in the third quarter a purchase price settlement payment of $4 million was received from Entergy. These resulted in an adjustment to the after-tax bargain purchase gain recorded at Generation. For the year ended December 31, 2017 , the after-tax bargain purchase gain of $233 million is included within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and primarily reflects differences in strategies between Generation and Entergy for the intended use and ultimate decommissioning of the plant. There are no further adjustments expected to be made to the allocation of the purchase price. See Note 15 - Asset Retirement Obligations and Note 16 - Retirement Benefits for additional information regarding the FitzPatrick decommissioning ARO and pension and OPEB updates.

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The following table summarizes the final acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the FitzPatrick acquisition by Generation as of December 31, 2017 :

Cash paid for purchase price	$	110
Cash paid for net cost reimbursement		125
Nuclear fuel transfer		54
Total consideration transferred	$	289
Identifiable assets acquired and liabilities assumed		
Current assets	$	60
Property, plant and equipment		298
Nuclear decommissioning trust funds		807
Other assets [(a)]		114
Total assets	$	1,279
Current liabilities	$	6
Nuclear decommissioning ARO		444
Pension and OPEB obligations		33
Deferred income taxes		149
Spent nuclear fuel obligation		110
Other liabilities		15
Total liabilities	$	757
Total net identifiable assets, at fair value	$	522
Bargain purchase gain (after-tax)	$	233

(a) Includes a $110 million asset associated with a contractual right to reimbursement from the New York Power Authority (NYPA), a prior owner of FitzPatrick, associated with the DOE one-time fee obligation. See Note 23 - Commitments and Contingencies for additional background regarding SNF obligations to the DOE.

For the year ended December 31, 2017 , Exelon and Generation incurred $57 million of merger and integration related costs which are included within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Acquisition of ConEdison Solutions (Exelon and Generation)

On September 1, 2016, Generation acquired the competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc. (ConEdison Solutions), a subsidiary of Consolidated Edison, Inc. for a purchase price of $257 million including net working capital of $204 million . The renewable energy, sustainable services and energy efficiency businesses of ConEdison Solutions are excluded from the transaction.

The fair values of ConEdison Solutions' assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows and future power and fuel market prices. The purchase price equaled the estimated fair value of the net assets acquired and the liabilities

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assumed and, therefore, no goodwill or bargain purchase was recorded as of the acquisition date. The purchase price allocation is now final.

The following table summarizes the final acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the ConEdison Solutions acquisition by Generation:

Total consideration transferred	$ 257
Identifiable assets acquired and liabilities assumed	
Working capital assets	$ 204
Property, plant and equipment	2
Mark-to-market derivative assets	6
Unamortized energy contract assets	100
Customer relationships	9
Other assets	1
Total assets	$ 322
Mark-to-market derivative liabilities	$ 65
Total liabilities	$ 65
Total net identifiable assets, at fair value	$ 257

Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

On March 23, 2016 , Exelon completed the merger contemplated by the Merger Agreement among Exelon, Purple Acquisition Corp., a wholly owned subsidiary of Exelon (Merger Sub) and Pepco Holdings, Inc. (PHI). As a result of that merger, Merger Sub was merged into PHI (the PHI Merger) with PHI surviving as a wholly owned subsidiary of Exelon and Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon which also owns Exelon's interests in ComEd, PECO and BGE (through a special purpose subsidiary in the case of BGE). Following the completion of the PHI Merger, Exelon and PHI completed a series of internal corporate organization restructuring transactions resulting in the transfer of PHI's unregulated business interests to Exelon and Generation and the transfer of PHI, Pepco, DPL and ACE to a special purpose subsidiary of EEDC.

Regulatory Matters

Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments including where applicable: customer rate credits, funding for energy efficiency and delivery system modernization programs, a green sustainability fund, workforce development initiatives, charitable contributions, renewable generation and other required commitments. In addition, the orders approving the merger in Delaware, New Jersey, and Maryland include a "most favored nation" provision which, generally, requires allocation of merger benefits proportionally across all the jurisdictions.

During the third and fourth quarters of 2016, Exelon and PHI filed proposals in Delaware, New Jersey and Maryland for amounts and allocations reflecting the application of the most favored nation provision, resulting in a total nominal cost of commitments of $513 million excluding renewable generation commitments (approximately $444 million on a net present value basis amount, excluding renewable

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generation commitments and charitable contributions). These filings reflected agreements reached with certain parties to the merger proceedings in these jurisdictions. In 2016, the DPSC and NJBPU approved the amounts and allocations of the additional merger benefits for Delaware and New Jersey, respectively. On April 12, 2017, the MDPSC issued an order approving the amounts of the additional merger benefits for Maryland, but amending the proposed allocations of the benefits. The amended allocations do not have a material effect on any of the Registrants' financial statements. No changes in commitment cost levels are required in the District of Columbia.

During the second quarter of 2017, Exelon finalized the application of $8 million funding for low- and moderate-income customers in the Pepco Maryland and DPL Maryland service territories. This resulted in an adjustment to merger commitment costs recorded at Exelon Corporate, Pepco, and DPL. Exelon Corporate recorded an increase of $8 million and Pepco and DPL recorded a decrease of $6 million and $2 million , respectively, in Operating and maintenance expense.

The following amounts represent total commitment costs for Exelon, PHI, Pepco, DPL and ACE that have been recorded since the acquisition date:

					Successor	
Description	Expected Payment Period	Pepco	DPL	ACE	PHI	Exelon
Rate credits	2016 - 2017	$ 91	$ 67	$ 101	$ 259	$ 259
Energy efficiency	2016 - 2021	—	—	—	—	122
Charitable contributions	2016 - 2026	28	12	10	50	50
Delivery system modernization	Q2 2017	—	—	—	—	22
Green sustainability fund	Q2 2017	—	—	—	—	14
Workforce development	2016 - 2020	—	—	—	—	17
Other		1	5	—	6	29
Total		$ 120	$ 84	$ 111	$ 315	$ 513

Pursuant to the orders approving the merger, Exelon made $73 million , $46 million and $49 million of equity contributions to Pepco, DPL and ACE, respectively, in the second quarter of 2016 to fund the after-tax amounts of the customer bill credit and the customer base rate credit commitments.

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new generation in Maryland, District of Columbia, and Delaware, 27 MWs of which are expected to be completed by 2018. These investments are expected to total approximately $137 million , are expected to be primarily capital in nature, and will generate future earnings at Exelon and Generation. Investment costs will be recognized as incurred and recorded on Exelon's and Generation's financial statements. Exelon has also committed to purchase 100 MWs of wind energy in PJM, to procure 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards, and to maintain and promote energy efficiency and demand response programs in the PHI jurisdictions.

Pursuant to the various jurisdictions' merger approval conditions, over specified periods Pepco, DPL and ACE are not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process and have made other commitments regarding hiring and relocation of positions.

In July 2015, the OPC, Public Citizen, Inc., the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed motions to stay the MDPSC order approving the merger. The Circuit Court judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC's order approving the merger and denied the petitions for judicial review filed

by the OPC, the Sierra Club, CCAN and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special Appeals, and on January 21, the Sierra Club and CCAN filed notices of appeal. On January 27, 2017, the Maryland Court of Special Appeals affirmed the Circuit Court's judgment that the MDPSC did not err in approving the merger. The OPC and Sierra Club filed petitions seeking further review in the Court of Appeals of Maryland, which is the highest court in Maryland. On June 21, 2017, the Court of Appeals granted discretionary review of the January 27, 2017 decision by the Maryland Court of Special Appeals. The Maryland Court of Appeals will review the OPC argument that the MDPSC did not properly consider the acquisition premium paid to PHI shareholders under Maryland's merger approval st and ard and the Sierra Club's argument that the merger would harm the renewable and distributed generation markets. The two lower courts examining these issues rejected these arguments, which Exelon believes are without merit. All briefs have been filed and oral arguments were presented to the court on October 10, 2017.

Between March 25, 2016 and April 22, 2016, various parties filed motions with the DCPSC to reconsider its March 23, 2016 order approving the merger. On June 17, 2016, the DCPSC denied all motions. In August 2016, the District Legal Entity of Columbia Office of People's Counsel, the District of Columbia Government, and Public Citizen jointly with DC Sun each filed petitions for judicial review of the DCPSC's March 23, 2016 order with the District of Columbia Court of Appeals. On July 20, 2017, the Court issued an opinion rejecting all of appellants' arguments and affirming the Commission's decision approving the merger.

Accounting for the Merger Transaction

The total purchase price consideration of approximately $7.1 billion for the PHI Merger consisted of cash paid to PHI shareholders, cash paid for PHI preferred securities and cash paid for PHI stock-based compensation equity awards as follows:

(In millions of dollars, except per share data)	Total Consideration
Cash paid to PHI shareholders at $27.25 per share (254 million shares outstanding at March 23, 2016)	$ 6,933
Cash paid for PHI preferred stock	180
Cash paid for PHI stock-based compensation equity awards [(a)]	29
Total purchase price	$ 7,142

(a) PHI's unvested time-based restricted stock units and performance-based restricted stock units issued prior to April 29, 2014 were immediately vested and paid in cash upon the close of the merger. PHI's remaining unvested time-based restricted stock units as of the close of the merger were cancelled. There were no remaining unvested performance-based restricted stock units as of the close of the merger.

PHI shareholders received $27.25 of cash in exchange for each share of PHI common stock outstanding as of the effective date of the merger. In connection with the Merger Agreement, Exelon entered into a Subscription Agreement under which it purchased $180 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI prior to December 31, 2015. On March 23, 2016 , the preferred securities were cancelled for no consideration to Exelon, and accordingly, the $180 million cash consideration previously paid to acquire the preferred securities was treated as purchase price consideration.

The preliminary valuations performed in the first quarter of 2016 were updated in the second, third, and fourth quarters of 2016. There were no adjustments to the purchase price allocation in the first quarter of 2017 and the purchase price allocation is now final.

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Exelon applied push-down accounting to PHI, and accordingly, the PHI assets acquired and liabilities assumed were recorded at their estimated fair values on Exelon's and PHI's Consolidated Balance Sheets as follows:

Purchase Price Allocation [a]		
Current assets	$	1,441
Property, plant and equipment		11,088
Regulatory assets		5,015
Other assets		248
Goodwill		4,005
Total assets	$	21,797
Current liabilities	$	2,752
Unamortized energy contracts		1,515
Regulatory liabilities		297
Long-term debt, including current maturities		5,636
Deferred income taxes		3,447
Pension and OPEB obligations		821
Other liabilities		187
Total liabilities	$	14,655
Total purchase price	$	7,142

(a) Amounts shown reflect the final purchase price allocation and the correction of a reporting error identified and corrected in the second quarter of 2016. The error had resulted in a gross up of certain assets and liabilities related to legacy PHI intercompany and income tax receivable and payable balances.

On its successor financial statements, PHI has recorded, beginning March 24, 2016, Membership interest equity of $7.2 billion , which is greater than the total $7.1 billion purchase price, reflecting the impact of a $59 million deferred tax liability recorded only at Exelon Corporate to reflect unitary state income tax consequences of the merger.

The excess of the purchase price over the estimated fair value of the assets acquired and the liabilities assumed totaled $4.0 billion , which was recognized as goodwill by PHI and Exelon at the acquisition date, reflecting the value associated with enhancing Exelon's regulated utility portfolio of businesses, including the ability to leverage experience and best practices across the utilities and the opportunities for synergies. For purposes of future required impairment assessments, the goodwill has been assigned to PHI's reportable units Pepco, DPL and ACE in the amounts of $1.7 billion , $1.1 billion and $1.2 billion , respectively. None of this goodwill is expected to be tax deductible.

Immediately following closing of the merger, $235 million of net assets included in the table above associated with PHI's unregulated business interests were distributed by PHI to Exelon. Exelon contributed $163 million of such net assets to Generation.

The fair values of PHI's assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows, future market prices and impacts of utility rate regulation. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired.

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(Dollars in millions, except per share data unless otherwise noted)

Through its wholly owned rate regulated utility subsidiaries, most of PHI's assets and liabilities are subject to cost-of-service rate regulation. Under such regulation, rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate base, generally measured at historical cost. In applying the acquisition method of accounting, for regulated assets and liabilities included in rate base or otherwise earning a return (primarily property, plant and equipment and regulatory assets earning a return), no fair value adjustments were recorded as historical cost is viewed as a reasonable proxy for fair value.

Fair value adjustments were applied to the historical cost bases of other assets and liabilities subject to rate regulation but not earning a return (including debt instruments and pension and OPEB obligations). In these instances, a corresponding offsetting regulatory asset or liability was also established, as the underlying utility asset and liability amounts are recoverable from or refundable to customers at historical cost (and not at fair value) through the rate setting process. Similar treatment was applied for fair value adjustments to record intangible assets and liabilities, such as for electricity and gas energy supply contracts as further described below. Regulatory assets and liabilities established to offset fair value adjustments are amortized in amounts and over time frames consistent with the realization or settlement of the fair value adjustments, with no impact on reported net income. See Note 3 - Regulatory Matters for additional information regarding the fair value of regulatory assets and liabilities established by Exelon and PHI.

Fair value adjustments were recorded at Exelon and PHI for the difference between the contract price and the market price of electricity and gas energy supply contracts of PHI's wholly owned rate regulated utility subsidiaries. These adjustments are intangible assets and liabilities classified as unamortized energy contracts on Exelon's and PHI's Consolidated Balance Sheets as of December 31, 2017 . The difference between the contract price and the market price at the acquisition date of the Merger was recognized for each contract as either an intangible asset or liability. In total, Exelon and PHI recorded a net $1.5 billion liability reflecting out-of-the-money contracts. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. In certain instances, the valuations were based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power prices and the discount rate. The unamortized energy contract fair value adjustment amounts and the corresponding offsetting regulatory asset and liability amounts are amortized through Purchased power and fuel expense or Operating revenues, as applicable, over the life of the applicable contract in relation to the present value of the underlying cash flows as of the merger date.

As mentioned, under cost-of-service rate regulation, rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate base, generally measured at historical cost. Historical cost information therefore is the most relevant presentation for the financial statements of PHI's rate regulated utility subsidiary registrants, Pepco, DPL and ACE. As such, Exelon and PHI did not push-down the application of acquisition accounting to PHI's utility registrants, and therefore the financial statements of Pepco, DPL and ACE do not reflect the revaluation of any assets and liabilities.

The current impact of PHI, including its unregulated businesses, on Exelon's Consolidated Statements of Operations and Comprehensive Income includes Operating revenues of $4,829 million and Net income of $364 million during the year ended December 31, 2017 , and Operating revenues of $3,785 million and Net loss of $ (66) million for the year ended December 31, 2016 .

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the periods ended December 31, 2017 and 2016 , the Registrants have recognized costs to achieve the PHI acquisition as follows:

	For the Year Ended December 31,	
Acquisition, Integration and Financing Costs [a]	2017	2016
Exelon	$ 16	$ 143
Generation	22	37
ComEd [b]	1	(6)
PECO	4	5
BGE [b]	4	(1)
Pepco [b]	(6)	28
DPL [b]	(7)	20
ACE [b]	(6)	19

	Successor		*Predecessor*
Acquisition, Integration and Financing Costs [a]	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
PHI [b]	$ (18)	$ 69	$ 29

(a) The costs incurred are classified primarily within Operating and maintenance expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the financing costs, which are included within Interest expense. Costs do not include merger commitments discussed above.
(b) For the year ended December 31, 2017 , includes deferrals of previously incurred integration costs to achieve distribution synergies related to the PHI acquisition of $24 million , $8 million , $8 million , and $8 million incurred at PHI, Pepco, DPL, and ACE, respectively, that have been recorded as a regulatory asset for anticipated recovery. For the year ended December 31, 2016 , includes deferrals of previously incurred integration costs to achieve distribution synergies related to the PHI acquisition of $8 million , $6 million , $11 million , and $4 million incurred at ComEd, BGE, Pepco, and DPL, respectively, that have been recorded as a regulatory asset for anticipated recovery. For the Successor period March 24, 2016 to December 31, 2016 , includes deferrals of previously incurred integration costs to achieve distribution synergies related to the PHI acquisition of $16 million incurred at PHI that have been recorded as a regulatory asset for anticipated recovery. See Note 3 - Regulatory Matters for more information.

Combined Notes to Consolidated Financial Statements - (Continued)
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Pro-forma Impact of the Merger

The following unaudited pro-forma financial information reflects the consolidated results of operations of Exelon as if the merger with PHI had taken place on January 1, 2015 . The unaudited pro forma information was calculated after applying Exelon's accounting policies and adjusting PHI's results to reflect purchase accounting adjustments.

The unaudited pro-forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Year Ended December 31,	
	2016 [a]	2015 [b]
Total operating revenues	$ 32,342	$ 33,823
Net income attributable to common shareholders	1,562	2,618
Basic earnings per share	$ 1.69	$ 2.85
Diluted earnings per share	1.69	2.84

(a) The amounts above exclude non-recurring costs directly related to the merger of $680 million and intercompany revenue of $171 million for the year ended December 31, 2016 .
(b) The amounts above exclude non-recurring costs directly related to the merger of $92 million and intercompany revenue of $559 million for the year ended December 31, 2015 .

Asset Dispositions (Exelon, Generation, PHI, Pepco and DPL)

EGTP, a Delaware limited liability company, was formed in 2014 with the purpose of financing a portfolio of assets comprised of two combined-cycle gas turbines (CCGTs) and three peaking/simple cycle facilities consisting of approximately 3.4 GW of generation capacity in ERCOT North and Houston Zones. EGTP is an indirect wholly owned subsidiary of Exelon and Generation. Each of the aforementioned facilities are held through a wholly owned direct subsidiary of EGTP. EGTP also owns two equity method investments in shared facility companies. EGTP, its direct parent and its wholly owned subsidiaries secured a nonrecourse senior secured term loan facility, a revolving loan facility and certain commodity and interest rate swaps.

EGTP's operating cash flows were negatively impacted by certain market conditions and the seasonality of its cash flows. On May 2, 2017, as a result of the negative impacts of certain market conditions and the seasonality of its cash flows, EGTP entered into a consent agreement with its lenders to permit EGTP to draw on its revolving credit facility and initiate an orderly sales process to sell the assets of its wholly owned subsidiaries. As a result, Exelon and Generation classified certain of EGTP assets and liabilities as held for sale at their respective fair values less costs to sell and recorded a $460 million pre-tax impairment loss . See Note 13 - Debt and Credit Agreements for details regarding the nonrecourse debt associated with EGTP and Note 7 - Impairment of Long-Lived Assets and Intangibles for further information.

On November 7, 2017, EGTP and all of its wholly owned subsidiaries (collectively with EGTP, the "Debtors") filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware. The Debtors sought Bankruptcy Court authorization to jointly administer the Chapter 11 cases. The Debtors are continuing to manage their assets and operate their businesses as "debtors in possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and the orders of the Bankruptcy Court. As a result of the bankruptcy filing, Exelon and Generation deconsolidated EGTP's

assets and liabilities from their consolidated financial statements, resulting in a pre-tax gain upon deconsolidation of $213 million . Concurrently with the Chapter 11 filings, Generation entered into an asset purchase agreement to acquire one of EGTP's generating plants, the Handley Generating Station, for approximately $60 million , subject to a potential adjustment for fuel oil and assumption of certain liabilities. In the Chapter 11 Filings, EGTP requested that the proposed acquisition of the Handley Generating Station be consummated through a court-approved and supervised sales process. The acquisition was approved by the Bankruptcy Court in January 2018 and the transaction is expected to be completed in the first half of 2018.

In December 2017, Pepco Building Services, Inc. entered into a purchase and sale agreement to sell its interest in an electrical contracting business that primarily installs, maintains and repairs underground and high-voltage cable transmission and distribution systems. The closing of the sale is expected to be completed in the first quarter of 2018. As a result, as of December 31, 2017 , certain assets and liabilities were classified as held for sale at their respective fair values less costs to sell and included in the Other current assets and Other current liabilities balances on Exelon's and Generation's Consolidated Balance Sheet.

During the fourth quarter 2016, as part of its continual assessment of growth and development opportunities, Generation reevaluated and in certain instances terminated or renegotiated certain projects and contracts. As a result, a pre-tax loss of $69 million was recorded within Loss on sale of assets and pre-tax impairment charges of $23 million was recorded within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

In July 2016, DPL completed the sale of a 9-acre land parcel located on South Madison Street in Wilmington, DE, resulting in a pre-tax gain of approximately $4 million . In December 2016, DPL completed the sale of a 48-acre land parcel located in Middletown, DE, resulting in a pre-tax gain of approximately $5 million . Due to the fair value adjustments recorded at Exelon and PHI as part of purchase accounting, no gain was recorded in Exelon's and PHI's Consolidated Statements of Operations and Comprehensive Income.

On June 16, 2016, Generation initiated the sales process of its Upstream business by executing a forbearance agreement with the lenders of the nonrecourse debt. See Note 13 - Debt and Credit Agreements for more information. In December 2016, Generation sold substantially all of the Upstream assets for $37 million which resulted in a pre-tax loss on sale of $10 million which is included in Gain (loss) on sales of assets on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016.

On May 2, 2016, Pepco completed the sale of the New York Avenue land parcel, located in Washington, D.C., resulting in a pre-tax gain of approximately $8 million at Pepco. Due to the fair value adjustments recorded at Exelon and PHI as part of purchase accounting, no gain was recorded in Exelon's and PHI's Consolidated Statements of Operations and Comprehensive Income.

On April 21, 2016, Generation completed the sale of the retired New Boston generating site, located in Boston, Massachusetts, resulting in a pre-tax gain of approximately $32 million .

On November 10, 2015, Pepco completed the sale of a 3.5-acre parcel of unimproved land (held as non-utility property) in the Buzzard Point area of southeast Washington, D.C., resulting in a pre-tax gain of $37 million .

On December 31, 2015, Pepco completed the sale of a 3.8-acre parcel of unimproved land (held as non-utility property) in the NoMa area of northeast Washington, D.C., resulting in a pre-tax gain of $9 million . The purchase and sale agreement also provided the third party with a 90-day option to purchase the remaining 1.8-acre land parcel.

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5 . Accounts Receivable (All Registrants)

Accounts receivable at December 31, 2017 and 2016 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

						Successor				
2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Unbilled customer revenues	$ 1,858	$ 1,017 [a]	$ 242	$ 162	$ 205	$ 232	$ 133	$ 68	$ 31
Allowance for uncollectible accounts [b]	(322)	(114)	(73)	(56) [c]	(24)	(55)	(21)	(16)	(18)

					Successor			
2016	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Unbilled customer revenues	$ 1,673	$ 910 [a]	$ 219	$ 140	$ 182	$ 222	$ 123	$ 58	$ 41
Allowance for uncollectible accounts [b]	(334)	(91)	(70)	(61) [c]	(32)	(80) [d]	(29) [d]	(24) [d]	(27) [d]

(a) Represents unbilled portion of retail receivables estimated under Exelon's unbilled critical accounting policy.
(b) Includes the estimated allowance for uncollectible accounts on billed customer and other accounts receivable.
(c) Excludes the non-current allowance for uncollectible accounts of $15 million and $23 million at December 31, 2017 and 2016 , respectively, related to PECO's current installment plan receivables described below.
(d) At December 31, 2016 , as explained in Note 1 — Significant Accounting Policies , PHI, Pepco, DPL and ACE estimated the allowance for uncollectible accounts on customer receivables by applying loss rates to the outstanding receivable balance by risk segment. The change in estimate resulted in an overall increase of $30 million , $14 million , $8 million , and $8 million in the allowance for uncollectible accounts with $20 million , $8 million , $4 million , and $8 million deferred as a regulatory asset on PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets at December 31, 2016, respectively. This also resulted in a $10 million , $6 million , and $4 million pre-tax charge to provision for uncollectible accounts expense for the year ended December 31, 2016 , which is included in Operating and maintenance expense on PHI's, Pepco's and DPL's Consolidated Statements of Operations and Comprehensive Income, respectively.

PECO Installment Plan Receivables (Exelon and PECO)

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $11 million and $9 million at December 31, 2017 and 2016 , respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1 — Significant Accounting Policies . The allowance for uncollectible accounts balance associated with these receivables at December 31, 2017 of $11 million consists of $3 million and $8 million for medium risk and high-risk segments, respectively. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2016 of $13 million consists of $1 million , $3 million and $9 million for low risk, medium risk and high risk-segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of December 31, 2017 and 2016 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable

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and reserved for in accordance with the methodology discussed in Note 1 — Significant Accounting Policies .

6 . Property, Plant and Equipment (All Registrants)

Exelon

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2017 and 2016 :

Asset Category	Average Service Life (years)	2017	2016
Electric—transmission and distribution	5-90	$ 49,506	$ 45,698
Electric—generation	2-56	29,019	27,193
Gas—transportation and distribution	5-90	5,050	4,642
Common—electric and gas	5-75	1,447	1,312
Nuclear fuel [a]	1-8	6,420	6,546
Construction work in progress	N/A	2,825	4,306
Other property, plant and equipment [b]	2-50	999	1,027
Total property, plant and equipment		95,266	90,724
Less: accumulated depreciation [c]		21,064	19,169
Property, plant and equipment, net		$ 74,202	$ 71,555

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,196 million and $1,326 million at December 31, 2017 and 2016 , respectively.
(b) Includes Generation's buildings under capital lease with a net carrying value of $7 million and $10 million at December 31, 2017 and 2016 , respectively. The original cost basis of the buildings was $47 million and $52 million , and total accumulated amortization was $40 million and $42 million , as of December 31, 2017 and 2016 , respectively. Also includes ComEd's buildings under capital lease with a net carrying value at both December 31, 2017 and 2016 , of $7 million . The original cost basis of the buildings was $8 million and total accumulated amortization was $1 million as of both December 31, 2017 and 2016 . Includes land held for future use and non-utility property at ComEd, PECO, BGE, Pepco, DPL and ACE of $44 million , $21 million , $26 million , $59 million , $15 million and $27 million , respectively, at December 31, 2017 . Includes the original cost and progress payments associated with Generation's turbine equipment held for future use with a carrying value of $0 million and $17 million as of December 31, 2017 and 2016 , respectively. Generation's turbine equipment was impaired by $11 million and the remaining $6 million was moved to the assets held for sale account at December 31, 2017 .
(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $3,159 million and $3,186 million as of December 31, 2017 and 2016 , respectively.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2017	2016	2015
Electric—transmission and distribution	2.75%	2.73%	2.83%
Electric—generation [a]	4.36% [a]	5.94% [a]	3.47%
Gas	2.10%	2.17%	2.17%
Common—electric and gas	7.05%	7.41%	7.79%

(a) See Note 8 — Early Nuclear Plant Retirements for additional information on the accelerated net depreciation and amortization of Clinton, Quad Cities and TMI.

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Generation

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2017 and 2016 :

	Average Service Life (years)	2017	2016
Asset Category			
Electric—generation	2-56	$ 29,019	$ 27,193
Nuclear fuel [a]	1-8	6,420	6,546
Construction work in progress	N/A	838	2,332
Other property, plant and equipment [b]	2-3	57	76
Total property, plant and equipment		36,334	36,147
Less: accumulated depreciation [c]		11,428	10,562
Property, plant and equipment, net		$ 24,906	$ 25,585

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,196 million and $1,326 million at December 31, 2017 and 2016 , respectively.
(b) Includes buildings under capital lease with a net carrying value of $7 million and $10 million at December 31, 2017 and 2016 , respectively. The original cost basis of the buildings was $47 million and $52 million , and total accumulated amortization was $40 million and $42 million , as of December 31, 2017 and 2016 , respectively. Includes the original cost and progress payments associated with Generation's turbine equipment held for future use with a carrying value of $0 million and $17 million as of December 31, 2017 and 2016 , respectively. Generation's turbine equipment was impaired by $11 million and the remaining $6 million was moved to the assets held for sale account at December 31, 2017 .
(c) Includes accumulated amortization of nuclear fuel in the reactor core of $3,159 million and $3,186 million as of December 31, 2017 and 2016 , respectively.

The annual depreciation provisions as a percentage of average service life for electric generation assets were 4.36% , 5.94% and 3.47% for the years ended December 31, 2017 , 2016 and 2015 , respectively. See Note 8 — Early Nuclear Plant Retirements for additional information on the accelerated net depreciation and amortization of Clinton, Quad Cities and TMI.

License Renewals

Generation's depreciation provisions are based on the estimated useful lives of its generating stations, which reflect the renewal of the licenses for all nuclear generating stations (except for Oyster Creek, Clinton and TMI) and the hydroelectric generating stations. As a result, the receipt of license renewals has no material impact on the Consolidated Statements of Operations and Comprehensive Income. Clinton depreciation provisions are based on 2027 which is the last year of the Illinois ZECs. In 2017, Oyster Creek and TMI depreciation provisions were based on their 2019 expected shutdown dates. Beginning February 2018, Oyster Creek depreciation provisions will be based on its announced shutdown date of 2018. See Note 3 — Regulatory Matters for additional information regarding license renewals and the Illinois ZECs. See Note 8 — Early Nuclear Plant Retirements for additional information on the impacts of expected and potential early plant retirement.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2017 and 2016 :

Asset Category	Average Service Life (years)	2017	2016
Electric—transmission and distribution	5-80	$ 24,423	$ 22,636
Construction work in progress	N/A	517	569
Other property, plant and equipment [a], [b]	36-50	52	67
Total property, plant and equipment		24,992	23,272
Less: accumulated depreciation		4,269	3,937
Property, plant and equipment, net		$ 20,723	$ 19,335

(a) Includes buildings under capital lease with a net carrying value at both December 31, 2017 and 2016 of $7 million . The original cost basis of the buildings was $8 million and total accumulated amortization was $1 million as of both December 31, 2017 and 2016 .
(b) Includes land held for future use and non-utility property.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 2.99% , 3.03% and 3.03% for the years ended December 31, 2017 , 2016 and 2015 , respectively.

PECO

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2017 and 2016 :

Asset Category	Average Service Life (years)	2017	2016
Electric—transmission and distribution	5-65	$ 7,975	$ 7,591
Gas—transportation and distribution	5-70	2,504	2,348
Common—electric and gas	5-50	710	670
Construction work in progress	N/A	254	188
Other property, plant and equipment [a]	50	21	21
Total property, plant and equipment		11,464	10,818
Less: accumulated depreciation		3,411	3,253
Property, plant and equipment, net		$ 8,053	$ 7,565

(a) Represents land held for future use and non-utility property.

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2017	2016	2015
Electric—transmission and distribution	2.37%	2.32%	2.39%
Gas	1.89%	1.82%	1.87%
Common—electric and gas	5.47%	5.11%	5.16%

BGE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2017 and 2016 :

Asset Category	Average Service Life (years)	2017	2016
Electric—transmission and distribution	5-90	$ 7,464	$ 7,067
Gas—distribution	5-90	2,379	2,170
Common—electric and gas	5-40	771	707
Construction work in progress	N/A	367	318
Other property, plant and equipment [(a)]	20	26	32
Total property, plant and equipment		11,007	10,294
Less: accumulated depreciation		3,405	3,254
Property, plant and equipment, net		$ 7,602	$ 7,040

(a) Represents land held for future use and non-utility property.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2017	2016	2015
Electric—transmission and distribution	2.58%	2.56%	2.62%
Gas	2.33%	2.45%	2.50%
Common—electric and gas	8.64%	9.45%	10.35%

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2017 and 2016 :

		Successor	
	Average Service Life (years)	2017	2016
Asset Category			
Electric—transmission and distribution	5-75	$ 11,517	$ 10,315
Gas—distribution	5-75	449	414
Common—electric and gas	5-75	82	65
Construction work in progress	N/A	835	892
Other property, plant and equipment [(a)]	3-43	102	107
Total property, plant and equipment		12,985	11,793
Less: accumulated depreciation		487	195
Property, plant and equipment, net		$ 12,498	$ 11,598

(a) Represents plant held for future use and non-utility property. Utility plant is generally subject to a first mortgage lien.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2017	2016	2015
Electric—transmission and distribution	2.63%	2.52%	2.48%
Gas	2.07%	2.57%	2.55%
Common—electric and gas	6.50%	8.12%	5.19%

Pepco

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2017 and 2016 :

	Average Service Life (years)	2017	2016
Asset Category			
Electric—transmission and distribution	5-75	$ 8,646	$ 8,018
Construction work in progress	N/A	473	537
Other property, plant and equipment [(a)]	25-33	59	66
Total property, plant and equipment		9,178	8,621
Less: accumulated depreciation		3,177	3,050
Property, plant and equipment, net		$ 6,001	$ 5,571

(a) Represents plant held for future use and non-utility property. Utility plant is generally subject to a first mortgage lien.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 2.35% , 2.17% and 2.13% for the years ended December 31, 2017 , 2016 and 2015 , respectively.

DPL

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2017 and 2016 :

	Average Service Life (years)	2017	2016
Asset Category			
Electric—transmission and distribution	5-70	$ 3,875	$ 3,574
Gas—distribution	5-75	614	580
Common—electric and gas	5-75	117	115
Construction work in progress	N/A	205	163
Other property, plant and equipment [a]	10-43	15	16
Total property, plant and equipment		4,826	4,448
Less: accumulated depreciation		1,247	1,175
Property, plant and equipment, net		$ 3,579	$ 3,273

(a) Represents plant held for future use and non-utility property. Utility plant is generally subject to a first mortgage lien.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2017	2016	2015
Electric—transmission and distribution	2.75%	2.49%	2.44%
Gas	2.07%	2.57%	2.55%
Common—electric and gas	4.14%	4.99%	4.24%

ACE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2017 and 2016 :

	Average Service Life (years)	2017	2016
Asset Category			
Electric—transmission and distribution	5-60	$ 3,607	$ 3,341
Construction work in progress	N/A	138	169
Other property, plant and equipment [a]	13-15	27	27
Total property, plant and equipment		3,772	3,537
Less: accumulated depreciation		1,066	1,016
Property, plant and equipment, net		$ 2,706	$ 2,521

(a) Represents plant held for future use and non-utility property. Utility plant is generally subject to a first mortgage lien.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 2.46% , 2.45% and 2.46% for the years ended December 31, 2017 , 2016 and 2015 , respectively.

See Note 1 — Significant Accounting Policies for further information regarding property, plant and equipment policies and accounting for capitalized software costs for the Registrants. See Note 13 — Debt and Credit Agreements for further information regarding Exelon's, ComEd's and PECO's property, plant and equipment subject to mortgage liens.

7 . Impairment of Long-Lived Assets and Intangibles (Exelon, Generation and PHI)

Long-Lived Assets (Exelon, Generation and PHI)

Registrants evaluate long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. At Generation, EGTP's operating cash flows have been negatively impacted by certain market conditions and the seasonality of its cash flows. On May 2, 2017, EGTP entered into a consent agreement with its lenders to initiate an orderly sales process to sell the assets of its wholly owned subsidiaries. As a result, Exelon and Generation classified certain of EGTP's assets and liabilities as held for sale at their respective fair values less costs to sell and recorded a pre-tax impairment charge of $460 million within Operating and maintenance expense on their Consolidated Statements of Operations and Comprehensive Income during 2017. On November 7, 2017, EGTP and its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware and, as a result, Exelon and Generation deconsolidated EGTP's assets and liabilities from their consolidated financial statements. See Note 4 — Mergers, Acquisitions and Dispositions and Note 13 — Debt and Credit Agreements , for further information.

In the third quarter of 2015, PHI entered into a sponsorship agreement with the District of Columbia for future sponsorship rights associated with public property within the District of Columbia and paid the District of Columbia $25 million , which Exelon and PHI had recorded as a finite-lived intangible asset as of December 31, 2016. The specific sponsorship rights were to be determined over time through future negotiations. In the fourth quarter of 2017, based upon the lack of currently available sponsorship opportunities, the asset was written off and a pre-tax impairment charge of $25 million was recorded within Operating and maintenance expense in Exelon's and PHI's Consolidated Statements of Operations and Comprehensive Income.

During the first quarter of 2016, significant changes in Generation's intended use of the Upstream oil and gas assets, developments with nonrecourse debt held by its Upstream subsidiary CEU Holdings, LLC (as described in Note 13 — Debt and Credit Agreements) and continued declines in both production volumes and commodity prices suggested that the carrying value may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of its Upstream properties were less than their carrying values. As a result, a pre-tax impairment charge of $119 million was recorded in March 2016 within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. On June 16, 2016, Generation initiated the sales process of its Upstream natural gas and oil exploration and production business by executing a forbearance agreement with the lenders of the nonrecourse debt, see Note 13 — Debt and Credit Agreements for additional information. An additional pre-tax impairment charge of $15 million was recorded in September 2016 within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income due to further declines in fair value. In December 2016, Generation sold substantially all of the Upstream Assets. See Note 4 — Mergers, Acquisitions and Dispositions for additional information.

In the second quarter of 2016, updates to Exelon's long-term view of energy and capacity prices suggested that the carrying value of a group of merchant wind assets, located in West Texas, may be impaired. Upon review, the estimated undiscounted future cash flows and fair value of the group were less than their carrying value. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result of the fair value analysis, long-lived merchant wind assets held and used with a carrying amount of approximately $60 million were written down to their fair value of $24 million and a pre-tax impairment charge of $36 million was recorded during the second quarter of 2016 in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Also in the second quarter of 2016, updates to Exelon's long-term view, as described above, in conjunction with the retirement announcements of the Quad Cities and Clinton nuclear plants in Illinois suggested that the carrying value of our Midwest asset group may be impaired. Generation completed a comprehensive review of the estimated undiscounted future cash flows of the Midwest asset group and no impairment charge was required.

The fair value analysis used in the above impairments was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue, generation and production forecasts, projected capital and maintenance expenditures and discount rates. Changes in the assumptions described above could potentially result in future impairments of Exelon's long-lived assets, which could be material.

Like-Kind Exchange Transaction (Exelon)

In June 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon Corporation, entered into transactions pursuant to which UII invested in coal-fired generating station leases (Headleases) with the Municipal Electric Authority of Georgia (MEAG). The generating stations were leased back to MEAG as part of the transactions (Leases).

Pursuant to the applicable authoritative guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other-than-temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments based on the income approach, which uses a discounted cash flow analysis, taking into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

All the Headleases were terminated by the second quarter of 2016, and no events occurred prior to the termination that required Exelon to review the estimated residual values of the direct financing lease investments in 2016. On March 31, 2016, UII and MEAG finalized an agreement to terminate the MEAG Headleases, the MEAG Leases, and other related agreements prior to their expiration dates. As a result of the lease termination, UII received an early termination payment of $360 million from MEAG and wrote-off the $356 million net investment in the MEAG Headleases and the Leases. The transaction resulted in a pre-tax gain of $4 million which is reflected in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income. See Note 14 — Income Taxes for additional information.

8 . Early Nuclear Plant Retirements (Exelon and Generation)

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation's nuclear plants. Factors that will continue to affect the economic value of Generation's nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure nuclear plants are fairly compensated for their carbon-free emissions, and the impact of final rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. The precise timing of an early retirement date for any nuclear plant, and the resulting financial statement impacts, may be affected by a number of factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, where applicable, and just prior to its next scheduled nuclear refueling outage.

In 2015 and 2016, Generation identified the Quad Cities, Clinton, Ginna, Nine Mile Point and Three Mile Island (TMI) nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. In 2017, PSEG has made public similar financial challenges facing its New Jersey nuclear plants including Salem, of which Generation owns a 42.59% ownership interest.

In Illinois, the Clinton and Quad Cities nuclear plants continued to face significant economic challenges and risk of retirement before the end of each unit's respective operating license period (2026 for Clinton and 2032 for Quad Cities). In April 2016, Clinton cleared the MISO primary reliability auction as a price taker for the 2016-2017 planning year. The resulting capacity price was insufficient to cover cash operating costs and a risk-adjusted rate of return to shareholders. In May 2016, Quad Cities did not clear in the PJM capacity auction for the 2019-2020 planning year. Based on these capacity auction results, and given the lack of progress on Illinois energy legislation and MISO market reforms, on June 2, 2016 Generation announced it would shut down the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively.

On December 7, 2016, Illinois FEJA was signed into law by the Governor of Illinois and included a ZES that provides compensation through the procurement of ZECs targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet specific eligibility criteria, much like the solution implemented with the New York CES. The Illinois ZES will have a 10-year duration extending from June 1, 2017 through May 31, 2027. See Note 3 - Regulatory Matters for additional discussion on the Illinois FEJA and the ZES. With the passage of the Illinois ZES, and subject to prevailing over any related potential administrative or legal challenges , in December 2016 Generation reversed its June 2016 decision to permanently cease generation operations at the Clinton and Quad Cities nuclear generating plants.

In New York, the Ginna and Nine Mile Point nuclear plants continue to face significant economic challenges and risk of retirement before the end of each unit's respective operating license period (2029 for Ginna and Nine Mile Point Unit 1, and 2046 for Nine Mile Point Unit 2). On August 1, 2016, the NYPSC issued an order adopting the CES, which would provide payments to Ginna and Nine Mile Point for the environmental attributes of their production. On November 18, 2016, Ginna and Nine Mile Point executed the necessary contracts with NYSERDA, as required under the CES. Subject to prevailing over any administrative or legal challenges, the New York CES will allow Ginna and Nine Mile Point to continue to operate at least through the life of the program (March 31, 2029). The assumed useful life for depreciation purposes is through the end of their current operating licenses. The approved RSSA required Ginna to operate through the RSSA term expiring on March 31, 2017 and required notification to the NYPSC if Ginna did not plan to retire shortly after the expiration of the RSSA. On September 30, 2016, Ginna filed the required notice with the NYPSC of its intent to continue operating beyond the expiry

of the RSSA. Refer to Note 3 - Regulatory Matters for additional discussion on the Ginna RSSA and the New York CES.

Assuming the successful implementation of the Illinois ZES and the New York CES and the continued effectiveness of these programs, Generation and CENG, through its ownership of Ginna and Nine Mile Point, no longer consider Clinton, Quad Cities, Ginna or Nine Mile Point to be at heightened risk for early retirement. However, to the extent either the Illinois ZES or the New York CES programs do not operate as expected over their full terms, each of these plants could again be at heightened risk for early retirement, which could have a material impact on Exelon's and Generation's future results of operations, cash flows and financial positions.

In Pennsylvania, the TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020-2021 planning year, the third consecutive year that TMI failed to clear the PJM base residual capacity auction. The plant is currently committed to operate through May 2019 and is licensed to operate through 2034. On May 30, 2017, based on these capacity auction results, prolonged periods of low wholesale power prices, and the absence of federal or state policies that place a value on nuclear energy for its ability to produce electricity without air pollution, Exelon announced that Generation will permanently cease generation operations at TMI on or about September 30, 2019. Generation has filed the required market and regulatory notifications to shut down the plant. PJM has subsequently notified Generation that it has not identified any reliability issues and has approved the deactivation of TMI as proposed.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

As a result of these plant retirement decisions, Exelon and Generation recognized one-time charges in Operating and maintenance expense related to materials and supplies inventory reserve adjustments, employee-related costs and CWIP impairments, among other items. In addition to these one-time charges, annual incremental non-cash charges to earnings stemming from shortening the expected economic useful lives primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions were also recorded. See Note 15 — Asset Retirement Obligations for additional detail on changes to the nuclear decommissioning ARO balances. The total annual impact of these charges by year are summarized in the table below.

Income statement expense (pre-tax)	2017 [a]	2016 [b]
Depreciation and Amortization		
Accelerated depreciation [c]	$ 250	$ 712
Accelerated nuclear fuel amortization	12	60
Operating and Maintenance		
One-time charges [d,e]	77	26
Change in ARO accretion, net of any contractual offset [f]	—	2
Contractual offset for ARC depreciation [f]	—	(86)
Total	$ 339	$ 714

(a) Reflects incremental charges for TMI including incremental accelerated depreciation and amortization from May 30, 2017 through December 31, 2017.
(b) Reflects incremental charges for Clinton and Quad Cities including incremental accelerated depreciation and amortization from June 2, 2016 through December 6, 2016. In December 2016, as a result of reversing its retirement decision for Clinton and Quad Cities, Exelon and Generation updated the expected economic useful life for both facilities, to 2027 for Clinton, commensurate with the end of the Illinois ZES, and to 2032 for Quad Cities, the end of its current operating license. Depreciation was therefore adjusted beginning December 7, 2016, to reflect these extended useful life estimates.
(c) Reflects incremental accelerated depreciation of plant assets, including any ARC.
(d) Primarily includes materials and supplies inventory reserve adjustments, employee related costs and CWIP impairments.
(e) In June 2016, as a result of the retirement decision for Clinton and Quad Cities, Exelon and Generation recognized one-time charges of $146 million . In December 2016, as a result of reversing its retirement decision for Clinton and Quad Cities, Exelon and Generation reversed approximately $120 million of these one-time charges initially recorded in June 2016.
(f) For Quad Cities based on the regulatory agreement with the Illinois Commerce Commission, decommissioning-related activities are offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability.

Although Salem is committed to operate through May 2021, the plant faces continued economic challenges and PSEG, as the operator of the plant, is exploring all options. The following table provides the balance sheet amounts as of December 31, 2017 for Generation’s ownership share of the significant assets and liabilities associated with Salem.

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(in millions)	12/31/2017
Asset Balances	
Materials and supplies inventory	$ 44
Nuclear fuel inventory, net	113
Completed plant, net	439
Construction work in progress	33
Liability Balances	
Asset retirement obligation	(442)

NRC License Renewal Term	2036 (unit 1)
	2040 (unit 2)

On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018. See Note 28 — Subsequent Events for additional information regarding the early retirement of Oyster Creek.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

9 . Jointly Owned Electric Utility Plant (Exelon, Generation, PECO, BGE, PHI, Pepco, DPL and ACE)

Exelon's, Generation's, PECO's, BGE's, PHI's and ACE's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2017 and 2016 were as follows:

	Nuclear Generation				Fossil-Fuel Generation	Transmission		Other
	Quad Cities	Peach Bottom	Salem [a]	Nine Mile Point Unit 2	Wyman	PA [b]	NJ/ DE [c]	Other [d]
Operator	Generation	Generation	PSEG Nuclear	Generation	FP&L	First Energy	PSEG/ DPL	various
Ownership interest	75.00%	50.00%	42.59%	82.00%	5.89%	various	various	various
Exelon's share at December 31, 2017:								
Plant [e]	$ 1,074	$ 1,417	$ 631	$ 839	$ 3	$ 27	$ 102	$ 15
Accumulated depreciation [e]	550	461	205	97	3	15	52	13
Construction work in progress	35	18	33	55	—	—	—	—
Exelon's share at December 31, 2016:								
Plant [e]	$ 1,054	$ 1,384	$ 596	$ 830	$ 3	$ 27	$ 97	$ 15
Accumulated depreciation [e]	515	407	186	68	3	15	52	13
Construction work in progress	—	16	41	37	—	—	—	—

(a) Generation also owns a proportionate share in the fossil-fuel combustion turbine at Salem, which is fully depreciated. The gross book value was $3 million at December 31, 2017 and 2016 .
(b) PECO, BGE, Pepco, DPL and ACE own a 22% , 7% , 27% , 9% and 8% share, respectively, in 127 miles of 500 kV lines located in Pennsylvania as well as a 20.72% , 10.56% , 9.72% , 3.72% and 3.83% share, respectively, of a 500 kV substation immediately outside of the Conemaugh fossil-generating station which supplies power to the 500 kV lines including, but not limited to, the lines noted above.
(c) PECO, DPL and ACE own a 42.55% , 1% and 13.9% share, respectively in 151.3 miles of 500 kV lines located in New Jersey and Delaware Station. PECO, DPL and ACE also own a 42.55% , 7.45% and 7.45% share, respectively, in 2.5 miles of 500 kV line located over the Delaware River. ACE also has a 21.78% share in a 500 kV New Freedom Switching
(d) Generation, DPL and ACE own a 44.24% , 4.83% and 11.91% share, respectively in assets located at Merrill Creek Reservoir located in New Jersey. Pepco, DPL and ACE own a 11.9% , 7.4% and 6.6% share, respectively, in Valley Forge Corporate Center.
(e) Excludes asset retirement costs.

Exelon's, Generation's, PECO's, BGE's, Pepco's, DPL's and ACE's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. Exelon's, Generation's, PECO's, BGE's, Pepco's, DPL's and ACE's share of direct expenses of the jointly owned plants are included in Purchased power and fuel and Operating and maintenance expenses on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and in Operating and maintenance expenses on PECO's, BGE's, Pepco, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements - (Continued)
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10 . Intangible Assets (Exelon, Generation, ComEd, PECO, PHI, Pepco, DPL and ACE)

Goodwill

Exelon's, Generation's, ComEd's, PHI's and DPL's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2017 and 2016 were as follows:

	Balance at January 1, 2016	Goodwill from business combination	Impairment losses	Measurement period adjustments [b]	Balance at December 31, 2016	Impairment losses	Balance at December 31, 2017
Exelon							
Gross amount	$ 4,655	$ 4,016	$ —	$ (11)	$ 8,660	$ —	$ 8,660
Accumulated impairment loss	1,983	—	—	—	1,983	—	1,983
Carrying amount	2,672	4,016	—	(11)	6,677	—	6,677
Generation							
Gross amount	47	—	—	—	47	—	47
Carrying amount	47	—	—	—	47	—	47
ComEd [a]							
Gross amount	4,608	—	—	—	4,608	—	4,608
Accumulated impairment loss	1,983	—	—	—	1,983	—	1,983
Carrying amount	2,625	—	—	—	2,625	—	2,625
DPL							
Gross amount	8	—	—	—	8	—	8
Carrying amount	8	—	—	—	8	—	8

Combined Notes to Consolidated Financial Statements - (Continued)
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For the Year Ended December 31, 2017	Beginning Balance	Goodwill from business combination	Impairment losses	Measurement period adjustments (b)	Ending Balance
PHI - *Successor*					
Gross amount	$ 4,005	$ —	$ —	$ —	$ 4,005
Accumulated impairment loss	—	—	—	—	—
Carrying Amount	4,005	—	—	—	4,005
March 24, 2016 to December 31, 2016					
PHI - *Successor*					
Gross amount	—	4,016	—	(11)	4,005
Accumulated impairment loss	—	—	—	—	—
Carrying amount	—	4,016	—	(11)	4,005
January 1, 2016 to March 23, 2016					
PHI - *Predecessor*					
Gross amount	1,418	—	—	—	1,418
Accumulated impairment loss	12	—	—	—	12
Carrying amount	1,406	—	—	—	1,406

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom (predecessor parent company of ComEd) merger net of amortization, resolution of tax matters and other non-impairment-related changes as allowed under previous authoritative guidance.

(b) Represents various measurement period adjustments to the valuation of the fair value of the PHI assets acquired and liabilities assumed as a result of the merger.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the Exelon, Generation, ComEd, PHI and DPL reporting unit below its carrying amount. Under the authoritative guidance for goodwill, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and its operating results are regularly reviewed by segment management. Generation's operating segments are Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as “Other Power Regions”, PHI's operating segments are Pepco, DPL and ACE, and ComEd and DPL have a single operating segment. See Note 25 — Segment Information for additional information. There is no level below these operating segments for which operating results are regularly reviewed by segment management. Therefore, the ComEd, Pepco, DPL and ACE operating segments are also considered reporting units for goodwill impairment testing purposes. Exelon's and ComEd's $2.6 billion of goodwill has been assigned entirely to the ComEd reporting unit, while Exelon's and PHI's $4 billion of goodwill has been assigned to the Pepco, DPL and ACE reporting units in the amounts of $1.7 billion , $1.1 billion and $1.2 billion , respectively. DPL's $8 million of goodwill is assigned entirely to the DPL reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors and entity-specific events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required.

If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed. Exelon's, Generation's, ComEd's, PHI's and DPL's accounting policy is to perform a quantitative test of goodwill at least once every three years. The first step in the quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for Generation's, ComEd's, Pepco's, DPL's and ACE's businesses and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

2017 and 2016 Goodwill Impairment Assessment. Generation performed a quantitative test as of November 1, 2017, for its 2017 annual goodwill impairment assessment. The first step of the test comparing the estimated fair value of Generation's reporting unit with goodwill to its carrying value, including goodwill, indicated no impairments of goodwill; therefore, the second step was not required. Generation performed a qualitative test as of November 1, 2016, for its 2016 annual goodwill impairment assessment. Based on the qualitative factors assessed, Generation concluded that the fair value of its reporting units is more likely than not greater than the carrying amount, and no further testing was required.

As of November 1, 2017, ComEd, PHI and DPL each qualitatively determined that it was more likely than not that the fair value of its reporting units exceeded their carrying values and, therefore, did not perform a quantitative assessment. As part of their qualitative assessments, ComEd, PHI and DPL evaluated, among other things, management's best estimate of projected operating and capital cash flows for their businesses, outcomes of recent regulatory proceedings, changes in certain market conditions, including the discount rate and regulated utility peer company EBITDA multiples, while also considering, the passing margin from their last quantitative assessments.

ComEd, PHI and DPL performed quantitative tests as of November 1, 2016, for their 2016 annual goodwill impairment assessments. The first step of the tests comparing the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units to their carrying values, including goodwill, indicated no impairments of goodwill; therefore, no second steps were required.

While the annual assessments indicated no impairments, certain assumptions used to estimate reporting unit fair values are highly sensitive to changes. Adverse regulatory actions or changes in significant assumptions could potentially result in future impairments of ComEd's, PHI's or DPL's goodwill, which could be material. Based on the results of the annual goodwill test performed as of November 1, 2016, the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units would have needed to decrease by more than 30% , 10% , 10% and 10% , respectively, for ComEd and PHI to fail the first step of their respective impairment tests. The $8 million of goodwill recorded at DPL is related to DPL's 1995 acquisition of the Conowingo Power Company and the fair value of the DPL reporting unit would have needed to decrease by more than 50% for DPL to fail the first step of the impairment test.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Other Intangible Assets and Liabilities

Exelon's, Generation's, ComEd's and PHI's other intangible assets and liabilities, included in Unamortized energy contract assets and liabilities and Other deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2017 and 2016 :

	December 31, 2017			December 31, 2016		
	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
Exelon						
Software License [a]	$ 95	$ (25)	$ 70	$ 95	$ (15)	$ 80
Generation						
Unamortized Energy Contracts [b]	1,938	(1,574)	364	1,926	(1,543)	383
Customer Relationships	305	(133)	172	299	(109)	190
Trade Name	243	(148)	95	243	(125)	118
Service Contract Backlog	—	—	—	9	(7)	2
ComEd						
Chicago Settlement Agreements [c]	162	(141)	21	162	(133)	29
PHI						
Unamortized Energy Contracts [b]	(1,515)	766	(749)	(1,515)	430	(1,085)
Pepco						
DC Sponsorship Agreement [d]	—	—	—	25	—	25
Total	$ 1,228	$ (1,255)	$ (27)	$ 1,244	$ (1,502)	$ (258)

(a) On May 31, 2015, Exelon entered into a long-term software license agreement. Exelon is required to make payments starting August 2015 through May 2024. The intangible asset recognized as a result of these payments is being amortized on a straight-line basis over the contract term.
(b) Includes unamortized energy contract assets and liabilities on Exelon's, Generations and PHI's Consolidated Balance Sheets.
(c) In March 1999 and February 2003, ComEd entered into separate agreements with the City of Chicago and Midwest Generation, LLC. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement.
(d) PHI entered into a sponsorship agreement with the District of Columbia for future sponsorship rights associated with public property within the District of Columbia. In December 2017, the asset was written off. See Note 7 - Impairment of Long-Lived Assets and Intangibles for additional information.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table summarizes the estimated future amortization expense related to intangible assets and liabilities as of December 31, 2017 :

For the Years Ending December 31,	Exelon	Generation	ComEd	PHI
2018	$ 10	$ 62	$ 7	$ (189)
2019	10	57	7	(119)
2020	10	68	7	(115)
2021	10	77	—	(92)
2022	10	54	—	(89)

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2017 , 2016 and 2015 :

For the Years Ended December 31,	Exelon [a]	Generation [a]	ComEd
2017	$ 92	$ 83	$ 7
2016	87	79	7
2015	76	69	7

(a) At Exelon, amortization of unamortized energy contracts totaling $35 million , $35 million and $22 million for the years ended December 31, 2017 , 2016 and 2015 , respectively, was recorded in Operating revenues or Purchased power and fuel expense within Exelon's Consolidated Statements of Operations and Comprehensive Income. At Generation, amortization of unamortized energy contracts totaling $35 million , $35 million and $22 million for the years ended December 31, 2017 , 2016 and 2015 , respectively, was recorded in Operating revenues or Purchased power and fuel expense within Generation's Consolidated Statements of Operations and Comprehensive Income

Acquired Intangible Assets and Liabilities

Accounting guidance for business combinations requires the acquirer to separately recognize identifiable intangible assets in the application of purchase accounting.

Unamortized Energy Contracts. Unamortized energy contract assets and liabilities represent the remaining unamortized fair value of non-derivative energy contracts that Exelon and Generation have acquired. The valuation of unamortized energy contracts was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise, the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. The Exelon Wind unamortized energy contracts are amortized on a straight-line basis over the period in which the associated contract revenues are recognized as a decrease in Operating revenues within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. In the case of Antelope Valley, Constellation, CENG, Integrys and ConEdison, the fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the acquisition dates through either Operating revenues or Purchased power and fuel expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. At PHI, offsetting regulatory assets or liabilities were also recorded. The unamortized energy contract assets and liabilities and any corresponding regulatory assets or liabilities, respectively, are amortized over the life of the contract in relation to the expected realization of the underlying cash flows.

Customer Relationships. The customer relationship intangibles were determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The accounting guidance requires that customer-based intangibles be amortized over the period expected to be benefited using the pattern of economic benefit. The amortization of the customer relationships recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Service Contract Backlog. The service contract backlog intangibles were determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the contracts. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include estimated revenues and expenses to complete the contracts as well as the discount rate. The accounting guidance requires that customer-based intangibles be amortized over the period expected to be benefited using the pattern of economic benefit. The amortization of the service contract backlog is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Trade Name. The Constellation trade name intangible was determined based on the relief from royalty method of income approach whereby fair value is determined to be the present value of the license fees avoided by owning the assets. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. The Constellation trade name intangible is amortized on a straight-line basis over a period of 10 years . The amortization of the trade name is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Renewable Energy Credits and Alternative Energy Credits (Exelon, Generation, PECO, PHI, DPL and ACE)

Exelon's, Generation's, ComEd's, PECO's, PHI's, DPL's and ACE's other intangible assets, included in Other current assets and Other deferred debits and other assets on the Consolidated Balance Sheets, include RECs (Exelon, Generation, ComEd, PHI, DPL and ACE) and AECs (Exelon and PECO). Purchased RECs are recorded at cost on the date they are purchased. The cost of RECs purchased on a stand-alone basis is based on the transaction price, while the cost of RECs acquired through PPAs represents the difference between the total contract price and the market price of energy at contract inception. Generally, revenue for RECs that are part of a bundled power sale is recognized when the power is produced and delivered to the customer, otherwise, the revenue is recognized upon physical transfer of the REC.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table summarizes the current and noncurrent Renewable and Alternative Energy Credits for the years ended December 31, 2017 and 2016 :

	As of December 31, 2017					
				Successor		
	Exelon	Generation	PECO	PHI	DPL	ACE
Current AEC's	$ 1	$ —	$ 1	$ —	$ —	$ —
Noncurrent AEC's	—	—	—	—	—	—
Current REC's	321	312	—	9	8	1
Noncurrent REC's	27	27	—	—	—	—

	As of December 31, 2016					
				Successor		
	Exelon	Generation	PECO	PHI	DPL	ACE
Current AEC's	$ 1	$ —	$ 1	$ —	$ —	$ —
Noncurrent AEC's	—	—	—	—	—	—
Current REC's	330	318	—	12	11	1
Noncurrent REC's	29	29	—	—	—	—

11 . Fair Value of Financial Assets and Liabilities (All Registrants)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of December 31, 2017 and 2016 :

Exelon

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 929	$ —	$ 929	$ —	$ 929
Long-term debt (including amounts due within one year) [a]	34,264	—	34,735	1,970	36,705
Long-term debt to financing trusts [b]	389	—	—	431	431
SNF obligation	1,147	—	936	—	936

	December 31, 2016				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 1,267	$ —	$ 1,267	$ —	$ 1,267
Long-term debt (including amounts due within one year) [a]	34,005	1,113	31,741	1,959	34,813
Long-term debt to financing trusts [b]	641	—	—	667	667
SNF obligation	1,024	—	732	—	732

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 2	$ —	$ 2	$ —	$ 2
Long-term debt (including amounts due within one year) [a]	8,990	—	7,839	1,673	9,512
SNF obligation	1,147	—	936	—	936

	December 31, 2016				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 699	$ —	$ 699	$ —	$ 699
Long-term debt (including amounts due within one year) [a]	9,241	—	7,482	1,670	9,152
SNF obligation	1,024	—	732	—	732

ComEd

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year) [a]	$ 7,601	$ —	$ 8,418	$ —	$ 8,418
Long-term debt to financing trusts [b]	205	—	—	227	227

	December 31, 2016				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year) [a]	$ 7,033	$ —	$ 7,585	$ —	$ 7,585
Long-term debt to financing trusts [b]	205	—	—	215	215

PECO

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year) [a]	$ 2,903	$ —	$ 3,194	$ —	$ 3,194
Long-term debt to financing trusts	184	—	—	204	204

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2016				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year) [a]	$ 2,580	$ —	$ 2,794	$ —	$ 2,794
Long-term debt to financing trusts	184	—	—	192	192

BGE

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 77	$ —	$ 77	$ —	$ 77
Long-term debt (including amounts due within one year) [a]	2,577	—	2,825	—	2,825

	December 31, 2016				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 45	$ —	$ 45	$ —	$ 45
Long-term debt (including amounts due within one year) [a]	2,322	—	2,467	—	2,467
Long-term debt to financing trusts [b]	252	—	—	260	260

PHI (Successor)

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 350	$ —	$ 350	$ —	$ 350
Long-term debt (including amounts due within one year) [a]	5,874	—	5,722	297	6,019

	December 31, 2016				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 522	$ —	$ 522	$ —	$ 522
Long-term debt (including amounts due within one year) [a]	5,898	—	5,520	289	5,809

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Pepco

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 26	$ —	$ 26	$ —	$ 26
Long-term debt (including amounts due within one year) [a]	2,540	—	3,114	9	3,123

	December 31, 2016				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 23	$ —	$ 23	$ —	$ 23
Long-term debt (including amounts due within one year) [a]	2,349	—	2,788	8	2,796

DPL

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 216	$ —	$ 216	$ —	$ 216
Long-term debt (including amounts due within one year) [a]	1,300	—	1,393	—	1,393

	December 31, 2016				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year) [a]	$ 1,340	$ —	$ 1,383	$ —	$ 1,383

ACE

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 108	$ —	$ 108	$ —	$ 108
Long-term debt (including amounts due within one year) [a]	1,121	—	949	288	1,237

	December 31, 2016				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year) [a]	$ 1,155	$ —	$ 1,007	$ 280	$ 1,287

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Includes unamortized debt issuance costs which are not fair valued of $201 million , $60 million , $52 million , $17 million , $17 million , $6 million , $32 million , $11 million and $5 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE respectively, as of December 31, 2017 . Includes unamortized debt issuance costs which are not fair valued of $200 million , $64 million , $46 million , $15 million , $15 million , $2 million , $30 million , $11 million and $6 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE respectively, as of December 31, 2016 .
(b) Includes unamortized debt issuance costs which are not fair valued of $1 million and $1 million for Exelon and ComEd, respectively, as of December 31, 2017 . Includes unamortized debt issuance costs which are not fair valued of $7 million , $1 million , and $6 million for Exelon, ComEd and BGE, respectively, as of December 31, 2016 .

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of dividends payable (included in Other current liabilities) (Level 1) and short-term borrowings (Level 2). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) and private placement taxable debt securities (Level 3) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. Due to low trading volume of private placement debt, qualitative factors such as market conditions, low volume of investors and investor demand, this debt is classified as Level 3. The fair value of Exelon's equity units (Level 1) are valued based on publicly traded securities issued by Exelon.

The fair value of Generation's and Pepco's non-government-backed fixed rate nonrecourse debt (Level 3) is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles. Given the low trading volume in the nonrecourse debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-backed fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate financing debt resets on a monthly or quarterly basis and the carrying value approximates fair value (Level 2). When trading data is available on variable rate financing debt, the fair value is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles (Level 2). Generation, Pepco, DPL and ACE also have tax-exempt debt (Level 2). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (e.g., conduit issuer political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above. Variable rate tax-exempt debt (Level 2) resets on a regular basis and the carrying value approximates fair value.

SNF Obligation . The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount

rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2030. The carrying amount also includes $114 million as of December 31, 2017 for the one-time fee obligation associated with closing of the FitzPatrick acquisition on March 31, 2017. The fair value was determined using a similar methodology, however the New York Power Authority's (NYPA) discount rate is used in place of Generation's given the contractual right to reimbursement from NYPA for the obligation; see Note 4 - Mergers, Acquisitions and Dispositions for additional information on Generation's acquisition of FitzPatrick.

Long-Term Debt to Financing Trusts . Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Additionally, there were no material transfers between Level 1 and Level 2 during the years ended December 31, 2017 and 2016 for Cash equivalents, Nuclear decommissioning trust fund investments, Pledged assets for Zion Station decommissioning, Rabbi trust investments, and Deferred compensation obligations. For derivative contracts, transfers into Level 2 from Level 3 generally occur when the contract tenor becomes more observable and due to changes in market liquidity or assumptions for certain commodity contracts.

Generation and Exelon

In accordance with the applicable guidance on fair value measurement, certain investments that are measured at fair value using the NAV per share as a practical expedient are no longer classified within the fair value hierarchy and are included under "Not subject to leveling" in the table below.

The following tables present assets and liabilities measured and recorded at fair value on Exelon's and Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2017 and 2016 :

	Generation					Exelon				
As of December 31, 2017	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets										
Cash equivalents [a]	$ 168	$ —	$ —	$ —	$ 168	$ 656	$ —	$ —	$ —	$ 656

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					Exelon				
As of December 31, 2017	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
NDT fund investments										
Cash equivalents [b]	135	85	—	—	220	135	85	—	—	220
Equities	4,163	915	—	2,176	7,254	4,163	915	—	2,176	7,254
Fixed income										
Corporate debt	—	1,614	251	—	1,865	—	1,614	251	—	1,865
U.S. Treasury and agencies	1,917	52	—	—	1,969	1,917	52	—	—	1,969
Foreign governments	—	82	—	—	82	—	82	—	—	82
State and municipal debt	—	263	—	—	263	—	263	—	—	263
Other [c]	—	47	—	510	557	—	47	—	510	557
Fixed income subtotal	1,917	2,058	251	510	4,736	1,917	2,058	251	510	4,736
Middle market lending	—	—	397	131	528	—	—	397	131	528
Private equity	—	—	—	222	222	—	—	—	222	222
Real estate	—	—	—	471	471	—	—	—	471	471
NDT fund investments subtotal [d]	6,215	3,058	648	3,510	13,431	6,215	3,058	648	3,510	13,431
Pledged assets for Zion Station decommissioning										
Cash equivalents	2	—	—	—	2	2	—	—	—	2
Equities	—	1	—	—	1	—	1	—	—	1
Middle market lending	—	—	12	24	36	—	—	12	24	36
Pledged assets for Zion Station decommissioning subtotal	2	1	12	24	39	2	1	12	24	39
Rabbi trust investments										
Cash equivalents	5	—	—	—	5	77	—	—	—	77
Mutual funds	23	—	—	—	23	58	—	—	—	58
Fixed income	—	—	—	—	—	—	12	—	—	12
Life insurance contracts	—	22	—	—	22	—	71	22	—	93
Rabbi trust investments subtotal	28	22	—	—	50	135	83	22	—	240
Commodity derivative assets										
Economic hedges	557	2,378	1,290	—	4,225	557	2,378	1,290	—	4,225
Proprietary trading	2	31	35	—	68	2	31	35	—	68
Effect of netting and allocation of collateral [e][f]	(585)	(1,769)	(635)	—	(2,989)	(585)	(1,769)	(635)	—	(2,989)
Commodity derivative assets subtotal	(26)	640	690	—	1,304	(26)	640	690	—	1,304

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					Exelon				
As of December 31, 2017	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	3	—	—	3	—	6	—	—	6
Economic hedges	—	10	—	—	10	—	10	—	—	10
Effect of netting and allocation of collateral	(2)	(5)	—	—	(7)	(2)	(5)	—	—	(7)
Interest rate and foreign currency derivative assets subtotal	(2)	8	—	—	6	(2)	11	—	—	9
Other investments	—	—	37	—	37	—	—	37	—	37
Total assets	6,385	3,729	1,387	3,534	15,035	6,980	3,793	1,409	3,534	15,716
Liabilities										
Commodity derivative liabilities										
Economic hedges	(712)	(2,226)	(845)	—	(3,783)	(713)	(2,226)	(1,101)	—	(4,040)
Proprietary trading	(2)	(42)	(9)	—	(53)	(2)	(42)	(9)	—	(53)
Effect of netting and allocation of collateral [e][f]	650	2,089	716	—	3,455	651	2,089	716	—	3,456
Commodity derivative liabilities subtotal	(64)	(179)	(138)	—	(381)	(64)	(179)	(394)	—	(637)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	(2)	—	—	(2)	—	(2)	—	—	(2)
Economic hedges	(1)	(8)	—	—	(9)	(1)	(8)	—	—	(9)
Effect of netting and allocation of collateral	2	5	—	—	7	2	5	—	—	7
Interest rate and foreign currency derivative liabilities subtotal	1	(5)	—	—	(4)	1	(5)	—	—	(4)
Deferred compensation obligation	—	(38)	—	—	(38)	—	(145)	—	—	(145)
Total liabilities	(63)	(222)	(138)	—	(423)	(63)	(329)	(394)	—	(786)
Total net assets	$ 6,322	$ 3,507	$ 1,249	$ 3,534	$ 14,612	$ 6,917	$ 3,464	$ 1,015	$ 3,534	$ 14,930

	Generation					Exelon				
As of December 31, 2016	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Assets										
Cash equivalents [a]	$ 39	$ —	$ —	$ —	$ 39	$ 373	$ —	$ —	$ —	$ 373
NDT fund investments										

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					Exelon				
As of December 31, 2016	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Cash equivalents [b]	110	19	—	—	129	110	19	—	—	129
Equities	3,551	452	—	2,011	6,014	3,551	452	—	2,011	6,014
Fixed income										
Corporate debt	—	1,554	250	—	1,804	—	1,554	250	—	1,804
U.S. Treasury and agencies	1,291	29	—	—	1,320	1,291	29	—	—	1,320
Foreign governments	—	37	—	—	37	—	37	—	—	37
State and municipal debt	—	264	—	—	264	—	264	—	—	264
Other [c]	—	59	—	493	552	—	59	—	493	552
Fixed income subtotal	1,291	1,943	250	493	3,977	1,291	1,943	250	493	3,977
Middle market lending	—	—	427	71	498	—	—	427	71	498
Private equity	—	—	—	148	148	—	—	—	148	148
Real estate	—	—	—	326	326	—	—	—	326	326
NDT fund investments subtotal [d]	4,952	2,414	677	3,049	11,092	4,952	2,414	677	3,049	11,092
Pledged assets for Zion Station decommissioning										
Cash equivalents	11	—	—	—	11	11	—	—	—	11
Equities	—	2	—	—	2	—	2	—	—	2
Fixed Income - U.S. Treasury and agencies	16	1	—	—	17	16	1	—	—	17
Middle market lending	—	—	19	64	83	—	—	19	64	83
Pledged assets for Zion Station decommissioning subtotal	27	3	19	64	113	27	3	19	64	113
Rabbi trust investments										
Cash equivalents	2	—	—	—	2	74	—	—	—	74
Mutual funds	19	—	—	—	19	50	—	—	—	50
Fixed income	—	—	—	—	—	—	16	—	—	16
Life insurance contracts	—	18	—	—	18	—	64	20	—	84
Rabbi trust investments subtotal	21	18	—	—	39	124	80	20	—	224
Commodity derivative assets										
Economic hedges	1,356	2,505	1,229	—	5,090	1,358	2,505	1,229	—	5,092
Proprietary trading	3	50	23	—	76	3	50	23	—	76
Effect of netting and allocation of collateral [e][f]	(1,162)	(2,142)	(481)	—	(3,785)	(1,164)	(2,142)	(481)	—	(3,787)
Commodity derivative assets subtotal	197	413	771	—	1,381	197	413	771	—	1,381

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					Exelon				
As of December 31, 2016	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	—	—	—	—	—	16	—	—	16
Economic hedges	—	28	—	—	28	—	28	—	—	28
Proprietary trading	3	2	—	—	5	3	2	—	—	5
Effect of netting and allocation of collateral	(2)	(19)	—	—	(21)	(2)	(19)	—	—	(21)
Interest rate and foreign currency derivative assets subtotal	1	11	—	—	12	1	27	—	—	28
Other investments	—	—	42	—	42	—	—	42	—	42
Total assets	5,237	2,859	1,509	3,113	12,718	5,674	2,937	1,529	3,113	13,253
Liabilities										
Commodity derivative liabilities										
Economic hedges	(1,267)	(2,378)	(794)	—	(4,439)	(1,267)	(2,378)	(1,052)	—	(4,697)
Proprietary trading	(3)	(50)	(26)	—	(79)	(3)	(50)	(26)	—	(79)
Effect of netting and allocation of collateral (e)(f)	1,233	2,339	542	—	4,114	1,233	2,339	542	—	4,114
Commodity derivative liabilities subtotal	(37)	(89)	(278)	—	(404)	(37)	(89)	(536)	—	(662)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	(10)	—	—	(10)	—	(10)	—	—	(10)
Economic hedges	—	(21)	—	—	(21)	—	(21)	—	—	(21)
Proprietary trading	(4)	—	—	—	(4)	(4)	—	—	—	(4)
Effect of netting and allocation of collateral	4	19	—	—	23	4	19	—	—	23
Interest rate and foreign currency derivative liabilities subtotal	—	(12)	—	—	(12)	—	(12)	—	—	(12)
Deferred compensation obligation	—	(34)	—	—	(34)	—	(136)	—	—	(136)
Total liabilities	(37)	(135)	(278)	—	(450)	(37)	(237)	(536)	—	(810)
Total net assets	$ 5,200	$ 2,724	$ 1,231	$ 3,113	$ 12,268	$ 5,637	$ 2,700	$ 993	$ 3,113	$ 12,443

(a) Generation excludes cash of $259 million and $252 million at December 31, 2017 and 2016 and restricted cash of $127 million and $157 million at December 31, 2017 and 2016 . Exelon excludes cash of $389 million and $360 million at December 31, 2017 and 2016 and restricted cash of $145 million and $180 million at December 31, 2017 and 2016 and includes long-term restricted cash of $85 million and $25 million at December 31, 2017 and 2016 , which is reported in Other deferred debits on the Consolidated Balance Sheets.
(b) Includes $77 million and $29 million of cash received from outstanding repurchase agreements at December 31, 2017 and 2016 , respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

(c) Includes derivative instruments of less than $1 million and $(2) million , which have a total notional amount of $811 million and $933 million at December 31, 2017 and 2016 , respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.
(d) Excludes net liabilities of $82 million and $31 million at December 31, 2017 and 2016 , respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.
(e) Collateral posted/(received) from counterparties totaled $65 million , $320 million and $81 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2017 . Collateral posted/(received) from counterparties totaled $71 million , $197 million and $61 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2016 .
(f) Of the collateral posted/(received), $(117) million and $(158) million represents variation margin on the exchanges as of December 31, 2017 and 2016 , respectively.

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on ComEd's, PECO's and BGE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2017 and 2016 :

	ComEd				PECO				BGE			
As of December 31, 2017	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents [a]	$ 98	$ —	$ —	$ 98	$ 228	$ —	$ —	$ 228	$ —	$ —	$ —	$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	6	—	—	6
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	7	10	—	17	6	—	—	6
Total assets	98	—	—	98	235	10	—	245	6	—	—	6
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(11)	—	(11)	—	(5)	—	(5)
Mark-to-market derivative liabilities [b]	—	—	(256)	(256)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(256)	(264)	—	(11)	—	(11)	—	(5)	—	(5)
Total net assets (liabilities)	$ 98	$ (8)	$ (256)	$ (166)	$ 235	$ (1)	$ —	$ 234	$ 6	$ (5)	$ —	$ 1

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	ComEd				PECO				BGE			
As of December 31, 2016	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents [a]	$ 20	$ —	$ —	$ 20	$ 45	$ —	$ —	$ 45	$ 36	$ —	$ —	$ 36
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	4	—	—	4
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	7	10	—	17	4	—	—	4
Total assets	20	—	—	20	52	10	—	62	40	—	—	40
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(11)	—	(11)	—	(4)	—	(4)
Mark-to-market derivative liabilities [b]	—	—	(258)	(258)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(258)	(266)	—	(11)	—	(11)	—	(4)	—	(4)
Total net assets (liabilities)	$ 20	$ (8)	$ (258)	$ (246)	$ 52	$ (1)	$ —	$ 51	$ 40	$ (4)	$ —	$ 36

(a) ComEd excludes cash of $45 million and $36 million at December 31, 2017 and 2016 and restricted cash of $2 million at December 31, 2016 and includes long-term restricted cash of $62 million at December 31, 2017 , which is reported in Other deferred debits on the Consolidated Balance Sheets. PECO excludes cash of $47 million and $22 million at December 31, 2017 and 2016 . BGE excludes cash of $17 million and $13 million at December 31, 2017 and 2016 and restricted cash of $1 million at December 31, 2017 and includes long-term restricted cash of $2 million at December 31, 2016 , which is reported in Other deferred debits on the Consolidated Balance Sheets.
(b) The Level 3 balance consists of the current and noncurrent liability of $21 million and $235 million , respectively, at December 31, 2017 , and $19 million and $239 million , respectively, at December 31, 2016 , related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI, Pepco, DPL and ACE

The following tables present assets and liabilities measured and recorded at fair value on PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2017 and 2016 :

	Successor							
	As of December 31, 2017				As of December 31, 2016			
PHI	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents [a]	$ 83	$ —	$ —	$ 83	$ 217	$ —	$ —	$ 217
Mark-to-market derivative assets [b]	—	—	—	—	2	—	—	2
Effect of netting and allocation of collateral	—	—	—	—	(2)	—	—	(2)
Mark-to-market derivative assets subtotal	—	—	—	—	—	—	—	—
Rabbi trust investments								
Cash equivalents	72	—	—	72	73	—	—	73
Fixed income	—	12	—	12	—	16	—	16
Life insurance contracts	—	23	22	45	—	22	20	42
Rabbi trust investments subtotal	72	35	22	129	73	38	20	131
Total assets	155	35	22	212	290	38	20	348
Liabilities								
Deferred compensation obligation	—	(25)	—	(25)	—	(28)	—	(28)
Mark-to-market derivative liabilities [b]	(1)	—	—	(1)	—	—	—	—
Effect of netting and allocation of collateral	1	—	—	1	—	—	—	—
Mark-to-market derivative liabilities subtotal	—	—	—	—	—	—	—	—
Total liabilities	—	(25)	—	(25)	—	(28)	—	(28)
Total net assets	$ 155	$ 10	$ 22	$ 187	$ 290	$ 10	$ 20	$ 320

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Pepco				DPL				ACE			
As of December 31, 2017	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents [a]	$ 36	$ —	$ —	$ 36	$ —	$ —	$ —	$ —	$ 29	$ —	$ —	$ 29
Rabbi trust investments												
Cash equivalents	44	—	—	44	—	—	—	—	—	—	—	—
Fixed income	—	12	—	12	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	22	45	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	44	35	22	101	—	—	—	—	—	—	—	—
Total assets	80	35	22	137	—	—	—	—	29	—	—	29
Liabilities												
Deferred compensation obligation	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Mark-to-market derivative liabilities [b]	—	—	—	—	(1)	—	—	(1)	—	—	—	—
Effect of netting and allocation of collateral	—	—	—	—	1	—	—	1	—	—	—	—
Mark-to-market derivative liabilities subtotal	—	—	—	—	—	—	—	—	—	—	—	—
Total liabilities	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$ 80	$ 31	$ 22	$ 133	$ —	$ (1)	$ —	$ (1)	$ 29	$ —	$ —	$ 29

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Pepco				DPL				ACE			
As of December 31, 2016	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents [a]	$ 33	$ —	$ —	$ 33	$ 42	$ —	$ —	$ 42	$ 130	$ —	$ —	$ 130
Mark-to-market derivative assets [b]	—	—	—	—	2	—	—	2	—	—	—	—
Effect of netting and allocation of collateral	—	—	—	—	(2)	—	—	(2)	—	—	—	—
Mark-to-market derivative assets subtotal	—	—	—	—	—	—	—	—	—	—	—	—
Rabbi trust investments												
Cash equivalents	43	—	—	43	—	—	—	—	—	—	—	—
Fixed income	—	16	—	16	—	—	—	—	—	—	—	—
Life insurance contracts	—	22	19	41	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	43	38	19	100	—	—	—	—	—	—	—	—
Total assets	76	38	19	133	42	—	—	42	130	—	—	130
Liabilities												
Deferred compensation obligation	—	(5)	—	(5)	—	(1)	—	(1)	—	—	—	—
Total liabilities	—	(5)	—	(5)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$ 76	$ 33	$ 19	$ 128	$ 42	$ (1)	$ —	$ 41	$ 130	$ —	$ —	$ 130

(a) PHI excludes cash of $12 million and $19 million at December 31, 2017 and 2016 and includes long term restricted cash of $23 million at both December 31, 2017 and 2016 which is reported in Other deferred debits on the Consolidated Balance Sheets. Pepco excludes cash of $4 million and $9 million at December 31, 2017 and 2016 . DPL excludes cash of $2 million and $4 million at December 31, 2017 and 2016 . ACE excludes cash of $2 million and $3 million at December 31, 2017 and 2016 and includes long-term restricted cash of $23 million at both December 31, 2017 and 2016 which is reported in Other deferred debits on the Consolidated Balance Sheets.
(b) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2017 and 2016 :

	Generation					ComEd	PHI		Exelon
For the year ended December 31, 2017	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation	Total
Balance as of January 1, 2017	$ 677	$ 19	$ 493	$ 42	$ 1,231	$ (258)	$ 20	$ —	$ 993
Total realized / unrealized gains (losses)									
Included in net income	3	—	(90) [a]	3	(84)	—	3	—	(81)
Included in noncurrent payables to affiliates	6	—	—	—	6	—	—	(6)	—
Included in payable for Zion Station decommissioning	—	(8)	—	—	(8)	—	—	—	(8)
Included in regulatory assets/liabilities	—	—	—	—	—	2 [b]	—	6	8
Change in collateral	—	—	20	—	20	—	—	—	20
Purchases, sales, issuances and settlements									
Purchases	64	1	178	5	248	—	—	—	248
Sales	—	—	(16)	—	(16)	—	—	—	(16)
Issuances	—	—	—	—	—	—	(1)	—	(1)
Settlements	(102)	—	(8) [c]	—	(110)	—	—	—	(110)
Transfers into Level 3	—	—	(6)	—	(6)	—	—	—	(6)
Transfers out of Level 3	—	—	(50)	(11)	(61)	—	—	—	(61)
Other miscellaneous	—	—	31 [d]	(2)	29	—	—	—	29
Balance as of December 31, 2017	$ 648	$ 12	$ 552	$ 37	$ 1,249	$ (256)	$ 22	$ —	$ 1,015
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2017	$ 1	$ —	$ 254	$ 3	$ 258	$ —	$ 3	$ —	$ 261

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

			Generation			ComEd	PHI (f)		Exelon
							Successor		
For the year ended December 31, 2016	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation	Total
Balance as of January 1, 2016	$ 670	$ 22	$ 1,051	$ 33	$ 1,776	$ (247)	$ —	$ —	$ 1,529
Included due to merger	—	—	—	—	—	—	20	—	20
Total realized / unrealized gains (losses)									
Included in net income	7	—	(568) (a)	1	(560)	—	3	—	(557)
Included in noncurrent payables to affiliates	16	—	—	—	16	—	—	(16)	—
Included in regulatory assets/liabilities	—	—	—	—	—	(11) (b)	—	16	5
Change in collateral	—	—	(141)	—	(141)	—	—	—	(141)
Purchases, sales, issuances and settlements									
Purchases	143	2	342 (c)	7	494	—	—	—	494
Sales	(1)	(5)	(9)	—	(15)	—	—	—	(15)
Issuances	—	—	—	—	—	—	(3)	—	(3)
Settlements	(144)	—	—	—	(144)	—	—	—	(144)
Transfers into Level 3	—	—	1	1	2	—	—	—	2
Transfers out of Level 3	(14)	—	(183)	—	(197)	—	—	—	(197)
Balance as of December 31, 2016	$ 677	$ 19	$ 493	$ 42	$ 1,231	$ (258)	$ 20	$ —	$ 993
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2016	$ 5	$ —	$ 109	$ —	$ 114	$ —	$ 2	$ —	$ 116

(a) Includes a reduction for the reclassification of $352 million and $677 million of realized gains due to the settlement of derivative contracts for the years ended December 31, 2017 and 2016 , respectively.
(b) Includes $18 million of decreases in fair value and an increase for realized losses due to settlements of $20 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2017 . Includes $29 million of decreases in fair value and an increase for realized losses due to settlements of $18 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2016 .
(c) Exelon includes the settlement value for any open contracts that were net settled prior to their scheduled maturity within this line item.
(d) As a result of the bankruptcy filing for EGTP on November 7, 2017, the net mark-to-market commodity contracts were deconsolidated from Exelon's and Generation's consolidated financial statements.
(e) Includes $168 million of fair value from contracts acquired as a result of portfolio acquisitions.
(f) Successor period represents activity from March 24, 2016 to December 31, 2016 . See tables below for PHI's predecessor periods, as well as activity for Pepco for the years ended December 31, 2017 and 2016 .

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Predecessor	
	January 1, 2016 to March 23, 2016	
PHI	**Preferred Stock**	**Life Insurance Contracts**
Beginning Balance	$ 18	$ 19
Total realized / unrealized (losses) gains		
Included in net income	(18)	1
Ending Balance	$ —	$ 20
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$ —	$ 1

	Life Insurance Contracts	
	For the year ended December 31,	
Pepco	**2017**	**2016**
Balance as of January 1	$ 20	$ 19
Total realized / unrealized gains (losses)		
Included in net income	3	3
Purchases, sales, issuances and settlements		
Issuances	(1)	(3)
Balance as of December 31	$ 22	$ 19
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$ 3	$ 3

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2017 and 2016 :

	Successor							
	Generation			PHI	Exelon			
	Operating Revenues	Purchased Power and Fuel	Other, net [a]	Operating and Maintenance	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net [a]
Total gains (losses) included in net income for the year ended December 31, 2017	$ 28	$ (126)	$ 6	$ 3	$ 28	$ (126)	$ 3	$ 6
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2017	290	(36)	4	3	290	(36)	3	4

	Successor						
	Generation			PHI [b]	Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net [a]	Other, net [a]	Operating Revenues	Purchased Power and Fuel	Other, net [a]
Total gains (losses) included in net income for the year ended December 31, 2016	$ (477)	$ (91)	$ 7	$ 3	$ (477)	$ (91)	$ 10
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2016	154	(45)	5	2	154	(45)	7

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Predecessor			
	PHI	Pepco		
	January 1, 2016 to March 23, 2016	December 31, 2017	December 31, 2017	December 31, 2016
	Other, net [a]	Operating and Maintenance	Other, net [a]	
Total (losses) gains included in net income	$ (17)	$ 3	$ —	$ 3
Change in the unrealized gains (losses) relating to assets and liabilities held	1	3	—	3

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation, accrued interest on a convertible promissory note at Generation and the life insurance contracts held by PHI and Pepco.
(b) Successor period represents activity from March 24, 2016 to December 31, 2016 . See the subsequent table for PHI's predecessor periods, as well as activity for Pepco for the year ended December 31, 2017 and 2016 .

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). The Registrants' cash equivalents include investments with original maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Preferred Stock Derivative (PHI). In connection with entering into the PHI Merger Agreement, PHI entered into a Subscription Agreement with Exelon dated April 29, 2014, pursuant to which PHI issued to Exelon shares of preferred stock. The preferred stock contained embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding preferred stock could be called and redeemed at a nominal par value upon a termination of the merger agreement under certain circumstances due to the failure to obtain required regulatory approvals. The embedded call and redemption features on the shares of the preferred stock in the event of such a termination were separately accounted for as derivatives. These preferred stock derivatives were valued quarterly using quantitative and qualitative factors, including management's assessment of the likelihood of a Regulatory Termination and therefore, were categorized in Level 3 in the fair value hierarchy. As a result of the PHI Merger, the PHI preferred stock derivative was reduced to zero as of March 23, 2016 . The write-off was charged to Other, net on the PHI Consolidated Statement of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in Equities and Fixed Income. Generation's and CENG's NDT fund investments policies outline investment guidelines for the trusts and limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds which are based on quoted prices in active markets are categorized in Level 1. Certain equity securities have been categorized as Level 2 because they are based on evaluated prices that reflect observable market

information, such as actual trade information or similar securities. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The fair values of private placement fixed income securities, which are included in Corporate debt, are determined using a third-party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity and fixed income commingled funds and mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives such as holding short-term fixed income securities or tracking the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For commingled funds and mutual funds, which are not publicly quoted, the funds are valued using NAV as a practical expedient for fair value, which is primarily derived from the quoted prices in active markets on the underlying securities, and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Derivative instruments consisting primarily of futures and interest rate swaps to manage risk are recorded at fair value. Over the counter derivatives are valued daily based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over the counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Middle market lending are investments in loans or managed funds which lend to private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in loans are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Managed funds are valued using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. The fair value of private equity and real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date.

Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are unobservable.

As of December 31, 2017 , Generation has outstanding commitments to invest in fixed income, middle market lending, private equity and real estate investments of approximately $65 million , $363 million , $220 million and $118 million , respectively. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of December 31, 2017 . Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2017 , there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation's NDT assets.

See Note 15 — Asset Retirement Obligations for further discussion on the NDT fund investments.

Rabbi Trust Investments (Exelon, Generation, PECO, BGE, PHI, Pepco, DPL and ACE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The Rabbi trusts' assets are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of money market funds, mutual funds, fixed income securities and life insurance policies. The mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Money market funds and mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The fair values of fixed income securities are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The life insurance policies are valued using the cash surrender value of the policies, net of loans against those policies, which is provided by a third-party. Certain life insurance policies, which consist primarily of mutual funds that are priced based on observable market data, have been categorized as Level 2 because the life insurance policies can be liquidated at the reporting date for the value of the underlying assets. Life insurance policies that are valued using unobservable inputs have been categorized as Level 3.

Mark-to-Market Derivatives (Exelon, Generation, ComEd, PHI and DPL) . Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' derivatives are predominantly at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information model inputs generally would include both observable and unobservable inputs. These valuations may include an

estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 12 — Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

The value of certain employment agreement obligations (which are included with the Deferred Compensation Obligation in the tables above) are based on a known and certain stream of payments to be made over time and are categorized as Level 2 within the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd, PHI, Pepco, DPL and ACE)

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending and certain corporate debt securities investments, the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on discounting the forecasted cash flows, market-based comparable data, credit and liquidity factors, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations.

Rabbi Trust Investments - Life insurance contracts (Exelon, PHI, Pepco, DPL and ACE). For life insurance policies categorized as Level 3, the fair value is determined based on the cash surrender value of the policy, which contains unobservable inputs and assumptions. Because Exelon relies on its third-party insurance provider to develop the inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Exelon. Exelon gains an understanding of the types of inputs

and assumptions used in preparing the valuations and performs procedures to assess the reasonableness of the valuations.

Mark-to-Market Derivatives (Exelon, Generation and ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas and certain transmission congestion contracts. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $2.99 and $0.42 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 12 — Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

The following tables present the significant inputs to the forward curve used to value these positions:

Type of trade	Fair Value at December 31, 2017	Valuation Technique	Unobservable Input	Range		
Mark-to-market derivatives—Economic hedges (Exelon and Generation) [a][b]	$ 445	Discounted Cash Flow	Forward power price	$3	-	$124
			Forward gas price	$1.27	-	$12.80
		Option Model	Volatility percentage	11%	-	139%
Mark-to-market derivatives—Proprietary trading (Exelon and Generation) [a][b]	$ 26	Discounted Cash Flow	Forward power price	$14	-	$94
Mark-to-market derivatives (Exelon and ComEd)	$ (256)	Discounted Cash Flow	Forward heat rate [c]	9x	-	10x
			Marketability reserve	4%	-	8%
			Renewable factor	88%	-	120%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) The fair values do not include cash collateral posted on level three positions of $81 million as of December 31, 2017 .
(c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

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(Dollars in millions, except per share data unless otherwise noted)

Type of trade	Fair Value at December 31, 2016	Valuation Technique	Unobservable Input	Range		
Mark-to-market derivatives—Economic hedges (Exelon and Generation) [a][b]	$ 435	Discounted Cash Flow	Forward power price	$11	-	$130
			Forward gas price	$1.72	-	$9.20
		Option Model	Volatility percentage	8%	-	173%
Mark-to-market derivatives— Proprietary trading (Exelon and Generation) [a][b]	$ (3)	Discounted Cash Flow	Forward power price	$19	-	$79
Mark-to-market derivatives (Exelon and ComEd)	$ (258)	Discounted Cash Flow	Forward heat rate [c]	8x	-	9x
			Marketability reserve	3%	-	8%
			Renewable factor	89%	-	121%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) The fair values do not include cash collateral posted on level three positions of $61 million as of December 31, 2016
(c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

12 . Derivative Financial Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk, interest rate risk and foreign exchange risk related to ongoing business operations.

Commodity Price Risk (All Registrants)

To the extent the total amount of power Generation produces and purchases differs from the amount of power it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. Each of the Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and commodity products. The Registrants believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

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Derivative authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchases and normal sales (NPNS), cash flow hedges and fair value hedges. For Generation, all derivative economic hedges related to commodities are recorded at fair value through earnings for the consolidated company, referred to as economic hedges in the following tables. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

Fair value authoritative guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation's use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e., to BB+ or Ba1). In the table below, Generation's energy related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral including initial margin on exchange positions, is aggregated in the collateral and netting column. As of December 31, 2017 and 2016 , $4 million and $8 million of cash collateral held, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or had no positions to offset as of the balance sheet date. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e., to BB+ or Ba1).

Cash collateral held by BGE and PECO must be deposited in a non-affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

In the table below, DPL's economic hedges are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting column.

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The following table provides a summary of the derivative fair value balances related to commodity contracts recorded by the Registrants as of December 31, 2017 :

											Successor
	Generation				ComEd	DPL			PHI	Exelon	
Description	Economic Hedges	Proprietary Trading	Collateral and Netting [b][c]	Subtotal [b]	Economic Hedges [c]	Economic Hedges [d]	Collateral and Netting [a]	Subtotal	Subtotal	Total Derivatives	
Mark-to-market derivative assets (current assets)	$ 3,061	$ 56	$ (2,144)	$ 973	$ —	$ —	$ —	$ —	$ —	$ 973	
Mark-to-market derivative assets (noncurrent assets)	1,164	12	(845)	331	—	—	—	—	—	331	
Total mark-to-market derivative assets	4,225	68	(2,989)	1,304	—	—	—	—	—	1,304	
Mark-to-market derivative liabilities (current liabilities)	(2,646)	(43)	2,480	(209)	(21)	(1)	1	—	—	(230)	
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,137)	(10)	975	(172)	(235)	—	—	—	—	(407)	
Total mark-to-market derivative liabilities	(3,783)	(53)	3,455	(381)	(256)	(1)	1	—	—	(637)	
Total mark-to-market derivative net assets (liabilities)	$ 442	$ 15	$ 466	$ 923	$ (256)	$ (1)	$ 1	$ —	$ —	$ 667	

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.
(b) Current and noncurrent assets are shown net of collateral of $169 million and $53 million , respectively, and current and noncurrent liabilities are shown net of collateral of $167 million and $77 million , respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $466 million at December 31, 2017.
(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.
(d) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.
(e) Of the collateral posted/(received), $(117) million represents variation margin on the exchanges.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides a summary of the derivative fair value balances related to commodity contracts recorded by the Registrants as of December 31, 2016 :

										Successor	
	Generation				ComEd	DPL			PHI	Exelon	
Description	Economic Hedges	Proprietary Trading	Collateral and Netting [a][b][c]	Subtotal [b]	Economic Hedges [c]	Economic Hedges [d]	Collateral and Netting [a]	Subtotal	Subtotal	Total Derivatives	
Mark-to-market derivative assets (current assets)	$ 3,623	$ 55	$ (2,769)	$ 909	$ —	$ 2	$ (2)	$ —	$ —	$ 909	
Mark-to-market derivative assets (noncurrent assets)	1,467	21	(1,016)	472	—	—	—	—	—	472	
Total mark-to-market derivative assets	5,090	76	(3,785)	1,381	—	2	(2)	—	—	1,381	
Mark-to-market derivative liabilities (current liabilities)	(3,165)	(54)	2,964	(255)	(19)	—	—	—	—	(274)	
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,274)	(25)	1,150	(149)	(239)	—	—	—	—	(388)	
Total mark-to-market derivative liabilities	(4,439)	(79)	4,114	(404)	(258)	—	—	—	—	(662)	
Total mark-to-market derivative net assets (liabilities)	$ 651	$ (3)	$ 329	$ 977	$ (258)	$ 2	$ (2)	$ —	$ —	$ 719	

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit and other forms of non-cash collateral. These are not reflected in the table above.
(b) Current and noncurrent assets are shown net of collateral of $100 million and $72 million , respectively, and current and noncurrent liabilities are shown net of collateral of $95 million and $62 million , respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $329 million at December 31, 2016 .
(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.
(d) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.
(e) Of the collateral posted/(received), $(158) million represents variation margin on the exchanges.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Economic Hedges (Commodity Price Risk)

Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. To manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis. For the years ended December 31, 2017 , 2016 and 2015 , Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also located in the "Net fair value changes related to derivatives" on the Consolidated Statements of Cash Flows.

	For the Years Ended December 31,		
	2017	2016	2015
Income Statement Location	Gain (Loss)		
Operating revenues	$ (126)	$ (490)	$ 196
Purchased power and fuel	(43)	459	54
Total Exelon and Generation	$ (169)	$ (31)	$ 250

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of December 31, 2017 , the percentage of expected generation hedged is 85% - 88% , 55% - 58% and 26% - 29% for 2018 , 2019 and 2020 , respectively.

On December 17, 2010, ComEd entered into several 20 -year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3 — Regulatory Matters for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3 — Regulatory Matters . Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's commodity price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts. PECO has certain full requirements contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2016 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2016 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 20% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's results of operations and financial position as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. BGE's commodity price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10% , but not more than 20% , of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. BGE's natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. The SOS rates charged recover Pepco's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for residential and commercial rate classes. Pepco's commodity price risk related to electric supply procurement is limited. Pepco locks in fixed prices for its SOS requirements through full requirements contracts. Certain of Pepco's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other Pepco full requirements contracts are not derivatives.

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. The SOS rates charged recover DPL's wholesale power supply costs. In Delaware, DPL is also entitled to recover a Reasonable Allowance for Retail Margin (RARM). The RARM includes a fixed annual margin of approximately $2.75 million , plus an incremental cost component and a cash working capital allowance. In Maryland, DPL charges an administrative fee intended to allow it to recover its administrative costs. DPL locks in fixed prices for its SOS requirements through full requirements contracts. DPL's commodity price risk related to electric supply procurement is limited. Certain of DPL's full requirements contracts, which are considered

derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

DPL provides natural gas to its customers under an Annual GCR mechanism approved by the DPSC. Under this mechanism, DPL's Annual GCR Filing establishes a future GCR for firm bundled sales customers by using a forecast of demand and commodity costs. The actual costs are trued up against forecast on a monthly basis and any shortfall or excess is carried forward as a recovery balance in the next GCR filing. The demand portion of the GCR is based upon DPL's firm transportation and storage contracts. DPL has firm deliverability of swing and seasonal storage; a liquefied natural gas facility and firm transportation capacity to meet customer demand and provide a reserve margin. The commodity portion of the GCR includes a commission approved hedging program which is intended to reduce gas commodity price volatility while limiting the firm natural gas customers' exposure to adverse changes in the market price of natural gas. The hedge program requires that DPL hedge, on a non-discretionary basis, an amount equal to 50% of estimated purchase requirements for each month, including estimated monthly purchases for storage injections. The 50% hedge monthly target is achieved by hedging 1/12th of the 50% target each month beginning 12-months prior to the month in which the physical gas is to be purchased. Currently, DPL uses only exchange traded futures for its gas hedging program, which are considered derivatives, however, it retains the capability to employ other physical and financial hedges if needed. DPL has not elected hedge accounting for these derivative financial instruments. Because of the DPSC-approved fuel adjustment clause for DPL's derivatives, the change in fair value of the derivatives each period, in addition to all premiums paid and other transaction costs incurred as part of the Gas Hedging Program, are fully recoverable and are recorded by DPL as regulatory assets or liabilities. DPL's physical gas purchases are currently all daily, monthly or intra-month transactions. From time to time, DPL will enter into seasonal purchase or sale arrangements, however, there are none currently in the portfolio. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. The BGS rates charged recover ACE's wholesale power supply costs. ACE does not make any profit or incur any loss on the supply component of the BGS it supplies to customers. ACE's commodity price risk related to electric supply procurement is limited. ACE locks in fixed prices for its BGS requirements through full requirements contracts. Certain of ACE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other ACE full requirements contracts are not derivatives.

Proprietary Trading (Commodity Price Risk)

Generation also executes commodity derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those executed with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. For the years ended December 31, 2017 , 2016 and 2015 , Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also included in the "Net fair value changes related to derivatives" on the Consolidated Statements of Cash Flows. The Utility Registrants do not execute derivatives for proprietary trading purposes.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the Years Ended December 31,		
	2017	2016	2015
Income Statement Location	Gain (Loss)		
Operating revenues	$ 6	$ 2	$ (6)

Interest Rate and Foreign Exchange Risk (All Registrants)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels, which are typically designated as cash flow hedges to manage interest rate risk. To manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are treated as economic hedges. Below is a summary of the interest rate and foreign exchange hedge balances as of December 31, 2017 :

	Generation					Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading	Collateral and Netting [a]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$ —	$ 10	$ —	$ (7)	$ 3	$ —	$ 3
Mark-to-market derivative assets (noncurrent assets)	3	—	—	—	3	3	6
Total mark-to-market derivative assets	3	10	—	(7)	6	3	9
Mark-to-market derivative liabilities (current liabilities)	(2)	(7)	—	7	(2)	—	(2)
Mark-to-market derivative liabilities (noncurrent liabilities)	—	(2)	—	—	(2)	—	(2)
Total mark-to-market derivative liabilities	(2)	(9)	—	7	(4)	—	(4)
Total mark-to-market derivative net assets (liabilities)	$ 1	$ 1	$ —	$ —	$ 2	$ 3	$ 5

(a) Exelon and Generation net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting counterparty exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral, which are not reflected in the table above.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2016 :

	Generation					Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$ —	$ 17	$ 4	$ (13)	$ 8	$ —	$ 8
Mark-to-market derivative assets (noncurrent assets)	—	11	1	(8)	4	16	20
Total mark-to-market derivative assets	—	28	5	(21)	12	16	28
Mark-to-market derivative liabilities (current liabilities)	(7)	(13)	(2)	14	(8)	—	(8)
Mark-to-market derivative liabilities (noncurrent liabilities)	(3)	(8)	(2)	9	(4)	—	(4)
Total mark-to-market derivative liabilities	(10)	(21)	(4)	23	(12)	—	(12)
Total mark-to-market derivative net assets (liabilities)	$ (10)	$ 7	$ 1	$ 2	$ —	$ 16	$ 16

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative authoritative guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases, Exelon and Generation may have other offsetting counterparty exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral, which are not reflected in the table above.

Fair Value Hedges (Interest Rate Risk)

For derivative instruments that qualify and are designated as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in earnings immediately. Exelon and Generation include the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps as follows:

		Year Ended December 31,					
		2017	2016	2015	2017	2016	2015
	Income Statement Location	Gain (Loss) on Swaps			Gain (Loss) on Borrowings		
Generation	Interest expense [a]	$ —	$ —	$ (1)	$ —	$ —	$ —
Exelon	Interest expense	(13)	(9)	3	28	23	14

(a) For the year ended December 31, 2015 , the loss on Generation swaps included $(1) million realized in earnings with an immaterial amount excluded from hedge effectiveness testing.

The table below provides the notional amounts of fixed-to-floating hedges outstanding held by Exelon at December 31, 2017 and 2016 .

	For the Years Ended December 31,	
	2017	2016
Fixed-to-floating hedges	$ 800	$ 800

During the years ended December 31, 2017 , 2016 and 2015 , the impact on the results of operations due to ineffectiveness from fair value hedges were gains of $15 million , $14 million and $17 million , respectively.

Cash Flow Hedges (Interest Rate Risk)

For derivative instruments that qualify and are designated as cash flow hedges, the gain or loss on the effective portion of the derivative will be deferred in AOCI and reclassified into earnings when the underlying transaction occurs. To mitigate interest rate risk, Exelon and Generation enter into floating-to-fixed interest rate swaps to manage a portion of interest rate exposure associated with debt issuances. The table below provides the notional amounts of floating-to-fixed hedges outstanding held by Exelon and Generation at December 31, 2017 and 2016 .

	For the Years Ended December 31,	
	2017	2016
Floating-to-fixed hedges	$ 636	$ 659

The tables below provide the activity of OCI related to cash flow hedges for the years ended December 31, 2017 and 2016 , containing information about the changes in the fair value of cash flow hedges and the reclassification from AOCI into results of operations. The amounts reclassified from AOCI, when combined with the impacts of the hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

		Total Cash Flow Hedge AOCI Activity, Net of Income Tax			
		Generation		Exelon	
For the Year Ended December 31, 2017	Income Statement Location	Total Cash Flow Hedges		Total Cash Flow Hedges	
AOCI derivative loss at December 31, 2016		$ (19)		$ (17)	
Effective portion of changes in fair value		(1)		(1)	
Reclassifications from AOCI to net income	Interest expense	4	(a)	4	(a)
AOCI derivative loss at December 31, 2017		$ (16)		$ (14)	

Combined Notes to Consolidated Financial Statements - (Continued)
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		Total Cash Flow Hedge AOCI Activity, Net of Income Tax	
		Generation	Exelon
For the Year Ended December 31, 2016	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
AOCI derivative loss at December 31, 2015		$ (21)	$ (19)
Effective portion of changes in fair value		(6)	(6)
Reclassifications from AOCI to net income	Interest expense	8 (b)	8 (b)
AOCI derivative loss at December 31, 2016		$ (19)	$ (17)

(a) Amount is net of related income tax expense of $1 million for the year ended December 31, 2017 .
(b) Amount is net of related income tax expense of $5 million for the year ended December 31, 2016 .

During the years ended December 31, 2017 , 2016 and 2015 , the impact on the results of operations due to the ineffectiveness from cash flow hedges that continue to be designated in hedging relationships was immaterial. The estimated amount of existing gains and losses that are reported in AOCI at the reporting date that are expected to be reclassified into earnings within the next twelve months is immaterial.

Economic Hedges (Interest Rate and Foreign Exchange Risk)

Exelon and Generation executes these instruments to mitigate exposure to fluctuations in interest rates or foreign exchange but for which the fair value or cash flow hedge elections were not made. Generation also enters into interest rate derivative contracts and foreign exchange currency swaps ("treasury") to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars.

At December 31, 2017 and 2016 , Generation had immaterial notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The following table provides notional amounts outstanding held by Exelon and Generation at December 31, 2017 and 2016 related to foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

	For the Years Ended December 31,	
	2017	2016
Foreign currency exchange rate swaps	$ 94	$ 85

For the years ended December 31, 2017 , 2016 and 2015 , Exelon and Generation recognized the following net pre-tax mark-to-market gains (losses) in the Consolidated Statements of Operations and Comprehensive Income and are included in “Net fair value changes related to derivatives” in Exelon’s and Generation’s Consolidated Statements of Cash Flows.

		For the Years Ended December 31,		
		2017	2016	2015
	Income Statement Location	Gain (Loss)		
Generation	Operating Revenues	$ (6)	$ (10)	$ 7
Generation	Interest Expense	(3)	—	—
Total Generation		$ (9)	$ (10)	$ 7

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

		For the Years Ended December 31,		
		2017	2016	2015
	Income Statement Location	Gain (Loss)		
Exelon	Operating Revenues	$ (6)	$ (10)	$ 7
Exelon	Interest Expense	(3)	—	100
Total Exelon		$ (9)	$ (10)	$ 107

Proprietary Trading (Interest Rate and Foreign Exchange Risk)

Generation also executes derivative contracts for proprietary trading purposes to hedge risk associated with the interest rate and foreign exchange components of underlying commodity positions. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. For the years ended December 31, 2017 , 2016 and 2015 , Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses).

	For the Years Ended December 31,		
	2017	2016	2015
Income Statement Location	Gain (Loss)		
Operating revenues	$ (1)	$ (1)	$ (2)

Credit Risk, Collateral and Contingent-Related Features (All Registrants)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties on executed derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For commodity derivatives, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

Combined Notes to Consolidated Financial Statements - (Continued)
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The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2017 . The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below exclude credit risk exposure from individual retail counterparties, nuclear fuel procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX and Nodal commodity exchanges. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $28 million , $22 million , $24 million , $36 million , $12 million and $6 million as of December 31, 2017 , respectively.

Rating as of December 31, 2017	Total Exposure Before Credit Collateral	Credit Collateral (a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 738	$ 4	$ 734	1	$ 244
Non-investment grade	90	12	78	—	—
No external ratings					
Internally rated — investment grade	253	—	253	—	—
Internally rated — non-investment grade	83	11	72	—	—
Total	$ 1,164	$ 27	$ 1,137	1	$ 244

Net Credit Exposure by Type of Counterparty	December 31, 2017
Financial institutions	$ 41
Investor-owned utilities, marketers, power producers	558
Energy cooperatives and municipalities	452
Other	86
Total	$ 1,137

(a) As of December 31, 2017 , credit collateral held from counterparties where Generation had credit exposure included $8 million of cash and $19 million of letters of credit. The credit collateral does not include non-liquid collateral.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on daily, updated forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price on a given day, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of December 31, 2017 , ComEd's net credit exposure to suppliers was approximately $1 million .

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters for additional information.

PECO's unsecured credit used by the suppliers represents PECO's net credit exposure. As of December 31, 2017 , PECO had no net credit exposure to suppliers.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows

PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2017 , PECO had no material credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters for additional information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. As of December 31, 2017 , BGE had no net credit exposure to suppliers.

BGE's regulated gas business is exposed to market-price risk. At December 31, 2017 , BGE had credit exposure of $4 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Pepco's, DPL's and ACE's power procurement contracts provide suppliers with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents Pepco's, DPL's and ACE's net credit exposure. As of December 31, 2017 , Pepco's, DPL's and ACE's net credit exposures to suppliers were immaterial.

Pepco is permitted to recover its costs of procuring energy through the MDPSC-approved and DCPSC-approved procurement tariffs. DPL is permitted to recover its costs of procuring energy through the MDPSC-approved and DPSC-approved procurement tariffs. ACE is permitted to recover its costs of procuring energy through the NJBPU-approved procurement tariffs. Pepco's, DPL's and ACE's counterparty credit risks are mitigated by their ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters for additional information.

DPL's natural gas procurement plan is reviewed and approved annually on a prospective basis by the DPSC. DPL's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the GCR, which allows DPL to adjust rates annually to reflect realized natural gas prices. To the extent that the fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder. As of December 31, 2017 , DPL's credit exposure under its natural gas supply and asset management agreements was immaterial.

Collateral (All Registrants)

As part of the normal course of business, Generation routinely enters into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges. The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of

the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

	For the Years Ended December 31,	
Credit-Risk Related Contingent Feature	2017	2016
Gross fair value of derivative contracts containing this feature [(a)]	$ (926)	$ (960)
Offsetting fair value of in-the-money contracts under master netting arrangements [(b)]	577	627
Net fair value of derivative contracts containing this feature [(c)]	$ (349)	$ (333)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features ignoring the effects of master netting agreements.
(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of $497 million and letters of credit posted of $293 million , and cash collateral held of $35 million and letters of credit held of $33 million as of December 31, 2017 for external counterparties with derivative positions. Generation had cash collateral posted of $347 million and letters of credit posted of $284 million and cash collateral held of $24 million and letters of credit held of $28 million at December 31, 2016 for external counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of $1.8 billion and $1.9 billion as of December 31, 2017 and 2016 , respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2017 , Generation's and Exelon's swaps were in an asset position with a fair value of $2 million and $5 million , respectively.

See Note 25 — Segment Information for further information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2017 , ComEd held approximately $10 million in collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's renewable energy certificate (REC) contracts, collateral postings are required to cover a percentage of the REC contract value. As of December 31, 2017 , ComEd held approximately $2 million in collateral from suppliers for REC contract obligations. Under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2017 , ComEd held approximately $19 million in collateral from suppliers for the long-term renewable energy contracts. If ComEd lost its investment grade credit rating as of December 31, 2017 , it would have been required to post approximately $14 million of collateral to its counterparties. See Note 3 — Regulatory Matters for additional information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2017 , PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2017 , PECO could have been required to post approximately $34 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2017 , BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2017 , BGE could have been required to post approximately $66 million of collateral to its counterparties.

DPL's natural gas procurement contracts contain provisions that could require DPL to post collateral. To the extent that the fair value of the natural gas derivative transaction in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The DPL obligations are standalone, without the guaranty of PHI. If DPL lost its investment grade credit rating as of December 31, 2017 , DPL could have been required to post an additional amount of approximately $11 million of collateral to its natural gas counterparties.

BGE's, Pepco's, DPL's and ACE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE, Pepco, DPL or ACE to post collateral.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

13 . Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. PHI meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at December 31, 2017 and 2016 :

	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
Commercial Paper Issuer	2017 [a][b][c]	2016 [a][b][c]	2017	2016	2017	2016
Exelon Corporate	$ 600	$ 600	$ —	$ —	1.16%	0.70%
Generation	5,300	5,300	—	620	1.23%	0.94%
ComEd	1,000	1,000	—	—	1.24%	0.77%
PECO	600	600	—	—	1.13%	N/A
BGE	600	600	77	45	1.28%	0.77%
Pepco	500	500	26	23	1.06%	0.71%
DPL	500	500	216	—	1.48%	0.68%
ACE	350	350	108	—	1.43%	0.65%
Total	$ 9,450	$ 9,450	$ 427	$ 688		

(a) Excludes $480 million and $500 million in bilateral credit facilities that do not back Generation's commercial paper program at December 31, 2017 and 2016 , respectively.
(b) Excludes additional credit facility agreements for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $49 million , $34 million , $34 million , $5 million , $2 million , $2 million and $2 million , respectively, arranged with minority and community banks located primarily within utilities' service territories. These facilities expire on October 12, 2018. These facilities are solely utilized to issue letters of credit. As of December 31, 2017 , letters of credit issued under these facilities totaled $5 million and $2 million for Generation and BGE, respectively.
(c) Pepco, DPL and ACE's revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL or ACE may not exceed $900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of outstanding commercial paper does not reduce available capacity under a Registrant's credit facility, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2017 , the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

					Available Capacity at December 31, 2017	
Borrower	Facility Type	Aggregate Bank Commitment [a][b]	Facility Draws	Outstanding Letters of Credit [c]	Actual	To Support Additional Commercial Paper [b][d]
Exelon Corporate	Syndicated Revolver	$ 600	$ —	$ 45	$ 555	$ 555
Generation	Syndicated Revolver	5,300	—	868	4,432	4,432
Generation	Bilaterals	480	—	231	249	—
ComEd	Syndicated Revolver	1,000	—	2	998	998
PECO	Syndicated Revolver	600	—	1	599	599
BGE	Syndicated Revolver	600	—	—	600	523
Pepco	Syndicated Revolver	300	—	—	300	274
DPL	Syndicated Revolver	300	—	—	300	84
ACE	Syndicated Revolver	300	—	—	300	192
Total		$ 9,480	$ —	$ 1,147	$ 8,333	$ 7,657

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $49 million , $34 million , $34 million , $5 million , $2 million , $2 million and $2 million , respectively, arranged with minority and community banks located primarily within utilities' service territories. These facilities expire on October 12, 2018. These facilities are solely utilized to issue letters of credit. As of December 31, 2017 , letters of credit issued under these facilities totaled $5 million and $2 million for Generation and BGE, respectively.
(b) Pepco, DPL and ACE's revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL or ACE may not exceed $900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility.
(c) Excludes nonrecourse debt letters of credit, see discussion below on Antelope Valley Solar Ranch One and Continental Wind.
(d) Excludes $480 million in bilateral credit facilities that do not back Generation's commercial paper program.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables present the short-term borrowings activity for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE during 2017 , 2016 and 2015 .

Exelon

	2017	2016	2015
Average borrowings	$ 823	$ 1,125	$ 499
Maximum borrowings outstanding	2,147	3,076	739
Average interest rates, computed on a daily basis	1.32%	0.88%	0.53%
Average interest rates, at December 31	1.24%	1.12%	0.88%

Generation

	2017	2016	2015
Average borrowings	$ 405	$ 536	$ 1
Maximum borrowings outstanding	1,455	1,735	50
Average interest rates, computed on a daily basis	1.23%	0.94%	0.49%
Average interest rates, at December 31	1.23%	1.14%	N/A

ComEd

	2017	2016	2015
Average borrowings	$ 200	$ 256	$ 461
Maximum borrowings outstanding	470	755	684
Average interest rates, computed on a daily basis	1.24%	0.77%	0.53%
Average interest rates, at December 31	1.24%	N/A	0.89%

PECO

	2017	2016	2015
Average borrowings	$ 2	$ —	$ —
Maximum borrowings outstanding	60	—	—
Average interest rates, computed on a daily basis	1.13%	N/A	N/A
Average interest rates, at December 31	1.13%	N/A	N/A

BGE

	2017	2016	2015
Average borrowings	$ 54	$ 143	$ 37
Maximum borrowings outstanding	165	369	210
Average interest rates, computed on a daily basis	1.28%	0.77%	0.48%
Average interest rates, computed at December 31	1.28%	0.95%	0.87%

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI Corporate

	Successor		Predecessor
	2017	2016	2015
Average borrowings	N/A	$ 153	$ 444
Maximum borrowings outstanding	N/A	559	784
Average interest rates, computed on a daily basis	N/A	1.03%	0.90%
Average interest rates, computed at December 31	N/A	N/A	1.22%

Pepco

	2017	2016	2015
Average borrowings	$ 51	$ 4	$ 34
Maximum borrowings outstanding	197	73	190
Average interest rates, computed on a daily basis	1.06%	0.71%	0.44%
Average interest rates, computed at December 31	1.06%	0.90%	0.68%

DPL

	2017	2016	2015
Average borrowings	$ 40	$ 33	$ 81
Maximum borrowings outstanding	216	116	179
Average interest rates, computed on a daily basis	1.48%	0.68%	0.47%
Average interest rates, computed at December 31	1.48%	N/A	0.79%

ACE

	2017	2016	2015
Average borrowings	$ 30	$ —	$ 175
Maximum borrowings outstanding	133	5	253
Average interest rates, computed on a daily basis	1.43%	0.65%	0.46%
Average interest rates, computed at December 31	1.43%	N/A	0.65%

Short-Term Loan Agreements

On July 30, 2015, PHI entered into a $300 million term loan agreement. The net proceeds of the loan were used to repay PHI's outstanding commercial paper and for general corporate purposes. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.95% , and all indebtedness thereunder is unsecured. On April 4, 2016, PHI repaid $300 million of its term loan in full.

On January 13, 2016, PHI entered into a $500 million term loan agreement, which was amended on March 28, 2016. The net proceeds of the loan were used to repay PHI's outstanding commercial paper, and for general corporate purposes. Pursuant to the loan agreement, as amended, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1% , and all indebtedness thereunder is unsecured. On March 23, 2017, the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement was fully repaid and the loan terminated. On March 23, 2017, Exelon Corporate entered into a similar type term loan for $500 million which expires on March 22, 2018. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal

to LIBOR plus 1% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheet within Short-Term borrowings.

On February 22, 2016, Generation and EDF entered into separate member revolving promissory notes with CENG to finance short-term working capital needs. The notes are scheduled to mature on January 31, 2017 and bear interest at a variable rate equal to LIBOR plus 1.75% . On July 25, 2016, CENG paid off the outstanding balances under each note.

Credit Agreement

On January 5, 2016, Generation entered into a credit agreement establishing a $150 million bilateral credit facility, scheduled to mature in January of 2019. This facility will solely be utilized by Generation to issue lines of credit. This facility does not back Generation's commercial paper program.

On April 1, 2016, the credit agreement for CENG's $100 million bilateral credit facility was amended to increase the overall facility size to $200 million . This facility is utilized by CENG to fund working capital and capital projects. The facility does not back Generation's commercial paper program.

On May 26, 2016, Exelon Corporate, Generation, ComEd, PECO and BGE entered into amendments to each of their respective syndicated revolving credit facilities, which extended the maturity of each of the facilities to May 26, 2021. Exelon Corporate also increased the size of its facility from $500 million to $600 million . On May 26, 2016, PHI, Pepco, DPL and ACE entered into an amendment to their Second Amended and Restated Credit Agreement dated as of August 1, 2011, which (i) extended the maturity date of the facility to May 26, 2021, (ii) removed PHI as a borrower under the facility, (iii) decreased the size of the facility from $1.5 billion to $900 million and (iv) aligned its financial covenant from debt to capitalization leverage ratio to interest coverage ratio. On May 26, 2017, each of the Registrants' respective syndicated revolving credit facilities had their maturity dates extended to May 26, 2022.

On January 9, 2017, the credit agreement for Generation's $75 million bilateral credit facility was amended and restated to increase the facility size to $100 million and extend the maturity to January 2019. This facility will solely be used by Generation to issue letters of credit.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's revolving credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant's credit rating. The adders for the prime based borrowings and LIBOR-based borrowings are presented in the following table:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Prime based borrowings	27.5	27.5	7.5	0.0	0.0	7.5	7.5	7.5
LIBOR-based borrowings	127.5	127.5	107.5	90.0	100.0	107.5	107.5	107.5

The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 90 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2017 :

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2017 , the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Interest coverage ratio	6.34	9.02	11.68	7.99	10.50	6.35	8.69	5.57

An event of default under Exelon, Generation, ComEd, PECO or BGE's indebtedness will not constitute an event of default under any of the others' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation will constitute an event of default under the Exelon Corporate credit facility. An event of default under Pepco, DPL or ACE's indebtedness will not constitute an event of default with respect to the other PHI Utilities under the PHI Utilities' combined credit facility.

The absence of a material adverse change in Exelon's or PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under any of the borrowers' credit agreement. None of the credit agreements include any rating triggers.

Variable Rate Demand Bonds

DPL has outstanding obligations in respect of Variable Rate Demand Bonds (VRDB). VRDBs are subject to repayment on the demand of the holders and, for this reason, are accounted for as short-term debt in accordance with GAAP. However, bonds submitted for purchase are remarketed by a remarketing agent on a best efforts basis. PHI expects that any bonds submitted for purchase will be remarketed successfully due to the creditworthiness of the issuer and, as applicable, the credit support, and because the remarketing resets the interest rate to the then-current market rate. The bonds may be converted to a fixed-rate, fixed-term option to establish a maturity which corresponds to the date of final maturity of the bonds. On this basis, PHI views VRDBs as a source of long-term financing. As of December 31, 2017 and December 31, 2016 , $79 million and $105 million , respectively, in variable rate demand bonds issued by DPL were outstanding and are included in the Long-term debt due within one year on Exelon's, PHI's and DPL's Consolidated Balance Sheet.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Long-Term Debt

The following tables present the outstanding long-term debt at the Registrants as of December 31, 2017 and 2016 :

Exelon

	Rates			Maturity Date	December 31, 2017	December 31, 2016
Long-term debt						
Rate stabilization bonds			5.82%	2017	$ —	$ 41
First mortgage bonds [a]	1.70%	-	7.90%	2018 - 2047	15,197	14,123
Senior unsecured notes	2.45%	-	7.60%	2019 - 2046	11,285	11,868
Unsecured notes	2.40%	-	6.35%	2021 - 2047	2,600	2,300
Pollution control notes	2.50%	-	2.70%	2025 - 2036	435	435
Nuclear fuel procurement contracts	3.15%	-	3.35%	2018 - 2020	82	105
Notes payable and other [b][c]	2.61%	-	8.88%	2018 - 2053	405	576
Junior subordinated notes			3.50%	2022	1,150	1,150
Contract payment - junior subordinated notes			2.50%	2017	—	19
Long-term software licensing agreement			3.95%	2024	79	103
Unsecured Tax-Exempt Bonds			5.40% —	2031	112	112
Medium-Terms Notes (unsecured)	6.81%	-	7.72% —	2018 - 2027	26	40
Transition bonds	5.05%	-	5.55% —	2020 - 2023	90	124
Nonrecourse debt:						
Fixed rates	2.29%	-	6.00%	2031 - 2037	1,331	1,400
Variable rates	3.18%	-	4.00%	2019 - 2024	865	915
Total long-term debt					33,657	33,311
Unamortized debt discount and premium, net					(57)	(68)
Unamortized debt issuance costs					(201)	(200)
Fair value adjustment					865	962
Long-term debt due within one year					(2,088)	(2,430)
Long-term debt					$ 32,176	$ 31,575
Long-term debt to financing trusts [d]						
Subordinated debentures to ComEd Financing III			6.35%	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III			7.38%	2028	81	81
Subordinated debentures to PECO Trust IV			5.75%	2033	103	103
Subordinated debentures to BGE Capital Trust II			6.20%	2043	—	258
Total long-term debt to financing trusts					390	648
Unamortized debt issuance costs					(1)	(7)
Long-term debt to financing trusts					$ 389	$ 641

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's, Pepco's, DPL's and ACE's assets are subject to the liens of their respective mortgage indentures.
(b) Includes capital lease obligations of $53 million and $69 million at December 31, 2017 and 2016 , respectively. Lease payments of $18 million , $20 million , $5 million , $1 million , $1 million and $8 million will be made in 2018 , 2019 , 2020 , 2021 , 2022 and thereafter, respectively.
(c) Includes financing related to Albany Green Energy, LLC (AGE). During the third quarter of 2017, Generation retired $228 million of its outstanding debt balance. As of December 31, 2016, $198 million was outstanding.
(d) Amounts owed to these financing trusts are recorded as Long-term debt to financing trusts within Exelon's Consolidated Balance Sheets.

Generation

	Rates	Maturity Date	December 31, 2017	December 31, 2016
Long-term debt				
Senior unsecured notes	2.95% - 7.60%	2019 - 2042	$ 6,019	$ 5,971
Pollution control notes	2.50% - 2.70%	2025 - 2036	435	435
Nuclear fuel procurement contracts	3.15% - 3.35%	2018 - 2020	82	105
Notes payable and other [(a)(b)]	2.61% - 8.88%	2018 - 2019	223	382
Nonrecourse debt:				
Fixed rates	2.29% - 6.00%	2031 - 2037	1,331	1,400
Variable rates	3.18% - 4.00%	2019 - 2024	865	915
Total long-term debt			8,955	9,208
Unamortized debt discount and premium, net			(8)	(17)
Unamortized debt issuance costs			(60)	(65)
Fair value adjustment			103	115
Long-term debt due within one year			(346)	(1,117)
Long-term debt			$ 8,644	$ 8,124

(a) Includes Generation's capital lease obligations of $18 million and $22 million at December 31, 2017 and 2016 , respectively. Generation will make lease payments of $5 million , $6 million , $5 million , $1 million and $1 million in 2018 , 2019 , 2020 , 2021 and 2022 respectively. The capital lease matures in 2022.
(b) Includes financing related to Albany Green Energy, LLC (AGE). During the third quarter of 2017, Generation retired $228 million of its outstanding debt balance. As of December 31, 2016, $198 million was outstanding.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd

	Rates	Maturity Date	December 31, 2017	December 31, 2016
Long-term debt				
First mortgage bonds [a]	2.15% - 6.45%	2018 - 2047	$ 7,529	$ 6,954
Notes payable and other [b]	6.95% - 7.49%	2018 - 2053	147	147
Total long-term debt			7,676	7,101
Unamortized debt discount and premium, net			(23)	(22)
Unamortized debt issuance costs			(52)	(46)
Long-term debt due within one year			(840)	(425)
Long-term debt			$ 6,761	$ 6,608
Long-term debt to financing trust [c]				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206
Total long-term debt to financing trusts			206	206
Unamortized debt issuance costs			(1)	(1)
Long-term debt to financing trusts			$ 205	$ 205

(a) Substantially all of ComEd's assets, other than expressly excepted property, are subject to the lien of its mortgage indenture.
(b) Includes ComEd's capital lease obligations of $8 million at both December 31, 2017 and 2016 , respectively. Lease payments of less than $1 million annually will be made from 2018 through expiration at 2053.
(c) Amount owed to this financing trust is recorded as Long-term debt to financing trust within ComEd's Consolidated Balance Sheets.

PECO

	Rates	Maturity Date	December 31, 2017	December 31, 2016
Long-term debt				
First mortgage bonds [a]	1.70% - 5.95%	2018 - 2047	$ 2,925	$ 2,600
Total long-term debt			2,925	2,600
Unamortized debt discount and premium, net			(5)	(5)
Unamortized debt issuance costs			(17)	(15)
Long-term debt due within one year			(500)	—
Long-term debt			$ 2,403	$ 2,580
Long-term debt to financing trusts [b]				
Subordinated debentures to PECO Trust III	7.38%	2028	$ 81	$ 81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Long-term debt to financing trusts			$ 184	$ 184

(a) Substantially all of PECO's assets are subject to the lien of its mortgage indenture.
(b) Amounts owed to this financing trust are recorded as Long-term debt to financing trusts within PECO's Consolidated Balance Sheets.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

	Rates	Maturity Date	December 31, 2017	December 31, 2016
Long-term debt				
Rate stabilization bonds	5.82%	2017	$ —	$ 41
Unsecured notes	2.40% - 6.35%	2021 - 2047	2,600	2,300
Total long-term debt			2,600	2,341
Unamortized debt discount and premium, net			(6)	(4)
Unamortized debt issuance costs			(17)	(15)
Long-term debt due within one year			—	(41)
Long-term debt			$ 2,577	$ 2,281
Long-term debt to financing trusts [a]				
Subordinated debentures to BGE Capital Trust II	6.20%	2043	$ —	$ 258
Total long-term debt to financing trusts			—	258
Unamortized debt issuance costs			—	(6)
Long-term debt to financing trusts			$ —	$ 252

(a) Amounts owed to this financing trust are recorded as Long-term debt to financing trusts within BGE's Consolidated Balance Sheets. On August 28, 2017, BGE redeemed all of the outstanding shares of BGE Capital Trust II 6.20% Preferred Securities ("Securities"), pursuant to the optional redemption provisions of the Indenture under which the Securities were issued. The redemption price per share was $25.19, which equaled the stated value per share plus accrued and unpaid dividends to, but excluding, the redemption date. No dividends on the Securities redeemed were accrued on or after the redemption date, nor did any interest accrue on amounts held to pay the redemption price.

PHI

			Successor December 31, 2017	*Successor* December 31, 2016
	Rates	Maturity Date		
Long-term debt				
First mortgage bonds [a]	3.05% - 7.90%	2018 - 2045	$ 4,743	$ 4,569
Senior unsecured notes	7.45%	2017 - 2032	185	266
Unsecured Tax-Exempt Bonds	5.40%	2031	112	112
Medium-Terms Notes (unsecured)	6.81% - 7.72%	2018 - 2027	26	40
Transition bonds [b]	5.05% - 5.55%	2020 - 2023	90	124
Notes payable and other [c]	6.20% - 8.88%	2018 - 2022	33	46
Total long-term debt			5,189	5,157
Unamortized debt discount and premium, net			5	1
Unamortized debt issuance costs			(6)	(2)
Fair value adjustment			686	742
Long-term debt due within one year			(396)	(253)
Long-term debt			$ 5,478	$ 5,645

(a) Substantially all of Pepco's, DPL's, and ACE's assets are subject to the lien of its respective mortgage indenture.
(b) Transition bonds are recorded as part of Long-term debt within ACE's Consolidated Balance Sheets.
(c) Includes Pepco's capital lease obligations of $27 million and $39 million at December 31, 2017 and 2016 , respectively.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Pepco

	Rates	Maturity Date	December 31, 2017	December 31, 2016
Long-term debt				
First mortgage bonds [a]	3.05% - 7.90%	2022 - 2043	$ 2,535	$ 2,335
Notes payable and other [b]	6.20% - 8.88%	2018 - 2022	35	46
Total long-term debt			2,570	2,381
Unamortized debt discount and premium, net			2	(2)
Unamortized debt issuance costs			(32)	(30)
Long-term debt due within one year			(19)	(16)
Long-term debt			$ 2,521	$ 2,333

(a) Substantially all of Pepco's assets are subject to the lien of its respective mortgage indenture.
(b) Includes capital lease obligations of $27 million and $39 million at December 31, 2017 and 2016 , respectively. Lease payments of $13 million and $14 million will be made in 2018 and 2019 , respectively.

DPL

	Rates	Maturity Date	December 31, 2017	December 31, 2016
Long-term debt				
First mortgage bonds [a]	3.50% - 4.15%	2023 - 2045	$ 1,171	$ 1,196
Unsecured Tax-Exempt Bonds	5.40%	2024 - 2031	112	112
Medium-Terms Notes (unsecured)	6.81% - 7.72%	2018 - 2027	26	40
Total long-term debt			1,309	1,348
Unamortized debt discount and premium, net			2	2
Unamortized debt issuance costs			(11)	(10)
Long-term debt due within one year			(83)	(119)
Long-term debt			$ 1,217	$ 1,221

(a) Substantially all of DPL's assets are subject to the lien of its respective mortgage indenture.

ACE

	Rates	Maturity Date	December 31, 2017	December 31, 2016
Long-term debt				
First mortgage bonds [a]	3.38% - 7.75%	2018 - 2036	$ 1,037	$ 1,038
Transition bonds [b]	5.05% - 5.55%	2020 - 2023	90	124
Total long-term debt			1,127	1,162
Unamortized debt discount and premium, net			(1)	(1)
Unamortized debt issuance costs			(5)	(6)
Long-term debt due within one year			(281)	(35)
Long-term debt			$ 840	$ 1,120

(a) Substantially all of ACE's assets are subject to the lien of its respective mortgage indenture.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

(b) Maturities of ACE's Transition Bonds outstanding at December 31, 2017 are $31 million in 2018, $18 million in 2019, $20 million in 2020 and $21 million in 2021.

Long-term debt maturities at Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE in the periods 2018 through 2022 and thereafter are as follows:

Year	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2018	$ 2,075	$ 346	$ 840	$ 500	$ —	$ 383	$ 19	$ 83	$ 281
2019	959	615	300	—	—	44	14	12	18
2020	3,564	2,144	500	—	—	20	—	—	20
2021	1,513	1	350	300	300	262	2	—	260
2022	3,084	1,024	—	350	250	310	310	—	—
Thereafter	22,852 [a]	4,825	5,892 [b]	1,959 [c]	2,050	4,170	2,225	1,214	548
Total	$ 34,047	$ 8,955	$ 7,882	$ 3,109	$ 2,600	$ 5,189	$ 2,570	$ 1,309	$ 1,127

(a) Includes $390 million due to ComEd and PECO financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.

Junior Subordinated Notes

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Each equity unit represented an undivided beneficial ownership interest in Exelon's $1.15 billion of 2.50% junior subordinated notes due in 2024 ("2024 notes") and a forward equity purchase contract. As contemplated in the June 2014 equity unit structure, in April 2017, Exelon completed the remarketing of the 2024 notes into $1.15 billion of 3.497% junior subordinated notes due in 2022 ("Remarketing"). Exelon conducted the Remarketing on behalf of the holders of equity units and did not directly receive any proceeds therefrom. Instead, the former holders of the 2024 notes used debt remarketing proceeds towards settling the forward equity purchase contract with Exelon on June 1, 2017. Exelon issued approximately 33 million shares of common stock from treasury stock and received $1.15 billion upon settlement of the forward equity purchase contract. When reissuing treasury stock Exelon uses the average price paid to repurchase shares to calculate a gain or loss on issuance and records gains or losses directly to retained earnings. A loss on reissuance of treasury shares of $1.05 billion was recorded to retained earnings as of December 31, 2017 . See Note 21 — Earnings Per Share for further information on the issuance of common stock.

Nonrecourse Debt

Exelon and Generation have issued nonrecourse debt financing, in which approximately $3 billion of generating assets have been pledged as collateral at December 31, 2017 . Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific nonrecourse debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives.

Denver Airport. In June 2011, Generation entered into a 20-year, $7 million solar loan agreement to finance a solar construction project in Denver, Colorado. The agreement is scheduled to mature on

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June 30, 2031. The agreement bears interest at a fixed rate of 5.50% annually with interest payable annually. As of December 31, 2017 , $ 6 million was outstanding.

CEU Upstream. In July 2011, CEU Holdings, LLC, a wholly owned subsidiary of Generation, entered into a 5-year reserve based lending agreement (RBL) associated with certain Upstream oil and gas properties. The lenders do not have recourse against Exelon or Generation in the event of default pursuant to the RBL. Borrowings under this arrangement are secured by the assets and equity of CEU Holdings.

In December 2016, substantially all of the Upstream natural gas and oil exploration and production assets were sold for $37 million . The proceeds were used to reduce the debt balance by $31 million . The remaining proceeds of $6 million were being held in escrow. In addition, during 2016, $15 million of the debt was repaid using CEU Holding's cash, resulting in an outstanding debt balance of $22 million at December 31, 2016. During 2017, additional assets were sold for $1 million and the remaining $6 million in escrow was released and applied to the debt balance resulting in an outstanding amount of $15 million at December 31, 2017. Upon final resolution, CEU Holdings will be released of its obligations regardless of the amount of asset sale proceeds received. The ultimate resolution of this matter has no direct effect on any Exelon or Generation credit facilities or other debt of an Exelon entity. At December 31, 2017, the outstanding debt balance of $15 million was classified within Long term debt due within one year on Exelon's and Generation's Consolidated Balance Sheets. See Note 4 — Mergers, Acquisitions and Dispositions and Note 7 — Impairment of Long-Lived Assets and Intangibles for additional information.

Holyoke Solar Cooperative. In October 2011, Generation entered into a 20-year, $11 million solar loan agreement related to a solar construction project in Holyoke, Massachusetts. The agreement is scheduled to mature on December 2031. The agreement bears interest at a fixed rate of 5.25% annually with interest payable monthly. As of December 31, 2017 , $9 million was outstanding.

Antelope Valley Solar Ranch One. In December 2011, the DOE Loan Programs Office issued a guarantee for up to $646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational in the first half of 2014. The loan will mature on January 5, 2037. Interest rates on the loan were fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity. The advances were completed as of December 31, 2015 and the outstanding loan balance will bear interest at an average blended interest rate of 2.82% . As of December 31, 2017 , $530 million was outstanding. In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2017 , Generation had $105 million in letters of credit outstanding related to the project.

Continental Wind. In September 2013, Continental Wind, LLC (Continental Wind), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million senior secured notes. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667 MW. The net proceeds were distributed to Generation for its general business purposes. The notes are scheduled to mature on February 28, 2033. The notes bear interest at a fixed rate of 6.00% with interest payable semi-annually. As of December 31, 2017 , $512 million was outstanding.

In addition, Continental Wind entered into a $131 million letter of credit facility and $10 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2017 , the Continental Wind letter of credit facility had $114 million in letters of credit outstanding related to the project.

ExGen Texas Power. In September 2014, EGTP, an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. The net proceeds were distributed to Generation for general business purposes. The loan was scheduled to

mature on September 18, 2021. In addition to the financing, EGTP entered into various interest rate swaps with an initial notional amount of approximately $505 million at an interest rate of 2.34% to hedge a portion of the interest rate exposure in connection with this financing, as required by the debt covenants.

On May 2, 2017, as a result of the negative impacts of certain market conditions and the seasonality of its cash flows, EGTP entered into a consent agreement with its lenders, which permitted EGTP to draw on its revolving credit facility and initiate an orderly sales process of its assets. On November 7, 2017, the debtors filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware. As a result, Exelon and Generation deconsolidated the nonrecourse senior secured term loan, the revolving credit facility, and the interest rate swaps from their consolidated financial statements as of December 31, 2017. Due to their nonrecourse nature, these borrowings are secured solely by the assets of EGTP and its subsidiaries.

Renewable Power Generation. In March 2016, RPG, an indirect subsidiary of Exelon and Generation, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to Generation for paydown of long term debt obligations at Sacramento PV Energy and Constellation Solar Horizons and for general business purposes. The loan is scheduled to mature on March 31, 2035. The term loan bears interest at a fixed rate of 4.11% payable semi-annually. As of December 31, 2017 , $127 million was outstanding.

SolGen. In September 2016, SolGen, LLC (SolGen), an indirect subsidiary of Exelon and Generation, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to Generation for general business purposes. The loan is scheduled to mature on September 30, 2036. The term loan bears interest at a fixed rate of 3.93% payable semi-annually. As of December 31, 2017 , $147 million was outstanding.

ExGen Renewables IV. In November 2017, EGR IV, an indirect subsidiary of Exelon and Generation, entered into an $850 million nonrecourse senior secured term loan credit facility agreement. The net proceeds of $785 million , after the initial funding of $50 million for debt service and liquidity reserves as well as deductions for original discount and estimated costs, fees and expenses incurred in connection with the execution and delivery of the credit facility agreement, were distributed to Generation for general corporate purposes. The $50 million of debt service and liquidity reserves was treated as restricted cash on Exelon's and Generation's Consolidated Balance Sheets and Consolidated Statements of Cash Flows. The loan is scheduled to mature on November 28, 2024. The term loan bears interest at a variable rate equal to LIBOR + 3% , subject to a 1% LIBOR floor with interest payable quarterly. As of December 31, 2017 , $850 million was outstanding. In addition to the financing, EGR IV entered into interest rate swaps with an initial notional amount of $636 million at an interest rate of 2.32% to manage a portion of the interest rate exposure in connection with the financing.

14 . Income Taxes (All Registrants)

Corporate Tax Reform (All Registrants)

On December 22, 2017, President Trump signed the TCJA into law. The TCJA makes many significant changes to the Internal Revenue Code, including, but not limited to, (1) reducing the U.S. federal corporate tax rate from 35% to 21% ; (2) creating a 30% limitation on deductible interest expense (not applicable to regulated utilities); (3) allowing 100% expensing for the cost of qualified property (not applicable to regulated utilities); (4) eliminating the domestic production activities deduction; (5) eliminating the corporate alternative minimum tax and changing how existing alternative minimum tax credits can be realized; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017. The most significant change that impacts the Registrants is the reduction of the corporate federal income tax rate from 35% to 21% beginning January 1, 2018.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Pursuant to the enactment of the TCJA, the Registrants remeasured their existing deferred income tax balances as of December 31, 2017 to reflect the decrease in the corporate income tax rate from 35% to 21% , which resulted in a material decrease to their net deferred income tax liability balances as shown in the table below. Generation recorded a corresponding net decrease to income tax expense, while the Utility Registrants recorded corresponding regulatory liabilities or assets to the extent such amounts are probable of settlement or recovery through customer rates and an adjustment to income tax expense for all other amounts. The amount and timing of potential settlements of the established net regulatory liabilities will be determined by the Utility Registrants' respective rate regulators, subject to certain IRS "normalization" rules. See Note 3 — Regulatory Matters for further information.

The Registrants have completed their assessment of the majority of the applicable provisions in the TCJA and have recorded the associated impacts as of December 31, 2017. As discussed further below, under SAB 118 issued by the SEC in December 2017, the Registrants have recorded provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation for which the impacts could not be finalized upon issuance of the Registrants' financial statements, but for which reasonable estimates could be determined.

For property acquired and placed-in-service after September 27, 2017, the TCJA repeals 50% bonus depreciation for all taxpayers and in addition provides for 100% expensing for taxpayers other than regulated utilities. As a result, Generation will be required to evaluate the contractual terms of its fourth quarter 2017 capital additions and determine if they qualify for 100% expensing under the TCJA as compared to 50% bonus depreciation under prior tax law. Similarly, the Utility Registrants will be required to evaluate the contractual terms of their fourth quarter 2017 capital additions to determine whether they still qualify for the prior tax law's 50% bonus depreciation as compared to no bonus depreciation pursuant to the TCJA. As of December 31, 2017, the Registrants have not completed this analysis but were able to record a reasonable estimate of the effects of these changes based on capital costs incurred at each of the Registrants prior to and after the beginning of the fourth quarter of 2017.

At Generation, any required changes to the provisional estimates during the measurement period related to the above item would result in an adjustment to current income tax expense at 35% and a corresponding adjustment to deferred income tax expense at 21% and such changes could be material to Generation's future results of operations. At the Utility Registrants, any required changes to the provisional estimates would result in the recording of regulatory assets or liabilities to the extent such amounts are probable of settlement or recovery through customer rates and a net change to income tax expense for any other amounts.

The Registrants expect any final adjustments to the provisional amounts to be recorded by the third quarter of 2018, which could be material to the Registrants' future results of operations or financial positions. The accounting for all other applicable provisions of the TCJA is considered complete based on our current interpretation of the provisions of the TCJA as enacted as of December 31, 2017.

While the Registrants have recorded the impacts of the TCJA based on their interpretation of the provisions as enacted, it is expected that technical corrections or other forms of guidance will be issued during 2018, which could result in material changes to previously finalized provisions. At this time, most states have not provided guidance regarding TCJA impacts and may issue guidance in 2018 which may impact estimates.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The one-time impacts recorded by the Registrants to remeasure their deferred income tax balances at the 21% corporate federal income tax rate as of December 31, 2017 are presented below:

						Successor			
	Exelon [b]	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net Decrease to Deferred Income Tax Liability Balances	$8,624	$1,895	$2,819	$1,407	$1,120	$1,944	$968	$540	$456

						Successor			
	Exelon	Generation	ComEd	PECO [c]	BGE	PHI	Pepco	DPL	ACE
Net Regulatory Liability Recorded [a]	$7,315	N/A	$2,818	$1,394	$1,124	$1,979	$976	$545	$458

						Successor			
	Exelon [b]	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net Deferred Income Tax Benefit/(Expense) Recorded	$1,309	$1,895	$1	$13	$(4)	$(35)	$(8)	$(5)	$(2)

(a) Reflects the net regulatory liabilities recorded on a pre-tax basis before taking into consideration the income tax benefits associated with the ultimate settlement with customers.
(b) Amounts do not sum across due to deferred tax adjustments recorded at the Exelon Corporation parent company, primarily related to certain employee compensation plans.
(c) Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO remains in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA. Refer to Note 3 - Regulatory Matters for additional information.

The net regulatory liabilities above include (1) amounts subject to IRS "normalization" rules that are required to be passed back to customers generally over the remaining useful life of the underlying assets giving rise to the associated deferred income taxes, and (2) amounts for which the timing of settlement with customers is subject to determinations by the rate regulators. The table below sets forth the Registrants' estimated categorization of their net regulatory liabilities as of December 31, 2017. The amounts in the table below are shown on an after-tax basis reflecting future net cash outflows after taking into consideration the income tax benefits associated with the ultimate settlement with customers.

					Successor			
	Exelon	ComEd	PECO [a]	BGE	PHI	PEPCO	DPL	ACE
Subject to IRS Normalization Rules	$3,040	$1,400	$533	$459	$648	$299	$195	$153
Subject to Rate Regulator Determination	1,694	573	43	324	754	391	194	170
Net Regulatory Liabilities	$4,734	$1,973	$576	$783	$1,402	$690	$389	$ 323

(a) Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO remains in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA. As a result, the amount of customer benefits resulting from the TCJA subject to the discretion of PECO's rate regulators are lower relative to the other Utility Registrants. Refer to Note 3 - Regulatory Matters for additional information.

The net regulatory liability amounts subject to the IRS normalization rules generally relate to property, plant and equipment with remaining useful lives ranging from 30 to 40 years across the Utility Registrants. For the other amounts, rate regulators could require the passing back of amounts to customers over shorter time frames.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Components of Income Tax Expense or Benefit

Income tax expense (benefit) from continuing operations is comprised of the following components:

	For the year ended December 31, 2017								
						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Included in operations:									
Federal									
Current	$ 194	$ 584	$ (191)	$ 71	$ 74	$ (60)	$ (20)	$ (24)	$ (12)
Deferred	(469)	(2,003)	523	28	101	250	114	82	34
Investment tax credit amortization	(25)	(21)	(2)	—	(1)	(1)	—	—	—
State									
Current	14	65	(49)	14	(5)	(4)	(2)	—	—
Deferred	161	—	136	(9)	49	32	13	13	4
Total	$ (125)	$ (1,375)	$ 417	$ 104	$ 218	$ 217	$ 105	$ 71	$ 26

	For the Year Ended December 31, 2016								Successor	Predecessor
									March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Included in operations:										
Federal										
Current	$ 60	$ 513	$ (135)	$ 63	$ 51	$ (118)	$ (88)	$ (26)	$ (281)	$ —
Deferred	607	(247)	379	72	88	136	97	22	283	10
Investment tax credit amortization	(24)	(20)	(2)	—	(1)	—	—	—	(1)	—
State										
Current	39	45	(4)	9	5	7	1	—	(11)	—
Deferred	79	(1)	63	5	31	16	12	—	13	7
Total	$ 761	$ 290	$ 301	$ 149	$ 174	$ 41	$ 22	$ (4)	$ 3	$ 17

	For the Year Ended December 31, 2015								
						Predecessor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Included in operations:									
Federal									
Current	$ 407	$ 546	$ (80)	$ 64	$ 25	$ 12	$ (54)	$ (27)	$ (2)
Deferred	566	16	310	69	126	103	126	73	27
Investment tax credit amortization	(22)	(19)	(2)	—	(1)	(1)	—	—	—
State									
Current	(86)	(90)	7	(10)	—	17	6	2	3
Deferred	208	49	45	20	39	32	24	1	5
Total	$ 1,073	$ 502	$ 280	$ 143	$ 189	$ 163	$ 102	$ 49	$ 33

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Rate Reconciliation

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

	For the Year Ended December 31, 2017								
						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	2.3	3.0	5.7	0.6	5.4	4.8	3.2	5.4	5.6
Qualified nuclear decommissioning trust fund income	3.8	10.0	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.9)	(2.2)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.2)	(0.4)
Plant basis differences [a]	(1.7)	—	0.3	(13.8)	0.1	1.1	(0.4)	2.0	3.6
Production tax credits and other credits	(1.8)	(4.8)	—	—	—	—	—	—	—
Noncontrolling interests	0.1	0.3	—	—	—	—	—	—	—
Like-kind exchange	(1.2)	—	1.3	—	—	—	—	—	—
Merger expenses	(3.7)	(1.3)	—	—	—	(9.5)	(6.3)	(7.8)	(19.8)
FitzPatrick bargain purchase gain	(2.2)	(5.7)	—	—	—	—	—	—	—
Tax Cut and Jobs Act of 2017 [b]	(33.1)	(130.1)	0.1	(2.3)	0.9	6.4	2.7	2.5	1.6
Other	0.1	(0.4)	0.2	(0.1)	0.2	(0.1)	(0.2)	0.1	(0.4)
Effective income tax rate	(3.3)%	(96.2)%	42.4 %	19.3 %	41.5 %	37.5 %	33.9 %	37.0 %	25.2 %

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the Year Ended December 31, 2016								Successor	Predecessor
									March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL (c)	ACE (c)	PHI (c)	PHI
U.S. Federal statutory rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) due to:										
State income taxes, net of Federal income tax benefit (d)	3.3	3.3	5.6	1.3	5.0	15.7	52.7	6.2	5.8	11.9
Qualified nuclear decommissioning trust fund income	3.4	7.8	—	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.2)	(2.3)	(0.3)	(0.1)	(0.1)	(0.2)	(3.7)	0.8	1.4	(0.9)
Plant basis differences	(4.8)	—	(0.6)	(9.6)	(2.7)	(22.8)	(25.5)	10.3	39.0	(13.5)
Production tax credits and other credits	(3.6)	(8.2)	—	—	—	—	—	—	—	—
Noncontrolling interests	(0.2)	(0.3)	—	—	—	—	—	—	—	—
Statute of limitations expiration	(0.4)	(1.7)	—	—	—	—	—	—	—	—
Penalties	1.9	—	4.5	—	—	—	—	—	(0.7)	—
Merger Expenses	5.5	1.1	—	—	—	23.5	112.9	(44.9)	(89.0)	11.1
Other (e)	(0.6)	(1.5)	0.1	(1.2)	—	(1.8)	(2.2)	1.3	3.3	3.6
Effective income tax rate	38.3 %	33.2 %	44.3 %	25.4 %	37.2 %	49.4 %	169.2 %	8.7 %	(5.2)%	47.2 %

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the Year Ended December 31, 2015								
						Predecessor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	3.7	1.0	4.9	1.0	5.3	6.6	6.7	1.7	5.7
Qualified nuclear decommissioning trust fund loss	(0.4)	(0.8)	—	—	—	—	—	—	—
Domestic production activities deduction	(0.7)	(1.3)	—	—	—	—	—	—	—
Health care reform legislation	—	—	—	—	0.1	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.9)	(1.5)	(0.3)	(0.1)	(0.1)	(0.2)	(0.1)	(0.4)	(0.6)
Plant basis differences	(1.5)	—	(0.1)	(8.7)	(0.7)	(4.3)	(5.8)	(2.3)	(1.3)
Production tax credits and other credits	(1.9)	(3.4)	—	—	—	—	—	—	—
Noncontrolling interests	0.3	0.5	—	—	—	—	—	—	—
Statute of limitations expiration	(1.4)	(2.4)	—	—	—	—	—	—	—
Other [f]	—	—	0.2	0.2	—	(3.2)	(0.5)	5.2	6.4
Effective income tax rate	32.2 %	27.1 %	39.7 %	27.4 %	39.6 %	33.9 %	35.3 %	39.2 %	45.2 %

(a) Includes the charges related to the transmission-related income tax regulatory asset for Exelon, ComEd, BGE, PHI, Pepco, DPL, and ACE of $ 35 million , $ 3 million , $ 5 million , $ 27 million , $ 14 million , $ 6 million , and $ 7 million , respectively (See Footnote 3 - Regulatory Matters).
(b) Included are impacts for TJCA other than the corporate rate change, including revisions further limiting tax deductions for compensation of certain highest paid executives, the write-off of foreign tax credit carryforwards, and loss of a 2015 domestic production activities deduction due to an NOL carryback.
(c) DPL and ACE recognized a loss before income taxes for the year ended December 31, 2016 , and PHI recognized a loss before income taxes for the period of March 24, 2016, through December 31, 2016 . As a result, positive percentages represent an income tax benefit for the periods presented.
(d) Includes a remeasurement of uncertain state income tax positions for Pepco and DPL.
(e) At PECO, includes a cumulative adjustment related to an anticipated gas repairs tax return accounting method change. The method change request was filed and accepted in 2017. No change to the results recorded as of December 31, 2016.
(f) Includes impacts of the PHI Global Settlement for Pepco, DPL, ACE and PHI.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Tax Differences and Carryforwards

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2017 and 2016 are presented below:

	As of December 31, 2017 [a]								
						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Plant basis differences	$ (12,490)	$ (2,819)	$ (3,825)	$ (1,762)	$ (1,368)	$ (2,521)	$ (1,152)	$ (717)	$ (607)
Accrual based contracts	150	(66)	—	—	—	216	—	—	—
Derivatives and other financial instruments	(85)	(66)	(2)	—	—	3	—	—	—
Deferred pension and postretirement obligation	1,463	(205)	(285)	(15)	(29)	(130)	(78)	(51)	(18)
Nuclear decommissioning activities	(553)	(553)	—	—	—	—	—	—	—
Deferred debt refinancing costs	217	26	(8)	(1)	(3)	203	(4)	(2)	(1)
Regulatory assets and liabilities	(688)	—	489	(90)	136	(184)	39	88	86
Tax loss carryforward	344	76	33	9	11	156	40	68	35
Tax credit carryforward	861	868	1	—	—	6	—	—	—
Investment in partnerships	(434)	(416)	—	—	—	—	—	—	—
Other, net	746	78	141	71	13	193	94	14	16
Deferred income tax liabilities (net)	$ (10,469)	$ (3,077)	$ (3,456)	$ (1,788)	$ (1,240)	$ (2,058)	$ (1,061)	$ (600)	$ (489)
Unamortized investment tax credits	(732)	(705)	(13)	(1)	(4)	(8)	(2)	(3)	(4)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (11,201)	$ (3,782)	$ (3,469)	$ (1,789)	$ (1,244)	$ (2,066)	$ (1,063)	$ (603)	$ (493)

(a) Includes remeasurement impacts related to the TCJA.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	As of December 31, 2016								
						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Plant basis differences	$ (17,966)	$ (4,192)	$ (5,034)	$ (3,095)	$ (1,977)	$ (3,586)	$ (1,678)	$ (973)	$ (869)
Accrual based contracts	434	(115)	—	—	—	548	—	—	—
Derivatives and other financial instruments	(179)	(162)	(3)	—	—	(1)	—	—	—
Deferred pension and postretirement obligation	2,287	(316)	(453)	(18)	(43)	(111)	(122)	(74)	(21)
Nuclear decommissioning activities	(509)	(509)	—	—	—	—	—	—	—
Deferred debt refinancing costs	325	44	(13)	(1)	(3)	293	(7)	(4)	(2)
Regulatory assets and liabilities	(3,319)	—	(226)	10	(240)	(1,205)	(194)	(75)	(69)
Tax loss carryforward	189	61	29	—	22	77	27	39	14
Tax credit carryforward	446	493	—	—	—	—	—	—	—
Investment in partnerships	(650)	(650)	—	—	—	—	—	—	—
Other, net	1,485	403	351	99	27	225	66	34	34
Deferred income tax liabilities (net)	$ (17,457)	$ (4,943)	$ (5,349)	$ (3,005)	$ (2,214)	$ (3,760)	$ (1,908)	$ (1,053)	$ (913)
Unamortized investment tax credits	(658)	(626)	(15)	(1)	(5)	(9)	(2)	(3)	(4)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (18,115)	$ (5,569)	$ (5,364)	$ (3,006)	$ (2,219)	$ (3,769)	$ (1,910)	$ (1,056)	$ (917)

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides the Registrants' carryforwards and any corresponding valuation allowances as of December 31, 2017 :

						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Federal									
Federal net operating loss	$ 624 [a]	$ —	$ 156	$ 7	$ —	$ 261	$ 82	$ 81	$ 63
Deferred taxes on Federal net operating loss	131	—	33	1	—	55	17	17	13
Federal general business credits carryforwards	861 [b]	868	1	—	1	5	—	—	—
State									
State net operating losses	3,555 [c]	1,479 [c]	—	98 [e]	177 [d]	1,440 [f]	347 [g]	753 [h]	299 [i]
Deferred taxes on state tax attributes (net)	233	97	—	8	12	98	23	51	21
Valuation allowance on state tax attributes	29	23	—	—	1	5	—	—	—

(a) Exelon's federal net operating loss will begin expiring in 2034.
(b) Exelon's federal general business credit carryforwards will begin expiring in 2033.
(c) Exelon's and Generation's state net operating losses and credit carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2018.
(d) BGE's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2026.
(e) PECO's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2031.
(f) PHI's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2036.
(g) Pepco's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2028.
(h) DPL's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2027.
(i) ACE's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2031.

Tabular Reconciliation of Unrecognized Tax Benefits

The following tables provide a reconciliation of the Registrants' unrecognized tax benefits as of December 31, 2017 , 2016 and 2015 :

						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Unrecognized tax benefits at January 1, 2017	$ 916	$ 490	$ (12)	$ —	$ 120	$ 172	$ 80	$ 37	$ 22
Increases based on tax positions related to 2017	—	—	—	—	—	—	—	—	—
Decreases based on tax positions related to 2017	—	—	—	—	—	—	—	—	—
Change to positions that only affect timing	—	—	—	—	—	—	—	—	—
Increases based on tax positions prior to 2017	28	—	14	—	—	14	—	—	14
Decreases based on tax positions prior to 2017	(196)	(17)	—	—	—	(61)	(21)	(16)	(22)
Decrease from settlements with taxing authorities	(5)	(5)	—	—	—	—	—	—	—
Decreases from expiration of statute of limitations	—	—	—	—	—	—	—	—	—
Unrecognized tax benefits at December 31, 2017	$ 743	$ 468	$ 2	$ —	$ 120	$ 125	$ 59	$ 21	$ 14

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Unrecognized tax benefits at January 1, 2016	$ 1,078	$ 534	$ 142	$ —	$ 120	$ 22	$ 8	$ 3	$ —
Merger balance transfer	22	5	—	—	—	(5)	—	—	—
Increases based on tax positions related to 2016	108	10	—	—	—	59	21	16	22
Decreases based on tax positions related to 2016	—	—	—	—	—	—	—	—	—
Change to positions that only affect timing	(332)	(12)	(154)	—	—	—	—	—	—
Increases based on tax positions prior to 2016	88	—	—	—	—	96	51	18	—
Decreases based on tax positions prior to 2016	(21)	(20)	—	—	—	—	—	—	—
Decrease from settlements with taxing authorities	(27)	(27)	—	—	—	—	—	—	—
Decreases from expiration of statute of limitations	—	—	—	—	—	—	—	—	—
Unrecognized tax benefits at December 31, 2016	$ 916	$ 490	$ (12)	$ —	$ 120	$ 172	$ 80	$ 37	$ 22

						Predecessor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Unrecognized tax benefits at January 1, 2015	$ 1,829	$ 1,357	$ 149	$ 44	$ —	$ 702	$ —	$ —	$ —
Increases based on tax positions related to 2015	108	—	—	—	106	—	—	—	—
Decreases based on tax positions related to 2015	—	—	—	—	—	—	—	—	—
Change to positions that only affect timing	(705)	(659)	(7)	(44)	—	(688)	—	—	—
Increases based on tax positions prior to 2015	79	65	—	—	14	11	8	3	—
Decreases based on tax positions prior to 2015	(116)	(112)	—	—	—	—	—	—	—
Decreases from settlements with taxing authorities	(31)	(31)	—	—	—	—	—	—	—
Decreases from expiration of statute of limitations	(86)	(86)	—	—	—	(3)	—	—	—
Unrecognized tax benefits at December 31, 2015	$ 1,078	$ 534	$ 142	$ —	$ 120	$ 22	$ 8	$ 3	$ —

Exelon established a liability for an uncertain tax position associated with the tax deductibility of certain merger commitments incurred by Exelon in connection with the acquisitions of Constellation in 2012 and PHI in 2016. In the first quarter 2017, as a part of its examination of Exelon's return, the IRS National Office issued guidance concurring with Exelon's position that the merger commitments were deductible. As a result, Exelon, Generation, PHI, Pepco, DPL, and ACE decreased their liability for unrecognized tax benefits by $146 million , $19 million , $59 million , $21 million , $16 million , and $22 million , respectively, in the first quarter of 2017 resulting in a benefit to Income taxes on Exelon's, Generation's, PHI's, Pepco's, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income and corresponding decreases in their effective tax rates.

Exelon reduced the liability related to the uncertain tax position associated with the like-kind exchange in the second quarter of 2017. Please see the Other Income Tax Matters section below for additional details related to the like-kind exchange adjustments made in the second quarter of 2017.

Exelon and Generation have $7 million of unrecognized tax benefits at December 31, 2017 for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits.

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Exelon, Generation, and ComEd had $83 million , $7 million , and $(12) million of unrecognized tax benefits at December 31, 2016 for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits.

Exelon, Generation, and ComEd had $415 million , $20 million and $142 million of unrecognized tax benefits at December 31, 2015 for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits.

The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to, or defer the receipt of the cash tax benefit from, the taxing authority to an earlier or later period respectively.

Unrecognized tax benefits that if recognized would affect the effective tax rate

Exelon, Generation, ComEd and PHI have $523 million , $461 million , $2 million , and $32 million , respectively, of unrecognized tax benefits at December 31, 2017 that, if recognized, would decrease the effective tax rate. BGE, PHI, Pepco, DPL, and ACE have $120 million , $94 million , $59 million , $21 million , and $14 million of unrecognized tax benefits at December 31, 2017 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Exelon, Generation, PHI, Pepco, DPL, and ACE had $633 million , $483 million , $93 million , $21 million , $16 million , and $22 million , respectively, of unrecognized tax benefits at December 31, 2016 that, if recognized, would decrease the effective tax rate. BGE, PHI, Pepco and DPL had $120 million , $80 million , $59 million , and $21 million of unrecognized tax benefits at December 31, 2016 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Exelon, Generation, and PHI had $538 million , $509 million , and $11 million , respectively, of unrecognized tax benefits at December 31, 2015 that, if recognized, would decrease the effective tax rate. BGE, PHI, Pepco and DPL had $120 million , $11 million , $8 million and $3 million of unrecognized tax benefits at December 31, 2015 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Reasonably possible the total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Like-Kind Exchange

As of December 31, 2017 , Exelon and ComEd have approximately $39 million and $ 2 million , respectively, of unrecognized federal and state income tax benefits that could significantly decrease within the 12 months after the reporting date due to a final resolution of the like-kind exchange litigation described below. The recognition of these unrecognized tax benefits would decrease Exelon and ComEd's effective tax rate.

Settlement of Income Tax Audits, Refund Claims, and Litigation

As of December 31, 2017 , Exelon, Generation, BGE, PHI, Pepco, DPL, and ACE have approximately $683 million , $469 million , $120 million , $94 million , $59 million , $ 21 million , $ 14 million respectively, of unrecognized federal and state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits, potential settlements, refund claims, and the outcomes of pending court cases. Of the above unrecognized tax benefits, Exelon and Generation have $462 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefit related to BGE, Pepco, DPL and ACE, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Total amounts of interest and penalties recognized

The following tables represent the net interest and penalties receivable (payable), including interest and penalties related to tax positions reflected in the Registrants' Consolidated Balance Sheets.

						Successor			
Net interest receivable (payable) as of	Exelon [a]	Generation	ComEd [a]	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2017	$ 233	$ (3)	$ 4	$ —	$ —	$ 2	$ —	$ —	$ —
December 31, 2016	(507)	46	(384)	8	(1)	2	1	—	1

						Successor			
Net penalties receivable (payable) as of	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2017	$ (17)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
December 31, 2016	(106)	—	(86)	—	—	—	—	—	—

(a) Change in balance attributable to Like-Kind Exchange interest payments, see Other Tax Matters for further discussion.

The following tables set forth the net interest and penalty expense, including interest and penalties related to tax positions, recognized in Interest expense, net and Other, net in Other income and deductions in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Net interest expense (income) for the years ended	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
December 31, 2017	$ 37	$ (1)	$ 11	$ —	$ —	$ —	$ —	$ —
December 31, 2016	165	(13)	117	—	—	6	—	(1)
December 31, 2015	(13)	(31)	7	—	—	(4)	—	—

Net penalty expense (income) for the years ended	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
December 31, 2017	$ (2)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
December 31, 2016	106	—	86	—	—	—	—	—
December 31, 2015	—	—	—	—	—	—	—	—

	Successor		Predecessor	
PHI	December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	December 31, 2015
Net interest expense (income)	$ —	$ (2)	$ —	$ (34)

Description of tax years open to assessment by major jurisdiction

Taxpayer	Open Years
Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns	1999, 2001-2016
PHI Holdings and subsidiaries consolidated Federal income tax returns	2013-2016
Exelon and subsidiaries Illinois unitary income tax returns	2013-2016
Constellation Illinois unitary income tax returns	2011-March 2012
Constellation combined New York corporate income tax returns	2010-March 2012
Exelon combined New York corporate income tax returns	2011-2016
Exelon New Jersey corporate income tax returns	2013-2015
Various separate company (excluding PECO) Pennsylvania corporate net income tax returns	2011-2016
PECO Pennsylvania separate company returns	2010-2016
DPL Delaware separate company returns	Same as Federal
ACE New Jersey separate company returns	2013-2016
Exelon and subsidiaries District of Columbia corporate income tax returns	2014-2016
PHI Holdings and subsidiaries District of Columbia corporate income tax returns	2014-2016
Various separate company Maryland corporate net income tax returns	Same as Federal

Other Tax Matters

Like-Kind Exchange

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $1.2 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities.

The IRS disagreed with this position and asserted that the entire gain of approximately $1.2 billion was taxable in 1999. Exelon was unable to reach agreement with the IRS regarding the dispute over the like-kind exchange position. The IRS asserted that the Exelon purchase and leaseback transaction was substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities did not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS also asserted a penalty of approximately $90 million for a substantial understatement of tax.

On September 30, 2013, the IRS issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court (Tax Court) and the trial took place in August of 2015. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue.

On September 19, 2016, the Tax Court rejected Exelon's position in the case and ruled that Exelon was not entitled to defer gain on the transaction. In addition, contrary to Exelon's evaluation that the penalty was unwarranted, the Tax Court ruled that Exelon is liable for the penalty and interest due on

the asserted penalty. In June of 2017, the IRS finalized its computation of tax, penalties and interest owed by Exelon pursuant to the Tax Court's decision. In September of 2017, Exelon appealed this decision to the U.S. Court of Appeals for the Seventh Circuit.

In the first quarter of 2013, Exelon concluded that it was no longer more likely than not that the like-kind exchange position would be sustained and recorded charges to earnings representing the amount of interest expense (after-tax) and incremental state income tax expense that would be payable in the event Exelon is unsuccessful in litigation. Exelon agreed to hold ComEd harmless from any unfavorable impacts on ComEd's equity of the after-tax interest and penalty amounts.

Prior to the Tax Court's decision, however, Exelon did not believe it was likely a penalty would be assessed based on applicable case law and the facts of the transaction. As a result, no charge had been recorded for the penalty or for after-tax interest on the penalty. While it has strong arguments on appeal with respect to both the merits and the penalty, Exelon has determined that, pursuant to the applicable authoritative guidance, it is no longer more likely than not to avoid ultimate imposition of the penalty. As a result, in the third quarter of 2016, Exelon and ComEd recorded a charge to earnings of approximately $ 106 million and $ 86 million , respectively, of penalty and approximately $ 94 million and $ 64 million , respectively, of after-tax interest. Exelon and ComEd recorded the penalty and pre-tax interest due on the asserted penalty to Other, net and Interest expense, net, respectively, on their Consolidated Statements of Operations. Consistent with Exelon's agreement to continue to hold ComEd harmless from any unfavorable impact on its equity from the like-kind exchange position, ComEd recorded on its Consolidated Balance Sheets as of September 30, 2016, an additional $ 150 million receivable and non-cash equity contributions from Exelon.

As a result of the IRS's finalization of its computation in the second quarter of 2017, Exelon recorded a benefit to earnings of approximately $ 26 million , consisting of an income tax benefit of $ 50 million and a reduction of penalties of $ 2 million , partially offset by after-tax interest expense of $ 26 million , while ComEd recorded a charge to earnings of approximately $ 23 million , consisting of income tax expense of $ 15 million and after-tax interest expense of $ 8 million .

In the second quarter of 2017, Exelon amended its agreement with ComEd to also hold ComEd harmless for the unfavorable impacts on its equity from the additional income tax amounts owed by ComEd as a result of the IRS's finalization of its computation related to the like-kind exchange position. Accordingly, in the second quarter of 2017, ComEd recorded an additional receivable and non-cash equity contribution from Exelon for the total $ 23 million . As of June 30, 2017, ComEd had a total receivable from Exelon pursuant to the hold harmless agreement of $ 369 million , which was included in Current Receivables from Affiliates on ComEd's Consolidated Balance Sheet.

In the fourth quarter of 2017, the IRS assessed the tax, penalties and interest of approximately $ 1.3 billion related to the like-kind exchange, including $ 300 million attributable to ComEd. While Exelon will receive a tax benefit of approximately $ 350 million associated with the deduction for the interest, Exelon currently has a net operating loss carryforward and thus does not expect to realize the cash benefit until 2018. After taking into account these interest deduction tax benefits, the total net cash outflow for the like-kind exchange is approximately $ 950 million , of which approximately $ 300 million is attributable to ComEd after giving consideration to Exelon's agreement to hold ComEd harmless from any unfavorable impacts on ComEd's equity from the like-kind exchange position. Following a final appellate decision, which is expected in 2018, Exelon expects to receive approximately $ 60 million related to final interest computations.

Of the above amounts payable, Exelon deposited with the IRS $ 1.25 billion in October of 2016. Exelon funded the $ 1.25 billion deposit with a combination of cash on hand and short-term borrowings. As a result of the IRS's assessment of the tax, penalties and interest in the fourth quarter of 2017, the deposit is no longer available to Exelon and thus was reclassified from a current asset and is now reflected as an offset to the related liabilities for the tax, penalties, and interest that are included on

Exelon's balance sheet as current liabilities. The remaining amount due of approximately $ 20 million was paid in the fourth quarter of 2017. The $ 300 million payable discussed above attributable to ComEd, net of ComEd's receivable pursuant to the hold harmless agreement, was settled with Exelon in the third quarter of 2017. No recovery will be sought from ComEd customers for any interest, penalty, or additional income tax payment amounts resulting from the like-kind exchange tax position.

As previously disclosed, in the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of $ 335 million . In the first quarter of 2016, Exelon terminated its interests in the remaining two municipal-owned electric generation properties in exchange for $ 360 million .

Long-Term State Tax Apportionment (Exelon, Generation and PHI)

Exelon, Generation and PHI periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of their respective deferred state income taxes. Events that may require Exelon, Generation and PHI to update their long-term state tax apportionment include significant changes in tax law and/or significant operational changes. Exelon's, PHI's and Pepco's long-term marginal state income tax rate were revised in the first quarter of 2017 as a result of a statutory rate change in Washington, D.C. As a result, Exelon, PHI and Pepco recorded a one-time decrease to Deferred income tax liability of $ 28 million , $ 8 million and $ 8 million , respectively, on their Consolidated Balance Sheets. Because income taxes are recovered through customer rates, Exelon, PHI and Pepco recorded a corresponding regulatory liability of $ 8 million , in the Consolidated Balance Sheets. In addition, Exelon recorded a decrease to Income tax expense of $ 20 million , net of federal taxes, in the Consolidated Statements of Operations and Comprehensive Income for the three months ended March 31, 2017.

In the third quarter of 2017, Exelon reviewed and updated its marginal state income tax rates based on 2016 state apportionment rates. In addition, Exelon, Generation and ComEd recorded the impacts of Illinois' statutory rate change, which increased the total corporate income tax rate from 7.75% to 9.5% effective July 1, 2017. As a result of the rate changes, in the third quarter of 2017, Exelon, Generation and ComEd recorded a one-time increase to Deferred income taxes of approximately $ 250 million , $ 20 million and $ 270 million , respectively, on their Consolidated Balance Sheets. Because income taxes are recovered through customer rates, each of Exelon and ComEd recorded a corresponding regulatory asset of $ 272 million . Further, Exelon recorded a decrease to Income tax expense of approximately $ 20 million and Generation recorded an increase to Income tax expense of approximately $ 20 million (each net of federal taxes) in their Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2017. The Illinois statutory rate increase is not expected to have a material ongoing impact to Exelon's, Generation's or ComEd's future results of operations.

Allocation of Tax Benefits (All Registrants)

Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2017, Generation, PECO, BGE, and PHI recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $102 million , $ 16 million , $ 10 million and $ 7 million respectively. ComEd, Pepco, DPL, and ACE did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss.

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During 2016, Generation, PECO and BGE recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $ 94 million , $ 18 million and $ 8 million respectively. ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss. PHI, Pepco, DPL and ACE did not record an allocation of Federal tax benefits from Exelon as they were not a part of Exelon's 2015 consolidated tax return.

During 2015, Generation, PECO and BGE recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $ 57 million , $ 16 million and $ 7 million respectively. ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss.

15 . Asset Retirement Obligations (All Registrants)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation updates its ARO annually unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets, from January 1, 2016 to December 31, 2017 :

	Exelon and Generation
Nuclear decommissioning ARO at January 1, 2016	$ 8,246
Accretion expense	436
Net increase for changes in and timing of estimated future cash flows	61
Costs incurred related to decommissioning plants	(9)
Nuclear decommissioning ARO at December 31, 2016 [(a)]	8,734
Accretion Expense	458
Acquisition of FitzPatrick	444
Net increase for changes in and timing of estimated future cash flows	34
Costs incurred related to decommissioning plants	(8)
Nuclear decommissioning ARO at December 31, 2017 [(a)]	$ 9,662

(a) Includes $ 13 million and $ 10 million as the current portion of the ARO at December 31, 2017 and 2016 , respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During 2017 , Generation's total nuclear ARO increased by approximately $928 million , primarily reflecting year-to-date accretion of the ARO liability due to the passage of time, the recording of the fair value of the ARO, including subsequent purchase accounting adjustments, for the acquisition of FitzPatrick (see Note 4 — Mergers, Acquisitions and Dispositions), the announced early retirement of TMI, and impacts of ARO updates completed during 2017 to reflect changes in amounts and timing of estimated decommissioning cash flows.

The net $34 million increase in the ARO during 2017 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year, some with offsetting impacts. These adjustments include a $ 178 million increase due to higher assumed probabilities of early retirement of Salem and a $ 138 million increase in TMI's ARO liability associated with the May 30, 2017 announcement to early retire the unit on September 30, 2019. The increase in the ARO liability for TMI incorporates the early shutdown date, increases the probabilities of longer term decommissioning scenarios, and reflects an increase in the estimated costs to decommission based on an updated decommissioning cost study. See Note 8 — Early Nuclear Plant Retirements for additional information regarding Salem and TMI. These increases in the ARO were partially offset by a $ 180 million decrease for refinements in estimated fleet wide labor costs expected to be incurred for certain on-site personnel during decommissioning as well as net decreases resulting from updates to the cost studies of Clinton, Quad Cities and Dresden.

During 2016 , Generation's ARO increased by approximately $488 million , primarily reflecting year-to-date accretion of the ARO liability of approximately $436 million due to the passage of time and impacts of ARO updates completed during 2016 to reflect changes in amounts and timing of estimated decommissioning cash flows. The $61 million increase in the ARO during 2016 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year, some with offsetting impacts. These adjustments include increases of $288 million resulting from the change in the assumed DOE spent fuel acceptance date for disposal from 2025 to 2030 as well as increases resulting from updates to the cost studies of Oyster Creek, Zion, Calvert Cliffs, Ginna and Nine Mile Point. These increases were partially offset by a decrease of $165 million resulting from changes to the decommissioning scenarios and their probabilities as well as reductions in estimated cost escalation rates, primarily for labor, energy and waste burial costs. Most of the increase to the ARO resulting from the June 2, 2016, announcement to early retire Clinton and Quad Cities was reversed pursuant to the December 7, 2016, enactment of the Illinois FEJA. See Note 8 — Early Nuclear Plant Retirements for additional information.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generation station unit to satisfy Generation's nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with Generation's nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. On March 31, 2017, PECO filed its Nuclear Decommissioning Cost Adjustment (NDCA) with the PAPUC proposing an annual recovery from customers of approximately $4 million . This amount reflects a decrease from the current approved annual collection of approximately $ 24 million primarily due to the removal of the collections for Limerick Units 1 and 2 as a result of the NRC approving the extension of the operating licenses for an additional 20 years. On August 8, 2017, the PAPUC approved the filing and the new rates became effective January 1, 2018.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been

transferred to a third-party (see Zion Station Decommissioning below) and the CENG units, where any shortfall is required to be funded by both Generation and EDF. Generation, through PECO, has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise Generation will not be allowed to collect amounts associated with the first $ 50 million of any shortfall of trust funds compared to decommissioning costs, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units. The initial $ 50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from utility customers for any of Generation's other nuclear units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to Generation's other nuclear units, Generation retains any funds remaining after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to nuclear decommissioning trust funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. Generation expects to comply with applicable regulations and timely commence and complete all required decommissioning activities.

At December 31, 2017 and 2016 , Exelon and Generation had NDT fund investments totaling $ 13,349 million and $11,061 million , respectively. The increase is primarily driven by improved market performance and the acquisition of FitzPatrick. For additional information related to the NDT fund investments, refer to Note 11 — Fair Value of Financial Assets and Liabilities .

The following table provides unrealized gains on NDT funds for 2017 , 2016 and 2015 :

	Exelon and Generation		
	For the Years Ended December 31,		
	2017	2016	2015
Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units [(a)]	$ 455	$ 216	$ (282)
Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units [(b)(c)]	521	194	(197)

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $ (10) million , $(1) million and $ 7 million of net unrealized gains (losses) related to the Zion Station pledged assets in 2017 , 2016 and 2015 , respectively. Net unrealized gains related to Zion Station pledged assets are included in the Other current liabilities and Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets in 2017 and 2016, respectively.
(c) Net unrealized gains (losses) related to Generation's NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement

Units are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Accounting Implications of the Regulatory Agreements with ComEd and PECO

Based on the regulatory agreement with the ICC that dictates Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the NDT funds are expected to exceed the total estimated decommissioning obligation, decommissioning-related activities, including realized and unrealized gains and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial positions could be material. As of December 31, 2017 , the NDT funds of each of the former ComEd units, except for Zion (see Zion Station Decommissioning below), are expected to exceed the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is different, as described below, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

Based on the regulatory agreement supported by the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the former PECO units, regardless of whether the funds held in the NDT funds are expected to exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial positions could be material.

The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Refer to Note 3 — Regulatory Matters and Note 26 — Related Party Transactions for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and

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ZionSolutions, under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation's transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF and decommission the SNF dry storage facility, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to its decommissioning efforts at Zion Station. During 2013, EnergySolutions entered a definitive acquisition agreement and was acquired by another company. Generation reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to Pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a Payable for Zion Station decommissioning in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the Payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately $ 114 million , which is included within the nuclear decommissioning ARO at December 31, 2017 . Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2017 and 2016 :

	Exelon and Generation	
	2017	2016
Carrying value of Zion Station pledged assets [a]	$ 39	$ 113
Payable to Zion Solutions [b]	37	104
Current portion of payable to Zion Solutions [c]	37	90
Cumulative withdrawals by Zion Solutions to pay decommissioning costs [d]	942	878

(a) Included in Other current assets within Exelon's and Generation's Consolidated Balance Sheets in 2017.
(b) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(c) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.
(d) Includes project expenses to decommission Zion Station and estimated tax payments on Zion Station NDT fund earnings.

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required decommissioning work according to an established schedule and constructed a dry cask storage facility on the land and has loaded the SNF from the SNF pools onto the dry cask storage facility at Zion Station.

Rent payable under the Lease Agreement is $ 1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with Zion Station and penalty rents may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by ZionSolutions, EnergySolutions provided a $ 200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. In accordance with the terms of the ASA, the letter of credit was reduced to $98 million in August 2017 due to the completion of key decommissioning milestones. EnergySolutions and its parent company have also provided a performance guarantee and EnergySolutions has entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in the type of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2017 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2018 for Oyster Creek and 2019 for TMI); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2017 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning and site restoration activities, as applicable, are completed under four possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the consideration of multiple end of life scenarios; (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 4.8% to 6.4% (as compared to a historical 5-year annual average pre-tax return of approximately 8%).

Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending

on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial positions may be significantly adversely affected.

Generation filed its biennial decommissioning funding status report with the NRC on March 31, 2017 for all units except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions (see Zion Station Decommissioning above) and FitzPatrick which is still owned by Entergy as of the NRC reporting period. This status report demonstrated adequate decommissioning funding assurance for all units except for Peach Bottom Unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom Unit 1 is provided by the NDT fund in addition to collections from PECO ratepayers. As discussed under Nuclear Decommissioning Trust Fund Investments above, the amount collected from PECO ratepayers has been adjusted in the March 31, 2017 filing to the PAPUC which was approved on August 8, 2017 and effective on January 1, 2018.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2018 for shutdown reactors and reactors within five years of shutdown. This report will reflect the status of decommissioning funding assurance as of December 31, 2017 and will include the early retirement of TMI announced on May 30, 2017, in addition to an adjustment for the February 2, 2018 announced retirement date for Oyster Creek. A shortfall at any unit could necessitate that Exelon post a parental guarantee for Generation's share of the funding assurance. However, the amount of any required guarantee will ultimately depend on the decommissioning approach adopted, the associated level of costs, and the decommissioning trust fund investment performance going forward.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO units, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Non-Nuclear Asset Retirement Obligations (All Registrants)

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. PHI and the Utility Registrants have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1 — Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

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The following table provides a rollforward of the non-nuclear AROs reflected on the Registrants' Consolidated Balance Sheets from January 1, 2016 to December 31, 2017 :

						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI (g)	Pepco	DPL	ACE
Non-nuclear AROs at January 1, 2016	$ 355	$ 197	$ 113	$ 27	$ 18	$ —	$ —	$ —	$ —
Merger with PHI [a]	8	1	—	—	—	—	—	—	—
Net increase due to changes in, and timing of, estimated future cash flows [b]	34	8	4	1	7	14	2	9	3
Development projects [c]	11	11	—	—	—	—	—	—	—
Accretion expense [d]	18	10	7	1	—	—	—	—	—
Sale of generating assets [e]	(22)	(22)	—	—	—	—	—	—	—
Payments	(11)	(6)	(3)	(1)	(1)	—	—	—	—
Non-nuclear AROs at December 31, 2016 [f]	393	199	121	28	24	14	2	9	3
Net increase (decrease) due to changes in, and timing of, estimated future cash flows [b]	(11)	(1)	(13)	(1)	2	2	1	1	—
Development projects [c]	1	1	—	—	—	—	—	—	—
Accretion expense [d]	18	10	7	1	—	—	—	—	—
Deconsolidation of EGTP [h]	(7)	(7)	—	—	—	—	—	—	—
Payments	(10)	(5)	(2)	(1)	(2)	—	—	—	—
Non-nuclear AROs at December 31, 2017 [f]	$ 384	$ 197	$ 113	$ 27	$ 24	$ 16	$ 3	$ 10	$ 3

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	Predecessor
	PHI (g)
	2016
Non-nuclear AROs at January 1, 2016	$ 8
Accretion expense	—
Non-nuclear AROs at March 23, 2016	$ 8

(a) Following the completion of the PHI merger on March 23, 2016, PHI's AROs related to its unregulated business interests were transferred to Exelon and Generation.
(b) During the year ended December 31, 2017 , ComEd recorded a decrease of $1 million in Operating and maintenance expense. Generation, PECO, BGE, Pepco, DPL and ACE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2017 . During the year ended December 31, 2016 , Generation recorded a increase of $1 million in Operating and maintenance expense. ComEd, PECO, BGE, Pepco, DPL and ACE did not record any adjustments in Operating and maintenance expense for the year ended December 31, 2016 .
(c) Relates to new AROs recorded due to the construction of solar, wind and other non-nuclear generating sites.
(d) For ComEd, PECO and BGE, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.
(e) Reflects a reduction to the ARO resulting primarily from the sales of the New Boston generating site and Upstream business in 2016. See Note 4 — Mergers, Acquisitions and Dispositions for further information.
(f) Excludes the current portion of the ARO at December 31, 2017 for Generation, ComEd and BGE of $1 million , $2 million and $2 million , respectively. Excludes the current portion of the ARO at December 31, 2016 for Generation, ComEd and BGE of $1 million , $2 million and $3 million , respectively. This is included in Other current liabilities on the Registrants' respective Consolidated Balance Sheets.
(g) For PHI, the successor period includes activity for the year ended December 31, 2017 and the period of March 24, 2016 through December 31, 2016 . The PHI predecessor periods include activity for the period of January 1, 2016 through March 23, 2016.
(h) See Note 4 — Mergers, Acquisitions and Dispositions for additional information.

16 . Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all current employees. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Effective February 1, 2018, most newly-hired Generation and BSC non-represented employees are not eligible for pension benefits, and will instead be eligible to receive an enhanced non-discretionary employer contribution in an Exelon defined contribution savings plan. Effective January 1, 2018, most newly-hired non-represented employees are not eligible for OPEB benefits and employees represented by Local 614 are not eligible for retiree health care benefits.

Effective March 23, 2016 , Exelon became the sponsor of all of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets. As a result, PHI's benefit plan net obligation and related regulatory assets were transferred to Exelon.

The table below shows the pension and other postretirement benefit plans in which employees of each operating company participated at December 31, 2017 :

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	Operating Company (e)								
Name of Plan:	Generation	ComEd	PECO	BGE	BSC	PHI	Pepco	DPL	ACE
Qualified Pension Plans:									
Exelon Corporation Retirement Program [a]	X	X	X	X	X				
Exelon Corporation Cash Balance Pension Plan [a]	X	X	X	X	X				
Exelon Corporation Pension Plan for Bargaining Unit Employees [a]	X	X			X				
Exelon New England Union Employees Pension Plan [a]	X								
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek [a]	X	X	X		X				
Pension Plan of Constellation Energy Group, Inc. [b]	X	X	X	X	X				
Pension Plan of Constellation Energy Nuclear Group, LLC [c]	X	X		X	X				
Nine Mile Point Pension Plan [c]	X				X				
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B [b]	X								
Pepco Holdings LLC Retirement Plan [d]	X					X	X	X	X
Non-Qualified Pension Plans:									
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan [a]	X	X	X		X				
Exelon Corporation Supplemental Management Retirement Plan [a]	X	X	X	X	X				
Constellation Energy Group, Inc. Senior Executive Supplemental Plan [b]	X			X	X				
Constellation Energy Group, Inc. Supplemental Pension Plan [b]	X			X	X				
Constellation Energy Group, Inc. Benefits Restoration Plan [b]	X	X		X	X				
Constellation Energy Nuclear Plan, LLC Executive Retirement Plan [c]	X				X				
Constellation Energy Nuclear Plan, LLC Benefits Restoration Plan [c]	X				X				
Baltimore Gas & Electric Company Executive Benefit Plan [b]	X			X	X				
Baltimore Gas & Electric Company Manager Benefit Plan [b]	X	X		X	X				
Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan [d]	X					X	X	X	X
Conectiv Supplemental Executive Retirement Plan [d]	X					X		X	X
Pepco Holdings LLC Combined Executive Retirement Plan [d]	X					X	X		
Atlantic City Electric Director Retirement Plan [d]									X

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Operating Company (e)								
Name of Plan:	Generation	ComEd	PECO	BGE	BSC	PHI	Pepco	DPL	ACE
Other Postretirement Benefit Plans:									
PECO Energy Company Retiree Medical Plan [a]	X	X	X	X	X				
Exelon Corporation Health Care Program [a]	X	X	X	X	X				
Exelon Corporation Employees' Life Insurance Plan [a]	X	X	X	X	X				
Exelon Corporation Health Reimbursement Arrangement Plan [a]	X	X	X	X	X				
Constellation Energy Group, Inc. Retiree Medical Plan [b]	X	X	X	X	X				
Constellation Energy Group, Inc. Retiree Dental Plan [b]	X			X	X				
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan [b]	X	X	X	X	X				
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan [b]	X								
Exelon New England Union Post-Employment Medical Savings Account Plan [a]	X								
Retiree Medical Plan of Constellation Energy Nuclear Group LLC [c]	X			X	X				
Retiree Dental Plan of Constellation Energy Nuclear Group LLC [c]	X			X	X				
Nine Mile Point Nuclear Station, LLC Medical Care and Prescription Drug Plan for Retired Employees [c]	X				X				
Pepco Holdings LLC Welfare Plan for Retirees [d]	X					X	X	X	X

(a) These plans are collectively referred to as the legacy Exelon plans.
(b) These plans are collectively referred to as the legacy Constellation Energy Group (CEG) Plans.
(c) These plans are collectively referred to as the legacy CENG plans.
(d) These plans are collectively referred to as the legacy PHI plans.
(e) Employees generally remain in their legacy benefit plans when transferring between operating companies.

Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Exelon has elected that the trusts underlying these plans be treated as qualified trusts under the IRC. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets and Funded Status

Exelon recognizes the overfunded or underfunded status of defined benefit pension and OPEB plans as an asset or liability on its balance sheet, with offsetting entries to AOCI and regulatory assets (liabilities), in accordance with the applicable authoritative guidance. The measurement date for the plans is December 31.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

During the first quarter of 2017, Exelon received an updated valuation of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2017. This valuation resulted in an increase to the pension obligation of $92 million and an increase to the other postretirement benefit obligation of $57 million . Additionally, accumulated other comprehensive loss increased by approximately $59 million (after tax), regulatory assets increased by approximately $57 million and regulatory liabilities increased by approximately $4 million .

In connection with the acquisition of FitzPatrick in the first quarter of 2017 , Exelon recorded pension and OPEB obligations for FitzPatrick employees of $16 million and $17 million , respectively. Refer to Note 4 — Mergers, Acquisitions and Dispositions for additional discussion of the acquisition of FitzPatrick.

The following tables provide a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
Exelon	**2017**	**2016 [a]**	**2017**	**2016 [a]**
Change in benefit obligation:				
Net benefit obligation at beginning of year	$ 21,060	$ 17,753	$ 4,457	$ 3,938
Service cost	387	354	106	107
Interest cost	842	830	182	185
Plan participants' contributions	—	—	53	54
Actuarial loss (gain)	1,182	567	350	(136)
Plan amendments	9	(60)	—	—
Acquisitions/divestitures [b]	16	2,667	17	589
Settlements	(34)	—	—	—
Gross benefits paid	(1,125)	(1,051)	(309)	(280)
Net benefit obligation at end of year	$ 22,337	$ 21,060	$ 4,856	$ 4,457

	Pension Benefits		Other Postretirement Benefits	
Exelon	**2017**	**2016 [a]**	**2017**	**2016 [a]**
Change in plan assets:				
Fair value of net plan assets at beginning of year	$ 16,791	$ 14,347	$ 2,578	$ 2,293
Actual return on plan assets	2,600	1,061	346	128
Employer contributions	341	347	64	50
Plan participants' contributions	—	—	53	54
Gross benefits paid	(1,125)	(1,051)	(309)	(280)
Acquisitions/divestitures [b]	—	2,087	—	333
Settlements	(34)	—	—	—
Fair value of net plan assets at end of year	$ 18,573	$ 16,791	$ 2,732	$ 2,578

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI	Predecessor	
	Pension Benefits	Other Postretirement Benefits
	January 1, 2016 to March 23, 2016	January 1, 2016 to March 23, 2016
Change in benefit obligation:		
Net benefit obligation at beginning of the period	$ 2,490	$ 563
Service cost	12	1
Interest cost	26	6
Actuarial (gain) loss	(30)	(5)
Gross benefits paid	(2)	(1)
Net benefit obligation at end of the period	$ 2,496	$ 564

PHI	Predecessor	
	Pension Benefits	Other Postretirement Benefits
	January 1, 2016 to March 23, 2016	January 1, 2016 to March 23, 2016
Change in plan assets:		
Fair value of net plan assets at beginning of the period	$ 2,018	$ 348
Employer and plan participant contributions	4	1
Gross benefits paid by plan	(2)	(1)
Fair value of net plan assets at end of the period	$ 2,020	$ 348

(a) 2016 amounts include PHI for the period of March 24, 2016 through December 31, 2016.
(b) Exelon recorded pension and OPEB obligations associated with its acquisition of Fitzpatrick on March 31, 2017. Effective March 23, 2016 , Exelon became the sponsor of PHI's defined benefit pension and other postretirement benefit plans.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

Exelon	Pension Benefits		Other Postretirement Benefits	
	2017	2016 [a]	2017	2016 [a]
Other current liabilities	$ 28	$ 21	$ 31	$ 31
Pension obligations	3,736	4,248	—	—
Non-pension postretirement benefit obligations	—	—	2,093	1,848
Unfunded status (net benefit obligation less plan assets)	$ 3,764	$ 4,269	$ 2,124	$ 1,879

(a) Effective March 23, 2016 , Exelon became the sponsor of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets.

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO), and fair value of plan assets for all pension plans with a PBO or ABO in excess of plan assets.

PBO in excess of plan assets

	Exelon	
	2017	2016
Projected benefit obligation	$ 22,337	$ 21,060
Fair value of net plan assets	18,573	16,791

ABO in excess of plan assets

	Exelon	
	2017	2016
Projected benefit obligation	$ 22,337	$ 21,060
Accumulated benefit obligation	21,153	19,930
Fair value of net plan assets	18,573	16,791

On a PBO basis, the Exelon plans were funded at 83% and 80% at December 31, 2017 and 2016 , respectively. On an ABO basis, the Exelon plans were funded at 88% and 84% at December 31, 2017 and 2016 , respectively. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The majority of the 2017 pension benefit cost for the Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 4.04% . The majority of the 2017 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.58% for funded plans and a discount rate of 4.04% .

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following tables present the components of Exelon's net periodic benefit costs, prior to capitalization, for the years ended December 31, 2017 , 2016 and 2015 and PHI's net periodic benefit costs, prior to capitalization, for the predecessor period of January 1, 2016 to March 23, 2016 .

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Exelon	Pension Benefits			Other Postretirement Benefits		
	2017 [a]	2016 [b]	2015	2017 [a]	2016 [b]	2015
Components of net periodic benefit cost:						
Service cost	$ 387	$ 354	$ 326	$ 106	$ 107	$ 119
Interest cost	842	830	710	182	185	167
Expected return on assets	(1,196)	(1,141)	(1,026)	(162)	(162)	(151)
Amortization of:						
Prior service cost (credit)	1	14	13	(188)	(185)	(174)
Actuarial loss	607	554	571	61	63	80
Settlement and other charges [c]	3	2	2	—	—	—
Net periodic benefit cost	$ 644	$ 613	$ 596	$ (1)	$ 8	$ 41

(a) FitzPatrick net benefit costs are included for the period after acquisition.
(b) PHI net periodic benefit costs for the period prior to the merger are not included in the table above.
(c) 2016 amount includes an additional termination benefit for PHI.

	Predecessor			
	Pension Benefits		Other Postretirement Benefits	
PHI	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
Components of net periodic benefit cost:				
Service cost	$ 12	$ 57	$ 1	$ 7
Interest cost	26	109	6	24
Expected return on assets	(30)	(140)	(5)	(22)
Amortization of:				
Prior service cost (credit)	—	2	(3)	(13)
Actuarial loss	14	65	2	8
Net periodic benefit cost	$ 22	$ 93	$ 1	$ 4

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Components of AOCI and Regulatory Assets

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets (liabilities) for the years ended December 31, 2017 , 2016 and 2015 for all plans combined and the components of PHI's predecessor AOCI and regulatory assets (liabilities) for the period January 1, 2016 to March 23, 2016 .

	Pension Benefits			Other Postretirement Benefits		
Exelon	**2017**	**2016 [a]**	**2015**	**2017**	**2016 [a]**	**2015**
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial (gain) loss	$ (222)	$ 644	$ 476	$ 166	$ (101)	$ (194)
Amortization of actuarial loss	(607)	(554)	(571)	(61)	(63)	(80)
Current year prior service cost (credit)	9	(60)	—	—	—	(23)
Amortization of prior service (cost) credit	(1)	(14)	(13)	188	185	174
Settlements	(3)	—	(2)	—	—	—
Acquisitions	—	994	—	—	94	—
Total recognized in AOCI and regulatory assets (liabilities)	$ (824)	$ 1,010	$ (110)	$ 293	$ 115	$ (123)
Total recognized in AOCI	$ (401)	$ 51	$ (64)	$ 168	$ 20	$ (63)
Total recognized in regulatory assets (liabilities)	$ (423)	$ 959	$ (46)	$ 125	$ 95	$ (60)

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Predecessor			
	Pension Benefits		Other Postretirement Benefits	
PHI	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):				
Current year actuarial loss (gain)	$ —	$ 50	$ —	$ (39)
Amortization of actuarial loss	(14)	(65)	(2)	(8)
Amortization of prior service (cost) credit	—	(2)	3	13
Total recognized in AOCI and regulatory assets (liabilities)	$ (14)	$ (17)	$ 1	$ (34)
Total recognized in AOCI	$ (1)	$ (11)	$ —	$ —
Total recognized in regulatory assets (liabilities)	$ (13)	$ (6)	$ 1	$ (34)

(a) 2016 amounts include PHI for the period of March 24, 2016 through December 31, 2016.

The following table provides the components of gross accumulated other comprehensive loss and regulatory assets (liabilities) that have not been recognized as components of periodic benefit cost at December 31, 2017 and 2016 , respectively, for all plans combined:

	Exelon		Exelon	
	Pension Benefits		Other Postretirement Benefits	
	2017	2016 [a]	2017	2016 [a]
Prior service (credit) cost	$ (24)	$ (31)	$ (522)	$ (710)
Actuarial loss	7,556	8,387	829	724
Total [a]	$ 7,532	$ 8,356	$ 307	$ 14
Total included in AOCI	$ 3,896	$ 4,297	$ 125	$ (42)
Total included in regulatory assets (liabilities)	$ 3,636	$ 4,059	$ 182	$ 56

(a) Effective March 23, 2016 , Exelon became the sponsor of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides the impact to Exelon's AOCI and regulatory assets (liabilities) at December 31, 2017 as a result of the components of periodic benefit costs that are expected to be amortized in 2018 . These estimates are subject to the completion of an actuarial valuation of Exelon's pension and other postretirement benefit obligations, which will reflect actual census data as of January 1, 2018 and actual claims activity as of December 31, 2017 . The valuation is expected to be completed in the first quarter of 2018 for the majority of the benefit plans.

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 2	$ (186)
Actuarial loss	640	66
Total [(a)]	$ 642	$ (120)

(a) Of the $642 million related to pension benefits at December 31, 2017 , $317 million and $325 million are expected to be amortized from AOCI and regulatory assets in 2018 , respectively. Of the $(120) million related to other postretirement benefits at December 31, 2017 , $(65) million and $(55) million are expected to be amortized from AOCI and regulatory assets (liabilities) in 2018 , respectively.

Average Remaining Service Period

For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants' average remaining service periods. The average remaining service period of Exelon's defined benefit pension plan participants was 11.8 years, 11.9 years and 11.9 years for the years ended December 31, 2017 , 2016 and 2015 , respectively. For the predecessor period, the average remaining service period of PHI's defined benefit plans was approximately 11 years for the year ended December 31, 2015 .

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants' average remaining service period to benefit eligibility age and amortizes certain actuarial gains and losses over participants' average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 8.2 years, 9.0 years and 10.8 years for the years ended December 31, 2017 , 2016 and 2015 , respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.6 years, 9.7 years and 9.7 years for the years ended December 31, 2017 , 2016 and 2015 , respectively. For the predecessor period, the average remaining service period of PHI's other postretirement benefit plans was approximately 11 years for the year ended December 31, 2015 .

Assumptions

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and inputs and accounting policy elections. The measurement of benefit obligations and costs is impacted by several assumptions and inputs, including the discount rate applied to benefit obligations, the long-term EROA, Exelon's expected level of contributions to the plans, the long-term expected investment rate credited to employees participating in cash balance plans and the anticipated rate of increase of health care costs. Additionally, assumptions related to plan participants include the incidence of mortality, the expected remaining service period, the level of compensation and rate of compensation increases, employee age and length of service, among other factors. When developing the required assumptions, Exelon considers historical information as well as future expectations.

Expected Rate of Return. In selecting the EROA, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Mortality. For the December 31, 2014 actuarial valuation, Exelon changed its assumption of mortality to reflect more recent expectations of future improvements in life expectancy. The change was supported through completion of an experience study and supplemental analyses performed by Exelon's actuaries. There were no changes to the mortality assumption in 2015 , 2016 or 2017 .

The following assumptions were used to determine the benefit obligations for the plans at December 31, 2017 , 2016 and 2015 . Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits			Other Postretirement Benefits		
Exelon	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Discount rate	3.62% [a]	4.04% [b]	4.29% [c]	3.61% [a]	4.04% [b]	4.29% [c]
Rate of compensation increase	[d]	[e]	[e]	[d]	[e]	[e]
Mortality table	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)
Health care cost trend on covered charges	N/A	N/A	N/A	5.00% with ultimate trend of 5.00% in 2017	5.00% with ultimate trend of 5.00% in 2017	5.50% decreasing to ultimate trend of 5.00% in 2017

	Predecessor		*Predecessor*	
	Pension Benefits		Other Postretirement Benefits	
PHI	**January 1, 2016 to March 23, 2016 [f]**	**2015**	**January 1, 2016 to March 23, 2016 [e]**	**2015**
Discount rate		4.65%/4.55% [g]		4.55%
Rate of compensation increase		5.00%		5.00%
Mortality table		RP-2014 table with improvement scale MP-2015		RP-2014 table with improvement scale MP-2015
Health care cost trend on covered charges		N/A		6.33% pre-65 and 5.40% post-65 decreasing to ultimate trend of 5.00% in 2020

(a) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2017. Certain benefit plans used individual rates ranging from 3.49% - 3.65% and 3.57% - 3.68% for pension and other postretirement plans, respectively.
(b) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2016. Certain benefit plans used individual rates ranging from 3.66% - 4.11% and 4.00% - 4.17% for pension and other postretirement plans, respectively.
(c) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2015. Certain benefit plans used individual rates ranging from 3.68% - 4.14% and 4.32% - 4.43% for pension and other postretirement plans, respectively.
(d) 3.25% through 2019 and 3.75% thereafter.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

(e) The legacy Exelon, CEG and CENG pension and other postretirement plans used a rate of compensation increase of 3.25% through 2019 and 3.75% thereafter, while the legacy PHI pension and other postretirement plans used a weighted-average rate of compensation increase of 5% for all periods.
(f) Obligation was not remeasured during this period.
(g) The discount rate for the qualified and non-qualified pension plans was 4.65% and 4.55% , respectively.

The following assumptions were used to determine the net periodic benefit costs for the plans for the years ended December 31, 2017 , 2016 and 2015 , as well as for the PHI predecessor period January 1, 2016 to March 23, 2016 :

	Pension Benefits			Other Postretirement Benefits		
Exelon	**2017**	**2016**	**2015**	**2017**	**2016**	**2015**
Discount rate	4.04% (a)	4.29% (b)	3.94% (c)	4.04% (a)	4.29% (b)	3.92% (c)
Expected return on plan assets	7.00% (d)	7.00% (d)	7.00% (d)	6.58% (d)	6.71% (d)	6.50% (d)
Rate of compensation increase	(e)	(e)	(e)	(e)	(e)	(e)
Mortality table	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)
Health care cost trend on covered charges	N/A	N/A	N/A	5.00% decreasing to ultimate trend of 5.00% in 2017	5.50% decreasing to ultimate trend of 5.00% in 2017	6.00% decreasing to ultimate trend of 5.00% in 2017

	Predecessor		*Predecessor*	
	Pension Benefits		**Other Postretirement Benefits**	
PHI	**January 1, 2016 to March 23, 2016**	**2015**	**January 1, 2016 to March 23, 2016**	**2015**
Discount rate	4.65%/4.55% (f)	4.20%	4.55%	4.15%
Expected return on plan assets (g)	6.50%	6.50%	6.75%	6.75%
Rate of compensation increase	5.00%	5.00%	5.00%	5.00%
Mortality table	RP-2014 table with improvement scale MP-2015	RP-2014 table with improvement scale MP-2014	RP-2014 table with improvement scale MP-2015	RP-2014 table with improvement scale MP-2014
Health care cost trend on covered charges	N/A	N/A	6.33% pre-65 and 5.40% post-65 decreasing to ultimate trend of 5.00% in 2020	6.67% pre-65 and 5.50% post-65 decreasing to ultimate trend of 5.00% in 2020

(a) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2017 . Certain benefit plans used individual rates ranging from 3.66% - 4.11% and 4.00% - 4.17% for pension and other postretirement plans, respectively.
(b) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2016 . Certain benefit plans used individual rates ranging from 3.68% - 4.14% and 4.32% - 4.43% for pension and other postretirement plans, respectively.
(c) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2015 . Certain benefit plans used the individual rates ranging from 3.29% - 3.82% and 3.99% - 4.06% for pension and other postretirement plans, respectively.
(d) Not applicable to pension and other postretirement benefit plans that do not have plan assets.

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(e) The legacy Exelon, CEG and CENG pension and other postretirement plans used a rate of compensation increase of 3.25% through 2019 and 3.75% thereafter, while the legacy PHI pension and other postretirement plans used a weighted-average rate of compensation increase of 5% for all periods.
(f) The discount rate for the qualified and non-qualified pension plans was 4.65% and 4.55% , respectively.
(g) Expected return on other postretirement benefit plan assets is pre-tax.

Assumed health care cost trend rates impact the other postretirement benefit plan costs reported for Exelon's participant populations with plan designs that do not have a cap on cost growth. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend:	
on 2017 total service and interest cost components	$ 9
on postretirement benefit obligation at December 31, 2017	125
Effect of a one percentage point decrease in assumed health care cost trend:	
on 2017 total service and interest cost components	(8)
on postretirement benefit obligation at December 31, 2017	(113)

Contributions

The following tables provide contributions to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2017 [a]	2016 [a]	2015 [a]	2017	2016	2015
Exelon	$ 341	$ 347	$ 462	$ 64	$ 50	$ 40
Generation	137	140	231	11	12	14
ComEd	36	33	143	5	5	7
PECO	24	30	40	—	—	—
BGE	39	31	1	14	18	16
BSC [b]	38	39	47	2	3	3
Pepco	62	24	—	10	8	2
DPL	—	22	—	2	—	—
ACE	—	15	—	20	2	3
PHISCO [c]	5	17	—	—	2	—

	Pension Benefits				Other Postretirement Benefits			
	Successor		*Predecessor*		*Successor*		*Predecessor*	
	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI	$ 67	$ 74	$ 4	$ —	$ 32	$ 12	$ —	$ 5

(a) Exelon's and Generation's pension contributions include $21 million , $25 million and $36 million related to the legacy CENG plans that was funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG for the years ended December 31, 2017 , 2016 and 2015 , respectively.
(b) Includes $4 million , $6 million , and $5 million of pension contributions funded by Exelon Corporate, for the years ended December 31, 2017 , 2016 , and 2015 , respectively.
(c) PHISCO's pension contributions for the year ended December 31, 2016 include $4 million of contributions made prior to the closing of Exelon's merger with PHI on March 23, 2016 .

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act),

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management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions below reflect a funding strategy of contributing the greater of (1) $300 million (which has been updated for the inclusion of PHI) until the qualified plans are fully funded on an ABO basis, and (2) the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

While other postretirement plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon's management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including liabilities management, levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). The amounts below include benefit payments related to unfunded plans.

The following table provides all registrants' planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to other postretirement plans in 2018:

	Qualified Pension Plans	Non-Qualified Pension Plans	Other Postretirement Benefits
Exelon	$ 301	$ 30	$ 42
Generation	119	11	13
ComEd	38	2	3
PECO	17	1	—
BGE	41	1	16
BSC	36	7	1
PHI	50	8	9
Pepco	4	2	8
DPL	—	1	—
ACE	6	—	—
PHISCO	40	5	1

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2017 were:

	Pension Benefits	Other Postretirement Benefits
2018	$ 1,166	$ 256
2019	1,165	262
2020	1,210	270
2021	1,236	276
2022	1,265	284
2023 through 2027	6,671	1,509
Total estimated future benefit payments through 2027	$ 12,713	$ 2,857

Allocation to Exelon Subsidiaries

All registrants account for their participation in Exelon's pension and other postretirement benefit plans by applying multi-employer accounting. Employee-related assets and liabilities, including both pension and postretirement liabilities, for the legacy Exelon plans were allocated by Exelon to its subsidiaries based on the number of active employees as of January 1, 2001 as part of Exelon's corporate restructuring. The obligation for Generation, ComEd and PECO reflects the initial allocation and the cumulative costs incurred and contributions made since January 1, 2001. Historically, Exelon has allocated the components of pension and other postretirement costs to the subsidiaries in the legacy Exelon plans based upon several factors, including the measures of active employee participation in each plan. Pension and other postretirement benefit contributions were allocated to legacy Exelon subsidiaries in proportion to active service costs recognized and total costs recognized, respectively. Beginning in 2015, Exelon began allocating costs related to its legacy Exelon pension and other postretirement benefit plans to its subsidiaries based on both active and retired employee participation and contributions are allocated based on accounting cost. The impact of this allocation methodology change was not material to any Registrant. For legacy CEG, legacy CENG, FitzPatrick, and legacy PHI plans, components of pension and other postretirement benefit costs and contributions have been, and will continue to be, allocated to the subsidiaries based on employee participation (both active and retired).

The amounts below were included in capital expenditures and operating and maintenance expense for the years ended December 31, 2017 , 2016 and 2015 , respectively, for each of the entities allocated portion of the pension and other postretirement benefit plan costs. These amounts include the recognized contractual termination benefit charges, curtailment gains, and settlement charges:

For the Years Ended December 31,	Exelon	Generation [a]	ComEd	PECO	BGE	BSC [b]	Pepco [c]	DPL [c]	ACE [c]	PHISCO [c][d]
2017	$ 643	$ 227	$ 176	$ 29	$ 64	$ 53	$ 25	$ 13	$ 13	$ 43
2016	621	218	166	33	68	48	31	18	15	47
2015	637	269	206	39	66	57	30	15	15	37

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Successor		Predecessor	
PHI	**For the Year Ended December 31, 2017**	**March 24, 2016 to December 31, 2016**	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**
Pension and Other Postretirement Benefit Costs	$ 94	$ 88	$ 23	$ 97

(a) FitzPatrick net benefit costs are included for the period after acquisition.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE, PHI, Pepco, DPL or ACE amounts above.
(c) Pepco's, DPL's, ACE's and PHISCO's pension and postretirement benefit costs for the year ended December 31, 2016 include $7 million , $4 million , $3 million and $9 million , respectively, of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016 .
(d) These amounts represent amounts billed to Pepco, DPL and ACE through intercompany allocations. These amounts are not included in Pepco, DPL or ACE amounts above.

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across Exelon's pension and other postretirement benefit plans for the year ended December 31, 2017 were 16.10% and 14.70% , respectively, compared to an expected long-term return assumption of 7.00% and 6.58% , respectively.

Exelon used an EROA of 7.00% and 6.60% to estimate its 2018 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations at December 31, 2017 and 2016 asset allocations were as follows:

Pension Plans

		Exelon	
		Percentage of Plan Assets at December 31,	
Asset Category	**Target Allocation**	**2017**	**2016**
Equity securities	35%	35%	33%
Fixed income securities	38%	39	39
Alternative investments [a]	27%	26	28
Total		100%	100%

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Other Postretirement Benefit Plans

		Exelon	
		Percentage of Plan Assets at December 31,	
Asset Category	Target Allocation	2017	2016
Equity securities	46%	47%	47%
Fixed income securities	28%	28	29
Alternative investments [a]	26%	25	24
Total		100%	100%

(a) Alternative investments include private equity, hedge funds, real estate, and private credit.

Concentrations of Credit Risk. Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2017 . Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2017 , there were no significant concentrations (defined as greater than 10% of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

Fair Value Measurements

The following tables present pension and other postretirement benefit plan assets measured and recorded at fair value on the Registrants' Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2017 and 2016 :

Exelon

December 31, 2017 [a][b]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Pension plan assets					
Cash equivalents	$ 585	$ —	$ —	$ —	$ 585
Equities [c]	3,565	—	2	3,077	6,644
Fixed income:					
U.S. Treasury and agencies	1,150	159	—	—	1,309
State and municipal debt	—	64	—	—	64
Corporate debt	—	3,931	232	—	4,163
Other [c]	—	447	—	756	1,203
Fixed income subtotal	1,150	4,601	232	756	6,739
Private equity	—	—	—	1,034	1,034
Hedge funds	—	—	—	1,770	1,770
Real estate	—	—	—	884	884
Private credit	—	—	—	919	919
Pension plan assets subtotal	$ 5,300	$ 4,601	$ 234	$ 8,440	$ 18,575

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

December 31, 2017 [a][b]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Other postretirement benefit plan assets					
Cash equivalents	$ 29	$ —	$ —	$ —	$ 29
Equities	523	2	—	764	1,289
Fixed income:					
U.S. Treasury and agencies	13	56	—	—	69
State and municipal debt	—	136	—	—	136
Corporate debt	—	47	—	—	47
Other	225	71	—	185	481
Fixed income subtotal	238	310	—	185	733
Hedge funds	—	—	—	430	430
Real estate	—	—	—	124	124
Private credit	—	—	—	123	123
Other postretirement benefit plan assets subtotal	$ 790	$ 312	$ —	$ 1,626	$ 2,728
Total pension and other postretirement benefit plan assets [d]	$ 6,090	$ 4,913	$ 234	$ 10,066	$ 21,303

December 31, 2016 [a][e]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Pension plan assets					
Cash equivalents	$ 325	$ —	$ —	$ —	$ 325
Equities [c]	3,144	—	2	2,535	5,681
Fixed income:					
U.S. Treasury and agencies	1,008	192	—	—	1,200
State and municipal debt	—	64	—	—	64
Corporate debt	—	3,641	206	—	3,847
Other [c]	—	340	—	748	1,088
Fixed income subtotal	1,008	4,237	206	748	6,199
Private equity	—	—	—	991	991
Hedge funds	—	—	—	1,962	1,962
Real estate	—	—	—	828	828
Private credit	—	—	—	833	833
Pension plan assets subtotal	$ 4,477	$ 4,237	$ 208	$ 7,897	$ 16,819

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

December 31, 2016 [a][e]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Other postretirement benefit plan assets					
Cash equivalents	$ 24	$ —	$ —	$ —	$ 24
Equities	547	2	—	644	1,193
Fixed income:					
U.S. Treasury and agencies	9	59	—	—	68
State and municipal debt	—	134	—	—	134
Corporate debt	—	43	—	—	43
Other	256	60	—	131	447
Fixed income subtotal	265	296	—	131	692
Hedge funds	—	—	—	445	445
Real estate	—	—	—	117	117
Private credit	—	—	—	107	107
Other postretirement benefit plan assets subtotal	$ 836	$ 298	$ —	$ 1,444	$ 2,578
Total pension and other postretirement benefit plan assets [d]	$ 5,313	$ 4,535	$ 208	$ 9,341	$ 19,397

(a) See Note 11 — Fair Value of Financial Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Effective March 31, 2017, Exelon became sponsor of FitzPatrick's defined benefit pension and other postretirement benefit plans, and assumed FitzPatrick's benefit plan obligations.
(c) Includes derivative instruments of $6 million and $1 million , which have a total notional amount of $3,606 million and $2,918 million at December 31, 2017 and 2016 , respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.
(d) Excludes net assets of $2 million and net liabilities of $28 million at December 31, 2017 and 2016 , respectively, which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables related to pending securities sales, interest and dividends receivable, and payables related to pending securities purchases.
(e) Effective March 23, 2016, Exelon became sponsor of PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets.

The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2017 and 2016 :

Exelon

	Fixed Income	Equities	Total
Pension Assets			
Balance as of January 1, 2017	$ 206	$ 2	$ 208
Actual return on plan assets:			
Relating to assets sold during the period	11	—	11
Purchases, sales and settlements:			
Purchases	31	—	31
Sales	(16)	—	(16)
Settlements [a]	—	—	—
Balance as of December 31, 2017	$ 232	$ 2	$ 234

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Fixed income	Equities	Total
Pension Assets			
Balance as of January 1, 2016	$ 165	$ 2	$ 167
Actual return on plan assets:			
Relating to assets still held at the reporting date	(2)	—	(2)
Purchases, sales and settlements:			
Purchases	69	—	69
Sales	(14)	—	(14)
Settlements [a]	(12)	—	(12)
Balance as of December 31, 2016	$ 206	$ 2	$ 208

(a) Represents cash settlements only.

There were no significant transfers between Level 1 and Level 2 during the year ended December 31, 2017 for the pension and other postretirement benefit plan assets.

Valuation Techniques Used to Determine Fair Value

Cash equivalents . Investments with original maturities of three months or less when purchased, including certain short-term fixed income securities and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

Equities . Equities consist of individually held equity securities, equity mutual funds and equity commingled funds in domestic and foreign markets. With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity securities held individually, including real estate investment trusts, rights and warrants, are primarily traded on exchanges that contain only actively traded securities due to the volume trading requirements imposed by these exchanges. Equity securities are valued based on quoted prices in active markets and are categorized as Level 1. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies, and certain investments are held in accordance with a stated set of fund objectives, which are consistent with the plans' overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Fixed income . For fixed income securities, which consist primarily of corporate debt securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security

if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The remaining fixed income securities, including certain other fixed income investments, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Other fixed income investments primarily consist of fixed income commingled funds and mutual funds, which are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Derivative instruments consisting primarily of futures and swaps to manage risk are recorded at fair value. Over-the-counter derivatives are valued daily based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over-the-counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Private equity . Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments and investments in natural resources. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include unobservable inputs such as cost, operating results, discounted future cash flows and market based comparable data. The fair value of private equity investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Hedge funds . Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or its equivalent as a practical expedient, and therefore, hedge funds are not classified within the fair value hierarchy. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate.

Real estate . Real estate funds are funds with a direct investment in pools of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. These valuation inputs are not highly observable. The fair value of real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Private credit. Private credit investments primarily consist of limited partnerships that invest in private debt strategies. These investments are generally less liquid assets with an underlying term of 3 to 5 years and are intended to be held to maturity. The fair value of these investments is determined by the fund manager or administrator and include unobservable inputs such as cost, operating results, and discounted cash flows. The fair value of private credit investments is determined using NAV or its

equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Defined Contribution Savings Plan (All Registrants)

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2017 , 2016 and 2015 :

For the Year Ended December 31,	Exelon (a)	Generation (a)	ComEd	PECO	BGE	BSC (b)	Pepco (c)	DPL (c)	ACE	PHISCO (c)(d)
2017	$ 128	$ 55	$ 31	$ 10	$ 10	$ 9	$ 3	$ 2	$ 2	$ 6
2016	164	79	34	10	12	19	3	2	2	6
2015	148	80	32	11	14	11	3	2	2	6

	Successor		Predecessor	
PHI	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
Saving Plan Matching Contributions	$ 13	$ 10	$ 3	$ 14

(a) Includes $13 million and $9 million related to CENG for the years ended December 31, 2016 and December 31, 2015.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, BGE, PHI, Pepco, DPL or ACE amounts above.
(c) Pepco's, DPL's and PHISCO's matching contributions include $1 million , $1 million and $1 million , respectively, of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016, which is not included in Exelon's matching contributions for the year ended December 31, 2016.
(d) These amounts primarily represent amounts billed to Pepco, DPL, and ACE through intercompany allocations. These amounts are not included in Pepco, DPL or ACE amounts above.

17 . Severance (All Registrants)

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

Ongoing Severance Plans

The Registrants provide severance and health and welfare benefits under Exelon's ongoing severance benefit plans to terminated employees in the normal course of business. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the years ended December 31, 2017 and 2016 , the Registrants recorded the following severance costs associated with ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

						Successor			
	Exelon	Generation [a]	ComEd [a]	PECO [a]	BGE [a]	PHI [a]	Pepco [a]	DPL [a]	ACE [a]
Year ended December 31,									
2017	$ 14	$ 6	$ 3	$ 1	$ —	$ 4	$ 2	$ 1	$ 1
2016	19	13	3	1	1	1	—	—	—

(a) The amounts above for Generation, ComEd, PECO, BGE, and PHI include immaterial amounts billed by BSC for the years ended December 31, 2017 and 2016 . Pepco, DPL, and ACE include immaterial amounts billed by PHISCO for the year ended December 31, 2017 . Pepco, DPL, and ACE did not have any ongoing severance plans for the year ended December 31, 2016 .

Cost Management Program-Related Severance

In August 2015, Exelon announced a cost management program focused on cost savings of approximately $400 million at BSC and Generation. Additionally, in November 2017, Exelon announced a new commitment for an additional $250 million of cost savings, primarily at Generation, to be achieved by 2020. These actions are in response to the continuing economic challenges confronting all parts of Exelon's business and industry, necessitating continued focus on cost management through enhanced efficiency and productivity. In connection with the program, certain positions have been identified for elimination and severance costs were recognized as both probable and estimable.

While there may be additional position eliminations identified leading to potential severance or other termination benefit changes, Exelon, Generation and BSC intend to manage any staff reductions through natural attrition to the extent possible to minimize impacts on employees. Any additional severance or other termination benefit charges related to this commitment will be recognized when such amounts are considered probable and can be reasonably estimated.

For the years ended December 31, 2017 and 2016 , the Registrants recorded the following severance costs related to the cost management program within Operating and maintenance expense in their Consolidated Statements of Operations:

	Exelon	Generation	ComEd	PECO	BGE
2017 [a]	$ 6	$ 9	$ (1)	$ (1)	$ (1)
2016 [b]	23	18	3	1	1

(a) The amounts for Generation, ComEd, PECO, and BGE include $(4) million , $(2) million , $(1) million , and $(1) million , respectively, for amounts billed by BSC through intercompany allocations for the year ended December 31, 2017 .
(b) The amounts above for Generation, ComEd, PECO and BGE include $7 million , $3 million , $1 million , and $1 million , respectively, for amounts billed by BSC through intercompany allocations for the year ended December 31, 2016 .

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Early Plant Retirement-Related Severance (Exelon and Generation)

As a result of the Three Mile Island plant retirement decision, Exelon and Generation will incur certain employee-related costs, including severance benefit costs. Severance costs will be provided to management employees that are eligible under the Company's severance policy, to the extent that those employees are not redeployed to other locations. In June 2017, Exelon and Generation recognized severance costs of $17 million related to expected management employee severances resulting from the plant retirements within Operating and maintenance expense in their Consolidated Statements of Operation and Comprehensive Income. Approximately half of the employees at this location fall under a collective bargaining union agreement and are not eligible for severance benefits under an existing plan. The union and Exelon will negotiate terms of any severance benefits. If severance benefits are successfully negotiated, the amounts will be accrued as a one-time employee termination benefit once the established plan is communicated to employees. The final amount of the severance cost will ultimately depend on the specific employees severed. See Note 8 - Early Nuclear Plant Retirements for additional information regarding the announced early retirement of TMI. See Note 28 - Subsequent Events for additional information regarding the early retirement of Oyster Creek.

Severance Costs Related to the PHI Merger

Upon closing the PHI Merger, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. Cash payments under the plan began in May 2016 and will continue through 2020.

For the year ended December 31, 2017 , the PHI Merger severance costs were immaterial. For the year ended December 31, 2016 , the Registrants recorded the following severance costs associated with the identified job reductions within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Severance Benefits									
Severance costs [(a)]	$ 57	$ 9	$ 2	$ 1	$ 1	$ 44	$ 21	$ 13	$ 10

(a) The amounts above for Generation, ComEd, PECO, BGE, Pepco, DPL, and ACE include $8 million , $2 million , $1 million , $1 million , $20 million , $12 million and $10 million , respectively, for amounts billed by BSC and/or PHISCO through intercompany allocations for the year ended December 31, 2016 .

PHI, Pepco, DPL and ACE record regulatory assets for merger related integration costs which include a portion of the severance costs in the table above related to the PHI Merger. These regulatory assets are either currently being recovered in rates or are deemed probable of recovery in future rates. See Note 3 — Regulatory Matters for further information.

Severance Liability

Amounts included in the table below represent the severance liability recorded for employees of each Registrant and exclude amounts included at Exelon and billed through intercompany allocations:

						Successor			
Severance Liability	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2015	$ 35	$ 23	$ 3	$ —	$ 1	$ —	$ —	$ —	$ —
Severance charges [(a)]	99	22	2	—	—	56	1	1	—
Payments	(46)	(9)	(2)	—	(1)	(27)	(1)	(1)	—
Balance at December 31, 2016	$ 88	$ 36	$ 3	$ —	$ —	$ 29	$ —	$ —	$ —
Severance charges [(a)]	35	31	2	—	—	3	—	—	—
Payments	(29)	(9)	(2)	—	—	(12)	—	—	—
Balance at December 31, 2017	$ 94	$ 58	$ 3	$ —	$ —	$ 20	$ —	$ —	$ —

(a) Includes salary continuance and health and welfare severance benefits.

18 . Mezzanine Equity (Exelon, Generation and PHI)

Contingently Redeemable Noncontrolling Interests (Exelon and Generation)

In November 2015, 2015 ESA Investco, LLC, a wholly owned subsidiary of Generation, entered into an arrangement to sell a portion of its equity to a tax equity investor. Pursuant to the operating agreement, in certain circumstances the equity contributed by the noncontrolling interests holder could be contingently redeemable. These circumstances were outside of the control of Generation and the noncontrolling interests holder resulting in a portion of the noncontrolling interests being considered contingently redeemable and thus was presented in mezzanine equity on the consolidated balance sheet.

There were no changes in the contingently redeemable noncontrolling interests for the year ended December 31, 2017 . The following table summarizes the changes in the contingently redeemable noncontrolling interests for the year ended December 31, 2016 :

	Contingently Redeemable NCI
Balance at December 31, 2015	$ 28
Cash received from noncontrolling interests	129
Release of contingency	(157)
Balance at December 31, 2016	$ —

Preferred Stock (PHI)

In connection with the PHI Merger Agreement, Exelon purchased 18,000 originally issued shares of PHI preferred stock for a purchase price of $180 million . PHI excluded the preferred stock from equity at December 31, 2015 since the preferred stock contained conditions for redemption that were not solely within the control of PHI. Management determined that the preferred stock contained embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding preferred stock could be called and redeemed at a nominal par value upon a termination of the merger agreement under certain circumstances due to the failure to obtain required regulatory approvals. The embedded call and redemption features on the shares of the preferred stock in the event of such a termination were separately accounted for as derivatives. As of December 31, 2015, the fair

value of the derivative related to the preferred stock was estimated to be $18 million based on PHI's updated assessment and was included in current assets with a corresponding increase in preferred stock on the Consolidated Balance Sheet. Immediately prior to the merger date, PHI updated its assessment of the fair value of the derivative and reduced the fair value to zero, recording the $18 million decrease in fair value as a reduction of Other, net within PHI's predecessor period, January 1, 2016 to March 23, 2016 , Statements of Operations and Comprehensive Income.

On March 23, 2016 , the preferred stock was cancelled and the $180 million cash consideration previously received by PHI to issue the preferred stock was treated as additional merger purchase price consideration.

19 . Shareholders' Equity (Exelon, ComEd, PECO, BGE, Pepco, DPL and ACE)

The following table presents common stock authorized and outstanding as of December 31, 2017 and 2016 :

			December 31,	
			2017	2016
	Par Value	Shares Authorized	Shares Outstanding	
Common Stock				
Exelon	no par value	2,000,000,000	963,335,888	924,035,059
ComEd	$ 12.50	250,000,000	127,021,246	127,017,157
PECO	no par value	500,000,000	170,478,507	170,478,507
BGE	no par value	1,500	1,000	1,000
Pepco	$ 0.01	200,000,000	100	100
DPL	$ 2.25	1,000	1,000	1,000
ACE	$ 3.00	25,000,000	8,546,017	8,546,017

ComEd had 60,584 and 72,859 warrants outstanding to purchase ComEd common stock at December 31, 2017 and 2016 , respectively. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants. At December 31, 2017 and 2016 , 20,195 and 24,286 shares of common stock, respectively, were reserved for the conversion of warrants.

Equity Securities Offering

In June 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share. In connection with such offering, Exelon entered into forward sale agreements with two counterparties. In July 2015, Exelon settled the forward sale agreement by the issuance of 57.5 million shares of Exelon common stock. Exelon received net cash proceeds of $1.87 billion , which was calculated based on a forward price of $32.48 per share as specified in the forward sale agreements. The net proceeds were used to fund the merger with PHI and related costs and expenses, and for general corporate purposes. The forward sale agreements are classified as equity transactions. As a result, no amounts were recorded in the consolidated financial statements until the July 2015 settlement of the forward sale agreements. However, prior to the July 2015 settlement, incremental shares, if any, were included within the calculation of diluted EPS using the treasury stock method.

Concurrent with the forward equity transaction, Exelon also issued $1.15 billion of junior subordinated notes in the form of 23 million equity units. On June 1, 2017, Exelon settled the forward

purchase contract, which was a component of the June 2014 equity units, through the issuance of Exelon common stock from treasury stock. See Note 13 — Debt and Credit Agreements for further information on the equity units.

Share Repurchases

Share Repurchase Programs

There currently is no Exelon Board of Director authority to repurchase shares. Any previous shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon's management. Under the previous share repurchase programs, 2 million and 35 million shares of common stock were held as treasury stock with a historical cost of $123 million and $2.3 billion at December 31, 2017 and 2016 , respectively. During 2017 , Exelon issued approximately 33 million shares of Exelon common stock from treasury stock in order to settle the forward purchase contract, which was a component of the June 2014 equity units discussed above. During 2016 and 2015 , Exelon had no common stock repurchases.

Preferred and Preference Securities of Subsidiaries

At December 31, 2017 and 2016 , Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

At December 31, 2017 and 2016 , ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

BGE had $190 million of cumulative preference stock that was redeemable at its option at any time after October 1, 2015 for the redemption price of $100 per share, plus accrued and unpaid dividends. On July 3, 2016, BGE redeemed all 400,000 shares of its outstanding 7.125% Cumulative Preference Stock, 1993 Series and all 600,000 shares of its outstanding 6.990% Cumulative Preference Stock, 1995 Series for $100 million , plus accrued and unpaid dividends. On September 18, 2016, BGE redeemed the remaining 500,000 shares of its outstanding 6.970% Cumulative Preference Stock, 1993 Series and the remaining 400,000 shares of its outstanding 6.700% Cumulative Preference Stock, 1993 Series for $90 million , plus accrued and unpaid dividends.

20 . Stock-Based Compensation Plans (All Registrants)

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At December 31, 2017 , there were approximately 13 million shares authorized for issuance under the LTIP. For the years ended December 31, 2017 , 2016 and 2015 , exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

ComEd, PECO, BGE and PHI grant cash awards. The following tables do not include expense related to these plans as they are not considered stock-based compensation plans under the applicable authoritative guidance .

In connection with the acquisition of PHI in March 2016, PHI's unvested time-based restricted stock units and performance-based restricted stock units issued prior to April 29, 2014 were immediately vested and paid in cash upon the close of the merger. PHI's remaining unvested time-based restricted stock units as of the close of the merger were cancelled. There were no remaining unvested performance-based restricted stock units as of the close of the merger.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the years ended December 31, 2017 , 2016 and 2015 , there were no significant modifications to the granted stock based awards.

The following tables present the stock-based compensation expense included in Exelon's and PHI's Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2017 , 2016 and 2015 and PHI's predecessor periods January 1, 2016 to March 23, 2016 and the year ended December 31, 2015 :

Exelon

	Year Ended December 31,		
Components of Stock-Based Compensation Expense	2017	2016 (a)	2015
Performance share awards	$ 107	$ 93	$ 41
Restricted stock units	77	75	71
Stock options	—	—	1
Other stock-based awards	7	7	6
Total stock-based compensation expense included in operating and maintenance expense	191	175	119
Income tax benefit	(74)	(68)	(46)
Total after-tax stock-based compensation expense	$ 117	$ 107	$ 73

(a) 2016 amounts include expense related to stock-based compensation granted to eligible PHI employees since the merger date of March 23, 2016 .

PHI

	Predecessor	
	January 1 to March 23,	Year Ended December 31,
Components of Stock-Based Compensation Expense	2016	2015
Time-based restricted stock units	$ 2	$ 7
Performance-based restricted stock units	1	5
Time-based restricted stock awards	—	1
Total stock-based compensation expense included in operating and maintenance expense	3	13
Income tax benefit	(1)	(5)
Total after-tax stock-based compensation expense	$ 2	$ 8

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables present the Registrants' stock-based compensation expense (pre-tax) for the years ended December 31, 2017 , 2016 and 2015 , as well as for the PHI predecessor periods January 1, 2016 to March 23, 2016 and the year ended December 31, 2015 :

	Year Ended December 31,		
Subsidiaries	2017	2016	2015
Exelon	$ 191	$ 175	$ 119
Generation	88	78	64
ComEd	7	8	6
PECO	3	3	3
BGE	1	1	3
BSC [a]	88	81	43
PHI Successor [b][c]	4	4	—

	Predecessor	
	January 1 to March 23,	For the Year Ended December 31,
	2016	2015
PHI	$ 3	$ 13

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE or PHI amounts above.
(b) Pepco's, DPL's and ACE's stock-based compensation expense for the years ended December 31, 2017 and 2016 was not material.
(c) These amounts primarily represent amounts billed to PHI's subsidiaries through PHISCO intercompany allocations.

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2017 , 2016 and 2015 for Exelon or PHI, or for PHI during the predecessor period January 1, 2016 to March 23, 2016 .

Exelon and PHI receive a tax deduction based on the intrinsic value of the award on the exercise date for stock options and the distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon and PHI recognize the tax benefit related to compensation costs. The following tables present information regarding Exelon's and PHI's tax benefits for the years ended December 31, 2017 , 2016 and 2015 and PHI's predecessor periods January 1, 2016 to March 23, 2016 and the year ended December 31, 2015 :

Exelon

	Year Ended December 31,		
	2017	2016	2015
Realized tax benefit when exercised/distributed:			
Restricted stock units	35	27	30
Performance share awards	29	18	18

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI

	Predecessor	
	January 1 to March 23, 2016	For the Year Ended December 31, 2015
Realized tax benefit when exercised/distributed:		
Time-based restricted stock units	$ —	$ 2
Performance-based restricted stock units	—	5

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock were granted under the LTIP through 2012. Due to changes in the LTIP, there were no stock options granted in 2017, 2016 or 2015. For all stock options granted through 2012, the exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. The vesting period of stock options is generally four years and all stock options will expire no later than ten years from the date of grant.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years . However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

The following table presents information with respect to stock option activity for the year ended December 31, 2017 :

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2016	12,531,591	$ 46.23	3.50	$ 13
Options exercised	(3,093,156)	34.69		
Options forfeited	—	—		
Options expired	(2,714,824)	55.78		
Balance of shares outstanding at December 31, 2017	6,723,611	$ 47.69	2.65	$ 7
Exercisable at December 31, 2017 [(a)]	6,723,611	$ 47.69	2.65	$ 7

(a) Includes stock options issued to retirement eligible employees.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2017 , 2016 and 2015 :

	Year Ended December 31,		
	2017	2016	2015
Intrinsic value [a]	$ 15	$ 11	$ —
Cash received for exercise price	107	19	—

(a) The difference between the market value on the date of exercise and the option exercise price.

At December 31, 2016 , all stock options were vested and at December 31, 2017 there were no unrecognized compensation costs related to nonvested stock options.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years . However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon processes forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes Exelon's nonvested restricted stock unit activity for the year ended December 31, 2017 :

Exelon

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2016 [a][c]	3,824,416	$ 30.49
Granted	2,266,199	34.98
Vested	(1,736,965)	30.98
Forfeited	(92,938)	33.12
Undistributed vested awards [b]	(871,209)	34.09
Nonvested at December 31, 2017 [a]	3,389,503	$ 32.24

(a) Excludes 1,488,383 and 1,319,372 of restricted stock units issued to retirement-eligible employees as of December 31, 2017 and 2016 , respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2017 .
(c) 2016 amounts include activity related to stock-based compensation granted to eligible PHI employees since the merger date of March 23, 2016 .

For Exelon, the weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2017 , 2016 and 2015 was $34.98 , $28.14 and $36.55 , respectively. At December 31, 2017 and 2016 , Exelon had obligations related to outstanding restricted stock units not yet settled of $108 million and $101 million , respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. For the years ended December 31, 2017 , 2016 and 2015 , Exelon

settled restricted stock units with fair value totaling $88 million , $68 million and $75 million , respectively. At December 31, 2017 , $51 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 1.7 years.

For PHI, the weighted average grant date fair value (per share) of time-based restricted stock units granted for the year ended December 31, 2015 was $27.40 and for performance-based restricted stock units was $26.08 for the same period. For the year ended December 31, 2015 , PHI settled time-based restricted stock units with fair value totaling $6 million and settled performance-based restricted stock units with fair value totaling $15 million , for the same period. There were no settled restricted stock units for the predecessor period January 1, 2016 to March 23, 2016 .

Performance Share Awards

Performance share awards are granted under the LTIP. The performance share awards are settled 50% in common stock and 50% in cash at the end of the three-year performance period, except for awards granted to vice presidents and higher officers that are settled 100% in cash if certain ownership requirements are satisfied.

The common stock portion of the performance share awards is considered an equity award and is valued based on Exelon's stock price on the grant date. The cash portion of the performance share awards is considered a liability award which is remeasured each reporting period based on Exelon’s current stock price. As the value of the common stock and cash portions of the awards are based on Exelon’s stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

Effective January 2017 for nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the straight-line method. For performance share awards granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period, which is the year of grant.

In 2016 and prior, for nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share awards granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period, which is the year of grant.

Exelon processes forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2017 :

Exelon

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2016 [a][c]	3,116,261	$ 30.77
Granted	1,632,186	35.00
Change in performance	545,793	30.97
Vested	(1,111,751)	29.11
Forfeited	(18,034)	33.74
Undistributed vested awards [b]	(1,207,489)	33.46
Nonvested at December 31, 2017 [a]	2,956,966	$ 32.65

(a) Excludes 2,723,440 and 2,443,409 of performance share awards issued to retirement-eligible employees as of December 31, 2017 and 2016 , respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2017 .
(c) 2016 amounts include activity related to stock-based compensation granted to eligible PHI employees since the merger date of March 23, 2016.

The following table summarizes the weighted average grant date fair value and the fair value of performance share awards granted and settled for the years ended December 31, 2017 , 2016 and 2015 :

	Year Ended December 31,		
	2017 [a]	2016	2015
Weighted average grant date fair value (per share)	$ 35.00	$ 28.85	$ 35.88
Fair value of performance shares settled	72	45	46
Fair value of performance shares settled in cash	56	28	29

(a) As of December 31, 2017 , $41 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.5 years.

For PHI, the weighted average grant date fair value (per share) of performance-based restricted stock awards was $26.10 for the year ended December 31, 2015 . There were no time-based restricted stock awards granted for the year ended December 31, 2015 . There were no time-based share settlements or performance-based share settlements for the year-ended December 31, 2015 or the predecessor period January 1, 2016 to March 23, 2016 .

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31,	
	2017	2016
Current liabilities [(a)]	$ 57	$ 49
Deferred credits and other liabilities [(b)]	100	52
Common stock	26	40
Total	$ 183	$ 141

(a) Represents the current liability related to performance share awards expected to be settled in cash.
(b) Represents the long-term liability related to performance share awards expected to be settled in cash.

21 . Earnings Per Share (Exelon)

Basic earnings per share is computed by dividing net income attributable to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding, including the effect of issuing common stock assuming (i) stock options are exercised, and (ii) performance share awards and restricted stock awards are fully vested under the treasury stock method.

The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock awards on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Year Ended December 31,		
	2017	2016	2015
Net income attributable to common shareholders	$ 3,770	$ 1,134	$ 2,269
Weighted average common shares outstanding — basic	947	924	890
Assumed exercise and/or distributions of stock-based awards	2	3	3
Weighted average common shares outstanding — diluted	949	927	893

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 8 million in 2017 , 12 million in 2016 , and 16 million in 2015 . There were no equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the years ended December 31, 2017 and 2016 . The number of equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect was 3 million for the year ended 2015 . Refer to Note 19 — Shareholders' Equity for further information regarding the equity units and equity forward units.

On June 1, 2017, Exelon settled the forward purchase contract, which was a component of the June 2014 equity units, through the issuance of approximately 33 million shares of Exelon common stock from treasury stock. The issuance of shares on June 1, 2017 triggered full dilution in the EPS calculation, which prior to settlement were included in the calculation of diluted EPS using the treasury stock method. Refer to Note 19 — Shareholders' Equity for further information regarding share repurchases.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

22 . Changes in Accumulated Other Comprehensive Income (Exelon, Generation, PECO and PHI)

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the years ended December 31, 2017 and 2016 :

For the Year Ended December 31, 2017	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon [a]						
Beginning balance	$ (17)	$ 4	$ (2,610)	$ (30)	$ (7)	$ (2,660)
OCI before reclassifications	(1)	6	11	7	6	29
Amounts reclassified from AOCI [b]	4	—	140	—	—	144
Net current-period OCI	3	6	151	7	6	173
Ending balance	$ (14)	$ 10	$ (2,459)	$ (23)	$ (1)	$ (2,487)
Generation [a]						
Beginning balance	$ (19)	$ 2	$ —	$ (30)	$ (7)	$ (54)
OCI before reclassifications	(1)	1	—	7	6	13
Amounts reclassified from AOCI [b]	4	—	—	—	—	4
Net current-period OCI	3	1	—	7	6	17
Ending balance	$ (16)	$ 3	$ —	$ (23)	$ (1)	$ (37)
PECO [a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI [b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2016	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon [a]						
Beginning balance	$ (19)	$ 3	$ (2,565)	$ (40)	$ (3)	$ (2,624)
OCI before reclassifications	(6)	1	(182)	5	(4)	(186)
Amounts reclassified from AOCI [b]	8	—	137	5	—	150
Net current-period OCI	2	1	(45)	10	(4)	(36)
Ending balance	$ (17)	$ 4	$ (2,610)	$ (30)	$ (7)	$ (2,660)
Generation [a]						
Beginning balance	$ (21)	$ 1	$ —	$ (40)	$ (3)	$ (63)
OCI before reclassifications	(6)	1	—	5	(4)	(4)
Amounts reclassified from AOCI [b]	8	—	—	5	—	13
Net current-period OCI	2	1	—	10	(4)	9
Ending balance	$ (19)	$ 2	$ —	$ (30)	$ (7)	$ (54)
PECO [a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI [b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1
PHI Predecessor [a]						
Beginning balance January 1, 2016	$ (8)	$ —	$ (28)	$ —	$ —	$ (36)
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI [b]	—	—	1	—	—	1
Net current-period OCI	—	—	1	—	—	1
Ending balance March 23, 2016 [c]	$ (8)	$ —	$ (27)	$ —	$ —	$ (35)

(a) All amounts are net of tax and noncontrolling interests. Amounts in parenthesis represent a decrease in AOCI.
(b) See next tables for details about these reclassifications.
(c) As a result of the PHI Merger, the PHI predecessor balances at March 23, 2016 were reduced to zero on March 24, 2016 due to purchase accounting adjustments applied to PHI.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd, PECO, BGE, Pepco, DPL and ACE did not have any reclassifications out of AOCI to Net income during the years ended December 31, 2017 and 2016 . The following tables present amounts reclassified out of AOCI to Net income for Exelon, Generation and PHI during the years ended December 31, 2017 and 2016 :

For the Year Ended December 31, 2017

Details about AOCI components	Items reclassified out of AOCI [a]		Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	
Gains and (losses) on cash flow hedges			
Other cash flow hedges	$ (5)	$ (5)	Interest expense
Total before tax	(5)	(5)	
Tax benefit	1	1	
Net of tax	$ (4)	$ (4)	Comprehensive income
Amortization of pension and other postretirement benefit plan items			
Prior service costs [b]	$ 92	$ —	
Actuarial losses [b]	(324)	—	
Total before tax	(232)	—	
Tax benefit	92	—	
Net of tax	$ (140)	$ —	Comprehensive Income
Total Reclassifications	$ (144)	$ (4)	Comprehensive income

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2016

Details about AOCI components	Items reclassified out of AOCI [a]			Affected line item in the Statement of Operations and Comprehensive Income
			Predecessor	
			January 1, 2016 to March 23, 2016	
	Exelon	Generation	PHI	
Loss on cash flow hedges				
Other cash flow hedges	$ (13)	$ (13)	$ —	Interest expense
Total before tax	(13)	(13)	—	
Tax benefit	5	5	—	
Net of tax	$ (8)	$ (8)	$ —	Comprehensive income
Amortization of pension and other postretirement benefit plan items				
Prior service costs [b]	$ 78	$ —	$ —	
Actuarial losses [b]	(302)	—	(1)	
Total before tax	(224)	—	(1)	
Tax benefit	87	—	—	
Net of tax	$ (137)	$ —	$ (1)	Comprehensive Income
Losses on foreign currency translation				
Loss	$ (5)	$ (5)	$ —	Other income and (deductions)
Total before tax	(5)	(5)	—	
Tax benefit	—	—	—	
Net of tax	$ (5)	$ (5)	$ —	
Total Reclassifications	$ (150)	$ (13)	$ (1)	Comprehensive income

(a) Amounts in parenthesis represent a decrease in net income.
(b) This AOCI component is included in the computation of net periodic pension and OPEB cost (see Note 16 — Retirement Benefits for additional details).

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the years ended December 31, 2017 and 2016 :

	For the Year Ended December 31,		
	2017	2016	2015
Exelon			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	$ 36	$ 30	$ 30
Actuarial loss reclassified to periodic benefit cost	(128)	(118)	(140)
Pension and non-pension postretirement benefit plans valuation adjustment	13	115	62
Change in unrealized loss on cash flow hedges	(7)	—	(6)
Change in unrealized (loss)/gain on equity investments	(3)	3	1
Change in unrealized loss on marketable securities	(1)	—	—
Total	$ (90)	$ 30	$ (53)

Generation			
Change in unrealized (loss)/gain on cash flow hedges	$ (6)	$ (2)	$ 2
Change in unrealized (loss)/gain on equity investments	(3)	3	1
Change in unrealized loss marketable securities	(1)	—	—
Total	$ (10)	$ 1	$ 3

	Predecessor	
	January 1 to March 23,	For the Year Ended December 31,
PHI	2016	2015
Pension and non-pension postretirement benefit plans:		
Actuarial loss reclassified to periodic cost	$ —	$ 6

23 . Commitments and Contingencies (All Registrants)

Commitments

Constellation Merger Commitments

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion .

The direct investment includes the construction of a new 21-story headquarters building in Baltimore for Generation's competitive energy business that was substantially complete in November 2016 and is now occupied by approximately 1,500 Exelon employees. Generation's investment includes leasehold improvements that are not expected to exceed $110 million . In addition, Generation entered into a 20 -year operating lease as the primary lessee of the building.

The direct investment commitment also includes $450 million to $500 million relating to Exelon and Generation's development or assistance in the development of 285 - 300 MWs of new generation

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in Maryland, which is expected to be completed within a period of 10 years. The MDPSC order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed or certain specified provisions are elected, making liquidated damages payments. Exelon and Generation have incurred $457 million towards satisfying the commitment for new generation development in the state of Maryland, with approximately 220 MW of the new generation commencing with commercial operations to date and an additional 10 MW commitment satisfied through a liquidated damages payment made in the fourth quarter of 2016. Additionally, during the fourth quarter of 2016, given continued declines in projected energy and capacity prices, Generation terminated rights to certain development projects originally intended to meet its remaining 55 MW commitment amount. The commitment will now most likely be satisfied via payment of liquidated damages or execution of a third party PPA, rather than by Generation constructing renewable generating assets. As a result, Exelon and Generation recorded a pre-tax $50 million loss contingency in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016.

Commercial Commitments

Exelon's commercial commitments as of December 31, 2017 , representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2018	2019	2020	2021	2022	2023 and beyond
Letters of credit (non-debt) [a]	$ 1,226	$ 1,056	$ 154	$ 16	$ —	$ —	$ —
Surety bonds [b]	1,381	1,293	66	16	6	—	—
Financing trust guarantees	378	—	—	—	—	—	378
Guaranteed lease residual values [c]	21	—	—	—	—	—	21
Total commercial commitments	$ 3,006	$ 2,349	$ 220	$ 32	$ 6	$ —	$ 399

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(c) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $56 million , $16 million of which is a guarantee by Pepco, $23 million by DPL and $15 million by ACE. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Generation's commercial commitments as of December 31, 2017 , representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2018	2019	2020	2021	2022	2023 and beyond
Letters of credit (non-debt) [a]	$ 1,177	$ 1,007	$ 154	$ 16	$ —	$ —	$ —
Surety bonds	1,209	1,164	45	—	—	—	—
Total commercial commitments	$ 2,386	$ 2,171	$ 199	$ 16	$ —	$ —	$ —

(a) Letters of credit (non-debt)—Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.

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ComEd's commercial commitments as of December 31, 2017 , representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2018	2019	2020	2021	2022	2023 and beyond
Letters of credit (non-debt) [a]	$ 2	$ 2	$ —	$ —	$ —	$ —	$ —
Surety bonds [b]	10	8	2	—	—	—	—
Financing trust guarantees	200	—	—	—	—	—	200
Total commercial commitments	$ 212	$ 10	$ 2	$ —	$ —	$ —	$ 200

(a) Letters of credit (non-debt)—ComEd maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

PECO's commercial commitments as of December 31, 2017 , representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2018	2019	2020	2021	2022	2023 and beyond
Surety bonds [a]	$ 9	$ 8	$ 1	$ —	$ —	$ —	$ —
Financing trust guarantees	178	—	—	—	—	—	178
Total commercial commitments	$ 187	$ 8	$ 1	$ —	$ —	$ —	$ 178

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

BGE's commercial commitments as of December 31, 2017 , representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2018	2019	2020	2021	2022	2023 and beyond
Letters of credit (non-debt) [a]	$ 2	$ 2	$ —	$ —	$ —	$ —	$ —
Surety bonds [b]	11	10	1	—	—	—	—
Total commercial commitments	$ 13	$ 12	$ 1	$ —	$ —	$ —	$ —

(a) Letters of credit (non-debt)—BGE maintains non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

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PHI commercial commitments (Successor) as of December 31, 2017 , representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2018	2019	2020	2021	2022	2023 and beyond
Surety bonds	$ 63	$ 48	$ 15	$ —	$ —	$ —	$ —
Guaranteed lease residual values [a]	21	—	—	—	—	—	21
Total commercial commitments	$ 84	$ 48	$ 15	$ —	$ —	$ —	$ 21

(a) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $56 million . The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Pepco commercial commitments as of December 31, 2017 , representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2018	2019	2020	2021	2022	2023 and beyond
Surety bonds [a]	$ 54	$ 41	$ 13	$ —	$ —	$ —	$ —
Guaranteed lease residual values [b]	6	—	—	—	—	—	6
Total commercial commitments	$ 60	$ 41	$ 13	$ —	$ —	$ —	$ 6

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $16 million . The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

DPL commercial commitments as of December 31, 2017 , representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2018	2019	2020	2021	2022	2023 and beyond
Surety bonds [a]	$ 4	$ 3	$ 1	$ —	$ —	$ —	$ —
Guaranteed lease residual values [b]	8	—	—	—	—	—	8
Total commercial commitments	$ 12	$ 3	$ 1	$ —	$ —	$ —	$ 8

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $23 million . The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

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ACE commercial commitments as of December 31, 2017 , representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2018	2019	2020	2021	2022	2023 and beyond
Surety bonds	$ 4	$ 3	$ 1	$ —	$ —	$ —	$ —
Guaranteed lease residual values [a]	6	—	—	—	—	—	6
Total commercial commitments	$ 10	$ 3	$ 1	$ —	$ —	$ —	$ 6

(a) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $15 million . The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Leases

Minimum future operating lease payments, including lease payments for contracted generation, vehicles, real estate, computers, rail cars, operating equipment and office equipment, as of December 31, 2017 were:

						Successor			
	Exelon (a)	Generation (a)	ComEd (a)(c)	PECO (a)(c)	BGE (a)(c)(d)(e)	PHI (a)	Pepco (a)	DPL (a)(c)	ACE (a)
2018	$ 188	$ 74	$ 7	$ 5	$ 34	$ 56	$ 8	$ 20	$ 9
2019	129	29	6	5	34	42	7	10	8
2020	147	47	4	5	34	44	6	13	8
2021	142	48	4	5	32	40	5	12	7
2022	119	46	2	5	17	39	4	12	6
Remaining years	787	573	—	—	19	194	8	54	19
Total minimum future lease payments	$ 1,512	$ 817	$ 23	$ 25	$ 170	$ 415	$ 38	$ 121	$ 57

(a) Includes amounts related to shared use land arrangements.
(b) Excludes Generation's contingent operating lease payments associated with contracted generation agreements.
(c) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, ComEd, PECO, BGE and DPL have excluded these payments from the remaining years as such amounts would not be meaningful. ComEd's, PECO's, BGE's and DPL's average annual obligation for these arrangements, included in each of the years 2018—2022, was $2 million , $5 million , $1 million and $2 million , respectively. Also includes amounts related to shared use land arrangements.
(d) Includes all future lease payments on a 99 -year real estate lease that expires in 2106 .
(e) The BGE column above includes minimum future lease payments associated with a 6-year lease for the Baltimore City conduit system that became effective during the fourth quarter of 2016. BGE's total commitments under the lease agreement are $25 million , $26 million , $28 million , $28 million and $14 million related to years 2018, 2019, 2020, 2021and 2022, respectively.

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The following table presents the Registrants' rental expense under operating leases for the years ended December 31, 2017, 2016 and 2015:

For the Year Ended December 31,	Exelon	Generation [a]	ComEd	PECO	BGE	Pepco	DPL	ACE
2017	$ 709	$ 578	$ 9	$ 9	$ 32	$ 11	$ 16	$ 14
2016	777	667	15	7	22	8	15	13
2015	922	851	12	9	32	7	14	13

	Successor		*Predecessor*	
	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015
PHI				
Rental expense under operating leases	$ 63	$ 49	$ 12	$ 60

(a) Includes contingent operating lease payments associated with contracted generation agreements that are not included in the minimum future operating lease payments table above. Payments made under Generation's contracted generation lease agreements totaled $508 million , $604 million and $798 million during 2017 , 2016 and 2015 , respectively. Excludes contract amortization associated with purchase accounting and contract acquisitions.

For information regarding capital lease obligations, see Note 13 —Debt and Credit Agreements.

Nuclear Insurance

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations. Generation has mitigated its financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2017 , the current liability limit per incident is $13.4 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors at least once every five years with the last adjustment effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. Effective January 1, 2017, the required amount of nuclear energy liability insurance purchased is $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool, as required by the Price Anderson-Act, which provides the additional $13.0 billion per incident in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Exelon's share of this secondary layer would be approximately $2.8 billion , however any amounts payable under this secondary layer would be capped at $420 million per year.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.4 billion limit for a single incident.

As part of the execution of the NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this

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indemnity. See Note 2 — Variable Interest Entities for additional information on Generation's operations relating to CENG.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. Generation's portion of the distribution declared by NEIL is estimated to be $60 million for 2017, and was $21 million for 2016 and 2015. The distributions were recorded as a reduction to Operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

Premiums paid to NEIL by its members are also subject to a potential assessment for adverse loss experience in the form of a retrospective premium obligation. NEIL has never assessed this retrospective premium since its formation in 1973, and Generation cannot predict the level of future assessments if any. The current maximum aggregate annual retrospective premium obligation for Generation is approximately $360 million . NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery by Exelon will be an aggregate of $ 3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon's and Generation's financial conditions, results of operations and cash flows.

Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation historically had paid the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. On November 19, 2013, the D.C. Circuit Court ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On May 9, 2014, the DOE notified Generation that the SNF disposal fee remained in effect through May 15, 2014, after which time the fee was set to zero. As a result, for the year ended December 31, 2017 , 2016 and 2015 , Generation did not incur any expense in SNF disposal fees. Until a new fee structure is in effect,

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Exelon and Generation will not accrue any further costs related to SNF disposal fees. This fee may be adjusted prospectively to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance has been, and is expected to be, delayed significantly.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama Administration devised a new strategy for long-term SNF management. The Blue Ribbon Commission (BRC) on America's Nuclear Future, appointed by the U.S. Energy Secretary, released a report on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's SNF and high-level radioactive waste.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that was planned to be operational in 2025. However, due to continued delays on the part of the DOE, Generation currently assumes the DOE will begin accepting SNF in 2030 and uses that date for purposes of estimating the nuclear decommissioning asset retirement obligations. The SNF acceptance date assumption is based on management's estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage.

In August 2004, Generation and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation, subject to certain damage limitations based on the extent of the government's breach, for costs associated with storage of SNF at Generation's nuclear stations pending the DOE's fulfillment of its obligations. Generation's settlement agreement does not include FitzPatrick and FitzPatrick does not currently have a settlement agreement in place. Calvert Cliffs, Ginna and Nine Mile Point each have separate settlement agreements in place with the DOE which were extended during 2017 to provide for the reimbursement of SNF storage costs through December 31, 2019. Generation submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

Under the settlement agreements, Generation has received cumulative cash reimbursements for costs incurred as follows:

	Total	Net [a]
Cumulative cash reimbursements [b]	$ 1,167	$ 1,006

(a) Total after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek.
(b) Includes $53 and $49 , respectively, for amounts received since April 1, 2014, for costs incurred under the CENG DOE Settlement Agreements prior to the consolidation of CENG.

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As of December 31, 2017 and 2016, the amount of SNF storage costs for which reimbursement has been or will be requested from the DOE under the DOE settlement agreements is as follows:

	December 31, 2017	December 31, 2016
DOE receivable - current [(a)]	$ 94	$ 109
DOE receivable - noncurrent [(b)]	15	15
Amounts owed to co-owners [(a)(c)]	(11)	(13)

(a) Recorded in Accounts receivable, other.
(b) Recorded in Deferred debits and other assets, other
(c) Non-CENG amounts owed to co-owners are recorded in Accounts receivable, other. CENG amounts owed to co-owners are recorded in Accounts payable. Represents amounts owed to the co-owners of Peach Bottom, Quad Cities, and Nine Mile Point Unit 2 generating facilities.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. The unfunded liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of Exelon's 2001 corporate restructuring. A prior owner of FitzPatrick also elected to defer payment of the one-time fee of $34 million for the FitzPatrick unit. As part of the FitzPatrick acquisition on March 31, 2017, Generation assumed a SNF liability for the DOE one-time fee obligation with interest related to FitzPatrick along with an offsetting asset for the contractual right to reimbursement from NYPA, a prior owner of FitzPatrick, for amounts paid for the FitzPatrick DOE one-time fee obligation. The amounts were recorded at fair value. See Note 4 - Mergers, Acquisitions and Dispositions for additional information on the FitzPatrick acquisition. As of December 31, 2017 and 2016 , the SNF liability for the one-time fee with interest was $1,147 million and $1,024 million , respectively, which is included in Exelon's and Generation's Consolidated Balance Sheets. Interest for Exelon's and Generation's SNF liabilities accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2017, was 1.149% . The outstanding one-time fee obligations for the Nine Mile Point, Ginna, Oyster Creek and TMI units remain with the former owners. The Clinton and Calvert Cliffs units have no outstanding obligation. See Note 11 — Fair Value of Financial Assets and Liabilities for additional information.

Environmental Remediation Matters

General. The Registrants' operations have in the past, and may in the future, require substantial expenditures to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, the Registrants cannot reasonably estimate whether they will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers. Additional costs could have a material, unfavorable impact on the Registrants' financial conditions, results of operations and cash flows.

MGP Sites

ComEd, PECO, BGE and DPL have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has identified 42 sites, 19 of which have been remediated and approved by the Illinois EPA or the U.S. EPA and 23 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2022.

- PECO has identified 26 sites, 17 of which have been remediated in accordance with applicable PA DEP regulatory requirements and 9 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2022.

- BGE has identified 13 former gas manufacturing or purification sites, 11 of which the remediation has been completed and approved by the MDE and 2 that require some level of remediation and/or ongoing monitoring. BGE has determined that a loss associated with these sites is probable and has recorded an estimated liability, which is included in the table below. However, it is reasonably possible that BGE's cost of remediation for one of its sites could be up to $13 million .

- DPL has identified 3 sites, 2 of which remediation has been completed and approved by the MDE or the Delaware Department of Natural Resources and Environmental Control. The remaining site is under study and the required cost at the site is not expected to be material.

The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, including probabilistic and deterministic modeling for ComEd and PECO, and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. See Note 3 — Regulatory Matters for additional information regarding the associated regulatory assets. While BGE and DPL do not have riders for MGP clean-up costs, they have historically received recovery of actual clean-up costs in distribution rates.

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As of December 31, 2017 and 2016 , the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

December 31, 2017	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 466	$ 315
Generation	117	—
ComEd	285	283
PECO	30	28
BGE	5	4
PHI	29	—
Pepco	27	—
DPL	1	—
ACE	1	—

December 31, 2016	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 429	$ 325
Generation	72	—
ComEd	292	291
PECO	33	31
BGE	2	2
PHI	30	1
Pepco	27	—
DPL	2	1
ACE	1	—

During the third quarter of 2017, ComEd, PECO, BGE and DPL completed an annual study of their future estimated MGP remediation requirements. The study resulted in a $13 million and $2 million increase to environmental liabilities and related regulatory assets for ComEd and PECO, respectively, and no change at BGE and DPL.

Solid and Hazardous Waste

Cotter Corporation. The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the EPA issued a Record of Decision (ROD) approving a landfill cover remediation approach. By letter dated January 11, 2010, the EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the supplemental feasibility study to the EPA for review. Since June 2012, the EPA has requested that the PRPs perform a series of additional analyses and groundwater and soil sampling as part of the supplemental feasibility study. This further analysis was focused on a partial excavation remedial option. The PRPs provided the draft final Remedial Investigation and Feasibility Study (RI/FS) to the EPA in January 2018, which formed the basis for EPA's proposed remedy selection, as further discussed below. There are currently three PRPs

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participating in the West Lake Landfill remediation proceeding. Investigation by Generation has identified a number of other parties who also may be PRPs and could be liable to contribute to the final remedy. Further investigation is ongoing. As of December 31, 2016, Generation had previously recorded an estimated liability for its anticipated share of a landfill cover remedy, which at the time was estimated to cost approximately $90 million in total.

On February 1, 2018, the EPA announced its proposed remedy involving partial excavation of the site with an enhanced landfill cover. The proposed remedy will be open for public comment through March 22, 2018 and Generation currently expects that a ROD will be issued during the third quarter of 2018. Thereafter, the EPA will seek to enter into a Consent Decree with the PRPs to effectuate the remedy, which Generation currently expects will occur in late 2018 or early 2019. The estimated cost of the remedy, taking into account the current EPA technical requirements and the total costs expected to be incurred by the PRPs in fully executing the remedy, is approximately $340 million , including cost escalation on an undiscounted basis, which would be allocated among the final group of PRPs. Generation has determined that a loss associated with the EPA's partial excavation and enhanced landfill cover remedy is probable and has recorded a liability as of December 31, 2017, included in the table above, that reflects management's best estimate of Cotter's allocable share of the ultimate cost for the entire remediation effort. Given the joint and several nature of this liability, the magnitude of Generation's ultimate liability will depend on the actual costs incurred to implement the ultimate required remediation remedy as well as on the nature and terms of any cost-sharing arrangements with the final group of PRPs. Therefore, it is reasonably possible that the ultimate cost and Generation's associated allocable share recorded as of December 31, 2017, could differ significantly once these uncertainties are resolved, which could have a material impact on Exelon's and Generation's future financial conditions, results of operations and cash flows.

On January 16, 2018, the PRPs were advised by the EPA that it will begin an additional investigation and evaluation of groundwater conditions at the West Lake Landfill. The PRPs have been provided with a draft statement of work that will form the basis of an Administrative Settlement Agreement and Order on Consent for the performance by the PRPs of the groundwater RI/FS and reimbursement of EPA's oversight costs. The purposes of this new RI/FS are to define the nature and extent of any groundwater contamination from the West Lake Landfill site, determine the potential risk posed to human health and the environment, and evaluate remedial alternatives. Generation estimates the undiscounted cost for the groundwater RI/FS for West Lake to be approximately $20 million and Generation has recorded a liability as of December 31, 2017, included in the table above, that reflects management's best estimate of Cotter's allocable share of the cost among the PRPs. At this time Generation cannot predict the likelihood or the extent to which, if any, remediation activities will be required and cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Generation's future results of operations and cash flows.

During December 2015, the EPA took two actions related to the West Lake Landfill designed to abate what it termed as imminent and dangerous conditions at the landfill. The first involved installation by the PRPs of a non-combustible surface cover to protect against surface fires in areas where radiological materials are believed to have been disposed. Generation has accrued what it believes to be an adequate amount to cover its anticipated liability for this interim action, and the work is expected to be completed in 2018. The second action involved EPA's public statement that it will require the PRPs to construct a barrier wall in an adjacent landfill to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Generation believes that the requirement to build a barrier wall is remote in light of other technologies that have been employed by the adjacent landfill owner. Finally, one of the other PRPs, the landfill owner and operator of the adjacent landfill, has indicated that it will be making a contribution claim against Cotter for costs that it has incurred to prevent the subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Exelon

and Generation do not possess sufficient information to assess this claim and therefore are unable to estimate a range of loss, if any. As such, no liability has been recorded for the potential contribution claim. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon's and Generation's financial conditions, results of operations and cash flows.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. Government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under FUSRAP. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million from all PRPs. The DOJ and the PRPs agreed to toll the statute of limitations until August 2018 so that settlement discussions could proceed. Generation has determined that a loss associated with this matter is probable under its indemnification agreement with Cotter and has recorded an estimated liability, which is included in the table above.

Commencing in February 2012, a number of lawsuits have been filed in the U.S. District Court for the Eastern District of Missouri. Among the defendants were Exelon, Generation and ComEd, all of which were subsequently dismissed from the case, as well as Cotter, which remains a defendant. The suits allege that individuals living in the North St. Louis area developed some form of cancer or other serious illness due to Cotter's negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs are asserting public liability claims under the Price-Anderson Act. Their state law claims for negligence, strict liability, emotional distress, and medical monitoring have been dismissed. The complaints do not contain specific damage claims. In the event of a finding of liability against Cotter, it is reasonably possible that Generation would be financially responsible due to its indemnification responsibilities of Cotter described above. The court has dismissed a number of the lawsuits as untimely, and that ruling is currently on appeal. Pre-trial motions and discovery are proceeding in the remaining cases and a pre-trial scheduling order has been filed with the court. At this stage of the litigation, Generation cannot estimate a range of loss, if any. As such, no liability has been recorded for these lawsuits.

Benning Road Site. In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility. That generating facility was deactivated in June 2012 and plant structure demolition was completed in July 2015. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a Consent Decree entered into by Pepco and Pepco Energy Services with the DOEE, which requires Pepco and Pepco Energy Services to conduct a Remediation Investigation (RI)/ Feasibility Study (FS) for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River. The RI/FS will form the basis for the remedial actions for the Benning Road site and for the Anacostia River sediment associated with the site. The Consent Decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DOEE will look to Pepco and Pepco Energy Services to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site. Pursuant to Exelon's March 23, 2016 acquisition of PHI, Pepco Energy Services was transferred to Generation.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Since 2013, Pepco and Pepco Energy Services (now Generation) have been performing RI work and have submitted multiple draft RI reports to the DOEE. Once the RI work is completed, Pepco and Generation will issue a draft "final" RI report for review and comment by DOEE and the public. Pepco and Generation will then proceed to develop an FS to evaluate possible remedial alternatives for submission to DOEE. The Court has established a schedule for completion of the RI and FS, and approval by the DOEE, by May 6, 2019.

Upon DOEE's approval of the final RI and FS Reports, Pepco and Generation will have satisfied their obligations under the Consent Decree. At that point, DOEE will prepare a Proposed Plan regarding further response actions. After considering public comment on the Proposed Plan, DOEE will issue a Record of Decision identifying any further response actions determined to be necessary.

PHI, Pepco and Generation have determined that a loss associated with this matter is probable and have accrued an estimated liability, which is included in the table above.

Anacostia River Tidal Reach . Contemporaneous with the Benning RI/FS being performed by Pepco and Generation, DOEE and certain federal agencies have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-D.C. boundary line to the confluence of the Anacostia and Potomac Rivers. In March 2016, DOEE released a draft of the river-wide RI Report for public review and comment. The river-wide RI incorporated the results of the river sampling performed by Pepco and Pepco Energy Services as part of the Benning RI/FS, as well as similar sampling efforts conducted by owners of other sites adjacent to this segment of the river and supplemental river sampling conducted by DOEE's contractor. DOEE asked Pepco, along with parties responsible for other sites along the river, to participate in a "Consultative Working Group" to provide input into the process for future remedial actions addressing the entire tidal reach of the river and to ensure proper coordination with the other river cleanup efforts currently underway, including cleanup of the river segment adjacent to the Benning Road site resulting from the Benning RI/FS. Pepco responded that it will participate in the Consultative Working Group but its participation is not an acceptance of any financial responsibility beyond the work that will be performed at the Benning Road site described above. DOEE has advised the Consultative Working Group that the federal and DOEE authorities are conducting the remedial investigation and that a feasibility study of potential remedies is being prepared. DOEE currently is working under a statutorily mandated date to complete the Record of Decision selecting the final remedy for the project by June 30, 2018. However, on January 11, 2018 the DOEE requested at a hearing of the District of Columbia Council Committee of the Environment that this statutory deadline be extended until December 31, 2019 to reflect the time necessary to complete the investigation. A recommendation by the Committee to the DC Council is expected in the near future. The District of Columbia Council will make the final determination to extend the deadline. An appropriate liability for Pepco's share of investigation costs has been accrued and is included in the table above. Although Pepco has determined that it is probable that costs for remediation will be incurred , Pepco cannot estimate the reasonably possible range of loss at this time and no liability has been accrued for those future costs.

Conectiv Energy Wholesale Power Generation Sites. In July 2010, PHI sold the wholesale power generation business of Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries (Conectiv Energy) to Calpine Corporation (Calpine). Under New Jersey's Industrial Site Recovery Act (ISRA), the transfer of ownership triggered an obligation on the part of Conectiv Energy to remediate any environmental contamination at each of the nine Conectiv Energy generating facility sites located in New Jersey. Under the terms of the sale, Calpine has assumed responsibility for performing the ISRA-required remediation and for the payment of all related ISRA compliance costs up to $10 million . Predecessor PHI was obligated to indemnify Calpine for any ISRA compliance remediation costs in excess of $10 million . According to PHI's estimates, the costs of ISRA-required remediation activities at the nine generating facility sites located in New Jersey are in the range of approximately $7 million to $18 million , and predecessor PHI recorded an estimated liability for its share of the estimated clean-up costs. Pursuant

to Exelon's March 2016 acquisition of PHI, the Conectiv Energy legal entity was transferred to Generation and the liability for Predecessor PHI's share of the estimated clean- up costs was also transferred to Generation and is included in the table above as a liability of Generation. The responsibility to indemnify Calpine is shared by PHI and Generation.

Brandywine Fly Ash Disposal Site. In February 2013, Pepco received a letter from the MDE requesting that Pepco investigate the extent of waste on a Pepco right-of-way that traverses the Brandywine fly ash disposal site in Brandywine, Prince George's County, Maryland, owned by NRG Energy, Inc. (as successor to GenOn MD Ash Management, LLC) (NRG). In July 2013, while reserving its rights and related defenses under a 2000 agreement covering the sale of this site, Pepco indicated its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way. Pepco submitted a schedule for development of a closure plan to MDE on September 30, 2013 and, by letter dated October 18, 2013, MDE approved the schedule.

Pepco has determined that a loss associated with this matter is probable and has recorded an estimated liability, which is included in the table above. Pepco believes that the costs incurred in this matter may be recoverable from NRG under the 2000 sale agreement, but has not recorded an associated receivable for any potential recovery.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims

Exelon and Generation. Generation maintains estimated liabilities for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The estimated liabilities are recorded on an undiscounted basis and exclude the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2017 and 2016 , Generation had recorded estimated liabilities of approximately $78 million and $83 million , respectively, in total for asbestos-related bodily injury claims. As of December 31, 2017 , approximately $21 million of this amount related to 230 open claims presented to Generation, while the remaining $57 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether adjustments to the estimated liabilities are necessary.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee's disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee's last employment-based exposure, and that therefore the exclusivity provision of the Act does not preclude such employee from suing his or her employer in court. The Supreme Court's ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee's last employment-based exposure to asbestos. Since the Pennsylvania Supreme Court's ruling in November 2013, Exelon, Generation, and PECO have experienced an increase in asbestos-related personal injury claims brought by former PECO employees, all of which have been accrued for on a claim by claim basis. Those additional claims are taken into account in projecting estimated future asbestos-related bodily injury claims.

On November 4, 2015, the Illinois Supreme Court found that the provisions of the Illinois' Workers' Compensation Act and the Workers' Occupational Diseases Act barred an employee from bringing a

direct civil action against an employer for latent diseases, including asbestos-related diseases that fall outside the 25-year limit of the statute of repose. The Illinois Supreme Court's ruling reversed previous rulings by the Illinois Court of Appeals, which initially ruled that the Illinois Worker's Compensation law should not apply in cases where the diagnosis of an asbestos related disease occurred after the 25-year maximum time period for filing a Worker's Compensation claim. As a result of this ruling, Exelon, Generation, and ComEd have not recorded an increase to the asbestos-related bodily injury liability as of December 31, 2017 .

There is a reasonable possibility that Exelon may have additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued and the increases could have a material unfavorable impact on Exelon's, Generation's and PECO's financial conditions, results of operations and cash flows.

Fund Transfer Restrictions (Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE)

Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." What constitutes "funds properly included in capital account" is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as: (1) the source of the dividends is clearly disclosed; (2) the dividend is not excessive; and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon's actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. On May 1, 2013, PECO redeemed all outstanding preferred securities. As a result, the above ratio calculation is no longer applicable. Additionally, PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally,

BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid.

Pepco is subject to certain dividend restrictions established by settlements approved in Maryland and the District of Columbia. Pepco is prohibited from paying a dividend on its common shares if (a) after the dividend payment, Pepco's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the commissions and the Board or (b) Pepco's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade.

DPL is subject to certain dividend restrictions established by settlements approved in Delaware and Maryland. DPL is prohibited from paying a dividend on its common shares if (a) after the dividend payment, DPL's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the commissions and the Board or (b) DPL's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade.

ACE is subject to certain dividend restrictions established by settlements approved in New Jersey. ACE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, ACE's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the commissions and the Board or (b) ACE's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade.

Conduit Lease with City of Baltimore

On September 23, 2015, the Baltimore City Board of Estimates approved an increase in annual rental fees for access to the Baltimore City underground conduit system effective November 1, 2015, from $12 million to $42 million , subject to an annual increase thereafter based on the Consumer Price Index. BGE subsequently entered into litigation with the City regarding the amount of and basis for establishing the conduit fee. On November 30, 2016, the Baltimore City Board of Estimates approved a settlement agreement entered into between BGE and the City to resolve the disputes and pending litigation related to BGE's use of and payment for the underground conduit system. As a result of the settlement, the parties have entered into a six-year lease that reduces the annual expense to $25 million in the first three years and caps the annual expense in the last three years to not more than $29 million . BGE recorded a decrease to Operating and maintenance expense in the fourth quarter of 2016 of approximately $28 million for the reversal of the previously higher fees accrued as well as the settlement of prior year disputed fee true-up amounts.

Deere Wind Energy Assets

In 2013, Deere & Company (Deere) filed a lawsuit against Generation in the Delaware Superior Court relating to Generation's acquisition of the Deere wind energy assets. Under the purchase agreement, Deere was entitled to receive earn-out payments if certain specific wind projects already under development in Michigan met certain development and construction milestones following the sale. In the complaint, Deere sought to recover a $ 14 million earn-out payment associated with one such project, which was never completed. On June 2, 2016, the Delaware Superior Court entered summary judgment in favor of Deere. As a result, in the second quarter of 2016, Generation increased its accrued liability to $14 million . On January 17, 2017, Generation filed an appeal with the Delaware Supreme Court. On December 18, 2017, the Delaware Supreme Court reversed the Superior Court decision and entered final judgment in favor of Generation. As a result, in the fourth quarter of 2017, Generation reversed its previously established liability of $14 million .

City of Everett Tax Increment Financing Agreement (Exelon)

On April 10, 2017, the City of Everett petitioned the Massachusetts Economic Assistance Coordinating Council (EACC) to revoke the 1999 tax increment financing agreement (TIF Agreement)

relating to Mystic 8 & 9 on the grounds that the total investment in Mystic 8 & 9 materially deviates from the investment set forth in the TIF Agreement. On October 31, 2017, a three-member panel of the EACC conducted an administrative hearing on the City's petition. On November 30, 2017, the hearing panel issued a tentative decision denying the City's petition, finding that there was no material misrepresentation that would justify revocation of the TIF Agreement. On December 13, 2017, the tentative decision was adopted by the full EACC. On January 12, 2018, the City filed a complaint in Massachusetts Superior Court requesting, among other things, that the court set aside the EACC's decision, grant the City's request to decertify the Project and the TIF Agreement, and award the City damages for alleged underpaid taxes over the period of the TIF Agreement. Generation vigorously contested the City's claims before the EACC and will continue to do so in the Massachusetts Superior Court proceeding. Generation continues to believe that the City's claim lacks merit. Accordingly, Generation has not recorded a liability for payment resulting from such a revocation, nor can Generation estimate a reasonably possible range of loss, if any, associated with any such revocation. Further, it is reasonably possible that property taxes assessed in future periods, including those following the expiration of the current TIF Agreement in 2019, could be material to Generation's results of operations and cash flows.

General

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Income Taxes

See Note 14 — Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil-generating assets.

24 . Supplemental Financial Information (All Registrants)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2017 , 2016 and 2015 .

	For the year ended December 31, 2017								
						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Taxes other than income									
Utility [a]	$ 898	$ 126	$ 240	$ 125	$ 89	$ 318	$ 300	$ 18	$ —
Property	545	269	28	14	132	101	62	32	3
Payroll	230	121	26	15	15	26	6	4	2
Other	58	39	2	—	4	7	3	3	1
Total taxes other than income	$ 1,731	$ 555	$ 296	$ 154	$ 240	$ 452	$ 371	$ 57	$ 6

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the year ended December 31, 2016								Successor	Predecessor
									March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Taxes other than income										
Utility [a]	$ 753	$ 122	$ 242	$ 136	$ 85	$ 312	$ 18	$ —	$ 253	$ 78
Property	483	246	27	13	123	53	31	3	73	18
Payroll	226	117	28	15	17	8	5	3	23	8
Other	114	21	(4)	—	4	4	1	1	5	1
Total taxes other than income	$ 1,576	$ 506	$ 293	$ 164	$ 229	$ 377	$ 55	$ 7	$ 354	$ 105

	For the year ended December 31, 2015								
						Predecessor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Taxes other than income									
Utility [a]	$ 474	$ 105	$ 236	$ 133	$ 85	$ 326	$ 308	$ 18	$ —
Property	407	250	27	11	119	94	57	28	3
Payroll	201	118	28	14	16	27	6	4	2
Other	118	16	5	2	4	8	5	1	2
Total taxes other than income	$ 1,200	$ 489	$ 296	$ 160	$ 224	$ 455	$ 376	$ 51	$ 7

(a) Generation's utility tax represents gross receipts tax related to its retail operations and ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's utility taxes represent municipal and state utility taxes and gross receipts taxes related to their operating revenues. The offsetting collection of utility taxes from customers is recorded in revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the year ended December 31, 2017								
						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds [a]									
Regulatory agreement units	$ 488	$ 488	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	209	209	—	—	—	—	—	—	—
Net unrealized gains on decommissioning trust funds									
Regulatory agreement units	455	455	—	—	—	—	—	—	—
Non-regulatory agreement units	521	521	—	—	—	—	—	—	—
Net unrealized losses on pledged assets									
Zion Station decommissioning	(10)	(10)	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(724)	(724)	—	—	—	—	—	—	—
Total decommissioning-related activities	939	939	—	—	—	—	—	—	—
Investment income	8	6	—	—	—	2	1	—	—
Interest income (expense) related to uncertain income tax positions	3	(1)	—	—	—	—	—	—	—
Penalty related to uncertain income tax positions [c]	2	—	—	—	—	—	—	—	—
AFUDC—Equity	73	—	12	9	16	36	23	7	6
Other	31	4	10	—	—	16	8	7	1
Other, net	$ 1,056	$ 948	$ 22	$ 9	$ 16	$ 54	$ 32	$ 14	$ 7

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the year ended December 31, 2016								Successor	Predecessor
									March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Other, Net										
Decommissioning-related activities:										
Net realized income on decommissioning trust funds [a]										
Regulatory agreement units	$ 237	$ 237	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	126	126	—	—	—	—	—	—	—	—
Net unrealized gains on decommissioning trust funds										
Regulatory agreement units	216	216	—	—	—	—	—	—	—	—
Non-regulatory agreement units	194	194	—	—	—	—	—	—	—	—
Net unrealized losses on pledged assets										
Zion Station decommissioning	(1)	(1)	—	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(372)	(372)	—	—	—	—	—	—	—	—
Total decommissioning-related activities	400	400	—	—	—	—	—	—	—	—
Investment income (loss)	17	8	—	(1)	2	1	—	1	1	—
Long-term lease income	4	—	—	—	—	—	—	—	—	—
Interest income (expense) related to uncertain income tax positions	13	—	—	—	—	1	—	—	(1)	—
Penalty related to uncertain income tax positions [c]	(106)	—	(86)	—	—	—	—	—	—	—
AFUDC—Equity	64	—	14	8	19	19	5	6	23	7
Loss on debt extinguishment	(3)	(2)	—	—	—	—	—	—	—	—
Other	24	(5)	7	1	—	15	8	2	21	(11)
Other, net	$ 413	$ 401	$ (65)	$ 8	$ 21	$ 36	$ 13	$ 9	$ 44	$ (4)

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the year ended December 31, 2015								
						Predecessor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds [a]									
Regulatory agreement units	$ 232	$ 232	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-regulatory agreement units	156	156	—	—	—	—	—	—	—
Net unrealized losses on decommissioning trust funds									
Regulatory agreement units	(282)	(282)	—	—	—	—	—	—	—
Non-regulatory agreement units	(197)	(197)	—	—	—	—	—	—	—
Net unrealized gains on pledged assets									
Zion Station decommissioning	7	7	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	21	21	—	—	—	—	—	—	—
Total decommissioning-related activities	(63)	(63)	—	—	—	—	—	—	—
Investment income (loss)	8	3	—	(2)	4	—	—	—	—
Long-term lease income	15	—	—	—	—	—	—	—	—
Interest income related to uncertain income tax positions	1	1	—	—	—	34	5	—	—
AFUDC—Equity	24	—	5	5	14	14	12	1	1
Terminated interest rate swaps [d]	(26)	—	—	—	—	—	—	—	—
PHI merger related debt exchange [e]	(22)	—	—	—	—	—	—	—	—
Other	17	(1)	16	2	—	40	11	9	2
Other, net	$ (46)	$ (60)	$ 21	$ 5	$ 18	$ 88	$ 28	$ 10	$ 3

(a) Includes investment income and realized gains and losses on sales of investments within the nuclear decommissioning trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 15 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(c) See Note 14 — Income Taxes for discussion of the penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position.
(d) In January 2015, in connection with Generation's $750 million issuance of five-year Senior Unsecured Notes, Exelon terminated certain floating-to-fixed interest rate swaps. As the original forecasted transactions were a series of future interest payments over a ten-year period, a portion of the anticipated interest payments are probable not to occur. As a result, $26 million of anticipated payments were reclassified from AOCI to Other, net in Exelon's Consolidated Statements of Operations and Comprehensive Income.
(e) See Note 13 — Debt and Credit Agreements and Note 4 — Mergers, Acquisitions and Dispositions for additional information on the PHI merger related debt exchange.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the years ended December 31, 2017 , 2016 and 2015 .

	For the year ended December 31, 2017								
						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Depreciation, amortization and accretion									
Property, plant and equipment	$ 3,293	$ 1,409	$ 777	$ 261	$ 312	$ 457	$ 203	$ 124	$ 89
Regulatory assets	478	—	73	25	161	218	118	43	57
Amortization of intangible assets, net	57	48	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities [a]	35	35	—	—	—	—	—	—	—
Nuclear fuel [b]	1,096	1,096	—	—	—	—	—	—	—
ARO accretion [c]	468	468	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$ 5,427	$ 3,056	$ 850	$ 286	$ 473	$ 675	$ 321	$ 167	$ 146

	For the year ended December 31, 2016								*Successor*	*Predecessor*
									March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Depreciation, amortization and accretion										
Property, plant and equipment	$ 3,477	$ 1,835	$ 708	$ 244	$ 299	$ 175	$ 110	$ 82	$ 325	$ 94
Regulatory assets	407	—	67	26	124	120	47	83	190	58
Amortization of intangible assets, net	52	44	—	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities [a]	35	35	—	—	—	—	—	—	—	—
Nuclear fuel [b]	1,159	1,159	—	—	—	—	—	—	—	—
ARO accretion [c]	446	446	—	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$ 5,576	$ 3,519	$ 775	$ 270	$ 423	$ 295	$ 157	$ 165	$ 515	$ 152

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the year ended December 31, 2015								
									Predecessor
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI
Depreciation, amortization and accretion									
Property, plant and equipment	$ 2,227	$ 1,007	$ 635	$ 240	$ 289	$ 164	$ 103	$ 76	$ 392
Regulatory assets	170	—	72	20	77	92	45	99	232
Amortization of intangible assets, net	54	47	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities [a]	22	22	—	—	—	—	—	—	—
Nuclear fuel [b]	1,116	1,116	—	—	—	—	—	—	—
ARO accretion [c]	398	397	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$ 3,987	$ 2,589	$ 707	$ 260	$ 366	$ 256	$ 148	$ 175	$ 624

(a) Included in Operating revenues or Purchased power and fuel on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(c) Included in Operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

	For the year ended December 31, 2017								
						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash paid (refunded) during the year:									
Interest (net of amount capitalized)	$ 2,430	$ 391	$ 307	$ 103	$ 96	$ 236	$ 114	$ 49	$ 59
Income taxes (net of refunds)	540	337	83	47	(2)	(144)	(104)	(49)	(2)
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$ 643	$ 227	$ 176	$ 29	$ 62	$ 94	$ 25	$ 13	$ 13
Loss (Gain) from equity method investments	32	33	—	—	—	(1)	—	—	—
Provision for uncollectible accounts	125	38	34	26	8	19	8	3	8
Provision for excess and obsolete inventory	56	51	3	—	—	2	1	1	—
Stock-based compensation costs	88	—	—	—	—	—	—	—	—
Other decommissioning-related activity [a]	(313)	(313)	—	—	—	—	—	—	—
Energy-related options [b]	7	7	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	9	—	4	1	—	4	2	1	1
Amortization of rate stabilization deferral	(10)	—	—	—	7	(17)	(17)	—	—
Amortization of debt fair value adjustment	(18)	(12)	—	—	—	(6)	—	—	—
Merger-related commitments [c]	—	—	—	—	—	(8)	(6)	(2)	—
Severance costs	35	31	—	—	—	3	—	—	—
Amortization of debt costs	64	37	5	2	2	4	2	—	1

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Discrete impacts from EIMA and FEJA [d]	(52)	—	(52)	—	—	—	—	—	—
Vacation accrual adjustment [e]	(68)	(35)	(12)	—	—	(8)	(8)	—	—
Long-term incentive plan	109	—	—	—	—	—	—	—	—
Change in environmental liabilities	44	44	—	—	—	—	—	—	—
Other	(30)	4	6	(4)	(14)	(27)	(12)	(7)	(6)
Total other non-cash operating activities	$ 721	$ 112	$ 164	$ 54	$ 65	$ 59	$ (5)	$ 9	$ 17
Non-cash investing and financing activities:									
Increase (decrease) in capital expenditures not paid	$ 42	$ 73	$ (61)	$ 22	$ 23	$ (12)	$ 5	$ 4	$ (13)
Change in PPE related to ARO update	29	29	—	—	—	—	—	—	—
Non-cash financing of capital projects	16	16	—	—	—	—	—	—	—
Indemnification of like-kind exchange position [f]	—	—	21	—	—	—	—	—	—
Dividends on stock compensation	7	—	—	—	—	—	—	—	—
Dissolution of financing trust due to long-term debt retirement	8	—	—	—	8	—	—	—	—
Fair value adjustment of long-term debt due to retirement	(5)	—	—	—	—	—	—	—	—
Fair value of pension and OPEB obligation transferred in connection with FitzPatrick	—	33	—	—	—	—	—	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) See Note 4 - Mergers, Acquisitions and Dispositions for more information.
(d) Reflects the change in ComEd's distribution and energy efficiency formula rates . See Note 3 — Regulatory Matters for more information.
(e) On December 1, 2017, Exelon adopted a single, standard vacation accrual policy for all non-represented, non-craft (represented and craft policies remained unchanged) employees effective January 1, 2018. To reflect the new policy, Exelon recorded a one-time, $68 million pre-tax credit to expense to reverse 2018 vacation cost originally accrued throughout 2017 that will now be accrued ratably over the year in 2018.
(f) See Note 14 — Income Taxes for discussion of the like-kind exchange tax position.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the year ended December 31, 2016								Successor	Predecessor
									March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Cash paid (refunded) during the year:										
Interest (net of amount capitalized)	$ 1,340	$ 339	$ 298	$ 104	$ 92	$ 118	$ 47	$ 62	$ 209	$ 43
Income taxes (net of refunds)	(441)	435	(444)	64	31	216	115	200	258	11
Other non-cash operating activities:										
Pension and non-pension postretirement benefit costs	$ 619	$ 218	$ 166	$ 33	$ 67	$ 31	$ 18	$ 15	$ 86	$ 23
Loss from equity method investments	24	25	—	—	—	—	—	—	—	—
Provision for uncollectible accounts	155	19	41	30	1	29	23	32	65	16
Stock-based compensation costs	111	—	—	—	—	—	—	—	—	3
Other decommissioning-related activity [a]	(384)	(384)	—	—	—	—	—	—	—	—
Energy-related options [b]	(11)	(11)	—	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	9	—	4	1	—	2	1	1	3	1
Amortization of rate stabilization deferral	76	—	—	—	81	(12)	2	—	(5)	5
Amortization of debt fair value adjustment	(11)	(11)	—	—	—	—	—	—	—	—
Merger-related commitments [c][d]	558	53	—	—	—	125	82	110	317	—
Severance costs	99	22	—	—	—	—	—	—	56	—
Discrete impacts from EIMA [e]	8	—	8	—	—	—	—	—	—	—
Amortization of debt costs	35	17	4	3	1	—	—	—	1	—
Provision for excess and obsolete inventory	12	6	4	—	—	3	1	1	1	1
Lower of cost or market inventory adjustment	37	36	—	1	—	—	—	—	—	—
Baltimore City Conduit Lease Settlement	(28)	—	—	—	(28)	—	—	—	—	—
Cash Working Capital Order	(13)	—	—	—	(13)	—	—	—	—	—
Asset Retirement Costs	2	—	—	—	—	—	1	2	2	—
Long-term incentive plan	70	—	—	—	—	—	—	—	—	—
Other	(35)	25	(12)	(3)	(21)	5	(14)	(6)	(12)	(3)
Total other non-cash operating activities	$ 1,333	$ 15	$ 215	$ 65	$ 88	$ 183	$ 114	$ 155	$ 514	$ 46
Non-cash investing and financing activities:										
Increase (decrease) in capital expenditures not paid	$ (128)	$ 50	$ (91)	$ (11)	$ (86)	$ 27	$ (12)	$ 11	$ 21	$ 11

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Change in PPE related to ARO update	191	191	—	—	—	—	—	—	—	—
Indemnification of like-kind exchange position [g]	—	—	158	—	—	—	—	—	—	—
Dividends on stock compensation	6	—	—	—	—	—	—	—	—	—
Non-cash financing of capital projects	95	95	—	—	—	—	—	—	—	—
Sale of Upstream assets [c]	37	37	—	—	—	—	—	—	—	—
Pending FitzPatrick Acquisition [h]	(54)	(54)	—	—	—	—	—	—	—	—
Fair value of net assets contributed to Generation in connection with the PHI merger, net of cash	—	119	—	—	—	—	—	—	—	—
Fair value of net assets distributed to Exelon in connection with the PHI Merger, net of cash [c][f]	—	—	—	—	—	—	—	—	127	—
Fair value of pension obligation transferred in connection with the PHI Merger [c][f]	—	—	—	—	—	—	—	—	53	—
Assumption of member purchase liability	—	—	—	—	—	—	—	—	29	—
Assumption of merger commitment liability	—	—	—	—	—	33	—	—	33	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) See Note 4 - Mergers, Acquisitions and Dispositions for more information.
(d) Excludes $5 million of forgiveness of Accounts receivable related to merger commitments recorded in connection with the PHI Merger, the balance is included within Provision for uncollectible accounts.
(e) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate. See Note 3 — Regulatory Matters for more information.
(f) Immediately following closing of the PHI Merger, the net assets associated with PHI's unregulated business interests were distributed by PHI to Exelon. Exelon contributed a portion of such net assets to Generation.
(g) See Note 14 — Income Taxes for discussion of the like-kind exchange tax position.
(h) Reflects the transfer of nuclear fuel to Entergy under the cost reimbursement provisions of the FitzPatrick acquisition agreements. See Note 4 - Mergers, Acquisitions and Dispositions for more information.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the year ended December 31, 2015								
						Predecessor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash paid (refunded) during the year:									
Interest (net of amount capitalized)	$ 930	$ 348	$ 308	$ 94	$ 120	$ 268	$ 116	$ 47	$ 63
Income taxes (net of refunds)	342	476	(265)	64	73	(13)	(6)	(5)	—
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$ 637	$ 269	$ 206	$ 39	$ 65	$ 97	$ 30	$ 15	$ 15
Loss from equity method investments	7	8	—	—	—	—	—	—	—
Provision for uncollectible accounts	120	22	53	30	15	61	21	20	20
Provision for excess and obsolete inventory	10	9	1	—	—	1	—	—	—
Stock-based compensation costs	97	—	—	—	—	13	—	—	—
Other decommissioning-related activity [a]	(82)	(82)	—	—	—	—	—	—	—
Energy-related options [b]	21	21	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	7	—	5	2	—	5	2	1	1
Amortization of rate stabilization deferral	73	—	—	—	73	(2)	1	(3)	—
Amortization of debt fair value adjustment	(17)	(17)	—	—	—	—	—	—	—
Discrete impacts from EIMA [c]	144	—	144	—	—	—	—	—	—
Amortization of debt costs	58	15	4	2	2	2	—	—	—
Lower of cost or market inventory adjustment	23	23	—	—	—	—	—	—	—
Long-term incentive plan	24	—	—	—	—	—	—	—	—
Other	(13)	—	3	(3)	(18)	(10)	—	—	1
Total other non-cash operating activities	$ 1,109	$ 268	$ 416	$ 70	$ 137	$ 167	$ 54	$ 33	$ 37
Non-cash investing and financing activities:									
Change in PPE related to ARO update	$ 885	$ 885	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Increase (decrease) in capital expenditures not paid	96	82	34	(13)	(9)	6	(1)	3	3
Nuclear fuel procurement [d]	57	57	—	—	—	—	—	—	—
Indemnification of like-kind exchange position [e]	—	—	7	—	—	—	—	—	—
Dividends on stock compensation	6	—	—	—	—	—	—	—	—
Non-cash financing of capital projects	77	77	—	—	—	—	—	—	—
Long-term software licensing agreement [f]	95	—	—	—	—	—	—	—	—

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate. See Note 3 — Regulatory Matters for more information.

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Combined Notes to Consolidated Financial Statements - (Continued)
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(d) Relates to the nuclear fuel procurement contracts for the purchase of fixed quantities of uranium, which was delivered to Generation in 2015. Generation is required to make payments starting September 30, 2018, with the final payment being due no later than September 30, 2020.
(e) See Note 14 — Income Taxes for discussion of the like-kind exchange tax position.
(f) Relates to a long-term software license agreement entered into on May 30, 2015. Exelon is required to make payments starting August of 2015 through May of 2024. See Note 13 - Debt and Credit Agreements .

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants at December 31, 2017 and 2016 .

						Successor			
December 31, 2017	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Investments									
Equity method investments:									
Financing trusts [a]	$ 14	$ —	$ 6	$ 8	$ —	$ —	$ —	$ —	$ —
Bloom	206	206	—	—	—	—	—	—	—
Net Power	76	76	—	—	—	—	—	—	—
Other equity method investments	1	1	—	—	—	—	—	—	—
Total equity method investments	297	283	6	8	—	—	—	—	—
Other investments:									
Employee benefit trusts and investments [b]	244	51	—	17	5	132	102	—	—
Other cost method investments	62	62	—	—	—	—	—	—	—
Other available for sale investments	37	37	—	—	—	—	—	—	—
Total investments	$ 640	$ 433	$ 6	$ 25	$ 5	$ 132	$ 102	$ —	$ —

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

						Successor			
December 31, 2016	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Investments									
Equity method investments:									
Financing trusts [a]	$ 22	$ —	$ 6	$ 8	$ 8	$ —	$ —	$ —	$ —
Bloom	216	216	—	—	—	—	—	—	—
Net Power	57	57	—	—	—	—	—	—	—
Other equity method investments	16	15	—	—	—	—	—	—	—
Total equity method investments	311	288	6	8	8	—	—	—	—
Other investments:									
Employee benefit trusts and investments [b]	232	44	—	17	4	133	102	—	—
Other cost method investments	52	52	—	—	—	—	—	—	—
Other available for sale investments	34	34	—	—	—	—	—	—	—
Total investments	$ 629	$ 418	$ 6	$ 25	$ 12	$ 133	$ 102	$ —	$ —

(a) Includes investments in affiliated financing trusts, which were not consolidated within the financial statements of Exelon and are shown as investments on the Consolidated Balance Sheets. See Note 1 — Significant Accounting Policies for additional information.
(b) The Registrants' investments in these marketable securities are recorded at fair market value.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables provide additional information about liabilities of the Registrants at December 31, 2017 and 2016 .

						Successor			
December 31, 2017	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Accrued expenses									
Compensation-related accruals [a]	$ 978	$ 407	$ 158	$ 64	$ 58	$ 106	$ 29	$ 17	$ 11
Taxes accrued	373	444	60	15	71	61	68	4	5
Interest accrued	328	78	102	33	34	48	23	8	12
Severance accrued	58	30	2	—	—	17	—	—	—
Other accrued expenses	98	61	5	2	1	29	17	6	5
Total accrued expenses	$ 1,835	$ 1,020	$ 327	$ 114	$ 164	$ 261	$ 137	$ 35	$ 33

						Successor			
December 31, 2016	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Accrued expenses									
Compensation-related accruals [a]	$ 1,199	$ 557	$ 199	$ 67	$ 64	$ 112	$ 30	$ 17	$ 11
Taxes accrued	723	239	330	4	78	65	48	4	9
Interest accrued	1,234	82	609	30	31	49	21	8	12
Severance accrued	44	15	2	—	—	19	—	—	—
Other accrued expenses	260	96	110	3	2	27	14	7	6
Total accrued expenses	$ 3,460	$ 989	$ 1,250	$ 104	$ 175	$ 272	$ 113	$ 36	$ 38

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.

25 . Segment Information (All Registrants)

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants.

In the first quarter of 2016, following the consummation of the PHI Merger, three new reportable segments were added: Pepco, DPL and ACE. As a result, Exelon has twelve reportable segments, which include ComEd, PECO, BGE, PHI's three reportable segments consisting of Pepco, DPL, and ACE, and Generation's six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as "Other Power Regions", which includes activities in the South, West and Canada. ComEd, PECO, BGE, Pepco, DPL and ACE each represent a single reportable segment, and as such, no separate segment information is provided for these Registrants. Exelon, ComEd, PECO, BGE, Pepco, DPL and ACE's CODMs evaluate the performance of and allocate resources to ComEd, PECO, BGE, Pepco, DPL and ACE based on net income and return on equity.

Effective with the consummation of the PHI Merger, PHI's reportable segments have changed based on the information used by the CODM to evaluate performance and allocate resources. PHI's reportable segments consist of Pepco, DPL and ACE. PHI's Predecessor periods' segment information was recast in 2016 to conform to the current Exelon presentation. The reclassification of the segment information did not impact PHI's reported consolidated revenues or net income. PHI's CODM evaluates the

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performance of and allocates resources to Pepco, DPL and ACE based on net income and return on equity.

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions :
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

The CODMs for Exelon and Generation evaluate the performance of Generation's electric business activities and allocate resources based on revenues net of purchased power and fuel expense (RNF). Generation believes that RNF is a useful measurement of operational performance. RNF is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's owned generation and fuel costs associated with tolling agreements. The results of Generation's other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in

Combined Notes to Consolidated Financial Statements - (Continued)
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the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, Generation's unrealized mark-to-market gains and losses on economic hedging activities and its amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the years ended December 31, 2017 , 2016 , and 2015 is as follows:

					Successor			
	Generation [a]	ComEd	PECO	BGE	PHI [e]	Other [b]	Intersegment Eliminations	Exelon
Operating revenues [c] :								
2017								
Competitive businesses electric revenues	$ 15,300	$ —	$ —	$ —	$ —	$ —	$ (1,105)	$ 14,195
Competitive businesses natural gas revenues	2,575	—	—	—	—	—	—	2,575
Competitive businesses other revenues	591	—	—	—	—	—	(1)	590
Rate-regulated electric revenues	—	5,536	2,375	2,489	4,469	—	(29)	14,840
Rate-regulated natural gas revenues	—	—	495	687	161	—	(10)	1,333
Shared service and other revenues	—	—	—	—	49	1,831	(1,880)	—
2016								
Competitive businesses electric revenues	$ 15,390	$ —	$ —	$ —	$ —	$ —	$ (1,430)	$ 13,960
Competitive businesses natural gas revenues	2,146	—	—	—	—	—	—	2,146
Competitive businesses other revenues	215	—	—	—	—	—	(4)	211
Rate-regulated electric revenues	—	5,254	2,531	2,609	3,506	—	(31)	13,869
Rate-regulated natural gas revenues	—	—	463	624	92	—	(13)	1,166
Shared service and other revenues	—	—	—	—	45	1,648	(1,686)	7
2015								
Competitive businesses electric revenues	$ 15,944	$ —	$ —	$ —	$ —	$ —	$ (744)	$ 15,200
Competitive businesses natural gas revenues	2,433	—	—	—	—	—	—	2,433

Combined Notes to Consolidated Financial Statements - (Continued)
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Competitive businesses other revenues	758	—	—	—	—	—	(1)		757
Rate-regulated electric revenues	—	4,905	2,486	2,490	—	—	(5)		9,876
Rate-regulated natural gas revenues	—	—	546	645	—	—	(15)		1,176
Shared service and other revenues	—	—	—	—	—	1,372	(1,367)		5
Intersegment revenues [d] :									
2017	$ 1,110	$ 15	$ 7	$ 16	$ 50	$ 1,824	$ (3,020)	$	2
2016	1,428	15	8	21	45	1,647	(3,159)		5
2015	745	4	2	14	—	1,367	(2,127)		5
Depreciation and amortization:									
2017	$ 1,457	$ 850	$ 286	$ 473	$ 675	$ 87	$ —	$	3,828
2016	1,879	775	270	423	515	74	—		3,936
2015	1,054	707	260	366	—	63	—		2,450
Operating expenses [c] :									
2017	$ 17,993	$ 4,214	$ 2,215	$ 2,562	$ 3,911	$ 1,851	$ (3,026)	$	29,720
2016	16,856	4,056	2,292	2,683	3,549	1,928	(3,164)		28,200
2015	16,872	3,889	2,404	2,578	—	1,444	(2,131)		25,056
Equity in earnings (losses) of unconsolidated affiliates:									
2017	$ (33)	$ —	$ —	$ —	$ —	$ 1	$ —	$	(32)
2016	(25)	—	—	—	—	1	—		(24)
2015	(8)	—	—	—	—	1	—		(7)
Interest expense, net:									
2017	$ 440	$ 361	$ 126	$ 105	$ 245	$ 283	$ —	$	1,560
2016	364	461	123	103	195	290	—		1,536
2015	365	332	114	99	—	123	—		1,033
Income (loss) before income taxes:									
2017	$ 1,429	$ 984	$ 538	$ 525	$ 578	$ (296)	$ (2)	$	3,756
2016	873	679	587	468	(58)	(555)	(5)		1,989
2015	1,850	706	521	477	—	(219)	(5)		3,330
Income taxes:									
2017	$ (1,375)	$ 417	$ 104	$ 218	$ 217	$ 294	$ —	$	(125)
2016	290	301	149	174	3	(156)	—		761
2015	502	280	143	189	—	(41)	—		1,073
Net income (loss):									
2017	$ 2,771	$ 567	$ 434	$ 307	$ 362	$ (590)	$ (2)	$	3,849
2016	558	378	438	294	(61)	(398)	(5)		1,204
2015	1,340	426	378	288	—	(177)	(5)		2,250
Capital expenditures:									
2017	$ 2,259	$ 2,250	$ 732	$ 882	$ 1,396	$ 65	$ —	$	7,584
2016	3,078	2,734	686	934	1,008	113	—		8,553
2015	3,841	2,398	601	719	—	65	—		7,624

Combined Notes to Consolidated Financial Statements - (Continued)
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Total assets:								
2017	$ 48,387	$ 29,726	$ 10,170	$ 9,104	$ 21,247	$ 8,618	$ (10,552)	$ 116,700
2016	46,974	28,335	10,831	8,704	21,025	10,369	(11,334)	114,904

(a) Generation includes the six reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. For the year ended December 31, 2017 , intersegment revenues for Generation include revenue from sales to PECO of $138 million , sales to BGE of $388 million , sales to Pepco of $255 million , sales to DPL of $179 million and sales to ACE of $29 million in the Mid-Atlantic region, and sales to ComEd of $121 million in the Midwest region, which eliminate upon consolidation. For the year ended December 31, 2016 , intersegment revenues for Generation include revenue from sales to PECO of $ 290 million and sales to BGE of $ 608 million in the Mid-Atlantic region, and sales to ComEd of $ 47 million in the Midwest region, which eliminate upon consolidation. For the Successor period of March 24, 2016 to December 31, 2016, intersegment revenues for Generation include revenue from sales to Pepco of $295 million , sales to DPL of $154 million and sales to ACE of $37 million in the Mid-Atlantic region, which eliminate upon consolidation. For the year ended December 31, 2015 , intersegment revenues for Generation include revenue from sales to PECO of $224 million and sales to BGE of $502 million in the Mid-Atlantic region, and sales to ComEd of $18 million in the Midwest region, which eliminate upon consolidation.
(b) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(c) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 24 — Supplemental Financial Information for total utility taxes for the years ended December 31, 2017 , 2016 and 2015 .
(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations and Comprehensive Income.
(e) Amounts included represent activity for PHI's successor period, March 24, 2016 through December 31, 2017 . PHI includes the three reportable segments: Pepco, DPL and ACE. See tables below for PHI's predecessor periods, including Pepco, DPL and ACE, for January 1, 2016 to March 23, 2016 and for the year ended December 31, 2015 .

Successor and Predecessor PHI:

	Pepco	DPL	ACE	Other [b]	Intersegment Eliminations	PHI
Operating revenues [a] :						
December 31, 2017 - Successor						
Rate-regulated electric revenues	$ 2,158	$ 1,139	$ 1,186	$ —	$ (14)	$ 4,469
Rate-regulated natural gas revenues	—	161	—	—	—	161
Shared service and other revenues	—	—	—	52	(3)	49
March 24, 2016 to December 31, 2016 - Successor						
Rate-regulated electric revenues	$ 1,675	$ 850	$ 989	$ 5	$ (13)	$ 3,506
Rate-regulated natural gas revenues	—	92	—	—	—	92
Shared service and other revenues	—	—	—	45	—	45
January 1, 2016 to March 23, 2016 - Predecessor						
Rate-regulated electric revenues	$ 511	$ 279	$ 268	$ 42	$ (4)	$ 1,096
Rate-regulated natural gas revenues	—	56	—	1	—	57
Shared service and other revenues	—	—	—	—	—	—
December 31, 2015 - Predecessor						
Rate-regulated electric revenues	$ 2,129	$ 1,138	$ 1,295	$ 210	$ (2)	$ 4,770
Rate-regulated natural gas revenues	—	164	—	1	—	165
Shared service and other revenues	—	—	—	—	—	—
Intersegment revenues:						
December 31, 2017 - Successor	$ 6	$ 8	$ 2	$ 53	$ (19)	$ 50
March 24, 2016 to December 31, 2016 - Successor	4	5	2	47	(13)	45

Combined Notes to Consolidated Financial Statements - (Continued)
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January 1, 2016 to March 23, 2016 - Predecessor		1		2		1		—		(4)		—
December 31, 2015 - Predecessor		5		6		4		—		(15)		—
Depreciation and amortization:												
December 31, 2017 - Successor	$	321	$	167	$	146	$	42	$	(1)	$	675
March 24, 2016 to December 31, 2016 - Successor		224		120		128		43		—	$	515
January 1, 2016 to March 23, 2016 - Predecessor		71		37		37		11		(4)	$	152
December 31, 2015 - Predecessor		256		148		175		45		—	$	624
Operating expenses:												
December 31, 2017 - Successor	$	1,760	$	1,071	$	1,029	$	68	$	(17)	$	3,911
March 24, 2016 to December 31, 2016 - Successor		1,577		952		1,000		33		(13)	$	3,549
January 1, 2016 to March 23, 2016 - Predecessor		443		284		251		73		(3)	$	1,048
December 31, 2015 - Predecessor		1,790		1,137		1,161		220		—	$	4,308
Interest expense, net:												
December 31, 2017 - Successor	$	121	$	51	$	61	$	13	$	(1)	$	245
March 24, 2016 to December 31, 2016 - Successor		98		38		47		12		—	$	195
January 1, 2016 to March 23, 2016 - Predecessor		29		12		15		11		(2)	$	65
December 31, 2015 - Predecessor		124		50		64		43		(1)	$	280
Income (loss) before income taxes:												
December 31, 2017 - Successor	$	310	$	192	$	103	$	377	$	(404)	$	578
March 24, 2016 to December 31, 2016 - Successor		36		(30)		(51)		(84)		71	$	(58)
January 1, 2016 to March 23, 2016 - Predecessor		47		43		5		59		(118)	$	36
December 31, 2015 - Predecessor		289		125		73		23		(29)	$	481
Income taxes:												
December 31, 2017 - Successor	$	105	$	71	$	26	$	15	$	—	$	217
March 24, 2016 to December 31, 2016 - Successor		26		5		(5)		(23)		—	$	3
January 1, 2016 to March 23, 2016 - Predecessor		15		17		1		(16)		—	$	17
December 31, 2015 - Predecessor		102		49		33		(48)		27	$	163
Net income (loss):												
December 31, 2017 - Successor	$	205	$	121	$	77	$	(91)	$	50	$	362
March 24, 2016 to December 31, 2016 - Successor		10		(35)		(47)		(34)		45	$	(61)
January 1, 2016 to March 23, 2016 - Predecessor		32		26		5		(44)		—	$	19
December 31, 2015 - Predecessor		187		76		40		25		(1)	$	327
Capital expenditures:												
December 31, 2017 - Successor	$	628	$	428	$	312	$	28	$	—	$	1,396
March 24, 2016 to December 31, 2016 - Successor		489		277		218		24		—	$	1,008

Combined Notes to Consolidated Financial Statements - (Continued)
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January 1, 2016 to March 23, 2016 - Predecessor	97	72	93	11	—	273
December 31, 2015 - Predecessor	544	352	300	34	—	1,230
Total assets:						
December 31, 2017 - Successor	$ 7,832	$ 4,357	$ 3,445	$ 10,600	$ (4,987)	$ 21,247
December 31, 2016 - Successor	7,335	4,153	3,457	10,804	(4,724)	21,025

(a) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 24 — Supplemental Financial Information for total utility taxes for the years ended December 31, 2017 , 2016 and 2015 .
(b) Other primarily includes PHI's corporate operations, shared service entities and other financing and investment activities. For the predecessor periods presented, Other includes the activity of PHI's unregulated businesses which were distributed to Exelon and Generation as a result of the PHI Merger.

Generation total revenues:

	2017			2016			2015		
	Revenues from external customers [a]	Intersegment revenues	Total revenues	Revenues from external customers [a]	Intersegment revenues	Total revenues	Revenues from external customers [a]	Intersegment revenues	Total revenues
Mid-Atlantic	$ 5,515	$ 25	$ 5,540	$ 6,212	$ (33)	$ 6,179	$ 5,974	$ (74)	$ 5,900
Midwest	4,206	(25)	4,181	4,402	10	4,412	4,712	(2)	4,710
New England	2,010	(8)	2,002	1,778	(9)	1,769	2,217	(5)	2,212
New York	1,535	(17)	1,518	1,198	(42)	1,156	996	(11)	985
ERCOT	958	4	962	831	6	837	863	(6)	857
Other Power Regions	1,076	(27)	1,049	969	(62)	907	1,182	(80)	1,102
Total Revenues for Reportable Segments	$ 15,300	$ (48)	$ 15,252	$ 15,390	$ (130)	$ 15,260	$ 15,944	$ (178)	$ 15,766
Other [b]	3,166	48	3,214	2,361	130	2,491	3,191	178	3,369
Total Generation Consolidated Operating Revenues	$ 18,466	$ —	$ 18,466	$ 17,751	$ —	$ 17,751	$ 19,135	$ —	$ 19,135

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.
(b) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a $38 million decrease to revenues, a $ 52 million decrease to revenues, and a $ 7 million increase to revenues for the amortization of intangible assets related to commodity contracts recorded at fair value for the years ended December 31, 2017 , 2016 , and 2015 , respectively, unrealized mark-to-market losses of $131 million , losses of $500 million , and gains of $203 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively, and elimination of intersegment revenues.

Combined Notes to Consolidated Financial Statements - (Continued)
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Generation total revenues net of purchased power and fuel expense:

	2017			2016			2015		
	RNF from external customers [a]	Intersegment RNF	Total RNF	RNF from external customers [a]	Intersegment RNF	Total RNF	RNF from external customers [a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 3,105	$ 109	$ 3,214	$ 3,282	$ 35	$ 3,317	$ 3,556	$ 15	$ 3,571
Midwest	2,810	10	2,820	2,969	2	2,971	2,912	(20)	2,892
New England	538	(24)	514	467	(29)	438	519	(58)	461
New York	975	1	976	761	(19)	742	584	50	634
ERCOT	575	(243)	332	412	(131)	281	425	(132)	293
Other Power Regions	476	(171)	305	483	(147)	336	440	(190)	250
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 8,479	$ (318)	$ 8,161	$ 8,374	$ (289)	$ 8,085	$ 8,436	$ (335)	$ 8,101
Other [b]	297	318	615	547	289	836	678	335	1,013
Total Generation Revenues net of purchased power and fuel expense	$ 8,776	$ —	$ 8,776	$ 8,921	$ —	$ 8,921	$ 9,114	$ —	$ 9,114

(a) Includes purchases and sales from third parties and affiliated sales to the Utility Registrants.
(b) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $54 million decrease in RNF, a $57 million decrease in RNF, and a $8 million increase in RNF for the amortization of intangible assets and liabilities related to commodity contracts for the years ended December 31, 2017 , 2016 , and 2015 , respectively, unrealized mark-to-market losses of $175 million , losses of $41 million , and gains of $257 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively, accelerated nuclear fuel amortization associated with the announced early retirement decision for Clinton and Quad Cities as discussed in Note 8 - Early Nuclear Plant Retirements of $12 million and $60 million for the year ended December 31, 2017 and 2016 , and the elimination of intersegment revenues net of purchased power and fuel expense.

26 . Related Party Transactions (All Registrants)

Exelon

The financial statements of Exelon include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2017	2016	2015
Operating revenues from affiliates:			
PECO [(a)]	$ 1	$ 1	$ 1
BGE [(a)]	4	4	4
Other	2	5	4
Total operating revenues from affiliates	$ 7	$ 10	$ 9
Interest expense to affiliates, net:			
ComEd Financing III	$ 14	$ 13	$ 13
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
BGE Capital Trust II	10	16	16
Total interest expense to affiliates, net	$ 36	$ 41	$ 41
Earnings (losses) in equity method investments:			
Qualifying facilities and domestic power projects	$ (33)	$ (25)	$ (8)
Other	1	1	1
Total losses in equity method investments	$ (32)	$ (24)	$ (7)

	December 31,	
	2017	2016
Payables to affiliates (current):		
ComEd Financing III	$ 4	$ 4
PECO Trust III	1	1
BGE Capital Trust II	—	3
Total payables to affiliates (current)	$ 5	$ 8
Long-term debt due to financing trusts:		
ComEd Financing III	$ 205	$ 205
PECO Trust III	81	81
PECO Trust IV	103	103
BGE Capital Trust II	—	252
Total long-term debt due to financing trusts	$ 389	$ 641

(a) The intersegment profit associated with the sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations. See Note 3 — Regulatory Matters for additional information.

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Transactions involving Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE are further described in the tables below.

Generation

The financial statements of Generation include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2017	2016	2015
Operating revenues from affiliates:			
ComEd [a]	$ 121	$ 47	$ 18
PECO [b]	138	290	224
BGE [c]	388	608	502
Pepco [d]	255	295	—
DPL [e]	179	154	—
ACE [f]	29	37	—
BSC	1	2	1
Other	4	6	4
Total operating revenues from affiliates	$ 1,115	$ 1,439	$ 749
Purchased power and fuel from affiliates:			
ComEd	$ 13	$ —	$ —
BGE	9	12	14
Other	(3)	—	—
Total purchased power and fuel from affiliates	$ 19	$ 12	$ 14
Operating and maintenance from affiliates:			
ComEd [g]	$ 7	$ 7	$ 4
PECO [g]	1	3	2
BGE [g]	1	1	—
Pepco	—	1	—
PHISCO	1	1	—
BSC [h]	689	650	614
Other	$ (2)	$ —	$ —
Total operating and maintenance from affiliates	$ 697	$ 663	$ 620
Interest expense to affiliates, net:			
Exelon Corporate [i]	$ 37	$ 39	$ 43
PCI	1	—	—
PECO	1	—	—
Total interest expense to affiliates, net:	39	39	43
Earnings (losses) in equity method investments			
Qualifying facilities and domestic power projects	$ (33)	$ (25)	$ (8)
Capitalized costs			
BSC [h]	$ 98	$ 98	$ 76
Cash distribution paid to member	$ 659	$ 922	$ 2,474
Contribution from member	$ 102	$ 142	$ 47

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Combined Notes to Consolidated Financial Statements - (Continued)
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	December 31,	
	2017	2016
Receivables from affiliates (current):		
ComEd [a]	$ 28	$ 14
PECO [b]	26	33
BGE [c]	24	26
Pepco [d]	36	44
DPL [e]	12	16
ACE [f]	6	9
PHISCO [h]	1	5
PCI	—	8
Other	7	1
Total receivables from affiliates (current)	$ 140	$ 156
Intercompany money pool (current):		
PCI	$ 54	$ 55
Payables to affiliates (current):		
Exelon Corporate [i]	$ 21	$ 22
BSC [h]	74	99
ComEd	12	9
PECO [b]	4	—
Other	12	7
Total payables to affiliates (current)	$ 123	$ 137
Long-term debt due to affiliates (noncurrent):		
Exelon Corporate [k]	$ 910	$ 922
Payables to affiliates (noncurrent):		
BSC [h]	$ —	$ 1
ComEd [j]	2,528	2,169
PECO [j]	537	438
Total payables to affiliates (noncurrent)	$ 3,065	$ 2,608

Combined Notes to Consolidated Financial Statements - (Continued)
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(a) Generation has an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. Generation also sells RECs to ComEd. In addition, Generation had revenue from ComEd associated with the settled portion of the financial swap contract established as part of the Illinois Settlement. See Note 3 — Regulatory Matters for additional information.
(b) Generation provides electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, Generation has a ten-year agreement with PECO to sell solar AECs. See Note 3 — Regulatory Matters for additional information.
(c) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3 — Regulatory Matters for additional information.
(d) Generation provides electric supply to Pepco under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC. See Note 3 — Regulatory Matters for additional information.
(e) Generation provides a portion of DPL's energy requirements under its MDPSC and DPSC approved market based SOS and gas commodity programs. See Note 3 — Regulatory Matters for additional information.
(f) Generation provides electric supply to ACE under contracts executed through ACE's competitive procurement process. See Note 3 — Regulatory Matters for additional information.
(g) Generation requires electricity for its own use at its generating stations. Generation purchases electricity and distribution and transmission services from PECO and BGE and only distribution and transmission services from ComEd for the delivery of electricity to its generating stations.
(h) Generation receives a variety of corporate support services from BSC and PHISCO, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(i) The balance consists of interest owed to Exelon Corporation related to the senior unsecured notes, as well as, expense related to certain invoices Exelon Corporation processed on behalf of Generation.
(j) Generation has long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 15 — Asset Retirement Obligations .
(k) In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-term Debt to affiliate on Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets.

ComEd

The financial statements of ComEd include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2017	2016	2015
Operating revenues from affiliates			
Generation	$ 9	$ 7	$ 4
BSC	6	6	—
PECO	—	1	—
BGE	—	1	—
Total operating revenues from affiliates	$ 15	$ 15	$ 4
Purchased power from affiliate			
Generation [a]	$ 108	$ 47	$ 18
Operating and maintenance from affiliates			
BSC [b]	$ 270	$ 225	$ 195
PECO	—	1	—
BGE	—	1	—
Total operating and maintenance from affiliates	$ 270	$ 227	$ 195
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
Capitalized costs			
BSC [b]	$ 118	$ 112	$ 103
Cash dividends paid to parent	$ 422	$ 369	$ 299
Contribution from parent	$ 651	$ 315	$ 202

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31,	
	2017	2016
Prepaid voluntary employee beneficiary association trust [c]	$ 2	$ 5
Receivable from affiliates (current):		
Voluntary employee beneficiary association trust	$ 1	$ 2
Generation	12	9
Exelon Corporate [d]	—	345
Total receivable from affiliates (current)	$ 13	$ 356
Receivable from affiliates (noncurrent):		
Generation [e]	$ 2,528	$ 2,169
Other	—	1
Total receivable from affiliates (noncurrent)	$ 2,528	$ 2,170
Payables to affiliates (current):		
Generation [a]	$ 28	$ 14
BSC [b]	39	42
ComEd Financing III	4	4
PECO	—	2
Exelon Corporate	3	3
Total payables to affiliates (current)	$ 74	$ 65
Long-term debt to ComEd financing trust		
ComEd Financing III	$ 205	$ 205

(a) ComEd procures a portion of its electricity supply requirements from Generation under an ICC-approved RFP contract. ComEd also purchases RECs from Generation. In addition, purchased power expense includes the settled portion of the financial swap contract with Generation, which expired in 2013. See Note 3 — Regulatory Matters and Note 12 — Derivative Financial Instruments for additional information.
(b) ComEd receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(c) The voluntary employee benefit association trusts covering active employees are included in corporate operations and are funded by the Registrants. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for ComEd's contributions to the plans, being higher than actual claim expense incurred by the plans over time. The prepayment is included in other current assets.
(d) Represents indemnification from Exelon Corporate related to the like-kind exchange.
(e) ComEd has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct for generating facilities previously owned by ComEd. To the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to ComEd for payment to ComEd's customers.

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PECO

The financial statements of PECO include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2017	2016	2015
Operating revenues from affiliates:			
Generation [a]	$ 1	$ 3	$ 2
BSC	5	3	—
ComEd	—	1	—
BGE	1	1	—
Total operating revenues from affiliates	$ 7	$ 8	$ 2
Purchased power from affiliate			
Generation [b]	$ 135	$ 287	$ 220
Operating and maintenance from affiliates:			
BSC [c]	$ 146	$ 142	$ 107
Generation	2	2	3
ComEd	—	1	—
BGE	1	1	—
Total operating and maintenance from affiliates	$ 149	$ 146	$ 110
Interest expense to affiliates, net:			
PECO Trust III	$ 6	$ 6	$ 6
PECO Trust IV	6	6	6
Generation	(1)	—	—
Total interest expense to affiliates, net:	$ 11	$ 12	$ 12
Capitalized costs			
BSC [c]	$ 59	$ 57	$ 40
Cash dividends paid to parent	$ 288	$ 277	$ 279
Contribution from parent	$ 16	$ 18	$ 16

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2017	December 31, 2016
Prepaid voluntary employee beneficiary association trust [d]	$ —	$ 1
Receivable from affiliate (current):		
ComEd	$ —	$ 2
BGE	—	2
Total receivable from affiliates (current)	$ —	$ 4
Receivable from affiliate (noncurrent):		
Generation [e]	$ 537	$ 438
Payables to affiliates (current):		
Generation [b]	$ 22	$ 33
BSC [c]	29	28
Exelon Corporate	1	1
PECO Trust III	1	1
Total payables to affiliates (current)	$ 53	$ 63
Long-term debt to financing trusts:		
PECO Trust III	$ 81	$ 81
PECO Trust IV	103	103
Total long-term debt to financing trusts	$ 184	$ 184

(a) PECO provides energy to Generation for Generation's own use.
(b) PECO purchases electric supply from Generation under contracts executed through its competitive procurement process. In addition, PECO has five-year and ten-year agreements with Generation to purchase non-solar and solar AECs, respectively. See Note 3 — Regulatory Matters for additional information on AECs.
(c) PECO receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) The voluntary employee beneficiary association trusts covering active employees are included in corporate operations and are funded by the Registrants. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for PECO's contributions to the plans, being higher than actual claim expense incurred by the plans over time.
(e) PECO has a long-term receivable from Generation as a result of the nuclear decommissioning contractual construct, whereby, to the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to PECO for payment to PECO's customers.

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

The financial statements of BGE include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2017	2016	2015
Operating revenues from affiliates:			
Generation [a]	$ 10	$ 13	$ 14
BSC	5	6	—
ComEd	—	1	—
PECO	1	1	—
Total operating revenues from affiliates	$ 16	$ 21	$ 14
Purchased power from affiliate			
Generation [b]	$ 384	$ 604	$ 498
Operating and maintenance from affiliates:			
BSC [c]	$ 152	$ 130	$ 118
ComEd	—	1	—
PECO	1	1	—
Total operating and maintenance from affiliates	$ 153	$ 132	$ 118
Interest expense to affiliates, net:			
BGE Capital Trust II	$ 10	$ 16	$ 16
Capitalized costs			
BSC [c]	$ 54	$ 36	$ 28
Cash dividends paid to parent	$ 198	$ 179	$ 158
Contribution from parent	$ 184	$ 61	$ 7

	December 31,	
	2017	2016
Receivable from affiliates (current):		
Other	$ 1	$ —
Payables to affiliates (current):		
Generation [b]	$ 24	$ 26
BSC [c]	25	22
Exelon Corporate	1	1
PECO	—	2
BGE Capital Trust II	—	3
Other	2	1
Total payables to affiliates (current)	$ 52	$ 55
Long-term debt to BGE financing trust		
BGE Capital Trust II	$ —	$ 252

(a) BGE provides energy to Generation for Generation's own use.
(b) BGE procures a portion of its electricity and gas supply requirements from Generation under its MDPSC-approved market-based SOS and gas commodity programs. See Note 3 — Regulatory Matters for additional information.
(c) BGE receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI

The financial statements of PHI include related party transactions as presented in the tables below:

	Successor	
	For the Year Ended December 31,	**March 24, 2016 to December 31,**
	2017	**2016**
Operating revenues from affiliates:		
BSC	$ 48	$ 44
PHISCO	2	—
Generation	—	1
Total operating revenues from affiliates	$ 50	$ 45
Purchased power from affiliate		
Generation	$ 463	$ 486
Operating and maintenance from affiliates:		
BSC [a]	$ 145	$ 86
Other	5	3
Total operating and maintenance from affiliates	$ 150	$ 89
Cash dividends paid to parent	$ 311	$ 273
Contribution from member	$ 758	$ 1,251

	Successor	
	December 31,	
	2017	**2016**
Payables to affiliates (current):		
Generation	$ 54	$ 74
BGE	1	—
BSC [a]	24	10
Exelon Corporate	6	6
Other	5	4
Total payables to affiliates (current)	$ 90	$ 94

(a) PHI receives a variety of corporate support services from BSC and PHISCO, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Pepco

The financial statements of Pepco include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2017	2016	2015
Operating revenues from affiliates:			
Generation [a]	$ —	$ 1	$ —
PHISCO	6	4	5
Total operating revenues from affiliates	$ 6	$ 5	$ 5
Purchased power from affiliate			
Generation [b]	$ 255	$ 295	$ —
Operating and maintenance:			
PHISCO [c]	$ 219	$ 263	$ 240
PES [d]	29	39	26
Total operating and maintenance	$ 248	$ 302	$ 266
Operating and maintenance from affiliates:			
BSC [c]	$ 53	$ 31	$ —
PHISCO [c]	5	4	4
Total operating and maintenance from affiliates	$ 58	$ 35	$ 4
Cash dividends paid to parent	$ 133	$ 136	$ 146
Contribution from parent	$ 161	$ 187	$ 112

	December 31,	
	2017	2016
Payables to affiliates (current):		
Generation [b]	$ 36	$ 44
BSC [c]	11	4
DPL	—	1
PHISCO [c]	27	25
Total payables to affiliates (current)	$ 74	$ 74

(a) Pepco provides energy to Generation for Generation's own use.
(b) Pepco procures a portion of its electricity and gas supply requirements from Generation under its MDPSC and DPSC approved market based SOS and gas commodity programs. See Note 3 — Regulatory Matters for additional information.
(c) Pepco receives a variety of corporate support services from BSC and PHISCO, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(d) PES performs underground transmission, distribution construction and maintenance services, including services that are treated as capital costs, for Pepco.

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

DPL

The financial statements of DPL include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2017	2016	2015
Operating revenues from affiliates:			
PHISCO	$ 6	$ 5	$ 5
Other	2	2	1
Total operating revenues from affiliates	$ 8	$ 7	$ 6
Purchased power from affiliate			
Generation [(a)]	$ 179	$ 154	$ —
Operating and maintenance:			
PHISCO [(b)]	$ 165	$ 194	$ 179
PES [(c)]	9	8	3
Total operating and maintenance	$ 174	$ 202	$ 182
Operating and maintenance from affiliates:			
BSC [(b)]	$ 31	$ 18	$ —
Other	1	1	1
Total operating and maintenance from affiliates	$ 32	$ 19	$ 1
Cash dividends paid to parent	$ 112	$ 54	$ 92
Contribution from parent	$ —	$ 152	$ 75

	December 31,	
	2017	2016
Receivables from affiliates (current):		
Pepco	$ —	$ 1
ACE	—	2
Total receivable from affiliates (current)	$ —	$ 3
Payables to affiliates (current):		
Generation [(a)]	$ 12	$ 16
BSC [(b)]	7	3
PHISCO [(b)]	27	19
Total payables to affiliates (current)	$ 46	$ 38

(a) DPL procures a portion of its electricity and gas supply requirements from Generation under its MDPSC and DPSC approved market based SOS and gas commodity programs. See Note 3 — Regulatory Matters for additional information.
(b) DPL receives a variety of corporate support services from BSC and PHISCO, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(c) PES performs underground transmission construction services, including services that are treated as capital costs, for DPL.

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Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

ACE

The financial statements of ACE include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2017	2016	2015
Operating revenues from affiliates:			
PHISCO	$ 1	$ 2	$ 2
Other	1	1	2
Total operating revenues from affiliates	$ 2	$ 3	$ 4
Purchased power from affiliate			
Generation [(a)]	$ 29	$ 37	$ —
Operating and maintenance:			
PHISCO [(b)]	$ 135	$ 155	$ 143
Operating and maintenance from affiliates:			
BSC [(b)]	$ 25	$ 15	$ —
Other	3	3	3
Total operating and maintenance from affiliates	$ 28	$ 18	$ 3
Cash dividends paid to parent	$ 68	$ 63	$ 12
Contribution from parent	$ —	$ 139	$ 95

	December 31,	
	2017	2016
Payables to affiliates (current):		
Generation [(a)]	$ 6	$ 9
BSC [(b)]	5	2
DPL	—	2
PHISCO [(b)]	18	16
Total payables to affiliates (current)	$ 29	$ 29

(a) ACE purchases electric supply from Generation under contracts executed through its competitive procurement process. See Note 3 — Regulatory Matters for additional information.
(b) ACE receives a variety of corporate support services from BSC and PHISCO, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

27 . Quarterly Data (Unaudited) (All Registrants)

Exelon

The data shown below, which may not equal the total for the year due to the effects of rounding and dilution, includes all adjustments that Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income Attributable to Common Shareholders	
	2017	2016	2017	2016	2017	2016
Quarter ended:						
March 31	$ 8,757	$ 7,573	$ 1,296	$ 483	$ 995	$ 173
June 30	7,623	6,910	232	647	80	267
September 30	8,769	9,002	1,475	1,267	824	490
December 31	8,381	7,875	1,258	714	1,871	204

	Average Basic Shares Outstanding (in millions)		Net Income per Basic Share	
	2017	2016	2017	2016
Quarter ended:				
March 31	928	923	$ 1.07	$ 0.19
June 30	934	924	0.09	0.29
September 30	962	925	0.86	0.53
December 31	964	925	1.94	0.22

	Average Diluted Shares Outstanding (in millions)		Net Income per Diluted Share	
	2017	2016	2017	2016
Quarter ended:				
March 31	930	925	$ 1.07	$ 0.19
June 30	936	926	0.09	0.29
September 30	965	927	0.85	0.53
December 31	967	928	1.93	0.22

The following table presents the New York Stock Exchange—Composite Common Stock Prices and dividends by quarter on a per share basis:

	2017				2016			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 42.67	$ 38.78	$ 37.44	$ 37.19	$ 36.36	$ 37.70	$ 36.37	$ 35.95
Low price	37.55	35.37	33.30	34.47	29.82	32.86	33.18	26.26
Close	39.41	37.67	36.07	35.98	35.49	33.29	36.36	35.86
Dividends	0.328	0.328	0.328	0.328	0.318	0.318	0.318	0.310

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation

The data shown below includes all adjustments that Generation considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating (Loss) Income		Net (Loss) Income Attributable to Membership Interest	
	2017	2016	2017	2016	2017	2016
Quarter ended:						
March 31	$ 4,888	$ 4,739	$ 387	$ 415	$ 423	$ 310
June 30	4,174	3,589	(467)	(13)	(250)	(8)
September 30	4,751	5,035	500	342	305	236
December 31	4,654	4,388	501	94	2,215	(41)

ComEd

The data shown below includes all adjustments that ComEd considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income	
	2017	2016	2017	2016	2017	2016
Quarter ended:						
March 31	$ 1,298	$ 1,249	$ 314	$ 274	$ 141	$ 115
June 30	1,357	1,286	319	324	118	145
September 30	1,571	1,497	404	389	189	37
December 31	1,309	1,223	286	217	120	80

PECO

The data shown below includes all adjustments that PECO considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income Attributable to Common Shareholders	
	2017	2016	2017	2016	2017	2016
Quarter ended:						
March 31	$ 796	$ 841	$ 192	$ 196	$ 127	$ 124
June 30	630	664	137	152	88	100
September 30	715	788	169	204	112	122
December 31	729	701	157	150	107	92

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

The data shown below includes all adjustments that BGE considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income Attributable to Common Shareholders	
	2017	2016	2017	2016	2017	2016
Quarter ended:						
March 31	$ 951	$ 929	$ 228	$ 187	$ 125	$ 98
June 30	674	680	98	59	45	31
September 30	738	812	124	115	62	54
December 31	813	812	163	190	76	103

PHI

The data shown below includes all adjustments that PHI considers necessary for a fair presentation of such amounts:

	Successor					
	Operating Revenues		Operating Income (Loss)		Net Income (Loss) Attributable to Membership Interest	
	2017	2016	2017	2016	2017	2016
Quarter ended:						
March 31	$ 1,175	$ 105 [(a)]	$ 180	$ (411) [(a)]	$ 140	$ (309) [(a)]
June 30	1,074	1,066	148	136	66	52
September 30	1,310	1,394	285	279	153	166
December 31	1,121	1,078	159	90	4	30

	Predecessor		
	Operating Revenues	Operating Income	Net Income Attributable to Membership Interest
January 1, 2016 - March 23, 2016	1,153	105	19

(a) Amounts for March 31, 2016 reflect the PHI Successor activity for the period March 24, 2016 to March 31, 2016.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Pepco

The data shown below includes all adjustments that Pepco considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income (Loss)		Net Income (Loss) Attributable to Common Shareholders	
	2017	2016	2017	2016	2017	2016
Quarter ended:						
March 31	$ 530	$ 551	$ 79	$ (105)	$ 58	$ (108)
June 30	514	509	84	97	43	49
September 30	604	635	149	132	87	79
December 31	510	491	87	51	17	23

DPL

The data shown below includes all adjustments that DPL considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income (Loss)		Net Income (Loss) Attributable to Common Shareholders	
	2017	2016	2017	2016	2017	2016
Quarter ended:						
March 31	$ 362	$ 362	$ 78	$ (72)	$ 57	$ (72)
June 30	282	281	41	30	19	12
September 30	327	331	59	72	31	44
December 31	330	303	52	20	14	7

ACE

The data shown below includes all adjustments that ACE considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income (Loss)		Net Income (Loss) Attributable to Common Shareholders	
	2017	2016	2017	2016	2017	2016
Quarter ended:						
March 31	$ 275	$ 291	$ 25	$ (121)	$ 28	$ (100)
June 30	270	270	25	19	8	3
September 30	370	421	79	83	41	47
December 31	271	275	28	26	—	8

28 . Subsequent Events (Exelon, Generation and ComEd)

Illinois ZEC Procurement

On January 25, 2018, the ICC announced that Generation's Clinton Unit 1, Quad Cities Unit 1 and Quad Cities Unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event. Generation executed the ZEC procurement contracts with Illinois utilities, including

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd, effective January 26, 2018 and will begin recognizing revenue. Winning bidders will be entitled to compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. In the first quarter of 2018, Generation will recognize approximately $150 million of revenue and ComEd will record an obligation to Generation and corresponding reduction to its regulatory liability of approximately $100 million related to ZECs generated from June 1, 2017 through December 31, 2017.

Early Retirement of Oyster Creek Generating Station

On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in October 2018. In 2010, Generation announced that Oyster Creek would retire by the end of 2019 as part of an agreement with the State of New Jersey to avoid significant costs associated with the construction of cooling towers to meet the State's then new environmental regulations. Since then, like other nuclear sites, Oyster Creek has continued to face rising operating costs amid a historically low wholesale power price environment. The decision to retire Oyster Creek in 2018 at the end of its current operating cycle involved consideration of several factors, including economic and operating efficiencies, and avoids a refueling outage scheduled for the fall of 2018 that would have required advanced purchasing of fuel fabrication and materials beginning in late February 2018.

Because of the decision to retire Oyster Creek in 2018, Exelon and Generation will recognize certain one-time charges in the first quarter of 2018 ranging from an estimated $25 million to $35 million (pre-tax) related to a materials and supplies inventory reserve adjustment, employee-related costs, and construction work-in-progress impairment, among other items. Estimated cash expenditures related to the one-time charges primarily for employee-related costs are expected to range from $5 million to $10 million.

In addition to these one-time charges, there will be financial impacts stemming from shortening the expected economic useful life of Oyster Creek primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions to reflect an earlier retirement date. The following table summarizes the estimated amount of expected incremental non-cash expense items expected to be incurred in 2018 because of the early retirement decision.

	Projected [b]
Income statement expense (pre-tax)	2018
Depreciation and Amortization	
Accelerated depreciation [a]	$110 to $140
Accelerated nuclear fuel amortization	$40
Operating and Maintenance	
Increased ARO accretion	Up to $5

(a) Includes the accelerated depreciation of plant assets including any ARC.
(b) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

All Registrants

None.

ITEM 9A. CONTROLS AND PROCEDURES

All Registrants—Disclosure Controls and Procedures

During the fourth quarter of 2017 , each registrant's management, including its principal executive officer and principal financial officer, evaluated the effectiveness of that registrant's disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in that registrant's periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by each registrant to ensure that (a) information relating to that registrant, including its consolidated subsidiaries, that is required to be included in filings under the Securities Exchange Act of 1934, is accumulated and made known to that registrant's management, including its principal executive officer and principal financial officer, by other employees of that registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of December 31, 2017 , the principal executive officer and principal financial officer of each registrant concluded that such registrant's disclosure controls and procedures were effective to accomplish their objectives.

All Registrants—Changes in Internal Control Over Financial Reporting

Each registrant continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. However, there have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2017 that have materially affected, or are reasonably likely to materially affect, any of the registrant's internal control over financial reporting.

All Registrants—Internal Control Over Financial Reporting

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2017 . As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2017 and, therefore, concluded that each registrant's internal control over financial reporting was effective. Management's Report on Internal Control Over Financial Reporting is included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA .

ITEM 9B. OTHER INFORMATION

All Registrants

None.

PART III

Exelon Generation Company, LLC, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section relating to Generation, PECO, BGE, PHI, Pepco, DPL and ACE are not presented.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants at February 9, 2018 .

Directors, Director Nomination Process and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at the annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)), the audit committee (Item 407(d)(4) and (d)(5)) and the beneficial reporting compliance (Sec. 16(a)) is incorporated herein by reference to information to be contained in Exelon's definitive 2018 proxy statement (2018 Exelon Proxy Statement) and the ComEd information statement (2018 ComEd Information Statement) to be filed with the SEC before April 29, 2018 pursuant to Regulation 14A or 14C, as applicable, under the Securities Exchange Act of 1934.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to Exelon's and ComEd's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. The Code of Business Conduct is filed as Exhibit 14 to this report and is available on Exelon's website at *www.exeloncorp.com* . The Code of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Carter C. Culver, Senior Vice President and Deputy General Counsel, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

If any substantive amendments to the Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Code of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or Corporate Controller, Exelon will disclose the nature of such amendment or waiver on Exelon's website, *www.exeloncorp.com* , or in a report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under *Executive Compensation Data* and *Report of the Compensation Committee* in the Exelon Proxy Statement for the 2018 Annual Meeting of Shareholders or the ComEd 2018 Information Statement, which are incorporated herein by reference.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The additional information required by this item will be set forth under *Ownership of Exelon Stock* in the Exelon Proxy Statement for the 2018 Annual Meeting of Shareholders or the ComEd 2018 Information Statement, which are incorporated herein by reference.

Securities Authorized for Issuance under Exelon Equity Compensation Plans

[A] Plan Category	[B] Number of securities to be issued upon exercise of outstanding Options, warrants and rights (Note 1)	[C] Weighted-average price of outstanding Options, warrants and rights (Note 2)	[D] Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column [B]) (Note 3)
Equity compensation plans approved by security holders	21,755,400	$ 28.13	23,634,900

(1) Balance includes stock options, unvested performance shares, and unvested restricted shares granted under the Exelon LTIP or predecessor company plans including shares awarded under those plans and deferred into the stock deferral plan, and deferred stock units granted to directors as part of their compensation. For performance shares granted in 2015, 2016 and 2017 , the total includes the number of shares that could be granted, if the performance and total shareholder return modifier metrics were both at maximum, representing a total of 9,546,000 shares. If the performance and total shareholder return modifier metrics were at target, the number of securities to be issued for such awards would be 4,773,000 . The deferred stock units granted to directors includes 384,900 shares to be issued upon the conversion of deferred stock units awarded to members of the Exelon Board of Directors, and 109,200 shares to be issued upon the conversion of stock units held by members of the Exelon Board of Directors that were earned under a legacy Constellation Energy Group plan. Conversion of the deferred stock units to shares will occur after the director terminates service to the Exelon board or the board of any of its subsidiary companies. See Note 20 — Stock-Based Compensation Plans of the Combined Notes to Consolidated Financial Statements for additional information about the material features of the plans.

(2) Includes outstanding restricted stock units and performance shares that can be exercised for no consideration. Without such instruments, the weighted-average price of outstanding options, warrants and rights shown in column [C] would be $47.69 .

(3) Includes 19,737,600 shares available for issuance from the company's employee stock purchase plan.

No ComEd securities are authorized for issuance under equity compensation plans.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The additional information required by this item will be set forth under *Related Persons Transactions* and *Director Independence* in the Exelon Proxy Statement for the 2018 Annual Meeting of Shareholders or the ComEd 2018 Information Statement, which are incorporated herein by reference.

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ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under *The Ratification of PricewaterhouseCoopers LLP as Exelon's Independent Accountant for 2018* in the Exelon Proxy Statement for the 2018 Annual Meeting of Shareholders and the ComEd 2018 Information Statement, which are incorporated herein by reference.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

Exelon

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 9, 2018 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2017, 2016 and 2015

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015

   Consolidated Balance Sheets at December 31, 2017 and 2016

   Consolidated Statements of Changes in Equity for the Years Ended December 31, 2017, 2016 and 2015

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule I—Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2017 and 2016 and for the Years Ended December 31, 2017, 2016 and 2015

   Schedule II—Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

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Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Statements of Operations and Other Comprehensive Income

(In millions)	For the Years Ended December 31, 2017	2016	2015
Operating expenses			
Operating and maintenance	$ 10	$ 221	$ —
Operating and maintenance from affiliates	25	51	43
Other	4	4	4
Total operating expenses	39	276	47
Operating loss	(39)	(276)	(47)
Other income and (deductions)			
Interest expense, net	(315)	(312)	(168)
Equity in earnings of investments	4,398	1,521	2,461
Interest income from affiliates, net	40	39	43
Other, net	1	7	(43)
Total other income	4,124	1,255	2,293
Income before income taxes	4,085	979	2,246
Income taxes	315	(155)	(23)
Net income	$ 3,770	$ 1,134	$ 2,269
Other comprehensive income (loss)			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic costs	$ (56)	$ (48)	$ (46)
Actuarial loss reclassified to periodic cost	197	184	220
Pension and non-pension postretirement benefit plan valuation adjustment	10	(181)	(99)
Unrealized gain on cash flow hedges	3	2	9
Unrealized gain on marketable securities	6	1	—
Unrealized gain (loss) on equity investments	6	(4)	(3)
Unrealized gain (loss) on foreign currency translation	7	10	(21)
Other comprehensive income (loss)	173	(36)	60
Comprehensive income	$ 3,943	$ 1,098	$ 2,329

See the Notes to Financial Statements

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Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2017	2016	2015
Net cash flows provided by operating activities	$ 1,921	$ 1,029	$ 3,071
Cash flows from investing activities			
Changes in Exelon intercompany money pool	(129)	1,390	(1,217)
Notes receivable from affiliates	—	—	550
Investment in affiliates	(1,717)	(1,757)	(212)
Acquisition of business	—	(6,962)	—
Other investing activities	(5)	5	(55)
Net cash flows used in investing activities	(1,851)	(7,324)	(934)
Cash flows from financing activities			
Issuance of long-term debt	—	1,800	4,200
Proceeds from short-term borrowings with maturities greater than 90 days	500	—	—
Retirement of long-term debt	(569)	(46)	(2,263)
Issuance of common stock	—	—	1,868
Common stock issued from treasury stock	1,150	—	—
Dividends paid on common stock	(1,236)	(1,166)	(1,105)
Proceeds from employee stock plans	150	55	32
Other financing activities	(9)	(20)	(58)
Net cash flows (used in) provided by financing activities	(14)	623	2,674
Increase (Decrease) in cash and cash equivalents	56	(5,672)	4,811
Cash and cash equivalents at beginning of period	18	5,690	879
Cash and cash equivalents at end of period	$ 74	$ 18	$ 5,690

See the Notes to Financial Statements

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Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 74	$ 18
Deposit with IRS	—	1,250
Accounts receivable, net		
Other accounts receivable	431	73
Accounts receivable from affiliates	33	48
Notes receivable from affiliates	217	88
Regulatory assets	284	263
Other	4	—
Total current assets	1,043	1,740
Property, plant and equipment, net	50	51
Deferred debits and other assets		
Regulatory assets	3,697	4,033
Investments in affiliates	39,272	34,869
Deferred income taxes	1,431	2,107
Notes receivable from affiliates	910	922
Other	234	256
Total deferred debits and other assets	45,544	42,187
Total assets	$ 46,637	$ 43,978

See the Notes to Financial Statements

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Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

(In millions)	December 31, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 500	$ —
Long-term debt due within one year	—	570
Accounts payable	2	2
Accrued expenses	99	489
Payables to affiliates	360	706
Regulatory liabilities	16	16
Pension obligations	65	58
Other	46	50
Total current liabilities	1,088	1,891
Long-term debt	7,161	7,193
Deferred credits and other liabilities		
Regulatory liabilities	15	31
Pension obligations	7,792	8,608
Non-pension postretirement benefit obligations	322	7
Deferred income taxes	220	226
Other	180	182
Total deferred credits and other liabilities	8,529	9,054
Total liabilities	16,778	18,138
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2000 shares authorized, 963 shares and 924 shares outstanding at December 31, 2017 and 2016, respectively)	18,966	18,797
Treasury stock, at cost (2 shares and 35 shares at December 31, 2017 and 2016, respectively)	(123)	(2,327)
Retained earnings	13,503	12,030
Accumulated other comprehensive loss, net	(2,487)	(2,660)
Total shareholders' equity	29,859	25,840
Total liabilities and shareholders' equity	$ 46,637	$ 43,978

See the Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

1. Basis of Presentation

Exelon Corporate is a holding company that conducts substantially all of its business operations through its subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of Exelon Corporation.

Exelon Corporate owns 100% of all of its significant subsidiaries, either directly or indirectly, except for Commonwealth Edison Company (ComEd), of which Exelon Corporate owns more than 99% , and BGE, of which Exelon owns 100% of the common stock but none of BGE's preferred stock. BGE redeemed all of its outstanding preferred stock in 2016.

2. Mergers

On March 23, 2016, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Purple Acquisition Corp., a wholly owned subsidiary of Exelon (Merger Sub) and Pepco Holdings, Inc. (PHI). As a result of that merger, Merger Sub was merged into PHI (the PHI Merger) with PHI surviving as a wholly owned subsidiary of Exelon and Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon which also owns Exelon's interests in ComEd, PECO and BGE (through a special purpose subsidiary in the case of BGE). See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the PHI Merger.

3. Debt and Credit Agreements

Short-Term Borrowings

Exelon Corporate meets its short-term liquidity requirements primarily through the issuance of commercial paper. Exelon Corporate had no commercial paper borrowings at both December 31, 2017 and December 31, 2016 .

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a $500 million term loan agreement which expires on March 22, 2018. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheet within Short-Term borrowings.

Credit Agreements

On May 26, 2016, Exelon Corporate amended and extended its syndicated revolving credit facility with aggregate bank commitments of $600 million through May 26, 2021. As of December 31, 2017 , Exelon Corporation had available capacity under those commitments of $555 million . See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon Corporation's credit agreement.

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

Long-Term Debt

The following tables present the outstanding long-term debt for Exelon Corporate as of December 31, 2017 and December 31, 2016 :

	Rates		Maturity Date	December 31, 2017	December 31, 2016
Long-term debt					
Junior subordinated notes		3.50%	2022	$ 1,150	$ 1,150
Contract payment - junior subordinated notes		2.50%	2017	—	19
Senior unsecured notes [(a)]	2.45%	7.60%	2020 - 2046	5,889	6,439
Total long-term debt				7,039	7,608
Unamortized debt discount and premium, net				(8)	(8)
Unamortized debt issuance costs				(49)	(57)
Fair value adjustment of consolidated subsidiary				179	220
Long-term debt due within one year				—	(570)
Long-term debt				$ 7,161	$ 7,193

(a) Senior unsecured notes include mirror debt that is held on both Generation and Exelon Corporation's balance sheets.

The debt maturities for Exelon Corporate for the periods 2018 , 2019 , 2020 , 2021 , 2022 and thereafter are as follows:

2018	$ —
2019	—
2020	1,450
2021	300
2022	1,150
Remaining years	4,139
Total long-term debt	$ 7,039

4. Commitments and Contingencies

See Note 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's commitments and contingencies related to environmental matters and fund transfer restrictions.

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Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

5. Related Party Transactions

The financial statements of Exelon Corporate include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
(In millions)	2017	2016	2015
Operating and maintenance from affiliates:			
BSC [a]	$ 23	$ 51	$ 43
Other	2	—	—
Total operating and maintenance from affiliates:	$ 25	$ 51	$ 43
Interest income from affiliates, net:			
Generation	$ 37	$ 39	$ 43
BSC	3	—	—
Total interest income from affiliates, net:	$ 40	$ 39	$ 43
Equity in earnings (losses) of investments:			
Exelon Energy Delivery Company, LLC [b]	$ 1,670	$ 1,041	$ 1,079
PCI	1	6	—
BSC	1	1	—
UII, LLC	41	(9)	20
Exelon Transmission Company, LLC	(10)	(13)	(8)
Exelon Enterprise	1	(1)	(1)
Generation	2,694	496	1,371
Total equity in earnings of investments	$ 4,398	$ 1,521	$ 2,461
Cash contributions received from affiliates	$ 1,879	$ 1,912	$ 3,209

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Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

(in millions)	December 31, 2017	December 31, 2016
Accounts receivable from affiliates (current):		
BSC [a]	$ 1	$ 15
Generation	21	22
ComEd	3	3
PECO	1	1
BGE	1	1
PHISCO	6	6
Total accounts receivable from affiliates (current)	$ 33	$ 48
Notes receivable from affiliates (current):		
BSC [a]	$ 217	$ 88
Investments in affiliates:		
BSC [a]	$ 196	$ 194
Exelon Energy Delivery Company, LLC [b]	25,082	23,003
PCI	78	77
UII, LLC	268	92
Exelon Transmission Company, LLC	1	5
Voluntary Employee Beneficiary Association trust	(4)	(5)
Exelon Enterprises	22	21
Generation	13,635	11,488
Other	(6)	(6)
Total investments in affiliates	$ 39,272	$ 34,869
Notes receivable from affiliates (non-current):		
Generation [c]	$ 910	$ 922
Accounts payable to affiliates (current):		
ComEd	$ —	$ 345
UII, LLC	360	361
Total accounts payable to affiliates (current)	$ 360	$ 706

(a) Exelon Corporate receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead.
(b) Exelon Energy Delivery Company, LLC consists of ComEd, PECO, BGE, PHI, Pepco, DPL and ACE.
(c) In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-Term Debt to affiliate on Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets.

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Exelon Corporation and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the year ended December 31, 2017					
Allowance for uncollectible accounts [a]	$ 334	$ 126	$ 27 [c]	$ 165 [d]	$ 322
Deferred tax valuation allowance	20	—	17	—	37
Reserve for obsolete materials	113	56	10	5	174
For the year ended December 31, 2016					
Allowance for uncollectible accounts [a]	$ 284	$ 162	$ 99 [b][c]	$ 211 [d]	$ 334
Deferred tax valuation allowance	13	—	10 [b]	3	20
Reserve for obsolete materials	105	12	1 [b]	5	113
For the year ended December 31, 2015					
Allowance for uncollectible accounts [a]	$ 311	$ 113	$ 27 [c]	$ 167 [d]	$ 284
Deferred tax valuation allowance	50	—	(27)	10	13
Reserve for obsolete materials	95	10	2	2	105

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $15 million , $23 million , and $8 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively.
(b) Primarily represents the addition of PHI's results as of March 23, 2016 , the date of the merger
(c) Includes charges for late payments and non-service receivables.
(d) Write-off of individual accounts receivable.

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Exelon Generation Company, LLC and Subsidiary Companies

Generation

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 9, 2018 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2017, 2016 and 2015

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015

   Consolidated Balance Sheets at December 31, 2017 and 2016

   Consolidated Statements of Changes in Equity for the Years Ended December 31, 2017, 2016 and 2015

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

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Exelon Generation Company, LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the year ended December 31, 2017					
Allowance for uncollectible accounts	$ 91	$ 34	$ —	$ 11	$ 114
Deferred tax valuation allowance	9	—	14	—	23
Reserve for obsolete materials	106	51	9	—	166
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 77	$ 19	$ 3	$ 8	$ 91
Deferred tax valuation allowance	11	—	—	2	9
Reserve for obsolete materials	102	6	—	2	106
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 60	$ 22	$ —	$ 5	$ 77
Deferred tax valuation allowance	48	—	(27)	10	11
Reserve for obsolete materials	93	9	—	—	102

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Commonwealth Edison Company and Subsidiary Companies

ComEd

1.	Financial Statements:
	Report of Independent Registered Public Accounting Firm dated February 9, 2018 of PricewaterhouseCoopers LLP
	Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2017, 2016 and 2015
	Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015
	Consolidated Balance Sheets at December 31, 2017 and 2016
	Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2017, 2016 and 2015
	Notes to Consolidated Financial Statements
2.	Financial Statement Schedules:
	Schedule II – Valuation and Qualifying Accounts
	Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

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Commonwealth Edison Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the year ended December 31, 2017					
Allowance for uncollectible accounts	$ 70	$ 39	$ 20 (a)	$ 56 (b)	$ 73
Reserve for obsolete materials	4	3	1	3	5
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 75	$ 45	$ 23 (a)	$ 73 (b)	$ 70
Reserve for obsolete materials	3	4	1	4	4
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 84	$ 39	$ 18 (a)	$ 66 (b)	$ 75
Reserve for obsolete materials	2	1	2	2	3

(a) Primarily charges for late payments and non-service receivables.
(b) Write-off of individual accounts receivable.

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PECO Energy Company and Subsidiary Companies

PECO

1.	Financial Statements:
	Report of Independent Registered Public Accounting Firm dated February 9, 2018 of PricewaterhouseCoopers LLP
	Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2017, 2016 and 2015
	Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015
	Consolidated Balance Sheets at December 31, 2017 and 2016
	Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2017, 2016 and 2015
	Notes to Consolidated Financial Statements
2.	Financial Statement Schedules:
	Schedule II – Valuation and Qualifying Accounts
	Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

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PECO Energy Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the year ended December 31, 2017					
Allowance for uncollectible accounts [a]	$ 61	$ 26	$ 4 [b]	$ 35 [c]	$ 56
Reserve for obsolete materials	2	—	—	—	2
For the year ended December 31, 2016					
Allowance for uncollectible accounts [a]	$ 83	$ 32	$ 7 [b]	$ 61 [c]	$ 61
Reserve for obsolete materials	1	1	—	—	2
For the year ended December 31, 2015					
Allowance for uncollectible accounts [a]	$ 100	$ 37	$ 9 [b]	$ 63 [c]	$ 83
Reserve for obsolete materials	1	—	—	—	1

(a) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables of $15 million , $23 million , and $8 million for the years ended December 31, 2017 , 2016 , and 2015 , respectively.
(b) Primarily charges for late payments.
(c) Write-off of individual accounts receivable.

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Baltimore Gas and Electric Company and Subsidiary Companies

BGE

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 9, 2018 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2017, 2016 and 2015

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015

   Consolidated Balance Sheets at December 31, 2017 and 2016

   Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2017, 2016 and 2015

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

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Baltimore Gas and Electric Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the year ended December 31, 2017					
Allowance for uncollectible accounts	$ 32	$ 8	$ (3)	$ 13 [(a)]	$ 24
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	—	—	—	—	—
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 49	$ 1	$ 9	$ 27 [(a)]	$ 32
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	—	—	—	—	—
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 67	$ 15	$ —	$ 33 [(a)]	$ 49
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	—	—	—	—	—

(a) Write-off of individual accounts receivable.

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Pepco Holdings LLC and Subsidiary Companies

PHI

1. *Successor Company Financial Statements:*

Report of Independent Registered Public Accounting Firm dated February 9, 2018 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Income (Loss) for the Year Ended December 31, 2017 and for the Period March 24, 2016 to December 31, 2016

Consolidated Statements of Cash Flows for the Year Ended December 31, 2017 and for the Period March 24, 2016 to December 31, 2016

Consolidated Balance Sheets at December 31, 2017 and 2016

Consolidated Statements of Changes in Equity for the Year Ended December 31, 2017 and for the Period March 24, 2016 to December 31, 2016

Notes to Consolidated Financial Statements

Predecessor Company Financial Statements:

Report of Independent Registered Public Accounting Firm dated February 13, 2017 of PricewaterhouseCoopers LLP

Consolidated Statements of Operations and Comprehensive Income (Loss) for the Period January 1, 2016 to March 23, 2016 and the Year Ended December 31, 2015

Consolidated Statements of Cash Flows for the Period January 1, 2016 to March 23, 2016 and for the Year Ended December 31, 2015

Consolidated Statements of Changes in Equity for the Period January 1, 2016 to March 23, 2016 and for the Year Ended December 31, 2015

Notes to Consolidated Financial Statements

2. *Successor Financial Statement Schedules:*

Schedule II – Valuation and Qualifying Accounts - For the Year Ended December 31, 2017 and the Period March 24, 2016 to December 31, 2016

Predecessor Financial Statement Schedules:

Schedule II – Valuation and Qualifying Accounts - For the Period January 1, 2016 to March 23, 2016 and For the Year Ended December 31, 2015

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Pepco Holdings LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the Year Ended December 31, 2017 *(Successor)*					
Allowance for uncollectible accounts	$ 80	$ 19	$ 6 [(a)]	$ 50 [(b)]	$ 55
Deferred tax valuation allowance	10	—	3	—	13
Reserve for obsolete materials	2	2	—	2	2
March 24, 2016 to December 31, 2016 *(Successor)*					
Allowance for uncollectible accounts	$ 52	$ 65	$ 5 [(a)]	$ 42 [(b)]	$ 80
Deferred tax valuation allowance	63	—	(53)	—	10
Reserve for obsolete materials	—	1	—	(1)	2
January 1, 2016 to March 23, 2016 *(Predecessor)*					
Allowance for uncollectible accounts	$ 56	$ 16	$ 2 [(a)]	$ 22 [(b)]	$ 52
Deferred tax valuation allowance	63	—	—	—	63
Reserve for obsolete materials	—	—	—	—	—
For the Year Ended December 31, 2015 *(Predecessor)*					
Allowance for uncollectible accounts	$ 40	$ 59	$ 5 [(a)]	$ 48 [(b)]	$ 56
Deferred tax valuation allowance	61	—	2	—	63
Reserve for obsolete materials	—	—	—	—	—

(a) Primarily charges for late payments.
(b) Write-off of individual accounts receivable.

S1-SSA-0009 - 16806

Potomac Electric Power Company

Pepco

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 9, 2018 of PricewaterhouseCoopers LLP

   Statements of Operations and Comprehensive Income for the Years Ended December 31, 2017, 2016 and 2015

   Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015

   Balance Sheets at December 31, 2017 and 2016

   Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2017, 2016 and 2015

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

S1-SSA-0009 - 16807

Potomac Electric Power Company

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the year ended December 31, 2017					
Allowance for uncollectible accounts	$ 29	$ 8	$ 2 [(a)]	$ 18 [(b)]	$ 21
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	1	1	—	1	1
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 17	$ 29	$ 3 [(a)]	$ 20 [(b)]	$ 29
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	3	—	2	1
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 16	$ 20	$ 1 [(a)]	$ 20 [(b)]	$ 17
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	—	—	—	—

(a) Primarily charges for late payments.
(b) Write-off of individual accounts receivable.

S1-SSA-0009 - 16808

Delmarva Power & Light Company

DPL

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 9, 2018 of PricewaterhouseCoopers LLP

   Statements of Operations and Comprehensive Income (Loss) for the Years Ended December 31, 2017, 2016 and 2015

   Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015

   Balance Sheets at December 31, 2017 and 2016

   Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2017, 2016 and 2015

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

S1-SSA-0009 - 16809

Delmarva Power & Light Company

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the year ended December 31, 2017					
Allowance for uncollectible accounts	$ 24	$ 3	$ 2 [(a)]	$ 13 [(b)]	$ 16
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	1	—	1	—
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 17	$ 23	$ 2 [(a)]	$ 18 [(b)]	$ 24
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	1	—	1	—
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 11	$ 20	$ 2 [(a)]	$ 16 [(b)]	$ 17
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	—	—	—	—

(a) Primarily charges for late payments.
(b) Write-off of individual accounts receivable.

S1-SSA-0009 - 16810

Atlantic City Electric Company and Subsidiary Company

ACE

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 9, 2018 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income (Loss) for the Years Ended December 31, 2017, 2016 and 2015

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016 and 2015

   Consolidated Balance Sheets at December 31, 2017 and 2016

   Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2017, 2016 and 2015

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

S1-SSA-0009 - 16811

Atlantic City Electric Company and Subsidiary Company

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For the year ended December 31, 2017					
Allowance for uncollectible accounts	$ 27	$ 8	$ 2 [(a)]	$ 19 [(b)]	$ 18
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	1	—	—	—	1
For the year ended December 31, 2016					
Allowance for uncollectible accounts	$ 17	$ 32	$ 2 [(a)]	$ 24 [(b)]	$ 27
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	1	—	—	1
For the year ended December 31, 2015					
Allowance for uncollectible accounts	$ 9	$ 18	$ 2 [(a)]	$ 12 [(b)]	$ 17
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	—	—	—	—	—

(a) Primarily charges for late payments.
(b) Write-off of individual accounts receivable.

S1-SSA-0009 - 16812

Exhibits required by Item 601 of Regulation S-K:

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
2-1	Agreement and Plan of Merger dated as of April 28, 2011 by and among Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc. (File No. 001-16169, Form 8-K dated April 28, 2011, Exhibit No. 2-1).
2-2	Distribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Constellation Energy Group, Inc. and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-3).
2-3	Contribution and Assignment Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Energy Delivery Company, LLC and RF HoldCo LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-4).
2-4	Contribution Agreement, dated as of March 12, 2012, by and among Exelon Corporation, Exelon Ventures Company, LLC and Exelon Generation Company, LLC (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 2-5).
2-5	Purchase Agreement dated as of August 8, 2012 by and between Constellation Power Source Generation, Inc. and Raven Power Holdings, LLC. (File No. 333-85496, Form 10-Q for the quarter ended September 30, 2012, Exhibit 2-1).
2-6	Master Agreement, dated as of October 26, 2010, by and between Electricite de France, S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 1, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
2-7	Put Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., Constellation Nuclear, LLC, and Constellation Energy Nuclear Group, LLC. (Designated as Exhibit No. 2.1 to the Current Report on Form 8-K dated November 8, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
2-8	Contribution Agreement, dated as of February 4, 2010, by and among Constellation Energy Group, Inc., Baltimore Gas and Electric Company and RF HoldCo LLC. (Designated as Exhibit No. 99.2 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
2-9	Purchase Agreement, dated as of February 4, 2010, by and between RF HoldCo LLC and GSS Holdings (Baltimore Gas and Electric Company Utility), Inc. (Designated as Exhibit No. 99.3 to the Current Report on Form 8-K dated February 4, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
2-10-1	Agreement and Plan of Merger, dated as of April 29, 2014, by and among Exelon Corporation, Pepco Holdings, Inc. and Purple Acquisition Corp. (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit 2.1).
2-10-2	Amended and Restated Agreement and Plan of Merger, dated as of July 18, 2014, among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp. (File No. 001-16169, Form 8-K dated July 21, 2014, Exhibit 2.1).

Exhibit No.	Description
2-10-3	Subscription Agreement for Series A Non-Voting Non-Convertible Preferred Stock, dated as of April 29, 2014, by and between Pepco Holdings, Inc. and Exelon Corporation (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit 2.2).
2-10-4	Letter Agreement, dated March 7, 2016, among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp. (File No. 001-31403, Form 8-K dated March 7, 2016, Exhibit 2)
3-1	Amended and Restated Articles of Incorporation of Exelon Corporation, as amended May 8, 2007 (File No. 001-16169, Form 10-Q for the quarter ended September 30, 2008, Exhibit 3-1-2).
3-2	Exelon Corporation Amended and Restated Bylaws, as amended on April 26, 2016 (File No. 001-16169, Form 8-K dated April 29, 2016, Exhibit 4.1).
3-3	Certificate of Formation of Exelon Generation Company, LLC (Registration Statement No. 333-85496, Form S-4, Exhibit 3-1).
3-4	First Amended and Restated Operating Agreement of Exelon Generation Company, LLC executed as of January 1, 2001 (File No. 333-85496, 2003 Form 10-K, Exhibit 3-8).
3-5	Restated Articles of Incorporation of Commonwealth Edison Company Effective February 20, 1985, including Statements of Resolution Establishing Series, relating to the establishment of three new series of Commonwealth Edison Company preference stock known as the "$9.00 Cumulative Preference Stock," the "$6.875 Cumulative Preference Stock" and the "$2.425 Cumulative Preference Stock" (File No. 1-1839, 1994 Form 10-K, Exhibit 3-2).
3-6	Commonwealth Edison Company Amended and Restated By-Laws, Effective January 23, 2006 As Further Amended January 28, 2008 and July 27, 2009. (File No. 001-1839, Form 8-K dated July 27, 2009, Exhibit 3.1).
3-7	Amended and Restated Articles of Incorporation of PECO Energy Company (File No. 1-01401, 2000 Form 10-K, Exhibit 3-3).
3-8	PECO Energy Company Amended Bylaws (File 000-16844, Form 8-K dated May 6, 2009, Exhibit 99.1).
3-9	Articles of Amendment to the Charter of Baltimore Gas and Electric Company as of February 2, 2010. (Designated as Exhibit No. 3.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File No. 1-1910).
3-10	Articles of Restatement to the Charter of Baltimore Gas and Electric Company, restated as of August 16, 1996. (Designated as Exhibit No. 3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 1996, filed by Baltimore Gas and Electric Company, File No. 1-1910).
3-11	Bylaws of Baltimore Gas and Electric Company, as amended and restated as of May 10, 2012. (File No. 1-16169, 2013 Form 10-K, Exhibit 3-11).
3-12	Operating Agreement, dated as of February 4, 2010, by and among RF HoldCo LLC, Constellation Energy Group, Inc. and GSS Holdings (BGE Utility), Inc. (Designated as Exhibit No. 99.1 to the Current Report on Form 8-K dated February 4, 2010, filed by Baltimore Gas and Electric Company, File Nos. 1-12869 and 1-1910).
3-13	Certificate of Conversion of Pepco Holdings LLC, dated March 23, 2016 (File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 3.1)
3-14	Certificate of Formation of Pepco Holdings LLC, dated March 23, 2016 (File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 3.2)

Exhibit No.	Description
3-15	Limited Liability Company Agreement of Pepco Holdings LLC, dated March 23, 2016 (File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 3.3)
3-16	Potomac Electric Power Company Restated Articles of Incorporation and Articles of Restatement of (as filed in the District of Columbia) (File No. 001-31403, Form 10-Q dated May 5, 2006, Exhibit 3.1)
3-17	Potomac Electric Power Company Restated Articles of Incorporation and Articles of Restatement of (as filed in Virginia) (File No. 001-01072, Form 10-Q dated November 4, 2011, Exhibit 3.3)
3-18	Delmarva Power & Light Company Articles of Restatement of Certificate and Articles of Incorporation (filed in Delaware and Virginia 02/22/07) (File No. 001-01405, Form 10-K dated March 1, 2007, Exhibit 3.3)
3-19	Atlantic City Electric Company Restated Certificate of Incorporation (filed in New Jersey on August 9, 2002) (File No. 001-03559, Amendment No. 1 to Form U5B dated February 13, 2003, Exhibit B.8.1)
3-20	Bylaws of Potomac Electric Power Company (File No. 001-01072, Form 10-Q dated May 5, 2006, Exhibit 3.2)
3-21	Bylaws of Delmarva Power & Light Company (File No. 001-01405, Form 10-Q dated May 9, 2005, Exhibit 3.2.1)
3-22	Bylaws of Atlantic City Electric Company (File No. 001-03559, Form 10-Q dated May 9, 2005, Exhibit 3.2.2)
4-1	First and Refunding Mortgage dated May 1, 1923 between The Counties Gas and Electric Company (predecessor to PECO Energy Company) and Fidelity Trust Company, Trustee (U.S. Bank National Association, as current successor trustee), (Registration No. 2-2281, Exhibit B-1). [(a)]
4-1-2	Reserved.
4-1-3	Supplemental Indentures to PECO Energy Company's First and Refunding Mortgage:

Dated as of	File Reference	Exhibit No.
May 1, 1927	2-2881 [(a)]	B-1(c)
March 1, 1937	2-2881 [(a)]	B-1(g)
December 1, 1941	2-4863 [(a)]	B-1(h)
November 1, 1944	2-5472 [(a)]	B-1(i)
December 1, 1946	2-6821 [(a)]	7-1(j)
September 1, 1957	2-13562 [(a)]	2(b)-17
May 1, 1958	2-14020 [(a)]	2(b)-18
March 1, 1968	2-34051 [(a)]	2(b)-24
March 1, 1981	2-72802 [(a)]	4-46
March 1, 1981	2-72802 [(a)]	4-47
December 1, 1984	1-01401, 1984 Form 10-K [(a)]	4-2(b)
March 1, 1993	1-01401, 1992 Form 10-K [(a)]	4(e)-86

May 1, 1993	1-01401, March 31, 1993 Form 10-Q [a]	4(e)-88
May 1, 1993	1-01401, March 31, 1993 Form 10-Q [a]	4(e)-89
April 15, 2004	0-6844, September 30, 2004 Form 10-Q [a]	4-1-1
September 15, 2006	000-16844, Form 8-K dated September 25, 2006	4.1
March 1, 2007	000-16844, Form 8-K dated March 19, 2007	4.1
March 15, 2009	000-16844, Form 8-K dated March 26, 2009	4.1
September 1, 2012	000-16844, Form 8-K dated September 17, 2012	4.1
September 15, 2013	000-16844, Form 8-K dated September 23, 2013	4.1
September 1, 2014	000-16844, Form 8-K dated September 15, 2014	4.1
September 15, 2015	000-16844, Form 8-K dated October 5, 2015	4.1
September 1, 2016	000-16844, Form 8-K dated September 21, 2016	4.1
September 1, 2017	000-16844, Form 8-K dated September 18, 2017	4.1

Exhibit No.	Description
4-2	Exelon Corporation Direct Stock Purchase Plan (Registration Statement No. 333-206474, Form S-3, Prospectus).
4-3	Mortgage of Commonwealth Edison Company to Illinois Merchants Trust Company, Trustee (BNY Mellon Trust Company of Illinois, as current successor Trustee), dated July 1, 1923, as supplemented and amended by Supplemental Indenture thereto dated August 1, 1944. (Registration No. 2-60201, Form S-7, Exhibit 2-1). [a]
4-3-1	Supplemental Indentures to Commonwealth Edison Company Mortgage.

Dated as of	File Reference	Exhibit No.
August 1, 1946	2-60201, Form S-7 [a]	2-1
April 1, 1953	2-60201, Form S-7 [a]	2-1
March 31, 1967	2-60201, Form S-7 [a]	2-1
April 1, 1967	2-60201, Form S-7 [a]	2-1
February 28, 1969	2-60201, Form S-7 [a]	2-1
May 29, 1970	2-60201, Form S-7 [a]	2-1
June 1, 1971	2-60201, Form S-7 [a]	2-1

Dated as of	File Reference	Exhibit No.
April 1, 1972	2-60201, Form S-7 [a]	2-1
May 31, 1972	2-60201, Form S-7 [a]	2-1
June 15, 1973	2-60201, Form S-7 [a]	2-1
May 31, 1974	2-60201, Form S-7 [a]	2-1
June 13, 1975	2-60201, Form S-7 [a]	2-1
May 28, 1976	2-60201, Form S-7 [a]	2-1
June 3, 1977	2-60201, Form S-7 [a]	2-1
May 17, 1978	2-99665, Form S-3 [a]	4-3
August 31, 1978	2-99665, Form S-3 [a]	4-3
June 18, 1979	2-99665, Form S-3 [a]	4-3
June 20, 1980	2-99665, Form S-3 [a]	4-3
April 16, 1981	2-99665, Form S-3 [a]	4-3
April 30, 1982	2-99665, Form S-3 [a]	4-3
April 15, 1983	2-99665, Form S-3 [a]	4-3
April 13, 1984	2-99665, Form S-3 [a]	4-3
April 15, 1985	2-99665, Form S-3 [a]	4-3
April 15, 1986	33-6879, Form S-3 [a]	4-9
January 13, 2003	001-01839, Form 8-K datedFebruary 13, 2003	4-4
February 22, 2006	001-01839, Form 8-K dated March 6, 2006	4.1
August 1, 2006	001-01839, Form 8-K dated August 28, 2006	4.1
September 15, 2006	001-01839, Form 8-K dated October 2, 2006	4.1
March 1, 2007	001-01839, Form 8-K dated March 23, 2007	4.1
August 30, 2007	001-01839, Form 8-K dated September 10, 2007	4.1
December 20, 2007	001-01839, Form 8-K dated January 16, 2008	4.1
March 10, 2008	001-01839, Form 8-K dated March 27, 2008	4.1
July 12, 2010	001-01839, Form 8-K dated August 2, 2010	4.1
August 22, 2011	001-01839, Form 8-K dated September 7, 2011	4.1

	Dated as of	File Reference	Exhibit No.
	September 17, 2012	001-01839, Form 8-K dated October 1, 2012	4.1
	August 1, 2013	001-01839, Form 8-K dated August 19, 2013	4.1
	January 2, 2014	001-01839, Form 8-K dated January 10, 2014	4.1
	October 28, 2014	001-01839, Form 8-K dated November 10, 2014	4.1
	February 18, 2015	001-01839, Form 8-K dated March 2, 2015	4.1
	November 4, 2015	001-01839, Form 8-K dated November 19, 2015	4.1
	June 15, 2016	001-01839, Form 8-K dated June 27, 2016	4.1
	August 9, 2017	001-01839, Form 8-K dated August 23, 2017	4.1

Exhibit No.	Description
4-3-2	Instrument of Resignation, Appointment and Acceptance dated as of February 20, 2002, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923, and Indentures Supplemental thereto, regarding corporate trustee (File No. 1-1839, 2001 Form 10-K, Exhibit 4-4-2).
4-3-3	Instrument dated as of January 31, 1996, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923 and Indentures Supplemental thereto, regarding individual trustee (File No. 1-1839, 1995 Form 10-K, Exhibit 4-29).
4-4	Indenture dated as of September 1, 1987 between Commonwealth Edison Company and Citibank, N.A. (U.S. Bank National Association, as current successor trustee), Trustee relating to Notes (Registration No. 33-20619, Form S-3, Exhibit 4-13). [(a)]
4-5	Indenture dated December 19, 2003 between Exelon Generation Company, LLC and U.S. Bank National Association (File No. 333-85496, 2003 Form 10-K, Exhibit 4-6).
4-6	Indenture to Subordinated Debt Securities dated as of June 24, 2003 between PECO Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (File No. 000-16844, June 30, 2003 Form 10-Q, Exhibit 4.1).
4-7	Form of 4.25% Senior Note due 2022 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.1).
4-8	Form of 5.60% Senior Note due 2042 issued by Exelon Generation Company, LLC. (File 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.2).
4-9	Form of 2.80% Senior Note due 2022 issued by Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated August 17, 2012, Exhibit 4.1).
4-10	Form of 3.35% Senior Note due 2023 Baltimore Gas and Electric Company. (File 1-1910, Form 8-K dated June 17, 2013, Exhibit 4.1).
4-11	Form of 6.000% Senior Secured Notes due 2033 issued by Exelon Generation Company, LLC (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.1).

Exhibit No.	Description
4-12	Preferred Securities Guarantee Agreement between PECO Energy Company, as Guarantor, and U.S. Bank National Association, as Trustee, dated as of June 24, 2003 (File No. 000-16844, June 30, 2003 Form 10-Q, Exhibit 4.2).
4-13	PECO Energy Capital Trust IV Amended and Restated Declaration of Trust among PECO Energy Company, as Sponsor, U.S. Bank Trust National Association, as Delaware Trustee and Property Trustee, and J. Barry Mitchell, George R. Shicora and Charles S. Walls as Administrative Trustees dated as of June 24, 2003 (File No. 000-16844, June 30, 2003 Form 10-Q, Exhibit 4.3).
4-14	Indenture dated May 1, 2001 between Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 1-16169, June 30, 2005 Form 10-Q, Exhibit 4-10).
4-15	Form of $500,000,000 5.625% senior notes due 2035 dated June 9, 2005 issued by Exelon Corporation (File No. 1-16169, Form 8-K dated June 9, 2005, Exhibit 99.3).
4-16	Indenture dated as of September 28, 2007 from Exelon Generation Company, LLC to U.S. Bank National Association, as trustee (File 333-85496, Form 8-K dated September 28, 2007, Exhibit 4.1).
4-17	Form of 5.20% Exelon Generation Company, LLC Senior Note due 2019 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.1).
4-18	Form of 6.25% Exelon Generation Company, LLC Senior Note due 2039 (File 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.2).
4-19	Form of 4.00% Exelon Generation Company, LLC Senior Note due 2020 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.1).
4-20	Form of 5.75% Exelon Generation Company, LLC Senior Note due 2041 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.2).
4-21	Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of March 24, 1999. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 dated March 29, 1999, filed by Constellation Energy Group, Inc., File No. 333-75217.)
4-22	First Supplemental Indenture between Constellation Energy Group, Inc. and the Bank of New York, Trustee dated as of January 24, 2003. (Designated as Exhibit No. 4(b) to the Registration Statement on Form S-3 dated January 24, 2003, filed by Constellation Energy Group, Inc., File No. 333-102723).
4-23	Indenture dated as of July 24, 2006 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991).
4-24	First Supplemental Indenture between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee, dated as of June 27, 2008. (Designated as Exhibit 4(a) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869).
4-25	Indenture dated June 19, 2008 between Constellation Energy Group, Inc. and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(a) to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
4-26	Indenture, dated as of September 30, 2013, among Continental Wind, LLC, the guarantors party thereto and Wilmington Trust, National Association, as trustee (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.1).

Exhibit No.	Description
4-27	Indenture dated July 1, 1985, between Baltimore Gas and Electric Company and The Bank of New York (Successor to Mercantile-Safe Deposit and Trust Company), Trustee. (Designated as Exhibit 4(a) to the Registration Statement on Form S-3, File No. 2-98443); as supplemented by Supplemental Indentures dated as of October 1, 1987 (Designated as Exhibit 4(a) to the Current Report on Form 8-K, dated November 13, 1987, File No. 1-1910) and as of January 26, 1993 (Designated as Exhibit 4(b) to the Current Report on Form 8-K, dated January 29, 1993, filed by Baltimore Gas and Electric Company, File No. 1-1910). [(a)]
4-28	Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee (including form of Baltimore Gas and Electric Company Officer's Certificate and form of Senior Secured Bond) (Designated as Exhibit Nos. 4(u) and 4(u)(1) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01).
4-29	Indenture dated as of July 24, 2006 between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit 4(b) to the Registration Statement on Form S-3 filed July 24, 2006, filed by Constellation Energy Group, Inc., File No. 333-135991).
4-30	Supplemental Indenture No. 1, dated as of October 1, 2009, to the Indenture and Security Agreement dated as of July 9, 2009, between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee. (Designated as Exhibit No. 4(c) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
4-31	Baltimore Gas and Electric Company Deed of Easement and Right-of-Way Grant dated as of July 9, 2009 (Designated as Exhibit No. 4(u)(2) to Post-Effective Amendment No. 1 to the Registration Statement on Form S-3 dated July 9, 2009, filed by Constellation Energy Group, Inc., File Nos. 333-157637 and 333-157637-01).
4-32	Indenture dated as of June 29, 2007, by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary. (Designated as Exhibit 4.1 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).
4-33	Series Supplement to Indenture dated as of June 29, 2007 by and between RSB BondCo LLC and Deutsche Bank Trust Company Americas, as Trustee and Securities Intermediary (Designated as Exhibit No. 4(b) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009, filed by Baltimore Gas and Electric Company, File No. 1-1910).
4-34	Replacement Capital Covenant dated June 27, 2008. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated June 30, 2008, filed by Constellation Energy Group, Inc., File No. 1-12869).
4-35	Amendment to Replacement Capital Covenant, dated as of March 12, 2012, amending the Replacement Capital Covenant, dated as of June 27, 2008 (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 99.4).
4-36	Officers' Certificate, dated December 14, 2010, establishing the 5.15% Notes due December 1, 2020 of Constellation Energy Group, Inc., with the form of Notes attached thereto. (Designated as Exhibit No. 4 (b) to the Current Report on Form 8-K dated December 14, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
4-37	Officers' Certificate, November 16, 2011, establishing the 3.50% Notes due November 15, 2021 of Baltimore Gas and Electric Company, with the form of Notes attached thereto. (Designated as Exhibit No. 4(b) to the Current Report on Form 8-K dated November 16, 2011, filed by Baltimore Gas and Electric Company, File No. 1-1910).

Exhibit No.	Description
4-38	Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee. (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.1).
4-38-1	First Supplemental Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee.(File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.2).
4-38-2	Form of 2.50% Notes due 2024 (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.1).
4-38-3	Purchase Contract and Pledge Agreement, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary. (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.4).
4-38-4	Form of Remarketing Agreement (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.5).
4-38-5	Form of Corporate Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.6).
4-38-6	Form of Treasury Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.7).
4-39	Indenture, dated as of June 11, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Exelon Corporation's Current Report on Form 8-K, filed on June 11, 2015).
4-39-1	First Supplemental Indenture, dated as of June 11, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to Exelon Corporation's Current Report on Form 8-K, filed on June 11, 2015).
4-39-2	Second Supplemental Indenture, dated as of December 2, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Exelon Corporation's Current Report on Form 8-K, filed on December 2, 2015).
4-39-3	Registration Rights Agreement, dated as of December 2, 2015, among Exelon Corporation,Barclays Capital Inc. and Goldman, Sachs & Co. (incorporated herein by reference to Exhibit 1.1 to Exelon Corporation's Current Report on Form 8-K, filed on December 2, 2015).
4-40	Form of Conversion Supplemental Indenture, dated March 23, 2016 (File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 4.1)
4-41	Third Supplemental Indenture, dated as of April 7, 2016, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee (File No. 001-16169, Form 8-K dated April 7, 2016, Exhibit 4.2)
4-42	Mortgage and Deed of Trust, dated July 1, 1936, of Potomac Electric Power Company to The Bank of New York Mellon as successor trustee, securing First Mortgage Bonds of Potomac Electric Power Company, and Supplemental Indenture dated July 1, 1936 (File No. 2-2232, Registration Statement dated June 19, 1936, Exhibit B-4) [a]
4-42-1	Supplemental Indentures to Potomac Electric Power Company Mortgage.

Dated as of	File Reference	Exhibit No.
December 10, 1939	Form 8-K, 1/3/40 [a]	B

Dated as of	File Reference	Exhibit No.
July 15, 1942	2-5032, Amendment No 2. To Registration Statement, 8/24/42 [(a)]	B-1
October 15, 1947	Form 8-K , 12/8/47 [(a)]	A
December 31, 1948	Form 10-K, 4/13/49 [(a)]	A-2
December 31, 1949	Form 8-K, 2/8/50 [(a)]	(a)-1
February 15, 1951	Form 8-K, 3/9/51 [(a)]	(a)
February 16, 1953	Form 8-K, 3/5/53 [(a)]	(a)-1
March 15, 1954 and March 15, 1955	2-11627, Registration Statement, 5/2/55 [(a)]	4-B
March 15, 1956	Form 10-K, 4/4/56 [(a)]	C
April 1, 1957	2-13884, Registration Statement, 2/5/58 [(a)]	4-B
May 1, 1958	2-14518, Registration Statement, 11/10/58 [(a)]	2-B
May 1, 1959	2-15027, Amendment No. 1 to Registration Statement, 5/13/59 [(a)]	4-B
May 2, 1960	2-17286, Registration Statement, 11/9/60 [(a)]	2-B
April 3, 1961	Form 10-K, 4/24/61 [(a)]	A-1
May 1, 1962	2-21037, Registration Statement, 1/25/63 [(a)]	2-B
May 1, 1963	2-21961, Registration Statement, 12/19/63 [(a)]	4-B
April 23, 1964	2-22344, Registration Statement, 4/24/64 [(a)]	2-B
May 3, 1965	2-24655, Registration Statement, 3/16/66 [(a)]	2-B
June 1, 1966	Form 10-K, 4/11/67 [(a)]	1
April 28, 1967	2-26356, Post-Effective Amendment No. 1 to Registration Statement, 5/3/67 [(a)]	2-B
July 3, 1967	2-28080, Registration Statement, 1/25/68 [(a)]	2-B
May 1, 1968	2-31896, Registration Statement, 2/28/69 [(a)]	2-B
June 16, 1969	2-36094, Registration Statement, 1/27/70 [(a)]	2-B

Dated as of	File Reference	Exhibit No.
May 15, 1970	2-38038, Registration Statement, 7/27/70 [a]	2-B
September 1, 1971	2-45591, Registration Statement, 9/1/72 [a]	2-C
June 17, 1981	Amendment No. 1 to Form 8-A, 6/18/81 [a]	2
November 1, 1985	Form 8-A, 11/1/85 [a]	2B
September 16, 1987	33-18229, Registration Statement, 10/30/87 [a]	4-B
May 1, 1989	33-29382, Registration Statement, 6/16/89 [a]	4-C
May 21, 1991	Form 10-K, 3/27/92 [a]	4
May 7, 1992	Form 10-K, 3/26/93 [a]	4
September 1, 1992	Form 10-K, 3/26/93 [a]	4
November 1, 1992	Form 10-K, 3/26/93 [a]	4
July 1, 1993	33-49973, Registration Statement, 8/11/93 [a]	4.4
February 10, 1994	001-01072, Form 10-K, 3/25/94	4
February 11, 1994	001-01072, Form 10-K, 3/25/94	4
October 2, 1997	001-01072, Form 10-K, 3/27/98	4
November 17, 2003	001-01072, Form 10-K, 3/12/04	4.1
March 16, 2004	001-01072, Form 8-K, 3/23/04	4.3
May 24, 2005	001-01072, Form 8-K, 5/26/05	4.2
April 1, 2006	001-01072, Form 8-K, 4/17/06	4.1
November 13, 2007	001-01072, Form 8-K, 11/15/07	4.2
March 24, 2008	001-01072, Form 8-K, 3/28/08	4.1
December 3, 2008	001-01072, Form 8-K, 12/8/08	4.2
March 28, 2012	001-01072, Form 8-K, 3/29/12	4.2
March 11, 2013	001-01072, Form 8-K, 3/12/13	4.2
November 14, 2013	001-01072, Form 8-K, 11/15/13	4.2

	Dated as of	File Reference	Exhibit No.
	March 11, 2014	001-01072, Form 8-K, 3/12/14	4.2
	March 9, 2015	001-01072, Form 8-K, 3/10/15	4.3
	May 15, 2017	001-01072, Form 8-K, 5/22/17	4.2

Exhibit No.	Description
4-43	Indenture, dated as of July 28, 1989, between Potomac Electric Power Company and The Bank of New York Mellon, Trustee, with respect to Medium-Term Note Program (File No. 001-01072, Form 8-K dated June 21, 1990, Exhibit 4) [(a)]
4-44	Senior Note Indenture, dated November 17, 2003 between Potomac Electric Power Company and The Bank of New York Mellon (File No. 001-01072, Form 8-K dated November 21, 2003, Exhibit 4.2)
4-44-1	Supplemental Indenture, dated March 3, 2008, to Senior Note Indenture between Potomac Electric Power Company and The Bank of New York Mellon (File No. 001-01072, Form 10-K dated March 2, 2009, Exhibit 4.3)
4-45	Mortgage and Deed of Trust of Delaware Power & Light Company to The Bank of New York Mellon (ultimate successor to the New York Trust Company), as trustee, dated as of October 1, 1943, and copies of the First through Sixty-Eighth Supplemental Indentures thereto (File No. 33-1763, Registration Statement dated November 27, 1985, Exhibit 4-A) [(a)]
4-45-1	Supplemental Indentures to Delmarva Power & Light Company Mortgage.

Dated as of	File Reference	Exhibit No.
January 1, 1986	33-39756, Registration Statement, 4/03/91 [(a)]	4-B
June 1, 1986	33-24955, Registration Statement, 10/13/88 [(a)]	4-B
January 1, 1987	33-24955, Registration Statement, 10/13/88 [(a)]	4-B
September 1, 1987	33-24955, Registration Statement, 10/13/88 [(a)]	4-B
October 1, 1987	33-24955, Registration Statement, 10/13/88 [(a)]	4-B
January 1, 1988	33-24955, Registration Statement, 10/13/88 [(a)]	4-B
December 1, 1988	33-39756, Registration Statement, 4/03/91 [(a)]	4-D
January 1, 1989	33-39756, Registration Statement, 4/03/91 [(a)]	4-E
March 1, 1990	33-39756, Registration Statement, 4/03/91 [(a)]	4-F
January 1, 1991	33-46892, Registration Statement, 4/1/92 [(a)]	4-E
July 1, 1991	33-46892, Registration Statement, 4/1/92 [(a)]	4-F

Dated as of	File Reference	Exhibit No.
February 1, 1992	33-49750, Registration Statement, 7/17/92 [a]	4
May 1, 1992	33-57652, Registration Statement, 1/29/93 [a]	4-G
October 1, 1992	33-63582, Registration Statement, 5/28/93 [a]	4-H
January 1, 1993	33-50453, Registration Statement, 10/1/93 [a]	99
June 1, 1993	33-53855, Registration Statement, 1/30/95 [a]	4-J
July 1, 1993	33-53855, Registration Statement, 1/30/95 [a]	4-K
October 1, 1993	33-53855, Registration Statement, 1/30/95 [a]	4-L
January 1, 1994	33-53855, Registration Statement, 1/30/95 [a]	4-M
October 1, 1994	33-53855, Registration Statement, 1/30/95 [a]	4-N
January 1, 1995	333-00505, Registration Statement, 1/29/96 [a]	4-K
June 1, 1995	333-00505, Registration Statement, 1/29/96 [a]	4-L
January 1, 1996	333-24059, Registration Statement, 3/27/97 [a]	4-L
January 1, 1997	001-01405, Form 10-K, 2/24/12	4.4
January 1, 1998	001-01405, Form 10-K, 2/24/12	4.4
January 1, 1999	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2000	333-145691-02, Post Effective Amendment No. 1 to Registration Statement, 11/18/08	4.24(k)
January 1, 2001	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2002	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2003	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2004	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2005	001-01405, Form 10-K, 2/24/12	4.4

Dated as of	File Reference	Exhibit No.
January 1, 2006	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2007	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2008	001-01405, Form 10-K, 2/24/12	4.4
January 1, 2009	001-01405, Form 10-K, 2/24/12	4.4
September 22, 2009	001-01405, Form 8-K, 10/1/09	4.4
January 1, 2010	001-01405, Form 10-K, 2/25/11	4.4
January 1, 2011	001-01405, Form 10-Q, 8/3/11	4.2
May 2, 2011	001-01405, Form 8-K, 6/3/11	4.2
January 1, 2012	001-01405, Form 10-Q, 8/7/12	4.3
June 19, 2012	001-01405, Form 8-K, 6/20/12	4.2
January 1, 2013	001-01405, Form 10-Q, 8/7/13	4.1
November 7, 2013	001-01405, Form 8-K, 11/8/13	4.2
January 1, 2014	001-01405, Form 10-K, 2/27/15	4.4
June 2, 2014	001-01405, Form 8-K, 6/3/14	4.3
January 1, 2015	001-01405, Form 10-K, 2/19/16	4.4
May 4, 2015	001-01405, Form 8-K, 5/5/15	4.2
January 1, 2016	Filed herewith.	
December 5, 2016	001-01405, Form 8-K, 12/12/16	4.2
April 5, 2017	001-01405, Form 10-Q, 5/3/17	4.5

Exhibit No.	Description
4-46	Indenture between Delmarva Power & Light Company and The Bank of New York Mellon Trust Company, N.A. (ultimate successor to Manufacturers Hanover Trust Company), as trustee, dated as of November 1, 1988 (File No. 33-46892, Registration Statement dated April 1, 1992, Exhibit 4-G) [a]
4-47	Mortgage and Deed of Trust, dated January 15, 1937, between Atlantic City Electric Company and The Bank of New York Mellon (formerly Irving Trust Company), as trustee (File No. 2-66280, Registration Statement dated December 21, 1979, Exhibit 2(a)) [a]
4-47-1	Supplemental Indentures to Atlantic City Electric Company Mortgage.

Dated as of	File Reference	Exhibit No.
June 1, 1949	2-66280, Registration Statement, 12/21/79 [a]	2(b)
July 1, 1950	2-66280, Registration Statement, 12/21/79 [a]	2(b)
November 1, 1950	2-66280, Registration Statement, 12/21/79 [a]	2(b)
March 1, 1952	2-66280, Registration Statement, 12/21/79 [a]	2(b)
January 1, 1953	2-66280, Registration Statement, 12/21/79 [a]	2(b)
March 1, 1954	2-66280, Registration Statement, 12/21/79 [a]	2(b)
March 1, 1955	2-66280, Registration Statement, 12/21/79 [a]	2(b)
January 1, 1957	2-66280, Registration Statement, 12/21/79 [a]	2(b)
April 1, 1958	2-66280, Registration Statement, 12/21/79 [a]	2(b)
April 1, 1959	2-66280, Registration Statement, 12/21/79 [a]	2(b)
March 1, 1961	2-66280, Registration Statement, 12/21/79 [a]	2(b)
July 1, 1962	2-66280, Registration Statement, 12/21/79 [a]	2(b)
March 1, 1963	2-66280, Registration Statement, 12/21/79 [a]	2(b)
February 1, 1966	2-66280, Registration Statement, 12/21/79 [a]	2(b)
April 1, 1970	2-66280, Registration Statement, 12/21/79 [a]	2(b)
September 1, 1970	2-66280, Registration Statement, 12/21/79 [a]	2(b)
May 1, 1971	2-66280, Registration Statement, 12/21/79 [a]	2(b)
April 1, 1972	2-66280, Registration Statement, 12/21/79 [a]	2(b)
June 1, 1973	2-66280, Registration Statement, 12/21/79 [a]	2(b)
January 1, 1975	2-66280, Registration Statement, 12/21/79 [a]	2(b)
May 1, 1975	2-66280, Registration Statement, 12/21/79 [a]	2(b)

Dated as of	File Reference	Exhibit No.
December 1, 1976	2-66280, Registration Statement, 12/21/79 [a]	2(b)
January 1, 1980	Form 10-K, 3/25/81 [a]	4(e)
May 1, 1981	Form 10-Q, 8/10/81 [a]	4(a)
November 1, 1983	Form 10-K, 3/30/84 [a]	4(d)
April 15, 1984	Form 10-Q, 5/14/84 [a]	4(a)
July 15, 1984	Form 10-Q, 8/13/84 [a]	4(a)
October 1, 1985	Form 10-Q, 11/12/85 [a]	4
May 1, 1986	Form 10-Q, 5/12/86 [a]	4
July 15, 1987	Form 10-K, 3/28/88 [a]	4(d)
October 1, 1989	Form 10-Q for quarter ended 9/30/89 [A]	4(a)
March 1, 1991	Form 10-K, 3/28/91 [a]	4(d)(1)
May 1, 1992	33-49279, Registration Statement, 1/6/93 [a]	4(b)
January 1, 1993	333-108861, Registration Statement, 9/17/03	4.05(hh)
August 1, 1993	Form 10-Q, 11/12/93 [a]	4(a)
September 1, 1993	Form 10-Q, 11/12/93 [a]	4(b)
November 1, 1993	Form 10-K, 3/29/94 [a]	4(c)(1)
June 1, 1994	Form 10-Q, 8/14/94 [a]	4(a)
October 1, 1994	Form 10-Q, 11/14/94 [a]	4(a)
November 1, 1994	Form 10-K, 3/21/95 [a]	4(c)(1)
March 1, 1997	001-03559, Form 8-K, 3/24/97	4(b)
April 1, 2004	001-03559, Form 8-K, 4/6/04	4.3
August 10, 2004	001-03559, Form 10-Q, 11/9/04	4
March 8, 2006	001-03559, Form 8-K, 3/17/06	4
November 6, 2008	001-03559, Form 8-K, 11/10/08	4.2
March 29, 2011	001-03559, Form 8-K, 4/1/11	4.2
August 18, 2014	001-03559, Form 8-K, 8/19/14	4.2
December 1, 2015	001-03559, Form 8-K, 12/2/15	4.2

Exhibit No.	Description
4-48	Indenture, dated as of March 1, 1997, between Atlantic City Electric Company and The Bank of New York Mellon, as trustee (File No. 001-03559, Form 8-K dated March 24, 1997, Exhibit 4.2)

Exhibit No.	Description
4-49	Senior Note Indenture, dated as of April 1, 2004, between Atlantic City Electric Company and The Bank of New York Mellon, as trustee (File No. 001-03559, Form 8-K dated April 6, 2004, Exhibit 4.2)
4-50	Indenture, dated as of December 19, 2002 between Atlantic City Electric Transition Funding LLC and The Bank of New York Mellon, as trustee (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 4.1)
4-51	2002-1 Series Supplement, dated as of December 19, 2002 between Atlantic City Electric Transition Funding LLC and The Bank of New York Mellon, as trustee (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 4.2)
4-52	2003-1 Series Supplement, dated as of December 23, 2003 between Atlantic City Electric Transition Funding LLC and The Bank of New York Mellon, as trustee (File No. 333-59558, Form 8-K dated December 23, 2003, Exhibit 4.2)
4-53	Indenture, dated September 6, 2002, between Pepco Holdings, Inc. and The Bank of New York Mellon, as trustee (File No. 333-100478, Registration Statement on Form S-3 dated October 10, 2002, Exhibit 4.03)
4-54	Corporate Commercial Paper Master Note (File No. 001-31403, Form 10-K dated February 24, 2012, Exhibit 4.13)
4-55	Pepco Holdings, Inc. Certificate of Series A Non-Voting Non-Convertible Preferred Stock (File No. 001-31403, Form 8-k dated April 30, 2014, Exhibit 3.1)
4-56	Form of 2.400% notes due 2026 (File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.1)
4-57	Form of 3.500% notes due 2046 (File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.2)
4-58	Form of Exelon Generation Company, LLC 2.950% senior notes due 2020 (File No. 333-85496, Form 8-K dated March 10, 2017, Exhibit 4.1)
4-59	Form of Exelon Generation Company, LLC 3.400% notes due 2022 (File No. 333-85496, Form 8-K dated March 10, 2017, Exhibit 4.2)
4-60	Second Supplemental Indenture, dated April 3, 2017, between Exelon and The Bank of New York Mellon Trust Company, N.A., as trustee, to that certain Indenture (For Unsecured Subordinated Debt Securities), dated June 17, 2014 (File No. 001-16169, Form 8-K dated April 4, 2017, Exhibit 4.3)
4-61	Form of Exelon Corporation 3.497% junior subordinated notes due 2022 (File No. 001-16169, Form 8-K dated April 4, 2017, Exhibit 4.4)
4-62	Form of First Mortgage Bond, 4.15% Series due March 15, 2043 (File No. 001-01072, Form 8-K dated May 22, 2017, Exhibit 4.3)
4-63	BGE Form of 3.750% notes due 2047 (File No. 001-01910, Form 8-K dated August 24, 2017, Exhibit 4.1)
10-1	Facility Credit Agreement, dated as of February 6, 2014, among ExGen Renewables I Holding, LLC and Barclays Bank PLC (File No. 333-85496, Form 8-K dated February 12, 2014, Exhibit 10.1).

Exhibit No.	Description
10-1-1	Credit Agreement, dated as of September 18, 2014, among ExGen Texas Power, LLC, ExGen Texas Power Holdings, LLC, Wolf Hollow I Power, LLC, Colorado Bend I Power, LLC, Laporte Power, LLC, Handley Power, LLC and Mountain Creek Power, LLC, the lenders party thereto from time to time, Bank of America, N.A., as administrative agent and collateral agent, and Wilmington Trust, National Association, as depositary agent. (File No. 1-16169, Form 8-K dated September 18, 2014, Exhibit 10.1).
10-2	Exelon Corporation Non-Employee Directors' Deferred Stock Unit Plan (As Amended and Restated Effective January 1, 2011). * (File No. 001-16169, 2010 Form 10-K, Exhibit 10.1).
10-3	Form of Exelon Corporation Unfunded Deferred Compensation Plan for Directors (as amended and restated Effective March 12, 2012). * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-3)
10-4	Reserved.
10-5	Form of Restricted Stock Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-1).
10-6	Forms of Transferable Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-2).
10-7	Forms of Stock Option Award Agreement under the Exelon Corporation Long-Term Incentive Plan* (File No. 1-16169, 2001 Form 10-K, Exhibit 10-6-3).
10-8	Unicom Corporation Deferred Compensation Unit Plan, as amended *(File Nos. 1-11375 and 1-1839, 1995 Form 10-K, Exhibit 10-12).
10-9	Amendment Number One to the Unicom Corporation Deferred Compensation Unit Plan, as amended January 1, 2008 * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.16).
10-10	Unicom Corporation Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-12).
10-11	Commonwealth Edison Company Retirement Plan for Directors, as amended *(Registration Statement No. 333-49780, Form S-8, Exhibit 4-13).
10-12	Exelon Corporation Supplemental Management Retirement Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.19).
10-13	PECO Energy Company Supplemental Pension Benefit Plan (As Amended and Restated Effective January 1, 2009) (File No. 000-16844, 2008 Form 10-K, Exhibit 10.20).
10-14	Exelon Corporation Annual Incentive Plan for Senior Executives (As Amended Effective January 1, 2014 * (File No. 1-16169, Exelon Proxy Statement dated April 1, 2014, Appendix A).
10-15	Form of change in control employment agreement for senior executives effective January 1, 2009 * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.23).
10-16	Form of change in control employment agreement (amended and restated as of January 1, 2009) * (File No. 001-16169, 2008 Form 10-K, Exhibit 10.24).
10-17	Exelon Corporation Employee Stock Purchase Plan, as amended and restated effective July 1, 2013. (File No. 1-16169, Schedule 14A dated March 14, 2013 Appendix A).
10-18	Exelon Corporation 2006 Long-Term Incentive Plan (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex H).

Exhibit No.	Description
10-19	Form of Stock Option Grant Instrument under the Exelon Corporation 2006 Long-Term Incentive Plan (File No. 1-16169, Form 8-K filed January 27, 2006, Exhibit 99.2).
10-20	Exelon Corporation Employee Stock Purchase Plan for Unincorporated Subsidiaries (Registration Statement No. 333-122704, Form S-4, Joint Proxy Statement-Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex I).
10-21	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective April 1, 2013).* (File No. 001-16169, 2013 Form 10-K, Exhibit 10.21).
10-21-1	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective November 1, 2015) * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-21-1)
10-22	Form of Separation Agreement under Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective November 1, 2015) * Filed herewith.
10-23	Facility Credit Agreement, dated as of November 4, 2010, among Exelon Generation Company, LLC and UBS AG, Stamford Branch (File No. 333-85496, Form 8-K dated February 22, 2011, Exhibit No. 10-1).
10-24	Exelon Corporation Executive Death Benefits Plan dated as of January 1, 2003 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-52).
10-25	First Amendment to Exelon Corporation Executive Death Benefits Plan, Effective January 1, 2006 * (File No. 1-16169, 2006 Form 10-K, Exhibit 10-53).
10-26	Amendment Number One to the Exelon Corporation 2006 Long-Term Incentive Plan, Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-54).
10-27	Amendment Number Two to the Exelon Corporation 2006 Long-Term Incentive Plan (As Amended and Restated Effective January 28, 2002), Effective December 4, 2006 (File No. 1-16169, 2006 Form 10-K, Exhibit 10-55).
10-28	Exelon Corporation Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-56).
10-29	Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, 2006 Form 10-K, Exhibit 10-57).
10-30	Commonwealth Edison Company Long-Term Incentive Plan, Effective January 1, 2007 (File No. 1-16169, March 31, 2007 Form 10-Q, Exhibit 10-1).
10-31	Amendment Number One to the Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1-16169, June 30, 2007 Form 10-Q, Exhibit 10-3).
10-32	Restricted stock unit award agreement (File 1-16169, Form 8-K dated August 31, 2007, Exhibit 99.1).
10-33	Reserved.
10-34	Form of Exelon Corporation 2011 Long-Term Incentive Plan, as amended effective December 18, 2014. * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-34)
10-34-1	Form of Exelon Corporation Long-Term Incentive Program, as amended and restated as of January 1, 2014. * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-34-1)
10-34-2	Form of Exelon Corporation Long-Term Incentive Program, as amended and restated as of January 1, 2015. * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-34-2)

Exhibit No.	Description
10-34-3	Amendment Number Two to the Exelon Corporation 2011 Long-Term Incentive Plan (As Amended and Restated Effective January 21, 2014), Effective October 26, 2015. * (File No. 1-16169, 2015 Form 10-K, Exhibit 10-34-3)
10-35	Form of Change in Control Employment Agreement Effective February 10, 2011. * (File 1-16169, 2010 Form 10-K, Exhibit 10-44).
10-36	Credit Agreement for $500,000,000 dated as of March 23, 2011 between Exelon Corporation and Various Financial Institutions (File No. 001-16169, Form 8-K dated March 23, 2011, Exhibit No. 99.1).
10-37	Credit Agreement for $5,300,000,000 dated as of March 23, 2011 between Exelon Generation Company, LLC and Various Financial Institutions (File No. 333-85496, Form 8-K dated March 23, 2011, Exhibit No. 99.2).
10-38	Credit Agreement for $600,000,000 dated as of March 23, 2011 between PECO Energy Company and Various Financial Institutions (File No. 000-16844, Form 8-K dated March 23, 2011, Exhibit No. 99.3).
10-39	Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, Various Financial Institutions, as Lenders, and JP Morgan Chase Bank, N.A., as Administrative Agent (File No. 001-01839, Form 8-K dated March 28, 2012, Exhibit No. 99-1).
10-40	Amendment No. 3 to Credit Agreement dated as of March 23, 2011 among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated August 10, 2013, Exhibit No. 99-1).
10-41	Amendment No. 1 to Credit Agreement dated as of March 28, 2012 among Commonwealth Edison Company, as Borrower, the various financial institutions named therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-1839, Form 8-K dated August 10, 2013, Exhibit No. 99-2).
10-42	Amendment No. 1 to Credit Agreement, dated as of December 21, 2011, to the Credit Agreement dated as of March 23, 2011, among Exelon Generation Company, LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated March 14, 2012, Exhibit No. 4-6).
10-43	Constellation Energy Group, Inc. Nonqualified Deferred Compensation Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-44	Constellation Energy Group, Inc. Deferred Compensation Plan for Non-Employee Directors, as amended and restated. * (Designated as Exhibit No. 10(c) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-45	Constellation Energy Group, Inc. Benefits Restoration Plan, amended and restated effective June 1, 2010. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-46	Constellation Energy Group, Inc. Supplemental Pension Plan, as amended and restated. * (Designated as Exhibit No. 10(e) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-47	Constellation Energy Group, Inc. Senior Executive Supplemental Plan, as amended and restated. * (Designated as Exhibit No. 10(f) to the Constellation Annual Report on Form 10-K for the year ended December 31, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).

Exhibit No.	Description
10-48	Executive Annual Incentive Plan of Constellation Energy Group, Inc., as amended and restated. * (Designated as Exhibit No. 10(d) to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-49	Constellation Energy Group, Inc. Executive Supplemental Benefits Plan, as amended and restated. * (Designated as Exhibit No. 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2008, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-50	Constellation Energy Group, Inc. 1995 Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit No. 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2004, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-51	Constellation Energy Group, Inc. Executive Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(b) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-52	Constellation Energy Group, Inc. 2002 Senior Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(a) to the Constellation Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-53	Constellation Energy Group, Inc. Management Long-Term Incentive Plan, as amended and restated. * (Designated as Exhibit 10(d) to the Constellation Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-54	Constellation Energy Group, Inc. Amended and Restated 2007 Long-Term Incentive Plan. * (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated June 4, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-55	Form of Grant Agreement for Stock Units with Sales Restriction. * (Designated as Exhibit No. 10(x) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-56	Rate Stabilization Property Servicing Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as servicer (Designated as Exhibit 10.2 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).
10-57	Administration Agreement dated as of June 29, 2007 by and between RSB BondCo LLC and Baltimore Gas and Electric Company, as administrator (Designated as Exhibit 10.3 to the Current Report on Form 8-K dated July 5, 2007, filed by Baltimore Gas and Electric Company, File No. 1-1910).
10-58	Second Amended and Restated Operating Agreement, dated as of November 6, 2009, by and among Constellation Energy Nuclear Group, LLC, Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Development Inc., and for certain limited purposes, E.D.F. International S.A. and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 12, 2009, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-59	Amendment No. 1 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(s) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).

Exhibit No.	Description
10-60	Amendment No. 2 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10(t) to the Annual Report on Form 10-K for the year ended December 31, 2010, filed by Constellation Energy Group, Inc., File Nos. 1-12869 and 1-1910).
10-61	Amendment No. 3 to the Second Amended and Restated Operating Agreement of Constellation Energy Nuclear Group, LLC, by and among Constellation Nuclear, LLC, CE Nuclear, LLC, EDF Inc. (formerly known as EDF Development, Inc.), and E.D.F. International S.A. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-62	Termination Agreement dated as of November 3, 2010, by and among EDF Inc. (formerly known as EDF Development, Inc.), E.D.F. International S.A., and Constellation Energy Group, Inc. (Designated as Exhibit No. 10.2 to the Current Report on Form 8-K dated November 3, 2010, filed by Constellation Energy Group, Inc., File No. 1-12869).
10-63	Settlement Agreement between EDF Inc., Exelon Corporation, Exelon Energy Delivery Company, LLC, Constellation Energy Group, Inc. and Baltimore Gas and Electric Company dated January 16, 2012. (Designated as Exhibit No. 10.1 to the Current Report on Form 8-K dated January 19, 2012, File Nos. 1-12869 and 1-1910).
10-64 - 10-70	Reserved.
10-71	Commitment Letter for $7.221 Billion Senior Unsecured Bridge Facility, dated April 29, 2014 (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit No. 10.1).
10-71-1	364-Day Bridge Term Loan Agreement, dated as of May 30, 2014, among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and Barclays Bank PLC, as Administrative Agent (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit No. 10.1).
10-71-2	Amendment No. 4 to Credit Agreement, dated May 30, 2014, among Exelon Corporation, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.2).
10-71-3	Amendment No. 4 to Credit Agreement, dated May 30, 2014, among Exelon Generation Company, LLC, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.3).
10-71-4	Amendment No. 3 to Credit Agreement, dated May 30, 2014, among PECO Energy Company, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.4).
10-71-5	Amendment No. 2 to Credit Agreement, dated as of May 30, 2014, among Baltimore Gas and Electric Company, as Borrower, the financial institutions signatory therein, as Lenders and The Royal Bank of Scotland plc, as Administrative Agent. (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.5).
10-72-1	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Barclays Capital, Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.1).

Exhibit No.	Description
10-72-2	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.2).
10-72-3	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Barclays Capital, Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.3).
10-72-4	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.4).
10-73	Bondable Transition Property Sale Agreement, dated as of December 19, 2002, between ACE Funding and ACE (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 10.1)
10-74	Bondable Transition Property Servicing Agreement, dated as of December 19, 2002, between ACE Funding and ACE (File No. 333-59558, Form 8-K dated December 23, 2002, Exhibit 10.2)
10-75	Purchase Agreement, dated as of April 20, 2010, by and among Pepco Holdings, Inc., Conectiv, LLC, Conectiv Energy Holding Company, LLC and New Development Holdings, LLC (File No. 001-31403, Form 8-K dated July 8, 2010, Exhibit 2.1)
10-76	Purchase Agreement, dated March 9, 2015, among Potomac Electric Power Company and BNY Mellon Capital Markets, LLC, Morgan Stanley & Co. LLC, and RBS Securities Inc., as representatives of the several underwriters named therein (File No. 001-01072, Form 8-K dated March 10, 2015, Exhibit 1.1)
10-77	Purchase Agreement, May 4, 2015, among Delmarva Power & Light Company and J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, and Scotia Capital (USA) Inc., as representatives of the several underwriters named therein (File No. 001-01405, Form 8-K dated May 5, 2015, Exhibit 1.1)
10-78	Bond Purchase Agreement, dated December 1, 2015, among Atlantic City Electric Company and the purchasers signatory thereto (File No. 001-03559, Form 8-K dated December 2, 2015, Exhibit 1.1)
10-79	$300,000,000 Term Loan Agreement by and among PHI, The Bank of Nova Scotia, as Administrative Agent, and the lenders party thereto, dated July 30, 2015 (File No. 001-31403, Form 8-K dated July 30, 2015, Exhibit 10)
10-80	First Amendment to Term Loan Agreement, dated as of October 29, 2015, by and among PHI, The Bank of Nova Scotia, as Administrative Agent, and the lenders party thereto (File No. 001-31403, Form 8-K dated October 29, 2015, Exhibit 10.2)
10-81	$500,000,000 Term Loan Agreement by and among PHI, The Bank of Nova Scotia, as Administrative Agent, and the lenders party thereto, dated January 13, 2016 (File No. 001-31403, Form 8-K dated January 14, 2016, Exhibit 10)
10-82	Second Amended and Restated Credit Agreement, dated as of August 1, 2011, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the lenders party thereto, Wells Fargo Bank, National Association, as agent, issuer and swingline lender, Bank of America, N.A., as syndication agent and issuer, The Royal Bank of Scotland plc and Citicorp USA, Inc., as co-documentation agents, Wells Fargo Securities, LLC and Merrill Lynch, Pierce, Fenner and Smith Incorporated, as active joint lead arrangers and joint book runners, and Citigroup Global Markets Inc. and RBS Securities, Inc. as passive joint lead arrangers and joint book runners (File No. 001-31403, Form 10-Q dated August 3, 2011, Exhibit 10.1)

Exhibit No.	Description
10-82-1	First Amendment, dated as of August 2, 2012, to Second Amended and Restated Credit Agreement, dated as of August 1, 2011, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions party thereto, Wells Fargo Bank, National Association, as agent, issuer of letters of credit and swingline lender, Bank of America, N.A., as syndication agent and issuer of letters of credit, and The Royal Bank of Scotland plc and Citibank, N.A., as co-documentation agents (File No. 001-31403, Form 10-K dated March 1, 2013, Exhibit 10.25.1)
10-82-2	Amendment and Consent to Second Amended and Restated Credit Agreement, dated as of May 20, 2014, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions from time to time party thereto, Bank of America, N.A. and Wells Fargo Bank, National Association (File No. 001-31403, Form 8-K dated May 20, 2014, Exhibit 10.1)
10-82-3	Third Amendment to Second Amended and Restated Credit Agreement, dated as of May 1, 2015, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions from time to time party thereto, Bank of America, N.A. and Wells Fargo Bank, National Association (File No. 001-31403, Form 8-K dated May 1, 2015, Exhibit 10.1)
10-82-4	Consent, dated as of October 29, 2015, by and among Pepco Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, the various financial institutions from time to time party thereto, Bank of America, N.A. and Wells Fargo Bank, National Association (File No. 001-31403, Form 8-K dated October 29, 2015, Exhibit 10.1)
10-83	Asset Purchase and Sale Agreement for Generating Plants and Related Assets, dated as of June 7, 2000, by and between Pepco and Southern Energy, Inc. (File No. 001-01072, Form 8-K dated June 13, 2000, Exhibit 10)
10-83-1	Amendment No. 1 to the Asset Purchase and Sale Agreement for Generating Plants and Related Assets, dated September 18, 2000, by and between Potomac Electric Power Company and Southern Energy, Inc. (File No. 001-01072, Form 8-K dated December 19, 2000, Exhibit 10.2)
10-83-2	Amendment No. 1 to the Asset Purchase and Sale Agreement for Generating Plants and Related Assets, dated December 19, 2000, by and between Potomac Electric Power Company and Southern Energy, Inc. (File No. 001-01072, Form 8-K dated December 19, 2000, Exhibit 10.2)
10-84	First Amendment to Loan Agreement, by and between Pepco Holdings LLC and The Bank of Nova Scotia, as administrative agent and lender, dated March 28, 2016 (File No. 001-31403, Form 8-K dated March 28, 2016, Exhibit 10)
10-85	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Corporation, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated May 27, 2016, Exhibit 99.1)
10-86	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Generation Company, LLC, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 333-85496, Form 8-K dated May 27, 2016, Exhibit 99.2)
10-87	Amendment No. 7 to Credit Agreement, dated as of March 23, 2011, among Exelon Generation Company, LLC, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 333-85496, Form 8-K dated May 27, 2016, Exhibit 99.2)

Exhibit No.	Description
10-88	Amendment No. 6 to Credit Agreement, dated as of March 23, 2011, among PECO Energy Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 000-16844, Form 8-K dated May 27, 2016, Exhibit 99.4)
10-89	Amendment No. 5 to Credit Agreement, dated as of March 23, 2011, among Baltimore Gas and Electric Company, as Borrower, the various financial institutions named therein, as Lenders, and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-01910, Form 8-K dated May 27, 2016, Exhibit 99.5)
10-90	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of August 1, 2011, among Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company, as Borrowers, the various financial institutions named therein, as Lenders, and Wells Fargo Bank, National Association, as Administrative Agent (File No. 001-31403, Form 8-K dated May 27, 2016, Exhibit 99.6)
10-91	2016 Form of Exelon Corporation Change in Control Agreement (File No. 001-16169, Form 10-Q dated October 26, 2016, Exhibit 10.1)
10-92	Execution Version-ZEC Standard Contract by and between the NYSERDA and Nine Mile Point Nuclear Station, LLC dated Nov. 18, 2016 (File No. 001-16169, Form 8-K dated November 18, 2016, Exhibit 10.1)
10-93	Execution Version-ZEC Standard Contract by and between the NYSERDA and R. E. Ginna Nuclear Power Plant, LLC dated Nov. 18, 2016 (File No. 001-16169, Form 8-K dated November 18, 2016, Exhibit 10.2)
10-94	Credit Agreement, dated as of November 28, 2017, as thereafter amended and conformed among ExGen Renewables IV, LLC, ExGen Renewables IV Holding, LLC, Morgan Stanley Senior Funding, Inc. as administrative agent, Wilmington Trust, National Association, as depository bank and collateral agent, and the lenders and other agents party thereto. (Certain portions of this exhibit have been omitted by redacting a portion of text, as indicated by asterisks in the text. This exhibit has been filed separately with the U.S. Securities and Exchange Commission pursuant to a request for confidential treatment.)
12-1	Exelon Corporation Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
12-2	Exelon Generation Company, LLC Computation of Ratio of Earnings to Fixed Charges.
12-3	Commonwealth Edison Company Computation of Ratio of Earnings to Fixed Charges.
12-4	PECO Energy Company Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
12-5	Baltimore Gas and Electric Company Computation of Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preference Stock Dividends.
12-6	Pepco Holdings LLC Computation of Ratio of Earnings to Fixed Charges.
12-7	Potomac Electric Power Company Computation of Ratio of Earnings to Fixed Charges.
12-8	Delmarva Power & Light Company Computation of Ratio of Earnings to Fixed Charges.
12-9	Atlantic City Electric Company Computation of Ratio of Earnings to Fixed Charges.
14	Exelon Code of Conduct, as amended March 12, 2012 (File No. 1-16169, Form 8-K dated March 14, 2012, Exhibit No. 14-1).

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Exhibit No.	Description
	Subsidiaries
21-1	Exelon Corporation
21-2	Exelon Generation Company, LLC
21-3	Commonwealth Edison Company
21-4	PECO Energy Company
21-5	Baltimore Gas and Electric Company
21-6	Pepco Holdings LLC
21-7	Potomac Electric Power Company
21-8	Delmarva Power & Light Company
21-9	Atlantic City Electric Company
	Consent of Independent Registered Public Accountants
23-1	Exelon Corporation
23-2	Exelon Generation Company, LLC
23-3	Commonwealth Edison Company
23-4	PECO Energy Company
23-5	Baltimore Gas and Electric Company
23-6	Potomac Electric Power Company
23-7	Delmarva Power & Light Company
23-8	Atlantic City Electric Company
	Power of Attorney (Exelon Corporation)
24-1	Anthony K. Anderson
24-2	Ann C. Berzin
24-3	Christopher M. Crane
24-4	Yves C. de Balmann
24-5	Nicholas DeBenedictis
24-6	Nancy L. Gioia
24-7	Linda P. Jojo
24-8	Paul Joskow
24-9	Robert J. Lawless
24-10	Richard W. Mies
24-11	Reserved.
24-12	John W. Rogers, Jr.

Exhibit No.	Description
24-13	Mayo A. Shattuck III
24-14	Stephen D. Steinour
	Power of Attorney (Commonwealth Edison Company)
24-15	James W. Compton
24-16	Christopher M. Crane
24-17	A. Steven Crown
24-18	Nicholas DeBenedictis
24-19	Peter V. Fazio, Jr.
24-20	Michael H. Moskow
24-21	Denis P. O'Brien
24-22	Anne R. Pramaggiore
24-23	Reserved.
24-24	Reserved.
	Power of Attorney (PECO Energy Company)
24-25	Craig L. Adams
24-26	Christopher M. Crane
24-27	M. Walter D'Alessio
24-28	Nicholas DeBenedictis
24-29	Nelson A. Diaz
24-30	Rosemarie B. Greco
24-31	Charisse R. Lillie
24-32	Denis P. O'Brien
24-33	Reserved.
	Power of Attorney (Baltimore Gas and Electric Company)
24-34	Ann C. Berzin
24-35	Calvin G. Butler, Jr.
24-36	Christopher M. Crane
24-37	Michael E. Cryor
24-38	James R. Curtiss
24-39	Joseph Haskins, Jr.
24-40	Denis P. O'Brien

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24-41	Michael D. Sullivan
24-42	Maria Harris Tildon
	Power of Attorney (Pepco Holdings LLC)
24-43	Christopher M. Crane
24-44	Linda Cropp
24-45	Michael E. Cryor
24-46	Ernest Dianastasis
24-47	Debra P. DiLorenzo
24-48	Denis P. O'Brien
24-49	David M. Velazquez
	Power of Attorney (Potomac Electric Power Company)
24-50	J. Tyler Anthony
24-51	Christopher M. Crane
24-52	Donna J. Kinzel
24-53	Kevin M. McGowan
24-54	Denis P. O'Brien
24-55	David M. Velazquez
	Power of Attorney (Delmarva Power & Light Company)
24-56	Denis P. O'Brien
24-57	David M. Velazquez
	Power of Attorney (Atlantic City Electric Company)
24-58	David M. Velazquez

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Annual Report on Form 10-K for the year ended December 31, 2017 filed by the following officers for the following registrants:

31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Jonathan W. Thayer for Exelon Corporation
31-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	Filed by Craig L. Adams for PECO Energy Company

31-8	Filed by Phillip S. Barnett for PECO Energy Company
31-9	Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
31-10	Filed by David M. Vahos for Baltimore Gas and Electric Company
31-11	Filed by David M. Velazquez for Pepco Holdings LLC
31-12	Filed by Donna J. Kinzel for Pepco Holdings LLC
31-13	Filed by David M. Velazquez for Potomac Electric Power Company
31-14	Filed by Donna J. Kinzel for Potomac Electric Power Company
31-15	Filed by David M. Velazquez for Delmarva Power & Light Company
31-16	Filed by Donna J. Kinzel for Delmarva Power & Light Company
31-17	Filed by David M. Velazquez for Atlantic City Electric Company
31-18	Filed by Donna J. Kinzel for Atlantic City Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Annual Report on Form 10-K for the year ended December 31, 2017 filed by the following officers for the following registrants:

32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Jonathan W. Thayer for Exelon Corporation
32-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
32-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
32-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
32-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32-7	Filed by Craig L. Adams for PECO Energy Company
32-8	Filed by Phillip S. Barnett for PECO Energy Company
32-9	Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
32-10	Filed by David M. Vahos for Baltimore Gas and Electric Company
32-11	Filed by David M. Velazquez for Pepco Holdings LLC
32-12	Filed by Donna J. Kinzel for Pepco Holdings LLC
32-13	Filed by David M. Velazquez for Potomac Electric Power Company
32-14	Filed by Donna J. Kinzel for Potomac Electric Power Company
32-15	Filed by David M. Velazquez for Delmarva Power & Light Company
32-16	Filed by Donna J. Kinzel for Delmarva Power & Light Company
32-17	Filed by David M. Velazquez for Atlantic City Electric Company
32-18	Filed by Donna J. Kinzel for Atlantic City Electric Company
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema

S1-SSA-0009 - 16841

101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

* Compensatory plan or arrangements in which directors or officers of the applicable registrant participate and which are not available to all employees.
(a) These filings are not available electronically on the SEC website as they were filed in paper previous to the electronic system that is currently in place.

ITEM 16. FORM 10-K SUMMARY

All Registrants

Registrants may voluntarily include a summary of information required by Form 10-K under this Item 16. The Registrants have elected not to include such summary information.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2018 .

EXELON CORPORATION

By: /s/ CHRISTOPHER M. CRANE
Name: Christopher M. Crane
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 9th day of February, 2018 .

Signature	Title
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ JONATHAN W. THAYER **Jonathan W. Thayer**	Senior Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ DUANE M. DESPARTE **Duane M. DesParte**	Senior Vice President and Corporate Controller (Principal Accounting Officer)

This annual report has also been signed below by Thomas S. O'Neil, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Anthony K. Anderson
Ann C. Berzin
Christopher M. Crane
Yves C. de Balmann
Nicholas DeBenedictis
Nancy L. Gioia
Linda P. Jojo
Paul Joskow
Robert J. Lawless
Richard W. Mies
John W. Rogers, Jr.
Mayo A. Shattuck III
Stephen D. Steinour

By: /s/ THOMAS S. O'NEILL
Name: Thomas S. O'Neill

February 9, 2018

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2018 .

EXELON GENERATION COMPANY, LLC

By: /s/ KENNETH W. CORNEW
Name: **Kenneth W. Cornew**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 9th day of February, 2018 .

Signature	**Title**
/s/ KENNETH W. CORNEW **Kenneth W. Cornew**	President and Chief Executive Officer (Principal Executive Officer)
/s/ BRYAN P. WRIGHT **Bryan P. Wright**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ MATTHEW N. BAUER **Matthew N. Bauer**	Vice President and Controller (Principal Accounting Officer)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2018 .

COMMONWEALTH EDISON COMPANY

By: /s/ ANNE R. PRAMAGGIORE
Name: **Anne R. Pramaggiore**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 9th day of February, 2018 .

Signature	**Title**
/s/ ANNE R. PRAMAGGIORE **Anne R. Pramaggiore**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ JOSEPH R. TRPIK, JR. **Joseph R. Trpik, Jr.**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ GERALD J. KOZEL **Gerald J. Kozel**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Anne R. Pramaggiore, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

James W. Compton
Christopher M. Crane
A. Steven Crown
Nicholas DeBenedictis
Peter V. Fazio, Jr.
Michael H. Moskow
Denis P. O'Brien

By: /s/ ANNE R. PRAMAGGIORE
Name: **Anne R. Pramaggiore**

February 9, 2018

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2018 .

PECO ENERGY COMPANY

By: /s/ CRAIG L. ADAMS
Name: **Craig L. Adams**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 9th day of February, 2018 .

Signature	**Title**
/s/ CRAIG L. ADAMS **Craig L. Adams**	President and Chief Executive Officer (Principal Executive Officer) and Director
/s/ PHILLIP S. BARNETT **Phillip S. Barnett**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ SCOTT A. BAILEY **Scott A. Bailey**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Craig L. Adams, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Christopher M. Crane
M. Walter D'Alessio
Nicholas DeBenedictis
Nelson A. Diaz
Rosemarie B. Greco
Charisse R. Lillie
Denis P. O'Brien

By: /s/ CRAIG L. ADAMS
Name: **Craig L. Adams**
February 9, 2018

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2018 .

BALTIMORE GAS AND ELECTRIC COMPANY

By: /s/ CALVIN G. BUTLER, JR.
Name: **Calvin G. Butler, Jr.**
Title: **Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 9th day of February, 2018 .

Signature	**Title**
/s/ CALVIN G. BUTLER, JR. **Calvin G. Butler, Jr.**	Chief Executive Officer (Principal Executive Officer) and Director
/s/ DAVID M. VAHOS **David M. Vahos**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ ANDREW W. HOLMES **Andrew W. Holmes**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by Calvin G. Butler, Jr., Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Ann C. Berzin
Christopher M. Crane
Michael E. Cryor
James R. Curtiss
Joseph Haskins, Jr.
Denis P. O'Brien
Michael D. Sullivan
Maria Harris Tildon

By: /s/ CALVIN G. BUTLER, JR. February 9, 2018
Name: **Calvin G. Butler, Jr.**

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2018 .

PEPCO HOLDINGS LLC

By: /s/ DAVID M. VELAZQUEZ
Name: **David M. Velazquez**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 9th day of February, 2018 .

Signature	**Title**
/s/ DAVID M. VELAZQUEZ **David M. Velazquez**	President and Chief Executive Officer (Principal Executive Officer)
/s/ DONNA J. KINZEL **Donna J. Kinzel**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ ROBERT M. AIKEN **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman and Director

This annual report has also been signed below by David M. Velazquez, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Christopher M. Crane
Linda Cropp
Michael E. Cryor
Ernest Dianastasis
Debra P. DiLorenzo
Denis P. O'Brien

By: /s/ DAVID M. VELAZQUEZ
Name: **David M. Velazquez**

February 9, 2018

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2018 .

POTOMAC ELECTRIC POWER COMPANY

By: /s/ DAVID M. VELAZQUEZ
Name: **David M. Velazquez**
Title: **President and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 9th day of February, 2018 .

Signature	**Title**
/s/ DAVID M. VELAZQUEZ **David M. Velazquez**	President and Chief Executive Officer (Principal Executive Officer)
/s/ DONNA J. KINZEL **Donna J. Kinzel**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ ROBERT M. AIKEN **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman

This annual report has also been signed below by David M. Velazquez, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

J. Tyler Anthony
Christopher M. Crane
Donna J. Kinzel
Kevin M. McGowan
Denis P. O'Brien

By: /s/ DAVID M. VELAZQUEZ
Name: **David M. Velazquez**

February 9, 2018

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2018 .

DELMARVA POWER & LIGHT COMPANY

By: /s/ DAVID M. VELAZQUEZ
Name: David M. Velazquez
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 9th day of February, 2018 .

Signature	**Title**
/s/ DAVID M. VELAZQUEZ **David M. Velazquez**	President and Chief Executive Officer (Principal Executive Officer)
/s/ DONNA J. KINZEL **Donna J. Kinzel**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ ROBERT M. AIKEN **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman

This annual report has also been signed below by David M. Velazquez, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Denis P. O'Brien

By: /s/ DAVID M. VELAZQUEZ
Name: David M. Velazquez

February 9, 2018

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2018 .

ATLANTIC CITY ELECTRIC COMPANY

By: /s/ DAVID M. VELAZQUEZ
Name: David M. Velazquez
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 9th day of February, 2018 .

Signature	Title
/s/ DAVID M. VELAZQUEZ **David M. Velazquez**	President and Chief Executive Officer (Principal Executive Officer)
/s/ DONNA J. KINZEL **Donna J. Kinzel**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ ROBERT M. AIKEN **Robert M. Aiken**	Vice President and Controller (Principal Accounting Officer)
/s/ CHRISTOPHER M. CRANE **Christopher M. Crane**	Chairman

U.S. $850,000,000

CREDIT AGREEMENT

Dated as of November 28, 2017

among

EXGEN RENEWABLES IV, LLC,

as Borrower,

EXGEN RENEWABLES IV HOLDING, LLC,

as Holding,

THE LENDERS PARTY HERETO,

WILMINGTON TRUST, NATIONAL ASSOCIATION,
as Depositary Bank,

MORGAN STANLEY SENIOR FUNDING, INC.,

as Administrative Agent,

and

WILMINGTON TRUST, NATIONAL ASSOCIATION,
as Collateral Agent

MORGAN STANLEY SENIOR FUNDING, INC.,

as Sole Lead Arranger and Sole Lead Bookrunner,

MORGAN STANLEY SENIOR FUNDING, INC.,

as Syndication Agent,

and

MORGAN STANLEY SENIOR FUNDING, INC.,

as Documentation Agent

[***] INDICATES MATERIAL THAT HAS BEEN OMITTED AND FOR WHICH CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ALL SUCH OMITTED MATERIAL HAS BEEN FILED WITH THE SECURITIES AND EXCHANGE COMMISSION PURSUANT TO RULE 24b-2 UNDER THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED.

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CREDIT AGREEMENT dated as of November 28, 2017, (as amended, amended and restated, supplemented or otherwise modified, this " **Agreement** "), a limited liability company organized under the laws of Delaware (the " **Borrower** "), EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" **Holding** "), the LENDERS party hereto from time to time, and MORGAN STANLEY SENIOR FUNDING, INC. (" **MSSF** "), as administrative agent (in such capacity, together with any successor administrative agent appointed pursuant to the provisions of Article VIII , the " **Administrative Agent** "), WILMINGTON TRUST, NATIONAL ASSOCIATION as collateral agent (in such capacity, together with any successor collateral agent appointed pursuant to the provisions of Article VIII , the " **Collateral Agent** ") for the Lenders and WILMINGTON TRUST, NATIONAL ASSOCIATION, as depositary bank (in such capacity, together with any successor depositary bank appointed pursuant to the provisions of Article VIII , the " **Depositary Bank** ").

W I T N E S S E T H :

WHEREAS, the Sponsor (such term and each other capitalized term used in these recitals and not otherwise previously defined, as hereinafter defined) has formed each of the Borrower and Holding;

WHEREAS, Holding owns all of the Equity Interests of the Borrower;

WHEREAS, as of the Closing Date, the Borrower owns (A) all of the Equity Interests in (i) ExGen Renewables Holdings, LLC, a limited liability company organized under the laws of Delaware (" **ExGen Renewables Holdings** "), (ii) SolGen Holding, LLC, a limited liability company organized under the laws of Delaware (" **SolGen Holding** ") and (iii) Exelon AVSR Holding, LLC, a limited liability company organized under the laws of Delaware (" **Exelon AVSR Holding** ") and (B) not less than 50% of the Equity Interests in Constellation DCO Albany Power Holdings, LLC, a limited liability company organized under the laws of Delaware (" **Albany Power Holdings** ");

WHEREAS, ExGen Renewables Holdings owns all of the JV Class A Membership Interests in ExGen Renewables Partners, LLC, a limited liability company organized under the laws of Delaware (" **ExGen Renewables JV** ");

WHEREAS, ExGen Renewables JV, SolGen Holding, Exelon AVSR Holding and Albany Power Holdings own, directly or indirectly, all (or a specified class of) the Equity Interests of each of the other Project Entities, which collectively own or lease the Projects;

WHEREAS, the Borrower has requested that the Lenders extend credit in the form of Loans on the Closing Date, in an aggregate U.S. Dollar amount for all such Loans of U.S. $850 million; and

WHEREAS, the Borrower intends to use the proceeds of the Loans to declare and consummate distributions to the Sponsor and/or its Affiliates and to pay fees and expenses associated with the Transactions.

NOW, THEREFORE, the Lenders are willing to extend such credit to the Borrower on the terms and subject to the conditions set forth herein. Accordingly, the parties hereto agree as follows:

Article I.
DEFINITIONS

Section 1.01 *Defined Terms*. As used in this Agreement, the following terms shall have the meanings specified below:

" **Acceptable Guarantor** " shall mean any Affiliate of the Borrower whose long-term debt is rated BBB- or better by S&P or Baa3 or better by Moody's.

2 " **Acceptable LC Issuer** " shall mean any bank or trust company that is organized under the laws of the United States (or any state or political subdivision thereof) and whose long-term debt, or whose parent holding company's long-term debt, is rated BBB+ or better by S&P and Baa1 or better by Moody's.

3 " **Account Letter of Credit** " shall mean (a) any letter of credit issued under the Revolving Facility, if any, or (b) any irrevocable standby letter of credit, in form and substance reasonably satisfactory to the Administrative Agent, (i) issued by an Acceptable LC Issuer on account of an applicant (which shall not be a Loan Party or a Subsidiary of a Loan Party), (ii) in respect of which no Loan Party or Subsidiary of a Loan Party has any reimbursement obligations or has provided any credit support therefor and (iii) which letter of credit shall name the Collateral Agent (for the benefit of the Secured Parties) as the beneficiary thereunder.

4 " **Additional Albany Green Entities** " shall mean any entities formed in connection with an AG Disposition to a Person other than ExGen Renewables JV.

5 " **Additional Project** " shall have the meaning assigned to such term in the definition of "Permitted Acquisition".

6 " **Additional Project Entity** " shall mean the one or more entities acquired pursuant to a Permitted Acquisition that own, directly and indirectly, all or a portion an Additional Project.

7 " **Administrative Agent** " shall have the meaning assigned to such term in the introductory paragraph of this Agreement.

8 " **Administrative Agent Fees** " shall have the meaning assigned to such term in Section 2.10(a) .

9 " **Administrative Questionnaire** " shall mean an Administrative Questionnaire in substantially the form of Exhibit J or any other form approved by the Administrative Agent.

10 " **Affiliate** " shall mean, of any specified Person, any other Person who directly, or indirectly through one or more intermediaries, controls or is controlled by or is under common control with such specified Person. For purposes of this definition, "control," as used with respect to any Person, means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of such Person, whether through the ownership of voting securities, by agreement or otherwise. For purposes of this definition, the terms "controlling," "controlled by" and "under common control with" have correlative meanings.

11 " **Affiliated Lender** " shall mean any Person that becomes a Lender that is the Sponsor or an Affiliate of the Sponsor (other than a Loan Party).

12 " **Affiliated Lender Assignment and Acceptance** " shall mean an assignment and acceptance entered into (x) by a Lender, as assignor, and an Affiliated Lender, as assignee or (y) by an Affiliated Lender, as assignor, and any other Eligible Assignee or Affiliated Lender, as assignee, to the extent permitted pursuant to Section 9.04(b) , and, in each case, accepted by the Administrative Agent, in substantially the form of Exhibit A-2 or such other form as shall be approved by the Administrative Agent.

13 " **Agent Parties** " shall have the meaning assigned to such term in Section 9.17(c) .

14 " **Agents** " shall mean the Administrative Agent, the Collateral Agent, the Depositary Bank, the Syndication Agent and the Documentation Agent.

15 " **Aggregate Interests** " shall mean all rights to receive dividends, distributions and other restricted payments as an owner of or member in a Person, and all rights to receive payments as a lender pursuant to a member loan (including the DCO Loan) or a financing arrangement similar to the DCO Loan with the applicable Person or its members.

16 " **Agreement** " shall have the meaning assigned to such term in the introductory paragraph of this Agreement.

17 " **AG Disposition** " shall have the meaning assigned to such term in Section 6.05(f).

18 " **AG Financing Documents** " shall have the meaning assigned to such term in Schedule 1.01A.

19 " **Albany Green Energy** " shall mean Albany Green Energy, LLC, a limited liability company organized under the laws of Georgia.

20 " **Albany Green Entities** " shall mean Albany Power Holdings and Albany Green Energy and, if applicable, any Additional Albany Green Entities.

21 " **Albany Green Project** " shall mean the approximately 50 MW biomass facility owned by Albany Green Energy and listed under the heading "Albany Green Project" in Schedule 1.01D, including the related Project site, and the facilities, structures and improvements erected on the related Project site and all other equipment and property leased or owned by Albany Green Energy and attached to or placed upon the related Project site or used in connection with the operation of the Albany Green Project.

22 " **Albany Power Holdings** " shall have the meaning assigned to such term in the recitals of this Agreement.

23 " **Applicable ECF Percentage** " shall mean (a) for each Quarterly Date occurring in 2018, 2019, 2020 and 2021, 100% and (b) for each Quarterly Date thereafter, 75%.

24 " **Applicable Margin** " shall mean for any day with respect to (a) any LIBOR Loan, 3.00% *per annum* and (b) any Base Rate Loan, 2.00% *per annum* .

25 " **Approved Fund** " shall mean any Person (other than a natural person) that is engaged in making, purchasing, holding or investing in bank loans and similar extensions of credit in the ordinary course and that is administered or managed by a Lender, an Affiliate of a Lender or an entity or an Affiliate of an entity that administers or manages a Lender.

26 " **Anti-Corruption Laws** " shall mean all laws, rules and regulations of any jurisdiction applicable to any Loan Party or any of the Loan Parties' Affiliates from time to time concerning or relating to bribery or corruption.

27 " **Anti-Terrorism Laws** " means (a) the U.S.A. Patriot Act, (b) Executive Order No. 13,224, 66 Fed. Reg. 49,079 (2001), issued by the President of the United States (Executive Order Blocking Property and Prohibiting Transactions with Persons Who Commit, Threaten to Commit or Support Terrorism) (the " **Executive Order** "), and (c) and any other similar legal requirements relating to terrorism or money laundering.

28 " **Assignment and Acceptance** " shall mean an assignment and acceptance entered into by a Lender and an assignee, and accepted by the Administrative Agent, in substantially the form of Exhibit A-1 or such other form as shall be approved by the Administrative Agent.

29 " **Available Cash** " shall mean, for any period, the sum (without duplication) of all amounts the Borrower or Holding actually receive in cash during such period in the form of dividends or similar distributions or fees, whether on account of operations, management or maintenance or otherwise, in each case, from the Project Entities pursuant to payments made in accordance with the Project Level Financing Documents or otherwise; *provided* , that any portion of Available Cash included in the calculation thereof with respect to any Test Quarter shall be included in the calculation of Available Cash for no more than four (4) consecutive Test Quarters.

30 " **AVSR Disposition** " shall have the meaning assigned to such term in Section 6.05(g).

31 " **AVSR Entities** " shall mean Exelon AVSR Holding and the other the entities listed in Part 1 of Schedule 1.01C.

32 " **AVSR Financing Documents** " shall have the meaning assigned to such term in Schedule 1.01A.

33 " **AV Solar Project** " shall mean the approximately 242 MW solar powered electrical generation facility owned by the AVSR Entities and listed under the heading "AV Solar Project" in Schedule 1.01D , including the related Project site, and the panels, facilities, structures and improvements erected on the related Project site and all other equipment and property leased or owned by the AVSR Entities and attached to or placed upon the related Project site or used in connection with the operation of the AV Solar Project.

34 " **Bail-In Action** " means the exercise of any Write-down and Conversion Powers by the applicable Resolution Authority.

35 " **Bail-In Legislation** " means in relation to an EEA Member Country that has implemented, or which at any time implements, Article 55 of Directive 2014/59/EU establishing a framework for the recovery and resolution of credit institutions and investment firms, the relevant implementing law or regulation as described in the EU Bail-In Legislation Schedule from time to time.

36 " **Bankruptcy Code** " shall mean Title 11 of the United States Code entitled "Bankruptcy," as now and hereafter in effect, or any successor statute.

37 " **Bankruptcy Law** " means the Bankruptcy Code and any other state or federal insolvency, reorganization, moratorium or similar law for the relief of debtors.

38 " **Base Case Model** " shall mean the Sponsor's financial model EGRIV Lender Model (11.15.2017) - Updated, delivered to the Lead Arranger prior to the Closing Date.

39 " **Base Rate** " shall mean, for any day, a rate *per annum* equal to the greatest of (a) the Prime Rate in effect on such day, (b) the Federal Funds Effective Rate for such day plus 0.50%, (c) the LIBO Rate for a LIBOR Loan with a one month interest period commencing on such day plus 1.00% and (d) 2.00%. Any change in the Base Rate due to a change in the Prime Rate, the Federal Funds Effective Rate or the LIBO Rate shall be effective as of the opening of business on the day of such change in the Prime Rate, the Federal Funds Effective Rate or the LIBO Rate, respectively.

40 " **Base Rate Borrowing** " shall mean a Borrowing comprised of Base Rate Loans.

41 " **Base Rate Loan** " shall mean any Loan bearing interest at a rate determined by reference to the Base Rate in accordance with the provisions of Article II .

42 " **BIS** " shall mean the U.S. Department of Commerce's Bureau of Industry and Security.

43 " **Bluestem Entities** " shall mean the entities listed in Part 3 of Schedule 1.01C.

44 " **Bluestem Financing Documents** " shall have the meaning assigned to such term in Schedule 1.01A.

45 " **Bluestem Project** " shall mean the wind power electric generation project owned by the Bluestem Entities and listed under the heading "Other Projects" in Schedule 1.01D , including the related Project site, and the panels, turbines, facilities, structures and improvements erected on such Project site and all other equipment and property leased or owned by the applicable Bluestem Entities with respect thereto and attached to or placed upon such Project site or used in connection with the operation of such Bluestem Project.

46 " **Board** " shall mean the Board of Governors of the Federal Reserve System of the United States.

47 " **Board of Directors** " shall mean (a) with respect to a corporation, the board of directors of the corporation and any committee thereof duly authorized to act on behalf of such board; (b) with respect to a partnership, the Board of Directors of the general partner of the partnership; (c) with respect to a limited liability company, the manager or managers thereof or any controlling committee of managers or members thereof; and (d) with respect to any other Person, the board or committee of such Person serving a similar function.

48 " **Borrower** " shall have the meaning assigned to such term in the introductory paragraph of this Agreement.

49 " **Borrower Liquidity Shortfall** " shall have the meaning assigned to such term in Section 2.19(e)(iii) .

50 " **Borrower Materials** " shall have the meaning assigned to such term in Section 9.17(b) .

51 " **Borrowing** " shall mean a group of Loans of a single Type and made on a single date to the Borrower and, in the case of LIBOR Loans, as to which a single Interest Period is in effect.

52 " **Borrowing Request** " shall mean a request by the Borrower in accordance with the terms of Section 2.03 and substantially in the form of Exhibit C .

53 " **Business Day** " shall mean any day that is not a Saturday, Sunday or other day on which commercial banks in New York City are authorized or required by law to remain closed; provided , that with respect to notices and determinations in connection with, and payments of principal and interest on, LIBOR Loans, such day is also a day for trading by and between banks in U.S. Dollar deposits in the interbank eurodollar market.

54 " **Capital Lease Obligations** " of any Person shall mean, at the time any determination is to be made, the amount of the liability in respect of a capital lease that would at that time be required to be capitalized on a balance sheet prepared in accordance with GAAP, and the Stated Maturity thereof shall be the date of the last payment of rent or any other amount due under such lease prior to the first date upon which such lease may be prepaid by the lessee without payment of a penalty.

55 " **Capital Stock** " shall mean:

(a) in the case of a corporation, corporate stock;

(b) in the case of an association or business entity, any and all shares, interests, participations, rights or other equivalents (however designated) of corporate stock;

(c) in the case of a partnership or limited liability company, partnership interests (whether general or limited) or membership interests; and

(d) any other interest or participation that confers on a Person the right to receive a share of the profits and losses of, or distributions of assets of, the issuing Person, but excluding from all of the foregoing any debt securities convertible into Capital Stock, whether or not such debt securities include any right of participation with Capital Stock.

56 " **Cash and Cash Equivalents** " shall mean:

(a) Marketable securities issued by the U.S. Government and supported by the full faith and credit of the U.S. Treasury, either by statute or an opinion of the Attorney General of the United States;

(b) Marketable debt securities issued by U. S. Government-sponsored enterprises, U. S . Federal agencies, U. S . Federal financing banks, and international institutions whose capital stock has been subscribed for by the United States;

(c) Certificates of Deposit, Time Deposits, and Bankers Acceptances of any bank or trust company incorporated under the laws of the United States or any state, *provided* that, at the date of acquisition, such investment, and/or the commercial paper or other short term debt obligation of such bank or trust company has a short-term credit rating or ratings from Moody's and/or S&P, each at least P-1 or A-1;

(d) Deposit accounts with any bank that is insured by the Federal Deposit Insurance Corporation and whose long-term obligations are rated A3 or better by Moody's and/or A- or better by S&P;

(e) Commercial paper of any corporation incorporated under the laws of the United States or any state thereof which on the date of acquisition is rated by Moody's and/or S&P, *provided* each such credit rating is least P-1 and/or A-1;

(f) Money market mutual funds that are registered with the Securities and Exchange Commission under the Investment Company Act of 1940, as amended, and operated in accordance with Rule 2a-7 and that at the time of such investment are rated Aaa by Moody's and/or AAAm by S&P, including such funds for which the Trustee or an affiliate provides investment advice or other services;

(g) Tax-exempt variable rate commercial paper, tax-exempt adjustable rate option tender bonds, and other tax-exempt bonds or notes issued by municipalities in the United States, having a short-term rating of "MIG-1" or "VMIG-1" or a long term rating of "AA" (Moody's), or a short-term rating of "A-1" or a long term rating of "AA" (S&P);

(h) Repurchase obligations with a term of not more than thirty days, 102 percent collateralized, for underlying securities of the types described in clauses (i) and (ii) above, entered into with any bank or trust company or its respective affiliate meeting the requirements specified in clause (iii) above; and

(i) Maturities on the above securities shall not exceed 365 days and all rating requirements and/or percentage restrictions are based on the time of purchase.

57 " **Cash Flow Available for Debt Service** " shall mean, as of any date of determination, Available Cash for the Test Period most recently ended as of such date (excluding for the avoidance of doubt, any funds required to be used to prepay the Loans pursuant to Section 2.09(b)) *minus* any Operating Expenses for such Test Period paid (or directed to be paid pursuant to a Withdrawal Certificate) in cash pursuant to Section 2.19(c)(i) during such Test Period.

58 " **Change in Control** " shall mean the consummation of any transaction or series of transactions as a result of which (a) the Sponsor shall cease to own and control of record and beneficially (within the meaning of Rule 13d-5 of the Exchange Act as in effect on the Closing Date), directly or indirectly, at least 51.0% of the voting power of the Voting Stock and economic interests represented by the issued and outstanding Equity Interests of Holding; provided that no Change in Control shall be deemed to have occurred in any circumstance set forth in this clause (a) if (i) each of S&P and Moody's shall have provided a Ratings Reaffirmation after giving effect to such transaction that otherwise would give rise to a Change in Control and (ii) the Person that (directly or indirectly) acquires the Capital Stock of Holding is a direct or indirect owner of one or more renewable electric generating facilities aggregating to at least 300 MW; or (b) Holding shall cease to own and control of record and beneficially (as defined above), directly, 100% of the voting power of the Voting Stock and economic interests represented by the issued and outstanding Equity Interests of the Borrower; or (c) the Borrower shall cease to own and control of record and beneficially (as defined above), directly, (i) with respect to Albany Power Holdings, the percentage of Aggregate Interests in Albany Power Holdings (or such lower percentage as it shall own and control following any AG Disposition) owned and controlled by it on the Closing Date and (ii) in the case of each other Project Holdco, 100% (or such lower percentage as it shall own and control following any AVSR Disposition (in the case of Exelon AVSR Holding) or SolGen Disposition (in the case of SolGen Holding)) of the voting power of the Voting Stock and economic interests represented by the issued and outstanding Equity Interests of such Project Holdco; or (d) either (1) ExGen Renewables Holding shall cease to own and control of record and beneficially (as defined above), directly, 100% of the JV Class A Membership Interests or (2) a Subsidiary of the Sponsor ceases to act as Managing Member (as defined in the ExGen Renewables JV Agreement); provided that no Change in Control shall be deemed to have occurred under this clause (d) so long as ExGen Renewables Holding owns and controls of record and beneficially (as defined above), directly more than 50% of the voting power of the Voting Stock and economic interests represented by the issued and outstanding Equity Interests of ExGen Renewables JV; or (e) Exelon AVSR Holding shall cease to own and control of record and beneficially (as defined above), directly or indirectly, 100% (or such lower percentage as it shall own

and control following any AVSR Disposition) of the voting power of the Voting Stock and economic interests represented by the issued and outstanding Equity Interests of each of the other AVSR Entities.

59 " **Change in Law** " shall mean (a) the adoption or implementation of any treaty, law, rule or regulation after the Closing Date, (b) any change in law, rule or regulation or in the interpretation or application thereof by any Governmental Authority after the Closing Date or (c) compliance by any Lender (or, for purposes of Section 2.13(b) , by any lending office of such Lender or by such Lender's holding company, if any) with any written request, guideline or directive (whether or not having the force of law but if not having the force of law, then being one with which the relevant party would customarily comply) of any Governmental Authority made or issued after the Closing Date; provided , that notwithstanding anything herein to the contrary, (i) the Dodd-Frank Wall Street Reform and Consumer Protection Act and all requests, rules, regulations, guidelines or directives thereunder or issued in connection therewith and (ii) all requests, rules, guidelines or directives promulgated by the Bank for International Settlements, the Basel Committee on Banking Supervision (or any successor or similar authority) or United States or foreign regulatory agencies, in each case, pursuant to Basel III, shall in each case be deemed to be a "Change in Law," regardless of the date enacted, adopted or issued.

60 " **Charges** " shall have the meaning assigned to such term in Section 9.09 .

61 " **Closing Date** " shall mean November 28, 2017, and " **Closing** " shall mean the making of the initial Loans on the Closing Date hereunder.

62 " **Code** " shall mean the Internal Revenue Code of 1986, as amended from time to time (except as otherwise provided herein).

63 " **Collateral** " shall mean all the "Collateral" as defined in any Security Document.

64 " **Collateral Agent** " shall have the meaning assigned to such term in the introductory paragraph of this Agreement.

65 " **Collateral and Guarantee Requirement** " shall mean the requirement that:

(a) on the Closing Date, the Collateral Agent shall have received from the Borrower a counterpart of the Security Agreement and from Holding and ExGen Renewables Holdings a counterpart of the Pledge Agreement (which shall include a Guarantee of the Obligations of the Borrower), duly executed and delivered on behalf of such Loan Party;

(b) on the Closing Date, the Collateral Agent shall be the beneficiary of a pledge of (i) (x) all the issued and outstanding Equity Interests of the Borrower and each Project Holdco other than Albany Power Holdings and (y) 50% of the issued and outstanding Equity Interests of Albany Power Holdings, and (ii) all the issued and outstanding JV Class A Membership Interests, and the Collateral Agent shall have received all certificates or other instruments (if any) representing such Equity Interests and JV Class A Membership Interests, together with stock powers or other instruments of transfer with respect thereto endorsed in blank or shall have otherwise received a security interest over such Equity Interests satisfactory to the Collateral Agent;

(c) on the Closing Date, the Collateral Agent shall have received from the Borrower, the Collateral Agent and the Depositary Bank a counterpart of a Control Agreement for the Depositary Accounts, in each case, duly executed and delivered on behalf of such Person;

(d) after the Closing Date, (i) to the extent any Loan Party establishes any securities account with the Depositary Bank, the Collateral Agent shall have received from the Borrower and the Depositary

Bank a fully executed Control Agreement for each such securities account and (ii) to the extent the Borrower or any Project Holdco establishes any deposit account with a bank, the Collateral Agent shall have received from the Borrower a fully executed Local Account Control Agreement for each such account, in each case, duly executed and delivered on behalf of such Person and the Depositary Bank or other bank, as applicable, within thirty (30) days of the establishment of such security account or Local Account (or such longer period as may be agreed to by the Administrative Agent in its sole discretion);

(e) with respect to any Equity Interests acquired by any Loan Party after the Closing Date (including, if applicable in the case of an AG Disposition to a Person other than ExGen Renewables JV, Equity Interests directly owned by the Borrower in any Additional Albany Green Entity), within thirty (30) days (or such longer period as may be agreed to by the Administrative Agent in its sole discretion) of such acquisition of Equity Interests, all such outstanding Equity Interests directly owned by a Loan Party shall have been pledged in accordance with the Security Documents, and the Collateral Agent shall have received all certificates or other instruments (if any) representing such Equity Interests, together with stock powers or other instruments of transfer with respect thereto endorsed in blank or shall have otherwise received a security interest over such Equity Interests reasonably satisfactory to the Collateral Agent; and

(f) UCC financing statements naming the applicable Loan Party, as the case may be, as debtor and the Collateral Agent as secured party, in form appropriate for filing as may be necessary to perfect the security interests purported to be created by the Security Documents, covering the applicable Collateral which constitutes personal property (in each case, including any supplements thereto) shall have been filed, registered or recorded or delivered to the Collateral Agent for filing, registration or recording and, as of the Closing Date, Collateral Agent shall have received reasonably satisfactory evidence that all other actions necessary to perfect the security interests purported to be created by the Security Documents have been taken;

provided , that, (x) the Collateral and Guarantee Requirement shall not require the grant of a Lien or provision of a guarantee by any Person over those assets as to which the Administrative Agent and the Collateral Agent shall determine in their reasonable discretion that the costs of obtaining such security interest are excessive in relation to the value of the security to be afforded thereby, and (y) no asset in respect of which a Lien has been granted to the Collateral Agent for the benefit of the Secured Parties shall be subject to any other Lien except for any Lien permitted under Section 6.02 .

66 " **Commitments** " shall mean, with respect to any Lender, the amount set forth on Schedule 2.01 under the heading Commitment. The aggregate amount of the Commitments on the Closing Date is U.S. $850 million.

67 " **Commodity Exchange Act** " shall mean the Commodity Exchange Act (7. U.S.C. §§ 1 *et seq* .), as amended from time to time, and any successor statute.

68 " **Commodity Hedge Agreement** " shall mean any agreement (including each confirmation entered into pursuant to any master agreement) providing for any swap, cap, collar, put, call, floor, future, option, spot, forward, power purchase and sale agreement (including heat rate options), tolling agreement, fuel purchase and sale agreement, emissions credit purchase or sale agreement, power transmission agreement, fuel transportation agreement, fuel storage agreement, energy management agreement, netting agreement or similar agreement entered into in respect of any commodity, whether physical or financial, and any agreement (including any guarantee, credit sleeve or similar arrangement) providing for credit support for the foregoing.

69 " **Communications** " shall have the meaning assigned to such term in Section 9.17(a) .

70 " **Completion Proceeds** " shall mean amounts released from the Bluestem Completion Account and distributed to ExGen Renewables Holdings in accordance with Section 3.13 of the ExGen Renewables JV Agreement.

71 " **Confidential Information Memorandum** " shall mean the Confidential Information Memorandum dated November 7, 2017, as modified or supplemented prior to the Closing Date.

72 " **Continental Wind Credit Agreement** " that certain Credit Agreement, dated as of September 30, 2013, among Continental Wind, LLC, Continental Wind Holding, LLC, the other Continental Wind Entities parties thereto, the lenders and issuing banks party thereto from time to time, and Crédit Agricole Corporate and Investment Bank, as administrative agent for the lenders thereunder.

73 " **Continental Wind Entities** " shall mean ExGen Renewables I Holding and the other entities listed in Part 6 of Schedule 1.01C and, if applicable, any Additional Project Entities owned, directly or indirectly, by ExGen Renewables I Holding.

74 " **Continental Wind Financing Documents** " shall have the meaning assigned to such term in Schedule 1.01A.

75 " **Continental Wind Projects** " shall mean each of the thirteen wind power electric generation projects owned by the Continental Wind Entities and listed under the heading "Continental Wind Projects" in Schedule 1.01D and, if applicable, any Additional Project owned by a Continental Wind Entity (each, individually, a " **Continental Wind Project** "), including with respect to each such Continental Wind Project the related Project site, and the panels, turbines, facilities, structures and improvements erected on such Project site and all other equipment and property leased or owned by the applicable Continental Wind Entities with respect to such Continental Wind Project and attached to or placed upon such Project site or used in connection with the operation of such Continental Wind Project.

76 " **Control** " shall mean the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of a Person, whether through the ownership of voting securities, by contract or otherwise, and "Controlling" and "Controlled" shall have meanings correlative thereto.

77 " **Control Agreement** " shall mean one or more control agreements, entered into by the Borrower, the Collateral Agent and the Depositary Bank, which (i) provides that the Depositary Bank will comply with any instructions or entitlement orders originated by the Borrower and, upon delivery of written notice that an Event of Default has occurred and is continuing, the Collateral Agent (but not, after such notice (until rescinded), the Borrower), (ii) is otherwise sufficient to establish the Collateral Agent's control per Section 9-104 and Section 8-106 of the UCC, as applicable, and (iii) is otherwise in form and substance reasonably satisfactory to the Collateral Agent and the Administrative Agent.

78 " **Credit Support** " shall mean "Credit Support" as defined in the Credit Support Reimbursement Agreement.

79 " **Credit Support Reimbursement Agreement** " shall mean the Reimbursement Agreement, dated as of November 28, 2017 among the Sponsor and the Borrower.

80 " **Credit Support Reimbursement Obligations** " shall mean "Obligations" as defined in the Credit Support Reimbursement Agreement.

81 " **Cure Amount** " shall mean the minimum amount which, if added to Available Cash for the Test Period in respect of which a Default in respect of the Financial Performance Covenant occurred,

would cause the Financial Performance Covenant for such Test Period to be satisfied (it being understood and agreed that for purposes of calculating such amount no effect shall be given to any prepayment of Loans with such proceeds).

82 " **Cure Right** " shall have the meaning assigned to such term in Section 7.02 .

83 " **DCO Loan** " shall have the meaning assigned to such term in Section 6.04(g) .

84 " **Debt Payment Deficiency** " shall have the meaning assigned to such term in Section 2.19(d)(iv) .

85 " **Debt Service** " shall mean, for the Borrower and for any period, the amount of Fees, interest (including, without duplication of interest amounts payable under this Agreement, ordinary course settlement amounts payable by the Borrower under any Interest Rate Swap Agreement, net of ordinary course settlement amounts received by the Borrower thereunder during the relevant period) and Scheduled Amortization Payments of principal due and payable under the Loan Documents during such period (excluding, under all circumstances, any such amounts due and payable on the Maturity Date).

86 " **Debt Service Coverage Ratio** " shall mean, for any period, the ratio of (a) Cash Flow Available for Debt Service for such period to (b) Debt Service for such period.

87 " **Debt Service Reserve Account** " shall have the meaning assigned to such term in Section 2.19(a) .

88 " **Default** " shall mean any event or condition that, with the passage of time or the giving of notice or both would be, an Event of Default.

89 " **Defaulting Lender** " shall mean any Lender that (a) has failed to (i) fund all or any portion of its Loans within two Business Days of the date such Loans were required to be funded hereunder unless such Lender notifies the Administrative Agent and the Borrower in writing that such failure is the result of such Lender's determination that one or more conditions precedent to funding (each of which conditions precedent, together with any applicable default, shall be specifically identified in such writing) has not been satisfied, or (ii) pay to the Administrative Agent or any other Lender any other amount required to be paid by it hereunder (including in respect of any participation in Account Letters of Credit) within two Business Days of the date when due, (b) has notified the Borrower or the Administrative Agent in writing that it does not intend to comply with its required funding obligations hereunder, or has made a public statement to that effect with respect to its required obligations hereunder or generally under the other agreements pursuant to which it has committed to extend credit (unless such writing or public statement relates to such Lender's obligation to fund a Loan hereunder and states that such position is based on such Lender's determination that a condition precedent to funding (which condition precedent, together with any applicable default, shall be specifically identified in such writing or public statement) cannot be satisfied), (c) has failed, within three Business Days after written request by the Administrative Agent or the Borrower, to confirm in writing to the Administrative Agent and the Borrower that it will comply with its prospective funding obligations hereunder (provided that such Lender shall cease to be a Defaulting Lender pursuant to this clause (c) upon receipt of such written confirmation by the Administrative Agent and the Borrower), or (d) has, or has a direct or indirect parent company that has, (i) become the subject of a proceeding under any Bankruptcy Law, (ii) had appointed for it a receiver, custodian, conservator, trustee, administrator, assignee for the benefit of creditors or similar Person charged with reorganization or liquidation of its business or assets, including the Federal Deposit Insurance Corporation or any other state or federal regulatory authority acting in such a capacity, (iii) taken any action in furtherance of, or indicated its consent to, approval of or acquiescence in or to any such proceeding or action or (iv) become the subject of a Bail-In Action; *provided* that a Lender shall

not be a Defaulting Lender solely by virtue of the ownership or acquisition of any equity interest in that Lender or any direct or indirect parent company thereof by a Governmental Authority so long as such ownership interest does not result in or provide such Lender with immunity from the jurisdiction of courts within the United States or from the enforcement of judgments or writs of attachment on its assets or permit such Lender (or such Governmental Authority) to reject, repudiate, disavow or disaffirm any contracts or agreements made with such Lender. Any determination by the Administrative Agent that a Lender is a Defaulting Lender under any one or more of clauses (a) through (d) above shall be conclusive and binding absent manifest error, and such Lender shall be deemed to be a Defaulting Lender upon the earlier to occur of (x) the delivery of written notice of such determination to the Borrower and each Lender by the Administrative Agent and (y) the fifth Business Day following the occurrence of the applicable event or circumstances described in clause (a), (b), (c) or (d) above (if such event or circumstance continues to exist on such date). No Lender that is Solvent shall be a Defaulting Lender solely by virtue of the precautionary appointment of an administrator guardian, custodian or other similar official with respect to such Lender or any direct or indirect parent company thereof by a Governmental Authority under or based on the law of the governing jurisdiction of such Lender or any direct or indirect parent company thereof if applicable law requires that such appointment not be disclosed.

90 " **Depositary Accounts** " shall have the meaning assigned to such term in Section 2.19(a) .

91 " **Depositary Bank** " shall have the meaning assigned to such term in the introductory paragraph of this Agreement.

92 " **Discharge of the Obligations** " shall mean, and shall have occurred, when (a) all Obligations owing shall have been paid in full in cash (other than (i) inchoate indemnity obligations that are expressly stated to survive termination and (ii) obligations and liabilities under Secured Swap Agreements that have been cash collateralized or as to which other arrangements satisfactory to the applicable Specified Swap Counterparties shall have been made) and (b) all Commitments shall have terminated or expired.

93 " **Disqualified Equity Interest** " shall mean any Equity Interest that, by its terms (or by the terms of any security into which it is convertible or for which it is exchangeable), or upon the happening of any event, (a) matures (excluding any maturity as the result of an optional redemption by the issuer thereof) or is mandatorily redeemable, pursuant to a sinking fund obligation or otherwise, or is redeemable at the option of the holder thereof, in whole or in part, or requires the payment of any cash dividend or any other scheduled payment constituting a return of capital, in each case at any time on or prior to one hundred and eighty (180) days after the Maturity Date, or (b) is convertible into or exchangeable (unless at the sole option of the issuer thereof) for (i) debt or debt securities or (ii) any Equity Interest referred to in clause (a) above, in each case at any time prior to one hundred and eighty (180) days after the Maturity Date.

94 " **Dividend** " shall have the meaning assigned to such term in Section 6.06 .

95 " **Documentation Agent** " shall mean MSSF in its capacity as documentation agent.

96 " **Drawing Amount** " shall mean, with respect to any Account Letter of Credit, as of any date of determination, the amount available to be drawn thereunder as of such date.

97 " **DSR Increase Payment** " shall have the meaning assigned to such term in Section 2.19(d)(i) .

98 " **DSR Requirement Amount** " shall mean, an amount, as calculated on the Closing Date for the six (6) month period following the Closing Date, and thereafter as recalculated on each Quarterly Date (commencing with May 2018) for the six (6) month period following each such Quarterly Date, equal to the amount of Debt Service reasonably anticipated on such date of determination to be due and payable over the six (6) month period commencing on such date of determination (calculated taking into account any amount that would be received or paid by the Borrower pursuant to Interest Rate Swap Agreements that are in effect during the applicable period), in each case based on the reasonable good faith projections of the Borrower and certified to by a Responsible Officer of the Borrower.

99 " **ECF Prepayment Account** " shall have the meaning assigned to such term in Section 2.19(a) .

100 " **ECF Sweep Date** " shall have the meaning assigned to such term in Section 2.09(b) .

101 " **Echo Entities** " shall mean the entities listed in Part 7 of Schedule 1.01C .

102 " **Echo LLC Agreements** " shall have the meaning assigned to such term in Schedule 1.01F .

103 " **Echo Projects** " shall mean each of the wind powered electric generation projects owned by the Echo Entities and listed under the heading "Other Projects" in Schedule 1.01D (each, individually, an " **Echo Project** "), including with respect to each such Echo Project the related Project site, and the panels, turbines, facilities, structures and improvements erected on such Project site and all other equipment and property leased or owned by the applicable Echo Entity with respect to such Echo Project and attached to or placed upon such Project site or used in connection with the operation of such Echo Project.

104 " **EEA Financial Institution** " means (a) any credit institution or investment firm established in any EEA Member Country which is subject to the supervision of an Resolution Authority, (b) any entity established in an EEA Member Country which is a parent of an institution described in clause (a) of this definition, or (c) any financial institution established in an EEA Member Country which is a subsidiary of an institution described in clauses (a) or (b) of this definition and is subject to consolidated supervision with its parent.

105 " **EEA Member Country** " means any member state of the European Union, Iceland, Liechtenstein and Norway.

106 " **Eligible Assignee** " shall mean any Person other than a natural Person that is (i) a Lender, an Affiliate of any Lender or an Approved Fund (any two or more related Approved Funds being treated as a single Eligible Assignee for all purposes hereof), or (ii) a commercial bank, insurance company, investment or mutual fund or other entity that is an "accredited investor" (as defined in Regulation D under the Securities Act) and which extends credit or buys loans in the ordinary course.

107 " **Engagement Letter** " shall mean that certain Engagement Letter, dated October 19, 2017, by and between the Borrower and the Lead Arranger, as amended, amended and restated, supplemented or otherwise modified prior to the date hereof.

108 " **Environment** " shall mean ambient and indoor air, surface water and groundwater (including potable water, navigable water and wetlands), the land surface or subsurface strata or sediment, and all other environmental media, and natural resources, including flora and fauna, including birds and bats, or as otherwise defined in any Environmental Law.

109 " **Environmental Claim** " shall mean any and all actions, suits, demand letters, claims, Liens, notices of noncompliance or violation, notices of liability or potential liability, investigations by a Governmental Authority, judicial, administrative or arbitral proceedings, consent orders or consent agreements relating to any violation or alleged violation of an Environmental Law or the Release of, or human exposure to, any Hazardous Material.

110 " **Environmental Law** " shall mean, collectively, all federal, state or local laws, including common law, statutes, ordinances, regulations, rules, codes, orders, judgments or other requirements or rules of law governing (a) the prevention, abatement or elimination of pollution, or the protection of the Environment, natural resources or human health or safety, or natural resource damages and (b) the use, generation, handling, treatment, storage, Release, transportation or regulation of, or human exposure to, Hazardous Materials, including the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. §§ 9601 et seq., the Endangered Species Act, 16 U.S.C. §§ 1531 et seq., the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act, 42 U.S.C. §§ 6901 et seq., the Clean Air Act, 42 U.S.C. §§ 7401 et seq., the Clean Water Act, 33 U.S.C. §§ 1251 et seq., the Toxic Substances Control Act, 15 U.S.C. §§ 2601 et seq., the Emergency Planning and Community Right to Know Act, 42 U.S.C. §§ 11001 et seq.; the National Environmental Policy Act, 42 U.S.C. §§ 4321 et. seq.; the Migratory Bird Treaty Act, 16 U.S.C. §§ 703 et. seq.; and the Bald and Golden Eagle Protection Act, 16 U.S.C. §§ 668 et. seq., each as amended, and their state or local counterparts or equivalents.

111 " **Equity Interests** " of any Person shall mean any and all shares, interests, rights to purchase, warrants, options, participation or other equivalents of or interests in (however designated) equity of such Person, including any preferred stock, any limited or general partnership interest and any limited liability company membership interest.

112 " **Equity Proceeds** " shall mean the cash proceeds of the issuance of Qualified Equity Interests of Holding or cash capital contributions (other than proceeds received as a result of the exercise of Cure Rights pursuant to Section 7.02) to Holding.

113 " **Equity Proceeds Account** " shall have the meaning assigned to such term in Section 2.19(a)(ii).

114 " **ERISA** " shall mean the Employee Retirement Income Security Act of 1974, as amended.

115 " **ERISA Affiliate** " shall mean any trade or business (whether or not incorporated) that, together with any Loan Party, is treated as a single employer under Section 414 of the Code.

116 " **ERISA Event** " shall mean, if at any time, (i) any Plan fails to comply with any material provision of ERISA and/or the Code (and applicable regulations under either) or with the material terms of such Plan, (ii) any Plan fails to satisfy the minimum funding standards of ERISA or the Code for any plan year or part thereof or a waiver of such standards or extension of any amortization period is sought or granted under Section 412 of the Code, (iii) a notice of intent to terminate any Plan is or is reasonably expected to be filed with the PBGC or the PBGC institutes proceedings under Section 4042 of ERISA to terminate or appoint a trustee to administer any Plan or the PBGC notifies the Borrower that a Plan may become a subject of any such proceedings, (iv) a Loan Party incurs or is reasonably expected to incur any liability pursuant to Title I of ERISA (other than routine claims for benefits) or the penalty or excise tax provisions of the Code relating to employee benefit plans, or a Loan Party or any ERISA Affiliate incurs or is reasonably expected to incur any liability pursuant to Title IV of ERISA (other than for timely paid premiums to the PBGC), (v) a Loan Party or any ERISA Affiliate withdraws from any Multiemployer Plan in a complete withdrawal or a partial withdrawal, (vi) a Loan Party or any ERISA Affiliate fails to make any required contribution to a Multiemployer Plan pursuant to Section 431 or 432

of the Code, (vii) any Multiemployer Plan is determined to be insolvent, or in “endangered” or “critical” status (within the meaning of Section 432 of the Code or Section 305 of ERISA), (viii) a Loan Party establishes or amends any employee welfare benefit plan that provides post-employment welfare benefits in a manner that would increase the liability of a Loan Party thereunder, (ix) a non-exempt “prohibited transaction” (within the meaning of Section 406 of ERISA and Section 4975(c) of the Code) occurs with respect to any Plan, (x) any ERISA Plan is determined to be in “at risk” status (within the meaning of Section 430 of the Code or Section 303 of ERISA), (xi) a “reportable event” occurs (within the meaning of Section 4043 of ERISA) for which notice thereof has not been waived pursuant to regulations as in effect on the date thereof, or (xii) a Foreign Plan Event occurs.

117 “ **ERISA Plan** ” shall mean any employee pension benefit plan (other than a Multiemployer Plan) subject to the provisions of Title IV of ERISA or Section 412 or 430 of the Code or Section 302 of ERISA and in respect of which any Loan Party or any ERISA Affiliate is (or if such plan were terminated would under Section 4069 of ERISA be deemed to be) an “employer” as defined in Section 3(5) of ERISA.

118 “ **EU Bail-In Legislation Schedule** ” means the document described as such and published by the Loan Market Association (or any successor person) from time to time.

119 “ **Event of Default** ” shall have the meaning assigned to such term in Section 7.01 .

120 “ **Excess Cash Flow** ” shall mean, for each Excess Cash Flow Period, an amount equal to 100% of Available Cash of the Borrower for such Excess Cash Flow Period and any other amounts deposited into the Revenue Account during such Excess Cash Flow Period less any amounts required to be disbursed pursuant to clauses (i) through (vi) of Section 2.19(c) during such Excess Cash Flow Period.

121 “ **Excess Cash Flow Period** ” shall mean (a) initially the period from the Closing Date until May, 2018 and (b) thereafter, each quarterly period ending on each Quarterly Date of each calendar year.

122 “ **Excess Liquidity Reserve Amount** ” shall have the meaning assigned to such term in Section 2.19(e)(ii)(C)

123 “ **Excess Project Disposition Proceeds** ” shall have the meaning assigned to such term in Section 2.09(b) .

124 “ **Excess Reserve Amount** ” shall have the meaning assigned to such term in Section 2.19(d)(iii)(A) .

125 “ **Exchange Act** ” shall mean the Securities Exchange Act of 1934, as amended.

126 “ **Excluded Indebtedness** ” shall mean all Indebtedness permitted to be incurred under Section 6.01 .

127 “ **Excluded Swap Obligation** ” shall mean with respect to the Guarantors (as defined in the Pledge Agreement), (x) as it relates to all or a portion of the Guarantee of the Guarantor, any Swap Obligation if, and to the extent that, such Swap Obligation (or any Guarantee thereof) is or becomes illegal under the Commodity Exchange Act or any rule, regulation or order of the Commodity Futures Trading Commission (or the application or official interpretation of any thereof) by virtue of the Guarantor’s failure for any reason to constitute an “eligible contract participant” as defined in the Commodity Exchange Act and the regulations thereunder at the time the Guarantee of the Guarantor becomes effective with respect to such Swap Obligation or (y) as it relates to all or a portion of the grant by the Guarantor of a

security interest, any Swap Obligation if, and to the extent that, such Swap Obligation (or such security interest in respect thereof) is or becomes illegal under the Commodity Exchange Act or any rule, regulation or order of the Commodity Futures Trading Commission (or the application or official interpretation of any thereof) by virtue of the Guarantor's failure for any reason to constitute an "eligible contract participant" as defined in the Commodity Exchange Act and the regulations thereunder at the time the security interest of the Guarantor becomes effective with respect to such Swap Obligation. If a Swap Obligation arises under a master agreement governing more than one swap, such exclusion shall apply only to the portion of such Swap Obligation that is attributable to swaps for which such Guarantee or security interest is or becomes illegal.

128 " **Excluded Taxes** " shall mean, with respect to any Agent, any Lender or any other recipient of any payment to be made by or on account of any obligation of any Loan Party hereunder, (a) Taxes imposed on or measured by its net income (however denominated), franchise Taxes, and branch profits Taxes, in each case (i) imposed as a result of the recipient being organized under the laws of, or having its principal office or, in the case of any Lender, its applicable lending office located in, the jurisdiction imposing such Tax (or any political subdivision thereof) or (ii) that are Other Connection Taxes, (b) in the case of a Lender, U.S. federal withholding Taxes imposed on amounts payable to or for the account of such Lender with respect to an applicable interest in a Loan or Commitment pursuant to a law in effect on the date on which (i) such Lender acquires such interest in the Loan or Commitment (other than pursuant to an assignment request by the Borrower under Section 2.17(b)) or (ii) such Lender changes its lending office, except in each case to the extent that, pursuant to Section 2.15(a) or Section 2.15(c) , amounts with respect to such Taxes were payable either to such Lender's assignor immediately before such Lender became a party hereto or to such Lender immediately before it changed its lending office, (c) Taxes attributable to such recipient's failure to comply with Section 2.15(e) , and (d) any U.S. federal withholding Taxes imposed under FATCA.

129 " **Executive Order** " has the meaning given to such term in the definition of "Anti-Terrorism Laws".

130 " **Exelon AVSR Holding** " shall have the meaning assigned to such term in the recitals hereto.

131 " **ExGen Renewables Entities** " means ExGen Renewables Holdings, ExGen Renewables JV, the Continental Wind Entities, the RPG Entities, the Bluestem Entities and the Other JV Entities and, if applicable, (a) any Additional Project Entities owned, directly or indirectly, by ExGen Renewables JV and (b) upon consummation of (i) the SolGen Disposition, the SolGen Entities, (ii) the AVSR Disposition, the AVSR Entities and (iii) the AG Disposition where the Albany Green Entities are sold to ExGen Renewables JV, the Albany Green Entities.

132 " **ExGen Renewables Holdings** " shall have the meaning assigned to such term in the recitals hereto.

133 " **ExGen Renewables I Holding** " shall mean ExGen Renewables I Holding, LLC, a Delaware limited liability company.

134 " **ExGen Renewables JV** " shall have the meaning assigned to such term in the recitals hereto.

135 " **ExGen Renewables JV Agreements** " shall have the meaning assigned to such term in Schedule 1.01A .

136 " **ExGen Renewables JV Projects** " shall mean the Continental Wind Projects, the RPG Projects, the Bluestem Project and the Other JV Projects and if applicable (a) any Additional Project owned by any ExGen Renewables Entity and (b) upon consummation of (i) the SolGen Disposition, the SolGen Projects, (ii) the AVSR Disposition, the AV Solar Project and (iii) the AG Disposition where the Albany Green Entities are sold to ExGen Renewables JV, the Albany Green Project.

137 " **Existing Project Level Financing Documents** " shall mean the agreements set forth on Schedule 1.01A.

138 " **FATCA** " shall mean Sections 1471 through 1474 of the Code, as of the date of this Agreement (or any amended or successor version that is substantively comparable and not materially more onerous to comply with), any current or future regulations and official interpretations thereof and any agreements entered into pursuant to Section 1471(b)(1) of the Code.

138 " **Federal Funds Effective Rate** " shall mean, for any day, the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System arranged by federal funds brokers, as published on the next succeeding Business Day by the Federal Reserve Bank of New York, or, if such rate is not so published for any day that is a Business Day, the average of the quotations for the day of such transactions received by the Administrative Agent from three (3) federal funds brokers of recognized standing selected by it.

139 " **Fee Letters** " shall mean (i) that certain Administrative Agent Fee Letter, dated as of November 28, 2017, by and between the Borrower and the Administrative Agent, (ii) that certain Collateral Agent and Depositary Services Agreement, dated October 5, 2017, by and between the Borrower and the Collateral Agent and (iii) any other fee letters between the Borrower and any Agent, in each case, as amended, amended and restated, supplemented or otherwise modified from time to time.

140 " **Fees** " shall mean the Administrative Agent Fees and any other fees payable under the Fee Letters, any other fees payable to the Collateral Agent or the Depositary Bank by the Loan Parties and any fees payable under the Engagement Letter.

141 " **Financial Assets** " shall have the meaning assigned to such term in Section 8.01(e) .

142 " **Financial Officer** " of any Person shall mean the Chief Financial Officer, principal accounting officer, Treasurer, Assistant Treasurer or Controller of such Person.

143 " **Financial Performance Covenant** " shall mean the covenant of the Borrower set forth in Section 6.10 .

144 " **Foreign Benefit Arrangement** " shall mean any employee benefit arrangement mandated by non-U.S. law that is maintained or contributed to by any Loan Party.

145 " **Foreign Plan** " shall mean each employee benefit plan (within the meaning of Section 3(3) of ERISA, whether or not subject to ERISA) that is not subject to U.S. law and is maintained or contributed to by any Loan Party.

146 " **Foreign Plan Event** " shall mean, with respect to any Foreign Benefit Arrangement or Foreign Plan, (a) the failure to make or, if applicable, accrue in accordance with normal accounting practices, any employer or employee contributions required by applicable law or by the terms of such Foreign Benefit Arrangement or Foreign Plan, (b) the failure to register or loss of good standing with applicable regulatory authorities of any such Foreign Benefit Arrangement or Foreign Plan required to be registered, or (c) the failure of any Foreign Benefit Arrangement or Foreign Plan to comply with any

material provisions of applicable law and regulations or with the material terms of such Foreign Benefit Arrangement or Foreign Plan.

147 " **FPA** " shall have the meaning assigned to such term in Section 3.08(c) .

148 " **Fully Funded** " shall mean, with respect to the Debt Service Reserve Account and as of any date of determination, that the sum of (a) the amount of Cash and Cash Equivalents on deposit in the Debt Service Reserve Accounts as of such date of determination *plus* (b) the maximum amount guaranteed pursuant to any Sponsor Guaranty credited to such account as of such date of determination *plus* (c) the aggregate Drawing Amounts as of such date of determination of any Account Letters of Credit in favor of the Collateral Agent credited to such account, is not less than the then applicable DSR Requirement Amount (*provided* , that (i) (x) such Sponsor Guaranty shall have not been terminated or disavowed in writing and no payment default shall have occurred thereunder and (y) the guarantor under any such Sponsor Guaranty has not ceased to be an Acceptable Guarantor, and (ii) (x) such Account Letter of Credit shall be in full force and effect (and shall not expire within thirty (30) days from the date of determination) unless the Collateral Agent has received notice from the issuer thereof that such Account Letter of Credit will be renewed in accordance with its terms or has received notice from the issuer thereof or the Borrower that such Account Letter of Credit will be extended or replaced (with another Account Letter of Credit, a Sponsor Guaranty or cash in a corresponding amount deposited in the Debt Service Reserve Accounts) on or prior to its stated expiration date) and (y) the issuer of such Account Letter of Credit has not ceased to be an Acceptable LC Issuer (unless such Account Letter of Credit has been replaced with another Account Letter of Credit, Sponsor Guaranty or cash in a corresponding amount deposited in the Debt Service Reserve Accounts)), and " **Fully Fund** " shall have a meaning correlative thereto.

149 " **GAAP** " shall mean generally accepted accounting principles and practices as in effect from time to time in the United States of America.

150 " **Governmental Authority** " shall mean any federal, state, provincial, local or foreign court or governmental agency, authority, instrumentality or regulatory or legislative body.

151 " **Government Official** " shall mean any officer or employee of a government or government-owned or controlled entity or of a public international organization, or any person acting in an official capacity for or on behalf of any of the foregoing, or any political party or party official or candidate for political office.

152 " **Guarantee** " shall mean a guarantee other than by endorsement of negotiable instruments for collection in the ordinary course of business, direct or indirect, in any manner including, without limitation, by way of a pledge of assets or through letters of credit or reimbursement agreements in respect thereof, of all or any part of any Indebtedness (whether arising by virtue of partnership arrangements, or by agreements to keep-well, to purchase assets, goods, securities or services, to take or pay or to maintain financial statement conditions or otherwise).

153 " **Hazardous Materials** " shall mean all pollutants, contaminants, wastes, chemicals, materials, substances and constituents, including explosive or radioactive substances or petroleum or petroleum distillates, asbestos or asbestos containing materials, polychlorinated biphenyls or radon gas, of any nature, in each case to the extent subject to regulation or for which liability can be imposed under any Environmental Law.

154 " **Hedging Obligations** " shall mean, with respect to any specified Person, the obligations of such Person under (a) interest rate swap agreements (whether from fixed to floating or from floating to fixed), interest rate cap agreements and interest rate collar agreements; (b) other agreements or

arrangements designed to manage interest rates or interest rate risk; and (c) other agreements or arrangements designed to protect such Person against fluctuations in currency exchange rates or commodity prices, including Commodity Hedge Agreements.

155 " **Holding** " shall have the meaning assigned to such term in the introductory paragraph of this Agreement.

156 " **Indebtedness** " shall mean, with respect to any specified Person, any indebtedness of such Person (excluding accrued expenses and trade payables), whether or not contingent:

(a) in respect of borrowed money;

(b) evidenced by bonds, notes, debentures or similar instruments;

(c) in respect of letters of credit, banker's acceptances or other similar instruments (or reimbursement agreements in respect thereof);

(d) representing Capital Lease Obligations;

(e) representing the balance deferred and unpaid of the purchase price of any property or services due more than 60 days after such property is acquired or such services are completed; or

(f) representing any Hedging Obligations,

if and to the extent any of the preceding items (other than letters of credit and Hedging Obligations) would appear as a liability upon a balance sheet of the specified Person prepared in accordance with GAAP. In addition, the term "Indebtedness" includes all Indebtedness of others secured by a Lien on any asset of the specified Person (whether or not such Indebtedness is assumed by the specified Person) and, to the extent not otherwise included, the Guarantee by the specified Person of any Indebtedness of any other Person. Indebtedness shall be calculated without giving effect to the effects of Statement of Financial Accounting Standards No. 133 and related interpretations to the extent such effects would otherwise increase or decrease an amount of Indebtedness for any purpose under this Agreement as a result of accounting for any embedded derivatives created by the terms of such Indebtedness.

157 " **Indemnified Taxes** " shall mean all Taxes, other than Excluded Taxes, imposed on or with respect to any payment made by or on account of any Obligation of any Loan Party under any Loan Document.

158 " **Indemnitee** " shall have the meaning assigned to such term in Section 9.05(b) .

159 " **Information** " shall have the meaning assigned to such term in Section 3.13(a) .

160 " **Interest Election Request** " shall mean a request by the Borrower to convert or continue a Borrowing in accordance with Section 2.05 , in substantially the form of Exhibit D .

161 " **Interest Payment Date** " shall mean (a) with respect to any LIBOR Loan, each Quarterly Date, (b) with respect to any Base Rate Loan, each Quarterly Date and (c) as to any Loan, the Maturity Date.

162 " **Interest Period** " shall mean, as to any Borrowing consisting of a LIBOR Loan, the period commencing on the date of such Borrowing or on the last day of the immediately preceding

Interest Period applicable to such Borrowing, as applicable, and ending on the next Quarterly Date that is one (1), three (3) or six (6) months thereafter, as the Borrower may elect; *provided* that, all of the foregoing provisions relating to Interest Periods are subject to the following: (i) if any Interest Period would otherwise end on a day that is not a Business Day, such Interest Period shall be extended to the next succeeding Business Day unless the result of such extension would be to carry such Interest Period into another calendar month in which event such Interest Period shall end on the immediately preceding Business Day; (ii) the Borrower may not select an Interest Period that would extend beyond the Maturity Date; (iii) any Interest Period that begins on the last Business Day of a calendar month (or on a day for which there is no numerically corresponding day in the calendar month at the end of such Interest Period) shall end on the last Business Day of a calendar month; and (iv) notwithstanding the foregoing, in connection with the LIBOR Borrowing made on the Closing Date, such LIBOR Borrowing may have an Interest Period commencing on the Closing Date and ending on the first Quarterly Date after the Closing Date. Interest shall accrue from and including the first day of an Interest Period to but excluding the last day of such Interest Period.

163 " **Interest Rate Swap Agreements** " shall have the meaning assigned to such term in Section 5.12.

164 " **Interpolated Rate** " shall mean at any time, the rate per annum (rounded to the same number of decimal places as the LIBO Screen Rate) determined by the Administrative Agent (which determination shall be conclusive and binding absent manifest error) to be equal to the rate that results from interpolating on a linear basis between: (a) the LIBO Screen Rate (for the longest period for which that LIBO Screen Rate is available in U.S. Dollars) that is shorter than the Impacted Interest Period and (b) the LIBO Screen Rate (for the shortest period for which that LIBO Screen Rate is available for U.S. Dollars) that exceeds the Impacted Interest Period, in each case, at approximately 11:00 a.m., London time, two Business Days prior to the commencement of such Interest Period. When determining the rate for a period which is less than the shortest period for which the LIBO Screen Rate is available, the LIBO Screen Rate for purposes of clause (a) above shall be deemed to be the overnight rate for U.S. Dollars determined by the Administrative Agent from such service as the Administrative Agent may select.

165 " **Investment** " shall have the meaning assigned to such term in Section 6.04 .

166 " **JV Class A Membership Interests** " shall mean the "Class A Interests" as defined in the ExGen Renewables JV Agreement.

167 " **Lead Arranger** " shall mean MSSF in its capacity as sole lead arranger and sole bookrunner.

168 " **Lender** " shall mean each financial institution listed on Schedule 2.01 , as well as any Person (other than a natural person) that becomes a "Lender" hereunder pursuant to Section 9.04 .

169 " **Lender Counterparty** " shall mean (a) the Administrative Agent, the Lead Arranger or any of their respective Affiliates or (b) any Lender or any of its Affiliates, in the case of this clause (b) with a credit rating (or having a guarantor with a credit rating) equal to or better than A- from S&P or A3 from Moody's at the time it enters into a Swap Agreement, in each case, in its capacity as a party to a Swap Agreement.

170 " **LIBO Base Rate** " shall mean, with respect to any LIBOR Loan for any Interest Period, (i) the rate appearing on the applicable Reuters screen page (or on any successor or substitute page or service providing quotations of interest rates applicable to dollar deposits in the London interbank market comparable to those currently provided on such page, as determined by the Administrative Agent from time to time) at approximately 11:00 a.m., London time, two Business Days prior to the

commencement of such Interest Period, as the rate for dollar deposits with a maturity comparable to such Interest Period or (ii) if the rate referenced in clause (i) above does not appear on such page or service or such page or service shall cease to be available, the rate per annum equal to the London interbank offered rate as administered by the ICE Benchmark Administration (or any other Person that takes over the administration of such rate) for U.S. Dollars for a period equal in length to such Interest Period as displayed on pages LIBOR01 or LIBOR02 of the Reuters Screen that displays such rate (or, in the event such rate does not appear on either of such Reuters pages, on any successor or substitute page on such screen that displays such rate, or on the appropriate page of such other information service that publishes such rate from time to time as selected by the Administrative Agent in its reasonable discretion) at approximately 11:00 a.m., London time, two Business Days prior to the commencement of such Interest Period (in each case, the " **LIBO Screen Rate** "); *provided* that if the LIBO Screen Rate shall be less than zero, such rate shall be deemed to be zero for purposes of this Agreement; *provided* , further, that if the LIBO Screen Rate shall not be available at such time for such Interest Period (an " **Impacted Interest Period** ") with respect to U.S. Dollars, then the LIBO Base Rate shall be the Interpolated Rate at such time (provided that if the Interpolated Rate shall be less than zero, such rate shall be deemed to be zero for purposes of this Agreement).

171 " **LIBO Rate** " shall mean, with respect to each day during each Interest Period pertaining to a LIBOR Loan, a rate per annum (rounded upwards, if necessary, to the nearest 1/100 of 1%) determined by the Administrative Agent to be equal to the greater of (x) the quotient obtained by dividing (a) the LIBO Base Rate for such LIBOR Loan for such Interest Period by (b) 1 minus the LIBOR Reserve Requirement for such LIBOR Loan for such Interest Period and (y) 1.00% per annum.

172 " **LIBOR Borrowing** " shall mean a Borrowing comprised of LIBOR Loans.

173 " **LIBOR Loans** " shall mean Loans that bear interest at rates based upon the LIBO Rate.

174 " **LIBOR Reserve Requirements** " shall mean, at any time, the maximum rate at which reserves (including, without limitation, any marginal, special, supplemental, or emergency reserves) are required to be maintained under regulations issued from time to time by the Board by member banks of the Federal Reserve System against "Eurocurrency liabilities" (as such term is used in Regulation D) (such requirement as set forth on www.federalreserve.gov/monetarypolicy/reservereq.htm or any similar website operated or made available from time to time by the Board either relating to reserve requirements in general or to the terms of Regulation D in particular). Without limiting the effect of the foregoing, the LIBOR Reserve Requirements shall reflect any other reserves required to be maintained by such member banks with respect to (i) any category of liabilities which includes deposits by reference to which the LIBO Rate is to be determined, or (ii) any category of extensions of credit or other assets which include LIBOR Loans. The LIBO Rate shall be adjusted automatically on and as of the effective date of any change in the Reserve Requirements.

175 " **Lien** " shall mean, with respect to any asset, (a) any mortgage, deed of trust, lien, hypothecation, pledge, encumbrance, charge or security interest in or on such asset, (b) the interest of a vendor or a lessor under any conditional sale agreement, capital lease or title retention agreement (or any financing lease having substantially the same economic effect as any of the foregoing) relating to such asset, and (c) in the case of securities, any purchase option, call or similar right of a third party with respect to such securities. For certainty, "Lien" shall not include any netting or set-off arrangements under any contract, agreement or other undertaking that is otherwise permitted to be entered into by ExGen Renewables JV, any Project Holdco or any Project Entity in accordance with the Project Level Financing Documents to which it (or its Subsidiaries) is a party.

176 " **Liquidity Reserve Account** " shall have the meaning assigned to such term in Section 2.19(a) .

177 " **Liquidity Reserve Maximum Balance** " shall mean $[***].

178 " **LLC Agreement** " shall mean (i) the Amended and Restated Limited Liability Company Agreement of the Borrower, effective as of November 10, 2017 and (ii) the Second Amended and Restated Limited Liability Company Agreement of Holding, effective as of November 10, 2017.

179 " **Loan Documents** " shall mean this Agreement, the Security Documents and any Notes issued under Section 2.07(d) .

180 " **Loan Parties** " shall mean the Borrower, Holding and ExGen Renewables Holdings. For the avoidance of doubt, none of the Sponsor, the Parent, or the Project Entities (other than ExGen Renewables Holdings) shall be (or be deemed for any purpose to be) Loan Parties.

181 " **Loans** " shall mean the term loans made by the Lenders to the Borrower pursuant to Section 2.01 .

182 " **Local Account Control Agreement** " shall mean (i) the Deposit Account Control Agreement, entered into as of November 28, 2017, among the Borrower, the Collateral Agent and Citibank, N.A. as depositary bank and (ii) any other account control agreement entered into to establish "control" (within the meaning of the UCC) over Local Accounts in form and substance reasonably satisfactory to the Administrative Agent.

183 " **Local Accounts** " shall mean one or more "local checking account(s)" or similar account(s) to be established by the Borrower or any Project Holdco at their respective election, which account(s) shall be subject to a perfected, first priority Lien of the Collateral Agent pursuant to the applicable Local Account Control Agreement but to which the Borrower or any such Project Holdco shall have at all times, other than upon the occurrence and continuation of a Trigger Event, full access and signing authority for the purpose of writing checks or wiring funds for the purposes permitted hereunder; *provided* that the aggregate $[***].

184 " **Major Revenue Contract** " shall mean (a) each agreement for the sale of all or a portion of the energy, capacity and/or ancillary services entered into by any Project Entity from time to time with respect to output of the AV Solar Project and (b) PTC Agreements, together with all amendments, modifications, supplements or replacements thereto or thereof to the extent permitted hereunder.

185 " **Margin Stock** " shall have the meaning assigned to such term in Regulation U.

186 " **Material Adverse Effect** " shall mean a material adverse effect on (i) the business, assets, properties, financial condition or results of operations of the Borrower and its Subsidiaries (including all Project Entities), taken as a whole, (ii) the rights and remedies of the Agents and the Lenders under any Loan Document or (iii) the ability of the Loan Parties (taken as a whole) to perform their payment and other material obligations under any Loan Document.

187 " **Material Indebtedness** " shall mean (x) with respect to any Loan Party, any outstanding Indebtedness (other than the Loans) of any such Person in an aggregate principal amount equal to or greater than U.S. $[***] and (y) with respect to any Project Entity (or, to the extent under a common financing arrangement, Project Entities), outstanding Indebtedness of any such Person in an aggregate principal amount equal to or greater than U.S. $[***](including under any Project Level Financing Documents).

188 " **Material Other Indebtedness Document** " shall mean any definitive documentation for any Indebtedness for borrowed money with a principal or committed amount equal to or greater than $[***] (and any Guarantees and security related thereto) of one or more Project Entities.

189 " **Material Project Level Agreements** " shall mean (i) the Project Level Financing Documents and (ii) the Major Revenue Contracts.

190 " **Material Project Subsidiary** " shall mean any of the Project Holdcos and AVSR Entities.

191 " **Maturity Date** " shall mean November 28, 2024 (or if such date is not a Business Day, the next succeeding Business Day, unless such Business Day is in the next calendar month, in which case the next preceding Business Day).

192 " **Maximum Rate** " shall have the meaning assigned to such term in Section 9.09 .

193 " **Moody's** " shall mean Moody's Investors Service, Inc., and its successors.

194 " **MSSF** " shall have the meaning assigned to such term in the introductory paragraph of this Agreement.

" **Multiemployer Plan** " shall mean any employee benefit plan of the type described in Section 4001(a)(3) of ERISA, to which any Loan Party or any ERISA Affiliate makes or is obligated to make contributions.

195 " **Net Proceeds** " shall mean:

(a) 100.0% of the proceeds constituting Cash and Cash Equivalents paid and actually received by a Loan Party (including any cash payments or payments consisting of Cash and Cash Equivalents paid and received by way of deferred payment of principal pursuant to a note or installment receivable or purchase price adjustment receivable and including casualty insurance settlements and condemnation awards, but only as and when paid and received) from any loss, damage, destruction or condemnation of, or any sale, transfer or other disposition (including any sale and leaseback of assets) to any Person of any asset or assets of any of the Loan Parties (other than those permitted under Section 6.05 , other than Section 6.05(e) but subject to the terms of the Project Level Financing Documents) net of (x) attorneys' fees, accountants' fees, investment banking fees, sales commissions, required debt payments and required payments of other obligations (including swap breakage costs) relating to the applicable asset (other than pursuant hereto) and any cash reserve for adjustment in respect of the sale price of such asset established in accordance with GAAP, including pension and post-employment benefit liabilities and liabilities related to environmental matters or against any indemnification obligations associated with such transaction, other customary expenses and brokerage, consultant and other customary fees actually incurred in connection therewith and (y) Taxes and Other Taxes paid or payable as a result thereof; and

(b) 100.0% of the proceeds constituting Cash and Cash Equivalents from the incurrence, issuance or sale by any of the Loan Parties of any Indebtedness (other than Excluded Indebtedness), net of all Taxes and fees (including investment banking fees), commissions, costs and other expenses, in each case incurred in connection with such incurrence, issuance or sale.

For purposes of calculating the amount of Net Proceeds, fees, commissions and other costs and expenses payable to the Borrower or any of their respective Affiliates shall be disregarded, except for financial advisory fees customary in type and amount paid to Affiliates of the Sponsor.

196 " **Non-Consenting Lender** " shall have the meaning assigned to such term in Section 2.17(c) .

197 " **Non-U.S. Lender** " shall have the meaning assigned to such term in Section 2.15(e) .

198 " **Note** " shall mean a promissory note delivered by the Borrower pursuant to Section 2.07(d) and substantially in the form of Exhibit H .

199 " **Obligations** " shall mean all amounts owing to any of the Agents, any Lender or any other Secured Party pursuant to the terms of this Agreement or any other Loan Document, or to any Specified Swap Counterparty pursuant to the terms of any Secured Swap Agreement, or pursuant to the terms of any Guarantee thereof, including with respect to any Loan, Secured Swap Agreement or other agreement, and all other obligations and liabilities of the Loan Parties of any kind and description to the Agents, any Lender or any other Secured Party, in each case, whether direct or indirect (including those acquired by assumption), absolute or contingent, due or to become due, now existing or hereafter arising and whether on account of principal, interest, fees, indemnities, costs, expenses, guarantee obligations or otherwise, which may arise under, out of, or in connection with, this Agreement or any other Loan Document, and including interest and fees that accrue after the commencement by or against any Loan Party or any Affiliate thereof of any proceeding under any bankruptcy or insolvency laws naming such Person as the debtor in such proceeding, regardless of whether such interest and fees are allowed claims in such proceeding; *provided* , that at no time shall Obligations include any Excluded Swap Obligations.

200 " **OFAC** " shall mean the Office of Foreign Assets Control of the U.S. Department of the Treasury.

201 " **Operating Expenses** " shall mean all costs and expenses of the Borrower and Holding incurred by the Borrower and Holding pursuant to or in respect of the Loan Documents (other than Fees).

202 " **Organizational Documents** " shall mean (i) with respect to any corporation or company, its certificate, memorandum or articles of incorporation, organization or association, as amended, and its by- laws, as amended, (ii) with respect to any limited partnership, its certificate or declaration of limited partnership, as amended, and its partnership agreement, as amended, (iii) with respect to any general partnership, its partnership agreement, as amended, and (iv) with respect to any limited liability company, its articles of organization, as amended, and its operating agreement, as amended.

203 " **Other Connection Taxes** " shall mean, with respect to any Agent or any Lender, Taxes imposed as a result of a present or former connection between such recipient and the jurisdiction imposing such Tax (other than connections arising from such recipient having executed, delivered, become a party to, performed its obligations under, received payments under, received or perfected a security interest under, engaged in any other transaction pursuant to or enforced any Loan Document, or sold or assigned an interest in any Loan or Loan Document).

204 " **Other JV Entities** " shall mean the entities listed in Part 8 of Schedule 1.01C and, if applicable, any Additional Project Entities owned, directly or indirectly, by ExGen Renewables JV and that are not Continental Wind Entities, Bluestem Entities or RPG Entities.

205 " **Other JV Projects** " shall mean each of the wind and solar power electric generation projects owned by the Other JV Entities and listed under the heading "Other Projects" in Schedule 1.01D and any Additional Project owned by any Other JV Entity (each, individually, an " **Other JV Project** "), including with respect to each such Other JV Project the related Project site, and the panels, turbines, facilities, structures and improvements erected on such Project site and all other equipment and property

leased or owned by the applicable Other JV Entity with respect to such Other JV Project and attached to or placed upon such Project site or used in connection with the operation of such Other JV Project.

206 " **Other Taxes** " shall mean any and all present or future stamp, court, documentary, intangible, recording, filing or similar Taxes arising from any payment made under any Loan Document or from the execution, delivery, performance, enforcement or registration of, from the receipt or perfection of a security interest under, or otherwise with respect to, any Loan Document, except any such Taxes that are Other Connection Taxes imposed with respect to an assignment (other than an assignment made pursuant to Section 2.17(b)).

207 " **Parent** " shall mean Exelon Corporation, a Pennsylvania corporation.

208 " **Participant** " shall have the meaning assigned to such term in Section 9.04(c)(i) .

209 " **Participant Register** " shall have the meaning assigned to such term in Section 9.04(c)(i) .

210 " **PBGC** " shall mean the Pension Benefit Guaranty Corporation referred to and defined in ERISA and any successor entity performing similar functions.

211 " **Permitted Acquisition** " shall mean (a) the acquisition, directly or indirectly, by the Borrower, whether by purchase, merger or otherwise (and in one or more transactions), of all or a portion of the Equity Interests in Albany Power Holdings that are not owned by it on the Closing Date and (b) any acquisition, directly or indirectly, by the Borrower, whether by purchase, merger or otherwise, of all or substantially all of the assets of, or all or a portion of the Equity Interests of, a Person owning any wholesale renewable electric generating facility or distributed electric generating portfolio in the United States (including any "ROFO Assets" as defined in the ExGen Renewables JV Agreement) (each an " **Additional Project** "); *provided* that (i) all transactions in connection therewith shall be consummated, in all material respects, in accordance with all applicable law and in conformity with all applicable consents, orders, permits and approvals of any Governmental Authority, (ii) such acquisition does not result in any default or event of default under any Material Project Level Agreement, (iii) to the extent the Person acquiring such assets or Equity Interests is a Loan Party, the Collateral and Guaranty Requirement shall have been satisfied and (iv) the Borrower shall have delivered to Administrative Agent a certificate of a Responsible Officer of the Borrower certifying compliance with the foregoing clauses (i) through (iii) .

212 " **Person** " shall mean any natural person, corporation, business trust, joint venture, association, company, partnership, limited liability company, individual or family trusts, or government or any agency or political subdivision thereof.

213 " **Plan** " shall mean any employee pension benefit plan (other than a Multiemployer Plan) that is maintained or is contributed to by a Loan Party or any ERISA Affiliate and is covered by Title IV of ERISA or is subject to minimum funding standards under Section 412 of the Code.

214 " **Platform** " shall have the meaning assigned to such term in Section 9.17(b) .

215 " **Pledge Agreement** " shall mean the Guarantee and Pledge Agreement, substantially in the form of Exhibit E-2 , between Holding, ExGen Renewables Holdings and the Collateral Agent.

216 " **Pledged Collateral** " with respect to particular Collateral, shall have the meaning assigned to such term, the term "Pledged Equity Interests" or similar term in the Security Document applicable to such Collateral.

217 " **Prepayment Notice** " shall mean a notice by the Borrower to prepay Loans in accordance with Section 2.08 , in substantially the form of Exhibit B .

218 " **Prime Rate** " shall mean the rate of interest per annum publicly announced from time to time by the Administrative Agent as its prime rate in effect at its principal office in New York, NY (the Prime Rate not being intended to be the lowest rate of interest charged by the Administrative Agent in connection with extensions of credit to debtors).

219 " **Prior Liens** " shall mean Liens permitted pursuant to Section 6.02 other than Liens permitted pursuant to clauses (b) , (d) and (h) of Section 6.02 .

220 " **Project Entities** " shall mean each of, or all of, as the context shall require, the AVSR Entities, the ExGen Renewables Entities, the SolGen Entities, the Albany Green Entities and any Additional Project Entities not otherwise included in the foregoing (but excluding, for purposes of clarity, any Project Entities transferred or otherwise disposed of in accordance with Section 6.05(e) from and after such disposition).

221 " **Project Holdcos** " each of, or all of, as the context shall require, (i) ExGen Renewables Holdings, (ii) SolGen Holding (until the consummation of the SolGen Disposition), (iii) Exelon AVSR Holding (until the consummation of the AVSR Disposition), and (iv) Albany Power Holdings (until the consummation of the AG Disposition where the Albany Green Entities are sold to ExGen Renewables JV) (or, if applicable in the case of an AG Disposition to a Person other than ExGen Renewables JV, any Additional Albany Green Entity directly owned by the Borrower).

222 " **Project Level Financing Documents** " shall mean (i) the Existing Project Level Financing Documents and (ii) any Material Other Indebtedness Document and any other definitive documentation for any Indebtedness for borrowed money of any Project Entity that is in full force and effect as of the Closing Date and set forth on Schedule 1.01B or entered into after the Closing Date (or, with respect to any Additional Project, was entered into on or prior to the date of the applicable Permitted Acquisition by the applicable Additional Project Entities), in each case, together with all amendments, modifications, supplements or replacements thereto or thereof to the extent permitted hereunder. Notwithstanding the foregoing, for the avoidance of doubt, solely for the purposes of Sections 6.01(h) , 6.02(h) , and 6.05(e) , the term "Project Level Financing Documents" shall only include those documents and agreements listed in clauses (i) and (ii) of the preceding sentence as such documents and agreements are in effect as of the Closing Date and without giving effect to any amendments, modifications, supplements or replacements thereto or thereof after the Closing Date (other than any amendments, modifications, supplements or replacements thereto or thereof as to which the Required Lenders shall have consented to in writing).

223 " **Project Level Indebtedness** " shall mean Indebtedness of the Project Entities existing on the Closing Date and set forth on Schedule 6.01(i) .

224 " **Project Liquidity Shortfall** " shall have the meaning assigned to such term in Section 2.19(e)(iii) .

225 " **Projections** " shall mean the projections of the Borrower and its Subsidiaries, including the Base Case Model, the *pro forma* balance sheet of the Borrower referred to in Section 3.05(c) and any other projections and any forward-looking statements (including statements with respect to booked business) of such entities furnished to the Lenders, the Lead Arranger or the Administrative Agent by or on behalf of Holding or any of its Subsidiaries prior to the Closing Date.

226 " **Projects** " shall mean each of, or all of, as the context shall require, the ExGen Renewables JV Projects (including the Continental Wind Projects, the RPG Projects and the Other JV Projects), the SolGen Projects (until the consummation of the SolGen Disposition), the AV Solar Project (until the consummation of the AVSR Disposition), the Albany Green Project (until the consummation of the AG Disposition where the Albany Green Entities are sold to ExGen Renewables JV) and any Additional Projects not otherwise included in the foregoing (but excluding, for purposes of clarity, any Projects transferred or otherwise disposed of in accordance with Section 6.05(e) from and after such disposition).

227 " **PTC Agreements** " shall mean (i) the Offtake Agreement, dated as of September 1, 2013, by and between Parent and Continental Wind, LLC and (ii) the Offtake Agreement, dated as of March 31, 2016, by and between Sponsor and Renewable Power Generation, LLC.

228 " **Public Lender** " shall have the meaning assigned to such term in Section 9.17(b) .

229 " **Public Side Information** " shall have the meaning assigned to such term in Section 9.17(b) .

230 " **PUHCA** " shall have the meaning assigned to such term in Section 3.08(c) .

231 " **Qualified Equity Interests** " of any Person shall mean any Equity Interest of such Person that is not a Disqualified Equity Interest.

232 " **Quarterly Date** " shall mean each February 28, May 31, August 31 and November 30 of each calendar year. The first Quarterly Date after the Closing Date shall be February 28, 2018.

233 " **Ratings Reaffirmation** " shall mean, in the case of an event or proposed event, a reaffirmation by each of S&P and Moody's that the then current ratings respectively assigned by such entities to the Term Loan Facility will not be lower, after giving effect to the event or proposed event, than the ratings respectively assigned by such entities to the Term Loan Facility immediately prior to such event or proposed event.

234 " **Register** " shall have the meaning assigned to such term in Section 9.04(b)(iv) .

235 " **Regulation D** " shall mean Regulation D of the Board as from time to time in effect and all official rulings and interpretations thereunder or thereof.

236 " **Regulation T** " shall mean Regulation T of the Board as from time to time in effect and all official rulings and interpretations thereunder or thereof.

237 " **Regulation U** " shall mean Regulation U of the Board as from time to time in effect and all official rulings and interpretations thereunder or thereof.

238 " **Regulation X** " shall mean Regulation X of the Board as from time to time in effect and all official rulings and interpretations thereunder or thereof.

239 " **Related Indemnitee** " shall mean, with respect to any Indemnitee, (i) any Affiliate of an Indemnitee and (ii) the Related Parties of such Indemnitee, in each case, only to the extent such Person is acting on the instructions of such Indemnitee or within the scope of such Person's employment or engagement by such Indemnitee.

240 " **Related Parties** " shall mean, with respect to any specified Person, such Person's Affiliates and the respective partners, directors, officers, employees, agents, trustees and advisors of such Person and such Person's Affiliates.

241 " **Release** " shall mean any placing, spilling, leaking, seepage, pumping, pouring, emitting, emptying, discharging, injecting, escaping, leaching, dumping, disposing, depositing or migrating in, into, onto or through the Environment, and " **Released** " shall have a meaning correlative thereto.

242 " **Relevant Parties** " shall have the meaning assigned to such term in Section 9.23(a) .

243 " **Repricing Event** " shall mean (i) (x) any voluntary prepayment of Loans pursuant to Section 2.09(a) , in whole or in part, with the proceeds of, or any conversion of any Loans into, any new or replacement tranche of debt financing bearing interest at an "effective" interest rate less than the "effective" interest rate applicable to the Loans or (y) any amendment to this Agreement that, directly or indirectly, reduces the "effective" interest rate applicable to the Loans or (ii) any assignment permitted under Section 2.17(c) of all or any portion of the Loans of any Lender in connection with any amendment under clause (i) of this definition. For purposes of this definition, the "effective" interest rate shall be deemed to include original issue discount and upfront fees (which fees shall be deemed to constitute like amounts of original issue discount being equated to interest margins in a manner consistent with generally accepted financial practice based on an assumed four-year life to maturity) and, in any event, will exclude arrangement, structuring or other fees paid in connection therewith that are not shared with all lenders in connection with such Repricing Event.

243 " **Required Lender Vote/Directive** " shall have the meaning assigned to such term in Section 9.22.

244 " **Required Lenders** " shall mean, at any time, Lenders having Loans and Commitments outstanding that, taken together, represent more than 50.0% of the sum of all Loans and Commitments outstanding. The Loans and Commitments of any Defaulting Lender shall be disregarded in determining Required Lenders at any time and the Loans and Commitments of any Affiliated Lenders shall, for purposes of this definition, be subject to Section 9.22 .

245 " **Resolution Authority** " means any public administrative authority or any person entrusted with public administrative authority of any EEA Member Country (including any delegee) having responsibility for the resolution of any EEA Financial Institution.

246 " **Responsible Officer** " of any Person shall mean any executive officer or Financial Officer of such Person and any other officer or similar official thereof responsible for the administration of the obligations of such Person in respect of the Loan Documents.

247 " **Revenue Account** " shall have the meaning assigned to such term in Section 2.19(a) .

248 " **Revolving Facility** " shall the meaning assigned to such term in Section 2.20(a) .

249 " **RPG Entities** " shall mean RPG Holdings and the other entities listed in Part 4 of Schedule 1.01C and, if applicable, any Additional Project Entities owned, directly or indirectly, by RPG Holdings.

250 " **RPG Financing Documents** " shall have the meaning assigned to such term in Schedule 1.01A .

" **RPG Holdings** " shall mean Renewable Power Generation Holdings, LLC, a Delaware limited liability company.

" **RPG Projects** " shall mean each of the seven wind and solar power electric generation projects owned by the RPG Entities and listed under the heading "RPG Projects" in Schedule 1.01D and any Additional Projects owned by any RPG Entity (each, individually, a " **RPG Project** "), including with respect to each such RPG Project the related Project site, and the panels, turbines, facilities, structures and improvements erected on such Project site and all other equipment and property leased or owned by RPG Holdings and its Subsidiaries with respect to such RPG Project and attached to or placed upon such Project site or used in connection with the operation of such RPG Project.

" **S&P** " shall mean S&P Global Ratings, acting through Standard & Poor's Financial Services LLC.

" **Sale and Lease-Back Transaction** " shall have the meaning assigned to such term in Section 6.03 .

" **Sanctioned Country** " shall mean, at any time, a country, region or territory which is itself the subject or target of any Sanctions (at the time of this Agreement: Crimea, Cuba, Iran, North Korea and Syria).

" **Sanctioned Person** " shall mean, at any time, any Person subject to or the target of Sanctions including, without limitation, (a) any Person listed in any of the following Sanctions-related lists of designated Persons: OFAC's Specially Designated Nationals ("SDN") List, BIS's Denied Persons, Unverified and Entity Lists, the U.S. Department of State's Debarred Persons List, the Consolidated United Nations Security Council Sanctions List, the U.K. HM Treasury Consolidated List of Targets, or the European Union's List of designated individuals and entities, (b) any Person organized or resident in a Sanctioned Country (unless otherwise permitted, exempted, excepted, generally licensed, or specifically licensed by the applicable administering agency) or (c) any Person owned or controlled by any such Person or Persons described in the foregoing clauses (a) or (b) .

" **Sanctions** " shall mean all economic or financial sanctions or trade embargoes imposed, administered or enforced from time to time by (a) the United States and administered by OFAC, BIS or the U.S. Department of State, or any successor agency, and (b) the United Nations Security Council, the European Union as administered by any European Union member state, or the United Kingdom's HM Treasury, or any sanctions authority of a jurisdiction where a Loan Party, Loan Party Subsidiary or Loan Party Affiliate is located or doing business.

" **Scheduled Amortization Payment** " shall have the meaning assigned to such term in Section 2.08(a) .

" **SEC** " shall mean the Securities and Exchange Commission or any successor thereto.

" **Secured Parties** " means the Agents, the Lead Arranger, the Lenders from time to time party hereto and each Specified Swap Counterparty.

" **Secured Swap Agreement** " shall mean any Swap Agreement settled by reference to interest rates that is entered into by the Borrower and any Specified Swap Counterparty, to the extent, the Borrower has notified the Administrative Agent of its entry thereof and designated the applicable Lender Counterparty as a Specified Swap Counterparty (for the avoidance of doubt, it being understood that such notification may cover all transactions that have been or may be entered into under a specific

master agreement and, in any event, that such notification and designation shall only need to be made once).

262 " **Securities Act** " shall mean the Securities Act of 1933, as amended.

263 " **Security Agreement** " shall mean the Pledge and Security Agreement, substantially in the form of Exhibit E-1 , among the Borrower and the Collateral Agent.

264 " **Security Documents** " shall mean the Security Agreement, the Pledge Agreement, the Control Agreements and each of the security agreements and other instruments and documents executed and delivered pursuant to any of the foregoing, the Collateral and Guarantee Requirement or Section 5.10 .

265 " **SolGen Disposition** " shall have the meaning assigned to such term in Section 6.05(h).

266 " **SolGen Entities** " shall mean SolGen Holding and the other entities listed in Part 5 of Schedule 1.01C and, if applicable, any Additional Project Entities owned, directly or indirectly, by SolGen Holding.

267 " **SolGen Financing Documents** " shall have the meaning assigned to such term in Schedule 1.01A .

268 " **SolGen Holding** " shall have the meaning assigned to such term in the recitals hereto.

269 " **SolGen Projects** " shall mean each of the thirty seven projects that comprise distributed solar photovoltaic generation assets on 192 sites owned by the SolGen Entities and listed under the heading "SolGen Projects" in Schedule 1.01D and any Additional Project owned by any SolGen Entity (each, individually, a " **SolGen Project** "), including with respect to each such SolGen Project the related Project sites, and the panels, facilities, structures and improvements erected on such Project sites and all other equipment and property leased or owned by the SolGen Entities with respect to such SolGen Project and attached to or placed upon such Project sites or used in connection with the operation of such SolGen Project.

270 " **Solvent** " or " **Solvency** " shall mean, with respect to any Person (on a consolidated basis) on any date of determination, that on such date (i) the fair value of the assets (for the avoidance of doubt, calculated to include goodwill and other intangibles) of such Person, at a fair valuation, will exceed the debts and liabilities, direct, subordinated, contingent or otherwise, of such Person; (ii) the present fair saleable value of the property of such Person will be greater than the amount that will be required to pay the probable liabilities of such Person on its debts and other liabilities, direct, subordinated, contingent or otherwise, as such debts and other liabilities become absolute and matured; (iii) such Person will be able to pay its debts and liabilities, direct, subordinated, contingent or otherwise, as such debts and liabilities become absolute and matured and (iv) such Person will not have unreasonably small capital with which to conduct the businesses in which it is engaged as such businesses are now conducted and are proposed to be conducted following such date.

271 " **Specified Swap Counterparty** " shall mean any Person that, at the time it enters into a Swap Agreement, is a Lender Counterparty.

272 " **Sponsor** " shall mean Exelon Generation Company, LLC, a Pennsylvania limited liability company.

273 " **Sponsor Guaranty** " shall mean a guaranty of payment in form and substance reasonably acceptable to the Administrative Agent issued by an Acceptable Guarantor, which guaranty shall name the Collateral Agent (for the benefit of the Lenders) as the beneficiary thereof.

274 " **Subsidiary** " shall mean, with respect to any Person (herein referred to as the " **parent** "), any corporation, partnership, association, joint venture, limited liability company or other business entity of which securities or other ownership interests representing more than 50.0% of the equity or more than 50.0% of the ordinary voting power or more than 50.0% of the general partnership interests are, at the time any determination is being made, directly or indirectly, owned, Controlled or held by such Person.

275 " **Successor Benchmark Rate** " shall have the meaning assigned to such term in Section 2.12(b) .

276 " **Swap Agreements** " shall mean any agreement with respect to any swap, forward, future or derivative transaction or option or similar agreement involving, or settled by reference to, rates, currencies, commodities, equity or debt instruments or securities, or economic, financial or pricing indices or measures of economic, financial or pricing risk or value or any similar transaction or any combination of these transactions; *provided* that no phantom stock or similar plan providing for payments only on account of services provided by current or former directors, officers, employees or consultants of any Loan Party or any of their respective Subsidiaries shall be a Swap Agreement.

277 " **Swap Obligation** " shall mean, with respect to any Guarantor (as defined in the Collateral Agreement), any obligation to pay or perform under any agreement, contract or transaction that constitutes a "swap" within the meaning of Section 1a(47) of the Commodity Exchange Act.

278 " **Syndication Agent** " shall mean MSSF in its capacity as syndication agent.

279 " **Target Balance Prepayment Amount** " shall mean, with respect to any ECF Sweep Date occurring in 2022 or thereafter, an amount equal to the lesser of (a) any Excess Cash Flow for the Excess Cash Flow Period most recently ended on such ECF Sweep Date remaining in the Revenue Account after giving effect to any transfers on such ECF Sweep Date pursuant to Section 2.19(c)(vii)(B) and (b) the amount of any remaining Excess Cash Flow for the Excess Cash Flow Period most recently ended on such ECF Sweep Date that, if applied to a prepayment of the Loans pursuant to Section 2.09(c) , would reduce the outstanding principal amount of Loans (pro forma after giving effect to such prepayment) to the Target Loan Balance for such ECF Sweep Date; *provided* that such amount shall not be less than zero.

280 " **Target Loan Balance** " shall mean, with respect to each ECF Sweep Date occurring in 2022 or thereafter, the amount noted on Schedule 1.01E for such ECF Sweep Date; *provided* that in the event of any prepayment of Loans pursuant to Section 2.09(b)(i) with any Target Sale Prepayment Amount, the amount set forth for each ECF Sweep Date thereafter set forth on Schedule 1.01E shall be adjusted by reducing each such amount by the amount of such Target Sale Prepayment Amount, and the Borrower shall promptly after any such prepayment provide an updated Schedule 1.01E to the Administrative Agent reflecting these reductions.

281 " **Target Sale Additional Prepayment Amount** " shall have the meaning assigned to such term in Section 2.09(b).

282 " **Target Sale Prepayment Amount** " shall mean the product of (a) the portion of the Equity Interests in AG Holdings, the AVSR Entities or the SolGen Entities (as the case may be) sold or transferred in connection with the applicable disposition (expressed as a fraction of the total Equity

Interests in the applicable Person(s)) *multiplied by* (b) with respect to (i) the AG Disposition, $[***], (ii) the AVSR Disposition, $[***] and (iii) the SolGen Disposition, $[***].

283 " **Taxes** " shall mean any and all present or future taxes, levies, imposts, duties (including stamp duties), deductions, charges (including ad valorem charges), withholdings (including backup withholding), assessments and other fees imposed by any Governmental Authority and any and all additions to tax, interest and penalties related thereto.

284 " **Term Loan Facility** " shall mean the Commitments and the Loans made hereunder.

285 " **Test Period** " shall mean, at any date of determination, the most recently completed four (4) consecutive Test Quarters of the Borrower ending on or prior to such date.

286 " **Test Quarter** " shall mean each three-month period ending on a Quarterly Date.

287 " **Transactions** " shall mean, collectively, (a) the execution and delivery of the Loan Documents, the Borrowings hereunder, the consummation of the Term Loan Facility and the use of the proceeds thereof, (b) the providing of a Guarantee by Holding and ExGen Renewables Holdings and the granting and perfection of security interests in connection with the transactions referred to in clause (a) above and (c) the payment of all fees and expenses due and payable on the Closing Date as expressly provided in the Engagement Letter, the Fee Letters and the Loan Documents in connection with the foregoing.

288 " **Trigger Event** " means an Event of Default exists and as a result thereof any Obligations become or are declared to be due and payable prior to their scheduled maturity (as notified in writing to the Collateral Agent).

289 " **Type** " shall mean LIBOR Loans or Base Rate Loans, as applicable, each of which constitutes a Type of Loan.

290 " **U.S. Dollars** " or " **U.S. $** " shall mean the lawful currency of the United States.

291 " **UCC** " shall mean the Uniform Commercial Code as the same may, from time to time, be in effect in the State of New York; *provided however* that, in the event that, by reason of mandatory provisions of law, any or all of the attachment, perfection or priority of the security interest in any Collateral is governed by the Uniform Commercial Code as in effect in a jurisdiction other than the State of New York, the term "UCC" means the Uniform Commercial Code as in effect in such other jurisdiction for purposes of the provisions hereof relating to such attachment, perfection or priority and for purposes of definitions related to such provisions.

292 " **United States** " or " **U.S.** " shall mean the United States of America.

293 " **U.S.A. Patriot Act** " means, the Uniting and Strengthening America by Providing Appropriate Tools Required to Intercept and Obstruct Terrorism Act of 2001, Public Law 107-56 (signed into law on October 26, 2001).

294 **"U.S. Person"** means, unless otherwise specified, any United States citizen, permanent resident alien, entity organized under the laws of the United States or any jurisdiction within the United States (including foreign branches), or any person in the United States.

295 " **Voting Stock** " of any specified Person as of any date shall mean the Capital Stock of such Person that is at the time entitled to vote in the election of the Board of Directors of such Person.

296 " **Withdrawal Certificate** " shall have the meaning assigned to such term in Section 2.19(c) .

297 " **Write-down and Conversion Powers** " means in relation to any Bail-In Legislation described in the EU Bail-In Legislation Schedule from time to time, the powers described as such in relation to that Bail-In Legislation in the EU Bail-In Legislation Schedule.

Section 1.02 *Terms Generally* . The definitions set forth or referred to in Section 1.01 shall apply equally to both the singular and plural forms of the terms defined. Whenever the context may require, any pronoun shall include the corresponding masculine, feminine and neuter forms. The words "include," "includes" and "including" shall be deemed to be followed by the phrase "without limitation." All references herein to Articles, Sections, Exhibits and Schedules shall be deemed references to Articles and Sections of, and Exhibits and Schedules to, this Agreement unless the context shall otherwise require. Except as otherwise expressly provided herein, any reference in this Agreement to any Loan Document or any other agreement or instrument delivered in connection herewith or therewith or referred to herein shall mean such document as amended, restated, supplemented or otherwise modified from time to time. Except with respect to the financial statements referenced in Section 3.05(b) and (c) and as otherwise expressly provided herein, all financial statements to be delivered pursuant to this Agreement shall be prepared in accordance with United States generally accepted accounting principles applied on a consistent basis (" **GAAP** ") and all terms of an accounting or financial nature shall be construed and interpreted in accordance with GAAP, as in effect from time to time; *provided* that, if the Borrower notifies the Administrative Agent that the Borrower requests an amendment to any provision hereof to eliminate the effect of any change occurring after the Closing Date in GAAP or in the application thereof on the operation of such provision (or if the Administrative Agent notifies the Borrower that the Required Lenders request an amendment to any provision hereof for such purpose), regardless of whether any such notice is given before or after such change in GAAP or in the application thereof, then such provision shall be interpreted on the basis of GAAP as in effect and applied immediately before such change shall have become effective until such notice shall have been withdrawn or such provision amended in accordance herewith.

Article II.
THE CREDITS

Section 2.01 *Commitments* . Subject to the terms and conditions set forth herein, each Lender party hereto agrees to make Loans to the Borrower in the applicable amounts set forth opposite each Lender's name on Schedule 2.01 on the Closing Date in U.S. Dollars in an aggregate principal amount that will not result in the aggregate amount of such Lender's Loans exceeding such Lender's Commitment. Amounts repaid or prepaid in respect of the Loans may not be reborrowed. The Term Loan Facility shall be made available as Base Rate Loans and LIBOR Loans.

Section 2.02 *Loans and Borrowings.*

(a) Each Loan to the Borrower shall be made as part of a Borrowing consisting of Loans of the same Type and in the same currency made by the Lenders on a *pro rata* basis in accordance with their respective Commitments. The failure of any Lender to make any Loan required to be made by it shall not relieve any other Lender of its obligations hereunder; *provided* that the Commitments of the Lenders are several and not joint, and no Lender shall be responsible for any other Lender's failure to make Loans as required.

(b) Subject to Section 2.12 , each Borrowing shall be comprised entirely of Base Rate Loans or LIBOR Loans as the Borrower may request in accordance herewith.

(c) Borrowings of more than one Type may be outstanding at the same time; *provided* that there shall not at any time be more than a total of five (5) Interest Periods in respect of Borrowings outstanding; *provided* , *further* , that Interest Periods for the Borrower that commence on the same day and that have the same duration shall be deemed to be one (1) interest period for the purpose of this Section 2.02(c) .

(d) Notwithstanding any other provision of this Agreement, the Borrower shall not be entitled to request, or to elect to convert or continue, any Borrowing if the Interest Period requested with respect thereto would end after the Maturity Date.

Section 2.03 *Requests for Borrowings* . Each Borrowing shall be made upon the Borrower's irrevocable notice to the Administrative Agent, which may be given by "pdf" or similar electronic format, in the form of a written Borrowing Request signed by the Borrower. Each such Borrowing Request must be received by the Administrative Agent (i) in the case of the Borrowing on the Closing Date, not later than 2:00 p.m. (New York City time), at least two (2) Business Days before the proposed Borrowing or (ii) otherwise, (A) in the case of a Borrowing consisting of LIBOR Loans, not later than 11:00 a.m. (New York City time), three (3) Business Days before the date of the proposed Borrowing or (B) in the case of a Borrowing consisting of Base Rate Loans, not later than 12:00 noon (New York City time), one (1) Business Day before the date of the proposed Borrowing. Each such written Borrowing Request shall specify the following information in compliance with Section 2.02 :

(a) the aggregate amount of the requested Borrowing;

(b) the date of such Borrowing, which shall be a Business Day;

(c) whether such Borrowing is to be an Base Rate Borrowing or a LIBOR Borrowing;

(d) in the case of a Borrowing consisting of a LIBOR Loan, the initial Interest Period to be applicable thereto; and

(e) the location and number of the Borrower's account to which funds are to be disbursed.

If no election as to the Type of Borrowing is specified, then the requested Borrowing shall be a Base Rate Borrowing. If no Interest Period is specified with respect to any requested LIBOR Borrowing, then such Borrower shall be deemed to have selected an Interest Period of three (3) months' duration. Promptly following receipt of a Borrowing Request in accordance with this Section 2.03 , the Administrative Agent shall advise each Lender of the details thereof and of the amount of such Lender's Loan to be made as part of the requested Borrowing.

Section 2.04 *Funding of Borrowings* .

(a) Each Lender shall make each Loan to be made by it to the Borrower hereunder on the proposed date thereof by wire transfer of immediately available funds by 1:00 p.m. (New York City time), to the account of the Administrative Agent most recently designated by it for such purpose by notice to the Lenders. The Administrative Agent will make such Loans available to the Borrower by promptly crediting the amounts so received, in like funds, to such account as is designated by the Borrower in its respective Borrowing Request.

(b) Unless the Agent shall have received notice from a Lender prior to the proposed time of any Borrowing that such Lender will not make available to the Administrative Agent such Lender's share of such Borrowing, the Administrative Agent may assume that such Lender has made such share available on such date in accordance with paragraph (a) of this Section 2.04 and may, in reliance upon

such assumption, make available to the Borrower a corresponding amount. In such event, if a Lender has not in fact made its share of the applicable Borrowing available to the Administrative Agent, then the applicable Lender and the Borrower severally agree to pay to the Administrative Agent forthwith on demand (without duplication) such corresponding amount with interest thereon, for each day from and including the date such amount is made available to the Borrower to but excluding the date of payment to the Administrative Agent, at (i) in the case of such Lender, the greater of the Federal Funds Effective Rate and a rate determined by the Administrative Agent in accordance with banking industry rules on interbank compensation or (ii) in the case of the Borrower, the interest rate applicable to Base Rate Loans. If such Lender pays such amount to the Administrative Agent, then such amount shall constitute such Lender's Loan included in such Borrowing.

Section 2.05 *Interest Elections* .

(a) Each Borrowing initially shall be of the Type specified in the applicable Borrowing Request and, in the case of a LIBOR Borrowing, shall have an initial Interest Period as specified in such Borrowing Request. Thereafter, the Borrower may elect, in the case of any Borrowing to convert such Borrowing to a different Type or to continue such Borrowing and, in the case of a LIBOR Borrowing, may elect Interest Periods therefor, all as provided in this Section 2.05 . The Borrower may elect different options with respect to different portions of the affected Borrowing, in which case each such portion shall be allocated on a *pro rata* basis among the Lenders holding the Loans comprising such Borrowing, and the Loans comprising each such portion shall be considered a separate Borrowing.

(b) Each interest election pursuant to this Section 2.05 shall be made upon the Borrower's irrevocable notice to the Administrative Agent, which may be given by "pdf" or similar electronic format, in the form of a written Interest Election Request signed by the Borrower.

(c) Each written Interest Election Request shall specify the following information in compliance with Section 2.02 :

(i) the Borrowing to which such Interest Election Request applies and, if different options are being elected with respect to different portions thereof, the portions thereof to be allocated to each resulting Borrowing (in which case the information to be specified pursuant to clauses (iii) and (iv) below shall be specified for each resulting Borrowing);

(ii) the effective date of the election made pursuant to such Interest Election Request, which shall be a Business Day;

(iii) whether the resulting Borrowing is to be an Base Rate Borrowing or a LIBOR Borrowing; and

(iv) if the resulting Borrowing is a LIBOR Borrowing, the Interest Period to be applicable thereto after giving effect to such election.

If any such Interest Election Request made by the Borrower requests a LIBOR Borrowing but does not specify an Interest Period, then the Borrower shall be deemed to have selected an Interest Period of three (3) months' duration.

(d) Promptly following receipt of an Interest Election Request, the Administrative Agent shall advise each Lender to which such Interest Election Request relates of the details thereof and of such Lender's portion of each resulting Borrowing.

(e) If the Borrower fails to deliver a timely Interest Election Request with respect to a LIBOR Borrowing prior to the end of the Interest Period applicable thereto, then, unless such Borrowing is repaid as provided herein, at the end of such Interest Period, the Borrower shall be deemed to have converted such Borrowing to a LIBOR Borrowing with an Interest Period of three (3) months' duration at the end of such Interest Period. Notwithstanding any contrary provision hereof, if an Event of Default has occurred and is continuing, then, so long as such Event of Default is continuing, (i) no outstanding Borrowing may be converted to or continued as a LIBOR Borrowing and (ii) unless repaid, each LIBOR Borrowing shall be converted to a Base Rate Borrowing at the end of the Interest Period applicable thereto.

Section 2.06 *Termination of Commitments* . Any undrawn Commitments will terminate at 5:00 p.m. (New York City time) on the Closing Date.

Section 2.07 *Evidence of Debt* .

(a) Each Lender shall maintain in accordance with its usual practice an account or accounts evidencing the indebtedness of the Borrower to such Lender resulting from each Loan made by such Lender, including the amounts of principal and interest payable and paid to such Lender from time to time hereunder.

(b) The Administrative Agent shall maintain accounts in which it shall record (i) the amount of each Loan made hereunder, the Type thereof and the Interest Period (if any) applicable thereto, (ii) the amount of any principal or interest due and payable or to become due and payable from the Borrower to each Lender hereunder and (iii) any amount received by the Administrative Agent hereunder for the account of the Lenders and each Lender's share thereof.

(c) The entries made in the accounts maintained pursuant to paragraph (a) or (b) of this Section 2.07 shall be prima facie evidence absent manifest error of the existence and amounts of the obligations recorded therein; *provided* that the failure of any Lender or the Administrative Agent to maintain such accounts or any error therein shall not in any manner affect the obligations of the Borrower to repay the Loans in accordance with the terms of this Agreement; *provided* , *further* , that in the event of any conflict between the accounts maintained pursuant to paragraph (a) or (b) of this Section 2.07 , the entries made in the Register shall control.

(d) Any Lender may request that Loans made by it to the Borrower be evidenced by a Note. In such event, the Borrower shall prepare, execute and deliver to such Lender a Note payable to such Lender (or, if requested by such Lender, to such Lender and its registered assigns). Thereafter, the Loans evidenced by such Note and interest thereon shall at all times (including, to the extent requested by any assignee, after assignment pursuant to Section 9.04) be represented by one or more Notes payable to the payee named therein (or to such payee and its registered assigns).

Section 2.08 *Repayment of Loans; Application of Prepayments* .

(a) The Borrower hereby unconditionally promises to pay to the Administrative Agent for the account of each Lender the then unpaid principal amount of each Loan made to the Borrower on such dates and in such amounts as provided in this Section 2.08 . Subject to adjustment pursuant to paragraph (c) of this Section 2.08 , (i) the Borrower shall repay on each Quarterly Date an aggregate principal amount equal to 0.25% of the aggregate principal amount of the Loans drawn on the Closing Date (each a " **Scheduled Amortization Payment** ") and (ii) the Borrower shall repay on the Maturity Date all remaining amounts of the Loans then outstanding. All payments under this Section 2.08(a) shall be allocated to the Lenders on a *pro rata* basis. For the avoidance of doubt, no Default or Event of Default shall arise solely as a result of the outstanding principal amount of the Loans exceeding the scheduled Target Loan Balance for any ECF Sweep Date after giving effect to any prepayments made pursuant to Section 2.09(c) for such ECF Sweep Date.

(b) To the extent not previously paid, all Loans shall be due and payable on the Maturity Date.

(c) Prepayment of the Loans (i) pursuant to Section 2.09(b), shall be applied to Scheduled Amortization Payments and the remaining unpaid principal amount of Loans due and payable on the Maturity Date in the inverse order of maturity, (ii) pursuant to Section 2.09(c) , shall be applied, *first* , in direct order of maturity to all Scheduled Amortization Payments in respect of the Loans due on the immediately succeeding four (4) Quarterly Dates from the date of such prepayment, *second* , to the remaining Scheduled Amortization Payments in respect of the Loans and the remaining unpaid principal amount of Loans due and payable on the Maturity Date in the inverse order of maturity, and (iii) from any optional prepayments pursuant to Section 2.09(a) shall be applied to the remaining Scheduled Amortization Payments in respect of the Loans as directed by the Borrower and thereafter to the remaining unpaid principal amount of Loans due and payable on the Maturity Date, and all such payments pursuant to clauses (i) , (ii) and (iii) shall be allocated ratably to the Lenders.

(d) Prior to any repayment of any Borrowing hereunder, the Borrower shall select the Borrowing or Borrowings to be repaid and shall notify the Administrative Agent by irrevocable notice to the Administrative Agent, which may be given by "pdf" or similar electronic format, in the form of a written Prepayment Notice signed by the Borrower. Such Prepayment Notice shall be received by the Administrative Agent not later than 2:00 p.m. (New York City time) (i) in the case of an Base Rate Borrowing, one (1) Business Day before the scheduled date of such repayment and (ii) in the case of a LIBOR Borrowing, three (3) Business Days before the scheduled date of such repayment. Each repayment of a Borrowing shall be allocated ratably to the Loans included in the repaid Borrowing.

Section 2.09 *Optional and Mandatory Prepayment of Loans* .

(a) The Borrower shall have the right at any time and from time to time to prepay Loans in whole or in part (but subject to Section 2.14 and Section 2.09(d)), in an aggregate principal amount that is an integral multiple of U.S. $1.0 million and not less than U.S. $1.0 million or, if less, the amount outstanding, subject to prior notice in the form of Exhibit B hereto provided in accordance with Section 2.08(d) .

(b) The Borrower shall apply Net Proceeds promptly upon (and in any event within three (3) Business Days of) receipt thereof by any of the Loan Parties as follows (i) with respect to Net Proceeds from the AG Disposition, AVSR Disposition and SolGen Disposition (A) Net Proceeds in an amount up to the applicable Target Sale Prepayment Amount and (B) 50% of the amount of Net Proceeds in excess of such applicable Target Sale Prepayment Amount (the " **Target Sale Additional Prepayment Amount** "), if any, shall be applied to prepay Loans in accordance with Section 2.08(c) and (ii) all other Net Proceeds shall be applied to prepay Loans made to the Borrower in accordance with Section 2.08(c) ; *provided* that, any amount of Net Proceeds from the AG Disposition, AVSR Disposition or SolGen Disposition (if any), in excess of the Target Sale Prepayment Amount and, if applicable, any Target Sale Additional Prepayment Amount (" **Excess Project Disposition Proceeds** ") shall not be subject to this Section 2.09(b) and may be deposited in the Equity Proceeds Account and transferred in accordance with Section 2.19(g) .

(c) On the date that is five (5) Business Days after the Quarterly Date occurring in May of each year (the " **ECF Sweep Date** "), the Borrower shall apply all amounts on deposit in the ECF Prepayment Account (after giving effect to transfers of Excess Cash Flow pursuant to Section 2.19(c)(vii) on such Quarterly Date) to prepay the Loans in accordance with Section 2.08(c) , in each case as calculated and certified by the Borrower pursuant to Section 5.04(e) .

(d) In the event that a Repricing Event is consummated in connection with all or any portion of the Loans on or prior to the period ending six months from the Closing Date, the Borrower shall pay to the Lenders a non-refundable fee equal to 1.00% of the aggregate principal amount of the Loans prepaid, converted or assigned in connection with such Repricing Event.

Section 2.10 *Fees* .

(a) The Borrower shall pay to the Administrative Agent, for the account of the Administrative Agent, the administrative fees set forth in the applicable Fee Letter at the times specified therein (the " **Administrative Agent Fees** ").

(b) The Borrower shall pay to the Collateral Agent, for the account of the Collateral Agent, and to the Depositary Bank, for the account of the Depositary Bank, the fees and other amounts set forth in the Fee Letters between the Borrower and the Collateral Agent and Depositary Bank (including attorneys' fees and expenses), respectively, at the times specified therein.

(c) The Borrower agrees to pay on the Closing Date such fees as are set forth in the Engagement Letter and the Fee Letters and expressly provided therein as being due and payable on the Closing Date (which fees shall be non-refundable and non-creditable thereafter).

(d) All Fees shall be paid on the dates due, in immediately available funds, to the Administrative Agent for distribution, if and as appropriate, among the Lenders. Once paid, none of the Fees shall be refundable under any circumstances.

Section 2.11 *Interest* .

(a) The Borrower shall pay interest on the unpaid principal amount of each Base Rate Loan made to the Borrower at the Base Rate *plus* the Applicable Margin.

(b) The Borrower shall pay interest on the unpaid principal amount of each LIBOR Loan made to the Borrower at the LIBO Rate for the Interest Period in effect for such LIBOR Loan *plus* the Applicable Margin.

(c) Notwithstanding the foregoing, if any principal of or interest on any Loan or any Fees or other amount payable by the Borrower hereunder is not paid when due, whether at stated maturity, upon acceleration or otherwise, then the Borrower shall pay interest on such overdue amount, after as well as before judgment, at a rate *per annum* equal to (x) in the case of overdue principal of any Loan, 2.00% *plus* the rate otherwise applicable to such Loan as provided in the preceding paragraphs of this Section 2.11 or (y) in the case of any other amount, 2.00% *plus* the rate applicable to Base Rate Loans in paragraph (a) of this Section 2.11 .

(d) Accrued interest on each Loan shall be payable by the Borrower from and after the Closing Date in arrears on each Interest Payment Date for such Loan, and on the Maturity Date; *provided* that (x) interest accrued pursuant to paragraph (c) of this Section 2.11 shall be payable on demand, (y) in the event of any repayment or prepayment of any Loan (other than a prepayment of an Base Rate Loan prior to its stated maturity (unless all Loans are being repaid)), accrued interest on the principal amount repaid or prepaid shall be payable on the date of such repayment or prepayment and (z) in the event of any conversion of any LIBOR Loan prior to the end of the current Interest Period therefor, accrued interest on such Loan shall be payable on the effective date of such conversion.

(e) All computations of interest shall be made by the Administrative Agent taking into account the actual number of days occurring in the period for which such interest is payable (including the first day but excluding the last day) pursuant to this Section 2.11 , and (i) if based on the Base Rate as calculated based on the Prime Rate, a year of 365 days or 366 days, as the case may be; or (ii) if based on the Base Rate (other than as calculated based on the Prime Rate) or the LIBO Rate, on the basis of a year of 360 days.

Section 2.12 *Alternate Rate of Interest* .

(a) If prior to the commencement of any Interest Period for a LIBOR Borrowing:

(i) the Administrative Agent determines in good faith that adequate and reasonable means do not exist for ascertaining the LIBO Rate for such Interest Period; or

(ii) the Administrative Agent is advised by the Required Lenders (acting in good faith) that the LIBO Rate for such Interest Period will not adequately and fairly reflect the cost to such Lenders of making or maintaining their Loans included in such Borrowing for such Interest Period;

then the Administrative Agent shall give written notice thereof to the Borrower and the Lenders as promptly as practicable thereafter and, until the Administrative Agent notifies the Borrower and the Lenders that the circumstances giving rise to such notice no longer exist, (x) any Interest Election Request that requests the conversion of any Borrowing to, or continuation of any Borrowing as, a LIBOR Borrowing shall be ineffective and such Borrowing shall be converted to an Base Rate Borrowing on the last day of the Interest Period

applicable thereto, and (y) if any Borrowing Request requests a LIBOR Borrowing, such Borrowing shall be made as an Base Rate Borrowing.

(b) If the Borrower and the Administrative Agent reasonably determine in good faith that an interest rate is not ascertainable pursuant to the provisions of the definition of "LIBO Base Rate" and the inability to ascertain such rate is unlikely to be temporary, the "LIBO Base Rate" shall be an alternate rate of interest established by the Administrative Agent and the Borrower that is commercially practicable for the Administrative Agent to administer (as determined by the Administrative Agent in its reasonable discretion) and is generally accepted as the then prevailing market convention for determining a rate of interest (including the making of appropriate adjustments to such alternate rate and this Agreement (x) to preserve pricing in effect at the time of selection of such alternate rate (but for the avoidance of doubt which shall not be at an interest rate less than the LIBO Base Rate prior to the adoption of the alternate rate) and (y) other changes necessary to reflect the available interest periods for such alternate rate) for syndicated leveraged loans of this type in the United States at such time (any such rate, the " **Successor Benchmark Rate** "), and the Administrative Agent and the Borrower shall enter into an amendment to this Agreement to reflect such alternate rate of interest and such other related changes to this Agreement as may be applicable and, notwithstanding anything to the contrary in Section 9.08 , such amendment shall become effective without any further action or consent of any other party to this Agreement; *provided* , that if a Successor Benchmark Rate has not been established pursuant to the foregoing, at the option of the Borrower, the Borrower and the Required Lenders (as defined below) may select a different Successor Benchmark Rate that is reasonably commercially practicable for the Administrative Agent to administer (as determined by the Administrative Agent in its reasonable discretion) and, upon not less than 15 Business Days' prior written notice to the Administrative Agent, the Administrative Agent, the Required Lenders and the Borrower shall enter into an amendment to this Agreement to reflect such alternate rate of interest and such other related changes to this Agreement as may be applicable and, notwithstanding anything to the contrary in Section 9.08 , such amendment shall become effective without any further action or consent of any other party to this Agreement; *provided, further* , that until such Successor Benchmark Rate has been determined pursuant to this paragraph, (i) any request for Borrowing, the conversion of any Borrowing to, or continuation of any Borrowing as, a LIBOR Loan shall be ineffective and (ii) all outstanding Borrowings shall be converted to a Base Rate Loan.

Section 2.13 *Increased Costs* .

(a) If any Change in Law shall:

(i) impose, modify or deem applicable any reserve, special deposit, compulsory loan, insurance charge or similar requirement against assets of, deposits with or for the account of, or credit extended by or participated in by, any Lender (except any such reserve requirement reflected in the LIBO Rate); or

(ii) impose on any Lender or the London interbank market any other condition affecting this Agreement or Loans made by such Lender or participation therein (including any Tax, cost or expense) (except, in each case, for (x) Indemnified Taxes indemnified pursuant to Section 2.15 , (y) Excluded Taxes and (z) Other Taxes);

and the result of any of the foregoing shall be to increase the cost to such Lender of making or maintaining any Loan (or of maintaining its obligation to make any such Loan) to the Borrower or to reduce the amount of any sum received or receivable by such Lender hereunder (whether of principal, interest or otherwise), then the Borrower will pay to such Lender such additional amount or amounts as will compensate such Lender for such additional costs incurred or reduction suffered in connection therewith.

(b) If any Lender reasonably determines in good faith that any Change in Law regarding capital or liquidity requirements has or would have the effect of reducing the rate of return on such Lender's capital

or on the capital of such Lender's holding company, if any, as a consequence of this Agreement or any of the Loans made by such Lender or as a consequence of the Commitments to make any of the foregoing, to a level below that which such Lender or such Lender's holding company could have achieved but for such Change in Law (taking into consideration such Lender's policies and the policies of such Lender's holding company with respect to capital adequacy), then from time to time the Borrower shall pay to such Lender such additional amount or amounts as will compensate such Lender or such Lender's holding company for any such reduction suffered in connection therewith.

(c) A certificate of a Lender setting forth the amount or amounts necessary to compensate such Lender or its holding company, as applicable, as specified in paragraph (a) or (b) of this Section 2.13 shall be delivered to the Borrower and shall be conclusive absent manifest error. The Borrower shall pay such Lender the amount shown as due on any such certificate within ten (10) days after receipt thereof.

(d) Promptly after any Lender has determined that it will make a request for increased compensation pursuant to this Section 2.13 , such Lender shall notify the Borrower thereof. Failure or delay on the part of any Lender to demand compensation pursuant to this Section 2.13 shall not constitute a waiver of such Lender's right to demand such compensation; *provided* that the Borrower shall not be required to compensate a Lender pursuant to this Section 2.13 for any increased costs or reductions incurred more than one hundred and eighty (180) days prior to the date that such Lender notifies the Borrower of the Change in Law giving rise to such increased costs or reductions and of such Lender's intention to claim compensation therefor; *provided further* that, if the Change in Law giving rise to such increased costs or reductions is retroactive, then the 180-day period referred to above shall be extended to include the period of retroactive effect thereof.

Section 2.14 *Break Funding Payments* . In the event of (a) the payment of any principal of any LIBOR Loan other than on the last day of an Interest Period applicable thereto (including as a result of an Event of Default), (b) the conversion of any LIBOR Loan other than on the last day of the Interest Period applicable thereto, (c) the failure to borrow, convert, continue or prepay any LIBOR Loan on the date specified in any notice delivered pursuant hereto or (d) the assignment of any LIBOR Loan other than on the last day of the Interest Period applicable thereto as a result of a request by the Borrower pursuant to Section 2.17 , then, in any such event, the Borrower shall compensate each Lender for the loss, cost and expense attributable to such event. Such loss, cost or expense to any Lender shall be deemed to be the amount determined by such Lender to be the excess, if any, of (i) the amount of interest which would have accrued on the principal amount of such LIBOR Loan had such event not occurred, at the LIBO Rate that would have been applicable to such Loan, for the period from the date of such event to the last day of the then current Interest Period therefor (or, in the case of a failure to borrow, convert or continue a LIBOR Loan, for the period that would have been the Interest Period for such Loan), over (ii) the amount of interest which would accrue on such principal amount for such period at the interest rate which such Lender would bid were it to bid, at the commencement of such period, for deposits in U.S. Dollars of a comparable amount and period from other banks in the eurodollar market. A certificate of any Lender setting forth any amount or amounts that such Lender is entitled to receive pursuant to this Section 2.14 shall be delivered to the Borrower and shall be conclusive absent manifest error. The Borrower shall pay such Lender the amount shown as due on any such certificate within ten (10) days after receipt thereof.

Section 2.15 *Taxes* .

(a) Any and all payments by or on account of any obligation of any Loan Party under any Loan Document shall be made free and clear of and without deduction for any Taxes, except to the extent required by applicable law. If any Indemnified Taxes or Other Taxes are required by applicable law to be deducted from any such payments, then (i) the sum payable by the Loan Party shall be increased as necessary so that after all required deductions (including deductions applicable to additional sums payable under this Section 2.15), each Agent or Lender, as applicable, receives an amount equal to the sum it would have received had no such deductions for Indemnified Taxes and Other Taxes been made, (ii) such Loan Party or the applicable withholding agent, if required to deduct any such Taxes, shall make such deductions and

(iii) such Loan Party or the applicable withholding agent, if required to deduct any such Taxes, shall timely pay the full amount deducted to the relevant Governmental Authority in accordance with applicable law.

(b) In addition, the Loan Parties shall pay any Other Taxes to the relevant Governmental Authority in accordance with applicable law.

(c) The Loan Parties shall indemnify each Agent and each Lender, within ten (10) days after written demand therefor, for the full amount of any Indemnified Taxes or Other Taxes paid by such Agent or such Lender, as applicable, on or with respect to any payment by or on account of any obligation of the Loan Parties under any Loan Document (including Indemnified Taxes and Other Taxes imposed or asserted on or attributable to amounts payable under this Section 2.15) and any reasonable expenses arising therefrom or with respect thereto, whether or not such Indemnified Taxes or Other Taxes were correctly or legally imposed or asserted by the relevant Governmental Authority; *provided* that a certificate as to the amount of such payment or liability and setting forth in reasonable detail the basis and calculation for such payment or liability delivered to the Borrower by a Lender or by the Administrative Agent on its own behalf or on behalf of a Lender or Agent, shall be conclusive absent manifest error of the Lender or the Administrative Agent, as applicable.

(d) As soon as practicable after any payment of Indemnified Taxes or Other Taxes by a Loan Party to a Governmental Authority, such Loan Party shall deliver to the Administrative Agent the original or a certified copy of a receipt issued by such Governmental Authority evidencing such payment, a copy of the return reporting such payment or other evidence of such payment reasonably satisfactory to the Administrative Agent.

(e) Each Lender that is not a "United States person" as defined in Section 7701(a)(30) of the Code (a " **Non-U.S. Lender** ") shall, to the extent it may lawfully do so, deliver to the Borrower and the Administrative Agent two executed originals of U.S. Internal Revenue Service Form W-8BEN or W-8BEN-E (claiming the benefits of an applicable income tax treaty), W-8EXP, W-8IMY (together with any required attachments) or Form W-8ECI, or, in the case of a Non-U.S. Lender claiming exemption from U.S. federal withholding tax under Section 871(h) or 881(c) of the Code with respect to payments of "portfolio interest," a statement substantially in the form of Exhibit I and a Form W-8BEN or W-8BEN-E, or any subsequent versions thereof or successors thereto, properly completed and duly executed by such Non-U.S. Lender (with any other required forms attached) claiming complete exemption from or a reduced rate of U.S. federal withholding tax on all payments by the Borrower under this Agreement and the other Loan Documents. Each Lender that is not a Non-U.S. Lender shall, to the extent it may lawfully do so, deliver to the Borrower and the Administrative Agent two executed originals of U.S. Internal Revenue Service Form W-9, properly completed and duly executed by such Lender, claiming complete exemption (or otherwise establishing an exemption) from U.S. backup withholding on all payments under this Agreement and the other Loan Documents. Such forms shall be delivered by each Lender, to the extent it may lawfully do so, on or before the date it becomes a party to this Agreement. In addition, each Lender, to the extent it may lawfully do so, shall deliver such forms promptly upon the obsolescence or inaccuracy of any form previously delivered by such Lender. Each Lender shall promptly notify the Borrower and the Administrative Agent at any time it determines that it is no longer in a position to provide any previously delivered certificate to the Borrower or the Administrative Agent (or any other form of certification adopted by the U.S. taxing authorities for such purpose). Without limiting the foregoing, any Lender that is entitled to an exemption from or reduction of withholding Tax otherwise indemnified against by a Loan Party pursuant to this Section 2.15 with respect to payments under any Loan Document shall deliver to the Borrower or the relevant Governmental Authority (with a copy to the Administrative Agent), to the extent such Lender is legally entitled to do so, at the time or times prescribed by applicable law such properly completed and executed documentation prescribed by applicable law as may reasonably be requested by the Borrower or the Administrative Agent to permit such payments to be made without such withholding tax or at a reduced rate; *provided* that in such Lender's reasonable judgment such completion, execution or submission would not materially prejudice such Lender. In addition, any Lender, if reasonably requested by the Borrower or the Administrative Agent, shall deliver such other documentation prescribed by applicable law or reasonably requested by the Borrower or the

Administrative Agent as will enable the Borrower or the Administrative Agent to determine whether or not such Lender is subject to backup withholding or information reporting requirements; *provided* that in such Lender's reasonable judgment such completion, execution or submission would not materially prejudice such Lender.

(f) If an Agent or a Lender determines, in good faith and in its sole discretion, that it has received a refund of Indemnified Taxes or Other Taxes as to which it has been indemnified by a Loan Party or with respect to which a Loan Party has paid additional amounts pursuant to this Section 2.15 , it shall pay over such refund to such Loan Party (but only to the extent of indemnity payments made, or additional amounts paid, by such Loan Party under this Section 2.15 with respect to the Indemnified Taxes or Other Taxes giving rise to such refund), net of all out-of-pocket expenses of such Agent or such Lender (including any Taxes imposed with respect to such refund) as is determined by such Agent or such Lender in good faith and in its sole discretion, and without interest (other than any interest paid by the relevant Governmental Authority with respect to such refund); *provided* that such Loan Party, upon the request of such Agent or such Lender, agrees to repay as soon as reasonably practicable the amount paid over to such Loan Party (plus any penalties, interest or other charges imposed by the relevant Governmental Authority) to such Agent or such Lender in the event such Agent or such Lender is required to repay such refund to such Governmental Authority. This paragraph (f) shall not be construed to require any Agent or any Lender to make available its Tax returns (or any other information relating to its Taxes which it deems confidential) to the Loan Parties or any other Person. Notwithstanding anything to the contrary in this paragraph (f) , in no event shall any Agent or Lender be required to pay any amount to any Loan Party pursuant to this paragraph (f) the payment of which would place such Agent or Lender in a less favorable net after-Tax position than it would have been in if the Tax subject to indemnification, or with respect to which additional amounts were paid, and giving rise to such refund had not been deducted, withheld or otherwise imposed and the indemnification payments or additional amounts with respect to the Tax had never been paid.

(g) If a payment made to a Lender under any Loan Document would be subject to U.S. federal withholding Tax imposed by FATCA if such Lender were to fail to comply with the applicable reporting requirements of FATCA (including those contained in Section 1471(b) or 1472(b) of the Code, as applicable), such Lender shall deliver to the Borrower and the Administrative Agent at the time or times prescribed by law and at such time or times reasonably requested by the Borrower or the Administrative Agent such documentation prescribed by applicable law (including as prescribed by Section 1471(b)(3)(C)(i) of the Code) and such additional documentation reasonably requested by the Borrower or the Administrative Agent as may be necessary for the Borrower and the Administrative Agent to comply with their obligations under FATCA and to determine that such Lender has complied with such Lender's obligations under FATCA or to determine the amount to deduct and withhold from such payment. Solely for purposes of this paragraph (g) , "FATCA" shall include any amendments made to FATCA after the date of this Agreement.

(h) Each Lender agrees that if any form or certification it previously delivered pursuant to Section 2.15(e) or 2.15(g) expires or becomes obsolete or inaccurate in any respect, it shall update such form or certification or promptly notify the Borrower and the Administrative Agent in writing of its legal inability to do so.

(i) For purposes of this Section 2.15 , the term "applicable law" shall include FATCA.

Section 2.16 *Payments Generally; Pro Rata Treatment; Sharing of Set-offs* .

(a) Unless otherwise specified, the Borrower shall make each payment required to be made by it hereunder (whether of principal, interest or fees, or of amounts payable under Section 2.13 , 2.14 or 2.15 , or otherwise) prior to 12:00 p.m. (New York City time), on the date when due, in immediately available funds, without condition or deduction for any defense, recoupment, set-off or counterclaim. Any amounts received after such time on any date may, in the discretion of the Administrative Agent, be deemed to have been received on the next succeeding Business Day for purposes of calculating interest thereon. All such payments shall be made to the Administrative Agent to the applicable account designated to the Borrower

by the Administrative Agent, except that payments pursuant to Sections 2.13 , 2.14 , 2.15 and 9.05 shall be made directly to the Persons entitled thereto. The Administrative Agent shall distribute any such payments received by it for the account of any other Person to the appropriate recipient promptly following receipt thereof. If any payment hereunder shall be due on a day that is not a Business Day, the date for payment shall be extended to the next succeeding Business Day, and, in the case of any payment accruing interest, interest thereon shall be payable for the period of such extension. All payments hereunder of principal or interest in respect of any Loan or of other amounts due hereunder or under any other Loan Document shall be made in U.S. Dollars. Any payment required to be made by the Administrative Agent hereunder shall be deemed to have been made by the time required if the Administrative Agent shall, at or before such time, have taken the necessary steps to make such payment in accordance with the regulations or operating procedures of the clearing or settlement system used by the Administrative Agent to make such payment.

(b) If at any time insufficient funds are received by and available to the Administrative Agent from the Borrower to pay fully all amounts of principal, interest and fees then due from the Borrower hereunder, such funds shall be applied (i) first, towards payment of interest and fees then due from the Borrower hereunder, ratably among the parties entitled thereto in accordance with the amounts of interest and fees then due to such parties, and (ii) second, towards payment of principal then due from the Borrower hereunder, ratably among the parties entitled thereto in accordance with the amounts of principal then due to such parties.

(c) If any Lender shall, by exercising any right of set-off or counterclaim, through the application of any proceeds of Collateral or otherwise, obtain payment in respect of any principal of or interest on any of its Loans resulting in such Lender receiving payment of a greater proportion of the aggregate amount of its Loans and accrued interest thereon than the proportion received by any other Lender, then the Lender receiving such greater proportion shall purchase (for cash at face value) participations in the Loans of other Lenders to the extent necessary so that the benefit of all such payments shall be shared by the Lenders ratably in accordance with the aggregate amount of principal of and accrued interest on their respective Loans; *provided* that (i) if any such participations are purchased and all or any portion of the payment giving rise thereto is recovered, such participations shall be rescinded and the purchase price restored to the extent of such recovery, without interest, and (ii) the provisions of this paragraph (c) shall not be construed to apply to any payment made by the Borrower pursuant to and in accordance with the express terms of this Agreement or any payment obtained by a Lender as consideration for the assignment of or sale of a participation in any of its Loans to any assignee or participant permitted pursuant to Section 9.04 . The Borrower consents to the foregoing and agrees, to the extent they may effectively do so under applicable law, that any Lender acquiring a participation pursuant to the foregoing arrangements may exercise against the Borrower rights of set-off and counterclaim with respect to such participation as fully as if such Lender were a direct creditor of the Borrower in the amount of such participation.

(d) Unless the Administrative Agent shall have received notice from the Borrower prior to the date on which any payment by the Borrower is due to the Administrative Agent for the account of the Lenders hereunder that the Borrower will not make such payment, the Administrative Agent may assume that the Borrower has made such payment on such date in accordance herewith and may, in reliance upon such assumption, distribute to the Lenders, as applicable, the amount due. In such event, if the Borrower has not in fact made such payment, then each of the Lenders severally agrees to repay to the Administrative Agent forthwith on demand the amount so distributed to such Lender with interest thereon, for each day from and including the date such amount is distributed to it to but excluding the date of payment to the Administrative Agent, at the greater of the Federal Funds Effective Rate and a rate determined by the Administrative Agent in accordance with banking industry rules on interbank compensation.

(e) If any Lender shall fail to make any payment required to be made by it pursuant to Section 2.04(b) or 2.16(d) , then the Administrative Agent may, in its discretion (notwithstanding any contrary provision hereof), apply any amounts thereafter received by the Administrative Agent for the account of such Lender to satisfy such Lender's obligations under such Sections until all such unsatisfied obligations are fully paid.

Section 2.17 *Mitigation Obligations; Replacement of Lenders* .

(a) (x) If any Lender requests compensation under Section 2.13 , (y) if any Loan Party is required to pay any additional amount to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.15 or (z) if any Lender exercises its rights under Section 2.18 , then such Lender shall use reasonable efforts to designate a different lending office for funding or booking its Loans hereunder or to assign its rights and obligations hereunder to another of its offices, branches or Affiliates, if, in the reasonable judgment of such Lender, such designation or assignment (i) would eliminate or reduce amounts payable pursuant to Section 2.13 or 2.15 , as applicable, in the future, or would eliminate such Lender's need to exercise its rights under Section 2.18 , and (ii) would not subject such Lender to any material unreimbursed cost or expense and would not otherwise be disadvantageous to such Lender in any material respect. The Borrower hereby agrees to pay all reasonable costs and expenses incurred by any Lender in connection with any such designation or assignment.

(b) If any Lender requests compensation under Section 2.13 , or if any Loan Party is required to pay any additional amount to any Lender or any Governmental Authority for the account of any Lender pursuant to Section 2.15 , or if any Lender is a Defaulting Lender, or if any Lender exercises its rights under Section 2.18 , then the Borrower may, at the Borrower's sole expense and effort, upon notice to such Lender and the Administrative Agent, require such Lender to assign and delegate, without recourse (in accordance with and subject to the restrictions contained in Section 9.04), all its interests, rights and obligations under this Agreement to an assignee that shall assume such obligations (which assignee may be another Lender, if a Lender accepts such assignment); *provided* that (i) the Borrower shall have received the prior written consent of the Administrative Agent, which consent shall not unreasonably be withheld, (ii) such Lender shall have received payment of an amount equal to the outstanding principal of its Loans, accrued interest thereon, accrued fees and all other amounts payable to it hereunder, from the assignee (to the extent of such outstanding principal and accrued interest and fees) or the Borrower (in the case of all other amounts) and (iii) in the case of any such assignment resulting from a claim for compensation under Section 2.13 or payments required to be made pursuant to Section 2.15 , such assignment will result in a reduction in such compensation or payments. Nothing in this Section 2.17 shall be deemed to prejudice any rights that any Loan Party may have against any Lender that is a Defaulting Lender.

(c) If any Lender (such Lender, a " **Non-Consenting Lender** ") has failed to consent to a proposed amendment, waiver, consent, discharge or termination which pursuant to the terms of Section 9.08 requires the consent of all of the Lenders affected or all of the Lenders and with respect to which the Required Lenders shall have granted their consent, then provided no Event of Default then exists, the Borrower shall have the right (unless such Non-Consenting Lender grants such consent) to replace such Non-Consenting Lender by requiring such Non-Consenting Lender to assign its Loans and its Commitments hereunder to one or more assignees reasonably acceptable to the Administrative Agent; *provided* that, (i) all Obligations of the Borrower due and payable to such Non-Consenting Lender being replaced shall be paid in full to such Non-Consenting Lender concurrently with such assignment, (including any such Obligation pursuant to Section 2.09(d)), (ii) the replacement Lender shall purchase the foregoing by paying to such Non-Consenting Lender a price equal to the principal amount thereof plus accrued and unpaid interest thereon and (iii) the replacement Lender shall have consented to the applicable amendment, waiver, consent, discharge or termination or provides such consent concurrently with such assignment. In connection with any such assignment the Borrower, the Administrative Agent, such Non-Consenting Lender and the replacement Lender shall otherwise comply with Section 9.04 . Each Lender agrees that if the Borrower exercises the Borrower's option hereunder to cause an assignment by such Lender as a Non-Consenting Lender, such Lender shall, promptly after receipt of written notice of such election, execute and deliver all documentation necessary to effectuate such assignment in accordance with Section 9.04 . Notwithstanding anything to the contrary herein, in the event that a Lender does not comply with the requirements of the immediately preceding sentence within

one (1) Business Day after receipt of such notice, such assignment shall be deemed to have occurred on such Business Day without such Lender's execution and delivery of any documentation required pursuant to Section 9.04 .

(d) A Lender shall not be required to make any such assignment or delegation under this Section 2.17 , if, prior thereto, as a result of a waiver by such Lender or otherwise, the circumstances entitling the Borrower to require such assignment cease to apply.

Section 2.18 *Illegality* . If any Lender reasonably determines that any Change in Law has made it unlawful, or that any Governmental Authority has asserted after the Closing Date that it is unlawful, for any Lender or its applicable lending office to make or maintain any LIBOR Loans, then, on notice thereof by such Lender to the Borrower through the Administrative Agent, any obligations of such Lender to make or continue LIBOR Loans or to convert Base Rate Borrowings to LIBOR Borrowings, as the case may be, shall be suspended until such Lender notifies the Administrative Agent and the Borrower that the circumstances giving rise to such determination no longer exist. Upon receipt of such notice, the Borrower shall, upon demand from such Lender (with a copy to the Administrative Agent), convert all such LIBOR Borrowings of such Lender to Base Rate Borrowings on the last day of the Interest Period therefor, if such Lender may lawfully continue to maintain such LIBOR Borrowings to such day, or immediately, if such Lender may not lawfully continue to maintain such Loans. Upon any such prepayment or conversion, the Borrower shall also pay accrued interest on the amount so prepaid or converted.

Section 2.19 *Depositary Accounts* .

(a) *Establishment of Accounts* . On or prior to the Closing Date, the Borrower shall establish the following deposit accounts (the " **Depositary Accounts** "), with the Depositary Bank, in each case, subject to fully perfected first priority security interest and Control Agreement in favor of the Collateral Agent for the benefit of the Secured Parties to secure the Obligations:

(i) a U.S. Dollar-denominated account in the name of the Borrower entitled "ExGen Renewables IV – Revenue" and numbered [***] (the " **Revenue Account** ");

(ii) a U.S. Dollar-denominated account in the name of the Borrower entitled "ExGen Renewables IV – Equity Proceeds" and numbered [***] (the " **Equity Proceeds Account** ");

(iii) a U.S. Dollar-denominated account in the name of the Borrower entitled "ExGen Renewables IV – Debt Service Reserve" and numbered [***] (the " **Debt Service Reserve Account** ");

(iv) a U.S. Dollar-denominated account in the name of the Borrower entitled "ExGen Renewables IV – Liquidity Reserve" and numbered [***] (the " **Liquidity Reserve Account** "); and

(v) a U.S. Dollar-denominated account in the name of the Borrower entitled "ExGen Renewables IV – ECF Prepayment" and numbered [***] (the " **ECF Prepayment Account** ").

All amounts on deposit in or credited to each Depositary Account from time to time shall (i) be disbursed in accordance with the terms hereof, (ii) constitute the property of the Borrower, (iii) be subject to the first priority Lien of the Collateral Agent (for the benefit of the Secured Parties), (iv) be held in the sole custody and "control" (within the meaning of Section 8-106(d) or Section 9-104 of the UCC) of the Collateral Agent for the purposes and on the terms set forth in this Agreement and the Security Documents and (v) constitute a part of the Collateral. No amounts on deposit in or credited to the Depositary Accounts from time to time shall constitute payment of any Obligations or any other obligation of any Loan Party.

(b) *Deposits into Accounts.*

(i) *Revenue Account* . All Cash and Cash Equivalents (including all Available Cash and any proceeds received by the Loan Parties as a result of the exercise of Cure Rights pursuant to Section 7.02) of each of the Loan Parties, all amounts required to be transferred to the Revenue Account from any other Depositary Accounts in accordance with the terms of this Agreement and all other amounts received by the Loan Parties on or after the Closing Date and not required to be deposited to another Depositary Account pursuant to this Agreement shall be deposited as and when received (without regard to whether the current fiscal period in which they arise has closed) directly to, and shall be retained in, the Revenue Account, subject to application in accordance with Section 2.19(c), other than Cash and Cash Equivalents (A) required to be deposited (or on deposit) in the Debt Service Reserve Account pursuant to Section 2.19(d), (B) deposited (or on deposit) in the Liquidity Reserve Account pursuant to Section 2.19(e) and (C) any Equity Proceeds, Completion Proceeds and any Excess Project Disposition Proceeds deposited in the Equity Proceeds Account.

(ii) *Equity Proceeds Account* . The Loan Parties may deposit in the Equity Proceeds Account as and when received any Equity Proceeds, Completion Proceeds and any Excess Project Disposition Proceeds, as determined by the Borrower (and any Equity Proceeds not so deposited shall be deposited into the Revenue Account).

(c) *Withdrawals from the Revenue Account* . Amounts in the Revenue Account shall be disbursed (A) by the Depositary Bank as directed by the Borrower (which disbursement shall be described in a certificate executed by a Responsible Officer of the Borrower to the Administrative Agent, the Collateral Agent and the Depositary Bank at least (1) five (5) Business Days prior to the applicable funding date, in the case of any Withdrawal Certificate that includes transfers for the payment of Debt Service pursuant to clauses (i) , (ii) or (iii) below; (2) in any other case, other than with respect to transfers pursuant to clause (vi) below, three (3) Business Days prior to the applicable funding date; or (3) in the case of any transfer with respect to clause (vi) below, no later than two (2) Business Days after the applicable Excess Cash Flow Period detailing the amounts and Persons to be paid in accordance with the following clauses (i) through (vi) and in substantially the form set forth in Exhibit K (such certificate, a " **Withdrawal Certificate** ")) (via wire transfer or by internal transfer between Depositary Accounts, if applicable), to the extent that funds are then available in the Revenue Account, in the following order of priority, or (B) upon the occurrence and during the continuance of a Default or Event of Default, from time to time as the Administrative Agent shall direct, to be applied against the Obligations of the Borrower that are then due and payable to the Agents, the Lenders and the other Secured Parties, in the order of priority set forth below or (C) if the Borrower fails to deliver a Withdrawal Certificate pursuant to this Section 2.19(c) on any date on which any amounts described in this Section 2.19(c) are due and payable to the Secured Parties, as the Administrative Agent may direct (with one Business Day's advance notice thereof and a copy of such Withdrawal Certificate to the Borrower and the Collateral Agent) in the order of priority set forth below:

(i) *first* , from time to time as necessary to pay as and when due Operating Expenses (*provided* that any such payments to Affiliates shall be in compliance with Section 6.07), including expenses, indemnity payments and other amounts (including reasonable and documented fees, charges and disbursements of counsel of any Agent) payable to the Administrative Agent, the Collateral Agent or the Depositary Bank, in their capacities as such (but excluding any amounts payable pursuant to clause (iv) below), and Fees, that have become due and payable and have not yet been paid, as set forth in the applicable Withdrawal Certificate (or, if applicable, direction from the Administrative Agent);

(ii) *second* , after giving effect to any withdrawals pursuant to clauses (i) above, on each Quarterly Date and otherwise from time to time as necessary to pay as and when due (x) to the Administrative Agent, the interest and any breakage costs on the Loans payable to the Lenders hereunder and (y) to each applicable Specified Swap Counterparty, scheduled ordinary course payments (but not termination payments) payable by a Loan Party under Secured Swap Agreements, as set forth in the applicable Withdrawal Certificate (or, if applicable, direction from the Administrative Agent);

(iii) *third* , after giving effect to the withdrawals pursuant to clauses (i) and (ii) above, on each Quarterly Date, as necessary to pay as and when due (x) to the Administrative Agent, any principal of (including Scheduled Amortization Payments) and premium, if any, on the Loans payable to the Lenders hereunder and (y) to each applicable Specified Swap Counterparty, termination payments payable by a Loan Party under Secured Swap Agreements, as set forth in the applicable Withdrawal Certificate (or, if applicable, direction from the Administrative Agent);

(iv) *fourth* , after giving effect to the withdrawals pursuant to clauses (i) through (iii) above, on each Quarterly Date and otherwise from time to time as necessary to pay as and

when due to the Persons entitled thereto all indemnities and other amounts (other than interest, Fees, principal and premium) payable to the Lenders and Specified Swap Counterparties under the Loan Documents and Secured Swap Agreements, as set forth in the applicable Withdrawal Certificate (or, if applicable, direction from the Administrative Agent);

(v) *fifth* , after giving effect to the withdrawals pursuant to clauses (i) through (iv) above, on each Quarterly Date, as necessary to fund the Debt Service Reserve Account such that the amount on deposit and available therein (taking into account any Sponsor Guaranty and Account Letter of Credit credited thereto) is at least equal to the DSR Requirement Amount, as set forth in the applicable Withdrawal Certificate (or, if applicable, direction from the Administrative Agent);

(vi) *sixth* , at the option of the Borrower in its sole discretion, after giving effect to the withdrawals pursuant to clauses (i) through (v) above, on each Quarterly Date, to fund the Liquidity Reserve Account and/or the Local Accounts in the amount, if any, determined by the Borrower (in its sole discretion), as set forth in the applicable Withdrawal Certificate; *provided* that, in no event, shall the aggregate amount of monies on deposit (1) in the Liquidity Reserve Account, after giving effect to any such transfer, exceed the Liquidity Reserve Maximum Balance or (2) in the Liquidity Reserve Account together with monies on deposit in the Local Accounts, after giving effect to any such transfer, exceed [$***];

(vii) *seventh* , after giving effect to the withdrawals pursuant to clauses (i) through (vi) above, as set forth in the applicable Withdrawal Certificate:

(A) on each Quarterly Date, the Applicable ECF Percentage of Excess Cash Flow for the Excess Cash Flow Period ending on such Quarterly Date remaining on deposit in the Revenue Account shall be applied as follows: (x) if no Credit Support Reimbursement Obligations are then outstanding and unpaid, all such Excess Cash Flow shall be transferred to the ECF Prepayment Account and (y) if Credit Support Reimbursement Obligations are then outstanding and unpaid, such Excess Cash Flow shall be allocated pro rata (based on the aggregate amount of the outstanding principal of the Loans and the Credit Support Reimbursement Obligations then outstanding and unpaid on such Quarterly Date), with (1) the amount allocated to the Loans transferred to the ECF Prepayment Account and (2) the amount allocated to Credit Support Reimbursement Obligations transferred to an Affiliate of the Borrower as directed in the applicable Withdrawal Certificate to be applied to the payment or prepayment of such Credit Support Reimbursement Obligations; and

(B) in addition, on each Quarterly Date occurring in May (commencing with the Quarterly Date occurring in May 2022), if applicable, after giving effect to the payment(s) described in the immediately preceding clause (A) on such Quarterly Date, an amount of funds remaining on deposit in the Revenue Account on such Quarterly Date equal to the Target Balance Prepayment Amount for the applicable ECF Sweep Date shall be transferred to the ECF Prepayment Account;

provided , that notwithstanding anything to the contrary in this clause (vii), to the extent any Credit Support Reimbursement Obligation remains outstanding for twelve (12) Quarterly Dates after the incurrence of such Credit Support Reimbursement Obligation, 100% of Excess Cash Flow remaining on deposit in the Revenue Account for the Excess Cash Flow Period ending on the last of such Quarterly Dates, and each Quarterly Date thereafter on which such Credit Support Reimbursement Obligation remains outstanding, shall be applied first to the payment of such Credit Support Reimbursement

Obligation until such Credit Support Reimbursement Obligation is paid in full, and then any remaining Excess Cash Flow after such application shall be applied as set forth above in this clause (vii); and

(viii) *eighth* , on each ECF Sweep Date (commencing with the ECF Sweep Date occurring in May 2022), so long as no Default or Event of Default has occurred and is continuing, any funds remaining on deposit in the Revenue Account after giving effect to the withdrawals pursuant to clauses (i) through (vii) above, shall be transferred, as set forth in the applicable Withdrawal Certificate (including to Holding or its Affiliates).

If funds being disbursed at any time pursuant to clause (ii), (iii) or (iv) above are insufficient on any date to make the transfers and payments specified in the applicable Withdrawal Certificate, then the amounts in the Revenue Account at such level at such time shall be transferred to the Persons entitled thereto *pro rata* based on the respective amounts then due and payable to such Persons.

(d) *Debt Service Reserve Account* .

(i) *Deposits into the Debt Service Reserve Account* . On the Closing Date, the Borrower shall Fully Fund the Debt Service Reserve Account up to the DSR Requirement Amount as of the Closing Date with cash or a Sponsor Guaranty. Thereafter, on each date referred to in the next sentence, the Borrower shall Fully Fund the Debt Service Reserve Account with, to the extent available, (x) cash withdrawals from the Revenue Account permitted under Section 2.19(c)(v) and/or (y) one or more Sponsor Guarantees (or supplements to existing Sponsor Guarantees) and/or Account Letters of Credit. Immediately prior to each Quarterly Date and on each ECF Sweep Date (prior to the application of such mandatory prepayment required pursuant to Section 2.09(c)) after the Closing Date, the Borrower shall deposit or cause to be deposited in the Debt Service Reserve Account an aggregate amount (the " **DSR Increase Payment** ") equal to no less than the amount necessary (if any) to Fully Fund the Debt Service Reserve Account as of such date; *provided* , that if such aggregate amount then available from the Revenue Account is less than the DSR Increase Payment, the full amount of such available amounts on deposit in the Revenue Account shall be deposited into the Debt Service Reserve Account, it being understood that the failure to fund the full DSR Increase Payment in accordance with this proviso shall not be deemed a Default or Event of Default hereunder.

(ii) *Drawings under Sponsor Guarantees and Account Letters of Credit* . Amounts on deposit in the Debt Service Reserve Account may be funded from time to time by any Sponsor Guaranty or Account Letter of Credit, and the Collateral Agent shall make a demand for payment under any Sponsor Guaranty or drawing upon any Account Letter of Credit if:

(A) In the case of a Sponsor Guaranty, the guarantor under such Sponsor Guaranty is not an Acceptable Guarantor and thirty (30) or more days have elapsed since such guarantor ceased to be an Acceptable Guarantor and such Sponsor Guaranty has not been replaced (with another Sponsor Guaranty, an Account Letter of Credit or cash); or

(B) In the case of an Account Letter of Credit, (1) the issuer of such Account Letter of Credit is not an Acceptable LC Issuer and thirty (30) or more days have elapsed since such issuer ceased to be an Acceptable LC Issuer and such Account Letter of Credit has not been replaced (with another Account Letter of Credit or cash); or (2) such Account Letter of Credit will expire within thirty (30) days and either (x) the Collateral Agent has received a notice from the issuer thereof that such Account Letter of Credit will not be renewed in accordance with its terms or (y) the Collateral Agent has not

received written evidence from the issuer thereof or the Borrower that such Account Letter of Credit will be extended or replaced (with another Account Letter of Credit, a Sponsor Guaranty or cash) upon or prior to its stated expiration date.

Upon obtaining knowledge thereof, the Borrower shall provide prompt written notice to the Collateral Agent if any guarantor under a Sponsor Guaranty is not an Acceptable Guarantor or whether any issuer of an Account Letter of Credit is not an Acceptable Credit Provider. Any such demand under a Sponsor Guaranty shall be in an amount equal to the lesser of (1) the DSR Requirement Amount at such time *minus* the sum of (x) the amount of Cash and Cash Equivalents on deposit in the Debt Service Reserve Account at such time and (y) the remaining Drawing Amounts of any Account Letters of Credit credited to the Debt Service Reserve Account at such time (to the extent such Account Letters of Credit are issued by an Acceptable LC Issuer and will not expire within thirty (30) days (unless the issuing bank or the Borrower has provided written evidence to the Collateral Agent that any such Account Letter of Credit will be extended or replaced upon or prior to its stated expiration date)) and the guaranteed amount then available for demand under any other Sponsor Guarantees credited to the Debt Service Reserve Account at such time (to the extent any such Sponsor Guaranty is issued by an Acceptable Guarantor, has not been terminated and no payment defaults have occurred thereunder) and (2) if applicable, the remaining guaranteed amount then available for demand under such Sponsor Guaranty, and the proceeds of such demand shall be deposited into the Debt Service Reserve Account by the Collateral Agent. Any such drawing under an Account Letter of Credit shall be in an amount equal to the lesser of (1) the DSR Requirement Amount at such time *minus* the sum of (x) the amount of Cash and Cash Equivalents on deposit in the Debt Service Reserve Account at such time and (y) the remaining Drawing Amounts of any other Account Letters of Credit credited to the Debt Service Reserve Account at such time (to the extent such Account Letters of Credit are issued by an Acceptable LC Issuer and will not expire within thirty (30) days (unless the issuing bank or the Borrower has provided written evidence to the Collateral Agent that any such Account Letter of Credit will be extended or replaced upon or prior to its stated expiration date)) and the guaranteed amount then available for demand under any Sponsor Guarantees credited to the Debt Service Reserve Account at such time (to the extent any such Sponsor Guaranty is issued by an Acceptable Guarantor, has not been terminated and no payment defaults have occurred thereunder) and (2) the remaining Drawing Amount under such Account Letter of Credit, and the proceeds of such drawing shall be deposited into the Debt Service Reserve Account by the Collateral Agent.

(iii) *Disbursements of Excess Amounts from the Debt Service Reserve Accounts; Reductions in Account Letters of Credit and Sponsor Guarantees* .

(A) So long as no Event of Default has occurred and is continuing, at any time that the sum of the aggregate Drawing Amounts under all Account Letters of Credit held by the Collateral Agent credited to the Debt Service Reserve Account at such time (to the extent such Account Letters of Credit are issued by an Acceptable LC Issuer and will not expire within thirty (30) days (unless the issuing bank or the Borrower has provided written evidence to the Collateral Agent that any such Account Letter of Credit will be extended or replaced upon or prior to its stated expiration date)) *plus* the aggregate guaranteed amount then available for demand under any Sponsor Guarantees held by the Collateral Agent credited to the Debt Service Reserve Account at such time (to the extent such Sponsor Guarantees are issued by an Acceptable Guarantor, has not been terminated and no payment defaults have occurred thereunder) *plus* the funds then on deposit in or credited to the Debt Service Reserve Account is greater than the DSR Requirement Amount as of such date (in each case, an " **Excess Reserve Amount** "), as specified in a certificate signed by a Responsible Officer of the Borrower (with a copy

to the Administrative Agent), certifying as to the amount of such Excess Reserve Amount, the Borrower shall be entitled pursuant to a Withdrawal Certificate to (1) transfer or cause to be transferred an amount of funds up to the Excess Reserve Amount from the Debt Service Reserve Account to the Revenue Account and (2) then, if any Excess Reserve Amount remains after giving effect to clause (1) , the Borrower shall be entitled to deliver to the Collateral Agent for countersignature (in the Administrative Agent's reasonable discretion), and shall thereafter deliver to the issuer of any Account Letter of Credit credited to the Debt Service Reserve Account at such time, a reduction certificate in the form attached to such Account Letter of Credit or otherwise in a form satisfactory to such issuer in the amount of such remaining Excess Reserve Amount, and the face amount of such Account Letter of Credit may be reduced as provided in such certificate; *provided* that if any Sponsor Guaranty is then also credited to the Debt Service Reserve Account, such Sponsor Guaranty shall be reduced pursuant to a supplement provided under such Sponsor Guaranty or documentation otherwise satisfactory to the Administrative Agent (with a copy to the Administrative Agent) for such remaining Excess Reserve Amount prior to the reduction of any Account Letter of Credit.

(B) So long as no Event of Default has occurred and is continuing, the Borrower shall be entitled to instruct the Depositary Bank to release funds from the Debt Service Reserve Account pursuant to a written request from a Responsible Officer of the Borrower (certifying as to no Event of Default), with a copy to the Administrative Agent, in the event that the Borrower has provided to the Collateral Agent a Sponsor Guaranty or an Account Letter of Credit in a guaranteed or stated amount equal to the amount of funds to be released from the Debt Service Reserve Account and amounts so released shall be transferred to such accounts or Persons as are specified in such instructions to the Depositary Bank. Such Sponsor Guaranty and Account Letter of Credit shall be subject to all of the terms of this Section 2.19(d) .

(C) The Borrower may at any time deliver Cash and Cash Equivalents and/or one or more Account Letters of Credit to the Depositary Agent for deposit in or credit to the Debt Service Reserve Account and upon delivery thereof, shall be entitled, (pursuant to a written request from a Responsible Officer of the Borrower to the applicable guarantor and the Collateral Agent, certifying that such reduction is in compliance with this clause (C), with a copy to the Administrative Agent) to a reduction in the then available guaranteed amount under any Sponsor Guaranty credited to the Debt Service Reserve Account pursuant to a supplement provided under such Sponsor Guaranty or documentation otherwise satisfactory to the Administrative Agent in the face or stated amount equal to the amount of Cash and Cash Equivalents and/or Account Letters of Credit to be deposited in or credited to the Debt Service Reserve Account. Any such reduction shall only be effective upon actual receipt by the Depositary Agent of the replacement Cash and Cash Equivalents and/or one or more Account Letters of Credit.

(D) For the avoidance of doubt, in no event shall the guaranteed amount of any Sponsor Guaranty or the stated amount of any Account Letter of Credit credited to the Debt Service Reserve Account be permitted to be reduced other than in connection with Section 2.19(d)(iii)(A) or 2.19(d)(iii)(C) or in connection with a cash payment made pursuant to any demand or draw, as applicable, thereunder paid to the Collateral Agent in accordance with the terms thereof.

(iv) *Disbursements to Pay Debt Service* . To the extent disbursements from the Revenue Account or other funds available to the Borrower or the other Loan Parties are not anticipated to be or are not adequate to pay (x) all interest and Fees due and payable to the Agents and the Lenders under or in respect of the Loan Documents, or (y) all principal or premium (if any) due and payable to the Lenders under or in respect of the Loan Documents (any such shortfall, a " **Debt Payment Deficiency** "), then:

(A) the Depositary Bank (at the written direction of (I) the Borrower pursuant to a Withdrawal Certificate or (II) if the Borrower has not so delivered such Withdrawal Certificate by 1:00 p.m. (New York City time) on the third Business Day prior to the date on which such amounts are due and not paid, the Administrative Agent) shall withdraw from the Debt Service Reserve Account and immediately transfer to the Administrative Agent cash in an aggregate amount equal to the Debt Payment Deficiency (or, if less, the aggregate amount of funds then on deposit in or credited to the Debt Service Reserve Accounts) for application (1) first, to that portion of the Debt Payment Deficiency that relates to amounts due in clause (x) above and (2) second, to that portion of the Debt Payment Deficiency that relates to amounts due in clause (y) above, in accordance with the Loan Documents, and if such funds are insufficient to meet the Debt Payment Deficiency, then

(B) after giving effect to clause (A) , to the extent any Debt Payment Deficiency remains outstanding, the Depositary Bank shall promptly so notify the Borrower, the Administrative Agent and the Collateral Agent, and the Collateral Agent shall (I) first , if any Sponsor Guaranty is then in effect, make a demand under such Sponsor Guaranty in an amount equal to the remaining Debt Payment Deficiency (or, if less, the full available guaranteed amount under such Sponsor Guaranty) and immediately transfer the proceeds thereof to the Administrative Agent and (II) second , to the extent any Debt Payment Deficiency remains outstanding, if any Account Letter of Credit is then in effect, make a drawing on such Account Letter of Credit in an amount equal to the remaining Debt Payment Deficiency (or, if less, the Drawing Amount under such Account Letter of Credit) and immediately transfer the proceeds thereof to the Administrative Agent. The Administrative Agent shall apply such proceeds (1) first, to that portion of the Debt Payment Deficiency that relates to amounts due in clause (x) above and (2) second, to that portion of the Debt Payment Deficiency that relates to amounts due in clause (y) above, in accordance with the Loan Documents.

(e) *Liquidity Reserve Account*

(i) *Deposits into the Liquidity Reserve Account* . On the Closing Date, the Borrower shall fund the Liquidity Reserve Account up to the Liquidity Reserve Maximum Balance with cash or a Sponsor Guaranty. Thereafter, on each Quarterly Date, the Borrower (at its option (in its sole discretion)) may fund the Liquidity Reserve Account with, to the extent available, cash withdrawals from the Revenue Account permitted under Section 2.19(c)(vi), up to the Liquidity Reserve Maximum Balance.

(ii) *Sponsor Guarantees and Account Letters of Credit* . Amounts on deposit in the Liquidity Reserve Account may be funded from time to time by any Sponsor Guaranty or Account Letter of Credit, and the Collateral Agent shall make a demand for payment under any Sponsor Guaranty or drawing upon any Account Letter of Credit if:

(A) In the case of a Sponsor Guaranty, the guarantor under such Sponsor Guaranty is not an Acceptable Guarantor and thirty (30) or more days have elapsed

since such guarantor ceased to be an Acceptable Guarantor and such Sponsor Guaranty has not been replaced (with another Sponsor Guaranty, an Account Letter of Credit or cash); or

(B) In the case of an Account Letter of Credit, (1) the issuer of such Account Letter of Credit is not an Acceptable LC Issuer and thirty (30) or more days have elapsed since such issuer ceased to be an Acceptable LC Issuer and such Account Letter of Credit has not been replaced (with another Account Letter of Credit or cash); or (2) such Account Letter of Credit will expire within thirty (30) days and either (x) the Collateral Agent has received a notice from the issuer thereof that such Account Letter of Credit will not be renewed in accordance with its terms or (y) the Collateral Agent has not received written evidence from the issuer thereof or the Borrower that such Account Letter of Credit will be extended or replaced (with another Account Letter of Credit, a Sponsor Guaranty or cash) upon or prior to its stated expiration date.

Upon obtaining knowledge thereof, the Borrower shall provide prompt written notice to the Collateral Agent if any guarantor under a Sponsor Guaranty is not an Acceptable Guarantor or whether any issuer of an Account Letter of Credit is not an Acceptable Credit Provider. Any such demand under a Sponsor Guaranty shall be in an amount equal to the remaining guaranteed amount then available for demand under such Sponsor Guaranty, and the proceeds of such demand shall be deposited into the Liquidity Reserve Accounts by the Collateral Agent. Any such drawing under an Account Letter of Credit shall be in an amount equal to the remaining Drawing Amount under such Account Letter of Credit, and the proceeds of such drawing shall be deposited into the Liquidity Reserve Account by the Collateral Agent.

(C) So long as no Event of Default has occurred and is continuing, at any time that the sum of the aggregate Drawing Amounts under all Account Letters of Credit held by the Collateral Agent credited to the Liquidity Reserve Account at such time (to the extent such Account Letters of Credit are issued by an Acceptable LC Issuer and will not expire within thirty (30) days (unless the issuing bank or the Borrower has provided written evidence to the Collateral Agent that any such Account Letter of Credit will be extended or replaced upon or prior to its stated expiration date)) *plus* the aggregate guaranteed amount then available for demand under any Sponsor Guarantees held by the Collateral Agent credited to the Liquidity Reserve Account at such time (to the extent such Sponsor Guarantees are issued by an Acceptable Guarantor, has not been terminated and no payment defaults have occurred thereunder) *plus* the funds then on deposit in or credited to the Liquidity Reserve Account is greater than the Liquidity Reserve Maximum Balance (in each case, an " **Excess Liquidity Reserve Amount** "), as specified in a certificate signed by a Responsible Officer of the Borrower (with a copy to the Administrative Agent), certifying as to the amount of such Excess Liquidity Reserve Amount, the Borrower shall be entitled pursuant to a Withdrawal Certificate to transfer or cause to be transferred an amount of funds up to the Excess Liquidity Reserve Amount from the Liquidity Reserve Account as directed in such Withdrawal Certificate.

(D) So long as no Event of Default has occurred and is continuing, the Borrower shall be entitled to instruct the Depositary Bank to release funds from the Liquidity Reserve Account pursuant to a written request from a Responsible Officer of the Borrower (certifying as to no Event of Default), with a copy to the Administrative Agent, in the event that the Borrower has provided to the Collateral Agent a Sponsor Guaranty or an Account Letter of Credit in a guaranteed or stated amount equal to the amount of funds to be released from the Liquidity Reserve Account and amounts so

released shall be transferred to such accounts or Persons as are specified in such instructions to the Depositary Bank. Such Sponsor Guaranty and Account Letter of Credit shall be subject to all of the terms of this Section 2.19(e) .

(E) The Borrower may at any time deliver Cash and Cash Equivalents and/or one or more Account Letters of Credit to the Depositary Agent for deposit in or credit to the Liquidity Reserve Account and upon delivery thereof, shall be entitled, (pursuant to a written request from a Responsible Officer of the Borrower to the applicable guarantor and the Collateral Agent, certifying that such reduction is in compliance with this clause (C), with a copy to the Administrative Agent) to a reduction in the then available guaranteed amount under any Sponsor Guaranty credited to the Liquidity Reserve Account pursuant to a supplement provided under such Sponsor Guaranty or documentation otherwise satisfactory to the Administrative Agent in the face or stated amount equal to the amount of Cash and Cash Equivalents and/or Account Letters of Credit to be deposited in or credited to the Liquidity Reserve Account. Any such reduction shall only be effective upon actual receipt by the Depositary Agent of the replacement Cash and Cash Equivalents and/or one or more Account Letters of Credit.

(F) For the avoidance of doubt, in no event shall the guaranteed amount of any Sponsor Guaranty or the stated amount of any Account Letter of Credit credited to the Liquidity Reserve Account be permitted to be reduced other than in connection with Section 2.19(e)(ii)(C) or (E) or in connection with a cash payment made pursuant to any demand or draw, as applicable, thereunder paid to the Collateral Agent in accordance with the terms thereof.

(G) At any time that the sum of the aggregate Drawing Amounts under all Account Letters of Credit credited to the Liquidity Reserve Account, the then available guaranteed amount under any Sponsor Guaranty credited to the Liquidity Reserve Account and the funds then on deposit in or credited to the Liquidity Reserve Account and the Local Accounts at such time is (i) less than the Liquidity Reserve Maximum Balance, net interest, if any, earned on funds on deposit in the Liquidity Reserve Account shall be accumulated therein or (ii) greater than the Liquidity Reserve Maximum Balance, net interest, if any, earned on funds on deposit in the Liquidity Reserve Account shall be transferred to the Revenue Account.

(iii) *Disbursements* . If (x) on any Quarterly Date, or any other date on which transfers are to be made, the amount available in the Revenue Account is insufficient to make all of the transfers required by clauses (i) through (iv) of Section 2.19(c) (a " **Borrower Liquidity Shortfall** ") or (y) there are insufficient funds at any Project Entity to make payments of amounts consisting of operation and maintenance costs or expenses attributable to any Project or payment of debt service or fees under any Project Level Financing Documents, as described in reasonable detail and certified by a Responsible Officer of the Borrower (a " **Project Liquidity Shortfall** "), the Depositary Bank (at the written direction of the Borrower pursuant to a Withdrawal Certificate) shall transfer an amount in cash equal to the lesser of (x) the Borrower Liquidity Shortfall or Project Liquidity Shortfall, as applicable, and (y) the amount then available in (i) the Liquidity Reserve Account and (ii) any Local Accounts, from the Liquidity Reserve Account or applicable Local Account and deposit such amount into, in the case of a Borrower Liquidity Shortfall, the Revenues Account for application on such date in accordance with Section 2.19(c) and in the case of a Project Liquidity Shortfall, to such accounts or Persons as are specified in such Withdrawal Certificate for application to such Project Liquidity Shortfall as specified in the corresponding Responsible Officer's certificate. In addition, in accordance with Section 2.19(g), the Borrower may submit a Withdrawal Certificate to transfer any amount on deposit in the

Liquidity Reserve Account to one or more Local Accounts as specified therein for application to any future Borrower Liquidity Shortfall or Project Liquidity Shortfall; *provided* that after giving effect to any such transfer, (1) the amount on deposit in the Liquidity Reserve Account shall not exceed the Liquidity Reserve Maximum Balance and (2) the aggregate amount on deposit in the Liquidity Reserve Account and the Local Accounts shall not exceed [$***]. To the extent any Borrower Liquidity Shortfall or Project Liquidity Shortfall, as applicable, remains outstanding after application of all cash in the Liquidity Reserve Account and the Local Accounts, the Depositary Bank shall promptly so notify the Borrower, the Administrative Agent and the Collateral Agent, and the Collateral Agent shall (I) first , if any Sponsor Guaranty is then in effect, make a demand under such Sponsor Guaranty in an amount equal to the remaining Borrower Liquidity Shortfall or Project Liquidity Shortfall, as applicable, (or, if less, the full available guaranteed amount under such Sponsor Guaranty) and immediately transfer the proceeds thereof to the applicable account and (II) second , to the extent any Borrower Liquidity Shortfall or Project Liquidity Shortfall, as applicable, remains outstanding, if any Account Letter of Credit is then in effect, make a drawing on such Account Letter of Credit in an amount equal to the remaining Borrower Liquidity Shortfall or Project Liquidity Shortfall, as applicable, (or, if less, the Drawing Amount under such Account Letter of Credit) and immediately transfer the proceeds thereof to the applicable account.

(f) *Local Accounts* . The Depositary Bank shall, pursuant to a Withdrawal Certificate delivered by the Borrower for such purpose in accordance with Section 2.19(e)(iii), transfer to the applicable Local Account the amount requested by the Borrower in the applicable Withdrawal Certificate for payment of Borrower Liquidity Shortfalls and Project Liquidity Shortfalls as, when and to the extent specified in such Withdrawal Certificate.

(g) *Equity Proceeds Account* . To the extent any Loan Party received Equity Proceeds, Completion Proceeds or Excess Project Disposition Proceeds, such Equity Proceeds, Completion Proceeds or Excess Project Disposition Proceeds may be deposited into the Equity Proceeds Account. The Borrower shall be permitted to transfer Cash and Cash Equivalents on deposit in or credited to the Equity Proceeds Account at any time pursuant to a Withdrawal Certificate delivered to the Depositary Agent (with a copy to the Administrative Agent), to an account (which may be any Depositary Account) or Person as directed by the Borrower in such Withdrawal Certificate, which funds may be applied for any purpose permitted by this Agreement and the other Loan Documents.

(h) *ECF Prepayment Account* . The Depositary Bank (at the written direction of (I) the Borrower pursuant to a Withdrawal Certificate or (II) if the Borrower has not so delivered such Withdrawal Certificate by 1:00 p.m. (New York City time) on the third Business Day prior to any ECF Sweep Date, the Administrative Agent) shall on each ECF Sweep Date withdraw from the ECF Prepayment Account and immediately transfer to the Administrative Agent cash equal to the aggregate amount of funds then on deposit in or credited to the ECF Prepayment Account for application to a mandatory prepayment of the Loans in accordance with Section 2.09(b).

(i) *Invasion of Accounts* . One (1) Business Day prior to any Business Day on which disbursements are required to be made from the Revenue Account in accordance with Section 2.19(c)(ii) or (iii), if the amounts on deposit in the Revenue Account are not sufficient to make such disbursements, and the Borrower has not transferred amounts from the Liquidity Reserve Account to cover such insufficiency, the Depositary Agent (at the written direction of (I) the Borrower pursuant to a Withdrawal Certificate or (II) if the Borrower has not so delivered such Withdrawal Certificate by 1:00 p.m. (New York City time) on the second Business Day prior to the Business Day on which such disbursements are required to be made, the Administrative Agent) shall transfer funds to the Revenue Account to cover such insufficiency first from the ECF Prepayment Account, second , from the Liquidity Reserve Account

and third , after giving effect to such transfers, from the Debt Service Reserve Account in accordance with Section 2.19(d).

(j) *Receipt of Certain Funds; Unidentified Funds.* If any Agent or Lender receives directly any amount that is payable to a Depositary Account (due to such amount not being paid directly to the applicable Depositary Account), such Person shall deposit or cause to be deposited such amount into the applicable Depositary Account, and the obligation of the Loan Parties to deposit such amount into such Depositary Account shall be deemed satisfied upon such deposit. If the Depositary Bank receives directly any amount that is not sufficiently identified or is not accompanied with adequate instructions as to which Depositary Account such amount is to be deposited, the Depositary Bank shall deposit such funds into the Revenue Account, and notify the Borrower and each Agent of the receipt of such funds. Upon receipt of written instructions from the Borrower (as confirmed in writing by the Administrative Agent), the Depositary Bank shall transfer such funds from the Revenue Account to the Depositary Account specified by such instructions.

Section 2.20 *Incremental Revolving Facility and Commitments.*

(a) The Borrower may, by written notice to the Administrative Agent, on one occasion, request a revolving facility (including, if desired, but without duplication, letter of credit capacity) in an aggregate principal amount not to exceed $50,000,000 (the " **Revolving Facility** "), to be used solely for working capital requirements, letter of credit capacity and other general corporate purposes of the Loan Parties. Upon the receipt of such request by the Administrative Agent, the Administrative Agent shall deliver a copy thereof to each Lender. Such notice shall set forth the amount of the requested Revolving Facility, which shall be in a minimum increments of $1,000,000 and a minimum amount of $10,000,000, and the date on which such Revolving Facility is requested to become effective (which shall be not less than 15 days nor more than 90 days after the date of such notice, which in any event must be prior to the Maturity Date), and shall offer each Lender the opportunity to participate by its applicable pro rata share of the proposed Revolving Facility, *provided* that any Agent or Lender may elect or decline, in its sole discretion, to provide a commitment in respect of the Revolving Facility.

(b) Each Lender shall, by notice to the Borrower and the Administrative Agent given not more than 10 days after the date of the Administrative Agent's notice described in clause (a) above is delivered to such Lender, either agree to issue a commitment for all or a portion of the offered amount (each agreeing Lender, a " **Participating Revolving Lender** ") or decline to issue a commitment (and any Lender that does

not deliver such a notice within such period of 10 days shall be deemed to have declined to provide a commitment) (each declining or deemed declining Lender, a " **Non- Participating Revolving Lender** ").

(c) In the event that, on the 15th day after the Administrative Agent shall have delivered a notice pursuant to the immediately preceding paragraph (b), the Participating Revolving Lenders shall have agreed pursuant to the preceding sentence to provide commitments by an aggregate amount less than the amount requested by the Borrower, the Borrower may arrange for one or more banks or other entities (each such bank or other entity, a " **New Revolving Lender** " and together with the Participating Revolving Lender, the " **Revolving Lenders** "), which may include any Lender or Agent, to issue commitments under the requested Revolving Facility, in an aggregate amount equal to the unsubscribed amount; *provided* , *however* , that each New Revolving Lender that is not a Lender shall be subject to the prior written approval of the Administrative Agent and, if such Revolving Facility is to include a letter of credit facility, each issuing bank thereunder (each, a " **Revolving Issuing Bank** ") (which approvals shall not be unreasonably withheld or delayed), and the Borrower and each New Revolving Lender and Revolving Issuing Bank shall execute all such documentation (including a joinder agreement, if applicable) as the Administrative Agent shall reasonably specify to evidence its commitments under the requested Revolving Facility and/or its status as a "Lender" or issuing bank under such Revolving Facility hereunder and shall share *pro rata* in the Collateral as a Secured Party. Any Revolving Facility may be made in an amount that is less than the amount requested by the Borrower if the Borrower is unable to arrange for, or chooses not to arrange for, New Revolving Lenders, but in no event less than $10,000,000.

(d) Notwithstanding the foregoing, no Revolving Facility shall become effective under this Section 2.20 unless:

(i) on the date of such incurrence, no Default or Event of Default shall have occurred and be continuing or would exist after giving effect to such Revolving Facility;

(ii) the representations and warranties set forth in Article III hereof shall be true and correct in all material respects on and as of the date of such incurrence with the same effect as though made on and as of such date, except to the extent such representations and warranties expressly relate to an earlier date (in which case such representations and warranties shall be true and correct in all material respects as of such earlier date); *provided* , that, in each case, such materiality qualifier shall not be applicable to any representations and warranties that are already qualified or modified by "materiality," "Material Adverse Effect" or similar language in the text thereof;

(iii) the final maturity date of such Revolving Facility shall be no later than the Maturity Date;

(iv) such Revolving Facility will rank *pari passu* in right of payment and *pari passu* with respect to security under the Security Documents with the Term Loan Facility;

(v) all fees and expenses relating to such Revolving Facility then due and payable shall have been paid in full, including to the Administrative Agent, the Collateral Agent and the Lender Parties;

(vi) the Borrower would be in compliance with the Financial Performance Covenant on the date of incurrence of such Revolving Facility and as of the most recently completed Test Period ending prior to the incurrence of such Revolving Facility, after giving pro forma effect to the incurrence of such Revolving Facility (assuming a full drawing under the commitments with respect to such Revolving Facility and after giving effect to other pro forma adjustment events reasonably acceptable to the Administrative Agent and any permanent repayment of Indebtedness after the beginning of the relevant determination period but prior to or simultaneous with such drawing) as if such incurrence had occurred as of the first day of such Test Period;

(vii) the Borrower shall have obtained a Ratings Reaffirmation after giving effect to such Revolving Facility;

(viii) the terms and conditions of the Revolving Facility shall be determined by the Borrower, the Administrative Agent, the Revolving Lenders and the Revolving Issuing Banks and, to the extent such terms are not consistent with those applicable to the Term Loan Facility, as applicable, such terms shall be reasonably satisfactory to the Administrative Agent; and

(ix) the Borrower shall have delivered to the Administrative Agent a certificate of a Responsible Officer of the Borrower certifying and showing (in reasonable detail and with appropriate calculations and computations, where applicable, in all respects reasonably satisfactory to the Administrative Agent) that the conditions set forth in clauses (i) and (v) above in connection with the incurrence of the Revolving Facility have been satisfied.

(e) Any Revolving Facility incurred pursuant to this Section 2.20 shall be effected pursuant to an amendment of this Agreement executed and delivered by the Borrower, each Revolving Lender, each Revolving Issuing Bank and the Administrative Agent, each of which shall be recorded in the Register. Notwithstanding anything to the contrary in this Agreement, each of the parties hereto hereby agrees that this Agreement and the other Loan Documents shall be amended (or amended and restated), without the consent of any other Lender Parties, to effect such amendments to this Agreement and the other Loan Documents as may be necessary or appropriate, in the opinion of the Administrative Agent to effect the provisions of this Section 2.20 and reflect the existence of the Revolving Facility (and, to the extent not consistent with the Term Loan Facility, in a manner reasonably satisfactory to the Administrative Agent).

Article III.
REPRESENTATIONS AND WARRANTIES

Each of Holding and the Borrower represents and warrants to each of the Lenders on and as of the Closing Date with respect to itself and the other Loan Parties that:

Section 3.01 *Organization; Powers* . Each of the Loan Parties (a) is duly organized, validly existing and (if applicable) in good standing under the laws of the jurisdiction of its organization, (b) has all requisite power and authority to own its property and assets and to carry on its business as now conducted, (c) is qualified to do business in each jurisdiction where such qualification is required, except where the failure to so qualify would not reasonably be expected to have a Material Adverse Effect and (d) has the power and authority to execute, deliver and perform its obligations under each of the Loan Documents and, in the case of the Borrower, to borrow and otherwise obtain credit hereunder.

Section 3.02 *Authorization; No Conflicts* . The execution, delivery and performance by the Loan Parties of each of the Loan Documents to which such Loan Party is a party, and the Borrowings hereunder and the other Transactions (a) have been duly authorized by all necessary corporate, stockholder, limited liability company or partnership action required to be obtained by each of the Loan Parties; (b) will not (i) violate any provision of (A) any applicable law, statute, rule or regulation binding on the Loan Parties or their properties or (B) the certificate or articles of incorporation or other constitutive documents or by-laws of any Loan Party, any applicable order of any court or any rule, regulation or order of any Governmental Authority binding on the Loan Parties or their properties or (C) any indenture, lease or other instrument or agreement to which any Loan Party is a party or by which any of them is or any of their respective property is or may be bound or any Material Project Level Agreements, or (ii) result in a breach of or constitute (alone or with notice or lapse of time or both) a default under, give rise to a right of or result in any cancellation or acceleration of any right or obligation (including any payment) under any such indenture, lease or other instrument or agreement (including the Material Project Level Agreements), where any such violation, breach or default referred to in clause (i) or (ii) of this clause (b) would reasonably be expected to have, individually or in the aggregate, a Material Adverse Effect; or (c) result in the creation or imposition of any Lien upon or

with respect to any property or assets now owned or hereafter acquired by any Loan Party, other than the Liens created by the Loan Documents and Prior Liens.

Section 3.03 *Enforceability* . This Agreement has been duly executed and delivered by each of the Loan Parties and constitutes, and each other Loan Document when executed and delivered by each Loan Party that is party thereto will constitute, a legal, valid and binding obligation of such Loan Party enforceable against each such Loan Party in accordance with its terms, subject to (a) the effects of bankruptcy, insolvency, moratorium, reorganization, fraudulent conveyance or other laws affecting creditors' rights generally, (b) general principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at law) and (c) implied covenants of good faith and fair dealing.

Section 3.04 *Governmental Approvals; Consents.* No action, consent or approval of, registration or filing with or any other action by any Governmental Authority or any other Person is or will be required in connection with the Transactions except for (a) the filing of UCC financing statements (or the filing of financing statements under any other local equivalent) or (b) such consents, authorizations, filings or other actions that have been made or obtained and are in full force and effect and such actions, consents, approvals, registrations or filings the failure of which to be obtained or made would not reasonably be expected to have a Material Adverse Effect.

Section 3.05 *Financial Statements.* There has heretofore been furnished to the Lenders the following (and the following representations and warranties are made with respect thereto (as applicable)):

(a) The audited consolidated balance sheet as of December 31, 2016 (and, solely with respect to Continental Wind, LLC and AV Solar Ranch 1, LLC, December 31, 2015) and the related audited consolidated statements of operations, cash flows and owners' equity of Renewable Power Generation, LLC, Continental Wind, LLC and AV Solar Ranch 1, LLC for the years ended December 31, 2016 (and, solely with respect to Continental Wind, LLC and AV Solar Ranch 1, LLC, December 31, 2015) were prepared in accordance with GAAP and fairly present in all material respects the consolidated financial position of Renewable Power Generation, LLC, Continental Wind, LLC and AV Solar Ranch 1, LLC (as applicable) as of the dates thereof and their respective consolidated results of operations and cash flows for the applicable periods then ended.

(b) The unaudited *pro forma* consolidated balance sheet (i) as of December 31, 2016 and the related unaudited *pro forma* consolidated statements of operations and cash flows of the Borrower for the fiscal year ended December 31, 2016 fairly present, in all material respects, the pro forma consolidated financial position of the Borrower as of the date thereof as though the ExGen Renewables JV Agreement had been in effect on such date and (ii) as of December 31, 2015 and the related unaudited *pro forma* consolidated statement of operations of the Borrower for the fiscal year ended December 31, 2015 fairly present, in all material respects, the pro forma consolidated financial position of the Borrower as of the date thereof as though the ExGen Renewables JV Agreement had been in effect on such date.

(c) The unaudited *pro forma* balance sheet of the Borrower as of June 30, 2017 and the related unaudited *pro forma* statements of operations and cash flows of the Borrower for the six month period ended June 30, 2017 fairly present, in all material respects, the pro forma financial position of the Borrower as of the date thereof as though the ExGen Renewables JV Agreement had been in effect on such date and no obligations had been outstanding under that certain receivables services agreement, dated as of June 9, 2015, by and between The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch and Albany Green Energy on such date.

Section 3.06 *No Material Adverse Effect* . Since December 31, 2016, there has been no event or occurrence which has resulted in or would reasonably be expected to result in, individually or in the aggregate, a Material Adverse Effect.

Section 3.07 *Properties* ; *Equity Interests* .

(a) The Loan Parties have good title to all of their respective material properties and assets, free and clear of Liens other than Liens permitted under Section 6.02 .

(b) None of the Loan Parties has any fee-owned real properties or has any leasehold interests in any real property.

(c) Schedule 3.07(c) sets forth as of the Closing Date the name and jurisdiction of incorporation, formation or organization of Holding and each Subsidiary of Holding and, as to each such Subsidiary, the percentage of each class of Equity Interests owned by Holding or by any such Subsidiary, indicating the ownership thereof.

(d) As of the Closing Date, there are no outstanding subscriptions, options, warrants, calls, rights or other agreements or commitments (other than stock options granted to employees or directors and directors' qualifying shares) of any nature relating to any Equity Interests of Holding or the Borrower or its Subsidiaries, other than as set forth on Schedule 3.07(d) .

Section 3.08 *Litigation; Compliance.*

(a) There are no actions, suits, investigations or proceedings at law or in equity or by or on behalf of any Governmental Authority or in arbitration now pending against, or, to the knowledge of the Borrower, threatened in writing against, any Loan Parties or any business, property or rights of any such Person (i) that involve any Loan Document or the Transactions or (ii) as to which there is a reasonable possibility of an adverse determination and that, if adversely determined, individually or in the aggregate would reasonably be expected to have a Material Adverse Effect. None of the Loan Parties nor any of their respective properties is in violation of any laws, rules, regulations or orders of any Governmental Authority currently applicable thereto, except any violation or non-compliance that would not reasonably be expected to have a Material Adverse Effect.

(b) No Loan Party, Loan Party's Subsidiary or Loan Party's Affiliate, nor the officers, directors or employees thereof, nor, to the knowledge of the Loan Parties, any agent or representative of any Loan Party, Loan Party Subsidiary or Loan Party Affiliate (i) has taken any action in furtherance of an offer, payment, promise to pay, or authorization or approval of the payment, giving or receipt of money, property, gifts or anything else of value, directly or indirectly, to any Government Official in order to improperly influence official action, or to any person in violation of any applicable Anti-Corruption Laws, (ii) has knowingly engaged in any dealings or transactions with any Sanctioned Person or in any Sanctioned Country unless lawfully authorized for a U.S. Person, (iii) is or has been in violation of any Anti-Terrorism Laws, Anti-Corruption Laws or Sanctions, or (iv) is any of the following: (A) a Sanctioned Person or (B) a Person with whom the Borrower is prohibited from dealing or otherwise engaging in any transaction by any Anti-Terrorism Law. The Loan Parties or any Loan Party Subsidiary will not directly or indirectly use the proceeds of the offering, or lend, contribute or otherwise make available such proceeds to any subsidiary, joint venture partner or other person or entity, in violation of any Anti-Terrorism Laws, Anti-Corruption Laws or applicable Sanctions. The Loan Parties have implemented and maintain in effect policies and procedures reasonably designed to ensure compliance by the Loan Parties, the Loan Parties' Affiliates and their respective directors, officers, employees and agents with Anti-Terrorism Laws, Anti-Corruption Laws and applicable Sanctions. No action, suit or proceeding by or before any court or governmental agency, authority or body or any arbitrator involving the Loan Parties or any Loan Party Subsidiary with respect to Anti-Terrorism Laws is pending or, to the best knowledge of the Loan Parties, threatened.

(c) (i) None of the Loan Parties is in violation of any currently applicable law, rule or regulation (including, but not limited to the Federal Power Act (" **FPA** "), Federal Energy Regulatory Commission regulations under the FPA, Environmental Law, zoning ordinance, code or approval or any building permit), or is in default with respect to any judgment, writ, injunction or decree of any Governmental Authority, where such violation or default would reasonably be expected to have, individually or in the aggregate, a Material Adverse Effect, (ii) each of the Loan Parties holds all permits, licenses, registrations,

certificates, approvals, consents, clearances and other authorizations from any Governmental Authority required under any currently applicable law, rule or regulation for the operation of its business as presently conducted, except as would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect, (iii) no Loan Party (A) is subject to regulation as a "public utility" under the FPA; or (B) is subject to regulation as a "public utility" or other similar term under the laws of any state and (iv) none of the Lenders or the Agents, solely by virtue of the execution, delivery and performance of this Agreement or the Loan Documents, or consummation of the Transactions contemplated hereby and thereby, shall be or become: (A) a "public-utility company," a "holding company," an "affiliate" of a "holding company," an "associate company" of a "holding company," or a "subsidiary company" of a "holding company," as each such term is defined in the Public Utility Holding Company Act of 2005 (" **PUHCA** "), or otherwise subject to regulation under PUHCA; (B) a "public utility" subject to regulation under the FPA; or (C) subject to regulation under the laws of any state with respect to public utilities.

(d) None of Holding or the Borrower is party to any actions, suits, investigations or proceedings at law or in equity or by or on behalf of any Governmental Authority or in arbitration which would reasonably be expected to result in the revocation or impairment of any of their relevant FERC authorizations and approvals, including, but not limited to, Qualifying Facility and Exempt Wholesale Generator status, authorization to sell energy, capacity and ancillary services at market-based rates pursuant to Section 205 of the FPA (including blanket authorization under Section 204 of the FPA), as well as all relevant exemptions including, but not limited to, exemption from regulation under PUHCA, in each case to the extent that such revocation or impairment, individually or in the aggregate, could reasonably be expected to result in a Material Adverse Effect.

Section 3.09 *Federal Reserve Regulations* . No Loan Party is engaged principally, or as one of its important activities, in the business of extending credit for the purpose of purchasing or carrying Margin Stock.

(a) The commitment to make, and the making of, the Loans and the granting and maintaining of the security interest in connection with the obligations created thereby, will not, whether directly or indirectly, and whether immediately, incidentally or ultimately, be a violation of, or inconsistent with, the provisions of the Regulations of the Board, including Regulation T, Regulation U or Regulation X.

Section 3.10 *Investment Company Act* . No Loan Party is an "investment company" as defined in, or subject to regulation under, the Investment Company Act of 1940, as amended.

Section 3.11 *Use of Proceeds* . The Borrower will use the proceeds of the Loans solely to (i) consummate the Transactions, (ii) make the distributions to Sponsor and/or its Affiliates described in Section 6.06(c) , (iii) except to the extent otherwise satisfied through the issuance and delivery of a Sponsor Guaranty or an Account Letter of Credit, to fund the DSR Requirement Amount in the Debt Service Reserve Account and the Liquidity Reserve Maximum Balance in the Liquidity Reserve Account (collectively with any Local Accounts) and (iv) fund the Local Accounts in additional amounts not to exceed (in the aggregate) $[***], in each case on the Closing Date.

Section 3.12 *Tax Returns* . Each Loan Party (i) has filed or caused to be filed all federal and all material state, local and non-U.S. Tax returns required to have been filed by it and (ii) has paid or caused to be paid all material Taxes due and payable by it, except for the Taxes being contested in good faith by appropriate proceedings in accordance with Section 5.03 and for which the applicable Loan Party has set aside on its books adequate reserves in accordance with GAAP.

Section 3.13 *No Material Misstatements* .

(a) All written information (other than the Projections, estimates and information of a general economic nature) (the " **Information** ") concerning the Loan Parties and their respective Subsidiaries, including the Project Entities, and the Transactions included in the Confidential Information Memorandum or otherwise

prepared by or on behalf of the Borrower in connection with the Transactions and furnished to the Lenders, when taken as a whole, was true and correct in all material respects, as of the date such Information was furnished to the Lenders and as of the Closing Date, and did not contain any untrue statement of a material fact as of any such date or omit to state any material fact necessary in order to make the statements contained therein not materially misleading in light of the circumstances under which such statements were made. As of the Closing Date, there is no fact known to the Loan Parties that, individually or in the aggregate, would reasonably be expected to have a Material Adverse Effect and that has not been set forth in the Loan Documents or in the other documents, certificates and other writings delivered by or on behalf of the Borrower to the Lead Arranger and the Lenders.

(b) The Projections and estimates and information of a general economic nature prepared by or on behalf of the Borrower and that have been made available to any Lenders or the Administrative Agent in connection with the Transactions or the other transactions contemplated hereby (i) have been prepared in good faith based upon assumptions believed by the Borrower to be reasonable as of the date thereof and as of the Closing Date (it being understood that projections are inherently uncertain and no assurances are being given that the results contained in such Projections will be achieved), and (ii) as of the Closing Date, have not been modified in any material respect by the Borrower.

Section 3.14 *Employee Benefit Plans* . Each Plan is in compliance with all applicable provisions and requirements of ERISA and the Code and the regulations and published interpretations thereunder, except for failures to so comply which would not reasonably be expected to result in a Material Adverse Effect, either individually or in the aggregate. No ERISA Event has occurred or is reasonably expected to occur that would subject any Loan Party to any Tax, penalty or other liabilities, which Tax, penalty or other liabilities which individually or in the aggregate would reasonably be expected to result in a Material Adverse Effect.

Section 3.15 *Environmental Matters* . Except for matters that would not reasonably be expected to have, individually or in the aggregate, a Material Adverse Effect (i) no written notice, request for information, order, complaint, Environmental Claim or penalty has been received or incurred by any Loan Party, and there are no judicial, administrative or other actions, suits or proceedings pending or, to the knowledge of any of the Loan Parties, threatened against any Loan Party, which allege a violation of or liability under any Environmental Laws, in each case relating to any Loan Party, (ii) each Loan Party has obtained, and maintains in full force and effect, all permits, registrations and licenses to the extent necessary for the conduct of its business and operations as currently conducted, to comply with all applicable Environmental Laws and each is, and has been, in compliance with the terms and conditions of such permits, registrations and licenses, and with all applicable Environmental Laws, (iii) no Loan Party is conducting, funding or responsible for any investigation, remediation, remedial action or cleanup of any Release or threatened Release of Hazardous Materials, (iv) to the knowledge of any of the Loan Parties there has been no Release or threatened Release of Hazardous Materials at or from any property currently or, to the knowledge of any of the Loan Parties, formerly owned, operated or leased by any Loan Party that would reasonably be expected to give rise to any liability of any Loan Party under any Environmental Laws or Environmental Claim against any Loan Party, and no Hazardous Material has been generated, owned or controlled by any Loan Party and transported for disposal to or Released at any location in a manner that would reasonably be expected to give rise to any liability of any Loan Party under any Environmental Laws or to any Environmental Claim against any Loan Party, (v) no Loan Party has entered into any agreement or contract to assume, guarantee or indemnify a third party for any Environmental Claims, and (vi) to the knowledge of any of the Loan Parties there are not currently and there have not been any underground storage tanks owned or operated by any Loan Party or located on any Loan Party's real property. Each Loan Party has made available to the Administrative Agent prior to the date hereof all environmental audits, assessment reports and other environmental documents in its possession or control with respect to the operations of, or any real property operated or leased by, any Loan Party, other than such audits, assessment reports and other documents not containing information that would reasonably be expected to result in any material Environmental Claims or liability to the Loan Parties, taken as a whole. Representations and warranties of the Loan Parties with respect to environmental matters are limited to those in this Section 3.15 unless expressly stated.

Section 3.16 *Solvency* . On the Closing Date, immediately after giving effect to the Transactions, the Loan Parties, on a consolidated basis with their Subsidiaries, are Solvent.

(a) The Borrower does not intend to incur debts beyond its ability to pay such debts as they mature, taking into account the timing and amounts of cash to be received by it and the timing and amounts of cash to be payable on or in respect of its Indebtedness.

Section 3.17 *Labor Matters* . There are no strikes pending or threatened against any Loan Party that, individually or in the aggregate, would reasonably be expected to have a Material Adverse Effect. The hours worked and payments made to employees of each Loan Party have not been in violation in any material respect of the Fair Labor Standards Act or any other applicable law dealing with such matters. All material payments due from any Loan Party or for which any claim may be made against any Loan Party on account of wages and employee health and welfare insurance and other benefits have been paid or accrued as a liability on the books of the applicable Loan Party to the extent required by GAAP.

Section 3.18 *Status as Senior Debt; Perfection of Security Interests* . The Obligations of the Borrower shall rank *pari passu* with any other senior Indebtedness or securities of the Borrower and shall constitute senior indebtedness of the Borrower under and as defined in any documentation documenting any junior indebtedness of the Borrower. Each Security Document delivered pursuant to Sections 4.01 and 5.10 will, upon execution and delivery thereof, be effective to create in favor of the Collateral Agent, for the benefit of the Secured Parties, a legal, valid and enforceable security interest in the Collateral described therein. When financing statements and other filings specified therein in appropriate form are filed in the offices specified therein, Control Agreements are entered into covering each Depositary Account and the Pledged Collateral that is certificated is delivered to the Collateral Agent, the Liens created by the Security Documents on such Collateral shall constitute fully perfected Liens on, and security interests in, all right, title and interest of the Loan Parties in such Collateral, in each case prior and superior in right to any other Person, subject, in the case of Collateral other than Pledged Collateral, to Prior Liens, and in the case of Pledged Collateral, to Liens arising (and that have priority) by operation of law.

Section 3.19 *Material Project Level Agreements* . As of the Closing Date, each of the Material Project Level Agreements is in full force and effect and constitutes the legal, valid and binding obligation of the Project Entities party thereto. The Borrower has delivered to the Administrative Agent a complete and correct copy of each Material Project Level Agreement in effect on the Closing Date. To the knowledge of the Borrower, (a) no "Default" or "Event of Default" or similar term (as used in the applicable Project Level Financing Documents or Material Other Indebtedness Documents, as applicable) has occurred and is continuing under any of the Project Level Financing Documents or Material Other Indebtedness Documents and (b) no "Default" or "Event of Default" or equivalent event or circumstance defined by a similar term (as used in the Major Revenue Contracts) has occurred and is continuing under any of the Major Revenue Contracts other than, in the case of this clause (b) , any such Default or Event of Default or equivalent event or circumstance which would not reasonably be expected to give rise to a termination of such agreement or otherwise have, individually or in the aggregate, be materially adverse to the Lenders.

Section 3.20 *Insurance.* The Loan Parties have purchased or provided (or caused to be purchased or provided) and are maintaining (or causing to be maintained), with financially sound and reputable insurance companies, insurance with respect to their respective properties and business against such risks (including with such deductibles, retentions and exclusions), including fire and other risks insured against by extended coverage, and loss or damage, in each case of the kinds customarily insured against by projects of a similar size in the same or similar business, and of such types and in such amounts as are customarily carried under similar circumstances by such other Persons and in accordance in all material respects with their respective applicable contractual obligations. As of the Closing Date, such insurance is in full force and effect. The Project Entities are in compliance with the covenants relating to maintenance of insurance set forth in the Project Level Financing Documents to which they are a party (or by which they are bound). Holding and the Borrower believe that the insurance maintained by or on behalf of them and their Subsidiaries is adequate.

Article IV.
CONDITIONS TO FUNDING

Section 4.01 *Closing Date* . The obligations of the Lenders to make Loans on the Closing Date are subject to the satisfaction of the following conditions:

(a) The Administrative Agent shall have received a Borrowing Request from the Borrower as required by Section 2.03 .

(b) The representations and warranties set forth in Article III hereof and in the other Loan Documents shall be true and correct in all material respects on and as of the Closing Date with the same effect as though made on and as of such date, except to the extent such representations and warranties expressly relate to an earlier date (in which case such representations and warranties shall be true and correct in all material respects as of such earlier date); *provided* , that, in each case, such materiality qualifier shall not be applicable to any representations and warranties that are already qualified or modified by "materiality," "Material Adverse Effect" or similar language in the text thereof.

(c) At the time of and immediately after giving effect to the Transactions and the other transactions contemplated hereby to occur on the Closing Date, no Event of Default or Default shall have occurred and be continuing.

(d) The Administrative Agent (or its counsel) shall have received (i) from each party hereto either (a) a counterpart of this Agreement signed on behalf of such party or (b) written evidence satisfactory to the Administrative Agent (which may include telecopy transmission, or electronic transmission of a PDF copy, of a signed signature page of this Agreement) that such party has signed a counterpart of this Agreement and (ii) a Note, signed by the Borrower, in favor of each Lender that has requested such a Note in writing not less than three (3) Business Days prior to the Closing Date pursuant to Section 2.07(d) .

(e) The Administrative Agent shall have received, on behalf of itself, the Collateral Agent, and the Lenders, a favorable written opinion of DLA Piper LLP, special counsel for the Loan Parties (A) dated the Closing Date, (B) addressed to the Administrative Agent, the Collateral Agent, the Depositary Bank and the Lenders and (C) in form and substance reasonably satisfactory to the Administrative Agent and covering such matters relating to the Loan Documents as are usual and customary for a financing of the type contemplated hereby as the Administrative Agent shall reasonably request, and each Loan Party hereby instructs its counsel to deliver such opinions.

(f) The Administrative Agent shall have received each of the following:

(i) a copy of the certificate or articles of incorporation, partnership agreement or limited liability agreement, including all amendments thereto, or other relevant constitutional documents under applicable law of each Loan Party and the Sponsor, each certified as of a recent date by the Secretary of State (or other similar official) of the state of such Person's organization and a certificate as to the good standing of each such Loan Party and the Sponsor as of a recent date from such Secretary of State (or other similar official); and

(ii) a certificate of the Secretary, Assistant Secretary, Director, Vice President, President or similar officer, or the general partner, managing member or sole member, of each Loan Party and, if applicable, the Sponsor, in each case dated the Closing Date and certifying:

(A) that attached thereto is a true and complete copy of the by-laws (or partnership agreement, memorandum and articles of association, limited liability company agreement or other equivalent governing documents) of such Person as in effect on the Closing Date and at all times since a date prior to the date of the resolutions described in clause (B) below,

(B) that attached thereto is a true and complete copy of resolutions duly adopted by the board of directors (or equivalent governing body) of such Person (or its managing general partner or managing member) authorizing the execution, delivery and performance of the Loan Documents to which such Person is a party or, if applicable, in the case of the Sponsor, any Sponsor Guaranty to which the Sponsor is a party, and, in the case of the Borrower, the Borrowings hereunder, and that such resolutions have not been modified, rescinded or amended and are in full force and effect on the Closing Date,

(C) that the certificate or articles of incorporation, partnership agreement or limited liability agreement of such Person has not been amended since the date of the last amendment thereto disclosed pursuant to clause (A) above, and

(D) as to the incumbency and specimen signature of each officer or director executing any Loan Document or any other document delivered in connection herewith on behalf of such Loan Party or, if applicable, in the case of the Sponsor, executing any Sponsor Guaranty to which the Sponsor is a party.

(g) The Collateral and Guarantee Requirement with respect to items expressly required to be completed as of the Closing Date shall have been satisfied or waived and the Administrative Agent shall have received the results of a search of the UCC (or equivalent under other similar law) filings made with respect to the Loan Parties in the relevant jurisdictions and copies of the financing statements (or similar documents) disclosed by such search and evidence reasonably satisfactory to the Administrative Agent that the Liens indicated by such financing statements (or similar documents) are permitted by Section 6.02 or have been released.

(h) The Transactions shall have been consummated or shall be consummated simultaneously with or immediately following the closing on the Closing Date.

(i) The Administrative Agent shall have received the financial statements referred to in Section 3.05 . The Administrative Agent shall have received a budget of the Borrower in effect for the period commencing on the Closing Date through December 31, 2018 and the Projections, in each case in form and substance reasonably satisfactory to the Administrative Agent.

(j) Immediately after giving effect to the Transactions and the other transactions contemplated hereby to occur on the Closing Date, the Loan Parties shall have outstanding no Indebtedness other than (i) the Indebtedness outstanding under this Agreement and (ii) other Indebtedness permitted pursuant to Section 6.01 .

(k) The Lenders shall have received a solvency certificate substantially in the form of Exhibit F and signed by a Financial Officer of the Borrower confirming the Solvency of the Loan Parties, on a consolidated basis with their Subsidiaries, after giving effect to the Transactions.

(l) Since December 31, 2016, there have been no events, changes or other occurrences that have had, continue to have or would reasonably be expected to have, individually or in the aggregate, a Material Adverse Effect.

(m) The Agents shall have received, all Fees payable thereto or to any Lender or to the Lead Arranger on or prior to the Closing Date and, to the extent invoiced at least four (4) Business Days prior to the Closing Date, all other amounts due and payable pursuant to the Loan Documents on or prior to the Closing Date, including reimbursement or payment of all reasonable out-of-pocket expenses required to be reimbursed or paid by the Loan Parties hereunder or under any Loan Document (it being understood that amounts under this paragraph (m) may be paid with proceeds of the Loans).

(n) The Administrative Agent shall have received a certificate signed by a Responsible Officer of the Borrower dated as of the Closing Date as to the matters set forth in clauses (b) , (c) , (j) and (l) of this Section 4.01 .

(o) The Administrative Agent shall have received, at least three (3) Business Days prior to the Closing Date, all documentation and other information required by regulatory authorities with respect to the Loan Parties under applicable "know your customer" and anti-money laundering rules and regulations, including the U.S.A. PATRIOT Act, that has been reasonably requested by the Administrative Agent or any other Agent or Lender.

(p) The Administrative Agent shall have received evidence of the establishment of each of the Depositary Accounts required to be established pursuant to Section 2.19(a) with the Depositary Bank. To the extent any Local Accounts have been established as of the Closing Date, the Administrative Agent shall have received Local Account Control Agreements executed by the Borrower or applicable Project Holdco, the Collateral Agent and the applicable account bank for each such Local Account.

(q) Substantially simultaneously with the funding of Loans hereunder, (i) the DSR Requirement Amount as of the Closing Date shall have been Fully Funded into the Debt Service Reserve Account and (ii) the Liquidity Reserve Account (collectively with any Local Accounts) shall have been funded or credited in an amount equal to the Liquidity Reserve Maximum Balance.

(r) The Administrative Agent shall have received (i) a report entitled "Independent Engineer's Report Nymeria" dated November 6, 2017, delivered by Leidos Engineering, LLC with respect to the Projects respectively owned by the AVSR Entities, Sacramento PV Energy, LLC and Constellation Solar Horizons, LLC, including all exhibits, appendices and any other attachments thereto, in form and substance reasonably satisfactory to the Administrative Agent, (ii) a report entitled "EGR IV Portfolio Technical Due Diligence Report Exelon Wind, LLC" dated November 2, 2017, delivered by DNV KEMA Renewables, Inc. with respect to the Projects owned by Subsidiaries of ExGen Renewables JV (excluding the Projects owned by Sacramento PV Energy, LLC, Constellation Solar Horizons, LLC, Denver Airport Solar, LLC and Constellation Solar New Jersey III, LLC), including all exhibits, appendices and any other attachments thereto, in form and substance reasonably satisfactory to the Administrative Agent, (iii) a report entitled "SolGen Solar DG Portfolio Independent Engineer's Report" dated August 5, 2016, delivered by Luminate, LLC with respect to the solar power Projects owned by the SolGen Entities identified therein, including all exhibits, appendices and any other attachments thereto, in form and substance reasonably satisfactory to the Administrative Agent and (iv) a report entitled "Albany Green Energy Independent Engineer's Report Project No. 98536" dated October 5, 2017, delivered by Burns & McDonnell Engineering Company, Inc. with respect to the Project owned by the Albany Green Entities, including all exhibits, appendices and any other attachments thereto, in form and substance reasonably satisfactory to the Administrative Agent, together in each case with a reliance letter in form and substance reasonably satisfactory to the Administrative Agent.

Article V.
AFFIRMATIVE COVENANTS

Each of Holding and the Borrower covenants and agrees with each Agent and each Lender that so long as this Agreement shall remain in effect and until the Discharge of the Obligations, unless the Required Lenders shall otherwise consent in writing, Holding and the Borrower shall:

Section 5.01 *Existence; Businesses and Properties* .

(a) Do or cause to be done all things necessary to preserve, renew and keep in full force and effect its legal existence.

(b) Do or cause to be done all things necessary to (i) in the Borrower's reasonable business judgment, obtain, preserve, renew, extend and keep in full force and effect the permits, franchises,

authorizations, patents, trademarks, service marks, trade names, copyrights, licenses and rights with respect thereto necessary to the normal conduct of its business, (ii) comply in all material respects with all material applicable laws, rules, regulations and judgments, writs, injunctions, decrees, permits, licenses, and orders of any Governmental Authority, whether now in effect or hereafter enacted and (iii) at all times maintain and preserve all property necessary to the normal conduct of its business and keep such property in good repair, working order and condition and from time to time make, or cause to be made, all needful and proper repairs, renewals, additions, improvements and replacements thereto necessary in order that the business carried on in connection therewith, if any, may be properly conducted at all times (in each case except as expressly permitted by this Agreement); in each case in this paragraph (b) except where the failure to do so would not reasonably be expected to have a Material Adverse Effect.

Section 5.02 *Insurance* . Keep, and cause its Subsidiaries to keep, its insurable properties insured at all times by financially sound and reputable insurers in such amounts as shall be customary for similar businesses and maintain such other reasonable insurance (including, to the extent consistent with past practices, self-insurance), of such types, to such extent and against such risks, as is customary with companies in the same or similar businesses and maintain such other insurance as may be required by applicable law.

Section 5.03 *Taxes; Payment of Obligations* .

(a) Pay and discharge promptly when due all material Taxes imposed upon it before the same shall become delinquent or in default, as well as all material lawful claims for labor, materials and supplies or otherwise that, if unpaid, might give rise to a Lien upon such properties or any part thereof; *provided* , *however* , that such payment and discharge shall not be required with respect to any such Tax or claim to the extent (i) the validity or amount thereof shall be contested in good faith by appropriate proceedings and the applicable Loan Party shall have set aside on its books reserves in accordance with GAAP with respect thereto or (ii) the aggregate amount of such Taxes or claims does not exceed U.S. $1.0 million.

(b) Pay, discharge or otherwise satisfy at maturity or before they become delinquent, as the case may be, all its material obligations of whatever nature, except where (i) the amount or validity thereof is currently being contested in good faith by appropriate proceedings and reserves in conformity with GAAP with respect thereto have been provided on the books of the relevant Loan Party or (ii) the failure to pay, discharge or otherwise satisfy such obligation would not reasonably be expected to have a Material Adverse Effect.

Section 5.04 *Financial Statements, Reports, Etc.* Furnish to the Administrative Agent (which will promptly furnish such information to the Lenders):

(a) no later than one hundred and fifty (150) days after the end of each fiscal year starting with the fiscal year ended December 31, 2017, consolidated balance sheets and related statements of operations, cash flows and owners' equity showing the financial position of the Borrower and its consolidated Subsidiaries as of the close of such fiscal year and the consolidated results of their operations during such year and (other than with respect to those for the fiscal years ending on December 31, 2017 and December 31, 2018) setting forth in comparative form the corresponding figures (if any) for the prior fiscal year, all (other than those for the fiscal year ending on December 31, 2017) audited by independent accountants of recognized national standing reasonably acceptable to the Administrative Agent and accompanied by an opinion of such accountants (which shall not be qualified in any material respect) to the effect that such consolidated financial statements fairly present, in all material respects, the financial position and results of operations of the Borrower and its Subsidiaries on a consolidated basis in accordance with GAAP;

(b) no later than seventy five (75) days after the end of each of the first three (3) fiscal quarters of each fiscal year, starting with the fiscal quarter ended March 31, 2018, consolidated balance sheets and related statements of operations and cash flows showing the financial position of the Borrower and its consolidated Subsidiaries as of the close of such fiscal quarter and the consolidated results of their operations during such fiscal quarter and the then-elapsed portion of the fiscal year and (other than with respect to those for the fiscal quarters ending during the 2018 fiscal year) setting forth in comparative form the corresponding figures (if any) for the corresponding periods of the prior fiscal year, all certified by a Financial Officer of the Borrower, on behalf of the Borrower, as fairly presenting, in all material respects, the financial position and results of operations of the Borrower and its Subsidiaries on a consolidated basis in accordance with GAAP (subject to normal year-end audit adjustments and the absence of footnotes);

(c) no later than two (2) Business Days after each Quarterly Date, with respect to the Test Quarter then ended on such Quarterly Date, a certificate of a Financial Officer of the Borrower in substantially the form of Exhibit G-2 or such other form as shall be approved by the Administrative Agent, (i) certifying that no Event of Default or Default has occurred and is continuing or, if such an Event of Default or Default has occurred and is continuing, specifying the nature and extent thereof and any corrective action taken or proposed to be taken with respect thereto, (ii) setting forth a computation of Available Cash for such Test Quarter in detail reasonably satisfactory to the Administrative Agent, (iii) providing evidence of the current balances in the Depositary Accounts (it being agreed that a screenshot of such balances as of such date or other similar statement from the Depositary Bank shall satisfy this clause (iii)) and (iv) setting forth a computation of the Financial Performance Covenant for such Test Quarter in detail reasonably satisfactory to the Administrative Agent;

(d) (i) no later than five (5) Business Days after delivery thereof pursuant to any Project Level Financing Document, any audited annual financial statements of ExGen Renewables JV, Renewable Power Generation, LLC, Continental Wind, LLC, SolGen, LLC and AV Solar Ranch 1, LLC delivered to the agents, lenders or investors party thereto; (ii) no later than five (5) Business Days after delivery thereof pursuant to any Project Level Financing Document, unaudited quarterly financial statements of ExGen Renewables JV, Renewable Power Generation, LLC, Continental Wind, LLC, SolGen, LLC and AV Solar Ranch 1, LLC delivered to the agents, lenders or investors party thereto; and (iii) no later than five (5) Business Days after delivery thereof pursuant to any Project Level Financing Document, an officer's certificate required thereunder relating to the satisfaction of distribution conditions and including calculations of any ratio tests required to be submitted with any such certificate pursuant to the terms of the applicable Project Level Financing Document;

(e) no later than two (2) Business Days after each Excess Cash Flow Period, the Borrower will deliver to the Administrative Agent a certificate signed by a Financial Officer of the Borrower setting forth the amount, if any, of Excess Cash Flow for such Excess Cash Flow Period and the calculation thereof in reasonable detail, including the proposed allocation of such Excess Cash Flow pursuant to Section 2.19(c)(vii) , in substantially the form of Exhibit G-1 or such other form as shall be approved by the Administrative Agent (which certificate shall serve as notice of prepayment pursuant to Section 2.08(d));

(f) promptly, from time to time, (i) copies of any original statement for the Local Accounts provided to the Borrower by the applicable depositary bank and (ii) such other information regarding the operations, business affairs and financial condition of any Loan Party or any Subsidiary of any Loan Party, or compliance with the terms of any Loan Document, as in each case the Administrative Agent may reasonably request (for itself or on behalf of any Lender);

(g) (i) promptly (but in any event no later than five (5) Business Days) after consummation of the AG Disposition to a Person other than ExGen Renewables JV, certified copies of any Organization Documents and any other joint venture or similar agreements entered into in connection with such AG Disposition of any Additional Albany Green Entities and (ii) promptly upon receipt thereof, a copy of any "Interest Notice" (as defined in the Credit Support Reimbursement Agreement);

(h) after the execution and delivery of any material amendment, modification, extension, assignment, variance or waiver of timely compliance of any terms or conditions of any Material Project Level Agreement or Organizational Documents of any Subsidiary of the Borrower or any new Material Project Level Agreement, the Borrower shall promptly furnish the Administrative Agent certified copies of such amendment, modification, extension, assignment, variance or waiver or new Material Project Level Agreement; and

(i) on the Closing Date and no later than one hundred and fifty (150) days following the first day of each fiscal year of the Borrower, a budget (which budgets may be prepared on a cash basis) for the Loan Parties for such fiscal year setting forth (i) the projected Available Cash to be received by the Borrower or Holding during such fiscal year and (ii) the projected Operating Expenses of the Loan Parties during such fiscal year, together with (except in the case of the budget for the Closing Date) a comparison of the prior fiscal year's budget to actual results, accompanied by a certificate of a Responsible Officer of the Borrower certifying to the knowledge of the person signatory thereto that such budget is accurate and complete in all material respects based upon the Borrower's good faith reasonable estimates of information contained therein.

Section 5.05 *Litigation and Other Notices* . Furnish to the Administrative Agent written notice of the following promptly after any Responsible Officer of any of the Loan Parties obtains actual knowledge thereof:

(a) (i) any Event of Default or Default, (ii) any "Event of Default" or "Default" (or similar event or circumstance) under any Project Level Financing Document and (iii) any material breach or default under a Major Revenue Contract which breach or default permits or would permit (with the passage of time and/or giving of notice or otherwise) the termination of such Major Revenue Contract by any party thereto, in each case specifying the nature and extent thereof and the corrective action (if any) proposed to be taken with respect thereto;

(b) the filing or commencement of, or any written threat or written notice of intention of any Person to file or commence, any action, suit or proceeding, whether at law or in equity or by or before any Governmental Authority or in arbitration, against any Loan Party or any of their respective Subsidiaries which would reasonably be expected to have a Material Adverse Effect;

(c) the occurrence of an event requiring a mandatory prepayment of the Loans hereunder (other than with Excess Cash Flow);

(d) any event specific to any of the Loan Parties, their respective Subsidiaries or the Projects that has had, or would reasonably be expected to have, a Material Adverse Effect;

(e) if at any time any of the events listed in clauses (i) through (xi) of Section 7.1(k) is reasonably likely to occur and would reasonably be expected to have a Material Adverse Effect, a written notice thereof, which notice shall state that it is an "ERISA Notice" for purposes of the Loan Documents;

(f) at any time following delivery by any Loan Party of an ERISA Notice, within ten (10) Business Days after becoming aware of any of the following, a written notice setting forth the nature thereof and the action, if any, that such Loan Party proposes to take with respect thereto:

(i) with respect to any Plan, any "reportable event," as defined in Section 4043 of ERISA and the regulations thereunder, for which notice thereof has not been waived pursuant to such regulations as in effect on the date hereof;

(ii) the taking by the PBGC of steps to institute, or the threatening by the PBGC of the institution of, proceedings under Section 4042 of ERISA for the termination of, or the appointment

of a trustee to administer, any Plan, or the receipt by any Company Entity of a notice from a Multiemployer Plan that such events have, or are reasonably expected to, taken place; or

(iii) any event (including an ERISA Event), transaction or condition that could result in the incurrence of any liability by any Company Entity pursuant to Title I or IV of ERISA or the penalty or excise tax provisions of the Code relating to employee benefit plans, or in the imposition of any Lien on any of the rights, properties or assets of any Company Entity pursuant to Title I or IV of ERISA or such penalty or excise tax provisions, if such liability or Lien, taken together with any other such liabilities or Liens then existing, would reasonably be expected to have a Material Adverse Effect; and

(g) the occurrence of (A) an "Event of Default" (as defined in the Credit Support Reimbursement Agreement), (B) the issuance of "Additional Credit Support" or extension of any existing "Credit Support" (each as defined in the Credit Support Reimbursement Agreement) pursuant to section 2.1 of the Credit Support Reimbursement Agreement or (C) any other material event or notification under the Credit Support Reimbursement Agreement.

Section 5.06 *Compliance with Laws* . Comply with all laws, rules, regulations and orders of any Governmental Authority applicable to it or its property (owned or leased) (including ERISA), except where the failure to do so, individually or in the aggregate, would not reasonably be expected to result in a Material Adverse Effect. The Loan Parties will maintain in effect and enforce policies and procedures reasonably designed to ensure compliance by the Loan Parties, the Loan Parties' Affiliates and their respective directors, officers, employees and agents with Anti-Terrorism Laws, Anti-Corruption Laws and Sanctions.

Section 5.07 *Maintaining Records; Access to Properties and Inspections* . Maintain all financial records in accordance with GAAP and, subject to the provisions of Section 9.16 , permit any Persons designated by the Administrative Agent or, upon the occurrence and during the continuance of an Event of Default, any Lender to visit and inspect the financial records and the properties of any of the Loan Parties at reasonable times, upon reasonable prior notice to the Borrower, and as often as reasonably requested and to make extracts from and copies of such financial records, and permit any Persons designated by the Administrative Agent or, upon the occurrence and during the continuance of an Event of Default, any Lender upon reasonable prior notice to the Borrower to discuss the affairs, finances and condition of any Loan Party with the officers thereof, or the general partner, managing member or sole member thereof, and independent accountants therefor (subject to reasonable requirements of confidentiality, including requirements imposed by law or by contract); *provided* that, during any calendar year absent the occurrence and continuation of an Event of Default, only one (1) such visit may be made by the Administrative Agent and shall be at the Borrower's expense; *provided* , *further* , that during the continuance of an Event of Default, the Administrative Agent or any Lender may do any of the foregoing at the expense of the Borrower.

Section 5.08 *Use of Proceeds* . Use the proceeds of the Loans solely for the purposes described in Section 3.11 . The Loan Parties will not request any borrowing or other extension of credit, and the Loan Parties shall not use, directly or indirectly, and shall not lend, contribute or otherwise make available the proceeds of any borrowing or other extension of credit to any subsidiary, joint venture partner or other Person (A) in furtherance of an offer, payment, promise to pay or authorization of the payment or giving of money, or anything else of value, to any Person in violation of any Anti-Terrorism Laws or Anti-Corruption Laws, (B) to fund, finance or facilitate any activities, business or transaction of or with any Sanctioned Person, or in any Sanctioned Country or (C) in any manner that would result in the violation of any Sanctions by any Person.

Section 5.09 *Compliance with Environmental Laws* . Comply, and make commercially reasonable efforts to cause all lessees and other Persons occupying its properties to comply, with all Environmental Laws applicable to its business, operations and properties; obtain and maintain in full force and effect all material authorizations, registrations, licenses and permits required pursuant to Environmental Law for its business, operations and properties; and perform any investigation, remedial action or cleanup required

pursuant to the Release of any Hazardous Materials as required pursuant to Environmental Laws, except, in each case with respect to this Section 5.09 , to the extent the failure to do so would not reasonably be expected to have, individually or in the aggregate, a Material Adverse Effect.

Section 5.10 *Further Assurances* .

(a) Execute any and all further documents, financing statements, agreements and instruments, and take all such further actions (including the filing and recording of financing statements, fixture filings, and other documents and recordings of Liens in stock registries or land title registries, as applicable), that may be required under any applicable law, or that the Administrative Agent may reasonably request, to cause the Collateral and Guarantee Requirement to be and remain satisfied, all at the expense of the Loan Parties, and provide to the Administrative Agent, from time to time upon reasonable request evidence reasonably satisfactory to the Administrative Agent as to the perfection and priority of the Liens created or intended to be created by the Security Documents.

(b) Promptly notify the Administrative Agent if any material portion of the Collateral is damaged or destroyed.

(c) Cause the Collateral and Guarantee Requirement to be and remain satisfied in accordance with the terms of the Security Documents.

Section 5.11 *Credit Ratings* . Use commercially reasonable efforts to obtain and to cause a public credit rating by S&P and by Moody's to be maintained with respect to the Term Loan Facility; *provided* , that nothing in this Section 5.11 shall require the maintenance of any minimum ratings by either S&P or Moody's.

Section 5.12 *Interest Rate Protection* . With respect to the Borrower, (a) no later than sixty (60) days following the Closing Date obtain, and at all times thereafter until at least the fourth (4 th) anniversary of the date such Swap Agreement or Swap Agreements were entered into, cause to be maintained protection against fluctuations in interest rates pursuant to one or more Swap Agreements (" **Interest Rate Swap Agreements** ") with Specified Swap Counterparties, covering a notional amount of not less than 50.0% but not more than 105.0% of the reasonably anticipated outstanding principal amount of the Term Loans (such amount to be reasonably determined by the Borrower in good faith and to reflect the projected Excess Cash Flow prepayments pursuant to Section 2.09(c) during such period, as based upon the Base Case Model); *provided* that if at any time such Interest Rate Swap Agreements cover more than 105% of a notional amount of the outstanding principal amount of the Term Loans, the Borrower shall be required to cure such over-hedged position within 30 days so that no more than 105% of the outstanding principal amount of the Term Loans shall be subject to such Interest Rate Swap Agreements (after giving effect to such cure). Upon entering into any Interest Rate Swap Agreement (including any confirmation under any master agreement), the Borrower shall provide a copy thereof to the Administrative Agent.

Section 5.13 *Accounts* . At all times maintain the Depositary Accounts with the Depositary Bank and cause all Available Cash and other amounts referred to in Section 2.19(b) as and when received to be deposited into the Revenue Account in accordance with Section 2.19(b) (or in the case of Equity Proceeds, Completion Proceeds and (as applicable) Excess Project Disposition Proceeds in the Equity Proceeds Account to the extent permitted under Section 2.19(b)) and any amounts if and when withdrawn from the Depositary Accounts to be disbursed in accordance with Section 2.19 , and maintain any Local Accounts subject to Local Account Control Agreements.

Section 5.14 *Existence of the Project Entities; Operation and Maintenance.* (a) Except to the extent that failure to maintain such existence or rights or privileges could not reasonably be expected to have, individually or in the aggregate, a Material Adverse Effect, do or cause to be done all things necessary to preserve, renew and keep in full force and effect the legal existence of each of its Subsidiaries and (b) cause the Project Entities to operate and maintain each Project in accordance with (x) in the case of the Continental Wind Entities, Section 5.4 of the Continental Wind Credit Agreement or (y) in the case of any

other Project Entities, the corresponding affirmative covenant with respect to "Conduct of Business, Maintenance or Properties, Etc." included in the Project Level Financing Documents to which they are a party (or by which they are bound), if any.

Section 5.15 *Subsidiary Distributions* . Subject to compliance with (i) the respective Organizational Documents of each Project Entity and (ii) the Material Project Level Agreements, cause all amounts that could be distributed to the Borrower and constitute Available Cash to be distributed by the Project Entities to the Borrower (no less frequently than quarterly).

Article VI.
NEGATIVE COVENANTS

Each of Holding and the Borrower covenant and agree with each Agent and each Lender that so long as this Agreement shall remain in effect and until the Discharge of the Obligations, unless the Required Lenders shall otherwise consent in writing, Holding and the Borrower shall not, and in the case of Sections 6.01 , 6.02 , 6.05 , 6.09 and 6.13 , shall not cause or permit any Project Entity to:

Section 6.01 *Indebtedness* . Incur, create, assume or permit to exist any Indebtedness or issue any Disqualified Equity Interests, except:

(a) Indebtedness created hereunder and under the other Loan Documents and all Guaranties thereof;

(b) Indebtedness of the Loan Parties pursuant to Swap Agreements permitted by Section 6.12 ;

(c) Indebtedness in respect of appeal or performance bonds and similar obligations, in each case provided in the ordinary course of business, including those incurred to secure health, safety and environmental obligations in the ordinary course of business;

(d) Indebtedness arising from the honoring by a bank or other financial institution of a check, draft or similar instrument drawn against insufficient funds in the ordinary course of business or other cash management services in the ordinary course of business; *provided* that (x) such Indebtedness (other than credit or purchase cards) is extinguished within five (5) Business Days of its incurrence and (y) such Indebtedness in respect of credit or purchase cards is extinguished within sixty (60) days from its incurrence;

(e) Guarantees by any Loan Party of any Indebtedness of any other Loan Party expressly permitted to be incurred under this Section 6.01 ;

(f) all premium (if any), interest (including post-petition interest), fees, expenses, charges and additional or contingent interest on obligations described in clauses (a) through (e) above;

(g) unsecured Credit Support Reimbursement Obligations, in an aggregate principal amount outstanding under this clause (g) (with any Credit Support being deemed to have an amount equal to the maximum potential liability of the Borrower or any other Loan Party thereunder) not to exceed $[***]; and

(h) (x) in the case of the Project Entities, Project Level Indebtedness and (y)(i) in the case of the Continental Wind Entities, additional Indebtedness incurred by any Continental Wind Entity to the extent permitted under both the Continental Wind Financing Documents and the ExGen Renewables JV Agreements; (ii) in the case of the RPG Entities, additional Indebtedness incurred by any RPG Entity to the extent permitted under both the RPG Financing Documents and the ExGen Renewables JV

Agreements; (iii) in the case of the Other JV Entities, additional Indebtedness incurred by any Other JV Entity to the extent permitted under the ExGen Renewables JV Agreements (and, in the case of the Echo Entities, the Echo LLC Agreements); (iv) in the case of the Bluestem Entities, additional Indebtedness incurred by any Bluestem Entity to the extent permitted under the ExGen Renewables JV Agreements and the Bluestem Financing Documents; (v) in the case of ExGen Renewables JV, additional Indebtedness incurred by it to the extent permitted under the ExGen Renewables JV Agreements; (vi) in the case of the SolGen Entities, additional Indebtedness incurred by any SolGen Entity to the extent permitted under the SolGen Financing Documents and, after the SolGen Disposition, if any, to the extent permitted under the ExGen Renewables JV Agreements, in each case as such documents and agreements are in effect on the date hereof; (vii) in the case of the AVSR Entities, additional Indebtedness incurred by any AVSR Entity to the extent permitted under the AVSR Financing Documents and, after the AVSR Disposition, if any, to the extent permitted under the ExGen Renewables JV Agreements, in each case as such documents and agreements are in effect on the date hereof and (viii) in the case of the Albany Green Entities, additional Indebtedness incurred by any Albany Green Entity to the extent permitted under the AG Financing Documents and, after the AG Disposition, if applicable in the case of an AG Disposition to ExGen Renewables JV, to the extent permitted under the ExGen Renewables JV Agreements, in each case as such documents and agreements are in effect on the date hereof.

Section 6.02 *Liens* . Create, incur, assume or permit to exist any Lien on any property or assets (including stock or other securities of any Person) at the time owned by it or on any income or revenues or rights in respect of any thereof, except (without duplication):

(a) Liens on property or assets of any Loan Party existing on the Closing Date and set forth on Schedule 6.02(a) ; *provided* that such Liens shall secure only those obligations that they secure on the Closing Date and shall not subsequently apply to any other property or assets of any Loan Party;

(b) any Lien created under the Loan Documents;

(c) Liens for Taxes, assessments, charges or levies not yet delinquent or that are being contested in accordance with Section 5.03 ;

(d) Liens securing judgments that do not constitute an Event of Default under Section 7.01(j) ;

(e) Liens that are contractual rights of set-off (i) relating to the establishment of depository relations with banks not given in connection with the issuance of Indebtedness or (ii) relating to pooled deposit or sweep accounts of any Loan Party to permit satisfaction of overdraft or similar obligations incurred in the ordinary course of business of such Loan Party;

(f) Liens arising solely by virtue of any statutory or common law provision relating to banker's liens, rights of set-off or similar rights;

(g) Liens arising from precautionary UCC financing statement filings regarding operating leases entered into by any Loan Party in the ordinary course of business;

(h) (i) in the case of the Continental Wind Entities, Liens to the extent permitted under the both Continental Wind Financing Documents and the ExGen Renewables JV Agreements; (ii) in the case of the RPG Entities, Liens to the extent permitted under both the RPG Financing Documents and the ExGen Renewables JV Agreements; (iii) in the case of the Other JV Entities, Liens to the extent permitted under the ExGen Renewables JV Agreements (and, in the case of the Echo Entities, the Echo LLC Agreements); (iv) in the case of the Bluestem Entities, Liens to the extent permitted under the ExGen Renewables JV Agreements and the Bluestem Financing Documents; (v) in the case of ExGen Renewables JV, Liens to the extent permitted under the ExGen Renewables JV Agreements; (vi) in the case of the SolGen Entities, Liens to the extent permitted under the SolGen Financing Documents and, after the SolGen Disposition, if any, to the extent permitted under the ExGen Renewables JV Agreements, in each case as such documents and agreements are in effect on the date hereof; (vii) in the case of the AVSR Entities, Liens to the extent permitted under the AVSR Financing Documents and, after the AVSR Disposition, if any, to the extent permitted under the ExGen Renewables JV Agreements, in each case as such documents and agreements are in effect on

the date hereof and (viii) in the case of the Albany Green Entities, Liens incurred by any Albany Green Entity to the extent permitted under the AG Financing Documents and, after the AG Disposition, if applicable in the case of an AG Disposition to ExGen Renewables JV, to the extent permitted under the ExGen Renewables JV Agreements, in each case as such documents and agreements are in effect on the date hereof;

(i) Lien imposed by law such as carriers', warehousemen's, mechanics', landlord's (or lessor's under operating leases), materialmen's, repairmen's, custom and revenue authorities', or other like Liens arising in the ordinary course of business and securing obligations that are not due and payable beyond the applicable grace period therefor or that are being contested in compliance with Section 5.03 ; and

(j) deposits to secure the performance of leases (other than Capital Lease Obligations), statutory obligations, liability to insurance carriers under insurance or self-insurance arrangements, surety and appeal bonds, performance bonds, statutory bankers' liens on moneys held in bank accounts and other obligations of a like nature, in each case incurred in the ordinary course of business.

Notwithstanding the foregoing, no Liens permitted pursuant to paragraphs (a), (e), (g), (h) or (j) of this Section shall be permitted to attach to any Pledged Collateral.

Section 6.03 *Sale and Lease-back Transactions* . Enter into any arrangement, directly or indirectly, with any Person whereby it shall sell or transfer any property, real or personal, used or useful in its business, whether now owned or hereafter acquired, and thereafter rent or lease such property or other property that it intends to use for substantially the same purpose or purposes as the property being sold or transferred (a " **Sale and Lease-Back Transaction** ").

Section 6.04 *Investments, Loans and Advances* . Purchase, hold or acquire (including pursuant to any merger or amalgamation with a Person) any Equity Interests, evidences of Indebtedness or other securities of, make or permit to exist any loans or advances (other than intercompany current liabilities incurred in the ordinary course of business in connection with the cash management operations of the Loan Parties, which cash management operations shall not extend to any other Person) to or Guarantees of the obligations of, or make or permit to exist any investment or any other interest in, any other Person (each, an " **Investment** "), except:

(a) Guarantees created under the Loan Documents;

(b) Investments (including Investments in Equity Interests and Guarantees of Indebtedness otherwise expressly permitted hereunder) by a Loan Party in another Loan Party, Equity Interests in Project Holdcos and, if applicable in the case of an AG Disposition to a Person other than ExGen Renewables JV, Equity Interests in any Additional Albany Green Entity;

(c) Cash and Cash Equivalents and Investments that were Cash and Cash Equivalents when made;

(d) Swap Agreements permitted under Section 6.12 ;

(e) Investments resulting from pledges and deposits referred to in Sections 6.02 and any exercise of the Cure Right;

(f) so long as no Event of Default shall have occurred and be continuing or would result therefrom, additional Investments (other than an Additional Project) in any Project Entity, if any, to the extent made with the proceeds of equity capital contributions (other than proceeds received as a result of the exercise of Cure Rights pursuant to Section 7.02) to Holding and on deposit in the Equity Proceeds Account;

(g) the loan to Peach Power, Inc. in the principal amount of $99,000,000 pursuant to that certain Purchase Money Loan Agreement, dated as of October 6, 2017, between the Borrower (as successor to

Constellation NewEnergy, Inc.) and Peach Power, Inc. (as in effect on the Closing Date) (the " **DCO Loan** "); and

(h) so long as no Event of Default shall have occurred and be continuing or would result therefrom, Permitted Acquisitions to the extent made with the proceeds of equity capital contributions (other than proceeds received as a result of the exercise of Cure Rights pursuant to Section 7.02) to Holding.

Section 6.05 *Mergers, Consolidations, Sales of Assets and Acquisitions* . Merge into, amalgamate with or consolidate with any other Person, or permit any other Person to merge into, amalgamate with or consolidate with it, or sell, transfer, lease or otherwise dispose of (in one transaction or in a series of transactions) all or any part of its assets (whether now owned or hereafter acquired) including Equity Interests held by it, or issue, sell, transfer or otherwise dispose of any Equity Interests of any Loan Party (other than Holding) or any Project Entity or purchase, lease or otherwise acquire (in one transaction or a series of transactions) all or any substantial part of the assets of any other Person, except that this Section 6.05 shall not prohibit:

(a) the disposition of Cash and Cash Equivalents in the ordinary course of business;

(b) Investments permitted by Section 6.04 , Liens permitted by Section 6.02 , Dividends described in Section 5.15 and Dividends permitted by Section 6.06 ;

(c) abandonment, cancellation or disposition of any intellectual property of any Loan Party in the ordinary course of business;

(d) issuances of Equity Interests (x) by (i) any Project Holdco to the Borrower, or (ii) the Borrower to Holding and (y) issuances of common Equity Interests by Holding (to the extent not constituting a Change in Control);

(e) (i) in the case of the Continental Wind Entities, mergers, amalgamations, consolidations and sales, transfers, leases or other dispositions of assets to the extent permitted pursuant to both the Continental Wind Financing Documents and the ExGen Renewables JV Agreements; (ii) in the case of the RPG Entities, mergers, amalgamations, consolidations and sales, transfers, leases or other dispositions of assets to the extent permitted pursuant to both the RPG Financing Documents and the ExGen Renewables JV Agreements; (iii) in the case of the Other JV Entities, mergers, amalgamations, consolidations and sales, transfers, leases or other dispositions of assets to the extent permitted pursuant to the ExGen Renewables JV Agreements (and, in the case of the Echo Entities, the Echo LLC Agreements); (iv) in the case of the Bluestem Entities, mergers, amalgamations, consolidations and sales, transfers, leases or other dispositions of assets to the extent permitted pursuant to the ExGen Renewables JV Agreements and the Bluestem Financing Documents; (v) in the case of the SolGen Entities, mergers, amalgamations, consolidations and sales, transfers, leases or other dispositions of assets to the extent permitted pursuant to the SolGen Financing Documents and, after the SolGen Disposition, if any, to the extent permitted under the ExGen Renewables JV Agreements; and (vi) in the case of the Albany Green Entities, mergers, amalgamations, consolidations and sales, transfers, leases or other dispositions of assets to the extent permitted pursuant to the AG Financing Documents and, if applicable in the case of an AG Disposition to ExGen Renewables JV, to the extent permitted under the ExGen Renewables JV Agreements, in each case as such documents and agreements are in effect on the date hereof; *provided* that, for the avoidance of doubt, (A) in no event shall any of the AVSR Entities (or any Equity Interests thereof) or the AV Solar Project be permitted to be sold, transferred, leased or otherwise disposed of except in connection with the AVSR Disposition; (B) in no event shall any JV Class A Membership Interests be permitted to be sold, transferred or otherwise disposed of by ExGen Renewables Holdings and (C) in no event shall any Albany Green Entity (or any Equity Interests thereof) or the Albany Green Project be permitted to be sold, transferred, leased or otherwise disposed except in connection with the AG Disposition;

(f) the sale or transfer of (x) up to all of the Equity Interests and Aggregate Interests in Albany Green Holdings held by the Borrower to ExGen Renewables JV or (y) up to 49.9% of the Aggregate Interests in Albany Green Holdings held by the Borrower to any other Person; *provided* that (i) no Default or Event of Default shall have occurred and be continuing or would result therefrom; (ii) if such sale or transfer is made to (A) ExGen Renewables JV, such sale or transfer is made in accordance with the ExGen Renewables JV Agreements or (B) any other Person, the Borrower shall continue to Control Albany Green Holdings, (iii) the Loan Parties shall have retained (directly or indirectly) greater than 50% of the Aggregate Interests with respect to Albany Green Holdings, (iv) in the case of a sale or transfer to a Person other than ExGen Renewables JV, the terms of such sale or transfer and any agreements relating thereto could not reasonably be expected to result in a material impairment of the Borrower's rights to receive distributions (including the timing and allocation thereof) from Albany Green Holdings or to have a material adverse effect on the Borrower's ability to repay the Loans, (v) the Net Proceeds payable in cash in respect of such sale or transfer shall not be less than the applicable Target Sale Prepayment Amount; and (vi) the Net Proceeds payable in connection with any such sale or transfer in an amount equal to the applicable Target Sale Prepayment Amount shall have been applied in accordance with Section 2.09(b) (such disposition, the " **AG Disposition** ");

(g) the sale or transfer of up to all of the Equity Interests in the AVSR Entities held by the Borrower to ExGen Renewables JV; *provided* that (i) no Default or Event of Default shall have occurred and be continuing or would result therefrom; (ii) such sale or transfer is made in accordance with the ExGen Renewables JV Agreements and the Loan Parties shall have retained (directly or indirectly) greater than 50% economic interest (in the aggregate) with respect to the AVSR Entities; (iii) the Net Proceeds payable in cash in respect of such sale or transfer shall not be less than the applicable Target Sale Prepayment Amount; and (iv) the Net Proceeds payable in connection with any such sale or transfer in an amount equal to the applicable Target Sale Prepayment Amount and Target Sale Additional Prepayment Amount, if applicable, shall have been applied in accordance with Section 2.09(b) (such disposition, the " **AVSR Disposition** "); and

(h) the sale or transfer of up to all of the Equity Interests in the SolGen Entities held by the Borrower to ExGen Renewables JV; *provided* that (i) no Default or Event of Default shall have occurred and be continuing or would result therefrom; (ii) such sale or transfer is made in accordance with the ExGen Renewables JV Agreements and the Loan Parties shall have retained (directly or indirectly) greater than 50% economic interest (in the aggregate) with respect to the SolGen Entities; (iii) the Net Proceeds payable in cash in respect of such sale or transfer shall not be less than the applicable Target Sale Prepayment Amount; and (iv) the Net Proceeds payable in connection with any such sale or transfer in an amount equal to the applicable Target Sale Prepayment Amount and Target Sale Additional Prepayment Amount, if applicable, shall have been applied in accordance with Section 2.09(b) (such disposition, the " **SolGen Disposition** ").

Section 6.06 *Dividends and Distributions* . Declare or pay, directly or indirectly, any dividend or make any other distribution (by reduction of capital or otherwise), whether in cash, property, securities or a combination thereof, with respect to any of its Equity Interests (other than dividends and distributions on Equity Interests payable solely by the issuance of additional shares of Equity Interests of the Person paying such dividends or distributions) or directly or indirectly redeem, purchase, retire or otherwise acquire for value (or permit any of its Subsidiaries to purchase or acquire) any shares of any class of its Equity Interests or set aside any amount for any such purpose (each, a " **Dividend** "); *provided* , *however* , that, notwithstanding the foregoing:

(a) Holding may make noncash repurchases, redemptions or exchanges of Equity Interests deemed to occur upon exercise of stock options or exchange of exchangeable shares if such Equity Interests represent a portion of the exercise price of such options;

(b) so long as no Event of Default shall have occurred and is continuing or would result therefrom, Holding and the Borrower may declare and pay Dividends in cash from Equity Proceeds on deposit in the Equity Proceeds Account;

(c) the Borrower and Holding shall be permitted to make distributions of the net cash proceeds of the Loans to the Sponsor and/or any of its Affiliates within five (5) Business Days following the Closing Date;

(d) the Borrower and Holding shall be permitted to make distributions of Completion Proceeds and Excess Project Disposition Proceeds; and

(e) the Borrower and Holding shall be permitted to make distributions of Excess Cash Flow as provided in Section 2.19(c)(viii) and other distributions as provided in Section 2.19(d)(iii)(B) and Section 2.19(e)(ii)(D) .

Section 6.07 *Transactions with Affiliates* .

(a) Sell or transfer any property or assets to, or purchase or acquire any property or assets from, or otherwise engage in any other transaction with, any of its Affiliates, unless such transaction, taken as a whole, is upon terms not materially less favorable to the applicable Loan Party than would be obtained in a comparable arm's-length transaction with a Person that is not an Affiliate.

(b) The foregoing paragraph (a) shall not prohibit, to the extent otherwise permitted under this Agreement:

(i) any issuance of securities, or other payments, awards or grants in cash, securities or otherwise pursuant to, or the funding of, employment arrangements, stock options, stock ownership plans, including restricted stock plans, stock grants, directed share programs and other equity based plans customarily maintained by similar companies and the granting and performance of registration rights approved by the board of directors (or equivalent governing body) of the Loan Parties;

(ii) transactions between or among the Loan Parties otherwise permitted by this Agreement;

(iii) any indemnification agreement or any similar arrangement entered into with members, directors, officers, consultants and employees of any of the Loan Parties in the ordinary course of business and the payment of fees and indemnities to directors, officers, consultants and employees of any of the Loan Parties in the ordinary course of business;

(iv) Investments otherwise permitted under Section 6.04(f) ;

(v) transactions pursuant to permitted agreements in existence on the Closing Date and set forth on Schedule 6.07(b) or any amendment thereto to the extent such amendment is not adverse to the Lenders in any material respect;

(vi) any employment agreement or employee benefit plan entered into by any of the Loan Parties in the ordinary course of business or consistent with past practice and payments pursuant thereto;

(vii) transactions otherwise permitted under Section 6.06 ; or

(viii) any purchase by the Sponsor or an Affiliate (other than a Loan Party or a Subsidiary of a Loan Party) of Equity Interests of Holding (to the extent not constituting a Change in Control).

Section 6.08 *Business of the Borrower and Holding* . Engage in any business or activity other than (a) in the case of Holding, the ownership of Equity Interests in the Borrower, and in the case of the Borrower, the ownership of Equity Interests in the Project Holdcos, (b) maintaining its legal existence, (c) participating in tax, accounting and other administrative and management activities for itself and as an entity that is part of a consolidated group of companies, (d) the execution and delivery of the Loan Documents to which it is a party and the performance of its obligations thereunder, (e) the execution and delivery of Swap Agreements permitted under Section 6.12 and the performance of its obligations thereunder, (f) the performance of its obligations under the Loan Documents (including those required by Article V) and its Organizational Documents; (g) activities incidental to the businesses or activities described in clauses (a) through (f) of this Section 6.08 and (h) any other transaction permitted by the Loan Documents to the extent incidental to the business or activities described in clauses (a) through (f) . In addition, the Loan Parties shall not acquire or hold any fee or leasehold interest in any real property.

Section 6.09 *Limitation on Modifications or Prepayments of Indebtedness; Modifications of Certificate of Incorporation, By-laws and Certain Other Agreements; Etc.*

(a) Amend, supplement, waive or modify, or permit the amendment, supplement, waiver or modification of, in any manner materially adverse to the Lenders, or grant any waiver or release under or terminate in any manner (if such granting or termination shall be materially adverse to the Lenders), the Organizational Documents of any Loan Party;

(b) Make, or agree or offer to pay or make, directly or indirectly, any payment or other distribution (whether in cash, securities or other property) of or in respect of principal of or interest on any Indebtedness (other than the Loans) of the Loan Parties or any payment or other distribution (whether in cash, securities or other property), including any sinking fund or similar deposit, on account of the purchase, redemption, retirement, acquisition, cancellation or termination of any Indebtedness of the Loan Parties, except for prepayments with the proceeds of Qualified Equity Interests of Holding issued for such purchase (other than proceeds from the exercise of the Cure Rights pursuant to Section 7.02);

(c) Enter into or permit any Subsidiary of the Borrower to enter into any agreement or instrument that by its terms restricts, (i) in the case of any such Subsidiary, the payment of dividends or distributions or the making of cash advances by such Subsidiary to the Borrower or any Subsidiary that is a direct or indirect parent of such Subsidiary or, (ii) in the case of the Loan Parties, the granting of Liens by the Loan Parties pursuant to the Security Documents, in each case, other than those arising under any Loan Document, except, in each case, restrictions existing by reason of:

(A) applicable law; or

(B) in the case of any Subsidiary (including the Project Entities), contractual encumbrances or restrictions in effect on the Closing Date in the Project Level Financing Documents.

(d) (i) Amend, supplement, waive or modify, or permit the amendment, supplement, waiver or modification of, the Organizational Documents of any of the Subsidiaries of the Borrower (including ExGen Renewables JV) in a manner that would delay or reduce in any material respect the amount, timing or allocation of dividends or distributions to a Loan Party, without the prior written consent of the Required Lenders, (ii) amend, supplement, waive or modify or permit the amendment, supplement, waiver or modification of, the Organizational Documents of ExGen Renewables JV that are in effect as of the date hereof in a manner that would (A) alter the ownership structure or relative rights with respect to Class A and Class B Membership Interests or (B) materially change the rights and responsibilities of the Managing Member or (iii) otherwise amend, supplement, waive or modify, or permit the amendment, supplement, waiver or modification of, the Organizational Documents of any of the Subsidiaries of the Borrower if, in the case of clauses (ii) or (iii) , such action could reasonably be expected to result in a

material impairment of Borrower's ability to prepay or repay the Loans or otherwise is in a manner materially adversely to the Lenders;

(e) (i) Amend, supplement, waive, rescind, terminate or otherwise modify, or permit the amendment, supplement, waiver, rescission, termination or modification of, (x) the conditions to dividends or other distributions (including satisfaction of any financial ratio tests with respect to such dividends or other distributions), or the timing, amount, allocation or other terms thereof, set forth in the Project Level Financing Documents or (y) the covenants limiting Indebtedness, Liens or mergers and sales or other dispositions of assets set forth in the Project Level Financing Documents, or (ii) otherwise amend, supplement, waive, rescind, terminate or otherwise modify, or permit the amendment, supplement, waiver, rescission, termination or modification of, any Project Level Financing Document, if in the case of this clause (ii), such action could reasonably be expected to result in a material impairment of Borrower's ability to prepay or repay the Loans or otherwise is in a manner materially adversely to the Lenders; or

(f) Amend, supplement or otherwise modify the Credit Support Reimbursement Agreement after the Closing Date in any manner that would accelerate the final maturity of, or increase the rate of interest on, any Credit Support Reimbursement Obligations.

Section 6.10 *Debt Service Coverage Ratio* . Beginning on November 30, 2018, for any Test Period, permit the Debt Service Coverage Ratio on each Quarterly Date to be [***].

Section 6.11 *Negative Pledge* . With respect to the Equity Interests of the Borrower or any Project Holdco, (i) create, incur, assume or permit to exist any Lien on such Equity Interests other than any Lien arising by operation of law or under the Security Documents, (ii) assign or sell any income or revenues in respect thereof other than in connection with a Dividend thereof permitted by Section 6.06 or (iii) file or permit the filing of any financing statement or other similar notice of any Lien with respect to such Equity Interests under the UCC or any state or under any similar recording or notice statute except any such financing statements or notices filed with respect to the Lien under the Security Documents.

Section 6.12 *Swap Agreements* . Enter into any Swap Agreement, other than the Swap Agreements required to be entered into pursuant to Section 5.12 .

Section 6.13 *Amendment of Major Revenue Contracts, Etc.* Cause or consent to or permit, any amendment, modification, extension, variance or waiver of timely compliance with any material terms or conditions of any Major Revenue Contract, or cause or consent to or permit any termination, cancellation, assignment or replacement (other than upon expiration in accordance with its terms) of any Major Revenue Contract unless such amendment, modification, extension, variance or waiver of timely compliance, termination, cancellation, assignment or replacement of any Major Revenue Contract is permitted pursuant to the terms of the applicable Project Level Financing Documents (without, for the avoidance of doubt, giving effect to any waiver of the terms thereof), as certified by a Responsible Officer of the Borrower.

Section 6.14 *Fiscal Year, Name, Location and EIN* . Change (a) its fiscal year end from December 31, or (b) its corporate or organization name, identity or organizational structure, jurisdiction of organization, federal employer identification number or other organization identification number or the location of its principal place of business, without, in the case of clause (b) , at least 10 days' prior written notice to the Administrative Agent and the Collateral Agent; *provided* that no Loan Party shall effect or permit any such change unless (x) all filings have been made, or will have been made within any statutory period, under the UCC or otherwise that are required in order for the Collateral Agent to continue at all times following such change to have a valid, legal and perfected security interest in all the Collateral for the benefit of the Secured Parties and (y) such change does not adversely affect the priority of the Collateral Agent's security interests.

Section 6.15 *No Subsidiaries or Joint Ventures* . Create, form or acquire any Subsidiary (other than the Project Entities, any Additional Project Entity and (if applicable) any Additional Albany Green Entities) or enter into any partnership or joint venture (other than any Permitted Acquisition or the exercise of any existing options set forth in the Organizational Documents of any Loan Party, Project Entity, Additional Project Entity or Additional Albany Green Entity as of the Closing Date to the extent, in each case, such a transaction

qualifies as a new partnership or joint venture or with respect to any Additional Albany Green Entities formed, if applicable, in the case of an AG Disposition to a Person other than ExGen Renewables JV).

Section 6.16 *Bank Accounts* . Maintain any bank account or similar account with any financial institution other than the Depositary Accounts and the Local Accounts.

Section 6.17 *Special Purpose Entity* . Fail to at all times (a) maintain entity records and books of account separate from those of any other entity (other than in the case of books and accounts, the other Loan Parties) which is an Affiliate of the Borrower or any Project Entity, (b) act solely in its name and through its duly authorized officers, managers, representatives or agents in the conduct of its businesses (it being understood that certain Affiliates will be providing services in accordance with certain Material Project Level Agreements), (c) conduct in all material respects its business solely in its own name, in a manner not misleading to other Persons as to its identity (without limiting the generality of the foregoing, all oral and written communications (if any), including invoices, purchase orders, and contracts), (d) comply in all material respects with the terms of its certificate of formation and limited liability company agreement (or similar constituent documents), (e) not commingle its funds or assets with those of any other entity (other than the other Loan Parties) which is an Affiliate of the Borrower or any Project Entity, and (f) comply with any provisions of its LLC Agreement intended to ensure that each of Holding and the Borrower are special purpose entities.

Article VII.
EVENTS OF DEFAULT

Section 7.01 *Events of Default* . In case of the happening of any of the following events (" **Events of Default** "):

(a) any representation or warranty made by any Loan Party in any Loan Document, or any representation, warranty or certification of any Loan Party contained in any report, certificate, financial statement or other instrument furnished in connection with or pursuant to any Loan Document, shall prove to have been false or misleading in any material respect when so made or furnished by such Loan Party; *provided* that such materiality qualifier shall not be applicable to any representation or warranty that is already qualified or modified by "materiality," "Material Adverse Effect" or similar language in the text thereof; and *provided, further,* that, in respect of any misrepresentation the impact of which is capable of being cured and the untruth of which would not reasonably be expected to result in a Material Adverse Effect, any such misrepresentation shall not be deemed to be an Event of Default if the impact of such misrepresentation is cured within thirty (30) days of the occurrence thereof;

(b) default shall be made in the payment of any principal of any Loan when and as the same shall become due and payable, whether at the due date thereof or at a date fixed for prepayment thereof or by acceleration thereof or otherwise;

(c) default shall be made in the payment of any interest on any Loan or in the payment of any Fee or any other amount (other than an amount referred to in paragraph (b) above) due under any Loan Document, when and as the same shall become due and payable, and such default shall continue unremedied for a period of three (3) Business Days;

(d) default shall be made in the due observance or performance by any Loan Party of any covenant, condition or agreement contained in Section 5.01(a) , Sections 5.04(a) , (b) , or (d) , Section 5.05(a)(i) , Section 5.08 or in Article VI ;

(e) default shall be made in the due observance or performance by any Loan Party of (i) the covenant contained in Section 6.10 and such default shall continue unremedied for the full ten (10) Business Day cure period following such Quarterly Date provided for exercise of the Cure Right in accordance with Section 7.02 or (ii) any covenant, condition or agreement of such Person contained in

any Loan Document (other than those specified in paragraphs (b) , (c) , (d) and (e)(i) above) and such default shall continue unremedied for a period of thirty (30) days after the earlier of (x) knowledge thereof by a Responsible Officer of any Loan Party and (y) written notice thereof from the Administrative Agent or any Lender to the Borrower;

(f) (i) any event or condition occurs that (x) results in any Material Indebtedness of any Loan Party becoming due prior to its scheduled maturity or (y) enables or permits (with all applicable grace periods having expired) the holder or holders of any Material Indebtedness of any Loan Party or any trustee or agent on its or their behalf to cause any such Material Indebtedness to become due, or to require the prepayment, repurchase, redemption or defeasance thereof, prior to its scheduled maturity, (ii) any event or condition occurs that results in any Material Indebtedness of any Project Entity becoming due prior to its scheduled maturity; (iii) any Project Entity shall fail to pay any amounts due and payable on any Material Indebtedness (with all applicable grace periods having expired) and such event of default has continued unremedied for an additional five (5) days after all such applicable grace periods have expired or (iv) an "Event of Default" occurs under the Credit Support Reimbursement Agreement; *provided* , that clauses (ii) , (iii) and (iv) shall not apply to the extent such event of default or acceleration is waived, rescinded or annulled in accordance with the terms of such Indebtedness or such Indebtedness is repaid prior to the exercise of remedies thereunder;

(g) there shall have occurred a Change in Control;

(h) an involuntary proceeding shall be commenced or an involuntary petition shall be filed in a court of competent jurisdiction seeking (i) relief in respect of any Loan Party or Material Project Subsidiary or of a substantial part of the property or assets of any Loan Party or Material Project Subsidiary under the Bankruptcy Code, or any other federal, state or foreign bankruptcy, insolvency, receivership or similar law, (ii) the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for a Loan Party or Material Project Subsidiary or for a substantial part of the property or assets of a Loan Party or Material Project Subsidiary, or (iii) the winding-up or liquidation of a Loan Party; and such proceeding or petition shall continue undismissed for sixty (60) days or an order or decree approving or ordering any of the foregoing shall be entered;

(i) any Loan Party or Material Project Subsidiary shall (i) voluntarily commence any proceeding or file any petition seeking relief under the Bankruptcy Code, as now constituted or hereafter amended, or any other federal, state or foreign bankruptcy, insolvency, receivership or similar law, (ii) consent to the institution of, or fail to contest in a timely and appropriate manner, any proceeding or the filing of any petition described in paragraph (i) above, (iii) apply for, request or consent to the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for any Loan Party or for a substantial part of the property or assets of any Loan Party or Material Project Subsidiary, (iv) file an answer admitting the material allegations of a petition filed against it in any such proceeding, (v) make a general assignment for the benefit of creditors or (vi) become unable, admit in writing its inability or fail generally to pay its debts as they become due;

(j) the failure by any Loan Party or Material Project Subsidiary to pay one or more final judgments aggregating in excess of U.S. $[***] (net of any amounts which are covered by insurance or bonded), which judgments are not discharged or effectively waived or stayed for a period of thirty (30) consecutive days, or any action shall be legally taken by a judgment creditor to levy upon assets or properties of any Loan Party or Material Project Subsidiary to enforce any such judgment;

(k) if, at any time, (i) any Plan fails to comply with any material provision of ERISA and/or the Code (and applicable regulations under either) or with the material terms of such Plan, (ii) any Plan fails to satisfy the minimum funding standards of ERISA or the Code for any plan year or part thereof or a waiver of such standards or extension of any amortization period is sought or granted under Section 412

of the Code, (iii) a notice of intent to terminate any Plan is or is reasonably expected to be filed with the PBGC or the PBGC institutes proceedings under Section 4042 of ERISA to terminate or appoint a trustee to administer any Plan or the PBGC notifies the Borrower that a Plan may become a subject of any such proceedings, (iv) a Loan Party incurs or is reasonably expected to incur any liability pursuant to Title I of ERISA (other than routine claims for benefits) or the penalty or excise tax provisions of the Code relating to employee benefit plans, or the Borrower or any ERISA Affiliate incurs or is reasonably expected to incur any liability pursuant to Title IV of ERISA (other than for timely paid premiums to the Pension Benefit Guaranty Corporation), (v) the Borrower or any ERISA Affiliate withdraws from any Multiemployer Plan in a complete withdrawal or a partial withdrawal, (vi) the Borrower or any ERISA Affiliate fails to make any required contribution to a Multiemployer Plan pursuant to Section 431 or 432 of the Code, (vii) any Multiemployer Plan is determined to be insolvent or in "endangered" or "critical" status (within the meaning of Section 432 of the Code or Section 305 of ERISA), (viii) a Loan Party establishes or amends any employee welfare benefit plan that provides post-employment welfare benefits in a manner that would increase the liability of a Loan Party thereunder; (ix) a non-exempt "prohibited transaction" (within the meaning of Section 406 of ERISA and Section 4975(c) of the Code) occurs with respect to any Plan, (x) any ERISA Plan is determined to be in "at risk" status (within the meaning of Section 430 of the Code or Section 303 of ERISA), or (xi) a Foreign Plan Event occurs, and any such event or events described in clauses (i) through (xi) above, either individually or together with any other such event or events, would reasonably be expected to have a Material Adverse Effect; or

(l) (i) any Loan Document, for any reason, shall cease to be, or shall be asserted in writing by any Loan Party not to be, a legal, valid and binding obligation of any party thereto, (ii) any security interest purported to be created by any Security Document and to extend to Collateral that is not immaterial to the Loan Parties on a consolidated basis shall cease to be, or shall be asserted in writing by any Loan Party not to be, a valid and perfected security interest (having the priority required by this Agreement or the relevant Security Document) in the securities, assets or properties covered thereby or (iii) the Guarantees pursuant to the Security Documents by a Loan Party of any of the Obligations shall cease to be in full force and effect (other than in accordance with the terms thereof) or shall be asserted in writing by a Loan Party not to be in effect or not to be legal, valid and binding obligations;

then, and in every such event (other than an event with respect to the Borrower described in paragraph (h) or (i) above), and at any time thereafter during the continuance of such event, the Administrative Agent, at the request of the Required Lenders, shall, by notice to the Borrower, take any or all of the following actions, at the same or different times: (i) terminate forthwith the Commitments, (ii) declare the Loans then outstanding to be forthwith due and payable in whole or in part, whereupon the principal of the Loans so declared to be due and payable, together with accrued interest thereon and any unpaid accrued Fees and all other liabilities of the Borrower accrued hereunder and under any other Loan Document, shall become forthwith due and payable, without presentment, demand, protest or any other notice of any kind, all of which are hereby expressly waived by the Borrower, anything contained herein or in any other Loan Document to the contrary notwithstanding, and in the case of any event described in paragraph (h) or (i) above, the Commitments shall automatically terminate, the principal of the Loans then outstanding, together with accrued interest thereon and any unpaid accrued Fees and all other liabilities of the Borrower accrued hereunder and under any other Loan Document, shall automatically become due and payable, without presentment, demand, protest or any other notice of any kind, all of which are hereby expressly waived by the Borrower, anything contained herein or in any other Loan Document to the contrary notwithstanding.

Section 7.02 *Right to Cure* . Notwithstanding anything to the contrary contained in Section 7.01 , in the event that the Borrower fails to comply with the Financial Performance Covenant on any Quarterly Date, the Loan Parties shall have the right, on or after such Quarterly Date and on or prior to the tenth (10 th) Business Day following such Quarterly Date, to effect a cure of such failure by receiving an additional equity investment from the Sponsor (or its designee) in the form of a cash equity contribution to the Borrower in an amount equal to the Cure Amount (collectively, the " **Cure Right** ") and upon the receipt by the Borrower of the Cure Amount, the Financial Performance Covenant shall be recalculated, giving effect to a pro forma increase to the Cash Flow Available for Debt Service for the relevant Test Period in an amount equal to such Cure Amount; *provided* that such pro forma adjustment to the Cash Flow Available for Debt Service shall be made solely for the purpose of curing the failure to comply with the Financial Performance Covenant with respect to the relevant Test Period that includes the Test Quarter for which such Cure Right was exercised (and shall be taken into account only in subsequent Test Periods that include the Test Quarter ended

immediately prior to the exercise of the Cure Right) and not for any other purpose under any Loan Document. If, after giving effect to the foregoing recalculations, the Borrower shall then be in compliance with the requirements of the Financial Performance Covenant, the Borrower shall be deemed to have satisfied the requirements of the Financial Performance Covenant as of the relevant date of determination with the same effect as though there had been no failure to comply therewith at such date, and the applicable breach or default of the Financial Performance Covenant (and any related Default or Event of Default as a result of such breach or default) that had occurred shall be deemed cured. Notwithstanding anything herein to the contrary, (i) Borrower may exercise the Cure Right with respect to only two (2) Test Quarters during any Test Period, (ii) the Cure Right shall not be exercised more than five (5) times during the term of this Agreement and (iii) any Cure Amount shall be deposited into the Revenue Account and applied in accordance with Section 2.19 .

Article VIII.
THE AGENTS; ADDITIONAL PROVISIONS FOR DEPOSITARY BANK

Section 8.01 *Appointment and Authority* .

(a) Each of the Lenders hereby irrevocably appoints MSSF to act on its behalf as the Administrative Agent hereunder and under the other Loan Documents and authorizes the Administrative Agent to take such actions on its behalf and to exercise such powers as are delegated to the Administrative Agent by the terms hereof or thereof, together with such actions and powers as are reasonably incidental thereto.

(b) Each of the Lenders hereby irrevocably appoints Wilmington Trust, National Association to act on its behalf as the Collateral Agent under the Loan Documents, and the Administrative Agent and each of the Lenders (including in any capacity as a potential Specified Swap Counterparty) hereby irrevocably appoints and authorizes the Collateral Agent to act as the agent of such Lender for purposes of acquiring, holding and enforcing any and all Liens on Collateral granted by any of the Loan Parties to secure any of the Obligations, together with such powers and discretion as are reasonably incidental thereto. In this connection, the Collateral Agent, and any co-agents, sub-agents and attorneys-in-fact appointed by the Collateral Agent pursuant to Section 8.05 for purposes of holding or enforcing any Lien on the Collateral (or any portion thereof) granted under the Security Documents, or for exercising any rights and remedies thereunder at the direction of the Administrative Agent or the Required Lenders, shall be entitled to the benefits of all provisions of this Article VIII (including Section 8.11) and Article IX as though the Collateral Agent, or such co-agents, sub-agents and attorneys-in-fact, were expressly referred to in such provisions.

(c) Each of the Lenders hereby irrevocably appoints MSSF as Syndication Agent.

(d) Each of the Lenders hereby irrevocably appoints MSSF as Documentation Agent

(e) Each of the Loan Parties, the Lenders and each Agent (other than the Depositary Bank) also hereby irrevocably appoints Wilmington Trust, National Association to act as their agent hereunder, with such powers as are expressly delegated to the Depositary Bank by the terms of this Agreement, together with such other powers as are reasonably incidental thereto. Each of the Agents and Lenders hereby authorizes and directs the Depositary Bank to act at the direction, or on the written instructions, of the Collateral Agent with respect to withdrawals, transfers and payments from and to the Depositary Accounts or as otherwise specified herein, in each case in accordance with the terms hereof. The Depositary Bank is hereby appointed to act, and hereby agrees to act, as Depositary Bank, as "securities intermediary" (within the meaning of Section 8-102(a)(14) of the UCC) with respect to the Depositary Accounts which are determined to be "securities accounts" (within the meaning of Section 8-501 of the UCC) and the "financial assets" (within the meaning of Section 8-102(a)(9) of the UCC, the " **Financial Assets** ") credited thereto and as "bank" (within the meaning of 9-102(a)(8) of the UCC) with respect to

the Depositary Accounts which are determined to be "deposit accounts" (within the meaning of Section 9-102(a)(29) of the UCC) and credit balances not constituting Financial Assets credited thereto, and to accept all payments, Cash and Cash Equivalents and other amounts to be delivered to or held by the Depositary Bank pursuant to the terms of this Agreement. The Depositary Bank shall hold and safeguard the Depositary Accounts during the term of this Agreement in accordance with the provisions of this Agreement.

(f) Except as provided expressly to the contrary herein, the provisions of this Article VIII are solely for the benefit of the Administrative Agent, the Collateral Agent, the Syndication Agent, the Documentation Agent, the Depositary Bank, any appointees thereof and the Lenders and neither the Borrower nor any other Loan Party shall have rights as a third party beneficiary of any of such provisions except as expressly provided to the contrary herein.

Section 8.02 *Rights as a Lender* . Any Person serving as an Agent hereunder shall have the same rights and powers in its capacity as a Lender as any other Lender and may exercise the same as though it were not an Agent, and the term "Lender" or "Lenders" shall, unless otherwise expressly indicated or unless the context otherwise requires, include a Person serving as an Agent hereunder in its individual capacity. Such Person and its Affiliates may accept deposits from, lend money to, act as the financial advisor or in any other advisory capacity for and generally engage in any kind of business with the Borrower or any Subsidiary or other Affiliate thereof as if such Person were not an Agent hereunder and without any duty to account therefor to the Lenders.

Section 8.03 *Exculpatory Provisions* . No Agent shall have any duties or obligations except those expressly set forth herein and in the other Loan Documents. Without limiting the generality of the foregoing, no Agent:

(a) shall be subject to any fiduciary or other implied duties, regardless of whether a Default or Event of Default has occurred and is continuing;

(b) shall have any duty to take any discretionary action or exercise any discretionary powers, except discretionary rights and powers expressly contemplated hereby or by the other Loan Documents that such Agent is required to exercise as directed in writing by the Required Lenders (or such other number or percentage of the Lenders as shall be expressly provided for herein or in the other Loan Documents); *provided* that no Agent shall be required to take any action that, in its opinion or the opinion of its counsel, may expose such Agent to liability or that is contrary to any Loan Document or applicable law;

(c) shall, except as expressly set forth herein and in the other Loan Documents, have any duty to disclose, and shall not be liable for the failure to disclose, any information relating to the Loan Parties or any of their respective Affiliates that is communicated to or obtained by the Person serving as such Agent or any of its Affiliates in any capacity;

(d) shall be liable for any action taken or not taken by it (i) with the consent or at the request of the Required Lenders (or such other number or percentage of the Lenders as shall be necessary, or as such Agent shall believe in good faith shall be necessary, under the circumstances as provided in Sections 9.08 and 7.01) or (ii) in the absence of its own gross negligence or willful misconduct (to the extent found in a final, non-appealable judgment by a court of competent jurisdiction);

(e) shall be responsible for or have any duty to ascertain or inquire into (i) any statement, warranty or representation made in or in connection with this Agreement or any other Loan Document, (ii) the contents of any certificate, report or other document delivered hereunder or thereunder or in connection herewith or therewith, (iii) the performance or observance of any of the covenants, agreements or other terms or conditions set forth herein or therein or the occurrence of any Default, (iv) the validity, enforceability, effectiveness or genuineness of this Agreement, any other Loan Document or any other agreement, instrument or document, or the creation, perfection or priority of any Lien purported to be created by the Security Documents, (v) the value or the sufficiency of any Collateral, or (vi) the satisfaction of any condition set forth in Article IV or elsewhere herein, other than to confirm receipt of items expressly required to be delivered to such Agent;

(f) shall be deemed to have knowledge of any Default or Event of Default unless and until written notice describing such Default or Event of Default is given to such Agent by any Loan Party or any Lender;

(g) shall be responsible or liable for special, indirect, punitive or consequential loss or damage of any kind whatsoever (including, but not limited to, loss of profit) irrespective of whether the respective Agent has been advised of the likelihood of such loss or damage and regardless of the form of action; and

(h) shall be responsible or liable for any failure or delay in the performance of its obligations hereunder arising out of or caused by, directly or indirectly, forces beyond its control, including, without limitation, strikes, work stoppages, accidents, acts of war or terrorism, civil or military disturbances, nuclear or natural catastrophes or acts of God, and interruptions, loss or malfunctions of utilities, communications or computer (software and hardware) services; it being understood that the respective Agent shall use reasonable efforts which are consistent with accepted practices in the banking industry to resume performance as soon as practicable under the circumstances;

provided that, notwithstanding the foregoing, the Depositary Bank shall take all actions as the other Agents or the Loan Parties shall direct it in writing to perform in accordance with the express provisions of this Agreement.

Section 8.04 *Reliance by Agents* . Each Agent shall be entitled to rely upon, and shall not incur any liability for relying upon, any notice, request, certificate, consent, statement, instrument, document or other writing (including any electronic message, Internet or intranet website posting or other distribution) believed by it to be genuine and to have been signed, sent or otherwise authenticated by the proper Person. Each Agent also may rely upon any statement made to it orally or by telephone and believed by it to have been made by the proper Person, and shall not incur any liability for relying thereon. In determining compliance with any condition hereunder to the making of a Loan that by its terms must be fulfilled to the satisfaction of a Lender, any Agent may presume that such condition is satisfactory to such Lender unless such Agent shall have received written notice to the contrary from such Lender prior to the making of such Loan. Each Agent may consult with legal counsel (who may be counsel for the Borrower), independent accountants and other experts selected by it, and shall not be liable for any action taken or not taken by it in accordance with the advice of any such counsel, accountants or experts.

Section 8.05 *Delegation of Duties* . Any Agent may perform any and all of its duties and exercise its rights and powers hereunder or under any other Loan Document by or through any one or more sub-agents appointed by such Agent. Any Agent and any such sub-agent may perform any and all of its duties and exercise its rights and powers by or through their respective Related Parties. The exculpatory provisions of this Article VIII shall apply to any such sub-agent and to the Related Parties of each Agent and any such sub-agent, and shall apply to their respective activities in connection with the syndication of the credit facilities provided for herein as well as activities as an Agent.

Section 8.06 *Resignation of the Agents* . Any Agent may at any time give notice of its resignation to the Lenders and the Borrower. Upon receipt of any such notice of resignation, the Required Lenders shall have the right to appoint a successor with the consent of the Borrower (not to be unreasonably conditioned, withheld or delayed) (unless an Event of Default shall have occurred and be continuing, in which case no consent of the Borrower shall be required), which shall be a financial institution with an office in the United States, or an Affiliate of any such financial institution with an office in the United States. If no such successor shall have been so appointed by the Required Lenders or the Borrower and shall not have accepted such appointment within thirty (30) days after the retiring Agent gives notice of its resignation, then such resignation shall nonetheless become effective in accordance with such notice and (a) the retiring Agent shall be discharged from its duties and obligations hereunder and under the other Loan Documents (except that in the case of any collateral security held by the Collateral Agent on behalf of the Secured Parties under any of the Loan Documents, the retiring Collateral Agent shall continue to hold such collateral security, as bailee, until such time as a successor Collateral Agent is appointed), (b) all payments, communications and

determinations provided to be made by, to or through the Administrative Agent shall instead be made by or to each Lender directly, until such time as the Required Lenders and the Borrower, if applicable, appoint a successor Administrative Agent as provided for above in this Section 8.06 and (c) the Borrower and the Lenders agree that in no event shall the retiring Agent or any of its Affiliates or any of their respective officers, directors, employees, agents, advisors or representatives have any liability to the Loan Parties, any Lender or any other Person or entity for damages of any kind, including direct or indirect, special, incidental or consequential damages, losses or expenses (whether in tort, contract or otherwise) arising out of the failure of a successor Agent to be appointed and to accept such appointment. Upon the acceptance of a successor's appointment as Agent hereunder, such successor shall succeed to and become vested with all of the rights, powers, privileges and duties of the retiring (or retired) Agent, and the retiring Agent shall be discharged from all of its duties and obligations hereunder and under the other Loan Documents (if not already discharged therefrom as provided above in this Section 8.06). The fees payable by the Borrower to a successor Agent shall be the same as those payable to its predecessor unless otherwise agreed between the Borrower and such successor. After the retiring Agent's resignation or removal hereunder and under the other Loan Documents, the provisions of this Article VIII (including Section 8.11) and Section 9.05 shall continue in effect for the benefit of such retiring Agent, its sub-agents and their respective Related Parties in respect of any actions taken or omitted to be taken by any of them while the retiring Agent was acting as Agent.

Section 8.07 *Non-Reliance on the Agents and Other Lenders* . Each Lender acknowledges that it has, independently and without reliance upon any Agent or any other Lender or any of their Related Parties and based on such documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement. Each Lender also acknowledges that it will, independently and without reliance upon any Agent or any other Lender or any of their Related Parties and based on such documents and information as it shall from time to time deem appropriate, continue to make its own decisions in taking or not taking action under or based upon this Agreement, any other Loan Document or any related agreement or any document furnished hereunder or thereunder.

Section 8.08 *No Other Duties, Etc.* Anything herein to the contrary notwithstanding, none of the Lead Arranger, the Syndication Agent or the Documentation Agent shall have any powers, duties or responsibilities under this Agreement or any of the other Loan Documents in its capacity as such.

Section 8.09 *Administrative Agent May File Proofs of Claim* . In case of the pendency of any proceeding under any federal, state or foreign bankruptcy, insolvency, receivership or similar law or any other judicial proceeding relative to any Loan Party, the Administrative Agent (irrespective of whether the principal of any Loan shall then be due and payable as herein expressed or by declaration or otherwise and irrespective of whether the Administrative Agent shall have made any demand on the Borrower) shall be entitled and empowered, by intervention in such proceeding or otherwise:

(a) to file and prove a claim for the whole amount of the principal and interest owing and unpaid in respect of the Loans and all other Obligations that are owing and unpaid and to file such other documents as may be necessary or advisable in order to have the claims of the Lenders and the Administrative Agent (including any claim for the reasonable compensation, expenses, disbursements and advances of the Lenders and the Administrative Agent and their respective agents and counsel and all other amounts due the Lenders and the Administrative Agent under Sections 2.10 , 8.11 and 9.05) allowed in such judicial proceeding; and

(b) to collect and receive any monies or other property payable or deliverable on any such claims and to distribute the same;

and any custodian, receiver, assignee, trustee, liquidator, sequestrator or other similar official in any such judicial proceeding is hereby authorized by each Lender to make such payments to the Administrative Agent and, if the Administrative Agent shall consent to the making of such payments directly to the Lenders, to pay to the Administrative Agent any amount due for the reasonable

compensation, expenses, disbursements and advances of the Administrative Agent and its agents and counsel, and any other amounts due the Administrative Agent under Sections 2.10 , 8.11 and 9.05 .

Nothing contained herein shall be deemed to authorize the Administrative Agent to authorize or consent to or accept or adopt on behalf of any Lender any plan of reorganization, arrangement, adjustment or composition affecting the Obligations or the rights of any Lender to authorize the Administrative Agent to vote in respect of the claim of any Lender in any such proceeding.

Section 8.10 *Collateral and Guarantee Matters* . Each of the Lenders irrevocably authorizes the Administrative Agent and the Collateral Agent to release Guarantees, Liens and security interests created by the Loan Documents in accordance with Section 9.18 . Upon request by the Administrative Agent or the Collateral Agent, at any time, each Lender will confirm in writing such Agent's authority provided for in the previous sentence.

Section 8.11 *Indemnification* . Each Lender agrees (i) to reimburse the Administrative Agent , the Depositary Bank and the Collateral Agent, on demand, in the amount of its *pro rata* share (based on its Commitments hereunder (or if such Commitments shall have expired or been terminated, in accordance with the respective principal amounts of its outstanding Loans)) of any reasonable expenses incurred for the benefit of the Lenders by the Administrative Agent, the Depositary Bank or the Collateral Agent, as applicable, including reasonable and documented counsel fees and compensation of agents and employees paid for services rendered on behalf of the Lenders which shall not have been reimbursed by the Borrower (and without limiting the Borrower's obligations to reimburse such amounts to the extent set forth in Section 9.05) and (ii) to indemnify and hold harmless the Administrative Agent, the Depositary Bank, the Collateral Agent and any of their respective directors, officers, employees or agents, on demand, in the amount of such *pro rata* share, from and against any and all liabilities, Taxes, obligations, losses, damages, penalties, actions, judgments, suits, costs, expenses or disbursements of any kind or nature whatsoever which may be imposed on, incurred by or asserted against it in its capacity as Administrative Agent, the Depositary Bank or Collateral Agent or any of them in any way relating to or arising out of this Agreement or any other Loan Document or any action taken or omitted by it or any of them under this Agreement or any other Loan Document, to the extent the same shall not have been reimbursed by the Borrower (and without limiting the Borrower's obligations to reimburse such amounts to the extent set forth in Section 9.05); *provided* that no Lender shall be liable to the Administrative Agent, the Depositary Bank or the Collateral Agent for any portion of such liabilities, obligations, losses, damages, penalties, actions, judgments, suits, costs, expenses or disbursements to the extent found in a final, non-appealable judgment by a court of competent jurisdiction to have resulted directly and primarily from the gross negligence or willful misconduct of the Administrative Agent, the Collateral Agent, the Depositary Bank or any of their respective directors, officers, employees or agents, as applicable; *provided* , *further* , that it is understood and agreed that any action taken by the Administrative Agent, the Collateral Agent, the Depositary Bank or any of their respective directors, officers, employees or agents in accordance with the directions of the Required Lenders or any other appropriate group of Lenders pursuant to Section 9.08 shall not be deemed to constitute gross negligence or willful misconduct for purposes of the immediately preceding proviso.

Section 8.12 *Withholding* . To the extent required by any applicable law, the Administrative Agent may withhold from any payment to any Lender an amount equivalent to any applicable withholding Tax. If any payment has been made to any Lender by the Administrative Agent without the applicable withholding Tax being withheld from such payment and the Administrative Agent has paid over the applicable withholding Tax to the Internal Revenue Service or any other Governmental Authority, or the Internal Revenue Service or any other Governmental Authority asserts a claim that the Administrative Agent did not properly withhold Tax from amounts paid to or for the account of any Lender because the appropriate form was not delivered or was not properly executed or because such Lender failed to notify the Administrative Agent of a change in circumstance which rendered the exemption from, or reduction of, withholding Tax ineffective or for any other reason, such Lender shall indemnify the Administrative Agent fully for all amounts paid, directly or indirectly, by the Administrative Agent as Tax or otherwise, including any penalties or interest and together with all expenses (including reasonable and documented legal expenses, allocated internal costs and out-

of-pocket expenses) incurred. Each Lender hereby authorizes the Administrative Agent to set off and apply any and all amounts at any time owing to such Lender under this Agreement or any other Loan Document against any amount due the Administrative Agent under this Section 8.12 . The agreements in this Section 8.12 shall survive the resignation and/or replacement of the Administrative Agent, any assignment of rights by, or the replacement of, a Lender, the termination of the Commitments and the repayment, satisfaction or discharge of all other Obligations.

Section 8.13 *Enforcement* . Notwithstanding anything to the contrary contained herein or in any other Loan Document, the authority to enforce rights and remedies hereunder and under the other Loan Documents against the Loan Parties or any of them shall be vested exclusively in, and all actions and proceedings at law in connection with such enforcement shall be instituted and maintained exclusively by, the Administrative Agent or the Collateral Agent in accordance with Section 7.01 and the Security Documents for the benefit of all the Lenders or Secured Parties, as applicable; *provided* , however, that the foregoing shall not prohibit (a) the Administrative Agent or the Collateral Agent from exercising on its own behalf the rights and remedies that inure to its benefit (solely in its capacity as Administrative Agent or Collateral Agent, as applicable) hereunder and under the other Loan Documents, (b) any Lender from exercising setoff rights in accordance with Section 9.06 (subject to the terms of Section 2.16(c)), or (c) any Lender from filing proofs of claim or appearing and filing pleadings on its own behalf during the pendency of a proceeding relative to any Loan Party under any federal, state or foreign bankruptcy, insolvency, receivership or similar law; *provided* , *further* , that if at any time there is no Person acting as the Administrative Agent or the Collateral Agent, as applicable, hereunder and under the other Loan Documents, then (i) the Required Lenders shall have the rights otherwise ascribed to the Administrative Agent or the Collateral Agent, as applicable, pursuant to Section 7.01 and the Security Documents, as applicable and (ii) in addition to the matters set forth in clauses (b) and (c) of the preceding proviso and subject to Section 2.16(c) , any Lender may, with the consent of the Required Lenders, enforce any rights and remedies available to it and as authorized by the Required Lenders.

Section 8.14 *Additional Depositary Bank Provisions.*

(a) The Loan Parties, the Lenders and each Agent agree that, for purposes of Articles 8 and 9 of the UCC, notwithstanding anything to the contrary contained in any other agreement relating to the establishment and operation of the Depositary Accounts, the jurisdiction of the Depositary Bank (in its capacity as securities intermediary and bank) is the State of New York and the laws of the State of New York govern the establishment and operation of the Depositary Accounts.

(b) The Depositary Bank shall exercise the same degree of care in administering the funds held on deposit in the Depositary Accounts and the investments purchased with such funds in accordance with the terms of this Agreement as the Depositary Bank exercises in the ordinary course of its day-to-day business in administering other funds and investments as required by applicable law. The Depositary Bank shall perform its obligations hereunder in accordance with generally accepted banking industry standards. The Depositary Bank is not party to and shall not execute and deliver, or otherwise become bound by, any agreement under which the Depositary Bank agrees with any Person other than the Collateral Agent to comply with entitlement orders or instructions originated by such Person relating to any of the Depositary Accounts or the security entitlements that are the subject of this Agreement. Except as expressly provided in Section 8.14(c) , the Depositary Bank shall not grant any Lien on any Financial Asset, other than any Lien granted to the Collateral Agent (on behalf of the Secured Parties) under the Security Documents and shall, if such a Lien is nevertheless created by the Depositary Bank, cause the prompt release or discharge of the same. The Depositary Bank may execute any of the trusts or powers hereunder or perform any duties hereunder either directly or by or through agents, legal counsel, custodians or nominees appointed with due care; *provided* that (i) the Depositary Bank's obligations under this Agreement shall remain unchanged, (ii) the Depositary Bank shall remain solely responsible to the other parties hereto for the performance of such obligations and (iii) the Loan Parties, the Independent Engineer and each other Agent shall continue to deal solely and directly with the Depositary Bank in connection with the Depositary Bank's rights and obligations under this Agreement and any rights of the Depositary Bank under the other Loan Documents.

Neither the Depositary Bank nor any of its officers, directors, employees, agents or sub-agents shall be liable for any action taken or omitted under this Agreement or in connection therewith except to the extent caused by the Depositary Bank's or their gross negligence or willful misconduct, *provided* that the Depositary Bank shall not be responsible for the negligence or misconduct of any agent appointed by it with due care. The Depositary Bank shall not be deemed to have knowledge of any Default or Event of Default unless the Depositary Bank shall have received written notice thereof. The rights, privileges, protections and benefits given to the Depositary Bank, including its rights to be indemnified, are extended to, and shall be enforceable by, the Depositary Bank in its capacity hereunder, and to each agent, custodian and other Person employed by the Depositary Bank in accordance herewith to act hereunder. In no event shall the Depositary Bank be responsible or liable for special, indirect, punitive or consequential loss or damage of any kind whatsoever (including, but not limited to, loss of profit) irrespective of whether the Depositary Bank has been advised of the likelihood of such loss or damage and regardless of the form of action.

(c) In the event that the Depositary Bank has or subsequently obtains by agreement, operation of law or otherwise a Lien on any Depositary Account, the Depositary Bank agrees that such Lien shall (except to the extent provided in the next sentence) be subordinate to any Lien of the Collateral Agent. The Financial Assets or funds standing to the credit of the Depositary Accounts will not be subject to deduction, set-off, counter-claim, banker's lien or any other right in favor of the Depositary Bank or any Person other than the Collateral Agent and, subject to the terms of this Agreement and the other Loan Documents, the Loan Parties (except to the extent of returned items and charge-backs either for uncollected checks or other items of payment and transfers previously credited to one or more of the Depositary Accounts, and the Loan Parties and the Collateral Agent hereby authorize the Depositary Bank to debit the applicable Depositary Accounts for such amounts).

(d) The Depositary Bank is hereby authorized to obey and comply with all writs, orders, judgments or decrees issued by any court or administrative agency of competent jurisdiction affecting any monies, documents or other Property held by the Depositary Bank. The Depositary Bank shall not be liable to any of the parties hereto or any of the Secured Parties or their successors, heirs or personal representatives by reason of the Depositary Bank's compliance with such writs, orders, judgments or decrees, notwithstanding such writ, order, judgment or decree is later reversed, modified, set aside or vacated.

(e) The Depositary Bank shall not be (i) required to initiate or conduct any litigation or collection proceeding hereunder or under any other Loan Document or (ii) responsible for any action taken or omitted to be taken by it hereunder or in connection with any other Loan Document (except for its own gross negligence or willful misconduct). Except as otherwise provided under this Agreement, the Depositary Bank shall take action under this Agreement only as it shall be directed in writing. The Depositary Bank shall have the right at any time to seek instructions concerning the administration of this Agreement from the applicable Agent, the Loan Parties or any court of competent jurisdiction. The Depositary Bank shall have no obligation to expend or risk its own funds or otherwise incur any financial liability in the performance of any of its duties hereunder. The Depositary Bank shall not be responsible or liable for any error of judgment made in good faith by an officer or officers of the Depositary Bank, any loss which may result from any investment made pursuant to this Agreement or for any loss resulting from the sale of such investment.

(f) To the extent permitted by applicable law, the Loan Parties shall assert, and the Loan Parties hereby waives, any claim against the Depositary Bank and its Affiliates and the officers, partners, members, shareholders, directors, trustees, advisors, employees, agents or sub-agents of the Depositary Bank or its Affiliates, on any theory of liability, for special, indirect, consequential or punitive damages (as opposed to direct or actual damages) (whether or not the claim therefor is based on contract, tort or duty imposed by any applicable law) arising out of, in connection with, as a result of, or in any way related to, this Agreement or any other Loan Document or any agreement or instrument contemplated hereby or thereby or referred to herein or therein, the transactions contemplated hereby or thereby or any act or omission or event occurring in connection therewith, and the Loan Parties hereby waives, releases and agrees not to sue upon any such claim or any such damages, whether or not accrued and whether or not known or suspected to exist in its favor.

(g) Neither the Depositary Bank nor the Collateral Agent shall be responsible for filing any financing or continuation statements or recording any documents or instruments in any public office at any time or times or otherwise perfecting, monitoring or maintaining the perfection of any security interest in the Collateral.

(h) Whenever in the administration of this Agreement the Depositary Bank shall deem it necessary or desirable that a factual or legal matter be proved or established in connection with the Depositary Bank taking, suffering or omitting to take any action hereunder, such matter (unless other evidence in respect thereof is herein specifically prescribed) may be deemed to be conclusively proved or established by a certificate of an Responsible Officer or a certificate of a senior officer of the applicable Agent, if appropriate, or from a legal opinion from counsel to the Loan Parties. The Depositary Bank shall have the right at any time to seek instructions concerning the administration of this Agreement from the applicable Agent, the Loan Parties or any court of competent jurisdiction. The Depositary Bank shall have no obligation to expend or risk its own funds or otherwise incur any financial liability in the performance of any of its duties hereunder. The Depositary Bank shall not be responsible or liable for any error of judgment made in good faith by an officer or officers of the Depositary Bank, any loss which may result from any investment made pursuant to this Agreement or for any loss resulting from the sale of such investment.

Section 8.15 *Cash Equivalent Investments in Depositary Accounts.*

(a) Unless otherwise instructed in writing by the Borrower and subject to Section 8.17 , all cash deposited in the Depositary Accounts that are "securities accounts" (within the meaning of Section 8-501(a) of the UCC) shall be invested by the Depositary Bank in Cash and Cash Equivalents as specifically directed in writing by the Borrower; *provided* that, if the Borrower fails to so direct the Depositary Bank, then such amounts held in the Depositary Accounts shall be invested and reinvested in Cash and Cash Equivalents as selected by the Borrower in advance (which may be in the form of a standing instruction) or, if the Borrower fails to select any Cash and Cash Equivalents in advance or the Depositary Bank is not able to determine whether a selection has been made in advance or is in effect, then such amounts shall be invested and reinvested in cash. Such investments will mature in such amounts and not later than such times as may be necessary to provide funds when needed to make payments from such funds as provided in this Agreement. Except as otherwise provided herein, net interest or gain received, if any, from such Cash and Cash Equivalents shall be deposited into the Revenue Account; *provided* that net interest or gain received, if any, from Cash and Cash Equivalents made with cash on deposit in the Debt Service Reserve Account shall be deposited into Debt Service Reserve Account until the Debt Service Reserve Account is Fully Funded (as each such reserve requirement shall be certified to the Depositary Bank by the Borrower prior to any such deposit), and any release therefrom shall be subject to Section 2.19(d) . Any loss shall be charged to the applicable Depositary Account. The Depositary Bank shall have no responsibility or liability for any loss which may result from any investment made pursuant to this Agreement, or for any loss resulting from the sale of any such investment.

(b) In the event that at any time amounts are funded into a Depositary Account after 1:00 p.m. (New York City time) on any Business Day, the Depositary Bank shall have no obligation to invest or reinvest such amounts until the next Business Day.

(c) If and when cash is required for the making of any withdrawal or transfer in accordance with this Agreement (it being understood that cash shall not be required for any transfer between Depositary Accounts unless Cash and Cash Equivalents do not exist in the Depositary Account from which funds are being transferred in appropriate amounts in order to permit such transfer), the Borrower shall cause Cash and Cash Equivalents to be sold or otherwise liquidated into cash (without regard to maturity) as and to the extent necessary in order to make such withdrawals or transfers. Subject to the applicable Control Agreement and Section 8.17 , the Depositary Bank shall comply with any instruction from the Borrower with respect to any such liquidation of Cash and Cash Equivalents. In the event any such investments are so redeemed prior to the maturity thereof, neither the Depositary Bank nor any other Secured Party shall be liable for any loss or penalties relating thereto.

(d) For purposes of determining responsibility for any income Taxes payable on account of any income or gain on any Cash and Cash Equivalents hereunder, such income or gain shall be for the account of the Borrower. The Borrower shall provide the Depositary Bank with certified tax identification numbers by furnishing appropriate forms W-8 or W-9 and such other forms and documents that the Depositary Bank may reasonably request.

Section 8.16 *Depositary Account Balance Statements* . The Depositary Bank shall, on a monthly basis within seven days after the end of each calendar month and at such other times as the Administrative Agent, the Collateral Agent or the Borrower may from time to time reasonably request in writing, provide to the Administrative Agent, the Collateral Agent and the Borrower fund balance statements in respect of each of the Depositary Accounts, sub-accounts and amounts segregated in any of the Depositary Accounts; *provided* that, notwithstanding the foregoing, if requested by the Borrower, the Depositary Bank shall provide the Borrower with internet access to fund balance statements and account activity summaries. Such balance statements and account activity summaries shall also include deposits, withdrawals and transfers from and to any Depositary Account and sub-accounts and the net investment income or gain received and collected in such Depositary Account and sub-account. The Depositary Bank shall retain records of all receipts, disbursements and investments of funds with respect to the Depositary Accounts until the third anniversary of the Discharge of the Obligations. The Depositary Bank shall promptly notify the Administrative Agent, the Collateral Agent and the Borrower of its receipt and the amount of any funds received from any Person that are, or are required hereunder to be, deposited into any Depositary Account, specifying the Depositary Account into which such funds have been deposited.

Section 8.17 *Application of Funds in Depositary Accounts upon Event of Default.* On and after any date on which the Depositary Bank receives written notice from the Collateral Agent that an Event of Default has occurred and is continuing and that the Collateral Agent is exercising its rights, on behalf of the Secured Parties, with respect to one or more of the Depositary Accounts pursuant to a direction by Required Lenders, notwithstanding anything herein to the contrary, the Depositary Bank shall thereafter accept all notices and instructions required or permitted to be given to the Depositary Bank pursuant to the terms of this Agreement only from the Administrative Agent or the Collateral Agent and not from the Borrower or any other Person, and the Depositary Bank shall not withdraw, transfer, pay or otherwise disburse any amounts in any of the Depositary Accounts except pursuant to such notices and instructions from the Administrative Agent or the Collateral Agent, unless such Event of Default no longer exists due to such Event of Default having been waived, cured or no longer existing, or having been deemed waived, in accordance with the terms of the applicable Loan Documents (as confirmed in writing to the Depositary Bank by the Collateral Agent), in which event the terms of this Section 8.17 shall thereafter be inapplicable to such Event of Default. Notwithstanding anything herein to the contrary, prior to any date on which the Depositary Bank receives notice that an Event of Default has occurred and is continuing from the Collateral Agent, the Depositary Agent shall continue to apply amounts pursuant to the terms of this Agreement.

Article IX.
MISCELLANEOUS

Section 9.01 *Notices* .

(a) Notices and other communications provided for herein shall be in writing and shall be delivered by hand or overnight courier service, mailed by certified or registered mail or sent by telecopy, as follows:

(i) if to the Borrower, Holding, the Project Holdcos or Exelon Renewables JV, to c/o Exelon Generation Company, LLC, 1310 Point Street, 12th Floor, Baltimore, MD 21231, Attention: Project Finance; with a copy to c/o Exelon Generation Company, LLC, 701 Ninth Street NW, 9 th Floor, Washington, DC 20068, Attention: Joseph Downs;

(ii) if to the Administrative Agent, to Morgan Stanley Senior Funding, Inc., 1300 Thames Street, 4 th Floor, Thames Street Wharf, Baltimore, MD 21231, Attention: Administrative Agent, Email: AGENCY.BORROWERS@morganstanley.com , with a copy to Simpson Thacher & Bartlett LLP, 425 Lexington Avenue, New York, New York 10017; Attention: Kenneth Wyman; Fax No.: 212-455-2502; Tel. No. 212-455-7435; Email: kwyman@stblaw.com;

(iii) if to the Collateral Agent, to Wilmington Trust, National Association, 1100 North Market Street, Wilmington Delaware 19890, Attention: Institutional Client Services/Project Finance; Fax No. 302-636-4149; Tel. No. 302-636-6973;

(iv) if to the Depositary Bank, to Wilmington Trust, National Association, 1100 North Market Street, Wilmington Delaware 19890, Attention: Institutional Client Services/Project Finance; Fax No. 302-636-4149; Tel. No. 302-636-6973; and/or

(v) if to any Lender, to the address, telecopier number, electronic mail address or telephone number specified in its Administrative Questionnaire.

(b) Notices and other communications to the Lenders hereunder may be delivered or furnished by electronic communications pursuant to procedures approved by the Administrative Agent; *provided* that the foregoing shall not apply to service of process, or to notices pursuant to Article II unless otherwise agreed by the Administrative Agent and the applicable Lender. Each of the Administrative Agent, the Collateral Agent and the Borrower may, in its discretion, agree to accept notices and other communications to it hereunder by electronic communications pursuant to procedures approved by it; *provided further* that approval of such procedures may be limited to particular notices or communications.

(c) All notices and other communications given to any party hereto in accordance with the provisions of this Agreement shall be deemed to have been given on the date of receipt if delivered by hand or overnight courier service or sent by telecopy or (to the extent permitted by paragraph (b) above) electronic means prior to 5:00 p.m. (New York City time) on such date, or on the date five (5) Business Days after dispatch by certified or registered mail if mailed, in each case delivered, sent or mailed (properly addressed) to such party as provided in this Section 9.01 or in accordance with the latest unrevoked direction from such party given in accordance with this Section 9.01 .

(d) Each of Holding, the Borrower, the Administrative Agent and the Collateral Agent may change its address or telecopy number for notices and other communications hereunder by notice to the other parties hereto. Each Lender may change its address or facsimile for notices and other communications hereunder by notice to Holding, the Borrower, the Administrative Agent and the Collateral Agent. In addition, each Lender agrees to notify the Administrative Agent from time to time to ensure that the Administrative Agent has on record (i) an effective address, contact name, facsimile number and electronic mail address to which notices and other communications may be sent and (ii) accurate wire instructions for such Lender.

Section 9.02 *Survival of Agreement* . All covenants, agreements, representations and warranties made by any Loan Party herein, in the other Loan Documents and in the certificates or other instruments prepared or delivered in connection with or pursuant to this Agreement or any other Loan Document shall be considered to have been relied upon by the Lenders and shall survive the making by the Lenders of the Loans and the execution and delivery of the Loan Documents, regardless of any investigation made by such Persons or on their behalf, and shall continue in full force and effect as long as the principal of or any accrued interest on any Loan or any Fee or any other amount payable under this Agreement or any other Loan Document is outstanding and unpaid or any Commitments remain in effect. Without prejudice to the survival of any other agreements contained herein, indemnification and reimbursement obligations contained herein (including pursuant to Sections 2.13 , 2.14 , 2.15 , 8.11 and 9.05) and the provisions of Section 8.14(f) shall

survive the payment in full of the principal and interest hereunder and the termination of the Commitments or this Agreement.

Section 9.03 *Binding Effect* . This Agreement shall become effective when it shall have been executed by each of Holding, the Borrower, the Administrative Agent and the Collateral Agent and when the Administrative Agent shall have received copies hereof which, when taken together, bear the signatures of each of the other parties hereto, and thereafter shall be binding upon and inure to the benefit of Holding, the Borrower, the Agents and each Lender and their respective permitted successors and assigns.

Section 9.04 *Successors and Assigns* .

(a) The provisions of this Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns permitted hereby, except that (i) the Borrower may not assign or otherwise transfer any of its rights or obligations hereunder without the prior written consent of each Lender (and any attempted assignment or transfer by such Borrower without such consent shall be null and void) and (ii) no Lender may assign or otherwise transfer its rights or obligations hereunder except in accordance with this Section 9.04 . Nothing in this Agreement, expressed or implied, shall be construed to confer upon any Person (other than the parties hereto, their respective successors and assigns permitted hereby, Participants (to the extent provided in paragraph (c) of this Section 9.04), the Lenders, the Agents and, to the extent expressly contemplated hereby, the Related Parties of each of the Agents and the Lenders, and the Indemnitees) any legal or equitable right, remedy or claim under or by reason of this Agreement:

(b) (i) Subject to the conditions set forth in Section 9.04(b)(ii) below, any Lender may assign to one or more assignees that are Eligible Assignees all or a portion of its rights and obligations under this Agreement (including all or a portion of its Commitment and the Loans at the time owing to it) with the prior written consent of the Administrative Agent (such consent not to be unreasonably withheld or delayed); *provided* that no consent of the Administrative Agent shall be required for an assignment of a Loan to a Person that is a Lender, an Affiliate of a Lender or Approved Fund immediately prior to giving effect to such assignment.

(ii) Assignments shall be subject to the following additional conditions:

(A) except in the case of an assignment to a Lender, an Affiliate of a Lender or an Approved Fund, an assignment of the entire remaining amount of the assigning Lender's Commitment or Loans or contemporaneous assignments to related Approved Funds that equal at least U.S. $1.0 million in the aggregate, the amount of the Commitment and/or Loans, as applicable, of the assigning Lender subject to each such assignment (determined as of the date the Assignment and Acceptance or Affiliated Lender Assignment and Acceptance, as applicable, with respect to such assignment is delivered to the Administrative Agent) shall not be less than U.S. $1.0 million and increments of U.S. $1.0 million in excess thereof unless the Borrower and the Administrative Agent otherwise consent; *provided* that no such consent of the Borrower shall be required if an Event of Default under paragraph (b) , (c) , (h) or (i) of Section 7.01 has occurred and is continuing;

(B) each partial assignment shall be made as an assignment of a proportionate part of all the assigning Lender's rights and obligations in respect of the Term Loan Facility under this Agreement;

(C) the parties to each assignment shall execute and deliver to the Administrative Agent an Assignment and Acceptance or an Affiliated Lender Assignment and Acceptance, as applicable;

(D) the assignee, if it shall not be a Lender, shall deliver to the Administrative Agent an Administrative Questionnaire and any other administrative information that the Administrative Agent may reasonably request;

(E) no such assignment shall be made to (x) a Defaulting Lender or Non-Consenting Lender or (y) the Borrower or any of the other Loan Parties or any of their respective Affiliates, other than any such Person (other than a Loan Party) in accordance with Section 9.04(e) ; and

(F) notwithstanding anything to the contrary herein, no such assignment shall be made to a natural person.

(iii) Subject to acceptance and recording thereof pursuant to paragraph (b)(iv) of this Section 9.04 , from and after the effective date specified in each Assignment and Acceptance or Affiliated Lender Assignment and Acceptance, as applicable, the assignee thereunder shall be a party hereto and, to the extent of the interest assigned by such Assignment and Acceptance or Affiliated Lender Assignment and Acceptance, as applicable, have the rights and obligations of a Lender under this Agreement, and the assigning Lender hereunder shall, to the extent of the interest assigned by such Assignment and Acceptance or Affiliated Lender Assignment and Acceptance, as applicable, be released from its obligations under this Agreement (and, in the case of an Assignment and Acceptance or Affiliated Lender Assignment and Acceptance, as applicable, covering all of the assigning Lender's rights and obligations under this Agreement, such Lender shall cease to be a party hereto but shall continue to be entitled to the benefits of Sections 2.13 , 2.14 , 2.15 and 9.05 with respect to the period that such Lender held Loans). Any assignment or transfer by a Lender of rights or obligations under this Agreement that does not comply with this Section 9.04 shall not be effective as an assignment hereunder.

(iv) The Administrative Agent, acting for this purpose as a non-fiduciary agent of the Borrower, shall maintain at one of its offices a copy of each Assignment and Acceptance or Affiliated Lender Assignment and Acceptance, as applicable, delivered to it and a register for the recordation of the names and addresses of the Lenders, and the Commitment of, and principal amount (and stated interest) of the Loans owing to, each Lender pursuant to the terms hereof from time to time (the " **Register** "). The entries in the Register shall be conclusive, and the Borrower, the Agents and the Lenders shall treat each Person whose name is recorded in the Register pursuant to the terms hereof as a Lender hereunder for all purposes of this Agreement, notwithstanding notice to the contrary. The Register shall be available for inspection by the Borrower and any Lender, at any reasonable time and from time to time upon reasonable prior notice (but only, in the case of a Lender, at the Administrative Agent's Office and with respect to any entry relating to such Lender's Commitments, Loans, and other Obligations).

(v) The assignor or assignee(s) to each assignment shall deliver to the Administrative Agent a processing and recordation fee in the amount of U.S. $3,500 (which shall be limited to one processing and recordation fee for each assignment to or between Approved Funds); *provided* , *however* , that the Administrative Agent may, in its sole discretion, elect to waive such processing and recordation fee in the case of any assignment. Upon its receipt (or waiver) of the processing and recording fee described in the preceding sentence, a duly completed Assignment and Acceptance or Affiliated Lender Assignment and Acceptance, as applicable, executed by an assigning Lender and an assignee, any administrative information reasonably requested by the Administrative Agent (unless the assignee shall already be a Lender hereunder) and any written consent to such assignment required by paragraph (b) of this Section 9.04 , the Administrative Agent

shall accept such Assignment and Acceptance or Affiliated Lender Assignment and Acceptance, as applicable, and record the information contained therein in the Register. No assignment shall be effective for purposes of this Agreement unless it has been recorded in the Register as provided in this paragraph.

(c) (i) Any Lender may at any time, without the consent of, or notice to, the Borrower or the Administrative Agent, sell participations to any Person (other than a natural person, or a holding company, investment vehicle or trust for, or owned and operated for the primary benefit of a natural Person or any of the Borrower or its respective Affiliates or Subsidiaries) (each, a " **Participant** ") in all or a portion of such Lender's rights and obligations under this Agreement (including all or a portion of its Commitment and the Loans owing to it); *provided* that (A) such Lender's obligations under this Agreement shall remain unchanged, (B) such Lender shall remain solely responsible to the other parties hereto for the performance of such obligations, (C) the Borrower, the Agents and the other Lenders shall continue to deal solely and directly with such Lender in connection with such Lender's rights and obligations under this Agreement and (D) such Lender shall, acting as a non-fiduciary agent of the Borrower (solely for tax purposes), maintain a register on which it enters the name and address of each Participant and the principal amounts (and stated interest) of each Participant's interest in the Loans (or other rights or obligations under the Loan Documents) held by it under the Loan Documents (the " **Participant Register** "), which entries shall be conclusive absent manifest error, and such Lender shall treat each Person whose name is recorded in the Participant Register as the owner of such participation for all purposes of this Agreement, notwithstanding notice to the contrary; *provided* that no Lender shall have any obligation to disclose all or any portion of the Participant Register (including the identity of any Participant or any information relating to a Participant's interest in any Commitments, Loans or its other obligations under any Loan Document) to any Person except to the extent that such disclosure is necessary to establish that such Commitment, Loan or other obligation is in registered form under Section 5f.103-1(c) of the United States Treasury Regulations. For the avoidance of doubt, the Administrative Agent (in its capacity as such) shall have no responsibility for maintaining a Participant Register. For the avoidance of doubt, each Lender shall be responsible for the indemnity under Section 8.11 with respect to any payments made by such Lender to its Participants. Any agreement or instrument pursuant to which a Lender sells such a participation shall provide that such Lender shall retain the sole right to exercise rights under and to enforce this Agreement and the other Loan Documents and to approve any amendment, modification or waiver of any provision of this Agreement and the other Loan Documents; *provided* that (x) such agreement or instrument may provide that such Lender will not, without the consent of the Participant, agree to any amendment, modification or waiver described in Section 9.04(a)(i) or clause (i) through (vi) of the first proviso to Section 9.08(b) that affects such Participant and (y) no other agreement (oral or written) in respect of the foregoing with respect to such Participant may exist between such Lender and such Participant. Subject to paragraph (c)(ii) of this Section 9.04 , the Borrower agrees that each Participant shall be entitled to the benefits (and subject to the requirements and limitations) of Sections 2.13 , 2.14 and 2.15 to the same extent as if it were a Lender that acquired its interest by assignment pursuant to paragraph (b) of this Section 9.04 . To the extent permitted by law, each Participant also shall be entitled to the benefits of Section 9.06 as though it were a Lender; *provided* such Participant agrees to be subject to Section 2.16(c) as though it were a Lender.

(ii) A Participant shall not be entitled to receive any greater payment under Section 2.13 , 2.14 or 2.15 than the applicable Lender would have been entitled to receive with respect to the participation sold to such Participant, except to the extent such entitlement to receive a greater payment results from a Change in Law that occurs after the Participant acquired the applicable participation, or unless the sale of the participation to such Participant is made with the Borrower's prior written consent.

(d) Any Lender may at any time pledge or assign a security interest in all or any portion of its rights under this Agreement and its Note, if any, to secure obligations of such Lender, including any pledge or assignment to secure obligations to a Federal Reserve Bank or any other central bank, and this Section 9.04 shall not apply to any such pledge or assignment of a security interest; *provided* that no such pledge or assignment of a security interest shall release a Lender from any of its obligations hereunder or substitute

any such pledgee or assignee for such Lender as a party hereto, and any such pledgee (other than a pledgee that is the Federal Reserve Bank or any other central bank) shall acknowledge in writing that its rights under such pledge are in all respects subject to the limitations applicable to the pledging Lender under this Agreement or the other Loan Documents.

(e) Subject to the other provisions of this Section 9.04 and the provisions of Section 9.21 , any Affiliated Lender may make Loans or Commitments or purchase or sell outstanding Loans or Commitments from the Closing Date until the Business Day immediately preceding the Maturity Date, on the following basis:

(1) any such purchase or sale of Loans or Commitments shall be consummated as an assignment otherwise in accordance with the provisions of this Section 9.04 and pursuant to an Affiliated Lender Assignment and Acceptance in lieu of an Assignment and Acceptance (it being understood and agreed that any such purchase or sale of Loans that does not comply with this Section 9.04 and Section 9.21 shall not be effective as an assignment hereunder);

(2) any such purchase of Loans may be made by the applicable Affiliated Lender from time to time from one or more Lenders of such Affiliated Lender's choosing and need not be made from all Lenders; and

(3) at the time of purchase, the aggregate principal amount of the Loans and Commitments held by all Affiliated Lenders shall not exceed 25.0% of the total Commitments and Loans outstanding at any time.

Section 9.05 *Expenses; Indemnity* .

(a) The Borrower agrees to pay all reasonable and documented out-of-pocket expenses (i) incurred by the Agents and the Lead Arranger (without duplication) in connection with the preparation of this Agreement and the other Loan Documents, and by the Agents and the Lead Arranger (without duplication) in connection with the syndication of the Commitments and the administration of this Agreement (including reasonable and documented out-of-pocket expenses incurred in connection with due diligence and the reasonable and documented fees, charges and disbursements for special New York counsel for the Administrative Agent, the Collateral Agent and the Lead Arranger and counsel to the Depositary Bank and, in the event of any perceived or actual conflict of interest, an additional firm of counsel for any similarly affected persons) and in connection with any amendments, modifications or waivers of the provisions hereof or thereof (whether or not the Transactions hereby contemplated shall be consummated); and (ii) incurred by the Agents and the Lead Arranger (without duplication) or any Lender in connection with the enforcement or protection of their rights in connection with this Agreement and the other Loan Documents or in connection with the Loans made hereunder, including the reasonable and documented fees, charges and disbursements of special New York counsel for the Administrative Agent and the Lead Arranger, counsel to the Collateral Agent and counsel to the Depositary Bank and, in connection with any such enforcement or protection, the reasonable and documented fees, charges and disbursements of any other necessary counsel; *provided* , that absent any conflict of interest, the Administrative Agent and the Lead Arranger shall not be entitled to payment for the fees, charges or disbursements of more than one counsel.

(b) The Borrower agrees to indemnify the Agents (including the Depositary Bank) and the Lead Arranger (without duplication), each Lender and each Related Party of any of the foregoing Persons (each such Person being called an " **Indemnitee** ") against, and to hold each Indemnitee harmless from, any and all claims, losses, damages, liabilities and related expenses, including reasonable and documented counsel fees, charges and disbursements (limited to no more than one firm as counsel to such Indemnitees, taken as a whole, one firm of local counsel for each relevant jurisdiction, one firm of specialty counsel, if applicable, and, in the event of any perceived or actual conflict of interest, an additional firm of counsel for any similarly affected persons), incurred by or asserted against any Indemnitee arising out of, in any way connected with, or as a result of (i) the execution or delivery of this Agreement or any other Loan Document or any agreement

or instrument contemplated hereby or thereby, the performance by the parties hereto and thereto of their respective obligations thereunder or the consummation of the Transactions and the other transactions contemplated hereby or thereby, (ii) the use or proposed use of the proceeds of the Loans, (iii) (A) any Environmental Claim related in any way to any Loan Party or any of its Subsidiaries or (B) any actual or alleged presence, Release or threatened Release of Hazardous Materials at, under, on or from any real property currently or formerly owned, leased or operated by any Loan Party or any of its Subsidiaries or by any predecessor of any Loan Party or any of its Subsidiaries, except to the extent such presence, Release or threatened Release first occurs after none of the Loan Parties or any of their Subsidiaries have possession or control of such real property or (C) the sending by any Loan Party or any of its Subsidiaries of any Hazardous Materials to any property for treatment, storage or disposal or (iv) any claim, litigation, investigation, inquiry or proceeding relating to any of the foregoing, whether or not the Borrower, any other Loan Party or any Indemnitee initiated or is a party thereto, in each case, whether or not caused by or arising, in whole or in part, out of the comparative, contributory or sole negligence of the Indemnitee; *provided* that such indemnity shall not, as to any Indemnitee, be available to the extent that such losses, claims, damages, liabilities or related expenses are determined in a final, non-appealable judgment by a court of competent jurisdiction to have resulted from (x) the gross negligence, bad faith, or willful misconduct of such Indemnitee or of any Related Indemnitee, (y) a material breach of this Agreement or any of the Loan Documents by such Indemnitee or by any Related Indemnitee or (z) any proceeding that does not involve an act or omission by any Loan Parties and that is brought by one Indemnitee against any other Indemnitee (other than any claims brought against any Agent or Lead Arranger in their respective capacities or fulfilling their respective roles as an arranger or agent or any similar role in connection with the Term Loan Facility). In no event shall any Indemnitee be liable to any Loan Party for any consequential, indirect, special or punitive damages. No Indemnitee shall be liable for any damages arising from the use by unintended recipients of any information or other materials distributed to such unintended recipients by such Indemnitee through telecommunications, electronic or other information transmission systems in connection with this Agreement or the other Loan Documents or the transactions contemplated hereby or thereby.

(c) All amounts due under this Section 9.05 shall be payable after written demand thereof accompanied by reasonable documentation with respect to any reimbursement, indemnification or other amount requested. This Section 9.05 shall not apply to Taxes other than any Taxes that represent losses, claims, damages, etc. to which Section 9.05 would otherwise apply arising from any non-Tax claim.

Section 9.06 *Right of Set-off* . If an Event of Default shall have occurred and be continuing, each Lender is hereby authorized at any time and from time to time, to the fullest extent permitted by law, to set off and apply any and all deposits (general or special, time or demand, provisional or final) at any time held and other indebtedness at any time owing by such Lender to or for the credit or the account of any Loan Party against any and all obligations of the Loan Parties now or hereafter existing under this Agreement or any other Loan Document held by such Lender, irrespective of whether or not such Lender shall have made any demand under this Agreement or such other Loan Document and although the obligations may be unmatured. The rights of each Lender under this Section 9.06 are in addition to other rights and remedies (including other rights of set-off) that such Lender may have. Each Lender agrees to notify the Borrower and the Administrative Agent promptly after any such setoff and application; *provided* that the failure to give such notice shall not affect the validity of such setoff and application.

Section 9.07 *Applicable Law* . THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS AND ANY DISPUTE, CLAIM OR CONTROVERSY ARISING OUT OF OR RELATING TO THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.

Section 9.08 *Waivers; Amendment* .

(a) No failure or delay of any Agent or any Lender in exercising any right or power hereunder or under any other Loan Document shall operate as a waiver thereof, nor shall any single or partial exercise of any such right or power, or any abandonment or discontinuance of steps to enforce such a right or power,

preclude any other or further exercise thereof or the exercise of any other right or power. The rights and remedies of the Agents and the Lenders hereunder and under the other Loan Documents are cumulative and are not exclusive of any rights or remedies that they would otherwise have. No waiver of any provision of this Agreement or any other Loan Document or consent to any departure by the Borrower or any other Loan Party therefrom shall in any event be effective unless the same shall be permitted by Section 9.08(b) , and then such waiver or consent shall be effective only in the specific instance and for the purpose for which given. No notice or demand on the Borrower or any other Loan Party in any case shall entitle such Person to any other or further notice or demand in similar or other circumstances.

(b) Neither this Agreement nor any other Loan Document nor any provision hereof or thereof may be waived, amended or modified except (x) in the case of this Agreement, pursuant to an agreement or agreements in writing entered into by the Borrower and the Required Lenders (or the Administrative Agent with the consent of the Required Lenders) and (y) in the case of any other Loan Document, pursuant to an agreement or agreements in writing entered into by each party thereto and consented to by the Required Lenders; *provided* , *however* , that no such agreement shall:

(i) decrease or forgive the principal amount of, or extend the final maturity of, or decrease the rate of interest on, any Loan, without the prior written consent of each Lender directly affected thereby,

(ii) increase or extend the Commitment of any Lender or decrease the fees payable to any Lender without the prior written consent of such Lender,

(iii) extend or waive any Scheduled Amortization Payment or reduce the amount due on any Scheduled Amortization Payment or extend any date on which payment of interest on any Loan or any Fee is due, without the prior written consent of each Lender adversely affected thereby,

(iv) amend or modify the provisions of Section 2.16(b) or (c) or any other provisions of this Agreement in a manner that would by its terms alter the *pro rata* sharing of payments required thereby or the application of payments required thereby, without the prior written consent of each Lender adversely affected thereby,

(v) amend or modify the provisions of Section 9.04(a)(i) or this Section 9.08 or the definition of the term “Required Lenders,” or any other provision hereof or of any other Loan Document specifying the number or percentage of Lenders required to waive, amend or modify any rights hereunder or under any other Loan Document or make any determination or grant any consent hereunder or under any other Loan Document, without the prior written consent of each Lender adversely affected thereby (it being understood that, with the consent of the Required Lenders, additional extensions of credit pursuant to this Agreement may be included in the determination of the Required Lenders on substantially the same basis as the Loans and Commitments are included on the Closing Date), or

(vi) release all or substantially all the Collateral or release any Guarantees of the Borrower, Holding, ExGen Renewables Holding or any other Loan Party, without the prior written consent of each Lender;

provided , *further* , that no such agreement shall amend, modify or otherwise affect the rights or duties of the Administrative Agent, the Depositary Bank or the Collateral Agent hereunder or under the other Loan Documents without the prior written consent of the Administrative Agent, the Depositary Bank or the Collateral Agent, as applicable. Each Lender shall be bound by any waiver, amendment or modification authorized by this Section 9.08 and any consent by any Lender pursuant to this Section 9.08 shall bind any assignee of such Lender.

(c) Without the consent of any Syndication Agent, Documentation Agent, Lead Arranger or Lender, the Loan Parties and the Administrative Agent, the Depositary Bank and/or Collateral Agent may (in their respective sole discretion, or shall, to the extent required by any Loan Document) enter into any amendment, modification or waiver of any Loan Document, or enter into any new agreement or instrument, to effect the granting, perfection, protection, expansion or enhancement of any security interest in any Collateral or additional property to become Collateral for the benefit of the Secured Parties, or as required by local law to give effect to or protect any security interest for the benefit of the Secured Parties in any property or so that the security interests therein comply with applicable law.

(d) Notwithstanding the foregoing, this Agreement may be amended (or amended and restated) with the written consent of the Required Lenders, the Administrative Agent and the Borrower (i) to add one or more additional credit facilities to this Agreement and to permit the extensions of credit from time to time outstanding thereunder and the accrued interest and fees in respect thereof to share ratably in the benefits of this Agreement and the other Loan Documents with the Loans and the accrued interest and fees in respect thereof and (ii) to include appropriately the Lenders holding such credit facilities in any determination of the Required Lenders.

(e) Notwithstanding the foregoing, any Loan Document may be amended, modified, supplemented or waived with the written consent of the Administrative Agent and the Borrower without the need to obtain the consent of any Lender if such amendment, modification, supplement or waiver is executed and delivered in order to cure an ambiguity, omission, mistake or defect in such Loan Document; *provided* that in connection with this clause (e) , in no event will the Administrative Agent be required to substitute its judgment for the judgment of the Lenders or the Required Lenders, and the Administrative Agent may in all circumstances seek the approval of the Required Lenders, the affected Lenders or all Lenders in connection with any such amendment, modification, supplement or waiver.

Section 9.09 *Interest Rate Limitation* . Notwithstanding anything herein to the contrary, if at any time the applicable interest rate, together with all fees and charges that are treated as interest under applicable law (collectively, the " **Charges** "), as provided for herein or in any other document executed in connection herewith, or otherwise contracted for, charged, received, taken or reserved by any Lender, shall exceed the maximum lawful rate (the " **Maximum Rate** ") that may be contracted for, charged, taken, received or reserved by such Lender in accordance with applicable law, the rate of interest payable hereunder, together with all Charges payable to such Lender, shall be limited to the Maximum Rate; *provided* that such excess amount shall be paid to such Lender on subsequent payment dates to the extent not exceeding the legal limitation.

Section 9.10 *Entire Agreement* . This Agreement, the other Loan Documents, the Fee Letters and the agreements regarding certain Fees referred to herein constitute the entire contract between the parties relative to the subject matter hereof and may not be contradicted by evidence of prior, contemporaneous or subsequent oral agreements of the parties. There are no unwritten oral agreements among the parties relative to the subject matter hereof. Any previous agreement among or representations from the parties or their Affiliates with respect to the subject matter hereof is superseded by this Agreement, the other Loan Documents and the Fee Letters. Notwithstanding the foregoing, Sections 2 (with respect to Fees), 4, 7 and 8 of the Engagement Letter shall survive the execution and delivery of this Agreement and

remain in full force and effect; *provided* , *however* , that Sponsor's obligations under Section 4 of the Engagement Letter shall automatically terminate and be deemed superseded immediately upon the execution and delivery of this Agreement. Nothing in this Agreement, in the other Loan Documents or in the Fee Letters, expressed or implied, is intended to confer upon any party other than the parties hereto and thereto any rights, remedies, obligations or liabilities under or by reason of this Agreement, the other Loan Documents or the Fee Letters.

Section 9.11 *Waiver of Jury Trial* . EACH PARTY HERETO HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN ANY LEGAL PROCEEDING DIRECTLY OR INDIRECTLY ARISING OUT OF OR RELATING TO THIS AGREEMENT OR ANY OTHER LOAN DOCUMENT. EACH PARTY HERETO (A) CERTIFIES THAT NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PERSON HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PERSON WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVER AND (B) ACKNOWLEDGES THAT IT AND THE OTHER PARTIES HERETO HAVE BEEN INDUCED TO ENTER INTO THIS AGREEMENT AND THE OTHER LOAN DOCUMENTS BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION 9.11 . EACH PARTY HERETO FURTHER REPRESENTS AND WARRANTS THAT IT HAS REVIEWED THIS WAIVER WITH ITS LEGAL COUNSEL AND THAT IT KNOWINGLY AND VOLUNTARILY WAIVES ITS JURY TRIAL RIGHTS FOLLOWING CONSULTATION WITH LEGAL COUNSEL.

Section 9.12 *Severability* . Any provision of this Agreement which is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. The parties hereto shall endeavor in good-faith negotiations to replace any invalid, illegal or unenforceable provisions with valid provisions the economic effect of which comes as close as possible to that of the invalid, illegal or unenforceable provisions.

Section 9.13 *Counterparts* . This Agreement may be executed by one or more of the parties to this Agreement on any number of separate counterparts (including by facsimile or other electronic imaging means), and all of said counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of an executed signature page of this Agreement by facsimile or other electronic transmission (e.g. ".pdf" or ".tif" format) shall be effective as delivery of a manually executed counterpart hereof.

Section 9.14 *Headings* . The article and section headings and Table of Contents used in this Agreement are for convenience of reference only and are not to affect the construction hereof or be taken into consideration in the interpretation hereof.

Section 9.15 *Jurisdiction; Consent to Service of Process* .

(a) Each of Holding and the Borrower, the Agents and the Lenders hereby irrevocably and unconditionally submits, for itself and its property, to the exclusive jurisdiction of any New York State court or federal court of the United States sitting in New York County, and any appellate court from any thereof, in any action or proceeding arising out of or relating to this Agreement or the other Loan Documents, or for recognition or enforcement of any judgment, and each of the parties hereto hereby irrevocably and unconditionally agrees that all claims in respect of any such action or proceeding may be heard and determined in such New York State or, to the extent permitted by law, in such federal court. Each of Holding and the Borrower further irrevocably consents to the service of process in any action or proceeding in such courts by the mailing thereof by any parties thereto by registered or certified mail, postage prepaid, to such Person at the address specified for the Loan Parties in Section 9.01 . Each of the parties hereto agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Nothing in this Agreement (other than

Section 8.09 or Section 8.14) shall affect any right that any Lender or Agent may otherwise have to bring any action or proceeding to enforce this Agreement or the other Loan Documents against the Borrower or any other Loan Party in the courts of any jurisdiction in which the Borrower, the Loan Parties or their properties are located.

(b) Each of Holding, the Borrower, the Agents, and the Lenders hereby irrevocably and unconditionally waives, to the fullest extent it may legally and effectively do so, any objection which it may now or hereafter have to the laying of venue of any suit, action or proceeding arising out of or relating to this Agreement or the other Loan Documents in any New York State or federal court sitting in New York County. Each of the parties hereto hereby irrevocably waives, to the fullest extent permitted by law, the defense of an inconvenient forum to the maintenance of such action or proceeding in any such court.

Section 9.16 *Confidentiality* . Each of the Lenders and each of the Agents agrees to maintain the confidentiality of the Information (as defined below), except that Information may be disclosed (a) to its Affiliates and to its Related Parties (it being understood that the Persons to whom such disclosure is made will be informed of the confidential nature of such Information and instructed to keep such Information confidential); (b) to the extent required or requested by any regulatory authority purporting to have jurisdiction over such Person or its Related Parties (including any self-regulatory authority, such as the National Association of Insurance Commissioners); (c) to the extent required by applicable laws or regulations or by any subpoena or similar legal process; (d) to any other party hereto; (e) in connection with the exercise of any remedies hereunder or under any other Loan Document or any action or proceeding relating to this Agreement or any other Loan Document or the enforcement of rights hereunder or thereunder; (f) subject to an agreement containing provisions substantially the same as those of this Section, to (i) any assignee of or Participant in, or any prospective assignee of or Participant in, any of its rights and obligations under this Agreement, or (ii) any actual or prospective party (or its Related Parties) to any swap, derivative or other transaction under which payments are to be made by reference to the Borrower and its obligations, this Agreement or payments hereunder (it being understood that the Information may be disclosed to any assignee or Participant, or prospective assignee or Participant, in reliance on this clause (f)); (g) on a confidential basis to (i) any rating agency in connection with rating the Borrower or its Subsidiaries or the Term Loan Facility or (ii) the CUSIP Service Bureau or any similar agency in connection with the issuance and monitoring of CUSIP numbers with respect to the Term Loan Facility; (h) with the consent of the Borrower; or (i) to the extent such Information (x) becomes publicly available other than as a result of a breach of this Section, or (y) becomes available to any Lender, any Agent or any of their respective Affiliates on a nonconfidential basis from a source other than the Borrower. In addition, each Agent and each Lender may disclose the existence of this Agreement and information about this Agreement to market data collectors, similar service providers to the lending industry and service providers to the Agents and the Lenders in connection with the administration of this Agreement, the other Loan Documents, and the Commitments.

For purposes of this Section, " Information " means all information received from the Borrower, Holding or any of its Subsidiaries relating to the Borrower, Holding, any of their respective Subsidiaries or any of their respective businesses, other than any such information that is available to any Lender or any Agent on a nonconfidential basis prior to disclosure by the Borrower or any of its Subsidiaries; *provided* that, in the case of information received from the Borrower or any of its Subsidiaries after the date hereof, such information is clearly identified at the time of delivery as confidential. Any Person required to maintain the confidentiality of Information as provided in this Section shall be considered to have complied with its obligation to do so if such Person has exercised the same degree of care to maintain the confidentiality of such Information as such Person would accord to its own confidential information.

Section 9.17 *Communications* .

(a) *Delivery* .

(i) Each Loan Party hereby agrees that it will use all reasonable efforts to provide to the Administrative Agent all information, documents and other materials that it is obligated to furnish

to the Administrative Agent pursuant to this Agreement and any other Loan Document, including all notices, requests, financial statements, financial and other reports, certificates and other information materials, but excluding any such communication that (A) relates to a request for a new, or a conversion of an existing, borrowing or other extension of credit (including any election of an interest rate or interest period relating thereto), (B) relates to the payment of any principal or other amount due under this Agreement prior to 5:00 p.m. (New York City time) on the scheduled date therefor, (C) provides notice of any Default or Event of Default under this Agreement or (D) is required to be delivered to satisfy any condition precedent to the effectiveness of this Agreement and/or any borrowing or other extension of credit hereunder (all such non-excluded communications collectively, the " **Communications** "), by transmitting the Communications in an electronic/soft medium in a format reasonably acceptable to the Administrative Agent at the address referenced in Section 9.01(a)(ii) . Nothing in this Section 9.17 shall prejudice the right of the Agents, the Syndication Agent, the Documentation Agent, the Lead Arranger or any Lender or any Loan Party to give any notice or other communication pursuant to this Agreement or any other Loan Document in any other manner specified in this Agreement or any other Loan Document.

(ii) The Administrative Agent agrees that receipt of the Communications by the Administrative Agent at the email address referenced in Schedule 9.01(a)(ii) shall constitute effective delivery of the Communications to the Administrative Agent for purposes of the Loan Documents. Each Lender agrees that notice to it (as provided in the next sentence) specifying that the Communications have been posted to the Platform shall constitute effective delivery of the Communications to such Lender for purposes of the Loan Documents. Each Lender agrees (A) to notify the Administrative Agent in writing (including by electronic communication) from time to time of such Lender's e-mail address to which the foregoing notice may be sent by electronic transmission and (B) that the foregoing notice may be sent to such e-mail address.

(b) *Posting* . Each Loan Party further agrees that the Administrative Agent may make the Communications available to the Lenders by posting the Communications on Intralinks, SyndTrak or a substantially similar electronic transmission system (the " **Platform** "). The Borrower hereby acknowledges that (i) the Administrative Agent and/or the Lead Arranger will make available to the Lenders materials and/or information provided by or on behalf of the Borrower hereunder (collectively, " **Borrower Materials** ") by posting the Borrower Materials on the Platform and (ii) certain of the Lenders (each, a " **Public Lender** ") may have personnel who wish to receive information that is not material non-public information concerning the Loan Parties, their Subsidiaries or their securities, if any, for purposes of United States Federal securities laws, (collectively, " **Public Side Information** ") and who may be engaged in investment and other market-related activities with respect to such Persons' securities. In addition, the Borrower and the Agents agree that unless specifically labeled "Public - Does Not Contain Material Non-Public Information," all information, documentation or other data disseminated to prospective Lenders in connection with the syndication of the Term Loan Facility, whether through an Internet site (including, without limitation, an IntraLinks or SyndTrak workspace), electronically, in presentations, at meetings or otherwise will be deemed to contain material non-public information concerning the Borrower, its Affiliates or their securities. The Borrower hereby agrees to identify that portion of the Borrower Materials that may be distributed to the Public Lenders and that (w) all such Borrower Materials shall be clearly and conspicuously marked "Public - Does Not Contain Material Non-Public Information," at a minimum, prominently on the first page thereof; (x) by marking Borrower Materials "Public - Does Not Contain Material Non-Public Information," the Borrower shall be deemed to have authorized the Administrative Agent, the Lead Arranger and the Lenders to treat such Borrower Materials as containing only Public Side Information (although it may be sensitive and proprietary); (y) all Borrower Materials marked "Public - Does Not Contain Material Non-Public Information" are permitted to be made available through a portion of the Platform designated "Public Side Information;" and (z) the Administrative Agent and the Lead Arranger shall be entitled to treat the Borrower Materials that are not marked "Public - Does Not Contain Material Non-Public Information" as being suitable only for posting on a portion of the Platform not designated Public Side Information. Notwithstanding the foregoing, no Borrower shall be under any obligation to mark Borrower Materials "Public - Does Not Contain Material Non-Public Information" to

the extent such Borrower determines that such Borrower Materials contain information that is not Public Side Information with respect to such Borrower or its Affiliates or their respective securities.

(c) *Platform* . The Platform is provided "as is" and "as available." The Agent Parties do not warrant the accuracy or completeness of the Communications, or the adequacy of the Platform and expressly disclaim liability for errors or omissions in the Communications. No warranty of any kind, express, implied or statutory, including any warranty of merchantability, fitness for a particular purpose, non-infringement of third party rights or freedom from viruses or other code defects, is made by any Agent Party in connection with the Communications or the Platform. In no event shall the Administrative Agent, the Collateral Agent or any of its or their affiliates or any of their respective officers, directors, employees, agents advisors or representatives (collectively, " **Agent Parties** ") have any liability to the Loan Parties, any Lender or any other Person or entity for damages of any kind, including direct or indirect, special, incidental or consequential damages, losses or expenses (whether in tort, contract or otherwise) arising out of any Loan Party's or the Administrative Agent's or the Collateral Agent's transmission of communications through the internet, except to the extent the liability of any Agent Party is found in a final, non-appealable judgment by a court of competent jurisdiction to have resulted primarily from such Agent Party's gross negligence or willful misconduct.

Section 9.18 *Release of Liens and Guarantees* . In the event that any Loan Party conveys, sells, leases, assigns, transfers or otherwise disposes of all or any portion of its assets (including the Equity Interests of any of its Subsidiaries) to a Person that is not (and is not required to become) a Loan Party in a transaction not prohibited by the Loan Documents, the Administrative Agent and the Collateral Agent shall promptly (and the Lenders hereby authorize the Administrative Agent and the Collateral Agent to) take such action and execute any such documents as may be reasonably requested by the Borrower and at the Borrower's expense to release any Liens created by any Loan Document in respect of such Equity Interests or assets that are the subject of such disposition. Any representation, warranty or covenant contained in any Loan Document relating to any such Equity Interests or assets shall no longer be deemed to be made once such Equity Interests or assets are so conveyed, sold, leased, assigned, transferred or disposed of. The Security Documents, the guarantees made therein, the Security Interest (as defined therein) and all other security interests granted thereby shall terminate, and each Loan Party shall automatically be released from its obligations thereunder and the security interests in the Collateral granted by any Loan Party shall be automatically released, upon the Discharge of the Obligations. At such time, the Administrative Agent and the Collateral Agent agree to take such actions as are reasonably requested by the Borrower at the Borrower's expense to evidence and effectuate such termination and release of the guarantees, Liens and security interests created by the Loan Documents.

Section 9.19 *Acknowledgment and Consent to Bail-in of EEA Financial Institutions* . Notwithstanding any other term of any Loan Document or any other agreement, arrangement or understanding among any such parties, each party acknowledges and accepts that any liability of any party to any other party under or in connection with the Loan Documents may be subject to Bail-In Action by the relevant Resolution Authority and acknowledges and accepts to be bound by the effect of:

(a) any Bail-In Action in relation to any such liability, including (without limitation):

(i) a reduction, in full or in part, in the principal amount, or outstanding amount due (including any accrued but unpaid interest) in respect of any such liability;

(ii) a conversion of all, or part of, any such liability, into shares or other instruments of ownership that may be issued to, or conferred on, it; and

(iii) a cancellation of any such liability; and

(b) variation of any term of any Loan Document to the extent necessary to give effect to any Bail-In Action in relation to any such liability.

Section 9.20 *U.S.A. PATRIOT Act and Similar Legislation* . Each Agent and each Lender hereby notifies each Loan Party that pursuant to the requirements of the U.S.A. PATRIOT Act and similar legislation, as applicable, it is required to obtain, verify and record information that identifies the Loan Parties, which information includes the name and address of each Loan Party and other information that will allow the Agents and the Lenders to identify such Loan Party in accordance with such legislation. Each Loan Party agrees to furnish such information promptly upon its receipt of a written request therefor from an Agent or a Lender.

Section 9.21 *No Fiduciary Duty* . Each Agent, each Lender and their respective Affiliates (collectively, solely for purposes of this Section 9.21 , the " **Lenders** "), may have economic interests that conflict with those of the Borrower and the other Loan Parties. Each of Holding and the Borrower hereby agrees, on behalf of itself and the other Loan Parties, that subject to applicable law, nothing in the Loan Documents or otherwise will be deemed to create an advisory, fiduciary or agency relationship or fiduciary or other implied duty between the Lenders and the Loan Parties, their equity-holders or their Affiliates. Each of Holding and the Borrower hereby acknowledges and agrees, on behalf of itself and the other Loan Parties, that (i) the transactions contemplated by the Loan Documents are arm's-length commercial transactions between the Lenders, on the one hand, and the Loan Parties, on the other, (ii) in connection therewith and with the process leading to such transaction none of the Lenders is acting as the agent or fiduciary of any Loan Party, its management, equity-holders, creditors or any other person, (iii) no Lender has assumed an advisory or fiduciary responsibility in favor of any Loan Party with respect to the transactions contemplated hereby or the process leading thereto (irrespective of whether any Lender or any of its Affiliates has advised or is currently advising such Loan Party on other matters) or any other obligation to any Loan Party except the obligations expressly set forth in the Loan Documents, (iv) each of the Borrower and each other Loan Party has consulted its own legal and financial advisors to the extent it has deemed appropriate, (v) the Lenders may be engaged in a broad range of transactions that involve interests that differ from those of the Borrower and its Affiliates and no Lender has an obligation to disclose any such interests to the Borrower or its Affiliates and (vi) it will not claim that any Lender has rendered advisory services of any nature or respect, or owes a fiduciary or similar duty to it in connection with such transaction or the process leading thereto, and agrees that each Lender shall have no liability (whether direct or indirect) in respect to such a claim or to any other Person asserting such a claim on their behalf. Each of Holding and the Borrower further acknowledges and agrees that it is responsible for making its own independent judgment with respect to such transactions and the process leading thereto.

Section 9.22 *Affiliated Lenders* . Notwithstanding anything in this Agreement or any other Loan Document to the contrary, with respect to any Loans at any time held by an Affiliated Lender, such Affiliated Lender shall have no right whatsoever, in its capacity as a Lender with respect to such Loans then held by such Affiliated Lender, whether or not any Loan Party is subject to a bankruptcy or other insolvency proceeding or otherwise, so long as such Lender is an Affiliated Lender, to (i) consent to any amendment, modification, waiver, consent or other such action with respect to, or otherwise vote on any matter related to, or vote in connection with any direction delivered to the Administrative Agent or the Collateral Agent by the Required Lenders pursuant to, any of the terms of the Agreement or any other Loan Document, in each case to the extent such amendment, modification, waiver, consent, other action, vote or direction is effective with only the consent of or action by the Required Lenders (each, a " **Required Lender Vote/Directive** ") and, if applicable, the Borrower or any other Loan Party; *provided* that for purposes of any Required Lender Vote/Directive, the Administrative Agent shall automatically deem any Loans held by such Affiliated Lender to be voted on a *pro rata* basis in accordance with the votes cast in respect of the Loans of all other Lenders in the aggregate (other than any Affiliated Lender) in connection with any such Required Lender Vote/Directive (including all voting and consent rights arising out of any bankruptcy or other insolvency proceedings (except for voting on any plan of reorganization or refraining from voting on any plan of reorganization, in which case the Administrative Agent shall vote or refrain from voting such Loans of such Affiliated Lender in the Administrative Agent's sole discretion)); *provided* , *further* , that no such Required Lender Vote/Directive shall

deprive such Affiliated Lender of its share of any payments or other recoveries which the Lenders are entitled to share on a *pro rata* basis under the Loan Documents and such Affiliated Lender's vote shall be counted to the extent any such plan of reorganization or other amendment proposes to treat the Obligations of the Affiliated Lender in a manner less favorable in any material respect to such Affiliated Lender than the proposed treatment of Obligations held by Lenders that are not Affiliates of the Borrower, (ii) attend any meeting (live or by any electronic means) in such Affiliated Lender's capacity as a Lender with any Agent or other Lender or receive any information from any Agent or other Lender except to the extent such information is made available to any Loan Party (or its representatives) and other than administrative notices given to all Lenders under Article II or (iii) have access to the Platform in such Affiliated Lender's capacity as a Lender.

Section 9.23 *Certain ERISA Matters* .

(a) Each Lender (x) represents and warrants, as of the date such Person became a Lender party hereto, to, and (y) covenants, from the date such Person became a Lender party hereto to the date such Person ceases being a Lender party hereto, solely for the benefit of, MSSF, the Administrative Agent, the Collateral Agent and the Lead Arranger and their respective Affiliates (the " **Relevant Parties** "), and not, for the avoidance of doubt, to or for the benefit of the Borrower, Holdings or any other Loan Party, that at least one of the following is and will be true:

(i) such Lender is not using "plan assets" (within the meaning of 29 CFR Section 2510.3-101, as modified by Section 3(42) of ERISA) of one or more Benefit Plans in connection with the Loans or the Commitments;

(ii) the transaction exemption set forth in one or more PTEs, such as PTE 84-14 (a class exemption for certain transactions determined by independent qualified professional asset managers), PTE 95-60 (a class exemption for certain transactions involving insurance company general accounts), PTE 90-1 (a class exemption for certain transactions involving insurance company pooled separate accounts), PTE 91-38 (a class exemption for certain transactions involving bank collective investment funds) or PTE 96-23 (a class exemption for certain transactions determined by in-house asset managers), is applicable with respect to such Lender's entrance into, participation in, administration of and performance of the Loans, the Commitments and this Agreement;

(iii) (A) such Lender is an investment fund managed by a "Qualified Professional Asset Manager" (within the meaning of Part VI of PTE 84-14), (B) such Qualified Professional Asset Manager made the investment decision on behalf of such Lender to enter into, participate in, administer and perform the Loans, the Commitments and this Agreement, (C) the entrance into, participation in, administration of and performance of the Loans, the Commitments and this Agreement satisfies the requirements of sub-sections (b) through (g) of Part I of PTE 84-14 and (D) to the best knowledge of such Lender, the requirements of subsection (a) of Part I of PTE 84-14 are satisfied with respect to such Lender's entrance into, participation in, administration of and performance of the Loans, the Commitments and this Agreement; or

(iv) such other representation, warranty and covenant as may be agreed in writing between the Administrative Agent, in its sole discretion, and such Lender.

(b) In addition, (I) unless sub-clause (i) in the immediately preceding clause (a) is true with respect to a Lender or (II) if such sub-clause (i) is not true with respect to a Lender and such Lender has not provided another representation, warranty and covenant as provided in sub-clause (iv) in the immediately preceding clause (a) , such Lender further (x) represents and warrants, as of the date such Person became a Lender party hereto, to, and (y) covenants, from the date such Person became a Lender party hereto to the date such Person ceases being a Lender party hereto, for the benefit of, the

Relevant Entities, and not, for the avoidance of doubt, to or for the benefit of the Borrower, Holdings or any other Loan Party, that:

(i) none of the Relevant Entities is a fiduciary with respect to the assets of such Lender (including in connection with the reservation or exercise of any rights by the Administrative Agent under this Agreement, or any of the other Loan Documents);

(ii) the Person making the investment decision on behalf of such Lender with respect to the entrance into, participation in, administration of and performance of the Loans the Commitments and this Agreement is independent (within the meaning of 29 CFR § 2510.3-21, as amended from time to time) and is a bank, an insurance carrier, a registered investment adviser, a registered broker-dealer or other person that has under management or control, total assets of at least $50 million, in each case as described in 29 CFR § 2510.3-21(c)(1)(i)(A)-(E), as amended from time to time;

(iii) the Person making the investment decision on behalf of such Lender with respect to the entrance into, participation in, administration of and performance of the Loans, the Commitments and this Agreement is capable of evaluating investment risks independently, both in general and with regard to particular transactions and investment strategies (including in respect of the Obligations);

(iv) the Person making the investment decision on behalf of such Lender with respect to the entrance into, participation in, administration of and performance of the Loans, the Commitments and this Agreement is a fiduciary under ERISA or the Code, or both, with respect to the Loans, the Commitments and this Agreement and is responsible for exercising independent judgment in evaluating the transactions hereunder; and

(v) no fee or other compensation is being paid directly to any Relevant Entity for investment advice (as opposed to other services) in connection with the Loans, the Commitments or this Agreement.

(c) Each of MSSF, the Administrative Agent, the Collateral Agent and the Lead Arranger hereby informs the Lenders that each such Person is not undertaking to provide impartial investment advice, or to give advice in a fiduciary capacity, in connection with the transactions contemplated hereby, and that such Person has a financial interest in the transactions contemplated hereby in that such Person or an Affiliate thereof (i) may receive interest or other payments with respect to the Loans, the Commitments and this Agreement, (ii) may recognize a gain if it extended the Loans or the Commitments for an amount less than the amount being paid for an interest in the Loans or the Commitments by such Lender or (iii) may receive fees or other payments in connection with the transactions contemplated hereby, the Loan Documents or otherwise, including structuring fees, commitment fees, arrangement fees, facility fees, upfront fees, underwriting fees, ticking fees, agency fees, administrative agent or collateral agent fees, utilization fees, minimum usage fees, letter of credit fees, fronting fees, deal-away or alternate transaction fees, amendment fees, processing fees, term out premiums, banker's acceptance fees, breakage or other early termination fees or fees similar to the foregoing.

For purposes of this Section 9.23 , the following definitions apply to each of the capitalized terms below:

" **Benefit Plan** " means any of (a) an "employee benefit plan" (as defined in ERISA) that is subject to Title I of ERISA, (b) a "plan" as defined in Section 4975 of the Code, to which Section 4975 of the Code applies or (c) any Person whose assets include (for purposes of ERISA Section 3(42) or otherwise for purposes of Title I of ERISA or Section 4975 of the Code) the assets of any such "employee benefit plan" or "plan".

" **PTE** " means a prohibited transaction class exemption issued by the U.S. Department of Labor, as any such exemption may be amended from time to time.

Section 9.24 *No Personal Liability of Directors, Officers, Employees and Equityholders* . No past, present or future director, officer, representative, Controlling person, executive, agent, employee, incorporator or shareholder (whether direct or indirect) of any Loan Party (including any holder of any membership interests in any Loan Party), as such, will have any liability for any obligations of any Loan Party under any Loan Document or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each Agent and Lender and other Secured Party hereby waives and releases all such liability. The waiver and release are part of the consideration for the incurrence of the Obligations and establishment of the Term Loan Facility.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their respective officers thereunto duly authorized, as of the date first above written.

EXGEN RENEWABLES IV, LLC,
as Borrower

By: _____
Name:
Title:

EXGEN RENEWABLES IV HOLDING, LLC,
as Holding

By: _____
Name:
Title:

MORGAN STANLEY SENIOR FUNDING, INC.,
as Administrative Agent, Syndication Agent, Documentation Agent and a Lender

By: _____
Name:
Title:

WILMINGTON TRUST, NATIONAL ASSOCIATION,
as Depositary Bank and Collateral Agent

By: _____
Name:
Title:

FORM OF
ASSIGNMENT AND ACCEPTANCE

This Assignment and Acceptance (the " **Assignment and Acceptance** ") is dated as of the Effective Date (as defined below) and is entered into by and between [INSERT NAME OF ASSIGNOR] (the " **Assignor** ") and [INSERT NAMES OF ASSIGNEE(S)] (the " **Assignee[s]** "). [It is understood and agreed that the rights and obligations of the Assignees hereunder are several and not joint]. Capitalized terms used but not defined herein shall have the meanings given to them in the Credit Agreement identified below (as may be amended from time to time, the " **Credit Agreement** "), receipt of a copy of which is hereby acknowledged by [the][each] Assignee. The Standard Terms and Conditions set forth in Annex 1 attached hereto (the " **Standard Terms and Conditions** ") are hereby agreed to and incorporated herein by reference and made a part of this Assignment and Acceptance as if set forth herein in full.

For an agreed consideration, the Assignor hereby irrevocably sells and assigns to [the][each] Assignee, and [the][each] Assignee hereby irrevocably purchases and assumes from the Assignor, subject to and in accordance with the Standard Terms and Conditions and the Credit Agreement, as of the Effective Date inserted by the Administrative Agent as contemplated below, (i) all of the Assignor's rights and obligations in its capacity as a Lender under the Credit Agreement and any other documents or instruments delivered pursuant thereto to the extent related to the amount and percentage interest identified below of all of such outstanding rights and obligations of the Assignor under the respective facilities identified below and (ii) to the extent permitted to be assigned under applicable law, all claims, suits, causes of action and any other right of the Assignor (in its capacity as a Lender) against any person, whether known or unknown, arising under or in connection with the Credit Agreement, any other documents or instruments delivered pursuant thereto or the loan transactions governed thereby or in any way based on or related to any of the foregoing, including contract claims, tort claims, malpractice claims, statutory claims and all other claims at law or in equity related to the rights and obligations sold and assigned pursuant to clause (i) above (the rights and obligations sold and assigned pursuant to clauses (i) and (ii) above being referred to herein collectively as the " **Assigned Interest** "). Such sale and assignment is without recourse to the Assignor and, except as expressly provided in this Assignment and Acceptance, without representation or warranty by the Assignor.

1. Assignor: _____

2. Assignee[(s)]: _____
[is a Lender][is an Affiliate/Approved Fund of [Identify Lender]][is an Eligible Assignee]

3. Administrative Agent: Morgan Stanley Senior Funding, Inc.

4. Credit Agreement: The Credit Agreement, dated as of November 28, 2017, among EXGEN RENEWABLES IV, LLC, a limited liability company organized under the laws of Delaware (the " **Borrower** "), EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" **Holding** "), the LENDERS party thereto from time to time, MORGAN STANLEY SENIOR FUNDING, INC., as Administrative Agent, WILMINGTON TRUST, NATIONAL ASSOCIATION, as Collateral Agent and WILMINGTON TRUST, NATIONAL ASSOCIATION, as Depositary Bank.

5. Assigned Interest Add additional table for each Assignee [1] :

Facility Assigned	Aggregate Amount of Commitment/ Loans for all Lenders	Amount of Commitment/Loans Assigned	Percentage Assigned of Commitment/ Loans*
Term Loan Facility	U.S. $850,000,000	U.S. $[___]	%

Effective Date: _____, __, 20__ (the " **Effective Date** "). [TO BE INSERTED BY ADMINISTRATIVE AGENT AND WHICH SHALL BE THE EFFECTIVE DATE OF RECORDATION OF TRANSFER IN THE REGISTER THEREFOR.]

[1] Add additional table for each Assignee.

* Calculate to nine (9) decimal places and show as a percentage of aggregate Loans of all Lenders in respect of the Term Loan Facility.

The terms set forth in this Assignment and Acceptance are hereby agreed to:

ASSIGNOR [NAME OF ASSIGNOR]
By: _____
Name:
Title:

ASSIGNEE [NAME OF ASSIGNEE] [2]

By: _____
Name:
Title:

[Consented [3] to and accepted:

MORGAN STANLEY SENIOR FUNDING, INC.,
as Administrative Agent
By: _____
Name:
Title:]

---

[2] Add additional signature blocks if there is more than one Assignee.

[3] Consent of the Administrative Agent to be included to the extent required by Section 9.04(b) of the Credit Agreement.

STANDARD TERMS AND CONDITIONS FOR ASSIGNMENT AND ACCEPTANCE

1. *Representations and Warranties* .

1.1 *Assignor* . The Assignor (a) represents and warrants that (i) it is the legal and beneficial owner of the Assigned Interest, (ii) the Assigned Interest is free and clear of any Lien, encumbrance or other adverse claim, (iii) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Acceptance and to consummate the transactions contemplated hereby and (iv) the assignment and assumption pursuant hereto complies with the terms of the Credit Agreement; and (b) assumes no responsibility with respect to (i) any statements, warranties or representations made in or in connection with the Credit Agreement or any other Loan Document, (ii) the execution, legality, validity, enforceability, genuineness, sufficiency or value of the Loan Documents or any collateral thereunder, (iii) the financial condition of any Loan Party or any Affiliates thereof, or any other person obligated in respect of any Loan Document or (iv) the performance or observance by any Loan Party or any Affiliates thereof or any other Person of any of their respective obligations under any Loan Document.

1.2 *Assignee* . [The] [Each] Assignee (a) represents and warrants that (i) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Acceptance and to consummate the transactions contemplated hereby and to become a Lender under the Credit Agreement, (ii) it meets all the requirements of an Eligible Assignee under the Credit Agreement and satisfies the requirements specified in Section 9.04(b) of the Credit Agreement that are required to be satisfied by it in order to acquire the Assigned Interest and become a Lender, (iii) from and after the Effective Date, it shall be bound by the provisions of the Credit Agreement as a Lender thereunder and, to the extent of the Assigned Interest, shall have the obligations of a Lender thereunder, (iv) it is sophisticated with respect to decisions to acquire assets of the type represented by the Assigned Interest and either it, or the person exercising discretion in making its decision to acquire the Assigned Interest, is experienced in acquiring assets of such type, (v) it has received a copy of the Credit Agreement, together with copies of the most recent financial statements delivered pursuant to Section 5.04 thereof, as applicable, and such other documents and information as it has deemed appropriate to make its own credit analysis and decision to enter into this Assignment and Acceptance and to purchase the Assigned Interest on the basis of which it has made such analysis and decision independently and without reliance on any Agent or any other Lender, (vi) attached to this Assignment and Acceptance is any documentation required to be delivered by it pursuant to the terms of the Credit Agreement, duly completed and executed by [the] [each] Assignee, (vii) the assignment and assumption pursuant hereto complies with the terms of the Credit Agreement and (viii) if it is a Non-U.S. Lender, attached to this Assignment and Acceptance is any documentation required to be delivered by it pursuant to the terms of the Credit Agreement, duly completed and executed by the Assignee; (b) appoints and authorizes the Agents to take such action as agent on its behalf and to exercise such powers and discretion under the Credit Agreement, the other Loan Documents or any other instrument or document furnished pursuant hereto or thereto as are delegated to the Agents by the terms thereof, together with such powers as are incidental thereto, including, without limitation, pursuant to Section 8.05 of the Credit Agreement; and (c) agrees that (i) it will, independently and without reliance on any Agent, the Assignor or any other Lender and, based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Loan Documents, and (ii) it will perform in accordance with their terms all of the obligations which by the terms of the Loan Documents are required to be performed by it as a Lender.

2. *Payments* . From and after the Effective Date, the Administrative Agent shall make all payments in respect of the Assigned Interest (including payments of principal, interest, fees and other

amounts) to the Assignor for amounts which have accrued to but excluding the Effective Date and to [the] [each] Assignee for amounts which have accrued from and after the Effective Date.

3. *General Provisions* . This Assignment and Acceptance shall be binding upon, and inure to the benefit of, the parties hereto and their respective successors and assigns. This Assignment and Acceptance may be executed in any number of counterparts, which together shall constitute one instrument. Delivery of an executed counterpart of a signature page of this Assignment and Acceptance by telecopy or other electronic transmission shall be effective as delivery of a manually executed counterpart of this Assignment and Acceptance; *provided* , *however* , that it shall be promptly followed by an original. This Assignment and Acceptance shall be governed by, and construed in accordance with, the law of the State of New York.

FORM OF
AFFILIATED LENDER ASSIGNMENT AND ACCEPTANCE

This Affiliated Lender Assignment and Acceptance (the " **Affiliated Lender Assignment and Acceptance** ") is dated as of the Effective Date (as defined below) and is entered into by and between **[** Insert name of Assignor **]** (the " **Assignor** ") and **[** Insert names of Assignee(s)] (the " **Assignee[s]** "). [It is understood and agreed that the rights and obligations of the Assignees hereunder are several and not joint]. Capitalized terms used but not defined herein shall have the meanings given to them in the Credit Agreement identified below (as may be amended from time to time, the " **Credit Agreement** "), receipt of a copy of which is hereby acknowledged by **[** the **] [** each **]** Assignee. The Standard Terms and Conditions set forth in Annex 1 attached hereto (the " **Standard Terms and Conditions** ") are hereby agreed to and incorporated herein by reference and made a part of this Affiliated Lender Assignment and Acceptance as if set forth herein in full.

For an agreed consideration, the Assignor hereby irrevocably sells and assigns to **[** the **] [** each **]** Assignee, and **[** the **] [** each **]** Assignee hereby irrevocably purchases and assumes from the Assignor, subject to and in accordance with the Standard Terms and Conditions and the Credit Agreement, as of the Effective Date inserted by the Administrative Agent as contemplated below (i) all of the Assignor's rights and obligations in its capacity as a Lender under the Credit Agreement and any other documents or instruments delivered pursuant thereto to the extent related to the amount and percentage interest identified below of all of such outstanding rights and obligations of the Assignor under the respective facilities identified below and (ii) to the extent permitted to be assigned under applicable law, all claims, suits, causes of action and any other right of the Assignor (in its capacity as a Lender) against any person, whether known or unknown, arising under or in connection with the Credit Agreement, any other documents or instruments delivered pursuant thereto or the loan transactions governed thereby or in any way based on or related to any of the foregoing, including contract claims, tort claims, malpractice claims, statutory claims and all other claims at law or in equity related to the rights and obligations sold and assigned pursuant to clause (i) above (the rights and obligations sold and assigned pursuant to clauses (i) and (ii) above being referred to herein collectively as the " **Assigned Interest** "). Such sale and assignment is without recourse to the Assignor and, except as expressly provided in this Affiliated Lender Assignment and Acceptance, without representation or warranty by the Assignor.

1. Assignor : _____ [is an Affiliated Lender].

2. Assignee **[** s **]** : _____ [is an Affiliated Lender].

3. Administrative Agent: MORGAN STANLEY SENIOR FUNDING, INC.

4. Credit Agreement: The Credit Agreement, dated as of November 28, 2017, among EXGEN RENEWABLES IV, LLC, a limited liability company organized under the laws of Delaware (the " **Borrower** "), EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" **Holding** "), the LENDERS party thereto from time to time, MORGAN STANLEY SENIOR FUNDING, INC., as Administrative Agent, WILMINGTON TRUST, NATIONAL ASSOCIATION, as Collateral Agent and WILMINGTON TRUST, NATIONAL ASSOCIATION, as Depositary Bank.

5. Assigned Interest [1]:

Facility Assigned	Aggregate Amount of Commitment/ Loans for all Lenders	Amount of Commitment/Loans Assigned	Percentage Assigned of Commitment/ Loans [2]
Term Loan Facility	U.S. $850,000,000	U.S. $[____]	%

Effective Date: _____, __, 20__ (the " **Effective Date** "). **[** TO BE INSERTED BY ADMINISTRATIVE AGENT AND WHICH SHALL BE THE EFFECTIVE DATE OF RECORDATION OF TRANSFER IN THE REGISTER THEREFOR. **]**

6. [Additional Representations and Covenants of Assignee . **[** The **][** Each **]** Assignee represents and warrants that (a) it is an Affiliated Lender pursuant to Section 9.04(e) of the Credit Agreement; (b) no Default or Event of Default has occurred or is continuing or would result therefrom, and (c) as of the Effective Date, after giving effect to this Affiliated Lender Assignment and Assumption, the aggregate principal amount of the Loans and Commitments held by all Affiliated Lenders does not exceed 25.0% of the total Commitments and Loans outstanding. By executing this Affiliated Lender Assignment and Assumption, each Affiliated Lender agrees to be bound by the terms of Section 9.22 of the Credit Agreement.] [3]

7. [Additional Representations and Covenants of Assignor . The Assignor represents and warrants that (a) it is an Affiliated Lender pursuant to Section 9.04(e) of the Credit Agreement; (b) no Default or Event of Default has occurred or is continuing or would result therefrom, and (c) as of the Effective Date, after giving effect to this Affiliated Lender Assignment and Assumption, the aggregate principal amount of the Loans and Commitments held by all Affiliated Lenders does not exceed 25.0% of the total Commitments and Loans outstanding. By executing this Affiliated Lender Assignment and Assumption, each Affiliated Lender agrees to be bound by the terms of Section 9.22 of the Credit Agreement.] [4]

_____

[1] Add additional table for each Assignee.

[2] Calculate to nine (9) decimal places and show as a percentage of aggregate Loans of all Lenders in respect of the Term Loan Facility.

[3] Only to be included if the Assignee is the Affiliated Lender.

[4] Only to be included if the Assignor is the Affiliated Lender.

The terms set forth in this Affiliated Lender Assignment and Acceptance are hereby agreed to:

ASSIGNOR **[** NAME OF ASSIGNOR **]**

By: _____
Name:
Title:

ASSIGNEE **[** NAME OF ASSIGNEE **]** [5]

By: _____
Name:
Title:

[Consented [6] to and accepted:

MORGAN STANLEY SENIOR FUNDING, INC., as Administrative Agent
By: _____
Name:
Title:]

[5] Add additional signature blocks if there is more than one Assignee .

[6] Consent of the Administrative Agent to be included to the extent required by Section 9.04(b) of the Credit Agreement.

STANDARD TERMS AND CONDITIONS FOR
AFFILIATED LENDER ASSIGNMENT AND ACCEPTANCE

1. *Representations and Warranties* .

1.1 *Assignor* . The Assignor (a) represents and warrants that (i) it is the legal and beneficial owner of the Assigned Interest, (ii) the Assigned Interest is free and clear of any Lien, encumbrance or other adverse claim, (iii) it has full power and authority, and has taken all action necessary, to execute and deliver this Affiliated Lender Assignment and Acceptance and to consummate the transactions contemplated hereby and (iv) the assignment and assumption pursuant hereto complies with the terms of the Credit Agreement; and (b) assumes no responsibility with respect to (i) any statements, warranties or representations made in or in connection with the Credit Agreement or any other Loan Document, (ii) the execution, legality, validity, enforceability, genuineness, sufficiency or value of the Loan Documents or any collateral thereunder, (iii) the financial condition of any Loan Party or any Affiliates thereof, or any other person obligated in respect of any Loan Document or (iv) the performance or observance by any Loan Party or any Affiliates thereof or any other Person of any of their respective obligations under any Loan Document.

1.2 *Assignee* . **[** The **] [** Each **]** Assignee (a) represents and warrants that (i) it has full power and authority, and has taken all action necessary, to execute and deliver this Affiliated Lender Assignment and Acceptance and to consummate the transactions contemplated hereby and to become a Lender under the Credit Agreement, (ii) it meets all the requirements of an Eligible Assignee under the Credit Agreement and satisfies the requirements, if any, specified in the Credit Agreement that are required to be satisfied by it in order to acquire the Assigned Interest and become a Lender, (iii) from and after the Effective Date, it shall be bound by the provisions of the Credit Agreement as a Lender thereunder and, to the extent of the Assigned Interest, shall have the obligations of a Lender thereunder, (iv) it is sophisticated with respect to decisions to acquire assets of the type represented by the Assigned Interest and either it, or the person exercising discretion in making its decision to acquire the Assigned Interest, is experienced in acquiring assets of such type, (v) it has received a copy of the Credit Agreement, together with copies of the most recent financial statements delivered pursuant to Section 5.04 thereof, as applicable, and such other documents and information as it has deemed appropriate to make its own credit analysis and decision to enter into this Affiliated Lender Assignment and Acceptance and to purchase the Assigned Interest on the basis of which it has made such analysis and decision independently and without reliance on any Agent or any other Lender, (vi) attached to this Affiliated Lender Assignment and Acceptance is any documentation required to be delivered by it pursuant to the terms of the Credit Agreement, duly completed and executed by **[** the **] [** each **]** Assignee, (vii) the assignment and assumption pursuant hereto complies with the terms of the Credit Agreement and (viii) if it is a Non-U.S. Lender, attached to this Assignment and Acceptance is any documentation required to be delivered by it pursuant to the terms of the Credit Agreement, duly completed and executed by the Assignee; (b) appoints and authorizes the Agents to take such action as agent on its behalf and to exercise such powers and discretion under the Credit Agreement, the other Loan Documents or any other instrument or document furnished pursuant hereto or thereto as are delegated to the Agents by the terms thereof, together with such powers as are incidental thereto, including, without limitation, pursuant to Section 8.05 of the Credit Agreement; and (c) agrees that (i) it will, independently and without reliance on any Agent, the Assignor or any other Lender and, based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Loan Documents, and (ii) it will perform in accordance with their terms all of the obligations which by the terms of the Loan Documents are required to be performed by it as a Lender and appoint Agents.

2. *Payments* . From and after the Effective Date, the Administrative Agent shall make all payments in respect of the Assigned Interest (including payments of principal, interest, fees and other amounts) to the Assignor for amounts which have accrued to but excluding the Effective Date and to **[** the **] [** each **]** Assignee for amounts which have accrued from and after the Effective Date.

3. *General Provisions* . This Affiliated Lender Assignment and Acceptance shall be binding upon, and inure to the benefit of, the parties hereto and their respective successors and assigns. This Affiliated Lender Assignment and Acceptance may be executed in any number of counterparts, which together shall constitute one instrument. Delivery of an executed counterpart of a signature page of this Affiliated Lender Assignment and Acceptance by telecopy or other electronic transmission shall be effective as delivery of a manually executed counterpart of this Affiliated Lender Assignment and Acceptance; *provided* , however, that it shall be promptly followed by an original. This Affiliated Lender Assignment and Acceptance shall be governed by, and construed in accordance with, the law of the State of New York.

FORM OF PREPAYMENT NOTICE

Morgan Stanley Senior Funding, Inc.,
as Administrative Agent
1300 Thames Street, 4th Floor
Thames Street Wharf
Baltimore, MD 21231
Attention: Administrative Agent
Email: [***]

[Date]

Ladies and Gentlemen:

Reference is made to the Credit Agreement dated as of November 28, 2017 (the " **Credit Agreement** "), among EXGEN RENEWABLES IV, LLC, a limited liability company organized under the laws of Delaware (the " **Borrower** "), EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" **Holding** "), the LENDERS party thereto from time to time, MORGAN STANLEY SENIOR FUNDING, INC., as Administrative Agent, WILMINGTON TRUST, NATIONAL ASSOCIATION, as Collateral Agent and WILMINGTON TRUST, NATIONAL ASSOCIATION, as Depositary Bank. Capitalized terms used herein and not otherwise defined herein shall have the meanings assigned to such terms in the Credit Agreement.

This Prepayment Notice is delivered to you pursuant to Section 2.08 of the Credit Agreement. The Borrower hereby gives notice of a prepayment of Loans as follows:

For a prepayment by Borrower,

1. (select Type(s) of Loans)

   Base Rate Loans in the aggregate principal amount of U.S. $_____.

   LIBOR Loans with an Interest Period ending _____, 20__ in the aggregate principal amount of U.S. $_____.

2. On _____, 20__ (a Business Day).

This Prepayment Notice and prepayment contemplated hereby comply with the Credit Agreement, including Section 2.09 of the Credit Agreement.

Very truly yours,
EXGEN RENEWABLES IV, LLC
By: _____
Name:
Title:

FORM OF BORROWING REQUEST

Morgan Stanley Senior Funding, Inc.,
as Administrative Agent
1300 Thames Street, 4th Floor
Thames Street Wharf
Baltimore, MD 21231
Attention: Administrative Agent
Email: [***]

[__], 2017

Ladies and Gentlemen:

The undersigned, EXGEN RENEWABLES IV, LLC, a limited liability company organized under the laws of Delaware (the " **Borrower** "), refers to that certain Credit Agreement, dated as of November 28, 2017 (the " **Credit Agreement** "), among the Borrower, EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware, the LENDERS party thereto from time to time, MORGAN STANLEY SENIOR FUNDING, INC., as Administrative Agent, WILMINGTON TRUST, NATIONAL ASSOCIATION, as Collateral Agent and WILMINGTON TRUST, NATIONAL ASSOCIATION, as Depositary Bank. Capitalized terms used herein and not otherwise defined herein shall have the meanings assigned to such terms in the Credit Agreement. The Borrower hereby gives you notice pursuant to Section 2.03 of the Credit Agreement that it requests a Borrowing under the Credit Agreement, and in connection therewith sets forth below the terms on which such Borrowing is requested to be made:

For a Borrowing by Borrower:

(A) Date of Borrowing (which shall be a Business Day):_____

(B) Principal amount of Borrowing: U.S. $_____

(C) Type of Borrowing (Base Rate or LIBOR): _____

(D) Interest Period and the last day thereof (if a LIBOR Borrowing): [1] _____

(E) Funds are requested to be disbursed to the Borrower's account with _____ (Account No._____).

[*Signature Page Follows*]

_____

[1] Which must comply with the definition of "Interest Period".

Very truly yours,
EXGEN RENEWABLES IV, LLC
By: _____
Name:
Title:

FORM OF
INTEREST ELECTION REQUEST

Morgan Stanley Senior Funding, Inc.,
as Administrative Agent
1300 Thames Street, 4th Floor
Thames Street Wharf
Baltimore, MD 21231
Attention: Administrative Agent
Email: [***]

[__], 2017

Ladies and Gentlemen:

Reference is made to the Credit Agreement dated as of November 28, 2017 (the " **Credit Agreement** "), among EXGEN RENEWABLES IV, LLC, a limited liability company organized under the laws of Delaware (the " **Borrower** "), EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" **Holding** "), the LENDERS party thereto from time to time, MORGAN STANLEY SENIOR FUNDING, INC., as Administrative Agent, WILMINGTON TRUST, NATIONAL ASSOCIATION, as Collateral Agent and WILMINGTON TRUST, NATIONAL ASSOCIATION, as Depositary Bank. Capitalized terms used herein and not otherwise defined herein shall have the meanings assigned to such terms in the Credit Agreement.

This Interest Election Request is delivered to you pursuant to Section 2.05 of the Agreement and relates to the following:

For a Borrowing by Borrower,

1. A conversion of a Borrowing A continuation of a Borrowing (select one).

2. In the aggregate principal amount of U.S. $_____.

3. which Borrowing is being maintained as a [Base Rate Borrowing] [LIBOR Borrowing with an Interest Period ending on _____, 20__].

4. (select relevant election)

If such Borrowing is a LIBOR Borrowing, such Borrowing shall be continued as a LIBOR Borrowing having an Interest Period of [____] months.

If such Borrowing is a LIBOR Borrowing, such Borrowing shall be converted to a Base Rate Borrowing.

If such Borrowing is a Base Rate Borrowing, such Borrowing shall be converted to a LIBOR Borrowing having an Interest Period of [____] months.

5. Such election to be effective on _____, 20__ (a Business Day).

This Interest Election Request and the election made herein comply with the Credit Agreement, including Section 2.05 of the Credit Agreement.

[*Signature Page Follows*]

Very truly yours,
EXGEN RENEWABLES IV, LLC
By: _____
Name:
Title:

PLEDGE AND SECURITY AGREEMENT

Dated as of November 28, 2017

by and between

EXGEN RENEWABLES IV, LLC
as the Grantor

and

WILMINGTON TRUST, NATIONAL ASSOCIATION,
as Collateral Agent

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This PLEDGE AND SECURITY AGREEMENT, dated as of November 28, 2017 (this " Agreement "), is entered into by and between EXGEN RENEWABLES IV, LLC, a limited liability company organized under the laws of Delaware (the " Grantor ") and WILMINGTON TRUST, NATIONAL ASSOCIATION, as collateral agent for the Secured Parties (in such capacity and together with its permitted successors, assigns and designees, the " Collateral Agent "). Capitalized terms used in this Agreement (including in this preamble and the recitals below) have the meanings assigned to such terms in Section 1.1 .

RECITALS:

WHEREAS, as of the Closing Date, the Grantor owns (A) all of the Equity Interests in (i) ExGen Renewables Holdings, LLC, a limited liability company organized under the laws of Delaware (" ExGen Renewables Holdings "), (ii) SolGen Holding, LLC, a limited liability company organized under the laws of Delaware (" SolGen Holding ") and (iii) Exelon AVSR Holding, LLC, a limited liability company organized under the laws of Delaware (" Exelon AVSR Holding ") and (B) not less than 50% of the Equity Interests in Constellation DCO Albany Power Holdings, LLC, a limited liability company organized under the laws of Delaware (" Albany Power Holdings " and, collectively with ExGen Renewables Holdings, SolGen Holding and Exelon AVSR Holding, the " Project Holdcos ");

WHEREAS, ExGen Renewables Holdings owns all of the JV Class A Membership Interests in ExGen Renewables Partners, LLC, a limited liability company organized under the laws of the State of Delaware (" ExGen Renewables JV ");

WHEREAS, ExGen Renewables JV, SolGen Holding, Exelon AVSR Holding and Albany Power Holdings own, directly or indirectly, all (or a specified class of) the Equity Interests of each of the other Project Entities, which collectively own or lease the Projects;

WHEREAS, the Grantor intends to enter into the Credit Agreement, dated as of the date hereof (as amended, amended and restated, supplemented, replaced or otherwise modified and in effect from time to time, the " Credit Agreement "), among the Grantor, ExGen Renewables IV Holding, LLC, a limited liability company organized under the laws of State of Delaware (" Holding "), the Lenders party thereto from time to time, Morgan Stanley Senior Funding Inc., as administrative agent (in such capacity, together with any successor administrative agent appointed pursuant to the provisions of Article VIII of the Credit Agreement, the " Administrative Agent "), the Collateral Agent, and Wilmington Trust, National Association, as Depositary Bank, pursuant to which the Grantor has requested that the Lenders extend credit in the form of Loans on the Closing Date, in an aggregate U.S. Dollar amount for all such Loans of U.S. $850 million; and

WHEREAS, the Grantor has agreed to secure all of the Obligations by granting to the Collateral Agent, for the benefit of the Secured Parties, a first priority Lien (subject to Liens permitted under the Credit Agreement) on substantially all of the assets and properties owned by the Grantor.

AGREEMENT:

NOW, THEREFORE, in consideration of the foregoing, the mutual covenants and obligations herein set forth and for other good and valuable consideration, the adequacy and receipt of which are hereby acknowledged and in reliance upon the representations, warranties and covenants contained herein, the parties hereto, intending to be legally bound, hereby agree as follows:

SECTION 1. DEFINITIONS

.

1.1 General Definitions

. Unless otherwise defined herein, terms defined in the Credit Agreement and used herein (including in the preamble and the recitals hereto) shall have the meanings given to them in the Credit Agreement. In addition to the terms defined in the Credit Agreement, the following terms shall have the following meanings:

" Account Debtor " means each Person who is obligated on a Receivable or any Supporting Obligation related thereto.

" Accounts " means all "accounts" as defined in Article 9 of the UCC.

" Additional Project Entity " has the meaning set forth in the Credit Agreement.

" Administrative Agent " has the meaning set forth in the recitals to this Agreement.

" Agreement " has the meaning set forth in the preamble to this Agreement.

" Albany Power Holdings " has the meaning assigned to such term in the recitals of this Agreement.

" Assigned Agreements " means all agreements, contracts and documents to which the Grantor is a party (including all exhibits and schedules thereto), as each such agreement, contract and document may be amended, supplemented or otherwise modified and in effect from time to time, including (i) all rights of the Grantor to receive moneys due and to become due under or pursuant to the Assigned Agreements, (ii) all rights of the Grantor to receive proceeds of any insurance, bond, indemnity, warranty, letter of credit or guaranty with respect to the Assigned Agreements, (iii) all claims of the Grantor for damages arising out of or for breach of or default under the Assigned Agreements and (iv) all rights of the Grantor to terminate, amend, supplement, modify or waive performance under the Assigned Agreements, to perform thereunder and to compel performance and otherwise to exercise all remedies thereunder.

" Bankruptcy Event " means any event described in Sections 7.01(h) and 7.01(i) of the Credit Agreement.

" Chattel Paper " means all "chattel paper" as defined in Article 9 of the UCC, including, without limitation, "electronic chattel paper" or "tangible chattel paper", as each term is defined in Article 9 of the UCC.
" Collateral " has the meaning assigned in Section 3.1 .

" Collateral Agent " has the meaning set forth in the preamble to this Agreement.

" Collateral Records " means books, records, ledger cards, files, correspondence, customer lists, supplier lists, blueprints, technical specifications, manuals, computer software and related documentation, computer printouts, tapes, disks and related data processing software and similar items that at any time evidence or contain information relating to any of the Collateral or are otherwise necessary or helpful in the collection thereof or realization thereupon.

" Collateral Support " means all property (real or personal) assigned, licensed, hypothecated or otherwise securing any Collateral and shall include any security agreement or other agreement granting a lien or security interest in such real or personal property in favor of the Grantor.

" Commercial Tort Claims " means all "commercial tort claims" as defined in Article 9 of the UCC, including, without limitation, all commercial tort claims listed on Schedule 4.8 (as such schedule may be amended or supplemented from time to time).

" Commodities Accounts " means all "commodity accounts" as defined in Article 9 of the UCC.

" Copyright Licenses " means any and all agreements, licenses and covenants providing for the granting of any right in or to Copyrights, including, without limitation, the grant of rights to manufacture, distribute, exploit and sell materials derived from any Copyright, or otherwise providing for a covenant not to sue (whether the Grantor is licensee or licensor thereunder).

" Copyrights " means all United States, and foreign copyrights (including Community designs), and rights in databases including but not limited to copyrights in software and databases, and all Mask Works (as defined under 17 U.S.C. 901 of the U.S. Copyright Act), whether registered or unregistered and whether published or unpublished, moral rights, reversionary interests, termination rights, all registrations and applications therefor, all extensions and renewals thereof, all rights corresponding thereto throughout the world, all rights to sue for past, present and future infringements thereof, and all Proceeds of the foregoing, including, without limitation, licenses, royalties, income, payments, claims, damages and proceeds of suit.

" Credit Agreement " has the meaning set forth in the recitals to this Agreement.

" Deposit Accounts " means all "deposit accounts" as defined in Article 9 of the UCC.

" Documents " means all "documents" as defined in Article 9 of the UCC.

" Equipment " means (i) all "equipment" as defined in Article 9 of the UCC, (ii) all machinery, manufacturing equipment, data processing equipment, computers, office equipment, furnishings, furniture, appliances, fixtures and tools (in each case, regardless of whether characterized as equipment under the UCC) and (iii) all accessions or additions thereto, all parts thereof, whether or not at any time of determination incorporated or installed therein or attached thereto, and all replacements therefor, wherever located, now or hereafter existing, including any fixtures.

" Event of Default " has the meaning assigned to such term in the Credit Agreement.

" Excluded Property " means any Permit, contract or agreement to which the Grantor is a party, and any of its rights or interest thereunder, if and to the extent that (a) the pledge or assignment of such Permit, contract or agreement hereunder, or a security interest granted therein, is prohibited by or in violation of (x) any Legal Requirement of a Governmental Authority applicable to the Grantor or (y) a term, provision or condition of any such Permit, contract or agreement; (b) the pledge or assignment of such Permit, contract or agreement hereunder would render such Permit, contract or agreement void, voidable, terminable or revocable or (c) the pledge or assignment of such Permit requires the consent of any third party or Government Authority, in each case except to the extent that such Legal Requirements or the term in such, Permit, contract or agreement providing for such prohibition or violation is ineffective under applicable law (including, without limitation, pursuant to Section 9-406, 9-407, 9-408 or 9-409 of the UCC); provided that any such property shall constitute Excluded Property only to the extent and for so long as the consequences specified above shall exist and shall cease to be an Excluded Property

and shall become subject to the Lien of the Security Documents immediately and automatically, during such time as such consequence shall not exist.

" Exelon AVSR Holdings " has the meaning assigned to such term in the recitals hereto.

" ExGen Renewables Holdings " has the meaning assigned to such term in the recitals hereto.

" Fixtures " means all "fixtures" as defined in Article 9 of the UCC.

" General Intangibles " (i) means all "general intangibles" as defined in Article 9 of the UCC, including "payment intangibles" also as defined in Article 9 of the UCC and (ii) includes, without limitation, all interest rate or currency protection or hedging arrangements, all tax refunds, all licenses, permits, concessions and authorizations, all Assigned Agreements and all Intellectual Property (in each case, regardless of whether characterized as general intangibles under the UCC).

" Goods " (i) means all "goods" as defined in Article 9 of the UCC and (ii) includes, without limitation, all Inventory and Equipment (in each case, regardless of whether characterized as goods under the UCC).

" Grantor " has the meaning set forth in the preamble to this Agreement.

" Instruments " means all "instruments" as defined in Article 9 of the UCC.

" Insurance " means (i) all insurance policies covering any or all of the Collateral (regardless of whether the Collateral Agent is the loss payee thereof) and (ii) any key man life insurance policies.

" Intellectual Property " means, collectively, all rights, priorities and privileges relating to intellectual property, whether arising under United States, multinational or foreign laws or otherwise, including, without limitation, the Copyrights, the Copyright Licenses, the Patents, the Patent Licenses, the Trademarks, the Trademark Licenses, the Trade Secrets and the Trade Secret Licenses.

" Intercompany Note " means any promissory note evidencing loans made by the Grantor to any of its Subsidiaries.

" Internal Revenue Code " means the Internal Revenue Code of 1986, as amended to the date hereof and from time to time thereafter, and any successor statute.

" Inventory " means (i) all "inventory" as defined in Article 9 of the UCC and (ii) all goods held for sale or lease or to be furnished under contracts of service or so leased or furnished, all raw materials, work in process, finished goods, and materials used or consumed in the manufacture, packing, shipping, advertising, selling, leasing, furnishing or production of such inventory or otherwise used or consumed in the Grantor's business; all goods in which the Grantor has an interest in mass or a joint or other interest or right of any kind; and all goods which are returned to or repossessed by the Grantor, all computer programs embedded in any goods and all accessions thereto and products thereof (in each case, regardless of whether characterized as inventory under the UCC).

" Investment Accounts " means the Depositary Accounts, the Securities Accounts, the Commodities Accounts and the Deposit Accounts.

" Investment Related Property " means: (i) all "investment property" (as such term is defined in Article 9 of the UCC) and (ii) all of the following (regardless of whether classified as investment property

under the UCC): all Pledged Equity Interests, Pledged Debt (including all Pledged Notes), Investment Accounts and certificates of deposit.

" Issuers " means the collective reference to each issuer of any Investment Related Property.

" Legal Requirements " means, as to any Person, any law, statute, rule, regulation, ordinance, order, code, treaty, judgment, decree, or any published directive or requirement which has the force of law, or other legally binding form of governmental restriction or decision of any Governmental Authority, in each case applicable to or binding upon such Person or any of its properties or to which such Person or any of its properties is subject.

" Letter of Credit Right " means "letter-of-credit right" as defined in Article 9 of the UCC.

" Lien " shall mean, with respect to any asset, (a) any mortgage, deed of trust, lien, hypothecation, pledge, encumbrance, charge or security interest in or on such asset, (b) the interest of a vendor or a lessor under any conditional sale agreement, capital lease or title retention agreement (or any financing lease having substantially the same economic effect as any of the foregoing) relating to such asset, and (c) in the case of securities, any purchase option, call or similar right of a third party with respect to such securities. For certainty, "Lien" shall not include any netting or set-off arrangements under any contract, agreement or other undertaking that is otherwise permitted to be entered into by ExGen Renewables JV, any Project Holdco or any Project Entity in accordance with the Project Level Financing Documents to which it (or its Subsidiaries) is a party.

" Money " means "money" as defined in the UCC.

" Obligations " has the meaning set forth in the Credit Agreement.

" Patent Licenses " means all agreements, licenses and covenants providing for the granting of any right in or to Patents or otherwise providing for a covenant not to sue (whether the Grantor is licensee or licensor thereunder).

" Patents " means all United States and foreign patents and certificates of invention, or similar industrial property rights, and applications for any of the foregoing, all reissues, divisions, continuations, continuations-in-part, extensions, renewals, and reexaminations thereof, all rights corresponding thereto throughout the world, all inventions and improvements described therein, all rights to sue for past, present and future infringements thereof, all licenses, claims, damages, and proceeds of suit arising therefrom, and all Proceeds of the foregoing, including, without limitation, licenses, royalties, income, payments, claims, damages, and proceeds of suit.

" Permits " means any and all franchises, licenses, leases, permits, approvals, notifications, certifications, registrations, authorizations, acceptances, exemptions, qualifications, easements, rights of way, Liens and other rights, privileges and approvals required to be obtained from a Governmental Authority.

" Pledge Supplement " means any supplement to this agreement in substantially the form of Exhibit A .

" Pledged Debt " means all debt for borrowed money owed to the Grantor (including, without limitation, all intercompany debt for borrowed money), the instruments evidencing such debt for borrowed money, and all interest, cash, instruments and other property or proceeds from time to time received, receivable or otherwise distributed in respect of or in exchange for any or all of such debt for borrowed money.

" Pledged Equity Interests " means all classes of Equity Interests owned by the Grantor, including, without limitation, all Equity Interests described on Schedule 4.4 under the heading "Pledged Equity Interests" (as such schedule may be amended or supplemented from time to time) and the certificates, if any, representing such Pledged Equity Interests, and all dividends, distributions, return of capital, cash, instruments and other property from time to time received, receivable or otherwise distributed in respect of or in exchange for any or all of the Pledged Equity Interests.

" Pledged Notes " means all promissory notes described on Schedule 1(b) under the heading "Pledged Notes" (as such schedule may be amended or supplemented from time to time), all Intercompany Notes at any time issued to any Pledgor and all other promissory notes issued to or held by any Pledgor (other than promissory notes issued in connection with extensions of trade credit by any Pledgor in the ordinary course of business).

" Proceeds " means (i) all "proceeds" as defined in Article 9 of the UCC, (ii) payments or distributions made with respect to any Investment Related Property and (iii) whatever is receivable or received when Collateral or proceeds are sold, exchanged, collected or otherwise disposed of, whether such disposition is voluntary or involuntary.

" Project Holdcos " has the meaning assigned to such term in the recitals hereto.

" Receivables " means all rights to payment, whether or not earned by performance or achievement of milestones, for goods or other property sold, leased, licensed, assigned or otherwise disposed of, or services rendered or to be rendered, including, without limitation all such rights constituting or evidenced by any Account, Chattel Paper, Instrument, General Intangible or Investment Related Property, together with all of the Grantor's rights, if any, in any goods or other property giving rise to such right to payment and all Collateral Support and Supporting Obligations related thereto and all Receivables Records.

" Receivables Records " means (i) all original copies of all documents, instruments or other writings or electronic records or other Records evidencing the Receivables, (ii) all books, correspondence, credit or other files, Records, ledger sheets or cards, invoices, and other papers relating to Receivables, including, without limitation, all tapes, cards, computer tapes, computer discs, computer runs, record keeping systems and other papers and documents relating to the Receivables, whether in the possession or under the control of the Grantor or any computer bureau or agent from time to time acting for the Grantor or otherwise, (iii) all evidences of the filing of financing statements and the registration of other instruments in connection therewith, and amendments, supplements or other modifications thereto, notices to other creditors or secured parties, and certificates, acknowledgments, or other writings, including, without limitation, lien search reports, from filing or other registration officers, (iv) all credit information, reports and memoranda relating thereto and (v) all other written or nonwritten forms of information related in any way to the foregoing or any Receivable.

" Record " has the meaning set forth in Article 9 of the UCC.

" Secured Parties " means the Agents, the Lead Arranger, the Lenders and any Specified Swap Counterparty.

" Securities " means any stock, shares, partnership interests, voting trust certificates, certificates of interest or participation in any profit-sharing agreement or arrangement, options, warrants, bonds, debentures, notes, or other evidences of indebtedness, secured or unsecured, convertible, subordinated or otherwise, or in general any instruments commonly known as "securities" or any certificates of interest, shares or participations in temporary or interim certificates for the purchase or acquisition of, or any right to subscribe to, purchase or acquire, any of the foregoing.

" Securities Accounts " means all "securities accounts" as defined in Article 8 of the UCC.

" SolGen Holdings " has the meaning assigned to such term in the recitals hereto.

" Supporting Obligation " means all "supporting obligations" as defined in Article 9 of the UCC in favor of the Grantor.

" Trade Secret Licenses " means any and all agreements providing for the granting of any right in or to Trade Secrets (whether the Grantor is licensee or licensor thereunder).

" Trade Secrets " means all trade secrets and all other confidential or proprietary information and know-how whether or not such Trade Secret has been reduced to a writing or other tangible form, including all documents and things embodying such Trade Secret, including but not limited to: (i) the right to sue for past, present and future misappropriation or other violation of any Trade Secret, and (ii) all Proceeds of the foregoing, including, without limitation, licenses, royalties, income, payments, claims, damages, and proceeds of suit.

" Trademark Licenses " means any and all agreements providing for the granting of any right in or to Trademarks or otherwise providing for a covenant not to sue or permitting coexistence (whether the Grantor is licensee or licensor thereunder).

" Trademarks " means all United States, and foreign trademarks, trade names, corporate names, company names, business names, fictitious business names, trade styles, Internet domain names, service marks, certification marks, collective marks, logos, other source or business identifiers, designs and general intangibles of a like nature, all registrations, recordings and applications for any of the foregoing, all common-law rights related thereto, all extensions or renewals of any of the foregoing, all of the goodwill of the business connected with the use of and symbolized by the foregoing, the right to sue for past, present and future infringement or dilution of any of the foregoing or for any injury to goodwill, and all Proceeds of the foregoing, including, without limitation, licenses, royalties, income, payments, claims, damages, and proceeds of suit.

" Uncertificated Securities Control Agreement " means an agreement substantially in the form of Exhibit B .

1.2 Definitions; Interpretation

. For all purposes of this Agreement, except as otherwise expressly provided or unless the context otherwise requires, the rules of interpretation set forth in Section 1.02 of the Credit Agreement are hereby incorporated by reference, *mutatis mutandis* , as if fully set forth herein. All capitalized terms used herein (including the preamble and recitals hereto) and not otherwise defined herein or in the Credit Agreement have the meanings ascribed thereto in the UCC. All references herein to provisions of the UCC shall include all successor provisions under any subsequent version or amendment to any Article of the UCC. The terms "lease" and "license" shall include "sub-lease" and "sub license", as applicable.

SECTION 2. [RESERVED].

SECTION 3. GRANT OF SECURITY

3.1 Grant of Security

. The Grantor hereby assigns and transfers to the Collateral Agent and hereby grants to the Collateral Agent, for the benefit of the Secured Parties, a security interest in and continuing Lien on all of the

Grantor's right, title and interest in, to and under all of the following property of the Grantor (subject to the exclusions set forth in Section 3.2), in each case whether now owned or existing or hereafter acquired or in which the Grantor now has or at any time in the future may acquire or arising and wherever located (all of which being hereinafter collectively referred to as the " Collateral "), as collateral security for prompt and complete payment and performance when due (whether at stated maturity, by acceleration or otherwise) of the Obligations:

(a) Accounts;

(b) Chattel Paper;

(c) Commercial Tort Claims described on Schedule 4.8 (as such schedule may be amended or supplemented from time to time);

(d) Deposit Accounts;

(e) Documents;

(f) Fixtures;

(g) General Intangibles;

(h) Goods;

(i) Instruments;

(j) Insurance;

(k) Intellectual Property

(l) Investment Related Property;

(m) Letter of Credit Rights;

(n) Money;

(o) Receivables and Receivable Records;

(p) all other property not otherwise described above (except for any property specifically excluded from any clause in this section above in accordance with Section 3.2 , and any property specifically excluded from any defined term used in any clause of this section above);

(q) to the extent not otherwise included above, all Collateral Records, Collateral Support and guarantees and Supporting Obligations relating to any of the foregoing; and

(r) to the extent not otherwise included above, all Proceeds, products, accessions, rents and profits of or in respect of any of the foregoing.

3.2 Certain Limited Exclusions

. Notwithstanding anything herein to the contrary, in no event shall the Collateral include or the security interest or Lien granted under Section 3.1 attach to any Excluded Property. The Grantor

and the Collateral Agent hereby acknowledge and agree that the Lien created hereby in the Collateral is not, in and of itself, to be construed as a grant of a fee interest (as opposed to a Lien) in any Intellectual Property, including any Copyrights, Patents or Trademarks.

3.3 Retention of Certain Rights

. So long as the Collateral Agent has not given written notice to the Grantor of its intention to exercise its rights with respect to the Collateral under this Agreement upon the occurrence and during the continuation an Event of Default, the Grantor reserves all rights with respect to the Collateral (except as limited by the Loan Documents), including all rights to use, apply, modify, dispose of or otherwise deal with such Collateral (except as limited by the Loan Documents).

SECTION 4. SECURITY FOR OBLIGATIONS; GRANTOR REMAINS LIABLE

4.1 Security for Obligations

. This Agreement secures, and the Collateral is collateral security for, the prompt and complete payment and performance in full when due, whether at stated maturity, by required prepayment, declaration, acceleration, demand or otherwise (including the payment of amounts that would become due but for the operation of the automatic stay under Section 362(a) of the Bankruptcy Code, 11 U.S.C. §362(a) (and any successor provision thereof)), of all Obligations.

4.2 Continuing Liability Under Collateral

. Notwithstanding anything herein to the contrary, (i) the Grantor shall remain liable for all obligations under the Collateral and nothing contained herein is intended or shall be a delegation of duties to the Collateral Agent or any Secured Party, (ii) the Grantor shall remain liable under each of the agreements included in the Collateral, including, without limitation, any Assigned Agreement and any agreements relating to Pledged Equity Interests, to perform all of the obligations undertaken by it thereunder all in accordance with and pursuant to the terms and provisions thereof and neither the Collateral Agent nor any other Secured Party shall have any obligation or liability under any of such agreements by reason of or arising out of this Agreement or any other document related thereto nor shall the Collateral Agent nor any other Secured Party have any obligation to make any inquiry as to the nature or sufficiency of any payment received by it or have any obligation to take any action to collect or enforce any rights under any agreement included in the Collateral, including, without limitation, any Assigned Agreement and any agreements relating to Pledged Equity Interests, and (iii) the exercise by the Collateral Agent of any of its rights hereunder shall not release the Grantor from any of its duties or obligations under the contracts and agreements included in the Collateral.

SECTION 5. CERTAIN RELATED REPRESENTATIONS; WARRANTIES AND COVENANTS

5.1 Generally

. The Grantor hereby represents and warrants, on the Closing Date, that:

(a) the Grantor has indicated on Schedule 4.1(A) : (i) the full legal name of the Grantor, (ii) the type of organization of the Grantor, (iii) the jurisdiction of organization of the Grantor and (iv) the location of the Grantor's chief executive office or sole place of business or principal residence, as the case may be;

(b) the Grantor has no trade names other than as listed on Schedule 4.1(B) ; and

(c) except as provided on Schedule 4.1(C) , it has not changed its name, jurisdiction or form of organization or the location of its chief executive office or sole place of business or principal residence, as the case may be, in any way since the date of its formation.

5.2 Equipment And Inventory

. The Grantor represents and warrants that, as of the Closing Date, it does not have any Equipment or Inventory included in the Collateral.

5.3 Receivables

(a) Covenants and Agreements

. Following the occurrence of and during the continuation of an Event of Default, the Collateral Agent shall have the right at any time, upon concurrent written notice to the Grantor of its intention to do so, (i) to notify, or direct the Grantor to notify, any Account Debtor of the Collateral Agent's security interest in the Receivables and any Supporting Obligation, (ii) to direct, or request that the Grantor direct, such Account Debtors to make payment of all amounts due or to become due to the Grantor thereunder directly to the Collateral Agent, and (iii) upon such concurrent notification and at the expense of the Grantor, to enforce collection of any such Receivables and to adjust, settle or compromise the amount or payment thereof, in the same manner and to the same extent as the Grantor might have done. After receipt by the Grantor of written notice from the Collateral Agent referred to in the preceding sentence, any payments of Receivables constituting Collateral received by the Grantor shall be forthwith (and in any event within five Business Days) deposited by the Grantor in the exact form received duly indorsed by the Grantor to the Collateral Agent if required, in an account maintained under the sole dominion and control of the Collateral Agent, and until so turned over, all amounts and proceeds (including checks and other instruments) received by the Grantor in respect of its Receivables constituting Collateral, any Supporting Obligation constituting Collateral or Collateral Support constituting Collateral shall be received in trust for the benefit of the Collateral Agent hereunder and shall be segregated from other funds of the Grantor and the Grantor shall not adjust, settle or compromise the amount or payment of any Receivable constituting Collateral, or release wholly or partly any Account Debtor or obligor thereof, or allow any credit or discount thereon.

(b) Delivery and Control of Receivables . With respect to any Receivables constituting Collateral hereafter arising in excess of $[***] (i) evidenced by, or constituting, Chattel Paper or Instruments, the Grantor shall cause each originally executed copy thereof to be delivered to the Collateral Agent (or its agent or designee) appropriately indorsed to the Collateral Agent or indorsed in blank, or (ii) which would constitute "electronic chattel paper" under Article 9 of the UCC, the Grantor shall take all steps necessary to give the Collateral Agent control over such Receivables (within the meaning of Section 9-105 of the UCC).

5.4 Investment Related Property

(a) Investment Related Property Generally .

(i) Covenants and Agreements . The Grantor hereby covenants and agrees that:

(A) with respect to any Investment Related Property constituting Collateral with a fair market value in excess of $[***]that is represented by a certificate or that is an Instrument (other than any Investment Related Property credited to a Securities Account) owned by the Grantor, it shall cause such

certificate or instrument to be delivered to the Collateral Agent, indorsed in blank by an "effective indorsement" (as defined in Section 8-107 of the UCC), regardless of whether such certificate constitutes a "certificated security" for purposes of the UCC (a " Certificated Security "); and

(B) with respect to any Investment Related Property constituting Collateral with a fair market value in excess of $[***] that is an "uncertificated security" for purposes of the UCC (other than any uncertificated securities credited to a Securities Account) (an " Uncertificated Security ") owned by the Grantor, it shall cause the Issuer of such Uncertificated Security to either (i) register the Collateral Agent as the registered owner thereof on the books and records of the Issuer or (ii) execute an agreement substantially in the form of Exhibit B or such other form reasonably satisfactory to the Collateral Agent, pursuant to which such Issuer agrees to comply with the Collateral Agent's instructions with respect to such Uncertificated Security without further consent by the Grantor; and

(C) in addition to the foregoing, upon the occurrence and during the continuation of an Event of Default, the Collateral Agent shall have the right, without notice to the Grantor, to (i) transfer all or any portion of the Investment Related Property to its name or the name of its nominee or agent and (ii) subject to the terms of the applicable Investment Related Property, to exchange any certificates or instruments representing such Investment Related Property constituting Collateral for certificates or instruments of smaller or larger denominations. In the event of a transfer pursuant to clause (i) of the immediately preceding sentence, the Collateral Agent shall within a reasonable period of time thereafter give the Grantor written notice of such transfer; provided , however , that (x) failure to give such notice shall have no effect on the rights of the Collateral Agent hereunder and (y) the Collateral Agent shall not be required to deliver any such notice if the Grantor is the subject of a Bankruptcy Event or the delivery of such notice is otherwise prohibited by applicable law.

(ii) Voting and Distributions .

(A) So long as no Event of Default shall have occurred and be continuing and until such time as the Grantor shall have received notice from the Collateral Agent pursuant to clause (B) below:

(1) the Grantor shall be entitled to exercise or refrain from exercising any and all voting and other consensual rights pertaining to the Investment Related Property constituting Collateral or any part thereof; provided , however , that no vote with respect to the Investment Related Property shall be cast (or refrained from being cast), right exercised (or refrained from being exercised) or other action taken (or refrained from being taken) which would be inconsistent with, or result in any violation of, any provision of any of this Agreement or any other Loan Document;

(2) the Collateral Agent shall promptly execute and deliver (or cause to be executed and delivered) to the Grantor all proxies, and other instruments as the Grantor, at its sole cost and expense, may

from time to time reasonably request for the purpose of enabling the Grantor to exercise the voting and other consensual rights when and to the extent which it is entitled to exercise pursuant to clause (1) above; and

(3) the Grantor shall be entitled to receive and retain any and all dividends, interest and other distributions paid in respect of any Investment Related Property for any purpose not inconsistent with the terms of this Agreement or the Loan Documents. To the extent that such distributions are made in accordance with the terms of the Loan Documents, the further distribution or payment of such monies to a Person which is not the Grantor shall not give rise to any claims or causes of action on the part of any Secured Party against the Grantor seeking the return or disgorgement of any such distributions or other payments unless the distributions or payments involve or result from fraud or willful misconduct of the Grantor.

(B) Upon the occurrence and during the continuation of an Event of Default and upon delivery of written notice of the occurrence and continuation of such Event of Default from the Collateral Agent to the Grantor (it being acknowledged and agreed that the Collateral Agent shall not be required to deliver any such notice if the Grantor is the subject of a Bankruptcy Event):

(1) all rights of the Grantor to receive the dividends, interest and other distributions that it would otherwise be authorized to receive and retain pursuant to Section 5.4(a)(ii)(A)(3) shall cease, and all such rights shall thereupon become vested in the Collateral Agent who shall thereupon have the sole right to receive and hold as Investment Related Property such dividends, interest and other distributions;

(2) in order to permit the Collateral Agent to exercise the voting and other consensual rights which it may be entitled to exercise pursuant hereto and to receive all dividends and other distributions which it may be entitled to receive hereunder, in each case, in respect of Investment Related Property constituting Collateral: (x) the Grantor shall promptly execute and deliver (or cause to be executed and delivered) to the Collateral Agent, at its sole cost and expense, all proxies, dividend payment orders and other instruments as the Collateral Agent may from time to time reasonably request and (y) the Grantor acknowledges that the Collateral Agent may utilize the power of attorney set forth in Section 7.1 ; and

(3) the Grantor hereby authorizes and instructs each Issuer of any Investment Related Property pledged by the Grantor hereunder to comply with any instruction received by it from the Collateral Agent in writing that (x) states that an Event of Default has occurred and is continuing and (y) is otherwise in accordance with the terms of this Agreement, without any other or further instructions from the Grantor.

(b) Pledged Equity Interests and Pledged Notes.

(i) Representations and Warranties

. The Grantor hereby represents and warrants, on the Closing Date, that:

(A) Schedule 4.4(a) sets forth under the heading "Pledged Equity Interests" all of the Pledged Equity Interests owned by the Grantor, and such Pledged Equity Interests constitute the percentage of issued and outstanding Equity Interests or percentage of beneficial interest of the respective Issuers thereof indicated on such Schedule 4.4(a) ; and

(B) Schedule 4.4(b) sets forth under the heading "Pledged Notes" all of the Pledged Notes owned by the Grantor; and

(C) each of the Pledged Equity Interests that is pledged by the Grantor hereunder is certificated as indicated on Schedule 4.4(a) and constitutes a "security" under Section 8-103 of the UCC or the corresponding code or statute of any other applicable jurisdiction and each such "security" is a Certificated Security or is represented by a certificate.

(ii) Covenants and Agreements .

(A) Pledged Equity Interests . The Grantor hereby covenants and agrees that, if the Grantor shall become entitled to receive or shall receive any certificate (including, without limitation, any certificate representing a dividend or a distribution in connection with any reclassification, increase or reduction of capital or any certificate issued in connection with any reorganization), option or rights in respect of the Equity Interests of any Issuer (including, without limitation, any Additional Project Entity), whether in addition to, in substitution of, as a conversion of, or in exchange for, any shares of the Pledged Equity Interests, or otherwise in respect thereof, the Grantor shall accept the same as the agent of the Collateral Agent, hold the same in trust for the Collateral Agent and deliver the same forthwith to the Collateral Agent in the exact form received, duly indorsed by the Grantor to the Collateral Agent, if required, together with an undated stock power covering such certificate duly executed in blank by the Grantor and with, if the Collateral Agent so requests, signature guaranteed, to be held by the Collateral Agent, subject to the terms hereof, as additional collateral security for the Obligations, and in the case Equity Interests in Additional Project Entities, a consent from the Issuer thereof substantially in the form of Exhibit C . Unless otherwise consented to by the Collateral Agent, Pledged Equity Interests required to be pledged hereunder in any Subsidiary that is organized as a limited liability company or limited partnership and pledged hereunder shall be represented by a certificate and, in the Organizational Documents of such Subsidiary, the Grantor shall cause the Issuer of such interests to elect to treat such interests as a "security" within the meaning of Article 8 of the Uniform Commercial Code of its jurisdiction of organization (and all certificates representing such Pledged Equity Interests (and any additional Pledged Equity Interests acquired or issued after the Closing Date) shall have been delivered to the Collateral Agent, together with duly executed instruments of transfer or assignment in blank).

(B) Pledged Notes . If the Grantor shall at any time hold or acquire any Instruments, the Grantor shall forthwith endorse, assign and deliver the same to the Collateral Agent, accompanied by such undated instruments of endorsement, transfer or assignment duly executed in blank as the Collateral Agent may from time to time reasonably specify; provided that the Collateral Agent shall return any such Instruments

for purposes of presentation, collection, renewal or replacement. The Grantor agrees to promptly deliver or cause to be delivered to the Collateral Agent any and all Pledged Notes held or acquired by the Grantor, accompanied by proper instruments of assignment duly executed by the Grantor and such other instruments or documents as the Collateral Agent may reasonably request; provided that the Collateral Agent shall return any such Pledged Note to the Borrower (x) to be amended or assigned in connection with a permitted disposition (including the AG Disposition) under the Credit Agreement to the extent required to facilitate such disposition so long as the Borrower delivers any replacement Pledged Note, if any, held by the Borrower after consummation of such disposition or (y) for purposes of presentation, collection, renewal or replacement.

5.5 Assigned Agreements

. The Grantor hereby covenants and agrees that, in addition to any rights under Section 5.3 , the Collateral Agent may at any time, after the occurrence and during the continuation of an Event of Default, notify, or direct the Grantor to notify, the counterparty on any Assigned Agreement of the security interest of the Collateral Agent therein. In addition, after the occurrence and during the continuation of an Event of Default, the Collateral Agent may upon written notice to the Grantor, notify, or direct the Grantor to notify, the counterparty that all payments under the Assigned Agreements shall be made directly to the Collateral Agent.

5.6 Letter of Credit Rights

(a) Representations and Warranties

. The Grantor hereby represents and warrants, on the Closing Date, that, to the knowledge of the Grantor, the Grantor does not have rights as beneficiary in any letter of credit constituting Collateral.

(b) Covenants and Agreements .

(i) The Grantor hereby covenants and agrees that with respect to any letter of credit constituting Collateral with a stated amount in excess of $[***] hereafter arising it shall use its commercially reasonable efforts to (x) obtain the consent of the issuer thereof to the assignment of the proceeds of the letter of credit to the Collateral Agent and (y) deliver to the Collateral Agent a completed Pledge Supplement, together with all Supplements to Schedules thereto.

(ii) Upon the occurrence and during the continuation of an Event of Default, the Grantor will, promptly upon request by the Collateral Agent, (x) notify (and the Grantor hereby authorizes the Collateral Agent to notify) the issuer and each nominated person with respect to any Supporting Obligations consisting of letters of credit of which the Grantor is the beneficiary that the proceeds thereof have been assigned to the Collateral Agent hereunder and any payments due or to become due in respect thereof are to be made directly to the Collateral Agent or its designee and (y) arrange for the Collateral Agent on behalf of the Secured Parties to become the transferee beneficiary of any such letter of credit.

5.7 Intellectual Property

(a) Non-Exclusive License . For the purpose of enabling the Collateral Agent to exercise rights and remedies under Section 8 , the Grantor hereby grants to the Collateral Agent, to the

extent assignable, an irrevocable, non-exclusive license to use, assign, license or sublicense any Intellectual Property included in the Collateral now owned or hereafter acquired by the Grantor, wherever the same may be located, including in such license reasonable access to all media in which any of the licensed items may be recorded or stored and to all computer programs used for the compilation or printout thereof.

(b) Use of Intellectual Property . Notwithstanding anything contained herein to the contrary, but subject to the provisions of the Loan Documents that limit the rights of the Grantor to dispose of its Intellectual Property, so long as no instruction by the Collateral Agent acting at the direction of the Secured Parties has been delivered in connection with the occurrence and continuance of an Event of Default, the Grantor may exploit, use, enjoy, protect, license sublicense, assign, sell, dispose of or take other actions with respect to the Intellectual Property in the ordinary course of the business of the Grantor. In furtherance of the foregoing, so long as no such instruction has been delivered in connection with the occurrence and continuance of an Event of Default, the Collateral Agent shall from time to time, upon the request and at the expense of the Grantor, execute and deliver any instruments, certificates or other documents, in the form so requested, that the Grantor shall have certified are appropriate (in its judgment) to allow it to take any action permitted above (including relinquishment of the license provided pursuant to clause (a) immediately above as to any specific Intellectual Property constituting Collateral). Further, upon the release of the Liens on the Collateral in accordance with the terms of Section 9.18 of the Credit Agreement, the Collateral Agent shall transfer to the Grantor the license granted pursuant to clause (a) immediately above. The exercise of rights and remedies under Section 8 by the Collateral Agent shall not terminate the rights of the holders of any licenses or sublicenses theretofore granted by the Grantor in accordance with the first sentence of this clause (b) .

(c) Events of Default . Upon the occurrence and during the continuance of an Event of Default, the Grantor shall, upon the request of the Collateral Agent, deliver to the Collateral Agent a schedule listing all Intellectual Property constituting Collateral and take such other action as the Collateral Agent shall deem necessary to perfect the Liens created hereunder in all such Collateral.

5.8 Commercial Tort Claims . If the Grantor shall at any time acquire a Commercial Tort Claim with potential value in excess of excess of $[***], the Grantor shall use its commercially reasonable efforts to, within 60 days of obtaining such Commercial Tort Claim, deliver to the Collateral Agent a completed Pledge Supplement, together with all Supplements to Schedules thereto, identifying such new Commercial Tort Claims, and such other documentation acceptable to the Collateral Agent to grant a security interest under the terms and provisions of this Agreement in and to such Commercial Tort Claim.

SECTION 6. FURTHER ASSURANCES.

6.1 Further Assurances

(a) The Grantor agrees that from time to time, at the sole cost and expense of the Grantor, that, upon its receipt of a written request therefor from the Collateral Agent, it shall promptly execute and deliver all further instruments and documents, and take all further action, that may be necessary in order to (x) create and/or maintain the validity and perfection of and otherwise protect any security interest in Collateral granted hereby or (y) enable the Collateral Agent to exercise and enforce its rights and remedies hereunder with respect to any Collateral. Without limiting the generality of the foregoing, the Grantor shall maintain the Liens created by this Agreement as a perfected security interest prior and superior in right to any other Person except Liens permitted under the Loan Documents, and, upon the reasonable written request of the Collateral Agent, execute and deliver such other agreements, instruments, endorsements, powers of attorney or notices as are necessary, or as the Collateral Agent may reasonably request, to grant, preserve, protect, reflect and perfect the security interests granted or

purported to be granted hereby. For the avoidance of doubt, nothing herein shall require the Collateral Agent to file financing statements or continuation statements, or be responsible for maintaining the security interests purported to be created as described herein (except for the safe custody of any Collateral in its possession and the accounting for moneys actually received by it hereunder or under any other Loan Document) and such responsibility shall be solely that of the Borrower.

(b) The Grantor hereby authorizes the Collateral Agent to file a Record or Records, including, without limitation, financing or continuation statements, intellectual property security agreements and amendments thereto, in any jurisdictions and with any filing offices as the Collateral Agent may reasonably determine, are necessary or advisable to perfect the security interest granted to the Collateral Agent herein. Such financing statements may describe the Collateral in the same manner as described herein or may contain an indication or description of collateral that describes such property in any other manner as the Collateral Agent may reasonably determine, are necessary, advisable or prudent to ensure the perfection of the security interest in the Collateral granted to the Collateral Agent herein, including, without limitation, describing such property as "all assets" or "all personal property, whether now owned or hereafter acquired." The Collateral Agent shall have no responsibility for or liability with respect to monitoring the compliance of any other party to the Loan Documents, this Agreement or any other document related hereto or thereto. The Collateral Agent has no duty to monitor the value or rating of any of the Collateral on an ongoing basis. The Grantor shall furnish to the Collateral Agent from time to time statements and schedules further identifying and describing the Collateral and such other reports in connection with the Collateral as the Collateral Agent may reasonably request, all in reasonable detail; provided that, so long as no Event of Default shall have occurred and be continuing, the Collateral Agent may not request updated schedules pursuant to this Section 6.1 from the Grantor more frequently than twice per calendar year.

SECTION 7. COLLATERAL AGENT APPOINTED ATTORNEY-IN-FACT

7.1 Power of Attorney

. The Grantor hereby irrevocably constitutes and appoints the Collateral Agent, acting for and on behalf of itself and the other Secured Parties and each successor or assign of the Collateral Agent as its true and lawful attorney-in-fact, with full power and authority in the place and stead of the Grantor and in the name of the Grantor or in its own name, at the Grantor's sole cost and expense, subject to the terms of this Agreement and applicable Legal Requirements, to enforce all rights, interests and remedies of the Grantor with respect to the Collateral upon the occurrence and during the continuation of an Event of Default, for the purpose of carrying out the provisions of this Agreement, including the right to:

(a) ask, demand, collect, sue for, recover, receive and give receipt and discharge for amounts due and to become due under and in respect of all or any part of the Collateral,

(b) in the name of the Grantor or its own name or otherwise, take possession of, receive and indorse and collect any check, Account, Chattel Paper, draft, note, acceptance or other Instrument for the payment of moneys due under any Account or general intangible, in each case, constituting Collateral,

(c) file any claims or take any other action that the Collateral Agent may deem necessary or advisable for the collection of all or any part of the Collateral,

(d) execute, in connection with any sale or disposition of the Collateral under this Agreement, any endorsements, assignments, bills of sale or other instruments of conveyance or transfer with respect to all or any part of the Collateral,

(e) in the case of any Intellectual Property constituting Collateral, execute and deliver, and have recorded, any agreement, instrument, document or paper as the Collateral Agent may request to evidence the Collateral Agent's security interest in such Intellectual Property and the goodwill and general intangibles of the Grantor relating thereto or represented thereby,

(f) pay or discharge Taxes and Liens levied or placed on or threatened against the Collateral (other than Liens permitted under the Credit Agreement), effect any repair or pay or discharge any insurance called for by the terms of this Agreement or the other Loan Documents (including all or any part of the premiums therefor and the costs thereof),

(g) direct any party liable for any payment under any Collateral to make payment of any moneys due or to become due thereunder directly to the Collateral Agent or as the Collateral Agent shall direct,

(h) sign and indorse any invoice, freight or express bill, bill of lading, storage or warehouse receipt, draft against debtors, assignment, verification, notice or other document in connection with any Collateral,

(i) commence and prosecute any suit, action or proceeding at law or in equity in any court of competent jurisdiction to collect any Collateral and to enforce any other right with respect to any Collateral,

(j) defend any suit, action or proceeding brought against the Grantor with respect to any Collateral,

(k) settle, compromise or adjust any such suit, action or proceeding with respect to any Collateral and, in connection therewith, give such discharges or releases as the Collateral Agent may deem appropriate,

(l) assign any Copyright, Patent or Trademark (along with the goodwill of the business to which any such Trademark pertains) throughout the world for such term or terms, on such conditions and in such manner as the Collateral Agent shall in its sole discretion determine, including the execution and filing of any document necessary to effectuate or record such assignment,

(m) notify the counterparty on any Assigned Agreement of the security interest of the Collateral Agent therein and that all payments thereunder shall be made directly to the Collateral Agent and cure any default by the Grantor under any Assigned Agreement, and

(n) upon foreclosure, generally, sell, transfer, pledge and make any agreement with respect to or otherwise deal with any Collateral as fully and completely as though the Collateral Agent were the absolute owner thereof for all purposes, and do, at the Collateral Agent's option and the Grantor's expense, at any time, or from time to time, all acts and things that the Collateral Agent reasonably deems necessary to protect, preserve or realize upon the Collateral and the Collateral Agent's and the other Secured Parties' Liens thereon and to effect the intent of this Agreement, all as fully and effectively as the Grantor might do.

This appointment as attorney-in-fact is irrevocable and coupled with an interest.

7.2 No Duty on Part of Collateral Agent or Other Secured Parties

. The powers conferred on the Collateral Agent hereunder are solely to protect the interests of the Secured Parties in the Collateral and shall not impose any duty upon the Collateral Agent or any other

Secured Party to exercise any such powers. The Collateral Agent and the other Secured Parties shall be accountable only for amounts that they actually receive as a result of the exercise of such powers, and neither they nor any of their officers, directors, employees or agents shall be responsible to the Grantor for any act or failure to act hereunder, except in the case of their own gross negligence or willful misconduct, except in the case of their own gross negligence or willful misconduct.

SECTION 8. REMEDIES

8.1 Generally

.

(a) If any Event of Default shall have occurred and be continuing, the Collateral Agent may exercise in respect of the Collateral, in addition to all other rights and remedies provided for herein or otherwise available to it at law or in equity, all the rights and remedies of the Collateral Agent on default under the UCC (whether or not the UCC applies to the affected Collateral) to collect, enforce or satisfy any Obligations then owing, whether by acceleration or otherwise, and also may pursue any of the following separately, successively or simultaneously:

(i) require the Grantor to, and the Grantor hereby agrees that it shall at its expense and promptly upon request of the Collateral Agent forthwith, assemble all or part of the Collateral as directed by the Collateral Agent and make it available to the Collateral Agent at a place to be designated by the Collateral Agent that is reasonably convenient to both parties;

(ii) enter onto the property where any Collateral is located and take possession thereof with or without judicial process;

(iii) prior to the disposition of the Collateral, store, process, repair or recondition the Collateral or otherwise prepare the Collateral for disposition in any manner to the extent the Collateral Agent deems appropriate; and

(iv) without notice except as specified below or under the UCC, sell, assign, lease, license (on an exclusive or nonexclusive basis) or otherwise dispose of the Collateral or any part thereof in one or more parcels at public or private sale, at any of the Collateral Agent's offices or elsewhere, for cash, on credit or for future delivery, at such time or times and at such price or prices and upon such other terms as the Collateral Agent in its reasonable discretion may deem commercially reasonable.

(b) The Collateral Agent or any other Secured Party may be the purchaser of any or all of the Collateral at any public or private (to the extent to the portion of the Collateral being privately sold is of a kind that is customarily sold on a recognized market or the subject of widely distributed standard price quotations) sale in accordance with the UCC and the Collateral Agent, as collateral agent for and representative of the Secured Parties, shall be entitled, for the purpose of bidding and making settlement or payment of the purchase price for all or any portion of the Collateral sold at any such sale made in accordance with the UCC, to use and apply any of the Obligations as a credit on account of the purchase price for any Collateral payable by the Collateral Agent at such sale. Each purchaser at any such sale shall hold the property sold absolutely free from any claim or right on the part of the Grantor, and the Grantor hereby waives (to the extent permitted by applicable law) all rights of redemption, stay and/or appraisal which it now has or may at any time in the future have under any rule of law or statute now existing or hereafter enacted. The Grantor agrees that, to the extent notice of sale shall be required by law, at least 10 days' notice to the Grantor of the time and place of any public sale or the

time after which any private sale is to be made shall constitute reasonable notification. The Collateral Agent shall not be obligated to make any sale of Collateral regardless of notice of sale having been given. The Collateral Agent may adjourn any public or private sale from time to time by announcement at the time and place fixed therefor, and such sale may, without further notice, be made at the time and place to which it was so adjourned. The Grantor agrees that it would not be commercially unreasonable for the Collateral Agent to dispose of the Collateral or any portion thereof by using Internet sites that provide for the auction of assets of the types included in the Collateral or that have the reasonable capability of doing so, or that match buyers and sellers of assets. So long as such sale is conducted in a commercially reasonable manner, the Grantor hereby waives any claims against the Collateral Agent arising by reason of the fact that the price at which any Collateral may have been sold at such a private sale was less than the price which might have been obtained at a public sale, even if the Collateral Agent accepts the first offer received and does not offer such Collateral to more than one offeree. If the proceeds of any sale or other disposition of the Collateral are insufficient to pay all the Obligations, the Grantor shall be liable for the deficiency and the reasonable fees and expenses of any attorneys employed by the Collateral Agent to collect such deficiency. The Grantor further agrees that a breach of any of the covenants contained in this Section 8.1 will cause irreparable injury to the Collateral Agent, that the Collateral Agent has no adequate remedy at law in respect of such breach and, as a consequence, that each and every covenant contained in this Section 8.1 shall be specifically enforceable against the Grantor, and the Grantor hereby waives and agrees not to assert any defenses against an action for specific performance of such covenants except for a defense that no default has occurred giving rise to the Obligations becoming due and payable prior to their stated maturities. Nothing in this Section 8.1 shall in any way alter the rights of the Collateral Agent hereunder.

(c) The Collateral Agent may sell the Collateral without giving any warranties as to the Collateral. The Collateral Agent may specifically disclaim or modify any warranties of title or the like. This procedure will not be considered to adversely affect the commercial reasonableness of any sale of the Collateral.

(d) The Collateral Agent shall have no obligation to marshal any of the Collateral.

8.2 Application of Proceeds

(a) Any Proceeds constituting Collateral to be applied by the Collateral Agent pursuant to the Loan Documents upon the occurrence and during the continuation of an Event of Default and in connection with the enforcement, collection or realization in respect of any Collateral by the Collateral Agent, shall be applied in the following order:

(i) First , to pay incurred and unpaid fees and expenses of the Agents under the Loan Documents;

(ii) Second , to the Collateral Agent, for application by it towards payment, without duplication, of (a) all interest, breakage costs and fees then due and payable under the Loan Documents and (b) any ordinary course settlement payments and any interest due and payable to any Specified Swap Counterparty under any Secured Swap Agreements, pro rata among the Secured Parties according to the amounts of such Obligations then due and owing and remaining unpaid to the Secured Parties;

(iii) Third , to the Collateral Agent, for application by it towards payment, without duplication, of (a) all principal and premium (if any) then due and payable under the Loan Documents and (b) any termination payments payable to any Specified Swap Counterparty under any Secured Swap Agreements, pro rata among the Secured Parties

according to the amounts of such Obligations then due and owing and remaining unpaid to the Secured Parties;

(iv) Fourth , to the Collateral Agent, on a pro rata basis, for application by it towards payment of all other Obligations due and owing and remaining unpaid to the Secured Parties under the Loan Documents and the Secured Swap Agreements; and

(v) Fifth , any balance remaining after the Discharge of the Obligations shall be paid over to the Grantor or to whomsoever may be lawfully entitled to receive the same.

(b) No sale or other disposition of all or any part of the Collateral pursuant to Section 8.1 shall be deemed to relieve the Grantor of its obligations under any Loan Document except to the extent the proceeds thereof are applied to the payment of such obligations.

8.3 Sales on Credit

. If the Collateral Agent sells any of the Collateral upon credit, the Grantor will be credited only with payments actually made by the purchaser and received by the Collateral Agent and applied to indebtedness of the purchaser. In the event the purchaser fails to pay for the Collateral, the Collateral Agent may resell the Collateral and the Grantor shall be credited with proceeds of the sale.

8.4 Investment Related Property

. The Grantor recognizes that the Collateral Agent may be unable to effect a public sale of any or all the Investment Related Property, by reason of certain prohibitions contained in the Securities Act and applicable state securities laws or otherwise, and may be compelled to resort to one or more private sales thereof to a restricted group of purchasers which will be obliged to agree, among other things, to acquire the Investment Related Property for their own account for investment and not with a view to the distribution or resale thereof. The Grantor acknowledges and agrees that any such private sale may result in prices and other terms less favorable than those obtainable through a public sale without such restrictions (including a public offering made pursuant to a registration statement under the Securities Act) and, notwithstanding such circumstances, agrees that any such private sale shall be deemed to have been made in a commercially reasonable manner. The Collateral Agent shall be under no obligation to delay a sale of any of the Investment Related Property for the period of time necessary to permit the Issuer thereof to register such securities for public sale under the Securities Act, or under applicable state securities laws, even if such Issuer would agree to do so. If the Collateral Agent exercises its right to sell any or all of the Investment Related Property, upon written request, the Grantor shall and shall cause each Issuer of any Pledged Equity Interests to be sold hereunder, each partnership and each limited liability company from time to time to furnish to the Collateral Agent all such information as the Collateral Agent may request in order to determine the number and nature of interest, shares or other instruments included in the Investment Related Property which may be sold by the Collateral Agent in exempt transactions under the Securities Act and the rules and regulations of the SEC thereunder, as the same are from time to time in effect.

8.5 Intellectual Property

(a) Anything contained herein to the contrary notwithstanding, upon the occurrence and during the continuation of an Event of Default:

(i) the Collateral Agent shall have the right (but not the obligation) to bring suit or otherwise commence any action or proceeding in the name of the Grantor, the

Collateral Agent or otherwise, in the Collateral Agent's sole discretion, to enforce any Intellectual Property constituting Collateral, in which event the Grantor shall, at the request of the Collateral Agent, do any and all lawful acts and execute any and all documents required by the Collateral Agent in aid of such enforcement and the Grantor shall promptly, upon demand, reimburse and indemnify the Collateral Agent as provided in Section 9.05 of the Credit Agreement in connection with the exercise of its rights under this Section, and, to the extent that the Collateral Agent shall elect not to bring suit to enforce any Intellectual Property as provided in this Section 8.5 , the Grantor agrees to use all reasonable measures, whether by action, suit, proceeding or otherwise, to prevent the infringement or other violation of any of the Grantor's rights in the Intellectual Property constituting Collateral by others and for that purpose agrees to diligently maintain any action, suit or proceeding against any Person so infringing as shall be necessary to prevent such infringement or violation;

(ii) upon written demand from the Collateral Agent, the Grantor shall grant, assign, convey or otherwise transfer to the Collateral Agent or such Collateral Agent's designee all of the Grantor's right, title and interest in and to the Intellectual Property constituting Collateral and shall execute and deliver to the Collateral Agent such documents as are necessary or appropriate to carry out the intent and purposes of this Agreement;

(iii) the Grantor agrees that such an assignment and/or recording shall be applied to reduce the Obligations outstanding only to the extent that the Collateral Agent (or any Secured Party) receives cash proceeds in respect of the sale of, or other realization upon, the Intellectual Property constituting Collateral; and

(iv) the Collateral Agent shall have the right to notify, or require the Grantor to notify, any obligors with respect to amounts due or to become due to the Grantor in respect of the Intellectual Property of the Grantor constituting Collateral, of the existence of the security interest created herein, to direct such obligors to make payment of all such amounts directly to the Collateral Agent, and, upon such notification and at the expense of the Grantor, to enforce collection of any such amounts and to adjust, settle or compromise the amount or payment thereof, in the same manner and to the same extent as the Grantor might have done;

(A) all amounts and proceeds (including checks and other instruments) received by the Grantor in respect of amounts due to the Grantor in respect of the Collateral or any portion thereof shall be received in trust for the benefit of the Collateral Agent hereunder, shall be segregated from other funds of the Grantor and shall be forthwith paid over or delivered to the Collateral Agent in the same form as so received (with any necessary endorsement) to be held as cash Collateral and applied as provided by Section 8.2 ; and

(B) the Grantor shall not adjust, settle or compromise the amount or payment of any such amount or release wholly or partly any obligor with respect thereto or allow any credit or discount thereon.

(b) If (i) an Event of Default shall have occurred and, by reason of cure, waiver, modification, amendment or otherwise, no longer be continuing, (ii) no other Event of Default shall have occurred and be continuing, (iii) an assignment or other transfer to the Collateral Agent of any rights, title and interests in and to the Intellectual Property constituting Collateral shall have been previously made and shall have become absolute and effective, and (iv) the Obligations shall not have become

immediately due and payable, upon the written request of the Grantor, the Collateral Agent shall promptly execute and deliver to the Grantor, at the Grantor's sole cost and expense, such assignments or other transfer as may be necessary to reassign to the Grantor any such rights, title and interests as may have been assigned to the Collateral Agent as aforesaid, subject to any disposition thereof that may have been made by the Collateral Agent; provided that, after giving effect to such reassignment, the Collateral Agent's security interest granted pursuant hereto, as well as all other rights and remedies of the Collateral Agent granted hereunder, shall continue to be in full force and effect; and provided , further , that the rights, title and interests so reassigned shall be free and clear of any other Liens granted by or on behalf of the Collateral Agent and the Secured Parties.

(c) Solely for the purpose of enabling the Collateral Agent to exercise rights and remedies under this Section 8 and at such time as the Collateral Agent shall be lawfully entitled to exercise such rights and remedies, the Grantor hereby grants to the Collateral Agent, to the extent it has the right to do so, an irrevocable, nonexclusive license (exercisable without payment of royalty or other compensation to the Grantor), subject, in the case of Trademarks, to sufficient rights to quality control and inspection in favor of the Grantor to avoid the risk of invalidation of said Trademarks, to use, operate under, license, or sublicense any Intellectual Property constituting Collateral now owned or hereafter acquired by the Grantor, and wherever the same may be located.

8.6 Investment Accounts

. If any Event of Default shall have occurred and be continuing, the Collateral Agent shall (at the written direction of the Administrative Agent) send to each bank, securities intermediary or issuer party to any Control Agreement or Uncertificated Securities Control Agreement, a "Notice of Sole Control" or similar notice as defined in and under such Agreement, and shall apply all proceeds therefrom in accordance with this Agreement and the other Security Documents.

SECTION 9. AMENDMENTS

. None of the terms or provisions of this Agreement may be waived, amended, supplemented or otherwise modified except pursuant to an agreement in writing entered into by the Grantor and the Collateral Agent and otherwise in accordance with the Credit Agreement; provided , however , that, notwithstanding any provision of any Loan Document to the contrary, any schedule hereto may be amended or supplemented from time to time solely by written notice to the Collateral Agent from the Grantor (and such amendment or supplement shall become effective upon delivery of any such notice).

SECTION 10. CONTINUING SECURITY INTEREST; TRANSFER OF ADVANCES

. This Agreement shall create a continuing security interest in the Collateral and shall remain in full force and effect until the Discharge of the Obligations, be binding upon the Grantor, its successors and assigns, and inure, together with the rights and remedies of the Collateral Agent hereunder, to the benefit of the Collateral Agent and its successors, transferees and assigns.

SECTION 11. STANDARD OF CARE; COLLATERAL AGENT MAY PERFORM

. The powers conferred on the Collateral Agent hereunder are solely to protect its interest in the Collateral and shall not impose any duty upon it to exercise any such powers. Except for the exercise of reasonable care in the custody of any Collateral in its possession and the accounting for moneys actually received by it hereunder and other requirements of law or the UCC, the Collateral Agent shall have no duty as to any Collateral or as to the taking of any necessary steps to preserve rights against prior parties or any other rights pertaining to any Collateral. To the extent permitted by law, the Collateral Agent shall be deemed to have exercised reasonable care in the custody and preservation of Collateral in its possession

if such Collateral is accorded treatment substantially equal to that which the Collateral Agent accords its own property. Beyond the exercise of reasonable care in the custody thereof, the Collateral Agent shall have no duty as to any of the Collateral in its possession or control or in the possession or control of any agent or bailee or any income thereon or as to preservation of rights against prior parties or any other rights pertaining thereto, and the Collateral Agent shall not be responsible for filing any financing or continuation statements or recording any documents or instruments in any public office at any time or times or otherwise perfecting or maintaining the perfection of any security interest in the Collateral. Neither the Collateral Agent nor any of its directors, officers, employees or agents shall be liable for failure to demand, collect or realize upon all or any part of the Collateral or for any delay in doing so or shall be under any obligation to sell or otherwise dispose of any Collateral upon the request of the Grantor or otherwise. If the Grantor fails to perform any agreement contained herein, the Collateral Agent may itself perform, or cause performance of, such agreement, and the expenses of the Collateral Agent incurred in connection therewith shall be payable by the Grantor under the Credit Agreement.

SECTION 12. NOTICES

. Any notice required or permitted to be given under this Agreement shall be given in accordance with the Credit Agreement.

SECTION 13. RELEASES

Upon the Discharge of the Obligations, and subject to Section 21 , the Collateral shall be automatically released from the Liens created hereby, and this Agreement and all obligations (other than those expressly stated to survive such termination) of the Collateral Agent and the Grantor hereunder shall terminate, all without delivery of any instrument or performance of any act by any party, and all rights to the Collateral shall revert to the Grantor. At the request and sole expense of the Grantor following any such termination, the Collateral Agent shall deliver to the Grantor any Collateral held by the Collateral Agent hereunder, and execute and deliver to the Grantor such documents or otherwise authorize the filing of such documents as the Grantor shall reasonably request to evidence such termination.

If any of the Collateral shall be sold, transferred or otherwise disposed of by the Grantor in a transaction permitted by any Loan Documents or consented to in accordance with the Loan Documents, then the Collateral Agent, at the request and at the sole expense of the Grantor (with written confirmation from the Administrative Agent), shall execute and deliver to the Grantor all releases or authorize the filing of other documents reasonably necessary or desirable for the release of the Liens created hereby on such Collateral; provided that the Grantor shall have delivered to the Collateral Agent and the Administrative Agent, at least 5 Business Days prior to the date of the proposed release, a written request for release identifying the relevant Collateral and the terms of the sale or other disposition in reasonable detail, including the price thereof and any expenses in connection therewith, together with a certification by the Grantor stating that such transaction is in compliance with the Loan Documents and the Proceeds of such Collateral will be applied in accordance with the terms of the Loan Documents, if applicable.

SECTION 14. MISCELLANEOUS

No failure or delay on the part of the Collateral Agent in the exercise of any power, right or privilege hereunder or under any other Loan Document shall impair such power, right or privilege or be construed to be a waiver of any default or acquiescence therein, nor shall any single or partial exercise of any such power, right or privilege preclude other or further exercise thereof or of any other power, right or privilege. All rights and remedies existing under this Agreement and the other Loan Documents are cumulative to, and not exclusive of, any rights or remedies otherwise available. In case any provision in or obligation under this Agreement shall be invalid, illegal or unenforceable in any jurisdiction, the validity, legality and enforceability of the remaining provisions or obligations, or of such provision or

obligation in any other jurisdiction, shall not in any way be affected or impaired thereby. All covenants hereunder shall be given independent effect so that if a particular action or condition is not permitted by any of such covenants, the fact that it would be permitted by an exception to, or would otherwise be within the limitations of, another covenant shall not avoid the occurrence of a default or an event of default under the Loan Documents if such action is taken or condition exists. This Agreement shall be binding upon and inure to the benefit of the Collateral Agent and the Grantor and their respective successors and assigns. The Grantor shall not, without the prior written consent of the Collateral Agent given in accordance with the Credit Agreement, assign any right, duty or obligation hereunder. There are no unwritten oral agreements between the parties. This Agreement may be executed in one or more counterparts and by different parties hereto in separate counterparts, each of which when so executed and delivered shall be deemed an original, but all such counterparts together shall constitute but one and the same instrument; signature pages may be detached from multiple separate counterparts and attached to a single counterpart so that all signature pages are physically attached to the same document. Delivery of an executed counterpart of a signature page of this Agreement or any document or instrument delivered in connection herewith by facsimile or other electronic delivery (including by certified electronic signature) shall be effective as delivery of a manually executed counterpart of this Agreement or such other document or instrument, as applicable.

The Grantor's waiver of rights or agreements in respect of Collateral, the exercise of remedies, standards of care, notice and the other matters covered by Sections 5 through 8 are in each case qualified that such waivers or agreements are being made to the fullest extent permitted by law.

SECTION 15. ACKNOWLEDGEMENTS

. The Grantor hereby acknowledges that (a) it has been advised by counsel in the negotiation, execution and delivery of this Agreement and the other Loan Documents to which it is a party; (b) neither the Collateral Agent nor any Secured Party has any fiduciary relationship with or duty to the Grantor arising out of or in connection with this Agreement or any of the other Loan Documents, and the relationship between the Grantor, on the one hand, and the Collateral Agent and Secured Parties, on the other hand, in connection herewith or therewith is solely that of debtor and creditor and (c) no joint venture is created hereby or by the other Loan Documents or otherwise exists by virtue of the transactions contemplated hereby among the Secured Parties or among the Grantor and the Secured Parties.

SECTION 16. HEADINGS

. Section headings and the Table of Contents used herein are for convenience of reference only, are not part of this Agreement and are not to affect the construction of, or to be taken into consideration in interpreting, this Agreement.

SECTION 17. APPLICABLE LAW

. THIS AGREEMENT SHALL BE GOVERNED BY, AND SHALL BE CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.

SECTION 18. CONSENT TO JURISDICTION; CONSENT TO SERVICE OF PROCESS

Each party hereto hereby irrevocably and unconditionally submits, for itself and its property, to the exclusive jurisdiction of any New York state court or federal court of the United States of America sitting in the County and City of New York, and any appellate court from any thereof, in any action or proceeding arising out of or relating to this Agreement, or for recognition or enforcement of any judgment, and each of the parties hereto hereby irrevocably and unconditionally agrees that all claims in respect of any such action or proceeding may be heard and determined in such New York state court or, to the

extent permitted by law, in such federal court. Each of the parties hereto agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Each party hereto hereby irrevocably and unconditionally waives, to the fullest extent it may legally and effectively do so, any objection which it may now or hereafter have to the laying of venue of any suit, action or proceeding arising out of or relating to this Agreement in any New York state or federal court. Each of the parties hereto hereby irrevocably waives, to the fullest extent permitted by law, the defense of an inconvenient forum to the maintenance of such action or proceeding in any such court.

Each party hereto further irrevocably consents to the service of process in any action or proceeding in such courts by the mailing thereof by any parties thereto by registered or certified mail, postage prepaid, to such party at its address specified in Section 12 . Nothing herein shall affect the right to serve process in any other manner permitted by law.

SECTION 19. WAIVER OF JURY TRIAL

. EACH PARTY HERETO HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY HERETO (A) CERTIFIES THAT NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVER AND (B) ACKNOWLEDGES THAT IT AND THE OTHER PARTIES HERETO HAVE BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION 19 .

SECTION 20. SECURITY INTEREST ABSOLUTE

. All rights of the Collateral Agent hereunder, the grant of a security interest in the Collateral and all obligations of the Grantor hereunder shall be absolute and unconditional irrespective of (a) any lack of validity or enforceability of any Loan Document, (b) any change in the time, manner or place of payment of, or in any other term of, all or any of the Obligations, or any other amendment or waiver of or any consent to any departure from any Loan Document, (c) any exchange, release or non-perfection of any security on any collateral, or any release or amendment or waiver of or consent under or departure from any guarantee, securing or guaranteeing all or any of the Obligations, or (d) any other circumstance that might otherwise constitute a defense available to, or a discharge of, the Grantor in respect of the Obligations or this Agreement (other than the payment in full of all of the Obligations or the benefit of any statute of limitations affecting the Grantor's obligations hereunder or the enforcement thereof).

SECTION 21. REINSTATEMENT

. This Agreement and the Liens created hereunder shall automatically be reinstated if and to the extent that for any reason any payment by or on behalf of the Grantor in respect of the Obligations is rescinded or must otherwise be restored by any Secured Party, whether as a result of any Bankruptcy Event or reorganization or otherwise, and the Grantor shall indemnify the Collateral Agent, each other Secured Party and its respective employees, officers and agents on demand for all reasonable fees, costs and expenses (including reasonable fees, costs and expenses of counsel) incurred by the Collateral Agent, such other Secured Party or their respective employees, officers or agents in connection with such reinstatement, rescission or restoration.

SECTION 22. COLLATERAL AGENT

. Notwithstanding anything herein to the contrary, the Collateral Agent shall be afforded all of the rights, powers, immunities and indemnities of the Collateral Agent set forth in the Credit Agreement and the Loan Documents, as if such rights, powers, immunities and indemnities were specifically set forth herein. The Grantor hereby acknowledges the appointment of the Collateral Agent pursuant to the Credit Agreement. The rights, privileges, protections and benefits given to the Collateral Agent, including its right to be indemnified, are extended to, and shall be enforceable by, the Collateral Agent in its capacity hereunder, and to each agent, custodian and other Person employed by the Collateral Agent in accordance herewith to act hereunder.

SECTION 23. LIMITED LIABILITY

. Notwithstanding anything in this Agreement or the other Loan Documents to the contrary, none of the Secured Parties shall have any claims with respect to the transactions contemplated hereunder or thereunder against Holdings, any past, present or future holder (whether direct or indirect) of any Equity Interests in Holdings or any of its Subsidiaries or Affiliates (other than the Loan Parties), shareholders, officers, incorporators, directors, employees, representatives, Controlling persons, executives or agents (collectively, the " Nonrecourse Persons "), such claims against the Nonrecourse Persons (including as may arise by operation of law) being expressly waived hereby; provided that the foregoing shall not (a) constitute a waiver, release or discharge (or otherwise impair the enforceability) of any of the Obligations or of any of the terms, covenants, conditions or provisions of this Agreement or any other Loan Document and the same shall continue (subject to clause (d) below, but without personal liability of the Nonrecourse Persons) until fully paid, discharged, observed or performed; (b) constitute a waiver, release or discharge of any Lien or security interest purported to be created pursuant to this Agreement or any other Loan Documents (or otherwise impair the ability of any Secured Party to realize or foreclose upon any Collateral); (c) in any way limit or restrict any right or remedy of the Collateral Agent or any other Secured Party (or any assignee or beneficiary thereof or successor thereto) with respect to, and each of the Nonrecourse Persons shall remain fully liable to the extent that it would otherwise be liable for its own actions with respect to, any fraud (which shall not include innocent or negligent misrepresentation), willful misrepresentation or misappropriation of revenues, profits or proceeds from the Projects or any Collateral, that should or would have been paid as provided in the relevant Loan Document or paid or delivered to the Collateral Agent or any other Secured Party (or any assignee or beneficiary thereof or successor thereto) towards any payment required under any Loan Document; or (d) affect or diminish in any way or constitute a waiver, release or discharge of any obligation, covenant, or agreement made by any of the Nonrecourse Persons (or any security granted by the Nonrecourse Persons in support of the obligations of any Person) under or in connection with any Loan Document (or as security for the Obligations), any Sponsor Guaranty or other agreement with any Secured Party. The limitations on recourse set forth in this Section 23 shall survive the Discharge of the Obligations and the performance of the Obligations under the Loan Documents.

[*Signature pages follow.* **]**

IN WITNESS WHEREOF, the Grantor and the Collateral Agent have caused this Agreement to be duly executed and delivered by their respective officers thereunto duly authorized as of the date first written above.

EXGEN RENEWABLES IV, LLC

By: _____
Name:
Title:

WILMINGTON TRUST, NATIONAL ASSOCIATION,
as Collateral Agent

By: _____
Name:
Title:

November 28, 2017

Wilmington Trust, National Association, in its capacity as Collateral Agent

RE: Pledge and Security Agreement, dated as of November 28, 2017, between ExGen Renewables IV, LLC, as Grantor, and Wilmington Trust, National Association, as Collateral Agent

Ladies and Gentlemen:

ExGen Renewables Holdings, LLC consents to the grant by the Grantor of a security interest in all of the Pledged Equity Interests constituting Collateral to the Collateral Agent and the terms of such grant set forth in the Pledge and Security Agreement, dated as of November 28, 2017, between ExGen Renewables IV, LLC as Grantor, and Wilmington Trust, National Association, as Collateral Agent (the " Security Agreement "; capitalized terms used herein are as defined in the Security Agreement).

ExGen Renewables Holdings, LLC

By: _____
Name:
Title:

November 28, 2017

Wilmington Trust, National Association, in its capacity as Collateral Agent

RE: Pledge and Security Agreement, dated as of November 28, 2017, between ExGen Renewables IV, LLC as Grantor and Wilmington Trust, National Association, as Collateral Agent

Ladies and Gentlemen:

SolGen Holding, LLC consents to the grant by the Grantor of a security interest in all of the Pledged Equity Interests constituting Collateral to the Collateral Agent and the terms of such grant set forth in the Pledge and Security Agreement, dated as of November 28, 2017, between ExGen Renewables IV, LLC, as Grantor, and Wilmington Trust, National Association, as Collateral Agent (the " Security Agreement "; capitalized terms used herein are as defined in the Security Agreement).

SolGen Holding, LLC

By: _____
Name:
Title:

November 28, 2017

Wilmington Trust, National Association, in its capacity as Collateral Agent

RE: Pledge and Security Agreement, dated as of November 28, 2017, between ExGen Renewables IV, LLC as Grantor and Wilmington Trust, National Association, as Collateral Agent

Ladies and Gentlemen:

Exelon AVSR Holding, LLC consents to the grant by the Grantor of a security interest in all of the Pledged Equity Interests constituting Collateral to the Collateral Agent and the terms of such grant set forth in the Pledge and Security Agreement, dated as of November 28, 2017, between ExGen Renewables IV, LLC, as Grantor and Wilmington Trust, National Association, as Collateral Agent (the " Security Agreement "; capitalized terms used herein are as defined in the Security Agreement).

Exelon AVSR Holding, LLC

By: _____
Name:
Title:

November 28, 2017

Wilmington Trust, National Association, in its capacity as Collateral Agent

RE: Pledge and Security Agreement, dated as of November 28, 2017, between ExGen Renewables IV, LLC as Grantor, and Wilmington Trust, National Association, as Collateral Agent

Ladies and Gentlemen:

Constellation DCO Albany Power Holdings, LLC consents to the grant by the Grantor of a security interest in all of the Pledged Equity Interests constituting Collateral to the Collateral Agent and the terms of such grant set forth in the Pledge and Security Agreement, dated as of November 28, 2017, between ExGen Renewables IV, LLC as Grantor, and Wilmington Trust, National Association, as Collateral Agent (the " Security Agreement "; capitalized terms used herein are as defined in the Security Agreement).

Constellation DCO Albany Power Holdings, LLC

By: _____
Name:
Title:

SCHEDULE 4.1

TO PLEDGE AND SECURITY AGREEMENT

GENERAL INFORMATION

(A) Full Legal Name, Type of Organization, Jurisdiction of Organization, organizational identification number (if one exists), and the location of the Grantor's chief executive office or sole place of business or principal residence, as the case may be:

Full Legal Name	**Type of Organization**	**Jurisdiction of Organization**	**Organizational Identification Number**	**Chief Executive Office/ Sole Place of Business or Principal Residence**
ExGen Renewables IV, LLC	Limited liability company	Delaware	[***]	10 South Dearborn Street, 49th Floor Chicago, IL 60603

(B) Other names (including any trade name or fictitious business name) under which the Grantor conducts business:

None.

(C) Changes in Name, Jurisdiction of Organization, form and the location of the Grantor's chief executive office or sole place of business or principal residence, as the case may be, since the date of its formation:

None.

SCHEDULE 4.4

TO PLEDGE AND SECURITY AGREEMENT

PLEDGED EQUITY INTERESTS

Owner	Issuer	Class of Stock or other Equity Interest	Percentage
ExGen Renewables IV, LLC	ExGen Renewables Holdings, LLC	Membership Interests	100%
ExGen Renewables IV, LLC	SolGen Holding, LLC	Membership Interests	100%
ExGen Renewables IV, LLC	Exelon AVSR Holding	Membership Interests	100%
ExGen Renewables IV, LLC	Constellation DCO Albany Power Holdings, LLC	Class A Membership Interests	50%

SCHEDULE 4.4(b)

TO PLEDGE AND SECURITY AGREEMENT

PLEDGED NOTES

Promissory Note in favor of ExGen Renewables IV, LLC (as assignee of Constellation NewEnergy, Inc.) ("Lender") by Peach Power, Inc. ("Borrower") in the amount of $99,000,000.

SCHEDULE 4.8

TO PLEDGE AND SECURITY AGREEMENT

COMMERCIAL TORT CLAIMS

None. EXHIBIT A

TO PLEDGE AND SECURITY AGREEMENT

FORM OF PLEDGE SUPPLEMENT

This **PLEDGE SUPPLEMENT** , dated **[** mm/dd/yy **]** , is delivered by EXGEN RENEWABLES IV, LLC, a Delaware limited liability company (the " Grantor ") pursuant to the Pledge and Security Agreement, dated as of November 28, 2017 (as it may be from time to time amended, restated, modified or supplemented, the " Security Agreement "), between EXGEN RENEWABLES IV, LLC, as Grantor, and WILMINGTON TRUST, NATIONAL ASSOCIATION, as the Collateral Agent. Capitalized terms used herein not otherwise defined herein shall have the meanings ascribed thereto in the Security Agreement (including by reference to definitions in other agreements).

The Grantor hereby confirms the grant to the Collateral Agent set forth in the Security Agreement of, and does hereby grant to the Collateral Agent for the benefit of the Secured Parties, a security interest in and continuing Lien on all of the Grantor's right, title and interest in, to and under all Collateral of the Grantor (excluding, for the avoidance of doubt, Excluded Property), in each case whether now owned or existing or hereafter acquired or arising and wherever located. The Grantor represents and warrants that the attached Supplements to Schedules accurately and completely set forth all additional information required pursuant to the Security Agreement and hereby agrees that such Supplements to Schedules shall constitute part of the Schedules to the Security Agreement.

IN WITNESS WHEREOF , the Grantor has caused this Pledge Supplement to be duly executed and delivered by its duly authorized officer as of **[mm/dd/yy]** .

EXGEN RENEWABLES IV, LLC

By: _____
Name:
Title:

SUPPLEMENT TO SCHEDULE 4.1

TO PLEDGE AND SECURITY AGREEMENT

(A) Full Legal Name, Type of Organization, Jurisdiction of Organization, organizational identification number (if one exists), and the location of the Grantor's chief executive office or sole place of business or principal residence, as the case may be:

Full Legal Name	Type of Organization	Jurisdiction of Organization	Organizational Identification Number	Chief Executive Office/ Sole Place of Business or Principal Residence

(B) Other names (including any trade name or fictitious business name) under which the Grantor has conducted business for the past five years:

(C) Changes in name, jurisdiction of organization, chief executive office/ sole place of business/ principal residence and corporate structure since its formation:

EXHIBIT B

TO PLEDGE AND SECURITY AGREEMENT

FORM OF UNCERTIFICATED SECURITIES CONTROL AGREEMENT

This Uncertificated Securities Control Agreement dated as of **[_____]** , 20 **[__]** among EXGEN RENEWABLES IV, LLC (the " Pledgor "), WILMINGTON TRUST, NATIONAL ASSOCIATION, as collateral agent for the Secured Parties (the " Collateral Agent "), and **[_____]** , a **[_____]** (the " Issuer "). Capitalized terms used but not defined herein shall have the meaning assigned in the Pledge and Security Agreement dated as of November 28, 2017, between the Pledgor and the Collateral Agent (as amended, restated, supplemented or otherwise modified from time to time, the " Security Agreement "). All references herein to the "UCC" means the Uniform Commercial Code as in effect in the State of New York.

Section 1. Registered Ownership of Shares . The Issuer hereby confirms and agrees that as of the date hereof the Pledgor is the registered owner of **[** ____ shares **] [** ___% of interests **]** of the Issuer's **[** common **]** equity (the " Pledged Shares ") and the Issuer shall not change the registered owner of the Pledged Shares without the prior written consent of the Collateral Agent.

Section 2. Instructions . If at any time the Issuer shall receive instructions originated by the Collateral Agent relating to the Pledged Shares, the Issuer shall comply with such instructions without further consent by the Pledgor or any other person.

Section 3. Additional Representations and Warranties of the Issuer . The Issuer hereby represents and warrants to the Collateral Agent:

(a) It has not entered into, and until the termination of this agreement will not enter into, any agreement with any other person relating to the Pledged Shares pursuant to which it has agreed to comply with instructions issued by such other person; and

(b) It has not entered into, and until the termination of this agreement will not enter into, any agreement with the Pledgor or the Collateral Agent purporting to limit or condition the obligation of the Issuer to comply with instructions as set forth in Section 2 hereof.

(c) Except for the claims and interest of the Collateral Agent and of the Pledgor in the Pledged Shares, the Issuer does not know of any claim to, or interest in, the Pledged Shares. If any person asserts any lien, encumbrance or adverse claim (including any writ, garnishment, judgment, warrant of attachment, execution or similar process) against the Pledged Shares, the Issuer will promptly notify the Collateral Agent and the Pledgor thereof.

(d) This Uncertificated Securities Control Agreement is the valid and legally binding obligation of the Issuer.

Section 4. Choice of Law . This Agreement shall be governed by the law of the State of New York.

Section 5. Conflict with Other Agreements . In the event of any conflict between this Agreement (or any portion thereof) and any other agreement now existing or hereafter entered into, the terms of this Agreement shall prevail. No amendment or modification of this Agreement or waiver of any right hereunder shall be binding on any party hereto unless it is in writing and is signed by all of the parties hereto.

Section 6. Voting Rights . Until such time as the Collateral Agent shall otherwise instruct the Issuer in writing upon the occurrence (and during the continuation of an Event of Default), the Pledgor shall have the right to vote the Pledged Shares.

Section 7. Successors; Assignment . The terms of this Agreement shall be binding upon, and shall inure to the benefit of, the parties hereto and their respective corporate successors or heirs and personal representatives who obtain such rights solely by operation of law. The Collateral Agent may assign its rights hereunder only with the express written consent of the Issuer and by sending written notice of such assignment to the Pledgor.

Section 8. Indemnification of Issuer . The Pledgor and the Collateral Agent hereby agree that (a) the Issuer is released from any and all liabilities to the Pledgor and the Collateral Agent arising from the terms of this Agreement and the compliance of the Issuer with the terms hereof, except to the extent that such liabilities arise from the Issuer's negligence and (b) the Pledgor, its successors and assigns shall at all times indemnify and save harmless the Issuer from and against any and all claims, actions and suits of others arising out of the terms of this Agreement or the compliance of the Issuer with the terms hereof, except to the extent that such claim, action or suit arises from the Issuer's negligence, and from and against any and all liabilities, losses, damages, costs, charges, counsel fees and other expenses of every nature and character arising by reason of the same, until the termination of this Agreement.

Section 9. Notices . Any notice, request or other communication required or permitted to be given under this Agreement shall be in writing and deemed to have been properly given when delivered in person, or when sent by facsimile or other electronic means and electronic confirmation of error free receipt is received or two days after being sent by certified or registered United States mail, return receipt requested, postage prepaid, addressed to the party at the address set forth below.

Pledgor: ExGen Renewables IV, LLC
c/o Exelon Generation Company, LLC
1310 Point Street, 12th Floor
Baltimore, MD 21231
Attention: Project Finance

with a copy to
c/o Exelon Generation Company, LLC
701 Ninth Street NW, 9th Floor
Washington, DC 20068
Attention: Joseph Downs

Collateral Agent: Wilmington Trust, National Association
1100 North Market Street
Wilmington Delaware 19890
Attention: Institutional Client Services/Project Finance
Facsimile: 302-636-4149
Telephone: 302-636-6973

Issuer: **[** Name of Issuer **]**

[Address **]**

Attention: **[** _____ **]**

Facsimile: **[_____]**

Any party may change its address for notices in the manner set forth above.

Section 10. Termination . The obligations of the Issuer to the Collateral Agent pursuant to this Agreement shall continue in effect until the security interests of the Collateral Agent in the Pledged Shares have been terminated pursuant to the terms of the Security Agreement and the Collateral Agent has notified the Issuer of such termination in writing. The Collateral Agent agrees to provide a Notice of Termination in substantially the form of Exhibit A hereto to the Issuer upon the request of the Pledgor on or after the termination of the Collateral Agent's security interest in the Pledged Shares pursuant to the terms of the Security Agreement. The termination of this Uncertificated Securities Control Agreement shall not terminate the Pledged Shares or alter the obligations of the Issuer to the Pledgor pursuant to any other agreement with respect to the Pledged Shares.

Section 11. Counterparts . This Agreement may be executed in any number of counterparts, all of which shall constitute one and the same instrument, and any party hereto may execute this Agreement by signing and delivering one or more counterparts.

EXGEN RENEWABLES IV, LLC
as Pledgor

By: _____
Name:
Title:

WILMINGTON TRUST, NATIONAL ASSOCIATION,
as Collateral Agent

By: _____
Name:
Title:

[NAME OF ISSUER],
as Issuer

By: _____
Name:
Title:

EXHIBIT A

TO EXHIBIT B TO PLEDGE AND SECURITY AGREEMENT

[Letterhead of Collateral Agent **]**

[Date **]**

[Name and Address of Issuer **]**

Attention: **[ ]**

Re: Termination of Control Agreement

You are hereby notified that the Uncertificated Securities Control Agreement between you, (the " Pledgor ") and the undersigned (a copy of which is attached) is terminated and you have no further obligations to the undersigned pursuant to such Agreement. Notwithstanding any previous instructions to you, you are hereby instructed to accept all future directions with respect to Pledged Shares (as defined in the Uncertificated Securities Control Agreement) from the Pledgor. This notice terminates any obligations you may have to the undersigned with respect to the Pledged Shares, however nothing contained in this notice shall alter any obligations which you may otherwise owe to the Pledgor pursuant to any other agreement.

You are instructed to deliver a copy of this notice by facsimile or other electronic transmission to the Pledgor.

Very truly yours,

WILMINGTON TRUST, NATIONAL ASSOCIATION,
as Collateral Agent

By: _____
Name:
Title:

EXHIBIT C
TO PLEDGE AND SECURITY AGREEMENT

FORM OF ISSUER CONSENT TO PLEDGED EQUITY INTEREST

[ ], 2017

Wilmington Trust, National Association, in its capacity as Collateral Agent

RE: Pledge and Security Agreement, dated as of November 28, 2017, between ExGen Renewables IV, LLC, as Grantor and Wilmington Trust, National Association, as Collateral Agent

Ladies and Gentlemen:

[NAME OF ISSUER] consents to the grant by the applicable Pledgor of a security interest in all of the Pledged Equity Interests constituting Collateral to the Collateral Agent and the terms of such grant set forth in the Pledge and Security Agreement, dated as of November 28, 2017, between ExGen Renewables IV, LLC, as Grantor and Wilmington Trust, National Association, as Collateral Agent (the " Pledge and Security Agreement "; capitalized terms used herein are as defined in the Pledge and Security Agreement).

[Name of issuer]

By: _____
Name:
Title:

GUARANTEE AND PLEDGE AGREEMENT

Dated as of November 28, 2017

by and among

EXGEN RENEWABLES IV HOLDING, LLC

and

EXGEN RENEWABLES HOLDINGS, LLC

as the Pledgors

and

WILMINGTON TRUST, NATIONAL ASSOCIATION,

as Collateral Agent

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SCHEDULES

SCHEDULE 1 - PLEDGED EQUITY INTERESTS
SCHEDULE 4.1 - GENERAL INFORMATION

This GUARANTEE AND PLEDGE AGREEMENT, dated as of November 28, 2017 (this " Agreement "), is entered into by and among EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" Holding "), EXGEN RENEWABLES HOLDINGS, LLC, a limited liability company organized under the laws of Delaware (" ExGen Renewables Holdings ", together with Holding, the " Pledgors ", and each a " Pledgor ") and WILMINGTON TRUST, NATIONAL ASSOCIATION, as collateral agent for the Secured Parties (in such capacity and together with its permitted successors, assigns and designees, the " Collateral Agent "). Capitalized terms used in this Agreement (including in this preamble and the recitals below) have the meanings assigned to such terms in Section 1.1 .

RECITALS:

WHEREAS, as of the date hereof, Holding owns the Equity Interests in ExGen Renewables IV, LLC, a limited liability company organized under the laws of the State of Delaware (the " Borrower ") described on Schedule 1;

WHEREAS, as of the Closing Date, the Borrower owns (A) all of the Equity Interests in (i) ExGen Renewables Holdings, (ii) SolGen Holding, LLC, a limited liability company organized under the laws of Delaware (" SolGen Holding ") and (iii) Exelon AVSR Holding, LLC, a limited liability company organized under the laws of Delaware (" Exelon AVSR Holding ") and (B) not less than 50% of the Equity Interests in Constellation DCO Albany Power Holdings, LLC, a limited liability company organized under the laws of Delaware (" Albany Power Holdings " and, collectively with ExGen Renewables Holdings, SolGen Holding and Exelon AVSR Holding, the " Project Holdcos ");

WHEREAS, ExGen Renewables Holdings owns all of the JV Class A Membership Interests (the " Class A Membership Interests ") in ExGen Renewables Partners, LLC, a limited liability company organized under the laws of the State of Delaware (" ExGen Renewables JV ", and together with the Borrower, the " Subsidiaries ") described on Schedule 1;

WHEREAS, ExGen Renewables JV, SolGen Holding, Exelon AVSR Holding and Albany Power Holdings own, directly or indirectly, all (or a specified class of) the Equity Interests of each of the other Project Entities, which collectively own or lease the Projects;

WHEREAS, the Borrower intends to enter into the Credit Agreement, dated as of the date hereof (as amended, amended and restated, supplemented, replaced or otherwise modified and in effect from time to time, the " Credit Agreement "), among the Borrower, Holding, the Lenders party thereto from time to time, Morgan Stanley Senior Funding, Inc., as administrative agent (in such capacity, together with any successor administrative agent appointed pursuant to the provisions of Article VIII of the Credit Agreement, the " Administrative Agent "), Wilmington Trust, National Association, as Collateral Agent and Wilmington Trust, National Association, as Depositary Bank, pursuant to which the Company has requested that the Lenders extend credit in the form of Loans on the Closing Date, in an aggregate U.S. Dollar amount for all such Loans of U.S. $850 million; and

WHEREAS, each of the Pledgors has agreed to secure all of the Pledgor Obligations by granting to the Collateral Agent, for the benefit of the Secured Parties, a Lien on all of the Collateral.

AGREEMENT:

Now, Therefore, in consideration of the foregoing, the mutual covenants and obligations herein set forth and for other good and valuable consideration, the adequacy and receipt of which are hereby acknowledged and in reliance upon the representations, warranties and covenants contained herein, the parties hereto, intending to be legally bound, hereby agree as follows:

SECTION 1. DEFINITIONS.

1.1 General Definitions

. Unless otherwise defined herein, terms defined in the Credit Agreement and used herein (including in the preamble and the recitals hereto) shall have the meanings given to them in the Credit Agreement. In addition to the terms defined in the Credit Agreement, the following terms shall have the following meanings:

" Administrative Agent " has the meaning set forth in the recitals to this Agreement.

" Agreement " has the meaning set forth in the preamble to this Agreement.

" Albany Power Holdings " has the meaning assigned to such term in the recitals of this Agreement.

" Bankruptcy Event " means any event described in Sections 7.01(h) and 7.01(i) of the Credit Agreement.

" Bankruptcy Law " means the Bankruptcy Code and any other state or federal insolvency, reorganization, moratorium or similar law for the relief of debtors.

" Borrower Obligations " has the meaning assigned in Section 2.1 .

" Collateral " has the meaning assigned in Section 3.1 .

" Collateral Agent " has the meaning set forth in the preamble to this Agreement.

" Company " has the meaning set forth in the recitals to this Agreement.

" Credit Agreement " has the meaning set forth in the recitals to this Agreement.

" Exelon AVSR Holding " has the meaning assigned to such term in the recitals hereto.

" ExGen Renewables Holdings " has the meaning assigned to such term in the recitals hereto.

" Issuer " means ExGen Renewables IV, LLC and ExGen Renewables Partners, LLC, as applicable.

" Legal Requirements " means, as to any Person, any law, statute, rule, regulation, ordinance, order, code, treaty, judgment, decree, or any published directive or requirement which has the force of law, or other legally binding form of governmental restriction or decision of any Governmental Authority, in each case applicable to or binding upon such Person or any of its properties or to which such Person or any of its properties is subject.

" LLC Interests " has the meaning given to such term in Section 3.1(a) .

" Obligations " has the meaning assigned to such term in the Credit Agreement.

" Operating Agreement " means the Amended and Restated Limited Liability Company Agreement of the Company, dated as of March 13, 2017.

" Pledged Equity Interests " means all classes of Equity Interests owned by any Pledgor, including, without limitation, the LLC Interests and the certificates, if any, representing such Pledged Equity Interests, and all dividends, distributions, return of capital, cash, instruments and other property from time to time received, receivable or otherwise distributed in respect of or in exchange for any or all of the Pledged Equity Interests.

" Pledgor Obligations " means all Obligations of the Pledgors including arising under Section 2 hereof.

" Proceeds " means (i) all "proceeds" as defined in Article 9 of the UCC, (ii) payments or distributions made with respect to the Pledged Equity Interests and (iii) whatever is receivable or received when Collateral or proceeds are sold, exchanged, collected or otherwise disposed of, whether such disposition is voluntary or involuntary.

" Project Holdcos " has the meaning assigned to such term in the recitals hereto.

" Record " has the meaning set forth in Article 9 of the UCC.

" Secured Parties " means the Agents, the Lenders and any Specified Swap Counterparty.

" SolGen Holding " has the meaning assigned to such term in the recitals hereto.

" UCC " means the Uniform Commercial Code as the same may, from time to time, be in effect in the State of New York; provided however that, in the event that, by reason of mandatory provisions of law, any or all of the attachment, perfection or priority of the security interest in any Collateral is governed by the Uniform Commercial Code as in effect in a jurisdiction other than the State of New York, the term "UCC" means the Uniform Commercial Code as in effect in such other jurisdiction for purposes of the provisions hereof relating to such attachment, perfection or priority and for purposes of definitions related to such provisions.

1.2 Definitions; Interpretation

. For all purposes of this Agreement, except as otherwise expressly provided or unless the context otherwise requires, the rules of interpretation set forth in Section 1.02 of the Credit Agreement are hereby incorporated by reference, mutatis mutandis, as if fully set forth herein. All capitalized terms used herein (including the preamble and recitals hereto) and not otherwise defined herein or in the Credit Agreement have the meanings ascribed thereto in the UCC. All references herein to provisions of the UCC shall include all successor provisions under any subsequent version or amendment to any Article of the UCC. The terms "lease" and "license" shall include "sub-lease" and "sub license", as applicable.

SECTION 2. GUARANTEE

2.1 Guarantee

(a) Subject to the provisions of this Section 2, each Pledgor hereby fully, unconditionally and irrevocably guarantees to the Collateral Agent for the ratable benefit of the Secured Parties and their respective successors, indorsees, transferees and assigns the full and punctual payment when due, whether at maturity, by acceleration or otherwise, of the Obligations of the Borrower (the " Borrower Obligations "). Each Pledgor further agrees that the Borrower Obligations may be extended or renewed, in whole or in part, without notice or further assent from it, and that it will remain bound under this Section 2 notwithstanding any extension or renewal of any Borrower Obligation.

(b) Each Pledgor waives notice of protest for nonpayment, notice of presentment for payment, demand, protest, and notice thereof as to any of the Borrower Obligations. Each Pledgor waives notice of any default under the Borrower Obligations.

(c) Each Pledgor further agrees that its guarantee herein constitutes a guarantee of payment when due (and not a guarantee of collection) and waives any right to require that any resort be had by the Collateral Agent, the Administrative Agent or any other Secured Party to any security held for payment of the Borrower Obligations.

(d) Except as set forth in Sections 9.08 and 9.18 of the Credit Agreement, the obligations of each Pledgor hereunder shall not be subject to any reduction, limitation, impairment or termination for any reason (other than payment of the Borrower Obligations in full or the benefit of any statute of limitations affecting such Pledgor's liability hereunder or the enforcement thereof), including any claim of waiver, release, surrender, alteration or compromise, and shall not be subject to any defense of setoff, counterclaim, recoupment or termination whatsoever or by reason of the invalidity, illegality or unenforceability of the Borrower Obligations or otherwise. Without limiting the generality of the foregoing, none of the Pledgor Obligations shall be discharged or impaired or otherwise affected by (a) the failure of the Collateral Agent, the Administrative Agent or any other Secured Party to assert any claim or demand or to enforce any right or remedy against the Borrower or any other person under this Agreement or any other agreement or otherwise; (b) any extension or renewal of any thereof; (c) any rescission, waiver, amendment or modification of any of the terms or provisions of this Agreement, any other Loan Document or any other agreement; (d) the release or non-perfection of any security held by any Lender or the Collateral Agent for the Borrower Obligations or any of them; (e) the failure of the Collateral Agent, the Administrative Agent or any other Secured Party to exercise any right or remedy against any other Loan Party; (f) any change in the ownership of any Loan Party; (g) any default, failure or delay, willful or otherwise, in the performance of the Borrower Obligations, or (h) any other act or thing or omission or delay to do any other act or thing which may or might in any manner or to any extent vary the risk of any Pledgor or would otherwise operate as a discharge of any Pledgor as a matter of law or equity.

(e) Each Pledgor agrees that its guarantee herein shall remain in full force and effect until the Discharge of the Obligations. Each Pledgor further agrees that its guarantee herein shall continue to be effective or be reinstated, as the case may be, if at any time payment, or any part thereof, of principal of, premium, if any, or interest on any of the Borrower Obligations is rescinded or must otherwise be restored by the Collateral Agent, the Administrative Agent or any other Secured Party upon the bankruptcy or reorganization of the Borrower or otherwise.

(f) Each Pledgor hereby guarantees that payments hereunder will be paid to the Collateral Agent in cash upon demand by the Collateral Agent without set-off or counterclaim.

(g) Each Pledgor further agrees that, as between it, on the one hand, and the Collateral Agent and the Secured Parties, on the other hand, (x) the maturity of the Borrower Obligations guaranteed hereby may be accelerated as provided in the Credit Agreement for the purposes of its Guarantee herein, notwithstanding any stay, injunction or other prohibition preventing such acceleration in respect of the Borrower Obligations guaranteed hereby arising in connection with any Bankruptcy Event with respect to any Loan Party or otherwise and (y) in the event of any such declaration of acceleration of such Borrower Obligations, such Borrower Obligations (whether or not due and payable) shall forthwith become due and payable by the Pledgors for the purposes of this Guarantee.

2.2 Limitation on Liability

. Any term or provision of this Agreement or the other Loan Documents to the contrary notwithstanding, the obligations of each Pledgor hereunder will be limited to the maximum amount as will, after giving effect to all other contingent and fixed liabilities of such Pledgor, result in the obligations of such Pledgor under its guarantee not constituting a fraudulent conveyance or fraudulent transfer under federal or state law and not otherwise being void or voidable under any similar laws affecting the rights of creditors generally.

2.3 No Subrogation

. Notwithstanding any payment or payments made by the Pledgors hereunder, no Pledgor shall be entitled to be subrogated to any of the rights of any Secured Party against the Borrower or any collateral security or guarantee or right of offset held by any Secured Party for the payment of the Borrower Obligations, nor shall any Pledgor seek or be entitled to seek any contribution or reimbursement from the Borrower in respect of payments made by such Pledgor hereunder, until all amounts owing to the Secured Parties by the Borrower on account of the Borrower Obligations are paid in full. If any amount shall be paid to any Pledgor on account of such subrogation rights at any time when all of the Borrower Obligations shall not have been paid in full, such amount shall be held by such Pledgor in trust for the Collateral Agent, the Administrative Agent and the Lenders, segregated from other funds of such Pledgor, and shall, forthwith upon receipt by such Pledgor, be turned over to the Collateral Agent in the exact form received by such Pledgor, to be applied against the Borrower Obligations.

2.4 Right of Contribution

. Each Pledgor hereby agrees that to the extent that any Pledgor shall have paid more than its proportionate share of any payment made on the Borrower Obligations, such Pledgor shall be entitled to seek and receive contribution from and against the other Pledgor who has not paid its proportionate share of such payment. The provisions of this Section 2.4 shall in no respect limit the obligations and liabilities of each Pledgor with respect to the Borrower Obligations and each Pledgor shall remain liable to the Secured Parties for the full amount guaranteed by such Pledgor hereunder.

SECTION 3. PLEDGE.

3.1 Pledge

. Each Pledgor hereby assigns and transfers to the Collateral Agent and hereby grants to the Collateral Agent, for the benefit of the Secured Parties, a security interest in and continuing Lien on all of such Pledgor's right, title and interest in all property of such Pledgor identified below, in each case whether now owned or existing or hereafter acquired or in which such Pledgor now has or at any time in the future may acquire or arising and wherever located (all of which being hereinafter collectively referred to as the " Collateral "), as collateral security for prompt and complete payment and performance when due (whether at stated maturity, by acceleration or otherwise) of the Pledgor Obligations:

(a) all of such Pledgor's limited liability company interests in the Issuers and all after acquired limited liability company interests in the Issuers (collectively, the " LLC Interests "), including but not limited to those LLC Interests described on Schedule 1 (as such schedule may be amended or supplemented from time to time), and all of such Pledgor's rights to acquire limited liability company interests in any Issuer in addition to or in exchange or substitution for the LLC Interests and all other Equity Interests in any Issuer owned by such Pledgor;

(b) all of such Pledgor's rights, privileges, authority and powers as a member of an Issuer under the Operating Agreement and the other Organizational Documents of the Issuers;

(c) all certificates or other documents representing any and all of the foregoing in clauses (a) and (b);

(d) all dividends, distributions, cash, securities, instruments and other property or proceeds of any kind to which such Pledgor may be entitled in its capacity as member of an Issuer by way of distribution, return of capital or otherwise, including from time to time received, receivable or otherwise distributed in respect of or in exchange for any or all of the LLC Interests;

(e) without affecting any obligations of such Pledgor or any Issuer under any of the other Loan Documents, in the event of any consolidation or merger in which any Issuer is not the surviving Person, all of such Pledgor's ownership interests of any class or character in the successor Person formed by or resulting from such consolidation or merger;

(f) any other claim which such Pledgor now has or may in the future acquire in its capacity as member of an Issuer against such Issuer and its property; and

(g) all Proceeds, products and accessions of and to any of the property described in the preceding clauses (a) through (f) above.

3.2 Security for Obligations

. This Agreement secures, and the Collateral is collateral security for, the prompt and complete payment and performance in full when due, whether at stated maturity, by required prepayment, declaration, acceleration, demand or otherwise (including the payment of amounts that would become due but for the operation of the automatic stay under Section 362(a) of the Bankruptcy Code, 11 U.S.C. §362(a) (and any successor provision thereof)), of all Pledgor Obligations.

3.3 Continuing Liability under Collateral

. Notwithstanding anything herein to the contrary, (i) each Pledgor shall remain liable for all obligations under the Collateral and nothing contained herein is intended or shall be a delegation of duties to the Collateral Agent or any Secured Party, (ii) each Pledgor shall remain liable under each of the agreements included in the Collateral, including, without limitation, any agreements relating to Pledged Equity Interests, to perform all of the obligations undertaken by it thereunder all in accordance with and pursuant to the terms and provisions thereof and neither the Collateral Agent nor any other Secured Party shall have any obligation or liability under any of such agreements by reason of or arising out of this Agreement or any other document related thereto nor shall the Collateral Agent nor any other Secured Party have any obligation to make any inquiry as to the nature or sufficiency of any payment received by it or have any obligation to take any action to collect or enforce any rights under any agreement included in the Collateral, including, without limitation, any agreements relating to Pledged Equity Interests, and (iii) the exercise by the Collateral Agent of any of its rights hereunder shall not release any Pledgor from any of its duties or obligations under the contracts and agreements included in the Collateral.

3.4 Delivery of Certificates and Instruments

. All certificates and instruments representing or evidencing any of the Pledged Equity Interests shall be delivered to and be held by or on behalf of the Collateral Agent in accordance with Section 5.2 and shall be in suitable form for transfer by delivery or shall be accompanied by duly executed instruments of transfer or assignment in blank, all in form and substance reasonably satisfactory to the Collateral Agent.

3.5 Voting; Distributions; Turnover

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(a) Unless an Event of Default shall have occurred and be continuing and the Collateral Agent shall have given written notice to the Pledgors of the Collateral Agent's intent to exercise its rights under this Section 3.5(a) (it being acknowledged and agreed that the Collateral Agent shall not be required to deliver any such notice to a Pledgor that is the subject of a Bankruptcy Event):

(i) each Pledgor shall be entitled to exercise or refrain from exercising any and all voting and other consensual rights with respect to the Collateral; provided , however , that no vote with respect to the Collateral shall be cast, right exercised or other action taken which would be inconsistent with, or result in any violation of, any provision of any of this Agreement or any other Loan Document. Upon the occurrence and during the continuation of an Event of Default, and after written notice thereof delivered by the Collateral Agent to the Pledgors in accordance with the terms of this Agreement (it being acknowledged and agreed that the Collateral Agent shall not be required to deliver any such notice to a Pledgor that is the subject of a Bankruptcy Event), all voting and other rights of each Pledgor with respect to the Collateral which such Pledgor would otherwise be entitled to exercise pursuant to the terms of this Agreement or otherwise shall cease;

(ii) the Collateral Agent shall promptly execute and deliver (or cause to be executed and delivered) to each Pledgor all proxies, and other instruments as such Pledgor, at its sole cost and expense, may from time to time reasonably request for the purpose of enabling such Pledgor to exercise the voting and other consensual rights when and to the extent which it is entitled to exercise pursuant to clause (i) above; and

(iii) each Pledgor shall be entitled to receive and retain any and all dividends, interest and other distributions paid in respect of the Pledged Equity Interests for any purpose not inconsistent with the terms of this Agreement or the Loan Documents. To the extent that such

distributions are made in accordance with the terms of the Loan Documents, the further distribution or payment of such monies to any other Person shall not give rise to any claims or causes of action on the part of any Secured Party against a Pledgor seeking the return or disgorgement of any such distributions or other payments unless the distributions or payments involve or result from fraud or willful misconduct of such Pledgor.

(b) Upon the occurrence and during the continuation of an Event of Default, and upon delivery of written notice of the occurrence and continuation of such Event of Default, to the Pledgors, and after notice thereof from the Collateral Agent to the Borrower (it being acknowledged and agreed that the Collateral Agent shall not be required to deliver any such notice if the Borrower is the subject of a Bankruptcy Event):

(i) the Collateral Agent shall have the right, without notice to any Pledgor, to (A) transfer all or any portion of the Pledged Equity Interests to its name or the name of its nominee or agent and (B) subject to the terms of the Pledged Equity Interests, exchange any certificates or instruments representing such Pledged Equity Interests for certificates or instruments of smaller or larger denominations. In the event of a transfer pursuant to clause (A) of the immediately preceding sentence, the Collateral Agent shall within a reasonable period of time thereafter give each Pledgor notice of such transfer; provided , however , that (x) failure to give such notice shall have no effect on the rights of the Collateral Agent hereunder and (y) the Collateral Agent shall not be required to deliver any such notice to a Pledgor that is the subject of a Bankruptcy Event or the delivery of such notice is otherwise prohibited by applicable law;

(ii) all respective rights of the Pledgors to receive the dividends, interest and other distributions that they would otherwise be authorized to receive and retain pursuant to Section 3.5(a)(iii) shall cease, and all such rights shall thereupon become vested in the Collateral Agent who shall thereupon have the sole right to receive and hold as Pledged Equity Interests such dividends, interest and other distributions;

(iii) in order to permit the Collateral Agent to exercise the voting and other consensual rights which it may be entitled to exercise pursuant hereto and to receive all dividends and other distributions which it may be entitled to receive hereunder, in each case, in respect of the Pledged Equity Interests constituting Collateral: (1) each Pledgor shall promptly execute and deliver (or cause to be executed and delivered) to the Collateral Agent, at such Pledgor's sole cost and expense, all proxies, dividend payment orders and other instruments as the Collateral Agent may from time to time reasonably request and (2) each Pledgor acknowledges that the Collateral Agent may utilize the power of attorney set forth in Section 6.1 ; and

(iv) each Pledgor hereby authorizes and instructs the Borrower to comply with any instruction received by it from the Collateral Agent in writing that (x) states that an Event of Default has occurred and is continuing and (y) is otherwise in accordance with the terms of this Agreement, without any other or further instructions from such Pledgor.

(c) All distributions and other amounts which are received by a Pledgor contrary to the provisions of this Agreement shall be received in trust for the benefit of the Collateral Agent, shall be segregated from other funds of such Pledgor and shall be forthwith paid over to the Collateral Agent as Collateral in the same form as so received (with any necessary endorsement).

3.6 Authorization

. At any time after the occurrence and during the continuation of an Event of Default, each Pledgor hereby authorizes and directs the Borrower to (i) comply with any instructions received by it from the

Collateral Agent in writing that (x) states that an Event of Default has occurred and is continuing and (y) is otherwise in accordance with the terms of this Agreement, without any other or further instructions from such Pledgor, and (ii) unless otherwise expressly permitted hereby, pay any dividend or other payments in respect of the Collateral directly to the Collateral Agent. The Company hereby agrees that the provisions of this Section 3.6 shall apply to it with respect to all actions that may be required of it pursuant to such Section.

SECTION 4. REPRESENTATIONS AND WARRANTIES.

4.1 Generally

. Each Pledgor hereby represents and warrants, on the Closing Date, that:

(a) it has indicated on Schedule 4.1(A) : (i) its full legal name, (ii) its type of organization, (iii) its jurisdiction of organization and (iv) the location of its chief executive office or sole place of business or principal residence, as the case may be;

(b) it has no trade names other than as listed on Schedule 4.1(B) ; and

(c) except as provided on Schedule 4.1(C) , it has not changed its name, jurisdiction or form of organization or the location of its chief executive office or sole place of business or principal residence, as the case may be, in any way since the date of its formation.

(d) Schedule 1 sets forth under the heading “Pledged Equity Interests” all of the Pledged Equity Interests owned by such Pledgor, and such Pledged Equity Interests constitute the percentage of issued and outstanding Equity Interests or percentage of beneficial interest of the respective issuers thereof indicated on such Schedule 1 ; and

(e) each of the Pledged Equity Interests pledged by the Pledgors hereunder on Schedule 1 constitutes a “security” under Section 8-103 of the UCC or the corresponding code or statute of any other applicable jurisdiction and each such “security” is a Certificated Security.

SECTION 5. COVENANTS.

Each Pledgor hereby respectively covenants and agrees (each on its own behalf) from and after the Closing Date until the termination of this Agreement in accordance with the provisions of Section 12 :

5.1 Further Assurances .

(a) Each Pledgor agrees that from time to time, at its sole cost and expense, upon its receipt of a written request therefor from the Collateral Agent, it shall promptly execute and deliver all further instruments and documents, and take all further action, that may be necessary in order to (x) create and/or maintain the validity and perfection of and otherwise protect any security interest in Collateral granted hereby or (y) enable the Collateral Agent to exercise and enforce its rights and remedies hereunder with respect to any Collateral. Without limiting the generality of the foregoing, each Pledgor shall maintain the Liens created by this Agreement as a perfected security interest prior and superior in right to any other Person except Liens permitted under the Loan Documents, and, upon the reasonable written request of the Collateral Agent, execute and deliver such other agreements, instruments, endorsements, powers of attorney or notices as are necessary, or as the Collateral Agent may reasonably request, to grant, preserve, protect, reflect and perfect the security interests granted or purported to be granted hereby. For the avoidance of doubt, nothing herein shall require the Collateral Agent to file financing statements or continuation statements, or be responsible for maintaining the security interests

purported to be created as described herein (except for the safe custody of any Collateral in its possession and the accounting for moneys actually received by it hereunder or under any other Loan Document) and such responsibility shall be solely that of the Borrower.

(b) Each Pledgor hereby authorizes the Collateral Agent to file a Record or Records, including, without limitation, financing or continuation statements, intellectual property security agreements and amendments thereto, in any jurisdictions and with any filing offices as the Collateral Agent may reasonably determine, are necessary or advisable to perfect the security interest granted to the Collateral Agent herein. Such financing statements may describe the Collateral in the same manner as described herein or may contain an indication or description of collateral that describes such property in any other manner as the Collateral Agent may reasonably determine, are necessary, advisable or prudent to ensure the perfection of the security interest in the Collateral granted to the Collateral Agent herein, including, without limitation, describing such property as "all assets" or "all personal property, whether now owned or hereafter acquired." The Collateral Agent shall have no responsibility for or liability with respect to monitoring the compliance of any other party to the Loan Documents, this Agreement or any other document related hereto or thereto. The Collateral Agent has no duty to monitor the value or rating of any of the Collateral on an ongoing basis.

5.2 Certificates and Instruments

. Each Pledgor hereby covenants and agrees that, if such Pledgor shall become entitled to receive or shall receive any certificate (including, without limitation, any certificate representing a dividend or a distribution in connection with any reclassification, increase or reduction of capital or any certificate issued in connection with any reorganization), option or rights in respect of the Pledged Equity Interests, whether in addition to, in substitution of, as a conversion of, or in exchange for, any shares of the Pledged Equity Interests, or otherwise in respect thereof, such Pledgor shall accept the same as the agent of the Collateral Agent, hold the same in trust for the Collateral Agent and deliver the same forthwith to the Collateral Agent in the exact form received, duly indorsed by such Pledgor to the Collateral Agent, if required, together with an undated stock power covering such certificate duly executed in blank by such Pledgor, to be held by the Collateral Agent, subject to the terms hereof, as additional collateral security for the Pledgor Obligations. Unless otherwise consented to by the Collateral Agent, Pledged Equity Interests required to be pledged hereunder shall be represented by a certificate and, in the Organizational Documents of the applicable Subsidiary, the applicable Pledgor shall cause the issuer of such interests to elect to treat such interests as a "security" within the meaning of Article 8 of the Uniform Commercial Code of its jurisdiction of organization (and all certificates representing such Pledged Equity Interests (and any additional Pledged Equity Interests acquired or issued after the Closing Date) shall have been delivered to the Collateral Agent, together with duly executed instruments of transfer or assignment in blank).

5.3 Records; Statements and Schedules

. Each Pledgor shall keep and maintain, at its own cost and expense, records of the Collateral owned by it, including records of all payments received with respect thereto, and it shall make the same available to the Collateral Agent for inspection at such Pledgor's chief executive office, at its own cost and expense upon reasonable notice (except after the occurrence and during the continuance of an Event of Default), at any time during normal business hours. Each Pledgor shall furnish to the Collateral Agent from time to time statements and schedules further identifying and describing the Collateral and such other reports in connection with the Collateral as the Collateral Agent may reasonably request, all in reasonable detail; provided that, so long as no Event of Default shall have occurred and be continuing, the Collateral Agent may not request updated schedules pursuant to this Section 5.3 more frequently than twice per calendar year.

5.4 Notices

. Each Pledgor shall promptly upon a Responsible Officer of such Pledgor obtaining actual knowledge of the occurrence of any Event of Default relating solely to such Pledgor, furnish to the Collateral Agent a notice of such event describing the same in reasonable detail.

5.5 Filing Fees

. Each Pledgor shall pay any applicable filing fees and related expenses in connection with any filing made by the Collateral Agent in accordance with Section 5.1(b) .

5.6 Bankruptcy; Dissolution

. Holding shall not authorize or permit the Borrower to:

(a) except upon compliance with the requirements of the Organizational Documents of the Borrower as in effect on the date hereof, (i) commence a voluntary case or other proceeding seeking liquidation, reorganization or other relief with respect to the Borrower or its debts under Bankruptcy Law now or hereafter in effect or seeking the appointment of a trustee, receiver, liquidator, custodian or other similar official of such Subsidiary or any substantial part of the Borrower's property, (ii) consent to any such relief or to the appointment of or taking possession by any such official in an involuntary case or other proceeding commenced against the Borrower or (iii) make a general assignment for the benefit of the Borrower's creditors;

(b) commence or join with any other Person (other than the Collateral Agent and the other Secured Parties) in commencing any proceeding against the Borrower under the U.S. Bankruptcy Code or statute now or hereafter in effect in any jurisdiction; or

(c) except as permitted by the Loan Documents, liquidate, wind-up or dissolve, or sell or lease or otherwise transfer or dispose of all or any substantial part of its property, assets or business or combine, merge or consolidate with or into any other entity, or change its legal form, or implement any material acquisition or purchase of assets from any Person.

5.7 Compliance with Organizational Documents of the Company

. Holding shall comply in all material respects with its obligations under the Operating Agreement and Organizational Documents of the Borrower.

SECTION 6. COLLATERAL AGENT APPOINTED ATTORNEY-IN-FACT.

6.1 Power of Attorney

. Each Pledgor hereby irrevocably constitutes and appoints the Collateral Agent, acting for and on behalf of itself and the other Secured Parties and each successor or assign of the Collateral Agent as its true and lawful attorney-in-fact, with full power and authority in the place and stead of such Pledgor and in the name of such Pledgor or in its own name, at such Pledgor's sole cost and expense, subject to the terms of this Agreement and applicable Legal Requirements, to enforce all rights, interests and remedies of such Pledgor with respect to the Collateral upon the occurrence and during the continuation of an Event of Default, for the purpose of carrying out the provisions of this Agreement, including the right to:

(i) ask, demand, collect, sue for, recover, receive and give receipt and discharge for amounts due and to become due under and in respect of all or any part of the Collateral,

(ii) in the name of such Pledgor or its own name or otherwise, take possession of, receive and indorse and collect any check, draft, note, acceptance or other Instrument (as defined in Article 9 of the UCC) for the payment of moneys due under any general intangible, in each case, constituting Collateral,

(iii) file any claims or take any other action that the Collateral Agent may deem necessary or advisable for the collection of all or any part of the Collateral,

(iv) pay or discharge Taxes and Liens levied or placed on or threatened against the Collateral (other than Liens permitted by the Loan Documents), effect any repair or pay or discharge any insurance called for by the terms of this Agreement or the other Loan Documents (including all or any part of the premiums therefor and the costs thereof),

(v) execute, in connection with any sale or disposition of the Collateral under this Agreement, any endorsements, assignments, bills of sale or other instruments of conveyance or transfer with respect to all or any part of the Collateral,

(vi) direct any party liable for any payment under any Collateral to make payment of any moneys due or to become due thereunder directly to the Collateral Agent or as the Collateral Agent shall direct,

(vii) commence and prosecute any suit, action or proceeding at law or in equity in any court of competent jurisdiction to collect any Collateral and to enforce any other right with respect to any Collateral,

(viii) defend any suit, action or proceeding brought against such Pledgor with respect to any Collateral,

(ix) settle, compromise or adjust any such suit, action or proceeding with respect to the Collateral and, in connection therewith, give such discharges or releases as the Collateral Agent may deem appropriate, and

(x) upon foreclosure, generally, sell, transfer, pledge and make any agreement with respect to or otherwise deal with any Collateral as fully and completely as though the Collateral Agent were the absolute owner thereof for all purposes, and do, at the Collateral Agent's option and such Pledgor's expense, at any time, or from time to time, all acts and things that the Collateral Agent reasonably deems necessary to protect, preserve or realize upon the Collateral and the Collateral Agent's and the other Secured Parties' Liens thereon and to effect the intent of this Agreement, all as fully and effectively as such Pledgor might do.

This appointment as attorney-in-fact is irrevocable and coupled with an interest.

6.2 No Duty on Part of Collateral Agent or Other Secured Parties

. The powers conferred on the Collateral Agent hereunder are solely to protect the interests of the Secured Parties in the Collateral and shall not impose any duty upon the Collateral Agent or any other Secured Party to exercise any such powers. The Collateral Agent and the other Secured Parties shall be accountable only for amounts that they actually receive as a result of the exercise of such powers, and neither they nor any of their officers, directors, employees or agents shall be responsible to the Pledgors for any act or failure to act hereunder, except in the case of their own gross negligence or willful misconduct, except in the case of their own gross negligence or willful misconduct.

SECTION 7. REMEDIES.

7.1 Generally

.

(a) If any Event of Default shall have occurred and be continuing, the Collateral Agent may exercise in respect of the Collateral, in addition to all other rights and remedies provided for herein or otherwise available to it at law or in equity, all the rights and remedies of the Collateral Agent on default under the UCC (whether or not the UCC applies to the affected Collateral) to collect, enforce or satisfy any Obligations then owing, whether by acceleration or otherwise, and also may pursue any of the following separately, successively or simultaneously:

(i) require the Pledgors to, and the Pledgors hereby agree that each Pledgor shall at its expense and promptly upon request of the Collateral Agent forthwith, assemble all or part of the Collateral as directed by the Collateral Agent and make it available to the Collateral Agent at a place to be designated by the Collateral Agent that is reasonably convenient to both parties;

(ii) enter onto the property where any Collateral is located and take possession thereof with or without judicial process; and

(iii) without notice except as specified below or under the UCC, sell, assign or otherwise dispose of the Collateral or any part thereof in one or more parcels at public or private sale, at any of the Collateral Agent's offices or elsewhere, for cash, on credit or for future delivery, at such time or times and at such price or prices and upon such other terms as the Collateral Agent in its reasonable discretion may deem commercially reasonable.

(b) The Collateral Agent or any other Secured Party may be the purchaser of any or all of the Collateral at any public or private (to the extent to the portion of the Collateral being privately sold is of a kind that is customarily sold on a recognized market or the subject of widely distributed standard price quotations) sale in accordance with the UCC and the Collateral Agent, as collateral agent for and representative of the Secured Parties, shall be entitled, for the purpose of bidding and making settlement or payment of the purchase price for all or any portion of the Collateral sold at any such sale made in accordance with the UCC, to use and apply any of the Pledgor Obligations as a credit on account of the purchase price for any Collateral payable by the Collateral Agent at such sale. Each purchaser at any such sale shall hold the property sold absolutely free from any claim or right on the part of any Pledgor, and each Pledgor hereby waives (to the extent permitted by applicable law) all rights of redemption, stay and/or appraisal which it now has or may at any time in the future have under any rule of law or statute now existing or hereafter enacted. Each Pledgor agrees that, to the extent notice of sale shall be required by law, at least 10 days' notice to such Pledgor of the time and place of any public sale or the time after which any private sale is to be made shall constitute reasonable notification. The Collateral Agent shall not be obligated to make any sale of Collateral regardless of notice of sale having been given. The Collateral Agent may adjourn any public or private sale from time to time by announcement at the time and place fixed therefor, and such sale may, without further notice, be made at the time and place to which it was so adjourned. Each Pledgor agrees that it would not be commercially unreasonable for the Collateral Agent to dispose of the Collateral or any portion thereof by using Internet sites that match buyers and sellers of assets. So long as such sale is conducted in a commercially reasonable manner, each Pledgor hereby waives any claims against the Collateral Agent arising by reason of the fact that the price at which any Collateral may have been sold at such a private sale was less than the price which might have been obtained at a public sale, even if the Collateral Agent accepts the first offer received and does not offer such Collateral to more than one offeree. If the proceeds of any sale or other disposition of the Collateral are insufficient to pay all the Obligations, each Pledgor

shall be liable for the deficiency and the reasonable fees of any attorneys employed by the Collateral Agent to collect such deficiency. Each Pledgor further agrees that a breach of any of the covenants contained in this Section 7.1 will cause irreparable injury to the Collateral Agent, that the Collateral Agent has no adequate remedy at law in respect of such breach and, as a consequence, that each and every covenant contained in this Section 7.1 shall be specifically enforceable against any Pledgor, and each Pledgor hereby waives and agrees not to assert any defenses against an action for specific performance of such covenants except for a defense that no default has occurred giving rise to the Obligations becoming due and payable prior to their stated maturities. Nothing in this Section 7.1 shall in any way alter the rights of the Collateral Agent hereunder.

(c) The Collateral Agent may sell the Collateral without giving any warranties as to the Collateral. The Collateral Agent may specifically disclaim or modify any warranties of title or the like. This procedure will not be considered to adversely affect the commercial reasonableness of any sale of the Collateral.

(d) The Collateral Agent shall have no obligation to marshal any of the Collateral.

7.2 Application of Proceeds

.

(a) Any Proceeds constituting Collateral to be applied by the Collateral Agent pursuant to the Loan Documents upon the occurrence and during the continuation of an Event of Default and in connection with the enforcement, collection or realization in respect of any Collateral by the Collateral Agent, shall be applied in the following order:

(i) First , to pay incurred and unpaid fees and expenses of the Agents under the Loan Documents;

(ii) Second , to the Collateral Agent, for application by it towards payment, without duplication, of (x) all interest, breakage costs and fees then due and payable under the Loan Documents and (y) any ordinary course settlement payments and any interest due and payable to any Specified Swap Counterparty under any Secured Swap Agreements, pro rata among the Secured Parties according to the amounts of such Obligations then due and owing and remaining unpaid to the Secured Parties ;

(iii) Third , to the Collateral Agent, for application by it towards payment, without duplication, of (x) all principal and premium (if any) then due and payable under the Loan Documents and (y) any termination payments payable to any Specified Swap Counterparty under any Secured Swap Agreements , pro rata among the Secured Parties according to the amounts of such Obligations then due and owing and remaining unpaid to the Secured Parties ;

(iv) Fourth , to the Collateral Agent, on a pro rata basis, for application by it towards payment of all other Obligations due and owing and remaining unpaid to the Secured Parties under the Loan Documents and the Secured Swap Agreements ; and

(v) Fifth , any balance remaining after the Discharge of the Obligations shall be paid over to the applicable Pledgor or to whomsoever may be lawfully entitled to receive the same.

Notwithstanding the foregoing, no amounts received from any Pledgor shall be applied to any Excluded Swap Obligations of such Pledgor.

(b) No sale or other disposition of all or any part of the Collateral pursuant to Section 7.1 shall be deemed to relieve any Pledgor of its obligations under any Loan Document except to the extent the proceeds thereof are applied to the payment of such obligations.

7.3 Sales on Credit

. If the Collateral Agent sells any of the Collateral upon credit, the applicable Pledgor will be credited only with payments actually made by the purchaser and received by the Collateral Agent and applied to indebtedness of the purchaser. In the event the purchaser fails to pay for the Collateral, the Collateral Agent may resell the Collateral and such Pledgor shall be credited with proceeds of the sale.

7.4 Pledged Equity Interests

. Each Pledgor recognizes that the Collateral Agent may be unable to effect a public sale of any or all the Pledged Equity Interests, by reason of certain prohibitions contained in the Securities Act and applicable state securities laws or otherwise, and may be compelled to resort to one or more private sales thereof to a restricted group of purchasers which will be obliged to agree, among other things, to acquire the Pledged Equity Interests for their own account for investment and not with a view to the distribution or resale thereof. Each Pledgor acknowledges and agrees that any such private sale may result in prices and other terms less favorable than those obtainable through a public sale without such restrictions (including a public offering made pursuant to a registration statement under the Securities Act) and, notwithstanding such circumstances, agrees that any such private sale shall be deemed to have been made in a commercially reasonable manner. The Collateral Agent shall be under no obligation to delay a sale of any of the Pledged Equity Interests for the period of time necessary to permit the issuer thereof to register such securities for public sale under the Securities Act, or under applicable state securities laws, even if such issuer would agree to do so. If the Collateral Agent exercises its right to sell any or all of the Pledged Equity Interests, upon written request, the applicable Pledgor shall and shall cause the issuer of such Pledged Equity Interests from time to time to furnish to the Collateral Agent all such information as the Collateral Agent may request in order to determine the number and nature of interest, shares or other instruments included in the Pledged Equity Interests which may be sold by the Collateral Agent in exempt transactions under the Securities Act and the rules and regulations of the SEC thereunder, as the same are from time to time in effect.

7.5 Enforcement Expenses

. (a) Each Pledgor agrees to pay or reimburse each Secured Party for all its reasonable and documented costs and expenses incurred in collecting against such Pledgor under the Guarantee contained in Section 2 or otherwise enforcing or protecting any rights under this Agreement, including, without limitation, the reasonable and documented fees and disbursements of counsel to the Collateral Agent and of any other necessary counsel.

(b) The agreement in this Section 7.5 shall survive the Discharge of the Obligations.

SECTION 8. AMENDMENTS

None of the terms or provisions of this Agreement may be waived, amended, supplemented or otherwise modified except pursuant to an agreement in writing entered into by each Pledgor and the Collateral Agent and otherwise in accordance with the Credit Agreement; provided , however , that, notwithstanding any provision of the Loan Documents to the contrary, any Schedule hereto may be amended or supplemented from time to time solely by written notice to the Collateral Agent from any Pledgor (and such amendment or supplement shall become effective upon delivery of any such notice).

SECTION 9. CONTINUING SECURITY INTEREST; TRANSFER OF ADVANCES.

This Agreement shall create a continuing security interest in the Collateral and shall remain in full force and effect until the Discharge of the Obligations, be binding upon each Pledgor, its successors and assigns, and inure, together with the rights and remedies of the Collateral Agent hereunder, to the benefit of the Collateral Agent and the Secured Parties and their successors, transferees and assigns.

SECTION 10. STANDARD OF CARE; COLLATERAL AGENT MAY PERFORM.

The powers conferred on the Collateral Agent hereunder are solely to protect its interest in the Collateral and shall not impose any duty upon it to exercise any such powers. Except for the exercise of reasonable care in the custody of any Collateral in its possession and the accounting for moneys actually received by it hereunder and other requirements of law or the UCC, the Collateral Agent shall have no duty as to any Collateral or as to the taking of any necessary steps to preserve rights against prior parties or any other rights pertaining to any Collateral. To the extent permitted by law, the Collateral Agent shall be deemed to have exercised reasonable care in the custody and preservation of Collateral in its possession if such Collateral is accorded treatment substantially equal to that which the Collateral Agent accords its own property. Beyond the exercise of reasonable care in the custody thereof, the Collateral Agent shall have no duty as to any of the Collateral in its possession or control or in the possession or control of any agent or bailee or any income thereon or as to preservation of rights against prior parties or any other rights pertaining thereto, and the Collateral Agent shall not be responsible for filing any financing or continuation statements or recording any documents or instruments in any public office at any time or times or otherwise perfecting or maintaining the perfection of any security interest in the Collateral. Neither the Collateral Agent nor any of its directors, officers, employees or agents shall be liable for failure to demand, collect or realize upon all or any part of the Collateral or for any delay in doing so or shall be under any obligation to sell or otherwise dispose of any Collateral upon the request of a Pledgor or otherwise. If any Pledgor fails to perform any agreement contained herein, the Collateral Agent may itself perform, or cause performance of, such agreement, and the expenses of the Collateral Agent incurred in connection therewith shall be payable by such Pledgor or the Borrower under the Credit Agreement.

SECTION 11. NOTICES.

Any notice required or permitted to be given under this Agreement shall be given in accordance with the Credit Agreement.

SECTION 12. RELEASE

Upon the Discharge of the Obligations, and subject to Section 19 , the Collateral shall be automatically released from the Liens created hereby, and this Agreement and all obligations (other than those expressly stated to survive such termination) of the Collateral Agent and the Pledgors hereunder shall terminate, all without delivery of any instrument or performance of any act by any party, and all rights to the Collateral shall revert to the Pledgors. At the request and sole expense of any Pledgor following any such termination, the Collateral Agent shall deliver to such Pledgor any Collateral held by the Collateral Agent hereunder, and execute and deliver to such Pledgor such documents or otherwise authorize the filing of such documents as such Pledgor shall reasonably request to evidence such termination.

If any of the Collateral shall be sold, transferred or otherwise disposed of by a Pledgor in a transaction permitted by any Loan Document or consented to in accordance with the Loan Documents, then the Collateral Agent, at the request and at the sole expense of such Pledgor (with written confirmation from the Administrative Agent), shall execute and deliver to such Pledgor all releases or authorize the filing of other documents reasonably necessary or desirable for the release of the Liens created hereby on such Collateral; provided that such Pledgor shall have delivered to the Collateral Agent and the Administrative Agent, at least 5 Business Days prior to the date of the proposed release, a written request for release identifying the Collateral and the terms of the sale or other disposition in reasonable detail, including the price thereof and any expenses in connection therewith, together with a certification by such Pledgor stating that such transaction is in compliance with the Loan Documents and the Proceeds of such Collateral will be applied in accordance with the terms of the Loan Documents, if applicable.

SECTION 13. MISCELLANEOUS.

No failure or delay on the part of the Collateral Agent in the exercise of any power, right or privilege hereunder or under any other Loan Document shall impair such power, right or privilege or be construed to be a waiver of any default or acquiescence therein, nor shall any single or partial exercise of any such power, right or privilege preclude other or further exercise thereof or of any other power, right or privilege. All rights and remedies existing under this Agreement and the other Loan Documents are cumulative to, and not exclusive of, any rights or remedies otherwise available. In case any provision in or obligation under this Agreement shall be invalid, illegal or unenforceable in any jurisdiction, the validity, legality and enforceability of the remaining provisions or obligations, or of such provision or obligation in any other jurisdiction, shall not in any way be affected or impaired thereby. All covenants hereunder shall be given independent effect so that if a particular action or condition is not permitted by any of such covenants, the fact that it would be permitted by an exception to, or would otherwise be within the limitations of, another covenant shall not avoid the occurrence of a default or an event of default under the Loan Documents if such action is taken or condition exists. This Agreement shall be binding upon and inure to the benefit of the Collateral Agent and the Pledgors and their respective successors and assigns. No Pledgor shall, without the prior written consent of the Collateral Agent given in accordance with the Credit Agreement, assign any right, duty or obligation hereunder. There are no unwritten oral agreements between the parties. This Agreement may be executed in one or more counterparts and by different parties hereto in separate counterparts, each of which when so executed and delivered shall be deemed an original, but all such counterparts together shall constitute but one and the same instrument; signature pages may be detached from multiple separate counterparts and attached to a single counterpart so that all signature pages are physically attached to the same document. Delivery of an executed counterpart of a signature page of this Agreement or any document or instrument delivered in connection herewith by facsimile or other electronic delivery (including by certified electronic signature) shall be effective as delivery of a manually executed counterpart of this Agreement or such other document or instrument, as applicable.

Each Pledgor's waiver of rights or agreements in respect of Collateral, the exercise of remedies, standards of care, notice and the other matters covered by Sections 2 through 7 are in each case qualified that such waivers or agreements are being made to the fullest extent permitted by law.

SECTION 14. ACKNOWLEDGEMENTS.

Each Pledgor hereby acknowledges that (a) it has been advised by counsel in the negotiation, execution and delivery of this Agreement and the other Loan Documents to which it is a party; (b) neither the Collateral Agent nor any Secured Party has any fiduciary relationship with or duty to any Pledgor arising out of or in connection with this Agreement or any of the other Loan Documents, and the relationship between each Pledgor, on the one hand, and the Collateral Agent and Secured Parties, on the other hand, in connection herewith or therewith is solely that of debtor and creditor and (c) no joint venture is created hereby or by the other Loan Documents or otherwise exists by virtue of the transactions contemplated hereby among the Secured Parties or among the Pledgors and the Secured Parties.

SECTION 15. HEADINGS.

Section headings and the Table of Contents used herein are for convenience of reference only, are not part of this Agreement and are not to affect the construction of, or to be taken into consideration in interpreting, this Agreement.

SECTION 16. APPLICABLE LAW.

THIS AGREEMENT SHALL BE GOVERNED BY, AND SHALL BE CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.

SECTION 17. CONSENT TO JURISDICTION; CONSENT TO SERVICE OF PROCESS

Each party hereto hereby irrevocably and unconditionally submits, for itself and its property, to the exclusive jurisdiction of any New York state court or federal court of the United States of America sitting in the County and City of New York, and any appellate court from any thereof, in any action or proceeding arising out of or relating to this Agreement, or for recognition or enforcement of any judgment, and each of the parties hereto hereby irrevocably and unconditionally agrees that all claims in respect of any such action or proceeding may be heard and determined in such New York state court or, to the extent permitted by law, in such federal court. Each of the parties hereto agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Each party hereto hereby irrevocably and unconditionally waives, to the fullest extent it may legally and effectively do so, any objection which it may now or hereafter have to the laying of venue of any suit, action or proceeding arising out of or relating to this Agreement in any New York state or federal court. Each of the parties hereto hereby irrevocably waives, to the fullest extent permitted by law, the defense of an inconvenient forum to the maintenance of such action or proceeding in any such court.

Each party hereto further irrevocably consents to the service of process in any action or proceeding in such courts by the mailing thereof by any parties thereto by registered or certified mail, postage prepaid, to such party at its address specified in Section 11 . Nothing herein shall affect the right to serve process in any other manner permitted by law.

SECTION 18. WAIVER OF JURY TRIAL.

EACH PARTY HERETO HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY HERETO (A) CERTIFIES THAT NO REPRESENTATIVE, AGENT OR ATTORNEY OF ANY OTHER PARTY HAS REPRESENTED, EXPRESSLY OR OTHERWISE, THAT SUCH OTHER PARTY WOULD NOT, IN THE EVENT OF LITIGATION, SEEK TO ENFORCE THE FOREGOING WAIVER AND (B) ACKNOWLEDGES THAT IT AND THE OTHER PARTIES HERETO HAVE BEEN INDUCED TO ENTER INTO THIS AGREEMENT BY, AMONG OTHER THINGS, THE MUTUAL WAIVERS AND CERTIFICATIONS IN THIS SECTION 18 .

SECTION 19. REINSTATEMENT.

This Agreement and the Liens created hereunder shall automatically be reinstated if and to the extent that for any reason any payment by or on behalf of any Pledgor in respect of the Pledgor Obligations is rescinded or must otherwise be restored by any Secured Party, whether as a result of any Bankruptcy Event or reorganization or otherwise, and each Pledgor shall indemnify the Collateral Agent, each other Secured Party and their respective employees, officers and agents on demand for all reasonable fees, costs and expenses (including reasonable fees, costs and expenses of counsel) incurred by the Collateral Agent, such other Secured Party or their respective employees, officers or agents in connection with such reinstatement, rescission or restoration.

SECTION 20. COLLATERAL AGENT.

Notwithstanding anything herein to the contrary, the Collateral Agent shall be afforded all of the rights, powers, immunities and indemnities of the Collateral Agent set forth in the Credit Agreement and the other Loan Documents, as if such rights, powers, immunities and indemnities were specifically set forth herein. Each Pledgor hereby acknowledges the appointment of the Collateral Agent pursuant to the Credit Agreement. The rights, privileges, protections and benefits given to the Collateral Agent, including its right to be indemnified, are extended to, and shall be enforceable by, the Collateral Agent in its capacity hereunder, and to each agent, custodian and other Person employed by the Collateral Agent in accordance herewith to act hereunder.

SECTION 21. SECURITY INTEREST ABSOLUTE.

All rights of the Collateral Agent hereunder, the grant of a security interest in the Collateral and all obligations of the Pledgors hereunder shall be absolute and unconditional irrespective of (a) any lack of validity or enforceability of any Loan Document, (b) any change in the time, manner or place of payment of, or in any other term of, all or any of the Borrower Obligations or the Pledgor Obligations, or any other amendment or waiver of or any consent to any departure from any Loan Document, (c) any exchange, release or non-perfection of any security on any collateral, or any release or amendment or waiver of or consent under or departure from any guarantee, securing or guaranteeing all or any of the Borrower Obligations or the Pledgor Obligations, or (d) any other circumstance that might otherwise constitute a defense available to, or a discharge of, any Pledgor in respect of the Borrower Obligations or the Pledgor Obligations or this Agreement (other than the payment in full of all of the Pledgor Obligations or the benefit of any statute of limitations affecting any Pledgor's obligations hereunder or the enforcement thereof).

SECTION 22. LIMITED LIABILITY.

Notwithstanding anything in this Agreement or the other Loan Documents to the contrary, none of the Secured Parties shall have any claims with respect to the transactions contemplated hereunder or thereunder against any past, present or future holder (whether direct or indirect) of any Equity Interests in any Pledgor or any of its subsidiaries or Affiliates (other than the Loan Parties), shareholders, officers, incorporators, directors, employees, representatives, Controlling persons, executives or agents (collectively, the " Nonrecourse Persons "), such claims against the Nonrecourse Persons (including as may arise by operation of law) being expressly waived hereby; provided that the foregoing shall not (a) constitute a waiver, release or discharge (or otherwise impair the enforceability) of any of the Borrower Obligations or the Pledgor Obligations or of any of the terms, covenants, conditions or provisions of this Agreement or any other Loan Document and the same shall continue (subject to clause (d) below, but without personal liability of the Nonrecourse Persons) until fully paid, discharged, observed or performed; (b) constitute a waiver, release or discharge of any Lien or security interest purported to be created pursuant to this Agreement or any other Loan Documents (or otherwise impair the ability of any Secured Party to realize or foreclose upon any Collateral); (c) in any way limit or restrict any right or remedy of the Collateral Agent or any other Secured Party (or any assignee or beneficiary thereof or successor thereto) with respect to, and each of the Nonrecourse Persons shall remain fully liable to the extent that it would otherwise be liable for its own actions with respect to, any fraud (which shall not include innocent or negligent misrepresentation), willful misrepresentation or misappropriation of revenues, profits or proceeds from the Projects or any Collateral, that should or would have been paid as provided in the relevant Loan Document or paid or delivered to the Collateral Agent or any other Secured Party (or any assignee or beneficiary thereof or successor thereto) towards any payment required under any Loan Document; or (d) affect or diminish in any way or constitute a waiver, release or discharge of any obligation, covenant, or agreement made by any of the Nonrecourse Persons (or any security granted by the Nonrecourse Persons in support of the obligations of any Person) under any Loan Document (or as

security for the Borrower Obligations or the Pledgor Obligations), any Sponsor Guaranty or other agreement with any Secured Party. The limitations on recourse set forth in this Section 22 shall survive the Discharge of the Obligations and the performance of the Borrower Obligations and the Pledgor Obligations under the Loan Documents.

[*Signature pages follow.* **]**

IN WITNESS WHEREOF, each Pledgor and the Collateral Agent have caused this Agreement to be duly executed and delivered by their respective officers thereunto duly authorized as of the date first written above.

EXGEN RENEWABLES IV HOLDING, LLC

By: _____
Name:
Title:

ExGen Renewables Holdings, LLC

By: _____
Name:
Title:

WILMINGTON TRUST, NATIONAL ASSOCIATION,
as Collateral Agent

By: _____
Name:
Title:

November 28, 2017

Wilmington Trust, National Association, in its capacity as Collateral Agent

RE: Guarantee and Pledge Agreement, dated as of November 28, 2017, among ExGen Renewables IV Holding, LLC, ExGen Renewables Holdings, LLC, each as Pledgor, and Wilmington Trust, National Association, as Collateral Agent (the " Guarantee and Pledge Agreement ")

Ladies and Gentlemen:

The Company consents to the grant by the Pledgors of a security interest in all of the Pledged Equity Interests constituting Collateral to the Collateral Agent and, without limiting the foregoing, consents to the transfer of any Pledged Equity Interest to the Collateral Agent or its nominee during the occurrence of an Event of Default and to the substitution of the Collateral Agent or its nominee as a partner in any partnership or as a member in any limited liability company with all the rights and powers related thereto. Capitalized terms used herein are as defined in the Guarantee and Pledge Agreement.

EXGEN RENEWABLES IV, LLC

By: _____
Name:
Title:

SCHEDULE 1

TO GUARANTEE AND PLEDGE AGREEMENT

PLEDGED EQUITY INTERESTS

Owner	Issuer	Class of Stock or other Equity Interest	Percentage
ExGen Renewable IV Holding, LLC	ExGen Renewables IV, LLC	Membership Interests	100%
ExGen Renewables Holdings, LLC	ExGen Renewables Partners, LLC	Class A Membership Interests	100%

SCHEDULE 4.1

TO GUARANTEE AND PLEDGE AGREEMENT

GENERAL INFORMATION

(A) Full Legal Name, Type of Organization, Jurisdiction of Organization, and Chief Executive Office/Sole Place of Business/Principal Residence:

Full Legal Name	**Type of Organization**	**Jurisdiction of Organization**	**Organizational Identification Number**	**Chief Executive Office/ Sole Place of Business/Principal Residence**
ExGen Renewables IV Holding, LLC	Limited liability company	Delaware	[***]	10 South Dearborn Street, 49th Floor Chicago, IL 60603
ExGen Renewables Holdings, LLC	Limited liability company	Delaware	[***]	10 South Dearborn Street, 49th Floor Chicago, IL 60603

(B) Other names (including any trade name or fictitious business name) under which each Pledgor has conducted business for the past five years:

None.

(C) Changes in name, jurisdiction of organization, chief executive office/ sole place of business/ principal residence and corporate structure since its formation.

None.

FORM OF
SOLVENCY CERTIFICATE

I, the undersigned, the [Chief Financial Officer] [title of other Financial Officer] of the Borrower (as defined below), **DO HEREBY CERTIFY** on behalf of the Borrower that:

1. This certificate is furnished pursuant to Section 4.01(k) of the Credit Agreement, dated as of November 28, 2017, among EXGEN RENEWABLES IV, LLC, a limited liability company organized under the laws of Delaware (the " **Borrower** "), EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" **Holding** "), the LENDERS party thereto from time to time, MORGAN STANLEY SENIOR FUNDING, INC., as Administrative Agent, WILMINGTON TRUST, NATIONAL ASSOCIATION, as Collateral Agent and WILMINGTON TRUST, NATIONAL ASSOCIATION, as Depositary Bank. Capitalized terms used herein and not otherwise defined herein shall have the meanings assigned to such terms in the Credit Agreement.

2. Immediately after giving effect to the Transactions, (a) the fair value of the assets (for the avoidance of doubt, calculated to include goodwill and other intangibles) of the Loan Parties and their Subsidiaries, on a consolidated basis, at a fair valuation, will exceed the debts and liabilities, direct, subordinated, contingent or otherwise, of the Loan Parties and their Subsidiaries, on a consolidated basis; (b) the present fair saleable value of the property of the Loan Parties and their Subsidiaries, on a consolidated basis, will be greater than the amount that will be required to pay the probable liabilities of the Loan Parties and their Subsidiaries, on a consolidated basis, on their debts and other liabilities, direct, subordinated, contingent or otherwise, as such debts and other liabilities become absolute and matured; (c) the Loan Parties and their Subsidiaries, on a consolidated basis, will be able to pay their debts and liabilities, direct, subordinated, contingent or otherwise, as such debts and liabilities become absolute and matured; and (d) the Loan Parties and their Subsidiaries, on a consolidated basis will not have unreasonably small capital with which to conduct the businesses in which they are engaged as such businesses are now conducted and are proposed to be conducted following the Closing Date.

3. The Borrower does not intend to incur debts beyond its ability to pay such debts as they mature, taking into account the timing and amounts of cash to be received by it, and the timing and amounts of cash to be payable on or in respect of its Indebtedness.

[***Signature Page Follows***]

IN WITNESS WHEREOF, I have hereunto set my hand this __ day of _____, 2017.

EXGEN RENEWABLES IV, LLC, as Borrower
By: _____
Name:
Title:[Chief Financial Officer][other Financial Officer]

FORM OF ECF SWEEP DATE CERTIFICATE

[DATE]

Pursuant to Section 5.04(e) of that certain Credit Agreement, dated as of November 28, 2017 (as amended, restated, amended and restated, replaced, supplemented or otherwise modified from time to time, the " **Credit Agreement** "; capitalized terms used herein and not otherwise defined herein shall have the meanings assigned to such terms in the Credit Agreement), among EXGEN RENEWABLES IV, LLC, a limited liability company organized under the laws of Delaware (the " **Borrower** "), EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" **Holding** "),the Lenders party thereto from time to time, MORGAN STANLEY SENIOR FUNDING, INC., as administrative agent for the Lenders (in such capacity, including any successor thereto in such capacity, the " **Administrative Agent** "), WILMINGTON TRUST, NATIONAL ASSOCIATION, as collateral agent for the Lenders (in such capacity, including any successor thereto in such capacity, the " **Collateral Agent** "), and WILMINGTON TRUST, NATIONAL ASSOCIATION, as Depositary Bank, the undersigned hereby certifies that he or she is the [INSERT title of Financial Officer] of the Borrower, and certifies in such capacity, and not in his or her individual capacity, that Excess Cash Flow for the Excess Cash Flow Period ending on [_____] [1] (the " **Subject Excess Cash Flow Period** ") is $[_____], which amount represents all funds on deposit in the Revenue Account as of the end of such Excess Cash Flow Period.

This ECF Sweep Date Certificate shall also serve as notice of prepayment pursuant to Section 2.08 in the amount of Excess Cash Flow set forth above.

As of the end of the Subject Excess Cash Flow Period:

1. The product of (i) The Applicable ECF Percentage and (ii) Excess Cash Flow for the Excess Cash Flow Period is U.S. $_____.
2. The outstanding principal amount of Loans is U.S. $_____.
3. [The outstanding and unpaid principal amount of Credit Support Reimbursement Obligations is U.S. $_____.] [2]
4. The amount allocated to Loans is U.S. $_____.
5. [The amount allocated to Credit Support Reimbursement Obligations is U.S. $_____.] [3]
6. [The Target Balance Prepayment Amount is U.S. $_____.] To be inserted for Quarterly Dates from and after May 2022.

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[1] To be the Excess Cash Flow Period most recently ended as of the date of this certificate.

[2] Pursuant to the proviso in Section 2.19(c)(vii) of the Credit Agreement, please insert the description of any Credit Support Reimbursement Obligations outstanding for twelve (12) Quarterly Dates after the incurrence of such Credit Support Reimbursement Obligations, if applicable.

[3] To be inserted if applicable.

The Borrower hereby gives notice of a prepayment of Loans as follows with all amounts in the ECF Prepayment Account: [5]

For a prepayment by Borrower,

1. (select Type(s) of Loans)

   Base Rate Loans in the aggregate principal amount of U.S. $_____.

   LIBOR Loans with an Interest Period ending _____, 20__ in the aggregate principal amount of U.S. $_____.

2. On _____, 20__ (a Business Day).

This ECF Sweep Date Certificate and prepayment contemplated hereby comply with the Credit Agreement, including Section 2.09 of the Credit Agreement.

[*Signature Page Follows*]

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[5] To be inserted only for ECF Sweep Dates.

IN WITNESS WHEREOF, the Borrower has caused this Certificate to be executed by one of their Financial Officers as of the date and year first above written.

EXGEN RENEWABLES IV, LLC, as Borrower
By: _____
Name:
Title:[INSERT title of Financial Officer]

FORM OF QUARTERLY DATE CERTIFICATE

[DATE]

Pursuant to Section 5.04(c) of that certain Credit Agreement, dated as of November 28, 2017 (as amended, restated, amended and restated, replaced, supplemented or otherwise modified from time to time, the " **Credit Agreement** "; capitalized terms used herein and not otherwise defined herein shall have the meanings assigned to such terms in the Credit Agreement), among EXGEN RENEWABLES IV, LLC, a limited liability company organized under the laws of Delaware (the " **Borrower** "), EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" **Holding** "),the Lenders party thereto from time to time, MORGAN STANLEY SENIOR FUNDING, INC., as administrative agent for the Lenders (in such capacity, including any successor thereto in such capacity, the " **Administrative Agent** "), WILMINGTON TRUST, NATIONAL ASSOCIATION, as collateral agent for the Lenders (in such capacity, including any successor thereto in such capacity, the " **Collateral Agent** "), and WILMINGTON TRUST, NATIONAL ASSOCIATION, as Depositary Bank, the undersigned hereby certifies that he or she is the [INSERT title of Financial Officer] of one of the Borrower, and certifies in such capacity, and not in his or her individual capacity, as follows with respect to the Quarterly Date occurring on [_____] (the " **Subject Quarterly Date** "):

1. No Event of Default or Default has occurred and is continuing as of the date hereof,
except as set forth in a separate attachment, if any, to this Quarterly Date Certificate, specifying the nature and extent thereof and the corrective action taken or proposed to be taken with respect thereto by the Borrower;

2. Annex A hereto sets forth the Borrower's calculation of Available Cash for the Test Quarter ended on the Subject Quarterly Date;

3. Annex B hereto sets forth evidence of the current balances in each of the Depositary Accounts as of the Subject Quarterly Date; and

4. Annex C hereto sets forth the Borrower's calculation of the Financial Performance Covenant for the Test Period ended on the Subject Quarterly Date.

[***Signature Page Follows***]

IN WITNESS WHEREOF, the Borrower has caused this Certificate to be executed by one of its Financial Officers as of the date and year first above written.

EXGEN RENEWABLES IV, LLC, as Borrower
By: _____
Name:
Title:[INSERT title of Financial Officer]

Calculation of Available Cash

APPLICABLE TEST QUARTER ENDING [_____], 20[__] [1]

Available Cash:

The sum (without duplication) of all amounts the Borrower and Holding actually receive in cash during the applicable Test Quarter in the form of:

dividends or similar distributions or fees, whether on account of operations, management or maintenance or otherwise, in each case, from the Project Entities pursuant to the Project Level Financing Documents or otherwise: $_____

[1] To be the Test Quarter ended as of the Quarterly Date set forth in this Quarterly Date Certificate.

Annex B to
Quarterly Date Certificate

Evidence of Cash Balances in each Depositary Account

[*Separately attached*]

Annex C to
Quarterly Date Certificate

Compliance with Financial Performance Covenant

APPLICABLE TEST PERIOD ENDING [_____], 20[__] [1]

Debt Service Coverage Ratio:

Means, for the applicable Test Period, the ratio of:

(a) Cash Flow Available for Debt Service for the applicable Test Period: $_____

to :

(b) Debt Service for the applicable Test Period: $_____

Debt Service Coverage Ratio = (a) to (b): _____

Cash Flow Available for Debt Service:

Means, as of any date of determination:

(a) Available Cash for the Test Period most recently ended as of such date: $_____

Minus

(b) Operating Expenses for such Test Period paid (or directed to be paid pursuant to a withdrawal certificate) in cash pursuant to Section 2.19(c)(i) during such Test Period: $_____

Debt Service:

Means, for any period, the amount of:

Fees, interest (including, without duplication of interest amounts payable under the Credit Agreement, ordinary course settlement amounts payable by the Borrower under any Interest Rate Swap Agreement, net of ordinary course settlement amounts received by the Borrower thereunder during the relevant period) and Scheduled Amortization Payments of principal due and payable under the Loan Documents during such Test Period (excluding any such amounts due and payable on the Maturity Date): $_____

---

[1] To be the Test Period ended as of the Subject Quarterly Date.

[2] As set forth on Annex A for each Quarterly Date Certificate delivered in respect of the Test Quarters in the relevant Test Period.

FORM OF TERM LOAN NOTE

U.S. $_____ Dated: _____, 2017

FOR VALUE RECEIVED, the undersigned, EXGEN RENEWABLES IV, LLC (the " **Borrower** "), HEREBY PROMISES TO PAY to [NAME OF LENDER] (the " **Lender** ") at the office of the Administrative Agent as provided for by the Credit Agreement referred to below, for the account of the Lender or its applicable lending office or its registered assigns, the principal amount of the Loans (as defined below) owing to the Lender by the Borrower pursuant to the Credit Agreement dated as of November 28, 2017 (as amended, amended and restated, supplemented or otherwise modified from time to time, the " **Credit Agreement** "; terms defined therein, unless otherwise defined herein, being used herein as therein defined), among the Borrower, EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" **Holding** "), the LENDERS party thereto from time to time and MORGAN STANLEY SENIOR FUNDING, INC., as Administrative Agent, WILMINGTON TRUST, NATIONAL ASSOCIATION, as Collateral Agent, and WILMINGTON TRUST, NATIONAL ASSOCIATION, as Depositary Bank, on the dates and in the principal amounts provided in the Credit Agreement.

The Borrower promises to pay to the Lender or its registered assigns interest on the unpaid principal amount of the Loan advanced to the Borrower from the date of such Loan, until such principal amount is paid in full, at such interest rates, and payable at such times, as are specified in the Credit Agreement.

Both principal and interest are payable in U.S. dollars to Morgan Stanley Senior Funding, Inc., as Administrative Agent, at 1300 Thames Street, 4th Floor, Thames Street Wharf, Baltimore, MD 21231, Attention: Administrative Agent, Email: [***], in immediately available funds. The Loan advanced to the Borrower and the maturity thereof, and all payments made on account of principal thereof, shall be recorded by the Lender and, prior to any transfer hereof, endorsed on the grid attached hereto, which is part of this promissory note (the " **Promissory Note** "); *provided, however* , that the failure of the Lender to make any such recordation or endorsement shall not affect the Obligations of the Borrower under this Promissory Note.

This Promissory Note is one of the Notes referred to in Section 2.07(d) of the Credit Agreement and is entitled to the benefits of the Credit Agreement. The Credit Agreement, among other things, (i) provides for the making of loans (the " **Loans** ") by the Lenders to or for the benefit of the Borrowers in an aggregate amount not to exceed at any time outstanding U.S. $850,000,000, the Indebtedness of the Borrower resulting from each such Loan being, on request of a Lender, evidenced by such promissory notes, and (ii) contains provisions for acceleration of the maturity hereof upon the happening of certain stated events and also for prepayments on account of principal hereof prior to the maturity hereof upon the terms and conditions therein specified. The Obligations of the Borrower under this Promissory Note and the other Loan Documents, and the Obligations of the other Loan Parties under the Loan Documents, are secured by the Collateral as provided in the Loan Documents.

The Borrower hereby irrevocably and unconditionally submits, for itself and its property, to the exclusive jurisdiction of any New York State court or federal court of the United States sitting in New York County, and any appellate court from any thereof, in any action or proceeding arising out of or relating to this Promissory Note or the other Loan Documents, or for recognition or enforcement of any judgment, and hereby irrevocably and unconditionally agrees that all claims in respect of any such action or proceeding may be heard and determined in such New York State or, to the extent permitted by law, in such federal court. The Borrower further irrevocably consents to the service of process in any action

or proceeding in such courts by the mailing thereof by any parties thereto by registered or certified mail, postage prepaid, to the Borrower at the address specified for the Loan Parties in Section 9.01(a) of the Credit Agreement. The Borrower agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Nothing in this Promissory Note shall affect any right that the Lender or Agent may otherwise have to bring any action or proceeding relating to this Promissory Note or the other Loan Documents against the Borrower or any other Loan Party or their properties in the courts of any jurisdiction in which the Borrower, the Loan Parties or their properties are located.

The Borrower hereby irrevocably and unconditionally waives, to the fullest extent it may legally and effectively do so, any objection which it may now or hereafter have to the laying of venue of any suit, action or proceeding arising out of or relating to this Promissory Note or the other Loan Documents in any New York State or federal court sitting in New York County. The Borrower hereby irrevocably waives, to the fullest extent permitted by law, the defense of an inconvenient forum to the maintenance of such action or proceeding in any such court.

This Promissory Note shall be governed by, and construed in accordance with, the law of the State of New York.

EXGEN RENEWABLES IV, LLC, as Borrower

By: _____

Name:

Title:

LOANS AND PAYMENTS OF PRINCIPAL

Date	Amount of Loans	Amount of Principal Paid or Prepaid	Unpaid Principal Balance	Notation Made By

FORM OF TAX CERTIFICATE

Reference is made to the Credit Agreement dated as of November 28, 2017 (the " **Credit Agreement** "), among EXGEN RENEWABLES IV, LLC, a limited liability company organized under the laws of Delaware (the " **Borrower** "), EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" **Holding** "), the LENDERS party thereto from time to time, MORGAN STANLEY SENIOR FUNDING, INC., as Administrative Agent, WILMINGTON TRUST, NATIONAL ASSOCIATION, as Collateral Agent, and WILMINGTON TRUST, NATIONAL ASSOCIATION, as Depositary Bank. Capitalized terms used herein and not otherwise defined herein shall have the meanings assigned to such terms in the Credit Agreement.

Pursuant to Section 2.15(e) of the Credit Agreement, [ ] (the " **Non-U.S. Lender** ") certifies that: [1]

I. The Non-U.S. Lender is not a "bank" (within the meaning of Section 881(c)(3)(A) of the Code).

II. The Non-U.S. is not a 10-percent shareholder of the Borrower (within the meaning of Section 881(c)(3)(B) or Section 871(h)(3)(B) of the Code).

III. The Non-U.S. Lender is not a controlled foreign corporation (as such term is defined in Section 881(c)(3)(C) of the Code) related to the Borrower (within the meaning of Section 864(d)(4) of the Code).

IV. The Non-U.S. Lender is the sole record and beneficial owner of the Loan(s) (as well as any Note(s) evidencing such Loan(s)) in respect of which it is providing this certificate.

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[1] If the Non-U.S. Lender is an intermediary, a foreign partnership or other flow-through entity, the following adjustments shall be made.

A. The following representations shall be provided as applied to the direct or indirect partners, members or beneficial owners claiming the portfolio interest exemption:
   - the status in Clause II, and
   - the status in Clause III,

B. The following representations shall be provided as applied to the Non-U.S. Lender as well as the direct or indirect partners, members or beneficial owners claiming the portfolio interest exemption:
   - the status in Clause I.

C. The following representation shall be provided instead of the representation in Clause IV: The Non-U.S. Lender is the sole record owner of the Loan(s) (as well as any Note(s) evidencing such Loan(s)) in respect of which it is providing this certificate, and its direct or indirect partners/members are the sole beneficial owners of such Loan(s) (as well as any Note(s) evidencing such Loan(s)).

D. The Non-U.S. Lender shall provide a U.S. Internal Revenue Service Form W-8IMY (with U.S. Internal Revenue Service Form W-8BEN, W-8BEN-E or W-9, as applicable, from each of its partners/ members/beneficial owners).

E. Appropriate adjustments shall be made in the case of tiered intermediaries or tiered partnerships/ flow-through entities.

The Non-U.S. Lender has furnished the Administrative Agent and the Borrower with a certificate of its non-U.S. person status on U.S. Internal Revenue Service Form W-8BEN or W-8BEN-E or any subsequent versions thereof or successors thereto. By executing this certificate, the undersigned agrees that (1) if the information provided on this certificate changes, the undersigned shall promptly so inform the Borrower and the Administrative Agent, and (2) the undersigned shall have at all times furnished the Borrower and the Administrative Agent with a properly executed certificate in either the calendar year in which each payment is to be made to the Non-U.S. Lender, or in either of the two calendar years preceding such payments.

[***Signature Page Follows***]

IN WITNESS WHEREOF, the undersigned has duly executed this certificate.

[Name of Non-U.S. Lender]

By: _____
Name: _____
Title: _____
[Address]

Dated:_____, 20__

FORM OF ADMINISTRATIVE QUESTIONNAIRE

Please email to the Administrative Agent at Morgan Stanley Senior Funding, Inc. [***]

Borrower: EXGEN RENEWABLES IV, LLC

Lender / Investor: (as name appears on assignment agreement): _____

An original, executed tax form (W8/W9) must be provided to the agent prior to the Lender / Investor being closed into the transaction.

Operations/Administrative Contacts (for draw downs, repayments, rate setting, etc.):

Name:	Name:
c/o:	c/o:
Address:	Address:
City, St, Zip:	City, St, Zip:
Attn:	Attn:
Phone:	Phone:
Email:	Email:

Wire Instructions:

Bank Name:
ABA #
BNF Name:
BNF Address:
A/C:
FFC:
Ref:

Credit Contact : Closing and Clear Par Contacts:

Name:	Name:
c/o:	c/o:
Address:	Address:
City, St, Zip:	City, St, Zip:
Attn:	Attn:
Phone:	Phone:
Email:	Email:

Intralinks Contacts:

Name:	Name:
c/o:	c/o:
Address:	Address:
City, St, Zip:	City, St, Zip:
Attn:	Attn:
Phone:	Phone:
Email:	Email:

Please forward Amendments, Waivers, Closing Documentation and Compliance to:

Name:	Name:
c/o:	c/o:
Address:	Address:
City, St, Zip:	City, St, Zip:
Attn:	Attn:
Phone:	Phone:
Email:	Email:

FORM OF WITHDRAWAL CERTIFICATE
WITHDRAWAL CERTIFICATE

Date: [1] _____

Withdrawal Date:_____

Wilmington Trust, National Association,
as Collateral Agent and Depositary Agent
1100 North Market Street
Wilmington, DE 19890
Attention: Institutional Client Services/Project Finance
Facsimile No.: [***]
Phone No.: [***]

Morgan Stanley Senior Funding, Inc.,
as the Administrative Agent
1300 Thames Street, 4th Floor
Thames Street Wharf
Baltimore, MD 21231
Attention: Administrative Agent
Email: [***]

Re: ExGen Renewables IV,

LLC Ladies and Gentlemen:

Reference is made to the Credit Agreement, dated as of November 28, 2017 (as amended, amended and restated, supplemented, replaced or otherwise modified and in effect from time to time, the " **Credit Agreement** "), among EXGEN RENEWABLES IV, LLC, a limited liability company organized under the laws of Delaware (the " **Borrower** "), EXGEN RENEWABLES IV HOLDING, LLC, a limited liability company organized under the laws of Delaware (" **Holding** "), the LENDERS party thereto from time to time, MORGAN STANLEY SENIOR FUNDING, INC., as Administrative Agent, WILMINGTON TRUST, NATIONAL ASSOCIATION, as Collateral Agent, and WILMINGTON TRUST, NATIONAL ASSOCIATION, as Depositary Bank. Capitalized terms used but not otherwise defined in this certificate (this " **Withdrawal Certificate** ") shall have the meanings assigned (whether directly or by reference to another agreement) to such terms in the Credit Agreement.

The undersigned is a Responsible Officer of the Borrower and is delivering this Withdrawal Certificate on behalf of the Borrower pursuant to Section **[** s **]** **[** 2.19(c) **]** **[** 2.19(d)(iii) **]** **[** 2.19(d)(iv) **]** **[** 2.19(e)(ii) **]** **[** 2.19(e)(iii) **]** **[** 2.19(f) **]** **[** 2.19(g) **]** **[** 2.19(h) **]** **[** 2.19(i) **]** of the Credit Agreement.

_____

[1] A copy of this Withdrawal Certificate must be received by the Depositary Agent and the Administrative Agent at least five Business Days prior to the proposed Withdrawal Date except as otherwise expressly provided in the Credit Agreement.

1. Revenue Account. The following transfers are requested to be made from the Revenue Account in accordance with this Withdrawal Certificate as set forth in greater detail in Part A of the attached Schedule I:

(a) **[** *From time to time as necessary* : **]** In accordance with Section 2.19(c)(i) of the Credit Agreement, we request that $ _____ be withdrawn and transferred to the applicable payees as set forth in greater detail in Part A of the attached Schedule I to pay Operating Expenses (and any Fees). Such amount requested equals the amount of Operating Expenses (and any Fees) that are due and have not yet been paid.

(b) **[** *On each Quarterly Date and otherwise from time to time as necessary* : **]** In accordance with Section 2.19(c)(ii) of the Credit Agreement, we request that: (x) $ _____ be withdrawn and transferred to the Administrative Agent as set forth in greater detail in Part A of the attached Schedule I , which amount requested equals the amount of interest and breakage costs on the Loans due and payable to the Lenders, and (y) $ _____ be withdrawn and transferred to each Specified Swap Counterparty as set forth in greater detail in Part A of the attached Schedule I , which amount requested equals the amount of scheduled ordinary course payments (but not termination payments) due and payable under Secured Swap Agreements.

(c) **[** *On each Quarterly Date* : **]** In accordance with Section 2.19(c)(iii) of the Credit Agreement, we request that: (x) $ _____ be withdrawn and transferred to the Administrative Agent as set forth in greater detail in Part A of the attached Schedule I , which amount requested equals the amount of principal of (including Scheduled Amortization Payments) and premium, if any, on the Loans due and payable to the Lenders, and (y) $ _____ be withdrawn and transferred to each Specified Swap Counterparty as set forth in greater detail in Part A of the attached Schedule I , which amount requested equals the amount of termination payments due and payable under Secured Swap Agreements.

(d) **[** *On each Quarterly Date and otherwise from time to time as necessary* : **]** In accordance with Section 2.19(c)(iv) of the Credit Agreement, we request that $ _____ be withdrawn to pay the applicable payees as set forth in greater detail in Part A of the attached Schedule I . Such amount requested equals the amount of indemnities and other amounts (other than interest, Fees, principal and premium) due to the Lenders under the Loan Documents.

(e) **[** *On each Quarterly Date, as necessary* : **]** In accordance with Section 2.19(c)(v) of the Credit Agreement, we request that $ _____ be withdrawn and transferred to the Debt Service Reserve Account. Such amount requested, together with the amount then on deposit in or credited to the Debt Service Reserve Account *plus* the aggregate guaranteed amount of each Sponsor Guaranty credited thereto and the aggregate Drawing Amount of each Account Letter of Credit credited thereto, equals the DSR Requirement Amount as of the Quarterly Date to which this Withdrawal Certificate relates. The undersigned hereby certifies that as of the Quarterly Date to which this Withdrawal Certificate relates, the DSR Requirement Amount for the six (6) month period following such Quarterly Date is $ [_____] and is based on the reasonable good faith projections of the Borrower.

(f) **[** *On each Quarterly Date, at the option of the Borrower* : **]** In accordance with Section 2.19(c)(vi) of the Credit Agreement, we request that $ _____ be withdrawn and transferred to the [Liquidity Reserve Account][and/or][Local Accounts]. Such amount requested, together with the amount then on deposit in the (x) Liquidity Reserve Account, after giving effect to such transfer, do not exceed the Liquidity Reserve Balance or (y) Liquidity Reserve Account together with the amount then on deposit in the Local Accounts, after giving effect to such transfer, do not exceed $30,000,000.

(g) **[** *On each Quarterly Date, as applicable* : **]** In accordance with Section 2.19(c)(vii)(A) of the Credit Agreement, we request that [(x)] $ _____ be withdrawn and transferred to the ECF Prepayment Account [and (y) $ _____ be withdrawn to pay the applicable payees as set forth in greater detail in Part A of the attached Schedule I to be applied to the payment or repayment of Credit Support Reimbursement Obligations]. Such amount requested equals the Applicable ECF Percentage of the remaining balance in the Revenue Account after all amounts have been withdrawn and transferred in accordance with Sections 2.19(c)(i) through 2.19(c)(vi) (as the case may be) of the Credit Agreement. [Such amounts are allocated pro rata (based on the aggregate amount of the outstanding principal of the Loans and the Credit Support Reimbursement Obligations then outstanding and unpaid on such Quarterly Date)].

(h) **[** *On each Quarterly Date, ending in May, as applicable, commencing May 2022* : **]** In accordance with Section 2.19(c)(vii)(B) of the Credit Agreement, we request that $ _____ be withdrawn and transferred to the ECF Prepayment Account. Such amount requested equals the Target Balance Prepayment Amount.

(h) **[** *On each ECF Sweep Date, commencing May 2022* : **]** In accordance with Section 2.19(c)(viii) of the Credit Agreement, we request that $ _____ be withdrawn and transferred to [ ] as set forth in greater detail in Part A of the attached Schedule I. Such amount requested equals all or a portion of the remaining funds in the Revenue Account after all amounts have been withdrawn and transferred in accordance with Sections 2.19(c)(i) through 2.19(c)(vii) (as the case may be) of the Credit Agreement. The Borrower certifies that no Default or Event of Default has occurred or is continuing.

2. Debt Service Reserve Account. The following transfers are requested to be made from the Debt Service Reserve Account in accordance with this Withdrawal Certificate as set forth in greater detail in Part B of the attached Schedule I :

(a) [*In the event there are Excess Reserve Amounts* :] In accordance with Section 2.19(d)(iii) of the Credit Agreement, we request that $_____ be withdrawn from the Debt Service Reserve Account and transferred to the Revenue Account pursuant to Section 2.19(d)(iii) . Such amount requested [equals the Excess Reserve Amount] [*If cash on deposit in the Debt Service Reserve Account is less than the Excess Reserve Amount* : does not exceed the Excess Reserve Amount] in accordance with Section 2.19(d)(iii) . The Borrower certifies that no Default or Event of Default has occurred or is continuing.

(b) In accordance with Section 2.19(d)(iv) of the Credit Agreement, we request that $_____ be withdrawn from the Debt Service Reserve Account and transferred to the Administrative Agent to pay:

(i.) **[** *If the funds on deposit in or credited to the Revenue Account are not anticipated to be, or are not, adequate to pay all amounts to be paid therefrom pursuant to Sections 2.19(c)(ii) of the Credit Agreement* : **]** **[** FIRST, interest, breakage costs and Fees then due and payable under the Loan Documents; and **]**

(ii) **[** *If the funds on deposit in or credited to the Revenue Account are not anticipated to be, or are not, adequate to pay all principal and premium, if any, pursuant to Section 2.19(c)(vi)* : **]** **[** SECOND, principal and premium (if any) then due and payable under the Loan Documents **].**

Such amount requested represents **[** an amount equal to the Debt Payment Deficiency **]** **[** the aggregate amount of funds on deposit or credited to the Debt Service Reserve Account **]** .

3. Liquidity Reserve Account. The following transfers are requested to be made from the Liquidity Reserve Account in accordance with this Withdrawal Certificate as set forth in greater detail in Part C of the attached Schedule I:

(a) [*In the event there are Excess Liquidity Reserve Amounts* :] In accordance with Section 2.19(e)(ii)(C) of the Credit Agreement, we request that $_____ be withdrawn from the Liquidity Reserve Account and transferred to the Revenue Account pursuant to Section 2.19(e)(ii)(C). Such amount requested [equals the Excess Liquidity Reserve Amount] [*If cash on deposit in the Liquidity Reserve Account is less than the Excess Liquidity Reserve Amount* : does not exceed the Excess Liquidity Reserve Amount] in accordance with Section 2.19(e)(ii)(C). The Borrower certifies that no Default or Event of Default has occurred or is continuing.

(b) [*In the event there is a Borrower Liquidity Shortfall or Project Liquidity Shortfall* :] In accordance with Section 2.19(e)(iii) of the Credit Agreement, we request that $ _____ be withdrawn from the Liquidity Account and [transferred to the Revenue Account. Such amount (together with any amounts transferred to the Revenue Account from the Local Accounts on such date) represents a Borrower Liquidity Shortfall] [transferred to the Persons as set forth in greater detail in Part C of the attached Schedule I. Such amount (together with any amounts transferred from the Local Accounts on such date) shall be used for application to the following Project Liquidity Shortfall: [*Insert reasonably detailed description* .]]

(c) In accordance with Section 2.19(e)(iii) of the Credit Agreement, we request that $ _____ be withdrawn from the Liquidity Account and transferred to the Local Account specified in greater detail in Part C of the attached Schedule I . Such amount shall be used for application to a Borrower Liquidity Shortfall or Project Liquidity Shortfall. After giving effect to such transfer, (1) the amount on deposit in the Liquidity Reserve Account shall not exceed the Liquidity Reserve Maximum Balance and (2) the aggregate amount on deposit in the Liquidity Reserve Account and the Local Accounts shall not exceed $30,000,000.

4. Equity Proceeds Account. In accordance with Section 2.19(g) of the Credit Agreement, we request that $ _____ be withdrawn from the Equity Proceeds Account and [transferred to [the Revenue Account][Debt Service Reserve Account][Liquidity Reserve Account][ECF Prepayment Account].] [transferred to the Persons as set forth in greater detail in Part D of the attached Schedule I. Such amount shall be used for a purpose permitted by the Credit Agreement and the other Loan Documents.]

---

5. ECF Prepayment Account. In accordance with Section 2.19(h) of the Credit Agreement, we request that $ _____ be withdrawn from the ECF Prepayment Account and transferred to the Administrative Agent for application to the mandatory prepayment of the Loans pursuant to Section 2.09(b). Such amount requested equals the balance in the ECF Prepayment Account.

6. Invasion of Accounts. (a) [*In the event the amounts on deposit in the Revenue Account are insufficient to make disbursements clauses 2.19(c)(ii) and (iii):* In accordance with Section 2.19(i) of the Credit Agreement, we request that $ _____ be withdrawn from the ECF Prepayment Account and transferred to the Revenue Account. Such amount requested shall be used to cover an insufficiency in the amounts on deposit in the Revenue Account to make disbursements in clauses 2.19(c)(ii) and (iii).]

(b) [*In the event the amounts on deposit in the Revenue Account and the ECF Prepayment Account are insufficient to make disbursements clauses 2.19(c)(ii) and (iii)* :] In accordance with Section 2.19(i) of the Credit Agreement, we request that $ _____ be withdrawn from the Liquidity Reserve Account and transferred to the Revenue Account. Such amount requested shall be used to cover an insufficiency in the amounts on deposit in the Revenue Account to make disbursements.

[*Signature page(s) follow.* **]**

IN WITNESS WHEREOF, the Borrower has caused this Withdrawal Certificate to be duly executed and delivered by a Responsible Officer of the Borrower as of the date first written above.

EXGEN RENEWABLES IV, LLC, as the Borrower

By: _____
Name:
Title:

Schedule I to
Withdrawal Certificate

Part A: Disbursements from Revenue Account

Transfer Date	Payee/Account and Purpose	Payment Date	Wiring or Other Payment Instructions	Amount
				$
[*Insert additional rows as necessary* **]**				$
			Total :	$

Part B: Disbursements from Debt Service Reserve Account

Transfer Date	Payee/Account and Purpose	Payment Date	Wiring or Other Payment Instructions	Amount
				$
[*Insert additional rows as necessary* **]**				$
			Total :	$

Part C: Disbursements from Liquidity Reserve Account

Transfer Date	Payee/Account and Purpose	Payment Date	Wiring or Other Payment Instructions	Amount
				$
[*Insert additional rows as necessary* **]**				$
			Total :	$

Part D: Disbursements from Equity Proceeds Account

Transfer Date	Payee/Account and Purpose	Payment Date	Wiring or Other Payment Instructions	Amount
				$
[*Insert additional rows as necessary* **]**				$
			Total :	$

Schedule 1.01A - Existing Project Level Financing Documents

A. The " **RPG Financing Documents** " are set forth below:

1. Each of (a) the Note Purchase Agreement, dated as of March 31, 2016, among Renewable Power Generation, LLC, Renewable Power Generation Holdings, LLC, their affiliates party thereto as guarantors and the purchasers listed as a party on Schedule B thereto, and (b) the other Financing Documents (as defined therein), in each case as amended, modified, supplemented and in effect on the Closing Date.

2. Each of (a) the Credit Agreement, dated as of March 31, 2016, among Renewable Power Generation, LLC, Renewable Power Generation Holdings, LLC, their other affiliates party thereto as guarantors, the lenders and issuing banks party thereto from time to time and Morgan Stanley Senior Funding, Inc., as Administrative Agent, and (b) the other Financing Documents (as defined therein), in each case as amended, modified, supplemented and in effect on the Closing Date.

B. The " **Continental Wind Financing Documents** " are set forth below:
1. Each of (a) the Indenture, dated as of September 30, 2013, among Continental Wind, LLC, Continental Wind Holdings, LLC, their other affiliates party thereto as guarantors and Wilmington Trust, National Association, as Trustee, and (b) the other Financing Documents (as defined therein), in each case as amended, modified, supplemented and in effect on the Closing Date.
2. Each of (a) the Credit Agreement, dated as of September 30, 2013, among Continental Wind, LLC, Continental Wind Holdings, LLC, their affiliates party thereto as guarantors, the lenders and issuing banks party thereto from time to time, and Credit Agricole Corporate and Investment Bank, as administrative agent for the lenders thereunder, and (b) the other Financing Documents (as defined therein), in each case as amended, modified, supplemented and in effect on the Closing Date.

C. The " **SolGen Financing Documents** " are set forth below:
1. Each of (a) the Note Purchase Agreement, dated as of September 30, 2016, among SolGen, LLC, SolGen Holding, LLC, their affiliates party thereto as guarantors, and each of the purchasers listed as a party on the purchasers schedule thereto, and (b) the other Financing Documents (as defined therein), in each case as amended, modified, supplemented and in effect on the Closing Date.
2. Each of (a) the Credit Agreement, dated as of September 30, 2016, among SolGen, LLC, SolGen Holding, LLC, their affiliates party thereto as guarantors, the lenders and issuing banks party thereto from time to time, and BNP Paribas, as administrative agent for the lenders thereunder, and (b) the other Financing Documents (as defined therein), in each case as amended, modified, supplemented and in effect on the Closing Date.

D. The " **Bluestem Financing Documents** " are set forth below:
1. Each of (a) the Membership Interest Purchase and Equity Capital Contribution Agreement, dated as of December 22, 2016, among Bluestem Wind Energy Holdings, LLC, Exelon Wind, LLC, Bluestem Wind Energy Member, LLC, BAL Investment & Advisory, Inc. and Antrim Corporation, and (b) the other Investment Documents (as defined therein), in each case as amended, modified, supplemented and in effect on the Closing Date.
2. Each of (a) the Amended and Restated Operating Agreement of Bluestem Wind Energy Holdings, LLC,, dated as of December 22, 2016, among Bluestem Wind Energy Member,

LLC, BAL Investment & Advisory, Inc. and Antrim Corporation, and (b) the other Investment Documents (as defined therein), in each case as amended, modified, supplemented and in effect on the Closing Date.

E. The " **AG Financing Documents** " are set forth below:
1. Bond Purchase Loan Agreement, dated as of December 1, 2014, by and between the Albany Dougherty Payroll Development Authority and Albany Green Energy, LLC, as amended, modified, supplemented and in effect on the Closing Date.
2. Each of (a) Lease Agreement, dated as of December 1, 2014, by and between the Albany Dougherty Payroll Development Authority and Albany Green Energy, LLC, and (b) the Bond, Bond Documents, Bond Resolution, Loan Documents, PILOT Agreement and Security Documents (as those terms are respectively defined therein), in each case as amended, modified, supplemented and in effect on the Closing Date.

F. The " **AVSR Financing Documents** " are set forth below:
1. Note Purchase Agreement, dated as of September 28, 2011, by and among the Federal Financing Bank, the Secretary of Energy (acting through the Department of Energy) and AV Solar Ranch 1, LLC, as amended, modified, supplemented and in effect on the Closing Date and the Future Advance Promissory Note, dated September 28, 2011.
2. Each of (a) Loan Guarantee Agreement, dated as of September 28, 2011, dated as of May 4, 2016, by and among AV Solar Ranch 1, LLC, the U.S. Department of Energy, as guarantor, and the U.S. Department of Energy, as loan servicer, and (b) the other Financing Documents (as defined therein), in each case as amended, modified, supplemented and in effect on the Closing Date.

G. The " **ExGen Renewables JV Agreements** " are set forth below:

1. Amended and Restated Limited Liability Company Agreement of ExGen Renewables Partners, LLC dated July 6, 2017 by and among ExGen Renewables Partners, LLC, ExGen Renewables Holdings, LLC, and John Hancock Life Insurance Company (U.S.A).

Schedule 1.01B - Material Other Indebtedness Documents

1. The Indebtedness and related obligations under the Existing Project Level Financing Documents set forth in Parts A - F of Schedule 1.01A.

2. Promissory Note, dated June 28, 2011, made by Denver Airport Solar, LLC to City and County of Denver
3. The Indebtedness and related obligations under the following agreements:

    a. Reimbursement Agreement, dated September 23, 2013, by and between Continental Wind, LLC and Exelon Generation Company, LLC
    b. Reimbursement Agreement, dated March 31, 2016, by and among Renewable Power Generation, LLC, Renewable Power Generation Holdings, LLC, and Exelon Generation Company, LLC
    c. Collateral Facility Agreement, dated September 30, 2016, by and among Exelon Generation Company, LLC, SolGen, LLC, SolGen Holding, LLC and each of the SolGen Projects
    d. Promissory Note, dated December 22, 2016, by and between Bluestem Wind Energy, LLC and Exelon Generation Company, LLC
    e. Reimbursement Agreement dated November 28, 2017, by and between Albany Green Energy, LLC and Exelon Generation Company, LLC.
    f. Reimbursement Agreement dated November 28, 2017, by and between ExGen Renewables IV, LLC and Exelon Generation Company, LLC.

Schedule 1.01C - Project Entities

1.	AV Solar Ranch Entities	Exelon AVSR Holding, LLC Exelon AVSR, LLC Exelon AVSR, LLC
2.	Albany Green Entities	Constellation DCO Albany Power Holdings, LLC Albany Green Energy, LLC
3.	Bluestem Entities	Bluestem Wind Energy Member Holdings, LLC Bluestem Wind Energy Member, LLC Bluestem Wind Energy Holdings, LLC Bluestem Wind Energy, LLC
4.	RPG Entities	Renewable Power Generation Holdings, LLC Renewable Power Generation, LLC Beebe 1B Renewable Energy, LLC Cow Branch Wind Power, L.L.C. CR Clearing, LLC Wind Capital Holdings, LLC Threemile Canyon Wind I, LLC Constellation Solar Horizons, LLC Sacramento PV Energy, LLC
5.	SolGen Entities	SolGen Holding, LLC SolGen, LLC Outback Solar, LLC Constellation Solar Arizona, LLC Mohave Sunrise Solar I, LLC Constellation Solar Georgia, LLC California PV Energy, LLC

6.	Continental Wind Entities	ExGen Renewables I Holding, LLC ExGen Renewables I, LLC Continental Wind Holding, LLC Continental Wind, LLC Shooting Star Wind Project, LLC Whitetail Wind Energy, LLC Beebe Renewable Energy, LLC Harvest II Windfarm, LLC High Mesa Energy, LLC Wildcat Wind LLC Wildcat Finance, LLC Michigan Wind 2, LLC Tuana Springs Energy, LLC Greensburg Wind Farm, LLC Cassia Gulch Wind Park, LLC Cassia Wind Farm LLC Four Corners Windfarm, LLC Four Mile Canyon Windfarm, LLC Harvest Windfarm, LLC Bennett Creek Windfarm, LLC Hot Springs Windfarm, LLC
7.	Echo Entities	Ward Butte Windfarm, LLC Sand Ranch Windfarm, LLC Oregon Trail Windfarm, LLC Pacific Canyon Windfarm, LLC Wagon Trail, LLC Big Top, LLC Butter Creek Power, LLC
8.	Other Project Entities	CP Windfarm, LLC Criterion Power Partners, LLC Fourmile Wind Energy, LLC Michigan Wind 1, LLC Sendero Wind Energy, LLC Denver Airport Solar, LLC Constellation Solar New Jersey III, LLC

Schedule 1.01D - Projects

Project	Fuel Type	Location
Albany Green Project		
Albany Green Project	Biomass	Albany, GA
AV Solar Project		
AV Solar Ranch Project	Solar	LA County, CA
Continental Wind Projects		
Shooting Star	Wind	Kiowa County, KS
Whitetail	Wind	Laredo, TX
Beebe 1A	Wind	Gratiot County, MI
Harvest	Wind	Elkton, MI
Harvest II	Wind	Elkton, MI
High Mesa	Wind	Bliss, ID
Wildcat	Wind	Lovington, NM
Michigan Wind 2	Wind	Minden City, MI
Tuana Springs	Wind	Hagerman, ID
Greensburg	Wind	Greensburg, KS
Cassia (Cassia Gulch and Cassia Wind)	Wind	Hagerman, ID
Echo II (Four Corners Wind Farm, Four Mile Canyon)	Wind	Morrow and Umatilla County, OR
Mt. Home (Bennet Creek and Hot Springs)	Wind	Elmore, ID
RPG Projects		
Beebe 1B	Wind	Ithaca, MI
Cow Branch	Wind	Tarkio, MO
Conception	Wind	Stanberry, MO
Bluegrass Ridge	Wind	King City, MO
Threemile Canyon	Wind	Boardman, OR
Clean Horizon	Solar	Emmitsburg, MD
Sacramento	Solar	Sacramento, CA
Other Projects		
CP Windfarm	Wind	Winnebago, MN
Criterion	Wind	Oakland, MD
Echo I (Ward Butte, Sand Ranch, Oregon Trail, Pacific Canyon)	Wind	Echo, OR
Echo III (Wagon Trail, Butter Creek, Big Top)	Wind	Echo, OR
Fourmile Ridge	Wind	Garrett County, MD
Michigan Wind	Wind	Ubly, MI
Sendero	Wind	Jim Hogg and Zapata Counties, TX
Denver (Solar)	Solar	Denver, CO
MTBOE (Constellation Solar NJ)	Solar	Cape May Court House, NJ
Bluestem Wind Project	Wind	Beaver County, OK

SolGen Projects		
Mohave Sunrise Solar Project		
Mohave Sunrise Solar	Solar	Mohave County, AZ
Constellation Solar Arizona Projects		
Buckeye	Solar	Buckeye, AZ
Casa Grande	Solar	Casa Grande, AZ
Crane I	Solar	Yuma, AZ
Crane II	Solar	Yuma, AZ
Dysart - Phase I to III	Solar	Maricopa County, AZ
Dysart IV	Solar	Surprise, AZ
Isaac	Solar	Phoenix, AZ
Marana	Solar	Marana and Tucson, AZ
Miami	Solar	Gila County, AZ
Peoria	Solar	Peoria, AZ
Somerton	Solar	Somerton, AZ
TUSD	Solar	Tucson, AZ
TUSD - Trico	Solar	Tucson, AZ
Vail	Solar	Tucson and Vail, AZ
Constellation Solar Georgia Projects		
Evergreen	Solar	Dublin, GA
Fresh Air	Solar	Sparta, GA
URE I - Coleman I	Solar	Wadley, GA
URE I - Coleman II	Solar	Wadley, GA
URE I - Hilliard	Solar	Cave Springs, GA
URE I - Mohawk	Solar	Summerville, GA
URE I - Prescott	Solar	Wrens, GA
URE I - SCDA	Solar	Eastanollee, GA
URE I - Williford	Solar	Gibson, GA
URE II	Solar	Toccoa, GA
California PV Energy Projects		
Castaic	Solar	Castaic, CA
Chaffey	Solar	San Bernardino, CA
Champagne	Solar	Ontario, CA
Central	Solar	Rancho Cucamonga, CA
Ironhouse	Solar	Oakley, CA
Jurupa	Solar	Ontario, CA
Keppel	Solar	Los Angeles County, CA
Palmdale	Solar	Palmdale, CA
Pomona	Solar	Pomona, CA
LADWP-Port of LA	Solar	San Pedro, CA
San Gabriel	Solar	San Gabriel, CA
Outback Solar Project		

Outback Solar	Solar	Lake County, OR

Schedule 1.01E - Target Loan Balance

Date	Target Debt Balance
5/31/2018	[***]
5/31/2019	[***]
5/31/2020	[***]
5/31/2021	[***]
5/31/2022	[***]
5/31/2023	[***]
5/31/2024	[***]

Schedule 1.01F - Echo LLC Agreements

The " **Echo LLC Agreements** " shall mean the documents set forth below:

1. Amended and Restated Limited Liability Company Agreement of Oregon Trail Windfarm, LLC dated August 4, 2008.

2. Amended and Restated Limited Liability Company Agreement Pacific Canyon Windfarm, LLC dated August 4, 2008.

3. Amended and Restated Limited Liability Company Agreement of Sand Ranch Windfarm, LLC dated August 4, 2008.

4. Amended and Restated Limited Liability Company Agreement of Ward Butte Windfarm, LLC dated August 4, 2008.

5. Amended and Restated Limited Liability Company Agreement of Big Top, LLC dated October 21, 2008.

6. Amended and Restated Limited Liability Company Agreement of Butter Creek Power, LLC dated October 21, 2008.

7. Amended and Restated Limited Liability Company Agreement of Wagon Trail, LLC dated October 21, 2008. **Schedule 2.01 - Commitments**

Lender	Commitment
Morgan Stanley Senior Funding, Inc.	$850,000,000

Schedule 3.07(c) - Subsidiaries

Subsidiary	Jurisdiction of Organization	Class of Stock or other Equity Interest	Percentage Owned
ExGen Renewables IV, LLC	Delaware	Membership Interests	100% by ExGen Renewables IV Holding, LLC
ExGen Renewables Holdings, LLC	Delaware	Membership Interests	100% owned by ExGen Renewables IV, LLC ("EGRIV")
ExGen Renewables Partners, LLC ("EGRP")	Delaware	Class A Membership Interests	100% owned by ExGen Renewables Holdings, LLC
Exelon AVSR Holding, LLC	Delaware	Membership Interests	100% owned by EGRIV
Exelon AVSR, LLC	Delaware	Membership Interests	100% owned by Exelon AVSR Holding, LLC
AV Solar Ranch 1, LLC	Delaware	Membership Interests	100% owned by Exelon AVSR, LLC
Constellation DCO Albany Power Holdings, LLC	Delaware	Class A Membership Interests	50.51% owned by EGRIV
Albany Green Energy, LLC	Georgia	Membership Interests	100% owned by Constellation DCO Albany Power Holdings, LLC
SolGen Holdings, LLC	Delaware	Membership Interests	100% owned by EGRIV
SolGen, LLC	Delaware	Membership Interests	100% owned by SolGen Holding, LLC
Outback Solar, LLC	Oregon	Membership Interests	100% owned by SolGen, LLC
Constellation Solar Arizona, LLC	Delaware	Membership Interests	100% owned by SolGen, LLC
Mohave Sunrise Solar I, LLC	Arizona	Membership Interests	100% owned by SolGen, LLC
Constellation Solar Georgia, LLC	Georgia	Membership Interests	100% owned by SolGen, LLC
California PV Energy, LLC	Delaware	Membership Interests	100% owned by SolGen, LLC
Big Top, LLC	Oregon	Class A Membership Interests	100% by ExGen JV
Bluestem Wind Energy Member Holdings, LLC	Delaware	Membership Interests	100% owned by EGRP
Bluestem Wind Energy Member, LLC	Delaware	Membership Interests	100% owned by Bluestem Wind Energy Member Holdings, LLC
Bluestem Wind Energy Holdings, LLC	Delaware	Class A Membership Interests	100% owned by Bluestem Wind Energy Member, LLC

Bluestem Wind Energy, LLC	Delaware	Membership Interests	100% owned by Bluestem Wind Energy Holdings, LLC
Butter Creek Power, LLC	Oregon	Class A Membership Interests	100% by EGRP
Constellation Solar New Jersey III, LLC	Delaware	Membership Interests	100% owned by EGRP
CP Windfarm, LLC	Minnesota	Membership Interests	100% owned by EGRP
Criterion Power Partners, LLC	Delaware	Membership Interests	100% owned by EGRP
Denver Airport Solar, LLC	Delaware	Membership Interests	100% owned by EGRP
Fourmile Wind Energy, LLC	Maryland	Membership Interests	100% owned by EGRP
Michigan Wind 1, LLC	Delaware	Membership Interests	100% owned by EGRP
Oregon Trail Windfarm, LLC	Oregon	Class A Membership Interests	100% by EGRP
Pacific Canyon Windfarm, LLC	Oregon	Class A Membership Interests	100% by EGRP
Sand Ranch Windfarm, LLC	Oregon	Class A Membership Interests	100% by EGRP
Sendero Wind Energy, LLC	Delaware	Membership Interests	100% owned by EGRP
Wagon Trail, LLC	Oregon	Class A Membership Interests	100% by EGRP
Ward Butte Windfarm, LLC	Oregon	Class A Membership Interests	100% by EGRP
ExGen Renewables I Holding, LLC	Delaware	Membership Interests	100% owned by EGRP
ExGen Renewables I, LLC	Delaware	Membership Interests	100% owned by ExGen Renewables I Holding, LLC
Continental Wind Holding, LLC	Delaware	Membership Interests	100% owned by ExGen Renewables I, LLC
Continental Wind, LLC ("CW")	Delaware	Membership Interests	100% owned by Continental Wind Holding, LLC
Beebe Renewable Energy, LLC	Delaware	Membership Interests	100% owned by CW
Bennett Creek Windfarm, LLC	Idaho	Membership Interests	100% owned by CW
Cassia Gulch Wind Park LLC	Idaho	Membership Interests	100% owned by CW
Cassia Wind Farm LLC	Idaho	Membership Interests	100% owned by CW
Four Corners Windfarm, LLC	Oregon	Membership Interests	100% owned by CW
Four Mile Canyon Windfarm, LLC	Oregon	Membership Interests	100% owned by CW

Greensburg Wind Farm, LLC	Delaware	Membership Interests	100% owned by CW
Harvest Windfarm, LLC	Michigan	Membership Interests	100% owned by CW
Harvest II Windfarm, LLC	Delaware	Membership Interests	100% owned by CW
High Mesa Energy, LLC	Idaho	Membership Interests	100% owned by CW
Hot Springs Windfarm, LLC	Idaho	Membership Interests	100% owned by CW
Michigan Wind 2, LLC	Delaware	Membership Interests	100% owned by CW
Shooting Star Wind Project, LLC	Delaware	Membership Interests	100% owned by CW
Tuana Springs Energy, LLC	Idaho	Membership Interests	100% owned by CW
Whitetail Wind Energy, LLC	Delaware	Membership Interests	100% owned by CW
Wildcat Wind LLC	New Mexico	Membership Interests	100% owned by CW
Wildcat Finance, LLC	Delaware	Membership Interests	100% owned by Wildcat Wind LLC
Renewable Power Generation Holdings, LLC	Delaware	Membership Interests	100% owned by EGRP
Renewable Power Generation, LLC (“RPG”)	Delaware	Membership Interests	100% owned by Renewable Power Generation Holdings, LLC
Beebe 1B Renewable Energy, LLC	Delaware	Membership Interests	100% owned by RPG
Constellation Solar Horizons, LLC	Delaware	Membership Interests	100% owned by RPG
Cow Branch Wind Power, L.L.C	Missouri	Membership Interests	100% owned by RPG
CR Clearing, LLC	Missouri	Membership Interests	100% owned by RPG
Sacramento PV Energy, LLC	Delaware	Membership Interests	100% owned by RPG
Threemile Canyon Wind I, LLC	Oregon	Membership Interests	100% owned by RPG
Wind Capital Holdings, LLC	Missouri	Membership Interests	100% owned by RPG

Schedule 3.07(d) - Equity Interests

1. The Organizational Documents of Holding, the Borrower and its Subsidiaries.
2. The rights of EGRIV and Peach Power, Inc., as the owners of the Class A Membership Interest, and the rights of DCO Energy, LLC, as the owner of the Class B Membership Interest, under the Amended and Restated Limited Liability Company Agreement of Constellation DCO Albany Power Holdings, LLC, dated as of October 6, 2017.
3. The rights of ExGen Renewables IV, LLC under the Call Option Agreement dated as of October 6, 2017.
4. The rights of ExGen Renewables Holdings, LLC, as the Class A Member, and the rights of John Hancock Life Insurance Company, as the Class B Member, under the Amended and Restated Limited Liability Company Agreement of ExGen Renewable Partners, LLC dated July 6, 2017.
5. The rights of Bluestem Wind Energy Member, LLC, as the Class A Member, under the Amended and Restated Limited Liability Company Agreement of Bluestem Wind Energy Holdings, LLC dated as of December 22, 2016.
6. The rights of Homestead Windfarm LLC (as assignee from Columbia Windfarm, LLC), as the Class B Member, under the Amended and Restated Limited Liability Company Agreement of Oregon Trail Windfarm, LLC dated August 4, 2008.
7. The rights of Oregon International Holding, Inc., as the Class B Member, under the Amended and Restated Limited Liability Company Agreement Pacific Canyon Windfarm, LLC dated August 4, 2008.
8. The rights of Homestead Windfarm LLC (as assignee from Columbia Windfarm, LLC), as the Class B Member, under the Amended and Restated Limited Liability Company Agreement of Sand Ranch Windfarm, LLC dated August 4, 2008.
9. The rights of Pacific Trail Windfarm, LLC, as the Class B Member, under the Amended and Restated Limited Liability Company Agreement of Ward Butte Windfarm, LLC dated August 4, 2008.
10. The rights of Frank Mader and LaVonne Mader, as the Class B Members, under the Amended and Restated Limited Liability Company Agreement of Big Top, LLC dated October 21, 2008
11. The rights of Kent Madison and Shannon Madison, as the Class B Members, under the Amended and Restated Limited Liability Company Agreement of Butter Creek Power, LLC dated October 21, 2008.
12. The rights of Shannon Rust and Tim Rust, as the Class B Members, under the Amended and Restated Limited Liability Company Agreement of Wagon Trail, LLC dated October 21, 2008.
13. Option Agreement, dated March 31, 2016, between Exelon Generation Company, LLC and Wilmington Trust, National Association, as collateral agent.

14. Call Option Agreement, dated April 26, 2011, between Belectric Solarkraftwerke GmbH and Sacramento PV Energy, LLC.

15. Option Agreement, dated September 30, 2013, between Exelon Corporation and Wilmington Trust, National Association, as collateral agent.

Schedule 6.01(i) - Project Level Indebtedness

The Indebtedness incurred pursuant to the documents set forth in Parts A-F of Schedule 1.01A and the documents set forth in Part 2 of Schedule 1.01B.

Schedule 6.02(a) - Liens

To the extent qualifying as a Lien, the matters set forth in Section 3.07(d) applicable to the Loan Parties and the terms and limitations set forth in the Organizational Documents for the Loan Parties.

Schedule 6.07(b) - Transactions with Affiliates

Various Projects

The contracts listed in part 3 of Schedule 1.01B

Echo I

(Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Pacific Canyon Windfarm, LLC and Ward Butte Windfarm, LLC)

1. REC Transfer Agreement, dated August 4, 2008, by and between Oregon Windfarms, LLC and Sand Ranch Windfarm, LLC.
2. REC Transfer Agreement, dated August 4, 2008, by and between Oregon Windfarms, LLC and Oregon Trail Windfarm, LLC.
3. REC Transfer Agreement, dated August 4, 2008, by and between Oregon Windfarms, LLC and Pacific Canyon Windfarm, LLC.
4. REC Transfer Agreement, dated August 4, 2008, by and between Oregon Windfarms, LLC and Ward Butte Windfarm, LLC.
5. Construction Management Agreement, dated August 4, 2008, by and between Sand Ranch Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC)
6. Construction Management Agreement, dated August 4, 2008, by and between Oregon Trail Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).
7. Construction Management Agreement, dated August 4, 2008, by and between Pacific Canyon Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).
8. Construction Management Agreement, dated August 4, 2008, by and between Ward Butte Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).
9. Operation and Maintenance Management Agreement, dated August 4, 2008, by and between Sand Ranch Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).
10. Operation and Maintenance Management Agreement, dated August 4, 2008, by and between Oregon Trail Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

11. Operation and Maintenance Management Agreement, dated August 4, 2008, by and between Pacific Canyon Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

12. Operation and Maintenance Management Agreement, dated August 4, 2008, by and between Ward Butte Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

13. Engineering & Procurement Agreement, dated September 16, 2008, by and among PacifiCorp and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC) as Shared Facilities Manager appointed by Four Mile Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Ward Butte Windfarm, LLC, Oregon Trail Windfarm, LLC, Four Corners Windfarm, LLC and Pacific Canyon Windfarm, LLC.

14. Commissioning and Final Completion Agreement, dated October 28, 2008, by and among Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Ward Butte Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, Big Top, LLC, Wagon Trail, LLC, Vestas-American Wind Technology, Inc. and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

15. Service and Maintenance Agreement, dated October 28, 2008, by and among Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Ward Butte Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, Big Top, LLC, Wagon Trail, LLC, Vestas-American Wind Technology, Inc. and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC), as amended by that First Amendment to Service and Maintenance Agreement, dated July 29, 2010.

16. Warranty Agreement, dated October 28, 2008, by and among Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Ward Butte Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, Big Top, LLC, Wagon Trail, LLC, Vestas-American Wind Technology, Inc. and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

17. Service and Maintenance Agreement, dated June 1, 2014, by and among Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Ward Butte Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, Big Top, LLC, Wagon Trail, LLC, Vestas-American Wind Technology, Inc. and Exelon Wind, LLC.

18. 69 KV Power Line 69 kV Line Agreement, dated February 20, 2012, by and among Oregon Windfarms, LLC, Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, High Plateau Windfarm, LLC, Lower Ridge Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and Exelon Wind, LLC.

19. Wind Turbine Lockout Agreement, dated February 14, 2012, by and among Sand Ranch Windfarm, LLC, and Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, High Plateau Windfarm, LLC, Lower Ridge Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and Exelon Wind, LLC.

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20. Agreement Regarding Shared Interconnection Facilities, dated January 18, 2012, by and among PacifiCorp, Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, Lower Ridge Windfarm, LLC, High Plateau Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and Exelon Wind, LLC.

21. Amended and Restated Assignment, Shared Premises, and Shared Facilities Agreement, dated October 21, 2008, by and among Oregon Windfarms, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, Big Top, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

22. Strategic Investment Program Agreement, dated December 17, 2008, by and among Morrow County, Umatilla County, Four Corners Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Ward Butte Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, Big Top, LLC and Wagon Trail, LLC.

23. Station Load, Losses and Net Output Allocation Algorithm for the Morrow Projects, dated January 2012, by and among Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, Lower Ridge Windfarm, LLC, High Plateau Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and PacifiCorp.

24. Transmit Electricity Agreement, dated July 27, 2009, by and among Oregon Windfarms, LLC, Four Mile Canyon Windfarm, LLC, Ward Butte Windfarm, LLC, Four Corners Windfarm, LLC, Pacific Canyon Windfarm, LLC, Wagon Trail, LLC, Big Top, LLC, Butter Creek Power, LLC, Sand Ranch Windfarm, LLC and Oregon Trail Windfarm, LLC.

25. Project Administration Agreement, dated August 4, 2008, by and between Sand Ranch Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

26. Project Administration Agreement, dated August 4, 2008, by and between Oregon Trail Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

27. Project Administration Agreement, dated August 4, 2008, by and between Pacific Canyon Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

28. Project Administration Agreement, dated August 4, 2008, by and between Ward Butte Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

29. Agreement for the Purchase and Sale of Renewable Energy Certificates, dated August 21, 2009, by and among Grey K Renewable Energy Limited, Oregon Windfarms, LLC, Sand Ranch Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

30. Agreement for the Purchase and Sale of Renewable Energy Certificates, dated August 21, 2009, by and among Grey K Renewable Energy Limited, Oregon Windfarms, LLC, Oregon Trail Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

31. Agreement for the Purchase and Sale of Renewable Energy Certificates, dated August 21, 2009, by and among Grey K Renewable Energy Limited, Oregon Windfarms, LLC, Pacific Canyon Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

32. Agreement for the Purchase and Sale of Renewable Energy Certificates, dated August 21, 2009, by and among Grey K Renewable Energy Limited, Oregon Windfarms, LLC, Ward Butte Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

33. Letter Agreement, dated August 3, 2013, by and among Oregon Windfarms, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, and Exelon Wind, LLC.

34. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, LLC, Oregon Windfarms, LLC, Oregon Trail Windfarm, LLC, and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

35. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, LLC, Oregon Windfarms, LLC, Pacific Canyon Windfarm, LLC, and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

36. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, LLC, Oregon Windfarms, LLC, Sand Ranch Windfarm, LLC, and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

37. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, LLC, Oregon Windfarms, LLC, Ward Butte Windfarm, LLC, and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

Echo III

(Big Top, LLC, Butter Creek Power, LLC and Wagon Trail, LLC)

1. Construction Management Agreement, dated October 21, 2008, by and between Big Top, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

2. Construction Management Agreement, dated October 21, 2008, by and between Butter Creek Power, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

3. Construction Management Agreement, dated October 21, 2008, by and between Wagon Trail, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

4. Operation and Maintenance Management Agreement, dated October 21, 2008, by and between Big Top, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

5. Operation and Maintenance Management Agreement, dated October 21, 2008, by and between Butter Creek Power, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

6. Operation and Maintenance Management Agreement, dated October 21, 2008, by and between Wagon Trail, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

7. Transmit Electricity Agreement, dated July 27, 2009, by and among Oregon Windfarms, LLC, Four Mile Canyon Windfarm, LLC, Ward Butte Windfarm, LLC, Four Corners Windfarm, LLC, Pacific Canyon Windfarm, LLC, Wagon Trail, LLC, Big Top, LLC, Butter Creek Power, LLC, Sand Ranch Windfarm, LLC and Oregon Trail Windfarm, LLC.

8. Service and Maintenance Agreement, dated June 1, 2014, by and among Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Ward Butte Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, Big Top, LLC, Wagon Trail, LLC, Vestas-American Wind Technology, Inc. and Exelon Wind, LLC.

9. 69 KV Power Line 69 kV Line Agreement, dated February 20, 2012, by and among Oregon Windfarms, LLC, Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, High Plateau Windfarm, LLC, Lower Ridge Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and Exelon Wind, LLC.

10. Wind Turbine Lockout Agreement, dated February 14, 2012, by and among Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, High Plateau Windfarm, LLC, Lower Ridge Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and Exelon Wind, LLC.

11. Agreement Regarding Shared Interconnection Facilities, dated January 18, 2012, by and among PacifiCorp, Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, and Wagon Trail, LLC, Lower Ridge Windfarm, LLC, High Plateau Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and Exelon Wind, LLC.

12. Commissioning and Final Completion Agreement, dated October 28, 2008, by and among Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Ward Butte Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, Big Top, LLC, Wagon Trail, LLC, Vestas-American Wind Technology, Inc. and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

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13. Amended and Restated Assignment, Shared Premises, and Shared Facilities Agreement, dated October 21, 2008, by and among Oregon Windfarms, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, Big Top, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

14. Strategic Investment Program Agreement, dated December 17, 2008, by and among Morrow County, Umatilla County, Four Corners Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Ward Butte Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, Big Top, LLC and Wagon Trail, LLC.

15. Station Load, Losses and Net Output Allocation Algorithm for the Morrow Projects, dated January 2012, by and among Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, Lower Ridge Windfarm, LLC, High Plateau Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and PacifiCorp.

16. Engineering & Procurement Agreement, dated September 16, 2008, by and between PacifiCorp and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC) as Shared Facilities Manager.

17. Balance of Plant Engineering and Construction Contract, dated July 23, 2008, by and between Exelon Wind, LLC (f/k/a John Deere Renewables, LLC) and Silvey Enterprises, Inc.

18. Project Administration Agreement, dated October 21, 2008, by and between Big Top, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

19. Project Administration Agreement, dated October 21, 2008, by and between Butter Creek Power, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

20. Project Administration Agreement, dated October 21, 2008, by and between Wagon Trail, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

21. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, and Big Top, LLC.

22. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, and Butter Creek Power, LLC.

23. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, and Wagon Trail, LLC.

Bluestem

1. Membership Interest Purchase and Equity Capital Contribution Agreement, dated December 22, 2016, by and among Bluestem Wind Energy Holdings, LLC, Exelon Wind, LLC, Bluestem Wind Energy Members, LLC, BAL Investment & Advisory, Inc. and Antrim Corporation.

2. Escrow Agreement, dated December 22, 2016, by and among Bluestem Wind Energy Member, LLC, Bluestem Wind Energy Holdings, LLC, BAL Investment & Advisory, Inc., Antrim Corporation and Wilmington Trust, National Association.

3. Global Services Agreement, dated December 22, 2016, by and among Bluestem Wind Energy Holdings, LLC, Bluestem Wind Energy, LLC and Exelon Generation Company, LLC.

4. Service Procurement Agreement, dated December 22, 2016, by and between Bluestem Wind Energy, LLC and Exelon Business Services Company, LLC.

5. Reimbursement Agreement, dated December 22, 2016, by and between Exelon Generation Company, LLC and Bluestem Wind Energy, LLC.

6. Assignment and Assumption Agreement, dated December 22, 2016, by and between Exelon Wind, LLC and Bluestem Wind Energy, LLC.

7. Promissory Note, dated December 22, 2016, by and between Bluestem Wind Energy, LLC and Exelon Generation Company, LLC.

Criterion

1. Shared Facilities Agreement, dated September 22, 2015, by and among Criterion Power Partners LLC, Fair Wind Power Partners, LLC and Exelon Wind, LLC.

Fourmile Wind

1. PTC Offtake Agreement, dated July 6, 2017, by and between Exelon Corporation and Fourmile Wind Energy, LLC.

Michigan Wind 1

1. Shared Facilities Agreement, dated September 27, 2013, by and between Michigan Wind 1, LLC and Michigan Wind 2, LLC.

2. Substation Site Easement Agreement, dated September 13, 2013, by and between Michigan Wind 1, LLC and Michigan Wind 2, LLC.

3. Management Services Agreement, dated May 1, 2007, by and between Harvest Wind Farm, LLC and Michigan Wind LLC.

4. Assignment of Amended and Restated Large Generator Interconnection Agreement, dated August 17, 2011, by and between Michigan Wind 1, LLC and Michigan Wind 2, LLC.

5. Consent to Assignment of Amended and Restated Large Interconnection Agreement, dated August 10, 2011, by and among Michigan Wind 1, LLC, Michigan Wind 2, LLC, International Transmission Company and Midwest Independent Transmission System Operator, Inc.

Sendero

1. PTC Offtake Agreement, dated July 6, 2017, by and between Exelon Corporation and Sendero Wind Energy, LLC.

Renewable Power Generation Projects

1. Service Procurement Agreement, dated March 31, 2016, by and between Renewable Power Generation, LLC and Exelon Business Services, LLC.

2. Global Management Services Agreement, dated March 31, 2016, by and between Renewable Power Generation, LLC and Exelon Generation Company, LLC.

3. PTC Offtake Agreement, dated March 31, 2016, by and between Exelon Generation Company, LLC and Renewable Power Generation, LLC.
4. PTC Option Agreement, dated March 31, 2016, by and between Exelon Generation Company, LLC and Renewable Power Generation, LLC.
5. Reimbursement Agreement (Insurance), dated March 31, 2016, by and between Exelon Generation Company and Renewable Power Generation, LLC.

6. Assignment and Assumption Agreement, dated March 31, 2016, by and between Exelon Wind, LLC and Renewable Power Generation, LLC (CG Power Systems USA, Inc.).

7. Assignment and Assumption Agreement, dated March 31, 2016, by and between Exelon Wind, LLC and Renewable Power Generation, LLC (Run Energy, L.P.).

Beebe 1B

1. Co-Tenancy, Shared Facilities and Easement Agreement, dated July 19, 2013, by and among Beebe Renewable Energy, LLC, Beebe 1B Renewable, LLC and Exelon Wind, LLC.

2. Substation Co-Tenancy, Shared Facilities and Easement Agreement, dated July 19, 2013, by and among Beebe Renewable Energy, LLC, Beebe 1B Renewable, LLC and Exelon Wind, LLC.

3. Build-Out Agreement, dated July 19, 2013, by and among Beebe Renewable Energy, LLC, Beebe 1B Renewable, LLC, and Exelon Wind, LLC.

4. Build-Out Agreement, dated August 9, 2013, by and among Beebe Renewable Energy, LLC, Beebe 1B Renewable, LLC, Beebe Renewable Energy 2, LLC and Exelon Wind, LLC.

5. Transmission Easement Agreement, dated July 19, 2013, by and between Beebe Renewable Energy, LLC and Beebe 1B Renewable Energy, LLC.

6. Interconnection Easement Agreement (Substation), dated July 19, 2013, by and between Beebe Renewable Energy, LLC and Beebe 1B Renewable Energy, LLC.

7. Shared Facilities Easement Agreement, dated July 19, 2013, by and between Beebe Renewable Energy, LLC and Beebe 1B Renewable Energy, LLC.

8. Wind Energy Project Sublease Agreement (Substation), dated July 19, 2013, by and between Beebe Renewable Energy, LLC and Beebe 1B Renewable Energy, LLC.

9. Substation Site Easement Agreement (Substation), dated July 19, 2013, by and between Beebe Renewable Energy, LLC and Beebe 1B Renewable Energy, LLC.

Cow Branch

1. Master Maintenance and Service Agreement, dated April 1, 2015, by and among Wind Capital Holdings, LLC, CR Clearing, LLC, Cow Branch Wind Power, L.L.C. and Suzlon Wind Energy Corporation.

Conception (CR Clearing, LLC)

1. Master Maintenance and Service Agreement, dated April 1, 2015, by and among Wind Capital Holdings, LLC, CR Clearing, LLC, Cow Branch Wind Power, L.L.C. and Suzlon Wind Energy Corporation.

Bluegrass (Wind Capital Holding, LLC)

1. Master Maintenance and Service Agreement, dated April 1, 2015, by and among Wind Capital Holdings, LLC, CR Clearing, LLC, Cow Branch Wind Power, L.L.C. and Suzlon Wind Energy Corporation.

Threemile Canyon

1. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, LLC, and Threemile Canyon Wind I, LLC.

Solar Horizons

1. Operation and Maintenance Agreement, dated September 7, 2012, by and between Constellation Solar Horizons, LLC and Constellation NewEnergy, Inc., as amended by First Amendment to Operation and Maintenance Agreement, dated March 31, 2016.

Continental Wind Projects

1. Services Agreement, dated 2015, by and between Constellation Power Source Generation, LLC (acting as Exelon Industrial Services) and Continental Wind, LLC.

2. Global Management Services Agreement, dated June 14, 2013, by and between Continental Wind, LLC and Exelon Generation Company, LLC.

3. PTC Offtake Agreement, dated September 1, 2013, between Exelon Corporation and Continental Wind, LLC.

4. PTC Option Agreement, dated September 1, 2013, between Exelon Corporation and Continental Wind, LLC.

5. Assignment and Assumption Agreement, dated September 30, 2013, by and between Exelon Wind, LLC and Continental Wind, LLC.

6. Reimbursement Agreement (Insurance), dated September 23, 2013, by and between Exelon Generation Company and Continental Wind, LLC.

7. Assignment of Renewable Energy Purchase Agreement, dated September 30, 2013 , by and among Harvest II Windfarm, LLC, Beebe Renewable Energy, LLC, Michigan Wind 2, LLC,

Consumers Energy Company, Wilmington Trust, National Association, and Credit Agricole Corporate and Investment Bank.

Whitetail

1. Electricity Supply Agreement, dated August 10, 2012, by and between Whitetail Wind Energy, LLC and Constellation NewEnergy, Inc.

Michigan Wind 2

1. Shared Facilities Agreement, dated September 27, 2013, by and between Michigan Wind 1, LLC and Michigan Wind 2, LLC.

2. Assignment of Amended and Restated Large Generator Interconnection Agreement, dated August 17, 2011, by and between Michigan Wind 1, LLC and Michigan Wind 2, LLC.

3. Consent to Assignment of Amended and Restated Large Interconnection Agreement, dated August 10, 2011, by and among Michigan Wind 1, LLC, Michigan Wind 2, LLC, International Transmission Company and Midwest Independent Transmission System Operator, Inc.

Beebe 1A

1. Co-Tenancy, Shared Facilities and Easement Agreement, dated July 19, 2013, by and among Beebe Renewable Energy, LLC, Beebe 1B Renewable Energy, LLC and Exelon Wind, LLC.

2. Substation Co-Tenancy, Shared Facilities and Easement Agreement, dated July 19, 2013, by and among Beebe Renewable Energy, LLC, Beebe 1B Renewable Energy, LLC and Exelon Wind, LLC.

3. Build-Out Agreement, dated July 19, 2013, by and among Beebe Renewable Energy, LLC, Beebe 1B Renewable Energy, LLC and Exelon Wind, LLC.

4. Build-Out Agreement, dated August 9, 2013, by and among Beebe Renewable Energy, LLC, Beebe 1B Renewable Energy, LLC, Beebe Renewable Energy 2, LLC and Exelon Wind, LLC.

5. Wind Energy Project Sublease Agreement, dated July 19, 2013, by and among Beebe Renewable Energy, LLC, Beebe 1B Renewable, LLC and Exelon Wind, LLC.

Harvest and Harvest II

1. Amended and Restated Generator Interconnection Agreement, dated July 3, 2012, by and among Harvest Windfarm, LLC, International Transmission Company (dba ITC Transmission) and Midwest Independent Transmission System Operator, Inc., as assigned by that Assignment Agreement, dated September 18, 2012, by and between Harvest Windfarm, LLC and Harvest II Windfarm, LLC.

2. Shared Facilities Agreement, dated January 1, 2012, by and between Harvest Wind Farm, LLC and Harvest II Wind Farm, LLC.

3. Management Services Agreement, dated May 1, 2007, by and between Harvest Wind Farm, LLC and Michigan Wind LLC.

4. Performance Bond and Guaranty, dated April 30, 2012, made by Harvest II Windfarm, LLC and Exelon Generation Company, LLC in favor of Huron County.

Mountain Home

1. Generator Interconnection Agreement, dated September 13, 2007, by and among Bennett Creek Windfarm, LLC, Hot Springs Windfarm, LLC, and Idaho Power Company - Delivery.

2. Master Maintenance and Service Agreement, dated April 1, 2015, by and among Suzlon Wind Energy Corporation, Bennett Creek Wind Farm, LLC, Cassia Gulch Wind Park LLC, Cassia Wind Farm LLC, Greensburg Wind Farm, LLC, Hot Springs Windfarm, LLC and Tuana Springs Energy, LLC.

High Mesa (High Mesa Energy, LLC)

1. Assignment and Assumption Agreement, dated September 30, 2013, by and among Exelon Wind, LLC, High Mesa Energy, LLC and Continental Wind, LLC.

2. Assignment and Assumption Agreement, dated August 30, 2012, by and between Exelon Wind, LLC and High Mesa Energy, LLC.

Cassia Wind Farm, LLC Cassia Gulch Wind Park, LLC and Tuana Springs, LLC

1. Generator Interconnection Agreement, dated February 11, 2009, by and among Cassia Gulch Wind Park, LLC, Cassia Wind Farm, LLC and Idaho Power Company - Delivery.

2. Master Maintenance and Service Agreement, dated April 1, 2015, by and among Suzlon Wind Energy Corporation, Bennett Creek Wind Farm, LLC, Cassia Gulch Wind Park LLC, Cassia Wind Farm LLC, Greensburg Wind Farm, LLC, Hot Springs Windfarm, LLC and Tuana Springs Energy, LLC.

3. Assignment, Shared Premises and Shared Facilities Agreement, dated April 10, 2010, by and among Cassia Gulch Wind Park, LLC, Cassia Wind Farm, LLC, Tuana Springs Energy, LLC, and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC), reference to which is made in that certain Memorandum of Assignment, Shared Premises and Shared Facilities Agreement, dated August 13, 2013 and recorded August 15, 2013.

4. Firm Energy Sales Agreement, dated August 5, 2009, by and between Cassia Gulch Wind Park LLC, Tuana Springs Energy, LLC and Idaho Power Company.

5. Generator Interconnection Agreement, dated February 26, 2010, among Cassia Gulch Wind Park, LLC, Tuana Springs Energy, LLC, and Idaho Power Company - Delivery.

Wildcat

1. Bond Purchase Agreement, dated March 23, 2012, by and between Wildcat Finance, LLC, Lea County, New Mexico and Wildcat Wind LLC.

Echo II

(Four Corners Windfarm, LLC and Four Mile Canyon Windfarm, LLC)

1. REC Sharing Agreement, dated August 4, 2008, by and between Oregon Windfarms, LLC and Four Corners Windfarm, LLC.

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2. REC Sharing Agreement, dated August 4, 2008, by and between Oregon Windfarms, LLC and Four Mile Canyon Windfarm, LLC.

3. 69 KV Power Line 69 kV Line Agreement, dated February 20, 2012, by and among Oregon Windfarms, LLC, Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, High Plateau Windfarm, LLC, Lower Ridge Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and Exelon Wind, LLC.

4. Wind Turbine Lockout Agreement, dated February 14, 2012, by and among Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, High Plateau Windfarm, LLC, Lower Ridge Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and Exelon Wind, LLC.

5. Agreement Regarding Shared Interconnection Facilities, dated January 18, 2012, by and among PacifiCorp, Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, Lower Ridge Windfarm, LLC, High Plateau Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and Exelon Wind, LLC.

6. Amended and Restated Assignment, Shared Premises, and Shared Facilities Agreement, dated October 21, 2008, by and among Oregon Windfarms, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, and Wagon Trail, LLC, Big Top, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

7. Strategic Investment Program Agreement, dated December 17, 2008, by and among Morrow County, Umatilla County, Four Corners Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Pacific Canyon Windfarm, LLC, Sand Ranch Windfarm, LLC, Ward Butte Windfarm, LLC, Oregon Trail Windfarm, LLC, Butter Creek Power, LLC, Big Top, LLC and Wagon Trail, LLC.

8. Station Load, Losses and Net Output Allocation Algorithm for the Morrow Projects, dated January 2012, by and among Sand Ranch Windfarm, LLC, Oregon Trail Windfarm, LLC, Ward Butte Windfarm, LLC, Pacific Canyon Windfarm, LLC, Four Mile Canyon Windfarm, LLC, Four Corners Windfarm, LLC, Big Top, LLC, Butter Creek Power, LLC, Wagon Trail, LLC, Lower Ridge Windfarm, LLC, High Plateau Windfarm, LLC, Mule Hollow Windfarm, LLC, Pine City Windfarm, LLC and PacifiCorp.

9. Agreement for the Purchase and Sale of Renewable Energy Certificates, dated August 21, 2009, by and between Grey K Renewable Energy Limited, Oregon Windfarms, LLC, Four Corners Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

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10. Agreement for the Purchase and Sale of Renewable Energy Certificates, dated August 21, 2009, between Grey K Renewable Energy Limited, Oregon Windfarms, LLC, Four Mile Canyon Windfarm, LLC and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

11. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, LLC, and Four Mile Canyon Windfarm, LLC.

12. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, LLC, and Four Corners Windfarm, LLC.

13. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, LLC, Oregon Windfarms, LLC, Four Mile Canyon Windfarm, LLC, and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

14. Assignment, Assumption, Consent and Release Agreement, dated August 16, 2017, by and among Grey K Renewable Energy Limited, Exelon Generation Company, LLC, Oregon Windfarms, LLC, Four Corners Windfarm, LLC, and Exelon Wind, LLC (f/k/a John Deere Renewables, LLC).

Greensburg

1. Master Maintenance and Service Agreement, dated April 1, 2015, by and among Suzlon Wind Energy Corporation, Bennett Creek Wind Farm, LLC, Cassia Gulch Wind Park LLC, Cassia Wind Farm LLC, Greensburg Wind Farm, LLC, Hot Springs Windfarm, LLC and Tuana Springs Energy, LLC.

Albany Green Energy Project

1. Operation and Maintenance Agreement, dated 2016, by and between Albany Green Energy, LLC and Exelon Generation Company, LLC.

2. Intercompany Steam Sales Agreement, dated September 30, 2016, by and between Albany Green Energy, LLC and Constellation NewEnergy, Inc.
3. Amended and Restated Operation and Maintenance Agreement, dated 2017, by and between Albany Green Energy, LLC and Exelon Generation Company, LLC.

4. Management Services Agreement, dated 2017, by and between Albany Green Energy, LLC and Exelon Generation Company, LLC.

5. Reimbursement Agreement (Insurance), dated 2017, by and between Exelon Generation Company, LLC and Albany Green Energy, LLC.

SolGen Projects

1. Operation and Maintenance Agreement, dated August 31, 2016, by and between California PV Energy, LLC and Constellation New Energy, Inc.

2. Operation and Maintenance Agreement, dated August 31, 2016, by and between Constellation Solar Arizona, LLC and Constellation New Energy, Inc.

3. Operation and Maintenance Agreement, dated August 31, 2016, by and between Constellation Solar Georgia, LLC and Constellation New Energy, Inc.

4. Operation and Maintenance Agreement, dated August 31, 2016, by and between Mohave Sunrise Solar I, LLC and Constellation New Energy, Inc.

5. Management Services Agreement, dated August 31, 2016, by and between SolGen, LLC and Constellation New Energy, Inc.

6. REC Marketing and Other Services Agreement, dated August 31, 2016, by and between SolGen, LLC and Exelon Generation Company, LLC.

7. Reimbursement Agreement, dated August 31, 2016, by and between SolGen, LLC and Exelon Generation Company, LLC.

8. Collateral Facility Agreement, dated September 30, 2016, by and among Exelon Generation Company, LLC, SolGen, LLC, SolGen Holding, LLC, and each of the SolGen Projects.

AV Solar Ranch Project

1. Administrative Services Agreement, dated September 27, 2011, by and between AV Solar Ranch 1, LLC and Exelon Generation Company, LLC, as amended by the First Amendment to the Administrative services Agreement, dated January 1, 2017.

Exelon Corporation
Ratio of Earnings to Fixed Charges

(In millions, except ratios)	Years Ended December 31, 2013	2014	2015	2016	2017
Pre-tax income from continuing operations	2,773	2,486	3,330	1,989	3,756
Plus: Loss (income) from equity investees	(10)	20	—	—	—
Less: Capitalized interest	(67)	(79)	(99)	(142)	(98)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	2,696	2,427	3,231	1,847	3,658
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	1,436	1,110	1,107	1,651	1,631
Interest component of rental expense [a]	269	288	300	259	236
Total fixed charges	1,705	1,398	1,407	1,910	1,867
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	4,401	3,825	4,638	3,757	5,525
Ratio of earnings to fixed charges	2.6	2.7	3.3	2.0	3.0

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exelon Corporation
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

(In millions, except ratios)	Years Ended December 31, 2013	2014	2015	2016	2017
Pre-tax income from continuing operations	2,773	2,486	3,330	1,989	3,756
Plus: Loss (income) from equity investees	(10)	20	—	—	—
Less: Capitalized interest	(67)	(79)	(99)	(142)	(98)
Preference security dividend requirements	(32)	(18)	(19)	(13)	—
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	2,664	2,409	3,212	1,834	3,658
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	1,436	1,110	1,107	1,651	1,631
Interest component of rental expense [a]	269	288	300	259	236
Preference security dividend requirements of consolidated subsidiaries	32	18	19	13	—
Total fixed charges	1,737	1,416	1,426	1,923	1,867
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	4,401	3,825	4,638	3,757	5,525
Ratio of earnings to fixed charges and preferred stock dividends	2.5	2.7	3.3	2.0	3.0

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Exelon Generation Company, LLC
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
(In millions, except ratios)	**2013**	**2014**	**2015**	**2016**	**2017**
Pre-tax income from continuing operations	1,675	1,226	1,850	873	1,429
Plus: Loss (income) from equity investees	(10)	20	—	—	—
Less: Capitalized interest	(54)	(63)	(79)	(107)	(63)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	1,611	1,183	1,771	766	1,366
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	445	396	427	454	491
Interest component of rental expense [a]	248	269	284	222	193
Total fixed charges	693	665	711	676	684
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	2,304	1,848	2,482	1,442	2,050
Ratio of earnings to combined fixed charges	3.3	2.8	3.5	2.1	3.0

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Commonwealth Edison Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
(In millions, except ratios)	**2013**	**2014**	**2015**	**2016**	**2017**
Pre-tax income from continuing operations	401	676	706	679	984
Less:Capitalized interest	(5)	(2)	(4)	(8)	(8)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	396	674	702	671	976
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	575	311	331	465	365
Interest component of rental expense [(a)]	5	5	4	5	3
Total fixed charges	580	316	335	470	368
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest plus fixed charges	976	990	1,037	1,141	1,344
Ratio of earnings to fixed charges	1.7	3.1	3.1	2.4	3.7

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

PECO Energy Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
(In millions, except ratios)	**2013**	**2014**	**2015**	**2016**	**2017**
Pre-tax income from continuing operations	557	466	521	587	538
Less: Capitalized interest	(2)	(2)	(2)	(3)	(3)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	555	464	519	584	535
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	114	112	114	125	128
Interest component of rental expense [a]	7	5	3	2	3
Total fixed charges	121	117	117	127	131
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	676	581	636	711	666
Ratio of earnings to combined fixed charges	5.6	5.0	5.4	5.6	5.1

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

PECO Energy Company
Ratio of Earnings to Fixed Charges and Preferred Stock Dividends

	Years Ended December 31,				
(In millions, except ratios)	**2013**	**2014**	**2015**	**2016**	**2017**
Pre-tax income from continuing operations	557	466	521	587	538
Less: Capitalized interest	(2)	(2)	(2)	(3)	(3)
Preference security dividend requirements	(10)	—	—	—	—
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements	545	464	519	584	535
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	114	112	114	125	128
Interest component of rental expense [a]	7	5	3	2	3
Preference security dividend requirements	10	—	—	—	—
Total fixed charges	131	117	117	127	131
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	676	581	636	711	666
Ratio of earnings to fixed charges and preferred stock dividends	5.2	5.0	5.4	5.6	5.1

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

BGE
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
(In millions, except ratios)	**2013**	**2014**	**2015**	**2016**	**2017**
Pre-tax income from continuing operations	344	351	477	468	525
Less: Capitalized interest	(6)	(12)	(14)	(11)	(6)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	338	339	463	457	519
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	127	118	113	115	110
Interest component of rental expense [a]	4	4	11	7	11
Total fixed charges	131	122	124	122	121
Pre-tax income from continuing operations after adjustment for income or loss from equity investees,					
capitalized interest and preference security dividend requirements plus fixed charges	469	461	587	579	640
Ratio of earnings to fixed charges	3.6	3.8	4.7	4.7	5.3

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

BGE
Ratio of Earnings to Fixed Charges and Preference Stock Dividends

	Years Ended December 31,				
(In millions, except ratios)	**2013**	**2014**	**2015**	**2016**	**2017**
Pre-tax income from continuing operations	344	351	477	468	525
Less: Capitalized interest	(6)	(12)	(14)	(11)	(6)
Preference security dividend requirements	(21)	(22)	(22)	(13)	—
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	317	317	441	444	519
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	127	118	113	115	110
Interest component of rental expense [a]	4	4	11	7	11
Preference security dividend requirements	21	22	22	13	—
Total fixed charges	152	144	146	135	121
Pre-tax income from continuing operations after adjustment for income or loss from equity investees, capitalized interest and preference security dividend requirements plus fixed charges	469	461	587	579	640
Ratio of earnings to fixed charges and preferred stock dividends	3.1	3.2	4.0	4.3	5.3

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Pepco Holdings LLC and Subsidiary Companies

Ratio of Earnings to Fixed Charges

	Predecessor				*Successor*	
	Years Ended December 31,					**Year Ended December 31,**
(In millions, except ratios)	**2013**	**2014**	**2015**	**January 1, 2016 to March 23, 2016**	**March 24, 2016 to December 31, 2016**	**2017**
Pre-tax income from continuing operations	304	380	481	36	(58)	578
Plus: (Income) loss from equity investees	(2)	—	—	—	—	—
Less: Capitalized interest	(2)	(3)	(2)	(3)	(12)	(18)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	300	377	479	33	(70)	560
Fixed Charges:						
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	279	276	288	69	210	261
Interest component of rental expense [a]	22	24	24	4	16	21
Total fixed charges	301	300	312	73	226	282
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	601	677	791	106	156	842
Ratio of earnings to fixed charges	2.0	2.3	2.5	1.5	0.7 [b]	3.0

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.
(b) The ratio coverage was less than 1:1. The registrant must generate additional earnings of $70 million to achieve a coverage ratio of 1:1.

Potomac Electric Power Company
Ratio of Earnings to Fixed Charges

(In millions, except ratios)	Years Ended December 31, 2013	2014	2015	2016	2017
Pre-tax income from continuing operations	235	264	289	83	310
Less: Capitalized interest	(1)	(2)	(1)	(10)	(12)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	234	262	288	73	298
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	114	121	130	137	131
Interest component of rental expense [(a)]	7	7	7	3	4
Total fixed charges	121	128	137	140	135
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	355	390	425	213	433
Ratio of earnings to fixed charges	2.9	3.0	3.1	1.5	3.2

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Delmarva Power & Light Company
Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
(In millions, except ratios)	**2013**	**2014**	**2015**	**2016**	**2017**
Pre-tax income from continuing operations	146	169	125	13	192
Less: Capitalized interest	—	—	—	(2)	(3)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	146	169	125	11	189
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	52	49	50	51	53
Interest component of rental expense [(a)]	3	4	4	5	5
Total fixed charges	55	53	54	56	58
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	201	222	179	67	247
Ratio of earnings to fixed charges	3.7	4.2	3.3	1.2	4.3

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.

Atlantic City Electric Company and Subsidiary Company

Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
(In millions, except ratios)	**2013**	**2014**	**2015**	**2016**	**2017**
Pre-tax income from continuing operations	78	76	73	(46)	103
Less: Capitalized interest	—	—	—	(3)	(3)
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest	78	76	73	(49)	100
Fixed Charges:					
Interest expensed and capitalized, amortization of debt discount and premium on all indebtedness	68	64	65	64	63
Interest component of rental expense [a]	4	4	4	4	5
Total fixed charges	72	68	69	68	68
Pre-tax income from continuing operations after adjustment for income or loss from equity investees and capitalized interest plus fixed charges	150	144	142	19	168
Ratio of earnings to fixed charges	2.1	2.1	2.1	0.3 [b]	2.5

(a) Represents one-third of rental expense relating to operating leases, which is a reasonable approximation of the interest factor.
(b) The ratio coverage was less than 1:1. The registrant must generate additional earnings of $49 million to achieve a coverage ratio of 1:1.

Exelon Corporation (50% and Greater)
12/31/2017

Subsidiary	Jurisdiction
2014 ESA HoldCo, LLC	Delaware
2014 ESA Project Company, LLC	Delaware
2015 ESA Holdco, LLC	Delaware
2015 ESA Investco, LLC	Delaware
2015 ESA Project Company, LLC	Delaware
A/C Fuels Company	Pennsylvania
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Albany Green Energy, LLC	Georgia
American Energy Corporation	Delaware
AMP Funding, L.L.C.	Delaware
Annova LNG Brownsville A, LLC	Delaware
Annova LNG Brownsville B, LLC	Delaware
Annova LNG Brownsville C, LLC	Delaware
Annova LNG Common Infrastructure, LLC	Delaware
Annova LNG, LLC	Delaware
Annova LNG, LLC, Series A Units	Delaware
Annova LNG, LLC, Series B Units	Delaware
Annova LNG, LLC, Series C Units	Delaware
Annova LNG, LLC, Series Z Units	Delaware
APS Constellation, LLC	Delaware
ATE Investment, Inc.	Delaware
Atlantic City Electric Company	New Jersey
Atlantic City Electric Transition Funding LLC	Delaware
Atlantic Generation, Inc.	New Jersey
Atlantic Southern Properties, Inc.	New Jersey
ATNP Finance Company	Delaware
AV Solar Ranch 1, LLC	Delaware
Baltimore Gas and Electric Company	Maryland
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
Bethlehem Renewable Energy, LLC	Delaware
BGE Capital Trust II	Delaware
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon

Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Blue Ridge Renewable Energy, LLC	Delaware
Bluestem Wind Energy Holdings, LLC	Delaware
Bluestem Wind Energy Member Holdings, LLC	Delaware
Bluestem Wind Energy Member, LLC	Delaware
Bluestem Wind Energy, LLC	Delaware
Butter Creek Power, LLC	Oregon
California PV Energy 2, LLC	Delaware
California PV Energy 3, LLC	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Nuclear, LLC	Delaware
CER Generation, LLC	Delaware
CEU Arkoma West, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Niobrara, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU W&D, LLC	Delaware
Chesapeake HVAC, Inc.	Delaware
Chester Transmission Construction Canada, Inc.	California
Christoffer Wind Energy I LLC	Minnesota

Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton Battery Utility, LLC	Delaware
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware
CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
CoLa Resources LLC	Delaware
Colorado Bend I Power, LLC	Delaware
Colorado Bend II Power, LLC	Delaware
Colorado Bend Services, LLC	Delaware
ComEd Financing III	Delaware
Commonwealth Edison Company	Illinois
Commonwealth Edison Company of Indiana, Inc.	Indiana
Conectiv Communications, Inc.	Delaware
Conectiv Energy Supply, Inc.	Delaware
Conectiv North East, LLC	Delaware
Conectiv Properties and Investments, Inc.	Delaware
Conectiv Services, Inc.	Delaware
Conectiv Solutions LLC	Delaware
Conectiv, LLC	Delaware
Constellation Connect, LLC	Delaware
Constellation DCO Albany Power Holdings, LLC	Delaware
Constellation EG, LLC	Delaware
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Gas Choice, LLC	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Power Choice, LLC	Delaware
Constellation Energy Resources, LLC	Delaware
Constellation Energy Upstream Holdings, LLC	Delaware
Constellation ESCO, LLC	Delaware
Constellation Holdings, LLC	Maryland
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy - Gas Division, LLC	Kentucky
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware

Constellation Nuclear, LLC	Delaware
Constellation Power Source Generation, LLC	Maryland
Constellation Power, Inc.	Maryland
Constellation Solar Arizona 2, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Georgia 2, LLC	Delaware
Constellation Solar Georgia, LLC	Georgia
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware
Constellation Solar MC, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey IV, LLC	Delaware
Constellation Solar New Jersey V, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar Texas, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CR Clearing, LLC	Missouri
Criterion Power Partners, LLC	Delaware
Delaware Operating Services Company, LLC	Delaware
Delmarva Power & Light Company	Delaware & Virginia
Denver Airport Solar, LLC	Delaware
Distributed Generation Partners, LLC	Delaware
Eastern Landfill Gas, LLC	Delaware

Energy Performance Services, Inc.	Pennsylvania
ETT Canada, Inc.	New Brunswick
Ewington Energy Systems LLC	Minnesota
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Business Services Company, LLC	Delaware
Exelon Energy Delivery Company, LLC	Delaware
Exelon Enterprises Company, LLC	Pennsylvania
Exelon FitzPatrick, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Fulton, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation Limited	United Kingdom
Exelon Mechanical, LLC	Delaware
Exelon Microgrid, LLC	Delaware
Exelon New Boston, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon Solar Chicago LLC	Delaware
Exelon Transmission Company, LLC	Delaware
Exelon West Medway II, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	California
Exelon Wind, LLC	Delaware

Exelon Wyman, LLC	Delaware
Ex-FM, Inc.	New York
Ex-FME, Inc.	Delaware
ExGen Energy, S. de R.L. de C.V.	Mexico
ExGen Handley Power, LLC	Delaware
ExGen Renewables Holdings II, LLC	Delaware
ExGen Renewables Holdings, LLC	Delaware
ExGen Renewables I Holding, LLC	Delaware
ExGen Renewables I, LLC	Delaware
ExGen Renewables II, LLC	Delaware
ExGen Renewables IV Holding, LLC	Delaware
ExGen Renewables IV, LLC	Delaware
ExGen Renewables Partners, LLC	Delaware
ExGen Texas II Power Holdings, LLC	Delaware
ExGen Texas II Power, LLC	Delaware
ExGen Texas Power Holdings, LLC	Delaware
ExGen Texas Power Services, LLC	Delaware
ExGen Texas Power, LLC	Delaware
ExGen Ventures International Holdings II Limited	United Kingdom
ExGen Ventures International Holdings Limited	United Kingdom
ExTel Corporation, LLC	Delaware
F & M Holdings Company, L.L.C.	Delaware
Fair Wind Power Partners, LLC	Delaware
Fauquier Landfill Gas, L.L.C.	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
Friendly Skies, Inc.	Virgin Islands, U.S.
Gateway Solar LLC	Delaware
Grande Prairie Generation, Inc.	Alberta
Greensburg Wind Farm, LLC	Delaware
Handley Power, LLC	Delaware
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho
JExel Nuclear Company	Japan
K & D Energy LLC	Minnesota

KC Energy LLC	Minnesota
KSS Turbines LLC	Minnesota
Lake Houston Power, LLC	Delaware
LaPorte Power, LLC	Delaware
Loess Hills Wind Farm, LLC	Missouri
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Millennium Account Services, LLC	Delaware
Minergy LLC	Wisconsin
Mohave Sunrise Solar I, LLC	Arizona
Mountain Creek Power, LLC	Delaware
Mountain Top Wind Power, LLC	Maryland
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Northwind Thermal Technologies Canada Inc.	New Brunswick
Oregon Trail Windfarm, LLC	Oregon
Outback Solar, LLC	Oregon
Pacific Canyon Windfarm, LLC	Oregon
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
PCI - BT Investing, L.L.C.	Delaware
PCI Air Management Corporation	Nevada
PCI Air Management Partners, L.L.C.	Delaware
PCI Energy Corporation	Delaware
PCI Engine Trading Ltd.	Bermuda
PCI Ever, Inc.	Delaware
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Company	Pennsylvania
PECO Wireless, LLC	Delaware
Pegasus Power Company, Inc.	California

Pepco Building Services Inc.	Delaware
Pepco Energy Cogeneration LLC	Delaware
Pepco Energy Solutions LLC	Delaware
Pepco Government Services LLC	Delaware
Pepco Holdings LLC	Delaware
PH Holdco LLC	Delaware
PHI Service Company	Delaware
Pinedale Energy, LLC	Colorado
POM Holdings, Inc.	Delaware
Potomac Capital Investment Corporation	Delaware
Potomac Delaware Leasing Corporation	Delaware
Potomac Electric Power Company	District of Columbia & Virgina
Potomac Leasing Associates, L.P.	Delaware
Potomac Power Resources, LLC	Delaware
Prairie Wind Power LLC	Minnesota
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Ramp Investments, L.L.C.	Delaware
Renewable Power Generation Holdings, LLC	Delaware
Renewable Power Generation, LLC	Delaware
Residential Solar Holding, LLC	Delaware
Residential Solar II, LLC	Delaware
RF HoldCo LLC	Delaware
RITELine Illinois, LLC	Illinois
RITELine Transmission Development, LLC	Delaware
Rolling Hills Landfill Gas, LLC	Delaware
RSB BondCo LLC	Delaware
Sacramento PV Energy, LLC	Delaware
Sand Ranch Windfarm, LLC	Oregon
Scherer Holdings 1, LLC	Delaware
Scherer Holdings 2, LLC	Delaware
Scherer Holdings 3, LLC	Delaware
Sendero Wind Energy, LLC	Delaware
Severn Construction Services, L.L.C.	Delaware
Shooting Star Wind Project, LLC	Delaware
Sky Valley, LLC	Delaware
SolGen Holding, LLC	Delaware
SolGen, LLC	Delaware
Sugar Beet Wind, LLC	Delaware
Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware

Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware
Tuana Springs Energy, LLC	Idaho
UII, LLC	Illinois
Vineland Cogeneration Limited Partnership	Delaware
Vineland General, Inc.	Delaware
Vineland Ltd., Inc.	Delaware
W&D Gas Partners, LLC	Delaware
W.A. Chester Corporation	Delaware
W.A. Chester, L.L.C.	Delaware
Wagon Trail, LLC	Oregon
Wansley Holdings 1, LLC	Delaware
Wansley Holdings 2, LLC	Delaware
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Western Path Development, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Wolf Hollow I Power, LLC	Delaware
Wolf Hollow II Power, LLC	Delaware
Wolf Hollow Services, LLC	Delaware

Exelon Generation Company, LLC (50% and Greater)
12/31/2017

Subsidiary	Jurisdiction
2014 ESA HoldCo, LLC	Delaware
2014 ESA Project Company, LLC	Delaware
2015 ESA Holdco, LLC	Delaware
2015 ESA Investco, LLC	Delaware
2015 ESA Project Company, LLC	Delaware
A/C Fuels Company	Pennsylvania
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
Albany Green Energy, LLC	Georgia
Annova LNG Brownsville A, LLC	Delaware
Annova LNG Brownsville B, LLC	Delaware
Annova LNG Brownsville C, LLC	Delaware
Annova LNG Common Infrastructure, LLC	Delaware
Annova LNG, LLC	Delaware
Annova LNG, LLC, Series A Units	Delaware
Annova LNG, LLC, Series B Units	Delaware
Annova LNG, LLC, Series C Units	Delaware
Annova LNG, LLC, Series Z Units	Delaware
APS Constellation, LLC	Delaware
ATE Investment, Inc.	Delaware
Atlantic Generation, Inc.	New Jersey
AV Solar Ranch 1, LLC	Delaware
BC Energy LLC	Minnesota
Beebe 1B Renewable Energy, LLC	Delaware
Beebe Renewable Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
Bethlehem Renewable Energy, LLC	Delaware
BGE Home Products & Services, LLC	Delaware
Big Top, LLC	Oregon
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Blue Ridge Renewable Energy, LLC	Delaware
Bluestem Wind Energy Holdings, LLC	Delaware
Bluestem Wind Energy Member Holdings, LLC	Delaware
Bluestem Wind Energy Member, LLC	Delaware
Bluestem Wind Energy, LLC	Delaware
Butter Creek Power, LLC	Oregon
California PV Energy 2, LLC	Delaware

California PV Energy 3, LLC	Delaware
California PV Energy, LLC	Delaware
Calvert Cliffs Nuclear Power Plant, LLC	Maryland
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
CD Panther I, Inc.	Maryland
CD Panther II, LLC	Delaware
CD Panther Partners, L.P.	Delaware
CD SEGS V, Inc.	Maryland
CD SEGS VI, Inc.	Maryland
CE Culm, Inc.	Maryland
CE FundingCo, LLC	Delaware
CE Nuclear, LLC	Delaware
CER Generation, LLC	Delaware
CEU Arkoma West, LLC	Delaware
CEU CoLa, LLC	Delaware
CEU East Fort Peck, LLC	Delaware
CEU Fayetteville, LLC	Delaware
CEU Floyd Shale, LLC	Delaware
CEU Holdings, LLC	Delaware
CEU Huntsville, LLC	Delaware
CEU Kingston, LLC	Delaware
CEU Niobrara, LLC	Delaware
CEU Ohio Shale, LLC	Delaware
CEU Paradigm, LLC	Delaware
CEU Pinedale, LLC	Delaware
CEU Plymouth, LLC	Delaware
CEU Simplicity, LLC	Delaware
CEU W&D, LLC	Delaware
Chesapeake HVAC, Inc.	Delaware
Chester Transmission Construction Canada, Inc.	California
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
CII Solarpower I, Inc.	Maryland
Cisco Wind Energy LLC	Minnesota
Clinton Battery Utility, LLC	Delaware
CLT Energy Services Group, L.L.C.	Pennsylvania
CNE Gas Holdings, LLC	Kentucky
CNE Gas Supply, LLC	Delaware

CNEG Holdings, LLC	Delaware
CNEGH Holdings, LLC	Delaware
CoLa Resources LLC	Delaware
Colorado Bend I Power, LLC	Delaware
Colorado Bend II Power, LLC	Delaware
Colorado Bend Services, LLC	Delaware
Conectiv Energy Supply, Inc.	Delaware
Conectiv North East, LLC	Delaware
Conectiv, LLC	Delaware
Constellation Connect, LLC	Delaware
Constellation DCO Albany Power Holdings, LLC	Delaware
Constellation EG, LLC	Delaware
Constellation Energy Canada, Inc.	Ontario
Constellation Energy Commodities Group Maine, LLC	Delaware
Constellation Energy Gas Choice, LLC	Delaware
Constellation Energy Nuclear Group, LLC	Maryland
Constellation Energy Power Choice, LLC	Delaware
Constellation Energy Resources, LLC	Delaware
Constellation Energy Upstream Holdings, LLC	Delaware
Constellation ESCO, LLC	Delaware
Constellation Holdings, LLC	Maryland
Constellation Mystic Power, LLC	Delaware
Constellation NewEnergy - Gas Division, LLC	Kentucky
Constellation NewEnergy, Inc.	Delaware
Constellation Nuclear Power Plants, LLC	Delaware
Constellation Nuclear, LLC	Delaware
Constellation Power Source Generation, LLC	Maryland
Constellation Power, Inc.	Maryland
Constellation Solar Arizona 2, LLC	Delaware
Constellation Solar Arizona, LLC	Delaware
Constellation Solar California, LLC	Delaware
Constellation Solar Connecticut, LLC	Delaware
Constellation Solar DC, LLC	Delaware
Constellation Solar Federal, LLC	Delaware
Constellation Solar Georgia 2, LLC	Delaware
Constellation Solar Georgia, LLC	Georgia
Constellation Solar Holding, LLC	Delaware
Constellation Solar Horizons, LLC	Delaware
Constellation Solar Maryland II, LLC	Delaware
Constellation Solar Maryland, LLC	Delaware
Constellation Solar Massachusetts, LLC	Delaware

Constellation Solar MC, LLC	Delaware
Constellation Solar Net Metering, LLC	Delaware
Constellation Solar New Jersey II, LLC	Delaware
Constellation Solar New Jersey III, LLC	Delaware
Constellation Solar New Jersey IV, LLC	Delaware
Constellation Solar New Jersey V, LLC	Delaware
Constellation Solar New Jersey, LLC	Delaware
Constellation Solar New York, LLC	Delaware
Constellation Solar Ohio, LLC	Delaware
Constellation Solar Texas, LLC	Delaware
Constellation Solar, LLC	Delaware
Continental Wind Holding, LLC	Delaware
Continental Wind, LLC	Delaware
COSI Central Wayne, Inc.	Maryland
COSI Sunnyside, Inc.	Maryland
Cow Branch Wind Power, L.L.C.	Missouri
CP Sunnyside I, Inc.	Maryland
CP Windfarm, LLC	Minnesota
CR Clearing, LLC	Missouri
Criterion Power Partners, LLC	Delaware
Delaware Operating Services Company, LLC	Delaware
Denver Airport Solar, LLC	Delaware
Distributed Generation Partners, LLC	Delaware
Eastern Landfill Gas, LLC	Delaware
Energy Performance Services, Inc.	Pennsylvania
Ewington Energy Systems LLC	Minnesota
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon FitzPatrick, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Fulton, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation Limited	United Kingdom
Exelon New Boston, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon Nuclear Partners International S.a r.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania

Exelon Solar Chicago LLC	Delaware
Exelon West Medway II, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind Canada Inc.	California
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
ExGen Energy, S. de R.L. de C.V.	Mexico
ExGen Handley Power, LLC	Delaware
ExGen Renewables Holdings II, LLC	Delaware
ExGen Renewables Holdings, LLC	Delaware
ExGen Renewables I Holding, LLC	Delaware
ExGen Renewables I, LLC	Delaware
ExGen Renewables II, LLC	Delaware
ExGen Renewables IV Holding, LLC	Delaware
ExGen Renewables IV, LLC	Delaware
ExGen Renewables Partners, LLC	Delaware
ExGen Texas II Power Holdings, LLC	Delaware
ExGen Texas II Power, LLC	Delaware
ExGen Texas Power Holdings, LLC	Delaware
ExGen Texas Power Services, LLC	Delaware
ExGen Texas Power, LLC	Delaware
ExGen Ventures International Holdings II Limited	United Kingdom
ExGen Ventures International Holdings Limited	United Kingdom
Fair Wind Power Partners, LLC	Delaware
Fauquier Landfill Gas, L.L.C.	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Fourmile Wind Energy, LLC	Maryland
Gateway Solar LLC	Delaware
Grande Prairie Generation, Inc.	Alberta

Greensburg Wind Farm, LLC	Delaware
Handley Power, LLC	Delaware
Handsome Lake Energy, LLC	Maryland
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Mesa Energy, LLC	Idaho
High Plains Wind Power, LLC	Texas
Holyoke Solar, LLC	Delaware
Hot Springs Windfarm, LLC	Idaho
JExel Nuclear Company	Japan
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
KSS Turbines LLC	Minnesota
Lake Houston Power, LLC	Delaware
LaPorte Power, LLC	Delaware
Loess Hills Wind Farm, LLC	Missouri
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Michigan Wind 3, LLC	Delaware
Minergy LLC	Wisconsin
Mohave Sunrise Solar I, LLC	Arizona
Mountain Creek Power, LLC	Delaware
Mountain Top Wind Power, LLC	Maryland
Nine Mile Point Nuclear Station, LLC	Delaware
North Shore District Energy, LLC	Delaware
Oregon Trail Windfarm, LLC	Oregon
Outback Solar, LLC	Oregon
Pacific Canyon Windfarm, LLC	Oregon
Panther Creek Holdings, Inc.	Delaware
Panther Creek Partners	Delaware
Pegasus Power Company, Inc.	California
Pepco Building Services Inc.	Delaware
Pepco Energy Cogeneration LLC	Delaware
Pepco Energy Solutions LLC	Delaware
Pepco Government Services LLC	Delaware

Pinedale Energy, LLC	Colorado
Potomac Power Resources, LLC	Delaware
Prairie Wind Power LLC	Minnesota
R.E. Ginna Nuclear Power Plant, LLC	Maryland
Renewable Power Generation Holdings, LLC	Delaware
Renewable Power Generation, LLC	Delaware
Residential Solar Holding, LLC	Delaware
Residential Solar II, LLC	Delaware
Rolling Hills Landfill Gas, LLC	Delaware
Sacramento PV Energy, LLC	Delaware
Sand Ranch Windfarm, LLC	Oregon
Sendero Wind Energy, LLC	Delaware
Severn Construction Services, L.L.C.	Delaware
Shooting Star Wind Project, LLC	Delaware
Sky Valley, LLC	Delaware
SolGen Holding, LLC	Delaware
SolGen, LLC	Delaware
Sugar Beet Wind, LLC	Delaware
Sunnyside II, Inc.	Delaware
Sunnyside II, L.P.	Delaware
Sunnyside III, Inc.	Delaware
Threemile Canyon Wind I, LLC	Oregon
Titan STC, LLC	Delaware
Tuana Springs Energy, LLC	Idaho
Vineland Cogeneration Limited Partnership	Delaware
Vineland General, Inc.	Delaware
Vineland Ltd., Inc.	Delaware
W&D Gas Partners, LLC	Delaware
W.A. Chester Corporation	Delaware
W.A. Chester, L.L.C.	Delaware
Wagon Trail, LLC	Oregon
Ward Butte Windfarm, LLC	Oregon
Water & Energy Savings Company, LLC	Delaware
Whitetail Wind Energy, LLC	Delaware
Wildcat Finance, LLC	Delaware
Wildcat Wind LLC	New Mexico
Wind Capital Holdings, LLC	Missouri
Wolf Hollow I Power, LLC	Delaware
Wolf Hollow II Power, LLC	Delaware
Wolf Hollow Services, LLC	Delaware

Commonwealth Edison Company (50% and Greater)
12/31/2017

Subsidiary	Jurisdiction
ComEd Financing III	Delaware
Commonwealth Edison Company of Indiana, Inc.	Indiana
RITELine Illinois, LLC	Illinois

PECO Energy Company (50% and Greater)
12/31/2017

Subsidiary	Jurisdiction
ATNP Finance Company	Delaware
ExTel Corporation, LLC	Delaware
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Wireless, LLC	Delaware

Baltimore Gas and Electric Company (50% and Greater)
12/31/2017

Subsidiary	Jurisdiction
BGE Capital Trust II	Delaware
RSB BondCo LLC	Delaware

Pepco Holdings LLC (50% and Greater)
12/31/2017

Subsidiary	Jurisdiction
Atlantic City Electric Company	New Jersey
Atlantic City Electric Transition Funding LLC	Delaware
Delmarva Power & Light Company	Delaware & Virginia
Millennium Account Services, LLC	Delaware
PHI Service Company	Delaware
Potomac Electric Power Company	District of Columbia & Virginia
POM Holdings, Inc.	Delaware

Potomac Electric Power Company (50% and Greater)
12/31/2017

Subsidiary	Jurisdiction
POM Holdings, Inc.	Delaware

Delmarva Power & Light Company
12/31/2017

Subsidiary	Jurisdiction
N/A	

Atlantic City Electric Company (50% and Greater)
12/31/2017

Subsidiary	Jurisdiction
Atlantic City Electric Transition Funding LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-213383), Form S-4 (No. 333-209209) and on Form S-8 (No. 333-219037, No. 333-215114, No.333-189849, No.333-175162, No.333-127377, No.333-37082, No.333-49780 and No. 333-61390) of Exelon Corporation of our report dated February 9, 2018 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2018

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-213383-06) and Form S-4 (No. 333-184712) of Exelon Generation Company, LLC of our report dated February 9, 2018 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 9, 2018

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-213383-05) of Commonwealth Edison Company of our report dated February 9, 2018 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2018

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-213383-04) of PECO Energy Company of our report dated February 9, 2018 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 9, 2018

Exhibit 23.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-213383-03) of Baltimore Gas and Electric Company of our report dated February 9, 2018 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 9, 2018

Exhibit 23.6

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-213383-02) of Potomac Electric Power Company of our report dated February 9, 2018, relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 9, 2018

Exhibit 23.7

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-213383-01) of Delmarva Power & Light Company of our report dated February 9, 2018, relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 9, 2018

Exhibit 23.8

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-3 (No. 333-213383-07) of Atlantic City Electric Company of our report dated February 9, 2018, relating to the financial statements and financial statement schedule, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Washington, D.C.
February 9, 2018

Exhibit 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anthony K. Anderson** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ANTHONY K. ANDERSON

Anthony K. Anderson

DATE: January 30, 2018

Exhibit 24.2

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin,** do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ANN C. BERZIN

Ann C. Berzin

DATE: January 30, 2018

Exhibit 24.3

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Thomas S. O'Neill attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

DATE: January 30, 2018

Exhibit 24.4

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Yves C. de Balmann** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ YVES C. DE BALMANN

Yves C. de Balmann

DATE: January 30, 2018

Exhibit 24.5

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ NICHOLAS DEBENEDICTIS

Nicholas DeBenedictis

DATE: January 30, 2018

Exhibit 24.6

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nancy L. Gioia** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ NANCY L. GIOIA

Nancy L. Gioia

DATE: January 30, 2018

Exhibit 24.7

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Linda P. Jojo** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ LINDA P. JOJO

Linda P. Jojo

DATE: January 30, 2018

Exhibit 24.8

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Paul Joskow** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ PAUL JOSKOW

Paul Joskow

DATE: January 30, 2018

Exhibit 24.9

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Robert J. Lawless** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ROBERT J. LAWLESS

Robert J. Lawless

DATE: January 30, 2018

Exhibit 24.10

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Richard W. Mies** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ RICHARD W. MIES

Richard W. Mies

DATE: January 30, 2018

Exhibit 24.12

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John W. Rogers, Jr.** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ JOHN W. ROGERS, JR.

John W. Rogers, Jr.

DATE: January 30, 2018

Exhibit 24.13

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Mayo A. Shattuck III** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ MAYO A. SHATTUCK III

Mayo A. Shattuck III

DATE: January 30, 2018

Exhibit 24.14

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Stephen D. Steinour** , do hereby appoint Christopher M. Crane and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ STEPHEN D. STEINOUR

Stephen D. Steinour

DATE: January 30, 2018

Exhibit 24.15

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James W. Compton** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ JAMES W. COMPTON

James W. Compton

DATE: February 1, 2018

Exhibit 24.16

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

DATE: January 30, 2018

Exhibit 24.17

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **A. Steven Crown** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ A. STEVEN CROWN

A. Steven Crown

DATE: January 30, 2018

Exhibit 24.18

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ NICHOLAS DEBENEDICTIS

Nicholas DeBenedictis

DATE: January 30, 2018

Exhibit 24.19

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Peter V. Fazio, Jr.** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ PETER V. FAZIO, JR.

Peter V. Fazio, Jr.

DATE: February 2, 2018

Exhibit 24.20

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael H. Moskow** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ MICHAEL H. MOSKOW

Michael H. Moskow

DATE: February 1, 2018

Exhibit 24.21

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Anne R. Pramaggiore and Verónica Gómez, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

DATE: January 30, 2018

Exhibit 24.22

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Anne R. Pramaggiore** , do hereby appoint Verónica Gómez attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ANNE R. PRAMAGGIORE

Anne R. Pramaggiore

DATE: February 1, 2018

Exhibit 24.25

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Craig L. Adams** , do hereby appoint Romulo L. Diaz, Jr. attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CRAIG L. ADAMS

Craig L. Adams

DATE: January 31, 2018

Exhibit 24.26

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

DATE: January 30, 2018

Exhibit 24.27

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **M. Walter D'Alessio** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ M. WALTER D'ALESSIO

M. Walter D'Alessio

DATE: January 31, 2018

Exhibit 24.28

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ NICHOLAS DEBENEDICTIS

Nicholas DeBenedictis

DATE: January 30, 2018

Exhibit 24.29

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nelson A. Diaz** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ NELSON A. DIAZ

Nelson A. Diaz

DATE: February 1, 2018

Exhibit 24.30

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Rosemarie B. Greco** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ROSEMARIE B. GRECO

Rosemarie B. Greco

DATE: February 2, 2018

Exhibit 24.31

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Charisse R. Lillie** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHARISSE R. LILLIE

Charisse R. Lillie

DATE: February 5, 2018

Exhibit 24.32

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Craig L. Adams and Romulo L. Diaz, Jr., or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

DATE: January 30, 2018

Exhibit 24.34

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ann C. Berzin** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ANN C. BERZIN

Ann C. Berzin

DATE: January 30, 2018

Exhibit 24.35

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Calvin G. Butler, Jr.,** do hereby appoint Daniel P. Gahagan attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CALVIN G. BUTLER, JR.

Calvin G. Butler, Jr.

DATE: January 31, 2018

Exhibit 24.36

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

DATE: January 30, 2018

Exhibit 24.37

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael E. Cryor** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ MICHAEL E. CRYOR

Michael E. Cryor

DATE: February 5, 2018

Exhibit 24.38

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James R. Curtiss** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ JAMES R. CURTISS

James R. Curtiss

DATE: February 5, 2018

Exhibit 24.39

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Joseph Haskins, Jr.** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ JOSEPH HASKINS, JR.

Joseph Haskins, Jr.

DATE: February 2, 2018

Exhibit 24.40

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

DATE: January 30, 2018

Exhibit 24.41

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael D. Sullivan** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ MICHAEL D. SULLIVAN

Michael D. Sullivan

DATE: February 3, 2018

Exhibit 24.42

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Maria Harris Tildon** , do hereby appoint Calvin G. Butler, Jr. and Daniel P. Gahagan, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Baltimore Gas & Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ MARIA HARRIS TILDON

Maria Harris Tildon

DATE: January 31, 2018

Exhibit 24.43

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

Date: January 30, 2018

Exhibit 24.44

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Linda Cropp** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ LINDA CROPP

Linda Cropp

Date: February 4, 2018

Exhibit 24.45

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael E. Cryor** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ MICHAEL CRYOR

Michael Cryor

Date: February 1, 2018

Exhibit 24.46

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ernest Dianastasis** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ ERNEST DIANASTASIS

Ernest Dianastasis

Date: February 2, 2018

Exhibit 24.47

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Debra P. DiLorenzo** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DEBRA P. DILORENZO

Debra P. DiLorenzo

Date: February 2, 2018

Exhibit 24.48

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

Date: January 30, 2018

Exhibit 24.49

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **David M. Velazquez** , do hereby appoint Wendy E. Stark as attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Pepco Holdings LLC, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DAVID M. VELAZQUEZ

David M. Velazquez

DATE: January 31, 2018

Exhibit 24.50

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **J. Tyler Anthony** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ J. TYLER ANTHONY

J. Tyler Anthony

DATE: February 1, 2018

Exhibit 24.51

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Christopher M. Crane** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane

DATE: January 30, 2018

Exhibit 24.52

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Donna J. Kinzel** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DONNA J. KINZEL

Donna J. Kinzel

DATE: January 31, 2018

Exhibit 24.53

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Kevin M. McGowan** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ KEVIN M. MCGOWAN

Kevin M. McGowan

DATE: January 31, 2018

Exhibit 24.54

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

DATE: January 30, 2018

Exhibit 24.55

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **David M. Velazquez** , do hereby appoint Wendy E. Stark, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Potomac Electric Power Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DAVID M. VELAZQUEZ

David M. Velazquez

DATE: January 31, 2018

Exhibit 24.56

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Denis P. O'Brien** , do hereby appoint David M. Velazquez and Wendy E. Stark, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Delmarva Power & Light Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DENIS P. O'BRIEN

Denis P. O'Brien

DATE: January 30, 2018

Exhibit 24.57

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **David M. Velazquez** , do hereby appoint Wendy E. Stark as attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Delmarva Power & Light Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DAVID M. VELAZQUEZ

David M. Velazquez

DATE: January 31, 2018

Exhibit 24.58

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **David M. Velazquez** , do hereby appoint Wendy E. Stark as attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10-K for 2017 of Atlantic City Electric Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ DAVID M. VELAZQUEZ

David M. Velazquez

DATE: January 31, 2018

Exhibit 31.1

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Christopher M. Crane

President and Chief Executive Officer

(Principal Executive Officer)

Date: February 9, 2018

Exhibit 31.2

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Jonathan W. Thayer

Senior Executive Vice President and Chief Financial Officer

(Principal Financial Officer)

Date: February 9, 2018

Exhibit 31.3

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Kenneth W. Cornew

President and Chief Executive Officer

(Principal Executive Officer)

Date: February 9, 2018

Exhibit 31.4

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this annual report on Form 10-K of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Bryan P. Wright

Senior Vice President and Chief Financial Officer

(Principal Financial Officer)

Date: February 9, 2018

Exhibit 31.5

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Anne R. Pramaggiore

President and Chief Executive Officer

(Principal Executive Officer)

Date: February 9, 2018

Exhibit 31.6

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Joseph R. Trpik, Jr.

Senior Vice President, Chief Financial Officer and Treasurer

(Principal Financial Officer)

Date: February 9, 2018

Exhibit 31.7

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Craig L. Adams

President and Chief Executive Officer

(Principal Executive Officer)

Date: February 9, 2018

Exhibit 31.8

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this annual report on Form 10-K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Phillip S. Barnett

Senior Vice President, Chief Financial Officer and Treasurer

(Principal Financial Officer)

Date: February 9, 2018

Exhibit 31.9

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Calvin G. Butler, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Calvin G. Butler, Jr.

Chief Executive Officer

(Principal Executive Officer)

Date: February 9, 2018

Exhibit 31.10

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Vahos, certify that:

1. I have reviewed this annual report on Form 10-K of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ David M. Vahos

Senior Vice President, Chief Financial Officer and Treasurer

(Principal Financial Officer)

Date: February 9, 2018

Exhibit 31.11

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this annual report on Form 10-K of Pepco Holdings LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ D AVID M. V ELAZQUEZ

President and Chief Executive Officer

(Principal Executive Officer)

Date: February 9, 2018

Exhibit 31.12

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this annual report on Form 10-K of Pepco Holdings LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DONNA J. KINZEL

Senior Vice President, Chief Financial Officer and Treasurer

(Principal Financial Officer)

Date: February 9, 2018

Exhibit 31.13

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this annual report on Form 10-K of Potomac Electric Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ D AVID M. V ELAZQUEZ

President and Chief Executive Officer

(Principal Executive Officer)

Date: February 9, 2018

Exhibit 31.14

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this annual report on Form 10-K of Potomac Electric Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DONNA J. KINZEL

Senior Vice President, Chief Financial Officer and Treasurer

(Principal Financial Officer)

Date: February 9, 2018

Exhibit 31.15

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this annual report on Form 10-K of Delmarva Power & Light Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DAVID M. VELAZQUEZ

President and Chief Executive Officer

(Principal Executive Officer)

Date: February 9, 2018

Exhibit 31.16

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this annual report on Form 10-K of Delmarva Power & Light Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DONNA J. KINZEL

Senior Vice President, Chief Financial Officer and Treasurer

(Principal Financial Officer)

Date: February 9, 2018

Exhibit 31.17

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Velazquez, certify that:

1. I have reviewed this annual report on Form 10-K of Atlantic City Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DAVID M. VELAZQUEZ

President and Chief Executive Officer

(Principal Executive Officer)

Date: February 9, 2018

Exhibit 31.18

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Donna J. Kinzel, certify that:

1. I have reviewed this annual report on Form 10-K of Atlantic City Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DONNA J. KINZEL

Senior Vice President, Chief Financial Officer and Treasurer

(Principal Financial Officer)

Date: February 9, 2018

Exhibit 32.1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ Christopher M. Crane

Christopher M. Crane

President and Chief Executive Officer

Date: February 9, 2018

Exhibit 32.2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Corporation for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ Jonathan W. Thayer

Jonathan W. Thayer

Senior Executive Vice President and Chief Financial Officer

Date: February 9, 2018

Exhibit 32.3

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ Kenneth W. Cornew

Kenneth W. Cornew

President and Chief Executive Officer

Date: February 9, 2018

Exhibit 32.4

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Exelon Generation Company, LLC for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ Bryan P. Wright

Bryan P. Wright

Senior Vice President and Chief Financial Officer

Date: February 9, 2018

Exhibit 32.5

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ Anne R. Pramaggiore

Anne R. Pramaggiore

President and Chief Executive Officer

Date: February 9, 2018

Exhibit 32.6

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Commonwealth Edison Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ Joseph R. Trpik, Jr.

Joseph R. Trpik, Jr.

Senior Vice President, Chief Financial Officer and Treasurer

Date: February 9, 2018

Exhibit 32.7

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ Craig L. Adams

Craig L. Adams

President and Chief Executive Officer

Date: February 9, 2018

Exhibit 32.8

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of PECO Energy Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ Phillip S. Barnett

Phillip S. Barnett

Senior Vice President, Chief Financial Officer and Treasurer

Date: February 9, 2018

Exhibit 32.9

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ Calvin G. Butler, Jr.

Calvin G. Butler, Jr.

Chief Executive Officer

Date: February 9, 2018

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Baltimore Gas and Electric Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ David M. Vahos

David M. Vahos

Senior Vice President, Chief Financial Officer and Treasurer

Date: February 9, 2018

Exhibit 32.11

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Pepco Holdings LLC for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Pepco Holdings LLC.

/s/ David M. Velazquez

David M. Velazquez

President and Chief Executive Officer

Date: February 9, 2018

Exhibit 32-12

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Pepco Holdings LLC for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Pepco Holdings LLC.

/s/ Donna J. Kinzel

Donna J. Kinzel

Senior Vice President, Chief Financial Officer and Treasurer

Date: February 9, 2018

Exhibit 32.13

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Potomac Electric Power Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Potomac Electric Power Company.

/s/ David M. Velazquez

David M. Velazquez

President and Chief Executive Officer

Date: February 9, 2018

Exhibit 32.14

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Potomac Electric Power Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Potomac Electric Power Company.

/s/ Donna J. Kinzel

Donna J. Kinzel

Senior Vice President, Chief Financial Officer and Treasurer

Date: February 9, 2018

Exhibit 32.15

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Delmarva Power & Light Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Delmarva Power & Light Company.

/s/ David M. Velazquez

David M. Velazquez

President and Chief Executive Officer

Date: February 9, 2018

Exhibit 32.16

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Delmarva Power & Light Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Delmarva Power & Light Company.

/s/ Donna J. Kinzel

Donna J. Kinzel

Senior Vice President, Chief Financial Officer and Treasurer

Date: February 9, 2018

Exhibit 32.17

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Atlantic City Electric Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Atlantic City Electric Company.

/s/ David M. Velazquez

David M. Velazquez

President and Chief Executive Officer

Date: February 9, 2018

Exhibit 32.18

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10-K of Atlantic City Electric Company for the year ended December 31, 2017 , that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Atlantic City Electric Company.

/s/ Donna J. Kinzel

Donna J. Kinzel

Senior Vice President, Chief Financial Officer and Treasurer

Date: February 9, 2018

10-Qs

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2013
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of July 16, 2013, Public Service Enterprise Group Incorporated had outstanding 505,857,262 shares of its sole class of Common Stock, without par value.

As of July 16, 2013, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, July 30, 2013 Powered by Morningstar® Document Research℠
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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1. Financial Statements—Note 9. Commitments and Contingent Liabilities, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations, and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC). These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission in the future, and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to balance our energy obligations, available supply and risks,
- any deterioration in our credit quality or the credit quality of our counterparties, including in our leveraged leases,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to sufficiently obtain coverage or recover proceeds of insurance on such matters,
- increases in competition in energy supply markets as well as competition for certain rate-based transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements, and
- changes in technology and customer usage patterns.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
OPERATING REVENUES	$ 2,310	$ 2,098	$ 5,096	$ 4,973
OPERATING EXPENSES				
Energy Costs	755	761	1,910	1,940
Operation and Maintenance	646	629	1,356	1,257
Depreciation and Amortization	283	255	573	511
Taxes Other Than Income Taxes	14	20	35	49
Total Operating Expenses	1,698	1,665	3,874	3,757
OPERATING INCOME	612	433	1,222	1,216
Income from Equity Method Investments	3	2	5	2
Other Income	52	51	113	95
Other Deductions	(13)	(19)	(42)	(35)
Other-Than-Temporary Impairments	(2)	(7)	(4)	(12)
Interest Expense	(101)	(103)	(203)	(204)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	551	357	1,091	1,062
Income Tax Expense	(218)	(146)	(438)	(358)
NET INCOME	$ 333	$ 211	$ 653	$ 704
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):				
BASIC	505,900	505,903	505,921	505,956
DILUTED	507,381	506,969	507,301	506,999
EARNINGS PER SHARE:				
BASIC				
INCOME FROM CONTINUING OPERATIONS	$ 0.66	$ 0.42	$ 1.29	$ 1.39
NET INCOME	$ 0.66	$ 0.42	$ 1.29	$ 1.39
DILUTED				
INCOME FROM CONTINUING OPERATIONS	$ 0.66	$ 0.42	$ 1.29	$ 1.39
NET INCOME	$ 0.66	$ 0.42	$ 1.29	$ 1.39
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.3600	$ 0.3550	$ 0.7200	$ 0.7100

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See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
NET INCOME	$ 333	$ 211	$ 653	$ 704
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $16, $17, $(11) and $(21) for the three and six months ended 2013 and 2012, respectively	(16)	(15)	11	22
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $0, $3, $0 and $(11) for the three and six months ended 2013 and 2012, respectively	—	(5)	—	15
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $1, $2, $3 and $17 for the three and six months ended 2013 and 2012, respectively	—	(5)	(4)	(25)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(7), $(6), $(14) and $(11) for the three and six months ended 2013 and 2012, respectively	9	8	19	15
Other Comprehensive Income (Loss), net of tax	(7)	(17)	26	27
COMPREHENSIVE INCOME	$ 326	$ 194	$ 679	$ 731

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 164	$ 379
Accounts Receivable, net of allowances of $61 and $56 in 2013 and 2012, respectively	1,133	1,069
Tax Receivable	226	227
Unbilled Revenues	257	314
Fuel	481	583
Materials and Supplies, net	435	422
Prepayments	312	283
Derivative Contracts	142	138
Deferred Income Taxes	32	49
Regulatory Assets	396	349
Other	37	56
Total Current Assets	3,615	3,869
PROPERTY, PLANT AND EQUIPMENT	28,515	27,402
Less: Accumulated Depreciation and Amortization	(7,954)	(7,666)
Net Property, Plant and Equipment	20,561	19,736
NONCURRENT ASSETS		
Regulatory Assets	3,628	3,830
Regulatory Assets of Variable Interest Entities (VIEs)	603	713
Long-Term Investments	1,323	1,324
Nuclear Decommissioning Trust (NDT) Fund	1,580	1,540
Other Special Funds	183	191
Goodwill	16	16
Other Intangibles	41	34
Derivative Contracts	161	153
Restricted Cash of VIEs	23	23
Other	325	296
Total Noncurrent Assets	7,883	8,120
TOTAL ASSETS	$ 32,059	$ 31,725

See Notes to Condensed Consolidated Financial Statements.

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Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, July 30, 2013 Powered by Morningstar® Document Research℠
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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2013	December 31, 2012
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 576	$ 1,026
Securitization Debt of VIEs Due Within One Year	232	226
Commercial Paper and Loans	157	263
Accounts Payable	1,046	1,304
Derivative Contracts	42	46
Accrued Interest	97	91
Accrued Taxes	31	17
Deferred Income Taxes	46	72
Clean Energy Program	204	153
Obligation to Return Cash Collateral	121	122
Regulatory Liabilities	120	67
Other	386	390
Total Current Liabilities	3,058	3,777
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	6,686	6,542
Regulatory Liabilities	215	209
Regulatory Liabilities of VIEs	11	10
Asset Retirement Obligations	644	627
Other Postretirement Benefit (OPEB) Costs	1,272	1,285
Accrued Pension Costs	717	876
Clean Energy Program	27	—
Environmental Costs	449	537
Derivative Contracts	158	122
Long-Term Accrued Taxes	167	164
Other	116	108
Total Noncurrent Liabilities	10,462	10,480
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	7,033	6,148
Securitization Debt of VIEs	385	496
Project Level, Non-Recourse Debt	24	43
Total Long-Term Debt	7,442	6,687
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2013 and 2012—533,556,660 shares	4,842	4,833
Treasury Stock, at cost, 2013— 27,699,398 shares; 2012— 27,664,188 shares	(615)	(607)
Retained Earnings	7,231	6,942
Accumulated Other Comprehensive Loss	(362)	(388)
Total Common Stockholders' Equity	11,096	10,780
Noncontrolling Interest	1	1
Total Stockholders' Equity	11,097	10,781
Total Capitalization	18,539	17,468
TOTAL LIABILITIES AND CAPITALIZATION	$ 32,059	$ 31,725

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17253

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, July 30, 2013 Powered by Morningstar® Document Research℠
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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2013	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 653	$ 704
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	573	511
Amortization of Nuclear Fuel	95	84
Provision for Deferred Income Taxes (Other than Leases) and ITC	146	165
Non-Cash Employee Benefit Plan Costs	122	134
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(26)	(98)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	20	(86)
Deferred Storm Costs	(81)	5
Net Change in Other Regulatory Assets and Liabilities	62	(94)
Cost of Removal	(46)	(44)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(47)	(26)
Net Change in Certain Current Assets and Liabilities	24	278
Employee Benefit Plan Funding and Related Payments	(194)	(175)
Other	42	20
Net Cash Provided By (Used In) Operating Activities	1,343	1,378
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,406)	(1,280)
Proceeds from Sale of Capital Leases and Investments	42	1
Proceeds from Sales of Available-for-Sale Securities	681	850
Investments in Available-for-Sale Securities	(684)	(867)
Other	(12)	(43)
Net Cash Provided By (Used In) Investing Activities	(1,379)	(1,339)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(106)	16
Issuance of Long-Term Debt	900	500
Redemption of Long-Term Debt, including Securitization Debt	(556)	(240)
Cash Dividends Paid on Common Stock	(364)	(359)
Other	(53)	(25)
Net Cash Provided By (Used In) Financing Activities	(179)	(108)
Net Increase (Decrease) in Cash and Cash Equivalents	(215)	(69)
Cash and Cash Equivalents at Beginning of Period	379	834
Cash and Cash Equivalents at End of Period	$ 164	$ 765
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 138	$ 114
Interest Paid, Net of Amounts Capitalized	$ 194	$ 197
Accrued Property, Plant and Equipment Expenditures	$ 222	$ 207

See Notes to Condensed Consolidated Financial Statements.

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Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, July 30, 2013 Powered by Morningstar® Document Research℠
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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
OPERATING REVENUES	$ 1,190	$ 985	$ 2,637	$ 2,546
OPERATING EXPENSES				
Energy Costs	496	447	1,356	1,269
Operation and Maintenance	280	284	562	525
Depreciation and Amortization	65	58	129	115
Total Operating Expenses	841	789	2,047	1,909
OPERATING INCOME	349	196	590	637
Other Income	35	37	82	67
Other Deductions	(10)	(17)	(38)	(32)
Other-Than-Temporary Impairments	(2)	(7)	(4)	(12)
Interest Expense	(29)	(32)	(59)	(62)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	343	177	571	598
Income Tax Expense	(139)	(73)	(230)	(241)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 204	$ 104	$ 341	$ 357

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17256

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, July 30, 2013 Powered by Morningstar® Document Research℠
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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
NET INCOME	$ 204	$ 104	$ 341	$ 357
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $16, $17, $(11) and $(22) for the three and six months ended 2013 and 2012, respectively	(14)	(15)	13	22
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $0, $3, $0 and $(11) for the three and six months ended 2013 and 2012, respectively	—	(5)	—	15
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $1, $2, $3 and $17 for the three and six months ended 2013 and 2012, respectively	(1)	(5)	(5)	(25)
Pension/OPEB adjustment, net of tax (expense) benefit of $(6), $(5), $(11) and $(10) for the three and six months ended 2013 and 2012, respectively	8	7	17	14
Other Comprehensive Income (Loss), net of tax	(7)	(18)	25	26
COMPREHENSIVE INCOME	$ 197	$ 86	$ 366	$ 383

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17257

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 4	$ 7
Accounts Receivable	279	269
Accounts Receivable—Affiliated Companies, net	145	340
Short-Term Loan to Affiliate	395	574
Fuel	481	583
Materials and Supplies, net	312	307
Derivative Contracts	106	118
Prepayments	12	17
Other	12	19
Total Current Assets	1,746	2,234
PROPERTY, PLANT AND EQUIPMENT	9,811	9,697
Less: Accumulated Depreciation and Amortization	(2,857)	(2,679)
Net Property, Plant and Equipment	6,954	7,018
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,580	1,540
Goodwill	16	16
Other Intangibles	42	34
Other Special Funds	38	36
Derivative Contracts	58	49
Other	136	105
Total Noncurrent Assets	1,870	1,780
TOTAL ASSETS	$ 10,570	$ 11,032

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17258

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND MEMBER'S EQUITY	June 30, 2013	December 31, 2012
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ —	$ 300
Accounts Payable	384	498
Derivative Contracts	42	46
Deferred Income Taxes	4	16
Accrued Interest	27	26
Other	94	81
Total Current Liabilities	551	967
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	1,690	1,575
Asset Retirement Obligations	380	369
Other Postretirement Benefit (OPEB) Costs	227	221
Derivative Contracts	20	15
Accrued Pension Costs	228	272
Long-Term Accrued Taxes	39	50
Other	89	84
Total Noncurrent Liabilities	2,673	2,586
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
LONG-TERM DEBT		
Total Long-Term Debt	2,041	2,040
MEMBER'S EQUITY		
Contributed Capital	2,028	2,028
Basis Adjustment	(986)	(986)
Retained Earnings	4,566	4,725
Accumulated Other Comprehensive Loss	(303)	(328)
Total Member's Equity	5,305	5,439
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 10,570	$ 11,032

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17259

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2013	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 341	$ 357
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	129	115
Amortization of Nuclear Fuel	95	84
Provision for Deferred Income Taxes and ITC	74	184
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	20	(86)
Non-Cash Employee Benefit Plan Costs	33	34
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(47)	(26)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	97	94
Margin Deposit	(8)	36
Accounts Receivable	25	40
Accounts Payable	(77)	(14)
Accounts Receivable/Payable-Affiliated Companies, net	197	73
Other Current Assets and Liabilities	(8)	(6)
Employee Benefit Plan Funding and Related Payments	(44)	(39)
Other	27	6
Net Cash Provided By (Used In) Operating Activities	854	852
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(222)	(344)
Proceeds from Sales of Available-for-Sale Securities	625	677
Investments in Available-for-Sale Securities	(637)	(692)
Short-Term Loan—Affiliated Company, net	179	170
Net Cash Provided By (Used In) Investing Activities	(55)	(189)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	(500)	(600)
Redemption of Long-Term Debt	(300)	(66)
Other	(2)	(7)
Net Cash Provided By (Used In) Financing Activities	(802)	(673)
Net Increase (Decrease) in Cash and Cash Equivalents	(3)	(10)
Cash and Cash Equivalents at Beginning of Period	7	12
Cash and Cash Equivalents at End of Period	$ 4	$ 2
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 60	$ 118
Interest Paid, Net of Amounts Capitalized	$ 56	$ 57
Accrued Property, Plant and Equipment Expenditures	$ 33	$ 49

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17260

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
OPERATING REVENUES	$ 1,423	$ 1,407	$ 3,418	$ 3,346
OPERATING EXPENSES				
Energy Costs	580	622	1,547	1,624
Operation and Maintenance	369	350	796	726
Depreciation and Amortization	207	188	422	378
Taxes Other Than Income Taxes	14	20	35	49
Total Operating Expenses	1,170	1,180	2,800	2,777
OPERATING INCOME	253	227	618	569
Other Income	15	12	28	23
Other Deductions	(1)	(1)	(2)	(2)
Interest Expense	(75)	(74)	(148)	(147)
INCOME BEFORE INCOME TAXES	192	164	496	443
Income Tax Expense	(71)	(63)	(196)	(145)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 121	$ 101	$ 300	$ 298

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17261

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
NET INCOME	$ 121	$ 101	$ 300	$ 298
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0, $0 and $1 for the three and six months ended 2013 and 2012, respectively	(1)	—	(1)	(1)
COMPREHENSIVE INCOME	$ 120	$ 101	$ 299	$ 297

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17262

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 19	$ 116
Accounts Receivable, net of allowances of $61 and $56 in 2013 and 2012, respectively	834	783
Accounts Receivable-Affiliated Companies, net	59	—
Unbilled Revenues	257	314
Materials and Supplies	120	114
Prepayments	221	29
Regulatory Assets	396	349
Derivative Contracts	21	5
Deferred Income Taxes	32	49
Other	17	24
Total Current Assets	1,976	1,783
PROPERTY, PLANT AND EQUIPMENT	18,015	17,006
Less: Accumulated Depreciation and Amortization	(4,851)	(4,726)
Net Property, Plant and Equipment	13,164	12,280
NONCURRENT ASSETS		
Regulatory Assets	3,628	3,830
Regulatory Assets of VIEs	603	713
Long-Term Investments	361	348
Other Special Funds	42	61
Derivative Contracts	76	62
Restricted Cash of VIEs	23	23
Other	121	123
Total Noncurrent Assets	4,854	5,160
TOTAL ASSETS	$ 19,994	$ 19,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17263

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	June 30, 2013	December 31, 2012
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 575	$ 725
Securitization Debt of VIEs Due Within One Year	232	226
Commercial Paper and Loans	157	263
Accounts Payable	510	630
Accounts Payable—Affiliated Companies, net	—	73
Accrued Interest	70	65
Clean Energy Program	204	153
Deferred Income Taxes	47	60
Obligation to Return Cash Collateral	121	122
Regulatory Liabilities	120	67
Other	257	269
Total Current Liabilities	2,293	2,653
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,288	4,223
Other Postretirement Benefit (OPEB) Costs	990	1,011
Accrued Pension Costs	364	463
Regulatory Liabilities	215	209
Regulatory Liabilities of VIEs	11	10
Clean Energy Program	27	—
Environmental Costs	398	486
Asset Retirement Obligations	256	250
Derivative Contracts	138	107
Long-Term Accrued Taxes	43	32
Other	47	38
Total Noncurrent Liabilities	6,777	6,829
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	4,965	4,070
Securitization Debt of VIEs	385	496
Total Long-Term Debt	5,350	4,566
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2013 and 2012 —132,450,344 shares	892	892
Contributed Capital	520	420
Basis Adjustment	986	986
Retained Earnings	3,175	2,875
Accumulated Other Comprehensive Income	1	2
Total Stockholder's Equity	5,574	5,175
Total Capitalization	10,924	9,741
TOTAL LIABILITIES AND CAPITALIZATION	$ 19,994	$ 19,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17264

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2013	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 300	$ 298
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	422	378
Provision for Deferred Income Taxes and ITC	75	75
Non-Cash Employee Benefit Plan Costs	78	89
Cost of Removal	(46)	(44)
Deferred Storm Costs	(81)	5
Net Change in Other Regulatory Assets and Liabilities	62	(94)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	6	108
Materials and Supplies	(6)	(8)
Prepayments	(192)	(126)
Accounts Payable	47	(24)
Accounts Receivable/Payable-Affiliated Companies, net	(137)	(94)
Other Current Assets and Liabilities	8	13
Employee Benefit Plan Funding and Related Payments	(134)	(121)
Other	19	4
Net Cash Provided By (Used In) Operating Activities	421	459
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,148)	(870)
Proceeds from Sale of Available-for-Sale Securities	32	71
Investments in Available-for-Sale Securities	(13)	(71)
Solar Loan Investments	(15)	(48)
Restricted Funds	—	3
Net Cash Provided By (Used In) Investing Activities	(1,144)	(915)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	(106)	16
Issuance of Long-Term Debt	900	500
Redemption of Long-Term Debt	(150)	(73)
Redemption of Securitization Debt	(106)	(101)
Contributed Capital	100	—
Other	(12)	(7)
Net Cash Provided By (Used In) Financing Activities	626	335
Net Increase (Decrease) In Cash and Cash Equivalents	(97)	(121)
Cash and Cash Equivalents at Beginning of Period	116	143
Cash and Cash Equivalents at End of Period	$ 19	$ 22
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 110	$ 4
Interest Paid, Net of Amounts Capitalized	$ 135	$ 139
Accrued Property, Plant and Equipment Expenditures	$ 189	$ 158

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17265

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This combined Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information relating to any individual company is filed by such company on its own behalf. Power and PSE&G each is only responsible for information about itself and its subsidiaries.

Note 1. Organization and Basis of Presentation

Organization

PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's four principal direct wholly owned subsidiaries are:

- **Power**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through three principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and the states in which they operate.
- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the FERC. PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs, which are regulated by the BPU.
- **PSEG Energy Holdings L.L.C. (Energy Holdings)**—which primarily has investments in leases and solar generation projects through its direct wholly owned subsidiaries. Certain Energy Holdings' subsidiaries are subject to regulation by the FERC and the states in which they operate. Energy Holdings has also been awarded a contract to manage the transmission and distribution assets of the Long Island Power Authority (LIPA) starting in 2014.
- **PSEG Services Corporation (Services)**—which provides management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2012 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2013.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All significant intercompany accounts and transactions are eliminated in consolidation, except as discussed in Note 18. Related-Party Transactions. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2012.

Note 2. Recent Accounting Standards

New Standards Adopted during 2013

Disclosures about Offsetting Assets and Liabilities

This accounting standard requires enhanced disclosures regarding assets and liabilities that are either offset in the financial statements, or are subject to an enforceable master netting arrangement or similar agreement. The guidance is applicable to certain financial instruments (e.g. derivatives) and securities borrowing and lending transactions. This standard requires entities:

- to disclose information about offsetting and related arrangements to enable users of financial statements to understand the effect of those arrangements on an entity's financial position, and

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- to present both net (offset amounts) and gross information in the notes to the financial statements for relevant assets and liabilities.

We adopted this standard retrospectively effective January 1, 2013. As this standard requires disclosures only, it did not have any impact on our consolidated financial position, results of operations or cash flows. For additional information, see Note 11. Financial Risk Management Activities.

Reclassification Adjustments out of Accumulated Other Comprehensive Income (AOCI)

This accounting standard requires entities to disclose the following information about reclassification adjustments related to AOCI:

- changes in AOCI balances by component; and
- significant amounts reclassified out of AOCI by respective line items of net income (for amounts that are required by GAAP to be reclassified to net income in their entirety in the same reporting period).

We adopted this standard prospectively effective January 1, 2013. As this standard requires disclosures only, it did not have any impact on our consolidated financial position, results of operations or cash flows. For additional information, see Note 15. Accumulated Other Comprehensive Income (Loss), Net of Tax.

New Accounting Standards Issued But Not Yet Adopted

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

This accounting standard was issued to address diversity in practice related to the presentation of an unrecognized tax benefit in certain cases. This standard requires entities to present an unrecognized tax benefit or a portion thereof on the Balance Sheet as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward.

However, in cases in which a net operating loss carryforward, a similar tax loss or a tax credit carryforward is not available at the reporting date under the tax law of the jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or the tax law of the jurisdiction does not require an entity to use, and the entity does not intend to use the deferred tax asset for such purpose, the unrecognized tax benefit will be presented on the Balance Sheet as a liability and will not be combined with deferred tax assets.

The standard is effective for fiscal years and interim periods beginning after December 15, 2013. We are currently analyzing the impact of this standard to our financial statements.

Note 3. Variable Interest Entities (VIEs)

Variable Interest Entities for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of these VIEs are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the Transition Funding and Transition Funding II assets are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II, respectively.

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of June 30, 2013 and December 31, 2012. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II during the first six months of 2013 or in 2012. Further, PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II.

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Note 4. Asset Disposition

In June 2013, Energy Holdings closed on the sale of its investments in a commercial office complex for proceeds of $41 million, resulting in an after-tax gain of $6 million.

Note 5. Rate Filings

The following information discusses significant updates regarding orders and pending rate filings. This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2012.

- ***Weather Normalization Clause (WNC)***—In April 2013, the BPU approved PSE&G's filing with respect to deficiency revenues from the 2011-2012 Winter Period. As a result, provisional rates were approved to recover $41 million from customers during the 2012-2013 Winter Period, with a carryover deficiency of $24 million to the 2013-2014 Winter Period. In July 2013, PSE&G filed a petition with the BPU seeking approval to recover $26 million in revenues from its customers during the 2013-2014 Winter Period inclusive of the $24 million carryover deficiency.
- ***Solar and Energy Efficiency Recovery Charges (formerly RRC and currently Green Program Recovery Charges (GPRC))*** —In May 2013, the BPU approved PSE&G's 2012 request for an increase in GPRC to recover approximately $62 million in additional electric revenue and $8 million in additional gas revenue, on an annual basis. In June 2013, PSE&G filed a petition with the BPU requesting a decrease in GPRC of approximately $1 million in electric revenue and $1 million in gas revenue, on an annual basis for the six Green Programs.

Note 6. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with Solar Renewable Energy Certificates (SRECs) generated from the installed solar electric system. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of June 30, 2013	As of December 31, 2012
	Millions	
Commercial/Industrial	$ 188	$ 174
Residential	16	15
Total	**$ 204**	**$ 189**

Energy Holdings

Energy Holdings, through various of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

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The table below shows Energy Holdings' gross and net lease investment as of June 30, 2013 and December 31, 2012, respectively.

	As of June 30, 2013	As of December 31, 2012
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 705	$ 721
Estimated Residual Value of Leased Assets	529	535
	1,234	1,256
Unearned and Deferred Income	(409)	(416)
Gross Investments in Leases	825	840
Deferred Tax Liabilities	(687)	(723)
Net Investments in Leases	**$ 138**	**$ 117**

The corresponding receivables associated with the lease portfolio are reflected below, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. "Not Rated" counterparties represent investments in lease receivables related to coal-fired assets and commercial real estate properties.

	Lease Receivables, Net of Non-Recourse Debt	
Counterparties' Credit Rating (Standard & Poor's (S&P))		
As of June 30, 2013	**As of June 30, 2013**	**As of December 31, 2012**
	Millions	
AA	$ 20	$ 21
AA-	58	73
BBB+ - BBB-	316	316
B	166	166
Not Rated	145	145
Total	**$ 705**	**$ 721**

The "B" rating and the "Not Rated" above include lease receivables related to coal-fired assets in Pennsylvania and Illinois, respectively. As of June 30, 2013, the gross investment in the leases of such assets, net of non-recourse debt, was $561 million ($40 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

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Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counter-parties' S&P Credit Ratings	Counterparty
		Millions		MW			
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	Not Rated	Edison Mission Energy
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	Not Rated	Edison Mission Energy
Keystone Station Units 1 and 2	PA	$ 116	17%	1,711	Coal	B	GenOn REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 117	17%	1,711	Coal	B	GenOn REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 110	100%	603	Coal	B	GenOn REMA, LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Indirect subsidiary companies of Energy Holdings lease three coal-fired generation facilities in Pennsylvania (Keystone, Conemaugh and Shawville) to GenOn REMA, LLC (GenOn REMA), a subsidiary of GenOn Energy Inc. (GenOn), which was acquired by NRG Energy, Inc. in December 2012. With respect to addressing various environmental controls: Keystone has installed a flue gas desulfurization (FGD) system for sulfur dioxide (SO_2), selective catalytic reduction (SCR) equipment for nitrogen oxide (NOx) and mercury control; Conemaugh has a FGD system, while SCR and mercury control equipment are scheduled to be installed and operational by the first quarter of 2015; and GenOn has disclosed its plan to place Shawville in a “long-term protective layup” by April 2015. GenOn has stated that it is evaluating whether to continue to pay the required rent and maintain the facility in accordance with the lease terms or terminate the lease for obsolescence in which case the lessee would be required, among other things, to pay the contractual termination value structured to recover Energy Holdings' indirect subsidiaries' lease investment as specified in the lease agreement.

Although all lease payments from the GenOn REMA leases are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

Nesbitt Asset Recovery, LLC (Nesbitt), (an indirect, wholly owned subsidiary of Energy Holdings), owns approximately 64% of the lease interest in the Powerton and Joliet coal units in Illinois, with the balance held by Associates Capital Investments, L.L.P. (Associates) (an affiliate of Citigroup, and, together with Nesbitt, the "Owner Participants"). These facilities are leased to Midwest Generation (MWG), an indirect subsidiary of Edison Mission Energy (EME).

On December 17, 2012, EME and MWG filed for relief under Chapter 11 of the U.S. Bankruptcy Code. Immediately prior to that filing, EME, MWG and the Owner Participants, as well as certain affiliated owner lessors, entered into a forbearance agreement with holders of a majority of the lease debt that financed the original sale-leaseback transaction. The forbearance agreement, which was approved by the bankruptcy court, expired on April 5, 2013. In June 2013, the parties reached an agreement, which was approved by the Bankruptcy Court, to again extend the deadline for MWG to assume or reject the leases until September 30, 2013. As part of this settlement, (i) MWG will make partial lease payments of $4 million each month during the extension period starting in July 2013, (ii) the unpaid rent for the utilization of the facilities by MWG during pendency of the bankruptcy will be treated as an administrative expense in bankruptcy and (iii) the parties agree to not reject

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the leases or foreclose on assets under lease during the extension period. Nesbitt is actively involved in the bankruptcy proceedings and continues to evaluate its options with respect to this lease.

MWG has substantially completed investments in mercury removal (Activated Carbon Injection) and NOx emission controls (low NOx burners and Selective Non-Catalytic Reduction systems), and plans to invest in SO_2 emission controls (Dry Sorbent Injection (Trona) systems). On April 4, 2013, MWG obtained approval from the Illinois Pollution Control Board to defer capital investments for up to two additional years to meet upcoming air emission compliance deadlines under Illinois law. Also, on July 8, 2013, the US Court of Appeals affirmed the judgment of the lower court dismissing claims brought by the U.S. Environmental Protection Agency (EPA) and the State of Illinois against EME and MWG for alleged violations of the Clean Air Act.

Note 7. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Fund

Power maintains an external master nuclear decommissioning trust to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third-party investment advisers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund:

	As of June 30, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 636	$ 202	$ (9)	$ 829
Debt Securities				
Government Obligations	388	5	(8)	385
Other Debt Securities	311	11	(4)	318
Total Debt Securities	699	16	(12)	703
Other Securities	48	—	—	48
Total NDT Available-for-Sale Securities	**$ 1,383**	**$ 218**	**$ (21)**	**$ 1,580**

	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 648	$ 147	$ (6)	$ 789
Debt Securities				
Government Obligations	274	11	—	285
Other Debt Securities	320	22	—	342
Total Debt Securities	594	33	—	627
Other Securities	124	—	—	124
Total NDT Available-for-Sale Securities	**$ 1,366**	**$ 180**	**$ (6)**	**$ 1,540**

These amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

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	As of June 30, 2013	As of December 31, 2012
	Millions	
Accounts Receivable	$ 45	$ 18
Accounts Payable	$ 57	$ 53

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of June 30, 2013				As of December 31, 2012			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 148	$ (9)	$ —	$ —	$ 139	$ (6)	$ —	$ —
Debt Securities								
Government Obligations (B)	208	(8)	1	—	34	—	1	—
Other Debt Securities (C)	146	(4)	2	—	31	—	6	—
Total Debt Securities	354	(12)	3	—	65	—	7	—
Other Securities	—	—	—	—	—	—	—	—
NDT Available-for-Sale Securities	**$ 502**	**$ (21)**	**$ 3**	**$ —**	**$ 204**	**$ (6)**	**$ 7**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of June 30, 2013.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency asset-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of June 30, 2013.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2013.

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The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	Millions			
Proceeds from NDT Fund Sales	$ 376	$ 290	$ 617	$ 635
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	23	26	60	42
Gross Realized Losses	(6)	(16)	(25)	(22)
Net Realized Gains (Losses) on NDT Fund	**$ 17**	**$ 10**	**$ 35**	**$ 20**

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $97 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheet as of June 30, 2013.

The NDT available-for-sale debt securities held as of June 30, 2013 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 58
1 - 5 years	171
6 - 10 years	191
11 - 15 years	39
16 - 20 years	9
Over 20 years	235
Total NDT Available-for-Sale Debt Securities	**$ 703**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2013, other-than-temporary impairments of $4 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as the "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

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	As of June 30, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 14	$ 7	$ —	$ 21
Debt Securities				
Government Obligations	110	1	(1)	110
Other Debt Securities	43	1	—	44
Total Debt Securities	153	2	(1)	154
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 169**	**$ 9**	**$ (1)**	**$ 177**

Securities in the Rabbi Trust in a gross unrealized loss position have been in such position for less than twelve months.

	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 13	$ 5	$ —	$ 18
Debt Securities				
Government Obligations	114	3	—	117
Other Debt Securities	45	2	—	47
Total Debt Securities	159	5	—	164
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 175**	**$ 10**	**$ —**	**$ 185**

These amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of June 30, 2013	As of December 31, 2012
	Millions	
Accounts Receivable	$ 4	$ 4
Accounts Payable	$ 3	$ 5

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In March 2012, PSEG restructured the fixed income component of the Rabbi Trust. The proceeds from the sales of and the net realized gains on securities in the Rabbi Trust Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	Millions			
Proceeds from Rabbi Trust Sales	**$ 47**	**$ 61**	**$ 64**	**$ 215**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ 4	$ 1	$ 4	$ 6
Gross Realized Losses	(3)	—	(3)	—
Net Realized Gains (Losses) on Rabbi Trust	**$ 1**	**$ 1**	**$ 1**	**$ 6**

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in the Condensed Consolidated Statements of Operations. Net unrealized gains of $4 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of June 30, 2013. The Rabbi Trust available-for-sale debt securities held as of June 30, 2013 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ —
1 - 5 years	59
6 - 10 years	28
11 - 15 years	8
16 - 20 years	5
Over 20 years	54
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 154**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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The fair value of assets in the Rabbi Trust related to PSEG, Power and PSE&G are detailed as follows:

	As of June 30, 2013	As of December 31, 2012
	Millions	
Power	$ 38	$ 36
PSE&G	42	61
Other	97	88
Total Rabbi Trust Available-for-Sale Securities	**$ 177**	**$ 185**

Note 8. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.

Pension and OPEB costs for PSEG are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012	2013	2012	2013	2012
	Millions							
Components of Net Periodic Benefit Cost								
Service Cost	$ 29	$ 25	$ 5	$ 4	$ 58	$ 50	$ 10	$ 8
Interest Cost	53	55	16	16	107	111	32	32
Expected Return on Plan Assets	(87)	(77)	(5)	(5)	(174)	(153)	(10)	(9)
Amortization of Net								
Transition Obligation	—	—	—	—	—	—	—	1
Prior Service Cost (Credit)	(4)	(4)	(3)	(3)	(9)	(9)	(7)	(7)
Actuarial Loss	47	42	10	8	94	84	21	16
Net Periodic Benefit Cost	$ 38	$ 41	$ 23	$ 20	$ 76	$ 83	$ 46	$ 41
Effect of Regulatory Asset	—	—	—	5	—	—	—	10
Total Benefit Costs, Including Effect of Regulatory Asset	**$ 38**	**$ 41**	**$ 23**	**$ 25**	**$ 76**	**$ 83**	**$ 46**	**$ 51**

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Pension and OPEB costs for Power, PSE&G and PSEG's other subsidiaries are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012	2013	2012	2013	2012
	Millions							
Power	$ 11	$ 12	$ 5	$ 4	$ 22	$ 25	$ 11	$ 9
PSE&G	22	25	17	20	45	49	33	40
Other	5	4	1	1	9	9	2	2
Total Benefit Costs	**$ 38**	**$ 41**	**$ 23**	**$ 25**	**$ 76**	**$ 83**	**$ 46**	**$ 51**

During the three months ended March 31, 2013, PSEG contributed its entire planned contributions for the year 2013 of $145 million and $14 million into its pension and postretirement healthcare plans, respectively.

Note 9. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The face value of Power's outstanding guarantees, current exposure and margin positions as of June 30, 2013 and December 31, 2012 are shown below:

	As of June 30, 2013	As of December 31, 2012
	Millions	
Face Value of Outstanding Guarantees	$ 1,569	$ 1,508
Exposure under Current Guarantees	$ 282	$ 226
Letters of Credit Margin Posted	$ 113	$ 124
Letters of Credit Margin Received	$ 38	$ 69
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$ 4	$ 15
Counterparty Cash Margin Received	$ —	$ (4)
Net Broker Balance Deposited (Received)	$ 41	$ 26
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that Could be Required	$ 679	$ 654
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,541	$ 3,531
Additional Amounts Posted		
Other Letters of Credit	$ 46	$ 45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 11. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P's, Moody's and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

The SEC and the Commodity Futures Trading Commission (CFTC) continue efforts to implement new rules to effect stricter regulation over swaps and derivatives. In 2012, the CFTC issued Final Rules regarding the definition of a swap dealer and the definition of a swap, and established reporting and record-keeping requirements for commercial end users including PSEG. In September 2012, a federal court vacated the CFTC's rule on monitoring of position limits for several commodities, including natural gas, thereby indefinitely delaying the effectiveness of these position limits rules. PSEG is carefully monitoring all of these new rules as they are issued to analyze the potential impact on its swap and derivatives transactions, including any potential increase in its collateral requirements.

In addition to amounts for outstanding guarantees, current exposure and margin positions, Power had posted letters of credit to support various other non-energy contractual and environmental obligations. See table above.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The EPA has determined that an eight-mile stretch of the Passaic River in the area of Newark, New Jersey is a "facility" within the meaning of that term under CERCLA. The EPA has determined the need to perform a study of the entire 17-mile tidal reach of the lower Passaic River.

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PSE&G and certain of its predecessors conducted operations at properties in this area on or adjacent to the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites. When the Essex Site was transferred from PSE&G to Power, PSE&G obtained releases and indemnities for liabilities arising out of the former Essex generating station and Power assumed any environmental liabilities.

The EPA notified the potentially responsible parties (PRPs) that the cost of its Remedial Investigation and Feasibility Study (RI/FS) is now estimated at approximately $110 million. Seventy-three PRPs, including Power and PSE&G, agreed to assume responsibility for the RI/FS and formed the Cooperating Parties Group (CPG) to divide the associated costs according to a mutually agreed upon formula. The CPG group, currently seventy members, is presently executing the RI/FS. Approximately five percent of the RI/FS costs were attributable to PSE&G's former MGP sites and approximately one percent to Power's generating stations on an interim basis under the CPG's group agreement. Power has provided notice to insurers concerning this potential claim.

In 2007, the EPA released a draft “Focused Feasibility Study” (FFS) that proposed various options to address the contamination cleanup of the lower eight miles of the Passaic River. The EPA estimated costs for the proposed remedy range from $1.3 billion to $3.7 billion. The work contemplated by the FFS is not subject to the cost sharing agreement discussed above. The EPA's revised proposed FFS may be released for public comment as early as the fourth quarter of 2013.

In June 2008, an agreement was announced between the EPA and Tierra Solutions, Inc. and Maxus Energy Corporation (Tierra/Maxus) for removal of a portion of the contaminated sediment in the Passaic River at an estimated cost of $80 million. Phase I of the removal work has been completed. Phase II is contingent on the approval of an appropriate sediment disposal facility. Tierra/Maxus have reserved their rights to seek contribution for the removal costs from the other PRPs, including Power and PSE&G.

The EPA has advised that the levels of contaminants at Passaic River mile 10.9 will require removal in advance of the completion of the RI/FS. The CPG members, with the exception of Tierra/Maxus, which are no longer members, have agreed to fund the removal, currently estimated at approximately $30 million. PSEG's share of that effort is approximately three percent.

Except for the Passaic River mile 10.9 removal, Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to the Passaic River matters.

New Jersey Spill Compensation and Control Act (Spill Act)

In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit against a PRP (Occidental Chemical Corporation (OCC)) and its related companies in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of the PRP's discharge of hazardous substances into both the Passaic River and the balance of the Newark Bay Complex. Power and PSE&G are alleged to have owned, operated or contributed hazardous substances to a total of 11 sites or facilities that impacted these water bodies. In 2009, third party complaints were filed against some 320 third party defendants, including Power and PSE&G, claiming that each of the third party defendants is responsible for its proportionate share of the clean-up costs for the hazardous substances it allegedly discharged into the Passaic River and the Newark Bay Complex. Power and PSE&G filed answers to the complaints in 2010. On March 22, 2013, Power and PSE&G signed an agreement to settle the NJDEP vs. OCC litigation at a nominal cost. That settlement is contingent upon a public comment and NJDEP response period and the issuance of an order approving the settlement by the Court after conducting a fairness hearing. A stay of third-party discovery remains in place and has been extended. Power and PSE&G believe they have good and valid defenses to the allegations contained in the third party complaints and will vigorously assert those defenses should the matter not settle. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

Natural Resource Damage Claims

In 2003, the NJDEP directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the Spill Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSEG is unable to estimate its portion of the possible loss or range of loss related to this matter.

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Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area and encouraged the PRPs to contact OCC to discuss participating in the RI/FS that OCC was conducting. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but it is uncertain at this time whether the PSEG companies will consent to fund the third phase. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $491 million and $578 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $491 million as of June 30, 2013. Of this amount, $104 million was recorded in Other Current Liabilities and $387 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $491 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a “major modification,” as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Hazardous Air Pollutants Regulation

In accordance with a ruling of the U.S. Court of Appeals of the District of Columbia (Court of Appeals), the EPA published a Maximum Achievable Control Technology (MACT) regulation in February 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the Court of Appeals in support of the EPA's implementation of MATS. Litigation of these matters remains pending and the impact on the implementation schedule is unknown at this time.

Power believes that it will not be necessary to install any additional material controls at its New Jersey facilities. Additional controls may be necessary at Power’s Bridgeport Harbor coal-fired unit at an immaterial cost. In December 2011, to comply with the MACT regulations, a decision was reached to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction (SCR) systems at Power’s jointly owned coal-fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be completed in the first quarter of 2015. Power's share of this investment is approximately $147 million.

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NOx Regulation

In April 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on Power's generation fleet, as it imposes NO_x emissions limits that will require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) and four older New Jersey steam electric generation units (approximately 400 MW) by May 30, 2015. Retirement notifications for the combustion turbines, except for Salem Unit 3, have been filed with the PJM Interconnection, LLC (PJM). The Salem Unit 3 combustion turbine (38 MW) will be transitioning to an emergency generator. Evaluations are ongoing for the steam electric generation units.

Under current Connecticut regulations, Power's Bridgeport and New Haven facilities have been utilizing Discrete Emission Reduction Credits (DERCs) to comply with certain NO_x emission limitations that were incorporated into the facilities' operating permits. In 2010, Power negotiated new agreements with the State of Connecticut extending the continued use of DERCs for certain emission units and equipment until May 31, 2014.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System (NPDES) permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

One of the most significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. Power prepared its renewal application in accordance with the FWPCA Section 316(b) and the 316(b) rules published in 2004.

As a result of several legal challenges to the 2004 316(b) rule by certain northeast states, environmentalists and industry groups, the rule has been suspended and has been returned to the EPA to be consistent with a 2009 United States Supreme Court decision which concluded that the EPA could rely upon cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II regulations.

In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule by July 27, 2012. In April 2011, the EPA published a proposed rule to establish marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. In July 2012, the EPA and environmental groups agreed to delay the deadline to June 27, 2013 for finalization of the Rule. On June 27, 2013, the EPA and environmental groups agreed to further extend the deadline to November 4, 2013.

Power is unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on its future capital requirements, financial condition, results of operations or cash flows. The results of further proceedings on this matter could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would have been approximately $575 million. These cost estimates have not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

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Capital Expenditures

The construction programs of PSEG and its subsidiaries are currently estimated to include a base level total investment of approximately $6.4 billion for the three years ended 2015. The three-year projected capital expenditures for PSEG, Power and PSE&G are as follows:

	2013	2014	2015
		Millions	
Power	$ 400	$ 365	$ 305
PSE&G	2,045	1,765	1,305
Other	95	40	30
Total PSEG	**$ 2,540**	**$ 2,170**	**$ 1,640**

Power's projected capital expenditures include baseline maintenance (investments to replace major parts and enhance operational performance), investments in response to environmental, regulatory or legal mandates and nuclear expansion. PSE&G's projections include material additions and replacements in its transmission and distribution systems to meet expected growth and manage reliability.

In May 2013, the BPU approved increased spending on renewable energy under PSE&G's Solar Loan and Solar 4 All investment programs (Solar Loan III and Solar 4 All Extension, respectively). PSE&G's projected expenditures through 2015 in the table above have been updated to include $215 million under its Solar Loan III and Solar 4 All Extension programs.

Power

During the six months ended June 30, 2013, Power made $171 million of capital expenditures, including interest capitalized during construction (IDC) but excluding $51 million for nuclear fuel, primarily related to various projects at its fossil and nuclear generation stations.

PSE&G

During the six months ended June 30, 2013, PSE&G made $1,167 million of capital expenditures, including $1,148 million of investment in plant, primarily for reliability of transmission and distribution systems and $19 million in solar loan investments. This does not include expenditures for cost of removal, net of salvage, of $46 million, which is included in operating cash flows.

Energy Holdings

Included in Other for 2013 in the preceding table is a 19 MW solar project currently under construction in Arizona for which Energy Holdings had issued an outstanding guarantee of $20 million as of June 30, 2013.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements for customers who do not purchase electric supply from third party suppliers through the annual New Jersey BGS auctions. Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with Power, as well as with other winning BGS suppliers, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

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PSE&G has contracted for its anticipated BGS-Fixed Price eligible load, as follows:

	Auction Year				
	2010	2011	2012	2013	
36-Month Terms Ending	May 2013	May 2014	May 2015	May 2016	(A)
Load (MW)	2,800	2,800	2,900	2,800	
$ per kWh	0.09577	0.09430	0.08388	0.09218	

(A) Prices set in the 2013 BGS auction became effective on June 1, 2013 when the 2010 BGS auction agreements expired.

PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 18. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power has various long-term fuel purchase commitments for coal through 2017 to support its fossil generation stations and for supply of nuclear fuel for the Salem, Hope Creek and Peach Bottom nuclear generating stations and for firm transportation and storage capacity for natural gas.

Power's strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2015 and a portion through 2017 at Salem, Hope Creek and Peach Bottom.

Power's various multi-year contracts for firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

As of June 30, 2013, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2017
	Millions
Nuclear Fuel	
Uranium	$ 470
Enrichment	$ 368
Fabrication	$ 137
Natural Gas	$ 953
Coal	$ 493

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Regulatory Proceedings

New Jersey Clean Energy Program

In June 2013, the BPU established the funding level for fiscal 2014 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2014 aggregate funding for all electric distribution companies (EDCs) is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a current liability of $204 million and a noncurrent liability of $27 million as of June 30, 2013 for its outstanding share of the fiscal 2014 and remaining fiscal 2013 funding. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

Long-Term Capacity Agreement Pilot Program (LCAPP)

In 2011, New Jersey enacted the LCAPP Act that resulted in the selection of three generators to build a total of approximately 2,000 MW of new combined-cycle generating facilities located in New Jersey. Each of the New Jersey EDCs, including PSE&G, was directed to execute a standard offer capacity agreement (SOCA) with the three selected generators, but did so under protest preserving their legal rights. The SOCA provides for the EDCs to guarantee specified annual capacity payments to the generators subject to the terms and conditions of the agreement. Legal challenges to the BPU's implementation of the LCAPP Act were filed in New Jersey appellate court and this appeal is pending. In addition, the LCAPP Act itself has been challenged on constitutional grounds in federal court and that proceeding is ongoing. In July 2013, the SOCA contract with New Jersey Power Development LLC, a subsidiary of NRG Energy, Inc., was terminated early as a result of a default by the generator. The generator has accepted this early termination and this SOCA contract is no longer in effect. The other two SOCA contracts are currently in effect. SOCA contracts are for a 15-year term, which are scheduled to commence for one of the generators in the 2015/2016 delivery year and for the other generator in the 2016/2017 delivery year. These two contracts are for the aggregate notional amount of approximately 1,300 MWs of installed capacity. Based upon the expected percentage of state load that PSE&G will be serving during the term of these contracts, PSE&G would be responsible for the positive difference of the contract price and the annual RPM clearing price for approximately 52% or 676 MW of this amount provided that these generators satisfy their obligations under the SOCA, including the requirement that the specific generation units set forth in the contract achieve commercial operation.

The current estimated fair value of the SOCAs is recorded as a Derivative Asset or Liability with an offsetting Regulatory Asset or Liability on PSE&G's Consolidated Balance Sheets. See Note 12. Fair Value Measurements for additional information.

Superstorm Sandy

In late October 2012, Superstorm Sandy caused damage to PSE&G's transmission and distribution system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure.

Power incurred an additional $22 million and $50 million of storm-related expense for the three months and six months ended June 30, 2013, respectively, primarily for repairs at certain generating stations in Power's fossil fleet. Power had incurred $85 million of costs in 2012. These costs were recognized in Operation and Maintenance Expense, offset by $25 million and $19 million of insurance recoveries in 2013 and 2012, respectively. Power's current estimate of the total costs required to restore its damaged facilities to their pre-Superstorm Sandy condition, including costs already incurred, is approximately $364 million.

Leveraged Lease Investments

In January 2012, PSEG entered into a specific matter closing agreement with the IRS settling all matters related to cross border lease transactions. This agreement settled the leasing dispute with finality for all tax periods in which PSEG realized tax deductions from these transactions. In January 2012, PSEG also signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. In March 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These two agreements concluded ten years of audits for PSEG and the leasing issue for all tax years. For PSEG, the impact of these agreements was an increase in financial statement Income Tax Expense of approximately $175 million in the first quarter of 2012. In prior periods, PSEG had established financial statement tax liabilities for uncertain tax positions in the amount of $246 million with respect to these tax years. Accordingly, the settlement resulted in a net $71 million decrease in the first quarter of 2012 in the Income Tax Expense of PSEG.

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Cash Impact

For tax years 1997 through 2003, the tax and interest PSEG owes the IRS as a result of this settlement will be reduced by the $320 million PSEG has on deposit with the IRS for this matter. PSEG paid a net deficiency for these years of approximately $4 million during the second quarter of 2012. Based upon the closing agreement and the Form 870-AD for tax years 2004 through 2006, PSEG owes the IRS approximately $620 million in tax and interest. Based on the settlement of the leasing dispute, for tax years 2007 through 2010, the IRS owes PSEG approximately $676 million. PSEG has filed amended returns for tax years 2007-2010 reflecting the impact of the settlement. These returns have been audited by the IRS and accepted as filed. As required by statute, the IRS presented the refund claim to the Joint Committee on Taxation for approval. In October 2012, PSEG was notified that the Joint Committee took no exception to the refund claim. In April 2013, PSEG received confirmation from the IRS which shows that overpayments from the 2008 through 2010 tax years have been applied to satisfy the liabilities due with respect to tax years 2004 through 2007. Accordingly, no further cash payments will be required with respect to the contested leasing transactions. In addition to the above, PSEG will claim a tax deduction for the accrued deficiency interest associated with this settlement in 2012, which gives rise to a cash tax savings of approximately $100 million.

Note 10. Changes in Capitalization

The following capital transactions occurred in the six months ended June 30, 2013:

Power

- paid cash dividends of $500 million to PSEG, and
- paid $300 million of 2.50% Senior Notes at maturity.

PSE&G

- issued $500 million of 2.375% Secured Medium-Term Notes, Series I due May 2023,
- paid $150 million of 5.00% Secured Medium-Term Notes at maturity,
- issued $400 million of 3.80% Secured Medium-Term Notes, Series H due January 2043,
- received $100 million capital contribution from PSEG,
- paid $100 million of Transition Funding's securitization debt, and
- paid $6 million of Transition Funding II's securitization debt.

Note 11. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions.

Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Commodity Prices

The availability and price of energy commodities are subject to fluctuations due to weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions, transmission availability and other events. Power uses physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. Derivative contracts that do not qualify for hedge accounting or normal purchases/normal sales treatment are marked to market (MTM) with changes in fair value recorded in the income statement. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

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Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps and futures contracts to hedge

- forecasted energy sales from its generation stations and the related load obligations, and
- certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

Certain of these derivative transactions are designated and effective as cash flow hedges. During the second quarter of 2012, Power de-designated certain of its commodity derivative transactions that had previously qualified as cash flow hedges as they were deemed to no longer be highly effective as required by the relevant accounting guidance. As a result, subsequent to June 1, 2012, Power recognizes all gains and losses from changes in the fair value of these derivatives immediately in earnings rather than deferring any such amounts in Accumulated Other Comprehensive Income (Loss). The fair values of Power's de-designated hedges were frozen in Accumulated Other Comprehensive Income (Loss) as the original forecasted transactions are still expected to occur and are reclassified into earnings as the original derivative transactions settle.

As of June 30, 2013 and December 31, 2012, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity were as follows:

	As of June 30, 2013	As of December 31, 2012
	Millions	
Fair Value of Cash Flow Hedges	$ 1	$ 3
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 4	$ 9

The expiration date of the longest-dated cash flow hedge at Power is in 2014. Power's after-tax unrealized gains on these derivatives that are expected to be reclassified to earnings during the next 12 months are $4 million. There was no ineffectiveness associated with qualifying hedges as of June 30, 2013.

Trading Derivatives

The primary purpose of Power's wholesale marketing operation is to optimize the value of the output of the generating facilities via various products and services available in the markets it serves. Historically, Power engaged in trading of electricity and energy-related products where such transactions were not associated with the output or fuel purchase requirements of its facilities. This trading consisted mostly of energy supply contracts where Power secured sales commitments with the intent to supply the energy services from purchases in the market rather than from its owned generation. Such trading activities were marked to market through the income statement and represented less than one percent of gross margin (revenues less energy costs) on an annual basis. Effective July 2011, Power discontinued trading activities and anticipates that it will not enter into any more trading derivative contracts.

Other Derivatives

Power enters into additional contracts that are derivatives, but do not qualify for or are not designated as cash flow hedges. These transactions are intended to mitigate exposure to fluctuations in commodity prices and optimize the value of its expected generation. Trade types include financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. Changes in the fair market value of these contracts are recorded in earnings. PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization. In addition, as further described in Note 9. Commitments and Contingent Liabilities, PSE&G was directed to execute long-term SOCAs with certain generators to support the LCAPP Act. These contracts qualify as derivatives and are marked to fair value with the offset recorded to Regulatory Assets and Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

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Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of June 30, 2013, PSEG had seven interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of June 30, 2013 and December 31, 2012, the fair value of all the underlying hedges was $42 million and $57 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was $(1) million and $(2) million as of June 30, 2013 and December 31, 2012, respectively.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. See Note 2. Recent Accounting Standards. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset in the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of June 30, 2013						
	Power (A)				PSE&G(A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 1	$ 306	$ (201)	$ 106	$ 21	$ 15	$ 142
Noncurrent Assets	—	99	(41)	58	76	27	161
Total Mark-to-Market Derivative Assets	**$ 1**	**$ 405**	**$ (242)**	**$ 164**	**$ 97**	**$ 42**	**$ 303**
Derivative Contracts							
Current Liabilities	$ —	$ (243)	$ 201	$ (42)	$ —	$ —	$ (42)
Noncurrent Liabilities	—	(62)	42	(20)	(138)	—	(158)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (305)**	**$ 243**	**$ (62)**	**$ (138)**	**$ —**	**$ (200)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 1**	**$ 100**	**$ 1**	**$ 102**	**$ (41)**	**$ 42**	**$ 103**

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	As of December 31, 2012						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 3	$ 332	$ (217)	$ 118	$ 5	$ 15	$ 138
Noncurrent Assets	—	75	(26)	49	62	42	153
Total Mark-to-Market Derivative Assets	**$ 3**	**$ 407**	**$ (243)**	**$ 167**	**$ 67**	**$ 57**	**$ 291**
Derivative Contracts							
Current Liabilities	$ —	$ (265)	$ 219	$ (46)	$ —	$ —	$ (46)
Noncurrent Liabilities	—	(41)	26	(15)	(107)	—	(122)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (306)**	**$ 245**	**$ (61)**	**$ (107)**	**$ —**	**$ (168)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 3**	**$ 101**	**$ 2**	**$ 106**	**$ (40)**	**$ 57**	**$ 123**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of June 30, 2013 and December 31, 2012. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the statement of financial position. As of June 30, 2013 and December 31, 2012, net cash collateral paid of $1 million and $2 million, respectively, were netted against the corresponding net derivative contract positions. Of the $1 million as of June 30, 2013, cash collateral of $1 million was netted against current liabilities. Of the $2 million as of December 31, 2012, cash collateral of $(3) million and $5 million were netted against current assets and current liabilities, respectively.

Certain of Power’s derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power’s credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded or lose its investment grade credit rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on NYMEX and ICE that are fully collateralized) was $82 million and $98 million as of June 30, 2013 and December 31, 2012, respectively. As of June 30, 2013 and December 31, 2012, Power had the contractual right of offset of $46 million and $61 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded or lost its investment grade rating, it would have had additional collateral obligations of $36 million and $37 million as of June 30, 2013 and December 31, 2012, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $679 million and $654 million as of June 30, 2013 and December 31, 2012, respectively, discussed in Note 9. Commitments and Contingent Liabilities.

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The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended June 30, 2013 and 2012:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended June 30,		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended June 30,		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Three Months Ended June 30,	
	2013	2012		2013	2012		2013	2012
	Millions							
PSEG (A)								
Energy-Related Contracts	$ —	$ (8)	Operating Revenues	$ 2	$ 13	Operating Revenues	$ —	$ 1
Energy-Related Contracts	—	—	Energy Costs	—	(5)		—	—
Interest Rate Swaps	—	—	Interest Expense	(1)	(1)		—	—
Total PSEG	**$ —**	**$ (8)**		**$ 1**	**$ 7**		**$ —**	**$ 1**
Power								
Energy-Related Contracts	$ —	$ (8)	Operating Revenues	$ 2	$ 13	Operating Revenues	$ —	$ 1
Energy-Related Contracts	—	—	Energy Costs	—	(5)		—	—
Total Power	**$ —**	**$ (8)**		**$ 2**	**$ 8**		**$ —**	**$ 1**

(A) Includes amounts for PSEG parent.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the six months ended June 30, 2013 and 2012:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Six Months Ended June 30,		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Six Months Ended June 30,		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Six Months Ended June 30,	
	2013	2012		2013	2012		2013	2012
	Millions							
PSEG (A)								
Energy-Related Contracts	$ —	$ 30	Operating Revenues	$ 8	$ 52	Operating Revenues	$ —	$ —
Energy-Related Contracts	—	(4)	Energy Costs	—	(9)		—	—
Interest Rate Swaps	—	—	Interest Expense	(1)	(1)		—	—
Total PSEG	**$ —**	**$ 26**		**$ 7**	**$ 42**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ —	$ 30	Operating Revenues	$ 8	$ 52	Operating Revenues	$ —	$ —
Energy-Related Contracts	—	(4)	Energy Costs	—	(9)		—	—
Total Power	**$ —**	**$ 26**		**$ 8**	**$ 43**		**$ —**	**$ —**

(A) Includes amounts for PSEG parent.

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The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis:

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2012	**$ 12**	**$ 7**
Less: Gain Reclassified into Income	(6)	(4)
Balance as of March 31, 2013	**$ 6**	**$ 3**
Less: Gain Reclassified into Income	(1)	—
Balance as of June 30, 2013	**$ 5**	**$ 3**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the three months and six months ended June 30, 2013 and 2012:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2013	2012	2013	2012
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ 163	$ 40	$ (46)	$ 235
Energy-Related Contracts	Energy Costs	(5)	3	53	(23)
Total PSEG and Power		**$ 158**	**$ 43**	**$ 7**	**$ 212**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $5 million for each of the three month periods and $10 million and $11 million for the six month periods ended June 30, 2013 and 2012, respectively.

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The following reflects the gross volume, on an absolute value basis, of derivatives as of June 30, 2013 and December 31, 2012:

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of June 30, 2013					
Natural Gas	Dth	495	—	325	170
Electricity	MWh	233	—	233	—
Capacity	MW days	4	—	—	4
FTRs	MWh	30	—	30	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
Oils	Gallons	1	—	1	—
As of December 31, 2012					
Natural Gas	Dth	596	—	404	192
Electricity	MWh	208	—	208	—
Capacity	MW days	4	—	—	4
FTRs	MWh	19	—	19	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
Coal	Tons	1	—	1	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of June 30, 2013, 95% of the credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

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The following table provides information on Power's credit risk from others, net of cash collateral, as of June 30, 2013. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 225	$ 36	$ 225	1	$ 114	(A)
Non-Investment Grade—External Rating	1	—	1	—	—	
Investment Grade—No External Rating	8	—	8	—	—	
Non-Investment Grade—No External Rating	11	—	11	—	—	
Total	**$ 245**	**$ 36**	**$ 245**	**1**	**$ 114**	

(A) Represents net exposure with PSE&G.

The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of June 30, 2013, Power had 176 active counterparties.

Note 12. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of June 30, 2013, these consist primarily of electric swaps whose basis is deemed significant to the fair value measurement, long-term electric load contracts, long-term gas supply and capacity contracts.

The following tables present information about PSEG's, Power's and PSE&G's respective assets and (liabilities) measured at fair value on a recurring basis as of June 30, 2013 and December 31, 2012, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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Description	Recurring Fair Value Measurements as of June 30, 2013			
	Total	Cash Collateral Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 261	$ —	$ —	$ 158	$ 103
Interest Rate Swaps (B)	$ 42	$ —	$ —	$ 42	$ —
NDT Fund (C)					
Equity Securities	$ 829	$ —	$ 829	$ —	$ —
Debt Securities—Govt Obligations	$ 385	$ —	$ —	$ 385	$ —
Debt Securities—Other	$ 318	$ —	$ —	$ 318	$ —
Other Securities	$ 48	$ —	$ —	$ 48	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 21	$ —	$ 21	$ —	$ —
Debt Securities—Govt Obligations	$ 110	$ —	$ —	$ 110	$ —
Debt Securities—Other	$ 44	$ —	$ —	$ 44	$ —
Other Securities	$ 2	$ —	$ —	$ 2	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (200)	$ 1	$ —	$ (63)	$ (138)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 164	$ —	$ —	$ 158	$ 6
NDT Fund (C)					
Equity Securities	$ 829	$ —	$ 829	$ —	$ —
Debt Securities—Govt Obligations	$ 385	$ —	$ —	$ 385	$ —
Debt Securities—Other	$ 318	$ —	$ —	$ 318	$ —
Other Securities	$ 48	$ —	$ —	$ 48	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 10	$ —	$ —	$ 10	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (62)	$ 1	$ —	$ (63)	$ —
PSE&G					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 97	$ —	$ —	$ —	$ 97
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 27	$ —	$ —	$ 27	$ —
Debt Securities—Other	$ 10	$ —	$ —	$ 10	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (138)	$ —	$ —	$ —	$ (138)

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Description	Recurring Fair Value Measurements as of December 31, 2012			
	Total	Cash Collateral Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 234	$ (3)	$ —	$ 157	$ 80
Interest Rate Swaps (B)	$ 57	$ —	$ —	$ 57	$ —
NDT Fund (C)					
Equity Securities	$ 789	$ —	$ 789	$ —	$ —
Debt Securities—Govt Obligations	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Other	$ 342	$ —	$ —	$ 342	$ —
Other Securities	$ 124	$ —	$ —	$ 124	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 18	$ —	$ 18	$ —	$ —
Debt Securities—Govt Obligations	$ 117	$ —	$ —	$ 117	$ —
Debt Securities—Other	$ 47	$ —	$ —	$ 47	$ —
Other Securities	$ 3	$ —	$ —	$ 3	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (168)	$ 5	$ —	$ (62)	$ (111)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 167	$ (3)	$ —	$ 157	$ 13
NDT Fund (C)					
Equity Securities	$ 789	$ —	$ 789	$ —	$ —
Debt Securities—Govt Obligations	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Other	$ 342	$ —	$ —	$ 342	$ —
Other Securities	$ 124	$ —	$ —	$ 124	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 3	$ —	$ 3	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 9	$ —	$ —	$ 9	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (61)	$ 5	$ —	$ (62)	$ (4)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (A)	$ 67	$ —	$ —	$ —	$ 67
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—Govt Obligations	$ 39	$ —	$ —	$ 39	$ —
Debt Securities—Other	$ 15	$ —	$ —	$ 15	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy Related Contracts (A)	$ (107)	$ —	$ —	$ —	$ (107)

(A) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most [illegible] (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction

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prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

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Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(B) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(C) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price (primarily Level 1). The Rabbi Trust equity index fund is valued based on quoted prices in an active market (Level 1).

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds and United States Treasury obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads (primarily Level 2). Short-term investments and certain commingled temporary investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield (primarily Level 2).

(D) Cash collateral netting represents collateral amounts netted against derivative assets and liabilities as permitted under the accounting guidance for Offsetting of Amounts Related to Certain Contracts.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group, and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

The following tables provide details surrounding significant Level 3 valuations as of June 30, 2013 and December 31, 2012. For Power, in general, electric swaps are valued based on at least two pricing inputs, basis and underlying. To the extent the basis component is based on a single broker quote and is significant to the fair value of the electric swap, it is categorized as Level 3. Power's electric load contracts in which load consumption may change hourly are fair valued using certain unobservable inputs, such as historic load variability. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. For Power and PSE&G, long-term gas supply contracts are measured at fair value using both actively traded pricing points as well as unobservable inputs such as gas prices beyond observable periods and long-term basis quotes and, accordingly, the fair value measurements are classified in Level 3. For PSE&G, long-term electric capacity contracts are measured at fair value using both observable capacity prices and unobservable inputs consisting of forecasts of future long-term electric capacity prices and include adjustments for contingencies, such as litigation risk and plant construction risk. Accordingly, the fair value measurements are classified as Level 3.

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Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of June 30, 2013 Assets	Fair Value as of June 30, 2013 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ 2	$ 3	Discounted cash flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Deals	1	(3)	Discounted cash flow	Historic Load Variability	-5% to +10%
Other	Various (A)	3	—			
Total Power		**$ 6**	**$ —**			
PSE&G						
Gas and Capacity	Forward Contracts (B)	$ 97	$ (138)	Discounted cash flow	Long-Term Gas Basis and Capacity Prices	(B)
Total PSE&G		**$ 97**	**$ (138)**			
TOTAL PSEG		**$ 103**	**$ (138)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2012 Assets	Fair Value as of December 31, 2012 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ 7	$ (1)	Discounted cash flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	1	(2)	Discounted cash flow	Historic Load Variability	-5% to +10%
Other	Various (A)	5	(1)			
Total Power		**$ 13**	**$ (4)**			
PSE&G						
Gas and Capacity	Forward Contracts (B)	$ 67	$ (107)	Discounted cash flow	Long-Term Gas Basis and Capacity Prices	(B)
Total PSE&G		**$ 67**	**$ (107)**			
TOTAL PSEG		**$ 80**	**$ (111)**			

(A) Includes long-term gas supply positions which are immaterial as of June 30, 2013 and December 31, 2012. Also includes long-term electric capacity positions which are immaterial as of December 31, 2012.

(B) Includes long-term gas supply and long-term electric capacity positions with various unobservable inputs. Significant unobservable inputs for the gas supply contracts include long-term basis prices in the range of $0 to $4/MMBTU of

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natural gas. Unobservable inputs for the long-term electric capacity contracts include forecasted capacity prices in the range of $100 to $400/MW day.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power and PSE&G are sellers, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value. For long-term electric capacity contracts where PSE&G is a buyer, an increase in the capacity price would increase the fair value.

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and six months ended June 30, 2013 and 2012, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended June 30, 2013

Description	Balance as of April 1, 2013	Total Gains or (Losses) Realized/Unrealized		Purchases (Sales)	Issuances (Settlements) (C)	Transfers In/Out (D)	Balance as of June 30, 2013
		Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)				
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ (57)	$ 17	$ (1)	$ —	$ —	$ 6	$ (35)
Power							
Net Derivative Assets (Liabilities)	$ (17)	$ 17	$ —	$ —	$ —	$ 6	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (40)	$ —	$ (1)	$ —	$ —	$ —	$ (41)

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Six Months Ended June 30, 2013

Description	Balance as of January 1, 2013	Total Gains or (Losses) Realized/Unrealized: Included in Income (E)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances (Settlements) (C)	Transfers In/Out (D)	Balance as of June 30, 2013
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (31)	$ (17)	$ (1)	$ —	$ 10	$ 4	$ (35)
Power							
Net Derivative Assets (Liabilities)	$ 9	$ (17)	$ —	$ —	$ 10	$ 4	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (40)	$ —	$ (1)	$ —	$ —	$ —	$ (41)

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended June 30, 2012

Description	Balance as of April 1, 2012	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances (Settlements) (C)	Transfers In/Out (D)	Balance as of June 30, 2012
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 61	$ 7	$ (90)	$ —	$ (14)	$ —	$ (36)
Non-Recourse Debt	$ (50)	$ 50	—	—	—	—	—
Power							
Net Derivative Assets (Liabilities)	$ 29	$ 7	$ —	$ —	$ (14)	$ —	$ 22
PSE&G							
Net Derivative Assets (Liabilities)	$ 32	$ —	$ (90)	$ —	$ —	$ —	$ (58)

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Six Months Ended June 30, 2012

Description	Balance as of January 1, 2012	Total Gains or (Losses) Realized/Unrealized: Included in Income (E)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances (Settlements) (C)	Transfers In/Out (D)	Balance as of June 30, 2012
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 21	$ 41	$ (55)	$ —	$ (43)	$ —	$ (36)
Non-Recourse Debt	$ (50)	$ 50	$ —	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 24	$ 41	$ —	$ —	$ (43)	$ —	$ 22
PSE&G							
Net Derivative Assets (Liabilities)	$ (3)	$ —	$ (55)	$ —	$ —	$ —	$ (58)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $17 million and $7 million in Operating Income in 2013 and 2012, respectively. Of the $17 million in Operating Income in 2013, $16 million is unrealized. Of the $7 million in Operating Income in 2012, $(7) million is unrealized. Energy Holdings' release from its obligation under the non-recourse debt is included in PSEG's Operating Income for 2012 and is offset by the write-off of the related assets.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or OCI, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $(14) million in settlements for the three months ended June 30, 2012. Includes $10 million and $(43) million in settlements for the six months ended June 30, 2013 and 2012, respectively.

(D) During the three months ended June 30, 2013 and six months ended June 30, 2013, $6 million and $4 million, respectively, of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. The transfer was recognized as of the beginning of the first quarter (i.e. the quarter in which the transfer occurred), as per PSEG's policy. There were no transfers among levels during the three months ended June 30, 2012 and the six months ended June 30, 2012.

(E) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $(17) million and $41 million in Operating Income in 2013 and 2012, respectively. Of the $(17) million in Operating Income in 2013, $(8) million is unrealized. Of the $41 million in Operating Income in 2012, $(2) million is unrealized. Energy Holdings' release from its obligation under the non-recourse debt is included in PSEG's Operating Income for 2012 and is offset by the write-off of the related assets.

As of June 30, 2013, PSEG carried $1.9 billion of net assets that are measured at fair value on a recurring basis, of which $35 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of June 30, 2012, PSEG carried $1.7 billion of net assets that are measured at fair value on a recurring basis, of which $36 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

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Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of June 30, 2013 and December 31, 2012.

	June 30, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 27	$ 42	$ 38	$ 57
Power -Recourse Debt (B)	2,041	2,361	2,340	2,818
PSE&G (B)	5,540	5,627	4,795	5,606
Transition Funding (PSE&G) (B)	590	643	690	765
Transition Funding II (PSE&G) (B)	27	28	32	34
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	25	25	44	44
Total Long-Term Debt	**$ 8,250**	**$ 8,726**	**$ 7,939**	**$ 9,324**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 13. Other Income and Deductions

Other Income	Power	PSE&G	Other (A)	Consolidated
		Millions		
Three Months Ended June 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ 33	$ —	$ —	$ 33
Allowance of Funds Used During Construction	—	6	—	6
Solar Loan Interest	—	5	—	5
Other	2	4	2	8
Total Other Income	**$ 35**	**$ 15**	**$ 2**	**$ 52**
Three Months Ended June 30, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$ 36	$ —	$ —	$ 36
Allowance of Funds Used During Construction	—	7	—	7
Solar Loan Interest	—	4	—	4
Other	1	1	2	4
Total Other Income	**$ 37**	**$ 12**	**$ 2**	**$ 51**
Six Months Ended June 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ 80	$ —	$ —	$ 80
Allowance of Funds Used During Construction	—	12	—	12
Solar Loan Interest	—	11	—	11
Other	2	5	3	10
Total Other Income	**$ 82**	**$ 28**	**$ 3**	**$ 113**
Six Months Ended June 30, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$ 64	$ —	$ —	$ 64
Allowance of Funds Used During Construction	—	11	—	11
Solar Loan Interest	—	8	—	8
Other	3	4	5	12
Total Other Income	**$ 67**	**$ 23**	**$ 5**	**$ 95**

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Other Deductions	Power	PSE&G	Other (A)	Consolidated
			Millions	
Three Months Ended June 30, 2013				
NDT Fund Realized Losses and Expenses	$ 9	$ —	$ —	$ 9
Other	1	1	2	4
Total Other Deductions	**$ 10**	**$ 1**	**$ 2**	**$ 13**
Three Months Ended June 30, 2012				
NDT Fund Realized Losses and Expenses	$ 17	$ —	$ —	$ 17
Other	—	1	1	2
Total Other Deductions	**$ 17**	**$ 1**	**$ 1**	**$ 19**
Six Months Ended June 30, 2013				
NDT Fund Realized Losses and Expenses	$ 29	$ —	$ —	$ 29
Other	9	2	2	13
Total Other Deductions	**$ 38**	**$ 2**	**$ 2**	**$ 42**
Six Months Ended June 30, 2012				
NDT Fund Realized Losses and Expenses	$ 25	$ —	$ —	$ 25
Other	7	2	1	10
Total Other Deductions	**$ 32**	**$ 2**	**$ 1**	**$ 35**

(A) Other primarily consists of activity at PSEG (as parent company), Energy Holdings, Services and intercompany eliminations.

Note 14. Income Taxes

PSEG's, Power's and PSE&G's effective tax rates for the three months and six months ended June 30, 2013 and 2012 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
PSEG	39.6%	40.9%	40.1%	33.7%
Power	40.6%	41.2%	40.3%	40.3%
PSE&G	37.2%	38.4%	39.6%	32.7%

For the three months ended June 30, 2013, as compared to the same period in the prior year, PSEG's and PSE&G's effective tax rates were lower due primarily to depreciation flow-through.

For the six months ended June 30, 2013, PSEG's and PSE&G's effective tax rates were higher than last year's effective tax rates due primarily to a settlement in 2012 with the IRS in regard to leveraged leases and the federal tax audit for tax years 1997 through 2006.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 was eligible for 50% bonus depreciation for tax purposes. On January 2, 2013, the President signed into law the American Taxpayer Relief Act of 2012 that further extends the 50% bonus depreciation for qualified property placed into service before January 1, 2014. These provisions contain rules which afford certain projects which have a long production period, the benefit of bonus depreciation. These provisions have generated

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cash for PSEG through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period.

In June 2009, September 2008 and December 2007, PSEG made tax deposits with the IRS in the amounts of $140 million, $80 million and $100 million, respectively, to defray potential interest costs associated with disputed tax assessments associated with certain lease investments. On January 31, 2012, PSEG signed a specific matter closing agreement with the IRS regarding this matter. Based on this agreement, these deposits were applied against tax and interest due pursuant to the closing agreement. Further, on the same date, PSEG signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. In March 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These two agreements concluded ten years of audits for PSEG and the leasing issue for all tax years. The financial statement impacts of these agreements, net of existing financial statement reserves, was a net decrease in tax expense in the first quarter of 2012 of $71 million for PSEG, including $30 million and $1 million for PSE&G and Power, respectively.

Note 15. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended June 30, 2013			
Accumulated Other Comprehensive Income (Loss)	**Derivative Contracts**	**Pension and OPEB Plans**	**Available-for -Sale Securities**	**Total**
		Millions		
Balance as of March 31, 2013	$ 3	$ (475)	$ 117	$ (355)
Other Comprehensive Income before Reclassifications	—	—	(16)	(16)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	9	—	9
Net Current Period Other Comprehensive Income (Loss)	—	9	(16)	(7)
Balance as of June 30, 2013	**$ 3**	**$ (466)**	**$ 101**	**$ (362)**

Power	Other Comprehensive Income (Loss) Three Months Ended June 30, 2013			
Accumulated Other Comprehensive Income (Loss)	**Derivative Contracts**	**Pension and OPEB Plans**	**Available-for -Sale Securities**	**Total**
		Millions		
Balance as of March 31, 2013	$ 5	$ (413)	$ 112	$ (296)
Other Comprehensive Income before Reclassifications	—	—	(14)	(14)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	8	—	7
Net Current Period Other Comprehensive Income (Loss)	(1)	8	(14)	(7)
Balance as of June 30, 2013	**$ 4**	**$ (405)**	**$ 98**	**$ (303)**

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PSEG	Other Comprehensive Income (Loss) Six Months Ended June 30, 2013			
Accumulated Other Comprehensive Income (Loss)	**Derivative Contracts**	**Pension and OPEB Plans**	**Available-for -Sale Securities**	**Total**
		Millions		
Balance as of December 31, 2012	$ 7	$ (485)	$ 90	$ (388)
Other Comprehensive Income before Reclassifications	—	—	11	11
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(4)	19	—	15
Net Current Period Other Comprehensive Income (Loss)	(4)	19	11	26
Balance as of June 30, 2013	**$ 3**	**$ (466)**	**$ 101**	**$ (362)**

Power	Other Comprehensive Income (Loss) Six Months Ended June 30, 2013			
Accumulated Other Comprehensive Income (Loss)	**Derivative Contracts**	**Pension and OPEB Plans**	**Available-for -Sale Securities**	**Total**
		Millions		
Balance as of December 31, 2012	$ 9	$ (422)	$ 85	$ (328)
Other Comprehensive Income before Reclassifications	—	—	13	13
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(5)	17	—	12
Net Current Period Other Comprehensive Income (Loss)	(5)	17	13	25
Balance as of June 30, 2013	**$ 4**	**$ (405)**	**$ 98**	**$ (303)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2013			Six Months Ended June 30, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Derivative Contracts							
Gains (Losses) on Cash Flow Hedges	Operating Revenues	$ 2	$ (1)	$ 1	$ 8	$ (3)	$ 5
Interest Rate Swaps	Interest Expense	(1)	—	(1)	(1)	—	$ (1)
Pension and OPEB Plans							
Amortization of Prior Service Cost (Credit)	Operation and Maintenance Expense	1	—	1	5	(2)	3
Amortization of Actuarial Loss	Operation and Maintenance Expense	(17)	7	(10)	(38)	16	(22)
Available-for-Sale Securities							
Realized Gains (Losses) on NDT Fund	Other Income	2	(1)	1	4	(2)	2
Other-Than-Temporary Impairments on NDT Fund	Other-Than-Temporary Impairments	(2)	1	(1)	(4)	2	(2)
Total		**$ (15)**	**$ 6**	**$ (9)**	**$ (26)**	**$ 11**	**$ (15)**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2013			Six Months Ended June 30, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Derivative Contracts							
Gains (Losses) on Cash Flow Hedges	Operating Revenues	$ 2	$ (1)	$ 1	$ 8	$ (3)	$ 5
Pension and OPEB Plans							
Amortization of Prior Service Cost (Credit)	Operation and Maintenance Expense	2	(1)	1	4	(2)	2
Amortization of Actuarial Loss	Operation and Maintenance Expense	(16)	7	(9)	(32)	13	(19)
Available-for-Sale Securities							
Realized Gains (Losses) on NDT Fund	Other Income	2	(1)	1	4	(2)	2
Other-Than-Temporary Impairments on NDT Fund	Other-Than-Temporary Impairments	(2)	1	(1)	(4)	2	(2)
Total		**$ (12)**	**$ 5**	**$ (7)**	**$ (20)**	**$ 8**	**$ (12)**

	Balance as of December 31, 2011	Other Comprehensive Income (Loss) Six Months Ended June 30, 2012			Balance as of June 30, 2012
		Power	PSE&G	Other	
	Millions				
Derivative Contracts	$ 31	$ (10)	$ —	$ —	$ 21
Pension and OPEB Plans	(438)	14	—	1	(423)
Available-for-Sale Securities	70	22	(1)	1	92
Accumulated Other Comprehensive Income (Loss)	**$ (337)**	**$ 26**	**$ (1)**	**$ 2**	**$ (310)**

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Note 16. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013		2012		2013		2012	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)								
Net Income	**$ 333**	**$ 333**	**$ 211**	**$ 211**	**$ 653**	**$ 653**	**$ 704**	**$ 704**
EPS Denominator (Thousands)								
Weighted Average Common Shares Outstanding	505,900	505,900	505,903	505,903	505,921	505,921	505,956	505,956
Effect of Stock Based Compensation Awards	—	1,481	—	1,066	—	1,380	—	1,043
Total Shares	**505,900**	**507,381**	**505,903**	**506,969**	**505,921**	**507,301**	**505,956**	**506,999**
EPS								
Net Income	**$ 0.66**	**$ 0.66**	**$ 0.42**	**$ 0.42**	**$ 1.29**	**$ 1.29**	**$ 1.39**	**$ 1.39**

	Three Months Ended June 30,		Six Months Ended June 30,	
Dividend Payments on Common Stock	**2013**	**2012**	**2013**	**2012**
Per Share	$ 0.3600	$ 0.3550	$ 0.7200	$ 0.7100
in Millions	$ 182	$ 180	$ 364	$ 359

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Note 17. Financial Information by Business Segments

	Power	PSE&G	Energy Holdings	Other (A)	Consolidated
			Millions		
Three Months Ended June 30, 2013					
Total Operating Revenues	$ 1,190	$ 1,423	$ 18	$ (321)	$ 2,310
Income (Loss) From Continuing Operations	204	121	4	4	333
Net Income (Loss)	204	121	4	4	333
Segment Earnings (Loss)	204	121	4	4	333
Gross Additions to Long-Lived Assets	79	576	21	6	682
Three Months Ended June 30, 2012					
Total Operating Revenues	$ 985	$ 1,407	$ 14	$ (308)	$ 2,098
Income (Loss) From Continuing Operations	104	101	2	4	211
Net Income (Loss)	104	101	2	4	211
Segment Earnings (Loss)	104	101	2	4	211
Gross Additions to Long-Lived Assets	107	435	44	7	593
Six Months Ended June 30, 2013					
Total Operating Revenues	$ 2,637	$ 3,418	$ 34	$ (993)	$ 5,096
Income (Loss) From Continuing Operations	341	300	4	8	653
Net Income (Loss)	341	300	4	8	653
Segment Earnings (Loss)	341	300	4	8	653
Gross Additions to Long-Lived Assets	222	1,148	27	9	1,406
Six Months Ended June 30, 2012					
Total Operating Revenues	$ 2,546	$ 3,346	$ 34	$ (953)	$ 4,973
Income (Loss) From Continuing Operations	357	298	42	7	704
Net Income (Loss)	357	298	42	7	704
Segment Earnings (Loss)	357	298	42	7	704
Gross Additions to Long-Lived Assets	344	870	55	11	1,280
As of June 30, 2013					
Total Assets	$ 10,570	$ 19,994	$ 1,431	$ 64	$ 32,059
Investments in Equity Method Subsidiaries	$ 40	$ —	$ 97	$ —	$ 137
As of December 31, 2012					
Total Assets	$ 11,032	$ 19,223	$ 1,454	$ 16	$ 31,725
Investments in Equity Method Subsidiaries	$ 40	$ —	$ 94	$ —	$ 134

(A) Other activities include amounts applicable to PSEG (as parent company), Services and intercompany eliminations, primarily relating to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are priced in accordance with applicable regulations, including affiliate pricing rules, at cost or, in the case of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 18. Related-Party Transactions.

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Note 18. Related-Party Transactions

The following discussion relates to intercompany transactions, the majority of which are eliminated during the PSEG consolidation process in accordance with GAAP.

Power

The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
		Millions		
Revenue from Affiliates:				
Billings to PSE&G through BGSS (A)	$ 128	$ 112	$ 606	$ 563
Billings to PSE&G through BGS (A)	192	192	385	381
Total Revenue from Affiliates	**$ 320**	**$ 304**	**$ 991**	**$ 944**
Expense Billings from Affiliates:				
Administrative Billings from Services (B)	$ (43)	$ (38)	$ (88)	$ (72)
Total Expense Billings from Affiliates	**$ (43)**	**$ (38)**	**$ (88)**	**$ (72)**

Related-Party Transactions	As of June 30, 2013	As of December 31, 2012
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$ 107	$ 238
Receivables from PSE&G Related to Gas Supply Hedges for BGSS (A)	28	27
Receivable from (Payable to) Services (B)	(26)	(31)
Tax Receivable from (Payable to) PSEG (C)	23	111
Receivable from (Payable to) PSEG	13	(5)
Accounts Receivable (Payable)—Affiliated Companies, net	**$ 145**	**$ 340**
Short-Term Loan to Affiliate (Demand Note to PSEG) (D)	**$ 395**	**$ 574**
Working Capital Advances to Services (E)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable (Payable) (C)	**$ (39)**	**$ (50)**

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
		Millions		
Expense Billings from Affiliates:				
Billings from Power through BGSS (A)	$ (128)	$ (112)	$ (606)	$ (563)
Billings from Power through BGS (A)	(192)	(192)	(385)	(381)
Administrative Billings from Services (B)	(62)	(57)	(123)	(107)
Total Expense Billings from Affiliates	**$ (382)**	**$ (361)**	**$ (1,114)**	**$ (1,051)**

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Related-Party Transactions	As of June 30, 2013	As of December 31, 2012
	Millions	
Payable to Power through BGS and BGSS Contracts (A)	$ (107)	$ (238)
Payable to Power Related to Gas Supply Hedges for BGSS (A)	(28)	(27)
Payable to Power for SREC Liability (F)	(9)	(7)
Receivable from (Payable to) Services (B)	(48)	(65)
Tax Receivable from (Payable to) PSEG (C)	244	256
Receivable from (Payable to) PSEG	3	6
Receivable from Energy Holdings	4	2
Accounts Receivable (Payable)—Affiliated Companies, net	**$ 59**	**$ (73)**
Working Capital Advances to Services (E)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Receivable (Payable) (C)	**$ (43)**	**$ (32)**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to Power and PSE&G at cost. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

(E) Power and PSE&G have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on Power's and PSE&G's Condensed Consolidated Balance Sheets.

(F) Pursuant to a BPU Order, certain BGS suppliers will be reimbursed for the cost they incurred above $300 per Solar Renewable Energy Certificate (SREC) or per Solar Alternative Compliance Payment (SACP) during the period June 1, 2008 through May 31, 2010 and such excess cost will be passed on to ratepayers. In a December 2012 order, the BPU approved a Stipulation of Settlement (Stipulation) that described the mechanism by which BGS suppliers recover reasonable and prudently-incurred costs for these SRECs. In accordance with the Stipulation, New Jersey's EDCs, including PSE&G, made a Verification Filing defining the proposed BGS Supplier payments. PSE&G has estimated and accrued a total liability for the excess SREC cost expected to be recovered from ratepayers of $17 million as of June 30, 2013 and December 31, 2012, including approximately $9 million and $7 million for Power's share which is included in PSE&G's Accounts Receivable (Payable)—Affiliated Companies as of June 30, 2013 and December 31, 2012, respectively. Under current accounting guidance, Power was unable to record the related intercompany receivable on its Condensed Consolidated Balance Sheet, until the BPU issued an Order approving such payments. As a result, PSE&G's liability to Power was not eliminated in consolidation and is included in Other Current Liabilities on PSEG's Condensed Consolidated Balance Sheet as of June 30, 2013 and December 31, 2012. On May 29, 2013, the BPU issued an Order approving the additional BGS payment for these SRECs with a 45 day appeal period which expired in July 2013 with no appeals filed. As a result, Power recorded its $9 million receivable from PSE&G in July 2013.

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Note 19. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LC. The following table presents condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended June 30, 2013					
Operating Revenues	$ —	$ 1,535	$ 34	$ (379)	$ 1,190
Operating Expenses	2	1,187	31	(379)	841
Operating Income (Loss)	(2)	348	3	—	349
Equity Earnings (Losses) of Subsidiaries	213	(2)	—	(211)	—
Other Income	10	35	—	(10)	35
Other Deductions	(2)	(9)	—	1	(10)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(26)	(6)	(6)	9	(29)
Income Tax Benefit (Expense)	11	(151)	1	—	(139)
Net Income (Loss)	**$ 204**	**$ 213**	**$ (2)**	**$ (211)**	**$ 204**
Comprehensive Income (Loss)	**$ 197**	**$ 198**	**$ —**	**$ (198)**	**$ 197**
Three Months Ended June 30, 2012					
Operating Revenues	$ —	$ 1,329	$ 31	$ (375)	$ 985
Operating Expenses	2	1,135	28	(376)	789
Operating Income (Loss)	(2)	194	3	1	196
Equity Earnings (Losses) of Subsidiaries	116	(1)	—	(115)	—
Other Income	11	39	—	(13)	37
Other Deductions	—	(17)	—	—	(17)
Other-Than-Temporary Impairments	—	(7)	—	—	(7)
Interest Expense	(31)	(10)	(4)	13	(32)
Income Tax Benefit (Expense)	10	(82)	—	(1)	(73)
Net Income (Loss)	**$ 104**	**$ 116**	**$ (1)**	**$ (115)**	**$ 104**
Comprehensive Income (Loss)	**$ 86**	**$ 91**	**$ (1)**	**$ (90)**	**$ 86**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Six Months Ended June 30, 2013					
Operating Revenues	$ —	$ 3,338	$ 67	$ (768)	$ 2,637
Operating Expenses	4	2,749	61	(767)	2,047
Operating Income (Loss)	(4)	589	6	(1)	590
Equity Earnings (Losses) of Subsidiaries	362	(2)	—	(360)	—
Other Income	19	83	—	(20)	82
Other Deductions	(10)	(29)	—	1	(38)
Other-Than-Temporary Impairments	—	(4)	—	—	(4)
Interest Expense	(53)	(16)	(10)	20	(59)
Income Tax Benefit (Expense)	27	(259)	2	—	(230)
Net Income (Loss)	**$ 341**	**$ 362**	**$ (2)**	**$ (360)**	**$ 341**
Comprehensive Income (Loss)	**$ 366**	**$ 370**	**$ —**	**$ (370)**	**$ 366**
Six Months Ended June 30, 2013					
Net Cash Provided By (Used In) Operating Activities	$ 386	$ 884	$ 3	$ (419)	$ 854
Net Cash Provided By (Used In) Investing Activities	$ 152	$ (411)	$ —	$ 204	$ (55)
Net Cash Provided By (Used In) Financing Activities	$ (538)	$ (476)	$ (3)	$ 215	$ (802)
Six Months Ended June 30, 2012					
Operating Revenues	$ —	$ 3,202	$ 57	$ (713)	$ 2,546
Operating Expenses	—	2,568	55	(714)	1,909
Operating Income (Loss)	—	634	2	1	637
Equity Earnings (Losses) of Subsidiaries	376	(4)	—	(372)	—
Other Income	24	70	—	(27)	67
Other Deductions	(7)	(25)	—	—	(32)
Other-Than-Temporary Impairments	—	(12)	—	—	(12)
Interest Expense	(60)	(20)	(8)	26	(62)
Income Tax Benefit (Expense)	24	(267)	2	—	(241)
Net Income (Loss)	**$ 357**	**$ 376**	**$ (4)**	**$ (372)**	**$ 357**
Comprehensive Income (Loss)	**$ 383**	**$ 388**	**$ (4)**	**$ (384)**	**$ 383**
Six Months Ended June 30, 2012					
Net Cash Provided By (Used In) Operating Activities	$ 301	$ 902	$ 3	$ (354)	$ 852
Net Cash Provided By (Used In) Investing Activities	$ 365	$ (601)	$ (23)	$ 70	$ (189)
Net Cash Provided By (Used In) Financing Activities	$ (666)	$ (310)	$ 19	$ 284	$ (673)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
As of June 30, 2013					
Current Assets	$ 3,981	$ 8,288	$ 844	$ (11,367)	$ 1,746
Property, Plant and Equipment, net	80	5,944	930	—	6,954
Investment in Subsidiaries	4,188	731	—	(4,919)	—
Noncurrent Assets	189	1,750	56	(125)	1,870
Total Assets	**$ 8,438**	**$ 16,713**	**$ 1,830**	**$ (16,411)**	**$ 10,570**
Current Liabilities	$ 583	$ 10,443	$ 891	$ (11,366)	$ 551
Noncurrent Liabilities	509	2,081	207	(124)	2,673
Long-Term Debt	2,041	—	—	—	2,041
Member's Equity	5,305	4,189	732	(4,921)	5,305
Total Liabilities and Member's Equity	**$ 8,438**	**$ 16,713**	**$ 1,830**	**$ (16,411)**	**$ 10,570**
As of December 31, 2012					
Current Assets	$ 3,922	$ 8,084	$ 940	$ (10,712)	$ 2,234
Property, Plant and Equipment, net	80	5,988	950	—	7,018
Investment in Subsidiaries	4,317	733	—	(5,050)	—
Noncurrent Assets	201	1,660	60	(141)	1,780
Total Assets	**$ 8,520**	**$ 16,465**	**$ 1,950**	**$ (15,903)**	**$ 11,032**
Current Liabilities	$ 482	$ 10,187	$ 1,010	$ (10,712)	$ 967
Noncurrent Liabilities	559	1,960	207	(140)	2,586
Long-Term Debt	2,040	—	—	—	2,040
Member's Equity	5,439	4,318	733	(5,051)	5,439
Total Liabilities and Member's Equity	**$ 8,520**	**$ 16,465**	**$ 1,950**	**$ (15,903)**	**$ 11,032**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by PSEG, Power and PSE&G. Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of three reportable segments, which are:

- **Power,** our wholesale energy supply company that integrates its generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States,
- **PSE&G,** our public utility company which provides electric transmission services and distribution of electric energy and natural gas in New Jersey; implements demand response and energy efficiency programs and invests in solar generation, and
- **Energy Holdings,** which principally owns energy-related leveraged leases and solar generation projects.

Our business discussion in Part I, Item 1. Business of our 2012 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I Item 1A of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Overview of 2012 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2013 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes, the 2012 Form 10-K and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2013.

OVERVIEW OF 2013 AND FUTURE OUTLOOK

Our business plan is designed to maintain earnings stability while achieving growth in recognition of market, regulatory and economic trends. We continue to focus on operational excellence to provide the foundation for our financial strength, which enables us to invest in a disciplined way.

Our financial results for the first six months of 2013 were lower when compared to the first half of 2012. In the power markets in which our generation fleet operates, natural gas prices have a major impact on the price that generators receive for their output. While wholesale natural gas prices during the period remained low relative to historic prices following multiple years of steep declines, financial results for our generation operations were favorably impacted by increased output and higher market prices driven by colder winter weather in the period as compared to the first six months in 2012, as well as cost controls, partially offset by mark-to market losses in 2013 due to the impact of rising prices on our forward sale positions.

Under the PJM capacity auction conducted in May 2013, Power cleared 8,637 MW of its generating capacity at an average price of $166 per MW-day for the 2016-2017 delivery period. While this year's auction resulted in lower clearing prices for the PJM Regional Transmission Organization (RTO), Power benefited from higher prices than the rest of the RTO, as the majority of its generation fleet is situated in the relatively constrained Eastern part of PJM. For a more detailed discussed on the RPM capacity auction, refer to Part II. Item 5. Other Information—Federal Regulation—Capacity Market Issues.

Our utility business benefited from increased transmission investment during the first half of the year, but financial results were impacted by the absence of last year's tax settlement. In the first six months of 2013, we continued to invest capital in transmission and distribution infrastructure projects, aimed at maintaining the reliability of our service to our customers. Over the past few years, these types of investments have altered the business mix of our results of operations to reflect a higher percentage contribution by our regulated utility.

In developing and implementing our strategy of operational excellence, financial strength and disciplined investment, we monitor significant regulatory and legislative developments. Competitive wholesale power market design is of particular importance to our results and we continue to advocate for policies and rules that promote competitive electricity markets. This includes opposing efforts to subsidize generation and procurement activities in New Jersey in connection with the Long-Term Capacity Agreement Pilot Program (LCAPP) and in Maryland through the Maryland Public Service Commission Request for Proposal and supporting rule changes which we believe are necessary to avoid artificial price suppression and other distortions in the energy and capacity markets.

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We continued to monitor and advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA). In particular, the EPA's 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. Clean Air Act regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology (MACT) rules are also of significance; however, we believe our generation business remains well-positioned for such regulations if and when they are implemented.

As discussed in further detail under Part II. Item 5. Other Information—Federal Regulation—Transmission Regulation— Transmission Policy Developments, the FERC's rules under Order 1000 altered the right of first refusal previously held by incumbent utilities to build all transmission within their respective service territories. We are challenging the FERC's determination in court as we do not believe that the FERC sufficiently justified its decision to alter this right embedded in the FERC-approved contracts and tariffs. At the same time, the FERC's action presents opportunities for us to construct transmission outside of our service territory.

At year-end 2012, we were severely impacted by Superstorm Sandy, which resulted in the highest level of customer outages in our history. We sustained significant damage to some of our generation, transmission and distribution facilities. The New Jersey Board of Public Utilities (BPU) issued an order allowing us to defer actually incurred prudent otherwise unreimbursed, incremental, storm restoration costs not otherwise recoverable through base rates or insurance. In February 2013, the BPU announced that it would initiate a generic proceeding to evaluate the prudency of extraordinary, storm-related costs incurred by all of the regulated utilities as a result of the natural disasters experienced in New Jersey in 2011 and 2012. In June 2013, we made a compliance filing with the BPU providing the details of our storm restoration costs for Superstorm Sandy as well as other major storms and seeking to demonstrate that we responded to these extreme weather events in a timely, diligent and thorough manner and that the costs incurred were prudent. We requested that the BPU issue an Order approving the compliance filing and specifically finding that the storm costs incurred were reasonable and prudent, and should be recovered from ratepayers.

As discussed further in Note 9. Commitments and Contingent Liabilities, in the first six months of 2013, Power incurred significant storm-related expenses, primarily for repair at certain of its coal and gas-fired generating stations. We are seeking recovery from our insurers for the property damage, above our self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. In June 2013, we filed suit against the insurance carriers seeking legal interpretation of certain terms in the insurance policies regarding losses resulting from damage caused by Superstorm Sandy's storm surge. For a more detailed discussion concerning this proceeding, refer to Part II Item 1. Legal Proceedings—Superstorm Sandy.

On February 20, 2013, we filed a petition with the BPU describing our Energy Strong program, consisting of $3.9 billion of proposed improvements we recommend making to our gas and electric distribution systems over a ten year period to harden and improve resiliency. In the petition, we sought approval for $2.6 billion of the $3.9 billion of investments over an initial five year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. We cannot predict the outcome of this pending proceeding, including whether the program will be approved or the terms under which it would be approved. We anticipate seeking BPU approval to complete our investment under the program at a later date. In addition, we anticipate investing an additional $1.5 billion in our transmission system for the same reason. As proposed, we believe that the rate impacts of the Energy Strong program will be significantly muted as a result of scheduled reductions to customer bills that will be taking place over the next few years and assuming continued low gas prices. See Part II Item 5. Other Information—State Regulation—Energy Strong Program for additional details.

We continue to take all necessary steps in connection with the expected January 1, 2014 commencement of our management of the Long Island Power Authority (LIPA) transmission and distribution (T&D) system. Legislation enacted in New York in July 2013 would enable us to have an expanded role in management of LIPA's T&D system. A proposed revised contract with LIPA is currently under negotiation. See Part II Item 5. Other Information—Business Operations and Strategy—Energy Holdings—Products and Services for additional details.

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Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented in the first half of the year as we remain diligent in managing costs. In the first six months of 2013, our

- outstanding performance allowed us to increase generation to meet loads, and
- construction of transmission and solar projects proceeded on schedule and within budget.

Financial Strength

Our financial position remained strong during the first six months of 2013 as we:

- had cash on hand of $164 million as of June 30, 2013,
- extended the expiration date of approximately half of our credit facilities, and maintained substantial liquidity and solid investment grade credit ratings, as evidenced by the recent credit rating upgrades by Standard & Poor's (S&P) of PSEG, Power and PSE&G as disclosed below in Liquidity and Capital Resources—Credit Ratings,
- completed pension and other postretirement benefit funding for 2013,
- refinanced PSE&G maturing debt at historically low rates and repaid Power's maturing debt with cash on hand, and
- increased our indicated annual dividend to $1.44.

We expect to be able to fund our proposed Energy Strong program with internally generated cash and external debt financing .

Disciplined Investment

We seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In addition to the proposed Energy Strong program discussed above, in the first six months of 2013 we

- made additional investments in transmission infrastructure projects,
- continued to execute our existing BPU-approved utility programs,
- obtained approval from the BPU to increase our spending up to $247 million and $199 million under our Solar 4 All Extension and Solar Loan III investment programs, respectively (see Part II. Item 5. Other Information—State Regulation for further detail), and
- continued construction of a 19 MW solar project in Arizona.

Delays in the construction schedules of our projects could impact their costs as well as the timing of expected revenues.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a difficult economy and cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully re-contract our open supply positions,
- execute our capital investment program, including investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and FERC of market design rules that continue to protect competition and achieve appropriate Reliability Pricing Model (RPM) and BGS pricing, and
- engage multiple stakeholders, including regulators, government officials, customers and investors.

For the remainder of 2013 and beyond, the key issues and challenges we expect our business to confront include

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- regulatory and political uncertainty, particularly with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation,
- uncertainty in the national and regional economic recovery and continuing customer conservation efforts, which impact customer demand,
- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate,
- the aftermath of Hurricane Irene and Superstorm Sandy, including addressing the BPU's review of performance and communications, as well as cost recovery and opportunities for investment in system strengthening, including our proposed Energy Strong program,
- financially-stressed power plant leveraged lease investments,
- delays and other obstacles that might arise in connection with the construction of our transmission and distribution projects, including in connection with permitting and regulatory approvals, and
- the successful transition to our management of the LIPA transmission and distribution system. See Part II Item 5. Other Information—Business Operations and Strategy—Products and Services for additional details.

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RESULTS OF OPERATIONS

The results for PSEG, PSE&G, Power and Energy Holdings for the three months and six months ended June 30, 2013 and 2012 are presented below:

Earnings (Losses)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	Millions			
Power	$ 204	$ 104	$ 341	$ 357
PSE&G	121	101	300	298
Energy Holdings	4	2	4	42
Other (A)	4	4	8	7
PSEG Net Income	**$ 333**	**$ 211**	**$ 653**	**$ 704**

Earnings Per Share (Diluted)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
PSEG Net Income	**$ 0.66**	**$ 0.42**	**$ 1.29**	**$ 1.39**

(A) Other primarily includes parent company interest and financing activity and certain administrative and general expenses.

Our results include the realized gains, losses and earnings on Power's Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity. This includes the net realized gains, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions. This also includes impairments on certain NDT securities which are included in Other-Than-Temporary Impairments and the interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO), which is recorded in Operation and Maintenance Expense and the depreciation related to the ARO asset.

Our results also include the after-tax impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the chart below:

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	Millions, after tax			
NDT Fund Income (Expense)	$ 8	$ 4	$ 17	$ 9
Non-Trading MTM Gains (Losses)	$ 80	$ (10)	$ (25)	$ 42

Our $122 million increase in Net Income for the three months ended June 30, 2013 was driven primarily by

- an increase in net MTM gains in 2013 resulting from a decrease in prices on forward positions, and
- higher revenues due to increased investments in transmission projects.

Our $51 million decrease in Net Income for the six months ended June 30, 2013 was driven primarily by

- lower average pricing and lower volumes of electricity sold under the BGS contracts and wholesale load contracts at Power,
- higher gas costs related to our BGSS contractual obligations and higher generation fuel costs,
- higher MTM losses due to an increase in prices on forward prices in PJM,

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- higher Operation and Maintenance Costs, including repairs related to damage caused by Superstorm Sandy, and
- higher Income Tax Expense due to the absence of tax benefits related to the settlement of the 1997-2006 Internal Revenue Service (IRS) audits in 2012.

The decreases were partially offset by

- higher capacity revenues and operating reserve revenues in PJM, and
- higher revenues due to increased investments in transmission projects.

PSEG

Our results of operations are primarily comprised of the results of operations of our operating subsidiaries, Power, PSE&G and Energy Holdings, excluding charges related to intercompany transactions, which are eliminated in consolidation. We also include certain financing costs, charitable contributions and general and administrative costs at the parent company. For additional information on intercompany transactions, see Note 18. Related-Party Transactions. For an explanation of the variances, see the discussions for Power, PSE&G and Energy Holdings that follow the table below:

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,310	$ 2,098	$ 212	10	$ 5,096	$ 4,973	$ 123	2
Energy Costs	755	761	(6)	(1)	1,910	1,940	(30)	(2)
Operation and Maintenance	646	629	17	3	1,356	1,257	99	8
Depreciation and Amortization	283	255	28	11	573	511	62	12
Taxes Other than Income Taxes	14	20	(6)	(30)	35	49	(14)	(29)
Income from Equity Method Investments	3	2	1	50	5	2	3	N/A
Other Income and (Deductions)	39	32	7	22	71	60	11	18
Other-Than-Temporary Impairments	2	7	(5)	(71)	4	12	(8)	(67)
Interest Expense	101	103	(2)	(2)	203	204	(1)	—
Income Tax Expense	218	146	72	49	438	358	80	22

Power

	Three Months Ended June 30,		Increase/ (Decrease)	Six Months Ended June 30,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012
	Millions					
Net Income	$ 204	$ 104	$ 100	$ 341	$ 357	$ (16)

For the three months ended June 30, 2013, the primary reason for the $100 million increase in Net Income was net MTM gains in 2013 resulting from a decrease in prices on forward positions as well as higher capacity payments, partially offset by lower generation prices and volumes.

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For the six months ended June 30, 2013, the primary reasons for the $16 million decrease in Net Income were:

- lower average pricing and lower volumes of electricity sold under our BGS contracts,
- lower volumes on wholesale load contracts in the PJM and New England regions,
- lower net revenues due to MTM losses in 2013 due to an increase in prices on forward positions in the PJM region,
- higher gas costs related to obligations under the BGSS contract and higher generation costs due to higher fuel costs, and
- higher Operation and Maintenance Costs in 2013, including costs related to damage caused by Superstorm Sandy at our fossil plants,

These decreases were partially offset by

- higher capacity revenues resulting from higher auction prices and an increase in operating reserve revenue in PJM, and
- higher sales volumes and gas prices under the BGSS contract due to colder average temperatures in 2013.

The quarter and year-to date details for these variances are discussed below:

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$1,190	$ 985	$ 205	21	$ 2,637	$ 2,546	$ 91	4
Energy Costs	496	447	49	11	1,356	1,269	87	7
Operation and Maintenance	280	284	(4)	(1)	562	525	37	7
Depreciation and Amortization	65	58	7	12	129	115	14	12
Other Income (Deductions)	25	20	5	25	44	35	9	26
Other-Than-Temporary Impairments	2	7	(5)	(71)	4	12	(8)	(67)
Interest Expense	29	32	(3)	(9)	59	62	(3)	(5)
Income Tax Expense	139	73	66	90	230	241	(11)	(5)

Three Months Ended June 30, 2013 As Compared to 2012

Operating Revenues increased $205 million due to changes in generation and gas supply revenues.

Generation Revenues increased $182 million due primarily to

- a net increase of $181 million due primarily to MTM gains in 2013 in the PJM and New York regions resulting from a change in prices on forward positions, and
- a net increase of $63 million due to higher capacity and other revenues, of which $54 million resulted from higher auction prices and $9 million from an increase in operating reserves in the PJM region,
- partially offset by a decrease of $37 million due to lower average pricing and lower volumes of electricity sold under our BGS contracts, and
- a decrease of $25 million due primarily to lower volumes on wholesale load contracts in the PJM and New England regions.

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Gas Supply Revenues increased $23 million due primarily to

- a net increase of $15 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during 2013 at higher average gas prices, and
- an increase of $8 million due to higher average prices from sales to third party customers, partially offset by lower volumes.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $49 million due to

- ***Generation costs*** increased $32 million due primarily to $64 million of higher fuel costs reflecting higher average realized natural gas prices and higher nuclear fuel prices and MTM losses resulting from lower prices on forward positions in 2013. This increase was partially offset by $16 million of lower load contract volumes in 2013 and $16 million related to lower congestion costs in the PJM region.
- ***Gas costs*** increased $17 million, principally related to obligations under the BGSS contract, reflecting higher sales volumes in 2013 due primarily to colder average temperatures in 2013 and higher average prices on third-party sales, partially offset by lower volumes.

Operation and Maintenance decreased $4 million due primarily to the recognition of a $25 million insurance recovery related to Superstorm Sandy, partially offset by $22 million in incremental costs associated with Superstorm Sandy.

Depreciation and Amortization increased $7 million due primarily to a higher depreciable asset base, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut in June 2012 and completion of the steam path retrofit upgrade at our co-owned Peach Bottom Unit 2 in October 2012.

Other Income and (Deductions) increased $5 million due primarily to higher net earnings from the NDT Fund in 2013.

Other-Than-Temporary Impairments decreased $5 million due primarily to a decrease in impairments on the NDT Fund in 2013.

Interest Expense decreased $3 million due primarily to a decrease from lower outstanding debt in 2013 resulting from certain debt redeemed prior to maturity in 2012, partially offset by higher interest costs in 2013 since interest capitalization ceased for our Kearny and New Haven gas-fired peaking projects on their June 2012 in-service date.

Income Tax Expense increased $66 million in 2013 due primarily to higher pre-tax income.

Six Months Ended June 30, 2013 As Compared to 2012

Operating Revenues increased $91 million due to changes in generation and gas supply revenues.

Gas Supply Revenues increased $94 million due primarily to

- a net increase of $65 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during 2013, partially offset by lower average gas prices, and
- an increase of $29 million due primarily to higher average gas prices partially offset by lower sales volumes to third party customers.

Generation Revenues decreased $3 million due primarily to

- a decrease of $70 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts,
- a net decrease of $73 million due to lower volumes on wholesale load contracts in the PJM and New England regions, and
- lower net revenues of $56 million due primarily to MTM losses in 2013 resulting from an increase in prices on forward positions in the PJM region, partially offset by higher generation sold in the PJM and New England regions at lower average realized prices in PJM,

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- partially offset by a net increase of $196 million due to higher capacity and other revenues resulting from higher auction prices and an increase in operating reserve revenue in PJM.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $87 million due to

- ***Gas costs*** increased $48 million, principally related to obligations under the BGSS contract, reflecting higher sales volumes in 2013 due to colder average temperatures in 2013, partially offset by lower average gas inventory costs.
- ***Generation costs*** increased $39 million due primarily to $119 million of higher fuel costs, reflecting the utilization of higher volumes of coal and oil and higher nuclear fuel costs, and higher unrealized natural gas prices. The increase was partially offset by $27 million of lower energy purchases primarily in the PJM region as a result of lower load contract demand in 2013 and a decrease of $53 million in congestion costs.

Operation and Maintenance increased $37 million due primarily to $50 million in costs incurred from Superstorm Sandy in 2013 at our fossil plants, and higher outage and maintenance costs in 2013, mainly at our Bergen gas-fired plant and our coal-fired Conemaugh plant in Pennsylvania. This was partially offset by the recognition of the $25 million insurance recovery related to Superstorm Sandy.

Depreciation and Amortization increased $14 million due primarily to a higher depreciable asset base, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut in June 2012 and completion of the steam path retrofit upgrade at our co-owned Peach Bottom Unit 2 in October 2012.

Other Income and (Deductions) increased $9 million due primarily to higher net earnings from the NDT Fund in 2013.

Other-Than-Temporary Impairments decreased $8 million due primarily to a decrease in impairments on the NDT Fund in 2013.

Interest Expense decreased $3 million due primarily to a decrease from lower outstanding debt in 2013 resulting from certain debt redeemed prior to maturity in 2012, partially offset by higher interest costs in 2013 since interest capitalization ceased for our Kearny and New Haven gas-fired peaking projects on their June 2012 in-service date.

Income Tax Expense decreased $11 million in 2013 due primarily to lower pre-tax income.

PSE&G

	Three Months Ended June 30,		Increase/ (Decrease)	Six Months Ended June 30,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012
	Millions					
Net Income	$ 121	$ 101	$ 20	$ 300	$ 298	$ 2

For the three months ended June 30, 2013, the primary reason for the $20 million increase in Net Income was higher transmission revenues due to increased investments in transmission projects.

For the six months ended June 30, 2013, the primary reasons for the $2 million increase in Net Income were

- higher transmission revenues due to increased investments in transmission projects, and
- higher Operation and Maintenance Expense primarily due to the Societal Benefits Charge (SBC) and the Capital Infrastructure programs (CIPs),
- partially offset by higher Income Tax Expense due to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012.

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The quarter and year-to-date details for these variances are discussed below:

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,423	$ 1,407	$ 16	1	$ 3,418	$ 3,346	$ 72	2
Energy Costs	580	622	(42)	(7)	1,547	1,624	(77)	(5)
Operation and Maintenance	369	350	19	5	796	726	70	10
Depreciation and Amortization	207	188	19	10	422	378	44	12
Taxes Other Than Income Taxes	14	20	(6)	(30)	35	49	(14)	(29)
Other Income (Deductions)	14	11	3	27	26	21	5	24
Interest Expense	75	74	1	1	148	147	1	1
Income Tax Expense	71	63	8	13	196	145	51	35

Three Months Ended June 30, 2013 As Compared to 2012

Operating Revenues increased $16 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $38 million due primarily to an increase in transmission revenues.

- Transmission revenues were $46 million higher due to net rate increases resulting primarily from increased capital investments.
- Electric distribution revenues increased $1 million due primarily to base rate increase of $8 million due to the roll in of the CIP from clause mechanism to inclusion in base rates, and higher Green Program Recovery Charges (GPRC) of $5 million, partially offset by lower Transitional Energy Facilities Assessment (TEFA) revenue of $6 million due to a lower TEFA rate and lower CIP revenue of $6 million due to the roll in to base rates.
- Gas distribution revenues decreased $9 million due primarily to lower Weather Normalization Clause (WNC) revenue of $22 million, partially offset by $10 million from higher sales volumes and $3 million of base rate increase due to the roll in of the CIP programs to base rates.

Clause Revenues increased $18 million due primarily to higher Securitization Transition Charge (STC) revenues of $10 million and higher SBC of $7 million. The changes in SBC and STC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in Operation and Maintenance (O&M), Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC or STC collections.

Other Operating Revenues increased $2 million due primarily to increased revenues from our appliance repair business.

Commodity Revenue decreased $42 million due to lower Electric revenues, partially offset by higher Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $57 million due primarily to $29 million in lower BGS revenues and $28 million in lower revenues from a lower volume of sales of Non-Utility Generation (NUG) energy and lower Non-Utility Generation Charges (NGC) due to lower tariff rates. BGS sales decreased 6% due primarily to customer migration to third party suppliers (TPS); in contrast, delivery sales increased by 3%.
- Gas revenues increased $15 million due to higher BGSS volumes of $11 million primarily due to weather and higher BGSS prices of $4 million. The average price of natural gas was 3% higher in 2013 than in 2012.

Energy Costs decreased $42 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $57 million or 11% due to $57 million in lower BGS and NUG volumes and $19 million of lower BGS and NUG prices, partially offset by $19 million for increased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.

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- Gas costs increased $15 million or 13% due to $11 million or 9% in higher sales volumes due primarily to weather and $4 million or 3% in higher prices.

Operation and Maintenance increased $19 million, due primarily to a $20 million increase in costs recognized related primarily to SBC and CIP. Due to the nature of the SBC and CIP clause mechanisms, this is entirely offset in revenues.

Depreciation and Amortization increased $19 million due primarily to

- a $13 million increase in amortization of Regulatory Assets, and
- a $6 million increase in depreciation of additional plant in service.

Taxes Other Than Income Taxes decreased $6 million due to a lower TEFA rate for electric and gas, partially offset by higher sales volumes for gas.

Other Income and (Deductions) net increase of $3 million was due primarily to an increase in Solar Loan interest income.

Interest Expense increased due primarily to higher average debt balances.

Income Tax Expense increased $8 million due primarily to higher pre-tax income.

Six Months Ended June 30, 2013 As Compared to 2012

Operating Revenues increased $72 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $92 million due primarily to an increase in transmission revenues.

- Transmission revenues were $85 million higher due to net rate increases resulting primarily from increased capital investments.
- Gas distribution revenues increased $12 million due primarily to $53 million from higher sales volumes and base rate increase of $14 million from the CIP base rate adjustment, partially offset by lower WNC revenue of $55 million.
- Electric distribution revenues decreased $5 million due primarily to lower TEFA revenue of $12 million due to a lower TEFA rate and lower CIP revenue of $11 million, partially offset by a base rate increase of $12 million from the CIP base rate adjustment, higher GPRC of $5 million and higher sales volumes of $1 million.

Clause Revenues increased $51 million due primarily to higher SBC of $25 million and higher STC revenues of $24 million. The changes in SBC and STC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC or STC collections.

Other Operating Revenues increased $6 million due primarily to increased revenues from our appliance repair business.

Commodity Revenue decreased $77 million due to lower Electric revenues, partially offset by higher Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $175 million due primarily to $123 million in lower BGS revenues and $52 million in lower revenues from a lower volume of sales of Non-Utility Generation (NUG) energy and lower Non-Utility Generation Charges (NGC) due to lower tariff rates. BGS sales decreased 6% due primarily to customer migration to third party suppliers (TPS); in contrast, delivery sales increased by 3%.
- Gas revenues increased $98 million due to higher BGSS volumes of $92 million and higher BGSS prices of $6 million. The average price of natural gas was 1% higher in 2013 than in 2012.

Energy Costs decreased $77 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $175 million or 16% due to $106 million in lower BGS and NUG volumes, $43 million of lower BGS and NUG prices, and $26 million for decreased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.
- Gas costs increased $98 million or 17% due to $92 million or 16% in higher sales volumes due primarily to weather and $6 million or 1% in higher prices.

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Operation and Maintenance increased $70 million, of which the most significant components were

- a $50 million increase in costs recognized related primarily to SBC and CIP. Due to the nature of the SBC and CIP clause mechanisms, this is entirely offset in revenues,
- a $8 million increase in costs relating to repairs from Superstorm Sandy and a colder winter, and
- a $6 million increase in appliance service costs.

Depreciation and Amortization increased $44 million due primarily to

- a $30 million increase in amortization of Regulatory Assets, and
- a $13 million increase in depreciation of additional plant in service.

Taxes Other Than Income Taxes decreased $14 million due to a lower TEFA rate for electric and gas, partially offset by higher sales volumes for gas.

Other Income and (Deductions) net increase of $5 million was due primarily to an increase in Solar Loan interest income.

Interest Expense increased due primarily to higher average debt balances.

Income Tax Expense increased $51 million due primarily to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012 and higher pre-tax income.

Energy Holdings

	Three Months Ended June 30,		Increase/ (Decrease)	Six Months Ended June 30,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012
	Millions					
Net Income	$ 4	$ 2	$ 2	$ 4	$ 42	$ (38)

For the six months ended June 30, 2013, the primary reason for the $38 million decrease in Net Income was the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in the prior year.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our three direct operating subsidiaries.

Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund capital expenditures and shareholder dividend payments.

For the six months ended June 30, 2013, our operating cash flow decreased $35 million as compared to the same period in 2012. The net change was due primarily to net changes from Power and PSE&G, as discussed below.

Power

Power's operating cash flow increased $2 million from $852 million to $854 million for the six months ended June 30, 2013, as compared to the same period in 2012, primarily resulting from a decrease in taxes paid of $58 million, partially offset by lower earnings and an increase of $44 million in margin deposits.

PSE&G

PSE&G's operating cash flow decreased $38 million from $459 million to $421 million for the six months ended June 30, 2013, as compared to the same period in 2012, due primarily to a decrease of $102 million related to higher customer billings due to colder weather, and $106 million related to higher tax payments. These were partially offset by higher earnings and an increase of $70 million due to a net change in regulatory deferrals primarily related to the recovery of gas costs and collection of Gas Weather Normalization Charges, offset by higher payments for storm related costs.

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Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our credit facilities are provided by a diverse bank group. In March 2013, Power, PSEG and PSE&G amended their respective 5-year credit agreements scheduled to end in 2016, extending the expiration dates from April 2016 to March 2018. Of the total commitments of $2.1 billion under these agreements, $2.0 billion has been extended until 2018. The commitments for the $100 million balance will terminate in 2016. As of June 30, 2013, our total credit capacity was $4.3 billion.

As of June 30, 2013, no single institution represented more than 8% of the total commitments in our credit facilities.

As of June 30, 2013, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of June 30, 2013 were as follows:

	As of June 30, 2013				
Company/Facility	**Total Facility**	**Usage**	**Available Liquidity**	**Expiration Date**	**Primary Purpose**
		Millions			
PSEG					
5-year Credit Facility	$ 500	$ 5 (D)	$ 495	Mar 2017	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—	500	Mar 2018	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 5**	**$ 995**		
Power					
5-year Credit Facility	$ 1,600	$ 54 (D)	$ 1,546	Mar 2017	Funding/Letters of Credit
5-year Credit Facility (B)	1,000	—	1,000	Mar 2018	Funding/Letters of Credit
Bilateral Credit Facility	100	100 (D)	—	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 154**	**$ 2,546**		
PSE&G					
5-year Credit Facility (C)	$ 600	$ 170 (E)	$ 430	Mar 2018	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 170**	**$ 430**		
Total	**$ 4,300**	**$ 329**	**$ 3,971**		

(A) In April 2016, this facility will be reduced by $23 million.

(B) In April 2016, this facility will be reduced by $48 million.

(C) In April 2016, this facility will be reduced by $29 million.

(D) Includes amounts related to letters of credit outstanding.

(E) Includes amounts related to CP and letters of credit outstanding.

Long-Term Debt Financing

PSE&G has $300 million of 5.38% MTN maturing in September 2013 and $275 million of 6.33% MTN maturing in November 2013. For a discussion of our long-term debt transactions during 2013, see Note 10. Changes in Capitalization.

Common Stock Dividends

On July 16, 2013, the Board of Directors declared a quarterly dividend of $0.36 per share of common stock for the third quarter of 2013. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For information related to cash dividends on our common stock, see Note 16. Earnings Per Share and Dividends.

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Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In April 2013, S&P upgraded the corporate credit ratings on PSEG, Power and PSE&G to BBB+ from BBB and PSE&G's Mortgage Bond rating to A from A-. PSEG's, Power's and PSE&G's outlooks were changed to stable from positive. In May 2013, Moody's published updated credit opinions on PSEG, Power and PSE&G. PSEG's, Power's and PSE&G's ratings and outlooks remained unchanged. In July 2013, Fitch published updated research on PSEG, Power and PSE&G which kept their ratings and outlooks unchanged.

	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	**Stable**	**Stable**	**Stable**
Commercial Paper	P2	A2	F2
Power			
Outlook	**Stable**	**Stable**	**Stable**
Senior Notes	Baa1	BBB+	BBB+
PSE&G			
Outlook	**Stable**	**Stable**	**Stable**
Mortgage Bonds	A1	A	A+
Commercial Paper	P2	A2	F2

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1+ (highest) to D (lowest) for short-term securities.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1+ (highest) to D (lowest) for short-term securities.

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CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. PSE&G has increased its projected base level capital expenditures by $215 million through 2015, as compared to the amounts disclosed in our Form 10-K for the year ended December 31, 2012. This increase primarily reflects our projected additional spending during the period under our Solar Loan III and Solar 4 All Extension programs which were approved by the BPU in May 2013. There were no other material changes to our projected capital expenditures at Power, PSE&G or Energy Holdings as compared to amounts disclosed in our Form 10-K for the year ended December 31, 2012. See Note 9. Commitments and Contingent Liabilities for additional information. Our revised projected capital construction and investment expenditures for the next three years are presented in the table below.

	2013	2014	2015
Power:		Millions	
Baseline Maintenance	$ 215	$ 170	$ 200
Environmental/Regulatory	70	70	15
Nuclear Expansion	115	125	90
Total Power	**$ 400**	**$ 365**	**$ 305**
PSE&G:			
Transmission			
Reliability Enhancements	$ 1,230	$ 1,040	$ 550
Facility Replacement	265	145	160
Support Facilities	10	15	10
Environmental/Regulatory	5	—	—
Distribution			
Reliability Enhancements	85	75	75
Facility Replacement	140	150	175
Support Facilities	45	50	45
New Business	125	130	135
Environmental/Regulatory	35	35	30
Renewables	105	125	125
Total PSE&G	**$ 2,045**	**$ 1,765**	**$ 1,305**
Non-Utility Renewables	50	—	—
Other	45	40	30
Total PSEG	**$ 2,540**	**$ 2,170**	**$ 1,640**

ACCOUNTING MATTERS

For information related to recent accounting matters, see Note 2. Recent Accounting Standards.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The market risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

Three Months Ended June 30, 2013	**MTM VaR**
	Millions
95% Confidence Level,	
Loss could exceed VaR one day in 20 days	
Period End	$ 19
Average for the Period	$ 15
High	$ 20
Low	$ 9
99.5% Confidence Level,	
Loss could exceed VaR one day in 200 days	
Period End	$ 30
Average for the Period	$ 23
High	$ 32
Low	$ 14

See Note 11. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the second quarter of 2013 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. Certain information reported under Item 3 of Part I of the 2012 Annual Report on Form 10-K and under Item 1 of Part II of the Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 is updated below. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2012 Annual Report on Form 10-K and under Item 1 of Part II of the Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, see Note 9. Commitments and Contingent Liabilities and Item 5. Other Information.

Superstorm Sandy

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. PSEG is seeking recovery from its insurers for the property damage, above its self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. PSEG has recorded proceeds of $50 million from its insurance carriers as advance payments, $25 million of which was recognized in this quarter and $25 million was recognized in the fourth quarter of 2012. PSEG does not believe that it has a basis for estimating additional probable insurance recoveries at this time. In June 2013, PSEG, Power and PSE&G filed suit in New Jersey state court against the insurance carriers seeking legal interpretation of certain terms in the insurance policies regarding losses resulting from damage caused by Superstorm Sandy's storm surge. The dispute concerns whether certain sub-limits in the policies apply to damage to property caused by Superstorm Sandy's storm surge. In that lawsuit, PSEG stated that its estimate of the total costs required to restore damaged facilities to their pre-Superstorm Sandy condition was approximately $426 million. Of these costs, $364 million and $62 million related to Power and PSE&G, respectively. No ruling has been issued on the suit.

Con Edison (Con Ed)

December 31, 2012 Form 10-K page 38. In 2001, Con Ed filed a complaint with the FERC against PSE&G, PJM and NYISO asserting a failure to comply with agreements between PSE&G and Con Ed covering 1,000 MW of transmission. In 2010, the FERC approved a settlement agreement of this matter entered into by PSE&G, Con Ed, PJM, NYISO and others, which provided the basis for moving forward with Con Ed upon the contracts' expiration and resolved all issues associated with the existing contracts. One party to the proceeding, however, appealed the FERC's approval to the D.C. Circuit Court of Appeals. By order dated June 14, 2013, the court denied the appeal, thereby upholding FERC's approval of the settlement and making the settlement agreement effective.

ITEM 1A. RISK FACTORS

There no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2012 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the second quarter of 2013:

Three Months Ended June 30, 2013	Total Number of Shares Purchased	Average Price Paid per Share
April 1 - April 30	—	$ —
May 1 - May 31	182,500	$ 35.85
June 1 - June 30	3,500	$ 33.03

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ITEM 5. OTHER INFORMATION

Certain information reported in the 2012 Annual Report on Form 10-K and Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2013 is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2012 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2013. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

BUSINESS OPERATIONS AND STRATEGY

Energy Holdings

Products and Services

December 31, 2012 Form 10-K page 13. Our ten-year contract, Operations Services Agreement (OSA), for the management of the Long Island Power Authority (LIPA) transmission and distribution system by PSEG Long Island LLC (PSEG LI) is scheduled to commence on January 1, 2014. On July 29, 2013, the Governor of New York signed legislation that will restructure LIPA, pursuant to which PSEG LI may undertake an expanded role in the management of LIPA's transmission and distribution system and other aspects of its operations in accordance with a proposed revised contract that is currently under negotiation. Assuming that an agreement is reached on the terms of a revised contract, implementation will depend, in part, on (i) issuance of a Private Letter Ruling by the Internal Revenue Service (IRS) on the continued tax-exempt status of certain LIPA debt securities and (ii) a disclaimer of jurisdiction by the FERC with regard to the contract. No assurances can be given as to the outcome of the negotiations or the actions of the IRS or the FERC.

We continue to take all necessary steps in connection with the expected January 1, 2014 commencement of our management responsibilities in accordance with the existing OSA.

FEDERAL REGULATION

FERC

PJM, the New York Independent System Operator (NYISO), and the Independent System Operator-New England (ISO-NE) each have capacity markets that have been approved by the FERC.

Capacity Market Issues—PJM

December 31, 2012 Form 10-K page 16. RPM is a locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of RPM in PJM continue to evolve and be refined in stakeholder proceedings in which we are active, and there is currently significant discussion about (i) the future role of demand response in the RPM market, including examining how demand response resources should be paid and how these resources and programs - both existing and planned - should be measured and verified to ensure their availability, (ii) the future process for submitting below Minimum Offer Price Rule (MOPR) bids by subsidized generation into the capacity market, as further discussed below and (iii) the impact of “seams” issues on the PJM capacity market, such as the extent to which the rules governing generation located within PJM are being equally applied to generation imported into PJM from the Midwest Independent System Operator (MISO), as further discussed below.

Capacity Market Issues—MISO

MISO does not have a mandatory capacity market in place, as load serving entities may submit Fixed Resource Adequacy Plans in lieu of participating in the capacity auction. Recently the difference between the MISO and PJM capacity markets has been highlighted, as significant amounts of MISO generation are being exported to PJM, and MISO is seeking to facilitate additional exports. The FERC is currently examining the "capacity portability" issue. To the extent that MISO generation is not subject to the same types of rules and requirements as generation located within PJM, Power could be adversely impacted.

Capacity Market Issues—Long-Term Capacity Agreement Pilot Program Act (LCAPP)

December 31, 2012 Form 10-K page 16 and March 31, 2013 Form 10-Q page 70. In 2011, the State of New Jersey concluded that new natural gas-fired generation was needed and enacted the LCAPP Act to subsidize approximately 2,000 MW of new generation. The LCAPP Act provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey Electric Distribution Companies (EDCs). The SOCA required each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers. Each of the New Jersey EDCs, including PSE&G, entered into the SOCAs as directed by the State, but did so under protest reserving their rights. In July 2013, the SOCA contract with New Jersey Power Development LLC, a subsidiary of NRG Energy, Inc., was terminated early as a result of a default by the generator. The generator has accepted this early termination and this SOCA contract is no longer in effect.

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Legal challenges to the BPU's implementation of the LCAPP Act were filed in New Jersey appellate court and the appeal remains pending. In addition, the LCAPP Act has been challenged on constitutional grounds in federal court. We are currently awaiting a decision by the federal court.

Maryland has also taken action to subsidize above-market new generation. On April 16, 2013, the Maryland Public Service Commission (PSC) issued an order directing the Maryland utility companies to execute a contract with CPV to build a new 661 MW natural gas-fired, combined cycle station in Maryland with an in-service date of June 2015. We have joined other generators in challenging Maryland's actions on constitutional grounds in federal court and we are currently awaiting a decision by the court in that case.

These efforts to artificially depress prices in the wholesale capacity markets were intended to be mitigated by the MOPR approved by the FERC. The MOPR was intended to restrict new generation from bidding in RPM at less than a minimum level established by PJM's Tariff, or a cost-based bid to the extent that the generator can demonstrate that its costs are lower than the MOPR. However, we do not believe these rules have worked as intended and have not protected the market against price suppression efforts. At the direction of the FERC, PJM has begun a stakeholder proceeding, the purpose of which is to develop an enhanced process applicable to subsidized generation seeking to bid into RPM at less than MOPR. We are currently working to ensure that this unit-specific review is both effective and transparent.

Transmission Regulations—Transmission Policy Developments

December 31, 2012 Form 10-K page 17 and March 31, 2013 Form 10-Q page 71. In 2010, the FERC initiated a proceeding to evaluate whether reforms to current transmission planning and cost allocation rules were necessary to stimulate additional transmission development. The FERC ultimately concluded in Order No. 1000, subject to certain exceptions, that the incumbent transmission owner should not always have a "right of first refusal" (ROFR) to construct and own transmission projects in its service territory. We have challenged the FERC's elimination of the ROFR in federal court, which challenge remains pending. The FERC has issued an order regarding PJM's implementation of these new transmission planning and cost allocation rules, under which the construction of certain types of transmission projects will no longer be subject to a ROFR for incumbents. The FERC's order also approved the "state agreement approach," under which transmission projects being built to address public policy concerns may be placed into PJM's planning process if the state sponsoring the project agrees to pay the costs of the project. To date, no such projects have been placed into the planning process but this mechanism could potentially facilitate transmission projects that are not needed for reliability or market efficiency under PJM standards for transmission, including potential offshore wind projects proposed by third parties, should a state or states agree to fund the costs of such projects.

Transmission Regulations—Transmission Rate Proceedings

December 31, 2012 Form 10-K page 18 and March 31, 2013 Form 10-Q page 71. In February 2013, several state utility commissions and consumer advocates, including the BPU and the New Jersey Division of Rate Counsel, filed a complaint at FERC challenging the base return on equity and formula transmission rate implementation protocols of transmission owners in Maryland, Pennsylvania, Delaware and New Jersey.

While we are not the subject of this complaint nor those reported in our 2012 Form 10-K, the results of these proceedings could set a precedent for the FERC-regulated transmission owners with formula rates in place, such as ours.

On June 7, 2013, the U.S. Seventh Circuit Court of Appeals issued a decision vacating a FERC order that had prevented MISO from allocating the costs of Multi-Value transmission projects (MVP), being built primarily to move renewable generation to load within MISO, to customers within PJM. The court held that the FERC had not adequately justified its decision and remanded the case back to the FERC to explain why such costs should not be allocated to PJM customers. Depending on the resolution of the remand proceeding at FERC, this court ruling may have adverse impacts on our business and our customers.

Nuclear Regulatory Commission (NRC)

December 31, 2012 Form 10-K page 19 and March 31, 2013 Form 10-Q page 71 . On March 19, 2013, the NRC initiated a rulemaking process for improvements to venting systems at 31 U.S. boiling water reactors (BWRs) with "Mark I" and "Mark II" containments (similar to those at Fukushima), which include our Hope Creek Unit and Peach Bottom Units 2 and 3. On June 6, 2013, the NRC issued orders requiring Mark I and Mark II licensees to upgrade or replace their reliable hardened vents with containment venting systems designed and installed to remain functional during severe accident conditions. For our Hope Creek and Peach Bottom units, final installation of the required modifications is expected to occur during the planned refueling outages in 2016-2018. The NRC is currently performing a technical evaluation to support rulemaking on the potential for vent filtering requirements. That evaluation is expected to be completed in March 2014. The NRC continues to evaluate potential revisions to its requirements in connection with its operational and safety reviews of nuclear facilities in the United States as a result of the Fukushima Daiichi incident in Japan in 2011. We are unable to predict the final outcome of

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these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to our Salem, Hope Creek and Peach Bottom facilities, but such cost could be material.

STATE REGULATION

Rates

Storm Damage Deferral

December 31, 2012 Form 10-K page 20. In December 2012, the BPU granted our request to defer on our books actually incurred prudent otherwise unreimbursed, incremental storm restoration costs not otherwise recoverable through base rates or insurance related to our gas and electric distribution systems associated with extraordinary storms, including Hurricane Irene and Superstorm Sandy. In February 2013, the BPU announced that it would initiate a generic proceeding to evaluate the prudency of extraordinary, storm-related costs incurred by all of the regulated utilities as a result of the natural disasters experienced in New Jersey in 2011 and 2012.

Energy Strong Program

December 31, 2012 Form 10-K page 20 and March 31, 2013 Form 10-Q page 71. In February 2013, we filed a petition with the BPU seeking approval of certain investments we recommend making to our BPU jurisdictional electric and gas system to harden and improve resiliency for the future through a clause recovery mechanism. We have continued to respond to data requests from the BPU and the New Jersey Division of Rate Counsel. In June 2013, the BPU issued an order designating a Presiding Officer for the Energy Strong Proceeding. The appointment of this Presiding Officer will enable the establishment of a procedural schedule for the proceeding. We cannot predict the outcome of this matter which remains pending before the BPU.

Energy Supply

BGSS

December 31, 2012 Form 10-K page 21. In September 2012, the BPU approved the Stipulation which lowered our BGSS rate effective October 1, 2012 on a provisional basis. In May 2013, the BPU approved a Stipulation that made the current BGSS rate final. Additionally, in May 2013 we made our annual BGSS filing with the BPU requesting no change to the current rate for the next BGSS period effective October 1, 2013 through September 30, 2014.

Energy Policy

Solar

March 31, 2013 Form 10-Q page 72. In May 2013, the BPU approved increased spending on renewable energy under our Solar Loan and Solar 4 All investment programs (Solar Loan III and Solar 4 All Extension, respectively). The Orders authorize us to invest up to $199 million on new solar (98MW) as part of the Solar Loan III program and provide for us to invest up to $247 million to develop new solar capacity (45MW), including a return on investment at a return on equity of 10%.

BPU Storm Generic Proceedings

March 31, 2013 Form 10-Q page 72. In March 2013, the BPU initiated two generic proceedings with the New Jersey utilities, including PSE&G. The first was an Order to evaluate the prudency of storm costs incurred in 2011 and 2012 and the second to evaluate major storm event mitigation proposals. In June 2013, we made our compliance filing in the storm cost prudency proceeding, providing outage information, capital expenditures, operation and maintenance (O&M) expenses and incremental O&M expenses. The review of the prudency of these expenses is now pending before the BPU. We cannot predict the outcome of this review.

BPU Storm Report

December 31, 2012 Form 10-K page 22. In 2011, the BPU commenced an investigation of all four New Jersey electric utilities, including PSE&G, to examine their preparations, performance and restoration efforts during Hurricane Irene and the October 2011 snow storm. In late 2012, the BPU commenced an investigation regarding the state of preparedness and responsiveness of the electric distribution companies prior to, during and after Superstorm Sandy. Following the completion of a report by its consultant, the BPU issued an order in January 2013, ordering the utilities to take specific action to improve their preparedness and responses to major storms. There are 103 separate measures contained in the Order, with most of the measures requiring utility implementation by September 2013. In May 2013, the BPU augmented its January 2013 order by directing the electric utilities to implement eight additional new requirements related to improving communications with customers during extreme weather events. PSE&G is in the process of implementing these BPU requirements.

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ENVIRONMENTAL MATTERS

Air Pollution Control

Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation

March 31, 2013 Form 10-Q page 72. On March 29 and April 1, 2013, we filed petitions at the EPA and in federal court, respectively, challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued on January 30, 2013. Among other things, the final EPA rule allows owners and operators of stationary emergency RICE to operate their engines as part of an emergency DR program without the installation and operation of emission controls or compliance with emission limits otherwise applicable to non-emergency counterparts. This waiver of NESHAP standards results in disparate treatment of different generation technology types. In our appeal, we are seeking more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. On June 28, 2013, the EPA announced that it would reconsider certain other items included in the final rule that are also subject to the appeal.

Cross-State Air Pollution Rule (CSAPR)

December 31, 2012 Form 10-K page 24 and March 31, 2013 Form 10-Q page 72. On July 6, 2011, the EPA issued the final CSAPR. CSAPR limits power plant emissions of SO_2 and annual and ozone season NOx in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards (NAAQS).

In August 2012, the U.S. Court of Appeals of the D.C. Circuit (D.C. Court) vacated CSAPR and ordered that the existing Clean Air Interstate Rule (CAIR) requirements remain in effect until an appropriate substitute rule has been promulgated. In October 2012, the EPA filed a request for rehearing which the D.C. Court denied on January 24, 2013. On June 24, 2013, the Supreme Court announced that it would review the D.C. Court's decision.

We currently anticipate that CSAPR, if implemented, will not have a material adverse impact to our capital investment program or our units' operations.

Climate Change

CO_2 Regulation Under the Clean Air Act (CAA)

December 31, 2012 Form 10-K page 24. In April 2013, several industrial groups petitioned the Supreme Court to review various EPA rules issued under the CAA, including the Tailoring Rule, to regulate greenhouse gas (GHG) emissions, including CO_2. The Tailoring Rule requires a new source or an existing source which undergoes a major modification, to evaluate and perhaps install best available control technology (BACT) for GHG emissions.

The EPA's BACT guidance does not define the specific technologies that should be considered BACT. The guidance does emphasize the use of energy efficiency, and specifically states that the technology of storing CO_2 under the earth, also known as carbon capture and storage, is not yet mature enough to be considered a viable alternative at this stage. In April 2012, the EPA published the proposed New Source Performance Standards (NSPS) for GHG for new power plants only. Typically, new or modified sources must employ BACT which is defined on a case-by-case basis and can be no less stringent than the applicable NSPS. Thus, for new power plants where the proposed NSPS identifies the applicable standard, if adopted as proposed, all permit decisions regarding BACT and application completeness should be made to reflect at least the level of stringency contained in those standards. On June 25, 2013, the President directed the EPA to propose revised NSPS for new power plants by September 20, 2013, propose GHG regulations for existing power plants by June 1, 2014, finalize such regulations by June 1, 2015 and require states to submit GHG implementation regulations by June 30, 2016.

Water Pollution Control

Cooling Water Intake Structure Regulation

December 31, 2012 Form 10-K page 25. In April 2011, the EPA published a proposed rule to establish marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. In July 2012, the EPA and environmental groups agreed to delay the deadline to June 27, 2013 for finalization of the Rule. On June 27, 2013, the EPA and environmental groups agreed to further extend the deadline to November 4, 2013.

If the rule were to be adopted as proposed, the impact on us would be material since the majority of our electric generating stations would be affected. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Note 9. Commitments and Contingent Liabilities for additional information.

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Steam Electric Effluent Guidelines

March 31, 2013 Form 10-Q page 72. On April 19, 2013, the EPA issued notice of a proposed rule that would further limit the discharge of pollutants in wastewater from the operation of coal-fired generating facilities. The EPA has established September 20, 2013 as the date comments must be filed. Our co-owned Keystone and Conemaugh facilities continue to use technologies that generate these wastewater discharges. However, our other coal-fired facilities no longer discharge many of these types of wastewater pollutants. We are unable to predict the impact on Keystone and Conemaugh but do not believe there would be any material impact on our other coal-fired facilities.

Fuel and Waste Disposal

Nuclear Fuel Disposal

December 31, 2012 Form 10-K page 26. The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In accordance with the Nuclear Waste Policy Act of 1982, in 2009 the U.S. Department of Energy (DOE) conducted its annual review of the adequacy of the Nuclear Waste Fee and concluded that the current fee of 1/10 cent per kWh was adequate to recover program costs. In 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit seeking suspension of the Nuclear Waste Fee. In June 2012, the U.S. Court of Appeals for the District of Columbia (D.C. Court) ruled that the DOE failed to justify continued payments by electricity consumers into the Nuclear Waste Fund and ordered the DOE to conduct a complete reassessment of this fee. In January 2013, the DOE completed its assessment and concluded that fee collection should be maintained. On January 31, 2013, motions were filed with the D.C. Court seeking to reopen the case and set a schedule for expedited review of the DOE fee adequacy report. In June 2013, the D.C. Court scheduled oral arguments for September 2013.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. Power:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. PSE&G:

Exhibit 4:	Supplemental Indenture, dated May 1, 2013
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: July 30, 2013

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PSEG POWER LLC
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: July 30, 2013

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SIGNATURE

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: July 30, 2013

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Exhibit 4

SUPPLEMENTAL MORTGAGE

Supplemental Indenture

Dated May 1, 2013

SUPPLEMENTAL TO
FIRST AND REFUNDING MORTGAGE
DATED AUGUST 1, 1924

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
TO
U.S. BANK NATIONAL ASSOCIATION
Trustee
21 South Street
Morristown, New Jersey 07960

PROVIDING FOR THE ISSUE OF
$1,800,000,000 FIRST AND REFUNDING MORTGAGE BONDS,
MEDIUM-TERM NOTES SERIES I

RECORD IN MORTGAGE BOOK AND RETURN TO:
M. COURTNEY McCORMICK, ESQ.
80 PARK PLAZA, T5B
NEWARK, N.J. 07102-4194

Prepared by

/s/ Donald S. Leibowitz

(DONALD S. LEIBOWITZ, ESQ.)

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SUPPLEMENTAL INDENTURE, dated the 1st day of May 2013 for convenience of reference and effective from the time of execution and delivery hereof, between PUBLIC SERVICE ELECTRIC AND GAS COMPANY, a corporation organized under the laws of the State of New Jersey, hereinafter called the "Company", party of the first part, and U.S. Bank National Association, a national banking association organized under the laws of the United States of America, as successor Trustee to Wachovia Bank, National Association (previously known as Fidelity Union Trust Company) under the indenture dated August 1, 1924, below mentioned, hereinafter called the "Trustee", party of the second part.

WHEREAS, on July 25, 1924, the Company executed and delivered to FIDELITY UNION TRUST COMPANY, a certain indenture dated August 1, 1924 (hereinafter called the "Indenture") to secure and to provide for the issue of First and Refunding Mortgage Gold Bonds of the Company; and

WHEREAS, the Indenture has been recorded in the following counties of the State of New Jersey, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Atlantic	Clerk's	1955 of Mortgages	160
Bergen	Clerk's	94 of Chattel Mortgages	123 etc.
Burlington	Clerk's	693 of Mortgages	88 etc.
		52 of Chattel Mortgages	Folio 8 etc.
Camden	Register's	177 of Mortgages	Folio 354 etc.
		45 of Chattel Mortgages	184 etc.
Cumberland	Clerk's	239 of Mortgages	1 etc.
		786 of Mortgages	638 & c.
Essex	Register's	437 of Chattel Mortgages	1-48
		T-51 of Mortgages	341-392
Gloucester	Clerk's	34 of Chattel Mortgages	123 etc.
Hudson	Register's	142 of Mortgages	7 etc.
		453 of Chattel Mortgages	9 etc.
		1245 of Mortgages	484, etc.
Hunterdon	Clerk's	151 of Mortgages	344
Mercer	Clerk's	67 of Chattel Mortgages	1 etc.
Middlesex	Clerk's	384 of Mortgages	1 etc.
		113 of Chattel Mortgages	3 etc.
		437 of Mortgages	294 etc.
Monmouth	Clerk's	951 of Mortgages	291 & c.
Morris	Clerk's	N-3 of Chattel Mortgages	446 etc.
		F-10 of Mortgages	269 etc.
Ocean	Clerk's	1809 of Mortgages	40
Passaic	Register's	M-6 of Chattel Mortgages	178, etc.
		R-13 of Mortgages	268 etc.
Salem	Clerk's	267 of Mortgages	249 etc.
Somerset	Clerk's	46 of Chattel Mortgages	207 etc.
Sussex	Clerk's	N-10 of Mortgages	1 etc.
		123 of Mortgages	10 & c.
Union	Register's	9584 of Mortgages	259 etc.
Warren	Clerk's	124 of Mortgages	141 etc.

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and

WHEREAS, the Indenture has also been recorded in the following counties of the Commonwealth of Pennsylvania, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Adams	Recorder's	22 of Mortgages	105
Armstrong	Recorder's	208 of Mortgages	381
Bedford	Recorder's	90 of Mortgages	917
Blair	Recorder's	671 of Mortgages	430
Cambria	Recorder's	407 of Mortgages	352
Cumberland	Recorder's	500 of Mortgages	136
Franklin	Recorder's	285 of Mortgages	373
Huntingdon	Recorder's	128 of Mortgages	47
Indiana	Recorder's	197 of Mortgages	281
Lancaster	Recorder's	984 of Mortgages	1
Montgomery	Recorder's	5053 of Mortgages	1221
Westmoreland	Recorder's	1281 of Mortgages	198
York	Recorder's	31-V of Mortgages	446

and

WHEREAS, the Indenture granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company, more fully set forth and described in the Indenture, then owned or which might thereafter be acquired by the Company; and

WHEREAS, the Company, by various supplemental indentures, supplemental to the Indenture, the last of which was dated June 1, 2012, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company acquired by it after the execution and delivery of the Indenture; and

WHEREAS, since the execution and delivery of said supplemental indenture dated May 1, 2012, the Company has acquired property which, in accordance with the provisions of the Indenture, is subject to the lien thereof and the Company desires to confirm such lien; and

WHEREAS, the Indenture has been amended or supplemented from time to time; and

WHEREAS, it is provided in the Indenture that no bonds other than those of the 5-1/2% Series due 1959 therein authorized may be issued thereunder unless a supplemental indenture providing for the issue of such additional bonds shall have been executed and delivered by the Company to the Trustee; and

WHEREAS, the Company is making provisions for the issuance and sale of its Secured Medium-Term Notes, Series I (the "Series I Notes"), to be issued under an Indenture of Trust (the "Note Indenture") dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as Trustee (the "Note Trustee"); and

WHEREAS, such Note Indenture provides, among other things, for the pledge and delivery by the Company of a series of First and Refunding Mortgage Bonds of the Company to evidence the Company's obligation to pay the principal and interest with respect to outstanding Series I Notes; and for such purpose and in order to service and secure payment of the principal and interest in respect of the Series I Notes, the Company desires to provide for the issue of $1,800,000,000 aggregate principal amount of bonds under the Indenture of a series to be designated as "First and Refunding Mortgage Bonds, Medium-Term Notes Series I" (hereinafter sometimes called "Bonds of the Medium-Term Notes Series I"); and

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WHEREAS, the text of the Bonds of the Medium-Term Notes Series I and of the certificate of authentication to be borne by the Bonds of the Medium-Term Notes Series I shall be substantially of the following tenor:

(FORM OF BOND)

This Bond is not transferable except as provided in the Indenture and in the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor trustee) as Trustee.

REGISTERED NUMBER R
REGISTERED AMOUNT
$1,800,000,000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
FIRST AND REFUNDING MORTGAGE BOND,
MEDIUM-TERM NOTES SERIES I

Public Service Electric and Gas Company (hereinafter called the "Company"), a corporation of the State of New Jersey, for value received, hereby promises to pay to The Bank of New York Mellon as successor trustee to The Chase Manhattan Bank (National Association)), under the Indenture of Trust dated as of July 1, 1993 between the Company and such trustee, or registered assigns, on the surrender hereof, the principal sum of One Billion Eight Hundred Million Dollars, on May 1, 2048, and to pay interest thereon from the date hereof, at the rate of 10% per annum, and until payment of said principal sum, such interest to be payable May 1 and November 1 in each year; provided, however, that the Company shall receive certain credits against such obligations as set forth in the Supplemental Indenture dated May 1, 2013 referred to below.

Both the principal hereof and interest hereon shall be paid at the principal corporate trust office of U.S. Bank National Association in the City of Morristown, State of New Jersey, or (at the option of the registered owner) at the corporate trust office of any paying agent appointed by the Company, in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts; provided, however, that any such payments of principal and interest shall be subject to receipt of certain credits against such payment obligations as set forth in the Supplemental Indenture dated May 1, 2013 referred to below.

This Bond is one of the First and Refunding Mortgage Bonds of the Company issued and to be issued under and pursuant to, and all equally secured by, an indenture of mortgage or deed of trust dated August 1, 1924, as supplemented and amended by supplemental indentures thereto, including the Supplemental Indenture dated May 1, 2013, duly executed by the Company and U.S. Bank National Association as Trustee. This Bond is one of the Bonds of the Medium-Term Notes Series I, which series is limited to the aggregate principal amount of $1,800,000,000 and is issued pursuant to said Supplemental Indenture dated May 1, 2013. Reference is hereby made to said indenture and all supplements thereto for a specification of the principal amount of Bonds from time to time issuable thereunder, and for a description of the properties mortgaged and conveyed or assigned to said Trustee or its successors, the nature and extent of the security, and the rights of the holders of said Bonds and any coupons appurtenant thereto, and of the Trustee in respect of such security.

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In and by said indenture, as amended and supplemented, it is provided that with the written approval of the Company and the Trustee, any of the provisions of said indenture may from time to time be eliminated or modified and other provisions may be added thereto provided the change does not alter the annual interest rate, redemption price or date, date of maturity or amount payable on maturity of any then outstanding Bond or conflict with the Trust Indenture Act of 1939 as then in effect, and provided the holders of 85% in principal amount of the Bonds secured by said indenture and then outstanding (including, if such change affects the Bonds of one or more series but less than all series then outstanding, a like percentage of the then outstanding Bonds of each series affected by such change, and excluding Bonds owned or controlled by the Company or by the parties owning at least 10% of the outstanding voting stock of the Company, as more fully specified in said indenture) consent in writing thereto, all as more fully set forth in said indenture, as amended and supplemented.

First and Refunding Mortgage Bonds issuable under said indenture are issuable in series, and the Bonds of any series may be for varying principal amounts and in the form of coupon bonds and of registered bonds without coupons, and the Bonds of any one series may differ from the Bonds of any other series as to date, maturity, interest rate and otherwise, all as in said indenture provided and set forth. The Bonds of the Medium-Term Notes Series I, in which this Bond is included, are designated "First and Refunding Mortgage Bonds, Medium-Term Notes Series I".

In case of the happening of an event of default as specified in said indenture and said supplemental indenture dated March 1, 1942, the principal sum of the Bonds of this series may be declared or may become due and payable forthwith, in the manner and with the effect in said indenture provided.

The Bonds of this series are subject to redemption as provided in the Supplemental Indenture dated May 1, 2013.

This Bond is transferable, but only as provided in said indenture and the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as trustee, upon surrender hereof, by the registered owner in person or by attorney duly authorized in writing, at either of said offices where the principal hereof and interest hereon are payable; upon any such transfer a new fully registered Bond similar hereto will be issued to the transferee. This Bond may in like manner be exchanged for one or more new fully registered Bonds of the same series of other authorized denominations but of the same aggregate principal amount. No service charge shall be made for any such transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto. The Company and the Trustee hereunder and any paying agent may deem and treat the person in whose name this Bond is registered as the absolute owner hereof for the purpose of receiving payment of or on account of the principal hereof and the interest hereon and for all other purposes; and neither the Company nor the Trustee hereunder nor any paying agent shall be affected by any notice to the contrary.

The Bonds of this series are issuable only in fully registered form, in any denomination authorized by the Company.

No recourse under or upon any obligation, covenant or agreement contained in said indenture or in any indenture supplemental thereto, or in any Bond issued thereunder, or because of any indebtedness arising thereunder, shall be had against any incorporator, or against any past, present or future stockholder, officer, or director, as such, of the Company or of any successor corporation, either directly or through the Company or any successor corporation, under any rule of law, statute or constitutional provision or by the enforcement of any assessment or by any legal or equitable proceeding or otherwise, it being expressly agreed and understood that said indenture, any indenture supplemental thereto and the obligations issued thereunder, are solely corporate obligations, and that no personal liability whatever shall attach to, or be incurred by, such incorporators, stockholders, officers or directors, as such, of the Company, or of any successor corporation, or any of them, because of the incurring of the indebtedness thereby authorized, or under or by reason of any of the obligations, covenants or agreements contained in the indenture or in any indenture supplemental thereto or in any of the Bonds issued thereunder, or implied therefrom.

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This Bond shall not be entitled to any security or benefit under said indenture, as amended and supplemented, and shall not become valid or obligatory for any purpose, until the certificate of authentication, hereon endorsed, shall have been signed by U.S. Bank National Association as Trustee, or by its successor in trust under said indenture.

IN WITNESS WHEREOF, the Company has caused this Bond to be duly executed by its proper officers under its corporate seal.

Dated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY,

By. . . . . .
(Vice) President

(Seal)

Attest:

. . . . . .
(Assistant) Secretary

(FORM OF CERTIFICATE OF AUTHENTICATION)
CERTIFICATE OF AUTHENTICATION

This Bond is one of the Bonds of the series designated therein which is described in the within-mentioned indenture and supplemental indenture dated May 1, 2013, as secured thereby.

U.S. BANK NATIONAL ASSOCIATION, TRUSTEE,

By. . . . .

. . . . . .

Authorized Signatory

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WHEREAS, the execution and delivery of this supplemental indenture have been duly authorized by the Board of Directors of the Company; and

WHEREAS, the Company represents that all things necessary to make the bond of the series hereinafter described, when duly authenticated by the Trustee and issued by the Company, a valid, and legal obligation of the Company, and to make this supplemental indenture a valid and binding agreement supplemental to the Indenture, have been done and performed:

NOW, THEREFORE, THIS SUPPLEMENTAL INDENTURE WITNESSETH that the Company, in consideration of the premises and the execution and delivery by the Trustee of this supplemental indenture, and in pursuance of the covenants and agreements contained in the Indenture and for other good and valuable consideration, the receipt of which is hereby acknowledged, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over, and by these presents does grant, bargain, sell, alien, remise, release, convey, confirm, assign, transfer and set over unto the Trustee, its successors and assigns, forever, all the right, title and interest of the Company in and to all property of every kind and description (except cash, accounts and bills receivable and all merchandise bought, sold or manufactured for sale in the ordinary course of the Company's business, stocks, bonds or other corporate obligations or securities, other than such as are described in Part V of the Granting Clauses of the Indenture, not acquired with the proceeds of bonds secured by the Indenture, and except as in the Indenture and herein otherwise expressly excluded) acquired by the Company since the execution and delivery of the supplemental indenture dated May 1, 2012, subsequent to the Indenture (except any such property duly released from, or disposed of, free from the lien of the Indenture, in accordance with the provisions thereof) and all such property which at any time hereafter may be acquired by the Company;

All of which property it is intended shall be included in and granted by this supplemental indenture and covered by the lien of the Indenture as heretofore and hereby amended and supplemented;

UNDER AND SUBJECT to any encumbrances or mortgages existing on property acquired by the Company at the time of such acquisition and not heretofore discharged of record; and

SUBJECT also, to the exceptions, reservations and provisions in the Indenture and in this supplemental indenture recited, and to the liens, reservations, exceptions, limitations, conditions and restrictions imposed by or contained in the several deeds, grants, franchises and contracts or other instruments through which the Company acquired or claims title to the aforesaid property; and Subject, also, to the existing leases, to liens on easements or rights of way, to liens for taxes, assessments and governmental charges not in default or the payment of which is deferred, pending appeal or other contest by legal proceedings, pursuant to Section 4 of Article Five of the Indenture, or the payment of which is deferred pending billing, transfer of title or final determination of amount, to easements for alleys, streets, highways, rights of way and railroads that may run across or encroach upon the said property, to joint pole and similar agreements, to undetermined liens and charges, if any, incidental to construction, and other encumbrances permitted by the Indenture as heretofore and hereby amended and supplemented;

TO HAVE AND TO HOLD the property hereby conveyed or assigned, or intended to be conveyed or assigned, unto the Trustee, its successor or successors and assigns, forever;

IN TRUST, NEVERTHELESS, upon the terms, conditions and trusts set forth in the Indenture as heretofore and hereby amended and supplemented, to the end that the said property shall be subject to the lien of the Indenture as heretofore and hereby amended and supplemented, with the same force and effect as though said property had been included in the Granting Clauses of the Indenture at the time of the execution and delivery thereof;

AND THIS SUPPLEMENTAL INDENTURE FURTHER WITNESSETH that for the considerations aforesaid, it is hereby covenanted between the Company and the Trustee as follows:

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ARTICLE I.

BONDS OF THE MEDIUM-TERM NOTES SERIES I.

The series of bonds authorized by this supplemental indenture to be issued under and secured by the Indenture shall be designated "First and Refunding Mortgage Bonds, Medium-Term Notes Series I"; shall be limited to the aggregate principal amount of $1,800,000,000; shall be issued initially to the Note Trustee and shall mature and bear interest as set forth in the form of bond set forth herein; provided, however, that the Company shall receive certain credits against principal and interest as set forth in Section 3.01 hereof. The date of each Bond of the Medium-Term Notes Series I shall be the interest payment date next preceding the date of authentication, unless such date of authentication be an interest payment date, in which case the date shall be the date of authentication, or unless such date of authentication be prior to the first semi-annual interest payment date, in which case the date shall be May 1, 2013.

Bonds of the Medium-Term Notes Series I shall be issuable only in the form of fully registered bonds in any denomination authorized by the Company. Interest on the Bonds of the Medium-Term Notes Series I shall be payable semi-annually in arrears on May 1 and November 1 of each year, payable initially on November 1, 2013, subject to receipt of certain credits against principal and interest as set forth in Section 3.01 hereof and shall be payable as to both principal and interest in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts, at the principal corporate trust office of the Trustee, or at the corporate trust office of any paying agent appointed.

Bonds of the Medium-Term Notes Series I shall be transferable and exchangeable, but only as provided in the Indenture and the Note Indenture, upon surrender thereof for cancellation by the registered owner in person or by attorney duly authorized in writing at either of said offices. The Company hereby waives any right to make a charge for any transfer or exchange of Bonds of the Medium-Term Notes Series I, but the Company may require payment of a sum sufficient to cover any tax or any other governmental charge that may be imposed in relation thereto.

ARTICLE II.

REDEMPTION OF BONDS OF MEDIUM-TERM NOTES SERIES I.

SECTION 2.01. *Redemption—Redemption Price*. Bonds of the Medium-Term Notes Series I shall be subject to redemption prior to maturity under the conditions, and upon payment of the amounts as may be specified in the following conditions:

(a) at any time in whole or in part at the option of the Company upon receipt by the Trustee of written certification of the Company and of the Note Trustee that the principal amount of the Series I Notes then outstanding under the Note Indenture is not in excess of such principal amount of the Bonds of the Medium-Term Notes Series I as shall remain pledged to the Note Trustee after giving effect to such redemption; (b) at any time by the application of any proceeds of released property or other money held by the Trustee and which, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, are applied to the redemption of Bonds of the Medium-Term Notes Series I, upon payment of 100% of the principal amount thereof, together with interest accrued to the redemption date, provided that any such payment shall be subject to receipt by the Company of certain credits against such obligations as set forth in Section 3.01 hereof or (c) automatically upon failure to pay the principal of any Series I Notes then outstanding under the Note Indenture when due, on their stated maturity date or earlier redemption or repayment date, in a principal amount of Bonds of the Medium-Term Notes Series I equal to the principal amount of such Series I Notes, in each case, at a price equal to 100% of the principal amount thereof, together with accrued interest, if applicable.

SECTION 2.02. *Redemptions Pursuant to Section 4C of Article Eight of the Indenture*. If, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, any proceeds of released property or other money then held by the Trustee shall be applied to the redemption of the Bonds of the Medium-Term Notes Series I, the Trustee shall give at least 45 days prior written notice of such redemption to the Note

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Trustee whereupon on the date fixed for redemption such principal amount thereof as is equal to such proceeds shall be redeemed; provided that no such redemption shall be made unless the Trustee shall be in receipt of a written certification of the Company and the Note Trustee that a like principal amount of Series I Notes shall have been theretofore redeemed in accordance with the provisions of the Note Indenture. For purposes of determining which of the Company's First and Refunding Mortgage Bonds are subject to such mandatory redemption, the Mortgage Trustee shall consider the 10% stated annual interest rate of the Bonds of the Medium-Term Notes Series I, not the weighted average interest rate of outstanding Series I Notes. Bonds of said series so redeemed shall be cancelled.

SECTION 2.03. *Interest on Called Bonds to Cease.* Each Bond of the Medium-Term Notes Series I or portion thereof called for redemption under Section 2.02 hereof shall be due and payable at the office of the Note Trustee, as paying agent hereunder, at its redemption price and on the specified redemption date, anything herein or in such Bond to the contrary notwithstanding. From and after the date when each Bond of the Medium-Term Notes Series I or portion thereof shall be due and payable as aforesaid (unless upon said date the full amount due thereon shall not be held by the Note Trustee, as paying agent hereunder, and be immediately available for payment), all further interest shall cease to accrue on such bond or on such portion thereof, as the case may be.

SECTION 2.04. *Bonds Called in Part.* If only a portion of any Bond of the Medium-Term Notes Series I shall be called for redemption pursuant to Section 2.02 hereof, upon payment of the portion so called for redemption, the Note Trustee shall make an appropriate notation upon the Bond of the principal amount so redeemed.

SECTION 2.05. *Provisions of Indenture Not Applicable*. The provisions of Article Four of the Indenture, as amended and supplemented, shall not apply to the procedure for the exercise of any right of redemption reserved by the Company, or to any mandatory redemption provided, in this Article in respect of the Bonds of the Medium-Term Notes Series I. There shall be no sinking fund for the Bonds of the Medium-Term Notes Series I.

ARTICLE III.

CREDITS WITH RESPECT TO BONDS OF THE MEDIUM-TERM NOTES SERIES I.

SECTION 3.01. *Credits.* In addition to any other credit, payment or satisfaction to which the Company is entitled with respect to the Bonds of the Medium-Term Notes Series I, the Company shall be entitled to credits against amounts otherwise payable in respect of the Bonds of the Medium-Term Notes Series I in an amount corresponding to (i) the principal amount of any of the Company's Series I Notes issued under the Note Indenture surrendered to the Note Trustee by the Company, or purchased by the Note Trustee, for cancellation, (ii) the amount of money held by the Note Trustee and available and designated for the payment of principal or redemption price (exclusive of any premium) of, and/or interest on, the Series I Notes, regardless of the source of payment to the Note Trustee of such moneys and (iii) the amount by which principal of and interest due on the Bonds of the Medium-Term Notes Series I exceeds principal of and interest due on the Series I Notes. The Note Trustee shall make notation on such Bonds authorized hereby of any such credit.

SECTION 3.02. *Certificate of the Company.* A certificate of the Company signed by the President or any Vice President, and attested to by the Secretary or any Assistant Secretary, and consented to by the Note Trustee, stating that the Company is entitled to a credit under Section 3.01 hereof or that Bonds of the Medium-Term Notes Series I have been cancelled, and setting forth the basis therefor in reasonable detail, shall be conclusive evidence of such entitlement, and the Trustee shall accept such certificate as such evidence without further investigation or verification of the matters stated therein.

ARTICLE IV.

MISCELLANEOUS.

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SECTION 4.01. *Authentication of Bonds of Medium-Term Notes Series I.* None of the Bonds of the Medium-Term Notes Series I, the issue of which is provided for by this supplemental indenture, shall be authenticated by or on behalf of the Trustee except in accordance with the provisions of the Indenture, as amended and supplemented, and this supplemental indenture, and upon compliance with the conditions in that behalf therein contained.

SECTION 4.02. *Additional Restrictions on Authentication of Additional Bonds Under Indenture.* The Company covenants that from and after the date of execution of this supplemental indenture no additional bonds (as defined in Section 1 of Article Two of the Indenture) shall be authenticated and delivered by the Trustee under Subdivision A of Section 4 of said Article Two on account of additions or improvements to the mortgaged property;

(1) unless the net earnings of the Company for the period required by Subdivision C of Section 6 of said Article Two shall have been at least twice the fixed charges (in lieu of 1-3/4 times such fixed charges, as required by said Subdivision C); and for the purpose of this condition (a) such fixed charges shall in each case include interest on the bonds applied for, notwithstanding the parenthetical provision contained in clause (4) of said Subdivision C, and (b) in computing such net earnings there shall be included in expenses of operation (under paragraph (c) of said Subdivision C) all charges against earnings for depreciation, renewals or replacements, and all certificates with respect to net earnings delivered to the Trustee in connection with any authentication of additional bonds under said Article Two shall so state; and (2) except to the extent of 60% (in lieu of 75% as permitted by Subdivision A of Section 7 of said Article Two) of the cost or fair value to the Company of the additions or improvements forming the basis for such authentication of additional bonds.

SECTION 4.03. *Restriction on Dividends.* The Company will not declare or pay any dividend on any shares of its common stock (other than dividends payable in shares of its common stock) or make any other distribution on any such shares, or purchase or otherwise acquire any such shares (except shares acquired without cost to the Company) whenever such action would reduce the earned surplus of the Company to an amount less than $10,000,000 or such lesser amount as may remain after deducting from said $10,000,000 all amounts appearing in the books of account of the Company on December 31, 1948, which shall thereafter, pursuant to any order or rule of any regulatory body entered after said date, be required to be removed, in whole or in part, from the books of account of the Company by charges to earned surplus.

SECTION 4.04. *Use of Facsimile Seal and Signatures.* The seal of the Company and any or all signatures of the officers of the Company upon any of the Bonds of the Medium-Term Notes Series I may be facsimiles.

SECTION 4.05. *Time for Making of Payment.* All payments of principal or redemption price of, and interest on, the Bonds of the Medium-Term Notes Series I shall be made either prior to the due date thereof or on the due date thereof in immediately available funds. In any case where the date of any such payment shall be a Saturday or Sunday or a legal holiday or a day on which banking institutions in the city of payment are authorized by law to close, then such payment need not be made on such date but may be made on the next succeeding business day with the same force and effect as if made on the due date, and no interest on such payment shall accrue for the period after such date.

SECTION 4.06. *Effective Period of Supplemental Indenture.* The preceding provisions of Articles I, II and III of this supplemental indenture shall remain in effect only so long as any of the Bonds of the Medium-Term Notes Series I shall remain outstanding.

SECTION 4.07. *Effect of Approval of Board of Public Utilities of the State of New Jersey.* The approval of the Board of Public Utilities of the State of New Jersey of the execution and delivery of these presents and of the issue of any Bond of the Medium-Term Notes Series I shall not be construed as approval of said Board of any other act, matter or thing which requires approval of said Board under the laws of the State of New Jersey.

SECTION 4.08. *Execution in Counterparts.* For the purpose of facilitating the recording hereof, this supplemental indenture has been executed in several counterparts, each of which shall be and shall be taken to be an original, and all collectively but one instrument.

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IN WITNESS WHEREOF, Public Service Electric and Gas Company, party hereto of the first part, after due corporate and other proceedings, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents and its corporate seal hereunto to be affixed and to be attested by the signature of its Secretary or an Assistant Secretary; and U.S. Bank National Association, as Trustee, party hereto of the second part, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents, and its corporate seal to be hereunto affixed and to be attested by the signature of its Secretary, Assistant Secretary, Vice President, or an Assistant Vice President. Executed and delivered this 2nd day of May 2013.

Attest:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By /s/ B.D. Huntington
. . . . . .
B.D. Huntington
Vice President

Attest:

/s/ M.C. McCormick
. . . . . .
M.C. McCormick
Secretary

U.S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes
. . . . . .
N. Barnes
Vice President

Attest:

/s/ P. O'Brien
. . . . . .
P. O'Brien
Vice President

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STATE OF NEW JERSEY)

SS:)
COUNTY OF ESSEX)

Be it Remembered, that on this 2nd day of May, 2013, before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared B.D. Huntington, who, I am satisfied, is a Vice President of Public Service Electric and Gas Company, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors, and that said corporation, the mortgagor, has received a true copy of said instrument.

/s/ Susan M. Costello
. . . . . .
Susan M. Costello
Notary Public of New Jersey
My Commission Expires March 26, 2017

STATE OF NEW JERSEY)

SS:)
COUNTY OF ESSEX)

Be it Remembered, that on this 2nd day of May 2013 before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared N. Barnes, who, I am satisfied, is a Vice President of U.S. Bank National Association, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, and that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors.

/s/ Melody A. Simpson
.....
Melody A. Simpson
Notary Public of New Jersey
My Commission Expires March 1, 2016

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CERTIFICATE OF RESIDENCE

U.S. Bank National Association, Mortgagee and Trustee within named, hereby certifies that its precise residence is 21 South Street, Morristown, New Jersey 07960.

U.S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes

. . . . . .

N. Barnes
Vice President

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,091	$ 1,062	$ 2,011	$ 2,384	$ 2,616	$ 2,636	$ 1,806
(Income) Loss from Equity Investees, net of Distributions	(2)	4	9	(4)	(19)	(25)	(5)
Fixed Charges	230	234	479	522	571	600	633
Capitalized Interest	(7)	(12)	(19)	(14)	(67)	(45)	(37)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	(2)	(6)	(6)
Total Earnings	$ 1,312	$ 1,288	$ 2,480	$ 2,888	$ 3,099	$ 3,160	$ 2,391
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 222	$ 227	$ 465	$ 509	$ 555	$ 581	$ 615
Interest Factor in Rentals	8	7	14	13	14	13	12
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	2	6	6
Total Fixed Charges	$ 230	$ 234	$ 479	$ 522	$ 571	$ 600	$ 633
Ratio of Earnings to Fixed Charges	5.70	5.50	5.18	5.53	5.43	5.27	3.78

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12.1

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 571	$ 598	$ 1,080	$ 1,687	$ 1,914	$ 1,958	$ 1,711
Fixed Charges	72	80	163	208	238	221	210
Capitalized Interest	1	(6)	(4)	(10)	(62)	(43)	(31)
Total Earnings	$ 644	$ 672	$ 1,239	$ 1,885	$ 2,090	$ 2,136	$ 1,890
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 70	$ 79	$ 161	$ 205	$ 235	$ 219	$ 208
Interest Factor in Rentals	2	1	2	3	3	2	2
Total Fixed Charges	$ 72	$ 80	$ 163	$ 208	$ 238	$ 221	$ 210
Ratio of Earnings to Fixed Charges	8.94	8.40	7.60	9.06	8.78	9.67	9.00

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 496	$ 443	$ 835	$ 861	$ 591	$ 551	$ 592
Fixed Charges	159	156	314	319	325	317	325
Capitalized Interest	(8)	(6)	(13)	(4)	(2)	(1)	—
Total Earnings	$ 647	$ 593	$ 1,136	$ 1,176	$ 914	$ 867	$ 917
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 156	$ 153	$ 308	$ 314	$ 320	$ 313	$ 325
Interest Factor in Rentals	3	3	6	5	5	4	—
Total Fixed Charges	$ 159	$ 156	$ 314	$ 319	$ 325	$ 317	$ 325
Ratio of Earnings to Fixed Charges	4.07	3.80	3.62	3.69	2.81	2.74	2.82

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.3

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Six Months Ended June 30,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 496	$ 443	$ 835	$ 861	$ 591	$ 551	$ 592
Fixed Charges	159	156	314	319	327	323	332
Capitalized Interest	(8)	(6)	(13)	(4)	(2)	(1)	—
Preferred Securities Dividend Requirements	—	—	—	—	(2)	(6)	(6)
Total Earnings	$ 647	$ 593	$ 1,136	$ 1,176	$ 914	$ 867	$ 918
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 156	$ 153	$ 308	$ 314	$ 320	$ 313	$ 325
Interest Factor in Rentals	3	3	6	5	5	4	—
Preferred Securities Dividend	—	—	—	—	1	4	4
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	—	—	1	2	2
Total Fixed Charges	$ 159	$ 156	$ 314	$ 319	$ 327	$ 323	$ 331
Ratio of Earnings to Fixed Charges	4.07	3.80	3.62	3.69	2.80	2.68	2.77

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 30, 2013

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 30, 2013

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 30, 2013

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 30, 2013

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 30, 2013

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 30, 2013

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
July 30, 2013

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer
July 30, 2013

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
July 30, 2013

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Caroline Dorsa

Caroline Dorsa

PSEG Power LLC
Chief Financial Officer
July 30, 2013

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
July 30, 2013

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer
July 30, 2013

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2014
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of July 15, 2014, Public Service Enterprise Group Incorporated had outstanding 505,886,756 shares of its sole class of Common Stock, without par value.

As of July 15, 2014, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words “anticipate,” “intend,” “estimate,” “believe,” “expect,” “plan,” “should,” “hypothetical,” “potential,” “forecast,” “project,” variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission in the future, and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- any deterioration in our credit quality or the credit quality of our counterparties,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as competition for certain transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies, and
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
OPERATING REVENUES	$ 2,249	$ 2,310	$ 5,472	$ 5,096
OPERATING EXPENSES				
Energy Costs	789	755	2,145	1,910
Operation and Maintenance	800	646	1,656	1,356
Depreciation and Amortization	295	283	601	573
Taxes Other Than Income Taxes	—	14	—	35
Total Operating Expenses	1,884	1,698	4,402	3,874
OPERATING INCOME	365	612	1,070	1,222
Income from Equity Method Investments	3	3	7	5
Other Income	62	52	110	113
Other Deductions	(10)	(13)	(22)	(42)
Other-Than-Temporary Impairments	(2)	(2)	(4)	(4)
Interest Expense	(94)	(101)	(191)	(203)
INCOME BEFORE INCOME TAXES	324	551	970	1,091
Income Tax Expense	(112)	(218)	(372)	(438)
NET INCOME	$ 212	$ 333	$ 598	$ 653
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):				
BASIC	505,875	505,900	505,976	505,921
DILUTED	508,056	507,381	507,949	507,301
NET INCOME PER SHARE:				
BASIC	$ 0.42	$ 0.66	$ 1.18	$ 1.29
DILUTED	$ 0.42	$ 0.66	$ 1.18	$ 1.29
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.37	$ 0.36	$ 0.74	$ 0.72

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
NET INCOME	$ 212	$ 333	$ 598	$ 653
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(9), $16, $(12) and $(11) for the three and six months ended 2014 and 2013, respectively	11	(16)	13	11
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $1, $(2) and $3 for the three and six months ended 2014 and 2013, respectively	1	—	3	(4)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(1), $(7), $(3) and $(14) for the three and six months ended 2014 and 2013, respectively	2	9	6	19
Other Comprehensive Income (Loss), net of tax	14	(7)	22	26
COMPREHENSIVE INCOME	$ 226	$ 326	$ 620	$ 679

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 570	$ 493
Accounts Receivable, net of allowances of $58 and $56 in 2014 and 2013, respectively	1,294	1,203
Tax Receivable	101	109
Unbilled Revenues	238	300
Fuel	426	545
Materials and Supplies, net	476	479
Prepayments	249	89
Derivative Contracts	73	98
Deferred Income Taxes	104	24
Regulatory Assets	229	243
Other	34	31
Total Current Assets	3,794	3,614
PROPERTY, PLANT AND EQUIPMENT	30,709	29,713
Less: Accumulated Depreciation and Amortization	(8,399)	(8,068)
Net Property, Plant and Equipment	22,310	21,645
NONCURRENT ASSETS		
Regulatory Assets	2,584	2,612
Regulatory Assets of Variable Interest Entities (VIEs)	355	476
Long-Term Investments	1,315	1,313
Nuclear Decommissioning Trust (NDT) Fund	1,777	1,701
Long-Term Receivable of VIE	409	—
Other Special Funds	657	613
Goodwill	16	16
Other Intangibles	90	33
Derivative Contracts	45	163
Restricted Cash of VIEs	24	24
Other	324	312
Total Noncurrent Assets	7,596	7,263
TOTAL ASSETS	$ 33,700	$ 32,522

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2014	December 31, 2013
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 844	$ 544
Securitization Debt of VIEs Due Within One Year	251	237
Commercial Paper and Loans	—	60
Accounts Payable	1,104	1,222
Derivative Contracts	88	76
Accrued Interest	95	95
Accrued Taxes	93	37
Clean Energy Program	200	142
Obligation to Return Cash Collateral	122	119
Regulatory Liabilities	176	43
Other	490	488
Total Current Liabilities	3,463	3,063
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	7,197	7,107
Regulatory Liabilities	169	233
Regulatory Liabilities of VIEs	11	11
Asset Retirement Obligations	697	677
Other Postretirement Benefit (OPEB) Costs	1,077	1,095
OPEB Costs of Servco	314	—
Accrued Pension Costs	122	121
Accrued Pension Costs of Servco	93	—
Clean Energy Program	27	—
Environmental Costs	381	414
Derivative Contracts	36	31
Long-Term Accrued Taxes	230	180
Other	107	119
Total Noncurrent Liabilities	10,461	9,988
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	7,782	7,587
Securitization Debt of VIEs	134	259
Project Level, Non-Recourse Debt	16	16
Total Long-Term Debt	7,932	7,862
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2014 and 2013—533,556,660 shares	4,865	4,861
Treasury Stock, at cost, 2014— 27,716,798 shares; 2013— 27,699,398 shares	(630)	(615)
Retained Earnings	7,681	7,457
Accumulated Other Comprehensive Loss	(73)	(95)
Total Common Stockholders' Equity	11,843	11,608
Noncontrolling Interest	1	1
Total Stockholders' Equity	11,844	11,609
Total Capitalization	19,776	19,471
TOTAL LIABILITIES AND CAPITALIZATION	$ 33,700	$ 32,522

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2014	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 598	$ 653
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	601	573
Amortization of Nuclear Fuel	98	95
Provision for Deferred Income Taxes (Other than Leases) and ITC	70	146
Non-Cash Employee Benefit Plan Costs	24	122
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(44)	(26)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	297	20
Change in Accrued Storm Costs	(3)	(81)
Net Change in Other Regulatory Assets and Liabilities	192	62
Cost of Removal	(50)	(46)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(59)	(47)
Net Change in Margin Deposit	(234)	(8)
Net Change in Certain Current Assets and Liabilities	(53)	32
Employee Benefit Plan Funding and Related Payments	(50)	(194)
Other	61	42
Net Cash Provided By (Used In) Operating Activities	1,448	1,343
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,229)	(1,406)
Proceeds from Sales of Capital Leases and Investments	11	42
Proceeds from Sales of Available-for-Sale Securities	584	681
Investments in Available-for-Sale Securities	(599)	(684)
Other	(49)	(12)
Net Cash Provided By (Used In) Investing Activities	(1,282)	(1,379)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(60)	(106)
Issuance of Long-Term Debt	500	900
Redemption of Long-Term Debt	—	(450)
Redemption of Securitization Debt	(111)	(106)
Cash Dividends Paid on Common Stock	(374)	(364)
Other	(44)	(53)
Net Cash Provided By (Used In) Financing Activities	(89)	(179)
Net Increase (Decrease) in Cash and Cash Equivalents	77	(215)
Cash and Cash Equivalents at Beginning of Period	493	379
Cash and Cash Equivalents at End of Period	$ 570	$ 164
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 296	$ 138
Interest Paid, Net of Amounts Capitalized	$ 192	$ 194
Accrued Property, Plant and Equipment Expenditures	$ 240	$ 222

See Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
OPERATING REVENUES	$ 986	$ 1,193	$ 2,686	$ 2,644
OPERATING EXPENSES				
Energy Costs	520	495	1,564	1,355
Operation and Maintenance	327	280	629	563
Depreciation and Amortization	72	67	144	133
Total Operating Expenses	919	842	2,337	2,051
OPERATING INCOME	67	351	349	593
Income from Equity Method Investments	3	5	7	8
Other Income	46	35	79	82
Other Deductions	(9)	(10)	(19)	(38)
Other-Than-Temporary Impairments	(2)	(2)	(4)	(4)
Interest Expense	(29)	(29)	(61)	(59)
INCOME BEFORE INCOME TAXES	76	350	351	582
Income Tax Expense	(22)	(140)	(133)	(231)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 54	$ 210	$ 218	$ 351

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
NET INCOME	$ 54	$ 210	$ 218	$ 351
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(9), $16, $(11) and $(11) for the three and six months ended 2014 and 2013, respectively	9	(14)	11	13
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(1), $1, $(2) and $3 for the three and six months ended 2014 and 2013, respectively	2	(1)	3	(5)
Pension/OPEB adjustment, net of tax (expense) benefit of $(1), $(6), $(3) and $(11) for the three and six months ended 2014 and 2013, respectively	2	8	5	17
Other Comprehensive Income (Loss), net of tax	13	(7)	19	25
COMPREHENSIVE INCOME	$ 67	$ 203	$ 237	$ 376

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 6	$ 6
Accounts Receivable	408	338
Accounts Receivable—Affiliated Companies, net	102	333
Short-Term Loan to Affiliate	740	790
Fuel	426	545
Materials and Supplies, net	349	362
Derivative Contracts	55	57
Prepayments	13	13
Deferred Income Taxes	78	30
Other	2	2
Total Current Assets	2,179	2,476
PROPERTY, PLANT AND EQUIPMENT	10,458	10,278
Less: Accumulated Depreciation and Amortization	(3,153)	(2,911)
Net Property, Plant and Equipment	7,305	7,367
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,777	1,701
Long-Term Investments	121	123
Goodwill	16	16
Other Intangibles	90	33
Other Special Funds	154	139
Derivative Contracts	9	72
Other	80	75
Total Noncurrent Assets	2,247	2,159
TOTAL ASSETS	$ 11,731	$ 12,002

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2014	December 31, 2013
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 44	$ 44
Accounts Payable	461	516
Derivative Contracts	88	76
Accrued Interest	27	28
Other	193	136
Total Current Liabilities	813	800
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	2,046	2,031
Asset Retirement Obligations	411	400
Other Postretirement Benefit (OPEB) Costs	212	206
Derivative Contracts	36	31
Accrued Pension Costs	35	35
Long-Term Accrued Taxes	88	53
Other	72	91
Total Noncurrent Liabilities	2,900	2,847
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT		
Total Long-Term Debt	2,498	2,497
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,336	4,693
Accumulated Other Comprehensive Loss	(44)	(63)
Total Member's Equity	5,520	5,858
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 11,731	$ 12,002

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2014	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 218	$ 351
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	144	133
Amortization of Nuclear Fuel	98	95
Provision for Deferred Income Taxes and ITC	(22)	74
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	297	20
Non-Cash Employee Benefit Plan Costs	7	33
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(59)	(47)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	132	97
Margin Deposit	(234)	(8)
Accounts Receivable	16	24
Accounts Payable	(72)	(91)
Accounts Receivable/Payable—Affiliated Companies, net	229	213
Other Current Assets and Liabilities	13	(8)
Employee Benefit Plan Funding and Related Payments	(3)	(44)
Other	50	24
Net Cash Provided By (Used In) Operating Activities	814	866
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(226)	(248)
Proceeds from Sales of Available-for-Sale Securities	563	625
Investments in Available-for-Sale Securities	(577)	(637)
Short-Term Loan—Affiliated Company, net	50	179
Other	(46)	—
Net Cash Provided By (Used In) Investing Activities	(236)	(81)
CASH FLOWS FROM FINANCING ACTIVITIES		
Redemption of Long-Term Debt	—	(300)
Cash Dividend Paid	(575)	(510)
Contributed Capital	—	24
Other	(3)	(2)
Net Cash Provided By (Used In) Financing Activities	(578)	(788)
Net Increase (Decrease) in Cash and Cash Equivalents	—	(3)
Cash and Cash Equivalents at Beginning of Period	6	7
Cash and Cash Equivalents at End of Period	$ 6	$ 4
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 47	$ 60
Interest Paid, Net of Amounts Capitalized	$ 62	$ 55
Accrued Property, Plant and Equipment Expenditures	$ 48	$ 46

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
OPERATING REVENUES	$ 1,435	$ 1,423	$ 3,580	$ 3,418
OPERATING EXPENSES				
Energy Costs	565	580	1,610	1,547
Operation and Maintenance	362	369	824	796
Depreciation and Amortization	217	207	444	422
Taxes Other Than Income Taxes	—	14	—	35
Total Operating Expenses	1,144	1,170	2,878	2,800
OPERATING INCOME	291	253	702	618
Other Income	14	15	28	28
Other Deductions	(1)	(1)	(1)	(2)
Interest Expense	(67)	(75)	(135)	(148)
INCOME BEFORE INCOME TAXES	237	192	594	496
Income Tax Expense	(86)	(71)	(229)	(196)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 151	$ 121	$ 365	$ 300

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
NET INCOME	$ 151	$ 121	$ 365	$ 300
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0 for the three and six months ended 2014 and 2013	—	(1)	—	(1)
COMPREHENSIVE INCOME	$ 151	$ 120	$ 365	$ 299

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 257	$ 18
Accounts Receivable, net of allowances of $58 and $56 in 2014 and 2013, respectively	846	832
Unbilled Revenues	238	300
Materials and Supplies	126	115
Prepayments	186	24
Regulatory Assets	229	243
Derivative Contracts	2	25
Deferred Income Taxes	18	16
Other	7	12
Total Current Assets	1,909	1,585
PROPERTY, PLANT AND EQUIPMENT	19,889	19,071
Less: Accumulated Depreciation and Amortization	(5,048)	(4,964)
Net Property, Plant and Equipment	14,841	14,107
NONCURRENT ASSETS		
Regulatory Assets	2,584	2,612
Regulatory Assets of VIEs	355	476
Long-Term Investments	360	361
Other Special Funds	374	354
Derivative Contracts	20	69
Restricted Cash of VIEs	24	24
Other	146	132
Total Noncurrent Assets	3,863	4,028
TOTAL ASSETS	$ 20,613	$ 19,720

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2014	December 31, 2013
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 800	$ 500
Securitization Debt of VIEs Due Within One Year	251	237
Commercial Paper and Loans	—	60
Accounts Payable	491	535
Accounts Payable—Affiliated Companies, net	93	190
Accrued Interest	67	67
Clean Energy Program	200	142
Deferred Income Taxes	—	30
Obligation to Return Cash Collateral	122	119
Regulatory Liabilities	176	43
Other	287	314
Total Current Liabilities	2,487	2,237
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,522	4,406
Other Postretirement Benefit (OPEB) Costs	814	839
Accrued Pension Costs	26	27
Regulatory Liabilities	169	233
Regulatory Liabilities of VIEs	11	11
Clean Energy Program	27	—
Environmental Costs	330	363
Asset Retirement Obligations	282	274
Long-Term Accrued Taxes	63	72
Other	58	47
Total Noncurrent Liabilities	6,302	6,272
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	5,264	5,066
Securitization Debt of VIEs	134	259
Total Long-Term Debt	5,398	5,325
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2014 and 2013—132,450,344 shares	892	892
Contributed Capital	695	520
Basis Adjustment	986	986
Retained Earnings	3,852	3,487
Accumulated Other Comprehensive Income	1	1
Total Stockholder's Equity	6,426	5,886
Total Capitalization	11,824	11,211
TOTAL LIABILITIES AND CAPITALIZATION	$ 20,613	$ 19,720

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2014	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 365	$ 300
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	444	422
Provision for Deferred Income Taxes and ITC	73	75
Non-Cash Employee Benefit Plan Costs	13	78
Cost of Removal	(50)	(46)
Change in Accrued Storm Costs	(3)	(81)
Net Change in Other Regulatory Assets and Liabilities	192	62
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	44	6
Materials and Supplies	(11)	(6)
Prepayments	(162)	(192)
Accounts Payable	16	47
Accounts Receivable/Payable—Affiliated Companies, net	(98)	(137)
Other Current Assets and Liabilities	(31)	8
Employee Benefit Plan Funding and Related Payments	(44)	(134)
Other	(11)	19
Net Cash Provided By (Used In) Operating Activities	737	421
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(996)	(1,148)
Proceeds from Sales of Available-for-Sale Securities	8	32
Investments in Available-for-Sale Securities	(6)	(13)
Solar Loan Investments	(1)	(15)
Net Cash Provided By (Used In) Investing Activities	(995)	(1,144)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	(60)	(106)
Issuance of Long-Term Debt	500	900
Redemption of Long-Term Debt	—	(150)
Redemption of Securitization Debt	(111)	(106)
Contributed Capital	175	100
Other	(7)	(12)
Net Cash Provided By (Used In) Financing Activities	497	626
Net Increase (Decrease) In Cash and Cash Equivalents	239	(97)
Cash and Cash Equivalents at Beginning of Period	18	116
Cash and Cash Equivalents at End of Period	$ 257	$ 19
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 102	$ 110
Interest Paid, Net of Amounts Capitalized	$ 127	$ 135
Accrued Property, Plant and Equipment Expenditures	$ 192	$ 189

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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This combined Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information relating to any individual company is filed by such company on its own behalf. Power and PSE&G each is only responsible for information about itself and its subsidiaries.

Note 1. Organization and Basis of Presentation

Organization

PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Power**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and the states in which they operate.
- **PSE&G**—which is an operating public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the FERC. PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which, effective January 1, 2014, operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a twelve-year Amended and Restated Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2013 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2014.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All significant intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2013.

On December 31, 2013, Energy Holdings distributed the outstanding equity of its 50% interest in a partnership that owns and operates a generation facility in Hawaii and its wholly owned interest in PSEG Solar Source LLC to PSEG. PSEG in turn contributed this distribution to Power as an additional equity investment. This transaction was accounted for as a non-cash transfer of equity interest between entities under common control with prior period financial statements for Power retrospectively adjusted to include the earnings related to the transfer. As a result, Power's Operating Revenues increased $3 million and $7 million for the three months and six months ended June 30, 2013, respectively, and Power's Net Income increased $6 million and $10 million for the three months and six months ended June 30, 2013, respectively.

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Note 2. Recent Accounting Standards

New Standards Adopted during 2014

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

This accounting standard was issued to address diversity in practice related to the presentation of an unrecognized tax benefit in certain cases. This standard requires entities to present an unrecognized tax benefit or a portion thereof on the Balance Sheet as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward.

However, the unrecognized tax benefit will be presented on the Balance Sheet as a liability and will not be combined with deferred tax assets in cases where that tax benefit cannot or will not, if permissible, be used to settle any additional income taxes that would result from the disallowance of a tax position.

The standard was effective for fiscal years and interim periods beginning after December 15, 2013. The impact of adopting this standard is immaterial.

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard was issued to clarify the principles for recognizing revenue and to develop a common standard that would remove inconsistencies in revenue requirements; improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provide improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The update is effective for annual and interim reporting periods beginning after December 15, 2016. Early application is not permitted. We are currently analyzing the impact of this standard on our financial statements.

Presentation of Financial Statements and Property, Plant and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

This accounting standard was issued to change the criteria for reporting discontinued operations. The standard requires that a component of an entity be reported in discontinued operations if the disposal represents a strategic shift that has, or will have, a major effect on the entity's operations and financial results, including a disposal of a major geographical area, a major line of business, a major equity method investment, or other major parts of an entity.

The amendment should be applied prospectively for all disposals of an entity that occur within interim and annual periods beginning on or after December 15, 2014; and all businesses that, on acquisition, are classified as held for sale that occur within interim and annual periods beginning on or after December 15, 2014. We will evaluate all future disposals under the new guidance beginning on January 1, 2015.

Transfers and Servicing - Repurchase-to-Maturity Transactions, Repurchase-Financings and Disclosures

This standard changes the accounting for repurchase-to-maturity transactions and linked repurchase-financings to secured borrowing accounting, which is consistent with the accounting for other repurchase agreements. It also requires disclosures for repurchase agreements, securities lending transactions, and repurchase-to-maturity transactions that are accounted for as secured borrowings.

This standard is effective for the first interim or annual period beginning after December 15, 2014.

We are currently analyzing this standard but do not expect its impact to be material to our financial statements.

Note 3. Variable Interest Entities (VIEs)

Variable Interest Entities for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are

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remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of Transition Funding and Transition Funding II are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the assets of these VIEs are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II.

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of June 30, 2014 and December 31, 2013. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II during the first six months of 2014 or in 2013. PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II.

Variable Interest Entity for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

PSEG recognized a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and other postretirement benefit (OPEB) liabilities. This receivable is presented separately on the Condensed Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted. See Note 7. Pension and Other Postretirement Benefits for additional information.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operations and Maintenance (O&M) Expense, respectively. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 4. Rate Filings

The following information discusses significant updates regarding orders and pending rate filings. This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2013.

- ***Remediation Adjustment Charge (RAC)***—On April 18, 2014, PSE&G filed a petition with the BPU requesting recovery of $66 million related to RAC 21 net manufactured gas plant expenditures through July 31, 2013. This matter is pending.
- ***Weather Normalization Clause (WNC)***—In April 2014, the BPU approved PSE&G's filing with respect to deficiency revenues from the 2012-2013 Winter Period. The BPU's approval of a final WNC resulted in no change to the provisional rate previously approved by the BPU and implemented effective October 1, 2013, which was set to recover $26 million from customers during the 2013-2014 Winter Period (October 1, 2013 through May 31, 2014).

  On July 1, 2014, PSE&G filed a petition with the BPU seeking approval to refund $45 million in revenues to its customers during the 2014-2015 Winter Period as a result of excess revenues collected during the colder than normal 2013-2014 Winter Period. This matter is pending.
- ***Basic Gas Supply Service (BGSS)***—In January and February 2014, PSE&G filed self-implementing one-month BGSS residential customer bill credits with the BPU for 25 cents per therm for the months of February and March

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2014. These credits provided approximately $93 million in total credits to residential customers, reducing the BGSS deferred balance. On April 1, 2014, the BGSS rate reverted back to the current rate.

In May, 2014, PSE&G made its Annual BGSS filing with the BPU requesting a reduction of $112 million in annual BGSS revenues. If approved, the BGSS rate would be reduced from approximately 54 cents to 45 cents per therm effective October 1, 2014.

- ***Capital Stimulus Infrastructure Programs (CIP II)***—In June 2014, the BPU approved PSE&G's petition to recover annual revenue requirements of approximately $28 million for program costs incurred for its CIP II investments through September 30, 2013, which represents the final phase of the program. Base rates were adjusted effective July 1, 2014 to reflect the recovery.
- ***Societal Benefits Charge (SBC) and Non-Utility Generation Charge (NGC)***—In May 2014, the BPU approved PSE&G's petition to recover actual SBC and NGC costs incurred through December 31, 2013 under its Energy Efficiency & Renewable Energy Programs, Social Programs and NGC. New rates were implemented on June 1, 2014 to recover approximately $400 million over the succeeding 12 months.
- ***Solar and Energy Efficiency-Green Program Recovery Charges (GPRC)***—In June 2014, PSE&G filed a petition with the BPU requesting recovery of costs and investments in the combined eight components of the electric and gas GPRC for the period October 1, 2014 through September 30, 2015. The rates proposed in our filing are designed to recover $111 million and $18 million in electric and gas revenues, respectively, on an annual basis. This matter is pending.

Note 5. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with Solar Renewable Energy Certificates generated from the installed solar electric system. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of June 30, 2014	As of December 31, 2013
	Millions	
Commercial/Industrial	$ 193	$ 192
Residential	14	15
Total	**$ 207**	**$ 207**

Energy Holdings

Energy Holdings, through various of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

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The following table shows Energy Holdings' gross and net lease investment as of June 30, 2014 and December 31, 2013, respectively.

	As of June 30, 2014	As of December 31, 2013
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 699	$ 701
Estimated Residual Value of Leased Assets	529	529
Unearned and Deferred Income	(397)	(405)
Gross Investment in Leases	831	825
Deferred Tax Liabilities	(688)	(727)
Net Investment in Leases	**$ 143**	**$ 98**

The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. "Not Rated" counterparties represent investments in lease receivables related to commercial real estate properties.

Counterparties' Credit Rating (Standard & Poor's (S&P)) As of June 30, 2014	Lease Receivables, Net of Non-Recourse Debt As of June 30, 2014
	Millions
AA	$ 19
AA-	56
BBB+ - BB+	316
BB-	134
B	165
Not Rated	9
Total	**$ 699**

The "BB-" and the "B" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of June 30, 2014, the gross investment in the leases of such assets, net of non-recourse debt, was $563 million ($30 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

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Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counter-parties' S&P Credit Ratings	Counterparty
		Millions		MW			
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 117	17%	1,711	Coal	B	GenOn REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 117	17%	1,711	Coal	B	GenOn REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 111	100%	603	Coal	B	GenOn REMA, LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, the indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

GenOn REMA, LLC, an indirect subsidiary of NRG Energy, Inc. (NRG) notified PJM that it no longer intends to place the coal-fired units at the Shawville generating facility in long-term protective layup. Instead, those units will be shut down temporarily beginning in April 2015, with an expected return to service no later than June 2016 using an alternative fuel.

Nesbitt Asset Recovery, LLC (Nesbitt), (an indirect, wholly owned subsidiary of Energy Holdings), owns approximately 64% of the lease interest in the Powerton and Joliet coal units in Illinois. These facilities are leased to Midwest Generation (MWG), which was an indirect subsidiary of Edison Mission Energy (EME). In December 2012, EME and MWG filed for relief under Chapter 11 of the U.S. Bankruptcy Code. In October 2013, NRG, EME, MWG, Nesbitt and other creditor parties involved in the bankruptcy executed a new agreement under which NRG would acquire substantially all of EME's assets, including the Powerton and Joliet leased assets. In March 2014, the Bankruptcy Court approved the transaction. As part of the transaction, (i) the leases for the Powerton and Joliet coal units were assumed on their existing terms, (ii) all past due rent under the leases was paid in full, (iii) NRG assumed EME's tax indemnity and guarantee obligations, and (iv) NRG agreed to invest up to $350 million in the Powerton and Joliet coal units so they can be operated in compliance with environmental regulations. On April 1, 2014, NRG and EME closed on the transaction in accordance with these terms, bringing the lease payments current.

Note 6. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Fund

Power maintains an external master nuclear decommissioning trust to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third party investment advisers who operate under investment guidelines developed by Power.

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Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of June 30, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 644	$ 294	$ (2)	$ 936
Debt Securities				
Government Obligations	434	6	(3)	437
Other Debt Securities	328	12	(1)	339
Total Debt Securities	762	18	(4)	776
Other Securities	65	—	—	65
Total NDT Available-for-Sale Securities	**$ 1,471**	**$ 312**	**$ (6)**	**$ 1,777**

	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 609	$ 290	$ (2)	$ 897
Debt Securities				
Government Obligations	438	3	(12)	429
Other Debt Securities	285	10	(4)	291
Total Debt Securities	723	13	(16)	720
Other Securities	84	—	—	84
Total NDT Available-for-Sale Securities	**$ 1,416**	**$ 303**	**$ (18)**	**$ 1,701**

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of June 30, 2014	As of December 31, 2013
	Millions	
Accounts Receivable	$ 40	$ 39
Accounts Payable	$ 42	$ 36

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The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of June 30, 2014				As of December 31, 2013			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 49	$ (2)	$ —	$ —	$ 30	$ (2)	$ 2	$ —
Debt Securities								
Government Obligations (B)	86	(2)	33	(1)	300	(11)	1	(1)
Other Debt Securities (C)	58	(1)	8	—	107	(4)	3	—
Total Debt Securities	144	(3)	41	(1)	407	(15)	4	(1)
NDT Available-for-Sale Securities	**$ 193**	**$ (5)**	**$ 41**	**$ (1)**	**$ 437**	**$ (17)**	**$ 6**	**$ (1)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of June 30, 2014.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of June 30, 2014.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2014.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	Millions			
Proceeds from NDT Fund Sales	$ 313	$ 376	$ 558	$ 617
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	33	23	56	60
Gross Realized Losses	(5)	(6)	(9)	(25)
Net Realized Gains (Losses) on NDT Fund	**$ 28**	**$ 17**	**$ 47**	**$ 35**

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $152 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of June 30, 2014.

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The NDT available-for-sale debt securities held as of June 30, 2014 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 19
1 - 5 years	224
6 - 10 years	200
11 - 15 years	60
16 - 20 years	42
Over 20 years	231
Total NDT Available-for-Sale Debt Securities	**$ 776**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the six months ended June 30, 2014, other-than-temporary impairments of $4 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of June 30, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 9	$ —	$ 21
Debt Securities				
Government Obligations	113	1	(1)	113
Other Debt Securities	49	2	—	51
Total Debt Securities	162	3	(1)	164
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 177**	**$ 12**	**$ (1)**	**$ 188**

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	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 14	$ 9	$ —	$ 23
Debt Securities				
Government Obligations	109	—	(2)	107
Other Debt Securities	46	1	(1)	46
Total Debt Securities	155	1	(3)	153
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 172**	**$ 10**	**$ (3)**	**$ 179**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of June 30, 2014	As of December 31, 2013
	Millions	
Accounts Receivable	$ 4	$ 1
Accounts Payable	$ 4	$ 2

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months.

	As of June 30, 2014				As of December 31, 2013			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	2	—	29	(1)	47	(2)	2	—
Other Debt Securities (C)	2	—	7	—	18	(1)	1	—
Total Debt Securities	4	—	36	(1)	65	(3)	3	—
Rabbi Trust Available-for-Sale Securities	**$ 4**	**$ —**	**$ 36**	**$ (1)**	**$ 65**	**$ (3)**	**$ 3**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell

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nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of June 30, 2014.

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2014.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	Millions			
Proceeds from Rabbi Trust Sales	**$ 14**	**$ 47**	**$ 26**	**$ 64**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ —	$ 4	$ 2	$ 4
Gross Realized Losses	(1)	(3)	(1)	(3)
Net Realized Gains (Losses) on Rabbi Trust	**$ (1)**	**$ 1**	**$ 1**	**$ 1**

Net unrealized gains of $6 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of June 30, 2014. The Rabbi Trust available-for-sale debt securities held as of June 30, 2014 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 2
1 - 5 years	64
6 - 10 years	28
11 - 15 years	8
16 - 20 years	5
Over 20 years	57
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 164**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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The fair value of assets in the Rabbi Trust related to PSEG, Power and PSE&G are detailed as follows:

	As of June 30, 2014	As of December 31, 2013
	Millions	
Power	$ 44	$ 39
PSE&G	40	42
Other	104	98
Total Rabbi Trust Available-for-Sale Securities	**$ 188**	**$ 179**

Note 7. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.

Pension and OPEB costs for PSEG, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013	2014	2013	2014	2013
	Millions							
Components of Net Periodic Benefit Cost								
Service Cost	$ 26	$ 29	$ 4	$ 5	$ 52	$ 58	$ 9	$ 10
Interest Cost	59	53	17	16	118	107	34	32
Expected Return on Plan Assets	(100)	(87)	(6)	(5)	(200)	(174)	(13)	(10)
Amortization of Net								
Prior Service Cost (Credit)	(4)	(4)	(3)	(3)	(9)	(9)	(7)	(7)
Actuarial Loss	14	47	6	10	28	94	12	21
Total Benefit Costs	**$ (5)**	**$ 38**	**$ 18**	**$ 23**	**$ (11)**	**$ 76**	**$ 35**	**$ 46**

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Pension and OPEB costs for Power, PSE&G and PSEG's other subsidiaries, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013	2014	2013	2014	2013
	Millions							
Power	$ (1)	$ 11	$ 5	$ 5	$ (3)	$ 22	$ 10	$ 11
PSE&G	(5)	22	12	17	(10)	45	23	33
Other	1	5	1	1	2	9	2	2
Total Benefit Costs	**$ (5)**	**$ 38**	**$ 18**	**$ 23**	**$ (11)**	**$ 76**	**$ 35**	**$ 46**

PSEG does not anticipate making contributions into its pension plan during 2014. However, during the three months ended March 31, 2014, PSEG contributed its entire planned contribution for the year 2014 of $14 million into its postretirement healthcare plan.

Servco Pension and OPEB

At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities (VIEs). These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. The pension-related revenues and costs for the three months and six months ended June 30, 2014 were $23 million and $46 million, respectively. Servco plans to contribute an additional $21 million to its pension plan trusts during 2014. There were no OPEB-related revenues earned or costs incurred for the three months and six months ended June 30, 2014.

Note 8. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and

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- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

The face value of Power's outstanding guarantees, current exposure and margin positions as of June 30, 2014 and December 31, 2013 are shown as follows:

	As of June 30, 2014	As of December 31, 2013
	Millions	
Face Value of Outstanding Guarantees	$ 1,830	$ 1,639
Exposure under Current Guarantees	$ 218	$ 246
Letters of Credit Margin Posted	$ 176	$ 132
Letters of Credit Margin Received	$ 17	$ 25
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (18)	$ —
Net Broker Balance Deposited (Received)	$ 332	$ 80
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that could be Required	$ 760	$ 691
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,478	$ 3,522
Additional Amounts Posted:		
Other Letters of Credit	$ 45	$ 45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P, Moody's and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See preceding table.

The SEC and the Commodity Futures Trading Commission (CFTC) continue efforts to implement new rules to effect stricter regulation over swaps and derivatives, including imposing reporting and record-keeping requirements. In August 2013, PSEG began reporting its swap transactions to a CFTC-approved swap data repository. PSEG continues to monitor developments in this area, as the CFTC considers additional requirements such as a new position limits rule for physical commodity futures contracts and swaps that are economically equivalent to those contracts.

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In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The U.S. Environmental Protection Agency (EPA) has determined that a 17-mile stretch of the Passaic River from Newark to Clifton, New Jersey is a "Super Fund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA has determined the need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

Seventy-three Potentially Responsible Parties (PRPs), including Power and PSE&G, agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) and formed the Cooperating Parties Group (CPG) to divide the associated costs according to a mutually agreed upon formula. The CPG group, currently 66 members, is presently conducting the RI/FS. The approximate seven percent allocation of the RI/FS costs currently attributable to PSE&G's former MGP sites and approximate one percent attributable to Power's generating stations are non-binding as it relates to the ultimate sharing of the remediation costs. Power has provided notice to insurers concerning this potential claim. The RI/FS is expected to be completed by the end of 2014 at an estimated cost of approximately $134 million. Of the estimated $134 million, as of December 31, 2013, the CPG Group had spent approximately $113 million, of which PSEG's total share had been approximately $7 million.

On April 11, 2014, the EPA released its revised "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the Passaic River's lower eight miles under various alternatives ranging in costs from $365 million to $3.25 billion. The EPA's preferred alternative would involve dredging the river bank to bank and installing an engineered cap at an estimated cost of $1.7 billion. The draft FFS is subject to a public comment period, the EPA's response, a design phase and at least five years for completion of the work. The work contemplated by the draft FFS is not subject to the cost sharing agreement discussed above.

In June 2008, an agreement was announced between the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) for removal of a portion of the contaminated sediment in the Passaic River at an estimated cost of $80 million. Phase I of the removal work has been completed. Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G.

At the EPA's direction, the CPG, with the exception of Tierra and Maxus, which are no longer members, has commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSEG's share of the cost of that effort is approximately three percent.

Based on the EPA estimates above, Power and PSE&G believe that their respective ultimate shares of the costs to clean up the Passaic River will be immaterial, but are unable to predict the ultimate outcome of this matter.

New Jersey Spill Compensation and Control Act (Spill Act)

In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of a certain PRP's discharge of hazardous substances into both the Passaic River and the balance of the Newark Bay Complex. In 2009, third party complaints were filed against some 320 third party defendants, including Power and PSE&G, claiming that each of the third party defendants is responsible for its proportionate share of the clean-up costs for the hazardous substances it allegedly discharged into the Passaic River and the Newark Bay Complex. Power and PSE&G are alleged to have owned, operated or contributed to a total of 11 sites or facilities that impacted these water bodies. The third party complaints sought statutory contribution and contribution under the Spill Act to recover past and future removal costs and damages. In December 2013, the Court approved a settlement of the entire third party action. Power and PSE&G's contributions to the settlement, either individually or in the aggregate, were immaterial.

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Natural Resource Damage Claims

In 2003, the NJDEP directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the Spill Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G is unable to estimate its portion of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $410 million and $486 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $410 million as of June 30, 2014. Of this amount, $89 million was recorded in Other Current Liabilities and $321 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $410 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Hazardous Air Pollutants Regulation

In accordance with a ruling of the U.S. Court of Appeals of the District of Columbia (D.C. Court), the EPA published a Maximum Achievable Control Technology (MACT) regulation on February 16, 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the D.C. Court in support of the EPA's implementation of MATS. On April 15, 2014, the D.C. Court denied all petitions for review of the existing source NESHAP. Several parties, including 21 states have filed petitions for review with the U.S. Supreme Court.

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Power believes that it will not be necessary to install any material controls at its New Jersey facilities. Additional controls are being installed at Power's Bridgeport Harbor coal-fired unit at an immaterial cost. In December 2011, to comply with the MACT regulations, the co-owners group, including Power, agreed to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction systems at Power's jointly owned coal-fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be operational in the first quarter of 2015. Power's share of this investment is approximately $110 million.

Nitrogen Oxide (NO_X) Regulation

In 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on Power's generation fleet, as it imposes NO_x emissions limits that will require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) by May 30, 2015. Retirement notifications for the combustion turbines have been submitted to PJM Interconnection L.L.C. (PJM). PJM was notified that the Salem Unit 3 combustion turbine will no longer be available as a capacity resource and will be transitioned to an emergency generator for site use only. Based upon Power's recently-completed evaluations of its steam electric generation units, an immaterial investment will be required to consistently reduce NO_x emissions below required limits beginning on May 1, 2015.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System (NPDES) permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The New Jersey Department of Environmental Protection manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

One of the most significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. Following the effective date of the rule, each state will implement the provisions of the rule when considering the renewal of permits for existing facilities on a case by case basis.

State permitting decisions could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would have been approximately $575 million. The filing has not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

In October 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court in New Jersey seeking to compel the NJDEP to take action on Power's pending application for permit renewal at Salem either by denying the application or issuing a draft for public comments. At the NJDEP's request, the case was transferred to the Appellate Division on December 16, 2013. Power is unable to predict the outcome of this proceeding.

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Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements for customers who do not purchase electric supply from third party suppliers through the annual New Jersey BGS auctions. Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with Power, as well as with other winning BGS suppliers, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has contracted for its anticipated BGS-Fixed Price eligible load, as follows:

	Auction Year				
	2011	2012	2013	2014	
36-Month Terms Ending	May 2014	May 2015	May 2016	May 2017	(A)
Load (MW)	2,800	2,900	2,800	2,800	
$ per kWh	0.09430	0.08388	0.09218	0.09739	

(A) Prices set in the 2014 BGS auction became effective on June 1, 2014 when the 2011 BGS auction agreements expired.

PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 17. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations and for supply of nuclear fuel for the Salem, Hope Creek and Peach Bottom nuclear generating stations and for firm transportation and storage capacity for natural gas.

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2018 at Salem, Hope Creek and Peach Bottom.

Power's various multi-year contracts for firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

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As of June 30, 2014, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2018
	Millions
Nuclear Fuel	
Uranium	$ 467
Enrichment	$ 403
Fabrication	$ 167
Natural Gas	$ 970
Coal	$ 389

Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. PSEG notified the FERC, PJM and the PJM Independent Market Monitor (IMM) of this issue. During the three months ended March 31, 2014, Power recorded a charge to income in the amount of $25 million related to these findings for these past errors based upon its best estimate available at the time. PSEG cannot provide any assurances that the total liability associated with this matter will not increase or decrease over the amount recorded.

Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed the FERC, PJM and the IMM of these additional issues, and has corrected these errors. Power is also in the process of implementing procedures to help mitigate the risk of similar issues occurring in the future.

The data required to calculate the full impact of the pricing errors is proprietary to PJM and PSEG does not have access to that information. In addition, PSEG does not have access to PJM's proprietary data to determine if the differences in quantity had any impact, and if so, the level of that impact. PSEG continues to conduct its investigation and is working with PJM and the IMM to determine the impact of the errors. The FERC has the authority to investigate the matter, which could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with these matters, or the applicability of mitigating factors. It is possible that Power will incur additional losses, and that such losses may be material, but PSEG cannot at the current time estimate the amount or range of any additional losses.

New Jersey Clean Energy Program

In June 2014, the BPU established the funding level for fiscal year 2015 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2015 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a current liability of $200 million and a noncurrent liability of $27 million as of June 30, 2014 for its outstanding share of the fiscal year 2015 and remaining fiscal year 2014 funding, respectively. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's T&D system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure.

Power had incurred $79 million and $85 million of storm-related expense in 2013 and 2012, respectively, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized in O&M Expense, offset by $25 million and $19 million of insurance recoveries in 2013 and 2012, respectively.

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Power incurred an additional $10 million and $19 million for the three months and six months ended June 30, 2014, primarily for repairs at certain generating stations in Power's fossil fleet.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. As previously reported, PSEG is seeking recovery from its insurers for the property damage resulting from Superstorm Sandy, above its self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. In June 2013, PSEG, Power and PSE&G filed suit in New Jersey state court against its insurance carriers seeking an interpretation that the insurance policies cover their losses resulting from damage caused by Superstorm Sandy's storm surge. In that lawsuit, PSEG stated that its estimate of the total costs related to damaged facilities was approximately $426 million. Of these costs, $364 million and $62 million related to Power and PSE&G, respectively. In August 2013, the insurance carriers filed an answer in which they denied most of the allegations made in the Complaint. Discovery is ongoing. In April 2014, PSEG notified the insurance carriers of a revised estimate of $579 million for total costs related to damaged facilities, of which $484 million and $95 million related to Power and PSE&G, respectively. We cannot predict the outcome of this proceeding.

Note 9. Changes in Capitalization

The following capital transactions occurred in the six months ended June 30, 2014:

Power

- paid cash dividends of $575 million to PSEG.

PSE&G

- issued $250 million of 1.80% Secured Medium-Term Notes, Series I due June 2019,
- issued $250 million of 4.00% Secured Medium-Term Notes, Series I due June 2044,
- paid $105 million of Transition Funding's securitization debt,
- paid $6 million of Transition Funding II's securitization debt, and
- received a $175 million capital contribution from PSEG.

Note 10. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Commodity Prices

The availability and price of energy commodities are subject to fluctuations due to weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions, transmission availability and other events. Power uses physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. Derivative contracts that do not qualify for hedge accounting or normal purchases/normal sales treatment are marked to market with changes in fair value recorded in the Consolidated Statements of Operations. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps and futures contracts to hedge

- forecasted energy sales from its generation stations and the related load obligations,
- the price of fuel to meet its fuel purchase requirements, and
- certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

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These derivative transactions are designated and effective as cash flow hedges. During the second quarter of 2012, Power de-designated certain of its commodity derivative transactions that had previously qualified as cash flow hedges as they were deemed to no longer be highly effective as required by the relevant accounting guidance. As a result, since June 1, 2012, Power recognizes all gains and losses from changes in the fair value of these derivatives immediately in earnings rather than deferring any such amounts in Accumulated Other Comprehensive Income (Loss). The fair values of Power's de-designated hedges were frozen in Accumulated Other Comprehensive Income (Loss) as the original forecasted transactions are still expected to occur and are reclassified into earnings as the original derivative transactions settle.

As of June 30, 2014 and December 31, 2013, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity were as follows:

	As of June 30, 2014	As of December 31, 2013
	Millions	
Fair Value of Cash Flow Hedges	$ 2	$ (4)
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 2	$ (1)

The expiration date of the longest-dated cash flow hedge at Power is in March 2015. Power's remaining $2 million of after-tax unrealized gains on these derivatives is expected to be reclassified to earnings during the next 12 months. There was no ineffectiveness associated with qualifying hedges as of June 30, 2014.

Other Derivatives

Power enters into additional contracts that are derivatives, but do not qualify for or are not designated as cash flow hedges. These transactions are intended to mitigate exposure to fluctuations in commodity prices and optimize the value of its expected generation. Trade types include financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. Changes in fair market value of these contracts are recorded in earnings. PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization. These natural gas contracts qualify as derivatives and are marked to fair market value with the offset recorded to Regulatory Assets and Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of June 30, 2014, PSEG had seven interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of June 30, 2014 and December 31, 2013, the fair value of all the underlying hedges was $32 million and $38 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was $(1) million as of June 30, 2014 and December 31, 2013.

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Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that, in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset in the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of June 30, 2014						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 2	$ 613	$ (560)	$ 55	$ 2	$ 16	$ 73
Noncurrent Assets	—	158	(149)	9	20	16	45
Total Mark-to-Market Derivative Assets	**$ 2**	**$ 771**	**$ (709)**	**$ 64**	**$ 22**	**$ 32**	**$ 118**
Derivative Contracts							
Current Liabilities	$ —	$ (799)	$ 711	$ (88)	$ —	$ —	$ (88)
Noncurrent Liabilities	—	(189)	153	(36)	—	—	(36)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (988)**	**$ 864**	**$ (124)**	**$ —**	**$ —**	**$ (124)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 2**	**$ (217)**	**$ 155**	**$ (60)**	**$ 22**	**$ 32**	**$ (6)**

	As of December 31, 2013						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ —	$ 323	$ (266)	$ 57	$ 25	$ 16	$ 98
Noncurrent Assets	—	155	(83)	72	69	22	163
Total Mark-to-Market Derivative Assets	**$ —**	**$ 478**	**$ (349)**	**$ 129**	**$ 94**	**$ 38**	**$ 261**
Derivative Contracts							
Current Liabilities	$ (4)	$ (343)	$ 271	$ (76)	$ —	$ —	$ (76)
Noncurrent Liabilities	—	(111)	80	(31)	—	—	(31)
Total Mark-to-Market Derivative (Liabilities)	**$ (4)**	**$ (454)**	**$ 351**	**$ (107)**	**$ —**	**$ —**	**$ (107)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ (4)**	**$ 24**	**$ 2**	**$ 22**	**$ 94**	**$ 38**	**$ 154**

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(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of June 30, 2014 and December 31, 2013. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheet. As of June 30, 2014 and December 31, 2013, net cash collateral (received) paid of $155 million and $2 million, respectively, were netted against the corresponding net derivative contract positions. Of the $155 million as of June 30, 2014, $(2) million and $(4) million of cash collateral was netted against current assets and noncurrent assets, respectively, and $153 million and $8 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $2 million as of December 31, 2013, cash collateral of $(3) million and $5 million were netted against noncurrent assets and current liabilities, respectively.

Certain of Power’s derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power’s credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded or lose its investment grade credit rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on NYMEX and ICE that are fully collateralized) was $116 million and $91 million as of June 30, 2014 and December 31, 2013, respectively. As of June 30, 2014 and December 31, 2013, Power had the contractual right of offset of $37 million and $39 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded or lost its investment grade rating, it would have had additional collateral obligations of $79 million and $52 million as of June 30, 2014 and December 31, 2013, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $760 million and $691 million as of June 30, 2014 and December 31, 2013, respectively, discussed in Note 8. Commitments and Contingent Liabilities.

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The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended June 30, 2014 and 2013.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended June 30, 2014	2013	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended June 30, 2014	2013	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Three Months Ended June 30, 2014	2013
				Millions				
PSEG								
Energy-Related Contracts	$ 1	$ —	Operating Revenues	$ —	$ 2	Operating Revenues	$ —	$ —
Interest Rate Swaps	—	—	Interest Expense	—	(1)		—	—
Total PSEG	**$ 1**	**$ —**		**$ —**	**$ 1**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ 1	$ —	Operating Revenues	$ —	$ 2	Operating Revenues	$ —	$ —
Total Power	**$ 1**	**$ —**		**$ —**	**$ 2**		**$ —**	**$ —**

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the six months ended June 30, 2014 and 2013.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Six Months Ended June 30, 2014	2013	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Six Months Ended June 30, 2014	2013	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Six Months Ended June 30, 2014	2013
				Millions				
PSEG								
Energy-Related Contracts	$ (7)	$ —	Operating Revenues	$ (12)	$ 8	Operating Revenues	$ —	$ —
Interest Rate Swaps	—	—	Interest Expense	—	(1)		—	—
Total PSEG	**$ (7)**	**$ —**		**$ (12)**	**$ 7**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ (7)	$ —	Operating Revenues	$ (12)	$ 8	Operating Revenues	$ —	$ —
Total Power	**$ (7)**	**$ —**		**$ (12)**	**$ 8**		**$ —**	**$ —**

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The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2013	**$ (4)**	**$ (2)**
Loss Recognized in AOCI	(8)	(5)
Loss Reclassified into Income	12	7
Balance as of March 31, 2014	**$ —**	**$ —**
Gain Recognized in AOCI	1	1
Loss Reclassified into Income	—	—
Balance as of June 30, 2014	**$ 1**	**$ 1**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the three months and six months ended June 30, 2014 and 2013.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2014	2013	2014	2013
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ (58)	$ 163	$ (852)	$ (46)
Energy-Related Contracts	Energy Costs	(36)	(5)	77	53
Total PSEG and Power		**$ (94)**	**$ 158**	**$ (775)**	**$ 7**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $5 million for each of the three months and $10 million for each of the six months ended June 30, 2014 and 2013, respectively.

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The following reflects the gross volume, on an absolute value basis, of derivatives as of June 30, 2014 and December 31, 2013.

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of June 30, 2014					
Natural Gas	Dth	513	—	386	127
Electricity	MWh	325	—	325	—
Financial Transmission Rights (FTRs)	MWh	27	—	27	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2013					
Natural Gas	Dth	614	—	466	148
Electricity	MWh	243	—	243	—
FTRs	MWh	16	—	16	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of June 30, 2014, 92% of the credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of June 30, 2014. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 75	$ 14	$ 75	2	$ 48	(A)
Non-Investment Grade—External Rating	—	—	—	—	—	
Investment Grade—No External Rating	1	—	1	—	—	
Non-Investment Grade—No External Rating	7	—	7	—	—	
Total	**$ 83**	**$ 14**	**$ 83**	**2**	**$ 48**	

(A) Includes net exposure of $18 million with PSE&G. The remaining net exposure of $30 million is with a nonaffiliated power purchaser which is a regulated investment grade counterparty.

The net exposure listed in the preceding table, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of June 30, 2014, Power had 153 active counterparties.

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Note 11. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of June 30, 2014, these consisted primarily of certain electric load contracts and long-term gas supply contracts.

The following tables present information about PSEG's, Power's and PSE&G's respective assets and (liabilities) measured at fair value on a recurring basis as of June 30, 2014 and December 31, 2013, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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Description	Recurring Fair Value Measurements as of June 30, 2014				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 501	$ —	$ 501	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 86	$ (709)	$ —	$ 772	$ 23
Interest Rate Swaps (C)	$ 32	$ —	$ —	$ 32	$ —
NDT Fund (D)					
Equity Securities	$ 936	$ —	$ 929	$ 7	$ —
Debt Securities—Govt Obligations	$ 437	$ —	$ —	$ 437	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 64	$ —	$ 63	$ 1	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 21	$ —	$ 21	$ —	$ —
Debt Securities—Govt Obligations	$ 113	$ —	$ —	$ 113	$ —
Debt Securities—Other	$ 51	$ —	$ —	$ 51	$ —
Other Securities	$ 3	$ —	$ —	$ 3	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (124)	$ 864	$ —	$ (978)	$ (10)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 64	$ (709)	$ —	$ 772	$ 1
NDT Fund (D)					
Equity Securities	$ 936	$ —	$ 929	$ 7	$ —
Debt Securities—Govt Obligations	$ 437	$ —	$ —	$ 437	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 64	$ —	$ 63	$ 1	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 26	$ —	$ —	$ 26	$ —
Debt Securities—Other	$ 12	$ —	$ —	$ 12	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (124)	$ 864	$ —	$ (978)	$ (10)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 224	$ —	$ 224	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 22	$ —	$ —	$ —	$ 22
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 4	$ —	$ 4	$ —	$ —
Debt Securities—Govt Obligations	$ 25	$ —	$ —	$ 25	$ —
Debt Securities—Other	$ 11	$ —	$ —	$ 11	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —

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Description	Recurring Fair Value Measurements as of December 31, 2013				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 439	$ —	$ 439	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 223	$ (349)	$ —	$ 474	$ 98
Interest Rate Swaps (C)	$ 38	$ —	$ —	$ 38	$ —
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 892	$ 5	$ —
Debt Securities—Govt Obligations	$ 429	$ —	$ —	$ 429	$ —
Debt Securities—Other	$ 291	$ —	$ —	$ 291	$ —
Other Securities	$ 84	$ —	$ 57	$ 27	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—Govt Obligations	$ 107	$ —	$ —	$ 107	$ —
Debt Securities—Other	$ 46	$ —	$ —	$ 46	$ —
Other Securities	$ 3	$ —	$ —	$ 3	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (107)	$ 351	$ —	$ (448)	$ (10)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 129	$ (349)	$ —	$ 474	$ 4
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 892	$ 5	$ —
Debt Securities—Govt Obligations	$ 429	$ —	$ —	$ 429	$ —
Debt Securities—Other	$ 291	$ —	$ —	$ 291	$ —
Other Securities	$ 84	$ —	$ 57	$ 27	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 10	$ —	$ —	$ 10	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (107)	$ 351	$ —	$ (448)	$ (10)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (B)	$ 94	$ —	$ —	$ —	$ 94
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 25	$ —	$ —	$ 25	$ —
Debt Securities—Other	$ 11	$ —	$ —	$ 11	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —

(A) Represents money market mutual funds.

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(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis

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adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The fair value measurement table excludes cash of $1 million which is part of the NDT Fund. The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds and United States Treasury obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheet. As of June 30, 2014, net cash collateral (received) paid of $155 million, was netted against the corresponding net derivative contract positions. Of the $155 million as of June 30, 2014, $(6) million of cash collateral was netted against assets, and $161 million was netted against liabilities. As of December 31, 2013, net cash collateral (received) paid of $2 million, was netted against the corresponding net derivative contract positions. Of the $2 million as of December 31, 2013, $(3) million of cash collateral was netted against assets, and $5 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group, and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and non-performance risk were not material to the financial statements.

For Power, in general, electric swaps are measured at fair value based on at least two pricing inputs, the underlying price of electricity at a liquid reference point and the basis difference between electricity prices at the liquid reference point and electricity prices at the respective delivery locations. To the extent the basis component is based on a single broker quote and is

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significant to the fair value of the electric swap, it is categorized as Level 3. The fair value of certain of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. For Power and PSE&G, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The following tables provide details surrounding significant Level 3 valuations as of June 30, 2014 and December 31, 2013.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of June 30, 2014 Assets	Fair Value as of June 30, 2014 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$ —	$ (10)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Other	Various (A)	1	—			
Total Power		**$ 1**	**$ (10)**			
PSE&G						
Gas	Forward Contracts	$ 22	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 22**	**$ —**			
Total PSEG		**$ 23**	**$ (10)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2013 Assets	Fair Value as of December 31, 2013 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ 3	$ (1)	Discounted Cash Flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	—	(8)	Discounted Cash Flow	Historic Load Variability	-5% to +10%
Other	Various (B)	1	(1)			
Total Power		**$ 4**	**$ (10)**			
PSE&G						
Gas	Forward Contracts	$ 94	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 94**	**$ —**			
Total PSEG		**$ 98**	**$ (10)**			

(A) Includes gas supply positions and long-term electric capacity positions which were immaterial as of June 30, 2014.

(B) Includes gas supply positions which were immaterial as of December 31, 2013.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in either the power basis or the

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load variability or the longer-term gas basis amounts would decrease the fair value. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value.

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and six months ended June 30, 2014 and June 30, 2013, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Six Months Ended June 30, 2014

	Three Months Ended June 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2014	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2014
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 1	$ 6	$ 10	$ —	$ (1)	$ (3)	$ 13
Power							
Net Derivative Assets (Liabilities)	$ (11)	$ 6	$ —	$ —	$ (1)	$ (3)	$ (9)
PSE&G							
Net Derivative Assets (Liabilities)	$ 12	$ —	$ 10	$ —	$ —	$ —	$ 22

	Six Months Ended June 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2014	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2014
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 88	$ (58)	$ (72)	$ —	$ 58	$ (3)	$ 13
Power							
Net Derivative Assets (Liabilities)	$ (6)	$ (58)	$ —	$ —	$ 58	$ (3)	$ (9)
PSE&G							
Net Derivative Assets (Liabilities)	$ 94	$ —	$ (72)	$ —	$ —	$ —	$ 22

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Six Months Ended June 30, 2013

	Three Months Ended June 30, 2013						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2013	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2013
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (57)	$ 17	$ (1)	$ —	$ —	$ 6	$ (35)
Power							
Net Derivative Assets (Liabilities)	$ (17)	$ 17	$ —	$ —	$ —	$ 6	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (40)	$ —	$ (1)	$ —	$ —	$ —	$ (41)

	Six Months Ended June 30, 2013						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2013	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2013
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (31)	$ (17)	$ (1)	$ —	$ 10	$ 4	$ (35)
Power							
Net Derivative Assets (Liabilities)	$ 9	$ (17)	$ —	$ —	$ 10	$ 4	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (40)	$ —	$ (1)	$ —	$ —	$ —	$ (41)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $6 million and $(58) million in Operating Income for the three months and six months ended June 30, 2014, respectively. The $6 million in Operating Income is unrealized. Of the $(58) million in Operating Income, $1 million is unrealized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $(1) million and $58 million in settlements for the three months and six months ended June 30, 2014. Includes $10 million in settlements for the six months ended June 30, 2013.

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(D) During the three months and six months ended June 30, 2014, $(3) million of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. During the three months and six months ended June 30, 2013, $6 million and $4 million, respectively, of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. The transfers were recognized as of the beginning of the quarters in which the transfers first occurred, as per PSEG's policy.

As of June 30, 2014, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $13 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of June 30, 2013, PSEG carried $1.9 billion of net assets that are measured at fair value on a recurring basis, of which $35 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of June 30, 2014 and December 31, 2013.

	As of June 30, 2014		As of December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 20	$ 32	$ 24	$ 38
Power -Recourse Debt (B)	2,542	2,929	2,541	2,846
PSE&G (B)	6,064	6,465	5,566	5,629
Transition Funding (PSE&G) (B)	371	391	476	511
Transition Funding II (PSE&G) (B)	14	15	20	21
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	16	16	16	16
Total Long-Term Debt	**$ 9,027**	**$ 9,848**	**$ 8,643**	**$ 9,061**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 12. Other Income and Deductions

Other Income	Power	PSE&G	Other (A)	Consolidated
		Millions		
Three Months Ended June 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ 46	$ —	$ —	$ 46
Allowance for Funds Used During Construction	—	7	—	7
Solar Loan Interest	—	6	—	6
Other	—	1	2	3
Total Other Income	**$ 46**	**$ 14**	**$ 2**	**$ 62**
Three Months Ended June 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ 33	$ —	$ —	$ 33
Allowance for Funds Used During Construction	—	6	—	6
Solar Loan Interest	—	5	—	5
Other	2	4	2	8
Total Other Income	**$ 35**	**$ 15**	**$ 2**	**$ 52**
Six Months Ended June 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ 78	$ —	$ —	$ 78
Allowance for Funds Used During Construction	—	13	—	13
Solar Loan Interest	—	12	—	12
Other	1	3	3	7
Total Other Income	**$ 79**	**$ 28**	**$ 3**	**$ 110**
Six Months Ended June 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ 80	$ —	$ —	$ 80
Allowance for Funds Used During Construction	—	12	—	12
Solar Loan Interest	—	11	—	11
Other	2	5	3	10
Total Other Income	**$ 82**	**$ 28**	**$ 3**	**$ 113**

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Other Deductions	Power	PSE&G	Other (A)	Consolidated
			Millions	
Three Months Ended June 30, 2014				
NDT Fund Realized Losses and Expenses	$ 8	$ —	$ —	$ 8
Other	1	1	—	2
Total Other Deductions	**$ 9**	**$ 1**	**$ —**	**$ 10**
Three Months Ended June 30, 2013				
NDT Fund Realized Losses and Expenses	$ 9	$ —	$ —	$ 9
Other	1	1	2	4
Total Other Deductions	**$ 10**	**$ 1**	**$ 2**	**$ 13**
Six Months Ended June 30, 2014				
NDT Fund Realized Losses and Expenses	$ 14	$ —	$ —	$ 14
Other	5	1	2	8
Total Other Deductions	**$ 19**	**$ 1**	**$ 2**	**$ 22**
Six Months Ended June 30, 2013				
NDT Fund Realized Losses and Expenses	$ 29	$ —	$ —	$ 29
Other	9	2	2	13
Total Other Deductions	**$ 38**	**$ 2**	**$ 2**	**$ 42**

(A) Other primarily consists of activity at PSEG (as parent company), Energy Holdings, Services and intercompany eliminations.

Note 13. Income Taxes

PSEG's, Power's and PSE&G's effective tax rates for the three months and six months ended June 30, 2014 and 2013 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
PSEG	34.8%	39.6%	38.4%	40.1%
Power	28.9%	39.9%	37.8%	39.6%
PSE&G	36.5%	37.2%	38.6%	39.6%

For the three months and six months ended June 30, 2014, as compared to the same periods in the prior year, the decrease in PSEG's and Power's effective tax rates were due primarily to Power's manufacturing deduction under Section 199 of the Internal Revenue Code.

PSEG's federal tax returns for the years 2007 through 2010 are currently being audited by the IRS. The audit is reasonably expected to be completed within the next 12 months.

In September 2013, the U.S. Department of the Treasury and the IRS released final regulations effective in 2014 that provide guidance on applying Section 263(a) of the IRC to amounts paid to acquire, produce, or improve tangible property, as well as rules for materials and supplies. Implementation of these regulations did not have any material impact on PSEG's and its subsidiaries' results of operations, financial condition or cash flows.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 was eligible for 50% bonus depreciation for tax purposes. The American Taxpayer Relief Act of 2012 further extended the 50% bonus depreciation for qualified property placed into service before January 1, 2014. In addition, long production property placed into service in 2014 is eligible for 50% bonus

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depreciation for tax purposes. These provisions have generated cash for PSEG through tax benefits related to the accelerated depreciation. These tax benefits otherwise would have been received over an estimated average 20 year period.

Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG

Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
	Other Comprehensive Income (Loss) Three Months Ended June 30, 2014			
		Millions		
Balance as of March 31, 2014	$ —	$ (234)	$ 147	$ (87)
Other Comprehensive Income before Reclassifications	1	—	23	24
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	2	(12)	(10)
Net Current Period Other Comprehensive Income (Loss)	1	2	11	14
Balance as of June 30, 2014	**$ 1**	**$ (232)**	**$ 158**	**$ (73)**

Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
	Other Comprehensive Income (Loss) Three Months Ended June 30, 2013			
		Millions		
Balance as of March 31, 2013	$ 3	$ (475)	$ 117	$ (355)
Other Comprehensive Income before Reclassifications	—	—	(16)	(16)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	9	—	9
Net Current Period Other Comprehensive Income (Loss)	—	9	(16)	(7)
Balance as of June 30, 2013	**$ 3**	**$ (466)**	**$ 101**	**$ (362)**

Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
	Other Comprehensive Income (Loss) Six Months Ended June 30, 2014			
		Millions		
Balance as of December 31, 2013	$ (2)	$ (238)	$ 145	$ (95)
Other Comprehensive Income before Reclassifications	(4)	—	34	30
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	7	6	(21)	(8)
Net Current Period Other Comprehensive Income (Loss)	3	6	13	22
Balance as of June 30, 2014	**$ 1**	**$ (232)**	**$ 158**	**$ (73)**

Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
	Other Comprehensive Income (Loss) Six Months Ended June 30, 2013			
		Millions		
Balance as of December 31, 2012	$ 7	$ (485)	$ 90	$ (388)
Other Comprehensive Income before Reclassifications	—	—	11	11
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(4)	19	—	15
Net Current Period Other Comprehensive Income (Loss)	(4)	19	11	26
Balance as of June 30, 2013	**$ 3**	**$ (466)**	**$ 101**	**$ (362)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of March 31, 2014	$ —	$ (201)	$ 144	$ (57)
Other Comprehensive Income before Reclassifications	2	—	21	23
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	2	(12)	(10)
Net Current Period Other Comprehensive Income (Loss)	2	2	9	13
Balance as of June 30, 2014	**$ 2**	**$ (199)**	**$ 153**	**$ (44)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2013			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of March 31, 2013	$ 5	$ (413)	$ 112	$ (296)
Other Comprehensive Income before Reclassifications	—	—	(14)	(14)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	8	—	7
Net Current Period Other Comprehensive Income (Loss)	(1)	8	(14)	(7)
Balance as of June 30, 2013	**$ 4**	**$ (405)**	**$ 98**	**$ (303)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2013	$ (1)	$ (204)	$ 142	$ (63)
Other Comprehensive Income before Reclassifications	(4)	—	31	27
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	7	5	(20)	(8)
Net Current Period Other Comprehensive Income (Loss)	3	5	11	19
Balance as of June 30, 2014	**$ 2**	**$ (199)**	**$ 153**	**$ (44)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2013			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 9	$ (422)	$ 85	$ (328)
Other Comprehensive Income before Reclassifications	—	—	13	13
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(5)	17	—	12
Net Current Period Other Comprehensive Income (Loss)	(5)	17	13	25
Balance as of June 30, 2013	**$ 4**	**$ (405)**	**$ 98**	**$ (303)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2014			Six Months Ended June 30, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ (12)	$ 5	$ (7)
Interest Rate Swaps	Interest Expense	—	—	—	—	—	—
Total Cash Flow Hedges		—	—	—	(12)	5	(7)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	5	(2)	3
Amortization of Actuarial Loss	O&M Expense	(6)	2	(4)	(14)	5	(9)
Total Pension and OPEB Plans		(3)	1	(2)	(9)	3	(6)
Available-for-Sale Securities							
Realized Gains	Other Income	33	(17)	16	58	(30)	28
Realized Losses	Other Deductions	(6)	3	(3)	(10)	5	(5)
Other-Than-Temporary Impairments (OTTI)	OTTI	(2)	1	(1)	(4)	2	(2)
Total Available-for-Sale Securities		25	(13)	12	44	(23)	21
Total		**$ 22**	**$ (12)**	**$ 10**	**$ 23**	**$ (15)**	**$ 8**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2013			Six Months Ended June 30, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ 2	$ (1)	$ 1	$ 8	$ (3)	$ 5
Interest Rate Swaps	Interest Expense	(1)	—	(1)	(1)	—	(1)
Total Cash Flow Hedges		1	(1)	—	7	(3)	4
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	1	—	1	5	(2)	3
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)	(38)	16	(22)
Total Pension and OPEB Plans		(16)	7	(9)	(33)	14	(19)
Available-for-Sale Securities							
Realized Gains	Other Income	2	(1)	1	4	(2)	2
OTTI	OTTI	(2)	1	(1)	(4)	2	(2)
Total Available-for-Sale Securities		—	—	—	—	—	—
Total		**$ (15)**	**$ 6**	**$ (9)**	**$ (26)**	**$ 11**	**$ (15)**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2014			Six Months Ended June 30, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ (12)	$ 5	$ (7)
Total Cash Flow Hedges		—	—	—	(12)	5	(7)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	2	(1)	1	4	(2)	2
Amortization of Actuarial Loss	O&M Expense	(6)	3	(3)	(12)	5	(7)
Total Pension and OPEB Plans		(4)	2	(2)	(8)	3	(5)
Available-for-Sale Securities							
Realized Gains	Other Income	33	(17)	16	56	(29)	27
Realized Losses	Other Deductions	(6)	3	(3)	(10)	5	(5)
OTTI	OTTI	(2)	1	(1)	(4)	2	(2)
Total Available-for-Sale Securities		25	(13)	12	42	(22)	20
Total		**$ 21**	**$ (11)**	**$ 10**	**$ 22**	**$ (14)**	**$ 8**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2013			Six Months Ended June 30, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ 2	$ (1)	$ 1	$ 8	$ (3)	$ 5
Total Cash Flow Hedges		2	(1)	1	8	(3)	5
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	2	(1)	1	4	(2)	2
Amortization of Actuarial Loss	O&M Expense	(16)	7	(9)	(32)	13	(19)
Total Pension and OPEB Plans		(14)	6	(8)	(28)	11	(17)
Available-for-Sale Securities							
Realized Gains	Other Income	2	(1)	1	4	(2)	2
Realized Losses	Other Deductions	—	—	—	—	—	—
OTTI	OTTI	(2)	1	(1)	(4)	2	(2)
Total Available-for-Sale Securities		—	—	—	—	—	—
Total		**$ (12)**	**$ 5**	**$ (7)**	**$ (20)**	**$ 8**	**$ (12)**

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Note 15. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under our stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)								
Net Income	**$ 212**	**$ 212**	**$ 333**	**$ 333**	**$ 598**	**$ 598**	**$ 653**	**$ 653**
EPS Denominator (Thousands)								
Weighted Average Common Shares Outstanding	505,875	505,875	505,900	505,900	505,976	505,976	505,921	505,921
Effect of Stock Based Compensation Awards	—	2,181	—	1,481	—	1,973	—	1,380
Total Shares	**505,875**	**508,056**	**505,900**	**507,381**	**505,976**	**507,949**	**505,921**	**507,301**
EPS								
Net Income	**$ 0.42**	**$ 0.42**	**$ 0.66**	**$ 0.66**	**$ 1.18**	**$ 1.18**	**$ 1.29**	**$ 1.29**

	Three Months Ended June 30,		Six Months Ended June 30,	
Dividend Payments on Common Stock	**2014**	**2013**	**2014**	**2013**
Per Share	$ 0.37	$ 0.36	$ 0.74	$ 0.72
In Millions	$ 187	$ 182	$ 374	$ 364

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Note 16. Financial Information by Business Segments

	Power	PSE&G	Other (A)	Eliminations (B)	Consolidated
			Millions		
Three Months Ended June 30, 2014					
Total Operating Revenues	$ 986	$ 1,435	$ 131	$ (303)	$ 2,249
Net Income (Loss)	54	151	7	—	212
Gross Additions to Long-Lived Assets	100	515	5	—	620
Six Months Ended June 30, 2014					
Total Operating Revenues	$ 2,686	$ 3,580	$ 236	$ (1,030)	$ 5,472
Net Income (Loss)	218	365	15	—	598
Gross Additions to Long-Lived Assets	226	996	7	—	1,229
Three Months Ended June 30, 2013					
Total Operating Revenues	$ 1,193	$ 1,423	$ 14	$ (320)	$ 2,310
Net Income (Loss)	210	121	2	—	333
Gross Additions to Long-Lived Assets	97	576	9	—	682
Six Months Ended June 30, 2013					
Total Operating Revenues	$ 2,644	$ 3,418	$ 26	$ (992)	$ 5,096
Net Income (Loss)	351	300	2	—	653
Gross Additions to Long-Lived Assets	248	1,148	10	—	1,406
As of June 30, 2014					
Total Assets	$ 11,731	$ 20,613	$ 1,890	$ (534)	$ 33,700
Investments in Equity Method Subsidiaries	$ 121	$ —	$ 3	$ —	$ 124
As of December 31, 2013					
Total Assets	$ 12,002	$ 19,720	$ 4,025	$ (3,225)	$ 32,522
Investments in Equity Method Subsidiaries	$ 123	$ —	$ 3	$ —	$ 126

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations, primarily related to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 17. Related-Party Transactions.

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Note 17. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

Power

The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	Millions			
Revenue from Affiliates:				
Billings to PSE&G through BGS and BGSS Contracts (A)	**$ 297**	**$ 320**	**$ 1,028**	**$ 991**
Expense Billings from Affiliates:				
Administrative Billings from Services (B)	**$ (46)**	**$ (43)**	**$ (88)**	**$ (88)**

Related-Party Transactions	As of June 30, 2014	As of December 31, 2013
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$ 114	$ 267
Receivable from (Payable to) Services (B)	(25)	(31)
Receivable from (Payable to) PSEG (C)	13	97
Accounts Receivable (Payable)—Affiliated Companies, net	**$ 102**	**$ 333**
Short-Term Loan to Affiliate (Demand Note to PSEG) (D)	**$ 740**	**$ 790**
Working Capital Advances to Services (E)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable (Payable)	**$ (88)**	**$ (53)**

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	Millions			
Expense Billings from Affiliates:				
Billings from Power through BGS and BGSS (A)	$ (297)	$ (320)	$ (1,028)	$ (991)
Administrative Billings from Services (B)	(64)	(62)	(124)	(123)
Total Expense Billings from Affiliates	**$ (361)**	**$ (382)**	**$ (1,152)**	**$ (1,114)**

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Related-Party Transactions	As of June 30, 2014	As of December 31, 2013
	Millions	
Payable to Power through BGS and BGSS Contracts (A)	$ (114)	$ (267)
Receivable from (Payable to) Services (B)	(53)	(73)
Receivable from (Payable to) PSEG (C)	74	150
Accounts Receivable (Payable)—Affiliated Companies, net	**$ (93)**	**$ (190)**
Working Capital Advances to Services (E)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Receivable (Payable)	**$ (63)**	**$ (72)**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to Power and PSE&G at cost. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

(E) Power and PSE&G have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on Power's and PSE&G's Condensed Consolidated Balance Sheets.

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Note 18. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following table presents condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended June 30, 2014					
Operating Revenues	$ —	$ 972	$ 42	$ (28)	$ 986
Operating Expenses	5	903	40	(29)	919
Operating Income (Loss)	(5)	69	2	1	67
Equity Earnings (Losses) of Subsidiaries	57	(3)	3	(54)	3
Other Income	8	47	—	(9)	46
Other Deductions	—	(8)	—	(1)	(9)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(27)	(6)	(5)	9	(29)
Income Tax Benefit (Expense)	21	(43)	—	—	(22)
Net Income (Loss)	**$ 54**	**$ 54**	**$ —**	**$ (54)**	**$ 54**
Comprehensive Income (Loss)	**$ 67**	**$ 66**	**$ —**	**$ (66)**	**$ 67**
Six Months Ended June 30, 2014					
Operating Revenues	$ —	$ 2,656	$ 82	$ (52)	$ 2,686
Operating Expenses	9	2,307	74	(53)	2,337
Operating Income (Loss)	(9)	349	8	1	349
Equity Earnings (Losses) of Subsidiaries	234	(3)	7	(231)	7
Other Income	16	80	—	(17)	79
Other Deductions	(4)	(14)	—	(1)	(19)
Other-Than-Temporary Impairments	—	(4)	—	—	(4)
Interest Expense	(55)	(13)	(10)	17	(61)
Income Tax Benefit (Expense)	36	(168)	(1)	—	(133)
Net Income (Loss)	**$ 218**	**$ 227**	**$ 4**	**$ (231)**	**$ 218**
Comprehensive Income (Loss)	**$ 237**	**$ 242**	**$ 4**	**$ (246)**	**$ 237**
Six Months Ended June 30, 2014					
Net Cash Provided By (Used In) Operating Activities	$ 292	$ 950	$ 32	$ (460)	$ 814
Net Cash Provided By (Used In) Investing Activities	$ 138	$ (415)	$ (16)	$ 57	$ (236)
Net Cash Provided By (Used In) Financing Activities	$ (430)	$ (534)	$ (17)	$ 403	$ (578)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended June 30, 2013					
Operating Revenues	$ —	$ 1,183	$ 37	$ (27)	$ 1,193
Operating Expenses	2	835	32	(27)	842
Operating Income (Loss)	(2)	348	5	—	351
Equity Earnings (Losses) of Subsidiaries	219	(2)	5	(217)	5
Other Income	10	35	—	(10)	35
Other Deductions	(2)	(9)	—	1	(10)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(26)	(6)	(6)	9	(29)
Income Tax Benefit (Expense)	11	(151)	—	—	(140)
Net Income (Loss)	**$ 210**	**$ 213**	**$ 4**	**$ (217)**	**$ 210**
Comprehensive Income (Loss)	**$ 203**	**$ 198**	**$ 4**	**$ (202)**	**$ 203**
Six Months Ended June 30, 2013					
Operating Revenues	$ —	$ 2,624	$ 74	$ (54)	$ 2,644
Operating Expenses	4	2,035	65	(53)	2,051
Operating Income (Loss)	(4)	589	9	(1)	593
Equity Earnings (Losses) of Subsidiaries	372	(2)	8	(370)	8
Other Income	19	83	—	(20)	82
Other Deductions	(10)	(29)	—	1	(38)
Other-Than-Temporary Impairments	—	(4)	—	—	(4)
Interest Expense	(53)	(16)	(10)	20	(59)
Income Tax Benefit (Expense)	27	(259)	1	—	(231)
Net Income (Loss)	**$ 351**	**$ 362**	**$ 8**	**$ (370)**	**$ 351**
Comprehensive Income (Loss)	**$ 376**	**$ 370**	**$ 8**	**$ (378)**	**$ 376**
Six Months Ended June 30, 2013					
Net Cash Provided By (Used In) Operating Activities	$ 386	$ 884	$ 15	$ (419)	$ 866
Net Cash Provided By (Used In) Investing Activities	$ 138	$ (411)	$ (26)	$ 218	$ (81)
Net Cash Provided By (Used In) Financing Activities	$ (524)	$ (476)	$ 11	$ 201	$ (788)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
As of June 30, 2014					
Current Assets	$ 4,186	$ 1,923	$ 109	$ (4,039)	$ 2,179
Property, Plant and Equipment, net	79	6,065	1,161	—	7,305
Investment in Subsidiaries	4,426	121	—	(4,547)	—
Noncurrent Assets	322	1,923	136	(134)	2,247
Total Assets	**$ 9,013**	**$ 10,032**	**$ 1,406**	**$ (8,720)**	**$ 11,731**
Current Liabilities	$ 647	$ 3,468	$ 737	$ (4,039)	$ 813
Noncurrent Liabilities	348	2,340	346	(134)	2,900
Long-Term Debt	2,498	—	—	—	2,498
Member's Equity	5,520	4,224	323	(4,547)	5,520
Total Liabilities and Member's Equity	**$ 9,013**	**$ 10,032**	**$ 1,406**	**$ (8,720)**	**$ 11,731**
As of December 31, 2013					
Current Assets	$ 4,413	$ 2,076	$ 102	$ (4,115)	$ 2,476
Property, Plant and Equipment, net	81	6,108	1,178	—	7,367
Investment in Subsidiaries	4,645	124	—	(4,769)	—
Noncurrent Assets	222	1,847	138	(48)	2,159
Total Assets	**$ 9,361**	**$ 10,155**	**$ 1,418**	**$ (8,932)**	**$ 12,002**
Current Liabilities	$ 697	$ 3,474	$ 745	$ (4,116)	$ 800
Noncurrent Liabilities	309	2,247	338	(47)	2,847
Long-Term Debt	2,497	—	—	—	2,497
Member's Equity	5,858	4,434	335	(4,769)	5,858
Total Liabilities and Member's Equity	**$ 9,361**	**$ 10,155**	**$ 1,418**	**$ (8,932)**	**$ 12,002**

Immaterial Correction of Prior Financial Information

The financial information included in the tables above has been corrected from the disclosure provided in Power's Form 10-Q filed on July 30, 2013 and Form 10-K filed on February 26, 2014 to conform to the requirements of Section 210.3-10 of SEC Regulation S-X.

In the prior disclosure, Operating Revenues and Operating Expenses among the Guarantor Subsidiaries were eliminated in the Consolidating Adjustments column. The revised presentation eliminates this activity in the Guarantor Subsidiaries column and removes such activity from the Consolidating Adjustments column. This decreased both Operating Revenues and Operating Expenses in both the Guarantor Subsidiaries and Consolidating Adjustments columns by $352 million and $714 million for the three months and six months ended June 30, 2013, respectively. This correction had no impact on Power's consolidated Operating Revenues and Operating Expenses.

In addition, the revised information was corrected to present the intercompany balances on a net basis when the right of offset exists in either Current Assets or Current Liabilities. This resulted in the following increases (decreases) to certain categories of the condensed consolidated balance sheet as of December 31, 2013 as follows:

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Increase (Decrease)		
			Millions		
As of December 31, 2013					
Current Assets	$ 253	$ (6,840)	$ (842)	$ 7,429	$ —
Investment in Subsidiaries	—	(605)	—	605	—
Total Assets	**$ 253**	**$ (7,445)**	**$ (842)**	**$ 8,034**	**$ —**
Current Liabilities	$ 253	$ (7,445)	$ (237)	$ 7,429	$ —
Member's Equity	—	—	(605)	605	—
Total Liabilities and Member's Equity	**$ 253**	**$ (7,445)**	**$ (842)**	**$ 8,034**	**$ —**

These corrections to the presentation had no impact to Power's condensed consolidated financial statements. These corrections to the presentation had no impact on any liquidity measures of Power. They did not alter the net increase or net decrease in cash for Power, the Guarantor Subsidiaries, or the Other Subsidiaries. There was no impact to Power's loan covenants as a result of these corrections. Management believes these corrections are immaterial.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **Power,** our wholesale energy supply company that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States, and
- **PSE&G,** our public utility company which primarily provides electric transmission services and distribution of electric energy and natural gas, implements demand response and energy efficiency programs and invests in solar generation in New Jersey.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which effective January 1, 2014, operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business of our 2013 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Overview of 2013 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2014 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2013 Form 10-K and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2014.

OVERVIEW OF 2014 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- Growing our utility operations through continued investment in T&D infrastructure projects with greater diversity of regulatory oversight, and
- Maintaining a reliable generation fleet with the flexibility to utilize a diverse mix of fuels to allow us to respond to market volatility and capitalize on opportunities as they arise in the locations in which we operate.

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Financial Results

The results for PSEG, PSE&G and Power for the three months and six months ended June 30, 2014 and 2013 are presented as follows:

Earnings (Losses)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	Millions			
Power	$ 54	$ 210	$ 218	$ 351
PSE&G	151	121	365	300
Other (A)	7	2	15	2
PSEG Net Income	**$ 212**	**$ 333**	**$ 598**	**$ 653**
PSEG Net Income Per Share (Diluted)	**$ 0.42**	**$ 0.66**	**$ 1.18**	**$ 1.29**

(A) Other includes activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	Millions, after tax			
NDT Fund Income (Expense) (A)	$ 14	$ 8	$ 23	$ 17
Non-Trading MTM Gains (Losses)	$ (42)	$ 80	$ (174)	$ (25)

(A) NDT Fund Income (Expense) includes the net realized gains, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in O&M Expense, as well as the depreciation related to the ARO asset.

Our $121 million decrease in Net Income for the three months ended June 30, 2014 was driven by

- MTM losses in 2014 due to an increase in prices on forward positions as compared to gains in 2013,
- lower volumes of generation sold in the PJM region at lower average realized prices, and
- higher Operation and Maintenance (O&M) costs largely due to planned outages at our fossil plants, including maintenance and installation of upgraded technology at our Linden station, partly offset by lower pension and other postretirement benefit (OPEB) costs and cost control measures.

These decreases were partially offset by higher revenues due to increased investments in transmission projects.

Our $55 million decrease in Net Income for the six months ended June 30, 2014 was driven by

- higher O&M costs due to higher planned outage and maintenance costs at our fossil plants, including maintenance and installation of upgraded technology at our Linden plant, partly offset by lower pension and other postretirement benefit (OPEB) costs and cost control measures,
- higher MTM losses in 2014 resulting from an increase in prices on forward positions,
- lower volumes of electricity sold under our basic generation service (BGS) contracts resulting from serving fewer tranches in 2014, and
- higher generation costs due to higher fuel costs and higher gas costs related to the basic gas supply service (BGSS) contract.

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These decreases were partially offset by

- higher revenues due to increased investments in transmission projects.
- higher average realized prices on sales in the New England (NE) and PJM regions, as well as higher capacity revenues, primarily in PJM resulting from higher average auction prices, and
- higher sales volumes under the BGSS contract due to colder average temperatures in the 2014 winter heating season.

Power's results also benefited from access to natural gas supplies through its existing firm pipeline transportation contracts during the cold weather experienced in the first quarter of 2014. Power manages these contracts for the benefit of PSE&G's customers through the BGSS arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to supply gas to its generating units in New Jersey and to make third party sales.

Under the PJM capacity auction conducted in May 2014, Power cleared 8,693 MW of its generating capacity at an average price of $164.61 MW-day for the 2017-2018 delivery period, a price consistent with what has been realized in the past three auctions. For a more detailed discussion on the Reliability Pricing Model (RPM) capacity auction, refer to Part II. Item 5. Other Information—Federal Regulation—Capacity Market Issues.

Power's 2014 results were unfavorably impacted by an extended refueling outage at Salem Unit 2. A planned refueling outage began on April 12, 2014 but was extended due to repairs to the Reactor Coolant Pump Turning Vanes. Salem Unit 2 returned to service on July 14, 2014.

At PSE&G, our regulated utility, we continued to invest capital in T&D infrastructure projects aimed at maintaining the reliability of our service to our customers. PSE&G's results for the first half of 2014 reflect the favorable impacts from these investments as well as a slowly improving economy. Effective January 1, 2014, PSE&G's annual formula rate increased our annual transmission revenues by approximately $171 million. Over the past few years, these types of investments have altered the business mix of PSEG's overall results of operations to reflect a higher percentage contribution by PSE&G.

Regulatory, Legislative and Other Developments

In developing and implementing our strategy of operational excellence, financial strength and disciplined investment, we closely monitor significant regulatory and legislative developments. Competitive wholesale power market design is of particular importance to our results and we continue to advocate for policies and rules that promote competitive electricity markets.

We also advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. On May 19, 2014, the EPA released the final Clean Water Act Section 316(b) rule on cooling water intake that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. Eight of Power's generating facilities and three of its jointly-owned generating facilities are subject to the rule. As adopted by the EPA, the rule requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts, primarily by reducing the amount of fish and shellfish that are impinged or entrained at a cooling water intake structure. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. However, the EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis, and will require facilities to conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. We are unable to predict the outcome that these permitting decisions may take and the effect, if any, that they may have on us although such impacts could be material. See Item 1. Financial Statements—Note 8. Commitments and Contingent Liabilities and Item 5. Other Information—Environmental Matters—Water Pollution Control for additional information.

On June 18, 2014, the EPA issued a proposed greenhouse gas emissions regulation for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction. States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions. The EPA is requesting comment on many aspects of the proposal and therefore, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact of the regulation. For a more detailed discussion of this proposed regulation, see Item 5. Other Information—Environmental Matters—Climate Change.

In addition, Clean Air Act (CAA) regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology rules are also of significance; however, we believe our generation business remains well-positioned for such air pollution control regulations if and when they are implemented.

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The FERC's rule under Order 1000 altered the right of first refusal previously held by incumbent utilities to build all transmission within their respective service territories. We are challenging the FERC's determination in court as we do not believe that the FERC sufficiently justified its decision to alter this right embedded in the FERC-approved contracts and tariffs. However, the FERC's action presents opportunities for us to construct transmission outside of our service territory. In April 2013, PJM initiated a solicitation process pursuant to Order 1000 to review technical solutions to improve the operational performance in the Artificial Island area, consisting of our Salem Units 1 and 2 and Hope Creek nuclear generation facilities. In June 2014, PJM's management recommended approval by its Board of a 500 kV project to be constructed by PSE&G to address performance issues at Artificial Island. On July 23, 2014, the PJM Board announced that it was deferring the selection of a project to enable four developers, including PSE&G, to supplement their project proposals by, among other things, re-evaluating the costs of their respective proposals. PJM currently expects to select a project by the end of 2014.

In May 2014, a federal court issued a rule that vacated a FERC Order in which the FERC determined that demand response providers should receive full market compensation for power and held that the FERC has no jurisdiction over demand response. The implications of these decisions could be significant for the capacity market. See Item 5. Other Information—Federal Regulation—Capacity Market Issues—for additional information.

In recent years we have been impacted by severe weather conditions, including Hurricane Irene in 2011 and Superstorm Sandy in 2012, the latter storm resulting in the highest level of customer outages in our history. For more detailed information, refer to Item 1—Note 8. Commitments and Contingent Liabilities—Superstorm Sandy. As a result, we filed a petition in early 2013 with the New Jersey Board of Public Utilities (BPU) in which we recommended making investments in our gas and electric distribution systems to improve resiliency. In May 2014, the BPU approved the settlement of our Energy Strong Proposal in a total amount of $1.22 billion. The settlement provides for cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated allowance for funds used during construction (AFUDC), through an accelerated recovery mechanism. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, which is to be filed no later than November 1, 2017. Work on the program, including some infrastructure replacement work and detailed engineering, has begun. We believe that the rate impacts of the Energy Strong program will be muted significantly as a result of scheduled reductions to customer bills that will be taking place over the next few years and the expectation that gas prices will remain low. For more detailed information, refer to Item 5. Other Information—Energy Strong Program.

On January 1, 2014, we commenced operation of the LIPA T&D system under a twelve-year contract with opportunity to extend for an additional eight years. Also, beginning in January 2015, Power will provide fuel procurement and power management services to LIPA under separate agreements.

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. We notified the FERC, PJM and the PJM Independent Market Monitor (IMM) of this issue. Upon discovery of the errors, we retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. We informed the FERC, PJM and the IMM of these additional issues, and have corrected these errors. Power is also in the process of implementing procedures to help mitigate the risk of similar issues occurring in the future. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with these matters, or the applicability of mitigating factors. For more detailed information regarding this matter, refer to Item 1. Financial Statements—Note 8. Commitments and Contingent Liabilities—FERC Compliance.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. In the first six months of 2014, our

- total nuclear fleet achieved an average capacity factor of 90%, despite the extended outage at Salem Unit 2,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 26,600 GWh, while addressing unit outages and balancing fuel availability and price volatility, and
- construction of transmission and solar projects proceeded on schedule and within budget.

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Financial Strength

Our financial strength is predicated on a solid balance sheet, positive cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first six months of 2014 as we

- had cash on hand of $570 million as of June 30, 2014,
- extended the expiration dates of PSEG's $500 million and Power's $1.6 billion five-year credit facilities from 2017 to 2019, and maintained substantial liquidity and solid investment grade credit ratings, including positive outlooks at S&P, and
- increased our indicated annual dividend for 2014 to $1.48 per share.

We expect to be able to fund our transmission projects required under PJM's reliability program, our Energy Strong program and other projects with internally generated cash and external debt financing.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first six months of 2014 we

- placed into service our 230 kV Burlington-Camden and 230 kV North Central Reliability transmission projects,
- made additional investments in transmission infrastructure projects,
- continued to execute our existing BPU-approved utility programs, and
- completed installation of equipment to increase output and improve efficiency at our Linden combined cycle gas generating plant and continue to plan for the installation of such equipment at our other combined cycle gas units.

In July 2014, we acquired rights to a 13 MW solar energy facility located near El Paso, Texas, which is expected to be operational in the fourth quarter of 2014 and a 3.6 MW solar energy facility located near Burlington, Vermont, which is expected to be operational late in the third quarter of 2014.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a difficult economy and cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments and to respond to the issues and challenges described below. In order to do this, we must continue to

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully re-contract our open supply positions,
- execute our capital investment program, including our Energy Strong program and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and the FERC of market design rules that continue to promote competition,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system.

For the remainder of 2014 and beyond, the key issues and challenges we expect our business to confront include

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer demand,

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- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate,
- the aftermath of Hurricane Irene and Superstorm Sandy, including addressing the BPU's review of performance and communications, and
- delays and other obstacles that might arise in connection with the construction of our T&D projects, including in connection with permitting and regulatory approvals.

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RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, Power and PSE&G, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Note 17. Related-Party Transactions.

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,249	$ 2,310	$ (61)	(3)	$ 5,472	$ 5,096	$ 376	7
Energy Costs	789	755	34	5	2,145	1,910	235	12
Operation and Maintenance	800	646	154	24	1,656	1,356	300	22
Depreciation and Amortization	295	283	12	4	601	573	28	5
Taxes Other than Income Taxes	—	14	(14)	(100)	—	35	(35)	(100)
Income from Equity Method Investments	3	3	—	—	7	5	2	40
Other Income and (Deductions)	52	39	13	33	88	71	17	24
Other-Than-Temporary Impairments	2	2	—	—	4	4	—	—
Interest Expense	94	101	(7)	(7)	191	203	(12)	(6)
Income Tax Expense	112	218	(106)	(49)	372	438	(66)	(15)

The 2014 amounts in the preceding table for Operating Revenues and O&M Costs each include $111 million and $200 million for the three months and six months ended June 30, 2014, respectively, for Long Island Electric Utility Servco, LLC, a wholly owned subsidiary of PSEG LI. These amounts represent the O&M pass-through costs for the Long Island operations, the full reimbursement of which is reflected in Operating Revenues. See Note 3. Variable Interest Entities for further explanation. The following discussions for Power and PSE&G provide a detailed explanation of their respective variances.

Power

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 986	$ 1,193	$ (207)	(17)	$ 2,686	$ 2,644	$ 42	2
Energy Costs	520	495	25	5	1,564	1,355	209	15
Operation and Maintenance	327	280	47	17	629	563	66	12
Depreciation and Amortization	72	67	5	7	144	133	11	8
Income from Equity Method Investments	3	5	(2)	(40)	7	8	(1)	(13)
Other Income (Deductions)	37	25	12	48	60	44	16	36
Other-Than-Temporary Impairments	2	2	—	—	4	4	—	—
Interest Expense	29	29	—	—	61	59	2	3
Income Tax Expense	22	140	(118)	(84)	133	231	(98)	(42)

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Three Months Ended June 30, 2014 as Compared to 2013

Operating Revenues decreased $207 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $224 million due primarily to

- lower net revenues of $212 million due primarily to MTM losses in 2014 resulting from an increase in prices on forward positions as compared to MTM gains in 2013 and lower generation sold in the PJM region at lower average realized prices, and
- a decrease of $28 million due primarily to lower volumes of electricity sold under our BGS contracts as a result of serving fewer tranches in 2014,
- partially offset by a net increase of $16 million due primarily to higher capacity revenues resulting from higher average auction prices.

Gas Supply Revenues increased $14 million due primarily to

- a net increase of $20 million due to higher sales volumes at lower average natural gas prices to third party customers,
- partially offset by a net decrease of $6 million due to lower sales prices under the BGSS contract.

Other Operating Revenues increased $3 million due to transition fees related to the fuel management and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $25 million due to

- ***Generation costs*** increased $27 million due primarily to higher congestion costs largely offset by lower net fuel costs, reflecting the utilization of lower volumes of natural gas at lower average prices and lower nuclear fuel costs.
- ***Gas costs*** decreased $2 million, reflecting lower average gas inventory costs on obligations under the BGSS contract, offset by higher sales volumes to third party customers at lower average prices in 2014.

Operation and Maintenance increased $47 million due primarily to

- higher planned outage costs of $32 million primarily at our Linden combined cycle gas generating plant, including maintenance and installation of upgraded technology,
- a net increase of $13 million due to a $25 million insurance reimbursement in June 2013 for Superstorm Sandy partially offset by lower storm costs in 2014, and
- a $4 million charge related to the New Jersey sales and use tax settlement in May 2014,
- partially offset by lower pension and OPEB expense of $12 million.

Depreciation and Amortization increased $5 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) increased $12 million primarily due to higher net realized gains related to the NDT Fund restructuring in May 2014.

Interest Expense experienced no material change.

Income Tax Expense decreased $118 million in 2014 due primarily to lower pre-tax income.

Six Months Ended June 30, 2014 as Compared to 2013

Operating Revenues increased $42 million due to changes in generation, gas supply and other operating revenues.

Gas Supply Revenues increased $108 million due primarily to

- a net increase of $72 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during the 2014 winter heating season, and
- a net increase of $36 million due to higher sales volumes at lower average sales prices to third party customers.

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Generation Revenues decreased $73 million due primarily to

- lower net revenues of $96 million due primarily to higher MTM losses in 2014 resulting from an increase in prices on forward positions, partially offset by higher average realized prices in the PJM and NE regions,
- a decrease of $43 million due primarily to lower volumes of electricity sold under our BGS contracts as a result of serving fewer tranches in 2014, and
- a net decrease of $18 million due to lower volumes on wholesale load contracts in the PJM and NE regions,
- partially offset by a net increase of $84 million in PJM due primarily to higher capacity revenues resulting from higher average auction prices and higher ancillary revenue, partially offset by a decrease in operating reserve revenue.

Other Operating Revenues increased $7 million due to transition fees related to the fuel management and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $209 million due to

- ***Generation costs*** increased $168 million due primarily to higher fuel costs, reflecting higher average realized natural gas prices, the unfavorable MTM impact from lower average unrealized natural gas prices on forward positions and the utilization of higher volumes of coal and oil. These increased costs were largely offset by $89 million of lower congestion costs in the PJM region.
- ***Gas costs*** increased $41 million, principally related to higher volumes sold under the BGSS contract and to third parties due to colder average temperatures during the 2014 winter heating season, partially offset by lower average gas inventory costs.

Operation and Maintenance increased $66 million due primarily to

- higher planned outage and maintenance costs of $86 million at our fossil plants, primarily at our Linden combined cycle gas generating plant, including maintenance and installation of upgraded technology, and
- higher nuclear outage and refueling costs of $8 million, primarily at our Salem facility,
- partially offset by lower pension and OPEB costs of $26 million, and
- a net decrease of $5 million due to a $25 million insurance reimbursement in June 2013, more than offset by lower storm costs of $30 million in 2014.

Depreciation and Amortization increased $11 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) increased $16 million due primarily to losses that were incurred in March 2013 as a result of rebalancing the NDT portfolio.

Interest Expense experienced no material change.

Income Tax Expense decreased $98 million in 2014 due primarily to lower pre-tax income.

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PSE&G

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,435	$ 1,423	$ 12	1	$ 3,580	$ 3,418	$ 162	5
Energy Costs	565	580	(15)	(3)	1,610	1,547	63	4
Operation and Maintenance	362	369	(7)	(2)	824	796	28	4
Depreciation and Amortization	217	207	10	5	444	422	22	5
Taxes Other Than Income Taxes	—	14	(14)	(100)	—	35	(35)	(100)
Other Income (Deductions)	13	14	(1)	(7)	27	26	1	4
Interest Expense	67	75	(8)	(11)	135	148	(13)	(9)
Income Tax Expense	86	71	15	21	229	196	33	17

Three Months Ended June 30, 2014 as Compared to 2013

Operating Revenues increased $12 million due to changes in delivery, commodity, clause, and other operating revenues.

Delivery Revenues increased $28 million due primarily to an increase in transmission revenues.

- Transmission revenues were $39 million higher due to net rate increases resulting primarily from increased capital investments.
- Electric distribution revenues decreased $9 million due primarily to lower TEFA revenue of $11 million due to elimination of the TEFA rate effective January 1, 2014 and lower sales volumes of $7 million, partially offset by higher revenue from Green Program Recovery Charges (GPRC) of $9 million.
- Gas distribution revenues decreased $2 million due primarily to lower Transitional Energy Facilities Assessment (TEFA) revenue of $3 million due to elimination of the TEFA rate effective January 1, 2014 and lower Capital Infrastructure Program (CIP) related revenue of $4 million, partially offset by $4 million from higher sales volumes.

Commodity Revenue decreased $15 million due to lower Electric revenues, partially offset by higher Gas revenues. This is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $31 million due primarily to $19 million in lower BGS revenues and $12 million in lower revenues from collection of Non-Utility Generation Charges (NGC) and sales of Non-Utility generation (NUG) energy due primarily to lower volume. BGS sales decreased 1% due primarily to weather.
- Gas revenues increased $16 million due primarily to higher BGSS volumes of $10 million and higher BGSS prices of $6 million.

Clause Revenues decreased $5 million due primarily to lower Societal Benefit Charges (SBC) of $4 million, and lower Securitization Transition Charge (STC) revenues of $4 million, partially offset by a higher Solar Pilot Recovery Charge (SPRC) of $3 million. The change in the SBC, STC and SPRC amounts were entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, STC or SPRC collections.

Other Operating Revenues increased $4 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Operating Expenses

Energy Costs decreased $15 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $31 million or 7% due primarily to $9 million of lower BGS and NUG prices and $21 million in lower BGS and NUG volumes. BGS and NUG volumes decreased 5% due primarily to customer migration to TPS and weather.

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- Gas costs increased $16 million or 13% due to $10 million or 8% in higher sales volumes and $6 million or 5% in higher prices.

Operation and Maintenance decreased $7 million, of which the most significant components were

- an $18 million decrease in pension and OPEB expenses,
- partially offset by a $6 million increase in costs related to clauses due primarily to higher GPRC of $15 million, partially offset by lower SBC and CIP of $9 million. Due to the nature of the GPRC, SBC and CIP clause mechanisms, these are entirely offset in revenues, and
- a $4 million increase in gas bad debt expense.

Depreciation and Amortization increased $10 million due primarily to

- a $12 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects,
- partially offset by a $4 million decrease in amortization of Regulatory Assets.

Taxes Other Than Income Taxes decreased $14 million due to elimination of the TEFA rate effective January 1, 2014.

Other Income and (Deductions) experienced no significant change.

Interest Expense decreased $8 million due primarily to a partial redemption of securitization debt and maturity of Medium-Term Notes (MTNs) in the second half of 2013, partially offset by the issuance of MTNs in the second half of 2013.

Income Tax Expense increased $15 million due primarily to higher pre-tax income.

Six Months Ended June 30, 2014 as Compared to 2013

Operating Revenues increased $162 million due to changes in delivery, commodity, clause, and other operating revenues.

Delivery Revenues increased $78 million due primarily to an increase in transmission revenues.

- Transmission revenues were $78 million higher due to net rate increases resulting primarily from increased capital investments.
- Gas distribution revenues increased $2 million due primarily to $52 million from higher sales volumes and higher revenue from GPRC of $6 million, partially offset by lower Weather Normalization Clause (WNC) revenue of $36 million due to colder than normal weather, lower TEFA revenue of $13 million due to elimination of the TEFA rate effective January 1, 2014 and lower CIP related revenues of $7 million.
- Electric distribution revenues decreased $2 million due primarily to lower TEFA revenue of $21 million due to elimination of the TEFA rate effective January 1, 2014 and lower sales volumes of $4 million, partially offset by higher revenue from GPRC of $24 million.

Commodity Revenue increased $63 million due to higher Electric and Gas revenues. This is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues increased $18 million due primarily to $32 million in higher volumes of BGS sales, partially offset by $14 million in lower revenues from collection of NGC and lower sales volumes of NUG energy. BGS sales increased 4% due primarily to weather.
- Gas revenues increased $45 million due primarily to higher BGSS volumes of $100 million, partially offset by lower BGSS prices of $55 million. The average price of natural gas was 8% lower in 2014.

Clause Revenues increased $10 million due primarily to higher SBC. The change in the SBC amount was entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC collections.

Other Operating Revenues increased $11 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

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Operating Expenses

Energy Costs increased $63 million. This is entirely offset by Commodity Revenue.

- Electric costs increased $18 million or 2% due to $51 million of increased deferred cost recovery, partially offset by $32 million in lower BGS and NUG volumes and $1 million of lower BGS and NUG prices. BGS and NUG volumes decreased 4% due primarily to customer migration to TPS.
- Gas costs increased $45 million or 7% due to $100 million or 15% in higher sales volumes, partially offset by $55 million or 8% in lower prices.

Operation and Maintenance increased $28 million, of which the most significant components were

- a $39 million increase in costs related primarily to GPRC and SBC. Due to the nature of the GPRC and SBC clause mechanisms, these are entirely offset in revenues, and
- a $20 million increase in operational expenses due primarily to winter storm-related costs of $7 million, damage claims of $6 million, transmission related costs of $4 million and general wage increases of $3 million,
- partially offset by a $36 million decrease in pension and OPEB expenses.

Depreciation and Amortization increased $22 million due primarily to a $20 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects.

Taxes Other Than Income Taxes decreased $35 million due to elimination of the TEFA rate effective January 1, 2014.

Other Income and (Deductions) experienced no significant change.

Interest Expense decreased $13 million due primarily to a partial redemption of securitization debt and maturity of MTNs in the second half of 2013, partially offset by the issuance of MTNs in the latter part of 2013.

Income Tax Expense increased $33 million due primarily to higher pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund planned capital expenditures and shareholder dividend payments.

For the six months ended June 30, 2014, our operating cash flow increased $105 million as compared to the same period in 2013. The net change was due primarily to higher federal tax payments made by the parent company in 2014 and the net changes from Power and PSE&G as discussed below.

Power

Power's operating cash flow decreased $52 million from $866 million to $814 million for the six months ended June 30, 2014, as compared to the same period in 2013, primarily resulting from increased working capital needs, partially offset by a $41 million decrease in employee benefit plan funding. The increased working capital needs were primarily due to higher margin deposit requirements.

PSE&G

PSE&G's operating cash flow increased $316 million from $421 million to $737 million for the six months ended June 30, 2014, as compared to the same period in 2013, due primarily to higher earnings, an increase in net regulatory liabilities related to BGS and NUG costs and over collections in Gas Weather Normalization Charges partly offset by GPRC rate recoveries and a $90 million decrease in employee benefit plan funding.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our $4.3 billion credit facilities are provided by a diverse bank group. As of June 30, 2014, our total available credit capacity was $4.1 billion.

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As of June 30, 2014, no single institution represented more than 8% of the total commitments in our credit facilities.

As of June 30, 2014, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. In April 2014, PSEG and Power amended their 2012 credit agreements ending in 2017, extending the expiration date from March 2017 to April 2019. PSEG's $500 million and Power's $1.6 billion facility amendments, resulting in total commitments of $2.1 billion, will mature in 2019.

Our total credit facilities and available liquidity as of June 30, 2014 were as follows:

	As of June 30, 2014				
Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
		Millions			
PSEG					
5-year Credit Facility	$ 500	$ 8	$ 492	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—	500	Mar 2018	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 8**	**$ 992**		
Power					
5-year Credit Facility	$ 1,600	$ 114	$ 1,486	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (B)	1,000	—	1,000	Mar 2018	Funding/Letters of Credit
Bilateral Credit Facility	100	100	—	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 214**	**$ 2,486**		
PSE&G					
5-year Credit Facility (C)	$ 600	$ 13	$ 587	Mar 2018	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 13**	**$ 587**		
Total	**$ 4,300**	**$ 235**	**$ 4,065**		

(A) In April 2016, this facility will be reduced by $23 million.

(B) In April 2016, this facility will be reduced by $48 million.

(C) In April 2016, this facility will be reduced by $29 million.

Long-Term Debt Financing

PSE&G has $250 million of 5.00%, Series D, Medium Term Notes and $250 million of 0.85%, Series G, Medium Term Notes (MTNs) both maturing in August 2014 and $300 million of 2.70%, Series G, MTNs maturing in May 2015.

Power has a $44 million pollution control facilities loan servicing and securing a Pennsylvania Economic Development Financing Authority (PEDFA) bond due November 2042. The bond is backed by a three-year letter of credit that expires in November 2014. The PEDFA bond has been reclassified as debt due within the year.

For a discussion of our long-term debt transactions during 2014, see Note 9. Changes in Capitalization.

Common Stock Dividends

On July 15, 2014, our Board of Directors approved a $0.37 per share common stock dividend for the third quarter of 2014. This reflects an indicated annual dividend rate of $1.48 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Note 15. Earnings Per Share (EPS) and Dividends.

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Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security. In January 2014, Moody's upgraded PSE&G's Mortgage Bond Rating from A1 to Aa3 and its commercial paper rating from P2 to P1. PSE&G's outlook is stable. In May 2014, Moody's published updated research reports on PSEG, PSE&G and Power and the existing ratings and outlooks were unchanged.

In May 2014, S&P published updated research reports and revised the outlooks to positive from stable for the corporate credit and senior unsecured long-term ratings of PSEG, PSE&G and Power. S&P also affirmed the senior unsecured rating of BBB+ at Power and senior secured rating of A at PSE&G.

	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	**Stable**	**Stable**	**Stable**
Commercial Paper	P2	A2	F2
Power			
Outlook	**Stable**	**Positive**	**Stable**
Senior Notes	Baa1	BBB+	BBB+
PSE&G			
Outlook	**Stable**	**Stable**	**Stable**
Mortgage Bonds	Aa3	A	A+
Commercial Paper	P1	A2	F2

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1+ (highest) to D (lowest) for short-term securities.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1+ (highest) to D (lowest) for short-term securities.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures at Power and Services as compared to amounts disclosed in our 2013 Form 10-K. PSE&G has increased its total projected capital expenditures through 2016 by $295 million, including $145 million for additional transmission reliability enhancements in 2015 and $50 million and $100 million in 2015 and 2016, respectively, related to additional distribution expenditures for reliability enhancements and facility replacement.

On May 21, 2014, the BPU issued an Order approving our Energy Strong program, agreeing that PSE&G would spend $1.22 billion to protect and strengthen PSE&G's electric and gas systems against severe weather conditions over primarily a three-year period with some projects extending over five years. This amount is not included in the projected capital expenditures disclosed in our 2013 Form 10-K or in the increases reported above. See Item 5. Other Information—Energy Strong Program for additional information.

Power

During the six months ended June 30, 2014, Power made capital expenditures of $185 million, excluding $41 million for nuclear fuel, primarily related to various projects at its fossil and nuclear generation stations.

PSE&G

During the six months ended June 30, 2014, PSE&G made capital expenditures of $996 million, primarily for transmission and distribution system reliability. This does not include expenditures for certain energy efficiency and renewable programs of $13 million or cost of removal, net of salvage, of $50 million, which are included in operating cash flows.

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ACCOUNTING MATTERS

For information related to recent accounting matters, see Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The market risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From April to June, MTM VaR remained relatively stable with less volatile price movements. The range of VaR was narrower for the three months ended June 30, 2014 as compared with the year ended December 31, 2013.

	MTM VaR	
	Three Months Ended June 30, 2014	Year Ended December 31, 2013
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 20	$ 12
Average for the Period	$ 20	$ 15
High	$ 24	$ 29
Low	$ 16	$ 8
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 31	$ 18
Average for the Period	$ 31	$ 23
High	$ 38	$ 46
Low	$ 25	$ 13

See Note 10. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the second quarter of 2014 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3. of Part I of the 2013 Annual Report on Form 10-K, see Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

There are no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2013 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the second quarter of 2014.

Three Months Ended June 30, 2014	Total Number of Shares Purchased	Average Price Paid per Share
April 1 - April 30	—	$ —
May 1 - May 31	127,319	$ 39.37
June 1 - June 30	7,033	$ 38.93

ITEM 5. OTHER INFORMATION

Certain information reported in the 2013 Annual Report on Form 10-K and Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2013 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2014. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

Business Operations and Strategy

Other

December 31, 2013 Form 10-K page 13. On July 1, 2014, PSEG LI submitted a proposal to invest up to $200 million of capital in equipment at customer facilities that would improve energy efficiency and reduce peak load. PSEG LI proposed to make the investments from 2015 through 2018 and recover its investment and earn a return over approximately 10 years. The New York State Department of Public Service will review the proposal and make a recommendation to the LIPA Board which will decide whether to enter into a contract with PSEG LI.

Federal Regulation

FERC

Regulation of Wholesale Sales—Generation/Market Issues

Energy Clearing Prices

December 31, 2013 Form 10-K page 16 and March 31, 2014 Form 10-Q page 69. As a result of the polar vortex and related cold weather events in January 2014, there were both gas and electric price spikes in the Northeast markets, including in PJM. The FERC is currently examining the facts surrounding these price spikes, as well as "lessons learned" from the various Regional Transmission Operators/Independent System Operators (RTO/ISO) and potential changes in market rules intended to encourage dual fuel capability of generating units, the purchase of firm fuel to fire these units and the construction of additional natural gas pipeline capacity. In addition, PJM's Market Monitor has requested information from all market participants in PJM, including Power, looking at bidding behavior to rule out underlying market manipulation. The FERC has also gathered information but has not commenced an investigation. We cannot predict what action, if any, the FERC may take.

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Capacity Market Issues

December 31, 2013 Form 10-K page 16 and March 31, 2014 Form 10-Q page 69. PJM, the New York ISO (NYISO), and the ISO-New England each have capacity markets that have been approved by the FERC. The FERC regulates these markets and continues to examine whether the market design for these three capacity markets is working optimally. One of the specific issues being considered by the FERC and addressed at an industry-wide technical conference in 2013 is whether capacity market rules are properly responding to, and fostering the development of, state public policies, demand response, fuel diversity and emerging technologies, as well as addressing concerns raised by future generation retirements. We cannot predict what action, if any, the FERC might take with regard to capacity market design. As noted below, one of the most significant developments, with the potential to impact all of the RTO/ISO capacity markets, is a May 2014 decision of the U.S. Court of Appeals for the D.C. Circuit (D.C. Court) holding that the FERC does not have jurisdiction over demand response. Capacity market rules continue to evolve on other fronts as well, including with respect to setting the demand curve for capacity and establishing new capacity zones. As discussed below, the ISO-NE, for example, recently established a downward sloping demand curve like the one in place in PJM that we believe should help to more appropriately incent the construction of new generation.

Capacity Market Issues—Demand Response

In May 2014, the D.C. Court issued a ruling vacating FERC Order No. 745, in which FERC determined that demand response providers should receive full Locational Marginal Pricing ("LMP") as compensation in energy markets. In so doing, the D.C. Court not only ruled that FERC's action in affording demand response providers full LMP was not just and reasonable; the D.C. Court further held that demand response itself is not within the FERC's jurisdiction. The implications of this decision on FERC-regulated energy and capacity markets, and demand response's future participation therein, could be significant and far-reaching. For example, if demand response is not able to participate in the capacity market in the future, or can participate but in a more limited or different fashion, this could in turn impact capacity prices. With respect to the D.C. Court's decision, several parties, including the FERC, PJM, the Maryland and Pennsylvania public utility commissions and various demand response providers, have filed petitions for rehearing before the full bench of judges of the D.C. Court. The effect of filing these petitions for rehearing is to stay the decision until after the D.C. Court rules on these petitions.

Capacity Market Issues—PJM

December 31, 2013 Form 10-K page 16 and March 31, 2014 Form 10-Q page 70. The FERC has issued orders (i) capping the amount of "limited" demand response resources (i.e. resources which can only be called on by PJM a limited number of times during the summer months) that can clear in PJM's capacity auctions, (ii) imposing requirements that these resources have "sell-offer" plans and accompanying officer certifications attesting to the resources' availability, and (iii) revising the operational requirements applicable to demand response, such as reducing the amount of advanced call time for such resources. We believe that capping "limited" demand response participation had an upward effect on capacity prices in the May 2014 auction. The FERC is also considering whether additional steps need to be taken to bar speculative sell offers from being submitted into PJM's capacity market auctions. In addition, the PJM Board has directed PJM management to develop a Performance Assurance proposal that includes both incentives and performance penalties to promote better generator performance during peak periods.

PJM has instituted a stakeholder proceeding to once again re-examine its rules for setting the Cost of New Entry (CONE), which in turn establishes the appropriate demand curve used in the capacity market auctions and affects capacity prices. This process is expected to result in a filing at the FERC to reset CONE for another three years beginning with the 2018/2019 delivery year.

Capacity Market Issues—Midwest Independent System Operator (MISO)

December 31, 2013 Form 10-K page 16 and March 31, 2014 Form 10-Q page 70. The import into PJM of significant amounts of MISO generation that is not subject to the same type of rules and requirements as generation that is located within PJM could adversely impact Power. The FERC issued an order permitting PJM to establish annual capacity import limits, which were then incorporated into the 2017/2018 planning parameters for the May 2014 base residual auction. We believe that these rules restricting capacity imports had an upward effect on prices in PJM in this auction.

Capacity Market Issues—ISO-New England (ISO-NE)

December 31, 2013 Form 10-K page 16. ISO-NE's market for installed capacity in New England provides fixed capacity payments for generators, imports and demand response. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. In June 2014, the FERC issued an order requiring the implementation of a downward sloping demand curve, similar to the design in place in PJM, for use in ISO-NE's ninth capacity market auction to be held in February 2015 and effective in the 2018-2019 planning year. This action is expected to result in greater stability of capacity prices in New England and is also expected to send more appropriate price signals that

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will incent the development of new generation. One aspect of this order that PSEG has not supported is the exemption from the Minimum Offer Price Rule afforded annually up to 600 MW of renewable resources. We are challenging this portion of the order on rehearing on the grounds that we believe that it is unduly discriminatory and will suppress capacity prices.

On May 30, 2014, the FERC issued a decision on ISO-NE's and NEPOOL's respective Performance Incentives proposals which were submitted in order to help address resource performance problems in New England by incenting enhanced generator performance. The provisions consist of a two settlement structure in which capacity resources are paid both a base case capacity payment and a performance payment or charge during scarcity conditions. Further, the provisions do not recognize any exceptions from penalties for non-performance during scarcity conditions.

Capacity Market Issues—NYISO

December 31, 2013 Form 10-K page 17 and March 31, 2014 Form 10-Q page 70. NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. Prior to 2013, the NYISO capacity model had recognized only two separate zones that potentially may separate in price: New York City and Long Island. In August 2013, the FERC issued an order approving a third capacity zone that will encompass the super zone that includes the lower Hudson Valley and New York City to take effect May 1, 2014.

In January 2014, the FERC issued an order accepting the NYISO's proposed reference unit (a generation unit with no environmental controls) that should be used for the purposes of establishing the CONE in the "rest of State" zone (excluding the lower Hudson Valley, New York City and Long Island), which may have the effect of depressing capacity prices. This order will set the demand curve on which future capacity prices paid to generators will be based for the period May 1, 2014 through April 30, 2017. That order was subsequently upheld by the FERC on rehearing in May 2014 and is now being challenged by the State of New York, the New York Public Service Commission and others in the federal appellate court.

Transmission Regulation—Transmission Policy Developments

December 31, 2013 Form 10-K page 17. The FERC concluded in Order No. 1000 that the incumbent transmission owner should not always have a "right of first refusal" (ROFR) to construct and own transmission projects in its service territory. We have challenged the FERC's elimination of the ROFR in federal court, which challenge remains pending. PJM is currently implementing new rules under which the construction of certain types of transmission projects is no longer subject to a ROFR for incumbents. In May 2014, the FERC approved PJM's rules, which retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including projects being built on existing right-of-way and whose construction would interfere with incumbents' use of its right-of-way. Several companies, including PSE&G, have appealed various aspects of this approval order. The FERC has also approved the "state agreement approach" to cost allocation under which transmission projects being built to address public policy concerns may be placed into PJM's planning process if the state sponsoring the project agrees to pay the costs of the project. To date, no such projects have been placed into the planning process but this mechanism could potentially facilitate transmission projects that are not needed for reliability or market efficiency under PJM standards for transmission, including potential offshore wind projects proposed by third parties, should a state or states agree to fund the costs of such projects.

We cannot predict the final outcome or impact on us; however, specific implementation of Order 1000 in the various regions, including within our service territory, may expose us to competition from third party construction of certain transmission projects within our service territory while at the same time providing opportunities to build transmission outside of our service territory.

Transmission Regulation—Transmission Rate Proceedings

December 31, 2013 Form 10-K page 18 and March 31, 2014 Form 10-Q page 70. In December 2013, PSE&G was assigned construction responsibility by PJM of a new transmission project that will provide a double-circuit 345 kV line in the Bergen-Linden Corridor (BLC Project) to maintain reliability. Phases One through Three of the BLC Project are scheduled to be in service in 2016, 2017 and 2018, respectively, with certain components of Phase One required to be in service as early as June 2015. The estimated construction costs of the BLC Project are $1.2 billion. The net increase in PSE&G's capital expenditures is expected to be less than the estimated cost of the BLC Project, as it will eliminate the need for certain other projects that had been previously assigned by PJM. On March 28, 2014, we filed a petition with FERC seeking incentives for the BLC Project, specifically recovery of Construction Work in Progress in rate base and authorization to recover 100% of all prudently incurred development and construction costs if the BLC Project is abandoned or canceled, in whole or in part, for reasons beyond the control of PSE&G. In May 2014, the FERC issued an order granting our petition requesting incentives. A customer is currently challenging that order for reasons related to its allocated cost responsibility for the BLC project.

In September 2011, a complaint was filed by several state utility commissions and consumer advocates against transmission owners in New England challenging their base return on equity (ROE). In June 2014, the FERC issued an order in this proceeding that provided for a new approach for determining the ROE for public utilities that, among other things, is intended to narrow the parameters set in calculating the ROE. In applying the new methodology to this case, the FERC tentatively

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found that the New England transmission owners' base ROE should be reduced by 57 basis points, and instituted a hearing to allow the participants in the proceeding an opportunity to submit evidence in writing solely concerning the application of the new approach. In addition, the FERC directed that the approach to determine ROE set forth in the New England transmission owners order should apply to all currently pending ROE-related complaint cases in which the FERC has not issued a final order, which cases include the following:

- In February 2013, several state utility commissions and consumer advocates, including the BPU and the New Jersey Division of Rate Counsel, also filed a complaint at the FERC challenging the base ROE and formula transmission rate implementation protocols of transmission owners in Maryland, Pennsylvania, Delaware and New Jersey. This complaint remains pending;
- On November 12, 2013, a group of industrial customers in MISO filed a complaint against the MISO transmission owners, requesting that the FERC reduce the transmission owners' base ROE and eliminate the ROE adders for among other things, participation in an RTO. Alternatively, the customers requested that the FERC find the base ROE to be unjust and unreasonable and expeditiously establish settlement procedures; and
- On February 6, 2014, a public power association in New York filed a complaint against one of the New York transmission owners asking the FERC to reduce the ROE used to calculate the transmission owner's rates.

Various parties to the New England transmission owners' case noted above have filed motions for reconsideration and rehearing with the FERC, and on July 31, 2014, the state utility commissions and consumer advocates that originally challenged the New England transmission owners' base ROE filed another complaint at the FERC challenging ROE, allegedly based on new data, application of the newly-announced methodology, and materially changed market conditions. Like the September 2011 New England transmission owners' case, the results of these proceedings could set a precedent for the FERC-regulated transmission owners with formula rates in place, such as ours.

Compliance—FERC

March 31, 2014 Form 10-Q page 70. In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, we retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with these matters, or the applicability of mitigating factors. See Part I, Item 1. Financial Statements—Note 8. Commitments and Contingent Liabilities—FERC Compliance for further discussion of this matter.

Compliance—Reliability Standards

December 31, 2013 Form 10-K page 18 and March 31, 2014 Form 10-Q page 70. Congress has required the FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the United States electric transmission and generation system (grid) and to prevent major system blackouts. There has been considerable focus recently on physical security in light of, among other things, a substation attack in California that occurred in 2013. As a result, the FERC directed the NERC to draft a physical security standard intended to further protect assets deemed "critical" to reliability of the grid. The NERC submitted a draft standard to the FERC for its review and approval by the end of May 2014. The draft standard would require utilities to identify critical substations as well as develop threat assessment plans to be reviewed by independent third parties. As part of these plans, utilities could decide to build additional redundancy into their systems. In July 2014, the FERC acted on the NERC submittal, proposing to modify the draft standard so that, among other things, governmental authorities such as FERC could add or subtract from a utility's list of critical substations. The FERC has sought public comment on its proposed modifications. Thus, the standard is not yet approved.

State Regulation

Energy Strong Program

December 31, 2013 Form 10-K page 20 and March 31, 2014 Form 10-Q page 71. On May 21, 2014, the BPU issued an Order approving the settlement of our Energy Strong program. The Energy Strong program encompasses infrastructure investments we will make to our BPU jurisdictional electric and gas system to improve resiliency for the future. Under the Order, PSE&G will invest $1.22 billion to (1) upgrade all of its electric substations that were damaged by water in recent storms; make investments that will create redundancy in the electric distribution system, reducing outages when damage occurs; and deploy technologies to better monitor system operations, enabling PSE&G to restore customers more quickly in

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the event of an electric outage, and (2) with respect to PSE&G's gas system, replace and modernize 250 miles of low-pressure cast iron gas mains in or near flood areas; and upgrade five natural gas metering stations and a liquefied natural gas station recently affected by severe weather or located in flood zones. The Order provides for cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated AFUDC, and will occur for completed projects on a semi-annual (for electric investments) or annual (for gas investments) basis. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, to be filed no later than November 1, 2017.

Environmental Matters

Air Pollution Control

Cross-State Air Pollution Rule (CSAPR)

December 31, 2013 Form 10-K page 21 and March 31, 2014 Form 10-Q page 71. In July 2011, the EPA issued the final CSAPR, which limited power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season NO_x in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards. In August 2012, the D.C. Court vacated CSAPR and ordered that the existing Clean Air Interstate Rule requirements remain in effect until an appropriate substitute rule has been promulgated. On April 29, 2014, the Supreme Court overturned the D.C. Court's ruling. On June 26, 2014, the EPA filed a motion to lift the stay on CSAPR and allow for implementation of Phase I to begin on January 1, 2015. The D.C. Court's decision is pending. We do not anticipate any material impact on our earnings or financial condition due to the CSAPR.

Climate Change

CO_2 Regulation Under the CAA

December 31, 2013 Form 10-K page 22. In April 2013, several industrial groups petitioned the Supreme Court to review various EPA rules issued under the CAA, including the Tailoring Rule, to regulate greenhouse gas (GHG) emissions, including CO_2. The Tailoring Rule requires a new source or an existing source which undergoes a major modification, to evaluate and perhaps install best available control technology (BACT) for GHG emissions. On June 23, 2014, the U.S. Supreme Court ruled that the EPA has authority to regulate CO_2 emissions of stationary sources but that the EPA lacked the authority to issue the Tailoring Rule. The Supreme Court ruled that stationary sources are not required to obtain permits under the Clean Air Act rules regarding Prevention of Significant Deterioration (PSD) on the sole basis of their potential GHG emissions, but that GHG emissions must be considered for sources that are otherwise subject to PSD review.

On June 25, 2013, the President directed the EPA to propose GHG regulations for existing power plants by June 1, 2014, finalize such regulations by June 1, 2015 and require states to submit GHG implementation regulations by June 30, 2016.

On June 18, 2014, the EPA issued a proposed GHG regulation for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction (BSER). The BSER consists of four components: (1) heat rate improvements at existing coal-fired power plants, (2) increased use of existing natural gas combined cycle capacity, (3) operation of zero-emitting generation (renewables and nuclear), and (4) increased use of demand-side energy efficiency. States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions. Comments are due October 16, 2014. The EPA is requesting comments on many aspects of the proposal and therefore, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact.

If relevant federal or state common law were to impose liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to our fossil generation operations could be material. However, approximately 60% of our generation output comes from nuclear facilities which are GHG-free and would not be impacted.

Regional Greenhouse Gas Initiative (RGGI)

December 31, 2013 Form 10-K page 22 and March 31, 2014 Form 10-Q page 72. In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. Certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions. Generators may acquire allowances through a regional auction or through secondary markets.

New Jersey withdrew from RGGI beginning in 2012. As a result, our New Jersey facilities are no longer obligated to acquire CO_2 emission allowances. This action has been challenged by environmental groups in the New Jersey state court. On March 25, 2014, the Appellate Division of the New Jersey Superior Court ruled that the New Jersey Department of Environmental Protection (NJDEP) improperly withdrew its regulation under which RGGI had been implemented. The Court gave the NJDEP 60 days to initiate a public process to either repeal or amend that regulation to provide that it is applicable only when New Jersey is a participant in a regional or other established greenhouse gas program. On July 7, 2014, the NJDEP published its intent to formally repeal the rules implementing RGGI in New Jersey. We cannot predict the outcome of this matter.

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Water Pollution Control

Cooling Water Intake Structure Regulation

December 31, 2013 Form 10-K page 23 and March 31, 2014 Form 10-Q page 72. On May 19, 2014, the EPA issued a final cooling water intake rule under Section 316(b) of the Clean Water Act that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA did not mandate closed cycle cooling as "Best Technology Available." Instead, the EPA set a fish impingement mortality standard that relies on a technology-based approach. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. The rule also requires that entrainment BTA decisions rely on site-specific analysis that includes an assessment of social costs-social benefits.

The EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the BTA of each facility that seeks permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications.

We are assessing the potential impact of the rule on each of our affected facilities and are unable to predict the outcome of permitting decisions and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Part I, Item 1. Financial Statements—Note 8. Commitments and Contingent Liabilities—Clean Water Act Permit Renewals for additional information.

Fuel and Waste Disposal

Nuclear Fuel Disposal

December 31, 2013 Form 10-K page 24 and March 31, 2014 Form 10-Q page 72. The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit in federal court seeking suspension of the Nuclear Waste Fee. In 2013, the federal court ordered the Secretary of the U.S. Department of Energy (DOE) to submit a proposal to Congress to adjust the fee to zero. In January 2014, the Secretary of the DOE comported with the court order and submitted the zero fee adjustment change letter to Congress, subject to DOE appeal rights. On May 9, 2014, the DOE served us with a letter stating that as of May 16, 2014, the Nuclear Waste fee was being suspended/reduced to zero. The elimination of this fee is expected to result in an annualized pre-tax benefit of approximately $30 million.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 10:	Key Executive Severance Plan, amended effective July 14, 2014
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. Power:

Exhibit 10:	Key Executive Severance Plan, amended effective July 14, 2014
Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. PSE&G:

Exhibit 10:	Key Executive Severance Plan, amended effective July 14, 2014
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: August 1, 2014

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SIGNATURE

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PSEG POWER LLC
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: August 1, 2014

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SIGNATURE

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: August 1, 2014

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Exhibit 10

KEY EXECUTIVE SEVERANCE PLAN OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Amended effective July 14, 2014

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ARTICLE I

PURPOSE OF THE PLAN

1.1 Purpose The Key Executive Severance Plan of Public Service Enterprise Group Incorporated ("Plan") is maintained by the Company to provide severance benefits to certain key executive-level employees of the Company and its affiliates whose employment is terminated under the circumstances described herein. The Plan was amended and restated effective December 17, 2012.

The Plan was amended effective January 1, 2014 to provide that (i) for Eligible Employees who become Schedule B Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to two times Annual Base Salary and Target Bonus, and (ii) for Eligible Employees who become Schedule A Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to 1.5 times Annual Base Salary and Target Bonus. The Plan was further amended to provide that the for purposes of determining the nonqualified plan change in control benefit under Section 5.5(a) of the Plan, with respect to Eligible Employees who become Schedule A or Schedule B Participants after December 31, 2013, their employment shall be assumed to have continued for 1.5 or two additional years (for Schedule A Participants and Schedule B Participants, respectively). Finally, the Plan was amended to update the Schedule A Participant list.

The Plan was amended effective June 16, 2014 to (i) add a new class of eligible Participants, Schedule C Participants, (ii) to provide that there will be no additions to Schedule B Participants, (iii) to provide that other than a current Schedule B Participant, an Eligible Employee newly hired or promoted into a position reflected on Schedule B as of June 16, 2014, shall become a Schedule A Participant, and (iv) to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

The Plan is being amended effective July 14, 2014 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan is intended to comply in operation and form with Section 409A to the Internal Revenue Code of 1986, as amended ("Code"). The timing and form of payment of benefits provided under the Plan will be deemed to be automatically modified, and a Participant's rights under the Plan will be limited so as to conform to any requirements under Section 409A of the Code.

ARTICLE II

DEFINITIONS

2.1 "Accrued Obligation" shall have the meaning set forth in Section 4.1 or 5.1 of the Plan.

2.2 "Affiliate" means any corporation, trade or business if it or the Company are members of a controlled group of corporations, are under common control or are members of an

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affiliated service group, within the meanings of Sections 414(b), 414(c) and 414(m), respectively, of the Code. The term "Affiliate" shall also include any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code.

2.3 "Annual Base Salary" means the annual rate of base salary payable to a Participant for services performed for an Employer, as in effect immediately prior to the Participant's Date of Termination.

2.4 "Board" means the board of directors of the Company.

2.5 "Cause" means:

(a) For purposes of Article IV:

(i) Misconduct, gross negligence, theft, or fraud against the Company;

(ii) For "Performance Reasons," as defined in Section 2.21 of the Plan;

(iii) Violation of the Standards of Integrity or other Company policy;

(iv) Insubordination;

(v) One or more significant acts of dishonesty;

(vi) Any act that is likely to have the effect of injuring the reputation, business, or business relationship of, the Company, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries;

(vii) Violation of any fiduciary duty;

(viii) Breach of any duty of loyalty;

(ix) Any breach of the restrictive covenants contained in Exhibit I below;

(x) One or more acts of moral turpitude that constitute a violation of applicable law (included but not limited to a felony); or

(xi) Conviction of a felony or plea of *nolo contendere* to a felony charge.

(b) For purposes of Article V:

(i) The willful and continued failure to substantially perform his employment duties;

(ii) The willful engaging in gross misconduct that is materially and demonstrably injurious to the Employer;

(iii) The willful violation of the Company's Standards of Integrity or other applicable corporate code of conduct, or

(iv) The conviction of a felony or a plea of *nolo contetendere* to a felony charge.

No act or failure to act on the part of the Participant shall be considered "willful" unless it is done, or omitted to be done, by the Participant in bad faith or without reasonable belief that the

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Participant's action or omission was in the best interests of the Employer. Any act or failure to act that is based upon authority given pursuant to a resolution duly adopted by the Board, or the advice of counsel for the Employer, shall be conclusively presumed to be done, or omitted to be done, by the Participant in good faith and in the best interests of the Employer.

Notwithstanding the forgoing, for purposes of the Plan, the termination of a Participant's employment with an Employer shall not be deemed to be for Cause unless such termination is effected in accordance with the following procedures. The Employer shall give the Participant written notice ("Notice of Termination for Cause") of its intention to terminate the Participant's employment for Cause, setting forth in reasonable detail the specific conduct of the Participant that it considers to constitute Cause. Such notice shall be given no later than 60 days after the act or failure (or the last in a series of acts or failures) that the Employer alleges to constitute Cause. The Participant shall have 30 days after receiving the Notice of Termination for Cause in which to cure such act or failure, to the extent such cure is possible. In the case of a termination under clause (a), (b) or (c) above, if the Participant fails to cure such act or failure to the reasonable satisfaction of the Employer, the Employer shall give the Participant a second written notice stating that in the good faith opinion of the Employer, the Participant is guilty of the conduct described in the Notice of Termination for Cause and that such conduct constitutes Cause under the Plan.

2.6 "Change in Control" means the occurrence of any of the following events:

(a) Any "person" (within the meaning of Section 13(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") is or becomes the beneficial owner within the meaning of Rule 13d-3 under the Exchange Act (a "Beneficial Owner"), directly or indirectly, of securities of the Company (not including in the securities beneficially owned by such person any securities acquired directly from the Company or its Affiliates) representing 25% or more of the combined voting power of the Company's then outstanding securities, excluding any person who becomes such a Beneficial Owner in connection with a transaction described in clause (i) of paragraph (c) below; or

(b) The following individuals cease for any reason to constitute a majority of the number of directors of the Company then serving: individuals who, on the Effective Date, constitute the Board and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's stockholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on the Effective Date or whose appointment, election or nomination for election was previously so approved or recommended; or

(c) There is consummated a merger or consolidation of the Company or any direct or indirect wholly-owned subsidiary of the Company with any other corporation, other than (i) a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation

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continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of the Company or of its Affiliates, at least 75% of the combined voting power of the securities of the Company or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (ii) a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the Beneficial Owner, directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company's then outstanding securities; or

(d) The shareholders of the Company approve a plan of complete liquidation or dissolution of the Company or there is consummated an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 75% of the combined voting power of the voting securities of which are owned by stockholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale.

Notwithstanding the foregoing, a "Change in Control" shall not be deemed to have occurred by virtue of the consummation of any transaction or series of integrated transactions immediately following which the record holders of the common stock of the Company immediately prior to such transaction or series of transactions continue to have substantially the same proportionate ownership in an entity which owns all or substantially all of the assets of the Company immediately following such transaction or series of transactions.

2.7 "Code" means the Internal Revenue Code of 1986, as amended, and the regulations promulgated thereunder.

2.8 "Committee" means the Organization and Compensation Committee of the Board or any successor of such Committee.

2.9 "Company" means Public Service Enterprise Group Incorporated and any successors thereto.

2.10 "Confidential Information" means all trade secrets, proprietary and confidential business information belonging to, used by, or in the possession of the Company or any of its Affiliates, including but not limited to information, knowledge or data related to business strategies, plans and financial information, mergers, acquisitions or consolidations, purchase or sale of property, leasing, pricing, sales programs or tactics, actual or past sellers, purchasers, lessees, lessors or customers, those with whom the Company or its Affiliates has begun negotiations for new business, costs, employee compensation, marketing and development plans, inventions and technology, whether such confidential information, knowledge or data is oral, written or electronically recorded or stored, except information in the public domain, information known by the Participant prior to employment with an Employer, and information received by

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the Participant from sources other than the Company or its Affiliates, without obligation of confidentiality.

2.11 "Date of Termination" means the date of a Participant's death, Disability Effective Date, or the date on which the termination of the Participant's employment by an Employer for Cause or without Cause or by the Participant for Good Reason or without Good Reason, including Retirement, is effective, as the case may be, provided that the termination constitutes a Separation from Service.

2.12 "Disability" means that the Participant (a) is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, or (b) is, by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, receiving income replacement benefits for a period of not less than three months under an accident or health plan covering employees of an Employer.

2.13 "Disability Effective Date" means the 30th day after the Participant's receipt of written notice of the Employer's intention to terminate the Participant's employment on account of Disability, provided that, within the 30 days after the Participant's receipt of such notice, the Participant shall not have returned to full-time performance of his employment duties.

2.14 "Eligible Employee" means an individual who is designated as such in accordance with Section 3.1.

2.15 "Effective Date" of the amendment and restatement is July 14, 2014.

2.16 "Employer" means the Company and each Affiliate, and any successors thereto.

2.17 "Good Reason" means:

(a) Any material reduction in the Participant's Annual Base Salary, Target Bonus or Target Long-Term Incentive, other than reductions pursuant to a broad-based compensation reduction program or policy affecting the Participant and all similarly situated employees of the Employer;

(b) Any material adverse change in the Participant's title, authority, duties, or responsibilities or the assignment to the Participant of any duties or responsibilities inconsistent in any respect with those customarily associated with the position of the Participant immediately prior to the Change in Control;

(c) The failure of any successor to the Company to assume this Plan in accordance with Section 11.5(b);

(d) Where the only comparable position offered to the Participant within the Employer following a Change in Control would otherwise meet the requirements of subsections (a) and (b) of this Section 2.17 of the Plan, but would require the

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Participant to increase his or her one-way commuting distance from his or her principal residence by more than 50 miles; or

(e) Any other material breach of the terms of the Plan by the Company that either is not taken in good faith or, even if taken in good faith, is not remedied by the Company promptly after receipt of notice thereof from the Participant.

Notwithstanding the forgoing, for purposes of the Plan, the termination of a Participant's employment with an Employer shall not be deemed to be for Good Reason unless such termination is effected in accordance with the following procedures. The Participant shall give his Employer a written notice ("Notice of Termination for Good Reason") of the termination, setting forth in reasonable detail the specific acts or omissions of the Employer that constitute Good Reason and the specific provision(s) of the Plan on which the Participant relies. Unless the Committee determines otherwise, a Notice of Termination for Good Reason by the Participant must be made within 60 days after the Participant first has actual knowledge of the act or omission (or the last in a series of acts or omissions) that the Participant alleges to constitute Good Reason, and the Employer shall have 30 days from the receipt of such Notice of Termination for Good Reason to cure the conduct cited therein. A termination of employment by the Participant for Good Reason shall be effective on the final day of such 30-day cure period unless prior to such time the Employer has cured the specific conduct asserted by the Participant to constitute Good Reason to the reasonable satisfaction of the Participant.

For purposes of the Plan, a Participant's determination that an act or failure to act constitutes Good Reason shall be presumed to be valid unless such determination is decided to be unreasonable by the Committee or its delegate pursuant to Article IX.

2.18 "Nonqualified Plan" the Retirement Income Reinstatement Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated.

2.19 "Other Benefits" shall have the meaning set forth in Articles IV and V, as applicable.

2.20 "Participant" means an Eligible Employee who has satisfied the conditions for participation in the Plan, as set out in Section 3.2, and is listed on either Schedule A, Schedule B or Schedule C hereto, as the same may be amended from time to time.

2.21 "Performance Reasons" means the Participant's failure meet the expectations established for his function in the Company as: (a) communicated to him by his manager during any performance review, or (b) may be communicated to him otherwise by his manager from time to time either orally or in writing.

2.22 "Plan" means this Key Executive Severance Plan of Public Service Enterprise Group Incorporated, as set forth herein and as may be amended, modified or supplemented from time to time.

2.23 "Prior Equity Awards" shall mean outstanding stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares and performance shares units.

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2.24 "Retirement" means a Separation from Service after the Participant has satisfied the eligibility requirements for early or normal retirement under the terms of the Retirement Plan in which the Participant participates. Notwithstanding the foregoing, for the purposes of determining benefit entitlements under Article V of the Plan, Retirement shall not include forced retirements or any termination by an Employer without Cause or voluntary termination by the Participant for Good Reason that occurs on a date on which the Participant is Retirement eligible.

2.25 "Retirement Plan" the retirement plan in which the Participant participates either the Pension Plan of Public Service Enterprise Group Incorporated or the Cash Balance Pension Plan of Public Service Enterprise Group Incorporated.

2.26 "Schedule A Participant" shall mean a Participant listed on Schedule A hereto.

2.27 "Schedule B Participant" shall mean a Participant listed on Schedule B hereto.

2.28 "Schedule C Participant" shall mean a Participant listed on Schedule C hereto.

2.29 "Separation from Service" shall be deemed to have occurred if a Participant and the Company or any Affiliate reasonably anticipates, based on the facts and circumstances, that either:

(a) The Participant will not provide any additional services for the Company or an Affiliate after a certain date; or

(b) The level of bona fide services performed by the Participant after a certain date will permanently decrease to no more than 50 percent of the average level of bona fide services performed by the Participant over the immediately preceding 36 months.

(c) If a Participant is absent from employment due to military leave, sick leave or any other bona fide leave of absence authorized by the Company or an Affiliate and there is a reasonable expectation that the Participant will return to perform services for the Company or an Affiliate, a Separation from Service will not occur until the later of: (i) the first date immediately following the date that is six months after the date that the Participant was first absent from employment; or (ii) the date the Participant no longer retains a right to reemployment, to the extent the Participant retains a right to reemployment with the Company or any Affiliates under applicable law or by contract. If a Participant fails to return to work upon the expiration of any military leave, sick leave or other bona fide leave of absence where such leave is for less than six months, the Separation from Service shall occur as of the date of the expiration of such leave, unless a greater period is provided for under applicable law.

2.30 "Specified Employee" shall mean any individual who is a key employee (as defined in Section 416(i) of the Code without regard to Section 416(i)(5)) of the Company at any time during the 12-month period ending on each December 31 (the "identification date"). If an individual is a key employee as of an identification date, the individual shall be treated as a Specified Employee for the 12-month period beginning on the

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April 1 following the identification date. Notwithstanding the foregoing, an individual shall not be treated as a Specified Employee unless any stock of the Company or an Affiliate is publicly traded on an established securities market or otherwise.

2.31 "Target Bonus" means the Participant's target annual bonus, if any, under the applicable annual incentive compensation plan of the Company for the fiscal year in which the Date of Termination occurs.

2.32 "Target Long-Term Incentive" means the Participant's target long-term incentive award, if any, under the applicable long-term incentive compensation plan of the Company.

ARTICLE III

ELIGIBILITY AND PARTICIPATION

3.1 Eligible Employees. Eligibility to participate in the Plan shall be limited to certain key executives of an Employer who (a) are not parties to individual employment or change in control agreements that provide for severance benefits, and (b) are designated, by duly adopted resolution of the Committee, as Eligible Employees.

3.2 Participation. As a condition to becoming a Participant and being entitled to the benefits and protections provided under the Plan, each Eligible Employee must execute and deliver to the Company, within 30 days after the later of the Effective Date and the date such individual is designated by the Committee as an Eligible Employee, a written agreement in the form attached hereto as Exhibit I (or in such other form as may be satisfactory to the Company) to be bound by the restrictive covenants set forth in Article VII. Schedules A, B and C hereto list the Eligible Employees who have satisfied the conditions for Plan participation and the date as of which each such Eligible Employee became a Participant. The Committee shall cause Schedules A, B and C to be updated from time to time to reflect the Participants who are currently participating in the Plan. An employee who becomes an Eligible Employee on or after January 1, 2014 shall become a Schedule C Participant, provided, however, that an employee who is hired or promoted to a position reflected on Schedule B as of the Effective Date and who is otherwise an Eligible Employee shall become a Schedule A Participant.

3.3 Release of Claims. Notwithstanding anything in the Plan to the contrary, payment of any benefits under the Plan is expressly contingent upon the Participant's execution and delivery to the Company, within 30 days after the Participant's Date of Termination, of a written agreement provided by the Company, wherein the Participant releases and discharges the Company and each of its Affiliates of any and all claims against the Company and its Affiliates related in any way to the Participant's employment with an Employer and the termination of such employment.

3.4 Committee Discretion. The Committee shall have the sole discretion to determine eligibility for benefits under the Plan.

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ARTICLE IV

SEVERANCE BENEFITS IN GENERAL

4.1 Termination by Employer Other than for Cause or by the Participant for Good Reason. Subject to Section 3.3 and Article VI of the Plan, if a Participant's employment is involuntarily terminated by an Employer for reasons other than Cause or a Participant terminates employment for Good Reason, the Participant shall be entitled to the benefits described in Sections 4.2 through 4.9 of the Plan. For purposes of clarity, subject to Section 3.3 and Article VI of the Plan, Participant shall be entitled to the benefits described in Sections 4.2 through 4.9 of the Plan if a Participant's employment is involuntarily terminated by an Employer due to a reduction in force or a reorganization of the Employer (as determined by the Committee), or a Participant experiences a cessation of employment in connection with a reduction in force or Employer reorganization (as determined by the Committee) where the only position offered to the Participant within the Company and Affiliates would require the Participant to accept a reduction in his or her annual rate of base salary of more than 20% below the annual rate of base salary of the Participant's position immediately prior to such action.

For the avoidance of any doubt, a Participant shall not be entitled to benefits under the Plan if (i) his employment terminates as a result of death, Disability, the Participant voluntarily terminates employment, except for Good Reason, or (ii) the Participant's cessation of employment is in connection with the sale of the Participant's Employer, line or unit of business of the Employer within which the Participant's position is located, business function of the Employer within which the Participant's position is located, or the assets related to the Employer, line or unit or business, or business function within which the Participant's position is located, and the Participant accepts employment with the purchaser within 90 days of the closing of the transaction in a position that has an annual rate of base salary that is at least 80 percent of the Participant's annual rate of base salary immediately prior to the closing of the sale).

4.2 Cash payment. The Company shall pay to the Participant a lump sum, in cash, the sum of (a) and (b):

(a) The Participant's base salary and accrued vacation pay through the Date of Termination to the extent not theretofore paid (hereinafter referred to as the "Accrued Obligations"); and

(b) An amount equal to the product of 1.0 times (0.5 times if the Participant were employed less than one year) the sum of the Participant's Annual Base Salary and Target Bonus.

4.3 Long-Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

4.4 Annual Incentive Awards. The Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the

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number of calendar days of employment in the calendar year in which the Participant's termination occurs through the Participant's Date of Termination. For purposes of this Section 4.4, calendar year shall mean 365 days.

Annual incentive awards with respect to the calendar year in which a Participant's Date of Termination occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

4.5 Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the Participant's Date of Termination or such earlier date designated by the Participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

4.6 Educational Assistance. Educational assistance shall be provided in accordance with the Employer's tuition program.

4.7 Health Care Benefits.

(a) Retiree Health Care Coverage**.** A Participant who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(i) The Participant has attained age 50 and completed ten or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80; or

(ii) The Participant has attained age 49 and completed 20 or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Participant's Termination Date. The Participant shall be charged the full cost of retiree coverage under these plans.

(b) COBRA Continuation Coverage**.** Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this Section 4.7 of the Plan shall be entitled, pursuant to any continuation coverage rights under the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended ("COBRA"), to continue individual and dependent coverage under the Company's group health care plans following the Participant's Date of Termination. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the one-year period following the Participant's Date of Termination, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of

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the cost of coverage) during the remainder of the COBRA coverage period, if any, and the full expense of dental and (if applicable) vision and hearing coverage (102 percent of the cost of coverage) during the entire COBRA coverage period.

4.8 Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled, for the one-year period following the Participant's Date of Termination to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination.

4.9 Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided hereunder or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time. (The amounts and benefits payable to the Participant pursuant to Sections 4.3 through 4.9 of the Plan shall be hereinafter referred to as the "Other Benefits").

4.10 Termination where a Participant experiences a cessation of employment in connection with a reduction in force or Employer reorganization where the only position offered to the Participant within the Company and Affiliates would require the Participant to increase his or her one-way commuting distance by more than 50 miles. Subject to Section 3.3 and Article V, if a Participant experiences a cessation of employment in connection with a reduction in force or an Employer reorganization (as determined by the Committee) where the only position offered to the Participant within the Company and Affiliates would require the Participant to increase his or her one-way commuting distance by more than 50 miles:

(a) Severance Pay. The Participant shall receive a lump sum cash payment in accordance with Section 6.1 of the Plan, based upon the amount of the Participant's base salary, the number of Years of Service completed as of the Participant's Termination Date, as follows:

(i) **Less than Thirteen Years of Service:** If, as of the Participant's Date of Termination, he has completed fewer than thirteen Years of Service, the amount of severance pay shall equal 26 weeks of base salary.

(ii) **Thirteen or More Years of Service:** If, as of the Participant's Date of Termination, he has completed thirteen or more Years of Service, the amount of severance pay shall equal two weeks of base salary for each Year of Service, up to a maximum of 52 weeks of base salary.

(b) Annual Incentive Awards. A Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of days of employment in the calendar

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year in which the participant's Termination of Employment occurs through the employee's Termination Date. Annual incentive awards with respect to the calendar year in which a Participant's Termination Date occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

(c) Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the participant's Termination Date or such earlier date designated by the participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

(d) Educational Assistance. Education assistance shall be provided in accordance with the Employer's tuition program.

(e) Health Care Benefits.

(i) Retiree Health Care Coverage**.** An Eligible Employee who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(A) The Participant has attained age 50 and completed ten or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80; or

(B) The Participant has attained age 49 and completed 20 or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Participant's Date of Date. The Participant shall be charged the full cost of retiree coverage under these plans.

(ii) COBRA Continuation Coverage. Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this subsection (i) shall be entitled, pursuant to any continuation coverage rights under COBRA to continue individual and dependent coverage under the Company's group health care plans following the Participant's Termination Date. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of the cost of coverage) during the remainder of the COBRA coverage period, if any, and the full

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expense of dental and (if applicable) vision and hearing coverage (102 percent of the cost of coverage) during the entire COBRA coverage period.

(f) Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination Date.

(g) Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided under the Plan or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time.

ARTICLE V

SEVERANCE BENEFITS AFTER A CHANGE IN CONTROL

5 . 1 Termination By Employer Other Than For Cause or By Participant For Good Reason (other than Good Reason as described in Subsection 2.17(d)) Within Two Years After a Change in Control . Subject to Section 3.3 and Article VI of the Plan, if, within two years following the occurrence of a Change in Control, either (a) an Employer shall terminate a Participant's employment other than for Cause or Disability, or (b) a Participant shall voluntarily terminate his employment for Good Reason pursuant to Subsections 2.17 (a), (b), (c) or (e), the Participant shall be entitled to benefits in Sections 5.2 through 5.8 of the Plan. For the avoidance of any doubt, a Participant shall not be entitled to benefits under the Plan if his employment terminates as a result of death, Disability or the Participant voluntarily terminates employment, except for Good Reason, except as otherwise provided under the Plan.

5.2 Cash Payment. The Company shall pay to the Participant, in a lump sum in cash, the aggregate of the amounts in (a) and (b) below:

(a) the sum of:

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(i) The Participant's base salary and accrued through the Date of Termination; and

(ii) The product of (x) the Participant's Target Bonus and (y) a fraction, the numerator of which is the number of days in the current calendar year through the Date of Termination, and the denominator of which is 365;

in each case to the extent not theretofore paid (the sum of the amounts described in clauses (i) and (ii) shall be hereinafter referred to as the "Accrued Obligations"); and

(b) Either (i), (ii) or (iii):

(i) In the case of a Schedule A Participant, the amount equal to the product of two times the sum of the Schedule A Participant's Annual Base Salary and Target Bonus;

(ii) In the case of a Schedule B Participant, the amount equal to the product of three times the sum of the Schedule B Participant's Annual Base Salary and Target Bonus; or

(iii) In the case of a Schedule C Participant, the amount equal to the product of one and half times the sum of the Schedule C Participant's Annual Base Salary and Target Bonus.

5.3 Long Term Incentive Awards . The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.4 Health Care and Other Welfare Benefits. The Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for 18 months after the Date of Termination provided that the Participant makes an election to continue such coverage in the Company's medical and dental employee benefit plans under COBRA, subject to the requirements and limitations thereof. Unless otherwise limited by applicable law, thereafter, the Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for an additional period of six months, in the case of a Schedule A Participant, or 18 months, in the case of a Schedule B Participant (for a Schedule C Participant, no additional period beyond the initial 18 months); provided however, that if the Participant becomes re-employed with another employer and is eligible to receive medical or dental benefits under another employer provided plan, the medical and dental benefits provided by the Company under this Plan shall be secondary to those provided under such other plan during the applicable period of eligibility.

Unless otherwise limited by applicable law, for two years after the Date of Termination in the case of a Schedule A Participant, three years after the Date of Termination in the case of a Schedule B Participant, or in the case of a Schedule C Participant, eighteen months after the Date of Termination (or for any Participant such longer period as may be provided by the terms of the

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appropriate plan, program, practice or policy), the Company shall continue benefits (other than medical and dental benefits) to the Participant and/or the Participant's family at least equal to those which would have been provided to them in accordance with the welfare plans, programs, practices and policies maintained by the Company if the Participant's employment had not been terminated or, if more favorable to the Participant, as in effect generally at any time thereafter with respect to other peer executives of the Employer and their families.

Unless otherwise limited by applicable law, the Participant's eligibility (but not the time of commencement of such benefits) for retiree benefits pursuant to the welfare plans, programs, practices and policies maintained by the Company shall be determined as if the Participant had (A) remained employed until two years (in the case of a Schedule A Participant), three years (in the case of a Schedule B Participant), or eighteen months (in the case of a Schedule C Participant) after the Date of Termination and (B) retired on the last day of such period.

5.5 Nonqualified Pension Benefit. The Participant shall be paid, in a lump sum payment in cash, an amount equal to the excess of:

(a) The actuarial equivalent of the benefit under the Company's applicable Retirement Plan (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the Effective Date), any benefit under the Nonqualified Plan and, to the extent applicable, any other defined benefit retirement arrangement between the Participant and the Company ("Other Pension Benefits") which the Participant would receive if the Participant's employment continued for two, three or one and half additional years (for Schedule A Participants, Schedule B and Schedule C Participants, respectively) beyond the Date of Termination and, assuming that the Participant's compensation for such deemed additional period was the Participant's Annual Base Salary as in effect immediately prior to the Date of Termination and assuming a bonus in each year during such deemed additional period equal to the Target Bonus, over

(b) The actuarial equivalent of the Participant's actual benefit (paid or payable), if any, under the Retirement Plan, the Nonqualified Plan and Other Pension Benefits as of the Date of Termination (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the effective date of the Change in Control).

5.6 Deferred Compensation. Any compensation previously deferred (other than pursuant to a tax-qualified plan) by or on behalf of the Participant (together with any accrued interest or earnings thereon), whether or not then vested, shall become vested on the Date of Termination and shall be paid in accordance with the terms of the applicable deferred compensation plan, policy or practice under which it was deferred to the extent permitted by Section 409A of the Code.

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5.7 Outplacement Services. The Company shall, at its sole expense as incurred, provide the Participant with outplacement services suitable to the Participant's position for a period not to exceed one year following the Date of Termination with a nationally recognized outplacement firm.

5.8 Other Benefits. To the extent not theretofore paid or provided, the Company shall pay or provide to the Participant any other amounts or benefits required to be paid or provided or which the Participant is entitled to receive under any plan, program, policy, practice, contract or agreement of the Company (or other Employer), including earned but unpaid stock and similar compensation, but excluding medical or dental benefits if the Participant is eligible for such benefits to be provided by a subsequent employer, and benefits payable under any severance plan or policy (such other amounts and benefits that are payable to the Participant shall be hereinafter referred to as the "Other Benefits").

5.9 Termination By Participant For Good Reason as described in Subsection 2.17(d) Within Two Years After a Change in Control. Subject to Section 3.3 and Article V of the Plan, if, within two years following the occurrence of a Change in Control, a Participant shall voluntarily terminate his or her employment for Good Reason as described in Subsection 2.17(d):

(a) Severance Pay. The Participant shall receive a lump sum payment in accordance with Section 6.1 of the Plan based upon the amount of the Participant's base salary, the number of Years of Service completed as of the Participant's Termination Date, as indicated below:

(i) **Less than Thirteen Years of Service:** If, as of the Participant's Termination Date he or she has completed fewer than thirteen Years of Service, the amount of severance pay shall equal 26 weeks of base salary.

(ii) **Thirteen or More Years of Service:** If, as of the Participant's Termination Date, he or she has completed thirteen or more Years of Service, the amount of severance pay shall equal two weeks of base salary for each Year of Service, up to a maximum of 52 weeks of base salary.

(b) Annual Incentive Awards. A Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of days of employment in the calendar year in which the participant's Termination of Employment occurs through the employee's Termination Date. Annual incentive awards with respect to the calendar year in which a Participant's Termination Date occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

(c) Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance

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or workshops, shall be available beginning on the Participant's Date of Termination or such earlier date designated by the participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

(d) Educational Assistance. Education assistance shall be provided in accordance with the Employer's tuition program.

(e) Health Care Benefits.

(i) Retiree Health Care Coverage**.** An Eligible Employee who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination Date, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(A) The Participant has attained age 50 and completed ten or more Years of Service as of his or her Termination Date but the sum of the Participant's age and Years of Service is less than 80; or

(B) The Participant has attained age 49 and completed 20 or more Years of Service as of his or her Termination Date but the sum of the Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Participant's Termination Date. The Participant shall be charged the full cost of retiree coverage under these plans.

(ii) COBRA Continuation Coverage. Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this subsection (e) shall be entitled, pursuant to any continuation coverage rights under COBRA to continue individual and dependent coverage under the Company's group health care plans following the Participant's Termination Date. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of the cost of coverage) during the remainder of the COBRA coverage period, if any, and the full expense of dental and (if applicable) vision and hearing coverage (102 percent of the cost of coverage) during the entire COBRA coverage period.

(f) Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled, during the period that the

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Participant would have received severance pay if severance pay had been paid in bi-weekly installments, to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination.

(g) Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided under the Plan or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time.

5.10 Termination By Employer For Cause or By Participant Other Than For Good Reason. If, at any time after a Change in Control, either (a) an Employer shall terminate a Participant's employment for Cause or (b) the Participant shall voluntarily terminate his employment other than for Good Reason, the Employer shall have no further payment obligations to the Participant other than for the Participant's base salary through the Date of Termination and any accrued but unpaid vacation pay. In such case, all such amounts shall be paid to the Participant in a lump sum in accordance with Section 6.1 of the Plan.

5.11 Death. If a Participant's employment terminates by reason of the Participant's death after a Change in Control, all Accrued Obligations as of the time of death shall be paid to the Participant's estate or beneficiary, as applicable, in a lump sum in cash in accordance with Section 6.1 of the Plan. The Participant's estate or beneficiary shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.12 Disability. If a Participant's employment is terminated by reason of Disability after a Change in Control, all Accrued Obligations shall be paid to the Participant in a lump sum in cash in accordance with Section 6.1 of the Plan. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.13 Retirement. If a Participant's employment terminates as a result of Retirement after a Change in Control, the Participant shall be paid the Accrued Obligations in a lump sum in cash in accordance with Section 6.1 of the Plan and the Participant shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

ARTICLE VI

TIMING OF, LIMITATIONS ON AND ADJUSTMENTS TO PLAN PAYMENTS

6.1 Time of Payments. Payments under the Plan shall be made to the Participant as follows:

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(a) With respect to benefits under Sections 4.2, 4.10(a), 5.2, 5.5, 5.9(a), 5.12 and 5.13 of the Plan, payment to a Participant who is not a Specified Employee shall be made within the 60-day period following the Participant's Date of Termination. With respect to benefits under Section 5.11 of the Plan, payment shall be made within the 60-day period following the Participant's date of the Participant's death. However, if the period to consider and revoke the written agreement required to receive the benefits described in Articles IV and V of the Plan (i.e., the waiver and release) spans two taxable years, in all events the payments will be made in second taxable year within 30 days following the later of the end of the first taxable year or the date the executed release is received by the Company.

(b) With respect to benefits under Sections 4.4, 4.10(b) and 5.9(b) of the Plan, payments shall be made to the Participants at the same time the payments are made to active employees.

(c) Notwithstanding anything to the contrary in the Plan, to the extent necessary to comply with Section 409A of the Code, payments to a Participant who is a Specified Employee shall be made within the 60-day period following the six-month anniversary of the Participant's Date of Termination (other than by reason of death).

(d) All payments under the Plan that are reimbursements of covered expenses incurred by the Participant shall be made within the taxable year in which the expense is incurred.

6.2 Payment Offsets. Notwithstanding anything in the Plan to the contrary, in the event a Participant is entitled to receive severance payments both under this Plan and under the terms of either (a) an individual change of control or employment agreement, (b) another severance pay plan or policy of an Employer or (c) any existing or future law or regulation, the benefits payable under this Plan shall be reduced by the amount of any severance benefits such Participant is entitled to receive under such individual agreement, plan, policy, law or regulation.

6.3 Cap on Excess Parachute Payments; Gross-Up Payments. Notwithstanding anything in the Plan to the contrary, if (a) a Participant is a "disqualified individual" (as defined in Section 280G(c) of the Code) and (b) the severance benefits provided under Articles IV or V, as applicable, together with any other payments the Participant has the right to receive from an Employer, would constitute a "parachute payment" (as defined in Section 280G(b) of the Code) ("Parachute Payments"), the following provisions shall apply:

(a) The severance benefits under Articles IV or V shall not exceed an amount which, together with any other Parachute Payments the Participant has a right to receive from the Employer, would be 2.99 times the Participant's "base amount" (as defined in Section 280G of the Code) so that no portion of the amounts received by the Participant shall be subject to the excise tax imposed under Section 4999 of the Code.

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(b) The determination of whether any limitation on the severance benefits payable under Articles IV or V is necessary shall be made by the Company's independent auditor or such other certified public accounting firm as may be jointly designated by the Participant and the Company (the "Accounting Firm"), which shall provide detailed supporting calculations to the Participant and the Company. The determinations of the Accounting Firm shall be conclusive and binding on the Company and the Participant. All fees and expenses of the Accounting Firm shall be borne solely by the Company.

(c) If through error or otherwise, a Participant shall receive payments under the Plan, together with other Parachute Payments the Participant has the right to receive from an Employer, in excess of 2.99 times his base amount, the Participant shall immediately repay the excess to the Employer upon notification from the Employer that an overpayment has been made. If the Participant fails to repay the excess to the Employer within 10 business days of the date of the Employer's notification, the Participant will become liable to the Employer for an amount equal to two (2) times the excess amount.

6 . 4 Compliance with Section 409A of the Code. Notwithstanding anything in the Plan to the contrary, all Plan benefit obligations and payments are subject to Section 409A of the Code. To the extent required, the Company may modify the severance benefits payable hereunder to comply with Section 409A of the Code; provided, however, that the present value of the aggregate Plan benefits payable to a Participant after such modification shall not be less than the present value of the Plan benefits payable to the Participant prior to the modification.

6 . 5 Tax Withholding. Notwithstanding any other provision of this Plan, the Company may withhold from any amounts payable under this Plan such Federal, state, local, employment or foreign taxes as shall be required to be withheld pursuant to any applicable law or regulation.

ARTICLE VII

RESTRICTIVE COVENANTS

7.1 Confidentiality. As a condition to participation in the Plan, each Participant agrees to hold in a fiduciary capacity for the benefit of the Company and its Affiliates all Confidential Information which shall have been obtained by the Participant during the Participant's employment by the Employer; except, however, that this Section 7.1 shall not apply to Confidential Information that is or becomes public knowledge, unless such Confidential Information became or becomes public knowledge due to acts of the Participant or representatives of the Participant in violation of this Section 7.1. Upon termination of the Participant's employment, he shall return to the Company all Confidential Information in his possession. After termination of the Participant's employment with the Employer, the Participant shall not, without the prior written consent of the Company or as may otherwise be required by law or legal process, communicate or divulge any such Confidential Information to anyone other than the Company and those designated by it, except (a) otherwise publicly available information, (b) as may be necessary to enforce his rights under the Plan or as necessary to defend himself against a claim asserted directly or indirectly by the Company or its Affiliates or (c) as may be compelled by service of a valid subpoena or other legal process. If the

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Participant is served with a valid subpoena or other legal process, he must so notify the Company within three business days. Unless and until a determination has been made in accordance with Section 7.4 that the Participant has violated this Section 7.1, an asserted violation of the provisions of this Section 7.1 shall not constitute a basis for deferring or withholding any amounts otherwise payable to the Participant under the Plan.

7 . 2 Non-Compete. As a condition to participation in the Plan, each Participant agrees, that, in the event the Participant voluntarily terminates his employment other than for Good Reason, for the period of one year from Date of Termination he will not, without the written consent of the Company, directly or indirectly own, manage, operate, join, control, become employed by, consult to or participate in the ownership, management, or control of any business which is in direct competition with the Company or its Affiliates.

7 . 3 Non-Solicitation. As a condition to participation in the Plan, each Participant agrees that, in the event the Participant voluntarily terminates his employment other than for Good Reason, for the period of one year following the Date of Termination, he will not, directly or indirectly, solicit or hire, or encourage the solicitation or hiring by any employer other than the Company or its Affiliates, for any position as an employee, independent contractor, consultant or otherwise, any person who was a managerial or higher level employee of an Employer at any time during the term of the Participant's employment by the Employer; provided, however, that this provision shall not apply with respect to the solicitation of any person after six months from the date on which such person's employment by an Employer has terminated.

7.4 Enforcement. In the event of a breach by the Participant of any of the covenants set forth in this Article VII, it is agreed that the Company shall suffer irreparable harm for which money damages are not an adequate remedy, and that, in the event of such breach, the Company shall be entitled to obtain an order of a court of competent jurisdiction for equitable relief from such breach, including, but not limited to, temporary restraining orders and preliminary and/or permanent injunctions against the breach of such covenants by the Participant. In the event that the Company should initiate any legal action for the breach or enforcement of any of the provisions contained in this Article VII and the Company does not prevail in such action, the Company shall promptly reimburse the Participant the full amount of any court costs, filing fees, attorney's fees which the Participant incurs in defending such action, and any loss of income during the period of such litigation.

ARTICLE VIII

AMENDMENT AND TERMINATION

8 . 1 Amendment. The Company may amend this Plan at any time, and from time to time, by action of the Committee; provided, however, that no amendment adopted after the effective date of a Change in Control shall have the effect of either (a) removing an individual from the list of Participants, (b) adding conditions for participation or the entitlement to receive benefits hereunder, (c) reducing the amount of benefits payable to a Participant or (d) otherwise restricting a Participant's right to receive benefits under the Plan, except as may otherwise be required to conform such payments to the requirements of Section 409A of the Code, as provided in Section 1.1.

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8.2 Termination. The Committee may terminate the Plan at any time prior to a Change in Control. The Plan may not be terminated after the effective date of a Change in Control.

ARTICLE IX

ADMINISTRATION

9.1 Plan Administrator. The Plan shall be administered by the Committee, which shall have the duties and responsibilities for administering the Plan as are specifically set forth in this Article IX.

9.2 Responsibilities of Committee.

(a) The Committee shall have responsibility for the day to day administration of the Plan. In addition, the Committee shall have the specific powers, duties, responsibilities and obligations specifically provided for herein.

(b) Subject to the express provisions of the Plan, the Committee shall have full and exclusive authority to interpret the Plan and to make all other factual determinations deemed necessary or advisable in the implementation and administration of the Plan, including but not limited to determinations with respect to the eligibility of Participants to receive benefits under the Plan and the status and rights of such Participants and all other persons affected hereunder. The Committee's interpretation and construction of the Plan shall be conclusive and binding on all persons.

(c) The Committee shall have sole authority to adopt rules and regulations, which shall be administered by the Committee. In addition, the Committee shall have the discretionary authority to issue rulings and interpretations concerning the Plan and all matters arising thereunder, on a uniform and nondiscriminatory basis, provided the same shall not be contrary to or inconsistent with any provision of the Plan.

(d) As a condition of distributing any benefit under the Plan, the Committee may prescribe the use of such forms and require the furnishing of such information as the Committee may deem appropriate for administering the Plan.

9.3 Allocation or Delegation of Duties and Responsibilities. In furtherance of its duties and responsibilities under the Plan, the Committee may:

(a) Employ agents to carry out non-fiduciary responsibilities;

(b) Employ agents to carry out fiduciary responsibilities;

(c) Consult with counsel, who may be counsel to the Company; and

(d) Delegate any of its duties and responsibilities hereunder to such officer or officers of the Company as the Committee shall designate; except, however, that the Committee may not delegate to any other person the designation of Eligible

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Employees under Section 3.1 or the authority to consider and determine appeals of alleged adverse benefit determinations.

9.4 Expenses.

Unless otherwise agreed to by the Company, no person acting as a fiduciary hereunder (who is an employee of an Employer) shall receive any compensation for services as such. Expenses incurred by fiduciaries in connection with the administration of the Plan shall be paid by the Company.

9.5 Indemnification of Plan Administrator.

The Company shall indemnify, to the fullest extent permitted by law, each person made or threatened to be made a party to any civil or criminal action or proceeding by reason of the fact that he, or his testator or intestate, was a member of the Committee, or a delegate of the Committee, acting in the capacity of Plan administrator.

9.6 Reliance Upon Others.

The Committee, any person to whom it may delegate such of its duties and powers as provided herein, and the officers and directors of the Company shall be entitled to rely conclusively upon and shall be fully protected in any action taken by them in good faith in reliance upon any tables, valuations, certificates, opinions, reports or other advice furnished to them by any duly appointed actuary, accountant, legal counsel (who may be counsel for the Company) or other specialist.

9.7 Notification.

All notices, reports and statements in connection with the Plan that are given, made, delivered or transmitted to a Participant shall be deemed duly given, made, delivered, or transmitted when mailed, by such class as the sender may deem appropriate, with postage prepaid and addressed to the Participant at the address last appearing on the records of the Employer with respect to this Plan. All notices, direct actions or other communications given, made, delivered or transmitted by a Participant to an Employer or Committee shall not be deemed to have been duly given, made, delivered, transmitted or received unless and until actually received by the Employer or Committee.

9.8 Multiple Capacities.

A person may serve in more than one fiduciary capacity with respect to the Plan.

ARTICLE X

CLAIMS PROCEDURE

10.1 Submission of Claims.

The initial claim by any Participant for benefits under this Plan shall be submitted in writing to the Committee (or its delegate) within 60 days after the occurrence of the termination of employment that the Participant claims to have triggered entitlement to Plan benefits.

10.2 Computation and Review of Claims.

All benefits shall be computed by the Committee or its delegate. All claims shall be approved or denied by the Committee (or its delegate) as soon as practicable, but in no event later than 90 days after application by the Participant. The Committee may take an additional 90 days to review the claim, provided that the Participant is notified in writing within the initial 90-day period.

(a) Initial Denial of Claim - Any denial of a claim shall include:

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(i) Reason or reasons for the denial;

(ii) Reference to pertinent Plan provisions on which the denial is based;

(iii) Description of any additional material or information necessary for the Participant to perfect the claim together with an explanation of why the material or information is necessary; and

(iv) Explanation of the Plan's claim review procedure, described below.

(b) Review of a Denied Claim - A Participant shall have a reasonable opportunity to appeal a denied claim to the Committee (or its delegate) for a full and fair review. The Participant or a duly authorized representative:

(i) Shall have 60 days, after receipt of written notification of the denial of claim in which to request a review.

(ii) May request a review upon written application to the Committee.

(iii) Shall submit written comments, documents, records and other information relating to the claim.

(iv) May review, free of charge, pertinent Plan documents, records and other information relevant to the claim.

(c) Committee Review - The Committee's (or its delegate's) review shall take into account all comments, documents, records and other information submitted by the Participant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

(d) Written Decision - The Committee (or its delegate) shall issue a decision on the reviewed claim promptly but no later than 60 days after receipt of the review. The Committee may take an additional 60 days to review the claim, provided that the Participant is notified in writing within the initial 60-day period. The Committee's decision shall be in writing and shall include:

(i) Reasons for the decision;

(ii) References to the Plan provisions on which the decision is based;

(iii) Statement that the Participant is entitled to receive, upon request, reasonable access to, and copies of, all documents, records and other information relevant to the claim; and

(iv) Statement that the Participant is entitled to bring a civil suit under Section 502(a) of ERISA.

(e) Binding Effect - The Committee's (or its delegate's) decision shall be final and binding on the Participant and the Employer.

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ARTICLE XI

GENERAL PROVISIONS

11.1 Construction. This Plan shall be construed and enforced in accordance with and governed by the internal substantive laws (and not the laws relating to conflict of laws or choice of laws) of the State of New Jersey, except to the extent that such laws are preempted by Federal law.

11.2 Unfunded Plan. The obligations of the Company under this Plan are not required to be funded in advance. Nothing contained in this Plan shall give an Eligible Employee or Participant any right, title or interest in any property of the Company or any of its Affiliates.

11.3 No Right to Continued Employment.

Nothing contained herein shall be deemed to give any Eligible Employee or Participant the right to be retained in the employment of an Employer or to limit the rights of any Employer to discharge any Eligible Employee or Participant at any time, with or without notice and with or without Cause.

11.4 Partial Invalidity. The invalidity or unenforceability of any term or provision, or any clause, or portion thereof, of this Plan shall in no way impair or affect the validity or enforceability of any other provision of this Plan, which shall remain in full force and effect.

11.5 Successors and Assigns.

(a) This Plan shall inure to the benefit of and be binding upon the Company and its successors and assigns.

(b) The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform the Company's obligations under the Plan in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place.

(c) In no event shall a Participant assign his interests under the Plan to any other person without the prior written consent of the Committee.

11.6 Waivers. Failure to strictly comply with any term, condition or requirement set forth in the Plan shall not be deemed a waiver of such term, condition or requirement, nor shall any waiver of any such term, condition or requirement at any one time or times be deemed to result in a waiver of such term, condition or requirement at any other time or times.

11.7 Gender and Number. Masculine pronouns include the feminine as well as the neuter genders, and the singular shall include the plural, unless indicated otherwise by the context.

11.8 Headings. The headings of the Plan are for purposes of reference only and shall not limit or otherwise affect the meaning hereof.

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* * *

_____ _____

Signature Date

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SCHEDULE A

As Amended as of July 14, 2014
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Stuart J. Black	VP & Controller (effective 8/4/14)	03/01/10
Robert C. Braun	SVP & Chief Operating Officer, PSEG Nuclear	12/4/09
Jorge L. Cardenas	VP - Asset Management and Centralized Services, PSE&G	1/23/07
Rose M. Chernick	VP - Finance (Energy Holdings) and Corp. Planning & Analysis	8/09/10
John Paul Cowan	SVP - Operations, PSEG Fossil	09/15/09
Lathrop B. Craig	VP - ISO Operations (ER&T)	09/05/11
Daniel J. Cregg	VP - Finance (PSE&G)	12/09/06
David M. Daly	President and COO - PSEG Long Island	1/28/08
Paul J. Davison	VP - Hope Creek, PSEG Nuclear	12/14/09
Derek DiRisio	President - PSEG Services Corporation (effective 8/4/14)	12/20/04
Diana L. Drysdale	VP - Renewables, PSEG Energy Holdings	02/15/10
Kathleen Fitzgerald	VP - Corporate Communications	01/03/12
Joseph A. Forline	VP - Customer Solutions, PSE&G	12/19/06
Carl J. Fricker	VP - Trading Support & Operations (ER&T)	12/14/09
Robert F. Friend	VP - Procurement	04/20/10
Kim C. Hanemann	SVP - Delivery Projects and Construction	12/21/10
Bradford D. Huntington	VP & Treasurer	04/16/11
Scott Jennings	VP - Corporate Strategy	10/18/05
Thomas P. Joyce	President & CNO, PSEG Nuclear	01/01/07
Robert C. Krueger, Jr	VP & Assistant Controller - Tax	12/19/06
Kathleen A. Lally	VP - Investor Relations	01/16/07
John R. Latka	SVP - Electric and Gas Operations, PSE&G	10/23/06
Shawn P. Leyden	VP & Deputy General Counsel	12/20/04
Tamara L. Linde	EVP and General Counsel	12/19/06
Richard P. Lopriore	President, PSEG Fossil	06/19/07
Kristen M. Ludecke	VP - Federal Affairs	02/22/10

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NAME	TITLE	PARTICIPATION DATE
Shahid Malik	President - Energy Resources & Trade (ER&T)	12/5/11
Christine T. Neely	VP - Internal Auditing Services	9/30/13
Michael S. Paszynsky	VP - Business Assurance and Resilience	03/01/10
Margaret M. Pego	SVP - Human Resources & CHRO	12/20/04
John F. Perry	VP - Salem, PSEG Nuclear	09/15/09
Kevin J. Quinn	VP - Finance (Power)	03/01/10
Sheila J. Rostiac	VP - Talent, Development and Diversity	08/20/12
Joseph Santamaria	VP - Information Technology & CIO	10/29/12
John P. Scarlata	VP- Gas Supply, PSEG ER&T	4/20/10
Christopher J. Schwarz	VP - Operations Support	8/05/13
Richard T. Thigpen	VP - - State Governmental Affairs	3/26/07
John F. Tiberi	VP - Employee Benefits, Health & Safety	07/09/12

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SCHEDULE B

As Amended as of July 14, 2014
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Ralph Izzo	Chairman of the Board, President and CEO	12/15/08
J. A. Bouknight, Jr.*	EVP and General Counsel	11/02/09
Caroline Dorsa	EVP and CFO, and President - Resources	04/09/09
Ralph A. LaRossa	President & COO - Public Service Electric and Gas Company, and COB, PSEG Long Island	10/17/06
William Levis	President & COO, PSEG Power LLC	01/01/07

* Retired July 1, 2014.

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SCHEDULE C

As Amended as of July 14, 2014
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Gregory Dunlap	VP Customer Operations - PSE&G	7/14/14
M. Courtney McCormick	VP Deputy General Counsel and Corporate Secretary	3/31/14
Laurent Pommier	VP Risk Management and Chief Risk Officer	7/14/14

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EXHIBIT I

Form of Restrictive Covenant Agreement

AGREEMENT, by and between Public Service Enterprise Group Incorporated, a New Jersey Corporation (the "Company") and [_____] ("Executive"), dated as of [_____].

WHEREAS, the Company maintains the Key Executive Severance Plan of Public Service Enterprise Group Incorporated (the "Plan"), effective December 17, 2012, and as thereafter amended, modified or supplemented;

WHEREAS, Executive was designated as an Eligible Employee under the Plan by the Organization and Compensation Committee of the Company's Board of Directors;

WHEREAS, pursuant to Section 3.2 of the Plan, in order to be a Participant in and be entitled to benefits and protections under the Plan, Executive must execute and delivery to the Company within 30 days after Executive was designated as an Eligible Employee a written agreement to be bound by the terms and conditions of certain covenants set out in Article VII of the Plan, which is hereby incorporated herein;

NOW THEREFORE, the parties agree as follows:

1. Executive has received a copy of the Plan and has read and understands the terms of conditions of Section 7.1, Confidentiality, Section 7.2, Non-Compete, and Section 7.3, Non-Solicitation, therein, as applied to Executive (the "Covenants").

2. Executive agrees to be bound by and comply with the terms of the Covenants in consideration for becoming a Participant in the Plan.

3. Executive acknowledges that the Covenants are reasonable in the scope of the activities restricted, the geographic area covered by the restrictions, the duration of the restrictions, and that such Covenants are reasonably necessary to protect the Company's legitimate interests in its Confidential Information and its relationships with its employees, customers and suppliers.

4. Executive acknowledges that the Covenants will not deprive Executive of the ability to earn a livelihood or to support Executive's dependents.

5. Executive shall be a Participant in the Plan and be entitled to all of the rights and benefits provided thereunder as of the date of this Agreement.

6. This Agreement shall be construed and enforced in accordance with and governed by the internal substantive laws (and not the laws relating to conflict of laws or choice of laws) of the State of New Jersey, except to the extent that such laws are preempted by Federal law.

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IN WITNESS WHEREOF, the parties have executed this Agreement as of the date and year first above written.

[This Agreement may be executed in counterparts.]

EXECUTIVE

PUBLIC SERVICE ENTERPRISE
GROUP INCORPORATED

By:_____

Title:_____

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2014	2013	2013	2012	2011	2010	2009
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	970	1,091	$ 2,055	$ 2,011	$ 2,384	$ 2,616	$ 2,636
(Income) Loss from Equity Investees, net of Distributions	2	(2)	(7)	9	(4)	(19)	(25)
Fixed Charges	222	230	458	479	522	571	600
Capitalized Interest	(8)	(7)	(16)	(19)	(14)	(67)	(45)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	(2)	(6)
Total Earnings	1,186	1,312	$ 2,490	$ 2,480	$ 2,888	$ 3,099	$ 3,160
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	211	222	$ 442	$ 465	$ 509	$ 555	$ 581
Interest Factor in Rentals	11	8	16	14	13	14	13
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	2	6
Total Fixed Charges	222	230	$ 458	$ 479	$ 522	$ 571	$ 600
Ratio of Earnings to Fixed Charges	5.34	5.70	5.44	5.18	5.53	5.43	5.27

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12.1

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2014	2013	2013	2012	2011	2010	2009
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	351	582	$1,063	$1,099	$1,703	$1,932	$1,969
(Income) Loss from Equity Investees, net of Distributions	1	(4)	(10)	(6)	(12)	(8)	(7)
Fixed Charges	75	72	143	164	208	238	221
Capitalized Interest	2	1	1	(6)	(10)	(63)	(43)
Total Earnings	$ 429	$ 651	$1,197	$1,251	$1,889	$2,099	$2,140
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	72	70	$ 139	$ 161	$ 205	$ 235	$ 219
Interest Factor in Rentals	3	2	4	3	3	3	2
Total Fixed Charges	$ 75	$ 72	$ 143	$ 164	$ 208	$ 238	$ 221
Ratio of Earnings to Fixed Charges	5.72	9.04	8.37	7.63	9.08	8.82	9.68

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2014	2013	2013	2012	2011	2010	2009
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	594	496	$ 993	$ 835	$ 861	$ 591	$ 551
Fixed Charges	150	159	316	314	319	325	317
Capitalized Interest	(9)	(8)	(16)	(13)	(4)	(2)	(1)
Total Earnings	$ 735	$ 647	$ 1,293	$ 1,136	$ 1,176	$ 914	$ 867
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	144	156	$ 309	$ 308	$ 314	$ 320	$ 313
Interest Factor in Rentals	6	3	7	6	5	5	4
Total Fixed Charges	$ 150	$ 159	$ 316	$ 314	$ 319	$ 325	$ 317
Ratio of Earnings to Fixed Charges	4.90	4.07	4.09	3.62	3.69	2.81	2.74

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.3

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Six Months Ended June 30,		Years Ended December 31,				
	2014	2013	2013	2012	2011	2010	2009
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 594	$ 496	$ 993	$ 835	$ 861	$ 591	$ 551
Fixed Charges	150	159	316	314	319	327	323
Capitalized Interest	(9)	(8)	(16)	(13)	(4)	(2)	(1)
Preferred Securities Dividend Requirements	—	—	—	—	—	(2)	(6)
Total Earnings	$ 735	$ 647	$1,293	$1,136	$1,176	$ 914	$ 867
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 144	$ 156	$ 309	$ 308	$ 314	$ 320	$ 313
Interest Factor in Rentals	6	3	7	6	5	5	4
Preferred Securities Dividend	—	—	—	—	—	1	4
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	—	—	—	1	2
Total Fixed Charges	$ 150	$ 159	$ 316	$ 314	$ 319	$ 327	$ 323
Ratio of Earnings to Fixed Charges	4.90	4.07	4.09	3.62	3.69	2.80	2.68

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2014

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2014

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2014

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2014

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2014

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2014

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer

S1-SSA-0009 - 17511

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
August 1, 2014

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer
August 1, 2014

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
August 1, 2014

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Caroline Dorsa

Caroline Dorsa

PSEG Power LLC
Chief Financial Officer
August 1, 2014

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
August 1, 2014

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer
August 1, 2014

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2015
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of July 21, 2015, Public Service Enterprise Group Incorporated had outstanding 505,874,772 shares of its sole class of Common Stock, without par value.

As of July 21, 2015, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulations, including market structures and transmission planning,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- any deterioration in our credit quality or the credit quality of our counterparties,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as for transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies, and
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

S1-SSA-0009 - 17520

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, July 31, 2015 Powered by Morningstar® Document Research℠

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
OPERATING REVENUES	$ 2,314	$ 2,249	$ 5,449	$ 5,472
OPERATING EXPENSES				
Energy Costs	668	789	1,762	2,145
Operation and Maintenance	761	800	1,424	1,656
Depreciation and Amortization	317	295	647	601
Total Operating Expenses	1,746	1,884	3,833	4,402
OPERATING INCOME	568	365	1,616	1,070
Income from Equity Method Investments	4	3	7	7
Other Income	76	62	124	110
Other Deductions	(10)	(10)	(22)	(22)
Other-Than-Temporary Impairments	(10)	(2)	(15)	(4)
Interest Expense	(97)	(94)	(195)	(191)
INCOME BEFORE INCOME TAXES	531	324	1,515	970
Income Tax Expense	(186)	(112)	(584)	(372)
NET INCOME	$ 345	$ 212	$ 931	$ 598
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	506	506	506	506
DILUTED	508	508	508	508
NET INCOME PER SHARE:				
BASIC	$ 0.68	$ 0.42	$ 1.84	$ 1.18
DILUTED	$ 0.68	$ 0.42	$ 1.83	$ 1.18
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.39	$ 0.37	$ 0.78	$ 0.74

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17521

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, July 31, 2015
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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
NET INCOME	$ 345	$ 212	$ 931	$ 598
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $15, $(9), $2 and $(12) for the three and six months ended 2015 and 2014, respectively	(15)	11	(1)	13
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $0, $7, and $(2) for the three and six months ended 2015 and 2014, respectively	—	1	(9)	3
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(6), $(1), $(12) and $(3) for three and six months ended 2015 and 2014, respectively	8	2	16	6
Other Comprehensive Income (Loss), net of tax	(7)	14	6	22
COMPREHENSIVE INCOME	$ 338	$ 226	$ 937	$ 620

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17522

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, July 31, 2015 Powered by Morningstar® Document Research℠
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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 597	$ 402
Accounts Receivable, net of allowances of $60 and $52 in 2015 and 2014, respectively	1,126	1,254
Tax Receivable	23	211
Unbilled Revenues	247	284
Fuel	358	538
Materials and Supplies, net	466	484
Prepayments	272	108
Derivative Contracts	155	240
Deferred Income Taxes	—	11
Regulatory Assets	235	323
Regulatory Assets of Variable Interest Entities (VIEs)	123	249
Other	25	15
Total Current Assets	3,627	4,119
PROPERTY, PLANT AND EQUIPMENT	33,603	32,196
Less: Accumulated Depreciation and Amortization	(8,796)	(8,607)
Net Property, Plant and Equipment	24,807	23,589
NONCURRENT ASSETS		
Regulatory Assets	3,170	3,192
Long-Term Investments	1,273	1,307
Nuclear Decommissioning Trust (NDT) Fund	1,792	1,780
Long-Term Tax Receivable	165	64
Long-Term Receivable of VIE	602	580
Other Special Funds	234	212
Goodwill	16	16
Other Intangibles	101	84
Derivative Contracts	107	77
Restricted Cash of VIEs	25	24
Other	293	289
Total Noncurrent Assets	7,778	7,625
TOTAL ASSETS	$ 36,212	$ 35,333

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17523

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2015	December 31, 2014
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 491	$ 624
Securitization Debt of VIEs Due Within One Year	134	259
Accounts Payable	1,156	1,178
Derivative Contracts	72	132
Accrued Interest	96	95
Accrued Taxes	148	21
Deferred Income Taxes	14	173
Clean Energy Program	200	142
Obligation to Return Cash Collateral	128	121
Regulatory Liabilities	143	186
Other	525	547
Total Current Liabilities	3,107	3,478
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	7,578	7,303
Regulatory Liabilities	176	258
Regulatory Liabilities of VIEs	47	39
Asset Retirement Obligations	765	743
Other Postretirement Benefit (OPEB) Costs	1,254	1,277
OPEB Costs of Servco	471	452
Accrued Pension Costs	392	440
Accrued Pension Costs of Servco	128	126
Clean Energy Program	27	—
Environmental Costs	421	417
Derivative Contracts	24	33
Long-Term Accrued Taxes	282	208
Other	143	112
Total Noncurrent Liabilities	11,708	11,408
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Total Long-Term Debt	8,689	8,261
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2015 and 2014—533,556,660 shares	4,883	4,876
Treasury Stock, at cost, 2015— 27,743,506 shares; 2014— 27,720,068 shares	(663)	(635)
Retained Earnings	8,764	8,227
Accumulated Other Comprehensive Loss	(277)	(283)
Total Common Stockholders' Equity	12,707	12,185
Noncontrolling Interest	1	1
Total Stockholders' Equity	12,708	12,186
Total Capitalization	21,397	20,447
TOTAL LIABILITIES AND CAPITALIZATION	$ 36,212	$ 35,333

See Notes to Condensed Consolidated Financial Statements.

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, July 31, 2015
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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2015	**2014**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 931	$ 598
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	647	601
Amortization of Nuclear Fuel	106	98
Provision for Deferred Income Taxes (Other than Leases) and ITC	170	70
Non-Cash Employee Benefit Plan Costs	81	24
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(22)	(44)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(9)	297
Change in Accrued Storm Costs	15	(3)
Net Change in Other Regulatory Assets and Liabilities	(53)	192
Cost of Removal	(58)	(50)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(21)	(59)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	188	9
Accrued Taxes	71	54
Margin Deposit	69	(234)
Other Current Assets and Liabilities	98	(116)
Employee Benefit Plan Funding and Related Payments	(67)	(50)
Other	88	61
Net Cash Provided By (Used In) Operating Activities	2,234	1,448
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,743)	(1,229)
Proceeds from Sales of Capital Leases and Investments	5	11
Proceeds from Sales of Available-for-Sale Securities	885	584
Investments in Available-for-Sale Securities	(918)	(599)
Other	(2)	(49)
Net Cash Provided By (Used In) Investing Activities	(1,773)	(1,282)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	—	(60)
Issuance of Long-Term Debt	600	500
Redemption of Long-Term Debt	(300)	—
Redemption of Securitization Debt	(125)	(111)
Cash Dividends Paid on Common Stock	(394)	(374)
Other	(47)	(44)
Net Cash Provided By (Used In) Financing Activities	(266)	(89)
Net Increase (Decrease) in Cash and Cash Equivalents	195	77
Cash and Cash Equivalents at Beginning of Period	402	493
Cash and Cash Equivalents at End of Period	$ 597	$ 570
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 184	$ 296
Interest Paid, Net of Amounts Capitalized	$ 195	$ 192
Accrued Property, Plant and Equipment Expenditures	$ 324	$ 240

See Notes to Condensed Consolidated Financial Statements.

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, July 31, 2015 Powered by Morningstar® Document Research℠
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
OPERATING REVENUES	$ 1,466	$ 1,435	$ 3,468	$ 3,580
OPERATING EXPENSES				
Energy Costs	544	565	1,436	1,610
Operation and Maintenance	368	362	780	824
Depreciation and Amortization	234	217	481	444
Total Operating Expenses	1,146	1,144	2,697	2,878
OPERATING INCOME	320	291	771	702
Other Income	19	14	37	28
Other Deductions	(1)	(1)	(2)	(1)
Interest Expense	(67)	(67)	(136)	(135)
INCOME BEFORE INCOME TAXES	271	237	670	594
Income Tax Expense	(104)	(86)	(261)	(229)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 167	$ 151	$ 409	$ 365

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17527

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
NET INCOME	$ 167	$ 151	$ 409	$ 365
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0 for the three and six months ended 2015 and 2014, respectively	(1)	—	(1)	—
COMPREHENSIVE INCOME	$ 166	$ 151	$ 408	$ 365

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17528

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 166	$ 310
Accounts Receivable, net of allowances of $60 and $52 in 2015 and 2014, respectively	848	864
Accounts Receivable-Affiliated Companies	52	274
Unbilled Revenues	247	284
Materials and Supplies	143	133
Prepayments	204	42
Regulatory Assets	235	323
Regulatory Assets of VIEs	123	249
Derivative Contracts	5	18
Deferred Income Taxes	—	24
Other	7	7
Total Current Assets	2,030	2,528
PROPERTY, PLANT AND EQUIPMENT	22,274	21,103
Less: Accumulated Depreciation and Amortization	(5,336)	(5,183)
Net Property, Plant and Equipment	16,938	15,920
NONCURRENT ASSETS		
Regulatory Assets	3,170	3,192
Long-Term Investments	346	348
Other Special Funds	54	53
Derivative Contracts	—	8
Restricted Cash of VIEs	25	24
Other	158	150
Total Noncurrent Assets	3,753	3,775
TOTAL ASSETS	$ 22,721	$ 22,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17529

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, July 31, 2015
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2015	December 31, 2014
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 171	$ 300
Securitization Debt of VIEs Due Within One Year	134	259
Accounts Payable	612	574
Accounts Payable—Affiliated Companies	215	379
Accrued Interest	68	68
Clean Energy Program	200	142
Deferred Income Taxes	13	165
Obligation to Return Cash Collateral	128	121
Regulatory Liabilities	143	186
Other	358	381
Total Current Liabilities	2,042	2,575
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,810	4,575
Other Postretirement Benefit (OPEB) Costs	936	967
Accrued Pension Costs	144	173
Regulatory Liabilities	176	258
Regulatory Liabilities of VIEs	47	39
Clean Energy Program	27	—
Environmental Costs	370	364
Asset Retirement Obligations	299	290
Long-Term Accrued Taxes	161	116
Other	74	67
Total Noncurrent Liabilities	7,044	6,849
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Total Long-Term Debt	6,440	6,012
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2015 and 2014—132,450,344 shares	892	892
Contributed Capital	695	695
Basis Adjustment	986	986
Retained Earnings	4,621	4,212
Accumulated Other Comprehensive Income	1	2
Total Stockholder's Equity	7,195	6,787
Total Capitalization	13,635	12,799
TOTAL LIABILITIES AND CAPITALIZATION	$ 22,721	$ 22,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17530

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2015	**2014**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 409	$ 365
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	481	444
Provision for Deferred Income Taxes and ITC	79	73
Non-Cash Employee Benefit Plan Costs	48	13
Cost of Removal	(58)	(50)
Change in Accrued Storm Costs	15	(3)
Net Change in Other Regulatory Assets and Liabilities	(53)	192
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	53	44
Materials and Supplies	(10)	(11)
Prepayments	(162)	(162)
Accounts Payable	48	16
Accounts Receivable/Payable—Affiliated Companies, net	154	(98)
Other Current Assets and Liabilities	(27)	(31)
Employee Benefit Plan Funding and Related Payments	(55)	(44)
Other	(13)	(11)
Net Cash Provided By (Used In) Operating Activities	909	737
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,230)	(996)
Proceeds from Sales of Available-for-Sale Securities	12	8
Investments in Available-for-Sale Securities	(14)	(6)
Other	12	(1)
Net Cash Provided By (Used In) Investing Activities	(1,220)	(995)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	—	(60)
Issuance of Long-Term Debt	600	500
Redemption of Long-Term Debt	(300)	—
Redemption of Securitization Debt	(125)	(111)
Contributed Capital	—	175
Other	(8)	(7)
Net Cash Provided By (Used In) Financing Activities	167	497
Net Increase (Decrease) In Cash and Cash Equivalents	(144)	239
Cash and Cash Equivalents at Beginning of Period	310	18
Cash and Cash Equivalents at End of Period	$ 166	$ 257
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (74)	$ 102
Interest Paid, Net of Amounts Capitalized	$ 131	$ 127
Accrued Property, Plant and Equipment Expenditures	$ 282	$ 192

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17531

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
OPERATING REVENUES	$ 1,025	$ 986	$ 2,750	$ 2,686
OPERATING EXPENSES				
Energy Costs	409	520	1,302	1,564
Operation and Maintenance	313	327	485	629
Depreciation and Amortization	75	72	151	144
Total Operating Expenses	797	919	1,938	2,337
OPERATING INCOME	228	67	812	349
Income from Equity Method Investments	5	3	8	7
Other Income	55	46	84	79
Other Deductions	(7)	(9)	(18)	(19)
Other-Than-Temporary Impairments	(10)	(2)	(15)	(4)
Interest Expense	(33)	(29)	(64)	(61)
INCOME BEFORE INCOME TAXES	238	76	807	351
Income Tax Expense	(72)	(22)	(306)	(133)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 166	$ 54	$ 501	$ 218

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17532

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
NET INCOME	$ 166	$ 54	$ 501	$ 218
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $14, $(9), $1 and $(11) for the three and six months ended 2015 and 2014, respectively	(14)	9	—	11
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $(1), $7 and $(2) for the three and six months ended 2015 and 2014, respectively	—	2	(9)	3
Pension/OPEB adjustment, net of tax (expense) benefit of $(5), $(1), $(10) and $(3) for the three and six months ended 2015 and 2014, respectively	7	2	14	5
Other Comprehensive Income (Loss), net of tax	(7)	13	5	19
COMPREHENSIVE INCOME	$ 159	$ 67	$ 506	$ 237

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17533

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 12	$ 9
Accounts Receivable	235	334
Accounts Receivable—Affiliated Companies	158	313
Tax Receivable	3	3
Short-Term Loan to Affiliate	950	584
Fuel	358	538
Materials and Supplies, net	321	350
Derivative Contracts	139	207
Prepayments	22	17
Other	13	4
Total Current Assets	2,211	2,359
PROPERTY, PLANT AND EQUIPMENT	10,942	10,732
Less: Accumulated Depreciation and Amortization	(3,235)	(3,217)
Net Property, Plant and Equipment	7,707	7,515
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,792	1,780
Long-Term Investments	116	121
Goodwill	16	16
Other Intangibles	101	84
Other Special Funds	57	49
Derivative Contracts	103	62
Other	63	60
Total Noncurrent Assets	2,248	2,172
TOTAL ASSETS	$ 12,166	$ 12,046

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17534

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2015	December 31, 2014
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 300	$ 300
Accounts Payable	387	424
Accounts Payable-Affiliated Companies	128	118
Derivative Contracts	72	132
Deferred Income Taxes	22	43
Accrued Interest	27	27
Other	141	140
Total Current Liabilities	1,077	1,184
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	2,152	2,065
Asset Retirement Obligations	462	450
Other Postretirement Benefit (OPEB) Costs	254	248
Derivative Contracts	24	33
Accrued Pension Costs	139	153
Long-Term Accrued Taxes	56	41
Other	94	71
Total Noncurrent Liabilities	3,181	3,061
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT		
Total Long-Term Debt	2,244	2,243
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,659	4,558
Accumulated Other Comprehensive Loss	(223)	(228)
Total Member's Equity	5,664	5,558
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,166	$ 12,046

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2015	**2014**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 501	$ 218
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	151	144
Amortization of Nuclear Fuel	106	98
Provision for Deferred Income Taxes and ITC	64	(22)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(9)	297
Non-Cash Employee Benefit Plan Costs	24	7
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(21)	(59)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	209	132
Margin Deposit	69	(234)
Accounts Receivable	76	16
Accounts Payable	(62)	(72)
Accounts Receivable/Payable—Affiliated Companies, net	123	229
Other Current Assets and Liabilities	(21)	13
Employee Benefit Plan Funding and Related Payments	(7)	(3)
Other	89	50
Net Cash Provided By (Used In) Operating Activities	1,292	814
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(487)	(226)
Proceeds from Sales of Available-for-Sale Securities	837	563
Investments in Available-for-Sale Securities	(854)	(577)
Short-Term Loan—Affiliated Company, net	(366)	50
Other	(17)	(46)
Net Cash Provided By (Used In) Investing Activities	(887)	(236)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	(400)	(575)
Other	(2)	(3)
Net Cash Provided By (Used In) Financing Activities	(402)	(578)
Net Increase (Decrease) in Cash and Cash Equivalents	3	—
Cash and Cash Equivalents at Beginning of Period	9	6
Cash and Cash Equivalents at End of Period	$ 12	$ 6
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 218	$ 47
Interest Paid, Net of Amounts Capitalized	$ 62	$ 62
Accrued Property, Plant and Equipment Expenditures	$ 42	$ 48

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

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This combined Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power each is only responsible for information about itself and its subsidiaries.

Note 1. Organization and Basis of Presentation

Organization

PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **PSE&G**—which is an operating public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- **Power**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the FERC, the Nuclear Regulatory Commission (NRC) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2014.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2014.

Note 2. Recent Accounting Standards

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard was issued to clarify the principles for recognizing revenue and to develop a common standard that would remove inconsistencies in revenue requirements; improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provide improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The update was originally effective for annual and interim reporting periods beginning after December 15, 2016; however, the Financial Accounting Standards Board has voted to proceed with a one-year deferral with an effective date beginning after December 31, 2017. Early application will be permitted as of the original effective date of December 31, 2016. We are currently analyzing the impact of this standard on our financial statements.

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Amendments to the Consolidation Analysis

This standard was issued to respond to concerns regarding the current accounting for consolidation of certain legal entities. Under the new standard, all legal entities are subject to reevaluation under a revised consolidation model which will determine whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities; eliminate the presumption that a general partner should consolidate a limited partnership; affect the consolidation analysis of reporting entities that are involved with VIEs and provide a scope exception from consolidation guidance for reporting entities with interests in certain legal entities who must comply with other requirements.

The update is effective for annual and interim reporting periods beginning after December 15, 2015. We are currently analyzing the impact of this standard on our financial statements.

Simplifying the Presentation of Debt Issuance Costs

This standard was issued to simplify presentation of debt issuance costs. The standard will require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by this standard.

The update is effective for annual and interim reporting periods beginning after December 15, 2015. We do not expect the impact of adoption of this standard to be material to our Condensed Consolidated Balance Sheets.

Note 3. Variable Interest Entities (VIEs)

Variable Interest Entities for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of Transition Funding and Transition Funding II are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the assets of these VIEs are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II.

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of June 30, 2015 and December 31, 2014. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II during the first six months of 2015 or in 2014. PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II.

Variable Interest Entity for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

PSEG recognized a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and other postretirement benefit (OPEB) liabilities. This receivable is presented separately on the Condensed Consolidated Balance Sheet

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of PSEG as a noncurrent asset because it is restricted. See Note 7. Pension and Other Postretirement Benefits for additional information.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operation and Maintenance (O&M) Expense, respectively. Servco recorded $84 million and $111 million for the three months and $166 million and $200 million for the six months ended June 30, 2015 and 2014, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 4. Rate Filings

The following information discusses significant updates regarding orders and pending rate filings. This Note should be read in conjunction with Note 5. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2014.

In addition to items previously reported in the Annual Report on Form 10-K, significant 2015 regulatory orders received and currently pending rate filings with the FERC and the BPU by PSE&G are as follows:

- ***Energy Strong Recovery Filing***—In June 2015, PSE&G updated its Energy Strong cost recovery petition seeking BPU approval to recover in base rates estimated annual increases in electric revenues of $6 million and gas revenues of $17 million. These increases represent recovery of Energy Strong investment costs in service as of May 31, 2015. The petition requests rates to be effective September 1, 2015, consistent with the BPU Order of approval of the Energy Strong program. This matter is pending.
- ***Basic Gas Supply Service (BGSS)***—On April 15, 2015, the BPU issued an Order approving PSE&G's provisional BGSS rate of 45 cents per therm which had been implemented on October 1, 2014. In March 2015, PSE&G filed a letter with the BPU to extend the 28 cents per therm residential rate reduction via a bill credit for one additional month through April 30, 2015, which provided an additional approximate $31 million credit to customers.

  On June 1, 2015, PSE&G made its Annual BGSS Filing with the BPU requesting a reduction of $70 million in annual BGSS revenues. If approved, the BGSS rate would be reduced from approximately 45 cents to 40 cents per therm effective October 1, 2015.
- ***Weather Normalization Clause***—On April 15, 2015, the BPU approved PSE&G's final filing with respect to excess revenues collected during the colder than normal 2013-2014 Winter Period (October 1, 2013 through May 31, 2014). Effective October 1, 2014, PSEG commenced returning $45 million in revenues to its customers during the 2014-2015 Winter Period (October 1, 2014 through May 31, 2015).

  In June 2015, PSE&G filed a petition requesting approval to refund excess revenues collected during the colder than normal 2014-2015 Winter Period. This refund would be made to customers over the 2015-2016 Winter Period (October 1, 2015 through May 31, 2016). Colder weather in the 2014-2015 Winter Period resulted in an excess collection of $40 million of revenues to be refunded to customers.
- ***Solar and Energy Efficiency - Green Program Recovery Charges (GPRC)***—In April 2015, the BPU approved PSE&G's petition for an Energy Efficiency Economic Stimulus Extension II Program (EEE Ext II) to extend three EEE subprograms (multi-family, direct install and hospital efficiency). The Order allows PSE&G to extend the subprogram offerings under the same clause recovery process as its existing EEE Program and allows for $95 million of additional capital expenditures over the next three years and $12 million of additional administrative expenses over the next 15 years. The EEE Ext II program was added as a ninth component of the GPRC rate effective May 1, 2015.

  In July of each year, PSE&G files for annual recovery for its Green Program investments which include a return on its investment and recovery of expenses. In May 2015, the BPU approved PSE&G's July 2014 filing requesting recovery of costs and investments in the first eight combined components of the electric and gas GPRC for the period October 1, 2014 through September 30, 2015. In July 2015, PSE&G filed its annual GPRC cost recovery petition with the BPU once again requesting recovery of costs and investments for the first eight combined components of the electric and gas GPRC. The filing proposes rates for the period October 1, 2015 through September 30, 2016 designed to recover approximately $64 million and $10 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved programs. The matter is pending.

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- ***Transmission Formula Rate Filings***—In June 2015, PSE&G filed its 2014 true-up adjustment pertaining to its formula rates in effect for 2014, which resulted in an adjustment of $19 million less than the 2014 filed revenues. The adjustment was primarily due to the impact of bonus depreciation and lower interest rates which PSE&G had recognized in its Consolidated Statement of Operations for the year ended December 31, 2014.

Note 5. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with Solar Renewable Energy Certificates generated from the installed solar electric system. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of June 30, 2015	As of December 31, 2014
	Millions	
Commercial/Industrial	$ 186	$ 188
Residential	13	13
Total	**$ 199**	**$ 201**

Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

The following table shows Energy Holdings' gross and net lease investment as of June 30, 2015 and December 31, 2014, respectively.

	As of June 30, 2015	As of December 31, 2014
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 661	$ 691
Estimated Residual Value of Leased Assets	519	525
Unearned and Deferred Income	(372)	(380)
Gross Investment in Leases	808	836
Deferred Tax Liabilities	(695)	(738)
Net Investment in Leases	**$ 113**	**$ 98**

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The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

Counterparties' Credit Rating (Standard & Poor's (S&P)) As of June 30, 2015	Lease Receivables, Net of Non-Recourse Debt As of June 30, 2015
	Millions
AA	$ 17
AA-	29
BBB+ — BBB-	316
BB-	134
B-	165
Total	**$ 661**

The "BB-" and the "B-" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of June 30, 2015, the gross investment in the leases of such assets, net of non-recourse debt, was $573 million ($4 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counter-parties' S&P Credit Ratings	Counterparty
		Millions		MW			
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	B-	NRG REMA LLC
Conemaugh Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	B-	NRG REMA LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 113	100%	603	Coal	B-	NRG REMA LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

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In early 2014, NRG REMA LLC, an indirect subsidiary of NRG Energy, Inc. (NRG) had disclosed its plan to place the Shawville generating facility in a "long-term protective layup" by April 2015 as it evaluated its alternatives under the lease. However, NRG has since notified PJM that it deactivated the coal-fired units at the Shawville generating facility in June 2015 and has disclosed that it expects to return the Shawville units to service in the summer of 2016 with the ability to use natural gas.

Note 6. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Fund

Power maintains an external master nuclear decommissioning trust to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third party investment advisers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of June 30, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 697	$ 234	$ (10)	$ 921
Debt Securities				
Government Obligations	451	7	(3)	455
Other Debt Securities	388	4	(6)	386
Total Debt Securities	839	11	(9)	841
Other Securities	30	—	—	30
Total NDT Available-for-Sale Securities	**$ 1,566**	**$ 245**	**$ (19)**	**$ 1,792**

	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 685	$ 220	$ (8)	$ 897
Debt Securities				
Government Obligations	430	9	(1)	438
Other Debt Securities	333	9	(3)	339
Total Debt Securities	763	18	(4)	777
Other Securities	106	—	—	106
Total NDT Available-for-Sale Securities	**$ 1,554**	**$ 238**	**$ (12)**	**$ 1,780**

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The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of June 30, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$ 42	$ 10
Accounts Payable	$ 32	$ 2

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of June 30, 2015				As of December 31, 2014			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 114	$ (10)	$ 3	$ —	$ 162	$ (8)	$ 1	$ —
Debt Securities								
Government Obligations (B)	156	(3)	22	—	95	—	28	(1)
Other Debt Securities (C)	199	(4)	22	(2)	99	(1)	30	(2)
Total Debt Securities	355	(7)	44	(2)	194	(1)	58	(3)
NDT Available-for-Sale Securities	**$ 469**	**$ (17)**	**$ 47**	**$ (2)**	**$ 356**	**$ (9)**	**$ 59**	**$ (3)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of June 30, 2015.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of June 30, 2015.

(C) Debt Securities (Other)—Power's investments in corporate bonds, collateralized mortgage obligations, asset-backed securities and municipal government obligations are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2015.

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The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	Millions			
Proceeds from NDT Fund Sales (A)	**$ 232**	**$ 313**	**$ 822**	**$ 558**
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	14	33	33	56
Gross Realized Losses	(4)	(5)	(13)	(9)
Net Realized Gains (Losses) on NDT Fund	**$ 10**	**$ 28**	**$ 20**	**$ 47**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $111 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of June 30, 2015.

The NDT available-for-sale debt securities held as of June 30, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 9
1 - 5 years	229
6 - 10 years	197
11 - 15 years	53
16 - 20 years	47
Over 20 years	306
Total NDT Available-for-Sale Debt Securities	**$ 841**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the six months ended June 30, 2015, other-than-temporary impairments of $15 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

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PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of June 30, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 10	$ —	$ 22
Debt Securities				
Government Obligations	99	1	—	100
Other Debt Securities	90	1	(1)	90
Total Debt Securities	189	2	(1)	190
Other Securities	—	—	—	—
Total Rabbi Trust Available-for-Sale Securities	**$ 201**	**$ 12**	**$ (1)**	**$ 212**

	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 11	$ —	$ 23
Debt Securities				
Government Obligations	89	2	—	91
Other Debt Securities	74	1	—	75
Total Debt Securities	163	3	—	166
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 177**	**$ 14**	**$ —**	**$ 191**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of June 30, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$ 3	$ 1
Accounts Payable	$ 2	$ —

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The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of June 30, 2015				As of December 31, 2014			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	19	—	1	—	2	—	—	—
Other Debt Securities (C)	39	(1)	7	—	24	—	—	—
Total Debt Securities	58	(1)	8	—	26	—	—	—
Rabbi Trust Available-for-Sale Securities	**$ 58**	**$ (1)**	**$ 8**	**$ —**	**$ 26**	**$ —**	**$ —**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of June 30, 2015.

(C) Debt Securities (Other)—PSEG's investments in corporate bonds, collateralized mortgage obligations, asset-backed securities and municipal government obligations are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2015.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	Millions			
Proceeds from Rabbi Trust Sales (A)	**$ 44**	**$ 14**	**$ 63**	**$ 26**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ 2	$ —	$ 2	$ 2
Gross Realized Losses	—	(1)	—	(1)
Net Realized Gains (Losses) on Rabbi Trust	**$ 2**	**$ (1)**	**$ 2**	**$ 1**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains disclosed in the preceding table were recognized in Other Income in the Condensed Consolidated Statements of Operations. Net unrealized gains of $6 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of June 30, 2015.

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The Rabbi Trust available-for-sale debt securities held as of June 30, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 1
1 - 5 years	56
6 - 10 years	37
11 - 15 years	9
16 - 20 years	8
Over 20 years	79
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 190**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

The fair value of assets in the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of June 30, 2015	As of December 31, 2014
	Millions	
PSE&G	$ 42	$ 41
Power	52	45
Other	118	105
Total Rabbi Trust Available-for-Sale Securities	**$ 212**	**$ 191**

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Note 7. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.

Pension and OPEB costs for PSEG, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014	2015	2014	2015	2014
	Millions							
Components of Net Periodic Benefit Costs (Credit)								
Service Cost	$ 31	$ 26	$ 6	$ 4	$ 62	$ 52	$ 11	$ 9
Interest Cost	58	59	17	17	117	118	34	34
Expected Return on Plan Assets	(104)	(100)	(8)	(6)	(207)	(200)	(15)	(13)
Amortization of Net								
Prior Service Cost (Credit)	(4)	(4)	(4)	(3)	(9)	(9)	(7)	(7)
Actuarial Loss	37	14	11	6	74	28	21	12
Total Benefit Costs (Credit)	**$ 18**	**$ (5)**	**$ 22**	**$ 18**	**$ 37**	**$ (11)**	**$ 44**	**$ 35**

Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014	2015	2014	2015	2014
	Millions							
PSE&G	$ 10	$ (5)	$ 14	$ 12	$ 20	$ (10)	$ 28	$ 23
Power	5	(1)	6	5	11	(3)	13	10
Other	3	1	2	1	6	2	3	2
Total Benefit Costs (Credit)	**$ 18**	**$ (5)**	**$ 22**	**$ 18**	**$ 37**	**$ (11)**	**$ 44**	**$ 35**

During the three months ended March 31, 2015, PSEG contributed its entire planned contributions for the year 2015 of $15 million into its pension plans and $14 million into its OPEB plan for 2015.

Servco Pension and OPEB

At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and

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for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco may contribute up to $30 million into its pension plan trusts during 2015. The pension-related revenues and costs were $7 million and $23 million for the three months ended June 30, 2015 and 2014, respectively, and were $13 million and $46 million for the six months ended June 30, 2015 and 2014, respectively. The OPEB-related revenues earned or costs incurred for each of the three months and six months ended June 30, 2015 and 2014 were immaterial.

Note 8. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The face value of Power's outstanding guarantees, current exposure and margin positions as of June 30, 2015 and December 31, 2014 are shown as follows:

	As of June 30, 2015	As of December 31, 2014
	Millions	
Face Value of Outstanding Guarantees	$ 1,775	$ 1,814
Exposure under Current Guarantees	$ 196	$ 273
Letters of Credit Margin Posted	$ 161	$ 159
Letters of Credit Margin Received	$ 74	$ 40
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (9)	$ (13)
Net Broker Balance Deposited (Received)	$ 42	$ 115
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that could be Required	$ 907	$ 945
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,494	$ 3,495
Additional Amounts Posted:		
Other Letters of Credit	$ 45	$ 45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P, Moody's and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG had also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline and a $23 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

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Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA further determined that there was a need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G. This agreement and the work undertaken pursuant to the action agreement will not affect the ultimate remedy that the EPA will select for the remediation of the 17-mile stretch of the lower Passaic River.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than in respect of their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSEG's share of the cost of that effort is approximately three percent. The remaining CPG members have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS sets forth various alternatives for remediating this portion of the Passaic River. The EPA's estimated costs to remediate the lower eight miles of the Passaic River range from $365 million for a targeted remedy to $3.25 billion for a deep dredge of this portion of the Passaic River. The EPA also identified in the revised draft FFS its preferred alternative, which would involve dredging the river bank to bank and installing an engineered cap. The estimated cost in the revised draft FFS for its preferred alternative is $1.7 billion. No provisional cost allocation has been made by the CPG for the work contemplated by the revised draft FFS, and the work contemplated by the revised draft FFS is not subject to the CPG's cost sharing allocation agreed to in connection with the removal work for River Mile 10.9 or in connection with the conduct of the RI/FS.

The revised draft FFS was subject to a public comment period, and remains subject to the EPA's response to comments submitted, a design phase and at least an estimated five years for completion of the work. The public comment period on the revised draft FFS closed on August 21, 2014. Over 300 comments were submitted by a variety of entities potentially impacted by the revised draft FFS, including the CPG, individual companies, municipalities, public officials, citizens groups, Amtrak, NJ Transit and others.

The CPG, which consisted of 61 members as of June 30, 2015, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost of the RI/FS is approximately $150 million, which the CPG continues to incur. Of the estimated $150 million, as of June 30, 2015, the CPG had spent approximately $132 million, of which PSEG's total share was approximately $9 million.

The draft FS sets forth various alternatives for remediating that portion of the Passaic River. The draft FS sets forth the CPG's estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranges from approximately $518 million to $772 million. No provisional cost allocation has been made by the CPG for the work contemplated by the draft FS. However, based on (i) the low end of the range of the

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current estimates of costs to remediate, (ii) PSE&G's and Power's estimates of their share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

The EPA will consider the comments received on its revised draft FFS and will consider the CPG's RI/FS prior to issuing a Record of Decision (ROD) of a selected remedy for the Passaic River. The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS is finalized, (ii) a final remedy is determined by the EPA or through litigation, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on our financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $445 million and $517 million through 2021, including its $10 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $445 million as of June 30, 2015. Of this amount, $84 million was recorded in Other Current Liabilities and $361 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $445 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

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Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The New Jersey Department of Environmental Protection (NJDEP) manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. On June 30, 2015, the NJDEP issued a draft Salem permit. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The draft permit is subject to a public notice and comment period after which the NJDEP may make revisions before issuing the final permit expected during the first half of 2016.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. On August 15, 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. On September 5, 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Second Circuit Court of Appeals. In two related actions on October 17, 2014 and November 20, 2014, several environmental non-governmental groups initiated challenges to the endangered species act provisions of the 316 (b) rule. Power is unable to determine the ultimate impact of these actions on the implementation of the rule.

State permitting decisions could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would have been approximately $575 million. The filing has not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the Connecticut Department of Energy and Environmental Protection of the

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issues and has taken actions to investigate and resolve the potential non-compliance. At this early stage Power cannot predict the impact of this matter.

Coal Combustion Residuals (CCRs)

On December 19, 2014, the EPA issued a final rule which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Power's Hudson and Mercer generating stations, along with its co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 14, 2015. Accordingly in June 2015, Power recorded an additional asset retirement obligation to comply with the final CCR rule which was not material to Power's results of operations, financial condition or cash flows.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, are residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category are larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2015 is $272.78 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2015 of $282.04 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2012	2013	2014	2015	
36-Month Terms Ending	May 2015	May 2016	May 2017	May 2018	(A)
Load (MW)	2,900	2,800	2,800	2,900	
$ per MWh	$83.88	$92.18	$97.39	$99.54	

(A) Prices set for the 2015 BGS auction year became effective on June 1, 2015 when the 2012 BGS auction agreements expired.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 17. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium,

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enrichment and fabrication requirements through 2017 and a significant portion through 2020 at Salem, Hope Creek and Peach Bottom.

Power has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations.

Power also has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available, Power can use the gas to supply its fossil generating stations.

As of June 30, 2015, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2019
	Millions
Nuclear Fuel	
Uranium	$ 443
Enrichment	$ 342
Fabrication	$ 185
Natural Gas	$ 1,072
Coal	$ 360

Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed the FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors and modified the bid quantities for its peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future. On September 2, 2014, the FERC Staff initiated a preliminary, non-public staff investigation into the matter. This investigation, which is ongoing, could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies.

During the three months ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. It is not possible at this time to reasonably estimate the potential range of loss or full impact or predict any resulting penalties or other costs associated with this matter, or the applicability of mitigating factors. As new information becomes available or future developments occur in this investigation, it is possible that Power will record additional estimated losses and such additional losses may be material.

New Jersey Clean Energy Program

In June 2015, the BPU established the funding level for fiscal year 2016 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2016 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a current liability of $200 million and a noncurrent liability of $27 million as of June 30, 2015 for its outstanding share of the fiscal year 2016 and remaining fiscal year 2015 funding, respectively. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's T&D system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. In June 2013, PSEG,

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PSE&G and Power filed suit in New Jersey state court (NJ Court) against its insurance carriers seeking an interpretation that the insurance policies cover their losses resulting from damage caused by Superstorm Sandy's storm surge.

As of December 31, 2012, PSE&G had incurred approximately $295 million of costs to restore service to PSE&G's distribution and transmission systems and $5 million to repair its infrastructure and return it to pre-storm conditions. Of the costs incurred, approximately $40 million was recognized in O&M Expense, $75 million was recorded as Property, Plant and Equipment and $180 million was recorded as a Regulatory Asset because such costs were deferred as approved by the BPU under an Order received in December 2012. Of the $295 million, $36 million related to insured property. In 2012, PSE&G recognized $6 million of insurance recoveries, which were deferred. There were no significant additional costs incurred since 2012.

PSE&G made a filing with the BPU to review the prudency of unreimbursed incremental storm restoration costs, including O&M and capital expenditures associated with Superstorm Sandy and certain other extreme weather events, for recovery in its next base rate case or sooner through a BPU-approved cost recovery mechanism. In September 2014, the BPU approved its filing.

Power had incurred a total of $193 million of storm-related costs from 2012 through 2014, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized primarily in O&M Expense, offset by $44 million of insurance recoveries in 2013 and 2012. Power incurred an additional $2 million of storm-related costs in 2015 which were recognized primarily in O&M Expense.

In the first half of 2015, PSEG reached settlements with its insurers with respect to claims for coverage of its Superstorm Sandy-related losses. PSEG received an additional $214 million under these settlements (consisting of $159 million and $55 million recognized in the three months ended March 31, 2015 and June 30, 2015, respectively), bringing cumulative insurance proceeds to $264 million. Of the $214 million recognized in 2015, PSE&G and Power recorded $35 million and $179 million, respectively. In addition to the $35 million recognized in 2015, PSE&G recognized the aforementioned $6 million of previously deferred insurance recoveries, resulting in reductions in Regulatory Assets of $20 million, O&M Expense of $10 million and Property, Plant and Equipment of $11 million. Power recorded reductions in both O&M Expense of $145 million and Property, Plant and Equipment of $6 million and an increase in Other Income of $28 million.

The claim filed by PSEG, PSE&G and Power related to Superstorm Sandy insurance coverage is now fully resolved.

Note 9. Changes in Capitalization

The following capital transactions occurred in the six months ended June 30, 2015:

PSE&G

- issued $350 million of 3.00% Secured Medium-Term Notes, Series K due May 2025,
- issued $250 million of 4.05% Secured Medium-Term Notes, Series K due May 2045,
- paid $300 million of 2.70% Secured Medium-Term Notes at maturity,
- paid $117 million of Transition Funding's securitization debt, and
- paid the final $8 million of Transition Funding II's securitization debt.

Power

- paid cash dividends of $400 million to PSEG.

Note 10. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available

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through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. Transactions receiving NPNS treatment are accounted for upon settlement. For a derivative instrument that qualifies and is designated as a cash flow hedge, the changes in the fair value of such a derivative that are highly effective are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. For a derivative instrument that qualifies and is designated as a fair value hedge, the gains or losses on the derivative as well as the offsetting losses or gains on the hedged item attributable to the hedged risk are recognized in earnings each period. Power and PSE&G enter into additional contracts that are derivatives, but do not qualify for or are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and changes in the fair value of these contracts are recorded in earnings each period.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

PSEG and Power use forward sale and purchase contracts, swaps and futures contracts to hedge certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G. These derivative transactions qualify and are designated as cash flow hedges.

As of June 30, 2015 and December 31, 2014, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity were as follows:

	As of June 30, 2015	As of December 31, 2014
	Millions	
Fair Value of Cash Flow Hedges	$ 1	$ 18
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 1	$ 10

The expiration date of the longest-dated cash flow hedge at Power is in December 2015. Power's remaining $1 million of after-tax unrealized gains on these derivatives is expected to be reclassified to earnings during the next 12 months. There was no ineffectiveness associated with qualifying hedges as of June 30, 2015.

Economic Hedges

Power enters into derivative contracts that do not qualify or are not designated as either cash flow or fair value hedges. Power enters into financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. These transactions are economic hedges, intended to mitigate exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of these contracts are recorded in earnings. PSE&G is a party to certain long-term natural gas sales derivative contracts to optimize its pipeline capacity utilization. Changes in the fair market value of these contracts are recorded in Regulatory Assets and Regulatory Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

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Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of June 30, 2015, PSEG had interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of June 30, 2015 and December 31, 2014, the fair value of all the underlying hedges was $15 million and $22 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was immaterial as of June 30, 2015 and December 31, 2014, respectively.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset on the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG.

The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of June 30, 2015						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 1	$ 483	$ (345)	$ 139	$ 5	$ 11	$ 155
Noncurrent Assets	—	220	(117)	103	—	4	107
Total Mark-to-Market Derivative Assets	**$ 1**	**$ 703**	**$ (462)**	**$ 242**	**$ 5**	**$ 15**	**$ 262**
Derivative Contracts							
Current Liabilities	$ —	$ (421)	$ 349	$ (72)	$ —	$ —	$ (72)
Noncurrent Liabilities	—	(145)	121	(24)	—	—	(24)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (566)**	**$ 470**	**$ (96)**	**$ —**	**$ —**	**$ (96)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 1**	**$ 137**	**$ 8**	**$ 146**	**$ 5**	**$ 15**	**$ 166**

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	As of December 31, 2014						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 18	$ 597	$ (408)	$ 207	$ 18	$ 15	$ 240
Noncurrent Assets	—	171	(109)	62	8	7	77
Total Mark-to-Market Derivative Assets	**$ 18**	**$ 768**	**$ (517)**	**$ 269**	**$ 26**	**$ 22**	**$ 317**
Derivative Contracts							
Current Liabilities	$ —	$ (568)	$ 436	$ (132)	$ —	$ —	$ (132)
Noncurrent Liabilities	—	(138)	105	(33)	—	—	(33)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (706)**	**$ 541**	**$ (165)**	**$ —**	**$ —**	**$ (165)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 18**	**$ 62**	**$ 24**	**$ 104**	**$ 26**	**$ 22**	**$ 152**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of June 30, 2015 and December 31, 2014. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of June 30, 2015 and December 31, 2014, net cash collateral (received) paid of $8 million and $24 million, respectively, were netted against the corresponding net derivative contract positions. Of the $8 million as of June 30, 2015, $(4) million and $(4) million of cash collateral were netted against current assets and noncurrent assets, respectively, and $7 million and $9 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $24 million as of December 31, 2014, $(4) million and $(8) million were netted against current assets and noncurrent assets, respectively, and $32 million and $4 million were netted against current liabilities and noncurrent liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $82 million and $127 million as of June 30, 2015 and December 31, 2014, respectively. As of June 30, 2015 and December 31, 2014, Power had the contractual right of offset of $18 million related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $64 million and $109 million as of June 30, 2015 and December 31, 2014, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This

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potential additional collateral is included in the $907 million and $945 million as of June 30, 2015 and December 31, 2014, respectively, discussed in Note 8. Commitments and Contingent Liabilities.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended June 30, 2015 and 2014.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended June 30,		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended June 30,		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Three Months Ended June 30,	
	2015	2014		2015	2014		2015	2014
	Millions							
PSEG								
Energy-Related Contracts	$ —	$ 1	Operating Revenues	$ —	$ —	Operating Revenues	$ —	$ —
Total PSEG	**$ —**	**$ 1**		**$ —**	**$ —**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ —	$ 1	Operating Revenues	$ —	$ —	Operating Revenues	$ —	$ —
Total Power	**$ —**	**$ 1**		**$ —**	**$ —**		**$ —**	**$ —**

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the six months ended June 30, 2015 and 2014.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Six Months Ended June 30,		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Six Months Ended June 30,		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Six Months Ended June 30,	
	2015	2014		2015	2014		2015	2014
	Millions							
PSEG								
Energy-Related Contracts	$ 1	$ (7)	Operating Revenues	$ 17	$ (12)	Operating Revenues	$ —	$ —
Total PSEG	**$ 1**	**$ (7)**		**$ 17**	**$ (12)**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ 1	$ (7)	Operating Revenues	$ 17	$ (12)	Operating Revenues	$ —	$ —
Total Power	**$ 1**	**$ (7)**		**$ 17**	**$ (12)**		**$ —**	**$ —**

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The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2014	**$ 17**	**$ 10**
Gain Recognized in AOCI	1	1
Less: Gain Reclassified into Income	(17)	(10)
Balance as of March 31, 2015	**$ 1**	**$ 1**
Gain Recognized in AOCI	—	—
Less: Gain Reclassified into Income	—	—
Balance as of June 30, 2015	**$ 1**	**$ 1**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the three months and six months ended June 30, 2015 and 2014.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2015	2014	2015	2014
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ 124	$ (58)	$ 48	$ (852)
Energy-Related Contracts	Energy Costs	(10)	(36)	—	77
Total PSEG and Power		**$ 114**	**$ (94)**	**$ 48**	**$ (775)**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the NPNS exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $5 million for each of the three months and $10 million for each of the six months ended June 30, 2015 and 2014, respectively.

The following reflects the gross volume, on an absolute value basis, of derivatives as of June 30, 2015 and December 31, 2014.

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of June 30, 2015					
Natural Gas	Dth	259	—	214	45
Electricity	MWh	299	—	299	—
Financial Transmission Rights (FTRs)	MWh	30	—	30	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2014					
Natural Gas	Dth	274	—	216	58
Electricity	MWh	310	—	310	—
FTRs	MWh	15	—	15	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—

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Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of June 30, 2015, 99.3% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of June 30, 2015. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 310	$ 82	$ 302	2	$ 119	(A)
Non-Investment Grade—External Rating	2	—	2	—	—	
Investment Grade—No External Rating	10	—	10	—	—	
Non-Investment Grade—No External Rating	—	—	—	—	—	
Total	**$ 322**	**$ 82**	**$ 314**	**2**	**$ 119**	

(A) Represents net exposure of $82 million with PSE&G. The remaining net exposure of $37 million is with a non- affiliated power purchaser which is an investment grade counterparty.

The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of June 30, 2015, Power had 138 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of June 30, 2015, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's suppliers' credit exposure is calculated each business day. As of June 30, 2015, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 11. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of June 30, 2015, these consisted primarily of long-term gas supply contracts and certain electric load contracts.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of June 30, 2015 and December 31, 2014, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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Description	Recurring Fair Value Measurements as of June 30, 2015				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 547	$ —	$ 547	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 247	$ (462)	$ —	$ 701	$ 8
Interest Rate Swaps (C)	$ 15	$ —	$ —	$ 15	$ —
NDT Fund (D)					
Equity Securities	$ 921	$ —	$ 920	$ 1	$ —
Debt Securities—Govt Obligations	$ 455	$ —	$ —	$ 455	$ —
Debt Securities—Other	$ 386	$ —	$ —	$ 386	$ —
Other Securities	$ 30	$ —	$ 30	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—Govt Obligations	$ 100	$ —	$ —	$ 100	$ —
Debt Securities—Other	$ 90	$ —	$ —	$ 90	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (96)	$ 470	$ —	$ (566)	$ —
PSE&G					
Assets:					
Cash Equivalents (A)	$ 151	$ —	$ 151	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 5	$ —	$ —	$ —	$ 5
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 4	$ —	$ 4	$ —	$ —
Debt Securities—Govt Obligations	$ 20	$ —	$ —	$ 20	$ —
Debt Securities—Other	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 242	$ (462)	$ —	$ 701	$ 3
NDT Fund (D)					
Equity Securities	$ 921	$ —	$ 920	$ 1	$ —
Debt Securities—Govt Obligations	$ 455	$ —	$ —	$ 455	$ —
Debt Securities—Other	$ 386	$ —	$ —	$ 386	$ —
Other Securities	$ 30	$ —	$ 30	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 25	$ —	$ —	$ 25	$ —
Debt Securities—Other	$ 22	$ —	$ —	$ 22	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (96)	$ 470	$ —	$ (566)	$ —

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Description	Recurring Fair Value Measurements as of December 31, 2014				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 295	$ (517)	$ —	$ 774	$ 38
Interest Rate Swaps (C)	$ 22	$ —	$ —	$ 22	$ —
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 896	$ 1	$ —
Debt Securities—Govt Obligations	$ 438	$ —	$ —	$ 438	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 106	$ —	$ 106	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—Govt Obligations	$ 91	$ —	$ —	$ 91	$ —
Debt Securities—Other	$ 75	$ —	$ —	$ 75	$ —
Other Securities	$ 2	$ —	$ —	$ 2	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (165)	$ 541	$ —	$ (705)	$ (1)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 294	$ —	$ 294	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ 26	$ —	$ —	$ —	$ 26
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 20	$ —	$ —	$ 20	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 269	$ (517)	$ —	$ 774	$ 12
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 896	$ 1	$ —
Debt Securities—Govt Obligations	$ 438	$ —	$ —	$ 438	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 106	$ —	$ 106	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (165)	$ 541	$ —	$ (705)	$ (1)

(A) Represents money market mutual funds

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(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded

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capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds, collateralized mortgage obligations, asset backed securities and government obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of June 30, 2015, net cash collateral (received) paid of $8 million, was netted against the corresponding net derivative contract positions. Of the $8 million as of June 30, 2015, $(8) million of cash collateral was netted against assets, and $16 million was netted against liabilities. As of December 31, 2014, net cash collateral (received) paid of $24 million, was netted against the corresponding net derivative contract positions. Of the $24 million as of December 31, 2014, $(12) million of cash collateral was netted against assets, and $36 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G and Power, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in

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which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. The following tables provide details surrounding significant Level 3 valuations as of June 30, 2015 and December 31, 2014.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of June 30, 2015 Assets	Fair Value as of June 30, 2015 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$ 5	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 5**	**$ —**			
Power						
Electricity	Electric Load Contracts	$ 3	$ —	Discounted Cash flow	Historic Load Variability	0% to +10%
Other	Various (A)	—	—			
Total Power		**$ 3**	**$ —**			
Total PSEG		**$ 8**	**$ —**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2014 Assets	Fair Value as of December 31, 2014 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$ 26	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 26**	**$ —**			
Power						
Electricity	Electric Load Contracts	$ 12	$ (1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Other	Various (B)	—	—			
Total Power		**$ 12**	**$ (1)**			
Total PSEG		**$ 38**	**$ (1)**			

(A) Includes long-term electric positions which were immaterial as of June 30, 2015.

(B) Includes gas supply positions and long-term electric capacity positions which were immaterial as of December 31, 2014.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value. For energy-related contracts in cases where Power is a seller, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and six months ended June 30, 2015 and June 30, 2014, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Six Months Ended June 30, 2015

	Three Months Ended June 30, 2015						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2015	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of June 30, 2015
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 9	$ 5	$ (2)	$ —	$ (4)	$ —	$ 8
PSE&G							
Net Derivative Assets (Liabilities)	$ 7	$ —	$ (2)	$ —	$ —	$ —	$ 5
Power							
Net Derivative Assets (Liabilities)	$ 2	$ 5	$ —	$ —	$ (4)	$ —	$ 3

	Six Months Ended June 30, 2015						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2015	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of June 30, 2015
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 37	$ 8	$ (21)	$ —	$ (16)	$ —	$ 8
PSE&G							
Net Derivative Assets (Liabilities)	$ 26	$ —	$ (21)	$ —	$ —	$ —	$ 5
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 8	$ —	$ —	$ (16)	$ —	$ 3

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Six Months Ended June 30, 2014

	Three Months Ended June 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2014	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2014
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 1	$ 6	$ 10	$ —	$ (1)	$ (3)	$ 13
PSE&G							
Net Derivative Assets (Liabilities)	$ 12	$ —	$ 10	$ —	$ —	$ —	$ 22
Power							
Net Derivative Assets (Liabilities)	$ (11)	$ 6	$ —	$ —	$ (1)	$ (3)	$ (9)

	Six Months Ended June 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2014	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2014
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 88	$ (58)	$ (72)	$ —	$ 58	$ (3)	$ 13
PSE&G							
Net Derivative Assets (Liabilities)	$ 94	$ —	$ (72)	$ —	$ —	$ —	$ 22
Power							
Net Derivative Assets (Liabilities)	$ (6)	$ (58)	$ —	$ —	$ 58	$ (3)	$ (9)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities includes $5 million and $8 million in Operating Income for the three months and six months ended June 30, 2015, respectively. The $5 million in Operating Income is realized. Of the $8 million in Operating Income, $(9) million is unrealized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $(4) million and $(16) million in settlements for the three months and six months ended June 30, 2015. Includes $(1) million and $58 million in settlements for the three months and six months ended June 30, 2014.

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(D) During the three months and six months ended June 30, 2014, $(3) million of net derivative assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. The transfers were recognized as of the beginning of the quarters in which the transfers first occurred as per PSEG's policy.

(E) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $6 million and $(58) million in Operating Income for the three months and six months ended June 30, 2014, respectively. The $6 million in Operating Income is unrealized. Of the $(58) million in Operating Income, $1 million is unrealized.

As of June 30, 2015, PSEG carried $2.7 billion of net assets that are measured at fair value on a recurring basis, of which $8 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of June 30, 2014, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $13 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of June 30, 2015 and December 31, 2014.

	As of June 30, 2015		As of December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 9	$ 15	$ 14	$ 22
PSE&G (B)	6,611	6,899	6,312	6,912
Transition Funding (PSE&G) (B)	134	137	251	261
Transition Funding II (PSE&G) (B)	—	—	8	8
Power -Recourse Debt (B)	2,544	2,885	2,543	2,930
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	16	16	16	16
Total Long-Term Debt	**$ 9,314**	**$ 9,952**	**$ 9,144**	**$ 10,149**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 12. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended June 30, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 25	$ —	$ 25
Allowance for Funds Used During Construction	12	—	—	12
Solar Loan Interest	6	—	—	6
Gain on Insurance Recovery	—	28	—	28
Other	1	2	2	5
Total Other Income	**$ 19**	**$ 55**	**$ 2**	**$ 76**
Six Months Ended June 30, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 54	$ —	$ 54
Allowance for Funds Used During Construction	22	—	—	22
Solar Loan Interest	12	—	—	12
Gain on Insurance Recovery	—	28	—	28
Other	3	2	3	8
Total Other Income	**$ 37**	**$ 84**	**$ 3**	**$ 124**
Three Months Ended June 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 46	$ —	$ 46
Allowance for Funds Used During Construction	7	—	—	7
Solar Loan Interest	6	—	—	6
Other	1	—	2	3
Total Other Income	**$ 14**	**$ 46**	**$ 2**	**$ 62**
Six Months Ended June 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 78	$ —	$ 78
Allowance for Funds Used During Construction	13	—	—	13
Solar Loan Interest	12	—	—	12
Other	3	1	3	7
Total Other Income	**$ 28**	**$ 79**	**$ 3**	**$ 110**

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Other Deductions	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended June 30, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 6	$ —	$ 6
Other	1	1	2	4
Total Other Deductions	**$ 1**	**$ 7**	**$ 2**	**$ 10**
Six Months Ended June 30, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 17	$ —	$ 17
Other	2	1	2	5
Total Other Deductions	**$ 2**	**$ 18**	**$ 2**	**$ 22**
Three Months Ended June 30, 2014				
NDT Fund Realized Losses and Expenses	$ —	$ 8	$ —	$ 8
Other	1	1	—	2
Total Other Deductions	**$ 1**	**$ 9**	**$ —**	**$ 10**
Six Months Ended June 30, 2014				
NDT Fund Realized Losses and Expenses	$ —	$ 14	$ —	$ 14
Other	1	5	2	8
Total Other Deductions	**$ 1**	**$ 19**	**$ 2**	**$ 22**

(A) Other primarily consists of activity at PSEG (as parent company), Energy Holdings, Services and intercompany eliminations.

Note 13. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months and six months ended June 30, 2015 and 2014 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
PSEG	35.0%	34.8%	38.5%	38.4%
PSE&G	38.4%	36.5%	39.0%	38.6%
Power	30.3%	28.9%	37.9%	37.8%

An explanation of the material changes in the effective tax rates is as follows:

For the three months ended June 30, 2015, PSE&G's effective tax rate was lower than the statutory tax rate of 40.85% due primarily to the beneficial impact of plant related flow-through items.

For the three months ended June 30, 2015, Power's effective tax rate was lower than the statutory tax rate of 40.85% due primarily to the beneficial impact of the manufacturing deduction under Section 199 of the Internal Revenue Code (IRC) and the benefit associated with the income tax rate differential of carrying back federal net operating tax losses under section 172(f) of the IRC.

For the three months ended June 30, 2015, as compared to the same period in the prior year, PSE&G's increase was due primarily to the absence of the 2014 tax flow-through benefit associated with injuries and damages and an unfavorable increase in the flow-through of bad debt expense for 2015.

For the three months ended June 30, 2015, as compared to the same period in the prior year, Power's increase was due primarily to the net reduction in the manufacturing deduction under Section 199 of the Internal Revenue Code and a reduction in purchased state income tax credits, partially offset by the tax benefit associated with the income tax rate differential of carrying back federal net operating tax losses under section 172(f) of the IRC.

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Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended June 30, 2015			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2015	$ 1	$ (403)	$ 132	$ (270)
Other Comprehensive Income before Reclassifications	—	—	(14)	(14)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	8	(1)	7
Net Current Period Other Comprehensive Income (Loss)	—	8	(15)	(7)
Balance as of June 30, 2015	**$ 1**	**$ (395)**	**$ 117**	**$ (277)**

PSEG	Other Comprehensive Income (Loss) Three Months Ended June 30, 2014			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2014	$ —	$ (234)	$ 147	$ (87)
Other Comprehensive Income before Reclassifications	1	—	23	24
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	2	(12)	(10)
Net Current Period Other Comprehensive Income (Loss)	1	2	11	14
Balance as of June 30, 2014	**$ 1**	**$ (232)**	**$ 158**	**$ (73)**

PSEG	Other Comprehensive Income (Loss) Six Months Ended June 30, 2015			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2014	$ 10	$ (411)	$ 118	$ (283)
Other Comprehensive Income before Reclassifications	1	—	2	3
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	16	(3)	3
Net Current Period Other Comprehensive Income (Loss)	(9)	16	(1)	6
Balance as of June 30, 2015	**$ 1**	**$ (395)**	**$ 117**	**$ (277)**

PSEG	Other Comprehensive Income (Loss) Six Months Ended June 30, 2014			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2013	$ (2)	$ (238)	$ 145	$ (95)
Other Comprehensive Income before Reclassifications	(4)	—	34	30
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	7	6	(21)	(8)
Net Current Period Other Comprehensive Income (Loss)	3	6	13	22
Balance as of June 30, 2014	**$ 1**	**$ (232)**	**$ 158**	**$ (73)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2015			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of March 31, 2015	$ 2	$ (344)	$ 126	$ (216)
Other Comprehensive Income before Reclassifications	—	—	(14)	(14)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	—	7
Net Current Period Other Comprehensive Income (Loss)	—	7	(14)	(7)
Balance as of June 30, 2015	**$ 2**	**$ (337)**	**$ 112**	**$ (223)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of March 31, 2014	$ —	$ (201)	$ 144	$ (57)
Other Comprehensive Income before Reclassifications	2	—	21	23
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	2	(12)	(10)
Net Current Period Other Comprehensive Income (Loss)	2	2	9	13
Balance as of June 30, 2014	**$ 2**	**$ (199)**	**$ 153**	**$ (44)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2015			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2014	$ 11	$ (351)	$ 112	$ (228)
Other Comprehensive Income before Reclassifications	1	—	2	3
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	14	(2)	2
Net Current Period Other Comprehensive Income (Loss)	(9)	14	—	5
Balance as of June 30, 2015	**$ 2**	**$ (337)**	**$ 112**	**$ (223)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2013	$ (1)	$ (204)	$ 142	$ (63)
Other Comprehensive Income before Reclassifications	(4)	—	31	27
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	7	5	(20)	(8)
Net Current Period Other Comprehensive Income (Loss)	3	5	11	19
Balance as of June 30, 2014	**$ 2**	**$ (199)**	**$ 153**	**$ (44)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2015			Six Months Ended June 30, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		—	—	—	17	(7)	10
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	6	(2)	4
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)	(34)	14	(20)
Total Pension and OPEB Plans		(14)	6	(8)	(28)	12	(16)
Available-for-Sale Securities							
Realized Gains	Other Income	16	(8)	8	35	(18)	17
Realized Losses	Other Deductions	(4)	2	(2)	(13)	7	(6)
Other-Than-Temporary Impairments (OTTI)	OTTI	(10)	5	(5)	(15)	7	(8)
Total Available-for-Sale Securities		2	(1)	1	7	(4)	3
Total		**$ (12)**	**$ 5**	**$ (7)**	**$ (4)**	**$ 1**	**$ (3)**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2014			Six Months Ended June 30, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ (12)	$ 5	$ (7)
Total Cash Flow Hedges		—	—	—	(12)	5	(7)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	5	(2)	3
Amortization of Actuarial Loss	O&M Expense	(6)	2	(4)	(14)	5	(9)
Total Pension and OPEB Plans		(3)	1	(2)	(9)	3	(6)
Available-for-Sale Securities							
Realized Gains	Other Income	33	(17)	16	58	(30)	28
Realized Losses	Other Deductions	(6)	3	(3)	(10)	5	(5)
OTTI	OTTI	(2)	1	(1)	(4)	2	(2)
Total Available-for-Sale Securities		25	(13)	12	44	(23)	21
Total		**$ 22**	**$ (12)**	**$ 10**	**$ 23**	**$ (15)**	**$ 8**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2015			Six Months Ended June 30, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		—	—	—	17	(7)	10
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	6	(2)	4
Amortization of Actuarial Loss	O&M Expense	(15)	6	(9)	(30)	12	(18)
Total Pension and OPEB Plans		(12)	5	(7)	(24)	10	(14)
Available-for-Sale Securities							
Realized Gains	Other Income	14	(7)	7	33	(17)	16
Realized Losses	Other Deductions	(4)	2	(2)	(13)	7	(6)
OTTI	OTTI	(10)	5	(5)	(15)	7	(8)
Total Available-for-Sale Securities		—	—	—	5	(3)	2
Total		**$ (12)**	**$ 5**	**$ (7)**	**$ (2)**	**$ —**	**$ (2)**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2014			Six Months Ended June 30, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ (12)	$ 5	$ (7)
Total Cash Flow Hedges		—	—	—	(12)	5	(7)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	2	(1)	1	4	(2)	2
Amortization of Actuarial Loss	O&M Expense	(6)	3	(3)	(12)	5	(7)
Total Pension and OPEB Plans		(4)	2	(2)	(8)	3	(5)
Available-for-Sale Securities							
Realized Gains	Other Income	33	(17)	16	56	(29)	27
Realized Losses	Other Deductions	(6)	3	(3)	(10)	5	(5)
OTTI	OTTI	(2)	1	(1)	(4)	2	(2)
Total Available-for-Sale Securities		25	(13)	12	42	(22)	20
Total		**$ 21**	**$ (11)**	**$ 10**	**$ 22**	**$ (14)**	**$ 8**

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Note 15. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under our stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015		2014		2015		2014	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)								
Net Income	**$ 345**	**$ 345**	**$ 212**	**$ 212**	**$ 931**	**$ 931**	**$ 598**	**$ 598**
EPS Denominator (Millions)								
Weighted Average Common Shares Outstanding	506	506	506	506	506	506	506	506
Effect of Stock Based Compensation Awards	—	2	—	2	—	2	—	2
Total Shares	**506**	**508**	**506**	**508**	**506**	**508**	**506**	**508**
EPS								
Net Income	**$ 0.68**	**$ 0.68**	**$ 0.42**	**$ 0.42**	**$ 1.84**	**$ 1.83**	**$ 1.18**	**$ 1.18**

	Three Months Ended June 30,		Six Months Ended June 30,	
Dividend Payments on Common Stock	**2015**	**2014**	**2015**	**2014**
Per Share	$ 0.39	$ 0.37	$ 0.78	$ 0.74
In Millions	$ 197	$ 187	$ 394	$ 374

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Note 16. Financial Information by Business Segments

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated
			Millions		
Three Months Ended June 30, 2015					
Total Operating Revenues	$ 1,466	$ 1,025	$ 108	$ (285)	$ 2,314
Net Income (Loss)	167	166	12	—	345
Gross Additions to Long-Lived Assets	631	348	17	—	996
Six Months Ended June 30, 2015					
Total Operating Revenues	$ 3,468	$ 2,750	$ 206	$ (975)	$ 5,449
Net Income (Loss)	409	501	21	—	931
Gross Additions to Long-Lived Assets	1,230	487	26	—	1,743
Three Months Ended June 30, 2014					
Total Operating Revenues	$ 1,435	$ 986	$ 131	$ (303)	$ 2,249
Net Income (Loss)	151	54	7	—	212
Gross Additions to Long-Lived Assets	515	100	5	—	620
Six Months Ended June 30, 2014					
Total Operating Revenues	$ 3,580	$ 2,686	$ 236	$ (1,030)	$ 5,472
Net Income (Loss)	365	218	15	—	598
Gross Additions to Long-Lived Assets	996	226	7	—	1,229
As of June 30, 2015					
Total Assets	$ 22,721	$ 12,166	$ 3,017	$ (1,692)	$ 36,212
Investments in Equity Method Subsidiaries	$ —	$ 116	$ 2	$ —	$ 118
As of December 31, 2014					
Total Assets	$ 22,223	$ 12,046	$ 2,799	$ (1,735)	$ 35,333
Investments in Equity Method Subsidiaries	$ —	$ 121	$ 2	$ —	$ 123

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations, primarily related to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 17. Related-Party Transactions.

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Note 17. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	Millions			
Billings from Affiliates:				
Billings from Power primarily through BGS and BGSS (A)	$ 297	$ 297	$ 993	$ 1,028
Administrative Billings from Services (B)	65	64	131	124
Total Billings from Affiliates	**$ 362**	**$ 361**	**$ 1,124**	**$ 1,152**

Related-Party Transactions	As of June 30, 2015	As of December 31, 2014
	Millions	
Receivable from PSEG (C)	**$ 52**	**$ 274**
Payable to Power (A)	$ 158	$ 313
Payable to Services (B)	57	66
Accounts Payable—Affiliated Companies	**$ 215**	**$ 379**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 161**	**$ 116**

Power

The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	Millions			
Billings to Affiliates:				
Billings to PSE&G primarily through BGS and BGSS Contracts (A)	**$ 297**	**$ 297**	**$ 993**	**$ 1,028**
Billings from Affiliates:				
Administrative Billings from Services (B)	**$ 46**	**$ 46**	**$ 91**	**$ 88**

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Related-Party Transactions	As of June 30, 2015	As of December 31, 2014
	Millions	
Receivables from PSE&G (A)	**$ 158**	**$ 313**
Payable to Services (B)	$ 27	$ 23
Payable to PSEG (C)	101	95
Accounts Payable—Affiliated Companies	**$ 128**	**$ 118**
Short-Term Loan (to) from Affiliate (Demand Note (to) PSEG) (E)	**$ 950**	**$ 584**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 56**	**$ 41**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

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Note 18. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended June 30, 2015					
Operating Revenues	$ —	$ 1,012	$ 39	$ (26)	$ 1,025
Operating Expenses	(1)	787	37	(26)	797
Operating Income (Loss)	1	225	2	—	228
Equity Earnings (Losses) of Subsidiaries	186	(1)	5	(185)	5
Other Income	12	55	—	(12)	55
Other Deductions	(1)	(6)	—	—	(7)
Other-Than-Temporary Impairments	—	(10)	—	—	(10)
Interest Expense	(33)	(7)	(5)	12	(33)
Income Tax Benefit (Expense)	1	(73)	—	—	(72)
Net Income (Loss)	**$ 166**	**$ 183**	**$ 2**	**$ (185)**	**$ 166**
Comprehensive Income (Loss)	**$ 159**	**$ 169**	**$ 2**	**$ (171)**	**$ 159**
Six Months Ended June 30, 2015					
Operating Revenues	$ —	$ 2,727	$ 107	$ (84)	$ 2,750
Operating Expenses	4	1,918	100	(84)	1,938
Operating Income (Loss)	(4)	809	7	—	812
Equity Earnings (Losses) of Subsidiaries	535	(2)	8	(533)	8
Other Income	23	85	—	(24)	84
Other Deductions	(1)	(17)	—	—	(18)
Other-Than-Temporary Impairments	—	(15)	—	—	(15)
Interest Expense	(62)	(16)	(10)	24	(64)
Income Tax Benefit (Expense)	10	(315)	(1)	—	(306)
Net Income (Loss)	**$ 501**	**$ 529**	**$ 4**	**$ (533)**	**$ 501**
Comprehensive Income (Loss)	**$ 506**	**$ 520**	**$ 4**	**$ (524)**	**$ 506**
Six Months Ended June 30, 2015					
Net Cash Provided By (Used In) Operating Activities	$ 410	$ 1,508	$ 61	$ (687)	$ 1,292
Net Cash Provided By (Used In) Investing Activities	$ (480)	$ (963)	$ (210)	$ 766	$ (887)
Net Cash Provided By (Used In) Financing Activities	$ 70	$ (543)	$ 150	$ (79)	$ (402)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended June 30, 2014					
Operating Revenues	$ —	$ 972	$ 42	$ (28)	$ 986
Operating Expenses	5	903	40	(29)	919
Operating Income (Loss)	(5)	69	2	1	67
Equity Earnings (Losses) of Subsidiaries	57	(3)	3	(54)	3
Other Income	8	47	—	(9)	46
Other Deductions	—	(8)	—	(1)	(9)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(27)	(6)	(5)	9	(29)
Income Tax Benefit (Expense)	21	(43)	—	—	(22)
Net Income (Loss)	**$ 54**	**$ 54**	**$ —**	**$ (54)**	**$ 54**
Comprehensive Income (Loss)	**$ 67**	**$ 66**	**$ —**	**$ (66)**	**$ 67**
Six Months Ended June 30, 2014					
Operating Revenues	$ —	$ 2,656	$ 82	$ (52)	$ 2,686
Operating Expenses	9	2,307	74	(53)	2,337
Operating Income (Loss)	(9)	349	8	1	349
Equity Earnings (Losses) of Subsidiaries	234	(3)	7	(231)	7
Other Income	16	80	—	(17)	79
Other Deductions	(4)	(14)	—	(1)	(19)
Other-Than-Temporary Impairments	—	(4)	—	—	(4)
Interest Expense	(55)	(13)	(10)	17	(61)
Income Tax Benefit (Expense)	36	(168)	(1)	—	(133)
Net Income (Loss)	**$ 218**	**$ 227**	**$ 4**	**$ (231)**	**$ 218**
Comprehensive Income (Loss)	**$ 237**	**$ 242**	**$ 4**	**$ (246)**	**$ 237**
Six Months Ended June 30, 2014					
Net Cash Provided By (Used In) Operating Activities	$ 292	$ 950	$ 32	$ (460)	$ 814
Net Cash Provided By (Used In) Investing Activities	$ 138	$ (415)	$ (16)	$ 57	$ (236)
Net Cash Provided By (Used In) Financing Activities	$ (430)	$ (534)	$ (17)	$ 403	$ (578)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
As of June 30, 2015					
Current Assets	$ 4,613	$ 1,678	$ 136	$ (4,216)	$ 2,211
Property, Plant and Equipment, net	80	6,290	1,337	—	7,707
Investment in Subsidiaries	4,409	289	—	(4,698)	—
Noncurrent Assets	258	2,026	132	(168)	2,248
Total Assets	**$ 9,360**	**$ 10,283**	**$ 1,605**	**$ (9,082)**	**$ 12,166**
Current Liabilities	$ 987	$ 3,532	$ 774	$ (4,216)	$ 1,077
Noncurrent Liabilities	465	2,534	350	(168)	3,181
Long-Term Debt	2,244	—	—	—	2,244
Member's Equity	5,664	4,217	481	(4,698)	5,664
Total Liabilities and Member's Equity	**$ 9,360**	**$ 10,283**	**$ 1,605**	**$ (9,082)**	**$ 12,166**
As of December 31, 2014					
Current Assets	$ 4,263	$ 2,037	$ 150	$ (4,091)	$ 2,359
Property, Plant and Equipment, net	81	6,265	1,169	—	7,515
Investment in Subsidiaries	4,516	120	—	(4,636)	—
Noncurrent Assets	278	1,952	137	(195)	2,172
Total Assets	**$ 9,138**	**$ 10,374**	**$ 1,456**	**$ (8,922)**	**$ 12,046**
Current Liabilities	$ 883	$ 3,606	$ 786	$ (4,091)	$ 1,184
Noncurrent Liabilities	454	2,442	360	(195)	3,061
Long-Term Debt	2,243	—	—	—	2,243
Member's Equity	5,558	4,326	310	(4,636)	5,558
Total Liabilities and Member's Equity	**$ 9,138**	**$ 10,374**	**$ 1,456**	**$ (8,922)**	**$ 12,046**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G,** our public utility company which primarily provides electric transmission services and distribution of electric energy and natural gas, implements demand response and energy efficiency programs and invests in solar generation in New Jersey, and
- **Power,** our wholesale energy supply company that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business of our 2014 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2014 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2015 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2014 Form 10-K.

EXECUTIVE OVERVIEW OF 2015 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- Growing our utility operations through continued investment in T&D infrastructure projects with greater diversity of regulatory oversight, and
- Maintaining a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the three months and six months ended June 30, 2015 and 2014 are presented as follows:

Earnings	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	Millions			
PSE&G	$ 167	$ 151	$ 409	$ 365
Power (A)	166	54	501	218
Other (B)	12	7	21	15
PSEG Net Income	**$ 345**	**$ 212**	**$ 931**	**$ 598**
PSEG Net Income Per Share (Diluted)	**$ 0.68**	**$ 0.42**	**$ 1.83**	**$ 1.18**

(A) Includes an after-tax insurance recovery for Superstorm Sandy of $27 million and $102 million in the three months and six months ended June 30, 2015, respectively. See Note 8. Commitments and Contingent Liabilities.

(B) Other includes activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	Millions, after tax			
NDT Fund Income (Expense) (A)	$ 1	$ 14	$ 3	$ 23
Non-Trading MTM Gains (Losses)	$ 28	$ (42)	$ 8	$ (174)

(A) NDT Fund Income (Expense) includes the realized gains and losses, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense.

Our $133 million and $333 million increases in Net Income for the three months and six months ended June 30, 2015 were driven primarily by:

- MTM gains in 2015 as compared to MTM losses in 2014,
- lower generation costs due to lower fuel costs,
- higher revenues due to increased investments in transmission projects, and
- insurance recoveries of Superstorm Sandy costs, primarily at Power.

At PSE&G, our regulated utility, we continued to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers. Effective January 1, 2015, PSE&G's formula rate increased our annual transmission revenues by approximately $182 million. Each year, transmission revenues are filed based on estimated data and subject to true up with actual current year data. The true-up adjustment for 2015 will primarily include the impact on rate base due to the extension of bonus depreciation, which was enacted after the filing was made, and is estimated to reduce our 2015 annual revenue increase by approximately $21 million. Over the past few years, these types of investments have altered the business mix of our overall results of operations to reflect a higher percentage contribution by PSE&G.

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Power's results benefited from access to natural gas supplies through its existing firm pipeline transportation contracts during the cold weather experienced in the first quarter of 2015. Power manages these contracts for the benefit of PSE&G's customers through the basic gas supply service (BGSS) arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to make third party sales and supply gas to its generating units in New Jersey.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission Planning

The FERC's rule under Order 1000 altered the right of first refusal (ROFR) previously held by incumbent utilities to build transmission within their respective service territories, creating the potential that new transmission projects in our service territory could be assigned to third parties rather than PSE&G. Order 1000 also presents opportunities for us to construct transmission outside of our service territory. In April 2013, PJM Interconnection, L.L.C. (PJM) initiated a solicitation process in which we participated to review technical solutions to improve the operational performance in the Artificial Island area, consisting of our Salem and Hope Creek nuclear generation facilities. On April 28, 2015, the PJM staff advised stakeholders that it intended to recommend a transmission project that would primarily be awarded to another entity, but that a portion at an estimated construction cost of between $100 million and $130 million would be assigned to PSE&G. We subsequently filed comments with the PJM Board of Managers (PJM Board) identifying what we believed were deficiencies in the PJM staff recommendation. On July 29, 2015, the PJM Board approved the PJM staff's recommendation. See Part II. Item 5. Other Information—Transmission Regulation—Transmission Policy Developments for additional information.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. In May 2014, a federal court issued a rule that vacated a FERC Order in which the FERC had determined that demand response (DR) providers should receive full market compensation for power and held that the FERC has no jurisdiction over DR. The U.S. Supreme Court has accepted this case for review. The U.S. Supreme Court's decision could have a material impact on capacity market outcomes in which DR currently participates as a supply resource under FERC jurisdiction.

In a separate development of significance to the wholesale capacity market, in December 2014 PJM filed at the FERC its proposal for a capacity performance product to include generators, DR and energy efficiency providers who would need to certify their availability during emergency conditions, as a supplement to base capacity. The proposal includes enhanced performance-based incentives and penalties. On June 9, 2015, the FERC conditionally accepted the proposal. The capacity performance market design will be implemented for the 2015 base residual auction, which is scheduled to begin on August 10, 2015. It further provides generation owners with greater flexibility in submitting capacity market bids that reflect the additional costs and risks of the more rigorous performance requirements. See Part II, Item 5. Other Information—Capacity Market Issues—PJM for additional information.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. In particular, the EPA's 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. As adopted by the EPA, the rule requires that cooling water intake structures reflect the best technology available for minimizing environmental impacts. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. However, the EPA has structured the rule so that each state will continue to consider renewal permits for power facilities on a case by case basis. On June 30, 2015, the New Jersey Department of Environmental Protection (NJDEP) issued a draft New Jersey Pollutant Discharge Elimination Systems (NJPDES) permit governing cooling water intake structures for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The draft permit is subject to a public notice and comment period after which the NJDEP may make revisions before issuing the final permit expected during the first half of 2016. See Part II, Item 5. Other Information—Water Pollution Control—Cooling Water Intake Structure Regulation for further information.

The EPA's proposed greenhouse gas emissions regulations are also of potential consequence to our results. We continue to work with the FERC and other federal and state regulators, as well as industry partners, to determine the potential impact of these regulations. Clean Air Act (CAA) regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology rules are also of significance; however, we believe our generation business remains well-positioned for such air pollution control regulations if and when they are implemented. For additional information, see Part II, Item 5. Other

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Information—Air Pollution Control—Hazardous Air Pollutants Control. In addition, state environmental regulations governing emissions from power plants also have a significant impact on our operations. In the second quarter of 2015, we retired 1,545 MW of fully depreciated combustion turbine capacity that would not be able to comply with the more stringent emission standards for high electric demand day units (HEDD) under the New Jersey HEDD regulations for nitrous oxide, which will reduce capacity revenues for this year.

Other Developments

In the first half of 2015, we continued to make investments and seek recovery on such investments made to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the New Jersey Board of Public Utilities (BPU) in 2014. As approved, the Energy Strong program provides for $1.22 billion of investment, with cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated allowance for funds used during construction, through an accelerated recovery mechanism. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, which is to be filed no later than November 1, 2017.

In February 2015, we filed a petition with the BPU seeking approval of a Gas System Modernization Program (GSMP) through which we propose to invest approximately $1.6 billion over the next five years, or about $320 million per year, to modernize PSE&G's gas systems. The matter is pending.

In June 2015, we acquired a development project to construct a 755 MW gas-fired combined cycle generating station (Keys Energy Center) in Maryland with completion expected in 2018 at an estimated investment of $825 million - $875 million.

The preliminary non-public staff investigation initiated by the FERC into Power's discovery and investigation of (i) incorrect calculations for certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market and (ii) differences in the quantity of energy that Power offered into the energy market for its fossil peaking units from the amount for which Power was compensated in the capacity market for those units continues. Power has an ongoing process of implementing improved procedures to help mitigate the risk of similar issues occurring in the future. This investigation could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with this matter, or the applicability of mitigating factors. For more detailed information, refer to Item 1. Note 8. Commitments and Contingent Liabilities—FERC Compliance.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. In the first six months of 2015, our

- total nuclear fleet achieved an average capacity factor of 91%,
- nuclear output increased by 2.6% and combined cycle output by 20.8% as compared to the first half of 2014,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 28 TWh while addressing unit outages and balancing fuel availability and price volatility, and
- construction of transmission projects proceeded on schedule and within budget.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first six months of 2015 as we

- had cash flow from operations of $2.2 billion as of June 30, 2015,
- maintained solid investment grade credit ratings,
- extended the expiration dates for approximately $2.0 billion of five-year credit facilities for PSEG, PSE&G and Power from 2018 to 2020, and
- increased our indicated annual dividend for 2015 to $1.56 per share.

We expect to be able to fund our transmission projects required under PJM's reliability program, our Energy Strong program, Keys Energy Center and other planned projects, as well as our proposed GSMP, without the issuance of new equity.

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Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first six months of 2015, in addition to our acquisition of the Keys Energy Center, we

- made additional investments in transmission infrastructure projects,
- secured approval to extend three Energy Efficiency Economic Stimulus subprograms to allow for $95 million of additional capital expenditures and $12 million of additional administrative expenses to provide energy efficiency assistance to hospitals, healthcare facilities and residential multi-family housing units,
- continued to execute our existing BPU-approved utility programs,
- completed the power ascension for the extended power uprate at our co-owned Peach Bottom 2 nuclear station, and
- completed installation of equipment to increase output and improve efficiency at our Bergen 2 combined cycle gas unit similar to our 2014 installation at our Linden plant.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-moving economy and a cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions,
- execute our capital investment program, including our Energy Strong program, proposed GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction of our Keys Energy Center and other generation projects,
- advocate for measures to ensure the implementation by PJM and the FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

For 2015 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate, and
- delays and other obstacles that might arise in connection with the construction of our T&D and other development projects, including in connection with permitting and regulatory approvals.

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RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 17. Related-Party Transactions.

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,314	$ 2,249	$ 65	3	$ 5,449	$ 5,472	$ (23)	—
Energy Costs	668	789	(121)	(15)	1,762	2,145	(383)	(18)
Operation and Maintenance	761	800	(39)	(5)	1,424	1,656	(232)	(14)
Depreciation and Amortization	317	295	22	7	647	601	46	8
Income from Equity Method Investments	4	3	1	33	7	7	—	—
Other Income and (Deductions)	66	52	14	27	102	88	14	16
Other-Than-Temporary Impairments	10	2	8	N/A	15	4	11	N/A
Interest Expense	97	94	3	3	195	191	4	2
Income Tax Expense	186	112	74	66	584	372	212	57

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,466	$ 1,435	$ 31	2	$ 3,468	$ 3,580	$ (112)	(3)
Energy Costs	544	565	(21)	(4)	1,436	1,610	(174)	(11)
Operation and Maintenance	368	362	6	2	780	824	(44)	(5)
Depreciation and Amortization	234	217	17	8	481	444	37	8
Other Income (Deductions)	18	13	5	38	35	27	8	30
Interest Expense	67	67	—	—	136	135	1	1
Income Tax Expense	104	86	18	21	261	229	32	14

Three Months Ended June 30, 2015 as Compared to 2014

Operating Revenues increased $31 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $69 million due primarily to an increase in transmission revenues.

- Transmission revenues were $49 million higher due to net rate increases resulting primarily from increased capital investments.
- Electric distribution revenues increased $13 million due primarily to higher sales volumes of $9 million and higher CIP II related revenues of $3 million due to the inclusion in base rates beginning in July 2014.

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- Gas distribution revenues increased $7 million due primarily to higher Weather Normalization Clause (WNC) revenue of $6 million as a result of warmer than normal weather in the second quarter of 2015.

Commodity Revenue decreased $21 million as a result of lower Gas revenues partially offset by higher Electric revenues. Commodity revenue for both electric and gas is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of basic generation service (BGS) and BGSS to retail customers.

- Gas revenues decreased $51 million due primarily to lower BGSS prices.
- Electric revenues increased $30 million due primarily to a $41 million or 11% increase in BGS revenues due to higher sales volumes. This increase was partially offset by an $11 million reduction in revenues due to lower collections of Non-Utility Generation Charges (NGC) and lower volumes of Non-Utility Generation (NUG) energy sold at lower prices.

Clause Revenues decreased $18 million due primarily to lower Societal Benefit Charges (SBC) of $12 million, lower Margin Adjustment Clause (MAC) revenue of $6 million and lower Solar Pilot Recovery Charges (SPRC) of $2 million, partially offset by higher Securitization Transition Charges (STC) of $2 million. The changes in the SBC, MAC, SPRC and STC amounts were entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, MAC, SPRC or STC collections.

Other Operating Revenues experienced no material change.

Operating Expenses

Energy Costs decreased $21 million due to lower Gas costs partially offset by higher Electric costs. This is entirely offset by decreased Commodity Revenue.

- Gas costs decreased $51 million or 34% due to lower prices.
- Electric costs increased by $30 million or 7% due to $11 million of higher BGS and NUG prices and $37 million in higher BGS volumes. BGS volumes increased 10% due primarily to reverse customer migration. These increases were partially offset by $14 million of lower NUG volumes and $4 million of decreased deferred cost recovery.

Operation and Maintenance increased $6 million, of which the most significant components were

- a $9 million increase in pension and OPEB expenses,
- increased gas bad debt expense of $5 million, and
- $12 million in operating expenses, including increases of $3 million in storm damages, $3 million of higher wages, $2 million in appliance service costs and $1 million for injuries and damages,
- partially offset by a $20 million decrease in costs related to a net decrease in SBC, MAC, GPRC, SPRC and STC. Due to the nature of the SBC, MAC, SPRC and STC clause mechanisms, these are entirely offset in revenues.

Depreciation and Amortization increased $17 million due primarily to a $13 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects and an increase of $4 million in amortization of Regulatory Assets.

Other Income and (Deductions) increased $5 million due primarily to an increase in Allowance for Funds used During Construction (AFUDC).

Income Tax Expense increased $18 million due primarily to higher pre-tax income.

Six Months Ended June 30, 2015 as Compared to 2014

Operating Revenues decreased $112 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $109 million due primarily to an increase in transmission revenues.

- Transmission revenues were $82 million higher due to net rate increases resulting primarily from increased capital investments.
- Electric distribution revenues increased $14 million due primarily to higher sales volumes of $9 million and an increase in CIP revenues of $4 million due to the inclusion of CIP II in base rates beginning in July 2014.
- Gas distribution revenues increased $13 million due primarily to $20 million from higher sales volumes outside the WNC clause, partially offset by lower WNC revenue of $9 million due to colder weather in 2015 compared to 2014.

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Commodity Revenue decreased $174 million due to lower Gas revenues offset partially by higher Electric revenues. Commodity revenue for both electric and gas is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Gas revenues decreased $200 million due primarily to lower BGSS prices of $278 million, of which $207 million was due to lower residential rates resulting from $133 million in residential bill credits and $74 million of lower commodity prices, partially offset by higher BGSS volumes of $78 million due to colder weather in 2015.
- Electric revenues increased $26 million due primarily to $58 million of higher net BGS revenues. BGS revenues increased by $87 million or 11%, due to higher sales volumes, which were partially offset by $29 million due to lower BGS prices. The increase from BGS was partially offset by $32 million in lower revenues from lower collection of NGC and lower sales prices and volumes of NUG energy.

Clause Revenues decreased $47 million due primarily to lower SBC of $25 million, lower MAC revenue of $24 million and lower SPRC of $1 million, partially offset by higher STC of $3 million. The changes in the SBC, MAC, SPRC and STC amounts were entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, MAC, SPRC or STC collections.

Other Operating Revenues experienced no material change.

Operating Expenses

Energy Costs decreased $174 million due to lower Gas costs partially offset by higher Electric costs. This is entirely offset by decreased Commodity Revenue.

- Gas costs decreased $200 million or 28% due to a $278 million or 39% decline in prices, partially offset by $78 million or 11% in higher sales volumes due to colder than normal weather.
- Electric costs increased $26 million or 3% due to a $72 million or 9% increase in BGS volumes, primarily reflecting reverse customer migration and a $23 million increase due to higher BGS and NUG prices, partially offset by $50 million of decreased deferred cost recovery and $19 million in lower NUG sales volumes.

Operation and Maintenance decreased $44 million, of which the most significant components were

- a $60 million decrease in costs related primarily to a net decrease in SBC, MAC, GPRC, CIP, SPRC and STC. Due to the nature of the SBC, MAC, SPRC and STC clause mechanisms, these are entirely offset in revenues.
- storm insurance recovery proceeds of $10 million,
- partially offset by an $18 million increase in pension and OPEB expenses, and
- increased gas bad debt expense of $5 million.

Depreciation and Amortization increased $37 million due primarily to a $28 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects and an increase of $10 million in amortization of Regulatory Assets.

Other Income and (Deductions) increased $8 million due primarily to an increase in AFUDC.

Interest Expense increased $1 million due primarily to net issuances of Medium Term Notes in the first half 2015 and latter half of 2014, partially offset by partial redemption of securitization debt.

Income Tax Expense increased $32 million due primarily to higher pre-tax income.

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Power

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,025	$ 986	$ 39	4	$ 2,750	$ 2,686	$ 64	2
Energy Costs	409	520	(111)	(21)	1,302	1,564	(262)	(17)
Operation and Maintenance	313	327	(14)	(4)	485	629	(144)	(23)
Depreciation and Amortization	75	72	3	4	151	144	7	5
Income from Equity Method Investments	5	3	2	67	8	7	1	14
Other Income (Deductions)	48	37	11	30	66	60	6	10
Other-Than-Temporary Impairments	10	2	8	N/A	15	4	11	N/A
Interest Expense	33	29	4	14	64	61	3	5
Income Tax Expense	72	22	50	N/A	306	133	173	N/A

Three Months Ended June 30, 2015 as Compared to 2014

Operating Revenues increased $39 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues increased $92 million due primarily to

- higher net revenues of $112 million due primarily to MTM gains in 2015 compared to MTM losses in 2014, coupled with higher generation volumes at higher average realized sales prices in the PJM region,
- an increase of $24 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and New England (NE) regions, and
- an increase of $10 million due to higher volumes of electricity sold under our BGS contract,
- partially offset by a decrease of $54 million due to lower capacity revenues resulting from lower average auction prices coupled with a decrease in operating reserve revenue in the PJM region in 2015.

Gas Supply Revenues decreased $55 million due primarily to

- a decrease of $24 million in sales under the BGSS contract substantially comprised of lower average sales prices, and
- a decrease of $31 million due to lower sales volumes at lower average sales prices to third party customers.

Operating Revenues increased $2 million due to higher fees received from fuel management and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $111 million due to

- ***Generation costs*** decreased $55 million due primarily to lower fuel costs, reflecting lower average realized natural gas prices, coupled with a 2014 unfavorable MTM impact from lower average unrealized natural gas prices on forward purchases. These decreased costs were partially offset by the utilization of higher volumes of natural gas and higher congestion costs in the PJM region.
- ***Gas costs*** decreased $56 million related to lower average gas inventory costs on both obligations under the BGSS contract and sales to third parties, coupled with lower volumes sold to third parties.

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Operation and Maintenance decreased $14 million due primarily to

- a decrease of $17 million due to insurance recovery related to Superstorm Sandy, and
- a net decrease of $17 million related to our fossil plants largely due to higher costs incurred in 2014 for planned outages and maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant, partly offset by installation of upgraded technology in 2015 at our combined cycle Bergen generating plant,
- partially offset by an increase of $23 million at our nuclear facilities, primarily due to a planned outage at our 100%-owned Hope Creek nuclear plant in 2015 as compared to a planned outage at our 57%-owned Salem nuclear unit 2 in 2014.

Depreciation and Amortization increased $3 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) increased $11 million due primarily to a $28 million insurance recovery related to Superstorm Sandy partly offset by lower realized gains from the NDT Fund.

Other-Than-Temporary Impairments increased $8 million due to an increase in impairments of the NDT Fund.

Interest Expense experienced no material change.

Income Tax Expense increased $50 million in 2015 due primarily to higher pre-tax income.

Six Months Ended June 30, 2015 as Compared to 2014

Operating Revenues increased $64 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues increased $200 million due primarily to

- higher net revenues of $239 million due primarily to MTM gains in 2015 compared to MTM losses in 2014, partially offset by lower energy volumes sold in the NE region at lower average realized sales prices, and
- an increase of $105 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions,
- partially offset by a net decrease of $153 million due primarily to lower capacity revenues resulting from lower average auction prices coupled with lower ancillary and operating reserve revenues in the PJM region.

Gas Supply Revenues decreased $138 million due primarily to

- a net decrease of $71 million in sales under the BGSS contract, substantially comprised of lower average sales prices partially offset by higher sales volumes due to colder average temperatures in the 2015 winter heating season, and
- a decrease of $67 million due to lower average sales prices and volumes to third party customers.

Other Operating Revenues increased $2 million due to higher fees received from fuel management and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $262 million due to

- ***Generation costs*** decreased $90 million due primarily to lower fuel costs, reflecting lower average realized natural gas prices and the utilization of lower volumes of oil, coupled with a 2014 unfavorable MTM impact from lower average unrealized natural gas prices on forward purchases. These decreased costs were partially offset by the utilization of higher volumes of natural gas and higher congestion costs in the PJM region.
- ***Gas costs*** decreased $172 million related to lower average gas inventory costs on both obligations under the BGSS contract and sales to third parties. This was partially offset by higher volumes sold under the BGSS contract due to colder average temperatures during the 2015 winter heating season.

Operation and Maintenance decreased $144 million due primarily to

- a decrease of $145 million due to insurance recoveries related to Superstorm Sandy, and

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- a net decrease of $36 million related to our fossil plants largely due to higher costs incurred in 2014 for planned outage costs, including maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant, partly offset by planned outage costs in 2015 at our Bethlehem Energy Center generating plant and installation of upgraded technology at our combined cycle Bergen plant,
- partially offset by an increase of $37 million at our nuclear facilities, primarily due to higher planned outage costs at our Hope Creek nuclear plant in 2015 as compared to our Salem nuclear unit 2 in 2014.

Depreciation and Amortization increased $7 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) increased $6 million due primarily to a $28 million insurance recovery related to Superstorm Sandy offset by lower realized gains from the NDT Fund.

Other-Than-Temporary Impairments increased $11 million due to an increase in impairments of the NDT Fund.

Interest Expense experienced no material change.

Income Tax Expense increased $173 million in 2015 due primarily to higher pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund planned capital expenditures and shareholder dividend payments.

For the six months ended June 30, 2015, our operating cash flow increased $786 million as compared to the same period in 2014. The net change was due primarily to higher tax payments in 2014 at the parent company and Energy Holdings and the net changes from PSE&G and Power as discussed below.

PSE&G

PSE&G's operating cash flow increased $172 million from $737 million to $909 million for the six months ended June 30, 2015, as compared to the same period in 2014, due primarily to higher earnings, a $176 million reduction in tax payments and increased customer collections of $9 million. These amounts were partially offset by a decrease of $227 million due to a change in regulatory deferrals primarily driven by the return of prior year overcollections to customers for BGSS gas costs, Gas Weather Normalization charges and Non-Utility Generation charges.

Power

Power's operating cash flow increased $478 million from $814 million to $1,292 million for the six months ended June 30, 2015, as compared to the same period in 2014, primarily due to higher earnings and a reduction in margin deposit requirements, partially offset by an increase of $171 million in tax payments.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our $4.3 billion credit facilities are provided by a diverse bank group. As of June 30, 2015, our total available credit capacity was $4.1 billion.

As of June 30, 2015, no single institution represented more than 8% of the total commitments in our credit facilities.

As of June 30, 2015, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of June 30, 2015 were as follows:

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Company/Facility	As of June 30, 2015 Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facility	$ 500	$ 8	$ 492	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—	500	Apr 2020	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 8**	**$ 992**		
PSE&G					
5-year Credit Facility (B)	$ 600	$ 14	$ 586	Apr 2020	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 14**	**$ 586**		
Power					
5-year Credit Facility	$ 1,600	$ 198	$ 1,402	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (C)	1,000	—	1,000	Apr 2020	Funding/Letters of Credit
Bilateral Credit Facility	100	—	100	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 198**	**$ 2,502**		
Total	**$ 4,300**	**$ 220**	**$ 4,080**		

(A) PSEG facility will be reduced by $23 million in April 2016 and $12 million in March 2018.

(B) PSE&G facility will be reduced by $29 million in April 2016 and $14 million in March 2018.

(C) Power facility will be reduced by $48 million in April 2016 and $24 million in March 2018.

Long-Term Debt Financing

PSE&G has $171 million of 6.75% Mortgage Bonds maturing in January 2016. Power has $300 million of 5.50% Senior Notes maturing in December 2015.

For a discussion of our long-term debt transactions during 2015, see Note 9. Changes in Capitalization.

Common Stock Dividends

On July 21, 2015, our Board of Directors approved a $0.39 per share common stock dividend for the third quarter of 2015. This reflects an indicated annual dividend rate of $1.56 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Note 15. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's and Fitch) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In May 2015, Moody's published research reports on PSEG, PSE&G and Power and the existing ratings and outlooks were unchanged. In May 2015, S&P published updated research reports and revised the outlook to stable from positive for PSEG's Corporate Credit Rating and Power's Senior Notes. S&P also affirmed the senior unsecured rating of BBB+ at Power and the mortgage bond rating of A at PSE&G.

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	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	**Stable**	**Stable**	**Stable**
Commercial Paper	P2	A2	F2
PSE&G			
Outlook	**Stable**	**Stable**	**Stable**
Mortgage Bonds	Aa3	A	A+
Commercial Paper	P1	A2	F2
Power			
Outlook	**Stable**	**Stable**	**Stable**
Senior Notes	Baa1	BBB+	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities. The Corporate Credit Rating outlook does not apply to PSEG's or PSE&G's Commercial Paper Rating or PSE&G's Mortgage Bond rating.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1 (highest) to D (lowest) for short-term securities.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing.

In February 2015, we filed a petition with the BPU seeking authority to invest $1.6 billion over the next 5 years, or about $320 million per year, to modernize PSE&G's gas systems.

In June 2015, we acquired a development project to construct a 755 MW gas-fired combined cycle generating station in Maryland (Keys Energy Center). We plan to start constructing this year with expected completion in 2018 at an estimated investment of $825 million - $875 million.

The estimated project expenditures related to the gas system modernization program at PSE&G and the Maryland project at Power are not included in the $8.7 billion three-year capital forecast table in our 2014 Form 10-K. There were no material changes to our projected capital expenditures at Services as compared to amounts disclosed in our 2014 Form 10-K.

PSE&G

During the six months ended June 30, 2015, PSE&G made capital expenditures of $1,230 million, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $58 million, which are included in operating cash flows.

Power

During the six months ended June 30, 2015, Power made capital expenditures of $360 million, excluding $127 million for nuclear fuel, primarily related to various projects at its fossil and nuclear generation stations, including the new Maryland generating station noted above.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Note 2. Recent Accounting Standards.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From April through June 2015, MTM VaR remained relatively stable. The range of VaR was narrower for the three months ended June 30, 2015 as compared with the year ended December 31, 2014.

	MTM VaR	
	Three Months Ended June 30, 2015	Year Ended December 31, 2014
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 15	$ 36
Average for the Period	$ 18	$ 30
High	$ 23	$ 195
Low	$ 12	$ 14
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 23	$ 56
Average for the Period	$ 28	$ 46
High	$ 36	$ 306
Low	$ 18	$ 22

See Note 10. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

There have been no changes in internal control over financial reporting that occurred during the second quarter of 2015 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2014 Annual Report on Form 10-K, see Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

There are no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2014 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the second quarter of 2015.

Three Months Ended June 30, 2015	Total Number of Shares Purchased	Average Price Paid per Share
April 1 - April 30	—	$ —
May 1- May 31	49,360	$ 42.70
June 1- June 30	—	$ —

ITEM 5. OTHER INFORMATION

Certain information reported in the 2014 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2014 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2015. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

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Federal Regulation

FERC

Regulation of Wholesale Sales—Generation/Market Issues

Capacity Market Issues—PJM

December 31, 2014 Form 10-K page 16 and March 31, 2015 Form 10-Q page 69. The RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. There is currently significant activity concerning two topics: (i) the future role of DR in the RPM market in light of a decision by the D.C. Circuit Court of Appeals (D.C. Court) holding that DR is not a FERC-jurisdictional product, and (ii) PJM's development of a new capacity product called a Capacity Performance (CP) product.

In May 2014, the D.C. Court held that DR is not a FERC-jurisdictional product, thereby calling into question DR resources' ability to participate in either the energy or capacity markets in the future. The U.S. Supreme Court has agreed to hear this case. A decision upholding the lower court decision would be expected to have a significant impact on the amount and manner of participation by DR in PJM's markets. However, until the U.S. Supreme Court rules on the case, DR will be allowed to participate in RPM for the upcoming base residual auction and capacity performance transitional auctions as supply resources under the recently accepted capacity performance rules described below.

On December 12, 2014, PJM filed a proposal at the FERC to implement a CP mechanism. Under this mechanism, PJM created a more robust capacity product definition with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. On June 9, 2015, the FERC conditionally accepted the CP mechanism which will be phased in over the next few years, with the participation of both the CP product and a base product that has less rigorous performance obligations. The CP mechanism will be implemented for the 2015 base residual auction which will begin on August 10, 2015. The CP product will be implemented fully for the 2020-2021 Delivery Year. The CP mechanism may provide the opportunity for enhanced capacity market revenue streams for Power. However, there may be requirements for additional investment and there are additional performance risks, as well as risks associated with our ability to bid in a manner that would ensure recovery of any required capital investment.

On June 30, 2015, a consumer coalition filed a complaint requesting that the load forecast that PJM is currently analyzing and updating to determine the amount of capacity it will procure in the 2016 base residual auction be implemented immediately for the upcoming 2015 transition auctions and base residual auction. If granted, use of the forecast values would likely decrease the amount of capacity to be procured and have an adverse impact on clearing prices in the 2015 base residual auction.

Capacity Market Issues—NYISO

December 31, 2014 Form 10-K page 17 and March 31, 2015 Form 10-Q page 70. Matters are pending before the FERC concerning potential changes to the NYISO capacity markets, including rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons. On March 19, 2015, the FERC issued an order which held that units receiving special reliability payments could properly take those payments into account in formulating capacity market bids. We believe that this ruling could have impacts on efficient price formation in the capacity market and could artificially suppress capacity market outcomes. On April 20, 2015, a trade association of which we are a member filed for rehearing by the FERC of this ruling. On May 8, 2015, the New York Public Service Commission and other New York agencies filed a complaint at the FERC requesting certain exemptions from the NYISO rules that prevent capacity suppliers from submitting bids that are not market competitive. If the exemptions are granted, market prices could be suppressed.

Transmission Regulation—Transmission Policy Developments

December 31, 2014 Form 10-K page 18 and March 31, 2015 Form 10-Q page 70. The FERC concluded in Order 1000 that the incumbent transmission owner should not always have a Right of First Refusal (ROFR) to construct and own transmission projects in its service territory. We and other companies appealed Order 1000 but this appeal was denied last year. The current PJM rules retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including projects being built on existing right-of-way and whose construction would interfere with incumbents' use of their right-of-way. While these carve-outs ameliorate the impacts of the Order 1000 ruling, we and several other companies appealed various aspects of the FERC order approving PJM's implementation of Order 1000 on the grounds that the FERC had not met the requisite legal burden in eliminating the ROFR from the PJM Tariff. This appeal remains pending in federal court.

In April 2013, PJM initiated its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues at Artificial Island off the shore of New Jersey. On April 28, 2015, the PJM staff advised stakeholders that it intended to recommend a transmission project to the PJM Board of Managers consisting of various components to be constructed by LS Power, PSE&G and Potomac Holding Company. Based on PJM's presentation, the total construction cost of the project components that would be assigned to PSE&G

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ranged between $100 million and $130 million. Interested parties were allowed to submit comments to the PJM Board of Managers (PJM Board) until May 29, 2015. We filed timely comments identifying what we believed were deficiencies in the PJM staff recommendation. On July 29, 2015, the PJM Board approved the PJM staff's recommendation. In a related matter, the FERC denied a complaint filed by PSE&G contending that PJM had failed to follow its rules during the Artificial Island solicitation process.

There have also been developments on two additional matters. In November 2014, Con Edison had brought a complaint against PJM at the FERC challenging PJM's allocation of costs for two PSE&G projects in northern New Jersey, including the Bergen-Linden Corridor Project. We had opposed Con Edison's complaint and, in June 2015, the FERC issued an order upholding our position. Con Edison has sought judicial review of certain aspects of FERC's order and has the right to seek rehearing of other aspects of the order. Also, in June 2015, a transmission developer filed a complaint against PJM claiming that PJM wrongfully refused to provide data and a transparent process for evaluating transmission network upgrade requests that the transmission developer had submitted to PJM. According to the complaint, PJM and certain transmission owners wrongfully inflated the scope and associated costs of mitigation work needed to accommodate the developer's proposal in order to prevent it from pursuing its projects. Although not named as a respondent in the complaint, PSE&G is identified as one of the companies claimed to have been involved. On July 10, 2015, PJM filed a response, which included a supporting affidavit from PSE&G, contesting the allegations.

State Regulation

Energy Efficiency Economic Stimulus Extension II (EEE Ext II)

December 31, 2014 Form 10-K page 22 and March 31, 2015 Form 10-Q page 71. On April 15, 2015, the BPU approved our petition for an EEE Ext II Program to extend three EEE subprograms (multi-family, direct install and hospital efficiency). The Order allows us to extend the subprogram offerings under the same clause recovery process as our existing EEE Program and allows for $95 million of additional capital expenditures over the next three years and $12 million of additional administrative expenses over the next 15 years. The EEE Ext II Program was added as a ninth component of the Green Program Recovery Charges rate effective May 1, 2015.

Connecticut Rate Filing

In June 2015, Power's subsidiary, PSEG New Haven LLC, filed a mandatory annual rate case with the Connecticut Public Utilities Regulatory Authority for recovery of its costs and investment in its Connecticut-based peaking unit. Power requested 2016 revenues of $22 million. This matter is pending.

Environmental Matters

Air Pollution Control

Hazardous Air Pollutants Regulation

December 31, 2014 Form 10-K page 22. In February 2012, the Environmental Protection Agency (EPA) published Mercury Air Toxics Standards (MATS) for both newly-built and existing electric generating sources under the National Emission Standard for Hazardous Air Pollutants (NESHAP) provisions of the Clean Air Act. The MATS established allowable levels for mercury as well as other hazardous air pollutants and went into effect in April 2015. On June 29, 2015, the U.S. Supreme Court held that it was unreasonable for the EPA to refuse to consider the materiality of costs in determining whether to regulate hazardous air pollutants from power plants. The case has been remanded back to the D.C. Circuit Court of Appeals (D.C. Court) and as a result the future of MATS remains unclear. If the D.C. Court decides to remand the rule to the EPA with a stay or vacate the rule in its entirety, power plants located in states with less stringent air pollution control requirements may choose to cease operating their newly installed controls. In addition, such a decision could impact decisions by other generators on plant retirements. Such uncertainty puts a downward pressure on power prices in the region. While the outcome of MATS remains uncertain, our power generation plants are already in compliance with MATS.

Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation

December 31, 2014 Form 10-K page 23. In March 2013, Power filed a petition at the EPA challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued in January 2013. Among other things, the final EPA rule includes two exemptions that allow owners and operators of stationery emergency RICE to operate their engines without the installation and operation of emission controls (1) as part of an emergency DR program for 100 hours per year (100 hour exemption) or (2) as part of a financial arrangement with another entity per specified restrictions in non-emergency situations for 50 hours per year (50 hour exemption). This waiver of NESHAP standards results in disparate treatment of different generation technology types. In its appeal, Power sought more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. In August 2014, the EPA denied the March 2013 petition and in October 2014, Power appealed the EPA's denial to the D.C. Court. On May 1, 2015, the D.C. Court vacated the 100 hour

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exemption. The impact of this ruling will likely benefit Power's and its competitors' operations of their power generation peaking units. The D.C. Court's decision on the 50 hour exemption remains pending.

Climate Change

CO_2 Regulation Under the Clean Air Act (CAA)

December 31, 2014 Form 10-K page 23 and March 31, 2015 Form 10-Q page 72. In June 2014, the EPA issued a proposed greenhouse gas (GHG) emissions regulation under the CAA for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction (BSER). The BSER consists of four components: (i) heat rate improvements at existing coal-fired power plants, (ii) increased use of existing natural gas combined cycle capacity, (iii) operation of zero-emitting generation (renewables and nuclear), and (iv) increased use of demand-side energy efficiency. States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions.

Since the EPA has requested comments on many aspects of the proposal, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact. A final rule is expected in August 2015.

The FERC held a series of technical conferences ending in early April 2015 to discuss the implications of compliance approaches to the EPA's proposed GHG regulation for existing power plants. The conferences focused on issues related to electric reliability, wholesale electric markets and operations and energy infrastructure. The FERC also solicited and received written comments. On May 15, 2015, the FERC issued a letter to the EPA expressing its willingness to work with the EPA to address reliability concerns as the EPA moves toward finalizing the rule.

Water Pollution Control

Cooling Water Intake Structure Regulation

December 31, 2014 Form 10-K page 25. On June 30, 2015, the NJDEP issued a draft permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The draft permit is subject to a sixty-day public notice and comment period after which the NJDEP may make revisions before issuing the final permit expected in the first half of 2016. We are reviewing the details of the draft, evaluating its potential impact and will participate in the comment process. For additional information, see Part I, Item 1. Note 8. Commitments and Contingent Liabilities.

Waters of the United States

December 31, 2014 Form 10-K page 25. In April 2014, the EPA Administrator and the Assistant Secretary of the Army (Civil Works) jointly published a proposed rule to clarify the definition of waters of the U.S. under the Clean Water Act (CWA) programs in order to protect the streams and wetlands that form the foundation of the nation's water resources. This definition will have broad application to all areas of compliance under the CWA, including permitted discharges and construction activities. On November 14, 2014, we participated with other energy companies in submitting comments on the proposed rule. The final rule was published on June 29, 2015 and we are reviewing it to determine the materiality of the impacts that might result from the final rule.

Endangered Species Act

On June 16, 2015, the Sierra Club and another environmental group submitted to the NJDEP a sixty-day notice of intent to sue alleging the agency has caused violations of the Endangered Species Act by allowing our Mercer generation station to operate in a manner which has caused the mortality of certain species of sturgeon. Among other things, the notice requested the NJDEP to prioritize completion of a permit renewal action for Mercer which addresses the alleged Endangered Species Act violations. We cannot predict the outcome of this action.

Fuel and Waste Disposal

Coal Combustion Residuals (CCRs)

December 31, 2014 Form 10-K page 26 and March 31, 2015 Form 10-Q page 72. On December 19, 2014, the EPA issued a final rule which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Our Hudson and Mercer generating stations, along with our co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 14, 2015. The impacts of this final rule were not material to our results of operations, financial condition or cash flows. See Part I, Item 1. Note 8. Commitments and Contingent Liabilities for additional information.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. PSE&G:

Exhibit 4 (a) (23)	Supplemental Indenture dated May 1, 2015
Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. Power:

Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: July 31, 2015

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: July 31, 2015

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: July 31, 2015

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SUPPLEMENTAL MORTGAGE

Supplemental Indenture

Dated May 1, 2015

SUPPLEMENTAL TO
FIRST AND REFUNDING MORTGAGE
DATED AUGUST 1, 1924

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
TO
U.S. BANK NATIONAL ASSOCIATION
Trustee
21 South Street
Morristown, New Jersey 07960

PROVIDING FOR THE ISSUE OF
$2,000,000,000 FIRST AND REFUNDING MORTGAGE BONDS,
MEDIUM-TERM NOTES SERIES K

RECORD IN MORTGAGE BOOK AND RETURN TO:
M. COURTNEY McCORMICK, ESQ.
80 PARK PLAZA, T5B
NEWARK, N.J. 07102-4194

Prepared by

/s/ Donald S. Leibowitz, Esq.

Donald S. Leibowitz, ESQ.

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SUPPLEMENTAL INDENTURE, dated the 1st day of May, 2015 for convenience of reference and effective from the time of execution and delivery hereof, between PUBLIC SERVICE ELECTRIC AND GAS COMPANY, a corporation organized under the laws of the State of New Jersey, hereinafter called the "Company", party of the first part, and U.S. Bank National Association, a national banking association organized under the laws of the United States of America, as successor Trustee to Wachovia Bank, National Association (previously known as Fidelity Union Trust Company) under the indenture dated August 1, 1924, below mentioned, hereinafter called the "Trustee", party of the second part.

WHEREAS, on July 25, 1924, the Company executed and delivered to FIDELITY UNION TRUST COMPANY, a certain indenture dated August 1, 1924 (hereinafter called the "Indenture") to secure and to provide for the issue of First and Refunding Mortgage Gold Bonds of the Company; and

WHEREAS, the Indenture has been recorded in the following counties of the State of New Jersey, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Atlantic	Clerk's	1955 of Mortgages	160
Bergen	Clerk's	94 of Chattel Mortgages	123 etc.
		693 of Mortgages	88 etc.
Burlington	Clerk's	52 of Chattel Mortgages	Folio 8 etc.
		177 of Mortgages	Folio 354 etc.
Camden	Register's	45 of Chattel Mortgages	184 etc.
		239 of Mortgages	1 etc.
Cumberland	Clerk's	786 of Mortgages	638 & c.
Essex	Register's	437 of Chattel Mortgages	1-48
		T-51 of Mortgages	341-392
Gloucester	Clerk's	34 of Chattel Mortgages	123 etc.
		142 of Mortgages	7 etc.
Hudson	Register's	453 of Chattel Mortgages	9 etc.
		1245 of Mortgages	484, etc.
Hunterdon	Clerk's	151 of Mortgages	344
Mercer	Clerk's	67 of Chattel Mortgages	1 etc.
		384 of Mortgages	1 etc.
Middlesex	Clerk's	113 of Chattel Mortgages	3 etc.
		437 of Mortgages	294 etc.
Monmouth	Clerk's	951 of Mortgages	291 & c.
Morris	Clerk's	N-3 of Chattel Mortgages	446 etc.
		F-10 of Mortgages	269 etc.
Ocean	Clerk's	1809 of Mortgages	40
Passaic	Register's	M-6 of Chattel Mortgages	178, etc.
		R-13 of Mortgages	268 etc.
Salem	Clerk's	267 of Mortgages	249 etc.
Somerset	Clerk's	46 of Chattel Mortgages	207 etc.
		N-10 of Mortgages	1 etc.
Sussex	Clerk's	123 of Mortgages	10 & c.
Union	Register's	9584 of Mortgages	259 etc.
Warren	Clerk's	124 of Mortgages	141 etc.

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and

WHEREAS, the Indenture has also been recorded in the following counties of the Commonwealth of Pennsylvania, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Adams	Recorder's	22 of Mortgages	105
Bedford	Recorder's	90 of Mortgages	917
Blair	Recorder's	671 of Mortgages	430
Cambria	Recorder's	407 of Mortgages	352
Cumberland	Recorder's	500 of Mortgages	136
Franklin	Recorder's	285 of Mortgages	373
Huntingdon	Recorder's	128 of Mortgages	47
Indiana	Recorder's	197 of Mortgages	281
Montgomery	Recorder's	5053 of Mortgages	1221
Westmoreland	Recorder's	1281 of Mortgages	198
York	Recorder's	31-V of Mortgages	446

and

WHEREAS, the Indenture granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company, more fully set forth and described in the Indenture, then owned or which might thereafter be acquired by the Company; and

WHEREAS, the Company, by various supplemental indentures, supplemental to the Indenture, the last of which was dated August 6, 2014, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company acquired by it after the execution and delivery of the Indenture; and

WHEREAS, since the execution and delivery of said supplemental indenture dated August 6, 2014, the Company has acquired property which, in accordance with the provisions of the Indenture, is subject to the lien thereof and the Company desires to confirm such lien; and

WHEREAS, the Indenture has been amended or supplemented from time to time; and

WHEREAS, it is provided in the Indenture that no bonds other than those of the 5-1/2% Series due 1959 therein authorized may be issued thereunder unless a supplemental indenture providing for the issue of such additional bonds shall have been executed and delivered by the Company to the Trustee; and

WHEREAS, the Company is making provisions for the issuance and sale of its Secured Medium-Term Notes, Series K (the "Series K Notes"), to be issued under an Indenture of Trust (the "Note Indenture") dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as Trustee (the "Note Trustee"); and

WHEREAS, such Note Indenture provides, among other things, for the pledge and delivery by the Company of a series of First and Refunding Mortgage Bonds of the Company to evidence the Company's obligation to pay the principal and interest with respect to outstanding Series K Notes; and for such purpose and in order to service and secure payment of the principal and interest in respect of the Series K Notes, the Company desires to provide for the issue of $2,000,000,000 aggregate principal amount of bonds under the Indenture of a series to be designated as "First and Refunding Mortgage Bonds, Medium-Term Notes Series K" (hereinafter sometimes called "Bonds of the Medium-Term Notes Series K"); and

WHEREAS, the text of the Bonds of the Medium-Term Notes Series K and of the certificate of authentication to be borne by the Bonds of the Medium-Term Notes Series K shall be substantially of the following tenor:

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(Form of Bond)

This Bond is not transferable except as provided in the Indenture and in the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor trustee) as Trustee.

REGISTERED NUMBER	REGISTERED AMOUNT
R	$2,000,000,000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
FIRST AND REFUNDING MORTGAGE BOND,

MEDIUM-TERM NOTES SERIES K

Public Service Electric and Gas Company (hereinafter called the "Company"), a corporation of the State of New Jersey, for value received, hereby promises to pay to The Bank of New York Mellon as successor trustee to The Chase Manhattan Bank (National Association)), under the Indenture of Trust dated as of July 1, 1993 between the Company and such trustee, or registered assigns, on the surrender hereof, the principal sum of Two Billion Dollars, on May 1, 2050, and to pay interest thereon from the date hereof, at the rate of 10% per annum, and until payment of said principal sum, such interest to be payable May 1 and November 1 in each year; provided, however, that the Company shall receive certain credits against such obligations as set forth in the Supplemental Indenture dated May 1, 2015 referred to below.

Both the principal hereof and interest hereon shall be paid at the principal corporate trust office of U.S. Bank National Association in the City of Morristown, State of New Jersey, or (at the option of the registered owner) at the corporate trust office of any paying agent appointed by the Company, in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts; provided, however, that any such payments of principal and interest shall be subject to receipt of certain credits against such payment obligations as set forth in the Supplemental Indenture dated May 1, 2015 referred to below.

This Bond is one of the First and Refunding Mortgage Bonds of the Company issued and to be issued under and pursuant to, and all equally secured by, an indenture of mortgage or deed of trust dated August 1, 1924, as supplemented and amended by supplemental indentures thereto, including the Supplemental Indenture dated May 1, 2015, duly executed by the Company and U.S. Bank National Association as Trustee. This Bond is one of the Bonds of the Medium-Term Notes Series K, which series is limited to the aggregate principal amount of $2,000,000,000 and is issued pursuant to said Supplemental Indenture dated May 1, 2015. Reference is hereby made to said indenture and all supplements thereto for a specification of the principal amount of Bonds from time to time issuable thereunder, and for a description of the properties mortgaged and conveyed or assigned to said Trustee or its successors, the nature and extent of the security, and the rights of the holders of said Bonds and any coupons appurtenant thereto, and of the Trustee in respect of such security.

In and by said indenture, as amended and supplemented, it is provided that with the written approval of the Company and the Trustee, any of the provisions of said indenture may from time to time be eliminated or modified and other provisions may be added thereto provided the change does not alter the annual interest rate, redemption price or date, date of maturity or amount payable on maturity of any then outstanding Bond or conflict with the Trust Indenture Act of 1939 as then in effect, and provided the holders of 85% in principal amount of the Bonds secured by said indenture and then outstanding (including, if such change affects the Bonds of one or more series but less than all series then outstanding, a like percentage of the then outstanding Bonds of each series affected by such change, and excluding Bonds owned or controlled by the Company or by the parties owning at least 10% of the outstanding voting stock of the Company, as more fully specified in said indenture) consent in writing thereto, all as more fully set forth in said indenture, as amended and supplemented.

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First and Refunding Mortgage Bonds issuable under said indenture are issuable in series, and the Bonds of any series may be for varying principal amounts and in the form of coupon bonds and of registered bonds without coupons, and the Bonds of any one series may differ from the Bonds of any other series as to date, maturity, interest rate and otherwise, all as in said indenture provided and set forth. The Bonds of the Medium-Term Notes Series K, in which this Bond is included, are designated "First and Refunding Mortgage Bonds, Medium-Term Notes Series K".

In case of the happening of an event of default as specified in said indenture and said supplemental indenture dated March 1, 1942, the principal sum of the Bonds of this series may be declared or may become due and payable forthwith, in the manner and with the effect in said indenture provided.

The Bonds of this series are subject to redemption as provided in the Supplemental Indenture dated May 1, 2015.

This Bond is transferable, but only as provided in said indenture and the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as trustee, upon surrender hereof, by the registered owner in person or by attorney duly authorized in writing, at either of said offices where the principal hereof and interest hereon are payable; upon any such transfer a new fully registered Bond similar hereto will be issued to the transferee. This Bond may in like manner be exchanged for one or more new fully registered Bonds of the same series of other authorized denominations but of the same aggregate principal amount. No service charge shall be made for any such transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto. The Company and the Trustee hereunder and any paying agent may deem and treat the person in whose name this Bond is registered as the absolute owner hereof for the purpose of receiving payment of or on account of the principal hereof and the interest hereon and for all other purposes; and neither the Company nor the Trustee hereunder nor any paying agent shall be affected by any notice to the contrary.

The Bonds of this series are issuable only in fully registered form, in any denomination authorized by the Company.

No recourse under or upon any obligation, covenant or agreement contained in said indenture or in any indenture supplemental thereto, or in any Bond issued thereunder, or because of any indebtedness arising thereunder, shall be had against any incorporator, or against any past, present or future stockholder, officer, or director, as such, of the Company or of any successor corporation, either directly or through the Company or any successor corporation, under any rule of law, statute or constitutional provision or by the enforcement of any assessment or by any legal or equitable proceeding or otherwise, it being expressly agreed and understood that said indenture, any indenture supplemental thereto and the obligations issued thereunder, are solely corporate obligations, and that no personal liability whatever shall attach to, or be incurred by, such incorporators, stockholders, officers or directors, as such, of the Company, or of any successor corporation, or any of them, because of the incurring of the indebtedness thereby authorized, or under or by reason of any of the obligations, covenants or agreements contained in the indenture or in any indenture supplemental thereto or in any of the Bonds issued thereunder, or implied therefrom.

This Bond shall not be entitled to any security or benefit under said indenture, as amended and supplemented, and shall not become valid or obligatory for any purpose, until the certificate of authentication, hereon endorsed, shall have been signed by U.S. Bank National Association as Trustee, or by its successor in trust under said indenture.

IN WITNESS WHEREOF, the Company has caused this Bond to be duly executed by its proper officers under its corporate seal.

Dated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY,

S1-SSA-0009 - 17612

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By. . . . . .
(Vice) President

(Seal)
Attest:

. . . . . .
(Assistant) Secretary

(FORM OF CERTIFICATE OF AUTHENTICATION)

CERTIFICATE OF AUTHENTICATION

This Bond is one of the Bonds of the series designated therein which is described in the within-mentioned indenture and supplemental indenture dated May 1, 2015, as secured thereby.

U.S. BANK NATIONAL ASSOCIATION, TRUSTEE,

By. . . . . .
Authorized Signatory

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WHEREAS, the execution and delivery of this supplemental indenture have been duly authorized by the Board of Directors of the Company; and

WHEREAS, the Company represents that all things necessary to make the bond of the series hereinafter described, when duly authenticated by the Trustee and issued by the Company, a valid, and legal obligation of the Company, and to make this supplemental indenture a valid and binding agreement supplemental to the Indenture, have been done and performed:

NOW, THEREFORE, THIS SUPPLEMENTAL INDENTURE WITNESSETH that the Company, in consideration of the premises and the execution and delivery by the Trustee of this supplemental indenture, and in pursuance of the covenants and agreements contained in the Indenture and for other good and valuable consideration, the receipt of which is hereby acknowledged, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over, and by these presents does grant, bargain, sell, alien, remise, release, convey, confirm, assign, transfer and set over unto the Trustee, its successors and assigns, forever, all the right, title and interest of the Company in and to all property of every kind and description (except cash, accounts and bills receivable and all merchandise bought, sold or manufactured for sale in the ordinary course of the Company's business, stocks, bonds or other corporate obligations or securities, other than such as are described in Part V of the Granting Clauses of the Indenture, not acquired with the proceeds of bonds secured by the Indenture, and except as in the Indenture and herein otherwise expressly excluded) acquired by the Company since the execution and delivery of the supplemental indenture dated August 6, 2014, subsequent to the Indenture (except any such property duly released from, or disposed of, free from the lien of the Indenture, in accordance with the provisions thereof) and all such property which at any time hereafter may be acquired by the Company;

All of which property it is intended shall be included in and granted by this supplemental indenture and covered by the lien of the Indenture as heretofore and hereby amended and supplemented;

UNDER AND SUBJECT to any encumbrances or mortgages existing on property acquired by the Company at the time of such acquisition and not heretofore discharged of record; and

SUBJECT also, to the exceptions, reservations and provisions in the Indenture and in this supplemental indenture recited, and to the liens, reservations, exceptions, limitations, conditions and restrictions imposed by or contained in the several deeds, grants, franchises and contracts or other instruments through which the Company acquired or claims title to the aforesaid property; and Subject, also, to the existing leases, to liens on easements or rights of way, to liens for taxes, assessments and governmental charges not in default or the payment of which is deferred, pending appeal or other contest by legal proceedings, pursuant to Section 4 of Article Five of the Indenture, or the payment of which is deferred pending billing, transfer of title or final determination of amount, to easements for alleys, streets, highways, rights of way and railroads that may run across or encroach upon the said property, to joint pole and similar agreements, to undetermined liens and charges, if any, incidental to construction, and other encumbrances permitted by the Indenture as heretofore and hereby amended and supplemented;

TO HAVE AND TO HOLD the property hereby conveyed or assigned, or intended to be conveyed or assigned, unto the Trustee, its successor or successors and assigns, forever;

IN TRUST, NEVERTHELESS, upon the terms, conditions and trusts set forth in the Indenture as heretofore and hereby amended and supplemented, to the end that the said property shall be subject to the lien of the Indenture as heretofore and hereby amended and supplemented, with the same force and effect as though said property had been included in the Granting Clauses of the Indenture at the time of the execution and delivery thereof;

AND THIS SUPPLEMENTAL INDENTURE FURTHER WITNESSETH that for the considerations aforesaid, it is hereby covenanted between the Company and the Trustee as follows:

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ARTICLE I.

BONDS OF THE MEDIUM-TERM NOTES SERIES KI.

The series of bonds authorized by this supplemental indenture to be issued under and secured by the Indenture shall be designated "First and Refunding Mortgage Bonds, Medium-Term Notes Series K"; shall be limited to the aggregate principal amount of $2,000,000,000; shall be issued initially to the Note Trustee and shall mature and bear interest as set forth in the form of bond set forth herein; provided, however, that the Company shall receive certain credits against principal and interest as set forth in Section 3.01 hereof. The date of each Bond of the Medium-Term Notes Series K shall be the interest payment date next preceding the date of authentication, unless such date of authentication be an interest payment date, in which case the date shall be the date of authentication, or unless such date of authentication be prior to the first semi-annual interest payment date, in which case the date shall be May 1, 2015.

Bonds of the Medium-Term Notes Series K shall be issuable only in the form of fully registered bonds in any denomination authorized by the Company. Interest on the Bonds of the Medium-Term Notes Series K shall be payable semi-annually in arrears on May 1 and November 1 of each year, payable initially on November 1, 2015, subject to receipt of certain credits against principal and interest as set forth in Section 3.01 hereof and shall be payable as to both principal and interest in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts, at the principal corporate trust office of the Trustee, or at the corporate trust office of any paying agent appointed.

Bonds of the Medium-Term Notes Series K shall be transferable and exchangeable, but only as provided in the Indenture and the Note Indenture, upon surrender thereof for cancellation by the registered owner in person or by attorney duly authorized in writing at either of said offices. The Company hereby waives any right to make a charge for any transfer or exchange of Bonds of the Medium-Term Notes Series K, but the Company may require payment of a sum sufficient to cover any tax or any other governmental charge that may be imposed in relation thereto.

ARTICLE II.

REDEMPTION OF BONDS OF MEDIUM-TERM NOTES SERIES K.

SECTION 2.01. *Redemption-Redemption Price*. Bonds of the Medium-Term Notes Series K shall be subject to redemption prior to maturity under the conditions, and upon payment of the amounts as may be specified in the following conditions:

(a) at any time in whole or in part at the option of the Company upon receipt by the Trustee of written certification of the Company and of the Note Trustee that the principal amount of the Series K Notes then outstanding under the Note Indenture is not in excess of such principal amount of the Bonds of the Medium-Term Notes Series K as shall remain pledged to the Note Trustee after giving effect to such redemption; (b) at any time by the application of any proceeds of released property or other money held by the Trustee and which, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, are applied to the redemption of Bonds of the Medium-Term Notes Series K, upon payment of 100% of the principal amount thereof, together with interest accrued to the redemption date, provided that any such payment shall be subject to receipt by the Company of certain credits against such obligations as set forth in Section 3.01 hereof or (c) automatically upon failure to pay the principal of any Series K Notes then outstanding under the Note Indenture when due, on their stated maturity date or earlier redemption or repayment date, in a principal amount of Bonds of the Medium-Term Notes Series K equal to the principal amount of such Series K Notes, in each case, at a price equal to 100% of the principal amount thereof, together with accrued interest, if applicable.

SECTION 2.02. *Redemptions Pursuant to Section 4C of Article Eight of the Indenture*. If, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, any proceeds of released property or other money then held by the Trustee shall be applied to the redemption of the Bonds of the Medium-Term Notes Series K, the Trustee shall give at least 45 days prior written notice of such redemption to the Note

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Trustee whereupon on the date fixed for redemption such principal amount thereof as is equal to such proceeds shall be redeemed; provided that no such redemption shall be made unless the Trustee shall be in receipt of a written certification of the Company and the Note Trustee that a like principal amount of Series K Notes shall have been theretofore redeemed in accordance with the provisions of the Note Indenture. For purposes of determining which of the Company's First and Refunding Mortgage Bonds are subject to such mandatory redemption, the Mortgage Trustee shall consider the 10% stated annual interest rate of the Bonds of the Medium-Term Notes Series K, not the weighted average interest rate of outstanding Series K Notes. Bonds of said series so redeemed shall be cancelled.

SECTION 2.03. *Interest on Called Bonds to Cease.* Each Bond of the Medium-Term Notes Series K or portion thereof called for redemption under Section 2.02 hereof shall be due and payable at the office of the Note Trustee, as paying agent hereunder, at its redemption price and on the specified redemption date, anything herein or in such Bond to the contrary notwithstanding. From and after the date when each Bond of the Medium-Term Notes Series K or portion thereof shall be due and payable as aforesaid (unless upon said date the full amount due thereon shall not be held by the Note Trustee, as paying agent hereunder, and be immediately available for payment), all further interest shall cease to accrue on such bond or on such portion thereof, as the case may be.

SECTION 2.04. *Bonds Called in Part.* If only a portion of any Bond of the Medium-Term Notes Series K shall be called for redemption pursuant to Section 2.02 hereof, upon payment of the portion so called for redemption, the Note Trustee shall make an appropriate notation upon the Bond of the principal amount so redeemed.

SECTION 2.05. *Provisions of Indenture Not Applicable*. The provisions of Article Four of the Indenture, as amended and supplemented, shall not apply to the procedure for the exercise of any right of redemption reserved by the Company, or to any mandatory redemption provided, in this Article in respect of the Bonds of the Medium-Term Notes Series K. There shall be no sinking fund for the Bonds of the Medium-Term Notes Series K.

ARTICLE III.

CREDITS WITH RESPECT TO BONDS OF THE MEDIUM-TERM NOTES SERIES K.

SECTION 3.01. *Credits.* In addition to any other credit, payment or satisfaction to which the Company is entitled with respect to the Bonds of the Medium-Term Notes Series K, the Company shall be entitled to credits against amounts otherwise payable in respect of the Bonds of the Medium-Term Notes Series K in an amount corresponding to (i) the principal amount of any of the Company's Series K Notes issued under the Note Indenture surrendered to the Note Trustee by the Company, or purchased by the Note Trustee, for cancellation, (ii) the amount of money held by the Note Trustee and available and designated for the payment of principal or redemption price (exclusive of any premium) of, and/or interest on, the Series K Notes, regardless of the source of payment to the Note Trustee of such moneys and (iii) the amount by which principal of and interest due on the Bonds of the Medium-Term Notes Series K exceeds principal of and interest due on the Series K Notes. The Note Trustee shall make notation on such Bonds authorized hereby of any such credit.

SECTION 3.02. *Certificate of the Company.* A certificate of the Company signed by the President or any Vice President, and attested to by the Secretary or any Assistant Secretary, and consented to by the Note Trustee, stating that the Company is entitled to a credit under Section 3.01 hereof or that Bonds of the Medium-Term Notes Series K have been cancelled, and setting forth the basis therefor in reasonable detail, shall be conclusive evidence of such entitlement, and the Trustee shall accept such certificate as such evidence without further investigation or verification of the matters stated therein.

ARTICLE IV.

MISCELLANEOUS.

SECTION 4.01. *Authentication of Bonds of Medium-Term Notes Series K.* None of the Bonds of the Medium-Term Notes Series K, the issue of which is provided for by this supplemental indenture, shall be authenticated by or on behalf of the Trustee except in accordance with the provisions of the Indenture, as amended and supplemented, and this supplemental indenture, and upon compliance with the conditions in that behalf therein contained.

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SECTION 4.02. *Additional Restrictions on Authentication of Additional Bonds Under Indenture.* The Company covenants that from and after the date of execution of this supplemental indenture no additional bonds (as defined in Section 1 of Article Two of the Indenture) shall be authenticated and delivered by the Trustee under Subdivision A of Section 4 of said Article Two on account of additions or improvements to the mortgaged property;

(1) unless the net earnings of the Company for the period required by Subdivision C of Section 6 of said Article Two shall have been at least twice the fixed charges (in lieu of 1-3/4 times such fixed charges, as required by said Subdivision C); and for the purpose of this condition (a) such fixed charges shall in each case include interest on the bonds applied for, notwithstanding the parenthetical provision contained in clause (4) of said Subdivision C, and (b) in computing such net earnings there shall be included in expenses of operation (under paragraph (c) of said Subdivision C) all charges against earnings for depreciation, renewals or replacements, and all certificates with respect to net earnings delivered to the Trustee in connection with any authentication of additional bonds under said Article Two shall so state; and (2) except to the extent of 60% (in lieu of 75% as permitted by Subdivision A of Section 7 of said Article Two) of the cost or fair value to the Company of the additions or improvements forming the basis for such authentication of additional bonds.

SECTION 4.03. *Restriction on Dividends.* The Company will not declare or pay any dividend on any shares of its common stock (other than dividends payable in shares of its common stock) or make any other distribution on any such shares, or purchase or otherwise acquire any such shares (except shares acquired without cost to the Company) whenever such action would reduce the earned surplus of the Company to an amount less than $10,000,000 or such lesser amount as may remain after deducting from said $10,000,000 all amounts appearing in the books of account of the Company on December 31, 1948, which shall thereafter, pursuant to any order or rule of any regulatory body entered after said date, be required to be removed, in whole or in part, from the books of account of the Company by charges to earned surplus.

SECTION 4.04. *Use of Facsimile Seal and Signatures.* The seal of the Company and any or all signatures of the officers of the Company upon any of the Bonds of the Medium-Term Notes Series K may be facsimiles.

SECTION 4.05. *Time for Making of Payment.* All payments of principal or redemption price of, and interest on, the Bonds of the Medium-Term Notes Series K shall be made either prior to the due date thereof or on the due date thereof in immediately available funds. In any case where the date of any such payment shall be a Saturday or Sunday or a legal holiday or a day on which banking institutions in the city of payment are authorized by law to close, then such payment need not be made on such date but may be made on the next succeeding business day with the same force and effect as if made on the due date, and no interest on such payment shall accrue for the period after such date.

SECTION 4.06. *Effective Period of Supplemental Indenture.* The preceding provisions of Articles I, II and III of this supplemental indenture shall remain in effect only so long as any of the Bonds of the Medium-Term Notes Series K shall remain outstanding.

SECTION 4.07. *Effect of Approval of Board of Public Utilities of the State of New Jersey.* The approval of the Board of Public Utilities of the State of New Jersey of the execution and delivery of these presents and of the issue of any Bond of the Medium-Term Notes Series K shall not be construed as approval of said Board of any other act, matter or thing which requires approval of said Board under the laws of the State of New Jersey.

SECTION 4.08. *Execution in Counterparts.* For the purpose of facilitating the recording hereof, this supplemental indenture has been executed in several counterparts, each of which shall be and shall be taken to be an original, and all collectively but one instrument.

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In WITNESS WHEREOF, Public Service Electric and Gas Company, party hereto of the first part, after due corporate and other proceedings, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents and its corporate seal hereunto to be affixed and to be attested by the signature of its Secretary or an Assistant Secretary; and U.S. Bank National Association, as Trustee, party hereto of the second part, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents, and to be attested by the signature of its Secretary, Assistant Secretary, Vice President, or an Assistant Vice President. Executed and delivered this 4th day of May 2015.

Attest:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By /s/ Bradford D. Huntington
. . . . . .
B.D. Huntington
Vice President

(Seal)
Attest:
/s/ Donald S. Leibowitz
. . . . . .
Donald S. Leibowitz
Assistant Secretary

U.S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes
. . . . . .
N. Barnes
Vice President

Attest:
A. Harris
. . . . . .
A. Harris
Vice President

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STATE OF NEW JERSEY)
SS:)
COUNTY OF ESSEX)

Be it Remembered, that on this 4th day of May, 2015, before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared B.D. Huntington, who, I am satisfied, is a Vice President of Public Service Electric and Gas Company, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors, and that said corporation, the mortgagor, has received a true copy of said instrument.

/s/ June Barnett
. . . . . .
June Barnett
Notary Public of New Jersey
My Commission Expires July 31, 2018

STATE OF NEW JERSEY)
SS:)
COUNTY OF ESSEX)

Be it Remembered, that on this 4th day of May 2015 before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared N. Barnes, who, I am satisfied, is a Vice President of U.S. Bank National Association, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, and that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors.

/ Melody A. Simpson

.....
Melody A. Simpson
Notary Public of New Jersey
My Commission Expires March 1, 2016

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CERTIFICATE OF RESIDENCE

U.S. Bank National Association, Mortgagee and Trustee within named, hereby certifies that its precise residence is 21 South Street, Morristown, New Jersey 07960.

U.S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes
. . . . . .
N. Barnes
Vice President

S1-SSA-0009 - 17620

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2015	2014	2014	2013	2012	2011	2010
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,515	970	$ 2,456	$ 2,055	$ 2,011	$ 2,384	$ 2,616
(Income) Loss from Equity Investees, net of Distributions	2	2	4	(7)	9	(4)	(19)
Fixed Charges	223 —	222	450	458	479	522	571
Capitalized Interest	(5)	(8)	(16)	(16)	(19)	(14)	(67)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	—	(2)
Total Earnings	$ 1,735	$ 1,186	$ 2,894	$ 2,490	$ 2,480	$ 2,888	$ 3,099
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 213	211	$ 430	$ 442	$ 465	$ 509	$ 555
Interest Factor in Rentals	10	11	20	16	14	13	14
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	—	2
Total Fixed Charges	$ 223	$ 222	$ 450	$ 458	$ 479	$ 522	$ 571
Ratio of Earnings to Fixed Charges	**7.78**	**5.34**	**6.43**	**5.44**	**5.18**	**5.53**	**5.43**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2015	2014	2014	2013	2012	2011	2010
			(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 670	594	$1,174	$ 993	$ 835	$ 861	$ 591
Fixed Charges	148	150	303	316	314	319	325
Capitalized Interest	(8)	(9)	(16)	(16)	(13)	(4)	(2)
Total Earnings	$ 810	$ 735	$1,461	$1,293	$ 1,136	$1,176	$ 914
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 144	144	$ 293	$ 309	$ 308	$ 314	$ 320
Interest Factor in Rentals	4	6	10	7	6	5	5
Total Fixed Charges	$ 148	$ 150	$ 303	$ 316	$ 314	$ 319	$ 325
Ratio of Earnings to Fixed Charges	**5.47**	**4.90**	**4.82**	**4.09**	**3.62**	**3.69**	**2.81**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Six Months Ended June 30,		Years Ended December 31,				
	2015	2014	2014	2013	2012	2011	2010
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 670	$ 594	$1,174	$ 993	$ 835	$ 861	$ 591
Fixed Charges	148	150	303	316	314	319	327
Capitalized Interest	(8)	(9)	(16)	(16)	(13)	(4)	(2)
Preferred Securities Dividend Requirements	—	—	—	—	—	—	(2)
Total Earnings	$ 810	$ 735	$1,461	$1,293	$1,136	$1,176	$ 914
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 144	$ 144	$ 293	$ 309	$ 308	$ 314	$ 320
Interest Factor in Rentals	4	6	10	7	6	5	5
Preferred Securities Dividend	—	—	—	—	—	—	1
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	—	—	—	—	1
Total Fixed Charges	$ 148	$ 150	$ 303	$ 316	$ 314	$ 319	$ 327
Ratio of Earnings to Fixed Charges	**5.47**	**4.90**	**4.82**	**4.09**	**3.62**	**3.69**	**2.80**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period, (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries, and (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 12.3

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2015	**2014**	**2014**	**2013**	**2012**	**2011**	**2010**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	807	351	$1,251	$1,063	$1,099	$1,703	$1,932
(Income) Loss from Equity Investees, net of Distributions	1	1	3	(10)	(6)	(12)	(8)
Fixed Charges	78	75	150	143	164	208	238
Capitalized Interest	2	2	1	1	(6)	(10)	(63)
Total Earnings	$ 888	$ 429	$1,405	$1,197	$1,251	$1,889	$2,099
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	75	72	$ 146	$ 139	$ 161	$ 205	$ 235
Interest Factor in Rentals	3	3	4	4	3	3	3
Total Fixed Charges	$ 78	$ 75	$ 150	$ 143	$ 164	$ 208	$ 238
Ratio of Earnings to Fixed Charges	**11.38**	**5.72**	**9.37**	**8.37**	**7.63**	**9.08**	**8.82**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2015

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2015

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer

S1-SSA-0009 - 17626

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2015

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2015

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2015

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2015

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
July 31, 2015

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer
July 31, 2015

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
July 31, 2015

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer
July 31, 2015

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
July 31, 2015

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Caroline Dorsa

Caroline Dorsa

PSEG Power LLC
Chief Financial Officer
July 31, 2015

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2016
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of July 19, 2016, Public Service Enterprise Group Incorporated had outstanding 505,916,520 shares of its sole class of Common Stock, without par value.

As of July 19, 2016, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or ongoing low pricing of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulations, including market structures and transmission planning,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators, including prudency reviews, disallowances and changes in authorized returns,
- any deterioration in our credit quality or the credit quality of our counterparties,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations or increase the cost of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- delays or unforeseen cost escalations in our construction and development activities, or the inability to recover the carrying amount of our assets,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- increases in competition in energy supply markets as well as for transmission projects,
- changes in technology, such as distributed generation, storage and micro grids, and greater reliance on these technologies,
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- an extended economic recession,
- an inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce, and
- changes in the credit quality and the ability of lessees to meet their obligations under our domestic leveraged leases.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected

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consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

FILING FORMAT

This combined Quarterly Report on Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to “we,” “us,” and “our” relate to PSEG or to the specific company or companies being discussed.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
OPERATING REVENUES	$ 1,905	$ 2,314	$ 4,521	$ 5,449
OPERATING EXPENSES				
Energy Costs	624	668	1,460	1,762
Operation and Maintenance	710	761	1,439	1,424
Depreciation and Amortization	224	317	448	647
Total Operating Expenses	1,558	1,746	3,347	3,833
OPERATING INCOME	347	568	1,174	1,616
Income from Equity Method Investments	4	4	6	7
Other Income	44	76	92	124
Other Deductions	(10)	(10)	(31)	(22)
Other-Than-Temporary Impairments	(10)	(10)	(20)	(15)
Interest Expense	(97)	(97)	(189)	(195)
INCOME BEFORE INCOME TAXES	278	531	1,032	1,515
Income Tax Expense	(91)	(186)	(374)	(584)
NET INCOME	$ 187	$ 345	$ 658	$ 931
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	505	506	505	506
DILUTED	508	508	508	508
NET INCOME PER SHARE:				
BASIC	$ 0.37	$ 0.68	$ 1.30	$ 1.84
DILUTED	$ 0.37	$ 0.68	$ 1.30	$ 1.83
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.41	$ 0.39	$ 0.82	$ 0.78

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
NET INCOME	$ 187	$ 345	$ 658	$ 931
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(10), $15, $(26) and $2 for the three and six months ended 2016 and 2015, respectively	10	(15)	26	(1)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $0, $(1) and $7 for the three and six months ended 2016 and 2015, respectively	(1)	—	1	(9)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(6), $(6), $(12) and $(12) for the three and six months ended 2016 and 2015, respectively	8	8	16	16
Other Comprehensive Income (Loss), net of tax	17	(7)	43	6
COMPREHENSIVE INCOME	$ 204	$ 338	$ 701	$ 937

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 648	$ 394
Accounts Receivable, net of allowances of $65 and $67 in 2016 and 2015, respectively	988	1,068
Tax Receivable	4	305
Unbilled Revenues	202	197
Fuel	351	463
Materials and Supplies, net	554	513
Prepayments	271	135
Derivative Contracts	152	242
Regulatory Assets	310	164
Other	9	13
Total Current Assets	3,489	3,494
PROPERTY, PLANT AND EQUIPMENT	37,285	35,494
Less: Accumulated Depreciation and Amortization	(9,271)	(8,955)
Net Property, Plant and Equipment	28,014	26,539
NONCURRENT ASSETS		
Regulatory Assets	3,120	3,196
Long-Term Investments	1,218	1,233
Nuclear Decommissioning Trust (NDT) Fund	1,797	1,754
Long-Term Tax Receivable	183	171
Long-Term Receivable of Variable Interest Entity (VIE)	513	495
Other Special Funds	246	227
Goodwill	16	16
Other Intangibles	131	102
Derivative Contracts	76	77
Other	242	231
Total Noncurrent Assets	7,542	7,502
TOTAL ASSETS	$ 39,045	$ 37,535

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2016	December 31, 2015
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 662	$ 734
Commercial Paper and Loans	—	364
Accounts Payable	1,308	1,369
Derivative Contracts	20	76
Accrued Interest	103	96
Accrued Taxes	107	42
Clean Energy Program	200	142
Obligation to Return Cash Collateral	128	128
Regulatory Liabilities	74	123
Regulatory Liabilities of VIEs	22	42
Other	496	459
Total Current Liabilities	3,120	3,575
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	8,545	8,166
Regulatory Liabilities	165	175
Asset Retirement Obligations	693	679
OPEB Costs	1,199	1,228
OPEB Costs of Servco	389	375
Accrued Pension Costs	429	487
Accrued Pension Costs of Servco	118	114
Clean Energy Program	27	—
Environmental Costs	402	415
Derivative Contracts	14	27
Long-Term Accrued Taxes	171	212
Other	181	181
Total Noncurrent Liabilities	12,333	12,059
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT	10,273	8,834
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2016 and 2015—534 shares	4,919	4,915
Treasury Stock, at cost, 2016—29 shares; 2015—28 shares	(709)	(671)
Retained Earnings	9,360	9,117
Accumulated Other Comprehensive Loss	(252)	(295)
Total Common Stockholders' Equity	13,318	13,066
Noncontrolling Interest	1	1
Total Stockholders' Equity	13,319	13,067
Total Capitalization	23,592	21,901
TOTAL LIABILITIES AND CAPITALIZATION	$ 39,045	$ 37,535

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2016	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 658	$ 931
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	448	647
Amortization of Nuclear Fuel	105	106
Provision for Deferred Income Taxes (Other than Leases) and ITC	334	170
Non-Cash Employee Benefit Plan Costs	63	81
Leveraged Lease (Income) Loss, Adjusted for Rents Received and Deferred Taxes	(30)	(22)
Net Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	153	(9)
Change in Accrued Storm Costs	(1)	15
Net Change in Other Regulatory Assets and Liabilities	(124)	(53)
Cost of Removal	(74)	(58)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(2)	(21)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	301	188
Accrued Taxes	94	71
Margin Deposit	(46)	69
Other Current Assets and Liabilities	(120)	98
Employee Benefit Plan Funding and Related Payments	(78)	(67)
Other	41	88
Net Cash Provided By (Used In) Operating Activities	1,722	2,234
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,971)	(1,743)
Proceeds from Sales of Available-for-Sale Securities	392	885
Investments in Available-for-Sale Securities	(407)	(918)
Other	(18)	3
Net Cash Provided By (Used In) Investing Activities	(2,004)	(1,773)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(364)	—
Issuance of Long-Term Debt	1,550	600
Redemption of Long-Term Debt	(171)	(300)
Redemption of Securitization Debt	—	(125)
Cash Dividends Paid on Common Stock	(415)	(394)
Other	(64)	(47)
Net Cash Provided By (Used In) Financing Activities	536	(266)
Net Increase (Decrease) in Cash and Cash Equivalents	254	195
Cash and Cash Equivalents at Beginning of Period	394	402
Cash and Cash Equivalents at End of Period	$ 648	$ 597
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (276)	$ 184
Interest Paid, Net of Amounts Capitalized	$ 176	$ 195
Accrued Property, Plant and Equipment Expenditures	$ 513	$ 324

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17645

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
OPERATING REVENUES	$ 1,350	$ 1,466	$ 3,062	$ 3,468
OPERATING EXPENSES				
Energy Costs	529	544	1,258	1,436
Operation and Maintenance	352	368	734	780
Depreciation and Amortization	136	234	275	481
Total Operating Expenses	1,017	1,146	2,267	2,697
OPERATING INCOME	333	320	795	771
Other Income	19	19	39	37
Other Deductions	(1)	(1)	(2)	(2)
Interest Expense	(74)	(67)	(142)	(136)
INCOME BEFORE INCOME TAXES	277	271	690	670
Income Tax Expense	(98)	(104)	(249)	(261)
NET INCOME	$ 179	$ 167	$ 441	$ 409

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17646

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
NET INCOME	$ 179	$ 167	$ 441	$ 409
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0 and $0 for the three and six months ended 2016 and 2015, respectively	1	(1)	1	(1)
COMPREHENSIVE INCOME	$ 180	$ 166	$ 442	$ 408

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17647

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 168	$ 198
Accounts Receivable, net of allowances of $65 and $67 in 2016 and 2015, respectively	736	787
Accounts Receivable—Affiliated Companies	—	222
Unbilled Revenues	202	197
Materials and Supplies	162	148
Prepayments	196	31
Regulatory Assets	310	164
Derivative Contracts	—	13
Other	8	9
Total Current Assets	1,782	1,769
PROPERTY, PLANT AND EQUIPMENT	24,976	23,732
Less: Accumulated Depreciation and Amortization	(5,627)	(5,504)
Net Property, Plant and Equipment	19,349	18,228
NONCURRENT ASSETS		
Regulatory Assets	3,120	3,196
Long-Term Investments	316	330
Other Special Funds	57	49
Other	113	105
Total Noncurrent Assets	3,606	3,680
TOTAL ASSETS	$ 24,737	$ 23,677

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17648

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2016	December 31, 2015
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 100	$ 171
Commercial Paper and Loans	—	153
Accounts Payable	680	724
Accounts Payable—Affiliated Companies	179	292
Accrued Interest	73	70
Clean Energy Program	200	142
Derivative Contracts	2	—
Obligation to Return Cash Collateral	127	128
Regulatory Liabilities	74	123
Regulatory Liabilities of VIEs	22	42
Other	339	297
Total Current Liabilities	1,796	2,142
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	5,503	5,181
OPEB Costs	904	937
Accrued Pension Costs	165	202
Regulatory Liabilities	165	175
Clean Energy Program	27	—
Environmental Costs	336	365
Asset Retirement Obligations	220	218
Derivative Contracts	—	11
Long-Term Accrued Taxes	99	109
Other	113	114
Total Noncurrent Liabilities	7,532	7,312
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT	7,394	6,650
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2016 and 2015—132 shares	892	892
Contributed Capital	695	695
Basis Adjustment	986	986
Retained Earnings	5,440	4,999
Accumulated Other Comprehensive Income	2	1
Total Stockholder's Equity	8,015	7,573
Total Capitalization	15,409	14,223
TOTAL LIABILITIES AND CAPITALIZATION	$ 24,737	$ 23,677

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17649

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2016	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 441	$ 409
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	275	481
Provision for Deferred Income Taxes and ITC	290	79
Non-Cash Employee Benefit Plan Costs	36	48
Cost of Removal	(74)	(58)
Change in Accrued Storm Costs	(1)	15
Net Change in Other Regulatory Assets and Liabilities	(124)	(53)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	50	53
Materials and Supplies	(14)	(10)
Prepayments	(165)	(162)
Accounts Payable	(29)	48
Accounts Receivable/Payable—Affiliated Companies, net	181	154
Other Current Assets and Liabilities	17	(27)
Employee Benefit Plan Funding and Related Payments	(62)	(55)
Other	(13)	(13)
Net Cash Provided By (Used In) Operating Activities	808	909
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,355)	(1,230)
Proceeds from Sales of Available-for-Sale Securities	12	12
Investments in Available-for-Sale Securities	(13)	(14)
Other	2	12
Net Cash Provided By (Used In) Investing Activities	(1,354)	(1,220)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	(153)	—
Issuance of Long-Term Debt	850	600
Redemption of Long-Term Debt	(171)	(300)
Redemption of Securitization Debt	—	(125)
Other	(10)	(8)
Net Cash Provided By (Used In) Financing Activities	516	167
Net Increase (Decrease) In Cash and Cash Equivalents	(30)	(144)
Cash and Cash Equivalents at Beginning of Period	198	310
Cash and Cash Equivalents at End of Period	$ 168	$ 166
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (255)	$ (74)
Interest Paid, Net of Amounts Capitalized	$ 134	$ 131
Accrued Property, Plant and Equipment Expenditures	$ 381	$ 282

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17650

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
OPERATING REVENUES	$ 714	$ 1,025	$ 2,027	$ 2,750
OPERATING EXPENSES				
Energy Costs	381	409	1,019	1,302
Operation and Maintenance	265	313	518	485
Depreciation and Amortization	80	75	159	151
Total Operating Expenses	726	797	1,696	1,938
OPERATING INCOME (LOSS)	(12)	228	331	812
Income from Equity Method Investments	4	5	6	8
Other Income	25	55	51	84
Other Deductions	(9)	(7)	(27)	(18)
Other-Than-Temporary Impairments	(10)	(10)	(20)	(15)
Interest Expense	(20)	(33)	(42)	(64)
INCOME (LOSS) BEFORE INCOME TAXES	(22)	238	299	807
Income Tax Benefit (Expense)	11	(72)	(118)	(306)
NET INCOME (LOSS)	$ (11)	$ 166	$ 181	$ 501

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17651

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
NET INCOME (LOSS)	$ (11)	$ 166	$ 181	$ 501
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(9), $14, $(25) and $1 for the three and six months ended 2016 and 2015, respectively	9	(14)	25	—
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $0, $0 and $7 for the three and six months ended 2016 and 2015, respectively	—	—	—	(9)
Pension/OPEB adjustment, net of tax (expense) benefit of $(5), $(5), $(10) and $(10) for the three and six months ended 2016 and 2015, respectively	7	7	14	14
Other Comprehensive Income (Loss), net of tax	16	(7)	39	5
COMPREHENSIVE INCOME	$ 5	$ 159	$ 220	$ 506

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17652

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 16	$ 12
Accounts Receivable	202	217
Accounts Receivable—Affiliated Companies	94	276
Short-Term Loan to Affiliate	1,335	363
Fuel	351	463
Materials and Supplies, net	389	363
Derivative Contracts	150	223
Prepayments	7	25
Other	4	7
Total Current Assets	2,548	1,949
PROPERTY, PLANT AND EQUIPMENT	11,969	11,354
Less: Accumulated Depreciation and Amortization	(3,491)	(3,227)
Net Property, Plant and Equipment	8,478	8,127
NONCURRENT ASSETS		
NDT Fund	1,797	1,754
Long-Term Investments	112	119
Goodwill	16	16
Other Intangibles	131	102
Other Special Funds	60	55
Derivative Contracts	76	77
Other	60	51
Total Noncurrent Assets	2,252	2,174
TOTAL ASSETS	$ 13,278	$ 12,250

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17653

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2016	December 31, 2015
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 553	$ 553
Accounts Payable	466	432
Accounts Payable—Affiliated Companies	102	33
Derivative Contracts	17	76
Accrued Interest	29	25
Other	96	107
Total Current Liabilities	1,263	1,226
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	2,418	2,347
Asset Retirement Obligations	470	457
OPEB Costs	234	230
Derivative Contracts	14	16
Accrued Pension Costs	151	166
Long-Term Accrued Taxes	22	35
Other	104	87
Total Noncurrent Liabilities	3,413	3,338
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT	2,380	1,684
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	5,195	5,014
Accumulated Other Comprehensive Loss	(201)	(240)
Total Member's Equity	6,222	6,002
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 13,278	$ 12,250

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17654

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2016	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 181	$ 501
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	159	151
Amortization of Nuclear Fuel	105	106
Provision for Deferred Income Taxes and ITC	37	64
Net Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	153	(9)
Non-Cash Employee Benefit Plan Costs	19	24
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(2)	(21)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	86	209
Margin Deposit	(46)	69
Accounts Receivable	(12)	76
Accounts Payable	(10)	(62)
Accounts Receivable/Payable—Affiliated Companies, net	179	123
Other Current Assets and Liabilities	11	(21)
Employee Benefit Plan Funding and Related Payments	(10)	(7)
Other	67	89
Net Cash Provided By (Used In) Operating Activities	917	1,292
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(598)	(487)
Proceeds from Sales of Available-for-Sale Securities	346	837
Investments in Available-for-Sale Securities	(359)	(854)
Short-Term Loan—Affiliated Company, net	(972)	(366)
Other	(24)	(17)
Net Cash Provided By (Used In) Investing Activities	(1,607)	(887)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Long-Term Debt	700	—
Cash Dividend Paid	—	(400)
Other	(6)	(2)
Net Cash Provided By (Used In) Financing Activities	694	(402)
Net Increase (Decrease) in Cash and Cash Equivalents	4	3
Cash and Cash Equivalents at Beginning of Period	12	9
Cash and Cash Equivalents at End of Period	$ 16	$ 12
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (53)	$ 218
Interest Paid, Net of Amounts Capitalized	$ 38	$ 62
Accrued Property, Plant and Equipment Expenditures	$ 132	$ 42

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17655

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Note 1. Organization and Basis of Presentation

Organization

PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- **Power**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy transacting functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2015.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2015.

Note 2. Recent Accounting Standards

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard clarifies the principles for recognizing revenue and removes inconsistencies in revenue recognition requirements; improves comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provides improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The standard was originally to be effective for annual and interim reporting periods beginning after December 15, 2016; however, the Financial Accounting Standards Board issued new guidance deferring the effective date by one year to periods beginning after December 31, 2017. Early application will be permitted as of the original effective date. PSEG is currently analyzing the impact of this standard on its financial statements.

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Recognition and Measurement of Financial Assets and Financial Liabilities

This accounting standard will change how entities measure equity investments that are not consolidated or accounted for under the equity method. Under the new guidance, equity investments (other than those accounted for using the equity method) will be measured at fair value through Net Income instead of Other Comprehensive Income (Loss). Entities that have elected the fair value option for financial liabilities will present changes in fair value due to a change in their own credit risk through Other Comprehensive Income (Loss). For equity investments which do not have readily determinable fair values, the impairment assessment will be simplified by requiring a qualitative assessment to identify impairments. The new standard also changes certain disclosures.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG is currently analyzing the impact of this standard on our financial statements; however, PSEG expects increased volatility in Net Income due to changes in fair value of our equity securities within the Nuclear Decommissioning Trust (NDT) and Rabbi Trust Funds.

Leases

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor will classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements.

The standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Stock Compensation-Improvements to Employee Share-Based Payment Accounting

This accounting standard was issued to simplify aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows.

Under the new guidance, all excess tax benefits and tax deficiencies will be recognized in income tax expense rather than recognized in additional paid in capital. In the statement of cash flows, excess tax benefits and deficiencies will be classified with other income tax cash flows as an operating activity rather than a financing activity as currently classified. In addition, the minimum statutory tax withholding requirements were simplified in order to facilitate equity classification of the award.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early adoption is permitted for an entity in any interim or annual period. An entity that elects early adoption must adopt all of the amendments in the same period; however, the amendments within this update require different adoption methods. PSEG is currently analyzing the impact of this standard on its financial statements.

Measurement of Credit Losses on Financial Instruments

This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however, this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

S1-SSA-0009 - 17657

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Note 3. Variable Interest Entities (VIEs)

VIEs for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which was pledged as collateral to a trustee. PSE&G acted as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds were remitted to Transition Funding and Transition Funding II and were used for interest and principal payments on the transition bonds and related costs. During 2015, Transition Funding and Transition Funding II paid their final securitization bond payments and as of December 31, 2015, no further debt or related costs remained with these VIEs. Effective January 1, 2016, PSE&G commenced refunding the overcollections from customers associated with these VIEs and expects to fully refund these liabilities in 2016.

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operation and Maintenance (O&M) Expense, respectively. Servco recorded $101 million and $84 million for the three months and $199 million and $166 million for the six months ended June 30, 2016 and 2015, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 4. Rate Filings

This Note should be read in conjunction with Note 5. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2015.

In addition to items previously reported in the Annual Report on Form 10-K, significant regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

Remediation Adjustment Charge (RAC)—In April 2016, the BPU approved PSE&G's filing with respect to its RAC 23 petition allowing recovery of $54 million effective May 7, 2016 related to net Manufactured Gas Plant expenditures from August 1, 2014 through July 31, 2015.

Energy Strong Recovery Filing—In March and September of each year, PSE&G files with the BPU for base rate recovery of Energy Strong investments which include a return of and on its investment. In June 2016, PSE&G updated its March cost recovery petition to include Energy Strong investments in service as of May 31, 2016 which represents estimated annual increases in electric and gas revenues of $16 million and $23 million, respectively. The petition requests rates to be effective September 1, 2016, consistent with the BPU Order of approval of the Energy Strong program. This matter is pending.

Basic Gas Supply Service (BGSS)—In June 2016, PSE&G made its annual BGSS filing with the BPU requesting a reduction of $87 million in annual BGSS revenues. If approved, the BGSS rate would be reduced from approximately 40 cents to 34 cents per therm effective October 1, 2016. This matter is pending.

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Transmission Formula Rate Filings—In June 2016, PSE&G filed its 2015 true-up adjustment pertaining to its transmission formula rates in effect for 2015. This resulted in an adjustment of $34 million less than the 2015 originally filed revenues primarily due to the impact of bonus depreciation legislation enacted after PSE&G filed its 2015 formula rate requirement in October 2014. PSE&G had recognized the majority of this adjustment in its Consolidated Statement of Operations for the year ended December 31, 2015.

Weather Normalization Clause—On July 1, 2016, PSE&G filed a petition requesting approval to collect $54 million in net deficiency gas revenues as a result of the warmer than normal 2015-2016 Winter Period. The deficiency gas revenues would be collected from customers over the 2016-2017 and 2017-2018 Winter Periods (October 1 through May 31). This matter is pending.

Solar and Energy Efficiency - Green Program Recovery Charges (GPRC)—Each year PSE&G files with the BPU for annual recovery of its Green Program investments which include a return on its investment and recovery of expenses. On July 1, 2016, PSE&G filed its 2016 GPRC cost recovery petition requesting recovery for the nine combined components of the electric and gas GPRC. The filing proposes rates for the period October 1, 2016 through September 30, 2017 designed to recover approximately $44 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved programs. This matter is pending.

Gas System Modernization Program (GSMP)—On July 29, 2016, PSE&G filed its initial annual GSMP cost recovery petition seeking BPU approval to recover in gas base rates an estimated annual revenue increase of $13 million effective January 1, 2017. This increase represents the return of and on investment for GSMP investments expected to be in service through September 30, 2016. This request will be updated in October 2016 for actual costs.

Note 5. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with solar renewable energy certificates generated from the installed solar electric system. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered “non-performing.”

Outstanding Loans by Class of Customer

Consumer Loans	As of June 30, 2016	As of December 31, 2015
	Millions	
Commercial/Industrial	$ 174	$ 177
Residential	12	12
Total	**$ 186**	**$ 189**

Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG’s Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings’ investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG’s Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG’s Condensed Consolidated Balance Sheets.

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The following table shows Energy Holdings' gross and net lease investment as of June 30, 2016 and December 31, 2015, respectively.

	As of June 30, 2016	As of December 31, 2015
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 630	$ 631
Estimated Residual Value of Leased Assets	519	519
Total Investment in Rental Receivables	1,149	1,150
Unearned and Deferred Income	(359)	(366)
Gross Investment in Leases	790	784
Deferred Tax Liabilities	(694)	(724)
Net Investment in Leases	**$ 96**	**$ 60**

The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

	Lease Receivables, Net of Non-Recourse Debt
Counterparties' Credit Rating Standard & Poor's (S&P) as of June 30, 2016	**As of June 30, 2016**
	Millions
AA	$ 16
BBB+ — BBB-	316
BB-	134
CCC	164
Total	**$ 630**

The "BB-" and the "CCC" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of June 30, 2016, the gross investment in the leases of such assets, net of non-recourse debt, was $573 million ($(5) million, net of deferred taxes). A more detailed description of such assets under lease, as of June 30, 2016, is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal (A)	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	CCC (C)	NRG REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	CCC (C)	NRG REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 113	100%	603	Coal (B)	CCC (C)	NRG REMA, LLC

(A) The Joliet facility is currently in the process of converting to natural gas.

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(B) NRG REMA, LLC (NRG REMA) notified PJM that it deactivated the coal-fired units at the Shawville generating facility in June 2015 and has disclosed that it expects to return the Shawville units to service in the fall of 2016 with the ability to use natural gas.

(C) On May 24, 2016, S&P lowered its corporate credit rating on GenOn Energy Inc. and affiliates (including NRG REMA) to "CCC" from "CCC+" due to a weaker forward power curve, milder weather patterns and weakening financial measures. PSEG continues to monitor any changes to GenOn's status and potential impacts on Energy Holdings' lease investments.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations which could be mitigated by tax indemnification claims with the counterparty. A bankruptcy of a lessee would likely delay and potentially limit any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service.

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

Note 6. Available-for-Sale Securities

NDT Fund

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third party investment advisers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of June 30, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 679	$ 198	$ (12)	$ 865
Debt Securities				
Government Obligations	503	23	—	526
Other	348	12	(3)	357
Total Debt Securities	851	35	(3)	883
Other Securities	49	—	—	49
Total NDT Available-for-Sale Securities	**$ 1,579**	**$ 233**	**$ (15)**	**$ 1,797**

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	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 693	$ 185	$ (13)	$ 865
Debt Securities				
Government Obligations	483	8	(3)	488
Other	366	3	(10)	359
Total Debt Securities	849	11	(13)	847
Other Securities	42	—	—	42
Total NDT Available-for-Sale Securities	**$ 1,584**	**$ 196**	**$ (26)**	**$ 1,754**

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of June 30, 2016	As of December 31, 2015
	Millions	
Accounts Receivable	$ 18	$ 17
Accounts Payable	$ 10	$ 10

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of June 30, 2016				As of December 31, 2015			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 108	$ (12)	$ 5	$ —	$ 151	$ (13)	$ 1	$ —
Debt Securities								
Government Obligations (B)	12	—	6	—	245	(2)	19	(1)
Other (C)	12	—	43	(3)	222	(7)	36	(3)
Total Debt Securities	24	—	49	(3)	467	(9)	55	(4)
NDT Available-for-Sale Securities	**$ 132**	**$ (12)**	**$ 54**	**$ (3)**	**$ 618**	**$ (22)**	**$ 56**	**$ (4)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of June 30, 2016.

(B) Debt Securities (Government Obligations)—Unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the U.S. government or an agency of the U.S. government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be

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more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of June 30, 2016.

(C) Debt Securities (Other)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2016.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	Millions			
Proceeds from NDT Fund Sales (A)	**$ 154**	**$ 232**	**$ 331**	**$ 822**
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	10	14	25	33
Gross Realized Losses	(6)	(4)	(22)	(13)
Net Realized Gains (Losses) on NDT Fund	**$ 4**	**$ 10**	**$ 3**	**$ 20**

(A) 2015 proceeds include activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $110 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of June 30, 2016.

The NDT available-for-sale debt securities held as of June 30, 2016 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 19
1 - 5 years	216
6 - 10 years	220
11 - 15 years	54
16 - 20 years	61
Over 20 years	313
Total NDT Available-for-Sale Debt Securities	**$ 883**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the six months ended June 30, 2016, other-than-temporary impairments of $20 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of June 30, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 11	$ 10	$ —	$ 21
Debt Securities				
Government Obligations	104	2	—	106
Other	90	1	(1)	90
Total Debt Securities	194	3	(1)	196
Other Securities	5	—	—	5
Total Rabbi Trust Available-for-Sale Securities	**$ 210**	**$ 13**	**$ (1)**	**$ 222**

	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 10	$ —	$ 22
Debt Securities				
Government Obligations	108	1	(1)	108
Other	82	—	(1)	81
Total Debt Securities	190	1	(2)	189
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 204**	**$ 11**	**$ (2)**	**$ 213**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of June 30, 2016	As of December 31, 2015
	Millions	
Accounts Receivable	$ 2	$ 1
Accounts Payable	$ 4	$ —

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The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of June 30, 2016				As of December 31, 2015			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	14	—	3	—	53	(1)	2	—
Other (C)	14	—	11	(1)	46	(1)	9	—
Total Debt Securities	28	—	14	(1)	99	(2)	11	—
Rabbi Trust Available-for-Sale Securities	**$ 28**	**$ —**	**$ 14**	**$ (1)**	**$ 99**	**$ (2)**	**$ 11**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government Obligations)—Unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the U.S. government or an agency of the U.S. government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of June 30, 2016.

(C) Debt Securities (Other)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2016.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	Millions			
Proceeds from Rabbi Trust Sales (A)	**$ 36**	**$ 44**	**$ 61**	**$ 63**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ 2	$ 2	$ 3	$ 2
Gross Realized Losses	(1)	—	(2)	—
Net Realized Gains (Losses) on Rabbi Trust	**$ 1**	**$ 2**	**$ 1**	**$ 2**

(A) 2015 proceeds include activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains disclosed in the preceding table were recognized in Other Income in the Condensed Consolidated Statements of Operations. Net unrealized gains of $7 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of June 30, 2016.

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The Rabbi Trust available-for-sale debt securities held as of June 30, 2016 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 8
1 - 5 years	45
6 - 10 years	48
11 - 15 years	6
16 - 20 years	7
Over 20 years	82
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 196**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

The fair value of assets in the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of June 30, 2016	As of December 31, 2015
	Millions	
PSE&G	$ 44	$ 42
Power	54	52
Other	124	119
Total Rabbi Trust Available-for-Sale Securities	**$ 222**	**$ 213**

Note 7. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria.

Effective January 1, 2016, PSEG changed the approach used to measure future service and interest costs for pension benefits. For 2015 and prior, PSEG calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, PSEG has elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows. PSEG believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations. As a change in accounting estimate, this change is being reflected prospectively. Pension and OPEB costs, net of amounts capitalized, were reduced by $8 million and $3 million, for the three months ended June 30, 2016 respectively, and $17 million and $6 million for the six months ended June 30, 2016, respectively, as compared to the 2016 amounts that would have been derived from applying PSEG's 2015 and prior years' methodology.

The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.

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Pension and OPEB costs for PSEG, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015	2016	2015	2016	2015
	Millions							
Components of Net Periodic Benefit Costs								
Service Cost	$ 27	$ 31	$ 4	$ 6	$ 54	$ 62	$ 8	$ 11
Interest Cost	51	58	14	17	101	117	29	34
Expected Return on Plan Assets	(99)	(104)	(7)	(8)	(197)	(207)	(15)	(15)
Amortization of Net								
Prior Service Cost (Credit)	(5)	(4)	(4)	(4)	(9)	(9)	(7)	(7)
Actuarial Loss	40	37	10	11	79	74	20	21
Total Benefit Costs	**$ 14**	**$ 18**	**$ 17**	**$ 22**	**$ 28**	**$ 37**	**$ 35**	**$ 44**

Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015	2016	2015	2016	2015
	Millions							
PSE&G	$ 7	$ 10	$ 11	$ 14	$ 14	$ 20	$ 22	$ 28
Power	4	5	5	6	8	11	11	13
Other	3	3	1	2	6	6	2	3
Total Benefit Costs	**$ 14**	**$ 18**	**$ 17**	**$ 22**	**$ 28**	**$ 37**	**$ 35**	**$ 44**

During the three months ended March 31, 2016, PSEG contributed its entire planned contributions for the year 2016 of $21 million into its pension plans and $14 million into its OPEB plan.

Servco Pension and OPEB

At the direction of LIPA, Servco sponsors benefit plans that cover its current and former employees who meet certain eligibility criteria. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco plans to contribute $28 million into its pension plan during 2016. Servco's pension-related revenues and costs were $6 million and $7 million for the three months ended June 30, 2016 and 2015, respectively, and $12 million and $13 million for the six months ended June 30, 2016 and 2015, respectively. The OPEB-related revenues earned and costs incurred for each of the three months and six months ended June 30, 2016 and 2015 were immaterial.

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Note 8. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of June 30, 2016 and December 31, 2015.

	As of June 30, 2016	As of December 31, 2015
	Millions	
Face Value of Outstanding Guarantees	$ 1,809	$ 1,734
Exposure under Current Guarantees	$ 136	$ 172
Letters of Credit Margin Posted	$ 160	$ 122
Letters of Credit Margin Received	$ 130	$ 192
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (4)	$ (15)
Net Broker Balance Deposited (Received)	$ 30	$ (5)
Additional Amounts Posted:		
Other Letters of Credit	$ 51	$ 51

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline and a $21 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a “Superfund” site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA determined that there was a need to perform a comprehensive study of the entire 17 miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the

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RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than with respect to their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. Construction is complete. The CPG is awaiting EPA approval of the construction report, long-term monitoring plan and confirmatory sampling plan. PSE&G's and Power's combined share of the cost of that effort is approximately three percent. The remaining CPG members have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplated the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS set forth various alternatives for remediating this portion of the Passaic River.

The CPG, which consisted of 53 members as of June 30, 2016, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost for the preparation of the RI/FS is approximately $163 million, which the CPG continues to incur. Of the estimated $163 million, as of June 30, 2016, the CPG had spent approximately $150 million, of which PSE&G's and Power's combined share was approximately $11 million.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River. It set forth the CPG's estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion on an undiscounted basis. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranged from approximately $518 million to $772 million. Based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimated share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

In March 2016, the EPA released its Record of Decision (ROD) for the FFS which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The ROD Remedy requires a bank-to-bank dredge ranging from approximately 5 to 30 feet deep in the federal navigation channel from River Mile 0 to River Mile 1.7 and an approximately 2.5 foot deep dredge everywhere else in the lower 8.3 miles of the river. An engineered cap approximately two feet thick will be placed over the dredged areas. Dredged sediments will be transported to facilities and landfills out-of-state. The EPA estimates the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation.

Based upon the estimated cost of the ROD Remedy, PSEG's estimate of PSE&G's and Power's shares of that cost, and the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued an additional $36 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued an additional $8 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2016. As of June 30, 2016, these accruals bring the total liability to approximately $57 million, $46 million applicable to PSE&G and $11 million applicable to Power.

Also in March 2016, the EPA sent a notice letter to 105 PRPs, including PSE&G, all other past and present members of the CPG, including Occidental Chemicals Corporation (OCC), and the towns of Newark, Kearny and Harrison and the Passaic Valley Sewerage Commission stating that the EPA wants to determine whether OCC, a successor company to Diamond Shamrock, will voluntarily perform the remedial design for the ROD Remedy. If the EPA secures a commitment to perform the

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Remedial Design from OCC, the EPA plans to begin negotiation of a remedial action consent decree, under which, OCC and the other "major" PRPs will implement and/or pay for the EPA's ROD Remedy for the lower 8.3 miles. "Major PRP" is undefined in the letter.

On June 16, 2016, Tierra and Maxus, successors to Diamond Shamrock, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Although PSEG does not currently anticipate that the filing for bankruptcy by Tierra and Maxus will affect its allocable share or total liability for the Passaic River matter, PSEG, through the CPG and independently, will monitor the bankruptcy proceedings to identify any potential impact on PSEG's share of the costs.

The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on PSEG's financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $426 million and $491 million through 2021, including its $46 million share for the Passaic River accrued as of June 30, 2016, as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $426 million as of June 30, 2016. Of this amount, $99 million was recorded in Other Current Liabilities and $327 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $426 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly. NJDEP, PSEG and EPA representatives have had discussions regarding whether sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.

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Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. On August 15, 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. On September 5, 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Second Circuit Court of Appeals. In two related actions on October 17, 2014 and November 20, 2014, several environmental non-governmental groups initiated challenges to the endangered species act provisions of the 316 (b) rule. Power is unable to determine the ultimate impact of these actions on the implementation of the rule.

On June 10, 2016, the NJDEP issued a final NJPDES permit for Salem with an effective date of August 1, 2016. The final permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the Clean Water Act, it requires additional studies and the selection of technology to address impingement for the service water system. On July 8, 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final permit for Salem. The Riverkeeper's filing does not change the effective date of the permit.

State permitting decisions could have a material impact on Power's ability to renew permits at its existing larger once-through cooled plants, including Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities, and could result in acceleration of decommissioning activities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1.0 billion, of which Power's share would have been approximately $575 million. The filing has not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA's Clean Water Act Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, Power would continue to operate BH3 without making the capital expenditures for modification to the existing

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intake structure and retire BH3 in 2021, which is four years earlier than the current estimated useful life ending in 2025. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in late 2016.

Separately, Power has also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that Power would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. The receipt of permits to allow construction and operation of the new facility could occur in 2017. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power will seek to operate BH3 through the current estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. Operations are expected to begin in mid-2019.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.

Steam Electric Effluent Guidelines

On September 30, 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Mercer and Bridgeport Harbor stations and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under this rule. Power is unable to predict if this rule will have a material impact on its future capital requirements, financial condition and results of operations.

Coal Combustion Residuals (CCRs)

On December 19, 2014, the EPA issued a final rule which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Power's Hudson and Mercer generating stations, along with its co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 19, 2015. Accordingly in June 2015, Power recorded an additional asset retirement obligation to comply with the final CCR rule which was not material to Power’s results of operations, financial condition or cash flows.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU’s approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G’s load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey’s renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2016 is $335.33 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2016 of $272.78 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

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PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2013	2014	2015	2016	
36-Month Terms Ending	May 2016	May 2017	May 2018	May 2019	(A)
Load (MW)	2,800	2,800	2,900	2,800	
$ per MWh	$92.18	$97.39	$99.54	$96.38	

(A) Prices set in the 2016 BGS auction year became effective on June 1, 2016 when the 2013 BGS auction agreements expired.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 17. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2020 at Salem, Hope Creek and Peach Bottom.

Power has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available beyond the needs of PSE&G's customers, Power can use the gas to supply its fossil generating stations.

Power also has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations.

As of June 30, 2016, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2020
	Millions
Nuclear Fuel	
Uranium	$ 454
Enrichment	$ 358
Fabrication	$ 180
Natural Gas	$ 972
Coal	$ 265

Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional

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pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future.

During the three month period ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. No additional charges to income have been recorded for this matter since that time.

Since September 2014, FERC Staff has been conducting a preliminary, non-public staff investigation into the matter and issued data requests covering a period from 2002 through the date of the self-report. This investigation is ongoing. Since that time, Power has responded to data requests from FERC Staff, including recent data requests in which Power has recalculated certain of its energy bids in PJM for a five year period, and may receive additional data requests or other fact finding. The FERC Staff investigation is still in the fact finding stage and there is considerable uncertainty around FERC's response to PSEG's legal arguments and the amount of disgorgement or other remedies FERC may ultimately seek.

PSEG is unable to reasonably estimate the range of possible loss for this matter; however, the amounts of potential disgorgement and other potential penalties that Power may incur span a wide range depending on the success of PSEG's legal arguments. These arguments include that Power's energy market bids in a substantial majority of the hours were below the allowed rate under the Tariff and therefore any errors in those hours were immaterial and that it is unclear whether the quantity of the bids violated any legal requirement. If PSEG's legal arguments do not prevail in whole or in part with FERC or in a judicial challenge that PSEG may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to PSEG's and Power's Consolidated Statements of Operations in the quarterly and annual periods in which they are recorded.

Nuclear Insurance Coverages

The following should be read in conjunction with Note 12. Commitments and Contingent Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2015.

Based upon a review of its nuclear insurance, Power made changes to its Nuclear Electric Insurance Limited (NEIL) insurance coverage of the excess layer for property damage which became effective on April 1, 2016. The excess layer provides coverage above the primary layer of NEIL insurance coverage for property damage of $1.5 billion. For the excess layer at the Salem/Hope Creek site, Power purchased coverage for property damage of $300 million due to a nuclear event and $300 million due to a non-nuclear event. For the excess layer at the Peach Bottom site, Power purchased coverage for its ownership interest for property damage of $300 million due to a nuclear event. For the excess layer at the Peach Bottom site, Exelon purchased coverage for property damage of $600 million due to a non-nuclear event which covers the ownership interest of Power.

Note 9. Debt and Credit Facilities

Long-Term Debt Financing Transactions

The following long-term debt transactions occurred in the six months ended June 30, 2016:

PSE&G

- issued $300 million of 1.90% Secured Medium-Term Notes, Series K due March 2021,
- issued $550 million of 3.80% Secured Medium-Term Notes, Series K due March 2046, and
- retired $171 million of 6.75% Secured First and Refunding Mortgage Bonds, Series VV at maturity.

Power

- issued $700 million of 3.00% Senior Notes due June 2021.

PSE&G

On July 1, 2016, PSE&G repurchased at par $100 million aggregate principal amount of Pollution Control Financing Authority of Salem County Bonds (Salem Bonds) and retired a like aggregate principal amount of its First and Refunding Mortgage Bonds which serviced and secured the Salem Bonds.

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Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under PSEG's $4.2 billion credit facilities are provided by a diverse bank group with no single institution representing more than 7% of the total commitments in PSEG's credit facilities. As of June 30, 2016, PSEG's total available credit capacity of $3.9 billion was in excess of its anticipated maximum liquidity requirements.

Each of PSEG's credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support its subsidiaries' liquidity needs. PSEG's total credit facilities and available liquidity as of June 30, 2016 were as follows:

	As of June 30, 2016				
Company/Facility	Total Facility	Usage (D)	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facility	$ 500	$ 10	$ 490	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—	500	Apr 2020	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 10**	**$ 990**		
PSE&G					
5-year Credit Facility (B)	$ 600	$ 14	$ 586	Apr 2020	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 14**	**$ 586**		
Power					
5-year Credit Facility	$ 1,600	$ 189	$ 1,411	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (C)	953	13	940	Apr 2020	Funding/Letters of Credit
Total Power	**$ 2,553**	**$ 202**	**$ 2,351**		
Total	**$ 4,153**	**$ 226**	**$ 3,927**		

(A) PSEG facility will be reduced by $12 million in March 2018.

(B) PSE&G facility will be reduced by $14 million in March 2018.

(C) Power facility will be reduced by $24 million in March 2018.

(D) The primary use of PSEG's and PSE&G's credit facilities is to support their respective CP Programs. PSEG and PSE&G had no amounts outstanding under their respective CP Programs as of June 30, 2016.

Note 10. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. Transactions receiving NPNS treatment are accounted for upon settlement. For a derivative instrument that qualifies and is designated as a cash flow hedge, the changes in the fair value of such a derivative that are highly effective are recorded in

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Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. For a derivative instrument that qualifies and is designated as a fair value hedge, the gains or losses on the derivative as well as the offsetting losses or gains on the hedged item attributable to the hedged risk are recognized in earnings each period. Power and PSE&G enter into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists. PSEG had no commodity derivative transactions designated as cash flow or fair value hedges as of June 30, 2016 and December 31, 2015.

Economic Hedges

Power enters into derivative contracts that are not designated as either cash flow or fair value hedges. Power enters into financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. These transactions are economic hedges, intended to mitigate exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of these contracts are recorded in earnings.

PSE&G is a party to a long-term natural gas sales derivative contract to optimize its pipeline capacity utilization. Changes in the fair market value of the contract are recorded in Regulatory Assets and Regulatory Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of June 30, 2016, PSEG had interest rate swaps outstanding totaling $550 million. These swaps convert $300 million of Power’s $303 million of 5.32% Senior Notes due September 2016 and Power’s $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of June 30, 2016 and December 31, 2015, the fair value of all the underlying hedges was $2 million and $6 million, respectively. The effect of these hedges reduced interest expense by $2 million and $5 million for the three months ended June 30, 2016 and 2015, respectively, and $4 million and $10 million for the six months ended June 30, 2016 and 2015, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. As of June 30, 2016, PSEG had interest rate hedges outstanding totaling $500 million. The hedge ineffectiveness associated with these hedges was immaterial. The total fair value of these interest rate hedges was $(1) million as of June 30, 2016. PSEG interest rate hedges totaling $400 million were terminated during the second quarter and a gain of $2 million was recorded in Accumulated Other Comprehensive Income (Loss) (after tax) and will amortize to interest expense over the remaining life of Power's $700 million of 3% Senior Notes due June 2021. For additional information see Note 9. Debt and Credit Facilities. There were no outstanding interest rate cash flow hedges as of December 31, 2015. The Accumulated Other Comprehensive Income (Loss) (after tax) related to existing and terminated interest rate derivatives designated as cash flow hedges was $1 million as of June 30, 2016 and was immaterial as of December 31, 2015. The after-tax unrealized gains on these hedges expected to be reclassified to earnings during the next 12 months are immaterial. The expiration date of the longest-dated interest rate hedge is in May 2021.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar

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agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with PSEG's accounting policy, these positions have been offset on the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of June 30, 2016 (A)					
	Power			PSE&G	PSEG	Consolidated
	Not Designated			Not Designated	Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 460	$ (310)	$ 150	$ —	$ 2	$ 152
Noncurrent Assets	264	(188)	76	—	—	76
Total Mark-to-Market Derivative Assets	**$ 724**	**$ (498)**	**$ 226**	**$ —**	**$ 2**	**$ 228**
Derivative Contracts						
Current Liabilities	$ (334)	$ 317	$ (17)	$ (2)	$ (1)	$ (20)
Noncurrent Liabilities	(203)	189	(14)	—	—	(14)
Total Mark-to-Market Derivative (Liabilities)	**$ (537)**	**$ 506**	**$ (31)**	**$ (2)**	**$ (1)**	**$ (34)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 187**	**$ 8**	**$ 195**	**$ (2)**	**$ 1**	**$ 194**

	As of December 31, 2015 (A)					
	Power			PSE&G	PSEG	Consolidated
	Not Designated			Not Designated	Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 700	$ (477)	$ 223	$ 13	$ 6	$ 242
Noncurrent Assets	208	(131)	77	—	—	77
Total Mark-to-Market Derivative Assets	**$ 908**	**$ (608)**	**$ 300**	**$ 13**	**$ 6**	**$ 319**
Derivative Contracts						
Current Liabilities	$ (513)	$ 437	$ (76)	$ —	$ —	$ (76)
Noncurrent Liabilities	(132)	116	(16)	(11)	—	(27)
Total Mark-to-Market Derivative (Liabilities)	**$ (645)**	**$ 553**	**$ (92)**	**$ (11)**	**$ —**	**$ (103)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 263**	**$ (55)**	**$ 208**	**$ 2**	**$ 6**	**$ 216**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of June 30, 2016 and December 31, 2015. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

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(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of June 30, 2016 and December 31, 2015, net cash collateral (received) paid of $8 million and $(55) million, respectively, were netted against the corresponding net derivative contract positions. Of the $8 million as of June 30, 2016, $(2) million of cash collateral was netted against current assets, and $10 million was netted against current liabilities. Of the $(55) million as of December 31, 2015, $(53) million and $(16) million were netted against current assets and noncurrent assets, respectively, and $12 million and $2 million were netted against current liabilities and noncurrent liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P and Moody's ratings. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized, and contracts designated as NPNS) was $26 million and $78 million as of June 30, 2016 and December 31, 2015, respectively. As of June 30, 2016 and December 31, 2015, Power had the contractual right of offset of $18 million and $12 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $8 million and $66 million as of June 30, 2016 and December 31, 2015, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended June 30, 2016 and 2015.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended June 30, 2016	2015	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended June 30, 2016	2015	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Three Months Ended June 30, 2016	2015
				Millions				
PSEG								
Energy-Related Contracts	$ —	$ —	Operating Revenues	$ —	$ —	Operating Revenues	$ —	$ —
Interest Rate Swaps	(1)	—	Interest Expense	—	—	Interest Expense	—	—
Total PSEG	**$ (1)**	**$ —**		**$ —**	**$ —**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ —	$ —	Operating Revenues	$ —	$ —	Operating Revenues	$ —	$ —
Total Power	**$ —**	**$ —**		**$ —**	**$ —**		**$ —**	**$ —**

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The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the six months ended June 30, 2016 and 2015.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Six Months Ended June 30, 2016	2015	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Six Months Ended June 30, 2016	2015	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Six Months Ended June 30, 2016	2015
				Millions				
PSEG								
Energy-Related Contracts	$ —	$ 1	Operating Revenues	$ —	$ 17	Operating Revenues	$ —	$ —
Interest Rate Swaps	2	—	Interest Expense	—	—	Interest Expense	—	—
Total PSEG	**$ 2**	**$ 1**		**$ —**	**$ 17**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ —	$ 1	Operating Revenues	$ —	$ 17	Operating Revenues	$ —	$ —
Total Power	**$ —**	**$ 1**		**$ —**	**$ 17**		**$ —**	**$ —**

The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2014	**$ 17**	**$ 10**
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	(20)	(12)
Balance as of December 31, 2015	**$ —**	**$ —**
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	—	—
Balance as of March 31, 2016	**$ 3**	**$ 2**
Loss Recognized in AOCI	(1)	(1)
Less: Gain Reclassified into Income	—	—
Balance as of June 30, 2016	**$ 2**	**$ 1**

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The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS, such as its BGS contracts and certain other energy supply contracts, for the three months and six months ended June 30, 2016 and 2015. Power's derivative contracts reflected in these tables include contracts to hedge the purchase and sale of electricity and natural gas, and the purchase of fuel.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2016	2015	2016	2015
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ (86)	$ 124	$ 130	$ 48
Energy-Related Contracts	Energy Costs	6	(10)	8	—
Total PSEG and Power		**$ (80)**	**$ 114**	**$ 138**	**$ 48**

The following reflects the gross volume, on an absolute value basis, of derivatives as of June 30, 2016 and December 31, 2015.

Type	Notional	Total	PSEG	Power	PSE&G
		Millions			
As of June 30, 2016					
Natural Gas	Dekatherm (Dth)	347	—	327	20
Electricity	MWh	326	—	326	—
Financial Transmission Rights (FTRs)	MWh	21	—	21	—
Interest Rate Swaps	U.S. Dollars	1,050	1,050	—	—
As of December 31, 2015					
Natural Gas	Dth	201	—	168	33
Electricity	MWh	299	—	299	—
FTRs	MWh	23	—	23	—
Interest Rate Swaps	U.S. Dollars	550	550	—	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of June 30, 2016, 90% of the credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

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The following table provides information on Power's credit risk from others, net of collateral, as of June 30, 2016. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 334	$ 129	$ 205	2	$ 125	(A)
Non-Investment Grade—External Rating	20	—	20	—	—	
Investment Grade—No External Rating	8	1	7	—	—	
Non-Investment Grade—No External Rating	3	—	3	—	—	
Total	**$ 365**	**$ 130**	**$ 235**	**2**	**$ 125**	

(A) Represents net exposure of $94 million with PSE&G. The remaining net exposure of $31 million is with a non-affiliated power purchaser which is an investment grade counterparty.

As of June 30, 2016, collateral held from counterparties where Power had credit exposure included $3 million in cash collateral and $127 million in letters of credit.

As of June 30, 2016, Power had 140 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of June 30, 2016, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's suppliers' credit exposure is calculated each business day. As of June 30, 2016, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 11. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of June 30, 2016, these consisted primarily of long-term gas supply contracts and certain electric load contracts.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of June 30, 2016 and December 31, 2015, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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Description	Recurring Fair Value Measurements as of June 30, 2016			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 570	$ —	$ 570	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 226	$ (498)	$ —	$ 717	$ 7
Interest Rate Swaps (C)	$ 2	$ —	$ —	$ 2	$ —
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—Govt Obligations	$ 526	$ —	$ —	$ 526	$ —
Debt Securities—Other	$ 357	$ —	$ —	$ 357	$ —
Other Securities	$ 49	$ —	$ 49	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 21	$ —	$ 21	$ —	$ —
Debt Securities—Govt Obligations	$ 106	$ —	$ —	$ 106	$ —
Debt Securities—Other	$ 90	$ —	$ —	$ 90	$ —
Other Securities	$ 5	$ —	$ 5	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (33)	$ 506	$ —	$ (537)	$ (2)
Interest Rate Swaps (C)	$ (1)	$ —	$ —	$ (1)	$ —
PSE&G					
Assets:					
Cash Equivalents (A)	$ 125	$ —	$ 125	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ —	$ —	$ —	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 4	$ —	$ 4	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (2)	$ —	$ —	$ —	$ (2)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 226	$ (498)	$ —	$ 717	$ 7
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—Govt Obligations	$ 526	$ —	$ —	$ 526	$ —
Debt Securities—Other	$ 357	$ —	$ —	$ 357	$ —
Other Securities	$ 49	$ —	$ 49	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 26	$ —	$ —	$ 26	$ —
Debt Securities—Other	$ 22	$ —	$ —	$ 22	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					

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Energy-Related Contracts (B)	$	(31)	$	506	$	—	$	(537)	$	—

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Description	Recurring Fair Value Measurements as of December 31, 2015			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 326	$ —	$ 326	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 313	$ (608)	$ —	$ 896	$ 25
Interest Rate Swaps (C)	$ 6	$ —	$ —	$ 6	$ —
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—Govt Obligations	$ 488	$ —	$ —	$ 488	$ —
Debt Securities—Other	$ 359	$ —	$ —	$ 359	$ —
Other Securities	$ 42	$ —	$ 42	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—Govt Obligations	$ 108	$ —	$ —	$ 108	$ —
Debt Securities—Other	$ 81	$ —	$ —	$ 81	$ —
Other Securities	$ 2	$ —	$ 2	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (103)	$ 553	$ —	$ (644)	$ (12)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 160	$ —	$ 160	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ 13	$ —	$ —	$ —	$ 13
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (11)	$ —	$ —	$ —	$ (11)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 300	$ (608)	$ —	$ 896	$ 12
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—Govt Obligations	$ 488	$ —	$ —	$ 488	$ —
Debt Securities—Other	$ 359	$ —	$ —	$ 359	$ —
Other Securities	$ 42	$ —	$ 42	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 26	$ —	$ —	$ 26	$ —
Debt Securities—Other	$ 20	$ —	$ —	$ 20	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (92)	$ 553	$ —	$ (644)	$ (1)

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(A) Represents money market mutual funds.

(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask

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midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds, collateralized mortgage obligations, asset backed securities and government obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of June 30, 2016, net cash collateral (received) paid of $8 million was netted against the corresponding net derivative contract positions. Of the $8 million as of June 30, 2016, $(2) million of cash collateral was netted against assets, and $10 million was netted against liabilities. As of December 31, 2015, net cash collateral (received) paid of $(55) million was netted against the corresponding net derivative contract positions. Of the $(55) million of cash collateral as of December 31, 2015, $(69) million was netted against assets, and $14 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

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For PSE&G, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The following tables provide details surrounding significant Level 3 valuations as of June 30, 2016 and December 31, 2015.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of June 30, 2016 Assets	Fair Value as of June 30, 2016 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$ —	$ (2)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ —**	**$ (2)**			
Power						
Electricity	Electric Load Contracts	$ 7	$ —	Discounted Cash flow	Historic Load Variability	0% to +10%
Total Power		**$ 7**	**$ —**			
Total PSEG		**$ 7**	**$ (2)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2015 Assets	Fair Value as of December 31, 2015 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$ 13	$ (11)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ 13**	**$ (11)**			
Power						
Electricity	Electric Load Contracts	$ 11	$ (1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Electricity	Other	1	—			
Total Power		**$ 12**	**$ (1)**			
Total PSEG		**$ 25**	**$ (12)**			

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value. For energy-related contracts in cases where Power is a seller, an increase in the load variability would decrease the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and six months ended June 30, 2016 and June 30, 2015, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Six Months Ended June 30, 2016

	Three Months Ended June 30, 2016						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2016	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2016
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 21	$ 1	$ (12)	$ —	$ (5)	$ —	$ 5
PSE&G							
Net Derivative Assets (Liabilities)	$ 10	$ —	$ (12)	$ —	$ —	$ —	$ (2)
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 1	$ —	$ —	$ (5)	$ —	$ 7

	Six Months Ended June 30, 2016						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2016	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2016
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 13	$ 16	$ (4)	$ —	$ (20)	$ —	$ 5
PSE&G							
Net Derivative Assets (Liabilities)	$ 2	$ —	$ (4)	$ —	$ —	$ —	$ (2)
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 16	$ —	$ —	$ (20)	$ —	$ 7

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Six Months Ended June 30, 2015

	Three Months Ended June 30, 2015						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2015	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2015
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 9	$ 5	$ (2)	$ —	$ (4)	$ —	$ 8
PSE&G							
Net Derivative Assets (Liabilities)	$ 7	$ —	$ (2)	$ —	$ —	$ —	$ 5
Power							
Net Derivative Assets (Liabilities)	$ 2	$ 5	$ —	$ —	$ (4)	$ —	$ 3

	Six Months Ended June 30, 2015						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2015	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2015
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 37	$ 8	$ (21)	$ —	$ (16)	$ —	$ 8
PSE&G							
Net Derivative Assets (Liabilities)	$ 26	$ —	$ (21)	$ —	$ —	$ —	$ 5
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 8	$ —	$ —	$ (16)	$ —	$ 3

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $1 million and $16 million in Operating Income for the three months and six months ended June 30, 2016, respectively. Of the $1 million in Operating Income, $(4) million is unrealized. Of the $16 million in Operating Income, $(4) million is unrealized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

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(C) Represents $(5) million and $(20) million in settlements for the three months and six months ended June 30, 2016, respectively. Represents $(4) million and $(16) million in settlements for the three months and six months ended June 30, 2015, respectively.

(D) There were no transfers among levels during the three months and six months ended June 30, 2016 and 2015.

(E) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $5 million and $8 million in Operating Income for the three months and six months ended June 30, 2015, respectively. The $5 million in Operating Income is realized. Of the $8 million in Operating Income, $(9) million is unrealized.

As of June 30, 2016, PSEG carried $2.8 billion of net assets that are measured at fair value on a recurring basis, of which $5 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of June 30, 2015, PSEG carried $2.7 billion of net assets that are measured at fair value on a recurring basis, of which $8 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of June 30, 2016 and December 31, 2015.

	As of June 30, 2016		As of December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 501	$ 502	$ 503	$ 506
PSE&G (B)	7,494	8,624	6,821	7,235
Power - Recourse Debt (B)	2,933	3,274	2,237	2,508
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	7	7	7	7
Total Long-Term Debt	**$ 10,935**	**$ 12,407**	**$ 9,568**	**$ 10,256**

(A) Fair value includes a $500 million floating rate term loan and net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. The fair value of the term loan debt (Level 2 measurement) was considered to be equal to the carrying value because the interest payments are based on LIBOR rates that are reset monthly. Carrying amount includes such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) Given that most bonds do not trade, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 12. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended June 30, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 23	$ —	$ 23
Allowance for Funds Used During Construction	10	—	—	10
Solar Loan Interest	5	—	—	5
Other	4	2	—	6
Total Other Income	**$ 19**	**$ 25**	**$ —**	**$ 44**
Six Months Ended June 30, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 48	$ —	$ 48
Allowance for Funds Used During Construction	21	—	—	21
Solar Loan Interest	11	—	—	11
Other	7	3	2	12
Total Other Income	**$ 39**	**$ 51**	**$ 2**	**$ 92**
Three Months Ended June 30, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 25	$ —	$ 25
Allowance for Funds Used During Construction	12	—	—	12
Solar Loan Interest	6	—	—	6
Gain on Insurance Recovery	—	28	—	28
Other	1	2	2	5
Total Other Income	**$ 19**	**$ 55**	**$ 2**	**$ 76**
Six Months Ended June 30, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 54	$ —	$ 54
Allowance for Funds Used During Construction	22	—	—	22
Solar Loan Interest	12	—	—	12
Gain on Insurance Recovery	—	28	—	28
Other	3	2	3	8
Total Other Income	**$ 37**	**$ 84**	**$ 3**	**$ 124**

Other Deductions	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended June 30, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 8	$ —	$ 8
Other	1	1	—	2
Total Other Deductions	**$ 1**	**$ 9**	**$ —**	**$ 10**
Six Months Ended June 30, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 26	$ —	$ 26
Other	2	1	2	5
Total Other Deductions	**$ 2**	**$ 27**	**$ 2**	**$ 31**
Three Months Ended June 30, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 6	$ —	$ 6
Other	1	1	2	4
Total Other Deductions	**$ 1**	**$ 7**	**$ 2**	**$ 10**
Six Months Ended June 30, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 17	$ —	$ 17
Other	2	1	2	5
Total Other Deductions	**$ 2**	**$ 18**	**$ 2**	**$ 22**

(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

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Note 13. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months and six months ended June 30, 2016 and 2015 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
PSEG	32.7%	35.0%	36.2%	38.5%
PSE&G	35.4%	38.4%	36.1%	39.0%
Power	50.0%	30.3%	39.5%	37.9%

For the three months and six months ended June 30, 2016, the overall decreases in PSEG's effective tax rates as compared to the same periods in the prior year as well as to the statutory tax rate of 40.85%, were due primarily to changes in uncertain tax positions, plant and other flow through items, offset by the absence of the benefit recorded in 2015 associated with the Nuclear Decommissioning Tax Carryback.

For the three months and six months ended June 30, 2016, the overall decreases in PSE&G's effective tax rates as compared to the same periods in the prior year as well as to the statutory tax rate of 40.85%, were due primarily to changes in uncertain tax positions and plant and other flow through items.

For the three months ended June 30, 2016, the increase in Power's effective tax rate as compared to the same period in the prior year as well as to the statutory tax rate of 40.85%, was due primarily to the absence of the benefit recorded in 2015 associated with the Nuclear Decommissioning Tax Carryback.

The Tax Increase Prevention Act of 2014 extended the 50% bonus depreciation rules for qualified property placed in service before January 1, 2015 and for long production property placed in service in 2015.

The Protecting Americans from Tax Hikes Act of 2015 (Tax Act) extended the 50% bonus depreciation rules for qualified property placed in service from January 1, 2015 through December 31, 2017. The rate is reduced to 40% and 30% for eligible property placed in service in 2018 and 2019, respectively. In addition, long production property placed in service in 2020 will also qualify for 30% bonus depreciation. The Tax Act also extended the 30% ITC for qualified property placed in service starting January 1, 2016 through December 31, 2019 but reduces the ITC rate to 26% and 22% for projects commenced in 2020 and 2021, respectively. The financial impact of the extensions of the ITC rate will depend upon future transactions.

These provisions have generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period. However, these tax benefits will have a negative impact on the rate base of several of PSE&G's programs.

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Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended June 30, 2016			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2016	$ 2	$ (378)	$ 107	$ (269)
Other Comprehensive Income before Reclassifications	(1)	—	8	7
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	8	2	10
Net Current Period Other Comprehensive Income (Loss)	(1)	8	10	17
Balance as of June 30, 2016	**$ 1**	**$ (370)**	**$ 117**	**$ (252)**

PSEG	Other Comprehensive Income (Loss) Three Months Ended June 30, 2015			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2015	$ 1	$ (403)	$ 132	$ (270)
Other Comprehensive Income before Reclassifications	—	—	(14)	(14)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	8	(1)	7
Net Current Period Other Comprehensive Income (Loss)	—	8	(15)	(7)
Balance as of June 30, 2015	**$ 1**	**$ (395)**	**$ 117**	**$ (277)**

PSEG	Other Comprehensive Income (Loss) Six Months Ended June 30, 2016			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2015	$ —	$ (386)	$ 91	$ (295)
Other Comprehensive Income before Reclassifications	1	—	18	19
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	16	8	24
Net Current Period Other Comprehensive Income (Loss)	1	16	26	43
Balance as of June 30, 2016	**$ 1**	**$ (370)**	**$ 117**	**$ (252)**

PSEG	Other Comprehensive Income (Loss) Six Months Ended June 30, 2015			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2014	$ 10	$ (411)	$ 118	$ (283)
Other Comprehensive Income before Reclassifications	1	—	2	3
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	16	(3)	3
Net Current Period Other Comprehensive Income (Loss)	(9)	16	(1)	6
Balance as of June 30, 2015	**$ 1**	**$ (395)**	**$ 117**	**$ (277)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2016			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2016	$ —	$ (320)	$ 103	$ (217)
Other Comprehensive Income before Reclassifications	—	—	6	6
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	3	10
Net Current Period Other Comprehensive Income (Loss)	—	7	9	16
Balance as of June 30, 2016	**$ —**	**$ (313)**	**$ 112**	**$ (201)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2015			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2015	$ 2	$ (344)	$ 126	$ (216)
Other Comprehensive Income before Reclassifications	—	—	(14)	(14)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	—	7
Net Current Period Other Comprehensive Income (Loss)	—	7	(14)	(7)
Balance as of June 30, 2015	**$ 2**	**$ (337)**	**$ 112**	**$ (223)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2016			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2015	$ —	$ (327)	$ 87	$ (240)
Other Comprehensive Income before Reclassifications	—	—	16	16
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	14	9	23
Net Current Period Other Comprehensive Income (Loss)	—	14	25	39
Balance as of June 30, 2016	**$ —**	**$ (313)**	**$ 112**	**$ (201)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2015			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2014	$ 11	$ (351)	$ 112	$ (228)
Other Comprehensive Income before Reclassifications	1	—	2	3
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	14	(2)	2
Net Current Period Other Comprehensive Income (Loss)	(9)	14	—	5
Balance as of June 30, 2015	**$ 2**	**$ (337)**	**$ 112**	**$ (223)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2016			Six Months Ended June 30, 2016		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	6	(2)	4
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)	(34)	14	(20)
Total Pension and OPEB Plans		(14)	6	(8)	(28)	12	(16)
Available-for-Sale Securities							
Realized Gains	Other Income	12	(6)	6	28	(14)	14
Realized Losses	Other Deductions	(7)	4	(3)	(24)	12	(12)
Other-Than-Temporary Impairments (OTTI)	OTTI	(10)	5	(5)	(20)	10	(10)
Total Available-for-Sale Securities		(5)	3	(2)	(16)	8	(8)
Total		**$ (19)**	**$ 9**	**$ (10)**	**$ (44)**	**$ 20**	**$ (24)**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2015			Six Months Ended June 30, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		—	—	—	17	(7)	10
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	6	(2)	4
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)	(34)	14	(20)
Total Pension and OPEB Plans		(14)	6	(8)	(28)	12	(16)
Available-for-Sale Securities							
Realized Gains	Other Income	16	(8)	8	35	(18)	17
Realized Losses	Other Deductions	(4)	2	(2)	(13)	7	(6)
OTTI	OTTI	(10)	5	(5)	(15)	7	(8)
Total Available-for-Sale Securities		2	(1)	1	7	(4)	3
Total		**$ (12)**	**$ 5**	**$ (7)**	**$ (4)**	**$ 1**	**$ (3)**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2016			Six Months Ended June 30, 2016		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 2	$ (1)	$ 1	$ 5	$ (2)	$ 3
Amortization of Actuarial Loss	O&M Expense	(14)	6	(8)	(29)	12	(17)
Total Pension and OPEB Plans		(12)	5	(7)	(24)	10	(14)
Available-for-Sale Securities							
Realized Gains	Other Income	10	(5)	5	25	(13)	12
Realized Losses	Other Deductions	(6)	3	(3)	(22)	11	(11)
OTTI	OTTI	(10)	5	(5)	(20)	10	(10)
Total Available-for-Sale Securities		(6)	3	(3)	(17)	8	(9)
Total		**$ (18)**	**$ 8**	**$ (10)**	**$ (41)**	**$ 18**	**$ (23)**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2015			Six Months Ended June 30, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		—	—	—	17	(7)	10
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	6	(2)	4
Amortization of Actuarial Loss	O&M Expense	(15)	6	(9)	(30)	12	(18)
Total Pension and OPEB Plans		(12)	5	(7)	(24)	10	(14)
Available-for-Sale Securities							
Realized Gains	Other Income	14	(7)	7	33	(17)	16
Realized Losses	Other Deductions	(4)	2	(2)	(13)	7	(6)
OTTI	OTTI	(10)	5	(5)	(15)	7	(8)
Total Available-for-Sale Securities		—	—	—	5	(3)	2
Total		**$ (12)**	**$ 5**	**$ (7)**	**$ (2)**	**$ —**	**$ (2)**

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Note 15. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2016		2015		2016		2015	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions):								
Net Income	**$ 187**	**$ 187**	**$ 345**	**$ 345**	**$ 658**	**$ 658**	**$ 931**	**$ 931**
EPS Denominator (Millions):								
Weighted Average Common Shares Outstanding	505	505	506	506	505	505	506	506
Effect of Stock Based Compensation Awards	—	3	—	2	—	3	—	2
Total Shares	**505**	**508**	**506**	**508**	**505**	**508**	**506**	**508**
EPS								
Net Income	**$ 0.37**	**$ 0.37**	**$ 0.68**	**$ 0.68**	**$ 1.30**	**$ 1.30**	**$ 1.84**	**$ 1.83**

There were approximately 0.3 million and 0.4 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the three months and six months ended June 30, 2016 and 2015, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
Dividend Payments on Common Stock	**2016**	**2015**	**2016**	**2015**
Per Share	$ 0.41	$ 0.39	$ 0.82	$ 0.78
In Millions	$ 208	$ 197	$ 415	$ 394

On July 19, 2016, PSEG's Board of Directors approved a $0.41 per share common stock dividend for the third quarter of 2016.

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Note 16. Financial Information by Business Segment

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated
			Millions		
Three Months Ended June 30, 2016					
Total Operating Revenues	$ 1,350	$ 714	$ 127	$ (286)	$ 1,905
Net Income (Loss)	179	(11)	19	—	187
Gross Additions to Long-Lived Assets	631	265	10	—	906
Six Months Ended June 30, 2016					
Operating Revenues	$ 3,062	$ 2,027	$ 249	$ (817)	$ 4,521
Net Income (Loss)	441	181	36	—	658
Gross Additions to Long-Lived Assets	1,355	598	18	—	1,971
Three Months Ended June 30, 2015					
Total Operating Revenues	$ 1,466	$ 1,025	$ 108	$ (285)	$ 2,314
Net Income (Loss)	167	166	12	—	345
Gross Additions to Long-Lived Assets	631	348	17	—	996
Six Months Ended June 30, 2015					
Operating Revenues	$ 3,468	$ 2,750	$ 206	$ (975)	$ 5,449
Net Income (Loss)	409	501	21	—	931
Gross Additions to Long-Lived Assets	1,230	487	26	—	1,743
As of June 30, 2016					
Total Assets	$ 24,737	$ 13,278	$ 2,873	$ (1,843)	$ 39,045
Investments in Equity Method Subsidiaries	$ —	$ 112	$ —	$ —	$ 112
As of December 31, 2015					
Total Assets	$ 23,677	$ 12,250	$ 2,810	$ (1,202)	$ 37,535
Investments in Equity Method Subsidiaries	$ —	$ 119	$ —	$ —	$ 119

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations primarily relate to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 17. Related-Party Transactions.

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Note 17. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	Millions			
Billings from Affiliates:				
Net Billings from Power primarily through BGS and BGSS (A)	$ 297	$ 297	$ 842	$ 993
Administrative Billings from Services (B)	82	65	151	131
Total Billings from Affiliates	**$ 379**	**$ 362**	**$ 993**	**$ 1,124**

Related-Party Transactions	As of June 30, 2016	As of December 31, 2015
	Millions	
Receivables from PSEG (C)	**$ —**	**$ 222**
Payable to Power (A)	$ 94	$ 212
Payable to Services (B)	79	80
Payable to PSEG (C)	6	—
Accounts Payable—Affiliated Companies	**$ 179**	**$ 292**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 99**	**$ 109**

Power

The financial statements for Power include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	Millions			
Billings to Affiliates:				
Net Billings to PSE&G primarily through BGS and BGSS (A)	**$ 297**	**$ 297**	**$ 842**	**$ 993**
Billings from Affiliates:				
Administrative Billings from Services (B)	**$ 45**	**$ 46**	**$ 90**	**$ 91**

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Related-Party Transactions	As of June 30, 2016	As of December 31, 2015
	Millions	
Receivables from PSE&G (A)	$ 94	$ 212
Receivables from PSEG (C)	—	64
Accounts Receivable—Affiliated Companies	**$ 94**	**$ 276**
Payable to Services (B)	$ 28	$ 33
Payable to PSEG (C)	74	—
Accounts Payable—Affiliated Companies	**$ 102**	**$ 33**
Short-Term Loan Due (to) from Affiliate (E)	**$ 1,335**	**$ 363**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 22**	**$ 35**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. In addition, Power and PSE&G provide certain technical services for each other in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

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Note 18. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries, as of June 30, 2016 and December 31, 2015 and for the three months and six months ended June 30, 2016 and 2015.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended June 30, 2016					
Operating Revenues	$ —	$ 700	$ 46	$ (32)	$ 714
Operating Expenses	2	716	40	(32)	726
Operating Income (Loss)	(2)	(16)	6	—	(12)
Equity Earnings (Losses) of Subsidiaries	(1)	1	4	—	4
Other Income	17	30	—	(22)	25
Other Deductions	—	(9)	—	—	(9)
Other-Than-Temporary Impairments	—	(10)	—	—	(10)
Interest Expense	(31)	(7)	(4)	22	(20)
Income Tax Benefit (Expense)	6	3	2	—	11
Net Income (Loss)	**$ (11)**	**$ (8)**	**$ 8**	**$ —**	**$ (11)**
Comprehensive Income (Loss)	**$ 5**	**$ 1**	**$ 8**	**$ (9)**	**$ 5**
Six Months Ended June 30, 2016					
Operating Revenues	$ —	$ 2,002	$ 88	$ (63)	$ 2,027
Operating Expenses	12	1,668	79	(63)	1,696
Operating Income (Loss)	(12)	334	9	—	331
Equity Earnings (Losses) of Subsidiaries	204	—	6	(204)	6
Other Income	34	62	—	(45)	51
Other Deductions	—	(27)	—	—	(27)
Other-Than-Temporary Impairments	—	(20)	—	—	(20)
Interest Expense	(61)	(17)	(9)	45	(42)
Income Tax Benefit (Expense)	16	(137)	3	—	(118)
Net Income (Loss)	**$ 181**	**$ 195**	**$ 9**	**$ (204)**	**$ 181**
Comprehensive Income (Loss)	**$ 220**	**$ 220**	**$ 9**	**$ (229)**	**$ 220**
Six Months Ended June 30, 2016					
Net Cash Provided By (Used In) Operating Activities	$ 337	$ 777	$ 159	$ (356)	$ 917
Net Cash Provided By (Used In) Investing Activities	$ (1,287)	$ (504)	$ (395)	$ 579	$ (1,607)
Net Cash Provided By (Used In) Financing Activities	$ 951	$ (273)	$ 239	$ (223)	$ 694

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended June 30, 2015					
Operating Revenues	$ —	$ 1,012	$ 39	$ (26)	$ 1,025
Operating Expenses	(1)	787	37	(26)	797
Operating Income (Loss)	1	225	2	—	228
Equity Earnings (Losses) of Subsidiaries	186	(1)	5	(185)	5
Other Income	12	55	—	(12)	55
Other Deductions	(1)	(6)	—	—	(7)
Other-Than-Temporary Impairments	—	(10)	—	—	(10)
Interest Expense	(33)	(7)	(5)	12	(33)
Income Tax Benefit (Expense)	1	(73)	—	—	(72)
Net Income (Loss)	**$ 166**	**$ 183**	**$ 2**	**$ (185)**	**$ 166**
Comprehensive Income (Loss)	**$ 159**	**$ 169**	**$ 2**	**$ (171)**	**$ 159**
Six Months Ended June 30, 2015					
Operating Revenues	$ —	$ 2,727	$ 107	$ (84)	$ 2,750
Operating Expenses	4	1,918	100	(84)	1,938
Operating Income (Loss)	(4)	809	7	—	812
Equity Earnings (Losses) of Subsidiaries	535	(2)	8	(533)	8
Other Income	23	85	—	(24)	84
Other Deductions	(1)	(17)	—	—	(18)
Other-Than-Temporary Impairments	—	(15)	—	—	(15)
Interest Expense	(62)	(16)	(10)	24	(64)
Income Tax Benefit (Expense)	10	(315)	(1)	—	(306)
Net Income (Loss)	**$ 501**	**$ 529**	**$ 4**	**$ (533)**	**$ 501**
Comprehensive Income (Loss)	**$ 506**	**$ 520**	**$ 4**	**$ (524)**	**$ 506**
Six Months Ended June 30, 2015					
Net Cash Provided By (Used In) Operating Activities	$ 410	$ 1,508	$ 61	$ (687)	$ 1,292
Net Cash Provided By (Used In) Investing Activities	$ (480)	$ (963)	$ (210)	$ 766	$ (887)
Net Cash Provided By (Used In) Financing Activities	$ 70	$ (543)	$ 150	$ (79)	$ (402)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
As of June 30, 2016					
Current Assets	$ 5,490	$ 1,655	$ 231	$ (4,828)	$ 2,548
Property, Plant and Equipment, net	58	6,476	1,944	—	8,478
Investment in Subsidiaries	4,419	345	—	(4,764)	—
Noncurrent Assets	134	2,041	128	(51)	2,252
Total Assets	**$ 10,101**	**$ 10,517**	**$ 2,303**	**$ (9,643)**	**$ 13,278**
Current Liabilities	$ 1,079	$ 3,719	$ 1,293	$ (4,828)	$ 1,263
Noncurrent Liabilities	420	2,652	392	(51)	3,413
Long-Term Debt	2,380	—	—	—	2,380
Member's Equity	6,222	4,146	618	(4,764)	6,222
Total Liabilities and Member's Equity	**$ 10,101**	**$ 10,517**	**$ 2,303**	**$ (9,643)**	**$ 13,278**
As of December 31, 2015					
Current Assets	$ 4,501	$ 1,912	$ 364	$ (4,828)	$ 1,949
Property, Plant and Equipment, net	83	6,502	1,542	—	8,127
Investment in Subsidiaries	4,501	346	—	(4,847)	—
Noncurrent Assets	155	1,959	136	(76)	2,174
Total Assets	**$ 9,240**	**$ 10,719**	**$ 2,042**	**$ (9,751)**	**$ 12,250**
Current Liabilities	$ 1,112	$ 3,866	$ 1,076	$ (4,828)	$ 1,226
Noncurrent Liabilities	442	2,597	375	(76)	3,338
Long-Term Debt	1,684	—	—	—	1,684
Member's Equity	6,002	4,256	591	(4,847)	6,002
Total Liabilities and Member's Equity	**$ 9,240**	**$ 10,719**	**$ 2,042**	**$ (9,751)**	**$ 12,250**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G,** our public utility company which is engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU, and
- **Power,** our multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy transacting functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA), and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business of our 2015 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2015 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2016 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2015 Form 10-K.

EXECUTIVE OVERVIEW OF 2016 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- improving utility operations through growth in investment in T&D and other infrastructure projects designed to enhance resiliency, and
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the three months and six months ended June 30, 2016 and 2015 are presented as follows:

Earnings	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	Millions			
PSE&G	$ 179	$ 167	$ 441	$ 409
Power (A)	(11)	166	181	501
Other (B)	19	12	36	21
PSEG Net Income	**$ 187**	**$ 345**	**$ 658**	**$ 931**
PSEG Net Income Per Share (Diluted)	**$ 0.37**	**$ 0.68**	**$ 1.30**	**$ 1.83**

(A) Includes an after-tax insurance recovery for Superstorm Sandy of $27 million and $102 million in the three months and six months ended June 30, 2015, respectively.

(B) Other includes activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with future delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	Millions, after tax			
NDT Fund Income (Expense) (A) (B)	$ (1)	$ 1	$ (6)	$ 3
Non-Trading MTM Gains (Losses) (C)	$ (101)	$ 28	$ (88)	8

(A) NDT Fund Income (Expense) includes the realized gains and losses, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense.

(B) Net of tax (expense) benefit of $(1) million, $(2) million, $2 million and $(7) million for the three and six months ended June 30, 2016 and 2015, respectively.

(C) Net of tax (expense) benefit of $70 million, $(20) million, $61 million and $(6) million for the three and six months ended June 30, 2016 and 2015, respectively.

Our $158 million decrease in Net Income for the three months ended June 30, 2016 was driven primarily by

- MTM losses in 2016 as compared to MTM gains in 2015,
- lower volumes of energy sold at lower average realized prices primarily in the PJM Interconnection, L.L.C. (PJM) region,
- higher congestion costs in PJM resulting from credits received in 2015 due to the colder than normal weather, and
- insurance recoveries received primarily by Power in 2015 related to Superstorm Sandy.

These decreases were partially offset by

- higher revenues due to increased investments in transmission projects,
- lower generation costs driven by lower natural gas prices and reduced generation output, and

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- lower O&M expense at Power due to higher costs incurred in 2015 for planned major outages.

Our $273 million decrease in Net Income for the six months ended June 30, 2016 was driven primarily by

- MTM losses in 2016 as compared to MTM gains in 2015,
- lower volumes of energy sold at lower average realized sales primarily in the PJM region and lower volumes of energy sold under wholesale load contracts,
- lower operating reserve revenues and capacity revenues in PJM,
- lower volumes of gas sold at lower average prices under the Basic Gas Supply Service (BGSS) contract, and
- insurance recoveries received primarily by Power in 2015 related to Superstorm Sandy.

These decreases were partially offset by

- lower generation costs driven by lower fuel costs and reduced generation output at Power,
- a decrease in O&M expense at Power due to higher costs incurred for planned outages in 2015, and
- higher revenues due to increased investments in transmission projects.

During the first half of 2016, we maintained a strong balance sheet. We continued to effectively deploy capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results and allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our multi-year, long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, our merchant generator, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, in 2016 we continued to make investments and seek recovery on such investments made to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the BPU in 2014. We also commenced modernizing PSE&G's gas distribution systems as part of our Gas System Modernization Program (GSMP) that was approved by the BPU in late 2015. Over the past few years, these types of investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G.

Despite the unseasonable weather patterns during the first six months of 2016, Power's results benefited from access to natural gas supplies through its existing firm pipeline transportation contracts. Power manages these contracts for the benefit of PSE&G's customers through the BGSS arrangement. The contracts are sized to provide for delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to make third party sales and supply gas to its generating units in New Jersey. Alternatively, gas supply and pipeline capacity constraints could adversely impact our ability to meet the needs of our utility customers and generating units. Power's strategic hedging practices and ability to capitalize on market opportunities help it to balance some of the volatility of the merchant power business.

Our recent investments in the latter half of 2015 and early 2016 in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to contribute to the overall efficiency of operations.

Since 2013, eight nuclear generating stations in the United States totaling over 8,300 MW of capacity have closed or announced early retirement due to economic reasons. Four additional stations totaling nearly 5,300 MW of capacity have been announced as being at risk for early retirement. This situation is generally due to low natural gas prices resulting from the growth of shale gas production since 2007, the continuing cost of regulatory compliance for nuclear facilities and both federal and state-level policies that provide credits to renewable energy such as wind and solar, but do not apply to nuclear generating stations. These trends have significantly reduced the revenues to nuclear generating stations while simultaneously raising the unit cost of production. This may result in the electric generation industry experiencing a shift from nuclear generation to natural gas-fired generation, creating greater reliance on natural gas pipelines for delivery and less diversity of the generation fleet. Additionally, we believe that the early retirement of nuclear plants will lead to an increase in replacement energy and environmental costs.

While our nuclear generating units are not currently at risk of early retirement, we continue to advocate for sound policies that recognize nuclear power as a source of clean energy and an important part of a diverse and reliable energy portfolio.

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Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission

In April 2013, PJM initiated its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues in New Jersey. In April 2016, PSE&G accepted construction responsibility for the three components of the Artificial Island project that PJM assigned to it, based on having reached agreement with PJM regarding an estimate for the project base cost of $273 million, plus risk and contingency for a total project cost of up to $340 million. PSE&G continues to work with PJM to optimize the scope and cost of the project.

In April 2016, PJM filed at FERC to incorporate a voltage threshold into PJM's Regional Transmission Expansion Plan (RTEP) process to exempt, except under certain circumstances, reliability violations on facilities below 200 kV from PJM's proposal window process. We generally support this reform as a measure to improve the efficiency of the open window procedure that will permit transmission developers to focus on the projects most likely to benefit from a competitive process.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey and may cause increased scrutiny regarding PSE&G's future capital investments. In addition, as a basic generation service (BGS) supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers may be entitled to an adjustment, subject to BPU approval. We do not believe that these matters will have a material effect on Power's business or results of operations.

Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base return on equity (ROE). Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. While we are not the subject of a challenge to the ROE employed in PSE&G's transmission formula rate, the results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Wholesale Power Market Design

In an important development in the proceedings concerning the actions that had been taken by the states of New Jersey and Maryland to subsidize new generation that is above market cost, in April 2016, the United States Supreme Court affirmed the decision of the lower courts that had held the action in Maryland to be unconstitutional. The Supreme Court's ruling upholds FERC's authority to foster competitive wholesale electricity markets and provides guidance to states in balancing their interests to encourage and support the development of renewables and other generating facilities.

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. In June 2015, FERC conditionally accepted a proposal from PJM for a capacity performance (CP) product to include generators, Demand Response and energy efficiency providers, which will be required to perform during emergency conditions, as a supplement to the base capacity product. The proposal included enhanced performance-based incentives and penalties. We believe that the auction pricing adequately reflects the increased costs that could result from operating under more stringent rules for generation availability. Based on the auction results, the CP mechanism appears to have provided the opportunity for enhanced capacity market revenue streams for Power, but future impacts cannot be assured. Further, there may be requirements for additional investment and there are additional performance and financial risks. Appeals of FERC's CP orders are pending.

In May 2016, PJM announced the results of the RPM capacity auction for the 2019-2020 delivery year. Power cleared 8,895 MW of its generating capacity at an average price of $116 per MW-day for the 2019-2020 delivery period. Of the cleared capacity, Power believes that nearly all is compliant with PJM's CP requirements. In the two prior capacity auctions covering the 2017-2018 and 2018-2019 delivery years, Power cleared approximately 8,700 MW at average prices of $177 per MW-day and $215 per MW-day, respectively. Prices in the most recent auction reflect PJM's downwardly-revised demand forecast, changes in the emergency transfer limits due to transmission expansion and the effects of both the new generation and uncleared generation from the prior year's auction.

An emerging issue in PJM involves the impact of subsidized existing generation on RPM market outcomes. These subsidies would likely enable the affected generators to submit bids into PJM capacity markets that are not reflective of their actual costs of operation and may prevent uneconomic generating facilities from retiring. Either of these conditions could artificially

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suppress capacity market prices, especially given that PJM's currently effective "minimum offer price rule" (MOPR) which applies only to new gas-fired units, would not apply to these plants. Given the uncertainty surrounding these possible subsidies, we cannot predict the effects this might have on capacity prices and the corresponding impact on our business. See Item 5. Other Information—Federal Regulation—Capacity Market Issues—PJM for additional information.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act (FWPCA) requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs. See Item 1. Note 8. Commitments and Contingent Liabilities for further information.

In October 2015, the EPA published the Clean Power Plan (CPP), a greenhouse gas emissions regulation under the Clean Air Act (CAA) for existing power plants. The regulation establishes state-specific emission targets based on implementation of the best systems of emission reduction. We continue to work with FERC and other federal and state regulators, as well as industry partners, to determine the potential impact of these regulations.

The U.S. Supreme Court's February 2016 decision to stay the implementation of the CPP will delay deadlines for submission of state requests for extensions and final plans. If the CPP is upheld, new deadlines will need to be established and the effective date of the compliance period may be impacted.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above as well as other matters that may impact our financial condition and results of operations, see Item 1. Note 8. Commitments and Contingent Liabilities.

FERC Compliance

Since September 2014, FERC Staff has been conducting a preliminary non-public investigation regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units. This investigation is ongoing. The amounts of potential disgorgement and other potential penalties that we may incur span a wide range depending on the success of our legal arguments. If our legal arguments do not prevail, in whole or in part with FERC or in a judicial challenge that we may choose to pursue, it is likely that Power would record losses that would be material to PSEG's and Power's results of operations in the quarterly and annual periods in which they are recorded. For additional information, see Item 1. Note 8. Commitments and Contingent Liabilities.

Salem Operations

In April 2016, during a scheduled refueling outage at Salem Unit 1, a visual inspection revealed degradation to a number of bolts inside the reactor vessel. The bolt replacement has been completed and the unit is in the process of returning to service. We expect to continue to inspect and replace degraded bolts at both Salem units over the next several refueling outage cycles and a strategic solution to maintain the long-term health of both reactor vessel internals is under review. Production and margin effects for the second quarter of 2016 were largely offset by the increased production at Peach Bottom as a result of the Extended Power Uprates made in 2015 being fully operational. Extension of the Salem Unit 1 outage into July and an unplanned outage at Salem Unit 2 will have a continuing effect on third quarter performance.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. For the first six months of 2016, our

- total nuclear fleet achieved an average capacity factor of 91.2%, and
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 26 terra-watt hours while addressing unit outages and balancing fuel availability and price volatility.

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Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first six months of 2016 as we

- had cash on hand of $648 million as of June 30, 2016,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2016 to $1.64 per share.

We expect to be able to fund our planned capital requirements, as described in Liquidity and Capital Resources, without the issuance of new equity.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first half of 2016, we

- made additional investments in transmission infrastructure projects,
- began executing our GSMP and continued executing Energy Strong and other existing BPU-approved utility programs,
- commenced construction of our Keys and Sewaren 7 generation projects for targeted commercial operation in 2018 and announced our plan to construct BH5 and commence operations in mid-2019, and
- acquired three solar energy projects totaling 100 MW-direct current in North Carolina and Colorado expected to go into service during 2016.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-growing economy and a cost-constrained environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions,
- execute our utility capital investment program, including our Energy Strong program, GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction of our Keys, Sewaren 7, BH5 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

For 2016 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- fair and timely rate relief from the BPU and FERC for recovery of costs and return on investments, including with respect to our base rate case which must be filed with the BPU no later than November 1, 2017,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,

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- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate,
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development projects, including in connection with permitting and regulatory approvals, and
- FERC Staff's continuing investigation of certain of Power's New Jersey fossil generating unit bids in the PJM energy market.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of transmission and distribution facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses, such as retail energy marketing,
- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency and modernizing existing infrastructure.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 17. Related-Party Transactions.

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2016	2015	2016 vs. 2015		2016	2015	2016 vs. 2015	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,905	$ 2,314	$ (409)	(18)	$ 4,521	$ 5,449	$ (928)	(17)
Energy Costs	624	668	(44)	(7)	1,460	1,762	(302)	(17)
Operation and Maintenance	710	761	(51)	(7)	1,439	1,424	15	1
Depreciation and Amortization	224	317	(93)	(29)	448	647	(199)	(31)
Income from Equity Method Investments	4	4	—	—	6	7	(1)	(14)
Other Income (Deductions)	34	66	(32)	(48)	61	102	(41)	(40)
Other-Than-Temporary Impairments	10	10	—	—	20	15	5	33
Interest Expense	97	97	—	—	189	195	(6)	(3)
Income Tax Expense	91	186	(95)	(51)	374	584	(210)	(36)

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

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PSE&G

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2016	2015	2016 vs. 2015		2016	2015	2016 vs. 2015	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,350	$ 1,466	$ (116)	(8)	$ 3,062	$ 3,468	$ (406)	(12)
Energy Costs	529	544	(15)	(3)	1,258	1,436	(178)	(12)
Operation and Maintenance	352	368	(16)	(4)	734	780	(46)	(6)
Depreciation and Amortization	136	234	(98)	(42)	275	481	(206)	(43)
Other Income (Deductions)	18	18	—	—	37	35	2	6
Interest Expense	74	67	7	10	142	136	6	4
Income Tax Expense	98	104	(6)	(6)	249	261	(12)	(5)

Three Months Ended June 30, 2016 as Compared to 2015

Operating Revenues decreased $116 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $28 million due primarily to an increase in transmission revenues.

- Transmission revenues were $48 million higher due to increased capital investments.
- Electric distribution revenues decreased $19 million due primarily to lower Green Program Recovery Charges (GPRC) of $14 million and $5 million in lower sales volumes.

Commodity Revenue decreased $15 million as a result of $30 million of lower Electric revenues, partially offset by $15 million in higher Gas revenues. Commodity revenue for both electric and gas is entirely offset with the change in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $30 million due primarily to $15 million of lower revenues from collections of Non-Utility Generation Charges (NGC), a $7 million or 2% decrease in BGS revenues due to lower sales volumes, and a decrease of $8 million due to lower volumes of Non-Utility Generation (NUG) energy sold.
- Gas revenues increased $15 million due to higher BGSS sales volumes.

Clause Revenues decreased $128 million due primarily to lower Securitization Transition Charges (STC) of $122 million and lower Societal Benefit Charges (SBC) of $5 million. The STC reduction is a result of rate reductions due to the completion of securitization collections in 2015. The changes in the STC and SBC amounts are entirely offset by decreases in the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC or SBC collections.

Operating Expenses

Energy Costs decreased $15 million. This is entirely offset by the change in Commodity Revenue.

Operation and Maintenance decreased $16 million, of which the most significant components were

- a $28 million net reduction in costs related to various clause mechanisms and GPRC,
- partially offset by a $7 million increase in distribution maintenance, due to increases of $4 million for vegetation management and $3 million for corrective maintenance.

Depreciation and Amortization decreased $98 million due to a decrease of $116 million in amortization of Regulatory Assets primarily as a result of the completion of the amortization of the securitization charges in 2015 (which is completely offset in STC Revenues), partially offset by a $17 million increase in depreciation due to additional plant in service.

Interest Expense increased $7 million due primarily to an increase of $8 million due to net debt issuances in 2015 and 2016.

Income Tax Expense decreased $6 million due primarily to plant and other flow through items and uncertain tax positions, partially offset by higher pre-tax income.

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Six Months Ended June 30, 2016 as Compared to 2015

Operating Revenues decreased $406 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $57 million due primarily to an increase in transmission revenues.

- Transmission revenues were $102 million higher due to increased capital investments.
- Electric distribution revenues decreased $42 million due primarily to lower GPRC of $26 million and $16 million in lower sales volumes.
- Gas distribution revenues decreased $3 million due primarily to $68 million of lower delivery volumes and lower GPRC of $7 million due to lower sales volumes from warmer winter weather. These decreases were almost entirely offset by $62 million in higher Weather Normalization Clause revenue and $10 million due to the roll in of Energy Strong into base rates effective September 1, 2015.

Commodity Revenue decreased $178 million as a result of lower Gas and Electric revenues. Commodity revenue for both gas and electric is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGSS and BGS to retail customers.

- Gas revenues decreased $94 million due primarily to lower BGSS sales volumes.
- Electric revenues decreased $84 million due primarily to a $42 million or 5% decrease in BGS revenues due to lower sales volumes, $26 million of lower revenues from collections of NGC and a decrease of $16 million due to lower volumes of NUG energy sold at lower prices.

Clause Revenues decreased $282 million due primarily to lower STC of $251 million and lower SBC of $38 million, partially offset by higher Margin Adjustment Clause (MAC) revenue of $14 million. The STC reduction is a result of rate reductions due to the completion of securitization collections in 2015. The changes in the STC, SBC and MAC amounts are entirely offset by decreases in the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC or MAC collections.

Operating Expenses

Energy Costs decreased $178 million. This is entirely offset by the change in Commodity Revenue.

Operation and Maintenance decreased $46 million, of which the most significant components were

- a $72 million net reduction in costs related to various clause mechanisms and GPRC,
- partially offset by an $11 million increase in distribution maintenance, due to increases of $6 million for corrective maintenance and $5 million for vegetation management and
- $10 million of storm insurance recovery proceeds received in 2015.

Depreciation and Amortization decreased $206 million due to a decrease of $239 million in amortization of Regulatory Assets primarily as a result of the completion of the amortization of the securitization charges in 2015 (which is completely offset in STC Revenues), partially offset by a $32 million increase in depreciation due to additional plant in service.

Interest Expense increased $6 million due primarily to an increase of $13 million due net debt issuances in 2015 and 2016, partially offset by an $8 million decrease due to the redemption of securitization debt in 2015.

Income Tax Expense decreased $12 million due primarily to plant and other flow through items and uncertain tax positions offset by higher pre-tax income.

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Power

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2016	2015	2016 vs. 2015		2016	2015	2016 vs. 2015	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 714	$ 1,025	$ (311)	(30)	$ 2,027	$ 2,750	$ (723)	(26)
Energy Costs	381	409	(28)	(7)	1,019	1,302	(283)	(22)
Operation and Maintenance	265	313	(48)	(15)	518	485	33	7
Depreciation and Amortization	80	75	5	7	159	151	8	5
Income from Equity Method Investments	4	5	(1)	(20)	6	8	(2)	(25)
Other Income (Deductions)	16	48	(32)	(67)	24	66	(42)	(64)
Other-Than-Temporary Impairments	10	10	—	—	20	15	5	33
Interest Expense	20	33	(13)	(39)	42	64	(22)	(34)
Income Tax Expense	(11)	72	(83)	N/A	118	306	(188)	(61)

Three Months Ended June 30, 2016 as Compared to 2015

Operating Revenues decreased $311 million due to changes in generation, gas supply and other revenues.

Generation Revenues decreased $300 million due primarily to

- a decrease of $212 million due to MTM losses in 2016 as compared to MTM gains in 2015. Of this amount, $187 million was due to changes in forward power prices, which increased in the current period and decreased during the comparable period in 2015. Also contributing to the decrease was $25 million from higher gains on positions reclassified to realized upon settlement this year compared to last year,
- a decrease of $66 million in energy sales primarily in the PJM region due to lower volumes and lower average realized prices,
- a decrease of $14 million in capacity revenue primarily in the PJM region due to the retirement of older peaking units in June 2015, and
- a net decrease of $8 million in electricity sold under our BGS contracts due primarily to lower volumes.

Gas Supply Revenues decreased $11 million due primarily to

- a net decrease of $15 million in sales under the BGSS contract primarily due to lower average sales prices and MTM losses, and
- a net increase of $4 million on sales to third party customers, of which $8 million was due to higher volumes sold partially offset by $4 million of lower average sales prices.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $28 million due to

- ***Generation costs*** decreased $37 million due primarily to lower natural gas and coal fuel costs of $30 million reflecting lower average realized prices and the utilization of lower volumes.
- ***Gas costs*** increased $9 million mainly related to higher volumes sold to third parties.

Operation and Maintenance decreased $48 million due primarily to

- a net decrease of $35 million related to our fossil plants, primarily due to higher costs incurred in 2015 for the installation of upgraded technology at our combined cycle Bergen generating plant, and

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- a net decrease of $33 million related to our nuclear facilities, largely due to a planned outage at our 100%-owned Hope Creek plant in 2015, partly offset in 2016 by an extended refueling outage at our 57%-owned Salem Unit 1 plant,
- partially offset by $17 million of insurance recoveries received in 2015 related to Superstorm Sandy,

Depreciation and Amortization increased $5 million due primarily to a higher depreciable nuclear asset base.

Other Income (Deductions) decreased $32 million due primarily to $28 million of insurance recoveries received in 2015 related to Superstorm Sandy and higher net realized gains from the NDT Fund in 2015.

Interest Expense decreased $13 million due primarily to the maturity of $300 million of 5.50% Senior Notes in December 2015 and higher capitalized interest in 2016.

Income Tax Expense decreased $83 million in 2016 due primarily to lower pre-tax income, partially offset by a benefit related to a Nuclear Decommissioning Tax Carryback transaction that was recorded in 2015.

Six Months Ended June 30, 2016 as Compared to 2015

Operating Revenues decreased $723 million due to changes in generation and gas supply revenues.

Generation Revenues decreased $474 million due primarily to

- a decrease of $173 million due to MTM losses in 2016 as compared to MTM gains in 2015. Of this amount, $103 million was due to higher gains on positions reclassified to realized upon settlement this year compared to last year. Also contributing to the decrease was $70 million from a decrease in forward power prices in 2015,
- a decrease of $140 million in energy sales volumes in the PJM and New England (NE) regions due primarily to milder weather and lower average realized prices in the PJM and New York regions,
- a net decrease of $87 million primarily in the PJM region due to lower operating reserve revenues coupled with lower capacity revenues resulting from the retirement of older peaking units in June 2015, and
- a decrease of $40 million in electricity sold under wholesale load contracts in the PJM and NE regions due primarily to lower volumes and lower average prices.

Gas Supply Revenues decreased $249 million due primarily to

- a net decrease of $234 million in sales under the BGSS contract, substantially comprised of lower sales volumes due to warmer average temperatures in the 2016 winter heating season, coupled with lower average sales prices, and
- a net decrease of $15 million on sales to third party customers, of which $47 million was due to lower average sales prices, partially offset by $32 million of higher volumes sold.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $283 million due to

Generation costs decreased $160 million due primarily to

- lower fuel costs of $267 million reflecting lower average realized prices for natural gas and the utilization of lower volumes of fuel, and
- a decrease of $18 million due to MTM gains in 2016 as compared to MTM losses in 2015. The 2016 MTM gains were primarily due to favorable forward price movements on natural gas, while the 2015 MTM losses were primarily due to higher gains on positions reclassified to realized upon settlement on transmission products,
- partially offset by higher congestion costs in PJM of $142 million, mainly as a result of credits received in the prior year due to extremely cold weather.

Gas costs decreased $123 million mainly related to

- a decrease of $136 million related to sales under the BGSS contract due primarily to lower volumes sold due to warmer average temperatures during the 2016 winter heating season and lower average gas costs,
- partially offset by a net increase of $13 million related to sales to third parties due primarily to an increase in volumes sold.

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Operation and Maintenance increased $33 million due primarily to

- $145 million of insurance recoveries received in 2015 related to Superstorm Sandy,
- partially offset by a net decrease of $85 million related to our fossil plants, largely due to higher costs incurred in 2015 for our planned major outages at the Bethlehem Energy Center and Bergen generating plants, and
- a net decrease of $38 million related to our nuclear plants due primarily to the aforementioned reasons provided for the second quarter variance.

Depreciation and Amortization increased $8 million due primarily to a higher depreciable nuclear asset base.

Other Income (Deductions) decreased $42 million due primarily to $28 million of insurance recoveries received in 2015 related to Superstorm Sandy and higher net realized gains from the NDT Fund in 2015.

Other-Than-Temporary Impairments increased $5 million due to an increase in impairments of equity securities in the NDT Fund in 2016.

Interest Expense decreased $22 million due primarily to the maturity of $300 million of 5.50% Senior Notes in December 2015 and higher capitalized interest in 2016.

Income Tax Expense decreased $188 million in 2016 due primarily to lower pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

We expect operating cash flows combined with cash on hand and financing activities to be sufficient to fund planned capital expenditures and shareholder dividend payments.

For the six months ended June 30, 2016, our operating cash flow decreased $512 million as compared to the same period in 2015. The net change was due primarily to the net changes from PSE&G and Power as discussed below.

PSE&G

PSE&G's operating cash flow decreased $101 million from $909 million to $808 million for the six months ended June 30, 2016, as compared to the same period in 2015, due primarily to a decrease of $87 million due to a change in regulatory deferrals primarily driven by lower volumes due to warmer weather impacting our Gas Weather Normalization, SBC, GPRC and BGSS clauses and a $77 million decrease due to higher vendor payments. These amounts were partially offset by higher earnings and higher tax refunds in 2016.

Power

Power's operating cash flow decreased $375 million from $1,292 million to $917 million for the six months ended June 30, 2016, as compared to the same period in 2015, primarily due to lower earnings, a $123 million decrease from fuels, materials and supplies, and a $115 million increase in margin deposit requirements, partially offset by a reduction in tax payments.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

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We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of June 30, 2016 were as follows:

	As of June 30, 2016		
Company/Facility	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$ 1,000	$ 10	$ 990
PSE&G	600	14	586
Power	2,553	202	2,351
Total	**$ 4,153**	**$ 226**	**$ 3,927**

As of June 30, 2016, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating, which would represent a three level downgrade from its current S&P and Moody's ratings. In the event of a deterioration of Power's credit rating certain of Power's agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $748 million and $864 million as of June 30, 2016 and December 31, 2015, respectively.

As of June 30, PSEG's credit facilities are available to back-stop its Commercial Paper Program and issue letters of credit. As of June 30, 2016, no Commercial Paper was outstanding. PSE&G's credit facility primary use is to support its Commercial Paper Program under which as of June 30, 2016, no amounts were outstanding. Most of our credit facilities expire in 2019 and 2020.

For additional information, see Item 1.Note 9. Debt and Credit Facilities.

Long-Term Debt Financing

Power has $303 million of 5.32% Senior Notes and $250 million of 2.75% Senior Notes maturing in September 2016.

For a discussion of our long-term debt transactions during 2016, see Item 1. Note 9. Debt and Credit Facilities.

Common Stock Dividends

On April 19, 2016, our Board of Directors approved a $0.41 per share of common stock dividend for the second quarter of 2016. On July 19, 2016, our Board of Directors declared a quarterly dividend of $0.41 per share of common stock for the third quarter of 2016. This reflects an indicative annual dividend rate of $1.64 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 1. Note 15. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In January 2016, S&P published updated research reports on PSEG and PSE&G and the existing ratings and outlooks were unchanged. In June 2016, Moody's published credit opinions on Power and PSE&G and the existing ratings and outlooks were unchanged. In June 2016, S&P published an updated research report on Power and the existing rating and outlook were unchanged.

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	Moody's (A)	S&P (B)
PSEG		
Outlook	**Positive**	**Stable**
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities. The Corporate Credit Rating outlook does not apply to PSEG's or PSE&G's Commercial Paper Rating or PSE&G's Mortgage Bond rating.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures at Power and Services as compared to amounts disclosed in our 2015 Form 10-K.

PSEG

In July 2016, PSEG partnered with Vectren Corporation on a FERC 1000 proposal to construct, own and operate a twenty mile, 345 kilovolt transmission line in the midwest region served by the Midcontinent Independent System Operator (MISO). MISO estimated the project would cost approximately $60 million and would go in service in 2021. MISO is expected to select a proposal in December 2016. This project is not included in PSEG's projected capital expenditures.

PSE&G

PSE&G increased its estimate of its capital expenditure program as reported in our 2015 Form 10-K by approximately $300 million from $8.3 billion to $8.6 billion primarily to address new business requests and to replace aging equipment and infrastructure.

In May 2016, PSE&G filed a petition with the BPU requesting an extension of its existing landfill/brownfield solar program to construct 100 MW of grid-connected solar facilities with projected capital expenditures of up to $240 million through approximately 2021. This is not included in PSE&G's projected capital expenditures.

During the six months ended June 30, 2016, PSE&G made capital expenditures of $1,355 million, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $74 million, which are included in operating cash flows.

Power

During the six months ended June 30, 2016, Power made capital expenditures of $505 million, excluding $93 million for nuclear fuel, primarily related to our Keys, Sewaren 7, BH5 and other generation projects.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Item 1. Note 2. Recent Accounting Standards.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From April through June 2016, MTM VaR remained relatively stable between low of $10 million to high of $18 million at 95% confidence level. The range of VaR was narrower for the three months ended June 30, 2016 as compared with the year ended December 31, 2015.

	MTM VaR	
	Three Months Ended June 30, 2016	Year Ended December 31, 2015
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 16	$ 24
Average for the Period	$ 15	$ 17
High	$ 18	$ 40
Low	$ 10	$ 8
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 25	$ 38
Average for the Period	$ 23	$ 26
High	$ 27	$ 63
Low	$ 16	$ 12

See Item 1. Note 10. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

There have been no changes in internal control over financial reporting that occurred during the second quarter of 2016 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2015 Annual Report on Form 10-K, see Part I, Item 1. Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

There are no additional Risk Factors to be added to those disclosed in Part I, Item 1A of our 2015 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the second quarter of 2016.

Three Months Ended June 30, 2016	Total Number of Shares Purchased	Average Price Paid per Share
April 1 - April 30	—	$ —
May 1 - May 31	228,639	$ 46.23
June 1- June 30	50,000	$ 44.50

ITEM 5. OTHER INFORMATION

Certain information reported in the 2015 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2015 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2016. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

Employee Relations

December 31, 2015 Form 10-K page 16 and March 31, 2016 Form 10-Q page 70. Since the beginning of 2016, six of our eight labor unions ratified extensions of their collective bargaining agreements with us, with expiration dates from 2019 to

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2021. The collective bargaining agreements for the remaining two unions expire in 2017 and 2018. We believe we maintain satisfactory relationships with our employees.

Federal Regulation

FERC

Capacity Market Issues—PJM

December 31, 2015 Form 10-K page 17 and March 31, 2016 Form 10-Q page 70. An emerging issue in PJM involves the impact of subsidized generation on RPM market outcomes. In particular, FirstEnergy Corp. (FE) and American Electric Power (AEP) have proposed to enter into power purchase agreements (PPAs) with their non-utility generation affiliates providing for above-market purchases from certain coal plants and a nuclear plant (in FE's case). The Ohio Public Utility Commission (PUCO) approved the PPAs on terms similar to the terms sought by those companies. The Dayton Power and Light Company has recently also filed for comparable arrangements covering generating plants that it owns. On April 27, 2016, FERC issued orders finding that the PPAs should be reviewed to determine whether they comport with the Commission's standards for contracts. FE subsequently submitted a modified arrangement to PUCO arguing that it is within PUCO's exclusive jurisdiction. This modified proposal is currently the subject of contested proceedings at both the PUCO and at FERC. In another proceeding at FERC, certain parties are claiming that PJM should be directed to expand the MOPR to apply to existing contracts, including the FE and AEP PPAs.

We are unable to predict the results of these pending proceedings or any future related proceedings or to calculate the potential impacts on our business.

Capacity Market Issues—ISO-New England

December 31, 2015 Form 10-K page 18 and March 31, 2016 Form 10-Q page 71. In March 2015, in conjunction with other companies, we filed a petition for review with the D.C. Circuit Court of Appeals (D.C. Court) of FERC's ruling accepting the exemption from the MOPR in the capacity market afforded for up to 200 MW annually (600 MW cumulatively) of renewable resources. On December 1, 2015, following a request by FERC for a voluntary remand of the order, the D.C. Court remanded the case to FERC for additional consideration. However, on April 8, 2016, FERC issued an order upholding the exemption. We and other companies continue to contest the reasonableness of the exemption.

Reactive Power Rates

December 31, 2015 Form 10-K page 19 and March 31, 2016 Form 10-Q page 71. In June 2015, Power submitted a tariff filing with FERC to increase Power's rates for reactive supply and voltage control service from approximately $27 million per year to about $39 million per year. Following settlement discussions with FERC Trial Staff, Power agreed to accept an overall rate of $34 million per year on the condition that we will refile in six years, which FERC approved in February 2016. FERC had earlier referred the filing to the FERC Office of Enforcement for its evaluation, which remains pending. More broadly, FERC has begun to review regulations relating to reactive power compensation. We cannot predict the impact of potential changes to reactive power compensation regulations on our business and results of operations.

Transmission Regulation

December 31, 2015 Form 10-K page 19. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. In June 2016, PSE&G filed its 2015 true-up adjustment pertaining to its transmission formula rates in effect for 2015, which resulted in an adjustment of $34 million less than the 2015 originally filed revenues. For additional information about our transmission formula rate, see Part I, Item 1. Financial Information—Note 4. Rate Filings.

Transmission Regulation—Transmission Policy Developments

December 31, 2015 Form 10-K page 19 and March 31, 2016 Form 10-Q page 71. FERC concluded in Order 1000 that the incumbent transmission owner should not always have a Right of First Refusal (ROFR) to construct and own transmission projects in its service territory. We and other companies appealed Order 1000 but this appeal was denied in 2014 by the D.C. Court. The current PJM rules retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including immediately needed reliability projects, upgrades to existing transmission facilities, projects cost-allocated to a single transmission zone, and projects being built on existing rights-of-way and whose construction would interfere with incumbents' use of their rights-of-way. While these carve-outs ameliorate the impacts of the Order 1000 ruling on incumbents, we and several other companies appealed various aspects of the FERC order approving PJM's implementation of Order 1000, including the elimination of the ROFR from the PJM Tariff. On July 1, 2016, the D.C. Court dismissed the case, thus upholding FERC's determination. We are currently analyzing the impact of the D.C. Court's decision on our operations and whether further action is appropriate.

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There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G contending that insufficient levels of costs are being allocated to PSE&G. Projects involved include the Artificial Island project, the Bergen-Linden project in New Jersey and a smaller project in Sewaren, New Jersey. On April 22, 2016, FERC issued orders denying the complaints and leaving the current cost allocation in effect as to the Artificial Island and Bergen-Linden projects. Due to an intervening FERC order concerning the allocation of costs for projects constructed to meet local reliability requirements, FERC directed that all of the Sewaren costs be allocated to PSE&G. It is anticipated that additional proceedings are likely to occur. It is anticipated that these various proceedings will not be resolved for several years.

Another proceeding is a matter remanded from a federal appellate court concerning the appropriate cost allocation for certain 500 kV projects in PJM that either have been built or are in the process of being built, including the Susquehanna-Roseland project. A proposed settlement was filed with FERC on June 15, 2016. The settlement, if adopted by FERC, will result in increased annual cost allocations to customers in the PSE&G Transmission Zone. Under this settlement, Power, as a BGS supplier could become obligated to pay amounts previously paid by other PJM transmission customers. However, we do not believe that the anticipated level of any such potential payments would have a material effect on Power's financial statements.

Con Edison Wheeling Agreement

In April 2016, Con Edison informed PJM that it would allow its Wheeling Agreement to expire effective as of May 1, 2017. The Wheeling Agreement enables Con Edison to move 1,000 MW of energy from southeast New York across the PSE&G system for delivery into New York City. Discussions are currently ongoing among PJM and NYISO stakeholders regarding future operational procedures and transmission planning assumptions associated with the affected transmission lines. Depending on the outcome of these discussions, which may require FERC to approve tariff revisions, there could be impacts on capacity and energy prices in the region as well as impacts on transmission planning. In addition, Regional Transmission Expansion Plan costs that would have been allocated to Con Edison under the Wheeling Agreement will be reallocated elsewhere, which will include some reallocations to the customers within the PSE&G Transmission Zone.

Nuclear Regulatory Commission (NRC)

December 31, 2015 Form 10-K page 21. As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in 2011, the NRC began performing additional operational and safety reviews of nuclear facilities in the United States. We believe that our nuclear plants currently meet the stringent applicable design and safety specifications of the NRC.

Among other things, the NRC advised the staff to give the highest priority to those activities that can achieve the greatest safety benefit and/or have the broadest applicability (Tier 1).

The NRC issued letters and orders to licensees implementing the Tier 1 recommendations in March 2012. In June 2013, the NRC issued an order requiring Mark I and Mark II licensees to upgrade or replace their reliable hardened vents with containment venting systems designed and installed to remain functional during severe accident conditions. We are implementing the diverse and flexible strategies and spent fuel pool level indication modifications in accordance with the regulatory requirements at the Salem, Hope Creek and Peach Bottom nuclear units. For our Hope Creek and Peach Bottom units, final installation of the required modifications is expected to be completed by 2018.

In March 2013, the NRC initiated a rulemaking process for filtering strategies with drywell filtration and severe accident management for U.S. Boiling Water Reactors with Mark I and Mark II containments. The NRC subsequently disapproved the staff plan to pursue rulemaking, based in part on the upgrades required by the June 2013 order. The NRC continues to evaluate potential revisions to its requirements in connection with its operational and safety reviews of nuclear facilities in the United States as a result of the Fukushima Daiichi incident.

We are unable to predict the final outcome of these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to our Salem, Hope Creek and Peach Bottom facilities, but such cost could be material.

State Regulation

Connecticut Rate Filing

December 31, 2015 Form 10-K page 23. On June 30, 2016, Power's subsidiary, PSEG New Haven LLC, filed a mandatory annual rate case with the Connecticut Public Utilities Regulatory Authority for recovery of its costs and investment in its Connecticut-based peaking unit. Power requested 2017 revenues of $20 million. This matter is pending.

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Solar 4 All Program Extension II

In May 2016, PSE&G filed a petition with the BPU requesting an extension of its existing landfill/brownfield solar program to construct 100 MW of grid-connected solar facilities with projected capital expenses of up to $240 million, through approximately 2021. This matter is pending.

Environmental Matters

Air Pollution Control

Hazardous Air Pollutants Regulation

December 31, 2015 Form 10-K page 24 and March 31, 2016 Form 10-Q page 72. In February 2012, the (EPA) published Mercury Air Toxics Standards (MATS) for both newly-built and existing electric generating sources under the National Emission Standard for Hazardous Air Pollutants (NESHAP) provisions of the CAA. The MATS established allowable levels for mercury as well as other hazardous air pollutants and went into effect in April 2015. In June 2015, the U.S. Supreme Court held that it was unreasonable for the EPA to refuse to consider the materiality of costs in determining whether to regulate hazardous air pollutants from power plants. On April 15, 2016, the EPA released the final Supplemental Finding that considers the materiality of costs in determining whether to regulate hazardous air pollutants from power plants in response to the U.S. Supreme Court's ruling. Industry participants and various state authorities have filed petitions with the D.C. Court challenging the EPA's Supplemental Finding. We do not expect this Supplemental Finding to impact operation of our facilities.

Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation

December 31, 2015 Form 10-K page 24. In March 2013, Power filed a petition at the EPA challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued in January 2013. Among other things, the NESHAP include two exemptions that allow owners and operators of stationery emergency RICE to operate their engines without the installation and operation of emission controls (1) as part of an emergency DR program for 100 hours per year (100 hour exemption) or (2) as part of a financial arrangement with another entity per specified restrictions in non-emergency situations for 50 hours per year (50 hour exemption). We believe this waiver of NESHAP standards results in disparate treatment of different generation technology types. In its appeal, Power sought more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. In August 2014, the EPA denied the March 2013 petition and in October 2014, Power appealed the EPA's denial to the D.C. Court. On September 23, 2015, the D.C. Court granted the EPA's motion for voluntary remand of the 50 hour exemption provision to the EPA. On May 4, 2016, the D.C. Court vacated the 100 hour exemption which removes that provision from the rule. We believe that the impact of the D.C. Court's rulings would likely benefit Power's and its competitors' operations of their power generation peaking units.

Cooling Water Intake Structure Regulation

December 31, 2015 Form10-K page 26. On June 10, 2016, the New Jersey Department of Environmental Protection (NJDEP) issued the final New Jersey Pollutant Discharge Elimination System (NJPDES) permit for Salem, with an effective date of August 1, 2016. The final permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the Clean Water Act, it requires additional studies and the selection of technology to address impingement for the service water system. On July 8, 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of a final NJPDES renewal permit for Salem. The Riverkeeper's filing does not change the effective date of the permit. For additional information, see Part I, Item 1. Note 8. Commitments and Contingent Liabilities.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 10a(10):	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective July 19, 2016
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. PSE&G:

Exhibit 10a(9):	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective July 19, 2016 (1)
Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. Power:

Exhibit 10a(8):	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective July 19, 2016 (1)
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

(1) Filed as Exhibit 10a(10) by PSEG with this Quarterly Report on Form 10-Q for the quarter ended June 30, 2016, File No. 001-09120 on July 29, 2026 and incorporated herein by this reference.

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: July 29, 2016

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: July 29, 2016

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: July 29, 2016

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EXHIBIT 10a(10)

KEY EXECUTIVE SEVERANCE PLAN OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Amended effective July 19, 2016

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ARTICLE I

PURPOSE OF THE PLAN

1.1 Purpose The Key Executive Severance Plan of Public Service Enterprise Group Incorporated ("Plan") is maintained by the Company to provide severance benefits to certain key executive-level employees of the Company and its affiliates whose employment is terminated under the circumstances described herein. The Plan was amended and restated effective December 17, 2012.

The Plan was amended effective January 1, 2014 to provide that (i) for Eligible Employees who become Schedule B Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to two times Annual Base Salary and Target Bonus, and (ii) for Eligible Employees who become Schedule A Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to 1.5 times Annual Base Salary and Target Bonus. The Plan was further amended to provide that the for purposes of determining the nonqualified plan change in control benefit under Section 5.5(a) of the Plan, with respect to Eligible Employees who become Schedule A or Schedule B Participants after December 31, 2013, their employment shall be assumed to have continued for 1.5 or two additional years (for Schedule A Participants and Schedule B Participants, respectively). Finally, the Plan was amended to update the Schedule A Participant list.

The Plan was amended effective June 16, 2014 to (i) add a new class of eligible Participants, Schedule C Participants, (ii) to provide that there will be no additions to Schedule B Participants, (iii) to provide that other than a current Schedule B Participant, an Eligible Employee newly hired or promoted into a position reflected on Schedule B as of June 16, 2014, shall become a Schedule A Participant, and (iv) to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

The Plan was amended effective July 14, 2014 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan was amended effective February 17, 2015 to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

The Plan was amended effective November 18, 2015 to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list, and to include the language to comply with the Securities and Exchange Commission's whistleblower protections.

The Plan was amended effective December 15, 2015 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan is being amended effective July 19, 2016 to update the Schedule A Participant list and the Schedule C Participant list. The Plan is also being amended to comply with the Defense of Trade Secrets Act regarding the confidentiality provision. Finally, the Plan is being

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amended to clarify that if an Eligible Employee is newly hired or promoted into a position reflected on Schedule B as of June 6, 2014, such Eligible Employee shall become a Schedule A Participant.

The Plan is intended to comply in operation and form with Section 409A to the Internal Revenue Code of 1986, as amended ("Code"). The timing and form of payment of benefits provided under the Plan will be deemed to be automatically modified, and a Participant's rights under the Plan will be limited so as to conform to any requirements under Section 409A of the Code.

ARTICLE II

DEFINITIONS

2.1 "Accrued Obligation" shall have the meaning set forth in Section 4.1 or 5.1 of the Plan.

2.2 "Affiliate" means any corporation, trade or business if it or the Company are members of a controlled group of corporations, are under common control or are members of an affiliated service group, within the meanings of Sections 414(b), 414(c) and 414(m), respectively, of the Code. The term "Affiliate" shall also include any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code.

2.3 "Annual Base Salary" means the annual rate of base salary payable to a Participant for services performed for an Employer, as in effect immediately prior to the Participant's Date of Termination.

2.4 "Board" means the board of directors of the Company.

2.5 "Cause" means:

(a) For purposes of Article IV:

(i) Misconduct, gross negligence, theft, or fraud against the Company;

(ii) For "Performance Reasons," as defined in Section 2.21 of the Plan;

(iii) Violation of the Standards of Integrity or other Company policy;

(iv) Insubordination;

(v) One or more significant acts of dishonesty;

(vi) Any act that is likely to have the effect of injuring the reputation, business, or business relationship of, the Company, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries;

(vii) Violation of any fiduciary duty;

(viii) Breach of any duty of loyalty;

(ix) Any breach of the restrictive covenants contained in Exhibit I below;

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(x) One or more acts of moral turpitude that constitute a violation of applicable law (included but not limited to a felony); or

(xi) Conviction of a felony or plea of *nolo contendere* to a felony charge.

(b) For purposes of Article V:

(i) The willful and continued failure to substantially perform his employment duties;

(ii) The willful engaging in gross misconduct that is materially and demonstrably injurious to the Employer;

(iii) The willful violation of the Company's Standards of Integrity or other applicable corporate code of conduct, or

(iv) The conviction of a felony or a plea of *nolo contetendere* to a felony charge.

No act or failure to act on the part of the Participant shall be considered "willful" unless it is done, or omitted to be done, by the Participant in bad faith or without reasonable belief that the Participant's action or omission was in the best interests of the Employer. Any act or failure to act that is based upon authority given pursuant to a resolution duly adopted by the Board, or the advice of counsel for the Employer, shall be conclusively presumed to be done, or omitted to be done, by the Participant in good faith and in the best interests of the Employer.

Notwithstanding the forgoing, for purposes of the Plan, the termination of a Participant's employment with an Employer shall not be deemed to be for Cause unless such termination is effected in accordance with the following procedures. The Employer shall give the Participant written notice ("Notice of Termination for Cause") of its intention to terminate the Participant's employment for Cause, setting forth in reasonable detail the specific conduct of the Participant that it considers to constitute Cause. Such notice shall be given no later than 60 days after the act or failure (or the last in a series of acts or failures) that the Employer alleges to constitute Cause. The Participant shall have 30 days after receiving the Notice of Termination for Cause in which to cure such act or failure, to the extent such cure is possible. In the case of a termination under clause (a), (b) or (c) above, if the Participant fails to cure such act or failure to the reasonable satisfaction of the Employer, the Employer shall give the Participant a second written notice stating that in the good faith opinion of the Employer, the Participant is guilty of the conduct described in the Notice of Termination for Cause and that such conduct constitutes Cause under the Plan.

2.6 "Change in Control" means the occurrence of any of the following events:

(a) Any "person" (within the meaning of Section 13(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") is or becomes the beneficial owner within the meaning of Rule 13d-3 under the Exchange Act (a "Beneficial Owner"), directly or indirectly, of securities of the Company (not including in the securities beneficially owned by such person any securities acquired directly from the Company or its Affiliates) representing 25% or more of the combined voting power of the Company's then outstanding securities, excluding any person who

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becomes such a Beneficial Owner in connection with a transaction described in clause (i) of paragraph (c) below; or

(b) The following individuals cease for any reason to constitute a majority of the number of directors of the Company then serving: individuals who, on the Effective Date, constitute the Board and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's stockholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on the Effective Date or whose appointment, election or nomination for election was previously so approved or recommended; or

(c) There is consummated a merger or consolidation of the Company or any direct or indirect wholly-owned subsidiary of the Company with any other corporation, other than (i) a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of the Company or of its Affiliates, at least 75% of the combined voting power of the securities of the Company or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (ii) a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the Beneficial Owner, directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company's then outstanding securities; or

(d) The shareholders of the Company approve a plan of complete liquidation or dissolution of the Company or there is consummated an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 75% of the combined voting power of the voting securities of which are owned by stockholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale.

Notwithstanding the foregoing, a "Change in Control" shall not be deemed to have occurred by virtue of the consummation of any transaction or series of integrated transactions immediately following which the record holders of the common stock of the Company immediately prior to such transaction or series of transactions continue to have substantially the same proportionate ownership in an entity which owns all or substantially all of the assets of the Company immediately following such transaction or series of transactions.

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2.7 "Code" means the Internal Revenue Code of 1986, as amended, and the regulations promulgated thereunder.

2.8 "Committee" means the Organization and Compensation Committee of the Board or any successor of such Committee.

2.9 "Company" means Public Service Enterprise Group Incorporated and any successors thereto.

2.10 "Confidential Information" means all trade secrets, proprietary and confidential business information belonging to, used by, or in the possession of the Company or any of its Affiliates, including but not limited to information, knowledge or data related to business strategies, plans and financial information, mergers, acquisitions or consolidations, purchase or sale of property, leasing, pricing, sales programs or tactics, actual or past sellers, purchasers, lessees, lessors or customers, those with whom the Company or its Affiliates has begun negotiations for new business, costs, employee compensation, marketing and development plans, inventions and technology, whether such confidential information, knowledge or data is oral, written or electronically recorded or stored, except information in the public domain, information known by the Participant prior to employment with an Employer, and information received by the Participant from sources other than the Company or its Affiliates, without obligation of confidentiality.

2.11 "Date of Termination" means the date of a Participant's death, Disability Effective Date, or the date on which the termination of the Participant's employment by an Employer for Cause or without Cause or by the Participant for Good Reason or without Good Reason, including Retirement, is effective, as the case may be, provided that the termination constitutes a Separation from Service.

2.12 "Disability" means that the Participant (a) is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, or (b) is, by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than 12 months, receiving income replacement benefits for a period of not less than three months under an accident or health plan covering employees of an Employer.

2.13 "Disability Effective Date" means the 30th day after the Participant's receipt of written notice of the Employer's intention to terminate the Participant's employment on account of Disability, provided that, within the 30 days after the Participant's receipt of such notice, the Participant shall not have returned to full-time performance of his employment duties.

2.14 "Eligible Employee" means an individual who is designated as such in accordance with Section 3.1.

2.15 "Effective Date" of the amendment and restatement is July 19, 2016.

2.16 "Employer" means the Company and each Affiliate, and any successors thereto.

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2.17 "Good Reason" means:

(a) Any material reduction in the Participant's Annual Base Salary, Target Bonus or Target Long-Term Incentive, other than reductions pursuant to a broad-based compensation reduction program or policy affecting the Participant and all similarly situated employees of the Employer;

(b) Any material adverse change in the Participant's title, authority, duties, or responsibilities or the assignment to the Participant of any duties or responsibilities inconsistent in any respect with those customarily associated with the position of the Participant immediately prior to the Change in Control;

(c) The failure of any successor to the Company to assume this Plan in accordance with Section 11.5(b);

(d) Where the only comparable position offered to the Participant within the Employer following a Change in Control would otherwise meet the requirements of subsections (a) and (b) of this Section 2.17 of the Plan, but would require the Participant to increase his or her one-way commuting distance from his or her principal residence by more than 50 miles; or

(e) Any other material breach of the terms of the Plan by the Company that either is not taken in good faith or, even if taken in good faith, is not remedied by the Company promptly after receipt of notice thereof from the Participant.

Notwithstanding the forgoing, for purposes of the Plan, the termination of a Participant's employment with an Employer shall not be deemed to be for Good Reason unless such termination is effected in accordance with the following procedures. The Participant shall give his Employer a written notice ("Notice of Termination for Good Reason") of the termination, setting forth in reasonable detail the specific acts or omissions of the Employer that constitute Good Reason and the specific provision(s) of the Plan on which the Participant relies. Unless the Committee determines otherwise, a Notice of Termination for Good Reason by the Participant must be made within 60 days after the Participant first has actual knowledge of the act or omission (or the last in a series of acts or omissions) that the Participant alleges to constitute Good Reason, and the Employer shall have 30 days from the receipt of such Notice of Termination for Good Reason to cure the conduct cited therein. A termination of employment by the Participant for Good Reason shall be effective on the final day of such 30-day cure period unless prior to such time the Employer has cured the specific conduct asserted by the Participant to constitute Good Reason to the reasonable satisfaction of the Participant.

For purposes of the Plan, a Participant's determination that an act or failure to act constitutes Good Reason shall be presumed to be valid unless such determination is decided to be unreasonable by the Committee or its delegate pursuant to Article IX.

2.18 "Nonqualified Plan" the Retirement Income Reinstatement Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated.

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2.19 "Other Benefits" shall have the meaning set forth in Articles IV and V, as applicable.

2.20 "Participant" means an Eligible Employee who has satisfied the conditions for participation in the Plan, as set out in Section 3.2, and is listed on either Schedule A, Schedule B or Schedule C hereto, as the same may be amended from time to time.

2.21 "Performance Reasons" means the Participant's failure meet the expectations established for his function in the Company as: (a) communicated to him by his manager during any performance review, or (b) may be communicated to him otherwise by his manager from time to time either orally or in writing.

2.22 "Plan" means this Key Executive Severance Plan of Public Service Enterprise Group Incorporated, as set forth herein and as may be amended, modified or supplemented from time to time.

2.23 "Prior Equity Awards" shall mean outstanding stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares and performance shares units.

2.24 "Retirement" means a Separation from Service after the Participant has satisfied the eligibility requirements for early or normal retirement under the terms of the Retirement Plan in which the Participant participates. Notwithstanding the foregoing, for the purposes of determining benefit entitlements under Article V of the Plan, Retirement shall not include forced retirements or any termination by an Employer without Cause or voluntary termination by the Participant for Good Reason that occurs on a date on which the Participant is Retirement eligible.

2.25 "Retirement Plan" the retirement plan in which the Participant participates either the Pension Plan of Public Service Enterprise Group Incorporated or the Cash Balance Pension Plan of Public Service Enterprise Group Incorporated.

2.26 "Schedule A Participant" shall mean a Participant listed on Schedule A hereto.

2.27 "Schedule B Participant" shall mean a Participant listed on Schedule B hereto.

2.28 "Schedule C Participant" shall mean a Participant listed on Schedule C hereto.

2.29 "Separation from Service" shall be deemed to have occurred if a Participant and the Company or any Affiliate reasonably anticipates, based on the facts and circumstances, that either:

(a) The Participant will not provide any additional services for the Company or an Affiliate after a certain date; or

(b) The level of bona fide services performed by the Participant after a certain date will permanently decrease to no more than 50 percent of the average level of bona fide services performed by the Participant over the immediately preceding 36 months.

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(c) If a Participant is absent from employment due to military leave, sick leave or any other bona fide leave of absence authorized by the Company or an Affiliate and there is a reasonable expectation that the Participant will return to perform services for the Company or an Affiliate, a Separation from Service will not occur until the later of: (i) the first date immediately following the date that is six months after the date that the Participant was first absent from employment; or (ii) the date the Participant no longer retains a right to reemployment, to the extent the Participant retains a right to reemployment with the Company or any Affiliates under applicable law or by contract. If a Participant fails to return to work upon the expiration of any military leave, sick leave or other bona fide leave of absence where such leave is for less than six months, the Separation from Service shall occur as of the date of the expiration of such leave, unless a greater period is provided for under applicable law.

2.30 "Specified Employee" shall mean any individual who is a key employee (as defined in Section 416(i) of the Code without regard to Section 416(i)(5)) of the Code) of the Company at any time during the 12-month period ending on each December 31 (the "identification date"). If an individual is a key employee as of an identification date, the individual shall be treated as a Specified Employee for the 12-month period beginning on the April 1 following the identification date. Notwithstanding the foregoing, an individual shall not be treated as a Specified Employee unless any stock of the Company or an Affiliate is publicly traded on an established securities market or otherwise.

2.31 "Target Bonus" means the Participant's target annual bonus, if any, under the applicable annual incentive compensation plan of the Company for the fiscal year in which the Date of Termination occurs.

2.32 "Target Long-Term Incentive" means the Participant's target long-term incentive award, if any, under the applicable long-term incentive compensation plan of the Company.

ARTICLE III

ELIGIBILITY AND PARTICIPATION

3.1 Eligible Employees. Eligibility to participate in the Plan shall be limited to certain key executives of an Employer who (a) are not parties to individual employment or change in control agreements that provide for severance benefits, and (b) are designated, by duly adopted resolution of the Committee, as Eligible Employees.

3.2 Participation. As a condition to becoming a Participant and being entitled to the benefits and protections provided under the Plan, each Eligible Employee must execute and deliver to the Company, within 30 days after the later of the Effective Date and the date such individual is designated by the Committee as an Eligible Employee, a written agreement in the form attached hereto as Exhibit I (or in such other form as may be satisfactory to the Company) to be bound by the restrictive covenants set forth in Article VII. Schedules A, B and C hereto list the Eligible Employees who have satisfied the conditions for Plan participation and the date as of which each such Eligible Employee became a Participant. The Committee shall cause Schedules A, B and C to be updated from time to time to reflect the Participants who are currently

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participating in the Plan. An employee who becomes an Eligible Employee on or after January 1, 2014 shall become a Schedule C Participant. However, if an Eligible Employee is newly hired or promoted into a position reflected on Schedule B as of June 6, 2014, the Eligible Employee shall become a Schedule A Participant.

3 . 3 Release of Claims. Notwithstanding anything in the Plan to the contrary, payment of any benefits under the Plan is expressly contingent upon the Participant's execution and delivery to the Company, within 30 days after the Participant's Date of Termination, of a written agreement provided by the Company, wherein the Participant releases and discharges the Company and each of its Affiliates of any and all claims against the Company and its Affiliates related in any way to the Participant's employment with an Employer and the termination of such employment.

3.4 Committee Discretion. The Committee shall have the sole discretion to determine eligibility for benefits under the Plan.

ARTICLE IV

SEVERANCE BENEFITS IN GENERAL

4.1 Termination by Employer Other than for Cause or by the Participant for Good Reason. Subject to Section 3.3 and Article VI of the Plan, if a Participant's employment is involuntarily terminated by an Employer for reasons other than Cause or a Participant terminates employment for Good Reason, the Participant shall be entitled to the benefits described in Sections 4.2 through 4.9 of the Plan. For purposes of clarity, subject to Section 3.3 and Article VI of the Plan, Participant shall be entitled to the benefits described in Sections 4.2 through 4.9 of the Plan if a Participant's employment is involuntarily terminated by an Employer due to a reduction in force or a reorganization of the Employer (as determined by the Committee), or a Participant experiences a cessation of employment in connection with a reduction in force or Employer reorganization (as determined by the Committee) where the only position offered to the Participant within the Company and Affiliates would require the Participant to accept a reduction in his or her annual rate of base salary of more than 20% below the annual rate of base salary of the Participant's position immediately prior to such action. For the avoidance of any doubt, a Participant shall not be entitled to benefits under the Plan if (i) his employment terminates as a result of death, Disability, the Participant voluntarily terminates employment, except for Good Reason, or (ii) the Participant's cessation of employment is in connection with the sale of the Participant's Employer, line or unit of business of the Employer within which the Participant's position is located, business function of the Employer within which the Participant's position is located, or the assets related to the Employer, line or unit or business, or business function within which the Participant's position is located, and the Participant accepts employment with the purchaser within 90 days of the closing of the transaction in a position that has an annual rate of base salary that is at least 80 percent of the Participant's annual rate of base salary immediately prior to the closing of the sale).

4.2 Cash payment. The Company shall pay to the Participant a lump sum, in cash, the sum of (a) and (b):

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(a) The Participant's base salary and accrued vacation pay through the Date of Termination to the extent not theretofore paid (hereinafter referred to as the "Accrued Obligations"); and

(b) An amount equal to the product of 1.0 times (0.5 times if the Participant were employed less than one year) the sum of the Participant's Annual Base Salary and Target Bonus.

4.3 Long-Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

4.4 Annual Incentive Awards. The Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of calendar days of employment in the calendar year in which the Participant's termination occurs through the Participant's Date of Termination. For purposes of this Section 4.4, calendar year shall mean 365 days.

Annual incentive awards with respect to the calendar year in which a Participant's Date of Termination occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

4.5 Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the Participant's Date of Termination or such earlier date designated by the Participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

4.6 Educational Assistance. Educational assistance shall be provided in accordance with the Employer's tuition program.

4.7 Health Care Benefits.

(a) Retiree Health Care Coverage**.** A Participant who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(i) The Participant has attained age 50 and completed ten or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80; or

(ii) The Participant has attained age 49 and completed 20 or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80.

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Such coverage shall commence no earlier than the Participant's Termination Date. The Participant shall be charged the full cost of retiree coverage under these plans.

(b) COBRA Continuation Coverage**.** Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this Section 4.7 of the Plan shall be entitled, pursuant to any continuation coverage rights under the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended ("COBRA"), to continue individual and dependent coverage under the Company's group health care plans following the Participant's Date of Termination. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the one-year period following the Participant's Date of Termination, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of the cost of coverage) during the remainder of the COBRA coverage period, if any, and the full expense of dental and (if applicable) vision and hearing coverage (102 percent of the cost of coverage) during the entire COBRA coverage period.

4.8 Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled, for the one-year period following the Participant's Date of Termination to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination.

4.9 Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided hereunder or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time. (The amounts and benefits payable to the Participant pursuant to Sections 4.3 through 4.9 of the Plan shall be hereinafter referred to as the "Other Benefits").

4.10 Termination where a Participant experiences a cessation of employment in connection with a reduction in force or Employer reorganization where the only position offered to the Participant within the Company and Affiliates would require the Participant to increase his or her one-way commuting distance by more than 50 miles. Subject to Section 3.3 and Article V, if a Participant experiences a cessation of employment in connection with a reduction in force or an Employer reorganization (as determined by the Committee) where the only position offered to the Participant within the Company and Affiliates would require the Participant to increase his or her one-way commuting distance by more than 50 miles:

(a) Severance Pay. The Participant shall receive a lump sum cash payment in accordance with Section 6.1 of the Plan, based upon the amount of the Participant's base salary, the number of Years of Service completed as of the Participant's Termination Date, as follows:

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(i) **Less than Thirteen Years of Service:** If, as of the Participant's Date of Termination, he has completed fewer than thirteen Years of Service, the amount of severance pay shall equal 26 weeks of base salary.

(ii) **Thirteen or More Years of Service:** If, as of the Participant's Date of Termination, he has completed thirteen or more Years of Service, the amount of severance pay shall equal two weeks of base salary for each Year of Service, up to a maximum of 52 weeks of base salary.

(b) Annual Incentive Awards. A Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of days of employment in the calendar year in which the participant's Termination of Employment occurs through the employee's Termination Date. Annual incentive awards with respect to the calendar year in which a Participant's Termination Date occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

(c) Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the participant's Termination Date or such earlier date designated by the participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

(d) Educational Assistance. Education assistance shall be provided in accordance with the Employer's tuition program.

(e) Health Care Benefits.

(i) Retiree Health Care Coverage**.** An Eligible Employee who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(A) The Participant has attained age 50 and completed ten or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80; or

(B) The Participant has attained age 49 and completed 20 or more Years of Service as of his Date of Termination but the sum of the Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Participant's Date of Date. The Participant shall be charged the full cost of retiree coverage under these plans.

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(ii) COBRA Continuation Coverage. Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this subsection (i) shall be entitled, pursuant to any continuation coverage rights under COBRA to continue individual and dependent coverage under the Company's group health care plans following the Participant's Termination Date. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of the cost of coverage) during the remainder of the COBRA coverage period, if any, and the full expense of dental and (if applicable) vision and hearing coverage (102 percent of the cost of coverage) during the entire COBRA coverage period.

(f) Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination Date.

(g) Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided under the Plan or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time.

ARTICLE V

SEVERANCE BENEFITS AFTER A CHANGE IN CONTROL

5.1 Termination By Employer Other Than For Cause or By Participant For Good Reason (other than Good Reason as described in Subsection 2.17(d)) Within Two Years After a Change in Control. Subject to Section 3.3 and Article VI of the Plan, if, within two years following the occurrence of a Change in Control, either (a) an Employer shall terminate a Participant's employment other than for Cause or Disability, or (b) a Participant shall voluntarily terminate his employment for Good Reason pursuant to Subsections 2.17 (a), (b), (c) or (e), the Participant shall be entitled to benefits in Sections 5.2 through 5.8 of the Plan. For the avoidance of any doubt, a Participant shall not be entitled to benefits under the Plan if his

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employment terminates as a result of death, Disability or the Participant voluntarily terminates employment, except for Good Reason, except as otherwise provided under the Plan.

5.2 Cash Payment. The Company shall pay to the Participant, in a lump sum in cash, the aggregate of the amounts in (a) and (b) below:

(a) the sum of:

(i) The Participant's base salary and accrued through the Date of Termination; and

(ii) The product of (x) the Participant's Target Bonus and (y) a fraction, the numerator of which is the number of days in the current calendar year through the Date of Termination, and the denominator of which is 365;

in each case to the extent not theretofore paid (the sum of the amounts described in clauses (i) and (ii) shall be hereinafter referred to as the "Accrued Obligations"); and

(b) Either (i), (ii) or (iii):

(i) In the case of a Schedule A Participant, the amount equal to the product of two times the sum of the Schedule A Participant's Annual Base Salary and Target Bonus;

(ii) In the case of a Schedule B Participant, the amount equal to the product of three times the sum of the Schedule B Participant's Annual Base Salary and Target Bonus; or

(iii) In the case of a Schedule C Participant, the amount equal to the product of one and half times the sum of the Schedule C Participant's Annual Base Salary and Target Bonus.

5.3 Long Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.4 Health Care and Other Welfare Benefits. The Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for 18 months after the Date of Termination provided that the Participant makes an election to continue such coverage in the Company's medical and dental employee benefit plans under COBRA, subject to the requirements and limitations thereof. Unless otherwise limited by applicable law, thereafter, the Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for an additional period of six months, in the case of a Schedule A Participant, or 18 months, in the case of a Schedule B Participant (for a Schedule C Participant, no additional period beyond the initial 18 months); provided however, that if the Participant becomes re-employed with another employer and is eligible to receive medical or dental benefits under another employer provided plan, the medical and dental benefits provided

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by the Company under this Plan shall be secondary to those provided under such other plan during the applicable period of eligibility.

Unless otherwise limited by applicable law, for two years after the Date of Termination in the case of a Schedule A Participant, three years after the Date of Termination in the case of a Schedule B Participant, or in the case of a Schedule C Participant, eighteen months after the Date of Termination (or for any Participant such longer period as may be provided by the terms of the appropriate plan, program, practice or policy), the Company shall continue benefits (other than medical and dental benefits) to the Participant and/or the Participant's family at least equal to those which would have been provided to them in accordance with the welfare plans, programs, practices and policies maintained by the Company if the Participant's employment had not been terminated or, if more favorable to the Participant, as in effect generally at any time thereafter with respect to other peer executives of the Employer and their families.

Unless otherwise limited by applicable law, the Participant's eligibility (but not the time of commencement of such benefits) for retiree benefits pursuant to the welfare plans, programs, practices and policies maintained by the Company shall be determined as if the Participant had (A) remained employed until two years (in the case of a Schedule A Participant), three years (in the case of a Schedule B Participant), or eighteen months (in the case of a Schedule C Participant) after the Date of Termination and (B) retired on the last day of such period.

5.5 Nonqualified Pension Benefit. The Participant shall be paid, in a lump sum payment in cash, an amount equal to the excess of:

(a) The actuarial equivalent of the benefit under the Company's applicable Retirement Plan (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the Effective Date), any benefit under the Nonqualified Plan and, to the extent applicable, any other defined benefit retirement arrangement between the Participant and the Company ("Other Pension Benefits") which the Participant would receive if the Participant's employment continued for two, three or one and half additional years (for Schedule A Participants, Schedule B and Schedule C Participants, respectively) beyond the Date of Termination and, assuming that the Participant's compensation for such deemed additional period was the Participant's Annual Base Salary as in effect immediately prior to the Date of Termination and assuming a bonus in each year during such deemed additional period equal to the Target Bonus, over

(b) The actuarial equivalent of the Participant's actual benefit (paid or payable), if any, under the Retirement Plan, the Nonqualified Plan and Other Pension Benefits as of the Date of Termination (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the effective date of the Change in Control).

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5.6 Deferred Compensation. Any compensation previously deferred (other than pursuant to a tax-qualified plan) by or on behalf of the Participant (together with any accrued interest or earnings thereon), whether or not then vested, shall become vested on the Date of Termination and shall be paid in accordance with the terms of the applicable deferred compensation plan, policy or practice under which it was deferred to the extent permitted by Section 409A of the Code.

5.7 Outplacement Services. The Company shall, at its sole expense as incurred, provide the Participant with outplacement services suitable to the Participant's position for a period not to exceed one year following the Date of Termination with a nationally recognized outplacement firm.

5.8 Other Benefits. To the extent not theretofore paid or provided, the Company shall pay or provide to the Participant any other amounts or benefits required to be paid or provided or which the Participant is entitled to receive under any plan, program, policy, practice, contract or agreement of the Company (or other Employer), including earned but unpaid stock and similar compensation, but excluding medical or dental benefits if the Participant is eligible for such benefits to be provided by a subsequent employer, and benefits payable under any severance plan or policy (such other amounts and benefits that are payable to the Participant shall be hereinafter referred to as the "Other Benefits").

5.9 Termination By Participant For Good Reason as described in Subsection 2.17(d) Within Two Years After a Change in Control.

Subject to Section 3.3 and Article V of the Plan, if, within two years following the occurrence of a Change in Control, a Participant shall voluntarily terminate his or her employment for Good Reason as described in Subsection 2.17(d):

(a) Severance Pay. The Participant shall receive a lump sum payment in accordance with Section 6.1 of the Plan based upon the amount of the Participant's base salary, the number of Years of Service completed as of the Participant's Termination Date, as indicated below:

(i) **Less than Thirteen Years of Service:** If, as of the Participant's Termination Date he or she has completed fewer than thirteen Years of Service, the amount of severance pay shall equal 26 weeks of base salary.

(ii) **Thirteen or More Years of Service:** If, as of the Participant's Termination Date, he or she has completed thirteen or more Years of Service, the amount of severance pay shall equal two weeks of base salary for each Year of Service, up to a maximum of 52 weeks of base salary.

(b) Annual Incentive Awards. A Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of days of employment in the calendar year in which the participant's Termination of Employment occurs through the

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employee's Termination Date. Annual incentive awards with respect to the calendar year in which a Participant's Termination Date occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

(c) Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the Participant's Date of Termination or such earlier date designated by the participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

(d) Educational Assistance. Education assistance shall be provided in accordance with the Employer's tuition program.

(e) Health Care Benefits.

(i) Retiree Health Care Coverage**.** An Eligible Employee who has not otherwise satisfied the eligibility criteria for participation prior to his Date of Termination Date, shall be entitled to elect retiree coverage under the Employer's applicable retiree group health care plans as though he or she otherwise satisfied such plans' eligibility requirements if:

(A) The Participant has attained age 50 and completed ten or more Years of Service as of his or her Termination Date but the sum of the Participant's age and Years of Service is less than 80; or

(B) The Participant has attained age 49 and completed 20 or more Years of Service as of his or her Termination Date but the sum of the Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Participant's Termination Date. The Participant shall be charged the full cost of retiree coverage under these plans.

(ii) COBRA Continuation Coverage. Each Participant who is not eligible for, or does not elect, the retiree health care coverage described in this subsection (e) shall be entitled, pursuant to any continuation coverage rights under COBRA to continue individual and dependent coverage under the Company's group health care plans following the Participant's Termination Date. If continuation coverage is elected, the Employer shall pay the same portion of the cost of medical coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, and the Participant shall pay the balance. The Participant shall be charged the full expense of medical coverage (102 percent of the cost of coverage)

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during the remainder of the COBRA coverage period, if any, and the full expense of dental and (if applicable) vision and hearing coverage (102 percent of the cost of coverage) during the entire COBRA coverage period.

(f) Life Insurance. A Participant who is not eligible for coverage under the Employer's retiree life insurance plan shall be entitled, during the period that the Participant would have received severance pay if severance pay had been paid in bi-weekly installments, to life insurance coverage at the Employer's expense in an amount equal to the group term life insurance coverage in effect for such Participant under the Employer's group term life insurance plan for active employees as of his Date of Termination.

(g) Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided under the Plan or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time.

5.10 Termination By Employer For Cause or By Participant Other Than For Good Reason. If, at any time after a Change in Control, either (a) an Employer shall terminate a Participant's employment for Cause or (b) the Participant shall voluntarily terminate his employment other than for Good Reason, the Employer shall have no further payment obligations to the Participant other than for the Participant's base salary through the Date of Termination and any accrued but unpaid vacation pay. In such case, all such amounts shall be paid to the Participant in a lump sum in accordance with Section 6.1 of the Plan.

5.11 Death. If a Participant's employment terminates by reason of the Participant's death after a Change in Control, all Accrued Obligations as of the time of death shall be paid to the Participant's estate or beneficiary, as applicable, in a lump sum in cash in accordance with Section 6.1 of the Plan. The Participant's estate or beneficiary shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.12 Disability. If a Participant's employment is terminated by reason of Disability after a Change in Control, all Accrued Obligations shall be paid to the Participant in a lump sum in cash in accordance with Section 6.1 of the Plan. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.13 Retirement. If a Participant's employment terminates as a result of Retirement after a Change in Control, the Participant shall be paid the Accrued Obligations in a lump sum in cash in accordance with Section 6.1 of the Plan and the Participant shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

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ARTICLE VI

TIMING OF, LIMITATIONS ON AND ADJUSTMENTS TO PLAN PAYMENTS

6.1 Time of Payments. Payments under the Plan shall be made to the Participant as follows:

(a) With respect to benefits under Sections 4.2, 4.10(a), 5.2, 5.5, 5.9(a), 5.12 and 5.13 of the Plan, payment to a Participant who is not a Specified Employee shall be made within the 60-day period following the Participant's Date of Termination. With respect to benefits under Section 5.11 of the Plan, payment shall be made within the 60-day period following the Participant's date of the Participant's death. However, if the period to consider and revoke the written agreement required to receive the benefits described in Articles IV and V of the Plan (i.e., the waiver and release) spans two taxable years, in all events the payments will be made in second taxable year within 30 days following the later of the end of the first taxable year or the date the executed release is received by the Company.

(b) With respect to benefits under Sections 4.4, 4.10(b) and 5.9(b) of the Plan, payments shall be made to the Participants at the same time the payments are made to active employees.

(c) Notwithstanding anything to the contrary in the Plan, to the extent necessary to comply with Section 409A of the Code, payments to a Participant who is a Specified Employee shall be made within the 60-day period following the six-month anniversary of the Participant's Date of Termination (other than by reason of death).

(d) All payments under the Plan that are reimbursements of covered expenses incurred by the Participant shall be made within the taxable year in which the expense is incurred.

6.2 Payment Offsets. Notwithstanding anything in the Plan to the contrary, in the event a Participant is entitled to receive severance payments both under this Plan and under the terms of either (a) an individual change of control or employment agreement, (b) another severance pay plan or policy of an Employer or (c) any existing or future law or regulation, the benefits payable under this Plan shall be reduced by the amount of any severance benefits such Participant is entitled to receive under such individual agreement, plan, policy, law or regulation.

6.3 Cap on Excess Parachute Payments; Gross-Up Payments. Notwithstanding anything in the Plan to the contrary, if (a) a Participant is a "disqualified individual" (as defined in Section 280G(c) of the Code) and (b) the severance benefits provided under Articles IV or V, as applicable, together with any other payments the Participant has the right to receive from an Employer, would constitute a "parachute payment" (as defined in Section 280G(b) of the Code) ("Parachute Payments"), the following provisions shall apply:

(a) The severance benefits under Articles IV or V shall not exceed an amount which, together with any other Parachute Payments the Participant has a right to receive

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from the Employer, would be 2.99 times the Participant's "base amount" (as defined in Section 280G of the Code) so that no portion of the amounts received by the Participant shall be subject to the excise tax imposed under Section 4999 of the Code.

(b) The determination of whether any limitation on the severance benefits payable under Articles IV or V is necessary shall be made by the Company's independent auditor or such other certified public accounting firm as may be jointly designated by the Participant and the Company (the "Accounting Firm"), which shall provide detailed supporting calculations to the Participant and the Company. The determinations of the Accounting Firm shall be conclusive and binding on the Company and the Participant. All fees and expenses of the Accounting Firm shall be borne solely by the Company.

(c) If through error or otherwise, a Participant shall receive payments under the Plan, together with other Parachute Payments the Participant has the right to receive from an Employer, in excess of 2.99 times his base amount, the Participant shall immediately repay the excess to the Employer upon notification from the Employer that an overpayment has been made. If the Participant fails to repay the excess to the Employer within 10 business days of the date of the Employer's notification, the Participant will become liable to the Employer for an amount equal to two (2) times the excess amount.

6.4 Compliance with Section 409A of the Code. Notwithstanding anything in the Plan to the contrary, all Plan benefit obligations and payments are subject to Section 409A of the Code. To the extent required, the Company may modify the severance benefits payable hereunder to comply with Section 409A of the Code; provided, however, that the present value of the aggregate Plan benefits payable to a Participant after such modification shall not be less than the present value of the Plan benefits payable to the Participant prior to the modification.

6.5 Tax Withholding. Notwithstanding any other provision of this Plan, the Company may withhold from any amounts payable under this Plan such Federal, state, local, employment or foreign taxes as shall be required to be withheld pursuant to any applicable law or regulation.

ARTICLE VII

RESTRICTIVE COVENANTS

7.1 Confidentiality. As a condition to participation in the Plan, each Participant agrees to hold in a fiduciary capacity for the benefit of the Company and its Affiliates all Confidential Information which shall have been obtained by the Participant during the Participant's employment by the Employer; except, however, that this Section 7.1 shall not apply to Confidential Information that is or becomes public knowledge, unless such Confidential Information became or becomes public knowledge due to acts of the Participant or representatives of the Participant in violation of this Section 7.1. Upon termination of the Participant's employment, he shall return to the Company all Confidential Information in his possession. After termination of the Participant's employment with the Employer, the

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Participant shall not, without the prior written consent of the Company or as may otherwise be required by law or legal process, communicate or divulge any such Confidential Information to anyone other than the Company and those designated by it, except (a) otherwise publicly available information, (b) as may be necessary to enforce his rights under the Plan or as necessary to defend himself against a claim asserted directly or indirectly by the Company or its Affiliates or (c) as may be compelled by service of a valid subpoena or other legal process (if the Participant is served with a valid subpoena or other legal process, he must so notify the Company within three business days). Furthermore, nothing contained in this Plan prevents a Participant from disclosing without notice to the Company any perceived violation of law to any federal, state, or local governmental agency or entity including, but not limited to, the Securities and Exchange Commission, or making other disclosures that are protected under the whistleblower provisions of any law. Finally, nothing in this Plan prevents a Participant - nor should a Participant be held civilly or criminally liable under any law - if the Participant discloses a trade secret: (a) in confidence to a Federal, State or local government official, either directly or indirectly, or to an attorney solely for the purpose of reporting or investigating a suspected violation of law; (b) in a complaint or other document filed in a lawsuit or other proceeding, if such filing is made under seal; (c) to the Participant's attorney in connection with a lawsuit alleging retaliation by an employer for reporting a suspected violation of law; or (d) in connection with a lawsuit described in the immediately preceding subparagraph (c), provided the Participant: (i) files any document containing the trade secret under seal; and (ii) does not disclose the trade secret, except pursuant to a court order. Unless and until a determination has been made in accordance with Section 7.4 that the Participant has violated this Section 7.1, an asserted violation of the provisions of this Section 7.1 shall not constitute a basis for deferring or withholding any amounts otherwise payable to the Participant under the Plan.

7 . 2 Non-Compete. As a condition to participation in the Plan, each Participant agrees, that, in the event the Participant voluntarily terminates his employment other than for Good Reason, for the period of one year from Date of Termination he will not, without the written consent of the Company, directly or indirectly own, manage, operate, join, control, become employed by, consult to or participate in the ownership, management, or control of any business which is in direct competition with the Company or its Affiliates.

7 . 3 Non-Solicitation. As a condition to participation in the Plan, each Participant agrees that, in the event the Participant voluntarily terminates his employment other than for Good Reason, for the period of one year following the Date of Termination, he will not, directly or indirectly, solicit or hire, or encourage the solicitation or hiring by any employer other than the Company or its Affiliates, for any position as an employee, independent contractor, consultant or otherwise, any person who was a managerial or higher level employee of an Employer at any time during the term of the Participant's employment by the Employer; provided, however, that this provision shall not apply with respect to the solicitation of any person after six months from the date on which such person's employment by an Employer has terminated.

7.4 Enforcement. In the event of a breach by the Participant of any of the covenants set forth in this Article VII, it is agreed that the Company shall suffer irreparable harm for which money damages are not an adequate remedy, and that, in the event of such breach, the Company shall be entitled to obtain an order of a court of competent jurisdiction for equitable relief from

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such breach, including, but not limited to, temporary restraining orders and preliminary and/or permanent injunctions against the breach of such covenants by the Participant. In the event that the Company should initiate any legal action for the breach or enforcement of any of the provisions contained in this Article VII and the Company does not prevail in such action, the Company shall promptly reimburse the Participant the full amount of any court costs, filing fees, attorney's fees which the Participant incurs in defending such action, and any loss of income during the period of such litigation.

Nothing in this Plan prohibits the Participant from reporting possible violations of Federal law or regulation to any governmental agency or entity, including but not limited to the Department of Justice, the Securities and Exchange Commission, the Congress, and any agency Inspector General, or making other disclosures that are protected under the whistleblower provisions of federal law or regulation. The Participant does not need the prior authorization of the Law Department to make any such reports or disclosures, and is not required to notify the Company that such reports or disclosures have been made.

ARTICLE VIII

AMENDMENT AND TERMINATION

8 . 1 Amendment. The Company may amend this Plan at any time, and from time to time, by action of the Committee; provided, however, that no amendment adopted after the effective date of a Change in Control shall have the effect of either (a) removing an individual from the list of Participants, (b) adding conditions for participation or the entitlement to receive benefits hereunder, (c) reducing the amount of benefits payable to a Participant or (d) otherwise restricting a Participant's right to receive benefits under the Plan, except as may otherwise be required to conform such payments to the requirements of Section 409A of the Code, as provided in Section 1.1.

8 . 2 Termination. The Committee may terminate the Plan at any time prior to a Change in Control. The Plan may not be terminated after the effective date of a Change in Control.

ARTICLE IX

ADMINISTRATION

9.1 Plan Administrator. The Plan shall be administered by the Committee, which shall have the duties and responsibilities for administering the Plan as are specifically set forth in this Article IX.

9.2 Responsibilities of Committee.

(a) The Committee shall have responsibility for the day to day administration of the Plan. In addition, the Committee shall have the specific powers, duties, responsibilities and obligations specifically provided for herein.

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(b) Subject to the express provisions of the Plan, the Committee shall have full and exclusive authority to interpret the Plan and to make all other factual determinations deemed necessary or advisable in the implementation and administration of the Plan, including but not limited to determinations with respect to the eligibility of Participants to receive benefits under the Plan and the status and rights of such Participants and all other persons affected hereunder. The Committee's interpretation and construction of the Plan shall be conclusive and binding on all persons.

(c) The Committee shall have sole authority to adopt rules and regulations, which shall be administered by the Committee. In addition, the Committee shall have the discretionary authority to issue rulings and interpretations concerning the Plan and all matters arising thereunder, on a uniform and nondiscriminatory basis, provided the same shall not be contrary to or inconsistent with any provision of the Plan.

(d) As a condition of distributing any benefit under the Plan, the Committee may prescribe the use of such forms and require the furnishing of such information as the Committee may deem appropriate for administering the Plan.

9.3 Allocation or Delegation of Duties and Responsibilities. In furtherance of its duties and responsibilities under the Plan, the Committee may:

(a) Employ agents to carry out non-fiduciary responsibilities;

(b) Employ agents to carry out fiduciary responsibilities;

(c) Consult with counsel, who may be counsel to the Company; and

(d) Delegate any of its duties and responsibilities hereunder to such officer or officers of the Company as the Committee shall designate; except, however, that the Committee may not delegate to any other person the designation of Eligible Employees under Section 3.1 or the authority to consider and determine appeals of alleged adverse benefit determinations.

9.4 Expenses. Unless otherwise agreed to by the Company, no person acting as a fiduciary hereunder (who is an employee of an Employer) shall receive any compensation for services as such. Expenses incurred by fiduciaries in connection with the administration of the Plan shall be paid by the Company.

9.5 Indemnification of Plan Administrator. The Company shall indemnify, to the fullest extent permitted by law, each person made or threatened to be made a party to any civil or criminal action or proceeding by reason of the fact that he, or his testator or intestate, was a member of the Committee, or a delegate of the Committee, acting in the capacity of Plan administrator.

9.6 Reliance Upon Others. The Committee, any person to whom it may delegate such of its duties and powers as provided herein, and the officers and directors of the Company shall be entitled to rely conclusively upon and shall be fully protected in any action taken by them in

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good faith in reliance upon any tables, valuations, certificates, opinions, reports or other advice furnished to them by any duly appointed actuary, accountant, legal counsel (who may be counsel for the Company) or other specialist.

9.7 Notification. All notices, reports and statements in connection with the Plan that are given, made, delivered or transmitted to a Participant shall be deemed duly given, made, delivered, or transmitted when mailed, by such class as the sender may deem appropriate, with postage prepaid and addressed to the Participant at the address last appearing on the records of the Employer with respect to this Plan. All notices, direct actions or other communications given, made, delivered or transmitted by a Participant to an Employer or Committee shall not be deemed to have been duly given, made, delivered, transmitted or received unless and until actually received by the Employer or Committee.

9.8 Multiple Capacities. A person may serve in more than one fiduciary capacity with respect to the Plan.

ARTICLE X

CLAIMS PROCEDURE

10.1 Submission of Claims. The initial claim by any Participant for benefits under this Plan shall be submitted in writing to the Committee (or its delegate) within 60 days after the occurrence of the termination of employment that the Participant claims to have triggered entitlement to Plan benefits.

10.2 Computation and Review of Claims. All benefits shall be computed by the Committee or its delegate. All claims shall be approved or denied by the Committee (or its delegate) as soon as practicable, but in no event later than 90 days after application by the Participant. The Committee may take an additional 90 days to review the claim, provided that the Participant is notified in writing within the initial 90-day period.

(a) Initial Denial of Claim - Any denial of a claim shall include:

(i) Reason or reasons for the denial;

(ii) Reference to pertinent Plan provisions on which the denial is based;

(iii) Description of any additional material or information necessary for the Participant to perfect the claim together with an explanation of why the material or information is necessary; and

(iv) Explanation of the Plan's claim review procedure, described below.

(b) Review of a Denied Claim - A Participant shall have a reasonable opportunity to appeal a denied claim to the Committee (or its delegate) for a full and fair review. The Participant or a duly authorized representative:

(i) Shall have 60 days, after receipt of written notification of the denial of claim in which to request a review.

(ii) May request a review upon written application to the Committee.

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(iii) Shall submit written comments, documents, records and other information relating to the claim.

(iv) May review, free of charge, pertinent Plan documents, records and other information relevant to the claim.

(c) Committee Review - The Committee's (or its delegate's) review shall take into account all comments, documents, records and other information submitted by the Participant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

(d) Written Decision - The Committee (or its delegate) shall issue a decision on the reviewed claim promptly but no later than 60 days after receipt of the review. The Committee may take an additional 60 days to review the claim, provided that the Participant is notified in writing within the initial 60-day period. The Committee's decision shall be in writing and shall include:

(i) Reasons for the decision;

(ii) References to the Plan provisions on which the decision is based;

(iii) Statement that the Participant is entitled to receive, upon request, reasonable access to, and copies of, all documents, records and other information relevant to the claim; and

(iv) Statement that the Participant is entitled to bring a civil suit under Section 502(a) of ERISA.

(e) Binding Effect - The Committee's (or its delegate's) decision shall be final and binding on the Participant and the Employer.

ARTICLE XI

GENERAL PROVISIONS

11.1 Construction. This Plan shall be construed and enforced in accordance with and governed by the internal substantive laws (and not the laws relating to conflict of laws or choice of laws) of the State of New Jersey, except to the extent that such laws are preempted by Federal law.

11.2 Unfunded Plan. The obligations of the Company under this Plan are not required to be funded in advance. Nothing contained in this Plan shall give an Eligible Employee or Participant any right, title or interest in any property of the Company or any of its Affiliates.

11.3 No Right to Continued Employment. Nothing contained herein shall be deemed to give any Eligible Employee or Participant the right to be retained in the employment of an Employer or to limit the rights of any Employer to discharge any Eligible Employee or Participant at any time, with or without notice and with or without Cause.

S1-SSA-0009 - 17755

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11.4 Partial Invalidity. The invalidity or unenforceability of any term or provision, or any clause, or portion thereof, of this Plan shall in no way impair or affect the validity or enforceability of any other provision of this Plan, which shall remain in full force and effect.

11.5 Successors and Assigns.

(a) This Plan shall inure to the benefit of and be binding upon the Company and its successors and assigns.

(b) The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform the Company's obligations under the Plan in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place.

(c) In no event shall a Participant assign his interests under the Plan to any other person without the prior written consent of the Committee.

11.6 Waivers. Failure to strictly comply with any term, condition or requirement set forth in the Plan shall not be deemed a waiver of such term, condition or requirement, nor shall any waiver of any such term, condition or requirement at any one time or times be deemed to result in a waiver of such term, condition or requirement at any other time or times.

11.7 Gender and Number. Masculine pronouns include the feminine as well as the neuter genders, and the singular shall include the plural, unless indicated otherwise by the context.

11.8 Headings. The headings of the Plan are for purposes of reference only and shall not limit or otherwise affect the meaning hereof.

* * *

/s/ Margaret M. Pego	7/21/2016
Signature	Date

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SCHEDULE A

As Amended as of July 19, 2016
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Stuart J. Black	VP and Controller	03/01/10
Jorge L. Cardenas	VP - Asset Management and Centralized Services, PSE&G	1/23/07
Rose M. Chernick	VP - Finance Holdings & Corporate Strategy & Planning	8/09/10
John Paul Cowan	SVP - Operations, PSEG Fossil	09/15/09
Lathrop B. Craig	VP - ISO Operations (ER&T)	09/05/11
Daniel J. Cregg	EVP & CFO, PSEG	12/09/06
David M. Daly	President and COO - PSEG Long Island	1/28/08
Paul J. Davison	VP - Hope Creek, PSEG Nuclear	12/14/09
Derek DiRisio	President - PSEG Services Corporation	12/20/04
Diana L. Drysdale	VP - Renewables	02/15/10
Kathleen Fitzgerald	VP - Corporate Communications	01/03/12
Joseph A. Forline	VP - Gas Operations	12/19/06
Carl J. Fricker	VP - Trading Support & Operations (ER&T)	12/14/09
Kim C. Hanemann	SVP - Delivery Projects and Construction	12/21/10
Bradford D. Huntington	VP & Treasurer	04/16/11
Scott Jennings	VP - Finance PSE&G	10/18/05
Robert C. Krueger, Jr	VP & Assistant Controller - Tax	12/19/06
Kathleen A. Lally	VP - Investor Relations	01/16/07
John R. Latka	SVP - Electric & Gas Operations, PSE&G	10/23/06
Shawn P. Leyden	VP and Deputy General Counsel	12/20/04
Tamara L. Linde	EVP and General Counsel	12/19/06
Kristen M. Ludecke	VP - Federal Affairs	02/22/10
Shahid Malik	President - Energy Resources & Trade (ER&T)	12/5/11
Christine T. Neely	VP - Internal Auditing Services	9/30/13
Margaret M. Pego	SVP - Human Resources & CHRO	12/20/04
John F. Perry	VP - Salem, PSEG Nuclear	09/15/09
Kevin J. Quinn	VP - Finance Power	03/01/10
Sheila J. Rostiac	VP - Total Rewards & Talent Management	08/20/12
Joseph Santamaria	VP - Information Technology & CIO	10/29/12
John P. Scarlata	VP - Gas Supply, PSEG ER&T	4/20/10
Richard T. Thigpen	VP - State Governmental Affairs	3/26/07

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SCHEDULE B

As Amended as of July 19, 2016
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Ralph Izzo	Chairman of the Board, President and CEO	12/15/08
Ralph A. LaRossa	President & COO - Public Service Electric and Gas Company, and COB, PSEG Long Island	10/17/06
William Levis	President & COO, PSEG Power LLC	01/01/07

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SCHEDULE C

As Amended as of July 19, 2016
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
John A. Bridges	VP Electric Operations	12/21/15
Kevin B. Cellars	VP Construction	2/17/15
Gregory Dunlap	VP Customer Operations - PSE&G	7/14/14
Aaron Ford	VP Business Assurance and Resilience	11/18/15
M. Courtney McCormick	VP Renewables and Energy Solutions	3/31/14
Laurent Pommier	VP Risk Management and Chief Risk Officer	7/14/14
Peter P. Sena III	President & CNO, PSEG Nuclear	3/21/16

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EXHIBIT I

Form of Restrictive Covenant Agreement

AGREEMENT, by and between Public Service Enterprise Group Incorporated, a New Jersey Corporation (the "Company") and [_____] ("Executive"), dated as of [_____].

WHEREAS, the Company maintains the Key Executive Severance Plan of Public Service Enterprise Group Incorporated (the "Plan"), effective July 19, 2016, and as thereafter amended, modified or supplemented;

WHEREAS, Executive was designated as an Eligible Employee under the Plan by the Organization and Compensation Committee of the Company's Board of Directors;

WHEREAS, pursuant to Section 3.2 of the Plan, in order to be a Participant in and be entitled to benefits and protections under the Plan, Executive must execute and delivery to the Company within 30 days after Executive was designated as an Eligible Employee a written agreement to be bound by the terms and conditions of certain covenants set out in Article VII of the Plan, which is hereby incorporated herein;

NOW THEREFORE, the parties agree as follows:

1. Executive has received a copy of the Plan and has read and understands the terms of conditions of Section 7.1, Confidentiality, Section 7.2, Non-Compete, and Section 7.3, Non-Solicitation, therein, as applied to Executive (the "Covenants").

2. Executive agrees to be bound by and comply with the terms of the Covenants in consideration for becoming a Participant in the Plan.

3. Executive acknowledges that the Covenants are reasonable in the scope of the activities restricted, the geographic area covered by the restrictions, the duration of the restrictions, and that such Covenants are reasonably necessary to protect the Company's legitimate interests in its Confidential Information and its relationships with its employees, customers and suppliers.

4. Executive acknowledges that the Covenants will not deprive Executive of the ability to earn a livelihood or to support Executive's dependents.

5. Executive shall be a Participant in the Plan and be entitled to all of the rights and benefits provided thereunder as of the date of this Agreement.

6. This Agreement shall be construed and enforced in accordance with and governed by the internal substantive laws (and not the laws relating to conflict of laws or choice of laws) of the State of New Jersey, except to the extent that such laws are preempted by Federal law.

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IN WITNESS WHEREOF, the parties have executed this Agreement as of the date and year first above written.

[This Agreement may be executed in counterparts.]

EXECUTIVE

_____

PUBLIC SERVICE ENTERPRISE
GROUP INCORPORATED

By: _____

Title:_____

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2016	2015	2015	2014	2013	2012	2011
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,032	$ 1,515	$ 2,680	$ 2,456	$ 2,055	$ 2,011	$ 2,384
(Income) Loss from Equity Investees, net of Distributions	3	2	3	4	(7)	9	(4)
Fixed Charges	232	223	457	450	458	479	522
Capitalized Interest	(19)	(5)	(18)	(16)	(16)	(19)	(14)
Total Earnings	$ 1,248	$ 1,735	$ 3,122	$ 2,894	$ 2,490	$ 2,480	$ 2,888
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 221	$ 213	$ 437	$ 430	$ 442	$ 465	$ 509
Interest Factor in Rentals	11	10	20	20	16	14	13
Total Fixed Charges	$ 232	$ 223	$ 457	$ 450	$ 458	$ 479	$ 522
Ratio of Earnings to Fixed Charges	**5.38**	**7.78**	**6.83**	**6.43**	**5.44**	**5.18**	**5.53**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Six Months Ended June 30,		Years Ended December 31,				
	2016	**2015**	**2015**	**2014**	**2013**	**2012**	**2011**
			(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 690	$ 670	$1,257	$1,174	$ 993	$ 835	$ 861
Fixed Charges	154	148	306	303	316	314	319
Capitalized Interest	(7)	(8)	(17)	(16)	(16)	(13)	(4)
Total Earnings	$ 837	$ 810	$1,546	$1,461	$ 1,293	$1,136	$1,176
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 149	$ 144	$ 297	$ 293	$ 309	$ 308	$ 314
Interest Factor in Rentals	5	4	9	10	7	6	5
Total Fixed Charges	$ 154	$ 148	$ 306	$ 303	$ 316	$ 314	$ 319
Ratio of Earnings to Fixed Charges	**5.44**	**5.47**	**5.05**	**4.82**	**4.09**	**3.62**	**3.69**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.2

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2016	2015	2015	2014	2013	2012	2011
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 299	$ 807	$1,367	$1,251	$1,063	$1,099	$1,703
(Income) Loss from Equity Investees, net of Distributions	3	1	1	3	(10)	(6)	(12)
Fixed Charges	69	78	152	150	143	164	208
Capitalized Interest	(12)	2	(1)	1	1	(6)	(10)
Total Earnings	$ 359	$ 888	$1,519	$1,405	$1,197	$1,251	$1,889
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 67	$ 75	$ 148	$ 146	$ 139	$ 161	$ 205
Interest Factor in Rentals	2	3	4	4	4	3	3
Total Fixed Charges	$ 69	$ 78	$ 152	$ 150	$ 143	$ 164	$ 208
Ratio of Earnings to Fixed Charges	**5.20**	**11.38**	**9.99**	**9.37**	**8.37**	**7.63**	**9.08**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 29, 2016

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 29, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 29, 2016

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 29, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

S1-SSA-0009 - 17768

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 29, 2016

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 29, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

S1-SSA-0009 - 17770

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
July 29, 2016

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
July 29, 2016

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
July 29, 2016

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
July 29, 2016

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
July 29, 2016

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
July 29, 2016

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2017
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐

If any of the registrants is an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of July 18, 2017, Public Service Enterprise Group Incorporated had outstanding 505,889,953 shares of its sole class of Common Stock, without par value.

As of July 18, 2017, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K. These factors include, but are not limited to:

- fluctuations in wholesale power and natural gas markets, including the potential impacts on the economic viability of our generation units;
- our ability to obtain adequate fuel supply;
- any inability to manage our energy obligations with available supply;
- increases in competition in wholesale energy and capacity markets;
- changes in technology related to energy generation, distribution and consumption and customer usage patterns;
- economic downturns;
- third-party credit risk relating to our sale of generation output and purchase of fuel;
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements;
- changes in state and federal legislation and regulations;
- the impact of pending rate case proceedings;
- regulatory, financial, environmental, health and safety risks associated with our ownership and operation of nuclear facilities;
- adverse changes in energy industry laws, policies and regulations, including market structures and transmission planning;
- changes in federal and state environmental regulations and enforcement;
- delays in receipt of, or an inability to receive, necessary licenses and permits;
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry;
- changes in tax laws and regulations;
- the impact of our holding company structure on our ability to meet our corporate funding needs, service debt and pay dividends;
- lack of growth or slower growth in the number of customers or changes in customer demand;
- any inability of Power to meet its commitments under forward sale obligations;
- reliance on transmission facilities that we do not own or control and the impact on our ability to maintain adequate transmission capacity;
- any inability to successfully develop or construct generation, transmission and distribution projects;
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers;
- our inability to exercise control over the operations of generation facilities in which we do not maintain a controlling interest;

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- any inability to maintain sufficient liquidity;
- any inability to realize anticipated tax benefits or retain tax credits;
- challenges associated with recruitment and/or retention of key executives and a qualified workforce;
- the impact of our covenants in our debt instruments on our operations; and
- the impact of acts of terrorism, cybersecurity attacks or intrusions.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business, prospects, financial condition, results of operations or cash flows. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even in light of new information or future events, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

FILING FORMAT

This combined Quarterly Report on Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to “we,” “us,” and “our” relate to PSEG or to the specific company or companies being discussed.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
OPERATING REVENUES	$ 2,133	$ 1,905	$ 4,725	$ 4,521
OPERATING EXPENSES				
Energy Costs	588	624	1,462	1,460
Operation and Maintenance	708	710	1,420	1,439
Depreciation and Amortization	641	224	1,469	448
Total Operating Expenses	1,937	1,558	4,351	3,347
OPERATING INCOME	196	347	374	1,174
Income from Equity Method Investments	5	4	8	6
Other Income	70	44	142	92
Other Deductions	(9)	(10)	(20)	(31)
Other-Than-Temporary Impairments	(3)	(10)	(4)	(20)
Interest Expense	(91)	(97)	(189)	(189)
INCOME BEFORE INCOME TAXES	168	278	311	1,032
Income Tax Expense	(59)	(91)	(88)	(374)
NET INCOME	$ 109	$ 187	$ 223	$ 658
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	505	505	505	505
DILUTED	507	508	507	508
NET INCOME PER SHARE:				
BASIC	$ 0.22	$ 0.37	$ 0.44	$ 1.30
DILUTED	$ 0.22	$ 0.37	$ 0.44	$ 1.30
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.43	$ 0.41	$ 0.86	$ 0.82

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
NET INCOME	$ 109	$ 187	$ 223	$ 658
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(9), $(10), $(25) and $(26) for the three and six months ended 2017 and 2016, respectively	10	10	25	26
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $0, $0 and $(1) for the three and six months ended 2017 and 2016, respectively	—	(1)	—	1
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(4), $(6), $(8) and $(12) for the three and six months ended 2017 and 2016, respectively	6	8	12	16
Other Comprehensive Income (Loss), net of tax	16	17	37	43
COMPREHENSIVE INCOME	$ 125	$ 204	$ 260	$ 701

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 430	$ 423
Accounts Receivable, net of allowances of $61 in 2017 and $68 in 2016	1,021	1,161
Tax Receivable	9	78
Unbilled Revenues	210	260
Fuel	270	326
Materials and Supplies, net	577	561
Prepayments	273	76
Derivative Contracts	113	163
Regulatory Assets	276	199
Other	9	7
Total Current Assets	3,188	3,254
PROPERTY, PLANT AND EQUIPMENT	38,794	39,337
Less: Accumulated Depreciation and Amortization	(9,157)	(10,051)
Net Property, Plant and Equipment	29,637	29,286
NONCURRENT ASSETS		
Regulatory Assets	3,349	3,319
Long-Term Investments	961	1,050
Nuclear Decommissioning Trust (NDT) Fund	1,968	1,859
Long-Term Tax Receivable	111	104
Long-Term Receivable of Variable Interest Entity (VIE)	600	589
Other Special Funds	224	217
Goodwill	16	16
Other Intangibles	120	98
Derivative Contracts	90	24
Other	260	254
Total Noncurrent Assets	7,699	7,530
TOTAL ASSETS	$ 40,524	$ 40,070

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2017	December 31, 2016
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 900	$ 500
Commercial Paper and Loans	—	388
Accounts Payable	1,293	1,459
Derivative Contracts	8	13
Accrued Interest	99	97
Accrued Taxes	46	31
Clean Energy Program	200	142
Obligation to Return Cash Collateral	134	132
Regulatory Liabilities	51	88
Other	433	426
Total Current Liabilities	3,164	3,276
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	8,755	8,658
Regulatory Liabilities	99	118
Clean Energy Program	27	—
Asset Retirement Obligations	744	726
OPEB Costs	1,304	1,324
OPEB Costs of Servco	467	452
Accrued Pension Costs	525	568
Accrued Pension Costs of Servco	124	128
Environmental Costs	378	401
Derivative Contracts	1	3
Long-Term Accrued Taxes	192	180
Other	205	211
Total Noncurrent Liabilities	12,821	12,769
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT	11,621	10,895
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2017 and 2016—534 shares	4,929	4,936
Treasury Stock, at cost, 2017 and 2016—29 shares	(747)	(717)
Retained Earnings	8,962	9,174
Accumulated Other Comprehensive Loss	(226)	(263)
Total Stockholders' Equity	12,918	13,130
Total Capitalization	24,539	24,025
TOTAL LIABILITIES AND CAPITALIZATION	$ 40,524	$ 40,070

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17784

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2017	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 223	$ 658
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,469	448
Amortization of Nuclear Fuel	101	105
Renewable Energy Credit (REC) Compliance Accrual	51	50
Provision for Deferred Income Taxes (Other than Leases) and ITC	91	334
Non-Cash Employee Benefit Plan Costs	45	63
Leveraged Lease (Income) Loss, Adjusted for Rents Received and Deferred Taxes	(30)	(30)
Net (Gain) Loss on Lease Investments	45	—
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(42)	153
Net Change in Regulatory Assets and Liabilities	(124)	(125)
Cost of Removal	(47)	(74)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(58)	(2)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	69	301
Accrued Taxes	15	94
Margin Deposit	59	(46)
Other Current Assets and Liabilities	(56)	(120)
Employee Benefit Plan Funding and Related Payments	(49)	(78)
Other	(6)	(9)
Net Cash Provided By (Used In) Operating Activities	1,756	1,722
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,981)	(1,971)
Purchase of Emissions Allowances and RECs	(29)	(36)
Proceeds from Sales of Available-for-Sale Securities	711	392
Investments in Available-for-Sale Securities	(726)	(407)
Other	36	18
Net Cash Provided By (Used In) Investing Activities	(1,989)	(2,004)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(388)	(364)
Issuance of Long-Term Debt	1,125	1,550
Redemption of Long-Term Debt	—	(171)
Cash Dividends Paid on Common Stock	(435)	(415)
Other	(62)	(64)
Net Cash Provided By (Used In) Financing Activities	240	536
Net Increase (Decrease) in Cash and Cash Equivalents	7	254
Cash and Cash Equivalents at Beginning of Period	423	394
Cash and Cash Equivalents at End of Period	$ 430	$ 648
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (30)	$ (276)
Interest Paid, Net of Amounts Capitalized	$ 189	$ 176
Accrued Property, Plant and Equipment Expenditures	$ 513	$ 513

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
OPERATING REVENUES	$ 1,368	$ 1,350	$ 3,180	$ 3,062
OPERATING EXPENSES				
Energy Costs	472	529	1,225	1,258
Operation and Maintenance	351	352	718	734
Depreciation and Amortization	166	136	337	275
Total Operating Expenses	989	1,017	2,280	2,267
OPERATING INCOME	379	333	900	795
Other Income	22	19	47	39
Other Deductions	(1)	(1)	(2)	(2)
Interest Expense	(69)	(74)	(144)	(142)
INCOME BEFORE INCOME TAXES	331	277	801	690
Income Tax Expense	(123)	(98)	(294)	(249)
NET INCOME	$ 208	$ 179	$ 507	$ 441

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17786

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
NET INCOME	$ 208	$ 179	$ 507	$ 441
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0, $1 and $0 for the three and six months ended 2017 and 2016, respectively	—	1	(1)	1
COMPREHENSIVE INCOME	$ 208	$ 180	$ 506	$ 442

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17787

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$ 192	$ 390
Accounts Receivable, net of allowances of $61 in 2017 and $68 in 2016	755	810
Accounts Receivable—Affiliated Companies	20	76
Unbilled Revenues	210	260
Materials and Supplies	198	180
Prepayments	193	9
Regulatory Assets	276	199
Other	6	6
Total Current Assets	1,850	1,930
PROPERTY, PLANT AND EQUIPMENT	27,562	26,347
Less: Accumulated Depreciation and Amortization	(5,930)	(5,760)
Net Property, Plant and Equipment	21,632	20,587
NONCURRENT ASSETS		
Regulatory Assets	3,349	3,319
Long-Term Investments	293	299
Other Special Funds	45	43
Other	104	110
Total Noncurrent Assets	3,791	3,771
TOTAL ASSETS	$ 27,273	$ 26,288

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17788

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	June 30, 2017	December 31, 2016
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 400	$ —
Accounts Payable	587	718
Accounts Payable—Affiliated Companies	146	260
Accrued Interest	78	76
Clean Energy Program	200	142
Derivative Contracts	—	5
Obligation to Return Cash Collateral	134	132
Regulatory Liabilities	51	88
Other	301	296
Total Current Liabilities	1,897	1,717
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	6,232	5,873
OPEB Costs	983	1,009
Accrued Pension Costs	223	250
Regulatory Liabilities	99	118
Clean Energy Program	27	—
Environmental Costs	310	332
Asset Retirement Obligations	215	213
Long-Term Accrued Taxes	115	130
Other	112	116
Total Noncurrent Liabilities	8,316	8,041
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT	7,842	7,818
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2017 and 2016—132 shares	892	892
Contributed Capital	945	945
Basis Adjustment	986	986
Retained Earnings	6,395	5,888
Accumulated Other Comprehensive Income	—	1
Total Stockholder's Equity	9,218	8,712
Total Capitalization	17,060	16,530
TOTAL LIABILITIES AND CAPITALIZATION	$ 27,273	$ 26,288

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2017	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 507	$ 441
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	337	275
Provision for Deferred Income Taxes and ITC	330	290
Non-Cash Employee Benefit Plan Costs	25	36
Cost of Removal	(47)	(74)
Net Change in Other Regulatory Assets and Liabilities	(124)	(125)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	108	50
Materials and Supplies	(15)	(14)
Prepayments	(184)	(165)
Accounts Payable	(30)	(29)
Accounts Receivable/Payable—Affiliated Companies, net	(72)	181
Other Current Assets and Liabilities	16	17
Employee Benefit Plan Funding and Related Payments	(42)	(62)
Other	(39)	(13)
Net Cash Provided By (Used In) Operating Activities	770	808
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,389)	(1,355)
Proceeds from Sales of Available-for-Sale Securities	28	12
Investments in Available-for-Sale Securities	(29)	(13)
Solar Loan Investments	(3)	2
Other	5	—
Net Cash Provided By (Used In) Investing Activities	(1,388)	(1,354)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	—	(153)
Issuance of Long-Term Debt	425	850
Redemption of Long-Term Debt	—	(171)
Other	(5)	(10)
Net Cash Provided By (Used In) Financing Activities	420	516
Net Increase (Decrease) In Cash and Cash Equivalents	(198)	(30)
Cash and Cash Equivalents at Beginning of Period	390	198
Cash and Cash Equivalents at End of Period	$ 192	$ 168
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (75)	$ (255)
Interest Paid, Net of Amounts Capitalized	$ 144	$ 134
Accrued Property, Plant and Equipment Expenditures	$ 319	$ 381

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17790

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
OPERATING REVENUES	$ 929	$ 714	$ 2,213	$ 2,027
OPERATING EXPENSES				
Energy Costs	397	381	1,104	1,019
Operation and Maintenance	254	265	484	518
Depreciation and Amortization	465	80	1,115	159
Total Operating Expenses	1,116	726	2,703	1,696
OPERATING INCOME (LOSS)	(187)	(12)	(490)	331
Income from Equity Method Investments	5	4	8	6
Other Income	46	25	84	51
Other Deductions	(7)	(9)	(14)	(27)
Other-Than-Temporary Impairments	(3)	(10)	(4)	(20)
Interest Expense	(13)	(20)	(29)	(42)
INCOME (LOSS) BEFORE INCOME TAXES	(159)	(22)	(445)	299
Income Tax Benefit (Expense)	62	11	178	(118)
NET INCOME (LOSS)	$ (97)	$ (11)	$ (267)	$ 181

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17791

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
NET INCOME (LOSS)	$ (97)	$ (11)	$ (267)	$ 181
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $ $(9), $(9), $(27) and $(25) for the three and six months ended 2017 and 2016, respectively	10	9	29	25
Pension/OPEB adjustment, net of tax (expense) benefit of $(3), $(5), $(7) and $(10) for the three and six months ended 2017 and 2016, respectively	5	7	10	14
Other Comprehensive Income (Loss), net of tax	15	16	39	39
COMPREHENSIVE INCOME (LOSS)	$ (82)	$ 5	$ (228)	$ 220

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17792

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$ 29	$ 11
Accounts Receivable	207	276
Accounts Receivable—Affiliated Companies	139	205
Short-Term Loan to Affiliate	233	87
Fuel	270	326
Materials and Supplies, net	379	381
Derivative Contracts	112	162
Prepayments	10	10
Other	3	2
Total Current Assets	1,382	1,460
PROPERTY, PLANT AND EQUIPMENT	10,881	12,655
Less: Accumulated Depreciation and Amortization	(3,055)	(4,135)
Net Property, Plant and Equipment	7,826	8,520
NONCURRENT ASSETS		
NDT Fund	1,968	1,859
Long-Term Investments	91	102
Goodwill	16	16
Other Intangibles	120	98
Other Special Funds	55	53
Derivative Contracts	90	24
Other	71	61
Total Noncurrent Assets	2,411	2,213
TOTAL ASSETS	$ 11,619	$ 12,193

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17793

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2017	December 31, 2016
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$ 536	$ 539
Accounts Payable—Affiliated Companies	20	25
Derivative Contracts	8	8
Accrued Interest	20	20
Other	95	88
Total Current Liabilities	679	680
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	1,979	2,170
Asset Retirement Obligations	526	511
OPEB Costs	256	251
Derivative Contracts	1	3
Accrued Pension Costs	179	191
Long-Term Accrued Taxes	93	77
Other	126	129
Total Noncurrent Liabilities	3,160	3,332
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
LONG-TERM DEBT	2,384	2,382
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,340	4,782
Accumulated Other Comprehensive Loss	(172)	(211)
Total Member's Equity	5,396	5,799
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 11,619	$ 12,193

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17794

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2017	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income (Loss)	$ (267)	$ 181
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,115	159
Amortization of Nuclear Fuel	101	105
Provision for Deferred Income Taxes and ITC	(226)	37
Interest Accretion on Asset Retirement Obligation	15	13
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(42)	153
Renewable Energy Credit (REC) Compliance Accrual	51	50
Non-Cash Employee Benefit Plan Costs	14	19
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(58)	(2)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	58	86
Margin Deposit	59	(46)
Accounts Receivable	36	(12)
Accounts Payable	(14)	(10)
Accounts Receivable/Payable—Affiliated Companies, net	75	179
Other Current Assets and Liabilities	7	11
Employee Benefit Plan Funding and Related Payments	(4)	(10)
Other	12	4
Net Cash Provided By (Used In) Operating Activities	932	917
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(576)	(598)
Purchase of Emissions Allowances and RECs	(29)	(36)
Proceeds from Sales of Available-for-Sale Securities	602	346
Investments in Available-for-Sale Securities	(616)	(359)
Short-Term Loan—Affiliated Company, net	(146)	(972)
Other	30	12
Net Cash Provided By (Used In) Investing Activities	(735)	(1,607)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Long-Term Debt	—	700
Cash Dividend Paid	(175)	—
Other	(4)	(6)
Net Cash Provided By (Used In) Financing Activities	(179)	694
Net Increase (Decrease) in Cash and Cash Equivalents	18	4
Cash and Cash Equivalents at Beginning of Period	11	12
Cash and Cash Equivalents at End of Period	$ 29	$ 16
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 66	$ (53)
Interest Paid, Net of Amounts Capitalized	$ 29	$ 38
Accrued Property, Plant and Equipment Expenditures	$ 194	$ 132

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17795

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Note 1. Organization and Basis of Presentation

Organization

Public Service Enterprise Group Incorporated (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Public Service Electric and Gas Company (PSE&G)**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- **PSEG Power LLC (Power)**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses through competitive energy sales in well-developed energy markets and fuel supply functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) electric transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2016.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2016.

Note 2. Recent Accounting Standards

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard clarifies the principles for recognizing revenue and removes inconsistencies in revenue recognition requirements; improves comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provides improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early application is permitted. PSEG expects the new guidance to result in more detailed disclosures of revenue compared to current guidance, and possible changes in presentation.

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PSE&G's regulated revenue recorded under tariffs, including the sale of default supply of electric and gas commodity, and the transmission and distribution of electricity and distribution of gas to retail residential and commercial and industrial customers, is in scope of the new accounting standard. PSEG expects no change in revenue recognition of PSE&G's regulated revenue recorded under tariffs. Revenue from contracts with customers will be recorded as electricity or gas is delivered to the customer. PSEG continues to evaluate contracts under its other revenue streams.

Certain implementation issues are currently being finalized by the AICPA's Financial Reporting Executive Committee, including the ability to recognize revenue for certain contracts where there is uncertainty regarding collection from customers and accounting for contributions in aid of construction. Upon formal resolution of the implementation issues noted above, and upon completion of contract evaluations, PSEG will elect its transition method.

Recognition and Measurement of Financial Assets and Financial Liabilities

This accounting standard will change how entities measure equity investments that are not consolidated or accounted for under the equity method. Under the new guidance, equity investments (other than those accounted for using the equity method) will be measured at fair value through Net Income instead of Other Comprehensive Income (Loss). Entities that have elected the fair value option for financial liabilities will present changes in fair value due to a change in their own credit risk through Other Comprehensive Income (Loss). For equity investments which do not have readily determinable fair values, the impairment assessment will be simplified by requiring a qualitative assessment to identify impairments. The new standard also changes certain disclosures.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG expects to record a cumulative effect adjustment by reclassifying the after-tax net unrealized gain (loss) related to equity investments from Accumulated Other Comprehensive Income to Retained Earnings as of January 1, 2018, and expects increased volatility in Net Income due to changes in fair value of its equity securities within the nuclear decommissioning (NDT) and Rabbi Trust Funds.

Leases

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor will classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. However, existing guidance related to leveraged leases will not change.

The standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Measurement of Credit Losses on Financial Instruments

This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however, this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments

This accounting standard reduces the diversity in practice in how certain cash receipts and cash payments are presented and classified in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt early, including in an interim period. PSEG is currently analyzing the impact of this standard on its financial statements.

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Statement of Cash Flows: Restricted Cash

This accounting standard requires entities to explain the change during the period in the total of cash and cash equivalents and include amounts described as restricted cash or restricted cash equivalents in their reconciliation of beginning-of-period and end-of-period amounts in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt early, including in an interim period. PSEG is currently analyzing the impact of this standard on its financial statements including its future disclosure requirements.

Business Combinations: Clarifying the Definition of a Business

This accounting standard was issued mainly to provide more consistency in how the definition of a business is applied to acquisitions or dispositions. The new guidance will generally reduce the number of transactions that will require treatment as a business combination. The definition of a business now includes a filter that would consider whether substantially all the fair value of the gross assets acquired or disposed of is concentrated in a single identifiable asset or a group of similar identifiable assets. If this condition is met, the transaction would not qualify as a business.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt it for transactions that have closed before the effective date but have not been reported in financial statements that have been issued or made available for issuance. PSEG does not have any current transactions impacted by this guidance and expects future acquisitions of individual solar plants will not qualify as business combinations. PSEG does not expect this guidance to materially impact its financial statements upon adoption.

Simplifying the Test for Goodwill Impairment

This accounting standard requires an entity to perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

An entity should apply this standard on a prospective basis and will be required to disclose the nature of and reason for the change in accounting principle upon transition. The new standard is effective for impairment tests for periods beginning January 1, 2020. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. PSEG is currently assessing the impact of this guidance upon its financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (OPEB)

This accounting standard was issued to improve the presentation of net periodic pension cost and net periodic OPEB cost.

Under the new guidance, entities are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by their employees during the period. The other components of net benefit cost are required to be presented in the Statement of Operations separately from the service cost component after Operating Income. Additionally, only the service cost component will be eligible for capitalization, when applicable.

The standard requires the amendments to be applied retrospectively for the presentation of the service cost component and the other cost components of net periodic pension cost and net periodic OPEB cost in the Statement of Operations and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension and OPEB costs.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early adoption is permitted for an entity in any interim or annual period. PSEG is currently analyzing the impact of this standard on its financial statements.

Premium Amortization on Purchased Callable Debt Securities

This accounting standard was issued to shorten the amortization period for certain callable debt securities held at a premium. Specifically, the standard requires the premium to be amortized to the earliest call date. The amendments do not require an accounting change for securities held at a discount; the discount continues to be amortized to maturity.

The standard is effective for annual and interim reporting periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period. If an entity early adopts the standard in an interim period, any
adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity should apply this standard on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the

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beginning of the period of adoption. Additionally, in the period of adoption, an entity should provide disclosures about a change in accounting principle.

PSEG is currently analyzing the impact of this standard on its financial statements.

Stock Compensation - Scope of Modification Accounting

This accounting standard provides clarity and reduces both diversity in practice and complexity when applying the stock compensation guidance to a change in the terms or conditions of a stock-based payment award. Specifically, the standard provides guidance as to which changes to the terms or conditions of a stock-based payment award require an entity to apply modification accounting.

The standard is effective for all entities for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted, including adoption in any interim period, for reporting periods for which financial statements have not yet been issued. This standard should be applied prospectively to an award modified on or after the adoption date. PSEG plans to adopt this standard effective January 1, 2018.

Note 3. Early Plant Retirements

Fossil

In October 2016, Power determined that it would cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. Power has filed deactivation notices with PJM for these existing units at both stations and final must-offer exception requests for the 2020-2021 PJM capacity auction to the PJM Independent Market Monitor. Both units were available to operate through May 31, 2017 and were subsequently retired from operation on June 1, 2017.

In the latter half of 2016, PSEG and Power recognized pre-tax charges in Energy Costs and Operation and Maintenance (O&M) of $62 million and $53 million, respectively, related to coal inventory adjustments, capacity penalties, materials and supplies inventory reserve adjustments for parts that cannot be used at other generating units, employee-related severance benefits costs and construction work in progress impairments, among other shut down items. In addition to these charges, Power recognized Depreciation and Amortization (D&A) during 2016 of $571 million due to the significant shortening of the expected economic useful lives of Hudson and Mercer.

In the three and six months ended June 30, 2017, Power recognized total D&A of $390 million and $964 million, respectively, for the Hudson and Mercer units. In the three and six months ended June 30, 2017, Power also recognized pre-tax charges in Energy Costs of $2 million and $9 million, respectively, primarily for coal inventory lower of cost or market adjustments. For the three and six months ended June 30, 2017, Power also recognized pre-tax charges in O&M of $4 million of shut down costs and an increase in the ARO liability due to settlements and changes in cash flow estimates, partially offset by changes in employee-related severance costs. Power currently anticipates using the sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such environmental remediation are neither currently probable nor estimable but may be material.

As of December 31, 2016, Power had reduced the estimated useful life of Bridgeport Harbor Station unit 3 (BH3) from 2025 to the summer of 2021 as it was more likely than not it will retire the unit by this time. The change in the estimated useful life did not have a material impact on Power's 2017 financial results.

PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the held for use classification of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Nuclear

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. This situation is generally due to low natural gas prices, and the related decline in market prices of energy, resulting from the growth of shale gas production since 2007, the continuing cost of

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regulatory compliance and enhanced security for nuclear facilities and both federal and state-level policies that provide financial incentives to renewable energy such as wind and solar, but generally do not apply to nuclear generating stations. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

If trends noted above continue or worsen, Power's nuclear generating units could cease being economically competitive which may cause Power to retire such units prior to the end of their useful lives. The costs associated with any such potential retirement, which may include, among other things, accelerated D&A or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs, and additional funding of the NDT Fund would likely have a material adverse impact on PSEG's and Power's future financial results. PSEG and Power continue to advocate for sound policies that recognize nuclear power as a source of reliable and air emissions free energy and an important part of a diverse and reliable energy portfolio.

The following table provides the balance sheet amounts by generating station as of June 30, 2017 for significant assets and liabilities associated with Power's owned share of its nuclear assets.

	As of June 30, 2017			
	Hope Creek	Salem	Support Facilities and Other (A)	Peach Bottom
	Millions			
Assets				
Materials and Supplies Inventory	$ 83	$ 80	$ —	$ 41
Nuclear Production, net of Accumulated Depreciation	453	561	208	758
Nuclear Fuel In-Service, net of Accumulated Depreciation	136	113	—	125
Construction Work in Progress (including nuclear fuel)	168	109	9	31
Total Assets	$ 840	$ 863	$ 217	$ 955
Liability				
Asset Retirement Obligation	$ 146	$ 159	$ —	$ 162
Total Liabilities	$ 146	$ 159	$ —	$ 162
Net Assets	$ 694	$ 704	$ 217	$ 793
NRC License Renewal Term	2046	2036/2040	—	2033/2034
% Owned	100%	57%	—	50%

(A) Includes Hope Creek's and Salem's shared support facilities and other nuclear development capital.

The precise timing of any potential early retirement and resulting financial statement impact may be affected by a number of factors, including co-owner considerations, the results of any transmission system reliability study assessments and decommissioning trust fund requirements and other commitments, as well as future energy prices. Power maintains a NDT Fund that funds its decommissioning obligations. See Note 7. Available-for-Sale Securities.

Note 4. Variable Interest Entity (VIE)

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management

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fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and O&M Expense, respectively. Servco recorded $112 million and $101 million for the three months and $224 million and $199 million for the six months ended June 30, 2017 and 2016, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 5. Rate Filings

This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2016.

In addition to items previously reported in the Annual Report on Form 10-K, significant regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

Energy Strong Recovery Filing—In March and September of each year, PSE&G files with the BPU for base rate recovery of Energy Strong investments which include a return of and on its investment. In June 2017, PSE&G updated its March cost recovery petition to include Energy Strong investments in service as of May 31, 2017 which represents estimated annual increases in electric and gas revenues of $16 million and $2 million, respectively. The petition requests rates to be effective September 1, 2017, consistent with the BPU Order of approval of the Energy Strong program. This matter is pending.

Basic Gas Supply Services (BGSS)—In June 2017, PSE&G made its annual BGSS filing with the BPU requesting an increase of $61 million in annual BGSS revenues. If approved, the BGSS rate would be increased from approximately 34 cents to 37 cents per therm for residential gas customers effective October 1, 2017. This matter is pending.

Green Program Recovery Charges (GPRC)—Each year PSE&G files with the BPU for annual recovery of its Green Program investments which include a return on its investment and recovery of expenses. In June 2017, PSE&G filed its 2017 GPRC cost recovery petition requesting recovery for the ten combined components of the electric and gas GPRC. The filing proposes rates for the period October 1, 2017 through September 30, 2018 designed to recover approximately $47 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU-approved programs. This matter is pending.

In March 2017, the BPU gave final approval to PSE&G's petition to recover approximately $37 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved GPRC programs. The rates were effective May 1, 2017. This Order also included the return of approximately $5 million in remaining overcollections from the completed Securitization Transition Charge.

Weather Normalization Clause—In April 2017, the BPU gave final approval to PSE&G's petition to collect $54 million in net deficiency gas revenues as a result of the warmer than normal 2015-2016 Winter Period.

In June 2017, PSE&G filed a petition requesting approval to collect $55 million in total net deficiency revenues comprised of $31 million in net deficiency gas revenues as a result of the warmer than normal 2016-2017 Winter Period and the remaining carryover balance of $24 million in net deficiency gas revenue from the 2015-2016 Winter Period. The deficiency gas revenue would be collected from customers over the 2017-2018 and 2018-2019 Winter Periods (October 1 through May 31). This matter is pending.

Transmission Formula Rate Filings—In June 2017, PSE&G filed its 2016 true-up adjustment pertaining to its transmission formula rates in effect for 2016. This resulted in an adjustment of $12 million more than the 2016 originally filed revenues.

Remediation Adjustment Charge (RAC)—In June 2017, the BPU approved PSE&G's filing with respect to its RAC 24 petition allowing recovery of $41 million effective July 10, 2017 related to net Manufactured Gas Plant expenditures from August 1, 2015 through July 31, 2016.

Gas System Modernization Program (GSMP)—In July 2017, PSE&G filed its annual GSMP cost recovery petition seeking BPU approval to recover in gas base rates an estimated annual revenue increase of $28 million effective January 1, 2018. This increase represents the return of and on investment for GSMP investments expected to be in service through September 30, 2017. This request will be updated in October 2017 for actual costs.

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Note 6. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with solar renewable energy certificates generated from the installed solar electric system. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Outstanding Loans by Class of Customer

Consumer Loans	As of June 30, 2017	As of December 31, 2016
	Millions	
Commercial/Industrial	$ 167	$ 164
Residential	11	11
Total	**$ 178**	**$ 175**

Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third-party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

During the third quarter of 2016, Energy Holdings completed its annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases. The outcome indicated that the revised residual value estimates were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM, as discussed in Note 3. Early Plant Retirements, negatively impacting the economic outlook of the leased assets. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016, calculated by comparing the gross investment in the leases before and after the revised residual estimates. During the fourth quarter of 2016, Energy Holdings recorded a $10 million pre-tax charge for its best estimate of loss related to the leveraged lease receivables as a result of the current liquidity issues facing REMA, which was reflected in Operating Revenues and is included in Gross Investments in Leases as of December 31, 2016.

During the first quarter of 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as certain recent discussions with REMA management, Energy Holdings recorded an additional $55 million pre-tax charge for its current best estimate of loss related to the lease receivables, which was reflected in Operating Revenues and is included in Gross Investments in Leases as of June 30, 2017.

In June 2017, GenOn Energy, Inc. (GenOn) and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code. GenOn is a subsidiary of NRG Energy, Inc. and is the parent of REMA. REMA was not included in the GenOn filing. Energy Holdings continues to monitor the restructuring of GenOn and its possible impacts on REMA. During the second quarter of 2017, Energy Holdings completed its review of estimated residual values embedded in its leveraged lease portfolio of generating assets and the outcome indicated that one of the residual value estimates was lower than the recorded residual value due to a further deterioration of market conditions and changes to operating cost estimates. This decline was determined to be other than temporary. As a result, a pre-tax write-down of $7 million was recorded in the quarter ended June 30, 2017. In addition, based on an ongoing review of (i) the liquidity challenges facing REMA and (ii) available alternatives, Energy Holdings recorded an additional $15 million pre-tax charge for its current best estimate of loss related to

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lease receivables. The second quarter 2017 pre-tax write-down and additional charge were reflected in Operating Revenues and are included in Gross Investment in Leases for June 30, 2017.

The following table shows Energy Holdings' gross and net lease investment as of June 30, 2017 and December 31, 2016, respectively.

	As of June 30, 2017	As of December 31, 2016
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 559	$ 629
Estimated Residual Value of Leased Assets	333	346
Total Investment in Rental Receivables	892	975
Unearned and Deferred Income	(315)	(326)
Gross Investment in Leases	577	649
Deferred Tax Liabilities	(619)	(674)
Net Investment in Leases	**$ (42)**	**$ (25)**

The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

	Lease Receivables, Net of Non-Recourse Debt
Counterparties' Credit Rating Standard & Poor's (S&P) as of June 30, 2017	**As of June 30, 2017**
	Millions
AA	$ 15
BBB+ — BBB-	317
BB-	133
CC	94
Total	**$ 559**

The "BB-" and the "CC" ratings in the preceding table represent lease receivables related to coal and gas-fired assets in Illinois and Pennsylvania, respectively. As of June 30, 2017, the gross investment in the leases of such assets, net of non-recourse debt, was $348 million ($(159) million, net of deferred taxes). A more detailed description of such assets under lease, as of June 30, 2017, is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 83	64%	1,036	Gas	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 20	17%	1,711	Coal	CC (A)	REMA
Conemaugh Station Units 1 and 2	PA	$ 20	17%	1,711	Coal	CC (A)	REMA
Shawville Station Units 1, 2, 3 and 4	PA	$ 91	100%	596	Gas	CC (A)	REMA

(A) REMA's parent company, GenOn, and certain of its subsidiaries (which did not include REMA) filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete. On June 16, 2017, Moody's downgraded the GenOn Corporate Family Rating to D-PD and provided a rating of Caa1 for REMA.

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The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease structures. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital and trigger certain material tax obligations which could wholly or partially be mitigated by tax indemnification claims against the counterparty. A bankruptcy of a lessee would likely delay and potentially limit any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's restructuring process or the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments. If lease rejections or foreclosures were to occur, Energy Holdings could potentially record additional pre-tax write-offs up to its gross investment in these facilities and may also be required to accelerate and pay material deferred tax liabilities to the Internal Revenue Service.

Additional factors that may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and their affiliates and the quality and condition of assets under lease.

Note 7. Available-for-Sale Securities

NDT Fund

Power maintains an external master NDT to fund its share of decommissioning costs for its five nuclear facilities upon termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The funds are managed by third-party investment managers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of June 30, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 699	$ 305	$ (5)	$ 999
Debt Securities				
Government	551	10	(4)	557
Corporate	356	6	(1)	361
Total Debt Securities	907	16	(5)	918
Other Securities	51	—	—	51
Total NDT Available-for-Sale Securities	**$ 1,657**	**$ 321**	**$ (10)**	**$ 1,968**

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	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 705	$ 263	$ (11)	$ 957
Debt Securities				
Government	518	8	(6)	520
Corporate	337	4	(4)	337
Total Debt Securities	855	12	(10)	857
Other Securities	44	—	—	44
Total NDT Available-for-Sale Securities (A)	**$ 1,604**	**$ 275**	**$ (21)**	**$ 1,858**

(A) The NDT available-for-sale securities table excludes cash of $1 million which is part of the NDT Fund.

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of June 30, 2017	As of December 31, 2016
	Millions	
Accounts Receivable	$ 25	$ 8
Accounts Payable	$ 22	$ 5

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of June 30, 2017				As of December 31, 2016			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 63	$ (5)	$ —	$ —	$ 120	$ (10)	$ 8	$ (1)
Debt Securities								
Government (B)	279	(4)	7	—	276	(6)	4	—
Corporate (C)	94	(1)	7	—	139	(3)	15	(1)
Total Debt Securities	373	(5)	14	—	415	(9)	19	(1)
Other Securities	51	—	—	—	—	—	—	—
NDT Available-for-Sale Securities	**$ 487**	**$ (10)**	**$ 14**	**$ —**	**$ 535**	**$ (19)**	**$ 27**	**$ (2)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of June 30, 2017.

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(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. Power also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2017.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2017.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	Millions			
Proceeds from NDT Fund Sales (A)	**$ 320**	**$ 154**	**$ 567**	**$ 331**
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	$ 32	$ 10	$ 53	$ 25
Gross Realized Losses	(5)	(6)	(9)	(22)
Net Realized Gains (Losses) on NDT Fund	**$ 27**	**$ 4**	**$ 44**	**$ 3**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $158 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of June 30, 2017.

The NDT available-for-sale debt securities held as of June 30, 2017 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 29
1 - 5 years	239
6 - 10 years	223
11 - 15 years	65
16 - 20 years	66
Over 20 years	296
Total NDT Available-for-Sale Debt Securities	**$ 918**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the six months ended June 30, 2017, Other-Than-Temporary Impairments (OTTI) of $4 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be

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recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of June 30, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 22	$ —	$ —	$ 22
Debt Securities				
Government	85	1	(1)	85
Corporate	113	2	—	115
Total Debt Securities	198	3	(1)	200
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 222**	**$ 3**	**$ (1)**	**$ 224**

	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 11	$ 11	$ —	$ 22
Debt Securities				
Government	105	—	(2)	103
Corporate	92	1	(2)	91
Total Debt Securities	197	1	(4)	194
Other Securities	1	—	—	1
Total Rabbi Trust Available-for-Sale Securities	**$ 209**	**$ 12**	**$ (4)**	**$ 217**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of June 30, 2017	As of December 31, 2016
	Millions	
Accounts Receivable	$ 2	$ 5
Accounts Payable	$ —	$ 3

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The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months.

	As of June 30, 2017				As of December 31, 2016			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government (B)	29	(1)	1	—	60	(2)	1	—
Corporate (C)	19	—	3	—	46	(2)	3	—
Total Debt Securities	48	(1)	4	—	106	(4)	4	—
Rabbi Trust Available-for-Sale Securities	**$ 48**	**$ (1)**	**$ 4**	**$ —**	**$ 106**	**$ (4)**	**$ 4**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. PSEG also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2017.

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2017.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	Millions			
Proceeds from Rabbi Trust Sales (A)	**$ 93**	**$ 36**	**$ 144**	**$ 61**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ 2	$ 2	$ 17	$ 3
Gross Realized Losses	(1)	(1)	(4)	(2)
Net Realized Gains (Losses) on Rabbi Trust	**$ 1**	**$ 1**	**$ 13**	**$ 1**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in the Condensed Consolidated Statements of Operations. Net unrealized gains/losses in Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets were immaterial as of June 30, 2017.

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The Rabbi Trust available-for-sale debt securities held as of June 30, 2017 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 1
1 - 5 years	35
6 - 10 years	29
11 - 15 years	6
16 - 20 years	18
Over 20 years	111
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 200**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in an indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the six months ended June 30, 2017, no OTTIs were recognized on securities in the Rabbi Trust. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of June 30, 2017	As of December 31, 2016
	Millions	
PSE&G	$ 45	$ 43
Power	55	53
Other	124	121
Total Rabbi Trust Available-for-Sale Securities	**$ 224**	**$ 217**

Note 8. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria.

As of December 31, 2016, PSEG merged its three qualified defined benefit pension plans (excluding Servco plans) into one plan, thereby also merging all of the pension plans' assets. As a result, the total net periodic benefit costs, net of amounts capitalized, decreased by approximately $12 million and $24 million for the three months and six months, ended June 30, 2017, respectively, as compared to the 2017 amounts that would have been recognized had the plans not been merged. This is due to the amortization period for gains and losses for the merged plan resulting in lower amortization than that of the individual plans. No changes were made to the benefit formulas, vesting provisions, or to the employees covered by the plans.

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The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis for PSEG, excluding Servco.

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016	2017	2016	2017	2016
	Millions							
Components of Net Periodic Benefit Costs								
Service Cost	$ 28	$ 27	$ 4	$ 4	$ 57	$ 54	$ 8	$ 8
Interest Cost	51	51	16	14	102	101	32	29
Expected Return on Plan Assets	(99)	(99)	(9)	(7)	(197)	(197)	(17)	(15)
Amortization of Net								
Prior Service Cost (Credit)	(4)	(5)	(2)	(4)	(9)	(9)	(5)	(7)
Actuarial Loss	25	40	12	10	49	79	25	20
Total Benefit Costs	**$ 1**	**$ 14**	**$ 21**	**$ 17**	**$ 2**	**$ 28**	**$ 43**	**$ 35**

Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, excluding Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016	2017	2016	2017	2016
	Millions							
PSE&G	$ (1)	$ 7	$ 13	$ 11	$ (2)	$ 14	$ 27	$ 22
Power	1	4	6	5	1	8	13	11
Other	1	3	2	1	3	6	3	2
Total Benefit Costs	**$ 1**	**$ 14**	**$ 21**	**$ 17**	**$ 2**	**$ 28**	**$ 43**	**$ 35**

During the three months ended March 31, 2017, PSEG contributed its entire planned contribution for the year 2017 of $14 million into its OPEB plan.

Servco Pension and OPEB

At the direction of LIPA, Servco sponsors benefit plans that cover its current and former employees who meet certain eligibility criteria. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 4. Variable Interest Entity. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco plans to contribute $35 million into its pension plan trusts during 2017. Servco's pension-related revenues and costs were $8 million and $6 million for the three months ended June 30, 2017 and 2016, respectively, and $17 million and $12 million for the six months ended June 30, 2017 and 2016, respectively. The OPEB-related revenues earned and costs incurred were $1 million and $2 million for the three months and six months ended June 30, 2017. The OPEB-related revenues earned and costs incurred were immaterial for the three months and six months ended June 30, 2016.

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Note 9. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees as a form of collateral.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- the net position of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. Current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of June 30, 2017 and December 31, 2016.

	As of June 30, 2017	As of December 31, 2016
	Millions	
Face Value of Outstanding Guarantees	$ 1,898	$ 1,806
Exposure under Current Guarantees	$ 137	$ 139
Letters of Credit Margin Posted	$ 142	$ 157
Letters of Credit Margin Received	$ 98	$ 99
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (1)	$ (1)
Net Broker Balance Deposited (Received)	$ (2)	$ 57
Additional Amounts Posted:		
Other Letters of Credit	$ 61	$ 51

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 11. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Condensed Consolidated Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG also issued a $21 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit. In June 2017, Power sold its minority equity interest in PennEast and upon disposition, PSEG's $106 million guarantee that had supported Power's obligations related to PennEast was terminated.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA determined that there was a need to perform a comprehensive study of the entire 17 miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17

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miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than with respect to their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. Construction is complete. The CPG is awaiting EPA approval of the construction report, long-term monitoring plan and confirmatory sampling plan. PSE&G's and Power's combined share of the cost of that effort is approximately three percent. The remaining CPG members, PSE&G and Power included, have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS sets forth various alternatives for remediating this portion of the Passaic River.

The CPG, which consisted of 51 members as of June 30, 2017, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost of the RI/FS is approximately $190 million, which the CPG continues to incur. Of the estimated $190 million, as of June 30, 2017, the CPG had spent approximately $163 million, of which PSEG's total share was approximately $12 million.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River. It set forth the CPG's estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion on an undiscounted basis. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranged from approximately $518 million to $772 million. Based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimated share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

In March 2016, the EPA released its Record of Decision (ROD) for the FFS which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The ROD Remedy requires a bank-to-bank dredge ranging from approximately 5 to 30 feet deep in the federal navigation channel from River Mile 0 to River Mile 1.7 and an approximately 2.5 foot deep dredge everywhere else in the lower 8.3 miles of the river. An engineered cap approximately two feet thick will be placed over the dredged areas. Dredged sediments will be transported to facilities and landfills out-of-state. The EPA estimates the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation.

Based upon the estimated cost of the ROD Remedy, PSEG's estimate of PSE&G's and Power's shares of that cost, and the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued an additional $36 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued an additional $8 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2016. As of June 30, 2017, these accruals bring the total liability to approximately $57 million, $46 million applicable to PSE&G and $11 million applicable to Power.

Also in March 2016, the EPA sent a notice letter to 105 PRPs, including PSE&G, all other past and present members of the CPG, including Occidental Chemical Corporation (OCC), and the towns of Newark, Kearny and Harrison and the Passaic Valley Sewerage Commission stating that the EPA wants to determine whether OCC, a successor company to Diamond Shamrock, would voluntarily perform the remedial design for the ROD Remedy. On September 30, 2016, OCC and the EPA

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executed an Administrative Settlement Agreement and Order on Consent for Remedial Design under which OCC agreed to conduct the remedial design for the ROD. With OCC's commitment to perform the remedial design, it is anticipated that the EPA will begin negotiation of a remedial action consent decree, under which OCC and the other "major PRPs" will implement and/or pay for the EPA's ROD Remedy for the lower 8.3 miles. The EPA has not defined "major PRPs."

In June 2016, Tierra and Maxus, successors to Diamond Shamrock, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Maxus and Tierra are subsidiaries of YPF Holdings, Inc. (YPF Holdings). YPF Holdings is a wholly owned subsidiary of YPF S.A. (YPF), a company controlled by the Argentinian government. Neither YPF Holdings nor YPF is a party to the bankruptcy proceedings. However, Tierra and Maxus have filed a plan of liquidation that may allow the parties to assert one or more causes of action to hold YPF responsible for certain amounts owed by Tierra and Maxus. PSEG cannot currently determine the impact, if any, that the bankruptcy of Tierra and Maxus or any related proceeding might have on its allocable share or total liability for the Passaic River matter, and therefore, PSEG, through the CPG and independently, will continue to monitor the bankruptcy proceedings to identify any potential impact on PSEG's share of the costs.

In March 2017, the EPA sent a letter to 20 PRPs that are considered by the EPA to have minimal responsibility for the Passaic River's contamination, offering "cash-out" settlements in return for payments by each PRP of $280,600. The PRPs that settle will be released from their CERCLA remediation liability for the lower 8.3 miles of the lower Passaic River. It is unclear how the EPA made that determination or how many PRPs will accept the proposal. The settlement is subject to a 30 day public comment period that has not yet commenced. The impact of this settlement on PSEG's responsibility for the remediation of the lower 8.3 miles is not material.

The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on PSEG's financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined

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that the estimated cost to remediate all MGP sites to completion could range between $373 million and $430 million through 2021, including its $46 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $373 million as of June 30, 2017. Of this amount, $74 million was recorded in Other Current Liabilities and $299 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $373 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly. NJDEP, PSEG and EPA representatives have had discussions regarding whether sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Clean Water Act (CWA) Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In May 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the best technology available for minimizing adverse environmental impacts of each facility that seeks a permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications.

In September 2014, several environmental non-governmental groups and certain energy industry groups filed petitions for review of the rule and the case has been assigned to the U.S. Second Circuit Court of Appeals (Second Circuit). Environmental organizations, including but not limited to the environmental petitioners in the Second Circuit, have also filed suit under the Endangered Species Act. The cases were subsequently consolidated at the Second Circuit and a decision is expected by mid-2017.

In June 2016, the NJDEP issued a final NJPDES permit for Salem with an effective date of August 1, 2016. The final permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the CWA, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final permit for Salem. The Riverkeeper's filing does not change the effective date of the permit. If the Riverkeeper's challenge were successful, Power may be required to incur additional costs to comply with the CWA. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

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State permitting decisions at Bridgeport and possibly New Haven could also have a material impact on Power's ability to renew permits at its existing larger once-through cooled plants without making significant upgrades to existing intake structures and cooling systems.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at BH3. To address compliance with the EPA's CWA Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, Power would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the previously estimated useful life ending in 2025. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in 2017. See Note 3. Early Plant Retirements.

Separately, Power has also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut and local community organizations. That CEBA provides that Power would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. The receipt of permits to allow construction and operation of the new facility could occur in 2017. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power may seek to operate BH3 through the previously estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. The Connecticut Siting Council issued an order to approve siting BH5. All major environmental permits have been obtained. Operations are expected to begin in mid-2019.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.

Jersey City, New Jersey Subsurface Feeder Cable Matter

In early October 2016, a discharge of dielectric fluid from subsurface feeder cables located in the Hudson River near Jersey City, New Jersey, was identified and reported to the NJDEP. The feeder cables are located within a subsurface easement granted to PSE&G by the property owners, Newport Associates Development Company (NADC) and Newport Associates Phase I Developer Limited Partnership. The feeder cables are subject to agreements between PSE&G and Consolidated Edison Company of New York, Inc. (Con Edison) and are jointly owned by PSE&G and Con Edison, with PSE&G owning the portion of the cables located in New Jersey and Con Edison owning the portion of the cables located in New York. The NJDEP has declared an emergency and an emergency response action has been undertaken to investigate, contain, remediate and stop the fluid discharge; to assess, repair and restore the cables to good working order, if feasible; and to restore the property. The regulatory agencies overseeing the emergency response, including the U.S. Coast Guard, the NJDEP and the Army Corps of Engineers, have issued multiple notices, orders and directives to the various parties related to this matter. The investigation and response actions related to the fluid discharge are ongoing, making it difficult to determine the timing and potential costs to resolve this matter, as well as responsibility for such costs between PSE&G, Con Edison and NADC. Based on currently available information and the potential scope of the actions necessary to address the leak and remediation work, the costs will likely be material. In addition, the timeline for completing the repairs was extended due to the presence of debris within PSE&G's easement. In November 2016, PSE&G filed an action in New Jersey Federal Court seeking an order requiring NADC to remove its debris from PSE&G's easement so that PSE&G and Con Edison may comply with NJDEP and U.S. Coast Guard directives and complete the necessary repairs. NADC subsequently informed PSE&G that it would comply with the U.S. Coast Guard's order and undertake debris removal activities so that PSE&G and Con Edison can complete the necessary repairs. NADC's initial debris removal activities were completed in May 2017. Since then, efforts have been ongoing to inspect portions of the pipe-type cables. As of mid-July 2017, the immediate vicinity of the leak appears to have been located and efforts are ongoing to identify the precise leak location and attempt repairs. If the leak cannot be located or if repairs cannot be effectuated at a reasonable cost and within a reasonable time frame, retirement of the affected facilities may be an option to address the leakage.

Steam Electric Effluent Guidelines

In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG Rule) for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom

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ash transport water, flue gas desulfurization and flue gas mercury control wastewater, and gasification wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges and that are regulated under this rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the rule. Power is unable to predict if this rule will have a material impact on its future capital requirements, financial condition and results of operations.

In April 2017, the EPA announced that it had granted a petition for reconsideration of the ELG Rule and issued an administrative stay of the compliance dates in the rule that were the subject of pending litigation. In June 2017, the EPA proposed a rule to postpone the compliance deadlines for the BAT limitations and pretreatment standards for the aforementioned waste streams. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2016 is $276.83 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2016 of $335.33 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2014	2015	2016	2017	
36-Month Terms Ending	May 2017	May 2018	May 2019	May 2020	(A)
Load (MW)	2,800	2,900	2,800	2,800	
$ per MWh	$97.39	$99.54	$96.38	$90.78	

(A) Prices set in the 2017 BGS auction year became effective on June 1, 2017 when the 2014 BGS auction agreements expired.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 18. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium,

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enrichment and fabrication requirements through 2018 and a significant portion through 2021 at Salem, Hope Creek and Peach Bottom.

Power has various multi-year contracts for natural gas and firm pipeline transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess pipeline capacity available beyond the needs of PSE&G's customers, Power can use the gas to make third-party sales and if excess volume remains after the third-party sales, supply its fossil generating stations in New Jersey.

Power also has various long-term fuel purchase commitments for coal through 2021 to support its Keystone and Conemaugh fossil generation stations.

As of June 30, 2017, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2021
	Millions
Nuclear Fuel	
Uranium	$ 301
Enrichment	$ 340
Fabrication	$ 184
Natural Gas	$ 1,040
Coal	$ 331

Regulatory Proceedings

FERC Compliance

PJM Bidding Matter

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power has implemented procedures to mitigate the risk of similar issues occurring in the future. During the three months ended March 31, 2014, based upon its best estimate available at the time, Power recorded a pre-tax charge to income in the amount of $25 million related to this matter.

Since September 2014, FERC Staff has been conducting a preliminary, non-public staff investigation into these matters. While considerable uncertainty remains as to the final resolution of these matters, based upon developments in the investigation in the first quarter of 2017, Power believes the disgorgement and interest costs related to the cost-based bidding matter may range between approximately $35 million and $135 million, depending on the legal interpretation of the principles under the PJM Tariff, plus penalties. Since no point within this range is more likely than any other, Power has accrued the low end of this range of $35 million by recording an additional pre-tax charge to income of $10 million during the three months ended March 31, 2017. Power is unable to reasonably estimate the range of possible loss, if any, for the quantity of energy offered matter or the penalties that FERC would impose relating to either the cost-based bidding or quantity of energy matter. However, any of these amounts could be individually material to PSEG and Power.

Power continues to believe that it has legal defenses that it may assert in a judicial challenge, including the legal defense that its cost-based bidding in a substantial majority of the hours was below the allowed rate under the Tariff and therefore any errors in those hours did not violate the Tariff or were immaterial. Furthermore, it is unclear whether the quantity of energy offered violated any legal requirement. As a result, PSEG and Power cannot predict the final outcome of these matters.

Financial Transmission Rights (FTR) Auction Matter

In January 2017, ER&T received requests from the FERC Office of Enforcement relating to the planning and implementation of ER&T's participation in PJM's annual FTR auction for the 2016-2017 planning year and the monthly PJM FTR auctions for February, March and April 2016. PSEG is cooperating with FERC in this matter. PSEG cannot predict the outcome of this matter at this time.

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Note 10. Debt and Credit Facilities

Long-Term Debt Financing Transactions

The following long-term debt transaction occurred in the six months ended June 30, 2017:

PSEG

- entered into an agreement for a new term loan maturing June 2019. The term loan has a balance of $700 million at an interest rate of 1 month LIBOR + 0.80% and can be terminated at any time without penalty.

PSE&G

- issued $425 million of 3.00% Secured Medium-Term Notes, Series L due May 2027.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

In March 2017, PSEG, Power and PSE&G amended their credit agreements, extending the expiration dates to March 2022. Concurrently, PSEG increased its existing $1 billion in credit facilities to $1.5 billion and Power decreased its existing $2.6 billion in credit facilities to $2.1 billion, which includes two new 3-year $100 million letter of credit facilities that expire in March 2020.

The commitments under the $4.2 billion credit facilities are provided by a diverse bank group. As of June 30, 2017, the total available credit capacity was $4.0 billion.

As of June 30, 2017, no single institution represented more than 8% of the total commitments in the credit facilities.

As of June 30, 2017, total credit capacity was in excess of the total anticipated maximum liquidity requirements of PSEG, PSE&G and Power.

Each of the credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support its subsidiaries' liquidity needs. The total credit facilities and available liquidity as of June 30, 2017 were as follows:

	As of June 30, 2017				
Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facilities (A)	$ 1,500	$ 13	$ 1,487	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSEG	**$ 1,500**	**$ 13**	**$ 1,487**		
PSE&G					
5-year Credit Facility (A)	$ 600	$ 15	$ 585	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 15**	**$ 585**		
Power					
3-year LC Facilities	$ 200	$ 140	$ 60	Mar 2020	Letters of Credit
5-year Credit Facilities	1,900	50	1,850	Mar 2022	Funding/Letters of Credit
Total Power	**$ 2,100**	**$ 190**	**$ 1,910**		
Total	**$ 4,200**	**$ 218**	**$ 3,982**		

(A) The primary use of PSEG's and PSE&G's credit facilities is to support their respective Commercial Paper Programs, under which as of June 30, 2017, neither PSEG nor PSE&G had amounts outstanding.

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Note 11. Financial Risk Management Activities

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchases and normal sales (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow or fair value hedges. Power and PSE&G enter into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk relating primarily to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of the derivative contracts are recorded in earnings.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. The changes in fair value of the interest rate swaps are fully offset by changes in the fair value of the underlying forecasted interest payments of the debt. There were no outstanding interest rate swaps as of June 30, 2017 or December 31, 2016. The fair value hedges reduced interest expense by $2 million and $4 million for the three months and six months ended June 30, 2016.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, related primarily to variable-rate debt instruments. As of June 30, 2017 and December 31, 2016, PSEG had interest rate hedges outstanding totaling $500 million. These hedges convert PSEG's $500 million variable rate term loan due November 2017 into a fixed rate loan. As of June 30, 2017 and December 31, 2016, the fair value of these hedges was $1 million. There was no ineffectiveness as of June 30, 2017 and December 31, 2016.

The Accumulated Other Comprehensive Income (Loss) (after tax) related to existing and terminated interest rate derivatives designated as cash flow hedges was $2 million as of June 30, 2017 and December 31, 2016. The after-tax unrealized gain expected to be reclassified to earnings during the next 12 months is $1 million.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with PSEG's accounting policy, these positions are offset on the Condensed Consolidated Balance Sheets of Power and PSEG.

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The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of June 30, 2017				
	Power (A)			PSEG (A)	Consolidated
	Not Designated			Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Interest Rate Swaps	Total Derivatives
	Millions				
Derivative Contracts					
Current Assets	$ 479	$ (367)	$ 112	$ 1	$ 113
Noncurrent Assets	268	(178)	90	—	90
Total Mark-to-Market Derivative Assets	**$ 747**	**$ (545)**	**$ 202**	**$ 1**	**$ 203**
Derivative Contracts					
Current Liabilities	$ (373)	$ 365	$ (8)	$ —	$ (8)
Noncurrent Liabilities	(170)	169	(1)	—	(1)
Total Mark-to-Market Derivative (Liabilities)	**$ (543)**	**$ 534**	**$ (9)**	**$ —**	**$ (9)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 204**	**$ (11)**	**$ 193**	**$ 1**	**$ 194**

	As of December 31, 2016					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions					
Derivative Contracts						
Current Assets	$ 435	$ (273)	$ 162	$ —	$ 1	$ 163
Noncurrent Assets	122	(98)	24	—	—	24
Total Mark-to-Market Derivative Assets	**$ 557**	**$ (371)**	**$ 186**	**$ —**	**$ 1**	**$ 187**
Derivative Contracts						
Current Liabilities	$ (285)	$ 277	$ (8)	$ (5)	$ —	$ (13)
Noncurrent Liabilities	(98)	95	(3)	—	—	(3)
Total Mark-to-Market Derivative (Liabilities)	**$ (383)**	**$ 372**	**$ (11)**	**$ (5)**	**$ —**	**$ (16)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 174**	**$ 1**	**$ 175**	**$ (5)**	**$ 1**	**$ 171**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of June 30, 2017 and December 31, 2016. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of June 30, 2017, net

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cash collateral (received) paid of $(11) million was netted against the corresponding net derivative contract positions. Of the $(11) million as of June 30, 2017, $(4) million was netted against current assets, $(9) million was netted against noncurrent assets, and $2 million was netted against current liabilities. As of December 31, 2016, net cash collateral (received) paid of $1 million was netted against the corresponding net derivative contract positions. Of the $1 million as of December 31, 2016, $(3) million was netted against noncurrent assets and $4 million was netted against current liabilities.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating by S&P or Moody's, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P or Moody's ratings. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $16 million and $19 million as of June 30, 2017 and December 31, 2016, respectively. As of June 30, 2017 and December 31, 2016, Power had the contractual right of offset of $11 million and $9 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $5 million and $10 million as of June 30, 2017 and December 31, 2016, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months and six months ended June 30, 2017 and 2016.

	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	
	Three Months Ended June 30,			Three Months Ended June 30,	
Derivatives in Cash Flow Hedging Relationships	2017	2016		2017	2016
	Millions			Millions	
PSEG					
Interest Rate Swaps	$ —	$ (1)	Interest Expense	$ —	$ —
Total PSEG	**$ —**	**$ (1)**		**$ —**	**$ —**

	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	
	Six Months Ended June 30,			Six Months Ended June 30,	
Derivatives in Cash Flow Hedging Relationships	2017	2016		2017	2016
	Millions			Millions	
PSEG					
Interest Rate Swaps	—	2	Interest Expense	—	—
Total PSEG	**$ —**	**$ 2**		**$ —**	**$ —**

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There were no pre-tax gains (losses) recognized in income on derivatives (ineffective portion) as of June 30, 2017 and 2016.

The following reconciles the AOCI for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2015	**$ —**	**$ —**
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	—	—
Balance as of December 31, 2016	**$ 3**	**$ 2**
Gain Recognized in AOCI	—	—
Less: Gain Reclassified into Income	—	—
Balance as of June 30, 2017	**$ 3**	**$ 2**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS for the three months and six months ended June 30, 2017 and 2016. Power's derivative contracts reflected in this table include contracts to hedge the purchase and sale of electricity and natural gas, and the purchase of fuel. The table does not include contracts for which Power has designated as NPNS, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives		Pre-Tax Gain (Loss) Recognized in Income on Derivatives	
		Three Months Ended June 30,		Six Months Ended June 30,	
		2017	2016	2017	2016
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ 113	$ (86)	$ 196	$ 130
Energy-Related Contracts	Energy Costs	(11)	6	(16)	8
Total PSEG and Power		**$ 102**	**$ (80)**	**$ 180**	**$ 138**

The following reflects the gross volume, on an absolute value basis, of derivatives as of June 30, 2017 and December 31, 2016.

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of June 30, 2017					
Natural Gas	Dekatherm (Dth)	321	—	321	—
Electricity	MWh	349	—	349	—
Financial Transmission Rights (FTRs)	MWh	6	—	6	—
Interest Rate Swaps	U.S. Dollars	500	500	—	—
As of December 31, 2016					
Natural Gas	Dth	357	—	348	9
Electricity	MWh	323	—	323	—
FTRs	MWh	9	—	9	—
Interest Rate Swaps	U.S. Dollars	500	500	—	—

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Credit Risk

Credit risk relates to the risk of loss that Power would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG has established credit policies that it believes significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of June 30, 2017, 97% of the net credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives, NPNS and non-derivatives).

The following table provides information on Power's credit risk from others, net of collateral, as of June 30, 2017. It further delineates that exposure by the credit rating of the counterparties, which is determined by the lowest rating from S&P, Moody's or an internal scoring model. In addition, it provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Collateral Held	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade	$ 420	$ 92	$ 328	1	$ 130	(A)
Non-Investment Grade	9	—	9	—	—	
Total	**$ 429**	**$ 92**	**$ 337**	**1**	**$ 130**	

(A) Represents net exposure of $130 million with PSE&G.

As of June 30, 2017, collateral held from counterparties where Power had credit exposure included $92 million in letters of credit.

As of June 30, 2017, Power had 152 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of June 30, 2017, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's BGS suppliers' credit exposure is calculated each business day. As of June 30, 2017, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 12. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds, as well as natural gas futures contracts executed on NYMEX.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of June 30, 2017, these consisted primarily of certain electric load contracts and gas contracts.

Certain derivative transactions may transfer from Level 2 to Level 3 if inputs become unobservable and internal modeling techniques are employed to determine fair value. Conversely, measurements may transfer from Level 3 to Level 2 if the inputs become observable.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of June 30, 2017 and December 31, 2016, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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Description	Recurring Fair Value Measurements as of June 30, 2017				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 367	$ —	$ 367	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 202	$ (545)	$ 9	$ 732	$ 6
Interest Rate Swaps (C)	$ 1	$ —	$ —	$ 1	$ —
NDT Fund (D)					
Equity Securities	$ 999	$ —	$ 997	$ 2	$ —
Debt Securities—US Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 330	$ —	$ —	$ 330	$ —
Debt Securities—Corporate	$ 361	$ —	$ —	$ 361	$ —
Other Securities	$ 51	$ —	$ 51	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—US Treasury	$ 51	$ —	$ —	$ 51	$ —
Debt Securities—Govt Other	$ 34	$ —	$ —	$ 34	$ —
Debt Securities—Corporate	$ 115	$ —	$ —	$ 115	$ —
Other Securities	$ 2	$ —	$ 2	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (9)	$ 534	$ (6)	$ (537)	$ —
Interest Rate Swaps (C)	$ —	$ —	$ —	$ —	$ —
PSE&G					
Assets:					
Cash Equivalents (A)	$ 169	$ —	$ 169	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—US Treasury	$ 10	$ —	$ —	$ 10	$ —
Debt Securities—Govt Other	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Corporate	$ 23	$ —	$ —	$ 23	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 202	$ (545)	$ 9	$ 732	$ 6
NDT Fund (D)					
Equity Securities	$ 999	$ —	$ 997	$ 2	$ —
Debt Securities—US Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 330	$ —	$ —	$ 330	$ —
Debt Securities—Corporate	$ 361	$ —	$ —	$ 361	$ —
Other Securities	$ 51	$ —	$ 51	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—US Treasury	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Govt Other	$ 8	$ —	$ —	$ 8	$ —
Debt Securities—Corporate	$ 29	$ —	$ —	$ 29	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					

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Derivative Contracts:										
Energy-Related Contracts (B)	$	(9)	$	534	$	(6)	$	(537)	$	—

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Description	Recurring Fair Value Measurements as of December 31, 2016				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 186	$ (371)	$ 17	$ 533	$ 7
Interest Rate Swaps (C)	$ 1	$ —	$ —	$ 1	$ —
NDT Fund (D)					
Equity Securities	$ 957	$ —	$ 954	$ 3	$ —
Debt Securities—US Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 293	$ —	$ —	$ 293	$ —
Debt Securities—Corporate	$ 337	$ —	$ —	$ 337	$ —
Other Securities	$ 44	$ —	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—US Treasury	$ 37	$ —	$ —	$ 37	$ —
Debt Securities—Govt Other	$ 66	$ —	$ —	$ 66	$ —
Debt Securities—Corporate	$ 91	$ —	$ —	$ 91	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (16)	$ 372	$ (18)	$ (364)	$ (6)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ —	$ —	$ —	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—US Treasury	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Govt Other	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Corporate	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (5)	$ —	$ —	$ —	$ (5)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 186	$ (371)	$ 17	$ 533	$ 7
NDT Fund (D)					
Equity Securities	$ 957	$ —	$ 954	$ 3	$ —
Debt Securities—US Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 293	$ —	$ —	$ 293	$ —
Debt Securities—Corporate	$ 337	$ —	$ —	$ 337	$ —
Other Securities	$ 44	$ —	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—US Treasury	$ 9	$ —	$ —	$ 9	$ —

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Debt Securities—Govt Other	$	16	$	—	$	—	$	16	$	—
Debt Securities—Corporate	$	23	$	—	$	—	$	23	$	—
Other Securities	$	—	$	—	$	—	$	—	$	—
Liabilities:										
Derivative Contracts:										
Energy-Related Contracts (B)	$	(11)	$	372	$	(18)	$	(364)	$	(1)

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(A) Represents money market mutual funds.

(B) Level 1— During 2016 a net fair value of $1 million relating to energy-related contracts was transferred from Level 2 into Level 1. These contracts represent natural gas futures contracts executed on NYMEX, and are being valued solely on settled pricing inputs which come directly from the exchange.

Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using settled prices from an exchange, such as NYMEX, ICE and Nodal Exchange, or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—Unobservable inputs are used for the valuation of certain contracts. See "Additional Information Regarding Level 3 Measurements" below for more information on the utilization of unobservable inputs.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The fair value measurement tables exclude an immaterial amount of cash as of June 30, 2017 and $1 million as of December 31, 2016, which is part of the NDT Fund. The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in a Russell 3000 index fund and various fixed income securities classified as "available for sale" as of June 30, 2017. The Rabbi Trust maintained investments in a S&P 500 index fund and various securities classified as "available for sale" as of December 31, 2016. These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities include primarily investment grade corporate bonds, collateralized mortgage obligations, asset backed securities and certain government and US Treasury obligations or Federal Agency asset-backed securities and municipal bonds with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. The preferred stocks are not actively traded on a daily basis and therefore, are also priced using an evaluated pricing methodology. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of June 30, 2017, net cash collateral (received) paid of $(11) million was netted against the corresponding net derivative contract positions. Of the $(11) million as of June 30, 2017, $(13) million of cash collateral was netted against assets, and $2 million was netted against liabilities. As of December 31, 2016, net cash collateral (received) paid of $1 million was netted against the corresponding net derivative contract positions. Of the $1 million of cash collateral as of December 31, 2016, $(3) million was netted against assets, and $4 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk

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management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Corporate Governance and Audit Committees of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G, the natural gas supply contract was measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The following tables provide details surrounding significant Level 3 valuations as of June 30, 2017 and December 31, 2016.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of June 30, 2017 Assets	Fair Value as of June 30, 2017 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$ 5	$ —	Discounted Cash flow	Historic Load Variability	0% to +10%
Gas (A)	Other	1	—			
Total Power		**$ 6**	**$ —**			
Total PSEG		**$ 6**	**$ —**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2016 Assets	Fair Value as of December 31, 2016 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contract	$ —	$ (5)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ —**	**$ (5)**			
Power						
Electricity	Electric Load Contracts	$ 7	$ (1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Gas (A)	Other	—	—			
Total Power		**$ 7**	**$ (1)**			
Total PSEG		**$ 7**	**$ (6)**			

(A) Includes gas positions which were immaterial as of June 30, 2017 and December 31, 2016.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in the load variability would decrease the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months ended June 30, 2017 and June 30, 2016, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Six Months Ended June 30, 2017

	Three Months Ended June 30, 2017						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2017	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2017
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 3	$ 7	$ (1)	$ —	$ (3)	$ —	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ 1	$ —	$ (1)	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 2	$ 7	$ —	$ —	$ (3)	$ —	$ 6

	Six Months Ended June 30, 2017						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2017	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2017
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 1	$ 26	$ 5	$ —	$ (25)	$ (1)	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (5)	$ —	$ 5	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 6	$ 26	$ —	$ —	$ (25)	$ (1)	$ 6

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Six Months Ended June 30, 2016

	Three Months Ended June 30, 2016						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2016	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2016
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 21	$ 1	$ (12)	$ —	$ (5)	$ —	$ 5
PSE&G							
Net Derivative Assets (Liabilities)	$ 10	$ —	$ (12)	$ —	$ —	$ —	$ (2)
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 1	$ —	$ —	$ (5)	$ —	$ 7

	Six Months Ended June 30, 2016						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2016	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2016
PSEG							
Net Derivative Assets (Liabilities)	$ 13	$ 16	$ (4)	$ —	$ (20)	$ —	$ 5
PSE&G							
Net Derivative Assets (Liabilities)	$ 2	$ —	$ (4)	$ —	$ —	$ —	$ (2)
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 16	$ —	$ —	$ (20)	$ —	$ 7

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $7 million and $26 million in Operating Income for the three months and six months ended June 30, 2017, respectively. Of the $7 million in Operating Income, $4 million is unrealized. Of the $26 million in Operating Income, $1 million is unrealized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

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(C) Represents $(3) million and $(25) million in settlements for the three months and six months ended June 30, 2017, respectively. Represents $(5) million and $(20) million in settlements for the three months and six months ended June 30, 2016, respectively.

(D) During the three months ended June 30, 2017 there were no transfers in to or out of Level 3. During the six months ended June 30, 2017, $(1) million of net derivatives assets/liabilities were transferred from Level 2 to Level 3. There were no transfers in to or out of Level 3 during three months and six months ended June 30, 2016.

(E) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $1 million and $16 million in Operating Income for the three months and six months ended June 30, 2016, respectively. Of the $1 million in Operating Income, $(4) million is unrealized. Of the $16 million in Operating Income, $(4) million is unrealized.

As of June 30, 2017, PSEG carried $2.8 billion of net assets that are measured at fair value on a recurring basis, of which $6 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of June 30, 2016, PSEG carried $2.8 billion of net assets that are measured at fair value on a recurring basis, of which $5 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of June 30, 2017 and December 31, 2016.

	As of June 30, 2017		As of December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 1,895	$ 1,888	$ 1,195	$ 1,185
PSE&G (B)	8,242	8,900	7,818	8,240
Power - Recourse Debt (B)	2,384	2,646	2,382	2,578
Total Long-Term Debt	**$ 12,521**	**$ 13,434**	**$ 11,395**	**$ 12,003**

(A) As of June 30, 2017, fair value includes a $700 million floating rate term loan term loan in addition to the $500 million floating rate term loan and net offsets as of December 31, 2016. The fair values of the term loan debt (Level 2 measurement) were considered to be equal to the carrying values because the interest payments are based on LIBOR rates that are reset monthly.

(B) Given that most bonds do not trade, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

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Note 13. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended June 30, 2017				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 45	$ —	$ 45
Allowance for Funds Used During Construction	14	—	—	14
Rabbi Trust Realized Gains, Interest and Dividends	1	1	2	$ 4
Solar Loan Interest	5	—	—	5
Other	2	—	—	2
Total Other Income	**$ 22**	**$ 46**	**$ 2**	**$ 70**
Six Months Ended June 30, 2017				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 76	$ —	$ 76
Allowance for Funds Used During Construction	28	—	—	28
Rabbi Trust Realized Gains, Interest and Dividends	4	5	11	20
Solar Loan Interest	10	—	—	10
Other	5	3	—	8
Total Other Income	**$ 47**	**$ 84**	**$ 11**	**$ 142**
Three Months Ended June 30, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 23	$ —	$ 23
Allowance for Funds Used During Construction	10	—	—	10
Rabbi Trust Realized Gains, Interest and Dividends	1	1	1	$ 3
Solar Loan Interest	5	—	—	5
Other	3	1	(1)	3
Total Other Income	**$ 19**	**$ 25**	**$ —**	**$ 44**
Six Months Ended June 30, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 48	$ —	$ 48
Allowance for Funds Used During Construction	21	—	—	21
Rabbi Trust Realized Gains, Interest and Dividends	1	2	3	6
Solar Loan Interest	11	—	—	11
Other	6	1	(1)	6
Total Other Income	**$ 39**	**$ 51**	**$ 2**	**$ 92**

Other Deductions	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended June 30, 2017				
NDT Fund Realized Losses and Expenses	$ —	$ 6	$ —	$ 6
Other	1	1	1	3
Total Other Deductions	**$ 1**	**$ 7**	**$ 1**	**$ 9**
Six Months Ended June 30, 2017				
NDT Fund Realized Losses and Expenses	$ —	$ 13	$ —	$ 13
Other	2	1	4	7
Total Other Deductions	**$ 2**	**$ 14**	**$ 4**	**$ 20**
Three Months Ended June 30, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 8	$ —	$ 8
Other	1	1	—	2
Total Other Deductions	**$ 1**	**$ 9**	**$ —**	**$ 10**
Six Months Ended June 30, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 26	$ —	$ 26
Other	2	1	2	5
Total Other Deductions	**$ 2**	**$ 27**	**$ 2**	**$ 31**

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(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

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Note 14. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months and six months ended June 30, 2017 and 2016 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
PSEG	35.1%	32.7%	28.3%	36.2%
PSE&G	37.2%	35.4%	36.7%	36.1%
Power	39.0%	50.0%	40.0%	39.5%

For the three months and six months ended June 30, 2017, the differences in PSEG's effective tax rates as compared to the same periods in the prior year as well as to the statutory tax rate of 40.85%, were due primarily to changes in uncertain tax positions, plant and other flow-through items. For the six months ended June 30, 2017, the effective tax rate was also favorably impacted by interest from a New Jersey State income tax refund.

For the three months and six months ended June 30, 2017, the differences in PSE&G's effective tax rates as compared to the same periods in the prior year as well as to the statutory tax rate of 40.85%, were due primarily to changes in uncertain tax positions, plant and other flow-through items.

For the three months ended June 30, 2017, the differences in Power's effective tax rate as compared to the same period in the prior year as well as to the statutory tax rate of 40.85%, were due primarily to changes in uncertain tax positions, ITC and manufacturing deduction.

The Protecting Americans from Tax Hikes Act of 2015 (Tax Act) extended the 50% bonus depreciation rules for qualified property placed in service from January 1, 2015 through December 31, 2017. The rate is reduced to 40% and 30% for eligible property placed in service in 2018 and 2019, respectively. On May 8, 2017 the IRS issued guidance allowing for 50% bonus depreciation on long production property that is placed in service in 2018. For long production property placed in service in 2019, qualified costs incurred before January 1, 2019 is afforded a 40% rate, while qualified costs incurred during 2019 receives a 30% rate. For long production property placed in service in 2020, subject to a written binding contract entered into before 2020, a 30% rate is allowed for qualified costs incurred before January 1, 2020, with a 0% rate thereafter. The Tax Act also extended the 30% ITC for qualified property placed in service starting January 1, 2016 through December 31, 2019 but reduces the ITC rate to 26% and 22% for projects commenced in 2020 and 2021, respectively. The financial impact of the extensions of the ITC rate will depend upon future transactions.

This provision has generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period. However, these tax benefits will have a negative impact on the rate base of several of PSE&G's programs.

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Note 15. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended June 30, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2017	$ 2	$ (392)	$ 148	$ (242)
Other Comprehensive Income before Reclassifications	—	—	23	23
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	6	(13)	(7)
Net Current Period Other Comprehensive Income (Loss)	—	6	10	16
Balance as of June 30, 2017	**$ 2**	**$ (386)**	**$ 158**	**$ (226)**

PSEG	Other Comprehensive Income (Loss) Three Months Ended June 30, 2016			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2016	$ 2	$ (378)	$ 107	$ (269)
Other Comprehensive Income before Reclassifications	(1)	—	8	7
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	8	2	10
Net Current Period Other Comprehensive Income (Loss)	(1)	8	10	17
Balance as of June 30, 2016	**$ 1**	**$ (370)**	**$ 117**	**$ (252)**

PSEG	Other Comprehensive Income (Loss) Six Months Ended June 30, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2016	$ 2	$ (398)	$ 133	$ (263)
Other Comprehensive Income before Reclassifications	—	—	53	53
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	12	(28)	(16)
Net Current Period Other Comprehensive Income (Loss)	—	12	25	37
Balance as of June 30, 2017	**$ 2**	**$ (386)**	**$ 158**	**$ (226)**

PSEG	Other Comprehensive Income (Loss) Six Months Ended June 30, 2016			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2015	$ —	$ (386)	$ 91	$ (295)
Other Comprehensive Income before Reclassifications	1	—	18	19
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	16	8	24
Net Current Period Other Comprehensive Income (Loss)	1	16	26	43
Balance as of June 30, 2016	**$ 1**	**$ (370)**	**$ 117**	**$ (252)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2017			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2017	$ —	$ (335)	$ 148	$ (187)
Other Comprehensive Income before Reclassifications	—	—	22	22
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	5	(12)	(7)
Net Current Period Other Comprehensive Income (Loss)	—	5	10	15
Balance as of June 30, 2017	**$ —**	**$ (330)**	**$ 158**	**$ (172)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2016			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2016	$ —	$ (320)	$ 103	$ (217)
Other Comprehensive Income before Reclassifications	—	—	6	6
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	3	10
Net Current Period Other Comprehensive Income (Loss)	—	7	9	16
Balance as of June 30, 2016	**$ —**	**$ (313)**	**$ 112**	**$ (201)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2017			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2016	$ —	$ (340)	$ 129	$ (211)
Other Comprehensive Income before Reclassifications	—	—	50	50
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	10	(21)	(11)
Net Current Period Other Comprehensive Income (Loss)	—	10	29	39
Balance as of June 30, 2017	**$ —**	**$ (330)**	**$ 158**	**$ (172)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2016			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2015	$ —	$ (327)	$ 87	$ (240)
Other Comprehensive Income before Reclassifications	—	—	16	16
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	14	9	23
Net Current Period Other Comprehensive Income (Loss)	—	14	25	39
Balance as of June 30, 2016	**$ —**	**$ (313)**	**$ 112**	**$ (201)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2017			Six Months Ended June 30, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 2	$ (1)	$ 1	$ 4	$ (2)	$ 2
Amortization of Actuarial Loss	O&M Expense	(12)	5	(7)	(24)	10	(14)
Total Pension and OPEB Plans		(10)	4	(6)	(20)	8	(12)
Available-for-Sale Securities							
Realized Gains	Other Income	34	(17)	17	70	(34)	36
Realized Losses	Other Deductions	(6)	4	(2)	(13)	7	(6)
OTTI	OTTI	(3)	1	(2)	(4)	2	(2)
Total Available-for-Sale Securities		25	(12)	13	53	(25)	28
Total		**$ 15**	**$ (8)**	**$ 7**	**$ 33**	**$ (17)**	**$ 16**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2016			Six Months Ended June 30, 2016		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 3	$ (1)	$ 2	$ 6	$ (2)	$ 4
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)	(34)	14	(20)
Total Pension and OPEB Plans		(14)	6	(8)	(28)	12	(16)
Available-for-Sale Securities							
Realized Gains	Other Income	12	(6)	6	28	(14)	14
Realized Losses	Other Deductions	(7)	4	(3)	(24)	12	(12)
OTTI	OTTI	(10)	5	(5)	(20)	10	(10)
Total Available-for-Sale Securities		(5)	3	(2)	(16)	8	(8)
Total		**$ (19)**	**$ 9**	**$ (10)**	**$ (44)**	**$ 20**	**$ (24)**

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Power

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2017			Six Months Ended June 30, 2017		
		Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 2	$ (1)	$ 1	$ 4	$ (2)	$ 2
Amortization of Actuarial Loss	O&M Expense	(10)	4	(6)	(21)	9	(12)
Total Pension and OPEB Plans		(8)	3	(5)	(17)	7	(10)
Available-for-Sale Securities							
Realized Gains	Other Income	32	(16)	16	57	(29)	28
Realized Losses	Other Deductions	(5)	3	(2)	(10)	5	(5)
OTTI	OTTI	(3)	1	(2)	(4)	2	(2)
Total Available-for-Sale Securities		24	(12)	12	43	(22)	21
Total		**$ 16**	**$ (9)**	**$ 7**	**$ 26**	**$ (15)**	**$ 11**

Power

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2016			Six Months Ended June 30, 2016		
		Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 2	$ (1)	$ 1	$ 5	$ (2)	$ 3
Amortization of Actuarial Loss	O&M Expense	(14)	6	(8)	(29)	12	(17)
Total Pension and OPEB Plans		(12)	5	(7)	(24)	10	(14)
Available-for-Sale Securities							
Realized Gains	Other Income	10	(5)	5	25	(13)	12
Realized Losses	Other Deductions	(6)	3	(3)	(22)	11	(11)
OTTI	OTTI	(10)	5	(5)	(20)	10	(10)
Total Available-for-Sale Securities		(6)	3	(3)	(17)	8	(9)
Total		**$ (18)**	**$ 8**	**$ (10)**	**$ (41)**	**$ 18**	**$ (23)**

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Note 16. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2017		2016		2017		2016	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions):								
Net Income	**$ 109**	**$ 109**	**$ 187**	**$ 187**	**$ 223**	**$ 223**	**$ 658**	**$ 658**
EPS Denominator (Millions):								
Weighted Average Common Shares Outstanding	505	505	505	505	505	505	505	505
Effect of Stock Based Compensation Awards	—	2	—	3	—	2	—	3
Total Shares	**505**	**507**	**505**	**508**	**505**	**507**	**505**	**508**
EPS								
Net Income	**$ 0.22**	**$ 0.22**	**$ 0.37**	**$ 0.37**	**$ 0.44**	**$ 0.44**	**$ 1.30**	**$ 1.30**

There were approximately 0.3 million of stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for each of the three month and six month periods ended June 30, 2017 and June 30, 2016.

Dividends

	Three Months Ended June 30,		Six Months Ended June 30,	
Dividend Payments on Common Stock	2017	2016	2017	2016
Per Share	$ 0.43	$ 0.41	$ 0.86	$ 0.82
In Millions	$ 217	$ 208	$ 435	$ 415

On July 18, 2017, PSEG's Board of Directors approved a $0.43 per share common stock dividend for the third quarter of 2017.

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Note 17. Financial Information by Business Segment

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Three Months Ended June 30, 2017					
Total Operating Revenues	$ 1,368	$ 929	$ 116	$ (280)	$ 2,133
Net Income (Loss)	208	(97)	(2)	—	109
Gross Additions to Long-Lived Assets	641	269	9	—	919
Six Months Ended June 30, 2017					
Operating Revenues	$ 3,180	$ 2,213	$ 199	$ (867)	$ 4,725
Net Income (Loss)	507	(267)	(17)	—	223
Gross Additions to Long-Lived Assets	1,389	576	16	—	1,981
Three Months Ended June 30, 2016					
Total Operating Revenues	$ 1,350	$ 714	$ 127	$ (286)	$ 1,905
Net Income (Loss)	179	(11)	19	—	187
Gross Additions to Long-Lived Assets	631	265	10	—	906
Six Months Ended June 30, 2016					
Operating Revenues	$ 3,062	$ 2,027	$ 249	$ (817)	$ 4,521
Net Income (Loss)	441	181	36	—	658
Gross Additions to Long-Lived Assets	1,355	598	18	—	1,971
As of June 30, 2017					
Total Assets	$ 27,273	$ 11,619	$ 2,425	$ (793)	$ 40,524
Investments in Equity Method Subsidiaries	$ —	$ 91	$ —	$ —	$ 91
As of December 31, 2016					
Total Assets	$ 26,288	$ 12,193	$ 2,373	$ (784)	$ 40,070
Investments in Equity Method Subsidiaries	$ —	$ 102	$ —	$ —	$ 102

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations relate primarily to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 18. Related-Party Transactions.

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Note 18. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	Millions			
Billings from Affiliates:				
Net Billings from Power primarily through BGS and BGSS (A)	$ 296	$ 297	$ 895	$ 842
Administrative Billings from Services (B)	79	82	144	151
Total Billings from Affiliates	**$ 375**	**$ 379**	**$ 1,039**	**$ 993**

Related-Party Transactions	As of June 30, 2017	As of December 31, 2016
	Millions	
Receivables from PSEG (C)	**$ 20**	**$ 76**
Payable to Power (A)	$ 90	$ 193
Payable to Services (B)	56	67
Accounts Payable—Affiliated Companies	**$ 146**	**$ 260**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 115**	**$ 130**

Power

The financial statements for Power include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	Millions			
Billings to Affiliates:				
Net Billings to PSE&G primarily through BGS and BGSS (A)	**$ 296**	**$ 297**	**$ 895**	**$ 842**
Billings from Affiliates:				
Administrative Billings from Services (B)	**$ 42**	**$ 45**	**$ 78**	**$ 90**

Related-Party Transactions	As of June 30, 2017	As of December 31, 2016
	Millions	
Receivables from PSE&G (A)	$ 90	$ 193
Receivables from PSEG (C)	49	12
Accounts Receivable—Affiliated Companies	**$ 139**	**$ 205**
Payable to Services (B)	$ 20	$ 25
Accounts Payable—Affiliated Companies	**$ 20**	**$ 25**
Short-Term Loan Due (to) from Affiliate (E)	**$ 233**	**$ 87**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 93**	**$ 77**

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(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. In addition, Power and PSE&G provide certain technical services for each other generally at cost in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

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Note 19. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries, as of June 30, 2017 and December 31, 2016 and for the three months and six months ended June 30, 2017 and 2016.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended June 30, 2017					
Operating Revenues	$ —	$ 910	$ 47	$ (28)	$ 929
Operating Expenses	(2)	1,103	43	(28)	1,116
Operating Income (Loss)	2	(193)	4	—	(187)
Equity Earnings (Losses) of Subsidiaries	(93)	(4)	5	97	5
Other Income	22	56	2	(34)	46
Other Deductions	—	(7)	—	—	(7)
Other-Than-Temporary Impairments	—	(3)	—	—	(3)
Interest Expense	(34)	(9)	(4)	34	(13)
Income Tax Benefit (Expense)	6	60	(4)	—	62
Net Income (Loss)	**$ (97)**	**$ (100)**	**$ 3**	**$ 97**	**$ (97)**
Comprehensive Income (Loss)	**$ (82)**	**$ (91)**	**$ 3**	**$ 88**	**$ (82)**
Six Months Ended June 30, 2017					
Operating Revenues	$ —	$ 2,180	$ 99	$ (66)	$ 2,213
Operating Expenses	2	2,672	95	(66)	2,703
Operating Income (Loss)	(2)	(492)	4	—	(490)
Equity Earnings (Losses) of Subsidiaries	(254)	(5)	8	259	8
Other Income	47	97	2	(62)	84
Other Deductions	(1)	(13)	—	—	(14)
Other-Than-Temporary Impairments	—	(4)	—	—	(4)
Interest Expense	(64)	(18)	(9)	62	(29)
Income Tax Benefit (Expense)	7	171	—	—	178
Net Income (Loss)	**$ (267)**	**$ (264)**	**$ 5**	**$ 259**	**$ (267)**
Comprehensive Income (Loss)	**$ (228)**	**$ (234)**	**$ 5**	**$ 229**	**$ (228)**
Six Months Ended June 30, 2017					
Net Cash Provided By (Used In) Operating Activities	$ (32)	$ 802	$ 111	$ 51	$ 932
Net Cash Provided By (Used In) Investing Activities	$ 683	$ 178	$ (241)	$ (1,355)	$ (735)
Net Cash Provided By (Used In) Financing Activities	$ (651)	$ (978)	$ 146	$ 1,304	$ (179)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended June 30, 2016					
Operating Revenues	$ —	$ 700	$ 46	$ (32)	$ 714
Operating Expenses	2	716	40	(32)	726
Operating Income (Loss)	(2)	(16)	6	—	(12)
Equity Earnings (Losses) of Subsidiaries	(1)	1	4	—	4
Other Income	17	30	—	(22)	25
Other Deductions	—	(9)	—	—	(9)
Other-Than-Temporary Impairments	—	(10)	—	—	(10)
Interest Expense	(31)	(7)	(4)	22	(20)
Income Tax Benefit (Expense)	6	3	2	—	11
Net Income (Loss)	**$ (11)**	**$ (8)**	**$ 8**	**$ —**	**$ (11)**
Comprehensive Income (Loss)	**$ 5**	**$ 1**	**$ 8**	**$ (9)**	**$ 5**
Six Months Ended June 30, 2016					
Operating Revenues	$ —	$ 2,002	$ 88	$ (63)	$ 2,027
Operating Expenses	12	1,668	79	(63)	1,696
Operating Income (Loss)	(12)	334	9	—	331
Equity Earnings (Losses) of Subsidiaries	204	—	6	(204)	6
Other Income	34	62	—	(45)	51
Other Deductions	—	(27)	—	—	(27)
Other-Than-Temporary Impairments	—	(20)	—	—	(20)
Interest Expense	(61)	(17)	(9)	45	(42)
Income Tax Benefit (Expense)	16	(137)	3	—	(118)
Net Income (Loss)	**$ 181**	**$ 195**	**$ 9**	**$ (204)**	**$ 181**
Comprehensive Income (Loss)	**$ 220**	**$ 220**	**$ 9**	**$ (229)**	**$ 220**
Six Months Ended June 30, 2016					
Net Cash Provided By (Used In) Operating Activities	$ 337	$ 777	$ 159	$ (356)	$ 917
Net Cash Provided By (Used In) Investing Activities	$ (1,287)	$ (504)	$ (395)	$ 579	$ (1,607)
Net Cash Provided By (Used In) Financing Activities	$ 951	$ (273)	$ 239	$ (223)	$ 694

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
As of June 30, 2017					
Current Assets	$ 4,156	$ 1,257	$ 182	$ (4,213)	$ 1,382
Property, Plant and Equipment, net	56	5,244	2,526	—	7,826
Investment in Subsidiaries	4,015	340	—	(4,355)	—
Noncurrent Assets	184	2,225	119	(117)	2,411
Total Assets	**$ 8,411**	**$ 9,066**	**$ 2,827**	**$ (8,685)**	**$ 11,619**
Current Liabilities	$ 88	$ 3,156	$ 1,648	$ (4,213)	$ 679
Noncurrent Liabilities	543	2,195	539	(117)	3,160
Long-Term Debt	2,384	—	—	—	2,384
Member's Equity	5,396	3,715	640	(4,355)	5,396
Total Liabilities and Member's Equity	**$ 8,411**	**$ 9,066**	**$ 2,827**	**$ (8,685)**	**$ 11,619**
As of December 31, 2016					
Current Assets	$ 4,412	$ 1,593	$ 152	$ (4,697)	$ 1,460
Property, Plant and Equipment, net	55	6,145	2,320	—	8,520
Investment in Subsidiaries	4,249	344	—	(4,593)	—
Noncurrent Assets	168	2,016	129	(100)	2,213
Total Assets	**$ 8,884**	**$ 10,098**	**$ 2,601**	**$ (9,390)**	**$ 12,193**
Current Liabilities	$ 171	$ 3,752	$ 1,454	$ (4,697)	$ 680
Noncurrent Liabilities	532	2,398	502	(100)	3,332
Long-Term Debt	2,382	—	—	—	2,382
Member's Equity	5,799	3,948	645	(4,593)	5,799
Total Liabilities and Member's Equity	**$ 8,884**	**$ 10,098**	**$ 2,601**	**$ (9,390)**	**$ 12,193**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU, and
- **Power**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses through competitive energy sales in well-developed energy markets and fuel supply functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) electric transmission and distribution (T&D) system under an Operations and Services Agreement contractual agreement; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Our business discussion in Part I, Item 1. Business of our 2016 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2016 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2017 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2016 Form 10-K.

EXECUTIVE OVERVIEW OF 2017 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- improving utility operations through investment in T&D and other infrastructure projects designed to enhance system reliability and resiliency and to meet customer expectations and public policy objectives,
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the three months and six months ended June 30, 2017 and 2016 are presented as follows:

Earnings (Losses)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	Millions			
PSE&G	$ 208	$ 179	$ 507	$ 441
Power (A)	(97)	(11)	(267)	181
Other (B)	(2)	19	(17)	36
PSEG Net Income	**$ 109**	**$ 187**	**$ 223**	**$ 658**
PSEG Net Income Per Share (Diluted)	**$ 0.22**	**$ 0.37**	**$ 0.44**	**$ 1.30**

(A) Includes after-tax expenses of $229 million and $563 million in the three months and six months ended June 30, 2017, respectively, primarily for accelerated depreciation related to the early retirement of Power's Hudson and Mercer coal/gas generation plants. See Item 1. Note 3. Early Plant Retirements for additional information.

(B) Other includes after-tax activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations. Energy Holdings recorded after-tax charges of $13 million and $45 million related to its investments in NRG REMA, LLC's leveraged leases in the three months and six months ended June 30, 2017, respectively. See Item 1. Note 6. Financing Receivables for additional information.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with future delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	Millions, after tax			
NDT Fund Income (Expense) (A) (B)	$ 14	$ (1)	$ 22	$ (6)
Non-Trading MTM Gains (Losses) (C)	$ 21	$ (101)	$ 27	$ (88)

(A) NDT Fund Income (Expense) includes the realized gains and losses, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization (D&A) Expense.

(B) Net of tax (expense) benefit of $(16) million, $(1) million, $(25) million and $2 million for the three and six months ended June 30, 2017 and 2016, respectively.

(C) Net of tax (expense) benefit of $(15) million $70 million, $(19) million and $61 million for the three and six months ended June 30, 2017 and 2016, respectively.

Our $78 million and $435 million decreases in Net Income for the three months and six months ended June 30, 2017, respectively, were driven primarily by

- accelerated depreciation related to the early retirement of our Hudson and Mercer coal/gas generation units at Power (see Item 1. Note 3. Early Plant Retirements), and
- charges related to leveraged lease investments (see Item 1. Note 6. Financing Receivables).

These decreases were partially offset by

- MTM gains in 2017 as compared to MTM losses in 2016,

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- higher transmission revenues, and
- higher realized gains in the NDT Fund.

During the first six months of 2017, we maintained a strong balance sheet. We continued to effectively deploy capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results, which when combined with the cash flow generated by Power, our merchant generator and power marketer, has allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, we continue to invest in transmission projects that focus on reliability improvements and replacement of aging infrastructure, including our $275 million Newark Switch project that was approved by PJM in July 2017. We also continue to make investments to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the BPU in 2014 and to seek recovery on such investments. We also continue to modernize PSE&G's gas distribution systems as part of our Gas System Modernization Program (GSMP) that was approved by the BPU in late 2015. Over the past few years, these types of investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G.

As a result of our Energy Strong Order from the BPU, we will be required to file a distribution base rate case proceeding by no later than November 1, 2017. The case will provide PSE&G with the opportunity to reset assumptions on sales and O&M growth as well as provide the opportunity to recover investments not recognized in various clause mechanisms since our last base rate proceeding in 2010, and to recover prior approved storm costs. PSE&G, as part of the filing, will also request approval for a de-coupling of electric revenue from sales. We cannot predict when the distribution base rate will be approved by the BPU and the impact this proceeding will have on our distribution business.

In July, we filed for a petition with the BPU for GSMP II, a five-year extension of GSMP, which would accelerate the pace of replacement of our aging cast iron and unprotected steel mains and associated service. We proposed to invest up to $540 million per year over this five-year program beginning in 2019. In July, we also reached an agreement in principle with the BPU Staff and Rate Counsel for an extension of our Energy Efficiency program. For additional information, see Part II, Item 5. Other Information.

Although the weather in the first three months of 2017 was warmer than normal, Power's results saw a continuing benefit from access to natural gas supplies through existing firm pipeline transportation contracts. Power manages these contracts for the benefit of PSE&G's customers through the BGSS arrangement. The contracts are sized to provide for delivery of a reliable gas supply to PSE&G customers on peak winter demand days. When pipeline capacity beyond the customers' needs is available, Power can use it to make third-party sales and if excess volume remains after the third-party sales, supply gas to its generating units in New Jersey. Alternatively, gas supply and pipeline capacity constraints could adversely impact our ability to meet the needs of our utility customers and generating units.

Power's hedging practices and ability to capitalize on market opportunities help it to balance some of the volatility of the merchant power business. Power's hedging program in combination with expected revenues from the capacity market mechanisms and certain ancillary service payments, such as reactive power, has secured approximately 60% of its estimated gross margin for the 2017-2019 period.

Our investments in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to improve our financial performance.

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced as being at risk for early retirement. This situation is generally due to low natural gas prices, and the related decline in market prices of energy, resulting from the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities and both federal and state-level policies that provide financial incentives to renewable energy such as wind and solar, but generally do not apply to nuclear generating stations. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

If trends noted above continue or worsen, our nuclear generating units could cease being economically competitive which may cause us to retire such units prior to the end of their useful lives. The costs associated with any such potential retirement, which may include, among other things, accelerated D&A or impairment charges, accelerated asset retirement costs, severance costs,

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environmental remediation costs, and additional funding of nuclear decommissioning trust funds would likely have a material adverse impact on future financial results. We continue to advocate for sound policies that recognize nuclear power as a source of reliable and air emissions free energy and an important part of a diverse and reliable energy portfolio. See Item 1. Note 3. Early Plant Retirements for additional information.

A number of states have either taken action or are investigating the situation faced by nuclear generating units. Recently, courts in Illinois and New York upheld challenges to the programs which established zero emissions credits (ZECs), recognizing the importance of nuclear units for providing air emissions free energy.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission

In April 2017, the PJM Board announced that it would be lifting the previously disclosed suspension of the Artificial Island transmission project and approved the award to PSE&G of the construction of necessary upgrade work at a cost of approximately $130 million. Also, in April 2017, PJM submitted a proposal to FERC concerning the cost responsibility assigned to certain entities, including PSE&G, for the Artificial Island project.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey. In addition, as a basic generation service (BGS) supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers may be entitled to recovery, subject to BPU approval. We do not believe that these matters will have a material effect on Power's business or results of operations.

Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base return on equity (ROE). Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. The results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. The CP product was implemented fully in the May 2017 RPM auction for the 2020-2021 Delivery Year. Subsequent to its implementation, FERC approved changes to the CP construct that will enhance the participation of intermittent and demand response resources (seasonal resources). However, two complaints remain pending that ask FERC to investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions.

In May 2017, PJM announced the results of the RPM capacity auction for the 2020-2021 delivery year. Power cleared approximately 7,800 MW of its generating capacity at an average price of $174 per MW-day for the 2020-2021 delivery period. In the two prior capacity auctions covering the 2019-2020 and 2018-2019 delivery years, Power cleared approximately 8,900 MW at an average price of $116 and approximately 8,700 MW at an average price of $215 per MW-day, respectively. Prices in the most recent auction reflect PJM's downwardly-revised demand forecast, changes in the emergency transfer limits due to transmission expansion and the effects of both the new generation and uncleared generation from the prior year's auction.

As a result of the efforts of certain entities in PJM to obtain financial support arrangements from their state commissions, a group of suppliers requested that FERC direct PJM to expand the currently effective "minimum offer price rule" to apply to certain existing units seeking subsidies. The suppliers' request was intended to avoid a scenario where the subsidized generators would submit bids into the PJM capacity market that did not reflect their actual costs of operation and could artificially suppress capacity market prices. We are currently awaiting FERC action on the suppliers' request and cannot predict the outcome of the proceeding.

Distribution

In June 2017, the BPU issued proposed Infrastructure Investment Program (IIP) regulations that would allow utilities to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to support the provision of safe and adequate service. Under the proposed regulations, utilities could seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the

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IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing infrastructure that enhances reliability, resiliency, and/or safety. The proposed regulations will be subject to comment from interested parties.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act (FWPCA) requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs.

In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the New Source Performance Standards, which establish emissions standards for CO_2 for certain new fossil power plants, and the Clean Power Plan, a greenhouse gas emissions regulation under the Clean Air Act for existing power plants that establishes state-specific emission rate targets based on implementation of the best system of emission reduction. Upon completion of the review, the EPA is expected to suspend, revise or rescind the rules as appropriate.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above as well as other matters that may impact our financial condition and results of operations, see Item 1. Note 9. Commitments and Contingent Liabilities.

FERC Compliance

Since September 2014, FERC Staff has been conducting a preliminary non-public investigation regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units. While considerable uncertainty remains as to the final resolution of these matters, based upon developments in the investigation in the first quarter of 2017, Power believes the disgorgement and interest costs related to the cost-based bidding matter may range between approximately $35 million and $135 million, depending on the legal interpretation of the principles under the PJM Tariff, plus penalties. Since no point within this range is more likely than any other, Power has accrued the low end of this range of $35 million by recording an additional pre-tax charge to income of $10 million during the three months ended March 31, 2017. PSEG is unable to reasonably estimate the range of possible loss, if any, for the quantity of energy offered matter or the penalties that FERC would impose relating to either the cost-based bidding or quantity of energy matter. However, any of these amounts could be individually material to PSEG and Power. We cannot predict the final outcome of these matters. For additional information, see Item 1. Note 9. Commitments and Contingent Liabilities.

Early Retirement of Hudson and Mercer Units

On June 1, 2017, Power completed its previously announced retirement of the generation operations of the existing coal/gas units at the Hudson and Mercer generating stations. The decision to retire the Hudson and Mercer units had a material effect on PSEG's and Power's results of operations in 2016 and continues to adversely impact their results of operations in 2017. During the first six months of 2017, Power recognized incremental D&A of $938 million ($964 million in total) due to the significant shortening of the expected economic useful lives of Hudson and Mercer. During the first half of 2017, Energy Costs of $9 million and O&M of $4 million were also incurred and other costs may be incurred during the remaining period in 2017. See Item 1. Note 3. Early Plant Retirements for additional information.

Power currently anticipates using the sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such remediation are neither currently probable nor estimable but may be material.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or

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capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Leveraged Lease Portfolio

GenOn Energy, Inc. (GenOn), the parent company of NRG REMA LLC, (REMA), and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code on June 14, 2017. REMA was not included in the GenOn bankruptcy filing. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's efforts to restructure its balance sheet and improve its liquidity. We continue to monitor the restructuring of GenOn and the possible related impact on REMA.

During the first quarter of 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as discussions with REMA management, Energy Holdings recorded an additional $55 million pre-tax charge for its current best estimate of loss relating to its REMA leveraged lease receivables, which was reflected in Operating Revenues. During the second quarter of 2017, Energy Holdings recorded an additional $22 million pre-tax charge for its current best estimate of loss related to lease receivables due to collectability of payments ($15 million) and economics impacting the residual value ($7 million) of certain leased assets. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments, which could include further write-downs of the values of Energy Holdings' leveraged lease receivables. For additional information, see Item 1. Note 6. Financing Receivables. There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.

Additional facilities in our leveraged lease portfolio include the Joliet and Powerton generating facilities. Similar to Shawville, Joliet was recently converted to use natural gas. Converted natural gas units such as Shawville and Joliet may have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units. Powerton is a coal-fired generating facility in Illinois. Each of these three facilities may not be as economically competitive as newer combined cycle gas units and could continue to be adversely impacted by the same economic conditions experienced by other less efficient natural gas and coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged lease receivables associated with these facilities.

Salem

Concurrently with the planned refueling outage at the Salem 2 unit that was conducted in the second quarter of 2017, we inspected and replaced baffle bolts as part of our strategy to replace baffle bolts at the Salem station. The unit was returned to service in June 2017.

Operational Excellence

We emphasize operational performance, exercising diligence in managing costs, while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of opportunities in a rapidly evolving market. For the first six months of 2017, our

- our utility continued top decile performance in electric reliability,
- total nuclear fleet achieved an average capacity factor of 95%,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 26 terawatt hours, and
- combined cycle fleet produced seven terawatt hours at an equivalent availability factor of 92%.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first six months of 2017 as we

- maintained sufficient liquidity,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2017 to $1.72 per share.

We expect to be able to fund our planned capital requirements without the issuance of new equity.

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Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first six months of 2017, we

- made additional investments in transmission infrastructure projects,
- continued to execute our GSMP, Energy Strong and other existing BPU-approved utility programs, and
- continued construction of our Keys and Sewaren 7 generation projects for targeted commercial operation in 2018 and began construction of BH5 for targeted commercial operations in mid-2019.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a cost-constrained environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions in response to changes in demand,
- successfully launch and grow our retail energy business, which complements our existing wholesale energy business,
- execute our utility capital investment program, including our Energy Strong program, GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction and start-up of our Keys, Sewaren 7, BH5 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

For 2017 and beyond, the key issues, challenges and opportunities we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- fair and timely rate relief from the BPU and FERC for recovery of costs and return on investments, including with respect to our distribution base rate case proceeding to be filed in 2017,
- the potential for comprehensive tax reform, particularly in light of public statements by the current U.S. administration and key members of Congress,
- uncertainty in the national and regional economic performance, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate,
- the impact of lower natural gas prices and increasing environmental compliance costs on the competitiveness of our nuclear and remaining coal-fired generation plants, and the potential for retirement of such plants earlier than their current useful lives,
- ensuring timely completion of construction of our T&D, generation and other development projects, including obtaining required permits and regulatory approvals,
- maintaining a diverse mix of fuels to mitigate risks associated with fuel price volatility and market demand cycles, and

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- FERC Staff's continuing investigation of certain of Power's New Jersey fossil generating unit bids in the PJM energy market.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of transmission and distribution facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses,
- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency, modernizing existing infrastructure and participation in transmission projects through FERC's "open window" solicitation process.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 18. Related-Party Transactions.

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2017	2016	2017 vs. 2016		2017	2016	2017 vs. 2016	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,133	$ 1,905	$ 228	12	$ 4,725	$ 4,521	$ 204	5
Energy Costs	588	624	(36)	(6)	1,462	1,460	2	—
Operation and Maintenance	708	710	(2)	—	1,420	1,439	(19)	(1)
Depreciation and Amortization	641	224	417	N/A	1,469	448	1,021	N/A
Income from Equity Method Investments	5	4	1	25	8	6	2	33
Other Income (Deductions)	61	34	27	79	122	61	61	100
Other-Than-Temporary Impairments	3	10	(7)	(70)	4	20	(16)	(80)
Interest Expense	91	97	(6)	(6)	189	189	—	—
Income Tax Expense	59	91	(32)	(35)	88	374	(286)	(76)

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

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PSE&G

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2017	2016	2017 vs. 2016		2017	2016	2017 vs. 2016	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,368	$ 1,350	$ 18	1	$ 3,180	$ 3,062	$ 118	4
Energy Costs	472	529	(57)	(11)	1,225	1,258	(33)	(3)
Operation and Maintenance	351	352	(1)	—	718	734	(16)	(2)
Depreciation and Amortization	166	136	30	22	337	275	62	23
Other Income (Deductions)	21	18	3	17	45	37	8	22
Interest Expense	69	74	(5)	(7)	144	142	2	1
Income Tax Expense	123	98	25	26	294	249	45	18

Three Months Ended June 30, 2017 as Compared to 2016

Operating Revenues increased $18 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $54 million due primarily to an increase in transmission revenues.

- Transmission revenues were $45 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.
- Electric distribution revenues increased $8 million due to a $6 million increase from the inclusion of Energy Strong in base rates and a $7 million increase due to higher sales volumes, partially offset by lower Green Program Recovery Charges (GPRC) of $5 million.
- Gas distribution revenues increased $1 million due to $6 million in higher Weather Normalization Clause (WNC) revenue, a $2 million increase from the inclusion of Energy Strong in base rates, and $1 million increases in both GSMP collections and GPRC. These increases were almost entirely offset by lower sales volumes.

Commodity Revenue decreased $57 million as a result of lower Electric and Gas revenues. The changes in Commodity revenue for both electric and gas are entirely offset by the changes in Energy Costs. PSE&G earns no margin on the provision of BGS and basic gas supply service (BGSS) to retail customers.

- Electric commodity revenues decreased $40 million due primarily to an $18 million decrease in BGS revenues due to lower sales volumes and prices, $18 million of lower revenues from collections of Non-Utility Generation Charges (NGC) and a decrease of $4 million due to lower volumes of Non-Utility Generation (NUG) energy sold.
- Gas commodity revenues decreased $17 million due to lower BGSS sales volumes of $24 million partially offset by higher BGSS sales prices of $7 million.

Clause Revenues increased $19 million due primarily to the return in 2016 to customers of $15 million of overcollections of Securitization Transition Charges (STC) and a $7 million increase in 2017 in Margin Adjustment Clause (MAC) revenues, partially offset by lower Societal Benefit Charges (SBC) of $3 million. The changes in the STC, MAC and SBC amounts are entirely offset by changes in the amortization of Regulatory Assets and Regulatory Liabilities and related costs in O&M, D&A and Interest Expense. PSE&G does not earn margin on STC, MAC or SBC collections.

Operating Expenses

Energy Costs decreased $57 million. This is entirely offset by the change in Commodity Revenue.

Operation and Maintenance decreased $1 million, primarily due to $6 million of lower distribution corrective and preventative maintenance, partially offset by a $5 million increase in transmission maintenance.

Depreciation and Amortization increased $30 million due primarily to an increase of $15 million in amortization of Regulatory Assets and a $14 million increase in depreciation due to additional plant in service.

Other Income and (Deductions) increased $3 million due primarily to an increase in Allowance for Funds Used During Construction (AFUDC).

Interest Expense decreased $5 million due primarily to a $9 million decrease predominantly driven by a reduction in clause interest. This decrease was partially offset by an increase of $4 million due to net debt issuances in 2016 and 2017.

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Income Tax Expense increased $25 million due primarily to higher pre-tax income.

Six Months Ended June 30, 2017 as Compared to 2016

Operating Revenues increased $118 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $112 million due primarily to an increase in transmission revenues.

- Transmission revenues were $82 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.
- Gas distribution revenues increased $25 million due to a $13 million increase due to the inclusion of Energy Strong in base rates, $8 million in higher WNC revenue, a $6 million increase due to the GSMP and higher GPRC of $2 million partially offset by $4 million of lower delivery volumes.
- Electric distribution revenues increased $5 million due to an $8 million increase due to the inclusion of Energy Strong in base rates and a $5 million increase due to higher sales volumes, partially offset by lower GPRC of $8 million.

Commodity Revenue decreased $33 million as a result of lower Electric revenues partially offset by higher Gas revenues. The changes in Commodity revenue for both electric and gas are entirely offset by the changes in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric commodity revenues decreased $90 million due primarily to $41 million of lower revenues from collections of NGC, a $35 million decrease in BGS revenues due to lower sales prices and volumes and a decrease of $14 million due to lower volumes of NUG energy sold.
- Gas commodity revenues increased $57 million due primarily to higher BGSS sales prices.

Clause Revenues increased $38 million due primarily to the 2016 return to customers of $30 million of overcollections of STC, and higher MAC revenues of $8 million in 2017. The changes in the STC and MAC amounts are entirely offset by increase in the amortization of Regulatory Assets and Regulatory Liabilities and related costs in O&M, D&A and Interest Expense. PSE&G does not earn margin on STC or MAC collections.

Operating Expenses

Energy Costs decreased $33 million. This is entirely offset by the change in Commodity Revenue.

Operation and Maintenance decreased $16 million, of which the most significant components were decreases of

- $10 million in distribution corrective and preventative maintenance,
- $8 million in appliance service costs,
- $6 million in gas bad debt and
- $4 million in pension and other postretirement benefit costs, net of capitalized amounts, partially offset by
- a $6 million increase in transmission maintenance costs and
- a $6 million net increase in operational expenses.

Depreciation and Amortization increased $62 million due primarily to an increase of $32 million in amortization of Regulatory Assets and a $29 million increase in depreciation due to additional plant in service.

Other Income and (Deductions) increased $8 million due primarily to an increase of $7 million in AFUDC and a $3 million increase in realized gains on Rabbi Trust investments, partially offset by a net $2 million decrease in Solar Loan interest.

Interest Expense increased $2 million due primarily to an increase of $11 million due to net debt issuances in 2016 and 2017, partially offset by $8 million decrease predominantly driven by a reduction in clause interest.

Income Tax Expense increased $45 million due primarily to higher pre-tax income.

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Power

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2017	2016	2017 vs. 2016		2017	2016	2017 vs. 2016	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 929	$ 714	$ 215	30	$ 2,213	$ 2,027	$ 186	9
Energy Costs	397	381	16	4	1,104	1,019	85	8
Operation and Maintenance	254	265	(11)	(4)	484	518	(34)	(7)
Depreciation and Amortization	465	80	385	N/A	1,115	159	956	N/A
Income from Equity Method Investments	5	4	1	25	8	6	2	33
Other Income (Deductions)	39	16	23	N/A	70	24	46	N/A
Other-Than-Temporary Impairments	3	10	(7)	(70)	4	20	(16)	(80)
Interest Expense	13	20	(7)	(35)	29	42	(13)	(31)
Income Tax Expense (Benefit)	(62)	(11)	51	N/A	(178)	118	N/A	N/A

Three Months Ended June 30, 2017 as Compared to 2016

Operating Revenues increased $215 million due to changes in generation and gas supply revenues.

Generation Revenues increased $223 million due primarily to

- an increase of $219 million due to MTM gains in 2017 as compared to MTM losses in 2016. Of this amount, $182 million was due to changes in forward power prices and $37 million was due to lower gains on positions reclassified to realized upon settlement this year as compared to gains last year, and
- a net increase of $15 million in electricity sold under wholesale load contracts in the New England (NE) region due to higher volumes sold,
- partially offset by a decrease of $11 million in electricity sold under our BGS contracts due primarily to lower volumes.

Gas Supply Revenues decreased $9 million due primarily to

- a net decrease of $17 million related to sales to third parties, of which $22 million was due to lower volumes sold, partially offset by $5 million of higher average sales prices,
- partially offset by a net increase of $9 million due to MTM gains in 2017 as compared to MTM losses in 2016.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $16 million due to

Generation costs increased $33 million due primarily to

- an increase of $20 million due to MTM losses in 2017 as compared to MTM gains in 2016,
- an increase of $21 million due primarily to higher natural gas costs reflecting higher average realized prices,
- an increase of $8 million in energy purchase volumes in the NE region to serve load obligations, and
- a $2 million charge associated with a lower of cost or market coal inventory adjustment at Hudson and Mercer,
- partially offset by a net decrease of $19 million primarily due to lower congestion rates coupled with less congestion volumes.

Gas costs decreased $17 million due mainly to a net decrease of $16 million related to sales to third parties, of which $21 million was due to lower volumes sold, partially offset by $5 million of higher average costs.

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Operation and Maintenance decreased $11 million due primarily to a $14 million decrease at our fossil plants, due largely to higher planned outage costs in the second quarter of 2016 and retirement of the Hudson and Mercer coal units on June 1, 2017.

Depreciation and Amortization increased $385 million due primarily to

- $380 million of accelerated depreciation due to the early retirement of the Hudson and Mercer units,
- $4 million of greater depreciation due to the accelerated retirement date at Bridgeport Harbor 3 (BH3), and
- $3 million of higher depreciation due to new solar projects.

Other Income (Deductions) increased $23 million due primarily to higher net realized gains in the NDT Fund.

Other-Than-Temporary Impairments decreased $7 million due to lower impairments of equity securities in the NDT Fund in 2017.

Interest Expense decreased $7 million due primarily to higher interest capitalized for the construction of three new fossil stations: BH5, Sewaren 7 and Keys.

Income Tax Expense (Benefit) reflected an increased tax benefit of $51 million due primarily to a higher pre-tax loss in 2017.

Six Months Ended June 30, 2017 as Compared to 2016

Operating Revenues increased $186 million due to changes in generation and gas supply revenues.

Generation Revenues increased $99 million due primarily to

- an increase of $196 million due to MTM gains in 2017 as compared to MTM losses in 2016. Of this amount, $106 million was due to lower gains on positions reclassified to realized upon settlement this year as compared to last year and $90 million due to changes in forward power prices, and
- a net increase of $24 million due primarily to higher volumes of electricity sold under wholesale load contracts in the NE region partially offset by lower average prices,
- partially offset by a net decrease of $90 million in energy sales in the PJM and NE regions due primarily to lower average realized prices,
- a net decrease of $8 million in electricity sold under our BGS contracts of which $21 million was due to lower volumes, partially offset by $13 million of higher average prices, and
- a charge of $10 million due to an increase in the FERC accrual related to the PJM bidding matter see Item 1. Note 9. Commitments and Contingent Liabilities.

Gas Supply Revenues increased $86 million due primarily to

- an increase of $45 million in sales under the BGSS contract, of which $37 million was due to higher average sales prices coupled with an $8 million increase in sales volumes due to periods of colder weather in March,
- an increase of $24 million related to sales to third parties, of which $48 million was due to higher average sales prices, partially offset by $24 million of lower volumes sold, and
- a net increase of $17 million due to MTM gains in 2017 as compared to MTM losses in 2016.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $85 million due to

Generation costs increased $32 million due primarily to

- higher fuel costs of $35 million reflecting higher average realized prices for natural gas coupled with the utilization of higher volumes of coal, partially offset by the utilization of lower volumes of gas and oil,
- an increase of $18 million due to MTM losses in 2017 as compared to MTM gains in 2016,
- an increase of $15 million in energy purchase volumes in the NE region to serve load obligations, and
- a $9 million charge associated with a lower of cost or market coal inventory adjustment at Hudson and Mercer,

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- partially offset by a net decrease of $45 million due primarily to lower congestion costs in PJM due to lower congestion rates coupled with less congestion volumes, partially offset by higher transmission charges due to higher rates.

Gas costs increased $53 million due mainly to

- an increase of $31 million related to sales under the BGSS contract due primarily to higher average gas costs and an increase in volumes sold due to periods of colder weather in March, and
- an increase of $22 million related to sales to third parties, of which $44 million was due to higher average gas costs, partially offset by a $22 million decrease in volumes sold.

Operation and Maintenance decreased $34 million due primarily to

- a $16 million decrease at our fossil plants, due primarily to the retirement of the Hudson and Mercer units and higher planned outage costs in 2016 as compared to 2017,
- an $11 million net decrease related to our nuclear plants due primarily to lower labor-related costs and outage costs, and
- a $9 million legal accrual for environmental expenses recorded in 2016,
- partially offset by $3 million of costs related to seven new solar plants placed into service since June 2016.

Depreciation and Amortization increased $956 million due primarily to

- $938 million of accelerated depreciation due to the early retirement of the Hudson and Mercer units,
- $8 million of greater depreciation due to the accelerated retirement date at BH3,
- a $6 million increase due to a higher nuclear asset base, and
- $6 million of higher depreciation due to new solar projects.

Other Income (Deductions) increased $46 million due primarily to $41 million of higher net realized gains in the NDT Fund and $3 million of higher realized gains in the Rabbi Trust Fund.

Other-Than-Temporary Impairments decreased $16 million due to lower impairments of equity securities in the NDT Fund in 2017.

Interest Expense decreased $13 million due primarily to higher interest capitalized for the construction of three new fossil stations: BH5, Sewaren 7 and Keys.

Income Tax Expense (Benefit) reflected a tax benefit of $(178) million in 2017 and a $118 million tax expense in 2016 due primarily to a pre-tax loss in 2017 as compared to pre-tax income in 2016.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the six months ended June 30, 2017, our operating cash flow increased $34 million as compared to the same period in 2016. The net change was due primarily to tax refunds in 2017 at Energy Holdings and the net changes from PSE&G and Power as discussed below.

PSE&G

PSE&G's operating cash flow decreased $38 million from $808 million to $770 million for the six months ended June 30, 2017, as compared to the same period in 2016, due primarily to lower tax refunds, partially offset by higher earnings.

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Power

Power's operating cash flow increased $15 million from $917 million to $932 million for the six months ended June 30, 2017, as compared to the same period in 2016, due primarily to a $105 million decrease in margin deposit requirements and a $48 million increase from net collection of counterparty receivables, partially offset by tax payments in 2017 as compared to tax refunds in 2016, a $28 million decrease from fuels, materials and supplies and lower earnings.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs.

In March 2017, PSEG, Power and PSE&G amended their credit agreements, extending the expiration dates to March 2022. Concurrently, PSEG increased its existing $1 billion in credit facilities to $1.5 billion, Power decreased its existing $2.6 billion in credit facilities to $2.1 billion, which includes two new 3-year $100 million letter of credit facilities that expire in March 2020.

Our total credit facilities and available liquidity as of June 30, 2017 were as follows:

	As of June 30, 2017		
Company/Facility	**Total Facility**	**Usage**	**Available Liquidity**
	Millions		
PSEG	$ 1,500	$ 13	$ 1,487
PSE&G	600	15	585
Power	2,100	190	1,910
Total	**$ 4,200**	**$ 218**	**$ 3,982**

As of June 30, 2017, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating from S&P or Moody's, which would represent a three level downgrade from its current S&P or Moody's ratings. In the event of a deterioration of Power's credit rating certain of Power's agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $808 million and $783 million as of June 30, 2017 and December 31, 2016, respectively. The early retirement of Power's Hudson and Mercer coal/gas generation units did not have a material impact on Power's debt covenant ratios or its ability to obtain credit facilities. See Item 1. Note 3. Early Plant Retirements.

For additional information, see Item 1. Note 10. Debt and Credit Facilities.

Long-Term Debt Financing

PSEG Parent has a floating rate $500 million term loan maturing in November 2017. PSE&G has $400 million of 5.30% Medium-Term Notes maturing in May 2018.

For a discussion of our long-term debt issuances and maturities during 2017, see Item 1. Note 10. Debt and Credit Facilities.

Common Stock Dividends

On April 18, 2017, our Board of Directors approved a $0.43 dividend per share of common stock for the second quarter of 2017. On July 18, 2017, our Board of Directors declared a $0.43 dividend per share of common stock for the third quarter of 2017. This reflects an indicative annual dividend rate of $1.72 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 1. Note16. Earnings Per Share (EPS) and Dividends.

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Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In April 2017, S&P published updated research and affirmed the ratings and outlooks of PSEG and PSE&G. In June 2017, S&P published updated research on Power and the rating and outlook remained unchanged. Also in June 2017, Moody's published updated research on PSE&G and Power and the ratings and outlooks remained unchanged. In July 2017, Moody's upgraded PSEG's senior unsecured rating to Baa1 from Baa2 and revised its outlook to Stable from Positive. Also in July, Moody's affirmed the ratings at PSE&G and Power.

	Moody's (A)	S&P (B)
PSEG		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures at PSE&G, Power and Services as compared to amounts disclosed in our 2016 Form 10-K.

PSE&G

During the six months ended June 30, 2017, PSE&G made capital expenditures of $1,389 million, primarily for T&D system reliability. This does not include expenditures for cost of removal, net of salvage, of $47 million, which are included in operating cash flows.

In July 2017, PSE&G filed a petition with the BPU for a GSMP II program, requesting extension of our gas system modernization program through which PSE&G has proposed investing up to $540 million per year beginning in 2019 to continue to modernize our gas system. Under this proposed program, PSE&G plans to replace up to 1,250 miles of gas mains and associated service lines. This is not included in PSE&G's projected capital expenditures.

Power

During the six months ended June 30, 2017, Power made capital expenditures of $518 million, excluding $58 million for nuclear fuel, primarily related to our Keys, Sewaren 7, BH5 and other generation projects.

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ACCOUNTING MATTERS

For information related to recent accounting matters, see Item 1. Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From April through June 2017, MTM VaR remained relatively stable between a low of $6 million and a high of $10 million at the 95% confidence level. The range of VaR was narrower for the three months ended June 30, 2017 as compared with the year ended December 31, 2016.

	MTM VaR	
	Three Months Ended June 30, 2017	Year Ended December 31, 2016
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 8	$ 26
Average for the Period	$ 8	$ 16
High	$ 10	$ 32
Low	$ 6	$ 10
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 13	$ 40
Average for the Period	$ 12	$ 25
High	$ 16	$ 51
Low	$ 9	$ 16

See Item 1. Note 11. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, PSE&G and Power

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of PSEG, PSE&G and Power. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of PSEG, PSE&G and Power have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, PSE&G and Power

There have been no changes in internal control over financial reporting that occurred during the second quarter of 2017 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2016 Annual Report on Form 10-K, see Part I, Item 1. Note 9. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

The discussion of our business and operations in this Quarterly Report on Form 10-Q should be read together with the risk factors contained in Part I, Item 1A of our 2016 Annual Report on Form 10-K and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, which describe various risks and uncertainties that could have a material adverse impact on our business, prospects, financial position, results of operations or cash flows and could cause results to differ materially from those expressed elsewhere in this report. There have been no material changes to the risk factors set forth in the above-referenced filings as of June 30, 2017.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the second quarter of 2017.

Three Months Ended June 30, 2017	Total Number of Shares Purchased	Average Price Paid per Share
April 1 - April 30	—	$ —
May 1 - May 31	130,749	$ 43.77
June 1- June 30	30,000	$ 44.72

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ITEM 5. OTHER INFORMATION

Certain information reported in the 2016 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2016 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2017. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

Federal Regulation

FERC

Capacity Market Issues

December 31, 2016 Form 10-K page 16 and March 31, 2017 Form 10-Q on page 76. PJM, the New York Independent System Operator (NYISO) and the Independent System Operator New England, Inc. each have capacity markets that have been approved by FERC. FERC regulates these markets and continues to examine whether the market design for each of these three capacity markets is working optimally. Various forums are considering how the competitive market framework can incorporate or be reconciled with state public policies that support particular resources or resource attributes, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market prices. FERC held a technical conference to seek input from the industry on potential options to integrate public policy goals in wholesale markets. We cannot predict what action, if any, FERC might take with regard to capacity market designs.

Capacity Market Issues—PJM

December 31, 2016 Form 10-K page 16 and March 31, 2017 Form 10-Q on page 76. During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. The Court of Appeals for the D.C. Circuit (D.C. Circuit) denied petitions challenging certain aspects of FERC's Order. The CP product was implemented fully in the May 2017 RPM auction for the 2020-2021 Delivery Year. FERC has approved changes to the CP construct that will enhance the participation of intermittent and DR resources (seasonal resources). Specifically, FERC approved PJM's modifications to the aggregation rules to improve the ability of seasonal resources to participate. However, two complaints remain pending that ask FERC to investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions. We do not expect action on the complaints until additional commissioners have been nominated and confirmed so that FERC has a quorum necessary to take action.

PJM issued a series of white papers in response to public policies that seek to recognize value associated with generation plants beyond their cost effectiveness and reliability attributes. The three proposals are intended to spur stakeholder discussion and include both potential capacity and energy market reforms. One energy market reform would allow inflexible generating units to set prices resulting in reduced uplift payments and improved price signals while the second energy market reform contemplates a voluntary carbon pricing program where states that elect to participate in the program would agree to put a price on carbon emissions. The capacity market proposal contemplates a two-stage capacity auction which, in its current form, would improve prices for unsubsidized resources, but would still continue to provide capacity payments for subsidized resources.

Transmission Regulation—Transmission Policy Developments

December 31, 2016 Form 10-K page 18 and March 31, 2017 Form 10-Q on page 77. In June 2015, a transmission developer filed a complaint against PJM claiming that PJM wrongfully refused to provide data and a transparent process for evaluating transmission network upgrade requests that the transmission developer had submitted to PJM. Although not named as a respondent in the complaint, according to the complaint, PSE&G is identified as one of the companies claimed to have been involved. FERC set the complaint for hearing and settlement procedures and the parties are currently engaged in discovery. We are unable to predict the outcome of these proceedings.

In August 2016, PJM announced that it had suspended the Artificial Island transmission project and would be performing a comprehensive analysis to support a future course of action. In March 2017, PJM staff made its final recommendation to the PJM Board with respect to the project. Under the recommended project, PSE&G will construct necessary upgrade work at a cost of approximately $130 million. In April 2017, the PJM Board announced that it would be lifting the suspension and approved the staff recommended project. Also, in April 2017, PJM submitted a proposal to FERC concerning the cost responsibility assigned to certain entities, including PSE&G, for the Artificial Island project. PSE&G plans to participate in this proceeding. However, we are unable to predict the outcome.

Transmission Regulation—Transmission Rate Proceedings

Numerous complaints have been filed at FERC in recent years seeking to reduce the base ROE of transmission owners across the country. Many of those complaints were resolved through agreement and settlement resulted in ROE reductions while others remain pending in the FERC adjudication process or are being litigated in the courts. Recent court decisions, as well as anticipated changes in the makeup at FERC, create some uncertainty as to the timing and outcome of these complaints. The

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results of these settlement and proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Transmission Regulation—Con Edison Wheeling Agreement

December 31, 2016 Form 10-K page 19 and March 31, 2017 Form 10-Q on page 77. Effective May 1, 2017, a wheeling arrangement which enabled Con Edison to move 1,000 MW of power from southeastern New York across the PSE&G system for delivery into New York City expired. NYISO and PJM revised their Joint Operating Agreement to modify the operational protocols for the affected interconnection between NYISO and PJM in a submittal to FERC that became effective, subject to refund, on May 1, 2017. PSE&G and the BPU jointly filed for rehearing of FERC's order. In a related filing, PJM submitted a proposal to FERC revising the cost responsibility assigned to certain entities, including PSE&G, due to the termination of the Wheeling Agreement. This filing was accepted, subject to refund, effective May 1, 2017. PSE&G will continue to recover the costs associated with the new arrangement through its formula rate. We cannot predict the outcome of this proceeding.

State Regulation

Gas System Modernization Program II (GSMP II)

In July 2017, we filed a petition with the BPU for a GSMP II program, requesting extension of our gas system modernization program through which PSE&G has proposed investing $2.7 billion over five years beginning in 2019 to continue to modernize our gas system. Under this proposed program, we plan to replace up to 1,250 miles of gas mains and associated service lines, with cost recovery at a 9.75% rate of return on equity through an accelerated recovery mechanism. This matter is pending. We believe the petition is consistent with the draft regulations that the BPU issued in June 2017 regarding infrastructure investment programs as described below.

Connecticut Rate Filing

December 31, 2016 Form 10-K page 21. In June 2017, Power's subsidiary, PSEG New Haven LLC, filed a mandatory annual rate case with the Connecticut Public Utilities Regulatory Authority for recovery of its costs and investment in its Connecticut-based peaking unit. Power requested 2018 revenues of $20 million. This matter is pending.

Energy Efficiency Program (Energy Efficiency 2017)

March 31, 2017 Form 10-Q on page 77. In July 2017, we reached an agreement in principle with BPU Staff and Rate Counsel related to our proposed Energy Efficiency program extension. Under the agreement, PSE&G would invest $69 million in energy efficiency equipment for hospitals, multi-family housing and other sectors and a residential energy efficiency offering for smart thermostats and data analytics. We would recover our investment with an initial ROE of 9.75% to be reset in our upcoming rate case and receive recovery of administrative costs. This agreement is subject to review by the BPU.

Infrastructure Investment Programs (IIP)

In June 2017, the BPU issued proposed IIP regulations that would allow utilities to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to support the provision of safe and adequate service. Under the proposed regulations, utilities could seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing infrastructure that enhances reliability, resiliency, and/or safety. The proposed regulations will be subject to comment from interested parties.

Environmental Matters

Climate Change

CO_2 Regulation under the Clean Air Act (CAA)

December 31, 2016 Form 10-K page 23 and March 31, 2017 Form 10-Q on page 77. In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the New Source Performance Standards that establish emissions standards for CO_2 for certain new fossil power plants and the Clean Power Plan, a greenhouse gas emissions regulation under the CAA for existing power plants that establishes state-specific emission rate targets based on implementation of the best system of emission reduction. In April 2017, the D.C. Circuit granted the EPA's motion to hold the case in abeyance for at least 60 days while the agency reviews the rule.

Upon completion of the review, the EPA is expected to suspend, revise or rescind the rules as appropriate. PSEG cannot estimate the impact of these actions on our business and future results of operations at this time.

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Water Pollution Control

Steam Electric Effluent Guidelines

December 31, 2016 Form 10-K page 23 and March 31, 2017 Form 10-Q on page 77. In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG Rule) for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater, and gasification wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges and that are regulated under this rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the rule. Power is unable to predict if this rule will have a material impact on its future capital requirements, financial condition and results of operations.

In April 2017, the EPA announced that it had granted a petition for reconsideration of the ELG Rule and issued an administrative stay of the compliance dates in the rule that were the subject of pending litigation. In June 2017, the EPA proposed a rule to postpone the compliance deadlines for the BAT limitations and pretreatment standards for the aforementioned waste streams. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

Waters of the United States

December 31, 2016 Form 10-K page 24 and March 31, 2017 Form 10-Q on page 78. In April 2014, the EPA and the U.S. Army Corps of Engineers jointly published a proposed rule to clarify the definition of waters of the United States under the Clean Water Act (CWA) programs in order to protect the streams and wetlands that form the foundation of the nation's water resources. This definition will have broad application to all areas of compliance under the CWA, including permitted discharges and construction activities. The final rule was published in June 2015 (June 2015 rule) and various states, industry coalitions and environmental organizations have initiated legal action related to the provisions of the June 2015 rule.

In February 2017, the President of the United States issued an Executive Order that instructed the EPA to review the June 2015 rule and issue a proposal to redefine "Waters of the United States." In June 2017, the EPA and the U.S. Army Corps of Engineers announced the agencies will be (1) issuing a proposed rule to rescind the 2015 Rule and reinstate the previously existing definition of "Waters of the United States" and (2) developing a new rule, including a revised definition of "Waters of the United States." Publication of the proposed rule to rescind the June 2015 rule is expected in the third quarter of 2017 and the process regarding a new rule will likely take several years.

Some states, including New Jersey, are subject to state requirements beyond those imposed under federal law. While we do not anticipate material impacts to projects in New Jersey, the new rule could impose requirements in other states and regions that could impact the development of renewables.

Endangered Species Act

December 31, 2016 Form 10-K page 25 and March 31, 2017 Form 10-Q on page 78. In June 2015, the Sierra Club and another environmental group submitted to the New Jersey Department of Environmental Protection (NJDEP) a sixty-day notice of intent to sue alleging the agency has caused violations of the Endangered Species Act by allowing our Mercer generation station to operate in a manner which has caused the mortality of certain species of sturgeon. Among other things, the notice requested the NJDEP to prioritize completion of a New Jersey Pollutant Discharge Elimination System (NJPDES) permit renewal action for Mercer which addresses the alleged Endangered Species Act violations. In May 2017, the NJDEP issued a final NJPDES renewal permit for Mercer effective June 1, 2017. The new permit will cover the waste water discharges that will be present during the period of decommissioning. In March 2017, we submitted an Incidental Take Permit application to the National Marine Fisheries Service outlining proposed operation and monitoring requirements through retirement of the Mercer generation station on June 1, 2017 and subsequent decommissioning.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 10.1:	Supplemental Executive Retirement Income Plan dated July 10, 2017
Exhibit 10.2:	Retirement Income Reinstatement Plan dated July 10, 2017
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. PSE&G:

Exhibit 10.1:	Supplemental Executive Retirement Income Plan dated July 10, 2017
Exhibit 10.2:	Retirement Income Reinstatement Plan dated July 10, 2017
Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. Power:

Exhibit 10.1:	Supplemental Executive Retirement Income Plan dated July 10, 2017
Exhibit 10.2:	Retirement Income Reinstatement Plan dated July 10, 2017
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: July 28, 2017

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: July 28, 2017

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: July 28, 2017

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Exhibit 10.1

SUPPLEMENTAL EXECUTIVE RETIREMENT INCOME PLAN

FOR NON-REPRESENTED EMPLOYEES OF

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

AND ITS AFFILIATES

Effective as of January 1, 2017

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SUPPLEMENTAL EXECUTIVE RETIREMENT INCOME PLAN FOR NON-REPRESENTED EMPLOYEES OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED AND ITS AFFILIATES

Public Service Enterprise Group Incorporated ("PSEG") had established two supplemental executive retirement plans for certain of its and its affiliates' non-represented employees: the Limited Supplemental Benefits Plan for Certain Employees of Public Service Enterprise Group Incorporated and its Subsidiaries (the "Limited Plan") and the Mid-Career Hire Supplemental Retirement Income Plan for Selected Employees of Public Service Enterprise Group Incorporated and its Affiliates (the "Mid-Career Plan"). These plans were established for the purpose of assisting in attracting and retaining a stable pool of key managerial and professional talent and developing long-term key employee commitment by providing specified supplemental retirement income benefits for certain employees who participate in a Qualified Plan.

The Limited Plan and the Mid-Career Plan were each intended to constitute an unfunded plan of deferred compensation for a select group of management or highly compensated employees for purposes of Title 1 of ERISA. Effective as of December 1, 2009, the Limited Plan and the Mid-Career Plan (together, the "Prior Plans") were merged into a single plan, this Supplemental Executive Retirement Income Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated and Its Affiliates ("SERP"). The merger of these plans was not intended to change the eligibility of or benefits payable to the participants in the Prior Plans.

The SERP was amended effective January 1, 2011 to reflect that participation as to the Mid-Career Hire benefit was frozen.

Effective as of January 1, 2012, the benefit formula under the Final Average Pay Component changed from a 5-year final average pay formula to a 7-year final average pay formula. The change in the benefit formula under the Final Average Pay Component affected the benefits provided under the SERP. Accordingly, the SERP was amended effective January 1, 2012 to reflect these changes. Notwithstanding anything in the SERP to the contrary, the foregoing change shall not apply to Robert Braun, Thomas Joyce and John Perry.

The SERP is being amended effective January 1, 2017 to make certain administrative clarifications.

Section 1. Definitions

When used herein, the words and phrases hereinafter defined shall have the following meanings unless a different meaning is clearly required by the context of the SERP:

1.1 "Affiliate" shall mean (a) any organization while it is a member of a controlled group of corporations (as defined in Section 414(b) of the Code) which includes PSEG ; or (b) any trades or businesses

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(whether or not incorporated) while they are under common control (as defined in Section 414(c) of the Code, as modified by Section 415(h) of the Code) with PSEG.

1.2 "Beneficiary" shall mean any person or persons designated by a Participant who may become eligible to receive the benefits provided under the SERP in the event of such Participant's death.

1.3 "Benefit Commencement Date" shall mean the date that is the Participant's last day worked plus one day.

1.4 "Board" or "Board of Directors" shall mean the Board of Directors of Public Service Enterprise Group Incorporated.

1.5 "Cash Balance Component" shall mean the Cash Balance Component of the Pension Plan. The Cash Balance Component was formerly the Public Service Enterprise Group Incorporated Cash Balance Pension Plan.

1.6 "CEO" shall mean the Chief Executive Officer of PSEG. If PSEG has no designated Chief Executive Officer, "CEO" shall mean the President of PSEG.

1.7 "Change in Control" shall mean the occurrence of any of the following events:

(a) Any "person" (within the meaning of Section 13(d) of the Securities Exchange Act of 1934, as amended from time to time (the "Act")) is or becomes the beneficial owner within the meaning of Rule 13d-3 under the Act (a "Beneficial Owner"), directly or indi-rectly, of PSEG's securities of (not including in the securities beneficially owned by such person any securities acquired directly from PSEG or its Affiliates) representing 25% or more of the combined voting power of PSEG then outstanding securi-ties, excluding any person who becomes such a Beneficial Owner in connection with a transaction described in clause (i) of paragraph (c) below; or

(b) The following individuals cease for any reason to consti-tute a majority of the number of directors then serving: individuals who, on December 15, 1998, constitute the Board of Directors and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, includ-ing but not limited to a consent solicitation, relating to the election of directors of PSEG) whose appointment or election by the Board or nomination for election by PSEG's stockholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors on December 15, 1998 or whose appointment, election or

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nomination for election was previously so approved or recom-mended; or

(c) There is consummated a merger or consolidation of PSEG or any direct or indirect wholly owned subsidiary of PSEG with any other corporation, other than (i) a merger or consolidation which would result in the voting securities of PSEG outstanding immediately prior to such merger or consoli-dation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of PSEG or any subsidiary of PSEG, at least 75% of the combined voting power of the securities of PSEG or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (ii) a merger or consolidation effected to implement a recapitalization of PSEG (or similar transaction) in which no person is or becomes the Beneficial Owner, directly or indirectly, of securities of PSEG representing 25% or more of the combined voting power of PSEG's then outstanding securities; or

(d) The stockholders of PSEG approve a plan of complete liquidation or dissolution of PSEG or there is consummated an agreement for the sale or disposition by PSEG of all or substantially all of PSEG's assets, other than a sale or disposition by PSEG of all or substantially all of PSEG's assets to an entity, at least 75% of the combined voting power of the voting securities of which are owned by stockholders of PSEG in substantially the same proportions as their own-ership of PSEG immediately prior to such sale.

Notwithstanding the foregoing subsection (a) through (d), a "Change in Control" shall not be deemed to have occurred by virtue of the consummation of any transaction or series of integrated transactions immediately following which the record holders of the common stock of PSEG immediately prior to such transaction or series of transactions continue to have substantially the same proportionate ownership in an entity which owns all or substantially all of the assets of PSEG immediately following such transaction or series of transactions.

1.8 "Code" shall mean the Internal Revenue Code of 1986, as amended. A reference to a section of the Code shall also refer to any regulations and other guidance issued under that section.

1.9 "Company" shall mean Public Service Enterprise Group Incorporated and each Participating Affiliate.

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1.10 "Compensation" with respect to any Participant shall mean base salary, bonuses (as described below) and overtime up to 20% of base salary. Compensation shall include amounts deferred to the Deferred Compensation Plan for Certain Employees of Public Service Enterprise Group Incorporated and its Affiliates ("Deferred Compensation Plan"). For the period prior to March 5, 2010, refer to the prior SERP document for the definition Compensation.

For purposes of calculating the Mid-Career Hire Benefit for a Participant who is a participant in the Cash Balance Component, Compensation shall not include amounts paid prior in 2006 under the MICP or the SMICP.

For clarification purposes, all bonuses paid under the PSEG Power LLC Incentive Compensation Program for PSEG Energy Resources & Trade LLC Employees ("ER&T Plan"), as limited hereunder, the Performance Incentive Plans ("PIPs") and the PSEG Power LLC Incentive Compensation Program for Certain Employees of PSEG Energy Solutions LLC ("Energy Solutions Plan") are included, except those paid under the Long Island Electric Utility ServCo LLC Performance Incentive Plan.

For Participants who are participants in the Cash Balance Component, Compensation for any such year shall not exceed 150 percent of the Participant's annual base salary in effect as of January 1 of that year. For Participants who are first hired during the Plan Year, for that year, the base salary in effect as of the date of hire shall be used. For Participants who are rehired, the base salary as of the date of rehire shall be used for determining Compensation of the year of the rehire.

For purpose of calculating the Limited Benefit, bonuses paid under the PIP, Energy Solutions Plan, MICP, SMICP and the ER&T Plan are included in Compensation for all years (including those paid prior to 2006).

For purposes of calculating SERP Benefits, bonuses paid under the PIP, Energy Solutions Plan, MICP, SMICP and the ER&T plan are included in Compensation only if the bonus is paid prior to the date of the Participant's Separation from Service.

1.11 "Credited Service" shall mean the aggregate of all periods of employment with PSEG, an Affiliate or former Affiliate and all periods of additional Credited Service granted to Participants listed on Schedule A by PSEG for which a Participant will be given credit in computing their SERP Benefit. Service with Long Island Electric Utility ServCo LLC, LIPA and/or National Grid shall be taken into account under the SERP to the extent such service is taken into account under the Qualified Plan.

1.12 "Employee" shall mean any individual in the employ of the Company who is not included within a unit of employees covered by a collective bargaining agreement. The term "Employee" shall not include a director of the Company who serves in no capacity other than as a director, a consultant or independent contractor doing work for the Company or a person employed by a consultant or independent contractor doing work for the Company (regardless of whether a determination is made by the Internal Revenue Service or other governmental agency

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or court after the individual is engaged to perform such services that the individual is an employee of the Company for the purposes of the Code or otherwise).

1.13 "Employee Benefits Committee" shall mean the Employee Benefits Committee of PSEG.

1.14 "Employee Benefits Policy Committee" shall mean the Employee Benefits Policy Committee of PSEG.

1.15 "ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended. A reference to a section of ERISA shall also refer to any regulations and other guidance issued under that section.

1.16 "Final Average Earnings" with respect to a Participant who is entitled to a Limited Benefit:

(a) And who incurs a Separation from Service before January 1, 2012, shall mean the annual average of the sum of:

(1) The Participant's last five years of Compensation, excluding any amounts received as an award under the MICP or the SMICP, without the application of the base pay cap in Section 1.10, and

(2) The MICP or SMICP awards for the five **most recent** bonus eligible years (including $0 awards) prior to the Participant's Separation from Service. If a Participant does not have at least five MICP/SMICP awards, the average shall be determined by using the number of bonus (including PIP bonuses, ER&T Plan bonuses and Energy Solutions Plan bonuses) eligible periods during the five most recent years.

Notwithstanding the foregoing, Final Average Earnings shall not exceed 150 percent of the average of the Participant's annual base salary in effect as of January 1 for the five years prior to and including the year in which the Participant's Separation from Service occurs. For the year in which the Participant is hired, the base salary in effect as of the date of hire shall be used. For Participants who are rehired, the base salary as of the date of rehire shall be used for determining Compensation of the year of the rehire.

Bonuses paid under the PIP, Energy Solutions Plan, MICP, SMICP and the ER&T Plan are included in Compensation only if the bonus is paid prior to the date of the Participant's Separation from Service.

(b) With respect to a Participant who incurs a Separation from Service on or after January 1, 2012, Final Average Earnings shall mean:

(1) With respect to periods of service prior to January 1, 2012, Final Average Earnings shall be determined in accordance with subsection (a) above,

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except that Separation from Service shall be replaced with December 31, 2011.

(2) With respect to periods of service after December 31, 2011, the annual average of the sum, (i) the Participant's last seven years of Compensation beginning after December 31, 2011, excluding any MICP and SMICP awards, without the application of the base pay cap in Section 1.8, and (ii) the MICP or SMICP awards for the seven **most recent** years (including $0 awards) beginning after December 31, 2011 and prior to the Participant's Separation from Service. If a Participant does not have at least seven MICP/SMICP awards during the seven most recent years after 2011, the average shall be determined by using the number of bonus (including PIP bonuses, ER&T Plan bonuses and Energy Solutions Plan bonuses) eligible periods after 2011 during the seven most recent years.

Notwithstanding the foregoing, Final Average Earnings shall not exceed 150 percent of the average of the Participant's annual base salary in effect as of January 1 for the seven years prior to and including the year in which the Participant's Separation from Service occurs (the annual base salary prior to January 1, 2012 shall not be used in such determination). For the year in which the Participant is hired, the base salary in effect as of the date of hire shall be used. For Participants who are rehired, the base salary as of the date of rehire shall be used for determining Compensation of the year of the rehire.

Bonuses paid under the PIP, Energy Solutions Plan, MICP, SMICP and the ER&T Program are included in Compensation only if the bonus is paid prior to the date of the Participant's Separation from Service.

1.17 "Final Average Pay Component" shall mean the Final Average Pay Component of the Pension Plan.

1.18 "Limited Benefit" shall mean the benefit payable to a Participant pursuant to Section 3 of the SERP.

1.19 "Mid-Career Hire Benefit" shall mean the benefit payable to a Participant pursuant to Section 2 of the SERP.

1.20 "Mid-Career Hire Surviving Spouse Benefit" shall mean the benefit payable to a Surviving Spouse pursuant to the SERP.

1.21 "Normal Retirement Date" shall mean the first day of the month coinciding with or next following a Participant's attainment of age 65. In the case of a Participant who is still employed beyond age 65, Normal Retirement Date shall mean the first day of the month coinciding with or next following the date on which the Participant's Separation from Service occurs.

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1.22 "Participant" shall mean any Employee or former Employee who meets the requirements of Sections 2 or 3 of the SERP.

1.23 "Participating Affiliate" shall mean any Affiliate of PSEG which (a) is the sponsor or a Participating Affiliate of the Qualified Plan; (b) adopts the SERP with the approval of the Board of Directors; (c) authorizes the Board of Directors and the Employee Benefits Committee to act for it in all matters arising under or with respect to the SERP; and (d) complies with such other terms and conditions relating to the SERP as may be imposed by the Board of Directors. Participating Affiliate shall not include Long Island Electric Utility ServCo LLC.

1.24 "Pension Plan" shall mean the Pension Plan of Public Service Enterprise Group Incorporated and each predecessor, successor or replacement plan.

1.25 "Qualified Benefit" shall mean the aggregate annual benefit payable to a Participant pursuant to the Qualified Plan by reason of the Participant's termination of employment with PSEG and all Affiliates for any reason other than death.

1.26 "Qualified Plan" shall mean the Final Average Pay Component or the Cash Balance Component.

1.27 "Qualified Surviving Spouse Benefit" shall mean the aggregate annual benefit payable to the Surviving Spouse of a Participant pursuant to the Qualified Plan, in the event of the death of the Participant at any time prior to commencement of payment of the Participant's Qualified Benefit.

1.28 "Plan Year" shall mean the calendar year.

1.29 "Reinstatement Plan" shall mean the Retirement Income Reinstatement Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated and its Affiliates.

1.230 "Reinstatement Benefit" shall mean the annual benefit payable to a Participant pursuant to the Reinstatement Plan for any reason other than death.

1.31 "Reinstatement Surviving Spouse Benefit" shall mean the annual benefit payable to the Surviving Spouse of a Participant pursuant to the Reinstatement Plan in the event of the death of the Participant at any time prior to commencement of payment of their Reinstatement Benefit.

1.32 "Retirement" shall mean:

(a) In the case of a Participant who is a participant in the Final Average Pay Component, a Separation from Service either (1) after attaining age 65, (2) following the date when the sum of the Participant's age and credited service (as defined in the Final Average Pay Component) equals or exceeds 80, or (3) a disability determination under the Final Average Pay Component.

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(b) In the case of a Participant who is a participant in the Cash Balance Component, a Separation from Service after either (1) attaining age 65, (2) attaining age 55 and completing five or more years of credited service (as defined in the Cash Balance Component), or (3) a disability determination under the Cash Balance Component.

1.33 "Retirement Plans" shall mean all qualified defined benefit plans maintained by employers other than PSEG or any of its Affiliates.

1.34 "Separation from Service" shall mean, subject to subsections (a) and (b) below, a Participant's termination from employment with PSEG and all Affiliates, whether by retirement or resignation from or discharge by PSEG or an Affiliate.

(a) A Separation from Service shall be deemed to have occurred if a Participant and PSEG or any Affiliate reasonably anticipates, based on the facts and circumstances, that either:

(i) The Participant will not provide any additional services for PSEG or an Affiliate after a certain date; or

(ii) The level of bona fide services performed by the Participant after a certain date will permanently decrease to no more than 50 percent of the average level of bona fide services performed by the Participant over the immediately preceding 36 months.

(b) If a Participant is absent from employment due to military leave, sick leave or any other bona fide leave of absence authorized by PSEG or an Affiliate and there is a reasonable expectation that the Participant will return to perform services for PSEG or an Affiliate, a Separation from Service will not occur until the later of:

(i) The first date immediately following the date that is six months after the date that the Participant was first absent from employment; or

(ii) The date the Participant no longer retains a right to reemployment, to the extent the Participant retains a right to reemployment with PSEG or any Affiliates under applicable law or by contract.

If a Participant fails to return to work upon the expiration of any military leave, sick leave or other bona fide leave of absence where such leave is for less than six months, the Separation from Service shall occur as of the date of the expiration of such leave.

1.35 "SERP" shall mean this Supplemental Executive Retirement Income Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated and Its Affiliates.

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1.36 "Specified Employee" shall mean any individual who is a key employee (as defined in Section 416(i) of the Code without regard to Section 416(i)(5) of the Code) of PSEG or an Affiliate at any time during the 12-month period ending on each December 31 (the "identification date"). If an individual is a key employee as of an identification date, the individual shall be treated as a Specified Employee for the 12-month period beginning on the April 1 following the identification date. Notwithstanding the foregoing, an individual shall not be treated as a Specified Employee unless any stock of PSEG or an Affiliate is publicly traded on an established securities market or otherwise.

1.37 "SERP Benefit" shall mean the benefit payable to a Participant pursuant to the SERP by reason of the Participant's Separation from Service with PSEG and all Affiliates for any reason other than death, which shall include the Mid-Career Hire Benefit and Limited Benefit.

1.38 "Surviving Spouse" shall mean a person who is married to a Participant on date of the Participant's death.

Section 2. Mid-Career Hire Benefit

2.1 Eligibility. Effective January 1, 2011, participation in the Mid-Career Hire Benefit was closed. Prior to January 1, 2011, the CEO selected Employees who were eligible for a Mid-Career Hire Benefit and who were granted extra Credited Service. These Employees are listed in Schedule A. Upon selection for participation in the SERP, the CEO designated the number of years of additional Credited Service to which such Participant shall be entitled to in the calculation of their Mid-Career Hire Benefit.

Each Participant listed on Schedule A that incurs a Separation from Service after becoming vested in their benefits payable under the Qualified Plan shall be eligible to receive a Mid-Career Hire Benefit. If a Participant described in the preceding sentence dies prior to commencement of payment of their Qualified Benefit, such Participant's Surviving Spouse shall be eligible to receive a Mid-Career Hire Surviving Spouse Benefit.

2.2 Benefit Formula. The Mid-Career Hire Benefit payable to an eligible Participant shall be equal to (a) or (b), as applicable:

(a) Final Average Pay Component Participant. The Mid-Career Hire Benefit payable to a Final Average Pay Component Participant shall be equal to the excess of (i) over (ii) where:

(i) Is the sum of (A) the amount of the Qualified Benefit, and (B) the amount of Reinstatement Benefit to which the Participant would have been entitled as of their Normal Retirement Date if such benefits were computed using the additional years of Credited Service granted to the Participant; and

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(ii) Is the sum of: (A) the Qualified Benefit, and (B) and Reinstatement Benefit as of their Normal Retirement Date.

The amounts described in (i) and (ii) shall be computed as of the date of Separation from Service of the Participant with PSEG and all Affiliates in the form of a single life annuity commencing on their Normal Retirement Date.

The Mid-Career Hire Benefit shall be calculated as a single life annuity commencing on the Participant's Normal Retirement Date. If payment of a Participant's Mid-Career Hire Benefit commences or is paid before their Normal Retirement Date, the benefit amount calculated pursuant to this paragraph (a) shall be reduced for early commencement in accordance with the early retirement reduction factors applicable to calculation of the Participant's benefit under the Final Average Pay Component.

For Final Average Pay Component Participants who incur a Separation from Service after December 31, 2011, the additional years of Credited Service shall be applied to the 7-year final average pay formula for the Qualified Benefit and Reinstatement Benefit.

(b) Cash Balance Component Participant. The Mid-Career Hire Benefit payable to a Cash Balance Component Participant shall be equal to the excess of (i) over (ii) where:

(i) Is the sum of (A) the amount of the Qualified Benefit, and (B) the amount of Reinstatement Benefit to which the Participant would have been entitled as of their Benefit Commencement Date if such benefits were computed using the additional years of Credited Service; and

(ii) Is the sum of: (A) the Qualified Benefit, and (B) Reinstatement Benefit as of their Benefit Commencement Date.

The Mid-Career Hire Benefit shall be calculated as of a single life annuity commencing on the Participant's Benefit Commencement Date.

The additional years of Credited Service shall be credited as of the Cash Balance Component Participant's date of hire once they become effective pursuant to individual agreement under which they were granted.

2.3 Form Payment.

(a) The Mid-Career Hire Benefit payable to a Participant shall be paid as follows:

(i) If the Participant's Separation from Service occurs prior to Retirement, the Mid-Career Hire Benefit shall be paid in a lump sum distribution (the lump sum amount shall be based on a deferred to age 65 lump sum factor).

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(ii) Except as provided in subsection (c), if the Participant's Separation from Service occurs on or after their Retirement, the Participant may elect to have the Mid-Career Hire Benefit paid in the form of a single life annuity or a joint and survivor annuity.

(A) The single life annuity option is an annuity providing equal monthly payments for the lifetime of the Participant with no survivor benefits.

(B) The joint and survivor annuity option is a reduced monthly benefit payable to the Participant for life and to a Beneficiary for the lifetime of the Beneficiary in an amount equal to 50 percent, 75 percent, or 100 percent (as elected by the Participant) of the amount payable during the Participant's lifetime. The pop-up rules under the Qualified Plan shall apply.

(b) A Participant election as to an annuity form of payment pursuant to paragraph (a)(ii) shall also apply to any benefits payable to the Participant under the Reinstatement Plan and the Limited Benefit. If a Participant fails to make a timely election, their Mid-Career Hire Benefit shall be paid in the form of:

(i) A single life annuity, if they are not married as of their Benefit Commencement Date; or

(i) A 50 percent joint and survivor annuity with their spouse as Beneficiary, if they are married as of their Benefit Commencement Date. The pop-up rules under the Qualified Plan shall apply.

If a Participant elects a joint and survivor annuity, but their Beneficiary dies before the Participant's Benefit Commencement Date, the Participant's Mid-Career Hire Benefit shall be paid in the form of a single life annuity unless the Participant validly elects a new form of payment pursuant to this subsection.

(c) Notwithstanding paragraphs (a) and (b), if the Participant's total vested benefit under the SERP and the Reinstatement Plan, as presently valued at the time of commencement of the payment of such benefit, does not exceed $30,000, benefits under the SERP and the Reinstatement Plan shall be paid in a single lump sum distribution. If the Participant does not meet the criteria for Retirement, the lump sum amount shall be based on the deferred to age 65 lump sum factor. If the Participant does meet the criteria for Retirement, the lump sum amount shall be based on the immediate lump sum factor.

2.4 Timing of Payment. Except as otherwise provided, payment of a Participant's Mid-Career Hire Benefit shall commence or shall be paid within the 90-day period following Benefit Commencement Date, but in no event later than the last day permitted under Section 409A of the

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Code for treating a delayed payment as having been made on such payment date. If a Mid-Career Hire Benefit is payable as a lump sum, no interest shall be paid to the Participant for the period between the Benefit Commencement Date and the actual payment date, except as provided for below with respect to Specified Employees.

If the Participant is a Specified Employee, payment of the Participant's Mid-Career Hire Benefit shall actually commence or shall be paid as of the last day of the month coinciding with or next following the six-month anniversary of the Participant's Separation from Service. In any case where the payment of benefits is delayed pursuant to this paragraph, the Participant's Mid-Career Hire Benefit shall be calculated as of the Benefit Commencement Date. Any annuity payments to which the Participant would be entitled during the first six months after their Separation from Service shall be accumulated and paid to the Participant without interest as of the last day of the month coinciding with or next following the six-month anniversary of their Separation from Service. If the Participant's Mid-Career Hire Benefit is payable in the form of a lump sum distribution, the benefit shall be increased with interest at the rate of:

(a) The first segment rate as determined pursuant to Section 417(e)(3)(C) and (D) of the Code for the second month preceding the first day of the Plan Year in which the Separation from Service occurs; or

(b) 6 percent, in the case of a Participant who is a participant in the Cash Balance Component.

Payment of the Participant's Mid-Career Hire Benefit shall not be delayed or accelerated, except as provided in this subsection. If the Employee Benefits Committee determines that a delay or acceleration of a Participant's Mid-Career Hire Benefit complies with the requirements of Section 409A of the Code (including an acceleration to pay employment taxes), the Employee Benefits Committee may either delay or accelerate the payment of the Mid-Career Hire Benefit in accordance with the terms of Section 409A of the Code as it deems advisable in its sole discretion. If any payment is delayed in accordance with this paragraph, the SERP shall pay such delayed payments without interest following the expiration of the delay.

2.5 A Mid-Career Hire Benefit which is payable in any form other than a single life annuity shall be the actuarial equivalent of the Mid-Career Hire Benefit set forth in Section 2.4 of the SERP, as determined by the same actuarial adjustments as those specified in the Qualified Plan, as applicable, with respect to determination of the amount of Qualified Benefit as of the Benefit Commencement Date, except as necessary to comply with Section 409A of the Code.

2.6 If a Participant who is receiving annuity payments under the SERP is rehired, such annuity payments shall continue during the period of reemployment. Since the Mid-Career Hire Benefit is closed to participation as of January 1, 2011, Participants rehired after such date shall not accrue an additional Mid-Career Hire Benefit.

2.7 Mid-Career Hire Surviving Spouse Benefit.

(a) Final Average Pay Component Participant. If a married Participant dies prior to commencement of payment of their Mid-Career Hire Benefit, a Mid-Career Hire

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Surviving Spouse Benefit shall be payable to the Participant's Surviving Spouse. The Mid-Career Hire Surviving Spouse Benefit shall be equal to the excess of (i) over (ii) where:

(i) Is the sum of: the amount of the Qualified Plan Surviving Spouse Benefit and the amount of Reinstatement Plan Surviving Spouse Benefit to which the Surviving Spouse would have been entitled under those plans, as of the Participant's Normal Retirement Date if such benefits were computed with the additional years of Credited Service; and

(ii) Is the sum of the Qualified Plan Surviving Spouse Benefit Surviving Spouse Benefit and Reinstatement Plan Surviving Spouse Benefit payable to the Surviving Spouse as of the Participant's Normal Retirement Date.

If applicable, the Mid-Career Hire Surviving Spouse Benefit shall be reduced for early commencement in accordance with the reduction factors applicable to calculation of a Qualified Plan Surviving Spouse Benefit.

(b) Cash Balance Component Participant. If a Participant dies prior to commencement of payment of their Mid-Career Hire Benefit, a Mid-Career Hire Surviving Spouse Benefit shall be payable to the Participant's Spouse. The Mid-Career Hire Surviving Spouse Benefit shall be equal to the excess of (i) over (ii) where:

(i) Is the sum of the amount of the Cash Balance Component account and the amount of Reinstatement Plan Surviving Spouse Benefit to which the Surviving Spouse would have been entitled under the Qualified Plan and the Reinstatement Plan, as of the Participant's Normal Retirement Date if such benefits were computed with the additional years of Credited Service; and

(ii) Is the sum of the Qualified Surviving Spouse Benefit and the Reinstatement Plan Surviving Spouse Benefit payable to the Surviving Spouse as of the Participant's Normal Retirement Date.

2.8 The Mid-Career Hire Surviving Spouse Benefit shall be paid as follows:

(a) If the Participant's death occurs prior to Retirement, the present value of the Mid-Career Hire Surviving Spouse Benefit shall be paid in a single lump sum distribution.

(b) If the Participant's death occurs on or after Retirement, the Mid-Career Hire Surviving Spouse Benefit shall be payable in monthly installments over the life of the Surviving Spouse. Notwithstanding the preceding sentence, if the present value of the total benefit payable to the Surviving Spouse under the SERP and the Reinstatement Plan does not exceed $20,000, the benefit payable shall be made in a single lump sum distribution.

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2.9 Payment of the Mid-Career Hire Surviving Spouse Benefit shall commence or shall be paid as of the last day of the month in which the Participant's death occurs and within 90 days after such date, but in no event later than the last day permitted under Section 409A of the Code for treating a delayed payment as having been made on such payment date.

2.10 With respect to Participants who had a Separation from Service prior to January 1, 2005, the provisions of the SERP as of December 31, 2004 regarding the timing and form of payment of Mid-Career Hire Benefits or Mid-Career Hire Surviving Spouse Benefits shall apply. The timing and form of payment of such Mid-Career Hire Benefits or Mid-Career Hire Surviving Spouse Benefits are linked to the timing and form of payment of the Qualified Benefits. As such, the SERP is considered "grandfathered" under Section 409A of the Code.

Section 3. Limited Benefits

3.1 Each Employee nominated by the CEO and designated by the Employee Benefits Policy Committee shall be a Schedule B Participant and shall be eligible to a Limited Benefit provided for in this Section 3 of the SERP. The CEO shall nominate such select and key Employees based upon such criteria as they shall deem appropriate due to the Employee's responsibilities and opportunity to contribute substantially to the financial and operating objectives of PSEG. The names of all Participants designated hereunder shall be listed in Schedule B to the SERP.

3.2 If a Schedule B Participant dies while in the active employment of PSEG or an Affiliate, the Participant's Beneficiary will receive an amount equal to 150% of the annual rate of salary of the Participant in effect at the date of death, adjusted to the nearest $1,000. Payment shall be made in a lump sum as of the first day of the month following the Participant's date of death, but in no event later than the last day permitted under Section 409A of the Code for treating a delayed payment as having been made on such payment date.

3.3 At Retirement, each Schedule B Participant will be eligible for a Limited Benefit calculated as provided in this Section 3 of the SERP.

Notwithstanding any other provision of the SERP to the contrary, the Limited Benefit hereunder payable to Frederick W. Lark and Richard D. Quinn, III, each of whom commenced a phased retirement during 2008, shall be calculated as of December 31, 2008 and shall be paid commencing as of January 31, 2009.

3.4 The Limited Benefit shall be calculated as follows:

(a) Final Average Pay Component Participants:

(i) The Participant's Compensation shall be multiplied by an amount equal to one one-hundredth of the sum of **(x)** the number of the Participant's years of Credited Service under the Final Average Pay Component at Retirement (including any additional years of age and Credited Service provided to the Participant in accordance with any employment, change in control, or similar arrangement applicable to the Participant so long as the

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Participant incurs a Separation from Service from PSEG and its Affiliates during the two-year period commencing upon the date of a Change in Control), **(y)** the number of any additional years of Credited Service credit to which the Participant may be entitled under Section 2 of the SERP or any written arrangement with PSEG or an Affiliate (excluding any written arrangement between PSEG or an Affiliate and the Participant relating to a Change in Control), and **(z)** 30; but, in no event, shall the multiple be greater than 0.75.

(ii) The amount determined under subparagraph (i) of this Section 3.4(a) shall be reduced by the sum of **(x)** the amount the Participant would be entitled to at Retirement as an annual pension benefit under the Final Average Pay Component, Section 2 of the SERP and the Reinstatement Plan calculated as a single life annuity payable at the Participant's Normal Retirement Date without reduction for any pre-retirement survivor's option coverage or any reduction for early retirement, **(y)** 100% of the amount of the unreduced annual Social Security benefit to which the Participant would be entitled at age 65 (or such other age which may be established by the Social Security Administration from time to time as the earliest age at which a Participant may receive an unreduced benefit thereunder), assuming that the Participant has no earnings from the date of Retirement to age 65 (or such other applicable age), or, if greater, any disability benefit under Social Security to which the Participant may be entitled, and **(z)** the aggregate of the annual benefits to which the Participant is entitled under all Retirement Plans as of the date the Participant is employed by PSEG or an Affiliate, such Social Security Benefits and benefits under all Retirement Plans to be calculated as single life annuities without any reductions, under rules, procedures and equivalents determined by the Employee Benefits Committee. To determine the amounts referred to under (y) and (z) above, the Participant shall file a declaration of all such amounts with the Corporate Benefits Department in such form as the Employee Benefits Committee may require from time to time. No benefit shall be paid under the SERP until such a declaration, in satisfactory form, shall be so filed. If a Participant is granted a disability Social Security benefit, they shall notify the Corporate Benefits Department thereof within 30 days thereof, and the Participant's retirement benefit under this section of the SERP shall be adjusted accordingly. The Company shall be entitled to rely on such statements in making payment, and if any such statement is incorrect or is not furnished, the Company shall be entitled to reimbursement from the Participant, the Beneficiary or their legal representatives for any overpayment and may reduce or suspend future payments to recover any such overpayment. In the event it is established to the satisfaction of the Employee Benefits Committee, in its sole discretion, that any such statement was intentionally false or omitted, the Participant or Beneficiary shall be entitled to no further payments under this section of the SERP, and the Company shall be entitled to recover any payments made hereunder.

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(iii) For Participants who incur a Separation from Service after December 31, 2011, the number of any additional years of Credited Service granted to a Participant under Subsection 3.4(a)(i)(y) of the SERP that a Participant may be entitled under Section 2 of the SERP or any written arrangement with PSEG or an Affiliate shall be applied to the 7-year final average pay formula. The 30 points credited to a Participant under Subsection 3.4(a)(i)(z) of the SERP shall be prorated based on the number of actual years of Credited Service that a Participant has as of December 31, 2011 and has during the period beginning on January 1, 2012 and ending on the date they incur a Separation from Service, without regard to any additional years of Credited Service granted to the Participant under Subsection 3.4(a)(i)(y) and without regards to any cap on Credited Service.

(b) Cash Balance Component Participants:

(i) The Participant's Compensation shall be multiplied by an amount equal to one one-hundredth of the sum of **(x)** the number of the Participant's years of Credited Service under the Final Average Pay Component with which such Participant would have been credited at Retirement had the Participant participated in the Final Average Pay Component from their date of hire and including any additional years of age and Credited Service provided to the Participant in accordance with any employment, change in control, or similar arrangement applicable to the Participant so long as the Participant incurs a termination of service from PSEG and its Affiliates during the two-year period commencing upon the date of a Change in Control, **(y)** the number of any additional years of Credited Service to which the Participant may be entitled under Section 3 of the SERP or any written arrangement with PSEG or an Affiliate (excluding any written arrangement between PSEG or an Affiliate relating to a Change in Control) and **(z)** 30; but, in no event, shall the multiple be greater than 0.75.

(ii) The amount determined under subparagraph (i) of this Subsection 3.4(b) shall be reduced by the sum of **(x)** the amount the Participant would be entitled to at Retirement as an annual pension benefit under the Cash Balance Component, Section 2 of the SERP and the Reinstatement Plan calculated as a single life annuity payable at the Participant's Normal Retirement Date**, (y)** 100% of the amount of the unreduced annual Social Security benefit to which the Participant would be entitled at age 65 (or such other age which may be established by the Social Security Administration from time to time as the earliest age at which a Participant may receive an unreduced benefit thereunder), assuming that the Participant has no earnings from the date of Retirement to age 65

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(or such other applicable age), or, if greater, any disability benefit under Social Security to which the Participant may be entitled, and **(z)** the aggregate of the annual benefits to which the Participant is entitled under all Retirement Plans as of the date the Participant is employed by PSEG or an Affiliate, such Social Security Benefits and benefits under all Retirement Plans to be calculated as single life annuities without any reductions, under rules, procedures and equivalents determined by the Employee Benefits Committee. To determine the amounts referred to under (y) and (z) above, the Participant shall file a declaration of all such amounts with the Corporate Benefits Department in such form as the Employee Benefits Committee may require from time to time. No benefit shall be paid under the SERP until such a declaration, in satisfactory form, shall be filed. If a Participant is granted a disability Social Security benefit, they shall notify the Corporate Benefits Department thereof within 30 days thereof, and the Participant's retirement benefit under the SERP shall be adjusted accordingly. The Company shall be entitled to rely on such statements in making payment, and if any such statement is incorrect or is not furnished, the Company shall be entitled to reimbursement from the Participant, the Beneficiary or their legal representatives for any overpayment and may reduce or suspend future payments to recover any such overpayment. In the event it is established to the satisfaction of the Employee Benefits Committee, in its sole discretion, that any such statement was intentionally false or omitted, the Participant or Beneficiary shall be entitled to no further payments under this section of the SERP, and the Company shall be entitled to recover any payments made hereunder.

(iii) For Participants who incur a Separation from Service after December 31, 2011, the number of any additional years of Credited Service granted to a Participant under Subsection 3.4(b)(i)(y) of the SERP that a Participant may be entitled under Section 2 of the SERP or any written arrangement with PSEG or an Affiliate shall be applied to the 7-year final average pay formula. The 30 points credited to a Participant under Subsection 3.4(b)(i)(z) of the SERP shall be prorated based on the number of actual years of Credited Service that a Participant has as of December 31, 2011 and has during the period beginning on January 1, 2012 and ending on the date they incur a Separation from Service, without regard to any additional years of Credited Service granted to the Participant under Subsection 3.4(b)(i)(y) and without regards to any cap on Credited Service.

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3.5 Forms of Payment.

(a) The annual amount determined under Section 3.4 shall be paid in the form of a life annuity; either a single life annuity or a joint and survivor annuity, as elected by the Participant.

(a) The single life annuity option is an annuity providing equal monthly payments for the lifetime of the Participant with no survivor benefits.

(i) The joint and survivor annuity option is a reduced monthly benefit payable to the Participant for life and to a surviving named Beneficiary for the lifetime of the Beneficiary in an amount equal to 50%, 75%, or 100% (as elected by the Participant) of the amount payable during the Participant's lifetime.

Notwithstanding the preceding provisions, if the present value of the Participant's total vested benefit under the Reinstatement Plan and the SERP does not exceed $30,000, their Limited Benefit shall be paid a single lump sum distribution. The lump sum amount shall be based on the immediate lump sum factor.

(b) A Participant may elect an annuity form of payment pursuant to paragraph (a) at any time before their Benefit Commencement Date. If a Participant fails to make a timely election, their retirement benefit shall be paid in the form of:

(i) A single life annuity, if they are not married as of their benefit commencement date; or

(ii) A 50 percent joint and survivor annuity with their spouse as Beneficiary, if they are married as of their benefit commencement date.

(c) Except as otherwise provided in this paragraph (c), payment of a Participant's Limited Benefit shall commence or be paid within the 90-day period following Benefit Commencement Date, but in no event later than the last day permitted under Section 409A of the Code for treating a delayed payment as having been made on such payment date.

If the Participant is a Specified Employee, payment of the Participant's Limited Benefit shall commence or shall be made as of the last day of the month coinciding with or next following the six-month anniversary of the Participant's Retirement date. In any case where the payment of benefits is delayed pursuant to this paragraph, the Participant's Limited Benefit shall be calculated as of the Participant's Benefit Commence Date. Any annuity payments to which the Participant would be entitled during the first six months after their Retirement shall be accumulated and paid to the Participant without interest as of the last day of the month coinciding with or next following the six-month anniversary of their Retirement.

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If the Participant's Limited Benefit is payable in the form of a lump sum distribution, the benefit shall be increased with interest at the first segment rate as determined pursuant to Section 417(e)(3)(C) and (D) of the Code for the second month preceding the first day of the Plan Year in which the Retirement occurs.

Payment of the Participant's benefit shall not be delayed or accelerated, except as provided in this subsection. If the Employee Benefits Committee determines that a delay or acceleration of a Participant's benefit complies with the requirements of Section 409A of the Code (including an acceleration to pay employment taxes), the Employee Benefits Committee may either delay or accelerate the payment of the benefit in accordance with the terms of Section 409A of the Code as it deems advisable in its sole discretion. If any payment is delayed in accordance with this paragraph, the SERP shall pay such delayed payments without interest following the expiration of the delay.

(d) If a Participant earns a Limited Benefit after a Retirement, any annuity benefits being paid to the Participant shall be increased to reflect such additional accruals as of the January 1 following the Plan Year in which such Limited Benefit accrues. If the Participant received a lump sum distribution of their Limited Benefit as of the earlier Retirement, the value of the additional accruals shall be paid to them in a lump sum distribution as of the January 1 following the Plan Year in which such additional benefit accrues.

Notwithstanding the foregoing, if a Participant named in Subsection 3.3 earns an additional retirement benefit after December 31, 2008, the additional accruals shall be payable as of the Participant's Retirement as otherwise provided in this Section 3.

3.6 With respect to Participants who had a Separation from Service prior to January 1, 2005, the provisions of the SERP as of December 31, 2004 regarding the timing and form of payment of Limited Benefits shall apply. The timing and form of payment of such Limited Benefits are linked to the timing and form of payment of the Qualified Benefits. As such, the SERP is considered "grandfathered" under Section 409A of the Code.

Section 4. Administration of the SERP

4.1 The Employee Benefits Committee shall be the named fiduciary of the SERP responsible for the general operation and administration of the SERP and for carrying out the provisions thereof. The Employee Benefits Committee shall have discretionary authority to construe the terms of the SERP and shall be the final arbiter of any questions that may arise under the SERP.

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4.2 The Employee Benefits Committee shall adopt such rules and procedures as it deems necessary and advisable to administer the SERP and to transact its business. Subject to the other requirements of this Section 4, the Employee Benefits Committee may:

(a) Employ agents to carry out non-fiduciary responsibilities;

(b) Employ agents to carry out fiduciary responsibilities (other than trustee responsibilities as defined in Section 405(c)(3) of ERISA);

(c) Consult with counsel, who may be counsel to PSEG or an Affiliate; and

(d) Provide for the allocation of fiduciary responsibilities (other than trustee responsibilities as defined in Section 405(c)(3) of ERISA) among its members.

However, any action described in paragraphs (b) or (d) of this Subsection 4.2, and any modification or rescission of any such action, may be effected by the Employee Benefits Committee only by a resolution approved by a majority of the Employee Benefits Committee. The Employee Benefits Committee shall be entitled to rely conclusively upon all tables, valuations, certificates, opinions and reports furnished by any actuary, accountant, controller, counsel or other person employed or engaged by the Employee Benefits Committee with respect to the SERP.

4.3 The Employee Benefits Committee shall keep written minutes of all its proceedings, which shall be open to inspection by the Board of Directors. In the case of any decision by the Employee Benefits Committee with respect to a claim for benefits under the SERP, such Employee Benefits Committee shall include in its minutes a brief explanation of the grounds upon which such decision was based.

4.4 In performing their duties, the members of the Employee Benefits Committee shall act solely in the interest of the Participants in the SERP and their Beneficiaries and

(a) For the exclusive purpose of providing benefits to Participants and their Beneficiaries;

(b) With the care, skill, prudence and diligence under the circumstances then prevailing that a prudent person acting in like capacity and familiar with such matters would use in the conduct of an enterprise of alike character and with like aims; and

(c) In accordance with the documents and instruments governing the SERP insofar as such documents and instruments are consistent with the provisions of Title I of ERISA.

4.5 In addition to any other duties the Employee Benefits Committee may have, the Employee Benefits Committee shall review the performance of all persons to whom the

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Employee Benefits Committee shall have delegated or allocated fiduciary duties pursuant to the provisions of this Section 4.

4.6 The Company agrees to indemnify and reimburse, to the fullest extent permitted by law, members of the Employee Benefits Committee, directors and employees of PSEG and its Affiliates, and all such former members, directors and employees, for any and all expenses, liabilities or losses arising out of any act or omission relating to the rendition of services for or the management and administration of the SERP.

4.7 No member of the Employee Benefits Committee nor any delegee thereof shall be personally liable by virtue of any contract, agreement or other instrument made or executed by them or on their behalf in such capacity.

Section 5. Claims Procedure and Status Determination

5.1 Claims for benefits under the SERP and requests for a status determination shall be filed in writing with the Employee Benefits Committee or its delegee.

5.2 In the case of a claim for benefits, written notice shall be given to the claiming Participant or Beneficiary of the disposition of such claim, setting forth specific reasons for any denial of such claim in whole or in part. If a claim is denied in whole or in part, the notice shall state that such Participant or Beneficiary may, within sixty days of the receipt of such denial, request in writing that the decision denying the claim be reviewed by the Employee Benefits Committee and provide the Employee Benefits Committee with information in support of their position by submitting such information in writing to the Secretary of the Employee Benefits Committee.

5.3 The Employee Benefits Committee shall review each claim for benefits which has been denied in whole or in part and for which such review has been requested and shall notify, in writing, the affected Participant or Beneficiary of its decision and the reasons therefor.

5.4 In the case of a request for status determination, written notice shall be given to the requesting person within a reasonable time setting forth specific reasons for the decision.

Section 6. Amendment or Termination

6.1 PSEG reserves the right to amend or terminate the SERP when, in the sole opinion of PSEG, such amendment or termination is advisable. Any such amendment or termination shall be made pursuant to a resolution of the Board or of the Employee Benefits Policy Committee and shall be effective as provided for in such resolution.

6.2 No amendment or termination of the SERP shall directly or indirectly deprive any current or former Participant, Beneficiary or Surviving Spouse of a previously acquired right unless such Participant or Beneficiary or legal representative shall consent to such change. Provided, further, however, that after a Change in Control, the SERP may not be terminated nor the benefit calculation reduced with respect to any Participant in the SERP on the date of such

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Change in Control unless such Participant or their Beneficiary or their legal representative shall consent to such change. No right to a death benefit under Section 3 of the SERP shall accrue until a Schedule B Participant's death and no right to a Limited Benefit under Section 3 of the SERP shall accrue until a Schedule B Participant's Retirement.

6.3 In the event of the termination of the SERP, vested benefits hereunder shall be distributed in a single lump sum as soon as practicable after the date the SERP is terminated if such distribution is permitted because the SERP is terminated in accordance with the termination provisions of Section 409A of the Code and related regulations or, in other cases, at the earliest time otherwise permitted under the terms of the SERP in accordance with Section 409A of the Code and related regulations.

Section 7. General Provisions

7.1 The SERP at all times shall be entirely unfunded and no provision shall at any time be made with respect to segregating any assets of PSEG or any Affiliate for payment of any benefits hereunder. No Participant, Beneficiary, Surviving Spouse or any other person shall have any interest in any particular assets of PSEG or any Affiliate by reason of the right to receive a benefit under the SERP and any such Participant, Beneficiary, Surviving Spouse or other person shall have only the rights of a general unsecured creditor with respect to any rights under the SERP.

7.2 Except as otherwise expressly provided herein, all terms and conditions of the Qualified Plan applicable to a Qualified Benefit or a Qualified Surviving Spouse Benefit shall also be applicable to a SERP Benefit or a SERP Surviving Spouse Benefits payable hereunder. Any Qualified Benefit or Qualified Surviving Spouse Benefit, or any other benefit payable under the Qualified Plan shall be paid solely in accordance with the terms and conditions of the Qualified Plan and nothing in the SERP shall operate or be construed in any way to modify, amend or affect the terms and provisions of the Qualified Plan.

7.3 Nothing contained in the SERP shall constitute a guaranty by the Company or any other entity or person that the assets of PSEG or any Affiliate will be sufficient to pay any benefit hereunder.

7.4 No Participant or Surviving Spouse shall have any right to a benefit under the SERP except in accordance with the terms of the SERP. The payment of any death or survivorship benefit under the SERP shall be contingent upon such evidence of death as may be reasonably required by the Employee Benefits Committee.

7.5 The SERP shall not constitute a contract for the continued employment of any Participant by the Company or any Affiliate. PSEG and each Affiliate reserve the right to modify a Participant's Compensation at any time and from time to time as it considers appropriate and to terminate any Participant's employment for any reason at any time notwithstanding the SERP.

7.6 No interest of any person or entity in, or right to receive a benefit under, the SERP shall be subject in any manner to sale, transfer, assignment, pledge, attachment, garnishment or

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other alienation or encumbrance of any kind; nor any such interest or right to receive a benefits be taken, either voluntarily or involuntarily, for the satisfaction of the debts of, or other obligations or claims against, such person or entity, including claims for alimony, support, separate maintenance and claims in bankruptcy proceedings.

7.7 The SERP shall be construed and administered under the laws of the United States and the State of New Jersey to the extent not superseded by Federal law. The SERP is specifically intended to comply with the provisions of Section 409A of the Code and it shall automatically incorporate all applicable restrictions of Section 409A of the Code and its related regulations, and PSEG will amend the SERP to the extent necessary to comply with those requirements. The timing under which a Participant will have a right to receive any payment under the SERP will be deemed to be automatically modified, and a Participant's rights under the SERP limited to conform to any requirements under Section 409A of the Code.

7.8 Actuarial assumptions to determine the present value of any benefit hereunder shall be the same as used to determine the present value of benefits under the Qualified Plan.

7.9 If any person entitled to a benefit payment under the SERP is deemed by the Employee Benefits Committee to be incapable of personally receiving and giving a valid receipt for such payment, then, unless and until claim therefor shall have been made by a duly appointed guardian or other legal representative of such person, the Employee Benefits Committee may provide for such payment or any part thereof to be made to any other person or institution then contributing toward or providing for the care and maintenance of such person. Any such payment shall be a payment for the account of such person and a complete discharge of any liability of the Company and the SERP therefor.

7.10 The SERP shall inure to the benefit of and be binding upon the Company, its successors and assigns, including but not limited to any corporation which may acquire all or substantially all of the Company's assets or businesses or with or into or which the Company may be consolidated or merged.

7.11 Any notice to a Participant, a Beneficiary or any legal representative hereunder shall be given in writing, by personal delivery, overnight express service or by United States mail, postage prepaid, addressed to such person's last known address. Any notice to the Company or the Employee Benefits Committee hereunder (including the filing of beneficiary designations) shall be given by delivering it in person or by overnight express service, or depositing it in the United States mail, postage prepaid, to the Secretary of the Employee Benefits Committee, Public Service Enterprise Group Incorporated, 80 Park Plaza, T-5, P.O. Box 1171, Newark, New Jersey, 07101.

7.12 Each Participant shall keep the Company informed of their current address and the current address of their spouse. The Company shall not be obligated to search for the whereabouts of any person. If the location of a Participant is not made known to the Company within three (3) years after the date on which payment of the Participant's SERP Benefit may first be made, payment may be made as though the Participant had died at the end of the three-year period. If, within one additional year after such three-year period has elapsed, or,

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within three years after the actual death of a Participant, the Company is unable to locate any Surviving Spouse of the Participant, then the Company shall have no further obligation to pay any benefit hereunder to such Participant or Surviving Spouse or any other person and such benefit shall be irrevocably forfeited.

7.13 Failure by the Company or the Employee Benefits Committee to insist upon strict compliance with any of the terms, covenants or conditions hereof shall not be deemed a waiver of any such term, covenant or condition, nor shall any waiver or relinquishment of any right or power hereunder at any one or more times be deemed a waiver or relinquishment of any such right or power at any other time or times.

7.14 The invalidity or unenforceability of any provision hereof shall in no way affect the validity or enforceability of any other provision of the SERP.

7.15 Notwithstanding any of the preceding provisions of the SERP, the Company, the Employee Benefits Committee or any individual acting as an employee or agent of the Company or the Employee Benefits Committee shall be liable to any Participant, former Participant, Surviving Spouse or any other person for any claim, loss, liability or expense incurred in connection with the SERP.

Section 8. Miscellaneous

8.1 As used herein, words in the masculine gender shall include the feminine and the singular shall include the plural, and vice versa, unless otherwise required by the context. Any headings used herein are included for ease of reference only and are not to be construed so as to alter the terms hereof.

* * *

/s/ Margaret M Pego ___July 10, 2017
Signature Date

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MID-CAREER HIRE BENEFITS

SCHEDULE A
PARTICIPANTS

1. Edwin Eilola Director Projects
2. Davison, Paul J. VP Nuclear Engineering
3. Izzo, Ralph Chairman of Board, President & CEO-PSEG
4. Knaide, Kenneth M. Sr. Dir. Engineering

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LIMITED BENEFITS

SCHEDULE B
PARTICIPANTS

1. Bishop, Craig, J. Sr. Director - IT Infrastructure & Ops
2. Cardenas, Jorge L. VP-Asset Mgmt & Centralized Srvs
3. Castellano, Raymond C. Mgr Application Support
4. Doherty, John F. Associate Gen. Environ. Counsel
5. Izzo, Ralph Chairman of Board, President & CEO-PSEG
6. Krueger, Jr. Robert C. VP - Assistant Controller - Tax
7. LaRossa, Ralph A. President & COO PSE&G & COB PSEG LI
8. Leibowitz, Donald S. Associate Gen. Corp Counsel
9. Levis, William (eff. 1/16/13) President & COO
10. Leyden, Shawn P. VP & Deputy General Counsel
11. MacDonald, Joan C. Project Mgr.
12. Mack, Ronald J. Exec. Director Medical
13. Mnich, Lorraine Mgr. Corp Capital Invest
14. Orticelle, Arthur (retired 4/1/17) Division Manager - Electric
15. Oster, Steven B. Dir. Asset Portfolio
16. Pego, Margaret M. SVP - HR & Chief HR Officer
17. Quinn, Kevin J. VP - Finance Power
18. Scarlata, John P. (retired 34/4/17_ VP - Gas Supply
19. Schroeder, Brian H. Principal Enterprise Architect
20. Sugam, Richard J. Dir. EH&S Compliance & Planning
21. Tripodi, Raymond A. Mgr. Transmission Permitting
22. Tuosto, Michael R. General Manager Public Affairs
23. Wernsing, Richard W. Dir. Strategic Rel & Delivery Planning
24. Weyant, Donald W. Mgr. Regulatory Compliance

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Exhibit 10.2

RETIREMENT INCOME REINSTATEMENT PLAN

FOR NON-REPRESENTED EMPLOYEES OF

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

AND ITS AFFILIATES

Amended January 1, 2017

S1-SSA-0009 - 17901

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**RETIREMENT INCOME REINSTATEMENT PLAN
FOR NON-REPRESENTED EMPLOYEES OF
PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
AND ITS AFFILIATES**

Public Service Electric and Gas Company ("PSE&G") had established, effective January 1, 1995, the Retirement Income Reinstatement Plan for Non-Represented Employees of Public Service Electric and Gas Company and its Affiliates. Effective December 13, 1999, PSE&G transferred sponsorship of the plan to Public Service Enterprise Group Incorporated ("PSEG") and renamed the plan the Retirement Income Reinstatement Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated and its Affiliates ("Reinstatement Plan").

The Reinstatement Plan was established for the purpose of assisting in attracting and retaining a stable pool of key managerial and professional talent and long-term key employee commitment by providing certain supplemental retirement benefits for certain of their employees who participate in a Qualified Plan.

The Reinstatement Plan is intended to constitute an unfunded "excess benefit plan" as defined in Section 3(36) of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), to the extent it provides benefits that would be paid under the Pension Plan but for the limitations of Section 415 of the Internal Revenue Code of 1974, as amended ("Code"), and an unfunded plan of deferred compensation for a select group of management or highly compensated employees for purposes of Title 1 of ERISA, to the extent it provides other benefits.

The Reinstatement Plan was amended, effective as of January 1, 2005, to comply with the requirements of the American Jobs Creation Act of 2004.

The Reinstatement Plan was amended, effective as of January 1, 2009, to provide for lump sum payments of certain benefits, to revise provisions relating to lump sum payments of de minimis benefits, to align the Reinstatement Plan to certain requirements of Section 409A of the Code, and to make certain other style and conforming changes. The terms contained therein superseded all prior iterations of the Reinstatement Plan.

The Reinstatement Plan was amended effective as of January 1, 2012 to reflect the change in the benefit formula under the Pension Plan from a 5-year final average pay formula to a 7-year final average pay formula.

The Reinstatement Plan is being amended effective January 1, 2017 to make certain administrative clarifications.

Section 1. Definitions

When used herein, the words and phrases hereinafter defined shall have the following meanings unless a different meaning is clearly required by the context of the Reinstatement Plan:

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1.1 "Affiliate" shall mean (a) any organization while it is a member of a controlled group of corporations (as defined in Section 414(b) of the Code) which includes PSEG; or (b) any trades or businesses (whether or not incorporated) while they are under common control (as defined in Section 414(c) of the Code) with PSEG.

1.2 "Beneficiary" shall mean any person or persons designated by a Participant who may become eligible to receive benefits provided under this Reinstatement Plan in the event of such Participant's death.

1.3 "Benefit Commencement Date" shall mean the date that is the Participant's last day worked plus one day.

1.4 "Board of Directors" or "Board" shall mean the Board of Directors of Public Service Enterprise Group Incorporated.

1.5 "Cash Balance Component" shall mean the Cash Balance Component of the Pension Plan". The Cash Balance Component was formerly the Public Service Enterprise Group Incorporated Cash Balance Pension Plan.

1.6 "Code" shall mean the Internal Revenue Code of 1986, as amended. A reference to a section of the Code shall also refer to any regulations and other guidance issued under that section.

1.7 "Company" shall mean Public Service Enterprise Group Incorporated and each Participating Affiliate.

1.8 "Compensation" with respect to any Participant shall mean base salary, bonuses (as described below) and overtime up to 20% of base salary. Compensation shall include amounts deferred to the Deferred Compensation Plan for Certain Employees of Public Service Enterprise Group Incorporated and its Affiliates ("Deferred Compensation Plan"). For the period prior to March 5, 2010, refer to the prior Reinstatement Plan document for the definition Compensation.

For purposes of calculating the Reinstatement Benefit payable to a Participant who is a participant in the Cash Balance Component, Compensation shall not include amounts paid prior to 2006 under the Management Incentive Compensation Plan ("MICP") or the Senior Management Incentive Compensation Plan ("SMICP"). For Participants who are participants in the Cash Balance Component, Compensation for any such year shall not exceed 150 percent of the Participant's annual base salary in effect as of January 1 of that year.

For clarification purposes, all bonuses paid under the PSEG Power LLC Incentive Compensation Program for PSEG Energy Resources & Trade LLC Employees ("ER&T Plan"), as limited hereunder, the Performance Incentive Plans (PIPs") and the PSEG Power LLC Incentive Compensation Program for Certain Employees of PSEG Energy Solutions LLC ("Energy Solutions Plan") are included in Compensation, except those paid under the Long Island Electric Utility ServCo LLC Performance Incentive Plan.

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Bonuses paid under the PIP, Energy Solutions Plan, MICP, SMICP and the ER&T Plan are included in Compensation only if the bonus is paid prior to the date of the Participant's Separation from Service.

For the year in which the Participant is hired, the base salary in effect as of the date of hire shall be used. For Participants who are rehired, the base salary as of the date of rehire shall be used for determining Compensation of the year of the rehire.

1.9 "Employee" shall mean any individual in the employ of the Company who is not included within a unit of employees covered by a collective bargaining agreement. The term "Employee" shall not include a director of the Company who serves in no capacity other than as a director, a consultant or independent contractor doing work for the Company or a person employed by a consultant or independent contractor doing work for the Company or a Participating Affiliate (regardless of whether a determination is made by the Internal Revenue Service or other governmental agency or court after the individual is engaged to perform such services that the individual is an employee of the Company for the purposes of the Code or otherwise).

1.10 "Employee Benefits Committee" shall mean the Employee Benefits Committee of Public Service Enterprise Group Incorporated.

1.11 "Employee Benefits Policy Committee" shall mean the Employee Benefits Policy Committee of Public Service Enterprise Group Incorporated.

1.12 "ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended. A reference to a section of ERISA shall also refer to any regulations and other guidance issued under that section.

1.13 "Final Average Earnings" with respect to a Participant who is entitled to a benefit under the Final Average Pay Component:

(a) And who incurs a Separation from Service before January 1, 2012, shall mean the annual average of the sum of:

(1) The Participant's **highest** five years of Compensation, excluding any amounts received as an award under the MICP or the SMICP, without the application of the base pay cap in Section 1.8; and

(2) The MICP or SMICP awards for the five **most recent** bonus eligible years (including $0 awards) prior to the Participant's Separation from Service. If a Participant does not have at least five MICP/SMICP awards, the average shall be determined by using the number of bonus (including PIP bonuses, ER&T Plan bonuses and Energy Solutions Plan bonuses) eligible periods during the five most recent years.

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Notwithstanding the foregoing, Final Average Earnings shall not exceed 150 percent of the average of the Participant's annual base salary in effect as of January 1 for the five years prior to and including the year in which the Participant's Separation from Service occurs. However, for a Participant who receives an award under the ER&T Plan, Final Average Earnings shall not be less than their Final Average Earnings determined as of December 31, 2006 in accordance with the preceding paragraph, without applying the 150 percent cap in the preceding sentence.

Bonuses paid under the PIP, Energy Solutions Plan, MICP, SMICP and the ER&T Plan are included in Compensation only if the bonus is paid prior to the date of the Participant's Separation from Service.

(b) With respect to a Participant who incurs a Separation from Service on or after January 1, 2012 and who is entitled to a benefit under the Final Average Pay Component, Final Average Earnings shall mean:

(1) With respect to periods of service prior to January 1, 2012, Final Average Earnings shall be determined in accordance with subsection (a) above, except that Separation from Service shall be replaced with December 31, 2011.

(2) With respect to periods of service after December 31, 2011, the annual average of the sum, (i) the Participant's highest seven years of Compensation beginning after December 31, 2011, excluding any MICP and SMICP awards, and (ii) the MICP or SMICP awards for the seven **most recent** years (including $0 awards) beginning after December 31, 2011 and prior to the Participant's Separation from Service, without the application of the base pay cap in Section 1.8. If a Participant does not have at least seven MICP/SMICP awards during the seven most recent years after 2011, the average shall be determined by using the number of bonus (including PIP bonuses, ER&T Plan bonuses and Energy Solutions Plan bonuses) eligible periods after 2011 during the seven most recent years.

Notwithstanding the foregoing, Final Average Earnings shall not exceed 150 percent of the average of the Participant's annual base salary in effect as of January 1 for the seven years prior to and including the year in which the Participant's Separation from Service occurs (the annual base salary prior to January 1, 2012 shall not be used in such determination).

Bonuses paid under the PIP, Energy Solutions Plan, MICP, SMICP and the ER&T Plan are included in Compensation only if the bonus is paid prior to the date of the Participant's Separation from Service.

1.14 "Final Average Pay Component" shall mean the Final Average Pay Component of the Pension Plan.

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1.15 "Normal Retirement Date" shall mean the first day of the month coinciding with or next following a Participant's attainment of age 65. In the case of a Participant who is still employed beyond age 65, Normal Retirement Date shall mean the first day of the month coinciding with or next following the date on which the Participant's Separation from Service occurs.

1.16 "Participant" shall mean any Employee or former Employee of the Company who meets the requirements of Subsection 2.1 of the Reinstatement Plan.

1.17 "Participating Affiliate" shall mean any Affiliate of PSEG which (a) is the sponsor or a Participating Affiliate of the Qualified Plan; (b) adopts the Reinstatement Plan with the approval of the Board of Directors; (c) authorizes the Board of Directors and the Employee Benefits Committee to act for it in all matters arising under or with respect to the Reinstatement Plan; and (d) complies with such other terms and conditions relating to the Reinstatement Plan as may be imposed by the Board of Directors. Participating Affiliate shall not include Long Island Electric Utility ServCo LLC.

1.18 "Pension Plan" shall mean the Pension Plan of Public Service Enterprise Group Incorporated and each successor or replacement plan.

1.19 "Qualified Benefit" shall mean the aggregate annual benefit payable to a Participant pursuant to the Qualified Plan, by reason of the Participant's termination of employment with the Company and all Affiliates for any reason other than death.

1.20 "Qualified Plan" shall mean the Final Average Pay Component or the Cash Balance Component.

1.21 "Qualified Surviving Spouse Benefit" shall mean the aggregate annual benefit payable to the Surviving Spouse of a Participant pursuant to the Qualified Plan, as the case may be, in the event of the death of the Participant at any time prior to commencement of payment of the Qualified Benefit.

1.22 "Plan Year" shall mean the calendar year.

1.23 "Reinstatement Plan" shall mean this Retirement Income Reinstatement Plan for Non--Represented Employees of Public Service Enterprise Group Incorporated and its Affiliates.

1.24 "Retirement" shall be defined as follows:

(a) In the case of a Participant who is a participant in the Final Average Pay Component, Retirement shall mean a Separation from Service either (1) after attaining age 65; (2) when the sum of the Participant's age and credited service (as defined in the Final Average Pay Component) equals or exceeds 80, or (3) a disability determination under the Final Average Pay Component.

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(b) In the case of a Participant who is a participant in the Cash Balance Component, Retirement shall mean a Separation from Service after either (1) attaining age 65, (2) attaining age 55 and completing five or more years of credited service (as defined in the Cash Balance Component), or (3) a disability determination under the Cash Balance Component.

1.25 "Separation from Service" shall mean, subject to subsections (a) and (b), a Participant's termination from employment with PSEG and all Affiliates, whether by retirement or resignation from or discharge by PSEG or an Affiliate.

(a) A Separation from Service shall be deemed to have occurred if a Participant and PSEG or any Affiliate reasonably anticipates, based on the facts and circumstances, that either:

(1) The Participant will not provide any additional services for PSEG or an Affiliate after a certain date; or

(2) The level of bona fide services performed by the Participant after a certain date will permanently decrease to no more than 50 percent of the average level of bona fide services performed by the Participant over the immediately preceding 36 months.

(b) If a Participant is absent from employment due to military leave, sick leave, or any other bona fide leave of absence authorized by PSEG or an Affiliate and there is a reasonable expectation that the Participant will return to perform services for PSEG or an Affiliate, a Separation from Service will not occur until the later of:

(1) The first date immediately following the date that is six months after the date that the Participant was first absent from employment; or

(2) The date the Participant no longer retains a right to reemployment, to the extent the Participant retains a right to reemployment with PSEG or any Affiliates under applicable law or by contract.

If a Participant fails to return to work upon the expiration of any military leave, sick leave, or other bona fide leave of absence where such leave is for less than six months, the Separation from Service shall occur as of the date of the expiration of such leave.

1.26 "SERP" shall mean the Supplemental Executive Retirement Income Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated and Its Affiliates.

1.27 "Specified Employee" shall mean an individual who is a key employee (as defined in Section 416(i) of the Code without regard to Section 416(i)(5) of the Code) of PSEG or an Affiliate at any time during the 12-month period ending on each December 31 (the "identification date"). If an individual is a key employee as of an identification date, the

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individual shall be treated as a Specified Employee for the 12-month period beginning on the April 1 following the identification date. Notwithstanding the foregoing, an individual shall not be treated as a Specified Employee unless any stock of PSEG or an Affiliate is publicly traded on an established securities market or otherwise.

1.28 "Reinstatement Benefit" shall mean the benefit payable to a Participant pursuant to the Reinstatement Plan by reason of the Participant's Separation from Service with PSEG and all Affiliates for any reason other than death.

1.29 "Surviving Spouse" shall mean a person who is married to a Participant at the date of the Participant's death.

1.30 "Reinstatement Surviving Spouse Benefit" shall mean the benefit payable to a Surviving Spouse pursuant to the Reinstatement Plan.

Section 2. Eligibility

2.1 An Employee may be eligible for a Reinstatement Benefit under the Reinstatement Plan if:

(a) For a Cash Balance Component participant, the Employee's Compensation for a Plan Year is in excess of the Section 401(a)(17) limit for such Plan Year;

(b) For a Final Average Pay Component participant, the Employee's Compensation for a twelve month period used in the Final Average Earnings calculation is in excess of the Section 401(a)(17) limit for such twelve month period.

(c) An Employee's whose Qualified Benefit exceeds the limit under Section 415(b) of the Code.

(d) An Employee who receives a bonus under the MICP or SMICP, or receives an ER&T Plan bonus above 150% of base pay.

(e) An Employee who pursuant to an individual agreement receives additional years of service that is not taken into account under SERP.

(f) Any other circumstances determined by PSEG.

2.2 The Surviving Spouse of a Participant who dies prior to commencement of payment of their Reinstatement Benefit shall be eligible to receive a Reinstatement Surviving Spouse Benefit under the Reinstatement Plan.

2.3 If a Participant was covered under a collective bargaining agreement prior to becoming an Employee, such Participant's service, Compensation and Qualified Benefit prior to the date the Participant became an Employee shall not be taken into account for purposes of benefit accrual under the Reinstatement Plan, but shall be taken into account for purposes of vesting and Retirement eligibility.

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Section 3. Reinstatement Benefit

3.1 The Reinstatement Benefit payable to an eligible Participant shall be determined as follows:

(a) A Participant in the Final Average Pay Component who incurs a Separation from Service and who is eligible for a Reinstatement Benefit shall be entitled to receive a benefit as of their Normal Retirement Date equal to the excess of (1) over (2) where:

(1) Is the amount of the Qualified Benefit to which the Participant would have been entitled under the Final Average Pay Component as of their Normal Retirement Date if such benefit were computed by applying the definition of Final Average Earnings under the Reinstatement Plan ; and

(2) Is the amount of the Participant's Qualified Benefit under the Final Average Pay Component as of their Normal Retirement Date.

(b) This Reinstatement Benefit shall be calculated as a single life annuity commencing on the Participant's Normal Retirement Date. If payment of a Participant's Reinstatement Benefit commences or is paid before their Normal Retirement Date, the benefit amount calculated pursuant to paragraph (a) or paragraph (b) shall be reduced for early commencement in accordance with the early retirement reduction factors applicable to calculation of the Participant's benefit under the Final Average Pay Component.

(c) Notwithstanding any other provision of the Reinstatement Plan to the contrary, the Reinstatement Benefit payable to Frederick W. Lark and Richard D. Quinn, III, shall be calculated as of December 31, 2008 and shall be paid commencing as of January 31, 2009.

(d) A Participant in the Cash Balance Component who is eligible for a Reinstatement Benefit shall be entitled to receive a benefit as of their Benefit Commencement Date equal to the excess of (1) over (2) where:

(1) Is the amount of the Qualified Benefit to which the Participant would be entitled under the Cash Balance Component as of their Benefit Commencement Date if such benefit were computed by applying the definition of Compensation under the Reinstatement Plan; and

(2) Is the amount of the Qualified Benefit payable to the Participant under the Cash Balance Component as of their Benefit Commencement Date.

(e) Notwithstanding any other provision of the Reinstatement Plan to the contrary, a Reinstatement Benefit shall be payable to a Participant in the Final Average Pay Component if the amount of the Participant's QSERP under the Qualified Plan is

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more than the sum of the Participant's Qualified Plan and Reinstatement Benefit, absent the QSERP. The amount of the Reinstatement Benefit is the difference between the QSERP amount and the sum of the Participant's Qualified Plan and Reinstatement Benefit, absent the QSERP.

3.2 The Reinstatement Benefit payable to Participant shall be paid:

(a) If the Participant's Separation from Service occurs prior to Retirement, the present value of their Reinstatement Benefit shall be paid in a single lump sum distribution (the lump sum amount shall be based on the deferred to age 65 lump sum factor);

(b) Except as otherwise provided in paragraph (d), if the Participant's Separation from Service occurs on or after their Retirement, the Participant may elect to receive their Reinstatement Benefit in the form of a single life annuity or a joint and survivor annuity.

(1) The single life annuity option is an annuity providing equal monthly payments for the lifetime of the Participant with no survivor benefits.

(2) The joint and survivor annuity option is a reduced monthly benefit payable to the Participant for life and to a surviving named Beneficiary for the lifetime of the Beneficiary in an amount equal to 50 percent, 75 percent, or 100 percent (as elected by the Participant) of the amount payable during the Participant's lifetime. The pop-up rules under the Qualified Plan shall apply to the Reinstatement Benefit.

(c) A Participant election as to an annuity form of payment pursuant to paragraph (b) shall also apply to any benefits payable to the Participant under the SERP. If a Participant fails to make a timely election, their Reinstatement Benefit shall be paid in the form of:

(1) A single life annuity, if they are not married as of their Benefit Commencement Date; or
(2) A 50 percent joint and survivor annuity with their spouse as Beneficiary, if they are married as of their Benefit Commencement Date. The pop-up rules under the Qualified Plan shall apply to the Reinstatement Benefit.

If a Participant elects a joint and survivor annuity, but their Beneficiary dies before the Participant's Benefit Commencement Date, the Participant's Reinstatement Benefit shall be paid in the form of a single life annuity unless the Participant validly elects a new form of payment pursuant to this subsection.

(d) Notwithstanding paragraphs (b) and (c), if the Participant's total vested benefit under the Reinstatement Plan and the SERP, as presently valued at the time of commencement of the payment of such benefit, does not exceed $30,000, their

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benefit under the Reinstatement Plan and the SERP shall be paid in a single lump sum distribution. If the Participant does not meet the criteria for Retirement, the lump sum amount shall be based on the deferred to age 65 lump sum factor. If the Participant does meet the criteria for Retirement, the lump sum amount shall be based on the immediate lump sum factor.

3.3 Except as otherwise provided in this subsection, payment of a Participant's Reinstatement Benefit shall commence or shall be paid within the 90-day period following Benefit Commencement Date, but in no event later than the last day permitted under Section 409A of the Code for treating a delayed payment as having been made on such payment date. Except as provided for below with respect to Specified Employees, if a Reinstatement Benefit is payable as a lump sum, no interest shall be paid to the Participant for the period between the Benefit Commencement Date and the actual payment date.

If the Participant is a Specified Employee, payment of the Participant's Reinstatement Benefit shall commence or shall be paid as of the last day of the month coinciding with or next following the six-month anniversary of the Participant's Separation from Service. In any case where the payment of benefits is delayed pursuant to this paragraph, the Participant's Reinstatement Benefit shall be calculated as of the Benefit Commencement Date. Any annuity payments to which the Participant would be entitled during the first six months after their Separation from Service shall be accumulated and paid to the Participant without interest as of the last day of the month coinciding with or next following the six-month anniversary of their Separation from Service. If the Participant's Reinstatement Benefit is payable in the form of a lump sum distribution, the benefit shall be increased with interest at the rate of:

(a) The first segment rate as determined pursuant to Section 417(e)(3)(C) and (D) of the Code for the second month preceding the first day of the Plan Year in which the Separation from Service occurs; or

(b) 6 percent, in the case of a Participant who is a participant in the Cash Balance Component.

Payment of the Participant's Reinstatement Benefit shall not be delayed or accelerated, except as provided in this subsection. If the Employee Benefits Committee determines that a delay or acceleration of a Participant's Reinstatement Benefit complies with the requirements of Section 409A of the Code (including an acceleration to pay employment taxes), the Employee Benefits Committee may either delay or accelerate the payment of the Reinstatement Benefit in accordance with the terms of Section 409A of the Code as it deems advisable in its sole discretion. If any payment is delayed in accordance with this paragraph, the Reinstatement Plan shall pay such delayed payments without interest following the expiration of the delay.

3.4 A Reinstatement Benefit which is payable in any form other than a single life annuity, shall be the actuarial equivalent of the Reinstatement Benefit set forth in Subsection 3.1 above as determined by the same actuarial adjustments as those specified in the Qualified Plan, as the case may be, with respect to determination of the amount of the Qualified Benefit as of the

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Benefit Commencement Date, except as otherwise necessary to comply with Section 409A of the Code.

3.5 If a Participant who is receiving annuity payments under the Reinstatement Plan is rehired, such annuity payments shall continue during the period of reemployment. If such Participant accrues an additional Reinstatement Benefit based on their rehired service, the additional Reinstatement Benefit shall be paid the same annuity form (or, if the Participant had elected a joint and annuity survivor annuity and the Beneficiary had died or the Participant was married and is no longer married on the second Benefit Commencement Date, an actuarially equivalent single life annuity).

If a Participant who received a lump sum from the Reinstatement Plan and was not retirement eligible at that time is rehired, and accrues an additional Reinstatement Benefit based on their rehired service, the additional accrual shall be paid in accordance with this Section 3, provided that the payment is in accordance with Section 409A of Code.

If a Participant who received a lump sum from the Reinstatement Plan and was retirement eligible at that time is rehired, and accrues an additional Reinstatement Benefit based on their rehired service, the additional accrual shall be paid in accordance with this Section 3, provided that the payment is in accordance with Section 409A of Code.

3.6 With respect to Participants who had a Separation from Service prior to January 1, 2005, the provisions of the Reinstatement Plan in effect on December 31, 2004 regarding the timing and form of payment of Reinstatement Benefits shall apply. The timing and form of payment of such Reinstatement Benefits are linked to the timing and form of payment of the Qualified Benefits. As such, the Reinstatement Plan is considered "grandfathered" under Section 409A of the Code.

Section 4. Reinstatement Surviving Spouse Benefit

4.1 If a Participant dies prior to commencement of payment of their Qualified Benefit under circumstances in which a Qualified Plan Surviving Spouse Benefit is payable to their Surviving Spouse, then a Reinstatement Surviving Spouse Benefit shall be payable to their Surviving Spouse as follows:.

(a) In the case of a Participant in the Final Average Pay Component, the Reinstatement Surviving Spouse Benefit shall be determined as of the Participant's Normal Retirement Date equal to the excess of (1) over (2) where:

(1) Is the amount of the Qualified Plan Surviving Spouse Benefit to which the Surviving Spouse would have been entitled under the Final Average Pay Component if such benefit were computed by applying the definition of Final Average Earnings under the Reinstatement Plan; and

(b) Is the amount of the Qualified Plan Surviving Spouse Benefit under the Final Average Pay Component.

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The Reinstatement Surviving Spouse Benefit shall be calculated as a single life annuity commencing on the Participant's Normal Retirement Date. If payment of the Reinstatement Surviving Spouse Benefit commences or is paid before the Participant's Normal Retirement Date, the benefit amount calculated pursuant to this paragraph (a) shall be reduced for early commencement, if applicable, in accordance with the reduction factors applicable to calculation of a Qualified Plan Surviving Spouse Benefit.

(b) In the case of a Participant in the Cash Balance Component, the Reinstatement Surviving Spouse Benefit shall be equal to the excess of (1) over (2) where:

(1) Is the amount of the Qualified Plan Surviving Spouse Benefit to which the Surviving Spouse would be entitled under the Cash Balance Component as of the Participant's date of death if such benefit were computed by applying the definition of Compensation under the Reinstatement Plan; and

(2) Is the amount of the Qualified Plan Surviving Spouse Benefit actually payable to the Surviving Spouse under the Cash Balance Component as of the Participant's date of death.

4.2 The Reinstatement Surviving Spouse Benefit shall be paid as follows:

(a) If the Participant's death occurs prior to Retirement, the present value of the Reinstatement Surviving Spouse Benefit shall be paid in a lump sum distribution.

(b) If the Participant's death occurs on or after Retirement, the Reinstatement Surviving Spouse Benefit shall be payable over the lifetime of the Surviving Spouse in monthly installments until the Surviving Spouse's death. Notwithstanding the preceding sentence, if the present value of the total benefit payable to the Surviving Spouse under the Reinstatement Plan and the SERP does not exceed $20,000, the benefit under the Reinstatement Plan and the SERP shall be paid in a lump sum distribution.

4.3 Payment of the Reinstatement Surviving Spouse Benefit shall commence or shall be paid within the 90-day period following the date of the death, but in no event later than the last day permitted under Section 409A of the Code for treating a delayed payment as having been made on such payment date.

Section 5. Administration of the Reinstatement Plan

5.1 The Employee Benefits Committee shall be the named fiduciary of the Reinstatement Plan responsible for the general operation and administration of the Reinstatement Plan and for carrying out the provisions thereof. The Employee Benefits Committee shall have discretionary authority to construe the terms of the Reinstatement Plan.

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5.2 The Employee Benefits Committee shall adopt such rules and procedures as it deems necessary and advisable to administer the Reinstatement Plan and to transact its business. Subject to the other requirements of this Section 5, the Employee Benefits Committee may:

(a) Employ agents to carry out non-fiduciary responsibilities;

(b) Employ agents to carry out fiduciary responsibilities (other than trustee responsibilities as defined in Section 405(c)(3) of ERISA);

(c) Consult with counsel, who may be counsel to PSEG or an Affiliate; and

(d) Provide for the allocation of fiduciary responsibilities (other than trustee responsibilities as defined in Section 405(c)(3) of ERISA) among its members.

However, any action described in paragraphs (b) or (d) above, and any modification or rescission of any such action, may be effected by the Employee Benefits Committee only by a resolution approved by a majority of the Employee Benefits Committee. The Employee Benefits Committee shall be entitled to rely conclusively upon all tables, valuations, certificates, opinions and reports furnished by any actuary, accountant, controller, counsel or other person employed or engaged by the Employee Benefits Committee with respect to the Reinstatement Plan.

5.3 The Employee Benefits Committee shall keep written minutes of all its proceedings, which shall be open to inspection by the Board of Directors. In the case of any decision by the Employee Benefits Committee with respect to a claim for benefits under the Reinstatement Plan, the Employee Benefits Committee shall include in its minutes a brief explanation of the grounds upon which such decision was based.

5.4 In performing their duties, the members of the Employee Benefits Committee shall act solely in the interest of the Participants in the Reinstatement Plan and their Beneficiaries and

(a) For the exclusive purpose of providing benefits to Participants and their Beneficiaries;

(b) With the care, skill, prudence and diligence under the circumstances then prevailing that a prudent person acting in like capacity and familiar with such matters would use in the conduct of an enterprise of alike character and with like aims; and

(c) In accordance with the documents and instruments governing the Reinstatement Plan insofar as such documents and instruments are consistent with the provisions of Title I of ERISA.

5.5 In addition to any other duties the Employee Benefits Committee may have, the Employee Benefits Committee shall review the performance of all persons to whom the Employee Benefits Committee shall have delegated or allocated fiduciary duties pursuant to the provisions of this Section 5.

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5.6 The Company agrees to indemnify and reimburse, to the fullest extent permitted by law, members of the Employee Benefits Committee, directors and employees of PSEG and its Affiliates, and all such former members, directors and employees, for any and all expenses, liabilities or losses arising out of any act or omission relating to the rendition of services for or the management and administration of the Reinstatement Plan.

5.7 No member of the Employee Benefits Committee nor any delegee thereof shall be personally liable by virtue of any contract, agreement or other instrument made or executed by them or on their behalf in such capacity.

Section 6. Claims Procedure and Status Determination

6.1 Claims for benefits under the Reinstatement Plan and requests for a status determination shall be filed in writing with the Employee Benefits Committee or its delegee.

6.2 In the case of a claim for benefits, written notice shall be given to the claiming Participant or Beneficiary of the disposition of such claim, setting forth specific reasons for any denial of such claim in whole or in part. If a claim is denied in whole or in part, the notice shall state that such Participant or Beneficiary may, within sixty days of the receipt of such denial, request in writing that the decision denying the claim be reviewed by the Employee Benefits Committee and provide the Employee Benefits Committee with information in support of their position by submitting such information in writing to the Secretary of the Employee Benefits Committee.

6.3 The Employee Benefits Committee shall review each claim for benefits which has been denied in whole or in part and for which such review has been requested and shall notify, in writing, the affected Participant or Beneficiary of its decision and the reasons therefor.

6.4 In the case of a request for status determination, written notice shall be given to the requesting person within a reasonable time setting forth specific reasons for the decision.

Section 7. Amendment or Termination

7.1 PSEG reserves the right to amend or terminate the Reinstatement Plan when, in the sole opinion of PSEG, such amendment or termination is advisable. Any such amendment or termination shall be made pursuant to a resolution of the Board or of the Employee Benefits Policy Committee and shall be effective as provided for in such resolution.

7.2 No amendment or termination of the Reinstatement Plan shall directly or indirectly deprive any current or former Participant, Beneficiary or Surviving Spouse of all or any portion of any Reinstatement Benefit or Reinstatement Surviving Spouse Benefit payment which has commenced prior to the effective date of such amendment or termination or the right to which has accrued on such effective date.

7.3 In the event of a Reinstatement Plan termination, Reinstatement Benefits and Reinstatement Surviving Spouse Benefits shall be distributed in a single lump sum within 90 days

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after the date the Reinstatement Plan is terminated if such distribution is permitted because the Reinstatement Plan is terminated in accordance with the termination provisions of Section 409A of the Code and related regulations or, in other cases, at the earliest time otherwise permitted under the terms of the Reinstatement Plan in accordance with Section 409A of the Code and related regulations.

Section 8. General Provisions

8.1 The Reinstatement Plan at all times shall be entirely unfunded and no provision shall at any time be made with respect to segregating any assets of the Company or any Affiliate for payment of any benefits hereunder. No Participant, Beneficiary, Surviving Spouse or any other person shall have any interest in any particular assets of the Company or any Affiliate by reason of the right to receive a benefit under the Reinstatement Plan and any such Participant, Beneficiary, Surviving Spouse or other person shall have only the rights of a general unsecured creditor with respect to any rights under the Reinstatement Plan.

8.2 Except as otherwise expressly provided herein, all terms and conditions of the Qualified Plan applicable to a Qualified Benefit or a Qualified Plan Surviving Spouse Benefit shall also be applicable to a Reinstatement Benefit or a Reinstatement Surviving Spouse Benefits payable hereunder. Any Qualified Benefit Qualified Surviving Spouse Benefit, or any other benefit payable under the Qualified Plan, as the case may be, shall be paid solely in accordance with the terms and conditions of the Qualified Plan, as the case may be, and nothing in the Reinstatement Plan shall operate or be construed in any way to modify, amend or affect the terms and provisions of the Qualified Plan.

8.3 Nothing contained in the Reinstatement Plan shall constitute a guaranty by the Company or any other entity or person that the assets of PSEG or any Affiliate will be sufficient to pay any benefit hereunder.

8.4 No Participant or Surviving Spouse shall have any right to a benefit under the Reinstatement Plan except in accordance with the terms of the Reinstatement Plan. Establishment of the Reinstatement Plan shall not be construed to give any Participant the right to be retained in the service of PSEG or any Affiliate.

8.5 No interest of any person or entity in, or right to receive a benefit under, the Reinstatement Plan shall be subject in any manner to sale, transfer, assignment, pledge, attachment, garnishment or other alienation or encumbrance of any kind; nor any such interest or right to receive a benefits be taken, either voluntarily or involuntarily, for the satisfaction of the debts of, or other obligations or claims against, such person or entity, including claims for alimony, support, separate maintenance and claims in bankruptcy proceedings.

8.6 The Reinstatement Plan shall be construed and administered under the laws of the United States and the State of New Jersey to the extent not superseded by Federal law. The Reinstatement Plan is specifically intended to comply with Section 409A of the Code and it shall automatically incorporate all applicable restrictions of Section 409A of the Code and its related regulations, and PSEG will amend the Reinstatement Plan to the extent necessary to comply with

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those requirements. The timing under which a Participant will have a right to receive any payment under the Reinstatement Plan will be deemed to be automatically modified, and a Participant's rights under the Reinstatement Plan limited to conform to any requirements under the Section 409A of the Code and its related regulations.

8.7 Actuarial assumptions to determine the present value of any benefit hereunder shall be the same as used to determine the present value of benefits under the Qualified Plan.

8.8 If any person entitled to a benefit payment under the Reinstatement Plan is deemed by the Employee Benefits Committee to be incapable of personally receiving and giving a valid receipt for such payment, then, unless and until claim therefor shall have been made by a duly appointed guardian or other legal representative of such person, the Employee Benefits Committee may provide for such payment or any part thereof to be made to any other person or institution then contributing toward or providing for the care and maintenance of such person. Any such payment shall be a payment for the account of such person and a complete discharge of any liability of the Company and the Reinstatement Plan therefor.

8.9 The Reinstatement Plan shall inure to the benefit of and be binding upon the Company, its successors and assigns, including but not limited to any corporation which may acquire all or substantially all of the Company's assets or businesses or with or into or which the Company may be consolidated or merged.

8.10 Each Participant shall keep the Company informed of their current address and the current address of their spouse. The Company shall not be obligated to search for the whereabouts of any person. If the location of a Participant is not made known to the Company within three (3) years after the date on which payment of the Reinstatement Benefit may first be made, payment may be made as though the Participant had died at the end of the three-year period. If, within one additional year after such three-year period has elapsed, or, within three years after the actual death of a Participant, the Company is unable to locate any. Surviving Spouse of the Participant, then the Company shall have no further obligation to pay any benefit hereunder to such Participant or Surviving Spouse or any other person and such benefit shall be irrevocably forfeited.

8.11 Notwithstanding any of the preceding provisions of the Reinstatement Plan, none of the Company, the Employee Benefits Committee or any individual acting as an employee or agent of the Company or the Employee Benefits Committee shall be liable to any Participant, former Participant, Surviving Spouse or any other person for any claim, loss, liability or expense incurred in connection with the Reinstatement Plan.

Section 9. Miscellaneous

9.1 As used herein, words in the masculine gender shall include the feminine and the singular shall include the plural, and vice versa, unless otherwise required by the context. Any headings used herein are included for ease of reference only and are not to be construed so as to alter the terms hereof.

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* * *

/s/ Margaret M. Pego__ July 10, 2017___
Margaret M. Pego Date

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2017	2016	2016	2015	2014	2013	2012
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 311	$ 1,032	$1,298	$2,680	$2,456	$2,055	$2,011
(Income) Loss from Equity Investees, net of Distributions	1	3	7	3	4	(7)	9
Fixed Charges	245	232	477	457	450	458	479
Capitalized Interest	33	(19)	(7)	(18)	(16)	(16)	(19)
Total Earnings	$ 590	$ 1,248	$1,775	$3,122	$2,894	$2,490	$2,480
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 233	$ 221	$ 456	$ 437	$ 430	$ 442	$ 465
Interest Factor in Rentals	12	11	21	20	20	16	14
Total Fixed Charges	$ 245	$ 232	$ 477	$ 457	$ 450	$ 458	$ 479
Ratio of Earnings to Fixed Charges	**2.41**	**5.38**	**3.72**	**6.83**	**6.43**	**5.44**	**5.18**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Six Months Ended June 30,		Years Ended December 31,				
	2017	**2016**	**2016**	**2015**	**2014**	**2013**	**2012**
			(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 801	$ 690	$1,404	$1,257	$ 1,174	$ 993	$ 835
Fixed Charges	157	154	316	306	303	316	314
Capitalized Interest	(9)	(7)	(17)	(17)	(16)	(16)	(13)
Total Earnings	$ 949	$ 837	$1,703	$1,546	$ 1,461	$1,293	$1,136
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 153	$ 149	$ 306	$ 297	$ 293	$ 309	$ 308
Interest Factor in Rentals	4	5	10	9	10	7	6
Total Fixed Charges	$ 157	$ 154	$ 316	$ 306	$ 303	$ 316	$ 314
Ratio of Earnings to Fixed Charges	**6.04**	**5.44**	**5.39**	**5.05**	**4.82**	**4.09**	**3.62**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period, (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries, and (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.2

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2017	2016	2016	2015	2014	2013	2012
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income (Loss) from Continuing Operations	$ (445)	$ 299	$ (43)	$1,367	$1,251	$1,063	$1,099
(Income) Loss from Equity Investees, net of Distributions	1	3	7	1	3	(10)	(6)
Fixed Charges	67	69	142	152	150	143	164
Capitalized Interest	42	(12)	11	(1)	1	1	(6)
Total Earnings	$ (335)	$ 359	$ 117	$1,519	$1,405	$1,197	$1,251
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 64	$ 67	$ 138	$ 148	$ 146	$ 139	$ 161
Interest Factor in Rentals	3	2	4	4	4	4	3
Total Fixed Charges	$ 67	$ 69	$ 142	$ 152	$ 150	$ 143	$ 164
Ratio of Earnings to Fixed Charges (C)	**(5.00)**	**5.20**	**0.82**	**9.99**	**9.37**	**8.37**	**7.63**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

(C) The ratio of earnings to fixed charges for the six months ended June 30, 2017, was (5.00), as noted above, which represents a deficiency of $402 million. The ratio of earnings to fixed charges for the year ended December 31, 2016, was 0.82, as noted above, which represents a deficiency of $25 million.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 28, 2017

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 28, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

S1-SSA-0009 - 17923

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 28, 2017

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 28, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

S1-SSA-0009 - 17925

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 28, 2017

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 28, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

S1-SSA-0009 - 17927

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
July 28, 2017

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
July 28, 2017

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
July 28, 2017

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
July 28, 2017

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
July 28, 2017

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
July 28, 2017

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2018
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102 973 430-7000	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐

If any of the registrants is an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of July 17, 2018, Public Service Enterprise Group Incorporated had outstanding 505,323,326 shares of its sole class of Common Stock, without par value.

As of July 17, 2018, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K. These factors include, but are not limited to:

- fluctuations in wholesale power and natural gas markets, including the potential impacts on the economic viability of our generation units;
- our ability to obtain adequate fuel supply;
- any inability to manage our energy obligations with available supply;
- increases in competition in wholesale energy and capacity markets;
- changes in technology related to energy generation, distribution and consumption and customer usage patterns;
- economic downturns;
- third-party credit risk relating to our sale of generation output and purchase of fuel;
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements;
- changes in state and federal legislation and regulations, and PSE&G's ability to recover costs and earn returns on authorized investments;
- the impact of pending and any future rate case proceedings;
- regulatory, financial, environmental, health and safety risks associated with our ownership and operation of nuclear facilities;
- adverse changes in energy industry laws, policies and regulations, including market structures and transmission planning;
- changes in federal and state environmental regulations and enforcement;
- delays in receipt of, or an inability to receive, necessary licenses and permits;
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry;
- changes in tax laws and regulations;
- the impact of our holding company structure on our ability to meet our corporate funding needs, service debt and pay dividends;
- lack of growth or slower growth in the number of customers or changes in customer demand;
- any inability of Power to meet its commitments under forward sale obligations;
- reliance on transmission facilities that we do not own or control and the impact on our ability to maintain adequate transmission capacity;
- any inability to successfully develop or construct generation, transmission and distribution projects;
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers;

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- our inability to exercise control over the operations of generation facilities in which we do not maintain a controlling interest;
- any inability to recover the carrying amount of our long-lived assets and leveraged leases;
- any inability to maintain sufficient liquidity;
- any inability to realize anticipated tax benefits or retain tax credits;
- challenges associated with recruitment and/or retention of key executives and a qualified workforce;
- the impact of our covenants in our debt instruments on our operations; and
- the impact of acts of terrorism, cybersecurity attacks or intrusions.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business, prospects, financial condition, results of operations or cash flows. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even in light of new information or future events, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

FILING FORMAT

This combined Quarterly Report on Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to “we,” “us,” and “our” relate to PSEG or to the specific company or companies being discussed.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
OPERATING REVENUES	$ 2,016	$ 2,142	$ 4,834	$ 4,733
OPERATING EXPENSES				
Energy Costs	600	588	1,552	1,456
Operation and Maintenance	725	718	1,479	1,435
Depreciation and Amortization	280	641	560	1,469
Total Operating Expenses	1,605	1,947	3,591	4,360
OPERATING INCOME	411	195	1,243	373
Income from Equity Method Investments	5	5	7	8
Net Gains (Losses) on Trust Investments	8	25	(14)	53
Other Income (Deductions)	34	33	66	65
Non-Operating Pension and OPEB Credits (Costs)	19	1	38	1
Interest Expense	(111)	(91)	(214)	(189)
INCOME BEFORE INCOME TAXES	366	168	1,126	311
Income Tax Expense	(97)	(59)	(299)	(88)
NET INCOME	$ 269	$ 109	$ 827	$ 223
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	504	505	504	505
DILUTED	507	507	507	507
NET INCOME PER SHARE:				
BASIC	$ 0.53	$ 0.22	$ 1.64	$ 0.44
DILUTED	$ 0.53	$ 0.22	$ 1.63	$ 0.44
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.45	$ 0.43	$ 0.90	$ 0.86

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
NET INCOME	$ 269	$ 109	$ 827	$ 223
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $4, $(9), $13 and $(25) for the three and six months ended 2018 and 2017, respectively	(5)	10	(19)	25
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $1, $0, $1 and $0 for the three and six months ended 2018 and 2017, respectively	(1)	—	(1)	—
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(3), $(4), $(6) and $(8) for the three and six months ended 2018 and 2017, respectively	7	6	15	12
Other Comprehensive Income (Loss), net of tax	1	16	(5)	37
COMPREHENSIVE INCOME	$ 270	$ 125	$ 822	$ 260

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 95	$ 313
Accounts Receivable, net of allowances of $59 in 2018 and 2017	1,163	1,348
Tax Receivable	111	127
Unbilled Revenues	189	296
Fuel	218	289
Materials and Supplies, net	574	577
Prepayments	324	118
Derivative Contracts	24	29
Regulatory Assets	296	211
Other	11	4
Total Current Assets	3,005	3,312
PROPERTY, PLANT AND EQUIPMENT	42,809	41,231
Less: Accumulated Depreciation and Amortization	(9,658)	(9,434)
Net Property, Plant and Equipment	33,151	31,797
NONCURRENT ASSETS		
Regulatory Assets	3,225	3,222
Long-Term Investments	924	932
Nuclear Decommissioning Trust (NDT) Fund	2,049	2,133
Long-Term Receivable of Variable Interest Entity (VIE)	688	686
Rabbi Trust Fund	224	231
Goodwill	16	16
Other Intangibles	127	114
Derivative Contracts	21	7
Other	277	266
Total Noncurrent Assets	7,551	7,607
TOTAL ASSETS	$ 43,707	$ 42,716

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2018	December 31, 2017
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 1,550	$ 1,000
Commercial Paper and Loans	270	542
Accounts Payable	1,348	1,694
Derivative Contracts	23	16
Accrued Interest	105	103
Accrued Taxes	104	48
Clean Energy Program	203	128
Obligation to Return Cash Collateral	131	129
Regulatory Liabilities	32	47
Other	478	461
Total Current Liabilities	4,244	4,168
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	5,475	5,240
Regulatory Liabilities	2,937	2,948
Clean Energy Program	27	—
Asset Retirement Obligations	1,047	1,024
OPEB Costs	1,423	1,455
OPEB Costs of Servco	551	542
Accrued Pension Costs	480	537
Accrued Pension Costs of Servco	122	129
Environmental Costs	332	357
Derivative Contracts	1	5
Long-Term Accrued Taxes	177	175
Other	223	221
Total Noncurrent Liabilities	12,795	12,633
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 10)		
CAPITALIZATION		
LONG-TERM DEBT	12,510	12,068
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2018 and 2017—534 shares	4,955	4,961
Treasury Stock, at cost, 2018—30 shares; 2017—29 shares	(813)	(763)
Retained Earnings	10,426	9,878
Accumulated Other Comprehensive Loss	(410)	(229)
Total Stockholders' Equity	14,158	13,847
Total Capitalization	26,668	25,915
TOTAL LIABILITIES AND CAPITALIZATION	$ 43,707	$ 42,716

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2018	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 827	$ 223
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	560	1,469
Amortization of Nuclear Fuel	95	101
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	46	51
Provision for Deferred Income Taxes (Other than Leases) and ITC	213	91
Non-Cash Employee Benefit Plan Costs	35	45
Leveraged Lease (Income) Loss, Adjusted for Rents Received and Deferred Taxes	8	(30)
Net (Gain) Loss on Lease Investments	14	45
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(54)	(42)
Net Change in Regulatory Assets and Liabilities	(58)	(124)
Cost of Removal	(84)	(47)
Net (Gains) Losses and (Income) Expense from NDT Fund	(8)	(58)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	16	69
Accrued Taxes	57	15
Margin Deposit	24	59
Other Current Assets and Liabilities	2	(58)
Employee Benefit Plan Funding and Related Payments	(58)	(49)
Other	(2)	(5)
Net Cash Provided By (Used In) Operating Activities	1,633	1,755
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(2,005)	(1,981)
Purchase of Emissions Allowances and RECs	(44)	(29)
Proceeds from Sales of Trust Investments	821	711
Purchases of Trust Investments	(829)	(726)
Other	30	36
Net Cash Provided By (Used In) Investing Activities	(2,027)	(1,989)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(272)	(388)
Issuance of Long-Term Debt	1,400	1,125
Redemption of Long-Term Debt	(400)	—
Cash Dividends Paid on Common Stock	(455)	(435)
Other	(83)	(62)
Net Cash Provided By (Used In) Financing Activities	190	240
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(204)	6
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	315	426
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 111	$ 432
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 52	$ (30)
Interest Paid, Net of Amounts Capitalized	$ 205	$ 189
Accrued Property, Plant and Equipment Expenditures	$ 625	$ 513

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
OPERATING REVENUES	$ 1,386	$ 1,393	$ 3,231	$ 3,219
OPERATING EXPENSES				
Energy Costs	488	488	1,270	1,250
Operation and Maintenance	353	359	744	729
Depreciation and Amortization	187	166	377	337
Total Operating Expenses	1,028	1,013	2,391	2,316
OPERATING INCOME	358	380	840	903
Net Gains (Losses) on Trust Investments	—	—	—	2
Other Income (Deductions)	20	21	40	43
Non-Operating Pension and OPEB Credits (Costs)	15	(1)	30	(3)
Interest Expense	(82)	(69)	(163)	(144)
INCOME BEFORE INCOME TAXES	311	331	747	801
Income Tax Expense	(80)	(123)	(197)	(294)
NET INCOME	$ 231	$ 208	$ 550	$ 507

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
NET INCOME	$ 231	$ 208	$ 550	$ 507
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0, $0 and $1 for the three and six months ended 2018 and 2017, respectively	1	—	—	(1)
COMPREHENSIVE INCOME	$ 232	$ 208	$ 550	$ 506

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17944

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 20	$ 242
Accounts Receivable, net of allowances of $59 in 2018 and 2017	796	882
Accounts Receivable—Affiliated Companies	18	—
Unbilled Revenues	189	296
Materials and Supplies	195	197
Prepayments	205	44
Regulatory Assets	296	211
Other	10	4
Total Current Assets	1,729	1,876
PROPERTY, PLANT AND EQUIPMENT	30,396	29,117
Less: Accumulated Depreciation and Amortization	(6,200)	(6,101)
Net Property, Plant and Equipment	24,196	23,016
NONCURRENT ASSETS		
Regulatory Assets	3,225	3,222
Long-Term Investments	285	280
Rabbi Trust Fund	45	46
Other	123	114
Total Noncurrent Assets	3,678	3,662
TOTAL ASSETS	$ 29,603	$ 28,554

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17945

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	June 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 600	$ 750
Commercial Paper and Loans	195	—
Accounts Payable	704	728
Accounts Payable—Affiliated Companies	150	340
Accrued Interest	79	78
Clean Energy Program	203	128
Obligation to Return Cash Collateral	131	129
Regulatory Liabilities	32	47
Other	376	311
Total Current Liabilities	2,470	2,511
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	3,570	3,391
OPEB Costs	1,066	1,103
Accrued Pension Costs	189	226
Regulatory Liabilities	2,937	2,948
Clean Energy Program	27	—
Environmental Costs	255	283
Asset Retirement Obligations	214	212
Long-Term Accrued Taxes	94	91
Other	111	114
Total Noncurrent Liabilities	8,463	8,368
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 10)		
CAPITALIZATION		
LONG-TERM DEBT	8,286	7,841
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2018 and 2017—132 shares	892	892
Contributed Capital	1,095	1,095
Basis Adjustment	986	986
Retained Earnings	7,411	6,861
Total Stockholder's Equity	10,384	9,834
Total Capitalization	18,670	17,675
TOTAL LIABILITIES AND CAPITALIZATION	$ 29,603	$ 28,554

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17946

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2018	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 550	$ 507
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	377	337
Provision for Deferred Income Taxes and ITC	160	330
Non-Cash Employee Benefit Plan Costs	19	25
Cost of Removal	(84)	(47)
Net Change in Regulatory Assets and Liabilities	(58)	(124)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	195	108
Materials and Supplies	2	(15)
Prepayments	(161)	(184)
Accounts Payable	(30)	(30)
Accounts Receivable/Payable—Affiliated Companies, net	(204)	(72)
Other Current Assets and Liabilities	66	14
Employee Benefit Plan Funding and Related Payments	(50)	(42)
Other	(20)	(38)
Net Cash Provided By (Used In) Operating Activities	762	769
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,447)	(1,389)
Proceeds from Sales of Trust Investments	9	28
Purchases of Trust Investments	(10)	(29)
Solar Loan Investments	(11)	(3)
Other	3	5
Net Cash Provided By (Used In) Investing Activities	(1,456)	(1,388)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	195	—
Issuance of Long-Term Debt	700	425
Redemption of Long-Term Debt	(400)	—
Other	(9)	(5)
Net Cash Provided By (Used In) Financing Activities	486	420
Net Increase (Decrease) In Cash, Cash Equivalents and Restricted Cash	(208)	(199)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	244	393
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 36	$ 194
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 97	$ (75)
Interest Paid, Net of Amounts Capitalized	$ 157	$ 144
Accrued Property, Plant and Equipment Expenditures	$ 436	$ 319

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
OPERATING REVENUES	$ 767	$ 918	$ 2,170	$ 2,187
OPERATING EXPENSES				
Energy Costs	373	386	1,119	1,078
Operation and Maintenance	268	256	514	488
Depreciation and Amortization	84	465	166	1,115
Total Operating Expenses	725	1,107	1,799	2,681
OPERATING INCOME (LOSS)	42	(189)	371	(494)
Income from Equity Method Investments	5	5	7	8
Net Gains (Losses) on Trust Investments	8	24	(14)	43
Other Income (Deductions)	13	12	24	23
Non-Operating Pension and OPEB Credits (Costs)	3	2	7	4
Interest Expense	(11)	(13)	(18)	(29)
INCOME (LOSS) BEFORE INCOME TAXES	60	(159)	377	(445)
Income Tax Benefit (Expense)	(19)	62	(102)	178
NET INCOME (LOSS)	$ 41	$ (97)	$ 275	$ (267)

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
NET INCOME (LOSS)	$ 41	$ (97)	$ 275	$ (267)
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $3, $(9), $11 and $(27) for the three and six months ended 2018 and 2017, respectively	(4)	10	(15)	29
Pension/OPEB adjustment, net of tax (expense) benefit of $(2), $(3), $(5) and $(7) for the three and six months ended 2018 and 2017, respectively	6	5	12	10
Other Comprehensive Income (Loss), net of tax	2	15	(3)	39
COMPREHENSIVE INCOME (LOSS)	$ 43	$ (82)	$ 272	$ (228)

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	June 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 20	$ 32
Accounts Receivable	313	380
Accounts Receivable—Affiliated Companies	81	221
Short-Term Loan to Affiliate	519	—
Fuel	218	289
Materials and Supplies, net	376	376
Derivative Contracts	24	29
Prepayments	10	11
Other	4	3
Total Current Assets	1,565	1,341
PROPERTY, PLANT AND EQUIPMENT	12,046	11,755
Less: Accumulated Depreciation and Amortization	(3,267)	(3,159)
Net Property, Plant and Equipment	8,779	8,596
NONCURRENT ASSETS		
NDT Fund	2,049	2,133
Long-Term Investments	87	87
Goodwill	16	16
Other Intangibles	127	114
Rabbi Trust Fund	56	57
Derivative Contracts	21	7
Other	72	67
Total Noncurrent Assets	2,428	2,481
TOTAL ASSETS	$ 12,772	$ 12,418

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2018	December 31, 2017
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 250	$ 250
Accounts Payable	468	712
Accounts Payable—Affiliated Companies	148	57
Short-Term Loan from Affiliate	—	281
Derivative Contracts	23	16
Accrued Interest	22	20
Other	62	99
Total Current Liabilities	973	1,435
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	1,451	1,406
Asset Retirement Obligations	831	810
OPEB Costs	287	283
Derivative Contracts	1	5
Accrued Pension Costs	169	184
Long-Term Accrued Taxes	45	52
Other	143	140
Total Noncurrent Liabilities	2,927	2,880
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 10)		
LONG-TERM DEBT	2,833	2,136
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	5,161	4,911
Accumulated Other Comprehensive Loss	(350)	(172)
Total Member's Equity	6,039	5,967
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,772	$ 12,418

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17951

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2018	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income (Loss)	$ 275	$ (267)
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	166	1,115
Amortization of Nuclear Fuel	95	101
Provision for Deferred Income Taxes and ITC	51	(226)
Interest Accretion on Asset Retirement Obligation	20	15
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(54)	(42)
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	46	51
Non-Cash Employee Benefit Plan Costs	11	14
Net (Gains) Losses and (Income) Expense from NDT Fund	(8)	(58)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	71	58
Margin Deposit	24	59
Accounts Receivable	84	36
Accounts Payable	(90)	(14)
Accounts Receivable/Payable—Affiliated Companies, net	227	75
Other Current Assets and Liabilities	(35)	7
Employee Benefit Plan Funding and Related Payments	(5)	(4)
Other	(9)	12
Net Cash Provided By (Used In) Operating Activities	869	932
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(547)	(576)
Purchase of Emissions Allowances and RECs	(44)	(29)
Proceeds from Sales of Trust Investments	785	602
Purchases of Trust Investments	(793)	(616)
Short-Term Loan—Affiliated Company	(519)	(146)
Other	23	30
Net Cash Provided By (Used In) Investing Activities	(1,095)	(735)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Long-Term Debt	700	—
Cash Dividend Paid	(200)	(175)
Short-Term Loan—Affiliated Company	(281)	—
Other	(5)	(4)
Net Cash Provided By (Used In) Financing Activities	214	(179)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(12)	18
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	32	11
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 20	$ 29
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (72)	$ 66
Interest Paid, Net of Amounts Capitalized	$ 18	$ 29
Accrued Property, Plant and Equipment Expenditures	$ 189	$ 194

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

S1-SSA-0009 - 17952

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Note 1. Organization, Basis of Presentation and Significant Accounting Policies

Organization

Public Service Enterprise Group Incorporated (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Public Service Electric and Gas Company (PSE&G)**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and energy efficiency and related programs in New Jersey, which are regulated by the BPU.
- **PSEG Power LLC (Power)**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) electric transmission and distribution (T&D) system under an Operations Services Agreement (OSA); PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2017.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All significant intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2017.

Significant Accounting Policies

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. Restricted cash consists primarily of deposits received related to various construction projects at PSE&G.

The following provides a reconciliation of cash, cash equivalents and restricted cash reported within the Condensed Consolidated Balance Sheets that sum to the total of the same such amounts for the beginning (December 31, 2017) and ending periods shown in the Condensed Consolidated Statements of Cash Flows for the six months ended June 30, 2018.

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	PSE&G	Power	Other (A)	Consolidated
			Millions	
As of December 31, 2017				
Cash and Cash Equivalents	$ 242	$ 32	$ 39	$ 313
Restricted Cash in Other Current Assets	—	—	—	—
Restricted Cash in Other Noncurrent Assets	2	—	—	2
Cash, Cash Equivalents and Restricted Cash	**$ 244**	**$ 32**	**$ 39**	**$ 315**
As of June 30, 2018				
Cash and Cash Equivalents	$ 20	$ 20	$ 55	$ 95
Restricted Cash in Other Current Assets	4	—	—	4
Restricted Cash in Other Noncurrent Assets	12	—	—	12
Cash, Cash Equivalents and Restricted Cash	**$ 36**	**$ 20**	**$ 55**	**$ 111**

(A) Includes amounts applicable to PSEG (parent corporation), Energy Holdings and Services.

Note 2. Recent Accounting Standards

New Standards Issued and Adopted

Revenue from Contracts With Customers—Accounting Standard Update (ASU) 2014-09, updated by ASUs 2015-14, 2016-08, 2016-10, 2016-12, 2016-20, 2017-13, 2017-14

This accounting standard, and related updates, were adopted on January 1, 2018 using the full retrospective transition method. There was no effect on net income as a result of adoption. However, certain retrospective adjustments were recorded in accordance with the new standard. At PSE&G, retrospective adjustments increased Operating Revenues by $25 million and $39 million, Energy Costs by $16 million and $25 million, and Operation and Maintenance (O&M) Expense by $9 million and $14 million for the three and six months ended June 30, 2017, respectively. At Power, retrospective adjustments reduced Operating Revenues and Energy Costs by $11 million and $26 million for the three and six months ended June 30, 2017, respectively. For disclosure requirements under this standard, including Nature of Goods and Services, Disaggregation of Revenues, and Remaining Performance Obligations under Fixed Consideration Contracts, see Note 3. Revenues.

Recognition and Measurement of Financial Assets and Financial Liabilities—ASU 2016-01

Power maintains an external master trust fund to provide for the costs of decommissioning upon termination of operations of its nuclear facilities. In addition, PSEG maintains a grantor trust which was established to meet the obligations related to its non-qualified pension plans and deferred compensation plans, commonly referred to as a "Rabbi Trust."

This accounting standard was adopted on January 1, 2018. Under the new guidance, equity investments in Power's Nuclear Decommissioning Trust (NDT) and PSEG's Rabbi Trust Funds are measured at fair value with the unrealized gains and losses now recognized through Net Income instead of Other Comprehensive Income (Loss). The debt securities in these trusts continue to be classified as available-for-sale with the unrealized gains and losses recorded as a component of Accumulated Other Comprehensive Income (Loss). Realized gains and losses on both equity and available-for-sale debt security investments are recorded in earnings and are included with the unrealized gains and losses on equity securities in Net Gains (Losses) on Trust Investments. Other-than-temporary impairments on NDT and Rabbi Trust securities are also included in Net Gains (Losses) on Trust Investments. A cumulative effect adjustment was made to reclassify the net unrealized gains related to equity investments of $342 million ($176 million, net of tax) from Accumulated Other Comprehensive Income to Retained Earnings on January 1, 2018. See Note 16. Accumulated Other Comprehensive Income (Loss), Net of Tax and Note 8. Trust Investments for further discussion.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments—ASU 2016-15

This accounting standard reduces the diversity in practice in how certain cash receipts and cash payments are presented and classified in the Statement of Cash Flows.

PSEG adopted this standard on January 1, 2018 using a retrospective transition method and had no changes in its presentation of its Statement of Cash Flows for each period presented.

Statement of Cash Flows: Restricted Cash—ASU 2016-18

This accounting standard was adopted on January 1, 2018. PSEG will continue the current balance sheet classification of restricted cash or restricted cash equivalents. PSEG has provided a reconciliation of cash and cash equivalents and restricted

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cash or restricted cash equivalents and has included a description of these amounts in Note 1. Organization, Basis of Presentation and Significant Accounting Policies. The effect of adoption on the June 30, 2018 Consolidated Statements of Cash Flows was immaterial.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (OPEB)—ASU 2017-07

This accounting standard was adopted on January 1, 2018. Under the new guidance, entities are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by their employees during the period. The other components of net benefit cost are required to be presented in the Statement of Operations separately from the service cost component after Operating Income. Additionally, only the service cost component is eligible for capitalization, when applicable. As a result of adopting this standard, PSE&G reduced its charge to expense for the three and six months ended June 30, 2018 by approximately $15 million and $29 million, respectively. The Condensed Consolidated Statements of Operations were recast to show retrospective adjustments of the non-service cost components of net benefit credits (costs) of $(1) million and $(3) million at PSE&G and $2 million and $4 million at Power, for the three and six months ended June 30, 2017, respectively, from O&M Expense to a new line item after Operating Income entitled Non-Operating Pension and OPEB Credits (Costs). See. Note 9. Pension and Other Postretirement Benefits (OPEB).

Stock Compensation - Scope of Modification Accounting—ASU 2017-09

This accounting standard was adopted on January 1, 2018. The standard will be applied prospectively to awards modified on or after January 1, 2018. PSEG does not expect a material impact from adoption of this new standard.

New Standards Issued But Not Yet Adopted

Leases—ASU 2016-02, updated by ASUs 2018-01, 2018-10 and 2018-11

This accounting standard, and related updates, replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor will classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard allows lessees and lessors to apply either (i) a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, or (ii) a prospective transition approach for leases existing as of January 1, 2019 with a cumulative effect adjustment to be recorded to Retained Earnings. PSEG intends to adopt this standard on a prospective basis. Existing guidance related to leveraged leases does not change.

This standard permits an entity to elect an optional transition practical expedient to exclude evaluation of land easements that exist or expired before the adoption of ASU 2016-02 and that were not previously accounted for as leases.

PSEG is currently analyzing the impact of this standard on its consolidated financial statements while undertaking the following implementation activities: (i) reviewing all contract types throughout PSEG to determine the lease population; (ii) implementing a lease accounting system to capture and account for long-term (greater than one year) leases to be operational on January 1, 2019; (iii) developing internal lease accounting policies and determining the practical expedients PSEG will elect; and (iv) drafting lease disclosures required in 2019. PSEG expects adoption of this standard to have a material impact on the balance sheets of PSEG and PSE&G, but has not yet quantified this impact.

The standard is effective for annual and interim periods beginning after December 15, 2018.

Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities—ASU 2017-12

This accounting standard's amendments more closely align hedge accounting with the companies' risk management activities in the financial statements. The amendments expand hedge accounting for both non-financial and financial risk components by permitting contractually specified components to be designated as the hedged risk in a cash flow hedge involving the purchase or sale of non-financial assets or variable rate financial instruments. The amendments also permit an entity to measure the interest rate risk on the hedged item in a partial-term fair value hedge assuming the hedged item has a term that reflects only the designated cash flows being hedged. Additionally, the amendments ease the operational burden of applying hedge accounting by allowing more time to prepare hedge documentation, and allowing effectiveness assessments to be performed on a qualitative basis after hedge inception.

The new guidance is effective for annual and interim periods beginning after December 15, 2018. The standard requires using a modified retrospective method upon adoption. Early adoption is permitted. PSEG analyzed the impact of this standard on its consolidated financial statements and has determined that the standard could enable PSEG to enter into certain transactions that

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can be deemed hedges that previously would not have qualified. Adoption of this standard is not expected to have a material impact on PSEG's financial statements.

Premium Amortization on Purchased Callable Debt Securities—ASU 2017-08

This accounting standard was issued to shorten the amortization period for certain callable debt securities held at a premium. Specifically, the standard requires the premium to be amortized to the earliest call date. The amendments do not require an accounting change for securities held at a discount; the discount continues to be amortized to maturity.

The standard is effective for annual and interim reporting periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period. If an entity early adopts the standard in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity should apply this standard on a modified retrospective basis through a cumulative effect adjustment directly to retained earnings as of the beginning of the period of adoption. Additionally, in the period of adoption, an entity should provide disclosures about a change in accounting principle. PSEG is currently analyzing the impact of this standard on its financial statements.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income—ASU 2018-02

This accounting standard would affect any entity that is required to apply the provisions of the Accounting Standards Codification topic, "Income Statement-Reporting Comprehensive Income," and has items of other comprehensive income for which the related tax effects are presented in other comprehensive income as required by GAAP. Specifically, this standard would allow entities to record a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the newly enacted federal corporate income tax rate. The amount of the reclassification would be the difference between the historical corporate income tax rate and the newly enacted 21% corporate income tax rate.

The standard is effective for all entities for annual periods and interim periods within those annual periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period for public business entities for reporting periods for which financial statements have not yet been issued or made available for issuance.

An entity would be able to choose to apply this standard retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the new tax legislation enacted in 2017 is recognized or apply the standard in the reporting period adopted. PSEG is currently analyzing the impact this standard, if adopted, could have on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments—ASU 2016-13

This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however, this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

Simplifying the Test for Goodwill Impairment—ASU 2017-04

This accounting standard requires an entity to perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

An entity should apply this standard on a prospective basis and will be required to disclose the nature of and reason for the change in accounting principle upon transition. The new standard is effective for impairment tests for periods beginning January 1, 2020. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. PSEG does not expect adoption of this standard to have a material impact on its financial statements.

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Note 3. Revenues

Nature of Goods and Services

The following is a description of principal activities by reportable segment from which PSEG, PSE&G and Power generate their revenues.

PSE&G

Revenues from Contracts with Customers

Electric and Gas Distribution and Transmission Revenues—PSE&G sells gas and electricity to customers under default commodity supply tariffs. PSE&G's regulated electric and gas default commodity supply and distribution services are separate tariffs which are satisfied as the product(s) and/or services are delivered to the customer. The electric and gas commodity and delivery tariffs are recurring contracts in effect until cancellation by the customer. Revenue is recognized over time as the service is rendered to the customer. Included in PSE&G's regulated revenues are unbilled electric and gas revenues which represent the estimated amount customers will be billed for services rendered from the most recent meter reading to the end of the respective accounting period.

PSE&G's transmission revenues are earned under a separate FERC tariff. The performance obligation of transmission service is satisfied over time as it is provided to and consumed by the customer. Revenue is recognized upon delivery of the transmission service. PSE&G's revenues from the transmission of electricity are recorded based on a FERC-approved annual formula rate mechanism. This mechanism provides for an annual filing of an estimated revenue requirement with rates effective January 1 of each year and a mechanism true-up to that estimate based on actual revenue requirements. The true-up mechanism is an alternative revenue which is outside the scope of revenue from contracts with customers.

Other Revenues from Contracts with Customers

Other revenues from contracts with customers, which are not a material source of PSE&G revenues, are generated primarily from appliance repair services and solar generation projects. The performance obligations under these contracts are satisfied and revenue is recognized as control of products is delivered or services are rendered.

Payment for services rendered and products transferred are typically due within 30 days of month of delivery.

Revenues Unrelated to Contracts with Customers

Other PSE&G revenues unrelated to contracts with customers are derived from alternative revenue mechanisms recorded pursuant to regulatory accounting guidance. These revenues, which include weather normalization, green energy program true-ups and transmission formula rate true-ups, are not a material source of PSE&G revenues.

Power

Revenues from Contracts with Customers

Electricity and Related Products—Wholesale and retail load contracts are executed in the different Independent System Operator (ISO) regions for the bundled supply of energy, capacity, renewable energy credits (RECs) and ancillary services representing Power's performance obligations. Revenue for these contracts is recognized over time as the bundled service is provided to the customer. Transaction terms generally run from several months to three years. Power also sells to the ISOs energy and ancillary services which are separately transacted in the day-ahead or real-time energy markets. The energy and ancillary services performance obligations are typically satisfied over time as delivered and revenue is recognized accordingly. Power generally reports electricity sales and purchases conducted with those individual ISOs net on an hourly basis in either Operating Revenues or Energy Costs in its Consolidated Statements of Operations. The classification depends on the net hourly activity.

Power enters into capacity sales and capacity purchases through the ISOs. The transactions are reported on a net basis dependent on Power's monthly net sale or purchase position through the individual ISOs. The performance obligations with the ISOs are satisfied over time upon delivery of the capacity and revenue is recognized accordingly. In addition to capacity sold through the ISOs, Power sells capacity through bilateral contracts and the related revenue is recognized over time upon delivery of the capacity.

Gas Contracts—Power sells wholesale natural gas, primarily through an index based full requirements Basic Gas Supply Service (BGSS) contract with PSE&G to meet the gas supply requirements of PSE&G's customers. The BGSS contract, which extends through March 2019, will renew year-to-year thereafter unless terminated by either party with a two year notice. The performance obligation is primarily delivery of gas which is satisfied over time. Revenue is recognized as gas is delivered. Based upon the availability of natural gas, storage and pipeline capacity beyond PSE&G's daily needs, Power also sells gas and

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pipeline capacity to other counterparties under bilateral contracts. The performance obligation under these contracts is satisfied over time upon delivery of the gas or capacity, and revenue is recognized accordingly.

Other Revenues from Contracts with Customers

Power enters into bilateral contracts to sell solar power and solar RECs from its solar facilities. Contract terms range from 15 to 30 years. The performance obligations are generally solar power and RECs which are transferred to customers upon generation. Revenue is recognized upon generation of the solar power.

Power has entered into long-term contracts with LIPA for energy management and fuel procurement services. Revenue is recognized over time as services are rendered.

Revenues Unrelated to Contracts with Customers

Power's revenues unrelated to contracts with customers include electric, gas and certain energy-related transactions accounted for in accordance with Derivatives and Hedging accounting guidance. See Note 12. Financial Risk Management Activities for further discussion. Power is also a party to solar contracts that qualify as leases and are accounted for in accordance with lease accounting guidance.

Other

Revenues from Contracts with Customers

PSEG LI has a contract with LIPA which generates revenues. PSEG LI's subsidiary, Long Island Electric Utility Servco, LLC (Servco) records costs which are recovered from LIPA and records the recovery of those costs as revenues when Servco is a principal in the transaction.

Revenues Unrelated to Contracts with Customers

Energy Holdings generates lease revenues which are recorded pursuant to lease accounting guidance.

Disaggregation of Revenues

	PSE&G	Power	Other	Eliminations	Consolidated
			Millions		
Three Months Ended June 30, 2018					
Revenues from Contracts with Customers					
Electric Distribution	$ 754	$ —	$ —	$ —	$ 754
Gas Distribution	248	—	—	(4)	244
Transmission	301	—	—	—	301
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	373	—	—	373
Sales to Affiliates	—	147	—	(147)	—
New York ISO	—	46	—	—	46
ISO New England	—	14	—	—	14
Gas Sales					
Third Party Sales	—	30	—	—	30
Sales to Affiliates	—	108	—	(108)	—
Other Revenues from Contracts with Customers (A)	63	13	125	(1)	200
Total Revenues from Contracts with Customers	1,366	731	125	(260)	1,962
Revenues Unrelated to Contracts with Customers (B)	20	36	(2)	—	54
Total Operating Revenues	**$ 1,386**	**$ 767**	**$ 123**	**$ (260)**	**$ 2,016**

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	PSE&G	Power	Other	Eliminations	Consolidated
			Millions		
Six Months Ended June 30, 2018					
Revenues from Contracts with Customers					
Electric Distribution	$ 1,444	$ —	$ —	$ —	$ 1,444
Gas Distribution	1,007	—	—	(7)	1,000
Transmission	613	—	—	—	613
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	871	—	—	871
Sales to Affiliates	—	323	—	(323)	—
New York ISO	—	105	—	—	105
ISO New England	—	61	—	—	61
Gas Sales					
Third Party Sales	—	94	—	—	94
Sales to Affiliates	—	505	—	(505)	—
Other Revenues from Contracts with Customers (A)	135	23	262	(2)	418
Total Revenues from Contracts with Customers	3,199	1,982	262	(837)	4,606
Revenues Unrelated to Contracts with Customers (B)	32	188	8	—	228
Total Operating Revenues	**$ 3,231**	**$ 2,170**	**$ 270**	**$ (837)**	**$ 4,834**

	PSE&G	Power	Other	Eliminations	Consolidated
			Millions		
Three Months Ended June 30, 2017					
Revenues from Contracts with Customers					
Electric Distribution	$ 757	$ —	$ —	$ —	$ 757
Gas Distribution	233	—	—	(6)	227
Transmission	307	—	—	—	307
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	302	—	—	302
Sales to Affiliates	—	171	—	(171)	—
New York ISO	—	50	—	—	50
ISO New England	—	9	—	—	9
Gas Sales					
Third Party Sales	—	11	—	—	11
Sales to Affiliates	—	107	—	(107)	—
Other Revenues from Contracts with Customers (A)	67	12	128	(1)	206
Total Revenues from Contracts with Customers	1,364	662	128	(285)	1,869
Revenues Unrelated to Contracts with Customers (B)	29	256	(12)	—	273
Total Operating Revenues	**$ 1,393**	**$ 918**	**$ 116**	**$ (285)**	**$ 2,142**

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	PSE&G	Power	Other	Eliminations	Consolidated
			Millions		
Six Months Ended June 30, 2017					
Revenues from Contracts with Customers					
Electric Distribution	$ 1,458	$ —	$ —	$ —	$ 1,458
Gas Distribution	988	—	—	(7)	981
Transmission	606	—	—	—	606
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	616	—	—	616
Sales to Affiliates	—	355	—	(355)	—
New York ISO	—	86	—	—	86
ISO New England	—	20	—	—	20
Gas Sales					
Third Party Sales	—	63	—	—	63
Sales to Affiliates	—	508	—	(508)	—
Other Revenues from Contracts with Customers (A)	129	22	256	(2)	405
Total Revenues from Contracts with Customers	3,181	1,670	256	(872)	4,235
Revenues Unrelated to Contracts with Customers (B)	38	517	(57)	—	498
Total Operating Revenues	**$ 3,219**	**$ 2,187**	**$ 199**	**$ (872)**	**$ 4,733**

(A) Includes primarily revenues from appliance repair services at PSE&G, solar power projects and energy management and fuel service contracts with LIPA at Power, and PSEG LI's OSA with LIPA in Other.

(B) Includes primarily alternative revenues at PSE&G, derivative contracts at Power, and lease contracts in Other. For the three and six months ended June 30, 2018, Other includes a $20 million loss and for the three and six months ended June 30, 2017, Other includes a $22 million loss and a $77 million loss, respectively, related to Energy Holdings' investments in leases.

Contract Balances

PSE&G

PSE&G does not have any material contract balances (rights to consideration for services already provided or obligations to provide services in the future for consideration already received) as of June 30, 2018 and December 31, 2017. Substantially all of PSE&G's accounts receivable result from contracts with customers. Allowances represented approximately seven percent of accounts receivable as of June 30, 2018 and December 31, 2017.

Power

Power generally collects consideration upon satisfaction of performance obligations, and therefore, Power had no material contract balances as of June 30, 2018 and December 31, 2017.

Power's accounts receivable include amounts resulting from contracts with customers and other contracts which are out of scope of accounting guidance for revenues from contracts with customers. The majority of these accounts receivable are subject to master netting agreements. As a result, accounts receivable resulting from contracts with customers and receivables unrelated to contracts with customers are netted within Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets. In the wholesale energy markets in which Power operates, payment for services rendered and products transferred are typically due within 30 days of month of delivery. As such, there is little credit risk associated with these receivables and Power typically records no allowances.

Other

PSEG LI does not have any material contract balances as of June 30, 2018 and December 31, 2017.

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Remaining Performance Obligations under Fixed Consideration Contracts

Power and PSE&G primarily record revenues as allowed by the guidance, which states that if an entity has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the entity's performance completed to date, the entity may recognize revenue in the amount to which the entity has a right to invoice. PSEG has future performance obligations under contracts with fixed consideration as follows:

Power

As stated above, capacity transactions with ISOs are reported on a net basis dependent on Power's monthly net sale or purchase position through the individual ISOs.

Capacity Payments from the PJM Reliability Pricing Model (RPM) Annual Base Residual and Incremental Auctions—The Base Residual Auction is conducted annually three years in advance of the operating period. Power expects to realize the following average capacity prices for capacity obligations to be satisfied resulting from the base and incremental auctions which have been completed:

Delivery Year	$ per MW-Day	MW Cleared
June 2018 to May 2019	$205	9,200
June 2019 to May 2020	$116	8,900
June 2020 to May 2021	$174	7,800
June 2021 to May 2022	$178	7,700

Capacity Payments from the New England ISO Forward Capacity Market—The Forward Capacity Market Auction (FCM) is conducted annually three years in advance of the operating period. The table below includes Power's cleared capacity in the FCM for the Bridgeport Harbor Station 5, which cleared the 2019/2020 auction at $231/MW-day for seven years, with escalations based on the Handy-Whitman Index and the planned retirement of Bridgeport Harbor Station 3 in 2021. Power expects to realize the following average capacity prices for capacity obligations to be satisfied resulting from the FCM auctions which have been completed:

Delivery Year	$ per MW-Day	MW Cleared
June 2018 to May 2019	$314	820
June 2019 to May 2020	$231	1,330
June 2020 to May 2021	$195	1,330
June 2021 to May 2022	$192	950
June 2022 to May 2023	$231	480
June 2023 to May 2024	$231	480
June 2024 to May 2025	$231	480
June 2025 to May 2026	$231	480

Bilateral capacity contracts—Capacity obligations pursuant to contract terms through 2029 are anticipated to result in revenues totaling $180 million.

Other

The LIPA OSA is a 12-year services contract ending in 2025 with annual fixed and incentive components. The fixed fee for the provision of services thereunder in 2018 is $64 million and could increase each year based on the change in the Consumer Price Index (CPI). The incentive for 2018 can range from zero to approximately $10 million and could increase each year thereafter based on the change in the CPI.

Note 4. Early Plant Retirements

Fossil

On June 1, 2017, Power completed its previously announced retirement of the generation operations of the existing coal/gas units at the Hudson and Mercer generating stations.

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For the three and six months ended June 30, 2017, Power recognized total Depreciation and Amortization of $390 million and $964 million, respectively, for the Hudson and Mercer units to reflect the significant shortening of their expected economic useful lives in 2017. In the three and six months ended June 30, 2018, Power recognized pre-tax charges (credits) in Energy Costs of $(1) million and $3 million, respectively, primarily for coal inventory lower of cost or market adjustments. In the three and six months ended June 30, 2017, Power recognized pre-tax charges of the same nature in Energy Costs of $2 million and $9 million, respectively. In the three and six months ended June 30, 2017, Power also recognized pre-tax charges in O&M of $4 million of shut down costs and a net increase in the Asset Retirement Obligation liability due to settlements and changes in cash flow estimates, partially offset by changes in employee-related severance costs. Power is exploring various opportunities with these sites, including using the sites for alternative industrial activity or the disposition of one or both of the sites. If Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such environmental remediation are neither currently probable nor estimable but may be material.

PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the held for use classification of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Nuclear

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. In February 2018, Exelon, a co-owner of the Salem units, announced its intention to accelerate the closure of its Oyster Creek nuclear plant located in New Jersey, one year earlier than previously planned for economic reasons. In addition, First Energy announced in March 2018 the early retirement of four nuclear units at the Davis-Besse, Perry Nuclear and Beaver Valley nuclear plants in Ohio and Pennsylvania by 2021. These closures and retirements are generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a further shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of our nuclear units beyond the current year, including whether and to what extent these units participate in RPM capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be influenced by the financial outlook of the units, including the progress, timing and continued outlook for selection of the units under the newly enacted legislation in the state of New Jersey. Power and Exelon have agreed to cancel the funding of future capital projects at the Salem generating station that are not required to meet NRC or other regulatory requirements or that are not required to ensure its safe operation. Power and Exelon have agreed to continue to assess and, when appropriate, approve the funding of individual capital projects to ensure compliance with regulatory requirements and the safe operation of the Salem generating station and that the funding of these projects may be restored if legislation enacted in New Jersey sufficiently values the attributes of nuclear generation and Salem benefits from such legislation.

If any or all of the Salem and Hope Creek units were shut down, it would significantly alter New Jersey's energy supply predominately by increasing New Jersey's reliance on natural gas generation. Such a decrease in fuel diversity could also increase the market's vulnerability to price fluctuations and power disruptions in times of high demand. In May 2018, the governor of New Jersey signed legislation that would provide a safety net in order to prevent the loss of environmental attributes from selected nuclear generating stations referred to as the zero emissions certificate (ZEC) program. The legislation calls for the BPU (within a 330-day period from enactment) to establish a collection process for a customer charge, determine eligibility and certification of need, and ultimately select nuclear plants to potentially receive ZECs starting in April 2019. Power cannot predict whether our nuclear generating stations in New Jersey will be selected or whether the legislation will provide a sufficient safety net for the continued operation of nuclear generating stations in New Jersey.

If energy market prices continue to be depressed, there are adverse impacts from potential changes to the capacity market construct being considered by FERC, or the ZEC program does not adequately compensate our nuclear generating stations for

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their attributes, Power anticipates it will no longer be covering its costs nor be adequately compensated for its market and operational risks at the Salem and Hope Creek nuclear units and would anticipate retiring these units early. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs and additional funding of the NDT Fund would be material to both PSEG and Power.

The following table provides the balance sheet amounts by generating station as of June 30, 2018 for significant assets and liabilities associated with Power's owned share of its nuclear assets.

	As of June 30, 2018			
	Hope Creek	Salem	Support Facilities and Other (A)	Peach Bottom
	Millions			
Assets				
Materials and Supplies Inventory	$ 83	$ 82	$ —	$ 42
Nuclear Production, net of Accumulated Depreciation	688	646	203	786
Nuclear Fuel In-Service, net of Accumulated Depreciation	171	89	—	119
Construction Work in Progress (including nuclear fuel)	140	105	2	24
Total Assets	$ 1,082	$ 922	$ 205	$ 971
Liability				
Asset Retirement Obligation	$ 309	$ 255	$ —	$ 210
Total Liabilities	$ 309	$ 255	$ —	$ 210
Net Assets	$ 773	$ 667	$ 205	$ 761
NRC License Renewal Term	2046	2036/2040	N/A	2033/2034
% Owned	100%	57%	Various	50%

(A) Includes Hope Creek's and Salem's shared support facilities and other nuclear development capital.

The precise timing of any potential early retirement and resulting financial statement impact may be affected by a number of factors, including co-owner considerations, the results of any transmission system reliability study assessments and decommissioning trust fund requirements and other commitments, as well as future energy prices. Power maintains a NDT Fund that funds its decommissioning obligations. See Note 8. Trust Investments.

Note 5. Variable Interest Entity (VIE)

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Servco, a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal and controls the services provided to LIPA, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and O&M Expense, respectively. Servco recorded $109 million and $112 million for the three months and $229 million and $224 million for the six months ended June 30, 2018 and

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2017, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 6. Rate Filings

This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2017.

In addition to items previously reported in the Annual Report on Form 10-K, significant regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

Electric and Gas Distribution Base Rate Filing—In January 2018, PSE&G filed a distribution base rate case as required as a condition of approval of its Energy Strong Program I (ESP I) approved by the BPU in 2014. The filing requested an approximate 1% increase in revenues and recovery of investments made to strengthen the electric and gas distribution systems. The requested increase took into account a reduction in the revenue requirement as a result of the federal corporate income tax rate reduction from 35% to 21% provided in the Tax Cuts and Jobs Act of 2017 (Tax Act), including the flow-back to customers of excess accumulated deferred income taxes. In March 2018, the BPU approved interim rate reductions for all their jurisdictional utilities, including PSE&G, reflecting the reduction in the federal corporate tax rate. The BPU approved a reduction to PSE&G's current base electric and gas revenues effective April 1, 2018 by $71 million and $43 million, respectively, on an annual basis (or about 2% combined). The refund to customers for overcollection of revenues at the higher tax rate for the January 1 to March 31, 2018 period, and the flow-back to customers of certain excess deferred income taxes will be addressed in PSE&G's ongoing base rate case proceeding. In May 2018, PSE&G updated its base rate filing to include nine months of actual data. As a result of the base rate reduction implemented on April 1, 2018, among other factors, PSE&G's updated filing requests an approximate 3% increase in revenues. PSE&G anticipates a decision by the BPU that new base rates will go into effect in the fourth quarter of 2018.

Transmission Formula Rate Filings—In January 2018, PSE&G filed with FERC a revised 2018 Annual Transmission Formula Rate Update reducing its 2018 transmission annual revenue requirement to reflect the federal corporate income tax rate reduction from 35% to 21% as a result of the Tax Act. This change in the federal corporate tax rate reduces the 2018 annual revenue requirement by $148 million, effective January 1, 2018. FERC continues to assess whether, and if so how, it will address changes and flow-backs to customers relating to accumulated deferred income taxes and bonus depreciation.

In June 2018, PSE&G filed its 2017 true-up adjustment pertaining to its transmission formula rates in effect for 2017. This resulted in an adjustment of $27 million more than the 2017 originally filed revenues, the impact of which PSE&G had primarily recognized in its Consolidated Statement of Operations for the year ended December 31, 2017.

BGSS—In June 2018, PSE&G made its annual BGSS filing with the BPU requesting a decrease in the annual BGSS revenues of $26 million. If approved, the BGSS rate would be decreased from approximately 37 cents to 35 cents per therm for residential gas customers to be effective October 1, 2018. This matter is pending.

In April 2018, the BPU approved the final BGSS rates which were effective October 1, 2017.

In December 2017, February 2018 and March 2018, PSE&G filed with the BPU for self-implementing monthly bill credits of 15 cents per therm for the months of January through April 2018. Monthly bill credits of $125 million were credited to customers for the months of January through April 2018.

ESP I Recovery Filing—In March and September of each year, PSE&G files with the BPU for base rate recovery of ESP I investments which include a return of and on its investment.

In February 2018, the BPU approved recovery of an annual revenue requirement of $8 million associated with electric ESP I capital investment costs placed in service from June 1, 2017 through November 30, 2017.

Societal Benefits Charge—In February 2018, the BPU approved PSE&G's petition to increase electric rates by approximately $20 million on an annual basis and to decrease gas rates by approximately $0.8 million on an annual basis, in order to recover electric and gas costs incurred through May 31, 2017 under its Energy Efficiency and Renewable Energy and Social Programs. The new rates were effective April 1, 2018.

Weather Normalization Clause (WNC)—In April 2018, the BPU gave final approval to PSE&G's petition to collect $55 million in net deficiency gas revenues as a result of the warmer than normal 2016-2017 Winter Period (October 1 through May 31), which resulted in a deficiency of $31 million, plus a carryover balance of $24 million from the 2015-2016 Winter Period.

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In June 2018, PSE&G filed its 2017-2018 WNC petition seeking a net recovery of $14 million to be collected over the 2018-2019 Winter Period. The $14 million net recovery is the result of $9 million of excess revenues from the colder-than- normal 2017-2018 Winter Period offset by $23 million of remaining prior Winter Period undercollection.

Green Program Recovery Charges (GPRC)—In June 2018, PSE&G filed its 2018 GPRC cost recovery petition requesting recovery of approximately $65 million and $6 million in electric and gas revenues, respectively, on an annual basis. This matter is pending.

Gas System Modernization Program I (GSMP I)—In July 2018, PSE&G filed its annual GSMP I cost recovery petition seeking BPU approval to recover in gas base rates an estimated annual revenue increase of $26 million effective January 1, 2019. This increase represents the return of and on investment for GSMP I investments expected to be in service through September 30, 2018. This request will be updated in October 2018 for actual costs.

Note 7. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. Interest income on the loans is recorded on an accrual basis. The loans are generally paid back with solar renewable energy certificates (SRECs) generated from the installed solar electric system. In the event of a loan default, the basis of the solar loan would be recovered through a regulatory recovery mechanism. None of the solar loans are impaired; however, in the event a loan becomes impaired, the basis of the loan would be recovered through a regulatory recovery mechanism. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Outstanding Loans by Class of Customer

Consumer Loans	As of June 30, 2018	As of December 31, 2017
	Millions	
Commercial/Industrial	$ 169	$ 158
Residential	9	10
Total	**$ 178**	**$ 168**

Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third-party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

During the first quarter of 2017, due to continuing liquidity issues facing NRG REMA, LLC (REMA), economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as certain discussions with REMA management, Energy Holdings recorded a $55 million pre-tax charge for its current best estimate of loss related to the lease receivables. Additional pre-tax charges of $22 million (including $7 million related to residual value impairment) were recorded in the quarter ended June 30, 2017. Subject to the terms of the Credit Support Forbearance and Rent Payment Forbearance described below, lease payments and adjustments to qualifying credit support on the REMA leases are due semiannually in January and July of each year.

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Based on an ongoing review of (i) the liquidity challenges facing REMA and (ii) available alternatives, Energy Holdings recorded an additional $20 million pre-tax charge in the quarter ended June 30, 2018 for its current best estimate of loss related to lease receivables. Pre-tax charges were reflected in Operating Revenues in the first half of 2018 and 2017 and are included in Gross Investment in Leases as of June 30, 2018.

Certain subsidiaries of Energy Holdings, REMA, certain holders of the pass-through certificates and other parties have entered into a forbearance agreement (Credit Support Forbearance) relating to REMA's obligation to procure additional qualifying credit support for the Conemaugh facility. In addition, certain subsidiaries of Energy Holdings, REMA, certain holders of the pass-through certificates and other parties have entered into forbearance agreements (Rent Payment Forbearance) relating to the Keystone, Conemaugh and Shawville facilities. The parties to the Rent Payment Forbearance have agreed to permit REMA to enter into agreements with third parties relating to certain energy management, operation and maintenance and other services and have agreed to temporarily forbear from exercising rights and remedies related to certain events of default relating to certain periodic lease rent payments required to be made by REMA in July 2018.

The Credit Support Forbearance will remain effective until the earlier of (i) two weeks following the date on which Energy Holdings subsidiaries, REMA and/or the consenting certificate holders provide written notice to REMA of its intention to terminate the Forbearance, and (ii) the date on which any event of termination as specified in the Credit Support Forbearance occurs. The Rent Payment Forbearance for each facility will remain effective until the earlier of (i) August 17, 2018 and (ii) the date on which any of the following events occur: (a) a new event of default occurs and is continuing under the operative documents governing the respective facilities; (b) REMA commences a case under title 11 of the United States Bankruptcy Code or (c) REMA terminates discussions with Energy Holdings and/or the consenting pass-through certificate holders regarding a potential restructuring by REMA.

PSEG cannot predict the outcome of GenOn's restructuring process or the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments. If lease rejections or foreclosures were to occur, Energy Holdings could potentially record additional pre-tax write-offs up to its gross investment in these facilities and may also be required to accelerate and pay material deferred tax liabilities to the Internal Revenue Service (IRS). Also, if energy markets continue to deteriorate, it is possible that additional write-downs, including residual value impairment, could occur.

The following table shows Energy Holdings' gross and net lease investment as of June 30, 2018 and December 31, 2017.

	As of June 30, 2018	As of December 31, 2017
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 525	$ 546
Estimated Residual Value of Leased Assets	326	326
Total Investment in Rental Receivables	851	872
Unearned and Deferred Income	(299)	(307)
Gross Investment in Leases	552	565
Deferred Tax Liabilities	(500)	(480)
Net Investment in Leases	**$ 52**	**$ 85**

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The corresponding receivables associated with the lease portfolio are reflected as follows, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

	Lease Receivables, Net of Non-Recourse Debt	
Counterparties' Credit Rating Standard & Poor's (S&P) as of June 30, 2018	**As of June 30, 2018**	
	Millions	
AA	$	14
BBB+ — BBB-		316
BB-		133
CCC-		62
Total	**$**	**525**

The "BB-" and the "CCC-" ratings in the preceding table represent lease receivables related to coal and gas-fired assets in Illinois and Pennsylvania, respectively. As of June 30, 2018, the gross investment in the leases of such assets, net of non-recourse debt, was $315 million ($(112) million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 132	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 85	64%	1,036	Gas	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 10	17%	1,711	Coal	CCC-	REMA (A)
Conemaugh Station Units 1 and 2	PA	$ 10	17%	1,711	Coal	CCC-	REMA (A)
Shawville Station Units 1, 2, 3 and 4	PA	$ 78	100%	596	Gas	CCC-	REMA (A)

(A) GenOn and certain of its subsidiaries (which did not include REMA) filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete. Certain subsidiaries of Energy Holdings, REMA, consenting holders of the pass-through certificates and other parties have entered into a Credit Support Forbearance relating to the Conemaugh facility and the Rent Payment Forbearance relating to the Keystone, Conemaugh and Shawville facilities, as described above.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease structures. These credit enhancement features vary from lease to lease. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital and trigger certain material tax obligations which could wholly or partially be mitigated by tax indemnification claims against the counterparty. A bankruptcy of a lessee would likely delay and potentially limit any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders.

Additional factors that may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and their affiliates and the quality and condition of assets under lease.

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Note 8. Trust Investments

NDT Fund

Power maintains an external master NDT to fund its share of decommissioning costs for its five nuclear facilities upon their respective termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The funds are managed by third-party investment managers who operate under investment guidelines developed by Power.

The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of June 30, 2018			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 471	$ 235	$ (8)	$ 698
International	321	76	(14)	383
Total Equity Securities	792	311	(22)	1,081
Available-for Sale Debt Securities				
Government	528	1	(12)	517
Corporate	464	—	(14)	450
Total Available-for-Sale Debt Securities	992	1	(26)	967
Other	1	—	—	1
Total NDT Fund Investments	**$ 1,785**	**$ 312**	**$ (48)**	**$ 2,049**

	As of December 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 497	$ 245	$ (2)	$ 740
International	311	99	(3)	407
Total Equity Securities	808	344	(5)	1,147
Available-for Sale Debt Securities				
Government	586	2	(4)	584
Corporate	400	4	(2)	402
Total Available-for-Sale Debt Securities	986	6	(6)	986
Total NDT Fund Investments	**$ 1,794**	**$ 350**	**$ (11)**	**$ 2,133**

Net unrealized gains (losses) on debt securities of $(14) million (after-tax) were included in Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of June 30, 2018. The portion of net unrealized gains (losses) recognized during the second quarter and first half of 2018 related to equity securities still held at the end of June 30, 2018 were $12 million and $(3) million, respectively.

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

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	As of June 30, 2018	As of December 31, 2017
	Millions	
Accounts Receivable	$ 11	$ 24
Accounts Payable	$ 8	$ 74

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of June 30, 2018				As of December 31, 2017			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)								
Domestic	$ 79	$ (8)	$ —	$ —	$ 40	$ (2)	$ —	$ —
International	74	(13)	4	(1)	29	(3)	2	—
Total Equity Securities	153	(21)	4	(1)	69	(5)	2	—
Available-for Sale Debt Securities								
Government (B)	402	(9)	64	(3)	343	(2)	91	(2)
Corporate (C)	358	(12)	25	(2)	191	(1)	27	(1)
Total Available-for-Sale Debt Securities	760	(21)	89	(5)	534	(3)	118	(3)
NDT Trust Investments	**$ 913**	**$ (42)**	**$ 93**	**$ (6)**	**$ 603**	**$ (8)**	**$ 120**	**$ (3)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. Effective January 1, 2018, unrealized gains and losses on these securities are recorded in Net Income.

(B) Debt Securities (Government)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). The unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. Power also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2018.

(C) Debt Securities (Corporate)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2018.

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The proceeds from the sales of and the net gains (losses) on securities in the NDT Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	Millions			
Proceeds from NDT Fund Sales (A)	**$ 402**	**$ 320**	**$ 774**	**$ 567**
Net Realized Gains (Losses) on NDT Fund				
Gross Realized Gains	$ 34	$ 32	$ 58	$ 53
Gross Realized Losses	(10)	(5)	(22)	(9)
Net Realized Gains (Losses) on NDT Fund (B)	**$ 24**	**$ 27**	**$ 36**	**$ 44**
Unrealized Gains (Losses) on Equity Securities in NDT Fund (C)	(16)	N/A	(50)	N/A
Other-Than-Temporary-Impairments	$ —	$ (3)	—	(4)
Net Gains (Losses) on NDT Fund Investments	**$ 8**	**$ 24**	**$ (14)**	**$ 40**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

(B) The cost of these securities was determined on the basis of specific identification.

(C) Effective January 1, 2018, unrealized gains (losses) on equity securities are recorded in Net Income instead of Other Comprehensive Income (Loss).

The NDT Fund debt securities held as of June 30, 2018 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 10
1 - 5 years	298
6 - 10 years	196
11 - 15 years	45
16 - 20 years	71
Over 20 years	347
Total NDT Available-for-Sale Debt Securities	**$ 967**

Power periodically assesses individual debt securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For these securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

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The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of June 30, 2018			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 21	$ 3	$ —	$ 24
International	—	—	—	—
Total Equity Securities	21	3	—	24
Available-for-Sale Debt Securities				
Government	96	—	(2)	94
Corporate	110	—	(4)	106
Total Available-for-Sale Debt Securities	206	—	(6)	200
Total Rabbi Trust Investments	**$ 227**	**$ 3**	**$ (6)**	**$ 224**

	As of December 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 24	$ 3	$ —	$ 27
International	—	—	—	—
Total Equity Securities	24	3	—	27
Available-for-Sale Debt Securities				
Government	85	1	(1)	85
Corporate	118	2	(1)	119
Total Available-for-Sale Debt Securities	203	3	(2)	204
Total Rabbi Trust Investments	**$ 227**	**$ 6**	**$ (2)**	**$ 231**

Net unrealized gains (losses) on debt securities of $(4) million (after-tax) were included in Accumulated Other Comprehensive Loss on PSEG's Condensed Consolidated Balance Sheet as of June 30, 2018. The portion of net unrealized gains (losses) recognized during both the second quarter and first half of 2018 related to equity securities still held at the end of June 30, 2018 was less than $1 million.

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of June 30, 2018	As of December 31, 2017
	Millions	
Accounts Receivable	$ 2	$ 2
Accounts Payable	$ —	$ 1

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The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months.

	As of June 30, 2018				As of December 31, 2017			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Available-for-Sale Debt Securities								
Government (A)	$ 57	$ (1)	23	(1)	$ 28	$ —	$ 25	$ (1)
Corporate (B)	93	(4)	6	—	39	(1)	9	—
Total Available-for-Sale Debt Securities	150	(5)	29	(1)	67	(1)	34	(1)
Rabbi Trust Investments	**$ 150**	**$ (5)**	**$ 29**	**$ (1)**	**$ 67**	**$ (1)**	**$ 34**	**$ (1)**

(A) Debt Securities (Government)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). The unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. PSEG also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2018.

(B) Debt Securities (Corporate)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2018.

The proceeds from the sales of and the net gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	Millions			
Proceeds from Rabbi Trust Sales (A)	**$ 22**	**$ 93**	**$ 47**	**$ 144**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ —	$ 2	$ 2	$ 17
Gross Realized Losses	—	(1)	(2)	(4)
Net Realized Gains (Losses) on Rabbi Trust (B)	**—**	**1**	**—**	**13**
Unrealized Gains (Losses) on Equity Securities in Rabbi Trust (C)	—	N/A	—	N/A
Other-Than-Temporary-Impairments	—	$ —	—	—
Net Gains (Losses) on Rabbi Trust Investments	**$ —**	**$ 1**	**$ —**	**$ 13**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

(B) The cost of these securities was determined on the basis of specific identification.

(C) Effective January 1, 2018, unrealized gains (losses) on equity securities are recorded in Net Income instead of Other Comprehensive Income (Loss).

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The Rabbi Trust debt securities held as of June 30, 2018 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 1
1 - 5 years	39
6 - 10 years	23
11 - 15 years	7
16 - 20 years	18
Over 20 years	112
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 200**

PSEG periodically assesses individual debt securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For these securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of June 30, 2018	As of December 31, 2017
	Millions	
PSE&G	$ 45	$ 46
Power	56	57
Other	123	128
Total Rabbi Trust Investments	**$ 224**	**$ 231**

Note 9. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria.

The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis for PSEG, excluding Servco. Amounts shown do not reflect the impacts of capitalization and co-owner allocations. Effective with the adoption of ASU 2017-07 on January 1, 2018, only the service cost component is eligible for capitalization, when applicable. For additional information, see Note 2. Recent Accounting Standards.

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	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
	Millions							
Components of Net Periodic Benefit (Credits) Costs								
Service Cost (included in O&M Expense)	$ 33	$ 28	$ 5	$ 4	$ 65	$ 57	$ 9	$ 8
Non-Service Components of Pension and OPEB (Credits) Costs								
Interest Cost	52	51	17	16	104	102	33	32
Expected Return on Plan Assets	(110)	(99)	(11)	(9)	(220)	(197)	(21)	(17)
Amortization of Net								
Prior Service Cost	(5)	(4)	—	(2)	(9)	(9)	—	(5)
Actuarial Loss	21	25	16	12	42	49	32	25
Non-Service Components of Pension and OPEB (Credits) Costs	**(42)**	**(27)**	**22**	**17**	**(83)**	**(55)**	**44**	**35**
Total Benefit (Credits) Costs	**$ (9)**	**$ 1**	**$ 27**	**$ 21**	**$ (18)**	**$ 2**	**$ 53**	**$ 43**

Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, excluding Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
	Millions							
PSE&G	$ (7)	$ (1)	$ 17	$ 13	$ (15)	$ (2)	$ 34	$ 27
Power	(3)	1	8	6	(5)	1	16	13
Other	1	1	2	2	2	3	3	3
Total Benefit (Credits) Costs	**$ (9)**	**$ 1**	**$ 27**	**$ 21**	**$ (18)**	**$ 2**	**$ 53**	**$ 43**

During the three months ended March 31, 2018, PSEG contributed its entire planned contribution for the year 2018 of $14 million into its OPEB plan.

Servco Pension and OPEB

At the direction of LIPA, Servco sponsors benefit plans that cover its current and former employees who meet certain eligibility criteria. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 5. Variable Interest Entity. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco plans to contribute $40 million into its pension plan trusts during 2018. Servco's pension-related revenues and costs were $10 million and $8 million for three months ended June 30, 2018 and 2017, respectively, and $20 million and $17 million for the six months ended June 30, 2018 and 2017, respectively. The OPEB-related revenues earned and costs incurred were $2 million and $1 million for the three months ended June 30, 2018 and 2017, respectively, and $3 million and $2 million for the six months ended June 30, 2018 and 2017, respectively.

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Note 10. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees as a form of collateral.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- the net position of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. Current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of June 30, 2018 and December 31, 2017.

	As of June 30, 2018	As of December 31, 2017
	Millions	
Face Value of Outstanding Guarantees	$ 1,780	$ 1,701
Exposure under Current Guarantees	$ 129	$ 153
Letters of Credit Margin Posted	$ 152	$ 103
Letters of Credit Margin Received	$ 18	$ 32
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (2)	$ (1)
Net Broker Balance Deposited (Received)	$ 124	$ 147
Additional Amounts Posted:		
Other Letters of Credit	$ 63	$ 61

As part of determining credit exposure, Power nets receivables and payables with the corresponding net fair values of energy contracts. See Note 12. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Condensed Consolidated Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power have posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The U.S. Environmental Protection Agency (EPA) has determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA and a comprehensive study of the entire 17 miles of the lower Passaic River needed to be performed. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, certain Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. The CPG has agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately 7.6 percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately 1.9 percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim. Certain PRPs are currently involved in discussions with the EPA regarding cost allocations and related indemnification matters. We cannot predict the outcome of these discussions, or whether individual PRPs will be able to meet their obligations, either of which could have a material impact on PSE&G's and Power's allocation of costs.

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The CPG's draft FS set forth various alternatives for remediating the lower Passaic River with an estimated cost to remediate the lower 17 miles of the Passaic River ranging from approximately $518 million to $3.2 billion on an undiscounted basis.

In March 2016, the EPA released its Record of Decision (ROD) for the EPA's own Focused Feasibility Study (FFS) which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The EPA estimated the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation. Occidental Chemical Corporation (OCC), one of the PRPs, has commenced performance of the remedial design required by the ROD Remedy, reserving its right of cost contribution from all other PRPs.

In September 2017, the EPA concluded that an Agency-commenced allocation process for the Passaic River's lower 8.3 miles should include only certain PRPs. The allocation is intended to lead to a consent decree in which certain of the PRPs agree to perform and pay for the remedial action under EPA oversight. The allocation process has commenced and is scheduled to be completed in late 2019. Conversations between the EPA and the PRPs regarding remediation of the Passaic River's upper 9 miles are ongoing.

In a separate matter, two PRPs, Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus), filed for Chapter 11 bankruptcy in Delaware Federal Bankruptcy Court. In June 2018, the trust representing the creditors in this proceeding filed a complaint asserting claims against the current and former parent entities of Tierra and Maxus, among other parties, for up to $14 billion. Any damages awarded may be used to fund, in part, the remediation costs of the lower 8.3 miles of the Passaic River. The creditor trust has reserved its right to file contribution claims against 28 PRPs, including PSEG. This matter is ongoing.

In June 2018, OCC filed a complaint in Federal District Court in Newark against various defendants, including PSE&G, seeking cost recovery and contribution under CERCLA for the remediation of the lower 8.3 miles of the Passaic River. The complaint does not quantify damages sought.

The Complaint alleges that "no single hazardous substance" is to blame for the contamination of the lower Passaic River and lists the eight Contaminants of Concern (COCs) identified by the EPA in the ROD. OCC alleges PSE&G is responsible for a portion of six of the eight COCs. PSE&G cannot predict the outcome of this matter.

Based upon the estimated cost of the ROD Remedy and PSEG's estimate of PSE&G's and Power's shares of that cost, as of June 30, 2018, PSEG has accrued approximately $57 million. Of this amount, PSE&G has accrued $46 million as an Environmental Costs Liability and a corresponding Regulatory Asset based on its continued ability to recover such costs in its rates. Power has accrued $11 million as an Other Noncurrent Liability with the corresponding O&M Expense recorded in prior years when the liability was accrued.

The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on PSEG's financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each

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of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $332 million and $378 million on an undiscounted basis through 2021, including its $46 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $332 million as of June 30, 2018. Of this amount, $79 million was recorded in Other Current Liabilities and $253 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $332 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly. NJDEP, PSEG and EPA representatives have had discussions regarding to what extent sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.

Clean Water Act (CWA) Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In May 2014, the EPA issued a final cooling water intake rule that establishes requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing power facilities on a case by case basis, based on studies related to impingement mortality and entrainment by the facilities seeking renewal permits.

Several environmental organizations and certain energy industry groups have filed suit under the CWA and the Endangered Species Act. The cases were consolidated at the Second Circuit, and in July 2018 the Second Circuit upheld the EPA's final cooling water intake rule. The Court's decision allows Permitting Directors to continue to issue permits in accordance with the flexible, site-specific provisions of the final rule.

In June 2016, the NJDEP issued a final NJPDES permit for Salem. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the CWA, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final NJPDES renewal permit for Salem. NJDEP has granted the hearing request, but it has not yet been scheduled. The Riverkeeper's filing does not change the effective date of the permit. If the Riverkeeper's challenge were successful, Power may be required to incur additional costs to comply with the CWA. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

State permitting decisions at Bridgeport and possibly New Haven could also have a material impact on Power's ability to renew permits at its existing larger once-through cooled plants without making significant upgrades to existing intakes and cooling systems.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at BH3. To address compliance with the EPA's CWA Section 316(b) final rule, Power has proposed to continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the previously estimated useful life ending in 2025. Power is currently awaiting action by the CTDEEP to issue a draft and then a final permit.

Power has entered into a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut and local community organizations. That CEBA provides that Power would retire BH3 early if all of its conditions precedent occur,

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which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power may seek to operate BH3 through the previously estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. The Connecticut Siting Council issued an order to approve siting Bridgeport Harbor Station Unit 5 (BH5). All major environmental permits have been received; however, secondary approvals are still being obtained to allow operations to begin in mid-2019. Power's obligations under the CEBA are being monitored regularly and carried out as needed.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.

Jersey City, New Jersey Subsurface Feeder Cable Matter

In October 2016, a discharge of dielectric fluid from subsurface feeder cables located in the Hudson River near Jersey City, New Jersey, was identified and reported to the NJDEP. The feeder cables are located within a subsurface easement granted to PSE&G by the property owners, Newport Associates Development Company (NADC) and Newport Associates Phase I Developer Limited Partnership. The feeder cables are subject to agreements between PSE&G and Consolidated Edison Company of New York, Inc. (Con Edison) and are jointly owned by PSE&G and Con Edison, with PSE&G owning the portion of the cables located in New Jersey and Con Edison owning the portion of the cables located in New York. The NJDEP declared an emergency and an emergency response action was undertaken to investigate, contain, remediate and stop the fluid discharge; to assess, repair and restore the cables to good working order, if feasible; and to restore the property. The regulatory agencies overseeing the emergency response, including the U.S. Coast Guard, the NJDEP and the Army Corps of Engineers, have issued multiple notices, orders and directives to the various parties related to this matter and the parties may also be subject to the assessment of civil penalties related to the discharge and response. The U.S. Coast Guard transitioned control of the federal response to the EPA in May 2018. As part of this transition, the U.S. Coast Guard rescinded its Administrative Order to PSE&G related to this matter.

The impacted cable was repaired in late September 2017; however, small amounts of residual dielectric fluid believed to be contained within the marina sediment continue to appear on the surface and response actions related to the fluid discharge are ongoing, although at a significantly reduced scale. PSE&G remains concerned about future leaks and potential environmental impacts as a result of reintroduction of fluid back into these lines and has determined that retirement of the affected facilities is appropriate. PSE&G has been unable to reach an agreement with Con Edison and, as a result, in May 2018, PSE&G filed an action at FERC to resolve the matter. Also ongoing is the process to determine ultimate responsibility for the costs to address the leak among PSE&G, Con Edison and NADC, including an action filed by PSE&G in federal court in New Jersey seeking damages from NADC. In that action, NADC has also pursued counterclaims against PSE&G and Con Edison seeking damages for its costs to address the leak. Based on the information currently available and depending on the outcome of the federal court action, PSE&G's portion of the costs to address the leak may be material; however, PSE&G anticipates that it will recover these costs through regulatory proceedings.

Steam Electric Effluent Guidelines

In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG Rule) for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under the ELG Rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the ELG Rule.

Through various orders, the EPA has stayed the compliance dates in the ELG Rule and has announced plans to further revise the requirements and compliance dates of the ELG Rule. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The

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winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2018 is $287.76 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2018 of $276.83 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2015	2016	2017	2018	
36-Month Terms Ending	May 2018	May 2019	May 2020	May 2021	(A)
Load (MW)	2,900	2,800	2,800	2,900	
$ per MWh	$99.54	$96.38	$90.78	$91.77	

(A) Prices set in the 2018 BGS auction year became effective on June 1, 2018 when the 2015 BGS auction agreements expired.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 19. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2020 and a significant portion through 2022 at Salem, Hope Creek and Peach Bottom.

Power has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available beyond the needs of PSE&G's customers, Power can use the gas to supply its fossil generating stations in New Jersey.

Power also has various long-term fuel purchase commitments for coal through 2021 to support its fossil generation stations.

As of June 30, 2018, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2022
	Millions
Nuclear Fuel	
Uranium	$ 244
Enrichment	$ 345
Fabrication	$ 161
Natural Gas	$ 990
Coal	$ 278

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Litigation

Sewaren 7 Construction

In June 2018, a complaint was filed in federal court in Newark against PSEG Fossil, LLC, a wholly owned subsidiary of Power, regarding an ongoing dispute with Durr Mechanical Construction, Inc. (Durr), a contractor on the Sewaren 7 project. Among other things, Durr seeks damages of $93 million and alleges that Power withheld money owed to Durr and that Power's intentional conduct led to the inability of Durr to obtain prospective contracts. Power intends to vigorously defend against these allegations. Based upon the preliminary nature of this matter, a loss is not considered probable nor is the amount of loss, if any, estimable as of June 30, 2018.

Newark Customer Incident

On the morning of July 5, 2018, PSE&G discontinued electricity to the home of a customer residing in Newark because of outstanding arrears on that customer's account. Subsequent to the discontinuation of electricity, that customer died on the afternoon of July 5th. The family of the customer, who was on hospice care, has raised allegations in the media regarding PSE&G's conduct surrounding the discontinuation and restoration of electricity to the home of the customer, claiming that the discontinuation of electric service prevented the customer from using life sustaining medical equipment. The BPU has initiated an investigation into the matter. In addition, PSE&G received a grand jury subpoena from the Essex County Prosecutor's Office (ECPO) for records and correspondence between PSE&G and the customer. PSE&G is fully cooperating with the BPU and the ECPO in both proceedings. The PSEG Board of Directors retained outside counsel to conduct an independent investigation of the facts surrounding this incident with the full support and cooperation of management. PSEG cannot predict the outcome of this matter.

Other Litigation and Legal Proceedings

PSEG and its subsidiaries are party to various lawsuits in the ordinary course of business. In view of the inherent difficulty in predicting the outcome of such matters, PSEG, PSE&G and Power generally cannot predict the eventual outcome of the pending matters, the timing of the ultimate resolution of these matters, or the eventual loss, fines or penalties related to each pending matter.

In accordance with applicable accounting guidance, a liability is accrued when those matters present loss contingencies that are both probable and reasonably estimable. In such cases, there may be an exposure to loss in excess of any amounts accrued. PSEG will continue to monitor the matter for further developments that could affect the amount of the accrued liability that has been previously established.

Based on current knowledge, management does not believe that loss contingencies arising from pending matters, other than the matters described herein, could have a material adverse effect on PSEG's, PSE&G's or Power's consolidated financial position or liquidity. However, in light of the inherent uncertainties involved in these matters, some of which are beyond PSEG's control, and the large or indeterminate damages sought in some of these matters, an adverse outcome in one or more of these matters could be material to PSEG's, PSE&G's or Power's results of operations or liquidity for any particular reporting period.

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Note 11. Debt and Credit Facilities

Long-Term Debt Financing Transactions

The following long-term debt transactions occurred in the six months ended June 30, 2018:

PSE&G

- issued $375 million of 3.70% Secured Medium-Term Notes, Series M, due May 2028,
- issued $325 million of 4.05% Secured Medium-Term Notes, Series M, due May 2048, and
- retired $400 million of 5.30% Medium-Term Notes at maturity.

Power

- issued $700 million of 3.85% Senior Notes due June 2023.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under the $4.2 billion credit facilities are provided by a diverse bank group. As of June 30, 2018, the total available credit capacity was $3.7 billion.

As of June 30, 2018, no single institution represented more than 8% of the total commitments in the credit facilities.

As of June 30, 2018, total credit capacity was in excess of the total anticipated maximum liquidity requirements over PSEG's 12-month planning horizon.

Each of the credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support its subsidiaries' liquidity needs. The total credit facilities and available liquidity as of June 30, 2018 were as follows:

	As of June 30, 2018				
Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facilities (A)	$ 1,500	$ 88	$ 1,412	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSEG	**$ 1,500**	**$ 88**	**$ 1,412**		
PSE&G					
5-year Credit Facility (A)	$ 600	$ 211	$ 389	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 211**	**$ 389**		
Power					
3-year Letter of Credit Facilities	$ 200	$ 162	$ 38	Mar 2020	Letters of Credit
5-year Credit Facilities	1,900	40	1,860	Mar 2022	Funding/Letters of Credit
Total Power	**$ 2,100**	**$ 202**	**$ 1,898**		
Total	**$ 4,200**	**$ 501**	**$ 3,699**		

(A) The primary use of PSEG's and PSE&G's credit facilities is to support their respective Commercial Paper Programs, under which as of June 30, 2018, PSEG had $75 million outstanding at a weighted average interest rate of 2.32%. PSE&G had $195 million outstanding at a weighted average interest rate of 2.29% under its Commercial Paper Program as of June 30, 2018.

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Note 12. Financial Risk Management Activities

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchases and normal sales (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow or fair value hedges. Power and PSE&G enter into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Power also uses derivatives to hedge a portion of its anticipated BGSS obligations with PSE&G. For additional information see Note 10. Commitments and Contingent Liabilities. Changes in the fair market value of these derivative contracts are recorded in earnings.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. The changes in fair value of the interest rate swaps are fully offset by changes in the fair value of the underlying forecasted interest payments of the debt. There were no outstanding interest rate swaps as of June 30, 2018 or December 31, 2017.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. PSEG interest rate hedges totaling $500 million were executed and terminated during the second quarter of 2018 and a loss of $(1) million was recorded in Accumulated Other Comprehensive Income (Loss) (after tax) and will amortize to interest expense over the remaining life of Power's $700 million of 3.85% Senior Notes due June 2023. For additional information see Note 11. Debt and Credit Facilities. There were no outstanding interest rate hedges as of June 30, 2018 and December 31, 2017. The Accumulated Other Comprehensive Income (Loss) (after tax) related to terminated interest rate derivatives designated as cash flow hedges was $(1) million as of June 30, 2018 and was immaterial as of December 31, 2017. The after-tax unrealized losses on these hedges expected to be reclassified to earnings during the next 12 months are immaterial.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with PSEG's accounting policy, these positions are offset on the Condensed Consolidated Balance Sheets of Power and PSEG. For additional information see Note 13. Fair Value Measurements.

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The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of June 30, 2018			
	Power (A)			Consolidated
	Not Designated			
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Total Derivatives
	Millions			
Derivative Contracts				
Current Assets	$ 256	$ (232)	$ 24	$ 24
Noncurrent Assets	132	(111)	21	21
Total Mark-to-Market Derivative Assets	**$ 388**	**$ (343)**	**$ 45**	**$ 45**
Derivative Contracts				
Current Liabilities	$ (254)	$ 231	$ (23)	$ (23)
Noncurrent Liabilities	(111)	110	(1)	(1)
Total Mark-to-Market Derivative (Liabilities)	**$ (365)**	**$ 341**	**$ (24)**	**$ (24)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 23**	**$ (2)**	**$ 21**	**$ 21**

	As of December 31, 2017			
	Power (A)			Consolidated
	Not Designated			
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Total Derivatives
	Millions			
Derivative Contracts				
Current Assets	$ 391	$ (362)	$ 29	$ 29
Noncurrent Assets	78	(71)	7	7
Total Mark-to-Market Derivative Assets	**$ 469**	**$ (433)**	**$ 36**	**$ 36**
Derivative Contracts				
Current Liabilities	$ (403)	$ 387	$ (16)	$ (16)
Noncurrent Liabilities	(95)	90	(5)	(5)
Total Mark-to-Market Derivative (Liabilities)	**$ (498)**	**$ 477**	**$ (21)**	**$ (21)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ (29)**	**$ 44**	**$ 15**	**$ 15**

(A) Substantially all of Power's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of June 30, 2018 and December 31, 2017.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of June 30, 2018 and December 31, 2017, Power had net cash collateral/margin payments to counterparties of $122 million and $146 million, respectively. Of these net cash/collateral margin payments $(2) million as of June 30, 2018 and $44 million as December 31, 2017 were netted against the corresponding net derivative contract positions. Of the $(2) million as of June 30, 2018, $(1) million was netted against current assets, and $(1) million was netted against noncurrent assets. Of the $44 million as of December 31, 2017, $(3) million was netted against current assets, $28 million was netted against current liabilities, and $19 million was netted against noncurrent liabilities.

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Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating by S&P or Moody's, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P or Moody's ratings. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $11 million and $30 million as of June 30, 2018 and December 31, 2017, respectively. As of June 30, 2018 and December 31, 2017, Power had the contractual right of offset of $6 million and $13 million, respectively, related to derivative instruments that are assets with the same counterparty under master agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $5 million and $17 million as of June 30, 2018 and December 31, 2017, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.

The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2016	**$ 3**	**$ 2**
Gain Recognized in AOCI	—	—
Less: Gain Reclassified into Income	(3)	(2)
Balance as of December 31, 2017	**$ —**	**$ —**
Loss Recognized in AOCI	(2)	(1)
Less: Loss Reclassified into Income	—	—
Balance as of June 30, 2018	**$ (2)**	**$ (1)**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS for the three months and six months ended June 30, 2018 and 2017. Power's derivative contracts reflected in this table include contracts to hedge the purchase and sale of electricity and natural gas, and the purchase of fuel. The table does not include contracts that Power has designated as NPNS, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives		Pre-Tax Gain (Loss) Recognized in Income on Derivatives	
		Three Months Ended June 30,		Six Months Ended June 30,	
		2018	2017	2018	2017
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ (64)	$ 112	$ (24)	$ 190
Energy-Related Contracts	Energy Costs	15	(10)	7	(10)
Total PSEG and Power		**$ (49)**	**$ 102**	**$ (17)**	**$ 180**

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The following table summarizes the net notional volume purchases/(sales) of open derivative transactions by commodity as of June 30, 2018 and December 31, 2017.

Type	Notional	Total	PSEG	Power	PSE&G
		Millions			
As of June 30, 2018					
Natural Gas	Dekatherm (Dth)	249	—	249	—
Electricity	MWh	(67)	—	(67)	—
Financial Transmission Rights (FTRs)	MWh	24	—	24	—
As of December 31, 2017					
Natural Gas	Dth	154	—	154	—
Electricity	MWh	(63)	—	(63)	—
FTRs	MWh	6	—	6	—

Credit Risk

Credit risk relates to the risk of loss that Power would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG has established credit policies that it believes significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

The following table provides information on Power's credit risk from ER&T wholesale counterparties, net of collateral, as of June 30, 2018. It further delineates that exposure by the credit rating of the counterparties, which is determined by the lowest rating from S&P, Moody's or an internal scoring model. In addition, it provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

As of June 30, 2018, 98% of the net credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives, NPNS and non-derivatives).

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
	Millions				Millions	
Investment Grade	$ 172	$ 12	$ 160	2	$ 74	(A)
Non-Investment Grade	4	1	3	—	—	
Total	**$ 176**	**$ 13**	**$ 163**	**2**	**$ 74**	

(A) Represents net exposure of $56 million with PSE&G and a non-affiliated counterparty of $18 million.

As of June 30, 2018, collateral held from counterparties where Power had credit exposure included $1 million in cash collateral and $12 million in letters of credit.

As of June 30, 2018, Power had 145 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of June 30, 2018, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's

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net credit exposure. PSE&G's BGS suppliers' credit exposure is calculated each business day. As of June 30, 2018, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

Note 13. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds, as well as natural gas futures contracts executed on NYMEX.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of June 30, 2018, these consisted primarily of certain electric load contracts and gas contracts.

Certain derivative transactions may transfer from Level 2 to Level 3 if inputs become unobservable and internal modeling techniques are employed to determine fair value. Conversely, measurements may transfer from Level 3 to Level 2 if the inputs become observable.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of June 30, 2018 and December 31, 2017, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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Description	Recurring Fair Value Measurements as of June 30, 2018				
	Total	Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Energy-Related Contracts (B)	$ 45	$ (343)	$ 16	$ 365	$ 7
NDT Fund (C)					
Equity Securities	$ 1,081	$ —	$ 1,079	$ 2	$ —
Debt Securities—U.S. Treasury	$ 211	$ —	$ —	$ 211	$ —
Debt Securities—Govt Other	$ 306	$ —	$ —	$ 306	$ —
Debt Securities—Corporate	$ 450	$ —	$ —	$ 450	$ —
Rabbi Trust (C)					
Equity Securities	$ 24	$ —	$ 24	$ —	$ —
Debt Securities—U.S. Treasury	$ 58	$ —	$ —	$ 58	$ —
Debt Securities—Govt Other	$ 36	$ —	$ —	$ 36	$ —
Debt Securities—Corporate	$ 106	$ —	$ —	$ 106	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (24)	$ 341	$ (8)	$ (354)	$ (3)
PSE&G					
Assets:					
Rabbi Trust (C)					
Equity Securities	$ 4	$ —	$ 4	$ —	$ —
Debt Securities—U.S. Treasury	$ 12	$ —	$ —	$ 12	$ —
Debt Securities—Govt Other	$ 8	$ —	$ —	$ 8	$ —
Debt Securities—Corporate	$ 21	$ —	$ —	$ 21	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 45	$ (343)	$ 16	$ 365	$ 7
NDT Fund (C)					
Equity Securities	$ 1,081	$ —	$ 1,079	$ 2	$ —
Debt Securities—U.S. Treasury	$ 211	$ —	$ —	$ 211	$ —
Debt Securities—Govt Other	$ 306	$ —	$ —	$ 306	$ —
Debt Securities—Corporate	$ 450	$ —	$ —	$ 450	$ —
Rabbi Trust (C)					
Equity Securities	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—U.S. Treasury	$ 14	$ —	$ —	$ 14	$ —
Debt Securities—Govt Other	$ 9	$ —	$ —	$ 9	$ —
Debt Securities—Corporate	$ 27	$ —	$ —	$ 27	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (24)	$ 341	$ (8)	$ (354)	$ (3)

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Description	Recurring Fair Value Measurements as of December 31, 2017				
	Total	Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 223	$ —	$ 223	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 36	$ (433)	$ 15	$ 442	$ 12
NDT Fund (C)					
Equity Securities	$ 1,147	$ —	$ 1,145	$ 2	$ —
Debt Securities—U.S. Treasury	$ 314	$ —	$ —	$ 314	$ —
Debt Securities—Govt Other	$ 270	$ —	$ —	$ 270	$ —
Debt Securities—Corporate	$ 402	$ —	$ —	$ 402	$ —
Rabbi Trust (C)					
Equity Securities	$ 27	$ —	$ 27	$ —	$ —
Debt Securities—U.S. Treasury	$ 51	$ —	$ —	$ 51	$ —
Debt Securities—Govt Other	$ 34	$ —	$ —	$ 34	$ —
Debt Securities—Corporate	$ 119	$ —	$ —	$ 119	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (21)	$ 477	$ (8)	$ (485)	$ (5)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 223	$ —	$ 223	$ —	$ —
Rabbi Trust (C)					
Equity Securities	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$ 10	$ —	$ —	$ 10	$ —
Debt Securities—Govt Other	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Corporate	$ 24	$ —	$ —	$ 24	$ —
Liabilities:					
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 36	$ (433)	$ 15	$ 442	$ 12
NDT Fund (C)					
Equity Securities	$ 1,147	$ —	$ 1,145	$ 2	$ —
Debt Securities—U.S. Treasury	$ 314	$ —	$ —	$ 314	$ —
Debt Securities—Govt Other	$ 270	$ —	$ —	$ 270	$ —
Debt Securities—Corporate	$ 402	$ —	$ —	$ 402	$ —
Rabbi Trust (C)					
Equity Securities	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—U.S. Treasury	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Govt Other	$ 8	$ —	$ —	$ 8	$ —
Debt Securities—Corporate	$ 30	$ —	$ —	$ 30	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (21)	$ 477	$ (8)	$ (485)	$ (5)

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(A) Represents money market mutual funds.

(B) Level 1—These contracts represent natural gas futures contracts executed on NYMEX, and are being valued solely on settled pricing inputs which come directly from the exchange.

Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using settled prices from similar assets and liabilities from an exchange, such as NYMEX, ICE and Nodal Exchange, or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain

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exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—Unobservable inputs are used for the valuation of certain contracts. See "Additional Information Regarding Level 3 Measurements" below for more information on the utilization of unobservable inputs.

(C) As of June 30, 2018, the fair value measurement table excludes foreign currency of $1 million, which is part of the NDT Fund. The NDT Fund maintains investments in various equity and fixed income securities. The Rabbi Trust maintains investments in various fixed income securities and a Russell 3000 index fund. These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain other equity securities in the NDT and Rabbi Trust Funds consist primarily of investments in Dreyfus money market funds which seek a high level of current income as is consistent with the preservation of capital and the maintenance of liquidity. To pursue its goals, the funds normally invest in diversified portfolios of high quality, short-term, dollar-denominated debt securities and government securities. The funds' Net Asset Value is priced and published daily. The Rabbi Trust also has an equity index fund which is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities include investment grade corporate bonds, collateralized mortgage obligations, asset-backed securities and certain government and U.S. Treasury obligations or Federal Agency asset-backed securities and municipal bonds with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. The preferred stocks are not actively traded on a daily basis and therefore, are also priced using an evaluated pricing methodology. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(D) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of June 30, 2018 and December 31, 2017, Power had net cash collateral/margin payments to counterparties of $122 million and $146 million, respectively. Of these net cash collateral/margin payments $(2) million as of June 30, 2018 and $44 million as of December 31, 2017 were netted against the corresponding net derivative contract positions. The $(2) million of cash collateral as of June 30, 2018 was netted against assets. Of the $44 million of cash collateral as of December 31, 2017, $(3) million was netted against assets and $47 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee (RMC) approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The RMC reports to the Corporate Governance and Audit Committees of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G, the natural gas supply contract is measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and

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accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The fair value of Power's gas physical contracts at certain illiquid delivery locations are measured using average historical basis and, accordingly, are categorized as Level 3. While these gas physical contracts have an unobservable component in their respective forward price curves, the fluctuations in fair value have been driven primarily by changes in the observable inputs. The following tables provide details surrounding significant Level 3 valuations as of June 30, 2018 and December 31, 2017.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of June 30, 2018 Assets	Fair Value as of June 30, 2018 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$ 2	$ (3)	Discounted Cash flow	Historic Load Variability	0% to 10%
Gas	Gas Physical Contracts	5	—	Discounted Cash flow	Average Historical Basis	-40% to 0%
Total Power		**$ 7**	**$ (3)**			
Total PSEG		**$ 7**	**$ (3)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2017 Assets	Fair Value as of December 31, 2017 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$ 1	$ (3)	Discounted Cash flow	Historic Load Variability	0% to 10%
Gas	Gas Physical Contracts	11	(2)	Discounted Cash flow	Average Historical Basis	-40% to -10%
Total Power		**$ 12**	**$ (5)**			
Total PSEG		**$ 12**	**$ (5)**			

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in the load variability would decrease the fair value. For gas-related contracts in cases where Power is a buyer, an increase in the average historical basis would increase the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and six months ended June 30, 2018 and June 30, 2017, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Six Months Ended June 30, 2018

	Three Months Ended June 30, 2018						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2018	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2018
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 7	$ (3)	$ —	$ —	$ —	$ —	$ 4
Power							
Net Derivative Assets (Liabilities)	$ 7	$ (3)	$ —	$ —	$ —	$ —	$ 4

	Six Months Ended June 30, 2018						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2018	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2018
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 7	$ (4)	$ —	$ —	$ 1	$ —	$ 4
Power							
Net Derivative Assets (Liabilities)	$ 7	$ (4)	$ —	$ —	$ 1	$ —	$ 4

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Six Months Ended June 30, 2017

	Three Months Ended June 30, 2017						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2017	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2017
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 3	$ 7	$ (1)	$ —	$ (3)	$ —	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ 1	$ —	$ (1)	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 2	$ 7	$ —	$ —	$ (3)	$ —	$ 6

	Six Months Ended June 30, 2017						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2017	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2017
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 1	$ 26	$ 5	$ —	$ (25)	$ (1)	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (5)	$ —	$ 5	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 6	$ 26	$ —	$ —	$ (25)	$ (1)	$ 6

(A) PSEG's and Power's gains(losses) attributable to changes in net derivative assets and liabilities for the three months and six months ended June 30, 2018 include $(7) million and $1 million, respectively, in Operating Revenues and $4 million and $(5) million, respectively, in Energy Costs. Both the $(7) million and $1 million in Operating Revenues are unrealized. Of the $4 million and $(5) million in Energy Costs, $3 million and $(6) million are unrealized. Unrealized gains (losses) represent the change in derivative assets and liabilities still held at the end of the reporting period.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

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(C) Represents $1 million in settlements for the six months ended June 30, 2018. Represents settlements of $(3) million and $(25) million for the three months and six months ended June 30, 2017, respectively.

(D) During the three months and six months ended June 30, 2018, there were no transfers into or out of Level 3. During the six months ended June 30, 2017, $(1) million of net derivatives were transferred from Level 2 to Level 3. There were no transfers into or out of Level 3 during the three months ended June 30, 2017.

(E) PSEG's and Power's gains(losses) attributable to changes in net derivative assets and liabilities for the three months and six months ended June 30, 2017 include $3 million and $17 million, respectively, in Operating Revenues and $4 million and $9 million, respectively, in Energy Costs. Of the $3 million and $17 million in Operating Revenues, $2 million and $(2) million, respectively, are unrealized. Of the $4 million and $9 million in Energy Costs, $2 million and $3 million are unrealized.

As of June 30, 2018, PSEG carried $2.3 billion of net assets that are measured at fair value on a recurring basis, of which $4 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of June 30, 2017, PSEG carried $2.8 billion of net assets that are measured at fair value on a recurring basis, of which $6 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of June 30, 2018 and December 31, 2017.

	As of June 30, 2018		As of December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (A) (B)	$ 2,091	$ 2,042	$ 2,091	$ 2,081
PSE&G (B)	8,886	9,055	8,591	9,322
Power (B)	3,083	3,249	2,386	2,659
Total Long-Term Debt	**$ 14,060**	**$ 14,346**	**$ 13,068**	**$ 14,062**

(A) Includes floating rate term loan of $700 million. The fair values of the term loan debt (Level 2 measurement) approximate the carrying values because the interest payments are based on LIBOR rates that are reset monthly and the debt is redeemable at face value by PSEG at any time.

(B) Given that these bonds do not trade actively, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

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Note 14. Other Income (Deductions)

	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended June 30, 2018				
NDT Fund Interest and Dividends	$ —	$ 15	$ —	$ 15
Allowance for Funds Used During Construction	13	—	—	13
Solar Loan Interest	5	—	—	5
Other	2	(2)	1	1
Total Other Income (Deductions)	**$ 20**	**$ 13**	**$ 1**	**$ 34**
Six Months Ended June 30, 2018				
NDT Fund Interest and Dividends	$ —	$ 27	$ —	$ 27
Allowance for Funds Used During Construction	27	—	—	27
Solar Loan Interest	9	—	—	9
Other	4	(3)	2	3
Total Other Income (Deductions)	**$ 40**	**$ 24**	**$ 2**	**$ 66**
Three Months Ended June 30, 2017				
NDT Fund Interest and Dividends	$ —	$ 13	$ —	$ 13
Allowance for Funds Used During Construction	14	—	—	14
Solar Loan Interest	5	—	—	5
Other	2	(1)	—	1
Total Other Income (Deductions)	**$ 21**	**$ 12**	**$ —**	**$ 33**
Six Months Ended June 30, 2017				
NDT Fund Interest and Dividends	$ —	$ 23	$ —	$ 23
Allowance for Funds Used During Construction	28	—	—	28
Solar Loan Interest	10	—	—	10
Other	5	—	(1)	4
Total Other Income (Deductions)	**$ 43**	**$ 23**	**$ (1)**	**$ 65**

(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

Note 15. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months and six months ended June 30, 2018 and 2017 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
PSEG	26.5%	35.1%	26.6%	28.3%
PSE&G	25.7%	37.2%	26.4%	36.7%
Power	31.7%	39.0%	27.1%	40.0%

For the three months and six months ended June 30, 2018, the differences in PSEG's effective tax rates as compared to the same periods in the prior year were due primarily to the change in the statutory federal tax rate from 35% to 21% as a result of the Tax Act offset by changes in uncertain tax positions, plant-related items and tax credits. For the three months and six months ended June 30, 2018, the differences in PSEG's effective tax rates as compared to the statutory tax rate of 28.11% were due primarily to plant-related items and tax credits.

For the three months and six months ended June 30, 2018, the differences in PSE&G's effective tax rates as compared to the same periods in the prior year were due primarily to the change in the statutory federal tax rate from 35% to 21% as a result of the Tax Act, offset by changes in uncertain tax positions, plant-related and other flow-through items. For the three months and

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six months ended June 30, 2018, the differences in PSE&G's effective tax rate as compared to the statutory tax rate of 28.11% were due primarily to plant-related items and tax credits.

For the three months and six months ended June 30, 2018, the differences in Power's effective tax rates as compared to the same periods in the prior year were due primarily to the change in the statutory federal tax rate from 35% to 21% as a result of the Tax Act, as well as changes in uncertain tax positions. For the three months and six months ended June 30, 2018, the differences in Power's effective tax rates as compared to the statutory tax rate of 28.11% were due primarily to changes in uncertain tax positions and tax credits.

PSEG's federal tax returns for the years 2011 and 2012 are currently being audited by the IRS. The audit and other related claims are reasonably expected to be completed within the next 12 months. As a result, it is reasonably possible that a decrease in PSEG's total unrecognized tax benefits may be necessary in the range of $80 million to $150 million based on current estimates.

In December 2017, the U.S. government enacted comprehensive tax legislation. The Tax Act establishes new tax laws that took effect in 2018, including, but not limited to (1) reduction of the U.S. federal corporate tax rate from a maximum of 35% to 21%; (2) elimination of the corporate alternative minimum tax; (3) a new limitation on deductible interest expense; (4) the repeal of the domestic production activity deduction; (5) limitations on the deductibility of certain executive compensation; and (6) limitations on net operating losses generated after December 31, 2017, to 80% of taxable income. In addition, certain changes were made to the bonus depreciation rules that will impact 2018.

The SEC staff issued Staff Accounting Bulletin 118 (SAB 118), which provides guidance on accounting for the tax effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date for companies to complete the accounting under ASC 740. PSEG, PSE&G and Power are subject to ASC 740. In accordance with SAB 118, PSEG, PSE&G and Power made reasonable, good faith estimates for which provisional amounts were recorded.

PSEG's accounting for certain elements of the Tax Act is incomplete. However, PSEG recorded provisional adjustments for the following: the tax rules regarding the appropriate bonus depreciation rate that should be applied to assets placed in service after September 27, 2017 for Power and PSE&G, including the information required to compute the applicable depreciable tax basis, and the impact on PSEG's, PSE&G's and Power's deferred taxes associated with FIN 48 reserves.

Further, the Tax Act is unclear in certain respects and will require interpretations and implementing regulations by the IRS, as well as state tax authorities. The Tax Act could also be subject to potential amendments and technical corrections which could impact PSEG, PSE&G and Power's financial statements.

The Protecting Americans from Tax Hikes Act of 2015 (2015 Tax Act), among other provisions, included an extension of the bonus depreciation rules and the 30% investment tax credit for qualified property placed into service after 2016. Qualified property that is placed into service from January 1, 2015 through December 31, 2017 is eligible for the 50% bonus depreciation. The provisions of the 2015 Tax Act have generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation.

For the period beginning September 28, 2017, subject to the transition rules, the Tax Act modified the bonus depreciation rules of the 2015 Tax Act. Subject to further guidance, it is expected that Power is entitled to 100% expensing and bonus depreciation will no longer apply to PSE&G.

In July 2018, the State of New Jersey made significant changes to its income tax laws, including imposing a temporary surtax on allocated corporate taxable income of 2.5% effective January 1, 2018 and 2019 and 1.5% in 2020 and 2021, as well as requiring corporate taxpayers to file in a combined reporting group as defined under New Jersey law starting in 2019. Both provisions include an exemption for public utilities. At this time, PSEG believes PSE&G meets the definition of a public utility and, therefore, will not be impacted by the temporary surtax or be included in the combined reporting group. PSEG expects these new provisions to unfavorably affect its non-utility business as it continues to analyze this newly enacted law and the impact it will have on PSEG.

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Note 16. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended June 30, 2018			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2018	$ —	$ (398)	$ (13)	$ (411)
Other Comprehensive Income before Reclassifications	(1)	—	(6)	(7)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	1	8
Net Current Period Other Comprehensive Income (Loss)	(1)	7	(5)	1
Balance as of June 30, 2018	**$ (1)**	**$ (391)**	**$ (18)**	**$ (410)**

PSEG	Other Comprehensive Income (Loss) Three Months Ended June 30, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2017	$ 2	$ (392)	$ 148	$ (242)
Other Comprehensive Income before Reclassifications	—	—	23	23
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	6	(13)	(7)
Net Current Period Other Comprehensive Income (Loss)	—	6	10	16
Balance as of June 30, 2017	**$ 2**	**$ (386)**	**$ 158**	**$ (226)**

PSEG	Other Comprehensive Income (Loss) Six Months Ended June 30, 2018			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2017	$ —	$ (406)	$ 177	$ (229)
Cumulative Effect Adjustment to Reclassify Unrealized Net Gains on Equity Investments to Retained Earnings	—	—	(176)	(176)
Current Period Other Comprehensive Income (Loss)				
Other Comprehensive Income before Reclassifications	(1)	—	(22)	(23)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	15	3	18
Net Current Period Other Comprehensive Income (Loss)	(1)	15	(19)	(5)
Net Change in Accumulative Other Comprehensive Income (Loss)	(1)	15	(195)	(181)
Balance as of June 30, 2018	**$ (1)**	**$ (391)**	**$ (18)**	**$ (410)**

PSEG	Other Comprehensive Income (Loss) Six Months Ended June 30, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2016	$ 2	$ (398)	$ 133	$ (263)
Other Comprehensive Income before Reclassifications	—	—	53	53
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	12		(6)

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Net Current Period Other Comprehensive Income (Loss)	—	12	25	37
Balance as of June 30, 2017	**$ 2**	**$ (386)**	**$ 158**	**$ (226)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2018			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2018	$ —	$ (341)	$ (11)	$ (352)
Other Comprehensive Income before Reclassifications	—	—	(5)	(5)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	6	1	7
Net Current Period Other Comprehensive Income (Loss)	—	6	(4)	2
Balance as of June 30, 2018	**$ —**	**$ (335)**	**$ (15)**	**$ (350)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2017			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of March 31, 2017	$ —	$ (335)	$ 148	$ (187)
Other Comprehensive Income before Reclassifications	—	—	22	22
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	5	(12)	(7)
Net Current Period Other Comprehensive Income (Loss)	—	5	10	15
Balance as of June 30, 2017	**$ —**	**$ (330)**	**$ 158**	**$ (172)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2018			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2017	$ —	$ (347)	$ 175	$ (172)
Cumulative Effect Adjustment to Reclassify Unrealized Net Gains on Equity Investments to Retained Earnings	—	—	(175)	(175)
Current Period Other Comprehensive Income (Loss)				
Other Comprehensive Income before Reclassifications	—	—	(18)	(18)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	12	3	15
Net Current Period Other Comprehensive Income (Loss)	—	12	(15)	(3)
Net Change in Accumulative Other Comprehensive Income (Loss)	—	12	(190)	(178)
Balance as of June 30, 2018	**$ —**	**$ (335)**	**$ (15)**	**$ (350)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2017			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2016	$ —	$ (340)	$ 129	$ (211)
Other Comprehensive Income before Reclassifications	—	—	50	50
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	10	(21)	(11)

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Net Current Period Other Comprehensive Income (Loss)	—	10	29	39
Balance as of June 30, 2017	**$ —**	**$ (330)**	**$ 158**	**$ (172)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2018			Six Months Ended June 30, 2018		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	$ 1	$ —	$ 1	$ 2	$ —	$ 2
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(11)	3	(8)	(23)	6	(17)
Total Pension and OPEB Plans		(10)	3	(7)	(21)	6	(15)
Available-for-Sale Debt Securities							
Realized Gains (Losses) and OTTI	Net Gains (Losses) on Trust Investments	(2)	1	(1)	(6)	3	(3)
Total Available-for-Sale Debt Securities		(2)	1	(1)	(6)	3	(3)
Total		**$ (12)**	**$ 4**	**$ (8)**	**$ (27)**	**$ 9**	**$ (18)**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2017			Six Months Ended June 30, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	$ 2	$ (1)	$ 1	$ 4	$ (2)	$ 2
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(12)	5	(7)	(24)	10	(14)
Total Pension and OPEB Plans		(10)	4	(6)	(20)	8	(12)
Available-for-Sale Securities							
Realized Gains (Losses) and OTTI	Net Gains (Losses) on Trust Investments	25	(12)	13	53	(25)	28
Total Available-for-Sale Securities		25	(12)	13	53	(25)	28
Total		**$ 15**	**$ (8)**	**$ 7**	**$ 33**	**$ (17)**	**$ 16**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2018			Six Months Ended June 30, 2018		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	$ 1	$ —	$ 1	$ 2	$ —	$ 2
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(9)	2	(7)	(19)	5	(14)
Total Pension and OPEB Plans		(8)	2	(6)	(17)	5	(12)
Available-for-Sale Debt Securities							
Realized Gains (Losses) and OTTI	Net Gains (Losses) on Trust Investments	(2)	1	(1)	(6)	3	(3)
Total Available-for-Sale Debt Securities		(2)	1	(1)	(6)	3	(3)
Total		**$ (10)**	**$ 3**	**$ (7)**	**$ (23)**	**$ 8**	**$ (15)**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2017			Six Months Ended June 30, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	$ 2	$ (1)	$ 1	$ 4	$ (2)	$ 2
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(10)	4	(6)	(21)	9	(12)
Total Pension and OPEB Plans		(8)	3	(5)	(17)	7	(10)
Available-for-Sale Securities							
Realized Gains (Losses) and OTTI	Net Gains (Losses) on Trust Investments	24	(12)	12	43	(22)	21
Total Available-for-Sale Securities		24	(12)	12	43	(22)	21
Total		**$ 16**	**$ (9)**	**$ 7**	**$ 26**	**$ (15)**	**$ 11**

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Note 17. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2018		2017		2018		2017	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions):								
Net Income	**$ 269**	**$ 269**	**$ 109**	**$ 109**	**$ 827**	**$ 827**	**$ 223**	**$ 223**
EPS Denominator (Millions):								
Weighted Average Common Shares Outstanding	504	504	505	505	504	504	505	505
Effect of Stock Based Compensation Awards	—	3	—	2	—	3	—	2
Total Shares	**504**	**507**	**505**	**507**	**504**	**507**	**505**	**507**
EPS								
Net Income	**$ 0.53**	**$ 0.53**	**$ 0.22**	**$ 0.22**	**$ 1.64**	**$ 1.63**	**$ 0.44**	**$ 0.44**

For the three months and six months ended June 30, 2017, there were approximately 0.3 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect.

Dividends

	Three Months Ended June 30,		Six Months Ended June 30,	
Dividend Payments on Common Stock	**2018**	**2017**	**2018**	**2017**
Per Share	$ 0.45	$ 0.43	$ 0.90	$ 0.86
In Millions	$ 228	$ 217	$ 455	$ 435

On July 17, 2018, PSEG's Board of Directors approved a $0.45 per share common stock dividend for the third quarter of 2018.

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Note 18. Financial Information by Business Segment

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Three Months Ended June 30, 2018					
Total Operating Revenues	$ 1,386	$ 767	$ 123	$ (260)	$ 2,016
Net Income (Loss)	231	41	(3)	—	269
Gross Additions to Long-Lived Assets	697	248	7	—	952
Six Months Ended June 30, 2018					
Operating Revenues	$ 3,231	$ 2,170	$ 270	$ (837)	$ 4,834
Net Income (Loss)	550	275	2	—	827
Gross Additions to Long-Lived Assets	1,447	547	11	—	2,005
Three Months Ended June 30, 2017					
Total Operating Revenues	$ 1,393	$ 918	$ 116	$ (285)	$ 2,142
Net Income (Loss)	208	(97)	(2)	—	109
Gross Additions to Long-Lived Assets	641	269	9	—	919
Six Months Ended June 30, 2017					
Operating Revenues	$ 3,219	$ 2,187	$ 199	$ (872)	$ 4,733
Net Income (Loss)	507	(267)	(17)	—	223
Gross Additions to Long-Lived Assets	1,389	576	16	—	1,981
As of June 30, 2018					
Total Assets	$ 29,603	$ 12,772	$ 2,407	$ (1,075)	$ 43,707
Investments in Equity Method Subsidiaries	$ —	$ 87	$ —	$ —	$ 87
As of December 31, 2017					
Total Assets	$ 28,554	$ 12,418	$ 2,666	$ (922)	$ 42,716
Investments in Equity Method Subsidiaries	$ —	$ 87	$ —	$ —	$ 87

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations primarily relate to intercompany transactions between PSE&G and Power. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 19. Related-Party Transactions.

Note 19. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
			Millions	
Billings from Affiliates:				
Net Billings from Power primarily through BGS and BGSS (A)	$ 272	$ 296	$ 850	$ 895
Administrative Billings from Services (B)	85	79	$ 168	144
Total Billings from Affiliates	**$ 357**	**$ 375**	**$ 1,018**	**$ 1,039**

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Related-Party Transactions	As of June 30, 2018	As of December 31, 2017
	Millions	
Receivables from PSEG (C)	$ 18	$ —
Payable to Power (A)	$ 81	$ 221
Payable to Services (B)	69	78
Payable to PSEG (C)	—	41
Accounts Payable—Affiliated Companies	**$ 150**	**$ 340**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 94**	**$ 91**

Power

The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
		Millions		
Billings to Affiliates:				
Net Billings to PSE&G primarily through BGS and BGSS (A)	**$ 272**	**$ 296**	**$ 850**	**$ 895**
Billings from Affiliates:				
Administrative Billings from Services (B)	**$ 32**	**$ 42**	**$ 75**	**$ 78**

Related-Party Transactions	As of June 30, 2018	As of December 31, 2017
	Millions	
Receivables from PSE&G (A)	**$ 81**	**$ 221**
Payable to Services (B)	$ 20	$ 28
Payable to PSEG (C)	128	29
Accounts Payable—Affiliated Companies	**$ 148**	**$ 57**
Short-Term Loan due (to) from Affiliate (E)	**$ 519**	**$ (281)**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 45**	**$ 52**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. The rates in the BGS and BGSS contracts are prescribed by the BPU. In addition, Power and PSE&G provide certain technical services for each other generally at cost in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense-Operating Activities short-term funding activities were immaterial.

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Note 20. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries, as of June 30, 2018 and December 31, 2017 and for the three months and six months ended June 30, 2018 and 2017.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended June 30, 2018					
Operating Revenues	$ —	$ 747	$ 51	$ (31)	$ 767
Operating Expenses	3	704	49	(31)	725
Operating Income (Loss)	(3)	43	2	—	42
Equity Earnings (Losses) of Subsidiaries	55	(4)	5	(51)	5
Net Gains (Losses) on Trust Investments	—	8	—	—	8
Other Income (Deductions)	41	40	—	(68)	13
Non-Operating Pension and OPEB Credits (Costs)	—	2	1	—	3
Interest Expense	(54)	(19)	(6)	68	(11)
Income Tax Benefit (Expense)	2	(23)	2	—	(19)
Net Income (Loss)	**$ 41**	**$ 47**	**$ 4**	**$ (51)**	**$ 41**
Comprehensive Income (Loss)	**$ 43**	**$ 44**	**$ 4**	**$ (48)**	**$ 43**
Six Months Ended June 30, 2018					
Operating Revenues	$ —	$ 2,133	$ 102	$ (65)	$ 2,170
Operating Expenses	3	1,760	101	(65)	1,799
Operating Income (Loss)	(3)	373	1	—	371
Equity Earnings (Losses) of Subsidiaries	289	(7)	7	(282)	7
Net Gains (Losses) on Trust Investments	—	(14)	—	—	(14)
Other Income (Deductions)	76	73	—	(125)	24
Non-Operating Pension and OPEB Credits (Costs)	—	6	1	—	7
Interest Expense	(96)	(36)	(11)	125	(18)
Income Tax Benefit (Expense)	9	(115)	4	—	(102)
Net Income (Loss)	**$ 275**	**$ 280**	**$ 2**	**$ (282)**	**$ 275**
Comprehensive Income (Loss)	**$ 272**	**$ 267**	**$ 2**	**$ (269)**	**$ 272**
Six Months Ended June 30, 2018					
Net Cash Provided By (Used In) Operating Activities	$ 34	$ 745	$ (8)	$ 98	$ 869
Net Cash Provided By (Used In) Investing Activities	$ (840)	$ (867)	$ (196)	$ 808	$ (1,095)
Net Cash Provided By (Used In) Financing Activities	$ 806	$ 123	$ 191	$ (906)	$ 214

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended June 30, 2017					
Operating Revenues	$ —	$ 899	$ 47	$ (28)	$ 918
Operating Expenses	(2)	1,094	43	(28)	1,107
Operating Income (Loss)	2	(195)	4	—	(189)
Equity Earnings (Losses) of Subsidiaries	(93)	(4)	5	97	5
Net Gains (Losses) on Trust Investments	(1)	25	—	—	24
Other Income (Deductions)	23	21	2	(34)	12
Non-Operating Pension and OPEB Credits (Costs)	—	2	—	—	2
Interest Expense	(34)	(9)	(4)	34	(13)
Income Tax Benefit (Expense)	6	60	(4)	—	62
Net Income (Loss)	**$ (97)**	**$ (100)**	**$ 3**	**$ 97**	**$ (97)**
Comprehensive Income (Loss)	**$ (82)**	**$ (91)**	**$ 3**	**$ 88**	**$ (82)**
Six Months Ended June 30, 2017					
Operating Revenues	$ —	$ 2,154	$ 99	$ (66)	$ 2,187
Operating Expenses	2	2,650	95	(66)	2,681
Operating Income (Loss)	(2)	(496)	4	—	(494)
Equity Earnings (Losses) of Subsidiaries	(254)	(5)	8	259	8
Net Gains (Losses) on Trust Investments	3	40	—	—	43
Other Income (Deductions)	43	40	2	(62)	23
Non-Operating Pension and OPEB Credits (Costs)	—	4	—	—	4
Interest Expense	(64)	(18)	(9)	62	(29)
Income Tax Benefit (Expense)	7	171	—	—	178
Net Income (Loss)	**$ (267)**	**$ (264)**	**$ 5**	**$ 259**	**$ (267)**
Comprehensive Income (Loss)	**$ (228)**	**$ (234)**	**$ 5**	**$ 229**	**$ (228)**
Three Months Ended June 30, 2017					
Net Cash Provided By (Used In) Operating Activities	$ (32)	$ 802	$ 111	$ 51	$ 932
Net Cash Provided By (Used In) Investing Activities	$ 683	$ 178	$ (241)	$ (1,355)	$ (735)
Net Cash Provided By (Used In) Financing Activities	$ (651)	$ (978)	$ 146	$ 1,304	$ (179)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
As of June 30, 2018					
Current Assets	$ 4,806	$ 1,411	$ 216	$ (4,868)	$ 1,565
Property, Plant and Equipment, net	52	5,048	3,679	—	8,779
Investment in Subsidiaries	4,977	1,129	—	(6,106)	—
Noncurrent Assets	243	2,258	110	(183)	2,428
Total Assets	**$ 10,078**	**$ 9,846**	**$ 4,005**	**$ (11,157)**	**$ 12,772**
Current Liabilities	$ 690	$ 3,164	$ 1,987	$ (4,868)	$ 973
Noncurrent Liabilities	516	2,097	497	(183)	2,927
Long-Term Debt	2,833	—	—	—	2,833
Member's Equity	6,039	4,585	1,521	(6,106)	6,039
Total Liabilities and Member's Equity	**$ 10,078**	**$ 9,846**	**$ 4,005**	**$ (11,157)**	**$ 12,772**
As of December 31, 2017					
Current Assets	$ 4,327	$ 1,500	$ 200	$ (4,686)	$ 1,341
Property, Plant and Equipment, net	54	5,778	2,764	—	8,596
Investment in Subsidiaries	4,844	404	—	(5,248)	—
Noncurrent Assets	100	2,349	110	(78)	2,481
Total Assets	**$ 9,325**	**$ 10,031**	**$ 3,074**	**$ (10,012)**	**$ 12,418**
Current Liabilities	$ 689	$ 3,586	$ 1,846	$ (4,686)	$ 1,435
Noncurrent Liabilities	533	1,966	459	(78)	2,880
Long-Term Debt	2,136	—	—	—	2,136
Member's Equity	5,967	4,479	769	(5,248)	5,967
Total Liabilities and Member's Equity	**$ 9,325**	**$ 10,031**	**$ 3,074**	**$ (10,012)**	**$ 12,418**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and energy efficiency and related programs in New Jersey, which are regulated by the BPU, and
- **Power**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement; PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Our business discussion in Part I, Item 1. Business of our 2017 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2017 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2018 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2017 Form 10-K.

EXECUTIVE OVERVIEW OF 2018 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including

- improving utility operations through investment in T&D and other infrastructure projects designed to enhance system reliability and resiliency and to meet customer expectations and public policy objectives, and
- managing a reliable, cost-effective generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the three months and six months ended June 30, 2018 and 2017 are presented as follows:

Earnings (Losses)	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
	Millions			
PSE&G	$ 231	$ 208	$ 550	$ 507
Power (A)	41	(97)	275	(267)
Other (B)	(3)	(2)	2	(17)
PSEG Net Income	**$ 269**	**$ 109**	**$ 827**	**$ 223**
PSEG Net Income Per Share (Diluted)	**$ 0.53**	**$ 0.22**	**$ 1.63**	**$ 0.44**

(A) Includes after-tax expenses of $229 million and $563 million in the three months and six months ended June 30, 2017, respectively, primarily for accelerated depreciation related to the early retirement of Power's Hudson and Mercer coal/gas generation plants. See Item 1. Note 4. Early Plant Retirements for additional information.

(B) Other includes after-tax activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations. Energy Holdings recorded after-tax charges related to its investments in NRG REMA, LLC's (REMA) leveraged leases of $14 million in the second quarter of 2018 and $13 million and $45 million in the three months and six months ended June 30, 2017, respectively. See Item 1. Note 7. Financing Receivables for additional information.

Power's results above include the Nuclear Decommissioning Trust (NDT) Fund activity and the impacts of non-trading commodity mark-to-market (MTM) activity, which consist of the financial impact from positions with future delivery dates.

The variances in our Net Income attributable to changes related to the NDT Fund and MTM are shown in the following table:

	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Six Months Ended June 30, 2018	Six Months Ended June 30, 2017
	Millions, after tax			
NDT Fund Income (Expense) (A) (B)	$ 5	$ 14	$ (11)	$ 22
Non-Trading MTM Gains (Losses) (C)	$ (48)	$ 21	$ 37	$ 27

(A) NDT Fund Income (Expense) includes gains and losses on NDT securities which are recorded in Net Gains (Losses) on Trust Investments. See Item 1. Note 8. Trust Investments for additional information. NDT Fund Income (Expense) also includes interest and dividend income and other costs related to the NDT Fund recorded in Other Income (Deductions), interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset recorded in Depreciation and Amortization (D&A) Expense.

(B) Net of tax (expense) benefit of $(4) million and $(16) million for the three months and $4 million and $(25) million for the six months ended June 30, 2018 and 2017, respectively.

(C) Net of tax (expense) benefit of $19 million and $(15) million for the three months and $(14) million and $(19) million for the six months ended June 30, 2018 and 2017, respectively.

Our $160 million increase in Net Income for the three months ended June 30, 2018 was driven largely by

- accelerated depreciation in 2017 related to early retirement of our Hudson and Mercer coal/gas generation units,
- the favorable impact at Power from the lower federal tax rate effective January 1, 2018, and
- higher earnings due to continued investment in transmission and distribution clause programs,
- partially offset by MTM net losses in 2018 as compared to MTM net gains in 2017, and

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- lower wholesale energy sales at Power in the PJM region.

Our $604 million increase in Net Income for the six months ended June 30, 2018 was driven largely by

- accelerated depreciation in 2017 related to early retirement of our Hudson and Mercer coal/gas generation units,
- the favorable impact at Power from the lower federal tax rate effective January 1, 2018,
- higher earnings due to continued investment in transmission and distribution clause programs, and
- lower charges in 2018 related to leveraged lease investments (see Item 1. Note 7. Financing Receivables),
- partially offset by unrealized losses on equity securities in the NDT Fund in 2018 related to new accounting guidance effective January 1, 2018. (See Item 1. Note 2. Recent Accounting Standards.)

During the first six months of 2018, we maintained a strong balance sheet. We continued to effectively deploy capital without the need to issue additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results, which when combined with the cash flow generated by Power, our merchant generator and power marketer, has allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our multi-year, long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability for our customers and bolstering our system resiliency. At Power, we strive to improve performance and reduce costs in order to optimize cash flow generation from our fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, we continue to invest in T&D projects that focus on reliability improvements and replacement of aging infrastructure. Over the next five years, we expect to invest between $12 billion and $15.5 billion in our business which is expected to provide an annual rate base growth of 8%—10%. We are forecasting completion of our Energy Strong Program I (ESP I) and Gas System Modernization Program I (GSMP I) this year. We have received approval for the GSMP II, an expanded, five-year program totaling $1.9 billion that will start in 2019. In June 2018, we filed for our Energy Strong Program II (ESP II), a proposed five-year $2.5 billion program to harden, modernize and make our electric and gas distribution systems more resilient. We also expect to file our proposed Clean Energy Future program later this year, a six-year estimated $2.9 billion program focused on achieving New Jersey's energy efficiency targets, as well as supporting electric vehicle infrastructure and battery storage initiatives. Over the past few years, these types of investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G.

Power continues to move its fleet towards improved efficiency and fuel diversity. We believe that its investment program enhances our competitive position with the addition of efficient, clean, reliable combined cycle gas turbine capacity. Our commitments for load, such as basic generation service (BGS) in New Jersey and other bilateral supply contracts, are backed by this generation or may be combined with the use of physical commodity purchases and financial instruments from the market to optimize the economic efficiency of serving our obligations. Power's hedging practices and ability to capitalize on market opportunities help it to balance some of the volatility of the merchant power business. More than half of Power's expected gross margin in 2018 relates to our hedging strategy, our expected revenues from the capacity market mechanisms and certain ancillary service payments such as reactive power.

Our investments in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station Unit 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to enhance the environmental profile and overall efficiency of Power's generation fleet.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets. For additional information about regulatory, legislative and other developments that may affect the company, see Part I, Item 1. Regulatory Issues in our 2017 Annual Report on Form 10-K and Item 5. Other Information in our Form 10-Q for the period ending March 31, 2018 and this Form 10-Q.

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Transmission Planning

There are several matters pending before FERC and the U. S. Court of Appeals for the District of Columbia Circuit that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by customers in New Jersey. In addition, as a BGS supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers would be entitled to recovery, subject to BPU approval. We do not believe that these matters will have a material effect on Power's business or results of operations.

Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base return on equity (ROE). Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. The results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. The CP product was implemented fully in the May 2017 RPM auction for the 2020-2021 Delivery Year. Subsequent to its implementation, FERC approved changes to the CP construct that will enhance the participation of intermittent and demand response resources (seasonal resources). However, FERC held a technical conference in response to two complaints to consider the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions. We cannot predict the outcome of these matters.

In April 2018, PJM submitted two proposed alternative and mutually exclusive capacity market reforms for FERC's approval. In June 2018, FERC issued an order finding that PJM's current capacity market is unjust and unreasonable because it allows resources supported by out-of-market payments to suppress capacity prices. FERC established a new proceeding to address an alternative approach in which PJM would: (1) modify PJM's Minimum Offer Price Rule (MOPR) so that it would apply to new and existing resources that receive out-of-market payments, regardless of resource type; and (2) establish an option that would allow, on a resource-specific basis, resources receiving out-of-market support to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time. FERC's potential action in this proceeding could cause nuclear units that receive ZEC payments to lose capacity market revenues if states do not take steps to address this potential loss of capacity revenues. In addition, depending on the outcome of this matter, our fossil generating stations could be adversely impacted. We cannot predict the outcome of this matter.

The PJM Board directed PJM staff to work with stakeholders to implement a series of price formation reforms, including a 30-minute reserve product in real-time, more dynamic reserve requirements to better capture operator actions taken to maintain reliability, and improvement to the curves used to price reserves during reserve shortage conditions. The PJM Board letter directs PJM staff to submit some of these reforms for FERC's approval so that they can be implemented in early 2019. If placed into effect, these reforms should improve energy and reserve prices by ensuring that when operators commit resources to ensure reliability, the commitments are reflected in market clearing prices. We cannot predict the outcome of this matter.

Distribution

The BPU has enacted Infrastructure Investment Program (IIP) regulations that allow utilities to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to support the provision of safe and adequate service. Under these regulations, utilities can seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing infrastructure that enhances reliability, resiliency, and/or safety.

In May 2018, the BPU approved a settlement regarding PSE&G's GSMP II program, which is the next phase of our GSMP I. Under GSMP II, PSE&G expects to invest $1.9 billion over five years beginning in 2019 to replace approximately 875 miles of cast iron and unprotected steel mains in addition to other improvements to the gas system. Approximately $1.6 billion will be recovered through periodic rate roll-ins, with the remaining $300 million to be recovered through a future base rate case. As part of the settlement, PSE&G agreed to file a base rate case no later than five years from the commencement of the program, to maintain a base level of gas distribution capital expenditures of $155 million per year and to achieve certain leak reduction targets. The ROE and certain other elements for the program will be determined in the pending base rate case proceeding.

As previously disclosed, PSE&G's ESP I, an investment program to harden and make the electric and gas distribution system more resilient, is expected to be completed during 2018. In June 2018, PSE&G filed its ESP II proposal with the BPU to invest

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an additional $2.5 billion over the next five years as an extension and expansion of its ESP I. The extension seeks to continue efforts to harden the electric system against storms and make it more resilient, to implement a more proactive life cycle replacement program to modernize the electric system and to make the gas system more reliable by mitigating the impacts of potential supply curtailments. The size and duration of ESP II, as well as PSE&G's ROE and certain other elements of the program, are subject to BPU approval.

In January 2018, PSE&G filed a distribution base rate case as required as a condition of approval of its ESP I approved by the BPU in 2014. The filing requested an approximate 1% increase in revenues and recovery of investments made to strengthen the electric and gas distribution systems. The requested increase took into account a reduction in the revenue requirement as a result of the federal corporate income tax rate reduction from 35% to 21% provided in the Tax Act, including the flow-back to customers of excess accumulated deferred income taxes. In March 2018, the BPU approved interim rate reductions for all their jurisdictional utilities, including PSE&G, reflecting the reduction in the federal corporate tax rate. The BPU approved a reduction to PSE&G's base electric and gas revenues effective April 1, 2018 by $71 million and $43 million, respectively, on an annual basis (or about 2% combined). The refund to customers for overcollection of revenues at the higher tax rate for the January 1 to March 31, 2018 period, and the flow-back to customers of certain excess deferred income taxes will be addressed in PSE&G's ongoing base rate case proceeding. As a result of the base rate reduction implemented on April 1, 2018, PSE&G's requested revenue requirement in its filing has increased accordingly. In May 2018, PSE&G filed a required update to its base rate case, requesting an approximate three percent increase in revenues. PSE&G anticipates a decision by the BPU that the new base rates will go into effect in the fourth quarter of 2018.

Energy Efficiency

Consistent with New Jersey's recently enacted energy efficiency legislation, which is more fully described under Part II, Item 5. Other Information, PSE&G has outlined a clean energy proposal to invest $2.9 billion over six years in energy efficiency and other programs that will reduce energy bills and combat climate change, which we refer to as our Clean Energy Future program. The program, which PSE&G expects to file with the BPU later this year, includes: $2.5 billion for energy efficiency to reduce customer bills and lower energy use, which will decrease air pollution, including emissions that accelerate climate change; $300 million for building a "smart" electric vehicle infrastructure; and $100 million for utility-scale energy storage systems that will enable greater development of renewable resources and enhance resiliency.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs.

In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the New Source Performance Standards that establish emissions standards for CO_2 for certain new fossil power plants, and the Clean Power Plan (CPP), a greenhouse gas emissions regulation under the Clean Air Act for existing power plants that establishes state-specific emission rate targets based on implementation of the best system of emission reduction. In October 2017, the EPA Administrator signed a proposed repeal of the CPP. The EPA Administrator concluded that the CPP exceeds the EPA's statutory authority by considering measures that are beyond the control of the owners of the affected sources (fossil fuel-fired electric generating units). The EPA is considering rulemaking to replace the CPP. PSEG cannot assess the impact of any such rulemaking on its business and future results of operations at this time.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above, as well as other matters that may impact our financial condition and results of operations, see Item 1. Note 10. Commitments and Contingent Liabilities.

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Early Plant Retirements

Fossil

On June 1, 2017, Power completed its previously announced retirement of the generation operations of the existing coal/gas units at the Hudson and Mercer generating stations. The decision to retire the Hudson and Mercer units had a material effect on PSEG's and Power's results of operations in 2016 and continued to adversely impact their results of operations in 2017. As of June 1, 2017, Power completed recognition of the incremental D&A of $938 million ($964 million in total) due to the significant shortening of the expected economic useful lives of Hudson and Mercer. See Item 1. Note 4. Early Plant Retirements for additional information.

Power is exploring various opportunities with these sites, including using the sites for alternative industrial activity or the disposition of one or both of the sites. If Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such remediation are neither currently probable nor estimable but may be material.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Nuclear

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. In February 2018, Exelon, a co-owner of the Salem units, announced its intention to accelerate the closure of its Oyster Creek nuclear plant located in New Jersey, one year earlier than previously planned for economic reasons. In addition, First Energy announced in March 2018 the early retirement of four nuclear units at the Davis-Besse, Perry Nuclear and Beaver Valley nuclear plants in Ohio and Pennsylvania by 2021. These closures and retirements are generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a further shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of our nuclear units beyond the current year, including whether and to what extent these units participate in RPM capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be influenced by the financial outlook of the units, including the progress, timing and continued outlook for selection of the units under the newly enacted legislation in the state of New Jersey. Power and Exelon have agreed to cancel the funding of future capital projects at the Salem generating station that are not required to meet NRC or other regulatory requirements or that are not required to ensure its safe operation. Power and Exelon have agreed to continue to assess and, when appropriate, approve the funding of individual capital projects to ensure compliance with regulatory requirements and the safe operation of the Salem generating station and that the funding of these projects may be restored if legislation enacted in New Jersey sufficiently values the attributes of nuclear generation and Salem benefits from such legislation.

If any or all of the Salem and Hope Creek units were shut down, it would significantly alter New Jersey's energy supply predominately by increasing New Jersey's reliance on natural gas generation. Such a decrease in fuel diversity could also increase the market's vulnerability to price fluctuations and power disruptions in times of high demand. In May 2018, the governor of New Jersey signed legislation that would provide a safety net in order to prevent the loss of environmental attributes from selected nuclear generating stations referred to as the zero emissions certificate (ZEC) program. The legislation calls for the BPU (within a 330-day period from enactment) to establish a collection process for a customer charge, determine eligibility and certification of need, and ultimately select nuclear plants to potentially receive ZECs starting in April 2019. Power cannot predict whether our nuclear generating stations in New Jersey will be selected or whether the legislation will provide a sufficient safety net for the continued operation of nuclear generating stations in New Jersey.

If energy market prices continue to be depressed, there are adverse impacts from potential changes to the capacity market construct being considered by FERC, or the ZEC program does not adequately compensate our nuclear generating stations for their attributes, Power anticipates it will no longer be covering its costs nor be adequately compensated for its market and

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operational risks at the Salem and Hope Creek nuclear units and would anticipate retiring these units early. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs and additional funding of the NDT Fund would be material to both PSEG and Power.

Leveraged Lease Impairments

GenOn Energy, Inc. (GenOn) and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code on June 14, 2017. REMA was not included in the GenOn bankruptcy filing. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete. PSEG cannot predict the outcome of GenOn's efforts to restructure its balance sheet and improve its liquidity.

PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments, which could include further write-downs of the values of Energy Holdings' leveraged lease receivables, and continues to discuss the situation with various parties relevant to this matter. Based on an ongoing review of (i) the liquidity challenges facing REMA and (ii) available alternatives, Energy Holdings recorded a $20 million pre-tax charge in the quarter ended June 30, 2018 for its current best estimate of loss related to lease receivables. For additional information, see Item 1. Note 7. Financing Receivables. There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.

Additional facilities in our leveraged lease portfolio include the Joliet and Powerton generating facilities. Converted natural gas units such as Shawville and Joliet may have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units. Powerton is a coal-fired generating facility in Illinois. Each of these three facilities may not be as economically competitive as newer combined cycle gas units and could continue to be adversely impacted by the same economic conditions experienced by other less efficient natural gas and coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged lease receivables associated with these facilities.

Tax Legislation

In December 2017, the U.S. government enacted comprehensive tax legislation (Tax Act), which, among other things, decreased the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018, and made certain changes to bonus depreciation rules.

As a result of the enacted reduction in the statutory U.S. corporate income tax rate, as well as other aspects of the Tax Act, in December 2017 PSE&G recorded excess deferred taxes of approximately $2.1 billion and recorded an approximate $2.9 billion revenue impact of these excess deferred taxes as Regulatory Liabilities where it is probable that refunds will be made to customers in future rates. The amount and timing of any such refund cannot be determined at this time.

Beginning in 2018, PSEG, on a consolidated basis, is incurring lower income tax expense resulting in a decrease in its projected effective income tax rate. This has increased PSEG's and Power's net income. To the extent allowed under the Tax Act, Power's operating cash flows will reflect the full expensing of capital investments for income tax purposes. PSEG and Power expect that the interest on their debt will continue to be fully tax deductible albeit at a lower tax rate. For PSE&G, the Tax Act has led to lower customer rates due to lower income tax expense recoveries and we have proposed to refund excess deferred income tax regulatory liabilities as part of our distribution rate case filing. The impact of the lower federal income tax rate on PSE&G was reflected in PSE&G's recently filed distribution base rate case and its 2018 transmission formula rate filings. The Tax Act is generally expected to result in lower operating cash flows for PSE&G resulting from the elimination of bonus depreciation, partially offset by higher revenues due to the higher rate base.

The impact of the Tax Act may differ from these estimates, possibly materially, due to, among other things, changes in interpretations and assumptions PSEG has made, guidance that may be issued and actions PSEG may take as a result of the Tax Act. For additional information, see Item 1. Note 15. Income Taxes.

As a result of the enactment of the Tax Act, various state regulatory authorities, including the BPU, have taken action to ensure that excess federal income taxes previously collected in rates are returned to customers. We have made filings to adjust the revenue requirement in certain of our rate matters as a result of the change in the federal income tax rate.

In addition, FERC continues to assess whether, and if so how, it will address changes and flow-backs to customers relating to accumulated deferred income taxes and bonus depreciation. See Item 1. Note 6. Rate Filings for additional information.

In July 2018, the State of New Jersey made significant changes to its income tax laws, including imposing a temporary surtax on allocated corporate taxable income of 2.5% effective January 1, 2018 and 2019 and 1.5% in 2020 and 2021, as well as requiring corporate taxpayers to file in a combined reporting group as defined under New Jersey law starting in 2019. Both provisions include an exemption for public utilities. We believe PSE&G meets the definition of a public utility and, therefore, will not be impacted by the temporary surtax or be included in the combined reporting group. We expect these new provisions

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to unfavorably affect our non-utility business and we continue to analyze this newly enacted law and the impact it will have on us.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of opportunities in a rapidly evolving market as we remain diligent in managing costs. For the first six months of 2018, our

- utility, beginning with comprehensive storm preparation, efficiently and safely completed our customer restorations and then assisted neighboring utilities with their restoration efforts,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 25 terawatt hours while addressing fuel availability and price volatility, and
- total nuclear fleet achieved an average capacity factor of 92.9%.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first six months of 2018 as we

- maintained sufficient liquidity,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2018 to $1.80 per share.

We expect to be able to fund our planned capital requirements and manage the impacts of the Tax Act without the issuance of new equity.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first six months of 2018, we

- made additional investments in transmission infrastructure projects,
- continued to execute our GSMP I, ESP I, Energy Efficiency and other existing BPU-approved utility programs, and
- commenced commercial operation of Sewaren 7 and continued construction of our BH5 generation project, which is targeted for commercial operation in mid-2019.

In early July 2018, we started commercial operation of our Keys generation facility.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in an environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions in response to changes in demand,
- obtain approval of and execute our utility capital investment program, including ESP II, GSMP I and II, our Clean Energy Future program and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers, and obtain approval for the extension of these programs,
- effectively manage construction of our BH5 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,

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- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

For 2018 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- fair and timely rate relief from the BPU and FERC for recovery of costs and return on investments, including with respect to our distribution base rate case which was filed with the BPU in January 2018, and the timing of the return of unprotected excess deferred taxes to customers,
- applying to the BPU to select our New Jersey nuclear generation units to receive payments under the ZEC program,
- continuing discussions regarding the restructuring of GenOn and REMA and its potential impact on the value of our Keystone, Conemaugh and Shawville leveraged leases,
- the continuing impacts of the Tax Act and changes in state tax laws,
- national and regional economic conditions, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate,
- the impact of lower natural gas prices and increasing environmental compliance costs on the competitiveness of our nuclear and remaining coal-fired generation plants, and the potential for retirement of such plants earlier than their current useful lives,
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development projects, including in connection with permitting and regulatory approvals, and
- maintaining a diverse mix of fuels to mitigate risks associated with fuel price volatility and market demand cycles.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of T&D facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses,
- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency, modernizing existing infrastructure and participation in transmission projects through FERC's "open window" solicitation process.

Power is developing a retail energy business to sell energy, which we believe complements our existing wholesale marketing business. Power began these marketing activities in 2017 and has been granted retail energy supplier licenses in New Jersey, Pennsylvania and Maryland.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

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RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 19. Related-Party Transactions.

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2018	2017	2018 vs. 2017		2018	2017	2018 vs. 2017	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,016	$ 2,142	$ (126)	(6)	$ 4,834	$ 4,733	$ 101	2
Energy Costs	600	588	12	2	1,552	1,456	96	7
Operation and Maintenance	725	718	7	1	1,479	1,435	44	3
Depreciation and Amortization	280	641	(361)	(56)	560	1,469	(909)	(62)
Income from Equity Method Investments	5	5	—	—	7	8	(1)	(13)
Net Gains (Losses) on Trust Investments	8	25	(17)	(68)	(14)	53	(67)	(79)
Other Income (Deductions)	34	33	1	3	66	65	1	2
Non-Operating Pension and OPEB Credits (Costs)	19	1	18	N/A	38	1	37	N/A
Interest Expense	111	91	20	22	214	189	25	13
Income Tax Expense	97	59	38	64	299	88	211	240

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2018	2017	2018 vs. 2017		2018	2017	2018 vs. 2017	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,386	$ 1,393	$ (7)	(1)	$ 3,231	$ 3,219	$ 12	—
Energy Costs	488	488	—	—	1,270	1,250	20	2
Operation and Maintenance	353	359	(6)	(2)	744	729	15	2
Depreciation and Amortization	187	166	21	13	377	337	40	12
Net Gains (Losses) on Trust Investments	—	—	—	—	—	2	(2)	(100)
Other Income (Deductions)	20	21	(1)	(5)	40	43	(3)	(7)
Non-Operating Pension and OPEB Credits (Costs)	15	(1)	16	N/A	30	(3)	33	N/A
Interest Expense	82	69	13	19	163	144	19	13
Income Tax Expense	80	123	(43)	(35)	197	294	(97)	(33)

Three Months Ended June 30, 2018 as Compared to 2017

Operating Revenues decreased $7 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues decreased $8 million due primarily to

- Transmission, gas distribution and electric distribution revenue requirements were $62 million lower as a result of rate reductions due to the Tax Act which reduced the corporate income tax rate. This decrease is offset in Income Tax Expense.

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- Transmission revenues were $34 million higher due to revenue requirements calculated through our transmission formula rate, primarily to recover increased investments.
- Gas distribution revenues increased $12 million due primarily to a $16 million increase from higher sales volumes and a $5 million increase from the inclusion of the GSMP I in base rates. These increases were partially offset by a $10 million decrease in Weather Normalization Clause (WNC) collections.
- Electric distribution revenues increased $8 million due to a $4 million increase from higher ESP I investments in base rates, $3 million in higher sales volumes, and higher Green Program Recovery Charges (GPRC) of $1 million.

Commodity Revenues were flat as a result of higher Gas revenues entirely offset by lower Electric revenues. The changes in Commodity revenues for both gas and electric are entirely offset by the changes in Energy Costs. PSE&G earns no margin on the provision of BGS and basic gas supply service (BGSS) to retail customers.

- Gas commodity revenues increased $4 million due to higher BGSS sales volumes of $22 million partially offset by lower BGSS sales prices of $18 million.
- Electric commodity revenues decreased $4 million due to $29 million from lower BGS prices partially offset by $25 million in higher BGS sales volumes.

Clause Revenues were flat due primarily to a $6 million decrease in Margin Adjustment Clause (MAC) revenues entirely offset by higher collections of Societal Benefit Charges (SBC) of $4 million and a $2 million increase in collections of GPRC. The changes in the MAC, SBC and GPRC amounts are entirely offset by changes in the amortization of Regulatory Assets and Regulatory Liabilities and related costs in O&M, D&A and Interest Expense. PSE&G does not earn margin on MAC, SBC or GPRC collections.

Operating Expenses

Energy Costs were flat. This is entirely offset by the change in Commodity Revenues.

Operation and Maintenance decreased $6 million due primarily to a $4 million reduction in injuries and damages and a $2 million decrease in distribution maintenance, partially offset by a $2 million increase in seasonal storm damages.

Depreciation and Amortization increased $21 million due primarily to an increase in depreciation due to additional plant placed into service.

Non-Operating Pension and OPEB Credits (Costs) reflected an increase of $16 million in credits due to the adoption of new accounting guidance effective January 1, 2018 which no longer allows capitalization of any portion of these benefit costs. See Item 1. Note 2. Recent Accounting Standards.

Interest Expense increased $13 million due primarily to increases of $7 million in clause interest and $5 million related to net debt issuances in May 2018 and December 2017.

Income Tax Expense decreased $43 million due primarily to the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018, partially offset by plant-related and flow-through items.

Six Months Ended June 30, 2018 as Compared to 2017

Operating Revenues increased $12 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $4 million due primarily to

- Transmission revenues were $80 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover increased investments.
- Gas distribution revenues increased $43 million primarily due to a $48 million increase due to higher sales volumes, a $22 million increase from the inclusion of the GSMP I in base rates and a $2 million increase in GPRC collections. These increases were partially offset by a $29 million decrease in WNC collections.
- Electric distribution revenues increased $8 million due to a $6 million increase from the inclusion of increased ESP I investments in base rates and $2 million in higher sales volumes.
- Transmission, gas distribution and electric distribution revenue requirements were $127 million lower as a result of rate reductions due to the Tax Act which reduced the corporate income tax rate. This decrease is offset in Income Tax Expense.

Commodity Revenues increased $20 million as a result of higher Electric revenues partially offset by lower Gas revenues. The changes in Commodity revenues for both electric and gas are entirely offset by the changes in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

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- Electric commodity revenues increased $30 million due primarily to $46 million in higher BGS sales volumes partially offset by $19 million in lower BGS prices and a $3 million increase from sales of solar renewable energy credits.
- Gas commodity revenues decreased $10 million due to lower BGSS prices of $49 million, partially offset by higher BGSS sales volumes of $39 million.

Clause Revenues decreased $11 million due primarily to an $11 million decrease in MAC revenues and lower SBC of $2 million. These decreases were partially offset by $1 million increases in GPRC and Solar Pilot Recovery Charges (SPRC). The changes in the MAC, SBC, GPRC and SPRC amounts are entirely offset by changes in the amortization of Regulatory Assets and Regulatory Liabilities and related costs in O&M, D&A and Interest Expense. PSE&G does not earn margin on MAC, SBC, GPRC or SPRC collections.

Operating Expenses

Energy Costs increased $20 million. This is entirely offset by the change in Commodity Revenues.

Operation and Maintenance increased $15 million, primarily due to increases of $9 million in storm costs, $8 million in transmission expenses, $7 million in appliance service costs and $7 million in the gas distribution tariff. These increases were partially offset by a net $10 million decrease in clause and renewable related expenditures and a $4 million reduction in injuries and damages.

Depreciation and Amortization increased $40 million due primarily to a $39 million increase in depreciation related to additional plant in service and an increase of $4 million in amortization of Regulatory Assets partially offset by a $3 million increase in capitalized depreciation.

Non-Operating Pension and OPEB Credits (Costs) reflected an increase of $33 million in credits due to the adoption of new accounting guidance effective January 1, 2018 which no longer allows capitalization of any portion of these benefit costs. See Item 1. Note 2. Recent Accounting Standards.

Interest Expense increased $19 million due primarily to an increase of $12 million related to net debt issuances in May 2018 and 2017 and December 2017 and a $7 million increase related to clauses.

Income Tax Expense decreased $97 million due primarily to the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018, partially offset by uncertain tax positions, plant-related and flow-through items.

Power

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2018	2017	2018 vs. 2017		2018	2017	2018 vs. 2017	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 767	$ 918	$ (151)	(16)	$ 2,170	$ 2,187	$ (17)	(1)
Energy Costs	373	386	(13)	(3)	1,119	1,078	41	4
Operation and Maintenance	268	256	12	5	514	488	26	5
Depreciation and Amortization	84	465	(381)	(82)	166	1,115	(949)	(85)
Income from Equity Method Investments	5	5	—	—	7	8	(1)	(13)
Net Gains (Losses) on Trust Investments	8	24	(16)	(67)	(14)	43	(57)	N/A
Other Income (Deductions)	13	12	1	8	24	23	1	4
Non-Operating Pension and OPEB Credits (Costs)	3	2	1	50	7	4	3	75
Interest Expense	11	13	(2)	(15)	18	29	(11)	(38)
Income Tax Expense (Benefit)	19	(62)	81	N/A	102	(178)	280	N/A

Three Months Ended June 30, 2018 as Compared to 2017

Operating Revenues decreased $151 million due to changes in generation and gas supply revenues.

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Generation Revenues decreased $187 million due primarily to

- a decrease of $123 million due to net MTM losses in 2018 as compared to net MTM gains in 2017. Of this amount, $133 million was due to changes in forward power prices, partially offset by $10 million due to lower losses on positions reclassified to realized upon settlement this year as compared to last year,
- a net decrease of $75 million in energy sales due primarily to lower generation volumes and lower average realized prices in the PJM region, and
- a decrease of $20 million in electricity sold under our BGS contracts due to lower prices and lower volumes,
- partially offset by a net increase of $28 million in electricity sold under other wholesale load contracts in the PJM region due to higher volumes sold.

Gas Supply Revenues increased $36 million due primarily to

- an increase of $26 million related to sales to third parties due primarily to an increase in sales volumes, partially offset by lower average sales prices, and
- an increase of $11 million in sales under the BGSS contract due primarily to an increase in sales volumes related to colder average temperatures in 2018, partially offset by lower average sales prices.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $13 million due to

Generation costs decreased $46 million due primarily to

- a decrease of $21 million due to net MTM gains in 2018 as compared to net MTM losses in 2017,
- lower fuel costs of $12 million due primarily to lower natural gas costs reflecting lower volumes in the PJM region, and
- a decrease of $9 million in energy purchases due primarily to lower volumes on wholesale load contracts in the New England (NE) region and lower cost to serve load in the PJM region.

Gas costs increased $33 million due mainly to

- an increase of $23 million related to sales to third parties due primarily to an increase in volumes sold, partially offset by lower average gas costs, and
- an increase of $10 million related to sales under the BGSS contract due primarily to increased volumes sold due to colder average temperatures in 2018, partially offset by lower average gas costs.

Operation and Maintenance increased $12 million due primarily to higher planned outage costs at our 100%-owned Hope Creek nuclear plant in 2018 as compared to planned outage costs incurred in 2017 for our 57%-owned Salem Unit 2 nuclear plant.

Depreciation and Amortization decreased $381 million due primarily to

- higher depreciation in 2017 for Hudson and Mercer due to the early retirement of those units,
- partially offset by a $5 million increase in 2018 due to a higher nuclear asset base primarily from increased capitalized asset retirement costs.

Net Gains (Losses) on Trust Investments decreased $16 million due primarily to the inclusion in 2018 of net unrealized losses on equity investments in the NDT Fund in accordance with new accounting guidance.

Income Tax Expense (Benefit) increased $81 million due primarily to pre-tax income in 2018 as compared to a pre-tax loss in 2017. This increase in income tax expense was diminished by the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018.

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Six Months Ended June 30, 2018 as Compared to 2017

Operating Revenues decreased $17 million due to changes in generation and gas supply revenues.

Generation Revenues decreased $47 million due primarily to

- a net decrease of $87 million in energy sales due primarily to lower generation volumes and lower average realized prices in the PJM region partially offset by higher average prices in the NE and New York (NY) regions, and
- a decrease of $29 million in electricity sold under our BGS contracts due primarily to lower prices,
- partially offset by a net increase of $36 million due primarily to higher volumes of electricity sold under other wholesale load contracts in the PJM region, partially offset by lower volumes of electricity sold under wholesale load contracts in the NE region,
- an increase of $11 million due to higher net MTM gains in 2018 as compared to 2017. Of this amount, $132 million was due to higher gains on positions reclassified to realized upon settlement this year as compared to last year, partially offset with a $121 million decrease due to changes in forward prices, and
- a net increase of $8 million in capacity revenues due primarily to an increase in cleared capacity auction prices in the NE region.

Gas Supply Revenues increased $30 million due primarily to

- an increase of $31 million in sales under the BGSS contract, of which $43 million was due to an increase in sales volumes resulting from colder average temperatures during the 2018 heating season, partially offset by $12 million due to lower average sales prices, and
- an increase of $15 million related to sales to third parties, of which $35 million was due to an increase in sales volumes, partially offset by $20 million due to lower average sales prices,
- partially offset by a decrease of $16 million due to net MTM losses in 2018 compared to net gains in 2017.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $41 million due to

Generation costs decreased $3 million due primarily to

- a net decrease of $24 million primarily due to a decrease in energy purchase volumes in the NE region to serve load obligations, and
- a decrease of $11 million due to net MTM gains in 2018 as compared to net losses in 2017. Of this amount, $14 million was due to changes in forward prices, partially offset by an increase of $3 million due to higher losses on positions reclassified to realized upon settlement this year as compared to last year,
- partially offset by higher fuel costs of $31 million reflecting utilization of higher volumes of oil in the PJM region coupled with higher prices of natural gas in the NY region and higher coal costs in the PJM and NE regions. This was partially offset by utilization of lower gas volumes in the PJM region.

Gas costs increased $44 million due mainly to

- an increase of $38 million related to sales under the BGSS contract due primarily to increased volumes sold resulting from colder average temperatures during the 2018 heating season, partially offset with lower average gas costs, and
- an increase of $6 million related to sales to third parties due primarily to an increase in volumes sold, partially offset by lower average gas costs.

Operation and Maintenance increased $26 million due primarily to

- a $21 million net increase due primarily to planned outage costs at our 100%-owned Hope Creek nuclear plant in 2018 as compared to planned outage costs incurred in 2017 for our 57%-owned Salem Unit 2, and
- an $8 million net increase at our fossil plants, due primarily to higher planned outage costs in 2018.

Depreciation and Amortization decreased $949 million due primarily to

- $964 million of higher depreciation in 2017 for Hudson and Mercer due to the early retirement of those units,

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- partially offset by a $10 million increase in 2018 due to a higher nuclear asset base primarily from increased capitalized asset retirement costs.

Net Gains (Losses) on Trust Investments decreased $57 million due primarily to the inclusion in 2018 of $50 million of net unrealized losses on equity investments in the NDT Fund in accordance with new accounting guidance and an $8 million decrease in net realized gains on NDT Fund investments.

Interest Expense decreased $11 million due primarily to higher interest capitalized for the construction of the BH5, Sewaren 7 and Keys fossil stations.

Income Tax Expense (Benefit) increased $280 million due primarily to pre-tax income in 2018 as compared to a pre-tax loss in 2017. This increase in income tax expense was diminished by the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the six months ended June 30, 2018, our operating cash flow decreased $122 million as compared to the same period in 2017. The net changes were primarily due to tax refunds in 2017 at Energy Holdings combined with net changes from our subsidiaries as discussed below.

PSE&G

PSE&G's operating cash flow decreased $7 million from $769 million to $762 million for the six months ended June 30, 2018, as compared to the same period in 2017, due primarily to a tax refund in 2017, partially offset by an increase of $87 million primarily due to a reduction in unbilled revenues resulting from lower prices and volumes in 2018, an increase of $66 million due to a change in regulatory deferrals, and higher earnings in 2018.

Power

Power's operating cash flow decreased $63 million from $932 million to $869 million for the six months ended June 30, 2018, as compared to the same period in 2017, due to lower earnings resulting from lower wholesale energy sales in the PJM region, an increase of $76 million in payments to counterparties and an increase in margin deposit requirements of $35 million, offset by tax refunds in 2018 compared to tax payments in 2017, and a $48 million increase from net collections of counterparty receivables.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs.

Our total credit facilities and available liquidity as of June 30, 2018 were as follows:

	As of June 30, 2018		
Company/Facility	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$ 1,500	$ 88	$ 1,412
PSE&G	600	211	389
Power	2,100	202	1,898
Total	**$ 4,200**	**$ 501**	**$ 3,699**

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As of June 30, 2018, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating from S&P or Moody's, which would represent a three level downgrade from its current S&P or Moody's ratings. In the event of a deterioration of Power's credit rating certain of Power's agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $828 million and $848 million as of June 30, 2018 and December 31, 2017, respectively.

For additional information, see Item 1. Note 11. Debt and Credit Facilities.

Long-Term Debt Financing

During the next twelve months, PSEG has a $700 million floating rate term loan maturing in June 2019, PSE&G has $350 million of 2.30% Medium-Term Notes maturing in September 2018 and $250 million of 1.80% Medium-Term Notes maturing in June 2019 and Power has $250 million of 2.45% Senior Notes maturing in November 2018.

For additional information see Item 1. Note 11. Debt and Credit Facilities.

Common Stock Dividends

On April 17, 2018, our Board of Directors approved a $0.45 dividend per share of common stock for the second quarter of 2018. On July 17, 2018, our Board of Directors declared a $0.45 dividend per share of common stock for the third quarter of 2018. These declarations reflect an indicative annual dividend rate of $1.80 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 1. Note17. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

	Moody's (A)	S&P (B)
PSEG		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

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CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures as compared to amounts disclosed in our 2017 Form 10-K.

PSE&G

During the six months ended June 30, 2018, PSE&G made capital expenditures of $1,458 million, primarily for T&D system reliability. This does not include expenditures for cost of removal, net of salvage, of $84 million, which are included in operating cash flows.

Power

During the six months ended June 30, 2018, Power made capital expenditures of $521 million, excluding $26 million for nuclear fuel, primarily related to our Keys, Sewaren 7, BH5 and other generation projects.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Item 1. Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From April through June 2018, MTM VaR was relatively stable between a low of $7 million and a high of $9 million at the 95% confidence level. The range of VaR was narrower for the three months ended June 30, 2018 as compared with the year ended December 31, 2017.

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	MTM VaR	
	Three Months Ended June 30, 2018	Year Ended December 31, 2017
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 8	$ 39
Average for the Period	$ 8	$ 10
High	$ 9	$ 39
Low	$ 7	$ 5
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 13	$ 60
Average for the Period	$ 12	$ 15
High	$ 15	$ 60
Low	$ 10	$ 8

See Item 1. Note 12. Financial Risk Management Activities for a discussion of credit risk.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, PSE&G and Power

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of PSEG, PSE&G and Power. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of PSEG, PSE&G and Power have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, PSE&G and Power

There have been no changes in internal control over financial reporting that occurred during the second quarter of 2018 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and environmental and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2017 Annual Report on Form 10-K, see Part I, Item 1. Note 10. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

The discussion of our business and operations in this Quarterly Report on Form 10-Q should be read together with the risk factors contained in Part I, Item 1A of our 2017 Annual Report on Form 10-K and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, which describe various risks and uncertainties that could have a material adverse impact on our business, prospects, financial position, results of operations or cash flows and could cause results to differ materially from those expressed elsewhere in this report. There have been no material changes to the risk factors set forth in the above-referenced filings as of June 30, 2018.

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ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

In December 2017, we entered into a share repurchase plan that complies with Rule 10b5-1 of the Securities Exchange Act of 1934, as amended, solely with respect to the repurchase of shares to satisfy obligations under equity compensation awards that are expected to vest or be exercised in 2018 and under PSEG's Employee Stock Purchase Plan for expected employee purchases in 2018. There were no common share repurchases in the open market during the second quarter of 2018.

ITEM 5. OTHER INFORMATION

Certain information reported in the 2017 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2017 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2018. References are to the related pages on the Form 10-K and 10-Q as printed and distributed.

Federal Regulation

Energy Clearing Prices

December 31, 2017 Form 10-K page 16 and March 31, 2018 Form 10-Q on page 80. FERC has ordered certain favorable changes to energy market price formation rules improving shortage pricing and enhancing bidding flexibility for units. We continue to advocate in this context for additional changes in market rules that would provide more transparency regarding operator actions affecting energy market prices and would promote better alignment between generation dispatch decisions and energy market price outcomes. The PJM Board has directed PJM staff to work with stakeholders to implement a series of price formation reforms, including a 30-minute reserve product in real-time, more dynamic reserve requirements to better capture operator actions taken to maintain reliability and improvement of the curves used to price reserves during reserve shortage conditions. The PJM Board letter directs PJM staff to submit some of these reforms for FERC's approval so that they can be implemented in early 2019. If placed into effect, these reforms should improve energy and reserve prices by ensuring that when operators commit resources to ensure reliability, the commitments are reflected in market clearing prices. We cannot predict the outcome of this matter.

Capacity Market Issues—PJM

December 31, 2017 Form 10-K page 16 and March 31, 2018 Form 10-Q on page 80. In April, 2018, PJM submitted two proposed alternative and mutually exclusive capacity market reforms for FERC's approval. One option would be to implement a two-tier clearing mechanism that accommodates states' subsidies and the other option would be to extend the existing MOPR to units that are receiving subsidies. In June 2018, FERC issued an order finding that PJM's current capacity market is unjust and unreasonable because it allows resources supported by out-of-market payments to suppress capacity prices. FERC established a new proceeding to address an alternative approach in which PJM would: (1) modify PJM's MOPR so that it would apply to new and existing resources that receive out-of-market payments, regardless of resource type; and (2) establish an option that would allow, on a resource-specific basis, resources receiving out-of-market support to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time. FERC's potential action in this proceeding could cause nuclear units that receive ZEC payments to lose capacity market revenues if states do not take steps to address the potential loss of capacity revenues. In addition, depending on the outcome of this matter, our fossil generating stations could be adversely impacted. We cannot predict the outcome of this matter.

Transmission Regulation—Transmission Policy Developments

December 31, 2017 Form 10-K page 19. In June 2016, a proposed settlement was filed with FERC for a matter remanded from the federal appellate court concerning the appropriate cost allocation for certain 500 kV projects in PJM that either have been built or are in the process of being built. In May 2018, FERC approved the settlement which will result in increased annual cost allocations to customers in the PSE&G transmission zone. Under this settlement, Power, as a BGS supplier will become obligated to pay amounts previously paid by other PJM transmission customers. However, we do not believe that the anticipated level of any such potential payments would have a material effect on Power's financial statements. We believe that there is a mechanism in place under the BGS contract for the pass-through of increases in transmission charges.

Transmission Regulation—Con Edison-PJM Wheel

December 31, 2017 Form 10-K page 19. Effective May 1, 2017, a wheeling arrangement which enabled Con Edison to move 1,000 MW of power from southeastern New York across the PSE&G system for delivery into New York City expired. Amounts that would have been recovered from Con Edison had this arrangement continued are now being recovered from other customers. PSE&G believes the current planning assumptions used by PJM are consistent with sound transmission planning principles. However, PSE&G disagrees with the absence of a mechanism to assign PJM transmission upgrade costs to Con

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Edison that reflect Con Edison's reliance on the PJM transmission grid. PSE&G and the BPU jointly filed a rehearing application at FERC seeking reversal of a determination not to create such a mechanism in connection with a PJM/NYISO joint operating agreement. In addition, in December 2017, the BPU filed a complaint at FERC against Con Edison, PJM, NYISO, New York Power Authority, Linden VFT, LLC and Hudson Transmission Partners, LLC petitioning FERC to create such a cost allocation mechanism that would assign PJM costs to New York, which complaint was denied. The BPU has sought rehearing of FERC's denial of its complaint. We cannot predict the outcome of this matter.

State Regulation

Energy Efficiency Initiatives

In May 2018, the New Jersey governor signed legislation that requires the state's electric and gas utilities to implement energy efficiency programs that are expected to achieve energy savings targets for electric and gas usage within five years of the utility's implementation of its BPU-approved energy efficiency programs. To meet these savings targets, energy usage reductions and peak demand reductions that result from utility and non-utility based programs and investments (including building code changes) will be counted. The specific energy savings target for each public electric and gas utility will be determined from an energy efficiency study to be completed within a year from enactment of the legislation. The legislation requires utilities to make annual filings with the BPU outlining their planned investments and proposed programs for cost-effectively achieving the targeted energy savings. These filings are also expected to address the utility's return of and on those investments and recovery of lost revenues associated with the lower sales. The BPU is required to adopt rules to implement the legislation within one year of enactment.

New Jersey Energy Master Plan (EMP)

New Jersey law requires that an EMP be developed every three years. While not having the force of law, the EMP provides an overview of energy policy in New Jersey. The EMP was last revised in December 2015.

In May 2018, the New Jersey governor signed an executive order requiring the BPU and other New Jersey executive branch agencies to prepare a new EMP by June 1, 2019. The new EMP will, among other issues: focus on New Jersey converting to 100% clean energy sources by January 1, 2050; incorporate New Jersey's offshore wind development goals; include provisions to guide the continued development of solar energy, including community solar; make recommendations to bolster energy storage in New Jersey; and explore methods to incentivize the use of clean, efficient energy and electric technology alternatives in New Jersey's transportation sector and at its ports.

With regard to offshore wind, the executive order directed the BPU and other state agencies to begin a process to achieve 3,500 MWs of offshore wind energy generation by the year 2030. In response, the BPU issued an order directing staff to establish a rulemaking for an offshore wind renewable energy certificate (OREC) funding mechanism and rules for the solicitation of 1,100 MWs of offshore wind capacity. We are analyzing the implications to our business.

BPU 2018 Storm Investigation

In July 2018, the BPU accepted the findings of an investigative report concerning a series of storms that hit New Jersey in March 2018 causing wide-spread infrastructure damage and power outages. The BPU implemented certain recommendations that it deemed essential to facilitate the continued provision of safe, proper and adequate service, to help mitigate future outages, and to help develop more effective responses and coordination of resources. These requirements supplement prior requirements set forth post-Hurricanes Irene and Superstorm Sandy. PSE&G is reviewing the BPU's report and its recommendations for improving storm response protocols.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. PSE&G:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. Power:

Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
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Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: August 1, 2018

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: August 1, 2018

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: August 1, 2018

S1-SSA-0009 - 18033

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Six Months Ended June 30,		Years Ended December 31,				
	2018	**2017**	**2017**	**2016**	**2015**	**2014**	**2013**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,126	$ 311	$1,268	$1,298	$2,680	$2,456	$2,055
(Income) Loss from Equity Investees, net of Distributions	(1)	1	4	7	3	4	(7)
Fixed Charges	290	245	518	477	457	450	458
Capitalized Interest	(47)	33	(9)	(7)	(18)	(16)	(16)
Total Earnings	$ 1,368	$ 590	$1,781	$1,775	$3,122	$2,894	$2,490
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 271	$ 233	$ 487	$ 456	$ 437	$ 430	$ 442
Interest Factor in Rentals	19	12	31	21	20	20	16
Total Fixed Charges	$ 290	$ 245	$ 518	$ 477	$ 457	$ 450	$ 458
Ratio of Earnings to Fixed Charges	**4.72**	**2.41**	**3.44**	**3.72**	**6.83**	**6.43**	**5.44**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred stock dividends, increased to reflect the pre-tax earnings requirement. There were no preferred stock dividends for any period presented.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2018	2017	2017	2016	2015	2014	2013
			(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 747	$ 801	$1,536	$1,404	$ 1,257	$1,174	$ 993
Fixed Charges	180	157	331	316	306	303	316
Capitalized Interest	(9)	(9)	(18)	(17)	(17)	(16)	(16)
Total Earnings	$ 918	$ 949	$1,849	$1,703	$ 1,546	$1,461	$1,293
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 172	$ 153	$ 321	$ 306	$ 297	$ 293	$ 309
Interest Factor in Rentals	8	4	10	10	9	10	7
Total Fixed Charges	$ 180	$ 157	$ 331	$ 316	$ 306	$ 303	$ 316
Ratio of Earnings to Fixed Charges	**5.10**	**6.04**	**5.59**	**5.39**	**5.05**	**4.82**	**4.09**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.2

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,		Years Ended December 31,				
	2018	2017	2017	2016	2015	2014	2013
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income (Loss) from Continuing Operations	$ 377	$ (445)	$ (250)	$ (43)	$1,367	$1,251	$1,063
(Income) Loss from Equity Investees, net of Distributions	(1)	1	4	7	1	3	(10)
Fixed Charges	72	67	139	142	152	150	143
Capitalized Interest	(38)	42	9	11	(1)	1	1
Total Earnings	$ 410	$ (335)	$ (98)	$ 117	$1,519	$1,405	$1,197
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 66	$ 64	$ 128	$ 138	$ 148	$ 146	$ 139
Interest Factor in Rentals	6	3	11	4	4	4	4
Total Fixed Charges	$ 72	$ 67	$ 139	$ 142	$ 152	$ 150	$ 143
Ratio of Earnings to Fixed Charges (C)	**5.69**	**(5.00)**	**(0.71)**	**0.82**	**9.99**	**9.37**	**8.37**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

(C) The ratio of earnings to fixed charges for the six months ended June 30, 2017, was (5.00), as noted above, which represents a deficiency of $402 million. The ratio of earnings to fixed charges for the year ended December 31, 2017, was (0.71), as noted above, which represents a deficiency of $237 million. The ratio of earnings to fixed charges for the year ended December 31, 2016, was 0.82, as noted above, which represents a deficiency of $25 million.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2018

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

S1-SSA-0009 - 18037

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

S1-SSA-0009 - 18038

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2018

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2018

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
August 1, 2018

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended June 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
August 1, 2018

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
August 1, 2018

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended June 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
August 1, 2018

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
August 1, 2018

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended June 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
August 1, 2018

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED March 31, 2013
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of April 16, 2013, Public Service Enterprise Group Incorporated had outstanding 505,968,562 shares of its sole class of Common Stock, without par value.

As of April 16, 2013, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1. Financial Statements—Note 8. Commitments and Contingent Liabilities, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations, and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC). These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission in the future, and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to balance our energy obligations, available supply and risks,
- any deterioration in our credit quality or the credit quality of our counterparties, including in our leveraged leases,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to sufficiently obtain coverage or recover proceeds of insurance on such matters,
- increase in competition in energy supply markets as well as competition for certain rate-based transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements, and
- changes in technology and customer usage patterns.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2013	**2012**
OPERATING REVENUES	$ 2,786	$ 2,875
OPERATING EXPENSES		
Energy Costs	1,155	1,179
Operation and Maintenance	710	628
Depreciation and Amortization	290	256
Taxes Other Than Income Taxes	21	29
Total Operating Expenses	2,176	2,092
OPERATING INCOME	610	783
Income from Equity Method Investments	2	—
Other Income	61	44
Other Deductions	(29)	(16)
Other-Than-Temporary Impairments	(2)	(5)
Interest Expense	(102)	(101)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	540	705
Income Tax (Expense) Benefit	(220)	(212)
NET INCOME	$ 320	$ 493
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):		
BASIC	505,942	506,010
DILUTED	507,220	507,029
EARNINGS PER SHARE:		
BASIC		
INCOME FROM CONTINUING OPERATIONS	$ 0.63	$ 0.97
NET INCOME	$ 0.63	$ 0.97
DILUTED		
INCOME FROM CONTINUING OPERATIONS	$ 0.63	$ 0.97
NET INCOME	$ 0.63	$ 0.97
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.3600	$ 0.3550

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See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18052

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2013	**2012**
NET INCOME	$ 320	$ 493
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(27) and $(38) for 2013 and 2012, respectively	27	37
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $0 and $(14) for 2013 and 2012, respectively	—	20
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $2 and $15 for 2013 and 2012, respectively	(4)	(20)
Pension/OPEB adjustment, net of tax (expense) benefit of $(7) and $(5) for 2013 and 2012, respectively	10	7
Other Comprehensive Income (Loss), net of tax	33	44
COMPREHENSIVE INCOME	$ 353	$ 537

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18053

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 420	$ 379
Accounts Receivable, net of allowances of $64 and $56 in 2013 and 2012, respectively	1,457	1,069
Tax Receivable	226	227
Unbilled Revenues	265	314
Fuel	318	583
Materials and Supplies, net	436	422
Prepayments	87	283
Derivative Contracts	77	138
Deferred Income Taxes	38	49
Regulatory Assets	282	349
Other	50	56
Total Current Assets	3,656	3,869
PROPERTY, PLANT AND EQUIPMENT	27,932	27,402
Less: Accumulated Depreciation and Amortization	(7,807)	(7,666)
Net Property, Plant and Equipment	20,125	19,736
NONCURRENT ASSETS		
Regulatory Assets	3,643	3,830
Regulatory Assets of Variable Interest Entities (VIEs)	658	713
Long-Term Investments	1,320	1,324
Nuclear Decommissioning Trust (NDT) Fund	1,602	1,540
Other Special Funds	202	191
Goodwill	16	16
Other Intangibles	37	34
Derivative Contracts	102	153
Restricted Cash of VIEs	22	23
Other	329	296
Total Noncurrent Assets	7,931	8,120
TOTAL ASSETS	$ 31,712	$ 31,725

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18054

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2013	December 31, 2012
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 876	$ 1,026
Securitization Debt of VIEs Due Within One Year	229	226
Commercial Paper and Loans	165	263
Accounts Payable	1,078	1,304
Derivative Contracts	27	46
Accrued Interest	114	91
Accrued Taxes	92	17
Deferred Income Taxes	10	72
Clean Energy Program	92	153
Obligation to Return Cash Collateral	125	122
Regulatory Liabilities	120	67
Other	478	390
Total Current Liabilities	3,406	3,777
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	6,604	6,542
Regulatory Liabilities	245	209
Regulatory Liabilities of VIEs	10	10
Asset Retirement Obligations	636	627
Other Postretirement Benefit (OPEB) Costs	1,270	1,285
Accrued Pension Costs	724	876
Environmental Costs	464	537
Derivative Contracts	123	122
Long-Term Accrued Taxes	160	164
Other	114	108
Total Noncurrent Liabilities	10,350	10,480
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	6,542	6,148
Securitization Debt of VIEs	442	496
Project Level, Non-Recourse Debt	25	43
Total Long-Term Debt	7,009	6,687
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2013 and 2012—533,556,660 shares	4,833	4,833
Treasury Stock, at cost, 2013—27,692,398 shares; 2012—27,664,188 shares	(612)	(607)
Retained Earnings	7,080	6,942
Accumulated Other Comprehensive Loss	(355)	(388)
Total Common Stockholders' Equity	10,946	10,780
Noncontrolling Interest	1	1
Total Stockholders' Equity	10,947	10,781
Total Capitalization	17,956	17,468
TOTAL LIABILITIES AND CAPITALIZATION	$ 31,712	$ 31,725

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2013	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 320	$ 493
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	290	256
Amortization of Nuclear Fuel	50	43
Provision for Deferred Income Taxes (Other than Leases) and ITC	(5)	12
Non-Cash Employee Benefit Plan Costs	61	68
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(6)	140
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	165	—
Deferred Storm Costs	(46)	4
Net Change in Regulatory Assets and Liabilities	80	(26)
Cost of Removal	(24)	(20)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(24)	(15)
Net Change in Certain Current Assets and Liabilities	207	279
Employee Benefit Plan Funding and Related Payments	(192)	(154)
Other	1	8
Net Cash Provided By (Used In) Operating Activities	877	1,088
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(724)	(687)
Proceeds from Sales of Available-for-Sale Securities	258	499
Investments in Available-for-Sale Securities	(271)	(511)
Other	4	(7)
Net Cash Provided By (Used In) Investing Activities	(733)	(706)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(98)	29
Issuance of Long-Term Debt	400	—
Redemption of Long-Term Debt, including Securitization Debt	(201)	(115)
Cash Dividends Paid on Common Stock	(182)	(179)
Other	(22)	(20)
Net Cash Provided By (Used In) Financing Activities	(103)	(285)
Net Increase (Decrease) in Cash and Cash Equivalents	41	97
Cash and Cash Equivalents at Beginning of Period	379	834
Cash and Cash Equivalents at End of Period	$ 420	$ 931
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 3	$ 3
Interest Paid, Net of Amounts Capitalized	$ 82	$ 84
Accrued Property, Plant and Equipment Expenditures	$ 265	$ 202

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18057

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2013	**2012**
OPERATING REVENUES	$ 1,447	$ 1,561
OPERATING EXPENSES		
Energy Costs	860	822
Operation and Maintenance	282	241
Depreciation and Amortization	64	57
Total Operating Expenses	1,206	1,120
OPERATING INCOME	241	441
Other Income	47	30
Other Deductions	(28)	(15)
Other-Than-Temporary Impairments	(2)	(5)
Interest Expense	(30)	(30)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	228	421
Income Tax (Expense) Benefit	(91)	(168)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 137	$ 253

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18058

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2013	**2012**
NET INCOME	$ 137	$ 253
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(27) and ($39) for 2013 and 2012, respectively	27	37
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $0 and $(14) for 2013 and 2012, respectively	—	20
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $2 and $15 for 2013, and 2012, respectively	(4)	(20)
Pension/OPEB adjustment, net of tax (expense) benefit of $(5) and $(5) for 2013 and 2012, respectively	9	7
Other Comprehensive Income (Loss), net of tax	32	44
COMPREHENSIVE INCOME	$ 169	$ 297

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18059

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 6	$ 7
Accounts Receivable	405	269
Accounts Receivable—Affiliated Companies, net	170	340
Short-Term Loan to Affiliate	748	574
Fuel	318	583
Materials and Supplies, net	313	307
Derivative Contracts	52	118
Prepayments	11	17
Deferred Income Taxes	28	—
Other	1	19
Total Current Assets	2,052	2,234
PROPERTY, PLANT AND EQUIPMENT	9,786	9,697
Less: Accumulated Depreciation and Amortization	(2,793)	(2,679)
Net Property, Plant and Equipment	6,993	7,018
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,602	1,540
Goodwill	16	16
Other Intangibles	38	34
Other Special Funds	38	36
Derivative Contracts	6	49
Other	120	105
Total Noncurrent Assets	1,820	1,780
TOTAL ASSETS	$ 10,865	$ 11,032

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18060

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2013	December 31, 2012
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 300	$ 300
Accounts Payable	408	498
Derivative Contracts	27	46
Deferred Income Taxes	—	16
Accrued Interest	41	26
Other	96	81
Total Current Liabilities	872	967
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	1,628	1,575
Asset Retirement Obligations	374	369
Other Postretirement Benefit (OPEB) Costs	224	221
Derivative Contracts	14	15
Accrued Pension Costs	230	272
Long-Term Accrued Taxes	38	50
Other	87	84
Total Noncurrent Liabilities	2,595	2,586
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT		
Total Long-Term Debt	2,040	2,040
MEMBER'S EQUITY		
Contributed Capital	2,028	2,028
Basis Adjustment	(986)	(986)
Retained Earnings	4,612	4,725
Accumulated Other Comprehensive Loss	(296)	(328)
Total Member's Equity	5,358	5,439
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 10,865	$ 11,032

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18061

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2013	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 137	$ 253
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	64	57
Amortization of Nuclear Fuel	50	43
Provision for Deferred Income Taxes and ITC	(33)	101
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	165	—
Non-Cash Employee Benefit Plan Costs	17	18
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(24)	(15)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	259	188
Margin Deposit	(117)	(34)
Accounts Receivable	3	47
Accounts Payable	(67)	(11)
Accounts Receivable/Payable-Affiliated Companies, net	121	145
Accrued Interest Payable	15	17
Other Current Assets and Liabilities	22	(39)
Employee Benefit Plan Funding and Related Payments	(45)	(38)
Other	5	(1)
Net Cash Provided By (Used In) Operating Activities	572	731
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(143)	(237)
Proceeds from Sales of Available-for-Sale Securities	244	375
Investments in Available-for-Sale Securities	(256)	(385)
Short-Term Loan—Affiliated Company, net	(174)	(128)
Other	8	10
Net Cash Provided By (Used In) Investing Activities	(321)	(365)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	(250)	(300)
Redemption of Long-Term Debt	—	(66)
Other	(2)	(7)
Net Cash Provided By (Used In) Financing Activities	(252)	(373)
Net Increase (Decrease) in Cash and Cash Equivalents	(1)	(7)
Cash and Cash Equivalents at Beginning of Period	7	12
Cash and Cash Equivalents at End of Period	$ 6	$ 5
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 2	$ (2)
Interest Paid, Net of Amounts Capitalized	$ 18	$ 15
Accrued Property, Plant and Equipment Expenditures	$ 41	$ 59

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18062

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2013	**2012**
OPERATING REVENUES	$ 1,995	$ 1,939
OPERATING EXPENSES		
Energy Costs	967	1,002
Operation and Maintenance	427	376
Depreciation and Amortization	215	190
Taxes Other Than Income Taxes	21	29
Total Operating Expenses	1,630	1,597
OPERATING INCOME	365	342
Other Income	13	11
Other Deductions	(1)	(1)
Interest Expense	(73)	(73)
INCOME BEFORE INCOME TAXES	304	279
Income Tax (Expense) Benefit	(125)	(82)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 179	$ 197

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18063

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2013	**2012**
NET INCOME	$ 179	$ 197
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0 and $1 for 2013 and 2012, respectively	—	(1)
COMPREHENSIVE INCOME	$ 179	$ 196

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18064

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 61	$ 116
Accounts Receivable, net of allowances of $64 and $56 in 2013 and 2012, respectively	1,032	783
Unbilled Revenues	265	314
Materials and Supplies	121	114
Prepayments	9	29
Regulatory Assets	282	349
Derivative Contracts	10	5
Deferred Income Taxes	38	49
Other	15	24
Total Current Assets	1,833	1,783
PROPERTY, PLANT AND EQUIPMENT	17,494	17,006
Less: Accumulated Depreciation and Amortization	(4,780)	(4,726)
Net Property, Plant and Equipment	12,714	12,280
NONCURRENT ASSETS		
Regulatory Assets	3,643	3,830
Regulatory Assets of VIEs	658	713
Long-Term Investments	361	348
Other Special Funds	61	61
Derivative Contracts	59	62
Restricted Cash of VIEs	22	23
Other	137	123
Total Noncurrent Assets	4,941	5,160
TOTAL ASSETS	$ 19,488	$ 19,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18065

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2013	December 31, 2012
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 575	$ 725
Securitization Debt of VIEs Due Within One Year	229	226
Commercial Paper and Loans	165	263
Accounts Payable	539	630
Accounts Payable—Affiliated Companies, net	89	73
Accrued Interest	73	65
Clean Energy Program	92	153
Deferred Income Taxes	43	60
Obligation to Return Cash Collateral	125	122
Regulatory Liabilities	120	67
Other	351	269
Total Current Liabilities	2,401	2,653
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,249	4,223
Other Postretirement Benefit (OPEB) Costs	992	1,011
Accrued Pension Costs	369	463
Regulatory Liabilities	245	209
Regulatory Liabilities of VIEs	10	10
Environmental Costs	413	486
Asset Retirement Obligations	254	250
Derivative Contracts	109	107
Long-Term Accrued Taxes	39	32
Other	44	38
Total Noncurrent Liabilities	6,724	6,829
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	4,467	4,070
Securitization Debt of VIEs	442	496
Total Long-Term Debt	4,909	4,566
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2013 and 2012—132,450,344 shares	892	892
Contributed Capital	520	420
Basis Adjustment	986	986
Retained Earnings	3,054	2,875
Accumulated Other Comprehensive Income	2	2
Total Stockholder's Equity	5,454	5,175
Total Capitalization	10,363	9,741
TOTAL LIABILITIES AND CAPITALIZATION	$ 19,488	$ 19,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2013	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 179	$ 197
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	215	190
Provision for Deferred Income Taxes and ITC	29	8
Non-Cash Employee Benefit Plan Costs	39	44
Cost of Removal	(24)	(20)
Deferred Storm Costs	(46)	4
Net Change in Regulatory Assets and Liabilities	80	(26)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	(200)	(14)
Materials and Supplies	(7)	(3)
Prepayments	20	52
Accounts Receivable/Payable-Affiliated Companies, net	64	(8)
Other Current Assets and Liabilities	112	51
Employee Benefit Plan Funding and Related Payments	(120)	(103)
Other	(12)	(6)
Net Cash Provided By (Used In) Operating Activities	329	366
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(572)	(435)
Proceeds from Sale of Available-for-Sale Securities	6	51
Investments in Available-for-Sale Securities	(6)	(51)
Solar Loan Investments	(7)	(19)
Restricted Funds	1	—
Net Cash Provided By (Used In) Investing Activities	(578)	(454)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	(98)	29
Issuance of Long-Term Debt	400	—
Redemption of Long-Term Debt	(150)	—
Redemption of Securitization Debt	(51)	(49)
Contributed Capital	100	—
Other	(7)	—
Net Cash Provided By (Used In) Financing Activities	194	(20)
Net Increase (Decrease) In Cash and Cash Equivalents	(55)	(108)
Cash and Cash Equivalents at Beginning of Period	116	143
Cash and Cash Equivalents at End of Period	$ 61	$ 35
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ —	$ (22)
Interest Paid, Net of Amounts Capitalized	$ 63	$ 69
Accrued Property, Plant and Equipment Expenditures	$ 224	$ 143

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

This combined Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information relating to any individual company is filed by such company on its own behalf. Power and PSE&G each is only responsible for information about itself and its subsidiaries.

Note 1. Organization and Basis of Presentation

Organization

PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's four principal direct wholly owned subsidiaries are:

- **Power**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through three principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and the states in which they operate.
- **PSE&G**—which is an operating public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the FERC. PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs, which are regulated by the BPU.
- **PSEG Energy Holdings L.L.C. (Energy Holdings)**—which primarily has investments in leveraged leases and solar generation projects through its direct wholly owned subsidiaries. Certain Energy Holdings' subsidiaries are subject to regulation by the FERC and the states in which they operate. Energy Holdings has also been awarded a contract to manage the transmission and distribution assets of the Long Island Power Authority (LIPA) starting in 2014.
- **PSEG Services Corporation (Services)**—which provides management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2012.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All significant intercompany accounts and transactions are eliminated in consolidation, except as discussed in Note 17. Related-Party Transactions. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2012.

Note 2. Recent Accounting Standards

New Standards Adopted during 2013

Disclosures about Offsetting Assets and Liabilities

This accounting standard requires enhanced disclosures regarding assets and liabilities that are either offset in the financial statements, or are subject to an enforceable master netting arrangement or similar agreement. The guidance is applicable to certain financial instruments (e.g. derivatives) and securities borrowing and lending transactions. This standard requires entities:

- to disclose information about offsetting and related arrangements to enable users of financial statements to understand the effect of those arrangements on an entity's financial position, and

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- to present both net (offset amounts) and gross information in the notes to the financial statements for relevant assets and liabilities.

We adopted this standard retrospectively effective January 1, 2013. As this standard requires disclosures only, it did not have any impact on our consolidated financial position, results of operations or cash flows. For additional information, see Note 10. Financial Risk Management Activities.

Reclassification Adjustments out of Accumulated Other Comprehensive Income (AOCI)

This accounting standard requires entities to disclose the following information about reclassification adjustments related to AOCI:

- changes in AOCI balances by component; and
- significant amounts reclassified out of AOCI by respective line items of net income (for amounts that are required by GAAP to be reclassified to net income in their entirety in the same reporting period).

We adopted this standard prospectively effective January 1, 2013. As this standard requires disclosures only, it did not have any impact on our consolidated financial position, results of operations or cash flows. For additional information, see Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax.

Note 3. Variable Interest Entities (VIEs)

Variable Interest Entities for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of these VIEs are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the Transition Funding and Transition Funding II assets are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II, respectively.

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of March 31, 2013 and December 31, 2012. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II during the first three months of 2013 or in 2012. Further, PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II.

Note 4. Rate Filings

The following information discusses significant updates regarding orders and pending rate filings. This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2012.

- ***Weather Normalization Clause (WNC)***—On April 29, 2013, the BPU approved PSE&G's filing with respect to deficiency revenues from the 2011-2012 Winter Period. As a result, provisional rates were approved which are recovering $41 million from customers during the 2012-2013 Winter Period, with a carryover deficiency of $24 million to the 2013-2014 Winter Period.
- ***Remediation Adjustment Charge (RAC)***—In April 2013, PSE&G filed a RAC 20 petition with the BPU requesting a decrease in electric and gas RAC revenues on an annual basis of $12 million and $7 million, respectively.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 5. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with Solar Renewable Energy Certificates (SRECs) generated from the installed solar electric system. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of March 31, 2013	As of December 31, 2012
	Millions	
Commercial/Industrial	$ 185	$ 174
Residential	16	15
Total	**$ 201**	**$ 189**

Energy Holdings

Energy Holdings, through various of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

The table below shows Energy Holdings' gross and net lease investment as of March 31, 2013 and December 31, 2012, respectively.

	As of March 31, 2013	As of December 31, 2012
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 705	$ 721
Estimated Residual Value of Leased Assets	529	535
	1,234	1,256
Unearned and Deferred Income	(412)	(416)
Gross Investments in Leases	822	840
Deferred Tax Liabilities	(704)	(723)
Net Investments in Leases	**$ 118**	**$ 117**

The corresponding receivables associated with the lease portfolio are reflected below, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. "Not Rated" counterparties relate to investments in leases of commercial real estate properties.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Counterparties' Credit Rating (Standard & Poor's (S&P)) As of March 31, 2013	Lease Receivables, Net of Non-Recourse Debt As of March 31, 2013	As of December 31, 2012
	Millions	
AA	$ 20	$ 21
AA-	58	73
BBB+ - BBB-	316	316
B	166	166
D	134	134
Not Rated	11	11
Total	**$ 705**	**$ 721**

The "B" and "D" ratings above represent lease receivables related to coal-fired assets in Pennsylvania and Illinois, respectively. As of March 31, 2013, the gross investment in the leases of such assets, net of non-recourse debt, was $560 million ($30 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the table below.

Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counter-parties' S&P Credit Ratings		Counterparty
		Millions		MW				
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	D	(A)	Edison Mission Energy
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	D	(A)	Edison Mission Energy
Keystone Station Units 1 and 2	PA	$ 116	17%	1,711	Coal	B		GenOn REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 116	17%	1,711	Coal	B		GenOn REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 110	100%	603	Coal	B		GenOn REMA, LLC

(A) On April 9, 2013, S&P withdrew its credit rating.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities.

Of facilities under lease by indirect subsidiary companies of Energy Holdings to GenOn REMA, LLC (GenOn REMA), a subsidiary of GenOn Energy Inc. (GenOn), which was acquired by NRG Energy, Inc. in December 2012, Keystone has installed flue gas desulfurization control for sulfur dioxide (SO_2), selective catalytic reduction (SCR) equipment for nitrogen oxide (NOx) and mercury control to meet current environmental requirements. Conemaugh has flue gas desulfurization control, while SCR and mercury control are scheduled to be installed and operational in the first quarter of 2015. GenOn has disclosed its plan for the coal-fired units at the Shawville facility to place them in a "long-term protective layup" by April 2015 while continuing to pay the required rent and maintaining the facility in accordance with the lease terms or terminating the lease for

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obsolescence in which case the lessee would be required, among other things, to pay the contractual termination value structured to recover Energy Holdings' indirect subsidiaries' lease investment as specified in the lease agreement.

Although all lease payments from the GenOn REMA leases are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel and electricity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

With respect to Energy Mission Energy's (EME) Midwest Generation (MWG) leases on the Powerton and Joliet coal units in Illinois, the lessee, MWG, substantially completed investments in mercury removal (Activated Carbon Injection) and NOx emission controls (low NOx burners and Selective Non-Catalytic Reduction systems), and plans to invest in SO_2 emission controls (Dry Sorbent Injection (Trona) systems). On April 4, 2013, MWG obtained approval from the Illinois Pollution Control Board to defer capital investments for up to two additional years to meet upcoming air emission compliance deadlines under Illinois law. Also, as previously disclosed, EME and MWG remain in litigation with the U.S. Environmental Protection Agency (EPA) and the State of Illinois regarding certain air emissions. EME does not anticipate a material change in this current approach in order to comply with existing federal and Illinois environmental rules.

On December 17, 2012, EME and MWG filed for relief under Chapter 11 of the U.S. Bankruptcy Code. Immediately prior to that filing, EME, MWG, Nesbitt Asset Recovery, LLC (Nesbitt) (an indirect, wholly owned subsidiary of Energy Holdings), and Associates Capital Investments, L.L.P. (Associates) (an affiliate of Citigroup, and, together with Nesbitt, the "Owner Participants"), as well as certain affiliated owner lessors and owner participants, entered into a forbearance agreement with holders of a majority of the lease debt that financed the original sale-leaseback transaction. The forbearance agreement, which was approved by the bankruptcy court, expired on April 5, 2013. In the absence of a forbearance agreement, the lease indenture trustee has the ability to accelerate or exercise other remedies with respect to the nonrecourse debt and, in June 2013, initiate foreclosure proceedings on the leased assets. Nesbitt is actively involved in the bankruptcy proceedings and is evaluating its options. In April 2013, MWG obtained an unopposed extension from the bankruptcy court to defer the deadline upon which it must assume or reject those leases, from April to July 2013, thereby providing it additional time to evaluate its position, including a potential restructuring. MWG did not make its scheduled $48 million rent payments on January 2, 2013 (which related to the prior six month period) on the Powerton and Joliet leases. A partial $5 million payment for the period from the date of the petition filing through January 2, 2013 was received in mid-February, pursuant to the terms of the forbearance agreement. The difference is a lessor pre-petition bankruptcy claim, while rent for the utilization of the facilities by MWG during pendency of the bankruptcy will likely be treated as an administrative expense in bankruptcy.

Note 6. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Fund

Power maintains an external master nuclear decommissioning trust to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third-party investment advisers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund:

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

	As of March 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 628	$ 205	$ (4)	$ 829
Debt Securities				
Government Obligations	370	9	(1)	378
Other Debt Securities	309	19	(1)	327
Total Debt Securities	679	28	(2)	705
Other Securities	68	—	—	68
Total NDT Available-for-Sale Securities	**$ 1,375**	**$ 233**	**$ (6)**	**$ 1,602**

	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 648	$ 147	$ (6)	$ 789
Debt Securities				
Government Obligations	274	11	—	285
Other Debt Securities	320	22	—	342
Total Debt Securities	594	33	—	627
Other Securities	124	—	—	124
Total NDT Available-for-Sale Securities	**$ 1,366**	**$ 180**	**$ (6)**	**$ 1,540**

These amounts do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of March 31, 2013	As of December 31, 2012
	Millions	
Accounts Receivable	$ 51	$ 18
Accounts Payable	$ 70	$ 53

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of March 31, 2013				As of December 31, 2012			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 67	$ (4)	$ —	$ —	$ 139	$ (6)	$ —	$ —
Debt Securities								
Government Obligations (B)	92	(1)	1	—	34	—	1	—
Other Debt Securities (C)	53	(1)	1	—	31	—	6	—
Total Debt Securities	145	(2)	2	—	65	—	7	—
Other Securities	—	—	—	—	—	—	—	—
NDT Available-for-Sale Securities	**$ 212**	**$ (6)**	**$ 2**	**$ —**	**$ 204**	**$ (6)**	**$ 7**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of March 31, 2013.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency asset-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of March 31, 2013.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2013.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended March 31,	
	2013	2012
	Millions	
Proceeds from NDT Fund Sales	**$ 241**	**$ 345**
Net Realized Gains (Losses) on NDT Fund:		
Gross Realized Gains	$ 37	$ 16
Gross Realized Losses	(19)	(6)
Net Realized Gains (Losses) on NDT Fund	**$ 18**	**$ 10**

Net realized gains disclosed in the above table were recognized in Other Income and Other Deductions in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $111 million (after-tax) were a component of Accumulated Other Comprehensive Loss on Power's Condensed Consolidated Balance Sheet as of March 31, 2013.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

The NDT available-for-sale debt securities held as of March 31, 2013 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 65
1 - 5 years	144
6 - 10 years	183
11 - 15 years	47
16 - 20 years	11
Over 20 years	255
Total NDT Available-for-Sale Debt Securities	**$ 705**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2013, other-than-temporary impairments of $2 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as the "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of March 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 13	$ 6	$ —	$ 19
Debt Securities				
Government Obligations	113	2	—	115
Other Debt Securities	46	1	—	47
Total Debt Securities	159	3	—	162
Other Securities	15	—	—	15
Total Rabbi Trust Available-for-Sale Securities	**$ 187**	**$ 9**	**$ —**	**$ 196**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 13	$ 5	$ —	$ 18
Debt Securities				
Government Obligations	114	3	—	117
Other Debt Securities	45	2	—	47
Total Debt Securities	159	5	—	164
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 175**	**$ 10**	**$ —**	**$ 185**

As of March 31, 2013, amounts in the above table do not include Accounts Receivable of $7 million and Accounts Payable of $6 million for Rabbi Trust Fund transactions which had not yet settled. These amounts are included on the Condensed Consolidated Balance Sheets.

In March 2012, PSEG restructured the fixed income component of the Rabbi Trust. The proceeds from the sales of and the net realized gains on securities in the Rabbi Trust Fund were:

	Three Months Ended March 31,	
	2013	2012
	Millions	
Proceeds from Rabbi Trust Sales	**$ 17**	**$ 154**
Net Realized Gains (Losses) on Rabbi Trust:		
Gross Realized Gains	$ —	$ 5
Gross Realized Losses	—	—
Net Realized Gains (Losses) on Rabbi Trust	**$ —**	**$ 5**

Gross realized gains disclosed in the above table were recognized in Other Income in the Condensed Consolidated Statements of Operations. Net unrealized gains of $6 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of March 31, 2013. The Rabbi Trust available-for-sale debt securities held as of March 31, 2013 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ —
1 - 5 years	61
6 - 10 years	29
11 - 15 years	10
16 - 20 years	5
Over 20 years	57
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 162**

The cost of these securities was determined on the basis of specific identification.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

The fair value of assets in the Rabbi Trust related to PSEG, Power and PSE&G are detailed as follows:

	As of March 31, 2013	As of December 31, 2012
	Millions	
Power	$ 38	$ 36
PSE&G	61	61
Other	97	88
Total Rabbi Trust Available-for-Sale Securities	**$ 196**	**$ 185**

Note 7. Pension and OPEB

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.

Pension and OPEB costs for PSEG are detailed as follows:

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2013	2012	2013	2012
	Millions			
Components of Net Periodic Benefit Cost				
Service Cost	$ 29	$ 25	$ 5	$ 4
Interest Cost	54	56	16	16
Expected Return on Plan Assets	(87)	(76)	(5)	(4)
Amortization of Net				
Transition Obligation	—	—	—	1
Prior Service Cost (Credit)	(5)	(5)	(4)	(4)
Actuarial Loss	47	42	11	8
Net Periodic Benefit Cost	$ 38	$ 42	$ 23	$ 21
Effect of Regulatory Asset	—	—	—	5
Total Benefit Costs, Including Effect of Regulatory Asset	**$ 38**	**$ 42**	**$ 23**	**$ 26**

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Pension and OPEB costs for Power, PSE&G and PSEG's other subsidiaries are detailed as follows:

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2013	2012	2013	2012
	Millions			
Power	$ 11	$ 13	$ 6	$ 5
PSE&G	23	24	16	20
Other	4	5	1	1
Total Benefit Costs	**$ 38**	**$ 42**	**$ 23**	**$ 26**

During the three months ended March 31, 2013, PSEG contributed its entire planned contributions for the year 2013 of $145 million and $14 million into its pension and postretirement healthcare plans, respectively.

Note 8. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

The face value of Power's outstanding guarantees, current exposure and margin positions as of March 31, 2013 and December 31, 2012 are shown below:

	As of March 31, 2013	As of December 31, 2012
	Millions	
Face Value of Outstanding Guarantees	$ 1,564	$ 1,508
Exposure under Current Guarantees	$ 259	$ 226
Letters of Credit Margin Posted	$ 119	$ 124
Letters of Credit Margin Received	$ 61	$ 69
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$ 6	$ 15
Counterparty Cash Margin Received	(1)	(4)
Net Broker Balance Deposited (Received)	149	26
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that Could be Required	$ 675	$ 654
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,536	$ 3,531
Additional Amounts Posted		
Other Letters of Credit	$ 45	$ 45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P's, Moody's and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

The SEC and the Commodity Futures Trading Commission (CFTC) continue efforts to implement new rules to enact stricter regulation over swaps and derivatives. In 2012, the CFTC issued Final Rules regarding the definition of a swap dealer and the definition of a swap, and established reporting and record-keeping requirements for commercial end users including PSEG. In September 2012, a federal court vacated the CFTC's rule on monitoring of position limits for several commodities, including natural gas, thereby indefinitely delaying the effectiveness of these position limits rules. PSEG is carefully monitoring all of these new rules as they are issued to analyze the potential impact on its swap and derivatives transactions, including any potential increase in its collateral requirements.

In addition to amounts for outstanding guarantees, current exposure and margin positions, Power had posted letters of credit to support various other non-energy contractual and environmental obligations. See table above.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The EPA has determined that an eight-mile stretch of the Passaic River in the area of Newark, New Jersey is a "facility" within the meaning of that term under CERCLA. The EPA has determined the need to perform a study of the entire 17-mile tidal reach of the lower Passaic River.

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PSE&G and certain of its predecessors conducted operations at properties in this area on or adjacent to the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites. When the Essex Site was transferred from PSE&G to Power, PSE&G obtained releases and indemnities for liabilities arising out of the former Essex generating station and Power assumed any environmental liabilities.

The EPA believes that certain hazardous substances were released from the Essex Site and one of PSE&G's former MGP locations (Harrison Site). In 2006, the EPA notified the potentially responsible parties (PRPs) that the cost of its Remedial Investigation and Feasibility Study (RI/FS) would greatly exceed the original estimated cost of $20 million. The total cost of the RI/FS is now estimated at approximately $110 million. Seventy-three PRPs, including Power and PSE&G, agreed to assume responsibility for the RI/FS and formed the Cooperating Parties Group (CPG) to divide the associated costs according to a mutually agreed upon formula. The CPG group, currently 70 members, is presently executing the RI/FS. Approximately five percent of the RI/FS costs are attributable to PSE&G's former MGP sites and approximately one percent to Power's generating stations. Power has provided notice to insurers concerning this potential claim.

In 2007, the EPA released a draft "Focused Feasibility Study" (FFS) that proposed six options to address the contamination cleanup of the lower eight miles of the Passaic River. The EPA estimated costs for the proposed remedy range from $1.3 billion to $3.7 billion. The work contemplated by the FFS is not subject to the cost sharing agreement discussed above. The EPA's revised proposed FFS may be released for public comment as early as the second quarter of 2013.

In June 2008, an agreement was announced between the EPA and Tierra Solutions, Inc. and Maxus Energy Corporation (Tierra/Maxus) for removal of a portion of the contaminated sediment in the Passaic River at an estimated cost of $80 million. Phase I of the removal work has been completed. Phase II is contingent on the approval of an appropriate sediment disposal facility. Tierra/Maxus have reserved their rights to seek contribution for the removal costs from the other PRPs, including Power and PSE&G.

The EPA has advised that the levels of contaminants at Passaic River mile 10.9 will require removal in advance of the completion of the RI/FS. The CPG members, with the exception of Tierra/Maxus, which are no longer members, have agreed to fund the removal, currently estimated at approximately $30 million. PSEG's share of that effort is approximately three percent.

Except for the Passaic River 10.9 mile removal, Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to the Passaic River matters.

New Jersey Spill Compensation and Control Act (Spill Act)

In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit against a PRP (Occidental Chemical Corporation (OCC)) and its related companies in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of the PRP's discharge of hazardous substances into both the Passaic River and the balance of the Newark Bay Complex. Power and PSE&G are alleged to have owned, operated or contributed hazardous substances to a total of 11 sites or facilities that impacted these water bodies. In February 2009, third party complaints were filed against some 320 third party defendants, including Power and PSE&G, claiming that each of the third party defendants is responsible for its proportionate share of the clean-up costs for the hazardous substances it allegedly discharged into the Passaic River and the Newark Bay Complex. The third party complaints seek statutory contribution and contribution under the Spill Act to recover past and future removal costs and damages. Power and PSE&G filed answers to the complaints in June 2010. A special master for discovery has been appointed by the court and document production has commenced. In October 2012, the Court issued a 90 day stay of discovery for the third party defendants to explore a possible settlement of this matter with the State of New Jersey. That settlement effort is ongoing. On March 22, 2013, Power and PSE&G signed an agreement to settle the NJDEP vs. OCC litigation at a nominal cost. That settlement is contingent upon a public comment and NJDEP response period that will extend for at least 120 days and the issuance of an order approving the settlement by the Court after conducting a fairness hearing. The stay of third-party discovery remains in place and has been extended. Power and PSE&G believe they have good and valid defenses to the allegations contained in the third party complaints and will vigorously assert those defenses. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

Natural Resource Damage Claims

In 2003, the NJDEP directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the Spill Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural

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resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSEG is unable to estimate its portion of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area and encouraged the PRPs to contact OCC to discuss participating in the RI/FS that OCC was conducting. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but it is uncertain at this time whether the PSEG companies will consent to fund the third phase. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $513 million and $649 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $513 million as of March 31, 2013. Of this amount, $111 million was recorded in Other Current Liabilities and $402 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $513 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Hazardous Air Pollutants Regulation

In accordance with a ruling of the U.S. Court of Appeals of the District of Columbia (Court of Appeals), the EPA published a Maximum Achievable Control Technology (MACT) regulation on February 16, 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the Court of Appeals in support of the EPA's implementation of MATS. Litigation of these matters remains pending and the impact on the implementation schedule is unknown at this time.

Power believes that it will not be necessary to install any additional material controls at its New Jersey facilities. Additional controls may be necessary at Power's Bridgeport Harbor coal-fired unit at an immaterial cost. In December 2011, to comply with the MACT regulators, a decision was reached to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction (SCR) systems at Power's jointly owned coal-fired generating facility at Conemaugh

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in Pennsylvania. This installation is expected to be completed in the first quarter of 2015. Power's share of this investment is approximately $147 million.

NOx Regulation

In April 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on Power's generation fleet, as it imposes NO_x emissions limits that will require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) and four older New Jersey steam electric generation units (approximately 400 MW) by May 30, 2015. Retirement notifications for the combustion turbines, except for Salem Unit 3, have been filed with the PJM Interconnection, LLC (PJM). The Salem Unit 3 combustion turbine (38 MW) will be transitioning to an emergency generator. Evaluations are ongoing for the steam electric generation units.

Under current Connecticut regulations, Power's Bridgeport and New Haven facilities have been utilizing Discrete Emission Reduction Credits (DERCs) to comply with certain NO_x emission limitations that were incorporated into the facilities' operating permits. In 2010, Power negotiated new agreements with the State of Connecticut extending the continued use of DERCs for certain emission units and equipment until May 31, 2014.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System (NPDES) permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

One of the most significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. Power prepared its renewal application in accordance with the FWPCA Section 316(b) and the 316(b) rules published in 2004.

As a result of several legal challenges to the 2004 316(b) rule by certain northeast states, environmentalists and industry groups, the rule has been suspended and has been returned to the EPA to be consistent with a 2009 United States Supreme Court decision which concluded that the EPA could rely upon cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II regulations.

In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule by July 27, 2012. In April 2011, the EPA published a new proposed rule which did not establish any particular technology as the best technology available (e.g. closed cycle cooling). Instead, the proposed rule established marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. In June 2012, the EPA posted two Notices of Data Availability (NODA) requesting comment on aspects of the April 2011 proposed rule. In July 2012, PSEG and industry trade associations submitted comments on both NODAs and the EPA and environmental groups agreed to delay the deadline for finalization of the Rule to June 27, 2013 to allow for more time to address public comments and analyze data submitted in response to the NODAs.

Power is unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on its future capital requirements, financial condition, results of operations or cash flows. The results of further proceedings on this matter could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would have been approximately $575 million. These cost estimates have not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

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Capital Expenditures

The construction programs of PSEG and its subsidiaries are currently estimated to include a base level total investment of approximately $6.1 billion for the three years ended 2015. The three-year projected capital expenditures for PSEG, Power and PSE&G are as follows:

	2013	2014	2015
		Millions	
Power	$ 400	$ 365	$ 305
PSE&G	2,040	1,680	1,180
Other	95	40	30
Total PSEG	**$ 2,535**	**$ 2,085**	**$ 1,515**

Power's projected capital expenditures include baseline maintenance (investments to replace major parts and enhance operational performance), investments in response to environmental, regulatory or legal mandates and nuclear expansion. PSE&G's projections include material additions and replacements in its transmission and distribution systems to meet expected growth and manage reliability.

Power

During the three months ended March 31, 2013, Power made $102 million of capital expenditures, including interest capitalized during construction (IDC) but excluding $41 million for nuclear fuel, primarily related to various projects at its fossil and nuclear generation stations.

PSE&G

During the three months ended March 31, 2013, PSE&G made $583 million of capital expenditures, including $572 million of investment in plant, primarily for reliability of transmission and distribution systems and $11 million in solar loan investments. This does not include expenditures for cost of removal, net of salvage, of $24 million, which is included in operating cash flows.

Energy Holdings

Included in Other for 2013 in the preceding table is a 19MW solar project currently under construction in Arizona for which Energy Holdings had issued an outstanding guarantee of $41 million as of March 31, 2013.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements for customers who do not purchase electric supply from third party suppliers through the annual New Jersey BGS auctions. Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with Power, as well as with other winning BGS suppliers, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

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PSE&G has contracted for its anticipated BGS-Fixed Price eligible load, as follows:

	Auction Year				
	2010	2011	2012	2013	
36-Month Terms Ending	May 2013	May 2014	May 2015	May 2016	(A)
Load (MW)	2,800	2,800	2,900	2,800	
$ per kWh	0.09577	0.09430	0.08388	0.09218	

(A) Prices set in the 2013 BGS auction will become effective on June 1, 2013 when the 2010 BGS auction agreements expire.

PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 17. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power has various long-term fuel purchase commitments for coal through 2017 to support its fossil generation stations and for supply of nuclear fuel for the Salem, Hope Creek and Peach Bottom nuclear generating stations and for firm transportation and storage capacity for natural gas.

Power's strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2015 and a portion through 2017 at Salem, Hope Creek and Peach Bottom.

Power's various multi-year contracts for firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

As of March 31, 2013, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2017	
		Millions
Nuclear Fuel		
Uranium	$	483
Enrichment	$	444
Fabrication	$	145
Natural Gas	$	1,035
Coal	$	508

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Regulatory Proceedings

New Jersey Clean Energy Program

In 2008, the BPU approved funding requirements for each New Jersey EDC applicable to its Renewable Energy and Energy Efficiency programs for the years 2009 to 2012. In late 2012, the BPU approved additional funding requirements for these programs for the first half of 2013. The aggregate funding for the first half of 2013 is $195 million. PSE&G has a current liability of $92 million as of March 31, 2013 for its outstanding share of the funding. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

The BPU has started a new Comprehensive Resource Analysis proceeding to determine SBC funding for the years 2013-2016. The proceeding has no impact on current SBC assessments.

Long-Term Capacity Agreement Pilot Program (LCAPP)

In 2011, New Jersey enacted the LCAPP Act that resulted in the selection of three generators to build a total of approximately 2,000 MW of new combined-cycle generating facilities located in New Jersey. Each of the New Jersey EDCs, including PSE&G, was directed to execute a standard offer capacity agreement (SOCA) with the three selected generators, but did so under protest preserving their legal rights. The SOCA provides for the EDCs to guarantee specified annual capacity payments to the generators subject to the terms and conditions of the agreement. Legal challenges to the BPU's implementation of the LCAPP Act were filed in New Jersey appellate court and this appeal is pending. In addition, the LCAPP Act itself has been challenged on constitutional grounds in federal court and that proceeding is ongoing.

In May 2012, two of the three generators cleared the Reliability Pricing Model auction for the 2015/2016 delivery year in the aggregate notional amount of approximately 1,300 MW of installed capacity. SOCA payments are for a 15-year term, which are scheduled to commence for one of the generators in the 2015/2016 delivery year and for the other generator in the 2016/2017 delivery year. Based upon the expected percentage of state load that PSE&G will be serving during the term of these contracts, PSE&G would be responsible for approximately 52% or 676 MW of this amount.

The current estimated fair value of the SOCAs is recorded as a Derivative Asset or Liability with an offsetting Regulatory Asset or Liability on PSE&G's Consolidated Balance Sheets. See Note 11. Fair Value Measurements for additional information.

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's transmission and distribution system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds resulted in a storm surge that caused damage to switching stations, substations and generating infrastructure.

Power incurred an additional $28 million of storm-related expense for the three months ended March 31, 2013, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized in Operation and Maintenance Expense. Power expects it will incur additional future costs, primarily relating to repairs to, and replacement of, equipment and property, which could be material.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. PSEG is seeking recovery from its insurers for the property damage, above its self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. PSEG received $25 million from its insurance carriers as an advance payment which was recorded in the fourth quarter of 2012. PSEG believes that additional insurance recoveries are not estimable as of March 31, 2013. PSEG is documenting its insurance claim which then will need to be submitted to and reviewed by its insurers. PSEG does not believe that it has a basis for estimating additional probable insurance recoveries at this time.

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Leveraged Lease Investments

On January 31, 2012, PSEG entered into a specific matter closing agreement with the Internal Revenue Service (IRS) settling all matters related to cross border lease transactions. This agreement settled the leasing dispute with finality for all tax periods in which PSEG realized tax deductions from these transactions. On January 31, 2012, PSEG also signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. On March 26, 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These two agreements concluded ten years of audits for PSEG and the leasing issue for all tax years. For PSEG, the impact of these agreements was an increase in financial statement Income Tax Expense of approximately $175 million in the first quarter of 2012. In prior periods, PSEG had established financial statement tax liabilities for uncertain tax positions in the amount of $246 million with respect to these tax years. Accordingly, the settlement resulted in a net $71 million decrease in the first quarter of 2012 in the Income Tax Expense of PSEG.

Cash Impact

For tax years 1997 through 2003, the tax and interest PSEG owes the IRS as a result of this settlement will be reduced by the $320 million PSEG has on deposit with the IRS for this matter. PSEG paid a net deficiency for these years of approximately $4 million during the second quarter of 2012. Based upon the closing agreement and the Form 870-AD for tax years 2004 through 2006, PSEG owes the IRS approximately $620 million in tax and interest for tax years from 2004 through 2006. Based on the settlement of the leasing dispute, for tax years 2007 through 2010, the IRS owes PSEG approximately $676 million. PSEG has filed amended returns for tax years 2007-2010 reflecting the impact of the settlement. These returns have been audited by the IRS and accepted as filed. As required by statute, the IRS presented the refund claim to the Joint Committee on Taxation for approval. On October 16, 2012, PSEG was notified that the Joint Committee took no exception to the refund claim. In April 2013, PSEG received confirmation from the IRS which shows that overpayments from the 2008 through 2010 tax years have been applied to satisfy the liabilities due with respect to tax years 2004 through 2007. Accordingly, no further cash payments will be required with respect to the contested leasing transactions. In addition to the above, PSEG will claim a tax deduction for the accrued deficiency interest associated with this settlement in 2012, which gives rise to a cash tax savings of approximately $100 million.

Note 9. Changes in Capitalization

The following capital transactions occurred in the first three months of 2013:

Power

- paid cash dividends of $250 million to PSEG.

PSE&G

- paid $150 million of 5.00% Secured Medium-Term Notes at maturity,
- issued $400 million of 3.80% Secured Medium-Term Notes, Series H due January 2043,
- received $100 million capital contribution from PSEG, and
- paid $51 million of Transition Funding's securitization debt.

Energy Holdings

- reclassified $18 million of non-recourse long-term debt associated with a commercial real estate property held for sale to Other Current Liabilities.

For additional information, see Note 11. Fair Value Measurements.

Note 10. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions.

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Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Commodity Prices

The availability and price of energy commodities are subject to fluctuations due to weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions, transmission availability and other events. Power uses physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. Derivative contracts that do not qualify for hedge accounting or normal purchases/normal sales treatment are marked to market (MTM) with changes in fair value recorded in the income statement. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps and futures contracts to hedge

- forecasted energy sales from its generation stations and the related load obligations, and
- certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

Certain of these derivative transactions are designated and effective as cash flow hedges. During the second quarter of 2012, Power de-designated certain of its commodity derivative transactions that had previously qualified as cash flow hedges as they were deemed to no longer be highly effective as required by the relevant accounting guidance. As a result, subsequent to June 1, 2012, Power recognizes all gains and losses from changes in the fair value of these derivatives immediately in earnings rather than deferring any such amounts in Accumulated Other Comprehensive Income (Loss). The fair values of Power's de-designated hedges were frozen in Accumulated Other Comprehensive Income (Loss) as the original forecasted transactions are still expected to occur and are reclassified into earnings as the original derivative transactions settle.

As of March 31, 2013 and December 31, 2012, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity was as follows:

	As of March 31, 2013	As of December 31, 2012
	Millions	
Fair Value of Cash Flow Hedges	$ —	$ 3
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 5	$ 9

The expiration date of the longest-dated cash flow hedge at Power is in 2014. Power's after-tax unrealized gains on these derivatives that are expected to be reclassified to earnings during the next 12 months are $4 million. There was no ineffectiveness associated with qualifying hedges as of March 31, 2013.

Trading Derivatives

The primary purpose of Power's wholesale marketing operation is to optimize the value of the output of the generating facilities via various products and services available in the markets it serves. Historically, Power engaged in trading of electricity and energy-related products where such transactions were not associated with the output or fuel purchase requirements of its facilities. This trading consisted mostly of energy supply contracts where Power secured sales commitments with the intent to supply the energy services from purchases in the market rather than from its owned generation. Such trading activities were marked to market through the income statement and represented less than one percent of gross margin (revenues less energy costs) on an annual basis. Effective July 2011, Power discontinued trading activities and anticipates that it will not enter into any more trading derivative contracts.

Other Derivatives

Power enters into additional contracts that are derivatives, but do not qualify for or are not designated as cash flow hedges. These transactions are intended to mitigate exposure to fluctuations in commodity prices and optimize the value of its expected generation. Trade types include financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity.

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Changes in the fair market value of these contracts are recorded in earnings. PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization. In addition, as further described in Note 8. Commitments and Contingent Liabilities, PSE&G was directed to execute long-term SOCAs with certain generators to support the LCAPP Act. These contracts qualify as derivatives and are marked to fair value with the offset recorded to Regulatory Assets and Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of March 31, 2013, PSEG had 7 interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of March 31, 2013 and December 31, 2012, the fair value of all the underlying hedges was $52 million and $57 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was $(2) million as of March 31, 2013 and December 31, 2012.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. See Note 2. Recent Accounting Standards. In general, the terms of our agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset in the Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

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	As of March 31, 2013						
	Power (A)				PSE&G(A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ —	$ 356	$ (304)	$ 52	$ 10	$ 15	$ 77
Noncurrent Assets	—	50	(44)	6	59	37	102
Total Mark-to-Market Derivative Assets	**$ —**	**$ 406**	**$ (348)**	**$ 58**	**$ 69**	**$ 52**	**$ 179**
Derivative Contracts							
Current Liabilities	$ —	$ (343)	$ 316	$ (27)	$ —	$ —	$ (27)
Noncurrent Liabilities	—	(72)	58	(14)	(109)	—	(123)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (415)**	**$ 374**	**$ (41)**	**$ (109)**	**$ —**	**$ (150)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ —**	**$ (9)**	**$ 26**	**$ 17**	**$ (40)**	**$ 52**	**$ 29**

	As of December 31, 2012						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 3	$ 332	$ (217)	$ 118	$ 5	$ 15	$ 138
Noncurrent Assets	—	75	(26)	49	62	42	153
Total Mark-to-Market Derivative Assets	**$ 3**	**$ 407**	**$ (243)**	**$ 167**	**$ 67**	**$ 57**	**$ 291**
Derivative Contracts							
Current Liabilities	$ —	$ (265)	$ 219	$ (46)	$ —	$ —	$ (46)
Noncurrent Liabilities	—	(41)	26	(15)	(107)	—	(122)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (306)**	**$ 245**	**$ (61)**	**$ (107)**	**$ —**	**$ (168)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 3**	**$ 101**	**$ 2**	**$ 106**	**$ (40)**	**$ 57**	**$ 123**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of March 31, 2013 and December 31, 2012. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where

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the right of offset exists, has been offset in the statement of financial position. As of March 31, 2013 and December 31, 2012, net cash collateral paid of $26 million and $2 million, respectively, were netted against the corresponding net derivative contract positions. Of the $26 million as of March 31, 2013, cash collateral of $12 million and $14 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $2 million as of December 31, 2012, cash collateral of $(3) million and $5 million were netted against current assets and current liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded or lose its investment grade credit rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on NYMEX and ICE that are fully collateralized) was $80 million and $98 million as of March 31, 2013 and December 31, 2012, respectively. As of March 31, 2013 and December 31, 2012, Power had the contractual right of offset of $61 million related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded or lost its investment grade rating, it would have had additional collateral obligations of $19 million and $37 million as of March 31, 2013 and December 31, 2012, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $675 million and $654 million as of March 31, 2013 and December 31, 2012, respectively, discussed in Note 8. Commitments and Contingent Liabilities.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended March 31, 2013 and 2012:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion)		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	
	Three Months Ended March 31,			Three Months Ended March 31,			Three Months Ended March 31,	
	2013	2012		2013	2012		2013	2012
	Millions							
PSEG								
Energy-Related Contracts	$ —	$ 38	Operating Revenues	$ 6	$ 39	Operating Revenues	$ —	$ (1)
Energy-Related Contracts	—	(4)	Energy Costs	—	(4)		—	—
Total PSEG	**$ —**	**$ 34**		**$ 6**	**$ 35**		**$ —**	**$ (1)**
Power								
Energy-Related Contracts	$ —	$ 38	Operating Revenues	$ 6	$ 39	Operating Revenues	$ —	$ (1)
Energy-Related Contracts	—	(4)	Energy Costs	—	(4)		—	—
Total Power	**$ —**	**$ 34**		**$ 6**	**$ 35**		**$ —**	**$ (1)**

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The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis:

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2011	**$ 54**	**$ 31**
Gain Recognized in AOCI	28	17
Less: Gain Reclassified into Income	(70)	(41)
Balance as of December 31, 2012	**$ 12**	**$ 7**
Less: Gain Reclassified into Income	(6)	(4)
Balance as of March 31, 2013	**$ 6**	**$ 3**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the three months ended March 31, 2013 and 2012:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives	
		Three Months Ended March 31,	
		2013	2012
		Millions	
PSEG and Power			
Energy-Related Contracts	Operating Revenues	$ (209)	$ 195
Energy-Related Contracts	Energy Costs	58	(26)
Total PSEG and Power		**$ (151)**	**$ 169**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $5 million and $6 million for the three month periods ended March 31, 2013 and 2012, respectively.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

The following reflects the gross volume, on an absolute value basis, of derivatives as of March 31, 2013 and December 31, 2012:

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of March 31, 2013					
Natural Gas	Dth	625	—	444	181
Electricity	MWh	231	—	231	—
Capacity	MW days	4	—	—	4
FTRs	MWh	8	—	8	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2012					
Natural Gas	Dth	596	—	404	192
Electricity	MWh	208	—	208	—
Capacity	MW days	4	—	—	4
FTRs	MWh	19	—	19	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
Coal	Tons	1	—	1	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of March 31, 2013, 96% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of March 31, 2013. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 311	$ 60	$ 310	1	$ 200	(A)
Non-Investment Grade—External Rating	12	—	12	—	—	
Investment Grade—No External Rating	3	—	3	—	—	
Non-Investment Grade—No External Rating	1	—	1	—	—	
Total	**$ 327**	**$ 60**	**$ 326**	**1**	**$ 200**	

(A) Represents net exposure with PSE&G.

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The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of March 31, 2013, Power had 172 active counterparties.

Note 11. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of March 31, 2013, these consist primarily of electric swaps whose basis is deemed significant to the fair value measurement, long-term electric load contracts and long-term gas supply contracts.

The following tables present information about PSEG's, Power's and PSE&G's respective assets and (liabilities) measured at fair value on a recurring basis as of March 31, 2013 and December 31, 2012, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Description	Recurring Fair Value Measurements as of March 31, 2013				
	Total	Cash Collateral Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 127	$ —	$ —	$ 56	$ 71
Interest Rate Swaps (B)	$ 52	$ —	$ —	$ 52	$ —
NDT Fund (C)					
Equity Securities	$ 829	$ —	$ 829	$ —	$ —
Debt Securities—Govt Obligations	$ 378	$ —	$ —	$ 378	$ —
Debt Securities—Other	$ 327	$ —	$ —	$ 327	$ —
Other Securities	$ 68	$ —	$ —	$ 68	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 19	$ —	$ 19	$ —	$ —
Debt Securities—Govt Obligations	$ 115	$ —	$ —	$ 115	$ —
Debt Securities—Other	$ 47	$ —	$ —	$ 47	$ —
Other Securities	$ 2	$ —	$ —	$ 2	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (150)	$ 26	$ —	$ (48)	$ (128)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 58	$ —	$ —	$ 56	$ 2
NDT Fund (C)					
Equity Securities	$ 829	$ —	$ 829	$ —	$ —
Debt Securities—Govt Obligations	$ 378	$ —	$ —	$ 378	$ —
Debt Securities—Other	$ 327	$ —	$ —	$ 327	$ —
Other Securities	$ 68	$ —	$ —	$ 68	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 4	$ —	$ 4	$ —	$ —
Debt Securities—Govt Obligations	$ 22	$ —	$ —	$ 22	$ —
Debt Securities—Other	$ 9	$ —	$ —	$ 9	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (41)	$ 26	$ —	$ (48)	$ (19)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (A)	$ 69	$ —	$ —	$ —	$ 69
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—Govt Obligations	$ 38	$ —	$ —	$ 38	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy Related Contracts (A)	$ (109)	$ —	$ —	$ —	$ (109)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Description	Recurring Fair Value Measurements as of December 31, 2012			
	Total	Cash Collateral Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 234	$ (3)	$ —	$ 157	$ 80
Interest Rate Swaps (B)	$ 57	$ —	$ —	$ 57	$ —
NDT Fund (C)					
Equity Securities	$ 789	$ —	$ 789	$ —	$ —
Debt Securities—Govt Obligations	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Other	$ 342	$ —	$ —	$ 342	$ —
Other Securities	$ 124	$ —	$ —	$ 124	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 18	$ —	$ 18	$ —	$ —
Debt Securities—Govt Obligations	$ 117	$ —	$ —	$ 117	$ —
Debt Securities—Other	$ 47	$ —	$ —	$ 47	$ —
Other Securities	$ 3	$ —	$ —	$ 3	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (168)	$ 5	$ —	$ (62)	$ (111)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 167	$ (3)	$ —	$ 157	$ 13
NDT Fund (C)					
Equity Securities	$ 789	$ —	$ 789	$ —	$ —
Debt Securities—Govt Obligations	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Other	$ 342	$ —	$ —	$ 342	$ —
Other Securities	$ 124	$ —	$ —	$ 124	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 3	$ —	$ 3	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 9	$ —	$ —	$ 9	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (61)	$ 5	$ —	$ (62)	$ (4)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (A)	$ 67	$ —	$ —	$ —	$ 67
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—Govt Obligations	$ 39	$ —	$ —	$ 39	$ —
Debt Securities—Other	$ 15	$ —	$ —	$ 15	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy Related Contracts (A)	$ (107)	$ —	$ —	$ —	$ (107)

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(A) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

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Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(B) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(C) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities). The fair value measurements table excludes a $13 million cash contribution made to the Rabbi Trust Fund as of March 31, 2013. Of the $13 million, $3 million and $10 million were contributed to Power's and Services' portions of the Rabbi Trust Fund, respectively.

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price (primarily Level 1). The Rabbi Trust equity index fund is valued based on quoted prices in an active market (Level 1).

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds and United States Treasury obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes, and issuer spreads (primarily Level 2). Short-term investments and certain commingled temporary investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield (primarily Level 2).

(D) Cash collateral netting represents collateral amounts netted against derivative assets and liabilities as permitted under the accounting guidance for Offsetting of Amounts Related to Certain Contracts.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group, and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

The following tables provide details surrounding significant Level 3 valuations as of March 31, 2013 and December 31, 2012. For Power, in general, electric swaps are valued based on at least two pricing inputs, basis and underlying. To the extent the basis component is based on a single broker quote and is significant to the fair value of the electric swap, it is categorized as Level 3. Power's electric load contracts in which load consumption may change hourly are fair valued using certain unobservable inputs, such as historic load variability. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. For Power and PSE&G, long-term gas supply contracts are measured at fair value using both actively traded pricing points as well as unobservable inputs such as gas prices beyond observable periods and long-term basis quotes and accordingly, the fair value measurements are classified in Level 3. For PSE&G, long-term electric capacity contracts are measured at fair value using both observable capacity prices and unobservable inputs consisting of forecasts of future long-term electric capacity prices and include

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adjustments for contingencies, such as litigation risk and plant construction risk. Accordingly, the fair value measurements are classified as Level 3.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of March 31, 2013 Assets	Fair Value as of March 31, 2013 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ —	$ (13)	Discounted cash flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	—	(6)	Discounted cash flow	Historic Load Variability	-5% to +10%
Other	Various (A)	2	—			
Total Power		**$ 2**	**$ (19)**			
PSE&G						
Gas and Capacity	Forward Contracts (B)	$ 69	$ (109)	Discounted cash flow	Long-Term Gas Basis and Capacity Prices	(B)
Total PSE&G		**$ 69**	**$ (109)**			
TOTAL PSEG		**$ 71**	**$ (128)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2012 Assets	Fair Value as of December 31, 2012 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ 7	$ (1)	Discounted cash flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	1	(2)	Discounted cash flow	Historic Load Variability	-5% to +10%
Other	Various (A)	5	(1)			
Total Power		**$ 13**	**$ (4)**			
PSE&G						
Gas and Capacity	Forward Contracts (B)	$ 67	$ (107)	Discounted cash flow	Long-Term Gas Basis and Capacity Prices	(B)
Total PSE&G		**$ 67**	**$ (107)**			
TOTAL PSEG		**$ 80**	**$ (111)**			

(A) Includes long-term gas supply positions which are immaterial as of March 31, 2013 and December 31, 2012. Also includes long-term electric capacity positions which are immaterial as of December 31, 2012.

(B) Includes long-term gas supply and long-term electric capacity positions with various unobservable inputs. Significant unobservable inputs for the gas supply contracts include long-term basis prices in the range of $0 to $2/MMBTU of natural gas. Unobservable inputs for the long-term electric capacity contracts include forecasted capacity prices in the range of $100 to $400/MW day.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power and PSE&G are sellers, an increase in either the power basis or the load variability or the longer-term basis amounts would decrease the fair value. For long-term electric capacity contracts where PSE&G is a buyer, an increase in the capacity price would increase the fair value.

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months ended March 31, 2013 and 2012 follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2013

Description	Balance as of January 1, 2013	Total Gains or (Losses) Realized/Unrealized Included in Income (A)	Total Gains or (Losses) Realized/Unrealized Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances (Settlements) (C)	Transfers In (Out) (D)	Balance as of March 31, 2013
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (31)	$ (34)	$ —	$ —	$ 10	$ (2)	$ (57)
Power							
Net Derivative Assets (Liabilities)	$ 9	$ (34)	$ —	$ —	$ 10	$ (2)	$ (17)
PSE&G							
Net Derivative Assets (Liabilities)	$ (40)	$ —	$ —	$ —	$ —	$ —	$ (40)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2012

Description	Balance as of January 1, 2012	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances (Settlements) (C)	Transfers In (Out) (D)	Balance as of March 31, 2012
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 21	$ 34	$ 35	$ —	$ (29)	$ —	$ 61
Non-Recourse Debt	$ (50)	$ —	$ —	$ —	$ —	$ —	$ (50)
Power							
Net Derivative Assets (Liabilities)	$ 24	$ 34	$ —	$ —	$ (29)	$ —	$ 29
PSE&G							
Net Derivative Assets (Liabilities)	$ (3)	$ —	$ 35	$ —	$ —	$ —	$ 32

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $(34) million and $34 million in Operating Income in 2013 and 2012, respectively. Of the $(34) million in Operating Income in 2013, $(24) million is unrealized. Of the $34 million in Operating Income in 2012, $5 million is unrealized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or OCI, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $10 million in settlements in 2013 and $(29) million in settlements in 2012.

(D) During the three months ended March 31, 2013, $2 million of net derivatives assets were transferred from Level 3 to Level 2, due to more observable pricing for the underlying securities. The transfer was recognized as of the beginning of the first quarter (i.e. the quarter in which the transfer occurred), as per PSEG's policy. There were no transfers among levels for the three months ended March 31, 2012.

As of March 31, 2013, PSEG carried $1.8 billion of net assets that are measured at fair value on a recurring basis, of which $57 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of March 31, 2012, PSEG carried $1.8 billion of net assets that are measured at fair value on a recurring basis, of which $11 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of March 31, 2013 and December 31, 2012.

	March 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 35	$ 52	$ 38	$ 57
Power -Recourse Debt (B)	2,340	2,781	2,340	2,818
PSE&G (B)	5,042	5,750	4,795	5,606
Transition Funding (PSE&G) (B)	639	703	690	765
Transition Funding II (PSE&G) (B)	32	34	32	34
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	26	26	44	44
Total Long-Term Debt	**$ 8,114**	**$ 9,346**	**$ 7,939**	**$ 9,324**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement. The $18 million of Non-Recourse Debt associated with a commercial real estate property held for sale was reclassified to Other Current Liabilities in 2013.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 12. Other Income and Deductions

Other Income	Power	PSE&G	Other (A)	Consolidated
		Millions		
Three Months Ended March 31, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ 47	$ —	$ —	$ 47
Allowance of Funds Used During Construction	—	6	—	6
Solar Loan Interest	—	6	—	6
Other	—	1	1	2
Total Other Income	**$ 47**	**$ 13**	**$ 1**	**$ 61**
Three Months Ended March 31, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$ 28	$ —	$ —	$ 28
Allowance of Funds Used During Construction	—	4	—	4
Solar Loan Interest	—	4	—	4
Other	2	3	3	8
Total Other Income	**$ 30**	**$ 11**	**$ 3**	**$ 44**

Other Deductions	Power	PSE&G	Other (A)	Consolidated
		Millions		
Three Months Ended March 31, 2013				
NDT Fund Realized Losses and Expenses	$ 20	$ —	$ —	$ 20
Other	8	1	—	9
Total Other Deductions	**$ 28**	**$ 1**	**$ —**	**$ 29**
Three Months Ended March 31, 2012				
NDT Fund Realized Losses and Expenses	$ 8	$ —	$ —	$ 8
Other	7	1	—	8
Total Other Deductions	**$ 15**	**$ 1**	**$ —**	**$ 16**

(A) Other primarily consists of activity at PSEG (as parent company), Energy Holdings, Services and intercompany eliminations.

Note 13. Income Taxes

PSEG's, Power's and PSE&G's effective tax rates for the three months ended March 31, 2013 and 2012 were as follows:

	Three Months Ended March 31,	
	2013	2012
PSEG	40.7%	30.1%
Power	39.8%	39.8%
PSE&G	41.1%	29.4%

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

PSEG's and PSE&G's effective tax rates for the three months ended March 31, 2012 were lower than their more typical 2013 effective tax rates due primarily to a settlement in 2012 with the IRS in regards to leveraged leases and the federal tax audit for tax years 1997 through 2006.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 was eligible for 50% bonus depreciation for tax purposes. On January 2, 2013, the President signed into law the American Taxpayer Relief Act of 2012 that further extends the 50% bonus depreciation for property placed into service before January 1, 2014. These provisions have generated cash for PSEG through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period.

On June 26, 2009, September 15, 2008 and December 17, 2007, PSEG made tax deposits with the IRS in the amounts of $140 million, $80 million and $100 million, respectively, to defray potential interest costs associated with disputed tax assessments associated with certain lease investments. On January 31, 2012, PSEG signed a specific matter closing agreement with the IRS regarding this matter. Based on this agreement, these deposits were applied against tax and interest due pursuant to the closing agreement. Further, on the same date, PSEG signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. On March 26, 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These two agreements concluded ten years of audits for PSEG and the leasing issue for all tax years. The financial statement impacts of these agreements, net of existing financial statement reserves, was a net decrease in tax expense in the first quarter of 2012 of $71 million for PSEG, including $30 million and $1 million for PSE&G and Power, respectively.

Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss)			
	Three Months Ended March 31, 2013			
Accumulated Other Comprehensive Income (Loss)	**Derivative Contracts**	**Pension and OPEB Plans**	**Available-for -Sale Securities**	**Total**
	Millions			
Balance as of December 31, 2012	$ 7	$ (485)	$ 90	$ (388)
Other Comprehensive Income before Reclassifications	—	—	27	27
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(4)	10	—	6
Net Current Period Other Comprehensive Income (Loss)	(4)	10	27	33
Balance as of March 31, 2013	**$ 3**	**$ (475)**	**$ 117**	**$ (355)**

Power	Other Comprehensive Income (Loss)			
	Three Months Ended March 31, 2013			
Accumulated Other Comprehensive Income (Loss)	**Derivative Contracts**	**Pension and OPEB Plans**	**Available-for -Sale Securities**	**Total**
	Millions			
Balance as of December 31, 2012	$ 9	$ (422)	$ 85	$ (328)
Other Comprehensive Income before Reclassifications	—	—	27	27
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(4)	9	—	5
Net Current Period Other Comprehensive Income (Loss)	(4)	9	27	32
Balance as of March 31, 2013	**$ 5**	**$ (413)**	**$ 112**	**$ (296)**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

PSEG

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement Three Months Ended March 31, 2013		
		Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Derivative Contracts				
Gains (Losses) on Cash Flow Hedges	Operating Revenues	$ 6	$ (2)	$ 4
Pension and OPEB Plans				
Amortization of Prior Service Cost (Credit)	Operation and Maintenance Expense	4	(2)	2
Amortization of Actuarial Loss	Operation and Maintenance Expense	(21)	9	(12)
Available-for-Sale Securities				
Realized Gains (Losses) on NDT Fund	Other Income	2	(1)	1
Other-Than-Temporary Impairments on NDT Fund	Other-Than-Temporary Impairments	(2)	1	(1)
Total		**$ (11)**	**$ 5**	**$ (6)**

Power

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement Three Months Ended March 31, 2013		
		Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Derivative Contracts				
Gains (Losses) on Cash Flow Hedges	Operating Revenues	$ 6	$ (2)	$ 4
Pension and OPEB Plans				
Amortization of Prior Service Cost (Credit)	Operation and Maintenance Expense	2	(1)	1
Amortization of Actuarial Loss	Operation and Maintenance Expense	(16)	6	(10)
Available-for-Sale Securities				
Realized Gains (Losses) on NDT Fund	Other Income	2	(1)	1
Other-Than-Temporary Impairments on NDT Fund	Other-Than-Temporary Impairments	(2)	1	(1)
Total		**$ (8)**	**$ 3**	**$ (5)**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

	Balance as of December 31, 2011	Other Comprehensive Income (Loss) Three Months Ended March 31, 2012			Balance as of March 31, 2012
		Power	PSE&G	Other	
			Millions		
Derivative Contracts	$ 31	$ —	$ —	$ —	$ 31
Pension and OPEB Plans	(438)	7	—	—	(431)
Available-for-Sale Securities	70	37	(1)	1	107
Accumulated Other Comprehensive Income (Loss)	**$ (337)**	**$ 44**	**$ (1)**	**$ 1**	**$ (293)**

Note 15. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended March 31,			
	2013		2012	
	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)				
Net Income	**$ 320**	**$ 320**	**$ 493**	**$ 493**
EPS Denominator (Thousands)				
Weighted Average Common Shares Outstanding	505,942	505,942	506,010	506,010
Effect of Stock Based Compensation Awards	—	1,278	—	1,019
Total Shares	**505,942**	**507,220**	**506,010**	**507,029**
EPS				
Net Income	**$ 0.63**	**$ 0.63**	**$ 0.97**	**$ 0.97**

	Three Months Ended March 31,	
Dividend Payments on Common Stock	2013	2012
Per Share	$ 0.3600	$ 0.3550
in Millions	$ 182	$ 179

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 16. Financial Information by Business Segments

	Power	PSE&G	Energy Holdings	Other (A)	Consolidated
			Millions		
Three Months Ended March 31, 2013					
Total Operating Revenues	$ 1,447	$ 1,995	$ 16	$ (672)	$ 2,786
Income (Loss) From Continuing Operations	137	179	—	4	320
Net Income (Loss)	137	179	—	4	320
Segment Earnings (Loss)	137	179	—	4	320
Gross Additions to Long-Lived Assets	143	572	6	3	724
Three Months Ended March 31, 2012					
Total Operating Revenues	$ 1,561	$ 1,939	$ 20	$ (645)	$ 2,875
Income (Loss) From Continuing Operations	253	197	40	3	493
Net Income (Loss)	253	197	40	3	493
Segment Earnings (Loss)	253	197	40	3	493
Gross Additions to Long-Lived Assets	237	435	11	4	687
As of March 31, 2013					
Total Assets	$ 10,865	$ 19,488	$ 1,437	$ (78)	$ 31,712
Investments in Equity Method Subsidiaries	$ 40	$ —	$ 97	$ —	$ 137
As of December 31, 2012					
Total Assets	$ 11,032	$ 19,223	$ 1,454	$ 16	$ 31,725
Investments in Equity Method Subsidiaries	$ 40	$ —	$ 94	$ —	$ 134

(A) Other activities include amounts applicable to PSEG (as parent company), Services and intercompany eliminations, primarily relating to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are priced in accordance with applicable regulations, including affiliate pricing rules, or at cost or, in the case of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 17. Related-Party Transactions.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 17. Related-Party Transactions

The following discussion relates to intercompany transactions, the majority of which are eliminated during the PSEG consolidation process in accordance with GAAP.

Power

The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended March 31, 2013	2012
	Millions	
Revenue from Affiliates:		
Billings to PSE&G through BGSS (A)	$ 478	$ 451
Billings to PSE&G through BGS (A)	193	189
Total Revenue from Affiliates	**$ 671**	**$ 640**
Expense Billings from Affiliates:		
Administrative Billings from Services (B)	$ (45)	$ (34)
Total Expense Billings from Affiliates	**$ (45)**	**$ (34)**

Related-Party Transactions	As of March 31, 2013	As of December 31, 2012
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$ 223	$ 238
Receivables from (Payable to) PSE&G Related to Gas Supply Hedges for BGSS (A)	(23)	27
Receivable from (Payable to) Services (B)	(26)	(31)
Tax Receivable from (Payable to) PSEG (C)	(6)	111
Receivable from (Payable to) PSEG	2	(5)
Accounts Receivable (Payable)—Affiliated Companies, net	**$ 170**	**$ 340**
Short-Term Loan to Affiliate (Demand Note to PSEG) (D)	**$ 748**	**$ 574**
Working Capital Advances to Services (E)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable (Payable) (C)	**$ (38)**	**$ (50)**

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended March 31, 2013	2012
	Millions	
Expense Billings from Affiliates:		
Billings from Power through BGSS (A)	$ (478)	$ (451)
Billings from Power through BGS (A)	(193)	(189)
Administrative Billings from Services (B)	(61)	(50)
Total Expense Billings from Affiliates	**$ (732)**	**$ (690)**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Related-Party Transactions	As of March 31, 2013	As of December 31, 2012
	Millions	
Payable to Power through BGS and BGSS Contracts (A)	$ (223)	$ (238)
Receivable from (Payable to) Power Related to Gas Supply Hedges for BGSS (A)	23	(27)
Payable to Power for SREC Liability (F)	(7)	(7)
Receivable from (Payable to) Services (B)	(52)	(65)
Tax Receivable from (Payable to) PSEG (C)	160	256
Receivable from (Payable to) PSEG	7	6
Receivable from Energy Holdings	3	2
Accounts Receivable (Payable)—Affiliated Companies, net	**$ (89)**	**$ (73)**
Working Capital Advances to Services (E)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Receivable (Payable) (C)	**$ (39)**	**$ (32)**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to Power and PSE&G at cost. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

(E) Power and PSE&G have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on Power's and PSE&G's Condensed Consolidated Balance Sheets.

(F) Pursuant to a BPU Order, certain BGS suppliers will be reimbursed for the cost they incurred above $300 per Solar Renewable Energy Certificate (SREC) or per Solar Alternative Compliance Payment (SACP) during the period June 1, 2008 through May 31, 2010 and such excess cost will be passed on to ratepayers. In a December 2012 order, the BPU approved a Stipulation of Settlement (Stipulation) that describes the mechanism by which BGS suppliers are to recover reasonable and prudently-incurred costs for these SRECs. In accordance with the Stipulation, New Jersey's EDCs, including PSE&G, made a Verification Filing defining the proposed BGS Supplier payments. PSE&G has estimated and accrued a total liability for the excess SREC cost expected to be recovered from ratepayers of $17 million as of March 31, 2013 and December 31, 2012, including approximately $7 million for Power's share which is included in PSE&G's Accounts Payable—Affiliated Companies as of March 31, 2013 and December 31, 2012. Under current accounting guidance, Power was unable to record the related intercompany receivable on its Condensed Consolidated Balance Sheet. As a result, PSE&G's liability to Power is not eliminated in consolidation and is included in Other Current Liabilities on PSEG's Condensed Consolidated Balance Sheet as of March 31, 2013 and December 31, 2012.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 18. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following table presents condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended March 31, 2013					
Operating Revenues	$ —	$ 1,803	$ 33	$ (389)	$ 1,447
Operating Expenses	2	1,562	30	(388)	1,206
Operating Income (Loss)	(2)	241	3	(1)	241
Equity Earnings (Losses) of Subsidiaries	149	—	—	(149)	—
Other Income	9	48	—	(10)	47
Other Deductions	(8)	(20)	—	—	(28)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(27)	(10)	(4)	11	(30)
Income Tax Benefit (Expense)	16	(108)	1	—	(91)
Net Income (Loss)	**$ 137**	**$ 149**	**$ —**	**$ (149)**	**$ 137**
Comprehensive Income (Loss)	**$ 169**	**$ 172**	**$ —**	**$ (172)**	**$ 169**
Three Months Ended March 31, 2013					
Net Cash Provided By (Used In) Operating Activities	$ 189	$ 574	$ (2)	$ (189)	$ 572
Net Cash Provided By (Used In) Investing Activities	$ 61	$ (353)	$ —	$ (29)	$ (321)
Net Cash Provided By (Used In) Financing Activities	$ (250)	$ (221)	$ 2	$ 217	$ (252)
Three Months Ended March 31, 2012					
Operating Revenues	$ —	$ 1,873	$ 26	$ (338)	$ 1,561
Operating Expenses	(2)	1,433	27	(338)	1,120
Operating Income (Loss)	2	440	(1)	—	441
Equity Earnings (Losses) of Subsidiaries	260	(3)	—	(257)	—
Other Income	13	31	—	(14)	30
Other Deductions	(7)	(8)	—	—	(15)
Other-Than-Temporary Impairments	—	(5)	—	—	(5)
Interest Expense	(29)	(10)	(4)	13	(30)
Income Tax Benefit (Expense)	14	(185)	2	1	(168)
Net Income (Loss)	**$ 253**	**$ 260**	**$ (3)**	**$ (257)**	**$ 253**
Comprehensive Income (Loss)	**$ 297**	**$ 297**	**$ (3)**	**$ (294)**	**$ 297**
Three Months Ended March 31, 2012					
Net Cash Provided By (Used In) Operating Activities	$ 124	$ 723	$ 2	$ (118)	$ 731
Net Cash Provided By (Used In) Investing Activities	$ 242	$ (656)	$ (13)	$ 62	$ (365)
Net Cash Provided By (Used In) Financing Activities	$ (366)	$ (73)	$ 10	$ 56	$ (373)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
As of March 31, 2013					
Current Assets	$ 3,926	$ 8,180	$ 942	$ (10,996)	$ 2,052
Property, Plant and Equipment, net	80	5,972	941	—	6,993
Investment in Subsidiaries	4,240	733	—	(4,973)	—
Noncurrent Assets	189	1,722	59	(150)	1,820
Total Assets	**$ 8,435**	**$ 16,607**	**$ 1,942**	**$ (16,119)**	**$ 10,865**
Current Liabilities	$ 529	$ 10,334	$ 1,001	$ (10,992)	$ 872
Noncurrent Liabilities	508	2,032	208	(153)	2,595
Long-Term Debt	2,040	—	—	—	2,040
Member's Equity	5,358	4,241	733	(4,974)	5,358
Total Liabilities and Member's Equity	**$ 8,435**	**$ 16,607**	**$ 1,942**	**$ (16,119)**	**$ 10,865**
As of December 31, 2012					
Current Assets	$ 3,922	$ 8,084	$ 940	$ (10,712)	$ 2,234
Property, Plant and Equipment, net	80	5,988	950	—	7,018
Investment in Subsidiaries	4,317	733	—	(5,050)	—
Noncurrent Assets	201	1,660	60	(141)	1,780
Total Assets	**$ 8,520**	**$ 16,465**	**$ 1,950**	**$ (15,903)**	**$ 11,032**
Current Liabilities	$ 482	$ 10,187	$ 1,010	$ (10,712)	$ 967
Noncurrent Liabilities	559	1,960	207	(140)	2,586
Long-Term Debt	2,040	—	—	—	2,040
Member's Equity	5,439	4,318	733	(5,051)	5,439
Total Liabilities and Member's Equity	**$ 8,520**	**$ 16,465**	**$ 1,950**	**$ (15,903)**	**$ 11,032**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by PSEG, Power and PSE&G. Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of three reportable segments, which are:

- **Power,** our wholesale energy supply company that integrates its generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States,
- **PSE&G,** our public utility company which provides electric transmission services and distribution of electric energy and natural gas in New Jersey; implements demand response and energy efficiency programs and invests in solar generation, and
- **Energy Holdings,** which principally owns energy-related leveraged leases and solar generation projects.

Our business discussion in Part I, Item 1. Business of our 2012 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I Item 1A of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Overview of 2012 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2013 and any changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes, and the 2012 Form 10-K.

OVERVIEW OF 2013 AND FUTURE OUTLOOK

Our business plan is designed to maintain earnings stability while achieving growth in recognition of market, regulatory and economic trends. We continue to focus on operational excellence to provide the foundation for our financial strength, which enables us to invest in a disciplined way.

Our financial results for the first three months of 2013 were lower when compared to the first quarter of 2012. In the power markets in which our generation fleet operates, natural gas prices have a major impact on the price that generators receive for their output. While wholesale natural gas prices during the period remained low relative to historic prices following multiple years of steep declines, our generation fleet was able to capitalize on price volatility in the quarter resulting from operating conditions on the interstate pipelines in New York and New England. Financial results for our generation operations were also favorably impacted by increased output and higher market prices driven by colder winter weather in the period as compared to the same period in 2012, partially offset by lower prices on basic generation service (BGS) and other contracted positions. Despite the modest improvements in pricing in the first quarter, the financial results for our generation operations include significant mark-to-market losses due to the impact of the rising prices on our forward sale positions.

Our utility business benefited from favorable weather and transmission formula rates, but financial results were impacted by the absence of last year's tax settlement. In the first quarter of 2013 we continued to invest capital in transmission and distribution infrastructure projects, aimed at maintaining the reliability and resiliency of our service to our customers. We receive contemporaneous and reasonable risk-adjusted returns on these projects. Over the past few years, these types of investments at our regulated utility have altered the business mix of our operations.

At year-end 2012, we were severely impacted by Superstorm Sandy, which resulted in the highest level of customer outages in our history. We sustained significant damage to some of our generation, transmission and distribution facilities. On February 20, 2013, we filed a petition with the New Jersey Board of Public Utilities (BPU) describing our Energy Strong program, consisting of $3.9 billion of proposed improvements we recommend making to our gas and electric distribution systems over a ten year period to harden and improve resiliency. In addition, we anticipate investing an additional $1.5 billion in our transmission system for the same reason. As proposed, we believe that the rate impacts of the Energy Strong program will be significantly muted as a result of scheduled reductions to customer bills that will be taking place over the next few years and assuming continued low gas prices.

In developing and implementing our strategy, we monitor significant regulatory and legislative developments which may affect our operations and financial results. Competitive wholesale power market design is of particular importance to our results and we continue to advocate for policies and rules in response to subsidized generation and procurement activities in

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New Jersey in connection with the Long-Term Capacity Agreement Pilot Program (LCAPP) and in Maryland through the Maryland Public Service Commission Request for Proposal (RFP), as well as at the Federal Energy Regulatory Commission (FERC) with regard to modifications to the Minimum Offer Price Rule (MOPR), changes which we believe are necessary to avoid artificial price suppression and other distortions in the capacity markets. Our involvement in litigation with respect to LCAPP, MOPR and the Maryland RFP continues.

We continued to monitor and advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA). In particular, the EPA's 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. Clean Air Act regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology (MACT) rules are also of significance; however, we believe our generation business remains well-positioned for such regulations if and when they are implemented.

FERC rules under Order 1000 altered the right of first refusal previously held by incumbent utilities to build all transmission within their respective service territories. We are opposing these rules in litigation and have worked with PJM to develop implementing rules that mitigate the adverse impact of Order 1000. Specific implementation of Order 1000 may expose us to competition within our service territory but could also provide opportunities for us to construct transmission outside of our service territory.

Operational Excellence

We emphasize operational performance while developing opportunities in our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented in the first quarter as we remain diligent in managing costs. In the first quarter of 2013, our

- outstanding performance allowed us to increase generation to meet loads, and
- construction of transmission and solar projects proceeded on schedule and within budget.

Financial Strength

Our financial position remained strong during the first quarter of 2013 as we:

- had cash on hand of $420 million as of the end of the first quarter of 2013,
- extended the expiration date of approximately half of our credit facilities, and maintained substantial liquidity and solid investment grade credit ratings, as evidenced by the recent credit rating upgrades by Standard & Poor's (S&P) of PSEG, Power and PSE&G as disclosed below in Liquidity and Capital Resources—Credit Ratings,
- completed pension and OPEB funding for 2013,
- refinanced PSE&G maturing debt at historically low rates and early in the second quarter repaid Power's maturing debt with cash on hand, and
- increased our indicated annual dividend to $1.44.

We expect to be able to fund our proposed Energy Strong program with internally generated cash and external debt financing.

Disciplined Investment

We seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In addition to the proposed Energy Strong program discussed above, in the first quarter of 2013 we

- made additional investments in transmission infrastructure projects,
- continued to execute our existing BPU-approved utility programs,
- in April 2013, reached a settlement with the BPU Staff and several parties with respect to our Solar 4 All and Solar Loan III programs as disclosed below in Part II. Item 5. Other Information—State Regulation, and
- initiated construction of a 19MW solar project in Arizona.

There is no guarantee that our projects currently underway or any future initiatives will be achieved since many issues need to be favorably resolved, such as regulatory approvals. Delays in the construction schedules of our projects could impact their costs as well as the timing of expected revenues.

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Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a difficult economy and cost-constrained environment and to respond to the issues and challenges described below and take advantage of these and other regulatory and legislative initiatives. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully re-contract our open supply positions,
- execute our capital investment program, including investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and FERC of market design rules that continue to protect competition and achieve appropriate RPM and BGS pricing, and
- reach out to and engage multiple stakeholders, including regulators, government officials, customers and investors.

For 2013 and beyond, the key issues and challenges we expect our business to confront include

- regulatory and political uncertainty, particularly with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation,
- uncertainty in the national and regional economic recovery and continuing customer conservation efforts, which impact customer demand,
- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate,
- the aftermath of Hurricane Irene and Superstorm Sandy, including addressing the BPU's review of performance and communications, as well as cost recovery and opportunities for investment in system strengthening, including our proposed Energy Strong program,
- financially-stressed power plant leveraged lease investments,
- delays and other obstacles that might arise in connection with the construction of our transmission and distribution projects, including in connection with permitting and regulatory approvals, and
- the successful transition to our management of the Long Island Power Authority's (LIPA) transmission and distribution system.

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RESULTS OF OPERATIONS

The results for PSEG, PSE&G, Power and Energy Holdings for the three months ended March 31, 2013 and 2012 are presented below:

Earnings (Losses)	Three Months Ended March 31, 2013	2012
	Millions	
Power	$ 137	$ 253
PSE&G	179	197
Energy Holdings	—	40
Other (A)	4	3
PSEG Net Income	**$ 320**	**$ 493**

Earnings Per Share (Diluted)	Three Months Ended March 31, 2013	2012
PSEG Net Income	**$ 0.63**	**$ 0.97**

(A) Other primarily includes parent company interest and financing activity and certain administrative and general expenses.

Our results include the realized gains, losses and earnings on Power's Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity. This includes the net realized gains, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions. This also includes impairments on certain NDT securities which are included in Other-Than-Temporary Impairments and the interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO), which is recorded in Operation and Maintenance Expense and the depreciation related to the ARO asset.

Our results also include the after-tax impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the chart below:

	Three Months Ended March 31, 2013	2012
	Millions, after tax	
NDT Fund Income (Expense)	$ 9	$ 5
Non-Trading MTM Gains (Losses)	$ (105)	$ 52

In addition to the changes in NDT and MTM, our $173 million decrease in Net Income for the three months ended March 31, 2013 was driven primarily by

- higher Operation and Maintenance Costs, including repairs related to damage caused by Superstorm Sandy, and
- higher Income Tax Expense due to the absence of tax benefits related to the settlement of the 1997-2006 Internal Revenue Service (IRS) audits in 2012.

The decrease was partially offset by

- higher capacity revenues and operating reserve revenues in PJM, and
- higher transmission revenues due to increased investments in transmission projects.

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PSEG

Our results of operations are primarily comprised of the results of operations of our operating subsidiaries, Power, PSE&G and Energy Holdings, excluding charges related to intercompany transactions, which are eliminated in consolidation. We also include certain financing costs, charitable contributions and general and administrative costs at the parent company. For additional information on intercompany transactions, see Note 17. Related-Party Transactions. For an explanation of the variances, see the discussions for Power, PSE&G and Energy Holdings that follow the table below:

	Three Months Ended March 31,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012	
	Millions		Millions	%
Operating Revenues	$ 2,786	$ 2,875	$ (89)	(3)
Energy Costs	1,155	1,179	(24)	(2)
Operation and Maintenance	710	628	82	13
Depreciation and Amortization	290	256	34	13
Taxes Other than Income Taxes	21	29	(8)	(28)
Income from Equity Method Investments	2	—	2	N/A
Other Income and (Deductions)	32	28	4	14
Other-Than-Temporary Impairments	2	5	(3)	(60)
Interest Expense	102	101	1	1
Income Tax Expense	220	212	8	4

Power

	Three Months Ended March 31,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012
	Millions		
Net Income	$ 137	$ 253	$ (116)

For the three months ended March 31, 2013, the primary reasons for the $116 million decrease in Net Income were:

- MTM losses in 2013 resulting from an increase in prices on forward positions in the PJM region, and
- higher Operation and Maintenance Costs, including costs related to damage caused by Superstorm Sandy at our fossil plants.

These decreases in Net Income were partially offset by higher capacity revenues and PJM operating reserve revenues.

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The quarter-over-quarter details for these variances are discussed below:

	Three Months Ended March 31,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012	
	Millions		Millions	%
Operating Revenues	$ 1,447	$ 1,561	$ (114)	(7)
Energy Costs	860	822	38	5
Operation and Maintenance	282	241	41	17
Depreciation and Amortization	64	57	7	12
Other Income (Deductions)	19	15	4	27
Other-Than-Temporary Impairments	2	5	(3)	(60)
Interest Expense	30	30	—	—
Income Tax Expense	91	168	(77)	(46)

Three Months Ended March 31, 2013 As Compared to 2012

Operating Revenues decreased $114 million due to

Generation Revenues decreased $185 million due primarily to

- lower net revenues of $244 million due primarily to MTM losses in 2013 resulting from an increase in prices on forward positions in the PJM region, partially offset by higher generation sold in the PJM and New England regions at lower average realized prices in PJM,
- a decrease of $32 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts, and
- a net decrease of $43 million due to lower volumes on wholesale load contracts in the PJM and New England regions,
- partially offset by a net increase of $134 million due to higher capacity revenues resulting from higher auction prices and an increase in operating reserve revenue in PJM in 2013.

Gas Supply Revenues increased $71 million due primarily to

- a net increase of $50 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during 2013, partially offset by lower average gas prices, and
- an increase of $21 million due to higher average prices from sales to third party customers.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $38 million due to

- ***Gas costs*** increased $31 million, principally related to obligations under the BGSS contract, reflecting higher sales volumes in 2013 due to colder average temperatures in 2013, partially offset by lower average gas inventory costs.
- ***Generation costs*** increased $6 million due primarily to an increase of $56 million, reflecting the utilization of higher volumes of coal, natural gas and oil and higher realized natural gas prices, partly offset by the favorable MTM impact from higher natural gas prices on forward positions in 2013. This increase was largely offset by $38 million of lower congestion costs in the PJM region and $12 million in lower energy purchases, primarily in the PJM region, as a result of lower load contract volumes in 2013.

Operation and Maintenance increased $41 million due primarily to $28 million in costs incurred from Superstorm Sandy in 2013 at our fossil plants, and higher outage and maintenance costs in 2013, mainly at our Bergen gas-fired plants and Mercer coal-fired plant in New Jersey, and our coal-fired Conemaugh plant in Pennsylvania.

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Depreciation and Amortization increased $7 million due primarily to a higher depreciable asset base, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut on June 1, 2012 and completion of the steam path retrofit upgrade at our co-owned Peach Bottom Unit 2 in October 2012.

Other-Than-Temporary Impairments decreased $3 million due primarily to a decrease in impairments on the NDT Fund in 2013.

Interest Expense was flat due primarily to a decrease from lower outstanding debt in 2013 resulting from certain debt redeemed prior to maturity in 2012, offset by an increase due to the absence in 2013 of capitalized interest on the Kearny and New Haven gas-fired peaking projects that were put into service on June 1, 2012.

Income Tax Expense decreased $77 million in 2013 due primarily to lower pre-tax income.

PSE&G

	Three Months Ended March 31,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012
	Millions		
Net Income	$ 179	$ 197	$ (18)

For the three months ended March 31, 2013, the primary reasons for the $18 million decrease in Net Income were

- higher Income Tax Expense due to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012, and
- higher Operation and Maintenance costs,
- partially offset by higher transmission revenues due to increased investments in transmission projects.

The quarter-over-quarter details for these variances are discussed below:

	Three Months Ended March 31,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012	
	Millions		Millions	%
Operating Revenues	$ 1,995	$ 1,939	$ 56	3
Energy Costs	967	1,002	(35)	(3)
Operation and Maintenance	427	376	51	14
Depreciation and Amortization	215	190	25	13
Taxes Other Than Income Taxes	21	29	(8)	(28)
Other Income (Deductions)	12	10	2	20
Interest Expense	73	73	—	—
Income Tax Expense (Benefit)	125	82	43	52

Three Months Ended March 31, 2013 As Compared to 2012

Operating Revenues increased $56 million due primarily to

Delivery Revenues increased $52 million due primarily to an increase in transmission revenues.

- Transmission revenues were $40 million higher due to net rate increases resulting primarily from increased capital investments.

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- Gas distribution revenues increased $18 million due primarily to $52 million from higher sales volumes, partially offset by lower Weather Normalization Clause (WNC) revenue of $33 million.
- Electric distribution revenues decreased $6 million due primarily to lower Transitional Energy Facilities Assessment (TEFA) revenue of $5 million due to a lower TEFA rate and lower Capital Infrastructure Program (CIP) revenue of $5 million, partially offset by higher sales volumes of $4 million.

Clause Revenues increased $35 million due primarily to higher Societal Benefit Charges (SBC) of $20 million and higher Securitization Transition Charge (STC) revenues of $14 million. The changes in SBC and STC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC or STC collections.

Other Operating Revenues increased $4 million due primarily to increased revenues from our appliance repair business.

Commodity Revenue decreased $35 million due to lower Electric revenues, partially offset by higher Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $118 million due primarily to $95 million in lower BGS revenues and $23 million in lower revenues from a lower volume of sales of Non-Utility Generation (NUG) energy and lower Non-Utility Generation Charges (NGC) due to lower tariff rates. BGS sales decreased 7% due primarily to customer migration to third party suppliers (TPS); in contrast, delivery sales increased by 2%.
- Gas revenues increased $83 million due to higher BGSS volumes of $79 million and higher BGSS prices of $4 million. The average price of natural gas was 1% higher in 2013 than in 2012.

Energy Costs decreased $35 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $118 million or 21% due to $50 million in lower BGS and NUG volumes, $22 million of lower BGS and NUG prices, and $46 million for decreased deferred cost recovery. BGS and NUG volumes decreased 9% due primarily to customer migration to TPS.
- Gas costs increased $83 million or 19% due to $79 million or 18% in higher sales volumes due primarily to weather and $4 million or 1% in higher prices.

Operation and Maintenance increased $51 million, of which the most significant components were

- a $30 million increase in costs recognized related primarily to SBC and CIP,
- a $7 million increase in costs relating to repairs from Superstorm Sandy and snow removal, and
- a $4 million increase in appliance service costs.

Depreciation and Amortization increased $25 million due primarily to

- a $17 million increase in amortization of Regulatory Assets, and
- a $7 million increase in additional plant in service.

Taxes Other Than Income Taxes decreased $8 million due to a lower TEFA rate for gas and lower sales volumes for electric.

Other Income and (Deductions) net increase of $2 million was due primarily to an increase in Solar Loan interest income.

Interest Expense was flat due primarily to partial redemption of securitization debt and higher interest capitalized related to higher construction work in progress, offset by new debt issued in 2013. See Note 9. Changes in Capitalization for details.

Income Tax Expense increased $43 million due primarily to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012 and higher pre-tax income.

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Energy Holdings

	Three Months Ended March 31,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012
	Millions		
Net Income	$ —	$ 40	$ (40)

For the three months ended March 31, 2013, the primary reason for the $40 million decrease in Net Income was the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in the prior year.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our three direct operating subsidiaries.

Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund capital expenditures and shareholder dividend payments.

For the three months ended March 31, 2013, our operating cash flow decreased $211 million as compared to the same period in 2012. The net change was due primarily to net changes from Power and PSE&G, as discussed below.

Power

Power's operating cash flow decreased $159 million from $731 million to $572 million for the three months ended March 31, 2013, as compared to the same period in 2012, primarily resulting from lower earnings and an increase of $83 million in margin deposits, partially offset by a net increase of $71 million due primarily to higher fuel inventories used to satisfy our gas supply obligations.

PSE&G

PSE&G's operating cash flow decreased $37 million from $366 million to $329 million for the three months ended March 31, 2013, as compared to the same period in 2012, due primarily to a decrease of $186 million related to higher customer billings due to colder weather in 2013, partially offset by an increase of $106 million due to a net change in Regulatory Assets and Liabilities primarily related to the overrecovery of gas costs and collection of Gas Weather Normalization Charges.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Both commercial paper programs are fully back-stopped by their own separate credit facilities.

The commitments under our credit facilities are provided by a diverse bank group. In March 2013, Power, PSEG and PSE&G amended their respective 5-year credit agreements scheduled to end in 2016, extending the expiration dates from April 2016 to March 2018. Of the total commitments of $2.1 billion under these agreements, $2.0 billion has been extended until 2018. The commitments for the $100 million balance will terminate in 2016. As of March 31, 2013, our total credit capacity was $4.3 billion.

As of March 31, 2013, no single institution represented more than 8% of the total commitments in our credit facilities.

As of March 31, 2013, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of March 31, 2013 were as follows:

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Company/Facility	As of March 31, 2013 Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facility	$ 500	$ 4 (D)	$ 496	Mar 2017	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—	500	Mar 2018	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 4**	**$ 996**		
Power					
5-year Credit Facility	$ 1,600	$ 60 (D)	$ 1,540	Mar 2017	Funding/Letters of Credit
5-year Credit Facility (B)	1,000	—	1,000	Mar 2018	Funding/Letters of Credit
Bilateral Credit Facility	100	100 (D)	—	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 160**	**$ 2,540**		
PSE&G					
5-year Credit Facility (C)	$ 600	$ 178 (E)	$ 422	Mar 2018	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 178**	**$ 422**		
Total	**$ 4,300**	**$ 342**	**$ 3,958**		

(A) In April 2016, this facility will be reduced by $23 million.

(B) In April 2016, this facility will be reduced by $48 million.

(C) In April 2016, this facility will be reduced by $29 million.

(D) Includes amounts related to letters of credit outstanding.

(E) Includes amounts related to CP and letters of credit.

Long-Term Debt Financing

Power had $300 million of 2.50% Senior Notes that matured in April 2013. PSE&G has $300 million of 5.38% Medium Term Notes maturing in September 2013 and $275 million of 6.33% Medium Term Notes maturing in November 2013. For a discussion of our long-term debt transactions during 2013, see Note 9. Changes in Capitalization.

Common Stock Dividends

For information related to cash dividends on our common stock, see Note 15. Earnings Per Share and Dividends.

We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In January 2013, Fitch published updated credit opinions on PSEG, Power and PSE&G. PSEG's, Power's and PSE&G's ratings and outlooks remained unchanged. In April 2013, S&P upgraded the corporate credit ratings on PSEG, Power and PSE&G to BBB+ from BBB and PSE&G's Mortgage Bond rating to A from A-. PSEG's, Power's and PSE&G's outlooks were changed to stable from positive.

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	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	**Stable**	**Stable**	**Stable**
Commercial Paper	P2	A2	F2
Power			
Outlook	**Stable**	**Stable**	**Stable**
Senior Notes	Baa1	BBB+	BBB+
PSE&G			
Outlook	**Stable**	**Stable**	**Stable**
Mortgage Bonds	A1	A	A+
Commercial Paper	P2	A2	F2

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1 (highest) to D (lowest) for short-term securities.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There have been no material changes to our projected construction and investment amounts through 2015 as disclosed in our Form 10-K for the year ended December 31, 2012. See Note 8. Commitments and Contingent Liabilities for additional information.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The market risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

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Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

Three Months Ended March 31, 2013	**MTM VaR**
	Millions
95% Confidence Level,	
Loss could exceed VaR one day in 20 days	
Period End	$ 10
Average for the Period	$ 19
High	$ 29
Low	$ 10
99.5% Confidence Level,	
Loss could exceed VaR one day in 200 days	
Period End	$ 15
Average for the Period	$ 29
High	$ 46
Low	$ 15

See Note 10. Financial Risk Management Activities for a discussion of credit risk.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the first quarter of 2013 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2012 Form 10-K, see Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

There no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2012 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the first quarter of 2013:

Three Months Ended March 31, 2013	Total Number of Shares Purchased	Average Price Paid per Share
January 1 - January 31	—	$ —
February 1 - February 28	93,189	$ 32.12
March 1 - March 31	117,330	$ 33.15

ITEM 5. OTHER INFORMATION

Certain information reported in the 2012 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2012 Annual Report on Form 10-K. References are to the related pages on the Form 10-K as printed and distributed.

FEDERAL REGULATION

FERC

PJM, the New York Independent System Operator (NYISO), and the Independent System Operator-New England (ISO-NE) each have capacity markets that have been approved by the FERC.

Capacity Market Issues—Long-Term Capacity Agreement Pilot Program Act (LCAPP)

December 31, 2012 Form 10-K page 16. In 2011, the State of New Jersey concluded that new natural gas-fired generation was needed and enacted the LCAPP Act to subsidize approximately 2,000 MW of new generation. The LCAPP Act provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey Electric Distribution Companies (EDCs). The SOCA required each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers. Each of the New Jersey EDCs, including PSE&G, entered into the SOCAs as directed by the State, but did so under protest reserving their rights. In May 2012, two of the three generators, CPV Shore, LLC (CPV), a subsidiary of Competitive Power Ventures, Inc. and Hess Newark, LLC (Hess), a subsidiary of Hess Corporation, that received SOCA contracts cleared the RPM auction for the 2015/2016 delivery year in the aggregate notional amount of approximately 1,300 MW of installed capacity.

Legal challenges to the BPU's implementation of the LCAPP Act were filed in New Jersey appellate court and the appeal remains pending. In addition, the LCAPP Act has been challenged on constitutional grounds in federal court and that proceeding is ongoing.

Maryland has also taken action to subsidize above-market new generation. On April 16, 2013, the Maryland Public Service Commission (PSC) issued an order directing the Maryland utility companies to execute a contract with CPV to build a new 661 MW natural gas-fired, combined cycle station in Maryland with an in-service date of June 2015. We have joined other generators in challenging Maryland's actions on constitutional grounds in federal court.

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Transmission Regulations—Transmission Policy Developments

December 31, 2012 Form 10-K page 17. In 2010, the FERC initiated a proceeding to evaluate whether reforms to current transmission planning and cost allocation rules were necessary to stimulate additional transmission development. The FERC ultimately concluded in Order No. 1000 that the construction of transmission should be opened up to competition by eliminating the "right of first refusal" (ROFR), subject to certain exceptions, under which incumbent transmission companies such as PSE&G have a ROFR to build transmission located within their respective service territories. We have challenged the FERC's elimination of the ROFR in federal court. The FERC has recently issued an order regarding PJM's implementation of these new transmission planning and cost allocation rules, under which the construction of certain types of transmission projects have been opened to competition in PJM.

Transmission Regulations—Transmission Expansion

December 31, 2012 Form 10-K page 17. In October 2012, the National Park Service (NPS) issued a final Environmental Impact Statement (EIS) for the new 500 kiloVolt (kV) Susquehanna-Roseland transmission line, selecting our and PPL Corporation's choice of route in certain federal park lands subject to the NPS' jurisdiction that follows the existing right of way. Several environmental groups had filed a complaint in federal court challenging the NPS' issuance of the final EIS, seeking to set aside the EIS and asking the court for an injunction that would generally prohibit construction of the project within the federal park lands at issue. On February 25, 2013, the federal court denied the environmental groups' request for an injunction (without prohibiting seeking an injunction at a later date) and set a schedule for all filings to be before the court by June 28, 2013. Construction has been underway in those areas where necessary permits have been obtained. Delays in the construction schedule could impact the cost of construction and the timing of expected transmission revenues.

Transmission Regulations—Transmission Rate Proceedings

December 31, 2012 Form 10-K page 18. In February 2013, several state utility commissions and consumer advocates, including the BPU and the New Jersey Division of Rate Counsel, filed a complaint at FERC challenging the base return on equity and formula transmission rate implementation protocols of transmission owners in Maryland, Pennsylvania, Delaware and New Jersey.

While we are not the subject of this complaint nor those reported in our 2012 Form 10-K, the results of these proceedings could set a precedent for the FERC-regulated transmission owners with formula rates in place, such as ours.

Commodity Futures Trading Commission (CFTC)

December 31, 2012 Form 10-K page 18. To implement the Dodd-Frank Act, the CFTC has issued rules defining the term "swap dealer" and "commercial end user." We are subject to record keeping and data reporting requirements applicable to commercial end users, but the CFTC has extended the compliance deadline to be phased in from August 19, 2013 to October 31, 2013. The CFTC also issued rules establishing position limits for trading in certain commodities, such as natural gas, but a federal court vacated these rules. The CFTC has appealed this decision to vacate the position limits rules, which appeal is pending.

Nuclear Regulatory Commission (NRC)

December 31, 2012 Form 10-K page 19. On March 19, 2013, the NRC initiated a rulemaking process for improvements to venting systems at 31 U.S. boiling water reactors (BWRs) with "Mark I" and "Mark II" containments (similar to those at Fukushima), which include our Hope Creek Unit and Peach Bottom Units 2 and 3. The NRC expects to finalize an order by June 2013 requiring Mark I and Mark II licensees to upgrade or replace their reliable hardened vent with a containment venting system designed and installed to remain functional during severe accident conditions. The NRC is also planning to perform a technical evaluation to support rulemaking on filtering within the next year.

STATE REGULATION

Energy Strong Program

December 31, 2012 Form 10-K page 20. In February 2013, we filed a petition with the BPU describing the investments we recommend making to our BPU jurisdictional electric and gas system to harden and improve resiliency for the future. We have submitted information to the BPU with regard to the expected impact of Energy Strong build on customers. The New Jersey Division of Rate Counsel has stated its opposition to certain aspects of our proposal, including implementation without a base rate case. We cannot predict the outcome of this matter which remains pending before the BPU.

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Energy Policy

Solar

PSE&G has reached an agreement with the Staff of the BPU and certain other parties on its proposal to increase spending on renewable energy under its Solar Loan and Solar 4 All investment programs. Under the agreement, which will now be subject to comment by all parties, PSE&G will invest up to $199 million on new solar (98 MW) as part of the Solar Loan III program. The agreement also provides for PSE&G to invest approximately $247 million to develop new solar capacity (42 MW) on landfills and brownfields and 3 MW in smaller pilot programs as part of the Solar 4 All extension. The capital investment would occur over a three year period of time. A decision by the BPU is anticipated no later than May 31, 2013.

BPU Storm Generic Proceedings

In March 2013, the BPU initiated two generic proceedings with the New Jersey utilities, including PSE&G. The first was an Order to evaluate the prudency of storm costs incurred in 2011 and 2012 and the second to evaluate major storm event mitigation proposals. We anticipate that our Energy Strong proposal will be evaluated in the context of this latter generic proceeding.

ENVIRONMENTAL MATTERS

Air Pollution Control

Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation

On March 29 and April 1, 2013, we filed petitions at the EPA and in federal court, respectively, challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued on January 30, 2013. The final EPA rule allows owners and operators of stationary emergency RICE to operate their engines as part of an emergency DR program without the installation and operation of emission controls or compliance with emission limits otherwise applicable to non-emergency counterparts. This waiver of NESHAP standards results in disparate treatment of different generation technology types. In our appeal, we are seeking more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market.

Bridgeport Opacity Litigation

Pursuant to the Clean Air Act (CAA), in January 2013 several environmental groups commenced litigation against us with regard to levels of opacity above the required standard at the Bridgeport Harbor Station. We believe the allegations contain many factual inaccuracies. While we cannot predict the outcome of this litigation, we do not expect any material impact on us.

Hazardous Air Pollutants Regulation

December 31, 2012 Form 10-K page 24. In February 2012**,** the EPA published the NESHAP Mercury Air Toxics Standards (MATS) for both newly-built and existing electric generating sources. In addition, the EPA published revisions to the New Source Performance Standards (NSPS) for newly-built electric generating units. The MATS are scheduled to go into effect on April 16, 2015 for existing sources and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. The NSPS establishes limits for non-hazardous air pollutants such as sulfur dioxide (SO_2), nitrogen oxides (NOx) and particulate matter (PM). In February 2012, members of the electric generating industry filed a petition challenging the MATS for existing electric generating units, the MATS for newly-built electric generating units and the NSPS. The EPA revised the MATS for newly-built electric generating units and the NSPS on March 28, 2013. The litigation regarding the MATS and NSPS remains pending.

Cross-State Air Pollution Rule (CSAPR)

December 31, 2012 Form 10-K page 24. On July 6, 2011, the EPA issued the final CSAPR. CSAPR limits power plant emissions of SO_2 and annual and ozone season NOx in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards (NAAQS).

In August 2012, the Court of Appeals vacated CSAPR and ordered that the existing Clean Air Interstate Rule (CAIR) requirements remain in effect until an appropriate substitute rule has been promulgated. In October 2012, the EPA filed a request for rehearing which the Court denied on January 24, 2013. On March 29, 2013, the EPA, as well as a number of environmental groups, petitioned the Supreme Court for review.

We currently anticipate that CSPAR, if implemented, will not have a material adverse impact to our capital investment program or our units' operations.

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Climate Change

Regional Greenhouse Gas Initiative (RGGI)

December 31, 2012 Form 10-K page 25. Certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions.

These rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three year period (e.g. 2009, 2010, and 2011). Allowances are available through the auction or through secondary markets and were required to be submitted to states by March 2012 for the first compliance period.

On February 7, 2013, the RGGI States released an updated Model Rule that, among other things, reduces the amount of available regional CO_2 allowances beginning in 2014. Each RGGI State must implement the changes through state-specific regulations. We do not expect these changes, or any future changes, to the RGGI rules will have a material impact on us.

Water Pollution Control

Steam Electric Effluent Guidelines

On April 19, 2013, the EPA issued notice of a proposed rule that would further limit the discharge of pollutants in wastewater from the operation of coal-fired generating facilities. Our co-owned Keystone and Conemaugh facilities continue to use technologies that generate these wastewater discharges. However, our other coal-fired facilities no longer discharge many of these types of wastewater pollutants. We are evaluating the proposed rule. We are unable to predict the impact on Keystone and Conemaugh but do not believe there would be any material impact on our other coal-fired facilities.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 10:	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. Power:

Exhibit 10:	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013
Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. PSE&G:

Exhibit 10:	2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: April 30, 2013

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: April 30, 2013

S1-SSA-0009 - 18130

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: April 30, 2013

S1-SSA-0009 - 18131

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EXHIBIT 10

Public Service Enterprise Group Incorporated
2004 Long-Term Incentive Plan
Amended and Restated as of April 16, 2013

1. Purposes.

The purposes of the Public Service Enterprise Group Incorporated 2004 Long-Term Incentive Plan ("Plan") are to promote the growth and profitability of the Company and its Subsidiaries by enabling them to attract and retain the best available personnel for positions of substantial responsibility; to motivate Participants, by means of appropriate incentives, to achieve long-range goals; to provide incentive compensation opportunities that are competitive with those of other similar companies; and to align Participants' interests with those of the Company's shareholders and thereby promote the long-term financial interest of the Company and its Subsidiaries, including the growth in value of the Company's equity and enhancement of long-term shareholder return.

2. Effective Date.

The Plan was effective as of April 20, 2004 and had a term of ten years from its effective date. The Plan was amended effective as of December 1, 2009 to change the provisions of Subsection 8(b) regarding option vesting following a Change in Control.

The Plan is being amended and restated effective as of April 16, 2013 (the "Effective Date") and shall have a term of ten years from the Effective Date, provided that shareholder approval is received on such date. Shareholder approval of the amendment and restatement of the Plan is needed to comply with Code section 162(m).

With respect to Awards granted prior to the Effective Date, the terms of the Plan in effect as of the grant date shall apply. On and after the Effective Date, Options or other awards shall be granted under the terms of the 2013 amendment and restatement. In the event of Plan termination or expiration, any then-outstanding Award shall remain in effect pursuant to the terms of its Award Grant.

3. Definitions.

Capitalized terms used in this Plan have the meanings specified in this Section 3:

"Award" means a grant to a Participant of Options, Stock Appreciation Rights, Restricted Stock, Stock Units, Performance Shares, Performance Share Units, Cash Awards or any combination thereof.

"Award Grant" means the written notification or agreement confirming an Award and setting forth the terms and conditions thereof.

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"Board of Directors" means the Board of Directors of the Company and, when used in the context of actions taken or authorized to be taken by the Board of Directors, means valid actions taken by not less than a quorum of the whole Board of Directors of the Company.

"Cash Award" means the right to receive a Performance Award denominated in cash with the eventual payment amount subject to achievement of goals relating to specified Performance Measures and subject to such other restrictions and conditions as may be established by the Committee.

"Cause" means an act of dishonesty, moral turpitude or an intentional or grossly negligent act, in each case, detrimental to the best interests of the Company or a Subsidiary, including violation of the Company's Standards of Integrity, as determined by the Committee in its sole discretion, and as may be further defined in the Award Grants.

"Change in Control" means the occurrence of any of the following events:

(1) any "Person" (within the meaning of Section 13(d) of the Exchange Act) is or becomes the beneficial owner within the meaning of Rule l3d-3 under the Exchange Act (a "Beneficial Owner"), directly or indirectly, of securities of the Company (not including in the securities beneficially owned by such Person any securities acquired directly from the Company or its affiliates) representing 25% or more of the combined voting power of the Company's then outstanding securities, excluding any Person who becomes such a Beneficial Owner in connection with a transaction described in clause (A) of paragraph (3) below; or

(2) the following individuals cease for any reason to constitute a majority of the number of directors then serving: individuals who, on April 17, 2013, constitute the Board of Directors and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the election of directors of the Company) whose appointment or election by the Board of Directors or nomination for election by the Company's shareholders was approved or recommended by a vote of at least two-thirds (2/3) of the directors then still in office who either were directors on April 17, 2013 or whose appointment, election or nomination for election was previously so approved or recommended; or

(3) there is consummated a merger or consolidation of the Company or any direct or indirect wholly owned Subsidiary of the Company with any other

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corporation, other than (A) a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of the Company or any Subsidiary, at least 75% of the combined voting power of the securities of the Company or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (B) a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no Person is or becomes the Beneficial Owner, directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company's then-outstanding securities; or

(4) the shareholders of the Company approve a plan of complete liquidation or dissolution of the Company or there is consummated an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 75% of the combined voting power of the voting securities of which is owned by shareholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale.

Notwithstanding the foregoing subparagraphs (1), (2), (3) and (4), a "Change in Control" shall not be deemed to have occurred by virtue of the consummation of any transaction or series of integrated transactions immediately following which the record holders of the Common Stock immediately prior to such transaction or series of transactions continue to have substantially the same proportionate ownership in an entity which owns all or substantially all of the assets of the Company immediately following such transaction or series of transactions.

"Code" means the Internal Revenue Code of 1986, as amended, and shall be deemed to include all official guidance issued thereunder.

"Committee" means the Organization and Compensation Committee of the Board of Directors described in Section 4, or any committee or other person or persons designated by the Board of Directors as successor to the powers and duties of the Organization and Compensation Committee as described in Section 4.

"Common Stock" means the Company's authorized Common Stock, no par value, except as this definition may be modified as provided in Section 13.

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"Company" means Public Service Enterprise Group Incorporated, a New Jersey corporation, or any successor thereto.

"Covered Employee" means a person defined as such in Code section 162(m)(3) and regulations and other guidance thereunder.

"Date of Termination" means the first day occurring on or after the date of grant of an Award on which the Participant is not performing services as an Employee for the Company or any Subsidiary, regardless of the reason for cessation of services; provided that a cessation of services shall not be deemed to occur by reason of a transfer of a Participant between the Company and a Subsidiary or between two Subsidiaries; and further provided that a Participant's services shall not be considered terminated while the Participant is on an approved leave of absence from the Company or a Subsidiary. Unless determined otherwise by the Committee, if, as a result of a sale or other transaction, the organization for which a Participant is performing services as an Employee ceases to be the Company or a Subsidiary and the Participant is not, at the end of the 30-day period following the transaction, performing services as an Employee for the Company or an organization that is then a Subsidiary, then the occurrence of such transaction shall be treated as the Participant's Date of Termination.

"Director" means any member of the Board of Directors who is not an Employee.

"Disability" shall have the meaning ascribed to such term in the Company's Long-Term Disability Plan. (regardless of whether the Participant is eligible for benefits under such plan). For the purposes of this Plan, the question of whether a Participant's condition shall be considered a Disability shall be determined in each case by the Committee and such determination by the Committee shall be final.

"Effective Date" shall have the meaning set forth in Section 2.

"Employee" means any employee of the Company or a Subsidiary who is receiving remuneration for personal services rendered to the Company or Subsidiary, including any such person who is an officer of the Company or Subsidiary, other than (1) solely as a director of the Company or a Subsidiary, (2) as a consultant, (3) as an independent contractor, (4) as an individual who is a "leased employee" within the meaning of Code section 414(n), or (5) any other individual engaged by the Company or Subsidiary in a relationship that the Company characterizes as other than an employment relationship or who has waived his rights to coverage as an employee (regardless of whether a determination is made by the Internal Revenue Service or other governmental agency or court after the individual is

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engaged to perform such services that the individual is an employee of the Company or Subsidiary for the purposes of the Code or otherwise).

"Exchange Act" means the Securities Exchange Act of 1934, as amended.

"Exercise Period" means the period beginning on the date on which an Option or Stock Appreciation Right becomes exercisable pursuant to its terms, and ending on the Expiration Date of such Option or Stock Appreciation Right.

"Exercise Price" means the price established by the Committee (or determined according to a method established by the Committee) at the time an Option or Stock Appreciation Right is granted and shall not be less than 100% of the Fair Market Value of a share of Common Stock on the date of grant of the Option or Stock Appreciation Right**.**

"Expiration Date" means, with respect to an Option or Stock Appreciation Right, the date specified in the Award Grant after which such Option or Stock Appreciation Right may not be exercised; provided that the Expiration Date (except as described below or in Section 8) shall not be later than the earliest to occur of:

(i) the ten-year anniversary of the date of grant;

(ii) if the Participant's Date of Termination occurs by reason of Retirement or Disability, the five-year anniversary of such Date of Termination;

(iii) if the Participant's Date of Termination occurs by reason of death, the third-year anniversary of such Date of Termination;

(iv) if the Participant's Date of Termination occurs by reason of involuntary termination without Cause, the 90th day after the Date of Termination;

(v) if the Participant's Date of Termination occurs by reason of involuntary termination for Cause, the Date of Termination;

(vi) if the Participant's Date of Termination occurs voluntarily or for any other reason not described above, the Date of Termination.

The Committee in its sole discretion may establish an Expiration Date later than as described above, but not later than the ten-year anniversary of the date of grant. Notwithstanding the foregoing, if the Participant's Date of Termination occurs by reason of an involuntary termination without Cause and death or Disability occurs after the involuntary termination without Cause and before the otherwise applicable Expiration Date, the Expiration Date for a Non-Statutory Option or a Stock Appreciation Right which was exercisable as a result of death or Disability shall not be earlier than the first anniversary of the date of Date of Termination, but in no event beyond the ten-year anniversary of the date of grant.

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"Fair Market Value" as of any specified date means the closing sale price of the Common Stock on the New York Stock Exchange - Composite Tape on such date or, if there are no sales on such date, on the next preceding day on which there are sales. If the shares are not then listed on the NYSE, and if the shares of Common Stock are then listed on any other national securities exchange or traded on the over-the-counter market, the fair market value shall be the closing price on such exchange or on the NASDAQ National Market System or the mean of the closing bid and asked prices of the shares of Common Stock on the over-the-counter market, as reported by the NASDAQ, the National Association of Securities Dealers OTC Bulletin Board or the National Quotation Bureau, Inc., as the case may be, on such date or, if there is no closing price or bid or asked price on that day, the closing price or mean of the closing bid and asked prices on the most recent day preceding such date for which such prices are available. In all events, with respect to Non-Statutory Options and Stock Appreciation Rights, Fair Market Value shall not be less than fair market value as determined under Code section 409A.

"Incentive Option" means an Option which is intended to be an "incentive stock option'' as defined in Code section 422.

"Non-Statutory Option" means an Option which is not intended to qualify as an Incentive Option as defined above.

"NYSE" means the New York Stock Exchange.

"Option" means an Incentive Option or a Non-Statutory Option granted by the Company pursuant to the Plan to purchase shares of Common Stock at an Exercise Price established by the Committee.

"Participant" means an Employee selected by the Committee to receive an Award. The term shall include any transferee or transferees of any person who has received an Award to the extent the transfer is permitted by the Plan and the applicable Award Grant.

"Performance Award" means an Award of Performance Shares, Performance Share Units and/or a Cash Award.

"Performance Goal" means a target based on Performance Measures that is established by the Committee in connection with a Performance Award. Performance Goals may be established on a corporate-wide basis or with respect to one or more business units, divisions, or Subsidiaries, and may be in either absolute terms or relative to the performance of one or more comparable companies or an index covering multiple companies.

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"Performance Measures" means criteria established by the Committee relating to any of the following: revenue; earnings before interest, taxes, depreciation and amortization (EBITDA); operating income; pre- or after-tax income; cash flow; cash flow per share; net earnings; earnings per share; return on equity; return on invested capital; return on assets; economic value added (or an equivalent metric); share price performance; total shareholder return; improvement in or attainment of expense levels; improvement in or attainment of working capital levels; safety performance; OSHA recordable rate; lost time accident rate; forced outage rate; nuclear capacity factor; INPO rating; availability factor; customer average interruption duration index (CAIDI); system average interruption frequency index (SAIFI); or leak rate per mile. Performance Measures may be applied by excluding the impact of charges for restructurings, discontinued operations, extraordinary items, and other unusual or non-recurring items, and the cumulative effects of accounting changes, each as defined by generally accepted accounting principles.

"Performance Share" means a grant of shares of Common Stock which is contingent on achievement of Performance Goals and satisfaction of such other restrictions and conditions as may be established by the Committee.

"Performance Share Unit" means a grant of a Stock Unit which is contingent on the achievement of Performance Goals and satisfaction of such restrictions and conditions as may be established by the Committee.

"Plan" means this Public Service Enterprise Group Incorporated 2004 Long-Term Incentive Plan, amended and restated as of April 16, 2013.

"Prior Plans" mean the Public Service Enterprise Group Incorporated 1989 Long-Term Incentive Plan and the Public Service Enterprise Group Incorporated 2001 Long-Term Incentive Plan.

"Restricted Stock" means a grant of shares of Common Stock subject to transfer restrictions and a risk of forfeiture or other restrictions that will lapse upon the completion of a period of service by the Participant, or achievement of other objectives, including Performance Goals, as determined by the Committee. Subject to any such forfeiture, and except as may otherwise be determined by the Committee at the time of grant, the Participant shall be currently entitled to dividends on such shares and shall be entitled to vote such shares.

"Restricted Stock Unit" means a grant of a Stock Unit which is subject to transfer restrictions and a risk of forfeiture or other restrictions that will lapse upon the completion of service

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by the Participant, or achievement of other objectives or conditions, as determined by the Committee.

"Retirement" means cessation of services as an Employee for the Company or a Subsidiary by reason of satisfying the criteria for retirement (normal retirement or early retirement) under the provisions of the qualified defined benefit plan of the Company or Subsidiary, in which the Employee participates on the date of the Employee's cessation of services.

"Stock Appreciation Right" means a grant of an Award that will enable the Participant to receive shares of Common Stock or cash equal to the appreciation in value, if any, of the Common Stock between the Fair Market Value of the Common Stock on the date the Stock Appreciation Right is granted and the Fair Market Value of the Common Stock on a future exercise date.

"Stock Unit" means a right to receive a share of Common Stock in the future.

"Subsidiary" means any corporation, limited liability company, partnership, joint venture or other entity during any period in which at least fifty percent of the voting or profits interest is owned, directly or indirectly, by the Company (or by any entity that is a successor to the Company), and any other business venture designated by the Committee in which the Company (or any entity that is a successor to the Company) has a significant interest, as determined in the discretion of the Committee.

"Successor" means the person or persons entitled in lieu of the Participant to receive any shares of Common Stock or other benefits under the Plan by reason of a beneficiary designation, will, laws of intestacy, or family assignments as permitted under the Plan. The Successor of a deceased Participant shall be the person or persons entitled to do so under a beneficiary designation in accordance with Section 11 or, if none, under the Participant's will or, if the Participant shall have failed to designate a beneficiary or make testamentary disposition of such Awards or shall have died intestate, by the Participant's legal representative or representatives.

4. Administration.

The Plan shall be administered by the Organization and Compensation Committee of the Board of Directors which shall consist of not less than three Directors of the Company appointed by the Board of Directors. No person shall be eligible or continue to serve as a member of such Committee unless such person is an "outside director" within the meaning of regulations under Code section 162(m) and a "non-employee director" within the meaning of Exchange Act Rule 16b-3.

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The Committee shall keep minutes of its meetings. The acts of a majority of the members present at any meeting of the Committee at which a quorum is present (as determined under the By Laws of the Company), or acts approved in writing by the entire Committee, shall be the acts of the Committee.

Within the limits of the express provisions of the Plan, the Committee shall have the authority, subject to such orders or resolutions, not inconsistent with the provisions of the Plan, as may from time to time be issued or adopted by the Board of Directors, in its discretion to determine the individuals to whom, and the time or times at which, Awards shall be granted, the type of Award grants, the number of shares of Common Stock to be subject to each Award, the limitations, restrictions and conditions applicable to each Award grant, the terms and provisions of agreements that may be entered into in connection with Award grants (which need not be identical), to interpret the Plan, to prescribe, amend and rescind rules and regulations relating to the Plan and to make all other determinations and take all other actions deemed necessary or advisable for the administration of the Plan.

In making its determinations relating to Award grants, the Committee may consult with the Chief Executive Officer of the Company and may take into account the recommendations of the Chief Executive Officer with respect to grants to be made to other Employees. The Committee may also take into account the nature of the services rendered by such individuals, their present and potential contributions to the Company's success and such other factors as the Committee, in its discretion, shall deem relevant.

The Committee's determinations on the matters regarding this Plan (including matters referred to in this Section 4) shall be conclusive and shall be binding on the Company, its Stockholders, its Affiliates, all Participants, all other Employees and all other persons. Except to the extent prohibited by applicable law or the applicable NYSE rules, the Committee may allocate all or any portion of its responsibilities and powers to any one or more of its members and may delegate all or any part of its responsibilities and powers to the Chief Executive Officer of the Company or a committee of officers of the Company, except with respect to Awards to any Covered Employee or to an officer or other person subject to Section 16 of the Exchange Act. Any such allocation or delegation may be revised or revoked by the Committee at any time.

5. Eligibility.

Subject to the provisions of the Plan, the Committee shall determine and designate, from time to time, those Employees who will be granted one or more Awards under the Plan, and who thereby will become "Participants" in the Plan.

(A) In determining eligibility to receive an Award, as well as in determining the type and amount of the Award to any Participant, the Committee shall consider the position and responsibilities of the Employee being considered, the nature and value to the Company or a Subsidiary of such Employee's services and accomplishments, such

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Employee's present and potential contribution to the success of the Company or its Subsidiaries and such other factors as the Committee may deem relevant.

(B) The Plan does not constitute a contract of employment or for provision of other services, and selection as a Participant will not give any Participant or other individual the right to be retained in the employ of or continue to provide services to the Company or any Subsidiary or give any Participant or other individual any right or claim to any benefit under the Plan, unless such right or claim has specifically accrued under the terms of the Plan, nor shall the Plan in any way interfere with the right of the Company or any Subsidiary to terminate the employment or services of any Participant or other individual at any time.

(C) Neither a Participant nor any other person shall, by reason of participation in the Plan, acquire any right in or title to any assets, funds or property of the Company or any Subsidiary whatsoever, including, without limitation, any specific funds, assets or other property which the Company or any Subsidiary, in its sole discretion, may set aside in anticipation of a liability under the Plan. A Participant shall have only a contractual right to the Common Stock or amounts, if any, payable under the Plan, unsecured by any assets of the Company or any Subsidiary, and nothing contained in the Plan shall constitute a guarantee that the assets of the Company or any Subsidiary shall be sufficient to pay any benefits to any person.

(D) Awards need not be uniform among Participants. The receipt of an Award by a Participant shall not entitle that Participant to receive an Award in the future.

6. Shares Available.

The type and number of shares of Common Stock for which Awards may be granted under the Plan shall be determined in accordance with this Section 6:

(A) The shares of Common Stock with respect to which Awards may be made under the Plan shall be shares authorized but unissued or currently held or shares reacquired by the Company and held as treasury shares, including shares purchased in the open market or in private transactions, all at the time of the Award.

(B) Subject to adjustment as provided in Section 13 herein, the maximum number of shares of Common Stock available for issuance to Participants under the Plan (the "Share Authorization") as of the Effective Date shall be 16,495,807**,** increased by the number of shares attributable to Awards issued under the Plan prior to the Effective Date that become available under the Plan on and after the Effective Date. This amendment and restatement of the Plan does not include any additional shares that were not available for issuance under the Plan on the date immediately preceding the Effective Date, other than the shares attributable to Awards issued under the Plan prior to the Effective Date that become available under the Plan on and after the Effective Date.

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(C) Subject to Section 13, the following additional maximums are imposed under the Plan:

(1)The maximum number of shares of Common Stock that may be issued by Options intended to be Incentive Options shall be one million (1,000,000).

(2) The maximum number of shares of Common Stock that may be issued by Options that are not intended to be Incentive Options shall be, in the aggregate, fifty percent (50%) of the total shares reserved for Awards pursuant to paragraph (B) above.

(3) The maximum number of shares of Common Stock that may be issued in conjunction with Awards granted pursuant to Section 9 (relating to Other Stock Awards) and Section 10 (relating to Performance Shares and Performance Share Units) shall be, in the aggregate, fifty percent (50%) of the total shares reserved for Awards pursuant to paragraph (B) above.

(4) The maximum number of shares that may be covered by Awards granted to any one individual pursuant to this Plan shall be five hundred thousand (500,000) shares during any calendar year.

(5) For Cash Awards that are intended to be "performance-based compensation" (within the meaning of regulations under Code section 162(m)), the maximum Awards payable in cash to any one individual for a 36-month performance period shall not exceed ten million dollars ($10,000,000). Such maximum shall be reduced proportionately in the case of a performance period of less than 36 months and shall be increased proportionately for a performance period of longer than 36 months (but no further adjustment shall be made in the case of a performance period of greater than 60 months). If, after an amount has been earned with respect to a Cash Award, the delivery of such amount is deferred pursuant to Section 7(B), any additional amount attributable to earnings during the deferral period shall be disregarded for purposes of this limitation.

(D) Shares of Common Stock covered by an Award shall only be counted as used to the extent they are actually issued and delivered to a Participant, or, if permitted by the Committee, a Participant's designated transferee. Any shares of Common Stock related to Awards which terminate by expiration, forfeiture, cancellation, or otherwise without the issuance, are settled in cash in lieu of shares, or are exchanged with the Committee's permission, prior to the issuance of the Common Stock, for Awards not involving shares of Common Stock, shall be available again for grant under the Plan. Moreover, if the Exercise Price of any Option granted under the Plan or the tax withholding requirements with respect to any Award granted under the Plan are satisfied by tendering shares of Common Stock to the Company (by either actual delivery or by attestation), or if a Stock Appreciation Right is exercised, only the number of shares of Common Stock issued, net of the shares tendered, if any, will be deemed delivered for purposes of determining the maximum number of shares

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of Common Stock available for delivery under the Plan. The maximum number of shares of Common Stock available for issuance under the Plan shall not be reduced to reflect any dividends or dividend equivalents that are reinvested into additional shares or credited as additional Restricted Stock, Restricted Stock Units, Performance Shares, Performance Share Units or Other Stock-Based Awards.

7. Awards.

The Committee shall have full and complete authority, in its discretion, subject to the provisions of the Plan, to grant Awards to Participants consisting of Options, Stock Appreciation Rights, Restricted Stock, Stock Units, Performance Shares, Performance Share Units, Cash Awards or any combination thereof, as more fully described in Sections 8 through 10, subject to such terms and conditions as the Committee deems appropriate. Awards may be granted singly, in combination or in tandem so that the settlement or payment of one automatically reduces or cancels the other. Awards may also be made in combination or in tandem with, in replacement of, as alternatives to, or as the payment form for, grants or rights under any other compensation plan of the Company or any Subsidiary, including the plan of any acquired entity. The Committee may permit or require that any Award be prorated to the date of any termination of employment.

(A) Dividends and Dividend Equivalents

The Committee may provide that Awards denominated in Common Stock earn dividends or dividend equivalents. Such dividend equivalents may be paid currently in cash or shares of Common Stock or may be credited to an account established by the Committee under the Plan in the name of the Participant. In addition, dividends or dividend equivalents paid on outstanding awards or issued shares may be credited to such account rather than paid currently. Any crediting of dividends or dividend equivalents may be subject to such restrictions and conditions as the Committee may establish, including reinvestment in additional shares or share equivalents.

(B) Deferrals

The Committee may require or permit Participants to elect to defer the issuance of shares or the settlement of Awards in cash under such rules and procedures as it may establish under the Plan or otherwise. It may also provide that deferred settlements include the payment or crediting of interest on the deferral amounts, conversion of deferred amounts into deferred Common Stock equivalents, or the payment or crediting of dividend equivalents on deferred settlements denominated in shares.

If a Participant elects to defer the issuance of shares of a Restricted Stock Unit or a Performance Share Unit, he or she must make such deferral election under the terms of the Public Service Enterprise Group Equity Deferral Plan.

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(C) Settlements

Settlement of Awards may be in the form of cash, shares of Common Stock, other Awards, or in such combinations thereof as the Committee shall determine at the time of grant, and with such restrictions as it may impose.

8. Options and Stock Appreciation Rights.

The Committee may grant Options containing such terms and conditions as shall be requisite, in the judgment of the Committee, to constitute either Incentive Options or Non-Statutory Options. Incentive and Non-Statutory Options shall be identified as such in the Award Grant. The Committee may grant Stock Appreciation Rights either (i) independently of Options or (ii) in tandem with Options such that the exercise of the Option or Stock Appreciation Right with respect to a share of Common Stock cancels the tandem Stock Appreciation Right or Option, respectively, with respect to such share. The grant of each Option or Stock Appreciation Right shall be confirmed in writing by an Award Grant in the form prescribed by the Committee.

(A) Exercise Price.

At the time an Option or Stock Appreciation Right is granted, the Committee shall determine the Exercise Price. Except for adjustments as provided in Section 13, the Exercise Price for any outstanding Option or Stock Appreciation Right may not be decreased after the date of grant nor may any outstanding Option or Stock Appreciation Right be surrendered to the Company as consideration for the grant of a new Option or Stock Appreciation Right with a lower Exercise Price.

Notwithstanding any provision in the Plan to the contrary, an outstanding Option or Stock Appreciation Right may not be (i) modified to reduce the Exercise Price thereof nor may a new Option or Stock Appreciation Right at a lower price be substituted for a surrendered Option or Stock Appreciation Right (other than adjustments or substitutions in accordance with Section 13), or (ii) repurchased by the Company if the per share option price of the Option or Stock Appreciation Right is less than the Fair Market Value of a share of Common Stock (other than a cancellation for no value in accordance with Section 15), unless such action is approved by the Stockholders of the Company.

(B) Exercise Period.

Each Option or Stock Appreciation Right granted under this Plan shall be exercisable during such period and under such circumstances as the Committee shall determine, subject to the following rules:

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(1) An Option or Stock Appreciation Right must be exercised prior to the Expiration Date.

(2) Each Option or Stock Appreciation Right shall become exercisable upon the occurence of a Change in Control unless it is replaced by the same type of award of equivalent value provided by the continuing entity, which replacement award vests not later than the outstanding Option or Stock Appreciation Right and, to the extent not previously vested, vests in full in the event the Participant's employment is involuntarily terminated, other than for Cause, within twenty-four months following the Change in Control whether or not otherwise then exercisable under the provisions of the applicable Award Grant relating thereto.

(3) The effect of a Participant's cessation of performance of services as an Employee for the Company or a Subsidiary shall be as follows:

(i) *Retirement.* If cessation of performance of services as an Employee is the result of Retirement, the Participant may exercise any outstanding Option or Stock Appreciation Right that had become exercisable under the terms of the applicable Award Grant prior to the Date of Termination before the Expiration Date.

(ii) *Death.* If a Participant dies while the Participant is continuing to perform services as an Employee for the Company or a Subsidiary, or during the period following Retirement and before the Expiration Date, the Successor may exercise the Participant's Options or Stock Appreciation Rights at any time prior to the Expiration Date, whether or not such Options or Stock Appreciation Rights were exercisable on the date of the Participant's death under the applicable Award Grant.

(iii) *Disability.* If the Committee determines that a Participant ceased to perform services as an Employee for the Company or a Subsidiary because of Disability, any Option or Stock Appreciation Right held by such Participant on the Date of Termination may be exercised (whether or not such Option or Stock Appreciation Right was exercisable on the Date of Termination under the provisions of the Award Grant relating thereto) at any time prior to the Expiration Date.

(iv) *Involuntary Termination without Cause.* If the Company or a Subsidiary terminates the Participant's employment services involuntarily without Cause, as determined in the sole discretion of the Committee, then the Participant may exercise any outstanding

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Option or Stock Appreciation Right which was vested on the Date of Termination at any time before the Expiration Date.

(v) *Involuntary Termination for Cause.* If the Participant ceases to perform services as an Employee for the Company or a Subsidiary involuntarily for Cause, any outstanding Option or Stock Appreciation Right held by such Participant shall be immediately cancelled.

(vi) *Other Termination.* If the Participant ceases to perform services for the Company or a Subsidiary for any reason other than as set forth in subparagraphs (i) through (v) above, any outstanding Option or Stock Appreciation Right held by such Participant shall be immediately cancelled.

(C) Exercise Procedures.

Each Option or Stock Appreciation Right granted under this Plan may be exercised to the extent exercisable, in whole or in part at any time during the Exercise Period, for such number of shares as shall be prescribed by the provisions of the Award Grant evidencing such Option or Stock Appreciation Right, provided that:

(1) An Option or Stock Appreciation Right may be exercised by the Participant or a Successor only by written notice (in the form prescribed by the Committee) to the Company specifying the number of shares to which such notice applies.

(2) The aggregate Exercise Price of the shares as to which an Option may be exercised shall be, in the discretion of the Committee, (a) paid in U.S. funds by any one or any combination of the following: cash, (including check, draft or wire transfer made payable to the order of the Company), or delivery of Common Stock certificates endorsed in blank or accompanied by executed stock powers with signatures guaranteed by a national bank or trust company or a member of a national securities exchange evidencing shares of Common Stock whose value shall be deemed to be the Fair Market Value on the date of exercise of such Common Stock, or (b) deemed to be paid in full provided the notice of the exercise of an Option is accompanied by a copy of irrevocable instructions to a broker to promptly deliver to the Company the amount of sale or loan proceeds sufficient to cover the Exercise Price or (c) paid upon such terms and conditions, including provision for securing the payment of the same, as the Committee, in its discretion, shall provide. Exercise of an Option shall be contingent upon the satisfaction of applicable withholding taxes. Payment of applicable taxes shall be effectuated in the same manner as the Exercise Price is paid.

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(3) As soon as practicable after receipt by the Company of notice of exercise and of payment in full of the Exercise Price of the shares with respect to which an Option has been exercised, a certificate or certificates representing such shares (which may be in book entry form) shall be recorded on the records of the Company (or its transfer agents or registrars) in the name or names of the Participant or Successor and shall be delivered to the Participant, Participant's agent or Successor (including through electronic delivery to a brokerage account).

(D) Special Rules Relating to Incentive Options.

(1) No Incentive Option may be granted to an individual who is not an Employee of the Company or a Subsidiary.

(2) The aggregate Fair Market Value (determined as of the time the Option is granted) of the Common Stock with respect to which Incentive Options are exercisable for the first time during any calendar year by an Employee under all plans of the Company and its Subsidiaries shall not exceed the greater of $100,000 or such sum as may from time to time be permitted under Code section 422.

9. Other Stock Awards.

The Committee may make Awards consisting of Restricted Stock or Stock Units containing such terms and conditions, and subject to such restrictions and contingencies as the Committee shall determine, subject to the provisions of the Plan. Unless otherwise authorized by the Committee, as a condition of receiving an Award consisting of Restricted Stock, a Participant must waive in writing the right to make an election under Code section 83(b) to report the value of the Restricted Stock as income on the Date of Grant. If the right to become vested in a Restricted Stock Award granted under this Section 9 is conditioned on the completion of a specified period of service as an Employee with the Company or the Subsidiaries, without achievement of Performance Measures or other performance objectives being required as a condition of vesting, and without it being granted in lieu of other compensation or to replace forfeited awards from a prior service recipient, then, unless otherwise determined by the Committee and set forth in a Participant's Award Grant, the required period of service for full vesting shall be not less than three years. Notwithstanding the foregoing, the Committee has the discretion to accelerate the vesting of an Award upon the occurrence of certain circumstances, including but not limited to, the Participant's Retirement, death, Disability, or termination by the Company without Cause. The circumstances which result in accelerated vesting shall be set forth in the Participant's Award Grant.

In the event of a Change in Control, unless such Award is replaced by the same type of award of equivalent value provided by the continuing entity which replacement award vests not later than the replaced Award and, to the extent not previously vested, the Award vests in full in the event of

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any involuntary cessation of performance of services for the continuing entity within the twenty-four month period following the Change in Control (other than involuntary termination for Cause).

10. Performance Awards.

The Committee may make Awards consisting of Performance Shares or Performance Share Units, containing such terms and conditions, and subject to such restrictions and contingencies as the Committee shall determine, subject to the provisions of the Plan. Performance Awards shall be conditioned on the achievement of Performance Goals, based on one or more Performance Measures, as determined by the Committee, over a performance period (not less than one year) prescribed by the Committee. For Awards under this Section 10 intended to be "performance-based compensation" within the meaning of regulations under Code section 162(m), the grant of the Awards and the performance goals shall be made during the period required under Code section 162(m). In the event that a Change in Control occurs after a Performance Award has been granted but before completion of the performance period, a pro-rata portion of such Award shall become payable as of the date of the Change in Control to the extent otherwise earned on the basis of achievement of the pro-rata portion of the Performance Goals relating to the portion of the performance period completed as of the date of the Change in Control. Notwithstanding the foregoing, if a Change in Control occurs that does not constitute a "change in control" under Code section 409A, the pro-rata portion of such Award shall be paid on the date that such Award would have been paid had a Change in Control not occurred. Unless otherwise directed by the Committee, as a condition of receiving an Award consisting of Performance Shares, a Participant must waive in writing the right to make an election under Code section 83(b) to report the value of the Performance Shares as income on the Date of Grant.

11. Non-Transferability.

Unless otherwise designated by the Committee to the contrary, each Award granted under the Plan shall by its terms be non-transferable by the Participant (except by will or the laws of descent and distribution). An Option or Stock Appreciation Right shall be exercisable during the Participant's lifetime only by the Participant, his or her guardian or legal representative or by such other means as the Committee may approve from time to time that is not inconsistent with or contrary to the provisions of either Section 16(b) of the Exchange Act or Rule 16b-3, as either may be amended from time to time, or any law, rule, regulation or other provision that may hereafter replace such Rule. A Participant may also designate a beneficiary to exercise his or her Awards after the Participant's death. The Committee may amend outstanding Awards to provide for transfer, without payment of consideration, to immediate family members of the Participant or to trusts or partnerships for such family members.

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12. Listing and Registration of Shares and Restrictions on Shares.

If at any time the Board of Directors shall determine, in its discretion, that the listing, registration or qualification of any of the shares subject to Awards under the Plan upon any securities exchange or under any state or federal law, or the consent or approval of any governmental regulatory body, is necessary or desirable as a condition of or in connection with the purchase or issue of shares thereunder, no outstanding Awards which would result in the purchase or issuance of shares may be exercised or otherwise settled unless such listing, registration, qualification, consent or approval shall have been effected or obtained free of any conditions not acceptable to the Board of Directors or the Committee. The Board of Directors or the Committee may require any Participant to make such representations and furnish such information as it may consider appropriate in connection with the issuance or delivery of the shares in compliance with applicable law and shall have the authority to cause the Company at its expense to take any action related to the Plan which may be required in connection with such listing, registration, qualification, consent or approval.

The Committee may impose such restrictions on any shares acquired pursuant to Restricted Stock Awards as it may deem advisable, including, without limitation, restrictions to comply with applicable Federal securities laws, with the requirements of any stock exchange or market upon which such shares are then listed and/or traded and with any blue sky or state securities laws applicable to such shares.

Certificates representing shares subject to Restricted Stock Awards may bear a legend substantially as follows:

> The sale or other transfer of the shares of stock represented by this certificate, whether voluntary, involuntary or by operation of law, is subject to certain restrictions on transfer as set forth in the Public Service Enterprise Group Incorporated 2004 Long-Term Incentive Plan, and in an award document. A copy of such Plan and award documents may be obtained from Public Service Enterprise Group Incorporated.

The Company shall have the right to retain (or escrow) certificates or shares that are subject to Restricted Stock Awards until such time as all restrictions applicable to such shares have been satisfied. Shares subject to Restricted Stock Awards shall become freely transferrable (subject to applicable laws and Company imposed trading restrictions), and legends on share certificates shall be removed, once all restrictions applicable to such shares have been satisfied.

All Awards made under this Plan are specifically made with the proviso that the Company may institute clawback and/or other forfeiture provisions as may be required by law, listing requirements or Company policy, including such provisions that are instituted with respect to Awards that are issued prior to implementation of such law, listing requirements or Company policy.

The Committee may require Participants to execute stock powers or other similar instruments in order to facilitate the return to the Company of shares upon forfeiture of Restricted Stock Awards.

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Neither the Participant nor his or her Successor will have any of the rights or privileges of a shareholder of the Company in respect of any shares deliverable hereunder unless and until certificates representing such shares (which may be in book entry form) will have been issued and recorded on the records of the Company or its transfer agents or registrars, and delivered to the Participant (including through electronic delivery to a brokerage account).

13. Adjustments.

The Committee may make such adjustments as it deems appropriate to meet the intent of the Plan in the event of changes that impact the Company's share price or share status, provided that any such actions are consistently and equitably applicable to all affected Participants and provided, further, that no such adjustment shall be made to Awards to Covered Employees if it would cause such Awards to no longer qualify as "performance-based compensation" for purposes of Code section 162(m).

In the event of any stock dividend, stock split, combination or exchange of shares, merger, consolidation, spin-off or other distribution (other than normal cash dividends) of Company assets to shareholders, or any other change affecting shares, such adjustments, if any, as the Committee in its discretion may deem appropriate to reflect such change shall be made with respect to (i) the aggregate number of shares that may be issued under the Plan or that may be subject to Awards of a specified type and/or to any individual; (ii) the number of shares covered by outstanding Awards to any individual under the Plan; and/or (iii) the applicable price per share with respect to any outstanding Options, Stock Appreciation Rights and other Awards under the Plan.

14. Tax Withholding.

Delivery of any cash, shares, dividends or any other benefits under the Plan is subject to withholding of applicable taxes. The Committee unilaterally or by arrangement with the Participant or Successor shall make appropriate provision for satisfaction of withholding taxes in the case of any transaction under the Plan, which gives rise to a withholding requirement. The Committee, in its discretion, and subject to such requirements as the Committee may impose prior to the occurrence of such withholding, may permit such withholding obligations to be satisfied through cash payment by the Participant, through the surrender of shares of Common Stock which the Participant already owns or (to the extent of minimum statutory withholding requirements) through withholding of shares of Common Stock to which the Participant is otherwise entitled under the Plan.

15. Amendments and Termination.

The Board of Directors may amend this Plan as it shall deem advisable, except that the Board of Directors may not, without further approval of the shareholders of the Company, (a) increase the total number of shares of Common Stock which may be issued under the Plan as set forth in Section 6(B) or the maximum number of shares that may be issued, as Awards pursuant to Sections 8 through 10, to any individual, or (b) change the class of individuals eligible for Awards. The Board of

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Directors may, in its discretion, terminate this Plan at any time. No amendment or termination may, in the absence of written consent to the amendment or termination by the affected Participant (or, if the Participant is not then living, the affected Successor), adversely affect the rights of any Participant or Successor under any Award granted under the Plan prior to the date such amendment or termination is effective, provided that adjustments pursuant to Section 13 are not subject to such limitation. Subject to the foregoing and the requirements of Code section 162(m), the Board of Directors may without further action on the part of the shareholders of the Company or the consent of Participants, amend the Plan to preserve the Company's tax deduction under Code section 162(m).

16. Foreign Jurisdictions.

The Committee may, from time to time, adopt, amend, and terminate under the Plan such arrangements, not inconsistent with the intent of the Plan, as it may deem necessary or desirable, to make available tax or other benefits of laws of any foreign jurisdiction to Participants who are subject to such laws and who receive Awards under the Plan.

17. Compliance with Code sections 162(m) and 409A.

With respect to Covered Employees, transactions under the Plan are intended to avoid loss of the deduction referred to in paragraph (1) of Code section 162(m). Anything in the Plan or elsewhere to the contrary notwithstanding, to the extent any provision of the Plan or action by the Committee would result in the loss of such deduction, it shall be deemed null and void as relates to Covered Employees, to the extent permitted by law and deemed advisable by the Committee.

With respect to performance-based compensation, the Company intends to comply with Code section 162(m). However, for business reasons, there may be instances where the Committee decides that certain grants of performance-based compensation will not comply with Code section 162(m).

The Company intends that this Plan shall comply with the requirements of Code section 409A, and it shall be interpreted and administered accordingly. To the extent that Code section 409A applies, the date of a termination of employment shall be determined in accordance with the separation from service rules under Code section 409A.

18. Notices.

All notices under the Plan shall be in writing, and if to the Company, shall be delivered to the Secretary of the Company or mailed to its principal office, 80 Park Plaza, Newark, New Jersey 07102, addressed to the attention of the Secretary; and if to the Participant, shall be delivered personally or mailed to the Participant at the address appearing in the payroll records of the Company or Subsidiary or, if applicable, to the Participant's Successor at the last known address appearing in the records of the Company. Such addresses may be changed at any time by written notice to the other party.

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19. General.

Except where otherwise indicated by the context, any masculine term used herein shall also include the feminine; the singular shall include the plural and the plural shall include the singular.

The titles and headings of the sections of the Plan are for convenience of reference only and, in the event of any conflict, the text of the Plan, rather than such titles or headings, shall control.

If any part of the Plan is declared to be unlawful or invalid, such unlawfulness or invalidity shall not invalidate any other part of the Plan. Any part of the Plan so declared to be unlawful or invalid shall, if possible, be construed in a manner that will give effect to the terms of such part to the fullest extent possible while remaining lawful and valid.

The provisions of the Plan shall take precedence over any conflicting provision contained in an Award. All matters relating to the Plan or an Award granted hereunder shall, to the extent not preempted by Federal law, be governed and construed in accordance with the laws of the State of New Jersey, without regard to the principles of conflict of laws.

The Plan and Award Grants shall be binding on Successors and on successors to the Company, whether the existence of such successor to the Company is the result of a direct or indirect purchase of all or substantially all of the business and/or assets of the Company, or a merger, consolidation, or otherwise.

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Month Ended March 31,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 540	$ 705	$ 2,011	$ 2,384	$ 2,616	$ 2,636	$ 1,806
(Income) Loss from Equity Investees, net of Distributions	5	1	9	(4)	(19)	(25)	(5)
Fixed Charges	115	116	479	522	571	600	633
Capitalized Interest	(3)	(6)	(19)	(14)	(67)	(45)	(37)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	(2)	(6)	(6)
Total Earnings	$ 657	$ 816	$ 2,480	$ 2,888	$ 3,099	$ 3,160	$ 2,391
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 111	$ 113	$ 465	$ 509	$ 555	$ 581	$ 615
Interest Factor in Rentals	4	3	14	13	14	13	12
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	2	6	6
Total Fixed Charges	$ 115	$ 116	$ 479	$ 522	$ 571	$ 600	$ 633
Ratio of Earnings to Fixed Charges	5.71	7.03	5.18	5.53	5.43	5.27	3.78

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12.1

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 228	$ 421	$ 1,080	$ 1,687	$ 1,914	$ 1,958	$ 1,711
Fixed Charges	36	39	163	208	238	221	210
Capitalized Interest	1	(4)	(4)	(10)	(62)	(43)	(31)
Total Earnings	$ 265	$ 456	$ 1,239	$ 1,885	$ 2,090	$ 2,136	$ 1,890
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 35	$ 39	$ 161	$ 205	$ 235	$ 219	$ 208
Interest Factor in Rentals	1	—	2	3	3	2	2
Total Fixed Charges	$ 36	$ 39	$ 163	$ 208	$ 238	$ 221	$ 210
Ratio of Earnings to Fixed Charges	7.36	11.69	7.60	9.06	8.78	9.67	9.00

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 304	$ 279	$ 835	$ 861	$ 591	$ 551	$ 592
Fixed Charges	79	76	314	319	325	317	325
Capitalized Interest	(4)	(2)	(13)	(4)	(2)	(1)	—
Total Earnings	$ 379	$ 353	$ 1,136	$ 1,176	$ 914	$ 867	$ 917
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 77	$ 75	$ 308	$ 314	$ 320	$ 313	$ 325
Interest Factor in Rentals	2	1	6	5	5	4	—
Total Fixed Charges	$ 79	$ 76	$ 314	$ 319	$ 325	$ 317	$ 325
Ratio of Earnings to Fixed Charges	4.80	4.64	3.62	3.69	2.81	2.74	2.82

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.3

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Three Months Ended March 31,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 304	$ 279	$ 835	$ 861	$ 591	$ 551	$ 592
Fixed Charges	79	76	314	319	327	323	332
Capitalized Interest	(4)	(2)	(13)	(4)	(2)	(1)	—
Preferred Securities Dividend Requirements	—	—	—	—	(2)	(6)	(6)
Total Earnings	$ 379	$ 353	$ 1,136	$ 1,176	$ 914	$ 867	$ 918
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 77	$ 75	$ 308	$ 314	$ 320	$ 313	$ 325
Interest Factor in Rentals	2	1	6	5	5	4	—
Preferred Securities Dividend	—	—	—	—	1	4	4
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	—	—	1	2	2
Total Fixed Charges	$ 79	$ 76	$ 314	$ 319	$ 327	$ 323	$ 331
Ratio of Earnings to Fixed Charges	4.80	4.64	3.62	3.69	2.80	2.68	2.77

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2013

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2013

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2013

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2013

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2013

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2013

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
April 30, 2013

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer
April 30, 2013

S1-SSA-0009 - 18164

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
April 30, 2013

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Caroline Dorsa

Caroline Dorsa

PSEG Power LLC
Chief Financial Officer
April 30, 2013

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
April 30, 2013

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer
April 30, 2013

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED March 31, 2014
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of April 15, 2014, Public Service Enterprise Group Incorporated had outstanding 505,928,448 shares of its sole class of Common Stock, without par value.

As of April 15, 2014, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words “anticipate,” “intend,” “estimate,” “believe,” “expect,” “plan,” “should,” “hypothetical,” “potential,” “forecast,” “project,” variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission in the future, and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to balance our energy obligations, available supply and risks,
- any deterioration in our credit quality or the credit quality of our counterparties,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as competition for certain transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements, and
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies and changes in customer behaviors, including energy efficiency, net-metering and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended March 31,	
	2014	**2013**
OPERATING REVENUES	$ 3,223	$ 2,786
OPERATING EXPENSES		
Energy Costs	1,356	1,155
Operation and Maintenance	856	710
Depreciation and Amortization	306	290
Taxes Other Than Income Taxes	—	21
Total Operating Expenses	2,518	2,176
OPERATING INCOME	705	610
Income from Equity Method Investments	4	2
Other Income	48	61
Other Deductions	(12)	(29)
Other-Than-Temporary Impairments	(2)	(2)
Interest Expense	(97)	(102)
INCOME BEFORE INCOME TAXES	646	540
Income Tax Expense	(260)	(220)
NET INCOME	$ 386	$ 320
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):		
BASIC	506,077	505,942
DILUTED	507,831	507,220
NET INCOME PER SHARE:		
BASIC	$ 0.76	$ 0.63
DILUTED	$ 0.76	$ 0.63
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.37	$ 0.36

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2014	**2013**
NET INCOME	$ 386	$ 320
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(3) and $(27) for 2014 and 2013, respectively	2	27
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(2) and $2 for 2014 and 2013, respectively	2	(4)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(2) and $(7) for 2014 and 2013, respectively	4	10
Other Comprehensive Income (Loss), net of tax	8	33
COMPREHENSIVE INCOME	$ 394	$ 353

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 655	$ 493
Accounts Receivable, net of allowances of $61 and $56 in 2014 and 2013, respectively	1,710	1,203
Tax Receivable	111	109
Unbilled Revenues	261	300
Fuel	271	545
Materials and Supplies, net	475	479
Prepayments	55	89
Derivative Contracts	43	98
Deferred Income Taxes	114	24
Regulatory Assets	125	243
Other	33	31
Total Current Assets	3,853	3,614
PROPERTY, PLANT AND EQUIPMENT	30,152	29,713
Less: Accumulated Depreciation and Amortization	(8,219)	(8,068)
Net Property, Plant and Equipment	21,933	21,645
NONCURRENT ASSETS		
Regulatory Assets	2,570	2,612
Regulatory Assets of Variable Interest Entities (VIEs)	414	476
Long-Term Investments	1,321	1,313
Nuclear Decommissioning Trust (NDT) Fund	1,734	1,701
Long-Term Receivable of VIE	418	—
Other Special Funds	635	613
Goodwill	16	16
Other Intangibles	48	33
Derivative Contracts	47	163
Restricted Cash of VIEs	24	24
Other	313	312
Total Noncurrent Assets	7,540	7,263
TOTAL ASSETS	$ 33,326	$ 32,522

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2014	December 31, 2013
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 544	$ 544
Securitization Debt of VIEs Due Within One Year	242	237
Commercial Paper and Loans	—	60
Accounts Payable	1,116	1,222
Derivative Contracts	75	76
Accrued Interest	112	95
Accrued Taxes	311	37
Clean Energy Program	85	142
Obligation to Return Cash Collateral	134	119
Regulatory Liabilities	159	43
Other	579	488
Total Current Liabilities	3,357	3,063
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	7,148	7,107
Regulatory Liabilities	172	233
Regulatory Liabilities of VIEs	11	11
Asset Retirement Obligations	687	677
Other Postretirement Benefit (OPEB) Costs	1,081	1,095
OPEB Costs of Servco	307	—
Accrued Pension Costs	122	121
Accrued Pension Costs of Servco	109	—
Environmental Costs	400	414
Derivative Contracts	28	31
Long-Term Accrued Taxes	186	180
Other	116	119
Total Noncurrent Liabilities	10,367	9,988
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	7,586	7,587
Securitization Debt of VIEs	200	259
Project Level, Non-Recourse Debt	16	16
Total Long-Term Debt	7,802	7,862
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2014 and 2013—533,556,660 shares	4,856	4,861
Treasury Stock, at cost, 2014— 27,680,836 shares; 2013— 27,699,398 shares	(626)	(615)
Retained Earnings	7,656	7,457
Accumulated Other Comprehensive Loss	(87)	(95)
Total Common Stockholders' Equity	11,799	11,608
Noncontrolling Interest	1	1
Total Stockholders' Equity	11,800	11,609
Total Capitalization	19,602	19,471
TOTAL LIABILITIES AND CAPITALIZATION	$ 33,326	$ 32,522

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2014	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 386	$ 320
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	306	290
Amortization of Nuclear Fuel	54	50
Provision for Deferred Income Taxes (Other than Leases) and ITC	(39)	(5)
Non-Cash Employee Benefit Plan Costs	11	61
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(22)	(6)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	224	165
Change in Accrued Storm Costs	(1)	(46)
Net Change in Other Regulatory Assets and Liabilities	177	80
Cost of Removal	(25)	(24)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(23)	(24)
Net Change in Certain Current Assets and Liabilities	80	207
Employee Benefit Plan Funding and Related Payments	(32)	(192)
Other	20	1
Net Cash Provided By (Used In) Operating Activities	1,116	877
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(609)	(724)
Proceeds from Sales of Available-for-Sale Securities	257	258
Investments in Available-for-Sale Securities	(269)	(271)
Other	(8)	4
Net Cash Provided By (Used In) Investing Activities	(629)	(733)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(60)	(98)
Issuance of Long-Term Debt	—	400
Redemption of Long-Term Debt	—	(150)
Redemption of Securitization Debt	(54)	(51)
Cash Dividends Paid on Common Stock	(187)	(182)
Other	(24)	(22)
Net Cash Provided By (Used In) Financing Activities	(325)	(103)
Net Increase (Decrease) in Cash and Cash Equivalents	162	41
Cash and Cash Equivalents at Beginning of Period	493	379
Cash and Cash Equivalents at End of Period	$ 655	$ 420
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 15	$ 3
Interest Paid, Net of Amounts Capitalized	$ 79	$ 82
Accrued Property, Plant and Equipment Expenditures	$ 247	$ 265

See Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2014	**2013**
OPERATING REVENUES	$ 1,700	$ 1,451
OPERATING EXPENSES		
Energy Costs	1,044	860
Operation and Maintenance	302	283
Depreciation and Amortization	72	66
Total Operating Expenses	1,418	1,209
OPERATING INCOME	282	242
Income from Equity Method Investments	4	3
Other Income	33	47
Other Deductions	(10)	(28)
Other-Than-Temporary Impairments	(2)	(2)
Interest Expense	(32)	(30)
INCOME BEFORE INCOME TAXES	275	232
Income Tax Expense	(111)	(91)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 164	$ 141

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2014	**2013**
NET INCOME	$ 164	$ 141
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(2) and $(27) for 2014 and 2013, respectively	2	27
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(1) and $2 for 2014 and 2013, respectively	1	(4)
Pension/OPEB adjustment, net of tax (expense) benefit of $(2) and $(5) for 2014 and 2013, respectively	3	9
Other Comprehensive Income (Loss), net of tax	6	32
COMPREHENSIVE INCOME	$ 170	$ 173

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 10	$ 6
Accounts Receivable	544	338
Accounts Receivable—Affiliated Companies, net	36	333
Short-Term Loan to Affiliate	942	790
Fuel	271	545
Materials and Supplies, net	347	362
Derivative Contracts	27	57
Prepayments	15	13
Deferred Income Taxes	105	30
Other	2	2
Total Current Assets	2,299	2,476
PROPERTY, PLANT AND EQUIPMENT	10,372	10,278
Less: Accumulated Depreciation and Amortization	(3,037)	(2,911)
Net Property, Plant and Equipment	7,335	7,367
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,734	1,701
Long-Term Investments	123	123
Goodwill	16	16
Other Intangibles	48	33
Other Special Funds	148	139
Derivative Contracts	9	72
Other	76	75
Total Noncurrent Assets	2,154	2,159
TOTAL ASSETS	$ 11,788	$ 12,002

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18180

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2014	December 31, 2013
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 44	$ 44
Accounts Payable	490	516
Derivative Contracts	67	76
Accrued Interest	43	28
Other	137	136
Total Current Liabilities	781	800
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	2,044	2,031
Asset Retirement Obligations	405	400
Other Postretirement Benefit (OPEB) Costs	209	206
Derivative Contracts	28	31
Accrued Pension Costs	35	35
Long-Term Accrued Taxes	49	53
Other	87	91
Total Noncurrent Liabilities	2,857	2,847
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT		
Total Long-Term Debt	2,497	2,497
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,482	4,693
Accumulated Other Comprehensive Loss	(57)	(63)
Total Member's Equity	5,653	5,858
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 11,788	$ 12,002

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2014	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 164	$ 141
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	72	66
Amortization of Nuclear Fuel	54	50
Provision for Deferred Income Taxes and ITC	(71)	(33)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	224	165
Non-Cash Employee Benefit Plan Costs	3	17
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(23)	(24)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	289	259
Margin Deposit	(261)	(117)
Accounts Receivable	(19)	2
Accounts Payable	(70)	(68)
Accounts Receivable/Payable—Affiliated Companies, net	279	121
Accrued Interest Payable	15	15
Other Current Assets and Liabilities	(4)	24
Employee Benefit Plan Funding and Related Payments	(2)	(45)
Other	24	2
Net Cash Provided By (Used In) Operating Activities	674	575
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(126)	(151)
Proceeds from Sales of Available-for-Sale Securities	247	244
Investments in Available-for-Sale Securities	(259)	(256)
Short-Term Loan—Affiliated Company, net	(152)	(174)
Other	(5)	8
Net Cash Provided By (Used In) Investing Activities	(295)	(329)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	(375)	(253)
Contributed Capital	—	8
Other	—	(2)
Net Cash Provided By (Used In) Financing Activities	(375)	(247)
Net Increase (Decrease) in Cash and Cash Equivalents	4	(1)
Cash and Cash Equivalents at Beginning of Period	6	7
Cash and Cash Equivalents at End of Period	$ 10	$ 6
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (93)	$ 2
Interest Paid, Net of Amounts Capitalized	$ 16	$ 18
Accrued Property, Plant and Equipment Expenditures	$ 62	$ 41

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2014	2013
OPERATING REVENUES	$ 2,145	$ 1,995
OPERATING EXPENSES		
Energy Costs	1,045	967
Operation and Maintenance	462	427
Depreciation and Amortization	227	215
Taxes Other Than Income Taxes	—	21
Total Operating Expenses	1,734	1,630
OPERATING INCOME	411	365
Other Income	14	13
Other Deductions	—	(1)
Interest Expense	(68)	(73)
INCOME BEFORE INCOME TAXES	357	304
Income Tax Expense	(143)	(125)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 214	$ 179

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2014	**2013**
NET INCOME	$ 214	$ 179
COMPREHENSIVE INCOME	$ 214	$ 179

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18184

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 177	$ 18
Accounts Receivable, net of allowances of $61 and $56 in 2014 and 2013, respectively	1,135	832
Unbilled Revenues	261	300
Materials and Supplies	126	115
Prepayments	6	24
Regulatory Assets	125	243
Derivative Contracts	—	25
Deferred Income Taxes	6	16
Other	14	12
Total Current Assets	1,850	1,585
PROPERTY, PLANT AND EQUIPMENT	19,424	19,071
Less: Accumulated Depreciation and Amortization	(4,993)	(4,964)
Net Property, Plant and Equipment	14,431	14,107
NONCURRENT ASSETS		
Regulatory Assets	2,570	2,612
Regulatory Assets of VIEs	414	476
Long-Term Investments	367	361
Other Special Funds	362	354
Derivative Contracts	20	69
Restricted Cash of VIEs	24	24
Other	137	132
Total Noncurrent Assets	3,894	4,028
TOTAL ASSETS	$ 20,175	$ 19,720

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2014	December 31, 2013
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 500	$ 500
Securitization Debt of VIEs Due Within One Year	242	237
Commercial Paper and Loans	—	60
Accounts Payable	490	535
Accounts Payable—Affiliated Companies, net	293	190
Accrued Interest	69	67
Clean Energy Program	85	142
Derivative Contracts	8	—
Deferred Income Taxes	4	30
Obligation to Return Cash Collateral	134	119
Regulatory Liabilities	159	43
Other	410	314
Total Current Liabilities	2,394	2,237
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,450	4,406
Other Postretirement Benefit (OPEB) Costs	822	839
Accrued Pension Costs	27	27
Regulatory Liabilities	172	233
Regulatory Liabilities of VIEs	11	11
Environmental Costs	349	363
Asset Retirement Obligations	278	274
Long-Term Accrued Taxes	82	72
Other	48	47
Total Noncurrent Liabilities	6,239	6,272
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	5,067	5,066
Securitization Debt of VIEs	200	259
Total Long-Term Debt	5,267	5,325
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2014 and 2013 —132,450,344 shares	892	892
Contributed Capital	695	520
Basis Adjustment	986	986
Retained Earnings	3,701	3,487
Accumulated Other Comprehensive Income	1	1
Total Stockholder's Equity	6,275	5,886
Total Capitalization	11,542	11,211
TOTAL LIABILITIES AND CAPITALIZATION	$ 20,175	$ 19,720

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2014	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 214	$ 179
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	227	215
Provision for Deferred Income Taxes and ITC	31	29
Non-Cash Employee Benefit Plan Costs	6	39
Cost of Removal	(25)	(24)
Change in Accrued Storm Costs	(1)	(46)
Net Change in Other Regulatory Assets and Liabilities	177	80
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	(264)	(200)
Materials and Supplies	(11)	(7)
Prepayments	18	20
Accounts Payable	14	8
Accounts Receivable/Payable—Affiliated Companies, net	120	64
Other Current Assets and Liabilities	112	104
Employee Benefit Plan Funding and Related Payments	(29)	(120)
Other	(10)	(12)
Net Cash Provided By (Used In) Operating Activities	579	329
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(481)	(572)
Proceeds from Sales of Available-for-Sale Securities	5	6
Investments in Available-for-Sale Securities	(3)	(6)
Solar Loan Investments	(2)	(7)
Restricted Funds	—	1
Net Cash Provided By (Used In) Investing Activities	(481)	(578)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	(60)	(98)
Issuance of Long-Term Debt	—	400
Redemption of Long-Term Debt	—	(150)
Redemption of Securitization Debt	(54)	(51)
Contributed Capital	175	100
Other	—	(7)
Net Cash Provided By (Used In) Financing Activities	61	194
Net Increase (Decrease) In Cash and Cash Equivalents	159	(55)
Cash and Cash Equivalents at Beginning of Period	18	116
Cash and Cash Equivalents at End of Period	$ 177	$ 61
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (37)	$ —
Interest Paid, Net of Amounts Capitalized	$ 62	$ 63
Accrued Property, Plant and Equipment Expenditures	$ 185	$ 224

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

This combined Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information relating to any individual company is filed by such company on its own behalf. Power and PSE&G each is only responsible for information about itself and its subsidiaries.

Note 1. Organization and Basis of Presentation

Organization

PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Power**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and the states in which they operate.
- **PSE&G**—which is an operating public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the FERC. PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which, effective January 1, 2014, operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a twelve year Amended and Restated Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2013.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All significant intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2013.

On December 31, 2013, Energy Holdings distributed the outstanding equity of its 50% interest in a partnership that owns and operates a generation facility in Hawaii and its wholly owned interest in PSEG Solar Source LLC to PSEG. PSEG in turn contributed this distribution to Power as an additional equity investment. This transaction was accounted for as a non-cash transfer of equity interest between entities under common control with prior period financial statements for Power retrospectively adjusted to include the earnings related to the transfer. As a result, Power's Operating Revenues and Net Income for the three months ended March 31, 2013 each increased by $4 million.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 2. Recent Accounting Standards

New Standards Adopted during 2014

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

This accounting standard was issued to address diversity in practice related to the presentation of an unrecognized tax benefit in certain cases. This standard requires entities to present an unrecognized tax benefit or a portion thereof on the Balance Sheet as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward.

However, the unrecognized tax benefit will be presented on the Balance Sheet as a liability and will not be combined with deferred tax assets in cases where that tax benefit cannot or will not, if permissible, be used to settle any additional income taxes that would result from the disallowance of a tax position.

The standard was effective for fiscal years and interim periods beginning after December 15, 2013. The impact of adopting this standard was immaterial.

Note 3. Variable Interest Entities (VIEs)

Variable Interest Entities for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of Transition Funding and Transition Funding II are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the assets of these VIEs are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II, respectively.

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of March 31, 2014 and December 31, 2013. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II during the first three months of 2014 or in 2013. PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II.

Variable Interest Entity for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation, nor expectation, to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by ServCo's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

PSEG recognized a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and other postretirement benefit (OPEB) liabilities. This receivable is presented separately on the Condensed Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted. See Note 7. Pension and Other Postretirement Benefits for additional information.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operations and Maintenance Expense, respectively. For transactions in which Servco acts as an

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agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 4. Rate Filings

The following information discusses significant updates regarding orders and pending rate filings. This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2013.

- ***Remediation Adjustment Charge (RAC)***—On April 18, 2014, PSE&G filed a petition with the BPU requesting recovery of $66 million related to RAC 21 net manufactured gas plant expenditures through July 31, 2013. This matter is pending .
- ***Weather Normalization Clause (WNC)***—In April 2014, the BPU approved PSE&G's filing with respect to deficiency revenues from the 2012-2013 Winter Period. The BPU's approval of a final WNC resulted in no change to the provisional rate previously approved by the BPU and implemented effective October 1, 2013, which was set to recover $26 million from customers during the 2013-2014 Winter Period (October 1, 2013 through May 31, 2014).
- ***Basic Gas Supply Service (BGSS)***—In January and February 2014, PSE&G filed self-implementing one-month BGSS residential customer bill credits with the BPU for 25 cents per therm for the months of February and March 2014. These credits provided approximately $93 million in total credits to residential customers, reducing the BGSS deferred balance. On April 1, 2014, the BGSS rate reverted back to the current rate.

Note 5. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with Solar Renewable Energy Certificates generated from the installed solar electric system. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of March 31, 2014	As of December 31, 2013
	Millions	
Commercial/Industrial	$ 197	$ 192
Residential	15	15
Total	**$ 212**	**$ 207**

Energy Holdings

Energy Holdings, through various of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

The following table shows Energy Holdings' gross and net lease investment as of March 31, 2014 and December 31, 2013, respectively.

	As of March 31, 2014	As of December 31, 2013
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 700	$ 701
Estimated Residual Value of Leased Assets	529	529
Total Investments in Rental Receivables	1,229	1,230
Unearned and Deferred Income	(401)	(405)
Gross Investments in Leases	828	825
Deferred Tax Liabilities	(708)	(727)
Net Investment in Leases	**$ 120**	**$ 98**

The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. "Not Rated" counterparties represent investments in lease receivables related to coal-fired assets and commercial real estate properties.

	Lease Receivables, Net of Non-Recourse Debt	
Counterparties' Credit Rating (Standard & Poor's (S&P)) As of March 31, 2014	**As of March 31, 2014**	**As of December 31, 2013**
	Millions	
AA	$ 19	$ 19
AA-	56	56
BBB+ - BB+	316	316
B	165	166
Not Rated	144	144
Total	**$ 700**	**$ 701**

The "B" rating and the "Not Rated" in the preceding table include lease receivables related to coal-fired assets in Pennsylvania and Illinois, respectively. As of March 31, 2014, the gross investment in the leases of such assets, net of non-recourse debt, was $562 million ($18 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counter-parties' S&P Credit Ratings	Counterparty
		Millions		MW			
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	Not Rated	Edison Mission Energy
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	Not Rated	Edison Mission Energy
Keystone Station Units 1 and 2	PA	$ 117	17%	1,711	Coal	B	GenOn REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 117	17%	1,711	Coal	B	GenOn REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 110	100%	603	Coal	B	GenOn REMA, LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, the indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease. GenOn REMA, LLC, an indirect subsidiary of NRG Energy, Inc. (NRG), has disclosed its plan to place Shawville in a "long term protective layup" by April 2015. NRG has stated that it is evaluating whether to continue to pay the required rent and maintain the facility in accordance with the lease terms or terminate the lease for obsolescence in which case the lessee would be required, among other things, to pay the contractual termination value structured to recover the lease investment of Energy Holdings' indirect subsidiaries as specified in the lease agreement.

Nesbitt Asset Recovery, LLC (Nesbitt), (an indirect, wholly owned subsidiary of Energy Holdings), owns approximately 64% of the lease interest in the Powerton and Joliet coal units in Illinois. These facilities are leased to Midwest Generation (MWG), which was an indirect subsidiary of Edison Mission Energy (EME). In December 2012, EME and MWG filed for relief under Chapter 11 of the U.S. Bankruptcy Code. In October 2013, NRG, EME, MWG, Nesbitt and other creditor parties involved in the bankruptcy executed a new agreement under which NRG would acquire substantially all of EME's assets, including the Powerton and Joliet leased assets. In March 2014, the Bankruptcy Court approved the transaction. As part of the transaction, (i) the leases for the Powerton and Joliet coal units were assumed on their existing terms, (ii) all past due rent under the leases was paid in full, (iii) NRG assumed EME's tax indemnity and guarantee obligations, and (iv) NRG agreed to invest up to $350 million in the Powerton and Joliet coal units so they can be operated in compliance with environmental regulations. On April 1, 2014, NRG and EME closed on the transaction in accordance with these terms, bringing the lease payments current. NRG's credit rating is BB-.

Note 6. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Fund

Power maintains an external master nuclear decommissioning trust to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains a qualified fund and a non-qualified fund. Section 468A of the

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third party investment advisers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund:

	As of March 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 619	$ 288	$ (3)	$ 904
Debt Securities				
Government Obligations	464	3	(7)	460
Other Debt Securities	306	11	(2)	315
Total Debt Securities	770	14	(9)	775
Other Securities	55	—	—	55
Total NDT Available-for-Sale Securities	**$ 1,444**	**$ 302**	**$ (12)**	**$ 1,734**

	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 609	$ 290	$ (2)	$ 897
Debt Securities				
Government Obligations	438	3	(12)	429
Other Debt Securities	285	10	(4)	291
Total Debt Securities	723	13	(16)	720
Other Securities	84	—	—	84
Total NDT Available-for-Sale Securities	**$ 1,416**	**$ 303**	**$ (18)**	**$ 1,701**

These amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of March 31, 2014	As of December 31, 2013
	Millions	
Accounts Receivable	$ 68	$ 39
Accounts Payable	$ 70	$ 36

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of March 31, 2014				As of December 31, 2013			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 56	$ (3)	$ 1	$ —	$ 30	$ (2)	$ 2	$ —
Debt Securities								
Government Obligations (B)	269	(7)	4	—	300	(11)	1	(1)
Other Debt Securities (C)	91	(2)	3	—	107	(4)	3	—
Total Debt Securities	360	(9)	7	—	407	(15)	4	(1)
NDT Available-for-Sale Securities	**$ 416**	**$ (12)**	**$ 8**	**$ —**	**$ 437**	**$ (17)**	**$ 6**	**$ (1)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of March 31, 2014.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of March 31, 2014.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2014.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended March 31,	
	2014	2013
	Millions	
Proceeds from NDT Fund Sales	**$ 245**	**$ 241**
Net Realized Gains (Losses) on NDT Fund:		
Gross Realized Gains	23	37
Gross Realized Losses	(4)	(19)
Net Realized Gains (Losses) on NDT Fund	**$ 19**	**$ 18**

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $143 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of March 31, 2014.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

The NDT available-for-sale debt securities held as of March 31, 2014 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 38
1 - 5 years	216
6 - 10 years	184
11 - 15 years	54
16 - 20 years	29
Over 20 years	254
Total NDT Available-for-Sale Debt Securities	**$ 775**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In the three months ended March 31, 2014, other-than-temporary impairments of $2 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of March 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 9	$ —	$ 21
Debt Securities				
Government Obligations	110	—	(1)	109
Other Debt Securities	46	1	(1)	46
Total Debt Securities	156	1	(2)	155
Other Securities	7	—	—	7
Total Rabbi Trust Available-for-Sale Securities	**$ 175**	**$ 10**	**$ (2)**	**$ 183**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 14	$ 9	$ —	$ 23
Debt Securities				
Government Obligations	109	—	(2)	107
Other Debt Securities	46	1	(1)	46
Total Debt Securities	155	1	(3)	153
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 172**	**$ 10**	**$ (3)**	**$ 179**

These amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of March 31, 2014	As of December 31, 2013
	Millions	
Accounts Receivable	$ 4	$ 1
Accounts Payable	$ 3	$ 2

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months.

	As of March 31, 2014				As of December 31, 2013			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	42	(1)	2	—	47	(2)	2	—
Other Debt Securities (C)	13	(1)	1	—	18	(1)	1	—
Total Debt Securities	55	(2)	3	—	65	(3)	3	—
Rabbi Trust Available-for-Sale Securities	**$ 55**	**$ (2)**	**$ 3**	**$ —**	**$ 65**	**$ (3)**	**$ 3**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors. PSEG does not consider these securities to be other-than-temporarily impaired as of March 31, 2014.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell nor

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will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of March 31, 2014.

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2014.

The proceeds from the sales of securities in the Rabbi Trust Fund were:

	Three Months Ended March 31,	
	2014	2013
	Millions	
Proceeds from Rabbi Trust Sales	**$ 12**	**$ 17**
Net Realized Gains (Losses) on Rabbi Trust:		
Gross Realized Gains	$ 2	$ —
Gross Realized Losses	—	—
Net Realized Gains (Losses) on Rabbi Trust	**$ 2**	**$ —**

Net unrealized gains of $4 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of March 31, 2014. The Rabbi Trust available-for-sale debt securities held as of March 31, 2014 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ —
1 - 5 years	60
6 - 10 years	27
11 - 15 years	9
16 - 20 years	4
Over 20 years	55
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 155**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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The fair value of assets in the Rabbi Trust related to PSEG, Power and PSE&G are detailed as follows:

	As of March 31, 2014	As of December 31, 2013
	Millions	
Power	$ 43	$ 39
PSE&G	39	42
Other	101	98
Total Rabbi Trust Available-for-Sale Securities	**$ 183**	**$ 179**

Note 7. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.

Pension and OPEB costs for PSEG, except for Servco, are detailed as follows:

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2014	2013	2014	2013
	Millions			
Components of Net Periodic Benefit Cost				
Service Cost	$ 26	$ 29	$ 5	$ 5
Interest Cost	59	54	17	16
Expected Return on Plan Assets	(100)	(87)	(7)	(5)
Amortization of Net				
Prior Service Cost (Credit)	(5)	(5)	(4)	(4)
Actuarial Loss	14	47	6	11
Total Benefit Costs	**$ (6)**	**$ 38**	**$ 17**	**$ 23**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Pension and OPEB costs for Power, PSE&G and PSEG's other subsidiaries, except for Servco, are detailed as follows:

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2014	2013	2014	2013
	Millions			
Power	$ (2)	$ 11	$ 5	$ 6
PSE&G	(5)	23	11	16
Other	1	4	1	1
Total Benefit Costs	**$ (6)**	**$ 38**	**$ 17**	**$ 23**

PSEG does not anticipate making contributions into its pension plan during 2014. However, during the three months ended March 31, 2014, PSEG contributed its entire planned contribution for the year 2014 of $14 million into its postretirement healthcare plan.

Servco Pension and OPEB

At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities (VIEs). These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. The pension-related revenues and costs for the three months ended March 31, 2014 were $23 million. As of March 31, 2014, Servco had funded 17% of its projected pension benefit obligation. Servco plans to contribute an additional $44 million to its pension plan trusts during 2014. There were no OPEB-related revenues earned or costs incurred for the three months ended March 31, 2014.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

The following assumptions were used to determine the benefit obligations of Servco:

	Pension Benefits	Other Benefits
	January 1, 2014	
Weighted-Average Assumptions Used to Determine Benefit Obligations as of January 1, 2014		
Discount Rate	5.50%	5.40%
Rate of Compensation Increase	2.50%	2.50%
Assumed Health Care Cost Trend Rates as of January 1, 2014		
Administrative Expense		5.00%
Dental Costs		5.00%
Pre-65 Medical Costs		
Immediate Rate		7.50%
Ultimate Rate		5.00%
Year Ultimate Rate Reached		2019
Post-65 Medical Costs		
Immediate Rate		7.50%
Ultimate Rate		5.00%
Year Ultimate Rate Reached	2019	
	Millions	
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs		
Postretirement Benefit Obligation	$ 62	
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs		
Postretirement Benefit Obligation	$ (49)	

Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to Servco's plan participants:

Year	Pension Benefits	Other Benefits
	Millions	
2014	$ —	$ 1
2015	—	3
2016	1	4
2017	2	6
2018	3	8
2019-2023	37	65
Total	**$ 43**	**$ 87**

Note 8. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

The face value of Power's outstanding guarantees, current exposure and margin positions as of March 31, 2014 and December 31, 2013 are shown as follows:

	As of March 31, 2014	As of December 31, 2013
	Millions	
Face Value of Outstanding Guarantees	$ 1,930	$ 1,639
Exposure under Current Guarantees	$ 236	$ 246
Letters of Credit Margin Posted	$ 130	$ 132
Letters of Credit Margin Received	$ 16	$ 25
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (19)	$ —
Net Broker Balance Deposited (Received)	$ 360	$ 80
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that could be Required	$ 802	$ 691
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,525	$ 3,522
Additional Amounts Posted:		
Other Letters of Credit	$ 45	$ 45

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P, Moody's and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See preceding table.

The SEC and the Commodity Futures Trading Commission (CFTC) continue efforts to implement new rules to effect stricter regulation over swaps and derivatives, including imposing reporting and record-keeping requirements. In August 2013, PSEG began reporting its swap transactions to a CFTC-approved swap data repository. PSEG continues to monitor developments in this area, as the CFTC considers additional requirements such as a new position limits rule for energy commodity swaps.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The U.S. Environmental Protection Agency (EPA) has determined that a 17-mile stretch of the Passaic River from Newark to Clifton, New Jersey is a "Super Fund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA has determined the need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

Seventy-three Potentially Responsible Parties (PRPs), including Power and PSE&G, agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) and formed the Cooperating Parties Group (CPG) to divide the associated costs according to a mutually agreed upon formula. The CPG group, currently 67 members, is presently conducting the RI/FS. The approximate seven percent allocation of the RI/FS costs currently attributable to PSE&G's former MGP sites and approximate one percent attributable to Power's generating stations are non-binding as it relates to the ultimate sharing of the remediation costs. Power has provided notice to insurers concerning this potential claim. The RI/FS is expected to be completed by the end of 2014 at an estimated cost of approximately $130 million. Of the estimated $130 million, as of December 31, 2013, the CPG Group had spent approximately $113 million, of which PSEG's total share had been approximately $7 million.

On April 11, 2014, the EPA released its revised "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the Passaic River's lower eight miles under various alternatives ranging in costs from $365 million to $3.25 billion. The EPA's preferred alternative would involve dredging the river bank to bank and installing an engineered cap at an estimated cost of $1.7 billion. The draft FFS is subject to a public comment period, the EPA's response, a design phase and at least five years for completion of the work. The work contemplated by the draft FFS is not subject to the cost sharing agreement discussed above.

In June 2008, an agreement was announced between the EPA and Tierra Solutions, Inc. and Maxus Energy Corporation (Tierra/Maxus) for removal of a portion of the contaminated sediment in the Passaic River at an estimated cost of $80 million. Phase I of the removal work has been completed. Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G.

At the EPA's direction, the CPG, with the exception of Tierra and Maxus, which are no longer members, has commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSEG's share of the cost of that effort is approximately three percent.

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Based on the EPA estimates above, Power and PSE&G believe that their respective ultimate shares of the costs to clean up the Passaic River will be immaterial, but are unable to predict the ultimate outcome of this matter.

New Jersey Spill Compensation and Control Act (Spill Act)

In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of a certain PRP's discharge of hazardous substances into both the Passaic River and the balance of the Newark Bay Complex. In 2009, third party complaints were filed against some 320 third party defendants, including Power and PSE&G, claiming that each of the third party defendants is responsible for its proportionate share of the clean-up costs for the hazardous substances it allegedly discharged into the Passaic River and the Newark Bay Complex. Power and PSE&G are alleged to have owned, operated or contributed to a total of 11 sites or facilities that impacted these water bodies. The third party complaints sought statutory contribution and contribution under the Spill Act to recover past and future removal costs and damages. In December 2013, the Court approved a settlement of the entire third party action. Power and PSE&G's contributions to the settlement, either individually or in the aggregate, were immaterial.

Natural Resource Damage Claims

In 2003, the NJDEP directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the Spill Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G is unable to estimate its portion of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $432 million and $509 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $432 million as of March 31, 2014. Of this amount, $93 million was recorded in Other Current Liabilities and $339 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $432 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent

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the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Hazardous Air Pollutants Regulation

In accordance with a ruling of the U.S. Court of Appeals of the District of Columbia (D.C. Court), the EPA published a Maximum Achievable Control Technology (MACT) regulation on February 16, 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the D.C. Court in support of the EPA's implementation of MATS. Oral arguments were held in December 2013. On April 15, 2014, the D.C. Court denied all petitions for review of the existing source NESHAP.

Power believes that it will not be necessary to install any material controls at its New Jersey facilities. Additional controls are being installed at Power's Bridgeport Harbor coal-fired unit at an immaterial cost. In December 2011, to comply with the MACT regulations, the co-owners group, including Power, agreed to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction (SCR) systems at Power's jointly owned coal-fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be completed in the first quarter of 2015. Power's share of this investment is approximately $110 million.

Nitrogen Oxide (NO_X) Regulation

In 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on Power's generation fleet, as it imposes NO_x emissions limits that will require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) and four older New Jersey steam electric generation units (approximately 400 MW) by May 30, 2015. Retirement notifications for the combustion turbines have been submitted to PJM Interconnection L.L.C. (PJM). PJM was notified that the Salem Unit 3 combustion turbine will no longer be available as a capacity resource and will be transitioned to an emergency generator for site use only. Based upon Power's recently-completed evaluations of its steam electric generation units, an immaterial investment will be required to consistently reduce NO_x emissions below required limits beginning on May 1, 2015.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System (NPDES) permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The New Jersey Department of Environmental Protection manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

One of the most significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued.

In April 2011, the EPA published a proposed rule to establish marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. The EPA is currently scheduled to issue a final rule on May 16, 2014.

Power is unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on its future capital requirements, financial condition, results of operations or cash flows. The results of further proceedings on this matter could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would

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have been approximately $575 million. The filing has not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

On October 1, 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court in New Jersey seeking to compel the NJDEP to take action on Power's pending application for permit renewal at Salem either by denying the application or issuing a draft for public comments. At the NJDEP's request, the case was transferred to the Appellate Division on December 16, 2013. Power is unable to predict the outcome of this proceeding.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements for customers who do not purchase electric supply from third party suppliers through the annual New Jersey BGS auctions. Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with Power, as well as with other winning BGS suppliers, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has contracted for its anticipated BGS-Fixed Price eligible load, as follows:

	Auction Year				
	2011	2012	2013	2014	
36-Month Terms Ending	May 2014	May 2015	May 2016	May 2017	(A)
Load (MW)	2,800	2,900	2,800	2,800	
$ per kWh	0.09430	0.08388	0.09218	0.09739	

(A) Prices set in the 2014 BGS auction will become effective on June 1, 2014 when the 2011 BGS auction agreements expire.

PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 17. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations and for supply of nuclear fuel for the Salem, Hope Creek and Peach Bottom nuclear generating stations and for firm transportation and storage capacity for natural gas.

Power's fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2016 and a significant portion through 2018 at Salem, Hope Creek and Peach Bottom.

Power's various multi-year contracts for firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

As of March 31, 2014, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type		Power's Share of Commitments through 2018
		Millions
Nuclear Fuel		
Uranium	$	505
Enrichment	$	455
Fabrication	$	173
Natural Gas	$	922
Coal	$	404

Regulatory Proceedings

FERC Compliance

Power has discovered that it incorrectly calculated certain components of its cost-based bids for certain generating units in the PJM energy market, with resulting over-collection of revenues related to its fossil fleet. Power has notified the FERC, PJM and the PJM Independent Market Monitor of this issue. This matter is still under review, and Power is unable to estimate the ultimate impact or predict any resulting penalties or other costs associated with this matter at the current time.

New Jersey Clean Energy Program

In June 2013, the BPU established the funding level for fiscal 2014 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2014 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a remaining current liability of $86 million as of March 31, 2014 for its outstanding share of fiscal 2014 funding. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's T&D system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure.

Power had incurred $79 million and $85 million of storm-related expense in 2013 and 2012, respectively, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized in O&M Expense, offset by $25 million and $19 million of insurance recoveries in 2013 and 2012, respectively.

Power incurred an additional $9 million for the three months ended March 31, 2014, primarily for repairs at certain generating stations in Power's fossil fleet.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. As previously reported, PSEG is seeking recovery from its insurers for the property damage resulting from Superstorm Sandy, above its self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. In June 2013, PSEG, Power and PSE&G filed suit in New Jersey state court against its insurance carriers seeking an interpretation that the insurance policies cover their losses resulting from damage caused by Superstorm Sandy's storm surge. In that lawsuit, PSEG stated that its estimate of the total costs related to damaged facilities was approximately $426 million. Of these costs, $364 million and $62 million related to Power and PSE&G, respectively. In August 2013, the insurance carriers filed an answer in which they denied most of the allegations made in the Complaint. Discovery is ongoing. In April 2014, PSEG notified the insurance carriers of a revised estimate of $579 million for total costs related to damaged facilities, of which $484 million and $95 million related to Power and PSE&G, respectively. We cannot predict the outcome of this proceeding.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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Note 9. Changes in Capitalization

The following capital transactions occurred in the three months ended March 31, 2014:

Power

- paid cash dividends of $375 million to PSEG.

PSE&G

- paid $54 million of Transition Funding's securitization debt, and
- received a $175 million capital contribution from PSEG.

Note 10. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Commodity Prices

The availability and price of energy commodities are subject to fluctuations due to weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions, transmission availability and other events. Power uses physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. Derivative contracts that do not qualify for hedge accounting or normal purchases/normal sales treatment are marked to market with changes in fair value recorded in the Consolidated Statements of Operations. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps and futures contracts to hedge

- forecasted energy sales from its generation stations and the related load obligations,
- the price of fuel to meet its fuel purchase requirements, and
- certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

These derivative transactions are designated and effective as cash flow hedges. During the second quarter of 2012, Power de-designated certain of its commodity derivative transactions that had previously qualified as cash flow hedges as they were deemed to no longer be highly effective as required by the relevant accounting guidance. As a result, since June 1, 2012, Power recognizes all gains and losses from changes in the fair value of these derivatives immediately in earnings rather than deferring any such amounts in Accumulated Other Comprehensive Income (Loss). The fair values of Power's de-designated hedges were frozen in Accumulated Other Comprehensive Income (Loss) as the original forecasted transactions are still expected to occur and are reclassified into earnings as the original derivative transactions settle.

As of March 31, 2014 and December 31, 2013, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity were as follows:

	As of March 31, 2014	As of December 31, 2013
	Millions	
Fair Value of Cash Flow Hedges	$ —	$ (4)
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 1	$ (1)

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The expiration date of the longest-dated cash flow hedge at Power is in December 2014. Power's remaining $1 million of after-tax unrealized gains on these derivatives is expected to be reclassified to earnings during the next 12 months. There was no ineffectiveness associated with qualifying hedges as of March 31, 2014.

Other Derivatives

Power enters into additional contracts that are derivatives, but do not qualify for or are not designated as cash flow hedges. These transactions are intended to mitigate exposure to fluctuations in commodity prices and optimize the value of its expected generation. Trade types include financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. Changes in fair market value of these contracts are recorded in earnings. PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization. These natural gas contracts qualify as derivatives and are marked to fair market value with the offset recorded to Regulatory Assets and Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of March 31, 2014, PSEG had seven interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of March 31, 2014 and December 31, 2013, the fair value of all the underlying hedges was $34 million and $38 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was $(1) million as of March 31, 2014 and December 31, 2013.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset in the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

	As of March 31, 2014						
	Power (A)				PSE&G(A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ —	$ 606	$ (579)	$ 27	$ —	$ 16	$ 43
Noncurrent Assets	—	137	(128)	9	20	18	47
Total Mark-to-Market Derivative Assets	**$ —**	**$ 743**	**$ (707)**	**$ 36**	**$ 20**	**$ 34**	**$ 90**
Derivative Contracts							
Current Liabilities	$ —	$ (793)	$ 726	$ (67)	$ (8)	$ —	$ (75)
Noncurrent Liabilities	—	(125)	97	(28)	—	—	(28)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (918)**	**$ 823**	**$ (95)**	**$ (8)**	**$ —**	**$ (103)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ —**	**$ (175)**	**$ 116**	**$ (59)**	**$ 12**	**$ 34**	**$ (13)**

	As of December 31, 2013						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ —	$ 323	$ (266)	$ 57	$ 25	$ 16	$ 98
Noncurrent Assets	—	155	(83)	72	69	22	163
Total Mark-to-Market Derivative Assets	**$ —**	**$ 478**	**$ (349)**	**$ 129**	**$ 94**	**$ 38**	**$ 261**
Derivative Contracts							
Current Liabilities	$ (4)	$ (343)	$ 271	$ (76)	$ —	$ —	$ (76)
Noncurrent Liabilities	—	(111)	80	(31)	—	—	(31)
Total Mark-to-Market Derivative (Liabilities)	**$ (4)**	**$ (454)**	**$ 351**	**$ (107)**	**$ —**	**$ —**	**$ (107)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ (4)**	**$ 24**	**$ 2**	**$ 22**	**$ 94**	**$ 38**	**$ 154**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of March 31, 2014 and December 31, 2013. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the

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right of offset exists, has been offset in the statement of financial position. As of March 31, 2014 and December 31, 2013, net cash collateral (received) paid of $116 million and $2 million, respectively, were netted against the corresponding net derivative contract positions. Of the $116 million as of March 31, 2014, $(33) million of cash collateral was netted against noncurrent assets and $147 million and $2 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $2 million as of December 31, 2013, cash collateral of $(3) million and $5 million were netted against noncurrent assets and current liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded or lose its investment grade credit rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on NYMEX and ICE that are fully collateralized) was $91 million as of March 31, 2014 and December 31, 2013. As of March 31, 2014 and December 31, 2013, Power had the contractual right of offset of $39 million related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded or lost its investment grade rating, it would have had additional collateral obligations of $52 million as of March 31, 2014 and December 31, 2013 related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $802 million and $691 million as of March 31, 2014 and December 31, 2013, respectively, discussed in Note 8. Commitments and Contingent Liabilities.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended March 31, 2014 and 2013:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended March 31,		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended March 31,		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Three Months Ended March 31,	
	2014	2013		2014	2013		2014	2013
	Millions							
PSEG								
Energy-Related Contracts	$ (8)	$ —	Operating Revenues	$ (12)	$ 6	Operating Revenues	$ —	$ —
Total PSEG	**$ (8)**	**$ —**		**$ (12)**	**$ 6**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ (8)	$ —	Operating Revenues	$ (12)	$ 6	Operating Revenues	$ —	$ —
Total Power	**$ (8)**	**$ —**		**$ (12)**	**$ 6**		**$ —**	**$ —**

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The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis:

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2012	**$ 12**	**$ 7**
Loss Recognized in AOCI	(4)	(2)
Gain Reclassified into Income	(12)	(7)
Balance as of December 31, 2013	**$ (4)**	**$ (2)**
Loss Recognized in AOCI	(8)	(5)
Loss Reclassified into Income	12	7
Balance as of March 31, 2014	**$ —**	**$ —**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the three months ended March 31, 2014 and 2013:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives	
		Three Months Ended March 31,	
		2014	2013
		Millions	
PSEG and Power			
Energy-Related Contracts	Operating Revenues	$ (794)	$ (209)
Energy-Related Contracts	Energy Costs	113	58
Total PSEG and Power		**$ (681)**	**$ (151)**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $5 million for each of the three month periods ended March 31, 2014 and 2013.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

The following reflects the gross volume, on an absolute value basis, of derivatives as of March 31, 2014 and December 31, 2013:

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of March 31, 2014					
Natural Gas	Dth	622	—	485	137
Electricity	MWh	304	—	304	—
Financial Transmission Rights (FTRs)	MWh	10	—	10	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2013					
Natural Gas	Dth	614	—	466	148
Electricity	MWh	243	—	243	—
FTRs	MWh	16	—	16	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of March 31, 2014, 97% of the credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of March 31, 2014. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 201	$ 33	$ 199	1	$ 164	(A)
Non-Investment Grade—External Rating	—	—	—	—	—	
Investment Grade—No External Rating	2	—	2	—	—	
Non-Investment Grade—No External Rating	5	—	5	—	—	
Total	**$ 208**	**$ 33**	**$ 206**	**1**	**$ 164**	

(A) Represents net exposure with PSE&G.

The net exposure listed in the preceding table, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of March 31, 2014, Power had 158 active counterparties.

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Note 11. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of March 31, 2014, these consisted primarily of electric swaps whose basis is deemed significant to the fair value measurement, certain electric load deals and long-term gas supply contracts.

The following tables present information about PSEG's, Power's and PSE&G's respective assets and (liabilities) measured at fair value on a recurring basis as of March 31, 2014 and December 31, 2013, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Description	Recurring Fair Value Measurements as of March 31, 2014			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 566	$ —	$ 566	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 56	$ (707)	$ —	$ 740	$ 23
Interest Rate Swaps (C)	$ 34	$ —	$ —	$ 34	$ —
NDT Fund (D)					
Equity Securities	$ 904	$ —	$ 898	$ 6	$ —
Debt Securities—Govt Obligations	$ 460	$ —	$ —	$ 460	$ —
Debt Securities—Other	$ 315	$ —	$ —	$ 315	$ —
Other Securities	$ 55	$ —	$ 55	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 21	$ —	$ 21	$ —	$ —
Debt Securities—Govt Obligations	$ 109	$ —	$ —	$ 109	$ —
Debt Securities—Other	$ 46	$ —	$ —	$ 46	$ —
Other Securities	$ 7	$ —	$ —	$ 7	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (103)	$ 823	$ —	$ (904)	$ (22)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 36	$ (707)	$ —	$ 740	$ 3
NDT Fund (D)					
Equity Securities	$ 904	$ —	$ 898	$ 6	$ —
Debt Securities—Govt Obligations	$ 460	$ —	$ —	$ 460	$ —
Debt Securities—Other	$ 315	$ —	$ —	$ 315	$ —
Other Securities	$ 55	$ —	$ 55	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 11	$ —	$ —	$ 11	$ —
Other Securities	$ 4	$ —	$ —	$ 4	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (95)	$ 823	$ —	$ (904)	$ (14)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 132	$ —	$ 132	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 20	$ —	$ —	$ —	$ 20
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 3	$ —	$ 3	$ —	$ —
Debt Securities—Govt Obligations	$ 26	$ —	$ —	$ 26	$ —
Debt Securities—Other	$ 10	$ —	$ —	$ 10	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (8)	$ —	$ —	$ —	$ (8)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Description	Recurring Fair Value Measurements as of December 31, 2013				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 439	$ —	$ 439	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 223	$ (349)	$ —	$ 474	$ 98
Interest Rate Swaps (C)	$ 38	$ —	$ —	$ 38	$ —
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 892	$ 5	$ —
Debt Securities—Govt Obligations	$ 429	$ —	$ —	$ 429	$ —
Debt Securities—Other	$ 291	$ —	$ —	$ 291	$ —
Other Securities	$ 84	$ —	$ 57	$ 27	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—Govt Obligations	$ 107	$ —	$ —	$ 107	$ —
Debt Securities—Other	$ 46	$ —	$ —	$ 46	$ —
Other Securities	$ 3	$ —	$ —	$ 3	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (107)	$ 351	$ —	$ (448)	$ (10)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 129	$ (349)	$ —	$ 474	$ 4
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 892	$ 5	$ —
Debt Securities—Govt Obligations	$ 429	$ —	$ —	$ 429	$ —
Debt Securities—Other	$ 291	$ —	$ —	$ 291	$ —
Other Securities	$ 84	$ —	$ 57	$ 27	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 10	$ —	$ —	$ 10	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (107)	$ 351	$ —	$ (448)	$ (10)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (B)	$ 94	$ —	$ —	$ —	$ 94
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 25	$ —	$ —	$ 25	$ —
Debt Securities—Other	$ 11	$ —	$ —	$ 11	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —

(A) Represents money market mutual funds.

(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Marketable energy contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction

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prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis

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adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds and United States Treasury obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheet. As of March 31, 2014, net cash collateral (received) paid of $116 million, was netted against the corresponding net derivative contract positions. Of the $116 million as of March 31, 2014, $(33) million of cash collateral was netted against assets, and $149 million was netted against liabilities. As of December 31, 2013, net cash collateral (received) paid of $2 million, was netted against the corresponding net derivative contract positions. Of the $2 million as of December 31, 2013, $(3) million of cash collateral was netted against assets, and $5 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group, and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and non-performance risk were not material to the financial statements.

For Power, in general, electric swaps are measured at fair value based on at least two pricing inputs, the underlying price of electricity at a liquid reference point and the basis difference between electricity prices at the liquid reference point and electricity prices at the respective delivery locations. To the extent the basis component is based on a single broker quote and is significant to the fair value of the electric swap, it is categorized as Level 3. The fair value of certain of Power's electric load

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contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. For Power and PSE&G, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The following tables provide details surrounding significant Level 3 valuations as of March 31, 2014 and December 31, 2013.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of March 31, 2014 Assets	Fair Value as of March 31, 2014 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ —	$ (5)	Discounted Cash Flow	Power Basis	-$3 to +$10/MWh
Electricity	Electric Load Contracts	1	(9)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Other	Various (A)	2	—			
Total Power		**$ 3**	**$ (14)**			
PSE&G						
Gas	Forward Contracts	$ 20	$ (8)	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 20**	**$ (8)**			
TOTAL PSEG		**$ 23**	**$ (22)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2013 Assets	Fair Value as of December 31, 2013 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ 3	$ (1)	Discounted Cash Flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	—	(8)	Discounted Cash Flow	Historic Load Variability	-5% to +10%
Other	Various (B)	1	(1)			
Total Power		**$ 4**	**$ (10)**			
PSE&G						
Gas	Forward Contracts	$ 94	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 94**	**$ —**			
TOTAL PSEG		**$ 98**	**$ (10)**			

(A) Includes gas supply positions and long-term electric capacity positions which are immaterial as of March 31, 2014.

(B) Includes gas supply positions which were immaterial as of December 31, 2013.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value.

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months ended March 31, 2014 and 2013, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2014

Description	Balance as of January 1, 2014	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of March 31, 2014
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 88	$ (64)	$ (82)	$ —	$ 59	$ —	$ 1
Power							
Net Derivative Assets (Liabilities)	$ (6)	$ (64)	$ —	$ —	$ 59	$ —	$ (11)
PSE&G							
Net Derivative Assets (Liabilities)	$ 94	$ —	$ (82)	$ —	$ —	$ —	$ 12

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2013

Description	Balance as of January 1, 2013	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of March 31, 2013
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (31)	$ (34)	$ —	$ —	$ 10	$ (2)	$ (57)
Power							
Net Derivative Assets (Liabilities)	$ 9	$ (34)	$ —	$ —	$ 10	$ (2)	$ (17)
PSE&G							
Net Derivative Assets (Liabilities)	$ (40)	$ —	$ —	$ —	$ —	$ —	$ (40)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $(64) million and $(34) million in Operating Income in 2014 and 2013, respectively. Of the $(64) million in Operating Income in 2014, $(5) million is unrealized. Of the $(34) million in Operating Income in 2013, $(24) million is unrealized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or OCI, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $59 million and $10 million in settlements for the three months ended March 31, 2014 and 2013.

(D) There were no transfers among levels during the three months ended March 31, 2014. During the three months ended March 31, 2013, $2 million of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. The transfer was recognized as of the beginning of the first quarter (i.e. the quarter in which the transfer occurred), as per PSEG's policy.

As of March 31, 2014, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $1 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of March 31, 2013, PSEG carried $1.8 billion of net assets that are measured at fair value on a recurring basis, of which $57 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of March 31, 2014 and December 31, 2013.

	As of March 31, 2014		As of December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 22	$ 34	$ 24	$ 38
Power -Recourse Debt (B)	2,541	2,889	2,541	2,846
PSE&G (B)	5,567	5,885	5,566	5,629
Transition Funding (PSE&G) (B)	422	450	476	511
Transition Funding II (PSE&G) (B)	20	21	20	21
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	16	16	16	16
Total Long-Term Debt	**$ 8,588**	**$ 9,295**	**$ 8,643**	**$ 9,061**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

Note 12. Other Income and Deductions

Other Income	Power	PSE&G	Other (A)	Consolidated
		Millions		
Three Months Ended March 31, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ 32	$ —	$ —	$ 32
Allowance of Funds Used During Construction	—	6	—	6
Solar Loan Interest	—	6	—	6
Other	1	2	1	4
Total Other Income	**$ 33**	**$ 14**	**$ 1**	**$ 48**
Three Months Ended March 31, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ 47	$ —	$ —	$ 47
Allowance of Funds Used During Construction	—	6	—	6
Solar Loan Interest	—	6	—	6
Other	—	1	1	2
Total Other Income	**$ 47**	**$ 13**	**$ 1**	**$ 61**

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Other Deductions	Power	PSE&G	Other (A)	Consolidated
			Millions	
Three Months Ended March 31, 2014				
NDT Fund Realized Losses and Expenses	$ 6	$ —	$ —	$ 6
Other	4	—	2	6
Total Other Deductions	**$ 10**	**$ —**	**$ 2**	**$ 12**
Three Months Ended March 31, 2013				
NDT Fund Realized Losses and Expenses	$ 20	$ —	$ —	$ 20
Other	8	1	—	9
Total Other Deductions	**$ 28**	**$ 1**	**$ —**	**$ 29**

(A) Other primarily consists of activity at PSEG (as parent company), Energy Holdings, Services and intercompany eliminations.

Note 13. Income Taxes

PSEG's, Power's and PSE&G's effective tax rates for the three months ended March 31, 2014 and 2013 were as follows:

	Three Months Ended March 31,	
	2014	2013
PSEG	40.2%	40.7%
Power	40.4%	39.8%
PSE&G	40.1%	41.1%

There were no material changes in the effective tax rates of PSEG, Power and PSE&G for the three months ended March 31, 2014 as compared to the same period in the prior year.

In September 2013, the U.S. Department of the Treasury and the IRS released final regulations that provide guidance on applying Section 263(a) of the Internal Revenue Code to amounts paid to acquire, produce, or improve tangible property, as well as rules for materials and supplies. These regulations became effective in 2014 and their implementation did not have any material impact on PSEG's and its subsidiaries' results of operations, financial condition or cash flows.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 was eligible for 50% bonus depreciation for tax purposes. On January 2, 2013, the President signed into law the American Taxpayer Relief Act of 2012 that further extended the 50% bonus depreciation for qualified property placed into service before January 1, 2014. In addition, long production property placed into service in 2014 is eligible for 50% bonus depreciation for tax purposes. These provisions have generated cash for PSEG through tax benefits related to the accelerated depreciation. These tax benefits otherwise would have been received over an estimated average 20 year period.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended March 31, 2014			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2013	(2)	$ (238)	$ 145	$ (95)
Other Comprehensive Income before Reclassifications	(5)	—	11	6
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	7	4	(9)	2
Net Current Period Other Comprehensive Income (Loss)	2	4	2	8
Balance as of March 31, 2014	**$ —**	**$ (234)**	**$ 147**	**$ (87)**

Power	Other Comprehensive Income (Loss) Three Months Ended March 31, 2014			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2013	$ (1)	$ (204)	$ 142	$ (63)
Other Comprehensive Income before Reclassifications	(6)	—	10	4
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	7	3	(8)	2
Net Current Period Other Comprehensive Income (Loss)	1	3	2	6
Balance as of March 31, 2014	**$ —**	**$ (201)**	**$ 144**	**$ (57)**

PSEG	Other Comprehensive Income (Loss) Three Months Ended March 31, 2013			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 7	$ (485)	$ 90	$ (388)
Other Comprehensive Income before Reclassifications	—	—	27	27
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(4)	10	—	6
Net Current Period Other Comprehensive Income (Loss)	(4)	10	27	33
Balance as of March 31, 2013	**$ 3**	**$ (475)**	**$ 117**	**$ (355)**

Power	Other Comprehensive Income (Loss) Three Months Ended March 31, 2013			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 9	$ (422)	$ 85	$ (328)
Other Comprehensive Income before Reclassifications	—	—	27	27
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(4)	9	—	5
Net Current Period Other Comprehensive Income (Loss)	(4)	9	27	32
Balance as of March 31, 2013	**$ 5**	**$ (413)**	**$ 112**	**$ (296)**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

PSEG

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended March 31, 2014			Three Months Ended March 31, 2013		
		Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ (12)	$ 5	$ (7)	$ 6	$ (2)	$ 4
Total Cash Flow Hedges		(12)	5	(7)	6	(2)	4
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	Operation and Maintenance (O&M) Expense	2	(1)	1	4	(2)	2
Amortization of Actuarial Loss	O&M Expense	(8)	3	(5)	(21)	9	(12)
Total Pension and OPEB Plans		(6)	2	(4)	(17)	7	(10)
Available-for-Sale Securities							
Realized Gains	Other Income	25	(13)	12	2	(1)	1
Realized Losses	Other Deductions	(4)	2	(2)	—	—	—
Other-Than-Temporary Impairments (OTTI)	Other-Than-Temporary Impairments (OTTI)	(2)	1	(1)	(2)	1	(1)
Total Available-for-Sale Securities		19	(10)	9	—	—	—
Total		**$ 1**	**$ (3)**	**$ (2)**	**$ (11)**	**$ 5**	**$ (6)**

Power

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended March 31, 2014			Three Months Ended March 31, 2013		
		Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ (12)	$ 5	$ (7)	$ 6	$ (2)	$ 4
Total Cash Flow Hedges		(12)	5	(7)	6	(2)	4
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	2	(1)	1	2	(1)	1
Amortization of Actuarial Loss	O&M Expense	(6)	2	(4)	(16)	6	(10)
Total Pension and OPEB Plans		(4)	1	(3)	(14)	5	(9)
Available-for-Sale Securities							
Realized Gains	Other Income	23	(12)	11	2	(1)	1
Realized Losses	Other Deductions	(4)	2	(2)	—	—	—
OTTI	OTTI	(2)	1	(1)	(2)	1	(1)
Total Available-for-Sale Securities		17	(9)	8	—	—	—
Total		**$ 1**	**$ (3)**	**$ (2)**	**$ (8)**	**$ 3**	**$ (5)**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 15. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under our stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended March 31,			
	2014		2013	
	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)				
Net Income	**$ 386**	**$ 386**	**$ 320**	**$ 320**
EPS Denominator (Thousands)				
Weighted Average Common Shares Outstanding	506,077	506,077	505,942	505,942
Effect of Stock Based Compensation Awards	—	1,754	—	1,278
Total Shares	**506,077**	**507,831**	**505,942**	**507,220**
EPS				
Net Income	**$ 0.76**	**$ 0.76**	**$ 0.63**	**$ 0.63**

	Three Months Ended March 31,	
Dividend Payments on Common Stock	2014	2013
Per Share	$ 0.37	$ 0.36
In Millions	$ 187	$ 182

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 16. Financial Information by Business Segments

	Power	PSE&G	Other (A)	Eliminations (B)	Consolidated
			Millions		
Three Months Ended March 31, 2014					
Total Operating Revenues	$ 1,700	$ 2,145	$ 105	$ (727)	$ 3,223
Net Income (Loss)	164	214	8	—	$ 386
Gross Additions to Long-Lived Assets	126	481	2	—	$ 609
Three Months Ended March 31, 2013					
Total Operating Revenues	$ 1,451	$ 1,995	$ 12	$ (672)	$ 2,786
Net Income (Loss)	141	179	—	—	320
Gross Additions to Long-Lived Assets	151	572	1	—	724
As of March 31, 2014					
Total Assets	$ 11,788	$ 20,175	$ 4,511	$ (3,148)	$ 33,326
Investments in Equity Method Subsidiaries	$ 123	$ —	$ 3	$ —	$ 126
As of December 31, 2013					
Total Assets	$ 12,002	$ 19,720	$ 4,025	$ (3,225)	$ 32,522
Investments in Equity Method Subsidiaries	$ 123	$ —	$ 3	$ —	$ 126

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations, primarily related to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 17. Related-Party Transactions.

Note 17. Related-Party Transactions

The following discussion relates to intercompany transactions, the majority of which are eliminated during the PSEG consolidation process in accordance with GAAP.

Power

The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended March 31, 2014	2013
	Millions	
Revenue from Affiliates:		
Billings to PSE&G through BGS and BGSS Contracts (A)	**$ 731**	**$ 671**
Expense Billings from Affiliates:		
Administrative Billings from Services (B)	$ (42)	$ (45)
Total Expense Billings from Affiliates	**$ (42)**	**$ (45)**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Related-Party Transactions	As of March 31, 2014	As of December 31, 2013
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$ 234	$ 267
Receivable from (Payable to) Services (B)	(26)	(31)
Receivable from (Payable to) PSEG (C)	(172)	97
Accounts Receivable (Payable)—Affiliated Companies, net	**$ 36**	**$ 333**
Short-Term Loan to Affiliate (Demand Note to PSEG) (D)	**$ 942**	**$ 790**
Working Capital Advances to Services (E)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable (Payable)	**$ (49)**	**$ (53)**

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended March 31, 2014	2013
	Millions	
Expense Billings from Affiliates:		
Billings from Power through BGS and BGSS (A)	$ (731)	$ (671)
Administrative Billings from Services (B)	(60)	(61)
Total Expense Billings from Affiliates	**$ (791)**	**$ (732)**

Related-Party Transactions	As of March 31, 2014	As of December 31, 2013
	Millions	
Payable to Power through BGS and BGSS Contracts (A)	$ (234)	$ (267)
Receivable from (Payable to) Services (B)	(53)	(73)
Receivable from (Payable to) PSEG (C)	(6)	150
Accounts Receivable (Payable)—Affiliated Companies, net	**$ (293)**	**$ (190)**
Working Capital Advances to Services (E)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Receivable (Payable)	**$ (82)**	**$ (72)**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to Power and PSE&G at cost. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

(E) Power and PSE&G have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on Power's and PSE&G's Condensed Consolidated Balance Sheets.

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Note 18. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LC. The following table presents condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended March 31, 2014					
Operating Revenues	$ —	$ 2,077	$ 40	$ (417)	$ 1,700
Operating Expenses	4	1,797	34	(417)	1,418
Operating Income (Loss)	(4)	280	6	—	282
Equity Earnings (Losses) of Subsidiaries	177	—	4	(177)	4
Other Income	8	33	—	(8)	33
Other Deductions	(4)	(6)	—	—	(10)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(28)	(7)	(5)	8	(32)
Income Tax Benefit (Expense)	15	(125)	(1)	—	(111)
Net Income (Loss)	**$ 164**	**$ 173**	**$ 4**	**$ (177)**	**$ 164**
Comprehensive Income (Loss)	**$ 170**	**$ 176**	**$ 4**	**$ (180)**	**$ 170**
Three Months Ended March 31, 2014					
Net Cash Provided By (Used In) Operating Activities	$ 291	$ 603	$ 1	$ (221)	$ 674
Net Cash Provided By (Used In) Investing Activities	$ 87	$ (315)	$ —	$ (67)	$ (295)
Net Cash Provided By (Used In) Financing Activities	$ (375)	$ (287)	$ (1)	$ 288	$ (375)
Three Months Ended March 31, 2013					
Operating Revenues	$ —	$ 1,803	$ 37	$ (389)	$ 1,451
Operating Expenses	2	1,562	33	(388)	1,209
Operating Income (Loss)	(2)	241	4	(1)	242
Equity Earnings (Losses) of Subsidiaries	153	—	3	(153)	3
Other Income	9	48	—	(10)	47
Other Deductions	(8)	(20)	—	—	(28)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(27)	(10)	(4)	11	(30)
Income Tax Benefit (Expense)	16	(108)	1	—	(91)
Net Income (Loss)	**$ 141**	**$ 149**	**$ 4**	**$ (153)**	**$ 141**
Comprehensive Income (Loss)	**$ 173**	**$ 172**	**$ 4**	**$ (176)**	**$ 173**
Three Months Ended March 31, 2013					
Net Cash Provided By (Used In) Operating Activities	$ 189	$ 574	$ 1	$ (189)	$ 575
Net Cash Provided By (Used In) Investing Activities	$ 56	$ (353)	$ (8)	$ (24)	$ (329)
Net Cash Provided By (Used In) Financing Activities	$ (245)	$ (221)	$ 7	$ 212	$ (247)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
As of March 31, 2014					
Current Assets	$ 4,109	$ 9,145	$ 951	$ (11,906)	$ 2,299
Property, Plant and Equipment, net	81	6,082	1,172	—	7,335
Investment in Subsidiaries	4,570	727	—	(5,297)	—
Noncurrent Assets	301	1,832	138	(117)	2,154
Total Assets	**$ 9,061**	**$ 17,786**	**$ 2,261**	**$ (17,320)**	**$ 11,788**
Current Liabilities	$ 603	$ 11,103	$ 980	$ (11,905)	$ 781
Noncurrent Liabilities	308	2,323	344	(118)	2,857
Long-Term Debt	2,497	—	—	—	2,497
Member's Equity	5,653	4,360	937	(5,297)	5,653
Total Liabilities and Member's Equity	**$ 9,061**	**$ 17,786**	**$ 2,261**	**$ (17,320)**	**$ 11,788**
As of December 31, 2013					
Current Assets	$ 4,160	$ 8,916	$ 944	$ (11,544)	$ 2,476
Property, Plant and Equipment, net	81	6,108	1,178	—	7,367
Investment in Subsidiaries	4,645	729	—	(5,374)	—
Noncurrent Assets	222	1,847	138	(48)	2,159
Total Assets	**$ 9,108**	**$ 17,600**	**$ 2,260**	**$ (16,966)**	**$ 12,002**
Current Liabilities	$ 444	$ 10,919	$ 982	$ (11,545)	$ 800
Noncurrent Liabilities	309	2,247	338	(47)	2,847
Long-Term Debt	2,497	—	—	—	2,497
Member's Equity	5,858	4,434	940	(5,374)	5,858
Total Liabilities and Member's Equity	**$ 9,108**	**$ 17,600**	**$ 2,260**	**$ (16,966)**	**$ 12,002**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **Power,** our wholesale energy supply company that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States, and
- **PSE&G,** our public utility company which provides electric transmission services and distribution of electric energy and natural gas, implements demand response and energy efficiency programs and invests in solar generation in New Jersey.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which effective January 1, 2014, operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business of our 2013 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Overview of 2013 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2014 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2013 Form 10-K.

OVERVIEW OF 2014 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth in response to market, regulatory and economic trends while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- Growing our utility operations through continued investment in T&D infrastructure projects with a consequential rebalancing of our business mix and greater diversification of regulatory oversight, and
- Maintaining a reliable generation fleet with the flexibility to utilize a diverse mix of fuels to allow us to respond to market volatility and capitalize on market opportunities as they arise in the locations in which we operate.

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Financial Results

The results for PSEG, PSE&G and Power for the three months ended March 31, 2014 and 2013 are presented as follows:

Earnings (Losses)	Three Months Ended March 31, 2014	2013
	Millions	
Power (A)	$ 164	$ 141
PSE&G	214	179
Other (B)	8	—
PSEG Net Income	**$ 386**	**$ 320**
PSEG Net Income Per Share (Diluted)	**$ 0.76**	**$ 0.63**

(A) Power's results in 2014 and 2013 include after-tax expenses of $9 million and $28 million, respectively, for Operations and Maintenance (O&M) costs due to severe damage caused by Superstorm Sandy. See Note 8. Commitments and Contingent Liabilities.

(B) Other primarily includes parent company interest and financing activity and certain administrative and general expenses.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended March 31, 2014	2013
	Millions, after tax	
NDT Fund Income (Expense) (A)	$ 9	$ 9
Non-Trading MTM Gains (Losses)	$ (132)	$ (105)

(A) NDT Fund Income (Expense) includes the net realized gains, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in O&M Expense, as well as the depreciation related to the ARO asset.

Our $66 million increase in Net Income for the three months ended March 31, 2014 includes the MTM and NDT activity presented in the preceding table and was also impacted by:

- higher energy volumes sold primarily in the PJM and New England (NE) regions at higher average realized prices as well as higher capacity revenues primarily in PJM resulting from higher average prices,
- higher sales volumes under the basic gas supply service (BGSS) contract due to colder average temperatures, and
- higher revenues due to increased investments in transmission projects.

These increases were partially offset by

- higher generation costs due to higher fuel costs and higher gas costs related to the BGSS contract, and
- higher O&M costs due to a planned outage at our Linden fossil station partly offset by lower pension and other postretirement benefit (OPEB) costs and cost control measures.

Power's results also benefited from access to reasonably-priced natural gas supplies through its existing firm pipeline transportation during the cold weather experienced in the first quarter of 2014. Power manages these contracts for the benefit of PSE&G's customers through the BGSS arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to supply gas to its generating units in New Jersey and to make third party sales.

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At PSE&G, our regulated utility, we continued to invest capital in T&D infrastructure projects aimed at maintaining the reliability of our service to our customers. PSE&G's results for the first quarter of 2014 reflect the favorable impacts from these investments. In December 2013, we filed a Modified 2014 Annual Formula Rate Update with the Federal Energy Regulatory Commission (FERC) which provides for approximately $171 million in increased annual transmission revenues effective January 1, 2014. Over the past few years, these types of investments have altered the business mix of PSEG's overall results of operations to reflect a higher percentage contribution by PSE&G.

Regulatory, Legislative and Other Developments

In developing and implementing our strategy of operational excellence, financial strength and disciplined investment, we monitor significant regulatory and legislative developments. Competitive wholesale power market design is of particular importance to our results and we continue to advocate for policies and rules that promote competitive electricity markets. This includes opposing efforts by states to subsidize generation while supporting rule changes which we believe are necessary to avoid artificial price suppression and other distortions in the energy and capacity markets.

We continue to advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. In particular, the EPA's 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. Clean Air Act (CAA) regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology (MACT) rules are also of significance; however, we believe our generation business remains well-positioned for such air pollution control regulations if and when they are implemented.

The FERC's rules under Order 1000 altered the right of first refusal previously held by incumbent utilities to build all transmission within their respective service territories. We are challenging the FERC's determination in court as we do not believe that the FERC sufficiently justified its decision to alter this right embedded in the FERC-approved contracts and tariffs. At the same time, the FERC's action presents opportunities for us to construct transmission outside of our service territory.

In the fourth quarter of 2012, we were severely impacted by Superstorm Sandy, which resulted in the highest level of customer outages in our history. For more detailed information, refer to Item 1—Note 8. Commitments and Contingent Liabilities—Superstorm Sandy. In February 2013, we filed a petition with the New Jersey Board of Public Utilities (BPU) describing our Energy Strong program, consisting of $3.9 billion of proposed improvements we recommend making to our gas and electric distribution systems over a ten-year period to improve resiliency. In the petition, we sought approval for $2.6 billion of the $3.9 billion of investments over an initial five-year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. On May 1, 2014, we reached a $1.22 billion settlement on our Energy Strong proposal. The settlement provides for cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated allowance for funds used during construction (AFUDC), through an accelerated recovery mechanism. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, to be filed no later than November 1, 2017. The stipulation, signed by the staff of the BPU, the New Jersey Division of Rate Counsel and AARP, is now being reviewed by the other parties and participants in the case and will be submitted to the BPU for review and approval. We believe that the rate impacts of the Energy Strong program will be significantly muted as a result of scheduled reductions to customer bills that will be taking place over the next few years and assuming continued low gas prices. For more detailed information, refer to Item 5. Other Information—Energy Strong Program.

On January 1, 2014, we commenced operation of the LIPA T&D system under a twelve-year contract with opportunity to extend for an additional eight years. Also, beginning in 2015, Power will provide fuel procurement and power management services to LIPA under separate agreements.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. In the first three months of 2014, our

- total nuclear fleet achieved an average capacity factor of 100%,
- solid performance, a diverse fuel mix and dispatch flexibility allowed us to increase generation as compared to the comparable 2013 period by 3% to meet demand, while balancing fuel availability and price volatility, and
- construction of transmission and solar projects proceeded on schedule and within budget.

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Financial Strength

Our financial strength is predicated on a solid balance sheet, positive cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first three months 2014 as we:

- had cash on hand of $655 million as of March 31, 2014,
- extended the expiration dates of PSEG's $500 million and Power's $1.6 billion five-year credit facilities from 2017 to 2019, and maintained substantial liquidity and solid investment grade credit ratings, and
- increased our indicated annual dividend for 2014 to $1.48 per share.

We expect to be able to fund our transmission projects required under PJM's reliability program, our Energy Strong program and other projects with internally generated cash and external debt financing.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first quarter of 2014 we:

- made additional investments in transmission infrastructure projects,
- continued to execute our existing BPU-approved utility programs,
- initiated installation of equipment to increase output and improve efficiency at our existing combined cycle gas turbine generation facilities, and
- commenced operation of a newly constructed 4 MW solar project in California.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a difficult economy and cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully re-contract our open supply positions,
- execute our capital investment program, including our Energy Strong program and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and the FERC of market design rules that continue to protect competition and achieve appropriate Reliability Pricing Model (RPM) and basic generation service (BGS) pricing,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system.

For the remainder of 2014 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, particularly with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer demand,
- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate,
- the aftermath of Hurricane Irene and Superstorm Sandy, including addressing the BPU's review of performance and communications, and
- delays and other obstacles that might arise in connection with the construction of our T&D projects, including in connection with permitting and regulatory approvals.

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RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, Power and PSE&G, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Note 17. Related-Party Transactions.

	Three Months Ended March 31,		Increase/ (Decrease)	
	2014	2013	2014 vs. 2013	
	Millions		Millions	%
Operating Revenues	$ 3,223	$ 2,786	$ 437	16
Energy Costs	1,356	1,155	201	17
Operation and Maintenance	856	710	146	21
Depreciation and Amortization	306	290	16	6
Taxes Other than Income Taxes	—	21	(21)	(100)
Income from Equity Method Investments	4	2	2	100
Other Income and (Deductions)	36	32	4	13
Other-Than-Temporary Impairments	2	2	—	—
Interest Expense	97	102	(5)	(5)
Income Tax Expense	260	220	40	18

The 2014 amounts in the preceding table for Operating Revenues and Operation and Maintenance (O&M) Costs each include $89 million for Long Island Electric Utility Servco, LLC, a wholly owned subsidiary of PSEG LI. These amounts represent the O&M pass-through costs for the Long Island operations, the full reimbursement of which is reflected in Operating Revenues. See Note 3. Variable Interest Entities for further explanation. The following discussions for Power and PSE&G provide a detailed explanation of their respective variances.

Power

	Three Months Ended March 31,		Increase/ (Decrease)	
	2014	2013	2014 vs. 2013	
	Millions		Millions	%
Operating Revenues	$ 1,700	$ 1,451	$ 249	17
Energy Costs	1,044	860	184	21
Operation and Maintenance	302	283	19	7
Depreciation and Amortization	72	66	6	9
Income from Equity Method Investments	4	3	1	33
Other Income (Deductions)	23	19	4	21
Other-Than-Temporary Impairments	2	2	—	—
Interest Expense	32	30	2	7
Income Tax Expense	111	91	20	22

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Three Months Ended March 31, 2014 as Compared to 2013

Operating Revenues increased $249 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues increased $151 million due primarily to

- higher net revenues of $111 million due primarily to higher energy volumes sold in the PJM and NE regions at higher average realized prices, partially offset by lower generation sold in the New York region and higher MTM losses in 2014 resulting from an increase in prices on forward positions, and
- a net increase of $65 million due primarily to higher capacity revenues resulting from higher average auction prices partially offset by a decrease in operating reserve revenues in PJM,
- partially offset by a decrease of $15 million due primarily to lower volumes of electricity sold under our BGS contracts as a result of serving fewer tranches than in 2013 and lower average pricing, and
- a net decrease of $11 million due to lower volumes on wholesale load contracts in the PJM and NE regions.

Gas Supply Revenues increased $94 million due primarily to

- a net increase of $79 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during the 2014 winter heating season, and
- an increase of $15 million due to higher sales volumes to third party customers with higher average sales prices.

Other Operating Revenues increased $4 million due to transition fees related to fuel management and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $184 million due to

- ***Generation costs*** increased $141 million due primarily to $247 million of higher fuel costs, reflecting higher average realized natural gas prices, high nuclear fuel costs, the utilization of higher volumes of natural gas, coal and oil and the unfavorable MTM impact from lower average unrealized natural gas prices on forward positions and $14 million in higher energy purchases, primarily in the PJM and NE regions as result of higher prices. These higher fuel costs and energy purchases were largely offset by $120 million of lower congestion costs in the PJM region.
- ***Gas costs*** increased $43 million, principally related to obligations under the BGSS contract, reflecting higher sales volumes in 2014 due to colder average temperatures during the 2014 winter heating season, partially offset by lower average gas inventory costs.

Operation and Maintenance increased $19 million due primarily to

- higher planned outage fossil costs of $54 million, primarily at our Linden plant in New Jersey, and
- higher outside service costs of $5 million,
- partially offset by lower storm costs of $19 million,
- a decrease in pension and OPEB costs of $14 million, and
- lower nuclear outage costs of $10 million largely due to the timing of planned outage costs at our Salem facility.

Depreciation and Amortization increased $6 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) experienced no material change.

Interest Expense increased $2 million due primarily to the issuance of $500 million of Senior Notes in November 2013, partially offset by the maturity of $300 million of Senior Notes in April 2013.

Income Tax Expense increased $20 million in 2014 due primarily to higher pre-tax income.

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PSE&G

	Three Months Ended March 31,		Increase/ (Decrease)	
	2014	2013	2014 vs. 2013	
	Millions		Millions	%
Operating Revenues	$ 2,145	$ 1,995	$ 150	8
Energy Costs	1,045	967	78	8
Operation and Maintenance	462	427	35	8
Depreciation and Amortization	227	215	12	6
Taxes Other Than Income Taxes	—	21	(21)	(100)
Other Income (Deductions)	14	12	2	17
Interest Expense	68	73	(5)	(7)
Income Tax Expense	143	125	18	14

Three Months Ended March 31, 2014 as Compared to 2013

Operating Revenues increased $150 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $54 million due primarily to an increase in transmission revenues.

- Transmission revenues were $39 million higher due to net rate increases resulting primarily from increased capital investments.
- Electric distribution revenues increased $9 million due primarily to higher revenue from Green Program Recovery Charges (GPRC) of $16 million and higher sales volumes of $4 million, partially offset by lower Transitional Energy Facilities Assessment (TEFA) revenue of $11 million due to elimination of the TEFA rate effective January 1, 2014.
- Gas distribution revenues increased $6 million due primarily to $51 million from higher sales volumes, partially offset by lower Weather Normalization Clause (WNC) revenue of $36 million due to colder than normal weather and lower TEFA revenue of $10 million due to elimination of TEFA rate effective January 1, 2014.

Commodity Revenue increased $78 million due to higher Electric and Gas revenues. This is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues increased $49 million due primarily to $52 million in higher BGS revenues, partially offset by $3 million in lower revenues from collection of Non-Utility Generation Charges (NGC) and sales of Non-Utility generation (NUG) energy due to lower volume, partially offset by higher prices. BGS sales increased 10% due primarily to weather, partially offset by customer migration to third party suppliers (TPS).
- Gas revenues increased $29 million due primarily to higher BGSS volumes of $90 million, partially offset by lower BGSS prices of $61 million The average price of natural gas was 12% lower in 2014.

Clause Revenues increased $16 million due primarily to higher Societal Benefit Charges (SBC). The change in the SBC amount was entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC collections.

Other Operating Revenues increased $2 million due to higher miscellaneous electric operating revenues.

Operating Expenses

Energy Costs increased $78 million. This is entirely offset by Commodity Revenue.

- Electric costs increased $49 million or 11% due to $52 million of increased deferred cost recovery and $8 million of higher BGS and NUG prices, partially offset by $11 million in lower BGS and NUG volumes. BGS and NUG volumes decreased 2% due primarily to customer migration to TPS.
- Gas costs increased $29 million or 5% due to $90 million or 17% in higher sales volumes, partially offset by $61 million or 12% in lower prices.

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Operation and Maintenance increased $35 million, of which the most significant components were

- a $34 million increase in costs related primarily to GPRC and SBC. Due to the nature of the GPRC and SBC clause mechanisms, these are entirely offset in revenues, and
- a $13 million increase in winter storm-related costs and extreme weather conditions,
- partially offset by an $18 million decrease in pension and OPEB expenses.

Depreciation and Amortization increased $12 million due primarily to

- an $8 million increase in depreciation of additional plant in service, and
- a $3 million increase in amortization of Regulatory Assets.

Taxes Other Than Income Taxes decreased $21 million due to elimination of the TEFA rate effective January 1, 2014.

Other Income and (Deductions) experienced no material change.

Interest Expense decreased $5 million due primarily to a lower average securitization debt balance.

Income Tax Expense increased $18 million due primarily to higher pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund planned capital expenditures and shareholder dividend payments.

For the three months ended March 31, 2014, our operating cash flow increased $239 million as compared to the same period in 2013. The net change was due primarily to net changes from Power and PSE&G, as discussed below.

Power

Power's operating cash flow increased $99 million from $575 million to $674 million for the three months ended March 31, 2014, as compared to the same period in 2013, primarily resulting from higher earnings, a net tax refund and a $43 million decrease in employee benefit plan funding, partially offset by an increase of $144 million related to margin deposits.

PSE&G

PSE&G's operating cash flow increased $250 million from $329 million to $579 million for the three months ended March 31, 2014, as compared to the same period in 2013, due primarily to higher earnings, an increase in regulatory liabilities from over-collections primarily related to BGSS gas costs and Gas Weather Normalization Charges, a $91 million decrease in employee benefit plan funding and a net tax refund.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our $4.3 billion credit facilities are provided by a diverse bank group. As of March 31, 2014, our total available credit capacity was $4.1 billion.

As of March 31, 2014, no single institution represented more than 8% of the total commitments in our credit facilities.

As of March 31, 2014, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. In April 2014, PSEG and Power amended their 2012 credit agreements ending in 2017, extending the expiration date from March 2017 to April 2019. PSEG's $500 million and Power's $1.6 billion facility amendments, resulting in total commitments of $2.1 billion, will mature in 2019.

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Our total credit facilities and available liquidity as of March 31, 2014 were as follows:

Company/Facility	As of March 31, 2014 Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
		Millions			
PSEG					
5-year Credit Facility (A)	$ 500	$ 8	$ 492	Mar 2017	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (B)	500	—	500	Mar 2018	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 8**	**$ 992**		
Power					
5-year Credit Facility (A)	$ 1,600	$ 67	$ 1,533	Mar 2017	Funding/Letters of Credit
5-year Credit Facility (C)	1,000	—	1,000	Mar 2018	Funding/Letters of Credit
Bilateral Credit Facility	100	100	—	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 167**	**$ 2,533**		
PSE&G					
5-year Credit Facility (D)	$ 600	$ 13	$ 587	Mar 2018	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 13**	**$ 587**		
Total	**$ 4,300**	**$ 188**	**$ 4,112**		

(A) In April 2014, the expiration dates of these facilities were extended to April 2019.

(B) In April 2016, this facility will be reduced by $23 million.

(C) In April 2016, this facility will be reduced by $48 million.

(D) In April 2016, this facility will be reduced by $29 million.

Long-Term Debt Financing

PSE&G has $250 million of 5.00%, Series D, Medium Term Notes and $250 million of 0.85%, Series G, Medium Term Notes both maturing in August 2014.

Power has a $44 million pollution control facilities loan servicing and securing a Pennsylvania Economic Development Financing Authority (PEDFA) bond due November 2042. The bond is backed by a three-year letter of credit that expires in November 2014. The PEDFA bond has been reclassified as debt due within the year.

For a discussion of our long-term debt transactions during 2014, see Note 9. Changes in Capitalization.

Common Stock Dividends

On February 18, 2014, our Board of Directors approved a $0.37 per share common stock dividend for the first quarter of 2014. On April 15, 2014, our Board of Directors declared a quarterly dividend of $0.37 per share of common stock for the second quarter of 2014. This reflects an indicated annual dividend rate of $1.48 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Note 15. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security. In January 2014, Moody's upgraded PSE&G's Mortgage Bond Rating from A1 to Aa3 and its commercial paper rating from P2 to P1. PSE&G's outlook is stable. In April 2014, S&P revised the outlooks to

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positive from stable for the corporate credit and senior unsecured long-term ratings of PSEG, PSE&G and Power. S&P also affirmed the senior unsecured rating of BBB+ at Power and senior secured rating of A at PSE&G.

	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	**Stable**	**Stable**	**Stable**
Commercial Paper	P2	A2	F2
Power			
Outlook	**Stable**	**Positive**	**Stable**
Senior Notes	Baa1	BBB+	BBB+
PSE&G			
Outlook	**Stable**	**Stable**	**Stable**
Mortgage Bonds	Aa3	A	A+
Commercial Paper	P1	A2	F2

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1+ (highest) to D (lowest) for short-term securities.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1+ (highest) to D (lowest) for short-term securities.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures at Power and Services as compared to amounts disclosed in our 2013 Form 10-K. PSE&G has increased its total projected capital expenditures through 2016 by $295 million, including $145 million for additional transmission reliability enhancements in 2015 and $50 million and $100 million in 2015 and 2016, respectively, related to additional distribution expenditures for reliability enhancements and facility replacement.

On May 1, 2014, we reached a settlement with the BPU Staff on our Energy Strong proposal, agreeing that PSE&G would spend $1.22 billion to protect and strengthen PSE&G's electric and gas systems against severe weather conditions over primarily a three-year period with some projects extending over five years. This amount is not included in the projected capital expenditures disclosed in our 2013 Form 10-K or in the increases reported above. See Item 5. Other Information—Energy Strong Program for additional information.

Power

During the three months ended March 31, 2014, Power made capital expenditures of $100 million, excluding $26 million for nuclear fuel, primarily related to various projects at is fossil and nuclear generation stations.

PSE&G

During the three months ended March 31, 2014, PSE&G made $483 million of capital expenditures, including $481 million of investment in plant, primarily for transmission and distribution system reliability and $2 million in solar loan investments. This does not include expenditure for cost of removal, net of salvage, of $25 million, which is included in operating cash flows.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Note 2. Recent Accounting Standards.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The market risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

During January 2014, extreme weather conditions drove increases in price volatility associated with energy commodities. This led to an increase in VaR during the month of January. VaR subsequently decreased during the months of February and March.

	MTM VaR	
	Three Months Ended March 31, 2014	Year Ended December 31, 2013
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 17	$ 12
Average for the Period	$ 52	$ 15
High	$ 195	$ 29
Low	$ 14	$ 8
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 26	$ 18
Average for the Period	$ 82	$ 23
High	$ 306	$ 46
Low	$ 22	$ 13

See Note 10. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the first quarter of 2014 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3. of Part I of the 2013 Annual Report on Form 10-K, see Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

There are no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2013 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the first quarter of 2014:

Three Months Ended March 31, 2014	Total Number of Shares Purchased	Average Price Paid per Share
January 1 - January 31	—	$ —
February 1 - February 28	427,711	$ 36.82
March 1 - March 31	341,606	$ 36.65

ITEM 5. OTHER INFORMATION

Certain information reported in the 2013 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2013 Annual Report on Form 10-K. References are to the related pages on the Form 10-K as printed and distributed.

Federal Regulation

FERC

Regulation of Wholesale Sales—Generation/Market Issues

Energy Clearing Prices

December 31, 2013 Form 10-K page 16. As a result of the polar vortex and related cold weather events in January 2014, there were both gas and electric price spikes in the Northeast markets, including in PJM. The FERC is currently examining the facts surrounding these price spikes, as well as "lessons learned" from the various Regional Transmission Operators/Independent System Operators (RTO/ISO) and potential changes in market rules intended to encourage dual fuel capability of generating units and purchase of firm fuel to fire these units. In addition, PJM's Market Monitor has requested information from all market participants in PJM, including Power, looking at bidding behavior to rule out underlying market manipulation. The FERC has also gathered information but has not commenced an investigation. We cannot predict what action, if any, the FERC may take.

Capacity Market Issues

December 31, 2013 Form 10-K page 16. PJM, the New York ISO (NYISO), and the ISO-New England each have capacity markets that have been approved by the FERC. The FERC regulates these markets and continues to examine whether the market design for these three capacity markets is working optimally. One of the specific issues being considered by the FERC and addressed at an industry-wide technical conference in 2013 is whether capacity market rules are properly responding to, and fostering the development of, state public policies, demand response, fuel diversity and emerging technologies, as well as addressing concerns raised by future generation retirements. We cannot predict what action, if any, the FERC might take with regard to capacity market design.

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Capacity Market Issues—PJM

December 31, 2013 Form 10-K page 16. The FERC has issued orders (i) capping the amount of "limited" demand response resources (i.e. resources which can only be called on by PJM a limited number of times during the summer months) that can clear in PJM's capacity auctions and (ii) imposing requirements that these resources have "sell-offer" plans and accompanying officer certifications attesting to the resources' availability. PJM expects that capping "limited" demand response participation will have an upward effect on capacity prices in the next auction. The FERC is also currently considering filings made by PJM to (i) impose additional operational requirements on demand response resources and (ii) limit the reliance of these resources on PJM's incremental auctions to buy back additional capacity to cover commitments made in the base residual auctions.

Capacity Market Issues—Midwest Independent System Operator (MISO)

December 31, 2013 Form 10-K page 16. The import into PJM of significant amounts of MISO generation that is not subject to the same type of rules and requirements as generation that is located within PJM could adversely impact Power. The FERC has recently issued an order permitting PJM to establish annual capacity import limits, which have been incorporated into the 2017/2018 planning parameters for the May 2014 base residual auction.

Capacity Market Issues—NYISO

December 31, 2013 Form 10-K page 17. NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. Prior to 2013, the NYISO capacity model had recognized only two separate zones that potentially may separate in price: New York City and Long Island. In 2013, the FERC issued an order approving a third capacity zone that will encompass the super zone that includes the lower Hudson Valley and New York City to take effect May 1, 2014. In January 2014, the FERC issued an order accepting the NYISO's proposed reference unit (a generation unit with no environmental controls) that should be used for the purposes of establishing the cost of new entry (CONE) in the "rest of State" zone (excluding the lower Hudson Valley, New York City and Long Island), which may have the effect of depressing capacity prices. This order is significant since it will set the demand curve on which future capacity prices paid to generators will be based for the period May 1, 2014 through April 30, 2017. This order is currently on rehearing.

Transmission Regulation—Transmission Rate Proceedings

In December 2013, PSE&G was assigned construction responsibility by PJM of a new transmission project that will provide a double-circuit 345 kV line in the Bergen-Linden Corridor (BLC Project) to maintain reliability. Phases One through Three of the BLC Project are scheduled to be in service in 2016, 2017 and 2018, respectively, with certain components of Phase One required to be in service as early as June 2015. The estimated construction costs of the BLC Project are $1.2 billion. The net increase in PSE&G's capital expenditures is expected to be less than the estimated cost of the BLC Project, as it will eliminate the need for certain other projects that had been previously assigned by PJM. On March 28, 2014, we filed a petition with FERC seeking recovery of Construction Work in Progress in rate base and authorization to recover 100% of all prudently incurred development and construction costs if the BLC Project is abandoned or canceled, in whole or in part, for reasons beyond the control of PSE&G. This matter is pending.

Compliance—FERC Audit

December 31, 2013 Form 10-K page 18. Each of the PSEG companies that have market-based rate (MBR) authority from the FERC is being audited by the FERC for compliance with its rules for (i) receiving and retaining MBR authority, (ii) the filing of electric quarterly reports, and (iii) our units' receipt of payments from the RTO/ISO when they are required to run for reliability reasons when it is not economical for them to do so.

Power has discovered that it incorrectly calculated certain components of its cost-based bids for certain generating units in the PJM energy market, with resulting over-collection of revenues related to its fossil fleet. Power has notified the FERC, PJM and the PJM Independent Market Monitor of this issue. This matter is still under review, and we are unable to estimate the ultimate impact or predict any resulting penalties or other costs associated with this matter at the current time.

Compliance—Reliability Standards

December 31, 2013 Form 10-K page 18. Congress has required the FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the United States electric transmission and generation system (grid) and to prevent major system blackouts. There has been considerable focus recently on physical security in light of a substation attack in California that occurred in 2013. As a result, the FERC has directed the NERC to draft a physical security standard intended to further protect assets deemed "critical" to reliability of the grid. The NERC is expected to submit a draft standard to the FERC for its review by the end of May 2014. The NERC may direct that additional controls be put in place at these "critical" assets or could direct that utilities build additional redundancy into their systems.

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Nuclear Regulatory Commission (NRC)

December 31, 2013 Form 10-K page 19. In 2011, the NRC task force submitted a report containing various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. The NRC staff also issued a document which provided for a prioritization of the task force recommendations. The NRC approved the staff's prioritization and implementation recommendations subject to a number of conditions. Among other things, the NRC advised the staff to give the highest priority to those activities that can achieve the greatest safety benefit and/or have the broadest applicability (Tier 1), to review filtration of boiling water reactor (BWR) primary containment vents and encouraged the staff to create requirements based on a performance-based system which allows for flexible approaches and the ability to address a diverse range of site-specific circumstances and conditions and strive to implement the requirements by 2016. The NRC issued letters and orders to licensees implementing the Tier 1 recommendations in March 2012. We are implementing the diverse and flexible strategies and spent fuel pool level indication modifications in accordance with the regulatory requirements at the Salem, Hope Creek and Peach Bottom nuclear units.

Separately, a petition was filed with the NRC in April 2011 seeking suspension of the operating licenses of all General Electric BWRs utilizing the Mark I containment design in the United States, including our Hope Creek and Peach Bottom units, pending completion of the NRC review. Fukushima Daiichi Units 1-4 are BWRs equipped with Mark I containments. The petition names 23 of the total 104 active commercial nuclear reactors in the United States. On March 26, 2014, the NRC formally closed the petition without opting to conduct further proceedings.

State Regulation

Basic Gas Supply Service Contract (BGSS)

PSE&G procures the supply requirements of its default service BGSS gas customers through a full requirements contract with Power. This long-term arrangement had been for an initial period which extended through March 31, 2012 and continued on a year-to-year basis unless terminated by either party with a one year notice. On March 19, 2014, the BPU approved an extension of the BGSS contract to March 31, 2019 and then year to year thereafter unless terminated by either party with a two year notice.

Energy Strong Program

December 31, 2013 Form 10-K page 20. In February 2013, we filed a petition with the BPU describing the improvements we recommend making to our BPU jurisdictional electric and gas system to improve resiliency for the future. The changes that were described, designated as the “Energy Strong Program,” would be made over a ten-year period. In this petition, we sought approval to invest $0.9 billion in our gas distribution system and $1.7 billion in our electric distribution system over an initial five-year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. On May 1, 2014, we reached a settlement on our Energy Strong proposal. The stipulation, signed by the BPU Staff, the New Jersey Division of Rate Counsel and AARP, and now being reviewed by the other parties and participants in the case, will be submitted to the BPU for review and approval. Under the settlement, if approved, PSE&G will invest $1.22 billion to (1) upgrade all of its electric substations that were damaged by water in recent storms; make investments that will create redundancy in the electric distribution system, reducing outages when damage occurs; and deploy technologies to better monitor system operations, enabling PSE&G to restore customers more quickly in the event of an electric outage, and (2) with respect to PSE&G’s gas system, replace and modernize 250 miles of low-pressure cast iron gas mains in or near flood areas; and upgrade five natural gas metering stations and a liquefied natural gas station recently affected by severe weather or located in flood zones. The settlement provides for cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated AFUDC, and will occur for completed projects on a semi-annual (for electric investments) or annual (for gas investments) basis. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, to be filed no later than November 1, 2017.

Environmental Matters

Air Pollution Control

Cross-State Air Pollution Rule (CSAPR)

December 31, 2013 Form 10-K page 21. In July 2011, the EPA issued the final CSAPR, which limited power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season NO_x in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards. In August 2012, the U.S. Court of Appeals for the D.C. Circuit (D.C. Court) vacated CSAPR and ordered that the existing Clean Air Interstate Rule requirements remain in effect until an appropriate substitute rule has been promulgated. In June 2013, the Supreme Court announced that it would review the D.C. Court's decision. Oral arguments were held in December 2013. On April 29, 2014, the Supreme Court overturned the D.C. Court's ruling. Since the case has to be remanded to the D.C. Court to lift the stay on CSAPR, the timing for implementation of CSAPR is unknown at this time. We do not anticipate any material impact on our earnings and financial condition.

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Climate Change

Regional Greenhouse Gas Initiative (RGGI)

December 31, 2013 Form 10-K page 22. In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. Certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions. Generators may acquire allowances through a regional auction or through secondary markets.

New Jersey withdrew from RGGI beginning in 2012. As a result, our New Jersey facilities are no longer obligated to acquire CO_2 emission allowances. This action has been challenged by environmental groups in the New Jersey state court. On March 25, 2014, the Appellate Division of the New Jersey Superior Court ruled that the New Jersey Department of Environmental Protection (NJDEP) improperly withdrew its regulation under which RGGI had been implemented. The Court gave the NJDEP 60 days to initiate a public process to either repeal or amend that regulation to provide that it is applicable only when New Jersey is a participant in a regional or other established greenhouse gas program. The ruling does not reinstate New Jersey into RGGI. New Jersey executive branch officials have stated that New Jersey will not rejoin RGGI. We cannot predict the outcome of this matter.

Water Pollution Control

Steam Electric Effluent Guidelines

December 31, 2013 Form 10-K page 23. In April 2013, the EPA issued notice of a proposed rule that would further limit the discharge of pollutants in wastewater from the operation of coal-fired generating facilities. Our co-owned Keystone and Conemaugh facilities continue to use technologies that generate these wastewater discharges. However, our other coal-fired facilities no longer discharge many of these types of wastewater pollutants. We are unable to predict the impact on Keystone and Conemaugh but do not believe there would be any material impact on our other coal-fired facilities. The EPA is expected to finalize the rule in September 2015.

Cooling Water Intake Structure Regulation

December 31, 2013 Form 10-K page 23. In 2011, the EPA published a new proposed rule under Section 316(b) which did not establish any particular technology as the best technology available (e.g. closed-cycle cooling). Instead, the proposed rule established marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. We reviewed the proposed rule, assessed the potential impact on our generating facilities and used this information to develop our comments to the EPA which were filed in August 2011. In June 2012, the EPA posted a Notice of Data Availability (NODA) requesting comment on a series of technical issues related to the impingement mortality proposed standards. The EPA also posted a second NODA outlining its plans to finalize a “Willingness to Pay” survey it initiated to develop non-use benefits data in support of the initial rule proposal. We and industry trade associations submitted comments on both NODAs in July 2012. The EPA has rescheduled the date for adoption of a final rule several times. The EPA is currently scheduled to issue a final rule on May 16, 2014.

If the rule were to be adopted as originally proposed, the impact on us would be material since the majority of our electric generating stations would be affected. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Part I, Item 1. Financial Statements and Supplementary Data—Note 8. Commitments and Contingent Liabilities for additional information.

Waters of the United States

On April 21, 2014, the EPA Administrator and the Assistant Secretary of the Army (Civil Works) jointly published a proposed rule to clarify the definition of waters of the U.S. under the Clean Water Act (CWA) programs in order to protect the streams and wetlands that form the foundation of the nation’s water resources. This definition will have broad application to all areas of compliance under the CWA, including permitted discharges and construction activities. We are currently reviewing the proposed rule to determine the extent or materiality of its impact on our operations.

Fuel and Waste Disposal

Nuclear Fuel Disposal

December 31, 2013 Form 10-K page 24. The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit in federal court seeking suspension of the Nuclear Waste Fee. In 2013, the federal court ordered the Secretary of the U.S. Department of Energy (DOE) to submit a proposal to Congress to adjust the fee to zero. In January 2014, the Secretary of the DOE comported with the court order and submitted the zero fee adjustment change letter to

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Congress, subject to DOE appeal rights. Absent Congressional and/or further Court action, the fee will revert to zero after ninety days of continuous legislative session. The earliest this is anticipated to occur is in the second quarter of 2014. If the fee were to be eliminated, Power would see an annualized pre-tax benefit of approximately $30 million.

Coal Combustion Residuals (CCRs)

***December 31, 2013 Form 10-K page 23*.** In 2010, the EPA published a proposed rule offering three main options for the management of CCRs under the Resource Conservation and Recovery Act (RCRA). One of these options regulates CCRs as a hazardous waste while the other two options would continue to regulate the disposal of CCRS as a nonhazardous waste. In 2012, several environmental organizations and CCR marketers brought a citizens' suit against the EPA in federal court arguing that the EPA failed to perform its mandatory duty under RCRA to review and revise, if necessary, the RCRA rule applicable to CCRs. In 2012, the Utility Solid Waste Activities Group, of which PSEG is a member, filed a Motion to Intervene in order to be in alignment with the EPA in defending against the environmental organizations' action. On January 29, 2014, a consent decree, signed by all parties, was filed with the federal court requiring the EPA to issue a final rule by December 19, 2014. The final outcome of the EPA's rulemaking cannot be predicted.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 10:	Stock Plan for Outside Directors, as amended April 15, 2014
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. Power:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. PSE&G:

Exhibit 10:	Stock Plan for Outside Directors, as amended April 15, 2014
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: May 1, 2014

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SIGNATURE

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PSEG POWER LLC
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: May 1, 2014

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: May 1, 2014

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Exhibit 10

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
AMENDED AND RESTATED
STOCK PLAN FOR OUTSIDE DIRECTORS
APRIL 15, 2014

I. PURPOSE

The purpose of this Public Service Enterprise Group Incorporated Stock Plan for Outside Directors is to advance the interests of the Company and its stockholders by assisting the Company in attracting and retaining individuals of superior talent, ability and achievement to serve on its Board of Directors.

II. DEFINITIONS

The following words and phrases shall have the meanings set forth below unless a different meaning is required by the context:

a) Adjustment Shares: New or additional or different shares of Common Stock or other securities (other than rights or warrants to purchase securities) received or entitled to be received by an owner of Restricted Stock as a result of a change in capitalization of the Company as set forth in Article VIII hereof.

a) Annual Meeting: The Annual Meeting of Stockholders of the Company.

c) Board: The Board of Directors of the Company.

d) Committee: Those persons who are members of the Board but who are not Outside Directors.

e) Common Stock: The Common Stock without nominal or par value of the Company.

f) Company: Public Service Enterprise Group Incorporated, a corporation organized and existing under the laws of the State of New Jersey, or its successor or successors.

g) Disability: Any physical or mental condition of a permanent nature which, in sole reasonable judgment of the Committee, renders an Outside Director incapable of performing the duties of a member of the Board.

h) Effective Date: January 1, 1996. The Plan is amended effective April 15, 2014.

i) Eligible Director: An Outside Director who meets the eligibility requirements for stock awards as set forth in Article IV hereof.

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j) Exchange Act: The Securities and Exchange Act of 1934, as amended, or as it may be amended from time to time.

k) NYSE: The New York Stock Exchange, Inc.

l) Outside Director: A member of the Board on or after the Effective Date who never has been employed by the Company or any of its affiliates.

m) Outside Directors' Pension Plan: The Public Service Enterprise Group Incorporated Pension Plan for Outside Directors Effective January 1, 1989.

n) Plan: This Public Service Enterprise Group Incorporated Stock Plan for Outside Directors, as it may be amended from time to time.

o) Restricted Stock: Shares of Common Stock subject to restrictions awarded pursuant to Article IV hereof.

p) Securities Act: The Securities Act of 1933, as amended, or as it may be amended from time to time.

q) Service: A Director's service as a member of the Board.

r) Year of Service: The annual period commencing the day of each Annual Meeting and ending on the day before the next Annual Meeting. For any person first elected a member of the Board after the date of an Annual Meeting, his/her first Year of Service shall commence upon his/her election as a Director and shall end on the day before the next Annual Meeting.

III. SHARES SUBJECT TO THE PLAN

100,000 shares of Common Stock may be awarded as Restricted Stock pursuant to the terms of this Plan. Such shares may be acquired directly from the Company or, at the discretion of the Company, purchased on the open market by the Company or its agent. In the event that any shares of Restricted Stock shall be forfeited, the shares so forfeited shall again be available for the awarding of Restricted Stock under the Plan.

IV. RESTRICTED STOCK AWARDS

A. Upon the commencement of each Year of Service as a member of the Board, each Outside Director shall be granted an award of Restricted Stock in an amount as shall be establish from time to time by the Board of Directors. The date of grant shall be the first business day of the month following the Annual Meeting or the Outside Director's first election as a member of the Board.

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B. Upon the Effective Date of this Plan, (i) each Outside Director who shall have completed five Years of Service as of December 31, 1995 shall be granted an award of shares of Restricted Stock equal to the present value (assuming commencement of payment at age 70) of what his/her vested accrued benefit under the Outside Directors' Pension Plan would have been had he/she terminated Service as of December 31, 1995. The actual number of shares will be determined by dividing said Outside Directors' Pension Plan assumed vested accrued benefit by the closing price of the Common Stock on the NYSE on December 29, 1995 and rounding up to the next whole share; (ii) each Outside Director who shall not have completed five Years of Service as of December 31, 1995 shall be granted an award of shares of Restricted Stock equal in number to 300 times the number of years he/she has been a member of the Board, all as reflected in Schedule A to the Plan.

C. The award of shares of Restricted Stock, including the restrictions thereon, shall be evidenced by a written instrument in such form and upon such terms and conditions as the Committee shall determine and as are consistent with the following provisions of the Plan:

i) Upon the retirement of an Outside Director as a member of the Board at the Annual Meeting next following the Outside Director's 70th birthday, the restrictions on the Restricted Stock shall lapse and the Company shall issue to the Outside Director a certificate for the shares which have been awarded to him/her without any legend or restriction of any kind and the Company shall return to the Outside Director or destroy any and all blank stock powers previously provided to it by such Outside Director. With respect to shares of restricted stock outstanding immediately prior to the April 15, 2014 Annual Meeting, upon the retirement of an Outside Director in accordance with the Retirement Policy for Directors under the Corporate Governance Principles in effect at the time of the Outside Director retires ("Retirement Policy"), the restrictions on the Restricted Stock shall lapse and the Company shall issue to the Outside Director a certificate for the shares which have been awarded to him/her without any legend or restriction of any kind and the Company shall return to the Outside Director or destroy any and all blank stock powers previously provided to it by such Outside Director.

ii) If the service as a member of the Board of an Outside Director who is the recipient of the shares of Restricted Stock terminates for any reason, other than on account of Disability, before the Annual Meeting next following said Outside Director's 70th birthday, such Outside Director shall forfeit any and all rights in and to the shares of Restricted Stock; provided, however, that, the Committee may, for good and valid business reasons, waive such restriction as the Committee deems appropriate.

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With respect to shares of restricted stock outstanding immediately prior to the April 15, 2014 Annual Meeting, if the service as a member of the Board of an Outside Director who is the recipient of the shares of Restricted Stock terminates for any reason, other than on account of Disability, before the date specified in the Retirement Policy, such Outside Director shall forfeit any and all rights in and to the shares of Restricted Stock; provided, however, that, the Committee may, for good and valid business reasons, waive such restriction as the Committee deems appropriate.

Notwithstanding any other provision of this Plan, upon the occurrence of a termination of Service following a Change in Control (as defined below), all restrictions on the Restricted Stock shall immediately lapse and be of no effect.

For the purposes of this Plan, "Change in Control" shall mean the occurrence of any of the following events:

a) any "person" (within the meaning of Section 13(d) of the Exchange Act is or becomes the beneficial owner within the meaning of Rule 13d-3 under the Exchange Act (a "Beneficial Owner"), directly or indirectly, of securities of the Company (not including in the securities beneficially owned by such person any securities acquired directly from the Company or its affiliates) representing 25% or more of the combined voting power of the Company's then outstanding securities, excluding any person who becomes such a Beneficial Owner in connection with a transaction described in clause (1) of paragraph (c) below; or

b) the following individuals cease for any reason to constitute a majority of the number of directors then serving: individuals who, on December 15, 1998, constitute the Board of Directors and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation. relating to the election of directors of the Company) whose appointment or election by the Board of Directors or nomination for election by the Company's stockholders was approved or recommended by a vote of at least two -thirds (2/3) of the directors then still in office who either were directors on December 15, 1998 or whose appointment, election or nomination for election was previously so approved or recom-mended: or

c) there is consummated a merger or consolidation of the Company or any direct or indirect wholly owned subsidiary of the Company with any other corporation other than (1) a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining

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outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of the Company or any subsidiary of the Company, at least 75% of the combined voting power of the securities of the Company or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (2) a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the Beneficial Owner, directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company's then outstanding securities; or

d) the stockholders of the Company approve a plan of complete liquidation or dissolution of the Company or there is consummated an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 75% of the combined voting power of the voting securities of which are owned by stockholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale.

Notwithstanding the foregoing subparagraphs (a), (b), (c) and (d), a "Change in Control" shall not be deemed to have occurred by virtue of the consummation of any transaction or series of integrated transactions immediately following which the record holders of the common stock of the Company immediately prior to such transaction or series of transactions continue to have substantially the same proportionate ownership in an entity which owns all or substantially all of the assets of the Company immediately following such transaction or series of transactions.

(iii) Shares of Restricted Stock may not be sold, assigned, transferred, pledged, hypothecated or otherwise disposed of, except by will or the laws of descent and distribution, for the period specified in or in accordance with Section IV(c)(i) and except in accordance with applicable laws and regulations. Any attempted sale, assignment, transfer, pledge, hypothecation or other disposition in contravention of the foregoing shall be null and void and without effect.

(iv) Shares of Restricted Stock will be issued in the name of the Outside Director receiving the award, but will be held by the Company for the account of such Outside Director (together with a blank stock power which such Outside Director shall execute and deliver to the Company), subject to all of the terms and conditions of the Plan, for the period specified in or in accordance with Section IV(c)(i).

(v) Except as otherwise provided herein and in the instrument evidencing the award of shares of Restricted Stock, the Outside Director receiving same shall have all

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rights of a stockholder with respect to shares of Restricted Stock issued in his/her name, including the right to vote and to receive dividends and other distributions.

(vi) If an Outside Director dies while serving as a member of the Board, and more than six months after the date on which the shares of Restricted Stock were awarded to him have elapsed, the restriction provided for in Section IV(c)(i) shall be deemed to have lapsed immediately prior to death.

(vii) If an Outside Director, as owner of shares of Restricted Stock, receives or shall be entitled to receive Adjustment Shares, the certificates representing the Adjustment Shares (together with a blank stock power executed by such Outside Director) shall be delivered to and held by the Company, subject to all of the terms and conditions of the Plan, for the period specified in or in accordance with Section IV(c)(i). Any Adjustment Shares shall be Restricted Stock for all purposes of the Plan, subject to the same restrictions as the shares of Restricted Stock to which they relate. If such Participant shall receive rights or warrants with respect to any shares of Restricted Stock or any Adjustment Shares, such rights or warrants may be held, exercised, sold or otherwise disposed of by such Outside Director, and any shares or other securities acquired by such Outside Director as a result of the exercise of such rights or warrants likewise may be held, sold, or otherwise disposed of by such Outside Director, free and clear of any restrictions.

V. FURTHER CONDITIONS

A. Unless the shares of Restricted Stock to be awarded under the Plan have been registered with the Securities and Exchange Commission under the Securities Act prior the issuance of the shares of Restricted Stock, the Outside Director receiving such Restricted Stock must represent in writing to the Company that such shares of Common Stock are being acquired for investment purposes only and not with a view towards the further resale or distribution thereof and must supply to the Company such other documentation as may be required by the Company, unless in the opinion of counsel to the Company such representation, agreement or documentation is not necessary to comply with the Securities Act.

B. The Company shall not be obligated to deliver any shares of Common Stock until they have been listed on each securities exchange on which the shares of Common Stock may then be listed or until there has been qualification under or compliance with such state or federal laws, rules or regulations as the Company may deem applicable. The Company shall use reasonable efforts to obtain such listing, qualification and compliance.

C. The Committee may make such provisions and take such steps as it may deem necessary or appropriate for the withholding of any taxes that the Company is required by any law or regulation of any governmental authority, whether federal, state or local, domestic or foreign, to withhold in connection with the award of any Restricted Stock, including, but not limited to (i) the withholding of delivery

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of certificates for shares of Common Stock until the Outside Director reimburses the Company for the amount the Company is required to withhold with respect to such taxes, (ii) the canceling of any number of shares of Common Stock issuable in an amount sufficient to reimburse the Company for the amount it is required to so withhold or (iii) withholding the amount due from any such Outside Director's other compensation.

VI. FORFEITURE OF BENEFITS

As long as an Outside Director is receiving or is a recipient of a Restricted Stock Award under the Plan, such Outside Director will not directly or indirectly enter into or in any manner take part in any business or other endeavor, as an employee, agent, independent contractor, owner or otherwise, which in any manner competes or conflicts with the business of the Company or is detrimental to the best interests of the Company, unless the Company consents thereto in writing. The failure of an Outside Director to comply with the provisions of this Article shall result in the forfeiture all Restricted Stock grants under the Plan. Before any such forfeiture, the Company shall mail notice to the Outside Director that consideration is being given to forfeiture pursuant to this Article. On written request of the Outside Director within sixty days following the mailing by the Company of the notice, the Committee shall afford the Outside Director an opportunity to demonstrate to the Committee that forfeiture would not be justified.

VII. ADMINISTRATION

The Plan shall be administered by the Committee, which shall have full and final authority to interpret the provisions of the Plan and to establish rules and regulations and otherwise make determinations regarding the administration and operation of the Plan. All decisions and determinations by the Committee with respect to the Plan or awards payable thereunder shall be final and binding upon all parties.

VIII. ADJUSTMENT UPON CHANCES IN CAPITALIZATION

In the event that the outstanding shares of Common Stock are hereafter changed by reason of recapitalization, reclassification, stock split, combination or exchange of shares of Common Stock or the like, or by the issuance of dividends payable in shares of Common Stock, an appropriate adjustment shall be made by the Committee in the number of shares of Restricted Stock outstanding

IX. TERMINATION, MODIFICATION AND AMENDMENT

A. The Board may, at any time, terminate the Plan or, from time to time, make such modifications or amendments of the Plan as it may deem advisable.

B. No termination, modification or amendment of the Plan may adversely affect the rights under any outstanding shares of Restricted Stock without the consent of the

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Outside Director to whom such shares of Restricted Stock shall have been previously awarded.

X. NOT A CONTRACT FOR CONTINUED SERVICE

Nothing contained in the Plan or in any restricted stock agreement executed pursuant hereto shall be deemed to confer upon any Outside Director to whom shares of Restricted Stock are or may be awarded hereunder any right to remain a member of the Board or in any way limit the right of the Board or the Stockholders to terminate or fail to renominate or reelect any such Outside Director as a member of the Board.

XI. MISCELLANEOUS

A. The costs and expenses of administering the Plan shall be borne by the Company and shall not be charged against any award or to any Outside Director receiving an award.

B. Any restricted stock agreement may contain, among other things, provisions prohibiting the Outside Director from competing with the Company or any affiliate in a form or forms acceptable to the Committee, in its sole discretion.

C. This Plan and actions taken in connection herewith shall be governed and construed in accordance with the laws of the State of New Jersey.

D. The captions and section numbers appearing in this Plan are inserted only as a matter of convenience. They do not define, limit or describe the scope or intent of the provisions of this Plan. In this Plan, words in the singular number include the plural and in the plural include the singular; and words of the masculine gender include the feminine and the neuter, and when the sense so indicates, words of the neuter gender may refer to any gender.

E. Whenever the time for payment or performance hereunder shall fall on a weekend or public holiday, such payment or performance shall be deemed to be timely if made on the next succeeding business day.

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2014	2013	2013	2012	2011	2010	2009
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	646	540	$ 2,055	$ 2,011	$ 2,384	$ 2,616	$ 2,636
(Income) Loss from Equity Investees, net of Distributions	—	5	(7)	9	(4)	(19)	(25)
Fixed Charges	111	115	458	479	522	571	600
Capitalized Interest	(4)	(3)	(16)	(19)	(14)	(67)	(45)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	(2)	(6)
Total Earnings	753	657	$ 2,490	$ 2,480	$ 2,888	$ 3,099	$ 3,160
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	107	111	$ 442	$ 465	$ 509	$ 555	$ 581
Interest Factor in Rentals	4	4	16	14	13	14	13
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	2	6
Total Fixed Charges	111	115	$ 458	$ 479	$ 522	$ 571	$ 600
Ratio of Earnings to Fixed Charges	6.78	5.71	5.44	5.18	5.53	5.43	5.27

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12.1

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2014	2013	2013	2012	2011	2010	2009
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	275	232	$ 1,063	$1,099	$ 1,703	$1,932	$1,969
(Income) Loss from Equity Investees, net of Distributions	—	(3)	(10)	(6)	(12)	(8)	(7)
Fixed Charges	39	36	143	164	208	238	221
Capitalized Interest	1	1	1	(6)	(10)	(63)	(43)
Total Earnings	$ 315	$ 266	$1,197	$1,251	$1,889	$2,099	$ 2,140
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	38	35	$ 139	$ 161	$ 205	$ 235	$ 219
Interest Factor in Rentals	1	1	4	3	3	3	2
Total Fixed Charges	$ 39	$ 36	$ 143	$ 164	$ 208	$ 238	$ 221
Ratio of Earnings to Fixed Charges	8.08	7.39	8.37	7.63	9.08	8.82	9.68

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2014	2013	2013	2012	2011	2010	2009
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	357	304	$ 993	$ 835	$ 861	$ 591	$ 551
Fixed Charges	74	79	316	314	319	325	317
Capitalized Interest	(4)	(4)	(16)	(13)	(4)	(2)	(1)
Total Earnings	$ 427	$ 379	$ 1,293	$ 1,136	$ 1,176	$ 914	$ 867
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	72	77	$ 309	$ 308	$ 314	$ 320	$ 313
Interest Factor in Rentals	2	2	7	6	5	5	4
Total Fixed Charges	$ 74	$ 79	$ 316	$ 314	$ 319	$ 325	$ 317
Ratio of Earnings to Fixed Charges	5.77	4.80	4.09	3.62	3.69	2.81	2.74

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.3

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Three Months Ended March 31,		Years Ended December 31,				
	2014	2013	2013	2012	2011	2010	2009
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 357	$ 304	$ 993	$ 835	$ 861	$ 591	$ 551
Fixed Charges	74	79	316	314	319	327	323
Capitalized Interest	(4)	(4)	(16)	(13)	(4)	(2)	(1)
Preferred Securities Dividend Requirements	—	—	—	—	—	(2)	(6)
Total Earnings	$ 427	$ 379	$1,293	$1,136	$1,176	$ 914	$ 867
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 72	$ 77	$ 309	$ 308	$ 314	$ 320	$ 313
Interest Factor in Rentals	2	2	7	6	5	5	4
Preferred Securities Dividend	—	—	—	—	—	1	4
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	—	—	—	1	2
Total Fixed Charges	$ 74	$ 79	$ 316	$ 314	$ 319	$ 327	$ 323
Ratio of Earnings to Fixed Charges	5.77	4.80	4.09	3.62	3.69	2.80	2.68

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2014

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2014

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2014

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2014

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2014

/s/ Ralph Izzo

Ralph Izzo
Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2014

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
May 1, 2014

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer
May 1, 2014

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer
May 1, 2014

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer
May 1, 2014

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo
Public Service Electric and Gas Company
Chief Executive Officer
May 1, 2014

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Electric and Gas Company
Chief Financial Officer
May 1, 2014

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED March 31, 2015
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of April 21, 2015, Public Service Enterprise Group Incorporated had outstanding 505,862,575 shares of its sole class of Common Stock, without par value.

As of April 21, 2015, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulations, including market structures and transmission planning,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- any deterioration in our credit quality or the credit quality of our counterparties,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as for transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies, and
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, May 04, 2015 Powered by Morningstar® Document Research℠

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended March 31,	
	2015	**2014**
OPERATING REVENUES	$ 3,135	$ 3,223
OPERATING EXPENSES		
Energy Costs	1,094	1,356
Operation and Maintenance	663	856
Depreciation and Amortization	330	306
Total Operating Expenses	2,087	2,518
OPERATING INCOME	1,048	705
Income from Equity Method Investments	3	4
Other Income	48	48
Other Deductions	(12)	(12)
Other-Than-Temporary Impairments	(5)	(2)
Interest Expense	(98)	(97)
INCOME BEFORE INCOME TAXES	984	646
Income Tax Expense	(398)	(260)
NET INCOME	$ 586	$ 386
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:		
BASIC	506	506
DILUTED	508	508
NET INCOME PER SHARE:		
BASIC	$ 1.16	$ 0.76
DILUTED	$ 1.15	$ 0.76
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.39	$ 0.37

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2015	**2014**
NET INCOME	$ 586	$ 386
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(13) and $(3) for 2015 and 2014, respectively	14	2
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $7 and $(2) for 2015 and 2014, respectively	(9)	2
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(6) and $(2) for 2015 and 2014, respectively	8	4
Other Comprehensive Income (Loss), net of tax	13	8
COMPREHENSIVE INCOME	$ 599	$ 394

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18282

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,008	$ 402
Accounts Receivable, net of allowances of $58 and $52 in 2015 and 2014, respectively	1,437	1,254
Tax Receivable	31	211
Unbilled Revenues	252	284
Fuel	266	538
Materials and Supplies, net	483	484
Prepayments	80	108
Derivative Contracts	87	240
Deferred Income Taxes	—	11
Regulatory Assets	258	323
Regulatory Assets of Variable Interest Entities (VIEs)	187	249
Other	70	15
Total Current Assets	4,159	4,119
PROPERTY, PLANT AND EQUIPMENT	32,805	32,196
Less: Accumulated Depreciation and Amortization	(8,827)	(8,607)
Net Property, Plant and Equipment	23,978	23,589
NONCURRENT ASSETS		
Regulatory Assets	3,164	3,192
Long-Term Investments	1,287	1,307
Nuclear Decommissioning Trust (NDT) Fund	1,821	1,780
Long-Term Receivable of VIE	592	580
Other Special Funds	235	212
Goodwill	16	16
Other Intangibles	87	84
Derivative Contracts	108	77
Restricted Cash of VIEs	25	24
Other	355	353
Total Noncurrent Assets	7,690	7,625
TOTAL ASSETS	$ 35,827	$ 35,333

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18283

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2015	December 31, 2014
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 793	$ 624
Securitization Debt of VIEs Due Within One Year	201	259
Accounts Payable	1,006	1,178
Derivative Contracts	94	132
Accrued Interest	119	95
Accrued Taxes	343	21
Deferred Income Taxes	87	173
Clean Energy Program	86	142
Obligation to Return Cash Collateral	130	121
Regulatory Liabilities	162	186
Other	601	547
Total Current Liabilities	3,622	3,478
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	7,436	7,303
Regulatory Liabilities	272	258
Regulatory Liabilities of VIEs	46	39
Asset Retirement Obligations	754	743
Other Postretirement Benefit (OPEB) Costs	1,257	1,277
OPEB Costs of Servco	462	452
Accrued Pension Costs	408	440
Accrued Pension Costs of Servco	128	126
Environmental Costs	427	417
Derivative Contracts	25	33
Long-Term Accrued Taxes	215	208
Other	127	112
Total Noncurrent Liabilities	11,557	11,408
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Total Long-Term Debt	8,090	8,261
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2015 and 2014—533,556,660 shares	4,873	4,876
Treasury Stock, at cost, 2015— 27,743,445 shares; 2014— 27,720,068 shares	(662)	(635)
Retained Earnings	8,616	8,227
Accumulated Other Comprehensive Loss	(270)	(283)
Total Common Stockholders' Equity	12,557	12,185
Noncontrolling Interest	1	1
Total Stockholders' Equity	12,558	12,186
Total Capitalization	20,648	20,447
TOTAL LIABILITIES AND CAPITALIZATION	$ 35,827	$ 35,333

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 586	$ 386
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	330	306
Amortization of Nuclear Fuel	55	54
Provision for Deferred Income Taxes (Other than Leases) and ITC	63	(39)
Non-Cash Employee Benefit Plan Costs	41	11
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	4	(22)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	37	224
Change in Accrued Storm Costs	7	(1)
Net Change in Other Regulatory Assets and Liabilities	(29)	177
Cost of Removal	(26)	(25)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(12)	(23)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	180	(2)
Accrued Taxes	322	273
Margin Deposit	14	(261)
Other Current Assets and Liabilities	109	70
Employee Benefit Plan Funding and Related Payments	(47)	(32)
Other	45	20
Net Cash Provided By (Used In) Operating Activities	1,679	1,116
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(747)	(609)
Proceeds from Sales of Available-for-Sale Securities	609	257
Investments in Available-for-Sale Securities	(638)	(269)
Other	(3)	(8)
Net Cash Provided By (Used In) Investing Activities	(779)	(629)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	—	(60)
Redemption of Securitization Debt	(58)	(54)
Cash Dividends Paid on Common Stock	(197)	(187)
Other	(39)	(24)
Net Cash Provided By (Used In) Financing Activities	(294)	(325)
Net Increase (Decrease) in Cash and Cash Equivalents	606	162
Cash and Cash Equivalents at Beginning of Period	402	493
Cash and Cash Equivalents at End of Period	$ 1,008	$ 655
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (175)	$ 15
Interest Paid, Net of Amounts Capitalized	$ 74	$ 79
Accrued Property, Plant and Equipment Expenditures	$ 276	$ 247

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2015	**2014**
OPERATING REVENUES	$ 2,002	$ 2,145
OPERATING EXPENSES		
Energy Costs	892	1,045
Operation and Maintenance	412	462
Depreciation and Amortization	247	227
Total Operating Expenses	1,551	1,734
OPERATING INCOME	451	411
Other Income	18	14
Other Deductions	(1)	—
Interest Expense	(69)	(68)
INCOME BEFORE INCOME TAXES	399	357
Income Tax Expense	(157)	(143)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 242	$ 214

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2015	2014
NET INCOME	$ 242	$ 214
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0 and $0 for 2015 and 2014, respectively	—	—
COMPREHENSIVE INCOME	$ 242	$ 214

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18287

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 336	$ 310
Accounts Receivable, net of allowances of $58 and $52 in 2015 and 2014, respectively	1,038	864
Accounts Receivable-Affiliated Companies	9	274
Unbilled Revenues	252	284
Materials and Supplies	142	133
Prepayments	5	42
Regulatory Assets	258	323
Regulatory Assets of VIEs	187	249
Derivative Contracts	—	18
Deferred Income Taxes	—	24
Other	15	7
Total Current Assets	2,242	2,528
PROPERTY, PLANT AND EQUIPMENT	21,610	21,103
Less: Accumulated Depreciation and Amortization	(5,263)	(5,183)
Net Property, Plant and Equipment	16,347	15,920
NONCURRENT ASSETS		
Regulatory Assets	3,164	3,192
Long-Term Investments	353	348
Other Special Funds	55	53
Derivative Contracts	7	8
Restricted Cash of VIEs	25	24
Other	152	150
Total Noncurrent Assets	3,756	3,775
TOTAL ASSETS	$ 22,345	$ 22,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18288

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	March 31, 2015	December 31, 2014
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 471	$ 300
Securitization Debt of VIEs Due Within One Year	201	259
Accounts Payable	524	574
Accounts Payable—Affiliated Companies	338	379
Accrued Interest	75	68
Clean Energy Program	86	142
Deferred Income Taxes	96	165
Obligation to Return Cash Collateral	130	121
Regulatory Liabilities	162	186
Other	461	381
Total Current Liabilities	2,544	2,575
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,652	4,575
Other Postretirement Benefit (OPEB) Costs	943	967
Accrued Pension Costs	155	173
Regulatory Liabilities	272	258
Regulatory Liabilities of VIEs	46	39
Environmental Costs	375	364
Asset Retirement Obligations	295	290
Long-Term Accrued Taxes	122	116
Other	71	67
Total Noncurrent Liabilities	6,931	6,849
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Total Long-Term Debt	5,841	6,012
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2015 and 2014—132,450,344 shares	892	892
Contributed Capital	695	695
Basis Adjustment	986	986
Retained Earnings	4,454	4,212
Accumulated Other Comprehensive Income	2	2
Total Stockholder's Equity	7,029	6,787
Total Capitalization	12,870	12,799
TOTAL LIABILITIES AND CAPITALIZATION	$ 22,345	$ 22,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 242	$ 214
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	247	227
Provision for Deferred Income Taxes and ITC	29	31
Non-Cash Employee Benefit Plan Costs	24	6
Cost of Removal	(26)	(25)
Change in Accrued Storm Costs	7	(1)
Net Change in Other Regulatory Assets and Liabilities	(29)	177
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	(142)	(264)
Materials and Supplies	(9)	(11)
Prepayments	37	18
Accounts Payable	16	14
Accounts Receivable/Payable—Affiliated Companies, net	253	120
Other Current Assets and Liabilities	77	112
Employee Benefit Plan Funding and Related Payments	(37)	(29)
Other	(12)	(10)
Net Cash Provided By (Used In) Operating Activities	677	579
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(599)	(481)
Proceeds from Sales of Available-for-Sale Securities	4	5
Investments in Available-for-Sale Securities	(5)	(3)
Solar Loan Investments	(2)	(2)
Other	9	—
Net Cash Provided By (Used In) Investing Activities	(593)	(481)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	—	(60)
Redemption of Securitization Debt	(58)	(54)
Contributed Capital	—	175
Net Cash Provided By (Used In) Financing Activities	(58)	61
Net Increase (Decrease) In Cash and Cash Equivalents	26	159
Cash and Cash Equivalents at Beginning of Period	310	18
Cash and Cash Equivalents at End of Period	$ 336	$ 177
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (180)	$ (37)
Interest Paid, Net of Amounts Capitalized	$ 58	$ 62
Accrued Property, Plant and Equipment Expenditures	$ 226	$ 185

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2015	**2014**
OPERATING REVENUES	$ 1,725	$ 1,700
OPERATING EXPENSES		
Energy Costs	893	1,044
Operation and Maintenance	172	302
Depreciation and Amortization	76	72
Total Operating Expenses	1,141	1,418
OPERATING INCOME	584	282
Income from Equity Method Investments	3	4
Other Income	29	33
Other Deductions	(11)	(10)
Other-Than-Temporary Impairments	(5)	(2)
Interest Expense	(31)	(32)
INCOME BEFORE INCOME TAXES	569	275
Income Tax Expense	(234)	(111)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 335	$ 164

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2015	**2014**
NET INCOME	$ 335	$ 164
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(13) and $(2) for 2015 and 2014, respectively	14	2
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $7 and $(1) for 2015 and 2014, respectively	(9)	1
Pension/OPEB adjustment, net of tax (expense) benefit of $(5) and $(2) for 2015 and 2014, respectively	7	3
Other Comprehensive Income (Loss), net of tax	12	6
COMPREHENSIVE INCOME	$ 347	$ 170

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 24	$ 9
Accounts Receivable	357	334
Accounts Receivable—Affiliated Companies	288	313
Tax Receivable	3	3
Short-Term Loan to Affiliate	1,055	584
Fuel	266	538
Materials and Supplies, net	338	350
Derivative Contracts	72	207
Prepayments	28	17
Other	51	4
Total Current Assets	2,482	2,359
PROPERTY, PLANT AND EQUIPMENT	10,825	10,732
Less: Accumulated Depreciation and Amortization	(3,348)	(3,217)
Net Property, Plant and Equipment	7,477	7,515
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,821	1,780
Long-Term Investments	121	121
Goodwill	16	16
Other Intangibles	87	84
Other Special Funds	57	49
Derivative Contracts	98	62
Other	61	60
Total Noncurrent Assets	2,261	2,172
TOTAL ASSETS	$ 12,220	$ 12,046

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND MEMBER'S EQUITY	March 31, 2015	December 31, 2014
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 300	$ 300
Accounts Payable	343	424
Accounts Payable-Affiliated Companies	208	118
Derivative Contracts	94	132
Deferred Income Taxes	12	43
Accrued Interest	43	27
Other	131	140
Total Current Liabilities	1,131	1,184
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	2,144	2,065
Asset Retirement Obligations	456	450
Other Postretirement Benefit (OPEB) Costs	251	248
Derivative Contracts	25	33
Accrued Pension Costs	144	153
Long-Term Accrued Taxes	42	41
Other	78	71
Total Noncurrent Liabilities	3,140	3,061
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT		
Total Long-Term Debt	2,244	2,243
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,693	4,558
Accumulated Other Comprehensive Loss	(216)	(228)
Total Member's Equity	5,705	5,558
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,220	$ 12,046

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2015	**2014**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 335	$ 164
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	76	72
Amortization of Nuclear Fuel	55	54
Provision for Deferred Income Taxes and ITC	37	(71)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	37	224
Non-Cash Employee Benefit Plan Costs	13	3
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(12)	(23)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	284	289
Margin Deposit	14	(261)
Accounts Receivable	(16)	(19)
Accounts Payable	(55)	(70)
Accounts Receivable/Payable—Affiliated Companies, net	86	279
Accrued Interest Payable	16	15
Other Current Assets and Liabilities	(56)	(4)
Employee Benefit Plan Funding and Related Payments	(6)	(2)
Other	42	24
Net Cash Provided By (Used In) Operating Activities	850	674
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(139)	(126)
Proceeds from Sales of Available-for-Sale Securities	594	247
Investments in Available-for-Sale Securities	(608)	(259)
Short-Term Loan—Affiliated Company, net	(471)	(152)
Other	(11)	(5)
Net Cash Provided By (Used In) Investing Activities	(635)	(295)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	(200)	(375)
Net Cash Provided By (Used In) Financing Activities	(200)	(375)
Net Increase (Decrease) in Cash and Cash Equivalents	15	4
Cash and Cash Equivalents at Beginning of Period	9	6
Cash and Cash Equivalents at End of Period	$ 24	$ 10
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 5	$ (93)
Interest Paid, Net of Amounts Capitalized	$ 16	$ 16
Accrued Property, Plant and Equipment Expenditures	$ 50	$ 62

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

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This combined Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power each is only responsible for information about itself and its subsidiaries.

Note 1. Organization and Basis of Presentation

Organization

PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **PSE&G**—which is an operating public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- **Power**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the FERC, the Nuclear Regulatory Commission (NRC) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2014.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2014.

Note 2. Recent Accounting Standards

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard was issued to clarify the principles for recognizing revenue and to develop a common standard that would remove inconsistencies in revenue requirements; improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provide improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The update is effective for annual and interim reporting periods beginning after December 15, 2016 although the Financial Accounting Standards Board is expected to issue an exposure draft deferring the effective date to periods beginning after December 31, 2017. Early application is not permitted. We are currently analyzing the impact of this standard on our financial statements.

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Amendments to the Consolidation Analysis

This standard was issued to respond to concerns regarding the current accounting for consolidation of certain legal entities. Under the new standard, all legal entities are subject to reevaluation under a revised consolidation model which will determine whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities; eliminate the presumption that a general partner should consolidate a limited partnership; affect the consolidation analysis of reporting entities that are involved with VIEs and provide a scope exception from consolidation guidance for reporting entities with interests in certain legal entities who must comply with other requirements.

The update is effective for annual and interim reporting periods beginning after December 15, 2015. We are currently analyzing the impact of this standard on our financial statements.

Simplifying the Presentation of Debt Issuance Costs

This standard was issued to simplify presentation of debt issuance costs. The standard will require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by this standard.

The update is effective for annual and interim reporting periods beginning after December 15, 2015.

Note 3. Variable Interest Entities (VIEs)

Variable Interest Entities for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of Transition Funding and Transition Funding II are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the assets of these VIEs are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II.

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of March 31, 2015 and December 31, 2014. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II during the first three months of 2015 or in 2014. PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II.

Variable Interest Entity for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

PSEG recognized a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and other postretirement benefit (OPEB) liabilities. This receivable is presented separately on the Condensed Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted. See Note 7. Pension and Other Postretirement Benefits for additional information.

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For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operation and Maintenance (O&M) Expense, respectively. Servco recorded $82 million and $89 million for the three months ended March 31, 2015 and 2014, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 4. Rate Filings

The following information discusses significant updates regarding orders and pending rate filings. This Note should be read in conjunction with Note 5. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2014.

In addition to items previously reported in the Annual Report on Form 10-K, significant 2015 regulatory orders received and currently pending rate filings with the FERC and the BPU by PSE&G are as follows:

- ***Energy Strong Recovery Filing***—In March 2015, PSE&G filed an Energy Strong cost recovery petition seeking BPU approval to recover in base rates estimated annual increases in electric revenues of $6 million and gas revenues of $17 million. These increases represent estimated Energy Strong investment costs expected to be in service as of May 31, 2015. The petition requests rates to be effective September 1, 2015, consistent with the BPU Order of approval of the Energy Strong program.
- ***Basic Gas Supply Service (BGSS)***—On April 15, 2015, the BPU issued an Order approving PSE&G's provisional BGSS rate of 45 cents per therm which had been implemented on October 1, 2014. In March 2015, PSE&G filed a letter with the BPU to extend the 28 cents per therm bill credit for one additional month through April 30, 2015, which is estimated to provide an additional approximate $20 million to customers.
- ***Weather Normalization Clause***—On April 15, 2015, the BPU approved PSE&G's final filing with respect to excess revenues collected during the colder than normal 2013-2014 Winter Period (October 1, 2013 through May 31, 2014). Effective October 1, 2014, PSEG had commenced returning $45 million in revenues to its customers during the 2014-2015 Winter Period.

Note 5. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with Solar Renewable Energy Certificates generated from the installed solar electric system. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of March 31, 2015	As of December 31, 2014
	Millions	
Commercial/Industrial	$ 191	$ 188
Residential	13	13
Total	**$ 204**	**$ 201**

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Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

The following table shows Energy Holdings' gross and net lease investment as of March 31, 2015 and December 31, 2014, respectively.

	As of March 31, 2015	As of December 31, 2014
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 663	$ 691
Estimated Residual Value of Leased Assets	525	525
Unearned and Deferred Income	(377)	(380)
Gross Investment in Leases	811	836
Deferred Tax Liabilities	(717)	(738)
Net Investment in Leases	**$ 94**	**$ 98**

The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. "Not Rated" counterparties represent investments in lease receivables related to commercial real estate properties.

Counterparties' Credit Rating (Standard & Poor's (S&P)) As of March 31, 2015	Lease Receivables, Net of Non-Recourse Debt As of March 31, 2015
	Millions
AA	$ 18
AA-	29
BBB+ — BBB-	316
BB-	134
B-	164
Not Rated	2
Total	**$ 663**

The "BB-" and the "B-" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of March 31, 2015, the gross investment in the leases of such assets, net of non-recourse debt, was $573 million ($(9) million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

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Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counter-parties' S&P Credit Ratings	Counterparty
		Millions		MW			
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	B-	NRG REMA LLC
Conemaugh Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	B-	NRG REMA LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 113	100%	603	Coal	B-	NRG REMA LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service.

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

In early 2014, NRG REMA LLC, an indirect subsidiary of NRG Energy, Inc. (NRG) had disclosed its plan to place the Shawville generating facility in a "long-term protective layup" by April 2015 as it evaluated its alternatives under the lease. However, NRG has since notified PJM that it intends to deactivate the coal-fired units at the Shawville generating facility by May 2015 and has disclosed that it expects to return the Shawville units to service no later than the summer of 2016 with the ability to use natural gas.

Note 6. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Fund

Power maintains an external master nuclear decommissioning trust to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third party investment advisers who operate under investment guidelines developed by Power.

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Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of March 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 692	$ 239	$ (8)	$ 923
Debt Securities				
Government Obligations	486	12	—	498
Other Debt Securities	360	12	(3)	369
Total Debt Securities	846	24	(3)	867
Other Securities	31	—	—	31
Total NDT Available-for-Sale Securities	**$ 1,569**	**$ 263**	**$ (11)**	**$ 1,821**

	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 685	$ 220	$ (8)	$ 897
Debt Securities				
Government Obligations	430	9	(1)	438
Other Debt Securities	333	9	(3)	339
Total Debt Securities	763	18	(4)	777
Other Securities	106	—	—	106
Total NDT Available-for-Sale Securities	**$ 1,554**	**$ 238**	**$ (12)**	**$ 1,780**

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of March 31, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$ 11	$ 10
Accounts Payable	$ 7	$ 2

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The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of March 31, 2015				As of December 31, 2014			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 122	$ (8)	$ —	$ —	$ 162	$ (8)	$ 1	$ —
Debt Securities								
Government Obligations (B)	31	—	16	—	95	—	28	(1)
Other Debt Securities (C)	52	(1)	24	(2)	99	(1)	30	(2)
Total Debt Securities	83	(1)	40	(2)	194	(1)	58	(3)
NDT Available-for-Sale Securities	**$ 205**	**$ (9)**	**$ 40**	**$ (2)**	**$ 356**	**$ (9)**	**$ 59**	**$ (3)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of March 31, 2015.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of March 31, 2015.

(C) Debt Securities (Other)—Power's investments in corporate bonds, collateralized mortgage obligations, asset-backed securities and municipal government obligations are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2015.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended March 31,	
	2015	2014
	Millions	
Proceeds from NDT Fund Sales (A)	**$ 590**	**$ 245**
Net Realized Gains (Losses) on NDT Fund:		
Gross Realized Gains	19	23
Gross Realized Losses	(9)	(4)
Net Realized Gains (Losses) on NDT Fund	**$ 10**	**$ 19**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $123 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of March 31, 2015.

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The NDT available-for-sale debt securities held as of March 31, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 5
1 - 5 years	242
6 - 10 years	193
11 - 15 years	61
16 - 20 years	45
Over 20 years	321
Total NDT Available-for-Sale Debt Securities	**$ 867**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the three months ended March 31, 2015, other-than-temporary impairments of $5 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of March 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 11	$ 11	$ —	$ 22
Debt Securities				
Government Obligations	107	2	—	109
Other Debt Securities	79	1	—	80
Total Debt Securities	186	3	—	189
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 200**	**$ 14**	**$ —**	**$ 214**

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	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 11	$ —	$ 23
Debt Securities				
Government Obligations	89	2	—	91
Other Debt Securities	74	1	—	75
Total Debt Securities	163	3	—	166
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 177**	**$ 14**	**$ —**	**$ 191**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of March 31, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$ 1	$ 1
Accounts Payable	$ (1)	$ —

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of March 31, 2015				As of December 31, 2014			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	6	—	—	—	2	—	—	—
Other Debt Securities (C)	25	—	—	—	24	—	—	—
Total Debt Securities	31	—	—	—	26	—	—	—
Rabbi Trust Available-for-Sale Securities	**$ 31**	**$ —**	**$ —**	**$ —**	**$ 26**	**$ —**	**$ —**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of March 31, 2015.

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(C) Debt Securities (Other)—PSEG's investments in corporate bonds, collateralized mortgage obligations, asset-backed securities and municipal government obligations are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2015.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended March 31,	
	2015	2014
	Millions	
Proceeds from Rabbi Trust Sales (A)	**$ 19**	**$ 12**
Net Realized Gains (Losses) on Rabbi Trust:		
Gross Realized Gains	$ —	$ 2
Gross Realized Losses	—	—
Net Realized Gains (Losses) on Rabbi Trust	**$ —**	**$ 2**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers

Gross realized gains disclosed in the preceding table were recognized in Other Income in the Condensed Consolidated Statements of Operations. Net unrealized gains of $9 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of March 31, 2015. The Rabbi Trust available-for-sale debt securities held as of March 31, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ —
1 - 5 years	62
6 - 10 years	35
11 - 15 years	9
16 - 20 years	7
Over 20 years	76
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 189**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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The fair value of assets in the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of March 31, 2015	As of December 31, 2014
	Millions	
PSE&G	$ 42	$ 41
Power	53	45
Other	119	105
Total Rabbi Trust Available-for-Sale Securities	**$ 214**	**$ 191**

Note 7. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.

Pension and OPEB costs for PSEG, except for Servco, are detailed as follows:

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2015	2014	2015	2014
	Millions			
Components of Net Periodic Benefit Costs (Credit)				
Service Cost	$ 31	$ 26	$ 5	$ 5
Interest Cost	59	59	17	17
Expected Return on Plan Assets	(103)	(100)	(7)	(7)
Amortization of Net				
Prior Service Cost (Credit)	(5)	(5)	(3)	(4)
Actuarial Loss	37	14	10	6
Total Benefit Costs (Credit)	**$ 19**	**$ (6)**	**$ 22**	**$ 17**

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Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, except for Servco, are detailed as follows:

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2015	2014	2015	2014
	Millions			
PSE&G	$ 10	$ (5)	$ 14	$ 11
Power	6	(2)	7	5
Other	3	1	1	1
Total Benefit Costs (Credit)	**$ 19**	**$ (6)**	**$ 22**	**$ 17**

During the three months ended March 31, 2015, PSEG contributed its entire planned contribution for the year 2015 of $15 million into its pension plans and its entire planned $14 million annual contribution to its OPEB plan for 2015.

Servco Pension and OPEB

At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco may contribute up to $30 million into its pension plan trusts during 2015. The pension-related revenues and costs for the three months ended March 31, 2015 and 2014 were $6 million and $23 million, respectively. The OPEB-related revenues earned or costs incurred for each of the three months ended March 31, 2015 and 2014 were immaterial.

Note 8. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

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Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

The face value of Power's outstanding guarantees, current exposure and margin positions as of March 31, 2015 and December 31, 2014 are shown as follows:

	As of March 31, 2015	As of December 31, 2014
	Millions	
Face Value of Outstanding Guarantees	$ 1,811	$ 1,814
Exposure under Current Guarantees	$ 244	$ 273
Letters of Credit Margin Posted	$ 140	$ 159
Letters of Credit Margin Received	$ 91	$ 40
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (9)	$ (13)
Net Broker Balance Deposited (Received)	$ 97	$ 115
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that could be Required	$ 881	$ 945
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,514	$ 3,495
Additional Amounts Posted:		
Other Letters of Credit	$ 45	$ 45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P, Moody's and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG

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had also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, this guarantee would have to be replaced by a letter of credit.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA further determined that there was a need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

The CPG, which consisted of 61 members as of March 31, 2015, continues to conduct the RI/FS which is expected to be completed during the second quarter of 2015 at an estimated cost of approximately $148 million. Of the estimated $148 million, as of March 2015, the CPG Group had spent approximately $130 million, of which PSEG's total share was approximately $9 million.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G. This agreement and the work undertaken pursuant to the action agreement will not affect the ultimate remedy that the EPA will select for the remediation of the 17-mile stretch of the lower Passaic River.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than in respect of their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSEG's share of the cost of that effort is approximately three percent. The remaining CPG members have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17 mile stretch of the Passaic River. The revised draft FFS sets forth various alternatives for remediating this portion of the Passaic River. The EPA's estimated costs to remediate the lower eight miles of the Passaic River range from $365 million for a targeted remedy to $3.25 billion for a deep dredge of this portion of the Passaic River. The EPA also identified in the revised draft FFS its preferred alternative, which would involve dredging the river bank to bank and installing an engineered cap. The estimated cost in the revised draft FFS for its preferred alternative is $1.7 billion. No provisional cost allocation has been made by the CPG for the work contemplated by the revised draft FFS, and the work contemplated by the revised draft FFS is not subject to the CPG's cost sharing allocation agreed to in connection with the removal work for River Mile 10.9 or in connection with the conduct of the RI/FS.

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The revised draft FFS was subject to a public comment period, and remains subject to the EPA's response to comments submitted, a design phase and at least an estimated five years for completion of the work. The public comment period on the revised draft FFS closed on August 21, 2014. Over 300 comments were submitted by a variety of entities potentially impacted by the revised draft FFS, including the CPG, individual companies, municipalities, public officials, citizens groups, Amtrak, NJ Transit and others.

On February 18, 2015, the CPG delivered a draft RI to the EPA and on April 30, 2015, the CPG delivered a draft FS to the EPA, both relating to the entire 17 miles of the lower Passaic River. The draft FS sets forth various alternatives for remediating that portion of the Passaic River. The draft FS sets forth the CPG's estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion. The CPG identified in the draft FS a targeted remedy, which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranges from approximately $518 million to $772 million. No provisional cost allocation has been made by the CPG for the work contemplated by the draft FS. However, based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimates of their share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Regulatory Asset and Power accrued $3 million of O&M Expense as of March 31, 2015 for their respective shares of the estimated costs of remediation.

The EPA will consider the comments received on its revised draft FFS and will consider the CPG's RI/FS prior to issuing a Record of Decision (ROD) of a selected remedy for the Passaic River. The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS is finalized, (ii) a final remedy is determined by the EPA or through litigation, (iii) PSE&G's and Power's respective share of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on our financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G is unable to estimate its portion of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their portion of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $452 million and $523 million through 2021, including its $10 million share for the Passaic River as discussed above. Since no amount within the range is considered

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to be most likely, PSE&G has recorded a liability of $452 million as of March 31, 2015. Of this amount, $86 million was recorded in Other Current Liabilities and $366 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $452 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The New Jersey Department of Environmental Protection (NJDEP) manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

One of the more significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued.

In October 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court of New Jersey seeking to force the NJDEP to take action on Power's pending application for permit renewal at Salem either by denying the application or issuing a draft for public comment. An application for renewal of the permit was submitted in January 2006 and the NJDEP had delayed action pending the EPA's finalization of the Clean Water Act 316 (b) regulations. In November 2014, the environmental groups announced settlement of the lawsuit filed with the NJDEP and that the NJDEP had committed to issue a draft permit by June 30, 2015.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. On August 15, 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. On September 5, 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Second Circuit Court of Appeals. In two related actions on October 17, 2014 and November 20, 2014, several environmental non-governmental groups initiated challenges to the endangered species act provisions of the 316 (b) rule. Power is unable to determine the ultimate impact of these actions on the implementation of the rule.

State permitting decisions could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would have been approximately $575 million. The filing has not been updated. Action on the issuance of a draft permit for Salem is anticipated

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by June 30, 2015. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the Connecticut Department of Energy and Environmental Protection of the issues and has taken actions to investigate and resolve the potential non-compliance. At this early stage Power cannot predict the impact of this matter.

Coal Combustion Residuals (CCRs)

On December 19, 2014, the EPA issued a final rule which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Power's Hudson and Mercer generating stations, along with its co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. The scope of the work entailed to comply has not yet been finalized but Power expects that the impacts of this rule will not be material to its results of operations, financial condition or cash flows.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, are residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category are larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2015 is $272.78 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2015 of $282.04 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2012	2013	2014	2015	
36-Month Terms Ending	May 2015	May 2016	May 2017	May 2018	(A)
Load (MW)	2,900	2,800	2,800	2,900	
$ per kWh	$83.88	$92.18	$97.39	$99.54	

(A) Prices set for the 2015 BGS auction year will become effective on June 1, 2015 when the 2012 BGS auction agreements expire.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements

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through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 17. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2020 at Salem, Hope Creek and Peach Bottom.

Power has various long-term fuel purchase commitments for coal through 2017 to support its fossil generation stations and for firm transportation and storage capacity for natural gas.

Power's various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

As of March 31, 2015, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type		Power's Share of Commitments through 2019
		Millions
Nuclear Fuel		
Uranium	$	432
Enrichment	$	428
Fabrication	$	185
Natural Gas	$	1,060
Coal	$	277

Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed the FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors and modified the bid quantities for its peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future. On September 2, 2014, the FERC Staff initiated a preliminary, non-public staff investigation into the matter. This investigation, which is ongoing, could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies.

During the three months ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. It is not possible at this time to reasonably estimate the potential range of loss or full impact or predict any resulting penalties or other costs associated with this matter, or the applicability of mitigating factors. As new information becomes available or future developments occur in this investigation, it is possible that Power will record additional estimated losses and such additional losses may be material.

New Jersey Clean Energy Program

In June 2014, the BPU established the funding level for fiscal year 2015 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2015 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a current liability of $86 million as of March 31, 2015 for its outstanding share of the fiscal year 2015. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory

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Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's T&D system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure.

As of December 31, 2012, PSE&G had incurred approximately $295 million of costs to restore service to PSE&G's distribution and transmission systems and $5 million to repair its infrastructure and return it to pre-storm conditions. Of the costs incurred, approximately $40 million was recognized in O&M Expense, $75 million was recorded as Property, Plant and Equipment and $180 million was recorded as a Regulatory Asset because such costs were deferred as approved by the BPU under an Order received in December 2012. Of the $295 million, $36 million related to insured property. In 2012, PSE&G recognized $6 million of insurance recoveries, which were deferred. There were no significant additional costs incurred since 2012.

PSE&G made a filing with the BPU to review the prudency of unreimbursed incremental storm restoration costs, including O&M and capital expenditures associated with Superstorm Sandy and certain other extreme weather events, for recovery in our next base rate case or sooner through a BPU-approved cost recovery mechanism. In September 2014, the BPU approved our filing.

Power has incurred a total of $194 million of storm-related costs from 2012 through March 31, 2015, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized primarily in O&M Expense, offset by $44 million of insurance recoveries in 2013 and 2012.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. In June 2013, PSEG, PSE&G and Power filed suit in New Jersey state court (NJ Court) against its insurance carriers seeking an interpretation that the insurance policies cover their losses resulting from damage caused by Superstorm Sandy's storm surge.

In March 2015, PSEG reached a settlement with certain of the insurers with respect to claims for coverage of its Superstorm Sandy-related losses. PSEG received an additional $159 million under this settlement, of which PSE&G and Power recognized $26 million and $133 million, respectively. In addition to the $26 million, PSE&G recorded a reduction of the aforementioned $6 million of previously deferred insurance recoveries, resulting in reductions in O&M Expense of $15 million, Property, Plant and Equipment of $9 million and Regulatory Assets of $8 million. Of the $133 million, Power recorded reductions in both O&M Expense of $128 million and Property, Plant and Equipment of $5 million.

In April 2015, PSEG reached settlements with the remaining insurers for an additional $54 million which will be recognized by PSE&G and Power in the quarter ending June 30, 2015. The claim filed by PSEG, PSE&G and Power related to Superstorm Sandy insurance coverage is now fully resolved.

Note 9. Changes in Capitalization

The following capital transactions occurred in the three months ended March 31, 2015:

PSE&G

- paid $58 million of Transition Funding's securitization debt.

Power

- paid cash dividends of $200 million to PSEG.

Note 10. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

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Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. Transactions receiving NPNS treatment are accounted for upon settlement. For a derivative instrument that qualifies and is designated as a cash flow hedge, the changes in the fair value of such a derivative that are highly effective are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. For a derivative instrument that qualifies and is designated as a fair value hedge, the gains or losses on the derivative as well as the offsetting losses or gains on the hedged item attributable to the hedged risk are recognized in earnings each period. Power and PSE&G enter into additional contracts that are derivatives, but do not qualify for or are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and changes in the fair value of these contracts are recorded in earnings each period.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

PSEG and Power use forward sale and purchase contracts, swaps and futures contracts to hedge certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G. These derivative transactions qualify and are designated as cash flow hedges.

As of March 31, 2015 and December 31, 2014, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity were as follows:

	As of March 31, 2015	As of December 31, 2014
	Millions	
Fair Value of Cash Flow Hedges	$ 2	$ 18
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 1	$ 10

The expiration date of the longest-dated cash flow hedge at Power is in December 2015. Power's remaining $1 million of after-tax unrealized gains on these derivatives is expected to be reclassified to earnings during the next 12 months. There was no ineffectiveness associated with qualifying hedges as of March 31, 2015.

Economic Hedges

PSEG and Power enter into derivative contracts that do not qualify or are not designated as either cash flow or fair value hedges. Power enters into financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. These transactions are economic hedges, intended to mitigate exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization. Changes in the fair market value of these contracts are recorded in earnings.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

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Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of March 31, 2015, PSEG had interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of March 31, 2015 and December 31, 2014, the fair value of all the underlying hedges was $18 million and $22 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was immaterial as of March 31, 2015 and December 31, 2014, respectively.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset on the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of March 31, 2015						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 2	$ 526	$ (456)	$ 72	$ —	$ 15	$ 87
Noncurrent Assets	—	241	(143)	98	7	3	108
Total Mark-to-Market Derivative Assets	**$ 2**	**$ 767**	**$ (599)**	**$ 170**	**$ 7**	**$ 18**	**$ 195**
Derivative Contracts							
Current Liabilities	$ —	$ (547)	$ 453	$ (94)	$ —	$ —	$ (94)
Noncurrent Liabilities	—	(175)	150	(25)	—	—	(25)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (722)**	**$ 603**	**$ (119)**	**$ —**	**$ —**	**$ (119)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 2**	**$ 45**	**$ 4**	**$ 51**	**$ 7**	**$ 18**	**$ 76**

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	As of December 31, 2014						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 18	$ 597	$ (408)	$ 207	$ 18	$ 15	$ 240
Noncurrent Assets	—	171	(109)	62	8	7	77
Total Mark-to-Market Derivative Assets	**$ 18**	**$ 768**	**$ (517)**	**$ 269**	**$ 26**	**$ 22**	**$ 317**
Derivative Contracts							
Current Liabilities	$ —	$ (568)	$ 436	$ (132)	$ —	$ —	$ (132)
Noncurrent Liabilities	—	(138)	105	(33)	—	—	(33)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (706)**	**$ 541**	**$ (165)**	**$ —**	**$ —**	**$ (165)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 18**	**$ 62**	**$ 24**	**$ 104**	**$ 26**	**$ 22**	**$ 152**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of March 31, 2015 and December 31, 2014. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of March 31, 2015 and December 31, 2014, net cash collateral (received) paid of $4 million and $24 million, respectively, were netted against the corresponding net derivative contract positions. Of the $4 million as of March 31, 2015, $(9) million and $(3) million of cash collateral were netted against current assets and noncurrent assets, respectively, and $6 million and $10 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $24 million as of December 31, 2014, $(4) million and $(8) million were netted against current assets and noncurrent assets, respectively, and $32 million and $4 million were netted against current liabilities and noncurrent liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $104 million and $127 million as of March 31, 2015 and December 31, 2014, respectively. As of March 31, 2015 and December 31, 2014, Power had the contractual right of offset of $26 million and $18 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $78 million and $109 million as of March 31, 2015 and December 31, 2014, respectively, related to its derivatives, net of the contractual right of offset under master agreements and

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the application of collateral. This potential additional collateral is included in the $881 million and $945 million as of March 31, 2015 and December 31, 2014, respectively, discussed in Note 8. Commitments and Contingent Liabilities.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended March 31, 2015 and 2014.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended March 31, 2015	2014	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended March 31, 2015	2014	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Three Months Ended March 31, 2015	2014
				Millions				
PSEG								
Energy-Related Contracts	$ 1	$ (8)	Operating Revenues	$ 17	$ (12)	Operating Revenues	$ —	$ —
Total PSEG	**$ 1**	**$ (8)**		**$ 17**	**$ (12)**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ 1	$ (8)	Operating Revenues	$ 17	$ (12)	Operating Revenues	$ —	$ —
Total Power	**$ 1**	**$ (8)**		**$ 17**	**$ (12)**		**$ —**	**$ —**

The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2013	**$ (4)**	**$ (2)**
Gain Recognized in AOCI	12	7
Plus: Loss Reclassified into Income	9	5
Balance as of December 31, 2014	**$ 17**	**$ 10**
Gain Recognized in AOCI	1	1
Less: Gain Reclassified into Income	(17)	(10)
Balance as of March 31, 2015	**$ 1**	**$ 1**

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The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the three months ended March 31, 2015 and 2014.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives	
		Three Months Ended March 31,	
		2015	2014
		Millions	
PSEG and Power			
Energy-Related Contracts	Operating Revenues	$ (76)	$ (794)
Energy-Related Contracts	Energy Costs	10	113
Total PSEG and Power		**$ (66)**	**$ (681)**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the NPNS exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $5 million for each of the three months ended March 31, 2015 and 2014, respectively.

The following reflects the gross volume, on an absolute value basis, of derivatives as of March 31, 2015 and December 31, 2014.

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of March 31, 2015					
Natural Gas	Dth	362	—	311	51
Electricity	MWh	307	—	307	—
Financial Transmission Rights (FTRs)	MWh	8	—	8	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2014					
Natural Gas	Dth	274	—	216	58
Electricity	MWh	310	—	310	—
FTRs	MWh	15	—	15	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of March 31, 2015, 96.7% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

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The following table provides information on Power's credit risk from others, net of cash collateral, as of March 31, 2015. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 396	$ 96	$ 388	1	$ 197	(A)
Non-Investment Grade—External Rating	2	—	2	—	—	
Investment Grade—No External Rating	4	—	4	—	—	
Non-Investment Grade—No External Rating	11	—	11	—	—	
Total	**$ 413**	**$ 96**	**$ 405**	**1**	**$ 197**	

(A) Represents net exposure with PSE&G.

The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of March 31, 2015, Power had 144 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of March 31, 2015, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's suppliers' credit exposure is calculated each business day. As of March 31, 2015, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 11. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of March 31, 2015, these consisted primarily of electric load contracts whose basis is deemed significant to the fair value measurement.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of March 31, 2015 and December 31, 2014, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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Description	Recurring Fair Value Measurements as of March 31, 2015				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 951	$ —	$ 951	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 177	$ (599)	$ —	$ 766	$ 10
Interest Rate Swaps (C)	$ 18	$ —	$ —	$ 18	$ —
NDT Fund (D)					
Equity Securities	$ 923	$ —	$ 922	$ 1	$ —
Debt Securities—Govt Obligations	$ 498	$ —	$ —	$ 498	$ —
Debt Securities—Other	$ 369	$ —	$ —	$ 369	$ —
Other Securities	$ 31	$ —	$ 31	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—Govt Obligations	$ 109	$ —	$ —	$ 109	$ —
Debt Securities—Other	$ 80	$ —	$ —	$ 80	$ —
Other Securities	$ 3	$ —	$ 3	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (119)	$ 603	$ —	$ (721)	$ (1)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 316	$ —	$ 316	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 7	$ —	$ —	$ —	$ 7
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 4	$ —	$ 4	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 170	$ (599)	$ —	$ 766	$ 3
NDT Fund (D)					
Equity Securities	$ 923	$ —	$ 922	$ 1	$ —
Debt Securities—Govt Obligations	$ 498	$ —	$ —	$ 498	$ —
Debt Securities—Other	$ 369	$ —	$ —	$ 369	$ —
Other Securities	$ 31	$ —	$ 31	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 27	$ —	$ —	$ 27	$ —
Debt Securities—Other	$ 20	$ —	$ —	$ 20	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (119)	$ 603	$ —	$ (721)	$ (1)

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Description	Recurring Fair Value Measurements as of December 31, 2014				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 295	$ (517)	$ —	$ 774	$ 38
Interest Rate Swaps (C)	$ 22	$ —	$ —	$ 22	$ —
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 896	$ 1	$ —
Debt Securities—Govt Obligations	$ 438	$ —	$ —	$ 438	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 106	$ —	$ 106	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—Govt Obligations	$ 91	$ —	$ —	$ 91	$ —
Debt Securities—Other	$ 75	$ —	$ —	$ 75	$ —
Other Securities	$ 2	$ —	$ —	$ 2	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (165)	$ 541	$ —	$ (705)	$ (1)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 294	$ —	$ 294	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ 26	$ —	$ —	$ —	$ 26
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 20	$ —	$ —	$ 20	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 269	$ (517)	$ —	$ 774	$ 12
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 896	$ 1	$ —
Debt Securities—Govt Obligations	$ 438	$ —	$ —	$ 438	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 106	$ —	$ 106	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (165)	$ 541	$ —	$ (705)	$ (1)

(A) Represents money market mutual funds

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(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded

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capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds, collateralized mortgage obligations, asset backed securities and government obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of March 31, 2015, net cash collateral (received) paid of $4 million, was netted against the corresponding net derivative contract positions. Of the $4 million as of March 31, 2015, $(12) million of cash collateral was netted against assets, and $16 million was netted against liabilities. As of December 31, 2014, net cash collateral (received) paid of $24 million, was netted against the corresponding net derivative contract positions. Of the $24 million as of December 31, 2014, $(12) million of cash collateral was netted against assets, and $36 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G and Power, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. For Power, in general, electric swaps are measured

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at fair value based on at least two pricing inputs, the underlying price of electricity at a liquid reference point and the basis difference between electricity prices at the liquid reference point and electricity prices at the respective delivery locations. To the extent the basis component is based on a single broker quote and is significant to the fair value of the electric swap, it is categorized as Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. The following tables provide details surrounding significant Level 3 valuations as of March 31, 2015 and December 31, 2014.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of March 31, 2015 Assets	Fair Value as of March 31, 2015 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Forward Contracts	$ 7	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 7**	**$ —**			
Power						
Electricity	Electric Load Contracts	$ 3	$ (1)	Discounted Cash flow	Historic Load Variability	0% to +10%
Other	Various (A)	—	—			
Total Power		**$ 3**	**$ (1)**			
Total PSEG		**$ 10**	**$ (1)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2014 Assets	Fair Value as of December 31, 2014 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Forward Contracts	$ 26	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 26**	**$ —**			
Power						
Electricity	Electric Load Contracts	$ 12	$ (1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Other	Various (B)	—	—			
Total Power		**$ 12**	**$ (1)**			
Total PSEG		**$ 38**	**$ (1)**			

(A) Includes long-term electric positions which were immaterial as of March 31, 2015.

(B) Includes gas supply positions and long-term electric capacity positions which were immaterial as of December 31, 2014.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the

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fair value. For energy-related contracts in cases where Power is a seller, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value.

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months ended March 31, 2015 follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2015

Description	Balance as of January 1, 2015	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of March 31, 2015
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 37	$ 3	$ (19)	$ —	$ (12)	$ —	$ 9
PSE&G							
Net Derivative Assets (Liabilities)	$ 26	$ —	$ (19)	$ —	$ —	$ —	$ 7
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 3	$ —	$ —	$ (12)	$ —	$ 2

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2014

Description	Balance as of January 1, 2014	Total Gains or (Losses) Realized/Unrealized: Included in Income (D)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of March 31, 2014
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 88	$ (64)	$ (82)	$ —	$ 59	$ —	$ 1
PSE&G							
Net Derivative Assets (Liabilities)	$ 94	$ —	$ (82)	$ —	$ —	$ —	$ 12
Power							
Net Derivative Assets (Liabilities)	$ (6)	$ (64)	$ —	$ —	$ 59	$ —	$ (11)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $3 million in Operating Income for the three months ended March 31, 2015, respectively. Of the $3 million in Operating Income, $(9) million is unrealized.

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(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $(12) million and $59 million in settlements for the three months ended March 31, 2015 and 2014.

(D) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $(64) million in Operating Income for the three months ended March 31, 2014. Of the $(64) million in Operating Income, $(5) million is unrealized.

As of March 31, 2015, PSEG carried $3.1 billion of net assets that are measured at fair value on a recurring basis, of which $9 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of March 31, 2014, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $1 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of March 31, 2015 and December 31, 2014.

	As of March 31, 2015		As of December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 11	$ 18	$ 14	$ 22
PSE&G (B)	6,312	7,138	6,312	6,912
Transition Funding (PSE&G) (B)	193	199	251	261
Transition Funding II (PSE&G) (B)	8	8	8	8
Power -Recourse Debt (B)	2,544	2,974	2,543	2,930
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	16	16	16	16
Total Long-Term Debt	**$ 9,084**	**$ 10,353**	**$ 9,144**	**$ 10,149**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 12. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated
			Millions	
Three Months Ended March 31, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 29	$ —	$ 29
Allowance for Funds Used During Construction	10	—	—	10
Solar Loan Interest	6	—	—	6
Other	2	—	1	3
Total Other Income	**$ 18**	**$ 29**	**$ 1**	**$ 48**
Three Months Ended March 31, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 32	$ —	$ 32
Allowance for Funds Used During Construction	6	—	—	6
Solar Loan Interest	6	—	—	6
Other	2	1	1	4
Total Other Income	**$ 14**	**$ 33**	**$ 1**	**$ 48**

Other Deductions	PSE&G	Power	Other (A)	Consolidated
			Millions	
Three Months Ended March 31, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 11	$ —	$ 11
Other	1	—	—	1
Total Other Deductions	**$ 1**	**$ 11**	**$ —**	**$ 12**
Three Months Ended March 31, 2014				
NDT Fund Realized Losses and Expenses	$ —	$ 6	$ —	$ 6
Other	—	4	2	6
Total Other Deductions	**$ —**	**$ 10**	**$ 2**	**$ 12**

(A) Other primarily consists of activity at PSEG (as parent company), Energy Holdings, Services and intercompany eliminations.

Note 13. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months ended March 31, 2015 and 2014 were as follows:

	Three Months Ended March 31,	
	2015	2014
PSEG	40.5%	40.2%
PSE&G	39.4%	40.1%
Power	41.1%	40.4%

There were no material changes in the effective tax rates of PSEG, PSE&G and Power for the three months ended March 31, 2015, as compared to the same period in the prior year.

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The American Taxpayer Relief Act of 2012 included a provision making long production property placed into service in 2014 eligible for 50% depreciation for tax purposes. The Tax Increase Prevention Act of 2014 further extended the 50% bonus depreciation rules for qualified property that was placed into service before January 1, 2015 and for long production property that is to be placed into service in 2015. These provisions generate cash for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation. These tax benefits otherwise would be received over an estimated average 20 year period.

Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG

	Other Comprehensive Income (Loss) Three Months Ended March 31, 2015			
Accumulated Other Comprehensive Income (Loss)	**Cash Flow Hedges**	**Pension and OPEB Plans**	**Available-for-Sale Securities**	**Total**
		Millions		
Balance as of December 31, 2014	$ 10	$ (411)	$ 118	$ (283)
Other Comprehensive Income before Reclassifications	1	—	16	17
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	8	(2)	(4)
Net Current Period Other Comprehensive Income (Loss)	(9)	8	14	13
Balance as of March 31, 2015	**$ 1**	**$ (403)**	**$ 132**	**$ (270)**

PSEG

	Other Comprehensive Income (Loss) Three Months Ended March 31, 2014			
Accumulated Other Comprehensive Income (Loss)	**Cash Flow Hedges**	**Pension and OPEB Plans**	**Available-for-Sale Securities**	**Total**
		Millions		
Balance as of December 31, 2013	$ (2)	$ (238)	$ 145	$ (95)
Other Comprehensive Income before Reclassifications	(5)	—	11	6
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	7	4	(9)	2
Net Current Period Other Comprehensive Income (Loss)	2	4	2	8
Balance as of March 31, 2014	**$ —**	**$ (234)**	**$ 147**	**$ (87)**

Power

	Other Comprehensive Income (Loss) Three Months Ended March 31, 2015			
Accumulated Other Comprehensive Income (Loss)	**Cash Flow Hedges**	**Pension and OPEB Plans**	**Available-for-Sale Securities**	**Total**
		Millions		
Balance as of December 31, 2014	$ 11	$ (351)	$ 112	$ (228)
Other Comprehensive Income before Reclassifications	1	—	16	17
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	7	(2)	(5)
Net Current Period Other Comprehensive Income (Loss)	(9)	7	14	12
Balance as of March 31, 2015	**$ 2**	**$ (344)**	**$ 126**	**$ (216)**

Power

	Other Comprehensive Income (Loss) Three Months Ended March 31, 2014			
Accumulated Other Comprehensive Income (Loss)	**Cash Flow Hedges**	**Pension and OPEB Plans**	**Available-for-Sale Securities**	**Total**
		Millions		
Balance as of December 31, 2013	$ (1)	$ (204)	$ 142	$ (63)
Other Comprehensive Income before Reclassifications	(6)	—	10	4
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	7	3	(8)	2
Net Current Period Other Comprehensive Income (Loss)	1	3		

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Balance as of March 31, 2014	**$ —**	**$ (201)**	**$ 144**	**$ (57)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		17	(7)	10
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)
Total Pension and OPEB Plans		(14)	6	(8)
Available-for-Sale Securities				
Realized Gains	Other Income	19	(10)	9
Realized Losses	Other Deductions	(9)	5	(4)
Other-Than-Temporary Impairments (OTTI)	OTTI	(5)	2	(3)
Total Available-for-Sale Securities		5	(3)	2
Total		**$ 8**	**$ (4)**	**$ 4**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ (12)	$ 5	$ (7)
Total Cash Flow Hedges		(12)	5	(7)
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	2	(1)	1
Amortization of Actuarial Loss	O&M Expense	(8)	3	(5)
Total Pension and OPEB Plans		(6)	2	(4)
Available-for-Sale Securities				
Realized Gains	Other Income	25	(13)	12
Realized Losses	Other Deductions	(4)	2	(2)
OTTI	OTTI	(2)	1	(1)
Total Available-for-Sale Securities		19	(10)	9
Total		**$ 1**	**$ (3)**	**$ (2)**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		17	(7)	10
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2
Amortization of Actuarial Loss	O&M Expense	(15)	6	(9)
Total Pension and OPEB Plans		(12)	5	(7)
Available-for-Sale Securities				
Realized Gains	Other Income	19	(10)	9
Realized Losses	Other Deductions	(9)	5	(4)
OTTI	OTTI	(5)	2	(3)
Total Available-for-Sale Securities		5	(3)	2
Total		**$ 10**	**$ (5)**	**$ 5**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ (12)	$ 5	$ (7)
Total Cash Flow Hedges		(12)	5	(7)
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	2	(1)	1
Amortization of Actuarial Loss	O&M Expense	(6)	2	(4)
Total Pension and OPEB Plans		(4)	1	(3)
Available-for-Sale Securities				
Realized Gains	Other Income	23	(12)	11
Realized Losses	Other Deductions	(4)	2	(2)
OTTI	OTTI	(2)	1	(1)
Total Available-for-Sale Securities		17	(9)	8
Total		**$ 1**	**$ (3)**	**$ (2)**

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Note 15. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under our stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS.

	Three Months Ended March 31,			
	2015		2014	
	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)				
Net Income	**$ 586**	**$ 586**	**$ 386**	**$ 386**
EPS Denominator (Millions)				
Weighted Average Common Shares Outstanding	506	506	506	506
Effect of Stock Based Compensation Awards	—	2	—	2
Total Shares	**506**	**508**	**506**	**508**
EPS				
Net Income	**$ 1.16**	**$ 1.15**	**$ 0.76**	**$ 0.76**

	Three Months Ended March 31,	
Dividend Payments on Common Stock	2015	2014
Per Share	$ 0.39	$ 0.37
In Millions	$ 197	$ 187

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Note 16. Financial Information by Business Segments

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated
			Millions		
Three Months Ended March 31, 2015					
Total Operating Revenues	$ 2,002	$ 1,725	$ 98	$ (690)	$ 3,135
Net Income (Loss)	242	335	9	—	586
Gross Additions to Long-Lived Assets	599	139	9	—	747
Three Months Ended March 31, 2014					
Total Operating Revenues	$ 2,145	$ 1,700	$ 105	$ (727)	$ 3,223
Net Income (Loss)	214	164	8	—	386
Gross Additions to Long-Lived Assets	481	126	2	—	609
As of March 31, 2015					
Total Assets	$ 22,345	$ 12,220	$ 3,168	$ (1,906)	$ 35,827
Investments in Equity Method Subsidiaries	$ —	$ 119	$ 2	$ —	$ 121
As of December 31, 2014					
Total Assets	$ 22,223	$ 12,046	$ 2,799	$ (1,735)	$ 35,333
Investments in Equity Method Subsidiaries	$ —	$ 121	$ 2	$ —	$ 123

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations, primarily related to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 17. Related-Party Transactions.

Note 17. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended March 31, 2015	2014
	Millions	
Billings from Affiliates:		
Billings from Power primarily through BGS and BGSS (A)	$ 696	$ 731
Administrative Billings from Services (B)	66	60
Total Billings from Affiliates	**$ 762**	**$ 791**

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Related-Party Transactions	As of March 31, 2015	As of December 31, 2014
	Millions	
Receivable from PSEG (C)	**$ 9**	**$ 274**
Payable to Power (A)	$ 288	$ 313
Payable to Services (B)	50	66
Accounts Payable—Affiliated Companies	**$ 338**	**$ 379**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 122**	**$ 116**

Power

The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended March 31, 2015	2014
	Millions	
Billings to Affiliates:		
Billings to PSE&G primarily through BGS and BGSS Contracts (A)	**$ 696**	**$ 731**
Billings from Affiliates:		
Administrative Billings from Services (B)	**$ 45**	**$ 42**

Related-Party Transactions	As of March 31, 2015	As of December 31, 2014
	Millions	
Receivables from PSE&G (A)	**$ 288**	**$ 313**
Payable to Services (B)	$ 29	$ 23
Payable to PSEG (C)	179	95
Accounts Payable—Affiliated Companies	**$ 208**	**$ 118**
Short-Term Loan (to) from Affiliate (Demand Note (to) PSEG) (E)	**$ 1,055**	**$ 584**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 42**	**$ 41**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

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Note 18. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended March 31, 2015					
Operating Revenues	$ —	$ 1,715	$ 68	$ (58)	$ 1,725
Operating Expenses	5	1,131	63	(58)	1,141
Operating Income (Loss)	(5)	584	5	—	584
Equity Earnings (Losses) of Subsidiaries	349	(1)	3	(348)	3
Other Income	11	30	—	(12)	29
Other Deductions	—	(11)	—	—	(11)
Other-Than-Temporary Impairments	—	(5)	—	—	(5)
Interest Expense	(29)	(9)	(5)	12	(31)
Income Tax Benefit (Expense)	9	(242)	(1)	—	(234)
Net Income (Loss)	**$ 335**	**$ 346**	**$ 2**	**$ (348)**	**$ 335**
Comprehensive Income (Loss)	**$ 347**	**$ 351**	**$ 2**	**$ (353)**	**$ 347**
Three Months Ended March 31, 2015					
Net Cash Provided By (Used In) Operating Activities	$ 327	$ 772	$ 11	$ (260)	$ 850
Net Cash Provided By (Used In) Investing Activities	$ (537)	$ (515)	$ (13)	$ 430	$ (635)
Net Cash Provided By (Used In) Financing Activities	$ 210	$ (242)	$ 2	$ (170)	$ (200)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended March 31, 2014					
Operating Revenues	$ —	$ 1,684	$ 40	$ (24)	$ 1,700
Operating Expenses	4	1,404	34	(24)	1,418
Operating Income (Loss)	(4)	280	6	—	282
Equity Earnings (Losses) of Subsidiaries	177	—	4	(177)	4
Other Income	8	33	—	(8)	33
Other Deductions	(4)	(6)	—	—	(10)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(28)	(7)	(5)	8	(32)
Income Tax Benefit (Expense)	15	(125)	(1)	—	(111)
Net Income (Loss)	**$ 164**	**$ 173**	**$ 4**	**$ (177)**	**$ 164**
Comprehensive Income (Loss)	**$ 170**	**$ 176**	**$ 4**	**$ (180)**	**$ 170**
Three Months Ended March 31, 2014					
Net Cash Provided By (Used In) Operating Activities	$ 291	$ 603	$ 1	$ (221)	$ 674
Net Cash Provided By (Used In) Investing Activities	$ (122)	$ (315)	$ —	$ 142	$ (295)
Net Cash Provided By (Used In) Financing Activities	$ (166)	$ (287)	$ (1)	$ 79	$ (375)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
As of March 31, 2015					
Current Assets	$ 4,554	$ 1,835	$ 136	$ (4,043)	$ 2,482
Property, Plant and Equipment, net	79	6,230	1,168	—	7,477
Investment in Subsidiaries	4,571	118	—	(4,689)	—
Noncurrent Assets	287	2,035	136	(197)	2,261
Total Assets	**$ 9,491**	**$ 10,218**	**$ 1,440**	**$ (8,929)**	**$ 12,220**
Current Liabilities	$ 1,093	$ 3,313	$ 768	$ (4,043)	$ 1,131
Noncurrent Liabilities	449	2,529	359	(197)	3,140
Long-Term Debt	2,244	—	—	—	2,244
Member's Equity	5,705	4,376	313	(4,689)	5,705
Total Liabilities and Member's Equity	**$ 9,491**	**$ 10,218**	**$ 1,440**	**$ (8,929)**	**$ 12,220**
As of December 31, 2014					
Current Assets	$ 4,263	$ 2,037	$ 150	$ (4,091)	$ 2,359
Property, Plant and Equipment, net	81	6,265	1,169	—	7,515
Investment in Subsidiaries	4,516	120	—	(4,636)	—
Noncurrent Assets	278	1,952	137	(195)	2,172
Total Assets	**$ 9,138**	**$ 10,374**	**$ 1,456**	**$ (8,922)**	**$ 12,046**
Current Liabilities	$ 883	$ 3,606	$ 786	$ (4,091)	$ 1,184
Noncurrent Liabilities	454	2,442	360	(195)	3,061
Long-Term Debt	2,243	—	—	—	2,243
Member's Equity	5,558	4,326	310	(4,636)	5,558
Total Liabilities and Member's Equity	**$ 9,138**	**$ 10,374**	**$ 1,456**	**$ (8,922)**	**$ 12,046**

Immaterial Correction of Prior Financial Information

The financial information included in the table above for the three months ended March 31, 2014 had been corrected from the disclosure provided in Power's Form 10-Q for the quarterly period ended March 31, 2014 filed on May 1, 2014 (Q1 2014) to the disclosure provided in Power's Form 10-Q filed on October 30, 2014 to conform to the requirements of Section 210.3-10 of SEC Regulation S-X.

In Q1 2014, Operating Revenues and Operating Expenses among the Guarantor Subsidiaries were eliminated in the Consolidating Adjustments column. The revised presentation eliminated this activity in the Guarantor Subsidiaries column and removed such activity from the Consolidating Adjustments column. This revised presentation decreased both Operating Revenues and Operating Expenses in both the Guarantor Subsidiaries and Consolidating Adjustments columns. This correction had no impact on Power's consolidated Operating Revenues and Operating Expenses. In Q1 2014, loans payable by Power parent company to one of its guarantor subsidiaries were netted against loans receivable in net cash flows used in investing activities. The revised presentation reclassified the increase in loans payable by the parent company to the guarantor subsidiary from net cash flows used in investing activities to net cash flows provided by financing activities. This revised presentation decreased net cash flows used in investing activities and increased net cash flows provided by financing activities in the Power column with corresponding offsets to the amounts in the Consolidating Adjustments Column.

The following table summarizes the adjustments reflected in the above table for the three months ended March 31, 2014:

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Increase (Decrease)		
			Millions		
Three Months Ended March 31, 2014					
Operating Revenues	$ —	$ (393)	$ —	$ 393	$ —
Operating Expenses	$ —	$ (393)	$ —	$ 393	$ —
Net Cash Provided By (Used In) Investing Activities	$ (209)	$ —	$ —	$ 209	$ —
Net Cash Provided By (Used In) Financing Activities	$ 209	$ —	$ —	$ (209)	$ —

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G,** our public utility company which primarily provides electric transmission services and distribution of electric energy and natural gas, implements demand response and energy efficiency programs and invests in solar generation in New Jersey, and
- **Power,** our wholesale energy supply company that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business of our 2014 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2014 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2015 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2014 Form 10-K.

EXECUTIVE OVERVIEW OF 2015 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- Growing our utility operations through continued investment in T&D infrastructure projects with greater diversity of regulatory oversight, and
- Maintaining a reliable generation fleet with the flexibility to utilize a diverse mix of fuels to allow us to respond to market volatility and capitalize on opportunities as they arise in the locations in which we operate.

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Financial Results

The results for PSEG, PSE&G and Power for the three months ended March 31, 2015 and 2014 are presented as follows:

Earnings	Three Months Ended March 31, 2015	2014
	Millions	
PSE&G	$ 242	$ 214
Power (A)	335	164
Other (B)	9	8
PSEG Net Income	**$ 586**	**$ 386**
PSEG Net Income Per Share (Diluted)	**$ 1.15**	**$ 0.76**

(A) Includes an after-tax insurance recovery for Superstorm Sandy of $75 million. See Note 8. Commitments and Contingent Liabilities.

(B) Other includes activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended March 31, 2015	2014
	Millions, after tax	
NDT Fund Income (Expense) (A)	$ 2	$ 9
Non-Trading MTM Gains (Losses)	$ (20)	$ (132)

(A) NDT Fund Income (Expense) includes the net realized gains, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense.

Our $200 million increase in Net Income for the three months ended March 31, 2015 was driven primarily by:

- lower MTM losses in 2015 resulting from higher price increases on forward positions in 2014,
- lower generation costs due to lower fuel costs,
- higher revenues due to increased investments in transmission projects, and
- an insurance recovery included in O&M Expense of Superstorm Sandy costs, primarily at Power.

These increases were partially offset by a decrease in capacity revenues due to lower prices, as well as lower ancillary and operating reserve revenues in PJM.

In October 2014, we filed our 2015 Formula Rate Update with the Federal Energy Regulatory Commission (FERC) for approximately $182 million in increased annual transmission revenues which went into effect on January 1, 2015. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. The adjustment for 2015 includes the impact on rate base due to the extension of bonus depreciation, which was enacted after the filing was made, and is estimated to reduce our 2015 revenue increase by approximately $21 million. Over the past few years, these types of investments have altered the business mix of our overall results of operations to reflect a higher percentage contribution by PSE&G.

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Power's results benefited from access to natural gas supplies through its existing firm pipeline transportation contracts during the cold weather experienced in the first quarter of 2015. Power manages these contracts for the benefit of PSE&G's customers through the basic gas supply service (BGSS) arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to make third party sales and supply gas to its generating units in New Jersey.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission Planning

The FERC's rule under Order 1000 altered the right of first refusal (ROFR) previously held by incumbent utilities to build transmission within their respective service territories, creating the potential that new transmission projects in our service territory could be assigned to third parties rather than PSE&G. Order 1000 also presents opportunities for us to construct transmission outside of our service territory. In April 2013, PJM Interconnection, L.L.C. (PJM) initiated a solicitation process in which we participated pursuant to Order 1000 to review technical solutions to improve the operational performance in the Artificial Island area, consisting of our Salem and Hope Creek nuclear generation facilities. On April 28, 2015, the PJM staff advised stakeholders that it intends to recommend a transmission project that would primarily be awarded to another entity, but that a portion at an estimated construction cost of between $100 million and $130 million would be assigned to PSE&G. We are currently reviewing the PJM staff recommendation. This is the same Artificial Island process that is the subject of a complaint filed by PSE&G against PJM at the FERC, in which PSE&G argued that PJM had failed to follow its rules during this process and requested that the FERC order PJM to do so. If the FERC grants this complaint, the FERC could order PJM to re-start the entire process or make changes to the rules governing future competitive solicitations. The FERC has not yet acted on the complaint.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. In May 2014, a federal court issued a rule that vacated a FERC Order in which the FERC had determined that demand response (DR) providers should receive full market compensation for power and held that the FERC has no jurisdiction over DR. We are presently awaiting a determination from the U.S. Supreme Court as to whether it accepts this case for review. The U.S. Supreme Court's decision could have a material impact on capacity market outcomes in which DR currently participates as a supply resource under FERC jurisdiction.

In a separate development of significance to the wholesale capacity market, in December 2014 PJM filed at the FERC its proposal for a capacity performance product to include generators, DR and energy efficiency providers who would need to certify their availability during emergency conditions, as a supplement to base capacity. The proposal includes enhanced performance-based incentives and penalties. If accepted, the filing will also provide generation owners with greater flexibility in submitting capacity market bids that reflect the additional costs and risks of the more rigorous performance requirements. We are generally supportive of PJM's proposal. The matter is currently pending before the FERC. It is not clear at present whether the FERC will approve the proposal in time for implementation in the next base residual auction. However, the FERC did grant PJM's request to delay the auction until no later than mid-August to so that it can consider PJM's proposal. See Part II, Item 5. Other Information—Capacity Market Issues—PJM for additional information.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. In particular, the EPA's 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. In addition, EPA's proposed greenhouse gas emissions regulations are of potential consequence to our results. We continue to work with the FERC and other federal and state regulators, as well as industry partners, to determine the potential impact of these regulations. Clean Air Act (CAA) regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology rules are also of significance; however, we believe our generation business remains well-positioned for such air pollution control regulations if and when they are implemented.

Other Developments

In the first quarter of 2015 we continued to make investments to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the New Jersey Board of Public Utilities (BPU) in 2014. As approved, the Energy Strong program provides for $1.22 billion of investment, with cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated allowance for funds used during construction, through an accelerated recovery mechanism. We will seek recovery of the remaining $220 million of investment in PSE&G's next base

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rate case, which is to be filed no later than November 1, 2017. In February 2015, the BPU approved our initial Energy Strong cost recovery petition which provides for an estimated annual revenue increase of $1.1 million effective March 1, 2015. In March 2015, PSE&G filed its second Energy Strong cost recovery petition seeking BPU approval to recover in base rates capitalized Energy Strong investment costs expected to be in service by May 31, 2015. The filing requests estimated annual increases in electric revenues of $6 million and gas revenues of $17 million effective September 1, 2015, consistent with the BPU-approved Energy Strong program.

In February 2015, we filed a petition with the BPU seeking approval of a Gas System Modernization Program (GSMP) through which we would invest approximately $1.6 billion over the next five years, or about $320 million per year, to modernize PSE&G's gas systems. The matter is pending. For more detailed information, refer to Part II, Item 5. Other Information—Gas System Modernization Program.

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, we retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. We informed the FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for its peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future. On September 2, 2014, the FERC Staff initiated a preliminary, non-public staff investigation into the matter. This investigation, which is ongoing, could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies.

During the three months ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. It is not possible, at this time, to reasonably estimate the potential range of loss or full impact or predict any resulting penalties or other costs associated with this matter, or the applicability of mitigating factors. As new information becomes available or future developments occur in this investigation, it is possible that Power will record additional estimated losses and such additional losses may be material.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. In the first three months of 2015, our

- total nuclear fleet achieved an average capacity factor of 95%,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 14,500 GWh, while addressing unit outages and balancing fuel availability and price volatility, and
- construction of transmission and solar projects proceeded on schedule and within budget.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first three months of 2015 as we

- had cash flow from operations of $1.7 billion as of March 31, 2015,
- maintained solid investment grade credit ratings,
- extended the expiration dates for approximately $2.0 billion of five-year credit facilities for PSEG, PSE&G and Power from 2018 to 2020, and
- increased our indicated annual dividend for 2015 to $1.56 per share.

We expect to be able to fund our transmission projects required under PJM's reliability program, our Energy Strong program and other planned projects, as well as our proposed GSMP, with internally generated cash and external debt financing.

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Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first three months of 2015 we

- made additional investments in transmission infrastructure projects,
- secured approval to extend three Energy Efficiency Economic Stimulus subprograms to allow for $95 million of additional capital expenditures and $12 million of additional administrative expenses to provide energy efficiency assistance to hospitals, healthcare facilities and residential multi-family housing units,
- continued to execute our existing BPU-approved utility programs,
- started the power ascension for the extended power uprate at our co-owned Peach Bottom 2 nuclear station, and
- commenced installation of equipment to increase output and improve efficiency at our Bergen 2 combined cycle gas unit similar to our 2014 installation at our Linden plant.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-moving economy and a cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions,
- execute our capital investment program, including our Energy Strong program and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and the FERC of market design rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system.

For 2015 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate, and
- delays and other obstacles that might arise in connection with the construction of our T&D projects, including in connection with permitting and regulatory approvals.

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RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 17. Related-Party Transactions.

	Three Months Ended March 31,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014	
	Millions		Millions	%
Operating Revenues	$ 3,135	$ 3,223	$ (88)	(3)
Energy Costs	1,094	1,356	(262)	(19)
Operation and Maintenance	663	856	(193)	(23)
Depreciation and Amortization	330	306	24	8
Income from Equity Method Investments	3	4	(1)	(25)
Other Income and (Deductions)	36	36	—	—
Other-Than-Temporary Impairments	5	2	3	150
Interest Expense	98	97	1	1
Income Tax Expense	398	260	138	53

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Three Months Ended March 31,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014	
	Millions		Millions	%
Operating Revenues	$ 2,002	$ 2,145	$ (143)	(7)
Energy Costs	892	1,045	(153)	(15)
Operation and Maintenance	412	462	(50)	(11)
Depreciation and Amortization	247	227	20	9
Other Income (Deductions)	17	14	3	21
Interest Expense	69	68	1	1
Income Tax Expense	157	143	14	10

Three Months Ended March 31, 2015 as Compared to 2014

Operating Revenues decreased $143 million due to changes in delivery, commodity, clause, and other operating revenues.

Delivery Revenues increased $39 million due primarily to an increase in transmission revenues.

- Transmission revenues were $33 million higher due to net rate increases resulting primarily from increased capital investments.
- Gas distribution revenues increased $3 million due primarily to $17 million from higher sales volumes, partially offset by lower Weather Normalization Clause (WNC) revenue of $15 million due to a higher deferral as a result of colder weather.

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- Electric distribution revenues increased $3 million due primarily to higher Capital Infrastructure Program (CIP) related revenues of $2 million due to the inclusion in base rates beginning in July 2014 and higher sales volumes of $1 million.

Commodity Revenue decreased $153 million due to lower Electric and Gas revenues. This is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of basic generation service (BGS) and BGSS to retail customers.

- Electric revenues decreased $4 million due primarily to $20 million in lower revenues from collection of Non-Utility Generation Charges (NGC) and lower sales volumes of Non-Utility Generation (NUG) energy, partially offset by $16 million of higher BGS revenues. BGS revenues increased $27 million or 6%, due to higher sales volumes, partially offset by $11 million of lower BGS prices.
- Gas revenues decreased $149 million due primarily to lower BGSS prices of $220 million, of which $162 million was due to lower rates resulting from residential bill credits, partially offset by higher BGSS volumes of $71 million due to colder weather in 2015.

Clause Revenues decreased $30 million due primarily to lower Margin Adjustment Clause (MAC) revenue of $18 million and lower Societal Benefit Charges (SBC) of $14 million, partially offset by higher Securitization Transition Charges (STC) of $2 million. The changes in the MAC, SBC and STC amounts were entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on MAC, SBC or STC collections.

Other Operating Revenues experienced no material change.

Operating Expenses

Energy Costs decreased $153 million. This is entirely offset by decreased Commodity Revenue.

- Electric costs declined $4 million or 1% due to $47 million of decreased deferred cost recovery largely offset by $28 million of higher BGS and NUG prices and $15 million in higher BGS volumes, partially offset by lower NUG volumes. BGS volumes increased 5% due primarily to reverse customer migration.
- Gas costs decreased $149 million or 27% due to a $220 million or 40% decline in prices, partially offset by $71 million or 13% in higher sales volumes.

Operation and Maintenance decreased $50 million, of which the most significant components were

- a $40 million decrease in costs related primarily to a net decrease in SBC, MAC, CIP and Green Program Recovery Charges (GPRC). Due to the nature of the SBC, MAC, CIP and GPRC clause mechanisms, these are entirely offset in revenues,
- storm insurance recovery proceeds of $15 million, and
- a $4 million net decrease in operational expenses due to reductions in damage claims of $6 million and storm-related costs of $3 million, partially offset by increases in transmission related costs of $2 million and general operating expenses of $3 million,
- partially offset by a $9 million increase in pension and OPEB expenses.

Depreciation and Amortization increased $20 million due primarily to a $15 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects and an increase of $5 million in amortization of Regulatory Assets.

Other Income and (Deductions) increased $3 million due primarily to an increase in Allowance for Funds used During Construction.

Interest Expense increased $1 million due primarily to a $9 million increase related to issuance of $1,250 million Medium Term Notes (MTN) in the latter half of 2014, partially offset by a $4 million decrease related to maturities of $500 million of MTN in the latter half of 2014 and a $4 million decrease due to the partial redemption of securitization debt.

Income Tax Expense increased $14 million due primarily to higher pre-tax income.

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Power

	Three Months Ended March 31,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014	
	Millions		Millions	%
Operating Revenues	$ 1,725	$ 1,700	$ 25	1
Energy Costs	893	1,044	(151)	(14)
Operation and Maintenance	172	302	(130)	(43)
Depreciation and Amortization	76	72	4	6
Income from Equity Method Investments	3	4	(1)	(25)
Other Income (Deductions)	18	23	(5)	(22)
Other-Than-Temporary Impairments	5	2	3	150
Interest Expense	31	32	(1)	(3)
Income Tax Expense	234	111	123	111

Three Months Ended March 31, 2015 as Compared to 2014

Operating Revenues increased $25 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues increased $108 million due primarily to

- higher net revenues of $127 million due primarily to lower MTM losses in 2015 resulting from higher price increases on forward positions in 2014, partially offset by lower energy volumes sold in PJM and NE regions at lower average realized prices, and
- an increase of $81 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions,
- partially offset by a net decrease of $98 million due primarily to lower capacity revenues resulting from lower average auction prices coupled with lower ancillary and operating reserve revenues in the PJM region.

Gas Supply Revenues decreased $83 million due primarily to

- a net decrease of $48 million in sales under the BGSS contract, substantially comprised of lower average sales prices partially offset by higher sales volumes due to colder average temperatures in the 2015 winter heating season, and
- a decrease of $35 million due to lower average sales prices to third party customers.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $151 million due to

- ***Generation costs*** decreased $35 million due primarily to lower fuel costs, reflecting lower average realized natural gas prices and the utilization of lower volumes of oil. These decreased costs were partially offset by higher congestion costs in the PJM region.
- ***Gas costs*** decreased $116 million, related to lower average gas inventory costs, partially offset by higher volumes sold under the BGSS contract due to colder average temperatures during the 2015 winter heating season.

Operation and Maintenance decreased $130 million due primarily to

- a decrease of $128 million due to insurance recovery related to Superstorm Sandy, and
- a net decrease of $18 million related to our fossil plants largely due to costs incurred in 2014 for maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant, partly offset by planned outage costs in 2015 at our combined cycle Bergen and Bethlehem Energy Center generating plants,

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- partially offset by an increase of $14 million at our nuclear facilities, primarily due to the preparation work for a planned outage at our Hope Creek nuclear plant.

Depreciation and Amortization increased $4 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) decreased $5 million due primarily to NDT Fund realized losses.

Other-Than-Temporary Impairments increased $3 million due to an increase in impairments of the NDT Fund.

Interest Expense experienced no material change.

Income Tax Expense increased $123 million in 2015 due primarily to higher pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund planned capital expenditures and shareholder dividend payments.

For the three months ended March 31, 2015, our operating cash flow increased $563 million as compared to the same period in 2014. The net change was due primarily to higher tax payments in 2014 at the parent company and Energy Holdings and the net changes from PSE&G and Power as discussed below.

PSE&G

PSE&G's operating cash flow increased $98 million from $579 million to $677 million for the three months ended March 31, 2015, as compared to the same period in 2014, due primarily to higher earnings, a $143 million higher net tax refund and increased customer collections of $122 million. These amounts were partially offset by a decrease of $198 million due to a change in regulatory deferrals primarily driven by the return of prior year overcollections to customers for BGSS gas costs, Gas Weather Normalization charges and Non Utility Generation charges.

Power

Power's operating cash flow increased $176 million from $674 million to $850 million for the three months ended March 31, 2015, as compared to the same period in 2014, primarily due to a reduction in margin deposit requirements and higher earnings, partially offset by an increase of $98 million in tax payments.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our $4.3 billion credit facilities are provided by a diverse bank group. As of March 31, 2015, our total available credit capacity was $4.1 billion.

As of March 31, 2015, no single institution represented more than 8% of the total commitments in our credit facilities.

As of March 31, 2015, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of March 31, 2015 were as follows:

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Company/Facility	As of March 31, 2015 Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facility	$ 500	$ 8	$ 492	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A) (B)	500	—	500	Mar 2018	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 8**	**$ 992**		
PSE&G					
5-year Credit Facility (A) (C)	$ 600	$ 14	$ 586	Mar 2018	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 14**	**$ 586**		
Power					
5-year Credit Facility	$ 1,600	$ 178	$ 1,422	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (A) (D)	1,000	—	1,000	Mar 2018	Funding/Letters of Credit
Bilateral Credit Facility	100	—	100	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 178**	**$ 2,522**		
Total	**$ 4,300**	**$ 200**	**$ 4,100**		

(A) In April 2015, expiration dates of these facilities were extended to April 2020.

(B) PSEG facility will be reduced by $23 million in April 2016 and $12 million in March 2018.

(C) PSE&G facility will be reduced by $29 million in April 2016 and $14 million in March 2018.

(D) Power facility will be reduced by $48 million in April 2016 and $24 million in March 2018.

Long-Term Debt Financing

PSE&G has $300 million of 2.70%, Series G, Medium Term Notes maturing in May 2015 and $171 million of 6.75%, Mortgage Bonds maturing in January 2016. Power has $300 million of 5.50% Senior Notes maturing in December 2015.

For a discussion of our long-term debt transactions during 2015, see Note 9. Changes in Capitalization.

Common Stock Dividends

On February 17, 2015, our Board of Directors approved a $0.39 per share common stock dividend for the first quarter of 2015. On April 21, 2015, our Board of Directors declared a quarterly dividend of $0.39 per share of common stock for the second quarter of 2015. This reflects an indicated annual dividend rate of $1.56 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Note 15. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

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	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	**Stable**	**Positive**	**Stable**
Commercial Paper	P2	A2	F2
PSE&G			
Outlook	**Stable**	**Positive**	**Stable**
Mortgage Bonds	Aa3	A	A+
Commercial Paper	P1	A2	F2
Power			
Outlook	**Stable**	**Positive**	**Stable**
Senior Notes	Baa1	BBB+	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1+ (highest) to D (lowest) for short-term securities. The Corporate Credit Rating outlook does not apply to PSEG's or PSE&G's Commercial Paper Rating or PSE&G's Mortgage Bond rating.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1+ (highest) to D (lowest) for short-term securities.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures at PSE&G, Power and Services as compared to amounts disclosed in our 2014 Form 10-K.

In February 2015, we filed a petition with the BPU seeking authority to invest $1.6 billion over the next 5 years, or about $320 million per year, to modernize PSE&G's gas systems. The estimated project expenditures related to this petition are not included in our $8.7 billion three-year capital forecast table in our 2014 Form 10-K. For additional information, see Part II, Item 5. Other Information—Gas System Modernization Program.

PSE&G

During the three months ended March 31, 2015, PSE&G made capital expenditures of $601 million, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $26 million, which are included in operating cash flows.

Power

During the three months ended March 31, 2015, Power made capital expenditures of $94 million, excluding $45 million for nuclear fuel, primarily related to various projects at its fossil and nuclear generation stations.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or

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non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From January through March 2015, MTM VaR remained relatively stable. The range of VaR was narrower for the three months ended March 31, 2015 as compared with the year ended December 31, 2014.

	MTM VaR	
	Three Months Ended March 31, 2015	Year Ended December 31, 2014
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 20	$ 36
Average for the Period	$ 20	$ 30
High	$ 26	$ 195
Low	$ 15	$ 14
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 31	$ 56
Average for the Period	$ 31	$ 46
High	$ 40	$ 306
Low	$ 24	$ 22

See Note 10. Financial Risk Management Activities for a discussion of credit risk.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

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Internal Controls

There have been no changes in internal control over financial reporting that occurred during the first quarter of 2015 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3. of Part I of the 2014 Annual Report on Form 10-K, see Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

There are no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2014 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the first quarter of 2015.

Three Months Ended March 31, 2015	Total Number of Shares Purchased	Average Price Paid per Share
January 1 - January 31	—	$ —
February 1- February 28	731,784	$ 42.80
March 1 - March 31	70,078	$ 42.37

ITEM 5. OTHER INFORMATION

Certain information reported in the 2014 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2014 Annual Report on Form 10-K. References are to the related pages on the Form 10-K as printed and distributed.

Federal Regulation

FERC

Regulation of Wholesale Sales—Generation/Market Issues

Capacity Market Issues—PJM

December 31, 2014 Form 10-K page 16. The RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. There is currently significant activity concerning two topics: (i) the future role of DR in the RPM market in light of a decision by the D.C. Circuit Court of Appeals (D.C. Court) holding that DR is not a FERC-jurisdictional product, and (ii) PJM's development of a new capacity product called a Capacity Performance (CP) product.

In May 2014, the D.C. Court held that DR is not a FERC-jurisdictional product, thereby calling into question DR resources' ability to participate in either the energy or capacity markets in the future. The U.S. Supreme Court is currently considering whether to hear this case. A decision not to hear the case or a ruling on merits of upholding the lower court decision would be expected to have a significant impact on the amount and manner of participation by DR in PJM's markets. However, unless the U.S. Supreme Court declines to hear the case, it appears that DR will be allowed to participate in RPM for the upcoming base residual auction as supply resources under the currently effective rules.

On December 12, 2014, PJM filed a proposal at the FERC to implement a CP mechanism. Under this mechanism, PJM created a more robust capacity product definition with enhanced incentives for performance during emergency conditions and

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significant penalties for non-performance. On March 31, 2015, the FERC issued a "deficiency letter" requiring PJM to submit additional information about its filing. Since that time, PJM has (i) sought to delay the residual capacity auction, currently scheduled to begin on May 11, 2015, for between 30 and 75 days, but no later than mid-August, to provide additional time for approval and implementation of the CP proposal; and (ii) responded to the March 31, 2015 deficiency letter in a manner that, if accepted by the FERC, would largely preserve the core elements of the proposal. We have filed in support of PJM's proposals. On April 24, 2015, the FERC approved PJM's request to delay the upcoming base residual auction. However, we are unable to predict whether the FERC will approve the CP proposal. This new product, if accepted by the FERC, will be phased in over the next few years, with full implementation for the 2020-2021 Delivery Year. PJM's approach may provide the opportunity for enhanced capacity market revenue streams for Power. However, there may be requirements for additional investment and there are additional performance risks, as well as risks associated with our ability to bid in a manner that would ensure recovery of any capital investment.

Capacity Market Issues—ISO-New England (ISO-NE)

December 31, 2014 Form 10-K page 17. ISO-NE's market for installed capacity in New England provides fixed capacity payments for generators, imports and DR. The market design consists of a forward-looking auction for installed capacity, employing an administratively determined demand curve, that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. One aspect of the current market design that we do disagree with is the exemption from the Minimum Offer Price Rule in the capacity market afforded for up to 200 MW annually (600 MW cumulatively) of renewable resources. We believe that the exemption is unduly discriminatory and will artificially suppress capacity prices. On March 31, 2015, in conjunction with other companies, we filed a petition for review with the D.C. Court of FERC's ruling accepting the exemption.

We anticipate that ISO-NE will complete an ongoing stakeholder process addressing zonal demand curves for its capacity market in the near future and will seek approval of those curves at the FERC. These curves will have a significant impact upon the revenues our generation can expect to receive in the capacity market in New England. Also under consideration in the ISO-NE stakeholder process are proposals that would place restrictions or impose penalties on generators wishing to retire. We believe that, if adopted, these proposals could have a disruptive effect on efficient price formation in the capacity market.

Capacity Market Issues—NYISO

December 31, 2014 Form 10-K page 17. NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. Prior to 2013, the NYISO capacity model had recognized only two separate zones that potentially may separate in price: New York City and Long Island. In August 2013, the FERC issued an order approving a third capacity zone that would encompass the super zone that includes the lower Hudson Valley and New York City which took effect on May 1, 2014. On April 2, 2015, the Second Circuit Court of Appeals upheld the FERC's decision.

Matters have been pending before the FERC concerning potential changes to the NYISO capacity markets, including rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons. On March 19, 2015, the FERC issued an order which held that units receiving special reliability payments could properly take those payments into account in formulating capacity market bids. We believe that this ruling could have impacts on efficient price formation in the capacity market and could artificially suppress capacity market outcomes. On April 20, 2015, a trade association of which we are a member filed for rehearing by the FERC of this ruling.

Transmission Regulation—Transmission Policy Developments

December 31, 2014 Form 10-K page 18. The FERC concluded in Order 1000 that the incumbent transmission owner should not always have a ROFR to construct and own transmission projects in its service territory. We and other companies appealed Order 1000 but this appeal was denied last year. The current PJM rules retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including projects being built on existing right-of-way and whose construction would interfere with incumbents' use of their right-of-way. While these carve-outs ameliorate the impacts of the Order 1000 ruling, we and several other companies appealed various aspects of the FERC order approving PJM's implementation of Order 1000 on the grounds that the FERC had not met the requisite legal burden in eliminating the ROFR from the PJM Tariff. This appeal remains pending in federal court. Moreover, on April 14, 2015, the D.C. Court reviewing another FERC decision addressing the issue of pre-Order 1000 participation by a non-incumbent transmission developer in the PJM transmission planning process (a case in which we are an appellant) found that such review was no longer needed due to the intervening events of Order 1000. At the same time, however, that court acknowledged that our pending appeal remained a "live" controversy.

PJM's first action toward complying with Order 1000 began in April 2013, when it initiated its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues at Artificial Island. On April 28, 2015, the PJM staff advised stakeholders that it intends to recommend a transmission project to the PJM Board of Managers consisting of various components to be constructed by LS Power, PSE&G and Potomac Holding Company. Based on PJM's presentation, PSE&G expects the total construction cost of

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the project components that would be assigned to it, if the recommendation is approved, to range between $100 million and $130 million. The recommendation will be open to public comment until May 29, 2015. The PJM Board is expected to act on the recommendation in either June or July. We are currently reviewing the PJM staff recommendation. Our related complaint against PJM at the FERC, asserting that PJM had failed to follow its tariff rules governing the Artificial Island "open window" process, still remains pending. For additional information, see Part I, Item 2. MD&A—Transmission Planning.

Compliance—FERC

December 31, 2014 Form 10-K page 19. In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, we retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. We informed the FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for its peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future. On September 2, 2014, the FERC Staff initiated a preliminary, non-public staff investigation into the matter. This investigation, which is ongoing, could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies.

During the three months ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. It is not possible, at this time, to reasonably estimate the potential range of loss or full impact or predict any resulting penalties or other costs associated with this matter, or the applicability of mitigating factors. As new information becomes available or future developments occur in this investigation, it is possible that Power will record additional estimated losses and such additional losses may be material.

State Regulation

Energy Strong Program

December 31, 2014 Form 10-K page 21. Our Energy Strong Program encompasses infrastructure investments of $1.22 billion that we will make to our BPU jurisdictional electric and gas system to improve resiliency for the future.

In February 2015, the BPU approved our initial Energy Strong cost recovery petition which provides for an estimated annual revenue increase of $1.1 million effective March 1, 2015.

In March 2015, PSE&G filed its second Energy Strong cost recovery petition seeking BPU approval to recover in base rates capitalized Energy Strong investment costs expected to be in service by May 31, 2015. The filing requests estimated annual increases in electric revenues of $6 million and gas revenues of $17 million effective September 1, 2015, consistent with the BPU Order of approval of the Energy Strong program.

Gas System Modernization Program (GSMP)

In February 2015, we filed a petition with the BPU seeking authority to invest approximately $1.6 billion over the next five years, or about $320 million per year, to modernize PSE&G's gas systems. PSE&G's GSMP would include the replacement of an average of approximately 160 miles of cast iron and unprotected steel gas mains and about 11,000 unprotected steel service lines to homes and businesses per each of five years. The mains and service lines would be replaced with stronger, more durable plastic piping, reducing the potential for leaks and release of methane gas. The new elevated pressure systems also enable the installation of excess flow valves that automatically shut off gas flow if a service line is damaged, and better support the use of high-efficiency appliances. The matter is pending.

Energy Efficiency Economic Stimulus Extension II (EEE Ext II)

December 31, 2014 Form 10-K page 22. On April 15, 2015, the BPU approved our petition to extend three EEE subprograms (multi-family, direct install and hospital efficiency). The Order allows for $95 million of additional capital expenditures and $12 million of additional administrative expenses effective May 1, 2015.

Environmental Matters

Air Pollution Control

Ozone Standard

On December 17, 2014, the EPA proposed a rule to lower the ambient air quality standard for the level of ozone in the atmosphere from 75 parts per billion (ppb) to a level in the range of 65-70 ppb. The Edison Electric Institute, of which we are a member, submitted comments on its members' behalf. The EPA is expected to finalize the rule by October 1, 2015. Depending on the level set, some portions of the Mid-Atlantic and New England states are not expected to be able to meet the new

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standard. To meet the proposed new standard, additional emission reduction strategies for NO_X and volatile organic compounds may have to be implemented. We cannot predict the outcome of this matter.

Climate Change

CO_2 Regulation Under the Clean Air Act (CAA)

December 31, 2014 Form 10-K page 23. In June 2014, the EPA issued a proposed greenhouse gas (GHG) emissions regulation under the CAA for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction (BSER). The BSER consists of four components: (i) heat rate improvements at existing coal-fired power plants, (ii) increased use of existing natural gas combined cycle capacity, (iii) operation of zero-emitting generation (renewables and nuclear), and (iv) increased use of demand-side energy efficiency. States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions.

Since the EPA has requested comments on many aspects of the proposal, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact. A final rule is expected in mid-summer 2015.

The FERC held a series of technical conferences ending in early April 2015 to discuss the implications of compliance approaches to the EPA's proposed GHG regulation for existing power plants. The conferences focused on issues related to electric reliability, wholesale electric markets and operations and energy infrastructure. The FERC also solicited and received written comments. It is expected that the FERC will provide guidance to the EPA in finalizing the rule for existing power plants.

Water Pollution Control

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, we determined that monitoring and reporting practices related to certain permitted wastewater discharges at our Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject us to fines and penalties. We have notified the Connecticut Department of Energy and Environmental Protection of the issues and have taken actions to investigate and resolve the potential non-compliance. At this early stage we cannot predict the impact of this matter.

Fuel and Waste Disposal

Coal Combustion Residuals (CCRs)

December 31, 2014 Form 10-K page 26. On December 19, 2014, the EPA issued a final rule which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Our Hudson and Mercer generating stations, along with our co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. The scope of the work entailed to comply has not yet been finalized but we expect that the impacts of this rule will not be material to our results of operations, financial condition or cash flows.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. PSE&G:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
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Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. Power:

Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: May 1, 2015

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: May 1, 2015

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SIGNATURE

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PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: May 1, 2015

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2015	2014	2014	2013	2012	2011	2010
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 984	646	$ 2,456	$ 2,055	$ 2,011	$ 2,384	$ 2,616
(Income) Loss from Equity Investees, net of Distributions	2	—	4	(7)	9	(4)	(19)
Fixed Charges	112 —	111	450	458	479	522	571
Capitalized Interest	(2)	(4)	(16)	(16)	(19)	(14)	(67)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	—	(2)
Total Earnings	$ 1,096	$ 753	$ 2,894	$ 2,490	$ 2,480	$ 2,888	$ 3,099
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 107	107	$ 430	$ 442	$ 465	$ 509	$ 555
Interest Factor in Rentals	5	4	20	16	14	13	14
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	—	2
Total Fixed Charges	$ 112	$ 111	$ 450	$ 458	$ 479	$ 522	$ 571
Ratio of Earnings to Fixed Charges	**9.79**	**6.78**	**6.43**	**5.44**	**5.18**	**5.53**	**5.43**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2015	2014	2014	2013	2012	2011	2010
			(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 399	357	$1,174	$ 993	$ 835	$ 861	$ 591
Fixed Charges	75	74	303	316	314	319	325
Capitalized Interest	(4)	(4)	(16)	(16)	(13)	(4)	(2)
Total Earnings	$ 470	$ 427	$1,461	$1,293	$ 1,136	$1,176	$ 914
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 73	72	$ 293	$ 309	$ 308	$ 314	$ 320
Interest Factor in Rentals	2	2	10	7	6	5	5
Total Fixed Charges	$ 75	$ 74	$ 303	$ 316	$ 314	$ 319	$ 325
Ratio of Earnings to Fixed Charges	**6.27**	**5.77**	**4.82**	**4.09**	**3.62**	**3.69**	**2.81**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Three Months Ended March 31,		Years Ended December 31,				
	2015	**2014**	**2014**	**2013**	**2012**	**2011**	**2010**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 399	$ 357	$1,174	$ 993	$ 835	$ 861	$ 591
Fixed Charges	75	74	303	316	314	319	327
Capitalized Interest	(4)	(4)	(16)	(16)	(13)	(4)	(2)
Preferred Securities Dividend Requirements	—	—	—	—	—	—	(2)
Total Earnings	$ 470	$ 427	$1,461	$1,293	$1,136	$1,176	$ 914
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 73	$ 72	$ 293	$ 309	$ 308	$ 314	$ 320
Interest Factor in Rentals	2	2	10	7	6	5	5
Preferred Securities Dividend	—	—	—	—	—	—	1
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	—	—	—	—	1
Total Fixed Charges	$ 75	$ 74	$ 303	$ 316	$ 314	$ 319	$ 327
Ratio of Earnings to Fixed Charges	**6.27**	**5.77**	**4.82**	**4.09**	**3.62**	**3.69**	**2.80**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period, (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries, and (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 12.3

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2015	**2014**	**2014**	**2013**	**2012**	**2011**	**2010**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	569	275	$1,251	$1,063	$1,099	$1,703	$1,932
(Income) Loss from Equity Investees, net of Distributions	1	—	3	(10)	(6)	(12)	(8)
Fixed Charges	38	39	150	143	164	208	238
Capitalized Interest	1	1	1	1	(6)	(10)	(63)
Total Earnings	$ 609	$ 315	$1,405	$1,197	$1,251	$1,889	$2,099
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	37	38	$ 146	$ 139	$ 161	$ 205	$ 235
Interest Factor in Rentals	1	1	4	4	3	3	3
Total Fixed Charges	$ 38	$ 39	$ 150	$ 143	$ 164	$ 208	$ 238
Ratio of Earnings to Fixed Charges	**16.03**	**8.08**	**9.37**	**8.37**	**7.63**	**9.08**	**8.82**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2015

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

S1-SSA-0009 - 18363

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2015

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer

S1-SSA-0009 - 18364

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2015

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2015

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2015

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 1, 2015

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
May 1, 2015

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer
May 1, 2015

S1-SSA-0009 - 18370

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
May 1, 2015

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer
May 1, 2015

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
May 1, 2015

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Caroline Dorsa

Caroline Dorsa

PSEG Power LLC
Chief Financial Officer
May 1, 2015

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Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED March 31, 2016
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of April 19, 2016, Public Service Enterprise Group Incorporated had outstanding 505,929,329 shares of its sole class of Common Stock, without par value.

As of April 19, 2016, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or ongoing low pricing of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulations, including market structures and transmission planning,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators, including prudency reviews and disallowances,
- any deterioration in our credit quality or the credit quality of our counterparties,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations or increase the cost of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- delays or unforeseen cost escalations in our construction and development activities, or the inability to recover the carrying amount of our assets,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- increases in competition in energy supply markets as well as for transmission projects,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies,
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- an extended economic recession,
- an inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce, and
- changes in the credit quality and the ability of lessees to meet their obligations under our domestic leveraged leases.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking

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statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

FILING FORMAT

This combined Quarterly Report on Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to “we,” “us,” and “our” relate to PSEG or to the specific company or companies being discussed.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended March 31,	
	2016	**2015**
OPERATING REVENUES	$ 2,616	$ 3,135
OPERATING EXPENSES		
Energy Costs	836	1,094
Operation and Maintenance	729	663
Depreciation and Amortization	224	330
Total Operating Expenses	1,789	2,087
OPERATING INCOME	827	1,048
Income from Equity Method Investments	2	3
Other Income	48	48
Other Deductions	(21)	(12)
Other-Than-Temporary Impairments	(10)	(5)
Interest Expense	(92)	(98)
INCOME BEFORE INCOME TAXES	754	984
Income Tax Expense	(283)	(398)
NET INCOME	$ 471	$ 586
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:		
BASIC	505	506
DILUTED	508	508
NET INCOME PER SHARE:		
BASIC	$ 0.93	$ 1.16
DILUTED	$ 0.93	$ 1.15
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.41	$ 0.39

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2016	**2015**
NET INCOME	$ 471	$ 586
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(16) and $(13) for 2016 and 2015, respectively	16	14
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(1) and $7 for 2016 and 2015, respectively	2	(9)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(6) and $(6) for 2016 and 2015, respectively	8	8
Other Comprehensive Income (Loss), net of tax	26	13
COMPREHENSIVE INCOME	$ 497	$ 599

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 592	$ 394
Accounts Receivable, net of allowances of $66 and $67 in 2016 and 2015, respectively	1,107	1,068
Tax Receivable	4	305
Unbilled Revenues	178	197
Fuel	306	463
Materials and Supplies, net	533	513
Prepayments	89	135
Derivative Contracts	230	242
Regulatory Assets	217	164
Other	7	13
Total Current Assets	3,263	3,494
PROPERTY, PLANT AND EQUIPMENT	36,393	35,494
Less: Accumulated Depreciation and Amortization	(9,119)	(8,955)
Net Property, Plant and Equipment	27,274	26,539
NONCURRENT ASSETS		
Regulatory Assets	3,150	3,196
Long-Term Investments	1,234	1,233
Nuclear Decommissioning Trust (NDT) Fund	1,778	1,754
Long-Term Tax Receivable	184	171
Long-Term Receivable of Variable Interest Entity (VIE)	506	495
Other Special Funds	246	227
Goodwill	16	16
Other Intangibles	112	102
Derivative Contracts	133	77
Other	230	231
Total Noncurrent Assets	7,589	7,502
TOTAL ASSETS	$ 38,126	$ 37,535

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2016	December 31, 2015
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 562	$ 734
Commercial Paper and Loans	12	364
Accounts Payable	1,192	1,369
Derivative Contracts	53	76
Accrued Interest	123	96
Accrued Taxes	155	42
Clean Energy Program	86	142
Obligation to Return Cash Collateral	130	128
Regulatory Liabilities	115	123
Regulatory Liabilities of VIEs	32	42
Other	482	459
Total Current Liabilities	2,942	3,575
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	8,377	8,166
Regulatory Liabilities	177	175
Asset Retirement Obligations	686	679
OPEB Costs	1,205	1,228
OPEB Costs of Servco	382	375
Accrued Pension Costs	458	487
Accrued Pension Costs of Servco	117	114
Environmental Costs	423	415
Derivative Contracts	14	27
Long-Term Accrued Taxes	176	212
Other	174	181
Total Noncurrent Liabilities	12,189	12,059
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT	9,676	8,834
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2016 and 2015—534 shares	4,908	4,915
Treasury Stock, at cost, 2016 - 29 shares; 2015— 28 shares	(702)	(671)
Retained Earnings	9,381	9,117
Accumulated Other Comprehensive Loss	(269)	(295)
Total Common Stockholders' Equity	13,318	13,066
Noncontrolling Interest	1	1
Total Stockholders' Equity	13,319	13,067
Total Capitalization	22,995	21,901
TOTAL LIABILITIES AND CAPITALIZATION	$ 38,126	$ 37,535

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2016	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 471	$ 586
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	224	330
Amortization of Nuclear Fuel	58	55
Provision for Deferred Income Taxes (Other than Leases) and ITC	182	63
Non-Cash Employee Benefit Plan Costs	32	41
Leveraged Lease (Income) Loss, Adjusted for Rents Received and Deferred Taxes	(15)	4
Net Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(21)	37
Change in Accrued Storm Costs	(1)	7
Net Change in Other Regulatory Assets and Liabilities	(104)	(29)
Cost of Removal	(35)	(26)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	3	(12)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	301	180
Accrued Taxes	144	322
Margin Deposit	(4)	14
Other Current Assets and Liabilities	27	109
Employee Benefit Plan Funding and Related Payments	(56)	(47)
Other	8	45
Net Cash Provided By (Used In) Operating Activities	1,214	1,679
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,065)	(747)
Proceeds from Sales of Available-for-Sale Securities	202	609
Investments in Available-for-Sale Securities	(207)	(638)
Other	(11)	(3)
Net Cash Provided By (Used In) Investing Activities	(1,081)	(779)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(352)	—
Issuance of Long-Term Debt	850	—
Redemption of Long-Term Debt	(171)	—
Redemption of Securitization Debt	—	(58)
Cash Dividends Paid on Common Stock	(207)	(197)
Other	(55)	(39)
Net Cash Provided By (Used In) Financing Activities	65	(294)
Net Increase (Decrease) in Cash and Cash Equivalents	198	606
Cash and Cash Equivalents at Beginning of Period	394	402
Cash and Cash Equivalents at End of Period	$ 592	$ 1,008
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (299)	$ (175)
Interest Paid, Net of Amounts Capitalized	$ 66	$ 74
Accrued Property, Plant and Equipment Expenditures	$ 434	$ 276

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2016	**2015**
OPERATING REVENUES	$ 1,712	$ 2,002
OPERATING EXPENSES		
Energy Costs	729	892
Operation and Maintenance	382	412
Depreciation and Amortization	139	247
Total Operating Expenses	1,250	1,551
OPERATING INCOME	462	451
Other Income	20	18
Other Deductions	(1)	(1)
Interest Expense	(68)	(69)
INCOME BEFORE INCOME TAXES	413	399
Income Tax Expense	(151)	(157)
NET INCOME	$ 262	$ 242

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2016	**2015**
NET INCOME	$ 262	$ 242
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0 and $0 for 2016 and 2015, respectively	—	—
COMPREHENSIVE INCOME	$ 262	$ 242

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 558	$ 198
Accounts Receivable, net of allowances of $66 and $67 in 2016 and 2015, respectively	831	787
Accounts Receivable—Affiliated Companies	3	222
Unbilled Revenues	178	197
Materials and Supplies	154	148
Prepayments	5	31
Regulatory Assets	217	164
Derivative Contracts	8	13
Other	5	9
Total Current Assets	1,959	1,769
PROPERTY, PLANT AND EQUIPMENT	24,347	23,732
Less: Accumulated Depreciation and Amortization	(5,584)	(5,504)
Net Property, Plant and Equipment	18,763	18,228
NONCURRENT ASSETS		
Regulatory Assets	3,150	3,196
Long-Term Investments	331	330
Other Special Funds	59	49
Derivative Contracts	2	—
Other	108	105
Total Noncurrent Assets	3,650	3,680
TOTAL ASSETS	$ 24,372	$ 23,677

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	March 31, 2016	December 31, 2015
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ —	$ 171
Commercial Paper and Loans	—	153
Accounts Payable	621	724
Accounts Payable—Affiliated Companies	258	292
Accrued Interest	83	70
Clean Energy Program	86	142
Obligation to Return Cash Collateral	130	128
Regulatory Liabilities	115	123
Regulatory Liabilities of VIEs	32	42
Other	329	297
Total Current Liabilities	1,654	2,142
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	5,341	5,181
OPEB Costs	912	937
Accrued Pension Costs	183	202
Regulatory Liabilities	177	175
Environmental Costs	354	365
Asset Retirement Obligations	219	218
Derivative Contracts	—	11
Long-Term Accrued Taxes	89	109
Other	116	114
Total Noncurrent Liabilities	7,391	7,312
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT	7,492	6,650
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2016 and 2015—132 shares	892	892
Contributed Capital	695	695
Basis Adjustment	986	986
Retained Earnings	5,261	4,999
Accumulated Other Comprehensive Income	1	1
Total Stockholder's Equity	7,835	7,573
Total Capitalization	15,327	14,223
TOTAL LIABILITIES AND CAPITALIZATION	$ 24,372	$ 23,677

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2016	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 262	$ 242
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	139	247
Provision for Deferred Income Taxes and ITC	147	29
Non-Cash Employee Benefit Plan Costs	18	24
Cost of Removal	(35)	(26)
Change in Accrued Storm Costs	(1)	7
Net Change in Other Regulatory Assets and Liabilities	(104)	(29)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	(26)	(142)
Materials and Supplies	(6)	(9)
Prepayments	26	37
Accounts Payable	(24)	16
Accounts Receivable/Payable—Affiliated Companies, net	197	253
Other Current Assets and Liabilities	35	77
Employee Benefit Plan Funding and Related Payments	(44)	(37)
Other	(16)	(12)
Net Cash Provided By (Used In) Operating Activities	568	677
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(724)	(599)
Proceeds from Sales of Available-for-Sale Securities	5	4
Investments in Available-for-Sale Securities	(5)	(5)
Solar Loan Investments	—	(2)
Other	—	9
Net Cash Provided By (Used In) Investing Activities	(724)	(593)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	(153)	—
Issuance of Long-Term Debt	850	—
Redemption of Long-Term Debt	(171)	—
Redemption of Securitization Debt	—	(58)
Other	(10)	—
Net Cash Provided By (Used In) Financing Activities	516	(58)
Net Increase (Decrease) In Cash and Cash Equivalents	360	26
Cash and Cash Equivalents at Beginning of Period	198	310
Cash and Cash Equivalents at End of Period	$ 558	$ 336
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (200)	$ (180)
Interest Paid, Net of Amounts Capitalized	$ 53	$ 58
Accrued Property, Plant and Equipment Expenditures	$ 318	$ 226

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2016	**2015**
OPERATING REVENUES	$ 1,313	$ 1,725
OPERATING EXPENSES		
Energy Costs	638	893
Operation and Maintenance	253	172
Depreciation and Amortization	79	76
Total Operating Expenses	970	1,141
OPERATING INCOME	343	584
Income from Equity Method Investments	2	3
Other Income	26	29
Other Deductions	(18)	(11)
Other-Than-Temporary Impairments	(10)	(5)
Interest Expense	(22)	(31)
INCOME BEFORE INCOME TAXES	321	569
Income Tax Expense	(129)	(234)
NET INCOME	$ 192	$ 335

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2016	**2015**
NET INCOME	$ 192	$ 335
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(16) and $(13) for 2016 and 2015, respectively	16	14
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0 and $7 for 2016 and 2015, respectively	—	(9)
Pension/OPEB adjustment, net of tax (expense) benefit of $(5) and $(5) for 2016 and 2015, respectively	7	7
Other Comprehensive Income (Loss), net of tax	23	12
COMPREHENSIVE INCOME	$ 215	$ 347

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 16	$ 12
Accounts Receivable	227	217
Accounts Receivable—Affiliated Companies	184	276
Short-Term Loan to Affiliate	672	363
Fuel	306	463
Materials and Supplies, net	377	363
Derivative Contracts	218	223
Prepayments	27	25
Other	4	7
Total Current Assets	2,031	1,949
PROPERTY, PLANT AND EQUIPMENT	11,690	11,354
Less: Accumulated Depreciation and Amortization	(3,364)	(3,227)
Net Property, Plant and Equipment	8,326	8,127
NONCURRENT ASSETS		
NDT Fund	1,778	1,754
Long-Term Investments	116	119
Goodwill	16	16
Other Intangibles	112	102
Other Special Funds	61	55
Derivative Contracts	127	77
Other	50	51
Total Noncurrent Assets	2,260	2,174
TOTAL ASSETS	$ 12,617	$ 12,250

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2016	December 31, 2015
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 553	$ 553
Accounts Payable	418	432
Accounts Payable—Affiliated Companies	152	33
Derivative Contracts	52	76
Accrued Interest	39	25
Other	98	107
Total Current Liabilities	1,312	1,226
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	2,402	2,347
Asset Retirement Obligations	463	457
OPEB Costs	232	230
Derivative Contracts	14	16
Accrued Pension Costs	158	166
Long-Term Accrued Taxes	38	35
Other	96	87
Total Noncurrent Liabilities	3,403	3,338
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT	1,685	1,684
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	5,206	5,014
Accumulated Other Comprehensive Loss	(217)	(240)
Total Member's Equity	6,217	6,002
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,617	$ 12,250

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2016	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 192	$ 335
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	79	76
Amortization of Nuclear Fuel	58	55
Provision for Deferred Income Taxes and ITC	34	37
Net Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(21)	37
Non-Cash Employee Benefit Plan Costs	10	13
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	3	(12)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	143	284
Margin Deposit	(4)	14
Accounts Receivable	(41)	(16)
Accounts Payable	(34)	(55)
Accounts Receivable/Payable—Affiliated Companies, net	184	86
Accrued Interest Payable	14	16
Other Current Assets and Liabilities	1	(56)
Employee Benefit Plan Funding and Related Payments	(8)	(6)
Other	53	42
Net Cash Provided By (Used In) Operating Activities	663	850
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(333)	(139)
Proceeds from Sales of Available-for-Sale Securities	183	594
Investments in Available-for-Sale Securities	(188)	(608)
Short-Term Loan—Affiliated Company, net	(309)	(471)
Other	(12)	(11)
Net Cash Provided By (Used In) Investing Activities	(659)	(635)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	—	(200)
Net Cash Provided By (Used In) Financing Activities	—	(200)
Net Increase (Decrease) in Cash and Cash Equivalents	4	15
Cash and Cash Equivalents at Beginning of Period	12	9
Cash and Cash Equivalents at End of Period	$ 16	$ 24
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (100)	$ 5
Interest Paid, Net of Amounts Capitalized	$ 11	$ 16
Accrued Property, Plant and Equipment Expenditures	$ 116	$ 50

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

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Note 1. Organization and Basis of Presentation

Organization

PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- **Power**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy transacting functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2015.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2015.

Note 2. Recent Accounting Standards

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard was issued to clarify the principles for recognizing revenue and to develop a common standard that would remove inconsistencies in revenue requirements; improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provide improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The update was originally to be effective for annual and interim reporting periods beginning after December 15, 2016; however, the Financial Accounting Standards Board issued new guidance deferring the effective date by one year to periods beginning after December 31, 2017. Early application will be permitted as of the original effective date. PSEG is currently analyzing the impact of this standard on its financial statements.

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Recognition and Measurement of Financial Assets and Financial Liabilities

This accounting standard will change how entities measure equity investments that are not consolidated or accounted for under the equity method and how they will present changes in the fair value of financial liabilities measured under the fair value option that are attributable to their own credit. Under the new guidance, equity investments (other than those accounted for using the equity method) will now have to be measured at fair value through Net Income instead of Other Comprehensive Income (Loss). For equity investments which do not have readily determinable fair values, the impairment assessment will be simplified by requiring a qualitative assessment to identify impairments. The new standard also changes certain disclosures.

The accounting standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG is currently analyzing the impact of this standard on our financial statements; however, PSEG expects increased volatility in net income due to changes in fair value of our equity securities within the Nuclear Decommissioning Trust (NDT) and Rabbi Trust Funds.

Leases

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee would recognize a lease asset and corresponding lease obligation. A lessee would classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor would classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements.

The accounting standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Stock Compensation-Improvements to Employee Share-Based Payment Accounting

This accounting standard was issued to simplify aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows.

Under the new guidance, all excess tax benefits and tax deficiencies should be recognized as income tax expense rather than recognized in additional paid in capital. In the statement of cash flows, excess tax benefits should be classified with other income tax cash flows as an operating activity rather than a financing activity as currently classified. In addition, the minimum statutory tax withholding requirements were simplified in order to facilitate equity classification of the award.

The accounting standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early adoption is permitted for an entity in any interim or annual period. An entity that elects early adoption must adopt all of the amendments in the same period; however, the amendments within this update require different adoption methods. PSEG is currently analyzing the impact of this standard on its financial statements.

Note 3. Variable Interest Entities (VIEs)

VIEs for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which was pledged as collateral to a trustee. PSE&G acted as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds were remitted to Transition Funding and Transition Funding II and were used for interest and principal payments on the transition bonds and related costs. During 2015, Transition Funding and Transition Funding II paid their final securitization bond payments and as of December 31, 2015, no further debt or related costs remained with these VIEs. Effective January 1, 2016, PSE&G commenced refunding the overcollections from customers associated with these VIEs and expects to fully refund these liabilities in 2016.

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VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operation and Maintenance (O&M) Expense, respectively. Servco recorded $98 million and $82 million for the three months ended March 31, 2016 and 2015, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 4. Rate Filings

This Note should be read in conjunction with Note 5. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2015.

In addition to items previously reported in the Annual Report on Form 10-K, significant regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

Remediation Adjustment Charge (RAC)—On April 27, 2016, the BPU approved PSE&G's filing with respect to its RAC 23 petition allowing recovery of $54 million effective May 7, 2016 related to net Manufactured Gas Plant expenditures from August 1, 2014 through July 31, 2015.

Note 5. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with solar renewable energy certificates generated from the installed solar electric system. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Outstanding Loans by Class of Customer

Consumer Loans	As of March 31, 2016	As of December 31, 2015
	Millions	
Commercial/Industrial	$ 178	$ 177
Residential	12	12
Total	**$ 190**	**$ 189**

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Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

The following table shows Energy Holdings' gross and net lease investment as of March 31, 2016 and December 31, 2015, respectively.

	As of March 31, 2016	As of December 31, 2015
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 631	$ 631
Estimated Residual Value of Leased Assets	519	519
Unearned and Deferred Income	(363)	(366)
Gross Investment in Leases	787	784
Deferred Tax Liabilities	(709)	(724)
Net Investment in Leases	**$ 78**	**$ 60**

The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

Counterparties' Credit Rating Standard & Poor's (S&P) as of March 31, 2016	Lease Receivables, Net of Non-Recourse Debt As of March 31, 2016
	Millions
AA	$ 17
BBB+ — BBB-	316
BB-	134
CCC+	164
Total	**$ 631**

The "BB-" and the "CCC+" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of March 31, 2016, the gross investment in the leases of such assets, net of non-recourse debt, was $573 million ($(18) million, net of deferred taxes). A more detailed description of such assets under lease, as of March 31, 2016, is presented in the following table.

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Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	CCC+	NRG REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	CCC+	NRG REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 113	100%	603	Coal	CCC+	NRG REMA, LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

NRG REMA, LLC (NRG) notified PJM that it deactivated the coal-fired units at the Shawville generating facility in June 2015 and has disclosed that it expects to return the Shawville units to service in the fall of 2016 with the ability to use natural gas.

Note 6. Available-for-Sale Securities

NDT Fund

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third party investment advisers who operate under investment guidelines developed by Power.

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Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of March 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 690	$ 195	$ (13)	$ 872
Debt Securities				
Government Obligations	487	15	—	502
Other	369	9	(6)	372
Total Debt Securities	856	24	(6)	874
Other Securities	32	—	—	32
Total NDT Available-for-Sale Securities	**$ 1,578**	**$ 219**	**$ (19)**	**$ 1,778**

	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 693	$ 185	$ (13)	$ 865
Debt Securities				
Government Obligations	483	8	(3)	488
Other	366	3	(10)	359
Total Debt Securities	849	11	(13)	847
Other Securities	42	—	—	42
Total NDT Available-for-Sale Securities	**$ 1,584**	**$ 196**	**$ (26)**	**$ 1,754**

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of March 31, 2016	As of December 31, 2015
	Millions	
Accounts Receivable	$ 16	$ 17
Accounts Payable	$ 9	$ 10

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The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of March 31, 2016				As of December 31, 2015			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 123	$ (13)	$ 1	$ —	$ 151	$ (13)	$ 1	$ —
Debt Securities								
Government Obligations (B)	29	—	19	—	245	(2)	19	(1)
Other (C)	61	(2)	48	(4)	222	(7)	36	(3)
Total Debt Securities	90	(2)	67	(4)	467	(9)	55	(4)
NDT Available-for-Sale Securities	**$ 213**	**$ (15)**	**$ 68**	**$ (4)**	**$ 618**	**$ (22)**	**$ 56**	**$ (4)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of March 31, 2016.

(B) Debt Securities (Government Obligations)—Unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the U.S. government or an agency of the U.S. government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of March 31, 2016.

(C) Debt Securities (Other)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2016.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended March 31,	
	2016	2015
	Millions	
Proceeds from NDT Fund Sales (A)	**$ 177**	**$ 590**
Net Realized Gains (Losses) on NDT Fund:		
Gross Realized Gains	15	19
Gross Realized Losses	(16)	(9)
Net Realized Gains (Losses) on NDT Fund	**$ (1)**	**$ 10**

(A) 2015 proceeds include activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $101 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of March 31, 2016.

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The NDT available-for-sale debt securities held as of March 31, 2016 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 24
1 - 5 years	215
6 - 10 years	209
11 - 15 years	57
16 - 20 years	53
Over 20 years	316
Total NDT Available-for-Sale Debt Securities	**$ 874**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the three months ended March 31, 2016, other-than-temporary impairments of $10 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of March 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 8	$ —	$ 20
Debt Securities				
Government Obligations	107	2	—	109
Other	84	1	(2)	83
Total Debt Securities	191	3	(2)	192
Other Securities	5	—	—	5
Total Rabbi Trust Available-for-Sale Securities	**$ 208**	**$ 11**	**$ (2)**	**$ 217**

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	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 10	$ —	$ 22
Debt Securities				
Government Obligations	108	1	(1)	108
Other	82	—	(1)	81
Total Debt Securities	190	1	(2)	189
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 204**	**$ 11**	**$ (2)**	**$ 213**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of March 31, 2016	As of December 31, 2015
	Millions	
Accounts Receivable	$ 3	$ 1
Accounts Payable	$ 5	$ —

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of March 31, 2016				As of December 31, 2015			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	10	—	2	—	53	(1)	2	—
Other (C)	30	(1)	11	(1)	46	(1)	9	—
Total Debt Securities	40	(1)	13	(1)	99	(2)	11	—
Rabbi Trust Available-for-Sale Securities	**$ 40**	**$ (1)**	**$ 13**	**$ (1)**	**$ 99**	**$ (2)**	**$ 11**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government Obligations)—Unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the U.S. government or an agency of the U.S. government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of March 31, 2016.

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(C) Debt Securities (Other)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2016.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended March 31,	
	2016	2015
	Millions	
Proceeds from Rabbi Trust Sales (A)	**$ 25**	**$ 19**
Net Realized Gains (Losses) on Rabbi Trust:		
Gross Realized Gains	$ 1	$ —
Gross Realized Losses	(1)	—
Net Realized Gains (Losses) on Rabbi Trust	**$ —**	**$ —**

(A) 2015 proceeds include activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains disclosed in the preceding table were recognized in Other Income in the Condensed Consolidated Statements of Operations. Net unrealized gains of $6 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of March 31, 2016.

The Rabbi Trust available-for-sale debt securities held as of March 31, 2016 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 9
1 - 5 years	42
6 - 10 years	47
11 - 15 years	5
16 - 20 years	9
Over 20 years	80
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 192**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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The fair value of assets in the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of March 31, 2016	As of December 31, 2015
	Millions	
PSE&G	$ 43	$ 42
Power	53	52
Other	121	119
Total Rabbi Trust Available-for-Sale Securities	**$ 217**	**$ 213**

Note 7. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria.

Effective January 1, 2016, PSEG changed the approach used to measure future service and interest costs for pension benefits. For 2015 and prior, PSEG calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, PSEG has elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows. PSEG believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations. As a change in accounting estimate, this change is being reflected prospectively. For the three months ended March 31, 2016, pension and OPEB costs, net of amounts capitalized, were reduced by $9 million and $3 million, respectively, as compared to the 2016 amounts that would have been derived from applying PSEG's 2015 and prior years' methodology.

The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.

Pension and OPEB costs for PSEG, except for Servco, are detailed as follows:

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2016	2015	2016	2015
	Millions			
Components of Net Periodic Benefit Costs				
Service Cost	$ 27	$ 31	$ 4	$ 5
Interest Cost	50	59	15	17
Expected Return on Plan Assets	(98)	(103)	(8)	(7)
Amortization of Net				
Prior Service Cost (Credit)	(4)	(5)	(3)	(3)
Actuarial Loss	39	37	10	10
Total Benefit Costs	**$ 14**	**$ 19**	**$ 18**	**$ 22**

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Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, except for Servco, are detailed as follows:

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2016	2015	2016	2015
	Millions			
PSE&G	$ 7	$ 10	$ 11	$ 14
Power	4	6	6	7
Other	3	3	1	1
Total Benefit Costs	**$ 14**	**$ 19**	**$ 18**	**$ 22**

During the three months ended March 31, 2016, PSEG contributed its entire planned contributions for the year 2016 of $21 million into its pension plans and $14 million into its OPEB plan.

Servco Pension and OPEB

At the direction of LIPA, Servco sponsors benefit plans that cover its current and former employees who meet certain eligibility criteria. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco plans to contribute $28 million into its pension plan during 2016. Servco's pension-related revenues and costs were $6 million for each of the three months ended March 31, 2016 and 2015. The OPEB-related revenues earned and costs incurred for each of the three months ended March 31, 2016 and 2015 were immaterial.

Note 8. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

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Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of March 31, 2016 and December 31, 2015.

	As of March 31, 2016	As of December 31, 2015
	Millions	
Face Value of Outstanding Guarantees	$ 1,786	$ 1,734
Exposure under Current Guarantees	$ 183	$ 172
Letters of Credit Margin Posted	$ 169	$ 122
Letters of Credit Margin Received	$ 220	$ 192
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (17)	$ (15)
Net Broker Balance Deposited (Received)	$ 1	$ (5)
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that could be Required	$ 851	$ 864
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,391	$ 3,215
Additional Amounts Posted:		
Other Letters of Credit	$ 51	$ 51

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P and Moody's ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline and a $21 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit.

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As of March 31, 2016, PSE&G had posted $14 million in letters of credit to support various environmental obligations. PSE&G had $615 million of liquidity available under its credit facility as of March 31, 2016.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA determined that there was a need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than with respect to their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSE&G's and Power's combined share of the cost of that effort is approximately three percent. The remaining CPG members have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplated the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS set forth various alternatives for remediating this portion of the Passaic River.

The CPG, which consisted of 53 members as of March 31, 2016, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost for the preparation of the RI/FS is approximately $156 million, which the CPG continues to incur. Of the estimated $156 million, as of March 31, 2016, the CPG had spent approximately $146 million, of which PSE&G's and Power's combined share was approximately $9 million.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River. It set forth the CPG's estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion on an undiscounted basis. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranged from approximately $518 million to $772 million. Based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimated share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and

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a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

In March 2016, the EPA released its Record of Decision (ROD) for the FFS which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The ROD Remedy requires a bank-to-bank dredge ranging from approximately 5 to 30 feet deep in the federal navigation channel from River Mile 0 to River Mile 1.7 and an approximately 2.5 foot deep dredge everywhere else in the lower 8.3 miles of the river. An engineered cap approximately two feet thick will be placed over the dredged areas. Dredged sediments will be transported to facilities and landfills out-of-state. The EPA estimates the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation.

Based upon the estimated cost of the ROD Remedy, PSEG's estimate of PSE&G's and Power's shares of that cost, and the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued an additional $36 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued an additional $8 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2016. As of March 31, 2016, these accruals bring the total liability to approximately $57 million, $46 million applicable to PSE&G and $11 million applicable to Power.

Also in March 2016, the EPA sent a notice letter to 105 PRPs, including PSE&G, all other past and present members of the CPG, including Occidental Chemicals Corporation (OCC), and the towns of Newark, Kearny and Harrison and the Passaic Valley Sewerage Commission stating that the EPA wants to determine whether OCC, a successor company to Diamond Shamrock, will voluntarily perform the remedial design for the ROD Remedy. If the EPA secures a commitment to perform the Remedial Design from OCC, the EPA plans to begin negotiation of a remedial action consent decree, under which, OCC and the other "major" PRPs will implement and/or pay for the EPA's ROD Remedy for the lower 8.3 miles. "Major PRP" is undefined in the letter.

The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on PSEG's financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

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MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $434 million and $500 million through 2021, including its $46 million share for the Passaic River accrued as of March 31, 2016, as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $434 million as of March 31, 2016. Of this amount, $90 million was recorded in Other Current Liabilities and $344 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $434 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. On June 30, 2015, the NJDEP issued a draft permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The draft permit was subject to a public notice and comment period. The NJDEP may make revisions before issuing the final permit expected during the first half of 2016. Power participated in the NJDEP's August 5, 2015 public hearing and submitted comments on the draft permit on September 18, 2015.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. On August 15, 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. On September 5, 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Second Circuit Court of Appeals. In two related actions on October 17, 2014 and November 20, 2014, several environmental non-governmental groups initiated challenges to the endangered species act provisions of the 316 (b) rule. Power is unable to determine the ultimate impact of these actions on the implementation of the rule.

State permitting decisions could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities, and could result in acceleration of decommissioning activities. For example, in Power's application to renew its

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Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1.0 billion, of which Power's share would have been approximately $575 million. The filing has not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA's Clean Water Act Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, Power would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the current estimated useful life ending in 2025. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in 2016.

Separately, Power has also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that Power would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. The receipt of permits to allow construction and operation of the new facility could occur in 2017. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power will seek to operate BH3 through the current estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. Operations are expected to begin in mid-2019.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. At this early stage, Power cannot predict the impact of this matter.

Steam Electric Effluent Guidelines

On September 30, 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Mercer and Bridgeport Harbor stations and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under this rule. Power is unable to predict if this rule will have a material impact on its future capital requirements, financial condition and results of operations.

Coal Combustion Residuals (CCRs)

On December 19, 2014, the EPA issued a final rule which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Power's Hudson and Mercer generating stations, along with its co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 19, 2015. Accordingly in June 2015, Power recorded an additional asset retirement obligation to comply with the final CCR rule which was not material to Power's results of operations, financial condition or cash flows.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the

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provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2016 is $335.33 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2016 of $272.78 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2013	2014	2015	2016	
36-Month Terms Ending	May 2016	May 2017	May 2018	May 2019	(A)
Load (MW)	2,800	2,800	2,900	2,800	
$ per MWh	$92.18	$97.39	$99.54	$96.38	

(A) Prices set in the 2016 BGS auction year will become effective on June 1, 2016 when the 2013 BGS auction agreements expire.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 17. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2020 at Salem, Hope Creek and Peach Bottom.

Power has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations.

Power also has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available beyond the needs of PSE&G's customers, Power can use the gas to supply its fossil generating stations.

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As of March 31, 2016, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2020
	Millions
Nuclear Fuel	
Uranium	$ 467
Enrichment	$ 348
Fabrication	$ 193
Natural Gas	$ 1,002
Coal	$ 277

Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future.

During the three month period ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. No additional charges to income have been recorded for this matter since that time.

In September 2014, FERC Staff initiated a preliminary, non-public staff investigation into the matter and issued data requests covering a period from 2002 through the date of the self-report. This investigation is ongoing. Since that time, Power has responded to data requests from FERC Staff, including recent data requests in which Power has recalculated certain of its energy bids in PJM for a five year period, and may receive additional data requests or other fact finding. The FERC Staff investigation is still in the fact finding stage and there is considerable uncertainty around FERC's response to PSEG's legal arguments and the amount of disgorgement or other remedies FERC may ultimately seek.

PSEG is unable to reasonably estimate the range of possible loss for this matter; however, the amounts of potential disgorgement and other potential penalties that Power may incur span a wide range depending on the success of PSEG's legal arguments. These arguments include that Power's energy market bids in a substantial majority of the hours were below the allowed rate under the Tariff and therefore any errors in those hours were immaterial and that it is unclear whether the quantity of the bids violated any legal requirement. If PSEG's legal arguments do not prevail in whole or in part with FERC or in a judicial challenge that PSEG may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to PSEG's and Power's Consolidated Statements of Operations in the quarterly and annual periods in which they are recorded.

Nuclear Insurance Coverages

The following should be read in conjunction with Note 12. Commitments and Contingent Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2015.

Based upon a review of its nuclear insurance, Power made changes to its Nuclear Electric Insurance Limited (NEIL) insurance coverage of the excess layer for property damage which became effective on April 1, 2016. The excess layer provides coverage above the primary layer of NEIL insurance coverage for property damage of $1.5 billion. For the excess layer at the Salem/Hope Creek site, Power purchased coverage for property damage of $300 million due to a nuclear event and $300 million due to a non-nuclear event. For the excess layer at the Peach Bottom site, Power purchased coverage for its ownership interest for property damage of $300 million due to a nuclear event. For the excess layer at the Peach Bottom site, Exelon purchased coverage for property damage of $600 million due to a non-nuclear event which covers the ownership interest of Power.

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Note 9. Changes in Capitalization

The following capital transactions occurred in the three months ended March 31, 2016:

PSE&G

- issued $300 million of 1.90% Secured Medium-Term Notes, Series K due March 2021,
- issued $550 million of 3.80% Secured Medium-Term Notes, Series K due March 2046, and
- retired $171 million of 6.75% Secured First and Refunding Mortgage Bonds, Series VV at maturity.

Note 10. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. Transactions receiving NPNS treatment are accounted for upon settlement. For a derivative instrument that qualifies and is designated as a cash flow hedge, the changes in the fair value of such a derivative that are highly effective are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. For a derivative instrument that qualifies and is designated as a fair value hedge, the gains or losses on the derivative as well as the offsetting losses or gains on the hedged item attributable to the hedged risk are recognized in earnings each period. Power and PSE&G enter into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists. PSEG had no commodity derivative transactions designated as cash flow or fair value hedges as of March 31, 2016 and December 31, 2015.

Economic Hedges

Power enters into derivative contracts that are not designated as either cash flow or fair value hedges. Power enters into financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. These transactions are economic hedges, intended to mitigate exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of these contracts are recorded in earnings.

PSE&G is a party to a long-term natural gas sales derivative contract to optimize its pipeline capacity utilization. Changes in the fair market value of the contract are recorded in Regulatory Assets and Regulatory Liabilities.

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Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of March 31, 2016, PSEG had interest rate swaps outstanding totaling $550 million. These swaps convert $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of March 31, 2016 and December 31, 2015, the fair value of all the underlying hedges was $4 million and $6 million, respectively. The effect of these hedges was to reduce interest expense by $2 million and $5 million for the three months ended March 31, 2016 and 2015, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. As of March 31, 2016, PSEG had interest rate hedges outstanding totaling $900 million. The hedge ineffectiveness associated with these hedges was immaterial. The total fair value of these interest rate hedges was $3 million as of March 31, 2016. There were no outstanding interest rate hedges as of December 31, 2015. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was $2 million as of March 31, 2016 and was immaterial as of December 31, 2015.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with PSEG's accounting policy, these positions have been offset on the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of March 31, 2016					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 718	$ (500)	$ 218	$ 8	$ 4	$ 230
Noncurrent Assets	346	(219)	127	2	4	133
Total Mark-to-Market Derivative Assets	**$ 1,064**	**$ (719)**	**$ 345**	**$ 10**	**$ 8**	**$ 363**
Derivative Contracts						
Current Liabilities	$ (533)	$ 481	$ (52)	$ —	$ (1)	$ (53)
Noncurrent Liabilities	(218)	204	(14)	—	—	(14)
Total Mark-to-Market Derivative (Liabilities)	**$ (751)**	**$ 685**	**$ (66)**	**$ —**	**$ (1)**	**$ (67)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 313**	**$ (34)**	**$ 279**	**$ 10**	**$ 7**	**$ 296**

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	As of December 31, 2015					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 700	$ (477)	$ 223	$ 13	$ 6	$ 242
Noncurrent Assets	208	(131)	77	—	—	77
Total Mark-to-Market Derivative Assets	**$ 908**	**$ (608)**	**$ 300**	**$ 13**	**$ 6**	**$ 319**
Derivative Contracts						
Current Liabilities	$ (513)	$ 437	$ (76)	$ —	$ —	$ (76)
Noncurrent Liabilities	(132)	116	(16)	(11)	—	(27)
Total Mark-to-Market Derivative (Liabilities)	**$ (645)**	**$ 553**	**$ (92)**	**$ (11)**	**$ —**	**$ (103)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 263**	**$ (55)**	**$ 208**	**$ 2**	**$ 6**	**$ 216**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of March 31, 2016 and December 31, 2015. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of March 31, 2016 and December 31, 2015, net cash collateral (received) paid of $(34) million and $(55) million, respectively, were netted against the corresponding net derivative contract positions. Of the $(34) million as of March 31, 2016, $(37) million and $(16) million of cash collateral were netted against current assets and noncurrent assets, respectively, and $19 million was netted against current liabilities. Of the $(55) million as of December 31, 2015, $(53) million and $(16) million were netted against current assets and noncurrent assets, respectively, and $12 million and $2 million were netted against current liabilities and noncurrent liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $62 million and $78 million as of March 31, 2016 and December 31, 2015, respectively. As of March 31, 2016 and December 31, 2015, Power had the contractual right of offset of $16 million and $12 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $46 million and $66 million as of March 31, 2016 and December 31, 2015, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $851 million and $864 million as of March 31, 2016 and December 31, 2015, respectively, discussed in Note 8. Commitments and Contingent Liabilities.

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The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended March 31, 2016 and 2015.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion)		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	
	Three Months Ended March 31,			Three Months Ended March 31,			Three Months Ended March 31,	
	2016	2015		2016	2015		2016	2015
	Millions							
PSEG								
Energy-Related Contracts	$ —	$ 1	Operating Revenues	$ —	$ 17	Operating Revenues	$ —	$ —
Interest Rate Swaps	3	—	Interest Expense	—	—	Interest Expense	—	—
Total PSEG	**$ 3**	**$ 1**		**$ —**	**$ 17**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ —	$ 1	Operating Revenues	$ —	$ 17	Operating Revenues	$ —	$ —
Total Power	**$ —**	**$ 1**		**$ —**	**$ 17**		**$ —**	**$ —**

The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2014	**$ 17**	**$ 10**
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	(20)	(12)
Balance as of December 31, 2015	**$ —**	**$ —**
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	—	—
Balance as of March 31, 2016	**$ 3**	**$ 2**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS for the three months ended March 31, 2016 and 2015.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives	
		Three Months Ended March 31,	
		2016	2015
		Millions	
PSEG and Power			
Energy-Related Contracts	Operating Revenues	$ 216	$ (76)
Energy-Related Contracts	Energy Costs	2	10
Total PSEG and Power		**$ 218**	**$ (66)**

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Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. The tables above do not include contracts for which Power has elected the NPNS exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load.

The following reflects the gross volume, on an absolute value basis, of derivatives as of March 31, 2016 and December 31, 2015.

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of March 31, 2016					
Natural Gas	Dekatherm (Dth)	298	—	272	26
Electricity	MWh	303	—	303	—
Financial Transmission Rights (FTRs)	MWh	14	—	14	—
Interest Rate Swaps	U.S. Dollars	1,450	1,450	—	—
As of December 31, 2015					
Natural Gas	Dth	201	—	168	33
Electricity	MWh	299	—	299	—
FTRs	MWh	23	—	23	—
Interest Rate Swaps	U.S. Dollars	550	550	—	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of March 31, 2016, 91% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of March 31, 2016. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 542	$ 230	$ 312	1	$ 178	(A)
Non-Investment Grade—External Rating	30	—	30	—	—	
Investment Grade—No External Rating	10	1	9	—	—	
Non-Investment Grade—No External Rating	—	—	—	—	—	
Total	**$ 582**	**$ 231**	**$ 351**	**1**	**$ 178**	

(A) Represents net exposure with PSE&G.

As of March 31, 2016, collateral held from counterparties where Power had credit exposure included $16 million in cash collateral and $215 million in letters of credit.

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As of March 31, 2016, Power had 137 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of March 31, 2016, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's suppliers' credit exposure is calculated each business day. As of March 31, 2016, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

Note 11. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of March 31, 2016, these consisted primarily of long-term gas supply contracts and certain electric load contracts.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of March 31, 2016 and December 31, 2015, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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Description	Recurring Fair Value Measurements as of March 31, 2016			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 521	$ —	$ 521	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 355	$ (719)	$ —	$ 1,053	$ 21
Interest Rate Swaps (C)	$ 8	$ —	$ —	$ 8	$ —
NDT Fund (D)					
Equity Securities	$ 872	$ —	$ 872	$ —	$ —
Debt Securities—Govt Obligations	$ 502	$ —	$ —	$ 502	$ —
Debt Securities—Other	$ 372	$ —	$ —	$ 372	$ —
Other Securities	$ 32	$ —	$ 32	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 20	$ —	$ 20	$ —	$ —
Debt Securities—Govt Obligations	$ 109	$ —	$ —	$ 109	$ —
Debt Securities—Other	$ 83	$ —	$ —	$ 83	$ —
Other Securities	$ 5	$ —	$ 5	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (66)	$ 685	$ —	$ (751)	$ —
Interest Rate Swaps (C)	$ (1)	$ —	$ —	$ (1)	$ —
PSE&G					
Assets:					
Cash Equivalents (A)	$ 521	$ —	$ 521	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 10	$ —	$ —	$ —	$ 10
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 4	$ —	$ 4	$ —	$ —
Debt Securities—Govt Obligations	$ 22	$ —	$ —	$ 22	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 345	$ (719)	$ —	$ 1,053	$ 11
NDT Fund (D)					
Equity Securities	$ 872	$ —	$ 872	$ —	$ —
Debt Securities—Govt Obligations	$ 502	$ —	$ —	$ 502	$ —
Debt Securities—Other	$ 372	$ —	$ —	$ 372	$ —
Other Securities	$ 32	$ —	$ 32	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 27	$ —	$ —	$ 27	$ —
Debt Securities—Other	$ 20	$ —	$ —	$ 20	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					

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Energy-Related Contracts (B)	$	(66)	$	685	$	—	$	(751)	$	—

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Description	Recurring Fair Value Measurements as of December 31, 2015			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 326	$ —	$ 326	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 313	$ (608)	$ —	$ 896	$ 25
Interest Rate Swaps (C)	$ 6	$ —	$ —	$ 6	$ —
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—Govt Obligations	$ 488	$ —	$ —	$ 488	$ —
Debt Securities—Other	$ 359	$ —	$ —	$ 359	$ —
Other Securities	$ 42	$ —	$ 42	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—Govt Obligations	$ 108	$ —	$ —	$ 108	$ —
Debt Securities—Other	$ 81	$ —	$ —	$ 81	$ —
Other Securities	$ 2	$ —	$ 2	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (103)	$ 553	$ —	$ (644)	$ (12)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 160	$ —	$ 160	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ 13	$ —	$ —	$ —	$ 13
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (11)	$ —	$ —	$ —	$ (11)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 300	$ (608)	$ —	$ 896	$ 12
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—Govt Obligations	$ 488	$ —	$ —	$ 488	$ —
Debt Securities—Other	$ 359	$ —	$ —	$ 359	$ —
Other Securities	$ 42	$ —	$ 42	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 26	$ —	$ —	$ 26	$ —
Debt Securities—Other	$ 20	$ —	$ —	$ 20	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (92)	$ 553	$ —	$ (644)	$ (1)

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(A) Represents money market mutual funds.

(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask

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midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds, collateralized mortgage obligations, asset backed securities and government obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of March 31, 2016, net cash collateral (received) paid of $(34) million was netted against the corresponding net derivative contract positions. Of the $(34) million as of March 31, 2016, $(53) million of cash collateral was netted against assets, and $19 million was netted against liabilities. As of December 31, 2015, net cash collateral (received) paid of $(55) million was netted against the corresponding net derivative contract positions. Of the $(55) million of cash collateral as of December 31, 2015, $(69) million was netted against assets, and $14 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

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For PSE&G, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The following tables provide details surrounding significant Level 3 valuations as of March 31, 2016 and December 31, 2015.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of March 31, 2016 Assets	Fair Value as of March 31, 2016 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$ 10	$ —	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ 10**	**$ —**			
Power						
Electricity	Electric Load Contracts	$ 11	$ —	Discounted Cash flow	Historic Load Variability	0% to +10%
Total Power		**$ 11**	**$ —**			
Total PSEG		**$ 21**	**$ —**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2015 Assets	Fair Value as of December 31, 2015 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$ 13	$ (11)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ 13**	**$ (11)**			
Power						
Electricity	Electric Load Contracts	$ 11	$ (1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Electricity	Other	1	—			
Total Power		**$ 12**	**$ (1)**			
Total PSEG		**$ 25**	**$ (12)**			

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value. For energy-related contracts in cases where Power is a seller, an increase in the load variability would decrease the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months ended March 31, 2016 and March 31, 2015, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2016

Description	Balance as of January 1, 2016	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of March 31, 2016
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 13	$ 15	$ 8	$ —	$ (15)	$ —	$ 21
PSE&G							
Net Derivative Assets (Liabilities)	$ 2	$ —	$ 8	$ —	$ —	$ —	$ 10
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 15	$ —	$ —	$ (15)	$ —	$ 11

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2015

Description	Balance as of January 1, 2015	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of March 31, 2015
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 37	$ 3	$ (19)	$ —	$ (12)	$ —	$ 9
PSE&G							
Net Derivative Assets (Liabilities)	$ 26	$ —	$ (19)	$ —	$ —	$ —	$ 7
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 3	$ —	$ —	$ (12)	$ —	$ 2

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $15 million and $3 million in Operating Income in 2016 and 2015, respectively. The $15 million in Operating Income in 2016 is realized. Of the $3 million in Operating Income, $(9) million is unrealized.

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(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $(15) million and $(12) million in settlements for the three months ended March 31, 2016 and 2015.

(D) There were no transfers among levels during the three months ended March 31, 2016 and 2015.

As of March 31, 2016, PSEG carried $2.8 billion of net assets that are measured at fair value on a recurring basis, of which $21 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of March 31, 2015, PSEG carried $3.1 billion of net assets that are measured at fair value on a recurring basis, of which $9 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of March 31, 2016 and December 31, 2015.

	As of March 31, 2016		As of December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 501	$ 504	$ 503	$ 506
PSE&G (B)	7,492	8,339	6,821	7,235
Power - Recourse Debt (B)	2,238	2,502	2,237	2,508
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	7	7	7	7
Total Long-Term Debt	**$ 10,238**	**$ 11,352**	**$ 9,568**	**$ 10,256**

(A) Fair value includes a $500 million floating rate term loan and net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. The fair value of the term loan debt (Level 2 measurement) was considered to be equal to the carrying value because the interest payments are based on LIBOR rates that are reset monthly. Carrying amount includes such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) Given that most bonds do not trade, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 12. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended March 31, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 25	$ —	$ 25
Allowance for Funds Used During Construction	11	—	—	11
Solar Loan Interest	6	—	—	6
Other	3	1	2	6
Total Other Income	**$ 20**	**$ 26**	**$ 2**	**$ 48**
Three Months Ended March 31, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 29	$ —	$ 29
Allowance for Funds Used During Construction	10	—	—	10
Solar Loan Interest	6	—	—	6
Other	2	—	1	3
Total Other Income	**$ 18**	**$ 29**	**$ 1**	**$ 48**

Other Deductions	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended March 31, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 18	$ —	$ 18
Other	1	—	2	3
Total Other Deductions	**$ 1**	**$ 18**	**$ 2**	**$ 21**
Three Months Ended March 31, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 11	$ —	$ 11
Other	1	—	—	1
Total Other Deductions	**$ 1**	**$ 11**	**$ —**	**$ 12**

(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

Note 13. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months ended March 31, 2016 and 2015 were as follows:

	Three Months Ended March 31,	
	2016	2015
PSEG	37.5%	40.5%
PSE&G	36.6%	39.4%
Power	40.2%	41.1%

For the three months ended March 31, 2016, the overall decreases in PSEG's and PSE&G's effective tax rates as compared to the same periods in the prior year as well as to the statutory tax rate of 40.85%, were due primarily to depreciation flow through items and changes in uncertain tax positions.

The Tax Increase Prevention Act of 2014 extended the 50% bonus depreciation rules for qualified property placed in service before January 1, 2015 and for long production property placed in service in 2015.

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The Protecting Americans from Tax Hikes Act of 2015 (Tax Act) extended the 50% bonus depreciation rules for qualified property placed in service from January 1, 2015 through December 31, 2017. The rate is reduced to 40% and 30% for eligible property placed in service in 2018 and 2019, respectively. In addition, long production property placed in service in 2020 will also qualify for 30% bonus depreciation. The Tax Act also extended the 30% ITC for qualified property placed in service starting January 1, 2016 through December 31, 2019 but reduces the ITC rate to 26% and 22% for projects commenced in 2020 and 2021, respectively. The financial impact of the extensions of the ITC rate will depend upon future transactions.

These provisions have generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period. However, these tax benefits will have a negative impact on the rate base of several of PSE&G's programs.

Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG

	Other Comprehensive Income (Loss) Three Months Ended March 31, 2016			
Accumulated Other Comprehensive Income (Loss)	**Cash Flow Hedges**	**Pension and OPEB Plans**	**Available-for-Sale Securities**	**Total**
		Millions		
Balance as of December 31, 2015	$ —	$ (386)	$ 91	$ (295)
Other Comprehensive Income before Reclassifications	2	—	10	12
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	8	6	14
Net Current Period Other Comprehensive Income (Loss)	2	8	16	26
Balance as of March 31, 2016	**$ 2**	**$ (378)**	**$ 107**	**$ (269)**

	Other Comprehensive Income (Loss) Three Months Ended March 31, 2015			
Accumulated Other Comprehensive Income (Loss)	**Cash Flow Hedges**	**Pension and OPEB Plans**	**Available-for-Sale Securities**	**Total**
		Millions		
Balance as of December 31, 2014	$ 10	$ (411)	$ 118	$ (283)
Other Comprehensive Income before Reclassifications	1	—	16	17
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	8	(2)	(4)
Net Current Period Other Comprehensive Income (Loss)	(9)	8	14	13
Balance as of March 31, 2015	**$ 1**	**$ (403)**	**$ 132**	**$ (270)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended March 31, 2016			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2015	$ —	$ (327)	$ 87	$ (240)
Other Comprehensive Income before Reclassifications	—	—	10	10
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	6	13
Net Current Period Other Comprehensive Income (Loss)	—	7	16	23
Balance as of March 31, 2016	**$ —**	**$ (320)**	**$ 103**	**$ (217)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended March 31, 2015			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2014	$ 11	$ (351)	$ 112	$ (228)
Other Comprehensive Income before Reclassifications	1	—	16	17
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	7	(2)	(5)
Net Current Period Other Comprehensive Income (Loss)	(9)	7	14	12
Balance as of March 31, 2015	**$ 2**	**$ (344)**	**$ 126**	**$ (216)**

PSEG

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement Three Months Ended March 31, 2016		
		Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)
Total Pension and OPEB Plans		(14)	6	(8)
Available-for-Sale Securities				
Realized Gains	Other Income	16	(8)	8
Realized Losses	Other Deductions	(17)	8	(9)
Other-Than-Temporary Impairments (OTTI)	OTTI	(10)	5	(5)
Total Available-for-Sale Securities		(11)	5	(6)
Total		**$ (25)**	**$ 11**	**$ (14)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		17	(7)	10
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)
Total Pension and OPEB Plans		(14)	6	(8)
Available-for-Sale Securities				
Realized Gains	Other Income	19	(10)	9
Realized Losses	Other Deductions	(9)	5	(4)
OTTI	OTTI	(5)	2	(3)
Total Available-for-Sale Securities		5	(3)	2
Total		**$ 8**	**$ (4)**	**$ 4**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2016		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2
Amortization of Actuarial Loss	O&M Expense	(15)	6	(9)
Total Pension and OPEB Plans		(12)	5	(7)
Available-for-Sale Securities				
Realized Gains	Other Income	15	(8)	7
Realized Losses	Other Deductions	(16)	8	(8)
OTTI	OTTI	(10)	5	(5)
Total Available-for-Sale Securities		(11)	5	(6)
Total		**$ (23)**	**$ 10**	**$ (13)**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Cash Flow Hedges				
Energy-Related Contracts	Operating Revenues	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		17	(7)	10
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2
Amortization of Actuarial Loss	O&M Expense	(15)	6	(9)
Total Pension and OPEB Plans		(12)	5	(7)
Available-for-Sale Securities				
Realized Gains	Other Income	19	(10)	9
Realized Losses	Other Deductions	(9)	5	(4)
OTTI	OTTI	(5)	2	(3)
Total Available-for-Sale Securities		5	(3)	2
Total		**$ 10**	**$ (5)**	**$ 5**

Note 15. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended March 31,			
	2016		2015	
	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions):				
Net Income	**$ 471**	**$ 471**	**$ 586**	**$ 586**
EPS Denominator (Millions):				
Weighted Average Common Shares Outstanding	505	505	506	506
Effect of Stock Based Compensation Awards	—	3	—	2
Total Shares	**505**	**508**	**506**	**508**
EPS				
Net Income	**$ 0.93**	**$ 0.93**	**$ 1.16**	**$ 1.15**

There were approximately 0.3 million and 0.4 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the three months ended March 31, 2016 and 2015, respectively.

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Dividend Payments on Common Stock	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
Per Share	$ 0.41	$ 0.39
In Millions	$ 207	$ 197

On April 19, 2016, PSEG's Board of Directors approved a $0.41 per share common stock dividend for the second quarter of 2016.

Note 16. Financial Information by Business Segment

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated
			Millions		
Three Months Ended March 31, 2016					
Operating Revenues	$ 1,712	$ 1,313	$ 122	$ (531)	$ 2,616
Net Income (Loss)	262	192	17	—	471
Gross Additions to Long-Lived Assets	724	333	8	—	1,065
Three Months Ended March 31, 2015					
Operating Revenues	$ 2,002	$ 1,725	$ 98	$ (690)	$ 3,135
Net Income (Loss)	242	335	9	—	586
Gross Additions to Long-Lived Assets	599	139	9	—	747
As of March 31, 2016					
Total Assets	$ 24,372	$ 12,617	$ 2,462	$ (1,325)	$ 38,126
Investments in Equity Method Subsidiaries	$ —	$ 116	$ —	$ —	$ 116
As of December 31, 2015					
Total Assets	$ 23,677	$ 12,250	$ 2,810	$ (1,202)	$ 37,535
Investments in Equity Method Subsidiaries	$ —	$ 119	$ —	$ —	$ 119

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations primarily relate to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 17. Related-Party Transactions.

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Note 17. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended March 31, 2016	2015
	Millions	
Billings from Affiliates:		
Net Billings from Power primarily through BGS and BGSS (A)	$ 545	$ 696
Administrative Billings from Services (B)	69	66
Total Billings from Affiliates	**$ 614**	**$ 762**

Related-Party Transactions	As of March 31, 2016	As of December 31, 2015
	Millions	
Receivables from PSEG (C)	**$ 3**	**$ 222**
Payable to Power (A)	$ 184	$ 212
Payable to Services (B)	74	80
Accounts Payable—Affiliated Companies	**$ 258**	**$ 292**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 89**	**$ 109**

Power

The financial statements for Power include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended March 31, 2016	2015
	Millions	
Billings to Affiliates:		
Net Billings to PSE&G primarily through BGS and BGSS (A)	**$ 545**	**$ 696**
Billings from Affiliates:		
Administrative Billings from Services (B)	**$ 45**	**$ 45**

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Related-Party Transactions	As of March 31, 2016	As of December 31, 2015
	Millions	
Receivables from PSE&G (A)	$ 184	$ 212
Receivables from PSEG (C)	—	64
Accounts Receivable—Affiliated Companies	**$ 184**	**$ 276**
Payable to Services (B)	$ 34	$ 33
Payable to PSEG (C)	118	—
Accounts Payable—Affiliated Companies	**$ 152**	**$ 33**
Short-Term Loan Due (to) from Affiliate (E)	**$ 672**	**$ 363**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 38**	**$ 35**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. In addition, Power and PSE&G provide certain technical services for each other in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

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Note 18. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries as of March 31, 2016 and December 31, 2015 and for the three months ended March 31, 2016 and 2015.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended March 31, 2016					
Operating Revenues	$ —	$ 1,302	$ 42	$ (31)	$ 1,313
Operating Expenses	10	952	39	(31)	970
Operating Income (Loss)	(10)	350	3	—	343
Equity Earnings (Losses) of Subsidiaries	205	(1)	2	(204)	2
Other Income	17	32	—	(23)	26
Other Deductions	—	(18)	—	—	(18)
Other-Than-Temporary Impairments	—	(10)	—	—	(10)
Interest Expense	(30)	(10)	(5)	23	(22)
Income Tax Benefit (Expense)	10	(140)	1	—	(129)
Net Income (Loss)	**$ 192**	**$ 203**	**$ 1**	**$ (204)**	**$ 192**
Comprehensive Income (Loss)	**$ 215**	**$ 219**	**$ 1**	**$ (220)**	**$ 215**
Three Months Ended March 31, 2016					
Net Cash Provided By (Used In) Operating Activities	$ 271	$ 480	$ 47	$ (135)	$ 663
Net Cash Provided By (Used In) Investing Activities	$ (598)	$ (428)	$ (246)	$ 613	$ (659)
Net Cash Provided By (Used In) Financing Activities	$ 326	$ (51)	$ 203	$ (478)	$ —

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended March 31, 2015					
Operating Revenues	$ —	$ 1,715	$ 68	$ (58)	$ 1,725
Operating Expenses	5	1,131	63	(58)	1,141
Operating Income (Loss)	(5)	584	5	—	584
Equity Earnings (Losses) of Subsidiaries	349	(1)	3	(348)	3
Other Income	11	30	—	(12)	29
Other Deductions	—	(11)	—	—	(11)
Other-Than-Temporary Impairments	—	(5)	—	—	(5)
Interest Expense	(29)	(9)	(5)	12	(31)
Income Tax Benefit (Expense)	9	(242)	(1)	—	(234)
Net Income (Loss)	**$ 335**	**$ 346**	**$ 2**	**$ (348)**	**$ 335**
Comprehensive Income (Loss)	**$ 347**	**$ 351**	**$ 2**	**$ (353)**	**$ 347**
Three Months Ended March 31, 2015					
Net Cash Provided By (Used In) Operating Activities	$ 327	$ 772	$ 11	$ (260)	$ 850
Net Cash Provided By (Used In) Investing Activities	$ (537)	$ (515)	$ (13)	$ 430	$ (635)
Net Cash Provided By (Used In) Financing Activities	$ 210	$ (242)	$ 2	$ (170)	$ (200)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
As of March 31, 2016					
Current Assets	$ 4,819	$ 1,934	$ 283	$ (5,005)	$ 2,031
Property, Plant and Equipment, net	88	6,465	1,773	—	8,326
Investment in Subsidiaries	4,615	345	—	(4,960)	—
Noncurrent Assets	138	2,046	133	(57)	2,260
Total Assets	**$ 9,660**	**$ 10,790**	**$ 2,189**	**$ (10,022)**	**$ 12,617**
Current Liabilities	$ 1,316	$ 3,809	$ 1,192	$ (5,005)	$ 1,312
Noncurrent Liabilities	441	2,637	382	(57)	3,403
Long-Term Debt	1,685	—	—	—	1,685
Member's Equity	6,218	4,344	615	(4,960)	6,217
Total Liabilities and Member's Equity	**$ 9,660**	**$ 10,790**	**$ 2,189**	**$ (10,022)**	**$ 12,617**
As of December 31, 2015					
Current Assets	$ 4,501	$ 1,912	$ 364	$ (4,828)	$ 1,949
Property, Plant and Equipment, net	83	6,502	1,542	—	8,127
Investment in Subsidiaries	4,501	346	—	(4,847)	—
Noncurrent Assets	155	1,959	136	(76)	2,174
Total Assets	**$ 9,240**	**$ 10,719**	**$ 2,042**	**$ (9,751)**	**$ 12,250**
Current Liabilities	$ 1,112	$ 3,866	$ 1,076	$ (4,828)	$ 1,226
Noncurrent Liabilities	442	2,597	375	(76)	3,338
Long-Term Debt	1,684	—	—	—	1,684
Member's Equity	6,002	4,256	591	(4,847)	6,002
Total Liabilities and Member's Equity	**$ 9,240**	**$ 10,719**	**$ 2,042**	**$ (9,751)**	**$ 12,250**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G,** our public utility company which is engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU, and
- **Power,** our multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy transacting functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA), and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business of our 2015 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2015 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2016 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2015 Form 10-K.

EXECUTIVE OVERVIEW OF 2016 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- growing our utility operations through continued investment in T&D and other infrastructure projects, and
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the three months ended March 31, 2016 and 2015 are presented as follows:

Earnings	Three Months Ended March 31, 2016	2015
	Millions	
PSE&G	$ 262	$ 242
Power (A)	192	335
Other (B)	17	9
PSEG Net Income	**$ 471**	**$ 586**
PSEG Net Income Per Share (Diluted)	**$ 0.93**	**$ 1.15**

(A) Includes an after-tax insurance recovery for Superstorm Sandy of $75 million in the three months ended March 31, 2015.

(B) Other includes activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended March 31, 2016	2015
	Millions, after tax	
NDT Fund Income (Expense) (A)	$ (5)	$ 2
Non-Trading MTM Gains (Losses)	$ 13	$ (20)

(A) NDT Fund Income (Expense) includes the realized gains and losses, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense.

Our $115 million decrease in Net Income for the three months ended March 31, 2016 was driven primarily by

- reduced volumes of gas sold at lower average prices under the BGSS contract,
- lower sales volumes of energy in the PJM and New England regions resulting from unseasonably warm temperatures in 2016 as compared to unusually cold temperatures in 2015,
- insurance recoveries received primarily by Power in 2015 related to Superstorm Sandy, and
- lower operating reserve revenues and capacity revenues in PJM.

These decreases were partially offset by

- higher revenues due to increased investments in transmission projects, and
- lower generation costs driven by lower natural gas prices at Power.

During the first quarter of 2016, we sustained a strong balance sheet. We continued to effectively deploy capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results and allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our multi-year, long-term approach to managing our company. Our focus

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has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, our merchant generator, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, in 2016 we continued to make investments and seek recovery on such investments made to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the BPU in 2014. We also commenced modernizing PSE&G's gas systems as part of our Gas System Modernization Program (GSMP) that was approved by the BPU in late 2015. Over the past few years, these types of investments have altered our business mix to reflect a higher percentage contribution by PSE&G.

During the first quarter of 2016, Power continued to improve its performance for both nuclear and fossil operations, with continued upgrades in efficiency and output, while mitigating environmental impacts. Power's results benefited from access to natural gas supplies through its existing firm pipeline transportation contracts. Power manages these contracts for the benefit of PSE&G's customers through the basic gas supply service (BGSS) arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to make third party sales and supply gas to its generating units in New Jersey. Power's strategic hedging practices and ability to use market conditions to its advantage help it to balance some of the volatility of the merchant power business.

Our recent investments in the latter half of 2015 and early 2016 in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to contribute to the overall efficiency of operations.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission Planning

In April 2013, PJM Interconnection, L.L.C. (PJM) initiated its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues at Artificial Island in New Jersey. In April 2016, PSE&G accepted construction responsibility for the three components of the project that PJM assigned to it, based on having reached agreement with PJM regarding an estimate for the project base cost of $273 million, plus risk and contingency for a total project cost of up to $340 million. PSE&G continues to work with PJM to optimize the scope and cost of the project.

In April 2016, PJM filed at FERC to incorporate a voltage threshold into PJM's Regional Transmission Expansion Plan (RTEP) process to exempt, except under certain circumstances, reliability violations on facilities below 200 kV from PJM's proposal window process. We generally support this reform as a measure to improve the efficiency of the open window procedure that will permit transmission developers to focus on the projects most likely to benefit from a competitive process.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey and may cause increased scrutiny regarding PSE&G's future capital investments. In addition, as a basic generation service (BGS) supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers may be entitled to an adjustment, subject to BPU approval. We do not believe that these matters will have a material effect on Power's business or results of operations.

Wholesale Power Market Design

In an important development in the proceedings concerning the actions that had been taken by the states of New Jersey and Maryland to subsidize above-market new generation, on April 19, 2016, the United States Supreme Court affirmed the decision of the lower courts that had held the action in Maryland to be unconstitutional. The Supreme Court's ruling upholds FERC's authority to foster competitive wholesale electricity markets and provides guidance to states in balancing their interests to encourage and support the development of renewables and other generating facilities. See Item 5. Other Information—Federal Regulation—Long-Term Capacity Agreement Pilot Program Act for additional information.

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Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. In June 2015, FERC conditionally accepted a proposal from PJM for a capacity performance (CP) product to include generators, Demand Response and energy efficiency providers, which will be required to perform during emergency conditions, as a supplement to the base capacity product. The proposal included enhanced performance-based incentives and penalties. We believe that the auction pricing adequately reflects the increased costs that could result from operating under more stringent rules for generation availability. Based on the auction results, the CP mechanism appears to have provided the opportunity for enhanced capacity market revenue streams for Power, but future impacts cannot be assured. Further, there may be requirements for additional investment and there are additional performance risks. Applications for rehearing of FERC's CP order are pending.

An emerging issue in PJM involves the impact of subsidized existing generation on RPM market outcomes. These subsidies would likely enable the affected generators to submit bids into PJM capacity markets that are not reflective of their actual costs of operation and may prevent uneconomic generating facilities from retiring. Either of these conditions could artificially suppress capacity market prices, especially given that PJM's currently effective "minimum offer price rule" (MOPR) which applies only to new gas-fired units, would not apply to these plants. See Item 5. Other Information—Federal Regulation—Capacity Market Issues for additional information.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act (FWPCA) requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs. See Item 1. Note 8. Commitments and Contingent Liabilities for further information.

In October 2015, the EPA published the Clean Power Plan (CPP), a greenhouse gas emissions regulation under the Clean Air Act (CAA) for existing power plants. The regulation establishes state-specific emission targets based on implementation of the best systems of emission reduction. We continue to work with FERC and other federal and state regulators, as well as industry partners, to determine the potential impact of these regulations.

The U.S. Supreme Court's February 2016 decision to stay the implementation of the CPP will delay deadlines for submission of state requests for extensions and final plans. If the CPP is upheld, new deadlines will need to be established and the effective date of the compliance period may be impacted.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above as well as other matters that may impact our financial condition and results of operations, see Item 1. Note 8. Commitments and Contingent Liabilities.

FERC Compliance

The FERC Staff has initiated a preliminary non-public investigation regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units. This investigation is ongoing. The amounts of potential disgorgement and other potential penalties that we may incur span a wide range depending on the success of our legal arguments. If our legal arguments do not prevail, in whole or in part with FERC or in a judicial challenge that we may choose to pursue, it is likely that Power would record losses that would be material to PSEG's and Power's results of operations in the quarterly and annual periods in which they are recorded. For additional information, see Item 1. Note 8. Commitments and Contingent Liabilities.

Salem Inspection

In April 2016, during a scheduled refueling outage at Salem Unit 1, a visual inspection revealed degradation to a series of bolts inside the reactor vessel. We have initiated further testing, which is ongoing and is expected to extend the refueling outage. The impact of the outage on Salem Unit 1's output, margin and cost will depend on the timing and results of the inspection and necessary repairs.

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Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. For the first quarter of 2016, our

- total nuclear fleet achieved an average capacity factor of 99.7%,
- nuclear output increased by 7.5% as compared to the same period in 2015, and
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 13 terra-watt hours while addressing unit outages and balancing fuel availability and price volatility.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first quarter of 2016 as we

- had cash on hand of $592 million as of March 31, 2016,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2016 to $1.64 per share.

We expect to be able to fund our planned capital requirements without the issuance of new equity.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first quarter of 2016, we

- made additional investments in transmission infrastructure projects,
- began executing our GSMP and continued executing Energy Strong and other existing BPU-approved utility programs,
- commenced construction of our Keys and Sewaren 7 generation projects for targeted commercial operation in 2018 and announced our plan to construct BH5 and commence operations in mid-2019, and
- acquired three solar energy projects totaling 100 MW-direct current in North Carolina and Colorado expected to go into service during 2016.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-moving economy and a cost-constrained environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions,
- execute our utility capital investment program, including our Energy Strong program, GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction of our Keys, Sewaren 7, BH5 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

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For 2016 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- FERC Staff's continuing investigation of certain of Power's New Jersey fossil generating unit bids in the PJM energy market,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate, and
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development projects, including in connection with permitting and regulatory approvals.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of transmission and distribution facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition of new businesses,
- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency and modernizing existing infrastructure.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

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RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 17. Related-Party Transactions.

	Three Months Ended March 31,		Increase/ (Decrease)	
	2016	2015	2016 vs. 2015	
	Millions		Millions	%
Operating Revenues	$ 2,616	$ 3,135	$ (519)	(17)
Energy Costs	836	1,094	(258)	(24)
Operation and Maintenance	729	663	66	10
Depreciation and Amortization	224	330	(106)	(32)
Income from Equity Method Investments	2	3	(1)	(33)
Other Income and (Deductions)	27	36	(9)	(25)
Other-Than-Temporary Impairments	10	5	5	N/A
Interest Expense	92	98	(6)	(6)
Income Tax Expense	283	398	(115)	(29)

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Three Months Ended March 31,		Increase/ (Decrease)	
	2016	2015	2016 vs. 2015	
	Millions		Millions	%
Operating Revenues	$ 1,712	$ 2,002	$ (290)	(14)
Energy Costs	729	892	(163)	(18)
Operation and Maintenance	382	412	(30)	(7)
Depreciation and Amortization	139	247	(108)	(44)
Other Income (Deductions)	19	17	2	12
Interest Expense	68	69	(1)	(1)
Income Tax Expense	151	157	(6)	(4)

Three Months Ended March 31, 2016 as Compared to 2015

Operating Revenues decreased $290 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $29 million due primarily to an increase in transmission revenues.

- Transmission revenues were $53 million higher due to increased capital investments.
- Electric distribution revenues decreased $23 million due primarily to lower Green Program Recovery Charges (GPRC) of $14 million and $10 million in lower sales volumes.
- Gas distribution revenues decreased $1 million due primarily to $76 million lower delivery volume and lower GPRC of $6 million due to lower sales volumes from warmer winter weather. These decreases were almost entirely offset by $73 million in higher Weather Normalization Clause (WNC) revenue and $8 million due to roll in of Energy Strong into base rates effective September 1, 2015.

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Commodity Revenue decreased $163 million as a result of lower Gas and Electric revenues. Commodity revenue for both gas and electric is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of Basic Gas Supply Service (BGSS) and basic generation service (BGS) to retail customers.

- Gas revenues decreased $109 million due to lower BGSS volume.
- Electric revenues decreased $54 million due primarily to a $35 million or 8% decrease in BGS revenues due to lower sales volumes, $11 million of lower revenues from collections of Non-Utility Generation Charges (NGC) and a decrease of $8 million due to higher volumes of Non-Utility Generation (NUG) energy sold at lower prices.

Clause Revenues decreased $155 million due primarily to lower Securitization Transition Charges (STC) of $129 million and lower Societal Benefit Charges (SBC) of $33 million, partially offset by higher Margin Adjustment Clause Revenue (MAC) of $12 million. The STC reduction is a result of rate reductions due to the completion of securitization collections in 2015. The changes in the STC, SBC and MAC amounts are entirely offset by decreases in the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC or MAC collections.

Other Operating Revenues experienced no material change.

Operating Expenses

Energy Costs decreased $163 million. This is entirely offset by Commodity Revenue.

Operation and Maintenance decreased $30 million, of which the most significant components were

- a $44 million net reduction in costs related to various clause mechanisms and GPRC,
- partially offset by $15 million of storm insurance recovery proceeds received in 2015.

Depreciation and Amortization decreased $108 million due to a decrease of $124 million in amortization of Regulatory Assets primarily as a result of the completion of the amortization of the securitization charges in 2015 (which is completely offset in STC Revenues), partially offset by a $16 million increase in depreciation due to of additional plant in service.

Income Tax Expense decreased $6 million due primarily to depreciation flow through items and uncertain tax positions offset by higher pre-tax income.

Power

	Three Months Ended March 31,		Increase/ (Decrease)	
	2016	2015	2016 vs. 2015	
	Millions		Millions	%
Operating Revenues	$ 1,313	$ 1,725	$ (412)	(24)
Energy Costs	638	893	(255)	(29)
Operation and Maintenance	253	172	81	47
Depreciation and Amortization	79	76	3	4
Income from Equity Method Investments	2	3	(1)	(33)
Other Income (Deductions)	8	18	(10)	(56)
Other-Than-Temporary Impairments	10	5	5	N/A
Interest Expense	22	31	(9)	(29)
Income Tax Expense	129	234	(105)	(45)

Three Months Ended March 31, 2016 as Compared to 2015

Operating Revenues decreased $412 million due to changes in generation and gas supply revenues.

Generation Revenues decreased $174 million due primarily to

- a decrease of $75 million primarily in the PJM region due to lower operating reserve revenue coupled with lower capacity revenues resulting from the retirement of older peaking units in June 2015,

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- lower net revenues of $75 million due primarily to milder weather which led to lower energy volumes sold in the PJM and NE regions and lower average realized prices,
- a decrease of $38 million due primarily to lower volumes of electricity sold under fewer wholesale load contracts in the PJM and NE regions coupled with lower average prices,
- a net decrease of $25 million due primarily to lower volumes of electricity sold under the BGS contracts as a result of milder weather partially offset by higher average prices, and
- partially offset by an increase of $39 million due to MTM gains in 2016 as compared to MTM losses in 2015.

Gas Supply Revenues decreased $238 million due primarily to

- a net decrease of $220 million in sales under the BGSS contract, substantially comprised of lower sales volumes due to warmer average temperatures in the 2016 winter heating season, coupled with lower average sales prices, and
- a net decrease of $18 million on sales to third party customers, of which $47 million was due to lower average sales prices, partially offset by $29 million of higher volumes sold.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $255 million due to

- ***Generation costs*** decreased $123 million due primarily to lower fuel costs of $234 million reflecting lower average realized natural gas prices and the utilization of lower volumes of coal, oil and gas. These decreased costs were partially offset by higher congestion costs in the PJM region of $145 million, mainly as a result of credits received in the prior year due to extremely cold weather. Also, lower MTM losses in 2016 resulted in a $20 million decrease.
- ***Gas costs*** decreased $132 million mainly related to a decrease in volumes sold under the BGSS contract coupled with lower average gas costs. Gas costs on sales to third parties were flat.

Operation and Maintenance increased $81 million due primarily to

- $128 million of insurance recoveries received in 2015 related to Superstorm Sandy,
- partially offset by a net decrease of $48 million related to our fossil plants, largely due to higher costs incurred in 2015 for planned major outages.

Other Income and (Deductions) decreased $10 million due primarily to higher net realized losses from the NDT Fund.

Other-Than-Temporary Impairments increased $5 million due primarily to an increase in impairments of equity securities in the NDT Fund.

Interest Expense decreased $9 million due primarily to the maturity of a $300 million 5.50% Senior Note in December 2015 and higher capitalized interest in 2016.

Income Tax Expense decreased $105 million in 2016 due primarily to lower pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

We expect operating cash flows combined with cash on hand and financing activities to be sufficient to fund planned capital expenditures and shareholder dividend payments.

For the three months ended March 31, 2016, our operating cash flow decreased $465 million as compared to the same period in 2015. The net change was due primarily to the net changes from PSE&G and Power as discussed below.

PSE&G

PSE&G's operating cash flow decreased $109 million from $677 million to $568 million for the three months ended March 31, 2016, as compared to the same period in 2015, due primarily to a decrease of $83 million due to a change in regulatory deferrals primarily driven by lower volumes due to warmer weather impacting our Gas Weather Normalization, SBC, GPRC

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and BGSS clauses, a $42 million decrease in other current assets and liabilities and a $40 million decrease due to vendor payments. These amounts were partially offset by higher earnings and a reduction in tax payments.

Power

Power's operating cash flow decreased $187 million from $850 million to $663 million for the three months ended March 31, 2016, as compared to the same period in 2015, primarily due to lower earnings and a $141 million decrease for fuel, materials and supplies, partially offset by a reduction in tax payments.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our $4.3 billion credit facilities are provided by a diverse bank group. As of March 31, 2016, our total available credit capacity was $4.0 billion.

As of March 31, 2016, no single institution represented more than 7% of the total commitments in our credit facilities.

As of March 31, 2016, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of March 31, 2016 were as follows:

	As of March 31, 2016				
Company/Facility	Total Facility	Usage (D)	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facility	$ 500	$ 10	$ 490	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	524	12	512	Apr 2020	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,024**	**$ 22**	**$ 1,002**		
PSE&G					
5-year Credit Facility (B)	$ 629	$ 14	$ 615	Apr 2020	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 629**	**$ 14**	**$ 615**		
Power					
5-year Credit Facility	$ 1,600	$ 202	$ 1,398	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (C)	1,000	9	991	Apr 2020	Funding/Letters of Credit
Total Power	**$ 2,600**	**$ 211**	**$ 2,389**		
Total	**$ 4,253**	**$ 247**	**$ 4,006**		

(A) PSEG facility will be reduced by $23 million in April 2016 and $12 million in March 2018; PSEG's 2020 credit facility was increased by $24 million in March 2016 in anticipation of the April expiration.

(B) PSE&G facility will be reduced by $29 million in April 2016 and $14 million in March 2018; PSE&G's 2020 facility was increased by $29 million in March 2016 in anticipation of the April expiration.

(C) Power facility will be reduced by $48 million in April 2016 and $24 million in March 2018.

(D) The primary use of PSEG's and PSE&G's credit facilities is to support their respective CP Programs under which as of March 31, 2016, PSEG had $12 million outstanding at a weighted average interest rate of 0.65%. PSE&G had no amounts outstanding under its CP Program as of March 31, 2016.

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Long-Term Debt Financing

Power has $303 million of 5.32% Senior Notes and $250 million of 2.75% Senior Notes maturing in September 2016.

For a discussion of our long-term debt transactions during 2016, see Item 1. Note 9. Changes in Capitalization.

Common Stock Dividends

On February 16, 2016, our Board of Directors approved a $0.41 per share common stock dividend for the first quarter of 2016. On April 19, 2016, our Board of Directors declared a quarterly dividend of $0.41 per share of common stock for the second quarter of 2016. This reflects an indicative annual dividend rate of $1.64 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 1. Note 15. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In January 2016, S&P published updated research reports on PSEG and PSE&G and the existing ratings and outlooks were unchanged. In March 2016, Moody's published an updated research report on Power and the existing rating and outlook were unchanged.

	Moody's (A)	S&P (B)
PSEG		
Outlook	**Positive**	**Stable**
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities. The Corporate Credit Rating outlook does not apply to PSEG's or PSE&G's Commercial Paper Rating or PSE&G's Mortgage Bond rating.

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CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures at PSE&G, Power and Services as compared to amounts disclosed in our 2015 Form 10-K.

PSE&G

During the three months ended March 31, 2016, PSE&G made capital expenditures of $724 million, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $35 million, which are included in operating cash flows.

Power

During the three months ended March 31, 2016, Power made capital expenditures of $283 million, excluding $50 million for nuclear fuel, primarily related to our Keys, Sewaren 7, BH5 and other generation projects.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Item 1. Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From January through March 2016, MTM VaR remained relatively stable between low of $11 million to high of $25 million at 95% confidence level. The range of VaR was narrower for the three months ended March 31, 2016 as compared with the year ended December 31, 2015.

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	MTM VaR	
	Three Months Ended March 31, 2016	Year Ended December 31, 2015
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 11	$ 24
Average for the Period	$ 17	$ 17
High	$ 25	$ 40
Low	$ 11	$ 8
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 17	$ 38
Average for the Period	$ 27	$ 26
High	$ 40	$ 63
Low	$ 17	$ 12

See Item 1. Note 10. Financial Risk Management Activities for a discussion of credit risk.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

There have been no changes in internal control over financial reporting that occurred during the first quarter of 2016 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2015 Annual Report on Form 10-K, see Part I, Item 1. Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

Environmental Matters

The following updates information previously reported in Item 3 of Part I of the 2015 Annual Report on Form 10-K.

(1) Claim by the EPA, Region III, under CERCLA with respect to the Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and the former and current site owners are alleged to be liable for contamination at the site and PSE&G has been named as a Potentially Responsible Party (PRP). The EPA approved the Final Revised Remedial Design for the Site in early 2008. This document presented the design details of the EPA's selected remedy. PSE&G and other utility companies as members of a PRP group entered into a Consent Decree and agreed to implement

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the negotiated EPA selected remedy. The EPA settled its claims against the site owners who did not join the Consent Decree to implement the remedy. The PRP group's implementation of the remedy was completed in 2010; however, an additional estimated cost of $200,000 will be incurred by PSE&G in 2016 to repair part of the remedy. Although the PRP Group has not received a formal Certification of Completion of the Remedy from the EPA, the PRP Group does not anticipate further significant costs at this time. Although subject to EPA approval and oversight, long-term monitoring, operations, and maintenance activities are anticipated through 2018 at a total estimated cost to PSE&G of $200,000.

ITEM 1A. RISK FACTORS

There are no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2015 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the first quarter of 2016.

Three Months Ended March 31, 2016	Total Number of Shares Purchased	Average Price Paid per Share
January 1 - January 31	—	$ —
February 1- February 29	621,983	$ 43.62
March 1- March 31	493,764	$ 42.92

ITEM 5. OTHER INFORMATION

Certain information reported in the 2015 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2015 Annual Report on Form 10-K. References are to the related pages on the Form 10-K as printed and distributed.

Employee Relations

December 31, 2015 Form 10-K page 16. During the first quarter of 2016, four of PSEG's eight labor unions ratified the extension of their respective collective bargaining agreements with PSEG for four years effective May 1, 2017. Collectively, these unions represent approximately 75 percent of PSEG's total union employees. Therefore, as of March 31, 2016, our collective bargaining agreements will expire in November 2016 with one union, in October 2017 with two unions, in May 2018 with one union and in April 2021 with four unions. We believe we maintain satisfactory relationships with our employees.

Federal Regulation

FERC

Capacity Market Issues—PJM

December 31, 2015 Form 10-K page 17. An emerging issue in PJM involves the impact of subsidized generation on RPM market outcomes. In particular, FirstEnergy Corp. (FE) and American Electric Power (AEP) have proposed to enter into power purchase agreements (PPAs) with their non-utility generation affiliates providing for above-market purchases from certain coal plants and a nuclear plant (in FE's case). The Ohio Public Utility Commission (PUCO) recently approved the PPAs on terms similar to the terms sought by those companies. The Dayton Power and Light Company has recently also filed for comparable arrangements covering generating plants that it owns. The subsidies under these contracts would likely enable the affected generators to submit bids into PJM capacity markets that are not reflective of their actual costs of operation and may prevent uneconomic generating facilities from retiring. Either of these conditions could artificially suppress capacity market prices, especially given that PJM's currently effective "minimum offer price rule" (MOPR) which applies only to new gas-fired units would not apply to these plants. On April 27, 2016, FERC issued orders finding that the PPAs should be reviewed to determine whether they comport with the Commission's standards for contracts. In another proceeding at FERC, certain parties are claiming that PJM should be directed to expand the MOPR to apply to existing contracts, including the FE and AEP PPAs.

We are unable to predict the results of these pending proceedings or any future related proceedings or to calculate the potential impacts on our business.

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Capacity Market Issues—ISO-New England

December 31, 2015 Form 10-K page 18. In March 2015, in conjunction with other companies, we filed a petition for review with the D.C. Court of FERC's ruling accepting the exemption from the MOPR in the capacity market afforded for up to 200 MW annually (600 MW cumulatively) of renewable resources. On December 1, 2015, following a request by FERC for a voluntary remand of the order, the D.C. Court remanded the case to FERC for additional consideration. However, on April 8, 2016, FERC issued an order reinstating the exemption. We are currently in the process of analyzing this development.

In December 2015, ISO-NE filed a proposal that would allow resource owners to submit bids into the capacity auction reflecting their desire to retire a resource. In April 2016, FERC accepted the proposal subject to a compliance filing by ISO-NE. We remain concerned that the new rules may be disruptive to efficient price formation in the capacity market.

Reactive Power Rates

December 31, 2015 Form 10-K page 19. In June 2015, Power submitted a tariff filing with FERC to increase Power's rates for reactive supply and voltage control service from approximately $27 million per year to about $39 million per year. Following settlement discussions with FERC Trial Staff, Power agreed to accept an overall rate of $34 million per year, which FERC approved in February 2016. FERC had earlier referred the filing to the FERC Office of Enforcement for its evaluation, which remains pending.

Long-Term Capacity Agreement Pilot Program Act (LCAPP)

December 31, 2015 Form 10-K page 21. In 2011, the State of New Jersey enacted the LCAPP to subsidize approximately 2,000 MW of new natural gas-fired generation. The LCAPP provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey EDCs.

In 2013, the U.S. District Court in New Jersey found that the LCAPP was unconstitutional and declared the LCAPP null and void. This federal court decision was subsequently challenged on appeal in the U.S. Third Circuit Court of Appeals (Third Circuit). The State of Maryland also took similar action to subsidize above-market new generation. This action was also determined to be unconstitutional in 2013 in the U.S. District Court in Maryland and such decision was challenged in the U.S. Fourth Circuit Court of Appeals (Fourth Circuit). Both appeals were denied. These denials were challenged on appeal to the U.S. Supreme Court. On April 19, 2016, the U.S. Supreme Court issued its ruling upholding the Fourth Circuit decision. The Supreme Court's ruling upholds FERC's authority to foster competitive wholesale electricity markets and provides guidance to states in balancing their interests to encourage and support the development of renewables and other generating facilities. On April 25, 2016, the U.S. Supreme Court denied the request to hear the appeal of the Third Circuit decision.

Transmission Regulation—Transmission Policy Developments

December 31, 2015 Form 10-K page 19. In April 2013, PJM initiated its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues at Artificial Island in New Jersey. In April 2016, PSE&G accepted construction responsibility for the three components of the project that PJM assigned to it, based on having reached agreement with PJM regarding an estimate for the project base cost of $273 million, plus risk and contingency for a total project cost of up to $340 million. PSE&G continues to work with PJM to optimize the scope and cost of the project.

On April 1, 2016, PJM filed at FERC to incorporate a voltage threshold into PJM's RTEP process to exempt, except under certain circumstances, reliability violations on facilities below 200 kV from PJM's proposal window process. We generally support this reform as a measure to improve the efficiency of the open window procedure that will permit transmission developers to focus on the projects most likely to benefit from a competitive process.

In June 2015, a transmission developer filed a complaint against PJM claiming that PJM wrongfully refused to provide data and a transparent process for evaluating transmission network upgrade requests that the transmission developer had submitted to PJM. According to the complaint, PJM and certain transmission owners wrongfully inflated the scope and associated costs of mitigation work needed to accommodate the developer's proposal in order to prevent it from pursuing its projects. Although not named as a respondent in the complaint, PSE&G is identified as one of the companies claimed to have been involved. The developer subsequently amended its complaint to add additional claims. Motions are pending before FERC seeking to dismiss both the original and the amended complaint. We are unable to predict the outcome of these proceedings.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G contending that insufficient levels of costs are being allocated to PSE&G. Projects involved include the Artificial Island project, the Bergen-Linden project in New Jersey and a smaller project in Sewaren, New Jersey. On April 22, 2016, FERC issued orders denying the complaints and leaving the current cost allocation in effect as to the Artificial Island and Bergen-Linden projects. Due to an intervening FERC order concerning the allocation of costs for projects constructed to meet local reliability requirements, FERC directed that all of the Sewaren costs be allocated to PSE&G. It is anticipated that additional proceedings are likely to occur.

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Compliance—Reliability Standards

December 31, 2015 Form 10-K page 21. FERC is considering whether to direct the North American Electric Reliability Council (NERC) to develop a new reliability standard to provide security controls for supply chain management associated with the procurement of industrial control system hardware, software, and services related to bulk electric system operations. If adopted, compliance with these new standards would be expected to impose additional obligations and costs on transmission providers.

State Regulation

BPU Cybersecurity Requirements for Regulated Entities

In March 2016, the BPU issued an Order for the regulated electric, natural gas, and water/wastewater utilities to further reduce the potential for cyber threats to the reliability and resiliency of utility service and to protect customers' information. The Order requires these regulated utilities, including PSE&G, to implement a cybersecurity program that defines and implements organization accountabilities and responsibilities for cyber risk management activities, and establishes policies, plans, processes and procedures for identifying and mitigating cyber risk to critical systems.

New Jersey utilities, including PSE&G, are required to be compliant with these requirements by October 31, 2017. We are currently evaluating the requirements. For a discussion of the risks associated with cyber threats, see Part I, Item 1A. Risk Factors—"Cyber security attacks or intrusions could adversely impact our businesses." in our 2015 Annual Report on
Form 10-K.

Environmental Matters

Air Pollution Control

Hazardous Air Pollutants Regulation

December 31, 2015 Form 10-K page 24. In February 2012**,** the Environmental Protection Agency (EPA) published Mercury Air Toxics Standards (MATS) for both newly-built and existing electric generating sources under the National Emission Standard for Hazardous Air Pollutants (NESHAP) provisions of the CAA. The MATS established allowable levels for mercury as well as other hazardous air pollutants and went into effect in April 2015. In June 2015, the U.S. Supreme Court held that it was unreasonable for the EPA to refuse to consider the materiality of costs in determining whether to regulate hazardous air pollutants from power plants and remanded the matter back to the D.C. Court. On December 15, 2015, the D.C. Court remanded the MATS to the EPA without vacating the rule. On April 15, 2016, the EPA released the final Supplemental Finding that considers the materiality of costs in determining whether to regulate hazardous air pollutants from power plants in response to the U.S. Supreme Court's June ruling. We do not expect this Supplemental Finding to impact operation of our facilities.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. PSE&G:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. Power:

Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

S1-SSA-0009 - 18453

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 29, 2016

S1-SSA-0009 - 18454

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 29, 2016

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 29, 2016

S1-SSA-0009 - 18456

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2016	2015	2015	2014	2013	2012	2011
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 754	$ 984	$ 2,680	$ 2,456	$ 2,055	$ 2,011	$ 2,384
(Income) Loss from Equity Investees, net of Distributions	2	2	3	4	(7)	9	(4)
Fixed Charges	112	112	457	450	458	479	522
Capitalized Interest	(8)	(2)	(18)	(16)	(16)	(19)	(14)
Total Earnings	$ 860	$ 1,096	$ 3,122	$ 2,894	$ 2,490	$ 2,480	$ 2,888
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 107	$ 107	$ 437	$ 430	$ 442	$ 465	$ 509
Interest Factor in Rentals	5	5	20	20	16	14	13
Total Fixed Charges	$ 112	$ 112	$ 457	$ 450	$ 458	$ 479	$ 522
Ratio of Earnings to Fixed Charges	**7.68**	**9.79**	**6.83**	**6.43**	**5.44**	**5.18**	**5.53**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Three Months Ended March 31,		Years Ended December 31,				
	2016	**2015**	**2015**	**2014**	**2013**	**2012**	**2011**
			(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 413	$ 399	$1,257	$1,174	$ 993	$ 835	$ 861
Fixed Charges	75	75	306	303	316	314	319
Capitalized Interest	(4)	(4)	(17)	(16)	(16)	(13)	(4)
Total Earnings	$ 484	$ 470	$1,546	$1,461	$ 1,293	$1,136	$1,176
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 72	$ 73	$ 297	$ 293	$ 309	$ 308	$ 314
Interest Factor in Rentals	3	2	9	10	7	6	5
Total Fixed Charges	$ 75	$ 75	$ 306	$ 303	$ 316	$ 314	$ 319
Ratio of Earnings to Fixed Charges	**6.45**	**6.27**	**5.05**	**4.82**	**4.09**	**3.62**	**3.69**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.2

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2016	2015	2015	2014	2013	2012	2011
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 321	$ 569	$1,367	$1,251	$1,063	$1,099	$1,703
(Income) Loss from Equity Investees, net of Distributions	2	1	1	3	(10)	(6)	(12)
Fixed Charges	34	38	152	150	143	164	208
Capitalized Interest	(4)	1	(1)	1	1	(6)	(10)
Total Earnings	$ 353	$ 609	$1,519	$1,405	$1,197	$1,251	$1,889
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 33	$ 37	$ 148	$ 146	$ 139	$ 161	$ 205
Interest Factor in Rentals	1	1	4	4	4	3	3
Total Fixed Charges	$ 34	$ 38	$ 152	$ 150	$ 143	$ 164	$ 208
Ratio of Earnings to Fixed Charges	**10.38**	**16.03**	**9.99**	**9.37**	**8.37**	**7.63**	**9.08**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 29, 2016

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 29, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

S1-SSA-0009 - 18461

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 29, 2016

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 29, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 29, 2016

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 29, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

S1-SSA-0009 - 18465

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
April 29, 2016

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
April 29, 2016

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
April 29, 2016

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
April 29, 2016

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
April 29, 2016

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
April 29, 2016

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED March 31, 2017
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐

If any of the registrants is an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of April 18, 2017, Public Service Enterprise Group Incorporated had outstanding 505,878,825 shares of its sole class of Common Stock, without par value.

As of April 18, 2017, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K. These factors include, but are not limited to:

- fluctuations in wholesale power and natural gas markets, including the potential impacts on the economic viability of our generation units;
- our ability to obtain adequate fuel supply;
- any inability to manage our energy obligations with available supply;
- increases in competition in wholesale energy and capacity markets;
- changes in technology related to energy generation, distribution and consumption and customer usage patterns;
- economic downturns;
- third-party credit risk relating to our sale of generation output and purchase of fuel;
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements;
- changes in state and federal legislation and regulations;
- the impact of pending rate case proceedings;
- regulatory, financial, environmental, health and safety risks associated with our ownership and operation of nuclear facilities;
- adverse changes in energy industry laws, policies and regulations, including market structures and transmission planning;
- changes in federal and state environmental regulations and enforcement;
- delays in receipt of, or an inability to receive, necessary licenses and permits;
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry;
- changes in tax laws and regulations;
- the impact of our holding company structure on our ability to meet our corporate funding needs, service debt and pay dividends;
- lack of growth or slower growth in the number of customers or changes in customer demand;
- any inability of Power to meet its commitments under forward sale obligations;
- reliance on transmission facilities that we do not own or control and the impact on our ability to maintain adequate transmission capacity;
- any inability to successfully develop or construct generation, transmission and distribution projects;
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers;
- our inability to exercise control over the operations of generation facilities in which we do not maintain a controlling interest;

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- any inability to maintain sufficient liquidity;
- any inability to realize anticipated tax benefits or retain tax credits;
- challenges associated with recruitment and/or retention of key executives and a qualified workforce;
- the impact of our covenants in our debt instruments on our operations; and
- the impact of acts of terrorism, cybersecurity attacks or intrusions.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business, prospects, financial condition, results of operations or cash flows. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even in light of new information or future events, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

FILING FORMAT

This combined Quarterly Report on Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to “we,” “us,” and “our” relate to PSEG or to the specific company or companies being discussed.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended March 31,	
	2017	**2016**
OPERATING REVENUES	$ 2,592	$ 2,616
OPERATING EXPENSES		
Energy Costs	874	836
Operation and Maintenance	712	729
Depreciation and Amortization	828	224
Total Operating Expenses	2,414	1,789
OPERATING INCOME	178	827
Income from Equity Method Investments	3	2
Other Income	72	48
Other Deductions	(11)	(21)
Other-Than-Temporary Impairments	(1)	(10)
Interest Expense	(98)	(92)
INCOME BEFORE INCOME TAXES	143	754
Income Tax Expense	(29)	(283)
NET INCOME	$ 114	$ 471
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:		
BASIC	505	505
DILUTED	508	508
NET INCOME PER SHARE:		
BASIC	$ 0.23	$ 0.93
DILUTED	$ 0.22	$ 0.93
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.43	$ 0.41

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2017	**2016**
NET INCOME	$ 114	$ 471
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(16) and $(16) for 2017 and 2016, respectively	15	16
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0 and $(1) for 2017 and 2016, respectively	—	2
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(4) and $(6) for 2017 and 2016, respectively	6	8
Other Comprehensive Income (Loss), net of tax	21	26
COMPREHENSIVE INCOME	$ 135	$ 497

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18477

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 193	$ 423
Accounts Receivable, net of allowances of $67 in 2017 and $68 in 2016	1,212	1,161
Tax Receivable	9	78
Unbilled Revenues	209	260
Fuel	173	326
Materials and Supplies, net	566	561
Prepayments	56	76
Derivative Contracts	114	163
Regulatory Assets	176	199
Other	8	7
Total Current Assets	2,716	3,254
PROPERTY, PLANT AND EQUIPMENT	40,195	39,337
Less: Accumulated Depreciation and Amortization	(10,850)	(10,051)
Net Property, Plant and Equipment	29,345	29,286
NONCURRENT ASSETS		
Regulatory Assets	3,287	3,319
Long-Term Investments	1,001	1,050
Nuclear Decommissioning Trust (NDT) Fund	1,913	1,859
Long-Term Tax Receivable	113	104
Long-Term Receivable of Variable Interest Entity (VIE)	595	589
Other Special Funds	221	217
Goodwill	16	16
Other Intangibles	106	98
Derivative Contracts	93	24
Other	258	254
Total Noncurrent Assets	7,603	7,530
TOTAL ASSETS	$ 39,664	$ 40,070

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2017	December 31, 2016
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 500	$ 500
Commercial Paper and Loans	315	388
Accounts Payable	1,245	1,459
Derivative Contracts	7	13
Accrued Interest	131	97
Accrued Taxes	172	31
Clean Energy Program	86	142
Obligation to Return Cash Collateral	135	132
Regulatory Liabilities	74	88
Other	446	426
Total Current Liabilities	3,111	3,276
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	8,567	8,658
Regulatory Liabilities	131	118
Asset Retirement Obligations	738	726
OPEB Costs	1,309	1,324
OPEB Costs of Servco	460	452
Accrued Pension Costs	547	568
Accrued Pension Costs of Servco	126	128
Environmental Costs	393	401
Derivative Contracts	1	3
Long-Term Accrued Taxes	180	180
Other	198	211
Total Noncurrent Liabilities	12,650	12,769
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT	10,898	10,895
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2017 and 2016—534 shares	4,920	4,936
Treasury Stock, at cost, 2017 and 2016—29 shares	(743)	(717)
Retained Earnings	9,070	9,174
Accumulated Other Comprehensive Loss	(242)	(263)
Total Stockholders' Equity	13,005	13,130
Total Capitalization	23,903	24,025
TOTAL LIABILITIES AND CAPITALIZATION	$ 39,664	$ 40,070

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2017	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 114	$ 471
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	828	224
Amortization of Nuclear Fuel	54	58
Renewable Energy Credit (REC) Compliance Accrual	26	27
Provision for Deferred Income Taxes (Other than Leases) and ITC	(85)	182
Non-Cash Employee Benefit Plan Costs	23	32
Leveraged Lease (Income) Loss, Adjusted for Rents Received and Deferred Taxes	(15)	(15)
Net (Gain) Loss on Lease Investments	32	—
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(5)	(21)
Net Change in Regulatory Assets and Liabilities	(60)	(105)
Cost of Removal	(24)	(35)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(23)	3
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	69	301
Accrued Taxes	143	144
Margin Deposit	(4)	(4)
Other Current Assets and Liabilities	163	27
Employee Benefit Plan Funding and Related Payments	(28)	(56)
Other	(12)	(19)
Net Cash Provided By (Used In) Operating Activities	1,196	1,214
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,062)	(1,065)
Purchase of Emissions Allowances and RECs	(15)	(16)
Proceeds from Sales of Available-for-Sale Securities	298	202
Investments in Available-for-Sale Securities	(307)	(207)
Other	7	5
Net Cash Provided By (Used In) Investing Activities	(1,079)	(1,081)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(73)	(352)
Issuance of Long-Term Debt	—	850
Redemption of Long-Term Debt	—	(171)
Cash Dividends Paid on Common Stock	(218)	(207)
Other	(56)	(55)
Net Cash Provided By (Used In) Financing Activities	(347)	65
Net Increase (Decrease) in Cash and Cash Equivalents	(230)	198
Cash and Cash Equivalents at Beginning of Period	423	394
Cash and Cash Equivalents at End of Period	$ 193	$ 592
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (80)	$ (299)
Interest Paid, Net of Amounts Capitalized	$ 77	$ 66
Accrued Property, Plant and Equipment Expenditures	$ 492	$ 434

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2017	**2016**
OPERATING REVENUES	$ 1,812	$ 1,712
OPERATING EXPENSES		
Energy Costs	753	729
Operation and Maintenance	367	382
Depreciation and Amortization	171	139
Total Operating Expenses	1,291	1,250
OPERATING INCOME	521	462
Other Income	25	20
Other Deductions	(1)	(1)
Interest Expense	(75)	(68)
INCOME BEFORE INCOME TAXES	470	413
Income Tax Expense	(171)	(151)
NET INCOME	$ 299	$ 262

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18481

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2017	**2016**
NET INCOME	$ 299	$ 262
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $1 and $0 for 2017 and 2016, respectively	(1)	—
COMPREHENSIVE INCOME	$ 298	$ 262

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$ 153	$ 390
Accounts Receivable, net of allowances of $67 in 2017 and $68 in 2016	895	810
Accounts Receivable—Affiliated Companies	34	76
Unbilled Revenues	209	260
Materials and Supplies	187	180
Prepayments	6	9
Regulatory Assets	176	199
Derivative Contracts	1	—
Other	7	6
Total Current Assets	1,668	1,930
PROPERTY, PLANT AND EQUIPMENT	26,931	26,347
Less: Accumulated Depreciation and Amortization	(5,849)	(5,760)
Net Property, Plant and Equipment	21,082	20,587
NONCURRENT ASSETS		
Regulatory Assets	3,287	3,319
Long-Term Investments	301	299
Other Special Funds	44	43
Other	105	110
Total Noncurrent Assets	3,737	3,771
TOTAL ASSETS	$ 26,487	$ 26,288

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	March 31, 2017	December 31, 2016
CURRENT LIABILITIES		
Accounts Payable	$ 574	$ 718
Accounts Payable—Affiliated Companies	218	260
Accrued Interest	83	76
Clean Energy Program	86	142
Derivative Contracts	—	5
Obligation to Return Cash Collateral	135	132
Regulatory Liabilities	74	88
Other	319	296
Total Current Liabilities	1,489	1,717
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	6,042	5,873
OPEB Costs	991	1,009
Accrued Pension Costs	237	250
Regulatory Liabilities	131	118
Environmental Costs	324	332
Asset Retirement Obligations	214	213
Long-Term Accrued Taxes	116	130
Other	114	116
Total Noncurrent Liabilities	8,169	8,041
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT	7,819	7,818
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2017 and 2016—132 shares	892	892
Contributed Capital	945	945
Basis Adjustment	986	986
Retained Earnings	6,187	5,888
Accumulated Other Comprehensive Income	—	1
Total Stockholder's Equity	9,010	8,712
Total Capitalization	16,829	16,530
TOTAL LIABILITIES AND CAPITALIZATION	$ 26,487	$ 26,288

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2017	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 299	$ 262
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	171	139
Provision for Deferred Income Taxes and ITC	160	147
Non-Cash Employee Benefit Plan Costs	13	18
Cost of Removal	(24)	(35)
Net Change in Other Regulatory Assets and Liabilities	(60)	(105)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	(34)	(26)
Materials and Supplies	(7)	(6)
Prepayments	3	26
Accounts Payable	(12)	(24)
Accounts Receivable/Payable—Affiliated Companies, net	15	197
Other Current Assets and Liabilities	40	35
Employee Benefit Plan Funding and Related Payments	(25)	(44)
Other	(25)	(16)
Net Cash Provided By (Used In) Operating Activities	514	568
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(748)	(724)
Proceeds from Sales of Available-for-Sale Securities	10	5
Investments in Available-for-Sale Securities	(10)	(5)
Solar Loan Investments	(4)	—
Other	2	—
Net Cash Provided By (Used In) Investing Activities	(750)	(724)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	—	(153)
Issuance of Long-Term Debt	—	850
Redemption of Long-Term Debt	—	(171)
Other	(1)	(10)
Net Cash Provided By (Used In) Financing Activities	(1)	516
Net Increase (Decrease) In Cash and Cash Equivalents	(237)	360
Cash and Cash Equivalents at Beginning of Period	390	198
Cash and Cash Equivalents at End of Period	$ 153	$ 558
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (26)	$ (200)
Interest Paid, Net of Amounts Capitalized	$ 65	$ 53
Accrued Property, Plant and Equipment Expenditures	$ 287	$ 318

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2017	**2016**
OPERATING REVENUES	$ 1,284	$ 1,313
OPERATING EXPENSES		
Energy Costs	707	638
Operation and Maintenance	230	253
Depreciation and Amortization	650	79
Total Operating Expenses	1,587	970
OPERATING INCOME (LOSS)	(303)	343
Income from Equity Method Investments	3	2
Other Income	38	26
Other Deductions	(7)	(18)
Other-Than-Temporary Impairments	(1)	(10)
Interest Expense	(16)	(22)
INCOME (LOSS) BEFORE INCOME TAXES	(286)	321
Income Tax Benefit (Expense)	116	(129)
NET INCOME (LOSS)	$ (170)	$ 192

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2017	**2016**
NET INCOME (LOSS)	$ (170)	$ 192
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(18) and $(16) for 2017 and 2016, respectively	19	16
Pension/OPEB adjustment, net of tax (expense) benefit of $(4) and $(5) for 2017 and 2016, respectively	5	7
Other Comprehensive Income (Loss), net of tax	24	23
COMPREHENSIVE INCOME (LOSS)	$ (146)	$ 215

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$ 18	$ 11
Accounts Receivable	263	276
Accounts Receivable—Affiliated Companies	175	205
Short-Term Loan to Affiliate	157	87
Fuel	173	326
Materials and Supplies, net	379	381
Derivative Contracts	111	162
Prepayments	13	10
Other	3	2
Total Current Assets	1,292	1,460
PROPERTY, PLANT AND EQUIPMENT	12,922	12,655
Less: Accumulated Depreciation and Amortization	(4,837)	(4,135)
Net Property, Plant and Equipment	8,085	8,520
NONCURRENT ASSETS		
NDT Fund	1,913	1,859
Long-Term Investments	103	102
Goodwill	16	16
Other Intangibles	106	98
Other Special Funds	55	53
Derivative Contracts	93	24
Other	66	61
Total Noncurrent Assets	2,352	2,213
TOTAL ASSETS	$ 11,729	$ 12,193

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2017	December 31, 2016
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$ 513	$ 539
Accounts Payable—Affiliated Companies	81	25
Derivative Contracts	7	8
Accrued Interest	42	20
Other	102	88
Total Current Liabilities	745	680
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	1,966	2,170
Asset Retirement Obligations	522	511
OPEB Costs	254	251
Derivative Contracts	1	3
Accrued Pension Costs	185	191
Long-Term Accrued Taxes	78	77
Other	117	129
Total Noncurrent Liabilities	3,123	3,332
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
LONG-TERM DEBT	2,383	2,382
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,437	4,782
Accumulated Other Comprehensive Loss	(187)	(211)
Total Member's Equity	5,478	5,799
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 11,729	$ 12,193

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2017	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income (Loss)	$ (170)	$ 192
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	650	79
Amortization of Nuclear Fuel	54	58
Provision for Deferred Income Taxes and ITC	(226)	34
Interest Accretion on Asset Retirement Obligation	8	7
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(5)	(21)
Renewable Energy Credit (REC) Compliance Accrual	26	27
Non-Cash Employee Benefit Plan Costs	7	10
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(23)	3
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	155	143
Margin Deposit	(4)	(4)
Accounts Receivable	24	(41)
Accounts Payable	(18)	(34)
Accounts Receivable/Payable—Affiliated Companies, net	71	184
Other Current Assets and Liabilities	33	15
Employee Benefit Plan Funding and Related Payments	(2)	(8)
Other	—	19
Net Cash Provided By (Used In) Operating Activities	580	663
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(307)	(333)
Purchase of Emissions Allowances and RECs	(15)	(16)
Proceeds from Sales of Available-for-Sale Securities	259	183
Investments in Available-for-Sale Securities	(268)	(188)
Short-Term Loan—Affiliated Company, net	(70)	(309)
Other	7	4
Net Cash Provided By (Used In) Investing Activities	(394)	(659)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	(175)	—
Other	(4)	—
Net Cash Provided By (Used In) Financing Activities	(179)	—
Net Increase (Decrease) in Cash and Cash Equivalents	7	4
Cash and Cash Equivalents at Beginning of Period	11	12
Cash and Cash Equivalents at End of Period	$ 18	$ 16
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 19	$ (100)
Interest Paid, Net of Amounts Capitalized	$ 5	$ 11
Accrued Property, Plant and Equipment Expenditures	$ 205	$ 116

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

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Note 1. Organization and Basis of Presentation

Organization

Public Service Enterprise Group Incorporated (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Public Service Electric and Gas Company (PSE&G)**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- **PSEG Power LLC (Power)**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses through competitive energy sales in well-developed energy markets and fuel supply functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2016.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2016.

Note 2. Recent Accounting Standards

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard clarifies the principles for recognizing revenue and removes inconsistencies in revenue recognition requirements; improves comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provides improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early application is permitted. PSEG expects the new guidance to result in more detailed disclosures of revenue compared to current guidance, and possible changes in presentation. PSEG continues to evaluate all of its revenue streams and its contracts. Certain implementation issues are currently being finalized by the AICPA's Revenue Recognition Working Group and the FASB's Transition Resource Group, including the ability to recognize revenue for certain contracts where there is uncertainty regarding

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collection from customers and accounting for contributions in aid of construction. Upon formal resolution of the implementation issues noted above, PSEG will elect its transition method.

Recognition and Measurement of Financial Assets and Financial Liabilities

This accounting standard will change how entities measure equity investments that are not consolidated or accounted for under the equity method. Under the new guidance, equity investments (other than those accounted for using the equity method) will be measured at fair value through Net Income instead of Other Comprehensive Income (Loss). Entities that have elected the fair value option for financial liabilities will present changes in fair value due to a change in their own credit risk through Other Comprehensive Income (Loss). For equity investments which do not have readily determinable fair values, the impairment assessment will be simplified by requiring a qualitative assessment to identify impairments. The new standard also changes certain disclosures.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG is currently analyzing the impact of this standard on its financial statements; however, PSEG expects increased volatility in Net Income due to changes in fair value of its equity securities within the nuclear decommissioning (NDT) and Rabbi Trust Funds.

Leases

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor will classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. However, existing guidance related to leveraged leases will not change.

The standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Measurement of Credit Losses on Financial Instruments

This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however, this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments

This accounting standard reduces the diversity in practice in how certain cash receipts and cash payments are presented and classified in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt early, including in an interim period. PSEG is currently analyzing the impact of this standard on its financial statements.

Statement of Cash Flows: Restricted Cash

This accounting standard requires entities to explain the change during the period in the total of cash and cash equivalents and include amounts described as restricted cash or restricted cash equivalents in their reconciliation of beginning-of-period and end-of-period amounts in the Statement of Cash Flows.

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The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt early, including in an interim period. PSEG is currently analyzing the impact of this standard on its financial statements including its future disclosure requirements.

Business Combinations: Clarifying the Definition of a Business

This accounting standard was issued mainly to provide more consistency in how the definition of a business is applied to acquisitions or dispositions. The new guidance will generally reduce the number of transactions that will require treatment as a business combination. The definition of a business now includes a filter that would consider whether substantially all the fair value of the gross assets acquired or disposed of is concentrated in a single identifiable asset or a group of similar identifiable assets. If this condition is met, the transaction would not qualify as a business.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt it for transactions that have closed before the effective date but have not been reported in financial statements that have been issued or made available for issuance. PSEG does not have any current transactions impacted by this guidance and expects future acquisitions of individual solar plants will not qualify as business combinations. PSEG does not expect this guidance to materially impact its financial statements upon adoption.

Simplifying the Test for Goodwill Impairment

This accounting standard requires an entity to perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

An entity should apply this standard on a prospective basis and will be required to disclose the nature of and reason for the change in accounting principle upon transition. The new standard is effective for impairment tests for periods beginning January 1, 2020. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. PSEG is currently assessing the impact of this guidance upon its financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (OPEB)

This accounting standard was issued to improve the presentation of net periodic pension cost and net periodic OPEB cost.

Under the new guidance, entities are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by their employees during the period. The other components of net benefit cost are required to be presented in the Statement of Operations separately from the service cost component after Operating Income. Additionally, only the service cost component will be eligible for capitalization, when applicable.

The standard requires the amendments to be applied retrospectively for the presentation of the service cost component and the other cost components of net periodic pension cost and net periodic OPEB cost in the Statement of Operations and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension and OPEB costs.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early adoption is permitted for an entity in any interim or annual period. PSEG is currently analyzing the impact of this standard on its financial statements.

Premium Amortization on Purchased Callable Debt Securities

This accounting standard was issued to shorten the amortization period for certain callable debt securities held at a premium. Specifically, the standard requires the premium to be amortized to the earliest call date. The amendments do not require an accounting change for securities held at a discount; the discount continues to be amortized to maturity.

The standard is effective for annual and interim reporting periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period. If an entity early adopts the standard in an interim period, any
adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity should apply this standard on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. Additionally, in the period of adoption, an entity should provide disclosures about a change in accounting principle.

PSEG is currently analyzing the impact of this standard on its financial statements.

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Note 3. Early Plant Retirements

Fossil

In October 2016, Power determined that it would cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. Power has filed deactivation notices with PJM for these existing units at both stations and final must-offer exception requests for the 2020-2021 PJM capacity auction to the PJM Independent Market Monitor. Power expects the units to continue to be available to generate electricity and receive previously cleared capacity payments through the date the units cease operations.

In the latter half of 2016, PSEG and Power recognized pre-tax charges in Energy Costs and Operation and Maintenance (O&M) of $62 million and $53 million, respectively, related to coal inventory adjustments, capacity penalties, materials and supplies inventory reserve adjustments for parts that cannot be used at other generating units, employee-related severance benefits costs and construction work in progress impairments, among other shut down items. In addition to these charges, Power recognized Depreciation and Amortization (D&A) during 2016 of $571 million due to the significant shortening of the expected economic useful lives of Hudson and Mercer.

In the first quarter of 2017, Power recognized total D&A of $574 million and expects to recognize additional total D&A of $389 million in 2017 for the Hudson and Mercer units. Power also recognized pre-tax charges in Energy Costs of $7 million primarily for coal inventory lower of cost or market adjustments. Power currently anticipates using the sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such environmental remediation are neither currently probable nor estimable but may be material.

As of December 31, 2016, Power had reduced the estimated useful life of Bridgeport Harbor Station unit 3 (BH3) from 2025 to the summer of 2021 as it was more likely than not it will retire the unit by this time. The change in the estimated useful life is not expected to have a material impact on Power's future financial results.

PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Nuclear

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. This situation is generally due to low natural gas prices, and the related decline in market prices of energy, resulting from the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities and both federal and state-level policies that provide financial incentives to renewable energy such as wind and solar, but generally do not apply to nuclear generating stations. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet and greater reliance on natural gas pipelines for fuel delivery.

If trends noted above continue or worsen, Power's nuclear generating units could cease being economically competitive which may cause Power to retire such units prior to the end of their useful lives. The costs associated with any such retirement, which may include, among other things, accelerated D&A or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs, and additional funding of the NDT Fund will likely have a material adverse impact on PSEG's and Power's future financial results. PSEG and Power continue to advocate for sound policies that recognize nuclear power as a source of reliable and clean energy and an important part of a diverse and reliable energy portfolio.

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The following table provides the balance sheet amounts by generating station as of March 31, 2017 for significant assets and liabilities associated with Power's owned share of its nuclear assets.

	As of March 31, 2017			
	Hope Creek	Salem	Support Facilities and Other (A)	Peach Bottom
	Millions			
Assets				
Materials and Supplies Inventory	$ 82	$ 86	$ —	$ 39
Nuclear Production, net of Accumulated Depreciation	456	545	208	774
Nuclear Fuel In-Service, net of Accumulated Depreciation	152	77	—	142
Construction Work in Progress (including nuclear fuel)	156	137	12	26
Total Assets	$ 846	$ 845	$ 220	$ 981
Liability				
Asset Retirement Obligation	$ 144	$ 157	$ —	$ 159
Total Liabilities	$ 144	$ 157	$ —	$ 159
Net Assets	$ 702	$ 688	$ 220	$ 822
NRC License Renewal Term	2046	2036/2040	—	2033/2034
% Owned	100%	57%	—	50%

(A) Includes Hope Creek's and Salem's shared support facilities and other nuclear development capital.

The precise timing of any potential early retirement and resulting financial statement impact may be affected by a number of factors, including co-owner considerations, the results of any transmission system reliability study assessments and decommissioning trust fund requirements and other commitments, as well as future energy prices. Power maintains a NDT Fund that funds its decommissioning obligations. See Note 7. Available-for-Sale Securities.

Note 4. Variable Interest Entity (VIE)

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and O&M Expense, respectively. Servco recorded $112 million and $98 million for the three months ended March 31, 2017 and 2016, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

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Note 5. Rate Filings

This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2016.

In addition to items previously reported in the Annual Report on Form 10-K, significant regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

Energy Strong Recovery Filing—In March 2017, PSE&G filed its Energy Strong electric and gas cost recovery petition seeking BPU approval to recover the revenue requirements associated with Energy Strong capitalized investment costs associated with electric and gas plant investments under the program that is anticipated to be in service by May 31, 2017. The petition requests rates to be effective September 1, 2017, consistent with the BPU Order of approval of the Energy Strong Program. The annualized requested increase in revenue requirement is approximately $22 million for electric and $3 million for gas. This matter is pending.

Green Program Recovery Charges—In March 2017, the BPU gave final approval to PSE&G's petition to recover approximately $37 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved programs. The rates are effective May 1, 2017. This Order also included the return of approximately $5 million in remaining overcollections from the completed Securitization Transition Charge.

Weather Normalization Clause—In April 2017, the BPU gave final approval to PSE&G's petition to collect $54 million in net deficiency gas revenues as a result of the warmer than normal 2015-2016 Winter Period.

Note 6. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with solar renewable energy certificates generated from the installed solar electric system. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Outstanding Loans by Class of Customer

Consumer Loans	As of March 31, 2017	As of December 31, 2016
	Millions	
Commercial/Industrial	$ 168	$ 164
Residential	11	11
Total	**$ 179**	**$ 175**

Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third-party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

During the third quarter of 2016, Energy Holdings completed its annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases. The outcome indicated that the revised residual value estimates were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM, as discussed in Note 3. Early Plant Retirements, negatively impacting the economic

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outlook of the leased assets. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016, calculated by comparing the gross investment in the leases before and after the revised residual estimates. During the fourth quarter of 2016, Energy Holdings recorded a $10 million pre-tax charge for its best estimate of loss related to the leveraged leases as a result of the current liquidity issues facing REMA, which was reflected in Operating Revenues and is included in Gross Investments in Leases as of December 31, 2016.

During the first quarter of 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as certain recent discussions with REMA management, Energy Holdings recorded an additional $55 million pre-tax charge for its current best estimate of loss related to the lease investments, which was reflected in Operating Revenues and is included in Gross Investments in Leases as of March 31, 2017.

The following table shows Energy Holdings' gross and net lease investment as of March 31, 2017 and December 31, 2016, respectively.

	As of March 31, 2017	As of December 31, 2016
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 574	$ 629
Estimated Residual Value of Leased Assets	346	346
Total Investment in Rental Receivables	920	975
Unearned and Deferred Income	(324)	(326)
Gross Investment in Leases	596	649
Deferred Tax Liabilities	(640)	(674)
Net Investment in Leases	**$ (44)**	**$ (25)**

The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

Counterparties' Credit Rating Standard & Poor's (S&P) as of March 31, 2017	Lease Receivables, Net of Non-Recourse Debt As of March 31, 2017
	Millions
AA	$ 16
BBB+ — BBB-	316
BB-	133
CCC-	109
Total	**$ 574**

The "BB-" and the "CCC-" ratings in the preceding table represent lease receivables related to coal and gas-fired assets in Illinois and Pennsylvania, respectively. As of March 31, 2017, the gross investment in the leases of such assets, net of non-recourse debt, was $371 million ($(154) million, net of deferred taxes). A more detailed description of such assets under lease, as of March 31, 2017, is presented in the following table.

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Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 83	64%	1,036	Gas	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 26	17%	1,711	Coal	CCC- (A)	REMA
Conemaugh Station Units 1 and 2	PA	$ 29	17%	1,711	Coal	CCC- (A)	REMA
Shawville Station Units 1, 2, 3 and 4	PA	$ 99	100%	596	Gas	CCC- (A)	REMA

(A) REMA's parent company, GenOn Energy Inc. (GenOn), reported in August 2016 that GenOn did not expect to have sufficient liquidity to repay its senior unsecured notes due in June 2017. In January 2017, S&P further lowered its corporate credit rating on GenOn and its affiliates (including REMA) to "CCC-" from "CCC" reflecting the primary credit concern of the near-term maturity of GenOn's senior unsecured notes in June 2017 and expressed a negative outlook reflecting the continuing pressure on financial measures. In October 2016, Moody's downgraded the GenOn Corporate Family Rating to "Caa3" to reflect its high debt burden relative to cash flow.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease structures. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital and trigger certain material tax obligations which could wholly or partially be mitigated by tax indemnification claims against the counterparty. A bankruptcy of a lessee would likely delay and potentially limit any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's efforts to restructure its portfolio and improve its liquidity and the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments. If lease rejections or foreclosures were to occur, Energy Holdings could potentially record additional pre-tax write-offs up to its gross investment in these facilities and may also be required to pay material cash tax liabilities to the Internal Revenue Service.

Additional factors that may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and their affiliates and the quality and condition of assets under lease.

Note 7. Available-for-Sale Securities

NDT Fund

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The funds are managed by third-party investment managers who operate under investment guidelines developed by Power.

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Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of March 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 717	$ 297	$ (7)	$ 1,007
Debt Securities				
Government	515	8	(6)	517
Corporate	342	5	(4)	343
Total Debt Securities	857	13	(10)	860
Other Securities	46	—	—	46
Total NDT Available-for-Sale Securities	**$ 1,620**	**$ 310**	**$ (17)**	**$ 1,913**

	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 705	$ 263	$ (11)	$ 957
Debt Securities				
Government	518	8	(6)	520
Corporate	337	4	(4)	337
Total Debt Securities	855	12	(10)	857
Other Securities	44	—	—	44
Total NDT Available-for-Sale Securities (A)	**$ 1,604**	**$ 275**	**$ (21)**	**$ 1,858**

(A) The NDT available-for-sale securities table excludes cash of $1 million which is part of the NDT Fund.

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of March 31, 2017	As of December 31, 2016
	Millions	
Accounts Receivable	$ 15	$ 8
Accounts Payable	$ 4	$ 5

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The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of March 31, 2017				As of December 31, 2016			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 80	$ (6)	$ 4	$ (1)	$ 120	$ (10)	$ 8	$ (1)
Debt Securities								
Government (B)	276	(6)	4	—	276	(6)	4	—
Corporate (C)	125	(3)	9	(1)	139	(3)	15	(1)
Total Debt Securities	401	(9)	13	(1)	415	(9)	19	(1)
NDT Available-for-Sale Securities	**$ 481**	**$ (15)**	**$ 17**	**$ (2)**	**$ 535**	**$ (19)**	**$ 27**	**$ (2)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of March 31, 2017.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. Power also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2017.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2017.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended March 31,	
	2017	2016
	Millions	
Proceeds from NDT Fund Sales (A)	**$ 247**	**$ 177**
Net Realized Gains (Losses) on NDT Fund:		
Gross Realized Gains	$ 21	$ 15
Gross Realized Losses	(4)	(16)
Net Realized Gains (Losses) on NDT Fund	**$ 17**	**$ (1)**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $149 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of March 31, 2017.

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The NDT available-for-sale debt securities held as of March 31, 2017 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 16
1 - 5 years	257
6 - 10 years	199
11 - 15 years	59
16 - 20 years	63
Over 20 years	266
Total NDT Available-for-Sale Debt Securities	**$ 860**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the three months ended March 31, 2017, Other-Than-Temporary Impairments (OTTI) of $1 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of March 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 22	$ —	$ —	$ 22
Debt Securities				
Government	99	—	(1)	98
Corporate	99	1	(1)	99
Total Debt Securities	198	1	(2)	197
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 222**	**$ 1**	**$ (2)**	**$ 221**

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	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 11	$ 11	$ —	$ 22
Debt Securities				
Government	105	—	(2)	103
Corporate	92	1	(2)	91
Total Debt Securities	197	1	(4)	194
Other Securities	1	—	—	1
Total Rabbi Trust Available-for-Sale Securities	**$ 209**	**$ 12**	**$ (4)**	**$ 217**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of March 31, 2017	As of December 31, 2016
	Millions	
Accounts Receivable	$ 1	$ 5
Accounts Payable	$ 1	$ 3

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months.

	As of March 31, 2017				As of December 31, 2016			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government (B)	53	(1)	1	—	60	(2)	1	—
Corporate (C)	36	(1)	3	—	46	(2)	3	—
Total Debt Securities	89	(2)	4	—	106	(4)	4	—
Rabbi Trust Available-for-Sale Securities	**$ 89**	**$ (2)**	**$ 4**	**$ —**	**$ 106**	**$ (4)**	**$ 4**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. PSEG also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2017.

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(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2017.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended March 31,	
	2017	2016
	Millions	
Proceeds from Rabbi Trust Sales (A)	**$ 51**	**$ 25**
Net Realized Gains (Losses) on Rabbi Trust:		
Gross Realized Gains	$ 15	$ 1
Gross Realized Losses	(3)	(1)
Net Realized Gains (Losses) on Rabbi Trust	**$ 12**	**$ —**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in the Condensed Consolidated Statements of Operations. Net unrealized losses of $(1) million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of March 31, 2017.

The Rabbi Trust available-for-sale debt securities held as of March 31, 2017 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 6
1 - 5 years	50
6 - 10 years	42
11 - 15 years	9
16 - 20 years	8
Over 20 years	82
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 197**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the three months ended March 31, 2017, no OTTIs were recognized on securities in the Rabbi Trust. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of March 31, 2017	As of December 31, 2016
	Millions	
PSE&G	$ 44	$ 43
Power	55	53
Other	122	121
Total Rabbi Trust Available-for-Sale Securities	**$ 221**	**$ 217**

Note 8. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria.

As of December 31, 2016, PSEG merged its three qualified defined benefit pension plans (excluding Servco plans) into one plan, thereby also merging all of the pension plans' assets. As a result, as of March 31, 2017, the total net periodic benefit costs decreased by approximately $12 million, net of amounts capitalized, as compared to the 2017 amounts that would have been recognized had the plans not been merged. This is due to the amortization period for gains and losses for the merged plan resulting in lower amortization than that of the individual plans. No changes were made to the benefit formulas, vesting provisions, or to the employees covered by the plans.

The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis for PSEG, except for Servco.

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2017	2016	2017	2016
	Millions			
Components of Net Periodic Benefit Costs				
Service Cost	$ 29	$ 27	$ 4	$ 4
Interest Cost	51	50	16	15
Expected Return on Plan Assets	(98)	(98)	(8)	(8)
Amortization of Net				
Prior Service Cost (Credit)	(5)	(4)	(3)	(3)
Actuarial Loss	24	39	13	10
Total Benefit Costs	**$ 1**	**$ 14**	**$ 22**	**$ 18**

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Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, except for Servco, are detailed as follows:

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2017	2016	2017	2016
	Millions			
PSE&G	$ (1)	$ 7	$ 14	$ 11
Power	—	4	7	6
Other	2	3	1	1
Total Benefit Costs	**$ 1**	**$ 14**	**$ 22**	**$ 18**

During the three months ended March 31, 2017, PSEG contributed its entire planned contribution for the year 2017 of $14 million into its OPEB plan.

Servco Pension and OPEB

At the direction of LIPA, Servco sponsors benefit plans that cover its current and former employees who meet certain eligibility criteria. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 4. Variable Interest Entity. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco plans to contribute $35 million into its pension plan trusts during 2017. Servco's pension-related revenues and costs were $9 million and $6 million for the three months ended March 31, 2017 and 2016, respectively. The OPEB-related revenues earned and costs incurred for the three months ended March 31, 2017 were $1 million and were immaterial for the three months ended March 31, 2016.

Note 9. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees as a form of collateral.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and

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- the net position of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. Current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of March 31, 2017 and December 31, 2016.

	As of March 31, 2017	As of December 31, 2016
	Millions	
Face Value of Outstanding Guarantees	$ 1,886	$ 1,806
Exposure under Current Guarantees	$ 151	$ 139
Letters of Credit Margin Posted	$ 183	$ 157
Letters of Credit Margin Received	$ 104	$ 99
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (1)	$ (1)
Net Broker Balance Deposited (Received)	$ 61	$ 57
Additional Amounts Posted:		
Other Letters of Credit	$ 69	$ 51

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 11. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline and a $21 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. As previously announced, Power is currently in the process of selling its minority equity interest in PennEast and upon disposition, PSEG's $106 million guarantee would terminate. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit.

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Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA determined that there was a need to perform a comprehensive study of the entire 17 miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than with respect to their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. Construction is complete. The CPG is awaiting EPA approval of the construction report, long-term monitoring plan and confirmatory sampling plan. PSE&G's and Power's combined share of the cost of that effort is approximately three percent. The remaining CPG members, PSE&G and Power included, have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS sets forth various alternatives for remediating this portion of the Passaic River.

The CPG, which consisted of 52 members as of March 31, 2017, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost of the RI/FS is approximately $190 million, which the CPG continues to incur. Of the estimated $190 million, as of March 31, 2017, the CPG had spent approximately $160 million, of which PSEG's total share was approximately $11 million.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River. It set forth the CPG's estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion on an undiscounted basis. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranged from approximately $518 million to $772 million. Based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimated share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

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In March 2016, the EPA released its Record of Decision (ROD) for the FFS which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The ROD Remedy requires a bank-to-bank dredge ranging from approximately 5 to 30 feet deep in the federal navigation channel from River Mile 0 to River Mile 1.7 and an approximately 2.5 foot deep dredge everywhere else in the lower 8.3 miles of the river. An engineered cap approximately two feet thick will be placed over the dredged areas. Dredged sediments will be transported to facilities and landfills out-of-state. The EPA estimates the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation.

Based upon the estimated cost of the ROD Remedy, PSEG's estimate of PSE&G's and Power's shares of that cost, and the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued an additional $36 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued an additional $8 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2016. As of March 31, 2017, these accruals bring the total liability to approximately $57 million, $46 million applicable to PSE&G and $11 million applicable to Power.

Also in March 2016, the EPA sent a notice letter to 105 PRPs, including PSE&G, all other past and present members of the CPG, including Occidental Chemical Corporation (OCC), and the towns of Newark, Kearny and Harrison and the Passaic Valley Sewerage Commission stating that the EPA wants to determine whether OCC, a successor company to Diamond Shamrock, would voluntarily perform the remedial design for the ROD Remedy. On September 30, 2016, OCC and the EPA executed an Administrative Settlement Agreement and Order on Consent for Remedial Design under which OCC agreed to conduct the remedial design for the ROD. With OCC's commitment to perform the remedial design, it is anticipated that the EPA will begin negotiation of a remedial action consent decree, under which OCC and the other "major PRPs" will implement and/or pay for the EPA's ROD Remedy for the lower 8.3 miles. The EPA has not defined "major PRPs."

In June 2016, Tierra and Maxus, successors to Diamond Shamrock, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Maxus and Tierra are subsidiaries of YPF Holdings, Inc. (YPF Holdings). YPF Holdings is a wholly owned subsidiary of YPF S.A. (YPF), a company controlled by the Argentinian government. Neither YPF Holdings nor YPF is a party to the bankruptcy proceedings. However, Tierra and Maxus have filed a plan of liquidation that may allow the parties to assert one or more causes of action to hold YPF responsible for certain amounts owed by Tierra and Maxus. PSEG cannot currently determine the impact, if any, that the bankruptcy of Tierra and Maxus or any related proceeding might have on its allocable share or total liability for the Passaic River matter, and therefore, PSEG, through the CPG and independently, will continue to monitor the bankruptcy proceedings to identify any potential impact on PSEG's share of the costs.

In March 2017, the EPA sent a letter to 20 PRPs, that are considered by the EPA to have minimal responsibility for the Passaic River's contamination, offering "cash-out" settlements in return for payments by each PRP of $280,600. The PRPs that settle will be released from their CERCLA remediation liability for the lower 8.3 miles of the lower Passaic River. It is unclear how the EPA made that determination or how many PRPs will accept the proposal. The settlement is subject to a 30 day public comment period that has not yet commenced. The impact of this settlement on PSEG's responsibility for the remediation of the lower 8.3 miles is not material.

The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on PSEG's financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and

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will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $386 million and $443 million through 2021, including its $46 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $386 million as of March 31, 2017. Of this amount, $74 million was recorded in Other Current Liabilities and $312 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $386 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly. NJDEP, PSEG and EPA representatives have had discussions regarding whether sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In May 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the best technology available for minimizing adverse environmental impacts of each facility that seeks a permit renewal, the rule requires that facilities conduct a wide range

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of studies related to impingement mortality and entrainment and submit the results with their permit applications.

In September 2014, several environmental non-governmental groups and certain energy industry groups filed petitions for review of the rule and the case has been assigned to the U.S. Second Circuit Court of Appeals (Second Circuit). Environmental organizations, including but not limited to the environmental petitioners in the Second Circuit, have also filed suit under the Endangered Species Act. The cases were subsequently consolidated at the Second Circuit and a decision is expected by mid-2017.

In June 2016, the NJDEP issued a final NJPDES permit for Salem with an effective date of August 1, 2016. The final permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the Clean Water Act, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final permit for Salem. The Riverkeeper's filing does not change the effective date of the permit. If the Riverkeeper's challenge were successful, Power may be required to incur additional costs to comply with the Clean Water Act. Such service water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

State permitting decisions at Bridgeport and possibly New Haven could also have a material impact on Power's ability to renew permits at its existing larger once-through cooled plants without making significant upgrades to existing intake structures and cooling systems.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at BH3. To address compliance with the EPA's Clean Water Act Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, Power would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the previously estimated useful life ending in 2025. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in 2017. See Note 3. Early Plant Retirements.

Separately, Power has also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut and local community organizations. That CEBA provides that Power would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. The receipt of permits to allow construction and operation of the new facility could occur in 2017. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power may seek to operate BH3 through the previously estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. The Connecticut Siting Council issued an order to approve siting BH5. All major environmental permits have been obtained. Operations are expected to begin in mid-2019.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.

Jersey City, New Jersey Subsurface Feeder Cable Matter

In early October 2016, a discharge of dielectric fluid from subsurface feeder cables located in the Hudson River near Jersey City, New Jersey, was identified and reported to the NJDEP. The feeder cables are located within a subsurface easement granted to PSE&G by the property owners, Newport Associates Development Company (NADC) and Newport Associates Phase I Developer Limited Partnership. The feeder cables are subject to agreements between PSE&G and Consolidated Edison Company of New York, Inc. (Con Edison) and are jointly owned by PSE&G and Con Edison, with PSE&G owning the portion of the cables located in New Jersey and Con Edison owning the portion of the cables located in New York. The NJDEP has declared an emergency and an emergency response action has been undertaken to investigate, contain, remediate and stop the fluid discharge; to assess, repair and restore the cables to good working order; and to restore the property. The regulatory agencies overseeing the emergency response, including the U.S. Coast Guard, the NJDEP and the Army Corps of Engineers, have issued multiple notices, orders and directives to the various parties related to this matter. The investigation and response actions related to the fluid discharge are ongoing. The investigation of the discharge and its potential cause is in the preliminary

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stages, making it difficult to determine the timing and potential costs to resolve this matter, as well as responsibility for such costs between PSE&G, Con Edison and NADC. Based on currently available information and the potential scope of the necessary repair and remediation work, the costs will likely be material. In addition, the timeline for completing the repairs has been extended due to the presence of debris within PSE&G's easement. In November 2016, PSE&G filed an action in New Jersey Federal Court seeking an order requiring NADC to remove its debris from PSE&G's easement so that PSE&G and Con Edison may comply with NJDEP and U.S. Coast Guard directives and complete the necessary repairs. NADC subsequently informed PSE&G that it would comply with the U.S. Coast Guard's order and undertake debris removal activities so that PSE&G and Con Edison can complete the necessary repairs. NADC's debris removal activities are ongoing.

Steam Electric Effluent Guidelines

In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG Rule) for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges and that are regulated under this rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the rule. Power is unable to predict if this rule will have a material impact on its future capital requirements, financial condition and results of operations.

In April 2017, the EPA announced that it had granted a petition for reconsideration of the ELG Rule and is acting promptly to issue an administrative stay of the compliance dates in the rule that have not yet passed pending judicial review. The deadlines that are expected to be stayed include the BAT limitations and pretreatment standards for each of the following waste streams: fly ash transport water, bottom ash transport water, flue gas desulfurization wastewater, flue gas mercury control wastewater, and gasification wastewater. Power is unable to determine how this will ultimately impact compliance requirements or the financial impact it may have on the company.

Coal Combustion Residuals (CCRs)

On December 19, 2014, the EPA issued a final rule that regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Power's Hudson and Mercer generating stations, along with its co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 19, 2015. Accordingly in June 2015, Power recorded an additional asset retirement obligation to comply with the final CCR rule which was not material to Power's results of operations, financial condition or cash flows.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2016 is $276.83 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2016 of $335.33 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

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PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2014	2015	2016	2017	
36-Month Terms Ending	May 2017	May 2018	May 2019	May 2020	(A)
Load (MW)	2,800	2,900	2,800	2,800	
$ per MWh	$97.39	$99.54	$96.38	$90.78	

(A) Prices set in the 2017 BGS auction year will become effective on June 1, 2017 when the 2014 BGS auction agreements expire.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 18. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2018 and a significant portion through 2021 at Salem, Hope Creek and Peach Bottom.

Power has various multi-year contracts for natural gas and firm pipeline transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess pipeline capacity available beyond the needs of PSE&G's customers, Power can use the gas to make third-party sales and if excess volume remains after the third-party sales, supply its fossil generating stations in New Jersey.

Power also has various long-term fuel purchase commitments for coal through 2019 to support its fossil generation stations.

As of March 31, 2017, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2021
	Millions
Nuclear Fuel	
Uranium	$ 301
Enrichment	$ 359
Fabrication	$ 192
Natural Gas	$ 1,101
Coal	$ 181

Regulatory Proceedings

FERC Compliance

PJM Bidding Matter

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist

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in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power has implemented procedures to mitigate the risk of similar issues occurring in the future. During the three months ended March 31, 2014, based upon its best estimate available at the time, Power recorded a pre-tax charge to income in the amount of $25 million related to this matter.

Since September 2014, FERC Staff has been conducting a preliminary, non-public staff investigation into these matters. While considerable uncertainty remains as to the final resolution of these matters, based upon recent developments in the investigation, Power believes the disgorgement and interest costs related to the cost-based bidding matter may range between approximately $35 million and $135 million, depending on the legal interpretation of the principles under the PJM Tariff, plus penalties. Since no point within this range is more likely than any other, Power has accrued the low end of this range of $35 million by recording an additional pre-tax charge to income of $10 million during the three months ended March 31, 2017. Power is unable to reasonably estimate the range of possible loss, if any, for the quantity of energy offered matter or the penalties that FERC would impose relating to either the cost-based bidding or quantity of energy matter. However, any of these amounts could be individually material to PSEG and Power.

Power continues to believe that it has legal defenses that it may assert in a judicial challenge, including the legal defense that its cost-based bidding in a substantial majority of the hours was below the allowed rate under the Tariff and therefore any errors in those hours did not violate the Tariff or were immaterial. Furthermore, it is unclear whether the quantity of energy offered violated any legal requirement. As a result, PSEG and Power cannot predict the final outcome of these matters.

Financial Transmission Rights (FTR) Auction Matter

In January 2017, ER&T received requests from the FERC Office of Enforcement relating to the planning and implementation of ER&T's participation in the annual FTR auction in PJM for the 2016-2017 planning year and the monthly FTR auctions in PJM for February, March and April 2016. PSEG is cooperating with FERC in this matter. PSEG cannot predict the outcome of this matter at this time.

Note 10. Debt and Credit Facilities

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

In March 2017, PSEG, Power and PSE&G amended their credit agreements, extending the expiration dates to March 2022. Concurrently, PSEG increased its existing $1 billion in credit facilities to $1.5 billion, Power decreased its existing $2.6 billion in credit facilities to $2.1 billion, which includes two new 3-year $100 million letter of credit facilities that expire in March 2020.

The commitments under the $4.2 billion credit facilities are provided by a diverse bank group. As of March 31, 2017, the total available credit capacity was $3.6 billion.

As of March 31, 2017, no single institution represented more than 8% of the total commitments in the credit facilities.

As of March 31, 2017, the total credit capacity was in excess of its anticipated maximum liquidity requirements.

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Each of the credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support its subsidiaries' liquidity needs. The total credit facilities and available liquidity as of March 31, 2017 were as follows:

	As of March 31, 2017				
Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
		Millions			
PSEG					
5-year Credit Facilities (A)	$ 1,500	$ 332	$ 1,168	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSEG	**$ 1,500**	**$ 332**	**$ 1,168**		
PSE&G					
5-year Credit Facility (A)	$ 600	$ 14	$ 586	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 14**	**$ 586**		
Power					
3-year LC Facilities	$ 200	$ 137	$ 63	Mar 2020	Letters of Credit
5-year Credit Facilities	1,900	98	1,802	Mar 2022	Funding/Letters of Credit
Total Power	**$ 2,100**	**$ 235**	**$ 1,865**		
Total	**$ 4,200**	**$ 581**	**$ 3,619**		

(A) The primary use of PSEG's and PSE&G's credit facilities is to support their respective Commercial Paper Programs, under which as of March 31, 2017, PSEG had $315 million outstanding at a weighted average interest rate of 1.25%. As of March 31, 2017, PSE&G had no amounts outstanding under its Commercial Paper Program.

Note 11. Financial Risk Management Activities

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchases and normal sales (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow or fair value hedges. Power and PSE&G enter into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of the derivative contracts are recorded in earnings.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

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Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. The changes in fair value of the interest rate swaps are fully offset by changes in the fair value of the underlying forecasted interest payments of the debt. There were no outstanding interest rate swaps as of March 31, 2017 or December 31, 2016. The fair value hedges reduced interest expense by $2 million for the three months ended March 31, 2016.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. As of March 31, 2017 and December 31, 2016, PSEG had interest rate hedges outstanding totaling $500 million. These hedges convert PSEG's $500 million variable rate term loan due November 2017 into a fixed rate loan. As of March 31, 2017 and December 31, 2016, the fair value of these hedges was $2 million and $1 million, respectively. There was no ineffectiveness as of March 31, 2017 and December 31, 2016.

The Accumulated Other Comprehensive Income (Loss) (after tax) related to existing and terminated interest rate derivatives designated as cash flow hedges was $2 million as of March 31, 2017 and December 31, 2016. The after-tax unrealized gains on these hedges expected to be reclassified to earnings during the next 12 months is $1 million.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with PSEG's accounting policy, these positions are offset on the Condensed Consolidated Balance Sheets of Power and PSEG.

The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of March 31, 2017					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 525	$ (414)	$ 111	$ 1	$ 2	$ 114
Noncurrent Assets	264	(171)	93	—	—	93
Total Mark-to-Market Derivative Assets	**$ 789**	**$ (585)**	**$ 204**	**$ 1**	**$ 2**	**$ 207**
Derivative Contracts						
Current Liabilities	$ (425)	$ 418	$ (7)	$ —	$ —	$ (7)
Noncurrent Liabilities	(168)	167	(1)	—	—	(1)
Total Mark-to-Market Derivative (Liabilities)	**$ (593)**	**$ 585**	**$ (8)**	**$ —**	**$ —**	**$ (8)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 196**	**$ —**	**$ 196**	**$ 1**	**$ 2**	**$ 199**

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	As of December 31, 2016					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 435	$ (273)	$ 162	$ —	$ 1	$ 163
Noncurrent Assets	122	(98)	24	—	—	24
Total Mark-to-Market Derivative Assets	**$ 557**	**$ (371)**	**$ 186**	**$ —**	**$ 1**	**$ 187**
Derivative Contracts						
Current Liabilities	$ (285)	$ 277	$ (8)	$ (5)	$ —	$ (13)
Noncurrent Liabilities	(98)	95	(3)	—	—	(3)
Total Mark-to-Market Derivative (Liabilities)	**$ (383)**	**$ 372**	**$ (11)**	**$ (5)**	**$ —**	**$ (16)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 174**	**$ 1**	**$ 175**	**$ (5)**	**$ 1**	**$ 171**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of March 31, 2017 and December 31, 2016. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of March 31, 2017 net cash collateral (received) paid was netted against the corresponding net derivative contract positions with $(4) million of cash collateral netted against noncurrent assets, and $4 million netted against current liabilities. As of December 31, 2016, net cash collateral (received) paid of $1 million was netted against the corresponding net derivative contract positions. Of the $1 million as of December 31, 2016, $(3) million was netted against noncurrent assets and $4 million was netted against current liabilities.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating by S&P or Moody's, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P or Moody's ratings. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $13 million and $19 million as of March 31, 2017 and December 31, 2016, respectively. As of March 31, 2017 and December 31, 2016, Power had the contractual right of offset of $7 million and $9 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $6 million and $10 million as of March 31, 2017 and December 31, 2016, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.

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The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended March 31, 2017 and 2016.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended March 31, 2017	2016	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended March 31, 2017	2016
	Millions			Millions	
PSEG					
Interest Rate Swaps	—	3	Interest Expense	—	—
Total PSEG	**$ —**	**$ 3**		**$ —**	**$ —**

There were no pre-tax gain (loss) recognized in income on derivatives (ineffective portion) as of March 31, 2017 and 2016.

The following reconciles the AOCI for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2015	**$ —**	**$ —**
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	—	—
Balance as of December 31, 2016	**$ 3**	**$ 2**
Gain Recognized in AOCI	—	—
Less: Gain Reclassified into Income	—	—
Balance as of March 31, 2017	**$ 3**	**$ 2**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS for the three months ended March 31, 2017 and 2016. Power's derivative contracts reflected in this table include contracts to hedge the purchase and sale of electricity and natural gas, and the purchase of fuel. The table does not include contracts for which Power has designated as NPNS, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives Three Months Ended March 31, 2017	2016
		Millions	
PSEG and Power			
Energy-Related Contracts	Operating Revenues	$ 83	$ 216
Energy-Related Contracts	Energy Costs	(5)	2
Total PSEG and Power		**$ 78**	**$ 218**

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The following reflects the gross volume, on an absolute value basis, of derivatives as of March 31, 2017 and December 31, 2016.

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of March 31, 2017					
Natural Gas	Dekatherm (Dth)	357	—	355	2
Electricity	MWh	346	—	346	—
Financial Transmission Rights (FTRs)	MWh	5	—	5	—
Interest Rate Swaps	U.S. Dollars	500	500	—	—
As of December 31, 2016					
Natural Gas	Dth	357	—	348	9
Electricity	MWh	323	—	323	—
FTRs	MWh	9	—	9	—
Interest Rate Swaps	U.S. Dollars	500	500	—	—

Credit Risk

Credit risk relates to the risk of loss that Power would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG has established credit policies that it believes significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of March 31, 2017, 98% of the net credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives, NPNS and non-derivatives).

The following table provides information on Power's credit risk from others, net of collateral, as of March 31, 2017. It further delineates that exposure by the credit rating of the counterparties, which is determined by the lowest rating from S&P, Moody's or an internal scoring model. In addition, it provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade	$ 433	$ 94	$ 339	1	$ 202	(A)
Non-Investment Grade	9	1	8	—	—	
Total	**$ 442**	**$ 95**	**$ 347**	**1**	**$ 202**	

(A) Represents net exposure of $202 million with PSE&G.

As of March 31, 2017, collateral held from counterparties where Power had credit exposure included $1 million in cash collateral and $94 million in letters of credit.

As of March 31, 2017, Power had 159 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the

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forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of March 31, 2017, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's BGS suppliers' credit exposure is calculated each business day. As of March 31, 2017, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

Note 12. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds, as well as natural gas futures contracts executed on NYMEX.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of March 31, 2017, these consisted primarily of certain electric load contracts and gas contracts.

Certain derivative transactions may transfer from Level 2 to Level 3 if inputs become unobservable and internal modeling techniques are employed to determine fair value. Conversely, measurements may transfer from Level 3 to Level 2 if the inputs become observable.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of March 31, 2017 and December 31, 2016, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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Description	Recurring Fair Value Measurements as of March 31, 2017			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 125	$ —	$ 125	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 205	$ (585)	$ 11	$ 774	$ 5
Interest Rate Swaps (C)	$ 2	$ —	$ —	$ 2	$ —
NDT Fund (D)					
Equity Securities	$ 1,007	$ —	$ 1,005	$ 2	$ —
Debt Securities—US Treasury	$ 223	$ —	$ —	$ 223	$ —
Debt Securities—Govt Other	$ 294	$ —	$ —	$ 294	$ —
Debt Securities—Corporate	$ 343	$ —	$ —	$ 343	$ —
Other Securities	$ 46	$ —	$ 46	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—US Treasury	$ 36	$ —	$ —	$ 36	$ —
Debt Securities—Govt Other	$ 62	$ —	$ —	$ 62	$ —
Debt Securities—Corporate	$ 99	$ —	$ —	$ 99	$ —
Other Securities	$ 2	$ —	$ 2	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (8)	$ 585	$ (6)	$ (585)	$ (2)
Interest Rate Swaps (C)	$ —	$ —	$ —	$ —	$ —
PSE&G					
Assets:					
Cash Equivalents (A)	$ 125	$ —	$ 125	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 1	$ —	$ —	$ —	$ 1
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—US Treasury	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Govt Other	$ 12	$ —	$ —	$ 12	$ —
Debt Securities—Corporate	$ 20	$ —	$ —	$ 20	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 204	$ (585)	$ 11	$ 774	$ 4
NDT Fund (D)					
Equity Securities	$ 1,007	$ —	$ 1,005	$ 2	$ —
Debt Securities—US Treasury	$ 223	$ —	$ —	$ 223	$ —
Debt Securities—Govt Other	$ 294	$ —	$ —	$ 294	$ —
Debt Securities—Corporate	$ 343	$ —	$ —	$ 343	$ —
Other Securities	$ 46	$ —	$ 46	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 6	$ —	$ 6	$ —	$ —

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Debt Securities—US Treasury	$	9	$	—	$	—	$	9	$	—
Debt Securities—Govt Other	$	15	$	—	$	—	$	15	$	—
Debt Securities—Corporate	$	25	$	—	$	—	$	25	$	—
Other Securities	$	—	$	—	$	—	$	—	$	—
Liabilities:										
Derivative Contracts:										
Energy-Related Contracts (B)	$	(8)	$	585	$	(6)	$	(585)	$	(2)

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Description	Recurring Fair Value Measurements as of December 31, 2016				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 186	$ (371)	$ 17	$ 533	$ 7
Interest Rate Swaps (C)	$ 1	$ —	$ —	$ 1	$ —
NDT Fund (D)					
Equity Securities	$ 957	$ —	$ 954	$ 3	$ —
Debt Securities—US Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 293	$ —	$ —	$ 293	$ —
Debt Securities—Corporate	$ 337	$ —	$ —	$ 337	$ —
Other Securities	$ 44	$ —	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—US Treasury	$ 37	$ —	$ —	$ 37	$ —
Debt Securities—Govt Other	$ 66	$ —	$ —	$ 66	$ —
Debt Securities—Corporate	$ 91	$ —	$ —	$ 91	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (16)	$ 372	$ (18)	$ (364)	$ (6)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ —	$ —	$ —	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—US Treasury	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Govt Other	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Corporate	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (5)	$ —	$ —	$ —	$ (5)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 186	$ (371)	$ 17	$ 533	$ 7
NDT Fund (D)					
Equity Securities	$ 957	$ —	$ 954	$ 3	$ —
Debt Securities—US Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 293	$ —	$ —	$ 293	$ —
Debt Securities—Corporate	$ 337	$ —	$ —	$ 337	$ —
Other Securities	$ 44	$ —	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—US Treasury	$ 9	$ —	$ —	$ 9	$ —
Debt Securities—Govt Other	$ 16	$ —	$ —	$ 16	$ —

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Debt Securities—Corporate	$ 23	$ —	$ —	$ 23	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (11)	$ 372	$ (18)	$ (364)	$ (1)

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(A) Represents money market mutual funds.

(B) Level 1— During 2016 a net fair value of $1 million relating to energy-related contracts was transferred from Level 2 into Level 1. These contracts represent natural gas futures contracts executed on NYMEX, and are being valued solely on settled pricing inputs which come directly from the exchange.

Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using settled prices from an exchange, such as NYMEX, ICE and Nodal Exchange, or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The fair value measurement tables exclude an immaterial amount of cash as of March 31, 2017 and $1 million as of December 31, 2016, which is part of the NDT Fund. The NDT Fund maintains investments in various equity and fixed income securities classified as “available for sale.” The Rabbi Trust maintains investments in a Russell 3000 index fund and various fixed income securities classified as “available for sale” as of March 31, 2017. The Rabbi Trust maintained investments in a S&P 500 index fund and various securities classified as “available for sale” as of December 31, 2016. These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities include investment grade corporate bonds, collateralized mortgage obligations, asset backed securities and certain government and US Treasury obligations or Federal Agency asset-backed securities and municipal bonds with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. The preferred stocks are not actively traded on a daily basis and therefore, are also priced using an evaluated pricing methodology. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of March 31, 2017, $(4) million of cash collateral was netted against assets, and $4 million was netted against liabilities. As of December 31, 2016, net cash collateral (received) paid of $1 million was netted against the corresponding net derivative contract positions. Of the $1 million of cash collateral as of December 31, 2016, $(3) million was netted against assets, and $4 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in

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Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Corporate Governance and Audit Committees of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G, the natural gas supply contract is measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The following tables provide details surrounding significant Level 3 valuations as of March 31, 2017 and December 31, 2016.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of March 31, 2017 Assets	Fair Value as of March 31, 2017 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contract	$ 1	$ —	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ 1**	**$ —**			
Power						
Electricity	Electric Load Contracts	$ 4	$ (2)	Discounted Cash flow	Historic Load Variability	0% to +10%
Gas (A)	Other	—	—			
Total Power		**$ 4**	**$ (2)**			
Total PSEG		**$ 5**	**$ (2)**			

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Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2016 Assets	Fair Value as of December 31, 2016 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contract	$ —	$ (5)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ —**	**$ (5)**			
Power						
Electricity	Electric Load Contracts	$ 7	$ (1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Gas (A)	Other	—	—			
Total Power		**$ 7**	**$ (1)**			
Total PSEG		**$ 7**	**$ (6)**			

(A) Includes gas positions which were immaterial as of March 31, 2017 and December 31, 2016.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value. For energy-related contracts in cases where Power is a seller, an increase in the load variability would decrease the fair value.

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months ended March 31, 2017 and March 31, 2016, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2017

	Three Months Ended March 31, 2017						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2017	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of March 31, 2017
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 1	$ 19	$ 6	$ —	$ (22)	$ (1)	$ 3
PSE&G							
Net Derivative Assets (Liabilities)	$ (5)	$ —	$ 6	$ —	$ —	$ —	$ 1
Power							
Net Derivative Assets (Liabilities)	$ 6	$ 19	$ —	$ —	$ (22)	$ (1)	$ 2

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2016

	Three Months Ended March 31, 2016						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2016	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of March 31, 2016
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 13	$ 15	$ 8	$ —	$ (15)	$ —	$ 21
PSE&G							
Net Derivative Assets (Liabilities)	$ 2	$ —	$ 8	$ —	$ —	$ —	$ 10
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 15	$ —	$ —	$ (15)	$ —	$ 11

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $19 million and $15 million in Operating Income for the three months ended March 31, 2017 and 2016, respectively. Of the $19 million in Operating Income, $3 million is unrealized. The $15 million in Operating Income is realized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $(22) million and $(15) million in settlements for the three months ended March 31, 2017 and 2016, respectively.

(D) During the three months ended March 31, 2017, $(1) million of net derivatives assets/liabilities were transferred from Level 2 to Level 3. There were no transfers in to or out of Level 3 during 2016.

As of March 31, 2017, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $3 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of March 31, 2016, PSEG carried $2.8 billion of net assets that are measured at fair value on a recurring basis, of which $21 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

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Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of March 31, 2017 and December 31, 2016.

	As of March 31, 2017		As of December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 1,196	$ 1,184	$ 1,195	$ 1,185
PSE&G (B)	7,819	8,349	7,818	8,240
Power - Recourse Debt (B)	2,383	2,611	2,382	2,578
Total Long-Term Debt	**$ 11,398**	**$ 12,144**	**$ 11,395**	**$ 12,003**

(A) Fair value includes a $500 million floating rate term loan and net offsets. The fair value of the term loan debt (Level 2 measurement) was considered to be equal to the carrying value because the interest payments are based on LIBOR rates that are reset monthly.

(B) Given that most bonds do not trade, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

Note 13. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended March 31, 2017				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 31	$ —	$ 31
Allowance for Funds Used During Construction	14	—	—	14
Rabbi Trust Realized Gains, Interest and Dividends	3	4	9	16
Solar Loan Interest	5	—	—	5
Other	3	3	—	6
Total Other Income	**$ 25**	**$ 38**	**$ 9**	**$ 72**
Three Months Ended March 31, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 25	$ —	$ 25
Allowance for Funds Used During Construction	11	—	—	11
Solar Loan Interest	6	—	—	6
Other	3	1	2	6
Total Other Income	**$ 20**	**$ 26**	**$ 2**	**$ 48**

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Other Deductions	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended March 31, 2017				
NDT Fund Realized Losses and Expenses	$ —	$ 7	$ —	$ 7
Other	1	—	3	4
Total Other Deductions	**$ 1**	**$ 7**	**$ 3**	**$ 11**
Three Months Ended March 31, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 18	$ —	$ 18
Other	1	—	2	3
Total Other Deductions	**$ 1**	**$ 18**	**$ 2**	**$ 21**

(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

Note 14. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months ended March 31, 2017 and 2016 were as follows:

	Three Months Ended March 31,	
	2017	2016
PSEG	20.3%	37.5%
PSE&G	36.4%	36.6%
Power	40.6%	40.2%

For the three months ended March 31, 2017, the overall decrease in PSEG's effective tax rates as compared to the same period in the prior year as well as to the statutory tax rate of 40.85%, was primarily due to changes in uncertain tax positions and interest on a New Jersey State refund.

The Protecting Americans from Tax Hikes Act of 2015 (Tax Act) extended the 50% bonus depreciation rules for qualified property placed in service from January 1, 2015 through December 31, 2017. The rate is reduced to 40% and 30% for eligible property placed in service in 2018 and 2019, respectively. In addition, long production property placed in service in 2020 will also qualify for 30% bonus depreciation. The Tax Act also extended the 30% ITC for qualified property placed in service starting January 1, 2016 through December 31, 2019 but reduces the ITC rate to 26% and 22% for projects commenced in 2020 and 2021, respectively. The financial impact of the extensions of the ITC rate will depend upon future transactions.

This provision has generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period. However, these tax benefits will have a negative impact on the rate base of several of PSE&G's programs.

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Note 15. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended March 31, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2016	$ 2	$ (398)	$ 133	$ (263)
Other Comprehensive Income before Reclassifications	—	—	30	30
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	6	(15)	(9)
Net Current Period Other Comprehensive Income (Loss)	—	6	15	21
Balance as of March 31, 2017	**$ 2**	**$ (392)**	**$ 148**	**$ (242)**

PSEG	Other Comprehensive Income (Loss) Three Months Ended March 31, 2016			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2015	$ —	$ (386)	$ 91	$ (295)
Other Comprehensive Income before Reclassifications	2	—	10	12
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	8	6	14
Net Current Period Other Comprehensive Income (Loss)	2	8	16	26
Balance as of March 31, 2016	**$ 2**	**$ (378)**	**$ 107**	**$ (269)**

Power	Other Comprehensive Income (Loss) Three Months Ended March 31, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2016	$ —	$ (340)	$ 129	$ (211)
Other Comprehensive Income before Reclassifications	—	—	28	28
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	5	(9)	(4)
Net Current Period Other Comprehensive Income (Loss)	—	5	19	24
Balance as of March 31, 2017	**$ —**	**$ (335)**	**$ 148**	**$ (187)**

Power	Other Comprehensive Income (Loss) Three Months Ended March 31, 2016			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2015	$ —	$ (327)	$ 87	$ (240)
Other Comprehensive Income before Reclassifications	—	—	10	10
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	6	13
Net Current Period Other Comprehensive Income (Loss)	—	7	16	23
Balance as of March 31, 2016	**$ —**	**$ (320)**	**$ 103**	**$ (217)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 2	$ (1)	$ 1
Amortization of Actuarial Loss	O&M Expense	(12)	5	(7)
Total Pension and OPEB Plans		(10)	4	(6)
Available-for-Sale Securities				
Realized Gains	Other Income	36	(17)	19
Realized Losses	Other Deductions	(7)	3	(4)
OTTI	OTTI	(1)	1	—
Total Available-for-Sale Securities		28	(13)	15
Total		**$ 18**	**$ (9)**	**$ 9**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2016		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 3	$ (1)	$ 2
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)
Total Pension and OPEB Plans		(14)	6	(8)
Available-for-Sale Securities				
Realized Gains	Other Income	16	(8)	8
Realized Losses	Other Deductions	(17)	8	(9)
OTTI	OTTI	(10)	5	(5)
Total Available-for-Sale Securities		(11)	5	(6)
Total		**$ (25)**	**$ 11**	**$ (14)**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 2	$ (1)	$ 1
Amortization of Actuarial Loss	O&M Expense	(11)	5	(6)
Total Pension and OPEB Plans		(9)	4	(5)
Available-for-Sale Securities				
Realized Gains	Other Income	25	(13)	12
Realized Losses	Other Deductions	(5)	2	(3)
OTTI	OTTI	(1)	1	—
Total Available-for-Sale Securities		19	(10)	9
Total		**$ 10**	**$ (6)**	**$ 4**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2016		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2
Amortization of Actuarial Loss	O&M Expense	(15)	6	(9)
Total Pension and OPEB Plans		(12)	5	(7)
Available-for-Sale Securities				
Realized Gains	Other Income	15	(8)	7
Realized Losses	Other Deductions	(16)	8	(8)
OTTI	OTTI	(10)	5	(5)
Total Available-for-Sale Securities		(11)	5	(6)
Total		**$ (23)**	**$ 10**	**$ (13)**

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Note 16. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended March 31,			
	2017		2016	
	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions):				
Net Income	**$ 114**	**$ 114**	**$ 471**	**$ 471**
EPS Denominator (Millions):				
Weighted Average Common Shares Outstanding	505	505	505	505
Effect of Stock Based Compensation Awards	—	3	—	3
Total Shares	**505**	**508**	**505**	**508**
EPS				
Net Income	**$ 0.23**	**$ 0.22**	**$ 0.93**	**$ 0.93**

There were approximately 0.3 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the three months ended March 31, 2017 and 2016.

Dividends

	Three Months Ended March 31,	
Dividend Payments on Common Stock	**2017**	**2016**
Per Share	$ 0.43	$ 0.41
In Millions	$ 218	$ 207

On April 18, 2017, PSEG's Board of Directors approved a $0.43 per share common stock dividend for the second quarter of 2017.

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Note 17. Financial Information by Business Segment

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated
			Millions		
Three Months Ended March 31, 2017					
Operating Revenues	$ 1,812	$ 1,284	$ 83	$ (587)	$ 2,592
Net Income (Loss)	299	(170)	(15)	—	114
Gross Additions to Long-Lived Assets	748	307	7	—	1,062
Three Months Ended March 31, 2016					
Operating Revenues	$ 1,712	$ 1,313	$ 122	$ (531)	$ 2,616
Net Income (Loss)	262	192	17	—	471
Gross Additions to Long-Lived Assets	724	333	8	—	1,065
As of March 31, 2017					
Total Assets	$ 26,487	$ 11,729	$ 2,249	$ (801)	$ 39,664
Investments in Equity Method Subsidiaries	$ —	$ 103	$ —	$ —	$ 103
As of December 31, 2016					
Total Assets	$ 26,288	$ 12,193	$ 2,373	$ (784)	$ 40,070
Investments in Equity Method Subsidiaries	$ —	$ 102	$ —	$ —	$ 102

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations primarily relate to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 18. Related-Party Transactions.

Note 18. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended March 31, 2017	2016
	Millions	
Billings from Affiliates:		
Net Billings from Power primarily through BGS and BGSS (A)	$ 599	$ 545
Administrative Billings from Services (B)	65	69
Total Billings from Affiliates	**$ 664**	**$ 614**

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Related-Party Transactions	As of March 31, 2017	As of December 31, 2016
	Millions	
Receivables from PSEG (C)	**$ 34**	**$ 76**
Payable to Power (A)	$ 175	$ 193
Payable to Services (B)	43	67
Accounts Payable—Affiliated Companies	**$ 218**	**$ 260**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 116**	**$ 130**

Power

The financial statements for Power include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended March 31, 2017	2016
	Millions	
Billings to Affiliates:		
Net Billings to PSE&G primarily through BGS and BGSS (A)	**$ 599**	**$ 545**
Billings from Affiliates:		
Administrative Billings from Services (B)	**$ 36**	**$ 45**

Related-Party Transactions	As of March 31, 2017	As of December 31, 2016
	Millions	
Receivables from PSE&G (A)	$ 175	$ 193
Receivables from PSEG (C)	—	12
Accounts Receivable—Affiliated Companies	**$ 175**	**$ 205**
Payable to Services (B)	$ 10	$ 25
Payable to PSEG (C)	71	—
Accounts Payable—Affiliated Companies	**$ 81**	**$ 25**
Short-Term Loan Due (to) from Affiliate (E)	**$ 157**	**$ 87**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 78**	**$ 77**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. In addition, Power and PSE&G provide certain technical services for each other generally at cost in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

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Note 19. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries, as of March 31, 2017 and December 31, 2016 and for the three months ended March 31, 2017 and 2016.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended March 31, 2017					
Operating Revenues	$ —	$ 1,270	$ 52	$ (38)	$ 1,284
Operating Expenses	4	1,569	52	(38)	1,587
Operating Income (Loss)	(4)	(299)	—	—	(303)
Equity Earnings (Losses) of Subsidiaries	(161)	(1)	3	162	3
Other Income	25	41	—	(28)	38
Other Deductions	(1)	(6)	—	—	(7)
Other-Than-Temporary Impairments	—	(1)	—	—	(1)
Interest Expense	(30)	(9)	(5)	28	(16)
Income Tax Benefit (Expense)	1	111	4	—	116
Net Income (Loss)	**$ (170)**	**$ (164)**	**$ 2**	**$ 162**	**$ (170)**
Comprehensive Income (Loss)	**$ (146)**	**$ (143)**	**$ 2**	**$ 141**	**$ (146)**
Three Months Ended March 31, 2017					
Net Cash Provided By (Used In) Operating Activities	$ 77	$ 377	$ 91	$ 35	$ 580
Net Cash Provided By (Used In) Investing Activities	$ 251	$ 20	$ (154)	$ (511)	$ (394)
Net Cash Provided By (Used In) Financing Activities	$ (328)	$ (395)	$ 68	$ 476	$ (179)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended March 31, 2016					
Operating Revenues	$ —	$ 1,302	$ 42	$ (31)	$ 1,313
Operating Expenses	10	952	39	(31)	970
Operating Income (Loss)	(10)	350	3	—	343
Equity Earnings (Losses) of Subsidiaries	205	(1)	2	(204)	2
Other Income	17	32	—	(23)	26
Other Deductions	—	(18)	—	—	(18)
Other-Than-Temporary Impairments	—	(10)	—	—	(10)
Interest Expense	(30)	(10)	(5)	23	(22)
Income Tax Benefit (Expense)	10	(140)	1	—	(129)
Net Income (Loss)	**$ 192**	**$ 203**	**$ 1**	**$ (204)**	**$ 192**
Comprehensive Income (Loss)	**$ 215**	**$ 219**	**$ 1**	**$ (220)**	**$ 215**
Three Months Ended March 31, 2016					
Net Cash Provided By (Used In) Operating Activities	$ 271	$ 480	$ 47	$ (135)	$ 663
Net Cash Provided By (Used In) Investing Activities	$ (598)	$ (428)	$ (246)	$ 613	$ (659)
Net Cash Provided By (Used In) Financing Activities	$ 326	$ (51)	$ 203	$ (478)	$ —

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
As of March 31, 2017					
Current Assets	$ 4,244	$ 1,332	$ 174	$ (4,458)	$ 1,292
Property, Plant and Equipment, net	56	5,582	2,447	—	8,085
Investment in Subsidiaries	4,104	343	—	(4,447)	—
Noncurrent Assets	175	2,154	129	(106)	2,352
Total Assets	**$ 8,579**	**$ 9,411**	**$ 2,750**	**$ (9,011)**	**$ 11,729**
Current Liabilities	$ 187	$ 3,436	$ 1,580	$ (4,458)	$ 745
Noncurrent Liabilities	531	2,171	527	(106)	3,123
Long-Term Debt	2,383	—	—	—	2,383
Member's Equity	5,478	3,804	643	(4,447)	5,478
Total Liabilities and Member's Equity	**$ 8,579**	**$ 9,411**	**$ 2,750**	**$ (9,011)**	**$ 11,729**
As of December 31, 2016					
Current Assets	$ 4,412	$ 1,593	$ 152	$ (4,697)	$ 1,460
Property, Plant and Equipment, net	55	6,145	2,320	—	8,520
Investment in Subsidiaries	4,249	344	—	(4,593)	—
Noncurrent Assets	168	2,016	129	(100)	2,213
Total Assets	**$ 8,884**	**$ 10,098**	**$ 2,601**	**$ (9,390)**	**$ 12,193**
Current Liabilities	$ 171	$ 3,752	$ 1,454	$ (4,697)	$ 680
Noncurrent Liabilities	532	2,398	502	(100)	3,332
Long-Term Debt	2,382	—	—	—	2,382
Member's Equity	5,799	3,948	645	(4,593)	5,799
Total Liabilities and Member's Equity	**$ 8,884**	**$ 10,098**	**$ 2,601**	**$ (9,390)**	**$ 12,193**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU, and
- **Power**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses through competitive energy sales in well-developed energy markets and fuel supply functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations and Services Agreement contractual agreement; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Our business discussion in Part I, Item 1. Business of our 2016 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2016 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2017 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2016 Form 10-K.

EXECUTIVE OVERVIEW OF 2017 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- improving utility operations through investment in T&D and other infrastructure projects designed to enhance system reliability and resiliency and to meet customer expectations and public policy objectives,
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the three months ended March 31, 2017 and 2016 are presented as follows:

Earnings (Losses)	Three Months Ended March 31, 2017	2016
	Millions	
PSE&G	$ 299	$ 262
Power (A)	(170)	192
Other (B)	(15)	17
PSEG Net Income	**$ 114**	**$ 471**
PSEG Net Income Per Share (Diluted)	**$ 0.22**	**$ 0.93**

(A) Includes after-tax expenses of $334 million primarily for accelerated depreciation related to the early retirement of Power's Hudson and Mercer coal/gas generation plants in the three months ended March 31, 2017. See Item 1. Note 3. Early Plant Retirements for additional information.

(B) Other includes after-tax activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations. Energy Holdings recorded an after-tax charge of $32 million related to its investments in NRG REMA, LLC's leveraged leases in the three months ended March 31, 2017. See Item 1. Note 6. Financing Receivables for additional information.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with future delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended March 31, 2017	2016
	Millions, after tax	
NDT Fund Income (Expense) (A) (B)	$ 8	$ (5)
Non-Trading MTM Gains (Losses) (C)	$ 6	$ 13

(A) NDT Fund Income (Expense) includes the realized gains and losses, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization (D&A) Expense.

(B) Net of tax (expense) benefit of $(9) million and $3 million for the three months ended March 31, 2017 and 2016, respectively.

(C) Net of tax (expense) benefit of $(4) million and $(10) million for the three months ended March 31, 2017 and 2016, respectively.

Our $357 million decrease in Net Income for the three months ended March 31, 2017 was driven primarily by

- accelerated depreciation related to the early retirement of our Hudson and Mercer coal/gas generation units at Power (see Item 1. Note 3. Early Plant Retirements),
- a decrease in energy sales due primarily to lower average realized sales prices, and
- a charge for estimated losses related to leveraged lease investments (see Item 1. Note 6. Financing Receivables).

These decreases were partially offset by:

- higher transmission revenues, and
- increased gas distribution revenues.

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During the first three months of 2017, we maintained a strong balance sheet. We continued to effectively deploy capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results, which when combined with the cash flow generated by Power, our merchant generator and power marketer, has allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our multi-year, long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, we continue to invest in transmission projects that focus on reliability improvements and replacement of aging infrastructure. We also continue to make investments to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the BPU in 2014 and to seek recovery on such investments. We also continue to modernize PSE&G's gas distribution systems as part of our Gas System Modernization Program (GSMP) that was approved by the BPU in late 2015. Over the past few years, these types of investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G. As a result of our Energy Strong Order from the BPU, we will be required to file a distribution base rate case proceeding by no later than November 1, 2017. We cannot predict the impact such proceeding will have on our distribution business.

Although the weather in the first quarter of 2017 was warmer than normal, Power's results saw a continuing benefit from access to natural gas supplies through existing firm pipeline transportation contracts. Power manages these contracts for the benefit of PSE&G's customers through the BGSS arrangement. The contracts are sized to provide for delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to make third-party sales and if excess volume remains after the third-party sales, supply gas to its generating units in New Jersey. Alternatively, gas supply and pipeline capacity constraints could adversely impact our ability to meet the needs of our utility customers and generating units. Power's hedging practices and ability to capitalize on market opportunities help it to balance some of the volatility of the merchant power business. More than half of Power's expected gross margin in 2017 relates to our hedging strategy, our expected revenues from the capacity market mechanisms and certain ancillary service payments such as reactive power.

Our investments in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to contribute to the overall efficiency of operations.

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced as being at risk for early retirement. This situation is generally due to low natural gas prices, and the related decline in market prices of energy, resulting from the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities and both federal and state-level policies that provide financial incentives to renewable energy such as wind and solar, but generally do not apply to nuclear generating stations. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet and greater reliance on natural gas pipelines for fuel delivery.

If trends noted above continue or worsen, our nuclear generating units could cease being economically competitive which may cause us to retire such units prior to the end of their useful lives. The costs associated with any such retirement, which may include, among other things, accelerated D&A or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs, and additional funding of nuclear decommissioning trust funds will likely have a material adverse impact on future financial results. We continue to advocate for sound policies that recognize nuclear power as a source of reliable and clean energy and an important part of a diverse and reliable energy portfolio. See Item 1. Note 3. Early Plant Retirements for additional information.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

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Transmission

In April 2017, the PJM Board announced that it would be lifting the previously disclosed suspension of the Artificial Island transmission project and approved the award to PSE&G of the construction of necessary upgrade work in Hope Creek at a cost of approximately $130 million.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey. In addition, as a basic generation service (BGS) supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers may be entitled to an adjustment, subject to BPU approval. We do not believe that these matters will have a material effect on Power's business or results of operations.

Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base return on equity (ROE). Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. While we are not the subject of a challenge to the ROE employed in PSE&G's transmission formula rate, the results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. The CP product is expected to be implemented fully for the 2020-2021 Delivery Year. Subsequent to its implementation, FERC approved changes to the CP construct that will enhance the participation of intermittent and demand response resources ("seasonal resources"). However, two complaints remain pending that ask FERC to investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions. We do not expect action on the complaints before the upcoming 2020/2021 base residual auction in May 2017.

As a result of the efforts of certain entities in PJM to obtain financial support arrangements from their state commissions, a group of suppliers requested that FERC direct PJM to expand the currently effective "minimum offer price rule" to apply to certain existing units seeking subsidies. The suppliers' request was intended to avoid a scenario where the subsidized generators would submit bids into the PJM capacity market that did not reflect their actual costs of operation and could artificially suppress capacity market prices. We are currently awaiting FERC action on the suppliers' request and cannot predict the outcome of the proceeding.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act (FWPCA) requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs.

In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the New Source Performance Standards, which establish emissions standards for CO_2 for certain new fossil power plants, and the Clean Power Plan, a greenhouse gas emissions regulation under the Clean Air Act for existing power plants that establishes state-specific emission rate targets based on implementation of the best system of emission reduction. Upon completion of the review, the EPA is expected to suspend, revise or rescind the rules as appropriate.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above as well as other matters that may impact our financial condition and results of operations, see Item 1. Note 9. Commitments and Contingent Liabilities.

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FERC Compliance

Since September 2014, FERC Staff has been conducting a preliminary non-public investigation regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units. While considerable uncertainty remains as to the final resolution of these matters, based upon recent developments in the investigation, Power believes the disgorgement and interest costs related to the cost-based bidding matter may range between approximately $35 million and $135 million, depending on the legal interpretation of the principles under the PJM Tariff, plus penalties. Since no point within this range is more likely than any other, Power has accrued the low end of this range of $35 million by recording an additional pre-tax charge to income of $10 million during the three months ended March 31, 2017. PSEG is unable to reasonably estimate the range of possible loss, if any, for the quantity of energy offered matter or the penalties that FERC would impose relating to either the cost-based bidding or quantity of energy matter. However, any of these amounts could be individually material to PSEG and Power. We cannot predict the final outcome of these matters. For additional information, see Note 9. Commitments and Contingent Liabilities.

Early Retirement of Hudson and Mercer Units

In October 2016, Power determined it will cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. The exact timing of the early retirement of these units may be impacted by operational and other conditions that could subsequently arise. The decision to retire the Hudson and Mercer units had a material effect on PSEG's and Power's results of operations in 2016 and continues to adversely impact their results of operations in 2017. During the first three months of 2017, Power recognized incremental D&A of $558 million ($574 million in total) and expects to recognize an additional incremental $379 million ($389 million in total) in 2017 due to the significant shortening of the expected economic useful lives of Hudson and Mercer. During the first quarter of 2017, Energy Costs of $7 million for coal inventory adjustments was also incurred and other costs may be incurred during the remaining period in 2017 prior to retirement. See Item 1. Note 3. Early Plant Retirements for additional information.

Power currently anticipates using the sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such remediation are neither currently probable nor estimable but may be material.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Leveraged Lease Portfolio

GenOn Energy, Inc. (GenOn), the parent company of NRG REMA LLC, (REMA), reported in August 2016 that it did not expect to have sufficient liquidity to repay their senior unsecured notes due in June 2017. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's efforts to restructure its portfolio and improve its liquidity and the possible related impact on REMA.

During the first quarter of 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as certain recent discussions with REMA management, Energy Holdings recorded an additional $55 million pre-tax charge for its current best estimate of loss relating to its investments in the REMA leases, which was reflected in Operating Revenues. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments, which could include further write-downs of the values of Energy Holdings' leveraged leases. For additional information, see Item 1. Note 6. Financing Receivables. There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.

Additional facilities in our leveraged lease portfolio include the Joliet and Shawville generating facilities, which were converted to use natural gas, and Powerton, a coal facility. However, these units may have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units. As a result, these facilities may not be as economically competitive as newer combined cycle gas units and could continue to be adversely impacted by the same economic conditions experienced by other coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged leases associated with these facilities.

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Salem

Concurrently with the planned refueling outage at the Salem 2 unit that is scheduled for the second quarter of 2017, we intend to inspect and replace degraded baffle bolts as part of our multi-year project to replace baffle bolts at the Salem station. As a result, we expect the duration of this outage to be modestly longer than our typical refueling outage, which will reduce production and lower the nuclear capacity factor for the second quarter of 2017 as compared to the first quarter of 2017.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of opportunities in a rapidly evolving market as we remain diligent in managing costs. For the first three months of 2017, our

- our utility continued top decile performance in electric reliability,
- total nuclear fleet achieved an average capacity factor of 100%,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 13 terawatt hours while addressing fuel availability and price volatility, and
- combined cycle fleet produced three terawatt hours at an equivalent availability factor of 94%.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first three months of 2017 as we

- maintained sufficient liquidity,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2017 to $1.72 per share.

We expect to be able to fund our planned capital requirements without the issuance of new equity.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first three months of 2017, we

- made additional investments in transmission infrastructure projects,
- continued to execute our GSMP, Energy Strong and other existing BPU-approved utility programs, and
- continued construction of our Keys and Sewaren 7 generation projects for targeted commercial operation in 2018 and began construction of BH5 for targeted commercial operations in mid-2019.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-growing economy and a cost-constrained environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions in response to changes in demand,
- execute our utility capital investment program, including our Energy Strong program, GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction and start-up of our Keys Energy Center (Keys) , Sewaren 7, (BH5) and other generation projects,

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- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

For 2017 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- fair and timely rate relief from the BPU and FERC for recovery of costs and return on investments, including with respect to our distribution base rate case proceeding to be filed in 2017,
- the potential for comprehensive tax reform, particularly in light of public statements by the current U.S. administration and key members of Congress,
- uncertainty in the national and regional economic performance, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate,
- the impact of lower natural gas prices and increasing environmental compliance costs on the competitiveness of our nuclear and remaining coal-fired generation plants, and the potential for retirement of such plants earlier than their current useful lives,
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development projects, including in connection with permitting and regulatory approvals,
- maintaining a diverse mix of fuels to mitigate risks associated with fuel price volatility and market demand cycles, and
- FERC Staff's continuing investigation of certain of Power's New Jersey fossil generating unit bids in the PJM energy market.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of transmission and distribution facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses,
- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency, modernizing existing infrastructure and participation in transmission projects through FERC's "open window" solicitation process.

In 2016, Power announced its intention to develop a retail platform to sell physical electricity and natural gas, which we believe would begin to complement our existing wholesale marketing business. Power was granted licenses in 2016 to sell both electricity and gas in the states of New Jersey and Pennsylvania.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

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RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 18. Related-Party Transactions.

	Three Months Ended March 31,		Increase/ (Decrease)	
	2017	2016	2017 vs. 2016	
	Millions		Millions	%
Operating Revenues	$ 2,592	$ 2,616	$ (24)	(1)
Energy Costs	874	836	38	5
Operation and Maintenance	712	729	(17)	(2)
Depreciation and Amortization	828	224	604	270
Income from Equity Method Investments	3	2	1	50
Other Income (Deductions)	61	27	34	126
Other-Than-Temporary Impairments	1	10	(9)	(90)
Interest Expense	98	92	6	7
Income Tax Expense	29	283	(254)	(90)

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Three Months Ended March 31,		Increase/ (Decrease)	
	2017	2016	2017 vs. 2016	
	Millions		Millions	%
Operating Revenues	$ 1,812	$ 1,712	$ 100	6
Energy Costs	753	729	24	3
Operation and Maintenance	367	382	(15)	(4)
Depreciation and Amortization	171	139	32	23
Other Income (Deductions)	24	19	5	26
Interest Expense	75	68	7	10
Income Tax Expense	171	151	20	13

Three Months Ended March 31, 2017 as Compared to 2016

Operating Revenues increased $100 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $58 million due primarily to an increase in transmission revenues.

- Transmission revenues were $37 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.
- Gas distribution revenues increased $24 million due to an $11 million increase due to the inclusion of Energy Strong in base rates, a $5 million increase due to the Gas System Modernization Program, $4 million of higher delivery volumes, higher Green Program Recovery Charges (GPRC) of $2 million and $2 million in higher Weather Normalization Clause revenue.
- Electric distribution revenues decreased $3 million due to lower GPRC of $3 million and a $2 million decrease due to lower sales volumes, partially offset by a $2 million increase due to the inclusion of Energy Strong in base rates.

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Commodity Revenue increased $24 million as a result of higher Gas revenues partially offset by lower Electric revenues. The changes in Commodity revenue for both gas and electric are entirely offset by the changes in Energy Costs. PSE&G earns no margin on the provision of basic gas supply service (BGSS) and BGS to retail customers.

- Gas commodity revenues increased $74 million due primarily to higher BGSS sales prices.
- Electric commodity revenues decreased $50 million due primarily to $23 million of lower revenues from collections of Non-Utility Generation Charges (NGC), a $17 million decrease in BGS revenues due to lower sales prices and volumes and a decrease of $10 million due to lower volumes of Non-Utility Generation (NUG) energy sold.

Clause Revenues increased $19 million due primarily to the 2016 return to customers of $15 million of overcollections of Securitization Transition Charges (STC), and higher Societal Benefit Charges (SBC) of $2 million in 2017. The changes in the STC and SBC amounts are entirely offset by decreases in the amortization of Regulatory Assets and Regulatory Liabilities and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC or SBC collections.

Operating Expenses

Energy Costs increased $24 million. This is entirely offset by the change in Commodity Revenue.

Operation and Maintenance decreased $15 million, of which the most significant components were

- a $6 million decrease in appliance service costs,
- a $4 million decrease in distribution corrective and preventative maintenance,
- a $2 million decrease in pension and OPEB costs, net of capitalized amounts and
- a $3 million net decrease in operational expenses.

Depreciation and Amortization increased $32 million due primarily to an increase of $17 million in amortization of Regulatory Assets and a $14 million increase in depreciation due to additional plant in service.

Other Income and (Deductions) increased $5 million due primarily to an increase of $3 million in Allowance for Funds Used During Construction and a $3 million increase in realized gains on Rabbi Trust investments.

Interest Expense increased $7 million due primarily to net debt issuances in 2016.

Income Tax Expense increased $20 million due primarily to higher pre-tax income.

Power

	Three Months Ended March 31,		Increase/ (Decrease)	
	2017	2016	2017 vs. 2016	
	Millions		Millions	%
Operating Revenues	$ 1,284	$ 1,313	$ (29)	(2)
Energy Costs	707	638	69	11
Operation and Maintenance	230	253	(23)	(9)
Depreciation and Amortization	650	79	571	N/A
Income from Equity Method Investments	3	2	1	50
Other Income (Deductions)	31	8	23	N/A
Other-Than-Temporary Impairments	1	10	(9)	(90)
Interest Expense	16	22	(6)	(27)
Income Tax Expense (Benefit)	(116)	129	(245)	N/A

Three Months Ended March 31, 2017 as Compared to 2016

Operating Revenues decreased $29 million due to changes in generation and gas supply revenues.

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Generation Revenues decreased $124 million due primarily to

- a net decrease of $95 million in energy sales in the PJM and New England (NE) regions due primarily to lower average realized prices, and
- a net decrease of $24 million due to MTM losses in 2017 as compared to MTM gains in 2016. Of this amount, $131 million was due to changes in forward power prices. The decrease was offset by an increase of $107 million due to losses on positions reclassified to realized upon settlement this year as compared to gains last year, and
- a charge of $10 million due to an increase in the FERC accrual related to the PJM bidding matter, see Note 9. Commitments and Contingent Liabilities,
- partially offset by a net increase of $10 million due primarily to higher volumes of electricity sold under wholesale load contracts in the NE region partially offset by lower average prices.

Gas Supply Revenues increased $95 million due primarily to

- an increase of $46 million in sales under the BGSS contract due primarily to higher average sales prices coupled with an increase in sales volumes due to periods of colder weather in March,
- an increase of $41 million related to sales to third parties due to higher average sales prices, and
- a net increase of $8 million due to higher MTM gains in 2017 as compared to 2016, primarily due to losses on positions reclassified to realized upon settlement this year as compared to gains last year.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $69 million due to

Generation costs decreased $1 million due primarily to

- a net decrease of $26 million primarily due to lower congestion costs in PJM due to lower congestion rates and volumes,
- partially offset by higher fuel costs of $14 million reflecting higher average realized prices for natural gas coupled with the utilization of higher volumes of coal, partially offset by the utilization of lower volumes of gas and oil,
- an increase of $8 million in energy purchase volumes in the NE region to serve load obligations, and
- a $7 million charge associated primarily with a lower of cost or market coal inventory adjustment at Mercer.

Gas costs increased $70 million due mainly to

- an increase of $39 million related to sales to third parties due to higher average gas costs, and
- an increase of $31 million related to sales under the BGSS contract due primarily to higher average gas costs and an increase in volumes sold due to periods of colder weather in March.

Operation and Maintenance decreased $23 million due primarily to

- a $15 million decrease related to our nuclear plants due primarily to lower labor-related costs, and
- a $7 million legal reserve for environmental expenses recorded in 2016.

Depreciation and Amortization increased $571 million due primarily to

- $558 million of accelerated depreciation due to the early retirement of the Hudson and Mercer units,
- $4 million of greater depreciation due to the accelerated retirement date at Bridgeport Harbor 3,
- a $4 million increase due to a higher nuclear asset base, and
- $3 million of higher depreciation due to new solar projects.

Other Income (Deductions) increased $23 million due primarily to $17 million of lower net realized losses from the NDT Fund in 2017 and $3 million of higher realized gains in the Rabbi Trust Fund.

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Other-Than-Temporary Impairments decreased $9 million due to lower impairments of equity securities in the NDT Fund in 2017.

Interest Expense decreased $6 million due primarily to higher interest capitalized for the construction of three new fossil stations: BH5, Sewaren 7 and Keys.

Income Tax Expense decreased $245 million in 2017 due primarily to a pre-tax loss in 2017 as compared to pre-tax income in 2016.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the three months ended March 31, 2017, our operating cash flow decreased $18 million as compared to the same period in 2016. The net change was primarily due to the net changes from PSE&G and Power as discussed below largely offset by higher tax refunds in 2017 at Energy Holdings.

PSE&G

PSE&G's operating cash flow decreased $54 million from $568 million to $514 million for the three months ended March 31, 2017, as compared to the same period in 2016, due primarily to lower tax refunds, partially offset by higher earnings, and an increase of $45 million due to a change in regulatory deferrals.

Power

Power's operating cash flow decreased $83 million from $663 million to $580 million for the three months ended March 31, 2017, as compared to the same period in 2016, primarily due to tax payments in 2017 as compared to tax refunds in 2016 and lower earnings, partially offset by a $65 million increase from net collection of counterparty receivables and a $12 million increase from fuels, materials and supplies.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs.

In March 2017, PSEG, Power and PSE&G amended their credit agreements, extending the expiration dates to March 2022. Concurrently, PSEG increased its existing $1 billion in credit facilities to $1.5 billion, Power decreased its existing $2.6 billion in credit facilities to $2.1 billion, which includes two new 3-year $100 million letter of credit facilities that expire in March 2020.

Our total credit facilities and available liquidity as of March 31, 2017 were as follows:

	As of March 31, 2017		
Company/Facility	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$ 1,500	$ 332	$ 1,168
PSE&G	600	14	586
Power	2,100	235	1,865
Total	**$ 4,200**	**$ 581**	**$ 3,619**

As of March 31, 2017, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating from S&P or Moody's, which

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would represent a three level downgrade from its current S&P or Moody's ratings. In the event of a deterioration of Power's credit rating certain of Power's agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $801 million and $783 million as of March 31, 2017 and December 31, 2016, respectively. The early retirement of Power's Hudson and Mercer coal/gas generation units is not expected to have a material impact on Power's debt covenant ratios or its ability to obtain credit facilities. See Item 1. Note 3. Early Plant Retirements.

For additional information, see Item 1. Note 10. Debt and Credit Facilities.

Long-Term Debt Financing

PSEG Parent has a floating rate $500 million term loan maturing in November 2017.

Common Stock Dividends

On February 21, 2017, our Board of Directors approved a $0.43 dividend per share of common stock for the first quarter of 2017. On April 18, 2017, our Board of Directors declared a $0.43 dividend per share of common stock for the second quarter of 2017. This reflects an indicative annual dividend rate of $1.72 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 1. Note16. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In April 2017, S&P published updated research and affirmed the ratings and outlooks of PSEG and PSE&G. PSEG Power's rating and outlook also remain unchanged.

	Moody's (A)	S&P (B)
PSEG		
Outlook	**Positive**	**Stable**
Senior Notes	Baa2	BBB
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

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CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures at PSE&G, Power and Services as compared to amounts disclosed in our 2016 Form 10-K.

PSE&G

During the three months ended March 31, 2017, PSE&G made capital expenditures of $752 million, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $24 million, which are included in operating cash flows.

Power

During the three months ended March 31, 2017, Power made capital expenditures of $274 million, excluding $33 million for nuclear fuel, primarily related to our Keys, Sewaren 7, BH5 and other generation projects.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Item 1. Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From January through March 2017, MTM VaR remained relatively stable between a low of $7 million and a high of $25 million at the 95% confidence level. The range of VaR was narrower for the three months ended March 31, 2017 as compared with the year ended December 31, 2016.

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	MTM VaR	
	Three Months Ended March 31, 2017	Year Ended December 31, 2016
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 7	$ 26
Average for the Period	$ 12	$ 16
High	$ 25	$ 32
Low	$ 7	$ 10
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 11	$ 40
Average for the Period	$ 19	$ 25
High	$ 39	$ 51
Low	$ 10	$ 16

See Item 1. Note 11. Financial Risk Management Activities for a discussion of credit risk.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, PSE&G and Power

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of PSEG, PSE&G and Power. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of PSEG, PSE&G and Power have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, PSE&G and Power

There have been no changes in internal control over financial reporting that occurred during the first quarter of 2017 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2016 Annual Report on Form 10-K, see Part I, Item 1. Note 9. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

The discussion of our business and operations in this Quarterly Report on Form 10-Q should be read together with the risk factors contained in Part I, Item 1A of our 2016 Annual Report on Form 10-K, which describe various risks and uncertainties that could have a material adverse impact on our business, prospects, financial position, results of operations or cash flows and could cause results to differ materially from those expressed elsewhere in this report. Except as follows, there have been no material changes to the risk factors set forth in the above-referenced filing as of March 31, 2017.

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We may be unable to obtain an adequate fuel supply in the future.

We obtain substantially all of our physical natural gas, coal and nuclear fuel supply from third parties pursuant to arrangements that vary in term, pricing structure, firmness and delivery flexibility. Our fuel supply arrangements must be coordinated with transportation agreements, balancing agreements, storage services, financial hedging transactions and other contracts to ensure that the natural gas, coal and nuclear fuel are delivered to our power plants at the times, in the quantities and otherwise in a manner that meets the needs of our generation portfolio and our customers. We must also comply with laws and regulations governing the transportation of such fuels.

Additionally, the PJM power market has recently experienced an increase in natural gas-fired generation assets that supply electricity to the region. As a result, there has been a corresponding increase in the need for natural gas transportation assets to serve power generation assets. When extreme cold temperatures significantly increase the demand for natural gas used for residential heating, it can also create constraints on natural gas pipelines that serve power generation assets. When these conditions exist, it could interrupt the fuel supply to our natural gas-fired power plants in the PJM power market.

We are exposed to increases in the price of natural gas, coal and nuclear fuel, and it is possible that sufficient supplies to operate our generating facilities profitably may not continue to be available to us. Significant changes in the price of natural gas, coal and nuclear fuel could affect our future results and impact our liquidity needs. In addition, we face risks with regard to the delivery to, and the use of natural gas, coal and nuclear fuel by, our power plants including the following:

- transportation may be unavailable if pipeline infrastructure is damaged or disabled;
- pipeline tariff changes may adversely affect our ability to, or cost to, deliver such fuels;
- creditworthiness of third-party suppliers, defaults by third-party suppliers on supply obligations and our ability to replace supplies currently under contract may delay or prevent timely delivery;
- market liquidity for physical supplies of such fuels or availability of related services (e.g. storage) may be insufficient or available only at prices that are not acceptable to us;
- variation in the quality of such fuels may adversely affect our power plant operations;
- legislative or regulatory actions or requirements, including those related to pipeline integrity inspections, may increase the cost of such fuels;
- fuel supplies diverted to residential heating may limit the availability of such fuels for our power plants; and
- the loss of critical infrastructure, terrorist attacks (including cybersecurity breaches) or catastrophic events such as fires, earthquakes, explosions, floods, severe storms or other similar occurrences could impede the delivery of such fuels.

Our nuclear units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel raw material needs over the next several years. However, each of our nuclear units has contracted with a single fuel fabrication services provider, and transitioning to an alternative provider could take an extended period of time. Certain of our other generation facilities also require fuel or other services that may only be available from one or a limited number of suppliers. The availability and price of this fuel may vary due to supplier financial or operational disruptions, transportation disruptions and force majeure. At times, such fuel may not be available at any price, or we may not be able to transport it to our facilities on a timely basis. In this case, we may not be able to run those facilities even if it would be profitable. If we had sold forward the power from such a facility, we could be required to supply or purchase power from alternate sources, perhaps at a loss. This could have a material adverse impact on our business, the financial results of specific plants and on our results of operations.

In March 2017, Westinghouse Electric Company (WEC) announced that it had filed for Chapter 11 bankruptcy in New York. WEC provides nuclear fuel fabrication services for Salem Units 1 and 2. In the event that WEC is unable to continue to provide fabrication services, we can provide no assurance that we would be able to find alternative providers of such services in a timely manner or on acceptable terms. As a result, a failure by WEC to perform its obligations during the pendency of, or following its emergence from, bankruptcy could have a material adverse impact on our business, the financial results of specific plants and on our results of operations.

Although our fuel contract portfolio provides a degree of hedging against these market risks, such hedging may not be effective and future increases in our fuel costs could materially and adversely affect our liquidity, financial condition and results of operations. While our generation runs on a mix of fuels, primarily natural gas and nuclear fuel, an increase in the cost of any particular fuel ultimately used could impact our results of operations.

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ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the first quarter of 2017.

Three Months Ended March 31, 2017	Total Number of Shares Purchased	Average Price Paid per Share
January 1 - January 31	—	$ —
February 1 - February 28	—	$ —
March 1- March 31	927,971	$ 44.94

ITEM 5. OTHER INFORMATION

Certain information reported in the 2016 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2016 Annual Report on Form 10-K. References are to the related pages on the Forms 10-K as printed and distributed.

Federal Regulation

FERC

Capacity Market Issues

December 31, 2016 Form 10-K page 16. PJM, NYISO and ISO-NE each have capacity markets that have been approved by FERC. FERC regulates these markets and continues to examine whether the market design for each of these three capacity markets is working optimally. Issues presented in various forums include consideration of whether the competitive market framework can be reconciled with state public policies that support particular resources or resource attributes, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market prices. We cannot predict what action, if any, FERC might take with regard to capacity market designs.

Capacity Market Issues—PJM

December 31, 2016 Form 10-K page 16. During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. However, aspects of FERC's order are currently pending appeal in the Court of Appeals for the D.C. Circuit (D.C. Circuit). The CP product will be implemented fully for the 2020-2021 Delivery Year. FERC has approved changes to the CP construct that will enhance the participation of intermittent and DR resources ("seasonal resources"). Specifically, FERC approved PJM's modifications to the aggregation rules to improve the ability of seasonal resources to participate. However, two complaints remain pending that ask FERC to investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions. We do not expect action on the complaints before the upcoming base residual auction in May 2017.

Capacity Market Issues—ISO-NE

December 31, 2016 Form 10-K page 17. ISO-NE's market for installed capacity in New England provides fixed capacity payments for generators, imports and DR. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. ISO-NE also employs a mechanism, similar to PJM's CP mechanism, that provides incentives for performance and that imposes charges for non-performance during times of system stress. We view this mechanism as generally positive for generating resources as providing more robust income streams. However, it also imposes additional financial risk for non-performance. One aspect of the current market design that we do not support and are currently challenging in the D.C. Circuit is the exemption from the MOPR in the capacity market afforded for up to 200 MW annually (600 MW cumulatively) of renewable resources.

Price Formation Initiatives

December 31, 2016 Form 10-K page 18. Power has been actively involved both through stakeholder processes and through filings at FERC in seeking improvements to the rules for setting prices for energy in the day-ahead and real-time markets administered by PJM and other system operators. FERC recently issued a notice of proposed rulemaking (NOPR) proposing that RTOs/ISOs modify their rules governing fast-start resources. Fast-start resources typically are committed in real-time, very

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close to the interval when needed and can respond quickly to unforeseen system needs. However, without fast-start pricing, some fast-start resources are ineligible to set prices due to inflexible operating limits. As a result, prices may not reflect the marginal cost of serving load. In a separate proceeding, PJM has submitted a proposal at FERC's request to modify its rules to allow market sellers to submit day-ahead offers that vary by hour and to allow market sellers to update their offers in real time on an hourly basis under certain circumstances. FERC has accepted PJM's proposal which will become effective on November 1, 2017. We believe that both changes will improve price formation in the energy and ancillary services markets.

Transmission Regulation—Transmission Policy Developments

December 31, 2016 Form 10-K page 18. In August 2016, PJM announced that it had suspended the Artificial Island transmission project and would be performing a comprehensive analysis to support a future course of action. In March 2017, PJM staff made its final recommendation to the PJM Board with respect to the project. Under the recommended project, PSE&G will construct necessary upgrade work in Hope Creek, at a cost of approximately $130 million. In April 2017, the PJM Board announced that it would be lifting the suspension and approved the staff recommended project. The PJM Board also stated that it would be analyzing project beneficiaries from an alternate perspective to potentially devise an alternative cost allocation methodology for stability projects.

Transmission Regulation—Con Edison Wheeling Agreement

December 31, 2016 Form 10-K page 19. In April 2016, Con Edison informed PJM that it would allow its Wheeling Agreement to expire effective as of May 1, 2017. The Wheeling Agreement enables Con Edison to move 1,000 MW of power from southeastern New York across the PSE&G system for delivery into New York City. NYISO and PJM submitted proposed tariff provisions in January 2017. The proposal concerns future operational procedures and transmission planning assumptions associated with the affected transmission lines. FERC accepted the proposal, subject to refund, effective May 1, 2017. We cannot predict the impact of the proposal on energy prices or transmission planning at this time. Both PSE&G and the BPU protested certain aspects of the proposal. In a related filing, PJM submitted a proposal to FERC revising the cost responsibility assigned to certain entities, including PSE&G, due to the termination of the Wheeling Agreement. Also, PSE&G will continue to recover the costs associated with the new arrangement through its formula rate. We cannot predict the outcome of this proceeding.

State Regulation

Energy Efficiency Program (Energy Efficiency 2017)

In March 2017, we filed a petition with the BPU for our Energy Efficiency 2017 program, requesting extension of three Energy Efficiency Economic sub-programs (multi-family, direct install and hospital efficiency) and the addition of two new sub-programs (smart thermostat and residential data analytics). The petition requested additional capital expenditures of approximately $74 million, additional administrative and other costs of $22 million and information technology system enhancement costs of $3 million. We proposed to recover our investment in these sub-programs under the same clause recovery process as currently approved. This matter is pending.

Environmental Matters

Climate Change

***CO_2 Regulation under the* Clean Air Act (CAA)**

December 31, 2016 Form 10-K page 23. In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the New Source Performance Standards that establish emissions standards for CO_2 for certain new fossil power plants and the Clean Power Plan, a greenhouse gas emissions regulation under the CAA for existing power plants that establishes state-specific emission rate targets based on implementation of the best system of emission reduction. Upon completion of the review, the EPA is expected to suspend, revise or rescind the rules as appropriate. PSEG cannot estimate the impact of these actions on our business and future results of operations at this time.

Water Pollution Control

Steam Electric Effluent Guidelines

December 31, 2016 Form 10-K page 23. In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG Rule) for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Bridgeport Harbor station and the jointly-

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owned Keystone and Conemaugh stations, have bottom ash transport water discharges and that are regulated under this rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the rule. Power is unable to predict if this rule will have a material impact on its future capital requirements, financial condition and results of operations.

In April 2017, the EPA announced that it had granted a petition for reconsideration of the ELG Rule and is acting promptly to issue an administrative stay of the compliance dates in the rule that have not yet passed pending judicial review. The deadlines that are expected to be stayed include the BAT limitations and pretreatment standards for each of the following waste streams: fly ash transport water, bottom ash transport water, flue gas desulfurization wastewater, flue gas mercury control wastewater, and gasification wastewater. Power is unable to determine how this will ultimately impact compliance requirements or the financial impact it may have on the company.

Waters of the United States

December 31, 2016 Form 10-K page 24. In April 2014, the EPA Administrator and the Assistant Secretary of the Army (Civil Works) jointly published a proposed rule to clarify the definition of waters of the United States under the CWA programs in order to protect the streams and wetlands that form the foundation of the nation's water resources. This definition will have broad application to all areas of compliance under the CWA, including permitted discharges and construction activities. The final rule was published in June 2015 and various states, industry coalitions and environmental organizations have initiated legal action related to the provisions of the final rule as well as which court has jurisdiction over the rule. The U.S. Supreme Court is expected to rule on the question of jurisdiction by June 2017. Some states, including New Jersey, are subject to state requirements beyond those imposed under federal law. While we do not anticipate material impacts to projects in New Jersey, the new definition could impose requirements in other states and regions that could impact the development of renewables.

In February 2017, the President of the United States issued an Executive Order that instructed the EPA to review the rule and issue a proposal to redefine "Waters of the United States."

Endangered Species Act

December 31, 2016 Form 10-K page 25. In June 2015, the Sierra Club and another environmental group submitted to the NJDEP a sixty-day notice of intent to sue alleging the agency has caused violations of the Endangered Species Act by allowing our Mercer generation station to operate in a manner which has caused the mortality of certain species of sturgeon. Among other things, the notice requested the NJDEP to prioritize completion of a permit renewal action for Mercer which addresses the alleged Endangered Species Act violations. In March 2017, we submitted our Incidental Take Permit to the National Marine Fisheries Service outlining operation and monitoring requirements through retirement of the Mercer generation station on June 1, 2017 and subsequent decommissioning.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. PSE&G:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. Power:

Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
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Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

S1-SSA-0009 - 18556

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 28, 2017

S1-SSA-0009 - 18557

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 28, 2017

S1-SSA-0009 - 18558

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 28, 2017

S1-SSA-0009 - 18559

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2017	2016	2016	2015	2014	2013	2012
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 143	$ 754	$1,298	$2,680	$2,456	$2,055	$2,011
(Income) Loss from Equity Investees, net of Distributions	1	2	7	3	4	(7)	9
Fixed Charges	125	112	477	457	450	458	479
Capitalized Interest	24	(8)	(7)	(18)	(16)	(16)	(19)
Total Earnings	$ 293	$ 860	$1,775	$3,122	$2,894	$2,490	$2,480
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 119	$ 107	$ 456	$ 437	$ 430	$ 442	$ 465
Interest Factor in Rentals	6	5	21	20	20	16	14
Total Fixed Charges	$ 125	$ 112	$ 477	$ 457	$ 450	$ 458	$ 479
Ratio of Earnings to Fixed Charges	**2.34**	**7.68**	**3.72**	**6.83**	**6.43**	**5.44**	**5.18**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Three Months Ended March 31,		Years Ended December 31,				
	2017	2016	2016	2015	2014	2013	2012
			(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 470	$ 413	$1,404	$1,257	$ 1,174	$ 993	$ 835
Fixed Charges	82	75	316	306	303	316	314
Capitalized Interest	(5)	(4)	(17)	(17)	(16)	(16)	(13)
Total Earnings	$ 547	$ 484	$1,703	$1,546	$ 1,461	$1,293	$1,136
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 80	$ 72	$ 306	$ 297	$ 293	$ 309	$ 308
Interest Factor in Rentals	2	3	10	9	10	7	6
Total Fixed Charges	$ 82	$ 75	$ 316	$ 306	$ 303	$ 316	$ 314
Ratio of Earnings to Fixed Charges	**6.67**	**6.45**	**5.39**	**5.05**	**4.82**	**4.09**	**3.62**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period, (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries, and (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.2

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2017	2016	2016	2015	2014	2013	2012
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ (286)	$ 321	$ (43)	$1,367	$1,251	$1,063	$1,099
(Income) Loss from Equity Investees, net of Distributions	1	2	7	1	3	(10)	(6)
Fixed Charges	34	34	142	152	150	143	164
Capitalized Interest	29	(4)	11	(1)	1	1	(6)
Total Earnings	$ (222)	$ 353	$ 117	$1,519	$1,405	$1,197	$1,251
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 33	$ 33	$ 138	$ 148	$ 146	$ 139	$ 161
Interest Factor in Rentals	1	1	4	4	4	4	3
Total Fixed Charges	$ 34	$ 34	$ 142	$ 152	$ 150	$ 143	$ 164
Ratio of Earnings to Fixed Charges (C)	**(6.53)**	**10.38**	**0.82**	**9.99**	**9.37**	**8.37**	**7.63**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

(C) The ratio of earnings to fixed charges for the three months ended March 31, 2017, was (6.53), as noted above, which represents a deficiency of $256 million. The ratio of earnings to fixed charges for the year ended December 31, 2016, was 0.82, as noted above, which represents a deficiency of $25 million.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2017

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

S1-SSA-0009 - 18564

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2017

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2017

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 28, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
April 28, 2017

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
April 28, 2017

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
April 28, 2017

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
April 28, 2017

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
April 28, 2017

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
April 28, 2017

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED March 31, 2018
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐

If any of the registrants is an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of April 17, 2018, Public Service Enterprise Group Incorporated had outstanding 505,217,435 shares of its sole class of Common Stock, without par value.

As of April 17, 2018, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K. These factors include, but are not limited to:

- fluctuations in wholesale power and natural gas markets, including the potential impacts on the economic viability of our generation units;
- our ability to obtain adequate fuel supply;
- any inability to manage our energy obligations with available supply;
- increases in competition in wholesale energy and capacity markets;
- changes in technology related to energy generation, distribution and consumption and customer usage patterns;
- economic downturns;
- third-party credit risk relating to our sale of generation output and purchase of fuel;
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements;
- changes in state and federal legislation and regulations;
- the impact of pending and any future rate case proceedings;
- regulatory, financial, environmental, health and safety risks associated with our ownership and operation of nuclear facilities;
- adverse changes in energy industry laws, policies and regulations, including market structures and transmission planning;
- changes in federal and state environmental regulations and enforcement;
- delays in receipt of, or an inability to receive, necessary licenses and permits;
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry;
- changes in tax laws and regulations;
- the impact of our holding company structure on our ability to meet our corporate funding needs, service debt and pay dividends;
- lack of growth or slower growth in the number of customers or changes in customer demand;
- any inability of Power to meet its commitments under forward sale obligations;
- reliance on transmission facilities that we do not own or control and the impact on our ability to maintain adequate transmission capacity;
- any inability to successfully develop or construct generation, transmission and distribution projects;
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers;
- our inability to exercise control over the operations of generation facilities in which we do not maintain a controlling interest;

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- any inability to recover the carrying amount of our long-lived assets and leveraged leases;
- any inability to maintain sufficient liquidity;
- any inability to realize anticipated tax benefits or retain tax credits;
- challenges associated with recruitment and/or retention of key executives and a qualified workforce;
- the impact of our covenants in our debt instruments on our operations; and
- the impact of acts of terrorism, cybersecurity attacks or intrusions.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business, prospects, financial condition, results of operations or cash flows. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even in light of new information or future events, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

FILING FORMAT

This combined Quarterly Report on Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to “we,” “us,” and “our” relate to PSEG or to the specific company or companies being discussed.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended March 31,	
	2018	**2017**
OPERATING REVENUES	$ 2,818	$ 2,591
OPERATING EXPENSES		
Energy Costs	952	868
Operation and Maintenance	754	717
Depreciation and Amortization	280	828
Total Operating Expenses	1,986	2,413
OPERATING INCOME	832	178
Income from Equity Method Investments	2	3
Net Gains (Losses) on Trust Investments	(22)	28
Other Income (Deductions)	32	32
Non-Operating Pension and OPEB Credits (Costs)	19	—
Interest Expense	(103)	(98)
INCOME BEFORE INCOME TAXES	760	143
Income Tax Expense	(202)	(29)
NET INCOME	$ 558	$ 114
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:		
BASIC	504	505
DILUTED	507	508
NET INCOME PER SHARE:		
BASIC	$ 1.11	$ 0.23
DILUTED	$ 1.10	$ 0.22
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.45	$ 0.43

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2018	**2017**
NET INCOME	$ 558	$ 114
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $9 and $(16) for 2018 and 2017, respectively	(14)	15
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(3) and $(4) for 2018 and 2017, respectively	8	6
Other Comprehensive Income (Loss), net of tax	(6)	21
COMPREHENSIVE INCOME	$ 552	$ 135

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 118	$ 313
Accounts Receivable, net of allowances of $62 in 2018 and $59 in 2017	1,320	1,348
Tax Receivable	121	127
Unbilled Revenues	196	296
Fuel	162	289
Materials and Supplies, net	574	577
Prepayments	114	118
Derivative Contracts	43	29
Regulatory Assets	139	211
Other	19	4
Total Current Assets	2,806	3,312
PROPERTY, PLANT AND EQUIPMENT	42,033	41,231
Less: Accumulated Depreciation and Amortization	(9,628)	(9,434)
Net Property, Plant and Equipment	32,405	31,797
NONCURRENT ASSETS		
Regulatory Assets	3,208	3,222
Long-Term Investments	938	932
Nuclear Decommissioning Trust (NDT) Fund	2,051	2,133
Long-Term Receivable of Variable Interest Entity (VIE)	690	686
Rabbi Trust Fund	225	231
Goodwill	16	16
Other Intangibles	131	114
Derivative Contracts	48	7
Other	272	266
Total Noncurrent Assets	7,579	7,607
TOTAL ASSETS	$ 42,790	$ 42,716

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	March 31, 2018	December 31, 2017
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 1,000	$ 1,000
Commercial Paper and Loans	594	542
Accounts Payable	1,295	1,694
Derivative Contracts	10	16
Accrued Interest	147	103
Accrued Taxes	173	48
Clean Energy Program	85	128
Obligation to Return Cash Collateral	136	129
Regulatory Liabilities	34	47
Other	474	461
Total Current Liabilities	3,948	4,168
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	5,329	5,240
Regulatory Liabilities	2,942	2,948
Asset Retirement Obligations	1,037	1,024
OPEB Costs	1,432	1,455
OPEB Costs of Servco	550	542
Accrued Pension Costs	508	537
Accrued Pension Costs of Servco	126	129
Environmental Costs	342	357
Derivative Contracts	2	5
Long-Term Accrued Taxes	176	175
Other	222	221
Total Noncurrent Liabilities	12,666	12,633
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 10)		
CAPITALIZATION		
LONG-TERM DEBT	12,072	12,068
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2018 and 2017—534 shares	4,946	4,961
Treasury Stock, at cost, 2018—30 shares; 2017—29 shares	(816)	(763)
Retained Earnings	10,385	9,878
Accumulated Other Comprehensive Loss	(411)	(229)
Total Stockholders' Equity	14,104	13,847
Total Capitalization	26,176	25,915
TOTAL LIABILITIES AND CAPITALIZATION	$ 42,790	$ 42,716

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2018	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 558	$ 114
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	280	828
Amortization of Nuclear Fuel	50	54
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	24	26
Provision for Deferred Income Taxes (Other than Leases) and ITC	76	(85)
Non-Cash Employee Benefit Plan Costs	17	23
Leveraged Lease (Income) Loss, Adjusted for Rents Received and Deferred Taxes	4	(15)
Net (Gain) Loss on Lease Investments	—	32
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(119)	(5)
Net Change in Regulatory Assets and Liabilities	(6)	(60)
Cost of Removal	(38)	(24)
Net (Gains) Losses and (Income) Expense from NDT Fund	12	(23)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	6	69
Accrued Taxes	125	143
Margin Deposit	25	(4)
Other Current Assets and Liabilities	160	163
Employee Benefit Plan Funding and Related Payments	(36)	(28)
Other	2	(11)
Net Cash Provided By (Used In) Operating Activities	1,140	1,197
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,053)	(1,062)
Purchase of Emissions Allowances and RECs	(17)	(15)
Proceeds from Sales of Trust Investments	397	298
Purchases of Trust Investments	(407)	(307)
Other	7	7
Net Cash Provided By (Used In) Investing Activities	(1,073)	(1,079)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	52	(73)
Cash Dividends Paid on Common Stock	(227)	(218)
Other	(73)	(56)
Net Cash Provided By (Used In) Financing Activities	(248)	(347)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(181)	(229)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	315	426
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 134	$ 197
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (4)	$ (80)
Interest Paid, Net of Amounts Capitalized	$ 73	$ 77
Accrued Property, Plant and Equipment Expenditures	$ 544	$ 492

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2018	**2017**
OPERATING REVENUES	$ 1,845	$ 1,826
OPERATING EXPENSES		
Energy Costs	782	762
Operation and Maintenance	391	370
Depreciation and Amortization	190	171
Total Operating Expenses	1,363	1,303
OPERATING INCOME	482	523
Net Gains (Losses) on Trust Investments	—	2
Other Income (Deductions)	20	22
Non-Operating Pension and OPEB Credits (Costs)	15	(2)
Interest Expense	(81)	(75)
INCOME BEFORE INCOME TAXES	436	470
Income Tax Expense	(117)	(171)
NET INCOME	$ 319	$ 299

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended March 31,	
	2018	**2017**
NET INCOME	$ 319	$ 299
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0 and $1 for 2018 and 2017, respectively	(1)	(1)
COMPREHENSIVE INCOME	$ 318	$ 298

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	March 31, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 48	$ 242
Accounts Receivable, net of allowances of $62 in 2018 and $59 in 2017	961	882
Unbilled Revenues	196	296
Materials and Supplies	199	197
Prepayments	22	44
Regulatory Assets	139	211
Other	17	4
Total Current Assets	1,582	1,876
PROPERTY, PLANT AND EQUIPMENT	29,689	29,117
Less: Accumulated Depreciation and Amortization	(6,154)	(6,101)
Net Property, Plant and Equipment	23,535	23,016
NONCURRENT ASSETS		
Regulatory Assets	3,208	3,222
Long-Term Investments	284	280
Rabbi Trust Fund	45	46
Other	120	114
Total Noncurrent Assets	3,657	3,662
TOTAL ASSETS	$ 28,774	$ 28,554

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2018	December 31, 2017
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 750	$ 750
Accounts Payable	613	728
Accounts Payable—Affiliated Companies	385	340
Accrued Interest	92	78
Clean Energy Program	85	128
Obligation to Return Cash Collateral	136	129
Regulatory Liabilities	34	47
Other	327	311
Total Current Liabilities	2,422	2,511
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	3,443	3,391
OPEB Costs	1,078	1,103
Accrued Pension Costs	207	226
Regulatory Liabilities	2,942	2,948
Environmental Costs	268	283
Asset Retirement Obligations	214	212
Long-Term Accrued Taxes	93	91
Other	112	114
Total Noncurrent Liabilities	8,357	8,368
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 10)		
CAPITALIZATION		
LONG-TERM DEBT	7,843	7,841
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2018 and 2017—132 shares	892	892
Contributed Capital	1,095	1,095
Basis Adjustment	986	986
Retained Earnings	7,180	6,861
Accumulated Other Comprehensive Income	(1)	—
Total Stockholder's Equity	10,152	9,834
Total Capitalization	17,995	17,675
TOTAL LIABILITIES AND CAPITALIZATION	$ 28,774	$ 28,554

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2018	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 319	$ 299
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	190	171
Provision for Deferred Income Taxes and ITC	40	160
Non-Cash Employee Benefit Plan Costs	9	13
Cost of Removal	(38)	(24)
Net Change in Regulatory Assets and Liabilities	(6)	(60)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	24	(34)
Materials and Supplies	(2)	(7)
Prepayments	22	3
Accounts Payable	(12)	(12)
Accounts Receivable/Payable—Affiliated Companies, net	40	15
Other Current Assets and Liabilities	39	40
Employee Benefit Plan Funding and Related Payments	(33)	(25)
Other	(15)	(24)
Net Cash Provided By (Used In) Operating Activities	577	515
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(750)	(748)
Proceeds from Sales of Trust Investments	5	10
Purchases of Trust Investments	(5)	(10)
Solar Loan Investments	(9)	(4)
Other	2	2
Net Cash Provided By (Used In) Investing Activities	(757)	(750)
CASH FLOWS FROM FINANCING ACTIVITIES		
Other	—	(1)
Net Cash Provided By (Used In) Financing Activities	—	(1)
Net Increase (Decrease) In Cash, Cash Equivalents and Restricted Cash	(180)	(236)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	244	393
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 64	$ 157
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ —	$ (26)
Interest Paid, Net of Amounts Capitalized	$ 65	$ 65
Accrued Property, Plant and Equipment Expenditures	$ 326	$ 287

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2018	**2017**
OPERATING REVENUES	$ 1,403	$ 1,269
OPERATING EXPENSES		
Energy Costs	746	692
Operation and Maintenance	246	232
Depreciation and Amortization	82	650
Total Operating Expenses	1,074	1,574
OPERATING INCOME (LOSS)	329	(305)
Income from Equity Method Investments	2	3
Net Gains (Losses) on Trust Investments	(22)	19
Other Income (Deductions)	11	11
Non-Operating Pension and OPEB Credits (Costs)	4	2
Interest Expense	(7)	(16)
INCOME (LOSS) BEFORE INCOME TAXES	317	(286)
Income Tax Benefit (Expense)	(83)	116
NET INCOME (LOSS)	$ 234	$ (170)

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
Millions
(Unaudited)

	Three Months Ended March 31,	
	2018	**2017**
NET INCOME (LOSS)	$ 234	$ (170)
Other Comprehensive Income (Loss), net of tax		
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $8 and $(18) for 2018 and 2017, respectively	(11)	19
Pension/OPEB adjustment, net of tax (expense) benefit of $(3) and $(4) for 2018 and 2017, respectively	6	5
Other Comprehensive Income (Loss), net of tax	(5)	24
COMPREHENSIVE INCOME (LOSS)	$ 229	$ (146)

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 11	$ 32
Accounts Receivable	301	380
Accounts Receivable—Affiliated Companies	215	221
Fuel	162	289
Materials and Supplies, net	370	376
Derivative Contracts	43	29
Prepayments	12	11
Other	4	3
Total Current Assets	1,118	1,341
PROPERTY, PLANT AND EQUIPMENT	11,980	11,755
Less: Accumulated Depreciation and Amortization	(3,291)	(3,159)
Net Property, Plant and Equipment	8,689	8,596
NONCURRENT ASSETS		
NDT Fund	2,051	2,133
Long-Term Investments	86	87
Goodwill	16	16
Other Intangibles	131	114
Rabbi Trust Fund	56	57
Derivative Contracts	48	7
Other	68	67
Total Noncurrent Assets	2,456	2,481
TOTAL ASSETS	$ 12,263	$ 12,418

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	March 31, 2018	December 31, 2017
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 250	$ 250
Accounts Payable	510	712
Accounts Payable—Affiliated Companies	69	57
Short-Term Loan from Affiliate	35	281
Derivative Contracts	10	16
Accrued Interest	43	20
Other	108	99
Total Current Liabilities	1,025	1,435
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	1,434	1,406
Asset Retirement Obligations	821	810
OPEB Costs	285	283
Derivative Contracts	2	5
Accrued Pension Costs	176	184
Long-Term Accrued Taxes	46	52
Other	141	140
Total Noncurrent Liabilities	2,905	2,880
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 10)		
LONG-TERM DEBT	2,137	2,136
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	5,320	4,911
Accumulated Other Comprehensive Loss	(352)	(172)
Total Member's Equity	6,196	5,967
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,263	$ 12,418

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Three Months Ended March 31,	
	2018	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income (Loss)	$ 234	$ (170)
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	82	650
Amortization of Nuclear Fuel	50	54
Provision for Deferred Income Taxes and ITC	33	(226)
Interest Accretion on Asset Retirement Obligation	10	8
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(119)	(5)
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	24	26
Non-Cash Employee Benefit Plan Costs	6	7
Net (Gains) Losses and (Income) Expense from NDT Fund	12	(23)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	133	155
Margin Deposit	25	(4)
Accounts Receivable	93	24
Accounts Payable	(89)	(18)
Accounts Receivable/Payable—Affiliated Companies, net	25	71
Other Current Assets and Liabilities	30	33
Employee Benefit Plan Funding and Related Payments	(2)	(2)
Other	(5)	—
Net Cash Provided By (Used In) Operating Activities	542	580
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(299)	(307)
Purchase of Emissions Allowances and RECs	(17)	(15)
Proceeds from Sales of Trust Investments	377	259
Purchases of Trust Investments	(389)	(268)
Short-Term Loan—Affiliated Company	—	(70)
Other	11	7
Net Cash Provided By (Used In) Investing Activities	(317)	(394)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	—	(175)
Short-Term Loan—Affiliated Company	(246)	—
Other	—	(4)
Net Cash Provided By (Used In) Financing Activities	(246)	(179)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(21)	7
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	32	11
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 11	$ 18
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 2	$ 19
Interest Paid, Net of Amounts Capitalized	$ 2	$ 5
Accrued Property, Plant and Equipment Expenditures	$ 218	$ 205

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

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Note 1. Organization, Basis of Presentation and Significant Accounting Policies

Organization

Public Service Enterprise Group Incorporated (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Public Service Electric and Gas Company (PSE&G)**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and energy efficiency and related programs in New Jersey, which are regulated by the BPU.
- **PSEG Power LLC (Power)**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) electric transmission and distribution (T&D) system under an Operations Services Agreement (OSA); PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2017.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All significant intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2017.

Significant Accounting Policies

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. Restricted cash consists primarily of deposits received related to various construction projects at PSE&G.

The following provides a reconciliation of cash, cash equivalents and restricted cash reported within the Condensed Consolidated Balance Sheets that sum to the total of the same such amounts for the beginning (December 31, 2017) and ending periods shown in the Condensed Consolidated Statements of Cash Flows for the three months ended March 31, 2018.

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	PSE&G	Power	Other (A)	Consolidated
			Millions	
As of December 31, 2017				
Cash and Cash Equivalents	$ 242	$ 32	$ 39	$ 313
Restricted Cash in Other Current Assets	—	—	—	—
Restricted Cash in Other Noncurrent Assets	2	—	—	2
Cash, Cash Equivalents and Restricted Cash	**$ 244**	**$ 32**	**$ 39**	**$ 315**
As of March 31, 2018				
Cash and Cash Equivalents	$ 48	$ 11	$ 59	$ 118
Restricted Cash in Other Current Assets	14	—	—	14
Restricted Cash in Other Noncurrent Assets	2	—	—	2
Cash, Cash Equivalents and Restricted Cash	**$ 64**	**$ 11**	**$ 59**	**$ 134**

(A) Includes amounts applicable to PSEG (parent corporation), Energy Holdings and Services.

Note 2. Recent Accounting Standards

New Standards Issued and Adopted

Revenue from Contracts With Customers—Accounting Standard Update (ASU) 2014-09, updated by ASUs 2015-14, 2016-08, 2016-10, 2016-12, 2016-20, 2017-13, 2017-14

This accounting standard, and related updates, were adopted on January 1, 2018 using the full retrospective transition method. There was no effect on net income as a result of adoption. However, certain retrospective adjustments were recorded in accordance with the new standard. At PSE&G, retrospective adjustments increased Operating Revenues by $14 million, Energy Costs by $9 million, and Operation and Maintenance (O&M) Expense by $5 million for the three months ended March 31, 2017. At Power, retrospective adjustments reduced Operating Revenues and Energy Costs by $15 million for the three months ended March 31, 2017. For disclosure requirements under this standard, including Nature of Goods and Services, Disaggregation of Revenues, and Remaining Performance Obligations under Fixed Consideration Contracts, see Note 3. Revenues.

Recognition and Measurement of Financial Assets and Financial Liabilities—ASU 2016-01

Power maintains an external master trust fund to provide for the costs of decommissioning upon termination of operations of its nuclear facilities. In addition, PSEG maintains a grantor trust which was established to meet the obligations related to its non-qualified pension plans and deferred compensation plans, commonly referred to as a "Rabbi Trust."

This accounting standard was adopted on January 1, 2018. Under the new guidance, equity investments in Power's Nuclear Decommissioning Trust (NDT) and PSEG's Rabbi Trust Funds are now measured at fair value with the unrealized gains and losses recognized through Net Income instead of Other Comprehensive Income (Loss). The debt securities in these trusts continue to be classified as available-for-sale with the unrealized gains and losses recorded as a component of Accumulated Other Comprehensive Income (Loss). Realized gains and losses on both equity and available-for-sale debt security investments are recorded in earnings and are included with the unrealized gains and losses on equity securities in Net Gains (Losses) on Trust Investments. Other-than-temporary impairments on NDT and Rabbi Trust securities are also included in Net Gains (Losses) on Trust Investments. A cumulative effect adjustment was made to reclassify the net unrealized gains related to equity investments of $342 million ($176 million, net of tax) from Accumulated Other Comprehensive Income to Retained Earnings on January 1, 2018. See Note 16. Accumulated Other Comprehensive Income (Loss), Net of Tax and Note 8. Trust Investments for further discussion.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments—ASU 2016-15

This accounting standard reduces the diversity in practice in how certain cash receipts and cash payments are presented and classified in the Statement of Cash Flows.

PSEG adopted this standard on January 1, 2018 using a retrospective transition method and had no changes in its presentation of its Statement of Cash Flows for each period presented.

Statement of Cash Flows: Restricted Cash—ASU 2016-18

This accounting standard was adopted on January 1, 2018. PSEG will continue the current balance sheet classification of restricted cash or restricted cash equivalents. PSEG has provided a reconciliation of cash and cash equivalents and restricted

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cash or restricted cash equivalents and has included a description of these amounts in Note 1. Organization, Basis of Presentation and Significant Accounting Policies. The effect of adoption on the March 31, 2017 Consolidated Statements of Cash Flows was immaterial.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (OPEB)—ASU 2017-07

This accounting standard was adopted on January 1, 2018. Under the new guidance, entities are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by their employees during the period. The other components of net benefit cost are required to be presented in the Statement of Operations separately from the service cost component after Operating Income. Additionally, only the service cost component will be eligible for capitalization, when applicable. As a result of adopting this standard, PSE&G reduced its charge to expense for the three months ended March 31, 2018 by approximately $14 million. For the three months ended March 31, 2017, the Condensed Consolidated Statements of Operations were recast to show retrospective adjustments of the non-service cost component of net benefit credits (costs) of $(2) million and $2 million at PSE&G and Power, respectively, from O&M Expense to a new line item after Operating Income entitled Non-Operating Pension and OPEB Credits (Costs). See Note 9. Pension and Other Postretirement Benefits (OPEB).

Stock Compensation - Scope of Modification Accounting—ASU 2017-09

This accounting standard was adopted on January 1, 2018. The standard will be applied prospectively to awards modified on or after January 1, 2018. PSEG does not expect a material impact from adoption of this new standard.

New Standards Issued But Not Yet Adopted

Leases—ASU 2016-02

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor will classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. However, existing guidance related to leveraged leases will not change.

ASU 2018-01 permits an entity to elect an optional transition practical expedient to exclude evaluation of land easements that exist or expired before the adoption of ASU 2016-02 and that were not previously accounted for as leases.

The standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its consolidated financial statements.

Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities—ASU 2017-12

This accounting standard's amendments more closely align hedge accounting with the companies' risk management activities in the financial statements. The amendments expand hedge accounting for both non-financial and financial risk components by permitting contractually specified components to be designated as the hedged risk in a cash flow hedge involving the purchase or sale of non-financial assets or variable rate financial instruments. Additionally, the amendments ease the operational burden of applying hedge accounting by allowing more time to prepare hedge documentation, and allowing effectiveness assessments to be performed on a qualitative basis after hedge inception.

The new guidance is effective for annual and interim periods beginning after December 15, 2018. The standard requires using a modified retrospective method upon adoption. Early adoption is permitted. PSEG is currently analyzing the impact of this standard on its consolidated financial statements.

Premium Amortization on Purchased Callable Debt Securities—ASU 2017-08

This accounting standard was issued to shorten the amortization period for certain callable debt securities held at a premium. Specifically, the standard requires the premium to be amortized to the earliest call date. The amendments do not require an accounting change for securities held at a discount; the discount continues to be amortized to maturity.

The standard is effective for annual and interim reporting periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period. If an entity early adopts the standard in an interim period, any

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adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity should apply this standard on a modified retrospective basis through a cumulative effect adjustment directly to retained earnings as of the beginning of the period of adoption. Additionally, in the period of adoption, an entity should provide disclosures about a change in accounting principle. PSEG is currently analyzing the impact of this standard on its financial statements.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income—ASU 2018-02

This accounting standard would affect any entity that is required to apply the provisions of the Accounting Standards Codification topic, "Income Statement-Reporting Comprehensive Income," and has items of other comprehensive income for which the related tax effects are presented in other comprehensive income as required by GAAP. Specifically, this standard would allow entities to record a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the newly enacted federal corporate income tax rate. The amount of the reclassification would be the difference between the historical corporate income tax rate and the newly enacted 21% corporate income tax rate.

The standard is effective for all entities for annual periods and interim periods within those annual periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period for public business entities for reporting periods for which financial statements have not yet been issued or made available for issuance.

An entity would be able to choose to apply this standard retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the new tax legislation enacted in 2017 is recognized or apply the standard in the reporting period adopted. PSEG is currently analyzing the impact this standard, if adopted, could have on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments—ASU 2016-13

This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however, this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

Simplifying the Test for Goodwill Impairment—ASU 2017-04

This accounting standard requires an entity to perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

An entity should apply this standard on a prospective basis and will be required to disclose the nature of and reason for the change in accounting principle upon transition. The new standard is effective for impairment tests for periods beginning January 1, 2020. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. PSEG is currently assessing the impact of this guidance upon its financial statements.

Note 3. Revenues

Nature of Goods and Services

The following is a description of principal activities by reportable segment from which PSEG, PSE&G and Power generate their revenues.

PSE&G

Revenues from Contracts with Customers

Electric and Gas Distribution and Transmission Revenues—PSE&G sells gas and electricity to customers under default commodity supply tariffs. PSE&G's regulated electric and gas default commodity supply and distribution services are separate

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tariffs which are satisfied as the product(s) and/or services are delivered to the customer. The electric and gas commodity and delivery tariffs are recurring contracts in effect until cancellation by the customer. Revenue is recognized over time as the service is rendered to the customer. Included in PSE&G's regulated revenues are unbilled electric and gas revenues which represent the estimated amount customers will be billed for services rendered from the most recent meter reading to the end of the respective accounting period.

PSE&G's transmission revenues are earned under a separate FERC tariff. The performance obligation of transmission service is satisfied over time as it is provided to and consumed by the customer. Revenue is recognized upon delivery of the transmission service. PSE&G's revenues from the transmission of electricity are recorded based on a FERC-approved annual formula rate mechanism. This mechanism provides for an annual filing of an estimated revenue requirement with rates effective January 1 of each year and a mechanism true-up to that estimate based on actual revenue requirements. The true-up mechanism is an alternative revenue which is outside the scope of revenue from contracts with customers.

Other Revenues from Contracts with Customers

Other revenues from contracts with customers, which are not a material source of PSE&G revenues, are generated primarily from appliance repair services and solar generation projects. The performance obligations under these contracts are satisfied and revenue is recognized as control of products is delivered or services are rendered.

Payment for services rendered and products transferred are typically due within 30 days of month of delivery.

Revenues Unrelated to Contracts with Customers

Other PSE&G revenues unrelated to contracts with customers are derived from alternative revenue mechanisms recorded pursuant to regulatory accounting guidance. These revenues, which include weather normalization, green energy program true-ups and transmission formula rate true-ups, are not a material source of PSE&G revenues.

Power

Revenues from Contracts with Customers

Electricity and Related Products—Wholesale and retail load contracts are executed in the different Independent System Operator (ISO) regions for the bundled supply of energy, capacity, renewable energy credits (RECs) and ancillary services representing Power's performance obligations. Revenue for these contracts is recognized over time as the bundled service is provided to the customer. Transaction terms generally run from several months to three years. Power also sells to the ISOs energy and ancillary services which are separately transacted in the day-ahead or real-time energy markets. The energy and ancillary services performance obligations are typically satisfied over time as delivered and revenue is recognized accordingly. Power generally reports electricity sales and purchases conducted with those individual ISOs net on an hourly basis in either Operating Revenues or Energy Costs in its Consolidated Statements of Operations. The classification depends on the net hourly activity.

Power enters into capacity sales and capacity purchases through the ISOs. The transactions are reported on a net basis dependent on Power's monthly net sale or purchase position through the individual ISOs. The performance obligations with the ISOs are satisfied over time upon delivery of the capacity and revenue is recognized accordingly. In addition to capacity sold through the ISOs, Power sells capacity through bilateral contracts and the related revenue is recognized over time upon delivery of the capacity.

Gas Contracts—Power sells wholesale natural gas, primarily through an indexed based full requirements Basic Gas Supply Service (BGSS) contract with PSE&G to meet the gas supply requirements of PSE&G's customers. The BGSS contract, which extends through March 2019, will renew year-to-year thereafter unless terminated by either party with a two year notice. The performance obligation is primarily delivery of gas which is satisfied over time. Revenue is recognized as gas is delivered. Based upon the availability of natural gas, storage and pipeline capacity beyond PSE&G's daily needs, Power also sells gas and pipeline capacity to other counterparties under bilateral contracts. The performance obligation under these contracts is satisfied over time upon delivery of the gas or capacity, and revenue is recognized accordingly.

Other Revenues from Contracts with Customers

Power enters into bilateral contracts to sell solar power and solar RECs from its solar facilities. Contract terms range from 15 to 30 years. The performance obligations are generally solar power and RECs which are transferred to customers upon generation. Revenue is recognized upon generation of the solar power.

Power has entered into long-term contracts with LIPA for energy management and fuel procurement services. Revenue is recognized over time as services are rendered.

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Revenues Unrelated to Contracts with Customers

Power's revenues unrelated to contracts with customers include electric, gas and certain energy-related transactions accounted for in accordance with Derivatives and Hedging accounting guidance. See Note 12. Financial Risk Management Activities for further discussion. Power is also a party to solar contracts that qualify as leases and are accounted for in accordance with lease accounting guidance.

Other

Revenues from Contracts with Customers

PSEG LI has a contract with LIPA which generates revenues. PSEG LI's subsidiary, Long Island Electric Utility Servco, LLC (Servco) records costs which are recovered from LIPA and records the recovery of those costs as revenues when Servco is a principal in the transaction.

Revenues Unrelated to Contracts with Customers

Energy Holdings generates lease revenues which are recorded pursuant to lease accounting guidance.

Disaggregation of Revenues

	PSE&G	Power	Other	Eliminations	Consolidated
			Millions		
Three Months Ended March 31, 2018					
Revenues from Contracts with Customers					
Electric Distribution	$ 690	$ —	$ —	$ —	$ 690
Gas Distribution	759	—	—	(3)	756
Transmission	312	—	—	—	312
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	498	—	—	498
Sales to Affiliates	—	176	—	(176)	—
New York ISO	—	59	—	—	59
ISO New England	—	47	—	—	47
Gas Sales					
Third Party Sales	—	64	—	—	64
Sales to Affiliates	—	397	—	(397)	—
Other Revenues from Contracts with Customers (A)	72	10	137	(1)	218
Total Revenues from Contracts with Customers	1,833	1,251	137	(577)	2,644
Revenues Unrelated to Contracts with Customers (B)	12	152	10	—	174
Total Operating Revenues	**$ 1,845**	**$ 1,403**	**$ 147**	**$ (577)**	**$ 2,818**

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	PSE&G	Power	Other	Eliminations	Consolidated
			Millions		
Three Months Ended March 31, 2017					
Revenues from Contracts with Customers					
Electric Distribution	$ 701	$ —	$ —	$ —	$ 701
Gas Distribution	755	—	—	(1)	754
Transmission	299	—	—	—	299
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	314	—	—	314
Sales to Affiliates	—	184	—	(184)	—
New York ISO	—	36	—	—	36
ISO New England	—	11	—	—	11
Gas Sales					
Third Party Sales	—	52	—	—	52
Sales to Affiliates	—	401	—	(401)	—
Other Revenues from Contracts with Customers (A)	62	10	128	(1)	199
Total Revenues from Contracts with Customers	1,817	1,008	128	(587)	2,366
Revenues Unrelated to Contracts with Customers (B)	9	261	(45)	—	225
Total Operating Revenues	**$ 1,826**	**$ 1,269**	**$ 83**	**$ (587)**	**$ 2,591**

(A) Includes primarily revenues from appliance repair services at PSE&G, solar power projects and energy management and fuel service contracts with LIPA at Power, and PSEG LI's OSA with LIPA in Other.

(B) Includes primarily alternative revenues at PSE&G, derivative contracts at Power, and lease contracts in Other. In 2017, Other includes a $55 million loss related to Energy Holdings' investments in leases.

Contract Balances

PSE&G

PSE&G does not have any material contract balances (rights to consideration for services already provided or obligations to provide services in the future for consideration already received) as of March 31, 2018 and 2017. Substantially all of PSE&G's accounts receivable result from contracts with customers. Allowances represented approximately six percent and seven percent of accounts receivable as of March 31, 2018 and 2017, respectively.

Power

Power generally collects consideration upon satisfaction of performance obligations, and therefore, Power had no material contract balances as of March 31, 2018 and 2017.

Power's accounts receivable include amounts resulting from contracts with customers and other contracts which are out of scope of accounting guidance for revenues from contracts with customers. The majority of these accounts receivable are subject to master netting agreements. As a result, accounts receivable resulting from contracts with customers and receivables unrelated to contracts with customers are netted within Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets. In the wholesale energy markets in which Power operates, payment for services rendered and products transferred are typically due within 30 days of month of delivery. As such, there is little credit risk associated with these receivables and Power typically records no allowances.

Other

PSEG LI does not have any material contract balances as of March 31, 2018 and 2017.

Remaining Performance Obligations under Fixed Consideration Contracts

Power and PSE&G primarily record revenues as allowed by the guidance, which states that if an entity has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the entity's performance

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completed to date, the entity may recognize revenue in the amount to which the entity has a right to invoice. PSEG has future performance obligations under contracts with fixed consideration as follows:

Power

As stated above, capacity transactions with ISOs are reported on a net basis dependent on Power's monthly net sale or purchase position through the individual ISOs.

Capacity Payments from the PJM RPM Annual Base Residual and Incremental Auctions—The Base Residual Auction is conducted annually three years in advance of the operating period. Power expects to realize the following average capacity prices for capacity obligations to be satisfied resulting from the base and incremental auctions which have been completed:

Delivery Year	$ per MW-Day	MW Cleared
June 2017 to May 2018	$171	9,700
June 2018 to May 2019	$205	9,200
June 2019 to May 2020	$116	8,900
June 2020 to May 2021	$174	7,800

Capacity Payments from the New England ISO Forward Capacity Market—The Forward Capacity Market Auction is conducted annually three years in advance of the operating period. Power expects to realize the following average capacity prices through May 2022 for capacity obligations to be satisfied resulting from the Forward Capacity Market auctions which have been completed:

Delivery Year	$ per MW-Day	MW Cleared
June 2017 to May 2018	$231	850
June 2018 to May 2019	$314	830
June 2019 to May 2020	$231	850
June 2020 to May 2021	$174	850
June 2021 to May 2022	$152	460

In addition to the capacity listed in the table above, Power expects to realize payments for capacity obligations of approximately 480 MW at $231/MW-day, adjusted annually, from 2019 to 2026 at the Bridgeport Harbor Station Unit 5.

Bilateral capacity contracts—Capacity obligations pursuant to contract terms through 2029 are anticipated to result in revenues totaling $180 million.

Other

The LIPA OSA is a 12-year services contract ending in 2025 with an annual fixed component. The fixed fee for the provision of services thereunder in 2018 is $64 million and will increase each year based on the change in the Consumer Price Index.

Note 4. Early Plant Retirements

Fossil

On June 1, 2017, Power completed its previously announced retirement of the generation operations of the existing coal/gas units at the Hudson and Mercer generating stations.

For the three months ended March 31, 2017, Power recognized total D&A of $574 million for the Hudson and Mercer units to reflect the significant shortening of their expected economic useful lives in 2017. In the three months ended March 31, 2018 and 2017, Power recognized pre-tax charges in Energy Costs of $4 million and $7 million, respectively, primarily for coal inventory lower of cost or market adjustments. Power is exploring various opportunities with these sites, including using the sites for alternative industrial activity or the disposition of one or both of the sites. If Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such environmental remediation are neither currently probable nor estimable but may be material.

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As of December 31, 2016, Power had reduced the estimated useful life of Bridgeport Harbor Station Unit 3 (BH3) from 2025 to the summer of 2021 as it was more likely than not it will retire the unit by this time.

PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the held for use classification of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Nuclear

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. In February 2018, Exelon, a co-owner of the Salem units, announced its intention to accelerate the closure of its Oyster Creek nuclear plant located in New Jersey, one year earlier than previously planned for economic reasons. In addition, First Energy announced in March 2018 the early retirement of four nuclear units at the Davis-Besse, Perry Nuclear and Beaver Valley nuclear plants in Ohio and Pennsylvania by 2021. These closures and retirements are generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a further shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of our nuclear units beyond the current year, including whether and to what extent these units participate in RPM capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be influenced by the financial outlook of the units, including the progress, timing and continued outlook for enactment of proposed legislation in the state of New Jersey. At a co-owners meeting in February 2018, Exelon and Power agreed to cancel the funding of future capital projects at the Salem generating station that are not required to meet NRC or other regulatory requirements or that are not required to ensure its safe operation. The companies agreed that the funding of these projects may be restored when and if legislation is enacted in New Jersey that sufficiently values the attributes of nuclear generation and Salem benefits from such legislation.

If any or all of the Salem and Hope Creek units were shut down, it would significantly alter New Jersey's energy supply predominately by increasing New Jersey's reliance on natural gas generation. Such a decrease in fuel diversity could also increase the market's vulnerability to price fluctuations and power disruptions in times of high demand. In April 2018, the New Jersey Legislature voted to pass legislation that would provide a safety net in order to prevent the loss of environmental attributes from selected nuclear generating stations. Power cannot predict whether the legislation will be enacted or, if enacted, whether our nuclear generating stations in New Jersey will be selected or whether the legislation will provide a sufficient safety net for the continued operation of nuclear generating stations in New Jersey.

If market prices continue to be depressed and legislation is not enacted that adequately compensates nuclear generating stations for their attributes, Power anticipates it will no longer be covering its costs nor be adequately compensated for its market and operational risks at the Salem and Hope Creek nuclear units and would anticipate retiring these units early. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs and additional funding of the NDT Fund would be material to both PSEG and Power.

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The following table provides the balance sheet amounts by generating station as of March 31, 2018 for significant assets and liabilities associated with Power's owned share of its nuclear assets.

	As of March 31, 2018			
	Hope Creek	Salem	Support Facilities and Other (A)	Peach Bottom
	Millions			
Assets				
Materials and Supplies Inventory	$ 84	$ 83	$ —	$ 41
Nuclear Production, net of Accumulated Depreciation	602	653	207	797
Nuclear Fuel In-Service, net of Accumulated Depreciation	88	107	—	136
Construction Work in Progress (including nuclear fuel)	296	97	1	20
Total Assets	$ 1,070	$ 940	$ 208	$ 994
Liability				
Asset Retirement Obligation	$ 305	$ 252	$ —	$ 207
Total Liabilities	$ 305	$ 252	$ —	$ 207
Net Assets	$ 765	$ 688	$ 208	$ 787
NRC License Renewal Term	2046	2036/2040	N/A	2033/2034
% Owned	100%	57%	Various	50%

(A) Includes Hope Creek's and Salem's shared support facilities and other nuclear development capital.

The precise timing of any potential early retirement and resulting financial statement impact may be affected by a number of factors, including co-owner considerations, the results of any transmission system reliability study assessments and decommissioning trust fund requirements and other commitments, as well as future energy prices. Power maintains a NDT Fund that funds its decommissioning obligations. See Note 8. Trust Investments.

Note 5. Variable Interest Entity (VIE)

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Servco, a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal and controls the services provided to LIPA, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and O&M Expense, respectively. Servco recorded $120 million and $112 million for the three months ended March 31, 2018 and 2017, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

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Note 6. Rate Filings

This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2017.

In addition to items previously reported in the Annual Report on Form 10-K, significant regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

Electric and Gas Distribution Base Rate Filing—In January 2018, PSE&G filed a distribution base rate case as required as a condition of approval of its Energy Strong Program approved by the BPU in 2014. The filing requested an approximate 1% increase in revenues and recovery of investments made to strengthen the electric and gas distribution systems. The requested increase took into account a reduction in the revenue requirement as a result of the federal corporate income tax rate reduction from 35% to 21% provided in the Tax Cuts and Jobs Act of 2017 (Tax Act), including the flow-back to customers of excess accumulated deferred income taxes. In March 2018, the BPU approved interim rate reductions for all their jurisdictional utilities, including PSE&G, reflecting the reduction in the federal corporate tax rate. The BPU approved a reduction to PSE&G's current base electric and gas revenues effective April 1, 2018 by $71 million and $43 million, respectively, on an annual basis (or about 2% combined). The refund to customers for over-collection of revenues at the higher tax rate for the January 1 to March 31, 2018 period, and the flow-back to customers of certain excess deferred income taxes will be addressed in PSE&G's ongoing base rate case proceeding. As a result of the base rate reduction implemented on April 1, 2018, among other factors, PSE&G's requested revenue requirement in its filing will increase accordingly. PSE&G anticipates a decision by the BPU that new base rates will go into effect in the fourth quarter of 2018.

Transmission Formula Rate Filings—In January 2018, PSE&G filed with FERC a revised 2018 Annual Transmission Formula Rate Update reducing its 2018 transmission annual revenue requirement to reflect the federal corporate income tax rate reduction from 35% to 21% as a result of the Tax Act. This change in the federal corporate tax rate reduces the 2018 annual revenue requirement by $148 million, effective January 1, 2018. FERC continues to assess whether, and if so how, it will address changes and flow-backs to customers relating to accumulated deferred income taxes and bonus depreciation.

BGSS—In April 2018, the BPU approved the final BGSS rates which were effective October 1, 2017.

In December 2017, February 2018 and March 2018, PSE&G filed with the BPU for self-implementing monthly bill credits of 15 cents per therm for the months of January through April 2018. Monthly bill credits of $104 million were credited to customers for the months of January through March and an additional $15 million is estimated to be credited in April.

Energy Strong Recovery Filing—In March and September of each year, PSE&G files with the BPU for base rate recovery of Energy Strong investments which include a return of and on its investment.

In February 2018, the BPU approved recovery of an annual revenue requirement of $8 million associated with electric Energy Strong capital investment costs placed in service from June 1, 2017 through November 30, 2017.

Societal Benefits Charge—In February 2018, the BPU approved PSE&G's petition to increase electric rates by approximately $20 million on an annual basis and to decrease gas rates by approximately $0.8 million on an annual basis, in order to recover electric and gas costs incurred through May 31, 2017 under its Energy Efficiency and Renewable Energy and Social Programs. The new rates are effective April 1, 2018.

Weather Normalization Clause—In April 2018, the BPU gave final approval to PSE&G's petition to collect $55 million in net deficiency gas revenues as a result of the warmer than normal 2016-2017 Winter Period, which resulted in a deficiency of $31 million, plus a carryover balance of $24 million from the 2015-2016 Winter period.

Note 7. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. Interest income on the loans is recorded on an accrual basis. The loans are generally paid back with solar renewable energy certificates (SRECs) generated from the installed solar electric system. In the event of a loan default, the basis of the solar loan would be recovered through a regulatory recovery mechanism. None of the solar loans are impaired; however, in the event a loan becomes impaired, the basis of the loan would be recovered through a regulatory recovery mechanism. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

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Outstanding Loans by Class of Customer

Consumer Loans	As of March 31, 2018	As of December 31, 2017
	Millions	
Commercial/Industrial	$ 168	$ 158
Residential	10	10
Total	**$ 178**	**$ 168**

Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third-party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

During the first quarter of 2017, due to continuing liquidity issues facing NRG REMA, LLC (REMA), economic challenges facing coal generation in PJM, as discussed in Note 4. Early Plant Retirements, and based upon an ongoing review of available alternatives as well as certain discussions with REMA management, Energy Holdings recorded a $55 million pre-tax charge for its current best estimate of loss related to the lease receivables. Lease payments and adjustments to qualifying credit support on the REMA leases are received semiannually in January and July of each year.

In June 2017, GenOn Energy, Inc. (GenOn) and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code. GenOn is a subsidiary of NRG Energy, Inc. and is the parent of REMA. REMA was not included in the GenOn filing. Energy Holdings continues to monitor the restructuring of GenOn and its possible impacts on REMA and continues to discuss the situation with various parties relevant to this matter. During the second quarter of 2017, Energy Holdings completed its review of estimated residual values embedded in its leveraged lease portfolio of generating assets and the outcome indicated that one of the residual value estimates was lower than the recorded residual value due to a further deterioration of market conditions and changes to operating cost estimates. This decline was determined to be other than temporary. As a result, a pre-tax write-down of $7 million was recorded in the quarter ended June 30, 2017. In addition, based on an ongoing review of (i) the liquidity challenges facing REMA and (ii) available alternatives, Energy Holdings recorded an additional $15 million pre-tax charge in the quarter ended June 30, 2017, for its current best estimate of loss related to lease receivables. Pre-tax write-downs and additional charges were reflected in Operating Revenues in the first half of 2017 and are included in Gross Investment in Leases as of March 31, 2018.

In January 2018, certain subsidiaries of Energy Holdings, REMA, certain holders of the pass-through certificates and other parties entered into a Forbearance Agreement (Forbearance) relating to the Conemaugh facility. Pursuant to the Forbearance, the parties thereto agreed to temporarily forbear from exercising rights and remedies related to certain events of default related to REMA's obligation to procure additional qualifying credit support. The Forbearance will remain effective until the earlier of (i) two weeks following the date on which Energy Holdings subsidiaries, REMA and/or the consenting certificate holders provide written notice to REMA of its intention to terminate the Forbearance, and (ii) the date on which any event of termination as specified in the Forbearance occurs. The Forbearance remains in effect.

PSEG cannot predict the outcome of GenOn's restructuring process or the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments. If lease rejections or foreclosures were to occur, Energy Holdings could potentially record additional pre-tax write-offs up to its gross investment in these facilities and may also be required to accelerate and pay material deferred tax liabilities to the Internal Revenue Service (IRS).

The following table shows Energy Holdings' gross and net lease investment as of March 31, 2018 and December 31, 2017, respectively.

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	As of March 31, 2018	As of December 31, 2017
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 545	$ 546
Estimated Residual Value of Leased Assets	326	326
Total Investment in Rental Receivables	871	872
Unearned and Deferred Income	(303)	(307)
Gross Investment in Leases	568	565
Deferred Tax Liabilities	(498)	(480)
Net Investment in Leases	**$ 70**	**$ 85**

The corresponding receivables associated with the lease portfolio are reflected as follows, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

Counterparties' Credit Rating Standard & Poor's (S&P) as of March 31, 2018	Lease Receivables, Net of Non-Recourse Debt As of March 31, 2018
	Millions
AA	$ 14
BBB+ — BBB-	316
BB-	133
CCC-	82
Total	**$ 545**

The "BB-" and the "CCC-" ratings in the preceding table represent lease receivables related to coal and gas-fired assets in Illinois and Pennsylvania, respectively. As of March 31, 2018, the gross investment in the leases of such assets, net of non-recourse debt, was $335 million ($(88) million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 132	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 85	64%	1,036	Gas	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 20	17%	1,711	Coal	CCC-	REMA (A)
Conemaugh Station Units 1 and 2	PA	$ 20	17%	1,711	Coal	CCC-	REMA (A)
Shawville Station Units 1, 2, 3 and 4	PA	$ 78	100%	596	Gas	CCC-	REMA (A)

(A) GenOn and certain of its subsidiaries (which did not include REMA) filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete. Certain subsidiaries of Energy Holdings, REMA, consenting holders of the pass-through certificates and other parties entered into a Forbearance relating to the Conemaugh facility.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease structures. These credit enhancement features vary from lease to lease. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and seek recovery of their investment, potentially

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including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital and trigger certain material tax obligations which could wholly or partially be mitigated by tax indemnification claims against the counterparty. A bankruptcy of a lessee would likely delay and potentially limit any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders.

Additional factors that may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and their affiliates and the quality and condition of assets under lease.

Note 8. Trust Investments

NDT Fund

Power maintains an external master NDT to fund its share of decommissioning costs for its five nuclear facilities upon their respective termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The funds are managed by third-party investment managers who operate under investment guidelines developed by Power.

The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of March 31, 2018			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 463	$ 226	$ (7)	$ 682
International	318	93	(7)	404
Total Equity Securities	781	319	(14)	1,086
Available-for Sale Debt Securities				
Government	518	1	(11)	508
Corporate	464	1	(9)	456
Total Available-for-Sale Debt Securities	982	2	(20)	964
Other	1	—	—	1
Total NDT Fund Investments (A)	**$ 1,764**	**$ 321**	**$ (34)**	**$ 2,051**

	As of December 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 497	$ 245	$ (2)	$ 740
International	311	99	(3)	407
Total Equity Securities	808	344	(5)	1,147
Available-for Sale Debt Securities				
Government	586	2	(4)	584
Corporate	400	4	(2)	402
Total Available-for-Sale Debt Securities	986	6	(6)	986
Total NDT Fund Investments	**$ 1,794**	**$ 350**	**$ (11)**	**$ 2,133**

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Net unrealized gains (losses) on debt securities of $(10) million (after-tax) were included in Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of March 31, 2018. The portion of net unrealized gains (losses) recognized during the first quarter of 2018 related to equity securities still held at the end of March 31, 2018 was $(10) million.

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of March 31, 2018	As of December 31, 2017
	Millions	
Accounts Receivable	$ 13	$ 24
Accounts Payable	$ 9	$ 74

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of March 31, 2018				As of December 31, 2017			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)								
Domestic	$ 117	$ (7)	$ —	$ —	$ 40	$ (2)	$ —	$ —
International	65	(7)	1	—	29	(3)	2	—
Total Equity Securities	182	(14)	1	—	69	(5)	2	—
Available-for Sale Debt Securities								
Government (B)	364	(7)	80	(4)	343	(2)	91	(2)
Corporate (C)	339	(8)	25	(1)	191	(1)	27	(1)
Total Available-for-Sale Debt Securities	703	(15)	105	(5)	534	(3)	118	(3)
NDT Trust Investments	**$ 885**	**$ (29)**	**$ 106**	**$ (5)**	**$ 603**	**$ (8)**	**$ 120**	**$ (3)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. Effective January 1, 2018, unrealized gains and losses on these securities are recorded in Net Income.

(B) Debt Securities (Government)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). The unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. Power also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2018.

(C) Debt Securities (Corporate)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2018.

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The proceeds from the sales of and the net gains (losses) on securities in the NDT Fund were:

	Three Months Ended March 31,	
	2018	2017
	Millions	
Proceeds from NDT Fund Sales (A)	**$ 372**	**$ 247**
Net Realized Gains (Losses) on NDT Fund		
Gross Realized Gains	$ 24	$ 21
Gross Realized Losses	(12)	(4)
Net Realized Gains (Losses) on NDT Fund (B)	**12**	**17**
Unrealized Gains (Losses) on Equity Securities in NDT Fund (C)	(34)	N/A
Other-Than-Temporary-Impairments	—	(1)
Net Gains (Losses) on NDT Fund Investments	**$ (22)**	**$ 16**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

(B) The cost of these securities was determined on the basis of specific identification.

(C) Effective January 1, 2018, unrealized gains (losses) on equity securities are recorded in Net Income instead of Other Comprehensive Income (Loss).

The NDT Fund debt securities held as of March 31, 2018 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 15
1 - 5 years	300
6 - 10 years	201
11 - 15 years	40
16 - 20 years	73
Over 20 years	335
Total NDT Available-for-Sale Debt Securities	**$ 964**

Power periodically assesses individual debt securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For these securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a “Rabbi Trust.”

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The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of March 31, 2018			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 21	$ 2	$ —	$ 23
International	—	—	—	—
Total Equity Securities	21	2	—	23
Available-for-Sale Debt Securities				
Government	91	—	(2)	89
Corporate	114	1	(2)	113
Total Available-for-Sale Debt Securities	205	1	(4)	202
Total Rabbi Trust Investments	**$ 226**	**$ 3**	**$ (4)**	**$ 225**

	As of December 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 24	$ 3	$ —	$ 27
International	—	—	—	—
Total Equity Securities	24	3	—	27
Available-for-Sale Debt Securities				
Government	85	1	(1)	85
Corporate	118	2	(1)	119
Total Available-for-Sale Debt Securities	203	3	(2)	204
Total Rabbi Trust Investments	**$ 227**	**$ 6**	**$ (2)**	**$ 231**

Net unrealized gains (losses) on debt securities of $(3) million (after-tax) were included in Accumulated Other Comprehensive Loss on PSEG's Condensed Consolidated Balance Sheet as of March 31, 2018. The portion of net unrealized gains (losses) recognized during the first quarter of 2018 related to equity securities still held at the end of March 31, 2018 was less than $(1) million.

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of March 31, 2018	As of December 31, 2017
	Millions	
Accounts Receivable	$ 2	$ 2
Accounts Payable	$ —	$ 1

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The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months.

	As of March 31, 2018				As of December 31, 2017			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)								
Domestic	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
International	—	—	—	—	—	—	—	—
Total Equity Securities	—	—	—	—	—	—	—	—
Available-for-Sale Debt Securities								
Government (B)	48	(1)	23	(1)	28	—	25	(1)
Corporate (C)	73	(2)	8	—	39	(1)	9	—
Total Available-for-Sale Debt Securities	121	(3)	31	(1)	67	(1)	34	(1)
Rabbi Trust Investments	**$ 121**	**$ (3)**	**$ 31**	**$ (1)**	**$ 67**	**$ (1)**	**$ 34**	**$ (1)**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors. Effective January 1, 2018, unrealized gains and losses on these securities are recorded in Net Income.

(B) Debt Securities (Government)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). The unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. PSEG also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2018.

(C) Debt Securities (Corporate)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of March 31, 2018.

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The proceeds from the sales of and the net gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended March 31,	
	2018	2017
	Millions	
Proceeds from Rabbi Trust Sales (A)	**$ 25**	**$ 51**
Net Realized Gains (Losses) on Rabbi Trust:		
Gross Realized Gains	$ 2	$ 15
Gross Realized Losses	(2)	(3)
Net Realized Gains (Losses) on Rabbi Trust (B)	**—**	**12**
Unrealized Gains (Losses) on Equity Securities in Rabbi Trust (C)	—	N/A
Other-Than-Temporary-Impairments	—	—
Net Gains (Losses) on Rabbi Trust Investments	**$ —**	**$ 12**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

(B) The cost of these securities was determined on the basis of specific identification.

(C) Effective January 1, 2018, unrealized gains (losses) on equity securities are recorded in Net Income instead of Other Comprehensive Income (Loss).

The Rabbi Trust debt securities held as of March 31, 2018 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 1
1 - 5 years	36
6 - 10 years	29
11 - 15 years	6
16 - 20 years	17
Over 20 years	113
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 202**

PSEG periodically assesses individual debt securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For these securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of March 31, 2018	As of December 31, 2017
	Millions	
PSE&G	$ 45	$ 46
Power	56	57
Other	124	128
Total Rabbi Trust Investments	**$ 225**	**$ 231**

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Note 9. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria.

The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis for PSEG, excluding Servco. Amounts shown do not reflect the impacts of capitalization. Effective with the adoption of ASU 2017-07 on January 1, 2018, only the service cost component is eligible for capitalization, when applicable. For additional information, see Note 2. Recent Accounting Standards.

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2018	2017	2018	2017
	Millions			
Components of Net Periodic Benefit (Credits) Costs				
Service Cost (included in O&M Expense)	$ 32	$ 29	$ 4	$ 4
Non-Operating Pension and OPEB (Credits) Costs				
Interest Cost	52	51	16	16
Expected Return on Plan Assets	(110)	(98)	(10)	(8)
Amortization of Net				
Prior Service Cost	(4)	(5)	—	(3)
Actuarial Loss	21	24	16	13
Non-Operating Pension and OPEB (Credits) Costs	**(41)**	**(28)**	**22**	**18**
Total Benefit (Credits) Costs	**$ (9)**	**$ 1**	**$ 26**	**$ 22**

Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, excluding Servco, are detailed as follows:

	Pension Benefits		OPEB	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2018	2017	2018	2017
	Millions			
PSE&G	$ (8)	$ (1)	$ 17	$ 14
Power	(2)	—	8	7
Other	1	2	1	1
Total Benefit (Credits) Costs	**$ (9)**	**$ 1**	**$ 26**	**$ 22**

During the three months ended March 31, 2018, PSEG contributed its entire planned contribution for the year 2018 of $14 million into its OPEB plan.

Servco Pension and OPEB

At the direction of LIPA, Servco sponsors benefit plans that cover its current and former employees who meet certain eligibility criteria. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 5. Variable Interest Entity. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

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Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco plans to contribute $40 million into its pension plan trusts during 2018. Servco's pension-related revenues and costs were $10 million and $9 million for the three months ended March 31, 2018 and 2017, respectively. The OPEB-related revenues earned and costs incurred were $1 million for each of the three months ended March 31, 2018 and 2017.

Note 10. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees as a form of collateral.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- the net position of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. Current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of March 31, 2018 and December 31, 2017.

	As of March 31, 2018	As of December 31, 2017
	Millions	
Face Value of Outstanding Guarantees	$ 1,755	$ 1,701
Exposure under Current Guarantees	$ 161	$ 153
Letters of Credit Margin Posted	$ 109	$ 103
Letters of Credit Margin Received	$ 18	$ 32
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (1)	$ (1)
Net Broker Balance Deposited (Received)	$ 122	$ 147
Additional Amounts Posted:		
Other Letters of Credit	$ 61	$ 61

As part of determining credit exposure, Power nets receivables and payables with the corresponding net fair values of energy contracts. See Note 12. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Condensed Consolidated Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power have posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The U.S. Environmental Protection Agency (EPA) has determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA and a comprehensive study of the entire 17 miles of the lower Passaic River needed to be performed. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, certain Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. The CPG has agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately 7.6 percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately 1.9 percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim. Certain PRPs are currently involved in discussions with the EPA regarding cost allocations and related indemnification matters.

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We cannot predict the outcome of these discussions, or whether individual PRPs will be able to meet their obligations, either of which could have a material impact on PSE&G's and Power's allocation of costs.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River with an estimated cost to remediate the lower 17 miles of the Passaic River ranging from approximately $518 million to $3.2 billion on an undiscounted basis.

In March 2016, the EPA released its Record of Decision (ROD) for the EPA's own Focused Feasibility Study (FFS) which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The EPA estimates the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation. Occidental Chemical Corporation, one of the PRPs, has committed to perform the remedial design required by the ROD Remedy, reserving its right of cost contribution from all other PRPs.

In September 2017, the EPA concluded that an Agency-commenced allocation process for the Passaic River's lower 8.3 miles should include only certain PRPs. The allocation is intended to lead to a consent decree in which certain of the PRPs agree to perform the remedial action under EPA oversight. Discussions on the matter are ongoing. Conversations between the EPA and the PRPs regarding remediation of the Passaic River's upper 9 miles are ongoing.

Based upon the estimated cost of the ROD Remedy and PSEG's estimate of PSE&G's and Power's shares of that cost, as of March 31, 2018, PSEG has accrued approximately $57 million. Of this amount, PSE&G has accrued $46 million as an Environmental Costs Liability and a corresponding Regulatory Asset based on its continued ability to recover such costs in its rates. Power has accrued $11 million as an Other Noncurrent Liability with the corresponding O&M Expense recorded in the periods when the liability was accrued.

The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on PSEG's financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

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MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $345 million and $391 million on an undiscounted basis through 2021, including its $46 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $345 million as of March 31, 2018. Of this amount, $79 million was recorded in Other Current Liabilities and $266 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $345 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly. NJDEP, PSEG and EPA representatives have had discussions regarding to what extent sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.

Clean Water Act (CWA) Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In May 2014, the EPA issued a final cooling water intake rule that establishes requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing power facilities on a case by case basis, based on studies related to impingement mortality and entrainment and submit the results with their permit applications to be conducted by the facilities seeking renewal permits.

Several environmental organizations and certain energy industry groups have filed suit under the CWA and the Endangered Species Act. The cases have been consolidated at the Second Circuit and a decision remains pending.

In June 2016, the NJDEP issued a final NJPDES permit for Salem. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the CWA, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final NJPDES renewal permit for Salem. NJDEP has granted the hearing request, but it has not yet been scheduled. The Riverkeeper's filing does not change the effective date of the permit. If the Riverkeeper's challenge were successful, Power may be required to incur additional costs to comply with the CWA. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

State permitting decisions at Bridgeport and possibly New Haven could also have a material impact on Power's ability to renew permits at its existing larger once-through cooled plants without making significant upgrades to existing intakes and cooling systems.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at BH3. To address compliance with the EPA's CWA Section 316(b) final rule, Power has proposed to continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the previously estimated useful life ending in 2025. Power is currently awaiting action by the CTDEEP to issue a draft and then a final permit.

Power has entered into a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut and local community organizations. That CEBA provides that Power would retire BH3 early if all of its conditions precedent occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power may seek to operate BH3 through the previously estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. The Connecticut Siting Council issued an order to approve siting Bridgeport Harbor Station Unit 5 (BH5). All major environmental

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permits have been received; however, secondary approvals are still being obtained to allow operations to begin in mid-2019. Power's obligations under the CEBA are being monitored regularly and carried out as needed.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.

Jersey City, New Jersey Subsurface Feeder Cable Matter

In October 2016, a discharge of dielectric fluid from subsurface feeder cables located in the Hudson River near Jersey City, New Jersey, was identified and reported to the NJDEP. The feeder cables are located within a subsurface easement granted to PSE&G by the property owners, Newport Associates Development Company (NADC) and Newport Associates Phase I Developer Limited Partnership. The feeder cables are subject to agreements between PSE&G and Consolidated Edison Company of New York, Inc. (Con Edison) and are jointly owned by PSE&G and Con Edison, with PSE&G owning the portion of the cables located in New Jersey and Con Edison owning the portion of the cables located in New York. The NJDEP declared an emergency and an emergency response action was undertaken to investigate, contain, remediate and stop the fluid discharge; to assess, repair and restore the cables to good working order, if feasible; and to restore the property. The regulatory agencies overseeing the emergency response, including the U.S. Coast Guard, the NJDEP and the Army Corps of Engineers, have issued multiple notices, orders and directives to the various parties related to this matter and the parties may also be subject to the assessment of civil penalties related to the discharge and response. The impacted cable was repaired in late-September 2017; however, dielectric fluid continues to appear on the surface and so the investigation and response actions related to the fluid discharge are ongoing. PSE&G may determine that retirement of the affected facilities would be appropriate. Also ongoing is the process to determine ultimate responsibility for the costs to address the leak among PSE&G, Con Edison and NADC, including an action filed by PSE&G in federal court in New Jersey seeking damages from NADC. In that action, NADC has also pursued counterclaims against PSE&G and Con Edison seeking damages for its costs to address the leak. Based on the information currently available and depending on the outcome of the federal court action, PSE&G's portion of the costs to address the leak may be material; however, PSE&G anticipates that it will recover these costs through regulatory proceedings.

Steam Electric Effluent Guidelines

In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG Rule) for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under the ELG Rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the ELG Rule.

Through various orders, the EPA has stayed the compliance dates in the ELG Rule and has announced plans to further revise the requirements and compliance dates of the ELG Rule. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2018 is $287.76 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2018 of $276.83 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

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PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2015	2016	2017	2018	
36-Month Terms Ending	May 2018	May 2019	May 2020	May 2021	(A)
Load (MW)	2,900	2,800	2,800	2,900	
$ per MWh	$99.54	$96.38	$90.78	$91.77	

(A) Prices set in the 2018 BGS auction year will become effective on June 1, 2018 when the 2015 BGS auction agreements expire.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 19. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2020 and a significant portion through 2021 at Salem, Hope Creek and Peach Bottom.

Power has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available beyond the needs of PSE&G's customers, Power can use the gas to supply its fossil generating stations in New Jersey.

Power also has various long-term fuel purchase commitments for coal through 2021 to support its fossil generation stations.

As of March 31, 2018, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2022
	Millions
Nuclear Fuel	
Uranium	$ 242
Enrichment	$ 346
Fabrication	$ 170
Natural Gas	$ 1,024
Coal	$ 286

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Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power has implemented procedures and continues to review its policies and practices to mitigate the risk of similar issues occurring in the future.

Since September 2014, FERC Staff has been conducting a preliminary, non-public staff investigation into these matters. In April 2018, a settlement agreement was entered into between PSEG and FERC Staff, approved by FERC on April 25, 2018, pursuant to which PSEG agreed to pay approximately $40 million for the full resolution of this matter. Accordingly, Power recorded an additional pre-tax charge to income of $5 million in the first quarter of 2018, resulting in a total liability of approximately $40 million accrued for the resolution of this matter. The settlement agreement does not require PSEG to change its business practices in a manner that would have a material impact on its ongoing business operations.

Other Litigation and Legal Proceedings

PSEG and its subsidiaries are party to various lawsuits in the ordinary course of business. In view of the inherent difficulty in predicting the outcome of such matters, PSEG, PSE&G and Power generally cannot predict the eventual outcome of the pending matters, the timing of the ultimate resolution of these matters, or the eventual loss, fines or penalties related to each pending matter.

In accordance with applicable accounting guidance, a liability is accrued when those matters present loss contingencies that are both probable and reasonably estimable. In such cases, there may be an exposure to loss in excess of any amounts accrued. PSEG will continue to monitor the matter for further developments that could affect the amount of the accrued liability that has been previously established.

Based on current knowledge, management does not believe that loss contingencies arising from pending matters, other than the matters described herein, could have a material adverse effect on PSEG's, PSE&G's or Power's consolidated financial position or liquidity. However, in light of the inherent uncertainties involved in these matters, some of which are beyond PSEG's control, and the large or indeterminate damages sought in some of these matters, an adverse outcome in one or more of these matters could be material to PSEG's, PSE&G's or Power's results of operations or liquidity for any particular reporting period.

Note 11. Debt and Credit Facilities

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under the $4.2 billion credit facilities are provided by a diverse bank group. As of March 31, 2018, the total available credit capacity was $3.4 billion.

As of March 31, 2018, no single institution represented more than 8% of the total commitments in the credit facilities.

As of March 31, 2018, total credit capacity was in excess of the total anticipated maximum liquidity requirements over PSEG's 12-month planning horizon.

Each of the credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support its subsidiaries' liquidity needs. The total credit facilities and available liquidity as of March 31, 2018 were as follows:

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Company/Facility	As of March 31, 2018 Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
		Millions			
PSEG					
5-year Credit Facilities (A)	$ 1,500	$ 609	$ 891	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSEG	**$ 1,500**	**$ 609**	**$ 891**		
PSE&G					
5-year Credit Facility (A)	$ 600	$ 16	$ 584	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 16**	**$ 584**		
Power					
3-year Letter of Credit Facilities	$ 200	$ 112	$ 88	Mar 2020	Letters of Credit
5-year Credit Facilities	1,900	46	1,854	Mar 2022	Funding/Letters of Credit
Total Power	**$ 2,100**	**$ 158**	**$ 1,942**		
Total	**$ 4,200**	**$ 783**	**$ 3,417**		

(A) The primary use of PSEG's and PSE&G's credit facilities is to support their respective Commercial Paper Programs, under which as of March 31, 2018, PSEG had $594 million outstanding at a weighted average interest rate of 2.57%. PSE&G had no amounts outstanding under its Commercial Paper Program as of March 31, 2018.

Note 12. Financial Risk Management Activities

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchases and normal sales (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow or fair value hedges. Power and PSE&G enter into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Power also uses derivatives to hedge a portion of its anticipated BGSS obligations with PSE&G. For additional information see Note 10. Commitments and Contingent Liabilities. Changes in the fair market value of these derivative contracts are recorded in earnings.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. The changes in fair value of the interest rate swaps are fully offset by changes in the fair value of the underlying forecasted interest payments of the debt. There were no outstanding interest rate swaps as of March 31, 2018 or December 31, 2017.

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Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. There were no outstanding interest rate hedges as of March 31, 2018 and December 31, 2017. The Accumulated Other Comprehensive Income (Loss) (after tax) related to existing and terminated interest rate derivatives designated as cash flow hedges was immaterial as of March 31, 2018 and December 31, 2017, respectively. The after-tax unrealized gains on these hedges expected to be reclassified to earnings during the next 12 months is immaterial.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with PSEG's accounting policy, these positions are offset on the Condensed Consolidated Balance Sheets of Power and PSEG. For additional information see Note 13. Fair Value Measurements.

The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of March 31, 2018			
	Power (A)			Consolidated
	Not Designated			
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Total Derivatives
	Millions			
Derivative Contracts				
Current Assets	$ 366	$ (323)	$ 43	$ 43
Noncurrent Assets	156	(108)	48	48
Total Mark-to-Market Derivative Assets	**$ 522**	**$ (431)**	**$ 91**	**$ 91**
Derivative Contracts				
Current Liabilities	$ (332)	$ 322	$ (10)	$ (10)
Noncurrent Liabilities	(109)	107	(2)	(2)
Total Mark-to-Market Derivative (Liabilities)	**$ (441)**	**$ 429**	**$ (12)**	**$ (12)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 81**	**$ (2)**	**$ 79**	**$ 79**

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	As of December 31, 2017			
	Power (A)			Consolidated
	Not Designated			
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Total Derivatives
	Millions			
Derivative Contracts				
Current Assets	$ 391	$ (362)	$ 29	$ 29
Noncurrent Assets	78	(71)	7	7
Total Mark-to-Market Derivative Assets	**$ 469**	**$ (433)**	**$ 36**	**$ 36**
Derivative Contracts				
Current Liabilities	$ (403)	$ 387	$ (16)	$ (16)
Noncurrent Liabilities	(95)	90	(5)	(5)
Total Mark-to-Market Derivative (Liabilities)	**$ (498)**	**$ 477**	**$ (21)**	**$ (21)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ (29)**	**$ 44**	**$ 15**	**$ 15**

(A) Substantially all of Power's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of March 31, 2018 and December 31, 2017.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of March 31, 2018 and December 31, 2017, Power had net cash collateral/margin payments to counterparties of $121 million and $146 million, respectively. Of these net cash/collateral margin payments $(2) million as of March 31, 2018 and $44 million as December 31, 2017 were netted against the corresponding net derivative contract positions. The $(2) million as of March 31, 2018 was netted against current assets. Of the $44 million as of December 31, 2017, $(3) million was netted against current assets, $28 million was netted against current liabilities, and $19 million was netted against noncurrent liabilities.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating by S&P or Moody's, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P or Moody's ratings. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $20 million and $30 million as of March 31, 2018 and December 31, 2017, respectively. As of March 31, 2018 and December 31, 2017, Power had the contractual right of offset of $9 million and $13 million, respectively, related to derivative instruments that are assets with the same counterparty under master agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $11 million and $17 million as of March 31, 2018 and December 31, 2017, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.

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The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2016	**$ 3**	**$ 2**
Gain Recognized in AOCI	—	—
Less: Gain Reclassified into Income	(3)	(2)
Balance as of December 31, 2017	**$ —**	**$ —**
Gain Recognized in AOCI	—	—
Less: Gain Reclassified into Income	—	—
Balance as of March 31, 2018	**$ —**	**$ —**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS for the three months ended March 31, 2018 and 2017. Power's derivative contracts reflected in this table include contracts to hedge the purchase and sale of electricity and natural gas, and the purchase of fuel. The table does not include contracts that Power has designated as NPNS, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives	
		Three Months Ended March 31,	
		2018	2017
		Millions	
PSEG and Power			
Energy-Related Contracts	Operating Revenues	$ 40	$ 78
Energy-Related Contracts	Energy Costs	(8)	—
Total PSEG and Power		**$ 32**	**$ 78**

The following table summarizes the net notional volume purchases/(sales) of open derivative transactions by commodity as of March 31, 2018 and December 31, 2017.

Type	Notional	Total	PSEG	Power	PSE&G
		Millions			
As of March 31, 2018					
Natural Gas	Dekatherm (Dth)	237	—	237	—
Electricity	MWh	(74)	—	(74)	—
Financial Transmission Rights (FTRs)	MWh	5	—	5	—
As of December 31, 2017					
Natural Gas	Dth	154	—	154	—
Electricity	MWh	(63)	—	(63)	—
FTRs	MWh	6	—	6	—

Credit Risk

Credit risk relates to the risk of loss that Power would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG has established credit policies that it believes significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral

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requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

The following table provides information on Power's credit risk from ER&T wholesale counterparties, net of collateral, as of March 31, 2018. It further delineates that exposure by the credit rating of the counterparties, which is determined by the lowest rating from S&P, Moody's or an internal scoring model. In addition, it provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

As of March 31, 2018, 99% of the net credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives, NPNS and non-derivatives).

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade	$ 337	$ 12	$ 325	1	$ 191	(A)
Non-Investment Grade	3	—	3	—	—	
Total	**$ 340**	**$ 12**	**$ 328**	**1**	**$ 191**	

(A) Represents net exposure with PSE&G.

As of March 31, 2018, collateral held from counterparties where Power had credit exposure was comprised of $12 million in letters of credit.

As of March 31, 2018, Power had 142 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of March 31, 2018, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's BGS suppliers' credit exposure is calculated each business day. As of March 31, 2018, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

Note 13. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds, as well as natural gas futures contracts executed on NYMEX.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

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Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of March 31, 2018, these consisted primarily of certain electric load contracts and gas contracts.

Certain derivative transactions may transfer from Level 2 to Level 3 if inputs become unobservable and internal modeling techniques are employed to determine fair value. Conversely, measurements may transfer from Level 3 to Level 2 if the inputs become observable.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of March 31, 2018 and December 31, 2017, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

	Recurring Fair Value Measurements as of March 31, 2018			
Description	Total	Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Energy-Related Contracts (B)	$ 91	$ (431)	$ 10	$ 505	$ 7
NDT Fund (C)					
Equity Securities	$ 1,086	$ —	$ 1,084	$ 2	$ —
Debt Securities—U.S. Treasury	$ 223	$ —	$ —	$ 223	$ —
Debt Securities—Govt Other	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Corporate	$ 456	$ —	$ —	$ 456	$ —
Rabbi Trust (C)					
Equity Securities	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—U.S. Treasury	$ 54	$ —	$ —	$ 54	$ —
Debt Securities—Govt Other	$ 35	$ —	$ —	$ 35	$ —
Debt Securities—Corporate	$ 113	$ —	$ —	$ 113	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (12)	$ 429	$ (6)	$ (435)	$ —
PSE&G					
Assets:					
Rabbi Trust (C)					
Equity Securities	$ 4	$ —	$ 4	$ —	$ —
Debt Securities—U.S. Treasury	$ 11	$ —	$ —	$ 11	$ —
Debt Securities—Govt Other	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Corporate	$ 23	$ —	$ —	$ 23	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 91	$ (431)	$ 10	$ 505	$ 7
NDT Fund (C)					
Equity Securities	$ 1,086	$ —	$ 1,084	$ 2	$ —
Debt Securities—U.S. Treasury	$ 223	$ —	$ —	$ 223	$ —
Debt Securities—Govt Other	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Corporate	$ 456	$ —	$ —	$ 456	$ —
Rabbi Trust (C)					
Equity Securities	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—U.S. Treasury	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Govt Other	$ 9	$ —	$ —	$ 9	$ —
Debt Securities—Corporate	$ 28	$ —	$ —	$ 28	$ —
Liabilities:					
Derivative Contracts:					

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Energy-Related Contracts (B)	$	(12)	$	429	$	(6)	$	(435)	$	—

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Description	Recurring Fair Value Measurements as of December 31, 2017			
	Total	Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 223	$ —	$ 223	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 36	$ (433)	$ 15	$ 442	$ 12
NDT Fund (C)					
Equity Securities	$ 1,147	$ —	$ 1,145	$ 2	$ —
Debt Securities—U.S. Treasury	$ 314	$ —	$ —	$ 314	$ —
Debt Securities—Govt Other	$ 270	$ —	$ —	$ 270	$ —
Debt Securities—Corporate	$ 402	$ —	$ —	$ 402	$ —
Rabbi Trust (C)					
Equity Securities	$ 27	$ —	$ 27	$ —	$ —
Debt Securities—U.S. Treasury	$ 51	$ —	$ —	$ 51	$ —
Debt Securities—Govt Other	$ 34	$ —	$ —	$ 34	$ —
Debt Securities—Corporate	$ 119	$ —	$ —	$ 119	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (21)	$ 477	$ (8)	$ (485)	$ (5)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 223	$ —	$ 223	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ —	$ —	$ —	$ —	$ —
Rabbi Trust (C)					
Equity Securities	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$ 10	$ —	$ —	$ 10	$ —
Debt Securities—Govt Other	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Corporate	$ 24	$ —	$ —	$ 24	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 36	$ (433)	$ 15	$ 442	$ 12
NDT Fund (C)					
Equity Securities	$ 1,147	$ —	$ 1,145	$ 2	$ —
Debt Securities—U.S. Treasury	$ 314	$ —	$ —	$ 314	$ —
Debt Securities—Govt Other	$ 270	$ —	$ —	$ 270	$ —
Debt Securities—Corporate	$ 402	$ —	$ —	$ 402	$ —
Rabbi Trust (C)					
Equity Securities	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—U.S. Treasury	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Govt Other	$ 8	$ —	$ —	$ 8	$ —
Debt Securities—Corporate	$ 30	$ —	$ —	$ 30	$ —
Liabilities:					
Derivative Contracts:					

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Energy-Related Contracts (B)	$	(21)	$	477	$	(8)	$	(485)	$	(5)

(A) Represents money market mutual funds.

(B) Level 1—These contracts represent natural gas futures contracts executed on NYMEX, and are being valued solely on settled pricing inputs which come directly from the exchange.

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Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using settled prices from similar assets and liabilities from an exchange, such as NYMEX, ICE and Nodal Exchange, or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—Unobservable inputs are used for the valuation of certain contracts. See "Additional Information Regarding Level 3 Measurements" below for more information on the utilization of unobservable inputs.

(C) As of March 31, 2018, the fair value measurement table excludes foreign currency of $1 million, which is part of the NDT Fund. The NDT Fund maintains investments in various equity and fixed income securities. The Rabbi Trust maintains investments in various fixed income securities and a Russell 3000 index fund. These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain other equity securities in the NDT and Rabbi Trust Funds consist primarily of investments in Dreyfus money market funds which seek a high level of current income as is consistent with the preservation of capital and the maintenance of liquidity. To pursue its goals, the funds normally invest in diversified portfolios of high quality, short-term, dollar-denominated debt securities and government securities. The funds' Net Asset Value is priced and published daily. The Rabbi Trust also has an equity index fund which is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities include investment grade corporate bonds, collateralized mortgage obligations, asset-backed securities and certain government and U.S. Treasury obligations or Federal Agency asset-backed securities and municipal bonds with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. The preferred stocks are not actively traded on a daily basis and therefore, are also priced using an evaluated pricing methodology. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(D) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of March 31, 2018 and December 31, 2017, Power had net cash collateral/margin payments to counterparties of $121 million and $146 million, respectively. Of these net cash collateral/margin payments $(2) million as of March 31, 2018 and $44 million as of December 31, 2017 were netted against the corresponding net derivative contract positions. The $(2) million of cash collateral as of March 31, 2018 was netted against assets. Of the $44 million of cash collateral as of December 31, 2017, $(3) million was netted against assets and $47 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee (RMC) approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The RMC reports to the Corporate Governance and Audit Committees of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and

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nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G, the natural gas supply contract is measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The fair value of Power's gas physical contracts at certain illiquid delivery locations are measured using average historical basis and, accordingly, are categorized as Level 3. While these gas physical contracts have an unobservable component in their respective forward price curves, the fluctuations in fair value have been driven primarily by changes in the observable inputs. The following tables provide details surrounding significant Level 3 valuations as of March 31, 2018 and December 31, 2017.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of March 31, 2018 Assets	Fair Value as of March 31, 2018 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$ 6	$ —	Discounted Cash flow	Historic Load Variability	0% to 10%
Gas	Gas Physical Contracts	1	—	Discounted Cash flow	Average Historical Basis	-40% to 0%
Total Power		**$ 7**	**$ —**			
Total PSEG		**$ 7**	**$ —**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2017 Assets	Fair Value as of December 31, 2017 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$ 1	$ (3)	Discounted Cash flow	Historic Load Variability	0% to 10%
Gas	Gas Physical Contracts	11	(2)	Discounted Cash flow	Average Historical Basis	-40% to -10%
Total Power		**$ 12**	**$ (5)**			
Total PSEG		**$ 12**	**$ (5)**			

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in the load variability would decrease the fair value. For gas-related contracts in cases where Power is a buyer, an increase in the average historical basis would increase the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months ended March 31, 2018 and March 31, 2017, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2018

	Three Months Ended March 31, 2018						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2018	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of March 31, 2018
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 7	$ (1)	$ —	$ —	$ 1	$ —	$ 7
Power							
Net Derivative Assets (Liabilities)	$ 7	$ (1)	$ —	$ —	$ 1	$ —	$ 7

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended March 31, 2017

	Three Months Ended March 31, 2017						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2017	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of March 31, 2017
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 1	$ 19	$ 6	$ —	$ (22)	$ (1)	$ 3
PSE&G							
Net Derivative Assets (Liabilities)	$ (5)	$ —	$ 6	$ —	$ —	$ —	$ 1
Power							
Net Derivative Assets (Liabilities)	$ 6	$ 19	$ —	$ —	$ (22)	$ (1)	$ 2

(A) PSEG's and Power's gains(losses) attributable to changes in net derivative assets and liabilities for the three months ended March 31, 2018 include $8 million in Operating Revenues, all of which is unrealized and $(9) million in Energy Costs, all of which is unrealized. For the three months ended March 31, 2017, $14 million is included in Operating Revenues, of which $(4) million is unrealized, and $5 million is in Energy Costs, of which $1 million is unrealized. Unrealized gains (losses) represent the change in derivative assets and liabilities still held at the end of the reporting period.

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(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $1 million and $(22) million in settlements for the three months ended March 31, 2018 and 2017, respectively.

(D) During the three months ended March 31, 2017, $(1) million of net derivatives were transferred from Level 2 to Level 3.

As of March 31, 2018, PSEG carried $2.4 billion of net assets that are measured at fair value on a recurring basis, of which $7 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of March 31, 2017, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $3 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of March 31, 2018 and December 31, 2017.

	As of March 31, 2018		As of December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (A) (B)	$ 2,092	$ 2,048	$ 2,091	$ 2,081
PSE&G (B)	8,593	8,908	8,591	9,322
Power (B)	2,387	2,566	2,386	2,659
Total Long-Term Debt	**$ 13,072**	**$ 13,522**	**$ 13,068**	**$ 14,062**

(A) Includes floating rate term loans of $700 million. The fair values of the term loan debt (Level 2 measurement) approximate the carrying values because the interest payments are based on LIBOR rates that are reset monthly and the debt is redeemable at face value by PSEG at any time.

(B) Given that these bonds do not trade actively, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

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Note 14. Other Income (Deductions)

	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended March 31, 2018				
NDT Fund Interest and Dividends	$ —	$ 12	$ —	$ 12
Allowance for Funds Used During Construction	14	—	—	14
Solar Loan Interest	4	—	—	4
Other	2	(1)	1	2
Total Other Income (Deductions)	**$ 20**	**$ 11**	**$ 1**	**$ 32**
Three Months Ended March 31, 2017				
NDT Fund Interest and Dividends	$ —	$ 10	$ —	$ 10
Allowance for Funds Used During Construction	14	—	—	14
Solar Loan Interest	5	—	—	5
Other	3	1	(1)	3
Total Other Income (Deductions)	**$ 22**	**$ 11**	**$ (1)**	**$ 32**

(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

Note 15. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months ended March 31, 2018 and 2017 were as follows:

	Three Months Ended March 31,	
	2018	2017
PSEG	26.6%	20.3%
PSE&G	26.8%	36.4%
Power	26.2%	40.6%

For the three months ended March 31, 2018, the difference in PSEG's effective tax rate as compared to the same period in the prior year was due primarily to the absence of benefits associated with uncertain tax positions and interest received in 2017 from a New Jersey state income tax refund, offset by the change in the statutory federal tax rate from 35% to 21% as a result of the Tax Act. For the three months ended March 31, 2018, the difference in PSEG's effective tax rate as compared to the statutory tax rate of 28.11% was due primarily to changes in uncertain tax positions, tax credits and plant-related items.

For the three months ended March 31, 2018, the difference in PSE&G's effective tax rate as compared to the same period in the prior year was due primarily to the change in the statutory federal tax rate from 35% to 21% as a result of the Tax Act, as well as changes in uncertain tax positions in 2017. For the three months ended March 31, 2018, the difference in PSE&G's effective tax rate as compared to the statutory tax rate of 28.11% was due primarily to plant-related items and tax credits.

For the three months ended March 31, 2018, the difference in Power's effective tax rate as compared to the same period in the prior year was due primarily to the change in the statutory federal tax rate from 35% to 21% as a result of the Tax Act, as well as changes in uncertain tax positions. For the three months ended March 31, 2018, the difference in Power's effective tax rate as compared to the statutory tax rate of 28.11% was due primarily to changes in uncertain tax positions and the additional tax benefit on a pre-tax loss on the NDT qualified fund being taxed at a higher rate than the statutory rate.

PSEG's federal tax returns for the years 2011 and 2012 are currently being audited by the IRS. The audit and other related claims are reasonably expected to be completed within the next 12 months. As a result, it is reasonably possible that a decrease in PSEG's total unrecognized tax benefits may be necessary in the range of $80 million to $180 million based on current estimates.

In December 2017, the U.S. government enacted comprehensive tax legislation. The Tax Act establishes new tax laws that took effect in 2018, including, but not limited to (1) reduction of the U.S. federal corporate tax rate from a maximum of 35% to 21%; (2) elimination of the corporate alternative minimum tax; (3) a new limitation on deductible interest expense; (4) the repeal of

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the domestic production activity deduction; (5) limitations on the deductibility of certain executive compensation; and (6) limitations on net operating losses generated after December 31, 2017, to 80% of taxable income. In addition, certain changes were made to the bonus depreciation rules that will impact 2018.

The SEC staff issued Staff Accounting Bulletin 118 (SAB 118), which provides guidance on accounting for the tax effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date for companies to complete the accounting under ASC 740. PSEG, PSE&G and Power are subject to ASC 740. In accordance with SAB 118, PSEG, PSE&G and Power made reasonable, good faith estimates for which provisional amounts were recorded.

PSEG's accounting for certain elements of the Tax Act is incomplete. However, PSEG recorded provisional adjustments for the following: the tax rules regarding the appropriate bonus depreciation rate that should be applied to assets placed in service after September 27, 2017 for Power and PSE&G, including the information required to compute the applicable depreciable tax basis, and the impact on PSEG's, PSE&G's and Power's deferred taxes associated with FIN 48 reserves.

Further, the Tax Act is unclear in certain respects and will require interpretations and implementing regulations by the IRS, as well as state tax authorities. The Tax Act could also be subject to potential amendments and technical corrections which could impact PSEG, PSE&G and Power's financial statements.

The Protecting Americans from Tax Hikes Act of 2015 (2015 Tax Act), among other provisions, included an extension of the bonus depreciation rules and the 30% investment tax credit for qualified property placed into service after 2016. Qualified property that is placed into service from January 1, 2015 through December 31, 2017 is eligible for the 50% bonus depreciation. The provisions of the 2015 Tax Act have generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation.

For the period beginning September 28, 2017, subject to the transition rules, the Tax Act modified the bonus depreciation rules of the 2015 Tax Act. Subject to further guidance, it is expected that Power is entitled to 100% expensing and bonus depreciation will no longer apply to PSE&G.

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Note 16. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended March 31, 2018			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2017	$ —	$ (406)	$ 177	$ (229)
Cumulative Effect Adjustment to Reclassify Unrealized Net Gains on Equity Investments to Retained Earnings	—	—	(176)	(176)
Current Period Other Comprehensive Income (Loss)				
Other Comprehensive Income before Reclassifications	—	—	(16)	(16)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	8	2	10
Net Current Period Other Comprehensive Income (Loss)	—	8	(14)	(6)
Net Change in Accumulative Other Comprehensive Income (Loss)	—	8	(190)	(182)
Balance as of March 31, 2018	**$ —**	**$ (398)**	**$ (13)**	**$ (411)**

PSEG	Other Comprehensive Income (Loss) Three Months Ended March 31, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2016	$ 2	$ (398)	$ 133	$ (263)
Other Comprehensive Income before Reclassifications	—	—	30	30
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	6	(15)	(9)
Net Current Period Other Comprehensive Income (Loss)	—	6	15	21
Balance as of March 31, 2017	**$ 2**	**$ (392)**	**$ 148**	**$ (242)**

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Power	Other Comprehensive Income (Loss) Three Months Ended March 31, 2018			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2017	$ —	$ (347)	$ 175	$ (172)
Cumulative Effect Adjustment to Reclassify Unrealized Net Gains on Equity Investments to Retained Earnings	—	—	(175)	(175)
Current Period Other Comprehensive Income (Loss)				
Other Comprehensive Income before Reclassifications	—	—	(13)	(13)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	6	2	8
Net Current Period Other Comprehensive Income (Loss)	—	6	(11)	(5)
Net Change in Accumulative Other Comprehensive Income (Loss)	—	6	(186)	(180)
Balance as of March 31, 2018	**$ —**	**$ (341)**	**$ (11)**	**$ (352)**

Power	Other Comprehensive Income (Loss) Three Months Ended March 31, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2016	$ —	$ (340)	$ 129	$ (211)
Other Comprehensive Income before Reclassifications	—	—	28	28
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	5	(9)	(4)
Net Current Period Other Comprehensive Income (Loss)	—	5	19	24
Balance as of March 31, 2017	**$ —**	**$ (335)**	**$ 148**	**$ (187)**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement Three Months Ended March 31, 2018		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions	
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	$ 1	$ —	$ 1
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(12)	3	(9)
Total Pension and OPEB Plans		(11)	3	(8)
Available-for-Sale Debt Securities				
Realized Gains (Losses)	Net Gains (Losses) on Trust Investments	(4)	2	(2)
Total Available-for-Sale Debt Securities		(4)	2	(2)
Total		**$ (15)**	**$ 5**	**$ (10)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	$ 2	$ (1)	$ 1
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(12)	5	(7)
Total Pension and OPEB Plans		(10)	4	(6)
Available-for-Sale Securities				
Realized Gains (Losses) and OTTI	Net Gains (Losses) on Trust Investments	28	(13)	15
Total Available-for-Sale Securities		28	(13)	15
Total		**$ 18**	**$ (9)**	**$ 9**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2018		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	$ 1	$ —	$ 1
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(10)	3	(7)
Total Pension and OPEB Plans		(9)	3	(6)
Available-for-Sale Debt Securities				
Realized Gains (Losses)	Net Gains (Losses) on Trust Investments	(4)	2	(2)
Total Available-for-Sale Debt Securities		(4)	2	(2)
Total		**$ (13)**	**$ 5**	**$ (8)**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement		
		Three Months Ended March 31, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions		
Pension and OPEB Plans				
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	$ 2	$ (1)	$ 1
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(11)	5	(6)
Total Pension and OPEB Plans		(9)	4	(5)
Available-for-Sale Securities				
Realized Gains (Losses) and OTTI	Net Gains (Losses) on Trust Investments	19	(10)	9
Total Available-for-Sale Securities		19	(10)	9
Total		**$ 10**	**$ (6)**	**$ 4**

Note 17. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended March 31,			
	2018		2017	
	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions):				
Net Income	**$ 558**	**$ 558**	**$ 114**	**$ 114**
EPS Denominator (Millions):				
Weighted Average Common Shares Outstanding	504	504	505	505
Effect of Stock Based Compensation Awards	—	3	—	3
Total Shares	**504**	**507**	**505**	**508**
EPS				
Net Income	**$ 1.11**	**$ 1.10**	**$ 0.23**	**$ 0.22**

For the three months ended March 31, 2017, there were approximately 0.3 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect.

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Dividends

Dividend Payments on Common Stock	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Per Share	$ 0.45	$ 0.43
In Millions	$ 227	$ 218

On April 17, 2018, PSEG's Board of Directors approved a $0.45 per share common stock dividend for the second quarter of 2018.

Note 18. Financial Information by Business Segment

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Three Months Ended March 31, 2018					
Operating Revenues	$ 1,845	$ 1,403	$ 147	$ (577)	$ 2,818
Net Income (Loss)	319	234	5	—	558
Gross Additions to Long-Lived Assets	750	299	4	—	1,053
Three Months Ended March 31, 2017					
Operating Revenues	$ 1,826	$ 1,269	$ 83	$ (587)	$ 2,591
Net Income (Loss)	299	(170)	(15)	—	114
Gross Additions to Long-Lived Assets	748	307	7	—	1,062
As of March 31, 2018					
Total Assets	$ 28,774	$ 12,263	$ 2,481	$ (728)	$ 42,790
Investments in Equity Method Subsidiaries	$ —	$ 86	$ —	$ —	$ 86
As of December 31, 2017					
Total Assets	$ 28,554	$ 12,418	$ 2,666	$ (922)	$ 42,716
Investments in Equity Method Subsidiaries	$ —	$ 87	$ —	$ —	$ 87

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations primarily relate to intercompany transactions between PSE&G and Power. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 19. Related-Party Transactions.

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Note 19. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended March 31, 2018	2017
	Millions	
Billings from Affiliates:		
Net Billings from Power primarily through BGS and BGSS (A)	$ 578	$ 599
Administrative Billings from Services (B)	83	65
Total Billings from Affiliates	**$ 661**	**$ 664**

Related-Party Transactions	As of March 31, 2018	As of December 31, 2017
	Millions	
Payable to Power (A)	$ 215	$ 221
Payable to Services (B)	65	78
Payable to PSEG (C)	105	41
Accounts Payable—Affiliated Companies	**$ 385**	**$ 340**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 93**	**$ 91**

Power

The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended March 31, 2018	2017
	Millions	
Billings to Affiliates:		
Net Billings to PSE&G primarily through BGS and BGSS (A)	**$ 578**	**$ 599**
Billings from Affiliates:		
Administrative Billings from Services (B)	**$ 43**	**$ 36**

Related-Party Transactions	As of March 31, 2018	As of December 31, 2017
	Millions	
Receivables from PSE&G (A)	$ 215	$ 221
Accounts Receivable—Affiliated Companies	**$ 215**	**$ 221**
Payable to Services (B)	$ 23	$ 28
Payable to PSEG (C)	46	29
Accounts Payable—Affiliated Companies	**$ 69**	**$ 57**
Short-Term Loan from Affiliate (E)	**$ 35**	**$ 281**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 46**	**$ 52**

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(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. The rates in the BGS and BGSS contracts are prescribed by the BPU. In addition, Power and PSE&G provide certain technical services for each other generally at cost in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

Note 20. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries, as of March 31, 2018 and December 31, 2017 and for the three months ended March 31, 2018 and 2017.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended March 31, 2018					
Operating Revenues	$ —	$ 1,386	$ 51	$ (34)	$ 1,403
Operating Expenses	—	1,056	52	(34)	1,074
Operating Income (Loss)	—	330	(1)	—	329
Equity Earnings (Losses) of Subsidiaries	234	(3)	2	(231)	2
Net Gains (Losses) on Trust Investments	—	(22)	—	—	(22)
Other Income (Deductions)	35	33	—	(57)	11
Non-Operating Pension and OPEB Credits (Costs)	—	4	—	—	4
Interest Expense	(42)	(17)	(5)	57	(7)
Income Tax Benefit (Expense)	7	(92)	2	—	(83)
Net Income (Loss)	**$ 234**	**$ 233**	**$ (2)**	**$ (231)**	**$ 234**
Comprehensive Income (Loss)	**$ 229**	**$ 223**	**$ (2)**	**$ (221)**	**$ 229**
Three Months Ended March 31, 2018					
Net Cash Provided By (Used In) Operating Activities	$ (5)	$ 525	$ (49)	$ 71	$ 542
Net Cash Provided By (Used In) Investing Activities	$ (215)	$ (625)	$ (82)	$ 605	$ (317)
Net Cash Provided By (Used In) Financing Activities	$ 220	$ 100	$ 111	$ (677)	$ (246)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended March 31, 2017					
Operating Revenues	$ —	$ 1,255	$ 52	$ (38)	$ 1,269
Operating Expenses	4	1,556	52	(38)	1,574
Operating Income (Loss)	(4)	(301)	—	—	(305)
Equity Earnings (Losses) of Subsidiaries	(161)	(1)	3	162	3
Net Gains (Losses) on Trust Investments	4	15	—	—	19
Other Income (Deductions)	20	19	—	(28)	11
Non-Operating Pension and OPEB Credits (Costs)	—	2	—	—	2
Interest Expense	(30)	(9)	(5)	28	(16)
Income Tax Benefit (Expense)	1	111	4	—	116
Net Income (Loss)	**$ (170)**	**$ (164)**	**$ 2**	**$ 162**	**$ (170)**
Comprehensive Income (Loss)	**$ (146)**	**$ (143)**	**$ 2**	**$ 141**	**$ (146)**
Three Months Ended March 31, 2017					
Net Cash Provided By (Used In) Operating Activities	$ 77	$ 377	$ 91	$ 35	$ 580
Net Cash Provided By (Used In) Investing Activities	$ 251	$ 20	$ (154)	$ (511)	$ (394)
Net Cash Provided By (Used In) Financing Activities	$ (328)	$ (395)	$ 68	$ 476	$ (179)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
As of March 31, 2018					
Current Assets	$ 4,168	$ 1,392	$ 189	$ (4,631)	$ 1,118
Property, Plant and Equipment, net	55	5,094	3,540	—	8,689
Investment in Subsidiaries	5,089	1,115	—	(6,204)	—
Noncurrent Assets	90	2,295	109	(38)	2,456
Total Assets	**$ 9,402**	**$ 9,896**	**$ 3,838**	**$ (10,873)**	**$ 12,263**
Current Liabilities	$ 548	$ 3,234	$ 1,874	$ (4,631)	$ 1,025
Noncurrent Liabilities	521	1,961	461	(38)	2,905
Long-Term Debt	2,137	—	—	—	2,137
Member's Equity	6,196	4,701	1,503	(6,204)	6,196
Total Liabilities and Member's Equity	**$ 9,402**	**$ 9,896**	**$ 3,838**	**$ (10,873)**	**$ 12,263**
As of December 31, 2017					
Current Assets	$ 4,327	$ 1,500	$ 200	$ (4,686)	$ 1,341
Property, Plant and Equipment, net	54	5,778	2,764	—	8,596
Investment in Subsidiaries	4,844	404	—	(5,248)	—
Noncurrent Assets	100	2,349	110	(78)	2,481
Total Assets	**$ 9,325**	**$ 10,031**	**$ 3,074**	**$ (10,012)**	**$ 12,418**
Current Liabilities	$ 689	$ 3,586	$ 1,846	$ (4,686)	$ 1,435
Noncurrent Liabilities	533	1,966	459	(78)	2,880
Long-Term Debt	2,136	—	—	—	2,136
Member's Equity	5,967	4,479	769	(5,248)	5,967
Total Liabilities and Member's Equity	**$ 9,325**	**$ 10,031**	**$ 3,074**	**$ (10,012)**	**$ 12,418**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and energy efficiency and related programs in New Jersey, which are regulated by the BPU, and
- **Power**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement; PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Our business discussion in Part I, Item 1. Business of our 2017 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2017 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2018 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2017 Form 10-K.

EXECUTIVE OVERVIEW OF 2018 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- improving utility operations through growth in investment in T&D and other infrastructure projects designed to enhance system reliability and resiliency and to meet customer expectations and public policy objectives, and
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the three months ended March 31, 2018 and 2017 are presented as follows:

Earnings (Losses)	Three Months Ended March 31, 2018	2017
	Millions	
PSE&G	$ 319	$ 299
Power (A)	234	(170)
Other (B)	5	(15)
PSEG Net Income	**$ 558**	**$ 114**
PSEG Net Income Per Share (Diluted)	**$ 1.10**	**$ 0.22**

(A) Includes after-tax expenses of $334 million primarily for accelerated depreciation related to the early retirement of Power's Hudson and Mercer coal/gas generation plants for the three months ended March 31, 2017. See Item 1. Note 4. Early Plant Retirements for additional information.

(B) Other includes after-tax activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations. Energy Holdings recorded after-tax charges of $32 million related to its investments in NRG REMA, LLC's (REMA) leveraged leases in the three months ended March 31, 2017. See Item 1. Note 7. Financing Receivables for additional information.

Power's results above include the Nuclear Decommissioning Trust (NDT) Fund activity and the impacts of non-trading commodity mark-to-market (MTM) activity, which consist of the financial impact from positions with future delivery dates.

The variances in our Net Income attributable to changes related to the NDT Fund and MTM are shown in the following table:

	Three Months Ended March 31, 2018	2017
	Millions, after tax	
NDT Fund Income (Expense) (A) (B)	$ (16)	$ 8
Non-Trading MTM Gains (Losses) (C)	$ 85	$ 6

(A) NDT Fund Income (Expense) includes realized gains and losses and other-than-temporary impairments on certain NDT securities in 2018 and 2017 and unrealized gains and losses on equity securities in 2018, all of which are recorded in Net Gains (Losses) on Trust Investments. NDT Fund Income (Expense) also includes interest and dividend income and other costs related to the NDT Fund recorded in Other Income (Deductions), interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset recorded in Depreciation and Amortization (D&A) Expense.

(B) Net of tax (expense) benefit of $8 million and $(9) million for the three months ended March 31, 2018 and 2017, respectively.

(C) Net of tax (expense) benefit of $(33) million and $(4) million for the three months ended March 31, 2018 and 2017, respectively.

Our $444 million increase in Net Income for the three months ended March 31, 2018 was driven largely by

- accelerated depreciation in 2017 related to the early retirement of our Hudson and Mercer coal/gas generation units,
- charges in 2017 for estimated losses related to our leveraged lease investments,
- the favorable impact at Power from the lower federal tax rate effective January 1, 2018,
- higher net MTM gains in 2018, and
- higher transmission revenues in 2018.

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During the first three months of 2018, we maintained a strong balance sheet. We continued to effectively deploy capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results, which when combined with the cash flow generated by Power, our merchant generator and power marketer, has allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our multi-year, long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, we continue to invest in transmission projects that focus on reliability improvements and replacement of aging infrastructure. We also continue to make investments to improve the resiliency of our gas and electric distribution system as part of our Energy Strong Program that was approved by the BPU in 2014 and to seek recovery on such investments. We are modernizing PSE&G's gas distribution systems as part of our Gas System Modernization Program (GSMP) that was approved by the BPU in late 2015. Over the past few years, these types of investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G.

Power manages its existing firm pipeline transportation contracts for the benefit of PSE&G's customers through the basic gas supply service (BGSS) arrangement. The contracts are sized to provide for delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power may use it to make third-party sales and supply gas to its generating units in New Jersey. Alternatively, gas supply and pipeline capacity constraints could adversely impact our ability to meet the needs of our utility customers and generating units. Power's hedging practices and ability to capitalize on market opportunities help it to balance some of the volatility of the merchant power business. More than half of Power's expected gross margin in 2018 relates to our hedging strategy, our expected revenues from the capacity market mechanisms and certain ancillary service payments such as reactive power.

Our investments in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station Unit 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to contribute to the overall efficiency of operations.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission Planning

There are several matters pending before FERC and the U. S. Court of Appeals for the District of Columbia Circuit that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by customers in New Jersey. In addition, as a basic generation service (BGS) supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers may be entitled to recovery, subject to BPU approval. We do not believe that these matters will have a material effect on Power's business or results of operations.

Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base return on equity (ROE). Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. The results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. The CP product was implemented fully in the May 2017 RPM auction for the 2020-2021 Delivery Year. Subsequent to its implementation, FERC approved changes to the CP construct that will enhance the participation of intermittent and demand response resources (seasonal resources). However, FERC recently scheduled a technical conference in response to two complaints requesting that FERC investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions. We cannot predict the outcome of these matters.

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In April 2018, PJM submitted two proposed alternative and mutually exclusive capacity market reforms for FERC's approval. One option would be to implement a two-tier clearing mechanism that accommodates states' subsidies and the other option would be to extend the existing Minimum Offer Price Rule (MOPR) to units that are receiving subsidies. We are currently evaluating these two proposals. In a related matter that is currently pending at FERC, a group of suppliers requested that FERC direct PJM to expand the currently effective MOPR to apply to certain existing units seeking subsidies. The suppliers' request was intended to avoid a scenario where the subsidized generators would submit bids into the PJM capacity market that did not reflect their actual costs of operation and could artificially suppress capacity market prices. We are currently awaiting FERC action on the suppliers' request and cannot predict the outcome of these proceedings.

In November 2017, PJM issued an energy price formation proposal to address a flaw in the energy market by allowing all resources selected for dispatch, both flexible and inflexible, to set price and consequently, result in prices that more accurately reflect the true cost to serve load. PJM's proposal would allow large, inflexible units to set price. If placed into effect, this proposal will improve price formation by ensuring that the marginal costs of units serving load will be better reflected in clearing prices. We cannot predict the outcome of this matter.

Distribution

The BPU has enacted Infrastructure Investment Program (IIP) regulations that allow utilities to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to support the provision of safe and adequate service. Under these regulations, utilities can seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing infrastructure that enhances reliability, resiliency, and/or safety.

In July 2017, we filed a petition with the BPU for a GSMP II program, an extension of GSMP to continue to modernize our gas system. In April 2018, we reached a settlement with the BPU Staff, Division of Rate Counsel and other parties. Under the GSMP II program, PSE&G will invest $1.9 billion over five years beginning in 2019 to replace approximately 175 miles of cast iron and unprotected steel mains in addition to other improvements to the gas system. Approximately $1.6 billion will be recovered through periodic rate roll-ins, with the remaining $300 million to be recovered through a future base rate case. As part of the settlement, PSE&G agreed to file a base rate case no later than five years from the commencement of the program, to maintain a base level of gas distribution capital expenditures of $155 million and to achieve certain leak reduction targets. The ROE and certain other elements for the program will be determined in the pending base rate case proceeding.

As previously disclosed, PSE&G's Energy Strong Program, a $1.2 billion investment program to harden and make the electric and gas distribution system more resilient, is expected to be completed during 2018. PSE&G expects to file for a five year extension and expansion of the Energy Strong Program in the second quarter of 2018. The extension would seek to continue efforts to harden the electric system against storms and make it more resilient, to implement a more proactive life cycle replacement program to modernize the electric system and to make the gas system more reliable by mitigating the impacts of potential supply curtailments. The size and duration of the Energy Strong Program extension, as well as PSE&G's return on equity and certain other elements of the program, are subject to BPU approval.

In January 2018, PSE&G filed a distribution base rate case as required as a condition of approval of its Energy Strong Program approved by the BPU in 2014. The filing requested an approximate 1% increase in revenues and recovery of investments made to strengthen the electric and gas distribution systems. The requested increase took into account a reduction in the revenue requirement as a result of the federal corporate income tax rate reduction from 35% to 21% provided in the Tax Act, including the flow-back to customers of excess accumulated deferred income taxes. In March 2018, the BPU approved interim rate reductions for all their jurisdictional utilities, including PSE&G, reflecting the reduction in the federal corporate tax rate. The BPU approved a reduction to PSE&G's base electric and gas revenues effective April 1, 2018 by $71 million and $43 million, respectively, on an annual basis (or about 2% combined). The refund to customers for over-collection of revenues at the higher tax rate for the January 1 to March 31, 2018 period, and the flow-back to customers of certain excess deferred income taxes will be addressed in PSE&G's ongoing base rate case proceeding. As a result of the base rate reduction implemented on April 1, 2018, PSE&G's requested revenue requirement in its filing will increase accordingly. PSE&G anticipates a decision by the BPU that the new base rates will go into effect in the fourth quarter of 2018.

Energy Efficiency

In April 2018, the New Jersey Legislature approved legislation that would require the state's electric and gas utilities to implement energy efficiency programs that would achieve energy savings of at least 2% per year for electric usage and 0.75% per year for gas usage within five years of the utility's implementation of its BPU-approved energy efficiency programs. To meet these savings targets, energy usage reductions and peak demand reductions that result from utility and non-utility based programs and investments (including building code changes) will be counted. The specific energy savings target for each public electric and gas utility will be determined from an energy efficiency study to be completed within a year from enactment of the

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legislation. The legislation will require utilities to make filings with the BPU outlining their planned investments and proposed programs for cost-effectively achieving the targeted energy savings. These filings are also expected to address the utility's return of and on those investments and recovery of lost revenues associated with the lower sales. PSE&G cannot predict whether the legislation will be enacted. If enacted, the BPU will issue rules to implement the legislation. PSE&G is evaluating opportunities to broaden its existing energy efficiency programs to achieve New Jersey's targeted results, as well as make investments to facilitate the development of the electric vehicle market and a pilot program for energy storage investments.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs.

In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the New Source Performance Standards that establish emissions standards for CO_2 for certain new fossil power plants, and the Clean Power Plan (CPP), a greenhouse gas emissions regulation under the Clean Air Act for existing power plants that establishes state-specific emission rate targets based on implementation of the best system of emission reduction. In October 2017, the EPA Administrator signed a proposed repeal of the CPP. The EPA Administrator concluded that the CPP exceeds the EPA's statutory authority by considering measures that are beyond the control of the owners of the affected sources (fossil fuel-fired electric generating units). The EPA is considering rulemaking to replace the CPP. PSEG cannot assess the impact of any such rulemaking on its business and future results of operations at this time.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above, as well as other matters that may impact our financial condition and results of operations, see Item 1. Note 10. Commitments and Contingent Liabilities.

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power has implemented procedures and continues to review its policies and practices to mitigate the risk of similar issues occurring in the future.

Since September 2014, FERC Staff has been conducting a preliminary, non-public staff investigation into these matters. In April 2018, a settlement agreement was entered into between PSEG and FERC Staff, approved by FERC on April 25, 2018, pursuant to which PSEG agreed to pay approximately $40 million for the full resolution of this matter. Accordingly, Power recorded an additional pre-tax charge to income of $5 million in the first quarter of 2018, resulting in a total liability of approximately $40 million accrued for the resolution of this matter. The settlement agreement does not require PSEG to change its business practices in a manner that would have a material impact on its ongoing business operations.

Early Retirement of Hudson and Mercer Units

On June 1, 2017, Power completed its previously announced retirement of the generation operations of the existing coal/gas units at the Hudson and Mercer generating stations. The decision to retire the Hudson and Mercer units had a material effect on PSEG's and Power's results of operations in 2016 and continued to adversely impact their results of operations in 2017. As of June 1, 2017, Power completed recognition of the incremental Depreciation and Amortization (D&A) of $938 million ($964 million in total) due to the significant shortening of the expected economic useful lives of Hudson and Mercer. See Item 1. Note 4. Early Plant Retirements for additional information.

Power is exploring various opportunities with these sites, including using the sites for alternative industrial activity or the disposition of one or both of the sites. If Power determines not to use the sites for alternative industrial activity, the early

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retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such remediation are neither currently probable nor estimable but may be material.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Nuclear

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. In February 2018, Exelon, a co-owner of the Salem units, announced its intention to accelerate the closure of its Oyster Creek nuclear plant located in New Jersey, one year earlier than previously planned for economic reasons. In addition, First Energy announced in March 2018 the early retirement of four nuclear units at the Davis-Besse, Perry Nuclear and Beaver Valley nuclear plants in Ohio and Pennsylvania by 2021. These closures and retirements are generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a further shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of our nuclear units beyond the current year, including whether and to what extent these units participate in RPM capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be influenced by the financial outlook of the units, including the progress, timing and continued outlook for enactment of proposed legislation in the state of New Jersey. At a co-owners meeting in February 2018, Exelon and Power agreed to cancel the funding of future capital projects at the Salem generating station that are not required to meet NRC or other regulatory requirements or that are not required to ensure its safe operation. The companies agreed that the funding of these projects may be restored when and if legislation is enacted in New Jersey that sufficiently values the attributes of nuclear generation and Salem benefits from such legislation.

If any or all of the Salem and Hope Creek units were shut down, it would significantly alter New Jersey's energy supply predominately by increasing New Jersey's reliance on natural gas generation. Such a decrease in fuel diversity could also increase the market's vulnerability to price fluctuations and power disruptions in times of high demand. In April 2018, the New Jersey Legislature voted to pass legislation that would provide a safety net in order to prevent the loss of environmental attributes from selected nuclear generating stations. Power cannot predict whether the legislation will be enacted or, if enacted, whether our nuclear generating stations in New Jersey will be selected or whether the legislation will provide a sufficient safety net for the continued operation of nuclear generating stations in New Jersey.

If market prices continue to be depressed and legislation is not enacted that adequately compensates nuclear generating stations for their attributes, Power anticipates it will no longer be covering its costs nor be adequately compensated for its market and operational risks at the Salem and Hope Creek nuclear units and would anticipate retiring these units early. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs and additional funding of the NDT Fund would be material to both PSEG and Power.

Leveraged Lease Impairments

GenOn Energy, Inc. (GenOn) and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code on June 14, 2017. REMA was not included in the GenOn bankruptcy filing. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete. PSEG cannot predict the outcome of GenOn's efforts to restructure its balance sheet and improve its liquidity.

PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments, which could include further write-downs of the values of Energy Holdings' leveraged lease receivables, and continue to discuss the situation with various parties relevant to this matter. For additional information, see Item 1. Note 7. Financing Receivables. There can be no assurance that a continuation or worsening of the adverse economic conditions would

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not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.

Additional facilities in our leveraged lease portfolio include the Joliet and Powerton generating facilities. Converted natural gas units such as Shawville and Joliet may have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units. Powerton is a coal-fired generating facility in Illinois. Each of these three facilities may not be as economically competitive as newer combined cycle gas units and could continue to be adversely impacted by the same economic conditions experienced by other less efficient natural gas and coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged lease receivables associated with these facilities.

Tax Legislation

In December 2017, the U.S. government enacted comprehensive tax legislation (Tax Act), which, among other things, decreased the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018, and made certain changes to bonus depreciation rules.

As a result of the enacted reduction in the statutory U.S. corporate income tax rate, as well as other aspects of the Tax Act, in December 2017 PSE&G recorded excess deferred taxes of approximately $2.1 billion and recorded an approximate $2.9 billion revenue impact of these excess deferred taxes as Regulatory Liabilities where it is probable that refunds will be made to customers in future rates. The amount and timing of any such refund cannot be determined at this time.

Beginning in 2018, PSEG, on a consolidated basis, is incurring lower income tax expense resulting in a decrease in its projected effective income tax rate. This is also expected to increase PSEG's and Power's net income. To the extent allowed under the Tax Act, Power's operating cash flows will reflect the full expensing of capital investments for income tax purposes. PSEG and Power expect that the interest on their debt will continue to be fully tax deductible albeit at a lower tax rate. For PSE&G, the Tax Act is expected to lead to lower customer rates due to lower income tax expense recoveries and the refund of deferred income tax regulatory liabilities, partially offset by the impacts of higher rate base. The impact of the lower federal income tax rate on PSE&G was reflected in PSE&G's recently filed distribution base rate case and its 2018 transmission formula rate filings. The Tax Act is generally expected to result in lower operating cash flows for PSE&G resulting from the elimination of bonus depreciation, partially offset by higher revenues due to the higher rate base. Due to the recent enactment of the Tax Act, the full impact of these and other provisions of the Tax Act cannot be determined at this time.

The impact of the Tax Act may differ from these estimates, possibly materially, due to, among other things, changes in interpretations and assumptions PSEG has made, guidance that may be issued and actions PSEG may take as a result of the Tax Act. For additional information, see Item 1. Note 15. Income Taxes.

As a result of the enactment of the Tax Act, various state regulatory authorities, including the BPU, have taken action to ensure that excess federal income taxes previously collected in rates are returned to customers. We have made filings to adjust the revenue requirement in certain of our rate matters as a result of the change in the federal income tax rate. We continue to assess whether we need to take any further action at this time.

In addition, FERC continues to assess whether, and if so how, it will address changes and flow-backs to customers relating to accumulated deferred income taxes and bonus depreciation. See Item 1. Note 6. Rate Filings for additional information.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of opportunities in a rapidly evolving market as we remain diligent in managing costs. For the first three months of 2018, our

- utility, beginning with comprehensive storm preparation, efficiently and safely completed our customer restorations and then assisted neighboring utilities with their restoration efforts,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 13 terawatt hours while addressing fuel availability and price volatility, and
- total nuclear fleet achieved an average capacity factor of 99.5%.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first three months of 2018 as we

- maintained sufficient liquidity,

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- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2018 to $1.80 per share.

We expect to be able to fund our planned capital requirements and manage the impacts of the Tax Act without the issuance of new equity.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first three months of 2018, we

- made additional investments in transmission infrastructure projects,
- continued to execute our GSMP, Energy Strong, Energy Efficiency and other existing BPU-approved utility programs, and
- continued construction of our Keys and Sewaren 7 generation projects for targeted commercial operation in 2018 and our BH5 generation project for targeted commercial operation in mid-2019.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-growing economy and a cost-constrained environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions in response to changes in demand,
- execute our utility capital investment program, including our Energy Strong Program, GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers, and obtain approval for the extension of these programs,
- effectively manage construction of our Keys, Sewaren 7, BH5 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

For 2018 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- fair and timely rate relief from the BPU and FERC for recovery of costs and return on investments, including with respect to our distribution base rate case which was filed with the BPU in January 2018,
- continuing discussions regarding the restructuring of GenOn and REMA and its potential impact on the value of our Keystone, Conemaugh and Shawville leveraged leases,
- the continuing impacts of the Tax Act,
- national and regional economic conditions, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate,

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- the impact of lower natural gas prices and increasing environmental compliance costs on the competitiveness of our nuclear and remaining coal-fired generation plants, and the potential for retirement of such plants earlier than their current useful lives,
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development projects, including in connection with permitting and regulatory approvals, and
- maintaining a diverse mix of fuels to mitigate risks associated with fuel price volatility and market demand cycles.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of T&D facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses,
- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency, modernizing existing infrastructure and participation in transmission projects through FERC's "open window" solicitation process.

Power is developing a retail energy business to sell energy, which we believe complements our existing wholesale marketing business. Power began these marketing activities in 2017 and has been granted retail energy supplier licenses in New Jersey, Pennsylvania and Maryland.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 19. Related-Party Transactions.

	Three Months Ended March 31,		Increase/ (Decrease)	
	2018	2017	2018 vs. 2017	
	Millions		Millions	%
Operating Revenues	$ 2,818	$ 2,591	$ 227	9
Energy Costs	952	868	84	10
Operation and Maintenance	754	717	37	5
Depreciation and Amortization	280	828	(548)	(66)
Income from Equity Method Investments	2	3	(1)	(33)
Net Gains (Losses) on Trust Investments	(22)	28	(50)	N/A
Other Income (Deductions)	32	32	—	—
Non-Operating Pension and OPEB Credits (Costs)	19	—	19	N/A
Interest Expense	103	98	5	5
Income Tax Expense	202	29	173	N/A

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The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Three Months Ended March 31,		Increase/ (Decrease)	
	2018	2017	2018 vs. 2017	
	Millions		Millions	%
Operating Revenues	$ 1,845	$ 1,826	$ 19	1
Energy Costs	782	762	20	3
Operation and Maintenance	391	370	21	6
Depreciation and Amortization	190	171	19	11
Net Gains (Losses) on Trust Investments	—	2	(2)	N/A
Other Income (Deductions)	20	22	(2)	(9)
Non-Operating Pension and OPEB Credits (Costs)	15	(2)	17	N/A
Interest Expense	81	75	6	8
Income Tax Expense	117	171	(54)	(32)

Three Months Ended March 31, 2018 as Compared to 2017

Operating Revenues increased $19 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $7 million due primarily to an increase in transmission revenues.

- Transmission revenues were $8 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.
- Gas distribution revenues increased $5 million due to a $17 million increase from the inclusion of the GSMP in base rates, and a $7 million increase due to higher sales volumes. These increases were partially offset by a $19 million decrease in Weather Normalization collections.
- Electric distribution revenues decreased $6 million due to $7 million in lower sales volumes and lower Green Program Recovery Charges of $1 million, partially offset by a $2 million increase from the Energy Strong Program in base rates.

Commodity Revenues increased $20 million as a result of higher Electric revenues partially offset by lower Gas revenues. The changes in Commodity revenues for both electric and gas are entirely offset by the changes in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric commodity revenues increased $34 million due primarily to a $29 million increase in BGS revenues due to $21 million in higher sales volumes and $8 million from higher prices, a $3 million increase from sales of solar renewable energy credits and $2 million of higher revenues from collections of Non-Utility Generation Charges.
- Gas commodity revenues decreased $14 million due to lower BGSS sales prices of $32 million, partially offset by higher BGSS sales volumes of $18 million.

Clause Revenues decreased $11 million due primarily to a $6 million decrease in Margin Adjustment Clause (MAC) revenues and lower Societal Benefit Charges (SBC) of $5 million. The changes in the MAC and SBC amounts are entirely offset by changes in the amortization of Regulatory Assets and Regulatory Liabilities and related costs in O&M, D&A and Interest Expense. PSE&G does not earn margin on MAC or SBC collections.

Operating Expenses

Energy Costs increased $20 million. This is entirely offset by the change in Commodity Revenues.

Operation and Maintenance increased $21 million, primarily due to a $10 million increase in transmission operating expenses, a $6 million increase in winter storm costs, a $5 million increase in appliance service costs, a $5 million increase in the gas distribution tariff, a $3 million increase in renewables and a $5 million increase in other operating expenses. These increases were partially offset by a $13 million reduction in clause-related expenditures.

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Depreciation and Amortization increased $19 million due primarily to an $18 million increase in depreciation due to additional plant in service and an increase of $2 million in amortization of Regulatory Assets.

Non-Operating Pension and OPEB Credits (Costs) reflected an increase of $17 million in credits due the adoption of new accounting guidance effective January 1, 2018 which no longer allows capitalization of any portion of these benefit costs. See Item 1. Note 2. Recent Accounting Standards.

Interest Expense increased $6 million due primarily to debt issuances in May and December 2017.

Income Tax Expense decreased $54 million due primarily to the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018, partially offset by uncertain tax positions and plant-related items.

Power

	Three Months Ended March 31,		Increase/ (Decrease)	
	2018	2017	2018 vs. 2017	
	Millions		Millions	%
Operating Revenues	$ 1,403	$ 1,269	$ 134	11
Energy Costs	746	692	54	8
Operation and Maintenance	246	232	14	6
Depreciation and Amortization	82	650	(568)	(87)
Income from Equity Method Investments	2	3	(1)	(33)
Net Gains (Losses) on Trust Investments	(22)	19	(41)	N/A
Other Income (Deductions)	11	11	—	—
Non-Operating Pension and OPEB Credits (Costs)	4	2	2	100
Interest Expense	7	16	(9)	(56)
Income Tax Expense (Benefit)	83	(116)	199	N/A

Three Months Ended March 31, 2018 as Compared to 2017

Operating Revenues increased $134 million due to changes in generation and gas supply revenues.

Generation Revenues increased $140 million due primarily to

- an increase of $134 million due to higher MTM gains in 2018 as compared to 2017. Of this amount, $112 million was due to higher gains on positions reclassified to realized upon settlement coupled with a $22 million increase due to changes in forward prices,
- a net increase of $10 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM region offset by lower volumes of electricity sold under wholesale load contracts in the New England (NE) region, and
- a net increase of $7 million in capacity revenues due primarily to increases in cleared capacity auction prices in the NE region,
- partially offset by a net decrease of $13 million in energy sales due primarily to lower volumes and lower average realized prices in the PJM region offset by higher average prices in the NE and New York (NY) regions, and
- a decrease of $9 million in electricity sold under our BGS contracts due primarily to lower prices offset by higher volumes.

Gas Supply Revenues decreased $6 million due primarily to

- a decrease of $13 million due to MTM losses in 2018 as compared to gains in 2017, and
- a decrease of $12 million related to sales to third parties due to lower average sales prices,
- partially offset by an increase of $19 million in sales under the BGSS contract due primarily to an increase in sales volumes due to colder average temperatures in the 2018 winter heating season.

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Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $54 million due to

Generation costs increased $43 million due primarily to

- higher fuel costs of $46 million reflecting utilization of higher volumes of oil in the PJM region coupled with utilization of higher volumes and higher prices of natural gas in the NY region, and
- an increase of $10 million due to MTM losses in 2018 as compared to gains in 2017. Of this amount, $6 million was due to changes in forward prices coupled with an increase of $4 million due to higher losses on positions reclassified to realized upon settlement in 2018,
- partially offset by a net decrease of $15 million primarily due to a decrease in energy purchase volumes in the NE region to serve load obligations.

Gas costs increased $11 million due mainly to

- an increase of $29 million related to sales under the BGSS contract due primarily to increased volumes sold, coupled with higher average gas costs due to colder average temperatures during the 2018 winter heating season,
- partially offset by a decrease of $18 million related to sales to third parties due primarily to lower average gas costs and a decrease in volumes sold.

Operation and Maintenance increased $14 million due primarily to

- a $10 million net increase at our fossil plants, due primarily to higher planned outage costs in 2018 as compared to 2017, and
- a $5 million net increase due primarily to higher planned outage costs at our 100%-owned Hope Creek nuclear plant in 2018 as compared to planned outage costs incurred in 2017 for our 57%-owned Salem Unit 2.

Depreciation and Amortization decreased $568 million due primarily to

- $574 million of higher depreciation in 2017 for Hudson and Mercer due to the early retirement of those units,
- partially offset by a $5 million increase in 2018 due to a higher nuclear asset base primarily from increased capitalized asset retirement costs.

Net Gains (Losses) on Trust Investments decreased $41 million due primarily to the inclusion in 2018 of $34 million of net unrealized losses on equity investments in the NDT Fund in accordance with new accounting guidance and a $5 million decrease in net realized gains on NDT Fund investments.

Interest Expense decreased $9 million due primarily to higher interest capitalized for the construction of the BH5, Sewaren 7 and Keys fossil stations.

Income Tax Expense (Benefit) increased $199 million due primarily to pre-tax income in 2018 as compared to a pre-tax loss in 2017. This increase in income tax expense was diminished by the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the three months ended March 31, 2018, our operating cash flow decreased $57 million as compared to the same period in 2017. The net changes were primarily due to tax refunds in 2017 at Energy Holdings combined with net changes from our subsidiaries as discussed below.

PSE&G

PSE&G's operating cash flow increased $62 million from $515 million to $577 million for the three months ended March 31, 2018, as compared to the same period in 2017, due primarily to an increase of $58 million primarily due to a reduction in

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unbilled revenues resulting from lower prices and volumes in 2018, an increase of $54 million due to a change in regulatory deferrals, and higher earnings in 2018, partially offset by a tax refund in 2017.

Power

Power's operating cash flow decreased $38 million from $580 million to $542 million for the three months ended March 31, 2018, as compared to the same period in 2017, due primarily to an increase of $71 million in payments to counterparties and a $22 million decrease from fuels, materials and supplies, offset by a $69 million increase from net collections of counterparty receivables.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs.

Our total credit facilities and available liquidity as of March 31, 2018 were as follows:

	As of March 31, 2018		
Company/Facility	**Total Facility**	**Usage**	**Available Liquidity**
	Millions		
PSEG	$ 1,500	$ 609	$ 891
PSE&G	600	16	584
Power	2,100	158	1,942
Total	**$ 4,200**	**$ 783**	**$ 3,417**

As of March 31, 2018, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating from S&P or Moody's, which would represent a three level downgrade from its current S&P or Moody's ratings. In the event of a deterioration of Power's credit rating certain of Power's agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $867 million and $848 million as of March 31, 2018 and December 31, 2017, respectively.

For additional information, see Item 1. Note 11. Debt and Credit Facilities.

Long-Term Debt Financing

During the next twelve months, PSE&G has $400 million of 5.30% Medium-Term Notes maturing in May 2018 and $350 million of 2.30% Medium-Term Notes maturing in September 2018. Power has $250 million of 2.45% Senior Notes maturing in November 2018.

For additional information see Item 1. Note 11. Debt and Credit Facilities.

Common Stock Dividends

On February 20, 2018, our Board of Directors approved a $0.45 dividend per share of common stock for the first quarter of 2018. On April 17, 2018, our Board of Directors declared a $0.45 dividend per share of common stock for the second quarter of 2018. This reflects an indicative annual dividend rate of $1.80 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 1. Note17. Earnings Per Share (EPS) and Dividends.

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Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

	Moody's (A)	S&P (B)
PSEG		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures as compared to amounts disclosed in our 2017 Form 10-K.

PSE&G

During the three months ended March 31, 2018, PSE&G made capital expenditures of $759 million, primarily for T&D system reliability. This does not include expenditures for cost of removal, net of salvage, of $38 million, which are included in operating cash flows.

Power

During the three months ended March 31, 2018, Power made capital expenditures of $283 million, excluding $16 million for nuclear fuel, primarily related to our Keys, Sewaren 7, BH5 and other generation projects.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Item 1. Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

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Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From January through March 2018, MTM VaR varied between a low of $8 million and a high of $38 million at the 95% confidence level. The range of VaR was narrower for the three months ended March 31, 2018 as compared with the year ended December 31, 2017.

	MTM VaR	
	Three Months Ended March 31, 2018	Year Ended December 31, 2017
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 9	$ 39
Average for the Period	$ 21	$ 10
High	$ 38	$ 39
Low	$ 8	$ 5
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 14	$ 60
Average for the Period	$ 32	$ 15
High	$ 60	$ 60
Low	$ 13	$ 8

See Item 1. Note 12. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, PSE&G and Power

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of PSEG, PSE&G and Power. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of PSEG, PSE&G and Power have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, PSE&G and Power

There have been no changes in internal control over financial reporting that occurred during the first quarter of 2018 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and environmental and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2017 Annual Report on Form 10-K, see Part I, Item 1. Note 10. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

The discussion of our business and operations in this Quarterly Report on Form 10-Q should be read together with the risk factors contained in Part I, Item 1A of our 2017 Annual Report on Form 10-K and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2018, which describe various risks and uncertainties that could have a material adverse impact on our business, prospects, financial position, results of operations or cash flows and could cause results to differ materially from those expressed elsewhere in this report. There have been no material changes to the risk factors set forth in the above-referenced filings as of March 31, 2018.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

In December 2017, we entered into a share repurchase plan that complies with Rule 10b5-1 of the Securities Exchange Act of 1934, as amended, solely with respect to the repurchase of shares to satisfy obligations under equity compensation awards that are expected to vest or be exercised in 2018 and under PSEG's Employee Stock Purchase Plan for expected employee purchases in 2018. The following table indicates our common share repurchases in the open market during the first quarter of 2018.

Three Months Ended March 31, 2018	Total Number of Shares Purchased	Average Price Paid per Share
January 1 - January 31	1,300,000	$ 50.00
February 1 - February 28	—	$ —
March 1- March 31	—	$ —

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ITEM 5. OTHER INFORMATION

Certain information reported in the 2017 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2017 Annual Report on Form 10-K. References are to the related pages on the Form 10-K as printed and distributed.

Federal Regulation

Energy Clearing Prices

December 31, 2017 Form 10-K page 16. FERC has ordered certain favorable changes to energy market price formation rules improving shortage pricing and enhancing bidding flexibility for units. We continue to advocate in this context for additional changes in market rules that would provide more transparency regarding operator actions affecting energy market prices and would promote better alignment between generation dispatch decisions and energy market price outcomes. In November 2017, PJM issued an energy price formation proposal to address a flaw in the energy market by allowing all resources selected for dispatch, both flexible and inflexible, to set price and consequently, result in prices that more accurately reflect the true cost to serve load. PJM's proposal would allow large, inflexible units to set price. If placed into effect, this proposal will improve price formation by ensuring that the marginal costs of units serving load will be better reflected in clearing prices. We cannot predict the outcome of this matter.

Capacity Market Issues—PJM

December 31, 2017 Form 10-K page 16. PJM fully implemented in the May 2017 RPM auction for the 2020-2021 Delivery Year a "Capacity Performance" (CP) mechanism that created a more robust capacity product with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. The CP mechanism is intended to enhance the participation of intermittent and demand response resources (seasonal resources). Specifically, FERC approved PJM's modifications to the aggregation rules to improve the ability of seasonal resources to participate. However, FERC recently scheduled a technical conference in response to two complaints requesting that FERC investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions. We cannot predict the outcome of these matters.

In April, 2018, PJM submitted two proposed alternative and mutually exclusive capacity market reforms for FERC's approval. One option would be to implement a two-tier clearing mechanism that accommodates states' subsidies and the other option would be to extend the existing Minimum Offer Price Rule to units that are receiving subsidies. We are currently evaluating these two proposals.

Capacity Market Issues— ISO-NE

Recently, ISO-NE submitted proposed changes to the Forward Capacity Market referred to as the Competitive Auctions and Sponsored Policy Resources (CASPR) proposal to accommodate clean and renewable energy policy resources. The CASPR design creates a second auction that commences immediately following the Forward Capacity Auction and provides the opportunity for certain renewable, clean and alternative energy resources to acquire supply obligations when they cannot clear economically in the Forward Capacity Auction. The CASPR design also proposed to phase out the exemption from the minimum offer price rule (MOPR) in the capacity market afforded for up to 200MW annually (600 MW cumulatively) of renewable resources, an aspect of the market design that we did not support due to the capacity market suppression associated with this mechanism. In March 2018, FERC approved the filing, including the phase out of the 200MW renewables exemptions, with an effective date beginning with the next Forward Capacity Auction to be held in February 2019.

Transmission Regulation—Transmission Policy Developments

December 31, 2017 Form 10-K page 18. In February 2018, FERC issued an order finding that the transmission planning procedures used by the PJM transmission owners, a group that includes PSE&G, for supplemental projects do not adhere to the coordination and transparency principles of FERC's Order No. 890. FERC determined that certain terms and conditions in the PJM governing documents are unjust and unreasonable. FERC directed PJM and the PJM transmission owners to submit certain revisions to the manner in which the stakeholder process for supplemental projects is conducted. PSE&G participated in the PJM transmission owners' compliance filing. A number of parties also sought rehearing of the FERC order seeking more onerous requirements that, if accepted, could be disruptive of the planning process.

State Regulation

BGSS Process

In November 2017, a filing was made by the Retail Energy Supply Association (RESA) with the BPU requesting that the BPU revisit the BGSS process and establish a gas capacity release program. This filing is applicable to all New Jersey gas utilities. In March 2018, the RESA filed an amended petition with the BPU requesting a formal proceeding to establish a gas capacity release program. This filing is applicable to all New Jersey gas utilities.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. PSE&G:

Exhibit 4a(15)	Supplemental Indenture dated April 1, 2018
Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. Power:

Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 30, 2018

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 30, 2018

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: April 30, 2018

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SUPPLEMENTAL MORTGAGE

Supplemental Indenture

Dated April 1, 2018

SUPPLEMENTAL TO
FIRST AND REFUNDING MORTGAGE
DATED AUGUST 1, 1924

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
TO
U.S. BANK NATIONAL ASSOCIATION
Trustee
21 South Street
Morristown, New Jersey 07960

PROVIDING FOR THE ISSUE OF
$2,500,000,000 FIRST AND REFUNDING MORTGAGE BONDS,
MEDIUM-TERM NOTES SERIES M

RECORD IN MORTGAGE BOOK AND RETURN TO:
ANDREW J. WOODWORTH, ESQ.
80 PARK PLAZA, T5
NEWARK, N.J. 07102

Prepared by

/s/ Andrew J. Woodworth

(Andrew J. Woodworth, Esq.)

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SUPPLEMENTAL INDENTURE, dated the 1st day of April 2018 for convenience of reference and effective from the time of execution and delivery hereof, between PUBLIC SERVICE ELECTRIC AND GAS COMPANY, a corporation organized under the laws of the State of New Jersey, hereinafter called the "Company", party of the first part, and U.S. Bank National Association, a national banking association organized under the laws of the United States of America, as successor Trustee to Wachovia Bank, National Association (previously known as Fidelity Union Trust Company) under the indenture dated August 1, 1924, below mentioned, hereinafter called the "Trustee", party of the second part.

WHEREAS, on July 25, 1924, the Company executed and delivered to FIDELITY UNION TRUST COMPANY, a certain indenture dated August 1, 1924 (hereinafter called the "Indenture") to secure and to provide for the issue of First and Refunding Mortgage Gold Bonds of the Company; and

WHEREAS, the Indenture has been recorded in the following counties of the State of New Jersey, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Atlantic	Clerk's	1955 of Mortgages	160
Bergen	Clerk's	94 of Chattel Mortgages	123 etc.
		693 of Mortgages	88 etc.
Burlington	Clerk's	52 of Chattel Mortgages	Folio 8 etc.
		177 of Mortgages	Folio 354 etc.
Camden	Register's	45 of Chattel Mortgages	184 etc.
		239 of Mortgages	1 etc.
Cumberland	Clerk's	786 of Mortgages	638 & c.
Essex	Register's	437 of Chattel Mortgages	1-48
		T-51 of Mortgages	341-392
Gloucester	Clerk's	34 of Chattel Mortgages	123 etc.
		142 of Mortgages	7 etc.
Hudson	Register's	453 of Chattel Mortgages	9 etc.
		1245 of Mortgages	484, etc.
Hunterdon	Clerk's	151 of Mortgages	344
Mercer	Clerk's	67 of Chattel Mortgages	1 etc.
		384 of Mortgages	1 etc.
Middlesex	Clerk's	113 of Chattel Mortgages	3 etc.
		437 of Mortgages	294 etc.
Monmouth	Clerk's	951 of Mortgages	291 & c.
Morris	Clerk's	N-3 of Chattel Mortgages	446 etc.
		F-10 of Mortgages	269 etc.
Ocean	Clerk's	1809 of Mortgages	40
Passaic	Register's	M-6 of Chattel Mortgages	178, etc.
		R-13 of Mortgages	268 etc.
Salem	Clerk's	267 of Mortgages	249 etc.
Somerset	Clerk's	46 of Chattel Mortgages	207 etc.
		N-10 of Mortgages	1 etc.
Sussex	Clerk's	123 of Mortgages	10 & c.
Union	Register's	9584 of Mortgages	259 etc.
Warren	Clerk's	124 of Mortgages	141 etc.

and

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WHEREAS, the Indenture has also been recorded in the following counties of the Commonwealth of Pennsylvania, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Adams	Recorder's	22 of Mortgages	105
Armstrong	Recorder's	208 of Mortgages	381
Bedford	Recorder's	90 of Mortgages	917
Blair	Recorder's	671 of Mortgages	430
Cambria	Recorder's	407 of Mortgages	352
Cumberland	Recorder's	500 of Mortgages	136
Franklin	Recorder's	285 of Mortgages	373
Huntingdon	Recorder's	128 of Mortgages	47
Indiana	Recorder's	197 of Mortgages	281
Lancaster	Recorder's	984 of Mortgages	1
Montgomery	Recorder's	5053 of Mortgages	1221
Westmoreland	Recorder's	1281 of Mortgages	198
York	Recorder's	31-V of Mortgages	446

and

WHEREAS, the Indenture granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company, more fully set forth and described in the Indenture, then owned or which might thereafter be acquired by the Company; and

WHEREAS, the Company, by various supplemental indentures, supplemental to the Indenture, the last of which was dated September 1, 2016, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company acquired by it after the execution and delivery of the Indenture; and

WHEREAS, since the execution and delivery of said supplemental indenture dated September 1, 2016, the Company has acquired property which, in accordance with the provisions of the Indenture, is subject to the lien thereof and the Company desires to confirm such lien; and

WHEREAS, the Indenture has been amended or supplemented from time to time; and

Whereas, it is provided in the Indenture that no bonds other than those of the 5-1/2% Series due 1959 therein authorized may be issued thereunder unless a supplemental indenture providing for the issue of such additional bonds shall have been executed and delivered by the Company to the Trustee; and

WHEREAS, the Company is making provisions for the issuance and sale of its Secured Medium-Term Notes, Series M (the "Series M Notes"), to be issued under an Indenture of Trust (the "Note Indenture") dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as Trustee (the "Note Trustee"); and

WHEREAS, such Note Indenture provides, among other things, for the pledge and delivery by the Company of a series of First and Refunding Mortgage Bonds of the Company to evidence the Company's obligation to pay the principal and interest with respect to outstanding Series M Notes; and for such purpose and in order to service and secure payment of the principal and interest in respect of the Series M Notes, the Company desires to provide for the issue of $2,500,000,000 aggregate principal amount of bonds under the Indenture of a series to be designated as "First and Refunding Mortgage Bonds, Medium-Term Notes Series M" (hereinafter sometimes called "Bonds of the Medium-Term Notes Series M"); and

WHEREAS, the text of the Bonds of the Medium-Term Notes Series M and of the certificate of authentication to be borne by the Bonds of the Medium-Term Notes Series M shall be substantially of the following tenor:

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(FORM OF BOND)

This Bond is not transferable except as provided in the Indenture and in the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor trustee) as Trustee.

REGISTERED	REGISTERED		
		NUMBER	AMOUNT
R	$2,500,000,000		

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
FIRST AND REFUNDING MORTGAGE BOND,

MEDIUM-TERM NOTES SERIES M

Public Service Electric and Gas Company (hereinafter called the "Company"), a corporation of the State of New Jersey, for value received, hereby promises to pay to The Bank of New York Mellon (as successor trustee to The Chase Manhattan Bank (National Association)), under the Indenture of Trust dated as of July 1, 1993 between the Company and such trustee, or registered assigns, on the surrender hereof, the principal sum of Two Billion Five Hundred Million Dollars, on April 1, 2053, and to pay interest thereon from the date hereof, at the rate of 10% per annum, and until payment of said principal sum, such interest to be payable April 1 and October 1 in each year; provided, however, that the Company shall receive certain credits against such obligations as set forth in the Supplemental Indenture dated April 1, 2018 referred to below.

Both the principal hereof and interest hereon shall be paid at the principal corporate trust office of U.S. Bank National Association in the City of Morristown, State of New Jersey, or (at the option of the registered owner) at the corporate trust office of any paying agent appointed by the Company, in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts; provided, however, that any such payments of principal and interest shall be subject to receipt of certain credits against such payment obligations as set forth in the Supplemental Indenture dated April 1, 2018 referred to below.

This Bond is one of the First and Refunding Mortgage Bonds of the Company issued and to be issued under and pursuant to, and all equally secured by, an indenture of mortgage or deed of trust dated August 1, 1924, as supplemented and amended by supplemental indentures thereto, including the Supplemental Indenture dated April 1, 2018, duly executed by the Company and U.S. Bank National Association as Trustee. This Bond is one of the Bonds of the Medium-Term Notes Series M, which series is limited to the aggregate principal amount of $2,500,000,000 and is issued pursuant to said Supplemental Indenture dated April 1, 2018. Reference is hereby made to said indenture and all supplements thereto for a specification of the principal amount of Bonds from time to time issuable thereunder, and for a description of the properties mortgaged and conveyed or assigned to said Trustee or its successors, the nature and extent of the security, and the rights of the holders of said Bonds and any coupons appurtenant thereto, and of the Trustee in respect of such security.

In and by said indenture, as amended and supplemented, it is provided that with the written approval of the Company and the Trustee, any of the provisions of said indenture may from time to time be eliminated or modified and other provisions may be added thereto provided the change does not alter the annual interest rate, redemption price or date, date of maturity or amount payable on maturity of any then outstanding Bond or conflict with the Trust Indenture Act of 1939 as then in effect, and provided the holders of 85% in principal amount of the Bonds secured by said indenture and then outstanding (including, if such change affects the Bonds of one or more series but less than all series then outstanding, a like percentage of the then outstanding Bonds of each series affected by such change, and excluding Bonds owned or controlled by the Company or by the parties owning at least 10% of the outstanding voting stock of the Company, as more fully specified in said indenture) consent in writing thereto, all as more fully set forth in said indenture, as amended and supplemented.

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First and Refunding Mortgage Bonds issuable under said indenture are issuable in series, and the Bonds of any series may be for varying principal amounts and in the form of coupon bonds and of registered bonds without coupons, and the Bonds of any one series may differ from the Bonds of any other series as to date, maturity, interest rate and otherwise, all as in said indenture provided and set forth. The Bonds of the Medium-Term Notes Series M, in which this Bond is included, are designated "First and Refunding Mortgage Bonds, Medium-Term Notes, Series M."

In case of the happening of an event of default as specified in said indenture and said supplemental indenture dated March 1, 1942, the principal sum of the Bonds of this series may be declared or may become due and payable forthwith, in the manner and with the effect in said indenture provided.

The Bonds of this series are subject to redemption as provided in Article II of the Supplemental Indenture dated April 1, 2018.

This Bond is transferable, but only as provided in said indenture and the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as trustee, upon surrender hereof, by the registered owner in person or by attorney duly authorized in writing, at either of said offices where the principal hereof and interest hereon are payable; upon any such transfer a new fully registered Bond similar hereto will be issued to the transferee. This Bond may in like manner be exchanged for one or more new fully registered Bonds of the same series of other authorized denominations but of the same aggregate principal amount. No service charge shall be made for any such transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto. The Company and the Trustee hereunder and any paying agent may deem and treat the person in whose name this Bond is registered as the absolute owner hereof for the purpose of receiving payment of or on account of the principal hereof and the interest hereon and for all other purposes; and neither the Company nor the Trustee hereunder nor any paying agent shall be affected by any notice to the contrary.

The Bonds of this series are issuable only in fully registered form, in any denomination authorized by the Company.

No recourse under or upon any obligation, covenant or agreement contained in said indenture or in any indenture supplemental thereto, or in any Bond issued thereunder, or because of any indebtedness arising thereunder, shall be had against any incorporator, or against any past, present or future stockholder, officer, or director, as such, of the Company or of any successor corporation, either directly or through the Company or any successor corporation, under any rule of law, statute or constitutional provision or by the enforcement of any assessment or by any legal or equitable proceeding or otherwise, it being expressly agreed and understood that said indenture, any indenture supplemental thereto and the obligations issued thereunder, are solely corporate obligations, and that no personal liability whatever shall attach to, or be incurred by, such incorporators, stockholders, officers or directors, as such, of the Company, or of any successor corporation, or any of them, because of the incurring of the indebtedness thereby authorized, or under or by reason of any of the obligations, covenants or agreements contained in the indenture or in any indenture supplemental thereto or in any of the Bonds issued thereunder, or implied therefrom.

This Bond shall not be entitled to any security or benefit under said indenture, as amended and supplemented, and shall not become valid or obligatory for any purpose, until the certificate of authentication, hereon endorsed, shall have been signed by U.S. Bank National Association as Trustee, or by its successor in trust under said indenture.

[To be executed and attested under seal in accordance with the provisions of the Indenture.]

(FORM OF CERTIFICATE OF AUTHENTICATION)

CERTIFICATE OF AUTHENTICATION

[To be authenticated in accordance with the provisions of the Indenture.]

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WHEREAS, the execution and delivery of this supplemental indenture have been duly authorized by the Board of Directors of the Company; and

WHEREAS, the Company represents that all things necessary to make the bond of the series hereinafter described, when duly authenticated by the Trustee and issued by the Company, a valid and legal obligation of the Company, and to make this supplemental indenture a valid and binding agreement supplemental to the Indenture, have been done and performed:

NOW, THEREFORE, THIS SUPPLEMENTAL INDENTURE WITNESSETH that the Company, in consideration of the premises and the execution and delivery by the Trustee of this supplemental indenture, and in pursuance of the covenants and agreements contained in the Indenture and for other good and valuable consideration, the receipt of which is hereby acknowledged, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over, and by these presents does grant, bargain, sell, alien, remise, release, convey, confirm, assign, transfer and set over unto the Trustee, its successors and assigns, forever, all the right, title and interest of the Company in and to all property of every kind and description (except cash, accounts and bills receivable and all merchandise bought, sold or manufactured for sale in the ordinary course of the Company's business, stocks, bonds or other corporate obligations or securities, other than such as are described in Part V of the Granting Clauses of the Indenture, not acquired with the proceeds of bonds secured by the Indenture, and except as in the Indenture and herein otherwise expressly excluded) acquired by the Company since the execution and delivery of the supplemental indenture dated September 1, 2016, subsequent to the Indenture (except any such property duly released from, or disposed of, free from the lien of the Indenture, in accordance with the provisions thereof) and all such property which at any time hereafter may be acquired by the Company;

All of which property it is intended shall be included in and granted by this supplemental indenture and covered by the lien of the Indenture as heretofore and hereby amended and supplemented;

UNDER AND SUBJECT to any encumbrances or mortgages existing on property acquired by the Company at the time of such acquisition and not heretofore discharged of record; and

SUBJECT also, to the exceptions, reservations and provisions in the Indenture and in this supplemental indenture recited, and to the liens, reservations, exceptions, limitations, conditions and restrictions imposed by or contained in the several deeds, grants, franchises and contracts or other instruments through which the Company acquired or claims title to the aforesaid property; and Subject, also, to the existing leases, to liens on easements or rights of way, to liens for taxes, assessments and governmental charges not in default or the payment of which is deferred, pending appeal or other contest by legal proceedings, pursuant to Section 4 of Article Five of the Indenture, or the payment of which is deferred pending billing, transfer of title or final determination of amount, to easements for alleys, streets, highways, rights of way and railroads that may run across or encroach upon the said property, to joint pole and similar agreements, to undetermined liens and charges, if any, incidental to construction, and other encumbrances permitted by the Indenture as heretofore and hereby amended and supplemented;

TO HAVE AND TO HOLD the property hereby conveyed or assigned, or intended to be conveyed or assigned, unto the Trustee, its successor or successors and assigns, forever;

IN TRUST, NEVERTHELESS, upon the terms, conditions and trusts set forth in the Indenture as heretofore and hereby amended and supplemented, to the end that the said property shall be subject to the lien of the Indenture as heretofore and hereby amended and supplemented, with the same force and effect as though said property had been included in the Granting Clauses of the Indenture at the time of the execution and delivery thereof;

AND THIS SUPPLEMENTAL INDENTURE FURTHER WITNESSETH that for the considerations aforesaid, it is hereby covenanted between the Company and the Trustee as follows:

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ARTICLE I.

BONDS OF THE MEDIUM-TERM NOTES SERIES M.

The series of bonds authorized by this supplemental indenture to be issued under and secured by the Indenture shall be designated "First and Refunding Mortgage Bonds, Medium-Term Notes Series M"; shall be limited to the aggregate principal amount of $2,500,000,000; shall be issued initially to the Note Trustee and shall mature and bear interest as set forth in the form of bond set forth herein; provided, however, that the Company shall receive certain credits against principal and interest as set forth in Section 3.01 hereof. The date of each Bond of the Medium-Term Notes Series M shall be the interest payment date next preceding the date of authentication, unless such date of authentication be an interest payment date, in which case the date shall be the date of authentication, or unless such date of authentication be prior to the first semi-annual interest payment date, in which case the date shall be April 1, 2018.

Bonds of the Medium-Term Notes Series M shall be issuable only in the form of fully registered bonds in any denomination authorized by the Company. Interest on the Bonds of the Medium-Term Notes Series M shall be payable semi-annually in arrears on April 1 and October 1 of each year, payable initially on October 1, 2018, subject to receipt of certain credits against principal and interest as set forth in Section 3.01 hereof and shall be payable as to both principal and interest in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts, at the principal corporate trust office of the Trustee, or at the corporate trust office of any paying agent appointed.

Bonds of the Medium-Term Notes Series M shall be transferable and exchangeable, but only as provided in the Indenture and the Note Indenture, upon surrender thereof for cancellation by the registered owner in person or by attorney duly authorized in writing at either of said offices. The Company hereby waives any right to make a charge for any transfer or exchange of Bonds of the Medium-Term Notes Series M, but the Company may require payment of a sum sufficient to cover any tax or any other governmental charge that may be imposed in relation thereto.

ARTICLE II.

REDEMPTION OF BONDS OF MEDIUM-TERM NOTES SERIES M.

SECTION 2.01. *Redemption-Redemption Price*. Bonds of the Medium-Term Notes Series M shall be subject to redemption prior to maturity under the conditions, and upon payment of the amounts as may be specified in the following conditions:

(a) at any time in whole or in part at the option of the Company upon receipt by the Trustee of written certification of the Company and of the Note Trustee that the principal amount of the Series M Notes then outstanding under the Note Indenture is not in excess of such principal amount of the Bonds of the Medium-Term Notes Series M as shall remain pledged to the Note Trustee after giving effect to such redemption; (b) at any time by the application of any proceeds of released property or other money held by the Trustee and which, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, are applied to the redemption of Bonds of the Medium-Term Notes Series M, upon payment of 100% of the principal amount thereof, together with interest accrued to the redemption date, provided that any such payment shall be subject to receipt by the Company of certain credits against such obligations as set forth in Section 3.01 hereof or (c) automatically upon failure to pay the principal of any Series M Notes then outstanding under the Note Indenture when due, on their stated maturity date or earlier redemption or repayment date, in a principal amount of Bonds of the Medium-Term Notes Series M equal to the principal amount of such Series M Notes, in each case, at a price equal to 100% of the principal amount thereof, together with accrued interest, if applicable.

SECTION 2.02. *Redemptions Pursuant to Section 4C of Article Eight of the Indenture*. If, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, any proceeds of released property or other money then held by the Trustee shall be applied to the redemption of the Bonds of the Medium-Term Notes Series M, the Trustee shall give at least 45 days prior written notice of such redemption to the Note Trustee whereupon on the date fixed for redemption such principal amount thereof as is equal to such proceeds shall be redeemed; provided that no such redemption shall be made unless the

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Trustee shall be in receipt of a written certification of the Company and the Note Trustee that a like principal amount of Series M Notes shall have been theretofore redeemed in accordance with the provisions of the Note Indenture. For purposes of determining which of the Company's First and Refunding Mortgage Bonds are subject to such mandatory redemption, the Mortgage Trustee shall consider the 10% stated annual interest rate of the Bonds of the Medium-Term Notes Series M, not the weighted average interest rate of outstanding Series M Notes. Bonds of said series so redeemed shall be cancelled.

SECTION 2.03. *Interest on Called Bonds to Cease.* Each Bond of the Medium-Term Notes Series M or portion thereof called for redemption under Section 2.02 hereof shall be due and payable at the office of the Note Trustee, as paying agent hereunder, at its redemption price and on the specified redemption date, anything herein or in such Bond to the contrary notwithstanding. From and after the date when each Bond of the Medium-Term Notes Series M or portion thereof shall be due and payable as aforesaid (unless upon said date the full amount due thereon shall not be held by the Note Trustee, as paying agent hereunder, and be immediately available for payment), all further interest shall cease to accrue on such bond or on such portion thereof, as the case may be.

SECTION 2.04. *Bonds Called in Part.* If only a portion of any Bond of the Medium-Term Notes Series M shall be called for redemption pursuant to Section 2.02 hereof, upon payment of the portion so called for redemption, the Note Trustee shall make an appropriate notation upon the Bond of the principal amount so redeemed.

SECTION 2.05. *Provisions of Indenture Not Applicable*. The provisions of Article Four of the Indenture, as amended and supplemented, shall not apply to the procedure for the exercise of any right of redemption reserved by the Company, or to any mandatory redemption provided, in this Article in respect of the Bonds of the Medium-Term Notes Series M. There shall be no sinking fund for the Bonds of the Medium-Term Notes Series M.

ARTICLE III.

CREDITS WITH RESPECT TO BONDS OF THE MEDIUM-TERM NOTES SERIES M.

SECTION 3.01. *Credits.* In addition to any other credit, payment or satisfaction to which the Company is entitled with respect to the Bonds of the Medium-Term Notes Series M, the Company shall be entitled to credits against amounts otherwise payable in respect of the Bonds of the Medium-Term Notes Series M in an amount corresponding to (i) the principal amount of any of the Company's Series M Notes issued under the Note Indenture surrendered to the Note Trustee by the Company, or purchased by the Note Trustee, for cancellation, (ii) the amount of money held by the Note Trustee and available and designated for the payment of principal or redemption price (exclusive of any premium) of, and/or interest on, the Series M Notes, regardless of the source of payment to the Note Trustee of such moneys and (iii) the amount by which principal of and interest due on the Bonds of the Medium-Term Notes Series M exceeds principal of and interest due on the Series M Notes. The Note Trustee shall make notation on such Bonds authorized hereby of any such credit.

SECTION 3.02. *Certificate of the Company.* A certificate of the Company signed by the President or any Vice President, and attested to by the Secretary or any Assistant Secretary, and consented to by the Note Trustee, stating that the Company is entitled to a credit under Section 3.01 hereof or that Bonds of the Medium-Term Notes Series M have been cancelled, and setting forth the basis therefor in reasonable detail, shall be conclusive evidence of such entitlement, and the Trustee shall accept such certificate as such evidence without further investigation or verification of the matters stated therein.

ARTICLE IV.

MISCELLANEOUS.

SECTION 4.01. *Authentication of Bonds of Medium-Term Notes Series M.* None of the Bonds of the Medium-Term Notes Series M, the issue of which is provided for by this supplemental indenture, shall be authenticated by or on behalf of the Trustee except in accordance with the provisions of the Indenture, as amended and supplemented, and this supplemental indenture, and upon compliance with the conditions in that behalf therein contained.

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SECTION 4.02. *Additional Restrictions on Authentication of Additional Bonds Under Indenture.* The Company covenants that from and after the date of execution of this supplemental indenture no additional bonds (as defined in Section 1 of Article Two of the Indenture) shall be authenticated and delivered by the Trustee under Subdivision A of Section 4 of said Article Two on account of additions or improvements to the mortgaged property;

(1) unless the net earnings of the Company for the period required by Subdivision C of Section 6 of said Article Two shall have been at least twice the fixed charges (in lieu of 1-3/4 times such fixed charges, as required by said Subdivision C); and for the purpose of this condition (a) such fixed charges shall in each case include interest on the bonds applied for, notwithstanding the parenthetical provision contained in clause (4) of said Subdivision C, and (b) in computing such net earnings there shall be included in expenses of operation (under paragraph (c) of said Subdivision C) all charges against earnings for depreciation, renewals or replacements, and all certificates with respect to net earnings delivered to the Trustee in connection with any authentication of additional bonds under said Article Two shall so state; and (2) except to the extent of 60% (in lieu of 75% as permitted by Subdivision A of Section 7 of said Article Two) of the cost or fair value to the Company of the additions or improvements forming the basis for such authentication of additional bonds.

SECTION 4.03. *Restriction on Dividends.* The Company will not declare or pay any dividend on any shares of its common stock (other than dividends payable in shares of its common stock) or make any other distribution on any such shares, or purchase or otherwise acquire any such shares (except shares acquired without cost to the Company) whenever such action would reduce the earned surplus of the Company to an amount less than $10,000,000 or such lesser amount as may remain after deducting from said $10,000,000 all amounts appearing in the books of account of the Company on December 31, 1948, which shall thereafter, pursuant to any order or rule of any regulatory body entered after said date, be required to be removed, in whole or in part, from the books of account of the Company by charges to earned surplus.

SECTION 4.04. *Use of Facsimile Seal and Signatures.* The seal of the Company and any or all signatures of the officers of the Company upon any of the Bonds of the Medium-Term Notes Series M may be facsimiles.

SECTION 4.05. *Time for Making of Payment.* All payments of principal or redemption price of, and interest on, the Bonds of the Medium-Term Notes Series M shall be made either prior to the due date thereof or on the due date thereof in immediately available funds. In any case where the date of any such payment shall be a Saturday or Sunday or a legal holiday or a day on which banking institutions in the city of payment are authorized by law to close, then such payment need not be made on such date but may be made on the next succeeding business day with the same force and effect as if made on the due date, and no interest on such payment shall accrue for the period after such date.

SECTION 4.06. *Effective Period of Supplemental Indenture.* The preceding provisions of Articles I, II and III of this supplemental indenture shall remain in effect only so long as any of the Bonds of the Medium-Term Notes Series M shall remain outstanding.

SECTION 4.07. *Effect of Approval of Board of Public Utilities of the State of New Jersey.* The approval of the Board of Public Utilities of the State of New Jersey of the execution and delivery of these presents and of the issue of any Bond of the Medium-Term Notes Series M shall not be construed as approval of said Board of any other act, matter or thing which requires approval of said Board under the laws of the State of New Jersey.

SECTION 4.08. *Execution in Counterparts.* For the purpose of facilitating the recording hereof, this supplemental indenture has been executed in several counterparts, each of which shall be and shall be taken to be an original, and all collectively but one instrument.

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IN WITHNESS WHEREOF, Public Service Electric and Gas Company, party hereto of the first part, after due corporate and other proceedings, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents and its corporate seal hereunto to be affixed and to be attested by the signature of its Secretary or an Assistant Secretary; and U.S. Bank National Association, as Trustee, party hereto of the second part, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents, and its corporate seal to be hereunto affixed and to be attested by the signature of its Secretary, Assistant Secretary, Vice President, or an Assistant Vice President. Executed and delivered this 1st day of April 2018.

Attest:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By /s/ B.D. Huntington
. . . . . .
B.D. Huntington
Vice President

Attest:
/s/ Donald S. Leibowitz
. . . . . .
Donald S. Leibowitz
Assistant Secretary

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U.S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes
. . . . . .
N. Barnes
Vice President

Attest:
/s/ A. Harris
. . . . . .
A. Harris
Vice President

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STATE OF NEW JERSEY)
SS:)
COUNTY OF ESSEX)

Be it Remembered, that on this 1st day of April, 2018, before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared B.D. Huntington, who, I am satisfied, is a Vice President of Public Service Electric and Gas Company, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors, and that said corporation, the mortgagor, has received a true copy of said instrument.

/s/ Mary Ryan
. . . . . .
Mary Ryan
Notary Public of New Jersey
My Commission Expires July 14, 2021

STATE OF NEW JERSEY)
SS:)
COUNTY OF ESSEX)

Be it Remembered, that on this 1st day of April 2018 before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared N. Barnes, who, I am satisfied, is a Vice President of U.S. Bank National Association, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, and that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors.

/s/ Mary Ryan

Mary Ryan
Notary Public of New Jersey
My Commission Expires July 14, 2021

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CERTIFICATE OF RESIDENCE

U.S. Bank National Association, Mortgagee and Trustee within named, hereby certifies that its precise residence is 21 South Street, Morristown, New Jersey 07960.

U.S. BANK NATIONAL ASSOCIATION

By /s/ N. Barnes
. . . . . .
N. Barnes
Vice President

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Three Months Ended March 31,		Years Ended December 31,				
	2018	**2017**	**2017**	**2016**	**2015**	**2014**	**2013**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 760	$ 143	$1,268	$1,298	$2,680	$2,456	$2,055
(Income) Loss from Equity Investees, net of Distributions	1	1	4	7	3	4	(7)
Fixed Charges	142	125	518	477	457	450	458
Capitalized Interest	(24)	24	(9)	(7)	(18)	(16)	(16)
Total Earnings	$ 879	$ 293	$1,781	$1,775	$3,122	$2,894	$2,490
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 133	$ 119	$ 487	$ 456	$ 437	$ 430	$ 442
Interest Factor in Rentals	9	6	31	21	20	20	16
Total Fixed Charges	$ 142	$ 125	$ 518	$ 477	$ 457	$ 450	$ 458
Ratio of Earnings to Fixed Charges	**6.19**	**2.34**	**3.44**	**3.72**	**6.83**	**6.43**	**5.44**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred stock dividends, increased to reflect the pre-tax earnings requirement. There were no preferred stock dividends for any period presented.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2018	2017	2017	2016	2015	2014	2013
			(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 436	$ 470	$1,536	$1,404	$ 1,257	$1,174	$ 993
Fixed Charges	89	82	331	316	306	303	316
Capitalized Interest	(4)	(5)	(18)	(17)	(17)	(16)	(16)
Total Earnings	$ 521	$ 547	$1,849	$1,703	$ 1,546	$1,461	$1,293
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 85	$ 80	$ 321	$ 306	$ 297	$ 293	$ 309
Interest Factor in Rentals	4	2	10	10	9	10	7
Total Fixed Charges	$ 89	$ 82	$ 331	$ 316	$ 306	$ 303	$ 316
Ratio of Earnings to Fixed Charges	**5.85**	**6.67**	**5.59**	**5.39**	**5.05**	**4.82**	**4.09**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, April 30, 2018
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EXHIBIT 12.2

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Years Ended December 31,				
	2018	**2017**	**2017**	**2016**	**2015**	**2014**	**2013**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income (Loss) from Continuing Operations	$ 317	$ (286)	$ (250)	$ (43)	$1,367	$1,251	$1,063
(Income) Loss from Equity Investees, net of Distributions	1	1	4	7	1	3	(10)
Fixed Charges	35	34	139	142	152	150	143
Capitalized Interest	(20)	29	9	11	(1)	1	1
Total Earnings	$ 333	$ (222)	$ (98)	$ 117	$1,519	$1,405	$1,197
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 32	$ 33	$ 128	$ 138	$ 148	$ 146	$ 139
Interest Factor in Rentals	3	1	11	4	4	4	4
Total Fixed Charges	$ 35	$ 34	$ 139	$ 142	$ 152	$ 150	$ 143
Ratio of Earnings to Fixed Charges (C)	**9.51**	**(6.53)**	**(0.71)**	**0.82**	**9.99**	**9.37**	**8.37**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

(C) The ratio of earnings to fixed charges for the three months ended March 31, 2017, was (6.53), as noted above, which represents a deficiency of $256 million. The ratio of earnings to fixed charges for the year ended December 31, 2017, was (0.71), as noted above, which represents a deficiency of $237 million.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2018

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

S1-SSA-0009 - 18685

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2018

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

S1-SSA-0009 - 18687

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2018

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 30, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
April 30, 2018

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended March 31, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
April 30, 2018

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, April 30, 2018 Powered by Morningstar® Document Research℠
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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
April 30, 2018

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended March 31, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
April 30, 2018

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
April 30, 2018

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended March 31, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
April 30, 2018

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2013
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of October 15, 2013, Public Service Enterprise Group Incorporated had outstanding 505,861,262 shares of its sole class of Common Stock, without par value.

As of October 15, 2013, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this communication about us and our subsidiaries future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission in the future, and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to balance our energy obligations, available supply and risks,
- any deterioration in our credit quality or the credit quality of our counterparties, including in our leveraged leases,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient coverage or recover proceeds of insurance on such matters,
- increases in competition in energy supply markets as well as competition for certain rate-based transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements, and
- changes in technology, such as distributed generation and microgrids, and resultant changes in customer usage patterns, including energy efficiency and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
OPERATING REVENUES	$ 2,554	$ 2,402	$ 7,650	$ 7,375
OPERATING EXPENSES				
Energy Costs	801	879	2,711	2,819
Operation and Maintenance	713	619	2,069	1,876
Depreciation and Amortization	313	286	886	797
Taxes Other Than Income Taxes	15	24	50	73
Total Operating Expenses	1,842	1,808	5,716	5,565
OPERATING INCOME	712	594	1,934	1,810
Income from Equity Method Investments	4	7	9	9
Other Income	59	121	172	216
Other Deductions	(12)	(26)	(54)	(61)
Other-Than-Temporary Impairments	(3)	(2)	(7)	(14)
Interest Expense	(100)	(106)	(303)	(310)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	660	588	1,751	1,650
Income Tax Expense	(270)	(241)	(708)	(599)
NET INCOME	$ 390	$ 347	$ 1,043	$ 1,051
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):				
BASIC	505,858	505,914	505,900	505,942
DILUTED	507,694	507,111	507,433	507,037
EARNINGS PER SHARE:				
BASIC				
INCOME FROM CONTINUING OPERATIONS	$ 0.77	$ 0.69	$ 2.06	$ 2.08
NET INCOME	$ 0.77	$ 0.69	$ 2.06	$ 2.08
DILUTED				
INCOME FROM CONTINUING OPERATIONS	$ 0.77	$ 0.68	$ 2.06	$ 2.07
NET INCOME	$ 0.77	$ 0.68	$ 2.06	$ 2.07
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.3600	$ 0.3550	$ 1.0800	$ 1.0650

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
NET INCOME	$ 390	$ 347	$ 1,043	$ 1,051
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(16), $5, $(27) and $(16) for the three and nine months ended 2013 and 2012, respectively	16	(10)	27	12
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $1, $8, $4 and $14 for the three and nine months ended 2013 and 2012, respectively	(1)	(10)	(5)	(20)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(6), $(5), $(20) and $(16) for the three and nine months ended 2013 and 2012, respectively	9	8	28	23
Other Comprehensive Income (Loss), net of tax	24	(12)	50	15
COMPREHENSIVE INCOME	$ 414	$ 335	$ 1,093	$ 1,066

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 448	$ 379
Accounts Receivable, net of allowances of $57 and $56 in 2013 and 2012, respectively	1,069	1,069
Tax Receivable	225	227
Unbilled Revenues	211	314
Fuel	599	583
Materials and Supplies, net	450	422
Prepayments	210	283
Derivative Contracts	107	138
Deferred Income Taxes	31	49
Regulatory Assets	348	349
Other	43	56
Total Current Assets	3,741	3,869
PROPERTY, PLANT AND EQUIPMENT	29,206	27,402
Less: Accumulated Depreciation and Amortization	(8,127)	(7,666)
Net Property, Plant and Equipment	21,079	19,736
NONCURRENT ASSETS		
Regulatory Assets	3,519	3,830
Regulatory Assets of Variable Interest Entities (VIEs)	532	713
Long-Term Investments	1,320	1,324
Nuclear Decommissioning Trust (NDT) Fund	1,635	1,540
Other Special Funds	181	191
Goodwill	16	16
Other Intangibles	52	34
Derivative Contracts	184	153
Restricted Cash of VIEs	23	23
Other	328	296
Total Noncurrent Assets	7,790	8,120
TOTAL ASSETS	$ 32,610	$ 31,725

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2013	December 31, 2012
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 775	$ 1,026
Securitization Debt of VIEs Due Within One Year	235	226
Commercial Paper and Loans	—	263
Accounts Payable	1,024	1,304
Derivative Contracts	36	46
Accrued Interest	114	91
Accrued Taxes	83	17
Deferred Income Taxes	48	72
Clean Energy Program	185	153
Obligation to Return Cash Collateral	118	122
Regulatory Liabilities	171	67
Other	446	390
Total Current Liabilities	3,235	3,777
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	6,807	6,542
Regulatory Liabilities	213	209
Regulatory Liabilities of VIEs	11	10
Asset Retirement Obligations	653	627
Other Postretirement Benefit (OPEB) Costs	1,274	1,285
Accrued Pension Costs	710	876
Environmental Costs	431	537
Derivative Contracts	163	122
Long-Term Accrued Taxes	183	164
Other	115	108
Total Noncurrent Liabilities	10,560	10,480
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	7,134	6,148
Securitization Debt of VIEs	326	496
Project Level, Non-Recourse Debt	16	43
Total Long-Term Debt	7,476	6,687
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2013 and 2012 —533,556,660 shares	4,852	4,833
Treasury Stock, at cost, 2013— 27,695,398 shares; 2012— 27,664,188 shares	(615)	(607)
Retained Earnings	7,439	6,942
Accumulated Other Comprehensive Loss	(338)	(388)
Total Common Stockholders' Equity	11,338	10,780
Noncontrolling Interest	1	1
Total Stockholders' Equity	11,339	10,781
Total Capitalization	18,815	17,468
TOTAL LIABILITIES AND CAPITALIZATION	$ 32,610	$ 31,725

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18702

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2013	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 1,043	$ 1,051
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	886	797
Amortization of Nuclear Fuel	145	129
Provision for Deferred Income Taxes (Other than Leases) and ITC	242	221
Non-Cash Employee Benefit Plan Costs	182	203
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(7)	(81)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	3	116
Change in Accrued Storm Costs	(87)	5
Net Change in Other Regulatory Assets and Liabilities	134	(82)
Cost of Removal	(66)	(71)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(76)	(107)
Net Change in Tax Receivable	2	16
Net Change in Certain Current Assets and Liabilities	173	305
Employee Benefit Plan Funding and Related Payments	(210)	(193)
Other	71	2
Net Cash Provided By (Used In) Operating Activities	2,435	2,311
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(2,102)	(1,969)
Proceeds from Sale of Capital Leases and Investments	42	—
Proceeds from Sales of Available-for-Sale Securities	914	1,473
Investments in Available-for-Sale Securities	(922)	(1,497)
Other	(20)	(58)
Net Cash Provided By (Used In) Investing Activities	(2,088)	(2,051)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(263)	—
Issuance of Long-Term Debt	1,500	850
Redemption of Long-Term Debt	(750)	(439)
Redemption of Securitization Debt	(162)	(154)
Repayment of Non-Recourse Debt	—	(1)
Cash Dividends Paid on Common Stock	(546)	(538)
Other	(57)	(32)
Net Cash Provided By (Used In) Financing Activities	(278)	(314)
Net Increase (Decrease) in Cash and Cash Equivalents	69	(54)
Cash and Cash Equivalents at Beginning of Period	379	834
Cash and Cash Equivalents at End of Period	$ 448	$ 780
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 222	$ 109
Interest Paid, Net of Amounts Capitalized	$ 274	$ 280
Accrued Property, Plant and Equipment Expenditures	$ 258	$ 259

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18704

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
OPERATING REVENUES	$ 1,169	$ 1,038	$ 3,806	$ 3,584
OPERATING EXPENSES				
Energy Costs	430	456	1,786	1,725
Operation and Maintenance	304	255	866	780
Depreciation and Amortization	66	60	195	175
Total Operating Expenses	800	771	2,847	2,680
OPERATING INCOME	369	267	959	904
Other Income	45	104	127	171
Other Deductions	(11)	(20)	(49)	(52)
Other-Than-Temporary Impairments	(3)	(2)	(7)	(14)
Interest Expense	(26)	(35)	(85)	(97)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	374	314	945	912
Income Tax Expense	(153)	(133)	(383)	(374)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 221	$ 181	$ 562	$ 538

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
NET INCOME	$ 221	$ 181	$ 562	$ 538
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(18), $6, $(29) and $(16) for the three and nine months ended 2013 and 2012, respectively	17	(11)	30	11
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $1, $8, $4 and $14 for the three and nine months ended 2013 and 2012, respectively	(1)	(11)	(6)	(21)
Pension/OPEB adjustment, net of tax (expense) benefit of $(6), $(4), $(17) and $(14) for the three and nine months ended 2013 and 2012, respectively	8	7	25	21
Other Comprehensive Income (Loss), net of tax	24	(15)	49	11
COMPREHENSIVE INCOME	$ 245	$ 166	$ 611	$ 549

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 9	$ 7
Accounts Receivable	211	269
Accounts Receivable—Affiliated Companies, net	34	340
Short-Term Loan to Affiliate	417	574
Fuel	599	583
Materials and Supplies, net	329	307
Derivative Contracts	72	118
Prepayments	16	17
Deferred Income Taxes	3	—
Other	—	19
Total Current Assets	1,690	2,234
PROPERTY, PLANT AND EQUIPMENT	10,035	9,697
Less: Accumulated Depreciation and Amortization	(2,973)	(2,679)
Net Property, Plant and Equipment	7,062	7,018
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,635	1,540
Goodwill	16	16
Other Intangibles	52	34
Other Special Funds	38	36
Derivative Contracts	89	49
Other	139	105
Total Noncurrent Assets	1,969	1,780
TOTAL ASSETS	$ 10,721	$ 11,032

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2013	December 31, 2012
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ —	$ 300
Accounts Payable	404	498
Derivative Contracts	36	46
Deferred Income Taxes	—	16
Accrued Interest	37	26
Other	109	81
Total Current Liabilities	586	967
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	1,732	1,575
Asset Retirement Obligations	385	369
Other Postretirement Benefit (OPEB) Costs	230	221
Derivative Contracts	23	15
Accrued Pension Costs	225	272
Long-Term Accrued Taxes	50	50
Other	90	84
Total Noncurrent Liabilities	2,735	2,586
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
LONG-TERM DEBT		
Total Long-Term Debt	2,041	2,040
MEMBER'S EQUITY		
Contributed Capital	2,028	2,028
Basis Adjustment	(986)	(986)
Retained Earnings	4,596	4,725
Accumulated Other Comprehensive Loss	(279)	(328)
Total Member's Equity	5,359	5,439
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 10,721	$ 11,032

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2013	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 562	$ 538
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	195	175
Amortization of Nuclear Fuel	145	129
Provision for Deferred Income Taxes and ITC	96	189
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	3	116
Non-Cash Employee Benefit Plan Costs	50	53
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(76)	(107)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	(38)	(10)
Margin Deposit	17	(107)
Accounts Receivable	69	50
Accounts Payable	(63)	(31)
Accounts Receivable/Payable-Affiliated Companies, net	306	193
Accrued Interest Payable	11	17
Other Current Assets and Liabilities	20	2
Employee Benefit Plan Funding and Related Payments	(45)	(40)
Other	32	5
Net Cash Provided By (Used In) Operating Activities	1,284	1,172
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(419)	(493)
Proceeds from Sales of Available-for-Sale Securities	849	1,295
Investments in Available-for-Sale Securities	(864)	(1,315)
Short-Term Loan—Affiliated Company, net	157	17
Other	(13)	(10)
Net Cash Provided By (Used In) Investing Activities	(290)	(506)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	(690)	(600)
Redemption of Long-Term Debt	(300)	(66)
Other	(2)	(7)
Net Cash Provided By (Used In) Financing Activities	(992)	(673)
Net Increase (Decrease) in Cash and Cash Equivalents	2	(7)
Cash and Cash Equivalents at Beginning of Period	7	12
Cash and Cash Equivalents at End of Period	$ 9	$ 5
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 107	$ 130
Interest Paid, Net of Amounts Capitalized	$ 72	$ 73
Accrued Property, Plant and Equipment Expenditures	$ 58	$ 84

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18709

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
OPERATING REVENUES	$ 1,666	$ 1,683	$ 5,084	$ 5,029
OPERATING EXPENSES				
Energy Costs	661	756	2,208	2,380
Operation and Maintenance	408	366	1,204	1,092
Depreciation and Amortization	236	216	658	594
Taxes Other Than Income Taxes	15	24	50	73
Total Operating Expenses	1,320	1,362	4,120	4,139
OPERATING INCOME	346	321	964	890
Other Income	13	16	41	39
Other Deductions	(1)	(6)	(3)	(8)
Interest Expense	(75)	(73)	(223)	(220)
INCOME BEFORE INCOME TAXES	283	258	779	701
Income Tax Expense	(115)	(103)	(311)	(248)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 168	$ 155	$ 468	$ 453

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18710

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
NET INCOME	$ 168	$ 155	$ 468	$ 453
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $(1), $1 and $0 for the three and nine months ended 2013 and 2012, respectively	—	1	(1)	—
COMPREHENSIVE INCOME	$ 168	$ 156	$ 467	$ 453

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18711

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 253	$ 116
Accounts Receivable, net of allowances of $57 and $56 in 2013 and 2012, respectively	839	783
Accounts Receivable-Affiliated Companies, net	94	—
Unbilled Revenues	211	314
Materials and Supplies	118	114
Prepayments	138	29
Regulatory Assets	348	349
Derivative Contracts	19	5
Deferred Income Taxes	31	49
Other	24	24
Total Current Assets	2,075	1,783
PROPERTY, PLANT AND EQUIPMENT	18,503	17,006
Less: Accumulated Depreciation and Amortization	(4,916)	(4,726)
Net Property, Plant and Equipment	13,587	12,280
NONCURRENT ASSETS		
Regulatory Assets	3,519	3,830
Regulatory Assets of VIEs	532	713
Long-Term Investments	356	348
Other Special Funds	41	61
Derivative Contracts	69	62
Restricted Cash of VIEs	23	23
Other	128	123
Total Noncurrent Assets	4,668	5,160
TOTAL ASSETS	$ 20,330	$ 19,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2013	December 31, 2012
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 775	$ 725
Securitization Debt of VIEs Due Within One Year	235	226
Commercial Paper and Loans	—	263
Accounts Payable	473	630
Accounts Payable—Affiliated Companies, net	—	73
Accrued Interest	77	65
Clean Energy Program	185	153
Deferred Income Taxes	55	60
Obligation to Return Cash Collateral	118	122
Regulatory Liabilities	171	67
Other	306	269
Total Current Liabilities	2,395	2,653
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,354	4,223
Other Postretirement Benefit (OPEB) Costs	989	1,011
Accrued Pension Costs	360	463
Regulatory Liabilities	213	209
Regulatory Liabilities of VIEs	11	10
Environmental Costs	380	486
Asset Retirement Obligations	260	250
Derivative Contracts	140	107
Long-Term Accrued Taxes	48	32
Other	46	38
Total Noncurrent Liabilities	6,801	6,829
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	5,066	4,070
Securitization Debt of VIEs	326	496
Total Long-Term Debt	5,392	4,566
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2013 and 2012 —132,450,344 shares	892	892
Contributed Capital	520	420
Basis Adjustment	986	986
Retained Earnings	3,343	2,875
Accumulated Other Comprehensive Income	1	2
Total Stockholder's Equity	5,742	5,175
Total Capitalization	11,134	9,741
TOTAL LIABILITIES AND CAPITALIZATION	$ 20,330	$ 19,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18713

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2013	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 468	$ 453
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	658	594
Provision for Deferred Income Taxes and ITC	153	131
Non-Cash Employee Benefit Plan Costs	117	134
Cost of Removal	(66)	(71)
Change in Accrued Storm Costs	(87)	5
Net Change in Other Regulatory Assets and Liabilities	134	(82)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	48	97
Materials and Supplies	(4)	(11)
Prepayments	(109)	(28)
Net Change in Tax Receivable	—	16
Accounts Payable	3	(20)
Accounts Receivable/Payable-Affiliated Companies, net	(171)	(41)
Other Current Assets and Liabilities	29	22
Employee Benefit Plan Funding and Related Payments	(147)	(137)
Other	23	(21)
Net Cash Provided By (Used In) Operating Activities	1,049	1,041
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,628)	(1,369)
Proceeds from Sales of Available-for-Sale Securities	35	73
Investments in Available-for-Sale Securities	(16)	(73)
Solar Loan Investments	(11)	(56)
Restricted Funds	—	1
Net Cash Provided By (Used In) Investing Activities	(1,620)	(1,424)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	(263)	—
Issuance of Long-Term Debt	1,500	850
Redemption of Long-Term Debt	(450)	(373)
Redemption of Securitization Debt	(162)	(154)
Contributed Capital	100	—
Other	(17)	(12)
Net Cash Provided By (Used In) Financing Activities	708	311
Net Increase (Decrease) In Cash and Cash Equivalents	137	(72)
Cash and Cash Equivalents at Beginning of Period	116	143
Cash and Cash Equivalents at End of Period	$ 253	$ 71
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 174	$ (30)
Interest Paid, Net of Amounts Capitalized	$ 199	$ 205
Accrued Property, Plant and Equipment Expenditures	$ 200	$ 175

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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This combined Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information relating to any individual company is filed by such company on its own behalf. Power and PSE&G each is only responsible for information about itself and its subsidiaries.

Note 1. Organization and Basis of Presentation

Organization

PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's four principal direct wholly owned subsidiaries are:

- **Power**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through three principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and the states in which they operate.
- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the FERC. PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs, which are regulated by the BPU.
- **PSEG Energy Holdings L.L.C. (Energy Holdings)**—which primarily has investments in leases and solar generation projects through its direct wholly owned subsidiaries. Certain Energy Holdings' subsidiaries are subject to regulation by the FERC and the states in which they operate. A subsidiary of Energy Holdings has been awarded a contract to manage the transmission and distribution assets of the Long Island Power Authority (LIPA) starting in 2014.
- **PSEG Services Corporation (Services)**—which provides management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2012 and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2013 and June 30, 2013.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All significant intercompany accounts and transactions are eliminated in consolidation, except as discussed in Note 18. Related-Party Transactions. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2012.

Note 2. Recent Accounting Standards

New Standards Adopted during 2013

Disclosures about Offsetting Assets and Liabilities

This accounting standard requires enhanced disclosures regarding assets and liabilities that are either offset in the financial statements, or are subject to an enforceable master netting arrangement or similar agreement. The guidance is applicable to certain financial instruments (e.g. derivatives) and securities borrowing and lending transactions. This standard requires entities:

- to disclose information about offsetting and related arrangements to enable users of financial statements to understand the effect of those arrangements on an entity's financial position, and

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- to present both net (offset amounts) and gross information in the notes to the financial statements for relevant assets and liabilities.

We adopted this standard retrospectively effective January 1, 2013. As this standard requires disclosures only, it did not have any impact on our consolidated financial position, results of operations or cash flows. For additional information, see Note 11. Financial Risk Management Activities.

Reclassification Adjustments out of Accumulated Other Comprehensive Income

This accounting standard requires entities to disclose the following information about reclassification adjustments related to Accumulated Other Comprehensive Income:

- changes in Accumulated Other Comprehensive Income balances by component, and
- significant amounts reclassified out of Accumulated Other Comprehensive Income by respective line items of net income (for amounts that are required by GAAP to be reclassified to net income in their entirety in the same reporting period).

We adopted this standard prospectively effective January 1, 2013. As this standard requires disclosures only, it did not have any impact on our consolidated financial position, results of operations or cash flows. For additional information, see Note 15. Accumulated Other Comprehensive Income (Loss), Net of Tax.

New Accounting Standards Issued But Not Yet Adopted

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

This accounting standard was issued to address diversity in practice related to the presentation of an unrecognized tax benefit in certain cases. This standard requires entities to present an unrecognized tax benefit or a portion thereof on the Balance Sheet as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward.

However, in cases in which a net operating loss carryforward, a similar tax loss or a tax credit carryforward is not available at the reporting date under the tax law of the jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or the tax law of the jurisdiction does not require an entity to use, and the entity does not intend to use the deferred tax asset for such purpose, the unrecognized tax benefit will be presented on the Balance Sheet as a liability and will not be combined with deferred tax assets.

The standard is effective for fiscal years and interim periods beginning after December 15, 2013. We are currently analyzing the impact of this standard to our financial statements.

Note 3. Variable Interest Entities (VIEs)

Variable Interest Entities for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of these VIEs are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the Transition Funding and Transition Funding II assets are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II, respectively.

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of September 30, 2013 and December 31, 2012. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II during the first nine months of 2013 or in 2012. PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II.

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Note 4. Asset Disposition

In June 2013, Energy Holdings closed on the sale of its investments in a commercial office complex for proceeds of $41 million, resulting in an after-tax gain of $6 million.

Note 5. Rate Filings

The following information discusses significant updates regarding orders and pending rate filings. This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2012.

- ***Weather Normalization Clause (WNC)***—In April 2013, the BPU approved PSE&G's filing with respect to deficiency revenues from the 2011-2012 Winter Period. As a result, provisional rates were approved to recover $41 million from customers during the 2012-2013 Winter Period, with a carryover deficiency of $24 million to the 2013-2014 Winter Period. In July 2013, PSE&G filed a petition with the BPU seeking approval to recover $26 million in revenues from its customers during the 2013-2014 Winter Period inclusive of the $24 million carryover deficiency. In September 2013, the BPU approved PSE&G's petition for $26 million of deficiency revenues which will be recovered from customers during the 2013-2014 Winter Period (October 1 through May 31).
- ***Universal Service Fund (USF) Lifeline***—In June 2013, New Jersey's electric and gas utilities, including PSE&G, filed requests to reset the statewide rates for the USF and Lifeline program. In September 2013, the BPU approved rates set to recover $274 million on a statewide basis. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on Net Income.
- ***Transmission Filing***—In October 2013, PSE&G filed its 2014 Annual Formula Rate Update with the FERC, which provides for approximately $176 million in increased annual transmission revenues effective January 1, 2014.
- ***BGSS***—In October 2013, PSE&G filed a self-implementing two-month BGSS bill credit with the BPU. This bill credit will be 35 cents per therm for the months of November and December 2013 and is designed to provide approximately $115 million to residential customers over the two months and reduce the BGSS deferred balance. The BGSS rate will revert back to the current rate on January 1, 2014.

Note 6. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with Solar Renewable Energy Certificates (SRECs) generated from the installed solar electric system. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of September 30, 2013	As of December 31, 2012
	Millions	
Commercial/Industrial	$ 183	$ 174
Residential	15	15
Total	**$ 198**	**$ 189**

Energy Holdings

Energy Holdings, through various of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases

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are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

The table below shows Energy Holdings' gross and net lease investment as of September 30, 2013 and December 31, 2012, respectively.

	As of September 30, 2013	As of December 31, 2012
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 701	$ 721
Estimated Residual Value of Leased Assets	529	535
	1,230	1,256
Unearned and Deferred Income	(405)	(416)
Gross Investments in Leases	825	840
Deferred Tax Liabilities	(705)	(723)
Net Investments in Leases	**$ 120**	**$ 117**

The corresponding receivables associated with the lease portfolio are reflected below, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. "Not Rated" counterparties represent investments in lease receivables related to coal-fired assets and commercial real estate properties.

Counterparties' Credit Rating (Standard & Poor's (S&P)) As of September 30, 2013	Lease Receivables, Net of Non-Recourse Debt	
	As of September 30, 2013	As of December 31, 2012
	Millions	
AA	$ 20	$ 21
AA-	56	73
BBB+ - BBB-	316	316
B	165	166
Not Rated	144	145
Total	**$ 701**	**$ 721**

The "B" rating and the "Not Rated" above include lease receivables related to coal-fired assets in Pennsylvania and Illinois, respectively. As of September 30, 2013, the gross investment in the leases of such assets, net of non-recourse debt, was $562 million ($23 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

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Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counter-parties' S&P Credit Ratings	Counterparty
		Millions		MW			
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	Not Rated	Edison Mission Energy
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	Not Rated	Edison Mission Energy
Keystone Station Units 1 and 2	PA	$ 117	17%	1,711	Coal	B	GenOn REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 117	17%	1,711	Coal	B	GenOn REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 110	100%	603	Coal	B	GenOn REMA, LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Indirect subsidiary companies of Energy Holdings lease three coal-fired generation facilities in Pennsylvania (Keystone, Conemaugh and Shawville) to GenOn REMA, LLC (GenOn REMA), a subsidiary of GenOn Energy Inc. (GenOn), which was acquired by NRG Energy, Inc. (NRG) in December 2012. With respect to addressing various environmental controls: Keystone has installed a flue gas desulfurization (FGD) system for sulfur dioxide (SO_2), selective catalytic reduction (SCR) equipment for nitrogen oxide (NO_X) and mercury control; Conemaugh has a FGD system, while SCR and mercury control equipment are scheduled to be installed and operational by the first quarter of 2015; and GenOn has disclosed its plan to place Shawville in a "long-term protective layup" by April 2015. GenOn has stated that it is evaluating whether to continue to pay the required rent and maintain the facility in accordance with the lease terms or terminate the lease for obsolescence in which case the lessee would be required, among other things, to pay the contractual termination value structured to recover Energy Holdings' indirect subsidiaries' lease investment as specified in the lease agreement.

Although all lease payments from the GenOn REMA leases are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

Nesbitt Asset Recovery, LLC (Nesbitt), (an indirect, wholly owned subsidiary of Energy Holdings), owns approximately 64% of the lease interest in the Powerton and Joliet coal units in Illinois, with the balance held by Associates Capital Investments, L.L.P. (Associates) (an affiliate of Citigroup, and, together with Nesbitt, the "Equity Investors"). These facilities are leased to Midwest Generation (MWG), an indirect subsidiary of Edison Mission Energy (EME).

MWG has substantially completed investments in mercury removal (Activated Carbon Injection) and NO_X emission controls (low NO_X burners and Selective Non-Catalytic Reduction systems). On April 4, 2013, MWG obtained approval from the Illinois Pollution Control Board to defer capital investments for up to two additional years to meet upcoming air emission compliance deadlines under Illinois law. Also, on July 8, 2013, the U.S. Court of Appeals affirmed the judgment of the lower court dismissing claims brought by the U.S. Environmental Protection Agency (EPA) and the State of Illinois against EME and MWG for alleged violations of the Clean Air Act.

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On December 17, 2012, EME and MWG filed for relief under Chapter 11 of the U.S. Bankruptcy Code. Immediately prior to that filing, EME, MWG and the Equity Investors, as well as certain affiliated owner lessors, entered into a forbearance agreement with holders of a majority of the lease debt that financed the original sale-leaseback transaction. The forbearance agreement, which was approved by the Bankruptcy Court, expired on April 5, 2013. In June 2013, the parties reached an agreement, which was approved by the Bankruptcy Court, to again extend the deadline for MWG to assume or reject the leases until September 30, 2013, and in September 2013, extended it to December 31, 2013. As part of this agreement, (i) MWG will make partial lease payments of $4 million each month during the extension period starting in July 2013, (ii) MWG will continue to make certain environmental capital expenditures at the units, and (iii) the parties reserve their rights, claims, and defenses with respect to whether the leases are secured financings, rent amounts due under the leases, and the classification of claims under the leases, among other things.

On October 18, 2013, NRG, EME, MWG, the Equity Investors and other creditor parties involved in the bankruptcy executed a new agreement, which was approved by the Bankruptcy Court on October 24, 2013. The new agreement contains the terms and conditions under which NRG would acquire substantially all of EME's assets, including the Powerton and Joliet leased assets. As part of the proposed transaction, (i) the leases for the Powerton and Joliet coal units would be assumed on their existing terms, (ii) all past due rent under the leases would be paid in full, (iii) NRG would assume EME's tax indemnity and guarantee obligations, and (iv) NRG would invest up to $350 million in the Powerton and Joliet coal units so they could be operated in compliance with all environmental regulations. The proposed transaction also requires approval by the FERC and other regulatory bodies, and there can be no assurances that the above transaction will be consummated. The terms of the aforementioned forbearance agreement will remain in effect beyond December 31, 2013 until such time as the NRG acquisition is consummated or terminated.

Note 7. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Fund

Power maintains an external master nuclear decommissioning trust to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third party investment advisers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund:

	As of September 30, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 615	$ 234	$ (6)	$ 843
Debt Securities				
Government Obligations	411	5	(6)	410
Other Debt Securities	313	11	(4)	320
Total Debt Securities	724	16	(10)	730
Other Securities	62	—	—	62
Total NDT Available-for-Sale Securities	**$ 1,401**	**$ 250**	**$ (16)**	**$ 1,635**

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	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 648	$ 147	$ (6)	$ 789
Debt Securities				
Government Obligations	274	11	—	285
Other Debt Securities	320	22	—	342
Total Debt Securities	594	33	—	627
Other Securities	124	—	—	124
Total NDT Available-for-Sale Securities	**$ 1,366**	**$ 180**	**$ (6)**	**$ 1,540**

These amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2013	As of December 31, 2012
	Millions	
Accounts Receivable	$ 43	$ 18
Accounts Payable	$ 47	$ 53

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of September 30, 2013				As of December 31, 2012			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 78	$ (6)	$ —	$ —	$ 139	$ (6)	$ —	$ —
Debt Securities								
Government Obligations (B)	158	(6)	—	—	34	—	1	—
Other Debt Securities (C)	131	(4)	—	—	31	—	6	—
Total Debt Securities	289	(10)	—	—	65	—	7	—
Other Securities	—	—	—	—	—	—	—	—
NDT Available-for-Sale Securities	**$ 367**	**$ (16)**	**$ —**	**$ —**	**$ 204**	**$ (6)**	**$ 7**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2013.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency asset-backed securities were caused by interest rate changes. Since these investments are

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guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2013.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2013.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	Millions			
Proceeds from NDT Fund Sales	$ 220	$ 617	$ 837	$ 1,252
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	35	94	95	136
Gross Realized Losses	(9)	(19)	(34)	(41)
Net Realized Gains (Losses) on NDT Fund	**$ 26**	**$ 75**	**$ 61**	**$ 95**

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $115 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of September 30, 2013.

The NDT available-for-sale debt securities held as of September 30, 2013 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 57
1 - 5 years	167
6 - 10 years	186
11 - 15 years	44
16 - 20 years	19
Over 20 years	257
Total NDT Available-for-Sale Debt Securities	**$ 730**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2013, other-than-temporary impairments of $7 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of September 30, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 14	$ 7	$ —	$ 21
Debt Securities				
Government Obligations	110	—	(2)	108
Other Debt Securities	45	—	(1)	44
Total Debt Securities	155	—	(3)	152
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 171**	**$ 7**	**$ (3)**	**$ 175**

Securities in the Rabbi Trust in a gross unrealized loss position have been in such position for less than twelve months.

	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 13	$ 5	$ —	$ 18
Debt Securities				
Government Obligations	114	3	—	117
Other Debt Securities	45	2	—	47
Total Debt Securities	159	5	—	164
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 175**	**$ 10**	**$ —**	**$ 185**

These amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2013	As of December 31, 2012
	Millions	
Accounts Receivable	$ 3	$ 4
Accounts Payable	$ 3	$ 5

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The proceeds from the sales of and the net realized gains on securities in the Rabbi Trust Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	Millions			
Proceeds from Rabbi Trust Sales	**$ 13**	**$ 6**	**$ 77**	**$ 221**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ —	$ —	$ 4	$ 6
Gross Realized Losses	—	—	(3)	—
Net Realized Gains (Losses) on Rabbi Trust	**$ —**	**$ —**	**$ 1**	**$ 6**

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in the Condensed Consolidated Statements of Operations. Net unrealized gains of $2 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of September 30, 2013. The Rabbi Trust available-for-sale debt securities held as of September 30, 2013 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ —
1 - 5 years	59
6 - 10 years	29
11 - 15 years	7
16 - 20 years	4
Over 20 years	53
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 152**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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The fair value of assets in the Rabbi Trust related to PSEG, Power and PSE&G are detailed as follows:

	As of September 30, 2013	As of December 31, 2012
	Millions	
Power	$ 38	$ 36
PSE&G	41	61
Other	96	88
Total Rabbi Trust Available-for-Sale Securities	**$ 175**	**$ 185**

Note 8. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.

Pension and OPEB costs for PSEG are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012	2013	2012	2013	2012
	Millions							
Components of Net Periodic Benefit Cost								
Service Cost	$ 29	$ 26	$ 6	$ 5	$ 87	$ 76	$ 16	$ 13
Interest Cost	54	56	15	17	161	167	47	49
Expected Return on Plan Assets	(87)	(76)	(6)	(4)	(261)	(229)	(16)	(13)
Amortization of Net								
Transition Obligation	—	—	—	1	—	—	—	2
Prior Service Cost (Credit)	(5)	(5)	(4)	(4)	(14)	(14)	(11)	(11)
Actuarial Loss	47	41	11	7	141	125	32	23
Net Periodic Benefit Cost	$ 38	$ 42	$ 22	$ 22	$ 114	$ 125	$ 68	$ 63
Special Termination Benefits	—	1	—	—	—	1	—	—
Effect of Regulatory Asset	—	—	—	4	—	—	—	14
Total Benefit Costs, Including Effect of Regulatory Asset	**$ 38**	**$ 43**	**$ 22**	**$ 26**	**$ 114**	**$ 126**	**$ 68**	**$ 77**

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Pension and OPEB costs for Power, PSE&G and PSEG's other subsidiaries are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012	2013	2012	2013	2012
	Millions							
Power	$ 11	$ 14	$ 6	$ 5	$ 33	$ 39	$ 17	$ 14
PSE&G	23	24	16	21	68	73	49	61
Other	4	5	—	—	13	14	2	2
Total Benefit Costs	**$ 38**	**$ 43**	**$ 22**	**$ 26**	**$ 114**	**$ 126**	**$ 68**	**$ 77**

During the three months ended March 31, 2013, PSEG contributed its entire planned contributions for the year 2013 of $145 million and $14 million into its pension and postretirement healthcare plans, respectively.

Note 9. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The face value of Power's outstanding guarantees, current exposure and margin positions as of September 30, 2013 and December 31, 2012 are shown below:

	As of September 30, 2013	As of December 31, 2012
	Millions	
Face Value of Outstanding Guarantees	$ 1,551	$ 1,508
Exposure under Current Guarantees	$ 201	$ 226
Letters of Credit Margin Posted	$ 121	$ 124
Letters of Credit Margin Received	$ 29	$ 69
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$ 12	$ 15
Counterparty Cash Margin Received	$ —	$ (4)
Net Broker Balance Deposited (Received)	$ 8	$ 26
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that Could be Required	$ 588	$ 654
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,537	$ 3,531
Additional Amounts Posted		
Other Letters of Credit	$ 42	$ 45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 11. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P's, Moody's and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

The SEC and the Commodity Futures Trading Commission (CFTC) continue efforts to implement new rules to effect stricter regulation over swaps and derivatives, including imposing reporting and record-keeping requirements. In August 2013, PSEG began reporting its swap transactions to a CFTC-approved swap data repository. We continue to monitor developments in this area, as the CFTC considers additional requirements such as a new position limits rule for energy commodity swaps.

In addition to amounts for outstanding guarantees, current exposure and margin positions, Power had posted letters of credit to support various other non-energy contractual and environmental obligations. See table above.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The EPA has determined that an eight-mile stretch of the Passaic River in the area of Newark, New Jersey is a "facility" within the meaning of that term under CERCLA. The EPA has determined the need to perform a study of the entire 17-mile tidal reach of the lower Passaic River.

PSE&G and certain of its predecessors conducted operations at properties in this area on or adjacent to the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites. When the Essex Site was transferred from PSE&G to Power,

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PSE&G obtained releases and indemnities for liabilities arising out of the former Essex generating station and Power assumed any environmental liabilities.

The EPA notified the potentially responsible parties (PRPs) that the cost of its Remedial Investigation and Feasibility Study (RI/FS) is now estimated at approximately $117 million. Seventy-three PRPs, including Power and PSE&G, agreed to assume responsibility for the RI/FS and formed the Cooperating Parties Group (CPG) to divide the associated costs according to a mutually agreed upon formula. The CPG group, currently seventy members, is presently executing the RI/FS. Approximately five percent of the RI/FS costs were attributable to PSE&G's former MGP sites and approximately one percent to Power's generating stations on an interim basis under the CPG's group agreement. Power has provided notice to insurers concerning this potential claim.

In 2007, the EPA released a draft “Focused Feasibility Study” (FFS) that proposed various options to address the contamination cleanup of the lower eight miles of the Passaic River. The EPA estimated costs for the proposed remedy range from $1.3 billion to $3.7 billion. The work contemplated by the FFS is not subject to the cost sharing agreement discussed above. The EPA's revised proposed FFS may be released for public comment before the end of 2013.

In June 2008, an agreement was announced between the EPA and Tierra Solutions, Inc. and Maxus Energy Corporation (Tierra/Maxus) for removal of a portion of the contaminated sediment in the Passaic River at an estimated cost of $80 million. Phase I of the removal work has been completed. Phase II is contingent on the approval of an appropriate sediment disposal facility. Tierra/Maxus have reserved their rights to seek contribution for the removal costs from the other PRPs, including Power and PSE&G.

The EPA has advised that the levels of contaminants at Passaic River mile 10.9 will require removal in advance of the completion of the RI/FS. The CPG members, with the exception of Tierra/Maxus, which are no longer members, have agreed to and are funding the removal, currently estimated at approximately $30 million. PSEG's share of that effort is approximately three percent.

Except for the Passaic River mile 10.9 removal, Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to the Passaic River matters.

New Jersey Spill Compensation and Control Act (Spill Act)

In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit against a PRP (Occidental Chemical Corporation (OCC)) and its related companies in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of the PRP's discharge of hazardous substances into both the Passaic River and the balance of the Newark Bay Complex. Power and PSE&G are alleged to have owned, operated or contributed hazardous substances to a total of 11 sites or facilities that impacted these water bodies. In 2009, third party complaints were filed against some 320 third party defendants, including Power and PSE&G, claiming that each of the third party defendants is responsible for its proportionate share of the clean-up costs for the hazardous substances it allegedly discharged into the Passaic River and the Newark Bay Complex. Power and PSE&G filed answers to the complaints in 2010. On March 22, 2013, Power and PSE&G signed an agreement to settle the NJDEP vs. OCC litigation at a nominal cost. That settlement is contingent upon a public comment and NJDEP response period and the issuance of an order approving the settlement by the Court after conducting a fairness hearing. A stay of third-party discovery remains in place and has been extended. Power and PSE&G believe they have good and valid defenses to the allegations contained in the third party complaints and will vigorously assert those defenses should the matter not settle. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

Natural Resource Damage Claims

In 2003, the NJDEP directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the Spill Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSEG is unable to estimate its portion of the possible loss or range of loss related to this matter.

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Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area and encouraged the PRPs to contact OCC to discuss participating in the RI/FS that OCC was conducting. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but it is uncertain at this time whether the PSEG companies will consent to fund the third phase. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $476 million and $552 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $476 million as of September 30, 2013. Of this amount, $107 million was recorded in Other Current Liabilities and $369 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $476 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a “major modification,” as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Hazardous Air Pollutants Regulation

In accordance with a ruling of the U.S. Court of Appeals of the District of Columbia (Court of Appeals), the EPA published a Maximum Achievable Control Technology (MACT) regulation in February 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the Court of Appeals in support of the EPA's implementation of MATS. Litigation of these matters remains pending and the impact on the implementation schedule is unknown at this time.

Power believes that it will not be necessary to install any additional material controls at its New Jersey facilities. Additional controls may be necessary at Power’s Bridgeport Harbor coal-fired unit at an immaterial cost. In December 2011, to comply with the MACT regulations, a decision was reached to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction (SCR) systems at Power’s jointly owned coal-fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be completed in the first quarter of 2015. Power's share of this investment is estimated to be up to $147 million.

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NOx Regulation

In April 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on Power's generation fleet, as it imposes NO_x emissions limits that will require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) and four older New Jersey steam electric generation units (approximately 400 MW) by May 30, 2015. Retirement notifications for the combustion turbines, except for Salem Unit 3, have been filed with the PJM Interconnection, LLC (PJM). The Salem Unit 3 combustion turbine (38 MW) will be transitioning to an emergency generator. Evaluations are ongoing for the steam electric generation units.

Under current Connecticut regulations, Power's Bridgeport and New Haven facilities have been utilizing Discrete Emission Reduction Credits (DERCs) to comply with certain NO_x emission limitations that were incorporated into the facilities' operating permits. In 2010, Power negotiated new agreements with the State of Connecticut extending the continued use of DERCs for certain emission units and equipment until May 31, 2014.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System (NPDES) permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

One of the most significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. Power prepared its renewal application in accordance with the FWPCA Section 316(b) and the 316(b) rules published in 2004.

As a result of several legal challenges to the 2004 316(b) rule by certain northeast states, environmentalists and industry groups, the rule has been suspended and has been returned to the EPA to be consistent with a 2009 United States Supreme Court decision which concluded that the EPA could rely upon cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II regulations.

In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule by July 27, 2012. In April 2011, the EPA published a proposed rule to establish marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. In July 2012, the EPA and environmental groups agreed to delay the deadline to June 27, 2013 for finalization of the Rule. On June 27, 2013, the EPA and environmental groups agreed to further extend the deadline to November 4, 2013.

Power is unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on its future capital requirements, financial condition, results of operations or cash flows. The results of further proceedings on this matter could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would have been approximately $575 million. These cost estimates have not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

On October 1, 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court of New Jersey seeking to compel the NJDEP to take action on Power's pending application for permit renewal at Salem either by denying the application or issuing a draft for public comment. Power is unable to predict the outcome of this proceeding.

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Capital Expenditures

The construction programs of PSEG and its subsidiaries are currently estimated to include a base level total investment of approximately $6.4 billion for the three years ended 2015. The three-year projected capital expenditures for PSEG, Power and PSE&G are as follows:

	2013	2014	2015
		Millions	
Power	$ 400	$ 365	$ 305
PSE&G	2,045	1,765	1,305
Other	95	40	30
Total PSEG	**$ 2,540**	**$ 2,170**	**$ 1,640**

Power's projected capital expenditures include baseline maintenance (investments to replace major parts and enhance operational performance), investments in response to environmental, regulatory or legal mandates and nuclear expansion. PSE&G's projections include material additions and replacements in its transmission and distribution systems to meet expected growth and manage reliability.

In May 2013, the BPU approved increased spending on renewable energy under PSE&G's Solar Loan and Solar 4 All investment programs (Solar Loan III and Solar 4 All Extension, respectively). PSE&G's projected expenditures through 2015 in the table above have been updated to include $215 million under its Solar Loan III and Solar 4 All Extension programs.

Power

During the nine months ended September 30, 2013, Power made $243 million of capital expenditures, including interest capitalized during construction (IDC) but excluding $176 million for nuclear fuel, primarily related to various projects at its fossil and nuclear generation stations.

PSE&G

During the nine months ended September 30, 2013, PSE&G made $1,648 million of capital expenditures, including $1,628 million of investment in plant, primarily for reliability of transmission and distribution systems and $20 million in solar loan investments. This does not include expenditures for cost of removal, net of salvage, of $66 million, which is included in operating cash flows.

Energy Holdings

Included in Other for 2013 in the preceding table is a solar project currently under construction in Arizona for which Energy Holdings had issued an outstanding guarantee of $10 million as of September 30, 2013.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements for customers who do not purchase electric supply from third party suppliers through the annual New Jersey BGS auctions. Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with Power, as well as with other winning BGS suppliers, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

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PSE&G has contracted for its anticipated BGS-Fixed Price eligible load, as follows:

	Auction Year				
	2010	2011	2012	2013	
36-Month Terms Ending	May 2013	May 2014	May 2015	May 2016	(A)
Load (MW)	2,800	2,800	2,900	2,800	
$ per kWh	0.09577	0.09430	0.08388	0.09218	

(A) Prices set in the 2013 BGS auction became effective on June 1, 2013 when the 2010 BGS auction agreements expired.

PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 18. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power has various long-term fuel purchase commitments for coal through 2017 to support its fossil generation stations and for supply of nuclear fuel for the Salem, Hope Creek and Peach Bottom nuclear generating stations and for firm transportation and storage capacity for natural gas.

Power's strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2015 and a portion through 2017 at Salem, Hope Creek and Peach Bottom.

Power's various multi-year contracts for firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

As of September 30, 2013, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2017
	Millions
Nuclear Fuel	
Uranium	$ 470
Enrichment	$ 386
Fabrication	$ 146
Natural Gas	$ 880
Coal	$ 446

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Regulatory Proceedings

New Jersey Clean Energy Program

In June 2013, the BPU established the funding level for fiscal 2014 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2014 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a remaining current liability of $185 million as of September 30, 2013 for its outstanding share of the fiscal 2014 and remaining fiscal 2013 funding. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

Long-Term Capacity Agreement Pilot Program (LCAPP)

In 2011, New Jersey enacted the LCAPP Act that resulted in the selection of three generators to build a total of approximately 2,000 MW of new combined-cycle generating facilities located in New Jersey. Each of the New Jersey EDCs, including PSE&G, was directed to execute a standard offer capacity agreement (SOCA) with the selected generators, but did so under protest preserving their legal rights. The SOCA provides for the EDCs to guarantee specified annual capacity payments to the generators subject to the terms and conditions of the agreement. In July 2013, the SOCA contract with New Jersey Power Development LLC, a subsidiary of NRG Energy, Inc., was terminated early as a result of a default by the generator. SOCA contracts are for a 15-year term, which are scheduled to commence for one of the generators in the 2015/2016 delivery year and for the other generator in the 2016/2017 delivery year. These contracts are for the aggregate notional amount of approximately 1,300 MWs of installed capacity. Based upon the expected percentage of state load that PSE&G will be serving during the term of these contracts, the contracts provide that PSE&G would be responsible for the positive difference of the contract price and the annual RPM clearing price for approximately 52% or 676 MW of this amount provided that these generators satisfy their obligations under the SOCA, including the requirement that the specific generation units set forth in the contract achieve commercial operation.

The current estimated fair value of the SOCAs is recorded as a Derivative Asset or Liability with an offsetting Regulatory Asset or Liability on PSE&G's Condensed Consolidated Balance Sheets. See Note 12. Fair Value Measurements for additional information.

PSE&G has taken several steps to challenge these subsidies, including joining several parties in challenging the LCAPP Act on constitutional grounds in federal court. On October 11, 2013, the U.S. District Court issued a decision finding that the LCAPP Act violated the Supremacy Clause of the U.S. Constitution and declaring the LCAPP Act null and void. On October 25, 2013, a final judgment was issued implementing the federal court's decision in this proceeding and also finding the SOCA contracts void, invalid and unenforceable and denying the request of the defendants to stay the decision pending appeal. The defendants may appeal the decision and may seek a stay from the U.S. Third Circuit Court of Appeals. Additionally, PSE&G joined an appeal in New Jersey state court challenging the BPU's implementation of the LCAPP Act. The New Jersey State Appellate Court dismissed that appeal, without prejudice, based on the fact that the federal court had found the LCAPP Act unconstitutional and void.

Superstorm Sandy

In late October 2012, Superstorm Sandy caused damage to PSE&G's transmission and distribution system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure. Power's estimate of the total costs required to restore its damaged facilities to their pre-Superstorm Sandy condition is approximately $364 million.

Power incurred an additional $17 million and $67 million of storm-related expense for the three months and nine months ended September 30, 2013, respectively, primarily for repairs at certain generating stations in Power's fossil fleet. Power had incurred $85 million of costs in 2012. These costs were recognized in Operation and Maintenance Expense, offset by $25 million and $19 million of insurance recoveries in the second quarter of 2013 and the fourth quarter of 2012, respectively.

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Leveraged Lease Investments

In January 2012, PSEG entered into a specific matter closing agreement with the IRS settling all matters related to cross border lease transactions. This agreement settled the leasing dispute with finality for all tax periods in which PSEG realized tax deductions from these transactions. In January 2012, PSEG also signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. In March 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These agreements concluded the audits for these years for PSEG and the leasing issue for all tax years. For PSEG, the impact of these agreements was an increase in financial statement Income Tax Expense of approximately $175 million in the first quarter of 2012. In prior periods, PSEG had established financial statement tax liabilities for uncertain tax positions in the amount of $246 million with respect to these tax years. Accordingly, the settlement resulted in a net $71 million decrease in the first quarter of 2012 in the Income Tax Expense of PSEG.

Cash Impact

For tax years 1997 through 2003, the tax and interest PSEG owes the IRS as a result of this settlement will be reduced by the $320 million PSEG has on deposit with the IRS for this matter. PSEG paid a net deficiency for these years of approximately $4 million during the second quarter of 2012. Based upon the closing agreement and the Form 870-AD for tax years 2004 through 2006, PSEG owes the IRS approximately $620 million in tax and interest. Based on the settlement of the leasing dispute, for tax years 2007 through 2010, the IRS owes PSEG approximately $676 million. PSEG has filed amended returns for tax years 2007-2010 reflecting the impact of the settlement. These returns have been audited by the IRS and accepted as filed. As required by statute, the IRS presented the refund claim to the Joint Committee on Taxation for approval. In October 2012, PSEG was notified that the Joint Committee took no exception to the refund claim. In April 2013, PSEG received confirmation from the IRS which shows that overpayments from the 2008 through 2010 tax years have been applied to satisfy the liabilities due with respect to tax years 2004 through 2007. Accordingly, no further cash payments will be required with respect to the contested leasing transactions. In addition to the above, PSEG claimed a tax deduction for the accrued deficiency interest associated with this settlement in 2012, which gives rise to a cash tax savings of approximately $100 million.

Note 10. Changes in Capitalization

The following capital transactions occurred in the nine months ended September 30, 2013:

Power

- paid cash dividends of $690 million to PSEG, and
- paid $300 million of 2.50% Senior Notes at maturity.

PSE&G

- issued $350 million of 2.30% Secured Medium-Term Notes, Series I due September 2018,
- issued $250 million of 3.75% Secured Medium-Term Notes, Series I due March 2024,
- paid $300 million of 5.375% Secured Medium-Term Notes at maturity,
- issued $500 million of 2.375% Secured Medium-Term Notes, Series I due May 2023,
- paid $150 million of 5.00% Secured Medium-Term Notes at maturity,
- issued $400 million of 3.80% Secured Medium-Term Notes, Series H due January 2043,
- received a $100 million capital contribution from PSEG,
- paid $156 million of Transition Funding's securitization debt, and
- paid $6 million of Transition Funding II's securitization debt.

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Note 11. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions.

Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Commodity Prices

The availability and price of energy commodities are subject to fluctuations due to weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions, transmission availability and other events. Power uses physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. Derivative contracts that do not qualify for hedge accounting or normal purchases/normal sales treatment are marked to market (MTM) with changes in fair value recorded in the income statement. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps and futures contracts to hedge

- forecasted energy sales from its generation stations and the related load obligations, and
- certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

Certain of these derivative transactions are designated and effective as cash flow hedges. During the second quarter of 2012, Power de-designated certain of its commodity derivative transactions that had previously qualified as cash flow hedges as they were deemed to no longer be highly effective as required by the relevant accounting guidance. As a result, subsequent to June 1, 2012, Power recognizes all gains and losses from changes in the fair value of these derivatives immediately in earnings rather than deferring any such amounts in Accumulated Other Comprehensive Income (Loss). The fair values of Power's de-designated hedges were frozen in Accumulated Other Comprehensive Income (Loss) as the original forecasted transactions are still expected to occur and are reclassified into earnings as the original derivative transactions settle.

As of September 30, 2013 and December 31, 2012, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity were as follows:

	As of September 30, 2013	As of December 31, 2012
	Millions	
Fair Value of Cash Flow Hedges	$ 1	$ 3
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 3	$ 9

The expiration date of the longest-dated cash flow hedge at Power is in 2014. Power's remaining $3 million of after-tax unrealized gains on these derivatives is expected to be reclassified to earnings during the next 12 months. There was no ineffectiveness associated with qualifying hedges as of September 30, 2013.

Trading Derivatives

The primary purpose of Power's wholesale marketing operation is to optimize the value of the output of the generating facilities via various products and services available in the markets it serves. Historically, Power engaged in trading of electricity and energy-related products where such transactions were not associated with the output or fuel purchase requirements of its facilities. This trading consisted mostly of energy supply contracts where Power secured sales commitments with the intent to supply the energy services from purchases in the market rather than from its owned generation. Such trading activities were marked to market through the income statement and represented less than one percent of gross margin (revenues

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less energy costs) on an annual basis. Effective July 2011, Power discontinued trading activities and anticipates that it will not enter into any more trading derivative contracts.

Other Derivatives

Power enters into additional contracts that are derivatives, but do not qualify for or are not designated as cash flow hedges. These transactions are intended to mitigate exposure to fluctuations in commodity prices and optimize the value of its expected generation. Trade types include financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. Changes in the fair market value of these contracts are recorded in earnings. PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization. In addition, as further described in Note 9. Commitments and Contingent Liabilities, PSE&G was directed to execute long-term SOCAs with certain generators to support the LCAPP Act. These contracts qualify as derivatives and are marked to fair value with the offset recorded to Regulatory Assets and Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of September 30, 2013, PSEG had seven interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of September 30, 2013 and December 31, 2012, the fair value of all the underlying hedges was $42 million and $57 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was $(1) million and $(2) million as of September 30, 2013 and December 31, 2012, respectively.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. See Note 2. Recent Accounting Standards. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset in the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

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	As of September 30, 2013						
	Power (A)				PSE&G(A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 1	$ 228	$ (157)	$ 72	$ 19	$ 16	$ 107
Noncurrent Assets	—	164	(75)	89	69	26	184
Total Mark-to-Market Derivative Assets	**$ 1**	**$ 392**	**$ (232)**	**$ 161**	**$ 88**	**$ 42**	**$ 291**
Derivative Contracts							
Current Liabilities	$ —	$ (193)	$ 157	$ (36)	$ —	$ —	$ (36)
Noncurrent Liabilities	—	(96)	73	(23)	(140)	—	(163)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (289)**	**$ 230**	**$ (59)**	**$ (140)**	**$ —**	**$ (199)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 1**	**$ 103**	**$ (2)**	**$ 102**	**$ (52)**	**$ 42**	**$ 92**

	As of December 31, 2012						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 3	$ 332	$ (217)	$ 118	$ 5	$ 15	$ 138
Noncurrent Assets	—	75	(26)	49	62	42	153
Total Mark-to-Market Derivative Assets	**$ 3**	**$ 407**	**$ (243)**	**$ 167**	**$ 67**	**$ 57**	**$ 291**
Derivative Contracts							
Current Liabilities	$ —	$ (265)	$ 219	$ (46)	$ —	$ —	$ (46)
Noncurrent Liabilities	—	(41)	26	(15)	(107)	—	(122)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (306)**	**$ 245**	**$ (61)**	**$ (107)**	**$ —**	**$ (168)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 3**	**$ 101**	**$ 2**	**$ 106**	**$ (40)**	**$ 57**	**$ 123**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of September 30, 2013 and December 31, 2012. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where

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the right of offset exists, has been offset in the statement of financial position. As of September 30, 2013 and December 31, 2012, net cash collateral (received) paid of $(2) million and $2 million, respectively, were netted against the corresponding net derivative contract positions. Of the $(2) million as of September 30, 2013, $(1) million of cash collateral was netted against current assets, $(2) million was netted against noncurrent assets and $1 million was netted against current liabilities. Of the $2 million as of December 31, 2012, cash collateral of $(3) million and $5 million were netted against current assets and current liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded or lose its investment grade credit rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on NYMEX and ICE that are fully collateralized) was $75 million and $98 million as of September 30, 2013 and December 31, 2012, respectively. As of September 30, 2013 and December 31, 2012, Power had the contractual right of offset of $42 million and $61 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded or lost its investment grade rating, it would have had additional collateral obligations of $33 million and $37 million as of September 30, 2013 and December 31, 2012, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $588 million and $654 million as of September 30, 2013 and December 31, 2012, respectively, discussed in Note 9. Commitments and Contingent Liabilities.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended September 30, 2013 and 2012:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion)		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	
	Three Months Ended September 30,			Three Months Ended September 30,			Three Months Ended September 30,	
	2013	2012		2013	2012		2013	2012
	Millions							
PSEG								
Energy-Related Contracts	$ 1	$ (3)	Operating Revenues	$ 3	$ 15	Operating Revenues	$ (1)	$ (1)
Total PSEG	**$ 1**	**$ (3)**		**$ 3**	**$ 15**		**$ (1)**	**$ (1)**
Power								
Energy-Related Contracts	$ 1	$ (3)	Operating Revenues	$ 3	$ 15	Operating Revenues	$ (1)	$ (1)
Total Power	**$ 1**	**$ (3)**		**$ 3**	**$ 15**		**$ (1)**	**$ (1)**

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The following shows the effect on the Condensed Consolidated Statements of Operations and on AOCI of derivative instruments designated as cash flow hedges for the nine months ended September 30, 2013 and 2012:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Nine Months Ended September 30, 2013	2012	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Nine Months Ended September 30, 2013	2012	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Nine Months Ended September 30, 2013	2012
				Millions				
PSEG (A)								
Energy-Related Contracts	$ 1	$ 27	Operating Revenues	$ 11	$ 67	Operating Revenues	$ (1)	$ (1)
Energy-Related Contracts	—	(4)	Energy Costs	—	(9)		—	—
Interest Rate Swaps	—	—	Interest Expense	(1)	(1)		—	—
Total PSEG	**$ 1**	**$ 23**		**$ 10**	**$ 57**		**$ (1)**	**$ (1)**
Power								
Energy-Related Contracts	$ 1	$ 27	Operating Revenues	$ 11	$ 67	Operating Revenues	$ (1)	$ (1)
Energy-Related Contracts	—	(4)	Energy Costs	—	(9)		—	—
Total Power	**$ 1**	**$ 23**		**$ 11**	**$ 58**		**$ (1)**	**$ (1)**

(A) Includes amounts for PSEG parent.

The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis:

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2012	**$ 12**	**$ 7**
Less: Gain Reclassified into Income	(7)	(4)
Balance as of June 30, 2013	**$ 5**	**$ 3**
Gain Recognized in AOCI	$ 1	1
Less: Gain Reclassified into Income	(3)	(2)
Balance as of September 30, 2013	**$ 3**	**$ 2**

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The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the three months and nine months ended September 30, 2013 and 2012:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2013	2012	2013	2012
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ 14	$ (90)	$ (32)	$ 145
Energy-Related Contracts	Energy Costs	10	6	63	(17)
Total PSEG and Power		**$ 24**	**$ (84)**	**$ 31**	**$ 128**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $4 million and $6 million for the three month periods and $14 million and $17 million for the nine month periods ended September 30, 2013 and 2012, respectively.

The following reflects the gross volume, on an absolute value basis, of derivatives as of September 30, 2013 and December 31, 2012:

Type	Notional	Total	PSEG	Power	PSE&G
		Millions			
As of September 30, 2013					
Natural Gas	Dth	537	—	377	160
Electricity	MWh	247	—	247	—
Capacity	MW days	4	—	—	4
FTRs	MWh	22	—	22	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2012					
Natural Gas	Dth	596	—	404	192
Electricity	MWh	208	—	208	—
Capacity	MW days	4	—	—	4
FTRs	MWh	19	—	19	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
Coal	Tons	1	—	1	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative

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exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of September 30, 2013, 95% of the credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of September 30, 2013. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 180	$ 17	$ 180	1	$ 90	(A)
Non-Investment Grade—External Rating	2	—	2	—	—	
Investment Grade—No External Rating	7	—	7	—	—	
Non-Investment Grade—No External Rating	8	—	8	—	—	
Total	**$ 197**	**$ 17**	**$ 197**	**1**	**$ 90**	

(A) Represents net exposure with PSE&G.

The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of September 30, 2013, Power had 142 active counterparties.

Note 12. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of September 30, 2013, these consist primarily of electric swaps whose basis is deemed significant to the fair value measurement, long-term electric load contracts, gas supply contracts and long-term capacity contracts.

The following tables present information about PSEG's, Power's and PSE&G's respective assets and (liabilities) measured at fair value on a recurring basis as of September 30, 2013 and December 31, 2012, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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Description	Recurring Fair Value Measurements as of September 30, 2013			
	Total	Cash Collateral Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 249	$ (3)	$ —	$ 156	$ 96
Interest Rate Swaps (B)	$ 42	$ —	$ —	$ 42	$ —
NDT Fund (C)					
Equity Securities	$ 843	$ —	$ 842	$ 1	$ —
Debt Securities—Govt Obligations	$ 410	$ —	$ —	$ 410	$ —
Debt Securities—Other	$ 320	$ —	$ —	$ 320	$ —
Other Securities	$ 62	$ —	$ —	$ 62	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 21	$ —	$ 21	$ —	$ —
Debt Securities—Govt Obligations	$ 108	$ —	$ —	$ 108	$ —
Debt Securities—Other	$ 44	$ —	$ —	$ 44	$ —
Other Securities	$ 2	$ —	$ —	$ 2	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (199)	$ 1	$ —	$ (58)	$ (142)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 161	$ (3)	$ —	$ 156	$ 8
NDT Fund (C)					
Equity Securities	$ 843	$ —	$ 842	$ 1	$ —
Debt Securities—Govt Obligations	$ 410	$ —	$ —	$ 410	$ —
Debt Securities—Other	$ 320	$ —	$ —	$ 320	$ —
Other Securities	$ 62	$ —	$ —	$ 62	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 10	$ —	$ —	$ 10	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (59)	$ 1	$ —	$ (58)	$ (2)
PSE&G					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 88	$ —	$ —	$ —	$ 88
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 26	$ —	$ —	$ 26	$ —
Debt Securities—Other	$ 10	$ —	$ —	$ 10	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (140)	$ —	$ —	$ —	$ (140)

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Description	Recurring Fair Value Measurements as of December 31, 2012			
	Total	Cash Collateral Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 234	$ (3)	$ —	$ 157	$ 80
Interest Rate Swaps (B)	$ 57	$ —	$ —	$ 57	$ —
NDT Fund (C)					
Equity Securities	$ 789	$ —	$ 789	$ —	$ —
Debt Securities—Govt Obligations	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Other	$ 342	$ —	$ —	$ 342	$ —
Other Securities	$ 124	$ —	$ —	$ 124	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 18	$ —	$ 18	$ —	$ —
Debt Securities—Govt Obligations	$ 117	$ —	$ —	$ 117	$ —
Debt Securities—Other	$ 47	$ —	$ —	$ 47	$ —
Other Securities	$ 3	$ —	$ —	$ 3	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (168)	$ 5	$ —	$ (62)	$ (111)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 167	$ (3)	$ —	$ 157	$ 13
NDT Fund (C)					
Equity Securities	$ 789	$ —	$ 789	$ —	$ —
Debt Securities—Govt Obligations	$ 285	$ —	$ —	$ 285	$ —
Debt Securities—Other	$ 342	$ —	$ —	$ 342	$ —
Other Securities	$ 124	$ —	$ —	$ 124	$ —
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 3	$ —	$ 3	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 9	$ —	$ —	$ 9	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (61)	$ 5	$ —	$ (62)	$ (4)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (A)	$ 67	$ —	$ —	$ —	$ 67
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—Govt Obligations	$ 39	$ —	$ —	$ 39	$ —
Debt Securities—Other	$ 15	$ —	$ —	$ 15	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy Related Contracts (A)	$ (107)	$ —	$ —	$ —	$ (107)

(A) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most [illegible] (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction

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prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

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Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(B) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(C) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price (primarily Level 1). The Rabbi Trust equity index fund is valued based on quoted prices in an active market (Level 1).

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds and United States Treasury obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads (primarily Level 2). Short-term investments and certain commingled temporary investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield (primarily Level 2).

(D) Cash collateral netting represents collateral amounts netted against derivative assets and liabilities as permitted under the accounting guidance for Offsetting of Amounts Related to Certain Contracts.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group, and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For Power, in general, electric swaps are measured at fair value based on at least two pricing inputs, the underlying price of electricity at a liquid reference point and the basis difference between electricity prices at the liquid reference point and electricity prices at the respective delivery locations. To the extent the basis component is based on a single broker quote and is significant to the fair value of the electric swap, it is categorized as Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. For Power and PSE&G, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. For PSE&G, long-term electric capacity contracts are measured at fair value using both observable capacity auction prices and unobservable future long-term capacity prices. The measurement of these contracts include adjustments for contingencies, such as the potential outcome of litigation specifically related to the contract and the risk related to the construction of the specified capacity facilities.

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Accordingly, the fair value measurements are classified as Level 3. The following tables provide details surrounding significant Level 3 valuations as of September 30, 2013 and December 31, 2012.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of September 30, 2013 Assets	Fair Value as of September 30, 2013 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ 7	$ —	Discounted Cash Flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	—	(2)	Discounted Cash Flow	Historic Load Variability	-5% to +10%
Other	Various (A)	1	—			
Total Power		**$ 8**	**$ (2)**			
PSE&G						
Gas and Capacity	Forward Contracts (B)	$ 88	$ (140)	Discounted Cash Flow	Long-Term Capacity Prices and Transportation Costs	(B)
Total PSE&G		**$ 88**	**$ (140)**			
TOTAL PSEG		**$ 96**	**$ (142)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2012 Assets	Fair Value as of December 31, 2012 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ 7	$ (1)	Discounted Cash Flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	1	(2)	Discounted Cash Flow	Historic Load Variability	-5% to +10%
Other	Various (A)	5	(1)			
Total Power		**$ 13**	**$ (4)**			
PSE&G						
Gas and Capacity	Forward Contracts (C)	$ 67	$ (107)	Discounted Cash Flow	Long-Term Gas Basis and Capacity Prices	(C)
Total PSE&G		**$ 67**	**$ (107)**			
TOTAL PSEG		**$ 80**	**$ (111)**			

(A) Includes gas supply positions which are immaterial as of September 30, 2013 and December 31, 2012. Also includes long-term electric capacity positions which are immaterial as of December 31, 2012.

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(B) Unobservable inputs for the long-term electric capacity contracts include forecasted capacity prices in the range of $100 to $400/MW day. Unobservable inputs for gas supply contracts include the weighted average cost of transporting gas in the range of $0.70 to $1 per dekatherm.

(C) Includes long-term electric capacity and long-term gas supply positions with various unobservable inputs. Unobservable inputs for the long-term electric capacity contracts include forecasted capacity prices in the range of $100 to $400/MW day. Significant unobservable inputs for the gas supply contracts include long-term basis prices in the range of $0 to $4/MMBTU of natural gas.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value. For long-term electric capacity contracts where PSE&G is a buyer, an increase in the capacity price would increase the fair value. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value.

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and nine months ended September 30, 2013 and 2012, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended September 30, 2013

Description	Balance as of July 1, 2013	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2013
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (35)	$ 1	$ (11)	$ —	$ (1)	$ —	$ (46)
Power							
Net Derivative Assets (Liabilities)	$ 6	$ 1	$ —	$ —	$ (1)	$ —	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (41)	$ —	$ (11)	$ —	$ —	$ —	$ (52)

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Nine Months Ended September 30, 2013

Description	Balance as of January 1, 2013	Total Gains or (Losses) Realized/Unrealized: Included in Income (E)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2013
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (31)	$ (16)	$ (12)	$ —	$ 9	$ 4	$ (46)
Power							
Net Derivative Assets (Liabilities)	$ 9	$ (16)	$ —	$ —	$ 9	$ 4	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (40)	$ —	$ (12)	$ —	$ —	$ —	$ (52)

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended September 30, 2012

Description	Balance as of July 1, 2012	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2012
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (36)	$ (1)	$ 25	$ —	$ (9)	$ —	$ (21)
Non-Recourse Debt	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 22	$ (1)	$ —	$ —	$ (9)	$ —	$ 12
PSE&G							
Net Derivative Assets (Liabilities)	$ (58)	$ —	$ 25	$ —	$ —	$ —	$ (33)

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Nine Months Ended September 30, 2012

Description	Balance as of January 1, 2012	Total Gains or (Losses) Realized/Unrealized: Included in Income (E)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2012
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 21	$ 40	$ (30)	$ —	$ (52)	$ —	$ (21)
Non-Recourse Debt	$ (50)	$ 50	$ —	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 24	$ 40	$ —	$ —	$ (52)	$ —	$ 12
PSE&G							
Net Derivative Assets (Liabilities)	$ (3)	$ —	$ (30)	$ —	$ —	$ —	$ (33)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $1 million and $(1) million in Operating Income in 2013 and 2012, respectively. The $1 million in Operating Income in 2013 is unrealized. Of the $(1) million in Operating Income in 2012, $(10) million is unrealized. Energy Holdings' release from its obligation under the non-recourse debt is included in PSEG's Operating Income for 2012 and is offset by the write-off of the related assets.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or OCI, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $(1) million and $(9) million in settlements for the three months ended September 30, 2013 and 2012. Includes $9 million and $(52) million in settlements for the nine months ended September 30, 2013 and 2012, respectively.

(D) During the nine months ended September 30, 2013, $4 million of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. The transfer was recognized as of the beginning of the first quarter (i.e. the quarter in which the transfer occurred), as per PSEG's policy. There were no transfers among levels during the three months ended September 30, 2013 and 2012 and the nine months ended September 30, 2012.

(E) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $(16) million and $40 million in Operating Income in 2013 and 2012, respectively. Of the $(16) million in Operating Income in 2013, $(7) million is unrealized. Of the $40 million in Operating Income in 2012, $(12) million is unrealized. Energy Holdings' release from its obligation under the non-recourse debt is included in PSEG's Operating Income for 2012 and is offset by the write-off of the related assets.

As of September 30, 2013, PSEG carried $1.9 billion of net assets that are measured at fair value on a recurring basis, of which $46 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of September 30, 2012, PSEG carried $1.8 billion of net assets that are measured at fair value on a recurring basis, of which $21 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

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Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of September 30, 2013 and December 31, 2012.

	September 30, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 27	$ 42	$ 38	$ 57
Power -Recourse Debt (B)	2,041	2,355	2,340	2,818
PSE&G (B)	5,841	6,058	4,795	5,606
Transition Funding (PSE&G) (B)	534	578	690	765
Transition Funding II (PSE&G) (B)	27	28	32	34
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	16	16	44	44
Total Long-Term Debt	**$ 8,486**	**$ 9,077**	**$ 7,939**	**$ 9,324**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 13. Other Income and Deductions

Other Income	Power	PSE&G	Other (A)	Consolidated
			Millions	
Three Months Ended September 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ 45	$ —	$ —	$ 45
Allowance of Funds Used During Construction	—	5	—	5
Solar Loan Interest	—	7	—	7
Other	—	1	1	2
Total Other Income	**$ 45**	**$ 13**	**$ 1**	**$ 59**
Three Months Ended September 30, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$ 103	$ —	$ —	$ 103
Allowance of Funds Used During Construction	—	6	—	6
Solar Loan Interest	—	5	—	5
Other	1	5	1	7
Total Other Income	**$ 104**	**$ 16**	**$ 1**	**$ 121**
Nine Months Ended September 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ 125	$ —	$ —	$ 125
Allowance of Funds Used During Construction	—	17	—	17
Solar Loan Interest	—	18	—	18
Other	2	6	4	12
Total Other Income	**$ 127**	**$ 41**	**$ 4**	**$ 172**
Nine Months Ended September 30, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$ 167	$ —	$ —	$ 167
Allowance of Funds Used During Construction	—	17	—	17
Solar Loan Interest	—	13	—	13
Other	4	9	6	19
Total Other Income	**$ 171**	**$ 39**	**$ 6**	**$ 216**

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Other Deductions	Power	PSE&G	Other (A)	Consolidated
			Millions	
Three Months Ended September 30, 2013				
NDT Fund Realized Losses and Expenses	$ 11	$ —	$ —	$ 11
Other	—	1	—	1
Total Other Deductions	**$ 11**	**$ 1**	**$ —**	**$ 12**
Three Months Ended September 30, 2012				
NDT Fund Realized Losses and Expenses	$ 20	$ —	$ —	$ 20
Other	—	6	—	6
Total Other Deductions	**$ 20**	**$ 6**	**$ —**	**$ 26**
Nine Months Ended September 30, 2013				
NDT Fund Realized Losses and Expenses	$ 40	$ —	$ —	$ 40
Other	9	3	2	14
Total Other Deductions	**$ 49**	**$ 3**	**$ 2**	**$ 54**
Nine Months Ended September 30, 2012				
NDT Fund Realized Losses and Expenses	$ 45	$ —	$ —	$ 45
Other	7	8	1	16
Total Other Deductions	**$ 52**	**$ 8**	**$ 1**	**$ 61**

(A) Other primarily consists of activity at PSEG (as parent company), Energy Holdings, Services and intercompany eliminations.

Note 14. Income Taxes

PSEG's, Power's and PSE&G's effective tax rates for the three months and nine months ended September 30, 2013 and 2012 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
PSEG	41.0%	41.0%	40.5%	36.3%
Power	41.0%	42.4%	40.6%	41.0%
PSE&G	40.6%	39.9%	40.0%	35.4%

For the three months ended September 30, 2013, as compared to the same period in the prior year, the decrease in Power's effective tax rate was due primarily to higher NDT income in 2012.

For the nine months ended September 30, 2013, PSEG's and PSE&G's effective tax rates were higher than last year's effective tax rates due primarily to a settlement in 2012 with the IRS in regard to leveraged leases and the federal tax audit for tax years 1997 through 2006.

In September 2013, the U.S. Department of the Treasury and the IRS released final regulations that provide guidance on applying Section 263(a) of the Internal Revenue Code to amounts paid to acquire, produce, or improve tangible property, as well as rules for materials and supplies. Implementation of these final regulations in September 2013 had no material impact on PSEG's and its subsidiaries' results of operations, financial condition or cash flows.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 was eligible for 50% bonus depreciation for tax purposes. On January 2, 2013, the President signed into law the American Taxpayer Relief Act of 2012 that further extends the 50% bonus depreciation for qualified property placed into service before January 1, 2014. These provisions have generated cash for

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PSEG through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period.

In June 2009, September 2008 and December 2007, PSEG made tax deposits with the IRS in the amounts of $140 million, $80 million and $100 million, respectively, to defray potential interest costs associated with disputed tax assessments associated with certain lease investments. On January 31, 2012, PSEG signed a specific matter closing agreement with the IRS regarding this matter. Based on this agreement, these deposits were applied against tax and interest due pursuant to the closing agreement. Further, on the same date, PSEG signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. In March 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These agreements concluded the audits for these years for PSEG and the leasing issue for all tax years. The financial statement impacts of these agreements, net of existing financial statement reserves, was a net decrease in tax expense in the first quarter of 2012 of $71 million for PSEG, including $30 million and $1 million for PSE&G and Power, respectively.

Note 15. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended September 30, 2013			
Accumulated Other Comprehensive Income (Loss)	Derivative Contracts	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of June 30, 2013	$ 3	$ (466)	$ 101	$ (362)
Other Comprehensive Income before Reclassifications	1	—	27	28
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(2)	9	(11)	(4)
Net Current Period Other Comprehensive Income (Loss)	(1)	9	16	24
Balance as of September 30, 2013	**$ 2**	**$ (457)**	**$ 117**	**$ (338)**

Power	Other Comprehensive Income (Loss) Three Months Ended September 30, 2013			
Accumulated Other Comprehensive Income (Loss)	Derivative Contracts	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of June 30, 2013	$ 4	$ (405)	$ 98	$ (303)
Other Comprehensive Income before Reclassifications	1	—	28	29
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(2)	8	(11)	(5)
Net Current Period Other Comprehensive Income (Loss)	(1)	8	17	24
Balance as of September 30, 2013	**$ 3**	**$ (397)**	**$ 115**	**$ (279)**

PSEG	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2013			
Accumulated Other Comprehensive Income (Loss)	Derivative Contracts	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 7	$ (485)	$ 90	$ (388)
Other Comprehensive Income before Reclassifications	1	—	53	54
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(6)	28	(26)	(4)
Net Current Period Other Comprehensive Income (Loss)	(5)	28	27	50
Balance as of September 30, 2013	**$ 2**	**$ (457)**	**$ 117**	**$ (338)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2013 Derivative Contracts	Pension and OPEB Plans	Available-for -Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 9	$ (422)	$ 85	$ (328)
Other Comprehensive Income before Reclassifications	1	—	56	57
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(7)	25	(26)	(8)
Net Current Period Other Comprehensive Income (Loss)	(6)	25	30	49
Balance as of September 30, 2013	**$ 3**	**$ (397)**	**$ 115**	**$ (279)**

PSEG

Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement: Three Months Ended September 30, 2013 Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Nine Months Ended September 30, 2013 Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
			Millions				
Cash Flow Hedges							
Energy Related Contracts	Operating Revenues	$ 3	$ (1)	$ 2	$ 11	$ (4)	$ 7
Interest Rate Swaps	Interest Expense	—	—	—	(1)	—	$ (1)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	Operation and Maintenance Expense	3	(1)	2	8	(3)	5
Amortization of Actuarial Loss	Operation and Maintenance Expense	(18)	7	(11)	(56)	23	(33)
Available-for-Sale Securities							
Realized Gains	Other Income	35	(18)	17	99	(51)	48
Realized Losses	Other Deductions	(9)	4	(5)	(37)	18	(19)
Other-Than-Temporary Impairments	Other-Than-Temporary Impairments	(3)	2	(1)	(7)	4	(3)
Total		**$ 11**	**$ (7)**	**$ 4**	**$ 17**	**$ (13)**	**$ 4**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2013			Nine Months Ended September 30, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy Related Contracts	Operating Revenues	$ 3	$ (1)	$ 2	$ 11	$ (4)	$ 7
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	Operation and Maintenance Expense	3	(1)	2	7	(3)	4
Amortization of Actuarial Loss	Operation and Maintenance Expense	(17)	7	(10)	(49)	20	(29)
Available-for-Sale Securities							
Realized Gains	Other Income	35	(18)	17	95	(49)	46
Realized Losses	Other Deductions	(9)	4	(5)	(34)	17	(17)
Other-Than-Temporary Impairments	Other-Than-Temporary Impairments	(3)	2	(1)	(7)	4	(3)
Total		**$ 12**	**$ (7)**	**$ 5**	**$ 23**	**$ (15)**	**$ 8**

	Balance as of December 31, 2011	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2012			Balance as of September 30, 2012
		Power	PSE&G	Other	
	Millions				
Derivative Contracts	$ 31	$ (21)	$ —	$ 1	$ 11
Pension and OPEB Plans	(438)	21	—	2	(415)
Available-for-Sale Securities	70	11	—	1	82
Accumulated Other Comprehensive Income (Loss)	**$ (337)**	**$ 11**	**$ —**	**$ 4**	**$ (322)**

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Note 16. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2012		2013		2012	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)								
Net Income	**$ 390**	**$ 390**	**$ 347**	**$ 347**	**$ 1,043**	**$ 1,043**	**$ 1,051**	**$ 1,051**
EPS Denominator (Thousands)								
Weighted Average Common Shares Outstanding	505,858	505,858	505,914	505,914	505,900	505,900	505,942	505,942
Effect of Stock Based Compensation Awards	—	1,836	—	1,197	—	1,533	—	1,095
Total Shares	**505,858**	**507,694**	**505,914**	**507,111**	**505,900**	**507,433**	**505,942**	**507,037**
EPS								
Net Income	**$ 0.77**	**$ 0.77**	**$ 0.69**	**$ 0.68**	**$ 2.06**	**$ 2.06**	**$ 2.08**	**$ 2.07**

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dividend Payments on Common Stock	2013	2012	2013	2012
Per Share	$ 0.3600	$ 0.3550	$ 1.0800	$ 1.0650
in Millions	$ 182	$ 180	$ 546	$ 538

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Note 17. Financial Information by Business Segments

	Power	PSE&G	Energy Holdings	Other (A)	Consolidated
			Millions		
Three Months Ended September 30, 2013					
Total Operating Revenues	$ 1,169	$ 1,666	$ 8	$ (289)	$ 2,554
Income (Loss) From Continuing Operations	221	168	(3)	4	390
Net Income (Loss)	221	168	(3)	4	390
Segment Earnings (Loss)	221	168	(3)	4	390
Gross Additions to Long-Lived Assets	197	480	13	6	696
Three Months Ended September 30, 2012					
Total Operating Revenues	$ 1,038	$ 1,683	$ 15	$ (334)	$ 2,402
Income (Loss) From Continuing Operations	181	155	7	4	347
Net Income (Loss)	181	155	7	4	347
Segment Earnings (Loss)	181	155	7	4	347
Gross Additions to Long-Lived Assets	149	499	30	11	689
Nine Months Ended September 30, 2013					
Total Operating Revenues	$ 3,806	$ 5,084	$ 42	$ (1,282)	$ 7,650
Income (Loss) From Continuing Operations	562	468	1	12	1,043
Net Income (Loss)	562	468	1	12	1,043
Segment Earnings (Loss)	562	468	1	12	1,043
Gross Additions to Long-Lived Assets	419	1,628	40	15	2,102
Nine Months Ended September 30, 2012					
Total Operating Revenues	$ 3,584	$ 5,029	$ 49	$ (1,287)	$ 7,375
Income (Loss) From Continuing Operations	538	453	49	11	1,051
Net Income (Loss)	538	453	49	11	1,051
Segment Earnings (Loss)	538	453	49	11	1,051
Gross Additions to Long-Lived Assets	493	1,369	85	22	1,969
As of September 30, 2013					
Total Assets	$ 10,721	$ 20,330	$ 1,448	$ 111	$ 32,610
Investments in Equity Method Subsidiaries	$ 40	$ —	$ 100	$ —	$ 140
As of December 31, 2012					
Total Assets	$ 11,032	$ 19,223	$ 1,454	$ 16	$ 31,725
Investments in Equity Method Subsidiaries	$ 40	$ —	$ 94	$ —	$ 134

(A) Other activities include amounts applicable to PSEG (as parent company), Services and intercompany eliminations, primarily relating to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are priced in accordance with applicable regulations, including affiliate pricing rules, or in the case of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 18. Related-Party Transactions.

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Note 18. Related-Party Transactions

The following discussion relates to intercompany transactions, the majority of which are eliminated during the PSEG consolidation process in accordance with GAAP.

Power

The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
		Millions		
Revenue from Affiliates:				
Billings to PSE&G through BGSS (A)	$ 48	$ 67	$ 654	$ 630
Billings to PSE&G through BGS (A)	236	258	621	639
Total Revenue from Affiliates	**$ 284**	**$ 325**	**$ 1,275**	**$ 1,269**
Expense Billings from Affiliates:				
Administrative Billings from Services (B)	$ (43)	$ (38)	$ (131)	$ (110)
Total Expense Billings from Affiliates	**$ (43)**	**$ (38)**	**$ (131)**	**$ (110)**

Related-Party Transactions	As of September 30, 2013	As of December 31, 2012
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$ 87	$ 238
Receivables from PSE&G Related to Gas Supply Hedges for BGSS (A)	28	27
Receivable from (Payable to) Services (B)	(26)	(31)
Tax Receivable from (Payable to) PSEG (C)	(54)	111
Receivable from (Payable to) PSEG	(1)	(5)
Accounts Receivable (Payable)—Affiliated Companies, net	**$ 34**	**$ 340**
Short-Term Loan to Affiliate (Demand Note to PSEG) (D)	**$ 417**	**$ 574**
Working Capital Advances to Services (E)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable (Payable) (C)	**$ (50)**	**$ (50)**

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
		Millions		
Expense Billings from Affiliates:				
Billings from Power through BGSS (A)	$ (48)	$ (67)	$ (654)	$ (630)
Billings from Power through BGS (A)	(236)	(258)	(621)	(639)
Administrative Billings from Services (B)	(61)	(58)	(184)	(165)
Total Expense Billings from Affiliates	**$ (345)**	**$ (383)**	**$ (1,459)**	**$ (1,434)**

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Related-Party Transactions	As of September 30, 2013	As of December 31, 2012
	Millions	
Payable to Power through BGS and BGSS Contracts (A)	$ (87)	$ (238)
Payable to Power Related to Gas Supply Hedges for BGSS (A)	(28)	(27)
Payable to Power for SREC Liability (F)	—	(7)
Receivable from (Payable to) Services (B)	(58)	(65)
Tax Receivable from (Payable to) PSEG (C)	263	256
Receivable from (Payable to) PSEG	3	6
Receivable from Energy Holdings	1	2
Accounts Receivable (Payable)—Affiliated Companies, net	**$ 94**	**$ (73)**
Working Capital Advances to Services (E)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Receivable (Payable) (C)	**$ (48)**	**$ (32)**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to Power and PSE&G at cost. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

(E) Power and PSE&G have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on Power's and PSE&G's Condensed Consolidated Balance Sheets.

(F) Pursuant to a 2008 BPU Order, certain BGS suppliers, including Power, would be reimbursed for the cost they incurred above $300 per Solar Renewable Energy Certificate (SREC) or per Solar Alternative Compliance Payment (SACP) during the period June 1, 2008 through May 31, 2010 and such excess cost would be passed onto ratepayers. In accordance with a Stipulation of Settlement approved by the BPU in a December 2012 Order describing the mechanism for BGS suppliers to recover these costs, PSE&G, as a New Jersey EDC, estimated and accrued a total liability for the excess SREC cost expected to be recovered from ratepayers of $ 17 million, including approximately $7 million for Power's share which was included in PSE&G's Accounts Receivable (Payable)-Affiliated Companies, as of December 31, 2012. Under current accounting guidance, Power was unable to record the related intercompany receivable on its Condensed Consolidated Balance Sheet until the BPU issued an Order approving such payments. As a result, PSE&G's liability to Power was not eliminated in consolidation and was included in Other Current Liabilities on PSEG's Condensed Consolidated Balance Sheet as of December 31, 2012. In May 2013, the BPU issued an Order approving the BGS payments for these SRECs. This Order was not appealed and went into effect in July 2013. As a result, Power recorded its $9 million then outstanding receivable from PSE&G. In August 2013, PSE&G reimbursed Power and its other BGS suppliers for the excess SREC costs.

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Note 19. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LC. The following table presents condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended September 30, 2013					
Operating Revenues	$ —	$ 1,511	$ 66	$ (408)	$ 1,169
Operating Expenses	2	1,145	62	(409)	800
Operating Income (Loss)	(2)	366	4	1	369
Equity Earnings (Losses) of Subsidiaries	226	(1)	—	(225)	—
Other Income	8	47	—	(10)	45
Other Deductions	1	(11)	—	(1)	(11)
Other-Than-Temporary Impairments	—	(3)	—	—	(3)
Interest Expense	(19)	(13)	(4)	10	(26)
Income Tax Benefit (Expense)	7	(160)	—	—	(153)
Net Income (Loss)	**$ 221**	**$ 225**	**$ —**	**$ (225)**	**$ 221**
Comprehensive Income (Loss)	**$ 245**	**$ 242**	**$ —**	**$ (242)**	**$ 245**
Three Months Ended September 30, 2012					
Operating Revenues	$ —	$ 1,358	$ 36	$ (356)	$ 1,038
Operating Expenses	(1)	1,095	32	(355)	771
Operating Income (Loss)	1	263	4	(1)	267
Equity Earnings (Losses) of Subsidiaries	191	—	—	(191)	—
Other Income	11	106	—	(13)	104
Other Deductions	—	(20)	—	—	(20)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(29)	(15)	(5)	14	(35)
Income Tax Benefit (Expense)	7	(142)	1	1	(133)
Net Income (Loss)	**$ 181**	**$ 190**	**$ —**	**$ (190)**	**$ 181**
Comprehensive Income (Loss)	**$ 166**	**$ 168**	**$ —**	**$ (168)**	**$ 166**

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Nine Months Ended September 30, 2013					
Operating Revenues	$ —	$ 4,849	$ 133	$ (1,176)	$ 3,806
Operating Expenses	6	3,894	123	(1,176)	2,847
Operating Income (Loss)	(6)	955	10	—	959
Equity Earnings (Losses) of Subsidiaries	588	(3)	—	(585)	—
Other Income	27	130	—	(30)	127
Other Deductions	(9)	(40)	—	—	(49)
Other-Than-Temporary Impairments	—	(7)	—	—	(7)
Interest Expense	(72)	(29)	(14)	30	(85)
Income Tax Benefit (Expense)	34	(419)	2	—	(383)
Net Income (Loss)	**$ 562**	**$ 587**	**$ (2)**	**$ (585)**	**$ 562**
Comprehensive Income (Loss)	**$ 611**	**$ 612**	**$ (2)**	**$ (610)**	**$ 611**
Nine Months Ended September 30, 2013					
Net Cash Provided By (Used In) Operating Activities	$ 425	$ 1,360	$ 5	$ (506)	$ 1,284
Net Cash Provided By (Used In) Investing Activities	$ 569	$ (869)	$ (1)	$ 11	$ (290)
Net Cash Provided By (Used In) Financing Activities	$ (990)	$ (492)	$ (4)	$ 494	$ (992)
Nine Months Ended September 30, 2012					
Operating Revenues	$ —	$ 4,560	$ 93	$ (1,069)	$ 3,584
Operating Expenses	(1)	3,663	87	(1,069)	2,680
Operating Income (Loss)	1	897	6	—	904
Equity Earnings (Losses) of Subsidiaries	567	(4)	—	(563)	—
Other Income	35	176	—	(40)	171
Other Deductions	(7)	(45)	—	—	(52)
Other-Than-Temporary Impairments	—	(14)	—	—	(14)
Interest Expense	(89)	(35)	(13)	40	(97)
Income Tax Benefit (Expense)	31	(409)	3	1	(374)
Net Income (Loss)	**$ 538**	**$ 566**	**$ (4)**	**$ (562)**	**$ 538**
Comprehensive Income (Loss)	**$ 549**	**$ 556**	**$ (4)**	**$ (552)**	**$ 549**
Nine Months Ended September 30, 2012					
Net Cash Provided By (Used In) Operating Activities	$ 409	$ 1,259	$ (3)	$ (493)	$ 1,172
Net Cash Provided By (Used In) Investing Activities	$ 257	$ (897)	$ (24)	$ 158	$ (506)
Net Cash Provided By (Used In) Financing Activities	$ (666)	$ (368)	$ 26	$ 335	$ (673)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
As of September 30, 2013					
Current Assets	$ 4,065	$ 8,609	$ 957	$ (11,941)	$ 1,690
Property, Plant and Equipment, net	81	6,059	922	—	7,062
Investment in Subsidiaries	4,331	730	—	(5,061)	—
Noncurrent Assets	197	1,842	56	(126)	1,969
Total Assets	**$ 8,674**	**$ 17,240**	**$ 1,935**	**$ (17,128)**	**$ 10,721**
Current Liabilities	$ 752	$ 10,778	$ 997	$ (11,941)	$ 586
Noncurrent Liabilities	522	2,130	208	(125)	2,735
Long-Term Debt	2,041	—	—	—	2,041
Member's Equity	5,359	4,332	730	(5,062)	5,359
Total Liabilities and Member's Equity	**$ 8,674**	**$ 17,240**	**$ 1,935**	**$ (17,128)**	**$ 10,721**
As of December 31, 2012					
Current Assets	$ 3,922	$ 8,084	$ 940	$ (10,712)	$ 2,234
Property, Plant and Equipment, net	80	5,988	950	—	7,018
Investment in Subsidiaries	4,317	733	—	(5,050)	—
Noncurrent Assets	201	1,660	60	(141)	1,780
Total Assets	**$ 8,520**	**$ 16,465**	**$ 1,950**	**$ (15,903)**	**$ 11,032**
Current Liabilities	$ 482	$ 10,187	$ 1,010	$ (10,712)	$ 967
Noncurrent Liabilities	559	1,960	207	(140)	2,586
Long-Term Debt	2,040	—	—	—	2,040
Member's Equity	5,439	4,318	733	(5,051)	5,439
Total Liabilities and Member's Equity	**$ 8,520**	**$ 16,465**	**$ 1,950**	**$ (15,903)**	**$ 11,032**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by PSEG, Power and PSE&G. Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of three reportable segments, which are:

- **Power,** our wholesale energy supply company that integrates its generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States,
- **PSE&G,** our public utility company which provides electric transmission services and distribution of electric energy and natural gas in New Jersey; implements demand response and energy efficiency programs and invests in solar generation, and
- **Energy Holdings,** which principally owns energy-related leveraged leases and solar generation projects. A subsidiary of Energy Holdings has been awarded a contract to manage the transmission and distribution assets of LIPA beginning on January 1, 2014.

Our business discussion in Part I, Item 1. Business of our 2012 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I Item 1A of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Overview of 2012 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2013 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes, the 2012 Form 10-K and the Quarterly Reports on Form 10-Q for the quarters ended June 30, 2013 and March 31, 2013.

OVERVIEW OF 2013 AND FUTURE OUTLOOK

Our business plan is designed to maintain earnings stability while achieving growth in recognition of market, regulatory and economic trends. We continue to focus on operational excellence to provide the foundation for our financial strength, which enables us to invest in a disciplined way.

Financial Results

The results for PSEG, PSE&G, Power and Energy Holdings for the three months and nine months ended September 30, 2013 and 2012 are presented below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Earnings (Losses)	**2013**	**2012**	**2013**	**2012**
		Millions		
Power	$ 221	$ 181	$ 562	$ 538
PSE&G	168	155	468	453
Energy Holdings	(3)	7	1	49
Other (A)	4	4	12	11
PSEG Net Income	**$ 390**	**$ 347**	**$ 1,043**	**$ 1,051**
Earnings Per Share (Diluted)				
PSEG Net Income	**$ 0.77**	**$ 0.68**	**$ 2.06**	**$ 2.07**

(A) Other primarily includes parent company interest and financing activity and certain administrative and general expenses.

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Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the chart below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	Millions, after tax			
NDT Fund Income (Expense) (A)	$ 12	$ 40	$ 29	$ 49
Non-Trading MTM Gains (Losses)	$ 3	$ (76)	$ (22)	$ (34)

(A) NDT Fund Income (Expense) includes the net realized gains, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions. This also includes impairments on certain NDT securities which are included in Other-Than-Temporary Impairments and the interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO), which is recorded in Operation and Maintenance Expense and the depreciation related to the ARO asset.

Our $43 million increase in Net Income for the three months ended September 30, 2013 includes the MTM and NDT activity above and was also impacted by:

- higher revenues due to increased investments in transmission projects, and
- higher capacity revenues, and
- higher Operation and Maintenance Costs due primarily to planned maintenance costs at our gas-fired Bethlehem Energy Center (BEC) in New York and costs related to damage caused by Superstorm Sandy at our fossil plants, partly offset by cost control measures.

Our $8 million decrease in Net Income for the nine months ended September 30, 2013 was driven primarily by:

- lower volumes of electricity sold under our basic generation service (BGS) contracts at lower average prices,
- lower volumes of wholesale load contracts in the PJM and NE regions,
- higher generation costs due to higher fuel costs,
- higher Operation and Maintenance Costs in 2013, including costs related to damage caused by Superstorm Sandy, partially offset by cost control measures,
- higher Income Tax Expense at PSE&G and Energy Holdings due to the absence of tax benefits related to the settlement of the 1997-2006 Internal Revenue Service (IRS) audits in 2012, and
- net realized gains in September 2012 resulting from restructuring our NDT Fund.

These decreases were largely offset by

- higher capacity pricing in the PJM region resulting from higher auction prices as well as higher generation sold primarily in the PJM region,
- higher average gas prices on sales to third party customers, and
- higher revenues due to increased investments in transmission projects,

Under the PJM capacity auction conducted in May 2013, Power cleared 8,637 MW of its generating capacity at an average price of $166 per MW-day for the 2016-2017 delivery period. While this year's auction resulted in lower clearing prices for the PJM Regional Transmission Organization (RTO), Power benefited from higher prices than the rest of the RTO, as the majority of its generation fleet is situated in the relatively constrained Eastern part of PJM.

Power's results also benefited from access to low cost natural gas from the Marcellus region through its existing transportation and storage contracts. Power manages these contracts primarily for the benefit of PSE&G's customers through the basic gas supply service (BGSS) arrangement. During times of low customer demand for gas, Power can use the remaining transportation that is available to supply the Marcellus gas to its generating units in New Jersey.

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At our regulated utility, we continued to invest capital in transmission and distribution infrastructure projects, aimed at maintaining the reliability of our service to our customers. PSE&G's results for 2013 reflect the favorable impacts from these investments. We filed our 2014 Annual Formula Rate Update with the FERC in October of this year, which would provide for approximately $176 million in increased annual transmission revenues effective January 1, 2014. Over the past few years, these types of investments have altered the business mix of PSEG's overall results of operations to reflect a higher percentage contribution by PSE&G.

Regulatory, Legislative and Other Developments

In developing and implementing our strategy of operational excellence, financial strength and disciplined investment, we monitor significant regulatory and legislative developments. Competitive wholesale power market design is of particular importance to our results and we continue to advocate for policies and rules that promote competitive electricity markets. This includes opposing efforts by states to subsidize generation and supporting rule changes which we believe are necessary to avoid artificial price suppression and other distortions in the energy and capacity markets. For a more detailed discussion of the status of these efforts, refer to Part II. Item 5. Other Information—Federal Regulation—Capacity Market Issues—LCAPP.

We continue to advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA). In particular, the EPA's 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. Clean Air Act (CAA) regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology (MACT) rules are also of significance; however, we believe our generation business remains well-positioned for such regulations if and when they are implemented. These matters are discussed in Part II. Item 5. Other Information—Environmental Matters—Climate Change—CO_2 Regulation under the CAA.

As discussed in further detail under Part II. Item 5. Other Information—Federal Regulation—Transmission Regulation— Transmission Policy Developments, the FERC's rules under Order 1000 altered the right of first refusal previously held by incumbent utilities to build all transmission within their respective service territories. We are challenging the FERC's determination in court as we do not believe that the FERC sufficiently justified its decision to alter this right embedded in the FERC-approved contracts and tariffs. At the same time, the FERC's action presents opportunities for us to construct transmission outside of our service territory.

In the fourth quarter of 2012, we were severely impacted by Superstorm Sandy, which resulted in the highest level of customer outages in our history. We sustained significant damage to some of our generation, transmission and distribution facilities. The New Jersey Board of Public Utilities (BPU) issued an order allowing us to defer actually incurred prudent, incremental storm restoration costs not otherwise recoverable through base rates or insurance. In February 2013, the BPU initiated a generic proceeding to evaluate the prudency of extraordinary storm-related costs incurred by all of the regulated utilities as a result of the natural disasters experienced in New Jersey in 2011 and 2012. In June 2013, we made a compliance filing with the BPU providing the details of our storm restoration costs for Superstorm Sandy as well as other major storms and seeking to demonstrate that we responded to these extreme weather events in a timely, diligent and thorough manner and that the costs incurred were prudent. We requested that the BPU issue an Order approving the compliance filing and specifically finding that the storm costs incurred were reasonable and prudent, and should be recovered from ratepayers.

Power also incurred significant storm-related expenses, primarily for repairs at certain of its coal and gas-fired generating stations in the first nine months of 2013 (See Note 9. Commitments and Contingent Liabilities). We are seeking recovery from our insurers for the property damage, above our self-insured retentions; however, no assurances can be given relative to the timing or amount of any such recovery. In June 2013, we filed suit against the insurance carriers seeking legal interpretation of certain terms in the insurance policies regarding losses resulting from damage caused by Superstorm Sandy's storm surge. For a more detailed discussion concerning this proceeding, refer to Part II. Item 1. Legal Proceedings—Superstorm Sandy.

On February 20, 2013, we filed a petition with the BPU describing our Energy Strong program, consisting of $3.9 billion of proposed improvements we recommend making to our gas and electric distribution systems over a ten-year period to harden and improve resiliency. In the petition, we sought approval for $2.6 billion of the $3.9 billion of investments over an initial five year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. We cannot predict the outcome of this pending proceeding, including whether the program will be approved or the terms under which it would be approved. We anticipate seeking BPU approval to complete our investment under the program at a later date. In addition, we anticipate investing an additional $1.5 billion in our transmission system for the same reason. As proposed, we believe that the rate impacts of the Energy Strong program will be significantly muted as a result of scheduled reductions to customer bills that will be taking place over the next few years and assuming continued low gas prices. See Part II Item 5. Other Information—State Regulation—Energy Strong Program for additional details.

We continue to take all necessary steps in connection with the expected January 1, 2014 commencement of our management of the Long Island Power Authority (LIPA) transmission and distribution (T&D) system. Legislation enacted in New York in July 2013 authorized an expanded role for us in the management of LIPA's T&D system. A revised contract with LIPA was approved by the LIPA Board in October 2013, but implementation of the new contract remains subject to a number of factors,

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including LIPA's receipt of a Private Letter Ruling from the IRS on the continued tax-exempt status of certain LIPA debt securities and LIPA's approval of the proposed 2014 and 2015 operating and capital pass-through budgets. See Part II. Item 5. Other Information—Business Operations and Strategy—Energy Holdings—Products and Services for additional details.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented in the first nine months of the year as we remain diligent in managing costs. In the first nine months of 2013, our

- outstanding performance allowed us to increase generation to meet loads, and
- construction of transmission and solar projects proceeded on schedule and within budget.

Financial Strength

Our financial position remained strong during the first nine months of 2013 as we:

- had cash on hand of $448 million as of September 30, 2013,
- extended the expiration date of approximately half of our credit facilities, and maintained substantial liquidity and solid investment grade credit ratings, as evidenced by the recent credit rating upgrades by Standard & Poor's (S&P) of PSEG, Power and PSE&G as disclosed below in Liquidity and Capital Resources—Credit Ratings,
- completed pension and other postretirement benefit funding for 2013,
- issued bonds at PSE&G to refinance its maturing debt at historically low rates and fund its capital program,
- repaid Power's maturing debt with cash on hand, and
- increased our indicated annual dividend to $1.44.

We expect to be able to fund our proposed Energy Strong program with internally generated cash and external debt financing .

Disciplined Investment

We seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first nine months of 2013 we

- made additional investments in transmission infrastructure projects,
- continued to execute our existing BPU-approved utility programs,
- obtained approval from the BPU to increase our spending up to $247 million and $199 million under our Solar 4 All Extension and Solar Loan III investment programs, respectively, and
- continued construction of a 19 MW solar project in Arizona.

Delays in the construction schedules of our projects could impact their costs as well as the timing of expected revenues.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a difficult economy and cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully re-contract our open supply positions,
- execute our capital investment program, including investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and the FERC of market design rules that continue to protect competition and achieve appropriate Reliability Pricing Model (RPM) and BGS pricing, and

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- engage multiple stakeholders, including regulators, government officials, customers and investors.

For the remainder of 2013 and beyond, the key issues and challenges we expect our business to confront include

- regulatory and political uncertainty, particularly with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation,
- uncertainty in the national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer demand,
- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate,
- the aftermath of Hurricane Irene and Superstorm Sandy, including addressing the BPU's review of performance and communications, as well as cost recovery and opportunities for investment in system strengthening, including our proposed Energy Strong program,
- financially-stressed power plant leveraged lease investments,
- delays and other obstacles that might arise in connection with the construction of our transmission and distribution projects, including in connection with permitting and regulatory approvals, and
- the successful transition to our management of the LIPA T&D system.

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RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our operating subsidiaries, Power, PSE&G and Energy Holdings, excluding charges related to intercompany transactions, which are eliminated in consolidation. We also include certain financing costs, charitable contributions and general and administrative costs at the parent company. For additional information on intercompany transactions, see Note 18. Related-Party Transactions. For an explanation of the variances, see the discussions for Power, PSE&G and Energy Holdings that follow the table below:

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,554	$ 2,402	$ 152	6	$ 7,650	$ 7,375	$ 275	4
Energy Costs	801	879	(78)	(9)	2,711	2,819	(108)	(4)
Operation and Maintenance	713	619	94	15	2,069	1,876	193	10
Depreciation and Amortization	313	286	27	9	886	797	89	11
Taxes Other than Income Taxes	15	24	(9)	(38)	50	73	(23)	(32)
Income from Equity Method Investments	4	7	(3)	(43)	9	9	—	N/A
Other Income and (Deductions)	47	95	(48)	(51)	118	155	(37)	(24)
Other-Than-Temporary Impairments	3	2	1	50	7	14	(7)	(50)
Interest Expense	100	106	(6)	(6)	303	310	(7)	(2)
Income Tax Expense	270	241	29	12	708	599	109	18

Power

	Three Months Ended September 30,		Increase/ (Decrease)	Nine Months Ended September 30,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012
	Millions					
Net Income	$ 221	$ 181	$ 40	$ 562	$ 538	$ 24

For the three months ended September 30, 2013, the primary reasons for the $40 million increase in Net Income were:

- significant MTM losses in 2012 resulting from an increase in prices on forward positions, and
- higher capacity revenues in 2013.

These increases were partially offset by

- higher Operation and Maintenance Costs, due primarily to planned maintenance costs at our BEC plant and costs related to damage caused by Superstorm Sandy at our fossil plants, and
- $59 million of net realized gains in September 2012 resulting from restructuring our NDT Fund.

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For the nine months ended September 30, 2013, the primary reasons for the $24 million increase in Net Income were:

- higher capacity pricing in the PJM region resulting from higher auction prices as well as higher generation sold primarily in the PJM region, and
- higher average gas prices on sales to third party customers.

These increases were largely offset by

- lower volumes of electricity sold under our BGS contracts at lower average prices,
- lower volumes of wholesale load contracts in the PJM and NE regions,
- higher generation costs due to higher fuel costs,
- higher Operation and Maintenance Costs in 2013, including costs related to damage caused by Superstorm Sandy at our fossil plants, and
- $59 million of net realized gains in September 2012 resulting from restructuring our NDT Fund.

The quarter and year-to date details for these variances are discussed below:

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,169	$ 1,038	$ 131	13	$ 3,806	$ 3,584	$ 222	6
Energy Costs	430	456	(26)	(6)	1,786	1,725	61	4
Operation and Maintenance	304	255	49	19	866	780	86	11
Depreciation and Amortization	66	60	6	10	195	175	20	11
Other Income (Deductions)	34	84	(50)	(60)	78	119	(41)	(34)
Other-Than-Temporary Impairments	3	2	1	50	7	14	(7)	(50)
Interest Expense	26	35	(9)	(26)	85	97	(12)	(12)
Income Tax Expense	153	133	20	15	383	374	9	2

Three Months Ended September 30, 2013 as Compared to 2012

Operating Revenues increased $131 million due to changes in generation and gas supply revenues.

Generation Revenues increased $133 million due primarily to

- an increase of $147 million largely due to a $137 million increase primarily attributable to significant MTM losses in 2012 in the PJM region resulting from increases in prices on forward positions, and
- an increase of $78 million due to higher capacity revenues resulting from higher average auction prices and an increase in operating reserve revenues in the PJM region,
- partially offset by a decrease of $74 million due primarily to lower volumes of electricity sold under our BGS contracts and lower average pricing, and
- a net decrease of $18 million due primarily to lower volumes in the NE region as well as lower average prices in the PJM and NE regions on wholesale load contracts.

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Gas Supply Revenues decreased $2 million due primarily to

- a net decrease of $5 million in sales under the BGSS contract, primarily due to lower average gas prices partly offset by higher sales volumes,
- partially offset by a net increase of $3 million partially due to higher sales volumes to third party customers.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $26 million due to

- ***Generation costs*** decreased $20 million due primarily to $28 million of lower fuel costs, reflecting utilization of lower volumes of coal and natural gas at lower average prices, partially offset by higher nuclear fuel prices. This decrease was partially offset by a net increase of $8 million due to energy purchases at higher average prices partly offset by the recovery of excess solar renewable energy credit (SREC) cost in PJM.
- ***Gas costs*** decreased $6 million due primarily to lower average prices under the BGSS contract and on sales to third party customers offset in part by higher sales volumes in 2013.

Operation and Maintenance increased $49 million due primarily to planned maintenance costs at our BEC plant and costs incurred from Superstorm Sandy in 2013 at our New Jersey fossil plants.

Depreciation and Amortization increased $6 million due primarily to a higher depreciable fossil asset base and completion of a steam path retrofit upgrade at our co-owned nuclear Peach Bottom Unit 2 in October 2012.

Other Income and (Deductions) decreased $50 million due primarily to net realized gains of $59 million resulting from restructuring our NDT Fund in September 2012, partially offset by lower NDT Fund realized losses in 2013.

Other-Than-Temporary Impairments increased $1 million due to higher impairments on the NDT Fund in 2013.

Interest Expense decreased $9 million due primarily to a decrease from lower outstanding debt in 2013 resulting from certain debt redeemed prior to maturity in December 2012, as well as the maturity of Senior Notes in April 2013, and lower interest expense due to interest costs we capitalized for projects under construction.

Income Tax Expense increased $20 million in 2013 due primarily to higher pre-tax income.

Nine Months Ended September 30, 2013 as Compared to 2012

Operating Revenues increased $222 million due to changes in generation and gas supply revenues.

Generation Revenues increased $130 million due primarily to

- an increase of $275 million due to higher capacity revenues resulting from higher average auction prices and an increase in operating reserve revenues in PJM, and
- higher revenues of $91 million due primarily to higher generation sold in the PJM and NE regions partly offset by lower average prices in PJM,
- partially offset by a decrease of $144 million due primarily to lower volumes of electricity sold under our BGS contracts and lower average pricing, and
- a net decrease of $92 million due to lower volumes on wholesale load contracts in the PJM and NE regions.

Gas Supply Revenues increased $92 million due primarily to

- a net increase of $60 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during the 2013 winter heating season, partially offset by lower average gas prices, and
- a net increase of $32 million due primarily to higher average gas prices, partially offset by lower sales volumes to third party customers.

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Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $61 million due to

- ***Generation costs*** increased $18 million due primarily to $83 million of higher fuel costs, reflecting higher average realized natural gas prices, higher nuclear fuel costs, and the utilization of higher volumes of coal and oil, partially offset by lower average coal prices. The increase was partially offset by $21 million of lower energy purchases, recovery of excess SREC costs and a decrease of $44 million in congestion costs in PJM.
- ***Gas costs*** increased $43 million, principally related to obligations under the BGSS contract, reflecting higher sales volumes in 2013 due to colder average temperatures during the 2013 winter heating season, partially offset by lower average gas inventory costs.

Operation and Maintenance increased $86 million due primarily to $63 million in costs incurred from Superstorm Sandy in 2013 at our fossil plants, and $48 million of higher planned outage and maintenance costs in 2013, mainly at BEC, our Bergen gas-fired plant in New Jersey and Conemaugh coal-fired plant in Pennsylvania. This was partially offset by the recognition of a $25 million insurance recovery related to Superstorm Sandy.

Depreciation and Amortization increased $20 million due primarily to a higher depreciable asset base at Fossil, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut in June 2012 and completion of the steam path retrofit upgrade at our co-owned Peach Bottom Unit 2 in October 2012.

Other Income and (Deductions) decreased $41 million due primarily to the factors disclosed in the above analysis for the three months ended September 30, 2013 versus 2012.

Other-Than-Temporary Impairments decreased $7 million due to lower impairments on the NDT Fund in 2013.

Interest Expense decreased $12 million due primarily to a decrease from lower outstanding debt in 2013 resulting from certain debt redeemed prior to maturity in December 2012, as well as the maturity of Senior Notes in April 2013, partially offset by higher interest costs in 2013 since interest capitalization ceased for our Kearny and New Haven gas-fired peaking projects on their June 2012 in-service date.

Income Tax Expense increased $9 million in 2013 due primarily to higher pre-tax income.

PSE&G

	Three Months Ended September 30,		Increase/ (Decrease)	Nine Months Ended September 30,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012
	Millions					
Net Income	$ 168	$ 155	$ 13	$ 468	$ 453	$ 15

For the three months ended September 30, 2013, the primary reason for the $13 million increase in Net Income was higher transmission revenues due to increased investments in transmission projects.

For the nine months ended September 30, 2013, the primary reasons for the $15 million increase in Net Income were

- higher transmission revenues due to increased investments in transmission projects,
- partially offset by higher Income Tax Expense due to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012.

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The quarter and year-to-date details for these variances are discussed below:

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,666	$ 1,683	$ (17)	(1)	$ 5,084	$ 5,029	$ 55	1
Energy Costs	661	756	(95)	(13)	2,208	2,380	(172)	(7)
Operation and Maintenance	408	366	42	11	1,204	1,092	112	10
Depreciation and Amortization	236	216	20	9	658	594	64	11
Taxes Other Than Income Taxes	15	24	(9)	(38)	50	73	(23)	(32)
Other Income (Deductions)	12	10	2	20	38	31	7	23
Interest Expense	75	73	2	3	223	220	3	1
Income Tax Expense	115	103	12	12	311	248	63	25

Three Months Ended September 30, 2013 as Compared to 2012

Operating Revenues decreased $17 million due to changes in delivery, clause, commodity and other operating revenues.

Commodity Revenue decreased $95 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $92 million due primarily to $40 million in lower BGS revenues and $52 million in lower revenues from a reduced volume of sales of Non-Utility Generation (NUG) energy and lower Non-Utility Generation Charges (NGC) due to lower tariff rates. BGS sales decreased 6% due to customer migration to third party suppliers (TPS) and weather.
- Gas revenues decreased $3 million due to lower BGSS prices of $5 million, partially offset by higher BGSS volumes of $2 million primarily due to weather. The average price of natural gas was 7% lower in 2013 than in 2012.

Delivery Revenues increased $52 million due primarily to an increase in transmission revenues.

- Transmission revenues were $46 million higher due to net rate increases resulting primarily from increased capital investments.
- Electric distribution revenues increased $7 million due primarily to an increase in Capital Infrastructure Program (CIP) related revenues of $14 million and higher Green Program Recovery Charges (GPRC) of $17 million, partially offset by lower sales volumes of $16 million, and lower Transitional Energy Facilities Assessment (TEFA) revenue of $8 million due to a lower TEFA rate.
- Gas distribution revenues decreased $1 million due primarily to lower Weather Normalization Clause (WNC) revenue of $6 million due to more normal weather compared to the prior period, partially offset by $3 million from higher sales volumes and $2 million from CIP related revenues.

Clause Revenues increased $22 million due primarily to higher Securitization Transition Charge (STC) revenues of $10 million, higher Solar Pilot Recovery Charge (SPRC) revenue of $5 million and higher Margin Adjustment Clause (MAC) revenue of $7 million. The changes in STC, SPRC and MAC amounts were entirely offset by the amortization of Regulatory Assets and related costs in Operation and Maintenance (O&M), Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SPRC or MAC collections.

Other Operating Revenues increased $4 million due primarily to increased revenues from our miscellaneous electric operating revenues.

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Energy Costs decreased $95 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $92 million or 14% due to $73 million in lower BGS and NUG volumes, $10 million of lower BGS and NUG prices and $9 million for decreased deferred cost recovery. BGS and NUG volumes decreased 11% due primarily to customer migration to TPS and weather.
- Gas costs decreased $3 million or 4% due to $5 million or 7% in lower prices, partially offset by $2 million or 3% in higher sales volumes due primarily to weather.

Operation and Maintenance increased $42 million, of which the most significant components were

- a $37 million increase in costs related primarily to Societal Benefit Charges (SBC), CIP and GPRC. Due to the nature of the SBC, CIP and GPRC clause mechanisms, these are entirely offset in revenues, and
- a $3 million increase in appliance service costs.

Depreciation and Amortization increased $20 million due primarily to

- an $11 million increase in amortization of Regulatory Assets, and
- an $8 million increase in depreciation of additional plant in service.

Taxes Other Than Income Taxes decreased $9 million due to a lower TEFA rate for electric and gas, partially offset by higher sales volumes for gas.

Other Income and (Deductions) net increase of $2 million was due primarily to an increase in Solar Loan interest income.

Interest Expense increased due primarily to higher average long-term debt partially offset by lower average securitization debt.

Income Tax Expense increased $12 million due primarily to higher pre-tax income.

Nine Months Ended September 30, 2013 as Compared to 2012

Operating Revenues increased $55 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $143 million due primarily to an increase in transmission revenues.

- Transmission revenues were $131 million higher due to net rate increases resulting primarily from increased capital investments.
- Gas distribution revenues increased $10 million due primarily to $58 million from higher sales volumes and an increase of $16 million in CIP related revenues, partially offset by lower WNC revenue of $61 million due to more normal weather compared to the prior period.
- Electric distribution revenues increased $2 million due primarily to an increase in CIP related revenues of $14 million and higher GPRC of $21 million, partially offset by lower TEFA revenue of $18 million due to a lower TEFA rate and lower sales volumes of $15 million.

Clause Revenues increased $74 million due primarily to higher STC revenues of $35 million, higher SBC of $29 million, higher SPRC revenue of $8 million and higher MAC revenue of $2 million. The changes in STC, SBC, SPRC and MAC amounts were entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC, SPRC or MAC collections.

Other Operating Revenues increased $10 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Commodity Revenue decreased $172 million due to lower Electric revenues, partially offset by higher Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $267 million due primarily to $164 million in lower BGS revenues and $103 million in lower revenues from a lower volume of sales of NUG energy and lower NGC due to lower tariff rates. BGS sales decreased 6% due primarily to customer migration to TPS.
- Gas revenues increased $95 million due primarily to higher BGSS volumes.

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Energy Costs decreased $172 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $267 million or 15% due to $177 million in lower BGS and NUG volumes, $54 million of lower BGS and NUG prices, and $36 million for decreased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.
- Gas costs increased $95 million or 15% due primarily to higher sales volumes.

Operation and Maintenance increased $112 million, of which the most significant components were

- an $87 million increase in costs recognized related primarily to SBC, CIP and GPRC. Due to the nature of the SBC, CIP and GPRC clause mechanisms, these are entirely offset in revenues,
- an $8 million increase in costs relating to repairs from Superstorm Sandy and a colder winter, and
- a $9 million increase in appliance service costs.

Depreciation and Amortization increased $64 million due primarily to

- a $41 million increase in amortization of Regulatory Assets, and
- a $21 million increase in depreciation of additional plant in service.

Taxes Other Than Income Taxes decreased $23 million due to a lower TEFA rate for electric and gas, partially offset by higher sales volumes for gas.

Other Income and (Deductions) net increase of $7 million was due primarily to an increase in Solar Loan interest income.

Interest Expense increased due primarily to higher average long-term debt partially offset by lower average securitization debt.

Income Tax Expense increased $63 million due primarily to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012 and higher pre-tax income.

Energy Holdings

	Three Months Ended September 30,		Increase/ (Decrease)	Nine Months Ended September 30,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012
	Millions					
Net Income	$ (3)	$ 7	$ (10)	$ 1	$ 49	$ (48)

For the three months ended September 30, 2013, the primary reasons for the $10 million decrease in Net Income were the impairment of real estate assets and legal expenses related to the LIPA contract expansion in 2013 and a gain on an asset sale in 2012.

For the nine months ended September 30, 2013, the primary reason for the $48 million decrease in Net Income was the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in the prior year.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our three direct operating subsidiaries.

Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund capital expenditures and shareholder dividend payments.

For the nine months ended September 30, 2013, our operating cash flow increased $124 million as compared to the same period in 2012. The net change was due primarily to net changes from Power and PSE&G, as discussed below.

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Power

Power's operating cash flow increased $112 million from $1,172 million to $1,284 million for the nine months ended September 30, 2013, as compared to the same period in 2012, primarily resulting from higher earnings and an increase of $124 million related to margin deposits.

PSE&G

PSE&G's operating cash flow increased $8 million from $1,041 million to $1,049 million for the nine months ended September 30, 2013, as compared to the same period in 2012, due primarily to higher earnings and an increase from a net change in regulatory deferrals primarily related to BGSS gas costs and the collection of Gas Weather Normalization Charges, offset by higher payments for storm related costs. The increases were partially offset by higher tax payments.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our credit facilities are provided by a diverse bank group. In March 2013, Power, PSEG and PSE&G amended their respective 5-year credit agreements scheduled to end in 2016, extending the expiration dates from April 2016 to March 2018. Of the total commitments of $2.1 billion under these agreements, $2.0 billion has been extended until 2018. The commitments for the $100 million balance will terminate in 2016. As of September 30, 2013, our total credit capacity was $4.3 billion.

As of September 30, 2013, no single institution represented more than 8% of the total commitments in our credit facilities.

As of September 30, 2013, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of September 30, 2013 were as follows:

	As of September 30, 2013			
Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions			
PSEG					
5-year Credit Facility	$ 500	$ 5 (D)	$ 495	Mar 2017	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—	500	Mar 2018	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 5**	**$ 995**		
Power					
5-year Credit Facility	$ 1,600	$ 58 (D)	$ 1,542	Mar 2017	Funding/Letters of Credit
5-year Credit Facility (B)	1,000	—	1,000	Mar 2018	Funding/Letters of Credit
Bilateral Credit Facility	100	100 (D)	—	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 158**	**$ 2,542**		
PSE&G					
5-year Credit Facility (C)	$ 600	$ 13 (D)	$ 587	Mar 2018	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 13**	**$ 587**		
Total	**$ 4,300**	**$ 176**	**$ 4,124**		

(A) In April 2016, this facility will be reduced by $23 million.

(B) In April 2016, this facility will be reduced by $48 million.

(C) In April 2016, this facility will be reduced by $29 million.

(D) Includes amounts related to letters of credit outstanding.

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Long-Term Debt Financing

PSE&G has $275 million of 6.33% Medium-Term Notes maturing in November 2013. For a discussion of our long-term debt transactions during 2013, see Note 10. Changes in Capitalization.

Common Stock Dividends

On July 16, 2013, the Board of Directors declared a quarterly dividend of $0.36 per share of common stock for the third quarter of 2013. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Note 16. Earnings Per Share and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In April 2013, S&P upgraded the corporate credit ratings on PSEG, Power and PSE&G to BBB+ from BBB and PSE&G's Mortgage Bond rating to A from A-. PSEG's, Power's and PSE&G's outlooks were changed to stable from positive. In May 2013, Moody's published updated credit opinions on PSEG, Power and PSE&G. PSEG's, Power's and PSE&G's ratings and outlooks remained unchanged. In July 2013, Fitch published updated research on PSEG, Power and PSE&G which kept their ratings and outlooks unchanged.

	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	**Stable**	**Stable**	**Stable**
Commercial Paper	P2	A2	F2
Power			
Outlook	**Stable**	**Stable**	**Stable**
Senior Notes	Baa1	BBB+	BBB+
PSE&G			
Outlook	**Stable**	**Stable**	**Stable**
Mortgage Bonds	A1	A	A+
Commercial Paper	P2	A2	F2

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1+ (highest) to D (lowest) for short-term securities.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1+ (highest) to D (lowest) for short-term securities.

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CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. In the Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, PSE&G reported an increase in its projected base level capital expenditures of $215 million through 2015, as compared to the amounts disclosed in our Form 10-K for the year ended December 31, 2012. This increase primarily reflects our projected additional spending during the period under our Solar Loan III and Solar 4 All Extension programs which were approved by the BPU in May 2013. There have been no additional material changes to our projected capital expenditures at Power, PSE&G and Energy Holdings as compared to amounts disclosed in our Form 10-K for the year ended December 31, 2012. See Note 9. Commitments and Contingent Liabilities for additional information.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The market risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

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	MTM VaR	
	Three Months Ended September 30, 2013	Year Ended December 31, 2012
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 9	$ 18
Average for the Period	$ 14	$ 16
High	$ 19	$ 29
Low	$ 9	$ 7
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 15	$ 28
Average for the Period	$ 22	$ 25
High	$ 30	$ 46
Low	$ 14	$ 11

See Note 11. Financial Risk Management Activities for a discussion of credit risk.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the third quarter of 2013 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. Certain information reported under Item 3 of Part I of the 2012 Annual Report on Form 10-K and under Item 1 of Part II of the Quarterly Reports on Form 10-Q for the quarters ended March 31, 2013 and June 30, 2013 are updated below. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2012 Annual Report on Form 10-K and under Item 1 of Part II of the Quarterly Report on Form 10-Q for the quarters ended March 31, 2013 and June 30, 2013, see Note 9. Commitments and Contingent Liabilities and Item 5. Other Information.

Superstorm Sandy

June 30, 2013 Form 10-Q page 81. PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. PSEG is seeking recovery from its insurers for the property damage, above its self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. PSEG has recorded proceeds of $50 million from its insurance carriers as advance payments, $25 million of which was recognized in the second quarter of 2013 and $25 million was recognized in the fourth quarter of 2012. PSEG does not believe that it has a basis for estimating additional probable insurance recoveries at this time. In June 2013, PSEG, Power and PSE&G filed suit in New Jersey state court against the insurance carriers seeking legal interpretation of certain terms in the insurance policies regarding losses resulting from damage caused by Superstorm Sandy's storm surge. The dispute concerns whether certain sub-limits in the policies apply to damage to property caused by Superstorm Sandy's storm surge. In that Complaint, PSEG stated that its estimate of the total costs required to restore damaged facilities to their pre-Superstorm Sandy condition was approximately $426 million. Of these costs, $364 million and $62 million related to Power and PSE&G, respectively. In August 2013, the insurance carriers filed an answer in which they denied most of the allegations made in the Complaint. Discovery is proceeding.

ITEM 1A. RISK FACTORS

There no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2012 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the third quarter of 2013:

Three Months Ended September 30, 2013	Total Number of Shares Purchased	Average Price Paid per Share
July 1 - July 31	—	$ —
August 1 - August 31	22,500	$ 33.70
September 1 -September 30	—	$ —

ITEM 5. OTHER INFORMATION

Certain information reported in the 2012 Annual Report on Form 10-K and Quarterly Reports on Form 10-Q for the Quarters Ended March 31, 2013 and June 30, 2013 are updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2012 Annual Report on Form 10-K and the Quarterly Reports on Form 10-Q for the Quarters Ended March 31, 2013 and June 30, 2013. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

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BUSINESS OPERATIONS AND STRATEGY

Energy Holdings

Products and Services

December 31, 2012 Form 10-K page 13 and June 30, 2013 Form 10-Q page 82. Our December 2011 ten-year contract, Operations Services Agreement (OSA), for the management of the Long Island Power Authority (LIPA) transmission and distribution system by PSEG Long Island LLC (PSEG LI) is scheduled to commence on January 1, 2014. We continue to take all necessary steps in connection with the expected January 1, 2014 commencement of our management responsibilities in accordance with this OSA.

On July 29, 2013, the Governor of New York signed legislation that will restructure LIPA, pursuant to which PSEG LI may undertake an expanded role in the management of LIPA's transmission and distribution system and other aspects of its operations. During September 2013, PSEG and LIPA concluded negotiations on an amendment to the OSA and several related agreements, including contracts to manage LIPA's fuel procurement and power supply obligations. The economic construct of the amended OSA is consistent with the original OSA, with PSEG LI taking on greater management responsibilities, using its brand and more fully integrating its support functions in return for greater compensation and an extension of the contract from the original ten years to twelve. In addition, there is an option for the parties to agree to extend the contract for an additional eight years. On September 27, 2013, the New York Department of Public Service issued its recommendation to LIPA to enter into those agreements. On October 3, 2013, the LIPA Board approved the agreements. On October 2, 2013, PSEG LI received its requested disclaimer of jurisdiction from the FERC. With those approvals received, the agreements' effectiveness is contingent upon LIPA's receipt of a Private Letter Ruling from the IRS on the continued tax-exempt status of certain LIPA debt securities and LIPA's approval of the proposed 2014 and 2015 operating and capital pass-through budgets.

FEDERAL REGULATION

FERC

Market Power

December 31, 2012 Form 10-K page 15. Under FERC regulations, public utilities must receive FERC authorization to sell power in interstate commerce. For a requesting company to receive market based rate ("MBR") authority, the FERC must first make a determination that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated.

PSE&G, PSEG Energy Resources & Trade LLC, PSEG Power Connecticut, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG New Haven LLC all have been granted MBR authority from the FERC. Each of these companies, except PSEG New Haven LLC (which received MBR authority in May 2012), will be filing a market power update with the FERC at the end of 2013, which the FERC must accept in order for these companies to retain MBR authority. Retention of MBR authority is important to the maintenance of our current generation business' revenues.

Capacity Market Issues

December 31, 2012 Form 10-K page 16 and June 30, 2013 Form 10-Q page 82. PJM, the New York Independent System Operator (NYISO), and the Independent System Operator-New England (ISO-NE) each have capacity markets that have been approved by the FERC. The FERC regulates these markets and recently held a technical conference to examine whether the market design for these three capacity markets is working optimally. One of the specific issues being considered by the FERC is whether capacity market rules are properly responding to, and fostering the development of, state public policies, demand response and emerging technologies.

Capacity Market Issues—NYISO

December 31, 2012 Form 10-K page 16. The NYISO capacity model currently recognizes only two separate zones that potentially may separate in price: New York City and Long Island. On August 13, 2013, the FERC issued an order approving NYISO's April 30, 2013 filing establishing the boundaries of a third capacity zone that will encompass the super zone that includes the lower Hudson Valley and New York City to take effect May 1, 2014. The NYISO is also currently considering what type of generation unit should be used as the reference unit for the purposes of establishing the Cost of New Entry in the "rest of State" zone (excluding the lower Hudson Valley, New York City and Long Island). This issue is significant since it will set the demand curve on which future capacity prices paid to generators will be based.

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Capacity Market Issues—Long-Term Capacity Agreement Pilot Program Act (LCAPP)

December 31, 2012 Form 10-K page 16, March 31, 2013 Form 10-Q page 70 and June 30, 2013 Form 10-Q page 82. In 2011, the State of New Jersey concluded that new natural gas-fired generation was needed and enacted the LCAPP Act to subsidize approximately 2,000 MW of new generation. The LCAPP Act provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey Electric Distribution Companies (EDCs). The SOCA required each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers. Each of the New Jersey EDCs, including PSE&G, entered into the SOCAs as directed by the State, but did so under protest reserving their rights. In July 2013, the SOCA contract with New Jersey Power Development LLC, a subsidiary of NRG Energy, Inc., was terminated early as a result of a default by the generator.

We have taken several steps to challenge these subsidies, including joining several other parties in challenging the LCAPP Act on constitutional grounds in federal court. On October 11, 2013, the U.S. District Court found that the LCAPP Act violated the Supremacy Clause of the U.S. Constitution and declared the LCAPP Act null and void. On October 25, 2013, a final judgment was issued implementing the federal court's decision and also finding the SOCA contracts void, invalid and unenforceable and denying the request of the defendants to stay the decision pending appeal. The defendants may appeal the decision and may seek a stay from the U.S. Third Circuit Court of Appeals. We also filed a challenge to the BPU's implementation of the LCAPP Act in the New Jersey State Appellate Court. This appeal was dismissed without prejudice on October 23, 2013 on the basis that the U.S. District Court found the LCAPP Act to be preempted by the Federal Power Act and in violation of the Supremacy Clause of the U.S. Constitution, and therefore null and void. In the event that the U.S. District Court decision is overturned on appeal, the New Jersey State Appellate Court action could be reopened.

Maryland also took action to subsidize above-market new generation. On April 16, 2013, the Maryland Public Service Commission (PSC) issued an order directing the Maryland utility companies to execute a contract with CPV Shore, LLC (CPV) to build a new 661 MW natural gas-fired, combined cycle station in Maryland. We joined other parties in challenging Maryland's actions on constitutional grounds in federal court in Maryland. On September 30, 2013, the U.S. District Court in Maryland ruled on our complaint and found that Maryland's actions violated the Supremacy Clause of the U.S. Constitution. This federal court decision invalidates the Maryland action, including the contract subsidizing CPV. On October 25, 2013, a final judgment in this proceeding was issued. This decision may be appealed.

These efforts by various states to artificially depress prices in the wholesale capacity markets were intended to be mitigated by the Minimum Offer Price Rule (MOPR) approved by the FERC. The MOPR was intended to restrict new generation from bidding in RPM at less than a minimum level established by PJM's Tariff, or a cost-based bid to the extent that the generator can demonstrate that its costs are lower than the MOPR. However, we do not believe these rules have worked as intended and have not protected the market against price suppression efforts. At the direction of the FERC, PJM is currently conducting a stakeholder proceeding, the purpose of which is to develop an enhanced process applicable to subsidized generation seeking to bid into RPM at less than MOPR. The outcome of this stakeholder process and eventual FERC review is uncertain at this time.

Transmission Regulations—Transmission Policy Developments

December 31, 2012 Form 10-K page 17, March 31, 2013 Form 10-Q page 71 and June 30, 2013 Form 10-Q page 83. The FERC has concluded in Order No. 1000 that the incumbent transmission owner should not always have a “right of first refusal” (ROFR) to construct and own transmission projects in its service territory. We have challenged the FERC's elimination of the ROFR in federal court, which challenge remains pending. PJM is currently implementing new rules under which the construction of certain types of transmission projects is no longer subject to a ROFR for incumbents. The FERC has also approved the “state agreement approach” to cost allocation under which transmission projects being built to address public policy concerns may be placed into PJM's planning process if the state sponsoring the project agrees to pay the costs of the project. To date, no such projects have been placed into the planning process but this mechanism could potentially facilitate transmission projects that are not needed for reliability or market efficiency under PJM standards for transmission, including potential offshore wind projects proposed by third parties, should a state or states agree to fund the costs of such projects.

Transmission Regulations—Transmission Expansion

December 31, 2012 Form 10-K page 17 and March 31, 2013 Form 10-Q page 71 . In February 2013, the federal court denied certain environmental groups’ action to seek an injunction to halt construction of the Susquehanna-Roseland transmission line by us and PPL Corporation and set aside the National Park Service’s (NPS) final Environmental Impact Statement (EIS) for the line, allowing its construction in certain federal park lands subject to the NPS' jurisdiction that follows the existing right of way. On August 19, 2013, the environmental groups filed a renewed preliminary injunction motion. On August 30, 2013, the court ruled in favor of NPS, PPL Corporation and us and denied the environmental groups’ renewed summary judgment and preliminary injunction motions. Construction activities in the park are ongoing.

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Transmission Regulations—Transmission Rate Proceedings

December 31, 2012 Form 10-K page 18, March 31, 2013 Form 10-Q page 71 and June 30, 2013 Form 10-Q page 83. In September 2011, a complaint was filed by several state utility commissions and consumer advocates against transmission owners in New England challenging their base return on equity (ROE). In August 2013, a FERC Administrative Law Judge (ALJ) issued a decision finding the utilities' base ROE to no longer be just and reasonable. In February 2013, several state utility commissions and consumer advocates, including the BPU and the New Jersey Division of Rate Counsel, also filed a complaint at the FERC challenging the base ROE and formula transmission rate implementation protocols of transmission owners in Maryland, Pennsylvania, Delaware and New Jersey. This complaint remains pending. While the August 2013 decision is subject to review by the FERC, and the February 2013 complaint is pending, the results of these proceedings could set a precedent for the FERC-regulated transmission owners with formula rates in place, such as ours.

The FERC has issued an order setting for hearing and settlement procedures certain rate challenges raised by a municipal electric cooperative against a transmission owner in PJM. Specifically, the electric cooperative challenged the prudency of categories of costs included by the transmission owner in its formula rate. The FERC found that the challenges raised issues of fact that warranted examination at hearing. While we are not the subject of the challenge, the result of this proceeding could set a precedent for other transmission owners with formula rates in place, including PSE&G.

STATE REGULATION

Rates

Weather Normalization Clause

December 31, 2012 Form 10-K page 20. In September 2013, the BPU approved recovery of $26 million in deficiency revenues, including $24 million of the carryover deficiency from the 2012-2013 Winter Period which we will recover from customers during the 2013-2014 Winter Period (October 1- May 31).

Energy Strong Program

December 31, 2012 Form 10-K page 20, March 31, 2013 Form 10-Q page 71 and June 30, 2013 Form 10-Q page 84. In February 2013, we filed a petition with the BPU seeking approval of certain investments we recommend making to our BPU jurisdictional electric and gas system to harden and improve resiliency for the future through a clause recovery mechanism. We have continued to respond to data requests from the BPU, the New Jersey Division of Rate Counsel and intervenors. All required public hearings were completed in October 2013, and the review of PSE&G's proposal is ongoing at the BPU. We cannot predict the outcome of this matter.

Energy Supply

BGSS

December 31, 2012 Form 10-K page 21 and June 30, 2013 Form 10-Q page 84. In September 2012, the BPU approved the Stipulation which lowered our BGSS rate effective October 1, 2012 on a provisional basis. In May 2013, the BPU approved a Stipulation that made the current BGSS rate final. Additionally, in May 2013 we made our annual BGSS filing with the BPU requesting no change to the current rate for the next BGSS period effective October 1, 2013 through September 30, 2014. In September 2013, the BPU approved our request to retain the current rate for the next BGSS period effective October 1, 2013 through September 30, 2014.

On October 23, 2013, we filed a self-implementing two-month BGSS bill credit with the BPU. This bill credit will be 35 cents per therm for the months of November and December 2013 and is designed to provide approximately $115 million to residential customers over the two months. The BGSS rate will revert back to the current rate on January 1, 2014.

ENVIRONMENTAL MATTERS

Air Pollution Control

Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation

March 31, 2013 Form 10-Q page 72 and June 30, 2013 Form 10-Q page 85. On March 29 and April 1, 2013, we filed petitions at the EPA and in federal court, respectively, challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued on January 30, 2013. Among other things, the final EPA rule allows owners and operators of stationary emergency RICE to operate their engines as part of an emergency DR program without the installation and operation of emission controls or compliance with emission limits otherwise applicable to non-emergency counterparts. This waiver of NESHAP standards results in disparate treatment of different generation technology types. In our appeal, we are seeking more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. On September 6, 2013, the EPA published its intent to reconsider certain items included in the final rule that are also subject to the appeal, with a 60 day comment period.

S1-SSA-0009 - 18783

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Climate Change

CO_2 Regulation Under the Clean Air Act (CAA)

December 31, 2012 Form 10-K page 24 and June 30, 2013 Form 10-Q page 85. In April 2013, several industrial groups petitioned the Supreme Court to review various EPA rules issued under the CAA, including the Tailoring Rule, to regulate greenhouse gas (GHG) emissions, including CO_2. The Tailoring Rule requires a new source or an existing source which undergoes a major modification, to evaluate and perhaps install best available control technology (BACT) for GHG emissions.

On October 15, 2013, the Supreme Court agreed to add the case to the docket for its current term to consider whether the EPA has authority to regulate CO_2 emissions of stationary sources, including power plants.

In April 2012, the EPA published the proposed New Source Performance Standards (NSPS) for GHG for new power plants only. On June 25, 2013, the President directed the EPA to propose revised NSPS for new power plants by September 20, 2013, propose GHG regulations for existing power plants by June 1, 2014, finalize such regulations by June 1, 2015 and require states to submit GHG implementation regulations by June 30, 2016.

On September 20, 2013, the EPA proposed revised NSPS for new power plants. The revised NSPS differs from those initially proposed in April 2012 in that standards would vary for different types of new power plants as opposed to the application of a single standard for all new power plants. The EPA is also requesting comment on use of an electric output sales threshold to determine applicability to the NSPS. This electric output sales threshold would eliminate the outright exclusion of simple cycle combustion turbines. Comments on the rule must be submitted within 60 days after publication.

Water Pollution Control

Cooling Water Intake Structure Regulation

December 31, 2012 Form 10-K page 25 and June 30, 2013 Form 10-Q page 85. In April 2011, the EPA published a proposed rule to establish marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. In July 2012, the EPA and environmental groups agreed to delay the deadline to June 27, 2013 for finalization of the Rule. On June 27, 2013, the EPA and environmental groups agreed to further extend the deadline to November 4, 2013.

If the rule were to be adopted as proposed, the impact on us would be material since the majority of our electric generating stations would be affected. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Note 9. Commitments and Contingent Liabilities for additional information.

On October 1, 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court of New Jersey seeking to force the New Jersey Department of Environmental Protection to take action on our pending application for permit renewal at Salem either by denying the application or issuing a draft for public comment. The permit is currently pending the EPA's finalization of the Clean Water Act Section 316(b) regulations. We were not named in the lawsuit nor do we know how this legal action will proceed but it could have a material impact on us.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. Power:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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Exhibit 101.INS:	XBRL Instance Document
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Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. PSE&G:

Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2013

S1-SSA-0009 - 18786

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2013

S1-SSA-0009 - 18787

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ DEREK M. DIRISIO

Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2013

S1-SSA-0009 - 18788

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,751	$ 1,650	$ 2,011	$ 2,384	$ 2,616	$ 2,636	$ 1,806
(Income) Loss from Equity Investees, net of Distributions	(5)	6	9	(4)	(19)	(25)	(5)
Fixed Charges	345	353	479	522	571	600	633
Capitalized Interest	(12)	(16)	(19)	(14)	(67)	(45)	(37)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	(2)	(6)	(6)
Total Earnings	$ 2,079	$ 1,993	$ 2,480	$ 2,888	$ 3,099	$ 3,160	$ 2,391
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 333	$ 343	$ 465	$ 509	$ 555	$ 581	$ 615
Interest Factor in Rentals	12	10	14	13	14	13	12
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	2	6	6
Total Fixed Charges	$ 345	$ 353	$ 479	$ 522	$ 571	$ 600	$ 633
Ratio of Earnings to Fixed Charges	6.03	5.65	5.18	5.53	5.43	5.27	3.78

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12.1

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 945	$ 912	$ 1,080	$ 1,687	$ 1,914	$ 1,958	$ 1,711
Fixed Charges	105	120	163	208	238	221	210
Capitalized Interest	1	(5)	(4)	(10)	(62)	(43)	(31)
Total Earnings	$ 1,051	$ 1,027	$ 1,239	$ 1,885	$ 2,090	$ 2,136	$ 1,890
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 102	$ 119	$ 161	$ 205	$ 235	$ 219	$ 208
Interest Factor in Rentals	3	1	2	3	3	2	2
Total Fixed Charges	$ 105	$ 120	$ 163	$ 208	$ 238	$ 221	$ 210
Ratio of Earnings to Fixed Charges	10.01	8.56	7.60	9.06	8.78	9.67	9.00

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 779	$ 701	$ 835	$ 861	$ 591	$ 551	$ 592
Fixed Charges	240	233	314	319	325	317	325
Capitalized Interest	(12)	(9)	(13)	(4)	(2)	(1)	—
Total Earnings	$ 1,007	$ 925	$ 1,136	$ 1,176	$ 914	$ 867	$ 917
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 235	$ 229	$ 308	$ 314	$ 320	$ 313	$ 325
Interest Factor in Rentals	5	4	6	5	5	4	—
Total Fixed Charges	$ 240	$ 233	$ 314	$ 319	$ 325	$ 317	$ 325
Ratio of Earnings to Fixed Charges	4.20	3.97	3.62	3.69	2.81	2.74	2.82

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.3

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Nine Months Ended September 30,		Years Ended December 31,				
	2013	2012	2012	2011	2010	2009	2008
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 779	$ 701	$ 835	$ 861	$ 591	$ 551	$ 592
Fixed Charges	240	233	314	319	327	323	332
Capitalized Interest	(12)	(9)	(13)	(4)	(2)	(1)	—
Preferred Securities Dividend Requirements	—	—	—	—	(2)	(6)	(6)
Total Earnings	$ 1,007	$ 925	$ 1,136	$ 1,176	$ 914	$ 867	$ 918
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 235	$ 229	$ 308	$ 314	$ 320	$ 313	$ 325
Interest Factor in Rentals	5	4	6	5	5	4	—
Preferred Securities Dividend	—	—	—	—	1	4	4
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	—	—	1	2	2
Total Fixed Charges	$ 240	$ 233	$ 314	$ 319	$ 327	$ 323	$ 331
Ratio of Earnings to Fixed Charges	4.20	3.97	3.62	3.69	2.80	2.68	2.77

(A) The term "earnings" shall be defined as pretax income from continuing operations. Add to pretax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2013

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2013

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2013

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2013

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2013

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2013

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
October 30, 2013

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer
October 30, 2013

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
October 30, 2013

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Caroline Dorsa

Caroline Dorsa

PSEG Power LLC
Chief Financial Officer
October 30, 2013

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
October 30, 2013

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2013 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer
October 30, 2013

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2014
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of October 15, 2014, Public Service Enterprise Group Incorporated had outstanding 505,959,967 shares of its sole class of Common Stock, without par value.

As of October 15, 2014, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, capacity market design, transmission planning and cost allocation rules, including how transmission projects are planned and who is permitted to build transmission in the future, and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- any deterioration in our credit quality or the credit quality of our counterparties,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as competition for certain transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies, and
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

S1-SSA-0009 - 18807

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
OPERATING REVENUES	$ 2,641	$ 2,554	$ 8,113	$ 7,650
OPERATING EXPENSES				
Energy Costs	863	801	3,008	2,711
Operation and Maintenance	714	713	2,370	2,069
Depreciation and Amortization	318	313	919	886
Taxes Other Than Income Taxes	—	15	—	50
Total Operating Expenses	1,895	1,842	6,297	5,716
OPERATING INCOME	746	712	1,816	1,934
Income from Equity Method Investments	3	4	10	9
Other Income	75	59	185	172
Other Deductions	(9)	(12)	(31)	(54)
Other-Than-Temporary Impairments	(10)	(3)	(14)	(7)
Interest Expense	(100)	(100)	(291)	(303)
INCOME BEFORE INCOME TAXES	705	660	1,675	1,751
Income Tax Expense	(261)	(270)	(633)	(708)
NET INCOME	$ 444	$ 390	$ 1,042	$ 1,043
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):				
BASIC	505,862	505,858	505,937	505,900
DILUTED	507,422	507,694	507,402	507,433
NET INCOME PER SHARE:				
BASIC	$ 0.88	$ 0.77	$ 2.06	$ 2.06
DILUTED	$ 0.87	$ 0.77	$ 2.05	$ 2.06
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.37	$ 0.36	$ 1.11	$ 1.08

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
NET INCOME	$ 444	$ 390	$ 1,042	$ 1,043
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $33, $(16), $21 and $(27) for the three and nine months ended 2014 and 2013, respectively	(30)	16	(17)	27
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(1), $1, $(3) and $4 for the three and nine months ended 2014 and 2013, respectively	1	(1)	4	(5)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(2), $(6), $(5) and $(20) for the three and nine months ended 2014 and 2013, respectively	3	9	9	28
Other Comprehensive Income (Loss), net of tax	(26)	24	(4)	50
COMPREHENSIVE INCOME	$ 418	$ 414	$ 1,038	$ 1,093

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18809

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 703	$ 493
Accounts Receivable, net of allowances of $55 and $56 in 2014 and 2013, respectively	1,267	1,203
Tax Receivable	14	109
Unbilled Revenues	228	300
Fuel	530	545
Materials and Supplies, net	495	479
Prepayments	175	89
Derivative Contracts	71	98
Deferred Income Taxes	128	24
Regulatory Assets	211	243
Other	24	31
Total Current Assets	3,846	3,614
PROPERTY, PLANT AND EQUIPMENT	31,328	29,713
Less: Accumulated Depreciation and Amortization	(8,492)	(8,068)
Net Property, Plant and Equipment	22,836	21,645
NONCURRENT ASSETS		
Regulatory Assets	2,569	2,612
Regulatory Assets of Variable Interest Entities (VIEs)	270	476
Long-Term Investments	1,309	1,313
Nuclear Decommissioning Trust (NDT) Fund	1,739	1,701
Long-Term Receivable of VIE	401	—
Other Special Funds	675	613
Goodwill	16	16
Other Intangibles	102	33
Derivative Contracts	29	163
Restricted Cash of VIEs	24	24
Other	331	312
Total Noncurrent Assets	7,465	7,263
TOTAL ASSETS	$ 34,147	$ 32,522

See Notes to Condensed Consolidated Financial Statements.

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Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, October 30, 2014 Powered by Morningstar® Document Research℠
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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	September 30, 2014	December 31, 2013
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 316	$ 544
Securitization Debt of VIEs Due Within One Year	258	237
Commercial Paper and Loans	—	60
Accounts Payable	1,111	1,222
Derivative Contracts	109	76
Accrued Interest	117	95
Accrued Taxes	168	37
Clean Energy Program	185	142
Obligation to Return Cash Collateral	120	119
Regulatory Liabilities	271	43
Other	481	488
Total Current Liabilities	3,136	3,063
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	7,298	7,107
Regulatory Liabilities	141	233
Regulatory Liabilities of VIEs	12	11
Asset Retirement Obligations	704	677
Other Postretirement Benefit (OPEB) Costs	1,073	1,095
OPEB Costs of Servco	321	—
Accrued Pension Costs	121	121
Accrued Pension Costs of Servco	78	—
Environmental Costs	438	414
Derivative Contracts	37	31
Long-Term Accrued Taxes	183	180
Other	132	119
Total Noncurrent Liabilities	10,538	9,988
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	8,321	7,587
Securitization Debt of VIEs	68	259
Project Level, Non-Recourse Debt	—	16
Total Long-Term Debt	8,389	7,862
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2014 and 2013—533,556,660 shares	4,873	4,861
Treasury Stock, at cost, 2014— 27,674,968 shares; 2013— 27,699,398 shares	(629)	(615)
Retained Earnings	7,938	7,457
Accumulated Other Comprehensive Loss	(99)	(95)
Total Common Stockholders' Equity	12,083	11,608
Noncontrolling Interest	1	1
Total Stockholders' Equity	12,084	11,609
Total Capitalization	20,473	19,471
TOTAL LIABILITIES AND CAPITALIZATION	$ 34,147	$ 32,522

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See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2014	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 1,042	$ 1,043
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	919	886
Amortization of Nuclear Fuel	151	145
Provision for Deferred Income Taxes (Other than Leases) and ITC	103	242
Non-Cash Employee Benefit Plan Costs	36	182
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(30)	(7)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	237	3
Change in Accrued Storm Costs	(3)	(87)
Net Change in Other Regulatory Assets and Liabilities	276	134
Cost of Removal	(68)	(66)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(99)	(76)
Net Change in Margin Deposit	(173)	17
Net Change in Certain Current Assets and Liabilities	119	158
Employee Benefit Plan Funding and Related Payments	(76)	(210)
Other	102	71
Net Cash Provided By (Used In) Operating Activities	2,536	2,435
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,922)	(2,102)
Proceeds from Sales of Investments	11	42
Proceeds from Sales of Available-for-Sale Securities	1,224	914
Investments in Available-for-Sale Securities	(1,241)	(922)
Other	(60)	(20)
Net Cash Provided By (Used In) Investing Activities	(1,988)	(2,088)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(60)	(263)
Issuance of Long-Term Debt	1,000	1,500
Redemption of Long-Term Debt	(500)	(750)
Redemption of Securitization Debt	(170)	(162)
Cash Dividends Paid on Common Stock	(561)	(546)
Other	(47)	(57)
Net Cash Provided By (Used In) Financing Activities	(338)	(278)
Net Increase (Decrease) in Cash and Cash Equivalents	210	69
Cash and Cash Equivalents at Beginning of Period	493	379
Cash and Cash Equivalents at End of Period	$ 703	$ 448
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 284	$ 222
Interest Paid, Net of Amounts Capitalized	$ 269	$ 274
Accrued Property, Plant and Equipment Expenditures	$ 286	$ 258

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18813

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
OPERATING REVENUES	$ 1,138	$ 1,174	$ 3,824	$ 3,818
OPERATING EXPENSES				
Energy Costs	472	430	2,036	1,785
Operation and Maintenance	242	305	871	868
Depreciation and Amortization	71	69	215	202
Total Operating Expenses	785	804	3,122	2,855
OPERATING INCOME	353	370	702	963
Income from Equity Method Investments	4	4	11	12
Other Income	56	45	135	127
Other Deductions	(6)	(11)	(25)	(49)
Other-Than-Temporary Impairments	(10)	(3)	(14)	(7)
Interest Expense	(31)	(26)	(92)	(85)
INCOME BEFORE INCOME TAXES	366	379	717	961
Income Tax Expense	(144)	(153)	(277)	(384)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 222	$ 226	$ 440	$ 577

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18814

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
NET INCOME	$ 222	$ 226	$ 440	$ 577
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $34, $(18), $23 and $(29) for the three and nine months ended 2014 and 2013, respectively	(30)	17	(19)	30
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $1, $(2) and $4 for the three and nine months ended 2014 and 2013, respectively	1	(1)	4	(6)
Pension/OPEB adjustment, net of tax (expense) benefit of $(1), $(6), $(4) and $(17) for the three and nine months ended 2014 and 2013, respectively	2	8	7	25
Other Comprehensive Income (Loss), net of tax	(27)	24	(8)	49
COMPREHENSIVE INCOME	$ 195	$ 250	$ 432	$ 626

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18815

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 12	$ 6
Accounts Receivable	385	338
Accounts Receivable—Affiliated Companies, net	52	333
Short-Term Loan to Affiliate	623	790
Fuel	530	545
Materials and Supplies, net	360	362
Derivative Contracts	50	57
Prepayments	20	13
Deferred Income Taxes	97	30
Other	1	2
Total Current Assets	2,130	2,476
PROPERTY, PLANT AND EQUIPMENT	10,613	10,278
Less: Accumulated Depreciation and Amortization	(3,229)	(2,911)
Net Property, Plant and Equipment	7,384	7,367
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,739	1,701
Long-Term Investments	122	123
Goodwill	16	16
Other Intangibles	102	33
Other Special Funds	159	139
Derivative Contracts	11	72
Other	87	75
Total Noncurrent Assets	2,236	2,159
TOTAL ASSETS	$ 11,750	$ 12,002

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18816

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2014	December 31, 2013
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ —	$ 44
Accounts Payable	435	516
Derivative Contracts	109	76
Accrued Interest	43	28
Other	160	136
Total Current Liabilities	747	800
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	2,092	2,031
Asset Retirement Obligations	415	400
Other Postretirement Benefit (OPEB) Costs	215	206
Derivative Contracts	37	31
Accrued Pension Costs	35	35
Long-Term Accrued Taxes	57	53
Other	94	91
Total Noncurrent Liabilities	2,945	2,847
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT		
Total Long-Term Debt	2,543	2,497
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,358	4,693
Accumulated Other Comprehensive Loss	(71)	(63)
Total Member's Equity	5,515	5,858
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 11,750	$ 12,002

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18817

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2014	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 440	$ 577
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	215	202
Amortization of Nuclear Fuel	151	145
Provision for Deferred Income Taxes and ITC	5	96
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	237	3
Non-Cash Employee Benefit Plan Costs	10	50
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(99)	(76)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	17	(38)
Margin Deposit	(173)	17
Accounts Receivable	49	68
Accounts Payable	(135)	(70)
Accounts Receivable/Payable—Affiliated Companies, net	299	329
Other Current Assets and Liabilities	28	21
Employee Benefit Plan Funding and Related Payments	(5)	(45)
Other	71	35
Net Cash Provided By (Used In) Operating Activities	1,110	1,314
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(414)	(458)
Proceeds from Sales of Available-for-Sale Securities	882	849
Investments in Available-for-Sale Securities	(898)	(864)
Short-Term Loan—Affiliated Company, net	167	157
Other	(63)	(13)
Net Cash Provided By (Used In) Investing Activities	(326)	(329)
CASH FLOWS FROM FINANCING ACTIVITIES		
Redemption of Long-Term Debt	—	(300)
Cash Dividend Paid	(775)	(705)
Contributed Capital	—	24
Other	(3)	(2)
Net Cash Provided By (Used In) Financing Activities	(778)	(983)
Net Increase (Decrease) in Cash and Cash Equivalents	6	2
Cash and Cash Equivalents at Beginning of Period	6	7
Cash and Cash Equivalents at End of Period	$ 12	$ 9
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 87	$ 107
Interest Paid, Net of Amounts Capitalized	$ 78	$ 72
Accrued Property, Plant and Equipment Expenditures	$ 66	$ 64

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18818

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
OPERATING REVENUES	$ 1,655	$ 1,666	$ 5,235	$ 5,084
OPERATING EXPENSES				
Energy Costs	668	661	2,278	2,208
Operation and Maintenance	366	408	1,190	1,204
Depreciation and Amortization	238	236	682	658
Taxes Other Than Income Taxes	—	15	—	50
Total Operating Expenses	1,272	1,320	4,150	4,120
OPERATING INCOME	383	346	1,085	964
Other Income	16	13	44	41
Other Deductions	(2)	(1)	(3)	(3)
Interest Expense	(71)	(75)	(206)	(223)
INCOME BEFORE INCOME TAXES	326	283	920	779
Income Tax Expense	(126)	(115)	(355)	(311)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 200	$ 168	$ 565	$ 468

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18819

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
NET INCOME	$ 200	$ 168	$ 565	$ 468
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0, $0 and $1 for the three and nine months ended 2014 and 2013, respectively	1	—	1	(1)
COMPREHENSIVE INCOME	$ 201	$ 168	$ 566	$ 467

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18820

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 305	$ 18
Accounts Receivable, net of allowances of $55 and $56 in 2014 and 2013, respectively	836	832
Unbilled Revenues	228	300
Materials and Supplies	130	115
Prepayments	116	24
Regulatory Assets	211	243
Derivative Contracts	5	25
Deferred Income Taxes	20	16
Other	20	12
Total Current Assets	1,871	1,585
PROPERTY, PLANT AND EQUIPMENT	20,347	19,071
Less: Accumulated Depreciation and Amortization	(5,057)	(4,964)
Net Property, Plant and Equipment	15,290	14,107
NONCURRENT ASSETS		
Regulatory Assets	2,569	2,612
Regulatory Assets of VIEs	270	476
Long-Term Investments	349	361
Other Special Funds	385	354
Derivative Contracts	8	69
Restricted Cash of VIEs	24	24
Other	151	132
Total Noncurrent Assets	3,756	4,028
TOTAL ASSETS	$ 20,917	$ 19,720

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18821

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	September 30, 2014	December 31, 2013
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 300	$ 500
Securitization Debt of VIEs Due Within One Year	258	237
Commercial Paper and Loans	—	60
Accounts Payable	520	535
Accounts Payable—Affiliated Companies, net	99	190
Accrued Interest	73	67
Clean Energy Program	185	142
Deferred Income Taxes	—	30
Obligation to Return Cash Collateral	120	119
Regulatory Liabilities	271	43
Other	296	314
Total Current Liabilities	2,122	2,237
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,538	4,406
Other Postretirement Benefit (OPEB) Costs	807	839
Accrued Pension Costs	26	27
Regulatory Liabilities	141	233
Regulatory Liabilities of VIEs	12	11
Environmental Costs	386	363
Asset Retirement Obligations	286	274
Long-Term Accrued Taxes	78	72
Other	63	47
Total Noncurrent Liabilities	6,337	6,272
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	5,763	5,066
Securitization Debt of VIEs	68	259
Total Long-Term Debt	5,831	5,325
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2014 and 2013—132,450,344 shares	892	892
Contributed Capital	695	520
Basis Adjustment	986	986
Retained Earnings	4,052	3,487
Accumulated Other Comprehensive Income	2	1
Total Stockholder's Equity	6,627	5,886
Total Capitalization	12,458	11,211
TOTAL LIABILITIES AND CAPITALIZATION	$ 20,917	$ 19,720

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18822

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2014	**2013**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 565	$ 468
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	682	658
Provision for Deferred Income Taxes and ITC	93	153
Non-Cash Employee Benefit Plan Costs	21	117
Cost of Removal	(68)	(66)
Change in Accrued Storm Costs	(3)	(87)
Net Change in Other Regulatory Assets and Liabilities	276	134
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	71	48
Materials and Supplies	(15)	(4)
Prepayments	(92)	(109)
Accounts Payable	(3)	3
Accounts Receivable/Payable—Affiliated Companies, net	(113)	(171)
Other Current Assets and Liabilities	(6)	29
Employee Benefit Plan Funding and Related Payments	(67)	(147)
Other	2	23
Net Cash Provided By (Used In) Operating Activities	1,343	1,049
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,493)	(1,628)
Proceeds from Sales of Available-for-Sale Securities	98	35
Investments in Available-for-Sale Securities	(96)	(16)
Solar Loan Investments	2	(11)
Restricted Funds	(1)	—
Net Cash Provided By (Used In) Investing Activities	(1,490)	(1,620)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	(60)	(263)
Issuance of Long-Term Debt	1,000	1,500
Redemption of Long-Term Debt	(500)	(450)
Redemption of Securitization Debt	(170)	(162)
Contributed Capital	175	100
Other	(11)	(17)
Net Cash Provided By (Used In) Financing Activities	434	708
Net Increase (Decrease) In Cash and Cash Equivalents	287	137
Cash and Cash Equivalents at Beginning of Period	18	116
Cash and Cash Equivalents at End of Period	$ 305	$ 253
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 174	$ 174
Interest Paid, Net of Amounts Capitalized	$ 188	$ 199
Accrued Property, Plant and Equipment Expenditures	$ 238	$ 200

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18823

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This combined Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information relating to any individual company is filed by such company on its own behalf. Power and PSE&G each is only responsible for information about itself and its subsidiaries.

Note 1. Organization and Basis of Presentation

Organization

PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Power**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and the states in which they operate.
- **PSE&G**—which is an operating public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the FERC. PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which, effective January 1, 2014, operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a twelve-year Amended and Restated Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2013 and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2014 and June 30, 2014.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All significant intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2013.

On December 31, 2013, Energy Holdings distributed the outstanding equity of its 50% interest in a partnership that owns and operates a generation facility in Hawaii and its wholly owned interest in PSEG Solar Source LLC to PSEG. PSEG in turn contributed this distribution to Power as an additional equity investment. This transaction was accounted for as a non-cash transfer of equity interest between entities under common control with prior period financial statements for Power retrospectively adjusted to include the earnings related to the transfer. As a result, Power's Operating Revenues increased $5 million and $12 million for the three months and nine months ended September 30, 2013, respectively, and Power's Net Income increased $5 million and $15 million for the three months and nine months ended September 30, 2013, respectively.

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Note 2. Recent Accounting Standards

New Standards Adopted during 2014

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

This accounting standard was issued to address diversity in practice related to the presentation of an unrecognized tax benefit in certain cases. This standard requires entities to present an unrecognized tax benefit or a portion thereof on the Balance Sheet as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward.

However, the unrecognized tax benefit will be presented on the Balance Sheet as a liability and will not be combined with deferred tax assets in cases where that tax benefit cannot or will not, if permissible, be used to settle any additional income taxes that would result from the disallowance of a tax position.

The standard was effective for fiscal years and interim periods beginning after December 15, 2013. The impact of adopting this standard was immaterial.

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard was issued to clarify the principles for recognizing revenue and to develop a common standard that would remove inconsistencies in revenue requirements; improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provide improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The update is effective for annual and interim reporting periods beginning after December 15, 2016. Early application is not permitted. We are currently analyzing the impact of this standard on our financial statements.

Presentation of Financial Statements and Property, Plant and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity

This accounting standard was issued to change the criteria for reporting discontinued operations. The standard requires that a component of an entity be reported in discontinued operations if the disposal represents a strategic shift that has, or will have, a major effect on the entity's operations and financial results, including a disposal of a major geographical area, a major line of business, a major equity method investment, or other major parts of an entity.

The amendment should be applied prospectively for all disposals of an entity that occur within interim and annual periods beginning on or after December 15, 2014; and all businesses that, on acquisition, are classified as held for sale that occur within interim and annual periods beginning on or after December 15, 2014. We will evaluate all future disposals under the new guidance beginning on January 1, 2015.

Transfers and Servicing - Repurchase-to-Maturity Transactions, Repurchase-Financings and Disclosures

This standard changes the accounting for repurchase-to-maturity transactions and linked repurchase-financings to secured borrowing accounting, which is consistent with the accounting for other repurchase agreements. It also requires disclosures for repurchase agreements, securities lending transactions, and repurchase-to-maturity transactions that are accounted for as secured borrowings.

This standard is effective for the first interim or annual period beginning after December 15, 2014.

We are currently analyzing this standard but do not expect its impact to be material to our financial statements.

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern

The amendments in this standard provide guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. Substantial doubt about an entity's ability to continue as a going concern exists when relevant conditions and events, considered in the aggregate, indicate that it is probable that the entity will be unable to meet its obligations as they become due within one year after the date that its financial statements are issued.

The update is effective for annual and interim reporting periods beginning after December 15, 2016.

The update requires that we identify, assess and evaluate uncertainties and their impact, if any, on our ability to meet financial obligations. However, we do not expect this standard to impact our financial statements.

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Note 3. Variable Interest Entities (VIEs)

Variable Interest Entities for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of Transition Funding and Transition Funding II are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the assets of these VIEs are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II.

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of September 30, 2014 and December 31, 2013. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II during the first nine months of 2014 or in 2013. PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II.

Variable Interest Entity for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

PSEG recognized a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and other postretirement benefit (OPEB) liabilities. This receivable is presented separately on the Condensed Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted. See Note 7. Pension and Other Postretirement Benefits for additional information.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operations and Maintenance (O&M) Expense, respectively. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

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Note 4. Rate Filings

The following information discusses significant updates regarding orders and pending rate filings. This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2013.

Significant regulatory orders received by PSE&G in 2014 are as follows:

- ***Storm Damage Deferral***—In September 2014, the BPU approved a Stipulation of Settlement finding that PSE&G's 2010 through 2012 major storm incremental O&M costs of $240 million (deferred as Regulatory Assets) and capital expenditures of $126 million were prudent and recoverable in a future base rate proceeding, subject to offset for the amount of insurance proceeds received.
- ***Weather Normalization Clause (WNC)***—In April 2014, the BPU approved PSE&G's filing with respect to deficiency revenues from the 2012-2013 Winter Period. The BPU's approval of a final WNC resulted in no change to the provisional rate previously approved by the BPU and implemented effective October 1, 2013, which was set to recover $26 million from customers during the 2013-2014 Winter Period (October 1, 2013 through May 31, 2014).

  In September 2014, the BPU provisionally approved PSE&G's filing with respect to excess revenues collected during the colder than normal 2013-2014 Winter Period. Effective October 1, 2014, PSE&G will return $45 million in revenues to its customers during the 2014-2015 Winter Period as a result of excess revenues collected during the colder than normal 2013-2014 Winter Period (October 1, 2014 through May 31, 2015).
- ***Basic Gas Supply Service (BGSS)***—In January and February 2014, PSE&G filed self-implementing one-month BGSS residential customer bill credits with the BPU for 25 cents per therm for the months of February and March 2014. These credits provided approximately $93 million in total credits to residential customers, reducing the BGSS deferred balance. On April 1, 2014, the BGSS rate reverted back to the current rate.

  In May 2014, PSE&G made its annual BGSS filing with the BPU requesting a reduction of $112 million in annual BGSS revenues. In September 2014, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was reduced from approximately 54 cents to 45 cents per therm effective October 1, 2014.

  In October 2014, PSE&G filed a self-implementing three-month bill credit for residential customers to be effective during November and December 2014 and January 2015. This credit will be 28 cents per therm for the three-month period and is estimated to provide approximately $160 million to customers. The specific amount returned will depend on actual usage over that period.
- ***Universal Service Fund (USF)/Lifeline***—In September 2014, the BPU approved rates set to recover costs incurred under the USF/Lifeline energy assistance programs effective October 1, 2014. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on Net Income.
- ***Capital Stimulus Infrastructure Programs (CIP II)***—In June 2014, the BPU approved PSE&G's petition to recover annual revenue requirements of approximately $28 million for program costs incurred for its CIP II investments through September 30, 2013, which represents the final phase of the program. Base rates were adjusted effective July 1, 2014 to reflect the recovery.
- ***SBC and Non-Utility Generation Charge (NGC)***—In May 2014, the BPU approved PSE&G's petition to recover actual SBC and NGC costs incurred through December 31, 2013 under its Energy Efficiency & Renewable Energy Programs, Social Programs and NGC. New rates were implemented on June 1, 2014 to recover approximately $400 million over the succeeding 12 months.

Significant pending rate filings are as follows:

- ***Transmission Formula Rate Filings***—In May 2014, PSE&G filed its 2014 True-Up Adjustment pertaining to its formula rates in effect for 2013, which resulted in an adjustment of $5 million above the 2013 filed revenues. In accordance with PSE&G's formula rate protocols, this Rate Year 2013 True-Up Adjustment has been incorporated into its Annual Formula Rate Update for the 2015 Rate Year. The 2015 Annual Formula Rate Update was filed with the FERC in October 2014 and provides for approximately $182 million in increased annual transmission revenues effective January 1, 2015.
- ***Energy Strong Recovery Filing***—On September 30, 2014, PSE&G filed its initial Energy Strong cost recovery petition, seeking BPU approval to recover in base rates an estimated annual revenue increase of $1.6 million effective

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March 1, 2015. This increase represents capitalized Energy Strong electric investment costs expected to be in service through November 30, 2014. This request will be updated in December 2014 for actual costs.

- ***Solar and Energy Efficiency-Green Program Recovery Charges (GPRC)***—In June 2014, PSE&G filed a petition with the BPU requesting recovery of costs and investments in the combined eight components of the electric and gas GPRC for the period October 1, 2014 through September 30, 2015. The rates proposed in our filing are designed to recover $111 million and $18 million in electric and gas revenues, respectively, on an annual basis.
- ***Remediation Adjustment Charge (RAC)***—On April 18, 2014, PSE&G filed a petition with the BPU requesting recovery of $66 million related to RAC 21 net manufactured gas plant expenditures through July 31, 2013.

Note 5. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with Solar Renewable Energy Certificates generated from the installed solar electric system. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of September 30, 2014	As of December 31, 2013
	Millions	
Commercial/Industrial	$ 187	$ 192
Residential	14	15
Total	**$ 201**	**$ 207**

Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

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The following table shows Energy Holdings' gross and net lease investment as of September 30, 2014 and December 31, 2013, respectively.

	As of September 30, 2014	As of December 31, 2013
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 698	$ 701
Estimated Residual Value of Leased Assets	529	529
Unearned and Deferred Income	(393)	(405)
Gross Investment in Leases	834	825
Deferred Tax Liabilities	(705)	(727)
Net Investment in Leases	**$ 129**	**$ 98**

The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. "Not Rated" counterparties represent investments in lease receivables related to commercial real estate properties.

Counterparties' Credit Rating (Standard & Poor's (S&P)) As of September 30, 2014	Lease Receivables, Net of Non-Recourse Debt As of September 30, 2014
	Millions
AA	$ 18
AA-	56
BBB+ - BBB-	316
BB-	134
B	165
Not Rated	9
Total	**$ 698**

The "BB-" and the "B" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of September 30, 2014, the gross investment in the leases of such assets, net of non-recourse debt, was $563 million ($13 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

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Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counter-parties' S&P Credit Ratings	Counterparty
		Millions		MW			
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 117	17%	1,711	Coal	B	GenOn REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 118	17%	1,711	Coal	B	GenOn REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 110	100%	603	Coal	B	GenOn REMA, LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, the indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges from the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

GenOn REMA, LLC, an indirect subsidiary of NRG Energy, Inc. (NRG) notified PJM that it no longer intends to place the coal-fired units at the Shawville generating facility in long-term protective layup. Instead, those units will be shut down temporarily beginning in April 2015, with an expected return to service no later than June 2016 using an alternative fuel.

Nesbitt Asset Recovery, LLC (Nesbitt), (an indirect, wholly owned subsidiary of Energy Holdings), owns approximately 64% of the lease interest in the Powerton and Joliet coal units in Illinois. These facilities are leased to Midwest Generation (MWG), which was an indirect subsidiary of Edison Mission Energy (EME). In December 2012, EME and MWG filed for relief under Chapter 11 of the U.S. Bankruptcy Code. In October 2013, NRG, EME, MWG, Nesbitt and other creditor parties involved in the bankruptcy executed a new agreement under which NRG would acquire substantially all of EME's assets, including the Powerton and Joliet leased assets. In March 2014, the Bankruptcy Court approved the transaction. As part of the transaction, (i) the leases for the Powerton and Joliet coal units were assumed on their existing terms, (ii) all past due rent under the leases was paid in full, (iii) NRG assumed EME's tax indemnity and guarantee obligations, and (iv) NRG agreed to invest up to $350 million in the Powerton and Joliet coal units so they can be operated in compliance with environmental regulations. On April 1, 2014, NRG and EME closed on the transaction in accordance with these terms, bringing the lease payments current.

Note 6. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Fund

Power maintains an external master nuclear decommissioning trust to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third party investment advisers who operate under investment guidelines developed by Power.

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Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of September 30, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 652	$ 240	$ (9)	$ 883
Debt Securities				
Government Obligations	471	5	(4)	472
Other Debt Securities	344	12	(2)	354
Total Debt Securities	815	17	(6)	826
Other Securities	30	—	—	30
Total NDT Available-for-Sale Securities	**$ 1,497**	**$ 257**	**$ (15)**	**$ 1,739**

	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 609	$ 290	$ (2)	$ 897
Debt Securities				
Government Obligations	438	3	(12)	429
Other Debt Securities	285	10	(4)	291
Total Debt Securities	723	13	(16)	720
Other Securities	84	—	—	84
Total NDT Available-for-Sale Securities	**$ 1,416**	**$ 303**	**$ (18)**	**$ 1,701**

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2014	As of December 31, 2013
	Millions	
Accounts Receivable	$ 41	$ 39
Accounts Payable	$ 35	$ 36

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The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of September 30, 2014				As of December 31, 2013			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 116	$ (9)	$ 1	$ —	$ 30	$ (2)	$ 2	$ —
Debt Securities								
Government Obligations (B)	148	(2)	68	(2)	300	(11)	1	(1)
Other Debt Securities (C)	101	(1)	32	(1)	107	(4)	3	—
Total Debt Securities	249	(3)	100	(3)	407	(15)	4	(1)
NDT Available-for-Sale Securities	**$ 365**	**$ (12)**	**$ 101**	**$ (3)**	**$ 437**	**$ (17)**	**$ 6**	**$ (1)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2014.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2014.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2014.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	Millions			
Proceeds from NDT Fund Sales (A)	$ 221	$ 220	$ 779	$ 837
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	45	35	101	95
Gross Realized Losses	(3)	(9)	(12)	(34)
Net Realized Gains (Losses) on NDT Fund	**$ 42**	**$ 26**	**$ 89**	**$ 61**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $121 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of September 30, 2014.

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The NDT available-for-sale debt securities held as of September 30, 2014 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 20
1 - 5 years	239
6 - 10 years	217
11 - 15 years	62
16 - 20 years	42
Over 20 years	246
Total NDT Available-for-Sale Debt Securities	**$ 826**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the nine months ended September 30, 2014, other-than-temporary impairments of $14 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of September 30, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 10	$ —	$ 22
Debt Securities				
Government Obligations	88	1	—	89
Other Debt Securities	75	1	—	76
Total Debt Securities	163	2	—	165
Other Securities	1	—	—	1
Total Rabbi Trust Available-for-Sale Securities	**$ 176**	**$ 12**	**$ —**	**$ 188**

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	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 14	$ 9	$ —	$ 23
Debt Securities				
Government Obligations	109	—	(2)	107
Other Debt Securities	46	1	(1)	46
Total Debt Securities	155	1	(3)	153
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	**$ 172**	**$ 10**	**$ (3)**	**$ 179**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2014	As of December 31, 2013
	Millions	
Accounts Receivable	$ 2	$ 1
Accounts Payable	$ 1	$ 2

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months.

	As of September 30, 2014				As of December 31, 2013			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	26	—	—	—	47	(2)	2	—
Other Debt Securities (C)	25	—	—	—	18	(1)	1	—
Total Debt Securities	51	—	—	—	65	(3)	3	—
Rabbi Trust Available-for-Sale Securities	**$ 51**	**$ —**	**$ —**	**$ —**	**$ 65**	**$ (3)**	**$ 3**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell

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nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of September 30, 2014.

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2014.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	Millions			
Proceeds from Rabbi Trust Sales (A)	**$ 419**	**$ 13**	**$ 445**	**$ 77**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ 2	$ —	$ 4	$ 4
Gross Realized Losses	(2)	—	(3)	(3)
Net Realized Gains (Losses) on Rabbi Trust	**$ —**	**$ —**	**$ 1**	**$ 1**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in the Condensed Consolidated Statements of Operations. Net unrealized gains of $7 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of September 30, 2014. The Rabbi Trust available-for-sale debt securities held as of September 30, 2014 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ —
1 - 5 years	51
6 - 10 years	28
11 - 15 years	7
16 - 20 years	7
Over 20 years	72
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 165**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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The fair value of assets in the Rabbi Trust related to PSEG, Power and PSE&G are detailed as follows:

	As of September 30, 2014	As of December 31, 2013
	Millions	
Power	$ 44	$ 39
PSE&G	40	42
Other	104	98
Total Rabbi Trust Available-for-Sale Securities	**$ 188**	**$ 179**

Note 7. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.

Pension and OPEB costs for PSEG, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013	2014	2013	2014	2013
	Millions							
Components of Net Periodic Benefit Cost								
Service Cost	$ 26	$ 29	$ 5	$ 6	$ 78	$ 87	$ 14	$ 16
Interest Cost	58	54	18	15	176	161	52	47
Expected Return on Plan Assets	(99)	(87)	(7)	(6)	(299)	(261)	(20)	(16)
Amortization of Net								
Prior Service Cost (Credit)	(5)	(5)	(4)	(4)	(14)	(14)	(11)	(11)
Actuarial Loss	14	47	6	11	42	141	18	32
Total Benefit Costs	**$ (6)**	**$ 38**	**$ 18**	**$ 22**	**$ (17)**	**$ 114**	**$ 53**	**$ 68**

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Pension and OPEB costs for Power, PSE&G and PSEG's other subsidiaries, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013	2014	2013	2014	2013
	Millions							
Power	$ (2)	$ 11	$ 5	$ 6	$ (5)	$ 33	$ 15	$ 17
PSE&G	(4)	23	12	16	(14)	68	35	49
Other	—	4	1	—	2	13	3	2
Total Benefit Costs	**$ (6)**	**$ 38**	**$ 18**	**$ 22**	**$ (17)**	**$ 114**	**$ 53**	**$ 68**

PSEG does not anticipate making any significant contributions into its pension plan during 2014. However, during the three months ended March 31, 2014, PSEG contributed its entire planned contribution for the year 2014 of $14 million into its postretirement healthcare plan.

Servco Pension and OPEB

At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities (VIEs). These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. The pension-related revenues and costs for the three months and nine months ended September 30, 2014 were $21 million and $67 million, respectively. Servco has contributed its entire planned contribution amount to its pension plan trusts during 2014. There were no OPEB-related revenues earned or costs incurred for the three months and nine months ended September 30, 2014.

Note 8. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and

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- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

The face value of Power's outstanding guarantees, current exposure and margin positions as of September 30, 2014 and December 31, 2013 are shown as follows:

	As of September 30, 2014	As of December 31, 2013
	Millions	
Face Value of Outstanding Guarantees	$ 1,719	$ 1,639
Exposure under Current Guarantees	$ 222	$ 246
Letters of Credit Margin Posted	$ 138	$ 132
Letters of Credit Margin Received	$ 17	$ 25
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (25)	$ —
Net Broker Balance Deposited (Received)	$ 278	$ 80
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that could be Required	$ 851	$ 691
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,516	$ 3,522
Additional Amounts Posted:		
Other Letters of Credit	$ 45	$ 45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P, Moody's and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See preceding table.

The SEC and the Commodity Futures Trading Commission (CFTC) continue efforts to implement new rules to effect stricter regulation over swaps and derivatives, including imposing reporting and record-keeping requirements. In August 2013, PSEG began reporting its swap transactions to a CFTC-approved swap data repository. PSEG continues to monitor developments in this area, as the CFTC considers additional requirements such as a new position limits rule for physical commodity futures contracts and swaps that are economically equivalent to those contracts.

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In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Super Fund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA further determined that there was a need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including Power and PSE&G, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River At such time, the CPG also agreed to allocate the associated costs of the RI/FS among the members of the CPG on the basis of a mutually agreed upon formula. For the purpose of this allocation, approximately seven percent of the RI/FS costs were deemed attributable to PSE&G's former MGP sites and approximately one percent was attributed to Power's generating stations. These allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. Power has provided notice to insurers concerning this potential claim.

The CPG, which consisted of 61 members as of September 30, 2014, continues to conduct the RI/FS and is expected to be completed by the first quarter of 2015 at an estimated cost of approximately $136 million. Of the estimated $136 million, as of August 31, 2014, the CPG Group had spent approximately $124 million, of which PSEG's total share had been approximately $9 million.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra and Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA, Tierra and Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G. This agreement and the work undertaken pursuant to the action agreement has no impact on the ultimate remedy that the EPA will select for the remediation of the 17 mile stretch of the lower Passaic River.

In 2012, Tierra and Maxus withdrew from the CPG and refused to participate as members going forward, other than in respect of their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSEG's share of the cost of that effort is approximately three percent. The remaining CPG members have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17 mile stretch of the Passaic River that had originally been designated as a Super Fund site. The FFS sets forth various alternatives for remediating this portion of the Passaic River. The EPA's estimated costs to remediate the lower eight miles of the Passaic River range from $365 million for a targeted remedy to $3.25 billion for a deep dredge of this portion of the Passaic River. The EPA also identified in the FFS its preferred alternative, which would involve dredging the river bank to bank and installing an engineered cap. The estimated cost in the FFS for its preferred alternative is $1.7 billion. No provisional cost allocation has been made by the CPG for the work contemplated by the draft FFS, and the work contemplated by the FFS is not subject to the CPG's cost sharing allocation agreed to in connection with the removal work for River Mile 10.9 or in connection with the conduct of the RI/FS.

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The draft FFS was subject to a public comment period, and remains subject to the EPA's response to comments submitted, a design phase and at least an estimated five years for completion of the work. The public comment period on the draft FFS closed on August 21, 2014. Over 300 comments were submitted by a variety of entities potentially impacted by the FFS, including the CPG, individual companies, municipalities, public officials, citizens groups, Amtrak, NJ Transit and others. The EPA will consider the comments received prior to issuing a Record of Decision (ROD) of a selected remedy for the lower eight miles. The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact Power's and PSE&G's ultimate liability.

Based on the facts and circumstance known at this time, and calculated in reference to the EPA estimate set forth in the FFS for its preferred remedy, Power and PSE&G believe that their respective shares of the costs to clean up the Passaic River will be immaterial. However, until (i) the RI/FS is completed, (ii) a final remedy is determined by the EPA or through litigation, (iii) Power and PSE&G's respective share of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on our financial statements.

New Jersey Spill Compensation and Control Act (Spill Act)

In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of a certain PRP's discharge of hazardous substances into both the Passaic River and the balance of the Newark Bay Complex. In 2009, third party complaints were filed against some 320 third party defendants, including Power and PSE&G, claiming that each of the third party defendants is responsible for its proportionate share of the clean-up costs for the hazardous substances it allegedly discharged into the Passaic River and the Newark Bay Complex. Power and PSE&G are alleged to have owned, operated or contributed to a total of 11 sites or facilities that impacted these water bodies. The third party complaints sought statutory contribution and contribution under the Spill Act to recover past and future removal costs and damages. In December 2013, the Court approved a settlement of the entire third party action. Power and PSE&G's contributions to the settlement, either individually or in the aggregate, were immaterial.

Natural Resource Damage Claims

In 2003, the NJDEP directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the Spill Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSEG is unable to estimate its portion of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $452 million and $524 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $452 million as of September 30, 2014. Of this amount, $75 million was recorded in Other Current Liabilities and $377 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $452 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

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Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Hazardous Air Pollutants Regulation

In accordance with a ruling of the U.S. Court of Appeals of the District of Columbia (D.C. Court), the EPA published a Maximum Achievable Control Technology (MACT) regulation in February 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the D.C. Court in support of the EPA's implementation of MATS. In April 2014, the D.C. Court denied all petitions for review of the existing source NESHAP. Several parties, including 21 states, have filed petitions for review with the U.S. Supreme Court.

Power believes that it will not be necessary to install any material controls at its New Jersey facilities. Additional controls are being installed at Power's Bridgeport Harbor coal-fired unit at an immaterial cost. In December 2011, to comply with the MACT regulations, the co-owners group, including Power, agreed to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction systems at Power's jointly owned coal-fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be operational in the first quarter of 2015. Power's share of this investment is approximately $110 million.

Nitrogen Oxide (NO_X) Regulation

In 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on Power's generation fleet, as it imposes NO_x emissions limits that will require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) by May 30, 2015. Retirement notifications for the combustion turbines have been submitted to PJM Interconnection L.L.C. (PJM). PJM was notified that the Salem Unit 3 combustion turbine will no longer be available as a capacity resource and will be transitioned to an emergency generator for site use only. Based upon Power's recently-completed evaluations of its steam electric generation units, an immaterial investment will be required to consistently reduce NO_x emissions below required limits beginning on May 1, 2015.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System (NPDES) permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The New Jersey Department of Environmental Protection manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

One of the most significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued.

In October 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court in New Jersey seeking to compel the NJDEP to take action on Power's pending application for permit renewal at Salem

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either by denying the application or issuing a draft for public comments. At the NJDEP's request, the case was transferred to the Appellate Division in December 2013. Power is unable to predict the outcome of this proceeding.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. On August 15, 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. On September 5, 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Fourth Circuit Court of Appeals. Power is unable to determine the ultimate impact of these actions on the implementation of the rule.

State permitting decisions could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power's share would have been approximately $575 million. The filing has not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements for customers who do not purchase electric supply from third party suppliers through the annual New Jersey BGS auctions. Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with Power, as well as with other winning BGS suppliers, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has contracted for its anticipated BGS-Fixed Price eligible load, as follows:

	Auction Year				
	2011	2012	2013	2014	
36-Month Terms Ending	May 2014	May 2015	May 2016	May 2017	(A)
Load (MW)	2,800	2,900	2,800	2,800	
$ per kWh	0.09430	0.08388	0.09218	0.09739	

(A) Prices set for the 2014 BGS auction year became effective on June 1, 2014 when the 2011 BGS auction agreements expired.

PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 17. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium,

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enrichment and fabrication requirements through 2017 and a significant portion through 2018 at Salem, Hope Creek and Peach Bottom.

Power has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations and for firm transportation and storage capacity for natural gas.

Power's various multi-year contracts for firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

As of September 30, 2014, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2018
	Millions
Nuclear Fuel	
Uranium	$ 450
Enrichment	$ 369
Fabrication	$ 174
Natural Gas	$ 877
Coal	$ 367

Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. PSEG notified the FERC, PJM and the PJM Independent Market Monitor (IMM) of this issue. During the three months ended March 31, 2014, Power recorded a charge to income in the amount of $25 million related to these findings for these past errors based upon its best estimate available at the time. PSEG cannot provide any assurances that the total liability associated with this matter will not increase or decrease over the amount recorded.

Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed the FERC, PJM and the IMM of these additional issues, and has corrected these errors. Power is also in the process of implementing procedures to help mitigate the risk of similar issues occurring in the future.

On September 2, 2014, the FERC Staff verbally informed PSEG that they have initiated a preliminary, non-public staff investigation into the matter. This investigation could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with this matter, or the applicability of mitigating factors. It is possible that Power will incur additional losses, and that such losses may be material, but PSEG cannot at the current time estimate the amount or range of any additional losses.

New Jersey Clean Energy Program

In June 2014, the BPU established the funding level for fiscal year 2015 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2015 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a current liability of $185 million as of September 30, 2014 for its outstanding share of the fiscal year 2015 and remaining fiscal year 2014 funding. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

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Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's T&D system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure.

Power had incurred $79 million and $85 million of storm-related expense in 2013 and 2012, respectively, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized in O&M Expense, offset by $25 million and $19 million of insurance recoveries in 2013 and 2012, respectively.

Power incurred an additional $4 million and $23 million for the three months and nine months ended September 30, 2014, primarily for repairs at certain generating stations in Power's fossil fleet.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. As previously reported, PSEG is seeking recovery from its insurers for the property damage resulting from Superstorm Sandy, above its self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. In June 2013, PSEG, Power and PSE&G filed suit in New Jersey state court against its insurance carriers seeking an interpretation that the insurance policies cover their losses resulting from damage caused by Superstorm Sandy's storm surge. In that lawsuit, PSEG stated that its estimate of the total costs related to damaged facilities was approximately $426 million. Of these costs, $364 million and $62 million related to Power and PSE&G, respectively. In August 2013, the insurance carriers filed an answer in which they denied most of the allegations made in the Complaint. In April 2014, PSEG notified the insurance carriers of a revised estimate of $579 million for total costs related to damaged facilities, of which $484 million and $95 million related to Power and PSE&G, respectively. Discovery in the case has been completed. On October 7, 2014, both parties filed cross-motions for summary judgment. We cannot predict the outcome of this proceeding.

Note 9. Changes in Capitalization

The following capital transactions occurred in the nine months ended September 30, 2014:

Power

- paid cash dividends of $775 million to PSEG.

PSE&G

- issued $250 million of 1.80% Secured Medium-Term Notes, Series I due June 2019,
- issued $250 million of 4.00% Secured Medium-Term Notes, Series I due June 2044,
- issued $250 million of 2.00% Secured Medium-Term Notes, Series J due August 2019,
- issued $250 million of 3.15% Secured Medium-Term Notes, Series J due August 2024,
- paid $250 million of 0.85% Secured Medium-Term Notes at maturity,
- paid $250 million of 5.00% Secured Medium-Term Notes at maturity,
- paid $164 million of Transition Funding's securitization debt,
- paid $6 million of Transition Funding II's securitization debt, and
- received a $175 million capital contribution from PSEG.

In October 2014, Power executed an extension of the letter of credit backing $44 million of Pennsylvania Economic Development Financing Authority Variable Rate Demand Bonds. The existing letter of credit, which was scheduled to expire on November 30, 2014, has now been extended through November 30, 2019.

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Note 10. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Commodity Prices

The availability and price of energy commodities are subject to fluctuations due to various factors, including but not limited to, weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions and transmission availability. Power uses physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. Derivative contracts that do not qualify for hedge accounting or normal purchases/normal sales treatment are marked to market with changes in fair value recorded in the Consolidated Statements of Operations. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps and futures contracts to hedge

- forecasted energy sales from its generation stations and the related load obligations,
- the price of fuel to meet its fuel purchase requirements, and
- certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

These derivative transactions are designated and effective as cash flow hedges. During the second quarter of 2012, Power de-designated certain of its commodity derivative transactions that had previously qualified as cash flow hedges as they were deemed to no longer be highly effective as required by the relevant accounting guidance. As a result, since June 1, 2012, Power recognizes all gains and losses from changes in the fair value of these derivatives immediately in earnings rather than deferring any such amounts in Accumulated Other Comprehensive Income (Loss). The fair values of Power's de-designated hedges were frozen in Accumulated Other Comprehensive Income (Loss) as the original forecasted transactions are still expected to occur and are reclassified into earnings as the original derivative transactions settle.

As of September 30, 2014 and December 31, 2013, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity were as follows:

	As of September 30, 2014	As of December 31, 2013
	Millions	
Fair Value of Cash Flow Hedges	$ 3	$ (4)
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 2	$ (1)

The expiration date of the longest-dated cash flow hedge at Power is in June 2015. Power's remaining $2 million of after-tax unrealized gains on these derivatives is expected to be reclassified to earnings during the next 12 months. There was no ineffectiveness associated with qualifying hedges as of September 30, 2014.

Other Derivatives

Power enters into additional contracts that are derivatives, but do not qualify for or are not designated as cash flow hedges. These transactions are intended to mitigate exposure to fluctuations in commodity prices and optimize the value of its expected generation. Trade types include financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. Changes in fair market value of these contracts are recorded in earnings. PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization. These natural gas contracts qualify as derivatives and are marked to fair market value with the offset recorded to Regulatory Assets and Liabilities.

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Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of September 30, 2014, PSEG had interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of September 30, 2014 and December 31, 2013, the fair value of all the underlying hedges was $26 million and $38 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was less than $(1) million and $(1) million as of September 30, 2014 and December 31, 2013, respectively.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that, in the event of an early termination, the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset in the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of September 30, 2014						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 4	$ 517	$ (471)	$ 50	$ 5	$ 16	$ 71
Noncurrent Assets	—	166	(155)	11	8	10	29
Total Mark-to-Market Derivative Assets	**$ 4**	**$ 683**	**$ (626)**	**$ 61**	**$ 13**	**$ 26**	**$ 100**
Derivative Contracts							
Current Liabilities	$ (1)	$ (702)	$ 594	$ (109)	$ —	$ —	$ (109)
Noncurrent Liabilities	—	(175)	138	(37)	—	—	(37)
Total Mark-to-Market Derivative (Liabilities)	**$ (1)**	**$ (877)**	**$ 732**	**$ (146)**	**$ —**	**$ —**	**$ (146)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 3**	**$ (194)**	**$ 106**	**$ (85)**	**$ 13**	**$ 26**	**$ (46)**

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	As of December 31, 2013						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Non Hedges			Non Hedges	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ —	$ 323	$ (266)	$ 57	$ 25	$ 16	$ 98
Noncurrent Assets	—	155	(83)	72	69	22	163
Total Mark-to-Market Derivative Assets	**$ —**	**$ 478**	**$ (349)**	**$ 129**	**$ 94**	**$ 38**	**$ 261**
Derivative Contracts							
Current Liabilities	$ (4)	$ (343)	$ 271	$ (76)	$ —	$ —	$ (76)
Noncurrent Liabilities	—	(111)	80	(31)	—	—	(31)
Total Mark-to-Market Derivative (Liabilities)	**$ (4)**	**$ (454)**	**$ 351**	**$ (107)**	**$ —**	**$ —**	**$ (107)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ (4)**	**$ 24**	**$ 2**	**$ 22**	**$ 94**	**$ 38**	**$ 154**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of September 30, 2014 and December 31, 2013. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of September 30, 2014 and December 31, 2013, net cash collateral (received) paid of $106 million and $2 million, respectively, were netted against the corresponding net derivative contract positions. Of the $106 million as of September 30, 2014, $(12) million and $(21) million of cash collateral was netted against current assets and noncurrent assets, respectively, and $135 million and $4 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $2 million as of December 31, 2013, cash collateral of $(3) million and $5 million were netted against noncurrent assets and current liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded or lose its investment grade credit rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on NYMEX and ICE that are fully collateralized) was $140 million and $91 million as of September 30, 2014 and December 31, 2013, respectively. As of September 30, 2014 and December 31, 2013, Power had the contractual right of offset of $31 million and $39 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded or lost its investment grade rating, it would have had additional collateral obligations of $109 million and $52 million as of September 30, 2014 and December 31, 2013, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $851 million and $691 million as of September 30, 2014 and December 31, 2013, respectively, discussed in Note 8. Commitments and Contingent Liabilities.

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The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended September 30, 2014 and 2013.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended September 30, 2014	2013	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended September 30, 2014	2013	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Three Months Ended September 30, 2014	2013
				Millions				
PSEG								
Energy-Related Contracts	$ 3	$ 1	Operating Revenues	$ 1	$ 3	Operating Revenues	$ —	$ (1)
Total PSEG	**$ 3**	**$ 1**		**$ 1**	**$ 3**		**$ —**	**$ (1)**
Power								
Energy-Related Contracts	$ 3	$ 1	Operating Revenues	$ 1	$ 3	Operating Revenues	$ —	$ (1)
Total Power	**$ 3**	**$ 1**		**$ 1**	**$ 3**		**$ —**	**$ (1)**

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the nine months ended September 30, 2014 and 2013.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Nine Months Ended September 30, 2014	2013	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Nine Months Ended September 30, 2014	2013	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Nine Months Ended September 30, 2014	2013
				Millions				
PSEG								
Energy-Related Contracts	$ (4)	$ 1	Operating Revenues	$ (11)	$ 11	Operating Revenues	$ —	$ (1)
Interest Rate Swaps	—	—	Interest Expense	—	(1)		—	—
Total PSEG	**$ (4)**	**$ 1**		**$ (11)**	**$ 10**		**$ —**	**$ (1)**
Power								
Energy-Related Contracts	$ (4)	$ 1	Operating Revenues	$ (11)	$ 11	Operating Revenues	$ —	$ (1)
Total Power	**$ (4)**	**$ 1**		**$ (11)**	**$ 11**		**$ —**	**$ (1)**

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The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2013	**$ (4)**	**$ (2)**
Net Loss Recognized in AOCI	(7)	(4)
Loss Reclassified into Income	12	7
Balance as of June 30, 2014	**$ 1**	**$ 1**
Gain Recognized in AOCI	3	2
Gain Reclassified into Income	(1)	(1)
Balance as of September 30, 2014	**$ 3**	**$ 2**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the three months and nine months ended September 30, 2014 and 2013.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2014	2013	2014	2013
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ 93	$ 14	$ (759)	$ (32)
Energy-Related Contracts	Energy Costs	(12)	10	65	63
Total PSEG and Power		**$ 81**	**$ 24**	**$ (694)**	**$ 31**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $5 million and $4 million for the three months and $15 million and $14 million for the nine months ended September 30, 2014 and 2013, respectively.

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The following reflects the gross volume, on an absolute value basis, of derivatives as of September 30, 2014 and December 31, 2013.

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of September 30, 2014					
Natural Gas	Dth	341	—	277	64
Electricity	MWh	329	—	329	—
Financial Transmission Rights (FTRs)	MWh	21	—	21	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2013					
Natural Gas	Dth	614	—	466	148
Electricity	MWh	243	—	243	—
FTRs	MWh	16	—	16	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of September 30, 2014, 99% of the credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of September 30, 2014. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 89	$ 27	$ 77	2	$ 52	(A)
Non-Investment Grade—External Rating	1	—	1	—	—	
Investment Grade—No External Rating	1	—	1	—	—	
Non-Investment Grade—No External Rating	—	—	—	—	—	
Total	**$ 91**	**$ 27**	**$ 79**	**2**	**$ 52**	

(A) Includes net exposure of $21 million with PSE&G. The remaining net exposure of $31 million is with a nonaffiliated power purchaser which is a regulated investment grade counterparty.

The net exposure listed in the preceding table, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would

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be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of September 30, 2014, Power had 136 active counterparties.

Note 11. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of September 30, 2014, these consisted primarily of certain electric load contracts and long-term gas supply contracts.

The following tables present information about PSEG's, Power's and PSE&G's respective assets and (liabilities) measured at fair value on a recurring basis as of September 30, 2014 and December 31, 2013, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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Description	Recurring Fair Value Measurements as of September 30, 2014			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 667	$ —	$ 667	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 74	$ (626)	$ —	$ 687	$ 13
Interest Rate Swaps (C)	$ 26	$ —	$ —	$ 26	$ —
NDT Fund (D)					
Equity Securities	$ 883	$ —	$ 876	$ 7	$ —
Debt Securities—Govt Obligations	$ 472	$ —	$ —	$ 472	$ —
Debt Securities—Other	$ 354	$ —	$ —	$ 354	$ —
Other Securities	$ 30	$ —	$ 30	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—Govt Obligations	$ 89	$ —	$ —	$ 89	$ —
Debt Securities—Other	$ 76	$ —	$ —	$ 76	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (146)	$ 732	$ —	$ (857)	$ (21)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 61	$ (626)	$ —	$ 687	$ —
NDT Fund (D)					
Equity Securities	$ 883	$ —	$ 876	$ 7	$ —
Debt Securities—Govt Obligations	$ 472	$ —	$ —	$ 472	$ —
Debt Securities—Other	$ 354	$ —	$ —	$ 354	$ —
Other Securities	$ 30	$ —	$ 30	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (146)	$ 732	$ —	$ (857)	$ (21)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 293	$ —	$ 293	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 13	$ —	$ —	$ —	$ 13
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 19	$ —	$ —	$ 19	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —

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Description	Recurring Fair Value Measurements as of December 31, 2013			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 439	$ —	$ 439	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 223	$ (349)	$ —	$ 474	$ 98
Interest Rate Swaps (C)	$ 38	$ —	$ —	$ 38	$ —
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 892	$ 5	$ —
Debt Securities—Govt Obligations	$ 429	$ —	$ —	$ 429	$ —
Debt Securities—Other	$ 291	$ —	$ —	$ 291	$ —
Other Securities	$ 84	$ —	$ 57	$ 27	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—Govt Obligations	$ 107	$ —	$ —	$ 107	$ —
Debt Securities—Other	$ 46	$ —	$ —	$ 46	$ —
Other Securities	$ 3	$ —	$ —	$ 3	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (107)	$ 351	$ —	$ (448)	$ (10)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 129	$ (349)	$ —	$ 474	$ 4
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 892	$ 5	$ —
Debt Securities—Govt Obligations	$ 429	$ —	$ —	$ 429	$ —
Debt Securities—Other	$ 291	$ —	$ —	$ 291	$ —
Other Securities	$ 84	$ —	$ 57	$ 27	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 23	$ —	$ —	$ 23	$ —
Debt Securities—Other	$ 10	$ —	$ —	$ 10	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (107)	$ 351	$ —	$ (448)	$ (10)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (B)	$ 94	$ —	$ —	$ —	$ 94
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 25	$ —	$ —	$ 25	$ —
Debt Securities—Other	$ 11	$ —	$ —	$ 11	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —

(A) Represents money market mutual funds.

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(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis

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adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The fair value measurement table excludes cash of less than $1 million which is part of the NDT Fund. The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds and United States Treasury obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of September 30, 2014, net cash collateral (received) paid of $106 million, was netted against the corresponding net derivative contract positions. Of the $106 million as of September 30, 2014, $(33) million of cash collateral was netted against assets, and $139 million was netted against liabilities. As of December 31, 2013, net cash collateral (received) paid of $2 million, was netted against the corresponding net derivative contract positions. Of the $2 million as of December 31, 2013, $(3) million of cash collateral was netted against assets, and $5 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group, and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and non-performance risk were not material to the financial statements.

For Power, in general, electric swaps are measured at fair value based on at least two pricing inputs, the underlying price of electricity at a liquid reference point and the basis difference between electricity prices at the liquid reference point and electricity prices at the respective delivery locations. To the extent the basis component is based on a single broker quote and is

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significant to the fair value of the electric swap, it is categorized as Level 3. The fair value of certain of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. For Power and PSE&G, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The following tables provide details surrounding significant Level 3 valuations as of September 30, 2014 and December 31, 2013.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of September 30, 2014 Assets	Fair Value as of September 30, 2014 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$ —	$ (21)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Other	Various (A)	—	—			
Total Power		**$ —**	**$ (21)**			
PSE&G						
Gas	Forward Contracts	$ 13	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 13**	**$ —**			
Total PSEG		**$ 13**	**$ (21)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2013 Assets	Fair Value as of December 31, 2013 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$ 3	$ (1)	Discounted Cash Flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	—	(8)	Discounted Cash Flow	Historic Load Variability	-5% to +10%
Other	Various (B)	1	(1)			
Total Power		**$ 4**	**$ (10)**			
PSE&G						
Gas	Forward Contracts	$ 94	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 94**	**$ —**			
Total PSEG		**$ 98**	**$ (10)**			

(A) Includes gas supply positions and long-term electric capacity positions which were immaterial as of September 30, 2014.

(B) Includes gas supply positions which were immaterial as of December 31, 2013.

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Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value.

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and nine months ended September 30, 2014 and September 30, 2013, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Nine Months Ended September 30, 2014

	Three Months Ended September 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of July 1, 2014	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2014
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 13	$ (8)	$ (9)	$ —	$ (4)	$ —	$ (8)
Power							
Net Derivative Assets (Liabilities)	$ (9)	$ (8)	$ —	$ —	$ (4)	$ —	$ (21)
PSE&G							
Net Derivative Assets (Liabilities)	$ 22	$ —	$ (9)	$ —	$ —	$ —	$ 13

	Nine Months Ended September 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2014	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2014
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 88	$ (66)	$ (81)	$ —	$ 54	$ (3)	$ (8)
Power							
Net Derivative Assets (Liabilities)	$ (6)	$ (66)	$ —	$ —	$ 54	$ (3)	$ (21)
PSE&G							
Net Derivative Assets (Liabilities)	$ 94	$ —	$ (81)	$ —	$ —	$ —	$ 13

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Nine Months Ended September 30, 2013

	Three Months Ended September 30, 2013						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of July 1, 2013	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2013
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (35)	$ 1	$ (11)	$ —	$ (1)	$ —	$ (46)
Power							
Net Derivative Assets (Liabilities)	$ 6	$ 1	$ —	$ —	$ (1)	$ —	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (41)	$ —	$ (11)	$ —	$ —	$ —	$ (52)

	Nine Months Ended September 30, 2013						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2013	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2013
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ (31)	$ (16)	$ (12)	$ —	$ 9	$ 4	$ (46)
Power							
Net Derivative Assets (Liabilities)	$ 9	$ (16)	$ —	$ —	$ 9	$ 4	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (40)	$ —	$ (12)	$ —	$ —	$ —	$ (52)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $(8) million and $(66) million in Operating Income for the three months and nine months ended September 30, 2014, respectively. Of the $(8) million in Operating Income $(12) million is unrealized. Of the $(66) million in Operating Income, $(11) million is unrealized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

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(C) Represents $(4) million and $54 million in settlements for the three months and nine months ended September 30, 2014. Represents $(1) million and $9 million in settlements for the three months and nine months ended September 30, 2013.

(D) There were no transfers among levels during the three months ended September 30, 2014 and 2013. During the nine months ended September 30, 2014, $(3) million, of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. During the nine months ended September 30, 2013, $4 million, of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. The transfers were recognized as of the beginning of the quarters in which the transfers first occurred, as per PSEG's policy.

(E) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $1 million and $(16) million in Operating Income for the three months and nine months ended September 30, 2013, respectively. The $1 million in Operating Income is unrealized. Of the $(16) million in Operating Income, $(7) million is unrealized.

As of September 30, 2014, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $8 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of September 30, 2013, PSEG carried $1.9 billion of net assets that are measured at fair value on a recurring basis, of which $46 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of September 30, 2014 and December 31, 2013.

	As of September 30, 2014		As of December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 15	$ 26	$ 24	$ 38
Power -Recourse Debt (B)	2,543	2,916	2,541	2,846
PSE&G (B)	6,063	6,497	5,566	5,629
Transition Funding (PSE&G) (B)	312	327	476	511
Transition Funding II (PSE&G) (B)	14	15	20	21
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	16	16	16	16
Total Long-Term Debt	**$ 8,963**	**$ 9,797**	**$ 8,643**	**$ 9,061**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 12. Other Income and Deductions

Other Income	Power	PSE&G	Other (A)	Consolidated
		Millions		
Three Months Ended September 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ 55	$ —	$ —	$ 55
Allowance for Funds Used During Construction	—	8	—	8
Solar Loan Interest	—	6	—	6
Other	1	2	3	6
Total Other Income	**$ 56**	**$ 16**	**$ 3**	**$ 75**
Three Months Ended September 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ 45	$ —	$ —	$ 45
Allowance for Funds Used During Construction	—	5	—	5
Solar Loan Interest	—	7	—	7
Other	—	1	1	2
Total Other Income	**$ 45**	**$ 13**	**$ 1**	**$ 59**
Nine Months Ended September 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ 133	$ —	$ —	$ 133
Allowance for Funds Used During Construction	—	21	—	21
Solar Loan Interest	—	18	—	18
Other	2	5	6	13
Total Other Income	**$ 135**	**$ 44**	**$ 6**	**$ 185**
Nine Months Ended September 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$ 125	$ —	$ —	$ 125
Allowance for Funds Used During Construction	—	17	—	17
Solar Loan Interest	—	18	—	18
Other	2	6	4	12
Total Other Income	**$ 127**	**$ 41**	**$ 4**	**$ 172**

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Other Deductions	Power	PSE&G	Other (A)	Consolidated
			Millions	
Three Months Ended September 30, 2014				
NDT Fund Realized Losses and Expenses	$ 4	$ —	$ —	$ 4
Other	2	2	1	5
Total Other Deductions	**$ 6**	**$ 2**	**$ 1**	**$ 9**
Three Months Ended September 30, 2013				
NDT Fund Realized Losses and Expenses	$ 11	$ —	$ —	$ 11
Other	—	1	—	1
Total Other Deductions	**$ 11**	**$ 1**	**$ —**	**$ 12**
Nine Months Ended September 30, 2014				
NDT Fund Realized Losses and Expenses	$ 18	$ —	$ —	$ 18
Other	7	3	3	13
Total Other Deductions	**$ 25**	**$ 3**	**$ 3**	**$ 31**
Nine Months Ended September 30, 2013				
NDT Fund Realized Losses and Expenses	$ 40	$ —	$ —	$ 40
Other	9	3	2	14
Total Other Deductions	**$ 49**	**$ 3**	**$ 2**	**$ 54**

(A) Other primarily consists of activity at PSEG (as parent company), Energy Holdings, Services and intercompany eliminations.

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Note 13. Income Taxes

PSEG's, Power's and PSE&G's effective tax rates for the three months and nine months ended September 30, 2014 and 2013 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
PSEG	37.0%	41.0%	37.8%	40.5%
Power	39.4%	40.5%	38.6%	40.0%
PSE&G	38.5%	40.6%	38.6%	40.0%

For the three months ended September 30, 2014, as compared to the same period in the prior year, the decrease in PSEG's and PSE&G's effective tax rates was due primarily to the audit settlement and depreciation flow-through, respectively.

For the nine months ended September 30, 2014, as compared to the same period in the prior year, the decrease in PSEG's effective tax rates was due primarily to the audit settlement.

On August 11, 2014, PSEG received notice from the Internal Revenue Service (IRS) that the audit settlement covering tax years 2007 through 2010 had been approved by the Joint Committee on Taxation. This effectively settles all issues with the IRS through 2010. On September 9, 2014, PSEG received refunds from the IRS totaling $121 million, representing the net settlement of all disputed amounts, including interest, through the tax year 2010. As a result of the settlement of this audit, PSEG recorded a $12 million reduction of tax expense in the quarter ended September 30, 2014.

PSEG's unrecognized tax benefits decreased by $156 million in the third quarter 2014 inclusive of interest, of which $62 million was attributable to the settlement of the IRS audit tax liability and the remaining $94 million was due to the reversal of positions taken in prior periods. As a result, the December 31, 2013 balance of unrecognized tax benefits that was reasonably possible to increase or decrease within the next twelve months decreased to an immaterial amount as of September 30, 2014.

There is no material increase or decrease in the interest and penalties associated with the unrecognized tax benefits. The impact on the accumulated deferred income taxes and regulatory tax benefits is not material. The change in the total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is not material.

In September 2013, the U.S. Department of the Treasury and the IRS released final regulations effective in 2014 that provide guidance on applying Section 263(a) of the Internal Revenue Code to amounts paid to acquire, produce, or improve tangible property, as well as rules for materials and supplies. Implementation of these regulations did not have any material impact on PSEG's and its subsidiaries' results of operations, financial condition or cash flows.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 was eligible for 50% bonus depreciation for tax purposes. The American Taxpayer Relief Act of 2012 further extended the 50% bonus depreciation for qualified property placed into service before January 1, 2014. In addition, long production property placed into service in 2014 is eligible for 50% bonus depreciation for tax purposes. These provisions have generated cash for PSEG through tax benefits related to the accelerated depreciation. These tax benefits otherwise would have been received over an estimated average 20 year period.

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Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of June 30, 2014	$ 1	$ (232)	$ 158	$ (73)
Other Comprehensive Income before Reclassifications	2	—	(15)	(13)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	3	(15)	(13)
Net Current Period Other Comprehensive Income (Loss)	1	3	(30)	(26)
Balance as of September 30, 2014	**$ 2**	**$ (229)**	**$ 128**	**$ (99)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2013			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of June 30, 2013	$ 3	$ (466)	$ 101	$ (362)
Other Comprehensive Income before Reclassifications	1	—	27	28
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(2)	9	(11)	(4)
Net Current Period Other Comprehensive Income (Loss)	(1)	9	16	24
Balance as of September 30, 2013	**$ 2**	**$ (457)**	**$ 117**	**$ (338)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2013	$ (2)	$ (238)	$ 145	$ (95)
Other Comprehensive Income before Reclassifications	(2)	—	19	17
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	6	9	(36)	(21)
Net Current Period Other Comprehensive Income (Loss)	4	9	(17)	(4)
Balance as of September 30, 2014	**$ 2**	**$ (229)**	**$ 128**	**$ (99)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2013			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2012	$ 7	$ (485)	$ 90	$ (388)
Other Comprehensive Income before Reclassifications	1	—	53	54
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(6)	28	(26)	(4)
Net Current Period Other Comprehensive Income (Loss)	(5)	28	27	50
Balance as of September 30, 2013	**$ 2**	**$ (457)**	**$ 117**	**$ (338)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2014	$ 2	$ (199)	$ 153	$ (44)
Other Comprehensive Income before Reclassifications	2	—	(14)	(12)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	2	(16)	(15)
Net Current Period Other Comprehensive Income (Loss)	1	2	(30)	(27)
Balance as of September 30, 2014	**$ 3**	**$ (197)**	**$ 123**	**$ (71)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2013			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2013	$ 4	$ (405)	$ 98	$ (303)
Other Comprehensive Income before Reclassifications	1	—	28	29
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(2)	8	(11)	(5)
Net Current Period Other Comprehensive Income (Loss)	(1)	8	17	24
Balance as of September 30, 2013	**$ 3**	**$ (397)**	**$ 115**	**$ (279)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2013	$ (1)	$ (204)	$ 142	$ (63)
Other Comprehensive Income before Reclassifications	(2)	—	17	15
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	6	7	(36)	(23)
Net Current Period Other Comprehensive Income (Loss)	4	7	(19)	(8)
Balance as of September 30, 2014	**$ 3**	**$ (197)**	**$ 123**	**$ (71)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2013			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2012	$ 9	$ (422)	$ 85	$ (328)
Other Comprehensive Income before Reclassifications	1	—	56	57
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(7)	25	(26)	(8)
Net Current Period Other Comprehensive Income (Loss)	(6)	25	30	49
Balance as of September 30, 2013	**$ 3**	**$ (397)**	**$ 115**	**$ (279)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2014			Nine Months Ended September 30, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ 1	$ —	$ 1	$ (11)	$ 5	$ (6)
Interest Rate Swaps	Interest Expense	—	—	—	—	—	—
Total Cash Flow Hedges		1	—	1	(11)	5	(6)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	8	(3)	5
Amortization of Actuarial Loss	O&M Expense	(8)	3	(5)	(22)	8	(14)
Total Pension and OPEB Plans		(5)	2	(3)	(14)	5	(9)
Available-for-Sale Securities							
Realized Gains	Other Income	47	(24)	23	105	(54)	51
Realized Losses	Other Deductions	(5)	2	(3)	(15)	7	(8)
Other-Than-Temporary Impairments (OTTI)	OTTI	(10)	5	(5)	(14)	7	(7)
Total Available-for-Sale Securities		32	(17)	15	76	(40)	36
Total		**$ 28**	**$ (15)**	**$ 13**	**$ 51**	**$ (30)**	**$ 21**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2013			Nine Months Ended September 30, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ 3	$ (1)	$ 2	$ 11	$ (4)	$ 7
Interest Rate Swaps	Interest Expense	—	—	—	(1)	—	(1)
Total Cash Flow Hedges		3	(1)	2	10	(4)	6
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	8	(3)	5
Amortization of Actuarial Loss	O&M Expense	(18)	7	(11)	(56)	23	(33)
Total Pension and OPEB Plans		(15)	6	(9)	(48)	20	(28)
Available-for-Sale Securities							
Realized Gains	Other Income	35	(18)	17	99	(51)	48
Realized Losses	Other Deductions	(9)	4	(5)	(37)	18	(19)
OTTI	OTTI	(3)	2	(1)	(7)	4	(3)
Total Available-for-Sale Securities		23	(12)	11	55	(29)	26
Total		**$ 11**	**$ (7)**	**$ 4**	**$ 17**	**$ (13)**	**$ 4**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2014			Nine Months Ended September 30, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ 1	$ —	$ 1	$ (11)	$ 5	$ (6)
Total Cash Flow Hedges		1	—	1	(11)	5	(6)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	7	(3)	4
Amortization of Actuarial Loss	O&M Expense	(6)	2	(4)	(18)	7	(11)
Total Pension and OPEB Plans		(3)	1	(2)	(11)	4	(7)
Available-for-Sale Securities							
Realized Gains	Other Income	45	(23)	22	101	(52)	49
Realized Losses	Other Deductions	(2)	1	(1)	(12)	6	(6)
OTTI	OTTI	(10)	5	(5)	(14)	7	(7)
Total Available-for-Sale Securities		33	(17)	16	75	(39)	36
Total		**$ 31**	**$ (16)**	**$ 15**	**$ 53**	**$ (30)**	**$ 23**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2013			Nine Months Ended September 30, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ 3	$ (1)	$ 2	$ 11	$ (4)	$ 7
Total Cash Flow Hedges		3	(1)	2	11	(4)	7
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	7	(3)	4
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)	(49)	20	(29)
Total Pension and OPEB Plans		(14)	6	(8)	(42)	17	(25)
Available-for-Sale Securities							
Realized Gains	Other Income	35	(18)	17	95	(49)	46
Realized Losses	Other Deductions	(9)	4	(5)	(34)	17	(17)
OTTI	OTTI	(3)	2	(1)	(7)	4	(3)
Total Available-for-Sale Securities		23	(12)	11	54	(28)	26
Total		**$ 12**	**$ (7)**	**$ 5**	**$ 23**	**$ (15)**	**$ 8**

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Note 15. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under our stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2014		2013		2014		2013	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)								
Net Income	**$ 444**	**$ 444**	**$ 390**	**$ 390**	**$ 1,042**	**$ 1,042**	**$ 1,043**	**$ 1,043**
EPS Denominator (Thousands)								
Weighted Average Common Shares Outstanding	505,862	505,862	505,858	505,858	505,937	505,937	505,900	505,900
Effect of Stock Based Compensation Awards	—	1,560	—	1,836	—	1,465	—	1,533
Total Shares	**505,862**	**507,422**	**505,858**	**507,694**	**505,937**	**507,402**	**505,900**	**507,433**
EPS								
Net Income	**$ 0.88**	**$ 0.87**	**$ 0.77**	**$ 0.77**	**$ 2.06**	**$ 2.05**	**$ 2.06**	**$ 2.06**

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dividend Payments on Common Stock	2014	2013	2014	2013
Per Share	$ 0.37	$ 0.36	$ 1.11	$ 1.08
In Millions	$ 187	$ 182	$ 561	$ 546

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Note 16. Financial Information by Business Segments

	Power	PSE&G	Other (A)	Eliminations (B)	Consolidated
			Millions		
Three Months Ended September 30, 2014					
Total Operating Revenues	$ 1,138	$ 1,655	$ 123	$ (275)	$ 2,641
Net Income (Loss)	222	200	22	—	444
Gross Additions to Long-Lived Assets	188	497	8	—	693
Nine Months Ended September 30, 2014					
Total Operating Revenues	$ 3,824	$ 5,235	$ 359	$ (1,305)	$ 8,113
Net Income (Loss)	440	565	37	—	1,042
Gross Additions to Long-Lived Assets	414	1,493	15	—	1,922
Three Months Ended September 30, 2013					
Total Operating Revenues	$ 1,174	$ 1,666	$ 3	$ (289)	$ 2,554
Net Income (Loss)	226	168	(4)	—	390
Gross Additions to Long-Lived Assets	210	480	6	—	696
Nine Months Ended September 30, 2013					
Total Operating Revenues	$ 3,818	$ 5,084	$ 29	$ (1,281)	$ 7,650
Net Income (Loss)	577	468	(2)	—	1,043
Gross Additions to Long-Lived Assets	458	1,628	16	—	2,102
As of September 30, 2014					
Total Assets	$ 11,750	$ 20,917	$ 1,907	$ (427)	$ 34,147
Investments in Equity Method Subsidiaries	$ 122	$ —	$ 3	$ —	$ 125
As of December 31, 2013					
Total Assets	$ 12,002	$ 19,720	$ 4,025	$ (3,225)	$ 32,522
Investments in Equity Method Subsidiaries	$ 123	$ —	$ 3	$ —	$ 126

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations, primarily related to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 17. Related-Party Transactions.

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Note 17. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

Power

The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	Millions			
Revenue from Affiliates:				
Billings to PSE&G through BGS and BGSS Contracts (A)	**$ 280**	**$ 284**	**$ 1,308**	**$ 1,275**
Expense Billings from Affiliates:				
Administrative Billings from Services (B)	**$ (41)**	**$ (43)**	**$ (129)**	**$ (131)**

Related-Party Transactions	As of September 30, 2014	As of December 31, 2013
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$ 132	$ 267
Receivable from (Payable to) Services (B)	(25)	(31)
Receivable from (Payable to) PSEG (C)	(55)	97
Accounts Receivable (Payable)—Affiliated Companies, net	**$ 52**	**$ 333**
Short-Term Loan to Affiliate (Demand Note to PSEG) (D)	**$ 623**	**$ 790**
Working Capital Advances to Services (E)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable (Payable)	**$ (57)**	**$ (53)**

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	Millions			
Expense Billings from Affiliates:				
Billings from Power through BGS and BGSS (A)	$ (280)	$ (284)	$ (1,308)	$ (1,275)
Administrative Billings from Services (B)	(59)	(61)	(183)	(184)
Total Expense Billings from Affiliates	**$ (339)**	**$ (345)**	**$ (1,491)**	**$ (1,459)**

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Related-Party Transactions	As of September 30, 2014	As of December 31, 2013
	Millions	
Payable to Power through BGS and BGSS Contracts (A)	$ (132)	$ (267)
Receivable from (Payable to) Services (B)	(48)	(73)
Receivable from (Payable to) PSEG (C)	81	150
Accounts Receivable (Payable)—Affiliated Companies, net	**$ (99)**	**$ (190)**
Working Capital Advances to Services (E)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Receivable (Payable)	**$ (78)**	**$ (72)**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to Power and PSE&G at cost. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

(E) Power and PSE&G have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on Power's and PSE&G's Condensed Consolidated Balance Sheets.

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Note 18. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended September 30, 2014					
Operating Revenues	$ —	$ 1,125	$ 36	$ (23)	$ 1,138
Operating Expenses	3	772	32	(22)	785
Operating Income (Loss)	(3)	353	4	(1)	353
Equity Earnings (Losses) of Subsidiaries	225	(1)	4	(224)	4
Other Income	9	55	—	(8)	56
Other Deductions	(3)	(4)	—	1	(6)
Other-Than-Temporary Impairments	—	(10)	—	—	(10)
Interest Expense	(24)	(10)	(4)	7	(31)
Income Tax Benefit (Expense)	18	(161)	(1)	—	(144)
Net Income (Loss)	**$ 222**	**$ 222**	**$ 3**	**$ (225)**	**$ 222**
Comprehensive Income (Loss)	**$ 195**	**$ 191**	**$ 3**	**$ (194)**	**$ 195**
Nine Months Ended September 30, 2014					
Operating Revenues	$ —	$ 3,781	$ 118	$ (75)	$ 3,824
Operating Expenses	12	3,079	106	(75)	3,122
Operating Income (Loss)	(12)	702	12	—	702
Equity Earnings (Losses) of Subsidiaries	459	(4)	11	(455)	11
Other Income	25	135	—	(25)	135
Other Deductions	(7)	(18)	—	—	(25)
Other-Than-Temporary Impairments	—	(14)	—	—	(14)
Interest Expense	(79)	(23)	(14)	24	(92)
Income Tax Benefit (Expense)	54	(329)	(2)	—	(277)
Net Income (Loss)	**$ 440**	**$ 449**	**$ 7**	**$ (456)**	**$ 440**
Comprehensive Income (Loss)	**$ 432**	**$ 433**	**$ 7**	**$ (440)**	**$ 432**
Nine Months Ended September 30, 2014					
Net Cash Provided By (Used In) Operating Activities	$ 471	$ 1,252	$ 53	$ (666)	$ 1,110
Net Cash Provided By (Used In) Investing Activities	$ 187	$ (559)	$ (24)	$ 70	$ (326)
Net Cash Provided By (Used In) Financing Activities	$ (652)	$ (693)	$ (29)	$ 596	$ (778)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended September 30, 2013					
Operating Revenues	$ —	$ 1,163	$ 71	$ (60)	$ 1,174
Operating Expenses	2	797	66	(61)	804
Operating Income (Loss)	(2)	366	5	1	370
Equity Earnings (Losses) of Subsidiaries	231	(1)	4	(230)	4
Other Income	8	47	—	(10)	45
Other Deductions	1	(11)	—	(1)	(11)
Other-Than-Temporary Impairments	—	(3)	—	—	(3)
Interest Expense	(19)	(13)	(4)	10	(26)
Income Tax Benefit (Expense)	7	(160)	—	—	(153)
Net Income (Loss)	**$ 226**	**$ 225**	**$ 5**	**$ (230)**	**$ 226**
Comprehensive Income (Loss)	**$ 250**	**$ 242**	**$ 5**	**$ (247)**	**$ 250**
Nine Months Ended September 30, 2013					
Operating Revenues	$ —	$ 3,787	$ 145	$ (114)	$ 3,818
Operating Expenses	6	2,832	131	(114)	2,855
Operating Income (Loss)	(6)	955	14	—	963
Equity Earnings (Losses) of Subsidiaries	603	(3)	12	(600)	12
Other Income	27	130	—	(30)	127
Other Deductions	(9)	(40)	—	—	(49)
Other-Than-Temporary Impairments	—	(7)	—	—	(7)
Interest Expense	(72)	(29)	(14)	30	(85)
Income Tax Benefit (Expense)	34	(419)	1	—	(384)
Net Income (Loss)	**$ 577**	**$ 587**	**$ 13**	**$ (600)**	**$ 577**
Comprehensive Income (Loss)	**$ 626**	**$ 612**	**$ 13**	**$ (625)**	**$ 626**
Nine Months Ended September 30, 2013					
Net Cash Provided By (Used In) Operating Activities	$ 425	$ 1,360	$ 35	$ (506)	$ 1,314
Net Cash Provided By (Used In) Investing Activities	$ 40	$ (869)	$ (40)	$ 540	$ (329)
Net Cash Provided By (Used In) Financing Activities	$ (461)	$ (492)	$ 5	$ (35)	$ (983)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
As of September 30, 2014					
Current Assets	$ 4,163	$ 1,891	$ 111	$ (4,035)	$ 2,130
Property, Plant and Equipment, net	81	6,140	1,163	—	7,384
Investment in Subsidiaries	4,358	120	—	(4,478)	—
Noncurrent Assets	293	1,901	139	(97)	2,236
Total Assets	**$ 8,895**	**$ 10,052**	**$ 1,413**	**$ (8,610)**	**$ 11,750**
Current Liabilities	$ 518	$ 3,510	$ 754	$ (4,035)	$ 747
Noncurrent Liabilities	319	2,379	344	(97)	2,945
Long-Term Debt	2,543	—	—	—	2,543
Member's Equity	5,515	4,163	315	(4,478)	5,515
Total Liabilities and Member's Equity	**$ 8,895**	**$ 10,052**	**$ 1,413**	**$ (8,610)**	**$ 11,750**
As of December 31, 2013					
Current Assets	$ 4,413	$ 2,076	$ 102	$ (4,115)	$ 2,476
Property, Plant and Equipment, net	81	6,108	1,178	—	7,367
Investment in Subsidiaries	4,645	124	—	(4,769)	—
Noncurrent Assets	222	1,847	138	(48)	2,159
Total Assets	**$ 9,361**	**$ 10,155**	**$ 1,418**	**$ (8,932)**	**$ 12,002**
Current Liabilities	$ 697	$ 3,474	$ 745	$ (4,116)	$ 800
Noncurrent Liabilities	309	2,247	338	(47)	2,847
Long-Term Debt	2,497	—	—	—	2,497
Member's Equity	5,858	4,434	335	(4,769)	5,858
Total Liabilities and Member's Equity	**$ 9,361**	**$ 10,155**	**$ 1,418**	**$ (8,932)**	**$ 12,002**

Immaterial Correction of Prior Financial Information

The financial information included in the tables above has been corrected from the disclosure provided in Power's Form 10-Q filed on October 30, 2013 and Form 10-K filed on February 26, 2014 (2013 10-K) to conform to the requirements of Section 210.3-10 of SEC Regulation S-X.

In the prior disclosure, Operating Revenues and Operating Expenses among the Guarantor Subsidiaries were eliminated in the Consolidating Adjustments column. The revised presentation eliminates this activity in the Guarantor Subsidiaries column and removes such activity from the Consolidating Adjustments column. This revised presentation decreased both Operating Revenues and Operating Expenses in both the Guarantor Subsidiaries and Consolidating Adjustments columns. This correction had no impact on Power's consolidated Operating Revenues and Operating Expenses.

In the prior disclosure, loans payable by Power parent company to one of its guarantor subsidiaries were netted against loans receivable in net cash flows used in investing activities. The revised presentation reclassifies the increase in loans payable by the parent company to the guarantor subsidiary from net cash flows used in investing activities to net cash flows provided by financing activities. This revised presentation decreased net cash flows used in investing activities and increased net cash flows provided by financing activities in the Power column with corresponding offsets to the amounts in the Consolidating Adjustments Column.

In addition, the revised information was corrected to present the intercompany balances on a net basis when the right of offset exists in either Current Assets or Current Liabilities. This revised presentation resulted in increases (decreases) to certain categories of the condensed consolidated balance sheet.

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The following three tables include corrected data for these aforementioned adjustments to the information previously filed in Power's Form 10-Q dated May 1, 2014 or 2013 10-K.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended March 31, 2014					
Operating Revenues	$ —	$ 1,684	$ 40	$ (24)	$ 1,700
Operating Expenses	4	1,404	34	(24)	1,418
Operating Income (Loss)	(4)	280	6	—	282
Equity Earnings (Losses) of Subsidiaries	177	—	4	(177)	4
Other Income	8	33	—	(8)	33
Other Deductions	(4)	(6)	—	—	(10)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(28)	(7)	(5)	8	(32)
Income Tax Benefit (Expense)	15	(125)	(1)	—	(111)
Net Income (Loss)	**$ 164**	**$ 173**	**$ 4**	**$ (177)**	**$ 164**
Comprehensive Income (Loss)	**$ 170**	**$ 176**	**$ 4**	**$ (180)**	**$ 170**
Three Months Ended March 31, 2014					
Net Cash Provided By (Used In) Operating Activities	$ 291	$ 603	$ 1	$ (221)	$ 674
Net Cash Provided By (Used In) Investing Activities	$ (122)	$ (315)	$ —	$ 142	$ (295)
Net Cash Provided By (Used In) Financing Activities	$ (166)	$ (287)	$ (1)	$ 79	$ (375)
Three Months Ended March 31, 2013					
Operating Revenues	$ —	$ 1,441	$ 37	$ (27)	$ 1,451
Operating Expenses	2	1,200	33	(26)	1,209
Operating Income (Loss)	(2)	241	4	(1)	242
Equity Earnings (Losses) of Subsidiaries	153	—	3	(153)	3
Other Income	9	48	—	(10)	47
Other Deductions	(8)	(20)	—	—	(28)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(27)	(10)	(4)	11	(30)
Income Tax Benefit (Expense)	16	(108)	1	—	(91)
Net Income (Loss)	**$ 141**	**$ 149**	**$ 4**	**$ (153)**	**$ 141**
Comprehensive Income (Loss)	**$ 173**	**$ 172**	**$ 4**	**$ (176)**	**$ 173**
Three Months Ended March 31, 2013					
Net Cash Provided By (Used In) Operating Activities	$ 189	$ 574	$ 1	$ (189)	$ 575
Net Cash Provided By (Used In) Investing Activities	$ (213)	$ (353)	$ (8)	$ 245	$ (329)
Net Cash Provided By (Used In) Financing Activities	$ 24	$ (221)	$ 7	$ (57)	$ (247)
As of March 31, 2014					
Current Assets	$ 4,436	$ 2,097	$ 107	$ (4,341)	$ 2,299
Property, Plant and Equipment, net	81	6,082	1,172	—	7,335
Investment in Subsidiaries	4,570	122	—	(4,692)	—
Noncurrent Assets	301	1,832	138	(117)	2,154
Total Assets	**$ 9,388**	**$ 10,133**	**$ 1,417**	**$ (9,150)**	**$ 11,788**
Current Liabilities	$ 930	$ 3,450	$ 741	$ (4,340)	$ 781
Noncurrent Liabilities	308	2,323	344	(118)	2,857
Long-Term Debt	2,497	—	—	—	2,497
Member's Equity	5,653	4,360	332	(4,692)	5,653

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Total Liabilities and Member's Equity	**$ 9,388**	**$ 10,133**	**$ 1,417**	**$ (9,150)**	**$ 11,788**

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2013					
Operating Revenues	$ —	$ 5,022	$ 190	$ (149)	$ 5,063
Operating Expenses	23	3,945	174	(149)	3,993
Operating Income (Loss)	(23)	1,077	16	—	1,070
Equity Earnings (Losses) of Subsidiaries	684	(5)	16	(679)	16
Other Income	35	157	—	(38)	154
Other Deductions	(14)	(35)	—	—	(49)
Other-Than-Temporary Impairments	—	(12)	—	—	(12)
Interest Expense	(93)	(42)	(19)	38	(116)
Income Tax Benefit (Expense)	55	(474)	—	—	(419)
Net Income (Loss)	**$ 644**	**$ 666**	**$ 13**	**$ (679)**	**$ 644**
Comprehensive Income (Loss)	**$ 909**	**$ 713**	**$ 11**	**$ (724)**	**$ 909**
Year Ended December 31, 2013					
Net Cash Provided By (Used In) Operating Activities	$ 288	$ 1,503	$ 82	$ (526)	$ 1,347
Net Cash Provided By (Used In) Investing Activities	$ (395)	$ (1,092)	$ (71)	$ 697	$ (861)
Net Cash Provided By (Used In) Financing Activities	$ 107	$ (412)	$ (11)	$ (171)	$ (487)
Year Ended December 31, 2012					
Operating Revenues	$ —	$ 4,850	$ 135	$ (112)	$ 4,873
Operating Expenses	7	3,730	125	(112)	3,750
Operating Income (Loss)	(7)	1,120	10	—	1,123
Equity Earnings (Losses) of Subsidiaries	707	(10)	15	(697)	15
Other Income	45	206	2	(52)	201
Other Deductions	(31)	(59)	—	—	(90)
Other-Than-Temporary Impairments	—	(18)	—	—	(18)
Interest Expense	(118)	(51)	(16)	53	(132)
Income Tax Benefit (Expense)	70	(501)	(2)	—	(433)
Net Income (Loss)	**$ 666**	**$ 687**	**$ 9**	**$ (696)**	**$ 666**
Comprehensive Income (Loss)	**$ 614**	**$ 681**	**$ 9**	**$ (690)**	**$ 614**
Year Ended December 31, 2012					
Net Cash Provided By (Used In) Operating Activities	$ 298	$ 1,562	$ 67	$ (474)	$ 1,453
Net Cash Provided By (Used In) Investing Activities	$ (14)	$ (1,206)	$ (151)	$ 899	$ (472)
Net Cash Provided By (Used In) Financing Activities	$ (284)	$ (361)	$ 83	$ (424)	$ (986)
As of December 31, 2012					
Current Assets	$ 4,255	$ 1,898	$ 104	$ (4,021)	$ 2,236
Property, Plant and Equipment, net	80	5,988	1,154	—	7,222
Investment in Subsidiaries	4,508	128	—	(4,636)	—
Noncurrent Assets	201	1,660	145	(141)	1,865
Total Assets	**$ 9,044**	**$ 9,674**	**$ 1,403**	**$ (8,798)**	**$ 11,323**
Current Liabilities	$ 815	$ 3,396	$ 778	$ (4,021)	$ 968
Noncurrent Liabilities	559	1,960	306	(140)	2,685
Long-Term Debt	2,040	—	—	—	2,040
Member's Equity	5,630	4,318	319	(4,637)	5,630
Total Liabilities and Member's Equity	**$ 9,044**	**$ 9,674**	**$ 1,403**	**$ (8,798)**	**$ 11,323**

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Year Ended December 31, 2011					
Operating Revenues	$ —	$ 6,139	$ 155	$ (144)	$ 6,150
Operating Expenses	5	4,360	157	(145)	4,377
Operating Income (Loss)	(5)	1,779	(2)	1	1,773
Equity Earnings (Losses) of Subsidiaries	1,186	92	14	(1,278)	14
Other Income	40	195	—	(45)	190
Other Deductions	(28)	(51)	—	—	(79)
Other-Than-Temporary Impairments	(1)	(19)	—	—	(20)
Interest Expense	(146)	(56)	(18)	45	(175)
Income Tax Benefit (Expense)	63	(762)	9	—	(690)
Income (Loss) on Discontinued Operations, net of Tax Benefit	—	—	97	(1)	96
Net Income (Loss)	**$ 1,109**	**$ 1,178**	**$ 100**	**$ (1,278)**	**$ 1,109**
Comprehensive Income (Loss)	**$ 928**	**$ 1,055**	**$ 100**	**$ (1,155)**	**$ 928**
Year Ended December 31, 2011					
Net Cash Provided By (Used In) Operating Activities	$ 609	$ 2,427	$ (279)	$ (940)	$ 1,817
Net Cash Provided By (Used In) Investing Activities	$ (268)	$ (1,171)	$ 594	$ 267	$ (578)
Net Cash Provided By (Used In) Financing Activities	$ (341)	$ (1,256)	$ (314)	$ 673	$ (1,238)

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The following two tables summarize the adjustments for all prior periods that have been revised in this Note.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Increase (Decrease)		
			Millions		
Three Months Ended March 31, 2014					
Operating Revenues	$ —	$ (393)	$ —	$ 393	$ —
Operating Expenses	$ —	$ (393)	$ —	$ 393	$ —
Net Cash Provided By (Used In) Investing Activities	$ (209)	$ —	$ —	$ 209	$ —
Net Cash Provided By (Used In) Financing Activities	$ 209	$ —	$ —	$ (209)	$ —
Three Months Ended March 31, 2013					
Operating Revenues	$ —	$ (362)	$ —	$ 362	$ —
Operating Expenses	$ —	$ (362)	$ —	$ 362	$ —
Net Cash Provided By (Used In) Investing Activities	$ (269)	$ —	$ —	$ 269	$ —
Net Cash Provided By (Used In) Financing Activities	$ 269	$ —	$ —	$ (269)	$ —
As of March 31, 2014					
Current Assets	$ 327	$ (7,048)	$ (844)	$ 7,565	$ —
Investment in Subsidiaries	—	(605)	—	605	—
Total Assets	**$ 327**	**$ (7,653)**	**$ (844)**	**$ 8,170**	**$ —**
Current Liabilities	$ 327	$ (7,653)	$ (239)	$ 7,565	$ —
Member's Equity	—	—	(605)	605	—
Total Liabilities and Member's Equity	**$ 327**	**$ (7,653)**	**$ (844)**	**$ 8,170**	**$ —**
Three Months Ended September 30, 2013					
Operating Revenues	$ —	$ (348)	$ —	$ 348	$ —
Operating Expenses	$ —	$ (348)	$ —	$ 348	$ —
Nine Months Ended September 30, 2013					
Operating Revenues	$ —	$ (1,062)	$ —	$ 1,062	$ —
Operating Expenses	$ —	$ (1,062)	$ —	$ 1,062	$ —
Net Cash Provided By (Used In) Investing Activities	$ (520)	$ —	$ —	$ 520	$ —
Net Cash Provided By (Used In) Financing Activities	$ 520	$ —	$ —	$ (520)	$ —

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Increase (Decrease)		
			Millions		
Year Ended December 31, 2013					
Operating Revenues	$ —	$ (1,468)	$ —	$ 1,468	$ —
Operating Expenses	$ —	$ (1,468)	$ —	$ 1,468	$ —
Net Cash Provided By (Used In) Investing Activities	$ (588)	$ —	$ —	$ 588	$ —
Net Cash Provided By (Used In) Financing Activities	$ 588	$ —	$ —	$ (588)	$ —
As of December 31, 2013					
Current Assets	$ 253	$ (6,840)	$ (842)	$ 7,429	$ —
Investment in Subsidiaries	—	(605)	—	605	—
Total Assets	**$ 253**	**$ (7,445)**	**$ (842)**	**$ 8,034**	**$ —**
Current Liabilities	253	$ (7,445)	$ (237)	$ 7,429	$ —
Member's Equity	—	—	(605)	605	—
Total Liabilities and Member's Equity	**$ 253**	**$ (7,445)**	**$ (842)**	**$ 8,034**	**$ —**
Year Ended December 31, 2012					
Operating Revenues	$ —	$ (1,388)	$ —	$ 1,388	$ —
Operating Expenses	$ —	$ (1,388)	$ —	$ 1,388	$ —
Net Cash Provided By (Used In) Investing Activities	$ (729)	$ —	$ —	$ 729	$ —
Net Cash Provided By (Used In) Financing Activities	$ 679	$ —	$ —	$ (679)	$ —
As of December 31, 2012					
Current Assets	$ 333	$ (6,186)	$ (838)	$ 6,691	$ —
Investment in Subsidiaries	—	(605)	—	605	—
Total Assets	**$ 333**	**$ (6,791)**	**$ (838)**	**$ 7,296**	**$ —**
Current Liabilities	$ 333	$ (6,791)	$ (233)	$ 6,691	$ —
Member's Equity	—	—	(605)	605	—
Total Liabilities and Member's Equity	**$ 333**	**$ (6,791)**	**$ (838)**	**$ 7,296**	**$ —**
Year Ended December 31, 2011					
Operating Revenues	$ —	$ (1,313)	$ —	$ 1,313	$ —
Operating Expenses	$ —	$ (1,313)	$ —	$ 1,313	$ —
Net Cash Provided By (Used In) Investing Activities	$ (864)	$ —	$ —	$ 864	$ —
Net Cash Provided By (Used In) Financing Activities	$ 869	$ —	$ —	$ (869)	$ —

These corrections to the presentation had no impact to Power's condensed consolidated financial statements. These corrections to the presentation had no impact on any liquidity measures of Power. There was no impact to Power's loan covenants as a result of these corrections. Management believes these corrections are immaterial.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **Power,** our wholesale energy supply company that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States, and
- **PSE&G,** our public utility company which primarily provides electric transmission services and distribution of electric energy and natural gas, implements demand response and energy efficiency programs and invests in solar generation in New Jersey.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which effective January 1, 2014, operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business of our 2013 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Overview of 2013 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2014 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2013 Form 10-K and the Quarterly Reports on Form 10-Q for the quarters ended June 30, 2014 and March 31, 2014.

OVERVIEW OF 2014 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- Growing our utility operations through continued investment in T&D infrastructure projects with greater diversity of regulatory oversight, and
- Maintaining a reliable generation fleet with the flexibility to utilize a diverse mix of fuels to allow us to respond to market volatility and capitalize on opportunities as they arise in the locations in which we operate.

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Financial Results

The results for PSEG, PSE&G and Power for the three months and nine months ended September 30, 2014 and 2013 are presented as follows:

Earnings (Losses)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	Millions			
Power	$ 222	$ 226	$ 440	$ 577
PSE&G	200	168	565	468
Other (A)	22	(4)	37	(2)
PSEG Net Income	**$ 444**	**$ 390**	**$ 1,042**	**$ 1,043**
PSEG Net Income Per Share (Diluted)	**$ 0.87**	**$ 0.77**	**$ 2.05**	**$ 2.06**

(A) Other includes activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	Millions, after tax			
NDT Fund Income (Expense) (A)	$ 17	$ 12	$ 40	$ 29
Non-Trading MTM Gains (Losses)	$ 36	$ 3	$ (138)	$ (22)

(A) NDT Fund Income (Expense) includes the net realized gains, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense.

Our $54 million increase in Net Income for the three months ended September 30, 2014 was driven by

- lower pension and other postretirement (OPEB) costs and lower maintenance costs due to a planned outage at our combined cycle Bethlehem Energy Center (BEC) fossil plant in 2013,
- higher revenues due to increased investments in transmission projects, and
- lower income tax expense due to tax benefits related to the settlement of the Internal Revenue Service audits for the years 2007-2010.

These increases were partially offset by lower capacity revenues resulting from lower average auction prices in PJM.

Our Net Income for the nine months ended September 30, 2014 remained nearly level with Net Income for the comparable prior year period. While we experienced

- higher sales volumes under the basic gas supply service (BGSS) contract due to colder average temperatures in the 2014 winter heating season,
- higher volumes of gas sold to third party customers,
- higher revenues due to increased investments in transmission projects, and
- lower pension and OPEB costs and lower storm costs related to Superstorm Sandy,

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such increases were completely offset by

- higher MTM losses in 2014 resulting from an increase in prices on forward positions,
- lower volumes of electricity sold under our basic generation service (BGS) contracts resulting from serving fewer tranches in 2014, and
- higher generation costs due to higher fuel costs and higher gas costs related to the BGSS contract.

Power's results benefited from access to natural gas supplies through its existing firm pipeline transportation contracts during the cold weather experienced in the first quarter of 2014. Power manages these contracts for the benefit of PSE&G's customers through the BGSS arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to supply gas to its generating units in New Jersey and to make third party sales.

Under the PJM capacity auction conducted in May 2014, Power cleared 8,693 MW of its generating capacity at an average price of $164.61 MW-day for the 2017-2018 delivery period, a price consistent with what has been realized in the past three auctions. For a more detailed discussion on the Reliability Pricing Model (RPM) capacity auction, refer to Part II, Item 5. Other Information—Federal Regulation—Capacity Market Issues—PJM.

Power's 2014 results were unfavorably impacted by an extended refueling outage at Salem Unit 2. A planned refueling outage began on April 12, 2014 but was extended due to repairs to the Reactor Coolant Pump Turning Vanes. Salem Unit 2 returned to service on July 14, 2014.

At PSE&G, our regulated utility, we continued to invest capital in T&D infrastructure projects aimed at maintaining the reliability of our service to our customers. PSE&G's results for the first half of 2014 reflect the favorable impacts from these investments as well as a slowly improving economy. Effective January 1, 2014, PSE&G's annual formula rate increased our annual transmission revenues by approximately $171 million. In October 2014, we filed our 2015 Annual Formula Rate Update with the Federal Energy Regulatory Commission (FERC), which would provide $182 million in increased annual transmission revenues effective January 1, 2015. Over the past few years, these types of investments have altered the business mix of our overall results of operations to reflect a higher percentage contribution by PSE&G.

Regulatory, Legislative and Other Developments

In developing and implementing our strategy of operational excellence, financial strength and disciplined investment, we closely monitor significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

We also advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. On May 19, 2014, the EPA released the final Clean Water Act Section 316(b) rule on cooling water intake that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. Eight of Power's generating facilities and three of its jointly-owned generating facilities are subject to the rule. As adopted by the EPA, the rule requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts, primarily by reducing the amount of fish and shellfish that are impinged or entrained at a cooling water intake structure. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. However, the EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis, and will require facilities to conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. A federal court challenge to the EPA rule is pending. We are unable to predict the outcome that these permitting decisions may take and the effect, if any, that they may have on us although such impacts could be material. See Item 1. Note 8. Commitments and Contingent Liabilities and Part II, Item 5. Other Information—Environmental Matters—Water Pollution Control for additional information.

On June 18, 2014, the EPA issued a proposed greenhouse gas emissions regulation for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction. States may choose these or other methodologies to achieve the necessary reductions of carbon dioxide emissions. The EPA is requesting comment on many aspects of the proposal and therefore, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact of the regulation. See Part II, Item 5. Other Information—Environmental Matters—Climate Change for additional information.

In addition, Clean Air Act (CAA) regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology rules are also of significance; however, we believe our generation business remains well-positioned for such air pollution control regulations if and when they are implemented.

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The FERC's rule under Order 1000 altered the right of first refusal previously held by incumbent utilities to build all transmission within their respective service territories. Our challenge to the rule itself was rejected by the federal court. However, PJM's implementation of the rule has minimized the risk associated with the FERC's changes to the right of first refusal by carving out categories of projects that will continue to default to incumbent transmission owners. Further, the FERC's action presents opportunities for us to construct transmission outside of our service territory. In April 2013, PJM initiated a solicitation process pursuant to Order 1000 to review technical solutions to improve the operational performance in the Artificial Island area, consisting of our Salem Units 1 and 2 and Hope Creek nuclear generation facilities. In June 2014, PJM's management recommended approval by its Board of a 500 kV project to be constructed by PSE&G to address performance issues at Artificial Island. In July 2014, the PJM Board announced that it was deferring the selection of a project to enable four developers, including PSE&G, to supplement their project proposals by, among other things, re-evaluating the costs of their respective proposals. In September 2014, PSE&G and three other finalists submitted supplemental proposals. PJM currently expects to select a project in the first quarter of 2015.

PJM has filed with the FERC to add a new "multi-driver" category of transmission projects, which projects may include a combination of reliability, economic and public policy elements. Changes to the factors used in making determinations in the PJM project planning and cost-allocation processes could have significant implications for the types of projects selected and the utility customers ultimately charged for the costs of such new transmission facilities.

Capacity market design, including the RPM, remains an important focus for us. In May 2014, a federal court issued a rule that vacated a FERC Order in which the FERC had determined that demand response (DR) providers should receive full market compensation for power and held that the FERC has no jurisdiction over DR. A subsequent challenge to the participation of DR as a resource in the PJM capacity market is pending at the FERC. In addition, PJM has filed at the FERC to reset the demand curve for the RPM, as is done every three years. We are working to assure that the demand curve is set at a level that accurately reflects the cost of building a new generating unit in New Jersey. Further, in response to last winter's polar vortex, PJM is developing a proposal to be filed with the FERC for a capacity performance product to include generators, DR and energy efficiency providers who would guarantee availability during peak winter and summer conditions, as a supplement to base capacity and with enhanced performance-based incentives and penalties. The implications of these developments could be significant for the capacity market. See Part II, Item 5. Other Information—Federal Regulation—Capacity Market Issues—PJM for additional information.

In 2014, appeals to challenge the federal court rulings that the New Jersey Long-Term Capacity Agreement Pilot Program Act to subsidize above-market new generation and a similar action taken by Maryland were unconstitutional and null and void were each denied. For additional information, refer to Part II, Item 5. Other Information—Federal Regulation—Capacity Market Issues—Long-Term Capacity Agreement Pilot Program Act.

A critical aspect of our wholesale energy marketing business is the continued retention of market-based rate (MBR) authority from the FERC for our operating subsidiaries that engage in such activities. On October 14, 2014, the FERC issued an Order that accepted our triennial market power update, concluding that our submission satisfied its requirements for retention of MBR authority.

In recent years we have been impacted by severe weather conditions, including Hurricane Irene in 2011 and Superstorm Sandy in 2012, the latter storm resulting in the highest level of customer outages in our history. For more detailed information, refer to Item 1—Note 8. Commitments and Contingent Liabilities—Superstorm Sandy. We have begun work in our gas and electric distribution systems to improve resiliency. The New Jersey Board of Public Utilities (BPU) approved the settlement of our Energy Strong Proposal in a total amount of $1.22 billion. The settlement provides for cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated allowance for funds used during construction, through an accelerated recovery mechanism. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, which is to be filed no later than November 1, 2017. For additional information, refer to Part II, Item 5. Other Information—State Regulation—Energy Strong Program.

In September 2014, the BPU approved substantially our entire request for a determination that our storm related costs, in the total amount of $366 million, were prudently incurred and recoverable in a future base rate proceeding, subject to offset for the amount of insurance proceeds received. For additional information, refer to Item 1. Note 4. Rate Filings.

On January 1, 2014, we commenced operation of the LIPA T&D system under a twelve-year contract with opportunity to extend for an additional eight years. Also, beginning in January 2015, Power will provide fuel procurement and power management services to LIPA under separate agreements.

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. We notified the FERC, PJM and the PJM Independent Market Monitor (IMM) of this issue. Upon discovery of the errors, we retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed

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from the amount for which Power was compensated in the capacity market for those units. We informed the FERC, PJM and the IMM of these additional issues, and have corrected these errors. Power is also in the process of implementing procedures to help mitigate the risk of similar issues occurring in the future. On September 2, 2014, the FERC Staff verbally informed us that they have initiated a preliminary, non-public staff investigation into the matter. This investigation could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with this matter, or the applicability of mitigating factors. For more detailed information regarding this matter, refer to Item 1. Note 8. Commitments and Contingent Liabilities—FERC Compliance.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. In the first nine months of 2014, our

- total nuclear fleet achieved an average capacity factor of 91%, while also completing an extended outage at Salem Unit 2,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 41,300 GWh, while addressing unit outages and balancing fuel availability and price volatility, and
- construction of transmission and solar projects proceeded on schedule and within budget.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first nine months of 2014 as we

- had cash on hand of $703 million as of September 30, 2014,
- extended the expiration dates of PSEG's $500 million and Power's $1.6 billion five-year credit facilities from 2017 to 2019, and maintained substantial liquidity,
- maintained solid investment grade credit ratings, and
- increased our indicated annual dividend for 2014 to $1.48 per share.

We expect to be able to fund our transmission projects required under PJM's reliability program, our Energy Strong program and other projects with internally generated cash and external debt financing.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first nine months of 2014 we

- placed into service our 230 kV Burlington-Camden and 230 kV North Central Reliability transmission projects,
- made additional investments in transmission infrastructure projects,
- continued to execute our existing BPU-approved utility programs,
- completed installation of equipment to increase output and improve efficiency at our Linden combined cycle gas generating plant and continue to plan for the installation of such equipment at our other combined cycle gas units,
- acquired an equity interest with an expected investment of $100-$120 million in the 105.5 mile PennEast pipeline to transport natural gas from eastern Pennsylvania to New Jersey, and
- acquired rights to solar energy facilities located near El Paso, Texas and Burlington, Vermont, totaling 16.6 MW which are expected to be operational in the fourth quarter of 2014.

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Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a difficult economy and cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments and to respond to the issues and challenges described below. In order to do this, we must continue to

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully re-contract our open supply positions,
- execute our capital investment program, including our Energy Strong program and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and the FERC of market design rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system.

For the remainder of 2014 and beyond, the key issues and challenges we expect our business to confront include

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate, and
- delays and other obstacles that might arise in connection with the construction of our T&D projects, including in connection with permitting and regulatory approvals.

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RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, Power and PSE&G, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Note 17. Related-Party Transactions.

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,641	$ 2,554	$ 87	3	$ 8,113	$ 7,650	$ 463	6
Energy Costs	863	801	62	8	3,008	2,711	297	11
Operation and Maintenance	714	713	1	—	2,370	2,069	301	15
Depreciation and Amortization	318	313	5	2	919	886	33	4
Taxes Other than Income Taxes	—	15	(15)	(100)	—	50	(50)	(100)
Income from Equity Method Investments	3	4	(1)	(25)	10	9	1	11
Other Income and (Deductions)	66	47	19	40	154	118	36	31
Other-Than-Temporary Impairments	10	3	7	N/A	14	7	7	100
Interest Expense	100	100	—	—	291	303	(12)	(4)
Income Tax Expense	261	270	(9)	(3)	633	708	(75)	(11)

The 2014 amounts in the preceding table for Operating Revenues and O&M Costs each include $107 million and $307 million for the three months and nine months ended September 30, 2014, respectively, for Long Island Electric Utility Servco, LLC, a wholly owned subsidiary of PSEG LI. These amounts represent the O&M pass-through costs for the Long Island operations, the full reimbursement of which is reflected in Operating Revenues. See Note 3. Variable Interest Entities for further explanation. The following discussions for Power and PSE&G provide a detailed explanation of their respective variances.

Power

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,138	$ 1,174	$ (36)	(3)	$ 3,824	$ 3,818	$ 6	—
Energy Costs	472	430	42	10	2,036	1,785	251	14
Operation and Maintenance	242	305	(63)	(21)	871	868	3	—
Depreciation and Amortization	71	69	2	3	215	202	13	6
Income from Equity Method Investments	4	4	—	—	11	12	(1)	(8)
Other Income (Deductions)	50	34	16	47	110	78	32	41
Other-Than-Temporary Impairments	10	3	7	N/A	14	7	7	100
Interest Expense	31	26	5	19	92	85	7	8
Income Tax Expense	144	153	(9)	(6)	277	384	(107)	(28)

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Three Months Ended September 30, 2014 as Compared to 2013

Operating Revenues decreased $36 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $55 million due primarily to

- a decrease of $71 million due to lower capacity revenues resulting from lower average auction prices partially coupled with a decrease in operating reserve revenue in PJM in 2014, and
- a decrease of $27 million due primarily to lower volumes of electricity sold under our BGS contracts as a result of serving fewer tranches in 2014,
- partially offset by higher net revenues of $23 million due primarily to higher generation volumes at higher average realized prices in the New York (NY) region and higher MTM gains in 2014 which were partially offset by lower average realized prices in the PJM and New England (NE) regions, and
- an increase of $20 million due to higher volumes on wholesale load contracts in the PJM region.

Gas Supply Revenues increased $15 million due primarily to higher sales volumes at lower average natural gas prices to third party customers.

Other Operating Revenues increased $4 million due to transition fees related to the fuel and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $42 million due to

- ***Generation costs*** increased $32 million due primarily to higher congestion costs and renewable energy credits, partially offset by the favorable MTM impact from lower average unrealized prices on forward positions.
- ***Gas costs*** increased $10 million, reflecting higher sales volumes to third party customers, partially offset by lower average gas inventory costs on obligations under the BGSS contract.

Operation and Maintenance decreased $63 million due primarily to

- lower planned outage costs of $39 million at our fossil stations, primarily at our BEC combined cycle gas generating plant due to maintenance on the low pressure turbine in 2013 and lower outage costs at our nuclear Peach Bottom facility,
- a decrease of $13 million due to lower storm costs related to Superstorm Sandy, and
- lower pension and OPEB expense of $14 million.

Depreciation and Amortization experienced no material change.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) increased $16 million primarily due to higher net realized gains related to the NDT Fund restructuring in May 2014.

Other-Than-Temporary Impairments increased $7 million due to an increase in impairments on the NDT Fund.

Interest Expense increased $5 million due primarily to the issuance of $500 million of Senior Notes in November 2013.

Income Tax Expense decreased $9 million in 2014 due primarily to lower pre-tax income.

Nine Months Ended September 30, 2014 as Compared to 2013

Operating Revenues increased $6 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $128 million due primarily to

- lower net revenues of $72 million due primarily to higher MTM losses in 2014 resulting from an increase in prices on forward positions, partially offset by higher energy volumes sold in the NY and NE regions, and
- a decrease of $70 million due to lower volumes of electricity sold under our BGS contracts as a result of serving fewer tranches in 2014 and lower average pricing,

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- partially offset by a net increase of $12 million due primarily to higher capacity revenues resulting from higher average auction prices and higher ancillary revenue in the PJM region, and
- a net increase of $2 million due primarily to higher volumes on wholesale load contracts in the PJM region.

Gas Supply Revenues increased $123 million due primarily to

- a net increase of $74 million in sales under the BGSS contract, substantially comprised of higher sales volume due to colder average temperatures during the 2014 winter heating season, and
- a net increase of $49 million due primarily to higher sales volumes at lower average prices to third party customers.

Other Operating Revenues increased $11 million due to transition fees related to the fuel management and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $251 million due to

- ***Generation costs*** increased $200 million due primarily to higher fuel costs, reflecting higher average realized natural gas prices, the unfavorable MTM impact from lower average unrealized natural gas prices on forward positions and the utilization of higher volumes of coal and oil.
- ***Gas costs*** increased $51 million, principally related to higher volumes sold under the BGSS contract and to third parties due to colder average temperatures during the 2014 winter heating season, partially offset by lower average gas inventory costs.

Operation and Maintenance increased $3 million due primarily to

- an increase of $62 million related primarily to higher planned outage and maintenance costs at our fossil plants, including maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant, partially offset by lower costs at our BEC fossil station as well as lower outage costs at our nuclear Peach Bottom facility, partially offset by
- lower pension and OPEB costs of $40 million, and
- a decrease of $19 million due to lower storm costs related to Superstorm Sandy.

Depreciation and Amortization increased $13 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) increased $32 million due primarily to net losses that were incurred in March 2013 as a result of rebalancing the NDT portfolio.

Other-Than-Temporary Impairments increased $7 million due to an increase in impairments on the NDT Fund.

Interest Expense increased $7 million due primarily to the issuance of $500 million of Senior Notes in November 2013, partially offset by the maturity of $300 million of Senior Notes in April 2013.

Income Tax Expense decreased $107 million in 2014 due primarily to lower pre-tax income.

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PSE&G

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,655	$ 1,666	$ (11)	(1)	$ 5,235	$ 5,084	$ 151	3
Energy Costs	668	661	7	1	2,278	2,208	70	3
Operation and Maintenance	366	408	(42)	(10)	1,190	1,204	(14)	(1)
Depreciation and Amortization	238	236	2	1	682	658	24	4
Taxes Other Than Income Taxes	—	15	(15)	(100)	—	50	(50)	(100)
Other Income (Deductions)	14	12	2	17	41	38	3	8
Interest Expense	71	75	(4)	(5)	206	223	(17)	(8)
Income Tax Expense	126	115	11	10	355	311	44	14

Three Months Ended September 30, 2014 as Compared to 2013

Operating Revenues decreased $11 million due to changes in delivery, commodity, clause, and other operating revenues.

Delivery Revenues increased $15 million due primarily to an increase in transmission revenues. The Transitional Energy Facilities Assessment (TEFA) reductions in electric and gas distribution revenues are entirely offset by the decrease in Taxes Other Than Income Taxes.

- Transmission revenues were $38 million higher due to net rate increases resulting primarily from increased capital investments.
- Electric distribution revenues decreased $22 million due primarily to lower TEFA revenue of $13 million due to elimination of the TEFA rate effective January 1, 2014 and lower sales volumes of $5 million, $3 million of lower Capital Infrastructure Program (CIP) related revenue due to the 2014 reduction in the Capital Adjustment Charge (CAC) tariff and lower revenue from Green Program Recovery Charges (GPRC) of $1 million.
- Gas distribution revenues decreased $1 million due primarily to lower TEFA revenue of $2 million due to elimination of the TEFA rate in 2014 and lower CIP related revenue of $2 million due to the 2014 reduction in the CAC tariff, partially offset by an increase of $3 million from higher sales volumes.

Commodity Revenue increased $7 million due to higher Gas revenues, partially offset by lower Electric revenues. This is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $3 million due primarily to $17 million in lower revenues from collection of Non-Utility Generation Charges (NGC) and lower sales volumes of Non-Utility generation (NUG) energy, partially offset by $14 million in higher BGS revenues. BGS sales volumes decreased 1% due primarily to weather.
- Gas revenues increased $10 million due primarily to higher BGSS volumes of $5 million and higher BGSS prices of $5 million.

Clause Revenues decreased $32 million due primarily to lower Societal Benefit Charges (SBC) of $19 million, lower Securitization Transition Charge (STC) revenues of $9 million and lower Margin Adjustment Clause (MAC) of $4 million. The change in the SBC, STC and MAC amounts were entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, STC or MAC collections.

Other Operating Revenues remained level with the prior period.

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Operating Expenses

Energy Costs increased $7 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $3 million or 1% due primarily to $9 million of lower BGS and NUG prices and $15 million in lower BGS and NUG volumes, partially offset by $21 million of increased deferred cost recovery. BGS and NUG volumes decreased 3% due primarily to customer migration to third party suppliers (TPS) and weather.
- Gas costs increased $10 million or 14% due to $5 million or 7% in higher sales volumes and $5 million or 7% in higher prices.

Operation and Maintenance decreased $42 million, of which the most significant components were

- a $28 million decrease in costs related to clauses due primarily to lower SBC, MAC, CIP and GPRC. Due to the nature of the SBC, MAC, CIP and GPRC clause mechanisms, these are entirely offset in revenues,
- an $18 million decrease in pension and OPEB expenses and partially offset by
- an increase in other operating expenses of $4 million.

Depreciation and Amortization increased $2 million due primarily to

- a $12 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects,
- partially offset by a $10 million decrease in amortization of Regulatory Assets.

Taxes Other Than Income Taxes decreased $15 million due to elimination of the TEFA rate in 2014. This is entirely offset by the reduction in electric and gas distribution revenues.

Other Income and (Deductions) experienced no material change.

Interest Expense decreased $4 million due primarily to a partial redemption of securitization debt.

Income Tax Expense increased $11 million due primarily to higher pre-tax income.

Nine Months Ended September 30, 2014 as Compared to 2013

Operating Revenues increased $151 million due to changes in delivery, commodity, clause, and other operating revenues.

Delivery Revenues increased $93 million due primarily to an increase in transmission revenues. The TEFA reductions in electric and gas distribution revenues are entirely offset by the decrease in Taxes Other Than Income Taxes.

- Transmission revenues were $115 million higher due to net rate increases resulting primarily from increased capital investments.
- Gas distribution revenues were flat due primarily to $53 million from higher sales volumes and higher revenue from GPRC of $6 million, offset by lower Weather Normalization Clause (WNC) revenue of $36 million due to colder than normal weather, lower TEFA revenue of $15 million due to elimination of the TEFA rate in 2014 and lower CIP related revenues of $8 million partially due to the 2014 reduction in the CAC tariff.
- Electric distribution revenues decreased $22 million due primarily to lower TEFA revenue of $35 million due to elimination of the TEFA rate in 2014, lower sales volumes of $7 million and lower CIP related revenues of $3 million due to the 2014 reduction in the CAC tariff, partially offset by higher revenue from the GPRC of $23 million.

Commodity Revenue increased $70 million due to higher Electric and Gas revenues. This is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues increased $15 million due primarily to $48 million in higher volumes and prices of BGS sales, partially offset by $33 million in lower revenues from collection of NGC and lower sales volumes of NUG energy. BGS sales volumes increased 2% due primarily to weather.
- Gas revenues increased $55 million due primarily to higher BGSS volumes of $106 million, partially offset by lower BGSS prices of $51 million. The average price of natural gas was 7% lower in 2014.

Clause Revenues decreased $20 million due primarily to lower STC of $12 million, lower SBC of $7 million and lower MAC of $7 million partially offset by higher Solar Pilot Recovery Charge (SPRC). The change in the STC, SBC MAC and SPRC

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amounts were entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC, MAC or SPRC collections.

Other Operating Revenues increased $8 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Operating Expenses

Energy Costs increased $70 million. This is entirely offset by Commodity Revenue.

- Electric costs increased $15 million or 1% due to $72 million of increased deferred cost recovery and $2 million of higher BGS and NUG prices, partially offset by $59 million in lower BGS and NUG volumes. BGS and NUG volumes decreased 4% due primarily to customer migration to TPS.
- Gas costs increased $55 million or 8% due to $106 million or 14% in higher sales volumes, partially offset by $51 million or 6% in lower prices.

Operation and Maintenance decreased $14 million, of which the most significant components were

- a $55 million decrease in pension and OPEB expenses, partially offset by,
- an $11 million increase in costs related primarily to a net increase in SBC, MAC, CIP and GPRC. Due to the nature of the SBC, MAC, CIP and GPRC clause mechanisms, these are entirely offset in revenues, and
- a $30 million increase in operational expenses due primarily to storm-related costs of $7 million, damage claims of $8 million, transmission related costs of $3 million, general wage increases of $2 million, tree trimming of $2 million and general operating expenses of $8 million.

Depreciation and Amortization increased $24 million due primarily to a $33 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects, partially offset by a decrease of $11 million in amortization of Regulatory Assets.

Taxes Other Than Income Taxes decreased $50 million due to elimination of the TEFA rate in 2014. This is entirely offset by the reduction in electric and gas distribution revenues.

Other Income and (Deductions) experienced no material change.

Interest Expense decreased $17 million due primarily to a partial redemption of securitization debt and maturity of Medium Term Notes (MTNs) in the second half of 2013, partially offset by the issuance of MTNs in the latter part of 2013 and 2014.

Income Tax Expense increased $44 million due primarily to higher pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund planned capital expenditures and shareholder dividend payments.

For the nine months ended September 30, 2014, our operating cash flow increased $101 million as compared to the same period in 2013. The net change was due primarily to the net changes from Power and PSE&G as discussed below and higher federal tax payments made by the parent company in 2014.

Power

Power's operating cash flow decreased $204 million from $1,314 million to $1,110 million for the nine months ended September 30, 2014, as compared to the same period in 2013, primarily resulting from an increase in working capital needs, largely due to higher margin deposit requirements, partially offset by a $40 million decrease in employee benefit plan funding.

PSE&G

PSE&G's operating cash flow increased $294 million from $1,049 million to $1,343 million for the nine months ended September 30, 2014, as compared to the same period in 2013, due primarily to higher earnings, an increase in net regulatory liabilities related to BGS and NUG costs and overcollections in Gas Weather Normalization Charges partly offset by GPRC rate recoveries and an $80 million decrease in employee benefit plan funding.

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Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our $4.3 billion credit facilities are provided by a diverse bank group. As of September 30, 2014, our total available credit capacity was $4.1 billion.

As of September 30, 2014, no single institution represented more than 8% of the total commitments in our credit facilities.

As of September 30, 2014, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. In April 2014, PSEG and Power amended their 2012 credit agreements ending in 2017, extending the expiration date from March 2017 to April 2019. PSEG's $500 million and Power's $1.6 billion facility amendments, resulting in total commitments of $2.1 billion, will mature in 2019.

Our total credit facilities and available liquidity as of September 30, 2014 were as follows:

	As of September 30, 2014				
Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facility	$ 500	$ 8	$ 492	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—	500	Mar 2018	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 8**	**$ 992**		
Power					
5-year Credit Facility	$ 1,600	$ 76	$ 1,524	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (B)	1,000	—	1,000	Mar 2018	Funding/Letters of Credit
Bilateral Credit Facility	100	100	—	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 176**	**$ 2,524**		
PSE&G					
5-year Credit Facility (C)	$ 600	$ 14	$ 586	Mar 2018	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 14**	**$ 586**		
Total	**$ 4,300**	**$ 198**	**$ 4,102**		

(A) In April 2016, this facility will be reduced by $23 million.

(B) In April 2016, this facility will be reduced by $48 million.

(C) In April 2016, this facility will be reduced by $29 million.

Long-Term Debt Financing

PSE&G has $300 million of 2.70%, Series G, Medium Term Notes maturing in May 2015.

For a discussion of our long-term debt transactions during 2014, see Note 9. Changes in Capitalization.

Common Stock Dividends

On July 15, 2014, our Board of Directors approved a $0.37 per share common stock dividend for the third quarter of 2014. This reflects an indicated annual dividend rate of $1.48 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Note 15. Earnings Per Share (EPS) and Dividends.

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Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security. In January 2014, Moody's upgraded PSE&G's Mortgage Bond Rating from A1 to Aa3 and its commercial paper rating from P2 to P1. PSE&G's outlook is stable. In May 2014, Moody's published updated research reports on PSEG, PSE&G and Power and the existing ratings and outlooks were unchanged.

In May 2014, S&P published updated research reports and revised the outlook to positive from stable for Power. S&P also affirmed the senior unsecured rating of BBB+ at Power and mortgage bond rating of A at PSE&G. In October 2014, Fitch affirmed the ratings and outlooks for PSEG, PSE&G and Power.

	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	**Stable**	**Stable**	**Stable**
Commercial Paper	P2	A2	F2
Power			
Outlook	**Stable**	**Positive**	**Stable**
Senior Notes	Baa1	BBB+	BBB+
PSE&G			
Outlook	**Stable**	**Stable**	**Stable**
Mortgage Bonds	Aa3	A	A+
Commercial Paper	P1	A2	F2

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1+ (highest) to D (lowest) for short-term securities.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1+ (highest) to D (lowest) for short-term securities.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures at Power and Services as compared to amounts disclosed in our 2013 Form 10-K. PSE&G has increased its total projected capital expenditures through 2016 by $295 million, including $145 million for additional transmission reliability enhancements in 2015 and $50 million and $100 million in 2015 and 2016, respectively, related to additional distribution expenditures for reliability enhancements and facility replacement.

On May 21, 2014, the BPU issued an Order approving our Energy Strong program, agreeing that PSE&G would spend $1.22 billion to protect and strengthen PSE&G's electric and gas systems against severe weather conditions over primarily a three-year period with some projects extending over five years. This amount is not included in the projected capital expenditures disclosed in our 2013 Form 10-K or in the increases reported above. See Item 5. Other Information—Energy Strong Program for additional information.

Power

During the nine months ended September 30, 2014, Power made capital expenditures of $298 million, excluding $116 million for nuclear fuel, primarily related to various projects at its fossil and nuclear generation stations.

PSE&G

During the nine months ended September 30, 2014, PSE&G made capital expenditures of $1.49 billion, primarily for transmission and distribution system reliability. This does not include expenditures for certain energy efficiency and renewable programs of $13 million or cost of removal, net of salvage, of $68 million, which are included in operating cash flows.

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ACCOUNTING MATTERS

For information related to recent accounting matters, see Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The market risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From July through September 2014, MTM VaR remained relatively stable. The range of VaR was narrower for the three months ended September 30, 2014 as compared with the year ended December 31, 2013.

	MTM VaR	
	Three Months Ended September 30, 2014	Year Ended December 31, 2013
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 20	$ 12
Average for the Period	$ 20	$ 15
High	$ 26	$ 29
Low	$ 15	$ 8
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 32	$ 18
Average for the Period	$ 31	$ 23
High	$ 40	$ 46
Low	$ 24	$ 13

See Note 10. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the third quarter of 2014 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3. of Part I of the 2013 Annual Report on Form 10-K, see Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

There are no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2013 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the third quarter of 2014.

Three Months Ended September 30, 2014	Total Number of Shares Purchased	Average Price Paid per Share
July 1 - July 31	—	$ —
August 1- August 31	46,894	$ 34.98
September 1 - September 30	—	$ —

ITEM 5. OTHER INFORMATION

Certain information reported in the 2013 Annual Report on Form 10-K and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2014 and June 30, 2014 is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2013 Annual Report on Form 10-K and the Quarterly Reports on Form 10-Q for the quarters ended March 31, 2014 and June 30, 2014. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

Business Operations and Strategy

Other

December 31, 2013 Form 10-K page 13 and June 30, 2014 Form 10-Q page 80. On July 1, 2014, PSEG LI submitted a proposal to LIPA to invest up to $200 million of capital in equipment at customer facilities that would improve energy efficiency and reduce peak load. PSEG LI proposed to make the investments from 2015 through 2018 and recover its investment and earn a return over approximately ten years. On October 6, 2014, PSEG LI filed an interim update which increased the size of the proposed program to approximately $345 million, reaffirmed its original investment proposal to fund up to $200 million of the program and also offered an alternate economic structure which included a performance incentive mechanism rather than utilizing PSEG LI's capital. The New York State Department of Public Service will review the proposal and make a recommendation to LIPA which is expected to take action on the proposal at its December 2014 meeting.

Federal Regulation

FERC

Regulation of Wholesale Sales—Generation/Market Issues

Market Power

Under FERC regulations, public utilities must receive FERC authorization to sell power in interstate commerce. They can sell power at cost-based rates or apply to the FERC for authority to make market-based rate (MBR) sales. For a requesting company to receive MBR authority, the FERC must first make a determination that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. The FERC requires that holders of MBR tariffs file an update every three years demonstrating that they continue to lack market power and/or that

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market power has been sufficiently mitigated and report in the interim to the FERC any material change in facts from those the FERC relied on in granting MBR authority. Retention of MBR authority is important to the maintenance of our generation business' revenues.

PSE&G, PSEG Energy Resources & Trade LLC, PSEG Power Connecticut, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG New Haven LLC all have been granted MBR authority from the FERC. Each of these companies, except PSEG New Haven LLC (which received MBR authority in May 2012), filed a market power update with the FERC at the end of 2013. In an order issued on October 14, 2014, the FERC accepted our filing as having satisfied the requirements for retention of MBR authority.

Energy Clearing Prices

December 31, 2013 Form 10-K page 16, March 31, 2014 Form 10-Q page 69 and June 30, 2014 Form 10-Q page 80. As a result of the polar vortex and related cold weather events in January 2014, there were both gas and electric price spikes in the Northeast markets, including in PJM. The FERC has examined the facts surrounding these price spikes, as well as "lessons learned" from the various Regional Transmission Operators/Independent System Operators (RTO/ISO) and potential changes in market rules intended to encourage dual fuel capability of generating units, the purchase of firm fuel to fire these units and the construction of additional natural gas pipeline capacity. As discussed below, PJM has proposed changes to its capacity market construct to develop a new capacity product that would be compensated for availability during peak winter periods. The FERC is also examining price formation issues, focusing on levels of compensation to generators in the energy and ancillary services markets. We cannot predict what action the FERC might take, but such an examination could lead to future rule changes.

Capacity Market Issues

December 31, 2013 Form 10-K page 16, March 31, 2014 Form 10-Q page 69 and June 30, 2014 Form 10-Q page 81. PJM, the New York ISO (NYISO), and the ISO-New England (ISO-NE) each have capacity markets that have been approved by the FERC. The FERC regulates these markets and continues to examine whether the market design for these three capacity markets is working optimally. Specific issues being considered by the FERC are whether capacity market rules properly address and foster the development of state public policies, demand response (DR) and emerging technologies, and whether generators are being sufficiently compensated in the capacity market. We cannot predict what action, if any, the FERC might take with regard to capacity market design.

Capacity Market Issues—PJM

December 31, 2013 Form 10-K page 16, March 31, 2014 Form 10-Q page 70 and June 30, 2014 Form 10-Q page 81. The Reliability Pricing Model (RPM) is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under the RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of the RPM in PJM continue to evolve and be refined in stakeholder proceedings and FERC proceedings in which we are active. There is currently significant activity concerning three topics: (i) the future role of DR in the RPM market in light of a decision by the D.C. Circuit Court of Appeals (D.C. Court) holding that DR is not a FERC-jurisdictional product, (ii) PJM's development of a new capacity product called a Capacity Performance (CP) product, and (iii) the setting of the Cost of New Entry (CONE) value for the RPM demand curve for the next three years.

On May 23, 2014, in a case involving the proper level of compensation for DR resources in the energy markets, the D.C. Court held that DR is not a FERC-jurisdictional product, thereby calling into question DR resources' ability to participate in either the energy or capacity markets in the future. The FERC and other parties to the case subsequently submitted petitions for rehearing before the entire court of judges, which petitions were denied on September 17, 2014. The FERC has obtained a stay of the court's decision until at least December 16, 2014, the due date for the FERC to file a petition for certiorari to the U.S. Supreme Court. Should the FERC file such a petition, the stay will remain in effect until such time as the Supreme Court disposes of the case. Upon lifting of the stay, the issue of the proper treatment of DR resources will be addressed by the FERC and the RTOs/ISOs. First Energy Corp. has filed a complaint at the FERC which argues that DR resources should no longer participate in the PJM capacity market and seeks to invalidate the results of the last RPM Base Residual Auction. PJM has also signaled that it may in the future only allow DR to participate in the capacity market through adjustment of the demand curve rather than as a capacity resource that receives a revenue stream, although PJM has not yet taken any formal action to effectuate this. Elimination of DR as a capacity resource would have a significant effect on future auction clearing prices should this actually occur.

PJM is currently developing a CP construct which it has stated it intends to file with the FERC by the beginning of December 2014. Under this construct, the details of which remain under development, PJM is creating a more robust capacity product definition with enhanced incentives for winter peak performance and penalties for non-performance. The CP product would be expected to be capable of providing energy when needed during both summer and winter peak-load conditions and extreme weather events and satisfying certain operational requirements. CP resources would be subject to a maximum penalty of 1.5

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times annual capacity revenues, with articulated penalty exceptions. This new product would be phased in over the next few years, with full implementation for the delivery year 2018-2019.

On September 25, 2014, PJM filed at the FERC to re-set the Variable Resource Requirement (VRR) curve for the RPM, as is done every three years. Establishment of the VRR curve is a critical component in determining how generators are paid in the capacity auction. We and other generators have challenged certain elements of this filing, including how PJM has calculated the cost of capital and labor costs that form the basis for the CONE component of the demand curve, which we believe have been set too low and do not accurately reflect the costs of building a new generating unit in PJM. This matter is currently pending at the FERC.

Capacity Market Issues—ISO-New England (ISO-NE)

December 31, 2013 Form 10-K page 16 and June 30, 2014 Form 10-Q page 81. ISO-NE's market for installed capacity in New England provides fixed capacity payments for generators, imports and DR. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. In June 2014, the FERC issued an order requiring the implementation of a downward sloping demand curve, similar to the design in place in PJM, for use in ISO-NE's ninth capacity market auction to be held in February 2015 and effective in the 2018-2019 planning year. This action is expected to result in greater stability of capacity prices in New England and is also expected to send more appropriate price signals that will incent the development of new generation. One aspect of this order that we did not support was the exemption from the Minimum Offer Price Rule afforded annually up to 600 MW of renewable resources. We challenged this portion of the order on rehearing on the grounds that we believe that it is unduly discriminatory and will suppress capacity prices. The rehearing request remains pending.

In addition, in the FERC order referenced above, the FERC directed the ISO-NE to develop demand curves for each capacity zone in the market. The ISO-NE is currently conducting a stakeholder proceeding and expects to make a filing with the FERC by January 2015. The shape of the demand curve in the zones will have a significant impact upon the revenues our generation receives in the capacity market in New England.

Capacity Market Issues—Long-Term Capacity Agreement Pilot Program Act (LCAPP)

December 31, 2013 Form 10-K page 17. In 2011, the State of New Jersey enacted the LCAPP to subsidize approximately 2,000 MW of new natural gas-fired generation. The LCAPP provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey EDCs. The SOCA required each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers. Each of the New Jersey EDCs, including PSE&G, entered into three SOCAs as directed by the State, but did so under protest reserving their rights.

In 2013, the U.S. District Court in New Jersey found that the LCAPP was unconstitutional and declared the LCAPP null and void. This federal court decision was subsequently challenged on appeal in the U.S. Third Circuit Court of Appeals. The State of Maryland also took action to subsidize above-market new generation. This action was also determined to be unconstitutional in 2013 in the U.S. District Court in Maryland and such decision was challenged in the U.S. Fourth Circuit Court of Appeals. Both appeals were denied, with the U.S. Fourth Circuit Court of Appeals denying the appeal regarding the State of Maryland's action in June 2014 and the U.S. Third Circuit Court of Appeals denying the LCAPP appeal in September 2014.

Transmission Regulation—Transmission Policy Developments

December 31, 2013 Form 10-K page 17 and June 30, 2014 Form 10-Q page 82. The FERC concluded in Order 1000 that the incumbent transmission owner should not always have a "right of first refusal" (ROFR) to construct and own transmission projects in its service territory. We had challenged the FERC's elimination of the ROFR in federal court. In August 2014, our challenge was rejected by the D.C. Court. PJM is currently implementing its rules under which the construction of certain types of transmission projects is no longer subject to a ROFR for incumbents. In May 2014, the FERC approved PJM's rules, which retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including projects being built on existing right-of-way and whose construction would interfere with incumbents' use of their right-of-way. Several companies, including PSE&G, have appealed various aspects of this approval order. The FERC has also approved the "state agreement approach" to cost allocation under which transmission projects being built to address public policy concerns may be placed into PJM's planning process if the state sponsoring the project agrees to pay the costs of the project. To date, no such projects have been placed into the planning process but this mechanism could potentially facilitate transmission projects that are not needed for reliability or market efficiency under PJM standards for transmission, including potential offshore wind projects proposed by third parties, should a state or states agree to fund the costs of such projects.

In addition, in September 2014, PJM filed at the FERC to add another category of project - the "multi-driver" project - to its planning process. This type of project would contain reliability, economic and/or public policy elements. Projects falling within this category would be required to independently satisfy all of the different drivers in order to be approved. However,

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this category could also serve as a vehicle for projects that may not be needed but are being supported for public policy purposes.

We cannot predict the final outcome or impact of these matters on us; however, specific implementation of Order 1000 in the various regions, including within our service territory, may expose us to competition from third party construction of certain transmission projects within our service territory while at the same time providing opportunities to build transmission outside of our service territory.

PJM's first action toward complying with Order 1000 commenced in April 2013, when it implemented its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues at Artificial Island. In June 2014, PJM's management recommended approval by its Board of a 500 kV project to be constructed by PSE&G to address these performance issues. However, in July 2014, the PJM Board announced that it was deferring selection of a project to enable four developers, including PSE&G, to supplement their proposals by, among other things, re-evaluating the costs of their respective proposals. In September 2014, PSE&G and the three other finalists submitted supplemental proposals. All of the finalists will meet with PJM in the presence of a FERC Administrative Law Judge to answer questions about the components of the supplemental proposals. PJM is also meeting with relevant environmental permitting agencies and the Nuclear Regulatory Commission to gauge constructability of the proposed projects. PJM has indicated that it expects to select a project in the first quarter of 2015.

Transmission Regulation—Transmission Rate Proceedings

December 31, 2013 Form 10-K page 18, March 31, 2014 Form 10-Q page 70 and June 30, 2014 Form 10-Q page 82. In September 2011, a complaint was filed by several state utility commissions and consumer advocates against transmission owners in New England challenging their base return on equity (ROE). In June 2014, the FERC issued an order in this proceeding that provided for a new approach to determining the ROE for public utilities that, among other things, is intended to narrow the parameters set in calculating the ROE. In applying the new methodology to this case, the FERC tentatively found that the New England transmission owners' base ROE should be reduced by 57 basis points, and instituted a hearing to allow the participants in the proceeding an opportunity to submit evidence in writing solely concerning the application of the new approach. In addition, the FERC directed that the approach to determine ROE set forth in the New England transmission owners' order should apply to all currently pending ROE-related complaint cases in which the FERC has not issued a final order. In July 2014, the parties filed motions for reconsideration and rehearing regarding the June 2014 order, and also in July 2014, the complaining parties filed another complaint at the FERC challenging the New England transmission owners' ROE.

On October 16, 2014, the FERC issued an order regarding the application of its new approach, setting the New England transmission owners' base ROE at 10.57%, the rate indicated in its June 2014 order, with a total or maximum ROE not exceeding the top of the range of reasonable returns, i.e., 11.74%, inclusive of transmission incentive ROE adders (the base ROE does not include basis point adders for participation in an ISO or other incentive adders). The motions for reconsideration/rehearing and the new complaint filed in July 2014 remain pending.

Compliance—FERC

March 31, 2014 Form 10-Q page 70 and June 30, 2014 Form 10-Q page 83. In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, we retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. On September 2, 2014, the FERC staff verbally informed us that they have initiated a preliminary, non-public staff investigation into the matter. This investigation could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with this matter, or the applicability of mitigating factors. See Part I, Item 1. Note 8. Commitments and Contingent Liabilities—FERC Compliance for further discussion of this matter.

Compliance—FERC Audit

December 31, 2013 Form 10-K page 18. In November 2012, the FERC commenced an audit of each of the PSEG companies that have MBR authority from the FERC. The companies were audited by the FERC for compliance with its rules for (i) receiving and retaining MBR authority, (ii) the filing of electric quarterly reports (EQRs), and (iii) our generating units' receipt of payments from the RTO/ISO when they are required to run for reliability reasons when it is not economical for them to do so. On October 16, 2014, the FERC issued a final, public audit report that contained two findings and recommendations for enhanced review and reporting of our EQRs. As required, we intend to submit a compliance plan within 30 days.

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State Regulation

Energy Strong Program

December 31, 2013 Form 10-K page 20, March 31, 2014 Form 10-Q page 71 and June 30, 2014 Form 10-Q page 83. On May 21, 2014, the BPU issued an Order approving the settlement of our Energy Strong program. This program encompasses infrastructure investments of $1.22 billion that we will make to our BPU jurisdictional electric and gas system to improve resiliency for the future. For additional information, see Part I, Item 1. MD&A—Overview of 2014 and Future Outlook—Regulatory, Legislative and Other Developments. On September 30, 2014, PSE&G filed its initial Energy Strong cost recovery petition, seeking BPU approval to recover in base rates an estimated annual revenue increase of $1.6 million effective March 1, 2015. This increase represents capitalized Energy Strong electric investment costs expected to be in service through November 30, 2014. This request will be updated in December 2014 for actual costs.

Storm Proceedings

December 31, 2013 Form 10-K page 20. In December 2012, the BPU issued an order allowing PSE&G to defer on its books actually incurred, prudent, incremental storm restoration costs associated with extraordinary storms, including Superstorm Sandy and Hurricane Irene, and not otherwise recoverable through base rates or insurance. In March 2013, the BPU initiated a proceeding to evaluate the prudency of storm costs incurred by New Jersey utilities. On September 30, 2014, the BPU approved a Stipulation of Settlement finding that $366 million, consisting of all of PSE&G's 2010 through 2012 major storm capital expenditures of $126 million, and virtually all of PSE&G's 2010 through 2012 major storm incremental O&M costs ($240.1 million of the $240.5 million identified) were prudent and recoverable in a future base rate proceeding, subject to offset for the amount of insurance proceeds received. See Part I, Item 1. Note 4. Rate Filings.

Energy Efficiency Economic Stimulus Extension II (EEE Ext II)

In August 2014, we filed for approval from the BPU of an EEE Ext II Program to extend three EEE subprograms (multi-family, direct install and hospital efficiency). We proposed to extend the subprograms' offerings under the same clause recovery process as currently approved while seeking additional capital expenditures of approximately $96 million and additional administrative costs of $14 million. The matter is pending.

Consolidated Tax Adjustments (CTA)

New Jersey is one of only a few states that make CTA in setting rates for regulated utilities. These adjustments to rate base are made during the rate setting process and are intended to allocate to utility customers a portion of the tax benefits realized from the filing of a consolidated federal tax return by the utility's parent corporation. The BPU has been considering the appropriateness of the adjustment and the methodology and mechanics of the calculation for some time. On October 22, 2014, the BPU approved a proposal by its Staff that limits the tax benefit period to be considered in the calculation to five years, sets the rate base adjustment at 25% of any such tax benefit, and eliminates from the process any tax benefits tied to transmission earnings. In accordance with this October action, this CTA policy will be applied only with respect to future rate cases. The adoption of these modifications by the BPU is not expected to have a material impact on PSE&G's current earnings nor in its next rate case filing.

Environmental Matters

Air Pollution Control

Demand Response (DR) and Reciprocating Internal Combustion Engines (RICE) Litigation

December 31, 2013 Form 10-K page 21. In March 2013, we filed a petition at the EPA challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued on January 30, 2013. Among other things, the final EPA rule allows owners and operators of stationary emergency RICE to operate their engines as part of an emergency DR program without the installation and operation of emission controls or compliance with emission limits otherwise applicable to non-emergency counterparts. This waiver of NESHAP standards results in disparate treatment of different generation technology types. In our appeal, we sought more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. On August 15, 2014, the EPA denied the March 2013 petition for reconsideration. We and other petitioners are considering whether to take further legal action.

Cross-State Air Pollution Rule (CSAPR)

December 31, 2013 Form 10-K page 21, March 31, 2014 Form 10-Q page 71 and June 30, 2014 Form 10-Q page 84. In July 2011, the EPA issued the final CSAPR, which limited power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season NO_x in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards. In August 2012, the D.C. Court vacated CSAPR and ordered that the existing Clean Air Interstate Rule requirements remain in effect until an appropriate substitute rule has been promulgated. On April 29, 2014, the Supreme Court overturned the D.C. Court's ruling. On June 26, 2014, the EPA filed a motion to lift the

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stay on CSAPR and allow for implementation of Phase I to begin on January 1, 2015. On October 23, 2014, the D.C. Court lifted the stay on CSAPR and we anticipate implementation effective January 2015 per the EPA's motion. We do not anticipate any material impact on our earnings or financial condition due to the CSAPR.

Climate Change

CO_2 Regulation Under the CAA

December 31, 2013 Form 10-K page 22 and June 30, 2014 Form 10-Q page 84. On June 18, 2014, the EPA issued a proposed greenhouse gas (GHG) emissions regulation for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction. In September 2014, the EPA extended the comment period from October 16, 2014 to December 1, 2014. The EPA is requesting comments on many aspects of the proposal and therefore, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact.

If relevant federal or state common law were to impose liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to our fossil generation operations could be material. However, approximately 60% of our generation output comes from nuclear facilities which are GHG-free and would not be impacted.

Water Pollution Control

Cooling Water Intake Structure Regulation

December 31, 2013 Form 10-K page 23, March 31, 2014 Form 10-Q page 72 and June 30, 2014 Form 10-Q page 85. On May 19, 2014, the EPA issued a final cooling water intake rule under Section 316(b) of the Clean Water Act that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

On August 15, 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. On September 5, 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Fourth Circuit Court of Appeals.

We are assessing the potential impact of the rule on each of our affected facilities and are unable to predict the outcome of permitting decisions and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Part I, Item 1. Note 8. Commitments and Contingent Liabilities—Clean Water Act Permit Renewals for additional information.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. Power:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. PSE&G:

Exhibit 4 (a) (22):	Supplemental Indenture dated August 1, 2014
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2014

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SIGNATURE

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PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2014

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2014

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Exhibit 4(a)(22)

SUPPLEMENTAL MORTGAGE

Supplemental Indenture

Dated August 1, 2014

SUPPLEMENTAL TO
FIRST AND REFUNDING MORTGAGE
DATED AUGUST 1, 1924

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
TO
U.S. BANK NATIONAL ASSOCIATION
Trustee
21 South Street
Morristown, New Jersey 07960

PROVIDING FOR THE ISSUE OF
$775,000,000 FIRST AND REFUNDING MORTGAGE BONDS,
MEDIUM-TERM NOTES SERIES J

RECORD IN MORTGAGE BOOK AND RETURN TO:
M. COURTNEY McCORMICK, ESQ.
80 PARK PLAZA, T5B
NEWARK, N.J. 07102-4194

Prepared by

/s/ Donald S. Leibowitz

(DONALD S. LEIBOWITZ, ESQ.)

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SUPPLEMENTAL INDENTURE, dated the 1st day of August 2014 for convenience of reference and effective from the time of execution and delivery hereof, between Public Service Electric and Gas Company, a corporation organized under the laws of the State of New Jersey, hereinafter called the "Company", party of the first part, and U.S. Bank National Association, a national banking association organized under the laws of the United States of America, as successor Trustee to Wachovia Bank, National Association (previously known as Fidelity Union Trust Company) under the indenture dated August 1, 1924, below mentioned, hereinafter called the "Trustee", party of the second part.

Whereas, on July 25, 1924, the Company executed and delivered to Fidelity Union Trust Company, a certain indenture dated August 1, 1924 (hereinafter called the "Indenture") to secure and to provide for the issue of First and Refunding Mortgage Gold Bonds of the Company; and

Whereas, the Indenture has been recorded in the following counties of the State of New Jersey, in the offices, and therein in the books and at the pages, as follows:

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County	Office	Book Number	Page Number
Atlantic	Clerk's	1955 of Mortgages	160
Bergen	Clerk's	94 of Chattel Mortgages	123 etc.
		693 of Mortgages	88 etc.
Burlington	Clerk's	52 of Chattel Mortgages	Folio 8 etc.
		177 of Mortgages	Folio 354 etc.
Camden	Register's	45 of Chattel Mortgages	184 etc.
		239 of Mortgages	1 etc.
Cumberland	Clerk's	786 of Mortgages	638 & c.
Essex	Register's	437 of Chattel Mortgages	1-48
		T-51 of Mortgages	341-392
Gloucester	Clerk's	34 of Chattel Mortgages	123 etc.
		142 of Mortgages	7 etc.
Hudson	Register's	453 of Chattel Mortgages	9 etc.
		1245 of Mortgages	484, etc.
Hunterdon	Clerk's	151 of Mortgages	344
Mercer	Clerk's	67 of Chattel Mortgages	1 etc.
		384 of Mortgages	1 etc.
Middlesex	Clerk's	113 of Chattel Mortgages	3 etc.
		437 of Mortgages	294 etc.
Monmouth	Clerk's	951 of Mortgages	291 & c.
Morris	Clerk's	N-3 of Chattel Mortgages	446 etc.
		F-10 of Mortgages	269 etc.
Ocean	Clerk's	1809 of Mortgages	40
Passaic	Register's	M-6 of Chattel Mortgages	178, etc.
		R-13 of Mortgages	268 etc.
Salem	Clerk's	267 of Mortgages	249 etc.
Somerset	Clerk's	46 of Chattel Mortgages	207 etc.
		N-10 of Mortgages	1 etc.
Sussex	Clerk's	123 of Mortgages	10 & c.
Union	Register's	9584 of Mortgages	259 etc.
Warren	Clerk's	124 of Mortgages	141 etc.

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and

Whereas, the Indenture has also been recorded in the following counties of the Commonwealth of Pennsylvania, in the offices, and therein in the books and at the pages, as follows:

County	Office	Book Number	Page Number
Adams	Recorder's	22 of Mortgages	105
Armstrong	Recorder's	208 of Mortgages	381
Bedford	Recorder's	90 of Mortgages	917
Blair	Recorder's	671 of Mortgages	430
Cambria	Recorder's	407 of Mortgages	352
Cumberland	Recorder's	500 of Mortgages	136
Franklin	Recorder's	285 of Mortgages	373
Huntingdon	Recorder's	128 of Mortgages	47
Indiana	Recorder's	197 of Mortgages	281
Lancaster	Recorder's	984 of Mortgages	1
Montgomery	Recorder's	5053 of Mortgages	1221
Westmoreland	Recorder's	1281 of Mortgages	198
York	Recorder's	31-V of Mortgages	446

and

Whereas, the Indenture granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company, more fully set forth and described in the Indenture, then owned or which might thereafter be acquired by the Company; and

Whereas, the Company, by various supplemental indentures, supplemental to the Indenture, the last of which was dated May 1, 2013, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over unto the Trustee certain property of the Company acquired by it after the execution and delivery of the Indenture; and

Whereas, since the execution and delivery of said supplemental indenture dated May 1, 2013, the Company has acquired property which, in accordance with the provisions of the Indenture, is subject to the lien thereof and the Company desires to confirm such lien; and

Whereas, the Indenture has been amended or supplemented from time to time; and

Whereas, it is provided in the Indenture that no bonds other than those of the 5-1/2% Series due 1959 therein authorized may be issued thereunder unless a supplemental indenture providing for the issue of such additional bonds shall have been executed and delivered by the Company to the Trustee; and

Whereas, the Company is making provisions for the issuance and sale of its Secured Medium-Term Notes, Series J (the "Series J Notes"), to be issued under an Indenture of Trust (the "Note Indenture") dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as Trustee (the "Note Trustee"); and

Whereas, such Note Indenture provides, among other things, for the pledge and delivery by the Company of a series of First and Refunding Mortgage Bonds of the Company to evidence the Company's obligation to pay the principal and interest with respect to outstanding Series J Notes; and for such purpose and in order to service and secure payment of the principal and interest in respect of the Series J Notes, the Company desires to provide for the issue of $775,000,000 aggregate principal amount of bonds under the Indenture of a series to be designated as "First and Refunding Mortgage Bonds, Medium-Term Notes Series J" (hereinafter sometimes called "Bonds of the Medium-Term Notes Series J"); and

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Whereas, the text of the Bonds of the Medium-Term Notes Series J and of the certificate of authentication to be borne by the Bonds of the Medium-Term Notes Series J shall be substantially of the following tenor:

(Form of Bond)

This Bond is not transferable except as provided in the Indenture and in the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) (The Bank of New York Mellon, successor trustee) as Trustee.

REGISTERED	REGISTERED
NUMBER	AMOUNT
R	$775,000,000

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
First and Refunding Mortgage Bond,

Medium-Term Notes Series J

Public Service Electric and Gas Company (hereinafter called the "Company"), a corporation of the State of New Jersey, for value received, hereby promises to pay to The Bank of New York Mellon as successor trustee to The Chase Manhattan Bank (National Association)), under the Indenture of Trust dated as of July 1, 1993 between the Company and such trustee, or registered assigns, on the surrender hereof, the principal sum of Seven Hundred Seventy Five Million Dollars, on August 1, 2049, and to pay interest thereon from the date hereof, at the rate of 10% per annum, and until payment of said principal sum, such interest to be payable February 1 and August 1 in each year; provided, however, that the Company shall receive certain credits against such obligations as set forth in the Supplemental Indenture dated August 1, 2014 referred to below.

Both the principal hereof and interest hereon shall be paid at the principal corporate trust office of U.S. Bank National Association in the City of Morristown, State of New Jersey, or (at the option of the registered owner) at the corporate trust office of any paying agent appointed by the Company, in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts; provided, however, that any such payments of principal and interest shall be subject to receipt of certain credits against such payment obligations as set forth in the Supplemental Indenture dated August 1, 2014 referred to below.

This Bond is one of the First and Refunding Mortgage Bonds of the Company issued and to be issued under and pursuant to, and all equally secured by, an indenture of mortgage or deed of trust dated August 1, 1924, as supplemented and amended by supplemental indentures thereto, including the Supplemental Indenture dated August 1, 2014, duly executed by the Company and U.S. Bank National Association as Trustee. This Bond is one of the Bonds of the Medium-Term Notes Series J, which series is limited to the aggregate principal amount of $775,000,000 and is issued pursuant to said Supplemental Indenture dated August 1, 2014. Reference is hereby made to said indenture and all supplements thereto for a specification of the principal amount of Bonds from time to time issuable thereunder, and for a description of the properties mortgaged and conveyed or assigned to said Trustee or its successors, the nature and extent of the security, and the rights of the holders of said Bonds and any coupons appurtenant thereto, and of the Trustee in respect of such security.

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In and by said indenture, as amended and supplemented, it is provided that with the written approval of the Company and the Trustee, any of the provisions of said indenture may from time to time be eliminated or modified and other provisions may be added thereto provided the change does not alter the annual interest rate, redemption price or date, date of maturity or amount payable on maturity of any then outstanding Bond or conflict with the Trust Indenture Act of 1939 as then in effect, and provided the holders of 85% in principal amount of the Bonds secured by said indenture and then outstanding (including, if such change affects the Bonds of one or more series but less than all series then outstanding, a like percentage of the then outstanding Bonds of each series affected by such change, and excluding Bonds owned or controlled by the Company or by the parties owning at least 10% of the outstanding voting stock of the Company, as more fully specified in said indenture) consent in writing thereto, all as more fully set forth in said indenture, as amended and supplemented.

First and Refunding Mortgage Bonds issuable under said indenture are issuable in series, and the Bonds of any series may be for varying principal amounts and in the form of coupon bonds and of registered bonds without coupons, and the Bonds of any one series may differ from the Bonds of any other series as to date, maturity, interest rate and otherwise, all as in said indenture provided and set forth. The Bonds of the Medium-Term Notes Series J, in which this Bond is included, are designated "First and Refunding Mortgage Bonds, Medium-Term Notes Series J".

In case of the happening of an event of default as specified in said indenture and said supplemental indenture dated March 1, 1942, the principal sum of the Bonds of this series may be declared or may become due and payable forthwith, in the manner and with the effect in said indenture provided.

The Bonds of this series are subject to redemption as provided in the Supplemental Indenture dated August 1, 2014.

This Bond is transferable, but only as provided in said indenture and the Indenture of Trust dated as of July 1, 1993 between the Company and The Chase Manhattan Bank (National Association) as predecessor trustee (The Bank of New York Mellon, as successor trustee to the predecessor trustee), as trustee, upon surrender hereof, by the registered owner in person or by attorney duly authorized in writing, at either of said offices where the principal hereof and interest hereon are payable; upon any such transfer a new fully registered Bond similar hereto will be issued to the transferee. This Bond may in like manner be exchanged for one or more new fully registered Bonds of the same series of other authorized denominations but of the same aggregate principal amount. No service charge shall be made for any such transfer or exchange, but the Company may require payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto. The Company and the Trustee hereunder and any paying agent may deem and treat the person in whose name this Bond is registered as the absolute owner hereof for the purpose of receiving payment of or on account of the principal hereof and the interest hereon and for all other purposes; and neither the Company nor the Trustee hereunder nor any paying agent shall be affected by any notice to the contrary.

The Bonds of this series are issuable only in fully registered form, in any denomination authorized by the Company.

No recourse under or upon any obligation, covenant or agreement contained in said indenture or in any indenture supplemental thereto, or in any Bond issued thereunder, or because of any indebtedness arising thereunder, shall be had against any incorporator, or against any past, present or future stockholder, officer, or director, as such, of the Company or of any successor corporation, either directly or through the Company or any successor corporation, under any rule of law, statute or constitutional provision or by the enforcement of any assessment or by any legal or equitable proceeding or otherwise, it being expressly agreed and understood that said indenture, any indenture supplemental thereto and the obligations issued thereunder, are solely corporate obligations, and that no personal liability whatever shall attach to, or be incurred by, such incorporators, stockholders, officers or directors, as such, of the Company, or of any successor corporation, or any of them, because of the incurring of the indebtedness thereby authorized, or under or by reason of any of the obligations, covenants or agreements contained in the indenture or in any indenture supplemental thereto or in any of the Bonds issued thereunder, or implied therefrom.

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This Bond shall not be entitled to any security or benefit under said indenture, as amended and supplemented, and shall not become valid or obligatory for any purpose, until the certificate of authentication, hereon endorsed, shall have been signed by U.S. Bank National Association as Trustee, or by its successor in trust under said indenture.

In Witness Whereof, the Company has caused this Bond to be duly executed by its proper officers under its corporate seal.

Dated

PUBLIC SERVICE ELECTRIC AND GAS COMPANY,

By. . . . . .
(Vice) President

(Seal)
Attest:

. . . . . .
(Assistant) Secretary

(Form of Certificate of Authentication)

Certificate of Authentication

This Bond is one of the Bonds of the series designated therein which is described in the within-mentioned indenture and supplemental indenture dated August 1, 2014, as secured thereby.

U.S. BANK NATIONAL ASSOCIATION, TRUSTEE,

By. . . . . .
Authorized Signatory

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Whereas, the execution and delivery of this supplemental indenture have been duly authorized by the Board of Directors of the Company; and

Whereas, the Company represents that all things necessary to make the bond of the series hereinafter described, when duly authenticated by the Trustee and issued by the Company, a valid, and legal obligation of the Company, and to make this supplemental indenture a valid and binding agreement supplemental to the Indenture, have been done and performed:

Now, therefore, this supplemental indenture witnesseth that the Company, in consideration of the premises and the execution and delivery by the Trustee of this supplemental indenture, and in pursuance of the covenants and agreements contained in the Indenture and for other good and valuable consideration, the receipt of which is hereby acknowledged, has granted, bargained, sold, aliened, remised, released, conveyed, confirmed, assigned, transferred and set over, and by these presents does grant, bargain, sell, alien, remise, release, convey, confirm, assign, transfer and set over unto the Trustee, its successors and assigns, forever, all the right, title and interest of the Company in and to all property of every kind and description (except cash, accounts and bills receivable and all merchandise bought, sold or manufactured for sale in the ordinary course of the Company's business, stocks, bonds or other corporate obligations or securities, other than such as are described in Part V of the Granting Clauses of the Indenture, not acquired with the proceeds of bonds secured by the Indenture, and except as in the Indenture and herein otherwise expressly excluded) acquired by the Company since the execution and delivery of the supplemental indenture dated May 1, 2013, subsequent to the Indenture (except any such property duly released from, or disposed of, free from the lien of the Indenture, in accordance with the provisions thereof) and all such property which at any time hereafter may be acquired by the Company;

All of which property it is intended shall be included in and granted by this supplemental indenture and covered by the lien of the Indenture as heretofore and hereby amended and supplemented;

Under and subject to any encumbrances or mortgages existing on property acquired by the Company at the time of such acquisition and not heretofore discharged of record; and

Subject also, to the exceptions, reservations and provisions in the Indenture and in this supplemental indenture recited, and to the liens, reservations, exceptions, limitations, conditions and restrictions imposed by or contained in the several deeds, grants, franchises and contracts or other instruments through which the Company acquired or claims title to the aforesaid property; and Subject, also, to the existing leases, to liens on easements or rights of way, to liens for taxes, assessments and governmental charges not in default or the payment of which is deferred, pending appeal or other contest by legal proceedings, pursuant to Section 4 of Article Five of the Indenture, or the payment of which is deferred pending billing, transfer of title or final determination of amount, to easements for alleys, streets, highways, rights of way and railroads that may run across or encroach upon the said property, to joint pole and similar agreements, to undetermined liens and charges, if any, incidental to construction, and other encumbrances permitted by the Indenture as heretofore and hereby amended and supplemented;

To have and to hold the property hereby conveyed or assigned, or intended to be conveyed or assigned, unto the Trustee, its successor or successors and assigns, forever;

In trust, nevertheless, upon the terms, conditions and trusts set forth in the Indenture as heretofore and hereby amended and supplemented, to the end that the said property shall be subject to the lien of the Indenture as heretofore and hereby amended and supplemented, with the same force and effect as though said property had been included in the Granting Clauses of the Indenture at the time of the execution and delivery thereof;

And this supplemental indenture further witnesseth that for the considerations aforesaid, it is hereby covenanted between the Company and the Trustee as follows:

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ARTICLE I.

Bonds of the Medium-Term Notes Series J.

The series of bonds authorized by this supplemental indenture to be issued under and secured by the Indenture shall be designated "First and Refunding Mortgage Bonds, Medium-Term Notes Series J"; shall be limited to the aggregate principal amount of $775,000,000; shall be issued initially to the Note Trustee and shall mature and bear interest as set forth in the form of bond set forth herein; provided, however, that the Company shall receive certain credits against principal and interest as set forth in Section 3.01 hereof. The date of each Bond of the Medium-Term Notes Series J shall be the interest payment date next preceding the date of authentication, unless such date of authentication be an interest payment date, in which case the date shall be the date of authentication, or unless such date of authentication be prior to the first semi-annual interest payment date, in which case the date shall be August 1, 2014.

Bonds of the Medium-Term Notes Series J shall be issuable only in the form of fully registered bonds in any denomination authorized by the Company. Interest on the Bonds of the Medium-Term Notes Series J shall be payable semi-annually in arrears on February 1 and August 1 of each year, payable initially on February 1, 2015, subject to receipt of certain credits against principal and interest as set forth in Section 3.01 hereof and shall be payable as to both principal and interest in such coin or currency of the United States of America as at the time of payment shall constitute legal tender for the payment of public and private debts, at the principal corporate trust office of the Trustee, or at the corporate trust office of any paying agent appointed.

Bonds of the Medium-Term Notes Series J shall be transferable and exchangeable, but only as provided in the Indenture and the Note Indenture, upon surrender thereof for cancellation by the registered owner in person or by attorney duly authorized in writing at either of said offices. The Company hereby waives any right to make a charge for any transfer or exchange of Bonds of the Medium-Term Notes Series J, but the Company may require payment of a sum sufficient to cover any tax or any other governmental charge that may be imposed in relation thereto.

ARTICLE II.

Redemption of Bonds of Medium-Term Notes Series J.

Section 2.01. *Redemption-Redemption Price*. Bonds of the Medium-Term Notes Series J shall be subject to redemption prior to maturity under the conditions, and upon payment of the amounts as may be specified in the following conditions:

(a) at any time in whole or in part at the option of the Company upon receipt by the Trustee of written certification of the Company and of the Note Trustee that the principal amount of the Series J Notes then outstanding under the Note Indenture is not in excess of such principal amount of the Bonds of the Medium-Term Notes Series J as shall remain pledged to the Note Trustee after giving effect to such redemption; (b) at any time by the application of any proceeds of released property or other money held by the Trustee and which, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, are applied to the redemption of Bonds of the Medium-Term Notes Series J, upon payment of 100% of the principal amount thereof, together with interest accrued to the redemption date, provided that any such payment shall be subject to receipt by the Company of certain credits against such obligations as set forth in Section 3.01 hereof or (c) automatically upon failure to pay the principal of any Series J Notes then outstanding under the Note Indenture when due, on their stated maturity date or earlier redemption or repayment date, in a principal amount of Bonds of the Medium-Term Notes Series J equal to the principal amount of such Series J Notes, in each case, at a price equal to 100% of the principal amount thereof, together with accrued interest, if applicable.

Section 2.02. *Redemptions Pursuant to Section 4C of Article Eight of the Indenture*. If, pursuant to Section 4C of Article Eight of the Indenture, as amended and supplemented, any proceeds of released property or other money then held by the Trustee shall be applied to the redemption of the Bonds of the Medium-Term Notes Series J, the Trustee shall give at least 45 days prior written

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notice of such redemption to the Note Trustee whereupon on the date fixed for redemption such principal amount thereof as is equal to such proceeds shall be redeemed; provided that no such redemption shall be made unless the Trustee shall be in receipt of a written certification of the Company and the Note Trustee that a like principal amount of Series J Notes shall have been theretofore redeemed in accordance with the provisions of the Note Indenture. For purposes of determining which of the Company's First and Refunding Mortgage Bonds are subject to such mandatory redemption, the Mortgage Trustee shall consider the 10% stated annual interest rate of the Bonds of the Medium-Term Notes Series J, not the weighted average interest rate of outstanding Series J Notes. Bonds of said series so redeemed shall be cancelled.

Section 2.03. *Interest on Called Bonds to Cease.* Each Bond of the Medium-Term Notes Series J or portion thereof called for redemption under Section 2.02 hereof shall be due and payable at the office of the Note Trustee, as paying agent hereunder, at its redemption price and on the specified redemption date, anything herein or in such Bond to the contrary notwithstanding. From and after the date when each Bond of the Medium-Term Notes Series J or portion thereof shall be due and payable as aforesaid (unless upon said date the full amount due thereon shall not be held by the Note Trustee, as paying agent hereunder, and be immediately available for payment), all further interest shall cease to accrue on such bond or on such portion thereof, as the case may be.

Section 2.04. *Bonds Called in Part.* If only a portion of any Bond of the Medium-Term Notes Series J shall be called for redemption pursuant to Section 2.02 hereof, upon payment of the portion so called for redemption, the Note Trustee shall make an appropriate notation upon the Bond of the principal amount so redeemed.

Section 2.05. *Provisions of Indenture Not Applicable*. The provisions of Article Four of the Indenture, as amended and supplemented, shall not apply to the procedure for the exercise of any right of redemption reserved by the Company, or to any mandatory redemption provided, in this Article in respect of the Bonds of the Medium-Term Notes Series J. There shall be no sinking fund for the Bonds of the Medium-Term Notes Series J.

ARTICLE III.

Credits with Respect to Bonds of the Medium-Term Notes Series J.

Section 3.01. *Credits.* In addition to any other credit, payment or satisfaction to which the Company is entitled with respect to the Bonds of the Medium-Term Notes Series J, the Company shall be entitled to credits against amounts otherwise payable in respect of the Bonds of the Medium-Term Notes Series J in an amount corresponding to (i) the principal amount of any of the Company's Series J Notes issued under the Note Indenture surrendered to the Note Trustee by the Company, or purchased by the Note Trustee, for cancellation, (ii) the amount of money held by the Note Trustee and available and designated for the payment of principal or redemption price (exclusive of any premium) of, and/or interest on, the Series J Notes, regardless of the source of payment to the Note Trustee of such moneys and (iii) the amount by which principal of and interest due on the Bonds of the Medium-Term Notes Series J exceeds principal of and interest due on the Series J Notes. The Note Trustee shall make notation on such Bonds authorized hereby of any such credit.

Section 3.02. *Certificate of the Company*. A certificate of the Company signed by the President or any Vice President, and attested to by the Secretary or any Assistant Secretary, and consented to by the Note Trustee, stating that the Company is entitled to a credit under Section 3.01 hereof or that Bonds of the Medium-Term Notes Series J have been cancelled, and setting forth the basis therefor in reasonable detail, shall be conclusive evidence of such entitlement, and the Trustee shall accept such certificate as such evidence without further investigation or verification of the matters stated therein.

ARTICLE IV.

Miscellaneous.

Section 4.01. *Authentication of Bonds of Medium-Term Notes Series J.* None of the Bonds of the Medium-Term Notes Series J, the issue of which is provided for by this supplemental indenture, shall be authenticated by or on behalf of the Trustee except in accordance with the provisions of the Indenture, as amended and supplemented, and this supplemental indenture, and upon compliance with the conditions in that behalf therein contained.

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Section 4.02. *Additional Restrictions on Authentication of Additional Bonds Under Indenture.* The Company covenants that from and after the date of execution of this supplemental indenture no additional bonds (as defined in Section 1 of Article Two of the Indenture) shall be authenticated and delivered by the Trustee under Subdivision A of Section 4 of said Article Two on account of additions or improvements to the mortgaged property;

(1) unless the net earnings of the Company for the period required by Subdivision C of Section 6 of said Article Two shall have been at least twice the fixed charges (in lieu of 1-3/4 times such fixed charges, as required by said Subdivision C); and for the purpose of this condition (a) such fixed charges shall in each case include interest on the bonds applied for, notwithstanding the parenthetical provision contained in clause (4) of said Subdivision C, and (b) in computing such net earnings there shall be included in expenses of operation (under paragraph (c) of said Subdivision C) all charges against earnings for depreciation, renewals or replacements, and all certificates with respect to net earnings delivered to the Trustee in connection with any authentication of additional bonds under said Article Two shall so state; and (2) except to the extent of 60% (in lieu of 75% as permitted by Subdivision A of Section 7 of said Article Two) of the cost or fair value to the Company of the additions or improvements forming the basis for such authentication of additional bonds.

Section 4.03. *Restriction on Dividends.* The Company will not declare or pay any dividend on any shares of its common stock (other than dividends payable in shares of its common stock) or make any other distribution on any such shares, or purchase or otherwise acquire any such shares (except shares acquired without cost to the Company) whenever such action would reduce the earned surplus of the Company to an amount less than $10,000,000 or such lesser amount as may remain after deducting from said $10,000,000 all amounts appearing in the books of account of the Company on December 31, 1948, which shall thereafter, pursuant to any order or rule of any regulatory body entered after said date, be required to be removed, in whole or in part, from the books of account of the Company by charges to earned surplus.

Section 4.04. *Use of Facsimile Seal and Signatures.* The seal of the Company and any or all signatures of the officers of the Company upon any of the Bonds of the Medium-Term Notes Series J may be facsimiles.

Section 4.05. *Time for Making of Payment.* All payments of principal or redemption price of, and interest on, the Bonds of the Medium-Term Notes Series J shall be made either prior to the due date thereof or on the due date thereof in immediately available funds. In any case where the date of any such payment shall be a Saturday or Sunday or a legal holiday or a day on which banking institutions in the city of payment are authorized by law to close, then such payment need not be made on such date but may be made on the next succeeding business day with the same force and effect as if made on the due date, and no interest on such payment shall accrue for the period after such date.

Section 4.06. *Effective Period of Supplemental Indenture.* The preceding provisions of Articles I, II and III of this supplemental indenture shall remain in effect only so long as any of the Bonds of the Medium-Term Notes Series J shall remain outstanding.

Section 4.07. *Effect of Approval of Board of Public Utilities of the State of New Jersey.* The approval of the Board of Public Utilities of the State of New Jersey of the execution and delivery of these presents and of the issue of any Bond of the Medium-Term Notes Series J shall not be construed as approval of said Board of any other act, matter or thing which requires approval of said Board under the laws of the State of New Jersey.

Section 4.08. *Execution in Counterparts.* For the purpose of facilitating the recording hereof, this supplemental indenture has been executed in several counterparts, each of which shall be and shall be taken to be an original, and all collectively but one instrument.

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In witness whereof, Public Service Electric and Gas Company, party hereto of the first part, after due corporate and other proceedings, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents and its corporate seal hereunto to be affixed and to be attested by the signature of its Secretary or an Assistant Secretary; and U.S. Bank National Association, as Trustee, party hereto of the second part, has caused this supplemental indenture to be signed and acknowledged or proved by its President or one of its Vice Presidents, and its corporate seal to be hereunto affixed and to be attested by the signature of its Secretary, Assistant Secretary, Vice President, or an Assistant Vice President. Executed and delivered this 1st day of August 2014.

Attest:

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By */s/ B. D. Huntington*
. . . . . .
B. D. Huntington
Vice President

Attest:
/s/ E. C. Fedak
. . . . . .
E. C. Fedak
Assistant Secretary

U.S. BANK NATIONAL ASSOCIATION

By */s/ N. Barnes*
. . . . . .
N. Barnes
Vice President

Attest:
/s/ A. Harris
. . . . . .
A. Harris
Vice President

STATE OF NEW JERSEY)
SS:)
COUNTY OF ESSEX)

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Be it Remembered, that on this 1st day of August, 2014, before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared B.D. Huntington, who, I am satisfied, is a Vice President of Public Service Electric and Gas Company, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors, and that said corporation, the mortgagor, has received a true copy of said instrument.

/s/ Susan M. Costello
. . . . . .
Susan M. Costello
Notary Public of New Jersey
My Commission Expires March 26, 2017

STATE OF NEW JERSEY)
SS:)
COUNTY OF ESSEX)

Be it Remembered, that on this 1st day of August 2014 before me, the subscriber, a Notary Public of the State of New Jersey, personally appeared N. Barnes, who, I am satisfied, is a Vice President of U.S. Bank National Association, one of the corporations named in and which executed the foregoing instrument, and is the person who signed the said instrument as such officer, for and on behalf of such corporation, and I having first made known to him the contents thereof, he did acknowledge that he signed the said instrument as such officer, that the said instrument was made by such corporation and sealed with its corporate seal, and that the said instrument is the voluntary act and deed of such corporation, made by virtue of authority from its Board of Directors.

/s/ June Barnett
.....
June Barnett
Notary Public of New Jersey
My Commission Expires July 31, 2018

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CERTIFICATE OF RESIDENCE

U.S. Bank National Association, Mortgagee and Trustee within named, hereby certifies that its precise residence is 21 South Street, Morristown, New Jersey 07960.

U.S. BANK NATIONAL ASSOCIATION

By */s/ N. Barnes*
. . . . . .
N. Barnes
Vice President

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2014	2013	2013	2012	2011	2010	2009
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,675	$ 1,751	$ 2,055	$ 2,011	$ 2,384	$ 2,616	$ 2,636
(Income) Loss from Equity Investees, net of Distributions	—	(5)	(7)	9	(4)	(19)	(25)
Fixed Charges	335	345	458	479	522	571	600
Capitalized Interest	(10)	(12)	(16)	(19)	(14)	(67)	(45)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	(2)	(6)
Total Earnings	$ 2,000	$ 2,079	$ 2,490	$ 2,480	$ 2,888	$ 3,099	$ 3,160
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 320	$ 333	$ 442	$ 465	$ 509	$ 555	$ 581
Interest Factor in Rentals	15	12	16	14	13	14	13
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	2	6
Total Fixed Charges	$ 335	$ 345	$ 458	$ 479	$ 522	$ 571	$ 600
Ratio of Earnings to Fixed Charges	**5.97**	**6.03**	**5.44**	**5.18**	**5.53**	**5.43**	**5.27**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12.1

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30		Years Ended December 31,				
	2014	**2013**	**2013**	**2012**	**2011**	**2010**	**2009**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 717	$ 961	$1,063	$1,099	$1,703	$1,932	$1,969
(Income) Loss from Equity Investees, net of Distributions	(1)	(8)	(10)	(6)	(12)	(8)	(7)
Fixed Charges	112	106	143	164	208	238	221
Capitalized Interest	2	1	1	(6)	(10)	(63)	(43)
Total Earnings	$ 830	$ 1,060	$1,197	$1,251	$1,889	$2,099	$2,140
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 109	$ 103	$ 139	$ 161	$ 205	$ 235	$ 219
Interest Factor in Rentals	3	3	4	3	3	3	2
Total Fixed Charges	$ 112	$ 106	$ 143	$ 164	$ 208	$ 238	$ 221
Ratio of Earnings to Fixed Charges	**7.41**	**10.00**	**8.37**	**7.63**	**9.08**	**8.82**	**9.68**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2014	**2013**	**2013**	**2012**	**2011**	**2010**	**2009**
			(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 920	$ 779	$ 993	$ 835	$ 861	$ 591	$ 551
Fixed Charges	226	240	316	314	319	325	317
Capitalized Interest	(12)	(12)	(16)	(13)	(4)	(2)	(1)
Total Earnings	$ 1,134	$ 1,007	$1,293	$1,136	$ 1,176	$ 914	$ 867
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 218	$ 235	$ 309	$ 308	$ 314	$ 320	$ 313
Interest Factor in Rentals	8	5	7	6	5	5	4
Total Fixed Charges	$ 226	$ 240	$ 316	$ 314	$ 319	$ 325	$ 317
Ratio of Earnings to Fixed Charges	**5.02**	**4.20**	**4.09**	**3.62**	**3.69**	**2.81**	**2.74**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.3

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Nine Months Ended September 30,		Years Ended December 31,				
	2014	**2013**	**2013**	**2012**	**2011**	**2010**	**2009**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 920	$ 779	$ 993	$ 835	$ 861	$ 591	$ 551
Fixed Charges	226	240	316	314	319	327	323
Capitalized Interest	(12)	(12)	(16)	(13)	(4)	(2)	(1)
Preferred Securities Dividend Requirements	—	—	—	—	—	(2)	(6)
Total Earnings	$ 1,134	$ 1,007	$1,293	$1,136	$1,176	$ 914	$ 867
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 218	$ 235	$ 309	$ 308	$ 314	$ 320	$ 313
Interest Factor in Rentals	8	5	7	6	5	5	4
Preferred Securities Dividend	—	—	—	—	—	1	4
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	—	—	—	1	2
Total Fixed Charges	$ 226	$ 240	$ 316	$ 314	$ 319	$ 327	$ 323
Ratio of Earnings to Fixed Charges	**5.02**	**4.20**	**4.09**	**3.62**	**3.69**	**2.80**	**2.68**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period, (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries, and (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2014

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2014

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2014

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2014

/s/ Caroline Dorsa

Caroline Dorsa
PSEG Power LLC
Chief Financial Officer

S1-SSA-0009 - 18928

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2014

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Caroline Dorsa, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2014

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer

S1-SSA-0009 - 18930

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
October 30, 2014

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Caroline Dorsa

Caroline Dorsa
Public Service Enterprise Group Incorporated
Chief Financial Officer
October 30, 2014

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
October 30, 2014

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Caroline Dorsa

Caroline Dorsa

PSEG Power LLC
Chief Financial Officer
October 30, 2014

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
October 30, 2014

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Caroline Dorsa, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Caroline Dorsa

Caroline Dorsa

Public Service Electric and Gas Company
Chief Financial Officer
October 30, 2014

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2015
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of October 20, 2015, Public Service Enterprise Group Incorporated had outstanding 505,961,856 shares of its sole class of Common Stock, without par value.

As of October 20, 2015, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulations, including market structures and transmission planning,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- any deterioration in our credit quality or the credit quality of our counterparties,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as for transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies, and
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
OPERATING REVENUES	$ 2,688	$ 2,641	$ 8,137	$ 8,113
OPERATING EXPENSES				
Energy Costs	815	863	2,577	3,008
Operation and Maintenance	746	714	2,170	2,370
Depreciation and Amortization	313	318	960	919
Total Operating Expenses	1,874	1,895	5,707	6,297
OPERATING INCOME	814	746	2,430	1,816
Income from Equity Method Investments	3	3	10	10
Other Income	47	75	171	185
Other Deductions	(14)	(9)	(36)	(31)
Other-Than-Temporary Impairments	(30)	(10)	(45)	(14)
Interest Expense	(96)	(100)	(291)	(291)
INCOME BEFORE INCOME TAXES	724	705	2,239	1,675
Income Tax Expense	(285)	(261)	(869)	(633)
NET INCOME	$ 439	$ 444	$ 1,370	$ 1,042
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	505	506	505	506
DILUTED	508	507	508	507
NET INCOME PER SHARE:				
BASIC	$ 0.87	$ 0.88	$ 2.71	$ 2.06
DILUTED	$ 0.87	$ 0.87	$ 2.70	$ 2.05
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.39	$ 0.37	$ 1.17	$ 1.11

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
NET INCOME	$ 439	$ 444	$ 1,370	$ 1,042
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $33, $33, $35 and $21 for the three and nine months ended 2015 and 2014, respectively	(31)	(30)	(32)	(17)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(1), $(1), $6 and $(3) for the three and nine months ended 2015 and 2014, respectively	—	1	(9)	4
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(5), $(2), $(17) and $(5) for three and nine months ended 2015 and 2014, respectively	9	3	25	9
Other Comprehensive Income (Loss), net of tax	(22)	(26)	(16)	(4)
COMPREHENSIVE INCOME	$ 417	$ 418	$ 1,354	$ 1,038

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 271	$ 402
Accounts Receivable, net of allowances of $59 and $52 in 2015 and 2014, respectively	1,199	1,254
Tax Receivable	5	211
Unbilled Revenues	203	284
Fuel	451	538
Materials and Supplies, net	472	484
Prepayments	180	108
Derivative Contracts	162	240
Deferred Income Taxes	23	11
Regulatory Assets	189	323
Regulatory Assets of Variable Interest Entities (VIEs)	—	249
Restricted Cash of VIEs	26	—
Other	23	15
Total Current Assets	3,204	4,119
PROPERTY, PLANT AND EQUIPMENT	34,625	32,196
Less: Accumulated Depreciation and Amortization	(9,020)	(8,607)
Net Property, Plant and Equipment	25,605	23,589
NONCURRENT ASSETS		
Regulatory Assets	3,161	3,192
Long-Term Investments	1,235	1,307
Nuclear Decommissioning Trust (NDT) Fund	1,715	1,780
Long-Term Tax Receivable	165	64
Long-Term Receivable of VIE	601	580
Other Special Funds	230	212
Goodwill	16	16
Other Intangibles	122	84
Derivative Contracts	91	77
Restricted Cash of VIEs	—	24
Other	279	289
Total Noncurrent Assets	7,615	7,625
TOTAL ASSETS	$ 36,424	$ 35,333

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2015	December 31, 2014
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 1,038	$ 624
Securitization Debt of VIEs Due Within One Year	68	259
Commercial Paper and Loans	20	—
Accounts Payable	1,046	1,178
Derivative Contracts	70	132
Accrued Interest	123	95
Accrued Taxes	204	21
Deferred Income Taxes	—	173
Clean Energy Program	185	142
Obligation to Return Cash Collateral	126	121
Regulatory Liabilities	208	186
Regulatory Liabilities of VIEs	3	—
Other	513	547
Total Current Liabilities	3,604	3,478
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	7,672	7,303
Regulatory Liabilities	181	258
Regulatory Liabilities of VIEs	—	39
Asset Retirement Obligations	776	743
Other Postretirement Benefit (OPEB) Costs	1,250	1,277
OPEB Costs of Servco	480	452
Accrued Pension Costs	373	440
Accrued Pension Costs of Servco	118	126
Environmental Costs	438	417
Derivative Contracts	23	33
Long-Term Accrued Taxes	287	208
Other	156	112
Total Noncurrent Liabilities	11,754	11,408
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Total Long-Term Debt	8,132	8,261
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2015 and 2014—533,556,660 shares	4,894	4,876
Treasury Stock, at cost, 2015— 28,238,912 shares; 2014— 27,720,068 shares	(667)	(635)
Retained Earnings	9,005	8,227
Accumulated Other Comprehensive Loss	(299)	(283)
Total Common Stockholders' Equity	12,933	12,185
Noncontrolling Interest	1	1
Total Stockholders' Equity	12,934	12,186
Total Capitalization	21,066	20,447
TOTAL LIABILITIES AND CAPITALIZATION	$ 36,424	$ 35,333

See Notes to Condensed Consolidated Financial Statements.

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, October 30, 2015
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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2015	**2014**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 1,370	$ 1,042
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	960	919
Amortization of Nuclear Fuel	162	151
Provision for Deferred Income Taxes (Other than Leases) and ITC	230	103
Non-Cash Employee Benefit Plan Costs	121	36
Leveraged Lease (Income) Loss, Adjusted for Rents Received and Deferred Taxes	6	(30)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(87)	237
Change in Accrued Storm Costs	15	(3)
Net Change in Other Regulatory Assets and Liabilities	26	276
Cost of Removal	(82)	(68)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(2)	(99)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	206	95
Accrued Taxes	127	127
Margin Deposit	142	(173)
Other Current Assets and Liabilities	15	(103)
Employee Benefit Plan Funding and Related Payments	(87)	(76)
Other	106	102
Net Cash Provided By (Used In) Operating Activities	3,228	2,536
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(2,782)	(1,922)
Proceeds from Sales of Capital Leases and Investments	12	11
Proceeds from Sales of Available-for-Sale Securities	1,120	1,224
Investments in Available-for-Sale Securities	(1,163)	(1,241)
Other	(28)	(60)
Net Cash Provided By (Used In) Investing Activities	(2,841)	(1,988)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	20	(60)
Issuance of Long-Term Debt	600	1,000
Redemption of Long-Term Debt	(300)	(500)
Redemption of Securitization Debt	(191)	(170)
Cash Dividends Paid on Common Stock	(592)	(561)
Other	(55)	(47)
Net Cash Provided By (Used In) Financing Activities	(518)	(338)
Net Increase (Decrease) in Cash and Cash Equivalents	(131)	210
Cash and Cash Equivalents at Beginning of Period	402	493
Cash and Cash Equivalents at End of Period	$ 271	$ 703
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 292	$ 284
Interest Paid, Net of Amounts Capitalized	$ 265	$ 269
Accrued Property, Plant and Equipment Expenditures	$ 321	$ 286

See Notes to Condensed Consolidated Financial Statements.

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Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, October 30, 2015 Powered by Morningstar® Document Research℠
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
OPERATING REVENUES	$ 1,766	$ 1,655	$ 5,234	$ 5,235
OPERATING EXPENSES				
Energy Costs	740	668	2,176	2,278
Operation and Maintenance	391	366	1,171	1,190
Depreciation and Amortization	231	238	712	682
Total Operating Expenses	1,362	1,272	4,059	4,150
OPERATING INCOME	404	383	1,175	1,085
Other Income	22	16	59	44
Other Deductions	—	(2)	(2)	(3)
Interest Expense	(67)	(71)	(203)	(206)
INCOME BEFORE INCOME TAXES	359	326	1,029	920
Income Tax Expense	(137)	(126)	(398)	(355)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 222	$ 200	$ 631	$ 565

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18946

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
NET INCOME	$ 222	$ 200	$ 631	$ 565
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0 for the three and nine months ended 2015 and 2014, respectively	—	1	(1)	1
COMPREHENSIVE INCOME	$ 222	$ 201	$ 630	$ 566

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18947

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 14	$ 310
Accounts Receivable, net of allowances of $59 and $52 in 2015 and 2014, respectively	938	864
Accounts Receivable-Affiliated Companies	7	274
Unbilled Revenues	203	284
Materials and Supplies	146	133
Prepayments	109	42
Regulatory Assets	189	323
Regulatory Assets of VIEs	—	249
Derivative Contracts	4	18
Deferred Income Taxes	47	24
Restricted Cash of VIEs	26	—
Other	17	7
Total Current Assets	1,700	2,528
PROPERTY, PLANT AND EQUIPMENT	22,940	21,103
Less: Accumulated Depreciation and Amortization	(5,419)	(5,183)
Net Property, Plant and Equipment	17,521	15,920
NONCURRENT ASSETS		
Regulatory Assets	3,161	3,192
Long-Term Investments	335	348
Other Special Funds	52	53
Derivative Contracts	—	8
Restricted Cash of VIEs	—	24
Other	140	150
Total Noncurrent Assets	3,688	3,775
TOTAL ASSETS	$ 22,909	$ 22,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18948

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, October 30, 2015 Powered by Morningstar® Document Research℠
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2015	December 31, 2014
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 171	$ 300
Securitization Debt of VIEs Due Within One Year	68	259
Commercial Paper and Loans	20	—
Accounts Payable	567	574
Accounts Payable—Affiliated Companies	208	379
Accrued Interest	80	68
Clean Energy Program	185	142
Deferred Income Taxes	—	165
Obligation to Return Cash Collateral	126	121
Regulatory Liabilities	208	186
Regulatory Liabilities of VIEs	3	—
Other	357	381
Total Current Liabilities	1,993	2,575
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,896	4,575
Other Postretirement Benefit (OPEB) Costs	929	967
Accrued Pension Costs	131	173
Regulatory Liabilities	181	258
Regulatory Liabilities of VIEs	—	39
Environmental Costs	387	364
Asset Retirement Obligations	304	290
Long-Term Accrued Taxes	165	116
Derivative Contracts	7	—
Other	58	67
Total Noncurrent Liabilities	7,058	6,849
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Total Long-Term Debt	6,441	6,012
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2015 and 2014—132,450,344 shares	892	892
Contributed Capital	695	695
Basis Adjustment	986	986
Retained Earnings	4,843	4,212
Accumulated Other Comprehensive Income	1	2
Total Stockholder's Equity	7,417	6,787
Total Capitalization	13,858	12,799
TOTAL LIABILITIES AND CAPITALIZATION	$ 22,909	$ 22,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18949

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 631	$ 565
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	712	682
Provision for Deferred Income Taxes and ITC	96	93
Non-Cash Employee Benefit Plan Costs	71	21
Cost of Removal	(82)	(68)
Change in Accrued Storm Costs	15	(3)
Net Change in Other Regulatory Assets and Liabilities	26	276
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	30	71
Materials and Supplies	(13)	(15)
Prepayments	(67)	(92)
Accounts Payable	34	(3)
Accounts Receivable/Payable—Affiliated Companies, net	190	(113)
Other Current Assets and Liabilities	(18)	(6)
Employee Benefit Plan Funding and Related Payments	(72)	(67)
Other	(35)	2
Net Cash Provided By (Used In) Operating Activities	1,518	1,343
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,946)	(1,493)
Proceeds from Sales of Available-for-Sale Securities	16	98
Investments in Available-for-Sale Securities	(18)	(96)
Other	13	1
Net Cash Provided By (Used In) Investing Activities	(1,935)	(1,490)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	20	(60)
Issuance of Long-Term Debt	600	1,000
Redemption of Long-Term Debt	(300)	(500)
Redemption of Securitization Debt	(191)	(170)
Contributed Capital	—	175
Other	(8)	(11)
Net Cash Provided By (Used In) Financing Activities	121	434
Net Increase (Decrease) In Cash and Cash Equivalents	(296)	287
Cash and Cash Equivalents at Beginning of Period	310	18
Cash and Cash Equivalents at End of Period	$ 14	$ 305
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (29)	$ 174
Interest Paid, Net of Amounts Capitalized	$ 186	$ 188
Accrued Property, Plant and Equipment Expenditures	$ 251	$ 238

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18950

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
OPERATING REVENUES	$ 1,096	$ 1,138	$ 3,846	$ 3,824
OPERATING EXPENSES				
Energy Costs	367	472	1,669	2,036
Operation and Maintenance	263	242	748	871
Depreciation and Amortization	75	71	226	215
Total Operating Expenses	705	785	2,643	3,122
OPERATING INCOME	391	353	1,203	702
Income from Equity Method Investments	3	4	11	11
Other Income	25	56	109	135
Other Deductions	(14)	(6)	(32)	(25)
Other-Than-Temporary Impairments	(30)	(10)	(45)	(14)
Interest Expense	(30)	(31)	(94)	(92)
INCOME BEFORE INCOME TAXES	345	366	1,152	717
Income Tax Expense	(139)	(144)	(445)	(277)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 206	$ 222	$ 707	$ 440

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18951

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
NET INCOME	$ 206	$ 222	$ 707	$ 440
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $32, $34, $33 and $23 for the three and nine months ended 2015 and 2014, respectively	(29)	(30)	(29)	(19)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(1), $0, $6 and $(2) for the three and nine months ended 2015 and 2014, respectively	—	1	(9)	4
Pension/OPEB adjustment, net of tax (expense) benefit of $(5), $(1), $(15) and $(4) for the three and nine months ended 2015 and 2014, respectively	7	2	21	7
Other Comprehensive Income (Loss), net of tax	(22)	(27)	(17)	(8)
COMPREHENSIVE INCOME	$ 184	$ 195	$ 690	$ 432

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18952

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2015	December 31, 2014
CURRENT ASSETS		
Cash and Cash Equivalents	$ 15	$ 9
Accounts Receivable	218	334
Accounts Receivable—Affiliated Companies	158	313
Tax Receivable	3	3
Short-Term Loan to Affiliate	865	584
Fuel	451	538
Materials and Supplies, net	324	350
Derivative Contracts	147	207
Prepayments	36	17
Other	7	4
Total Current Assets	2,224	2,359
PROPERTY, PLANT AND EQUIPMENT	11,273	10,732
Less: Accumulated Depreciation and Amortization	(3,366)	(3,217)
Net Property, Plant and Equipment	7,907	7,515
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,715	1,780
Long-Term Investments	116	121
Goodwill	16	16
Other Intangibles	122	84
Other Special Funds	56	49
Derivative Contracts	91	62
Other	67	60
Total Noncurrent Assets	2,183	2,172
TOTAL ASSETS	$ 12,314	$ 12,046

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18953

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2015	December 31, 2014
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 853	$ 300
Accounts Payable	315	424
Accounts Payable-Affiliated Companies	117	118
Derivative Contracts	70	132
Deferred Income Taxes	44	43
Accrued Interest	43	27
Other	132	140
Total Current Liabilities	1,574	1,184
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	2,148	2,065
Asset Retirement Obligations	469	450
Other Postretirement Benefit (OPEB) Costs	258	248
Derivative Contracts	16	33
Accrued Pension Costs	134	153
Long-Term Accrued Taxes	54	41
Other	121	71
Total Noncurrent Liabilities	3,200	3,061
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT		
Total Long-Term Debt	1,691	2,243
MEMBER'S EQUITY		
Contributed Capital	2,215	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,865	4,558
Accumulated Other Comprehensive Loss	(245)	(228)
Total Member's Equity	5,849	5,558
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,314	$ 12,046

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18954

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2015	**2014**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 707	$ 440
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	226	215
Amortization of Nuclear Fuel	162	151
Provision for Deferred Income Taxes and ITC	109	5
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(87)	237
Non-Cash Employee Benefit Plan Costs	36	10
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(2)	(99)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	113	17
Margin Deposit	142	(173)
Accounts Receivable	54	49
Accounts Payable	(99)	(135)
Accounts Receivable/Payable—Affiliated Companies, net	115	299
Other Current Assets and Liabilities	(26)	28
Employee Benefit Plan Funding and Related Payments	(9)	(5)
Other	117	71
Net Cash Provided By (Used In) Operating Activities	1,558	1,110
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(797)	(414)
Proceeds from Sales of Available-for-Sale Securities	1,057	882
Investments in Available-for-Sale Securities	(1,083)	(898)
Short-Term Loan—Affiliated Company, net	(281)	167
Other	(46)	(63)
Net Cash Provided By (Used In) Investing Activities	(1,150)	(326)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	(400)	(775)
Other	(2)	(3)
Net Cash Provided By (Used In) Financing Activities	(402)	(778)
Net Increase (Decrease) in Cash and Cash Equivalents	6	6
Cash and Cash Equivalents at Beginning of Period	9	6
Cash and Cash Equivalents at End of Period	$ 15	$ 12
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 284	$ 87
Interest Paid, Net of Amounts Capitalized	$ 76	$ 78
Accrued Property, Plant and Equipment Expenditures	$ 70	$ 66

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

S1-SSA-0009 - 18955

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This combined Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power each is only responsible for information about itself and its subsidiaries.

Note 1. Organization and Basis of Presentation

Organization

PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **PSE&G**—which is an operating public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- **Power**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2014.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2014.

Note 2. Recent Accounting Standards

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard was issued to clarify the principles for recognizing revenue and to develop a common standard that would remove inconsistencies in revenue requirements; improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provide improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The update was originally to be effective for annual and interim reporting periods beginning after December 15, 2016; however, the Financial Accounting Standards Board issued new guidance deferring the effective date by one year to periods beginning after December 31, 2017. Early application will be permitted as of the original effective date. We are currently analyzing the impact of this standard on our financial statements.

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Amendments to the Consolidation Analysis

This standard was issued to respond to concerns regarding the current accounting for consolidation of certain legal entities. Under the new standard, all legal entities are subject to reevaluation under a revised consolidation model which will determine whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities; eliminate the presumption that a general partner should consolidate a limited partnership; affect the consolidation analysis of reporting entities that are involved with VIEs and provide a scope exception from consolidation guidance for reporting entities with interests in certain legal entities who must comply with other requirements.

The update is effective for annual and interim reporting periods beginning after December 15, 2015. We are currently analyzing the impact of this standard on our financial statements.

Simplifying the Presentation of Debt Issuance Costs

This standard was issued to simplify presentation of debt issuance costs. The standard will require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by this standard.

The update is effective for annual and interim reporting periods beginning after December 15, 2015. We do not expect the impact of adoption of this standard to be material to our Condensed Consolidated Balance Sheets.

Note 3. Variable Interest Entities (VIEs)

Variable Interest Entities for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of Transition Funding and Transition Funding II are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the assets of these VIEs are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II.

PSE&G's maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of September 30, 2015 and December 31, 2014. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II during the first nine months of 2015 or in 2014. PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II. In June 2015, Transition Funding II paid its final securitization bond payment and Transition Funding I is scheduled to make its final securitization bond payment in December 2015.

Variable Interest Entity for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

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PSEG recognized a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and other postretirement benefit (OPEB) liabilities. This receivable is presented separately on the Condensed Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted. See Note 7. Pension and Other Postretirement Benefits for additional information.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operation and Maintenance (O&M) Expense, respectively. Servco recorded $96 million and $107 million for the three months and $262 million and $307 million for the nine months ended September 30, 2015 and 2014, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 4. Rate Filings

The following information discusses significant updates regarding orders and pending rate filings. This Note should be read in conjunction with Note 5. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2014.

In addition to items previously reported in the Annual Report on Form 10-K, significant 2015 regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

- ***Energy Strong Recovery Filing***—In June 2015, PSE&G updated its Energy Strong electric and gas cost recovery petition filed in March 2015 seeking BPU approval to recover in base rates estimated annual increases in electric revenues of $6 million and gas revenues of $17 million. These increases represent a return on investment and recovery of Energy Strong capitalized investment costs placed in service from December 1, 2014 through May 31, 2015 for electric and from June 1, 2014 through May 31, 2015 for gas. In August 2015, the BPU provisionally approved PSE&G's request effective September 1, 2015.

  In September 2015, PSE&G filed its Energy Strong electric cost recovery petition seeking BPU approval to recover the revenue requirements associated with Energy Strong capitalized investment costs placed in service from June 1, 2015 through November 30, 2015. The annualized requested increase in electric revenue requirements is $14 million. The petition requests rates to be effective March 1, 2016, consistent with the BPU Order of approval of the Energy Strong Program. This matter is pending.

- ***Basic Gas Supply Service (BGSS)***—In March 2015, PSE&G filed a letter with the BPU to extend the 28 cents per therm residential rate reduction via a bill credit for one additional month through April 30, 2015, which provided an additional approximate $31 million credit to customers.

  In April 2015, the BPU issued an Order approving PSE&G's provisional BGSS rate of 45 cents per therm which had been implemented on October 1, 2014.

  In June 2015, PSE&G made its Annual BGSS Filing with the BPU requesting a reduction of $70 million in annual BGSS revenues. In September 2015, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was reduced from approximately 45 cents to 40 cents per therm effective October 1, 2015.

- ***Weather Normalization Clause***—On April 15, 2015, the BPU approved PSE&G's final filing with respect to excess revenues collected during the colder than normal 2013-2014 Winter Period (October 1, 2013 through May 31, 2014). Effective October 1, 2014, PSEG commenced returning $45 million in revenues to its customers during the 2014-2015 Winter Period (October 1, 2014 through May 31, 2015).

  In September 2015, the BPU approved PSE&G's filing on a provisional basis with respect to excess revenues collected during the colder than normal 2014-2015 Winter Period. Effective October 1, 2015, PSE&G commenced returning $40 million in revenues to its customers during the 2015-2016 Winter Period (October 1, 2015 through May 31, 2016).

- ***Solar and Energy Efficiency - Green Program Recovery Charges (GPRC) and Solar Pilot Recovery Charge (SPRC)***—In April 2015, the BPU approved PSE&G's petition for an Energy Efficiency Economic Stimulus Extension II Program (EEE Ext II) to extend three EEE subprograms (multi-family, direct install and hospital efficiency). The Order allows PSE&G to extend the subprogram offerings under the same clause recovery process as its existing EEE Program and allows for $95 million of additional capital expenditures over the next three years and an allowance for

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$12 million of additional administrative expenses over the next 15 years. The EEE Ext II program was added as a ninth component of the GPRC rate effective May 1, 2015.

In July of each year, PSE&G files for annual recovery for its Green Program investments which include a return on its investment and recovery of expenses. In May 2015, the BPU approved PSE&G's July 2014 filing requesting recovery of costs and investments in the first eight combined components of the electric and gas GPRC for the period October 1, 2014 through September 30, 2015. In July 2015, PSE&G filed its annual GPRC and SPRC cost recovery petitions with the BPU, requesting recovery of costs and investments for the first eight combined components of the electric and gas GPRC, as well as the electric SPRC. The filings proposed rates for the period October 1, 2015 through September 30, 2016 designed to recover approximately $66 million and $10 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved programs. In September 2015, the BPU approved the July 2015 filings on a provisional basis, with new rates effective October 1, 2015.

- ***Transmission Formula Rate Filings***—In June 2015, PSE&G filed its 2014 true-up adjustment pertaining to its formula rates in effect for 2014, which resulted in an adjustment of $19 million less than the 2014 filed revenues. The adjustment was primarily due to the impact of bonus depreciation and lower interest rates which PSE&G had recognized in its Consolidated Statement of Operations for the year ended December 31, 2014.

  The 2016 Annual Formula Rate Update was filed with FERC in October 2015 and provides for approximately $146 million in increased annual transmission revenues effective January 1, 2016.
- ***Remediation Adjustment Charge (RAC)***—In August 2015, the BPU approved PSE&G's filing with respect to its RAC 22 petition allowing recovery of $85 million effective September 1, 2015 related to net Manufactured Gas Plant expenditures from August 1, 2013 through July 31, 2014.
- ***Universal Service Fund (USF)/Lifeline***—In September 2015, the BPU approved rates set to recover costs incurred under the USF/Lifeline energy assistance programs effective October 1, 2015. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on Net Income.

Note 5. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with Solar Renewable Energy Certificates generated from the installed solar electric system. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of September 30, 2015	As of December 31, 2014
	Millions	
Commercial/Industrial	$ 180	$ 188
Residential	13	13
Total	**$ 193**	**$ 201**

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Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

The following table shows Energy Holdings' gross and net lease investment as of September 30, 2015 and December 31, 2014, respectively.

	As of September 30, 2015	As of December 31, 2014
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 631	$ 691
Estimated Residual Value of Leased Assets	519	525
Unearned and Deferred Income	(368)	(380)
Gross Investment in Leases	782	836
Deferred Tax Liabilities	(706)	(738)
Net Investment in Leases	**$ 76**	**$ 98**

The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

	Lease Receivables, Net of Non-Recourse Debt
Counterparties' Credit Rating (Standard & Poor's (S&P))	**As of**
As of September 30, 2015	**September 30, 2015**
	Millions
AA	$ 17
BBB+ — BBB-	316
BB-	134
B-	164
Total	**$ 631**

The "BB-" and the "B-" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of September 30, 2015, the gross investment in the leases of such assets, net of non-recourse debt, was $573 million ($(13) million, net of deferred taxes). A more detailed description of such assets under lease, as of September 30, 2015, is presented in the following table.

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Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counter-parties' S&P Credit Ratings As of September 30, 2015 (A)	Counterparty
		Millions		MW			
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	B-	NRG REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 121	17%	1,711	Coal	B-	NRG REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 113	100%	603	Coal	B-	NRG REMA, LLC

(A) On October 2, 2015, S&P lowered the B- rating for NRG REMA, LLC, an indirect subsidiary of NRG Energy, Inc., to CCC+. Potential adverse consequences relevant to the downgrade are discussed in the following paragraph.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

In early 2014, NRG REMA, LLC had disclosed its plan to place the Shawville generating facility in a "long-term protective layup" by April 2015 as it evaluated its alternatives under the lease. However, NRG has since notified PJM that it deactivated the coal-fired units at the Shawville generating facility in June 2015 and has disclosed that it expects to return the Shawville units to service in the summer of 2016 with the ability to use natural gas.

Note 6. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Fund

Power maintains an external master nuclear decommissioning trust to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third party investment advisers who operate under investment guidelines developed by Power.

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Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of September 30, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 667	$ 176	$ (18)	$ 825
Debt Securities				
Government Obligations	445	10	(1)	454
Other Debt Securities	402	6	(7)	401
Total Debt Securities	847	16	(8)	855
Other Securities	35	—	—	35
Total NDT Available-for-Sale Securities	**$ 1,549**	**$ 192**	**$ (26)**	**$ 1,715**

	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 685	$ 220	$ (8)	$ 897
Debt Securities				
Government Obligations	430	9	(1)	438
Other Debt Securities	333	9	(3)	339
Total Debt Securities	763	18	(4)	777
Other Securities	106	—	—	106
Total NDT Available-for-Sale Securities	**$ 1,554**	**$ 238**	**$ (12)**	**$ 1,780**

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$ 10	$ 10
Accounts Payable	$ 4	$ 2

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The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of September 30, 2015				As of December 31, 2014			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 143	$ (18)	$ 1	$ —	$ 162	$ (8)	$ 1	$ —
Debt Securities								
Government Obligations (B)	90	(1)	15	—	95	—	28	(1)
Other Debt Securities (C)	164	(5)	29	(2)	99	(1)	30	(2)
Total Debt Securities	254	(6)	44	(2)	194	(1)	58	(3)
NDT Available-for-Sale Securities	**$ 397**	**$ (24)**	**$ 45**	**$ (2)**	**$ 356**	**$ (9)**	**$ 59**	**$ (3)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2015.

(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2015.

(C) Debt Securities (Other)—Power's investments in corporate bonds, collateralized mortgage obligations, asset-backed securities and municipal government obligations are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2015.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	Millions			
Proceeds from NDT Fund Sales (A)	**$ 215**	**$ 221**	**$ 1,037**	**$ 779**
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	14	45	47	101
Gross Realized Losses	(11)	(3)	(24)	(12)
Net Realized Gains (Losses) on NDT Fund	**$ 3**	**$ 42**	**$ 23**	**$ 89**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $82 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of September 30, 2015.

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The NDT available-for-sale debt securities held as of September 30, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 8
1 - 5 years	236
6 - 10 years	201
11 - 15 years	51
16 - 20 years	51
Over 20 years	308
Total NDT Available-for-Sale Debt Securities	**$ 855**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the nine months ended September 30, 2015, other-than-temporary impairments of $45 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of September 30, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 11	$ 9	$ —	$ 20
Debt Securities				
Government Obligations	106	1	(1)	106
Other Debt Securities	86	—	(2)	84
Total Debt Securities	192	1	(3)	190
Other Securities	1	—	—	1
Total Rabbi Trust Available-for-Sale Securities	**$ 204**	**$ 10**	**$ (3)**	**$ 211**

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	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 11	$ —	$ 23
Debt Securities				
Government Obligations	89	2	—	91
Other Debt Securities	74	1	—	75
Total Debt Securities	163	3	—	166
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 177**	**$ 14**	**$ —**	**$ 191**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$ 1	$ 1
Accounts Payable	$ 1	$ —

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of September 30, 2015				As of December 31, 2014			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	47	(2)	2	—	2	—	—	—
Other Debt Securities (C)	41	(1)	9	—	24	—	—	—
Total Debt Securities	88	(3)	11	—	26	—	—	—
Rabbi Trust Available-for-Sale Securities	**$ 88**	**$ (3)**	**$ 11**	**$ —**	**$ 26**	**$ —**	**$ —**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of September 30, 2015.

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(C) Debt Securities (Other)—PSEG's investments in corporate bonds, collateralized mortgage obligations, asset-backed securities and municipal government obligations are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2015.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	Millions			
Proceeds from Rabbi Trust Sales (A)	**$ 20**	**$ 419**	**$ 83**	**$ 445**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ —	$ 2	$ 2	$ 4
Gross Realized Losses	(1)	(2)	(1)	(3)
Net Realized Gains (Losses) on Rabbi Trust	**$ (1)**	**$ —**	**$ 1**	**$ 1**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains disclosed in the preceding table were recognized in Other Income in the Condensed Consolidated Statements of Operations. Net unrealized gains of $4 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of September 30, 2015.

The Rabbi Trust available-for-sale debt securities held as of September 30, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 5
1 - 5 years	49
6 - 10 years	39
11 - 15 years	8
16 - 20 years	9
Over 20 years	80
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 190**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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The fair value of assets in the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of September 30, 2015	As of December 31, 2014
	Millions	
PSE&G	$ 42	$ 41
Power	52	45
Other	117	105
Total Rabbi Trust Available-for-Sale Securities	**$ 211**	**$ 191**

Note 7. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.

Pension and OPEB costs for PSEG, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014	2015	2014	2015	2014
	Millions							
Components of Net Periodic Benefit Costs (Credit)								
Service Cost	$ 30	$ 26	$ 5	$ 5	$ 92	$ 78	$ 16	$ 14
Interest Cost	59	58	16	18	176	176	50	52
Expected Return on Plan Assets	(103)	(99)	(7)	(7)	(310)	(299)	(22)	(20)
Amortization of Net								
Prior Service Cost (Credit)	(5)	(5)	(4)	(4)	(14)	(14)	(11)	(11)
Actuarial Loss	38	14	11	6	112	42	32	18
Total Benefit Costs (Credit)	**$ 19**	**$ (6)**	**$ 21**	**$ 18**	**$ 56**	**$ (17)**	**$ 65**	**$ 53**

Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014	2015	2014	2015	2014
	Millions							
PSE&G	$ 10	$ (4)	$ 13	$ 12	$ 30	$ (14)	$ 41	$ 35
Power	5	(2)	7	5	16	(5)	20	15
Other	4	—	1	1	10	2	4	3
Total Benefit Costs (Credit)	**$ 19**	**$ (6)**	**$ 21**	**$ 18**	**$ 56**	**$ (17)**	**$ 65**	**$ 53**

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During the three months ended March 31, 2015, PSEG contributed its entire planned contributions for the year 2015 of $15 million into its pension plans and $14 million into its OPEB plan for 2015.

Servco Pension and OPEB

At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco's pension-related revenues and costs were $17 million and $30 million for the three months and nine months ended September 30, 2015, respectively, completing its entire planned contribution for the year 2015. Servco's pension-related revenues and costs were $21 million and $67 million for the three months and nine months ended September 30, 2014, respectively. The OPEB-related revenues earned and costs incurred for each of the three months and nine months ended September 30, 2015 and 2014 were immaterial.

Note 8. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The face value of Power's outstanding guarantees, current exposure and margin positions as of September 30, 2015 and December 31, 2014 are shown as follows:

	As of September 30, 2015	As of December 31, 2014
	Millions	
Face Value of Outstanding Guarantees	$ 1,733	$ 1,814
Exposure under Current Guarantees	$ 184	$ 273
Letters of Credit Margin Posted	$ 178	$ 159
Letters of Credit Margin Received	$ 80	$ 40
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (44)	$ (13)
Net Broker Balance Deposited (Received)	$ 4	$ 115
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that could be Required	$ 796	$ 945
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$ 3,375	$ 3,495
Additional Amounts Posted:		
Other Letters of Credit	$ 47	$ 45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power's credit rating to below investment grade, which would represent a three level downgrade from its current S&P and Moody's ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG had also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline and a $21 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

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Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA further determined that there was a need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G. This agreement and the work undertaken pursuant to the action agreement will not affect the ultimate remedy that the EPA will select for the remediation of the 17-mile stretch of the lower Passaic River.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than with respect to their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSEG's share of the cost of that effort is approximately three percent. The remaining CPG members have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS sets forth various alternatives for remediating this portion of the Passaic River. The EPA's estimated costs to remediate the lower eight miles of the Passaic River range from $365 million for a targeted remedy to $3.3 billion for a deep dredge of this portion of the Passaic River. The EPA also identified in the revised draft FFS its preferred alternative, which would involve dredging the lower eight miles of the river bank-to-bank and installing an engineered cap. The estimated cost in the revised draft FFS for the EPA's preferred alternative is $1.7 billion. No provisional cost allocation has been made by the CPG for the work contemplated by the revised draft FFS, and the work contemplated by the revised draft FFS is not subject to the CPG's cost sharing allocation agreed to in connection with the removal work for River Mile 10.9 or in connection with the conduct of the RI/FS.

The revised draft FFS was subject to a public comment period, and remains subject to the EPA's response to comments submitted, a design phase and at least an estimated five years for completion of the work. The public comment period for the revised draft FFS closed on August 21, 2014. Over 300 comments were submitted by a variety of entities potentially impacted by the revised draft FFS, including the CPG, individual companies, municipalities, public officials, citizens groups, Amtrak, NJ Transit and others.

The CPG, which consisted of 60 members as of September 30, 2015, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost of the RI/FS is approximately $151 million, which the CPG continues to incur. Of the estimated $151 million, as of August 31, 2015, the CPG had spent approximately $141 million, of which PSEG's total share was approximately $9 million.

The draft FS sets forth various alternatives for remediating the lower Passaic River. The draft FS sets forth the CPG's estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranges from approximately $518 million to $772 million. No provisional cost allocation has been made

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by the CPG for the work contemplated by the draft FS. However, based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimates of their share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

The EPA will consider the comments received on its revised draft FFS and is expected to consider the CPG's RI/FS prior to issuing a Record of Decision (ROD) of a selected remedy for the lower Passaic River. The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS is finalized, (ii) a final remedy is determined by the EPA or through litigation, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on our financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $450 million and $518 million through 2021, including its $10 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $450 million as of September 30, 2015. Of this amount, $73 million was recorded in Other Current Liabilities and $377 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $450 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

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Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The New Jersey Department of Environmental Protection (NJDEP) manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. On June 30, 2015, the NJDEP issued a draft Salem permit. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The draft permit was subject to a public notice and comment period. The NJDEP may make revisions before issuing the final permit expected during the first half of 2016. Power participated in the NJDEP's August 5, 2015 public hearing and submitted comments on the draft permit on September 18, 2015.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. On August 15, 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. On September 5, 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Second Circuit Court of Appeals. In two related actions on October 17, 2014 and November 20, 2014, several environmental non-governmental groups initiated challenges to the endangered species act provisions of the 316 (b) rule. Power is unable to determine the ultimate impact of these actions on the implementation of the rule.

State permitting decisions could have a material impact on Power's ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power's once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power's application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1.0 billion, of which Power's share would have been approximately $575 million. The filing has not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power's forecasted capital expenditures.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the Connecticut Department of Energy and Environmental Protection of the

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issues and has taken actions to investigate and resolve the potential non-compliance. At this early stage Power cannot predict the impact of this matter.

Steam Electric Effluent Guidelines

On September 30, 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Mercer and Bridgeport Harbor stations have bottom ash transport water discharges that are regulated under this rule. Power is unable to predict if these new standards will have a material impact on Power's future capital requirements, financial condition or results of operations.

Coal Combustion Residuals (CCRs)

On December 19, 2014, the EPA issued a final rule which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Power's Hudson and Mercer generating stations, along with its co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 19, 2015. Accordingly in June 2015, Power recorded an additional asset retirement obligation to comply with the final CCR rule which was not material to Power's results of operations, financial condition or cash flows.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, are residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category are larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2015 is $272.78 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2015 of $282.04 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2012	2013	2014	2015	
36-Month Terms Ending	May 2015	May 2016	May 2017	May 2018	(A)
Load (MW)	2,900	2,800	2,800	2,900	
$ per MWh	$83.88	$92.18	$97.39	$99.54	

(A) Prices set for the 2015 BGS auction year became effective on June 1, 2015 when the 2012 BGS auction agreements expired.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

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PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 17. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2020 at Salem, Hope Creek and Peach Bottom.

Power has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations.

Power also has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available, Power can use the gas to supply its fossil generating stations.

As of September 30, 2015, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2019
	Millions
Nuclear Fuel	
Uranium	$ 440
Enrichment	$ 345
Fabrication	$ 179
Natural Gas	$ 1,001
Coal	$ 331

Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors and modified the bid quantities for its peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future. On September 2, 2014, FERC Staff initiated a preliminary, non-public staff investigation into the matter. This investigation, which is ongoing, could result in FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies.

During the three months ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. It is not possible at this time to reasonably estimate the potential range of loss or full impact or predict any resulting penalties or other costs associated with this matter, or the applicability of mitigating factors. As new information becomes available or future developments occur in this investigation, it is possible that Power will record additional estimated losses and such additional losses may be material.

New Jersey Clean Energy Program

In June 2015, the BPU established the funding level for fiscal year 2016 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2016 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a current liability of $185 million as of September 30, 2015 for its outstanding share of the fiscal

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year 2016 and remaining fiscal year 2015 funding, respectively. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's T&D system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. In June 2013, PSEG, PSE&G and Power filed suit in New Jersey state court (NJ Court) against its insurance carriers seeking an interpretation that the insurance policies cover their losses resulting from damage caused by Superstorm Sandy's storm surge.

As of December 31, 2012, PSE&G had incurred approximately $295 million of costs to restore service to PSE&G's distribution and transmission systems and $5 million to repair its infrastructure and return it to pre-storm conditions. Of the costs incurred, approximately $40 million was recognized in O&M Expense, $75 million was recorded as Property, Plant and Equipment and $180 million was recorded as a Regulatory Asset because such costs were deferred as approved by the BPU under an Order received in December 2012. Of the $295 million, $36 million related to insured property. In 2012, PSE&G recognized $6 million of insurance recoveries, which were deferred. There were no significant additional costs incurred since 2012.

PSE&G made a filing with the BPU to review the prudency of unreimbursed incremental storm restoration costs, including O&M and capital expenditures associated with Superstorm Sandy and certain other extreme weather events, for recovery in its next base rate case or sooner through a BPU-approved cost recovery mechanism. In September 2014, the BPU approved its filing.

Power had incurred a total of $193 million of storm-related costs from 2012 through 2014, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized primarily in O&M Expense, offset by $44 million of insurance recoveries in 2013 and 2012. Power incurred an additional $2 million of storm-related costs in 2015 which were recognized primarily in O&M Expense.

In the first half of 2015, PSEG reached settlements with its insurers with respect to claims for coverage of its Superstorm Sandy-related losses. PSEG received an additional $214 million under these settlements (consisting of $159 million and $55 million recognized in the three months ended March 31, 2015 and June 30, 2015, respectively), bringing cumulative insurance proceeds to $264 million. Of the $214 million recognized in 2015, PSE&G and Power recorded $35 million and $179 million, respectively. In addition to the $35 million recognized in 2015, PSE&G recognized the aforementioned $6 million of previously deferred insurance recoveries, resulting in reductions in Regulatory Assets of $20 million, O&M Expense of $10 million and Property, Plant and Equipment of $11 million. Power recorded reductions in both O&M Expense of $145 million and Property, Plant and Equipment of $6 million and an increase in Other Income of $28 million.

The claim filed by PSEG, PSE&G and Power related to Superstorm Sandy insurance coverage is now fully resolved.

Note 9. Changes in Capitalization

The following capital transactions occurred in the nine months ended September 30, 2015:

PSE&G

- issued $350 million of 3.00% Secured Medium-Term Notes, Series K due May 2025,
- issued $250 million of 4.05% Secured Medium-Term Notes, Series K due May 2045,
- paid $300 million of 2.70% Secured Medium-Term Notes at maturity,
- paid $183 million of Transition Funding's securitization debt, and
- paid the final $8 million of Transition Funding II's securitization debt.

Power

- paid cash dividends of $400 million to PSEG.

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Note 10. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. Transactions receiving NPNS treatment are accounted for upon settlement. For a derivative instrument that qualifies and is designated as a cash flow hedge, the changes in the fair value of such a derivative that are highly effective are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. For a derivative instrument that qualifies and is designated as a fair value hedge, the gains or losses on the derivative as well as the offsetting losses or gains on the hedged item attributable to the hedged risk are recognized in earnings each period. Power and PSE&G enter into additional contracts that are derivatives, but do not qualify for or are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and changes in the fair value of these contracts are recorded in earnings each period.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

PSEG and Power use forward sale contracts, swaps and futures contracts to hedge certain forecasted natural gas sales made to support the BGSS contract with PSE&G. These derivative transactions qualify and are designated as cash flow hedges.

As of September 30, 2015 and December 31, 2014, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity were as follows:

	As of September 30, 2015	As of December 31, 2014
	Millions	
Fair Value of Cash Flow Hedges	$ 2	$ 18
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 1	$ 10

The expiration date of the longest-dated cash flow hedge at Power is in December 2015. Power's remaining $1 million of after-tax unrealized gains on these derivatives is expected to be reclassified to earnings during the next 12 months. There was no ineffectiveness associated with qualifying hedges as of September 30, 2015.

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Economic Hedges

Power enters into derivative contracts that do not qualify or are not designated as either cash flow or fair value hedges. Power enters into financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. These transactions are economic hedges, intended to mitigate exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of these contracts are recorded in earnings. PSE&G is a party to certain long-term natural gas sales derivative contracts to optimize its pipeline capacity utilization. Changes in the fair market value of these contracts are recorded in Regulatory Assets and Regulatory Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of September 30, 2015, PSEG had interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of September 30, 2015 and December 31, 2014, the fair value of all the underlying hedges was $11 million and $22 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was immaterial as of September 30, 2015 and December 31, 2014, respectively.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset on the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG.

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The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of September 30, 2015						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 2	$ 413	$ (268)	$ 147	$ 4	$ 11	$ 162
Noncurrent Assets	—	284	(193)	91	—	—	91
Total Mark-to-Market Derivative Assets	**$ 2**	**$ 697**	**$ (461)**	**$ 238**	**$ 4**	**$ 11**	**$ 253**
Derivative Contracts							
Current Liabilities	$ —	$ (311)	$ 241	$ (70)	$ —	$ —	$ (70)
Noncurrent Liabilities	—	(178)	162	(16)	(7)	—	(23)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (489)**	**$ 403**	**$ (86)**	**$ (7)**	**$ —**	**$ (93)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 2**	**$ 208**	**$ (58)**	**$ 152**	**$ (3)**	**$ 11**	**$ 160**

	As of December 31, 2014						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
	Cash Flow Hedges	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 18	$ 597	$ (408)	$ 207	$ 18	$ 15	$ 240
Noncurrent Assets	—	171	(109)	62	8	7	77
Total Mark-to-Market Derivative Assets	**$ 18**	**$ 768**	**$ (517)**	**$ 269**	**$ 26**	**$ 22**	**$ 317**
Derivative Contracts							
Current Liabilities	$ —	$ (568)	$ 436	$ (132)	$ —	$ —	$ (132)
Noncurrent Liabilities	—	(138)	105	(33)	—	—	(33)
Total Mark-to-Market Derivative (Liabilities)	**$ —**	**$ (706)**	**$ 541**	**$ (165)**	**$ —**	**$ —**	**$ (165)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 18**	**$ 62**	**$ 24**	**$ 104**	**$ 26**	**$ 22**	**$ 152**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of September 30, 2015 and December 31, 2014. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of September 30, 2015 and

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December 31, 2014, net cash collateral (received) paid of $(58) million and $24 million, respectively, were netted against the corresponding net derivative contract positions. Of the $(58) million as of September 30, 2015, $(32) million and $(38) million of cash collateral were netted against current assets and noncurrent assets, respectively, and $5 million and $7 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $24 million as of December 31, 2014, $(4) million and $(8) million were netted against current assets and noncurrent assets, respectively, and $32 million and $4 million were netted against current liabilities and noncurrent liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $78 million and $127 million as of September 30, 2015 and December 31, 2014, respectively. As of September 30, 2015 and December 31, 2014, Power had the contractual right of offset of $12 million and $18 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $66 million and $109 million as of September 30, 2015 and December 31, 2014, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $796 million and $945 million as of September 30, 2015 and December 31, 2014, respectively, discussed in Note 8. Commitments and Contingent Liabilities.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended September 30, 2015 and 2014.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion)		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	
	Three Months Ended September 30,			Three Months Ended September 30,			Three Months Ended September 30,	
	2015	2014		2015	2014		2015	2014
	Millions							
PSEG								
Energy-Related Contracts	$ 1	$ 3	Operating Revenues	$ —	$ 1	Operating Revenues	$ —	$ —
Total PSEG	**$ 1**	**$ 3**		**$ —**	**$ 1**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ 1	$ 3	Operating Revenues	$ —	$ 1	Operating Revenues	$ —	$ —
Total Power	**$ 1**	**$ 3**		**$ —**	**$ 1**		**$ —**	**$ —**

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The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the nine months ended September 30, 2015 and 2014.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Nine Months Ended September 30,		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Nine Months Ended September 30,		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Nine Months Ended September 30,	
	2015	2014		2015	2014		2015	2014
	Millions							
PSEG								
Energy-Related Contracts	$ 2	$ (4)	Operating Revenues	$ 17	$ (11)	Operating Revenues	$ —	$ —
Total PSEG	**$ 2**	**$ (4)**		**$ 17**	**$ (11)**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ 2	$ (4)	Operating Revenues	$ 17	$ (11)	Operating Revenues	$ —	$ —
Total Power	**$ 2**	**$ (4)**		**$ 17**	**$ (11)**		**$ —**	**$ —**

The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2014	**$ 17**	**$ 10**
Gain Recognized in AOCI	1	1
Less: Gain Reclassified into Income	(17)	(10)
Balance as of June 30, 2015	**$ 1**	**$ 1**
Gain Recognized in AOCI	1	—
Less: Gain Reclassified into Income	—	—
Balance as of September 30, 2015	**$ 2**	**$ 1**

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The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the three months and nine months ended September 30, 2015 and 2014.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2015	2014	2015	2014
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ 154	$ 93	$ 202	$ (759)
Energy-Related Contracts	Energy Costs	(4)	(12)	(4)	65
Total PSEG and Power		**$ 150**	**$ 81**	**$ 198**	**$ (694)**

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the NPNS exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $5 million for each of the three months and $15 million for each of the nine months ended September 30, 2015 and 2014, respectively.

The following reflects the gross volume, on an absolute value basis, of derivatives as of September 30, 2015 and December 31, 2014.

Type	Notional	Total	PSEG	Power	PSE&G
		Millions			
As of September 30, 2015					
Natural Gas	Dth	193	—	154	39
Electricity	MWh	291	—	291	—
Financial Transmission Rights (FTRs)	MWh	21	—	21	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2014					
Natural Gas	Dth	274	—	216	58
Electricity	MWh	310	—	310	—
FTRs	MWh	15	—	15	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of September 30, 2015, 98% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

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The following table provides information on Power's credit risk from others, net of cash collateral, as of September 30, 2015. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 348	$ 118	$ 230	2	$ 127	(A)
Non-Investment Grade—External Rating	1	—	1	—	—	
Investment Grade—No External Rating	11	—	11	—	—	
Non-Investment Grade—No External Rating	4	—	4	—	—	
Total	**$ 364**	**$ 118**	**$ 246**	**2**	**$ 127**	

(A) Represents net exposure of $87 million with PSE&G. The remaining net exposure of $40 million is with a non- affiliated power purchaser which is an investment grade counterparty.

As of September 30, 2015, collateral held from counterparties where Power had credit exposure included $43 million in cash collateral and $75 million in letters of credit.

As of September 30, 2015, Power had 133 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of September 30, 2015, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's suppliers' credit exposure is calculated each business day. As of September 30, 2015, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 11. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of September 30, 2015, these consisted primarily of long-term gas supply contracts and certain electric load contracts.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of September 30, 2015 and December 31, 2014, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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Description	Recurring Fair Value Measurements as of September 30, 2015			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 226	$ —	$ 226	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 242	$ (461)	$ —	$ 694	$ 9
Interest Rate Swaps (C)	$ 11	$ —	$ —	$ 11	$ —
NDT Fund (D)					
Equity Securities	$ 825	$ —	$ 824	$ 1	$ —
Debt Securities—Govt Obligations	$ 454	$ —	$ —	$ 454	$ —
Debt Securities—Other	$ 401	$ —	$ —	$ 401	$ —
Other Securities	$ 35	$ —	$ 35	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 20	$ —	$ 20	$ —	$ —
Debt Securities—Govt Obligations	$ 106	$ —	$ —	$ 106	$ —
Debt Securities—Other	$ 84	$ —	$ —	$ 84	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (93)	$ 403	$ —	$ (489)	$ (7)
PSE&G					
Assets:					
Cash Equivalents (A)	$ —	$ —	$ —	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 4	$ —	$ —	$ —	$ 4
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 4	$ —	$ 4	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 17	$ —	$ —	$ 17	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (7)	$ —	$ —	$ —	$ (7)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 238	$ (461)	$ —	$ 694	$ 5
NDT Fund (D)					
Equity Securities	$ 825	$ —	$ 824	$ 1	$ —
Debt Securities—Govt Obligations	$ 454	$ —	$ —	$ 454	$ —
Debt Securities—Other	$ 401	$ —	$ —	$ 401	$ —
Other Securities	$ 35	$ —	$ 35	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 26	$ —	$ —	$ 26	$ —
Debt Securities—Other	$ 21	$ —	$ —	$ 21	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (86)	$ 403	$ —	$ (489)	$ —

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Description	Recurring Fair Value Measurements as of December 31, 2014			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
			Millions		
PSEG					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 295	$ (517)	$ —	$ 774	$ 38
Interest Rate Swaps (C)	$ 22	$ —	$ —	$ 22	$ —
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 896	$ 1	$ —
Debt Securities—Govt Obligations	$ 438	$ —	$ —	$ 438	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 106	$ —	$ 106	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—Govt Obligations	$ 91	$ —	$ —	$ 91	$ —
Debt Securities—Other	$ 75	$ —	$ —	$ 75	$ —
Other Securities	$ 2	$ —	$ —	$ 2	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (165)	$ 541	$ —	$ (705)	$ (1)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 294	$ —	$ 294	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ 26	$ —	$ —	$ —	$ 26
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 20	$ —	$ —	$ 20	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 269	$ (517)	$ —	$ 774	$ 12
NDT Fund (D)					
Equity Securities	$ 897	$ —	$ 896	$ 1	$ —
Debt Securities—Govt Obligations	$ 438	$ —	$ —	$ 438	$ —
Debt Securities—Other	$ 339	$ —	$ —	$ 339	$ —
Other Securities	$ 106	$ —	$ 106	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ 1	$ —	$ —	$ 1	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (165)	$ 541	$ —	$ (705)	$ (1)

(A) Represents money market mutual funds.

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(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the

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absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds, collateralized mortgage obligations, asset backed securities and government obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of September 30, 2015, net cash collateral (received) paid of $(58) million, was netted against the corresponding net derivative contract positions. Of the $(58) million as of September 30, 2015, $(70) million of cash collateral was netted against assets, and $12 million was netted against liabilities. As of December 31, 2014, net cash collateral (received) paid of $24 million, was netted against the corresponding net derivative contract positions. Of the $24 million as of December 31, 2014, $(12) million of cash collateral was netted against assets, and $36 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G and Power, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation

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costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. The following tables provide details surrounding significant Level 3 valuations as of September 30, 2015 and December 31, 2014.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of September 30, 2015 Assets	Fair Value as of September 30, 2015 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$ 4	$ (7)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.90/dekatherm
Total PSE&G		**$ 4**	**$ (7)**			
Power						
Electricity	Electric Load Contracts	$ 4	$ —	Discounted Cash flow	Historic Load Variability	0% to +10%
Other	Various (A)	1	—			
Total Power		**$ 5**	**$ —**			
Total PSEG		**$ 9**	**$ (7)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2014 Assets	Fair Value as of December 31, 2014 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$ 26	$ —	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		**$ 26**	**$ —**			
Power						
Electricity	Electric Load Contracts	$ 12	$ (1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Other	Various (B)	—	—			
Total Power		**$ 12**	**$ (1)**			
Total PSEG		**$ 38**	**$ (1)**			

(A) Includes long-term electric positions which were immaterial as of September 30, 2015.

(B) Includes gas supply positions and long-term electric capacity positions which were immaterial as of December 31, 2014.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value. For energy-related contracts in cases where Power is a seller, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and nine months ended September 30, 2015 and September 30, 2014, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Nine Months Ended September 30, 2015

	Three Months Ended September 30, 2015						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of July 1, 2015	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of September 30, 2015
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 8	$ 4	$ (8)	$ —	$ (2)	$ —	$ 2
PSE&G							
Net Derivative Assets (Liabilities)	$ 5	$ —	$ (8)	$ —	$ —	$ —	$ (3)
Power							
Net Derivative Assets (Liabilities)	$ 3	$ 4	$ —	$ —	$ (2)	$ —	$ 5

	Nine Months Ended September 30, 2015						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2015	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of September 30, 2015
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 37	$ 12	$ (29)	$ —	$ (18)	$ —	$ 2
PSE&G							
Net Derivative Assets (Liabilities)	$ 26	$ —	$ (29)	$ —	$ —	$ —	$ (3)
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 12	$ —	$ —	$ (18)	$ —	$ 5

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Nine Months Ended September 30, 2014

	Three Months Ended September 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of July 1, 2014	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2014
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ 13	$ (8)	$ (9)	$ —	$ (4)	$ —	$ (8)
PSE&G							
Net Derivative Assets (Liabilities)	$ 22	$ —	$ (9)	$ —	$ —	$ —	$ 13
Power							
Net Derivative Assets (Liabilities)	$ (9)	$ (8)	$ —	$ —	$ (4)	$ —	$ (21)

	Nine Months Ended September 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2014	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2014
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ 88	$ (66)	$ (81)	$ —	$ 54	$ (3)	$ (8)
PSE&G							
Net Derivative Assets (Liabilities)	$ 94	$ —	$ (81)	$ —	$ —	$ —	$ 13
Power							
Net Derivative Assets (Liabilities)	$ (6)	$ (66)	$ —	$ —	$ 54	$ (3)	$ (21)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities includes $4 million and $12 million in Operating Income for the three months and nine months ended September 30, 2015, respectively. Of the $4 million in Operating Income, $3 million is unrealized. Of the $12 million in Operating Income, $(6) million is unrealized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

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(C) Represents $(2) million and $(18) million in settlements for the three months and nine months ended September 30, 2015. Includes $(4) million and $54 million in settlements for the three months and nine months ended September 30, 2014.

(D) There were no transfers among levels during the three months ended September 30, 2015 and 2014 and the nine months ended September 30, 2015. During the nine months ended September 30, 2014, $(3) million of net derivative assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. The transfers were recognized as of the beginning of the quarters in which the transfers first occurred as per PSEG's policy.

(E) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $(8) million and $(66) million in Operating Income for the three months and nine months ended September 30, 2014, respectively. Of the $(8) million in Operating Income, $(12) million is unrealized. Of the $(66) million in Operating Income, $(11) million is unrealized.

As of September 30, 2015, PSEG carried $2.3 billion of net assets that are measured at fair value on a recurring basis, of which $2 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of September 30, 2014, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $8 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of September 30, 2015 and December 31, 2014.

	As of September 30, 2015		As of December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 7	$ 11	$ 14	$ 22
PSE&G (B)	6,612	7,102	6,312	6,912
Transition Funding (PSE&G) (B)	68	69	251	261
Transition Funding II (PSE&G) (B)	—	—	8	8
Power - Recourse Debt (B)	2,544	2,856	2,543	2,930
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	7	7	16	16
Total Long-Term Debt	**$ 9,238**	**$ 10,045**	**$ 9,144**	**$ 10,149**

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 12. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended September 30, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 24	$ —	$ 24
Allowance for Funds Used During Construction	14	—	—	14
Solar Loan Interest	6	—	—	6
Other	2	1	—	3
Total Other Income	**$ 22**	**$ 25**	**$ —**	**$ 47**
Nine Months Ended September 30, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 78	$ —	$ 78
Allowance for Funds Used During Construction	36	—	—	36
Solar Loan Interest	18	—	—	18
Gain on Insurance Recovery	—	28	—	28
Other	5	3	3	11
Total Other Income	**$ 59**	**$ 109**	**$ 3**	**$ 171**
Three Months Ended September 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 55	$ —	$ 55
Allowance for Funds Used During Construction	8	—	—	8
Solar Loan Interest	6	—	—	6
Other	2	1	3	6
Total Other Income	**$ 16**	**$ 56**	**$ 3**	**$ 75**
Nine Months Ended September 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 133	$ —	$ 133
Allowance for Funds Used During Construction	21	—	—	21
Solar Loan Interest	18	—	—	18
Other	5	2	6	13
Total Other Income	**$ 44**	**$ 135**	**$ 6**	**$ 185**

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Other Deductions	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended September 30, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 13	$ —	$ 13
Other	—	1	—	1
Total Other Deductions	**$ —**	**$ 14**	**$ —**	**$ 14**
Nine Months Ended September 30, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 30	$ —	$ 30
Other	2	2	2	6
Total Other Deductions	**$ 2**	**$ 32**	**$ 2**	**$ 36**
Three Months Ended September 30, 2014				
NDT Fund Realized Losses and Expenses	$ —	$ 4	$ —	$ 4
Other	2	2	1	5
Total Other Deductions	**$ 2**	**$ 6**	**$ 1**	**$ 9**
Nine Months Ended September 30, 2014				
NDT Fund Realized Losses and Expenses	$ —	$ 18	$ —	$ 18
Other	3	7	3	13
Total Other Deductions	**$ 3**	**$ 25**	**$ 3**	**$ 31**

(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

Note 13. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months and nine months ended September 30, 2015 and 2014 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
PSEG	39.4%	37.0%	38.8%	37.8%
PSE&G	38.2%	38.5%	38.7%	38.6%
Power	40.3%	39.4%	38.6%	38.6%

For the three months ended September 30, 2015, PSE&G's effective tax rate was lower than the statutory tax rate of 40.85% due primarily to the beneficial impact of plant related flow-through items.

For the nine months ended September 30, 2015, PSEG's and Power's effective tax rates were lower than the statutory tax rate of 40.85% primarily due to a manufacturing deduction under Section 199 of the Internal Revenue Code (IRC) and the tax benefit associated with the income tax rate differential of carrying back federal net operating tax losses under section 172(f) of the IRC. PSE&G's effective tax rate was lower than the statutory tax rate due primarily to the beneficial impact of plant related flow-through items.

For the three months and nine months ended September 30, 2015, as compared to the same periods in the prior year, PSEG's increase was due primarily to the absence of the 2014 audit settlement.

In August 2014, PSEG received notice from the Internal Revenue Service (IRS) that the audit settlement covering tax years 2007 through 2010 had been approved by the Joint Committee on Taxation. This effectively settled all issues with the IRS through 2010. In September 2014, PSEG received refunds from the IRS totaling $121 million, representing the net settlement of all disputed amounts, including interest, through the tax year 2010. As a result of the settlement of this audit, PSEG recorded a $12 million reduction of tax expense in the quarter ended September 30, 2014.

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Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2015			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of June 30, 2015	$ 1	$ (395)	$ 117	$ (277)
Other Comprehensive Income before Reclassifications	—	—	(46)	(46)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	9	15	24
Net Current Period Other Comprehensive Income (Loss)	—	9	(31)	(22)
Balance as of September 30, 2015	**$ 1**	**$ (386)**	**$ 86**	**$ (299)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of June 30, 2014	$ 1	$ (232)	$ 158	$ (73)
Other Comprehensive Income before Reclassifications	2	—	(15)	(13)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	3	(15)	(13)
Net Current Period Other Comprehensive Income (Loss)	1	3	(30)	(26)
Balance as of September 30, 2014	**$ 2**	**$ (229)**	**$ 128**	**$ (99)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2015			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2014	$ 10	$ (411)	$ 118	$ (283)
Other Comprehensive Income before Reclassifications	1	—	(44)	(43)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	25	12	27
Net Current Period Other Comprehensive Income (Loss)	(9)	25	(32)	(16)
Balance as of September 30, 2015	**$ 1**	**$ (386)**	**$ 86**	**$ (299)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2013	$ (2)	$ (238)	$ 145	$ (95)
Other Comprehensive Income before Reclassifications	(2)	—	19	17
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	6	9	(36)	(21)
Net Current Period Other Comprehensive Income (Loss)	4	9	(17)	(4)
Balance as of September 30, 2014	**$ 2**	**$ (229)**	**$ 128**	**$ (99)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2015			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2015	$ 2	$ (337)	$ 112	$ (223)
Other Comprehensive Income before Reclassifications	—	—	(43)	(43)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	14	21
Net Current Period Other Comprehensive Income (Loss)	—	7	(29)	(22)
Balance as of September 30, 2015	**$ 2**	**$ (330)**	**$ 83**	**$ (245)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2014	$ 2	$ (199)	$ 153	$ (44)
Other Comprehensive Income before Reclassifications	2	—	(14)	(12)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	2	(16)	(15)
Net Current Period Other Comprehensive Income (Loss)	1	2	(30)	(27)
Balance as of September 30, 2014	**$ 3**	**$ (197)**	**$ 123**	**$ (71)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2015			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2014	$ 11	$ (351)	$ 112	$ (228)
Other Comprehensive Income before Reclassifications	1	—	(41)	(40)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	21	12	23
Net Current Period Other Comprehensive Income (Loss)	(9)	21	(29)	(17)
Balance as of September 30, 2015	**$ 2**	**$ (330)**	**$ 83**	**$ (245)**

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2013	$ (1)	$ (204)	$ 142	$ (63)
Other Comprehensive Income before Reclassifications	(2)	—	17	15
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	6	7	(36)	(23)
Net Current Period Other Comprehensive Income (Loss)	4	7	(19)	(8)
Balance as of September 30, 2014	**$ 3**	**$ (197)**	**$ 123**	**$ (71)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2015			Nine Months Ended September 30, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		—	—	—	17	(7)	10
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	9	(3)	6
Amortization of Actuarial Loss	O&M Expense	(17)	6	(11)	(51)	20	(31)
Total Pension and OPEB Plans		(14)	5	(9)	(42)	17	(25)
Available-for-Sale Securities							
Realized Gains	Other Income	14	(7)	7	49	(25)	24
Realized Losses	Other Deductions	(12)	5	(7)	(25)	12	(13)
Other-Than-Temporary Impairments (OTTI)	OTTI	(30)	15	(15)	(45)	22	(23)
Total Available-for-Sale Securities		(28)	13	(15)	(21)	9	(12)
Total		**$ (42)**	**$ 18**	**$ (24)**	**$ (46)**	**$ 19**	**$ (27)**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2014			Nine Months Ended September 30, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ 1	$ —	$ 1	$ (11)	$ 5	$ (6)
Total Cash Flow Hedges		1	—	1	(11)	5	(6)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	8	(3)	5
Amortization of Actuarial Loss	O&M Expense	(8)	3	(5)	(22)	8	(14)
Total Pension and OPEB Plans		(5)	2	(3)	(14)	5	(9)
Available-for-Sale Securities							
Realized Gains	Other Income	47	(24)	23	105	(54)	51
Realized Losses	Other Deductions	(5)	2	(3)	(15)	7	(8)
OTTI	OTTI	(10)	5	(5)	(14)	7	(7)
Total Available-for-Sale Securities		32	(17)	15	76	(40)	36
Total		**$ 28**	**$ (15)**	**$ 13**	**$ 51**	**$ (30)**	**$ 21**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2015			Nine Months Ended September 30, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		—	—	—	17	(7)	10
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	9	(3)	6
Amortization of Actuarial Loss	O&M Expense	(15)	6	(9)	(45)	18	(27)
Total Pension and OPEB Plans		(12)	5	(7)	(36)	15	(21)
Available-for-Sale Securities							
Realized Gains	Other Income	14	(7)	7	47	(24)	23
Realized Losses	Other Deductions	(11)	5	(6)	(24)	12	(12)
OTTI	OTTI	(30)	15	(15)	(45)	22	(23)
Total Available-for-Sale Securities		(27)	13	(14)	(22)	10	(12)
Total		**$ (39)**	**$ 18**	**$ (21)**	**$ (41)**	**$ 18**	**$ (23)**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2014			Nine Months Ended September 30, 2014		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ 1	$ —	$ 1	$ (11)	$ 5	$ (6)
Total Cash Flow Hedges		1	—	1	(11)	5	(6)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	7	(3)	4
Amortization of Actuarial Loss	O&M Expense	(6)	2	(4)	(18)	7	(11)
Total Pension and OPEB Plans		(3)	1	(2)	(11)	4	(7)
Available-for-Sale Securities							
Realized Gains	Other Income	45	(23)	22	101	(52)	49
Realized Losses	Other Deductions	(2)	1	(1)	(12)	6	(6)
OTTI	OTTI	(10)	5	(5)	(14)	7	(7)
Total Available-for-Sale Securities		33	(17)	16	75	(39)	36
Total		**$ 31**	**$ (16)**	**$ 15**	**$ 53**	**$ (30)**	**$ 23**

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Note 15. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under our stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS.

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2015		2014		2015		2014	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)								
Net Income	**$ 439**	**$ 439**	**$ 444**	**$ 444**	**$ 1,370**	**$ 1,370**	**$ 1,042**	**$ 1,042**
EPS Denominator (Millions)								
Weighted Average Common Shares Outstanding	505	505	506	506	505	505	506	506
Effect of Stock Based Compensation Awards	—	3	—	1	—	3	—	1
Total Shares	**505**	**508**	**506**	**507**	**505**	**508**	**506**	**507**
EPS								
Net Income	**$ 0.87**	**$ 0.87**	**$ 0.88**	**$ 0.87**	**$ 2.71**	**$ 2.70**	**$ 2.06**	**$ 2.05**

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dividend Payments on Common Stock	**2015**	**2014**	**2015**	**2014**
Per Share	$ 0.39	$ 0.37	$ 1.17	$ 1.11
In Millions	$ 198	$ 187	$ 592	$ 561

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Note 16. Financial Information by Business Segments

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated
			Millions		
Three Months Ended September 30, 2015					
Total Operating Revenues	$ 1,766	$ 1,096	$ 120	$ (294)	$ 2,688
Net Income (Loss)	222	206	11	—	439
Gross Additions to Long-Lived Assets	716	310	13	—	1,039
Nine Months Ended September 30, 2015					
Total Operating Revenues	$ 5,234	$ 3,846	$ 326	$ (1,269)	$ 8,137
Net Income (Loss)	631	707	32	—	1,370
Gross Additions to Long-Lived Assets	1,946	797	39	—	2,782
Three Months Ended September 30, 2014					
Total Operating Revenues	$ 1,655	$ 1,138	$ 123	$ (275)	$ 2,641
Net Income (Loss)	200	222	22	—	444
Gross Additions to Long-Lived Assets	497	188	8	—	693
Nine Months Ended September 30, 2014					
Total Operating Revenues	$ 5,235	$ 3,824	$ 359	$ (1,305)	$ 8,113
Net Income (Loss)	565	440	37	—	1,042
Gross Additions to Long-Lived Assets	1,493	414	15	—	1,922
As of September 30, 2015					
Total Assets	$ 22,909	$ 12,314	$ 2,775	$ (1,574)	$ 36,424
Investments in Equity Method Subsidiaries	$ —	$ 116	$ 1	$ —	$ 117
As of December 31, 2014					
Total Assets	$ 22,223	$ 12,046	$ 2,799	$ (1,735)	$ 35,333
Investments in Equity Method Subsidiaries	$ —	$ 121	$ 2	$ —	$ 123

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations, primarily related to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 17. Related-Party Transactions.

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Note 17. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	Millions			
Billings from Affiliates:				
Billings from Power primarily through BGS and BGSS (A)	$ 294	$ 280	$ 1,287	$ 1,308
Administrative Billings from Services (B)	66	59	197	183
Total Billings from Affiliates	**$ 360**	**$ 339**	**$ 1,484**	**$ 1,491**

Related-Party Transactions	As of September 30, 2015	As of December 31, 2014
	Millions	
Receivable from PSEG (C)	**$ 7**	**$ 274**
Payable to Power (A)	$ 158	$ 313
Payable to Services (B)	50	66
Accounts Payable—Affiliated Companies	**$ 208**	**$ 379**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 165**	**$ 116**

Power

The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	Millions			
Billings to Affiliates:				
Billings to PSE&G primarily through BGS and BGSS (A)	**$ 294**	**$ 280**	**$ 1,287**	**$ 1,308**
Billings from Affiliates:				
Administrative Billings from Services (B)	**$ 44**	**$ 41**	**$ 135**	**$ 129**

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Related-Party Transactions	As of September 30, 2015	As of December 31, 2014
	Millions	
Receivables from PSE&G (A)	**$ 158**	**$ 313**
Payable to Services (B)	$ 26	$ 23
Payable to PSEG (C)	91	95
Accounts Payable—Affiliated Companies	**$ 117**	**$ 118**
Short-Term Loan Due (to) from Affiliate (E)	**$ 865**	**$ 584**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 54**	**$ 41**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

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Note 18. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended September 30, 2015					
Operating Revenues	$ —	$ 1,084	$ 37	$ (25)	$ 1,096
Operating Expenses	3	692	35	(25)	705
Operating Income (Loss)	(3)	392	2	—	391
Equity Earnings (Losses) of Subsidiaries	220	(2)	3	(218)	3
Other Income	10	26	—	(11)	25
Other Deductions	—	(14)	—	—	(14)
Other-Than-Temporary Impairments	—	(30)	—	—	(30)
Interest Expense	(28)	(8)	(5)	11	(30)
Income Tax Benefit (Expense)	7	(148)	2	—	(139)
Net Income (Loss)	**$ 206**	**$ 216**	**$ 2**	**$ (218)**	**$ 206**
Comprehensive Income (Loss)	**$ 184**	**$ 187**	**$ 2**	**$ (189)**	**$ 184**
Nine Months Ended September 30, 2015					
Operating Revenues	$ —	$ 3,811	$ 144	$ (109)	$ 3,846
Operating Expenses	7	2,610	135	(109)	2,643
Operating Income (Loss)	(7)	1,201	9	—	1,203
Equity Earnings (Losses) of Subsidiaries	755	(4)	11	(751)	11
Other Income	33	111	—	(35)	109
Other Deductions	(1)	(31)	—	—	(32)
Other-Than-Temporary Impairments	—	(45)	—	—	(45)
Interest Expense	(90)	(24)	(15)	35	(94)
Income Tax Benefit (Expense)	17	(463)	1	—	(445)
Net Income (Loss)	**$ 707**	**$ 745**	**$ 6**	**$ (751)**	**$ 707**
Comprehensive Income (Loss)	**$ 690**	**$ 707**	**$ 6**	**$ (713)**	**$ 690**
Nine Months Ended September 30, 2015					
Net Cash Provided By (Used In) Operating Activities	$ 435	$ 1,826	$ 66	$ (769)	$ 1,558
Net Cash Provided By (Used In) Investing Activities	$ (656)	$ (1,382)	$ (303)	$ 1,191	$ (1,150)
Net Cash Provided By (Used In) Financing Activities	$ 221	$ (446)	$ 245	$ (422)	$ (402)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Three Months Ended September 30, 2014					
Operating Revenues	$ —	$ 1,125	$ 36	$ (23)	$ 1,138
Operating Expenses	3	772	32	(22)	785
Operating Income (Loss)	(3)	353	4	(1)	353
Equity Earnings (Losses) of Subsidiaries	225	(1)	4	(224)	4
Other Income	9	55	—	(8)	56
Other Deductions	(3)	(4)	—	1	(6)
Other-Than-Temporary Impairments	—	(10)	—	—	(10)
Interest Expense	(24)	(10)	(4)	7	(31)
Income Tax Benefit (Expense)	18	(161)	(1)	—	(144)
Net Income (Loss)	**$ 222**	**$ 222**	**$ 3**	**$ (225)**	**$ 222**
Comprehensive Income (Loss)	**$ 195**	**$ 191**	**$ 3**	**$ (194)**	**$ 195**
Nine Months Ended September 30, 2014					
Operating Revenues	$ —	$ 3,781	$ 118	$ (75)	$ 3,824
Operating Expenses	12	3,079	106	(75)	3,122
Operating Income (Loss)	(12)	702	12	—	702
Equity Earnings (Losses) of Subsidiaries	459	(4)	11	(455)	11
Other Income	25	135	—	(25)	135
Other Deductions	(7)	(18)	—	—	(25)
Other-Than-Temporary Impairments	—	(14)	—	—	(14)
Interest Expense	(79)	(23)	(14)	24	(92)
Income Tax Benefit (Expense)	54	(329)	(2)	—	(277)
Net Income (Loss)	**$ 440**	**$ 449**	**$ 7**	**$ (456)**	**$ 440**
Comprehensive Income (Loss)	**$ 432**	**$ 433**	**$ 7**	**$ (440)**	**$ 432**
Nine Months Ended September 30, 2014					
Net Cash Provided By (Used In) Operating Activities	$ 471	$ 1,252	$ 53	$ (666)	$ 1,110
Net Cash Provided By (Used In) Investing Activities	$ 187	$ (559)	$ (24)	$ 70	$ (326)
Net Cash Provided By (Used In) Financing Activities	$ (652)	$ (693)	$ (29)	$ 596	$ (778)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
As of September 30, 2015					
Current Assets	$ 4,678	$ 1,786	$ 134	$ (4,374)	$ 2,224
Property, Plant and Equipment, net	82	6,390	1,435	—	7,907
Investment in Subsidiaries	4,555	349	—	(4,904)	—
Noncurrent Assets	264	1,962	133	(176)	2,183
Total Assets	**$ 9,579**	**$ 10,487**	**$ 1,702**	**$ (9,454)**	**$ 12,314**
Current Liabilities	$ 1,581	$ 3,595	$ 772	$ (4,374)	$ 1,574
Noncurrent Liabilities	458	2,563	355	(176)	3,200
Long-Term Debt	1,691	—	—	—	1,691
Member's Equity	5,849	4,329	575	(4,904)	5,849
Total Liabilities and Member's Equity	**$ 9,579**	**$ 10,487**	**$ 1,702**	**$ (9,454)**	**$ 12,314**
As of December 31, 2014					
Current Assets	$ 4,263	$ 2,037	$ 150	$ (4,091)	$ 2,359
Property, Plant and Equipment, net	81	6,265	1,169	—	7,515
Investment in Subsidiaries	4,516	120	—	(4,636)	—
Noncurrent Assets	278	1,952	137	(195)	2,172
Total Assets	**$ 9,138**	**$ 10,374**	**$ 1,456**	**$ (8,922)**	**$ 12,046**
Current Liabilities	$ 883	$ 3,606	$ 786	$ (4,091)	$ 1,184
Noncurrent Liabilities	454	2,442	360	(195)	3,061
Long-Term Debt	2,243	—	—	—	2,243
Member's Equity	5,558	4,326	310	(4,636)	5,558
Total Liabilities and Member's Equity	**$ 9,138**	**$ 10,374**	**$ 1,456**	**$ (8,922)**	**$ 12,046**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G,** our public utility company which primarily provides electric transmission services and distribution of electric energy and natural gas, implements demand response and energy efficiency programs and invests in solar generation in New Jersey, and
- **Power,** our wholesale energy supply company that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business of our 2014 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2014 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2015 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2014 Form 10-K.

EXECUTIVE OVERVIEW OF 2015 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- Growing our utility operations through continued investment in T&D and other infrastructure projects, and
- Maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the three months and nine months ended September 30, 2015 and 2014 are presented as follows:

Earnings	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	Millions			
PSE&G	$ 222	$ 200	$ 631	$ 565
Power (A)	206	222	707	440
Other (B)	11	22	32	37
PSEG Net Income	**$ 439**	**$ 444**	**$ 1,370**	**$ 1,042**
PSEG Net Income Per Share (Diluted)	**$ 0.87**	**$ 0.87**	**$ 2.70**	**$ 2.05**

(A) Includes an after-tax insurance recovery for Superstorm Sandy of $102 million in the nine months ended September 30, 2015. See Item 1. Note 8. Commitments and Contingent Liabilities.

(B) Other includes activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
	Millions, after tax			
NDT Fund Income (Expense) (A)	$ (14)	$ 17	$ (11)	$ 40
Non-Trading MTM Gains (Losses)	$ 50	$ 36	$ 58	$ (138)

(A) NDT Fund Income (Expense) includes the realized gains and losses, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense.

Our $5 million decrease in Net Income for the three months ended September 30, 2015 was driven primarily by:

- lower net realized gains and higher other-than-temporary impairments related to the NDT Fund, and
- higher maintenance costs related to the earlier start in 2015 of the planned annual outage of our Peach Bottom Unit 3 nuclear facility and higher pension and OPEB costs.

These decreases were largely offset by

- higher revenues due to increased investments in transmission projects, and
- higher MTM gains.

Our $328 million increase in Net Income for the nine months ended September 30, 2015 was driven primarily by:

- MTM gains in 2015 as compared to MTM losses in 2014,
- higher volumes of electricity sold under wholesale load contracts and under the BGS contract, the latter at higher average prices,
- lower generation costs due to lower fuel costs,

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- higher revenues due to increased investments in transmission projects, and
- insurance recoveries of Superstorm Sandy costs, primarily at Power.

These year-to date increases were partially offset by

- lower realized gains and higher other-than-temporary impairments related to the NDT Fund,
- higher planned outage costs at our nuclear plants and higher pension and OPEB costs, and
- higher Depreciation Expense largely related to increased investments in transmission and distribution projects and a higher depreciable nuclear and fossil asset base.

At PSE&G, our regulated utility, we continued to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers. Effective January 1, 2015, PSE&G's formula rate increased our annual transmission revenues by approximately $182 million. Each year, transmission revenues are filed based on estimated data and subject to true up with actual current year data. The true-up adjustment for 2015, which will be filed in the Spring of 2016, will primarily include the impact on rate base due to the extension of bonus depreciation, which was enacted after the filing was made, and is estimated to reduce our 2015 annual revenue increase by approximately $21 million. In October 2015, we filed our 2016 Annual Formula Rate Update with the Federal Energy Regulatory Commission (FERC), which will provide $146 million in increased annual transmission revenues effective January 1, 2016.

Over the past few years, these types of investments have altered the business mix of our overall results of operations to reflect a higher percentage contribution by PSE&G.

Power's results benefited from access to natural gas supplies through its existing firm pipeline transportation contracts during the cold weather experienced in the first quarter of 2015. Power manages these contracts for the benefit of PSE&G's customers through the basic gas supply service (BGSS) arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to make third party sales and supply gas to its generating units in New Jersey.

Gas prices have remained relatively low this year as a result of the expansion of shale gas production, primarily in the Marcellus/Utica regions. These low prices benefit PSE&G's gas customers and provide a low cost fuel supply for Power's combined cycle units. However, they have also resulted in a decline in power prices. Our contractual hedges currently in place have helped mitigate some of the effects of low prices this year and for 2016. However, as these arrangements expire and new hedges are set at lower price levels, our margins will be impacted. A sustained continuation of low prices could have an adverse impact on the earnings from our nuclear and coal-fired units.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission Planning

FERC's rule under Order 1000 altered the right of first refusal (ROFR) previously held by incumbent utilities to build transmission within their respective service territories, creating the potential that new transmission projects in our service territory could be assigned to third parties rather than PSE&G. Order 1000 also presents opportunities for us to construct transmission outside of our service territory. In April 2013, PJM Interconnection, L.L.C. (PJM) initiated a solicitation process in which we participated to review technical solutions to improve the operational performance in the Artificial Island area, consisting of our Salem and Hope Creek nuclear generation facilities. In April 2015, the PJM staff advised stakeholders that it intended to recommend a transmission project that would primarily be awarded to another entity, but that a portion would be assigned to PSE&G. We subsequently filed comments with the PJM Board of Managers (PJM Board) identifying what we believed were deficiencies in the PJM staff recommendation. In July 2015, the PJM Board approved the PJM staff's recommendation and in August 2015, PJM provided notice to PSE&G of its designation for construction responsibility with respect to three components of the project, estimated by PJM to cost approximately $126 million. PSE&G is currently in discussions with PJM regarding the accuracy of this estimate given the complexities associated with construction work at Artificial Island. See Part II. Item 5. Other Information—Transmission Regulation—Transmission Policy Developments for additional information.

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Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. In May 2014, a federal court issued a rule that vacated a FERC Order in which FERC had determined that demand response (DR) providers should receive full market compensation for power and held that FERC has no jurisdiction over DR. In October 2015, the U.S. Supreme Court heard oral arguments on this case. Although a reversal by the U.S. Supreme Court of the federal court's decision regarding FERC's lack of jurisdiction is not expected to have significant impacts on capacity markets, a decision that upholds such decision could have a material impact on capacity market outcomes.

In a separate development of significance to the wholesale capacity market, in December 2014 PJM filed at FERC its proposal for a capacity performance product to include generators, DR and energy efficiency providers who would need to certify their availability during emergency conditions, as a supplement to base capacity. The proposal included enhanced performance-based incentives and penalties. In June 2015, FERC conditionally accepted the proposal. PJM commenced the auction on August 10, 2015 and announced the auction results on August 21, 2015. Power cleared 8,634 MW of its generating capacity at an average price of $214.72 MW-day for the 2018-2019 delivery period. Of the cleared capacity, Power believes that nearly all is compliant with PJM's CP requirements. In the two prior capacity auctions covering the 2016-2017 and 2017-2018 delivery years, Power cleared approximately 8,700 MW at average prices of $172 MW-day and $177 MW-day, respectively. The capacity that Power cleared for the 2018-2019 delivery year included Sewaren 7 and Keys Energy Center generation plants. See Other Developments below for additional details about our construction of these two new projects. We believe that this pricing adequately reflects the increased costs that could result from operating under more stringent rules for generation availability. No assurances can be given that similar pricing will continue in future auctions.

Applications for rehearing of FERC's capacity performance order are pending. See Part II, Item 5. Other Information—Capacity Market Issues—PJM for additional information.

We have also been actively involved both through stakeholder processes and through filings at FERC in seeking improvements to the rules for setting prices for energy in the day-ahead and real-time markets administered by PJM and other system operators. A recent development which we view as positive involves a September 2015 FERC notice of proposed rulemaking on two issues: aligning settlements with dispatch intervals (more granular “5-minute pricing” in real-time markets) and improving real-time scarcity pricing. Comments made by FERC commissioners stressed these two items are intended to be the first of a series of steps FERC will take on energy price formation in the future. See Part II, Item 5. Other Information—Price Formation Initiatives for additional information.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. In particular, the EPA’s 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. As adopted by the EPA, the rule requires that cooling water intake structures reflect the best technology available for minimizing environmental impacts. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. However, the EPA has structured the rule so that each state will continue to consider renewal permits for power facilities on a case by case basis. In June 2015, the New Jersey Department of Environmental Protection (NJDEP) issued a draft New Jersey Pollutant Discharge Elimination Systems (NJPDES) permit governing cooling water intake structures for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with required system modifications. The draft permit was subject to a sixty-day public notice and comment period. The NJDEP may make revisions before issuing the final permit expected during the first half of 2016. We participated in the NJDEP’s August 2015 public hearing and submitted comments on the draft permit in September 2015. See Item 1. Note 8. Commitments and Contingent Liabilities for further information.

The EPA’s greenhouse gas (GHG) emissions regulations are also of potential consequence to our results. In October 2015, the EPA published the Clean Power Plan (CPP), a GHG emissions regulation under the Clean Air Act (CAA) for existing power plants. The regulation establishes state-specific emission targets based on implementation of the best systems of emission reduction. Each state must submit a compliance plan to the EPA by September 6, 2016 or seek a two-year extension to September 6, 2018. We continue to work with FERC and other federal and state regulators, as well as industry partners, to determine the potential impact of these regulations. The EPA, FERC and the U.S. Department of Energy have announced that they plan to meet at least quarterly to evaluate states' plans and identify reliability concerns so adjustments can be made before the final plans are submitted. The agencies are engaging various stakeholders, including the Regional Transmission Operators/Independent System Operators. The agencies will continue to meet after the states' plans are in effect to assess if revisions are required. See Part II, Item 5. Other Information—CO_2 Regulation Under the Clean Air Act.

CAA regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology rules are also of significance; however, we believe our generation business remains well-positioned for such regulations if and when they are implemented. In addition, state environmental regulations governing emissions from power plants also have a significant

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impact on our operations. In the second quarter of 2015, we retired 1,545 MW of fully depreciated combustion turbine capacity that would not be able to comply with the more stringent emission standards for high electric demand day units (HEDD) under the New Jersey HEDD regulations for nitrous oxide, which will reduce capacity revenues for this year.

Other Developments

In the first nine months of 2015, we continued to make investments and seek recovery on such investments made to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the New Jersey Board of Public Utilities (BPU) in 2014. As approved, the Energy Strong program provides for $1.2 billion of investment, with cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated allowance for funds used during construction, through an accelerated recovery mechanism. We will seek recovery of up to $220 million of investment in PSE&G's next base rate case, which is to be filed no later than November 1, 2017.

In September 2015, we reached a settlement in principle with the BPU Staff and the New Jersey Division of Rate Counsel regarding PSE&G's Gas System Modernization Program (GSMP) through which, if approved, we will invest $905 million over the next three years to modernize PSE&G's gas systems. The settlement in principle provides for cost recovery at a 9.75% rate of return on equity on the first $650 million of the investment through an accelerated recovery mechanism. Under the settlement in principle, PSE&G will seek recovery of the remaining $255 million of investment in its next base rate case, which is to be filed no later than November 1, 2017. For additional information, see Part II, Item 5. Other Information—Gas System Modernization Program.

In August 2015, we announced our plan to construct Sewaren 7, a new 540 MW duel-fueled combined cycle generating plant in Woodbridge, New Jersey scheduled to be in-service for the summer of 2018 at an estimated investment of $625 million - $675 million. The Sewaren 7 plant will replace Sewaren Units 1, 2, 3 and 4.

In June 2015, we acquired a development project to construct a 755 MW gas-fired combined cycle generating station (Keys Energy Center) in Maryland with completion expected in 2018 at an estimated investment of $825 million - $875 million.

The preliminary non-public staff investigation initiated by FERC into Power's discovery and investigation of (i) incorrect calculations for certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market and (ii) differences in the quantity of energy that Power offered into the energy market for its fossil peaking units from the amount for which Power was compensated in the capacity market for those units continues. Power has an ongoing process of implementing improved procedures to help mitigate the risk of similar issues occurring in the future. This investigation could result in FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with this matter, or the applicability of mitigating factors. For more detailed information, refer to Item 1. Note 8. Commitments and Contingent Liabilities—FERC Compliance.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. In the first nine months of 2015, our

- total nuclear fleet achieved an average capacity factor of 92%,
- nuclear output increased by 2.7% and combined cycle output by 14.9% as compared to the same period in 2014, and
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 42.5 TWh while addressing unit outages and balancing fuel availability and price volatility.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during 2015 as we

- had cash flow from operations of $3.2 billion as of September 30, 2015,
- maintained solid investment grade credit ratings,
- extended the expiration dates for approximately $2.0 billion of five-year credit facilities for PSEG, PSE&G and Power from 2018 to 2020, and
- increased our indicated annual dividend for 2015 to $1.56 per share.

We expect to be able to fund our transmission projects required under PJM's reliability program, Energy Strong distribution program, Keys Energy Center and other planned projects, as well as our GSMP, without the issuance of new equity.

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Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In 2015, in addition to our acquisition of the Keys Energy Center and clearance of Sewaren 7 in the 2018/2019 capacity auction, each of which is under construction, we

- placed into service the final phase of our 500 kV Susquehanna-Roseland and 230 kV Mickleton-Gloucester-Camden transmission projects,
- made additional investments in transmission infrastructure projects,
- secured approval to extend three Energy Efficiency Economic Stimulus subprograms to allow for additional capital expenditures and administrative expenses to provide energy efficiency assistance to hospitals, healthcare facilities and residential multi-family housing units,
- continued to execute our existing BPU-approved utility programs,
- completed the power ascension for the extended power uprate at our co-owned Peach Bottom 2 nuclear station,
- completed installation of equipment to increase output and improve efficiency at our Bergen 2 combined cycle gas unit similar to our 2014 installation at our Linden plant, and
- placed into service a 13 MWdc solar energy facility near Waldorf, Maryland and acquired and placed into service a 25 MWdc solar energy facility near San Francisco, California.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-moving economy and a cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions,
- execute our capital investment program, including our Energy Strong program, proposed GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction of our Keys Energy Center, Sewaren 7 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

For 2015 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate, and
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development projects, including in connection with permitting and regulatory approvals.

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RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 17. Related-Party Transactions.

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,688	$ 2,641	$ 47	2	$ 8,137	$ 8,113	$ 24	—
Energy Costs	815	863	(48)	(6)	2,577	3,008	(431)	(14)
Operation and Maintenance	746	714	32	4	2,170	2,370	(200)	(8)
Depreciation and Amortization	313	318	(5)	(2)	960	919	41	4
Income from Equity Method Investments	3	3	—	—	10	10	—	—
Other Income and (Deductions)	33	66	(33)	(50)	135	154	(19)	(12)
Other-Than-Temporary Impairments	30	10	20	N/A	45	14	31	N/A
Interest Expense	96	100	(4)	(4)	291	291	—	—
Income Tax Expense	285	261	24	9	869	633	236	37

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,766	$ 1,655	$ 111	7	$ 5,234	$ 5,235	$ (1)	—
Energy Costs	740	668	72	11	2,176	2,278	(102)	(4)
Operation and Maintenance	391	366	25	7	1,171	1,190	(19)	(2)
Depreciation and Amortization	231	238	(7)	(3)	712	682	30	4
Other Income (Deductions)	22	14	8	57	57	41	16	39
Interest Expense	67	71	(4)	(6)	203	206	(3)	(1)
Income Tax Expense	137	126	11	9	398	355	43	12

Three Months Ended September 30, 2015 as Compared to 2014

Operating Revenues increased $111 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $67 million due primarily to increases in transmission and electric distribution revenues.

- Transmission revenues were $41 million higher due to increases resulting primarily from increased capital investments.
- Electric distribution revenues increased $29 million due primarily to higher sales volumes of $24 million, higher Green Program Recovery Charges (GPRC) of $3 million and $2 million due to the roll in of Energy Strong into base rates effective September 1, 2015.

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- Gas distribution revenues decreased $3 million due primarily to lower delivery volume.

Commodity Revenue increased $72 million as a result of higher Electric revenues partially offset by lower Gas revenues. Commodity revenue for both electric and gas is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of basic generation service (BGS) and Basic Gas Supply Service (BGSS) to retail customers.

- Electric revenues increased $81 million due primarily to an $83 million or 16% increase in BGS revenues due to higher sales volumes and $2 million of higher revenues from collections of Non-Utility Generation Charges (NGC). These increases were partially offset by a $4 million reduction in revenues due to lower volumes on Non-Utility Generation (NUG) energy sold at lower prices.
- Gas revenues decreased $9 million due primarily to $11 million in lower BGSS prices, partially offset by $2 million in higher prices.

Clause Revenues decreased $28 million due primarily to lower Securitization Transition Charges (STC) of $28 million, lower Solar Pilot Recovery Charges (SPRC) of $3 million, and lower Margin Adjustment Clause Revenue of $1 million, partially offset by higher Societal Benefit Charges (SBC) of $4 million. The changes in the STC, SPRC, MAC and SBC amounts are entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SPRC, MAC or SBC collections.

Other Operating Revenues experienced no material change.

Operating Expenses

Energy Costs increased $72 million due to higher Electric costs partially offset by lower Gas costs. This is entirely offset by decreased Commodity Revenue.

- Electric costs increased $81 million or 14% due to $45 million of higher BGS and NUG prices and $68 million in higher BGS volumes. BGS volumes increased due to higher sales volumes due to warmer weather and reverse customer migration. These increases were partially offset by $19 million of decreased deferred cost recovery and $13 million of lower NUG volumes.
- Gas costs decreased $9 million or 11% due to $11 million in lower prices, partially offset by $2 million in higher volumes.

Operation and Maintenance increased $25 million, of which the most significant components were

- $10 million increase in pension and OPEB expenses,
- $7 million increase in transmission operating expenses,
- $8 million increase in other operating expenses, including $4 million in appliance service costs, $3 million in higher preventive maintenance and tree trimming and $1 million increase in general operating expenses,
- partially offset by a $3 million decrease in costs related to a net decrease in SBC, MAC, GPRC, SPRC and STC. Due to the nature of the SBC, MAC, SPRC and STC clause mechanisms, these are entirely offset in revenue.

Depreciation and Amortization decreased $7 million due primarily to a decrease of $22 million in amortization of Regulatory Assets, partially offset by a $13 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects.

Other Income and (Deductions) increased $8 million due primarily to an increase in Allowance for Funds used During Construction (AFUDC).

Interest Expense decreased $4 million due primarily to partial redemption of securitization debt and clause interest, partially offset by net issuances of Medium Term Notes during 2015 and the latter half of 2014.

Income Tax Expense increased $11 million due primarily to higher pre-tax income.

Nine Months Ended September 30, 2015 as Compared to 2014

Operating Revenues decreased $1 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $178 million due primarily to increases in transmission and electric distribution revenues.

- Transmission revenues were $124 million higher due to increases resulting primarily from increased capital investments.

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- Electric distribution revenues increased $45 million due primarily to higher sales volumes of $37 million, an increase in Capital Stimulus Infrastructure Program (CIP) revenues of $5 million due to the inclusion of CIP II in base rates beginning in July 2014 and $3 million of higher revenues from GPRC.
- Gas distribution revenues increased $9 million due primarily to $16 million from higher sales volumes and an increase in CIP revenues of $2 million, partially offset by lower Weather Normalization Charges (WNC) revenue of $9 million due to colder weather in 2015 compared to 2014.

Commodity Revenue decreased $102 million due to lower Gas revenues offset partially by higher Electric revenues. Commodity revenue for both electric and gas is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Gas revenues decreased $209 million due primarily to lower BGSS prices of $290 million, of which $215 million was due to lower residential rates resulting from $133 million in residential bill credits and $82 million of lower commodity prices, partially offset by higher BGSS volumes of $81 million due to colder weather in 2015.
- Electric revenues increased $107 million due primarily to $140 million of higher net BGS revenues. BGS revenues increased $171 million or 13%, due to higher sales volumes, which were partially offset by $31 million due to lower BGS rates. The increase from BGS was partially offset by $33 million in lower revenues from lower collection of NGC and lower sales prices and volumes of NUG energy.

Clause Revenues decreased $75 million due primarily to lower MAC revenue of $24 million, lower STC of $24 million, lower SBC of $23 million and lower SPRC of $4 million. The changes in the MAC, STC, SBC and SPRC amounts were entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on MAC, STC, SBC or SPRC collections.

Other Operating Revenues experienced no material change.

Operating Expenses

Energy Costs decreased $102 million due to lower Gas costs partially offset by higher Electric costs. This is entirely offset by decreased Commodity Revenue.

- Gas costs decreased $209 million or 27% due to a $290 million or 37% decline in prices, partially offset by $81 million or 10% in higher sales volumes due to colder than normal weather.
- Electric costs increased $107 million or 7% due to a $140 million or 11% increase in BGS volumes, due to reverse customer migration and higher sales volumes due to warmer weather and a $57 million increase due to higher BGS and NUG prices, partially offset by $69 million of decreased deferred cost recovery and $21 million in lower NUG sales volumes.

Operation and Maintenance decreased $19 million, of which the most significant components were

- a $63 million decrease in costs related primarily to a net decrease in SBC, MAC, GPRC, CIP, SPRC and STC. Due to the nature of the SBC, MAC, SPRC and STC clause mechanisms, these are entirely offset in revenues,
- storm insurance recovery proceeds of $10 million, and
- decreased injuries and damages of $6 million,
- partially offset by a $28 million increase in pension and OPEB expenses,
- increased transmission operating expenses of $10 million,
- $8 million of higher appliance service costs,
- increased bad debt expense of $6 million, and
- an $8 million increase in other general operating expenses.

Depreciation and Amortization increased $30 million due primarily to a $42 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects, offset by a decrease of $13 million in amortization of Regulatory Assets which is fully offset in Clause Revenues.

Other Income and (Deductions) increased $16 million due primarily to an increase in AFUDC.

Interest Expense decreased $3 million due primarily to partial redemption of securitization debt partially offset by net issuances of Medium Term Notes in 2015 and the latter half of 2014.

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Income Tax Expense increased $43 million due primarily to higher pre-tax income.

Power

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,096	$ 1,138	$ (42)	(4)	$ 3,846	$ 3,824	$ 22	1
Energy Costs	367	472	(105)	(22)	1,669	2,036	(367)	(18)
Operation and Maintenance	263	242	21	9	748	871	(123)	(14)
Depreciation and Amortization	75	71	4	6	226	215	11	5
Income from Equity Method Investments	3	4	(1)	(25)	11	11	—	—
Other Income (Deductions)	11	50	(39)	(78)	77	110	(33)	(30)
Other-Than-Temporary Impairments	30	10	20	N/A	45	14	31	N/A
Interest Expense	30	31	(1)	(3)	94	92	2	2
Income Tax Expense	139	144	(5)	(3)	445	277	168	61

Three Months Ended September 30, 2015 as Compared to 2014

Operating Revenues decreased $42 million due to changes in generation, gas supply and other operating revenues.

Gas Supply Revenues decreased $44 million due primarily to

- a decrease of $14 million in sales under the BGSS contract substantially comprised of lower average sales prices, and
- a decrease of $30 million due to lower average sales prices and volumes to third party customers.

Generation Revenues increased $3 million due primarily to

- an increase of $39 million due to higher volumes of electricity sold under our BGS contract at higher average prices,
- partially offset by a decrease of $27 million due primarily to lower volumes sold under the wholesale load contracts in the PJM and New England (NE) regions.

Other Operating Revenues decreased $1 million due to lower fees received from fuel management and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $105 million due to

- ***Generation costs*** decreased $59 million due primarily to lower fuel costs, reflecting lower average realized natural gas prices and the utilization of lower coal volumes at lower average realized prices, coupled with higher MTM gains in 2015. These decreased costs were partially offset by higher congestion costs in the PJM region.
- ***Gas costs*** decreased $46 million related to lower average gas inventory costs on both obligations under the BGSS contract and sales to third parties, coupled with lower volumes sold to third parties.

Operation and Maintenance increased $21 million due primarily to

- a net increase of $24 million at our nuclear facilities, primarily due to the start of the 2015 fall outage one month sooner than in 2014 at our 50%-owned Peach Bottom nuclear unit 3,

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- partially offset by a decrease of $5 million related to our fossil plants, largely due to higher costs incurred in 2014 for planned outages and maintenance.

Depreciation and Amortization increased $4 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) decreased $39 million due primarily to lower net realized gains from the NDT Fund.

Other-Than-Temporary Impairments increased $20 million due to an increase in impairments of the NDT Fund.

Interest Expense experienced no material change.

Income Tax Expense decreased $5 million in 2015 due primarily to lower pre-tax income.

Nine Months Ended September 30, 2015 as Compared to 2014

Operating Revenues increased $22 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues increased $203 million due primarily to

- higher net revenues of $232 million due primarily to MTM gains in 2015 compared to MTM losses in 2014, partially offset by lower energy volumes sold in the NE region and lower average realized prices in the NE and New York (NY) regions,
- an increase of $78 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions, and
- an increase of $48 million due primarily to higher volumes of electricity sold under the BGS contract at higher average prices,
- partially offset by a decrease of $155 million due primarily to lower capacity revenues resulting from lower average auction prices coupled with lower ancillary and operating reserve revenues in the PJM region.

Gas Supply Revenues decreased $182 million due primarily to

- a net decrease of $86 million in sales under the BGSS contract, substantially comprised of lower average sales prices, partially offset by higher volumes due to colder average temperatures in the 2015 winter heating season, and
- a decrease of $96 million due to lower average sales prices and volumes to third party customers.

Other Operating Revenues increased $1 million due to higher fees received from fuel management and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $367 million due to

- ***Generation costs*** decreased $149 million due primarily to lower fuel costs, reflecting lower average realized natural gas and oil prices and the utilization of lower volumes of coal, coupled with MTM gains in 2015 as compared to MTM losses in 2014. These decreased costs were partially offset by the utilization of higher volumes of natural gas, coupled with higher congestion costs in the PJM region.
- ***Gas costs*** decreased $218 million related to lower average gas inventory costs on both obligations under the BGSS contract and sales to third parties, coupled with lower volumes sold to third parties. This was partially offset by higher volumes sold under the BGSS contract due to colder average temperatures during the 2015 winter heating season.

Operation and Maintenance decreased $123 million due primarily to

- a decrease of $145 million due to insurance recoveries related to Superstorm Sandy, and
- a net decrease of $48 million related to our fossil plants, largely due to higher costs incurred in 2014 for planned outage costs, including maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant, partially offset by planned outage costs in 2015 at our Bethlehem Energy Center generating plant and installation of upgraded technology at our combined cycle Bergen plant,

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- partially offset by an increase of $48 million at our nuclear facilities, primarily due to higher planned outage costs at our 100%-owned Hope Creek and 50%-owned Peach Bottom 3 nuclear plants in 2015 as compared to our 57%-owned Salem nuclear unit 2 in 2014, and
- a $22 million increase due to higher pension and OPEB costs.

Depreciation and Amortization increased $11 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) decreased $33 million due primarily to lower net realized gains from the NDT Fund partially offset by a $28 million insurance recovery related to Superstorm Sandy.

Other-Than-Temporary Impairments increased $31 million due to an increase in impairments of the NDT Fund.

Interest Expense experienced no material change.

Income Tax Expense increased $168 million in 2015 due primarily to higher pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund planned capital expenditures and shareholder dividend payments.

For the nine months ended September 30, 2015, our operating cash flow increased $692 million as compared to the same period in 2014. The net change was due primarily to the net changes from PSE&G and Power as discussed below.

PSE&G

PSE&G's operating cash flow increased $175 million from $1,343 million to $1,518 million for the nine months ended September 30, 2015, as compared to the same period in 2014, due primarily to higher earnings, a $203 million reduction in tax payments, $37 million reduction in vendor payments and a $25 million decrease in prepayments. These amounts were partially offset by a decrease of $232 million due to a change in regulatory deferrals primarily driven by the return of prior year overcollections to customers for BGSS gas costs, Gas Weather Normalization charges and Non-Utility Generation charges.

Power

Power's operating cash flow increased $448 million from $1,110 million to $1,558 million for the nine months ended September 30, 2015, as compared to the same period in 2014, primarily due to higher earnings and a reduction in margin deposit requirements, partially offset by an increase of $197 million in tax payments.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our $4.2 billion credit facilities are provided by a diverse bank group. As of September 30, 2015, our total available credit capacity was $3.9 billion.

As of September 30, 2015, no single institution represented more than 7% of the total commitments in our credit facilities.

As of September 30, 2015, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of September 30, 2015 were as follows:

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Company/Facility	As of September 30, 2015 Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facility	$ 500	$ 10	$ 490	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—	500	Apr 2020	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 10**	**$ 990**		
PSE&G					
5-year Credit Facility (B)	$ 600	$ 34	$ 566	Apr 2020	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 34**	**$ 566**		
Power					
5-year Credit Facility	$ 1,600	$ 201	$ 1,399	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (C)	1,000	14	986	Apr 2020	Funding/Letters of Credit
Total Power	**$ 2,600**	**$ 215**	**$ 2,385**		
Total	**$ 4,200**	**$ 259**	**$ 3,941**		

(A) PSEG facility will be reduced by $23 million in April 2016 and $12 million in March 2018.

(B) PSE&G facility will be reduced by $29 million in April 2016 and $14 million in March 2018.

(C) Power facility will be reduced by $48 million in April 2016 and $24 million in March 2018.

Long-Term Debt Financing

PSE&G has $171 million of 6.75% Mortgage Bonds maturing in January 2016. Power has $300 million of 5.50% Senior Notes maturing in December 2015 and $303 million of 5.32% Senior Notes and $250 million of 2.75% Senior Notes maturing in September 2016.

For a discussion of our long-term debt transactions during 2015, see Item 1. Note 9. Changes in Capitalization.

Common Stock Dividends

On July 21, 2015, our Board of Directors approved a $0.39 per share common stock dividend for the third quarter of 2015. This reflects an indicated annual dividend rate of $1.56 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 1. Note 15. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In May 2015, Moody's published research reports on PSEG, PSE&G and Power and the existing ratings and outlooks were unchanged. In May 2015, S&P published updated research reports and revised the outlook to stable from positive for PSEG's Corporate Credit Rating and Power's Senior Notes. S&P also affirmed the senior unsecured rating of BBB+ at Power and the mortgage bond rating of A at PSE&G. In September 2015, Moody's published an updated research report on PSEG and revised the outlook to positive from stable. In September and October 2015, Fitch published full rating reports on PSEG and Power leaving ratings and outlooks unchanged. As of October 2015, PSEG has ended a contractual agreement with Fitch to provide credit rating services for PSEG, PSE&G and Power.

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	Moody's (A)	S&P (B)
PSEG		
Outlook	**Positive**	**Stable**
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities. The Corporate Credit Rating outlook does not apply to PSEG's or PSE&G's Commercial Paper Rating or PSE&G's Mortgage Bond rating.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing.

In September 2015, we reached a settlement in principle with the BPU Staff and the New Jersey Division of Rate Counsel regarding our GSMP, through which, if approved, we will invest $905 million over the next three years to modernize PSE&G's gas systems.

In June 2015, we acquired a development project to construct a 755 MW gas-fired combined cycle generating station in Maryland (Keys Energy Center). We plan to start constructing this year with expected completion in 2018 at an estimated investment of $825 million - $875 million.

In August 2015, we announced our plan to construct Sewaren 7, a new 540 MW duel-fueled combined cycle generating plant in Woodbridge, New Jersey scheduled to be in-service for the summer of 2018 at an estimated investment of $625 million - $675 million.

The aforementioned estimated project expenditures related to the GSMP at PSE&G and the Maryland and Woodbridge, New Jersey projects at Power are not included in the $8.7 billion three-year capital forecast table in our 2014 Form 10-K. There were no material changes to our projected capital expenditures at Services as compared to amounts disclosed in our 2014 Form 10-K.

PSE&G

During the nine months ended September 30, 2015, PSE&G made capital expenditures of $1,946 million, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $82 million, which are included in operating cash flows.

Power

During the nine months ended September 30, 2015, Power made capital expenditures of $597 million, excluding $200 million for nuclear fuel, primarily related to various projects at its fossil and nuclear generation stations, including the new Maryland generating station noted above.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Item 1. Note 2. Recent Accounting Standards.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From July through September 2015, MTM VaR remained relatively stable between low of $8 million to high of $14 million at 95% confidence level. The range of VaR was narrower for the three months ended September 30, 2015 as compared with the year ended December 31, 2014.

	MTM VaR	
	Three Months Ended September 30, 2015	Year Ended December 31, 2014
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 10	$ 36
Average for the Period	$ 10	$ 30
High	$ 14	$ 195
Low	$ 8	$ 14
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 16	$ 56
Average for the Period	$ 15	$ 46
High	$ 23	$ 306
Low	$ 12	$ 22

See Item 1. Note 10. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

There have been no changes in internal control over financial reporting that occurred during the third quarter of 2015 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2014 Annual Report on Form 10-K, see see Part I, Item 1. Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

There are no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2014 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the third quarter of 2015.

Three Months Ended September 30, 2015	Total Number of Shares Purchased	Average Price Paid per Share
July 1 - July 31	—	$ —
August 1- August 31	189,018	$ 42.23
September 1- September 30	20,000	$ 38.97

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ITEM 5. OTHER INFORMATION

Certain information reported in the 2014 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2014 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the quarters ended March 31, 2015 and June 30, 2015. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

Federal Regulation

FERC

Regulation of Wholesale Sales—Generation/Market Issues

Capacity Market Issues—PJM

December 31, 2014 Form 10-K page 16, March 31, 2015 Form 10-Q page 69 and June 30, 2015 Form 10-Q page 78. The RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity.

On December 12, 2014, PJM filed a proposal at FERC to implement a Capacity Performance (CP) mechanism. Under this mechanism, PJM created a more robust capacity product definition with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. On June 9, 2015, FERC conditionally accepted the CP mechanism which will be phased in over the next few years, with the participation of both the CP product and a base product that has less rigorous performance obligations. The CP mechanism was implemented for the 2015 base residual auction (covering the 2018-2019 Delivery Year) which concluded on August 21, 2015. The CP product will be implemented fully for the 2020-2021 Delivery Year. Based upon the August 2015 base residual auction results, the CP mechanism appears to have provided the opportunity for enhanced capacity market revenue streams for Power but future impacts cannot be assured. Further, there may be requirements for additional investment and there are additional performance risks.

On June 30, 2015, a consumer coalition filed a complaint requesting that the load forecast that PJM was currently analyzing and updating to determine the amount of capacity it would procure in the 2016 base residual auction be implemented immediately for the upcoming 2015 transition auctions and base residual auction. FERC did not address the complaint prior to the auctions, effectively denying it.

Price Formation Initiatives

Power has been actively involved both through stakeholder processes and through filings at FERC in seeking improvements to the rules for setting prices for energy in the day-ahead and real-time markets administered by PJM and other system operators. A recent development which we consider positive involves a September 17, 2015 FERC notice of proposed rulemaking on two issues: aligning settlements with dispatch intervals (more granular “5-minute pricing” in real-time markets) and improving real-time scarcity pricing. Comments made by FERC commissioners stressed these two items are intended to be the first of a series of steps FERC will take on energy price formation in the future.

Reactive Power Rates

In June 2015, Power submitted a tariff filing with FERC to increase Power’s rates for reactive supply and voltage control service from approximately $27 million per year to about $39 million per year. The rates were last adjusted in 2008 and since that time various generating units have been de-activated, activated or improved with the net impact supportive of an upward rate adjustment. FERC accepted Power’s rate filing increase to become effective in January 2016, subject to refund, hearing and settlement procedures. FERC also referred the filing to the FERC Office of Enforcement for its evaluation. Power has participated in two settlement conferences to date with the FERC trial staff.

Long-Term Capacity Agreement Pilot Program Act (LCAPP)

December 31, 2014 Form 10-K page 18. In 2011, the State of New Jersey enacted the LCAPP to subsidize approximately 2,000 MW of new natural gas-fired generation. The LCAPP provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey EDCs.

In 2013, the U.S. District Court in New Jersey found that the LCAPP was unconstitutional and declared the LCAPP null and void. This federal court decision was subsequently challenged on appeal in the U.S. Third Circuit Court of Appeals. The State of Maryland also took similar action to subsidize above-market new generation. This action was also determined to be unconstitutional in 2013 in the U.S. District Court in Maryland and such decision was challenged in the U.S. Fourth Circuit Court of Appeals. Both appeals were denied, with the U.S. Fourth Circuit Court of Appeals (Fourth Circuit) denying the appeal regarding the State of Maryland’s action in June 2014 and the U.S. Third Circuit Court of Appeals denying the LCAPP appeal in September 2014. These denials have been challenged on appeal to the U.S. Supreme Court. In October 2015, the U.S. Supreme Court announced that it would consider the appeal of the Fourth Circuit's decision involving Maryland. The U.S. Supreme Court is expected to consider this case in 2016. We cannot predict the outcome of this appeal.

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Transmission Regulation—Transmission Policy Developments

December 31, 2014 Form 10-K page 18, March 31, 2015 Form 10-Q page 70 and June 30, 2015 Form 10-Q page 78.
In April 2013, PJM initiated its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues at Artificial Island off the shore of New Jersey. In April 2015, the PJM staff advised stakeholders that it intended to recommend a transmission project to the PJM Board of Managers consisting of various components to be constructed by LS Power, PSE&G and Potomac Holding Company. On July 29, 2015, the PJM Board approved the PJM staff's recommendation. In August 2015, PJM sent PSE&G a Construction Responsibility Letter (to which PSE&G will be responding on November 9) awarding PSE&G three components of the project, estimated by PJM to cost approximately $126 million. PSE&G is currently in discussions with PJM regarding the accuracy of this estimate given the complexities associated with construction work at Artificial Island. In a related matter, FERC denied a complaint filed by PSE&G contending that PJM had failed to follow its rules during the Artificial Island solicitation process. PSE&G, however, continues to work with both PJM and its stakeholders to improve the rules governing open window processes in PJM.

In November 2014, Con Edison had brought a complaint against PJM at FERC challenging PJM's allocation of costs for two PSE&G projects in northern New Jersey, including the Bergen-Linden Corridor Project (BLC). In June 2015, FERC issued an order dismissing the complaint. Con Edison and a merchant generator have sought judicial review of certain aspects of FERC's order and Con Edison has filed a rehearing request with FERC.

There have been developments on several additional matters involving cost allocation issues. In May 2015 and as amended in July 2015, a merchant transmission operator filed a complaint against PJM challenging PJM's allocation of costs for four PSE&G projects, including BLC. PSE&G filed opposition to the complaint and the matter is currently pending at FERC. In August 2015, the Delaware Public Service Commission and the Maryland Public Service Commission filed a complaint against PJM and certain transmission owners that have voting rights over cost allocation and rate design, including PSE&G, alleging that PJM tariff provisions allocate an excessive share of the Artificial Island project costs to them relative to the actual benefits of the project to residents of Delaware and Maryland. PSE&G intends to participate in a group filing of transmission owners that will oppose the complaint.

In June 2015, a transmission developer filed a complaint against PJM claiming that PJM wrongfully refused to provide data and a transparent process for evaluating transmission network upgrade requests that the transmission developer had submitted to PJM. According to the complaint, PJM and certain transmission owners wrongfully inflated the scope and associated costs of mitigation work needed to accommodate the developer's proposal in order to prevent it from pursuing its projects. Although not named as a respondent in the complaint, PSE&G is identified as one of the companies claimed to have been involved. In July 2015, PJM filed a response, which included a supporting affidavit from PSE&G, contesting the allegations. The matter is pending.

State Regulation

Gas System Modernization Program (GSMP)

March 31, 2015 Form 10-Q page 71. In September 2015, PSE&G reached a settlement in principle with the BPU Staff and the New Jersey Division of Rate Counsel regarding PSE&G's GSMP through which, if approved, PSE&G will invest $905 million over the next three years to modernize its gas system. The settlement in principle will enable the utility to replace up to 510 miles of gas mains and 38,000 service lines over a three-year period, with cost recovery at a 9.75% rate of return on equity on the first $650 million of the investment through an accelerated recovery mechanism. Under the settlement in principle, PSE&G will seek recovery of the remaining $255 million of investment in its next base rate case, which is to be filed no later than November 1, 2017.

Connecticut Rate Filing

June 30, 2015 Form 10-Q page 79. In June 2015, Power's subsidiary PSEG New Haven LLC, filed a mandatory annual rate case with the Connecticut Public Utilities Regulatory Authority (PURA) for recovery of its costs and investment in its Connecticut-based peaking unit. Power requested 2016 revenues of $22 million. On October 22, 2015, PURA issued a Proposed Final Decision to approve the entirety of Power's request. A Final Decision is expected to be issued on November 4, 2015.

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Environmental Matters

Air Pollution Control

Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation

December 31, 2014 Form 10-K page 23 and June 30, 2015 Form 10-Q page 79. In March 2013, Power filed a petition at the EPA challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued in January 2013. Among other things, the final EPA rule includes two exemptions that allow owners and operators of stationery emergency RICE to operate their engines without the installation and operation of emission controls (1) as part of an emergency DR program for 100 hours per year (100 hour exemption) or (2) as part of a financial arrangement with another entity per specified restrictions in non-emergency situations for 50 hours per year (50 hour exemption). This waiver of NESHAP standards results in disparate treatment of different generation technology types. In its appeal, Power sought more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. In August 2014, the EPA denied the March 2013 petition and in October 2014, Power appealed the EPA's denial to the D.C. Court. On May 1, 2015, the D.C. Court vacated the 100 hour exemption but thereafter granted a stay until May 1, 2016. On September 23, 2015, the D.C. Court granted the EPA's motion for voluntary remand of the 50 hour exemption provision to the EPA. While both provisions remain in place, the EPA will undergo proceedings to address the D.C. Court's orders. We believe that the impact of the D.C. Court's rulings would likely benefit Power's and its competitors' operations of their power generation peaking units.

Ozone Standard

March 31, 2015 Form 10-Q page 71. In December 2014, the EPA proposed a rule to lower the ambient air quality standard for the level of ozone in the atmosphere from 75 parts per billion (ppb) to a level in the range of 65-70 ppb. On October 1, 2015, the EPA finalized a standard of 70 ppb. To meet the new standard, the EPA and the states have to implement additional emission reduction strategies for NO_X and volatile organic compounds. Some portions of the Mid-Atlantic and New England states are not expected to be able to meet the new standard. Although the majority of our fossil generating units employ state-of-the-art NO_X emission controls, we cannot predict the outcome of this matter since new requirements of the EPA and the states are unknown at this time. A coal mining company has filed a petition for review with the D.C. Court to challenge the rule.

Climate Change

CO2 Regulation Under the Clean Air Act (CAA)

December 31, 2014 Form 10-K page 23, March 31, 2015 Form 10-Q page 72 and June 30, 2015 Form 10-Q page 80. On October 23, 2015, the EPA published the Clean Power Plan (CPP), a greenhouse gas (GHG) emissions regulation under the CAA for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction (BSER). The BSER consists of three components: (i) heat rate improvements at existing coal-fired power plants, (ii) increased use of existing natural gas combined cycle capacity, and (iii) operation of incremental zero-emitting generation (renewables and nuclear). States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions.

Each state must submit a compliance plan to the EPA by September 6, 2016 or seek a two-year extension to September 6, 2018. States can comply using an emission rate-based plan (pounds CO_2/MWh) or a mass-based plan (tons). Compliance with the final rule is effective January 1, 2022.

The EPA, FERC and the U.S. Department of Energy announced that they plan to meet at least quarterly to evaluate states' plans and identify reliability concerns so adjustments can be made before the final plans are submitted. The agencies are engaging various stakeholders, including the Regional Transmission Operators/Independent System Operators. The agencies will continue to meet after the states' plans are in effect to assess if revisions are required.

On October 23, 2015, the EPA also published proposed federal implementation requirements for states that do not submit an EPA-approved compliance plan. Comments are due by January 21, 2016.

Numerous states, including New Jersey, and several industry groups have filed petitions for review with the D.C. Court to challenge the CPP. In addition, the petitioners are seeking a stay of the rule.

Water Pollution Control

Steam Electric Effluent Guidelines

December 31, 2014 Form 10-K page 24. On September 30, 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power has two electric generation facilities, its dual-

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fuel (gas/coal) Mercer station in New Jersey and coal-fired Bridgeport Harbor station in Connecticut, that have bottom ash transport water discharges that are regulated under this rule. We are unable to predict if these new standards will have a material impact on Power's future capital requirements, financial condition or results of operations.

Cooling Water Intake Structure Regulation

December 31, 2014 Form 10-K page 25 and June 30, 2015 Form 10-Q page 80. On June 30, 2015, the NJDEP issued a draft permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The draft permit is subject to a sixty-day public notice and comment period. We participated in the NJDEP's August 5, 2015 public hearing and submitted comments on the draft permit on September 18, 2015. The NJDEP may make revisions before issuing the final permit expected in the first half of 2016. For additional information, see Part I, Item 1. Note 8. Commitments and Contingent Liabilities.

Waters of the United States

December 31, 2014 Form 10-K page 25 and June 30, 2015 Form 10-Q page 80. In April 2014, the EPA Administrator and the Assistant Secretary of the Army (Civil Works) jointly published a proposed rule to clarify the definition of waters of the U.S. under the Clean Water Act (CWA) programs in order to protect the streams and wetlands that form the foundation of the nation's water resources. This definition will have broad application to all areas of compliance under the CWA, including permitted discharges and construction activities. The final rule was published on June 29, 2015 and we are reviewing it to determine the materiality of the impacts that might result from the final rule. Some states, including New Jersey, are subject to state requirements beyond those imposed under federal law. While we do not anticipate material impacts to projects in New Jersey, the new definition could impose requirements in other states and regions that could impact the development of renewables.

Various states, industry coalitions and environmental organizations have initiated legal action related to the provisions of the final rule. On October 9, 2015, the Sixth Circuit Court of Appeals issued a stay of the rule pending further court action.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 10	Employment Agreement with Daniel J. Cregg. dated September 22, 2015
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. PSE&G:

Exhibit 10	Employment Agreement with Daniel J. Cregg, dated September 22, 2015
Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. Power:

Exhibit 10	Employment Agreement with Daniel J. Cregg, dated September 22, 2015
Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2015

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2015

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PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2015

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EXHIBIT 10

Margaret M. Pego **Human Resources**
Senior Vice President-Human Resources 80 Park Plaza, T4, Newark, NJ 07102
and Chief Human Resources Officer tel: 973-430-7243 fax: 973-242-5176
email: Margaret.Pego@pseg.com

September 22, 2015

Daniel J. Cregg
21 Branford Drive
Robbinsville, NJ 08691

Dear Dan:

I am pleased to offer you the position of Executive Vice President and Chief Financial Officer of Public Service Enterprise Group Incorporated ("PSEG" or "Enterprise") in PSEG Services Corporation, effective October 8, 2015. In this position, you will be paid a base annual salary of $520,000. You shall be eligible for your next salary review in January 2017. Salary reviews will be conducted annually thereafter.

You will be eligible to participate in PSEG's Senior Management Incentive Compensation Plan ("SMICP") under the terms and conditions of the SMICP. Your target incentive award for 2015 will be 75% of your base salary, however, you may be eligible to receive up to 112.5% of your base salary dependent upon business results. Targets and awards may be adjusted from time to time in accordance with established plan procedures. There is no guarantee of payment under the SMICP, and any such payment will be contingent upon your establishment and successful completion of goals and objectives. Your first award under the SMICP, if earned, will be based upon the successful completion of goals and objectives for 2015 and payable in 2016. Any SMICP award for 2015 will be prorated based on your promotion date of October 8, 2015. You will be eligible for a prorated Management Incentive Compensation Plan ("MICP") award for the period January 1 to October 7, 2015 for your position as VP Finance, PSE&G.

You will continue to be a participant in the PSEG 2004 Long-Term Incentive Plan as amended ("LTIP"). It will be recommended to the Organization and Compensation Committee ("O&CC") that you be granted a 2016 LTIP award of $800,000. As a Senior Officer, this and future grants will be in the form of 40% as Restricted Stock Units ("RSUs") and 60% as Performance Share Units ("PSUs"). In the future, the number and form of LTIP grants recommended in any given year will appropriately reflect your responsibilities and ability to contribute to the long-term success of PSEG and is subject to the approval of the O&CC of the Board. All future grants under the LTIP will be subject to the terms of the LTIP and the related grant award agreements.

You will continue to be eligible to participate in the PSEG Deferred Compensation Plan For Certain Employees ("Deferred Compensation Plan"), which will allow you to defer all or a portion of your base pay and/or any cash incentive you may receive in any given year. In November, you will receive information regarding participation in the Deferred Compensation Plan for 2016.

For 2016, you will continue to be eligible to participate in the PSEG Equity Deferral Plan ("Deferred Equity Plan"), which will allow you to defer all or a portion of the receipt of shares under

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the LTIP. In November, you will receive information regarding participation in the Deferred Equity Plan for 2016.

If, at the time you terminate from employment, you are determined to be a “specified employee” as defined in Section 409A of the Internal Revenue Code of 1986, as amended (“Section 409A”), your nonqualified deferred compensation payments will be delayed for six months following your termination of employment to the extent necessary to satisfy Section 409A.

You will continue to be a Schedule A participant in the Key Executive Severance Plan of Public Service Enterprise Group Incorporated, as amended from time to time.

You will be eligible for an annual physical examination through the University of Pennsylvania.

You will continue to be provided a parking space in the Company parking garage in Newark, NJ. Aditionally, you will be eligible for a monthly vehicle stipend of $1,000.

You will be required to own and retain a level of company stock commensurate with your new position as outlined in the attached Officer Stock Ownership and Retention Policy.

At all times, your employment with PSEG Services Corporation is and will be considered at-will, which means that either you or the Company is free to terminate the employment relationship at any time, for any reason, with or without cause.

This letter shall not be construed, nor is it intended to be construed, as a binding contract of employment.

Additionally, enclosed is a booklet referencing the Responsibilities of Corporate Officers and Directors.

Finally, you will be required to sign the enclosed Confidentiality, Non-Competition, and Non-Solicitation Agreement, and the enclosed Arbitration Agreement.

If the foregoing is in accordance with your understanding, please sign this letter and the enclosed Agreements, and return them to me.

Sincerely,

/s/ Margaret M. Pego

Margaret M. Pego
Senior Vice President - Human Resources
and Chief Human Resources Officer

Agreed to this 22 day of September, 2015.

/s/ Daniel J. Cregg_____
Daniel J. Cregg

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Attachments:

1. Officer Stock Ownership & Retention Policy
2. Responsibilities of Corporate Officers and Directors
3. Confidentiality, Non-Competition and Non-Solicitation Agreement
4. Arbitration Agreement

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2015	2014	2014	2013	2012	2011	2010
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 2,239	1,675	$ 2,456	$ 2,055	$ 2,011	$ 2,384	$ 2,616
(Income) Loss from Equity Investees, net of Distributions	4	—	4	(7)	9	(4)	(19)
Fixed Charges	335	335	450	458	479	522	571
Capitalized Interest	(10)	(10)	(16)	(16)	(19)	(14)	(67)
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	—	(2)
Total Earnings	$ 2,568	$ 2,000	$ 2,894	$ 2,490	$ 2,480	$ 2,888	$ 3,099
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 321	320	$ 430	$ 442	$ 465	$ 509	$ 555
Interest Factor in Rentals	14	15	20	16	14	13	14
Preferred Securities Dividend Requirements of Subsidiaries	—	—	—	—	—	—	2
Total Fixed Charges	$ 335	$ 335	$ 450	$ 458	$ 479	$ 522	$ 571
Ratio of Earnings to Fixed Charges	**7.67**	**5.97**	**6.43**	**5.44**	**5.18**	**5.53**	**5.43**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2015	2014	2014	2013	2012	2011	2010
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,029	920	$1,174	$ 993	$ 835	$ 861	$ 591
Fixed Charges	222	226	303	316	314	319	325
Capitalized Interest	(13)	(12)	(16)	(16)	(13)	(4)	(2)
Total Earnings	$ 1,238	$ 1,134	$1,461	$1,293	$ 1,136	$1,176	$ 914
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 216	218	$ 293	$ 309	$ 308	$ 314	$ 320
Interest Factor in Rentals	6	8	10	7	6	5	5
Total Fixed Charges	$ 222	$ 226	$ 303	$ 316	$ 314	$ 319	$ 325
Ratio of Earnings to Fixed Charges	**5.58**	**5.02**	**4.82**	**4.09**	**3.62**	**3.69**	**2.81**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 12.2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Nine Months Ended September 30,		Years Ended December 31,				
	2015	**2014**	**2014**	**2013**	**2012**	**2011**	**2010**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,029	$ 920	$1,174	$ 993	$ 835	$ 861	$ 591
Fixed Charges	222	226	303	316	314	319	327
Capitalized Interest	(13)	(12)	(16)	(16)	(13)	(4)	(2)
Preferred Securities Dividend Requirements	—	—	—	—	—	—	(2)
Total Earnings	$ 1,238	$ 1,134	$1,461	$1,293	$1,136	$1,176	$ 914
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 216	$ 218	$ 293	$ 309	$ 308	$ 314	$ 320
Interest Factor in Rentals	6	8	10	7	6	5	5
Preferred Securities Dividend	—	—	—	—	—	—	1
Adjustments to state Preferred Securities Dividends on a pre-income tax basis	—	—	—	—	—	—	1
Total Fixed Charges	$ 222	$ 226	$ 303	$ 316	$ 314	$ 319	$ 327
Ratio of Earnings to Fixed Charges	**5.58**	**5.02**	**4.82**	**4.09**	**3.62**	**3.69**	**2.80**

(A) The term "earnings" shall be defined as pre-tax income from continuing operations. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period, (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries, and (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount and premium expense (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G.

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EXHIBIT 12.3

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2015	**2014**	**2014**	**2013**	**2012**	**2011**	**2010**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	1,152	717	$1,251	$1,063	$1,099	$1,703	$1,932
(Income) Loss from Equity Investees, net of Distributions	2	(1)	3	(10)	(6)	(12)	(8)
Fixed Charges	115	112	150	143	164	208	238
Capitalized Interest	2	2	1	1	(6)	(10)	(63)
Total Earnings	$ 1,271	$ 830	$1,405	$1,197	$1,251	$1,889	$2,099
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	112	109	$ 146	$ 139	$ 161	$ 205	$ 235
Interest Factor in Rentals	3	3	4	4	3	3	3
Total Fixed Charges	$ 115	$ 112	$ 150	$ 143	$ 164	$ 208	$ 238
Ratio of Earnings to Fixed Charges	**11.05**	**7.41**	**9.37**	**8.37**	**7.63**	**9.08**	**8.82**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2015

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2015

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

S1-SSA-0009 - 19038

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2015

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2015

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2015

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2015

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
October 30, 2015

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
October 30, 2015

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
October 30, 2015

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
October 30, 2015

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
October 30, 2015

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
October 30, 2015

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2016
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of October 18, 2016, Public Service Enterprise Group Incorporated had outstanding 505,896,218 shares of its sole class of Common Stock, without par value.

As of October 18, 2016, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or ongoing low pricing of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulations, including market structures and transmission planning,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators, including prudency reviews, disallowances and changes in authorized returns,
- any deterioration in our credit quality or the credit quality of our counterparties,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations or increase the cost of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- delays or unforeseen cost escalations in our construction and development activities, or the inability to recover the carrying amount of our assets,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- increases in competition in energy supply markets as well as for transmission projects,
- changes in technology, such as distributed generation, storage and micro grids, and greater reliance on these technologies,
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover insurance proceeds with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- economic recessions,
- an inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce, and
- changes in the credit quality and the ability of lessees to meet their obligations under our domestic leveraged leases.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected

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consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

FILING FORMAT

This combined Quarterly Report on Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to “we,” “us,” and “our” relate to PSEG or to the specific company or companies being discussed.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
OPERATING REVENUES	$ 2,450	$ 2,688	$ 6,971	$ 8,137
OPERATING EXPENSES				
Energy Costs	866	815	2,326	2,577
Operation and Maintenance	776	746	2,215	2,170
Depreciation and Amortization	231	313	679	960
Total Operating Expenses	1,873	1,874	5,220	5,707
OPERATING INCOME	577	814	1,751	2,430
Income from Equity Method Investments	3	3	9	10
Other Income	47	47	139	171
Other Deductions	(8)	(14)	(39)	(36)
Other-Than-Temporary Impairments	(5)	(30)	(25)	(45)
Interest Expense	(99)	(96)	(288)	(291)
INCOME BEFORE INCOME TAXES	515	724	1,547	2,239
Income Tax Expense	(188)	(285)	(562)	(869)
NET INCOME	$ 327	$ 439	$ 985	$ 1,370
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	505	505	505	505
DILUTED	508	508	508	508
NET INCOME PER SHARE:				
BASIC	$ 0.65	$ 0.87	$ 1.95	$ 2.71
DILUTED	$ 0.64	$ 0.87	$ 1.94	$ 2.70
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.41	$ 0.39	$ 1.23	$ 1.17

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
NET INCOME	$ 327	$ 439	$ 985	$ 1,370
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(24), $33, $(50) and $35 for the three and nine months ended 2016 and 2015, respectively	24	(31)	50	(32)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $(1), $(1) and $6 for the three and nine months ended 2016 and 2015, respectively	1	—	2	(9)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(5), $(5), $(17) and $(17) for the three and nine months ended 2016 and 2015, respectively	9	9	25	25
Other Comprehensive Income (Loss), net of tax	34	(22)	77	(16)
COMPREHENSIVE INCOME	$ 361	$ 417	$ 1,062	$ 1,354

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 450	$ 394
Accounts Receivable, net of allowances of $67 in 2016 and 2015	1,031	1,068
Tax Receivable	23	305
Unbilled Revenues	180	197
Fuel	366	463
Materials and Supplies, net	591	513
Prepayments	145	135
Derivative Contracts	149	242
Regulatory Assets	253	164
Other	21	13
Total Current Assets	3,209	3,494
PROPERTY, PLANT AND EQUIPMENT	38,225	35,494
Less: Accumulated Depreciation and Amortization	(9,421)	(8,955)
Net Property, Plant and Equipment	28,804	26,539
NONCURRENT ASSETS		
Regulatory Assets	3,124	3,196
Long-Term Investments	1,066	1,233
Nuclear Decommissioning Trust (NDT) Fund	1,857	1,754
Long-Term Tax Receivable	177	171
Long-Term Receivable of Variable Interest Entity (VIE)	509	495
Other Special Funds	243	227
Goodwill	16	16
Other Intangibles	154	102
Derivative Contracts	86	77
Other	243	231
Total Noncurrent Assets	7,475	7,502
TOTAL ASSETS	$ 39,488	$ 37,535

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2016	December 31, 2015
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ —	$ 734
Commercial Paper and Loans	255	364
Accounts Payable	1,363	1,369
Derivative Contracts	40	76
Accrued Interest	127	96
Accrued Taxes	214	42
Clean Energy Program	185	142
Obligation to Return Cash Collateral	132	128
Regulatory Liabilities	96	123
Regulatory Liabilities of VIEs	9	42
Other	383	459
Total Current Liabilities	2,804	3,575
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	8,661	8,166
Regulatory Liabilities	151	175
Asset Retirement Obligations	708	679
OPEB Costs	1,207	1,228
OPEB Costs of Servco	395	375
Accrued Pension Costs	400	487
Accrued Pension Costs of Servco	108	114
Environmental Costs	430	415
Derivative Contracts	13	27
Long-Term Accrued Taxes	197	212
Other	241	181
Total Noncurrent Liabilities	12,511	12,059
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT	10,697	8,834
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2016 and 2015—534 shares	4,928	4,915
Treasury Stock, at cost, 2016—29 shares; 2015—28 shares	(714)	(671)
Retained Earnings	9,480	9,117
Accumulated Other Comprehensive Loss	(218)	(295)
Total Common Stockholders' Equity	13,476	13,066
Noncontrolling Interest	—	1
Total Stockholders' Equity	13,476	13,067
Total Capitalization	24,173	21,901
TOTAL LIABILITIES AND CAPITALIZATION	$ 39,488	$ 37,535

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19056

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2016	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 985	$ 1,370
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	679	960
Amortization of Nuclear Fuel	154	162
Impairment Costs	102	—
Provision for Deferred Income Taxes (Other than Leases) and ITC	445	230
Non-Cash Employee Benefit Plan Costs	95	121
Leveraged Lease (Income) Loss, Adjusted for Rents Received and Deferred Taxes	(12)	6
Loss on Leases, Net of Tax	86	—
Net Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	96	(87)
Change in Accrued Storm Costs	(6)	15
Net Change in Other Regulatory Assets and Liabilities	(66)	26
Cost of Removal	(109)	(82)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(12)	(2)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	282	206
Accrued Taxes	202	127
Margin Deposit	(4)	142
Other Current Assets and Liabilities	(229)	15
Employee Benefit Plan Funding and Related Payments	(81)	(87)
Other	154	106
Net Cash Provided By (Used In) Operating Activities	2,761	3,228
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(2,985)	(2,782)
Proceeds from Sales of Capital Leases and Investments	—	12
Proceeds from Sales of Available-for-Sale Securities	551	1,120
Investments in Available-for-Sale Securities	(576)	(1,163)
Other	(44)	(28)
Net Cash Provided By (Used In) Investing Activities	(3,054)	(2,841)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(109)	20
Issuance of Long-Term Debt	1,975	600
Redemption of Long-Term Debt	(824)	(300)
Redemption of Securitization Debt	—	(191)
Cash Dividends Paid on Common Stock	(622)	(592)
Other	(71)	(55)
Net Cash Provided By (Used In) Financing Activities	349	(518)
Net Increase (Decrease) in Cash and Cash Equivalents	56	(131)
Cash and Cash Equivalents at Beginning of Period	394	402
Cash and Cash Equivalents at End of Period	$ 450	$ 271
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (274)	$ 292
Interest Paid, Net of Amounts Capitalized	$ 252	$ 265
Accrued Property, Plant and Equipment Expenditures	$ 579	$ 321

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
OPERATING REVENUES	$ 1,684	$ 1,766	$ 4,746	$ 5,234
OPERATING EXPENSES				
Energy Costs	721	740	1,979	2,176
Operation and Maintenance	376	391	1,110	1,171
Depreciation and Amortization	137	231	412	712
Total Operating Expenses	1,234	1,362	3,501	4,059
OPERATING INCOME	450	404	1,245	1,175
Other Income	22	22	61	59
Other Deductions	(1)	—	(3)	(2)
Interest Expense	(72)	(67)	(214)	(203)
INCOME BEFORE INCOME TAXES	399	359	1,089	1,029
Income Tax Expense	(144)	(137)	(393)	(398)
NET INCOME	$ 255	$ 222	$ 696	$ 631

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19059

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
NET INCOME	$ 255	$ 222	$ 696	$ 631
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0 and $0 for the three and nine months ended 2016 and 2015, respectively	—	—	1	(1)
COMPREHENSIVE INCOME	$ 255	$ 222	$ 697	$ 630

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19060

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 406	$ 198
Accounts Receivable, net of allowances of $67 in 2016 and 2015	806	787
Accounts Receivable—Affiliated Companies	28	222
Unbilled Revenues	180	197
Materials and Supplies	190	148
Prepayments	94	31
Regulatory Assets	253	164
Derivative Contracts	—	13
Other	20	9
Total Current Assets	1,977	1,769
PROPERTY, PLANT AND EQUIPMENT	25,617	23,732
Less: Accumulated Depreciation and Amortization	(5,701)	(5,504)
Net Property, Plant and Equipment	19,916	18,228
NONCURRENT ASSETS		
Regulatory Assets	3,124	3,196
Long-Term Investments	305	330
Other Special Funds	54	49
Other	110	105
Total Noncurrent Assets	3,593	3,680
TOTAL ASSETS	$ 25,486	$ 23,677

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19061

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2016	December 31, 2015
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ —	$ 171
Commercial Paper and Loans	—	153
Accounts Payable	702	724
Accounts Payable—Affiliated Companies	214	292
Accrued Interest	83	70
Clean Energy Program	185	142
Derivative Contracts	4	—
Obligation to Return Cash Collateral	132	128
Regulatory Liabilities	96	123
Regulatory Liabilities of VIEs	9	42
Other	276	297
Total Current Liabilities	1,701	2,142
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	5,703	5,181
OPEB Costs	908	937
Accrued Pension Costs	147	202
Regulatory Liabilities	151	175
Environmental Costs	364	365
Asset Retirement Obligations	220	218
Derivative Contracts	—	11
Long-Term Accrued Taxes	92	109
Other	114	114
Total Noncurrent Liabilities	7,699	7,312
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT	7,816	6,650
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2016 and 2015—132 shares	892	892
Contributed Capital	695	695
Basis Adjustment	986	986
Retained Earnings	5,695	4,999
Accumulated Other Comprehensive Income	2	1
Total Stockholder's Equity	8,270	7,573
Total Capitalization	16,086	14,223
TOTAL LIABILITIES AND CAPITALIZATION	$ 25,486	$ 23,677

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19062

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2016	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 696	$ 631
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	412	712
Provision for Deferred Income Taxes and ITC	482	96
Non-Cash Employee Benefit Plan Costs	55	71
Cost of Removal	(109)	(82)
Change in Accrued Storm Costs	(6)	15
Net Change in Other Regulatory Assets and Liabilities	(66)	26
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	2	30
Materials and Supplies	(42)	(13)
Prepayments	(63)	(67)
Accounts Payable	(30)	34
Accounts Receivable/Payable—Affiliated Companies, net	154	190
Other Current Assets and Liabilities	(6)	(18)
Employee Benefit Plan Funding and Related Payments	(64)	(72)
Other	(14)	(35)
Net Cash Provided By (Used In) Operating Activities	1,401	1,518
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(2,035)	(1,946)
Proceeds from Sales of Available-for-Sale Securities	16	16
Investments in Available-for-Sale Securities	(17)	(18)
Other	6	13
Net Cash Provided By (Used In) Investing Activities	(2,030)	(1,935)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	(153)	20
Issuance of Long-Term Debt	1,275	600
Redemption of Long-Term Debt	(271)	(300)
Redemption of Securitization Debt	—	(191)
Other	(14)	(8)
Net Cash Provided By (Used In) Financing Activities	837	121
Net Increase (Decrease) In Cash and Cash Equivalents	208	(296)
Cash and Cash Equivalents at Beginning of Period	198	310
Cash and Cash Equivalents at End of Period	$ 406	$ 14
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (279)	$ (29)
Interest Paid, Net of Amounts Capitalized	$ 194	$ 186
Accrued Property, Plant and Equipment Expenditures	$ 404	$ 251

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19063

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
OPERATING REVENUES	$ 1,075	$ 1,096	$ 3,102	$ 3,846
OPERATING EXPENSES				
Energy Costs	462	367	1,481	1,669
Operation and Maintenance	289	263	807	748
Depreciation and Amortization	86	75	245	226
Total Operating Expenses	837	705	2,533	2,643
OPERATING INCOME	238	391	569	1,203
Income from Equity Method Investments	3	3	9	11
Other Income	23	25	74	109
Other Deductions	(6)	(14)	(33)	(32)
Other-Than-Temporary Impairments	(5)	(30)	(25)	(45)
Interest Expense	(24)	(30)	(66)	(94)
INCOME BEFORE INCOME TAXES	229	345	528	1,152
Income Tax Benefit (Expense)	(90)	(139)	(208)	(445)
NET INCOME	$ 139	$ 206	$ 320	$ 707

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19064

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
NET INCOME	$ 139	$ 206	$ 320	$ 707
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(23), $32, $(48) and $33 for the three and nine months ended 2016 and 2015, respectively	22	(29)	47	(29)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $(1), $0 and $6 for the three and nine months ended 2016 and 2015, respectively	—	—	—	(9)
Pension/OPEB adjustment, net of tax (expense) benefit of $(5), $(5), $(15) and $(15) for the three and nine months ended 2016 and 2015, respectively	7	7	21	21
Other Comprehensive Income (Loss), net of tax	29	(22)	68	(17)
COMPREHENSIVE INCOME	$ 168	$ 184	$ 388	$ 690

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19065

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2016	December 31, 2015
CURRENT ASSETS		
Cash and Cash Equivalents	$ 12	$ 12
Accounts Receivable	174	217
Accounts Receivable—Affiliated Companies	126	276
Short-Term Loan to Affiliate	514	363
Fuel	366	463
Materials and Supplies, net	399	363
Derivative Contracts	149	223
Prepayments	16	25
Other	3	7
Total Current Assets	1,759	1,949
PROPERTY, PLANT AND EQUIPMENT	12,271	11,354
Less: Accumulated Depreciation and Amortization	(3,564)	(3,227)
Net Property, Plant and Equipment	8,707	8,127
NONCURRENT ASSETS		
NDT Fund	1,857	1,754
Long-Term Investments	106	119
Goodwill	16	16
Other Intangibles	154	102
Other Special Funds	60	55
Derivative Contracts	86	77
Other	65	51
Total Noncurrent Assets	2,344	2,174
TOTAL ASSETS	$ 12,810	$ 12,250

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19066

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2016	December 31, 2015
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ —	$ 553
Accounts Payable	477	432
Accounts Payable—Affiliated Companies	156	33
Derivative Contracts	36	76
Accrued Interest	43	25
Other	82	107
Total Current Liabilities	794	1,226
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	2,375	2,347
Asset Retirement Obligations	485	457
OPEB Costs	238	230
Derivative Contracts	13	16
Accrued Pension Costs	143	166
Long-Term Accrued Taxes	79	35
Other	162	87
Total Noncurrent Liabilities	3,495	3,338
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
LONG-TERM DEBT	2,381	1,684
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	5,084	5,014
Accumulated Other Comprehensive Loss	(172)	(240)
Total Member's Equity	6,140	6,002
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,810	$ 12,250

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19067

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2016	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 320	$ 707
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	245	226
Amortization of Nuclear Fuel	154	162
Provision for Deferred Income Taxes and ITC	(34)	109
Net Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	96	(87)
Impairment Costs	102	—
Non-Cash Employee Benefit Plan Costs	28	36
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(12)	(2)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	(27)	113
Margin Deposit	(4)	142
Accounts Receivable	(11)	54
Accounts Payable	(29)	(99)
Accounts Receivable/Payable—Affiliated Companies, net	235	115
Other Current Assets and Liabilities	20	(26)
Employee Benefit Plan Funding and Related Payments	(10)	(9)
Other	187	117
Net Cash Provided By (Used In) Operating Activities	1,260	1,558
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(923)	(797)
Proceeds from Sales of Available-for-Sale Securities	490	1,057
Investments in Available-for-Sale Securities	(512)	(1,083)
Short-Term Loan—Affiliated Company, net	(151)	(281)
Other	(55)	(46)
Net Cash Provided By (Used In) Investing Activities	(1,151)	(1,150)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Long-Term Debt	700	—
Cash Dividend Paid	(250)	(400)
Redemption of Long-Term Debt	(553)	—
Other	(6)	(2)
Net Cash Provided By (Used In) Financing Activities	(109)	(402)
Net Increase (Decrease) in Cash and Cash Equivalents	—	6
Cash and Cash Equivalents at Beginning of Period	12	9
Cash and Cash Equivalents at End of Period	$ 12	$ 15
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (7)	$ 284
Interest Paid, Net of Amounts Capitalized	$ 51	$ 76
Accrued Property, Plant and Equipment Expenditures	$ 175	$ 70

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

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Note 1. Organization and Basis of Presentation

Organization

Public Service Enterprise Group (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Public Service Electric and Gas Company (PSE&G)**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- **PSEG Power LLC (Power)**—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy transacting functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2015.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2015.

Note 2. Recent Accounting Standards

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard clarifies the principles for recognizing revenue and removes inconsistencies in revenue recognition requirements; improves comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provides improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The standard was originally to be effective for annual and interim reporting periods beginning after December 15, 2016; however, the Financial Accounting Standards Board issued new guidance deferring the effective date by one year to periods beginning after December 31, 2017. Early application will be permitted as of the original effective date. PSEG is currently analyzing the impact of this standard on its financial statements and disclosures as well as the transition method to use to adopt the guidance. PSEG is considering the impacts of outstanding industry related issues currently being addressed by the AICPA's Revenue Recognition Working Group and the FASB's Transition Resource Group, including its ability to recognize revenue for

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certain contracts where there is uncertainty regarding collection, bundled price sales contracts and accounting for contributions in aid of construction.

Recognition and Measurement of Financial Assets and Financial Liabilities

This accounting standard will change how entities measure equity investments that are not consolidated or accounted for under the equity method. Under the new guidance, equity investments (other than those accounted for using the equity method) will be measured at fair value through Net Income instead of Other Comprehensive Income (Loss). Entities that have elected the fair value option for financial liabilities will present changes in fair value due to a change in their own credit risk through Other Comprehensive Income (Loss). For equity investments which do not have readily determinable fair values, the impairment assessment will be simplified by requiring a qualitative assessment to identify impairments. The new standard also changes certain disclosures.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG is currently analyzing the impact of this standard on our financial statements; however, PSEG expects increased volatility in Net Income due to changes in fair value of our equity securities within the Nuclear Decommissioning Trust (NDT) and Rabbi Trust Funds.

Leases

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor will classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. However, existing guidance related to leveraged leases will not change.

The standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Stock Compensation-Improvements to Employee Share-Based Payment Accounting

This accounting standard was issued to simplify aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows.

Under the new guidance, all excess tax benefits and tax deficiencies will be recognized in income tax expense rather than recognized in additional paid in capital. In the statement of cash flows, excess tax benefits and deficiencies will be classified with other income tax cash flows as an operating activity rather than a financing activity as currently classified. In addition, the minimum statutory tax withholding requirements were simplified in order to facilitate equity classification of the award.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early adoption is permitted for an entity in any interim or annual period. An entity that elects early adoption must adopt all of the amendments in the same period; however, the amendments within this update require different adoption methods. PSEG is evaluating early adoption of the standard in the fourth quarter of 2016; however, PSEG does not expect adoption to materially affect its financial statements.

Measurement of Credit Losses on Financial Instruments

This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however, this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

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Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments

This accounting standard reduces the diversity in practice in how certain cash receipts and cash payments are presented and classified in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt early including in an interim period. PSEG is currently analyzing the impact of this standard on its financial statements.

Note 3. Early Plant Retirements

On October 3, 2016, Power determined that it will cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. Power has filed deactivation notices with PJM for these existing units at both stations and final must-offer exception requests for the 2020-2021 PJM capacity auction to the PJM Independent Market Monitor. Power expects the units to continue to be available to generate electricity and receive previously cleared capacity payments through the date the units cease operations. The exact timing of the early retirement of these units will be reviewed for reliability impacts by PJM, the regional transmission organization that controls the area where these units are located, and may be impacted by operational and other conditions that could subsequently arise.

PSEG and Power undertake their annual five year strategic planning process primarily during the third and fourth quarters of each year. The primary factors considered during this process that contributed to the decision to retire these units early include significant declines in revenues and margin caused by a sustained period of depressed wholesale power prices and reduced capacity factors caused by lower natural gas prices making coal generation less economically competitive than natural gas-fired generation. Despite experiencing recent warmer than normal weather in PJM this summer, Power did not experience the usual increase in electricity prices in PJM as it had in past hot summers. This trend has a further adverse economic impact to these units because they generally dispatch and earn energy margin on peak hot and cold days. In addition, the upcoming PJM capacity auction in May 2017 for the capacity period from June 2020 to May 2021 will be the first to require all generating units to meet the increased operating performance standards of PJM's new capacity performance regulations. During the current annual five-year strategic planning process, Power determined, on October 3, 2016, that the costs to upgrade the existing units at the Hudson and Mercer stations to comply with these higher reliability standards to be too significant and not economic given current market conditions, including anticipated future capacity prices, current forward energy prices and past operational performance results of the units. While these units have the capability to run on both coal and natural gas, they have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units.

The decision to retire the Hudson and Mercer units early will have a material effect on PSEG's and Power's results of operations. In the third quarter of 2016, PSEG and Power recognized the following one-time pre-tax charges in Energy Costs, Operation and Maintenance and Depreciation expense:

	Three Months Ended September 30, 2016
	Millions
Statement of Operations Expense (pre-tax)	
Energy Costs	
Coal Inventory Lower of Cost or Market Adjustments and Capacity Penalties	$ 62
Operation and Maintenance	
Materials and Supplies Obsolescence	31
Write-down of Construction Work in Progress	14
Other (A)	3
Depreciation and Amortization	
Accelerated Depreciation including Asset Retirement Costs	4
Total Pre-Tax Expense	**$ 114**

(A) Includes severance and miscellaneous costs.

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In addition to these one-time charges, Power will recognize incremental Depreciation and Amortization during the remainder of 2016 of $568 million and $946 million into 2017 due to the significant shortening of the expected economic useful lives of Hudson and Mercer. Additional employee-related salary continuance and severance costs and various miscellaneous costs may also be incurred during the period prior to retirement. Finally, Power currently anticipates using the sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at these sites would trigger investigation and possible remediation of identified environmental contamination. The amounts for any such environmental investigation or remediation are neither currently probable nor estimable but may be material.

PSEG and Power evaluate long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, including a current expectation that a long-lived asset will be sold or disposed of significantly before the end of its previously estimated useful life, could potentially indicate an asset's or asset group's carrying amount may not be recoverable. In such an event, an undiscounted cash flow analysis is performed to determine if an impairment exists. When a long-lived asset's or asset group's carrying amount exceeds the associated undiscounted estimated future cash flows, the asset/asset group is considered impaired to the extent that its fair value is less than its carrying amount. As disclosed for Power, cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generation units are generally evaluated at a regional portfolio level (PJM, NYISO, ISO-NE) along with cash flows generated from the customer supply and risk management activities, inclusive of cash flows from contracts, including those that are accounted for as derivatives or that meet the normal purchases and normal sales exemption. An impairment would result in a reduction of the value of the long-lived asset/asset group through a noncash charge to earnings.

Because the Hudson and Mercer generating units will cease operations significantly before the end of their previously estimated useful lives, Power performed a recoverability test for its portfolio of generating assets in the PJM region to determine if an impairment exists. As of September 30, 2016, the estimated undiscounted future cash flows of the PJM asset group exceeded the carrying amount and no impairment was identified.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone, Conemaugh and Bridgeport Harbor generating stations, to ensure their economic viability through the end of their designated useful lives. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement of our other coal units before the end of their current estimated useful lives may have a material adverse impact on PSEG's and Power's future financial results.

Note 4. Variable Interest Entities (VIEs)

VIEs for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which was pledged as collateral to a trustee. PSE&G acted as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds were remitted to Transition Funding and Transition Funding II and were used for interest and principal payments on the transition bonds and related costs. During 2015, Transition Funding and Transition Funding II paid their final securitization bond payments and as of December 31, 2015, no further debt or related costs remained with these VIEs. Effective January 1, 2016, PSE&G commenced refunding the overcollections from customers associated with these VIEs and expects to fully refund these liabilities in 2016.

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management

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fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operation and Maintenance (O&M) Expense, respectively. Servco recorded $116 million and $96 million for the three months and $315 million and $262 million for the nine months ended September 30, 2016 and 2015, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 5. Rate Filings

This Note should be read in conjunction with Note 5. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2015.

In addition to items previously reported in the Annual Report on Form 10-K, significant regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

Transmission Formula Rate Filings—In June 2016, PSE&G filed its 2015 true-up adjustment pertaining to its transmission formula rates in effect for 2015. This resulted in an adjustment of $34 million less than the 2015 originally filed revenues primarily due to the impact of bonus depreciation legislation enacted after PSE&G filed its 2015 formula rate requirement in October 2014. PSE&G had recognized the majority of this adjustment in its Consolidated Statement of Operations for the year ended December 31, 2015.

In October 2016, the 2017 Annual Formula Rate Update was filed with FERC and requests approximately $121 million in increased annual transmission revenues effective January 1, 2017, subject to true-up.

Energy Strong Recovery Filing—In March and September of each year, PSE&G files with the BPU for base rate recovery of Energy Strong investments which include a return of and on its investment. In June 2016, PSE&G updated its March cost recovery petition to include Energy Strong investments in service as of May 31, 2016 which represents estimated annual increases in electric and gas revenues of $16 million and $23 million, respectively. In August 2016, the BPU approved these rate increases effective September 1, 2016.

In September 2016, PSE&G filed its Energy Strong electric cost recovery petition seeking BPU approval to recover the revenue requirements associated with Energy Strong capitalized investment costs placed in service from June 1, 2016 through November 30, 2016. The petition requests rates to be effective March 1, 2017, consistent with the BPU Order of approval of the Energy Strong Program. The annualized requested increase in electric revenue requirement is approximately $15 million. This matter is pending.

Basic Gas Supply Service (BGSS)—In June 2016, PSE&G made its annual BGSS filing with the BPU requesting a reduction of $87 million in annual BGSS revenues. In September 2016, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was reduced from approximately 40 cents to 34 cents per therm effective October 1, 2016. The rate is subject to final settlement.

Weather Normalization Clause—On July 1, 2016, PSE&G filed a petition requesting approval to collect $54 million in net deficiency gas revenues as a result of the warmer than normal 2015-2016 Winter Period. The deficiency gas revenues would be collected from customers over the 2016-2017 and 2017-2018 Winter Periods (October 1 through May 31). In September 2016, the BPU approved PSE&G's filing on a provisional basis with respect to the $54 million in deficiency revenues to be collected from customers effective October 1, 2016.

Solar and Energy Efficiency - Green Program Recovery Charges (GPRC)—Each year PSE&G files with the BPU for annual recovery of its Green Program investments which include a return on its investment and recovery of expenses. On July 1, 2016, PSE&G filed its 2016 GPRC cost recovery petition requesting recovery for the nine combined components of the electric and gas GPRC. The filing proposes rates for the period October 1, 2016 through September 30, 2017 designed to recover approximately $44 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved programs. In September 2016, the BPU approved the July 2016 filing on a provisional basis, with new rates effective October 1, 2016.

Gas System Modernization Program (GSMP)—In October 2016, PSE&G updated its initial annual GSMP cost recovery petition seeking BPU approval to recover in gas base rates an estimated annual revenue increase of $10 million effective

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January 1, 2017. This increase represents the return of and on investment for GSMP investments in service through September 30, 2016. This matter is pending.

Universal Service Fund (USF)/Lifeline—In September 2016, the BPU approved rates set to recover state-wide costs incurred by New Jersey electric and gas distribution companies under the State's USF/Lifeline energy assistance programs effective October 1, 2016. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on its Consolidated Statement of Operations.

Remediation Adjustment Charge (RAC)—In April 2016, the BPU approved PSE&G's filing with respect to its RAC 23 petition allowing recovery of $54 million effective May 7, 2016 related to net Manufactured Gas Plant expenditures from August 1, 2014 through July 31, 2015.

Note 6. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with solar renewable energy certificates generated from the installed solar electric system. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

Outstanding Loans by Class of Customer

Consumer Loans	As of September 30, 2016	As of December 31, 2015
	Millions	
Commercial/Industrial	$ 165	$ 177
Residential	11	12
Total	**$ 176**	**$ 189**

Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

During the third quarter of 2016, Energy Holdings completed its annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases. The outcome indicated that the revised residual value estimates were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM, as discussed in Note 3. Early Plant Retirements, negatively impacting the economic outlook of the leased assets. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016, calculated by comparing the gross investment in the leases before and after the revised residual estimates.

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The following table shows Energy Holdings' gross and net lease investment as of September 30, 2016 and December 31, 2015, respectively.

	As of September 30, 2016	As of December 31, 2015
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 630	$ 631
Estimated Residual Value of Leased Assets	346	519
Total Investment in Rental Receivables	976	1,150
Unearned and Deferred Income	(320)	(366)
Gross Investment in Leases	656	784
Deferred Tax Liabilities	(661)	(724)
Net Investment in Leases	**$ (5)**	**$ 60**

The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

Counterparties' Credit Rating Standard & Poor's (S&P) as of September 30, 2016	Lease Receivables, Net of Non-Recourse Debt As of September 30, 2016
	Millions
AA	$ 16
BBB+ — BBB-	316
BB-	134
CCC	164
Total	**$ 630**

The "BB-" and the "CCC" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of September 30, 2016, the gross investment in the leases of such assets, net of non-recourse debt, was $436 million ($(108) million, net of deferred taxes). A more detailed description of such assets under lease, as of September 30, 2016, is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 134	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 83	64%	1,044	Gas	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 55	17%	1,711	Coal	CCC (B)	REMA
Conemaugh Station Units 1 and 2	PA	$ 55	17%	1,711	Coal	CCC (B)	REMA
Shawville Station Units 1, 2, 3 and 4	PA	$ 109	100%	603	Coal (A)	CCC (B)	REMA

(A) REMA notified PJM that it deactivated the coal-fired units at the Shawville generating facility in June 2015 and has disclosed that it expects to return the Shawville units to service in the late fall of 2016 with the ability to use natural gas.

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(B) On May 24, 2016, S&P lowered its corporate credit rating on REMA's parent company, GenOn Energy Inc. (GenOn) and affiliates (including REMA) to "CCC" from "CCC+" due to a weaker forward power curve, milder weather patterns and weakening financial measures. On October 7, 2016, Moody's downgraded the GenOn Corporate Family Rating to Caa3 to reflect its high debt burden relative to cash flow. GenOn reported in August 2016 that it did not expect to have sufficient liquidity to repay the senior unsecured notes due in June 2017.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations which could be mitigated by tax indemnification claims with the counterparty. A bankruptcy of a lessee would likely delay and potentially limit any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's efforts to restructure its portfolio and improve its liquidity and the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service.

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and their affiliates and the quality and condition of assets under lease.

Note 7. Available-for-Sale Securities

NDT Fund

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third party investment advisers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of September 30, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 691	$ 238	$ (7)	$ 922
Debt Securities				
Government Obligations	509	21	—	530
Other	349	13	(2)	360
Total Debt Securities	858	34	(2)	890
Other Securities	45	—	—	45
Total NDT Available-for-Sale Securities	**$ 1,594**	**$ 272**	**$ (9)**	**$ 1,857**

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	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 693	$ 185	$ (13)	$ 865
Debt Securities				
Government Obligations	483	8	(3)	488
Other	366	3	(10)	359
Total Debt Securities	849	11	(13)	847
Other Securities	42	—	—	42
Total NDT Available-for-Sale Securities	**$ 1,584**	**$ 196**	**$ (26)**	**$ 1,754**

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2016	As of December 31, 2015
	Millions	
Accounts Receivable	$ 9	$ 17
Accounts Payable	$ 7	$ 10

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of September 30, 2016				As of December 31, 2015			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 101	$ (6)	$ 4	$ (1)	$ 151	$ (13)	$ 1	$ —
Debt Securities								
Government Obligations (B)	41	—	4	—	245	(2)	19	(1)
Other (C)	34	—	25	(2)	222	(7)	36	(3)
Total Debt Securities	75	—	29	(2)	467	(9)	55	(4)
NDT Available-for-Sale Securities	**$ 176**	**$ (6)**	**$ 33**	**$ (3)**	**$ 618**	**$ (22)**	**$ 56**	**$ (4)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2016.

(B) Debt Securities (Government Obligations)—Unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the U.S. government or an agency of the U.S. government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be

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more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2016.

(C) Debt Securities (Other)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2016.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	Millions			
Proceeds from NDT Fund Sales (A)	**$ 139**	**$ 215**	**$ 470**	**$ 1,037**
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	$ 11	$ 14	$ 36	$ 47
Gross Realized Losses	(3)	(11)	(25)	(24)
Net Realized Gains (Losses) on NDT Fund	**$ 8**	**$ 3**	**$ 11**	**$ 23**

(A) 2015 proceeds include activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $131 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of September 30, 2016.

The NDT available-for-sale debt securities held as of September 30, 2016 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 22
1 - 5 years	233
6 - 10 years	214
11 - 15 years	56
16 - 20 years	62
Over 20 years	303
Total NDT Available-for-Sale Debt Securities	**$ 890**

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the nine months ended September 30, 2016, other-than-temporary impairments of $25 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of September 30, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 11	$ 11	$ —	$ 22
Debt Securities				
Government Obligations	104	3	—	107
Other	91	3	—	94
Total Debt Securities	195	6	—	201
Other Securities	1	—	—	1
Total Rabbi Trust Available-for-Sale Securities	**$ 207**	**$ 17**	**$ —**	**$ 224**

	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 12	$ 10	$ —	$ 22
Debt Securities				
Government Obligations	108	1	(1)	108
Other	82	—	(1)	81
Total Debt Securities	190	1	(2)	189
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 204**	**$ 11**	**$ (2)**	**$ 213**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2016	As of December 31, 2015
	Millions	
Accounts Receivable	$ 1	$ 1
Accounts Payable	$ —	$ —

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The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of September 30, 2016				As of December 31, 2015			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government Obligations (B)	4	—	1	—	53	(1)	2	—
Other (C)	9	—	5	—	46	(1)	9	—
Total Debt Securities	13	—	6	—	99	(2)	11	—
Rabbi Trust Available-for-Sale Securities	**$ 13**	**$ —**	**$ 6**	**$ —**	**$ 99**	**$ (2)**	**$ 11**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government Obligations)—Unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the U.S. government or an agency of the U.S. government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of September 30, 2016.

(C) Debt Securities (Other)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2016.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	Millions			
Proceeds from Rabbi Trust Sales	**$ 20**	**$ 20**	**$ 81**	**$ 83**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ 2	$ —	$ 5	$ 2
Gross Realized Losses	(2)	(1)	(4)	(1)
Net Realized Gains (Losses) on Rabbi Trust	**$ —**	**$ (1)**	**$ 1**	**$ 1**

Gross realized gains disclosed in the preceding table were recognized in Other Income in the Condensed Consolidated Statements of Operations. Net unrealized gains of $10 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of September 30, 2016.

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The Rabbi Trust available-for-sale debt securities held as of September 30, 2016 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 9
1 - 5 years	42
6 - 10 years	48
11 - 15 years	9
16 - 20 years	9
Over 20 years	84
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 201**

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the nine months ended September 30, 2016, no other-than-temporary impairments were recognized on securities in the Rabbi Trust. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

The fair value of assets in the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of September 30, 2016	As of December 31, 2015
	Millions	
PSE&G	$ 44	$ 42
Power	55	52
Other	125	119
Total Rabbi Trust Available-for-Sale Securities	**$ 224**	**$ 213**

Note 8. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria.

Effective January 1, 2016, PSEG changed the approach used to measure future service and interest costs for pension benefits. For 2015 and prior, PSEG calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, PSEG has elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows. PSEG believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations. As a change in accounting estimate, this change is being reflected prospectively. Pension and OPEB costs, net of amounts capitalized, were reduced by $9 million and $3 million, for the three months ended September 30, 2016, respectively, and $26 million and $9 million for the nine months ended September 30, 2016, respectively, as compared to the 2016 amounts that would have been derived from applying PSEG's 2015 and prior years' methodology.

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The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis for PSEG, except for Servco.

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015	2016	2015	2016	2015
	Millions							
Components of Net Periodic Benefit Costs								
Service Cost	$ 28	$ 30	$ 5	$ 5	$ 82	$ 92	$ 13	$ 16
Interest Cost	50	59	15	16	151	176	44	50
Expected Return on Plan Assets	(98)	(103)	(8)	(7)	(295)	(310)	(23)	(22)
Amortization of Net								
Prior Service Cost (Credit)	(5)	(5)	(4)	(4)	(14)	(14)	(11)	(11)
Actuarial Loss	39	38	10	11	118	112	30	32
Total Benefit Costs	**$ 14**	**$ 19**	**$ 18**	**$ 21**	**$ 42**	**$ 56**	**$ 53**	**$ 65**

Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015	2016	2015	2016	2015
	Millions							
PSE&G	$ 8	$ 10	$ 11	$ 13	$ 22	$ 30	$ 33	$ 41
Power	3	5	6	7	11	16	17	20
Other	3	4	1	1	9	10	3	4
Total Benefit Costs	**$ 14**	**$ 19**	**$ 18**	**$ 21**	**$ 42**	**$ 56**	**$ 53**	**$ 65**

PSEG contributed its entire planned contributions for the year 2016 of $21 million into its pension plans and $14 million into its OPEB plan during 2016.

Servco Pension and OPEB

At the direction of LIPA, Servco sponsors benefit plans that cover its current and former employees who meet certain eligibility criteria. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 4. Variable Interest Entities. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco has contributed its entire planned contribution of $28 million into its pension plan trusts during 2016. Servco's pension-related revenues and costs were $16 million and $17 million for the three months ended September 30, 2016 and 2015, respectively, and $28 million and $30 million for the nine months ended September 30, 2016 and 2015, respectively. The OPEB-related revenues earned and costs incurred for each of the three months and nine months ended September 30, 2016 and 2015 were immaterial.

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Note 9. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. Current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of September 30, 2016 and December 31, 2015.

	As of September 30, 2016	As of December 31, 2015
	Millions	
Face Value of Outstanding Guarantees	$ 1,797	$ 1,734
Exposure under Current Guarantees	$ 143	$ 172
Letters of Credit Margin Posted	$ 164	$ 122
Letters of Credit Margin Received	$ 136	$ 192
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (4)	$ (15)
Net Broker Balance Deposited (Received)	$ (12)	$ (5)
Additional Amounts Posted:		
Other Letters of Credit	$ 51	$ 51

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 11. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power had posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline and a $21 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA determined that there was a need to perform a comprehensive study of the entire 17 miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17

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miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than with respect to their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. Construction is complete. The CPG is awaiting EPA approval of the construction report, long-term monitoring plan and confirmatory sampling plan. PSE&G's and Power's combined share of the cost of that effort is approximately three percent. The remaining CPG members have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplated the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS set forth various alternatives for remediating this portion of the Passaic River.

The CPG, which consisted of 52 members as of September 30, 2016, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost for the preparation of the RI/FS is approximately $167 million, which the CPG continues to incur. Of the estimated $167 million, as of September 30, 2016, the CPG had spent approximately $156 million, of which PSE&G's and Power's combined share was approximately $10 million.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River. It set forth the CPG's estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion on an undiscounted basis. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranged from approximately $518 million to $772 million. Based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimated share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

In March 2016, the EPA released its Record of Decision (ROD) for the FFS which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The ROD Remedy requires a bank-to-bank dredge ranging from approximately 5 to 30 feet deep in the federal navigation channel from River Mile 0 to River Mile 1.7 and an approximately 2.5 foot deep dredge everywhere else in the lower 8.3 miles of the river. An engineered cap approximately two feet thick will be placed over the dredged areas. Dredged sediments will be transported to facilities and landfills out-of-state. The EPA estimates the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation.

Based upon the estimated cost of the ROD Remedy, PSEG's estimate of PSE&G's and Power's shares of that cost, and the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued an additional $36 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued an additional $8 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2016. As of September 30, 2016, these accruals bring the total liability to approximately $57 million, $46 million applicable to PSE&G and $11 million applicable to Power.

Also in March 2016, the EPA sent a notice letter to 105 PRPs, including PSE&G, all other past and present members of the CPG, including Occidental Chemical Corporation (OCC), and the towns of Newark, Kearny and Harrison and the Passaic Valley Sewerage Commission stating that the EPA wants to determine whether OCC, a successor company to Diamond

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Shamrock, would voluntarily perform the remedial design for the ROD Remedy. On September 30, 2016, OCC and the EPA executed an Administrative Settlement Agreement and Order on Consent for Remedial Design under which OCC agreed to conduct the remedial design for the ROD. With OCC's commitment to perform the remedial design, it is anticipated that the EPA will begin negotiation of a remedial action consent decree, under which OCC and the other "major PRPs" will implement and/or pay for the EPA's ROD Remedy for the lower 8.3 miles. The EPA has not defined "major PRP."

On June 16, 2016, Tierra and Maxus, successors to Diamond Shamrock, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Although PSEG does not currently anticipate that the filing for bankruptcy by Tierra and Maxus will affect its allocable share or total liability for the Passaic River matter, PSEG, through the CPG and independently, will monitor the bankruptcy proceedings to identify any potential impact on PSEG's share of the costs.

The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on PSEG's financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $424 million and $481 million through 2021, including its $46 million share for the Passaic River accrued as of September 30, 2016, as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $424 million as of September 30, 2016. Of this amount, $70 million was recorded in Other Current Liabilities and $354 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $424 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly. NJDEP, PSEG and EPA representatives have had discussions regarding whether sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.

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Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. On August 15, 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. On September 5, 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Second Circuit Court of Appeals. In two related actions on October 17, 2014 and November 20, 2014, several environmental non-governmental groups initiated challenges to the endangered species act provisions of the 316 (b) rule. Power is unable to determine the ultimate impact of these actions on the implementation of the rule.

On June 10, 2016, the NJDEP issued a final NJPDES permit for Salem with an effective date of August 1, 2016. The final permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the Clean Water Act, it requires additional studies and the selection of technology to address impingement for the service water system. On July 8, 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final permit for Salem. The Riverkeeper's filing does not change the effective date of the permit. If the Riverkeeper's challenge were successful, Power may be required to incur additional costs to comply with the Clean Water Act. Such service water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

State permitting decisions at Bridgeport and possibly New Haven could also have a material impact on Power's ability to renew permits at its existing larger once-through cooled plants without making significant upgrades to existing intake structures and cooling systems.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA's Clean Water Act Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, Power would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the current estimated useful life ending in 2025. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in late 2016.

Separately, Power has also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that Power would retire BH3 early if all its precedent conditions occur, which include receipt

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of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. The receipt of permits to allow construction and operation of the new facility could occur in 2017. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power will seek to operate BH3 through the current estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. Operations are expected to begin in mid-2019.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.

Jersey City, New Jersey Subsurface Feeder Cable Matter

In early October 2016, a discharge of mineral oil dielectric fluid from subsurface feeder cables located in the Hudson River near Jersey City, New Jersey, was identified and reported to the New Jersey Department of Environmental Protection (NJDEP). The feeder cables are located within a subsurface easement granted to PSE&G by the property owners, Newport Associates Development Company (NADC) and Newport Associates Phase I Developer Limited Partnership. The feeder cables are subject to agreements between PSE&G and Consolidated Edison Company of New York, Inc. (Con Edison) and are jointly owned by PSE&G and Con Edison, with PSE&G owning the portion of the cables located in New Jersey and Con Edison owning the portion of the cables located in New York. The NJDEP has declared an emergency and an emergency response action has been undertaken to investigate, contain, remediate and stop the fluid discharge; to assess, repair and restore the cables to good working order; and to restore the property. The U.S. Coast Guard has issued Notices of Federal Interest for an Oil Pollution Incident, to the property owners, PSE&G and Con Edison, and the NJDEP has issued a Field Directive to both PSE&G and Con Edison. The investigation and response actions related to the fluid discharge are ongoing. The investigation of the discharge and its potential cause is in the preliminary stages, making it difficult to determine the timing and potential costs to resolve this matter, as well as responsibility for such costs between PSE&G, Con Edison and NADC; however, based on currently available information and the potential scope of the necessary repair and remediation work, the costs could be material.

Steam Electric Effluent Guidelines

On September 30, 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under this rule. Power is unable to predict if this rule will have a material impact on its future capital requirements, financial condition and results of operations.

Coal Combustion Residuals (CCRs)

On December 19, 2014, the EPA issued a final rule which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Power's Hudson and Mercer generating stations, along with its co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 19, 2015. Accordingly in June 2015, Power recorded an additional asset retirement obligation to comply with the final CCR rule which was not material to Power's results of operations, financial condition or cash flows.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity

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including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2016 is $335.33 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2016 of $272.78 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2013	2014	2015	2016	
36-Month Terms Ending	May 2016	May 2017	May 2018	May 2019	(A)
Load (MW)	2,800	2,800	2,900	2,800	
$ per MWh	$92.18	$97.39	$99.54	$96.38	

(A) Prices set in the 2016 BGS auction year became effective on June 1, 2016 when the 2013 BGS auction agreements expired.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 18. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2020 at Salem, Hope Creek and Peach Bottom.

Power has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available beyond the needs of PSE&G's customers, Power can use the gas to supply its fossil generating stations.

Power also has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations.

As of September 30, 2016, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2020	
	Millions	
Nuclear Fuel		
Uranium	$	338
Enrichment	$	307
Fabrication	$	179
Natural Gas	$	904
Coal	$	235

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Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future.

During the three month period ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. No additional charges to income have been recorded for this matter since that time.

Since September 2014, FERC Staff has been conducting a preliminary, non-public staff investigation into the matter and issued data requests covering a period from 2002 through the date of the self-report. This investigation is ongoing. Since that time, Power has responded to data requests from FERC Staff, including recent data requests in which Power has recalculated certain of its energy bids in PJM for a five year period, and may receive additional data requests or other fact finding. The FERC Staff investigation is still in the fact finding stage and there is considerable uncertainty around FERC's response to PSEG's legal arguments and the amount of disgorgement or other remedies FERC may ultimately seek.

PSEG is unable to reasonably estimate the range of possible loss for this matter; however, the amounts of potential disgorgement and other potential penalties that Power may incur span a wide range depending on the success of PSEG's legal arguments. These arguments include that Power's energy market bids in a substantial majority of the hours were below the allowed rate under the Tariff and therefore any errors in those hours were immaterial and that it is unclear whether the quantity of the bids violated any legal requirement. If PSEG's legal arguments do not prevail in whole or in part with FERC or in a judicial challenge that PSEG may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to PSEG's and Power's Consolidated Statements of Operations in the quarterly and annual periods in which they are recorded.

Nuclear Insurance Coverages

The following should be read in conjunction with Note 12. Commitments and Contingent Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2015.

Based upon a review of its nuclear insurance, Power made changes to its Nuclear Electric Insurance Limited (NEIL) insurance coverage of the excess layer for property damage which became effective on April 1, 2016. The excess layer provides coverage above the primary layer of NEIL insurance coverage for property damage of $1.5 billion. For the excess layer at the Salem/Hope Creek site, Power purchased coverage for property damage of $300 million due to a nuclear event and $300 million due to a non-nuclear event. For the excess layer at the Peach Bottom site, Power purchased coverage for its ownership interest for property damage of $300 million due to a nuclear event. For the excess layer at the Peach Bottom site, Exelon purchased coverage for property damage of $600 million due to a non-nuclear event which covers the ownership interest of Power.

Note 10. Debt and Credit Facilities

Long-Term Debt Financing Transactions

The following long-term debt transactions occurred in the nine months ended September 30, 2016:

PSE&G

- issued $300 million of 1.90% Secured Medium-Term Notes, Series K due March 2021,
- issued $550 million of 3.80% Secured Medium-Term Notes, Series K due March 2046,
- issued $425 million of 2.25% Secured Medium-Term Notes, Series L due September 2026,
- retired $171 million of 6.75% Secured First and Refunding Mortgage Bonds, Series VV at maturity, and

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- repurchased at par $100 million of Pollution Control Financing Authority of Salem County Bonds (Salem Bonds) and retired a like aggregate principal amount of its First and Refunding Mortgage Bonds which serviced and secured the Salem Bonds.

Power

- issued $700 million of 3.00% Senior Notes due June 2021,
- retired $303 million of 5.32% Senior Notes due September 2016 and
- retired $250 million of 2.75% Senior Notes due September 2016.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under PSEG's $4.2 billion credit facilities are provided by a diverse bank group with no single institution representing more than 7% of the total commitments in PSEG's credit facilities. As of September 30, 2016, PSEG's total available credit capacity of $3.7 billion was in excess of its anticipated maximum liquidity requirements.

Each of PSEG's credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support its subsidiaries' liquidity needs. PSEG's total credit facilities and available liquidity as of September 30, 2016 were as follows:

Company/Facility	As of September 30, 2016 Total Facility	Usage (D)	Available Liquidity	Expiration Date	Primary Purpose
		Millions			
PSEG					
5-year Credit Facility	$ 500	$ 10	$ 490	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	255	245	Apr 2020	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 265**	**$ 735**		
PSE&G					
5-year Credit Facility (B)	$ 600	$ 14	$ 586	Apr 2020	CP Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 14**	**$ 586**		
Power					
5-year Credit Facility	$ 1,600	$ 194	$ 1,406	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (C)	953	11	942	Apr 2020	Funding/Letters of Credit
Total Power	**$ 2,553**	**$ 205**	**$ 2,348**		
Total	**$ 4,153**	**$ 484**	**$ 3,669**		

(A) PSEG facility will be reduced by $12 million in March 2018.

(B) PSE&G facility will be reduced by $14 million in March 2018.

(C) Power facility will be reduced by $24 million in March 2018.

(D) The primary use of PSEG's and PSE&G's credit facilities is to support their respective CP Programs. As of September 30, 2016, PSEG had $255 million outstanding under its CP Program at a weighted average interest rate of 0.79%. As of September 30, 2016, PSE&G had no amounts outstanding under its CP Program.

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Note 11. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. Transactions receiving NPNS treatment are accounted for upon settlement. For a derivative instrument that qualifies and is designated as a cash flow hedge, the changes in the fair value of such a derivative that are highly effective are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. For a derivative instrument that qualifies and is designated as a fair value hedge, the gains or losses on the derivative as well as the offsetting losses or gains on the hedged item attributable to the hedged risk are recognized in earnings each period. Power and PSE&G enter into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists. PSEG had no commodity derivative transactions designated as cash flow or fair value hedges as of September 30, 2016 and December 31, 2015.

Economic Hedges

Power enters into derivative contracts that are not designated as either cash flow or fair value hedges. Power enters into financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. These transactions are economic hedges, intended to mitigate exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of these contracts are recorded in earnings.

PSE&G is a party to a long-term natural gas sales derivative contract to optimize its pipeline capacity utilization. Changes in the fair market value of the contract are recorded in Regulatory Assets and Regulatory Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. The changes in fair value of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. Interest rate swaps totaling $550 million that converted the retired Power's Senior Notes due September 2016 into variable-rate debt matured in the third quarter. There were no outstanding interest rate swaps as of September 30, 2016. As of December 31, 2015, the fair value of all the underlying hedges was $6 million. The effect of these hedges reduced interest expense by $2 million and $5 million for the three months ended September 30, 2016 and 2015, respectively, and $6 million and $15 million for the nine months ended September 30, 2016 and 2015, respectively.

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Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. As of September 30, 2016, PSEG had interest rate hedges outstanding totaling $500 million. These hedges convert PSEG's $500 million variable rate term loan due November 2017 into a fixed rate loan. The fair value of these hedges and the related ineffectiveness were immaterial as of September 30, 2016. PSEG interest rate hedges totaling $400 million were terminated during the second quarter and a gain of $2 million was recorded in Accumulated Other Comprehensive Income (Loss) (after tax) and will amortize to interest expense over the remaining life of Power's $700 million of 3% Senior Notes due June 2021. For additional information see Note 10. Debt and Credit Facilities. There were no outstanding interest rate cash flow hedges as of December 31, 2015. The Accumulated Other Comprehensive Income (Loss) (after tax) related to existing and terminated interest rate derivatives designated as cash flow hedges was $2 million as of September 30, 2016 and was immaterial as of December 31, 2015. The after-tax unrealized gains on these hedges expected to be reclassified to earnings during the next 12 months are immaterial. The expiration date of the longest-dated interest rate hedge is in May 2021.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with PSEG's accounting policy, these positions have been offset on the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of September 30, 2016 (A)					
	Power			PSE&G	PSEG	Consolidated
	Not Designated			Not Designated	Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 432	$ (283)	$ 149	$ —	$ —	$ 149
Noncurrent Assets	305	(219)	86	—	—	86
Total Mark-to-Market Derivative Assets	**$ 737**	**$ (502)**	**$ 235**	**$ —**	**$ —**	**$ 235**
Derivative Contracts						
Current Liabilities	$ (314)	$ 278	$ (36)	$ (4)	$ —	$ (40)
Noncurrent Liabilities	(219)	206	(13)	—	—	(13)
Total Mark-to-Market Derivative (Liabilities)	**$ (533)**	**$ 484**	**$ (49)**	**$ (4)**	**$ —**	**$ (53)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 204**	**$ (18)**	**$ 186**	**$ (4)**	**$ —**	**$ 182**

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	As of December 31, 2015 (A)					
	Power			PSE&G	PSEG	Consolidated
	Not Designated			Not Designated	Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
				Millions		
Derivative Contracts						
Current Assets	$ 700	$ (477)	$ 223	$ 13	$ 6	$ 242
Noncurrent Assets	208	(131)	77	—	—	77
Total Mark-to-Market Derivative Assets	**$ 908**	**$ (608)**	**$ 300**	**$ 13**	**$ 6**	**$ 319**
Derivative Contracts						
Current Liabilities	$ (513)	$ 437	$ (76)	$ —	$ —	$ (76)
Noncurrent Liabilities	(132)	116	(16)	(11)	—	(27)
Total Mark-to-Market Derivative (Liabilities)	**$ (645)**	**$ 553**	**$ (92)**	**$ (11)**	**$ —**	**$ (103)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 263**	**$ (55)**	**$ 208**	**$ 2**	**$ 6**	**$ 216**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of September 30, 2016 and December 31, 2015. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of September 30, 2016 and December 31, 2015, net cash collateral (received) paid of $(18) million and $(55) million, respectively, were netted against the corresponding net derivative contract positions. Of the $(18) million as of September 30, 2016, $(13) million and $(14) million of cash collateral were netted against current assets and noncurrent assets, respectively, and $9 million was netted against current liabilities. Of the $(55) million as of December 31, 2015, $(53) million and $(16) million were netted against current assets and noncurrent assets, respectively, and $12 million and $2 million were netted against current liabilities and noncurrent liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P and Moody's ratings. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized, and contracts designated as NPNS) was $42 million and $78 million as of September 30, 2016 and December 31, 2015, respectively. As of September 30, 2016 and December 31, 2015, Power had the contractual right of offset of $11 million and $12 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $31 million and $66 million as of September 30, 2016 and December 31, 2015, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.

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The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended September 30, 2016 and 2015.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended September 30, 2016	2015	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended September 30, 2016	2015	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Three Months Ended September 30, 2016	2015
				Millions				
PSEG								
Energy-Related Contracts	$ —	$ 1	Operating Revenues	$ —	$ —	Operating Revenues	$ —	$ —
Interest Rate Swaps	1	—	Interest Expense	—	—	Interest Expense	—	—
Total PSEG	**$ 1**	**$ 1**		**$ —**	**$ —**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ —	$ 1	Operating Revenues	$ —	$ —	Operating Revenues	$ —	$ —
Total Power	**$ —**	**$ 1**		**$ —**	**$ —**		**$ —**	**$ —**

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the nine months ended September 30, 2016 and 2015.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Nine Months Ended September 30, 2016	2015	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Nine Months Ended September 30, 2016	2015	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Nine Months Ended September 30, 2016	2015
				Millions				
PSEG								
Energy-Related Contracts	$ —	$ 2	Operating Revenues	$ —	$ 17	Operating Revenues	$ —	$ —
Interest Rate Swaps	3	—	Interest Expense	—	—	Interest Expense	—	—
Total PSEG	**$ 3**	**$ 2**		**$ —**	**$ 17**		**$ —**	**$ —**
Power								
Energy-Related Contracts	$ —	$ 2	Operating Revenues	$ —	$ 17	Operating Revenues	$ —	$ —
Total Power	**$ —**	**$ 2**		**$ —**	**$ 17**		**$ —**	**$ —**

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The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2015	**$ —**	**$ —**
Gain Recognized in AOCI	2	1
Less: Gain Reclassified into Income	—	—
Balance as of June 30, 2016	**$ 2**	**$ 1**
Gain Recognized in AOCI	1	1
Less: Gain Reclassified into Income	—	—
Balance as of September 30, 2016	**$ 3**	**$ 2**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS, such as its BGS contracts and certain other energy supply contracts, for the three months and nine months ended September 30, 2016 and 2015. Power's derivative contracts reflected in these tables include contracts to hedge the purchase and sale of electricity and natural gas, and the purchase of fuel.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2016	2015	2016	2015
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ 125	$ 154	$ 255	$ 202
Energy-Related Contracts	Energy Costs	(11)	(4)	(3)	(4)
Total PSEG and Power		**$ 114**	**$ 150**	**$ 252**	**$ 198**

The following reflects the gross volume, on an absolute value basis, of derivatives as of September 30, 2016 and December 31, 2015.

Type	Notional	Total	PSEG	Power	PSE&G
		Millions			
As of September 30, 2016					
Natural Gas	Dekatherm (Dth)	315	—	300	15
Electricity	MWh	349	—	349	—
Financial Transmission Rights (FTRs)	MWh	14	—	14	—
Interest Rate Swaps	U.S. Dollars	500	500	—	—
As of December 31, 2015					
Natural Gas	Dth	201	—	168	33
Electricity	MWh	299	—	299	—
FTRs	MWh	23	—	23	—
Interest Rate Swaps	U.S. Dollars	550	550	—	—

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Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of September 30, 2016, 92% of the net credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of collateral, as of September 30, 2016. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities Held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade—External Rating	$ 384	$ 135	$ 249	2	$ 147	(A)
Non-Investment Grade—External Rating	24	—	24	—	—	
Investment Grade—No External Rating	9	—	9	—	—	
Non-Investment Grade—No External Rating	1	1	—	—	—	
Total	**$ 418**	**$ 136**	**$ 282**	**2**	**$ 147**	

(A) Represents net exposure of $114 million with PSE&G. The remaining net exposure of $33 million is with a non-affiliated power purchaser which is an investment grade counterparty.

As of September 30, 2016, collateral held from counterparties where Power had credit exposure included $3 million in cash collateral and $133 million in letters of credit.

As of September 30, 2016, Power had 135 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of September 30, 2016, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's suppliers' credit exposure is calculated each business day. As of September 30, 2016, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 12. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of September 30, 2016, these consisted primarily of long-term gas supply contracts and certain electric load contracts.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of September 30, 2016 and December 31, 2015, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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Description	Recurring Fair Value Measurements as of September 30, 2016				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 357	$ —	$ 357	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 235	$ (502)	$ —	$ 722	$ 15
Interest Rate Swaps (C)	$ —	$ —	$ —	$ —	$ —
NDT Fund (D)					
Equity Securities	$ 922	$ —	$ 922	$ —	$ —
Debt Securities—Govt Obligations	$ 530	$ —	$ —	$ 530	$ —
Debt Securities—Other	$ 360	$ —	$ —	$ 360	$ —
Other Securities	$ 45	$ —	$ 45	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—Govt Obligations	$ 107	$ —	$ —	$ 107	$ —
Debt Securities—Other	$ 94	$ —	$ —	$ 94	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (53)	$ 484	$ —	$ (533)	$ (4)
Interest Rate Swaps (C)	$ —	$ —	$ —	$ —	$ —
PSE&G					
Assets:					
Cash Equivalents (A)	$ 357	$ —	$ 357	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ —	$ —	$ —	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 4	$ —	$ 4	$ —	$ —
Debt Securities—Govt Obligations	$ 22	$ —	$ —	$ 22	$ —
Debt Securities—Other	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (4)	$ —	$ —	$ —	$ (4)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 235	$ (502)	$ —	$ 722	$ 15
NDT Fund (D)					
Equity Securities	$ 922	$ —	$ 922	$ —	$ —
Debt Securities—Govt Obligations	$ 530	$ —	$ —	$ 530	$ —
Debt Securities—Other	$ 360	$ —	$ —	$ 360	$ —
Other Securities	$ 45	$ —	$ 45	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—Govt Obligations	$ 26	$ —	$ —	$ 26	$ —
Debt Securities—Other	$ 23	$ —	$ —	$ 23	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					

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Energy-Related Contracts (B)	$	(49)	$	484	$	—	$	(533)	$	—

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Description	Recurring Fair Value Measurements as of December 31, 2015			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 326	$ —	$ 326	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 313	$ (608)	$ —	$ 896	$ 25
Interest Rate Swaps (C)	$ 6	$ —	$ —	$ 6	$ —
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—Govt Obligations	$ 488	$ —	$ —	$ 488	$ —
Debt Securities—Other	$ 359	$ —	$ —	$ 359	$ —
Other Securities	$ 42	$ —	$ 42	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—Govt Obligations	$ 108	$ —	$ —	$ 108	$ —
Debt Securities—Other	$ 81	$ —	$ —	$ 81	$ —
Other Securities	$ 2	$ —	$ 2	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (103)	$ 553	$ —	$ (644)	$ (12)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 160	$ —	$ 160	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ 13	$ —	$ —	$ —	$ 13
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 21	$ —	$ —	$ 21	$ —
Debt Securities—Other	$ 16	$ —	$ —	$ 16	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (11)	$ —	$ —	$ —	$ (11)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 300	$ (608)	$ —	$ 896	$ 12
NDT Fund (D)					
Equity Securities	$ 865	$ —	$ 865	$ —	$ —
Debt Securities—Govt Obligations	$ 488	$ —	$ —	$ 488	$ —
Debt Securities—Other	$ 359	$ —	$ —	$ 359	$ —
Other Securities	$ 42	$ —	$ 42	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—Govt Obligations	$ 26	$ —	$ —	$ 26	$ —
Debt Securities—Other	$ 20	$ —	$ —	$ 20	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (92)	$ 553	$ —	$ (644)	$ (1)

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(A) Represents money market mutual funds.

(B) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask

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midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds, collateralized mortgage obligations, asset backed securities and government obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of September 30, 2016, net cash collateral (received) paid of $(18) million was netted against the corresponding net derivative contract positions. Of the $(18) million as of September 30, 2016, $(27) million of cash collateral was netted against assets, and $9 million was netted against liabilities. As of December 31, 2015, net cash collateral (received) paid of $(55) million was netted against the corresponding net derivative contract positions. Of the $(55) million of cash collateral as of December 31, 2015, $(69) million was netted against assets, and $14 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

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For PSE&G, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The following tables provide details surrounding significant Level 3 valuations as of September 30, 2016 and December 31, 2015.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of September 30, 2016 Assets	Fair Value as of September 30, 2016 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$ —	$ (4)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ —**	**$ (4)**			
Power						
Electricity	Electric Load Contracts	$ 12	$ —	Discounted Cash flow	Historic Load Variability	0% to +10%
Gas (A)	Other	3	—			
Total Power		**$ 15**	**$ —**			
Total PSEG		**$ 15**	**$ (4)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2015 Assets	Fair Value as of December 31, 2015 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$ 13	$ (11)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ 13**	**$ (11)**			
Power						
Electricity	Electric Load Contracts	$ 11	$ (1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Electricity	Other	1	—			
Total Power		**$ 12**	**$ (1)**			
Total PSEG		**$ 25**	**$ (12)**			

(A) Includes gas supply positions that are immaterial.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value. For energy-related contracts in cases where Power is a seller, an increase in the load variability would decrease the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and nine months ended September 30, 2016 and September 30, 2015, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Nine Months Ended September 30, 2016

	Three Months Ended September 30, 2016						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of July 1, 2016	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2016
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 5	$ 8	$ (2)	$ 4	$ (4)	$ —	$ 11
PSE&G							
Net Derivative Assets (Liabilities)	$ (2)	$ —	$ (2)	$ —	$ —	$ —	$ (4)
Power							
Net Derivative Assets (Liabilities)	$ 7	$ 8	$ —	$ 4	$ (4)	$ —	$ 15

	Nine Months Ended September 30, 2016						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2016	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2016
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 13	$ 24	$ (6)	$ 4	$ (24)	$ —	$ 11
PSE&G							
Net Derivative Assets (Liabilities)	$ 2	$ —	$ (6)	$ —	$ —	$ —	$ (4)
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 24	$ —	$ 4	$ (24)	$ —	$ 15

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Nine Months Ended September 30, 2015

	Three Months Ended September 30, 2015						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of July 1, 2015	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2015
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 8	$ 4	$ (8)	$ —	$ (2)	$ —	$ 2
PSE&G							
Net Derivative Assets (Liabilities)	$ 5	$ —	$ (8)	$ —	$ —	$ —	$ (3)
Power							
Net Derivative Assets (Liabilities)	$ 3	$ 4	$ —	$ —	$ (2)	$ —	$ 5

	Nine Months Ended September 30, 2015						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2015	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2015
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$ 37	$ 12	$ (29)	$ —	$ (18)	$ —	$ 2
PSE&G							
Net Derivative Assets (Liabilities)	$ 26	$ —	$ (29)	$ —	$ —	$ —	$ (3)
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 12	$ —	$ —	$ (18)	$ —	$ 5

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $8 million and $24 million in Operating Income for the three months and nine months ended September 30, 2016, respectively. Of the $8 million in Operating Income, $4 million is unrealized. The $24 million in Operating Income is realized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $(4) million and $(24) million in settlements for the three months and nine months ended September 30, 2016, respectively. Represents $(2) million and $(18) million in settlements for the three months and nine months ended September 30, 2015, respectively.

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(D) There were no transfers among levels during the three months and nine months ended September 30, 2016 and 2015.

(E) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $4 million and $12 million in Operating Income for the three months and nine months ended September 30, 2015, respectively. Of the $4 million in Operating Income, $3 million is unrealized. Of the $12 million in Operating Income, $(6) million is unrealized.

As of September 30, 2016, PSEG carried $2.6 billion of net assets that are measured at fair value on a recurring basis, of which $11 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of September 30, 2015, PSEG carried $2.3 billion of net assets that are measured at fair value on a recurring basis, of which $2 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of September 30, 2016 and December 31, 2015.

	As of September 30, 2016		As of December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$ 500	$ 500	$ 503	$ 506
PSE&G (B)	7,816	8,996	6,821	7,235
Power - Recourse Debt (B)	2,381	2,788	2,237	2,508
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	—	—	7	7
Total Long-Term Debt	**$ 10,697**	**$ 12,284**	**$ 9,568**	**$ 10,256**

(A) Fair value includes a $500 million floating rate term loan and net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. The fair value of the term loan debt (Level 2 measurement) was considered to be equal to the carrying value because the interest payments are based on LIBOR rates that are reset monthly. Carrying amount includes such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) Given that most bonds do not trade, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 13. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended September 30, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 21	$ —	$ 21
Allowance for Funds Used During Construction	14	—	—	14
Solar Loan Interest	6	—	—	6
Other	2	2	2	6
Total Other Income	**$ 22**	**$ 23**	**$ 2**	**$ 47**
Nine Months Ended September 30, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 69	$ —	$ 69
Allowance for Funds Used During Construction	35	—	—	35
Solar Loan Interest	17	—	—	17
Other	9	5	4	18
Total Other Income	**$ 61**	**$ 74**	**$ 4**	**$ 139**
Three Months Ended September 30, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 24	$ —	$ 24
Allowance for Funds Used During Construction	14	—	—	14
Solar Loan Interest	6	—	—	6
Other	2	1	—	3
Total Other Income	**$ 22**	**$ 25**	**$ —**	**$ 47**
Nine Months Ended September 30, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 78	$ —	$ 78
Allowance for Funds Used During Construction	36	—	—	36
Solar Loan Interest	18	—	—	18
Gain on Insurance Recovery	—	28	—	28
Other	5	3	3	11
Total Other Income	**$ 59**	**$ 109**	**$ 3**	**$ 171**

Other Deductions	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended September 30, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 5	$ —	$ 5
Other	1	1	1	3
Total Other Deductions	**$ 1**	**$ 6**	**$ 1**	**$ 8**
Nine Months Ended September 30, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 31	$ —	$ 31
Other	3	2	3	8
Total Other Deductions	**$ 3**	**$ 33**	**$ 3**	**$ 39**
Three Months Ended September 30, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 13	$ —	$ 13
Other	—	1	—	1
Total Other Deductions	**$ —**	**$ 14**	**$ —**	**$ 14**
Nine Months Ended September 30, 2015				
NDT Fund Realized Losses and Expenses	$ —	$ 30	$ —	$ 30
Other	2	2	2	6
Total Other Deductions	**$ 2**	**$ 32**	**$ 2**	**$ 36**

(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

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Note 14. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months and nine months ended September 30, 2016 and 2015 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
PSEG	36.5%	39.4%	36.3%	38.8%
PSE&G	36.1%	38.2%	36.1%	38.7%
Power	39.3%	40.3%	39.4%	38.6%

For the three months and nine months ended September 30, 2016, the overall decreases in PSEG's effective tax rates as compared to the same periods in the prior year as well as to the statutory tax rate of 40.85%, were due primarily to changes in uncertain tax positions and plant related items.

For the three months and nine months ended September 30, 2016, the overall decreases in PSE&G's effective tax rates as compared to the same periods in the prior year as well as to the statutory tax rate of 40.85%, were due primarily to changes in uncertain tax positions and plant and other flow through items.

The Tax Increase Prevention Act of 2014 extended the 50% bonus depreciation rules for qualified property placed in service before January 1, 2015 and for long production property placed in service in 2015.

The Protecting Americans from Tax Hikes Act of 2015 (Tax Act) extended the 50% bonus depreciation rules for qualified property placed in service from January 1, 2015 through December 31, 2017. The rate is reduced to 40% and 30% for eligible property placed in service in 2018 and 2019, respectively. In addition, long production property placed in service in 2020 will also qualify for 30% bonus depreciation. The Tax Act also extended the 30% ITC for qualified property placed in service starting January 1, 2016 through December 31, 2019 but reduces the ITC rate to 26% and 22% for projects commenced in 2020 and 2021, respectively. The financial impact of the extensions of the ITC rate will depend upon future transactions.

These provisions have generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period. However, these tax benefits will have a negative impact on the rate base of several of PSE&G's programs.

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Note 15. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended September 30, 2016			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2016	$ 1	$ (370)	$ 117	$ (252)
Other Comprehensive Income before Reclassifications	1	—	26	27
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	9	(2)	7
Net Current Period Other Comprehensive Income (Loss)	1	9	24	34
Balance as of September 30, 2016	**$ 2**	**$ (361)**	**$ 141**	**$ (218)**

PSEG	Other Comprehensive Income (Loss) Three Months Ended September 30, 2015			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2015	$ 1	$ (395)	$ 117	$ (277)
Other Comprehensive Income before Reclassifications	—	—	(46)	(46)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	9	15	24
Net Current Period Other Comprehensive Income (Loss)	—	9	(31)	(22)
Balance as of September 30, 2015	**$ 1**	**$ (386)**	**$ 86**	**$ (299)**

PSEG	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2016			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2015	$ —	$ (386)	$ 91	$ (295)
Other Comprehensive Income before Reclassifications	2	—	44	46
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	25	6	31
Net Current Period Other Comprehensive Income (Loss)	2	25	50	77
Balance as of September 30, 2016	**$ 2**	**$ (361)**	**$ 141**	**$ (218)**

PSEG	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2015			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2014	$ 10	$ (411)	$ 118	$ (283)
Other Comprehensive Income before Reclassifications	1	—	(44)	(43)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	25	12	27
Net Current Period Other Comprehensive Income (Loss)	(9)	25	(32)	(16)
Balance as of September 30, 2015	**$ 1**	**$ (386)**	**$ 86**	**$ (299)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2016			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2016	$ —	$ (313)	$ 112	$ (201)
Other Comprehensive Income before Reclassifications	—	—	24	24
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	(2)	5
Net Current Period Other Comprehensive Income (Loss)	—	7	22	29
Balance as of September 30, 2016	**$ —**	**$ (306)**	**$ 134**	**$ (172)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2015			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2015	$ 2	$ (337)	$ 112	$ (223)
Other Comprehensive Income before Reclassifications	—	—	(43)	(43)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	14	21
Net Current Period Other Comprehensive Income (Loss)	—	7	(29)	(22)
Balance as of September 30, 2015	**$ 2**	**$ (330)**	**$ 83**	**$ (245)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2016			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2015	$ —	$ (327)	$ 87	$ (240)
Other Comprehensive Income before Reclassifications	—	—	40	40
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	21	7	28
Net Current Period Other Comprehensive Income (Loss)	—	21	47	68
Balance as of September 30, 2016	**$ —**	**$ (306)**	**$ 134**	**$ (172)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2015			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2014	$ 11	$ (351)	$ 112	$ (228)
Other Comprehensive Income before Reclassifications	1	—	(41)	(40)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	21	12	23
Net Current Period Other Comprehensive Income (Loss)	(9)	21	(29)	(17)
Balance as of September 30, 2015	**$ 2**	**$ (330)**	**$ 83**	**$ (245)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2016			Nine Months Ended September 30, 2016		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 3	$ (2)	$ 1	$ 9	$ (4)	$ 5
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)	(51)	21	(30)
Total Pension and OPEB Plans		(14)	5	(9)	(42)	17	(25)
Available-for-Sale Securities							
Realized Gains	Other Income	13	(6)	7	41	(20)	21
Realized Losses	Other Deductions	(5)	3	(2)	(29)	15	(14)
Other-Than-Temporary Impairments (OTTI)	OTTI	(5)	2	(3)	(25)	12	(13)
Total Available-for-Sale Securities		3	(1)	2	(13)	7	(6)
Total		**$ (11)**	**$ 4**	**$ (7)**	**$ (55)**	**$ 24**	**$ (31)**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2015			Nine Months Ended September 30, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		—	—	—	17	(7)	10
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	9	(3)	6
Amortization of Actuarial Loss	O&M Expense	(17)	6	(11)	(51)	20	(31)
Total Pension and OPEB Plans		(14)	5	(9)	(42)	17	(25)
Available-for-Sale Securities							
Realized Gains	Other Income	14	(7)	7	49	(25)	24
Realized Losses	Other Deductions	(12)	5	(7)	(25)	12	(13)
OTTI	OTTI	(30)	15	(15)	(45)	22	(23)
Total Available-for-Sale Securities		(28)	13	(15)	(21)	9	(12)
Total		**$ (42)**	**$ 18**	**$ (24)**	**$ (46)**	**$ 19**	**$ (27)**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2016			Nine Months Ended September 30, 2016		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 3	$ (1)	$ 2	$ 8	$ (3)	$ 5
Amortization of Actuarial Loss	O&M Expense	(15)	6	(9)	(44)	18	(26)
Total Pension and OPEB Plans		(12)	5	(7)	(36)	15	(21)
Available-for-Sale Securities							
Realized Gains	Other Income	12	(5)	7	37	(18)	19
Realized Losses	Other Deductions	(4)	2	(2)	(26)	13	(13)
OTTI	OTTI	(5)	2	(3)	(25)	12	(13)
Total Available-for-Sale Securities		3	(1)	2	(14)	7	(7)
Total		**$ (9)**	**$ 4**	**$ (5)**	**$ (50)**	**$ 22**	**$ (28)**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2015			Nine Months Ended September 30, 2015		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$ —	$ —	$ —	$ 17	$ (7)	$ 10
Total Cash Flow Hedges		—	—	—	17	(7)	10
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	9	(3)	6
Amortization of Actuarial Loss	O&M Expense	(15)	6	(9)	(45)	18	(27)
Total Pension and OPEB Plans		(12)	5	(7)	(36)	15	(21)
Available-for-Sale Securities							
Realized Gains	Other Income	14	(7)	7	47	(24)	23
Realized Losses	Other Deductions	(11)	5	(6)	(24)	12	(12)
OTTI	OTTI	(30)	15	(15)	(45)	22	(23)
Total Available-for-Sale Securities		(27)	13	(14)	(22)	10	(12)
Total		**$ (39)**	**$ 18**	**$ (21)**	**$ (41)**	**$ 18**	**$ (23)**

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Note 16. Earnings Per Share (EPS) and Dividends

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2016		2015		2016		2015	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions):								
Net Income	**$ 327**	**$ 327**	**$ 439**	**$ 439**	**$ 985**	**$ 985**	**$ 1,370**	**$ 1,370**
EPS Denominator (Millions):								
Weighted Average Common Shares Outstanding	505	505	505	505	505	505	505	505
Effect of Stock Based Compensation Awards	—	3	—	3	—	3	—	3
Total Shares	**505**	**508**	**505**	**508**	**505**	**508**	**505**	**508**
EPS								
Net Income	**$ 0.65**	**$ 0.64**	**$ 0.87**	**$ 0.87**	**$ 1.95**	**$ 1.94**	**$ 2.71**	**$ 2.70**

There were approximately 0.4 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect for the three months and nine months ended September 30, 2016 and 2015.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dividend Payments on Common Stock	**2016**	**2015**	**2016**	**2015**
Per Share	$ 0.41	$ 0.39	$ 1.23	$ 1.17
In Millions	$ 207	$ 198	$ 622	$ 592

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Note 17. Financial Information by Business Segment

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated
			Millions		
Three Months Ended September 30, 2016					
Total Operating Revenues	$ 1,684	$ 1,075	$ 7	$ (316)	$ 2,450
Net Income (Loss)	255	139	(67)	—	327
Gross Additions to Long-Lived Assets	680	325	9	—	1,014
Nine Months Ended September 30, 2016					
Operating Revenues	$ 4,746	$ 3,102	$ 256	$ (1,133)	$ 6,971
Net Income (Loss)	696	320	(31)	—	985
Gross Additions to Long-Lived Assets	2,035	923	27	—	2,985
Three Months Ended September 30, 2015					
Total Operating Revenues	$ 1,766	$ 1,096	$ 120	$ (294)	$ 2,688
Net Income (Loss)	222	206	11	—	439
Gross Additions to Long-Lived Assets	716	310	13	—	1,039
Nine Months Ended September 30, 2015					
Operating Revenues	$ 5,234	$ 3,846	$ 326	$ (1,269)	$ 8,137
Net Income (Loss)	631	707	32	—	1,370
Gross Additions to Long-Lived Assets	1,946	797	39	—	2,782
As of September 30, 2016					
Total Assets	$ 25,486	$ 12,810	$ 2,385	$ (1,193)	$ 39,488
Investments in Equity Method Subsidiaries	$ —	$ 106	$ —	$ —	$ 106
As of December 31, 2015					
Total Assets	$ 23,677	$ 12,250	$ 2,810	$ (1,202)	$ 37,535
Investments in Equity Method Subsidiaries	$ —	$ 119	$ —	$ —	$ 119

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations primarily relate to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 18. Related-Party Transactions.

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Note 18. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	Millions			
Billings from Affiliates:				
Net Billings from Power primarily through BGS and BGSS (A)	$ 320	$ 294	$ 1,162	$ 1,287
Administrative Billings from Services (B)	73	66	224	197
Total Billings from Affiliates	**$ 393**	**$ 360**	**$ 1,386**	**$ 1,484**

Related-Party Transactions	As of September 30, 2016	As of December 31, 2015
	Millions	
Receivables from PSEG (C)	**$ 28**	**$ 222**
Payable to Power (A)	$ 126	$ 212
Payable to Services (B)	88	80
Accounts Payable—Affiliated Companies	**$ 214**	**$ 292**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 92**	**$ 109**

Power

The financial statements for Power include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	Millions			
Billings to Affiliates:				
Net Billings to PSE&G primarily through BGS and BGSS (A)	**$ 320**	**$ 294**	**$ 1,162**	**$ 1,287**
Billings from Affiliates:				
Administrative Billings from Services (B)	**$ 44**	**$ 44**	**$ 134**	**$ 135**

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Related-Party Transactions	As of September 30, 2016	As of December 31, 2015
	Millions	
Receivables from PSE&G (A)	$ 126	$ 212
Receivables from PSEG (C)	—	64
Accounts Receivable—Affiliated Companies	**$ 126**	**$ 276**
Payable to Services (B)	$ 27	$ 33
Payable to PSEG (C)	129	—
Accounts Payable—Affiliated Companies	**$ 156**	**$ 33**
Short-Term Loan Due (to) from Affiliate (E)	**$ 514**	**$ 363**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 79**	**$ 35**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. In addition, Power and PSE&G provide certain technical services for each other in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

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Note 19. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries, as of September 30, 2016 and December 31, 2015 and for the three months and nine months ended September 30, 2016 and 2015.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended September 30, 2016					
Operating Revenues	$ —	$ 1,059	$ 43	$ (27)	$ 1,075
Operating Expenses	(2)	826	40	(27)	837
Operating Income (Loss)	2	233	3	—	238
Equity Earnings (Losses) of Subsidiaries	143	(1)	3	(142)	3
Other Income	18	26	—	(21)	23
Other Deductions	(2)	(4)	—	—	(6)
Other-Than-Temporary Impairments	—	(5)	—	—	(5)
Interest Expense	(30)	(12)	(3)	21	(24)
Income Tax Benefit (Expense)	8	(97)	(1)	—	(90)
Net Income (Loss)	**$ 139**	**$ 140**	**$ 2**	**$ (142)**	**$ 139**
Comprehensive Income (Loss)	**$ 168**	**$ 161**	**$ 2**	**$ (163)**	**$ 168**
Nine Months Ended September 30, 2016					
Operating Revenues	$ —	$ 3,061	$ 131	$ (90)	$ 3,102
Operating Expenses	10	2,494	119	(90)	2,533
Operating Income (Loss)	(10)	567	12	—	569
Equity Earnings (Losses) of Subsidiaries	347	(1)	9	(346)	9
Other Income	52	88	—	(66)	74
Other Deductions	(2)	(31)	—	—	(33)
Other-Than-Temporary Impairments	—	(25)	—	—	(25)
Interest Expense	(91)	(29)	(12)	66	(66)
Income Tax Benefit (Expense)	24	(234)	2	—	(208)
Net Income (Loss)	**$ 320**	**$ 335**	**$ 11**	**$ (346)**	**$ 320**
Comprehensive Income (Loss)	**$ 388**	**$ 381**	**$ 11**	**$ (392)**	**$ 388**
Nine Months Ended September 30, 2016					
Net Cash Provided By (Used In) Operating Activities	$ 175	$ 1,261	$ 234	$ (410)	$ 1,260
Net Cash Provided By (Used In) Investing Activities	$ (588)	$ (1,166)	$ (549)	$ 1,152	$ (1,151)
Net Cash Provided By (Used In) Financing Activities	$ 413	$ (95)	$ 315	$ (742)	$ (109)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended September 30, 2015					
Operating Revenues	$ —	$ 1,084	$ 37	$ (25)	$ 1,096
Operating Expenses	3	692	35	(25)	705
Operating Income (Loss)	(3)	392	2	—	391
Equity Earnings (Losses) of Subsidiaries	220	(2)	3	(218)	3
Other Income	10	26	—	(11)	25
Other Deductions	—	(14)	—	—	(14)
Other-Than-Temporary Impairments	—	(30)	—	—	(30)
Interest Expense	(28)	(8)	(5)	11	(30)
Income Tax Benefit (Expense)	7	(148)	2	—	(139)
Net Income (Loss)	**$ 206**	**$ 216**	**$ 2**	**$ (218)**	**$ 206**
Comprehensive Income (Loss)	**$ 184**	**$ 187**	**$ 2**	**$ (189)**	**$ 184**
Nine Months Ended September 30, 2015					
Operating Revenues	$ —	$ 3,811	$ 144	$ (109)	$ 3,846
Operating Expenses	7	2,610	135	(109)	2,643
Operating Income (Loss)	(7)	1,201	9	—	1,203
Equity Earnings (Losses) of Subsidiaries	755	(4)	11	(751)	11
Other Income	33	111	—	(35)	109
Other Deductions	(1)	(31)	—	—	(32)
Other-Than-Temporary Impairments	—	(45)	—	—	(45)
Interest Expense	(90)	(24)	(15)	35	(94)
Income Tax Benefit (Expense)	17	(463)	1	—	(445)
Net Income (Loss)	**$ 707**	**$ 745**	**$ 6**	**$ (751)**	**$ 707**
Comprehensive Income (Loss)	**$ 690**	**$ 707**	**$ 6**	**$ (713)**	**$ 690**
Nine Months Ended September 30, 2015					
Net Cash Provided By (Used In) Operating Activities	$ 435	$ 1,826	$ 66	$ (769)	$ 1,558
Net Cash Provided By (Used In) Investing Activities	$ (656)	$ (1,382)	$ (303)	$ 1,191	$ (1,150)
Net Cash Provided By (Used In) Financing Activities	$ 221	$ (446)	$ 245	$ (422)	$ (402)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
As of September 30, 2016					
Current Assets	$ 4,889	$ 1,845	$ 287	$ (5,262)	$ 1,759
Property, Plant and Equipment, net	57	6,570	2,080	—	8,707
Investment in Subsidiaries	4,709	483	—	(5,192)	—
Noncurrent Assets	157	2,140	123	(76)	2,344
Total Assets	**$ 9,812**	**$ 11,038**	**$ 2,490**	**$ (10,530)**	**$ 12,810**
Current Liabilities	$ 818	$ 3,888	$ 1,350	$ (5,262)	$ 794
Noncurrent Liabilities	473	2,704	394	(76)	3,495
Long-Term Debt	2,381	—	—	—	2,381
Member's Equity	6,140	4,446	746	(5,192)	6,140
Total Liabilities and Member's Equity	**$ 9,812**	**$ 11,038**	**$ 2,490**	**$ (10,530)**	**$ 12,810**
As of December 31, 2015					
Current Assets	$ 4,501	$ 1,912	$ 364	$ (4,828)	$ 1,949
Property, Plant and Equipment, net	83	6,502	1,542	—	8,127
Investment in Subsidiaries	4,501	346	—	(4,847)	—
Noncurrent Assets	155	1,959	136	(76)	2,174
Total Assets	**$ 9,240**	**$ 10,719**	**$ 2,042**	**$ (9,751)**	**$ 12,250**
Current Liabilities	$ 1,112	$ 3,866	$ 1,076	$ (4,828)	$ 1,226
Noncurrent Liabilities	442	2,597	375	(76)	3,338
Long-Term Debt	1,684	—	—	—	1,684
Member's Equity	6,002	4,256	591	(4,847)	6,002
Total Liabilities and Member's Equity	**$ 9,240**	**$ 10,719**	**$ 2,042**	**$ (9,751)**	**$ 12,250**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G,** our public utility company which is engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU, and
- **Power,** our multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy transacting functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA), and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business of our 2015 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2015 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2016 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2015 Form 10-K.

EXECUTIVE OVERVIEW OF 2016 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- improving utility operations through growth in investment in T&D and other infrastructure projects designed to enhance resiliency, and
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the three months and nine months ended September 30, 2016 and 2015 are presented as follows:

Earnings	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	Millions			
PSE&G	$ 255	$ 222	$ 696	$ 631
Power (A) (B)	139	206	320	707
Other (C)	(67)	11	(31)	32
PSEG Net Income	**$ 327**	**$ 439**	**$ 985**	**$ 1,370**
PSEG Net Income Per Share (Diluted)	**$ 0.64**	**$ 0.87**	**$ 1.94**	**$ 2.70**

(A) Includes after-tax expenses of $67 million related to the early retirement of Power's Hudson and Mercer coal/gas generation plants in the three months and nine months ended September 30, 2016. See Item 1. Note 3. Early Plant Retirements for additional information.

(B) Includes an after-tax insurance recovery for Superstorm Sandy of $102 million in the nine months ended September 30, 2015.

(C) Other includes activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations. Energy Holdings recorded an after-tax impairment of $86 million related to its investments in NRG REMA, LLC's leveraged leases in the three months and nine months ended September 30, 2016. See Item 1. Note 6. Financing Receivables for further information.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with future delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	Millions, after tax			
NDT Fund Income (Expense) (A) (B)	$ 2	$ (14)	$ (4)	$ (11)
Non-Trading MTM Gains (Losses) (C)	$ 34	$ 50	$ (54)	$ 58

(A) NDT Fund Income (Expense) includes the realized gains and losses, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense.

(B) Net of tax (expense) benefit of $(2) million, $10 million, $0 million and $3 million for the three and nine months ended September 30, 2016 and 2015, respectively.

(C) Net of tax (expense) benefit of $(24) million, $(34) million, $37 million and $(40) million for the three and nine months ended September 30, 2016 and 2015, respectively.

Our $112 million decrease in Net Income for the three months ended September 30, 2016 was driven primarily by

- an impairment related to investments in certain leveraged leases at Energy Holdings (See Item 1. Note 6. Financing Receivables),
- charges related to the early retirement of two coal/gas generation units at Power (See Item 1. Note 3. Early Plant Retirements), and

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- lower volumes of energy sold at lower average realized prices and lower capacity revenues, primarily in the PJM Interconnection, L.L.C. (PJM) region.

These decreases were partially offset by

- higher revenues due to increased investments in transmission projects,
- higher electricity sales under non-BGS wholesale load contracts in PJM and New England (NE) and higher volumes of electricity sold at higher prices under our Basic Generation Service (BGS) contracts, and
- lower other-than-temporary impairments of the NDT Fund.

Our $385 million decrease in Net Income for the nine months ended September 30, 2016 was driven primarily by

- the aforementioned charges in the 2016 third quarter for the early retirement of the two coal/gas generation units at Power,
- MTM losses in 2016 as compared to MTM gains in 2015,
- lower volumes of energy sold at lower average realized sales prices,
- lower capacity and operating reserve revenues in PJM,
- higher 2016 congestion costs in PJM as a result of credits received in 2015 due to extremely colder weather,
- lower volumes of gas sold at lower average prices under the Basic Gas Supply Service (BGSS) contract,
- insurance recoveries received primarily by Power in 2015 related to Superstorm Sandy, and
- the aforementioned third quarter 2016 impairment on leveraged leases at Energy Holdings.

These decreases were partially offset by

- lower generation costs driven by lower fuel costs, particularly for natural gas, and reduced generation output at Power,
- higher costs incurred at Power for planned outages in 2015, and
- higher revenues due to increased investments in transmission projects.

During the first nine months of 2016, we maintained a strong balance sheet. We continued to effectively deploy capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results and allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our multi-year, long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, our merchant generator, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, in 2016 we continue to make investments to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the BPU in 2014 and to seek recovery on such investments. We also commenced modernizing PSE&G's gas distribution systems as part of our Gas System Modernization Program (GSMP) that was approved by the BPU in late 2015. Over the past few years, these types of investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G. In 2017, as a result of our Energy Strong Order from the BPU, we will be required to file a Distribution rate case proceeding. We cannot predict the impact such proceeding will have on our distribution business.

Despite the unseasonable warm winter weather patterns in 2016, Power's results benefited from access to natural gas supplies through existing firm pipeline transportation contracts. Power manages these contracts for the benefit of PSE&G's customers through the BGSS arrangement. The contracts are sized to provide for delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers' needs is available, Power can use it to make third party sales and supply gas to its generating units in New Jersey. Alternatively, gas supply and pipeline capacity constraints could adversely impact our ability to meet the needs of our utility customers and generating units. Power's strategic hedging practices and ability to capitalize on market opportunities help it to balance some of the volatility of the merchant power business.

Our recent investments in the latter half of 2015 and early 2016 in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. These additions to

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our fleet both expand our geographic diversity and adjust our fuel mix and are expected to contribute to the overall efficiency of operations.

Since 2013, eight nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, and four additional stations have been announced as being at risk for early retirement. This situation is generally due to low natural gas prices resulting from the growth of shale gas production since 2007, the continuing cost of regulatory compliance for nuclear facilities and both federal and state-level policies that provide credits to renewable energy such as wind and solar, but do not apply to nuclear generating stations. These trends have significantly reduced the revenues to nuclear generating stations while simultaneously raising the unit cost of production. This may result in the electric generation industry experiencing a shift from nuclear generation to natural gas-fired generation, creating greater reliance on natural gas pipelines for delivery and less diversity of the generation fleet.

If trends noted above continue or worsen, our nuclear generating units could cease being economically competitive which may cause us to retire such units prior to the end of their useful lives. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs and environmental remediation costs, could be material. We continue to advocate for sound policies that recognize nuclear power as a source of clean energy and an important part of a diverse and reliable energy portfolio.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission

In April 2013, PJM initiated its first “open window” solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues in New Jersey. In February 2016, FERC issued an order granting PSE&G’s request that it be permitted to seek recovery of 100% of its portion of prudently incurred Artificial Island project costs if the project is cancelled for reasons beyond PSE&G’s control. In April 2016, PSE&G accepted construction responsibility for three components of the Artificial Island project that PJM assigned to us. On August 5, 2016, PJM announced that it has suspended the Artificial Island transmission project and is performing a comprehensive analysis to determine a future course of action, which is expected to be completed by February 2017. We may also from time to time have opportunities to submit transmission project proposals in regions where we are not the incumbent. However, there can be no assurance that any such proposals would be successful.

In April 2016, PJM filed at FERC to incorporate a voltage threshold into PJM’s Regional Transmission Expansion Plan (RTEP) process to exempt, except under certain circumstances, reliability violations on facilities below 200 kV from PJM’s proposal window process. We generally support this reform as a measure to improve the efficiency of the open window procedure that will permit transmission developers to focus on the projects most likely to benefit from a competitive process.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G’s ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey and may cause increased scrutiny regarding PSE&G’s future capital investments. In addition, as a basic generation service (BGS) supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers may be entitled to an adjustment, subject to BPU approval. We do not believe that these matters will have a material effect on Power’s business or results of operations.

Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners’ base return on equity (ROE). Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners’ base ROEs. While we are not the subject of a challenge to the ROE employed in PSE&G’s transmission formula rate, the results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

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Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. In June 2015, FERC conditionally accepted a proposal from PJM for a capacity performance product to include generators, Demand Response and energy efficiency providers, which will be required to perform during emergency conditions, as a supplement to the base capacity product. The proposal included enhanced performance-based incentives and penalties. We believe that the auction pricing adequately reflects the increased costs that could result from operating under more stringent rules for generation availability. Based on the auction results, the capacity performance mechanism appears to have provided the opportunity for enhanced capacity market revenue streams for Power, but future impacts cannot be assured. Further, there may be requirements for additional investment and there are additional performance and financial risks. Appeals of FERC's capacity performance orders are pending.

In May 2016, PJM announced the results of the RPM capacity auction for the 2019-2020 delivery year. Power cleared 8,895 MW of its generating capacity at an average price of $116 per MW-day for the 2019-2020 delivery period. Of the cleared capacity, Power believes that nearly all is compliant with PJM's capacity performance requirements. In the two prior capacity auctions covering the 2017-2018 and 2018-2019 delivery years, Power cleared approximately 8,700 MW at average prices of $177 per MW-day and $215 per MW-day, respectively. Prices in the most recent auction reflect PJM's downwardly-revised demand forecast, changes in the emergency transfer limits due to transmission expansion and the effects of both the new generation and uncleared generation from the prior year's auction.

As a result of the efforts of certain entities in PJM to obtain financial support arrangements from their state commission, a group of suppliers requested that FERC direct PJM to expand the currently effective "minimum offer price rule" to apply to certain existing units seeking subsidies. The suppliers' request was intended to avoid a scenario where the subsidized generators would submit bids into the PJM capacity market that did not reflect their actual costs of operation and could artificially suppress capacity market prices. We are currently awaiting FERC action on the suppliers' request and cannot predict the outcome of the proceeding. See Part II, Item 5. Other Information—Federal Regulation—Capacity Market Issues—PJM for additional information.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act (FWPCA) requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs. See Item 1. Note 9. Commitments and Contingent Liabilities for further information.

In October 2015, the EPA published the Clean Power Plan (CPP), a greenhouse gas emissions regulation under the Clean Air Act (CAA) for existing power plants. The regulation establishes state-specific emission targets based on implementation of the best systems of emission reduction. We continue to work with FERC and other federal and state regulators, as well as industry partners, to determine the potential impact of these regulations.

The U.S. Supreme Court's February 2016 decision to stay the implementation of the CPP will delay deadlines for submission of state requests for extensions and final plans. If the CPP is upheld, new deadlines will need to be established and the effective date of the compliance period may be impacted.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above as well as other matters that may impact our financial condition and results of operations, see Item 1. Note 9. Commitments and Contingent Liabilities.

FERC Compliance

Since September 2014, FERC Staff has been conducting a preliminary non-public investigation regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units. This investigation is ongoing. The amounts of potential disgorgement and other potential penalties that we may incur span a wide range depending on the success of our legal arguments. If our legal arguments do not prevail, in whole or in part with FERC or in a judicial challenge that we may

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choose to pursue, it is likely that Power would record losses that would be material to PSEG's and Power's results of operations in the quarterly and annual periods in which they are recorded. For additional information, see Item 1. Note 9. Commitments and Contingent Liabilities.

Early Retirement of Hudson and Mercer Units

In October 2016, Power determined it will cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. The exact timing of the early retirement of these units will be reviewed for reliability impacts by PJM, and may be impacted by operational and other conditions that could subsequently arise. The decision to retire the Hudson and Mercer units will have a material effect on PSEG's and Power's results of operations. In the third quarter of 2016, PSEG and Power recognized one-time pre-tax charges in Energy Costs, Operation and Maintenance and Depreciation and Amortization of $62 million, $48 million and $4 million, respectively, related to coal inventory adjustments, capacity penalties, materials and supplies inventory reserve adjustments for parts that cannot be used at other generating units, employee-related severance benefits costs, construction work in progress impairments, and asset retirement obligation (ARO) adjustments, among other shut down items. In addition to these one-time charges, Power will recognize incremental Depreciation and Amortization during the remainder of 2016 of $568 million and $946 million into 2017 due to the significant shortening of the expected economic useful lives of Hudson and Mercer. Additional employee-related salary continuance and severance costs and various miscellaneous costs may also be incurred during the period prior to retirement. Finally, Power currently anticipates using the sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger investigation and possible remediation of identified environmental contamination. The amounts for any such environmental investigation or remediation are not currently probable or estimable but may be material. For additional information, including our estimated costs through 2017, see Item 1. Note 3. Early Plant Retirements.

The primary factors considered during our annual five-year strategic planning process that contributed to the decision to retire these units early include significant declines in revenues and margin caused by a sustained period of depressed wholesale power prices and reduced capacity factors caused by lower natural gas prices making coal generation less economically competitive than natural gas-fired generation. Despite experiencing recent warmer than normal weather in PJM this summer, Power did not experience the usual increase in electricity prices in PJM as it had in past hot summers. This trend has a further adverse economic impact to these units because they generally dispatch and earn energy margin on peak hot and cold days. In addition, the upcoming PJM capacity auction in May 2017 will be the first to require all generating units to meet the increased operating performance standards of PJM's new capacity performance construct. Power determined that the costs to upgrade the existing units at the Hudson and Mercer stations to be able to comply with these higher reliability standards are too significant and not economic given current market conditions.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone, Conemaugh and Bridgeport Harbor generating stations, to ensure their economic viability through the end of their designated useful lives. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact our ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement of our other coal units before the end of their current estimated useful lives may have a material adverse impact on PSEG's and Power's future financial results.

Leveraged Lease Impairments

During the third quarter of 2016, Energy Holdings completed its annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases. The outcome indicated that the revised residual value estimates were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM, as discussed in Note 3. Early Plant Retirements, negatively impacting the economic outlook of the leased assets. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016, calculated by comparing the gross investment in the leases before and after the revised residual estimates. There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.

Additional facilities in our leveraged lease portfolio include the Joliet facility, which has converted to natural gas. The coal-fired units at the Shawville generating facility are expected to return to service in the fall of 2016 with the ability to use natural gas. However, these units may have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units. As a result, these facilities may not be as economically competitive as newer combined cycle gas units and could continue to be adversely impacted by the same economic conditions experienced by coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged leases associated with these facilities.

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REMA's parent company, GenOn Energy, Inc. (GenOn), reported in August 2016 that it did not expect to have sufficient liquidity to repay their senior unsecured notes due in June 2017. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's efforts to restructure its portfolio and improve its liquidity and the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments, which could include further write-downs of the values of Energy Holdings' leveraged leases.

Salem Operations

The previously announced bolt replacement at Salem Unit 1 was completed and the unit returned to service on July 30, 2016. We expect to continue to inspect and replace degraded bolts at both Salem units over the next several refueling outage cycles. We are participating with the Electric Power Research Institute, the Nuclear Energy Institute and other operators of similarly-designed pressurized water reactors in developing a strategy to maintain the long-term health of the reactor vessel internals.

Extension of the Salem Unit 1 outage into July and an unplanned outage at Salem Unit 2 due to transformer issues reduced output from the Salem units in the third quarter, which was partially offset by increased production at our Hope Creek and Peach Bottom units. As a result, our nuclear capacity factor for the nine months ended September 30, 2016 was 88%.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of opportunities in a rapidly evolving market as we remain diligent in managing costs. For the first nine months of 2016, our

- diverse fuel mix and dispatch flexibility allowed us to generate approximately 40 terra-watt hours while addressing fuel availability and price volatility and compensating for the extended outages at our Salem units, and
- combined cycle fleet produced 13 terawatt hours at an average capacity factor of 63%.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first nine months of 2016 as we

- had cash on hand of $450 million as of September 30, 2016,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2016 to $1.64 per share.

We expect to be able to fund our planned capital requirements, as described in Liquidity and Capital Resources, without the issuance of new equity.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first nine months of 2016, we

- made additional investments in transmission infrastructure projects,
- began executing our GSMP and continued executing Energy Strong and other existing BPU-approved utility programs,
- commenced construction of our Keys and Sewaren 7 generation projects for targeted commercial operation in 2018 and announced our plan to construct BH5 and commence operations in mid-2019, and
- acquired three solar energy projects totaling 100 MW-direct current. Two of these projects are already in service in North Carolina and Colorado. The third project is in Colorado and expected to be in service by year end.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-growing economy and a cost-constrained environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,

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- successfully manage our energy obligations and re-contract our open supply positions in response to changes in demand,
- execute our utility capital investment program, including our Energy Strong program, GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction of our Keys, Sewaren 7, BH5 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

For 2016 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- fair and timely rate relief from the BPU and FERC for recovery of costs and return on investments, including with respect to our base rate case which must be filed with the BPU no later than November 1, 2017,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate,
- the impact of lower natural gas prices and increasing environmental compliance costs on the competitiveness of our nuclear and remaining coal-fired generation plants, and the potential for retirement of such plants earlier than their current useful lives,
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development projects, including in connection with permitting and regulatory approvals,
- maintaining a diverse mix of fuels to mitigate risks associated with fuel price volatility and market demand cycles, and
- FERC Staff's continuing investigation of certain of Power's New Jersey fossil generating unit bids in the PJM energy market.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of transmission and distribution facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses,
- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency, modernizing existing infrastructure and participation in transmission projects through FERC's "open window" solicitation process.

We continue to actively explore opportunities in the retail energy marketing business, which we believe would complement our existing wholesale marketing business. Our entry into the retail energy marketing business is subject to market conditions and regulatory approval, among other things.

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There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 18. Related-Party Transactions.

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2016	2015	2016 vs. 2015		2016	2015	2016 vs. 2015	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,450	$ 2,688	$ (238)	(9)	$ 6,971	$ 8,137	$ (1,166)	(14)
Energy Costs	866	815	51	6	2,326	2,577	(251)	(10)
Operation and Maintenance	776	746	30	4	2,215	2,170	45	2
Depreciation and Amortization	231	313	(82)	(26)	679	960	(281)	(29)
Income from Equity Method Investments	3	3	—	—	9	10	(1)	(10)
Other Income (Deductions)	39	33	6	18	100	135	(35)	(26)
Other-Than-Temporary Impairments	5	30	(25)	(83)	25	45	(20)	(44)
Interest Expense	99	96	3	3	288	291	(3)	(1)
Income Tax Expense	188	285	(97)	(34)	562	869	(307)	(35)

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2016	2015	2016 vs. 2015		2016	2015	2016 vs. 2015	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,684	$ 1,766	$ (82)	(5)	$ 4,746	$ 5,234	$ (488)	(9)
Energy Costs	721	740	(19)	(3)	1,979	2,176	(197)	(9)
Operation and Maintenance	376	391	(15)	(4)	1,110	1,171	(61)	(5)
Depreciation and Amortization	137	231	(94)	(41)	412	712	(300)	(42)
Other Income (Deductions)	21	22	(1)	(5)	58	57	1	2
Interest Expense	72	67	5	7	214	203	11	5
Income Tax Expense	144	137	7	5	393	398	(5)	(1)

Three Months Ended September 30, 2016 as Compared to 2015

Operating Revenues decreased $82 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $57 million due primarily to an increase in transmission revenues.

- Transmission revenues were $50 million higher due to increased capital investments.
- Electric distribution revenues increased $8 million due primarily to $12 million in higher sales volumes and $12 million due to the inclusion of Energy Strong in base rates, partially offset by lower Green Program Recovery Charges (GPRC) of $16 million.

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Commodity Revenue decreased $19 million as a result of $14 million of lower Gas revenues and $5 million of lower Electric revenues. Commodity revenue for both gas and electric is entirely offset with the change in Energy Costs. PSE&G earns no margin on the provision of BGSS and BGS to retail customers.

- Gas revenues decreased $14 million due to $25 million of lower BGSS sales volumes, partially offset by $11 million in higher prices.
- Electric revenues decreased $5 million due primarily to $17 million of lower revenues from collections of Non-Utility Generation Charges (NGC) and a decrease of $14 million due to lower volumes of Non-Utility Generation (NUG) energy sold at lower prices. These decreases were partially offset by a $26 million increase in BGS revenues due to higher sales volumes.

Clause Revenues decreased $121 million due primarily to lower Securitization Transition Charges (STC) of $118 million. The STC reduction was a result of rate reductions due to the completion of securitization collections in 2015. The changes in the STC amounts are entirely offset by decreases in the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC collections.

Operating Expenses

Energy Costs decreased $19 million. This is entirely offset by the change in Commodity Revenue.

Operation and Maintenance decreased $15 million, of which the most significant components were

- a $23 million net reduction in costs related to various clause mechanisms, including SBC and STC, and GPRC, and
- a $2 million decrease in pension and OPEB costs, net of capitalized amounts,
- partially offset by a net increase of $10 million in operating expenses, including increases in appliance service costs, gas distribution costs and electric distribution corrective maintenance.

Depreciation and Amortization decreased $94 million due to a decrease of $114 million in amortization of Regulatory Assets primarily as a result of the completion of the amortization of the securitization charges in 2015 (which is completely offset in STC Revenues), partially offset by an $18 million increase in depreciation due to additional plant in service.

Interest Expense increased $5 million due primarily to an increase of $7 million due to net debt issuances in 2015 and 2016, partially offset by a $2 million decrease due to the redemption of securitization debt in 2015.

Income Tax Expense increased $7 million due primarily to higher pre-tax income, partially offset by plant-related items and uncertain tax positions.

Nine Months Ended September 30, 2016 as Compared to 2015

Operating Revenues decreased $488 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $116 million due primarily to an increase in transmission revenues.

- Transmission revenues were $152 million higher due to increased capital investments.
- Electric distribution revenues decreased $30 million due primarily to lower GPRC of $42 million and a $4 million decrease due to lower sales volumes partially offset by $16 million increase due to the inclusion of Energy Strong in base rates.
- Gas distribution revenues decreased $6 million due primarily to $75 million of lower delivery volumes and lower GPRC of $7 million due to lower sales volumes from warmer winter weather. These decreases were almost entirely offset by $64 million in higher Weather Normalization Clause revenue and a $12 million increase due to the inclusion of Energy Strong in base rates effective September 1, 2015.

Commodity Revenue decreased $197 million as a result of lower Gas and Electric revenues. Commodity revenue for both gas and electric is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGSS and BGS to retail customers.

- Gas revenues decreased $108 million due primarily to lower BGSS sales volumes.
- Electric revenues decreased $89 million due primarily to $43 million of lower revenues from collections of NGC, a decrease of $31 million due to lower volumes of NUG energy sold and a $15 million or 1% decrease in BGS revenues due primarily to lower sales volumes.

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Clause Revenues decreased $402 million due primarily to lower STC of $370 million, lower SBC of $38 million and $9 million of lower SPRC, partially offset by higher Margin Adjustment Clause (MAC) revenue of $15 million. The STC reduction is a result of rate reductions due to the completion of securitization collections in 2015. The changes in the STC, SBC, SPRC and MAC amounts are entirely offset by decreases in the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC, SPRC or MAC collections.

Operating Expenses

Energy Costs decreased $197 million. This is entirely offset by the change in Commodity Revenue.

Operation and Maintenance decreased $61 million, of which the most significant components were

- a $95 million net reduction in costs related to various clause mechanisms, including SBC, SPRC, STC and MAC, and GPRC, and
- a $10 million decrease in pension and OPEB costs, net of capitalized amounts,
- partially offset by $10 million of storm insurance recovery proceeds received in 2015,
- an $8 million increase in electric distribution corrective maintenance,
- a $5 million increase in vegetation management,
- a $5 million increase in transmission related maintenance and
- a $16 million increase in operating expenses, including $3 million increases related to both appliance service costs and gas distribution costs.

Depreciation and Amortization decreased $300 million due to a decrease of $353 million in amortization of Regulatory Assets primarily as a result of the completion of the amortization of the securitization charges in 2015 (which is completely offset in STC Revenues), partially offset by a $49 million increase in depreciation due to additional plant in service.

Interest Expense increased $11 million due primarily to an increase of $20 million due to net debt issuances in 2015 and 2016, partially offset by a $10 million decrease due to the redemption of securitization debt in 2015.

Income Tax Expense decreased $5 million due primarily to uncertain tax positions, plant-related and other flow through items, partially offset by higher pre-tax income.

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Power

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2016	2015	2016 vs. 2015		2016	2015	2016 vs. 2015	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,075	$ 1,096	$ (21)	(2)	$ 3,102	$ 3,846	$ (744)	(19)
Energy Costs	462	367	95	26	1,481	1,669	(188)	(11)
Operation and Maintenance	289	263	26	10	807	748	59	8
Depreciation and Amortization	86	75	11	15	245	226	19	8
Income from Equity Method Investments	3	3	—	—	9	11	(2)	(18)
Other Income (Deductions)	17	11	6	55	41	77	(36)	(47)
Other-Than-Temporary Impairments	5	30	(25)	(83)	25	45	(20)	(44)
Interest Expense	24	30	(6)	(20)	66	94	(28)	(30)
Income Tax Expense	90	139	(49)	(35)	208	445	(237)	(53)

Three Months Ended September 30, 2016 as Compared to 2015

Operating Revenues decreased $21 million due to changes in generation, gas supply and other revenues.

Generation Revenues decreased $23 million due primarily to

- a decrease of $73 million in energy sales volumes and lower average realized prices, primarily in the PJM region, and
- a decrease of $24 million in capacity revenue, primarily in the PJM region,
- partially offset by a net increase of $44 million in electricity sold under non-BGS wholesale load contracts in the PJM and NE regions due to higher volumes sold partially offset by lower average prices, and
- an increase of $24 million in electricity sold under our BGS contracts due primarily to higher volumes as a result of warmer weather, coupled with higher average prices.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $95 million due primarily to

Generation costs increased $93 million due to

- a $62 million charge associated with the announced early retirement of the coal/gas Mercer and Hudson generation units, primarily related to a coal inventory write-down of $57 million,
- an increase of $32 million due to MTM losses in 2016 as compared to MTM gains in 2015. Of this amount, $25 million was due to lower gains on positions reclassified to realized upon settlement this year compared to last year, and
- an increase of $13 million due to increases in purchases of renewable energy credits and energy to serve load contracts,
- partially offset by a decrease of $20 million due primarily to lower natural gas costs reflecting lower average realized prices.

Operation and Maintenance increased $26 million due primarily to

- $48 million of charges related to the early retirement of the Hudson and Mercer units,
- partially offset by a net decrease of $18 million due to the timing of a planned outage at our 50%-owned Peach Bottom nuclear plant.

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Depreciation and Amortization increased $11 million due primarily to

- a $7 million increase due primarily to a higher nuclear asset base, and
- $4 million of accelerated depreciation on asset retirement costs from previously retired assets at the Hudson and Mercer plants.

Other Income (Deductions) increased $6 million due primarily to lower net realized losses from the NDT Fund in 2016.

Other-Than-Temporary Impairments decreased $25 million due to lower impairments of equity securities in the NDT Fund in 2016.

Interest Expense decreased $6 million due primarily to higher capitalized interest in 2016.

Income Tax Expense decreased $49 million in 2016 due primarily to lower pre-tax income.

Nine Months Ended September 30, 2016 as Compared to 2015

Operating Revenues decreased $744 million due to changes in generation, gas supply and other revenues.

Generation Revenues decreased $497 million due primarily to

- a decrease of $213 million in energy sales volumes in the PJM, NE and New York (NY) regions due primarily to milder weather and lower average realized prices,
- a decrease of $166 million due to MTM losses in 2016 as compared to MTM gains in 2015. Of this amount, $127 million was due to higher gains on positions reclassified to realized upon settlement this year compared to last year. Also contributing to the decrease were lower MTM gains of $39 million due to minor changes in forward power prices this year compared to last year,
- a net decrease of $113 million primarily in the PJM region due to lower capacity revenue resulting from the retirement of older peaking units in June 2015, coupled with lower operating reserve revenue, and
- a net decrease of $10 million in electricity sold under our BGS contracts due primarily to lower volumes as a result of milder weather, partially offset by higher average prices.

Gas Supply Revenues decreased $248 million due primarily to

- a decrease of $241 million in sales under the BGSS contract, substantially comprised of lower sales volumes due to warmer average temperatures in the 2016 winter heating season, coupled with lower average sales prices, and
- a net decrease of $7 million in sales to third party customers, of which $45 million was due to lower average prices, partially offset by $38 million of higher volumes sold.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $188 million due to

Generation costs decreased $67 million due primarily to

- lower fuel costs of $287 million reflecting lower average realized prices for natural gas and the utilization of lower volumes of fuel,
- partially offset by higher congestion costs in PJM of $137 million, mainly as a result of credits received in the prior year due to extremely cold winter weather,
- a $62 million charge associated with the announced early retirement of the Mercer and Hudson units, primarily related to a coal inventory write-down of $57 million, and
- a net increase of $15 million due to lower MTM gains in 2016 as compared to 2015. Of this amount, $10 million was due to lower gains on positions reclassified to realized upon settlement this year compared to last year.

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Gas costs decreased $121 million mainly related to

- a decrease of $142 million related to sales under the BGSS contract due primarily to lower volumes sold due to warmer average temperatures during the 2016 winter heating season and lower average gas costs,
- partially offset by a net increase of $21 million related to sales to third parties due primarily to an increase in volumes sold.

Operation and Maintenance increased $59 million due primarily to

- $145 million of insurance recoveries received in 2015 related to Superstorm Sandy,
- $48 million of charges related to early retirement of the Hudson and Mercer units,
- partially offset by a net decrease of $75 million related to our fossil plants, largely due to higher costs incurred in 2015 for our planned major outages at the Bethlehem Energy Center and Bergen generating plants, and
- a net decrease of $58 million related to our nuclear plants due primarily to a planned outage at our 100%-owned Hope Creek plant and our 50%-owned Peach Bottom plant in 2015, partly offset in 2016 by an extended refueling outage at our 57%-owned Salem Unit 1 plant.

Depreciation and Amortization increased $19 million due primarily to

- a $12 million increase due primarily to a higher nuclear asset base,
- $4 million of accelerated depreciation on asset retirement costs from previously retired assets at the Hudson and Mercer plants, and
- $3 million of higher depreciation due to new solar projects.

Other Income (Deductions) decreased $36 million due primarily to $28 million of insurance recoveries received in 2015 related to Superstorm Sandy and lower net realized gains from the NDT Fund in 2016.

Other-Than-Temporary Impairments decreased $20 million due to lower impairments of equity securities in the NDT Fund in 2016.

Interest Expense decreased $28 million due primarily to higher capitalized interest in 2016 and the maturity of $300 million of 5.50% Senior Notes in December 2015, partially offset by the issuance of $700 million of 3.00% Senior Notes in June 2016.

Income Tax Expense decreased $237 million in 2016 due primarily to lower pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

We expect operating cash flows combined with cash on hand and financing activities to be sufficient to fund planned capital expenditures and shareholder dividend payments.

For the nine months ended September 30, 2016, our operating cash flow decreased $467 million as compared to the same period in 2015. The net change was due primarily to the net changes from PSE&G and Power as discussed below.

PSE&G

PSE&G's operating cash flow decreased $117 million from $1,518 million to $1,401 million for the nine months ended September 30, 2016, as compared to the same period in 2015, due primarily to a decrease of $113 million due to a change in regulatory deferrals, a $64 million decrease due to higher vendor payments and a decrease due to the completion of securitization collections in 2015. These amounts were partially offset by higher earnings and higher tax refunds in 2016.

Power

Power's operating cash flow decreased $298 million from $1,558 million to $1,260 million for the nine months ended September 30, 2016, as compared to the same period in 2015, primarily due to lower earnings, a $140 million decrease from fuels, materials and supplies, and a $146 million increase in margin deposit requirements, partially offset by a reduction in tax payments.

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Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of September 30, 2016 were as follows:

	As of September 30, 2016		
Company/Facility	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$ 1,000	$ 265	$ 735
PSE&G	600	14	586
Power	2,553	205	2,348
Total	**$ 4,153**	**$ 484**	**$ 3,669**

As of September 30, 2016, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating, which would represent a three level downgrade from its current S&P and Moody's ratings. In the event of a deterioration of Power's credit rating certain of Power's agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $807 million and $864 million as of September 30, 2016 and December 31, 2015, respectively. The early retirement of Power's Hudson and Mercer coal/gas generation units is not expected to have a material impact on Power's debt covenant ratios or its ability to obtain credit facilities. See Item 1. Note 3. Early Plant Retirements.

As of September 30, 2016, PSEG's credit facilities are primarily available to back-stop its Commercial Paper Program under which PSEG had $255 million outstanding. PSE&G's credit facility primary use is to support its Commercial Paper Program under which as of September 30, 2016, no amounts were outstanding. Most of our credit facilities expire in 2019 and 2020.

For additional information, see Item 1.Note 10. Debt and Credit Facilities.

Long-Term Debt Financing

For a discussion of our long-term debt transactions during 2016, see Item 1. Note 10. Debt and Credit Facilities.

Common Stock Dividends

On July 19, 2016, our Board of Directors approved a quarterly dividend of $0.41 per share of common stock for the third quarter of 2016. This reflects an indicative annual dividend rate of $1.64 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 1. Note 16. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In January 2016, S&P published updated research reports on PSEG and PSE&G and the existing ratings and outlooks were unchanged. In June 2016, Moody's published credit opinions on Power and PSE&G and the existing ratings and outlooks were

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unchanged. In June 2016, S&P published an updated research report on Power and the existing rating and outlook were unchanged. In September 2016, Moody's published an updated research report on PSEG and the existing rating and outlook were unchanged.

	Moody's (A)	S&P (B)
PSEG		
Outlook	**Positive**	**Stable**
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities. The Corporate Credit Rating outlook does not apply to PSEG's or PSE&G's Commercial Paper Rating or PSE&G's Mortgage Bond rating.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures at Power and Services as compared to amounts disclosed in our 2015 Form 10-K.

PSEG

In July 2016, PSEG partnered with Vectren Corporation on a FERC 1000 proposal to construct, own and operate a twenty mile, 345 kilovolt transmission line in the midwest region served by the Midcontinent Independent System Operator (MISO). MISO estimated the project would cost approximately $60 million and would go in service in 2021. MISO is expected to select a proposal in December 2016. This project is not included in PSEG's projected capital expenditures.

PSE&G

PSE&G increased its estimate of its capital expenditure program as reported in our 2015 Form 10-K by approximately $300 million from $8.3 billion to $8.6 billion primarily to address new business requests and replace aging equipment and infrastructure.

In August 2016, PSE&G filed a petition with the BPU requesting approval of the $268 million investment and an associated cost recovery mechanism to develop a project where PSE&G would rebuild New Jersey Transit's Mason substation and related facilities in Kearny, NJ. This is not included in PSE&G's projected capital expenditures.

On October 20, 2016, PSE&G submitted a settlement agreement to the BPU providing for an extension of the existing landfill/brownfield solar program to construct up to 33 MW of grid connected facilities with projected capital expenditures of approximately $80 million through May 2020. This extension is pending approval by the BPU. This is not included in PSE&G's projected capital expenditures.

During the nine months ended September 30, 2016, PSE&G made capital expenditures of $2,035 million, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $109 million, which are included in operating cash flows.

Power

During the nine months ended September 30, 2016, Power made capital expenditures of $767 million, excluding $156 million for nuclear fuel, primarily related to our Keys, Sewaren 7, BH5 and other generation projects.

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ACCOUNTING MATTERS

For information related to recent accounting matters, see Item 1. Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From July through September 2016, MTM VaR remained relatively stable between low of $11 million to high of $16 million at 95% confidence level. The range of VaR was narrower for the three months ended September 30, 2016 as compared with the year ended December 31, 2015.

	MTM VaR	
	Three Months Ended September 30, 2016	Year Ended December 31, 2015
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 11	$ 24
Average for the Period	$ 13	$ 17
High	$ 16	$ 40
Low	$ 11	$ 8
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 17	$ 38
Average for the Period	$ 21	$ 26
High	$ 25	$ 63
Low	$ 17	$ 12

See Item 1. Note 11. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, Public Service Electric and Gas Company and PSEG Power LLC have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

There have been no changes in internal control over financial reporting that occurred during the third quarter of 2016 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2015 Annual Report on Form 10-K, see Part I, Item 1. Note 9. Commitments and Contingent Liabilities and Item 5. Other Information.

Ewing Explosion

In February 2014, pursuant to an existing contract, PSE&G assigned Henkels and McCoy (Henkels) to replace the electrical service at a home in the South Fork Townhouse Community in Ewing Township, Mercer County, New Jersey. In March 2014, after Henkels began work to install new electric service, a gas explosion occurred in the townhouse community resulting in damage to numerous properties, personal injuries and one fatality.

Twenty-two lawsuits have been filed to date relating to the gas explosion, of which PSE&G was named as a defendant in nineteen cases. To date, six of these cases have resolved through private negotiations and/or mediation. In one of the remaining pending matters, plaintiffs representing the estate of the decedent are seeking damages under the New Jersey Wrongful Death Act and the New Jersey Survivors Act as well as punitive damages. PSE&G has denied all allegations of liability. We intend to continue to vigorously defend these lawsuits. At this stage of the litigation, we are unable to determine or predict the ultimate outcome of any of the remaining lawsuits.

ITEM 1A. RISK FACTORS

There are no additional Risk Factors to be added to those disclosed in Part I, Item 1A of our 2015 Annual Report on Form 10-K.

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ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the third quarter of 2016.

Three Months Ended September 30, 2016	Total Number of Shares Purchased	Average Price Paid per Share
July 1 - July 31	—	$ —
August 1 - August 31	167,430	$ 45.21
September 1- September 30	43,000	$ 42.85

ITEM 5. OTHER INFORMATION

Certain information reported in the 2015 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2015 Annual Report on Form 10-K and the Quarterly Reports on Form 10-Q for the quarters ended March 31, 2016 and June 30, 2016. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

Federal Regulation

FERC

Capacity Market Issues-PJM

December 31, 2015 Form 10-K page 17, March 31, 2016 Form 10-Q page 70 and June 30, 2016 Form 10-Q page 80. Over the past several years, certain entities in PJM, namely, FirstEnergy Corp. (FE) and American Electric Power (AEP) have been looking to the Ohio Public Utility Commission (PUCO) to provide financial support arrangements for their coal plants and a nuclear plant (FE). FE and AEP originally proposed to enter into power purchase agreements (PPAs) with their non-utility generation affiliates providing for above-market purchases from certain coal plants and a nuclear plant (in FE's case). The PUCO Staff proposed a payment to support modernization of the distribution system (distribution modernization rider) in the FE case which was ultimately accepted by the PUCO. The Dayton Power and Light Company also recently filed for a distribution modernization rider for the generating plants that it owns.

The PUCO proceedings created a concern that subsidized units within the PJM footprint would submit bids in the capacity market that are not reflective of their actual operating costs and would, in turn, artificially suppress capacity prices. As a result, certain parties requested that FERC should direct PJM to expand the “minimum offer price rule” to apply to existing units.

We are unable to predict the results of these pending proceedings or any future related proceedings or to calculate the potential impacts on our business.

Transmission Regulation

December 31, 2015 Form 10-K page 19 and June 30, 2016 Form 10-Q page 80. In October 2016, PSE&G filed its 2017 Annual Formula Rate Update with FERC which requests approximately $121 million in increased annual transmission revenues effective January 1, 2017, subject to true-up. For additional information about our transmission formula rate, see Part 1, Item 1. Financial Information—Note 5. Recent Rate Filings.

Transmission Regulation—Transmission Policy Developments

December 31, 2015 Form 10-K page 19, March 31, 2016 Form 10-Q page 71 and June 30, 2016 Form 10-Q page 80. FERC concluded in Order 1000 that the incumbent transmission owner should not always have a Right of First Refusal (ROFR) to construct and own transmission projects in its service territory. We and other companies appealed various aspects of the FERC order approving PJM’s implementation of Order 1000, including the elimination of the ROFR from the PJM Tariff. In July 2016, the D.C. Court dismissed the case, thus upholding FERC’s determination. We have decided not to pursue further action on this decision.

In April 2016, PSE&G accepted construction responsibility for the three components of the transmission project involving upgrades at Artificial Island in New Jersey. On August 5, 2016, PJM announced that it has suspended the Artificial Island transmission project and is performing a comprehensive analysis to determine a future course of action, which is expected to be completed by February 2017.

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In August 2016, FERC issued an order to PJM and the PJM Transmission Owners with respect to their compliance with a previous FERC order (Order 890) that requires transparency in the transmission planning process. The order directs PJM and PJM Transmission Owners to propose revisions to the PJM governing documents to ensure compliance with Order 890 or show cause why they should not do so. The PJM Transmission Owners jointly filed for rehearing of the order to show cause and jointly responded to FERC's directives. FERC is also evaluating issues related to competitive transmission development processes, including the use of cost containment provisions. PSE&G has argued against the use of cost caps in the assessment of Order 1000 open window project bids. We are unable to predict at this time the results of these proceedings and the impact they will have on our business.

State Regulation

Solar 4 All Program Extension II

On October 20, 2016, PSE&G submitted a settlement agreement to the BPU providing for an extension of the existing landfill/brownfield solar program to construct up to 33 MW of grid connected facilities with projected capital expenditures of approximately $80 million through May 2020. This matter is pending approval by the BPU.

Environmental Matters

Air Pollution Control

Cross-State Air Pollution Rule (CSAPR)

December 31, 2015 Form 10-K page 24. In September 2016, the EPA published the final CSAPR Updating Rule to address the 2008 National Ambient Air Quality Standards for ground-level ozone. The rule establishes more stringent annual ozone season (May 1 through September 30) caps beginning in May 2017. We do not anticipate any material impact on our business or financial condition due to the CSAPR.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. PSE&G:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. Power:

Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
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Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 31, 2016

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 31, 2016

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 31, 2016

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2016	2015	2015	2014	2013	2012	2011
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,547	$ 2,239	$ 2,680	$ 2,456	$ 2,055	$ 2,011	$ 2,384
(Income) Loss from Equity Investees, net of Distributions	5	4	3	4	(7)	9	(4)
Fixed Charges	354	335	457	450	458	479	522
Capitalized Interest	(32)	(10)	(18)	(16)	(16)	(19)	(14)
Total Earnings	$ 1,874	$ 2,568	$ 3,122	$ 2,894	$ 2,490	$ 2,480	$ 2,888
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 339	$ 321	$ 437	$ 430	$ 442	$ 465	$ 509
Interest Factor in Rentals	15	14	20	20	16	14	13
Total Fixed Charges	$ 354	$ 335	$ 457	$ 450	$ 458	$ 479	$ 522
Ratio of Earnings to Fixed Charges	**5.29**	**7.67**	**6.83**	**6.43**	**5.44**	**5.18**	**5.53**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Nine Months Ended September 30,		Years Ended December 31,				
	2016	**2015**	**2015**	**2014**	**2013**	**2012**	**2011**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,089	$ 1,029	$1,257	$1,174	$ 993	$ 835	$ 861
Fixed Charges	234	222	306	303	316	314	319
Capitalized Interest	(12)	(13)	(17)	(16)	(16)	(13)	(4)
Total Earnings	$ 1,311	$ 1,238	$1,546	$1,461	$ 1,293	$1,136	$1,176
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 226	$ 216	$ 297	$ 293	$ 309	$ 308	$ 314
Interest Factor in Rentals	8	6	9	10	7	6	5
Total Fixed Charges	$ 234	$ 222	$ 306	$ 303	$ 316	$ 314	$ 319
Ratio of Earnings to Fixed Charges	**5.60**	**5.58**	**5.05**	**4.82**	**4.09**	**3.62**	**3.69**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period, (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries, and (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.2

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2016	**2015**	**2015**	**2014**	**2013**	**2012**	**2011**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 528	$ 1,152	$1,367	$1,251	$1,063	$1,099	$1,703
(Income) Loss from Equity Investees, net of Distributions	5	2	1	3	(10)	(6)	(12)
Fixed Charges	108	115	152	150	143	164	208
Capitalized Interest	(20)	2	(1)	1	1	(6)	(10)
Total Earnings	$ 621	$ 1,271	$1,519	$1,405	$1,197	$1,251	$1,889
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 105	$ 112	$ 148	$ 146	$ 139	$ 161	$ 205
Interest Factor in Rentals	3	3	4	4	4	3	3
Total Fixed Charges	$ 108	$ 115	$ 152	$ 150	$ 143	$ 164	$ 208
Ratio of Earnings to Fixed Charges	**5.75**	**11.05**	**9.99**	**9.37**	**8.37**	**7.63**	**9.08**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2016

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

S1-SSA-0009 - 19150

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2016

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2016

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2016

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
October 31, 2016

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
October 31, 2016

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
October 31, 2016

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
October 31, 2016

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
October 31, 2016

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2016 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
October 31, 2016

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2017
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐

If any of the registrants is an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of October 17, 2017, Public Service Enterprise Group Incorporated had outstanding 506,038,791 shares of its sole class of Common Stock, without par value.

As of October 17, 2017, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K. These factors include, but are not limited to:

- fluctuations in wholesale power and natural gas markets, including the potential impacts on the economic viability of our generation units;
- our ability to obtain adequate fuel supply;
- any inability to manage our energy obligations with available supply;
- increases in competition in wholesale energy and capacity markets;
- changes in technology related to energy generation, distribution and consumption and customer usage patterns;
- economic downturns;
- third-party credit risk relating to our sale of generation output and purchase of fuel;
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements;
- changes in state and federal legislation and regulations;
- the impact of pending rate case proceedings;
- regulatory, financial, environmental, health and safety risks associated with our ownership and operation of nuclear facilities;
- adverse changes in energy industry laws, policies and regulations, including market structures and transmission planning;
- changes in federal and state environmental regulations and enforcement;
- delays in receipt of, or an inability to receive, necessary licenses and permits;
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry;
- changes in tax laws and regulations;
- the impact of our holding company structure on our ability to meet our corporate funding needs, service debt and pay dividends;
- lack of growth or slower growth in the number of customers or changes in customer demand;
- any inability of Power to meet its commitments under forward sale obligations;
- reliance on transmission facilities that we do not own or control and the impact on our ability to maintain adequate transmission capacity;
- any inability to successfully develop or construct generation, transmission and distribution projects;
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers;
- our inability to exercise control over the operations of generation facilities in which we do not maintain a controlling interest;

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- any inability to maintain sufficient liquidity;
- any inability to realize anticipated tax benefits or retain tax credits;
- challenges associated with recruitment and/or retention of key executives and a qualified workforce;
- the impact of our covenants in our debt instruments on our operations; and
- the impact of acts of terrorism, cybersecurity attacks or intrusions.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business, prospects, financial condition, results of operations or cash flows. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even in light of new information or future events, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

FILING FORMAT

This combined Quarterly Report on Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to “we,” “us,” and “our” relate to PSEG or to the specific company or companies being discussed.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
OPERATING REVENUES	$ 2,263	$ 2,450	$ 6,988	$ 6,971
OPERATING EXPENSES				
Energy Costs	638	866	2,100	2,326
Operation and Maintenance	680	776	2,100	2,215
Depreciation and Amortization	252	231	1,721	679
Total Operating Expenses	1,570	1,873	5,921	5,220
OPERATING INCOME	693	577	1,067	1,751
Income from Equity Method Investments	3	3	11	9
Other Income	66	47	208	139
Other Deductions	(10)	(8)	(30)	(39)
Other-Than-Temporary Impairments	(5)	(5)	(9)	(25)
Interest Expense	(100)	(99)	(289)	(288)
INCOME BEFORE INCOME TAXES	647	515	958	1,547
Income Tax Expense	(252)	(188)	(340)	(562)
NET INCOME	$ 395	$ 327	$ 618	$ 985
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	505	505	505	505
DILUTED	507	508	507	508
NET INCOME PER SHARE:				
BASIC	$ 0.78	$ 0.65	$ 1.22	$ 1.95
DILUTED	$ 0.78	$ 0.64	$ 1.22	$ 1.94
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.43	$ 0.41	$ 1.29	$ 1.23

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
NET INCOME	$ 395	$ 327	$ 618	$ 985
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(15), $(24), $(40) and $(50) for the three and nine months ended 2017 and 2016, respectively	17	24	42	50
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $0, $0 and $(1) for the three and nine months ended 2017 and 2016, respectively	(1)	1	(1)	2
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(4), $(5), $(12) and $(17) for the three and nine months ended 2017 and 2016, respectively	6	9	18	25
Other Comprehensive Income (Loss), net of tax	22	34	59	77
COMPREHENSIVE INCOME	$ 417	$ 361	$ 677	$ 1,062

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$ 278	$ 423
Accounts Receivable, net of allowances of $59 in 2017 and $68 in 2016	1,022	1,161
Tax Receivable	127	78
Unbilled Revenues	176	260
Fuel	348	326
Materials and Supplies, net	588	561
Prepayments	200	76
Derivative Contracts	84	163
Regulatory Assets	239	199
Other	19	7
Total Current Assets	3,081	3,254
PROPERTY, PLANT AND EQUIPMENT	39,916	39,337
Less: Accumulated Depreciation and Amortization	(9,383)	(10,051)
Net Property, Plant and Equipment	30,533	29,286
NONCURRENT ASSETS		
Regulatory Assets	3,336	3,319
Long-Term Investments	936	1,050
Nuclear Decommissioning Trust (NDT) Fund	2,012	1,859
Long-Term Tax Receivable	—	104
Long-Term Receivable of Variable Interest Entity (VIE)	599	589
Other Special Funds	229	217
Goodwill	16	16
Other Intangibles	88	98
Derivative Contracts	62	24
Other	265	254
Total Noncurrent Assets	7,543	7,530
TOTAL ASSETS	$ 41,157	$ 40,070

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	September 30, 2017	December 31, 2016
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 1,250	$ 500
Commercial Paper and Loans	202	388
Accounts Payable	1,305	1,459
Derivative Contracts	7	13
Accrued Interest	136	97
Accrued Taxes	146	31
Clean Energy Program	184	142
Obligation to Return Cash Collateral	132	132
Regulatory Liabilities	44	88
Other	425	426
Total Current Liabilities	3,831	3,276
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	8,931	8,658
Regulatory Liabilities	89	118
Asset Retirement Obligations	748	726
OPEB Costs	1,301	1,324
OPEB Costs of Servco	474	452
Accrued Pension Costs	504	568
Accrued Pension Costs of Servco	113	128
Environmental Costs	399	401
Derivative Contracts	1	3
Long-Term Accrued Taxes	173	180
Other	195	211
Total Noncurrent Liabilities	12,928	12,769
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT	11,274	10,895
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2017 and 2016—534 shares	4,938	4,936
Treasury Stock, at cost, 2017 and 2016—29 shares	(750)	(717)
Retained Earnings	9,140	9,174
Accumulated Other Comprehensive Loss	(204)	(263)
Total Stockholders' Equity	13,124	13,130
Total Capitalization	24,398	24,025
TOTAL LIABILITIES AND CAPITALIZATION	$ 41,157	$ 40,070

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19168

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, October 31, 2017 Powered by Morningstar® Document Research℠
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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2017	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 618	$ 985
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,721	679
Amortization of Nuclear Fuel	152	154
Renewable Energy Credit (REC) Compliance Accrual	79	87
Impairment Costs for Early Plant Retirements	—	102
Provision for Deferred Income Taxes (Other than Leases) and ITC	227	445
Non-Cash Employee Benefit Plan Costs	67	95
Leveraged Lease (Income) Loss, Adjusted for Rents Received and Deferred Taxes	(7)	(12)
Net (Gain) Loss on Lease Investments	48	86
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	8	96
Net Change in Regulatory Assets and Liabilities	(121)	(72)
Cost of Removal	(72)	(109)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(86)	(12)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	64	282
Accrued Taxes	115	202
Margin Deposit	64	(4)
Other Current Assets and Liabilities	(69)	(229)
Employee Benefit Plan Funding and Related Payments	(64)	(81)
Other	(10)	67
Net Cash Provided By (Used In) Operating Activities	2,734	2,761
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(3,046)	(2,985)
Purchase of Emissions Allowances and RECs	(90)	(77)
Proceeds from Sales of Available-for-Sale Securities	1,013	551
Investments in Available-for-Sale Securities	(1,029)	(576)
Other	48	33
Net Cash Provided By (Used In) Investing Activities	(3,104)	(3,054)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(186)	(109)
Issuance of Long-Term Debt	1,125	1,975
Redemption of Long-Term Debt	—	(824)
Cash Dividends Paid on Common Stock	(652)	(622)
Other	(62)	(71)
Net Cash Provided By (Used In) Financing Activities	225	349
Net Increase (Decrease) in Cash and Cash Equivalents	(145)	56
Cash and Cash Equivalents at Beginning of Period	423	394
Cash and Cash Equivalents at End of Period	$ 278	$ 450
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (16)	$ (274)
Interest Paid, Net of Amounts Capitalized	$ 261	$ 252
Accrued Property, Plant and Equipment Expenditures	$ 604	$ 579

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
OPERATING REVENUES	$ 1,509	$ 1,684	$ 4,689	$ 4,746
OPERATING EXPENSES				
Energy Costs	535	721	1,760	1,979
Operation and Maintenance	346	376	1,064	1,110
Depreciation and Amortization	169	137	506	412
Total Operating Expenses	1,050	1,234	3,330	3,501
OPERATING INCOME	459	450	1,359	1,245
Other Income	23	22	70	61
Other Deductions	(1)	(1)	(3)	(3)
Interest Expense	(79)	(72)	(223)	(214)
INCOME BEFORE INCOME TAXES	402	399	1,203	1,089
Income Tax Expense	(156)	(144)	(450)	(393)
NET INCOME	$ 246	$ 255	$ 753	$ 696

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19171

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
NET INCOME	$ 246	$ 255	$ 753	$ 696
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0, $1 and $0 for the three and nine months ended 2017 and 2016, respectively	—	—	(1)	1
COMPREHENSIVE INCOME	$ 246	$ 255	$ 752	$ 697

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19172

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, October 31, 2017
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$ 239	$ 390
Accounts Receivable, net of allowances of $59 in 2017 and $68 in 2016	762	810
Accounts Receivable—Affiliated Companies	—	76
Unbilled Revenues	176	260
Materials and Supplies	196	180
Prepayments	115	9
Regulatory Assets	239	199
Other	18	6
Total Current Assets	1,745	1,930
PROPERTY, PLANT AND EQUIPMENT	28,301	26,347
Less: Accumulated Depreciation and Amortization	(6,019)	(5,760)
Net Property, Plant and Equipment	22,282	20,587
NONCURRENT ASSETS		
Regulatory Assets	3,336	3,319
Long-Term Investments	283	299
Other Special Funds	46	43
Other	110	110
Total Noncurrent Assets	3,775	3,771
TOTAL ASSETS	$ 27,802	$ 26,288

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19173

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, October 31, 2017
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	September 30, 2017	December 31, 2016
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 750	$ —
Accounts Payable	624	718
Accounts Payable—Affiliated Companies	178	260
Accrued Interest	89	76
Clean Energy Program	184	142
Derivative Contracts	—	5
Obligation to Return Cash Collateral	132	132
Regulatory Liabilities	44	88
Other	278	296
Total Current Liabilities	2,279	1,717
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	6,408	5,873
OPEB Costs	977	1,009
Accrued Pension Costs	209	250
Regulatory Liabilities	89	118
Environmental Costs	325	332
Asset Retirement Obligations	216	213
Long-Term Accrued Taxes	83	130
Other	109	116
Total Noncurrent Liabilities	8,416	8,041
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT	7,493	7,818
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2017 and 2016—132 shares	892	892
Contributed Capital	1,095	945
Basis Adjustment	986	986
Retained Earnings	6,641	5,888
Accumulated Other Comprehensive Income	—	1
Total Stockholder's Equity	9,614	8,712
Total Capitalization	17,107	16,530
TOTAL LIABILITIES AND CAPITALIZATION	$ 27,802	$ 26,288

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2017	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 753	$ 696
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	506	412
Provision for Deferred Income Taxes and ITC	497	482
Non-Cash Employee Benefit Plan Costs	37	55
Cost of Removal	(72)	(109)
Net Change in Other Regulatory Assets and Liabilities	(121)	(72)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	136	2
Materials and Supplies	(13)	(42)
Prepayments	(106)	(63)
Accounts Payable	(37)	(30)
Accounts Receivable/Payable—Affiliated Companies, net	(61)	154
Other Current Assets and Liabilities	(12)	(6)
Employee Benefit Plan Funding and Related Payments	(55)	(64)
Other	(59)	(14)
Net Cash Provided By (Used In) Operating Activities	1,393	1,401
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(2,118)	(2,035)
Proceeds from Sales of Available-for-Sale Securities	33	16
Investments in Available-for-Sale Securities	(34)	(17)
Solar Loan Investments	(2)	—
Other	7	6
Net Cash Provided By (Used In) Investing Activities	(2,114)	(2,030)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	—	(153)
Issuance of Long-Term Debt	425	1,275
Redemption of Long-Term Debt	—	(271)
Contributed Capital	150	—
Other	(5)	(14)
Net Cash Provided By (Used In) Financing Activities	570	837
Net Increase (Decrease) In Cash and Cash Equivalents	(151)	208
Cash and Cash Equivalents at Beginning of Period	390	198
Cash and Cash Equivalents at End of Period	$ 239	$ 406
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ (107)	$ (279)
Interest Paid, Net of Amounts Capitalized	$ 208	$ 194
Accrued Property, Plant and Equipment Expenditures	$ 363	$ 404

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19175

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
OPERATING REVENUES	$ 873	$ 1,075	$ 3,086	$ 3,102
OPERATING EXPENSES				
Energy Costs	357	462	1,461	1,481
Operation and Maintenance	227	289	711	807
Depreciation and Amortization	76	86	1,191	245
Total Operating Expenses	660	837	3,363	2,533
OPERATING INCOME (LOSS)	213	238	(277)	569
Income from Equity Method Investments	3	3	11	9
Other Income	43	23	127	74
Other Deductions	(8)	(6)	(22)	(33)
Other-Than-Temporary Impairments	(5)	(5)	(9)	(25)
Interest Expense	(12)	(24)	(41)	(66)
INCOME (LOSS) BEFORE INCOME TAXES	234	229	(211)	528
Income Tax Benefit (Expense)	(98)	(90)	80	(208)
NET INCOME (LOSS)	$ 136	$ 139	$ (131)	$ 320

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19176

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
NET INCOME (LOSS)	$ 136	$ 139	$ (131)	$ 320
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(14), $(23), $(41) and $(48) for the three and nine months ended 2017 and 2016, respectively	15	22	44	47
Pension/OPEB adjustment, net of tax (expense) benefit of $(4), $(5), $(11) and $(15) for the three and nine months ended 2017 and 2016, respectively	5	7	15	21
Other Comprehensive Income (Loss), net of tax	20	29	59	68
COMPREHENSIVE INCOME (LOSS)	$ 156	$ 168	$ (72)	$ 388

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2017	December 31, 2016
CURRENT ASSETS		
Cash and Cash Equivalents	$ 22	$ 11
Accounts Receivable	206	276
Accounts Receivable—Affiliated Companies	86	205
Short-Term Loan to Affiliate	1	87
Fuel	348	326
Materials and Supplies, net	391	381
Derivative Contracts	84	162
Prepayments	20	10
Other	4	2
Total Current Assets	1,162	1,460
PROPERTY, PLANT AND EQUIPMENT	11,256	12,655
Less: Accumulated Depreciation and Amortization	(3,184)	(4,135)
Net Property, Plant and Equipment	8,072	8,520
NONCURRENT ASSETS		
NDT Fund	2,012	1,859
Long-Term Investments	90	102
Goodwill	16	16
Other Intangibles	88	98
Other Special Funds	57	53
Derivative Contracts	62	24
Other	72	61
Total Noncurrent Assets	2,397	2,213
TOTAL ASSETS	$ 11,631	$ 12,193

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19178

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, October 31, 2017
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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2017	December 31, 2016
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$ 499	$ 539
Accounts Payable—Affiliated Companies	128	25
Derivative Contracts	7	8
Accrued Interest	43	20
Other	87	88
Total Current Liabilities	764	680
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	1,962	2,170
Asset Retirement Obligations	530	511
OPEB Costs	258	251
Derivative Contracts	1	3
Accrued Pension Costs	174	191
Long-Term Accrued Taxes	57	77
Other	123	129
Total Noncurrent Liabilities	3,105	3,332
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
LONG-TERM DEBT	2,385	2,382
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,301	4,782
Accumulated Other Comprehensive Loss	(152)	(211)
Total Member's Equity	5,377	5,799
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 11,631	$ 12,193

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19179

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2017	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income (Loss)	$ (131)	$ 320
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	1,191	245
Amortization of Nuclear Fuel	152	154
Provision for Deferred Income Taxes and ITC	(259)	(34)
Interest Accretion on Asset Retirement Obligation	23	20
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	8	96
Impairment Costs for Early Plant Retirements	—	102
Renewable Energy Credit (REC) Compliance Accrual	79	87
Non-Cash Employee Benefit Plan Costs	21	28
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(86)	(12)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	(32)	(27)
Margin Deposit	64	(4)
Accounts Receivable	19	(11)
Accounts Payable	(32)	(29)
Accounts Receivable/Payable—Affiliated Companies, net	205	235
Other Current Assets and Liabilities	11	20
Employee Benefit Plan Funding and Related Payments	(5)	(10)
Other	21	80
Net Cash Provided By (Used In) Operating Activities	1,249	1,260
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(903)	(923)
Purchase of Emissions Allowances and RECs	(90)	(77)
Proceeds from Sales of Available-for-Sale Securities	886	490
Investments in Available-for-Sale Securities	(900)	(512)
Short-Term Loan—Affiliated Company, net	86	(151)
Other	37	22
Net Cash Provided By (Used In) Investing Activities	(884)	(1,151)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Long-Term Debt	—	700
Cash Dividend Paid	(350)	(250)
Redemption of Long-Term Debt	—	(553)
Other	(4)	(6)
Net Cash Provided By (Used In) Financing Activities	(354)	(109)
Net Increase (Decrease) in Cash and Cash Equivalents	11	—
Cash and Cash Equivalents at Beginning of Period	11	12
Cash and Cash Equivalents at End of Period	$ 22	$ 12
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 75	$ (7)
Interest Paid, Net of Amounts Capitalized	$ 30	$ 51
Accrued Property, Plant and Equipment Expenditures	$ 241	$ 175

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

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Note 1. Organization and Basis of Presentation

Organization

Public Service Enterprise Group Incorporated (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Public Service Electric and Gas Company (PSE&G)**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and related programs in New Jersey, which are regulated by the BPU.
- **PSEG Power LLC (Power)**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) electric transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2016.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2016.

Note 2. Recent Accounting Standards

New Standard Issued and Adopted

Business Combinations: Clarifying the Definition of a Business

This accounting standard was issued mainly to provide more consistency in how the definition of a business is applied to acquisitions or dispositions. The new guidance will generally reduce the number of transactions that will require treatment as a business combination. The definition of a business now includes consideration of whether substantially all the fair value of the gross assets acquired or disposed of is concentrated in a single identifiable asset or a group of similar identifiable assets. If this condition is met, the transaction would not qualify as a business.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt it for transactions that have closed before the effective date but have not been reported in financial statements that have been issued or made available for issuance. PSEG adopted this standard in the third quarter 2017 with the acquisition of a solar project. This standard upon adoption had no impact on PSEG's financial statements.

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New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard clarifies the principles for recognizing revenue and removes inconsistencies in revenue recognition requirements; improves comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provides improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early application is permitted. PSEG expects the new guidance to result in more detailed disclosures of revenue compared to current guidance and possible changes in presentation. Included in the scope of the new standard are PSE&G's regulated revenue recorded under tariffs, including the sale of default supply of electric and gas commodity, and the distribution of electricity and gas to retail residential and commercial and industrial customers, and transmission revenues. The tariff revenue comprises substantially all of PSE&G's revenue. PSEG expects no material change in revenue recognition of PSE&G's regulated revenue recorded under tariffs. PSE&G's revenue from contracts with customers will continue to be recorded as electricity or gas is delivered to the customer. PSEG continues to evaluate contracts under its other revenue streams.

Certain implementation issues are currently being finalized by the AICPA's Financial Reporting Executive Committee, including the ability to recognize revenue for certain contracts where there is uncertainty regarding collection from customers and accounting for contributions in aid of construction. While those issues are out for comment, based on tentative conclusions PSEG does not expect any material changes to its revenue due to those issues. PSEG will adopt this standard on January 1, 2018 and anticipates electing the full retrospective method of transition. Under this method, PSEG will restate its prior period financial statements to align with the 2018 presentation. Certain reclassifications may affect revenue and expense due to the application of this standard; however, PSEG does not anticipate any material impact to net income.

Recognition and Measurement of Financial Assets and Financial Liabilities

This accounting standard will change how entities measure equity investments that are not consolidated or accounted for under the equity method. Under the new guidance, equity investments (other than those accounted for using the equity method) will be measured at fair value through Net Income instead of Other Comprehensive Income (Loss). Entities that have elected the fair value option for financial liabilities will present changes in fair value due to a change in their own credit risk through Other Comprehensive Income (Loss). For equity investments which do not have readily determinable fair values, the impairment assessment will be simplified by requiring a qualitative assessment to identify impairments. The new standard also changes certain disclosures.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG expects to record a cumulative effect adjustment by reclassifying the after-tax net unrealized gain (loss) related to equity investments from Accumulated Other Comprehensive Income to Retained Earnings as of January 1, 2018, and expects increased volatility in Net Income due to changes in fair value of its equity securities within the nuclear decommissioning (NDT) and Rabbi Trust Funds.

Leases

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor will classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. However, existing guidance related to leveraged leases will not change.

The standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities

This accounting standard's amendments more closely align hedge accounting with the companies' risk management activities in the financial statements. The amendments expand hedge accounting for both non-financial and financial risk components by

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permitting contractually specified components to designate as the hedged risk in a cash flow hedge involving the purchase or sale of non-financial assets or variable rate financial instruments. Additionally, the amendments ease the operational burden of applying hedge accounting by allowing more time to prepare hedge documentation, and allow effectiveness assessments to be performed on a qualitative basis after hedge inception.

The new guidance is effective for annual and interim periods beginning after December 15, 2018. The standard requires using a modified retrospective method upon adoption. Early adoption is permitted. PSEG is currently analyzing the impact of this standard on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments

This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however, this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments

This accounting standard reduces the diversity in practice in how certain cash receipts and cash payments are presented and classified in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt early, including in an interim period. PSEG does not anticipate any current impact on PSEG's financial statements. PSEG will adopt this standard as of January 1, 2018 using a retrospective transition method to each period presented.

Statement of Cash Flows: Restricted Cash

This accounting standard requires entities to explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents, either in a narrative or a tabular format. Amounts generally described as restricted cash or restricted cash equivalents should be included in entities' reconciliation of beginning-of-period and end-of-period amounts in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt early, including in an interim period. PSEG plans to adopt this standard on January 1, 2018 using a retrospective transition method for each period presented. PSEG will continue the current balance sheet classification of restricted cash or restricted cash equivalents. PSEG will provide a reconciliation of cash and cash equivalents and restricted cash or restricted cash equivalents and include a description of these amounts.

Simplifying the Test for Goodwill Impairment

This accounting standard requires an entity to perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

An entity should apply this standard on a prospective basis and will be required to disclose the nature of and reason for the change in accounting principle upon transition. The new standard is effective for impairment tests for periods beginning January 1, 2020. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. PSEG is currently assessing the impact of this guidance upon its financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (OPEB)

This accounting standard was issued to improve the presentation of net periodic pension cost and net periodic OPEB cost.

Under the new guidance, entities are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by their employees during the period. The other components of net benefit

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cost are required to be presented in the Statement of Operations separately from the service cost component after Operating Income. Additionally, only the service cost component will be eligible for capitalization, when applicable.

The standard requires the amendments to be applied retrospectively for the presentation of the service cost component and the other cost components of net periodic pension cost and net periodic OPEB cost in the Statement of Operations and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension and OPEB costs.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early adoption is permitted for an entity in any interim or annual period. PSEG is currently analyzing the impact of this standard on its financial statements.

Premium Amortization on Purchased Callable Debt Securities

This accounting standard was issued to shorten the amortization period for certain callable debt securities held at a premium. Specifically, the standard requires the premium to be amortized to the earliest call date. The amendments do not require an accounting change for securities held at a discount; the discount continues to be amortized to maturity.

The standard is effective for annual and interim reporting periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period. If an entity early adopts the standard in an interim period, any
adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity should apply this standard on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. Additionally, in the period of adoption, an entity should provide disclosures about a change in accounting principle. PSEG is currently analyzing the impact of this standard on its financial statements.

Stock Compensation - Scope of Modification Accounting

This accounting standard provides clarity and reduces both diversity in practice and complexity when applying the stock compensation guidance to a change in the terms or conditions of a stock-based payment award. Specifically, the standard provides guidance as to which changes to the terms or conditions of a stock-based payment award require an entity to apply modification accounting.

The standard is effective for all entities for annual periods, and interim periods within those annual periods, beginning after December 15, 2017. Early adoption is permitted, including adoption in any interim period, for reporting periods for which financial statements have not yet been issued. This standard should be applied prospectively to an award modified on or after the adoption date. PSEG plans to adopt this standard effective January 1, 2018.

Note 3. Early Plant Retirements

Fossil

In October 2016, Power determined that it would cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. Both units were available to operate through May 31, 2017 and were subsequently retired from operation on June 1, 2017.

In the latter half of 2016, PSEG and Power recognized pre-tax charges in Energy Costs and Operation and Maintenance (O&M) of $62 million and $53 million, respectively, related to coal inventory adjustments, capacity penalties, materials and supplies inventory reserve adjustments for parts that cannot be used at other generating units, employee-related severance benefits costs and construction work in progress impairments, among other shut down items. In addition to these charges, Power recognized Depreciation and Amortization (D&A) during 2016 of $571 million due to the significant shortening of the expected economic useful lives of Hudson and Mercer.

As of June 1, 2017, Power recognized total D&A of $964 million for the Hudson and Mercer units to reflect the end of their economic useful lives in 2017. In the three and nine months ended September 30, 2017, Power recognized pre-tax charges in Energy Costs of $1 million and $10 million, respectively, primarily for coal inventory lower of cost or market adjustments. For the three and nine months ended September 30, 2017, Power also recognized pre-tax charges in O&M of $8 million and $12 million, respectively, of shut down costs and an increase in the Asset Retirement Obligation due to settlements and changes in cash flow estimates, partially offset by changes in employee-related severance costs. Power currently anticipates using the sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such environmental remediation are neither currently probable nor estimable but may be material.

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As of December 31, 2016, Power had reduced the estimated useful life of Bridgeport Harbor Station unit 3 (BH3) from 2025 to the summer of 2021 as it was more likely than not it will retire the unit by this time.

PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the held for use classification of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Nuclear

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. This situation is generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities and both federal and state-level policies that provide financial incentives to renewable energy such as wind and solar, but generally do not apply to nuclear generating stations. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

If the market trends noted above continue or worsen, Power's New Jersey nuclear generating units could cease being economically competitive which may cause Power to retire such units prior to the end of their useful lives. The costs associated with any such potential retirement, which may include, among other things, accelerated D&A or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs, and additional funding of the NDT Fund would likely have a material adverse impact on PSEG's and Power's future financial results and cash flows. PSEG and Power continue to advocate for sound policies that recognize nuclear power as a source of reliable clean energy, free of air emissions and an important part of a diverse and reliable energy portfolio.

The following table provides the balance sheet amounts by generating station as of September 30, 2017 for significant assets and liabilities associated with Power's owned share of its nuclear assets.

	As of September 30, 2017			
	Hope Creek	Salem	Support Facilities and Other (A)	Peach Bottom
	Millions			
Assets				
Materials and Supplies Inventory	$ 85	$ 81	$ —	$ 41
Nuclear Production, net of Accumulated Depreciation	452	557	204	753
Nuclear Fuel In-Service, net of Accumulated Depreciation	120	94	—	109
Construction Work in Progress (including nuclear fuel)	216	130	9	92
Total Assets	$ 873	$ 862	$ 213	$ 995
Liability				
Asset Retirement Obligation	$ 148	$ 162	$ —	$ 164
Total Liabilities	$ 148	$ 162	$ —	$ 164
Net Assets	$ 725	$ 700	$ 213	$ 831
NRC License Renewal Term	2046	2036/2040	—	2033/2034
% Owned	100%	57%	—	50%

(A) Includes Hope Creek's and Salem's shared support facilities and other nuclear development capital.

The precise timing of any potential early retirement and resulting financial statement impact may be affected by a number of factors, including co-owner considerations, the results of any transmission system reliability study assessments and

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decommissioning trust fund requirements and other commitments, as well as future energy prices. Power maintains a NDT Fund that funds its decommissioning obligations. See Note 7. Available-for-Sale Securities.

Note 4. Variable Interest Entity (VIE)

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and O&M Expense, respectively. Servco recorded $114 million and $116 million for the three months and $338 million and $315 million for the nine months ended September 30, 2017 and 2016, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 5. Rate Filings

This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2016.

In addition to items previously reported in the Annual Report on Form 10-K, significant regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

Transmission Formula Rate Filings—In June 2017, PSE&G filed its 2016 true-up adjustment pertaining to its transmission formula rates in effect for 2016. This resulted in an adjustment of $12 million more than the 2016 originally filed revenues.

In October 2017, the 2018 Annual Formula Rate update was filed with FERC and requests approximately $212 million in increased annual transmission revenue effective January 1, 2018, subject to true-up.

Gas System Modernization Program (GSMP)—In July of each year, PSE&G files with the BPU for base rate recovery of GSMP investments which include a return of and on its investment.

In October 2017, PSE&G submitted the planned update to its annual GSMP cost recovery petition, originally filed in July 2017, to include GSMP investments in service as of September 30, 2017. This filing seeks BPU approval to recover in gas base rates an annual revenue increase of $25 million effective January 1, 2018. This increase represents the return of and on investment for GSMP investments in service through September 30, 2017. This proceeding is ongoing.

Energy Strong Recovery Filing—In March and September of each year, PSE&G files with the BPU for base rate recovery of Energy Strong investments which include a return of and on its investment.

In June 2017, PSE&G submitted the planned update to its March Energy Strong cost recovery petition, originally filed in March 2017, to include Energy Strong investments in service as of May 31, 2017. This filing requested estimated annual increases in electric and gas revenues of $16 million and $2 million, respectively. In August 2017, the BPU approved these rate increases effective September 1, 2017.

In September 2017, PSE&G filed its Energy Strong electric cost recovery petition seeking BPU approval to recover the revenue requirements associated with Energy Strong capitalized investment costs placed in service from June 1, 2017 through November 30, 2017. The petition requests rates to be effective March 1, 2018, consistent with the BPU Order of approval of the

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Energy Strong program. The annualized requested increase in electric revenue requirement is approximately $9 million. This proceeding is ongoing.

Basic Gas Supply Services (BGSS)—In June 2017, PSE&G made its annual BGSS filing with the BPU requesting an increase in the BGSS rate from approximately 34 cents to 37 cents per therm effective October 1, 2017. In September 2017, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was increased.

Weather Normalization Clause—In April 2017, the BPU gave final approval to PSE&G's petition to collect $54 million in net deficiency gas revenues as a result of the warmer than normal 2015-2016 Winter Period.

In June 2017, PSE&G filed a petition requesting approval to collect $55 million in total net deficiency revenues comprised of $31 million in net deficiency gas revenues as a result of the warmer than normal 2016-2017 Winter Period and the remaining carryover balance of $24 million in net deficiency gas revenue from the 2015-2016 Winter Period. The deficiency gas revenue would be collected from customers over the 2017-2018 and 2018-2019 Winter Periods (October 1 through May 31). In September 2017, the BPU approved this petition on a provisional basis with rates effective October 1, 2017, allowing recovery during the 2017-2018 Winter Period.

Green Program Recovery Charges (GPRC)—In August 2017, the BPU approved PSE&G's petition for an Energy Efficiency 2017 Program (EE 2017) to extend three existing energy efficiency subprograms (multi-family, direct install and hospital efficiency) and establish two new residential energy efficiency offerings. The two new offerings include deployment of smart thermostats and a pilot program to provide residential customers with energy usage information enabling them to reduce consumption. The Order allows PSE&G to extend the subprogram offerings and establish the residential energy efficiency sub-programs under its existing energy efficiency clause recovery process. The EE 2017 allows for $69 million of additional investment and $16 million of additional administrative and information technology costs. The EE 2017 was added as the 11th component of the GPRC rate effective September 1, 2017.

Each year PSE&G files with the BPU for annual recovery for the 11 combined components of its electric and gas Green Program investments which include a return on its investment and recovery of expenses.

In March 2017, the BPU gave final approval to PSE&G's 2016 GPRC cost recovery petition to recover approximately $37 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved GPRC programs for the period October 1, 2016 through September 30, 2017. The rates were effective May 1, 2017. This Order also included the return of approximately $5 million in remaining overcollections from the completed Securitization Transition Charge.

In June 2017, PSE&G filed its 2017 GPRC cost recovery petition requesting recovery of approximately $47 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU-approved programs for the period October 1, 2017 through September 30, 2018. This proceeding is ongoing.

Remediation Adjustment Charge (RAC)—In June 2017, the BPU approved PSE&G's filing with respect to its RAC 24 petition allowing recovery of $41 million effective July 10, 2017 related to net Manufactured Gas Plant expenditures from August 1, 2015 through July 31, 2016.

Note 6. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with solar renewable energy certificates generated from the installed solar electric system. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

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Outstanding Loans by Class of Customer

Consumer Loans	As of September 30, 2017	As of December 31, 2016
	Millions	
Commercial/Industrial	$ 160	$ 164
Residential	10	11
Total	**$ 170**	**$ 175**

Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third-party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

During the third quarter of 2016, Energy Holdings completed its annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases. The outcome indicated that the revised residual value estimates were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM, as discussed in Note 3. Early Plant Retirements, negatively impacting the economic outlook of the leased assets. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016, calculated by comparing the gross investment in the leases before and after the revised residual estimates. During the fourth quarter of 2016, Energy Holdings recorded a $10 million pre-tax charge for its best estimate of loss related to the leveraged lease receivables as a result of the current liquidity issues facing REMA, which was reflected in Operating Revenues and is included in Gross Investments in Leases as of December 31, 2016.

During the first quarter of 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as certain recent discussions with REMA management, Energy Holdings recorded an additional $55 million pre-tax charge for its current best estimate of loss related to the lease receivables, which was reflected in Operating Revenues and is included in Gross Investments in Leases as of September 30, 2017.

In June 2017, GenOn Energy, Inc. (GenOn) and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code. GenOn is a subsidiary of NRG Energy, Inc. and is the parent of REMA. REMA was not included in the GenOn filing. Energy Holdings continues to monitor the restructuring of GenOn and its possible impacts on REMA and continues to discuss the situation with GenOn. During the second quarter of 2017, Energy Holdings completed its review of estimated residual values embedded in its leveraged lease portfolio of generating assets and the outcome indicated that one of the residual value estimates was lower than the recorded residual value due to a further deterioration of market conditions and changes to operating cost estimates. This decline was determined to be other than temporary. As a result, a pre-tax write-down of $7 million was recorded in the quarter ended June 30, 2017. In addition, based on an ongoing review of (i) the liquidity challenges facing REMA and (ii) available alternatives, Energy Holdings recorded an additional $15 million pre-tax charge for its current best estimate of loss related to lease receivables. The second quarter 2017 pre-tax write-down and additional charge were reflected in Operating Revenues and are included in Gross Investment in Leases for September 30, 2017.

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The following table shows Energy Holdings' gross and net lease investment as of September 30, 2017 and December 31, 2016, respectively.

	As of September 30, 2017	As of December 31, 2016
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 546	$ 629
Estimated Residual Value of Leased Assets	326	346
Total Investment in Rental Receivables	872	975
Unearned and Deferred Income	(309)	(326)
Gross Investment in Leases	563	649
Deferred Tax Liabilities	(631)	(674)
Net Investment in Leases	**$ (68)**	**$ (25)**

The corresponding receivables associated with the lease portfolio are reflected in the following table, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

Counterparties' Credit Rating Standard & Poor's (S&P) as of September 30, 2017	Lease Receivables, Net of Non-Recourse Debt As of September 30, 2017
	Millions
AA	$ 15
BBB+ — BBB-	316
BB-	133
CCC-	82
Total	**$ 546**

The "BB-" and the "CCC-" ratings in the preceding table represent lease receivables related to coal and gas-fired assets in Illinois and Pennsylvania, respectively. As of September 30, 2017, the gross investment in the leases of such assets, net of non-recourse debt, was $337 million ($(184) million, net of deferred taxes). A more detailed description of such assets under lease, as of September 30, 2017, is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 133	64%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 84	64%	1,036	Gas	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 20	17%	1,711	Coal	CCC-	REMA (A)
Conemaugh Station Units 1 and 2	PA	$ 20	17%	1,711	Coal	CCC-	REMA (A)
Shawville Station Units 1, 2, 3 and 4	PA	$ 80	100%	596	Gas	CCC-	REMA (A)

(A) REMA's parent company, GenOn, and certain of its subsidiaries (which did not include REMA) filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete.

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The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease structures. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital and trigger certain material tax obligations which could wholly or partially be mitigated by tax indemnification claims against the counterparty. A bankruptcy of a lessee would likely delay and potentially limit any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's restructuring process or the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments and continues to discuss the situation with GenOn. If lease rejections or foreclosures were to occur, Energy Holdings could potentially record additional pre-tax write-offs up to its gross investment in these facilities and may also be required to accelerate and pay material deferred tax liabilities to the Internal Revenue Service (IRS).

Additional factors that may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and their affiliates and the quality and condition of assets under lease.

Note 7. Available-for-Sale Securities

NDT Fund

Power maintains an external master NDT to fund its share of decommissioning costs for its five nuclear facilities upon termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The funds are managed by third-party investment managers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of September 30, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 706	$ 331	$ (5)	$ 1,032
Debt Securities				
Government	561	10	(4)	567
Corporate	352	7	(1)	358
Total Debt Securities	913	17	(5)	925
Other Securities	55	—	—	55
Total NDT Available-for-Sale Securities	**$ 1,674**	**$ 348**	**$ (10)**	**$ 2,012**

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	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 705	$ 263	$ (11)	$ 957
Debt Securities				
Government	518	8	(6)	520
Corporate	337	4	(4)	337
Total Debt Securities	855	12	(10)	857
Other Securities	44	—	—	44
Total NDT Available-for-Sale Securities (A)	**$ 1,604**	**$ 275**	**$ (21)**	**$ 1,858**

(A) The NDT available-for-sale securities table excludes cash of $1 million which is part of the NDT Fund.

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2017	As of December 31, 2016
	Millions	
Accounts Receivable	$ 11	$ 8
Accounts Payable	$ 5	$ 5

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of September 30, 2017				As of December 31, 2016			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ 67	$ (5)	$ —	$ —	$ 120	$ (10)	$ 8	$ (1)
Debt Securities								
Government (B)	237	(2)	62	(2)	276	(6)	4	—
Corporate (C)	60	—	36	(1)	139	(3)	15	(1)
Total Debt Securities	297	(2)	98	(3)	415	(9)	19	(1)
Other Securities	3	—	—	—	—	—	—	—
NDT Available-for-Sale Securities	**$ 367**	**$ (7)**	**$ 98**	**$ (3)**	**$ 535**	**$ (19)**	**$ 27**	**$ (2)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2017.

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(B) Debt Securities (Government)—Unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. Power also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2017.

(C) Debt Securities (Corporate)—Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2017.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	Millions			
Proceeds from NDT Fund Sales (A)	**$ 278**	**$ 139**	**$ 845**	**$ 470**
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	$ 29	$ 11	$ 82	$ 36
Gross Realized Losses	(5)	(3)	(14)	(25)
Net Realized Gains (Losses) on NDT Fund	**$ 24**	**$ 8**	**$ 68**	**$ 11**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

The cost of these securities was determined on the basis of specific identification.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $172 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of September 30, 2017.

The NDT available-for-sale debt securities held as of September 30, 2017 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 37
1 - 5 years	236
6 - 10 years	230
11 - 15 years	62
16 - 20 years	67
Over 20 years	293
Total NDT Available-for-Sale Debt Securities	**$ 925**

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the nine months ended September 30, 2017, Other-Than-Temporary Impairments (OTTI) of$9 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be

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recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of September 30, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 22	$ 1	$ —	$ 23
Debt Securities				
Government	82	2	—	84
Corporate	118	3	(1)	120
Total Debt Securities	200	5	(1)	204
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	**$ 224**	**$ 6**	**$ (1)**	**$ 229**

	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$ 11	$ 11	$ —	$ 22
Debt Securities				
Government	105	—	(2)	103
Corporate	92	1	(2)	91
Total Debt Securities	197	1	(4)	194
Other Securities	1	—	—	1
Total Rabbi Trust Available-for-Sale Securities	**$ 209**	**$ 12**	**$ (4)**	**$ 217**

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2017	As of December 31, 2016
	Millions	
Accounts Receivable	$ 2	$ 5
Accounts Payable	$ —	$ 3

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The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months.

	As of September 30, 2017				As of December 31, 2016			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Debt Securities								
Government (B)	25	—	3	—	60	(2)	1	—
Corporate (C)	14	(1)	4	—	46	(2)	3	—
Total Debt Securities	39	(1)	7	—	106	(4)	4	—
Rabbi Trust Available-for-Sale Securities	**$ 39**	**$ (1)**	**$ 7**	**$ —**	**$ 106**	**$ (4)**	**$ 4**	**$ —**

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. PSEG also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2017.

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2017.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	Millions			
Proceeds from Rabbi Trust Sales (A)	**$ 24**	**$ 20**	**$ 168**	**$ 81**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ —	$ 2	$ 17	$ 5
Gross Realized Losses	(1)	(2)	(5)	(4)
Net Realized Gains (Losses) on Rabbi Trust	**$ (1)**	**$ —**	**$ 12**	**$ 1**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

The cost of these securities was determined on the basis of specific identification.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in the Condensed Consolidated Statements of Operations. Net unrealized gains of $3 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of September 30, 2017.

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The Rabbi Trust available-for-sale debt securities held as of September 30, 2017 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ —
1 - 5 years	40
6 - 10 years	27
11 - 15 years	6
16 - 20 years	19
Over 20 years	112
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 204**

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in an indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). For the nine months ended September 30, 2017, no OTTIs were recognized on securities in the Rabbi Trust. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of September 30, 2017	As of December 31, 2016
	Millions	
PSE&G	$ 46	$ 43
Power	57	53
Other	126	121
Total Rabbi Trust Available-for-Sale Securities	**$ 229**	**$ 217**

Note 8. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria.

As of December 31, 2016, PSEG merged its three qualified defined benefit pension plans (excluding Servco plans) into one plan, thereby also merging all of the pension plans' assets. As a result, the total net periodic benefit costs, net of amounts capitalized, decreased by approximately $12 million and $36 million for the three months and nine months, ended September 30, 2017, respectively, as compared to the 2017 amounts that would have been recognized had the plans not been merged. This is due to the amortization period for gains and losses for the merged plan resulting in lower amortization than that of the individual plans. No changes were made to the benefit formulas, vesting provisions, or to the employees covered by the plans.

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The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis for PSEG, excluding Servco.

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016	2017	2016	2017	2016
	Millions							
Components of Net Periodic Benefit Costs								
Service Cost	$ 29	$ 28	$ 4	$ 5	$ 86	$ 82	$ 12	$ 13
Interest Cost	51	50	15	15	153	151	47	44
Expected Return on Plan Assets	(98)	(98)	(8)	(8)	(295)	(295)	(25)	(23)
Amortization of Net								
Prior Service Cost (Credit)	(5)	(5)	(3)	(4)	(14)	(14)	(8)	(11)
Actuarial Loss	24	39	13	10	73	118	38	30
Total Benefit Costs	**$ 1**	**$ 14**	**$ 21**	**$ 18**	**$ 3**	**$ 42**	**$ 64**	**$ 53**

Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, excluding Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016	2017	2016	2017	2016
	Millions							
PSE&G	$ (1)	$ 8	$ 13	$ 11	$ (3)	$ 22	$ 40	$ 33
Power	—	3	7	6	1	11	20	17
Other	2	3	1	1	5	9	4	3
Total Benefit Costs	**$ 1**	**$ 14**	**$ 21**	**$ 18**	**$ 3**	**$ 42**	**$ 64**	**$ 53**

During the three months ended March 31, 2017, PSEG contributed its entire planned contribution for the year 2017 of $14 million into its OPEB plan.

Servco Pension and OPEB

At the direction of LIPA, Servco sponsors benefit plans that cover its current and former employees who meet certain eligibility criteria. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 4. Variable Interest Entity. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco's pension-related revenues and costs were $18 million and $16 million for the three months ended September 30, 2017 and 2016, respectively, and $35 million and $28 million for the nine months ended September 30, 2017 and 2016, respectively. Servco's pension-related costs of $35 million for the nine months ended September 30, 2017 represent its entire planned contribution for the year 2017. The OPEB-related revenues earned and costs incurred were $1 million and $3 million for the three months and nine months ended September 30, 2017. The OPEB-related revenues earned and costs incurred were immaterial for the three months and nine months ended September 30, 2016.

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Note 9. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees as a form of collateral.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- the net position of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. Current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of September 30, 2017 and December 31, 2016.

	As of September 30, 2017	As of December 31, 2016
	Millions	
Face Value of Outstanding Guarantees	$ 1,846	$ 1,806
Exposure under Current Guarantees	$ 108	$ 139
Letters of Credit Margin Posted	$ 134	$ 157
Letters of Credit Margin Received	$ 59	$ 99
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (2)	$ (1)
Net Broker Balance Deposited (Received)	$ (6)	$ 57
Additional Amounts Posted:		
Other Letters of Credit	$ 61	$ 51

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 11. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Condensed Consolidated Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG also issued a $21 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit. In June 2017, Power sold its minority equity interest in PennEast and upon disposition, PSEG's $106 million guarantee that had supported Power's obligations related to PennEast was terminated.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the EPA determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA determined that there was a need to perform a comprehensive study of the entire 17 miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the

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RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than with respect to their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. Construction is complete. The CPG is awaiting EPA approval of the construction report, long-term monitoring plan and confirmatory sampling plan. PSE&G's and Power's combined share of the cost of that effort is approximately three percent. The remaining CPG members, PSE&G and Power included, have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS sets forth various alternatives for remediating this portion of the Passaic River.

The CPG, which consisted of 50 members as of September 30, 2017, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost of the RI/FS is approximately $195 million, which the CPG continues to incur. Of the estimated $195 million, as of September 30, 2017, the CPG had spent approximately $168 million, of which PSEG's total share was approximately $12 million.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River. It set forth the CPG's estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion on an undiscounted basis. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranged from approximately $518 million to $772 million. Based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimated share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

In March 2016, the EPA released its Record of Decision (ROD) for the FFS which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The ROD Remedy requires a bank-to-bank dredge ranging from approximately 5 to 30 feet deep in the federal navigation channel from River Mile 0 to River Mile 1.7 and an approximately 2.5 foot deep dredge everywhere else in the lower 8.3 miles of the river. An engineered cap approximately two feet thick will be placed over the dredged areas. Dredged sediments will be transported to facilities and landfills out-of-state. The EPA estimates the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation.

Based upon the estimated cost of the ROD Remedy, PSEG's estimate of PSE&G's and Power's shares of that cost, and the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued an additional $36 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued an additional $8 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2016. These accruals brought the total liability to approximately $57 million, $46 million applicable to PSE&G and $11 million applicable to Power. There have been no additional accruals recorded since the first quarter of 2016.

Also in March 2016, the EPA sent a notice letter to 105 PRPs, including PSE&G, all other past and present members of the CPG, including Occidental Chemical Corporation (OCC), and the towns of Newark, Kearny and Harrison and the Passaic Valley Sewerage Commission stating that the EPA wants to determine whether OCC, a successor company to Diamond Shamrock, would voluntarily perform the remedial design for the ROD Remedy. On September 30, 2016, OCC and the EPA

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executed an Administrative Settlement Agreement and Order on Consent for Remedial Design under which OCC agreed to conduct the remedial design for the ROD. With OCC's commitment to perform the remedial design, it is anticipated that the EPA will begin negotiation of a remedial action consent decree, under which OCC and the other "major PRPs" will implement and/or pay for the EPA's ROD Remedy for the lower 8.3 miles. The EPA has not defined "major PRPs."

In June 2016, Tierra and Maxus, successors to Diamond Shamrock, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Maxus and Tierra are subsidiaries of YPF Holdings, Inc. (YPF Holdings). YPF Holdings is a wholly owned subsidiary of YPF S.A. (YPF), a company controlled by the Argentinian government. Neither YPF Holdings nor YPF is a party to the bankruptcy proceedings. However, Tierra and Maxus have filed a plan of liquidation that may allow the parties to assert one or more causes of action to hold YPF responsible for certain amounts owed by Tierra and Maxus. The bankruptcy plan ordered by the Delaware Court in July, 2017 created a Liquidating Trust to pursue outstanding creditors' claims, including alter ego claims against YPF. PSEG cannot currently determine the impact, if any, that the bankruptcy of Tierra and Maxus or any related proceeding might have on its allocable share or total liability for the Passaic River matter, and therefore, PSEG, through the CPG and independently, will continue to monitor the bankruptcy proceedings to identify any potential impact on PSEG's share of the costs.

In March 2017, the EPA sent a letter to certain PRPs that are considered by the EPA to have minimal responsibility for the Passaic River's contamination, offering "cash-out" settlements. The PRPs that settle will be released from their CERCLA remediation liability for the lower 8.3 miles of the lower Passaic River. The impact of this proposed settlement on PSEG's responsibility for the remediation of the lower 8.3 miles is not material.

In September 2017, the EPA concluded that an Agency-commenced allocation process for the Passaic River's lower 8.3 miles should include only certain PRPs that received General Notice letters (excluding PRPs that settle pursuant to the early cash-out settlement that the EPA offered in March 2017, among others). The allocation is intended to lead to a consent decree in which certain of the PRPs agree to perform the remedial action under EPA oversight. Discussions on the matter are ongoing.

The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on PSEG's financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

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MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $390 million and $440 million on an undiscounted basis through 2021, including its $46 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $390 million as of September 30, 2017. Of this amount, $74 million was recorded in Other Current Liabilities and $316 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $390 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly. NJDEP, PSEG and EPA representatives have had discussions regarding to what extent sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Clean Water Act (CWA) Permit Renewals

Pursuant to the Federal Water Pollution Control Act, National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In May 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the best technology available for minimizing adverse environmental impacts of each facility that seeks a permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications.

In September 2014, several environmental non-governmental groups and certain energy industry groups filed petitions for review of the rule and the case has been assigned to the U.S. Court of Appeals for the Second Circuit (Second Circuit). Environmental organizations, including but not limited to the environmental petitioners in the Second Circuit, have also filed suit under the Endangered Species Act. The cases were subsequently consolidated at the Second Circuit and a decision remains pending.

In June 2016, the NJDEP issued a final NJPDES permit for Salem with an effective date of August 1, 2016. The final permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the CWA, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final permit for Salem. This matter is still pending. The Riverkeeper's filing does not change the effective date of the permit. If the Riverkeeper's challenge were successful, Power may be required to incur additional costs to comply with

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the CWA. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

State permitting decisions at Bridgeport and possibly New Haven could also have a material impact on Power's ability to renew permits at its existing larger once-through cooled plants without making significant upgrades to existing intake structures and cooling systems.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at BH3. To address compliance with the EPA's CWA Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, Power would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the previously estimated useful life ending in 2025. Power is currently awaiting action by the CTDEEP to issue a draft and then a final permit.

Separately, Power has also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut and local community organizations. That CEBA provides that Power would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power may seek to operate BH3 through the previously estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. The Connecticut Siting Council (CSC) issued an order to approve siting Bridgeport Harbor Station unit 5. All major environmental permits have been received; however, secondary approvals are still being obtained to allow operations to begin by June 2019. Power's obligations under the CEBA are being monitored regularly and carried out as needed.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.

Jersey City, New Jersey Subsurface Feeder Cable Matter

In early October 2016, a discharge of dielectric fluid from subsurface feeder cables located in the Hudson River near Jersey City, New Jersey, was identified and reported to the NJDEP. The feeder cables are located within a subsurface easement granted to PSE&G by the property owners, Newport Associates Development Company (NADC) and Newport Associates Phase I Developer Limited Partnership. The feeder cables are subject to agreements between PSE&G and Consolidated Edison Company of New York, Inc. (Con Edison) and are jointly owned by PSE&G and Con Edison, with PSE&G owning the portion of the cables located in New Jersey and Con Edison owning the portion of the cables located in New York. The NJDEP has declared an emergency and an emergency response action has been undertaken to investigate, contain, remediate and stop the fluid discharge; to assess, repair and restore the cables to good working order, if feasible; and to restore the property. The regulatory agencies overseeing the emergency response, including the U.S. Coast Guard, the NJDEP and the Army Corps of Engineers, have issued multiple notices, orders and directives to the various parties related to this matter. The impacted cable was repaired in late-September 2017; however, the investigation and response actions related to the fluid discharge are ongoing. Also ongoing is the process to determine ultimate responsibility for the costs to address the leak among PSE&G, Con Edison and NADC, including an action filed by PSE&G in New Jersey federal court seeking damages from NADC. Based on the information currently available and depending on the outcome of the New Jersey federal action, PSE&G's portion of the costs to address the leak may be material; however, PSE&G anticipates that it will recover these costs through regulatory proceedings.

Steam Electric Effluent Guidelines

In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG Rule) for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater, and gasification wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Bridgeport Harbor station and the jointly-owned Keystone and

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Conemaugh stations, have bottom ash transport water discharges that are regulated under this rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the rule.

In April 2017, the EPA announced that it had granted a petition for reconsideration of the ELG Rule and issued an administrative stay of the compliance dates in the rule that were the subject of pending litigation. In June 2017, the EPA proposed a rule to postpone the compliance deadlines for the BAT limitations for the aforementioned waste streams. In September 2017, the EPA issued a rule postponing for two years compliance dates solely related to bottom ash transport water and flue gas desulfurization wastewater. The EPA has announced plans to issue a new rule by November 2020 addressing revised requirements and compliance dates for these two waste streams. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2016 is $276.83 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2016 of $335.33 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2014	2015	2016	2017	
36-Month Terms Ending	May 2017	May 2018	May 2019	May 2020	(A)
Load (MW)	2,800	2,900	2,800	2,800	
$ per MWh	$97.39	$99.54	$96.38	$90.78	

(A) Prices set in the 2017 BGS auction year became effective on June 1, 2017 when the 2014 BGS auction agreements expired.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 18. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2020 and a significant portion through 2021 at Salem, Hope Creek and Peach Bottom.

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Power has various multi-year contracts for natural gas and firm pipeline transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess pipeline capacity available beyond the needs of PSE&G's customers, Power can use the gas to make third-party sales and if excess volume remains after the third-party sales, supply its fossil generating stations in New Jersey.

Power also has various long-term fuel purchase commitments for coal through 2021 to support its Keystone and Conemaugh fossil generation stations.

As of September 30, 2017, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2021
	Millions
Nuclear Fuel	
Uranium	$ 257
Enrichment	$ 328
Fabrication	$ 178
Natural Gas	$ 963
Coal	$ 308

Regulatory Proceedings

FERC Compliance

PJM Bidding Matter

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional pricing errors in the bids were identified. It was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power has implemented procedures and continues to review its policies and practices to mitigate the risk of similar issues occurring in the future. During the three months ended March 31, 2014, based upon its best estimate available at the time, Power recorded a pre-tax charge to income in the amount of $25 million related to this matter.

Since September 2014, FERC Staff has been conducting a preliminary, non-public staff investigation into these matters. While considerable uncertainty remains as to the final resolution of these matters, based upon developments in the investigation in the first quarter of 2017, Power believes the disgorgement and interest costs related to the cost-based bidding matter may range between approximately $35 million and $135 million, depending on the legal interpretation of the principles under the PJM Tariff, plus penalties. Since no point within this range is more likely than any other, Power has accrued the low end of this range of $35 million by recording an additional pre-tax charge to income of $10 million during the three months ended March 31, 2017. Power is unable to reasonably estimate the range of possible loss, if any, for the quantity of energy offered matter or the penalties that FERC would impose relating to either the cost-based bidding or quantity of energy matter. However, any of these amounts could be individually material to PSEG and Power.

Power continues to believe that it has legal defenses that it may assert in a judicial challenge, including the legal defense that its cost-based bidding in a substantial majority of the hours was below the allowed rate under the Tariff and therefore any errors in those hours did not violate the Tariff or were immaterial. Furthermore, it is unclear whether the quantity of energy offered violated any legal requirement. As a result, PSEG and Power cannot predict the final outcome of these matters.

Financial Transmission Rights (FTR) Auction Matter

In January 2017, ER&T received requests from the FERC Office of Enforcement relating to the planning and implementation of ER&T's participation in PJM's annual FTR auction for the 2016-2017 planning year and the monthly PJM FTR auctions for February, March and April 2016. In October 2017, FERC Staff closed the investigation with no impact to PSEG's operations or future earnings results.

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Note 10. Debt and Credit Facilities

Long-Term Debt Financing Transactions

The following long-term debt transactions occurred in the nine months ended September 30, 2017:

PSEG

- entered into an agreement for a new term loan maturing June 2019. The term loan has a balance of $700 million at an interest rate of 1 month LIBOR + 0.80% and can be terminated at any time without penalty.

PSE&G

- issued $425 million of 3.00% Secured Medium-Term Notes, Series L due May 2027.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

In March 2017, PSEG, Power and PSE&G amended their credit agreements, extending the expiration dates to March 2022. Concurrently, PSEG increased its existing $1 billion in credit facilities to $1.5 billion and Power decreased its existing $2.6 billion in credit facilities to $2.1 billion, which includes two new 3-year $100 million letter of credit facilities that expire in March 2020.

The commitments under the $4.2 billion credit facilities are provided by a diverse bank group. As of September 30, 2017, the total available credit capacity was $3.8 billion.

As of September 30, 2017, no single institution represented more than 8% of the total commitments in the credit facilities.

As of September 30, 2017, total credit capacity was in excess of the total anticipated maximum liquidity requirements of PSEG, PSE&G and Power.

Each of the credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support its subsidiaries' liquidity needs. The total credit facilities and available liquidity as of September 30, 2017 were as follows:

	As of September 30, 2017				
Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
		Millions			
PSEG					
5-year Credit Facilities (A)	$ 1,500	$ 215	$ 1,285	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSEG	**$ 1,500**	**$ 215**	**$ 1,285**		
PSE&G					
5-year Credit Facility (A)	$ 600	$ 15	$ 585	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 15**	**$ 585**		
Power					
3-year LC Facilities	$ 200	$ 112	$ 88	Mar 2020	Letters of Credit
5-year Credit Facilities	1,900	70	1,830	Mar 2022	Funding/Letters of Credit
Total Power	**$ 2,100**	**$ 182**	**$ 1,918**		
Total	**$ 4,200**	**$ 412**	**$ 3,788**		

(A) The primary use of PSEG's and PSE&G's credit facilities is to support their respective Commercial Paper Programs, under which as of September 30, 2017, PSEG had $202 million outstanding at a weighted average interest rate of 1.37%. PSE&G had no amounts outstanding under its Commercial Paper Program as of September 30, 2017.

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Note 11. Financial Risk Management Activities

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchases and normal sales (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow or fair value hedges. Power and PSE&G enter into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk relating primarily to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of the derivative contracts are recorded in earnings.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. The changes in fair value of the interest rate swaps are fully offset by changes in the fair value of the underlying forecasted interest payments of the debt. There were no outstanding interest rate swaps as of September 30, 2017 or December 31, 2016. The fair value hedges reduced interest expense by $2 million and $6 million for the three months and nine months ended September 30, 2016.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, related primarily to variable-rate debt instruments. As of September 30, 2017 and December 31, 2016, PSEG had interest rate hedges outstanding totaling $500 million. These hedges convert PSEG's $500 million variable rate term loan due November 2017 into a fixed rate loan. As of December 31, 2016, the fair value of these hedges was $1 million and was immaterial as of September 30, 2017. There was no ineffectiveness as of September 30, 2017 and December 31, 2016.

The Accumulated Other Comprehensive Income (Loss) (after tax) related to existing and terminated interest rate derivatives designated as cash flow hedges was $1 million and $2 million as of September 30, 2017 and December 31, 2016, respectively. The after-tax unrealized gain expected to be reclassified to earnings during the next 12 months is immaterial.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with PSEG's accounting policy, these positions are offset on the Condensed Consolidated Balance Sheets of Power and PSEG.

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The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of September 30, 2017				
	Power (A)			PSEG (A)	Consolidated
	Not Designated			Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Interest Rate Swaps	Total Derivatives
	Millions				
Derivative Contracts					
Current Assets	$ 352	$ (268)	$ 84	$ —	$ 84
Noncurrent Assets	178	(116)	62	—	62
Total Mark-to-Market Derivative Assets	**$ 530**	**$ (384)**	**$ 146**	**$ —**	**$ 146**
Derivative Contracts					
Current Liabilities	$ (268)	$ 261	$ (7)	$ —	$ (7)
Noncurrent Liabilities	(110)	109	(1)	—	(1)
Total Mark-to-Market Derivative (Liabilities)	**$ (378)**	**$ 370**	**$ (8)**	**$ —**	**$ (8)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 152**	**$ (14)**	**$ 138**	**$ —**	**$ 138**

	As of December 31, 2016					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Designated as Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions					
Derivative Contracts						
Current Assets	$ 435	$ (273)	$ 162	$ —	$ 1	$ 163
Noncurrent Assets	122	(98)	24	—	—	24
Total Mark-to-Market Derivative Assets	**$ 557**	**$ (371)**	**$ 186**	**$ —**	**$ 1**	**$ 187**
Derivative Contracts						
Current Liabilities	$ (285)	$ 277	$ (8)	$ (5)	$ —	$ (13)
Noncurrent Liabilities	(98)	95	(3)	—	—	(3)
Total Mark-to-Market Derivative (Liabilities)	**$ (383)**	**$ 372**	**$ (11)**	**$ (5)**	**$ —**	**$ (16)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 174**	**$ 1**	**$ 175**	**$ (5)**	**$ 1**	**$ 171**

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of September 30, 2017 and December 31, 2016. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of September 30, 2017, net cash collateral (received) paid of $(14) million was netted against the corresponding net derivative contract

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positions. Of the $(14) million as of September 30, 2017, $(7) million was netted against current assets, and $(7) million was netted against noncurrent assets. As of December 31, 2016, net cash collateral (received) paid of $1 million was netted against the corresponding net derivative contract positions. Of the $1 million as of December 31, 2016, $(3) million was netted against noncurrent assets, and $4 million was netted against current liabilities.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating by S&P or Moody's, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P or Moody's ratings. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $16 million and $19 million as of September 30, 2017 and December 31, 2016, respectively. As of each of September 30, 2017 and December 31, 2016, Power had the contractual right of offset of $9 million related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $7 million and $10 million as of September 30, 2017 and December 31, 2016, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months and nine months ended September 30, 2017 and 2016.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended September 30, 2017	2016	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended September 30, 2017	2016
	Millions			Millions	
PSEG					
Interest Rate Swaps	$ 1	$ 1	Interest Expense	$ 2	$ —
Total PSEG	**$ 1**	**$ 1**		**$ 2**	**$ —**

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Nine Months Ended September 30, 2017	2016	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Nine Months Ended September 30, 2017	2016
	Millions			Millions	
PSEG					
Interest Rate Swaps	$ 1	$ 3	Interest Expense	$ 2	$ —
Total PSEG	**$ 1**	**$ 3**		**$ 2**	**$ —**

There were no pre-tax gains (losses) recognized in income on derivatives (ineffective portion) as of September 30, 2017 and 2016.

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The following reconciles the AOCI for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2015	**$ —**	**$ —**
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	—	—
Balance as of December 31, 2016	**$ 3**	**$ 2**
Gain Recognized in AOCI	1	—
Less: Gain Reclassified into Income	(2)	(1)
Balance as of September 30, 2017	**$ 2**	**$ 1**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS for the three months and nine months ended September 30, 2017 and 2016. Power's derivative contracts reflected in this table include contracts to hedge the purchase and sale of electricity and natural gas, and the purchase of fuel. The table does not include contracts for which Power has designated as NPNS, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2017	2016	2017	2016
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ 25	$ 125	$ 221	$ 255
Energy-Related Contracts	Energy Costs	(3)	(11)	(19)	(3)
Total PSEG and Power		**$ 22**	**$ 114**	**$ 202**	**$ 252**

The following reflects the gross volume, on an absolute value basis, of derivatives as of September 30, 2017 and December 31, 2016.

Type	Notional	Total	PSEG	Power	PSE&G
		Millions			
As of September 30, 2017					
Natural Gas	Dekatherm (Dth)	265	—	265	—
Electricity	MWh	332	—	332	—
Financial Transmission Rights (FTRs)	MWh	5	—	5	—
Interest Rate Swaps	U.S. Dollars	500	500	—	—
As of December 31, 2016					
Natural Gas	Dth	357	—	348	9
Electricity	MWh	323	—	323	—
FTRs	MWh	9	—	9	—
Interest Rate Swaps	U.S. Dollars	500	500	—	—

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Credit Risk

Credit risk relates to the risk of loss that Power would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG has established credit policies that it believes significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of September 30, 2017, 99% of the net credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives, NPNS and non-derivatives).

The following table provides information on Power's credit risk from others, net of collateral, as of September 30, 2017. It further delineates that exposure by the credit rating of the counterparties, which is determined by the lowest rating from S&P, Moody's or an internal scoring model. In addition, it provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Collateral Held	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
		Millions			Millions	
Investment Grade	$ 318	$ 55	$ 263	2	$ 128	(A)
Non-Investment Grade	5	1	4	—	—	
Total	**$ 323**	**$ 56**	**$ 267**	**2**	**$ 128**	

(A) Includes net exposure of $97 million with PSE&G.

As of September 30, 2017, collateral held from counterparties where Power had credit exposure included $3 million in cash collateral and $53 million in letters of credit.

As of September 30, 2017, Power had 144 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of September 30, 2017, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's BGS suppliers' credit exposure is calculated each business day. As of September 30, 2017, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 12. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds, as well as natural gas futures contracts executed on NYMEX.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of September 30, 2017, these consisted primarily of certain electric load contracts and gas contracts.

Certain derivative transactions may transfer from Level 2 to Level 3 if inputs become unobservable and internal modeling techniques are employed to determine fair value. Conversely, measurements may transfer from Level 3 to Level 2 if the inputs become observable.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of September 30, 2017 and December 31, 2016, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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Description	Recurring Fair Value Measurements as of September 30, 2017			
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 220	$ —	$ 220	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 146	$ (384)	$ 11	$ 513	$ 6
NDT Fund (D)					
Equity Securities	$ 1,032	$ —	$ 1,030	$ 2	$ —
Debt Securities—U.S. Treasury	$ 249	$ —	$ —	$ 249	$ —
Debt Securities—Govt Other	$ 318	$ —	$ —	$ 318	$ —
Debt Securities—Corporate	$ 358	$ —	$ —	$ 358	$ —
Other Securities	$ 55	$ —	$ 55	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 23	$ —	$ 23	$ —	$ —
Debt Securities—U.S. Treasury	$ 51	$ —	$ —	$ 51	$ —
Debt Securities—Govt Other	$ 33	$ —	$ —	$ 33	$ —
Debt Securities—Corporate	$ 120	$ —	$ —	$ 120	$ —
Other Securities	$ 2	$ —	$ 2	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (8)	$ 370	$ (6)	$ (372)	$ —
PSE&G					
Assets:					
Cash Equivalents (A)	$ 220	$ —	$ 220	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$ 10	$ —	$ —	$ 10	$ —
Debt Securities—Govt Other	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Corporate	$ 24	$ —	$ —	$ 24	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 146	$ (384)	$ 11	$ 513	$ 6
NDT Fund (D)					
Equity Securities	$ 1,032	$ —	$ 1,030	$ 2	$ —
Debt Securities—U.S. Treasury	$ 249	$ —	$ —	$ 249	$ —
Debt Securities—Govt Other	$ 318	$ —	$ —	$ 318	$ —
Debt Securities—Corporate	$ 358	$ —	$ —	$ 358	$ —
Other Securities	$ 55	$ —	$ 55	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—U.S. Treasury	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Govt Other	$ 8	$ —	$ —	$ 8	$ —
Debt Securities—Corporate	$ 30	$ —	$ —	$ 30	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					

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Energy-Related Contracts (B)	$	(8)	$	370	$	(6)	$	(372)	$	—

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Description	Recurring Fair Value Measurements as of December 31, 2016				
	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$ 186	$ (371)	$ 17	$ 533	$ 7
Interest Rate Swaps (C)	$ 1	$ —	$ —	$ 1	$ —
NDT Fund (D)					
Equity Securities	$ 957	$ —	$ 954	$ 3	$ —
Debt Securities—U.S. Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 293	$ —	$ —	$ 293	$ —
Debt Securities—Corporate	$ 337	$ —	$ —	$ 337	$ —
Other Securities	$ 44	$ —	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 22	$ —	$ 22	$ —	$ —
Debt Securities—U.S. Treasury	$ 37	$ —	$ —	$ 37	$ —
Debt Securities—Govt Other	$ 66	$ —	$ —	$ 66	$ —
Debt Securities—Corporate	$ 91	$ —	$ —	$ 91	$ —
Other Securities	$ 1	$ —	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (16)	$ 372	$ (18)	$ (364)	$ (6)
PSE&G					
Assets:					
Cash Equivalents (A)	$ 365	$ —	$ 365	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$ —	$ —	$ —	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Govt Other	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Corporate	$ 18	$ —	$ —	$ 18	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (5)	$ —	$ —	$ —	$ (5)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ 186	$ (371)	$ 17	$ 533	$ 7
NDT Fund (D)					
Equity Securities	$ 957	$ —	$ 954	$ 3	$ —
Debt Securities—U.S. Treasury	$ 227	$ —	$ —	$ 227	$ —
Debt Securities—Govt Other	$ 293	$ —	$ —	$ 293	$ —
Debt Securities—Corporate	$ 337	$ —	$ —	$ 337	$ —
Other Securities	$ 44	$ —	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$ 9	$ —	$ —	$ 9	$ —

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Debt Securities—Govt Other	$ 16	$ —	$ —	$ 16	$ —
Debt Securities—Corporate	$ 23	$ —	$ —	$ 23	$ —
Other Securities	$ —	$ —	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$ (11)	$ 372	$ (18)	$ (364)	$ (1)

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(A) Represents money market mutual funds.

(B) Level 1— During 2016 a net fair value of $1 million relating to energy-related contracts was transferred from Level 2 into Level 1. These contracts represent natural gas futures contracts executed on NYMEX, and are being valued solely on settled pricing inputs which come directly from the exchange.

Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using settled prices from an exchange, such as NYMEX, ICE and Nodal Exchange, or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

Level 3—Unobservable inputs are used for the valuation of certain contracts. See "Additional Information Regarding Level 3 Measurements" below for more information on the utilization of unobservable inputs.

(C) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(D) The fair value measurement tables exclude an immaterial amount of cash as of September 30, 2017 and $1 million as of December 31, 2016, which is part of the NDT Fund. The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in a Russell 3000 index fund and various fixed income securities classified as "available for sale" as of September 30, 2017. The Rabbi Trust maintained investments in a S&P 500 index fund and various securities classified as "available for sale" as of December 31, 2016. These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities include primarily investment grade corporate bonds, collateralized mortgage obligations, asset backed securities and certain government and U.S. Treasury obligations or Federal Agency asset-backed securities and municipal bonds with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. The preferred stocks are not actively traded on a daily basis and therefore, are also priced using an evaluated pricing methodology. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Condensed Consolidated Balance Sheets. As of September 30, 2017, net cash collateral (received) paid of $(14) million was netted against the corresponding net derivative contract positions. The $(14) million of cash collateral as of September 30, 2017 was netted against assets. As of December 31, 2016, net cash collateral (received) paid of $1 million was netted against the corresponding net derivative contract positions. Of the $1 million of cash collateral as of December 31, 2016, $(3) million was netted against assets, and $4 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in

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Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee (RMC) approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The RMC reports to the Corporate Governance and Audit Committees of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G, the natural gas supply contract was measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The following tables provide details surrounding significant Level 3 valuations as of September 30, 2017 and December 31, 2016.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of September 30, 2017 Assets	Fair Value as of September 30, 2017 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$ 5	$ —	Discounted Cash flow	Historic Load Variability	0% to +10%
Gas	Other	1	—			
Total Power		**$ 6**	**$ —**			
Total PSEG		**$ 6**	**$ —**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2016 Assets	Fair Value as of December 31, 2016 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contract	$ —	$ (5)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		**$ —**	**$ (5)**			
Power						
Electricity	Electric Load Contracts	$ 7	$ (1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Gas (A)	Other	—	—			
Total Power		**$ 7**	**$ (1)**			
Total PSEG		**$ 7**	**$ (6)**			

(A) Includes gas positions which were immaterial.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in the load variability would decrease the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months ended September 30, 2017 and September 30, 2016, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Nine Months Ended September 30, 2017

	Three Months Ended September 30, 2017						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of July 1, 2017	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2017
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ 6	$ 3	$ —	$ —	$ (3)	$ —	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 6	$ 3	$ —	$ —	$ (3)	$ —	$ 6

	Nine Months Ended September 30, 2017						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2017	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2017
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ 1	$ 29	$ 5	$ —	$ (28)	$ (1)	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (5)	$ —	$ 5	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 6	$ 29	$ —	$ —	$ (28)	$ (1)	$ 6

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Nine Months Ended September 30, 2016

	Three Months Ended September 30, 2016						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of July 1, 2016	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2016
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 5	$ 8	$ (2)	$ 4	$ (4)	$ —	$ 11
PSE&G							
Net Derivative Assets (Liabilities)	$ (2)	$ —	$ (2)	$ —	$ —	$ —	$ (4)
Power							
Net Derivative Assets (Liabilities)	$ 7	$ 8	$ —	$ 4	$ (4)	$ —	$ 15

	Nine Months Ended September 30, 2016						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2016	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2016
PSEG							
Net Derivative Assets (Liabilities)	$ 13	$ 24	$ (6)	$ 4	$ (24)	$ —	$ 11
PSE&G							
Net Derivative Assets (Liabilities)	$ 2	$ —	$ (6)	$ —	$ —	$ —	$ (4)
Power							
Net Derivative Assets (Liabilities)	$ 11	$ 24	$ —	$ 4	$ (24)	$ —	$ 15

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $3 million and $29 million in Operating Income for the three months and nine months ended September 30, 2017, respectively. The $3 million in Operating Income is realized. Of the $29 million in Operating Income, $1 million is unrealized.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Represents $(3) million and $(28) million in settlements for the three months and nine months ended September 30, 2017, respectively. Represents $(4) million and $(24) million in settlements for the three months and nine months

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ended September 30, 2016, respectively.

(D) During the three months ended September 30, 2017 there were no transfers in to or out of Level 3. During the nine months ended September 30, 2017, $(1) million of net derivatives assets/liabilities were transferred from Level 2 to Level 3. There were no transfers in to or out of Level 3 during three months and nine months ended September 30, 2016.

(E) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $8 million and $24 million in Operating Income for the three months and nine months ended September 30, 2016, respectively. Of the $8 million in Operating Income, $4 million is unrealized. The $24 million in Operating Income is realized.

As of September 30, 2017, PSEG carried $2.6 billion of net assets that are measured at fair value on a recurring basis, of which $6 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of September 30, 2016, PSEG carried $2.6 billion of net assets that are measured at fair value on a recurring basis, of which $11 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of September 30, 2017 and December 31, 2016.

	As of September 30, 2017		As of December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A) (B)	$ 1,896	$ 1,891	$ 1,195	$ 1,185
PSE&G (B)	8,243	8,857	7,818	8,240
Power - Recourse Debt (B)	2,385	2,657	2,382	2,578
Total Long-Term Debt	**$ 12,524**	**$ 13,405**	**$ 11,395**	**$ 12,003**

(A) As of September 30, 2017, fair value includes a $700 million floating rate term loan in addition to the $500 million floating rate term loan and net offsets as of December 31, 2016. The fair values of the term loan debt (Level 2 measurement) approximate the carrying values because the interest payments are based on LIBOR rates that are reset monthly and the debt is redeemable at face value by PSEG at any time.

(B) Given that these bonds do not trade actively, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

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Note 13. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended September 30, 2017				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 41	$ —	$ 41
Allowance for Funds Used During Construction	14	—	—	14
Rabbi Trust Realized Gains, Interest and Dividends	1	1	—	2
Solar Loan Interest	6	—	—	6
Other	2	1	—	3
Total Other Income	**$ 23**	**$ 43**	**$ —**	**$ 66**
Nine Months Ended September 30, 2017				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 117	$ —	$ 117
Allowance for Funds Used During Construction	42	—	—	42
Rabbi Trust Realized Gains, Interest and Dividends	5	6	11	22
Solar Loan Interest	16	—	—	16
Other	7	4	—	11
Total Other Income	**$ 70**	**$ 127**	**$ 11**	**$ 208**
Three Months Ended September 30, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 21	$ —	$ 21
Allowance for Funds Used During Construction	14	—	—	14
Rabbi Trust Realized Gains, Interest and Dividends	1	—	3	4
Solar Loan Interest	6	—	—	6
Other	1	2	(1)	2
Total Other Income	**$ 22**	**$ 23**	**$ 2**	**$ 47**
Nine Months Ended September 30, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$ —	$ 69	$ —	$ 69
Allowance for Funds Used During Construction	35	—	—	35
Rabbi Trust Realized Gains, Interest and Dividends	2	2	6	10
Solar Loan Interest	17	—	—	17
Other	7	3	(2)	8
Total Other Income	**$ 61**	**$ 74**	**$ 4**	**$ 139**

Other Deductions	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended September 30, 2017				
NDT Fund Realized Losses and Expenses	$ —	$ 8	$ —	$ 8
Other	1	—	1	2
Total Other Deductions	**$ 1**	**$ 8**	**$ 1**	**$ 10**
Nine Months Ended September 30, 2017				
NDT Fund Realized Losses and Expenses	$ —	$ 21	$ —	$ 21
Other	3	1	5	9
Total Other Deductions	**$ 3**	**$ 22**	**$ 5**	**$ 30**
Three Months Ended September 30, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 5	$ —	$ 5
Other	1	1	1	3
Total Other Deductions	**$ 1**	**$ 6**	**$ 1**	**$ 8**
Nine Months Ended September 30, 2016				
NDT Fund Realized Losses and Expenses	$ —	$ 31	$ —	$ 31
Other	3	2	3	8
Total Other Deductions	**$ 3**	**$ 33**	**$ 3**	**$ 39**

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(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

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Note 14. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months and nine months ended September 30, 2017 and 2016 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
PSEG	38.9%	36.5%	35.5%	36.3%
PSE&G	38.8%	36.1%	37.4%	36.1%
Power	41.9%	39.3%	37.9%	39.4%

For the three months and nine months ended September 30, 2017, the differences in PSEG's effective tax rates as compared to the same periods in the prior year, as well as to the statutory tax rate of 40.85%, were due primarily to changes in uncertain tax positions and the NDT Fund. For the nine months ended September 30, 2017, the effective tax rate was also favorably impacted by interest from a New Jersey State income tax refund.

For the three months and nine months ended September 30, 2017, the differences in PSE&G's effective tax rates as compared to the same periods in the prior year, as well as to the statutory tax rate of 40.85%, were due primarily to changes in uncertain tax positions, plant and other flow-through items.

For the three months and nine months ended September 30, 2017, the differences in Power's effective tax rates as compared to the same periods in the prior year, as well as to the statutory tax rate of 40.85%, were due primarily to changes in uncertain tax positions, manufacturing deduction and the NDT Fund.

PSEG's federal tax returns for the years 2011 and 2012 are currently being audited by the IRS. The audit and other related claims are reasonably expected to be completed within the next 12 months. As a result, it is reasonably possible that a decrease in PSEG's total unrecognized tax benefits may be necessary in the range of $80 million to $180 million based on current estimates.

The Protecting Americans from Tax Hikes Act of 2015 (Tax Act) extended the 50% bonus depreciation rules for qualified property placed in service from January 1, 2015 through December 31, 2017. The rate is reduced to 40% and 30% for eligible property placed in service in 2018 and 2019, respectively. On May 8, 2017 the IRS issued guidance allowing for 50% bonus depreciation on long production property that is placed in service in 2018. For long production property placed in service in 2019, qualified costs incurred before January 1, 2019 is afforded a 40% rate, while qualified costs incurred during 2019 receives a 30% rate. For long production property placed in service in 2020, subject to a written binding contract entered into before 2020, a 30% rate is allowed for qualified costs incurred before January 1, 2020, with a 0% rate thereafter. The Tax Act also extended the 30% ITC for qualified property placed in service starting January 1, 2016 through December 31, 2019 but reduces the ITC rate to 26% and 22% for projects commenced in 2020 and 2021, respectively. The financial impact of the extensions of the ITC rate will depend upon future transactions.

This provision has generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period. However, these tax benefits will have a negative impact on the rate base of several of PSE&G's programs.

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Note 15. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended September 30, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of June 30, 2017	$ 2	$ (386)	$ 158	$ (226)
Other Comprehensive Income before Reclassifications	—	—	25	25
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	6	(8)	(3)
Net Current Period Other Comprehensive Income (Loss)	(1)	6	17	22
Balance as of September 30, 2017	**$ 1**	**$ (380)**	**$ 175**	**$ (204)**

PSEG	Other Comprehensive Income (Loss) Three Months Ended September 30, 2016			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of June 30, 2016	$ 1	$ (370)	$ 117	$ (252)
Other Comprehensive Income before Reclassifications	1	—	26	27
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	9	(2)	7
Net Current Period Other Comprehensive Income (Loss)	1	9	24	34
Balance as of September 30, 2016	**$ 2**	**$ (361)**	**$ 141**	**$ (218)**

PSEG	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2016	$ 2	$ (398)	$ 133	$ (263)
Other Comprehensive Income before Reclassifications	—	—	78	78
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	18	(36)	(19)
Net Current Period Other Comprehensive Income (Loss)	(1)	18	42	59
Balance as of September 30, 2017	**$ 1**	**$ (380)**	**$ 175**	**$ (204)**

PSEG	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2016			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2015	$ —	$ (386)	$ 91	$ (295)
Other Comprehensive Income before Reclassifications	2	—	44	46
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	25	6	31
Net Current Period Other Comprehensive Income (Loss)	2	25	50	77
Balance as of September 30, 2016	**$ 2**	**$ (361)**	**$ 141**	**$ (218)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2017			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2017	$ —	$ (330)	$ 158	$ (172)
Other Comprehensive Income before Reclassifications	—	—	24	24
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	5	(9)	(4)
Net Current Period Other Comprehensive Income (Loss)	—	5	15	20
Balance as of September 30, 2017	**$ —**	**$ (325)**	**$ 173**	**$ (152)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2016			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2016	$ —	$ (313)	$ 112	$ (201)
Other Comprehensive Income before Reclassifications	—	—	24	24
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	(2)	5
Net Current Period Other Comprehensive Income (Loss)	—	7	22	29
Balance as of September 30, 2016	**$ —**	**$ (306)**	**$ 134**	**$ (172)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2017			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2016	$ —	$ (340)	$ 129	$ (211)
Other Comprehensive Income before Reclassifications	—	—	74	74
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	15	(30)	(15)
Net Current Period Other Comprehensive Income (Loss)	—	15	44	59
Balance as of September 30, 2017	**$ —**	**$ (325)**	**$ 173**	**$ (152)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2016			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2015	$ —	$ (327)	$ 87	$ (240)
Other Comprehensive Income before Reclassifications	—	—	40	40
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	21	7	28
Net Current Period Other Comprehensive Income (Loss)	—	21	47	68
Balance as of September 30, 2016	**$ —**	**$ (306)**	**$ 134**	**$ (172)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2017			Nine Months Ended September 30, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Interest Rate Swaps	Interest Expense	$ 2	$ (1)	$ 1	$ 2	$ (1)	$ 1
Total Cash Flow Hedges		2	(1)	1	2	(1)	1
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	7	(3)	4
Amortization of Actuarial Loss	O&M Expense	(13)	5	(8)	(37)	15	(22)
Total Pension and OPEB Plans		(10)	4	(6)	(30)	12	(18)
Available-for-Sale Securities							
Realized Gains	Other Income	29	(15)	14	99	(49)	50
Realized Losses	Other Deductions	(6)	2	(4)	(19)	9	(10)
OTTI	OTTI	(5)	3	(2)	(9)	5	(4)
Total Available-for-Sale Securities		18	(10)	8	71	(35)	36
Total		**$ 10**	**$ (7)**	**$ 3**	**$ 43**	**$ (24)**	**$ 19**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2016			Nine Months Ended September 30, 2016		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 3	$ (2)	$ 1	$ 9	$ (4)	$ 5
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)	(51)	21	(30)
Total Pension and OPEB Plans		(14)	5	(9)	(42)	17	(25)
Available-for-Sale Securities							
Realized Gains	Other Income	13	(6)	7	41	(20)	21
Realized Losses	Other Deductions	(5)	3	(2)	(29)	15	(14)
OTTI	OTTI	(5)	2	(3)	(25)	12	(13)
Total Available-for-Sale Securities		3	(1)	2	(13)	7	(6)
Total		**$ (11)**	**$ 4**	**$ (7)**	**$ (55)**	**$ 24**	**$ (31)**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2017			Nine Months Ended September 30, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 2	$ (1)	$ 1	$ 6	$ (3)	$ 3
Amortization of Actuarial Loss	O&M Expense	(11)	5	(6)	(32)	14	(18)
Total Pension and OPEB Plans		(9)	4	(5)	(26)	11	(15)
Available-for-Sale Securities							
Realized Gains	Other Income	29	(15)	14	86	(44)	42
Realized Losses	Other Deductions	(5)	2	(3)	(15)	7	(8)
OTTI	OTTI	(5)	3	(2)	(9)	5	(4)
Total Available-for-Sale Securities		19	(10)	9	62	(32)	30
Total		**$ 10**	**$ (6)**	**$ 4**	**$ 36**	**$ (21)**	**$ 15**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2016			Nine Months Ended September 30, 2016		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	$ 3	$ (1)	$ 2	$ 8	$ (3)	$ 5
Amortization of Actuarial Loss	O&M Expense	(15)	6	(9)	(44)	18	(26)
Total Pension and OPEB Plans		(12)	5	(7)	(36)	15	(21)
Available-for-Sale Securities							
Realized Gains	Other Income	12	(5)	7	37	(18)	19
Realized Losses	Other Deductions	(4)	2	(2)	(26)	13	(13)
OTTI	OTTI	(5)	2	(3)	(25)	12	(13)
Total Available-for-Sale Securities		3	(1)	2	(14)	7	(7)
Total		**$ (9)**	**$ 4**	**$ (5)**	**$ (50)**	**$ 22**	**$ (28)**

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Note 16. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2017		2016		2017		2016	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions):								
Net Income	**$ 395**	**$ 395**	**$ 327**	**$ 327**	**$ 618**	**$ 618**	**$ 985**	**$ 985**
EPS Denominator (Millions):								
Weighted Average Common Shares Outstanding	505	505	505	505	505	505	505	505
Effect of Stock Based Compensation Awards	—	2	—	3	—	2	—	3
Total Shares	**505**	**507**	**505**	**508**	**505**	**507**	**505**	**508**
EPS								
Net Income	**$ 0.78**	**$ 0.78**	**$ 0.65**	**$ 0.64**	**$ 1.22**	**$ 1.22**	**$ 1.95**	**$ 1.94**

There were approximately 0.3 million for the three months and nine months ended September 30, 2017 and approximately 0.4 million for the three months and nine months ended September 30, 2016 of stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect.

Dividends

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dividend Payments on Common Stock	**2017**	**2016**	**2017**	**2016**
Per Share	$ 0.43	$ 0.41	$ 1.29	$ 1.23
In Millions	$ 217	$ 207	$ 652	$ 622

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Note 17. Financial Information by Business Segment

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Three Months Ended September 30, 2017					
Total Operating Revenues	$ 1,509	$ 873	$ 135	$ (254)	$ 2,263
Net Income (Loss)	246	136	13	—	395
Gross Additions to Long-Lived Assets	729	327	9	—	1,065
Nine Months Ended September 30, 2017					
Operating Revenues	$ 4,689	$ 3,086	$ 334	$ (1,121)	$ 6,988
Net Income (Loss)	753	(131)	(4)	—	618
Gross Additions to Long-Lived Assets	2,118	903	25	—	3,046
Three Months Ended September 30, 2016					
Total Operating Revenues	$ 1,684	$ 1,075	$ 7	$ (316)	$ 2,450
Net Income (Loss)	255	139	(67)	—	327
Gross Additions to Long-Lived Assets	680	325	9	—	1,014
Nine Months Ended September 30, 2016					
Operating Revenues	$ 4,746	$ 3,102	$ 256	$ (1,133)	$ 6,971
Net Income (Loss)	696	320	(31)	—	985
Gross Additions to Long-Lived Assets	2,035	923	27	—	2,985
As of September 30, 2017					
Total Assets	$ 27,802	$ 11,631	$ 2,288	$ (564)	$ 41,157
Investments in Equity Method Subsidiaries	$ —	$ 90	$ —	$ —	$ 90
As of December 31, 2016					
Total Assets	$ 26,288	$ 12,193	$ 2,373	$ (784)	$ 40,070
Investments in Equity Method Subsidiaries	$ —	$ 102	$ —	$ —	$ 102

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations relate primarily to intercompany transactions between PSE&G and Power. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 18. Related-Party Transactions.

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Note 18. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	Millions			
Billings from Affiliates:				
Net Billings from Power primarily through BGS and BGSS (A)	$ 259	$ 320	$ 1,154	$ 1,162
Administrative Billings from Services (B)	82	73	226	224
Total Billings from Affiliates	**$ 341**	**$ 393**	**$ 1,380**	**$ 1,386**

Related-Party Transactions	As of September 30, 2017	As of December 31, 2016
	Millions	
Receivables from PSEG (C)	**$ —**	**$ 76**
Payable to Power (A)	$ 86	$ 193
Payable to Services (B)	46	67
Payable to PSEG (C)	46	—
Accounts Payable—Affiliated Companies	**$ 178**	**$ 260**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 83**	**$ 130**

Power

The financial statements for Power include transactions with related parties as follows:

Related-Party Transactions	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	Millions			
Billings to Affiliates:				
Net Billings to PSE&G primarily through BGS and BGSS (A)	**$ 259**	**$ 320**	**$ 1,154**	**$ 1,162**
Billings from Affiliates:				
Administrative Billings from Services (B)	**$ 39**	**$ 44**	**$ 117**	**$ 134**

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Related-Party Transactions	As of September 30, 2017	As of December 31, 2016
	Millions	
Receivables from PSE&G (A)	$ 86	$ 193
Receivables from PSEG (C)	—	12
Accounts Receivable—Affiliated Companies	**$ 86**	**$ 205**
Payable to Services (B)	$ 17	$ 25
Payable to PSEG (C)	111	—
Accounts Payable—Affiliated Companies	**$ 128**	**$ 25**
Short-Term Loan Due (to) from Affiliate (E)	**$ 1**	**$ 87**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 57**	**$ 77**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. In addition, Power and PSE&G provide certain technical services for each other generally at cost in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

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Note 19. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries, as of September 30, 2017 and December 31, 2016 and for the three months and nine months ended September 30, 2017 and 2016.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended September 30, 2017					
Operating Revenues	$ —	$ 856	$ 46	$ (29)	$ 873
Operating Expenses	2	643	44	(29)	660
Operating Income (Loss)	(2)	213	2	—	213
Equity Earnings (Losses) of Subsidiaries	143	(3)	3	(140)	3
Other Income	24	58	(2)	(37)	43
Other Deductions	—	(8)	—	—	(8)
Other-Than-Temporary Impairments	—	(5)	—	—	(5)
Interest Expense	(32)	(12)	(5)	37	(12)
Income Tax Benefit (Expense)	3	(103)	2	—	(98)
Net Income (Loss)	**$ 136**	**$ 140**	**$ —**	**$ (140)**	**$ 136**
Comprehensive Income (Loss)	**$ 156**	**$ 154**	**$ —**	**$ (154)**	**$ 156**
Nine Months Ended September 30, 2017					
Operating Revenues	$ —	$ 3,036	$ 145	$ (95)	$ 3,086
Operating Expenses	4	3,315	139	(95)	3,363
Operating Income (Loss)	(4)	(279)	6	—	(277)
Equity Earnings (Losses) of Subsidiaries	(111)	(8)	11	119	11
Other Income	71	155	—	(99)	127
Other Deductions	(1)	(21)	—	—	(22)
Other-Than-Temporary Impairments	—	(9)	—	—	(9)
Interest Expense	(96)	(30)	(14)	99	(41)
Income Tax Benefit (Expense)	10	68	2	—	80
Net Income (Loss)	**$ (131)**	**$ (124)**	**$ 5**	**$ 119**	**$ (131)**
Comprehensive Income (Loss)	**$ (72)**	**$ (80)**	**$ 5**	**$ 75**	**$ (72)**
Nine Months Ended September 30, 2017					
Net Cash Provided By (Used In) Operating Activities	$ (55)	$ 1,159	$ 142	$ 3	$ 1,249
Net Cash Provided By (Used In) Investing Activities	$ 738	$ (289)	$ (343)	$ (990)	$ (884)
Net Cash Provided By (Used In) Financing Activities	$ (683)	$ (869)	$ 211	$ 987	$ (354)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended September 30, 2016					
Operating Revenues	$ —	$ 1,059	$ 43	$ (27)	$ 1,075
Operating Expenses	(2)	826	40	(27)	837
Operating Income (Loss)	2	233	3	—	238
Equity Earnings (Losses) of Subsidiaries	143	(1)	3	(142)	3
Other Income	18	26	—	(21)	23
Other Deductions	(2)	(4)	—	—	(6)
Other-Than-Temporary Impairments	—	(5)	—	—	(5)
Interest Expense	(30)	(12)	(3)	21	(24)
Income Tax Benefit (Expense)	8	(97)	(1)	—	(90)
Net Income (Loss)	**$ 139**	**$ 140**	**$ 2**	**$ (142)**	**$ 139**
Comprehensive Income (Loss)	**$ 168**	**$ 161**	**$ 2**	**$ (163)**	**$ 168**
Nine Months Ended September 30, 2016					
Operating Revenues	$ —	$ 3,061	$ 131	$ (90)	$ 3,102
Operating Expenses	10	2,494	119	(90)	2,533
Operating Income (Loss)	(10)	567	12	—	569
Equity Earnings (Losses) of Subsidiaries	347	(1)	9	(346)	9
Other Income	52	88	—	(66)	74
Other Deductions	(2)	(31)	—	—	(33)
Other-Than-Temporary Impairments	—	(25)	—	—	(25)
Interest Expense	(91)	(29)	(12)	66	(66)
Income Tax Benefit (Expense)	24	(234)	2	—	(208)
Net Income (Loss)	**$ 320**	**$ 335**	**$ 11**	**$ (346)**	**$ 320**
Comprehensive Income (Loss)	**$ 388**	**$ 381**	**$ 11**	**$ (392)**	**$ 388**
Nine Months Ended September 30, 2016					
Net Cash Provided By (Used In) Operating Activities	$ 175	$ 1,261	$ 234	$ (410)	$ 1,260
Net Cash Provided By (Used In) Investing Activities	$ (588)	$ (1,166)	$ (549)	$ 1,152	$ (1,151)
Net Cash Provided By (Used In) Financing Activities	$ 413	$ (95)	$ 315	$ (742)	$ (109)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
As of September 30, 2017					
Current Assets	$ 4,089	$ 1,324	$ 182	$ (4,433)	$ 1,162
Property, Plant and Equipment, net	57	5,408	2,607	—	8,072
Investment in Subsidiaries	4,168	338	—	(4,506)	—
Noncurrent Assets	184	2,211	116	(114)	2,397
Total Assets	**$ 8,498**	**$ 9,281**	**$ 2,905**	**$ (9,053)**	**$ 11,631**
Current Liabilities	$ 233	$ 3,221	$ 1,743	$ (4,433)	$ 764
Noncurrent Liabilities	503	2,192	524	(114)	3,105
Long-Term Debt	2,385	—	—	—	2,385
Member's Equity	5,377	3,868	638	(4,506)	5,377
Total Liabilities and Member's Equity	**$ 8,498**	**$ 9,281**	**$ 2,905**	**$ (9,053)**	**$ 11,631**
As of December 31, 2016					
Current Assets	$ 4,412	$ 1,593	$ 152	$ (4,697)	$ 1,460
Property, Plant and Equipment, net	55	6,145	2,320	—	8,520
Investment in Subsidiaries	4,249	344	—	(4,593)	—
Noncurrent Assets	168	2,016	129	(100)	2,213
Total Assets	**$ 8,884**	**$ 10,098**	**$ 2,601**	**$ (9,390)**	**$ 12,193**
Current Liabilities	$ 171	$ 3,752	$ 1,454	$ (4,697)	$ 680
Noncurrent Liabilities	532	2,398	502	(100)	3,332
Long-Term Debt	2,382	—	—	—	2,382
Member's Equity	5,799	3,948	645	(4,593)	5,799
Total Liabilities and Member's Equity	**$ 8,884**	**$ 10,098**	**$ 2,601**	**$ (9,390)**	**$ 12,193**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and related programs in New Jersey, which are regulated by the BPU, and
- **Power**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) electric transmission and distribution (T&D) system under a contractual Operations and Services Agreement; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Our business discussion in Part I, Item 1. Business of our 2016 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2016 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2017 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2016 Form 10-K.

EXECUTIVE OVERVIEW OF 2017 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- improving utility operations through investment in T&D and other infrastructure projects designed to enhance system reliability and resiliency and to meet customer expectations and public policy objectives,
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the three months and nine months ended September 30, 2017 and 2016 are presented as follows:

Earnings (Losses)	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	Millions			
PSE&G	$ 246	$ 255	$ 753	$ 696
Power (A)	136	139	(131)	320
Other (B)	13	(67)	(4)	(31)
PSEG Net Income	**$ 395**	**$ 327**	**$ 618**	**$ 985**
PSEG Net Income Per Share (Diluted)	**$ 0.78**	**$ 0.64**	**$ 1.22**	**$ 1.94**

(A) Includes after-tax expenses of $5 million and $568 million in the three months and nine months ended September 30, 2017, respectively, and after-tax expenses of $67 million for the three months and nine months ended September 30, 2016 related to the early retirement of Power's Hudson and Mercer coal/gas generation plants. See Item 1. Note 3. Early Plant Retirements for additional information.

(B) Other includes after-tax activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations. Energy Holdings recorded after-tax charges of $45 million for the nine months ended September 30, 2017, and an after-tax impairment of $86 million for the three months and nine months ended September 30, 2016 related to its investments in NRG REMA, LLC's (REMA) leveraged leases. See Item 1. Note 6. Financing Receivables for additional information.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with future delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the following table:

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	Millions, after tax			
NDT Fund Income (Expense) (A) (B)	$ 10	$ 2	$ 32	$ (4)
Non-Trading MTM Gains (Losses) (C)	$ (27)	$ 34	$ —	$ (54)

(A) NDT Fund Income (Expense) includes the realized gains and losses, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization (D&A) Expense.

(B) Net of tax (expense) benefit of $(12) million, $(2) million, $(37) million and $0 million for the three and nine months ended September 30, 2017 and 2016, respectively.

(C) Net of tax (expense) benefit of $19 million $(24) million, $0 million and $37 million for the three and nine months ended September 30, 2017 and 2016, respectively.

Our $68 million increase in Net Income for the three months ended September 30, 2017 was driven primarily by

- an impairment in 2016 related to investments in certain leveraged leases at Energy Holdings,
- higher charges in 2016 related to early retirement of our Hudson and Mercer coal/gas generation units at Power,
- lower generation costs driven by lower natural gas costs and congestion costs, and
- higher transmission revenues.

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These favorable variances were partially offset by

- lower sales of electricity sold under the Basic Generation Service contract and in PJM, and
- MTM losses in 2017 as compared to MTM gains in 2016.

Our $367 million decrease in Net Income for the nine months ended September 30, 2017 was driven largely by higher charges, primarily accelerated depreciation, related to the early retirement of our Hudson and Mercer coal/gas generation units at Power. These decreases were partially offset by

- lower O&M Expense due to cost control efforts,
- lower charges related to investments in certain leveraged leases at Energy Holdings,
- MTM losses in 2016, and
- higher NDT gains and lower NDT losses in 2017.

During the first nine months of 2017, we maintained a strong balance sheet. We continued to effectively deploy capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results, which when combined with the cash flow generated by Power, our merchant generator and power marketer, has allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, we continue to invest in transmission projects that focus on reliability improvements and replacement of aging infrastructure, including our $275 million Newark Switch project that was approved by PJM in July 2017. We also continue to make investments to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the BPU in 2014 and to seek recovery on such investments. We also continue to modernize PSE&G's gas distribution systems as part of our Gas System Modernization Program (GSMP) that was approved by the BPU in late 2015. Over the past few years, these types of investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G.

As a result of our Energy Strong Order from the BPU, we are required to file a distribution base rate case. Following discussions with BPU Staff and Rate Counsel, and as approved by the BPU at its October 20, 2017 meeting, the deadline for filing PSE&G's distribution base rate case was moved from November 1, 2017 to December 1, 2017. The initial filing will now be based upon three months of actual data and nine months of forecasted data updated for actual data throughout the proceeding. The distribution base rate case will provide PSE&G the opportunity to recover investments made since its last distribution base rate case, including investments that were not recovered through clauses, such as the stipulated base investment associated with GSMP, the portion of Energy Strong investment not recovered through the clause, and investments that exceeded our depreciation levels in revenues. Recovery of these investments, coupled with updates to O&M and other adjustments, are anticipated to result in a proposed mid-single digit percentage increase in PSE&G distribution revenues. The distribution base rate case filing will include a test year through June 30, 2018 and will request the inclusion of known and measurable changes in rate base through December 31, 2018, a 10.3% return on equity (ROE) and a capitalization structure with a 54% equity component, and we expect to request new rates effective October 1, 2018. As part of the filing, we will also request approval to decouple electric and gas revenues from sales volumes for most distribution customer classes. We cannot predict the outcome of this proceeding.

In July 2017, we filed a petition with the BPU for GSMP II, a five-year extension of GSMP, which would accelerate the pace of replacement of our aging cast iron and unprotected steel mains and associated service. We proposed to invest up to $540 million per year over this five-year program beginning in 2019. In August 2017, the BPU approved our request for an extension of our Energy Efficiency program.

Although the weather in the first three months of 2017 was warmer than normal, Power's results saw a continuing benefit from access to natural gas supplies through existing firm pipeline transportation contracts. Power manages these contracts for the benefit of PSE&G's customers through the basic gas supply (BGSS) arrangement. The contracts are sized to provide for delivery of a reliable gas supply to PSE&G customers on peak winter demand days. When pipeline capacity beyond the customers' needs is available, Power can use it to make third-party sales and if excess volume remains after the third-party sales, supply gas to its generating units in New Jersey. Alternatively, gas supply and pipeline capacity constraints could adversely impact our ability to meet the needs of our utility customers and generating units.

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Power's hedging practices and ability to capitalize on market opportunities help us to balance some of the volatility of the merchant power business. Power's hedging program in combination with expected revenues from the capacity market mechanisms and certain ancillary service payments, such as reactive power, has secured approximately 60% of its estimated gross margin for the 2017-2019 period.

Our investments in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station unit 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. These highly efficient additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to improve our financial performance.

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced as being at risk for early retirement. This situation is generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities and both federal and state-level policies that provide financial incentives to renewable energy such as wind and solar, but generally do not apply to nuclear generating stations. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

If the market trends noted above continue or worsen, our New Jersey nuclear generating units could cease being economically competitive, which may cause us to retire such units prior to the end of their useful lives. The costs associated with any such potential retirement, which may include, among other things, accelerated D&A or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs, and additional funding of NDT funds would likely have a material adverse impact on future financial results. We continue to advocate for sound policies that recognize nuclear power as a source of reliable and clean energy, free of air emissions and an important part of a diverse and reliable energy portfolio. See Item 1. Note 3. Early Plant Retirements for additional information.

In addition, a number of states have either taken action or are investigating the situation faced by nuclear generating units. Recently, courts in Illinois and New York upheld challenges to the programs which established zero emissions credits, recognizing the importance of nuclear units for providing clean energy, free of air emissions.

In September 2017, the Secretary of the U.S. Department of Energy (DOE) issued a Notice of Proposed Rulemaking (NOPR) directing FERC to act within 60 days to develop a mechanism that would allow for the recovery of costs of fuel-secure generation units such as nuclear and coal. To be eligible for compensation under the NOPR, units must be able to provide certain essential energy and ancillary reliability services, have a 90-day fuel supply on site and not subject to cost-of-service rate regulation by any State or local authority. PSEG is evaluating the potential effects this NOPR could have on its generating fleet. PSEG filed comments in support of the DOE's NOPR and contended that it should be implemented immediately as an interim measure to prevent the premature retirement of fuel-secure baseload units. PSEG also requested that FERC direct the regional transmission organizations (RTOs) to work with stakeholders to develop a long-term market-based methodology for valuing resiliency in the generator fleet. Additionally, PSEG argued that FERC should expedite the implementation of pending price formation reforms, including fast-start pricing and uplift allocation and market transparency. Finally, PSEG requested that FERC direct PJM to file its proposal that would allow baseload units to set the locational marginal prices during low load conditions. We cannot predict the outcome of this matter.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission

In April 2017, the PJM Board announced that it would be lifting the previously disclosed suspension of the Artificial Island transmission project and approved the award to PSE&G of the construction of necessary upgrade work at a cost of approximately $130 million. Also, in April 2017, PJM submitted a proposal to FERC concerning the cost responsibility assigned to certain entities, including PSE&G, for the Artificial Island project. In October 2017, FERC accepted PJM's filing on the grounds that PJM correctly applied its Tariff, but deferred any further ruling on whether the cost allocation methodology applied to the Artificial Island project is appropriate. FERC will decide this issue in a separate proceeding that is currently pending before it.

There are several matters pending before FERC and the U. S. Court of Appeals for the District of Columbia Circuit that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey. In addition, as a basic generation

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service (BGS) supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers may be entitled to recovery, subject to BPU approval. We do not believe that these matters will have a material effect on Power's business or results of operations.

Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base return on equity (ROE). Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. The results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. The CP product was implemented fully in the May 2017 RPM auction for the 2020-2021 Delivery Year. Subsequent to its implementation, FERC approved changes to the CP construct that will enhance the participation of intermittent and demand response resources (seasonal resources). However, two complaints remain pending that ask FERC to investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions.

In May 2017, PJM announced the results of the RPM capacity auction for the 2020-2021 delivery year. Power cleared approximately 7,800 MW of its generating capacity at an average price of $174 per MW-day for the 2020-2021 delivery period. In the two prior capacity auctions covering the 2019-2020 and 2018-2019 delivery years, Power cleared approximately 8,900 MW at an average price of $116 and approximately 8,700 MW at an average price of $215 per MW-day, respectively. Prices in the most recent auction reflect PJM's downwardly-revised demand forecast, changes in the emergency transfer limits due to transmission expansion and the effects of both the new generation and uncleared generation from the prior year's auction.

As a result of the efforts of certain entities in PJM to obtain financial support arrangements from their state commissions, a group of suppliers requested that FERC direct PJM to expand the currently effective "minimum offer price rule" to apply to certain existing units seeking subsidies. The suppliers' request was intended to avoid a scenario where the subsidized generators would submit bids into the PJM capacity market that did not reflect their actual costs of operation and could artificially suppress capacity market prices. We are currently awaiting FERC action on the suppliers' request and cannot predict the outcome of the proceeding.

In June 2017, PJM issued an energy price formation proposal to address a flaw in the energy market in which energy prices during off-peak periods often do not reflect the production costs of generators during these periods even though they are serving load. PJM's proposal would allow large, inflexible units to set price. If placed into effect, this proposal will improve price formation by ensuring that the marginal costs of units serving load will be better reflected in clearing prices. We cannot predict the outcome of this matter.

Distribution

In June 2017, the BPU issued proposed Infrastructure Investment Program (IIP) regulations that would allow utilities to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to support the provision of safe and adequate service. Under the proposed regulations, utilities could seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing infrastructure that enhances reliability, resiliency, and/or safety. The proposed regulations will be subject to comment from interested parties.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs.

In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the New Source Performance Standards, which establish emissions standards for CO_2 for certain new fossil power plants, and the Clean Power Plan (CPP), a greenhouse gas emissions regulation under the Clean Air Act for existing power plants that establishes state-specific emission rate targets based on implementation of the best system of emission reduction. In October 2017, the EPA Administrator signed a proposed repeal of the CPP. The Administrator concluded that the CPP exceeds the EPA's statutory authority by considering measures that are beyond the control of the owners of the affected sources (fossil fuel-fired electric

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generating units). Whether the EPA chooses to propose a replacement rule has not been decided. PSEG cannot estimate the impact of these actions on our business and future results of operations at this time.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above, as well as other matters that may impact our financial condition and results of operations, see Item 1. Note 9. Commitments and Contingent Liabilities.

FERC Compliance

Since September 2014, FERC Staff has been conducting a preliminary non-public investigation regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units. While considerable uncertainty remains as to the final resolution of these matters, based upon developments in the investigation in the first quarter of 2017, Power believes the disgorgement and interest costs related to the cost-based bidding matter may range between approximately $35 million and $135 million, depending on the legal interpretation of the principles under the PJM Tariff, plus penalties. Since no point within this range is more likely than any other, Power has accrued the low end of this range of $35 million by recording an additional pre-tax charge to income of $10 million during the three months ended March 31, 2017. PSEG is unable to reasonably estimate the range of possible loss, if any, for the quantity of energy offered matter or the penalties that FERC would impose relating to either the cost-based bidding or quantity of energy matter. However, any of these amounts could be individually material to PSEG and Power. We cannot predict the final outcome of these matters. For additional information, see Item 1. Note 9. Commitments and Contingent Liabilities.

Early Retirement of Hudson and Mercer Units

On June 1, 2017, Power completed its previously announced retirement of the generation operations of the existing coal/gas units at the Hudson and Mercer generating stations. The decision to retire the Hudson and Mercer units had a material effect on PSEG's and Power's results of operations in 2016 and continued to adversely impact their results of operations in 2017. As of June 1, 2017, Power completed recognition of the incremental D&A of $938 million ($964 million in total) due to the significant shortening of the expected economic useful lives of Hudson and Mercer. During the first nine months of 2017, Energy Costs of $10 million and O&M of $12 million were also incurred and other costs may be incurred during the remaining period in 2017. See Item 1. Note 3. Early Plant Retirements for additional information.

Power currently anticipates using the sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such remediation are neither currently probable nor estimable but may be material.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Leveraged Lease Portfolio

GenOn Energy, Inc. (GenOn), the parent company of REMA, and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code on June 14, 2017. REMA was not included in the GenOn bankruptcy filing. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's efforts to restructure its balance sheet and improve its liquidity. We continue to monitor the restructuring of GenOn and the possible related impact on REMA and continue to discuss the situation with GenOn.

During the first quarter of 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as discussions with REMA management, Energy Holdings recorded an additional $55 million pre-tax charge for its current best estimate of loss relating to its REMA leveraged

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lease receivables, which was reflected in Operating Revenues. During the second quarter of 2017, Energy Holdings recorded an additional $22 million pre-tax charge for its current best estimate of loss related to lease receivables due to collectability of payments ($15 million) and economics impacting the residual value ($7 million) of certain leased assets. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments, which could include further write-downs of the values of Energy Holdings' leveraged lease receivables. For additional information, see Item 1. Note 6. Financing Receivables. There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.

Additional facilities in our leveraged lease portfolio include the Joliet and Powerton generating facilities. Similar to Shawville, Joliet was recently converted to use natural gas. Converted natural gas units such as Shawville and Joliet may have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units. Powerton is a coal-fired generating facility in Illinois. Each of these three facilities may not be as economically competitive as newer combined cycle gas units and could continue to be adversely impacted by the same economic conditions experienced by other less efficient natural gas and coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged lease receivables associated with these facilities.

Salem

Concurrently with the planned refueling outage at the Salem 2 unit that was conducted in the second quarter of 2017, we inspected and replaced baffle bolts as part of our strategy to replace baffle bolts at the Salem station. The unit was returned to service in June 2017.

Operational Excellence

We emphasize operational performance, exercising diligence in managing costs, while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of opportunities in a rapidly evolving market. For the first nine months of 2017, our

- utility continued top decile performance in electric reliability,
- total nuclear fleet achieved an average capacity factor of 95%,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 39 terawatt hours, and
- combined cycle fleet produced 11 terawatt hours at an equivalent availability factor of 94%.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first nine months of 2017 as we

- maintained sufficient liquidity,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2017 to $1.72 per share.

We expect to be able to fund our planned capital requirements without the issuance of new equity.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first nine months of 2017, we

- made additional investments in transmission infrastructure projects,
- continued to execute our BPU-approved utility programs, and
- continued construction of our Keys and Sewaren 7 generation projects for targeted commercial operation in 2018 and began construction of BH5 for targeted commercial operations in mid-2019.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a cost-constrained environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative

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developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions in response to changes in demand,
- successfully launch and grow our retail energy business, which complements our existing wholesale energy business,
- execute our utility capital investment program, including our Energy Strong program, GSMP and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction and start-up of our Keys, Sewaren 7, BH5 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

For 2017 and beyond, the key issues, challenges and opportunities we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- fair and timely rate relief from the BPU and FERC for recovery of costs and return on investments, including with respect to our distribution base rate case proceeding to be filed in 2017,
- the potential for comprehensive tax reform, particularly in light of public statements by the current U.S. administration and key members of Congress,
- uncertainty in the national and regional economic performance, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate,
- the impact of lower natural gas prices and increasing environmental compliance costs on the competitiveness of our nuclear and remaining coal-fired generation plants, and the potential for retirement of such plants earlier than their current useful lives,
- ensuring timely completion of construction of our T&D, generation and other development projects, including obtaining required permits and regulatory approvals,
- maintaining a diverse mix of fuels to mitigate risks associated with fuel price volatility and market demand cycles, and
- FERC Staff's continuing investigation of certain of Power's New Jersey fossil generating unit bids in the PJM energy market.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of transmission and distribution facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses,
- the expansion of our geographic footprint,

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- continued or expanded participation in solar, energy efficiency and related programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency, modernizing existing infrastructure and participation in transmission projects through FERC's "open window" solicitation process.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 18. Related-Party Transactions.

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2017	2016	2017 vs. 2016		2017	2016	2017 vs. 2016	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,263	$ 2,450	$ (187)	(8)	$ 6,988	$ 6,971	$ 17	—
Energy Costs	638	866	(228)	(26)	2,100	2,326	(226)	(10)
Operation and Maintenance	680	776	(96)	(12)	2,100	2,215	(115)	(5)
Depreciation and Amortization	252	231	21	9	1,721	679	1,042	N/A
Income from Equity Method Investments	3	3	—	—	11	9	2	22
Other Income (Deductions)	56	39	17	44	178	100	78	78
Other-Than-Temporary Impairments	5	5	—	—	9	25	(16)	(64)
Interest Expense	100	99	1	1	289	288	1	—
Income Tax Expense	252	188	64	34	340	562	(222)	(40)

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2017	2016	2017 vs. 2016		2017	2016	2017 vs. 2016	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,509	$ 1,684	$ (175)	(10)	$ 4,689	$ 4,746	$ (57)	(1)
Energy Costs	535	721	(186)	(26)	1,760	1,979	(219)	(11)
Operation and Maintenance	346	376	(30)	(8)	1,064	1,110	(46)	(4)
Depreciation and Amortization	169	137	32	23	506	412	94	23
Other Income (Deductions)	22	21	1	5	67	58	9	16
Interest Expense	79	72	7	10	223	214	9	4
Income Tax Expense	156	144	12	8	450	393	57	15

Three Months Ended September 30, 2017 as Compared to 2016

Operating Revenues decreased $175 million due to changes in delivery, commodity, clause and other operating revenues.

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Delivery Revenues increased $10 million due primarily to an increase in transmission revenues.

- Transmission revenues were $34 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.
- Gas distribution revenues increased $5 million due to a $1 million increase from the inclusion of Energy Strong in base rates, and $1 million increases in both GSMP collections and Green Program Recovery Charges (GPRC) and higher sales volumes.
- Electric distribution revenues decreased $29 million due to a $38 million decrease due to lower sales volumes and lower GPRC of $6 million, partially offset by a $15 million increase from the inclusion of Energy Strong in base rates.

Commodity Revenue decreased $186 million as a result of lower Electric and Gas revenues. The changes in Commodity revenue for both electric and gas are entirely offset by the changes in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric commodity revenues decreased $176 million due primarily to a $153 million decrease in BGS revenues due to $97 million in lower sales volumes and $56 million from lower prices and $23 million of lower revenues from collections of Non-Utility Generation Charges (NGC).
- Gas commodity revenues decreased $10 million due to lower BGSS sales prices of $22 million, partially offset by higher BGSS sales volumes of $12 million.

Clause Revenues increased $1 million due primarily to the return of $20 million to customers in 2016 of overcollections of Securitization Transition Charges (STC), partially offset by lower Societal Benefit Charges (SBC) of $12 million and a $6 million decrease in 2017 in Margin Adjustment Clause (MAC) revenues. The changes in the STC, SBC and MAC amounts are entirely offset by changes in the amortization of Regulatory Assets and Regulatory Liabilities and related costs in O&M, D&A and Interest Expense. PSE&G does not earn margin on STC, SBC or MAC collections.

Operating Expenses

Energy Costs decreased $186 million. This is entirely offset by the change in Commodity Revenue.

Operation and Maintenance decreased $30 million, primarily due to a $17 million reduction in clause-related costs, $6 million in lower appliance service costs, $6 million of lower distribution corrective and preventative maintenance and a $5 million reduction in GPRC related costs, partially offset by a net increase of $4 million in certain operational expenses.

Depreciation and Amortization increased $32 million due primarily to an increase of $19 million in amortization of Regulatory Assets and a $14 million increase in depreciation due to additional plant in service.

Interest Expense increased $7 million due primarily to an increase of $5 million due to net debt issuances in 2016 and 2017 and a $2 million increase in other interest.

Income Tax Expense increased $12 million due primarily to uncertain tax positions and plant-related items.

Nine Months Ended September 30, 2017 as Compared to 2016

Operating Revenues decreased $57 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $119 million due primarily to an increase in transmission revenues.

- Transmission revenues were $116 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.
- Gas distribution revenues increased $29 million due to a $14 million increase due to the inclusion of Energy Strong in base rates, $8 million in higher Weather Normalization Clause (WNC) revenue, a $7 million increase due to the GSMP and higher GPRC of $3 million, partially offset by $3 million of lower delivery volumes.
- Electric distribution revenues decreased $26 million due to a $36 million decrease due to lower sales volumes and lower GPRC of $14 million, partially offset by a $24 million increase due to the inclusion of Energy Strong in base rates.

Commodity Revenue decreased $219 million as a result of lower Electric revenues partially offset by higher Gas revenues. The changes in Commodity revenue for both electric and gas are entirely offset by the changes in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric commodity revenues decreased $266 million due primarily to a $188 million decrease in BGS revenues due to $116 million in lower sales volumes and $72 million of lower prices, $64 million of lower revenues from collections of NGC and a decrease of $14 million due to lower volumes of Non-Utility Generation energy sold.

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- Gas commodity revenues increased $47 million due primarily to $69 million of higher BGSS sales prices, partially offset by $22 million of lower sales volumes.

Clause Revenues increased $41 million due primarily to the 2016 return to customers of $50 million of overcollections of STC, and higher MAC revenues of $2 million in 2017, partially offset by a $12 million decrease in collections of SBC. The changes in the STC, MAC and SBC amounts are entirely offset by changes in the amortization of Regulatory Assets and Regulatory Liabilities and related costs in O&M, D&A and Interest Expense. PSE&G does not earn margin on STC, MAC or SBC collections.

Operating Expenses

Energy Costs decreased $219 million. This is entirely offset by the change in Commodity Revenue.

Operation and Maintenance decreased $46 million, of which the most significant components were decreases of $17 million in distribution corrective and preventative maintenance, $14 million in appliance service costs, $11 million in clause-related costs and $11 million in GPRC costs, partially offset by a $10 million net increase in certain operational expenses.

Depreciation and Amortization increased $94 million due primarily to an increase of $51 million in amortization of Regulatory Assets and a $43 million increase in depreciation due to additional plant in service.

Other Income and (Deductions) increased $9 million due primarily to an increase of $7 million in allowance for funds used during construction and a $3 million increase in realized gains on Rabbi Trust investments, partially offset by a net $1 million decrease in Solar Loan interest.

Interest Expense increased $9 million due primarily to an increase of $16 million due to net debt issuances in 2016 and 2017, partially offset by a $7 million decrease predominantly driven by a reduction in clause interest.

Income Tax Expense increased $57 million due primarily to higher pre-tax income and changes in uncertain tax positions.

Power

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2017	2016	2017 vs. 2016		2017	2016	2017 vs. 2016	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 873	$ 1,075	$ (202)	(19)	$ 3,086	$ 3,102	$ (16)	(1)
Energy Costs	357	462	(105)	(23)	1,461	1,481	(20)	(1)
Operation and Maintenance	227	289	(62)	(21)	711	807	(96)	(12)
Depreciation and Amortization	76	86	(10)	(12)	1,191	245	946	N/A
Income from Equity Method Investments	3	3	—	—	11	9	2	22
Other Income (Deductions)	35	17	18	N/A	105	41	64	N/A
Other-Than-Temporary Impairments	5	5	—	—	9	25	(16)	(64)
Interest Expense	12	24	(12)	(50)	41	66	(25)	(38)
Income Tax Expense (Benefit)	98	90	8	9	(80)	208	(288)	N/A

Three Months Ended September 30, 2017 as Compared to 2016

Operating Revenues decreased $202 million due to changes in generation and gas supply revenues.

Generation Revenues decreased $200 million due primarily to

- a decrease of $110 million due to MTM losses in 2017 as compared to MTM gains in 2016. Of this amount, $98 million was due to changes in forward prices and $12 million was due to greater gains on positions reclassified to realized upon settlement this year as compared to last year,
- a decrease of $83 million in electricity sold under our BGS contracts due to lower volumes and lower prices, and
- a decrease of $25 million in energy sales in the PJM region due to lower generation volumes and lower average realized prices,

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- partially offset by a net increase of $18 million due primarily to higher capacity revenue and electricity sold under wholesale load contracts at higher average prices, coupled with new solar projects.

Gas Supply Revenues decreased $2 million due to lower MTM gains in 2017 as compared to 2016.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $105 million due to

Generation costs decreased $108 million due primarily to

- a net decrease of $59 million due to charges associated with the early retirement of the Mercer and Hudson units announced in October 2016, primarily related to a coal inventory write-down, partially offset by additional retirement costs incurred in 2017,
- a net decrease of $26 million due primarily to lower natural gas costs reflecting lower volumes,
- a net decrease of $11 million primarily due to lower congestion costs in PJM due to lower congestion rates coupled with less congestion volumes, and
- a decrease of $8 million due to MTM gains in 2017 as compared to MTM losses in 2016.

Gas costs increased $3 million due mainly to a net increase of $2 million related to sales to third parties, of which $5 million was due to higher average gas costs, partially offset by $3 million due to lower volumes sold.

Operation and Maintenance decreased $62 million due primarily to

- a $51 million decrease at our fossil plants, due to the retirement of the Hudson and Mercer units on June 1, 2017, and
- a $10 million net decrease related to our nuclear plants due primarily to lower labor-related costs.

Depreciation and Amortization decreased $10 million due primarily to

- $19 million of lower depreciation due to the retirement of the Hudson and Mercer units,
- partially offset by $4 million of increased depreciation due to the accelerated retirement date at Bridgeport Harbor Station unit 3 (BH3),
- $3 million of higher depreciation due to new solar projects, and
- a $2 million increase due to additional nuclear plant placed into service.

Other Income (Deductions) increased $18 million due primarily to higher net realized gains in the NDT Fund.

Interest Expense decreased $12 million due primarily to

- a $7 million decrease due to higher interest capitalized for the construction of three new fossil stations: BH5, Sewaren 7 and Keys, and
- a $5 million decrease due to debt maturities in September 2016.

Income Tax Expense (Benefit) reflected an increased tax expense of $8 million due primarily to changes in the manufacturing deduction and higher pre-tax income in 2017.

Nine Months Ended September 30, 2017 as Compared to 2016

Operating Revenues decreased $16 million due to changes in generation and gas supply revenues.

Generation Revenues decreased $101 million due primarily to

- a net decrease of $115 million in energy sales in the PJM and New England regions due primarily to lower average realized prices,
- a decrease of $91 million in electricity sold under our BGS contracts due to lower volumes and lower prices,
- a net decrease of $11 million in operating reserves in the PJM region, and
- a charge of $10 million due to an increase in the FERC reserve accrual related to the PJM bidding matter see Item 1. Note 9. Commitments and Contingent Liabilities,

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- partially offset by an increase of $86 million due to lower MTM losses in 2017 as compared to 2016. Of this amount, $110 million was due to lower gains on positions reclassified to realized upon settlement this year as compared to last year partially offset by a decrease of $24 million due to changes in forward power prices.
- a net increase of $31 million due primarily to higher volumes of electricity sold under wholesale load contracts in the NE region, and
- an increase of $10 million due to new solar projects.

Gas Supply Revenues increased $84 million due primarily to

- an increase of $45 million in sales under the BGSS contract due primarily to higher average sales prices,
- an increase of $25 million related to sales to third parties, of which $52 million was due to higher average sales prices, partially offset by $27 million of lower volumes sold, and
- a net increase of $14 million due to MTM gains in 2017 as compared to MTM losses in 2016.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs decreased $20 million due to

Generation costs decreased $76 million due primarily to

- a net decrease of $57 million primarily due to lower congestion costs in PJM due to lower congestion rates coupled with less congestion volumes, partially offset by higher transmission charges due to higher rates,
- a net decrease of $49 million due to charges associated with the announced early retirement of the Mercer and Hudson units in 2016, primarily related to a coal inventory write-down partially offset by additional retirement costs incurred in 2016,
- partially offset by higher fuel costs of $12 million reflecting higher average realized prices for natural gas coupled with the utilization of higher volumes of coal, partially offset by the utilization of lower volumes of gas and oil,
- a net increase of $10 million primarily due to an increase in energy purchase volumes in the NE region to serve load obligations, and
- an increase of $9 million due to MTM losses in 2017 as compared to MTM gains in 2016.

Gas costs increased $56 million due mainly to

- an increase of $32 million related to sales under the BGSS contract due to higher average gas costs, and
- an increase of $24 million related to sales to third parties, of which $48 million was due to higher average gas costs, partially offset by a $24 million decrease in volumes sold.

Operation and Maintenance decreased $96 million due primarily to

- a $71 million decrease at our fossil plants, due primarily to the retirement of the Hudson and Mercer units and higher planned outage costs in 2016 as compared to 2017,
- a $20 million net decrease related to our nuclear plants due primarily to lower labor-related costs and outage costs, and
- an $8 million legal accrual for environmental expenses recorded in 2016,
- partially offset by $3 million of costs related to new solar plants placed into service since September 2016.

Depreciation and Amortization increased $946 million due primarily to

- $914 million of higher depreciation due to the early retirement of the Hudson and Mercer units,
- $11 million of increased depreciation due to the accelerated retirement date at BH3,
- $9 million of higher depreciation due to new solar projects, and
- a $9 million increase due to additional nuclear plant placed into service.

Other Income (Deductions) increased $64 million due primarily to $57 million of higher net realized gains in the NDT Fund and $3 million of higher net realized gains in the Rabbi Trust Fund.

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Other-Than-Temporary Impairments decreased $16 million due to lower impairments of equity securities in the NDT Fund in 2017.

Interest Expense decreased $25 million due primarily to

- a $16 million decrease due to higher interest capitalized for the construction of three new fossil stations: BH5, Sewaren 7 and Keys, and
- a net $7 million decrease due to debt maturities in September 2016, partially offset by a debt issuance in June 2016.

Income Tax Expense (Benefit) decreased $288 million in 2017 due primarily to a pre-tax loss in 2017 as compared to pre-tax income in 2016.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the nine months ended September 30, 2017, our operating cash flow decreased $27 million as compared to the same period in 2016. The net change was due primarily to net changes from PSE&G and Power as discussed below as well as net tax payments at PSEG and its other subsidiaries.

PSE&G

PSE&G's operating cash flow decreased $8 million from $1,401 million to $1,393 million for the nine months ended September 30, 2017, as compared to the same period in 2016, due primarily to lower tax refunds and a decrease of $49 million due to a change in regulatory deferrals, partially offset by higher earnings.

Power

Power's operating cash flow decreased $11 million from $1,260 million to $1,249 million for the nine months ended September 30, 2017, as compared to the same period in 2016, due primarily to tax payments in 2017 as compared to tax refunds in 2016 and lower earnings, partially offset by a $68 million decrease in margin deposit requirements and a $30 million increase from net collection of counterparty receivables.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs.

Our total credit facilities and available liquidity as of September 30, 2017 were as follows:

	As of September 30, 2017		
Company/Facility	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$ 1,500	$ 215	$ 1,285
PSE&G	600	15	585
Power	2,100	182	1,918
Total	**$ 4,200**	**$ 412**	**$ 3,788**

As of September 30, 2017, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating from S&P or Moody's, which would represent a three level downgrade from its current S&P or Moody's ratings. In the event of a deterioration of Power's

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credit rating certain of Power's agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $899 million and $783 million as of September 30, 2017 and December 31, 2016, respectively.

For additional information, see Item 1. Note 10. Debt and Credit Facilities.

Long-Term Debt Financing

During the next twelve months, PSEG has a floating rate $500 million term loan maturing in November 2017. PSE&G has $400 million of 5.30% Medium-Term Notes maturing in May 2018 and $350 million of 2.30% Medium-Term Notes maturing in September 2018.

For a discussion of our long-term debt issuances and maturities during 2017, see Item 1. Note 10. Debt and Credit Facilities.

Common Stock Dividends

On July 18, 2017, our Board of Directors approved a $0.43 dividend per share of common stock for the third quarter of 2017. This reflects an indicative annual dividend rate of $1.72 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 1. Note16. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In April 2017, S&P published updated research and affirmed the ratings and outlooks of PSEG and PSE&G. In June 2017, S&P published updated research on Power and the rating and outlook remained unchanged. In July 2017, Moody's upgraded PSEG's senior unsecured rating to Baa1 from Baa2 and revised its outlook to Stable from Positive. Also in July, Moody's affirmed the ratings at PSE&G and Power.

	Moody's (A)	S&P (B)
PSEG		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

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CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures as compared to amounts disclosed in our 2016 Form 10-K.

PSE&G

During the nine months ended September 30, 2017, PSE&G made capital expenditures of $2,118 million, primarily for T&D system reliability. This does not include expenditures for cost of removal, net of salvage, of $72 million, which are included in operating cash flows.

In July 2017, PSE&G filed a petition with the BPU for a GSMP II program, requesting extension of our gas system modernization program through which PSE&G has proposed investing up to $540 million per year beginning in 2019 to continue to modernize our gas system. Under this proposed program, PSE&G plans to replace up to 1,250 miles of gas mains and associated service lines. This is not included in PSE&G's projected capital expenditures.

Power

During the nine months ended September 30, 2017, Power made capital expenditures of $779 million, excluding $124 million for nuclear fuel, primarily related to our Keys, Sewaren 7, BH5 and other generation projects.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Item 1. Note 2. Recent Accounting Standards.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From July through September 2017, MTM VaR remained relatively stable between a low of $5 million and a high of $9 million at the 95% confidence level. The range of VaR was narrower for the three months ended September 30, 2017 as compared with the year ended December 31, 2016.

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	MTM VaR	
	Three Months Ended September 30, 2017	Year Ended December 31, 2016
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 8	$ 26
Average for the Period	$ 7	$ 16
High	$ 9	$ 32
Low	$ 5	$ 10
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 13	$ 40
Average for the Period	$ 11	$ 25
High	$ 15	$ 51
Low	$ 8	$ 16

See Item 1. Note 11. Financial Risk Management Activities for a discussion of credit risk.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, PSE&G and Power

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of PSEG, PSE&G and Power. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of PSEG, PSE&G and Power have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, PSE&G and Power

There have been no changes in internal control over financial reporting that occurred during the third quarter of 2017 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2016 Annual Report on Form 10-K, see Part I, Item 1. Note 9. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

The discussion of our business and operations in this Quarterly Report on Form 10-Q should be read together with the risk factors contained in Part I, Item 1A of our 2016 Annual Report on Form 10-K and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2017, which describe various risks and uncertainties that could have a material adverse impact on our business, prospects, financial position, results of operations or cash flows and could cause results to differ materially from those expressed elsewhere in this report. Except as discussed below, there have been no material changes to the risk factors set forth in the above-referenced filings as of September 30, 2017.

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Cybersecurity attacks or intrusions could adversely impact our businesses.

Cybersecurity threats to the U.S. energy market infrastructure are increasing in sophistication, magnitude and frequency. We rely on information technology systems that utilize sophisticated digital systems and network infrastructure to operate our generation, transmission and distribution systems. We also store sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers and vendors on our systems and conduct power marketing and hedging activities. In addition, the operation of our business is dependent upon the information technology systems of third parties, including our vendors, regulators, RTOs and Independent System Operators (ISOs), among others. Our and third-party information technology systems may be vulnerable to cybersecurity attacks involving domestic or foreign sources. A cybersecurity attack may also leverage such information technology to cause disruptions at a third party. Cybersecurity impacts to our operations include:

- disruption of the operation of our assets and the power grid,
- theft of confidential company, employee, shareholder, vendor or customer information, which may cause us to be in breach of certain covenants and contractual obligations,
- general business system and process interruption or compromise, including preventing us from servicing our customers, collecting revenues or the ability to record, process and/or report financial information correctly, and
- breaches of vendors' infrastructures where our confidential information is stored.

We have experienced and expect to continue to experience actual or attempted cyber-attacks on our information technology systems; however, none of these incidents has had a material impact on our operations or financial condition. If a significant cybersecurity event or breach should occur within our company or with one of our material vendors, we could be exposed to significant loss of revenue, material repair costs to intellectual and physical property, significant fines and penalties for non-compliance with existing laws and regulations, significant litigation costs, increased costs to finance our businesses, reputational damage and loss of confidence from our customers, regulators, investors, vendors and employees. Similarly, a significant cybersecurity event or breach experienced by a competitor, regulatory authority, RTO, ISO, or vendor could also materially impact our business and results of operations via enhanced legal and regulatory requirements. For a discussion of state and federal cybersecurity regulatory requirements and information regarding our cybersecurity program, see Part 1, Item 1. Regulatory Issues in our Annual Report on Form 10-K for the year ended December 31, 2016 and Item 5. Other Information in this Quarterly Report on Form 10-Q.

The market for cybersecurity insurance is relatively new and coverage available for cybersecurity events may evolve as the industry matures. While we maintain insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damage we experience.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the third quarter of 2017.

Three Months Ended September 30, 2017	Total Number of Shares Purchased	Average Price Paid per Share
July 1 - July 31	—	$ —
August 1 - August 31	135,277	$ 45.25
September 1- September 30	—	$ —

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ITEM 5. OTHER INFORMATION

Certain information reported in the 2016 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2016 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the quarters ended March 31, 2017 and June 30, 2017. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

Employee Relations

December 31, 2016 Form 10-K page 15. In 2016, six of our eight labor unions ratified extensions of their collective bargaining agreements with us, with expiration dates from 2019 to 2021. In 2017, each of the remaining two unions ratified extensions of their collective bargaining agreements with us with expiration dates in 2021 and 2022.

Federal Regulation

FERC

Energy Clearing Prices/Price Formation Initiatives

December 31, 2016 Form 10-K page 16 and March 31, 2017 Form 10-Q on page 76. Energy clearing prices in the markets in which we operate are generally based on bids submitted by generating units. Under FERC-approved market rules, bids are subject to price caps and mitigation rules applicable to certain generation units. FERC rules also govern the overall design of these markets. At present, all units within a delivery zone receive a clearing price based on the bid of the marginal unit (i.e. the last unit that must be dispatched to serve the needs of load) which can vary by location. In addition, recent rule changes in the energy markets administered by PJM and ISO-NE (see Capacity Market Issues below) impose rigorous performance obligations and nonperformance penalties on resources during times of system stress. These FERC rules provide an opportunity for bonus payments or require the payment of penalties depending on whether a unit is available during a performance hour.

FERC has also recently ordered certain favorable changes to energy market price formation rules improving shortage pricing and enhancing bidding flexibility for units. We continue to advocate in this context for additional changes in market rules that would provide more transparency about energy market prices. We cannot predict what action FERC might ultimately take, but such an examination could lead to future rule changes.

In June 2017, PJM issued an energy price formation proposal to address a flaw in the energy market in which energy prices during off-peak periods often do not reflect the production costs of generators during these periods even though they are serving load. PJM's proposal would allow large, inflexible units to set price. If placed into effect, this proposal will improve price formation by ensuring that the marginal costs of units serving load will be better reflected in clearing prices. We cannot predict the outcome of this matter.

Notice of Proposed Rulemaking on Baseload Generation

In September 2017, the Secretary of the U.S. Department of Energy issued a Notice of Proposed Rulemaking (NOPR) to allow a full recovery of costs for certain eligible units physically located within the FERC-approved organized markets. The NOPR directs FERC to take final action within 60 days. The NOPR contemplates a cost-of-service payment and a fair rate of return for units that are able to provide certain essential energy and ancillary reliability services, have a 90-day fuel supply on site and are not subject to cost-of-service rate regulation by any State or local authority. We are participating in this proceeding, but we are unable to predict the outcome.

Capacity Market Issues

December 31, 2016 Form 10-K page 16, March 31, 2017 Form 10-Q on page 76 and June 30, 2017 Form 10-Q on page 83. PJM, the New York Independent System Operator (NYISO) and the Independent System Operator New England, Inc. each have capacity markets that have been approved by FERC. FERC regulates these markets and continues to examine whether the market design for each of these three capacity markets is working optimally. Various forums are considering how the competitive market framework can incorporate or be reconciled with state public policies that support particular resources or resource attributes, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market prices. FERC held a technical conference to seek input from the industry on potential options to integrate public policy goals in wholesale markets. We cannot predict what action, if any, FERC might take with regard to capacity market designs.

Capacity Market Issues—PJM

December 31, 2016 Form 10-K page 16, March 31, 2017 Form 10-Q on page 76 and June 30, 2017 Form 10-Q page 83. PJM issued a series of white papers in response to public policies that seek to recognize value associated with generation plants beyond their cost effectiveness and reliability attributes. The three proposals are intended to spur stakeholder discussion and include both potential capacity and energy market reforms. The first energy market reform (see Energy Clearing Prices/Price Formation Initiatives) would allow inflexible generating units to set prices resulting in reduced uplift payments and improved

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price signals while the second energy market reform contemplates a voluntary carbon pricing program where states that elect to participate in the program would agree to put a price on carbon emissions. The capacity market proposal contemplates a two-stage capacity auction which, in its current form, would improve prices for unsubsidized resources, but would still continue to provide capacity payments for subsidized resources.

Transmission Regulation

December 31, 2016 Form 10-K page 18. In October 2017, PSE&G filed its 2018 Annual Formula Rate Update with FERC which requests approximately $212 million in increased annual transmission revenues effective January 1, 2018, subject to true-up. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. For additional information about our transmission formula rate, see Part I Item 1. Note 5. Rate Filings.

Transmission Regulation—Transmission Policy Developments

December 31, 2016 Form 10-K page 18, March 31, 2017 Form 10-Q on page 77 and June 30, 2017 Form 10-Q on page 83.
In a February 2016 order, FERC reversed a previous order and accepted a filing by the PJM transmission owners seeking authority to assign costs for Regional Transmission Expansion Plan projects (subject to PJM Board approval requirements) solely addressing localized needs to customers within the local transmission owner's zone. FERC's action in this order provides an exemption from the Order 1000 open window procedures for projects constructed by transmission owners to meet local transmission planning criteria. FERC's orders have been challenged at the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) and PSE&G has intervened in support of FERC.

In April 2017, the PJM Board announced that it would be lifting the previously disclosed suspension of the Artificial Island transmission project and approved the award to PSE&G of the construction of necessary upgrade work at a cost of approximately $130 million. In October 2017, FERC accepted PJM's filing on the grounds that PJM correctly applied its Tariff. However, FERC deferred a ruling on whether the cost allocation methodology applied to the Artificial Island project is appropriate. FERC will decide this issue in a separate proceeding that is currently pending. We are unable to predict the outcome.

Nuclear Regulatory Commission (NRC)

December 31, 2016 Form 10-K page 20. The NRC continues to evaluate potential revisions to its requirements in connection with its operational and safety reviews of nuclear facilities in the United States as a result of the Fukushima Daiichi incident. We are also subject to cybersecurity regulations promulgated by the NRC.

We are unable to predict the final outcome of these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to our Salem, Hope Creek and Peach Bottom facilities, but such cost could be material.

State Regulation

Cybersecurity Requirements for Regulated Entities

December 31, 2016 Form 10-K page 21. In March 2016, the BPU issued an order for the regulated electric, natural gas and water/wastewater utilities to further reduce the potential for cyber threats to the reliability and resiliency of utility service and to protect customers' information. The order requires these regulated utilities, including PSE&G, to, among other conditions, implement a cybersecurity program that defines and implements organization accountabilities and responsibilities for cyber risk management activities, and establishes policies, plans, processes and procedures for identifying and mitigating cyber risk to critical systems. New Jersey utilities, including PSE&G, were required to be compliant with these requirements by October 1, 2017. We have submitted the required certification of compliance to the BPU.

In an effort to reduce the likelihood and severity of cyber incidents, we have a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of our company and our customers' information and our systems. In addition, we are subject to maintaining key cybersecurity controls to meet mandatory cybersecurity regulatory requirements. Our cybersecurity program is built on technical, procedural, and people-focused measures to detect, protect against, respond to, and recover from cyber threats to our systems and information including company, employee and customer data. Features of our program include: identifying critical information and systems; conducting cyber risk assessments of our and third party systems; maintaining awareness of cyber threats and vulnerabilities through partnerships with public and private entities, as well as industry groups; maintaining and testing our cybersecurity incident response plans and systems; training personnel on cybersecurity issues; and raising cybersecurity awareness throughout our company with electronic notices and seminars. We cannot assure that our cybersecurity program will be effective in preventing or mitigating cybersecurity incidents. For a discussion of the risks associated with cybersecurity threats, see Item 1A. Risk Factors.

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Energy Efficiency 2017 Program (EE 2017)

In August 2017, the BPU approved PSE&G's petition for an Energy Efficiency 2017 Program (EE 2017) to extend three existing energy efficiency subprograms (multi-family, direct install and hospital efficiency) and establish two new residential energy efficiency offerings. The two new offerings include deployment of smart thermostats and a pilot program to provide residential customers with energy usage information enabling them to reduce consumption. The Order allows PSE&G to extend the subprogram offerings and establish the residential energy efficiency sub-programs under its existing energy efficiency clause recovery process. The EE 2017 allows for $69 million of additional investment and $16 million of additional administrative and information technology costs. The EE 2017 was added as the 11th component of the GPRC rate effective September 1, 2017.

Consolidated Tax Adjustments (CTA)

December 31, 2016 Form 10-K page 21. New Jersey is one of only a few states that make CTA in setting rates for regulated utilities. These adjustments to rate base are made during the rate setting process and are intended to allocate to utility customers a portion of the tax benefits realized from the filing of a consolidated federal tax return by the utility's parent corporation. The BPU has been considering the appropriateness of the adjustment and the methodology and mechanics of the calculation for some time. In October 2014, the BPU approved a proposal by its Staff that limits the tax benefit period to be considered in the calculation to five years, sets the distribution rate base adjustment at 25% of any such tax benefit and eliminates from the process any tax benefits tied to transmission earnings. In accordance with this October action, this CTA policy will be applied only with respect to future distribution rate base cases. In November 2014, the New Jersey Division of Rate Counsel appealed the BPU's decision and in September 2017, the New Jersey Superior Court, Appellate Division granted that appeal on procedural grounds. While the issue has now been remanded to the BPU, it is not expected that application of a CTA will have a material impact on PSE&G's current earnings or in its upcoming rate case filing.

Environmental Matters

Air Pollution Control

Hazardous Air Pollutants Regulation

December 31, 2016 Form 10-K page 22. In June 2015, the U.S. Supreme Court held that it was unreasonable for the EPA to refuse to consider the materiality of costs in determining whether to regulate hazardous air pollutants from power plants. In April 2016, the EPA released the final Supplemental Finding that considers the materiality of costs in determining whether to regulate hazardous air pollutants from power plants in response to the U.S. Supreme Court's ruling. Industry participants and various state authorities have filed petitions with the D.C. Circuit challenging the EPA's Supplemental Finding. The D.C. Circuit is holding the case in abeyance pending further directions from the EPA. We do not expect this Supplemental Finding to impact operation of our facilities.

Climate Change

CO_2 Regulation under the Clean Air Act (CAA)

December 31, 2016 Form 10-K page 23. In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the New Source Performance Standards that establish emissions standards for CO_2 for certain new fossil power plants and the Clean Power Plan (CPP), a greenhouse gas emissions regulation under the CAA for existing power plants that establishes state-specific emission rate targets based on implementation of the best system of emission reduction. In April 2017, the D.C. Circuit granted the EPA's motion to hold the case in abeyance for at least 60 days while the agency reviews the rule, which was subsequently extended by the D.C. Circuit in August 2017. In October 2017, upon completion of the review, the EPA Administrator signed a proposed repeal of the CPP. The EPA Administrator concluded that the CPP exceeds the EPA's statutory authority by considering measures that are beyond the control of the owners of the affected sources (fossil fuel-fired electric generating units). Whether the EPA chooses to propose a replacement rule has not been decided. PSEG cannot estimate the impact of these actions on our business and future results of operations at this time.

Regional Greenhouse Gas Initiative (RGGI)

December 31, 2016 Form 10-K page 23. In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. New Jersey withdrew from RGGI in 2012. However, certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions. These rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three-year period. Allowances are available through the auction or through secondary markets.

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In September 2017, the RGGI States announced their new post-2020 program for a cap on regional CO_2 emissions, which would require a decline in CO_2 emissions in 2021 and each year thereafter, resulting in a 30% reduction in the CO_2 emissions cap by 2030.

Water Pollution Control

Steam Electric Effluent Guidelines

December 31, 2016 Form 10-K page 23, March 31, 2017 Form 10-Q on page 77 and June 30, 2017 Form 10-Q on page 85. In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG Rule) for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater, and gasification wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges and that are regulated under this rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the rule.

In April 2017, the EPA announced that it had granted a petition for reconsideration of the ELG Rule and issued an administrative stay of the compliance dates in the rule that were the subject of pending litigation. In June 2017, the EPA proposed a rule to postpone the compliance deadlines for the BAT limitations for the aforementioned waste streams. In September 2017, the EPA issued a rule postponing for two years compliance dates related solely to bottom ash transport water and flue gas desulfurization wastewater. The EPA has announced plans to issue a new rule by November 2020 addressing revised requirements and compliance dates for these two waste streams. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

Cooling Water Intake Structure

December 31, 2016 Form 10-K page 24. In May 2014, the EPA issued a final cooling water intake rule under Section 316(b) of the Clean Water Act (CWA) that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. In September 2014, several environmental non-governmental groups and certain energy industry groups filed petitions for review of the rule and the case has been assigned to the U.S. Second Circuit Court of Appeals (Second Circuit). Environmental organizations, including but not limited to the environmental petitioners in the Second Circuit, have also filed suit under the Endangered Species Act. The cases were subsequently consolidated at the Second Circuit and a decision remains pending.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 10	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective July 18, 2017
Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. PSE&G:

Exhibit 10	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective July 18, 2017
Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. Power:

Exhibit 10	Key Executive Severance Plan of Public Service Enterprise Group Incorporated, Amended effective July 18, 2017
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 31, 2017

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SIGNATURE

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 31, 2017

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PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK

Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 31, 2017

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Exhibit 10

KEY EXECUTIVE SEVERANCE PLAN OF PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

Amended effective July 18, 2017

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ARTICLE I

PURPOSE OF THE PLAN

1.1 Purpose. The Key Executive Severance Plan of Public Service Enterprise Group Incorporated ("Plan") is maintained by the Company to provide severance benefits to certain key executive-level employees of the Company and its affiliates whose employment is terminated under the circumstances described herein. The Plan was amended and restated effective December 17, 2012.

The Plan was amended effective January 1, 2014 to provide that (i) for Eligible Employees who become Schedule B Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to two times Annual Base Salary and Target Bonus, and (ii) for Eligible Employees who become Schedule A Participants after December 31, 2013, their Change in Control benefit under Section 5.2(b) of the Plan shall be equal to 1.5 times Annual Base Salary and Target Bonus. The Plan was further amended to provide that the for purposes of determining the nonqualified plan change in control benefit under Section 5.5(a) of the Plan, with respect to Eligible Employees who become Schedule A or Schedule B Participants after December 31, 2013, their employment shall be assumed to have continued for 1.5 or 2 additional years (for Schedule A Participants and Schedule B Participants, respectively). Finally, the Plan was amended to update the Schedule A Participant list.

The Plan was amended effective June 16, 2014 to (i) add a new class of eligible Participants, Schedule C Participants, (ii) to provide that there will be no additions to Schedule B Participants, (iii) to provide that other than a current Schedule B Participant, an Eligible Employee newly hired or promoted into a position reflected on Schedule B as of June 16, 2014, shall become a Schedule A Participant, and (iv) to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

The Plan was amended effective July 14, 2014 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan was amended effective February 17, 2015 to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list.

The Plan was amended effective November 18, 2015 to update the Schedule A Participant list, the Schedule B Participant list and the Schedule C Participant list, and to include the language to comply with the Securities and Exchange Commission's whistleblower protections.

The Plan was amended effective December 15, 2015 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan was amended effective July 19, 2016 to update the Schedule A Participant list and the Schedule C Participant list. The Plan was amended to comply with the Defense of Trade Secrets Act regarding the confidentiality provision. Finally, the Plan was amended

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to clarify that if an Eligible Employee is newly hired or promoted into a position reflected on Schedule B as of June 6, 2014, such Eligible Employee shall become a Schedule A Participant.

The Plan was amended effective November 14, 2016 to (i) revise the definition of Cause, (ii) align the severance benefits in Article IV, (iii) align the Change in Control benefits in Article V, (iv) update the Schedule A Participant list and the Schedule C Participant list, and (v) to make administrative clarifications. The Plan is intended to comply in operation and form with Section 409A of the Internal Revenue Code of 1986, as amended ("Code"). The timing and form of payment of benefits provided under the Plan will be deemed to be automatically modified, and a Participant's rights under the Plan will be limited so as to conform to any requirements under Section 409A of the Code.

The Plan was amended effective February 20, 2017 to update the Schedule A Participant list.

The Plan was amended effective April 17, 2017 to update the Schedule A Participant list and the Schedule C Participant list.

The Plan is being amended effective July18, 2017 (unless otherwise noted) to update the Schedule A Participant list, the Schedule B Participant List and the Schedule C Participant list.

ARTICLE II

DEFINITIONS

2.1 "Accrued Obligation" shall have the meaning set forth in Sections 4.2 and 5.2 of the Plan.

2.2 "Affiliate" means any corporation, trade or business if it or the Company are members of a controlled group of corporations, are under common control or are members of an affiliated service group within the meanings of Sections 414(b), 414(c) and 414(m), respectively, of the Code. The term "Affiliate" shall also include any other entity required to be aggregated with the Company pursuant to regulations under Section 414(o) of the Code.

2.3 "Annual Base Salary" means the annual rate of base salary payable to a Participant for services performed for an Employer, as in effect immediately prior to the Participant's Date of Termination.

2.4 "Benefits 2000 Participant" means a Participant who is a participant in the Public Service Enterprise Group Incorporated Benefits 2000 Health and Welfare Benefits Plan.

2.5 "Board" means the board of directors of the Company.

2.6 "Cause" means:

(a) For purposes of Article IV and Article V:

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(i) Misconduct, gross negligence, theft, or fraud against the Company, including an isolated incident, that is determined by the Committee's delegate to be material misconduct or material gross negligence;

(ii) For "Performance Reasons," as defined in Section 2.20 of the Plan;

(iii) Material violation of the Standards of Integrity or other Company policy;

(iv) Insubordination, including an isolated incident, that is determined by the Committee's delegate to be material insubordination;

(v) One or more significant acts of dishonesty;

(vi) Any act that is likely to have the effect of injuring the reputation, business, or business relationship of, the Company, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries;

(vii) Violation of any fiduciary duty, including an isolated incident, that is determined by the Committee's delegate to be a material violation;

(viii) Breach of any duty of loyalty including an isolated incident, that is determined by the Committee's delegate to be a material breach;

(ix) Any breach of the restrictive covenants contained in Exhibit I below;

(x) One or more acts of moral turpitude that constitute a violation of applicable law (included but not limited to a felony);

(xi) Conviction of a felony or plea of *nolo contendere* to a felony charge;

(xii) Pattern of behaviors that fail to meet the Company's expectations described in "PSEG Values, Behaviors, and Leadership Competencies." or

(xiii) Any other reason determined to be Cause by the Chief Executive Officer of the Company.

2.7 "Change in Control" means the occurrence of any of the following events:

(a) Any "person" (within the meaning of Section 13(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) is or becomes the beneficial owner within the meaning of Rule 13d-3 under the Exchange Act (a "Beneficial Owner"), directly or indirectly, of securities of the Company (not including in the securities beneficially owned by such person any securities acquired directly from the Company or its Affiliates) representing 25% or more of the combined voting power of the Company's then outstanding securities, excluding any person who becomes such a Beneficial Owner in connection with a transaction described in clause (i) of paragraph (c) below; or

(b) The following individuals cease for any reason to constitute a majority of the number of directors of the Company then serving: individuals who, on the Effective Date, constitute the Board and any new director (other than a director whose initial assumption of office is in connection with an actual or threatened election contest, including but not limited to a consent solicitation, relating to the

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election of directors of the Company) whose appointment or election by the Board or nomination for election by the Company's stockholders was approved or recommended by a vote of at least two-thirds of the directors then still in office who either were directors on the Effective Date or whose appointment, election or nomination for election was previously so approved or recommended; or

(c) There is consummated a merger or consolidation of the Company or any direct or indirect wholly-owned subsidiary of the Company with any other corporation, other than (i) a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior to such merger or consolidation continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent thereof), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of the Company or of its Affiliates, at least 75% of the combined voting power of the securities of the Company or such surviving entity or any parent thereof outstanding immediately after such merger or consolidation, or (ii) a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no person is or becomes the Beneficial Owner, directly or indirectly, of securities of the Company representing 25% or more of the combined voting power of the Company's then outstanding securities; or

(d) The shareholders of the Company approve a plan of complete liquidation or dissolution of the Company or there is consummated an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets, other than a sale or disposition by the Company of all or substantially all of the Company's assets to an entity, at least 75% of the combined voting power of the voting securities of which are owned by stockholders of the Company in substantially the same proportions as their ownership of the Company immediately prior to such sale.

Notwithstanding the foregoing, a "Change in Control" shall not be deemed to have occurred by virtue of the consummation of any transaction or series of integrated transactions immediately following which the record holders of the common stock of the Company immediately prior to such transaction or series of transactions continue to have substantially the same proportionate ownership in an entity which owns all or substantially all of the assets of the Company immediately following such transaction or series of transactions.

2.8 "Code" means the Internal Revenue Code of 1986, as amended, and the regulations promulgated thereunder.

2.9 "Committee" means the Organization and Compensation Committee of the Board or any successor of such Committee.

2.10 "Company" means Public Service Enterprise Group Incorporated and any successors thereto.

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2.11 "Confidential Information" means all trade secrets, proprietary and confidential business information belonging to, used by, or in the possession of the Company or any of its Affiliates, including but not limited to information, knowledge or data related to business strategies, plans and financial information, mergers, acquisitions or consolidations, purchase or sale of property, leasing, pricing, sales programs or tactics, actual or past sellers, purchasers, lessees, lessors or customers, those with whom the Company or its Affiliates has begun negotiations for new business, costs, employee compensation, marketing and development plans, inventions and technology, whether such confidential information, knowledge or data is oral, written or electronically recorded or stored, except information in the public domain, information known by the Participant prior to employment with an Employer, and information received by the Participant from sources other than the Company or its Affiliates, without obligation of confidentiality.

2.12 "Date of Termination" means, provided that the termination constitutes a Separation from Service, (i) the date of a Participant's death, (ii) the date on which the termination of the Participant's employment by an Employer for Cause or without Cause, or (iii) the date on which the Participant terminates employment for Good Reason or without Good Reason, including Retirement and Disability.

2.13 "Disability" means (a) if the Participant is a participant in the Pension Plan, the Participant is determined to be totally and permanently disabled by the Company's medical director; or (ii) if the Participant is a participant in the Cash Balance Plan, the Participant is receiving benefits from the Company's long-term disability plan.

2.14 "Eligible Employee" means an individual who is designated as such in accordance with Section 3.1. An Eligible Employee shall not include a "project employee."

2.15 "Effective Date" of the amendment and restatement is July 18, 2017.

2.16 "Employer" means the Company and each Affiliate, and any successors thereto.

2.17 "Good Reason" means:

(a) Any material reduction in the Participant's Annual Base Salary, Target Bonus or Target Long-Term Incentive, other than reductions pursuant to a broad-based compensation reduction program or policy affecting the Participant and all similarly situated employees of the Employer. Notwithstanding the foregoing, this Subsection (a) shall not apply if the Participant moves into a position with ER&T;

(b) Any material adverse change in the Participant's title, authority, duties, or responsibilities or the assignment to the Participant of any duties or responsibilities inconsistent in any respect with those customarily associated with the position of the Participant immediately prior to the Change in Control. Notwithstanding the foregoing, this Subsection (b) shall not apply if the Participant moves into a position with ER&T;

(c) The failure of any successor to the Company to assume this Plan in accordance with Section 11.5(b);

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(d) Where the only comparable position offered to the Participant within the Employer following a Change in Control would otherwise meet the requirements of Subsections (a) and (b) of this Section 2.17 of the Plan, but would require the Participant to increase their one-way commuting distance from their principal residence by more than 50 miles; or

(e) Any other material breach of the terms of the Plan by the Company that either is not taken in good faith or, even if taken in good faith, is not remedied by the Company promptly after receipt of notice thereof from the Participant.

Notwithstanding the forgoing, for purposes of the Plan, the termination of a Participant's employment with an Employer shall not be deemed to be for Good Reason unless such termination is effected in accordance with the following procedures. The Participant shall give the Employer a written notice ("Notice of Termination for Good Reason") of the termination, setting forth in reasonable detail the specific acts or omissions of the Employer that constitute Good Reason and the specific provision(s) of the Plan on which the Participant relies. Unless the Committee determines otherwise, a Notice of Termination for Good Reason by the Participant must be made within 60 days after the Participant first has actual knowledge of the act or omission (or the last in a series of acts or omissions) that the Participant alleges to constitute Good Reason, and the Employer shall have 30 days from the receipt of such Notice of Termination for Good Reason to cure the conduct cited therein. A termination of employment by the Participant for Good Reason shall be effective on the final day of such 30-day cure period unless prior to such time the Employer has cured the specific conduct asserted by the Participant to constitute Good Reason to the reasonable satisfaction of the Participant.

For purposes of the Plan, a Participant's determination that an act or failure to act constitutes Good Reason shall be presumed to be valid unless such determination is decided to be unreasonable by the Committee or its delegate pursuant to Article IX.

2.18 "Nonqualified Plan" means the Retirement Income Reinstatement Plan for Non-Represented Employees of Public Service Enterprise Group Incorporated.

2.19 "Participant" means an Eligible Employee who is listed on either Schedule A, Schedule B or Schedule C hereto, as the same may be amended from time to time.

2.20 "Performance Reasons" means the Participant's failure meet the expectations established for such Participant's function in the Company as: (i) communicated to the Participant by their manager during any performance review, or (ii) may be communicated to the Participant otherwise by their manager from time to time either orally or in writing.

2.21 "Plan" means this Key Executive Severance Plan of Public Service Enterprise Group Incorporated, as set forth herein and as may be amended, modified or supplemented from time to time.

2.22 "Prior Equity Awards" means outstanding stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares and performance shares units.

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2.23 "Retiree Medical Plan" means the Public Service Enterprise Group Incorporated Medical Benefits Plan for Retired Employees.

2.24 "Retirement" means a Separation from Service after the Participant has satisfied the eligibility requirements for early or normal retirement under the terms of the Retirement Plan in which the Participant participates. Notwithstanding the foregoing, for the purposes of determining benefit entitlements under Article V of the Plan, Retirement shall not include forced retirements or any termination by an Employer without Cause or voluntary termination by the Participant for Good Reason that occurs on a date on which the Participant is Retirement eligible.

2.25 "Retirement Plan" means the retirement plan in which the Participant participates in either the Pension Plan of Public Service Enterprise Group Incorporated or the Cash Balance Pension Plan of Public Service Enterprise Group Incorporated.

2.26 "Schedule A Participant" means a Participant listed on Schedule A hereto.

2.27 "Schedule B Participant" means a Participant listed on Schedule B hereto.

2.28 "Schedule C Participant" means a Participant listed on Schedule C hereto.

2.29 "Selectline Participant" means a Participant who is a participant in the Public Service Enterprise Group Incorporated Selectline Benefits Plan.

2.30 "Separation from Service" shall be deemed to have occurred if a Participant and the Company or any Affiliate reasonably anticipates, based on the facts and circumstances, that either:

(a) The Participant will not provide any additional services for the Company or an Affiliate after a certain date; or
(b) The level of bona fide services performed by the Participant after a certain date will permanently decrease to no more than 50 percent of the average level of bona fide services performed by the Participant over the immediately preceding 36 months.

If a Participant is absent from employment due to military leave, sick leave or any other bona fide leave of absence authorized by the Company or an Affiliate and there is a reasonable expectation that the Participant will return to perform services for the Company or an Affiliate, a Separation from Service will not occur until the later of: (i) the first date immediately following the date that is six months after the date that the Participant was first absent from employment; or (ii) the date the Participant no longer retains a right to reemployment, to the extent the Participant retains a right to reemployment with the Company or any Affiliates under applicable law or by contract. If a Participant fails to return to work upon the expiration of any military leave, sick leave or other bona fide leave of absence where such leave is for less than six months, the Separation from Service shall occur as of the date of the expiration of such leave, unless a greater period is provided for under applicable law.

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2.31 "Specified Employee" means any individual who is a key employee (as defined in Section 416(i) of the Code without regard to Section 416(i)(5) of the Code) of the Company at any time during the 12-month period ending on each December 31 (the "identification date"). If an individual is a key employee as of an identification date, the individual shall be treated as a Specified Employee for the 12-month period beginning on the April 1 following the identification date. Notwithstanding the foregoing, an individual shall not be treated as a Specified Employee unless any stock of the Company or an Affiliate is publicly traded on an established securities market or otherwise.

2.32 "Target Bonus" means the Participant's target annual bonus, if any, under the applicable annual incentive compensation plan of the Company for the fiscal year in which the Date of Termination occurs.

2.33 "Target Long-Term Incentive" means the Participant's target long-term incentive award, if any, under the applicable long-term incentive compensation plan of the Company.

ARTICLE III

ELIGIBILITY AND PARTICIPATION

3.1 Eligible Employees. Eligibility to participate in the Plan shall be limited to certain key executives of an Employer who (a) are not parties to individual employment or change in control agreements that provide for severance benefits, and (b) are designated, by duly adopted resolution of the Committee, as Eligible Employees.

3.2 Participation. Schedules A, B and C hereto list the Eligible Employees who have satisfied the conditions for Plan participation and the date as of which each such Eligible Employee became a Participant. The Committee shall cause Schedules A, B and C to be updated from time to time to reflect the Participants who are currently participating in the Plan. An employee who becomes an Eligible Employee on or after January 1, 2014 shall become a Schedule C Participant. However, if an Eligible Employee is newly hired or promoted into a position reflected on Schedule B as of June 6, 2014, the Eligible Employee shall become a Schedule A Participant.

3.3 Release of Claims. Notwithstanding anything in the Plan to the contrary, payment of any benefits under the Plan is expressly contingent upon the Participant's execution and delivery to the Company, within 30 days after the Participant's Date of Termination, of a written agreement provided by the Company, wherein the Participant releases and discharges the Company and each of its Affiliates of any and all claims against the Company and its Affiliates related in any way to the Participant's employment with an Employer and the termination of such employment.

3.4 Committee Discretion. The Committee shall have the sole discretion to determine eligibility for benefits under the Plan.

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ARTICLE IV

SEVERANCE BENEFITS IN GENERAL

4.1 Eligible Terminations. If a Participant's employment is involuntarily terminated by an Employer for any reason other than Cause, the Participant shall be eligible for the benefits described in this Article IV.

If a Participant terminates employment for Good Reason, other than in connection with a change in employment on account of Performance Reasons, the Participant shall be eligible for the benefits described in this Article IV.

If a Participant experiences a cessation of employment in connection with a reduction in force or an Employer reorganization (as determined by the Committee) where the only position offered to the Participant within the Company and Affiliates would require the Participant to increase their one-way commuting distance by more than 50 miles, the Participant shall be eligible for benefits described in this Article IV.

For the avoidance of any doubt, a Participant shall not be entitled to benefits under the Plan if termination from employment is the result of death, Disability, the Participant voluntarily terminates employment, except for Good Reason other than in connection with a change in employment on account of Performance Reasons. Also, the Participant shall not be entitled to benefits under the Plan if the Participant's cessation of employment is in connection with the sale of the Participant's Employer, line or unit of business of the Employer within which the Participant's position is located, business function of the Employer within which the Participant's position is located, or the assets related to the Employer, line or unit or business, or business function within which the Participant's position is located, and the Participant accepts employment with the purchaser within 90 days of the closing of the transaction in a position that has an annual rate of base salary that is at least 80 percent of the Participant's annual rate of base salary immediately prior to the closing of the sale.

If a Participant enters into a Voluntary Separation Agreement ("VSA") with an Employer, such Participant shall not be eligible for benefits under the Plan.

4.2 Cash payment. The Company shall pay to the Participant a lump sum, in cash, the sum of (a) and (b):

(a) The Participant's base salary and accrued vacation pay through the Date of Termination to the extent not theretofore paid (hereinafter referred to as the "Accrued Obligations"); and

(b) An amount equal to the product of 1.0 times (0.5 times if the Participant were employed less than one year) the sum of the Participant's Annual Base Salary and Target Bonus.

4.3 Long-Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

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4.4 Annual Incentive Awards. The Participant shall receive a prorated annual incentive award pursuant to the performance incentive program, if applicable, for the calendar year in which the Participant's Termination of Employment occurs. The award shall be calculated based solely on 100 percent of the target incentive award and prorated based on the number of calendar days of employment in the calendar year in which the Participant's termination occurs through the Participant's Date of Termination. For purposes of this Section 4.4, calendar year shall mean 365 days.

Annual incentive awards with respect to the calendar year in which a Participant's Date of Termination occurs will be paid at the same time as awards for such calendar year are paid to active employees of the Employer.

4.5 Outplacement Services. Outplacement services approved by the Committee, which may include individual or group counseling and administrative assistance or workshops, shall be available beginning on the Participant's Date of Termination or such earlier date designated by the Participant's business unit leadership. Outplacement services shall continue to be available for the period up to 12 months.

4.6 Educational Assistance. Educational assistance shall be provided in accordance with the Employer's tuition program.

4.7 Health Care Benefits.

(a) Medical Coverage for Selectline Participants.

(i) A Selectline Participant who has satisfied the eligibility requirements for medical coverage under the Retiree Medical Plan on the Date of Termination shall be eligible to elect coverage thereunder in accordance with the terms of the Retiree Medical Plan.

(ii) A Selectline Participant who has not otherwise satisfied the eligibility criteria for participation in the Retiree Medical Plan prior to the Date of Termination, shall be eligible to elect coverage under the Retiree Medical Plan as though such Selectline Participant has otherwise satisfied the eligibility requirements if:

(A) The Selectline Participant has attained age 50 and completed ten or more Years of Service as of the Date of Termination but the sum of the Selectline Participant's age and Years of Service is less than 80; or

(B) The Selectline Participant has attained age 49 and completed 20 or more Years of Service as of the Date of Termination but the sum of the Selectline Participant's age and Years of Service is less than 80.

Such coverage shall commence no earlier than the Selectline Participant's Date of Termination. The Selectline Participant shall be charged the full cost of coverage under the Retiree Medical Plan.

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(iii) If a Selectline Participant who is not eligible for, or does not elect, coverage under the Retiree Medical Plan, timely elects continuation coverage under the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended ("COBRA"), the Employer shall pay the same portion of the cost of medical and/or dental coverage that it paid immediately prior to the Selectline Participant's Date of Termination for active employees during the one-year period following the Selectline Participant's Date of Termination. During the one-year period, the Participant shall pay the difference between the total cost of medical and/or dental coverage and the Employer's portion of the cost. After the expiration of the one-year period, the Selectline Participant shall be charged the COBRA rate for medical and/or dental coverage for the remainder of the COBRA period. If the Participant does not timely elect COBRA medical and/or dental coverage, the Participant shall not be entitled to the benefit under this Subsection (iii). Following the one-year period, the Selectline Participant shall not be permitted to elect coverage, or be covered, under the Retiree Medical Plan. During the entire COBRA period, the Selectline Participant shall be responsible for the full cost of COBRA vision and hearing coverage, as applicable.

(b) Medical Coverage for Benefits 2000 Participants**.** If a Benefits 2000 Participant who is not eligible for, or does not elect, coverage under the Retiree Plan, timely elects COBRA continuation medical and/or dental coverage, the Employer shall pay the same portion of the cost of medical and/or dental coverage that it paid immediately prior to the Participant's Date of Termination for active employees during the one-year period following the Participant's Date of Termination. During the one-year period, the Participant shall pay the difference between the total cost of medical and/or dental coverage and the Employer's portion of the cost. After the expiration of the one-year period, the Benefits 2000 Participant shall be charged the COBRA rate for medical and/or dental coverage for the remainder of the COBRA period. If the Participant does not timely elect COBRA medical and/or dental coverage, the Participant shall not be entitled to the benefit under this Subsection (b). Following the one-year period, the Benefits 2000 Participant shall not be permitted to elect coverage, or be covered, under the Retiree Medical Plan. During the entire COBRA period, the Benefits 2000 Participant shall be responsible for the full cost of COBRA vision.

4.8 Other Benefits. A Participant shall not be entitled to any severance, separation or early retirement incentive pay or benefits other than as provided hereunder or under any qualified or nonqualified retirement plan or deferred compensation arrangement maintained by the Employer. Except as provided in the foregoing sentence, a Participant's rights under any other employee benefit plans maintained by the Company or an Affiliate shall be determined in accordance with the provisions of such plans, including the Company's right to amend or terminate such plans at any time.

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ARTICLE V

SEVERANCE BENEFITS AFTER A CHANGE IN CONTROL

5.1 Eligible Terminations After a Change in Control. If, within two years following the occurrence of a Change in Control, either (a) an Employer shall terminate a Participant's employment for any reason other than for Cause, or (b) a Participant shall voluntarily terminate employment for Good Reason, the Participant shall be eligible for benefits described in this Article V of the Plan. Notwithstanding anything in the Plan to the contrary, a Participant shall not be entitled to benefits under the Plan if termination from employment is the result of death, Disability or the Participant voluntarily terminates employment, except for Good Reason and except as otherwise provided under the Plan.

If a Participant enters into a VSA with an Employer, such Participant shall not be eligible for benefits under the Plan.

5.2 Cash Payment. The Company shall pay to the Participant, in a lump sum in cash, the aggregate of the amounts in (a) and (b) below:

(a) The sum of:

(i) The Participant's base salary and accrued vacation through the Date of Termination; and

(ii) The product of (x) the Participant's Target Bonus and (y) a fraction, the numerator of which is the number of days in the current calendar year through the Date of Termination, and the denominator of which is 365;

in each case to the extent not theretofore paid (the sum of the amounts described in clauses (i) and (ii) shall be hereinafter referred to as the "Accrued Obligations"); and

(b) Either (i), (ii) or (iii):

(i) In the case of a Schedule A Participant, the amount equal to the product of two times the sum of the Schedule A Participant's Annual Base Salary and Target Bonus;

(ii) In the case of a Schedule B Participant, the amount equal to the product of three times the sum of the Schedule B Participant's Annual Base Salary and Target Bonus; or

(iii) In the case of a Schedule C Participant, the amount equal to the product of one and one-half times the sum of the Schedule C Participant's Annual Base Salary and Target Bonus.

5.3 Long Term Incentive Awards. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.4 Health Care and Other Welfare Benefits. The Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the

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Company's medical and dental employee benefit plans for 18 months after the Date of Termination provided that the Participant timely makes an election to continue such coverage in the Company's medical and dental employee benefit plans under COBRA, subject to the requirements and limitations thereof. Unless otherwise limited by applicable law, thereafter, the Company shall pay the cost of the continued coverage of the Participant and/or the Participant's family under the Company's medical and dental employee benefit plans for an additional period of six months, in the case of a Schedule A Participant, or 18 months, in the case of a Schedule B Participant (for a Schedule C Participant, no additional period beyond the initial 18 months); provided however, that if the Participant becomes re-employed with another employer and is eligible to receive medical or dental benefits under another employer provided plan, the medical and dental benefits provided by the Company under this Plan shall be secondary to those provided under such other plan during the applicable period of eligibility. If the Participant does not timely elect COBRA coverage, the Participant shall not be entitled to the COBRA continuation benefit under this Section 5.4 of the Plan.

Unless otherwise limited by applicable law or by a third-party vendor contract, for two years after the Date of Termination in the case of a Schedule A Participant, three years after the Date of Termination in the case of a Schedule B Participant, or in the case of a Schedule C Participant, eighteen months after the Date of Termination (or for any Participant such longer period as may be provided by the terms of the appropriate plan, program, practice or policy), the Company shall continue benefits (other than medical and dental benefits) to the Participant and/or the Participant's family at least equal to those which would have been provided to them in accordance with the welfare plans, programs, practices and policies maintained by the Company if the Participant's employment had not been terminated or, if more favorable to the Participant, as in effect generally at any time thereafter with respect to other peer executives of the Employer and their families.

Unless otherwise limited by applicable law or by a third-party vendor contract, the Participant's eligibility (but not the time of commencement of such benefits) for retiree benefits pursuant to the welfare plans, programs, practices and policies maintained by the Company shall be determined as if the Participant had (A) remained employed until two years (in the case of a Schedule A Participant), three years (in the case of a Schedule B Participant), or eighteen months (in the case of a Schedule C Participant) after the Date of Termination and (B) retired on the last day of such period.

5.5 Nonqualified Pension Benefit. The Participant shall be paid, in a lump sum payment in cash, an amount equal to the excess of (a) - (b):

(a) The actuarial equivalent of the benefit under the Company's applicable Retirement Plan (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the Effective Date), any benefit under the Nonqualified Plan and, to the extent applicable, any other defined benefit retirement arrangement between the Participant and the Company ("Other Pension Benefits") which the Participant would receive if the

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Participant's employment continued for two, three or one and one-half additional years (for Schedule A Participants, Schedule B and Schedule C Participants, respectively) beyond the Date of Termination and, assuming that the Participant's compensation for such deemed additional period was the Participant's Annual Base Salary as in effect immediately prior to the Date of Termination and assuming a bonus in each year during such deemed additional period equal to the Target Bonus,

(b) The actuarial equivalent of the Participant's actual benefit (paid or payable), if any, under the Retirement Plan, the Nonqualified Plan and Other Pension Benefits as of the Date of Termination (utilizing the rate used to determine lump sums and, to the extent applicable, other actuarial assumptions no less favorable to the Participant than those in effect under the Retirement Plan immediately prior to the effective date of the Change in Control).

5.6 Deferred Compensation. Any compensation previously deferred (other than pursuant to a tax-qualified plan) by or on behalf of the Participant (together with any accrued interest or earnings thereon), whether or not then vested, shall become vested on the Date of Termination and shall be paid in accordance with the terms of the applicable deferred compensation plan, policy or practice under which it was deferred to the extent permitted by Section 409A of the Code.

5.7 Outplacement Services. The Company shall, at its sole expense as incurred, provide the Participant with outplacement services suitable to the Participant's position for a period not to exceed one year following the Date of Termination with a nationally recognized outplacement firm.

5.8 Other Benefits. To the extent not theretofore paid or provided, the Company shall pay or provide to the Participant any other amounts or benefits required to be paid or provided or which the Participant is entitled to receive under any plan, program, policy, practice, contract or agreement of the Company (or other Employer), including earned but unpaid stock and similar compensation, but excluding medical or dental benefits if the Participant is eligible for such benefits to be provided by a subsequent employer, and benefits payable under any severance plan or policy.

5.9 Termination By Employer For Cause or By Participant Other Than For Good Reason. If, at any time after a Change in Control, either (a) an Employer shall terminate a participant's employment for Cause or (b) the Participant shall voluntarily terminate employment other than for Good Reason, the Employer shall have no further payment obligations to the Participant other than for the Participant's base salary through the Date of Termination and any accrued but unpaid vacation pay. In such case, all such amounts shall be paid to the Participant in a lump sum in accordance with Section 6.1 of the Plan.

5.10 Death. If a Participant's employment terminates by reason of the Participant's death after a Change in Control, all Accrued Obligations as of the time of death shall be paid to the Participant's estate or beneficiary, as applicable, in a lump sum in cash in accordance with Section 6.1 of the Plan. The Participant's estate or beneficiary shall be entitled to

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any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.11 Disability. If a Participant's employment is terminated by reason of Disability after a Change in Control, all Accrued Obligations shall be paid to the Participant in a lump sum in cash in accordance with Section 6.1 of the Plan. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

5.12 Retirement. If a Participant's employment terminates as a result of Retirement after a Change in Control, the Participant shall be paid the Accrued Obligations in a lump sum in cash in accordance with Section 6.1 of the Plan and the Participant shall be entitled to any Other Benefits in accordance with their terms. The treatment of Prior Equity Awards shall be governed by the terms of the Long-Term Incentive Plan and the related award agreements.

ARTICLE VI

TIMING OF, LIMITATIONS ON AND ADJUSTMENTS TO PLAN PAYMENTS

6.1 Time of Payments. Payments under the Plan shall be made to the Participant as follows:

(a) With respect to benefits, except those under Sections 4.4 and 5.10 of the Plan, payment to a Participant who is not a Specified Employee shall be made within the 60-day period following the Participant's Date of Termination. However, if the period to consider and revoke the written agreement required to receive the benefits described in Articles IV and V of the Plan (i.e., the waiver and release) spans two taxable years, in all events the payments will be made in the second taxable year within 30 days following the later of the end of the first taxable year or the date the executed release is received by the Company.

(b) With respect to benefits under Section 5.10 of the Plan, payment shall be made within the 60-day period following the Participant's date of the Participant's death.

(c) With respect to benefits under Section 4.4 of the Plan, payments shall be made to the Participant at the same time the payments are made to active employees.

(d) Notwithstanding anything to the contrary in the Plan, to the extent necessary to comply with Section 409A of the Code, payments to a Participant who is a Specified Employee shall be made within the 60-day period following the six-month anniversary of the Participant's Date of Termination (other than by reason of death).

(e) All payments under the Plan that are reimbursements of covered expenses incurred by the Participant shall be made within the taxable year in which the expense is incurred.

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6.2 Payment Offsets. Notwithstanding anything in the Plan to the contrary, in the event a Participant is entitled to receive severance payments both under this Plan and under the terms of either (a) an individual change of control or employment agreement, (b) another severance pay plan or policy of an Employer or (c) any existing or future law or regulation, the benefits payable under this Plan shall be reduced by the amount of any severance benefits such Participant is entitled to receive under such individual agreement, plan, policy, law or regulation.

6.3 Cap on Excess Parachute Payments; Gross-Up Payments. Notwithstanding anything in the Plan to the contrary, if (a) a Participant is a "disqualified individual" (as defined in Section 280G(c) of the Code) and (b) the severance benefits provided under Articles IV or V, as applicable, together with any other payments the Participant has the right to receive from an Employer, would constitute a "parachute payment" (as defined in Section 280G(b) of the Code) ("Parachute Payments"), the following provisions shall apply:

(a) The severance benefits under Articles IV or V shall not exceed an amount which, together with any other Parachute Payments, the Participant has a right to receive from the Employer, would be 2.99 times the Participant's "base amount" (as defined in Section 280G of the Code) so that no portion of the amounts received by the Participant shall be subject to the excise tax imposed under Section 4999 of the Code.

(b) The determination of whether any limitation on the severance benefits payable under Articles IV or V is necessary shall be made by the Company's independent auditor or such other certified public accounting firm as may be jointly designated by the Participant and the Company (the "Accounting Firm"), which shall provide detailed supporting calculations to the Participant and the Company. The determinations of the Accounting Firm shall be conclusive and binding on the Company and the Participant. All fees and expenses of the Accounting Firm shall be borne solely by the Company.

(c) If through error or otherwise, a Participant shall receive payments under the Plan, together with other Parachute Payments the Participant has the right to receive from an Employer, in excess of 2.99 times the Participant's base amount, the Participant shall immediately repay the excess to the Employer upon notification from the Employer that an overpayment has been made. If the Participant fails to repay the excess to the Employer within 10 business days of the date of the Employer's notification, the Participant will become liable to the Employer for an amount equal to two (2) times the excess amount.

6.4 Compliance with Section 409A of the Code. Notwithstanding anything in the Plan to the contrary, all Plan benefit obligations and payments are subject to Section 409A of the Code. To the extent required, the Company may modify the severance benefits payable hereunder to comply with Section 409A of the Code; provided, however, that the present value of the aggregate Plan benefits payable to a Participant after such modification shall not be less than the present value of the Plan benefits payable to the Participant prior to the modification.

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6.5 Tax Withholding. Notwithstanding any other provision of this Plan, the Company may withhold from any amounts payable under this Plan such Federal, state, local, employment or foreign taxes as shall be required to be withheld pursuant to any applicable law or regulation.

ARTICLE VII

RESTRICTIVE COVENANTS

7.1 Confidentiality. As a condition to participation in the Plan, each Participant agrees to hold in a fiduciary capacity for the benefit of the Company and its Affiliates all Confidential Information which shall have been obtained by the Participant during the Participant's employment by the Employer; except, however, that this Section 7.1 shall not apply to Confidential Information that is or becomes public knowledge, unless such Confidential Information became or becomes public knowledge due to acts of the Participant or representatives of the Participant in violation of this Section 7.1. Upon termination of the Participant's employment, the Participant shall return to the Company all Confidential Information in their possession. After termination of the Participant's employment with the Employer, the Participant shall not, without the prior written consent of the Company or as may otherwise be required by law or legal process, communicate or divulge any such Confidential Information to anyone other than the Company and those designated by it, except (a) otherwise publicly available information, (b) as may be necessary to enforce the Participant's rights under the Plan or as necessary for the Participant to defend against a claim asserted directly or indirectly by the Company or its Affiliates, or (c) as may be compelled by service of a valid subpoena or other legal process (if the Participant is served with a valid subpoena or other legal process, the Participant must so notify the Company within three business days). Furthermore, nothing contained in this Plan prevents a Participant from disclosing without notice to the Company any perceived violation of law to any Federal, state, or local governmental agency or entity including, but not limited to, the Securities and Exchange Commission, or making other disclosures that are protected under the whistleblower provisions of any law. Finally, nothing in this Plan prevents a Participant - nor should a Participant be held civilly or criminally liable under any law - if the Participant discloses a trade secret: (a) in confidence to a Federal, State or local government official, either directly or indirectly, or to an attorney solely for the purpose of reporting or investigating a suspected violation of law; (b) in a complaint or other document filed in a lawsuit or other proceeding, if such filing is made under seal; (c) to the Participant's attorney in connection with a lawsuit alleging retaliation by an employer for reporting a suspected violation of law; or (d) in connection with a lawsuit described in the immediately preceding subparagraph (c), provided the Participant: (i) files any document containing the trade secret under seal; and (ii) does not disclose the trade secret, except pursuant to a court order. Unless and until a determination has been made in accordance with Section 7.4 that the Participant has violated this Section 7.1, an asserted violation of the provisions of this Section 7.1 shall not constitute a basis for deferring or withholding any amounts otherwise payable to the Participant under the Plan.

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7.2 Non-Compete. As a condition to participation in the Plan, each Participant agrees that in the event the Participant voluntarily terminates employment other than for Good Reason, for the period of one year from Date of Termination, the Participant will not, without the written consent of the Company, directly or indirectly own, manage, operate, join, control, become employed by, consult to or participate in the ownership, management, or control of any business which is in direct competition with the Company or its Affiliates.

7.3 Non-Solicitation. As a condition to participation in the Plan, each Participant agrees that, in the event the Participant voluntarily terminates employment other than for Good Reason, for the period of one year following the Date of Termination, the Participant will not, directly or indirectly, solicit or hire, or encourage the solicitation or hiring by any employer other than the Company or its Affiliates, for any position as an employee, independent contractor, consultant or otherwise, any person who was a managerial or higher level employee of an Employer at any time during the term of the Participant's employment by the Employer; provided, however, that this provision shall not apply with respect to the solicitation of any person after six months from the date on which such person's employment by an Employer has terminated.

7.4 Enforcement. In the event of a breach by the Participant of any of the covenants set forth in this Article VII, it is agreed that the Company shall suffer irreparable harm for which money damages are not an adequate remedy, and that, in the event of such breach, the Company shall be entitled to obtain an order of a court of competent jurisdiction for equitable relief from such breach, including, but not limited to, temporary restraining orders and preliminary and/or permanent injunctions against the breach of such covenants by the Participant. In the event that the Company should initiate any legal action for the breach or enforcement of any of the provisions contained in this Article VII and the Company does not prevail in such action, the Company shall promptly reimburse the Participant the full amount of any court costs, filing fees, attorney's fees which the Participant incurs in defending such action, and any loss of income during the period of such litigation.

Nothing in this Plan prohibits the Participant from reporting possible violations of Federal law or regulation to any governmental agency or entity, including but not limited to the Department of Justice, the Securities and Exchange Commission, the Congress, and any agency Inspector General, or making other disclosures that are protected under the whistleblower provisions of Federal law or regulation. The Participant does not need the prior authorization of the Law Department to make any such reports or disclosures, and is not required to notify the Company that such reports or disclosures have been made.

ARTICLE VIII

AMENDMENT AND TERMINATION

8.1 Amendment. The Company may amend this Plan at any time, and from time to time, by action of the Committee; provided, however, that no amendment adopted after the effective date of a Change in Control shall have the effect of either (a) removing an

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individual from the list of Participants, (b) adding conditions for participation or the entitlement to receive benefits hereunder, (c) reducing the amount of benefits payable to a Participant, or (d) otherwise restricting a Participant's right to receive benefits under the Plan, except as may otherwise be required to conform such payments to the requirements of Section 409A of the Code.

8.2 Termination. The Committee may terminate the Plan at any time prior to a Change in Control. The Plan may not be terminated after the effective date of a Change in Control.

ARTICLE IX

ADMINISTRATION

9.1 Plan Administrator. The Plan shall be administered by the Committee, which shall have the duties and responsibilities for administering the Plan as are specifically set forth in this Article IX.

9.2 Responsibilities of Committee.

(a) The Committee shall have responsibility for the day to day administration of the Plan. In addition, the Committee shall have the specific powers, duties, responsibilities and obligations specifically provided for herein.

(b) Subject to the express provisions of the Plan, the Committee shall have full and exclusive authority to interpret the Plan and to make all other factual determinations deemed necessary or advisable in the implementation and administration of the Plan, including but not limited to determinations with respect to the eligibility of Participants to receive benefits under the Plan and the status and rights of such Participants and all other persons affected hereunder. The Committee's interpretation and construction of the Plan shall be conclusive and binding on all persons.

(c) The Committee shall have sole authority to adopt rules and regulations, which shall be administered by the Committee. In addition, the Committee shall have the discretionary authority to issue rulings and interpretations concerning the Plan and all matters arising thereunder, on a uniform and nondiscriminatory basis, provided the same shall not be contrary to or inconsistent with any provision of the Plan.

(d) As a condition of distributing any benefit under the Plan, the Committee may prescribe the use of such forms and require the furnishing of such information as the Committee may deem appropriate for administering the Plan.

9.3 Allocation or Delegation of Duties and Responsibilities. In furtherance of its duties and responsibilities under the Plan, the Committee may:

(a) Employ agents to carry out non-fiduciary responsibilities;

(b) Employ agents to carry out fiduciary responsibilities;
(c) Consult with counsel, who may be counsel to the Company; and
(d) Delegate any of its duties and responsibilities hereunder to such officer or officers of the Company as the Committee shall designate; except, however, that the

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Committee may not delegate to any other person the designation of Eligible Employees under Section 3.1 or the authority to consider and determine appeals of alleged adverse benefit determinations.

The Committee delegates to the Chief Executive Officer of the Company the responsibility and authority to interpret the terms of the Plan, including the benefits payable thereunder. Furthermore, the Committee delegates to the Senior Vice President of Human Resources, Chief Human Resources Officer of the Company the authority to enter into a VSA with a Participant in lieu of providing benefits under the Plan.

9.4 Expenses. Unless otherwise agreed to by the Company, no person acting as a fiduciary hereunder (who is an employee of an Employer) shall receive any compensation for services as such. Expenses incurred by fiduciaries in connection with the administration of the Plan shall be paid by the Company.

9.5 Indemnification of Plan Administrator. The Company shall indemnify, to the fullest extent permitted by law, each person made or threatened to be made a party to any civil or criminal action or proceeding by reason of the fact that such person, or such person's testator or intestate, was a member of the Committee, or a delegate of the Committee, acting in the capacity of Plan administrator.

9.6 Reliance Upon Others. The Committee, any person to whom it may delegate such of its duties and powers as provided herein, and the officers and directors of the Company shall be entitled to rely conclusively upon and shall be fully protected in any action taken by them in good faith in reliance upon any tables, valuations, certificates, opinions, reports or other advice furnished to them by any duly appointed actuary, accountant, legal counsel (who may be counsel for the Company) or other specialist.

9.7 Notification. All notices, reports and statements in connection with the Plan that are given, made, delivered or transmitted to a Participant shall be deemed duly given, made, delivered, or transmitted when mailed, by such class as the sender may deem appropriate, with postage prepaid and addressed to the Participant at the address last appearing on the records of the Employer with respect to this Plan. All notices, direct actions or other communications given, made, delivered or transmitted by a Participant to an Employer or Committee shall not be deemed to have been duly given, made, delivered, transmitted or received unless and until actually received by the Employer or Committee.

9.8 Multiple Capacities. A person may serve in more than one fiduciary capacity with respect to the Plan.

ARTICLE X
CLAIMS PROCEDURE

10.1 Submission of Claims. The initial claim by any Participant for benefits under this Plan shall be submitted in writing to the Committee (or its delegate) within 60 days after the occurrence of the termination of employment that the Participant claims to have triggered entitlement to Plan benefits.

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10.2 Computation and Review of Claims. All benefits shall be computed by the Committee or its delegate. All claims shall be approved or denied by the Committee (or its delegate) as soon as practicable, but in no event later than 90 days after application by the Participant. The Committee may take an additional 90 days to review the claim, provided that the Participant is notified in writing within the initial 90-day period.

(a) Initial Denial of Claim - Any denial of a claim shall include:

(i) Reason or reasons for the denial;

(ii) Reference to pertinent Plan provisions on which the denial is based;

(iii) Description of any additional material or information necessary for the Participant to perfect the claim together with an explanation of why the material or information is necessary; and

(iv) Explanation of the Plan's claim review procedure, described below.

(b) Review of a Denied Claim - A Participant shall have a reasonable opportunity to appeal a denied claim to the Committee (or its delegate) for a full and fair review. The Participant or a duly authorized representative shall have 60 days after receipt of written notification of the denial of claim in which to file an appeal with the Committee. The request for review shall be in writing and the Participant or a duly authorized representative shall submit written comments, documents, records and other information relating to the appeal. The Participant or a duly authorized representative may review, free of charge, pertinent Plan documents, records and other information relevant to the appeal.

(c) Committee Review - The Committee's (or its delegate's) review shall take into account all comments, documents, records and other information submitted by the Participant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

(d) Written Decision - The Committee (or its delegate) shall issue a decision on the reviewed claim promptly but no later than 60 days after receipt of the review. The Committee may take an additional 60 days to review the claim, provided that the Participant is notified in writing within the initial 60-day period. The Committee's decision shall be in writing and shall include:

(i) Reasons for the decision;

(ii) References to the Plan provisions on which the decision is based;

(iii) Statement that the Participant is entitled to receive, upon request, reasonable access to, and copies of, all documents, records and other information relevant to the claim; and

(iv) Statement that the Participant is entitled to bring a civil suit under Section 502(a) of ERISA.

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(e) Binding Effect - The Committee's (or its delegate's) decision shall be final and binding on the Participant and the Employer.

ARTICLE XI
GENERAL PROVISIONS

11.1 Construction. This Plan shall be construed and enforced in accordance with and governed by the internal substantive laws (and not the laws relating to conflict of laws or choice of laws) of the State of New Jersey, except to the extent that such laws are preempted by Federal law.

11.2 Unfunded Plan. The obligations of the Company under this Plan are not required to be funded in advance. Nothing contained in this Plan shall give an Eligible Employee or Participant any right, title or interest in any property of the Company or any of its Affiliates.

11.3 No Right to Continued Employment. Nothing contained herein shall be deemed to give any Eligible Employee or Participant the right to be retained in the employment of an Employer or to limit the rights of any Employer to discharge any Eligible Employee or Participant at any time, with or without notice and with or without Cause.

11.4 Partial Invalidity. The invalidity or unenforceability of any term or provision, or any clause, or portion thereof, of this Plan shall in no way impair or affect the validity or enforceability of any other provision of this Plan, which shall remain in full force and effect.

11.5 Successors and Assigns.

(a) This Plan shall inure to the benefit of and be binding upon the Company and its successors and assigns.

(b) The Company shall require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform the Company's obligations under the Plan in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place.

(c) In no event shall a Participant assign their interests under the Plan to any other person without the prior written consent of the Committee.

11.6 Waivers. Failure to strictly comply with any term, condition or requirement set forth in the Plan shall not be deemed a waiver of such term, condition or requirement, nor shall any waiver of any such term, condition or requirement at any one time or times be deemed to result in a waiver of such term, condition or requirement at any other time or times.

11.7 Gender and Number. The singular shall include the plural, unless indicated otherwise by the context.

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11.8 Headings. The headings of the Plan are for purposes of reference only and shall not limit or otherwise affect the meaning hereof.

* * *

/s/ Margaret M. Pego July 19, 2017

Signature Date

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SCHEDULE A

As Amended as of July 18, 2017
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Stuart J. Black	VP and Controller	03/01/10
Jorge L. Cardenas	VP - Asset Management and Centralized Services, PSE&G	1/23/07
Rose M. Chernick	VP - Finance Holdings & Corporate Strategy & Planning	8/09/10
John Paul Cowan	SVP - Operations, PSEG Fossil	09/15/09
Lathrop B. Craig	VP - ISO Operations (ER&T)	09/05/11
Daniel J. Cregg	EVP & CFO, PSEG	12/19/06
David M. Daly	President and COO - PSEG Long Island President & COO, PSE&G & COB PSEG LI (effective 10/2/17)	1/28/08
Paul J. Davison	VP - Nuclear Engineering, PSEG Nuclear	12/14/09
Derek DiRisio	President - PSEG Services Corporation	12/20/04
Diana L. Drysdale	VP - Renewables	02/15/10
Joseph A. Forline	VP - Gas Operations	12/19/06
Carl J. Fricker	VP - Trading Support & Operations (ER&T)	12/14/09
Kim C. Hanemann	SVP - Delivery Projects and Construction	12/21/10
Bradford D. Huntington	VP & Treasurer	04/16/11
Scott Jennings	VP - Finance PSE&G	10/18/05
Robert C. Krueger, Jr	VP & Assistant Controller - Tax	12/19/06
Kathleen A. Lally	VP - Investor Relations	01/16/07
John R. Latka	SVP - Electric & Gas Operations, PSE&G	10/23/06
Shawn P. Leyden	VP and Deputy General Counsel	12/20/04
Tamara L. Linde	EVP and General Counsel	12/19/06
Kristen M. Ludecke	VP - Federal Affairs	02/22/10
Shahid Malik	President - Energy Resources & Trade (ER&T)	12/5/11
Christine T. Neely	VP - Internal Auditing Services	9/30/13
Margaret M. Pego	SVP - Human Resources & CHRO	12/20/04
Kevin J. Quinn	VP - Finance Power Scheduled to have a last day of work on 10/5/17	03/01/10
Sheila J. Rostiac	VP - Total Rewards & Talent Management	08/20/12
Joseph Santamaria	VP - Information Technology & CIO	10/29/12
Richard T. Thigpen	VP - State Governmental Affairs	3/26/07

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SCHEDULE B

As Amended as of July 18, 2017
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
Ralph Izzo	Chairman of the Board, President and CEO	12/15/08
Ralph A. LaRossa	President & COO - Public Service Electric and Gas Company, and COB, PSEG Long Island President & COO, PSEG Power LLC (effective 10/2/17)	10/17/06
William Levis	President & COO, PSEG Power LLC Scheduled to have a last day of work on 10/1/17	01/01/07

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SCHEDULE C

As Amended as of July 18, 2017
PARTICIPANTS

NAME	TITLE	PARTICIPATION DATE
John A. Bridges	VP Electric Operations	12/21/15
David F. Caffery	VP Gas Supply	3/6/17
Eric Carr	VP Hope Creek - PSEG Nuclear	10/3/16
Kevin B. Cellars	VP Construction	2/17/15
Brian J. Clark	VP Procurement	8/29/16
Gregory C. Dunlap	VP Customer Operations - PSE&G	7/14/14
Daniel Eichhorn	President & COO, PSEG LI	10/2/17
Aaron T. Ford	VP Business Assurance and Resilience	11/18/15
M. Courtney McCormick	VP Renewables and Energy Solutions	3/31/14
Charles V. McFeaters	VP Salem - PSEG Nuclear	10/3/16
Timothy P. Pellegrin	VP Finance - Power & Merger & Acquisitions	10/9/17
Laurent C. Pommier	VP Risk Management and Chief Risk Officer	7/14/14
Peter P. Sena III	President & CNO, PSEG Nuclear	3/21/16

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2017	2016	2016	2015	2014	2013	2012
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 958	$ 1,547	$1,298	$2,680	$2,456	$2,055	$2,011
(Income) Loss from Equity Investees, net of Distributions	2	5	7	3	4	(7)	9
Fixed Charges	379	354	477	457	450	458	479
Capitalized Interest	13	(32)	(7)	(18)	(16)	(16)	(19)
Total Earnings	$ 1,352	$ 1,874	$1,775	$3,122	$2,894	$2,490	$2,480
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 358	$ 339	$ 456	$ 437	$ 430	$ 442	$ 465
Interest Factor in Rentals	21	15	21	20	20	16	14
Total Fixed Charges	$ 379	$ 354	$ 477	$ 457	$ 450	$ 458	$ 479
Ratio of Earnings to Fixed Charges	**3.57**	**5.29**	**3.72**	**6.83**	**6.43**	**5.44**	**5.18**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) the actual amount of any preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority-owned subsidiaries stated on a pre-tax level. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Nine Months Ended September 30,		Years Ended December 31,				
	2017	**2016**	**2016**	**2015**	**2014**	**2013**	**2012**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,203	$ 1,089	$1,404	$1,257	$ 1,174	$ 993	$ 835
Fixed Charges	244	234	316	306	303	316	314
Capitalized Interest	(14)	(12)	(17)	(17)	(16)	(16)	(13)
Total Earnings	$ 1,433	$ 1,311	$1,703	$1,546	$ 1,461	$1,293	$1,136
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 237	$ 226	$ 306	$ 297	$ 293	$ 309	$ 308
Interest Factor in Rentals	7	8	10	9	10	7	6
Total Fixed Charges	$ 244	$ 234	$ 316	$ 306	$ 303	$ 316	$ 314
Ratio of Earnings to Fixed Charges	**5.87**	**5.60**	**5.39**	**5.05**	**4.82**	**4.09**	**3.62**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period, (b) the actual amount of any preferred securities dividend requirements of majority owned subsidiaries, and (c) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred securities dividend requirements of majority owned subsidiaries and preferred stock dividends, increased to reflect the pre-tax earnings requirement for PSE&G. There were no preferred stock dividend requirements for any period presented.

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EXHIBIT 12.2

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2017	2016	2016	2015	2014	2013	2012
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income (Loss) from Continuing Operations	$ (211)	$ 528	$ (43)	$1,367	$1,251	$1,063	$1,099
(Income) Loss from Equity Investees, net of Distributions	2	5	7	1	3	(10)	(6)
Fixed Charges	104	108	142	152	150	143	164
Capitalized Interest	27	(20)	11	(1)	1	1	(6)
Total Earnings	$ (78)	$ 621	$ 117	$1,519	$1,405	$1,197	$1,251
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 96	$ 105	$ 138	$ 148	$ 146	$ 139	$ 161
Interest Factor in Rentals	8	3	4	4	4	4	3
Total Fixed Charges	$ 104	$ 108	$ 142	$ 152	$ 150	$ 143	$ 164
Ratio of Earnings to Fixed Charges (C)	**(0.75)**	**5.75**	**0.82**	**9.99**	**9.37**	**8.37**	**7.63**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

(C) The ratio of earnings to fixed charges for the nine months ended September 30, 2017, was (0.75), as noted above, which represents a deficiency of $182 million. The ratio of earnings to fixed charges for the year ended December 31, 2016, was 0.82, as noted above, which represents a deficiency of $25 million.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2017

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2017

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2017

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 31, 2017

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
October 31, 2017

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
October 31, 2017

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
October 31, 2017

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
October 31, 2017

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
October 31, 2017

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2017 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
October 31, 2017

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

(Mark One)

☒ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2018
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 973 430-7000	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102 973 430-7000	22-3663480

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐	Smaller reporting company ☐	Emerging growth company ☐
Public Service Electric and Gas Company	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐
PSEG Power LLC	Large accelerated filer ☐	Accelerated filer ☐	Non-accelerated filer ☒	Smaller reporting company ☐	Emerging growth company ☐

If any of the registrants is an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of October 16, 2018, Public Service Enterprise Group Incorporated had outstanding 505,449,710 shares of its sole class of Common Stock, without par value.

As of October 16, 2018, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

Public Service Electric and Gas Company and PSEG Power LLC are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K. These factors include, but are not limited to:

- fluctuations in wholesale power and natural gas markets, including the potential impacts on the economic viability of our generation units;
- our ability to obtain adequate fuel supply;
- any inability to manage our energy obligations with available supply;
- increases in competition in wholesale energy and capacity markets;
- changes in technology related to energy generation, distribution and consumption and customer usage patterns;
- economic downturns;
- third-party credit risk relating to our sale of generation output and purchase of fuel;
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements;
- changes in state and federal legislation and regulations, and PSE&G's ability to recover costs and earn returns on authorized investments;
- the impact of pending and any future rate case proceedings;
- risks associated with our ownership and operation of nuclear facilities, including regulatory risks, such as compliance with the Atomic Energy Act and trade control, environmental and other regulations, as well as financial, environmental and health and safety risks;
- adverse changes in energy industry laws, policies and regulations, including market structures and transmission planning;
- changes in federal and state environmental regulations and enforcement;
- delays in receipt of, or an inability to receive, necessary licenses and permits;
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry;
- changes in tax laws and regulations;
- the impact of our holding company structure on our ability to meet our corporate funding needs, service debt and pay dividends;
- lack of growth or slower growth in the number of customers or changes in customer demand;
- any inability of Power to meet its commitments under forward sale obligations;
- reliance on transmission facilities that we do not own or control and the impact on our ability to maintain adequate transmission capacity;
- any inability to successfully develop or construct generation, transmission and distribution projects;
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers;

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- our inability to exercise control over the operations of generation facilities in which we do not maintain a controlling interest;
- any inability to recover the carrying amount of our long-lived assets and leveraged leases;
- any inability to maintain sufficient liquidity;
- any inability to realize anticipated tax benefits or retain tax credits;
- challenges associated with recruitment and/or retention of key executives and a qualified workforce;
- the impact of our covenants in our debt instruments on our operations; and
- the impact of acts of terrorism, cybersecurity attacks or intrusions.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business, prospects, financial condition, results of operations or cash flows. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even in light of new information or future events, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

FILING FORMAT

This combined Quarterly Report on Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to “we,” “us,” and “our” relate to PSEG or to the specific company or companies being discussed.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
OPERATING REVENUES	$ 2,394	$ 2,254	$ 7,228	$ 6,987
OPERATING EXPENSES				
Energy Costs	804	616	2,356	2,072
Operation and Maintenance	742	693	2,221	2,128
Depreciation and Amortization	294	252	854	1,721
Total Operating Expenses	1,840	1,561	5,431	5,921
OPERATING INCOME	554	693	1,797	1,066
Income from Equity Method Investments	5	3	12	11
Net Gains (Losses) on Trust Investments	45	18	31	71
Other Income (Deductions)	33	33	99	98
Non-Operating Pension and OPEB Credits (Costs)	19	—	57	1
Interest Expense	(127)	(100)	(341)	(289)
INCOME BEFORE INCOME TAXES	529	647	1,655	958
Income Tax Expense	(117)	(252)	(416)	(340)
NET INCOME	$ 412	$ 395	$ 1,239	$ 618
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	504	505	504	505
DILUTED	507	507	507	507
NET INCOME PER SHARE:				
BASIC	$ 0.82	$ 0.78	$ 2.46	$ 1.22
DILUTED	$ 0.81	$ 0.78	$ 2.44	$ 1.22
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.45	$ 0.43	$ 1.35	$ 1.29

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
NET INCOME	$ 412	$ 395	$ 1,239	$ 618
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $2, $(15), $15 and $(40) for the three and nine months ended 2018 and 2017, respectively	(4)	17	(23)	42
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $0, $1 and $0 for the three and nine months ended 2018 and 2017, respectively	—	(1)	(1)	(1)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(3), $(4), $(9) and $(12) for the three and nine months ended 2018 and 2017, respectively	7	6	22	18
Other Comprehensive Income (Loss), net of tax	3	22	(2)	59
COMPREHENSIVE INCOME	$ 415	$ 417	$ 1,237	$ 677

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 88	$ 313
Accounts Receivable, net of allowances of $56 in 2018 and $59 in 2017	1,240	1,348
Tax Receivable	225	127
Unbilled Revenues	155	296
Fuel	329	289
Materials and Supplies, net	590	577
Prepayments	214	118
Derivative Contracts	11	29
Regulatory Assets	317	211
Other	46	4
Total Current Assets	3,215	3,312
PROPERTY, PLANT AND EQUIPMENT	43,613	41,231
Less: Accumulated Depreciation and Amortization	(9,832)	(9,434)
Net Property, Plant and Equipment	33,781	31,797
NONCURRENT ASSETS		
Regulatory Assets	3,761	3,222
Long-Term Investments	923	932
Nuclear Decommissioning Trust (NDT) Fund	2,096	2,133
Long-Term Receivable of Variable Interest Entity (VIE)	682	686
Rabbi Trust Fund	225	231
Goodwill	16	16
Other Intangibles	107	114
Derivative Contracts	2	7
Other	265	266
Total Noncurrent Assets	8,077	7,607
TOTAL ASSETS	$ 45,073	$ 42,716

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2018	December 31, 2017
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 1,450	$ 1,000
Commercial Paper and Loans	419	542
Accounts Payable	1,317	1,694
Derivative Contracts	13	16
Accrued Interest	159	103
Accrued Taxes	36	48
Clean Energy Program	187	128
Obligation to Return Cash Collateral	130	129
Regulatory Liabilities	303	47
Other	471	461
Total Current Liabilities	4,485	4,168
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	5,720	5,240
Regulatory Liabilities	3,286	2,948
Asset Retirement Obligations	1,059	1,024
OPEB Costs	1,410	1,455
OPEB Costs of Servco	560	542
Accrued Pension Costs	451	537
Accrued Pension Costs of Servco	108	129
Environmental Costs	348	357
Derivative Contracts	2	5
Long-Term Accrued Taxes	152	175
Other	224	221
Total Noncurrent Liabilities	13,320	12,633
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 10)		
CAPITALIZATION		
LONG-TERM DEBT	12,909	12,068
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2018 and 2017—534 shares	4,966	4,961
Treasury Stock, at cost, 2018—30 shares; 2017—29 shares	(811)	(763)
Retained Earnings	10,611	9,878
Accumulated Other Comprehensive Loss	(407)	(229)
Total Stockholders' Equity	14,359	13,847
Total Capitalization	27,268	25,915
TOTAL LIABILITIES AND CAPITALIZATION	$ 45,073	$ 42,716

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2018	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 1,239	$ 618
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	854	1,721
Amortization of Nuclear Fuel	143	152
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	74	79
Provision for Deferred Income Taxes (Other than Leases) and ITC	510	227
Non-Cash Employee Benefit Plan Costs	52	67
Leveraged Lease (Income) Loss, Adjusted for Rents Received and Deferred Taxes	(27)	(7)
Net (Gain) Loss on Lease Investments	14	48
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	78	8
Net Change in Regulatory Assets and Liabilities	(35)	(121)
Cost of Removal	(121)	(72)
Net (Gains) Losses and (Income) Expense from NDT Fund	(62)	(86)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	(98)	64
Accrued Taxes	(12)	115
Margin Deposit	(77)	64
Other Current Assets and Liabilities	12	(71)
Employee Benefit Plan Funding and Related Payments	(85)	(64)
Other	33	(9)
Net Cash Provided By (Used In) Operating Activities	2,492	2,733
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(3,028)	(3,046)
Purchase of Emissions Allowances and RECs	(111)	(90)
Proceeds from Sales of Trust Investments	1,085	1,013
Purchases of Trust Investments	(1,100)	(1,029)
Other	41	48
Net Cash Provided By (Used In) Investing Activities	(3,113)	(3,104)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(123)	(186)
Issuance of Long-Term Debt	2,050	1,125
Redemption of Long-Term Debt	(750)	—
Cash Dividends Paid on Common Stock	(682)	(652)
Other	(83)	(62)
Net Cash Provided By (Used In) Financing Activities	412	225
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(209)	(146)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	315	426
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 106	$ 280
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 64	$ (16)
Interest Paid, Net of Amounts Capitalized	$ 292	$ 261
Accrued Property, Plant and Equipment Expenditures	$ 543	$ 604

See Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19312

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
OPERATING REVENUES	$ 1,595	$ 1,530	$ 4,826	$ 4,749
OPERATING EXPENSES				
Energy Costs	593	543	1,863	1,793
Operation and Maintenance	389	357	1,133	1,086
Depreciation and Amortization	192	169	569	506
Total Operating Expenses	1,174	1,069	3,565	3,385
OPERATING INCOME	421	461	1,261	1,364
Net Gains (Losses) on Trust Investments	—	—	—	2
Other Income (Deductions)	21	22	61	65
Non-Operating Pension and OPEB Credits (Costs)	14	(2)	44	(5)
Interest Expense	(83)	(79)	(246)	(223)
INCOME BEFORE INCOME TAXES	373	402	1,120	1,203
Income Tax Expense	(95)	(156)	(292)	(450)
NET INCOME	$ 278	$ 246	$ 828	$ 753

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19313

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
NET INCOME	$ 278	$ 246	$ 828	$ 753
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0, $0 and $1 for the three and nine months ended 2018 and 2017, respectively	(1)	—	(1)	(1)
COMPREHENSIVE INCOME	$ 277	$ 246	$ 827	$ 752

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19314

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 25	$ 242
Accounts Receivable, net of allowances of $56 in 2018 and $59 in 2017	842	882
Accounts Receivable—Affiliated Companies	55	—
Unbilled Revenues	155	296
Materials and Supplies	200	197
Prepayments	117	44
Regulatory Assets	317	211
Other	26	4
Total Current Assets	1,737	1,876
PROPERTY, PLANT AND EQUIPMENT	30,997	29,117
Less: Accumulated Depreciation and Amortization	(6,241)	(6,101)
Net Property, Plant and Equipment	24,756	23,016
NONCURRENT ASSETS		
Regulatory Assets	3,761	3,222
Long-Term Investments	278	280
Rabbi Trust Fund	46	46
Other	116	114
Total Noncurrent Assets	4,201	3,662
TOTAL ASSETS	$ 30,694	$ 28,554

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19315

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

LIABILITIES AND CAPITALIZATION	September 30, 2018	December 31, 2017
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 500	$ 750
Commercial Paper and Loans	40	—
Accounts Payable	666	728
Accounts Payable—Affiliated Companies	164	340
Accrued Interest	96	78
Clean Energy Program	187	128
Obligation to Return Cash Collateral	130	129
Regulatory Liabilities	303	47
Other	367	311
Total Current Liabilities	2,453	2,511
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	3,718	3,391
OPEB Costs	1,052	1,103
Accrued Pension Costs	171	226
Regulatory Liabilities	3,286	2,948
Environmental Costs	271	283
Asset Retirement Obligations	215	212
Long-Term Accrued Taxes	67	91
Other	118	114
Total Noncurrent Liabilities	8,898	8,368
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 10)		
CAPITALIZATION		
LONG-TERM DEBT	8,682	7,841
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2018 and 2017—132 shares	892	892
Contributed Capital	1,095	1,095
Basis Adjustment	986	986
Retained Earnings	7,689	6,861
Accumulated Other Comprehensive Income	(1)	—
Total Stockholder's Equity	10,661	9,834
Total Capitalization	19,343	17,675
TOTAL LIABILITIES AND CAPITALIZATION	$ 30,694	$ 28,554

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19316

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2018	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 828	$ 753
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	569	506
Provision for Deferred Income Taxes and ITC	330	497
Non-Cash Employee Benefit Plan Costs	28	37
Cost of Removal	(121)	(72)
Net Change in Regulatory Assets and Liabilities	(35)	(121)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	184	136
Materials and Supplies	(3)	(13)
Prepayments	(73)	(106)
Accounts Payable	(7)	(37)
Accounts Receivable/Payable—Affiliated Companies, net	(232)	(61)
Other Current Assets and Liabilities	10	(14)
Employee Benefit Plan Funding and Related Payments	(73)	(55)
Other	(8)	(58)
Net Cash Provided By (Used In) Operating Activities	1,397	1,392
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(2,213)	(2,118)
Proceeds from Sales of Trust Investments	15	33
Purchases of Trust Investments	(17)	(34)
Solar Loan Investments	(15)	(2)
Other	6	7
Net Cash Provided By (Used In) Investing Activities	(2,224)	(2,114)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	40	—
Issuance of Long-Term Debt	1,350	425
Contributed Capital	—	150
Redemption of Long-Term Debt	(750)	—
Other	(14)	(5)
Net Cash Provided By (Used In) Financing Activities	626	570
Net Increase (Decrease) In Cash, Cash Equivalents and Restricted Cash	(201)	(152)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	244	393
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 43	$ 241
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 60	$ (107)
Interest Paid, Net of Amounts Capitalized	$ 223	$ 208
Accrued Property, Plant and Equipment Expenditures	$ 375	$ 363

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19317

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
OPERATING REVENUES	$ 868	$ 846	$ 3,038	$ 3,033
OPERATING EXPENSES				
Energy Costs	431	330	1,550	1,408
Operation and Maintenance	231	229	745	717
Depreciation and Amortization	94	76	260	1,191
Total Operating Expenses	756	635	2,555	3,316
OPERATING INCOME (LOSS)	112	211	483	(283)
Income from Equity Method Investments	5	3	12	11
Net Gains (Losses) on Trust Investments	44	19	30	62
Other Income (Deductions)	14	11	38	34
Non-Operating Pension and OPEB Credits (Costs)	4	2	11	6
Interest Expense	(29)	(12)	(47)	(41)
INCOME (LOSS) BEFORE INCOME TAXES	150	234	527	(211)
Income Tax Benefit (Expense)	(25)	(98)	(127)	80
NET INCOME (LOSS)	$ 125	$ 136	$ 400	$ (131)

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19318

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	**2017**	**2018**	**2017**
NET INCOME (LOSS)	$ 125	$ 136	$ 400	$ (131)
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $2, $(14), $13 and $(41) for the three and nine months ended 2018 and 2017, respectively	(4)	15	(19)	44
Pension/OPEB adjustment, net of tax (expense) benefit of $(3), $(4), $(8) and $(11) for the three and nine months ended 2018 and 2017, respectively	7	5	19	15
Other Comprehensive Income (Loss), net of tax	3	20	—	59
COMPREHENSIVE INCOME (LOSS)	$ 128	$ 156	$ 400	$ (72)

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19319

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

ASSETS	September 30, 2018	December 31, 2017
CURRENT ASSETS		
Cash and Cash Equivalents	$ 41	$ 32
Accounts Receivable	343	380
Accounts Receivable—Affiliated Companies	121	221
Short-Term Loan to Affiliate	119	—
Fuel	329	289
Materials and Supplies, net	386	376
Derivative Contracts	11	29
Prepayments	20	11
Other	6	3
Total Current Assets	1,376	1,341
PROPERTY, PLANT AND EQUIPMENT	12,277	11,755
Less: Accumulated Depreciation and Amortization	(3,408)	(3,159)
Net Property, Plant and Equipment	8,869	8,596
NONCURRENT ASSETS		
NDT Fund	2,096	2,133
Long-Term Investments	88	87
Goodwill	16	16
Other Intangibles	107	114
Rabbi Trust Fund	57	57
Derivative Contracts	2	7
Other	70	67
Total Noncurrent Assets	2,436	2,481
TOTAL ASSETS	$ 12,681	$ 12,418

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19320

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2018	December 31, 2017
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 250	$ 250
Accounts Payable	465	712
Accounts Payable—Affiliated Companies	21	57
Short-Term Loan from Affiliate	—	281
Derivative Contracts	13	16
Accrued Interest	51	20
Other	69	99
Total Current Liabilities	869	1,435
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	1,577	1,406
Asset Retirement Obligations	841	810
OPEB Costs	289	283
Derivative Contracts	2	5
Accrued Pension Costs	161	184
Long-Term Accrued Taxes	1	52
Other	140	140
Total Noncurrent Liabilities	3,011	2,880
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 10)		
LONG-TERM DEBT	2,834	2,136
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	5,086	4,911
Accumulated Other Comprehensive Loss	(347)	(172)
Total Member's Equity	5,967	5,967
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 12,681	$ 12,418

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19321

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2018	**2017**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income (Loss)	$ 400	$ (131)
Adjustments to Reconcile Net Income (Loss) to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	260	1,191
Amortization of Nuclear Fuel	143	152
Provision for Deferred Income Taxes and ITC	177	(259)
Interest Accretion on Asset Retirement Obligation	31	23
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	78	8
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	74	79
Non-Cash Employee Benefit Plan Costs	17	21
Net (Gains) Losses and (Income) Expense from NDT Fund	(62)	(86)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	(50)	(32)
Margin Deposit	(77)	64
Accounts Receivable	42	19
Accounts Payable	(22)	(32)
Accounts Receivable/Payable—Affiliated Companies, net	65	205
Other Current Assets and Liabilities	(11)	11
Employee Benefit Plan Funding and Related Payments	(7)	(5)
Other	(53)	21
Net Cash Provided By (Used In) Operating Activities	1,005	1,249
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(800)	(903)
Purchase of Emissions Allowances and RECs	(111)	(90)
Proceeds from Sales of Trust Investments	1,024	886
Purchases of Trust Investments	(1,037)	(900)
Short-Term Loan—Affiliated Company	(119)	86
Other	33	37
Net Cash Provided By (Used In) Investing Activities	(1,010)	(884)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Long-Term Debt	700	—
Cash Dividend Paid	(400)	(350)
Short-Term Loan—Affiliated Company	(281)	—
Other	(5)	(4)
Net Cash Provided By (Used In) Financing Activities	14	(354)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	9	11
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	32	11
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 41	$ 22
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 31	$ 75
Interest Paid, Net of Amounts Capitalized	$ 32	$ 30
Accrued Property, Plant and Equipment Expenditures	$ 168	$ 241

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

S1-SSA-0009 - 19322

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Note 1. Organization, Basis of Presentation and Significant Accounting Policies

Organization

Public Service Enterprise Group Incorporated (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's principal direct wholly owned subsidiaries are:

- **Public Service Electric and Gas Company (PSE&G)**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and energy efficiency and related programs in New Jersey, which are regulated by the BPU.
- **PSEG Power LLC (Power)**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) electric transmission and distribution (T&D) system under an Operations Services Agreement (OSA); PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2017.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All significant intercompany accounts and transactions are eliminated in consolidation. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2017.

Significant Accounting Policies

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. Restricted cash consists primarily of deposits received related to various construction projects at PSE&G.

The following provides a reconciliation of cash, cash equivalents and restricted cash reported within the Condensed Consolidated Balance Sheets that sum to the total of the same such amounts for the beginning (December 31, 2017) and ending periods shown in the Condensed Consolidated Statements of Cash Flows for the nine months ended September 30, 2018.

S1-SSA-0009 - 19323

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	PSE&G	Power	Other (A)	Consolidated
			Millions	
As of December 31, 2017				
Cash and Cash Equivalents	$ 242	$ 32	$ 39	$ 313
Restricted Cash in Other Current Assets	—	—	—	—
Restricted Cash in Other Noncurrent Assets	2	—	—	2
Cash, Cash Equivalents and Restricted Cash	**$ 244**	**$ 32**	**$ 39**	**$ 315**
As of September 30, 2018				
Cash and Cash Equivalents	$ 25	$ 41	$ 22	$ 88
Restricted Cash in Other Current Assets	6	—	—	6
Restricted Cash in Other Noncurrent Assets	12	—	—	12
Cash, Cash Equivalents and Restricted Cash	**$ 43**	**$ 41**	**$ 22**	**$ 106**

(A) Includes amounts applicable to PSEG (parent corporation), Energy Holdings and Services.

Note 2. Recent Accounting Standards

New Standards Issued and Adopted

Revenue from Contracts With Customers—Accounting Standard Update (ASU) 2014-09, updated by ASUs 2015-14, 2016-08, 2016-10, 2016-12, 2016-20, 2017-13, 2017-14

This accounting standard, and related updates, were adopted on January 1, 2018 using the full retrospective transition method. There was no effect on net income as a result of adoption. However, certain retrospective adjustments were recorded in accordance with the new standard. At PSE&G, retrospective adjustments increased Operating Revenues by $21 million and $60 million, Energy Costs by $8 million and $33 million, and Operation and Maintenance (O&M) Expense by $13 million and $27 million for the three and nine months ended September 30, 2017, respectively. At Power, retrospective adjustments reduced Operating Revenues and Energy Costs by $27 million and $53 million for the three and nine months ended September 30, 2017, respectively. For disclosure requirements under this standard, including Nature of Goods and Services, Disaggregation of Revenues, and Remaining Performance Obligations under Fixed Consideration Contracts, see Note 3. Revenues.

Recognition and Measurement of Financial Assets and Financial Liabilities—ASU 2016-01

Power maintains an external master trust fund to provide for the costs of decommissioning upon termination of operations of its nuclear facilities. In addition, PSEG maintains a grantor trust which was established to meet the obligations related to its non-qualified pension plans and deferred compensation plans, commonly referred to as a "Rabbi Trust."

This accounting standard was adopted on January 1, 2018. Under the new guidance, equity investments in Power's Nuclear Decommissioning Trust (NDT) and PSEG's Rabbi Trust Funds are measured at fair value with the unrealized gains and losses now recognized through Net Income instead of Other Comprehensive Income (Loss). The debt securities in these trusts continue to be classified as available-for-sale with the unrealized gains and losses recorded as a component of Accumulated Other Comprehensive Income (Loss). Realized gains and losses on both equity and available-for-sale debt security investments are recorded in earnings and are included with the unrealized gains and losses on equity securities in Net Gains (Losses) on Trust Investments. Other-than-temporary impairments on NDT and Rabbi Trust securities are also included in Net Gains (Losses) on Trust Investments. A cumulative effect adjustment was made to reclassify the net unrealized gains related to equity investments of $342 million ($176 million, net of tax) from Accumulated Other Comprehensive Income to Retained Earnings on January 1, 2018. See Note 16. Accumulated Other Comprehensive Income (Loss), Net of Tax and Note 8. Trust Investments for further discussion.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments—ASU 2016-15

This accounting standard reduces the diversity in practice in how certain cash receipts and cash payments are presented and classified in the Statement of Cash Flows.

PSEG adopted this standard on January 1, 2018 using a retrospective transition method and had no changes in its presentation of its Statement of Cash Flows for each period presented.

Statement of Cash Flows: Restricted Cash—ASU 2016-18

This accounting standard was adopted on January 1, 2018. PSEG will continue the current balance sheet classification of restricted cash or restricted cash equivalents. PSEG has provided a reconciliation of cash and cash equivalents and restricted

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cash or restricted cash equivalents and has included a description of these amounts in Note 1. Organization, Basis of Presentation and Significant Accounting Policies. The effect of adoption on the September 30, 2018 Consolidated Statements of Cash Flows was immaterial.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (OPEB)—ASU 2017-07

This accounting standard was adopted on January 1, 2018. Under the new guidance, entities are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by their employees during the period. The other components of net benefit cost are required to be presented in the Statement of Operations separately from the service cost component after Operating Income. Additionally, only the service cost component is eligible for capitalization, when applicable. As a result of adopting this standard, PSE&G reduced its charge to expense for the three and nine months ended September 30, 2018 by approximately $15 million and $44 million, respectively. The Condensed Consolidated Statements of Operations were recast to show retrospective adjustments of the non-service cost components of net benefit credits (costs) of $(2) million and $(5) million at PSE&G and $2 million and $6 million at Power, for the three and nine months ended September 30, 2017, respectively, from O&M Expense to a new line item after Operating Income entitled Non-Operating Pension and OPEB Credits (Costs). See Note 9. Pension and Other Postretirement Benefits (OPEB).

Stock Compensation - Scope of Modification Accounting—ASU 2017-09

This accounting standard was adopted on January 1, 2018. The standard will be applied prospectively to awards modified on or after January 1, 2018. PSEG does not expect a material impact from adoption of this new standard.

New Standards Issued But Not Yet Adopted

Leases—ASU 2016-02, updated by ASUs 2018-01, 2018-10 and 2018-11

This accounting standard, and related updates, replace existing lease accounting guidance and require lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor will classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard allows lessees and lessors to apply either (i) a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, or (ii) a prospective transition approach for leases existing as of January 1, 2019 with a cumulative effect adjustment to be recorded to Retained Earnings. PSEG intends to adopt this standard on a prospective basis. Existing guidance related to leveraged leases does not change.

This standard permits an entity to elect an optional transition practical expedient to exclude evaluation of land easements that exist or expired before the adoption of ASU 2016-02 and that were not previously accounted for as leases.

PSEG is currently analyzing the impact of this standard on its consolidated financial statements while undertaking the following implementation activities: (i) reviewing all contract types throughout PSEG to determine the lease population; (ii) implementing a lease accounting system to capture and account for long-term (greater than one year) leases to be operational on January 1, 2019; (iii) developing internal lease accounting policies and determining the practical expedients PSEG will elect; and (iv) drafting lease disclosures required in 2019. Pending finalization of those activities, PSEG expects adoption of this standard on January 1, 2019 to impact its consolidated balance sheet by increasing its assets and liabilities by up to $300 million. PSE&G expects its assets and liabilities to each increase by up to $100 million and Power expects its assets and liabilities to each increase by up to $60 million. PSEG does not expect adoption to have a material impact on the Consolidated Statements of Operations of PSEG, PSE&G and Power.

The standard is effective for annual and interim periods beginning after December 15, 2018.

Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities—ASU 2017-12

This accounting standard's amendments more closely align hedge accounting with the companies' risk management activities in the financial statements. The amendments expand hedge accounting for both non-financial and financial risk components by permitting contractually specified components to be designated as the hedged risk in a cash flow hedge involving the purchase or sale of non-financial assets or variable rate financial instruments. The amendments also permit an entity to measure the interest rate risk on the hedged item in a partial-term fair value hedge assuming the hedged item has a term that reflects only the designated cash flows being hedged. Additionally, the amendments ease the operational burden of applying hedge accounting by allowing more time to prepare hedge documentation, and allowing effectiveness assessments to be performed on a qualitative basis after hedge inception.

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The new guidance is effective for annual and interim periods beginning after December 15, 2018. The standard requires using a modified retrospective method upon adoption. Early adoption is permitted. PSEG analyzed the impact of this standard on its consolidated financial statements and has determined that the standard could enable PSEG to enter into certain transactions that can be deemed hedges that previously would not have qualified. Adoption of this standard is not expected to have a material impact on PSEG's financial statements.

Premium Amortization on Purchased Callable Debt Securities—ASU 2017-08

This accounting standard was issued to shorten the amortization period for certain callable debt securities held at a premium. Specifically, the standard requires the premium to be amortized to the earliest call date. The amendments do not require an accounting change for securities held at a discount; the discount continues to be amortized to maturity.

The standard is effective for annual and interim reporting periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period. If an entity early adopts the standard in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity should apply this standard on a modified retrospective basis through a cumulative effect adjustment directly to retained earnings as of the beginning of the period of adoption. Additionally, in the period of adoption, an entity should provide disclosures about a change in accounting principle. PSEG is currently analyzing the impact of this standard on its financial statements.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income—ASU 2018-02

This accounting standard would affect any entity that is required to apply the provisions of the Accounting Standards Codification (ASC) topic, "Income Statement-Reporting Comprehensive Income," and has items of other comprehensive income for which the related tax effects are presented in other comprehensive income as required by GAAP. Specifically, this standard would allow entities to record a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the newly enacted federal corporate income tax rate. The amount of the reclassification would be the difference between the historical corporate income tax rate and the newly enacted 21% corporate income tax rate.

The standard is effective for all entities for annual periods and interim periods within those annual periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period for public business entities for reporting periods for which financial statements have not yet been issued or made available for issuance.

An entity would be able to choose to apply this standard retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the new tax legislation enacted in 2017 is recognized or apply the standard in the reporting period adopted. PSEG is currently analyzing the impact this standard, if adopted, could have on its consolidated financial statements.

Measurement of Credit Losses on Financial Instruments—ASU 2016-13

This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however, this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement—ASU 2018-13

This accounting standard modifies the disclosure requirements for fair value measurements. Certain current disclosure requirements relating to Level 3 fair value measurements, and transfers between Level 1 and Level 2 fair value measurements will be eliminated. The standard will also add certain other disclosure requirements for Level 3 fair value measurements.

The standard is effective for annual and interim periods beginning after December 15, 2019. Certain amendments in the standard should be applied prospectively for only the most recent interim or annual period presented in the initial fiscal year of adoption. All other amendments of the standard should be applied retrospectively to all periods presented upon their effective date. Early adoption is permitted.

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Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract—ASU 2018-15

This accounting standard aligns the capitalization requirements for implementation costs incurred in a hosting arrangement that is a service contract with capitalization requirements for implementation costs incurred to develop or obtain internal-use software, including hosting arrangements that include an internal use software license. The standard follows the guidance in ASC 350—Intangibles—Goodwill and Other to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The standard requires the amortization of capitalized costs to be presented in O&M Expense. In addition, the standard also adds presentation requirements for these costs in the statements of cash flows and financial position.

The standard is effective for annual and interim periods beginning after December 15, 2019. Early adoption is permitted, including adoption in any interim period. This standard should be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. PSEG is currently analyzing the impact of this standard on its financial statements.

Simplifying the Test for Goodwill Impairment—ASU 2017-04

This accounting standard requires an entity to perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

An entity should apply this standard on a prospective basis and will be required to disclose the nature of and reason for the change in accounting principle upon transition. The new standard is effective for impairment tests for periods beginning January 1, 2020. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. PSEG does not expect adoption of this standard to have a material impact on its financial statements.

Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans—ASU 2018-14

This accounting standard modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans, including the elimination of certain current disclosure requirements. Certain other disclosure requirements related to interest crediting rates have been added and certain clarifications were made to other disclosure requirements.

The standard is effective for fiscal years ending after December 15, 2020 and early adoption is permitted. An entity should apply the amendments in this standard on a retrospective basis to all periods presented.

Note 3. Revenues

Nature of Goods and Services

The following is a description of principal activities by reportable segment from which PSEG, PSE&G and Power generate their revenues.

PSE&G

Revenues from Contracts with Customers

Electric and Gas Distribution and Transmission Revenues—PSE&G sells gas and electricity to customers under default commodity supply tariffs. PSE&G's regulated electric and gas default commodity supply and distribution services are separate tariffs which are satisfied as the product(s) and/or services are delivered to the customer. The electric and gas commodity and delivery tariffs are recurring contracts in effect until cancellation by the customer. Revenue is recognized over time as the service is rendered to the customer. Included in PSE&G's regulated revenues are unbilled electric and gas revenues which represent the estimated amount customers will be billed for services rendered from the most recent meter reading to the end of the respective accounting period.

PSE&G's transmission revenues are earned under a separate FERC tariff. The performance obligation of transmission service is satisfied over time as it is provided to and consumed by the customer. Revenue is recognized upon delivery of the transmission service. PSE&G's revenues from the transmission of electricity are recorded based on a FERC-approved annual formula rate mechanism. This mechanism provides for an annual filing of an estimated revenue requirement with rates effective January 1 of each year and a mechanism true-up to that estimate based on actual revenue requirements. The true-up mechanism is an alternative revenue which is outside the scope of revenue from contracts with customers.

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Other Revenues from Contracts with Customers

Other revenues from contracts with customers, which are not a material source of PSE&G revenues, are generated primarily from appliance repair services and solar generation projects. The performance obligations under these contracts are satisfied and revenue is recognized as control of products is delivered or services are rendered.

Payment for services rendered and products transferred are typically due within 30 days of month of delivery.

Revenues Unrelated to Contracts with Customers

Other PSE&G revenues unrelated to contracts with customers are derived from alternative revenue mechanisms recorded pursuant to regulatory accounting guidance. These revenues, which include weather normalization, green energy program true-ups and transmission formula rate true-ups, are not a material source of PSE&G revenues.

Power

Revenues from Contracts with Customers

Electricity and Related Products—Wholesale and retail load contracts are executed in the different Independent System Operator (ISO) regions for the bundled supply of energy, capacity, renewable energy credits (RECs) and ancillary services representing Power's performance obligations. Revenue for these contracts is recognized over time as the bundled service is provided to the customer. Transaction terms generally run from several months to three years. Power also sells to the ISOs energy and ancillary services which are separately transacted in the day-ahead or real-time energy markets. The energy and ancillary services performance obligations are typically satisfied over time as delivered and revenue is recognized accordingly. Power generally reports electricity sales and purchases conducted with those individual ISOs net on an hourly basis in either Operating Revenues or Energy Costs in its Consolidated Statements of Operations. The classification depends on the net hourly activity.

Power enters into capacity sales and capacity purchases through the ISOs. The transactions are reported on a net basis dependent on Power's monthly net sale or purchase position through the individual ISOs. The performance obligations with the ISOs are satisfied over time upon delivery of the capacity and revenue is recognized accordingly. In addition to capacity sold through the ISOs, Power sells capacity through bilateral contracts and the related revenue is reported on a gross basis and recognized over time upon delivery of the capacity.

Gas Contracts—Power sells wholesale natural gas, primarily through an index based full requirements Basic Gas Supply Service (BGSS) contract with PSE&G to meet the gas supply requirements of PSE&G's customers. The BGSS contract, which extends through March 2019, will renew year-to-year thereafter unless terminated by either party with a two year notice. The performance obligation is primarily delivery of gas which is satisfied over time. Revenue is recognized as gas is delivered. Based upon the availability of natural gas, storage and pipeline capacity beyond PSE&G's daily needs, Power also sells gas and pipeline capacity to other counterparties under bilateral contracts. The performance obligation under these contracts is satisfied over time upon delivery of the gas or capacity, and revenue is recognized accordingly.

Other Revenues from Contracts with Customers

Power enters into bilateral contracts to sell solar power and solar RECs from its solar facilities. Contract terms range from 15 to 30 years. The performance obligations are generally solar power and RECs which are transferred to customers upon generation. Revenue is recognized upon generation of the solar power.

Power has entered into long-term contracts with LIPA for energy management and fuel procurement services. Revenue is recognized over time as services are rendered.

Revenues Unrelated to Contracts with Customers

Power's revenues unrelated to contracts with customers include electric, gas and certain energy-related transactions accounted for in accordance with Derivatives and Hedging accounting guidance. See Note 12. Financial Risk Management Activities for further discussion. Power is also a party to solar contracts that qualify as leases and are accounted for in accordance with lease accounting guidance.

Other

Revenues from Contracts with Customers

PSEG LI has a contract with LIPA which generates revenues. PSEG LI's subsidiary, Long Island Electric Utility Servco, LLC (Servco) records costs which are recovered from LIPA and records the recovery of those costs as revenues when Servco is a principal in the transaction.

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Revenues Unrelated to Contracts with Customers

Energy Holdings generates lease revenues which are recorded pursuant to lease accounting guidance.

Disaggregation of Revenues

	PSE&G	Power	Other	Eliminations	Consolidated
			Millions		
Three Months Ended September 30, 2018					
Revenues from Contracts with Customers					
Electric Distribution	$ 1,072	$ —	$ —	$ —	$ 1,072
Gas Distribution	142	—	—	(6)	136
Transmission	312	—	—	—	312
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	558	—	—	558
Sales to Affiliates	—	166	—	(166)	—
New York ISO	—	56	—	—	56
ISO New England	—	12	—	—	12
Gas Sales					
Third Party Sales	—	24	—	—	24
Sales to Affiliates	—	47	—	(47)	—
Other Revenues from Contracts with Customers (A)	60	12	142	(1)	213
Total Revenues from Contracts with Customers	1,586	875	142	(220)	2,383
Revenues Unrelated to Contracts with Customers (B)	9	(7)	9	—	11
Total Operating Revenues	**$ 1,595**	**$ 868**	**$ 151**	**$ (220)**	**$ 2,394**

	PSE&G	Power	Other	Eliminations	Consolidated
			Millions		
Nine Months Ended September 30, 2018					
Revenues from Contracts with Customers					
Electric Distribution	$ 2,516	$ —	$ —	$ —	$ 2,516
Gas Distribution	1,149	—	—	(13)	1,136
Transmission	925	—	—	—	925
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	1,429	—	—	1,429
Sales to Affiliates	—	489	—	(489)	—
New York ISO	—	161	—	—	161
ISO New England	—	73	—	—	73
Gas Sales					
Third Party Sales	—	118	—	—	118
Sales to Affiliates	—	552	—	(552)	—
Other Revenues from Contracts with Customers (A)	195	35	404	(3)	631
Total Revenues from Contracts with Customers	4,785	2,857	404	(1,057)	6,989
Revenues Unrelated to Contracts with Customers (B)	41	181	17	—	239
Total Operating Revenues	**$ 4,826**	**$ 3,038**	**$ 421**	**$ (1,057)**	**$ 7,228**

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	PSE&G	Power	Other	Eliminations	Consolidated
			Millions		
Three Months Ended September 30, 2017					
Revenues from Contracts with Customers					
Electric Distribution	$ 1,014	$ —	$ —	$ —	$ 1,014
Gas Distribution	136	—	—	(4)	132
Transmission	308	—	—	—	308
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	300	—	—	300
Sales to Affiliates	—	208	—	(208)	—
New York ISO	—	49	—	—	49
ISO New England	—	15	—	—	15
Gas Sales					
Third Party Sales	—	26	—	—	26
Sales to Affiliates	—	44	—	(44)	—
Other Revenues from Contracts with Customers (A)	59	11	130	(1)	199
Total Revenues from Contracts with Customers	1,517	653	130	(257)	2,043
Revenues Unrelated to Contracts with Customers (B)	13	193	5	—	211
Total Operating Revenues	**$ 1,530**	**$ 846**	**$ 135**	**$ (257)**	**$ 2,254**

	PSE&G	Power	Other	Eliminations	Consolidated
			Millions		
Nine Months Ended September 30, 2017					
Revenues from Contracts with Customers					
Electric Distribution	$ 2,472	$ —	$ —	$ —	$ 2,472
Gas Distribution	1,124	—	—	(11)	1,113
Transmission	914	—	—	—	914
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	916	—	—	916
Sales to Affiliates	—	563	—	(563)	—
New York ISO	—	135	—	—	135
ISO New England	—	35	—	—	35
Gas Sales					
Third Party Sales	—	89	—	—	89
Sales to Affiliates	—	552	—	(552)	—
Other Revenues from Contracts with Customers (A)	188	33	386	(3)	604
Total Revenues from Contracts with Customers	4,698	2,323	386	(1,129)	6,278
Revenues Unrelated to Contracts with Customers (B)	51	710	(52)	—	709
Total Operating Revenues	**$ 4,749**	**$ 3,033**	**$ 334**	**$ (1,129)**	**$ 6,987**

(A) Includes primarily revenues from appliance repair services at PSE&G, solar power projects and energy management and fuel service contracts with LIPA at Power, and PSEG LI's OSA with LIPA in Other.

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(B) Includes primarily alternative revenues at PSE&G, derivative contracts at Power, and lease contracts in Other. For the nine months ended September 30, 2018 and 2017, Other includes a $20 million loss and a $77 million loss, respectively, related to Energy Holdings' investments in leases.

Contract Balances

PSE&G

PSE&G does not have any material contract balances (rights to consideration for services already provided or obligations to provide services in the future for consideration already received) as of September 30, 2018 and December 31, 2017. Substantially all of PSE&G's accounts receivable result from contracts with customers. Allowances represented approximately seven percent of accounts receivable as of September 30, 2018 and December 31, 2017.

Power

Power generally collects consideration upon satisfaction of performance obligations, and therefore, Power had no material contract balances as of September 30, 2018 and December 31, 2017.

Power's accounts receivable include amounts resulting from contracts with customers and other contracts which are out of scope of accounting guidance for revenues from contracts with customers. The majority of these accounts receivable are subject to master netting agreements. As a result, accounts receivable resulting from contracts with customers and receivables unrelated to contracts with customers are netted within Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets. In the wholesale energy markets in which Power operates, payment for services rendered and products transferred are typically due within 30 days of month of delivery. As such, there is little credit risk associated with these receivables and Power typically records no allowances.

Other

PSEG LI does not have any material contract balances as of September 30, 2018 and December 31, 2017.

Remaining Performance Obligations under Fixed Consideration Contracts

Power and PSE&G primarily record revenues as allowed by the guidance, which states that if an entity has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the entity's performance completed to date, the entity may recognize revenue in the amount to which the entity has a right to invoice. PSEG has future performance obligations under contracts with fixed consideration as follows:

Power

As stated above, capacity transactions with ISOs are reported on a net basis dependent on Power's monthly net sale or purchase position through the individual ISOs.

Capacity Payments from the PJM Reliability Pricing Model (RPM) Annual Base Residual and Incremental Auctions—The Base Residual Auction is conducted annually three years in advance of the operating period. Power expects to realize the following average capacity prices for capacity obligations to be satisfied resulting from the base and incremental auctions which have been completed:

Delivery Year	$ per MW-Day	MW Cleared
June 2018 to May 2019	$205	9,200
June 2019 to May 2020	$116	8,900
June 2020 to May 2021	$170	8,100
June 2021 to May 2022	$178	7,700

Capacity Payments from the New England ISO Forward Capacity Market—The Forward Capacity Market Auction (FCM) is conducted annually three years in advance of the operating period. The table below includes Power's cleared capacity in the FCM for the Bridgeport Harbor Station 5, which cleared the 2019/2020 auction at $231/MW-day for seven years, with escalations based on the Handy-Whitman Index and the planned retirement of Bridgeport Harbor Station 3 in 2021. Power expects to realize the following average capacity prices for capacity obligations to be satisfied resulting from the FCM auctions which have been completed:

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Delivery Year	$ per MW-Day	MW Cleared
June 2018 to May 2019	$314	820
June 2019 to May 2020	$231	1,330
June 2020 to May 2021	$195	1,330
June 2021 to May 2022	$192	950
June 2022 to May 2023	$231	480
June 2023 to May 2024	$231	480
June 2024 to May 2025	$231	480
June 2025 to May 2026	$231	480

Bilateral capacity contracts—Capacity obligations pursuant to contract terms through 2029 are anticipated to result in revenues totaling $171 million.

Other

The LIPA OSA is a 12-year services contract ending in 2025 with annual fixed and incentive components. The fixed fee for the provision of services thereunder in 2018 is $64 million and could increase each year based on the change in the Consumer Price Index (CPI). The incentive for 2018 can range from zero to approximately $10 million and could increase each year thereafter based on the change in the CPI.

Note 4. Early Plant Retirements

Fossil

On June 1, 2017, Power completed its previously announced retirement of the generation operations of the existing coal/gas units at the Hudson and Mercer generating stations.

As of June 1, 2017, Power recognized total Depreciation and Amortization of $964 million for the Hudson and Mercer units to reflect the significant shortening of their expected economic useful lives in 2017. In the three and nine months ended September 30, 2017, Power recognized pre-tax charges of $1 million and $10 million, respectively, in Energy Costs primarily for coal inventory lower of cost or market adjustments. In the three and nine months ended September 30, 2017, Power also recognized pre-tax charges in O&M of $8 million and $12 million, respectively, of shut down costs and a net increase in the Asset Retirement Obligation liability due to settlements and changes in cash flow estimates, partially offset by changes in employee-related severance costs. In 2018, no material costs were recorded. Power is exploring various opportunities with these sites, including using the sites for alternative industrial activity or the disposition of one or both of the sites. If Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such environmental remediation are neither currently probable nor estimable but may be material.

PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the held for use classification of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Nuclear

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. In September 2018, Exelon, a co-owner of the Salem units, shut down its Oyster Creek nuclear plant located in New Jersey, one year earlier than previously planned for economic reasons. In addition, First Energy announced in March 2018 the early retirement of four nuclear units at the Davis-Besse, Perry Nuclear and Beaver Valley nuclear plants in Ohio and Pennsylvania by 2021. These closures and retirements are generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production. These trends have significantly reduced

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the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a further shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

In May 2018, the governor of New Jersey signed legislation that would provide a safety net in order to prevent the loss of environmental attributes from selected nuclear generating stations referred to as the ZEC (Zero Emissions Certificate) program. The legislation calls for the BPU to establish a collection process for a customer charge, determine eligibility and certification of need, and potentially select nuclear plants to receive ZECs starting in April 2019. The law mandates each New Jersey electric distribution company (EDC), including PSE&G, to purchase ZECs and recover its procurement of ZECs through a non-bypassable charge (ZEC charge) in the amount of $0.004 per kilowatt-hour.

In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of Power's nuclear units beyond the current year, including whether and to what extent these units participate in RPM capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be influenced by the financial outlook of the units, including the progress, timing and continued outlook for selection of the units under the newly enacted legislation in the state of New Jersey. Power and Exelon have agreed to continue to assess and, when appropriate, approve the funding of individual capital projects to ensure compliance with regulatory requirements and the safe operation of the Salem generating station and that the funding of previously postponed projects may be restored as a result of the legislation enacted in New Jersey sufficiently values the attributes of nuclear generation and Salem benefits from such legislation.

Power believes it may be unable to cover its costs and would be inadequately compensated for its market and operational risks at the Salem and Hope Creek nuclear units, which would result in Power retiring these units early if (i) energy market prices continue to be depressed, (ii) there are adverse impacts from potential changes to the capacity market construct being considered by FERC, or (iii) Salem and/or Hope Creek are not selected to participate in the ZEC program or the ZEC program does not adequately compensate our nuclear generating stations for their attributes. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs and additional funding of the NDT Fund would be material to both PSEG and Power. If any or all of the Salem and Hope Creek units were shut down, it would significantly alter New Jersey's energy supply predominately by increasing New Jersey's reliance on natural gas generation. Such a decrease in fuel diversity could also increase the market's vulnerability to price fluctuations and power disruptions in times of high demand.

The following table provides the balance sheet amounts by generating station as of September 30, 2018 for significant assets and liabilities associated with Power's owned share of its nuclear assets.

	As of September 30, 2018			
	Hope Creek	Salem	Support Facilities and Other (A)	Peach Bottom
	Millions			
Assets				
Materials and Supplies Inventory	$ 83	$ 72	$ —	$ 42
Nuclear Production, net of Accumulated Depreciation	684	642	199	775
Nuclear Fuel In-Service, net of Accumulated Depreciation	155	72	—	103
Construction Work in Progress (including nuclear fuel)	144	156	2	87
Total Assets	**$ 1,066**	**$ 942**	**$ 201**	**$ 1,007**
Liability				
Asset Retirement Obligation	$ 313	$ 258	$ —	$ 213
Total Liabilities	**$ 313**	**$ 258**	**$ —**	**$ 213**
Net Assets	**$ 753**	**$ 684**	**$ 201**	**$ 794**
NRC License Renewal Term	2046	2036/2040	N/A	2033/2034
% Owned	100%	57%	Various	50%

(A) Includes Hope Creek's and Salem's shared support facilities and other nuclear development capital.

The precise timing of any potential early retirement and resulting financial statement impact may be affected by a number of factors, including co-owner considerations, the results of any transmission system reliability study assessments and decommissioning trust fund requirements and other commitments, as well as future energy prices. Power maintains a NDT Fund that funds its decommissioning obligations. See Note 8. Trust Investments.

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Note 5. Variable Interest Entity (VIE)

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Servco, a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal and controls the services provided to LIPA, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and O&M Expense, respectively. Servco recorded $126 million and $114 million for the three months and $355 million and $338 million for the nine months ended September 30, 2018 and 2017, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 6. Rate Filings

This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2017.

In addition to items previously reported in the Annual Report on Form 10-K, significant regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

Electric and Gas Distribution Base Rate Filings—In October 2018, the BPU issued an Order approving the settlement of PSE&G's distribution base rate case with new rates effective November 1, 2018. The settlement resulted in a net reduction in overall annual revenues of approximately $13 million, comprised of a $212 million increase in base revenues, including recovery of deferred storm costs, offset by the return of tax benefits of approximately $225 million. The tax benefits include the flow-back to customers of excess accumulated deferred income taxes resulting from the reduction of the federal income tax rates provided in the Tax Cuts and Jobs Act of 2017 (Tax Act) as well as the accumulated deferred income taxes from previously realized tax repair deductions and tax benefits from future tax repair deductions as realized. As a result of the agreement to flow back tax repair-related accumulated deferred income taxes in the settlement, PSE&G recognized a $581 million regulatory liability and a corresponding regulatory asset as of September 30, 2018. The Order provides for a $9.5 billion rate base, a 9.6% return on equity for PSE&G's distribution business and a 54% equity component of its capitalization structure. In addition to the $13 million annual revenue reduction, the Order provides for a $28 million one-time refund to customers in November and December 2018 for taxes collected at the higher federal income tax rate for the January 1 to March 31, 2018 period. The BPU approved a rate reduction effective April 1, 2018, to PSE&G's then current electric and gas base rates of approximately $71 million and $43 million, respectively, on an annual basis, to reflect the lower federal income tax rate for the period April 1 and forward.

Transmission Formula Rate Filings—In October 2018, PSE&G made two FERC filings with respect to its Transmission Formula Rate. PSE&G filed its 2019 Annual Transmission Formula Rate update with FERC requesting approximately $100 million in increased annual transmission revenue effective January 1, 2019, subject to true-up. In addition, PSE&G filed a Section 205 filing that seeks FERC approval to refund approximately $155 million of transmission related "unprotected excess deferred income tax benefits" to transmission customers over the 2019 twelve month period. The amount of unprotected excess deferred taxes is subject to change pending further Internal Revenue Service (IRS) guidance. FERC approval of PSE&G's Section 205 filing is required to commence any refund to customers and as such, the Annual Transmission Formula Rate update request does not include the impact of the tax refund. This matter is pending.

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In June 2018, PSE&G filed its 2017 true-up adjustment pertaining to its transmission formula rates in effect for 2017. This resulted in an adjustment of $27 million more than the 2017 originally filed revenues, the impact of which PSE&G had primarily recognized in its Consolidated Statement of Operations for the year ended December 31, 2017.

BGSS—In September 2018, the BPU provisionally approved PSE&G's request to decrease its BGSS rates which will decrease annual BGSS revenues by $26 million. The BGSS rate decreased from approximately 37 cents to 35 cents per therm for residential gas customers effective October 1, 2018.

In April 2018, the BPU approved the final BGSS rates which were effective October 1, 2017.

Green Program Recovery Charges (GPRC)—In October 2018, the BPU approved PSE&G's 2017 GPRC cost recovery petition requesting recovery of approximately $58 million and $15 million in electric and gas revenues, respectively, on an annual basis.

In June 2018, PSE&G filed its 2018 GPRC cost recovery petition requesting recovery of approximately $65 million and $6 million in electric and gas revenues, respectively, on an annual basis.

Remediation Adjustment Charge (RAC)—In October 2018, the BPU approved PSE&G's filing with respect to its RAC 25 petition allowing recovery of $63 million effective November 1, 2018 related to Manufactured Gas Plant expenditures from August 1, 2016 through July 31, 2017.

Energy Strong Program I (ES I) Recovery Filing—In August 2018, the BPU approved recovery of PSE&G's ES I capital investment petition of an annual revenue requirement increase of $0.6 million and $0.1 million associated with electric and gas investment costs, respectively. This represents the final recovery of electric and gas ES I capital investment costs consistent with the BPU Order of Approval of the Energy Strong Program.

In February 2018, the BPU approved recovery of an annual revenue requirement of $8 million associated with electric ES I capital investment costs placed in service from June 1, 2017 through November 30, 2017.

Weather Normalization Clause (WNC)—In October 2018, the BPU approved PSE&G's 2017-2018 WNC petition on a provisional basis allowing a net recovery of $14 million to be collected over the 2018-2019 Winter Period with the new rate effective November 1, 2018. The $14 million net recovery is the result of $9 million of excess revenues from the colder-than-normal 2017-2018 Winter Period offset by $23 million of remaining prior Winter Period undercollection.

In April 2018, the BPU gave final approval to PSE&G's petition to collect $55 million in net deficiency gas revenues as a result of the warmer than normal 2016-2017 Winter Period, which resulted in a deficiency of $31 million, plus a carryover balance of $24 million from the 2015-2016 Winter Period.

Gas System Modernization Program I (GSMP I)—In October 2018, PSE&G updated its annual GSMP I cost recovery petition to include GSMP I investments in service as of September 30, 2018. The petition seeks BPU approval to recover in gas base rates an estimated annual revenue increase of $21 million effective January 1, 2019.

Societal Benefits Charge—In February 2018, the BPU approved PSE&G's petition to increase electric rates by approximately $20 million on an annual basis and to decrease gas rates by approximately $0.8 million on an annual basis, in order to recover electric and gas costs incurred through May 31, 2017 under its Energy Efficiency and Renewable Energy and Social Programs. The new rates were effective April 1, 2018.

Note 7. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. Interest income on the loans is recorded on an accrual basis. The loans are generally paid back with solar renewable energy certificates (SRECs) generated from the installed solar electric system. In the event of a loan default, the basis of the solar loan would be recovered through a regulatory recovery mechanism. None of the solar loans are impaired; however, in the event a loan becomes impaired, the basis of the loan would be recovered through a regulatory recovery mechanism. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which are considered "non-performing."

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Outstanding Loans by Class of Customer

Consumer Loans	As of September 30, 2018	As of December 31, 2017
	Millions	
Commercial/Industrial	$ 166	$ 158
Residential	9	10
Total	**$ 175**	**$ 168**

Energy Holdings

Energy Holdings, through several of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third-party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Condensed Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

During the first quarter of 2017, due to continuing liquidity issues facing NRG REMA, LLC (REMA), economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as certain discussions with REMA management, Energy Holdings recorded a $55 million pre-tax charge for its current best estimate of loss related to the lease receivables. Additional pre-tax charges of $22 million (including $7 million related to residual value impairment) were recorded in the quarter ended June 30, 2017.

Based on an ongoing review of (i) the liquidity challenges facing REMA and (ii) available alternatives, Energy Holdings recorded an additional $20 million pre-tax charge in the three months ended June 30, 2018 for its current best estimate of loss related to lease receivables. Pre-tax charges were reflected in Operating Revenues in 2018 and 2017 and are included in Gross Investment in Leases as of September 30, 2018.

In September 2018, certain subsidiaries of Energy Holdings (PSEG Entities) entered into a Restructuring Support Agreement (RSA) with REMA. Pursuant to the RSA, the PSEG Entities have agreed to support implementation of restructuring and related transactions with respect to REMA's indebtedness. Such restructuring transactions will be implemented by REMA on an in-court basis under Chapter 11 of the Bankruptcy Code. The RSA outlines a plan of reorganization under which, in addition to other terms, the ownership interest in the leases relating to the Keystone and Conemaugh investments will be transferred to debtholders of REMA. Upon consummation of the restructuring transactions, the PSEG Entities will receive $31.5 million in cash in exchange for (a) the full satisfaction of all claims asserted against REMA and (b) approval of certain amendments to the Shawville lease. The Shawville lease amendments, among other things, will allow REMA to express tentative interest in a renewal on or after November 24, 2019, with similar changes to the other milestones in the lease renewal procedures. In addition, REMA has agreed to fund qualifying credit support up to $36 million.

Energy Holdings will be required upon resolution of this matter to accelerate and pay approximately $40 million of state deferred tax liabilities and accelerate and pay and/or reduce $85 million of a forecasted federal tax loss to the IRS.

As of September 30, 2018, no additional charges were recorded because the anticipated proceeds of $31.5 million from the transactions described above are in excess of the September 30, 2018 recorded amounts for the Keystone and Conemaugh lease investments.

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The following table shows Energy Holdings' gross and net lease investment as of September 30, 2018 and December 31, 2017.

	As of September 30, 2018	As of December 31, 2017
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 524	$ 546
Estimated Residual Value of Leased Assets	326	326
Total Investment in Rental Receivables	850	872
Unearned and Deferred Income	(294)	(307)
Gross Investment in Leases	556	565
Deferred Tax Liabilities	(470)	(480)
Net Investment in Leases	**$ 86**	**$ 85**

The corresponding receivables associated with the lease portfolio are reflected as follows, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

	Lease Receivables, Net of Non-Recourse Debt
Counterparties' Credit Rating Standard & Poor's (S&P) as of September 30, 2018	**As of September 30, 2018**
	Millions
AA	$ 13
BBB+ — BBB-	316
BB	133
NR	62
Total	**$ 524**

The "BB" and the "NR" ratings in the preceding table represent lease receivables related to coal and gas-fired assets in Illinois and Pennsylvania, respectively. As of September 30, 2018, the gross investment in the leases of such assets, net of non-recourse debt, was $316 million ($(83) million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 133	64%	1,538	Coal	BB	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 85	64%	1,036	Gas	BB	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 10	17%	1,711	Coal	NR	REMA (A)
Conemaugh Station Units 1 and 2	PA	$ 9	17%	1,711	Coal	NR	REMA (A)
Shawville Station Units 1, 2, 3 and 4	PA	$ 79	100%	596	Gas	NR	REMA (A)

(A) REMA filed a voluntary petition for relief under Chapter 11 of the U.S. Bankruptcy Code. See above for a discussion of the RSA entered into by REMA and the PSEG Entities relating to certain restructuring transactions by REMA.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease structures. These credit enhancement features vary from lease to lease. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and seek recovery of their investment, potentially

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including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital and trigger certain material tax obligations which could, for certain leases, wholly or partially be mitigated by tax indemnification claims against the counterparty. A bankruptcy of a lessee would likely delay and potentially limit any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders.

Additional factors that may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and their affiliates and the quality and condition of assets under lease.

Note 8. Trust Investments

NDT Fund

Power maintains an external master NDT to fund its share of decommissioning costs for its five nuclear facilities upon their respective termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code (IRC) limits the amount of money that can be contributed into a qualified fund. The funds are managed by third-party investment managers who operate under investment guidelines developed by Power.

The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of September 30, 2018			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 467	$ 268	$ (7)	$ 728
International	330	78	(16)	392
Total Equity Securities	797	346	(23)	1,120
Available-for Sale Debt Securities				
Government	537	—	(17)	520
Corporate	468	1	(13)	456
Total Available-for-Sale Debt Securities	1,005	1	(30)	976
Other	—	—	—	—
Total NDT Fund Investments	**$ 1,802**	**$ 347**	**$ (53)**	**$ 2,096**

	As of December 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 497	$ 245	$ (2)	$ 740
International	311	99	(3)	407
Total Equity Securities	808	344	(5)	1,147
Available-for Sale Debt Securities				
Government	586	2	(4)	584
Corporate	400	4	(2)	402
Total Available-for-Sale Debt Securities	986	6	(6)	986
Total NDT Fund Investments	**$ 1,794**	**$ 350**	**$ (11)**	**$ 2,133**

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Net unrealized gains (losses) on debt securities of $(17) million (after-tax) were included in Accumulated Other Comprehensive Loss on PSEG's and Power's Condensed Consolidated Balance Sheets as of September 30, 2018. The portion of net unrealized gains (losses) recognized during the third quarter and first nine months of 2018 related to equity securities still held at the end of September 30, 2018 were $41 million and $26 million, respectively.

The amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2018	As of December 31, 2017
	Millions	
Accounts Receivable	$ 13	$ 24
Accounts Payable	$ 14	$ 74

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of September 30, 2018				As of December 31, 2017			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)								
Domestic	$ 78	$ (7)	$ 4	$ —	$ 40	$ (2)	$ —	$ —
International	87	(14)	8	(2)	29	(3)	2	—
Total Equity Securities	165	(21)	12	(2)	69	(5)	2	—
Available-for Sale Debt Securities								
Government (B)	342	(10)	153	(7)	343	(2)	91	(2)
Corporate (C)	342	(11)	49	(2)	191	(1)	27	(1)
Total Available-for-Sale Debt Securities	684	(21)	202	(9)	534	(3)	118	(3)
NDT Trust Investments	**$ 849**	**$ (42)**	**$ 214**	**$ (11)**	**$ 603**	**$ (8)**	**$ 120**	**$ (3)**

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. Effective January 1, 2018, unrealized gains and losses on these securities are recorded in Net Income.

(B) Debt Securities (Government)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). The unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. Power also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2018.

(C) Debt Securities (Corporate)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). Power's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2018.

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The proceeds from the sales of and the net gains (losses) on securities in the NDT Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	Millions			
Proceeds from NDT Fund Sales (A)	**$ 231**	**$ 278**	**$ 1,005**	**$ 845**
Net Realized Gains (Losses) on NDT Fund				
Gross Realized Gains	$ 17	$ 29	$ 75	$ 82
Gross Realized Losses	(7)	(5)	(29)	(14)
Net Realized Gains (Losses) on NDT Fund (B)	**$ 10**	**$ 24**	**$ 46**	**$ 68**
Unrealized Gains (Losses) on Equity Securities in NDT Fund (C)	34	N/A	(16)	N/A
Other-Than-Temporary-Impairments (OTTI)	$ —	$ (5)	—	(9)
Net Gains (Losses) on NDT Fund Investments	**$ 44**	**$ 19**	**$ 30**	**$ 59**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

(B) The cost of these securities was determined on the basis of specific identification.

(C) Effective January 1, 2018, unrealized gains (losses) on equity securities are recorded in Net Income instead of Other Comprehensive Income (Loss).

The NDT Fund debt securities held as of September 30, 2018 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 11
1 - 5 years	282
6 - 10 years	201
11 - 15 years	47
16 - 20 years	73
Over 20 years	362
Total NDT Available-for-Sale Debt Securities	**$ 976**

Power periodically assesses individual debt securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For these securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a “Rabbi Trust.”

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The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of September 30, 2018			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 21	$ 4	$ —	$ 25
International	—	—	—	—
Total Equity Securities	21	4	—	25
Available-for-Sale Debt Securities				
Government	103	—	(4)	99
Corporate	104	—	(3)	101
Total Available-for-Sale Debt Securities	207	—	(7)	200
Total Rabbi Trust Investments	**$ 228**	**$ 4**	**$ (7)**	**$ 225**

	As of December 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$ 24	$ 3	$ —	$ 27
International	—	—	—	—
Total Equity Securities	24	3	—	27
Available-for-Sale Debt Securities				
Government	85	1	(1)	85
Corporate	118	2	(1)	119
Total Available-for-Sale Debt Securities	203	3	(2)	204
Total Rabbi Trust Investments	**$ 227**	**$ 6**	**$ (2)**	**$ 231**

Net unrealized gains (losses) on debt securities of $(5) million (after-tax) were included in Accumulated Other Comprehensive Loss on PSEG's Condensed Consolidated Balance Sheet as of September 30, 2018. The portion of net unrealized gains (losses) recognized during the third quarter and first nine months of 2018 related to equity securities still held at the end of September 30, 2018 were $1 million and $2 million, respectively.

The amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2018	As of December 31, 2017
	Millions	
Accounts Receivable	$ 1	$ 2
Accounts Payable	$ —	$ 1

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The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months.

	As of September 30, 2018				As of December 31, 2017			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Available-for-Sale Debt Securities								
Government (A)	$ 70	$ (2)	$ 28	$ (2)	$ 28	$ —	$ 25	$ (1)
Corporate (B)	76	(3)	14	—	39	(1)	9	—
Total Available-for-Sale Debt Securities	146	(5)	42	(2)	67	(1)	34	(1)
Rabbi Trust Investments	**$ 146**	**$ (5)**	**$ 42**	**$ (2)**	**$ 67**	**$ (1)**	**$ 34**	**$ (1)**

(A) Debt Securities (Government)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). The unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. PSEG also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2018.

(B) Debt Securities (Corporate)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2018.

The proceeds from the sales of and the net gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	Millions			
Proceeds from Rabbi Trust Sales (A)	**$ 33**	**$ 24**	**$ 80**	**$ 168**
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$ —	$ —	$ 2	$ 17
Gross Realized Losses	(1)	(1)	(3)	(5)
Net Realized Gains (Losses) on Rabbi Trust (B)	**(1)**	**(1)**	**(1)**	**12**
Unrealized Gains (Losses) on Equity Securities in Rabbi Trust (C)	2	N/A	2	N/A
OTTI	—	—	—	—
Net Gains (Losses) on Rabbi Trust Investments	**$ 1**	**$ (1)**	**$ 1**	**$ 12**

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

(B) The cost of these securities was determined on the basis of specific identification.

(C) Effective January 1, 2018, unrealized gains (losses) on equity securities are recorded in Net Income instead of Other Comprehensive Income (Loss).

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The Rabbi Trust debt securities held as of September 30, 2018 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 3
1 - 5 years	28
6 - 10 years	32
11 - 15 years	7
16 - 20 years	22
Over 20 years	108
Total Rabbi Trust Available-for-Sale Debt Securities	**$ 200**

PSEG periodically assesses individual debt securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For these securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of September 30, 2018	As of December 31, 2017
	Millions	
PSE&G	$ 46	$ 46
Power	57	57
Other	122	128
Total Rabbi Trust Investments	**$ 225**	**$ 231**

Note 9. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria.

The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis for PSEG, excluding Servco. Amounts shown do not reflect the impacts of capitalization and co-owner allocations. Effective with the adoption of ASU 2017-07 on January 1, 2018, only the service cost component is eligible for capitalization, when applicable. For additional information, see Note 2. Recent Accounting Standards.

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	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
	Millions							
Components of Net Periodic Benefit (Credits) Costs								
Service Cost (included in O&M Expense)	$ 32	$ 29	$ 4	$ 4	$ 97	$ 86	$ 13	$ 12
Non-Service Components of Pension and OPEB (Credits) Costs								
Interest Cost	52	51	16	15	156	153	49	47
Expected Return on Plan Assets	(111)	(98)	(9)	(8)	(331)	(295)	(30)	(25)
Amortization of Net								
Prior Service Cost	(4)	(5)	(1)	(3)	(13)	(14)	(1)	(8)
Actuarial Loss	22	24	16	13	64	73	48	38
Non-Service Components of Pension and OPEB (Credits) Costs	**(41)**	**(28)**	**22**	**17**	**(124)**	**(83)**	**66**	**52**
Total Benefit (Credits) Costs	**$ (9)**	**$ 1**	**$ 26**	**$ 21**	**$ (27)**	**$ 3**	**$ 79**	**$ 64**

Pension and OPEB costs for PSE&G, Power and PSEG's other subsidiaries, excluding Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017	2018	2017	2018	2017
	Millions							
PSE&G	$ (8)	$ (1)	$ 17	$ 13	$ (23)	$ (3)	$ 51	$ 40
Power	(2)	—	8	7	(7)	1	24	20
Other	1	2	1	1	3	5	4	4
Total Benefit (Credits) Costs	**$ (9)**	**$ 1**	**$ 26**	**$ 21**	**$ (27)**	**$ 3**	**$ 79**	**$ 64**

During the three months ended March 31, 2018, PSEG contributed its entire planned contribution for the year 2018 of $14 million into its OPEB plan.

Servco Pension and OPEB

At the direction of LIPA, Servco sponsors benefit plans that cover its current and former employees who meet certain eligibility criteria. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 5. Variable Interest Entity. These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. Servco has contributed its entire planned contribution amount of $40 million into its pension plan trusts during 2018. Servco's pension-related revenues and costs were $20 million and $18 million for three months ended September 30, 2018 and 2017, respectively, and $40 million and $35 million for the nine months ended September 30, 2018 and 2017, respectively. The OPEB-related revenues earned and costs incurred were $1 million for each of the three months ended September 30, 2018 and 2017, and $4 million and $3 million for the nine months ended September 30, 2018 and 2017, respectively.

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Note 10. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees as a form of collateral.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- the net position of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. Current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of September 30, 2018 and December 31, 2017.

	As of September 30, 2018	As of December 31, 2017
	Millions	
Face Value of Outstanding Guarantees	$ 1,787	$ 1,701
Exposure under Current Guarantees	$ 140	$ 153
Letters of Credit Margin Posted	$ 163	$ 103
Letters of Credit Margin Received	$ 17	$ 32
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$ —	$ —
Counterparty Cash Margin Received	$ (3)	$ (1)
Net Broker Balance Deposited (Received)	$ 226	$ 147
Additional Amounts Posted:		
Other Letters of Credit	$ 63	$ 61

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As part of determining credit exposure, Power nets receivables and payables with the corresponding net fair values of energy contracts. See Note 12. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Condensed Consolidated Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power have posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The U.S. Environmental Protection Agency (EPA) has determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA and a comprehensive study of the entire 17 miles of the lower Passaic River needed to be performed. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, certain Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. The CPG has agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately 7.6 percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately 1.9 percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River with an estimated cost to remediate the lower 17 miles of the Passaic River ranging from approximately $518 million to $3.2 billion on an undiscounted basis.

In March 2016, the EPA released its Record of Decision (ROD) for the EPA's own Focused Feasibility Study (FFS) which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The EPA estimated the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation. Occidental Chemical Corporation (OCC), one of the PRPs, has commenced performance of the remedial design required by the ROD Remedy, reserving its right of cost contribution from all other PRPs.

In September 2017, the EPA concluded that an Agency-commenced allocation process for the Passaic River's lower 8.3 miles should include only certain PRPs. The allocation is intended to lead to a consent decree in which certain of the PRPs agree to perform and pay for the remedial action under EPA oversight. The allocation process has commenced and is scheduled to be completed in late 2019.

In October 2018, the EPA Region 2 issued a Directive to the CPG instructing the CPG to focus the ongoing RI/FS evaluation on various adaptive management scenarios for remediation of the upper 9 miles of the Passaic River, which approach has been agreed to in concept by the EPA and the CPG. The Directive does not contain estimates for anticipated costs. Adaptive management focuses on removing targeted "hot spots" of contaminated sediments rather than removing all of the Passaic River's sediments as in a "bank to bank" approach.

In a separate matter, two PRPs, Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus), filed for Chapter 11 bankruptcy in Delaware Federal Bankruptcy Court. In June 2018, the trust representing the creditors in this proceeding filed a complaint asserting claims against the current and former parent entities of Tierra and Maxus, among other parties, for up to $14 billion. Any damages awarded may be used to fund, in part, the remediation costs of the lower 8.3 miles of the Passaic River. The creditor trust has reserved its right to file contribution claims against 28 PRPs, including PSEG. This matter is ongoing.

In June 2018, OCC filed a complaint in Federal District Court in Newark against various defendants, including PSE&G, seeking cost recovery and contribution under CERCLA for the remediation of the lower 8.3 miles of the Passaic River. The

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complaint does not quantify damages sought.

The Complaint alleges that "no single hazardous substance" is to blame for the contamination of the lower Passaic River and lists the eight Contaminants of Concern (COCs) identified by the EPA in the ROD. OCC alleges PSE&G is responsible for a portion of six of the eight COCs. PSE&G cannot predict the outcome of this matter.

Based upon the estimated cost of the ROD Remedy and PSEG's estimate of PSE&G's and Power's shares of that cost, as of September 30, 2018, PSEG has accrued approximately $57 million. Of this amount, PSE&G has accrued $46 million as an Environmental Costs Liability and a corresponding Regulatory Asset based on its continued ability to recover such costs in its rates. Power has accrued $11 million as an Other Noncurrent Liability with the corresponding O&M Expense recorded in prior years when the liability was accrued.

The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on PSEG's financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $343 million and $388 million on an undiscounted basis through 2021, including its $46 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $343 million as of September 30, 2018. Of this amount, $75 million was recorded in Other Current Liabilities and $268 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $343 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly. NJDEP, PSEG and EPA representatives have had discussions regarding to what extent sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.

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Clean Water Act (CWA) Permit Renewals

Pursuant to the Federal Water Pollution Control Act, National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In May 2014, the EPA issued a final cooling water intake rule that establishes requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing power facilities on a case by case basis, based on studies related to impingement mortality and entrainment by the facilities seeking renewal permits.

Several environmental organizations and certain energy industry groups have filed suit under the CWA and the Endangered Species Act. The cases were consolidated at the Second Circuit, and in July 2018 the Second Circuit upheld the EPA's final cooling water intake rule. The Court's decision allows Permitting Directors to continue to issue permits in accordance with the flexible, site-specific provisions of the final rule.

In June 2016, the NJDEP issued a final NJPDES permit for Salem. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the CWA, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final NJPDES renewal permit for Salem. NJDEP has granted the hearing request, but it has not yet been scheduled. The Riverkeeper's filing does not change the effective date of the permit. If the Riverkeeper's challenge were successful, Power may be required to incur additional costs to comply with the CWA. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

State permitting decisions at Bridgeport and possibly New Haven could also have a material impact on Power's ability to renew permits at its existing larger once-through cooled plants without making significant upgrades to existing intakes and cooling systems.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA's CWA Section 316(b) final rule, Power has proposed to continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the previously estimated useful life ending in 2025. Power is currently awaiting action by the CTDEEP to issue a draft and then a final permit.

Power has entered into a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut and local community organizations. That CEBA provides that Power would retire BH3 early if all of its conditions precedent occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power may seek to operate BH3 through the previously estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. The Connecticut Siting Council issued an order to approve siting Bridgeport Harbor Station Unit 5 (BH5). All major environmental permits have been received; however, secondary approvals are still being obtained to allow operations to begin in mid-2019. Power's obligations under the CEBA are being monitored regularly and carried out as needed.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.

Jersey City, New Jersey Subsurface Feeder Cable Matter

In October 2016, a discharge of dielectric fluid from subsurface feeder cables located in the Hudson River near Jersey City,

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New Jersey, was identified and reported to the NJDEP. The feeder cables are located within a subsurface easement granted to PSE&G by the property owners, Newport Associates Development Company (NADC) and Newport Associates Phase I Developer Limited Partnership. The feeder cables are subject to agreements between PSE&G and Consolidated Edison Company of New York, Inc. (Con Edison) and are jointly owned by PSE&G and Con Edison, with PSE&G owning the portion of the cables located in New Jersey and Con Edison owning the portion of the cables located in New York. The NJDEP declared an emergency and an emergency response action was undertaken to investigate, contain, remediate and stop the fluid discharge; to assess, repair and restore the cables to good working order, if feasible; and to restore the property. The regulatory agencies overseeing the emergency response, including the U.S. Coast Guard, the NJDEP and the Army Corps of Engineers, have issued multiple notices, orders and directives to the various parties related to this matter and the parties may also be subject to the assessment of civil penalties related to the discharge and response. The U.S. Coast Guard transitioned control of the federal response to the EPA in May 2018. In August 2018, the EPA ended the federal response to the matter. The response has now transitioned to the NJDEP site remediation program.

The impacted cable was repaired in late September 2017; however, small amounts of residual dielectric fluid believed to be contained within the marina sediment continue to appear on the surface and response actions related to the fluid discharge are ongoing, although at a significantly reduced scale. PSE&G remains concerned about future leaks and potential environmental impacts as a result of reintroduction of fluid back into these lines and has determined that retirement of the affected facilities is appropriate. PSE&G has been unable to reach an agreement with Con Edison and, as a result, in May 2018, PSE&G filed an action at FERC to resolve the matter. FERC dismissed PSE&G's Complaint against Con Edison in September 2018. Also ongoing is the lawsuit in federal court to determine ultimate responsibility for the costs to address the leak among PSE&G, Con Edison and NADC. In addition, Con Edison filed counter claims against PSE&G and NADC, including seeking injunctive relief and damages. Based on the information currently available and depending on the outcome of the federal court action, PSE&G's portion of the costs to address the leak may be material; however, PSE&G anticipates that it will recover these costs through regulatory proceedings.

Steam Electric Effluent Guidelines

In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG Rule) for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under the ELG Rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the ELG Rule.

Through various orders, the EPA has stayed the compliance dates in the ELG Rule and has announced plans to further revise the requirements and compliance dates of the ELG Rule. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU's approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G's load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey's renewable portfolio standards.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2018 is $287.76 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2018 of $276.83 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

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PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2015	2016	2017	2018	
36-Month Terms Ending	May 2018	May 2019	May 2020	May 2021	(A)
Load (MW)	2,900	2,800	2,800	2,900	
$ per MWh	$99.54	$96.38	$90.78	$91.77	

(A) Prices set in the 2018 BGS auction year became effective on June 1, 2018 when the 2015 BGS auction agreements expired.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey EDCs with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 19. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2021 and a significant portion through 2022 at Salem, Hope Creek and Peach Bottom.

Power has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available beyond the needs of PSE&G's customers, Power can use the gas to supply its fossil generating stations in New Jersey.

Power also has various long-term fuel purchase commitments for coal through 2021 to support its fossil generation stations.

As of September 30, 2018, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2022
	Millions
Nuclear Fuel	
Uranium	$ 227
Enrichment	$ 312
Fabrication	$ 158
Natural Gas	$ 922
Coal	$ 240

Litigation

Sewaren 7 Construction

In June 2018, a complaint was filed in federal court in Newark against PSEG Fossil, LLC, a wholly owned subsidiary of Power, regarding an ongoing dispute with Durr Mechanical Construction, Inc. (Durr), a contractor on the Sewaren 7 project. Among other things, Durr seeks damages of $93 million and alleges that Power withheld money owed to Durr and that Power's intentional conduct led to the inability of Durr to obtain prospective contracts. Power intends to vigorously defend against these allegations. Based upon the preliminary nature of this matter, a loss is not considered probable nor is the amount of loss, if any, estimable as of September 30, 2018.

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Newark Customer Incident

On the morning of July 5, 2018, PSE&G discontinued electricity to the home of a customer residing in Newark because of outstanding arrears on that customer's account. Subsequent to the discontinuation of electricity, that customer died on the afternoon of July 5th. The family of the customer, who was on hospice care, raised allegations in the media regarding PSE&G's conduct surrounding the discontinuation and restoration of electricity to the home of the customer, claiming that the discontinuation of electric service prevented the customer from using life sustaining medical equipment. The BPU initiated an investigation into the matter and that investigation is ongoing. In addition, PSE&G received a grand jury subpoena from the Essex County Prosecutor's Office (ECPO) for records and correspondence between PSE&G and the customer. PSE&G is fully cooperating with the BPU and the ECPO in both proceedings. PSEG cannot predict the outcome of the pending proceedings regarding this incident at this time.

The PSEG Board of Directors (PSEG Board) retained outside counsel to conduct an independent investigation of the facts surrounding this incident with the full support and cooperation of management. The independent investigation concluded that the disconnection itself was not improper; however, it did identify issues related to PSE&G's response once it was notified of the disconnection. The PSEG Board reviewed and considered the findings and conclusions of the investigation and PSE&G's proposed corrective actions. PSE&G's progress on implementation of the corrective actions will continue to be overseen by the PSEG Board.

Caithness Energy, L.L.C. (Caithness)

In August 2018, Caithness, a Long Island power plant developer, filed a complaint in federal district court in the Eastern District of New York against PSEG and PSEG LI alleging violations of state and federal antitrust laws and a claim of intentional interference of prospective business relations. Caithness alleges that PSEG and PSEG LI interfered with LIPA's consideration of the Caithness proposal for a 750 MW combined cycle generation project that was identified as a finalist for a Request For Proposal issued by LIPA. In addition, Caithness claims that PSEG and PSEG LI induced LIPA to agree to eliminate the proposed project as a potential competitor to other PSEG affiliates with power supply operations. The complaint alleges hundreds of millions of dollars of harm and seeks treble and punitive damages. We intend to vigorously defend against these allegations. Based upon the preliminary nature of this matter, a loss is not considered probable nor is the amount of loss, if any, estimable as of September 30, 2018.

Other Litigation and Legal Proceedings

PSEG and its subsidiaries are party to various lawsuits in the ordinary course of business. In view of the inherent difficulty in predicting the outcome of such matters, PSEG, PSE&G and Power generally cannot predict the eventual outcome of the pending matters, the timing of the ultimate resolution of these matters, or the eventual loss, fines or penalties related to each pending matter.

In accordance with applicable accounting guidance, a liability is accrued when those matters present loss contingencies that are both probable and reasonably estimable. In such cases, there may be an exposure to loss in excess of any amounts accrued. PSEG will continue to monitor the matter for further developments that could affect the amount of the accrued liability that has been previously established.

Based on current knowledge, management does not believe that loss contingencies arising from pending matters, other than the matters described herein, could have a material adverse effect on PSEG's, PSE&G's or Power's consolidated financial position or liquidity. However, in light of the inherent uncertainties involved in these matters, some of which are beyond PSEG's control, and the large or indeterminate damages sought in some of these matters, an adverse outcome in one or more of these matters could be material to PSEG's, PSE&G's or Power's results of operations or liquidity for any particular reporting period.

Note 11. Debt and Credit Facilities

Long-Term Debt Financing Transactions

The following long-term debt transactions occurred in the nine months ended September 30, 2018:

PSE&G

- issued $375 million of 3.70% Secured Medium-Term Notes, Series M, due May 2028,
- issued $325 million of 4.05% Secured Medium-Term Notes, Series M, due May 2048,
- issued $325 million of 3.25% Secured Medium-Term Notes, Series M, due September 2023,

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- issued $325 million of 3.65% Secured Medium-Term Notes, Series M, due September 2028,
- retired $400 million of 5.30% Medium-Term Notes at maturity, and
- retired $350 million of 2.30% Medium-Term Notes at maturity.

Power

- issued $700 million of 3.85% Senior Notes due June 2023.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under the $4.3 billion credit facilities are provided by a diverse bank group. As of September 30, 2018, the total available credit capacity was $3.6 billion.

As of September 30, 2018, no single institution represented more than 9% of the total commitments in the credit facilities.

As of September 30, 2018, total credit capacity was in excess of the total anticipated maximum liquidity requirements over PSEG's 12-month planning horizon.

In September 2018, Power amended an existing 3-year $100 million letter of credit facility, extending the expiration date to September 2021. The second letter of credit facility, which is scheduled to expire in March 2020, will be terminated during the fourth quarter of 2018. Power also executed a new 3-year $100 million letter of credit facility that expires in September 2021.

Each of the credit facilities is restricted as to availability and use to the specific companies as listed in the following table; however, if necessary, the PSEG facilities can also be used to support its subsidiaries' liquidity needs. The total credit facilities and available liquidity as of September 30, 2018 were as follows:

	As of September 30, 2018				
Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facilities (A)	$ 1,500	$ 393	$ 1,107	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSEG	**$ 1,500**	**$ 393**	**$ 1,107**		
PSE&G					
5-year Credit Facility (A)	$ 600	$ 56	$ 544	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSE&G	**$ 600**	**$ 56**	**$ 544**		
Power					
3-year Letter of Credit Facility	$ 100	$ 62	$ 38	Mar 2020	Letters of Credit
3-year Letter of Credit Facilities	200	100	$ 100	Sept 2021	Letters of Credit
5-year Credit Facilities	1,900	51	1,849	Mar 2022	Funding/Letters of Credit
Total Power	**$ 2,200**	**$ 213**	**$ 1,987**		
Total	**$ 4,300**	**$ 662**	**$ 3,638**		

(A) The primary use of PSEG's and PSE&G's credit facilities is to support their respective Commercial Paper Programs, under which as of September 30, 2018, PSEG had $379 million outstanding at a weighted average interest rate of 2.54%. PSE&G had $40 million outstanding at a weighted average interest rate of 2.35% under its Commercial Paper Program as of September 30, 2018.

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Note 12. Financial Risk Management Activities

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchases and normal sales (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow or fair value hedges. Power enters into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Power also uses derivatives to hedge a portion of its anticipated BGSS obligations with PSE&G. For additional information see Note 10. Commitments and Contingent Liabilities. Changes in the fair market value of these derivative contracts are recorded in earnings.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. The changes in fair value of the interest rate swaps are fully offset by changes in the fair value of the underlying forecasted interest payments of the debt. There were no outstanding interest rate swaps as of September 30, 2018 or December 31, 2017.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. PSEG interest rate hedges totaling $500 million were executed and terminated during the second quarter of 2018 and a loss of $(1) million was recorded in Accumulated Other Comprehensive Income (Loss) (after tax) and will amortize to interest expense over the remaining life of Power's $700 million of 3.85% Senior Notes due June 2023. For additional information see Note 11. Debt and Credit Facilities. There were no outstanding interest rate hedges as of September 30, 2018 and December 31, 2017. The Accumulated Other Comprehensive Income (Loss) (after tax) related to terminated interest rate derivatives designated as cash flow hedges was $(1) million as of September 30, 2018 and was immaterial as of December 31, 2017. The after-tax unrealized losses on these hedges expected to be reclassified to earnings during the next 12 months are immaterial.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with PSEG's accounting policy, these positions are offset on the Condensed Consolidated Balance Sheets of Power and PSEG. For additional information see Note 13. Fair Value Measurements.

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The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of September 30, 2018			
	Power (A)			Consolidated
	Not Designated			
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Total Derivatives
	Millions			
Derivative Contracts				
Current Assets	$ 301	$ (290)	$ 11	$ 11
Noncurrent Assets	123	(121)	2	2
Total Mark-to-Market Derivative Assets	**$ 424**	**$ (411)**	**$ 13**	**$ 13**
Derivative Contracts				
Current Liabilities	$ (389)	$ 376	$ (13)	$ (13)
Noncurrent Liabilities	(149)	147	(2)	(2)
Total Mark-to-Market Derivative (Liabilities)	**$ (538)**	**$ 523**	**$ (15)**	**$ (15)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ (114)**	**$ 112**	**$ (2)**	**$ (2)**

	As of December 31, 2017			
	Power (A)			Consolidated
	Not Designated			
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Total Derivatives
	Millions			
Derivative Contracts				
Current Assets	$ 391	$ (362)	$ 29	$ 29
Noncurrent Assets	78	(71)	7	7
Total Mark-to-Market Derivative Assets	**$ 469**	**$ (433)**	**$ 36**	**$ 36**
Derivative Contracts				
Current Liabilities	$ (403)	$ 387	$ (16)	$ (16)
Noncurrent Liabilities	(95)	90	(5)	(5)
Total Mark-to-Market Derivative (Liabilities)	**$ (498)**	**$ 477**	**$ (21)**	**$ (21)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ (29)**	**$ 44**	**$ 15**	**$ 15**

(A) Substantially all of Power's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of September 30, 2018 and December 31, 2017.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset on the Condensed Consolidated Balance Sheets. As of September 30, 2018 and December 31, 2017, Power had net cash collateral/margin payments to counterparties of $223 million and $146 million, respectively. Of these net cash/collateral margin payments $112 million as of September 30, 2018 and $44 million as December 31, 2017 were netted against the corresponding net derivative contract positions. Of the $112 million as of September 30, 2018, $(2) million was netted against current assets, and $(1) million was netted against noncurrent assets, $88 million was netted against current liabilities, and $27 million was netted against noncurrent liabilities. Of the $44 million as of December 31, 2017, $(3) million was netted against current assets, $28 million was netted against current liabilities, and $19 million was netted against noncurrent liabilities.

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Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating by S&P or Moody's, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P or Moody's ratings. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $23 million and $30 million as of September 30, 2018 and December 31, 2017, respectively. As of September 30, 2018 and December 31, 2017, Power had the contractual right of offset of $7 million and $13 million, respectively, related to derivative instruments that are assets with the same counterparty under master agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $16 million and $17 million as of September 30, 2018 and December 31, 2017, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.

The following reconciles the Accumulated Other Comprehensive Income (Loss) for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income (Loss)	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2016	**$ 3**	**$ 2**
Gain Recognized in AOCI	—	—
Less: Gain Reclassified into Income	(3)	(2)
Balance as of December 31, 2017	**$ —**	**$ —**
Loss Recognized in AOCI	(2)	(1)
Less: Loss Reclassified into Income	—	—
Balance as of September 30, 2018	**$ (2)**	**$ (1)**

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS for the three months and nine months ended September 30, 2018 and 2017. Power's derivative contracts reflected in this table include contracts to hedge the purchase and sale of electricity and natural gas, and the purchase of fuel. The table does not include contracts that Power has designated as NPNS, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives		Pre-Tax Gain (Loss) Recognized in Income on Derivatives	
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2018	2017	2018	2017
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ (130)	$ 26	$ (154)	$ 216
Energy-Related Contracts	Energy Costs	5	(4)	12	(14)
Total PSEG and Power		**$ (125)**	**$ 22**	**$ (142)**	**$ 202**

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The following table summarizes the net notional volume purchases/(sales) of open derivative transactions by commodity as of September 30, 2018 and December 31, 2017.

Type	Notional	Total	PSEG	Power	PSE&G
		Millions			
As of September 30, 2018					
Natural Gas	Dekatherm (Dth)	281	—	281	—
Electricity	MWh	(66)	—	(66)	—
Financial Transmission Rights (FTRs)	MWh	24	—	24	—
As of December 31, 2017					
Natural Gas	Dth	154	—	154	—
Electricity	MWh	(63)	—	(63)	—
FTRs	MWh	6	—	6	—

Credit Risk

Credit risk relates to the risk of loss that Power would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG has established credit policies that it believes significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

The following table provides information on Power's credit risk from wholesale counterparties, net of collateral, as of September 30, 2018. It further delineates that exposure by the credit rating of the counterparties, which is determined by the lowest rating from S&P, Moody's or an internal scoring model. In addition, it provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

As of September 30, 2018, 97% of the net credit exposure for Power's wholesale operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives, NPNS and non-derivatives).

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
	Millions				Millions	
Investment Grade	$ 112	$ 12	$ 100	2	$ 50	(A)
Non-Investment Grade	6	2	4	—	—	
Total	**$ 118**	**$ 14**	**$ 104**	**2**	**$ 50**	

(A) Represents net exposure of $39 million with PSE&G and $11 million with a non-affiliated counterparty.

As of September 30, 2018, collateral held from counterparties where Power had credit exposure included $2 million in cash collateral and $12 million in letters of credit.

As of September 30, 2018, Power had 137 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of September 30, 2018, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers

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represents PSE&G's net credit exposure. PSE&G's BGS suppliers' credit exposure is calculated each business day. As of September 30, 2018, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

Note 13. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds, as well as natural gas futures contracts executed on NYMEX.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of September 30, 2018, these consisted primarily of certain electric load contracts and gas contracts.

Certain derivative transactions may transfer from Level 2 to Level 3 if inputs become unobservable and internal modeling techniques are employed to determine fair value. Conversely, measurements may transfer from Level 3 to Level 2 if the inputs become observable.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of September 30, 2018 and December 31, 2017, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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Description	Recurring Fair Value Measurements as of September 30, 2018				
	Total	Netting (C)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Energy-Related Contracts (A)	$ 13	$ (411)	$ 12	$ 404	$ 8
NDT Fund (B)					
Equity Securities	$ 1,120	$ —	$ 1,118	$ 2	$ —
Debt Securities—U.S. Treasury	$ 209	$ —	$ —	$ 209	$ —
Debt Securities—Govt Other	$ 311	$ —	$ —	$ 311	$ —
Debt Securities—Corporate	$ 456	$ —	$ —	$ 456	$ —
Rabbi Trust (B)					
Equity Securities	$ 25	$ —	$ 25	$ —	$ —
Debt Securities—U.S. Treasury	$ 60	$ —	$ —	$ 60	$ —
Debt Securities—Govt Other	$ 39	$ —	$ —	$ 39	$ —
Debt Securities—Corporate	$ 101	$ —	$ —	$ 101	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (15)	$ 523	$ (10)	$ (519)	$ (9)
PSE&G					
Assets:					
Rabbi Trust (B)					
Equity Securities	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$ 12	$ —	$ —	$ 12	$ —
Debt Securities—Govt Other	$ 8	$ —	$ —	$ 8	$ —
Debt Securities—Corporate	$ 21	$ —	$ —	$ 21	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 13	$ (411)	$ 12	$ 404	$ 8
NDT Fund (B)					
Equity Securities	$ 1,120	$ —	$ 1,118	$ 2	$ —
Debt Securities—U.S. Treasury	$ 209	$ —	$ —	$ 209	$ —
Debt Securities—Govt Other	$ 311	$ —	$ —	$ 311	$ —
Debt Securities—Corporate	$ 456	$ —	$ —	$ 456	$ —
Rabbi Trust (B)					
Equity Securities	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—U.S. Treasury	$ 15	$ —	$ —	$ 15	$ —
Debt Securities—Govt Other	$ 10	$ —	$ —	$ 10	$ —
Debt Securities—Corporate	$ 26	$ —	$ —	$ 26	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (15)	$ 523	$ (10)	$ (519)	$ (9)

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Description	Recurring Fair Value Measurements as of December 31, 2017				
	Total	Netting (C)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (D)	$ 223	$ —	$ 223	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (A)	$ 36	$ (433)	$ 15	$ 442	$ 12
NDT Fund (B)					
Equity Securities	$ 1,147	$ —	$ 1,145	$ 2	$ —
Debt Securities—U.S. Treasury	$ 314	$ —	$ —	$ 314	$ —
Debt Securities—Govt Other	$ 270	$ —	$ —	$ 270	$ —
Debt Securities—Corporate	$ 402	$ —	$ —	$ 402	$ —
Rabbi Trust (B)					
Equity Securities	$ 27	$ —	$ 27	$ —	$ —
Debt Securities—U.S. Treasury	$ 51	$ —	$ —	$ 51	$ —
Debt Securities—Govt Other	$ 34	$ —	$ —	$ 34	$ —
Debt Securities—Corporate	$ 119	$ —	$ —	$ 119	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (21)	$ 477	$ (8)	$ (485)	$ (5)
PSE&G					
Assets:					
Cash Equivalents (D)	$ 223	$ —	$ 223	$ —	$ —
Rabbi Trust (B)					
Equity Securities	$ 5	$ —	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$ 10	$ —	$ —	$ 10	$ —
Debt Securities—Govt Other	$ 7	$ —	$ —	$ 7	$ —
Debt Securities—Corporate	$ 24	$ —	$ —	$ 24	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 36	$ (433)	$ 15	$ 442	$ 12
NDT Fund (B)					
Equity Securities	$ 1,147	$ —	$ 1,145	$ 2	$ —
Debt Securities—U.S. Treasury	$ 314	$ —	$ —	$ 314	$ —
Debt Securities—Govt Other	$ 270	$ —	$ —	$ 270	$ —
Debt Securities—Corporate	$ 402	$ —	$ —	$ 402	$ —
Rabbi Trust (B)					
Equity Securities	$ 6	$ —	$ 6	$ —	$ —
Debt Securities—U.S. Treasury	$ 13	$ —	$ —	$ 13	$ —
Debt Securities—Govt Other	$ 8	$ —	$ —	$ 8	$ —
Debt Securities—Corporate	$ 30	$ —	$ —	$ 30	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (21)	$ 477	$ (8)	$ (485)	$ (5)

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(A) Level 1—These contracts represent natural gas futures contracts executed on NYMEX, and are being valued solely on settled pricing inputs which come directly from the exchange.

Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using settled prices from similar assets and liabilities from an exchange, such as NYMEX, ICE and Nodal Exchange, or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered

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significant to the overall inputs.

Level 3—Unobservable inputs are used for the valuation of certain contracts. See "Additional Information Regarding Level 3 Measurements" below for more information on the utilization of unobservable inputs.

(B) The NDT Fund maintains investments in various equity and fixed income securities. The Rabbi Trust maintains investments in various fixed income securities and a Russell 3000 index fund. These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain other equity securities in the NDT and Rabbi Trust Funds consist primarily of investments in Dreyfus money market funds which seek a high level of current income as is consistent with the preservation of capital and the maintenance of liquidity. To pursue its goals, the funds normally invest in diversified portfolios of high quality, short-term, dollar-denominated debt securities and government securities. The funds' Net Asset Value is priced and published daily. The Rabbi Trust also has an equity index fund which is valued based on quoted prices in an active market.

Level 2—NDT and Rabbi Trust fixed income securities include investment grade corporate bonds, collateralized mortgage obligations, asset-backed securities and certain government and U.S. Treasury obligations or Federal Agency asset-backed securities and municipal bonds with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. The preferred stocks are not actively traded on a daily basis and therefore, are also priced using an evaluated pricing methodology. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(C) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. See Note 12. Financial Risk Management Activities for additional detail.

(D) Represents money market mutual funds.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee (RMC) approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The RMC reports to the Corporate Governance and Audit Committees of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The fair value of Power's gas physical contracts at certain illiquid delivery locations are measured using average historical basis and, accordingly, are categorized as Level 3. While these gas physical contracts have an unobservable component in their respective forward price curves, the fluctuations in fair value have been driven primarily by changes in the observable inputs. The following tables provide details surrounding significant Level 3 valuations as of September 30, 2018 and December 31, 2017.

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Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of September 30, 2018 Assets	Fair Value as of September 30, 2018 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$ —	$ (9)	Discounted Cash flow	Historic Load Variability	0% to 10%
Gas	Gas Physical Contracts	8	—	Discounted Cash flow	Average Historical Basis	-40% to 0%
Total Power		**$ 8**	**$ (9)**			
Total PSEG		**$ 8**	**$ (9)**			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2017 Assets	Fair Value as of December 31, 2017 (Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$ 1	$ (3)	Discounted Cash flow	Historic Load Variability	0% to 10%
Gas	Gas Physical Contracts	11	(2)	Discounted Cash flow	Average Historical Basis	-40% to -10%
Total Power		**$ 12**	**$ (5)**			
Total PSEG		**$ 12**	**$ (5)**			

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in the load variability would decrease the fair value. For gas-related contracts in cases where Power is a buyer, an increase in the average historical basis would increase the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and nine months ended September 30, 2018 and September 30, 2017, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Nine Months Ended September 30, 2018

	Three Months Ended September 30, 2018						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of July 1, 2018	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2018
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ 4	$ (4)	$ —	$ —	$ (1)	$ —	$ (1)
Power							
Net Derivative Assets (Liabilities)	$ 4	$ (4)	$ —	$ —	$ (1)	$ —	$ (1)

	Nine Months Ended September 30, 2018						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2018	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2018
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ 7	$ (8)	$ —	$ —	$ —	$ —	$ (1)
Power							
Net Derivative Assets (Liabilities)	$ 7	$ (8)	$ —	$ —	$ —	$ —	$ (1)

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months and Nine Months Ended September 30, 2017

	Three Months Ended September 30, 2017						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of July 1, 2017	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2017
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 6	$ 3	$ —	$ —	$ (3)	$ —	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 6	$ 3	$ —	$ —	$ (3)	$ —	$ 6

	Nine Months Ended September 30, 2017						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2017	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2017
			Millions				
PSEG							
Net Derivative Assets (Liabilities)	$ 1	$ 29	$ 5	$ —	$ (28)	$ (1)	$ 6
PSE&G							
Net Derivative Assets (Liabilities)	$ (5)	$ —	$ 5	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$ 6	$ 29	$ —	$ —	$ (28)	$ (1)	$ 6

(A) PSEG's and Power's gains(losses) attributable to changes in net derivative assets and liabilities for the three months and nine months ended September 30, 2018 include $(8) million and $(7) million, respectively, in Operating Revenues and $4 million and $(1) million, respectively, in Energy Costs. Both the $(8) million and $(7) million in Operating Revenues are unrealized. Of the $4 million and $(1) million in Energy Costs, $5 million and $(1) million are unrealized. Unrealized gains (losses) represent the change in derivative assets and liabilities still held at the end of the reporting period.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

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(C) Represents settlements of $(1) million for the three months ended September 30, 2018. Represents settlements of $(3) million and $(28) million for the three months and nine months ended September 30, 2017, respectively.

(D) During the three months and nine months ended September 30, 2018, there were no transfers into or out of Level 3. During the nine months ended September 30, 2017, $(1) million of net derivatives were transferred from Level 2 to Level 3. There were no transfers into or out of Level 3 during the three months ended September 30, 2017.

(E) PSEG's and Power's gains(losses) attributable to changes in net derivative assets and liabilities for the three months and nine months ended September 30, 2017 include $5 million and $22 million, respectively, in Operating Revenues and $(2) million and $7 million, respectively, in Energy Costs. The $5 million in Operating Revenues and $(2) million in Energy Costs for the three months ended September 30, 2017 are realized. Of the $22 million in Operating Revenues and the $7 million in Energy Costs, $(2) million and $3 million, respectively, are unrealized for the nine months ended September 30, 2017.

As of September 30, 2018, PSEG carried $2.3 billion of net assets that are measured at fair value on a recurring basis, of which $1 million of net liabilities was measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of September 30, 2017, PSEG carried $2.6 billion of net assets that are measured at fair value on a recurring basis, of which $6 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of September 30, 2018 and December 31, 2017.

	As of September 30, 2018		As of December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (A) (B)	$ 2,093	$ 2,051	$ 2,091	$ 2,081
PSE&G (B)	9,182	9,292	8,591	9,322
Power (B)	3,084	3,254	2,386	2,659
Total Long-Term Debt	**$ 14,359**	**$ 14,597**	**$ 13,068**	**$ 14,062**

(A) Includes floating rate term loan of $700 million. The fair values of the term loan debt (Level 2 measurement) approximate the carrying values because the interest payments are based on LIBOR rates that are reset monthly and the debt is redeemable at face value by PSEG at any time.

(B) Given that these bonds do not trade actively, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

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Note 14. Other Income (Deductions)

	PSE&G	Power	Other (A)	Consolidated
		Millions		
Three Months Ended September 30, 2018				
NDT Fund Interest and Dividends	$ —	$ 13	$ —	$ 13
Allowance for Funds Used During Construction	13	—	—	13
Solar Loan Interest	5	—	—	5
Other	3	1	(2)	2
Total Other Income (Deductions)	**$ 21**	**$ 14**	**$ (2)**	**$ 33**
Nine Months Ended September 30, 2018				
NDT Fund Interest and Dividends	$ —	$ 40	$ —	$ 40
Allowance for Funds Used During Construction	40	—	—	40
Solar Loan Interest	14	—	—	14
Other	7	(2)	—	5
Total Other Income (Deductions)	**$ 61**	**$ 38**	**$ —**	**$ 99**
Three Months Ended September 30, 2017				
NDT Fund Interest and Dividends	$ —	$ 12	$ —	$ 12
Allowance for Funds Used During Construction	14	—	—	14
Solar Loan Interest	6	—	—	6
Other	2	(1)	—	1
Total Other Income (Deductions)	**$ 22**	**$ 11**	**$ —**	**$ 33**
Nine Months Ended September 30, 2017				
NDT Fund Interest and Dividends	$ —	$ 35	$ —	$ 35
Allowance for Funds Used During Construction	42	—	—	42
Solar Loan Interest	16	—	—	16
Other	7	(1)	(1)	5
Total Other Income (Deductions)	**$ 65**	**$ 34**	**$ (1)**	**$ 98**

(A) Other consists of activity at PSEG (as parent company), Energy Holdings, Services, PSEG LI and intercompany eliminations.

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Note 15. Income Taxes

PSEG's, PSE&G's and Power's effective tax rates for the three months and nine months ended September 30, 2018 and 2017 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
PSEG	22.1%	38.9%	25.1%	35.5%
PSE&G	25.5%	38.8%	26.1%	37.4%
Power	16.7%	41.9%	24.1%	37.9%

For the three months and nine months ended September 30, 2018, the differences in PSEG's effective tax rates as compared to the same periods in the prior year were due primarily to the change in the statutory federal tax rate from 35% to 21% as a result of the Tax Act and the remeasurement of uncertain tax positions and associated interest in connection with a 2015 claim to carry back tax-defined nuclear decommissioning costs under IRC 172(f) (nuclear carryback claim) and 2011 and 2012 federal tax audit, offset by the New Jersey (NJ) surtax, plant-related items and tax credits. For the three months and nine months ended September 30, 2018, the differences in PSEG's effective tax rates as compared to the statutory tax rate of 28.11% were due primarily to the remeasurement of uncertain tax positions and associated interest in connection with the nuclear carryback claim and 2011 and 2012 federal tax audit, plant-related items and tax credits, offset by the NJ surtax.

In August 2018, the IRS completed its audit of PSEG's nuclear carryback claim and federal tax returns for the years 2011 and 2012. The completion of the IRS' audit resulted in a settlement agreement with the IRS, which is subject to review by the Joint Committee on Taxation (JCT). As a result of this new information, PSEG remeasured certain unrecognized tax benefits that impacted the effective tax rate in the amount of $28 million, primarily related to the nuclear carryback claim and the associated interest, in the three months ended September 30, 2018.

For the three months and nine months ended September 30, 2018, the differences in PSE&G's effective tax rates as compared to the same periods in the prior year were due primarily to the change in the statutory federal tax rate from 35% to 21% as a result of the Tax Act, offset by changes in uncertain tax positions, plant-related and other flow-through items. For the three months and nine months ended September 30, 2018, the differences in PSE&G's effective tax rate as compared to the statutory tax rate of 28.11% were due primarily to plant-related and other flow-through items, tax credits and changes in uncertain tax positions.

For the three months and nine months ended September 30, 2018, the differences in Power's effective tax rates as compared to the same periods in the prior year were due primarily to the change in the statutory federal tax rate from 35% to 21% as a result of the Tax Act and the remeasurement of uncertain tax positions and associated interest in connection with the nuclear carryback claim and 2011 and 2012 federal tax audit, offset by the NJ surtax. For the three months and nine months ended September 30, 2018, the differences in Power's effective tax rates as compared to the statutory tax rate of 28.11% were due primarily to the remeasurement of uncertain tax positions and associated interest in connection with the nuclear carryback claim and 2011 and 2012 federal tax audit, offset by the NJ surtax.

Uncertain Tax Positions

In August 2018, the IRS completed its audit of PSEG's nuclear carryback claim and federal tax returns for the years 2011 and 2012. The JCT is required to review all claims over $5 million, and the tax years are not considered concluded until the JCT's review has been completed. As a result, it is reasonably possible that PSEG's total unrecognized tax benefits may decrease in the range of $50 million to $120 million based on current estimates within the next 12 months.

Tax Act

PSEG, PSE&G and Power recorded the impact of the Tax Act in their December 31, 2017 consolidated financial statements, including certain provisional amounts, in accordance with SEC guidance under Staff Accounting Bulletin 118 (SAB 118). PSEG's accounting for certain elements of the Tax Act remains incomplete.

In August 2018, the IRS issued a Notice of Proposed Rulemaking (Notice) regarding the application of tax depreciation rules as amended by the Tax Act. In September 2018, PSEG recorded additional provisional adjustments that increased plant-related deferred taxes in the amount of $53 million and $35 million to the Regulatory Liability for the associated excess deferred taxes. PSEG continues to analyze the Notice and, as such, the amounts recorded for bonus depreciation for 2017 and 2018 remain provisional.

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Further, the Tax Act is unclear in certain respects and will require interpretations and implementing regulations by the IRS, as well as state tax authorities. The Tax Act could also be subject to potential amendments and technical corrections which could impact PSEG's, PSE&G's and Power's financial statements.

The Protecting Americans from Tax Hikes Act of 2015 (2015 Tax Act), among other provisions, included an extension of the bonus depreciation rules and the 30% investment tax credit for qualified property placed into service after 2016. Qualified property that is placed into service from January 1, 2015 through December 31, 2017 is eligible for the 50% bonus depreciation. The provisions of the 2015 Tax Act have generated significant cash tax benefits for PSEG, PSE&G and Power through tax benefits related to the accelerated depreciation.

For the period beginning September 28, 2017, subject to the transition rules, the Tax Act modified the bonus depreciation rules of the 2015 Tax Act. Subject to further review of the Notice, it is expected that Power will be entitled to 100% expensing for qualifying 2018 plant additions and bonus depreciation will no longer apply to PSE&G.

New Jersey State Tax Reform

In July 2018, the State of New Jersey made significant changes to its income tax laws, including imposing a temporary surtax on allocated corporate taxable income of 2.5% effective January 1, 2018 and 2019 and 1.5% in 2020 and 2021, as well as requiring corporate taxpayers to file in a combined reporting group as defined under New Jersey law starting in 2019. Both provisions include an exemption for public utilities. At this time, PSEG believes PSE&G meets the definition of a public utility and, therefore, will not be impacted by the temporary surtax or be included in the combined reporting group. PSEG expects these new provisions to unfavorably affect its non-utility business. The newly enacted New Jersey tax legislation did not have a material impact on PSEG's deferred income tax balance.

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Note 16. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended September 30, 2018			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2018	$ (1)	$ (391)	$ (18)	$ (410)
Other Comprehensive Income before Reclassifications	—	—	(6)	(6)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	2	9
Net Current Period Other Comprehensive Income (Loss)	—	7	(4)	3
Balance as of September 30, 2018	**$ (1)**	**$ (384)**	**$ (22)**	**$ (407)**

PSEG	Other Comprehensive Income (Loss) Three Months Ended September 30, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2017	$ 2	$ (386)	$ 158	$ (226)
Other Comprehensive Income before Reclassifications	—	—	25	25
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	6	(8)	(3)
Net Current Period Other Comprehensive Income (Loss)	(1)	6	17	22
Balance as of September 30, 2017	**$ 1**	**$ (380)**	**$ 175**	**$ (204)**

PSEG	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2018			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2017	$ —	$ (406)	$ 177	$ (229)
Cumulative Effect Adjustment to Reclassify Unrealized Net Gains on Equity Investments to Retained Earnings	—	—	(176)	(176)
Current Period Other Comprehensive Income (Loss)				
Other Comprehensive Income before Reclassifications	(1)	—	(28)	(29)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	22	5	27
Net Current Period Other Comprehensive Income (Loss)	(1)	22	(23)	(2)
Net Change in Accumulative Other Comprehensive Income (Loss)	(1)	22	(199)	(178)
Balance as of September 30, 2018	**$ (1)**	**$ (384)**	**$ (22)**	**$ (407)**

PSEG	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2017			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2016	$ 2	$ (398)	$ 133	$ (263)
Other Comprehensive Income before Reclassifications	—	—		

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Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	18	(36)	(19)
Net Current Period Other Comprehensive Income (Loss)	(1)	18	42	59
Balance as of September 30, 2017	**$ 1**	**$ (380)**	**$ 175**	**$ (204)**

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2018			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2018	$ —	$ (335)	$ (15)	$ (350)
Other Comprehensive Income before Reclassifications	—	—	(5)	(5)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	1	8
Net Current Period Other Comprehensive Income (Loss)	—	7	(4)	3
Balance as of September 30, 2018	**$ —**	**$ (328)**	**$ (19)**	**$ (347)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended September 30, 2017			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of June 30, 2017	$ —	$ (330)	$ 158	$ (172)
Other Comprehensive Income before Reclassifications	—	—	24	24
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	5	(9)	(4)
Net Current Period Other Comprehensive Income (Loss)	—	5	15	20
Balance as of September 30, 2017	**$ —**	**$ (325)**	**$ 173**	**$ (152)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2018			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2017	$ —	$ (347)	$ 175	$ (172)
Cumulative Effect Adjustment to Reclassify Unrealized Net Gains on Equity Investments to Retained Earnings	—	—	(175)	(175)
Current Period Other Comprehensive Income (Loss)				
Other Comprehensive Income before Reclassifications	—	—	(23)	(23)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	19	4	23
Net Current Period Other Comprehensive Income (Loss)	—	19	(19)	—
Net Change in Accumulative Other Comprehensive Income (Loss)	—	19	(194)	(175)
Balance as of September 30, 2018	**$ —**	**$ (328)**	**$ (19)**	**$ (347)**

Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2017			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
		Millions		
Balance as of December 31, 2016	$ —	$ (340)	$ 129	$ (211)
Other Comprehensive Income before Reclassifications	—	—	74	74

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Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	15	(30)	(15)
Net Current Period Other Comprehensive Income (Loss)	—	15	44	59
Balance as of September 30, 2017	**$ —**	**$ (325)**	**$ 173**	**$ (152)**

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2018			Nine Months Ended September 30, 2018		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	$ 1	$ —	$ 1	$ 3	$ —	$ 3
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(11)	3	(8)	(34)	9	(25)
Total Pension and OPEB Plans		(10)	3	(7)	(31)	9	(22)
Available-for-Sale Debt Securities							
Realized Gains (Losses) and OTTI	Net Gains (Losses) on Trust Investments	(2)	—	(2)	(8)	3	(5)
Total Available-for-Sale Debt Securities		(2)	—	(2)	(8)	3	(5)
Total		**$ (12)**	**$ 3**	**$ (9)**	**$ (39)**	**$ 12**	**$ (27)**

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2017			Nine Months Ended September 30, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Cash Flow Hedges							
Interest Rate Swaps	Interest Expense	$ 2	$ (1)	$ 1	$ 2	$ (1)	$ 1
Total Cash Flow Hedges		2	(1)	1	2	(1)	1
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	3	(1)	2	7	(3)	4
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(13)	5	(8)	(37)	15	(22)
Total Pension and OPEB Plans		(10)	4	(6)	(30)	12	(18)
Available-for-Sale Securities							
Realized Gains (Losses) and OTTI	Net Gains (Losses) on Trust Investments	18	(10)	8	71	(35)	36
Total Available-for-Sale Securities		18	(10)	8	71	(35)	36
Total		**$ 10**	**$ (7)**	**$ 3**	**$ 43**	**$ (24)**	**$ 19**

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2018			Nine Months Ended September 30, 2018		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	$ 1	$ —	$ 1	$ 3	$ —	$ 3
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(11)	3	(8)	(30)	8	(22)
Total Pension and OPEB Plans		(10)	3	(7)	(27)	8	(19)
Available-for-Sale Debt Securities							
Realized Gains (Losses) and OTTI	Net Gains (Losses) on Trust Investments	(1)	—	(1)	(7)	3	(4)
Total Available-for-Sale Debt Securities		(1)	—	(1)	(7)	3	(4)
Total		**$ (11)**	**$ 3**	**$ (8)**	**$ (34)**	**$ 11**	**$ (23)**

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2017			Nine Months Ended September 30, 2017		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	Non-Operating Pension and OPEB Credits (Costs)	$ 2	$ (1)	$ 1	$ 6	$ (3)	$ 3
Amortization of Actuarial Loss	Non-Operating Pension and OPEB Credits (Costs)	(11)	5	(6)	(32)	14	(18)
Total Pension and OPEB Plans		(9)	4	(5)	(26)	11	(15)
Available-for-Sale Securities							
Realized Gains (Losses) and OTTI	Net Gains (Losses) on Trust Investments	19	(10)	9	62	(32)	30
Total Available-for-Sale Securities		19	(10)	9	62	(32)	30
Total		**$ 10**	**$ (6)**	**$ 4**	**$ 36**	**$ (21)**	**$ 15**

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Note 17. Earnings Per Share (EPS) and Dividends

EPS

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2018		2017		2018		2017	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions):								
Net Income	**$ 412**	**$ 412**	**$ 395**	**$ 395**	**$ 1,239**	**$ 1,239**	**$ 618**	**$ 618**
EPS Denominator (Millions):								
Weighted Average Common Shares Outstanding	504	504	505	505	504	504	505	505
Effect of Stock Based Compensation Awards	—	3	—	2	—	3	—	2
Total Shares	**504**	**507**	**505**	**507**	**504**	**507**	**505**	**507**
EPS								
Net Income	**$ 0.82**	**$ 0.81**	**$ 0.78**	**$ 0.78**	**$ 2.46**	**$ 2.44**	**$ 1.22**	**$ 1.22**

For the three months and nine months ended September 30, 2017, there were approximately 0.3 million stock options excluded from the weighted average common shares used for diluted EPS due to their antidilutive effect.

Dividends

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dividend Payments on Common Stock	2018	2017	2018	2017
Per Share	$ 0.45	$ 0.43	$ 1.35	$ 1.29
In Millions	$ 227	$ 217	$ 682	$ 652

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Note 18. Financial Information by Business Segment

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated Total
			Millions		
Three Months Ended September 30, 2018					
Total Operating Revenues	$ 1,595	$ 868	$ 151	$ (220)	$ 2,394
Net Income (Loss)	278	125	9	—	412
Gross Additions to Long-Lived Assets	766	253	4	—	1,023
Nine Months Ended September 30, 2018					
Operating Revenues	$ 4,826	$ 3,038	$ 421	$ (1,057)	$ 7,228
Net Income (Loss)	828	400	11	—	1,239
Gross Additions to Long-Lived Assets	2,213	800	15	—	3,028
Three Months Ended September 30, 2017					
Total Operating Revenues	$ 1,530	$ 846	$ 135	$ (257)	$ 2,254
Net Income (Loss)	246	136	13	—	395
Gross Additions to Long-Lived Assets	729	327	9	—	1,065
Nine Months Ended September 30, 2017					
Operating Revenues	$ 4,749	$ 3,033	$ 334	$ (1,129)	$ 6,987
Net Income (Loss)	753	(131)	(4)	—	618
Gross Additions to Long-Lived Assets	2,118	903	25	—	3,046
As of September 30, 2018					
Total Assets	$ 30,694	$ 12,681	$ 2,249	$ (551)	$ 45,073
Investments in Equity Method Subsidiaries	—	88	—	—	88
As of December 31, 2017					
Total Assets	$ 28,554	$ 12,418	$ 2,666	$ (922)	$ 42,716
Investments in Equity Method Subsidiaries	—	87	—	—	87

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations primarily relate to intercompany transactions between PSE&G and Power. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 19. Related-Party Transactions.

Note 19. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
			Millions	
Billings from Affiliates:				
Net Billings from Power primarily through BGS and BGSS (A)	$ 229	$ 259	$ 1,079	$ 1,154
Administrative Billings from Services (B)	78	82	246	226
Total Billings from Affiliates	**$ 307**	**$ 341**	**$ 1,325**	**$ 1,380**

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Related-Party Transactions	As of September 30, 2018	As of December 31, 2017
	Millions	
Receivables from PSEG (C)	**$ 55**	**$ —**
Payable to Power (A)	$ 97	$ 221
Payable to Services (B)	67	78
Payable to PSEG (C)	—	41
Accounts Payable—Affiliated Companies	**$ 164**	**$ 340**
Working Capital Advances to Services (D)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable	**$ 67**	**$ 91**

Power
The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
		Millions		
Billings to Affiliates:				
Net Billings to PSE&G primarily through BGS and BGSS (A)	**$ 229**	**$ 259**	**$ 1,079**	**$ 1,154**
Billings from Affiliates:				
Administrative Billings from Services (B)	**$ 38**	**$ 39**	**$ 113**	**$ 117**

Related-Party Transactions	As of September 30, 2018	As of December 31, 2017
	Millions	
Receivables from PSE&G (A)	$ 97	$ 221
Receivables from PSEG (C)	24	—
Accounts Receivable—Affiliated Companies	**$ 121**	**$ 221**
Payable to Services (B)	$ 21	$ 28
Payable to PSEG (C)	—	29
Accounts Payable—Affiliated Companies	**$ 21**	**$ 57**
Short-Term Loan to (from) Affiliate (E)	**$ 119**	**$ (281)**
Working Capital Advances to Services (D)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Payable	**$ 1**	**$ 52**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. The rates in the BGS and BGSS contracts are prescribed by the BPU. In addition, Power and PSE&G provide certain technical services for each other generally at cost in compliance with FERC and BPU affiliate rules.

(B) Services provides and bills administrative services to PSE&G and Power at cost. In addition, PSE&G and Power have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

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(D) PSE&G and Power have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on PSE&G's and Power's Condensed Consolidated Balance Sheets.

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(E) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

Note 20. Guarantees of Debt

Power's Senior Notes are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following tables present condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries, as of September 30, 2018 and December 31, 2017 and for the three months and nine months ended September 30, 2018 and 2017.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended September 30, 2018					
Operating Revenues	$ —	$ 849	$ 59	$ (40)	$ 868
Operating Expenses	2	733	61	(40)	756
Operating Income (Loss)	(2)	116	(2)	—	112
Equity Earnings (Losses) of Subsidiaries	117	(7)	5	(110)	5
Net Gains (Losses) on Trust Investments	—	45	(1)	—	44
Other Income (Deductions)	40	45	—	(71)	14
Non-Operating Pension and OPEB Credits (Costs)	—	4	—	—	4
Interest Expense	(65)	(28)	(7)	71	(29)
Income Tax Benefit (Expense)	35	(64)	4	—	(25)
Net Income (Loss)	**$ 125**	**$ 111**	**$ (1)**	**$ (110)**	**$ 125**
Comprehensive Income (Loss)	**$ 128**	**$ 107**	**$ (1)**	**$ (106)**	**$ 128**
Nine Months Ended September 30, 2018					
Operating Revenues	$ —	$ 2,982	$ 161	$ (105)	$ 3,038
Operating Expenses	5	2,493	162	(105)	2,555
Operating Income (Loss)	(5)	489	(1)	—	483
Equity Earnings (Losses) of Subsidiaries	406	(14)	12	(392)	12
Net Gains (Losses) on Trust Investments	—	31	(1)	—	30
Other Income (Deductions)	116	118	—	(196)	38
Non-Operating Pension and OPEB Credits (Costs)	—	10	1	—	11
Interest Expense	(161)	(64)	(18)	196	(47)
Income Tax Benefit (Expense)	44	(179)	8	—	(127)
Net Income (Loss)	**$ 400**	**$ 391**	**$ 1**	**$ (392)**	**$ 400**
Comprehensive Income (Loss)	**$ 400**	**$ 374**	**$ 1**	**$ (375)**	**$ 400**
Nine Months Ended September 30, 2018					
Net Cash Provided By (Used In) Operating Activities	$ (255)	$ 1,169	$ (26)	$ 117	$ 1,005
Net Cash Provided By (Used In) Investing Activities	$ (417)	$ (1,132)	$ (290)	$ 829	$ (1,010)
Net Cash Provided By (Used In) Financing Activities	$ 672	$ (32)	$ 320	$ (946)	$ 14

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
Three Months Ended September 30, 2017					
Operating Revenues	$ —	$ 829	$ 46	$ (29)	$ 846
Operating Expenses	2	618	44	(29)	635
Operating Income (Loss)	(2)	211	2	—	211
Equity Earnings (Losses) of Subsidiaries	143	(3)	3	(140)	3
Net Gains (Losses) on Trust Investments	—	19	—	—	19
Other Income (Deductions)	24	26	(2)	(37)	11
Non-Operating Pension and OPEB Credits (Costs)	—	2	—	—	2
Interest Expense	(32)	(12)	(5)	37	(12)
Income Tax Benefit (Expense)	3	(103)	2	—	(98)
Net Income (Loss)	**$ 136**	**$ 140**	**$ —**	**$ (140)**	**$ 136**
Comprehensive Income (Loss)	**$ 156**	**$ 154**	**$ —**	**$ (154)**	**$ 156**
Nine Months Ended September 30, 2017					
Operating Revenues	$ —	$ 2,983	$ 145	$ (95)	$ 3,033
Operating Expenses	4	3,268	139	(95)	3,316
Operating Income (Loss)	(4)	(285)	6	—	(283)
Equity Earnings (Losses) of Subsidiaries	(111)	(8)	11	119	11
Net Gains (Losses) on Trust Investments	3	59	—	—	62
Other Income (Deductions)	67	66	—	(99)	34
Non-Operating Pension and OPEB Credits (Costs)	—	6	—	—	6
Interest Expense	(96)	(30)	(14)	99	(41)
Income Tax Benefit (Expense)	10	68	2	—	80
Net Income (Loss)	**$ (131)**	**$ (124)**	**$ 5**	**$ 119**	**$ (131)**
Comprehensive Income (Loss)	**$ (72)**	**$ (80)**	**$ 5**	**$ 75**	**$ (72)**
Nine Months Ended September 30, 2017					
Net Cash Provided By (Used In) Operating Activities	$ (55)	$ 1,159	$ 142	$ 3	$ 1,249
Net Cash Provided By (Used In) Investing Activities	$ 738	$ (289)	$ (343)	$ (990)	$ (884)
Net Cash Provided By (Used In) Financing Activities	$ (683)	$ (869)	$ 211	$ 987	$ (354)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Total
			Millions		
As of September 30, 2018					
Current Assets	$ 4,497	$ 1,353	$ 302	$ (4,776)	$ 1,376
Property, Plant and Equipment, net	55	5,074	3,740	—	8,869
Investment in Subsidiaries	5,086	1,124	—	(6,210)	—
Noncurrent Assets	245	2,302	106	(217)	2,436
Total Assets	**$ 9,883**	**$ 9,853**	**$ 4,148**	**$ (11,203)**	**$ 12,681**
Current Liabilities	$ 616	$ 3,030	$ 1,999	$ (4,776)	$ 869
Noncurrent Liabilities	466	2,129	633	(217)	3,011
Long-Term Debt	2,834	—	—	—	2,834
Member's Equity	5,967	4,694	1,516	(6,210)	5,967
Total Liabilities and Member's Equity	**$ 9,883**	**$ 9,853**	**$ 4,148**	**$ (11,203)**	**$ 12,681**
As of December 31, 2017					
Current Assets	$ 4,327	$ 1,500	$ 200	$ (4,686)	$ 1,341
Property, Plant and Equipment, net	54	5,778	2,764	—	8,596
Investment in Subsidiaries	4,844	404	—	(5,248)	—
Noncurrent Assets	100	2,349	110	(78)	2,481
Total Assets	**$ 9,325**	**$ 10,031**	**$ 3,074**	**$ (10,012)**	**$ 12,418**
Current Liabilities	$ 689	$ 3,586	$ 1,846	$ (4,686)	$ 1,435
Noncurrent Liabilities	533	1,966	459	(78)	2,880
Long-Term Debt	2,136	—	—	—	2,136
Member's Equity	5,967	4,479	769	(5,248)	5,967
Total Liabilities and Member's Equity	**$ 9,325**	**$ 10,031**	**$ 3,074**	**$ (10,012)**	**$ 12,418**

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- **PSE&G**—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and energy efficiency and related programs in New Jersey, which are regulated by the BPU, and
- **Power**—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries are: PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement; PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Our business discussion in Part I, Item 1. Business of our 2017 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Executive Overview of 2017 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2018 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes and the 2017 Form 10-K.

EXECUTIVE OVERVIEW OF 2018 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand.

PSE&G

At PSE&G, our focus is on investing capital in T&D infrastructure projects that enhance system reliability and resiliency, and clean energy projects to meet customer expectations and support public policy objectives. Over the past few years, our investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G. Over the next five years, we expect to invest between $12 billion and $16 billion in our business which is expected to provide an annual rate base growth of 8%—10%. We have completed our Energy Strong Program I (ES I) and are forecasting completion of our Gas System Modernization Program I (GSMP I) early next year.

In May 2018, we received approval for the Gas System Modernization Program II (GSMP II), an expanded, five-year program to invest $1.9 billion over five years beginning in 2019 to replace approximately 875 miles of cast iron and unprotected steel mains in addition to other improvements to the gas system. Approximately $1.6 billion will be recovered through periodic rate roll-ins, with the remaining $300 million to be recovered through a future base rate case. As part of the settlement, PSE&G agreed to file a base rate case no later than five years from the commencement of the program, to maintain a base level of gas distribution capital expenditures of $155 million per year and to achieve certain leak reduction targets.

In June 2018, we filed for our Energy Strong Program II (ES II), a proposed five-year $2.5 billion program to harden, modernize and make our electric and gas distribution systems more resilient. The size and duration of ES II, as well as certain other elements of the program, are subject to BPU approval.

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In October 2018, we filed our proposed Clean Energy Future (CEF) program with the BPU, a six-year estimated $3.6 billion investment program focused on achieving New Jersey's energy efficiency targets, supporting electric vehicle infrastructure, deploying energy storage, and implementing an Energy Cloud program which will include installing 2.2 million advanced meter infrastructure (AMI) smart meters and associated infrastructure.

Also, in October 2018, the BPU issued an Order approving the settlement of our distribution base rate case with new rates effective November 1, 2018. The settlement resulted in a net reduction in overall annual revenues of approximately $13 million, comprised of a $212 million increase in base revenues, which includes the recovery of deferred storm costs, and the return of tax benefits largely due to tax reform of approximately $225 million. The Order provides for a distribution rate base of $9.5 billion, a 9.6% return on equity (ROE) for our distribution business and a 54% equity component of our capitalization structure. In addition to the $13 million annual revenue reduction, the Order provides for a one-time refund for taxes collected at the higher federal income tax rate for the January 1 to March 31, 2018 period. As a result, PSE&G will refund $28 million to customers in November and December 2018.

Power

At Power, we strive to improve performance and reduce costs in order to optimize cash flow generation from our fleet in light of low wholesale power and gas prices, environmental considerations and competitive market forces that reward efficiency and reliability. Power continues to move its fleet towards improved efficiency and believes that its investment program enhances its competitive position with the addition of efficient, clean, reliable combined cycle gas turbine capacity. Our commitments for load, such as basic generation service (BGS) in New Jersey and other bilateral supply contracts, are backed by this generation or may be combined with the use of physical commodity purchases and financial instruments from the market to optimize the economic efficiency of serving our obligations. Power's hedging practices and ability to capitalize on market opportunities help it to balance some of the volatility of the merchant power business. More than half of Power's expected gross margin in 2018 relates to our hedging strategy, our expected revenues from the capacity market mechanisms and certain ancillary service payments such as reactive power.

Our investments in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station Unit 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to enhance the environmental profile and overall efficiency of Power's generation fleet.

Financial Results

The results for PSEG, PSE&G and Power for the three months and nine months ended September 30, 2018 and 2017 are presented as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Earnings (Losses)	**2018**	**2017**	**2018**	**2017**
	Millions			
PSE&G	$ 278	$ 246	$ 828	$ 753
Power (A)	125	136	400	(131)
Other (B)	9	13	11	(4)
PSEG Net Income	**$ 412**	**$ 395**	**$ 1,239**	**$ 618**
PSEG Net Income Per Share (Diluted)	**$ 0.81**	**$ 0.78**	**$ 2.44**	**$ 1.22**

(A) Includes after-tax expenses of $5 million and $568 million in the three months and nine months ended September 30, 2017, respectively, related to the early retirement of Power's Hudson and Mercer coal/gas generation plants. See Item 1. Note 4. Early Plant Retirements for additional information.

(B) Other includes after-tax activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations. Energy Holdings recorded after-tax charges related to its investments in NRG REMA, LLC's (REMA) leveraged leases of $14 million and $45 million in the nine months ended September 30, 2018 and 2017, respectively. See Item 1. Note 7. Financing Receivables for additional information.

Power's results above include the Nuclear Decommissioning Trust (NDT) Fund activity and the impacts of non-trading commodity mark-to-market (MTM) activity, which consist of the financial impact from positions with future delivery dates.

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The variances in our Net Income attributable to changes related to the NDT Fund and MTM are shown in the following table:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
	Millions, after tax			
NDT Fund Income (Expense) (A) (B)	$ 27	$ 10	$ 16	$ 32
Non-Trading MTM Gains (Losses) (C)	$ (96)	$ (27)	$ (59)	$ —

(A) NDT Fund Income (Expense) includes gains and losses on NDT securities which are recorded in Net Gains (Losses) on Trust Investments. See Item 1. Note 8. Trust Investments for additional information. NDT Fund Income (Expense) also includes interest and dividend income and other costs related to the NDT Fund recorded in Other Income (Deductions), interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) recorded in Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset recorded in Depreciation and Amortization (D&A) Expense.

(B) Net of tax (expense) benefit of $(16) million and $(12) million for the three months and $(12) million and $(37) million for the nine months ended September 30, 2018 and 2017, respectively.

(C) Net of tax (expense) benefit of $37 million and $19 million for the three months and $23 million and $0 million for the nine months ended September 30, 2018 and 2017, respectively.

Our $17 million increase in Net Income for the three months ended September 30, 2018 was driven largely by

- higher earnings due to continued investment in transmission and distribution clause programs,
- the favorable impact at Power from the lower federal tax rate effective January 1, 2018 and remeasurement of uncertain tax positions and associated interest in connection with the nuclear carryback claim and 2011 and 2012 federal tax audit, and
- higher volumes of electricity sold in the PJM region generated by our new Keys and Sewaren combined cycle facilities,
- largely offset by higher MTM net losses in 2018, and
- higher generation costs driven by increased volumes of gas purchased at higher average prices in the PJM region.

Our $621 million increase in Net Income for the nine months ended September 30, 2018 was driven largely by

- accelerated depreciation in 2017 related to early retirement of our Hudson and Mercer coal/gas generation units,
- the favorable impact at Power from the lower federal tax rate effective January 1, 2018 and remeasurement of uncertain tax positions and associated interest in connection with the nuclear carryback claim and 2011 and 2012 federal tax audit,
- higher earnings due to continued investment in transmission and distribution clause programs,
- higher volumes of electricity sold under wholesale load contracts in the PJM region, and
- lower charges in 2018 related to leveraged lease investments (see Item 1. Note 7. Financing Receivables),
- partially offset by MTM losses in 2018,
- higher fuel generation costs,
- and lower volumes of electricity sold at lower prices under our BGS contracts.

The greater emphasis on capital spending in recent years for projects on which we receive contemporaneous returns at PSE&G has yielded strong results, which when combined with the cash flow generated by Power, has allowed us to increase our dividend annually. These actions to meet customer needs, market conditions and investor expectations reflect our long-term

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approach to managing our company. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of opportunities in a rapidly evolving market as we remain diligent in managing costs. For the first nine months of 2018, our

- utility achieved continued strong reliability and customer satisfaction results, as well as comprehensive storm preparation and restoration efforts, and ongoing cost control,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 42 terawatt hours while addressing fuel availability and price volatility, and
- total nuclear fleet achieved a capacity factor of 92.9%.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first nine months of 2018 as we

- maintained sufficient liquidity,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2018 to $1.80 per share.

We expect to be able to fund our planned capital requirements and manage the impacts of the Tax Act without the issuance of new equity. For additional information on the impacts of the Tax Act, see Item 1. Note 6. Rate Filings and Note 15. Income Taxes.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In the first nine months of 2018, we

- made additional investments in T&D infrastructure projects,
- continued to execute our GSMP I, Energy Efficiency and other existing BPU-approved utility programs,
- received approval for our GSMP II program and filed our proposed ES II and CEF programs, and
- commenced commercial operation of Sewaren 7 and Keys generation facilities and continued construction of our BH5 generation project, which is targeted for commercial operation in mid-2019.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets. For additional information about regulatory, legislative and other developments that may affect the company, see Part I, Item 1. Regulatory Issues in our 2017 Annual Report on Form 10-K and Item 5. Other Information in our Forms 10-Q for the periods ending March 31, 2018 and June 30, 2018 and this Form 10-Q.

Transmission Planning

There are several matters pending before FERC and the U. S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) that may impact the allocation of costs associated with transmission projects, including those being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by customers in New Jersey. In addition, as a BGS supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers would be entitled to recovery, subject to BPU approval. We do not believe that these matters will have a material effect on Power's business or results of operations.

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Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base ROE. Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. The results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

In October 2018, FERC issued an order establishing a new framework for determining whether a company's ROE is unjust and unreasonable. FERC proposes to rely on financial models to establish a composite zone of reasonableness that will be used to determine whether an ROE complaint should be dismissed. If FERC determines that an existing ROE is unjust and unreasonable, it intends to reset the ROE based on averaging the results of various financial models. We are still analyzing the potential impact of these methodologies and cannot predict the outcome of this proceeding. See Part II, Item 5. Other Information for additional information.

Wholesale Power Market Design

In June 2018, FERC issued an order finding that PJM's current capacity market is unjust and unreasonable because it allows resources supported by out-of-market payments to suppress capacity prices. FERC established a proceeding to consider an alternative capacity market design. FERC's potential action in this proceeding could cause nuclear units that receive zero emissions certificates (ZEC) payments to lose capacity market revenues if states do not take steps to address this potential loss of capacity revenues. In addition, depending on the outcome of this matter, our fossil generating stations could also be impacted. We cannot predict the outcome of this matter.

The PJM Board directed PJM staff to work with stakeholders to implement a series of price formation reforms, including a 30-minute reserve product in real-time, more dynamic reserve requirements to better capture operator actions taken to maintain reliability, and improvement to the curves used to price reserves during reserve shortage conditions. The PJM Board letter directs PJM staff to submit some of these reforms for FERC's approval so that they can be implemented in early 2019. If placed into effect, these reforms should improve energy and reserve prices by ensuring that when operators commit resources to ensure reliability, the commitments are reflected in market clearing prices. We cannot predict the outcome of this matter.

Distribution

The BPU has enacted Infrastructure Investment Program (IIP) regulations that allow utilities to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to support the provision of safe and adequate service. Under these regulations, utilities can seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain traditional utility infrastructure that enhances reliability, resiliency, and/or safety.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs.

In August 2018, the EPA released the proposed Affordable Clean Energy (ACE) rule as a replacement for the EPA's Clean Power Plan. The proposed ACE rule gives states great flexibility to evaluate specific heat rate improvement technologies and practices to be applied at coal-fired electric generating units. States have three years from the date of finalization to submit a plan that establishes a standard of performance that reflects the degree of emission limitation through the application of heat rate improvement technologies and practices. We cannot estimate the impact of this action on our business or results of operations at this time.

We are also subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above, as well as other matters that may impact our financial condition and results of operations, see Item 1. Note 10. Commitments and Contingent Liabilities.

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Early Plant Retirements

Fossil

On June 1, 2017, Power completed its previously announced retirement of the generation operations of the existing coal/gas units at the Hudson and Mercer generating stations. The decision to retire the Hudson and Mercer units had a material effect on PSEG's and Power's results of operations in 2016 and continued to adversely impact their results of operations in 2017. As of June 1, 2017, Power completed recognition of the incremental D&A Expense of $938 million ($964 million in total) due to the significant shortening of the expected economic useful lives of Hudson and Mercer. See Item 1. Note 4. Early Plant Retirements for additional information.

Power is exploring various opportunities with these sites, including using the sites for alternative industrial activity or the disposition of one or both of the sites. If Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such remediation are neither currently probable nor estimable but may be material.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

Nuclear

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. In September 2018, Exelon, a co-owner of the Salem units, shut down its Oyster Creek nuclear plant located in New Jersey one year earlier than previously planned for economic reasons. In addition, First Energy announced in March 2018 the early retirement of four nuclear units at the Davis-Besse, Perry Nuclear and Beaver Valley nuclear plants in Ohio and Pennsylvania by 2021. These closures and retirements are generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a further shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

In May 2018, the governor of New Jersey signed legislation that would provide a safety net in order to prevent the loss of environmental attributes from selected nuclear generating stations referred to as the ZEC program. The legislation calls for the BPU to establish a collection process for a customer charge, determine eligibility and certification of need, and potentially select nuclear plants to receive ZECs starting in April 2019. The law mandates each New Jersey electric distribution company, including PSE&G, to purchase ZECs and recover its procurement of ZECs through a non-bypassable charge (ZEC charge) in the amount of $0.004 per kilowatt-hour.

In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of our nuclear units beyond the current year, including whether and to what extent these units participate in Reliability Pricing Model capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be influenced by the financial outlook of the units, including the progress, timing and continued outlook for selection of the units under the newly enacted legislation in the state of New Jersey. Power and Exelon have agreed to continue to assess and, when appropriate, approve the funding of individual capital projects to ensure compliance with regulatory requirements and the safe operation of the Salem generating station and that the funding of previously postponed projects may be restored as a result of the legislation enacted in New Jersey sufficiently values the attributes of nuclear generation and Salem benefits from such legislation.

Power believes it may be unable to cover its costs and would be inadequately compensated for its market and operational risks at the Salem and Hope Creek nuclear units, which would result in Power retiring these units early, if (i) energy market prices continue to be depressed, (ii) there are adverse impacts from potential changes to the capacity market construct being considered by FERC, or (iii) Salem and/or Hope Creek are not selected to participate in the ZEC program or the ZEC program does not adequately compensate our nuclear generating stations for their attributes. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs, environmental remediation costs and additional funding of the NDT Fund would be material to both PSEG and Power. If

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any or all of the Salem and Hope Creek units were shut down, it would significantly alter New Jersey's energy supply predominately by increasing New Jersey's reliance on natural gas generation. Such a decrease in fuel diversity could also increase the market's vulnerability to price fluctuations and power disruptions in times of high demand.

Leveraged Leases

In September 2018, certain subsidiaries of Energy Holdings (PSEG Entities) entered into a Restructuring Support Agreement (RSA) with REMA. Pursuant to the RSA, the PSEG Entities have agreed to support the implementation of restructuring and related transactions with respect to REMA's indebtedness. Such restructuring transactions will be implemented by REMA on an in-court basis under Chapter 11 of the Bankruptcy Code. The RSA outlines a plan of reorganization under which, in addition to other terms, the ownership interest in the leases relating to the Keystone and Conemaugh investments will be transferred to holders of certain debtholders of REMA. Upon consummation of the restructuring transactions, the PSEG Entities will receive $31.5 million in cash in exchange for (a) the full satisfaction of all claims asserted against REMA and (b) approval of certain amendments to the Shawville lease. The Shawville lease amendments, among other things, will allow REMA to express tentative interest in a renewal on or after November 24, 2019, with similar changes to the other milestones in the lease renewal procedures. In addition, REMA has agreed to fund qualifying credit support up to $36 million. Energy Holdings will be required upon resolution of this matter to accelerate and pay approximately $40 million of state deferred tax liabilities and accelerate and pay and/or reduce $85 million of a forecasted federal tax loss to the Internal Revenue Service.

Additional facilities in our leveraged lease portfolio include the Joliet and Powerton generating facilities. Converted natural gas units such as Shawville and Joliet may have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units. Powerton is a coal-fired generating facility in Illinois. Each of these three facilities may not be as economically competitive as newer combined cycle gas units and could continue to be adversely impacted by the same economic conditions experienced by other less efficient natural gas and coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged lease receivables associated with these facilities.

Tax Legislation

In December 2017, the U.S. government enacted comprehensive tax legislation (Tax Act), which, among other things, decreased the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018, and made certain changes to bonus depreciation rules.

As a result of the enacted reduction in the statutory U.S. corporate income tax rate, as well as other aspects of the Tax Act, in December 2017 PSE&G recorded excess deferred taxes of approximately $2.1 billion and recorded an approximate $2.9 billion revenue impact of these excess deferred taxes as Regulatory Liabilities.

Beginning in 2018, PSEG, on a consolidated basis, is incurring lower income tax expense resulting in a decrease in its projected effective income tax rate. This has increased PSEG's and Power's net income. To the extent allowed under the Tax Act, Power's operating cash flows will reflect the full expensing of capital investments for income tax purposes. PSEG and Power expect that the interest on their debt will continue to be fully tax deductible albeit at a lower tax rate. For PSE&G, the Tax Act has led to lower customer rates due to lower income tax expense recoveries and the BPU has approved our proposal to refund excess deferred income tax regulatory liabilities. The impact of the lower federal income tax rate on PSE&G was reflected in PSE&G's distribution base rate case and its 2018 transmission formula rate filings. The Tax Act is generally expected to result in lower operating cash flows for PSE&G resulting from the elimination of bonus depreciation, partially offset by higher revenues due to the higher rate base.

In August 2018, the Internal Revenue Service issued a Notice of Proposed Rulemaking (Notice) regarding the application of tax depreciation rules as amended by the Tax Act. While the Notice provides some guidance as to the application of the changes made by the Tax Act to the bonus depreciation rules, certain aspects still remain unclear. Until clarity is provided, the amounts recorded for bonus depreciation for 2017 and 2018 remain provisional and are based on a reasonable interpretation of the Notice.

The impact of the Tax Act may differ from these estimates, possibly materially, due to, among other things, changes in interpretations and assumptions PSEG has made, guidance that may be issued and actions PSEG may take as a result of the Tax Act. For additional information, see Item 1. Note 15. Income Taxes.

As a result of the enactment of the Tax Act, various state regulatory authorities, including the BPU, have taken action to ensure that excess federal income taxes previously collected in rates are returned to customers. We have made filings to adjust the revenue requirement in certain of our rate matters as a result of the change in the federal income tax rate.

In addition, FERC continues to assess whether, and if so how, it will address changes and flow-backs to customers relating to accumulated deferred income taxes and bonus depreciation. See Item 1. Note 6. Rate Filings for additional information.

In July 2018, the State of New Jersey made significant changes to its income tax laws, including imposing a temporary surtax on allocated corporate taxable income of 2.5% effective January 1, 2018 and 2019 and 1.5% in 2020 and 2021, as well as

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requiring corporate taxpayers to file in a combined reporting group as defined under New Jersey law starting in 2019. Both provisions include an exemption for public utilities. We believe PSE&G meets the definition of a public utility and, therefore, will not be impacted by the temporary surtax or be included in the combined reporting group. We expect these new provisions to unfavorably affect our non-utility business. In accordance with GAAP accounting for income taxes, deferred taxes are required to be measured at the enacted tax rate expected to apply to taxable income in the periods in which the deferred taxes are expected to settle. The newly enacted New Jersey tax legislation did not have a material impact on PSEG's deferred income tax balance.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in an environment with low gas prices, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions in response to changes in prices and demand,
- obtain approval of and execute our utility capital investment program, including ES II, GSMP II, our CEF program and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction of our BH5 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

In addition to the risks describe elsewhere in this Form 10-Q and our Form 10-K for the year ended December 31, 2017, for 2018 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceedings,
- applying to the BPU to select our New Jersey nuclear generation units to receive payments under the ZEC program,
- the continuing impacts of the Tax Act and changes in state tax laws, and
- the impact of reductions in demand and lower natural gas and electricity prices and increasing environmental compliance costs.

We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators, customers and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of T&D facilities, clean energy investments and/or generation projects, in each case including offshore wind opportunities,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses,
- the expansion of our geographic footprint, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency, modernizing existing infrastructure and participation in transmission projects through FERC's "open window" solicitation process.

Power has stopped taking new customers in its retail energy business. Power will continue to meet all of its obligations to our existing customers through the end of their current contracts.

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There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

RESULTS OF OPERATIONS

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 19. Related-Party Transactions.

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2018	2017	2018 vs. 2017		2018	2017	2018 vs. 2017	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,394	$ 2,254	$ 140	6	$ 7,228	$ 6,987	$ 241	3
Energy Costs	804	616	188	31	2,356	2,072	284	14
Operation and Maintenance	742	693	49	7	2,221	2,128	93	4
Depreciation and Amortization	294	252	42	17	854	1,721	(867)	(50)
Income from Equity Method Investments	5	3	2	67	12	11	1	9
Net Gains (Losses) on Trust Investments	45	18	27	N/A	31	71	(40)	(56)
Other Income (Deductions)	33	33	—	—	99	98	1	1
Non-Operating Pension and OPEB Credits (Costs)	19	—	19	N/A	57	1	56	N/A
Interest Expense	127	100	27	27	341	289	52	18
Income Tax Expense	117	252	(135)	(54)	416	340	76	22

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2018	2017	2018 vs. 2017		2018	2017	2018 vs. 2017	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,595	$ 1,530	$ 65	4	$ 4,826	$ 4,749	$ 77	2
Energy Costs	593	543	50	9	1,863	1,793	70	4
Operation and Maintenance	389	357	32	9	1,133	1,086	47	4
Depreciation and Amortization	192	169	23	14	569	506	63	12
Net Gains (Losses) on Trust Investments	—	—	—	N/A	—	2	(2)	N/A
Other Income (Deductions)	21	22	(1)	(5)	61	65	(4)	(6)
Non-Operating Pension and OPEB Credits (Costs)	14	(2)	16	N/A	44	(5)	49	N/A
Interest Expense	83	79	4	5	246	223	23	10
Income Tax Expense	95	156	(61)	(39)	292	450	(158)	(35)

Three Months Ended September 30, 2018 as Compared to 2017

Operating Revenues increased $65 million due to changes in delivery, commodity, clause and other operating revenues.

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Delivery Revenues increased $8 million due primarily to

- Transmission, electric distribution and gas distribution revenue requirements were $78 million lower as a result of rate reductions due to the Tax Act which reduced the corporate income tax rate. This decrease is offset in Income Tax Expense.
- Gas distribution revenues decreased $1 million due primarily to a $2 million decrease from lower sales volumes and a $1 million decrease from ES I investments, partially offset by a $2 million increase from the inclusion of the GSMP I in base rates.
- Electric distribution revenues increased $45 million due to $33 million in higher sales volumes, a $10 million increase from higher ES I investments in base rates and higher Green Program Recovery Charges (GPRC) of $2 million.
- Transmission revenues were $42 million higher due to revenue requirements calculated through our transmission formula rate, primarily to recover increased investments.

Commodity Revenues increased $50 million as a result of higher Electric and Gas revenues. The changes in Commodity revenues for both electric and gas are entirely offset by the changes in Energy Costs. PSE&G earns no margin on the provision of BGS and basic gas supply service (BGSS) to retail customers.

- Electric commodity revenues increased $47 million due to $79 million in higher BGS sales volumes, partially offset by $32 million from lower BGS prices.
- Gas commodity revenues increased $3 million due primarily to higher BGSS sales prices of $4 million, partially offset by lower BGSS sales volumes of $1 million.

Clause Revenues increased $5 million due primarily to higher collections of Societal Benefit Charges (SBC) of $6 million and a $5 million increase in Margin Adjustment Clause (MAC) revenues, partially offset by a $7 million decrease in collections of GPRC. The changes in the SBC, MAC and GPRC amounts are entirely offset by changes in the amortization of Regulatory Assets and Regulatory Liabilities and related costs in O&M, D&A and Interest Expense. PSE&G does not earn margin on SBC, MAC or GPRC collections.

Operating Expenses

Energy Costs increased. This is entirely offset by the change in Commodity Revenues.

Operation and Maintenance increased $32 million due primarily to increases of $7 million in clause and renewable related net expenditures, $7 million in distribution maintenance, $6 million in transmission maintenance, $5 million in injuries and damages and $4 million in appliance service costs.

Depreciation and Amortization increased $23 million due primarily to an increase in depreciation due to additional plant placed into service.

Non-Operating Pension and OPEB Credits (Costs) reflected an increase of $16 million in credits due to the adoption of new accounting guidance effective January 1, 2018 which no longer allows capitalization of any portion of these benefit costs. See Item 1. Note 2. Recent Accounting Standards.

Interest Expense increased $4 million due primarily to $6 million related to net debt issuances in May and September 2018 and December 2017, partially offset by a reduction of $1 million related to clauses.

Income Tax Expense decreased $61 million due primarily to the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018.

Nine Months Ended September 30, 2018 as Compared to 2017

Operating Revenues increased $77 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $9 million due primarily to

- Transmission, electric distribution and gas distribution revenue requirements were $207 million lower as a result of rate reductions due to the Tax Act which reduced the corporate income tax rate. This decrease is offset in Income Tax Expense.
- Transmission revenues were $122 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover increased investments.
- Electric distribution revenues increased $52 million due to $36 million in higher sales volumes and a $16 million increase from the inclusion of increased ES I investments in base rates.

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- Gas distribution revenues increased $42 million due primarily to a $44 million increase due to higher sales volumes, a $24 million increase from the inclusion of the GSMP I in base rates and a $3 million increase in GPRC collections. These increases were partially offset by a $29 million decrease in WNC collections.

Commodity Revenues increased $70 million as a result of higher Electric revenues partially offset by lower Gas revenues. The changes in Commodity revenues for both electric and gas are entirely offset by the changes in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric commodity revenues increased $77 million due primarily to $127 million in higher BGS sales volumes and a $3 million increase from sales of solar renewable energy credits, partially offset by $53 million in lower BGS prices.
- Gas commodity revenues decreased $7 million due to lower BGSS prices of $47 million, partially offset by higher BGSS sales volumes of $40 million.

Clause Revenues decreased $7 million due to a $6 million decrease in MAC revenues and a $6 million decrease in GPRC. These decreases were partially offset by higher SBC collections of $4 million and a $1 million increase in collections of Solar Pilot Recovery Charges (SPRC). The changes in the MAC, GPRC, SBC and SPRC amounts are entirely offset by changes in the amortization of Regulatory Assets and Regulatory Liabilities and related costs in O&M, D&A and Interest Expense. PSE&G does not earn margin on MAC, GPRC, SBC or SPRC collections.

Other Operating Revenues increased $5 million due primarily to an increase in appliance service revenues.

Operating Expenses

Energy Costs increased $70 million. This is entirely offset by the change in Commodity Revenues.

Operation and Maintenance increased $47 million, due primarily to increases of $13 million in transmission maintenance, $12 million in appliance service costs, $9 million in storm costs, $9 million in distribution maintenance and $7 million in the gas distribution tariff. These increases were partially offset by a net $4 million decrease in clause and renewable related expenditures.

Depreciation and Amortization increased $63 million due primarily to a $61 million increase in depreciation related to additional plant placed into service and an increase of $5 million in amortization of Regulatory Assets, partially offset by a $4 million increase in capitalized depreciation.

Non-Operating Pension and OPEB Credits (Costs) reflected an increase of $49 million in credits due to the adoption of new accounting guidance effective January 1, 2018 which no longer allows capitalization of any portion of these benefit costs. See Item 1. Note 2. Recent Accounting Standards.

Interest Expense increased $23 million due primarily to an increase of $17 million related to net debt issuances in May and September 2018 and December 2017 and a $6 million increase related to clauses.

Income Tax Expense decreased $158 million due primarily to the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018, partially offset by uncertain tax positions, plant-related and flow-through items.

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Power

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2018	2017	2018 vs. 2017		2018	2017	2018 vs. 2017	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 868	$ 846	$ 22	3	$ 3,038	$ 3,033	$ 5	—
Energy Costs	431	330	101	31	1,550	1,408	142	10
Operation and Maintenance	231	229	2	1	745	717	28	4
Depreciation and Amortization	94	76	18	24	260	1,191	(931)	(78)
Income from Equity Method Investments	5	3	2	67	12	11	1	9
Net Gains (Losses) on Trust Investments	44	19	25	N/A	30	62	(32)	(52)
Other Income (Deductions)	14	11	3	27	38	34	4	12
Non-Operating Pension and OPEB Credits (Costs)	4	2	2	100	11	6	5	83
Interest Expense	29	12	17	N/A	47	41	6	15
Income Tax Expense (Benefit)	25	98	(73)	(74)	127	(80)	207	N/A

Three Months Ended September 30, 2018 as Compared to 2017

Operating Revenues increased $22 million due primarily to changes in generation and gas supply revenues.

Gas Supply Revenues increased $24 million due primarily to an increase in sales to third parties due primarily to higher average sale prices coupled with an increase in sales volumes.

Generation Revenues decreased $1 million due primarily to

- a decrease of $84 million due to higher net MTM losses in 2018 as compared to 2017. Of this amount, $136 million was due to changes in forward power prices, partially offset by $52 million due to lower losses on positions reclassified to realized upon settlement this year as compared to last year, and
- a net decrease of $14 million in electricity sold under our BGS contracts due primarily to lower prices,
- partially offset by a net increase of $48 million in energy sales due primarily to higher net volumes sold, which includes the commencement of commercial operations of Keys and Sewaren 7, partially offset by lower average realized prices in the PJM region,
- an increase of $41 million due to higher volumes of electricity sold under wholesale load contracts primarily in the PJM region, and
- a net increase of $8 million in capacity revenues due primarily to increases in cleared capacity and auction prices in the PJM region.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $101 million due to

Generation costs increased $75 million due primarily to higher fuel costs reflecting utilization of higher volumes of gas and higher natural gas prices in the PJM region. Higher gas volumes were primarily driven by the commencement of commercial operations of Keys and Sewaren 7.

Gas costs increased $26 million due mainly to an increase in sales to third parties due primarily to higher average gas costs coupled with an increase in volumes sold.

Depreciation and Amortization increased $18 million due primarily to

- an $11 million increase due to Keys and Sewaren 7 fossil stations placed into service, and

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- a $6 million increase due primarily to a higher nuclear asset base from increased capitalized asset retirement costs.

Net Gains (Losses) on Trust Investments increased $25 million due primarily to the inclusion in 2018 of $34 million of net unrealized gains on equity investments in the NDT Fund in accordance with new accounting guidance and a $5 million decrease in other-than-temporary impairments of equity securities in the NDT Fund, offset by a $14 million decrease in net realized gains on NDT Fund investments.

Interest Expense increased $17 million due primarily to $11 million in lower interest capitalized from Keys and Sewaren 7 fossil stations being placed into service, partially offset by higher interest capitalized for the construction of BH5 and a $7 million increase due to a June 2018 debt issuance.

Income Tax Expense (Benefit) decreased $73 million due primarily to lower pre-tax income resulting in $34 million of the decrease, the remeasurement of the reserve for uncertain tax positions in connection with the nuclear carryback claim and 2011 and 2012 federal tax audit of $28 million and the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018 of $19 million, partially offset by the New Jersey surtax of $7 million.

Nine Months Ended September 30, 2018 as Compared to 2017

Operating Revenues increased $5 million due primarily to changes in generation and gas supply revenues.

Gas Supply Revenues increased $54 million due primarily to

- an increase of $40 million related to sales to third parties due primarily to an increase in sales volumes, and
- a net increase of $31 million in sales under the BGSS contract, of which $43 million was due to an increase in sales volumes due to colder average temperatures during the 2018 heating season, partially offset by $12 million due to lower average sales prices,
- partially offset by a decrease of $17 million due to net MTM losses in 2018 compared to net gains in 2017.

Generation Revenues decreased $48 million due primarily to

- a decrease of $73 million due to higher net MTM losses in 2018 as compared to 2017. Of this amount, there was a $214 million decrease due to changes in forward prices, partially offset by $141 million in gains on positions reclassified to realized upon settlement this year as compared to last year,
- a decrease of $43 million in electricity sold under our BGS contracts due primarily to lower prices, and
- a net decrease of $39 million in energy sales due primarily to lower average realized prices in the PJM region partially offset by higher net volumes in PJM, which includes the commencement of commercial operations of Keys and Sewaren 7, and higher average prices in the New England (NE) and New York (NY) regions,
- partially offset by a net increase of $77 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM region, partially offset by lower volumes of electricity sold under wholesale load contracts in the NE region,
- a net increase of $16 million in capacity revenues due primarily to increases in cleared capacity and auction prices in the PJM and NE regions, and
- a net increase of $7 million due to higher sales related to new solar projects.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $142 million due to

Generation costs increased $72 million due primarily to

- higher fuel costs of $109 million reflecting utilization of higher volumes of gas and oil in the PJM region, due primarily to the commencement of commercial operations of Keys and Sewaren 7, coupled with higher prices of natural gas in the PJM and NY regions and higher coal costs in the PJM and NE regions,
- partially offset by a net decrease of $24 million due primarily to a decrease in the volume of energy purchased in the NE region to serve load obligations, and
- a decrease of $10 million due to MTM gains in 2018 as compared to losses in 2017 due to changes in forward prices.

S1-SSA-0009 - 19398

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Gas costs increased $70 million due mainly to

- a net increase of $38 million related to sales under the BGSS contract due primarily to increased volumes sold due to colder average temperatures during the 2018 heating season, partially offset by lower average gas costs, and
- a net increase of $32 million related to sales to third parties due primarily to an increase in the volume of gas purchased, partially offset by lower average gas costs.

Operation and Maintenance increased $28 million due primarily to a net increase related to our nuclear plants, due primarily to planned outage costs at our 100%-owned Hope Creek nuclear plant in 2018 as compared to planned outage costs incurred in 2017 for our 57%-owned Salem Unit 2.

Depreciation and Amortization decreased $931 million due primarily to

- $964 million of higher depreciation in 2017 for Hudson and Mercer due to the early retirement of those units,
- partially offset by a $15 million increase in 2018 due primarily to a higher nuclear asset base from increased capitalized asset retirement costs, and
- a $14 million increase due to Keys and Sewaren 7 fossil stations placed into service.

Net Gains (Losses) on Trust Investments decreased $32 million due primarily to a $22 million decrease in net realized gains on NDT Fund investments and the inclusion in 2018 of $16 million of net unrealized losses on equity investments in the NDT Fund in accordance with new accounting guidance, partially offset by a $9 million decrease in other-than-temporary impairments of equity securities in the NDT Fund.

Interest Expense increased $6 million due primarily to a $9 million increase due to a June 2018 debt issuance, partially offset by a decrease of $2 million in capitalized interest.

Income Tax Expense (Benefit) increased $207 million due primarily to pre-tax income in 2018 as compared to a pre-tax loss in 2017. This increase in income tax expense was diminished by the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018 and the remeasurement of the reserve for uncertain tax positions in connection with the nuclear carryback claim and the 2011 and 2012 federal tax audit.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the nine months ended September 30, 2018, our operating cash flow decreased $241 million as compared to the same period in 2017. The net change was due primarily to the net change from Power as discussed below.

PSE&G

PSE&G's operating cash flow increased $5 million from $1,392 million to $1,397 million for the nine months ended September 30, 2018, as compared to the same period in 2017, due primarily to an increase of $86 million due to a change in regulatory deferrals, higher earnings, and an increase of $48 million due primarily to a reduction in unbilled revenues resulting from lower prices and volumes in 2018, offset by a tax refund in 2017.

Power

Power's operating cash flow decreased $244 million from $1,249 million to $1,005 million for the nine months ended September 30, 2018, as compared to the same period in 2017, due to an increase in margin deposit requirements of $141 million, and higher generation costs, offset by lower tax payments in 2018 compared to 2017, a $23 million increase from net collections of counterparty receivables, and a decrease of $10 million in payments to counterparties.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

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We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs.

Our total credit facilities and available liquidity as of September 30, 2018 were as follows:

Company/Facility	As of September 30, 2018		
	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$ 1,500	$ 393	$ 1,107
PSE&G	600	56	544
Power	2,200	213	1,987
Total	**$ 4,300**	**$ 662**	**$ 3,638**

As of September 30, 2018, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating from S&P or Moody's, which would represent a three level downgrade from its current S&P or Moody's ratings. In the event of a deterioration of Power's credit rating certain of Power's agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $888 million and $848 million as of September 30, 2018 and December 31, 2017, respectively.

For additional information, see Item 1. Note 11. Debt and Credit Facilities.

Long-Term Debt Financing

During the next twelve months, PSEG has a $700 million floating rate term loan maturing in June 2019, PSE&G has $250 million of 1.80% Medium-Term Notes maturing in June 2019 and $250 million of 2.00% Medium-Term Notes maturing in August 2019 and Power has $250 million of 2.45% Senior Notes maturing in November 2018.

For additional information see Item 1. Note 11. Debt and Credit Facilities.

Common Stock Dividends

On July 17, 2018, our Board of Directors approved a $0.45 dividend per share of common stock for the third quarter of 2018. These declarations reflect an indicative annual dividend rate of $1.80 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For additional information related to cash dividends on our common stock, see Item 1. Note17. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

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	Moody's (A)	S&P (B)
PSEG		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB
Commercial Paper	P2	A2
PSE&G		
Outlook	**Stable**	**Stable**
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2
Power		
Outlook	**Stable**	**Stable**
Senior Notes	Baa1	BBB+

(A) Moody's ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. There were no material changes to our projected capital expenditures as compared to amounts disclosed in our 2017 Form 10-K other than the inclusion of GSMP II, which was approved in May 2018. See Executive Overview of 2018 and Future Outlook for additional information.

PSE&G

During the nine months ended September 30, 2018, PSE&G made capital expenditures of $2,228 million, primarily for T&D system reliability. This does not include expenditures for cost of removal, net of salvage, of $121 million, which are included in operating cash flows.

Power

During the nine months ended September 30, 2018, Power made capital expenditures of $679 million, excluding $121 million for nuclear fuel, primarily related to our Keys, Sewaren 7, BH5 and other generation projects.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Item 1. Note 2. Recent Accounting Standards.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses.

MTM VaR consists of MTM derivatives that are economic hedges. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

From July through September 2018, MTM VaR was relatively stable between a low of $6 million and a high of $11 million at the 95% confidence level. The range of VaR was narrower for the three months ended September 30, 2018 as compared with the year ended December 31, 2017.

	MTM VaR	
	Three Months Ended September 30, 2018	Year Ended December 31, 2017
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$ 10	$ 39
Average for the Period	$ 7	$ 10
High	$ 11	$ 39
Low	$ 6	$ 5
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$ 16	$ 60
Average for the Period	$ 11	$ 15
High	$ 17	$ 60
Low	$ 9	$ 8

See Item 1. Note 12. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, PSE&G and Power

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the "Exchange Act") that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of PSEG, PSE&G and Power. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of PSEG, PSE&G and Power have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

PSEG, PSE&G and Power

There have been no changes in internal control over financial reporting that occurred during the third quarter of 2018 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and environmental and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2017 Annual Report on Form 10-K, see Part I, Item 1. Note 10. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS

The discussion of our business and operations in this Quarterly Report on Form 10-Q should be read together with the risk factors contained in Part I, Item 1A of our 2017 Annual Report on Form 10-K, which describes various risks and uncertainties that could have a material adverse impact on our business, prospects, financial position, results of operations or cash flows and could cause results to differ materially from those expressed elsewhere in this report. There have been no material changes to the risk factors set forth in the above-referenced filings as of September 30, 2018.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

In December 2017, we entered into a share repurchase plan that complies with Rule 10b5-1 of the Securities Exchange Act of 1934, as amended, solely with respect to the repurchase of shares to satisfy obligations under equity compensation awards that are expected to vest or be exercised in 2018 and under PSEG's Employee Stock Purchase Plan for expected employee purchases in 2018. There were no common share repurchases in the open market during the third quarter of 2018.

ITEM 5. OTHER INFORMATION

Certain information reported in the 2017 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2017 Annual Report on Form 10-K and the Quarterly Reports on Form 10-Q for the quarters ended March 31, 2018 and June 30, 2018. References are to the related pages on the Form 10-K and 10-Q as printed and distributed.

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Federal Regulation

Capacity Market Issues—PJM

December 31, 2017 Form 10-K page 16, March 31, 2018 Form 10-Q on page 80 and June 30, 2018 Form 10-Q on page 88. In June 2018, FERC issued an order finding that PJM's current capacity market is unjust and unreasonable and established a new proceeding to address an alternative approach in which PJM would: (1) modify PJM's Minimum Offer Price Rule so that it would apply to new and existing resources that receive out-of-market payments, regardless of resource type; and (2) establish an option that would allow, on a resource-specific basis, resources receiving out-of-market support to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time. In response, PJM proposed a two-settlement auction mechanism in which the first stage would set the resource commitment and the second stage would establish the clearing price. During the second stage, the resources receiving out-of-market support would be removed from the auction before the price is established. We generally support PJM's proposal, but have some concerns about aspects of it that could reduce payments to nuclear units that receive out-of-market support payments. FERC's potential action in this proceeding could cause nuclear units that receive ZEC payments to lose capacity market revenues if states do not take steps to address the potential loss of capacity revenues. In addition, depending on the outcome of this matter, our fossil generating stations could be impacted. We cannot predict the outcome of this matter.

Transmission Regulation-Transmission Policy Developments

March 31, 2018 Form 10-Q on page 80. In February 2018, FERC issued an order finding that the transmission planning procedures used by the PJM transmission owners, a group that includes PSE&G, for supplemental projects do not adhere to the coordination and transparency principles of FERC's Order No. 890. FERC determined that certain terms and conditions in the PJM governing documents are unjust and unreasonable. FERC directed PJM and the PJM transmission owners to submit certain revisions to the manner in which the stakeholder process for supplemental projects is conducted. PSE&G participated in the PJM transmission owners' compliance filing, which was approved by FERC.

Transmission Regulation—Return on Equity (ROE)

In October 2018, FERC issued an order establishing a new framework for determining whether a company's ROE is unjust and unreasonable. The order was issued in a proceeding that was remanded to FERC from D.C. Circuit concerning the establishment of the New England Transmission Owners' ROE. FERC's order proposes a new method for evaluating whether an existing ROE remains just and reasonable. Under FERC's approach, FERC will determine a composite zone of reasonableness based on the results of three financial models, and if the targeted utility's existing ROE falls within the range of just and reasonable ROEs for its risk profile, FERC will dismiss the complaint. However, if FERC determines that an existing ROE is unjust and unreasonable, it proposes to rely on four financial models: a discounted cash flow, a risk premium analysis, a capital-asset pricing model analysis and an expected earnings analysis. We are still analyzing the potential impact of these methodologies and cannot predict the outcome of this proceeding.

Environmental Matters

Climate Change—$C0_2$ Regulation under the Clean Air Act

December 31, 2017 Form 10-K on page 22. In August 2018, the EPA released the proposed Affordable Clean Energy (ACE) rule as a replacement for the EPA's Clean Power Plan (CPP). In 2017, The EPA Administrator signed a proposed repeal of the CPP which had established state-specific greenhouse gas emissions targets on the basis that the CPP exceeded the EPA's statutory authority by considering measures that were beyond the control of the owners of existing fossil fuel-fired electric generating units. The proposed ACE rule gives states great flexibility to evaluate specific heat rate improvement technologies and practices to be applied at coal-fired electric generating units. States have three years from the date of finalization to submit a plan that establishes a standard of performance that reflects the degree of emission limitation through the application of heat rate improvement technologies and practices. We cannot estimate the impact of this action on our business or results of operations.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. PSE&G:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. Power:

Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2018

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2018

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2018

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EXHIBIT 12

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
Plus Preferred Security Dividend Requirements

	Nine Months Ended September 30,		Years Ended December 31,				
	2018	**2017**	**2017**	**2016**	**2015**	**2014**	**2013**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,655	$ 958	$1,268	$1,298	$2,680	$2,456	$2,055
(Income) Loss from Equity Investees, net of Distributions	(1)	2	4	7	3	4	(7)
Fixed Charges	437	379	518	477	457	450	458
Capitalized Interest	(54)	13	(9)	(7)	(18)	(16)	(16)
Total Earnings	$ 2,037	$ 1,352	$1,781	$1,775	$3,122	$2,894	$2,490
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 411	$ 358	$ 487	$ 456	$ 437	$ 430	$ 442
Interest Factor in Rentals	26	21	31	21	20	20	16
Total Fixed Charges	$ 437	$ 379	$ 518	$ 477	$ 457	$ 450	$ 458
Ratio of Earnings to Fixed Charges	**4.66**	**3.57**	**3.44**	**3.72**	**6.83**	**6.43**	**5.44**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude (a) the amount of any interest capitalized during the period and (b) preferred stock dividends which were included in such fixed charges amount but not deducted in the determination of pre-tax income.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, (c) an estimate of interest implicit in rentals, and (d) preferred stock dividends, increased to reflect the pre-tax earnings requirement. There were no preferred stock dividends for any period presented.

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EXHIBIT 12.1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2018	**2017**	**2017**	**2016**	**2015**	**2014**	**2013**
			(Millions, except ratios)				
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income from Continuing Operations	$ 1,120	$ 1,203	$1,536	$1,404	$ 1,257	$1,174	$ 993
Fixed Charges	270	244	331	316	306	303	316
Capitalized Interest	(13)	(14)	(18)	(17)	(17)	(16)	(16)
Total Earnings	$ 1,377	$ 1,433	$1,849	$1,703	$ 1,546	$1,461	$1,293
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 259	$ 237	$ 321	$ 306	$ 297	$ 293	$ 309
Interest Factor in Rentals	11	7	10	10	9	10	7
Total Fixed Charges	$ 270	$ 244	$ 331	$ 316	$ 306	$ 303	$ 316
Ratio of Earnings to Fixed Charges	**5.10**	**5.87**	**5.59**	**5.39**	**5.05**	**4.82**	**4.09**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

Source: PUBLIC SERVICE ELECTRIC & GAS CO, 10-Q, October 30, 2018 Powered by Morningstar® Document Research℠
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EXHIBIT 12.2

PSEG POWER LLC
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Nine Months Ended September 30,		Years Ended December 31,				
	2018	**2017**	**2017**	**2016**	**2015**	**2014**	**2013**
	(Millions, except ratios)						
Earnings as Defined in Regulation S-K (A):							
Pre-tax Income (Loss) from Continuing Operations	$ 527	$ (211)	$ (250)	$ (43)	$1,367	$1,251	$1,063
(Income) Loss from Equity Investees, net of Distributions	(1)	2	4	7	1	3	(10)
Fixed Charges	112	104	139	142	152	150	143
Capitalized Interest	(41)	27	9	11	(1)	1	1
Total Earnings	$ 597	$ (78)	$ (98)	$ 117	$1,519	$1,405	$1,197
Fixed Charges as Defined in Regulation S-K (B)							
Interest Expense	$ 104	$ 96	$ 128	$ 138	$ 148	$ 146	$ 139
Interest Factor in Rentals	8	8	11	4	4	4	4
Total Fixed Charges	$ 112	$ 104	$ 139	$ 142	$ 152	$ 150	$ 143
Ratio of Earnings to Fixed Charges (C)	**5.33**	**(0.75)**	**(0.71)**	**0.82**	**9.99**	**9.37**	**8.37**

(A) The term "earnings" shall be defined as pre-tax Income from Continuing Operations before income or loss from equity method investees plus distributed income from equity investees. Add to pre-tax income the amount of fixed charges adjusted to exclude the amount of any interest capitalized during the period.

(B) Fixed Charges represent (a) interest, whether expensed or capitalized, (b) amortization of debt discount, premium and expense, and (c) an estimate of interest implicit in rentals.

(C) The ratio of earnings to fixed charges for the nine months ended September 30, 2017, was (0.75), as noted above, which represents a deficiency of $182 million. The ratio of earnings to fixed charges for the year ended December 31, 2017, was (0.71), as noted above, which represents a deficiency of $237 million. The ratio of earnings to fixed charges for the year ended December 31, 2016, was 0.82, as noted above, which represents a deficiency of $25 million.

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EXHIBIT 31

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2018

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer

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EXHIBIT 31.1

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Enterprise Group Incorporated;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer

S1-SSA-0009 - 19411

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EXHIBIT 31.2

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2018

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer

S1-SSA-0009 - 19412

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EXHIBIT 31.3

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Public Service Electric and Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer

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EXHIBIT 31.4

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Ralph Izzo, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2018

/s/ Ralph Izzo

Ralph Izzo
PSEG Power LLC
Chief Executive Officer

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EXHIBIT 31.5

Certification Pursuant to Rules 13a-14 and 15d-14
of the 1934 Securities Exchange Act

I, Daniel J. Cregg, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of PSEG Power LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: October 30, 2018

/s/ Daniel J. Cregg

Daniel J. Cregg
PSEG Power LLC
Chief Financial Officer

S1-SSA-0009 - 19415

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EXHIBIT 32

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Ralph Izzo

Ralph Izzo
Public Service Enterprise Group Incorporated
Chief Executive Officer
October 30, 2018

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EXHIBIT 32.1

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Enterprise Group Incorporated, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Enterprise Group Incorporated on Form 10-Q for the quarter ended September 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Enterprise Group Incorporated.

/s/ Daniel J. Cregg

Daniel J. Cregg
Public Service Enterprise Group Incorporated
Chief Financial Officer
October 30, 2018

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EXHIBIT 32.2

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Ralph Izzo

Ralph Izzo

Public Service Electric and Gas Company
Chief Executive Officer
October 30, 2018

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EXHIBIT 32.3

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of Public Service Electric and Gas Company, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of Public Service Electric and Gas Company on Form 10-Q for the quarter ended September 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Public Service Electric and Gas Company.

/s/ Daniel J. Cregg

Daniel J. Cregg

Public Service Electric and Gas Company
Chief Financial Officer
October 30, 2018

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EXHIBIT 32.4

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Ralph Izzo, Chief Executive Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Ralph Izzo

Ralph Izzo

PSEG Power LLC
Chief Executive Officer
October 30, 2018

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EXHIBIT 32.5

Certification Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code

I, Daniel J. Cregg, Chief Financial Officer of PSEG Power LLC, to the best of my knowledge, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that (i) the Quarterly Report of PSEG Power LLC on Form 10-Q for the quarter ended September 30, 2018 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended and (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of PSEG Power LLC.

/s/ Daniel J. Cregg

Daniel J. Cregg

PSEG Power LLC
Chief Financial Officer
October 30, 2018

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10-Qs - Exelon

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Quarterly Period Ended June 30, 2013

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number	Name of Registrant; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definition of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
Exelon Corporation	☒			
Exelon Generation Company, LLC			☒	
Commonwealth Edison Company			☒	
PECO Energy Company			☒	
Baltimore Gas and Electric Company			☒	

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Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The number of shares outstanding of each registrant’s common stock as of June 30, 2013 was:

Exelon Corporation Common Stock, without par value	856,563,385
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,818
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively

Other Terms and Abbreviations

Note "—" of the Exelon 2012 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2012 Annual Report on Form 10-K
1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA
EE&C	Energy Efficiency and Conservation/Demand Response
EGS	Electric Generation Supplier
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste
LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midwest Independent Transmission System Operator, Inc.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SFC	Supplier Forward Contract
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
TEG	Termoelectrica del Golfo
TEP	Termoelectrica Penoles
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

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FILING FORMAT

This combined Form 10-Q is being filed separately by the Registrants. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company and Baltimore Gas and Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2012 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 19; (2) Exelon's First Quarter 2013 Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants' websites at www.exeloncorp.com. Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions, except per share data)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Operating revenues	$ 6,141	$ 5,966	$12,223	$10,656
Operating expenses				
Purchased power and fuel	2,419	2,606	5,400	4,371
Operating and maintenance	1,892	1,841	3,656	3,809
Depreciation and amortization	533	494	1,076	876
Taxes other than income	271	254	548	448
Total operating expenses	5,115	5,195	10,680	9,504
Equity in loss of unconsolidated affiliates	(21)	(57)	(30)	(79)
Operating income	1,005	714	1,513	1,073
Other income and (deductions)				
Interest expense	(246)	(250)	(863)	(439)
Interest expense to affiliates, net	(6)	(6)	(13)	(12)
Other, net	(17)	(43)	155	152
Total other income and (deductions)	(269)	(299)	(721)	(299)
Income before income taxes	736	415	792	774
Income taxes	239	126	294	284
Net income	497	289	498	490
Net income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	7	3	12	4
Net income attributable to common shareholders	490	286	486	486
Comprehensive income (loss), net of income taxes				
Net income	497	289	498	490
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	—	1	1	1
Actuarial loss reclassified to periodic cost	50	41	100	82
Transition obligation reclassified to periodic cost	—	—	—	2
Pension and non-pension postretirement benefit plans valuation adjustment	2	(3)	77	(11)
Deferred compensation unit valuation adjustment	10	—	10	—
Change in unrealized (loss) gain on cash flow hedges	(65)	(156)	(123)	59
Change in unrealized income on equity investments	8	6	36	6
Change in unrealized loss on foreign currency translation	(5)	(2)	(6)	(2)
Change in unrealized loss on marketable securities	—	(1)	(1)	—
Other comprehensive income (loss)	—	(114)	94	137
Comprehensive income	$ 497	$ 175	$ 592	$ 627
Average shares of common stock outstanding:				
Basic	856	853	856	779
Diluted	860	856	859	781
Earnings per average common share:				
Basic	$ 0.57	$ 0.34	$ 0.57	$ 0.62
Diluted	$ 0.57	$ 0.33	$ 0.57	$ 0.62
Dividends per common share	$ 0.31	$ 0.53	$ 0.84	$ 1.05

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2013	2012
Cash flows from operating activities		
Net income	$ 498	$ 490
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	1,972	1,895
Deferred income taxes and amortization of investment tax credits	(468)	227
Net fair value changes related to derivatives	(28)	(323)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(27)	(70)
Other non-cash operating activities	576	959
Changes in assets and liabilities:		
Accounts receivable	131	414
Inventories	(18)	45
Accounts payable, accrued expenses and other current liabilities	(583)	(1,063)
Option premiums paid, net	(10)	(108)
Counterparty collateral (posted) received, net	(259)	451
Income taxes	705	259
Pension and non-pension postretirement benefit contributions	(284)	(90)
Other assets and liabilities	133	(373)
Net cash flows provided by operating activities	2,338	2,713
Cash flows from investing activities		
Capital expenditures	(2,518)	(2,800)
Proceeds from nuclear decommissioning trust fund sales	1,448	5,371
Investment in nuclear decommissioning trust funds	(1,565)	(5,483)
Cash and restricted cash acquired from Constellation	—	964
Proceeds from sales of investments	4	12
Purchases of investments	(3)	(5)
Change in restricted cash	22	(15)
Other investing activities	63	(12)
Net cash flows used in investing activities	(2,549)	(1,968)
Cash flows from financing activities		
Changes in short-term debt	662	179
Issuance of long-term debt	509	850
Retirement of long-term debt	(616)	(649)
Redemption of preferred securities	(93)	—
Dividends paid on common stock	(716)	(773)
Dividends paid to former Constellation shareholders	—	(51)
Proceeds from employee stock plans	32	42
Other financing activities	(62)	(10)
Net cash flows used in financing activities	(284)	(412)
(Decrease) increase in cash and cash equivalents	(495)	333
Cash and cash equivalents at beginning of period	1,486	1,016
Cash and cash equivalents at end of period	$ 991	$ 1,349

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 956	$ 1,411
Cash and cash equivalents of variable interest entities	35	75
Restricted cash and investments	61	86
Restricted cash and investments of variable interest entities	53	47
Accounts receivable, net		
Customer ($286 and $289 gross accounts receivable pledged as collateral as of June 30, 2013 and December 31, 2012, respectively)	2,609	2,795
Other	1,224	1,141
Accounts receivable, net, variable interest entities	252	292
Mark-to-market derivative assets	845	938
Unamortized energy contract assets	573	886
Inventories, net		
Fossil fuel	214	246
Materials and supplies	805	768
Deferred income taxes	288	131
Regulatory assets	804	764
Other	690	560
Total current assets	9,409	10,140
Property, plant and equipment, net	45,994	45,186
Deferred debits and other assets		
Regulatory assets	6,519	6,497
Nuclear decommissioning trust funds	7,463	7,248
Investments	1,171	1,184
Investments in affiliates	22	22
Investment in CENG	1,876	1,849
Goodwill	2,625	2,625
Mark-to-market derivative assets	772	937
Unamortized energy contracts assets	856	1,073
Pledged assets for Zion Station decommissioning	538	614
Other	1,175	1,186
Total deferred debits and other assets	23,017	23,235
Total assets	$ 78,420	$ 78,561

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 662	$ —
Short-term notes payable — accounts receivable agreement	210	210
Long-term debt due within one year	1,944	975
Long-term debt due within one year of variable interest entities	87	72
Accounts payable	2,210	2,446
Accounts payable of variable interest entities	147	202
Accrued expenses	1,382	1,800
Deferred income taxes	45	58
Regulatory liabilities	357	368
Mark-to-market derivative liabilities	147	352
Unamortized energy contract liabilities	360	455
Other	823	853
Total current liabilities	8,374	7,791
Long-term debt	16,121	17,190
Long-term debt to financing trusts	648	648
Long-term debt of variable interest entities	449	508
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,519	11,551
Asset retirement obligations	5,202	5,074
Pension obligations	3,164	3,428
Non-pension postretirement benefit obligations	2,706	2,662
Spent nuclear fuel obligation	1,020	1,020
Regulatory liabilities	4,044	3,981
Mark-to-market derivative liabilities	178	281
Unamortized energy contract liabilities	399	528
Payable for Zion Station decommissioning	373	432
Other	2,635	1,650
Total deferred credits and other liabilities	31,240	30,607
Total liabilities	56,832	56,744
Commitments and contingencies		
Preferred securities of subsidiary	—	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 857 shares and 855 shares outstanding at June 30, 2013 and December 31, 2012, respectively)	16,693	16,632
Treasury stock, at cost (35 shares at June 30, 2013 and December 31, 2012, respectively)	(2,327)	(2,327)
Retained earnings	9,660	9,893
Accumulated other comprehensive loss, net	(2,673)	(2,767)
Total shareholders' equity	21,353	21,431
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	42	106
Total equity	21,588	21,730
Total liabilities and shareholders' equity	$ 78,420	$ 78,561

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Non-controlling Interest	Preferred and Preference Stock	Total Equity
Balance, December 31, 2012	889,525	$16,632	$(2,327)	$ 9,893	$ (2,767)	$ 106	$ 193	$21,730
Net income (loss)	—	—	—	486	—	(1)	13	498
Long-term incentive plan activity	1,782	61	—	—	—	—	—	61
Common stock dividends	—	—	—	(719)	—	—	—	(719)
Consolidated VIE dividend to non-controlling interest	—	—	—	—	—	(63)	—	(63)
Redemption of preferred securities	—	—	—	—	—	—	(6)	(6)
Preferred and preference stock dividends	—	—	—	—	—	—	(7)	(7)
Other comprehensive income net of income taxes of $(67)	—	—	—	—	94	—	—	94
Balance, June 30, 2013	891,307	$16,693	$(2,327)	$ 9,660	$ (2,673)	$ 42	$ 193	$21,588

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Operating revenues				
Operating revenues	$ 3,718	$ 3,345	$ 6,859	$ 5,718
Operating revenues from affiliates	352	420	744	790
Total operating revenues	4,070	3,765	7,603	6,508
Operating expenses				
Purchased power and fuel	1,946	1,852	4,114	2,896
Operating and maintenance	1,041	990	2,007	2,029
Operating and maintenance from affiliates	148	188	295	327
Depreciation and amortization	210	204	424	357
Taxes other than income	101	90	194	164
Total operating expenses	3,446	3,324	7,034	5,773
Equity in loss of unconsolidated affiliates	(21)	(57)	(30)	(79)
Operating income	603	384	539	656
Other income and (deductions)				
Interest expense	(93)	(85)	(176)	(138)
Other, net	(33)	(76)	95	103
Total other income and (deductions)	(126)	(161)	(81)	(35)
Income before income taxes	477	223	458	621
Income taxes	149	58	148	289
Net income	328	165	310	332
Net loss attributable to noncontrolling interests	(2)	(1)	(1)	(2)
Net income attributable to membership interest	330	166	311	334
Comprehensive income (loss), net of income taxes				
Net income	328	165	310	332
Other comprehensive (loss) income, net of income taxes				
Change in unrealized loss on cash flow hedges	(137)	(266)	(267)	(14)
Change in unrealized income on equity investments	8	6	36	6
Change in unrealized loss on foreign currency translation	(5)	(2)	(6)	(2)
Change in unrealized loss on marketable securities	—	(1)	(1)	(1)
Other comprehensive loss	(134)	(263)	(238)	(11)
Comprehensive income (loss)	$ 194	$ (98)	$ 72	$ 321

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2013	2012
Cash flows from operating activities		
Net income	$ 310	$ 332
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	1,358	1,423
Deferred income taxes and amortization of investment tax credits	(44)	168
Net fair value changes related to derivatives	(21)	(307)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(27)	(70)
Other non-cash operating activities	315	318
Changes in assets and liabilities:		
Accounts receivable	88	306
Receivables from and payables to affiliates, net	(29)	(42)
Inventories	(38)	30
Accounts payable, accrued expenses and other current liabilities	(426)	(732)
Option premiums paid, net	(10)	(108)
Counterparty collateral (paid) received, net	(303)	443
Income taxes	265	314
Pension and non-pension postretirement benefit contributions	(120)	(35)
Other assets and liabilities	(168)	(174)
Net cash flows provided by operating activities	1,150	1,866
Cash flows from investing activities		
Capital expenditures	(1,277)	(1,820)
Proceeds from nuclear decommissioning trust fund sales	1,448	5,371
Investment in nuclear decommissioning trust funds	(1,565)	(5,483)
Change in restricted cash	(11)	6
Cash acquired from Constellation	—	708
Other investing activities	27	(66)
Net cash flows used in investing activities	(1,378)	(1,284)
Cash flows from financing activities		
Issuance of long-term debt	209	850
Retirement of long-term debt	(458)	(56)
Change in short-term debt	288	(42)
Changes in Exelon intercompany money pool borrowings	263	—
Distribution to member	(474)	(891)
Other financing activities	(49)	(9)
Net cash flows used in financing activities	(221)	(148)
(Decrease) increase in cash and cash equivalents	(449)	434
Cash and cash equivalents at beginning of period	671	496
Cash and cash equivalents at end of period	$ 222	$ 930

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 187	$ 596
Cash and cash equivalents of variable interest entities	35	75
Restricted cash and cash equivalents of variable interest entities	27	16
Accounts receivable, net		
Customer	1,464	1,482
Other	347	472
Accounts receivable, net, variable interest entities	242	292
Mark-to-market derivative assets	845	938
Mark-to-market derivative assets with affiliates	—	226
Receivables from affiliates	123	141
Unamortized energy contract assets	573	886
Inventories, net		
Fossil fuel	133	130
Materials and supplies	648	626
Deferred income taxes	195	—
Other	488	331
Total current assets	5,307	6,211
Property, plant and equipment, net	19,678	19,531
Deferred debits and other assets		
Nuclear decommissioning trust funds	7,463	7,248
Investments	409	420
Investment in CENG	1,876	1,849
Mark-to-market derivative assets	740	924
Prepaid pension asset	1,982	1,975
Pledged assets for Zion Station decommissioning	538	614
Unamortized energy contract assets	856	1,073
Other	829	836
Total deferred debits and other assets	14,693	14,939
Total assets	$ 39,678	$ 40,681

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 288	$ —
Long-term debt due within one year	500	24
Long-term debt due within one year of variable interest entities	8	4
Accounts payable	1,134	1,346
Accounts payable of variable interest entities	147	202
Accrued expenses	812	1,116
Payables to affiliates	148	193
Borrowings from Exelon intercompany money pool	263	—
Deferred income taxes	35	128
Mark-to-market derivative liabilities	131	334
Unamortized energy contract liabilities	315	378
Other	321	372
Total current liabilities	4,102	4,097
Long-term debt	4,975	5,245
Long-term debt to affiliate	1,534	2,007
Long-term debt of variable interest entities	196	203
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,647	5,398
Asset retirement obligations	5,065	4,938
Non-pension postretirement benefit obligations	814	755
Spent nuclear fuel obligation	1,020	1,020
Payables to affiliates	2,433	2,397
Mark-to-market derivative liabilities	109	232
Unamortized energy contract liabilities	393	516
Payable for Zion Station decommissioning	373	432
Other	820	776
Total deferred credits and other liabilities	16,674	16,464
Total liabilities	27,481	28,016
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	8,873	8,876
Undistributed earnings	3,005	3,168
Accumulated other comprehensive income, net	275	513
Total member’s equity	12,153	12,557
Noncontrolling interest	44	108
Total equity	12,197	12,665
Total liabilities and equity	$ 39,678	$ 40,681

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income, net	Noncontrolling Interest	Total Equity
Balance, December 31, 2012	$ 8,876	$ 3,168	$ 513	$ 108	$12,665
Net income (loss)	—	311	—	(1)	310
Noncontrolling interest acquired	(3)	—	—	—	(3)
Distribution to member	—	(474)	—	—	(474)
Consolidated VIE dividend to non-controlling interest	—	—	—	(63)	(63)
Other comprehensive loss, net of income taxes of $152	—	—	(238)	—	(238)
Balance, June 30, 2013	$ 8,873	$ 3,005	$ 275	$ 44	$12,197

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Operating revenues				
Operating revenues	$ 1,080	$ 1,280	$ 2,238	$ 2,669
Operating revenues from affiliates	—	1	1	1
Total operating revenues	1,080	1,281	2,239	2,670
Operating expenses				
Purchased power	127	384	364	757
Purchased power from affiliate	121	203	266	451
Operating and maintenance	319	293	611	569
Operating and maintenance from affiliate	40	38	76	81
Depreciation and amortization	170	152	337	300
Taxes other than income	71	69	145	144
Total operating expenses	848	1,139	1,799	2,302
Operating income	232	142	440	368
Other income and (deductions)				
Interest expense	(72)	(71)	(422)	(150)
Interest expense to affiliates, net	(4)	(3)	(7)	(6)
Other, net	6	3	11	7
Total other income and (deductions)	(70)	(71)	(418)	(149)
Income before income taxes	162	71	22	219
Income taxes	66	29	8	90
Net income	96	42	14	129
Other comprehensive income, net of income taxes				
Change in unrealized gain on marketable securities	—	—	—	1
Other comprehensive income	—	—	—	1
Comprehensive income	$ 96	$ 42	$ 14	$ 130

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2013	2012
Cash flows from operating activities		
Net income	$ 14	$ 129
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	337	300
Deferred income taxes and amortization of investment tax credits	(226)	116
Other non-cash operating activities	39	241
Changes in assets and liabilities:		
Accounts receivable	18	(26)
Receivables from and payables to affiliates, net	(26)	(18)
Inventories	(11)	(7)
Accounts payable, accrued expenses and other current liabilities	20	(54)
Counterparty collateral received, net	45	8
Income taxes	240	149
Pension and non-pension postretirement benefit contributions	(119)	(12)
Other assets and liabilities	172	(104)
Net cash flows provided by operating activities	503	722
Cash flows from investing activities		
Capital expenditures	(711)	(585)
Proceeds from sales of investments	4	12
Purchases of investments	(3)	(5)
Change in restricted cash	(3)	—
Other investing activities	20	11
Net cash flows used in investing activities	(693)	(567)
Cash flows from financing activities		
Changes in short-term debt	374	178
Retirement of long-term debt	(125)	(450)
Dividends paid on common stock	(110)	(85)
Other financing activities	—	(3)
Net cash flows provided by (used in) financing activities	139	(360)
Decrease in cash and cash equivalents	(51)	(205)
Cash and cash equivalents at beginning of period	144	234
Cash and cash equivalents at end of period	$ 93	$ 29

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 93	$ 144
Restricted cash	3	—
Accounts receivable, net		
Customer	455	539
Other	518	452
Inventories, net	102	91
Deferred income taxes	32	83
Counterparty collateral deposited	8	53
Regulatory assets	274	388
Other	26	25
Total current assets	1,511	1,775
Property, plant and equipment, net	14,233	13,826
Deferred debits and other assets		
Regulatory assets	732	666
Investments	6	8
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,244	2,039
Prepaid pension asset	1,680	1,661
Other	312	299
Total deferred debits and other assets	7,605	7,304
Total assets	$ 23,349	$ 22,905

See the Combined Notes to Consolidated Financial Statements

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 374	$ —
Long-term debt due within one year	744	252
Accounts payable	432	379
Accrued expenses	253	295
Payables to affiliates	70	97
Customer deposits	135	136
Regulatory liabilities	151	170
Mark-to-market derivative liability	16	18
Mark-to-market derivative liability with affiliate	—	226
Other	81	82
Total current liabilities	2,256	1,655
Long-term debt	4,707	5,315
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,997	4,272
Asset retirement obligations	100	99
Non-pension postretirement benefits obligations	327	273
Regulatory liabilities	3,276	3,229
Mark-to-market derivative liability	69	49
Other	1,010	484
Total deferred credits and other liabilities	8,779	8,406
Total liabilities	15,948	15,582
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,188	5,014
Retained earnings	625	721
Total shareholders' equity	7,401	7,323
Total liabilities and shareholders' equity	$ 23,349	$ 22,905

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Accumulated Other Comprehensive Income, net	Total Shareholders' Equity
Balance, December 31, 2012	$ 1,588	$5,014	$ (1,639)	$ 2,360	$ —	$ 7,323
Net income	—	—	14	—	—	14
Appropriation of retained earnings for future dividends	—	—	(14)	14	—	—
Common stock dividends	—	—	—	(110)	—	(110)
Parent tax matter indemnification	—	174	—	—	—	174
Balance, June 30, 2013	$ 1,588	$5,188	$ (1,639)	$ 2,264	$ —	$ 7,401

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Operating revenues				
Operating revenues	$ 672	$ 714	$1,567	$1,588
Operating revenues from affiliates	—	1	—	2
Total operating revenues	672	715	1,567	1,590
Operating expenses				
Purchased power and fuel	161	171	426	472
Purchased power from affiliate	97	125	238	235
Operating and maintenance	155	146	319	318
Operating and maintenance from affiliates	26	26	50	57
Depreciation and amortization	56	54	113	107
Taxes other than income	39	42	80	74
Total operating expenses	534	564	1,226	1,263
Operating income	138	151	341	327
Other income and (deductions)				
Interest expense	(25)	(28)	(51)	(56)
Interest expense to affiliates, net	(3)	(3)	(6)	(6)
Other, net	—	2	3	5
Total other income and (deductions)	(28)	(29)	(54)	(57)
Income before income taxes	110	122	287	270
Income taxes	32	42	87	93
Net income	78	80	200	177
Preferred security dividends and redemption	6	1	7	2
Net income attributable to common shareholder	72	79	193	175
Comprehensive income, net of income taxes				
Net income	78	80	200	177
Other comprehensive income, net of income taxes				
Change in unrealized gains on marketable securities	—	—	—	1
Other comprehensive income	—	—	—	1
Comprehensive income	$ 78	$ 80	$ 200	$ 178

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2013	2012
Cash flows from operating activities		
Net income	$ 200	$ 177
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	113	107
Deferred income taxes and amortization of investment tax credits	25	19
Other non-cash operating activities	50	66
Changes in assets and liabilities:		
Accounts receivable	55	62
Receivables from and payables to affiliates, net	(18)	9
Inventories	27	26
Accounts payable, accrued expenses and other current liabilities	35	(83)
Income taxes	39	121
Pension and non-pension postretirement benefit contributions	(10)	(8)
Other assets and liabilities	(49)	(87)
Net cash flows provided by operating activities	467	409
Cash flows from investing activities		
Capital expenditures	(254)	(179)
Changes in intercompany money pool	(263)	18
Change in restricted cash	(1)	(3)
Other investing activities	4	7
Net cash flows used in investing activities	(514)	(157)
Cash flows from financing activities		
Dividends paid on common stock	(166)	(172)
Dividends paid on preferred securities	(1)	(2)
Redemption of preferred securities	(93)	—
Other financing activities	1	—
Net cash flows used in financing activities	(259)	(174)
Increase (decrease) in cash and cash equivalents	(306)	78
Cash and cash equivalents at beginning of period	362	194
Cash and cash equivalents at end of period	$ 56	$ 272

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 56	$ 362
Restricted cash and cash equivalents	1	—
Accounts receivable, net ($286 and $289 gross accounts receivable pledged as collateral as of June 30, 2013 and December 31, 2012, respectively)		
Customer	286	364
Other	141	161
Inventories, net		
Fossil fuel	36	65
Materials and supplies	20	19
Deferred income taxes	42	40
Receivable from Exelon intercompany money pool	263	—
Prepaid utility taxes	71	21
Regulatory assets	35	32
Other	43	30
Total current assets	994	1,094
Property, plant and equipment, net	6,207	6,078
Deferred debits and other assets		
Regulatory assets	1,400	1,378
Investments	23	22
Investments in affiliates	8	8
Receivable from affiliates	366	360
Prepaid pension asset	373	373
Other	36	40
Total deferred debits and other assets	2,206	2,181
Total assets	$ 9,407	$ 9,353

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term notes payable — accounts receivable agreement	$ 210	$ 210
Long-term debt due within one year	300	300
Accounts payable	264	244
Accrued expenses	107	82
Payables to affiliates	60	76
Customer deposits	48	51
Regulatory liabilities	166	169
Other	34	26
Total current liabilities	1,189	1,158
Long-term debt	1,648	1,647
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,397	2,331
Asset retirement obligations	30	29
Non-pension postretirement benefits obligations	295	284
Regulatory liabilities	547	538
Other	108	113
Total deferred credits and other liabilities	3,377	3,295
Total liabilities	6,398	6,284
Commitments and contingencies		
Preferred securities	—	87
Shareholder's equity		
Common stock	2,388	2,388
Retained earnings	620	593
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,009	2,982
Total liabilities and shareholders' equity	$ 9,407	$ 9,353

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholders' Equity
Balance, December 31, 2012	$ 2,388	$ 593	$ 1	$ 2,982
Net income	—	200	—	200
Common stock dividends	—	(166)	—	(166)
Preferred security dividends	—	(1)	—	(1)
Redemption of preferred securities	—	(6)	—	(6)
Balance, June 30, 2013	$ 2,388	$ 620	$ 1	$ 3,009

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Operating revenues				
Operating revenues	$ 649	$ 614	$ 1,525	$ 1,307
Operating revenues from affiliates	4	2	8	5
Total operating revenues	653	616	1,533	1,312
Operating expenses				
Purchased power and fuel	189	201	501	494
Purchased power from affiliate	99	84	212	176
Operating and maintenance	139	136	266	297
Operating and maintenance from affiliates	21	25	37	59
Depreciation and amortization	82	71	175	150
Taxes other than income	54	47	109	95
Total operating expenses	584	564	1,300	1,271
Operating income	69	52	233	41
Other income and (deductions)				
Interest expense	(32)	(34)	(66)	(75)
Other, net	4	7	9	13
Total other income and (deductions)	(28)	(27)	(57)	(62)
Income (loss) before income taxes	41	25	176	(21)
Income taxes	16	9	70	(7)
Net income (loss)	25	16	106	(14)
Preference stock dividends	3	3	6	6
Net income (loss) attributable to common shareholder	$ 22	$ 13	$ 100	$ (20)
Comprehensive income (loss)	$ 25	$ 16	$ 106	$ (14)

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2013	2012
Cash flows from operating activities		
Net (loss) income	$ 106	$ (14)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	175	150
Deferred income taxes and amortization of investment tax credits	98	91
Other non-cash operating activities	61	100
Changes in assets and liabilities:		
Accounts receivable	(58)	76
Receivables from and payables to affiliates, net	(11)	(3)
Inventories	4	37
Accounts payable, accrued expenses and other current liabilities	(28)	(71)
Income taxes	(33)	(48)
Pension and non-pension postretirement benefit contributions	(11)	(8)
Other assets and liabilities	63	43
Net cash flows provided by operating activities	366	353
Cash flows from investing activities		
Capital expenditures	(264)	(266)
Change in restricted cash	3	8
Other investing activities	4	(10)
Net cash flows used in investing activities	(257)	(268)
Cash flows from financing activities		
Issuance of long-term debt	300	—
Repayment of long-term debt	(33)	(141)
Dividends paid on preference stock	(6)	(6)
Contributions from parent	—	66
Other financing activities	(2)	—
Net cash flows provided by (used in) financing activities	259	(81)
Increase in cash and cash equivalents	368	4
Cash and cash equivalents at beginning of period	89	49
Cash and cash equivalents at end of period	$ 457	$ 53

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 457	$ 89
Restricted cash and cash equivalents of variable interest entity	27	30
Accounts receivable, net		
Customer	415	409
Other	145	111
Income taxes receivable	30	3
Inventories, net		
Gas held in storage	44	51
Materials and supplies	34	31
Deferred income taxes	13	1
Prepaid utility taxes	1	57
Regulatory assets	142	190
Other	6	8
Total current assets	1,314	980
Property, plant and equipment, net	5,637	5,498
Deferred debits and other assets		
Regulatory assets	536	522
Investments	5	5
Investments in affiliates	8	8
Prepaid pension asset	445	467
Other	23	26
Total deferred debits and other assets	1,017	1,028
Total assets	$ 7,968	$ 7,506

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS

(In millions)	June 30, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 400	$ 400
Long-term debt of variable interest entity due within one year	68	67
Accounts payable	138	195
Accrued expenses	105	106
Deferred income taxes	9	—
Payables to affiliates	59	65
Customer deposits	69	71
Regulatory liabilities	40	29
Other	60	47
Total current liabilities	948	980
Long-term debt	1,746	1,446
Long-term debt to financing trust	258	258
Long-term debt of variable interest entity	230	265
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,761	1,658
Asset retirement obligations	7	8
Non-pension postretirement benefits obligations	223	229
Regulatory liabilities	221	214
Other	116	90
Total deferred credits and other liabilities	2,328	2,199
Total liabilities	5,510	5,148
Commitments and contingencies		
Shareholders' equity		
Common stock	1,360	1,360
Retained earnings	908	808
Total shareholder's equity	2,268	2,168
Preference stock not subject to mandatory redemption	190	190
Total equity	2,458	2,358
Total liabilities and shareholders' equity	$ 7,968	$ 7,506

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$2,358
Net income	—	106	106	—	106
Preference stock dividends	—	(6)	(6)	—	(6)
Balance, June 30, 2013	$ 1,360	$ 908	$ 2,268	$ 190	$2,458

See the Combined Notes to Consolidated Financial Statements

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in millions, except per share data, unless otherwise noted)

1. Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses. Prior to March 12, 2012, Exelon's principal, wholly owned subsidiaries included ComEd, PECO and Generation. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger (the "Merger Agreement"). As a result of the merger transaction, Generation now includes the former Constellation generation and customer supply operations. BGE, formerly Constellation's regulated utility subsidiary, is now a subsidiary of Exelon. Refer to Note 4 — Merger and Acquisitions for further information regarding the merger transaction.

The energy generation business includes:

- *Generation* : Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other regions.

The energy delivery businesses include:

- *ComEd* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

For financial statement purposes, beginning on March 12, 2012, disclosures that solely relate to Constellation or BGE activities now also apply to Exelon, unless otherwise noted. When appropriate, Exelon, Generation, ComEd, PECO and BGE are named specifically for their related activities and disclosures.

Exelon did not apply push-down accounting to BGE. As a result, BGE continues to maintain its reporting requirements as an SEC registrant. The information disclosed for BGE represents the activity of the standalone entity for the three and six months ended June 30, 2013 and 2012 and the financial position as of June 30, 2013 and December 31, 2012. However, for Exelon's financial reporting, Exelon is reporting BGE activity for the three and six months ended June 30, 2013 and from March 12, 2012 through June 30, 2012 and the financial position as of June 30, 2013 and December 31, 2012.

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

For the six months ended June 30, 2013, BGE recorded a $2 million correcting adjustment to decrease amortization expense related to regulatory assets that was originally recorded during 2012. Exelon and BGE have concluded that this correcting adjustment is not material to their respective results of operations or cash flows for

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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the six months ended June 30, 2013 or any prior period. Exelon and BGE do not expect this correcting adjustment to have a material impact on their respective results of operations or cash flows for the year ended December 31, 2013.

The accompanying consolidated financial statements as of June 30, 2013 and 2012 and for the three and six months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2012 Consolidated Balance Sheets were obtained from audited financial statements. Certain prior year amounts in BGE's Consolidated Statements of Cash Flows, Exelon's, Generation's and BGE's Consolidated Statements of Operations and Comprehensive Income and in Exelon's, Generation's, ComEd's, and BGE's Consolidated Balance Sheets have been reclassified between line items for comparative purposes. The reclassifications did not materially affect any of the Registrants' net income or cash flows from operating activities. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for fiscal year ended December 31, 2013. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. These notes should be read in conjunction with the Notes to Combined Consolidated Financial Statements of all Registrants included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA of their respective 2012 Form 10-K Reports.

2. New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

The following recently issued accounting standards were adopted by the Registrants during the period.

Presentation of Unrecognized Tax Benefits When Net Operating Loss Carryforwards, Similar Tax Losses or Tax Credit Carryforwards Exist

In July 2013, the FASB issued authoritative guidance requiring entities to present unrecognized tax benefits as a reduction to deferred tax assets for losses or other tax carryforwards that would be available to settle the uncertain tax positions at the reporting date. Currently, the Registrants present their unrecognized tax benefits as liabilities on a gross basis unless an unrecognized tax benefit is directly associated with a tax position taken in a tax year that results in the recognition of a net operating loss or other tax carryforward for that year. This guidance is effective for the Registrants for periods beginning after December 15, 2013 and is required to be applied prospectively, with retroactive application permitted. The Registrants are currently assessing the impacts this guidance may have on their financial positions and cash flows. The adoption of this standard will not impact the Registrants' results of operations.

Inclusion of the Fed Funds Effective Swap Rate as a Benchmark Interest Rate for Hedge Accounting Purposes

In July 2013, the FASB issued authoritative guidance permitting entities to designate the Fed Funds Effective Swap Rate as a U.S. benchmark interest rate for hedge accounting purposes. Prior to the issuance of this guidance, only interest rates on direct treasury obligations of the U.S. government and the LIBOR swap rate were considered benchmark interest rates in the U.S. This guidance is effective immediately and can be applied prospectively for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. Currently, the Registrants do not use the Fed Funds Effective Swap Rate as a benchmark interest rate, but may in the future.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Presentation of Items Reclassified out of Accumulated Other Comprehensive Income

In February 2013, the FASB issued authoritative guidance requiring entities to present either in the notes or parenthetically on the face of the financial statements, reclassifications from each component of accumulated other comprehensive income and the affected income statement line items. Entities only need to disclose the affected income statement line item for components reclassified to net income in their entirety; otherwise, a cross-reference to the related note should be provided. This guidance is effective for the Registrants for periods beginning after December 15, 2012 and was required to be applied prospectively. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants' results of operations, cash flows or financial positions. See Note 16 — Changes in Accumulated Other Comprehensive Income for the new disclosures.

Disclosures About Offsetting Assets and Liabilities

In December 2011, the FASB issued (and amended in January 2013), authoritative guidance requiring entities to disclose both gross and net information about recognized derivative instruments, including bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing or lending transactions that are offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. This guidance is effective for the Registrants for periods beginning on or after January 1, 2013 and is required to be applied retrospectively. This guidance is primarily applicable to certain derivative transactions for Exelon and Generation. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants' results of operations, cash flows or financial positions. See Note 10 — Derivative Financial Instruments for the new disclosures.

3. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Under the applicable authoritative guidance, a VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly impact the entity's economic performance.

As of June 30, 2013 and December 31, 2012, the Registrants' consolidated five VIEs or VIE groups for which the Registrants were the primary beneficiary, and the Registrants had significant interests in eight other VIEs for which the Registrants do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary.

Consolidated Variable Interest Entities

Exelon, Generation and BGE's consolidated VIEs consist of:

- BondCo, a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, and issue and service bonds secured by rate stabilization property;
- a retail gas group formed to enter into a collateralized gas supply agreement with a third-party gas supplier;
- a retail power supply company;

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

- a group of solar project limited liability companies formed to build, own and operate solar power facilities, and,
- several wind project companies designed to develop, construct and operate wind generation facilities.

As of June 30, 2013, ComEd and PECO do not have any consolidated VIEs.

For each of the consolidated VIEs, except as otherwise noted:

- The assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE. In the case of BondCo, BGE is required to remit all payments it receives from all residential customers through non-bypassable, rate stabilization charges to BondCo. During the three and six months ended June 30, 2013, BGE remitted $17 million and $39 million, respectively, to BondCo. During the three and six months ended June 30, 2012, BGE remitted $15 million and $35 million, respectively, to BondCo.
- Except for providing capital funding to the solar entities for ongoing construction of the solar power facilities and a $75 million parental guarantee to the third-party gas supplier in support of the retail gas group, during the six months ended June 30, 2013 and year ended December 31, 2012:
  - Exelon, Generation and BGE did not provide any additional financial support to the VIEs;
  - Exelon, Generation and BGE did not have any contractual commitments or obligations to provide financial support to the VIEs; and
  - the creditors of the VIEs did not have recourse to Exelon's, Generation's or BGE's general credit.

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in Exelon, Generation, and BGE's consolidated financial statements at June 30, 2013 and December 31, 2012 are as follows:

	June 30, 2013			December 31, 2012		
	Exelon (a)(b)	Generation (b)	BGE	Exelon (a)(b)	Generation (b)	BGE
Current assets	$ 462	$ 426	$ 27	$ 550	$ 519	$ 30
Noncurrent assets	1,961	1,938	—	1,802	1,762	—
Total assets	$2,423	$ 2,364	$ 27	$2,352	$ 2,281	$ 30
Current liabilities	$ 474	$ 391	$ 73	$ 685	$ 613	$ 71
Noncurrent liabilities	981	728	230	837	532	265
Total liabilities	$1,455	$ 1,119	$303	$1,522	$ 1,145	$336

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total assets of $115 million and total liabilities of $57 million as of June 30, 2013 and total assets of $116 million and total liabilities of $62 million as of December 31, 2012 related to deferred and accrued taxes that have been recorded and are not restricted for use by three of the consolidated VIEs.

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include three transaction types: (1) equity method investments, (2) energy purchase and sale contracts, and (3) fuel purchase commitments. For the equity method investments, the carrying amount of the investments is reflected on their Consolidated Balance Sheets in Investments in affiliates. For the energy purchase and sale contracts and the fuel

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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purchase commitments (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, or provided liquidity arrangements, performance guarantees or other commitments associated with these commercial agreements.

The Registrants' unconsolidated VIEs consist of:

- Energy purchase and sale agreements with VIEs for which Generation has concluded that consolidation is not required.
- ZionSolutions, LLC asset sale agreement with EnergySolutions, Inc. and certain subsidiaries in which Generation has a variable interest but has concluded that consolidation is not required.
- Fuel purchase commitments where Generation has a variable interest, but the variable interest is not significant and Generation is not the primary beneficiary, thus consolidation is not required.
- ComEd's, PECO's and BGE's retail operations frequently include the purchase of electricity and RECs through procurement contracts of varying durations. None of ComEd, PECO or BGE considers itself the primary beneficiary of any VIEs as a result of these commercial arrangements.
- Investment in energy development projects for which Generation has concluded that consolidation is not required.

As of June 30, 2013 and December 31, 2012, Exelon and Generation did have significant variable interests in eight and nine, respectively, VIEs for which they were not the primary beneficiary; including certain equity method investments and certain commercial agreements. The following tables present summary information about the significant unconsolidated VIE entities:

June 30, 2013	Commercial Agreement VIEs	Equity Method Investment VIEs	Total
Total assets(a)	$ 202	$ 348	$550
Total liabilities(a)	83	108	191
Registrants' ownership interest(a)	—	97	97
Other ownership interests(a)	119	143	262
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	78	78
Contract intangible asset	8	—	8
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning(b)	47	—	47

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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December 31, 2012	Commercial Agreement VIEs	Equity Method Investment VIEs	Total
Total assets(a)	$ 386	$ 354	$740
Total liabilities(a)	219	114	333
Registrants' ownership interest(a)	—	97	97
Other ownership interests(a)	167	143	310
Registrants' maximum exposure to loss:			
Letters of credit	5	—	5
Carrying amount of equity method investments	—	77	77
Contract intangible asset	8	—	8
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning(b)	50	—	50

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.

(b) These items represent amounts on Generation's and Exelon's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $538 million and $614 million as of June 30, 2013 and December 31, 2012, respectively; offset by payables to ZionSolutions LLC of $491 million and $564 million as of June 30, 2013 and December 31, 2012, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

For each unconsolidated VIE, Exelon and Generation assess the risk of a loss equal to their maximum exposure to be remote and, accordingly Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would affect the fair value or risk of their variable interests in these variable interest entities.

4. Merger and Acquisitions

Merger with Constellation (Exelon, Generation, ComEd, PECO and BGE)

Description of Transaction

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation's interest in RF HoldCo LLC, which holds Constellation's interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon's interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

Regulatory Matters

In December 2011, Exelon and Constellation reached a settlement with the State of Maryland and the City of Baltimore and other interested parties in connection with the regulatory proceedings related to the merger that were pending before the MDPSC. As part of this settlement and the application for approval of the merger by MDPSC, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of more than $1 billion.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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The direct investment estimate includes $95 million to $120 million relating to the construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a 20 year lease agreement that is contingent upon the developer obtaining financing for the construction of the building. Once the financing conditions are met, construction will commence and the building is expected to be ready for occupancy within 2 years. The direct investment estimate also includes $625 million for Exelon's and Generation's commitment to develop or assist in development of 285 — 300 MWs of new generation in Maryland, expected to be completed over a period of 10 years. Such costs, which are expected to be primarily capital in nature, will be recognized as incurred. As of June 30, 2013, amounts reflected in the Exelon and Generation consolidated financial statements for these expenditure commitments were immaterial. On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland site with 120MW of new natural gas-fired generation to satisfy certain of these commitments, the total commitment under the contract is $89 million and achievement of commercial operation is expected in 2015.

The settlement agreement contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. If in the future Exelon determines that it is probable that it will make subsidy, compliance or liquidated damages payments related to the new generation development commitments, Exelon will record a liability at that time. As of June 30, 2013, it is reasonably possible that Exelon will be required to make subsidy or liquidated damages payments of approximately $40 million rather than build one of the generation projects contemplated by the commitments, given that the generation build is dependent upon the passage of legislation and other conditions that Exelon does not control.

Associated with certain of the regulatory approvals required for the merger, on November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, to Raven Power Holdings LLC (Raven Power), a subsidiary of Riverstone Holdings LLC. In 2012, Exelon and Generation recorded a pre-tax loss of $272 million to reflect the difference between the sales price and the carrying value of the generating stations and associated assets. In the first quarter of 2013, Exelon and Generation recorded a pre-tax gain of $8 million to reflect the final settlement of the sales price with Raven Power.

Accounting for the Merger Transaction

The fair value of Constellation's non-regulated business assets acquired and liabilities assumed was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The financial statements of BGE do not include fair value adjustments for assets or liabilities subject to rate-setting provisions for BGE. BGE is subject to the rate-setting authority of FERC and the MDPSC and is accounted for pursuant to the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for BGE provide revenue derived from costs including a return on investment of assets and liabilities included in rate base. Except for debt, fuel supply contracts and regulatory assets not earning a return, the fair values of BGE's tangible and intangible assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore, do not reflect any net adjustments

related to these amounts. For BGE's debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE's assets acquired and liabilities assumed is recorded as a regulatory asset and liability at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 1 — Basis of Presentation for additional information on BGE's push-down accounting treatment. Also see Note 5 — Regulatory Matters for additional information on BGE's regulatory assets.

The preliminary valuations performed in the first quarter of 2012 were updated in the second, third and fourth quarters of 2012, with the most significant adjustments to the preliminary valuation amounts having been made to the fair values assigned to the acquired power supply and fuel contracts, unregulated property, plant and equipment and investments in affiliates. There were no significant adjustments to the purchase price allocation in the first quarter of 2013 and the purchase price allocation was final as of March 31, 2013.

The final purchase price allocation of the Merger of Exelon with Constellation and Exelon's contribution of certain subsidiaries of Constellation to Generation was as follows:

Purchase Price Allocation, excluding amortization	Exelon	Generation
Current assets	$ 4,936	$ 3,638
Property, plant and equipment	9,342	4,054
Unamortized energy contracts	3,218	3,218
Other intangibles, trade name and retail relationships	457	457
Investment in affiliates	1,942	1,942
Pension and OPEB regulatory asset	740	—
Other assets	2,265	1,266
Total assets	22,900	14,575
Current liabilities	3,408	2,804
Unamortized energy contracts	1,722	1,512
Long-term debt, including current maturities	5,632	2,972
Noncontrolling interest	90	90
Deferred credits and other liabilities and preferred securities	4,683	1,933
Total liabilities, preferred securities and noncontrolling interest	15,535	9,311
Total purchase price	$ 7,365	$ 5,264

Intangible Assets Recorded

For the power supply and fuel contracts acquired from Constellation, the difference between the contract price and the market price at the date of the merger was recognized as either an intangible asset or liability based on whether the contracts were in or out-of-the-money. The fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the merger date. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Exelon and Generation present separately in their Consolidated Balance Sheets the unamortized energy contract assets and liabilities for these contracts. Exelon's and Generation's amortization expense for the three and six months ended June 30, 2013 amounted to $162 million and $332 million, respectively. Exelon's and Generation's amortization expense for the three months ended June 30, 2012 and for the period March 12, 2012 to June 30, 2012 amounted to $370 million and $501 million, respectively. In addition, Exelon Corporate has established a regulatory asset and an unamortized energy contract liability related to BGE's power supply and fuel contracts. The power supply and fuel contracts regulatory asset amortization was $19 million and $38 million for the three and six months ended June 30, 2013, respectively, and $9 million and $12 million for the three months ended June 30, 2012 and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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for the period March 12, 2012 to June 30, 2012, respectively. An equally offsetting amortization of the unamortized energy contract liability has been recorded at Exelon Corporate in the Consolidated Statement of Operations. The weighted-average amortization period is approximately 1.5 years.

Exelon's and Generation's amortization expense for the fair value of the Constellation trade name intangible asset for the three and six months ended June 30, 2013 amounted to $6 million and $12 million, respectively. Exelon's and Generation's straight line amortization expense for the fair value of the Constellation trade name intangible asset for the three months ended June 30, 2012 and the period March 12, 2012 to June 30, 2012 amounted to $6 million and $8 million, respectively. The amortization period is approximately 10 years. The trade name intangible asset is included in deferred debits and other assets within Exelon's and Generation's Consolidated Balance Sheets.

The intangible assets for the fair value of the retail relationships are amortized as amortization expense on a straight line basis over the useful life of the underlying assets averaging approximately 12.4 years. Exelon's and Generation's straight line amortization expense for the three and six months ended June 30, 2013 amounted to $4 million and $9 million, respectively. Exelon's and Generation's straight line amortization expense for the three months ended June 30, 2012 and the period March 12, 2012 to June 30, 2012 amounted to $6 million and $7 million, respectively. The retail relationships intangible assets are included in deferred debits and other assets within Exelon's and Generation's Consolidated Balance Sheets.

Exelon's intangible assets and liabilities acquired through the merger with Constellation included in its Consolidated Balance Sheets, along with the future estimated amortization, were as follows as of June 30, 2013:

					Estimated amortization expense					
Description	Weighted Average Amortization (Years)	Gross	Accumulated Amortization	Net	Remainder of 2013	2014	2015	2016	2017	2018 and Beyond
Unamortized energy contracts, net(a)	1.5	$1,499	$ (1,279)	$220	$ 99	$ 75	$18	$(30)	$(21)	$ 79
Trade name	10.0	243	(32)	211	12	24	24	24	24	103
Retail relationships	12.4	214	(23)	191	10	19	19	19	19	105
Total, net		$1,956	$ (1,334)	$622	$ 121	$118	$61	$ 13	$ 22	$ 287

(a) Includes the fair value of BGE's power and gas supply contracts of $52 million for which an offsetting regulatory asset was also recorded.

Impact of Merger

It is impracticable to determine the overall financial statement impact for the Constellation subsidiaries contributed down to Generation following the Upstream Merger for the three and six months ended June 30, 2013 and 2012. Upon closing of the merger, the operations of these Constellation subsidiaries were integrated into Generation's operations and are therefore not fully distinguishable after the merger.

The impact of BGE on Exelon's Consolidated Statement of Operations and Comprehensive Income included operating revenues of $653 million and net income of $25 million during the three months ended June 30, 2013, and operating revenues of $1,533 million and net income of $106 million during the six months ended June 30, 2013.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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The impact of BGE on Exelon's Consolidated Statement of Operations and Comprehensive Income included operating revenues of $616 million and net income of $16 million during the three months ended June 30, 2012, and operating revenues of $668 million and net loss of $49 million during the six months ended June 30, 2012.

During the three months ended June 30, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $30 million, $20 million, $5 million, $2 million and $1 million, respectively. During the six months ended June 30, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $63 million, $43 million, $9 million, $5 million and $3 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $10 million, $8 million and $2 million as a regulatory asset as of June 30, 2013. Additionally, Exelon and BGE established a regulatory asset of $6 million as of June 30, 2013 for previously incurred 2012 merger and integration-related costs.

During the three months ended June 30, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $119 million, $94 million, $8 million, $4 million and $2 million, respectively. During the six months ended June 30, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $635 million, $204 million, $26 million, $11 million and $171 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $41 million, $23 million and $18 million as a regulatory asset as of June 30, 2012. The costs incurred are classified primarily within Operating and Maintenance Expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the BGE customer rate credit and the credit facility fees, which are included as a reduction to operating revenues and other, net, respectively, for the three and six months ended June 30, 2012.

Severance Costs

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit. Exelon adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. In addition, certain employees identified during the staffing and selection process also receive pension and other postretirement benefits that are deemed contractual termination benefits, which the Registrants recorded during the second quarter of 2012.

There was no severance expense associated with the post-merger integration recognized for the three months ended June 30, 2013 for Exelon, Generation, ComEd, PECO and BGE. The amount of severance expense associated with the post-merger integration recognized for the six months ended June 30, 2013 for Exelon, Generation, ComEd, PECO and BGE were $3 million, $3 million, $0 million, $0 million and $0 million, respectively. For Generation, the $3 million represents amounts billed by BSC through intercompany allocations. Estimated costs to be incurred after June 30, 2013 are not material.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

For the three and six months ended June 30, 2012, the Registrants recorded the following severance benefits costs associated with the identified job reductions within operating and maintenance expense in their Consolidated Statements of Operations, except for ComEd and BGE:

Three Months Ended June 30, 2012

Severance Benefits(a)	Exelon	Generation	ComEd(b)	PECO	BGE(c)
Severance charges	$ 42	$ 29	$ 6	$ 4	$ 3
Stock compensation	(5)	(3)	(1)	(1)	(1)
Other charges(d)	(1)	(1)	—	(1)	—
Total severance benefits	$ 36	$ 25	$ 5	$ 2	$ 2

Six Months Ended June 30, 2012

Severance Benefits(a)	Exelon	Generation	ComEd(b)	PECO	BGE(c)
Severance charges	$ 109	$ 64	$ 15	$ 7	$ 17
Stock compensation	3	2	—	—	—
Other charges(d)	7	4	1	—	1
Total severance benefits	$ 119	$ 70	$ 16	$ 7	$ 18

(a) The amounts above include $10 million and $40 million at Generation, $3 million and $14 million at ComEd, $2 million and $7 million at PECO, and $1 million and $6 million at BGE, for amounts billed by BSC through intercompany allocations for the three and six months ended June 30, 2012, respectively.
(b) ComEd established regulatory assets of $5 million and $16 million for severance benefits costs for the three and six months ended June 30, 2012, respectively. The majority of these costs are expected to be recovered over a five-year period.
(c) BGE established regulatory assets of $2 million and $18 million for severance benefits costs for the three and six months ended June 30, 2012, respectively. The majority of these costs are being recovered over a five-year period beginning in March 2013.
(d) Primarily includes life insurance, employer payroll taxes, educational assistance and outplacement services.

Amounts included in the table below represent the severance liability recorded by Exelon, Generation, ComEd, PECO and BGE for employees of those Registrants and exclude amounts billed through intercompany allocations:

Six Months Ended June 30, 2013

Severance liability	Exelon	Generation	ComEd	PECO	BGE
Balance at December 31, 2012	$ 111	$ 33	$ 1	$ —	$11
Severance charges(a)	2	—	—	—	—
Stock compensation	1	—	—	—	—
Payments	(37)	(13)	—	—	(3)
Balance at June 30, 2013	$ 77	$ 20	$ 1	$ —	$ 8

(a) Includes salary continuance and health and welfare severance benefits. Amounts represent ongoing severance plan benefits. Amounts also include one-time termination benefits of $1 million for Exelon as of June 30, 2013.

Cash payments under the plan began in the second quarter of 2012. Substantially all cash payments under the plan are expected to be made by the end of 2016.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon and Generation as if the merger with Constellation had taken place on January 1, 2011. The unaudited pro forma information was calculated after applying Exelon's and Generation's accounting policies and adjusting Constellation's results to reflect purchase accounting adjustments.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Three Months Ended June 30, 2012	
	Generation	Exelon
Total Revenues	$ 4,051	$ 6,256
Net income attributable to Exelon	397	528
Basic Earnings Per Share	n.a.	$ 0.62
Diluted Earnings Per Share	n.a.	0.62

	Six Months Ended June 30, 2012	
	Generation	Exelon
Total Revenues	$ 8,523	$13,284
Net income attributable to Exelon	567	979
Basic Earnings Per Share	n.a.	$ 1.26
Diluted Earnings Per Share	n.a.	1.25

5. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

Regulatory and Legislative Proceedings (Exelon, Generation, ComEd, PECO and BGE)

Except for the matters noted below, the disclosures set forth in Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K appropriately represent, in all material respects, the current status of regulatory and legislative proceedings of the Registrants. The following is an update to that discussion.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd). Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement (s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. As of June 30, 2013, and December 31, 2012, ComEd had recorded a net regulatory asset associated with the distribution formula rate of $329 million and $209 million, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

During March 2013, the Illinois House and Senate each passed Senate Bill 9 with supermajority votes to clarify the intent of EIMA on three major issues: the use of year-end rather than average rate base and capital structure in the annual reconciliation, the use of ComEd's weighted average cost of capital interest rate to apply to the annual reconciliation and an allowed return on ComEd's pension asset. On May 22, 2013, the Illinois General Assembly overrode the Governor's May 5, 2013 veto of Senate Bill 9, which resulted in the legislation becoming effective immediately. The enactment of Senate Bill 9 resulted in increased operating revenue of $10 million for the three and six months ended June 30, 2013. ComEd projects the override of Senate Bill 9 will result in increased operating revenues of approximately $15 million for the remainder of 2013 and $65 million in 2014. Also, ComEd projects that Senate Bill 9 will accelerate capital expenditures by approximately $40 million and $45 million in 2013 and 2014, respectively .

On May 30, 2013, ComEd updated the distribution formula structure to reflect the impacts of Senate Bill 9. On June 5, 2013, the ICC approved the May 30 filing implementing ComEd's formula structure change as well as the resulting reduction to the current revenue requirement in effect of $14 million, which was reflected in customer rates effective July 1, 2013.

In addition, on May 31, 2013, ComEd updated its April 29, 2013 distribution formula rate filing to reflect the impacts of Senate Bill 9. The May 31 filing establishes the revenue requirement used to set the rates that will take effect in January 2014 after the ICC's review and approval, which is due by December 25, 2013. The revenue requirement requested in the filing is based on 2012 actual costs and projected 2013 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2012 to the actual costs incurred for that year. ComEd requested a total increase to the revenue requirement including the impacts of Senate Bill 9, of $359 million, reflecting an increase of $165 million for the initial revenue requirement for 2013 and an increase of $194 million for the annual reconciliation for 2012. The revenue requirement provides for a weighted average debt and equity return on distribution rate base of 6.91% inclusive of an allowed return on common equity of 8.72%, reflecting the average rate on 30-year treasury notes plus 580 basis points.

On April 1, 2013, ComEd filed annual progress reports on both its AMI Implementation Plan and Infrastructure Investment Plan as required by EIMA. On April 9, 2013, the ICC initiated an investigation to review ComEd's progress on its AMI Implementation Plan. The ICC did not initiate an investigation on ComEd's Infrastructure Investment Plan. On June 5, 2013, the ICC issued an interim order approving ComEd's accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. In September 2013, ComEd will begin smart grid deployment with 60,000 meters to be installed by the end of 2013. On June 26, 2013, the ICC issued a final order on the overall progress of ComEd's AMI Implementation Plan with no significant findings.

2010 Illinois Electric Distribution Rate Case (Exelon and ComEd) . On June 30, 2010, ComEd filed its 2010 electric distribution rate case (2010 Rate Case) requesting ICC approval for an increase of $396 million to its annual delivery services revenue requirement. This request was subsequently reduced to $343 million to account for changes in tax law, corrections, acceptance of limited adjustments proposed by certain parties and the amounts expected to be recovered in the AMI pilot program tariff. The request to increase the annual revenue requirement was to allow ComEd to recover the costs of substantial investments made since its last rate filing in 2007. The requested increase also reflected increased costs, most notably pension and OPEB, since ComEd's rates were last determined. The original requested rate of return on common equity was 11.5%. In addition, ComEd requested future recovery of certain amounts that were previously recorded as expense that would allow ComEd to recognize a one-time benefit of up to $40 million (pre-tax). The requested increase also included $22 million for increased uncollectible accounts expense, which would increase the threshold for determining over/under recoveries under ComEd's uncollectible accounts tariff.

On May 24, 2011, the ICC issued an order, which became effective on June 1, 2011. The order approved a $143 million increase to ComEd's annual delivery services revenue requirement and a 10.5% rate of return on

common equity. As expected, the ICC followed the Illinois Appellate Court's ruling in ComEd's 2007 electric distribution rate case (2007 Rate Case) on the post-test year accumulated depreciation issue. The order allowed ComEd to establish or reestablish a net amount of approximately $40 million of previously expensed plant balances or new regulatory assets, which was reflected as a reduction in operating and maintenance expense and income tax expense in 2011. The order also affirmed the current regulatory asset for severance costs, which was challenged by an intervener in the 2010 Rate Case. The order was appealed to the Illinois Appellate Court by several parties on a number of issues. On May 16, 2013, the Illinois Appellate Court dismissed as moot the appeals of the ICC's order in the 2010 Rate Case as ComEd now recovers distribution costs under EIMA through a pre-established formula rate tariff. See Note 3 of Exelon's 2012 Form 10-K for further details on ComEd's 2007 Rate Case and 2010 Rate Case.

Illinois Procurement Proceedings (Exelon and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. The IPA's 2013 procurement plan, approved by the ICC, provides for curtailment of the existing long-term contracts for renewable energy and RECs in response to the increased number of ComEd's customers purchasing their energy from alternative energy suppliers on their own or through municipal aggregation. In March 2013, ICC staff and the IPA approved ComEd's updated load forecast. Purchases under the existing long-term contracts for energy and the associated RECs were reduced on a pro-rata basis under the terms of those contracts for the June 2013 – May 2014 period to keep the purchases under the statutory rate impact cap. The curtailment's impact on ComEd's financial position and cash flows was immaterial.

On December 19, 2012, the ICC issued an order directing ComEd and Ameren (the Utilities) to enter into sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The proposed term of the sourcing agreement is 20 years. The project was approved by the DOE on February 4, 2013. The sourcing agreement was approved by the ICC on June 26, 2013 in a separate proceeding, with the ICC ordering ComEd to execute the sourcing agreement no later than 60 days after the date of the order. The sourcing agreement stipulates that the utilities will pay FutureGen's contract prices, which are set annually based on a formula rate construct. The contract prices are based on the difference between the costs of the facility and the revenues FutureGen receives from selling capacity and energy from the unit into the MISO or other markets, as well as any other revenue FutureGen receives from the operation of the facility. The order also directs the utilities to recover (or pass along) these costs from the utilities' distribution system customers, regardless of whether they purchase electricity from the utility or from an alternative electric generation supplier. On January 22, 2013, ComEd filed an application for rehearing, requesting the ICC reconsider its December order requiring the utilities to procure the entire output of the FutureGen facility. On January 29, 2013, the ICC denied ComEd's rehearing request. ComEd filed an appeal on February 22, 2013, questioning the legality of requiring ComEd to procure power for its non-eligible retail customers. Depending on the ultimate outcome of the appeals, the eventual market conditions and the cost of the facility, the sourcing agreement could have a material adverse impact on Exelon's and ComEd's cash flows and financial positions.

See Note 18 — Commitments and Contingencies for additional information on ComEd's energy commitments.

Pennsylvania Regulatory Matters

Pennsylvania Procurement Proceedings (Exelon and PECO). PECO's current PAPUC approved DSP Program, under which PECO is providing default electric service, has a 29-month-term that ended May 31, 2013. On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO's second DSP Program, which

was filed with the PAPUC in January 2012. The program, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129.

In the second DSP Program, PECO will procure electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes will be served through competitively procured fixed price, full requirements contracts of two years or less. For the large commercial and industrial class load, PECO will competitively procure contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in June 2013. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Statement of Operations and Comprehensive Income.

In addition, the second DSP Program includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs beginning April 2014. On May 1, 2013, PECO filed its CAP Shopping Plan with the PAPUC.

Smart Meter and Smart Grid Investments (Exelon and PECO). Pursuant to Act 129 and the follow-on Implementation Order of 2009, in April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million smart meters and an AMI communication network by 2020. The first phase of PECO's SMPIP, which was completed on June 19, 2013, included the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC. The Joint Petition for Settlement supports all material aspects of PECO's universal deployment plan, including cost recovery, excluding certain amounts discussed below. Universal deployment is the second phase of PECO's SMPIP, under which PECO will deploy the remainder of the 1.6 million smart meters on an accelerated basis by the end of 2014. In total, PECO currently expects to spend up to $595 million, excluding the cost of the original meters (as further described below), on its smart meter infrastructure and approximately $120 million on smart grid investments through 2014 of which $200 million will be funded by SGIG as discussed below. As of June 30, 2013, PECO has spent $312 million and $107 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO's existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of June 30, 2013, PECO has received $167 million of the $200 million in reimbursements. PECO's outstanding receivable from the DOE for reimbursable costs was $10 million as of June 30, 2013, which has been recorded in Other accounts receivable, net on Exelon's and PECO's Consolidated Balance Sheets.

On August 15, 2012, PECO suspended installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO has replaced the previously installed

meters with an alternative vendor's meters. PECO intends to move forward with the alternative meters during universal deployment and continues to evaluate meters from several vendors and may use more than one meter vendor during universal deployment.

Following PECO's decision, as of October 9, 2012, PECO will no longer use the original smart meters. For the meters that will no longer be used, the accounting guidance requires that any difference between the carrying value and net realizable value be recognized in the current period's earnings, before considering potential regulatory recovery. The cost of the original meters, including installation and removal costs, owned by PECO was approximately $19 million, net of approximately $16 million of reimbursements from the DOE. PECO is seeking full recovery of all incurred costs related to the original deployment of meters. For amounts not recovered from the vendor, PECO will seek regulatory rate recovery in a future filing with the PAPUC. PECO did not seek recovery of original meter costs in the January 2013 universal deployment filing, as resolution with the vendor is still pending. In November 2012, PECO requested and received approval from the DOE that the original meters continue to be allowable costs. In addition, PECO remains eligible for the full $200 million in SGIG funds. In the May 31, 2013 Joint Petition for Settlement of the universal deployment plan, the parties agreed to defer any potential challenges to cost recovery of the original meters as discussed above.

As of June 30, 2013, PECO believes the amounts incurred for the original meters and related installation and removal costs are probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As a result, a regulatory asset of $17 million, representing the cost of the original meters, net of accumulated depreciation and DOE reimbursements, was recorded on Exelon's and PECO's Consolidated Balance Sheets. If PECO later determines that the regulatory asset is no longer probable of recovery, PECO would be required to recognize a charge in earnings in the period in which that determination was made.

Energy Efficiency Programs (Exelon and PECO). PECO's PAPUC-approved Phase I EE&C Plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I Plan set forth how PECO would meet the required reduction targets established by Act 129's EE&C provisions, which included a 3% reduction in electric consumption in PECO's service territory and a 4.5% reduction in PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013. The peak demand period ended on September 30, 2012 and PECO communicated its compliance with the reduction targets in a preliminary report with the PAPUC on March 1, 2013. The final compliance report is due to the PAPUC by November 15, 2013.

On March 29, 2013, PECO filed a Petition with the PAPUC to change the recovery period of certain Direct Load Control (DLC) Program costs necessary to implement the Phase I Plan. The Petition seeks approval to allow PECO to recover $12 million in equipment, installation and information technology costs for its Residential DLC program with the amounts collected for the Phase I Plan. As the Phase I Plan was implemented at a cost less than originally budgeted, PECO proposed to recover these expenses from its Phase I Energy Efficiency Program Charge over-collection consistent with PAPUC guidance to recover all Phase I costs through Phase I funding. The PAPUC approved PECO's Petition on May 9, 2013. A regulatory liability was established for the DLC program costs that will be amortized as a credit to the income statement to offset the related depreciation expense during the same period.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129's EE&C programs, which went into effect on June 1, 2013. The PAPUC deferred a decision on peak demand reduction requirements until mid-2013. On February 28, 2013, the PAPUC approved PECO's three-year EE&C Phase II plan that was filed on November 1, 2012, and sets forth how PECO will reduce electric consumption by at least 2.9% in its service territory for the period June 1, 2013 through May 31, 2016.

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On March 15, 2013, PECO filed a Petition for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers from June 1, 2013 to May 31, 2014. PECO proposed to fund the estimated $10 million cost of the one-year program by modifying incentive levels for other Phase II programs. On May 9, 2013, the PAPUC approved PECO's amended EE&C Phase II plan. The costs of DLC program will be recovered through PECO's Energy Efficiency Program Charge along with all other Phase II Plan costs.

Investigation of Pennsylvania Retail Electricity Market (Exelon and PECO). On July 28, 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania's retail electric market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. On March 1, 2012, the PAPUC issued the final order describing more detailed recommendations to be implemented prior to the expiration of the electric distribution company's current default service plan and providing guidelines for electric distribution companies for development of their next default service plan. On October 12, 2012, the PAPUC approved PECO's second DSP Program, which includes several new programs to continue PECO's support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011. Further, the PAPUC issued a final order on February 14, 2013, outlining its proposed end-state for default service, which included default service pricing for residential and small commercial customers based on three month full requirements contracts, full requirement contracts using hourly spot market pricing for large commercial and industrial default service customers, and the inclusion of CAP customers in the customer choice programs.

Pennsylvania Act 11 of 2012 (Exelon and PECO). On February 13, 2012, Act 11 was signed into law by the Governor. Act 11 seeks to clarify the PAPUC's authority to approve alternative ratemaking mechanisms, which would allow for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems in Pennsylvania. Act 11 also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the first year that rates are in effect. The PAPUC's implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure, approved by the PAPUC prior to implementing a DSIC. On May 9, 2013, the PAPUC approved PECO's LTIIP for its Gas Operations, which was filed on February 8, 2013.

Maryland Regulatory Matters

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of June 30, 2013 and December 31, 2012, BGE recorded a regulatory asset of $45 million and $31 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. Additionally, the MDPSC has determined that the cost recovery for the non-AMI meters that BGE retires will be considered in a future depreciation proceeding. The MDPSC continues to evaluate the impacts of a customer opt-out feature in BGE's Smart Grid program. In March 2013, BGE filed a description of the overall additional costs associated with allowing customers to retain their current meter, and for radio frequency (RF)-Free and RF-Minimizing options related to the installation of their smart meters as well as a proposed cost

recovery mechanism. The MDPSC will hold a hearing in August 2013 to consider the filings made by BGE and other Maryland electric utilities. The ultimate resolution related to this feature could affect BGE's ability to demonstrate cost-effectiveness of the advanced metering system. Overall, BGE continues to believe the recovery of smart grid initiative costs in future rates is probable as BGE expects to be able to demonstrate that the program benefits exceed costs. Pursuant to the ARRA of 2009, BGE is a recipient of $200 million in federal funding from the DOE for its smart grid and other related initiatives, which substantially reduces the total cost of these initiatives to BGE's ratepayers. The project to install the smart meters began in late April 2012.

As of June 30, 2013, BGE had received $176 million in reimbursements from the DOE. As of June 30, 2013, BGE's outstanding receivable from the DOE for reimbursable costs was $17 million, which has been recorded in Other accounts receivable, net on Exelon's and BGE's Consolidated Balance Sheets.

New Electric Generation (Exelon, Generation and BGE). On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that CPV projected will be in commercial operation by June 1, 2015. The initial term of the proposed contract is 20 years. The CfD mandates that BGE and the other utilities pay (or receive) the difference between CPV's contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The MDPSC's Order requires the three Maryland utilities to enter into a CfD in amounts proportionate to their relative SOS load.

On April 16, 2013, the MDPSC issued an order that required BGE to execute a specific form of contract with CPV, and the parties executed the contract as of June 6, 2013. As of June 30, 2013, there is no impact on Exelon's and BGE's results of operations, cash flows and financial positions. Furthermore, the agreement does not become effective until the resolution of certain items, including all current litigation.

On April 27, 2012, a civil complaint was filed in the United States District Court for the District of Maryland by certain unaffiliated parties that challenges the actions taken by the MDPSC on Federal law grounds. Among other requests for relief, the plaintiffs seek to enjoin the MDPSC from executing or otherwise putting into effect any part of its order. The MDPSC and CPV filed motions to dismiss the Federal lawsuit, which were both denied by the U.S. District Court on August 3, 2012. Trial of this matter occurred in March 2013, and a decision from the trial judge is now pending.

On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order. That petition was subsequently transferred to the Circuit Court for Baltimore City and consolidated with similar appeals that have been filed by other interested parties. The Circuit Court proceeding is currently in the pre-hearing briefing stage, and a hearing before the Circuit Court Judge is scheduled for September 10, 2013.

Depending on the ultimate outcome of the pending litigation, on the eventual market conditions and on the manner of cost recovery as of the effective date of the agreement, the CfD could have a material impact on Exelon and BGE's results of operations, cash flows and financial positions.

Exelon believes that this and other states' projects may have artificially suppressed capacity prices in PJM and may continue to do so in future auctions to the detriment of Exelon's market driven position. In addition to this litigation, Exelon is working with other market participants to implement market rules that will appropriately limit the market suppressing effect of such state activities.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. On February 22, 2013, the

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MDPSC issued an order in BGE's 2012 electric and natural gas distribution rate case for increases in annual distribution service revenue of $81 million and $32 million, respectively. The electric distribution rate increase was set using an allowed return on equity of 9.75% and the gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved electric and natural gas distribution rates became effective for services rendered on or after February 23, 2013. As part of the rate order, the MDPSC approved both recovery of and return on merger integration costs incurred during the test year, including severance. As a result, the order affirmed the treatment of $20 million of severance-related costs that BGE had recorded as a regulatory asset in 2012, consistent with prior MDPSC decisions. Additionally, BGE established a new regulatory asset related to non-severance merger integration costs, which is $8 million as of June 30, 2013 and includes $6 million of costs incurred during 2012. Current Maryland PSC treatment of these merger integration regulatory assets is to provide recovery over a five year period.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 that requires BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improving reliability and grid resiliency that are due at various times before August 30, 2013.

BGE's May 17, 2013 distribution rate case included a short-term plan to improve reliability as well as a proposal for a surcharge to recover incremental capital expenditures and operating costs associated with the short-term plan. BGE cannot predict the outcome of these proceedings, which may result in increased capital expenditures and operating costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law; which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. The new surcharge rates are expected to take effect in the first quarter of 2014. BGE cannot predict the outcome of this proceeding or how much of the requested planned and related surcharge the MDPSC will approve.

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, BGE filed an application for increases of $101 million and $30 million to its electric and gas base rates, respectively, with the MDPSC. The requested rates of return on equity in the application are 10.50% and 10.35% for electric and gas distribution, respectively. In addition to these requested rate increases, BGE's application includes a request for recovery of incremental capital expenditures and operating costs associated with BGE's proposed short-term reliability improvement plan in response to a MDPSC order through a surcharge separate from base rates. The new electric and gas distribution base rates are expected to take effect in December 2013. BGE cannot predict the outcome of this proceeding or how much of the requested increases the MDPSC will approve.

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Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd's and BGE's transmission rates are each established based on a FERC-approved formula.

ComEd's most recent annual formula rate update filed in April 2013 reflects 2012 actual costs plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $488 million plus a $25 million adjustment related to the reconciliation of 2012 actual costs for a net revenue requirement of $513 million. This compares to the May 2012 updated revenue requirement of $450 million offset by a $5 million reduction related to the reconciliation of 2011 actual costs for a net revenue requirement of $445 million. The increase in the revenue requirement was primarily driven by increased plant investment, higher pension and post-retirement healthcare costs, and higher operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory asset associated with the true-up is being amortized as the associated amounts are recovered through rates.

ComEd's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.70%, a decrease from the 8.91% return previously authorized. The decrease in return was primarily due to lower interest rates on ComEd's long-term debt outstanding. As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 55%.

BGE's most recent annual formula rate update filed in April 2013 reflects actual 2012 expenses and investments plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $158 million offset by a $1 million reduction related to the reconciliation of 2012 actual costs for a net revenue requirement of $157 million. This compares to the April 2012 updated revenue requirement of $156 million increased by $2 million related to the reconciliation of 2011 actual costs for a net revenue requirement of $158 million. The decrease in the revenue requirement was primarily driven by a lower authorized rate of return and reduced rate base, offset partially by higher depreciation and operating and maintenance costs. The 2013 net revenue requirement became effective June 1, 2013, and is being recovered over the period extending through May 31, 2014. The regulatory asset associated with the true-up is being amortized as the associated amounts are recovered through rates.

BGE's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.35%, a decrease from the 8.43% return previously authorized. The decrease in return was primarily due to a debt issuance in 2012 and lower interest rates on BGE's debt outstanding. As part of the FERC-approved settlement in 2006 of BGE's 2005 transmission rate case and updated by FERC's November 2007 order in BGE's 2007 incentive rate filing, the base rate of return on common equity for BGE's electric transmission business is 11.3%.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity for most investments included in its rate base. The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the earliest date from which the base return on equity could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint. As of June 30, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base return on equity, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE's base return on equity to 8.7%, the estimated annual impact would be a reduction in revenues of approximately $10 million.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, that court issued its decision affirming FERC's order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On March 30, 2012, FERC issued an order on remand affirming the cost allocation in its April 2007 order. On March 22, 2013, FERC issued an order denying rehearing and made it clear that the cost allocation at issue concerns only projects approved prior to February 1, 2013. A number of entities have filed appeals of the FERC orders. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent that any rate design changes are retroactive to periods prior to January 1, 2011, there may be an impact on PECO's results of operations. BGE anticipates that all impacts of any rate design changes effective after the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE's results of operations, cash flows or financial position.

On October 11, 2012, the PJM Transmission Owners filed with FERC a cost allocation for new transmission facilities asking that the new cost allocation methodology apply to all transmission approved by the PJM Board on or after February 1, 2013. The proposed methodology is a hybrid methodology that would socialize 50% of the costs of new facilities at 500kV and above and double-circuit 345kV lines, and allocate the remaining 50% to direct beneficiaries. For all other facilities, the costs would be allocated to the direct beneficiaries. On March 22, 2013, FERC issued an order accepting the cost allocation with minor exceptions and requiring a compliance filing on those few issues within 120 days of the order. The compliance filing was made on July 22, 2013.

PJM Minimum Offer Price Rule (Exelon and Generation). PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The proceedings leading to FERC's approval of the MOPR were extensive, and there have been numerous changes to the MOPR and litigation related to it since it was originally implemented. For example, in 2011 the parties disputed numerous elements of the MOPR including: (i) the default price that should apply to bids found subject to the MOPR, (ii) the duration of the MOPR and (iii) the application of the MOPR to self-supplying capacity and state-sponsored capacity. The FERC orders approving that MOPR have been appealed to the Third Circuit Court of Appeals. A resolution of that appeal is not expected until sometime in late 2013.

In May 2012 (based on the MOPR provisions the FERC approved in 2011), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2016. Several new units with state-sanctioned subsidy contracts cleared in the auction at prices below the MOPR. Potentially, these states could expand such state-sanctioned subsidy programs or other states may seek to establish similar programs. Generation believed that further revisions to that MOPR were necessary to ensure that the potential to artificially reduce capacity

auction prices is appropriately limited in PJM. In early December 2012, PJM filed a new MOPR for approval at the FERC, which Exelon believed would be more effective in preventing state-sanctioned subsidy contracts from artificially reducing capacity prices. Generation was actively involved in the process through which those MOPR changes were developed and supported the changes. On May 3, 2013, the FERC issued its order. While the FERC order accepted certain aspects of the proposal that Exelon supported (such as applying the MOPR to all of PJM and not just certain zones within PJM), the FERC required PJM to retain a key element of its previous MOPR structure, the unit-specific exemption, an element that Exelon had supported removing. Several entities, including two capacity suppliers that Exelon has been working with sought rehearing of that order.

In May 2013 (based on the MOPR provisions the FERC approved earlier that month), PJM announced the results of its capacity auction covering the delivery year ending May 31, 2017. Exelon is working with PJM stakeholders on several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts) cannot inappropriately affect capacity auction prices in PJM.

Reliability Pricing Model (Exelon, Generation and BGE). PJM's RPM auctions take place 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2017 occurred in May 2013.

License Renewals (Exelon and Generation). On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively. In June 2012, the United States District Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. The temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear plants for up to 60 years beyond the original and renewed licensed operating life of the plants and that licensing renewal decisions do not require discussion of the environmental impact of spent fuel stored on site. In August 2012, the NRC placed a hold on issuing new or renewed operating licenses that depend on the temporary storage rule until the court's decision is addressed. In September 2012, the NRC directed NRC Staff to revise the temporary storage rule through rulemaking no later than September 6, 2014. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

On May 29, 2013, Generation submitted applications to the NRC to extend the operating licenses of Byron Units 1 and 2 and Braidwood Units 1 and 2 by 20 years. The current operating licenses for Byron Units 1 and 2 expire in 2024 and 2026, respectively. The current operating licenses for Braidwood Units 1 and 2 expire in 2026 and 2027, respectively. Generation does not expect the NRC to issue license renewals for Byron and Braidwood until 2015 at the earliest.

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively. Generation is working with stakeholders to resolve licensing issues, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. In the third quarter of 2013, Exelon expects to file a water quality certification application pursuant to Section 401 of the Clean Water Act with the MDE for Conowingo, and a water quality certification application pursuant to Section 401 of the Clean Water Act with the PA DEP for Muddy Run, addressing these and other issues. The stations are being depreciated over their useful lives, which includes the license renewal period. Although Generation expects that these licenses will be renewed, it cannot predict the conditions that may be imposed. Resolution of these issues may require a substantial increase in capital expenditures or may result in increased operating costs and significantly affect Generation's results of operations or financial position. Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run's current license on August 31, 2014,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

and the expiration of Conowingo's license on September 1, 2014. However, the stations would continue to operate under annual licenses until FERC takes action on the 46-year license applications.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE each prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of June 30, 2013 and December 31, 2012. For additional information on the specific regulatory assets and liabilities, refer to Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K.

June 30, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits(a)	$ 308	$ 3,622	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	14	1,409	5	64	—	1,279	9	66
AMI programs	4	99	4	22	—	32	—	45
AMI meter events	—	17	—	—	—	17	—	—
Under-recovered distribution service costs	84	245	84	245	—	—	—	—
Debt costs	12	63	9	58	3	5	1	9
Fair value of BGE long-term debt(b)	—	233	—	—	—	—	—	—
Fair value of BGE supply contract(c)	46	6	—	—	—	—	—	—
Severance	29	14	25	—	—	—	4	14
Asset retirement obligations	—	93	—	68	—	25	—	—
MGP remediation costs	49	215	42	184	6	30	1	1
RTO start-up costs	2	1	2	1	—	—	—	—
Under-recovered electric universal service fund costs	3	—	—	—	3	—	—	—
Renewable energy and associated RECs	16	69	16	69	—	—	—	—
Under-recovered energy and transmission costs	71	—	71	—	—	—	—	—
DSP Program costs	—	3	—	—	—	3	—	—
DSP II Program costs	2	1	—	—	2	1	—	—
Deferred storm costs	3	4	—	—	—	—	3	4
Electric generation-related regulatory asset	13	37	—	—	—	—	13	37
Rate stabilization deferral	68	194	—	—	—	—	68	194
Energy efficiency and demand response programs	42	152	—	—	—	—	42	152
Merger integration costs(d)	1	10	—	—	—	—	1	10
Other	37	32	16	21	21	8	—	4
Total regulatory assets	$ 804	6,519	$ 274	$ 732	$ 35	$ 1,400	$ 142	$ 536

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

June 30, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$ —	$ 2,434	$ —	$ 2,068	$ —	$ 366	$ —	$ —
Removal costs	99	1,422	78	1,201	—	—	21	221
Energy efficiency and demand response programs	98	—	31	—	67	—	—	—
DLC Program Costs	1	11	—	—	1	11	—	—
Energy efficiency Phase 2	—	7	—	—	—	7	—	—
Electric distribution tax repairs	20	121	—	—	20	121	—	—
Gas distribution tax repairs	8	42			8	42		
Over-recovered energy and transmission costs	78	4	2	4	66(e)	—	10(i)	—
Over-recovered gas universal service fund costs	3	—	—	—	3	—	—	—
Revenue subject to refund(f)	40	—	40	—	—	—	—	—
Over-recovered electric and gas revenue decoupling(g)	8	—	—	—	—	—	8	—
Other	2	3	—	3	1	—	1	—
Total regulatory liabilities	$ 357	$ 4,044	$ 151	$ 3,276	$ 166	$ 547	$ 40	$ 221

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits(a)	$ 304	$ 3,673	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	14	1,382	5	62	—	1,255	9	65
AMI programs	3	70	3	10	—	29	—	31
AMI meter events	—	17	—	—	—	17	—	—
Under-recovered distribution service costs	18	191	18	191	—	—	—	—
Debt costs	14	68	11	62	3	6	1	9
Fair value of BGE long-term debt(b)	—	256	—	—	—	—	—	—
Fair value of BGE supply contract(c)	77	12	—	—	—	—	—	—
Severance	29	28	25	12	—	—	4	16
Asset retirement obligations	—	90	—	65	—	25	—	—
MGP remediation costs	58	232	51	197	6	33	1	2
RTO start-up costs	3	2	3	2	—	—	—	—
Under-recovered electric universal service fund costs	11	—	—	—	11	—	—	—
Financial swap with Generation	—	—	226	—	—	—	—	—
Renewable energy and associated RECs	18	49	18	49	—	—	—	—
Under-recovered energy and transmission costs	43	—	14	—	1(h)	—	28(i)	—
DSP Program costs	1	3	—	—	1	3	—	—
DSP II Program costs	1	2	—	—	1	2	—	—
Deferred storm costs	3	6	—	—	—	—	3	6
Electric generation-related regulatory asset	16	40	—	—	—	—	16	40
Rate stabilization deferral	67	225	—	—	—	—	67	225
Energy efficiency and demand response programs	56	126	—	—	—	—	56	126
Under-recovered electric revenue decoupling(g)	5	—	—	—	—	—	5	—
Other	23	25	14	16	9	8	—	2
Total regulatory assets	$ 764	$ 6,497	$ 388	$ 666	$ 32	$ 1,378	$ 190	$ 522

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$ —	$ 2,397	$ —	$ 2,037	$ —	$ 360	$ —	$ —
Removal costs	97	1,406	75	1,192	—	—	22	214
Energy efficiency and demand response programs	131	—	43	—	88	—	—	—
Electric distribution tax repairs	20	132	—	—	20	132	—	—
Gas distribution tax repairs	8	46	—	—	8	46		
Over-recovered uncollectible accounts	6	—	6	—	—	—	—	—
Over-recovered energy and transmission costs	54	—	6	—	48(e)	—	—	—
Over-recovered gas universal service fund costs	3	—	—	—	3	—	—	—
Over-recovered AEPS costs	2	—	—	—	2	—	—	—
Revenue subject to refund(f)	40	—	40	—	—	—	—	—
Over-recovered gas revenue decoupling(g)	7	—	—	—	—	—	7	—
Total regulatory liabilities	$ 368	$ 3,981	$ 170	$ 3,229	$ 169	$ 538	$ 29	$ 214

(a) Pension and other postretirement benefit regulatory assets include a regulatory asset established at the date of the merger related to BGE's portion of the deferred costs associated with legacy Constellation's pension and other postretirement benefit plans. That BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the merger

(b) Represents the regulatory asset recorded at Exelon Corporate for the difference in the fair value of the long-term debt of BGE as of the merger date. The asset is amortized over the life of the underlying debt. See Note 11 — Debt and Credit Agreements for additional information.

(c) Represents the regulatory asset recorded at Exelon Corporate representing the fair value of BGE's supply contracts as of the close of the merger date. BGE is allowed full recovery of the costs of its electric and gas supply contracts through approved, regulated rates. The asset is amortized over a period of approximately 3 years.

(d) ReIates to integration costs to achieve distribution synergies related to the merger transaction.

(e) Includes $35 million related to the over-recovered electric supply costs under the GSA, $24 million related to the over-recovered natural gas costs under the PGC and $7 million related to over-recovered electric transmission costs as of June 30, 2013. As of December 31, 2012, includes $47 million related to the over-recovered electric supply costs under the GSA and $1 million related to the over-recovered natural gas costs under the PGC.

(f) Primarily represents the regulatory liability for revenue subject to refund recorded pursuant to the ICC's order in the 2007 Rate Case. See Note 3 of Exelon's 2012 Form 10-K for additional information regarding the 2007 Rate Case.

(g) Represents the electric and gas distribution costs recoverable from or refundable to customers under BGE's decoupling mechanism. As of June 30, 2013, includes $1 million of under-recovered electric distribution costs and $9 million of over-recovered gas distribution costs under BGE's decoupling mechanism. As of December 31, 2012, relates to $5 million of under-recovered electric distribution costs and $7 million of over-recovered gas distribution costs under BGE's decoupling mechanism.

(h) Relates to under-recovered transmission costs.

(i) Relates to $7 million of over-recovered natural gas supply costs and to $3 million of over-recovered natural electric supply costs as of June 30, 2013. As of December 31, 2012, includes to $9 million of under-recovered electric supply costs and $19 million of under-recovered natural gas supply costs.

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities' consolidated billing, ComEd, PECO and BGE must purchase their

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

customer accounts receivables. ComEd and BGE purchase receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO and BGE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon's, ComEd's, PECO's and BGE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of June 30, 2013 and December 31, 2012.

As of June 30, 2013	Exelon	ComEd	PECO	BGE
Purchased receivables(a)	$ 230	$ 87	$ 70	$73
Allowance for uncollectible accounts(b)	(24)	(13)	(6)	(5)
Purchased receivables, net	$ 206	$ 74	$ 64	$68

As of December 31, 2012	Exelon	ComEd	PECO	BGE
Purchased receivables(a)	$ 191	$ 55	$ 65	$71
Allowance for uncollectible accounts(b)	(21)	(9)	(6)	(6)
Purchased receivables, net	$ 170	$ 46	$ 59	$65

(a) PECO's gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.

(b) For ComEd and BGE, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing (PORCB) tariff.

6. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation's total equity in earnings (losses) on the investment in CENG is as follows:

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012
Equity investment income	$ 11	$ 4
Amortization of basis difference in CENG	(30)	(62)
Total equity in losses — CENG	$ (19)	$ (58)

	Six Months Ended June 30, 2013	For the Period March 12, through June 30, 2012
Equity investment income (loss)	$ 26	$ (5)
Amortization of basis difference in CENG	(57)	(74)
Total equity in losses — CENG	$ (31)	$ (79)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of March 12, 2012, Generation had an initial basis difference of approximately $204 million between the initial carrying value of its investment in CENG and its underlying equity in CENG. This basis difference resulted from the requirement to record the investment in CENG at fair value under purchase accounting while the underlying assets and liabilities within CENG continue to be accounted for on a historical cost basis. Generation is amortizing this basis difference over the respective useful lives of the assets and liabilities of CENG or as those assets and liabilities affect the earnings of CENG.

Based on tax sharing provisions contained in the operating agreement for CENG, Generation may be eligible for distributions from its investment in CENG in excess of its 50.01% ownership interest. Through purchase accounting, Generation has recorded the fair value of expected future distributions. When these distributions are realized, Generation will record a reduction in its investment in CENG. Any distributions in excess of Generation's investment in CENG would be recorded in earnings.

Related Party Transactions (Exelon and Generation)

CENG

Generation has an agreement under which it is purchasing 85% of the output of CENG's nuclear plants that is not sold to third parties under pre-existing firm and unit contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit contingent basis 50.01% of the output of CENG's nuclear plants, and EDF will purchase on a unit contingent basis 49.99% of the output.

In addition to the PPA, Generation has a power services agency agreement (PSAA) with the CENG plants, which expires on December 31, 2014. The PSAA is a five-year agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the services.

In addition to the PSAA, Exelon has a shared services agreement (SSA) with CENG, which expires in 2017. Pursuant to an agreement between Exelon and EDF, the pricing in the SSA for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services subject to an annual cap for most SSA services provided.

The affect of transactions under these agreements on Exelon's and Generation's Consolidated Financial Statements is summarized below:

Agreement	Income/ (Expense) Three Months Ended June 30, 2013	Income/ (Expense) Six Months Ended June 30, 2013	Income Statement Classification	Accounts Receivable/ (Accounts Payable) At June 30, 2013
PPA	$ (231)	$ (479)	Purchased power and fuel	$ (91)
PSAA	1	2	Operating revenues	—
SSA	11	22	Operating revenues	4

Agreement	Income/ (Expense) Three Months Ended June 30, 2012	Income/(Expense) For the Period March 12 through June 30, 2012	Income Statement Classification	Accounts Receivable/ (Accounts Payable) At June 30, 2012
PPA	$ (216)	$ (251)	Purchased power and fuel	$ (90)
PSAA	2	2	Operating revenues	—
SSA	12	15	Operating revenues	4

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

On July 29, 2013, Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with Electricité de France, S.A. (EDF), EDF Inc. (EDFI), a subsidiary of EDF, CENG, and subsidiaries of CENG. The Master Agreement contemplates that the parties will execute a series of additional agreements at a closing that will occur following the receipt of regulatory approvals and the satisfaction of other customary closing conditions. Exelon currently expects that the closing will occur late in the first quarter or early in the second quarter of 2014.

At the closing, Generation, CENG and subsidiaries of CENG will execute a Nuclear Operating Services Agreement pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI's rights as a member of CENG. CENG will reimburse Generation for its direct and allocated costs for such services.

At closing, Generation will make a $400 million loan to CENG bearing interest at 5.25% per annum, payable out of specified available cash flows of CENG. Immediately following receipt of the proceeds of such loan, CENG will make a $400 million special distribution to EDFI. The parties will also execute a Fourth Amended and Restated Operating Agreement for CENG, pursuant to which, among other things, CENG will commit to make preferred distributions to Generation (after repayment of the $400 million loan) quarterly out of specified available cash flows, until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from the date of the special distribution to EDFI.

Generation and EDFI will also enter into a Put Option Agreement at closing pursuant to which EDFI will have the option, exercisable beginning in 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. The beginning of the exercise period will be accelerated if Exelon's affiliates cease to own a majority of CENG and exercise a related right to terminate the Nuclear Operating Services Agreement. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Generation will execute an Indemnity Agreement pursuant to which Generation will indemnify EDF and its affiliates against third party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon will guarantee Generation's obligations under this indemnity.

Currently Generation accounts for its investment in CENG under the equity method of accounting. The execution of the agreements described above at the closing could result in Generation being required to consolidate the financial position and results of operations of CENG following the closing. If that accounting change were to occur, Generation would be required to re-measure its investment in CENG to fair value, with any difference between the carrying value and fair value at that date recognized as a gain or loss, which could be material to Generation's and Exelon's results of operations.

7. Impairment of Long-Lived Assets (Exelon and Generation)

Nuclear Uprate Program (Exelon and Generation)

Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan has been adjusted in both the first and second quarters

of 2013 to cancel certain projects. During the first quarter of 2013, the Measurement Uncertainty Recapture (MUR) uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. For these cancelled projects, Generation recorded approximately $21 million of operating and maintenance expense during the first quarter of 2013 to accrue remaining costs and reverse previously capitalized costs. During the second quarter of 2013, market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. For these cancelled projects, Generation recorded a charge during the second quarter of 2013 to operating and maintenance expense and interest expense of approximately $92 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Like-Kind Exchange Transaction (Exelon)

Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in coal-fired generating station leases located in Georgia and Texas with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. See Note 12 — Income Taxes for further information. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange for a third party to bid on a service contract for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying value. Exelon estimates the fair value of the residual value of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

Based on the review performed in the second quarter of 2013, the estimated residual value of one of Exelon's direct financing leases experienced an other than temporary decline given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $14 million impairment charge during the second quarter of 2013, which was recorded in Investments and Operating and maintenance in the Consolidated Balance

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Sheet and the Consolidated Statements of Operations and Comprehensive Income, respectively. Changes in the assumptions described above could potentially result in future impairments of Exelon's direct financing lease investments, which could be material.

As of December 31, 2012, Exelon concluded that the estimated fair values of the residual values at the end of the lease terms exceeded the residual values established at the lease dates.

At June 30, 2013 and December 31, 2012, the components of the net investment in long-term leases were as follows:

	June 30, 2013	December 31, 2012
Estimated residual value of leased assets	$1,465	$ 1,492
Less: unearned income	782	807
Net investment in long-term leases	$ 683	$ 685

8. Goodwill (Exelon and ComEd)

Goodwill

Under the authoritative guidance for the accounting for goodwill, ComEd is required to perform an assessment for possible impairment of its goodwill at least annually or more frequently if an event occurs that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Management concluded the remeasurement of the like-kind exchange position and the charge to ComEd's earnings in the first quarter of 2013 triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of January 31, 2013.

The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. Consistent with prior impairment tests, the estimated fair value of ComEd was determined using a weighted combination of a discounted cash flow analysis and a market multiples analysis. The discounted cash flow analysis relies on a single scenario reflecting "base case" or management's best estimate of projected cash flows for ComEd's business. The discounted cash flow analysis used in the interim goodwill impairment assessment reflected Exelon's indemnity to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts related to the like-kind exchange position on ComEd's equity.

While the interim assessment indicated no impairment of ComEd's goodwill, certain assumptions used to estimate the fair value of ComEd are highly sensitive to changes. Adverse regulatory actions, such as the early termination of EIMA or changes in significant assumptions, including the discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd's business, and the fair value of debt, could potentially result in a future impairment of ComEd's goodwill, which could be material. Based on the results of the interim goodwill test, the estimated fair value of ComEd would have needed to decrease by more than 10 percent for ComEd to fail the first step of the impairment test.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

9. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures), and preferred securities as of June 30, 2013 and December 31, 2012:

Exelon

	June 30, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 875	$ 3	$ 872	$ —	$ 875
Long-term debt (including amounts due within one year)	18,601	—	18,926	461	19,387
Long-term debt to financing trusts	648	—	—	650	650
SNF obligation	1,020	—	777	—	777

	December 31, 2012				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 214	$ 4	$ 210	$ —	$ 214
Long-term debt (including amounts due within one year)	18,745	—	20,244	276	20,520
Long-term debt to financing trusts	648	—	—	664	664
SNF obligation	1,020	—	763	—	763
Preferred securities of subsidiary	87	—	82	—	82

Generation

	June 30, 2013				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 288	$ —	$ 288	$ —	$ 288
Long-term debt (including amounts due within one year)	7,213	—	6,817	443	7,260
SNF obligation	1,020	—	777	—	777

	December 31, 2012				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 7,483	$ —	$7,591	$ 258	$7,849
SNF obligation	1,020	—	763	—	763

ComEd

	June 30, 2013				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 374	$ —	$ 374	$ —	$ 374
Long-term debt (including amounts due within one year)	5,451	—	6,033	18	6,051
Long-term debt to financing trust	206	—	—	210	210

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	December 31, 2012				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 5,567	$ —	$6,530	$ 18	$6,548
Long-term debt to financing trust	206	—	—	212	212

PECO

	June 30, 2013				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 210	$ —	$ 210	$ —	$ 210
Long-term debt (including amounts due within one year)	1,948	—	2,122	—	2,122
Long-term debt to financing trusts	184	—	—	182	182

	December 31, 2012				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 210	$ —	$ 210	$ —	$ 210
Long-term debt (including amounts due within one year)	1,947	—	2,264	—	2,264
Long-term debt to financing trusts	184	—	—	188	188
Preferred securities	87	—	82	—	82

BGE

	June 30, 2013				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 3	$ 3	$ —	$ —	$ 3
Long-term debt (including amounts due within one year)	2,444	—	2,598	—	2,598
Long-term debt to financing trusts	258	—	—	257	257

	December 31, 2012				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,178	$ —	$2,468	$ —	$2,468
Long-term debt to financing trusts	258	—	—	263	263

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2), short-term notes payable related to PECO's accounts receivable agreement (Level 2), and dividends payable (included in other current liabilities) (Level 1). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments. See Note 11 — Debt and Credit Agreements for additional information on PECO's accounts receivable agreement.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt

securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

Generation has fixed rate project financing debt (Level 3), the fair value of which is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, for certain government-backed debt, discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value.

The Registrants also have tax-exempt debt (Level 3). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (i.e., political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above.

SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

Long-Term Debt to Financing Trusts. Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Preferred Securities. The fair value of these securities is determined based on the last closing price prior to quarter end, less accrued interest. The securities are registered with the SEC and are public. PECO redeemed all outstanding series of preferred securities on May 1, 2013. See Note 17—Earnings Per Share and Equity for additional information.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to access as of the reporting date. Financial assets and liabilities utilizing Level 1 inputs include active exchange-traded equity securities, certain exchange-based derivatives, and money market funds.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. Financial assets and liabilities utilizing Level 2 inputs include fixed income securities, non- exchange-based derivatives, commingled and mutual investment funds priced at NAV per fund share and fair value hedges.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability. Financial assets and liabilities utilizing Level 3 inputs include infrequently traded non-exchange-based derivatives, investments priced using an alternative pricing mechanism, and middle market lending using third party valuations.

There were no transfers between Level 1 and Level 2 during the six months ended June 30, 2013.

Exelon

The following tables present assets and liabilities measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2013 and December 31, 2012:

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 589	$ —	$ —	$ 589
Nuclear decommissioning trust fund investments				
Cash equivalents	229	—	—	229
Equity				
Individually held	1,691	—	—	1,691
Commingled funds	—	2,071	—	2,071
Equity funds subtotal	1,691	2,071	—	3,762
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	966	—	—	966
Debt securities issued by states of the United States and political subdivisions of the states	—	314	—	314
Debt securities issued by foreign governments	—	85	—	85
Corporate debt securities	—	1,727	—	1,727
Federal agency mortgage-backed securities	—	18	—	18
Commercial mortgage-backed securities (non-agency)	—	41	—	41
Residential mortgage-backed securities (non-agency)	—	10	—	10
Mutual funds	—	37	—	37
Fixed income subtotal	966	2,232	—	3,198
Middle market lending	—	—	240	240
Other debt obligations	—	12	—	12
Nuclear decommissioning trust fund investments subtotal(b)	2,886	4,315	240	7,441
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	62	—	62
Equity				
Individually held	1	—	—	1
Equity funds subtotal	1	—	—	1

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	143	8	—	151
Debt securities issued by states of the United States and political subdivisions of the states	—	27	—	27
Corporate debt securities	—	193	—	193
Federal agency mortgage-backed securities	—	17	—	17
Commercial mortgage-backed securities (non-agency)	—	1	—	1
Fixed income subtotal	143	246	—	389
Middle market lending	—	—	111	111
Other debt obligations	—	3	—	3
Pledged assets for Zion Station decommissioning subtotal(c)	144	311	111	566
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds(d)(e)	67	—	—	67
Rabbi trust investments subtotal	69	—	—	69
Commodity mark-to-market derivative assets				
Economic hedges	721	2,659	676	4,056
Proprietary trading	839	1,445	162	2,446
Effect of netting and allocation of collateral(f)	(1,645)	(3,087)	(226)	(4,958)
Commodity mark-to-market assets subtotal	(85)	1,017	612	1,544
Interest rate mark-to-market derivative assets	36	74	—	110
Effect of netting and allocation of collateral	(36)	(1)	—	(37)
Interest rate mark-to-market derivative assets subtotal	—	73	—	73
Other investments	1	—	11	12
Total assets	3,604	5,716	974	10,294
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(977)	(1,974)	(276)	(3,227)
Proprietary trading	(855)	(1,371)	(141)	(2,367)
Effect of netting and allocation of collateral(f)	1,833	3,217	236	5,286
Commodity mark-to-market liabilities subtotal(h)	1	(128)	(181)	(308)
Interest rate mark-to-market derivative liabilities	(36)	(18)	—	(54)
Effect of netting and allocation of collateral	36	1	—	37
Interest rate mark-to-market derivative liabilities subtotal	—	(17)	—	(17)
Deferred compensation obligation	—	(105)	—	(105)
Total liabilities	1	(250)	(181)	(430)
Total net assets	$ 3,605	$ 5,466	$ 793	$ 9,864

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 995	$ —	$ —	$ 995
Nuclear decommissioning trust fund investments				
Cash equivalents	245	—	—	245
Equity				
Individually held	1,480	—	—	1,480
Commingled funds	—	1,933	—	1,933
Equity funds subtotal	1,480	1,933	—	3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057	—	—	1,057
Debt securities issued by states of the United States and political subdivisions of the states	—	321	—	321
Debt securities issued by foreign governments	—	93	—	93
Corporate debt securities	—	1,788	—	1,788
Federal agency mortgage-backed securities	—	24	—	24
Commercial mortgage-backed securities (non-agency)	—	45	—	45
Residential mortgage-backed securities (non-agency)	—	11	—	11
Mutual funds	—	23	—	23
Fixed income subtotal	1,057	2,305	—	3,362
Middle market lending	—	—	183	183
Other debt obligations	—	15	—	15
Nuclear decommissioning trust fund investments subtotal(b)	2,782	4,253	183	7,218
Pledged assets for Zion decommissioning				
Cash equivalents	—	23	—	23
Equity				
Individually held	14	—	—	14
Commingled funds	—	9	—	9
Equity funds subtotal	14	9	—	23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12	—	130
Debt securities issued by states of the United States and political subdivisions of the states	—	37	—	37
Corporate debt securities	—	249	—	249
Federal agency mortgage-backed securities	—	49	—	49
Commercial mortgage-backed securities (non-agency)	—	6	—	6
Fixed income subtotal	118	353	—	471
Middle market lending	—	—	89	89
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal(c)	132	386	89	607
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds(d)(e)	69	—	—	69
Rabbi trust investments subtotal	71	—	—	71

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Commodity mark-to-market derivative assets				
Cash flow hedges	—	—	—	—
Economic hedges	861	3,173	641	4,675
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral(f)	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal(g)	80	1,076	656	1,812
Interest rate mark-to-market derivative assets	—	114	—	114
Effect of netting and allocation of collateral	—	(51)	—	(51)
Interest rate mark-to-market derivative assets subtotal	—	63	—	63
Other Investments	2	—	17	19
Total assets	4,062	5,778	945	10,785
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(236)	(3,566)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral(f)	2,042	4,020	25	6,087
Commodity mark-to-market liabilities subtotal(g)(h)	(83)	(228)	(289)	(600)
Interest rate mark-to-market derivative liabilities	—	(84)	—	(84)
Effect of netting and allocation of collateral	—	51	—	51
Interest rate mark-to-market derivative liabilities subtotal	—	(33)	—	(33)
Deferred compensation obligation	—	(102)	—	(102)
Total liabilities	(83)	(363)	(289)	(735)
Total net assets	$ 3,979	$ 5,415	$ 656	$10,050

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets of $22 million and $30 million at June 30, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net (liabilities) assets of $(28) million and $7 million at June 30, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) The mutual funds held by the Rabbi trusts include $51 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan at June 30, 2013, and $53 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan at December 31, 2012. These funds are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(e) Excludes $29 million and $28 million of the cash surrender value of life insurance investments at June 30, 2013 and December 31, 2012, respectively.
(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $188 million, $130 million and $10 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2013. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.
(g) The Level 3 balance does not include current assets for Generation and current liabilities for ComEd of $226 million at December 31, 2012, related to the fair value of Generation's financial swap contract with ComEd.
(h) The Level 3 balance includes the current and noncurrent liability of $16 million and $69 million at June 30, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2013 and 2012:

Three Months Ended June 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2013	$ 210	$ 104	$ 260	$ 9	$583
Total realized / unrealized gains (losses)					
Included in net income	1	—	158(a)	—	159
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	8	—	(10)(b)	—	(2)
Included in payable for Zion Station decommissioning	—	1	—	—	1
Change in collateral	—	—	10	—	10
Purchases, sales, issuances and settlements					
Purchases	35	11	13	2	61
Sales	(11)	(5)	(4)	—	(20)
Settlements	(3)	—	—	—	(3)
Transfers into Level 3	—	—	3	—	3
Transfers out of Level 3	—	—	1	—	1
Balance as of June 30, 2013	$ 240	$ 111	$ 431	$ 11	$793
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the three months ended June 30, 2013	$ 1	$ —	$ 187	$ —	$188

Six Months Ended June 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2012	$ 183	$ 89	$ 367	$ 17	$656
Total realized / unrealized gains (losses)					
Included in net income	2	—	31(a)	—	33
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	9	—	(18)(b)	—	(9)
Included in payable for Zion Station decommissioning	—	1	—	—	1
Change in collateral	—	—	43	—	43
Purchases, sales, issuances and settlements					
Purchases	67	33	8(c)	2	110
Sales	(13)	(12)	(8)	(8)	(41)
Settlements	(8)	—	—	—	(8)
Transfers into Level 3	—	—	7	—	7
Transfers out of Level 3	—	—	1	—	1
Balance as of June 30, 2013	$ 240	$ 111	$ 431	$ 11	$793
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the six months ended June 30, 2013	$ 1	$ —	$ 108	$ —	$109

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(a) Includes the reclassification of $29 million and $77 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2013.
(b) Excludes decreases in fair value of $3 million and $11 million and realized losses reclassified due to settlements of $82 million and $215 million associated with Generation's financial swap contract with ComEd for the three and six months ended June 30, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes $10 million which Generation was paid to enter into out of the money purchase contracts.

Three Months Ended June 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2012	$ 13	$ 42	$ 359	$ 14	$428
Total realized / unrealized gains (losses)					
Included in net income	—	—	(64)(a)	—	(64)
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	—	—	30(b)	—	30
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Change in collateral	—	—	44	—	44
Purchases, sales, issuances and settlements					
Purchases	41	26	—	3	70
Sales	—	(8)	—	—	(8)
Transfers into Level 3	—	—	(34)	—	(34)
Transfers out of Level 3	—	—	(40)	—	(40)
Balance as of June 30, 2012	$ 54	$ 59	$ 295	$ 17	$425
The amount of total gains included in income attributed to the change in unrealized losses related to assets and liabilities held for the three months ended June 30, 2012	$ —	$ —	$ 2	$ —	$ 2

Six Months Ended June 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2011	$ 13	$ 37	$ 17	$ —	$ 67
Total realized / unrealized gains (losses)					
Included in net income	—	—	19(a)	—	19
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	—	—	(5)(b)	—	(5)
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Change in collateral	—	—	8	—	8
Purchases, sales, issuances and settlements					
Purchases	41	32	329(c)	17	419
Sales	—	(9)	—	—	(9)
Transfers into Level 3	—	—	(34)	—	(34)
Transfers out of Level 3	—	—	(39)	—	(39)
Balance as of June 30, 2012	$ 54	$ 59	$ 295	$ 17	$425
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the six months ended June 30, 2012	$ —	$ —	$ 104	$ —	$104

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(a) Includes the reclassification of $66 million and $85 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2012, respectively.
(b) Excludes $14 million and $121 million of decreases in fair value and $161 million and $308 million of realized losses due to settlements for the three and six months ended June 30, 2012 of Generation's financial swap contract with ComEd, which eliminates upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2013 and 2012:

	Operating Revenue	Purchased Power and Fuel	Other, net(a)
Total gains included in income for the three months ended June 30, 2013	$ 137	$ 21	$ 1
Total gains (losses) included in income for the six months ended June 30, 2013	$ (22)	$ 53	$ 2
Change in the unrealized gains relating to assets and liabilities held for the three months ended June 30, 2013	$ 156	$ 31	$ 1
Change in the unrealized gains relating to assets and liabilities held for the six months ended June 30, 2013	$ 39	$ 69	$ 1

	Operating Revenue	Purchased Power and Fuel	Other, net
Total gains (losses) included in income for the three months ended June 30, 2012	$ (69)	$ 5	$ —
Total gains (losses) included in income for the six months ended June 30, 2012	$ 23	$ (4)	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2012	$ 5	$ (3)	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2012	$ 125	$ (21)	$ —

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

Generation

The following tables present assets and liabilities measured and recorded at fair value on Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2013 and December 31, 2012:

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 45	$ —	$ —	$ 45
Nuclear decommissioning trust fund investments				
Cash equivalents	229	—	—	229
Equity				
Individually held	1,691	—	—	1,691
Commingled funds	—	2,071	—	2,071
Equity funds subtotal	1,691	2,071	—	3,762

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	966	—	—	966
Debt securities issued by states of the United States and political subdivisions of the states	—	314	—	314
Debt securities issued by foreign governments	—	85	—	85
Corporate debt securities	—	1,727	—	1,727
Federal agency mortgage-backed securities	—	18	—	18
Commercial mortgage-backed securities (non-agency)	—	41	—	41
Residential mortgage-backed securities (non-agency)	—	10	—	10
Mutual funds	—	37	—	37
Fixed income subtotal	966	2,232	—	3,198
Middle market lending	—	—	240	240
Other debt obligations	—	12	—	12
Nuclear decommissioning trust fund investments subtotal(b)	2,886	4,315	240	7,441
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	62	—	62
Equity				
Individually held	1	—	—	1
Equity funds subtotal	1	—	—	1
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	143	8	—	151
Debt securities issued by states of the United States and political subdivisions of the states	—	27	—	27
Corporate debt securities	—	193	—	193
Federal agency mortgage-backed securities	—	17	—	17
Commercial mortgage-backed securities (non-agency)	—	1	—	1
Fixed income subtotal	143	246	—	389
Middle market lending	—	—	111	111
Other debt obligations	—	3	—	3
Pledged assets for Zion Station decommissioning subtotal(c)	144	311	111	566
Rabbi trust investments				
Mutual funds(d)(e)	13	—	—	13
Rabbi trust investments subtotal	13	—	—	13
Commodity mark-to-market derivative assets				
Economic hedges	721	2,659	676	4,056
Proprietary trading	839	1,445	162	2,446
Effect of netting and allocation of collateral(f)	(1,645)	(3,087)	(226)	(4,958)
Commodity mark-to-market assets subtotal	(85)	1,017	612	1,544
Interest rate mark-to-market derivative assets	36	42	—	78
Effect of netting and allocation of collateral	(36)	(1)	—	(37)
Interest rate mark-to-market derivative assets subtotal	—	41	—	41
Other investments	1	—	11	12
Total assets	3,004	5,684	974	9,662

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(977)	(1,974)	(191)	(3,142)
Proprietary trading	(855)	(1,371)	(141)	(2,367)
Effect of netting and allocation of collateral(f)	1,833	3,217	236	5,286
Commodity mark-to-market liabilities subtotal	1	(128)	(96)	(223)
Interest rate mark-to-market derivative liabilities	(36)	(18)	—	(54)
Effect of netting and allocation of collateral	36	1	—	37
Interest rate mark-to-market derivative liabilities subtotal	—	(17)	—	(17)
Deferred compensation obligation	—	(25)	—	(25)
Total liabilities	1	(170)	(96)	(265)
Total net assets	$3,005	$ 5,514	$ 878	$ 9,397

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 487	$ —	$ —	$ 487
Nuclear decommissioning trust fund investments				
Cash equivalents	245	—	—	245
Equity				
Individually held	1,480	—	—	1,480
Commingled funds	—	1,933	—	1,933
Equity funds subtotal	1,480	1,933	—	3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057	—	—	1,057
Debt securities issued by states of the United States and political subdivisions of the states	—	321	—	321
Debt securities issued by foreign governments	—	93	—	93
Corporate debt securities	—	1,788	—	1,788
Federal agency mortgage-backed securities	—	24	—	24
Commercial mortgage-backed securities (non-agency)	—	45	—	45
Residential mortgage-backed securities (non-agency)	—	11	—	11
Mutual funds	—	23	—	23
Fixed income subtotal	1,057	2,305	—	3,362
Middle market lending	—	—	183	183
Other debt obligations	—	15	—	15
Nuclear decommissioning trust fund investments subtotal(b)	2,782	4,253	183	7,218
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	23	—	23
Equity				
Individually held	14	—	—	14
Commingled funds	—	9	—	9
Equity funds subtotal	14	9	—	23

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12	—	130
Debt securities issued by states of the United States and political subdivisions of the states	—	37	—	37
Corporate debt securities	—	249	—	249
Federal agency mortgage-backed securities	—	49	—	49
Commercial mortgage-backed securities (non-agency)	—	6	—	6
Fixed income subtotal	118	353	—	471
Middle market lending	—	—	89	89
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal(c)	132	386	89	607
Rabbi trust investments				
Cash equivalents	1	—	—	1
Mutual funds(d)(e)	13	—	—	13
Rabbi trust investments subtotal	14	—	—	14
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	867	4,901
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral(f)	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal(g)	80	1,076	882	2,038
Interest rate mark-to-market derivative assets	—	101	—	101
Effect of netting and allocation of collateral	—	(51)	—	(51)
Interest rate mark-to-market derivative assets subtotal	—	50	—	50
Other investments	2	—	17	19
Total assets	3,497	5,765	1,171	10,433
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(169)	(3,499)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral(f)	2,042	4,020	25	6,087
Commodity mark-to-market liabilities subtotal	(83)	(228)	(222)	(533)
Interest rate mark-to-market derivative liabilities	—	(84)	—	(84)
Effect of netting and allocation of collateral	—	51	—	51
Interest rate mark-to-market derivative liabilities	—	(33)	—	(33)
Deferred compensation obligation	—	(28)	—	(28)
Total liabilities	(83)	(289)	(222)	(594)
Total net assets	$ 3,414	$ 5,476	$ 949	$ 9,839

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets of $22 million and $30 million at June 30, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(c) Excludes net (liabilities) assets of $(28) million and $7 million at June 30, 2013 December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) The mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(e) Excludes $9 million and $8 million of the cash surrender value of life insurance investments at June 30, 2013 and December 31, 2012, respectively.
(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $188 million, $130 million and $10 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2013. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.
(g) The level 3 balance includes current assets for Generation of $226 million at December 31, 2012, related to the fair value of Generation's financial swap contract with ComEd, which eliminates upon consolidation in Exelon's Consolidated Financial Statements.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2013 and 2012:

Three Months Ended June 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2013	$ 210	$ 104	$ 420	$ 9	$743
Total realized / unrealized gains (losses)					
Included in net income	1	—	168(a)(b)	—	169
Included in other comprehensive income	—	—	(95)(b)	—	(95)
Included in noncurrent payables to affiliates	8	—	—	—	8
Included in payable for Zion Station decommissioning	—	1	—	—	1
Change in collateral	—	—	10	—	10
Purchases, sales, issuances and settlements					
Purchases	35	11	13	2	61
Sales	(11)	(5)	(4)	—	(20)
Settlements	(3)	—	—	—	(3)
Transfers into Level 3	—	—	3	—	3
Transfers out of Level 3	—	—	1	—	1
Balance as of June 30, 2013	$ 240	$ 111	$ 516	$ 11	$878
The amount of total losses included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the three months ended June 30, 2013	$ 1	$ —	$ 183	$ —	$184

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2012	$ 183	$ 89	$ 660	$ 17	$ 949
Total realized / unrealized gains (losses)					
Included in net income	2	—	24(a)(b)	—	26
Included in other comprehensive income	—	—	(219)(b)	—	(219)
Included in noncurrent payables to affiliates	9	—	—	—	9
Included in payable for Zion Station decommissioning	—	1	—	—	1
Change in collateral		—	43	—	43
Purchases, sales, issuances and settlements					
Purchases	67	33	8(c)	2	110
Sales	(13)	(12)	(8)	(8)	(41)
Settlements	(8)	—	—	—	(8)
Transfers into Level 3	—	—	7		7
Transfers out of Level 3	—	—	1	—	1
Balance as of June 30, 2013	$ 240	$ 111	$ 516	$ 11	$ 878
The amount of total losses included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the six months ended June 30, 2013	$ 1	$ —	$ 97	$ —	$ 98

(a) Includes the reclassification of $15 million and $73 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2013, respectively.
(b) Includes $3 million of decreases in fair value and $11 million of increases in fair value and realized losses due to settlements of $82 million and $215 million associated with Generation's financial swap contract with ComEd for the three and six months ended June 30, 2013, respectively. This position eliminates upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes $10 million which Generation was paid to enter into out of the money purchase contracts.

Three Months Ended June 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2012	$ 13	$ 42	$ 1,182	$ 14	$1,251
Total realized / unrealized gains (losses)					
Included in net income	—	—	(69)(a)	—	(69)
Included in other comprehensive income	—	—	(171)(b)	—	(171)
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Changes in collateral	—	—	44	—	44
Purchases, sales, issuances and settlements					
Purchases	41	26	—	3	70
Sales	—	(8)	—	—	(8)
Transfers into Level 3	—	—	(34)	—	(34)
Transfers out of Level 3	—	—	(40)	—	(40)
Balance as of June 30, 2012	$ 54	$ 59	$ 912	$ 17	$1,042
The amount of total gains included in income attributed to the change in unrealized (losses) related to assets and liabilities held for the three months ended June 30, 2012	$ —	$ —	$ (13)	$ —	$ (13)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2011	$ 13	$ 37	$ 817	$ —	$ 867
Total realized / unrealized gains (losses)					
Included in net income	—	—	3(a)	—	3
Included in other comprehensive income	—	—	(172)(b)	—	(172)
Included in payable for Zion Station decommissioning	—	(1)	—	—	(1)
Changes in collateral	—	—	8	—	8
Purchases, sales, issuances and settlements					—
Purchases	41	32	329(c)	17	419
Sales	—	(9)	—	—	(9)
Transfers into Level 3	—	—	(34)	—	(34)
Transfers out of Level 3	—	—	(39)	—	(39)
Balance as of June 30, 2012	$ 54	$ 59	$ 912	$ 17	$1,042
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the six months ended June 30, 2012	$ —	$ —	$ 78	$ —	$ 78

(a) Includes the reclassification of $56 million and $75 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2012, respectively.
(b) Includes $14 million of decreases in fair value and $121 million of increases in fair value and realized losses due to settlements of $161 million and $308 million associated with Generation's financial swap contract with ComEd for the three and six months ended June 30, 2012, respectively. This position was re-designated as a cash flow hedge prior to the merger date. All prospective changes in fair value and reclassifications of realized amounts are being recorded to income offset by the amortization of the frozen mark in OCI. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes $310 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2013 and 2012:

	Operating Revenue	Purchased Power and Fuel	Other, net (a)
Total gains included in net income for the three months ended June 30, 2013	$ 148	$ 20	$ 1
Total gains (losses) included in net income for the six months ended June 30, 2013	$ (28)	$ 52	$ 2
Change in the unrealized gains relating to assets and liabilities held for the three months ended June 30, 2013	$ 153	$ 30	$ 1
Change in the unrealized gains relating to assets and liabilities held for the six months ended June 30, 2013	$ 29	$ 68	$ 1

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Operating Revenue	Purchased Power and Fuel	Other, net
Total gains (losses) included in net income for the three months ended June 30, 2012	$ (74)	$ 5	$ —
Total gains (losses) included in net income for the six months ended June 30, 2012	$ 7	$ (4)	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2012	$ (10)	$ (3)	$ —
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2012	$ 99	$ (21)	$ —

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

ComEd

The following tables present assets and liabilities measured and recorded at fair value on ComEd's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2013 and December 31, 2012:

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 70	$ —	$ —	$ 70
Rabbi trust investments				
Mutual funds(a)	6	—	—	6
Rabbi trust investments subtotal	6	—	—	6
Total assets	$ 76	$ —	$ —	$ 76
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities(b)	—	—	(85)	(85)
Total liabilities	—	(8)	(85)	(93)
Total net assets (liabilities)	$ 76	$ (8)	$ (85)	$(17)

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 111	$ —	$ —	$ 111
Rabbi trust investments				
Mutual funds(a)	8	—	—	8
Rabbi trust investments subtotal	8	—	—	8
Total assets	$ 119	$ —	$ —	$ 119
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities(b)(c)	—	—	(293)	(293)
Total liabilities	—	(8)	(293)	(301)
Total net assets (liabilities)	$ 119	$ (8)	$(293)	$(182)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(a) The mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(b) The Level 3 balance includes the current and noncurrent liability of $16 million and $69 million at June 30, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.
(c) The Level 3 balance includes the current liability of $226 million at December 31, 2012, related to the fair value of ComEd's financial swap contract with Generation which eliminated upon consolidation in Exelon's Consolidated Financial Statements.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2013 and 2012:

Three Months Ended June 30, 2013	Mark-to-Market Derivatives
Balance as of March 31, 2013	$ (160)
Total realized / unrealized gains included in regulatory assets(a)(b)	75
Balance as of June 30, 2013	$ (85)

Six Months Ended June 30, 2013	Mark-to-Market Derivatives
Balance as of December 31, 2012	$ (293)
Total realized / unrealized gains included in regulatory assets(a)(b)	208
Balance as of June 30, 2013	$ (85)

(a) Includes $3 million of increases in fair value and $11 million of decreases in fair value and realized gains due to settlements of $82 million and $215 million associated with ComEd's financial swap contract with Generation for the three and six months ended June 30, 2013, respectively. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(b) Includes $9 million and $20 million of increases in the fair value and realized losses due to settlements of $1 million and $4 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and six months ended June 30, 2013, respectively.

Three Months Ended June 30, 2012	Mark-to-Market Derivatives
Balance as of March 31, 2012	$ (823)
Total realized / unrealized gains included in regulatory assets(a)(b)	206
Balance as of June 30, 2012	$ (617)

Six Months Ended June 30, 2012	Mark-to-Market Derivatives
Balance as of December 31, 2011	$ (800)
Total realized / unrealized gains included in regulatory assets(a)(b)	183
Balance as of June 30, 2012	$ (617)

(a) Includes $14 million of increases in fair value and $121 million of decreases in fair value and realized gains due to settlements of $161 million and $308 million of associated with ComEd's financial swap contract with Generation for the three and six months ended June 30, 2012, respectively. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(b) Includes $30 million of decreases in fair value and $5 million of increases in fair value of floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and six months ended June 30, 2012, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

PECO

The following tables present assets and liabilities measured and recorded at fair value on PECO's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2013 and December 31, 2012:

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 13	$ —	$ —	$ 13
Rabbi trust investments				
Mutual funds(a)(b)	9	—	—	9
Rabbi trust investments subtotal	9	—	—	9
Total assets	22	—	—	22
Liabilities				
Deferred compensation obligation	—	(16)	—	(16)
Total liabilities	—	(16)	—	(16)
Total net assets (liabilities)	$ 22	$ (16)	$ —	$ 6

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 346	$ —	$ —	$346
Rabbi trust investments				
Mutual funds(a)(b)	9	—	—	9
Rabbi trust investments subtotal	9	—	—	9
Total assets	355	—	—	355
Liabilities				
Deferred compensation obligation	—	(18)	—	(18)
Total liabilities	—	(18)	—	(18)
Total net assets (liabilities)	$ 355	$ (18)	$ —	$337

(a) The mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(b) Excludes $14 million and $13 million of the cash surrender value of life insurance investments at June 30, 2013 and December 31, 2012, respectively.

PECO had no Level 3 assets or liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2013 and 2012.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

BGE

The following tables present assets and liabilities measured and recorded at fair value on BGE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2013 and December 31, 2012:

As of June 30, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 365	$ —	$ —	$365
Rabbi trust investments				
Mutual funds(a)	5	—	—	5
Rabbi trust investments subtotal	5	—	—	5
Total assets	370	—	—	370
Liabilities				
Deferred compensation obligation	—	(5)	—	(5)
Total liabilities	—	(5)	—	(5)
Total net assets (liabilities)	$ 370	$ (5)	$ —	$365

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 33	$ —	$ —	$ 33
Rabbi trust investments				
Mutual funds(a)	5	—	—	5
Rabbi trust investments subtotal	5	—	—	5
Total assets	38	—	—	38
Liabilities				
Deferred compensation obligation	—	(5)	—	(5)
Total liabilities	—	(5)	—	(5)
Total net assets (liabilities)	$ 38	$ (5)	$ —	$ 33

(a) The mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.

BGE had no Level 3 assets or liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2013 and 2012.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE). The Registrants' cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to fund Generation's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds. Generation's investment policies place limitations on the types and investment grade ratings of the securities that may be held by the trusts. These policies limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2.

Equity and fixed income commingled funds and fixed income mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of fixed income commingled and mutual funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining equity commingled funds in which Exelon and Generation invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. In general, equity commingled funds are redeemable daily. Commingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities. See Note 13 — Nuclear Decommissioning for further discussion on the NDT fund investments.

Middle market lending funds are investments in loans or managed funds which invest in private companies. Generation elected the fair value option for its investments held by certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in middle market lending are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The investments in the Rabbi trusts are included in investments in the Registrants' Consolidated Balance Sheets. The investments are in fixed- income commingled funds and mutual funds, including short-term investment funds. These funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Fixed-income commingled funds and mutual funds, such as money market funds, are publicly quoted and have been categorized as Level 1 given the clear observability of the prices.

Mark-to-Market Derivatives (Exelon, Generation, and ComEd) . Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain non-exchange-based derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of non-exchange-based derivative contracts is valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For non-exchange-based derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' non-exchange-based derivatives are predominately at liquid trading points. For non-exchange-based derivatives that trade in less liquid markets with limited pricing information, such as the financial swap contract between Generation and ComEd, model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 10 — Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO and BGE). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized in Level 2 in the fair value hierarchy.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd)

Mark-to-Market Derivatives (Exelon, Generation, ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Exelon Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at Exelon. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements. Transfers in and out of levels are recognized as of the end of the reporting period the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 generally do not occur. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and notional size. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, certain transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price is generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are highly liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is generally less than $2.10 and $0.14 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 3. — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrant's mark-to-market derivative assets and liabilities.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 10 — Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk. The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at June 30, 2013(c)	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Generation)(a)				
	$ 485	Discounted Cash Flow	Forward power price	$15 - $87
			Forward gas price	$3.54 - $4.72
		Option Model	Volatility percentage	28% - 363%
Mark-to-market derivatives — Proprietary trading (Generation)(a)				
	$ 21	Discounted Cash Flow	Forward power price	$16 - $87
		Option Model	Volatility percentage	11% - 23%
Mark-to-market derivatives (ComEd)				
	$ (85)	Discounted Cash Flow	Forward heat rate(b)	8% - 9%
			Marketability reserve	3.5% - 8%
			Renewable factor	85% - 129%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
c) The fair values do not include cash collateral held on level three positions of $10 million as of June 30, 2013.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Type of trade	Fair Value at December 31, 2012(d)	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Generation)(a)	$ 473	Discounted Cash Flow	Forward power price	$14 - $79
			Forward gas price	$3.26 - $6.27
		Option Model	Volatility percentage	28% - 132%
Mark-to-market derivatives — Proprietary trading (Generation)(a)	$ (6)	Discounted Cash Flow	Forward power price	$15 - $106
		Option Model	Volatility percentage	16% - 48%
Mark-to-market derivatives — Transactions with Affiliates (Generation and ComEd)(b)	$ 226	Discounted Cash Flow	Marketability reserve	8% - 9%
Mark-to-market derivatives (ComEd)	$ (67)	Discounted Cash Flow	Forward heat rate(c)	8% - 9.5%
			Marketability reserve	3.5% - 8.3%
			Renewable factor	81% - 123%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Includes current assets for Generation and current liabilities for ComEd of $226 million, related to the fair value of the five-year financial swap contract between Generation and ComEd, which eliminates in consolidation.
c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
d) The fair values do not include cash collateral held on level three positions of $33 million as of December 31, 2012.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending, the fair value of these loans is determined using a combination of valuations models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as

well as other factors that may impact value. Significant judgment is required in the applications of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its' middle market lending, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations. For a sample of its' middle market lending, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

As of June 30, 2013, Generation has outstanding commitments to invest in middle market lending of approximately $168 million. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

10. Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. The Registrants employ established policies and procedures to manage their risks associated with market fluctuations by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivative economic hedges for commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 19 — Commitments and Contingencies of the Exelon

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

2012 Form 10-K. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of June 30, 2013, the percentage of expected generation hedged for the major reportable segments was 96%-99%, 78%-81%, and 41%-44% for 2013, 2014, and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including, Generation's sales to ComEd, PECO and BGE to serve their retail load.

In order to fulfill a requirement of the Illinois Settlement Legislation, Generation and ComEd entered into a five-year financial swap contract that expired May 31, 2013. The financial swap was designed to hedge spot market purchases, which, along with ComEd's remaining energy procurement contracts, met its load service requirements. The terms of the financial swap contract required Generation to pay the around-the-clock market price for a portion of ComEd's electricity supply requirement, while ComEd paid a fixed price.

As the contract expired May 31, 2013, all realized impacts have been included in Generation's and ComEd's results of operations. In Exelon's consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

In addition, the physical contracts that Generation has entered into with ComEd and that ComEd has entered into with Generation and other suppliers as part of the ComEd power procurement process, which are further discussed in Note 3 – Regulatory Matters of the Exelon 2012 Form 10-K qualify and are accounted for under the NPNS exception. Based on the Illinois Settlement Legislation and ICC-approved procurement methodologies permitting ComEd to recover its electricity procurement costs from retail customers with no ComEd's price risk related to power procurement is limited.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts for energy and associate RECs were reduced in the first quarter of 2013. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 5 — Regulatory Matters for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 — Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts and block contracts. PECO has certain full requirements contracts and block contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2012 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2012 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE's price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has

sufficient pipeline transportation capacity to meet customer requirements. All of BGE's natural gas supply and asset management agreements qualify for the NPNS exception and result in physical delivery.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 1,995 GWhs and 3,567 GWhs for the three and six months ended June 30, 2013, respectively, and 4,248 GWhs and 6,077 GWhs for the three and six months ended June 30, 2012, respectively, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At June 30, 2013, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and $570 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper and PECO Accounts Receivables Facility) and fixed-to-floating swaps would result in less than a $1 million decrease in Exelon Consolidated pre-tax income for the six months ended June 30, 2013. To manage foreign rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign rate derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign currency hedges as of June 30, 2013.

	Generation					Other	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading (a)	Collateral and Netting (b)	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (Current Assets)	$ —	$ 4	$ 18	$ (19)	$ 3	$ —	$ 3
Mark-to-market derivative assets (Noncurrent Assets)	31	6	19	(18)	38	32	70
Total mark-to-market derivative assets	$ 31	$ 10	$ 37	$ (37)	$ 41	$ 32	$ 73
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (2)	$ (18)	$ 18	$ (3)	$ —	$ (3)
Mark-to-market derivative liabilities (Noncurrent liabilities)	(15)	—	(18)	19	(14)	—	(14)
Total mark-to-market derivative liabilities	$ (16)	$ (2)	$ (36)	$ 37	$ (17)	$ —	$ (17)
Total mark-to-market derivative net assets (liabilities)	$ 15	$ 8	$ 1	$ —	$ 24	$ 32	$ 56

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.
(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

The following table provides a summary of the interest rate hedge balances recorded by the Registrants as of December 31, 2012:

	Generation					Other	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading (a)	Collateral and Netting (b)	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (Current Assets)	$ —	$ 3	$ 20	$ (19)	$ 4	$ —	$ 4
Mark-to-market derivative assets (Noncurrent Assets)	38	8	32	(32)	46	13	59
Total mark-to-market derivative assets	$ 38	$ 11	$ 52	$ (51)	$ 50	$ 13	$ 63
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$ (19)	$ 19	$ (2)	$ —	$ (2)
Mark-to-market derivative liabilities (Noncurrent liabilities)	(31)	—	(32)	32	(31)	—	(31)
Total mark-to-market derivative liabilities	$ (32)	$ (1)	$ (51)	$ 51	$ (33)	$ —	$ (33)
Total mark-to-market derivative net assets (liabilities)	$ 6	$ 10	$ 1	$ —	$ 17	$ 13	$ 30

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.
(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

Fair Value Hedges . For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

	Gain (Loss) on Swaps Six Months Ended June 30,		Gain (Loss) on Borrowings Six Months Ended June 30,	
Income Statement Classification	2013	2012	2013	2012
Interest expense(a)	$ (9)	$ (2)	$ 1	$ (3)

(a) For the six months ended June 30, 2013, the loss on the swaps in the table above includes $8 million reclassified to earnings, with an immaterial amount excluded from hedge effectiveness testing.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

At June 30, 2013 and December 31, 2012, Exelon and Generation had $650 million of notional amounts of fixed-to-floating fair value hedges outstanding related to interest rate swaps, with unrealized gain of $38 million and $49 million, respectively, which expire in 2015. Upon merger closing, $550 million of fixed-to-floating interest rate swaps previously at Constellation with a fair value of $44 million, as of March 12, 2012, were re-designated as fair value hedges. During the six months ended June 30, 2013 and June 30, 2012, the impact of loss on the results of operations as a result of ineffectiveness from fair value hedges was immaterial.

Cash Flow Hedges . In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 11 — Debt and Credit Agreements, Generation entered into a floating-to-fixed forward starting interest rate swap with a notional amount of $485 million and a mandatory early termination date of April 5, 2014, by which date Generation anticipates the DOE loan to be fully drawn. The swap hedges approximately 75% of Generation's future interest rate exposure associated with the financing and was designated as a cash flow hedge. As such, the effective portion of the hedge is recorded in other comprehensive income within Generation's Consolidated Balance Sheets, with any ineffectiveness recorded in Generation's Consolidated Statements of Operations and Comprehensive Income. Net gains (or losses) from settlement of the hedges, to the extent effective, are amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

Every time Generation draws down on the loan, an offsetting hedge (fixed-to-floating) is executed and a portion of the cash flow hedge, with a notional amount equal to the offsetting hedge, is de-designated and the related gains or losses going forward are reflected in earnings, which are largely offset by the losses or gains in the offsetting hedge.

Antelope Valley received its first loan advance on April 5, 2012, and several additional advances subsequently. Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $321 million, approximately 75% of the loan advance amount to offset portions of the original interest rate hedge, which are not designated as cash flow hedges. The remaining cash flow hedge has a notional amount of $164 million. At June 30, 2013, Generation's mark-to-market non-current derivative liability relating to the interest rate swaps in connection with the loan agreement to fund Antelope Valley was $14 million.

During the third quarter of 2011, a subsidiary of Constellation entered into floating-to-fixed interest rate swaps to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Sacramento PV Energy. The swaps have a total notional amount of $29 million as of June 30, 2013 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At June 30, 2013, the subsidiary had an immaterial current and a $2 million non-current derivative liability related to these swaps.

During the third quarter of 2012, a subsidiary of Exelon Generation entered into a floating-to-fixed interest rate swap to manage a portion of the interest rate exposure of anticipated long-term borrowings to finance Constellation Solar Horizons. The swap has a notional amount of $28 million as of June 30, 2013 and expires in 2030. This swap is designated as a cash flow hedge. At June 30, 2013, the subsidiary had an immaterial current derivative liability and an immaterial current derivative asset related to the swap.

Since the third quarter of 2012, Exelon has entered into $350 million floating-to-fixed interest rate hedges to manage interest rate risks associated with anticipated future debt issuance. These swaps are designated as cash flow hedges. At June 30, 2013, Exelon had a $23 million current derivative asset related to these swaps.

During the six months ended June 30, 2013 and 2012, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Economic Hedges . At June 30, 2013, Generation had $336 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $31 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

At June 30, 2013, Exelon and Generation had $150 million in notional amounts of fixed-to-floating interest rate swaps that are marked-to-market, with unrealized gains of $3 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the six months ended June 30, 2013 and the period from March 12 to June 30, 2012, the impact on the results of operations was immaterial.

Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon, Generation, ComEd, PECO and BGE)

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place either as the contracts deliver, when collateral is requested or in the event of default. Generation's use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e. to BB+ or Ba1). In the table below, Generation's energy related economic hedges and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, is aggregated in the collateral and netting column. As of June 30, 2013 and December 31, 2012, $3 million of cash collateral posted and $3 million of cash collateral received, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e. to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in a non affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of June 30, 2013:

	Generation				ComEd	Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting(a)	Subtotal (b)	Economic Hedges (c)	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,585	$ 1,924	$ (3,667)	$ 842	$ —	$ 842
Mark-to-market derivative assets (noncurrent assets)	1,471	522	(1,291)	702	—	702
Total mark-to-market derivative assets	$ 4,056	$ 2,446	$ (4,958)	$1,544	$ —	$ 1,544
Mark-to-market derivative liabilities (current liabilities)	$ (2,201)	$ (1,865)	$ 3,938	$ (128)	$ (16)	$ (144)
Mark-to-market derivative liabilities (noncurrent liabilities)	(941)	(502)	1,348	(95)	(69)	(164)
Total mark-to-market derivative liabilities	$ (3,142)	$ (2,367)	$ 5,286	$ (223)	$ (85)	$ (308)
Total mark-to-market derivative net assets (liabilities)	$ 914	$ 79	$ 328	$1,321	$ (85)	$ 1,236

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $17 million and $49 million, respectively, and current and noncurrent liabilities are shown net of collateral of $254 million and $106 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $328 million at June 30, 2013.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2012:

	Generation				ComEd		Exelon
Derivatives	Economic Hedges (a)	Proprietary Trading	Collateral and Netting (b)	Subtotal (c)	Economic Hedges (a)(d)	Intercompany Eliminations (a)	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,883	$ 2,469	$ (4,418)	$ 934	$ —	$ —	$ 934
Mark-to-market derivative assets with affiliate (current assets)	226	—	—	226	—	(226)	—
Mark-to-market derivative assets (noncurrent assets)	1,792	724	(1,638)	878	—	—	878
Mark-to-market							
Total mark-to-market derivative assets	$ 4,901	$ 3,193	$ (6,056)	$2,038	$ —	$ (226)	$ 1,812
Mark-to-market derivative liabilities (current liabilities)	$ (2,419)	$ (2,432)	$ 4,519	$ (332)	$ (18)	$ —	$ (350)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	(226)	226	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,080)	(689)	1,568	(201)	(49)	—	(250)
Mark-to-market							
Total mark-to-market derivative liabilities	$ (3,499)	$ (3,121)	$ 6,087	$ (533)	$ (293)	$ 226	$ (600)
Total mark-to-market derivative net assets (liabilities)	$ 1,402	$ 72	$ 31	$1,505	$ (293)	$ —	$ 1,212

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $226 million related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation excludes $28 million of noncurrent liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit. These are not reflected in the table above.

(c) Current and noncurrent assets are shown net of collateral of $113 million and $201 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(214) million and $(131) million, respectively. The total cash collateral received, net of cash collateral posted and offset against mark-to-market assets and liabilities was $31 million at December 31, 2012.

(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon, Generation and ComEd). As discussed previously, effective prior to the merger with Constellation, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and is reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective changes in the fair value of these instruments through current earnings

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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from the date of de-designation. The net unrealized gains associated with the de-designated cash flow hedges prior to the merger was $1,928 million including $693 million related to the intercompany swap with ComEd. Approximately $326 million of these net pre-tax unrealized gains within accumulated OCI are expected to be reclassified from accumulated OCI during the next twelve months by Generation. Generation expects the settlement of the majority of its cash flow hedges will occur during 2013 through 2014.

Exelon discontinues hedge accounting prospectively when it determines that the derivative is no longer effective in offsetting changes in the cash flows of a hedged item or when it is no longer probable that the forecasted transaction will occur. For the three months ended June 30, 2013 and 2012, amounts reclassified into earnings as a result of the discontinuance of cash flow hedges were immaterial.

The tables below provide the activity of accumulated OCI related to cash flow hedges for the three and six months ended June 30, 2013 and 2012, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended June 30, 2013	Income Statement Location	Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at March 31, 2013		$ 397(a)(c)	$ 310
Effective portion of changes in fair value		—	21(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(142)(b)	(86)
Accumulated OCI derivative gain at June 30, 2013		$ 255(c)	$ 245

(a) Includes $58 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of March 31, 2013.
(b) Includes $58 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $11 million of losses and $16 million of losses net of taxes, related to interest rate swaps and treasury rate locks as of June 30, 2013 and March 31, 2013, respectively.
(d) Includes $18 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Six Months Ended June 30, 2013	Income Statement Location	Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2012		$ 532(a)(c)	$ 368
Effective portion of changes in fair value		—	21(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(277)(b)	(144)
Accumulated OCI derivative gain at June 30, 2013		$ 255(c)	$ 245

(a) Includes $133 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of December 31, 2012.

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(b) Includes $133 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $11 million of losses and $20 million of losses, net of taxes, related to interest rate swaps and treasury locks as of June 30, 2013 and December 31, 2012, respectively.
(d) Includes $22 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.

Three Months Ended June 30, 2012	Income Statement Location	Generation Energy-Related Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at March 31, 2012		$ 1,166(a)(c)	$ 703
Effective portion of changes in fair value		—(e)	(17)(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(243)(b)	(139)
Accumulated OCI derivative gain at June 30, 2012		$ 923(a)(c)	$ 547

(a) Includes $315 million and $419 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd as of June 30, 2012 and March 31, 2012, respectively.
(b) Includes a $104 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $23 million of losses and $12 million of gains, net of taxes, related to interest rate swaps and treasury rate locks for the three months ended June 30, 2012 and month ended March 31, 2012, respectively.
(d) Includes $12 million of losses, net of taxes, at Generation related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.
(e) Due to de-designation of all commodity cash flow positions prior to the merger date, there are no changes in fair value.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Six Months Ended June 30, 2012	Income Statement Location	Generation Energy-Related Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2011		$ 925(a)(c)	$ 488
Effective portion of changes in fair value		432(e)	300(d)
Reclassifications from accumulated OCI to net income	Operating Revenues	(437)(b)	(244)
Ineffective portion recognized in income	Operating Revenues	3	3
Accumulated OCI derivative gain at June 30, 2012		$ 923(a)(c)	$ 547

(a) Includes $315 million and $420 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of June 30, 2012 and December 31, 2011.
(b) Includes $193 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $23 million of losses and $10 million of losses, net of taxes, related to interest rate swaps and treasury rate locks for the six months ended June 30, 2012 and year ended December 31, 2011, respectively.
(d) Includes $23 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.
(e) Includes $88 million of gains, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd through the date of de-designation prior to the merger.

During the three and six months ended June 30, 2013 and 2012, Generation's former energy related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $236 million and a $459 million pre-tax gain and $402 million and $722 million pre-tax gain,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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respectively. Given that the cash flow hedges had primarily consisted of forward power sales and power swaps and did not include power and gas options or sales, the ineffectiveness of Generation's cash flow hedges was primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. This price difference was actively managed through other instruments, which include financial transmission rights, whose changes in fair value are recognized in earnings each period, and auction revenue rights. Changes in cash flow hedge ineffectiveness, were losses of $5 million for the six months ended June 30, 2012.

Exelon's former energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $141 million and $240 million pre-tax gain for the three and six months ended June 30, 2013, respectively, and a $230 million and $403 million pre-tax gain for the three and six months ended June 30, 2012,respectively. Changes in cash flow hedge ineffectiveness was losses of $5 million for the six months ended June 30, 2012. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods as all energy-related cash flow hedge positions were de-designated prior to the merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, and physical forward sales and purchases but for which the fair value or cash flow hedge elections were not made. For the three and six months ended June 30, 2013 and 2012, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Generation			Intercompany Eliminations	Exelon
Three Months Ended June 30, 2013	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues(a)	Total
Change in fair value	$ 460	$ (77)	$383	$ (13)	$ 370
Reclassification to realized at settlement	44	1	45	3	48
Net mark-to-market gains (losses)	$ 504	$ (76)	$428	$ (10)	$ 418

	Generation			Intercompany Eliminations	Exelon
Six Months Ended June 30, 2013	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues(a)	Total
Change in fair value	$ (26)	$ 69	$ 43	$ (6)	$ 37
Reclassification to realized at settlement	(56)	38	(18)	13	(5)
Net mark-to-market gains (losses)	$ (82)	$ 107	$ 25	$ 7	$ 32

	Generation			Intercompany Eliminations	Exelon
Three Months Ended June 30, 2012	Operating Revenues	Purchased Power and Fuel	Total	Operating Revenues(a)	Total
Change in fair value	$ 44	$ 12	$ 56	$ 16	$ 72
Reclassification to realized at settlement	(54)	198	144	(10)	134
Net mark-to-market (losses)	$ (10)	$ 210	$200	$ 6	$ 206

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Six Months Ended June 30, 2012	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Total	Intercompany Eliminations Operating Revenues(a)	Exelon Total
Change in fair value	$ 177	$ (28)	$149	$ 27	$ 176
Reclassification to realized at settlement	(109)	225	116	(10)	106
Net mark-to-market (losses)	$ 68	$ 197	$265	$ 17	$ 282

(a) Prior to the merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value are recorded to operating revenues and eliminated in consolidation.

Proprietary Trading Activities (Exelon and Generation). For the three and six months ended June 30, 2013 and 2012, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on derivative instruments entered into for proprietary trading purposes. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Change in fair value	Operating Revenue	$ 5	$ 12	$ 1	$ 14
Reclassification to realized at settlement	Operating Revenue	(2)	31	4	32
Net mark-to-market gains	Operating Revenue	$ 3	$ 43	$ 5	$ 46

Credit Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $41 million, $44 million and $33 million, respectively.

Rating as of June 30, 2013	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,744	$ 139	$ 1,605	1	$ 462
Non-investment grade	40	31	9	—	—
No external ratings					
Internally rated — investment grade	456	5	451	1	247
Internally rated — non-investment grade	62	1	61	—	—
Total	$ 2,302	$ 176	$ 2,126	2	$ 709

Net Credit Exposure by Type of Counterparty	As of June 30, 2013
Investor-owned utilities, marketers and power producers	$ 761
Energy cooperatives and municipalities	926
Financial institutions	386
Other	53
Total	$ 2,126

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of June 30, 2013, ComEd's credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K for further information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is

executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of June 30, 2013, PECO had no net credit exposure with suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 - Regulatory Matters for further information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of June 30, 2013, PECO had immaterial credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 - Regulatory Matters for further information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The seller's credit exposure is calculated each business day. As of June 30, 2013, BGE had no net credit exposure to suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At June 30, 2013, BGE had credit exposure of $2 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third party suppliers.

Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e., NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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(based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Feature		June 30, 2013
Gross Fair Value of Derivative Contracts Containing this Feature(a)	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements(b)	Net Fair Value of Derivative Contracts Containing This Feature(c)
$ (1,222)	$1,046	$ (176)

Credit-Risk Related Contingent Feature		December 31, 2012
Gross Fair Value of Derivative Contracts Containing this Feature(a)	Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements(b)	Net Fair Value of Derivative Contracts Containing This Feature(c)
$ (1,849)	$1,426	$ (423)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk related contingent features ignoring the effects of master netting agreements.
(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of $546 million and letters of credit posted of $356 million and cash collateral held of $215 million and letters of credit held of $30 million as of June 30, 2013 and cash collateral posted of $527 million and letters of credit posted of $563 million and cash collateral held of $499 million and letters of credit held of $45 million at December 31, 2012 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ or Ba1), Generation could be required to post additional collateral of $1,878 million as of June 30, 2013 and $2,007 million as of December 31, 2012. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of June 30, 2013, Generation's and Exelon's swaps were in an asset position, with a fair value of $24 million and $56 million, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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See Note 21 — Segment Information of the Exelon 2012 Form 10-K for further information regarding the letters of credit supporting the cash collateral.

Generation entered into SFCs with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of June 30, 2013, ComEd held immaterial amounts of collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of June 30, 2013, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K for further information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of June 30, 2013, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of June 30, 2013, PECO could have been required to post approximately $31 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of June 30, 2013, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of June 30, 2013, BGE could have been required to post approximately $86 million of collateral to its counterparties.

11. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The Registrants had the following amounts of commercial paper borrowings outstanding as of June 30, 2013 and December 31, 2012:

Commercial Paper Borrowings	June 30, 2013	December 31, 2012
Exelon Corporate	$ —	$ —
Generation	276	—
ComEd	374	—
PECO	—	—
BGE	—	—

Credit Facilities

Exelon had bank lines of credit under committed credit facilities at June 30, 2013 for short-term financial needs, as follows:

Type of Credit Facility	Amount(a) (In billions)	Expiration Dates	Capacity Type
Exelon Corporate			
Syndicated Revolver	$ 0.5	August 2017	Letters of credit and cash
Generation			
Syndicated Revolver	5.3	August 2017	Letters of credit and cash
Bilateral	0.3	December 2015 and March 2016	Letters of credit and cash
Bilateral	0.1	January 2015	Letters of credit
ComEd			
Syndicated Revolver	1.0	March 2018	Letters of credit and cash
PECO			
Syndicated Revolver	0.6	August 2017	Letters of credit and cash
BGE			
Syndicated Revolver	0.6	August 2017	Letters of credit and cash
Total	$ 8.4		

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expire on October 18, 2013 and are solely utilized to issue letters of credit. As of June 30, 2013, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled $24 million, $26 million, $21 million and $1 million, respectively.

As of June 30, 2013, there were no borrowings under the Registrants' credit facilities.

On March 14, 2013, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2018, and ComEd may request another one-year extension of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extension or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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registrant's credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 27.5, 0.0 and 7.5 basis points for prime based borrowings and 127.5, 127.5, 127.5, 100.0 and 107.5 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreement also requires each entity to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of each entity.

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. The credit agreement expires in January 2015. This facility will solely be utilized by Generation to issue letters of credit.

On June 10, 2013, Exelon Corporate, Generation, PECO and BGE began the process of extending their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively. The transactions are expected to close and become effective in August 2013, with maturities of five years from the close of the transactions. The new covenants are expected to be substantially consistent with existing covenants. Generally, it is expected that costs incurred to amend and extend the facilities will be amortized over the newly extended lives of the facilities.

Long-Term Debt

Issuance of Long-Term Debt

During the six months ended June 30, 2013, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Upstream Gas Lending Agreement	2.210%	July 22, 2016	$ 3	Used to fund Upstream gas activities
Generation	DOE Project Financing	2.535 - 2.922%	January 5, 2037	$ 197	Funding for Antelope Valley Solar Development
Generation	Energy Efficiency Project Financing	4.400%	August 31, 2014	$ 9	Funding to install energy conservation measures in Beckley, West Virginia
BGE	Senior Notes	3.350%	July 1, 2023	$ 300	Used to partially refinance Notes due July 1, 2013 and for general corporate purposes

During the six months ended June 30, 2012, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Senior Notes	4.250%	June 15, 2022	$ 523	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	Senior Notes	5.600%	June 15, 2042	$ 787	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	DOE Project Financing	3.092%	January 5, 2037	$ 69	Funding for Antelope Valley Solar Development

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Retirement of Current and Long-Term Debt

During the six months ended June 30, 2013, the following long-term debt was retired:

Company	Type	Interest Rate	Maturity	Amount
Generation	Kennett Square Capital Lease	7.830%	September 20, 2020	$ 1
Generation	Solar Revolver	1.950%	July 7, 2014	$ 6
Generation	Clean Horizons	2.563%	September 7, 2030	$ 1
Generation(a)	Series A Junior Subordinated Debentures	8.625%	June 15, 2063	$ 450
ComEd	First Mortgage Bonds Series 92	7.625%	April 15, 2013	$ 125
BGE	Rate Stabilization Bonds	5.720%	April 1, 2017	$ 33

(a) Represents debt obligations assumed by Exelon as part of the merger on March 12, 2012 that became callable at face value on June 15, 2013. Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable as of December 31, 2012 included in long-term debt to affiliate on Generation's Consolidated Balance Sheets and notes receivable from affiliates at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets. The third-party debt obligations were reported in Long-term Debt on Exelon's Consolidated Balance Sheets as of December 31, 2012. The debentures were redeemed and the intercompany loan agreements repaid on June 15, 2013.

On July 1, 2013, ComEd retired $127 million aggregate principal of its 7.500% Series 94 First Mortgage Bonds due July 1, 2013.

On July 1, 2013, BGE retired $400 million aggregate principal of its 6.125% Senior Notes due July 1, 2013

During the six months ended June 30, 2012, the following long-term debt was retired:

Company	Type	Interest Rate	Maturity	Amount
ComEd	First Mortgage Bond Series 98	6.15%	March 15, 2012	$ 450
BGE	Rate Stabilization Bonds	5.68%	April 1, 2017	$ 31
BGE	Medium Term Notes	6.73 - 6.75%	June 15, 2012	$ 110
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 1
Generation	Armstrong Co. tax-exempt	5.00%	December 1, 2042	$ 46
Generation	Solar Revolver	2.49%	July 7, 2014	$ 6
Generation	Upstream Gas Lending Agreement	2.27%	July 16, 2016	$ 3
Exelon	Senior Notes	7.60%	April 1, 2032	$ 441
Exelon	Medium Term Notes	7.30%	June 1, 2012	$ 2

Accounts Receivable Agreement

PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $210 million, which is classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets. As of June 30, 2013 and December 31, 2012, the financial institution's undivided interest in Exelon's and PECO's gross accounts receivable was equivalent to $286 million and $289 million, respectively, which represents the financial institution's interest in PECO's eligible receivables as calculated under the terms of the agreement. The agreement requires PECO to maintain eligible receivables at least equivalent to the financial

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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institution's undivided interest. Upon termination or liquidation of this agreement, the financial institution is entitled to recover up to $210 million plus the accrued yield payable from its undivided interest in PECO's receivables. The amended agreement terminates on August 30, 2013 unless extended in accordance with its terms. As of June 30, 2013, PECO was in compliance with the requirements of the agreement. In the event the agreement is not extended, PECO has sufficient short-term liquidity and may seek alternate financing.

12. Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

For the Three Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	4.1	3.5	5.6	2.9	5.6
Qualified nuclear decommissioning trust fund income	(1.8)	(2.7)	—	—	—
Domestic production activities deduction	0.1	0.2	—	—	—
Tax exempt income	(0.1)	(0.2)	—	—	—
Health care reform legislation	0.1	—	0.4	—	(0.3)
Amortization of investment tax credit, net deferred taxes	(1.8)	(2.5)	(0.3)	(0.1)	(0.6)
Plant basis differences	(1.4)	—	(0.4)	(8.6)	(0.7)
Production tax credits and other credits	(1.4)	(2.2)	—	—	—
Other	(0.3)	0.1	0.4	(0.1)	—
Effective income tax rate	32.5 %	31.2 %	40.7 %	29.1 %	39.0 %

For the Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	8.6	0.4	4.1	2.9	5.7
Qualified nuclear decommissioning trust fund income	2.8	4.8	—	—	—
Domestic production activities deduction	—	(0.1)	—	—	—
Tax exempt income	(0.2)	(0.4)	—	—	—
Health care reform legislation	0.2	—	5.7	—	0.2
Amortization of investment tax credit, net deferred taxes	(3.5)	(5.6)	(4.9)	(0.1)	(0.3)
Plant basis differences	(3.1)	—	(8.7)	(7.5)	(0.6)
Production tax credits and other credits	(2.8)	(4.9)	(0.3)	—	—
Other	0.1	3.1	5.5	—	(0.2)
Effective income tax rate	37.1 %	32.3 %	36.4 %	30.3 %	39.8 %

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For the Three Months Ended June 30, 2012	Exelon(a)	Generation(a)	ComEd	PECO	BGE(b)
U.S. Federal statutory rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	3.5	2.3	5.2	3.1	6.2
Qualified nuclear decommissioning trust fund income	(2.0)	(3.8)	—	—	—
Domestic production activities deduction	0.7	1.6	—	—	—
Tax exempt income	(0.4)	(0.8)	—	—	—
Health care reform legislation	0.3	—	1.0	—	2.7
Amortization of investment tax credit, net deferred taxes	(0.7)	(0.7)	(0.8)	(0.3)	(1.7)
Plant basis differences	(0.7)	—	0.1	(3.6)	(4.7)
Production tax credits and other credits	(2.2)	(4.0)	—	—	—
Merger expenses(c)	(0.8)	—	—	—	—
Other	(2.3)	(3.6)	0.3	0.2	(1.5)
Effective income tax rate	30.4 %	26.0 %	40.8 %	34.4 %	36.0 %

For the Six Months Ended June 30, 2012	Exelon(a)	Generation(a)	ComEd	PECO	BGE(b)
U.S. Federal statutory rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(10.7)	1.6	5.7	3.3	2.3
Qualified nuclear decommissioning trust fund income	6.3	8.0	—	—	—
Domestic production activities deduction	(0.2)	(0.2)	—	—	—
Tax exempt income	(0.4)	(0.5)	—	—	—
Health care reform legislation	0.2	—	0.6	—	(3.1)
Amortization of investment tax credit, net deferred taxes	(0.7)	(0.6)	(0.5)	(0.3)	3.8
Plant basis differences	(0.6)	—	—	(3.6)	10.6
Production tax credits and other credits	(2.6)	(3.4)	—	—	—
Fines and Penalties	6.1	7.6	—	—	—
Merger expenses(c)	5.6	—	—	—	(18.3)
Other	(1.3)	(1.0)	0.3	—	3.0
Effective income tax rate	36.7 %	46.5 %	41.1 %	34.4 %	33.3 %

(a) Exelon activity for the three and six months ended June 30, 2012 includes the results of Constellation and BGE for March 12, 2012 — June 30, 2012. Generation activity for the three and six months ended June 30, 2012 includes the results of Constellation for March 12, 2012 — June 30, 2012.

(b) BGE activity represents the activity for the three and six months ended June 30, 2012. BGE recognized a loss before income taxes for the six months ended June 30, 2012. As a result, positive percentages represent an income tax benefit for BGE for the six months ended June 30, 2012.

(c) Prior to the close of the merger, the Registrants recorded the applicable taxes on merger transaction costs assuming the merger would not be completed. Upon closing of the merger, the Registrants reversed such taxes for those merger transaction costs that were determined to be non tax-deductible upon successful completion of a merger.

Accounting for Uncertainty in Income Taxes

Exelon, Generation, ComEd, PECO, and BGE have $2,220 million, $1,363 million, $331 million, $44 million, and $0 million, of unrecognized tax benefits as of June 30, 2013, respectively, and $1,024 million, $876 million, $67 million, $44 million, and $0 million, of unrecognized tax benefits as of December 31, 2012,

respectively. The unrecognized tax benefits as of June 30, 2013 reflect an increase at Exelon and ComEd attributable to the like-kind exchange position discussed below. Furthermore, Exelon's and Generation's unrecognized tax benefits were increased by $446 million and $446 million, respectively, in the second quarter in anticipation of filing a refund claim with respect to legacy Constellation taxable years.

Reasonably possible the total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Settlement of income tax audits

In 2013, as a result of the anticipated completion of federal income tax audits for legacy Constellation, it is reasonably possible Exelon and Generation may reduce their unrecognized tax benefits by approximately $35 million and $35 million, respectively.

Other Income Tax Matters

Involuntary Conversion, Like-Kind Exchange and Competitive Transition Charges

1999 Sale of Fossil Generating Assets (Exelon and ComEd) . Exelon, through its ComEd subsidiary, took two positions on its 1999 income tax return to defer approximately $2.8 billion of tax gain on the sale of ComEd's fossil generating assets. Exelon deferred approximately $1.6 billion of the gain under the involuntary conversion provisions of the IRC. Exelon believed that it was economically compelled to dispose of ComEd's fossil generating plants as a result of the Illinois Act and that the proceeds from the sale of the fossil plants were properly reinvested in qualifying replacement property such that the gain could be deferred over the lives of the replacement property under the involuntary conversion provisions. The remaining approximately $1.2 billion of the gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with both positions and asserted that the entire gain of approximately $2.8 billion was taxable in 1999.

Competitive Transition Charges (Exelon, ComEd, and PECO) . Exelon contended that the Illinois Act and the Competition Act resulted in the taking of certain of ComEd's and PECO's assets used in their respective businesses of providing electricity services in their defined service areas. Exelon filed refund claims with the IRS taking the position that CTCs collected during ComEd's and PECO's transition periods represent compensation for that taking and, accordingly, were excludible from taxable income as proceeds from an involuntary conversion. The tax basis of property acquired with the funds provided by the CTCs would be reduced such that the benefits of the position are temporary in nature. The IRS disallowed the refund claims for the 1999-2001 tax years.

Status of Involuntary Conversion and CTC Positions. In the second quarter of 2010, the IRS offered to settle the disagreement over the involuntary conversion and CTC positions. Exelon concluded, based on that offer, that it had sufficient new information that a remeasurement of the involuntary conversion and CTC positions was required in accordance with applicable accounting standards. As a result of the required remeasurement, Exelon recorded $65 million (after-tax) of interest expense, of which $36 million (after-tax) and $22 million (after-tax) were recorded at ComEd and PECO, respectively. ComEd also recorded a current tax expense of $70 million offset with a tax benefit recorded at Generation of $70 million. In the third quarter of 2010, Exelon and the IRS reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion on terms consistent with the settlement offer received in the second quarter. As a result of the preliminary agreement, Exelon and ComEd eliminated any liability for unrecognized tax benefits and established a current

tax payable to the IRS. Exelon paid $302 million in late 2010 in advance of the final settlement and the assessment. In November 2012, the IRS and Exelon finalized and executed definitive agreements to resolve Exelon's involuntary conversion and CTC positions.

Status of Like-Kind Exchange Position. Exelon has been unable to reach agreement with the IRS regarding the dispute over the like kind exchange position. The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately $86 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Exelon expects to initiate litigation in 2013 to contest the IRS's disallowance of the like-kind exchange position. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison's deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon's current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013 Exelon recorded a non-cash charge to earnings of approximately $265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $170 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition, ComEd will continue to record a receivable and non-cash equity contribution from Exelon in amounts equal to the additional interest recorded by ComEd on the uncertain tax position. The IRS also continues to assert an $86 million penalty for a substantial understatement of tax with respect to the like-kind exchange position. Exelon continues to believe that it is unlikely that the penalty assertion will ultimately be sustained and therefore no liability for the penalty has been recorded.

This determination for accounting purposes does not alter Exelon's intent to aggressively litigate the issue through appeals, if necessary, which could take three to five years. Exelon currently expects to initiate the litigation in the United States Tax Court, whose decisions are not controlled by the Federal Circuit's decision in Consolidated Edison.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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As of June 30, 2013, in the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and interest, exclusive of penalties, that could become currently payable may be as much as $840 million, of which approximately $306 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

Accounting for Generation Repairs (Exelon and Generation).

On April 30, 2013, the IRS issued guidance that will facilitate the determination of the appropriate tax treatment of costs incurred to repair electric generation assets. Exelon and Generation will assess its impact and expect to file a request for change in method of tax accounting for repair costs beginning with its 2014 taxable year.

13. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets from December 31, 2012 to June 30, 2013:

Nuclear decommissioning ARO at December 31, 2012(a)	$4,741
Accretion expense	129
Costs incurred to decommission retired plants	(2)
Nuclear decommissioning ARO at June 30, 2013(a)	$4,868

(a) Includes $10 million as the current portion of the ARO at June 30, 2013 and December 31, 2012, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with the former ComEd, former PECO and former AmerGen units have been funded with amounts collected from ComEd customers, PECO customers and the previous owners of the former AmerGen plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO currently collects funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are expected to continue through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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deposited into the NDT funds. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. With respect to the former AmerGen units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts collected from ComEd and PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation. Generation has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after decommissioning has been completed are required to be refunded to ComEd’s or PECO’s customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units, Generation retains any funds remaining in the funds after decommissioning.

At June 30, 2013 and December 31, 2012, Exelon and Generation had NDT fund investments totaling $7,463 million and $7,248 million, respectively. The following table provides unrealized gains (losses) on NDT funds for the three and six months ended June 30, 2013 and 2012:

	Exelon and Generation			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net unrealized gains (losses) on decommissioning trust funds — Regulatory Agreement Units(a)	$ (102)	$ (96)	$ 92	$ 150
Net unrealized gains (losses) on decommissioning trust funds — Non-Regulatory Agreement Units(b)(c)	(40)	(35)	24	30

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.

(b) Excludes $2 million and $ 4 million of net unrealized gains related to the Zion Station pledged assets for the three months ended June 30, 2013 and 2012, respectively, and $3 million and $38 million of net unrealized gains related to the Zion Station pledged assets for the six months ended June 30, 2013 and 2012, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.

(c) Net unrealized gains (losses) related to Generation's NDT funds associated with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

See Note 3 — Regulatory Matters and Note 22 – Related Party Transactions of the Exelon 2012 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning. On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. On January 7, 2013, EnergySolutions announced that it had entered a definitive acquisition agreement to be acquired by another Company. Generation reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA. See Note 13 — Asset Retirement Obligations of the Exelon 2012 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction.

On July 14, 2011, three people filed a purported class action lawsuit in the United States District Court for the Northern District of Illinois naming ZionSolutions and Bank of New York Mellon as defendants and seeking, among other things, an accounting for use of NDT funds, an injunction against the use of NDT funds, the appointment of a trustee for the NDT funds, and the return of NDT funds to customers of ComEd to the extent legally entitled thereto. If the plaintiffs prevail on the merits of their claims, some or all of the NDT funds may no longer be available to ZionSolutions for decommissioning Zion Station, in which case, the contractual arrangement would require ZionSolutions to utilize a line of credit to complete the decommissioning. In addition, the appointment of a NDT fund trustee in this matter could impact Generation's future decommissioning activities at other stations by setting a precedent for the appointment of trustees for NDT funds. On July 20, 2012, ZionSolutions and Bank of New York Mellon filed a motion to dismiss the amended complaint for failing to state a claim. On July 29, 2013, United States District Court for the Northern District of Illinois dismissed the amended complaint.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a payable to ZionSolutions in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers. Generation has retained its obligation to transfer the SNF at Zion Station to the DOE for ultimate disposal and has a liability of approximately $81 million, which is included within the nuclear decommissioning ARO at June 30, 2013. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table provides the pledged assets and payable to ZionSolutions, and withdrawals by ZionSolutions at June 30, 2013 and December 31, 2012:

	Exelon and Generation	
	June 30, 2013	December 31, 2012
Carrying value of Zion Station pledged assets	$538	$ 614
Payable to Zion Solutions(a)	491	564
Current portion of payable to Zion Solutions(b)	118	132
Withdrawals by Zion Solutions to pay decommissioning costs(c)	414	335

(a) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.
(c) Cumulative withdrawals since September 1, 2010.

NRC Minimum Funding Requirements . NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. On April 1, 2013, Generation submitted its NRC-required biennial decommissioning funding status report as of December 31, 2012. As of December 31, 2012, Generation provided adequate funding assurance for all of its units, including Limerick Unit 1, where Generation has in place a $115 million parent guarantee to cover the NRC minimum funding assurance requirements.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential "apparent violations" of its regulations because of alleged inaccuracies in the Decommissioning Funding Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation's status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. Generation met with the NRC on April 30, 2013 for a pre-decisional enforcement conference to provide additional information to explain why Generation believes that it complied with the regulatory requirements and did not deliberately or otherwise provide incomplete or inaccurate information in its decommissioning funding status reports. While Generation does not believe that any sanction is appropriate, the ultimate outcome of this proceeding including the amount of a potential fine or sanction, if any, is uncertain. Generation anticipates that the NRC will issue its findings sometime this year. The January 31, 2013 letter from the NRC does not take issue with Generation's current funding status, and as reflected in Generation's April 1, 2013 decommissioning funding status report referenced above, Generation continues to provide adequate funding assurance for each of its units.

In addition, on June 24, 2013, Exelon received a subpoena from the SEC requesting that Exelon provide the SEC with certain documents generally relating to Exelon and Generation's reporting and funding of the future decommissioning of Exelon's nuclear power plants. Exelon and Generation are cooperating with the SEC and providing the requested documents.

14. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2013, Exelon received an updated valuation of its legacy Exelon pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $8 million and a decrease to the other postretirement benefit obligation of $39 million. Additionally, accumulated other comprehensive loss decreased by approximately $75 million (after tax) and regulatory assets increased approximately by $93 million. During the second quarter of 2013, Exelon received the updated valuation for the legacy Constellation pension and other postretirement obligations to reflect actual census data as of January 1, 2013. This valuation resulted in an increase to the pension obligation of $23 million and a decrease to the other postretirement benefit obligation of $12 million. Additionally, accumulated other comprehensive loss increased by approximately $2 million (after tax) and regulatory assets increased by approximately $14 million.

The following tables present the components of Exelon's net periodic benefit costs for the three and six months ended June 30, 2013 and 2012. The 2013 pension benefit cost for all plans is calculated using an expected long-term rate of return on plan assets of 7.50% and a discount rate of 3.92%. The 2013 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.45% for funded plans and a discount rate of 4.00% for all plans. Legacy Constellation other postretirement benefit plans are not funded. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

	Pension Benefits Three Months Ended June 30,		Other Postretirement Benefits Three Months Ended June 30,	
	2013	2012	2013	2012
Service cost	$ 79	$ 74	$ 40	$ 39
Interest cost	163	179	49	54
Expected return on assets	(254)	(253)	(33)	(29)
Amortization of:				
Transition obligation	—	—	—	2
Prior service cost (benefit)	4	3	(6)	(3)
Actuarial loss	141	115	21	19
Contractual termination benefit cost(a)	—	14	—	6
Curtailment gain	—	—	—	(2)
Net periodic benefit cost	$ 133	$ 132	$ 71	$ 86

	Pension Benefits Six Months Ended June 30,		Other Postretirement Benefits Six Months Ended June 30,	
	2013	2012	2013	2012
Service cost	$ 159	$ 135	$ 81	$ 76
Interest cost	326	343	97	104
Expected return on assets	(508)	(484)	(66)	(58)
Amortization of:				
Transition obligation	—	—	—	6
Prior service cost (benefit)	7	7	(10)	(6)
Actuarial loss	281	221	42	38
Contractual termination benefit cost(a)	—	14	—	6
Curtailment gain	—	—	—	(2)
Net periodic benefit cost	$ 265	$ 236	$ 144	$ 164

(a) ComEd and BGE established regulatory assets of $1 million and $4 million, respectively, for their portion of the second quarter 2012 contractual termination benefit charge.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The amounts below were included in capital additions and operating and maintenance expense during the three and six months ended June 30, 2013 and 2012, for Generation's, ComEd's, PECO's, BGE's and BSC's allocated portion of the pension and postretirement benefit plan costs.

Pension and Other Postretirement Benefit Costs	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Generation	$ 87	$ 94	$ 173	$ 175
ComEd	77	68	154	137
PECO	10	13	21	26
BGE(a)(b)	14	18	27	32
BSC(c)	16	25	34	42

(a) BGE's pension and postretirement benefit costs for the six months ended June 30, 2012 include $12 million of costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. These amounts are not included in Exelon's net periodic benefit costs for the six months ended June 30, 2012 shown in the first table of the Defined Benefit Pension and Other Postretirement Benefits section above.
(b) BGE's pension and other postretirement benefit costs for the three and six months ended June 30, 2012 includes a $3 million contractual termination benefit charge, which was recorded as a regulatory asset as of June 30, 2012.
(c) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above. As of June 30, 2012, ComEd and BGE each recorded a regulatory asset of $1 million related to their BSC-billed portion of the second quarter 2012 contractual termination benefit charge.

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. Exelon expects to contribute $255 million to its qualified pension plans in 2013, of which Generation, ComEd, PECO and BGE will contribute $113 million, $115 million, $11 million and $0 million, respectively. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $81 million in 2013, of which Generation, ComEd, PECO, and BGE will make payments of $7 million, $1 million, $1 million, and $2 million, respectively.

Unlike qualified pension plans, other postretirement plans are not subject to regulatory minimum contribution requirements. Exelon's management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). In 2013, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans previously sponsored by Constellation and AmerGen, which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $276 million in 2013, of which Generation, ComEd, PECO, and BGE expect to contribute $108 million, $112 million, $21 million, and $17 million, respectively.

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

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(Dollars in millions, except per share data, unless otherwise noted)

Exelon has developed and implemented an investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. This investment strategy would tend to result in a lower expected rate of return on plan assets in future years. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30,		Six Months Ended June 30,	
Savings Plan Matching Contributions	2013	2012	2013	2012
Exelon	$ 21	$ 19	$ 43	$ 35
Generation	10	8	21	16
ComEd	5	5	10	9
PECO	2	2	4	4
BGE(a)	2	1	4	3
BSC(b)	2	3	4	4

(a) BGE's matching contributions for the six months ended June 30, 2012 include $1 million of costs incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012, which is not included in Exelon's matching contributions for the six months ended June 30, 2012.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO or BGE amounts above.

15. Stock-Based Compensation Plans (Exelon, Generation, ComEd, PECO and BGE)

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At June 30, 2013, there were approximately 16 million shares authorized for issuance under the LTIP. For the three and six months ended June 30, 2013 and 2012, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

The Compensation Committee of Exelon's Board of Directors changed the mix of awards granted under the LTIP in 2013 by eliminating stock options in favor of the use of full value shares, consisting of performance shares and restricted stock. The performance share awards granted in 2013 will vest at the end of a three-year performance period. The performance share awards granted in 2012 and earlier had a one-year performance period and vested ratably over three years. To address the reduction in annual award opportunity resulting from the transition to a three-year performance period, the Compensation Committee also approved a one-time grant of performance share transition awards in 2013, which will vest one-third after one year, with the remaining balance vesting over a two-year performance period.

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(Dollars in millions, except per share data, unless otherwise noted)

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30,		Six Months Ended June 30,	
Components of Stock-Based Compensation Expense	2013	2012	2013	2012
Performance share awards	$ 13	$ 10	$ 29	$ 26
Stock options	1	4	2	11
Restricted stock units	16	11	36	30
Other stock-based awards	2	1	3	2
Total stock-based compensation expense included in operating and maintenance expense	32	26	70	69
Income tax benefit	(12)	(10)	(27)	(26)
Total after-tax stock-based compensation expense	$ 20	$ 16	$ 43	$ 43

The following table presents stock-based compensation expense (pre-tax) for the three and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30,		Six Months Ended June 30,	
Subsidiaries	2013	2012	2013	2012
Generation	$ 13	$ 9	$ 28	$ 24
ComEd	2	2	4	7
PECO	1	1	3	3
BGE(a)	2	1	4	3
BSC(b)	14	13	31	32
Total(c)	$ 32	$ 26	$ 70	$ 69

(a) BGE's stock-based compensation expense (pre-tax) for the six months ended June 30, 2012 includes $2 million of cost incurred prior to the closing of Exelon's merger with Constellation on March 12, 2012. This amount is not included in Exelon's stock-based compensation expense for the six months ended June 30, 2012 shown in the table titled Components of Stock-Based Compensation Expense above.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO and BGE amounts above.

(c) The stock-based compensation expense (pre-tax) for the three and six months ended June 30, 2013 reflects the impact of changes to the retirement eligibility requirements for employees participating in the LTIP. In addition, the stock-based compensation expense at ComEd reflects the adoption of the ComEd Key Manager Long-Term Performance Program in 2013 for certain employees, which is not consider stock-based compensation expense under the applicable authoritative guidance. In 2012, these employees participated in the Exelon Restricted Stock Award Program.

There were no significant stock-based compensation costs capitalized during the three and six months ended June 30, 2013 and 2012.

Stock Options

Non-qualified stock options are granted under the LTIP with exercise prices equal to the fair market value of the underlying stock at the date of grant. Generally, the stock options vest ratably over a four-year vesting period and expire ten years from the date of grant.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

There were no stock options granted in 2013. The Compensation Committee eliminated stock option grants by changing the mix of long-term incentives for Senior Vice Presidents (SVPs) and higher officers from 75% performance shares and 25% stock options to 67% performance shares and 33% restricted stock units ("RSUs").

At June 30, 2013, $3 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 2.0 years.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility.

At June 30, 2013 and December 31, 2012, Exelon had obligations related to outstanding restricted stock units not yet settled of $60 million and $58 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. As of June 30, 2013 and December 31, 2012, Exelon had no obligations related to outstanding restricted stock units that will be settled in cash. During the three months ended June 30, 2013 and 2012, Exelon settled restricted stock units with a fair value totaling $1 million and $2 million, respectively. During the six months ended June 30, 2013 and 2012, Exelon settled restricted stock units with a fair value totaling $23 million and $21 million, respectively. At June 30, 2013, $81 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.4 years.

Performance Share and Performance Share Transition Awards

Performance share awards are granted under the LTIP with the 2013 performance share awards being settled 50% in common stock and 50% in cash at the end of the three-year performance period except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. The 2012 performance share awards are being settled 50% in common stock and 50% in cash over the three-year vesting term with executive vice presidents and higher officers receiving 100% cash if certain ownership requirements are satisfied. The performance shares granted prior to 2012 generally vest and settle over a three-year period with the holders receiving shares of common stock and/or cash annually during the vesting period.

The one-time 2013 performance share transition awards, which provide an opportunity to earn an award contingent on company performance, will be settled 50% in common stock and 50% in cash, except for awards granted to executive vice presidents and higher officers that may be settled 100% in cash if certain ownership requirements are satisfied. One-third of the award vests and is payable after a one-year performance period while the remaining two-thirds vests and is payable after a two-year performance period.

The payout of the 2013 performance share awards and one-time performance share transition awards are based on the Company's performance against specific operational and financial goals set annually during the respective performance periods. As a result, the 2013 performance share awards have been divided into equal tranches for the purpose of expense recognition as though the respective award were multiple awards; with each tranche representing a corresponding fiscal year. The one-time performance share transition awards have also been divided into multiple tranches for the purpose of expense recognition. One tranche reflects the one-third of the awards that vests and are payable after a one-year period. The two-thirds of the one-time performance share

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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transition awards that are subject to a two-year performance period have also been divided into equal tranches; with each tranche representing a corresponding fiscal year. The grant date for each tranche of the 2013 performance share and one-time performance share transition awards is the date in which the performance goals for that fiscal year are approved and communicated, which typically occurs at the corresponding January Compensation Committee meeting.

The 2013 performance share awards and one-time performance share transition awards are recorded at fair value at the grant dates for each tranche, with the estimated grant date fair value based on the expected payout of the award, which may range from 50% to 150% of the payout target. The 2013 performance share awards also include a total shareholder return modifier (TSR) that may increase or decrease the award up to 25% and an individual performance modifier (IPM) that can decrease the award by up to 50% or increase the award by up to 10% for senior vice presidents and higher officers or up to 20% for vice presidents. The one-time performance share transition award is not affected by either TSR or the IPM.

The common stock portion of the performance share and one-time performance share transition awards is considered an equity award being valued based on Exelon's stock price on the grant date. The cash portion of the awards is considered a liability award which is remeasured each reporting period based on Exelon's current stock price. As the value of the common stock and cash portions of the awards are based on Exelon's stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

The 2012 performance share awards are recorded at fair value at the date of grant with the estimated grant date fair value based on the expected payout of the award, which may range from 75% to 125% of the payout target. The common stock portion is considered an equity award with the 75% payout floor being valued based on Exelon's stock price on the grant date. The cash portion of the award is considered a liability award with the 75% payout floor being remeasured each reporting period based on Exelon's current stock price. The expected payout in excess of the 75% floor for the equity and liability portions are remeasured each reporting period based on Exelon's current stock price and changes in the expected payout of the award; therefore these portions of the award are subject to volatility until the payout is established.

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share and one-time performance share transition awards granted to retirement-eligible employees, the value of the performance shares in recognized ratably over the vesting period, which is the year of grant.

At June 30, 2013 and December 31, 2012, Exelon had obligations related to outstanding performance shares not yet settled of $54 million and $53 million, respectively. During the three months ended June 30, 2013 and 2012, Exelon settled performance shares with a fair value totaling $1 million and $19 million, respectively, of which $1 million and $3 million was paid in cash, respectively. During the six months ended June 30, 2013 and 2012, Exelon settled performance shares with a fair value totaling $23 million and $19 million, respectively, of which $10 million and $3 million was paid in cash, respectively. As of June 30, 2013, $39 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 2.5 years. In addition, as of June 30, 2013, $25 million of total unrecognized compensation costs related to nonvested one-time performance share transition awards are expected to be recognized over the remaining weighted-average period of 1.6 years.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

16. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, and PECO)

The following table presents changes in accumulated other comprehensive income (loss) (AOCI) by component for six months ended June 30, 2013:

	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon(a)						
Beginning balance	$ 368	$ —	$ (3,137)	$ —	$ 2	$(2,767)
OCI before reclassifications	24	(1)	87	(6)	31	135
Amounts reclassified from AOCI(b)	(147)	—	101	—	5	(41)
Net current-period OCI	(123)	(1)	188	(6)	36	94
Ending balance	$ 245	$ (1)	$ (2,949)	$ (6)	$ 38	$(2,673)
Generation(a)						
Beginning balance	$ 512	$ —	$ —	$ —	$ 1	$ 513
OCI before reclassifications	12	(1)	—	(6)	31	36
Amounts reclassified from AOCI(b)	(279)	—	—	—	5	(274)
Net current-period OCI	(267)	(1)	—	(6)	36	(238)
Ending balance	$ 245	$ (1)	$ —	$ (6)	$ 37	$ 275
PECO(a)						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI(b)	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See next table for details about these reclassifications.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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The following table presents amounts reclassified out of AOCI to Net Income during the three and six months ended June 30, 2013:

Three Months Ended June 30, 2013

Details about AOCI components	Items reclassified out of AOCI (a)					Affected line item in the statement where Net Income is presented
	Exelon	Generation	ComEd	PECO	BGE	
Gains and (losses) on cash flow hedges						
Energy related hedges	$ 141	$ 236	$ —	$ —	$—	Operating revenues
Other cash flow hedges	—	1	—	—	—	Interest expense
	141	237	—	—	—	Total before tax
	(52)	(93)	—	—	—	Tax (expense)
	$ 89	$ 144	$ —	$ —	$—	Net of tax
Amortization of pension and other postretirement benefit plan items						
Prior service costs	$ (1)	$ —	$ —	$ —	$—	(b)
Actuarial gains/ (losses)	(82)	—	—	—	—	(b)
	(83)	—	—	—	—	Total before tax
	32	—	—	—	—	Tax benefit
	$ (51)	$ —	$ —	$ —	$—	Net of tax
Equity investments						
Capital activity	$ (5)	$ (5)	$ —	$ —	$—	Equity in losses of unconsolidated affiliates
	(5)	(5)	—	—	—	Total before tax
	2	2	—	—	—	Tax benefit
	$ (3)	$ (3)	$ —	$ —	$—	Net of tax
Total Reclassifications for the period	$ 35	$ 141	$ —	$ —	$—	Net of Tax

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Six Months Ended June 30, 2013

Details about AOCI components	Items reclassified out of AOCI (a)					Affected line item in the statement where Net Income is presented
	Exelon	Generation	ComEd	PECO	BGE	
Gains and (losses) on cash flow hedges						
Energy related hedges	$ 240	$ 459	$ —	$ —	$—	Operating revenues
Other cash flow hedges	(1)	1	—	—	—	Interest expense
	239	460	—	—	—	Total before tax
	(92)	(181)	—	—	—	Tax (expense)
	$ 147	$ 279	$ —	$ —	$—	Net of tax
Amortization of pension and other postretirement benefit plan items						
Prior service costs	$ (1)	$ —	$ —	$ —	$—	(b)
Actuarial gains/ (losses)	(165)	—	—	—	—	(b)
	(166)	—	—	—	—	Total before tax
	65	—	—	—	—	Tax benefit
	$(101)	$ —	$ —	$ —	$—	Net of tax
Equity investments						
Capital activity	$ (8)	$ (8)	$ —	$ —	$—	Equity in losses of unconsolidated affiliates
	(8)	(8)	—	—	—	Total before tax
	3	3	—	—	—	Tax benefit
	$ (5)	$ (5)	$ —	$ —	$—	Net of tax
Total Reclassifications for the period	$ 41	$ 274	$ —	$ —	$—	Net of Tax

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see note 14 for additional details).

17. Earnings Per Share and Equity (Exelon and PECO)

Earnings per Share (Exelon)

Diluted earnings per share is calculated by dividing net income attributable to common shareholders by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding (in millions) used in calculating diluted earnings per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income attributable to common shareholders	$ 490	$ 286	$ 486	$ 486
Average common shares outstanding — basic	856	853	856	779
Assumed exercise of stock options, performance share awards and restricted stock	4	3	3	2
Average common shares outstanding — diluted	860	856	859	781

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 17 million and 18 million for the three and six months ended June 30, 2013, respectively, and 17 million and 13 million for the three and six months ended June 30, 2012, respectively.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of June 30, 2013. In 2008, Exelon management decided to defer indefinitely any share repurchases.

Preferred Securities Redemption (Exelon and PECO)

On March 25, 2013, PECO announced that it issued a notice of redemption for all of its outstanding preferred securities with a redemption date of May 1, 2013. PECO had $87 million of cumulative preferred securities that were redeemable at its option at any time for the redemption price established when each series of securities were issued. The redemption premium of $6 million is treated as a reduction to Net income to arrive at Net income attributable to common shareholders utilized in the calculation of the earnings per share for Exelon. As a result of the redemption, PECO is now indirectly, wholly-owned by Exelon.

18. Commitments and Contingencies (Exelon, Generation, ComEd, PECO and BGE)

The following is an update to the current status of commitments and contingencies set forth in Note 19 of the Exelon 2012 Form 10-K.

Commitments

Energy Commitments

As of June 30, 2013, Generation's short-and long-term commitments relating to purchases from unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following table:

	Net Capacity Purchases(a)	Power-Related Purchases(b)	Transmission Rights Purchases(c)	Purchased Energy from CENG	Total
2013	$ 192	$ 30	$ 14	$ 406	$ 642
2014	372	98	26	668	1,164
2015	367	65	13	—	445
2016	283	39	2	—	324
2017	222	10	2	—	234
Thereafter	528	4	34	—	566
Total	$ 1,964	$ 246	$ 91	$ 1,074	$3,375

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at June 30, 2013, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. These capacity payments represent the fixed, or pre-determined, payment for output from contracted generation facilities. Output in this context generally includes products such as energy, capacity, and various ancillary services associated with generating facilities. Expected payments include certain capacity charges which are contingent on plant availability.

(b) Power-Related Purchases include firm REC purchase agreements. The table excludes renewable energy purchases that are contingent in nature.

(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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In connection with Constellation's comprehensive agreement with EDF in October 2010, Constellation's and EDF's existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements, CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the available output of CENG's nuclear plants at market prices. Generation discloses in the table above commitments to purchase from CENG at fixed prices. All commitments to purchase at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 6 — Investment in Constellation Energy Nuclear Group, LLC for more details on this arrangement.

ComEd's, PECO's and BGE's electric supply procurement, curtailment services, REC and AEC purchase commitments as of June 30, 2013 are as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
ComEd							
Electric supply procurement(a)	$1,053	$317	$323	$136	$137	$140	$ —
Renewable energy and RECs(b)	1,615	31	67	74	76	77	1,290
PECO							
Electric supply procurement(c)	886	516	308	62	—	—	—
AECs	22	5	5	2	2	2	6
BGE							
Electric supply procurement(d)	1,480	557	689	234	—	—	—
Curtailment services(e)	160	26	46	41	34	13	—

(a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. See Note 5 — Regulatory Matters for additional information.

(b) ComEd entered into 20-year contracts for renewable energy and RECs beginning June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts for energy and associate RECs were reduced in the first quarter of 2013. See Note 5 — Regulatory Matters for additional information.

(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2013 and 2015. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 5 — Regulatory Matters for additional information.

(d) BGE entered into various contracts for the procurement of electricity that expire between 2013 and 2015. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 5 — Regulatory Matters for additional information.

(e) BGE entered into various contracts with curtailment services providers related to transactions in PJM's capacity market. See Note 5 — Regulatory Matters for additional information.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation (and with respect to coal, commitments to sell coal). PECO and BGE have commitments to purchase natural gas, related to transportation, storage capacity and services to serve customers in their gas distribution service territory. As of June 30, 2013, these net commitments were as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Generation	$8,485	$820	$1,207	$1,244	$1,027	$1,078	$ 3,109
PECO	492	91	117	95	72	36	81
BGE	593	71	84	52	51	51	284

Other Purchase Obligations

The Registrants' other purchase obligations as of June 30, 2013, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Exelon	$719	$184	$205	$130	$42	$39	$ 119
Generation	616	142	156	127	41	38	112
ComEd	16	2	14	—	—	—	—
PECO	48	19	19	1	1	1	7
BGE	2	1	1	—	—	—	—

Construction Commitments

Generation has committed to the construction of a solar PV facility in Los Angeles County, California. The first portion of the project began operations in December 2012, with additional phases to come online and an expectation of full commercial operation in December 2013. Exelon has been informed by First Solar of issues relating to potential delays in the certification of certain components relating to the final two blocks of the project which could delay commercial operation of these two blocks until the first quarter of 2014. Generation's estimated remaining commitment for the project is $239 million.

On July 3, 2013, Generation executed a Turbine Supply Agreement to expand its Beebe project in Michigan, the total commitment under the contract is $58 million and achievement of commercial operations is expected in 2014.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland site with 120MW of new natural gas-fired generation to satisfy certain merger commitments, the total commitment under the contract is $89 million and achievement of commercial operation is expected in 2015. See Note 4 — Mergers and Acquisitions for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the merger.

Refer to Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K for information on investment programs associated with regulatory mandates, such as ComEd's Infrastructure Investment Plan under EIMA, PECO's Smart Meter Procurement and Installation Plan and BGE's comprehensive smart grid initiative.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Constellation Merger Commitments

In December 2011, Exelon and Constellation reached a settlement with the State of Maryland and the City of Baltimore and other interested parties in connection with the regulatory proceedings related to the merger that was pending before the MDPSC. As part of this settlement and the application for approval of the merger by MDPSC, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of more than $1 billion.

On February 17, 2012, the MDPSC approved the merger with conditions. Many of the conditions were reflective of the settlement agreements described above. The following costs were recognized after the closing of the merger and are included in Exelon's, Generation's and BGE's Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2012. See Note 4 – Merger and Acquisitions of the Exelon 2012 Form 10-K for additional information on the merger.

Description	Payment Period	BGE	Generation	Exelon	Statement of Operations Location
BGE rate credit of $100 per residential customer(a)	Q2 2012	$113	$ —	$ 113	Revenues
Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers	2012 to 2014	—	—	113.5	O&M Expense
Contribution for renewable energy, energy efficiency or related projects in Baltimore	2012 to 2014	—	—	2	O&M Expense
Charitable contributions at $7 million per year for 10 years	2012 to 2021	28	35	70	O&M Expense
State funding for offshore wind development projects	Q2 2012	—	—	32	O&M Expense
Miscellaneous tax benefits	Q2 2012	(2)	—	(2)	Taxes Other Than Income
Total		$139	$ 35	$328.5	

(a) Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

Contingencies

Commercial Commitments

The Registrants' commercial commitments as of June 30, 2013, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Letters of credit (non-debt)(a)	$1,405	$ 1,354	$ 26	$ 22	$ 1
Guarantees	5,506(b)	1,214(c)	209(d)	181(e)	252(f)
Nuclear insurance premiums(g)	2,585	2,585	—	—	—
Total commercial commitments	$9,496	$ 5,153	$ 235	$203	$253

(a) Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.
(b) Primarily reflects parental guarantees issued on behalf of Generation to allow the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Also reflects guarantees issued to ensure performance

under specific contracts, preferred securities of financing trusts, property leases, indemnifications, NRC minimum funding assurance requirements and $211 million on behalf of CENG nuclear generating facilities for credit support and miscellaneous guarantees. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $0.8 billion at June 30, 2013, which represents the total amount Exelon could be required to fund based on June 30, 2013 market prices.

(c) Primarily reflects guarantees issued to ensure performance under energy marketing and other specific contracts and $211 million on behalf of CENG nuclear generating facilities for credit support. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $0.2 billion at June 30, 2013, which represents the total amount Generation could be required to fund based on June 30, 2013 market prices.

(d) Primarily reflects full and unconditional guarantees of $200 million Trust Preferred Securities of ComEd Financing III, which is a 100% owned finance subsidiary of ComEd.

(e) Primarily reflects full and unconditional guarantees of $178 million Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.

(f) Primarily reflects full and unconditional guarantees of $250 million Trust Preferred Securities of BGE Capital Trust II, which is a 100% owned finance subsidiary of BGE.

(g) Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

Nuclear Insurance (Exelon and Generation)

The Price-Anderson Act requires mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in $12.2 billion in funds available for public liability claims for any single incident at any power reactor site that exceeds the primary level of financial protection currently required ($375 million). Additionally, Generation is also required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member. Premiums paid to NEIL by its members are subject to assessment for adverse loss experience (the retrospective premium obligation). The maximum combined retrospective premium amount that Generation could be required to pay due to participation in the Price-Anderson Act retrospective rating plan for power reactors and the NEIL retrospective premium obligation is $2.6 billion, which is included above in the Commercial Commitments table. See the Nuclear Insurance section within Note 19 — Commitments and Contingencies of the Exelon 2012 Form 10-K for additional details on Generation's nuclear insurance premiums.

Indemnifications Related to Sale of Sithe (Exelon and Generation)

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. Specifically, subsidiaries of Generation consummated the acquisition of Reservoir Capital Group's 50% interest in Sithe and subsequently sold 100% of Sithe to Dynegy, Inc. (Dynegy).

The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at June 30, 2013. Generation believes that it is remote that it will be required to make any additional payments under the guarantee, and currently has no recorded liabilities associated with this guarantee. Generation expects that the exposure covered by this guarantee will expire in 2014. The guarantee is included above in the Commercial Commitments table under guarantees.

Indemnifications Related to Sale of TEG and TEP (Exelon and Generation)

On February 9, 2007, Tamuin International Inc. (TII), a wholly owned subsidiary of Generation, sold its 49.5% ownership interests in TEG and TEP to a subsidiary of AES Corporation for $95 million in cash plus certain purchase price adjustments. In connection with the transaction, Generation entered into a guarantee agreement under which Generation guarantees the timely payment of TII's obligations to the subsidiary of AES Corporation pursuant to the terms of the purchase and sale agreement relating to the sale of TII's ownership interests. Generation would be required to perform in the event that TII does not pay any obligation covered by the guarantee that is not otherwise subject to a dispute resolution process. Generation's maximum obligation under the guarantee is $95 million as of June 30, 2013. Generation believes that it is remote that it will be required to make payments under the guarantee and has not recorded a liability associated with this guarantee. The exposures covered by this guarantee expired in part during 2008. Generation expects that the remaining exposure will expire in the third quarter of 2013. The guarantee of $95 million is included above in the Commercial Commitments table under guarantees.

Environmental Issues

General. The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, ComEd, PECO or BGE is one of several PRPs that may be responsible for ultimate remediation of each location.

- ComEd has identified 42 sites, 16 of which have been approved for cleanup by the Illinois EPA or the U.S. EPA and 26 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2016.
- PECO has identified 26 sites, 16 of which have been approved for cleanup by the PA DEP and 10 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2019.
- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. BGE is authorized to and is currently recovering environmental costs for the remediation of former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. ComEd, PECO and BGE have recorded regulatory assets for the recovery of these costs. See Note 5 — Regulatory Matters for additional information regarding the associated regulatory assets.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of June 30, 2013 and December 31, 2012, the Registrants had accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

June 30, 2013	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 334	$ 283
Generation	42	—
ComEd	245	240
PECO	46	43
BGE	1	—

December 31, 2012	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 338	$ 298
Generation	42	—
ComEd	261	254
PECO	47	44
BGE	1	—

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water Quality

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's and CENG's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected. For Generation, those facilities are Clinton, Dresden, Eddystone, Fairless Hills, Gould Street, Handley, Mountain Creek, Mystic 7, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. For CENG, those facilities are Calvert Cliffs, Nine Mile Point Unit 1 and R.E. Ginna.

On March 28, 2011, the U.S. EPA issued the proposed regulation under Section 316(b). The proposal does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment. The proposal provides the state permitting agency with discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The proposed rule also imposes limits on impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or another technology at the intake. Exelon filed comments on the proposed regulation on August 18, 2011, stating its support for a number of its provisions (e.g., cooling towers not required as best technology available, and the use of site-specific and cost benefit analysis) while also noting a number of technical provisions that require revision to take into account existing unit operations and practices within the industry.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

In June 2012, the U.S. EPA published two Notices of Data Availability (NODA) seeking public comment on alternate compliance technologies for impingement and the use of a public opinion survey to calculate the so-called "non-use" benefits of the rule. Exelon filed comments for each NODA, supporting the additional flexibility afforded by the impingement NODA, and opposing the NODA relating to calculation of non-use benefits due to its inaccurate and unreliable methodologies that would artificially inflate the benefits of proposed technologies that would otherwise not be cost-effective. On June 27, 2013, the U.S. EPA agreed to amend the court approved Settlement Agreement to extend the deadline to issue a final rule until November 4, 2013. Until the rule is finalized, the state permitting agencies will continue to apply their best professional judgment to address impingement and entrainment.

Salem and Other Power Generation Facilities. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG, in July 2004 that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon's and Generation's share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $430 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment.

It is unknown at this time whether the NJDEP permit programs will require closed-cycle cooling at Salem. In addition, the economic viability of Generation's other power generation facilities, as well as CENG's, without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation and CENG.

Given the uncertainties associated with the requirements that will be contained in the final rule, Generation cannot predict the eventual outcome or estimate the effect that compliance with any resulting Section 316(b) or interim state requirements will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows and financial position.

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Prior to the merger, Constellation recorded a liability in its Consolidated Balance Sheets of approximately $23 million to comply with the consent decree. The remaining liability as of June 30, 2013, is approximately $3 million. In addition, a private party has asserted claims relating to groundwater contamination. Generation believes that these claims are without merit and is vigorously contesting them. As of June 30, 2013, Generation believes that it is remote that it will be required to make payments under these private party claims.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Air Quality

Cross State Air Pollution Rule (CSAPR). On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of SO_2 and NO_x. The D.C. Circuit Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the D.C. Circuit Court's July 11, 2008 opinion. On July 7, 2011, the U.S. EPA published the final rule, known as the CSAPR. The CSAPR requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states.

Numerous entities challenged the CSAPR in the D.C. Circuit Court, and some requested a stay of the rule pending the Court's consideration of the matter on the merits. On December 30, 2011, the Court granted a stay of the CSAPR, and directed the U.S. EPA to continue the administration of CAIR in the interim. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. On January 24, 2013, the Court denied petitions for reconsideration of the ruling by the three-judge panel. In June 2013, the U.S. Supreme Court granted the U.S. EPA's petition to review the D.C. Circuit Court's CSAPR decision.

Under the CSAPR, generation units were to receive allowances based on historic heat input and intrastate, and limited interstate, trading of allowances was permitted. The CSAPR restricted entirely the use of pre-2012 allowances. Existing SO_2 allowances under the ARP would remain available for use under ARP. As of June 30, 2013, Generation had $57 million of emission allowances carried at the lower of weighted average cost or market.

EPA Mercury and Air Toxics Standards (MATS). The MATS rule became final on April 16, 2012. The MATS rule reduces emissions of toxic air pollutants, and finalized the new source performance standards for fossil fuel-fired electric utility steam generating units (EGUs). The MATS rule requires coal-fired EGUs to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that smaller, older, uncontrolled coal units will retire rather than make these investments. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. In addition, the new standards will require oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court may not occur until 2014. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS.

In addition, as of June 30, 2013, Exelon had a $683 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases extending through 2028-2032. While Exelon currently estimates the value

of these plants at the end of the lease term will be in excess of the recorded residual lease values, after the impairment recorded in the second quarter of 2013, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material. See Note 7 — Impairment of Long-Lived Assets for additional information.

National Ambient Air Quality Standards (NAAQS). The U.S. EPA previously announced that it would complete a review of all NAAQS by 2014. Oral argument in the litigation (*State of Miss. v. EPA*) of the final 2008 ozone standard occurred in the D.C. Circuit Court in November 2012 and a final Court decision was issued on July 23, 2013 with the 2008 primary ozone standard upheld, but the secondary standard remanded to EPA for reconsideration. Concurrent with litigation of the 2008 ozone standard, the U.S. EPA continues its regular, periodic review of the ozone NAAQS and is expected to propose revisions in the fall of 2014, with preliminary indications that the U.S. EPA will likely propose a tightened standard. It is unclear at this point in time whether the U.S. EPA will be able to respond to the Court remand of the secondary 2008 ozone standard on a timeframe that would be any quicker than that of the U.S. EPA's current, periodic review schedule. In December 2012, the U.S. EPA issued its final revisions to the Agency's particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation. It is unclear if the vacatur of the CSAPR, one of the regulations that the U.S. EPA is relying on to assist with future PM reduction, would alter the U.S. EPA's view since either CAIR or a finalized CSAPR regulation would be in effect leading up to 2020. In March 2013, a number of industry coalitions filed a joint lawsuit challenging the new PM2.5 standard. Also during early 2013, the D.C. Circuit remanded several rules for implementation of earlier PM2.5 NAAQS to the U.S. EPA for revision of certain aspects of the rules, with a requirement that the U.S. EPA re-promulgate regulations in conformance with the correct subparts of the Clean Air Act.

In addition to these NAAQS, the U.S. EPA also finalized nonattainment designations for certain areas in the United States for the 2010 one-hour SO_2 standard on August 5, 2013, and indicated that additional nonattainment areas will be designated in a future rulemaking. EPA will require states to submit state implementation plans (SIPs) for nonattainment areas by April 2015. With regard to Texas and Maryland, no nonattainment areas were identified in EPA's final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. The U.S. EPA will follow the approach outlined in a February 2013 EPA strategy document that establishes a process and timeline for the Agency to address additional designations in states' counties under a future rulemaking. Nonattainment county compliance with the one-hour SO_2 standard is required by October 2018. While significant SO2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the requirements of pending states' SIPs to further reduce SO_2 emissions in support of attainment of the one hour SO_2 standard.

Notices and Finding of Violations and Midwest Generation Bankruptcy. In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

On August 6, 2007, ComEd received a NOV addressed to it and Midwest Generation from the U.S. EPA, alleging, in relevant part, that ComEd and Midwest Generation violated and are continuing to violate provisions of the Clean Air Act as a result of the modification and/or operation of six electric generation stations located in northern Illinois that have been owned and operated by Midwest Generation since their purchase from ComEd in 1999. In August 2009, the United States and the State of Illinois filed a complaint against Midwest Generation with the U.S. District Court for the Northern District of Illinois initiating enforcement proceedings with respect to most of the alleged Clean Air Act violations set forth in the NOV. Neither ComEd nor Exelon was named as a defendant in this original complaint. In March 2010, the District Court granted Midwest Generation's partial motion to dismiss all but one of the claims against Midwest Generation. The District Court held that Midwest Generation cannot be liable for any alleged violations relating to construction that occurred prior to Midwest Generation's ownership of the stations. In May 2010, the government plaintiffs filed an amended complaint against Midwest Generation asserting claims substantially similar to those in the original complaint, and added ComEd and EME as defendants. The amended complaint seeks injunctive relief and civil penalties against all defendants, although not all of the claims specifically pertain to ComEd. On March 16, 2011, the District Court granted ComEd's motion to dismiss the May 2010 complaint in its entirety as it relates to ComEd. On January 3, 2012, upon leave of the District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals for the Seventh Circuit. On July 8, 2013, the Circuit Court affirmed the District Court's dismissal of the complaint against ComEd. Exelon, Generation and ComEd have concluded that, in light of the Circuit Court decision, the likelihood of loss is remote. Therefore, no reserve has been established.

On December 17, 2012 (Petition Date), EME and certain of its subsidiaries, including Midwest Generation, filed for protection under Chapter 11 of the U.S. Bankruptcy Code.

The Bankruptcy Court approved the rejection of a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations. The rejection left Generation as the party responsible to make remaining payments under the lease. In January 2013, Generation made the final $10 million payment due under the lease agreement which had been reserved for at December 31, 2012. As a result of the bankruptcy filing, Exelon and Generation have recorded liabilities as of June 30, 2013 of $3 million for estimated payments for asbestos personal injury claims filed pre-Petition Date. Exelon and Generation currently expect Midwest Generation or its successor will remain responsible for asbestos personal injury claims filed post-Petition Date, and as such have recorded no liability for such amounts. Requirements for Generation to ultimately satisfy such claims could have a material adverse impact on Exelon's and Generation's future results of operations. During the second quarter of 2013, ComEd filed proofs of claim of $21 million with the Bankruptcy Court for amounts owed by EME and Midwest Generation for the coal rail car lease, ComEd utility payments and certain legal costs. As of June 30, 2013, Exelon and ComEd have not recorded a receivable for the filed proofs of claim because recovery of such amount cannot be assured at this point in the bankruptcy. Exelon and ComEd will not record financial benefits associated with claim recoveries until realized.

As of the Petition Date, Generation had wholesale power transactions with Edison Mission Marketing and Trading, an affiliate of Midwest Generation not included in the bankruptcy proceeding. Generation expects these transactions to be fully settled in the normal course.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in the 2001 restructuring to assume ComEd's rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors, including the impact of Midwest Generation's bankruptcy. Additionally, the obligations of EME and Midwest Generation to ComEd

under the sale agreement, including the environmental indemnity, may be discharged in the bankruptcy proceeding. In such circumstances, ComEd (and Generation, through ComEd) may only have an unsecured claim against EME and Midwest Generation for the environmental remediation costs that would have otherwise been obligations of EME and Midwest Generation under the sale agreement. This unsecured claim may yield a fractional, or possibly no, recovery for ComEd and Generation.

ComEd and Generation continue to monitor the bankruptcy proceedings and available public information as to potential environmental exposures regarding the Midwest Generation plant sites. Midwest Generation publicly disclosed in its 2012 Form 10-K that (i) it has accrued a probable amount of approximately $9 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at four Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Crawford, Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to reasonably assess the potential likelihood or magnitude of any such exposures. Further, Midwest Generation's reorganization process will likely extend beyond one year and the outcome is uncertain, including whether the facilities will continue to operate and the identity or financial wherewithal of potential future plant owners. For these reasons, ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations, and no liability has been recorded as of June 30, 2013. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the anticipated landfill cover remediation for the site is approximately $42 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the supplemental feasibility study that could take up to one year to complete, and subsequently requested additional analysis sampling and modeling to be conducted in 2013. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage

and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2014 so that settlement discussions could proceed. Based on Exelon's preliminary review, it appears probable that Exelon has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the "Exelon defendants") and Cotter. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the defendants' negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which were subsequently granted. On October 23, 2012, a third lawsuit was filed in the same court on behalf of three additional plaintiffs against Cotter and seven other defendants, but not Exelon. On April 19, 2013, a fourth lawsuit was filed in the same court on behalf of two additional plaintiffs against Cotter and seven other defendants, but not Exelon. On June 18, 2013, a fifth lawsuit was filed in the same court on behalf of one plaintiff against eight defendants, including Cotter but not Exelon. On July 31, 2013, a sixth lawsuit was filed in the same court on behalf of two plaintiffs against Cotter and four other defendants, but not Exelon. The allegations in these latter four complaints mirror the initially filed lawsuits. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price–Anderson Act. On July 8, 2013, the plaintiffs filed amended complaints under the Price–Anderson Act. At this stage of the litigation, Exelon cannot estimate a range of loss, if any.

68 th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The potentially responsible parties submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. The U.S. EPA is expected to make a final selection of one of the alternatives in 2013. Based on Exelon's preliminary review, it appears probable that Exelon has liability and has established an appropriate accrual for its share of the estimated clean-up costs. BGE is indemnified by a wholly owned subsidiary of Generation for most of the costs related to this settlement and clean-up of the site.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, MD. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S.

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EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRP's signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRP's to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA's position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations (the Tailoring Rule) relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a CO_2 equivalent basis, and to modifications to existing sources that result in emissions increases greater than 75,000 tons per year on a CO_2 equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. On July 2, 2012 the U.S. EPA declined to lower GHG permit thresholds in its final "Step 3" Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per cunum* decision, dismissed industry and state petitions challenging the U.S. EPA's Tailoring Rule based on petitioners' lack of standing. Further, in the same decision, the court denied all challenges to U.S. EPA's endangerment finding, and the Agency's "Tailpipe Rule" for cars and light trucks. In August 2012, several industry parties filed petitions for an *en banc* rehearing of the Agency's GHG regulations with the D.C. Circuit court. On September 6, 2012 the Circuit Court ordered the U.S. EPA, intervening groups, and some states to reply to the industry petitions. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case by case basis. Generation could be significantly affected by the regulations if it were to build new plants or modify existing plants.

On June 25, 2013, President Obama announced "The President's Climate Action Plan," a summary of executive branch actions intended to: reduce carbon emissions; prepare the United States for the impacts of climate change; and lead international efforts to combat global climate change and prepare for its impacts. Concurrent with the announcement of the Administration's plan, the President also issued a Memorandum for the Administrator of the Environmental Protection Agency that focused on power generation sector carbon reductions under the Section 111 New Source Performance Standards (NSPS) section of the federal Clean Air Act. The memorandum directs the EPA Administrator to issue two sets of proposed rulemakings with regard to power plant carbon emissions under Section 111 of the Clean Air Act.

The first rulemaking, under Section 111(a) of the Clean Air Act is to focus on establishing carbon regulations for new fossil-fuel power plants. This rulemaking is to be proposed no later than September 20, 2013 and is to be finalized "in a timely fashion." This rulemaking will replace, in an as yet unknown manner, the April 13, 2012 proposed rulemaking for new fossil-fired power plants that EPA had previously published in the Federal Register.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The second rulemaking, under Section 111(d) of the Clean Air Act is to focus on modified, reconstructed and existing fossil power plants. The rulemaking is to be proposed no later than June 1, 2014, be finalized no later than June 1, 2015, and require that states submit to EPA their implementation plans no later than June 30, 2016. In developing this rulemaking, EPA is directed to consider a number of factors, including options to reduce costs, options to ensure the continued use of a range of energy sources and technologies, options that are consistent with reliable and affordable power, and options that allow for the use of market-based instruments, performance standards and other regulatory flexibilities.

Given the low carbon nature of Generation's fleet and the absence of actual proposed rulemaking language, Generation is unable to estimate the potential impacts of Section 111(a) and Section 111(d).

Litigation and Regulatory Matters

Except to the extent noted below, the circumstances set forth in Note 19 of the Exelon 2012 Form 10-K describe, in all material respects, the current status of litigation matters. The following is an update to that discussion.

Asbestos Personal Injury Claims (Exelon, Generation and BGE)

Exelon and Generation . Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At June 30, 2013 and December 31, 2012, Generation had reserved approximately $66 million and $63 million, respectively, in total for asbestos-related bodily injury claims. As of June 30, 2013, approximately $18 million of this amount related to 198 open claims presented to Generation, while the remaining $48 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary.

BGE . Since 1993, BGE and certain Constellation subsidiaries (now Generation) have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and certain Constellation subsidiaries knew of and exposed individuals to an asbestos hazard. In addition to BGE and certain Constellation subsidiaries, numerous other parties are defendants in these cases.

Approximately 480 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.

Discovery begins in these cases after they are placed on the trial docket. At present, only two of the pending cases are set for trial. Given the limited discovery in these cases, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

- the identity of the facilities at which the plaintiffs allegedly worked as contractors;
- the names of the plaintiffs' employers;

- the dates on which and the places where the exposure allegedly occurred; and
- the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

Continuous Power Interruption (ComEd)

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd's service territory, as well as for five other storm systems that affected ComEd's customers during June and July 2011 (Summer 2011 Storm Docket). In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket).

On June 5, 2013, the ICC approved a complete waiver of liability for five of the six summer storms and the February 2011 blizzard. However, the ICC held that for the July 11, 2011 storm, 34,559 interruptions were preventable and therefore no waiver should apply. As required by the ICC's Order, ComEd will notify relevant customers that they may be entitled to seek reimbursement of incurred costs in accordance with a claims procedure established under ICC rules and regulations. In addition, the ICC found that ComEd did not systematically fail in its duty to provide adequate, reliable and safe service. As a result, the ICC rejected the Illinois Attorney General's request for the ICC to open an investigation into ComEd's infrastructure and storm hardening investments.

Following the ICC's June 26, 2013 denial of ComEd's request for rehearing, on June 27, 2013 ComEd filed an appeal of both the summer and winter storm dockets with the Illinois Appellate Court regarding the ICC's interpretation of Section 16-125 of the Illinois Public Utilities Act. ComEd cannot predict the outcome of appeals.

As a result of the ICC's June 5, 2013 ruling, ComEd established a liability as of June 30, 2013, which was not material, for potential reimbursements for actual damages incurred by the 34,559 customers covered by the ICC's June 5, 2013 Order. The liability recorded represents the low end of a range of potential losses given that no amount within the range represents a better estimate. ComEd's ultimate liability will be based on actual claims eligible for reimbursement as well as the outcome of the appeal. Although reimbursements for actual damages will differ from the estimated accrual recorded at June 30, 2013, at this time ComEd does not expect the difference to be material to ComEd's results of operations or cash flows.

ComEd has not recorded an accrual for reimbursement of local governmental emergency and contingency expenses as a range of loss, if any, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Securities Class Action (Exelon)

Three federal securities class action lawsuits were filed in the United States District Courts for the Southern District of New York and the District of Maryland between September 2008 and November 2008 against Constellation. The cases were filed on behalf of a proposed class of persons who acquired publicly traded securities, including the Series A Junior Subordinated Debentures (Debentures), of Constellation between January 30, 2008 and September 16, 2008, and who acquired Debentures in an offering completed in June 2008. The securities class actions generally allege that Constellation, a number of its former officers or directors, and the underwriters violated the securities laws by issuing a false and misleading registration statement and prospectus in connection with Constellation's June 27, 2008 offering of the Debentures. The securities class actions also allege that Constellation issued false or misleading statements or was aware of material undisclosed information which contradicted public statements, including in connection with its announcements of financial results for 2007, the fourth quarter of 2007, the first quarter of 2008 and the second quarter of 2008 and the filing of its first quarter 2008 Form 10-Q. The securities class actions sought, among other things, certification of the cases as class actions, compensatory damages, reasonable costs and expenses, including counsel fees, and rescission damages.

The Southern District of New York granted the defendants' motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On May 9, 2013, the federal court in Maryland preliminarily approved the settlement of Constellation's 2008 Securities Class Action for a payment of $4 million, which will be paid by Constellation's insurer. Notice of the settlement was provided to class members in June, 2013 and opt-outs and objections are due by August 19, 2013 with a final settlement hearing scheduled for November 1, 2013. This settlement will resolve all of Constellation's litigation arising from the 2008 Securities Class Action lawsuit.

General (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

See Note 12 — Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

19. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2013 and 2012:

Three Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 47	$ 47	$ —	$ —	$—
Non-Regulatory Agreement Units	16	16	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory Agreement Units	(102)	(102)	—	—	—
Non-Regulatory Agreement Units	(40)	(40)	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	2	2	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	40	40	—	—	—
Total decommissioning-related activities	(37)	(37)	—	—	—
Investment income	2	—	—	(1)	2(c)
Long-term lease income	5	—	—	—	—
Interest income (expense) related to uncertain income tax positions	(1)	(2)	—	—	—
AFUDC — Equity	5	—	3	1	2
Other	9	6	3	—	—
Other, net	$ (17)	$ (33)	$ 6	$ —	$ 4

Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 84	$ 84	$ —	$ —	$—
Non-Regulatory Agreement Units	30	30	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory Agreement Units	92	92	—	—	—
Non-Regulatory Agreement Units	24	24	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	3	3	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	(148)	(148)	—	—	—
Total decommissioning-related activities	85	85	—	—	—
Investment income (expense)	5	(1)	—	(1)	5(c)
Long-term lease income	13	—	—	—	—
Interest income related to uncertain income tax positions	24	3	—	—	—
AFUDC — Equity	12	—	6	2	4
Other	16	8	5	2	—
Other, net	$ 155	$ 95	$ 11	$ 3	$ 9

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Three Months Ended June 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 50	$ 50	$ —	$ —	$—
Non-Regulatory Agreement Units	19	19	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory Agreement Units	(97)	(97)	—	—	—
Non-Regulatory Agreement Units	(35)	(35)	—	—	—
Net unrealized losses on pledged assets					
Zion Station decommissioning	4	4	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	31	31	—	—	—
Total decommissioning-related activities	(28)	(28)	—	—	—
Investment income	6	1	—	1	3
Long-term lease income	7	—	—	—	—
Interest income related to uncertain income tax positions	14	—	1	—	—
Credit facility termination fees	(42)	(42)	—	—	—
AFUDC — Equity	3	—	—	1	3
Other	(3)	(7)	2	—	1
Other, net	$ (43)	$ (76)	$ 3	$ 2	$ 7

Six Months Ended June 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds(a)					
Regulatory Agreement Units	$ 110	$ 110	$ —	$ —	$—
Non-Regulatory Agreement Units	67	67	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory Agreement Units	150	150	—	—	—
Non-Regulatory Agreement Units	30	30	—	—	—
Net unrealized income on pledged assets					
Zion Station decommissioning	38	38	—	—	—
Regulatory offset to decommissioning trust fund-related activities(b)	(245)	(245)	—	—	—
Total decommissioning-related activities	150	150	—	—	—
Investment income	10	—	—	2	6
Long-term lease income	15	—	—	—	—
Interest income related to uncertain income tax positions	14	—	1	—	—
Credit facility termination fees	(42)	(42)	—	—	—
AFUDC — Equity	7	—	1	2	6
Other	(2)	(5)	5	1	1
Other, net	$ 152	$ 103	$ 7	$ 5	$13

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund-related activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 13 — Asset Retirement Obligations of the Exelon 2012 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE's rate stabilization deferral. See Note 5 — Regulatory Matters for additional information regarding the rate stabilization deferral.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the six months ended June 30, 2013 and 2012:

Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 942	$ 402	$ 275	$109	$128
Regulatory assets	112	—	62	4	47
Amortization of intangible assets, net	22	22	—	—	—
Amortization of energy contract assets and liabilities(a)	306	344	—	—	—
Nuclear fuel(a)	454	454	—	—	—
ARO accretion(b)	136	136	—	—	—
Total depreciation, amortization, accretion and depletion	$1,972	$ 1,358	$ 337	$113	$175

Six Months Ended June 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 806	$ 343	$ 262	$102	$123
Regulatory assets	56	—	38	5	27
Amortization of intangible assets, net	14	14	—	—	—
Amortization of energy contract assets and liabilities(a)	485	532	—	—	—
Nuclear fuel(a)	419	419	—	—	—
ARO accretion(b)	115	115	—	—	—
Total depreciation, amortization, accretion and depletion	$1,895	$ 1,423	$ 300	$107	$150

(a) Included in revenues or fuel expense, or operating revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in operating and maintenance expense on the Registrants' Consolidated Statements of Operations.

Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 409	$ 173	$ 154	$ 21	$27
Loss in equity method investments	30	30	—	—	—
Provision for uncollectible accounts	55	10	4	27	14
Stock-based compensation costs	70	—	—	—	—
Other decommissioning-related activity(a)	(62)	(62)	—	—	—
Energy-related options(b)	65	65	—	—	—
Amortization of regulatory asset related to debt costs	6	—	5	1	—
Amortization of rate stabilization deferral	29	—	—	—	29
Amortization of debt fair value adjustment	(22)	(22)	—	—	—
Discrete impacts from EIMA(c)	(126)	—	(126)	—	—
Amortization of debt costs	8	5	2	1	—
Merger integration costs(d)	(6)	—	—	—	(6)
Impairment of investments in direct financing leases(e)	14	—	—	—	—
Increase in inventory reserve	13	13	—	—	—
Impairment charges(f)	110	110	—	—	—
Other	(17)	(7)	—	—	(3)
Total other non-cash operating activities	$ 576	$ 315	$ 39	$ 50	$61

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (24)	$ —	$ (61)	$ 19	$ 18
Other regulatory assets and liabilities	3	—	(28)	(5)	(82)
Other current assets	(123)	(134)	2	(62)	99
Other noncurrent assets and liabilities	277	(34)	259(g)	(1)	28
Total changes in other assets and liabilities	$ 133	$ (168)	$ 172	$ (49)	$ 63
Non-cash investing and financing activities:					
Consolidated VIE dividend to non-controlling interest	$ 63	$ 63	$ —	$ —	$ —
Indemnification of like-kind exchange position(h)	—	—	174	—	—
Total non-cash investing and financing activities:	$ 63	$ 63	$ 174	$ —	$ —

Six Months Ended June 30, 2012	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 400	$ 175	$ 137	$ 26	$ 32
Provision for uncollectible accounts	60	(1)	21	26	17
Stock-based compensation costs	56	—	—	—	—
Other decommissioning-related activity(a)	(62)	(62)	—	—	—
Energy-related options(b)	64	64	—	—	—
Amortization of regulatory asset related to debt costs	9	—	7	1	1
Amortization of rate stabilization deferral	15	—	—	—	25
Amortization of debt fair value adjustment	(26)	(11)	—	—	—
Discrete impacts from EIMA(c)	69	—	69	—	—
Amortization of debt costs	—	—	2	—	—
Merger-related commitments(i)	188	35	—	—	28
Severance cost	119	30	—	7	—
Loss in equity method investments	79	79	—	—	—
Other	(12)	9	5	6	(3)
Total other non-cash operating activities	$ 959	$ 318	$ 241	$ 66	$100
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (37)	$ —	$ (58)	$ 18	$ 2
Other regulatory assets and liabilities	(514)	—	(39)	12	(28)
Other current assets	190	(97)	(1)	(110)	55
Other noncurrent assets and liabilities	(12)	(77)	(6)	(7)	14
Total changes in other assets and liabilities	$ (373)	$ (174)	$(104)	$ (87)	$ 43
Non-cash investing and financing activities:					
Merger with Constellation, common stock issued	$7,365	$ 5,272	$ —	$ —	$ —
Total non-cash investing and financing activities:	$7,365	$ 5,272	$ —	$ —	$ —

(a) Includes the elimination of NDT fund-related activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 13 of the Exelon 2012 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 5 — Regulatory Matters for more information.
(d) Relates to integration costs to achieve distribution synergies related to the merger transaction. See Note 5 — Regulatory Matters for more information.
(e) Relates to an other than temporary decline in the estimated residual value of one of Exelon's direct financing leases. See Note 7 — Impairment of Long-Lived Assets for more information.
(f) Relates to the cancellation of uprate projects at Generation. See Note 7 — Impairment of Long-Lived Assets for additional information.
(g) Relates primarily to interest payable related to like-kind exchange tax position. See Note 12 — Income Taxes for discussion of the like-kind exchange tax position.
(h) See Note 12 — Income Taxes for discussion of the like-kind exchange tax position.
(i) See Note 4 — Mergers and Acquisitions for more information on merger-related commitments.

DOE Smart Grid Investment Grant (Exelon, PECO and BGE). For the six months ended June 30, 2013, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $41 million, $12 million and $29 million, respectively, and reimbursements of $50 million, $16 million and $34 million, respectively, related to PECO's and BGE's DOE SGIG programs. For the six months ended June 30, 2012, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $52 million, $34 million and $18 million, respectively, and reimbursements of $65 million, $46 million and $19 million, respectively, related to PECO's and BGE's DOE SGIG programs. See Note 5 — Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of June 30, 2013 and December 31, 2012.

June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$12,905(a)	$ 6,521(a)	$3,035	$2,874	$2,656
Accounts receivable:					
Allowance for uncollectible accounts	306	85	68	115	38

December 31, 2012	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$12,184(b)	$ 6,014(b)	$2,998	$2,797	$2,595
Accounts receivable:					
Allowance for uncollectible accounts	293	84	70	99	40

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $2,220 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,078 million.

PECO Installment Plan Receivables (Exelon and PECO)

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current

portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $23 million as of June 30, 2013 and $18 million as of December 31, 2012. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1 — Significant Account Policies of the Exelon 2012 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at June 30, 2013 of $21 million consists of $1 million, $4 million and $16 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2012 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of June 30, 2013 and December 31, 2012 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1 — Significant Accounting Policies of the Exelon 2012 Form 10-K.

20. Segment Information (Exelon, Generation, ComEd, PECO and BGE)

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation's six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other regions not considered individually significant referred to collectively as "Other Regions"; including the South, West and Canada. Generation's expanded number of reportable segments is the result of the acquisition of Constellation on March 12, 2012. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon evaluates the performance of ComEd, PECO and BGE based on net income.

The foundation of Generation's six reportable segments is based on the geographic location of its assets, and is largely representative of the footprints of an ISO / RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the entire United States footprint of MISO, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

- Other Regions not considered individually significant:
  - South represents operations in the FRCC and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

Exelon and Generation evaluate the performance of Generation's power marketing activities based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's own generation and fuel costs associated with tolling agreements. Generation's other business activities, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, are not allocated to regions. Further, Generation's compensation under the reliability-must-run rate schedule, results of operations from the Brandon Shores, Wagner, and C.P. Crane Maryland generating stations, and other miscellaneous revenues, mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger are also not allocated to a region.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three and six months ended June 30, 2013 and 2012 is as follows:

Three Months Ended June 30, 2013 and 2012

	Generation(a)	ComEd	PECO	BGE	Other(b)	Intersegment Eliminations	Exelon
Total revenues(c):							
2013	$ 4,070	$ 1,080	$ 672	$ 653	$ 297	$ (631)	$ 6,141
2012	3,765	1,281	715	616	363	(774)	5,966
Intersegment revenues:							
2013	$ 329	$ —	$ —	$ 4	$ 298	$ (631)	$ —
2012	408	1	1	2	362	(774)	—
Net income (loss):							
2013	$ 328	$ 96	$ 78	$ 25	$ (30)	$ —	$ 497
2012	165	42	80	16	(14)	—	289
Total assets:							
June 30, 2013	$ 39,678	$23,349	$9,407	$7,968	$ 9,763	$ (11,745)	$78,420
December 31, 2012	40,681	22,905	9,353	7,506	10,432	(12,316)	78,561

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the three months ended June 30, 2013 include revenue from sales to PECO of $97 million and sales to BGE of $99 million in the Mid-Atlantic region, and sales to ComEd of $121 million in the Midwest region, net of $10 million related to the unrealized mark-to-market gains related to the ComEd swap, which eliminate upon consolidation. For the three months ended June 30, 2012 intersegment revenues for Generation include revenue from sales to PECO of $125 million and sales to BGE of $84 million in the Mid-Atlantic region, and sales to ComEd of $203 million in the Midwest region, net of $4 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation.
(b) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(c) For the three months ended June 30, 2013 and 2012, utility taxes of $18 million and $19 million, respectively, are included in revenues and expenses for Generation. For the three months ended June 30, 2013 and 2012, utility taxes of $56 million and $54 million, respectively, are included in revenues and expenses for ComEd. For the three months ended June 30, 2013 and 2012, utility taxes of $31 million and $34 million, respectively, are included in revenues and expenses for PECO. For the three months ended June 30, 2013 and 2012, utility taxes of $19 million and $19 million, respectively, are included in revenues and expenses for BGE.

Generation total revenues (three months ended):

	2013			2012		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 1,220	$ 9	$ 1,229	$ 1,433	$ (28)	$ 1,405
Midwest	1,076	(5)	1,071	1,193	8	1,201
New England	209	(20)	189	296	32	328
New York	175	(1)	174	166	(22)	144
ERCOT	319	(4)	315	412	1	413
Other Regions(b)	246	(6)	240	219	25	244
Total Revenues for Reportable Segments	$ 3,245	$ (27)	$ 3,218	$ 3,719	$ 16	$ 3,735
Other(c)	825	27	852	46	(16)	30
Total Generation Consolidated Operating Revenues	$ 4,070	$ —	$ 4,070	$ 3,765	$ —	$ 3,765

(a) Includes all electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of $234 million and $534 million, for the three months ended June 30, 2013 and 2012, respectively, and elimination of intersegment revenues.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Generation total revenues net of purchased power and fuel expense (three months ended):

	2013			2012		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 770	$ (2)	$ 768	$ 911	$ (28)	$ 883
Midwest	687	(3)	684	756	8	764
New England	85	(35)	50	28	32	60
New York	—	14	14	61	(22)	39
ERCOT	143	(31)	112	118	1	119
Other Regions(b)	111	(52)	59	9	25	34
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 1,796	$ (109)	$1,687	$ 1,883	$ 16	$1,899
Other(c)	328	109	437	30	(16)	14
Total Generation Revenues net of purchased power and fuel expense	$ 2,124	$ —	$2,124	$ 1,913	$ —	$1,913

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions includes the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of $167 million and $414 million for the three months ended June 30, 2013 and 2012, respectively.

Six Months Ended June 30, 2013 and 2012

	Generation(a)	ComEd	PECO	BGE(b)	Other(c)	Intersegment Eliminations	Exelon
Total revenues(d):							
2013	$ 7,603	$2,239	$1,567	$1,533	$ 615	$ (1,334)	$12,223
2012	6,508	2,670	1,590	668	714	(1,494)	10,656
Intersegment revenues(e):							
2013	$ 710	$ 1	$ —	$ 8	$ 615	$ (1,334)	$ —
2012	774	1	2	3	715	(1,494)	1
Net income (loss):							
2013	$ 310	$ 14	$ 200	$ 106	$ (132)	$ —	$ 498
2012	332	129	177	(49)	(99)	—	490

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the six months ended June 30, 2013 include revenue from sales to PECO of $238 million and sales to BGE of $212 million in the Mid-Atlantic region, and sales to ComEd of $266 million in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the six months ended June 30, 2012 intersegment revenues for Generation include revenue from sales to PECO of $235 million in the Mid-Atlantic region and sales to BGE of $103 million in the Mid-Atlantic region, and sales to ComEd of $451 million in the Midwest region, net of $15 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation.
(b) Amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through June 30, 2012.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(d) For the six months ended June 30, 2013 and 2012, utility taxes of $39 million and $32 million, respectively, are included in revenues and expenses for Generation. For the six months ended June 30, 2013 and 2012, utility taxes of $117 million and $115 million, respectively, are included in revenues and expenses for ComEd. For the six months ended June 30, 2013 and 2012, utility taxes of $64 million and $68 million, respectively, are included in revenues and expenses for PECO. For the six months ended June 30, 2013 and period of March 12, 2012 through June 30, 2012, utility taxes of $41 million and $22 million, respectively, are included in revenues and expenses for BGE.
(e) The intersegment profit associated with Generation's sale of AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K for additional information on AECs. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.

Generation total revenues (six months ended):

	2013			2012		
	Revenues from external customers(a)	Intersegment revenues	Total Revenues	Revenues from external customers(a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 2,551	$ 1	$ 2,552	$ 2,404	$ (33)	$ 2,371
Midwest	2,257	2	2,259	2,407	12	2,419
New England	600	(8)	592	386	35	421
New York	350	(7)	343	211	(24)	187
ERCOT	612	(4)	608	541	—	541
Other Regions(b)	429	36	465	294	29	323
Total Revenues for Reportable Segments	$ 6,799	$ 20	$ 6,819	$ 6,243	$ 19	$ 6,262
Other(c)	804	(20)	784	265	(19)	246
Total Generation Consolidated Operating Revenues	$ 7,603	$ —	$ 7,603	$ 6,508	$ —	$ 6,508

(a) Includes all wholesale and retail electric sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date of $478 million and $686 million, for the six months ended June 30, 2013 and 2012, respectively, and elimination of intersegment revenues.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Generation total revenues net of purchased power and fuel expense (six months ended):

	2013			2012		
	RNF from external customers(a)	Intersegment RNF	Total RNF	RNF from external customers(a)	Intersegment RNF	Total RNF
Mid-Atlantic	$ 1,622	$ (10)	$1,612	$ 1,686	$ (33)	$1,653
Midwest	1,397	4	1,401	1,569	12	1,581
New England	103	(23)	80	64	35	99
New York	(16)	8	(8)	71	(24)	47
ERCOT	255	(42)	213	153	—	153
Other Regions(b)	122	(17)	105	19	29	48
Total Revenues net of purchased power and fuel expense for Reportable Segments	$ 3,483	$ (80)	$3,403	$ 3,562	$ 19	$3,581
Other(c)	6	80	86	50	(19)	31
Total Generation Revenues net of purchased power and fuel expense	$ 3,489	$ —	$3,489	$ 3,612	$ —	$3,612

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions includes the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date of $341 million and $537 million, for the six months ended June 30, 2013 and 2012, respectively.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

(Dollars in millions except per share data, unless otherwise noted)

EXELON CORPORATION

General

Exelon, a utility services holding company, operates through the following principal subsidiaries:

- *Generation*, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Generation operates as an integrated business, leveraging its owned and contracted electric generation capacity to market and sell power to wholesale and retail supply customers. Generation's customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation also sells natural gas and renewable and other energy-related offerings, and engages in natural gas exploration and production activities.
- *ComEd*, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO*, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE*, whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Exelon has nine reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and other regions in Generation), ComEd, PECO and BGE. See Note 20 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

Exelon's consolidated financial information includes the results of its four separate operating subsidiary registrants, Generation, ComEd, PECO and BGE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO and BGE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Executive Overview

Financial Results. The following consolidated financial results reflect the results of Exelon for the three and six months ended June 30, 2013 compared to the same period in 2012. The financial results for the six months ended June 30, 2012 only include the operations of Constellation and BGE from the date of the merger with Constellation, March 12, 2012, through June 30, 2012. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended June 30, 2013						2012	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	Variance
Operating revenues	$ 4,070	$1,080	$672	$653	$(334)	$6,141	$5,966	$ 175
Purchased power and fuel	1,946	248	258	288	(321)	2,419	2,606	187
Revenue net of purchased power and fuel(a)	2,124	832	414	365	(13)	3,722	3,360	362
Other operating expenses								
Operating and maintenance	1,189	359	181	160	3	1,892	1,841	(51)
Depreciation and amortization	210	170	56	82	15	533	494	(39)
Taxes other than income	101	71	39	54	6	271	254	(17)
Total other operating expenses	1,500	600	276	296	24	2,696	2,589	(107)
Equity in loss of unconsolidated affiliates	(21)	—	—	—	—	(21)	(57)	36
Operating income (loss)	603	232	138	69	(37)	1,005	714	291
Other income and (deductions)								
Interest expense, net	(93)	(76)	(28)	(32)	(23)	(252)	(256)	4
Other, net	(33)	6	—	4	6	(17)	(43)	26
Total other income and (deductions)	(126)	(70)	(28)	(28)	(17)	(269)	(299)	30
Income (loss) before income taxes	477	162	110	41	(54)	736	415	321
Income taxes	149	66	32	16	(24)	239	126	(113)
Net income (loss)	328	96	78	25	(30)	497	289	208
Net (loss) income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	(2)	—	6	3	—	7	3	(4)
Net income (loss) attributable to common shareholders	$ 330	$ 96	$ 72	$ 22	$ (30)	$ 490	$ 286	$ 204

	Six Months Ended June 30, 2013						2012	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	Variance
Operating revenues	$ 7,603	$2,239	$1,567	$1,533	$(719)	$12,223	$10,656	$ 1,567
Purchased power and fuel	4,114	630	664	713	(721)	5,400	4,371	(1,029)
Revenue net of purchased power and fuel(a)	3,489	1,609	903	820	2	6,823	6,285	538
Other operating expenses								
Operating and maintenance	2,302	687	369	303	(5)	3,656	3,809	153
Depreciation and amortization	424	337	113	175	27	1,076	876	(200)
Taxes other than income	194	145	80	109	20	548	448	(100)
Total other operating expenses	2,920	1,169	562	587	42	5,280	5,133	(147)
Equity in loss of unconsolidated affiliates	(30)	—	—	—	—	(30)	(79)	49
Operating income (loss)	539	440	341	233	(40)	1,513	1,073	440
Other income and (deductions)								
Interest expense, net	(176)	(429)	(57)	(66)	(148)	(876)	(451)	(425)
Other, net	95	11	3	9	37	155	152	3
Total other income and (deductions)	(81)	(418)	(54)	(57)	(111)	(721)	(299)	(422)
Income (loss) before income taxes	458	22	287	176	(151)	792	774	18
Income taxes	148	8	87	70	(19)	294	284	(10)
Net income (loss)	310	14	200	106	(132)	498	490	8
Net (loss) income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	(1)	—	7	6	—	12	4	(8)
Net income (loss) attributable to common shareholders	$ 311	$ 14	$ 193	$ 100	$(132)	$ 486	$ 486	$ —

(a) The Registrants' evaluate operating performance using the measure of revenue net of purchased power and fuel expense. The Registrants' believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. Exelon's net income attributable to common shareholders was $490 million for the three months ended June 30, 2013 as compared to net income attributable to common shareholders of $286 million for the three months ended June 30, 2012, and diluted earnings per average common share were $ 0.57 for the three months ended June 30, 2013 as compared to $0.33 for the three months ended June 30, 2012.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $362 million for the three months ended June 30, 2013 as compared to the same period in 2012. The year-over-year increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase in Generation's mark-to-market gains from economic hedging activities of $228 million;

- Decrease in Generation's amortization expense for the acquired energy contracts recorded at fair value at the merger date of $247 million;
- Increase in ComEd's revenue net of purchased power and fuel expense of $138 million primarily due to the ICC's May 2012 Order, increased distribution revenue due to recovery of increased costs and capital investment pursuant to the formula rate under EIMA and the 2013 enactment of Senate Bill 9, partially offset by unfavorable weather; and
- Increase in BGE's revenue net of purchased power and fuel expense of $34 million primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 in accordance with the 2012 MDPSC approved electric and natural gas distribution rate case order.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

- Decrease in Generation's electric revenue net of purchased power and fuel expense of $212 million primarily due to lower realized energy prices, lower capacity revenue, lower load volume and increased nuclear fuel expense, partially offset by lower energy supply costs as a result of the integration of the energy generation and load serving businesses following the merger; and
- Reduced margin at Generation of $57 million in 2013 associated with the Maryland Clean Coal assets that were sold in November 2012 and lost compensation from the FERC-approved reliability-must-run program with PJM for retired fossil generating assets that expired on May 31, 2012.

Operating and maintenance expense increased by $51 million for the three months ended June 30, 2013 as compared to the same period in 2012 primarily due to the following unfavorable factors:

- Long-lived asset impairment and related charges of $106 million in the second quarter of 2013, primarily related to Generation's cancellation of nuclear uprate projects; and
- Increase in labor, other benefits, contracting and materials costs of $27 million due to the impact of inflation across all operating companies, partially offset by realized merger synergy savings at Exelon's corporate operations and shared service entities and at Generation.

The year-over-year increase in operating and maintenance expense was partially offset by the following favorable factors:

- Decrease in Constellation merger and integration costs of $32 million; and
- Decrease in operating and maintenance expense associated with the generating assets retired or divested during 2012 of $42 million.

Depreciation and amortization expense increased by $39 million primarily due to ongoing capital expenditures across the operating companies, the completion of wind and solar facilities placed into service in the second half of 2012 and in 2013 at Generation and increased regulatory asset amortization related to higher MGP remediation expenditures and higher costs for energy efficiency and demand response programs at ComEd and BGE, respectively.

Equity in loss of unconsolidated affiliates decreased by $36 million primarily due to higher net income generated from Generation's equity investment in CENG in the second quarter of 2013 compared to the same period in 2012 and lower amortization of the basis difference of Generation's ownership interest in CENG recorded at fair value in connection with the merger.

Exelon's effective income tax rates for the three months ended June 30, 2013 and 2012 were 32.5% and 30.4%, respectively. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. Exelon's net income attributable to common shareholders was $486 million for the six months ended June 30, 2013 as compared to net income attributable to common shareholders of $486 million for the six months ended June 30, 2012, and diluted earnings per average common share were $0.57 for the six months ended June 30, 2013 as compared to $0.62 for the six months ended June 30, 2012.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $538 million for the six months ended June 30, 2013 as compared to the same period in 2012. The year-over-year increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase in BGE's revenue net of purchased power and fuel expense of $504 million, primarily as a result of the inclusion of BGE's results for the full period in 2013 and the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 in accordance with the 2012 MDPSC approved electric and natural gas distribution rate case order;
- Increase in Generation's net margin of $174 million on other activities, including proprietary trading, retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of customer sited solar facilities, primarily due to the addition of Constellation;
- Decrease in Generation's amortization expense for the acquired energy contracts recorded at fair value at the merger date of $196 million;
- Increase in ComEd's revenue net of purchased power and fuel expense of $147 million primarily due to the ICC's May 2012 Order and increased distribution revenue due to recovery of increased costs and capital investment pursuant to the formula rate under EIMA; and
- Increase in PECO's revenue net of purchased power and fuel expense of $20 million primarily due to favorable weather conditions, partially offset by lower realized prices.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

- Decrease in Generation's mark-to-market gains from economic hedging activities of $235 million;
- Decrease in Generation's electric revenue net of purchased power and fuel expense of $178 million primarily due to lower realized energy prices, lower capacity revenue, lower load volume and increased nuclear fuel expense, partially offset by lower energy supply costs as a result of the integration of the energy generation and load serving businesses following the merger; and
- Reduced margin at Generation of $80 million in 2013 associated with the Maryland Clean Coal assets that were sold in November 2012 and lost compensation on the reliability-must-run program with PJM for retired fossil generating assets that expired on May 31, 2012.

Operating and maintenance expense decreased by $153 million for the six months ended June 30, 2013 as compared to the same period in 2012 primarily due to the following favorable factors:

- Costs incurred in March 2012 of $216 million as part of the Maryland order approving the merger and of $195 million associated with a settlement with the FERC; and
- Decrease in Constellation merger and integration costs of $152 million in 2013.

The year-over-year decrease in operating and maintenance expense was partially offset by the following unfavorable factors:

- Increase in labor, other benefits, contracting and materials costs of $264 million and increase in pension and non-pension postretirement benefit expenses of $18 million, primarily due to the addition of BGE and Constellation for the full period in 2013; and

- Long-lived asset impairment and related charges of $127 million in 2013, primarily related to Generation's cancellation of nuclear uprate projects.

Depreciation and amortization expense increased by $200 million primarily due to higher plant balances resulting from the addition of BGE's and Constellation's plant balances in 2012, ongoing capital expenditures across the operating companies, the completion of wind and solar facilities placed into service in the second half of 2012 and in 2013 at Generation and increased regulatory asset amortization related to higher MGP remediation expenditures and higher costs for energy efficiency and demand response programs at ComEd and BGE, respectively.

Equity in loss of unconsolidated affiliates decreased $49 million primarily due to higher net income generated from Generation's equity investment in CENG in 2013 compared to the same period in 2012 and lower amortization of the basis difference of Generation's ownership interest in CENG recorded at fair value in connection with the merger.

Interest expense increased by $425 million primarily due to an increase in interest expense at ComEd related to the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013, an increase in debt obligations as a result of the merger and an increase in debt issued at Generation in June 2012.

Exelon's effective income tax rates for the six months ended June 30, 2013 and June 30, 2012 were 37.1% and 36.7%, respectively. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the three and six months ended June 30, 2013, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings. Exelon's adjusted (non-GAAP) operating earnings for the three months ended June 30, 2013 were $ 454 million, or $ 0.53 per diluted share, compared with adjusted (non-GAAP) operating earnings of $ 522 million, or $ 0.61 per diluted share, for the same period in 2012. Exelon's adjusted (non-GAAP) operating earnings for the six months ended June 30, 2013 were $1,056 million, or $1.23 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,125 million, or $1.44 per diluted share, for the same period in 2012. In addition to net income attributable to common shareholders, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three and six months ended June 30, 2013 as compared to the same period in 2012:

	Three Months Ended June 30,			
	2013		2012	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 490	$ 0.57	$ 286	$ 0.33
Mark-to-Market Impact of Economic Hedging Activities(a)	(253)	(0.30)	(123)	(0.15)
Unrealized Losses Related to NDT Fund Investments(b)	22	0.03	19	0.02
Plant Retirement and Divestitures(c)	—	—	(1)	—
Constellation Merger and Integration Costs(d)	15	0.02	67	0.08
Amortization of Commodity Contract Intangibles(e)	115	0.13	281	0.33
Amortization of the Fair Value of Certain Debt(f)	(4)	—	(3)	—
Non-Cash Remeasurement of State Deferred Income Taxes(g)	—	—	(4)	—
Long-Lived Asset Impairment(h)	69	0.08	—	—
Adjusted (non-GAAP) Operating Earnings	$ 454	$ 0.53	$ 522	$ 0.61

	Six Months Ended June 30,			
	2013		2012	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 486	$ 0.57	$ 486	$ 0.62
Mark-to-Market Impact of Economic Hedging Activities(a)	(18)	(0.02)	(167)	(0.21)
Unrealized Gains Related to NDT Fund Investments(b)	(14)	(0.02)	(17)	(0.02)
Plant Retirement and Divestitures(c)	(13)	(0.02)	7	0.01
Constellation Merger and Integration Costs(d)	43	0.05	180	0.23
Amortization of Commodity Contract Intangibles(e)	232	0.27	358	0.46
Amortization of the Fair Value of Certain Debt(f)	(7)	(0.01)	(3)	—
Non-Cash Remeasurement of State Deferred Income Taxes(g)	—	—	(121)	(0.16)
Long-Lived Asset Impairment(h)	82	0.10	—	—
Remeasurement of Like-Kind Exchange Tax Position(i)	265	0.31	—	—
Other Acquisition Costs(j)	—	—	3	—
Maryland Commitments(k)	—	—	227	0.29
FERC Settlement(l)	—	—	172	0.22
Adjusted (non-GAAP) Operating Earnings	$1,056	$ 1.23	$1,125	$ 1.44

(a) Reflects the impact of gains for the three and six months ended June 30, 2013 (net of taxes of $(163) million and $(13) million, respectively) and for the three and six months ended June 30, 2012 (net of taxes of $(81) million and $(109) million, respectively), on Generation's economic hedging activities. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized (gains) losses for the three and six months ended June 30, 2013 (net of taxes of $41 million and $(27) million, respectively) and for the three and six months ended June 30, 2012 (net of taxes of $37 million and $(46) million, respectively) on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 13 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Reflects the impacts associated with the sale or retirement of generating stations for the six months ended June 30, 2013 (net of taxes of $5 million) and for the three and six months ended June 30, 2012 (net of taxes of $1 million and $3 million, respectively). See "Results of Operations — Generation" for additional detail related to the generating station retirements.

(d) Reflects certain costs incurred for the three and six months ended June 30, 2013 (net of taxes of $10 million and $4 million, respectively) and for the three and six months ended June 30, 2012 (net of taxes of $44 million and $76 million, respectively) associated with the Constellation merger, including transaction costs, employee-related expenses (e.g. severance, retirement, relocation and retention bonuses) integration initiatives and certain pre-acquisition contingencies, partially offset in 2013 by a one-time benefit pursuant to the BGE 2012 electric and gas distribution rate case order for the recovery of previously incurred integration costs. See Note 4 — Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(e) Reflects the non-cash impact for the three and six months ended June 30, 2013 and 2012 (net of taxes of $73 million and $148 million, respectively) and for the three and six months ended June 30, 2012 (net of taxes of $183 million and $234 million, respectively) of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger date. See Note 4 — Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(f) Reflects the non-cash amortization of certain debt for the three and six months ended June 30, 2013 (net of taxes of $(3) million and $(5) million, respectively) and for the three and six months ended June 30, 2012 (net of taxes of $(2) million and $(2) million, respectively) recorded at fair value at the merger date which debt was retired in the second quarter of 2013. See Note 4 — Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes as a result of the Constellation merger. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

(h) Reflects 2013 impairment and related charges to earnings for the three and six months ended June 30, 2013 (net of taxes of $44 million and $53 million, respectively) primarily related to Generation's cancellation of nuclear uprate projects.

(i) Reflects a non-cash charge to earnings for the six months ended June 30, 2013 (net of taxes of $102 million) resulting from the first quarter 2013 remeasurement of a like-kind exchange tax position taken on ComEd's 1999 sale of fossil generating assets. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

(j) Reflects certain costs incurred for the six months ended June 30, 2012 (net of taxes of $2 million) associated with various acquisitions.

(k) Reflects costs incurred for the three months ended June 30, 2012 associated with the Constellation merger (net of taxes of $101 million) as part of the Maryland order approving the merger transaction. See Note 4 — Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(l) Reflects costs incurred for the six months ended June 30, 2012 (net of taxes of $23 million) as part of a settlement with the FERC to resolve a dispute related to Constellation's pre-merger hedging and risk management transactions. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

As discussed above, Exelon has incurred and will continue to incur costs associated with the Constellation merger including, meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former Constellation businesses into Exelon.

For the three and six months ended June 30, 2013, expense has been recognized for costs incurred to achieve the merger as follows:

	Pre-tax Expense Three Months Ended June 30, 2013				
Merger and Integration Costs:	Generation (a)	ComEd	PECO	BGE (a)	Exelon (a)
Employee-Related(b)	7	—	—	—	7
Other(c)	13	—	2	1(d)	18
Total	$ 20	$ —	$ 2	$ 1	$ 25

	Pre-tax Expense Six Months Ended June 30, 2013				
Merger and Integration Costs:	Generation (a)	ComEd	PECO	BGE (a)	Exelon (a)
Employee-Related(b)	13	—	1	—	14
Other(c)	30	—	4	(5)	32
Total	$ 43	$ —	$ 5	$ (5)	$ 46

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Merger and Integration Costs:	Pre-tax Expense Three Months Ended June 30, 2012 Generation (a)	ComEd	PECO	BGE (a)	Exelon (a)
Transaction(e)	—	—	—	—	2
Employee-Related(b)	39	—	2	—	43
Other(c)	55	—	2	2(d)	66
Total	$ 94	$ —	$ 4	$ 2	$ 111

Merger and Integration Costs:	Pre-tax Expense Six Months Ended June 30, 2012 Generation (a)	ComEd	PECO	BGE (a)	Exelon (a)
Transaction(e)	—	—	—	—	52
Maryland Commitments	35	—	—	139	328
Employee-Related(b)	86	—	7	—	101
Other(c)	83	2	4	3	103
Total	$ 204	$ 2	$ 11	$142	$ 584

(a) For Exelon, Generation and BGE, includes the operations of the acquired businesses for the six months ended June 30, 2013 and from the date of the merger, March 12, 2012, through June 30, 2012.

(b) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd established regulatory assets of $0 million and $4 million during the three months ended June 30, 2013 and June 30, 2012 and $1 million and $16 million during the six months ended June 30, 2013 and June 30, 2012, respectively. For ComEd, the majority of these costs are expected to be recovered over a five-year period. ComEd and BGE established a regulatory asset of $16 million and $18 million, respectively, during the six months ended June 30, 2012, for severance benefit costs and the majority of these costs will be recovered over a five-year period. These costs are not included in the table above.

(c) Costs to integrate Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. ComEd established a regulatory asset of $4 million and $3 million during the three months ended June 30, 2013 and 2012 and $7 million and $7 million during the six months ended June 30, 2013 and June 30, 2012, respectively, for certain other merger and integration costs, which are not included in the table above. BGE established a regulatory asset of $2 million during the six months June 30, 2013 for certain other merger integration costs, which are not included in the table above.

(d) BGE established a regulatory asset of $6 million at June 30, 2013 for certain 2012 other merger integration costs as part of the 2013 electric and gas distribution rate case order.

(e) External, third-party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of the transaction.

As of June 30, 2013, Exelon projects incurring total additional merger-related expenses, primarily in 2013, of approximately $95 million.

Pursuant to the conditions set forth by the MDPSC in its approval of the merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of more than $1 billion. The direct investment estimate includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a twenty year lease agreement that is contingent upon the developer obtaining financing for the construction of the building. Once the financing conditions are met, construction of the building will commence and is expected to be ready for occupancy in 2 years. The direct investment estimate also includes $625 million in expenditures relating to the development of 285-300 MW of new electric generation facilities in Maryland (expected to be completed over the next ten years).

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Exelon's Strategy and Outlook for the remainder of 2013 and Beyond

Exelon's value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline.

On March 12, 2012, the Exelon and Constellation merger was completed. The merger creates incremental strategic value by matching Exelon's clean generation fleet with Constellation's leading customer-facing platform, as well as creating economies of scale through expansion across the energy value chain. Exelon supports customer switching to alternative electric generation suppliers and the addition of Constellation's competitive retail operations provides another outlet for Exelon to grow its business in competitive markets.

Generation's nuclear, fossil fuel, hydroelectric and renewable energy electricity generation strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding its regional and technological footprint. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in spot markets. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation's presence in well-developed energy markets, its integrated hedging strategy mitigating short-term market volatility, and its low cost nuclear generating fleet operating consistently at high capacity factors, position it well to succeed in competitive energy markets.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results.

Exelon's financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, and to return value to Exelon's shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

In pursuing its strategies, Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the power markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular, the prices of natural gas and coal, which drive the market prices that Generation can obtain for the output of its power plants' output, (2) the rate of expansion of subsidized low carbon generation in the markets in which Generation's output is sold, (3) the effects on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel.

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Since the third quarter of 2011, forward natural gas prices for 2013 and 2014 have declined significantly; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Subsidized Generation . The rate of expansion of subsidized low carbon generation such as wind and solar energy in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have implemented or proposed legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices. For example, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected will be in

commercial operation by June 1, 2015. CPV has subsequently extended that date. The CfD mandates that utilities (including BGE) pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Similarly, in January 2011, New Jersey passed legislation that provides guaranteed cost recovery through a CfD for the development of up to 2,000 MWs of new base load or mid-merit generation, so long as it clears in PJM's capacity market. Three generation developers were chosen for the New Jersey CfD, for which contracts were executed in 2011 by the state's utilities under protest. Similarly, in Illinois, legislation has been debated for over four years that passed in the Senate and is currently being considered in the House which would require consumers to subsidize the development of an Integrated Gasification Combined Cycle plant by purchasing its electricity through 30 year power purchase agreements at prices significantly above market prices. A new version was recently introduced in the current Illinois General Assembly but its prospects are unclear at this time.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others are also challenging the selection of the three generation developers in New Jersey state court proceedings and the MDPSC actions in Maryland state court.

As required under their CfDs, two of the New Jersey generator developers and one in Maryland offered and cleared in PJM's capacity market auctions held in May 2012 and 2013. Given the state-required customer subsidy provided under their respective CfDs, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon's market driven position. A continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR), could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish similar programs, which could substantially impact Exelon's market driven position and could have a significant effect on Exelon's financial results of operations, financial position and cash flows.

PJM's capacity market rules include a MOPR, which is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. However, as described above, Exelon does not believe that the existing MOPR will work effectively with respect to generator developers who have a state-sponsored subsidy and has concerns with certain other aspects of PJM's rules related to the capacity auction. Accordingly, Exelon is working with other market stakeholders on several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts) cannot inappropriately affect capacity auction prices in PJM.

Energy Demand. The continued tepid economic environment and growing energy efficiency initiatives have limited the demand for electricity across the Exelon utilities. ComEd is projecting load volumes to remain essentially flat in 2013 compared to 2012, while PECO and BGE are projecting an increase (decrease) of 0.5% and (1.0%), respectively, in 2013 compared to 2012.

Retail Competition. Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Recently, sustained low forward natural gas and power prices and low market volatility have caused retail competitors to aggressively pursue market share, and wholesale generators (including Generation) to use their retail operations to hedge generation output. These factors have adversely affected overall gross margins and profitability in Generation's retail operations.

Strategic Policy Alignment

Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's Board of Directors declared the first quarter 2013 dividend of $0.525 per share, and in response to low forward energy prices and weaker financial expectations, among other factors, Exelon's Board of Directors approved a revised dividend policy going forward. The first quarter dividend was paid on March 8, 2013 to shareholders of record on February 19, 2013 and was based on Exelon's previous dividend of $2.10 per share on an annualized basis. The second quarter dividend is based on Exelon's new dividend policy of $0.31 per share quarterly dividend ($1.24 per share on an annualized basis). Consistent with past practice, all future quarterly dividends require approval by Exelon's Board of Directors.

Continuation of recent power price volatility and demand trends could adversely affect the Registrants' ability to fund discretionary uses of cash such as growth projects and dividends. In addition, economic conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Generation's results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2013 and 2014. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of June 30, 2013, the percentage of expected generation hedged for the major reportable segments was 96%-99%, 78%-81% and 41%-44% for 2013, 2014, and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including Generation's sales of energy to ComEd, PECO and BGE relating to their respective retail load obligations. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal, oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2013 through 2017 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position. ComEd, PECO and BGE mitigate such exposure through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

Exelon is currently pursuing growth in both the utility and generation businesses focused primarily on smart meter and smart grid initiatives at the utilities and on renewables development and the nuclear uprate program at Generation. The utilities also anticipate making significant future investments in infrastructure modernization and improvement initiatives. Management continually evaluates growth opportunities aligned with Exelon's existing businesses in electric and gas distribution, electric transmission, generation, customer supply of electric and natural gas products and services, and natural gas exploration and production activities, leveraging Exelon's expertise in those areas.

Smart Meter and Smart Grid Initiatives.

ComEd's Smart Meter and Smart Grid Investments. ComEd plans to invest approximately $1.3 billion on smart meters and smart grid under EIMA, including $1.0 billion through the AMI Deployment Plan. On June 5, 2012, the ICC issued an interim order approving ComEd's accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. The deployment plan provides for the installation of 4 million electric smart meters, including 60,000 meters to be installed by the end of 2013.

PECO's Smart Meter and Smart Grid Investments. In 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, under which PECO will install more than 1.6 million smart meters. PECO plans to spend up to a total of $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, of which $200 million will be funded by SGIG.

BGE Smart Grid Initiative. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million electric and gas smart meters at an expected total cost of approximately $480 million, before considering the $200 million SGIG for smart grid and other related initiatives.

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

Generation Renewable Development . On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which developed and will build, operate, and maintain the project. The first portion of the project began operations in December 2012, with four additional blocks coming online in the first half of 2013 and an expectation of full commercial operation in December 2013. Exelon has been informed by First Solar of issues relating to potential delays in the certification of certain components relating to the final two blocks of the project which could delay commercial operation of these two blocks until the first quarter of 2014. The delay, if any, would not have a material financial effect on Exelon. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA, approved by the CPUC, with Pacific Gas & Electric Company for the full output of the plant. Upon completion, the facility will add 230 MWs to Generation's renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through June 30, 2013 were approximately $890 million. In addition, Generation constructed and placed into service 400MWs of additional wind generation in 2012 at a cost of $710 million and another 46MW will be added to Generation's wind portfolio in 2014 with the expansion of its Beebe project in Michigan.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan has been adjusted in both the first and second quarters of 2013 to cancel certain projects. During the first quarter of 2013, the Measurement

Uncertainty Recapture uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. For these cancelled projects, Generation recorded approximately $21 million of operating and maintenance expense during the first quarter of 2013 to accrue remaining costs and reverse the previously capitalized costs. During the second quarter of 2013, market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. For these cancelled projects, Generation recorded a pre-tax charge during the second quarter of 2013 to operating and maintenance expense and interest expense of approximately $92 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Under the nuclear uprate program, Generation has placed into service projects representing 314 MWs of new nuclear generation at a cost of $891 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's consolidated balance sheets. At June 30, 2013, Generation has capitalized $167 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 202 MWs of new nuclear generation, that are in the installation phase across four nuclear stations; Peach Bottom in Pennsylvania and Byron, Braidwood and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $400 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected to not be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

Liquidity

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.4 billion.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets. The ongoing European debt crisis has contributed to the instability in global credit markets. Further disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of June 30, 2013, approximately 30%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.4 billion was available as of June 30, 2013. There were no borrowings under the Registrants' credit facilities as of June 30, 2013. See Note 11 – Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

Exelon has exposure related to various uncertain tax positions which Exelon manages through planning and implementation of tax planning strategies. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon supports the promulgation of certain environmental regulations by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to their low emission generation portfolios, Generation and CENG will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air Quality. In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a review of the current 2008 ozone NAAQS that is expected to result in a proposed revision of the ozone NAAQS sometime in mid-2014. These updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Until the U.S. EPA re-issues CSAPR, Exelon cannot determine the impacts of the rule, including any that would impact power prices. In June 2013, the U.S. Supreme Court granted the U.S. EPA's petition to review the D.C. Circuit Court's CSAPR decision.

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon has been granted permission by the Court to intervene in support of the rule. A decision by the Court may not occur until 2014. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

The cumulative impact of these air regulations could be to require power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO_2 and acid gases, and selective catalytic reduction technology for NO_x. Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS by January 1, 2015. In addition, Keystone already has SCR and Flue-gas desulfurization (FGD) controls in place.

On January 15, 2013, EPA issued a final rule for NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE NESHAP/NSPS). The final rule allows diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but requires units that operate over 15 hours to burn low sulfur fuel and report key engine information. The final rule eliminates after May 2014 the 50 hour exemption for peak shaving and other non-emergency demand response that was included in the proposed rule and, therefore, is not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act, including permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources that became effective January 2, 2011. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis. On April 13, 2012, the U.S. EPA published proposed regulations for NSPS for GHG emissions from new fossil-fueled power plants greater than 25 MW that would require the plants to limit CO_2 emissions. The U.S. EPA will re-propose the regulations by September 2013. The U.S. EPA is also expected to propose by June 2014 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and to issue final regulations by June 2015. It is not yet known what the nature and impact of the final regulations will be.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On March 28, 2011, the U.S. EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by November 4, 2013. The proposed rule does not require closed cycle cooling (e.g., cooling towers) as the best technology available, and also provides some flexibility in the use of cost-benefit considerations and site-specific factors. The proposed rule affords the state permitting agency wide discretion to determine the best technology available, which, depending on the site characteristics, could include closed cycle cooling, advanced screen technology at the intake, or retention of the current technology.

It is unknown at this time whether the final regulations will require closed-cycle cooling. The economic viability of Generation's facilities without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost-benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation.

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Generation's plants that would be affected by the proposed rules are Keystone and Conemaugh in Pennsylvania, which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has not announced a target date for finalization of the CCR rules.

See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

Japan Earthquake and Tsunami and the Nuclear Industry's Response. On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. Generation believes its nuclear generating facilities do not have the same operating risks as the Fukushima Daiichi plant because they meet the NRC's requirement that specifies all plants must be able to withstand the most severe natural phenomena historically reported for each plant's surrounding area, with a significant margin for uncertainty. In addition, Generation's plants are not located in significant earthquake zones or in regions where tsunamis are a threat. Generation believes its nuclear generating facilities are able to shut down safely and keep the fuel cooled through multiple redundant systems specifically designed to maintain electric power when electricity is lost from the grid. Further, Generation's nuclear generating facilities also undergo frequent scenario drills to ensure the proper function of the redundant safety protocols.

Since the events in Japan took place, Generation has continued to work with regulators and nuclear industry organizations to understand the events in Japan and apply lessons learned. Early on, the nuclear industry took a number of specific steps to respond, including actions requested by the Institute of Nuclear Power Operations (INPO) to perform tests that verified Generation's emergency equipment is available and functional, conduct walk-downs on its procedures related to critical safety equipment, confirm event response procedures and readiness to protect the spent fuel pool, and verify current qualifications of operators and support staff needed to implement the procedures. Generation has been addressing additional actions requested by INPO for improving and maintaining core and spent fuel pool cooling during an extended loss of power for at least 24 hours.

In April 2011, the NRC named six senior managers and staff to its task force for examining the agency's regulatory requirements, programs, processes, and implementation in light of information from the Fukushima Daiichi site in Japan, following the March 11 earthquake and tsunami (Task Force). On July 12, 2011, the NRC Task Force issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The Task Force's report did not recommend any changes to the existing nuclear licensing process in the United States or changes in the storage of spent nuclear fuel within the plant's spent nuclear fuel pools. During the fourth quarter of 2011, the NRC staff issued its recommendations for prioritizing and implementing the Task Force recommendations and an implementation schedule which was approved by the NRC subject to a number of conditions. The NRC staff confirmed the Task Force's conclusions that none of the findings arising from the Task Force review presented an imminent risk to public health and safety.

In March 2012, the NRC authorized its staff to issue three immediately effective orders (Tier 1 orders) to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. In addition, in November 2012, the NRC staff recommended to the NRC the installation of engineered containment filtered venting systems for boiling-water reactors (BWR) with Mark I and Mark II containment structures. In summary, through the initial and/or subsequent orders and the NRC approved implementation guidance, the Tier I orders currently: (1) require licensees to provide sufficient onsite portable equipment and resources to maintain or restore cooling capabilities for the core and spent fuel pool and to maintain containment integrity until offsite equipment is available and have offsite equipment and resources available to sustain cooling functions indefinitely; (2) provide requirements for vents for BWR's with Mark I and Mark II containments to remain functional during severe accident conditions including the ability to vent the containment following core damage; and (3) require licensees to install instrumentation to provide a reliable indication of water level in the spent fuel pool. Finally, the NRC has directed the NRC staff to produce a technical evaluation to support rulemaking that considers filtering and performance-based strategies as options for BWR's with Mark I and Mark II containments. The NRC staff must then develop a final rule by March 2017.

Additionally, the NRC has issued a detailed information request to every operating commercial nuclear power plant in the United States. The information requested requires: (1) use of the current NRC guidance to

reevaluate current seismic and flood risk hazards against the design basis and provide a plan of actions to address vulnerabilities, including risks exceeding the design basis; (2) performance of walk downs to ensure the ability to respond to seismic and external flooding events and provide a corrective action plan to the NRC to address deficiencies; and (3) assessment of the means to provide power for communications equipment during a severe natural event and identify staffing required to implement the emergency plan for an event affecting all units with an extended loss of alternating current power and impeded access to the site. The nuclear industry proposed an augmented approach to the seismic hazard analysis to accommodate industry wide availability of qualified technical resources needed to perform the required analysis. The NRC approved this augmented approach.

Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for the period from 2013 through 2017 is expected to be approximately $350 million and $50 million of capital and operating expense, respectively, as previously anticipated in Generation's planning projections. As Generation completes the design and installation planning for its actions, Generation will update these estimates. Further, Generation believes that additional expenditures could be incurred during the period from 2018 to 2020 ranging from $25 million to $50 million in order to make the hardened vents at the eleven Mark I and II units capable of functioning under severe accident conditions and to complete seismic re-evaluations that have moved to this later time frame as a result of NRC acceptance of the augmented approach to seismic hazard analysis. Finally, Generation estimates incremental costs of $15 to $20 million per unit at eleven Mark I and II units for the installation of filtered vents, if ultimately required by the NRC. Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors of the Exelon 2012 Form 10-K, for further discussion of the risk factors.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing, exchange trading, margin requirements, and other transparency requirements. The Dodd-Frank Act, however, also preserves the ability of end users in the energy industry to hedge their risks. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Exelon has determined that it will conduct its commercial business in a manner that does not require registration as a swap dealer or major swap participant. Notwithstanding, there are additional rulemakings that have not yet been issued, including the capital and margin rules, which will further define the scope of the regulations and provide clarity as to the impact on the Registrants' business, as well as to potential new opportunities. Depending on these final rules, the Registrants could be subject to significant new obligations.

The proposed regulations addressing collateral and capital requirements and exchange margin cash postings, when final, could require Generation to increase collateral requirements or cash postings in lieu of letters of credit currently issued to collateralize Swaps. Exelon had previously estimated that it could be required to make up to $1 billion of additional collateral postings under its bilateral credit lines. Given the swap dealer and the major swap participant definitions will not apply to Generation, the actual amount of collateral postings that will be required may be lower than Exelon's previous expectations due to the following factors: (a) the majority of Generation's physical wholesale portfolio does not meet the final CFTC Swap definition; (b) there will be minimal incremental costs associated with Generation's positions that are currently cleared and subject to exchange margin; and (c) Generation will not be a swap dealer or major swap participant and proposed capital requirements applicable to these entities will not apply to Generation.

The actual level of collateral required will depend on many factors, including but not limited to market conditions, the outcome of final margin rules for Swaps, the extent of its trading activity in Swaps, and Generation's credit ratings. Nonetheless, Generation has adequate credit facilities and flexibility in its hedging program to meet its anticipated collateral requirements estimated based on conservative assumptions.

In addition, the new regulations will impose new and ongoing compliance and infrastructure costs on Generation, which may amount to several million dollars per year.

Exelon and Generation continue to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on their results of operations, cash flows or financial position.

ComEd, PECO and BGE could also be subject to various Dodd-Frank Act requirements to the extent they enter into Swap transactions. However, at this time, management of ComEd, PECO and BGE do not expect to be materially affected by this legislation.

Energy Infrastructure Modernization Act . Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. In addition, as long as ComEd is subject to EIMA, ComEd will fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

ComEd files an annual reconciliation of the revenue requirement in effect in a given year to reflect the actual costs that the ICC determines are prudently and reasonably incurred for such year. Under the terms of EIMA, ComEd's target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program.

During March 2013, the Illinois House and Senate each passed Senate Bill 9 with supermajority votes to clarify the intent of EIMA on three major issues: average vs. year-end rate base and capital structure, return on pension asset, and a weighted average cost of capital interest rate on the prior year reconciliation. On May 22, 2013, the Illinois General Assembly overrode the Governor's May 5, 2013 veto of Senate Bill 9, which resulted in the legislation becoming effective immediately. The ICC issued a rate order on June 5, 2013 approving ComEd's May 30, 2013 filing to update 2013 rates reflecting Senate Bill 9 impacts. In addition, the ICC issued an interim order approving ComEd's accelerated meter deployment plan. ComEd projects the override of Senate Bill 9 will result in increased operating revenues of approximately $15 million for the remainder of 2013 and $65 million in 2014, respectively. Also, ComEd projects that due to the Senate Bill 9 override it will accelerate capital expenditures by approximately $40 million and $45 million in 2013 and 2014, respectively .

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

FERC Ameren Order. In July 2012, FERC issued an order indicating that Ameren Corporation (Ameren) had improperly included acquisition premiums/goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. Ameren has filed for rehearing regarding the July 2012 FERC order. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

FERC Order No. 1000 Compliance. In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods

applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements a federal right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners including ComEd, PECO and BGE (collectively, the PJM Transmission Owners) submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC's " *Mobile-Sierra* " standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order on the PJM Compliance Filing and the filing of these PJM Transmission Owners (1) rejecting the arguments of such PJM Transmission Owners that the PJM governing documents were entitled to review under the *Mobile-Sierra* standard, (2) accepting most of the PJM filing, removing the right-of-first refusal from the PJM tariffs; and (3) directing PJM to remove certain exceptions that it included in its compliance filing that FERC found did not comply with Order No. 1000. FERC's order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd's, PECO's and BGE's financial return on new investments in energy transmission facilities. Numerous parties sought rehearing of the FERC's March 22, 2013 order, including the PJM Transmission Owners who sought rehearing of the FERC's rejection of their Mobile-Sierra and related arguments. The compliance filing was made on July 22, 2013.

FERC Transmission Complaint. On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. As of June 30, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base ROE, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE's base ROE to 8.7%, the annual impact would be a reduction in revenues of approximately $10 million.

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

2013 Maryland Electric and Gas Distribution Rate Case. On May 17, 2013, BGE filed an application for increases of $101 million and $30 million to its electric and gas base rates, respectively with the MDPSC. The requested rates of return on equity in the application are 10.50% and 10.35% for electric and gas distribution, respectively. The new electric and gas distribution base rates are expected to take effect in December 2013. BGE cannot predict how much of the requested increases the MDPSC will approve.

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Critical Accounting Policies and Estimates

Management of each of the Registrants makes a number of significant estimates, assumptions and judgments in the preparation of its financial statements. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Estimates" in the Exelon's, Generation's, ComEd's, PECO's and BGE's combined 2012 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants' accounting for AROs, purchase accounting, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies and revenue recognition. At June 30, 2013, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2012.

Results of Operations

Net Income (Loss) Attributable to Common Shareholders by Registrant

	Three Months Ended June 30,		Favorable (Unfavorable)	Six Months Ended June 30,		Favorable (Unfavorable)
	2013	2012	Variance	2013	2012 (a)	Variance
Exelon	$ 490	$ 286	$ 204	$ 486	$ 486	$ —
Generation	330	166	164	311	334	(23)
ComEd	96	42	54	14	129	(115)
PECO	72	79	(7)	193	175	18
BGE	22	13	9	100	(20)	120

(a) For BGE, reflects BGE's operations for the six months ended June 30, 2012. For Exelon and Generation, includes the operations of the acquired businesses from the date of the merger, March 12, 2012, through June 30, 2012.

Results of Operations — Generation

	Three Months Ended June 30,		Favorable (Unfavorable)	Six Months Ended June 30,		Favorable (Unfavorable)
	2013	2012	Variance	2013	2012(a)	Variance
Operating revenues	$4,070	$3,765	$ 305	$7,603	$6,508	$ 1,095
Purchased power and fuel expense	1,946	1,852	(94)	4,114	2,896	(1,218)
Revenue net of purchased power and fuel(b)	2,124	1,913	211	3,489	3,612	(123)
Other operating expenses						
Operating and maintenance	1,189	1,178	(11)	2,302	2,356	54
Depreciation and amortization	210	204	(6)	424	357	(67)
Taxes other than income	101	90	(11)	194	164	(30)
Total other operating expenses	1,500	1,472	(28)	2,920	2,877	(43)
Equity in earnings (losses) of unconsolidated affiliates	(21)	(57)	36	(30)	(79)	49
Operating income	603	384	219	539	656	(117)
Other income and (deductions)						
Interest expense	(93)	(85)	(8)	(176)	(138)	(38)
Other, net	(33)	(76)	43	95	103	(8)
Total other income and (deductions)	(126)	(161)	35	(81)	(35)	(46)
Income before income taxes	477	223	254	458	621	(163)
Income taxes	149	58	(91)	148	289	141
Net income	328	165	163	310	332	(22)
Net loss attributable to noncontrolling interests	(2)	(1)	1	(1)	(2)	(1)
Net income on common stock	$ 330	$ 166	$ 164	$ 311	$ 334	$ (23)

(a) Includes the operations of the acquired businesses from the date of the merger, March 12, 2012, through June 30, 2012.

(b) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012 . Generation's net income increased compared to the same period in 2012 due to higher revenues, net of purchased power and fuel expense, higher earnings from Generation's interest in CENG and decreases in transaction costs and employee-related costs associated with the merger; partially offset by the impairment of certain generating assets in 2013, higher depreciation expense, higher property taxes, and unfavorable NDT fund performance. The increase in revenues, net of purchased power and fuel expense was primarily due to higher mark-to-market gains in 2013.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. Generation's net income decreased compared to the same period in 2012 due to lower revenue, net of purchased power and fuel, unfavorable NDT fund performance, higher depreciation expense, higher property taxes; partially offset by lower operating and maintenance expense and higher earnings from Generation's interest in CENG. The decrease in revenue, net of purchased power and fuel was primarily due to lower mark-to-market gains in 2013. The decrease in operating and maintenance was largely due to 2012 costs associated with a settlement with FERC in March 2012 and decreases in transaction costs and employee-related costs associated with the merger.

Revenue Net of Purchased Power and Fuel Expense

Generation's six reportable segments are based on the geographic location of its assets, and are largely representative of the footprints of an ISO / RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the entire United States footprint of MISO, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within New York ISO, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
  - South represents operations in the FRCC and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems. Further, the following activities are not allocated to a region, and are reported in Other: compensation under the reliability-must-run rate schedule; results of operations from the Maryland Clean-Coal assets sold in the fourth quarter of 2012; unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements.

For the three and six months ended June 30, 2013 and 2012, Generation's revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended June 30,			
	2013	2012	Variance	% Change
Mid-Atlantic(b)	$ 768	$ 883	$ (115)	(13.0%)
Midwest(c)	684	764	(80)	(10.5%)
New England	50	60	(10)	(16.7%)
New York	14	39	(25)	(64.1%)
ERCOT	112	119	(7)	(5.9%)
Other Regions(d)	59	34	25	73.5%
Total electric revenue net of purchased power and fuel expense	$ 1,687	$ 1,899	$ (212)	(11.2%)
Proprietary Trading	3	15	(12)	(80.0%)
Mark-to-market gains	428	200	228	114.0%
Other(e)	6	(201)	207	(103.0%)
Total revenue net of purchased power and fuel expense	$ 2,124	$ 1,913	$ 211	11.0%

	Six Months Ended June 30,			
	2013	2012(a)	Variance	% Change
Mid-Atlantic(b)	$1,612	$1,653	$ (41)	(2.5%)
Midwest(c)	1,401	1,581	(180)	(11.4%)
New England	80	99	(19)	(19.2%)
New York	(8)	47	(55)	(117.0%)
ERCOT	213	153	60	39.2%
Other Regions(d)	105	48	57	118.8%
Total electric revenue net of purchased power and fuel expense	$3,403	$3,581	$ (178)	(5.0%)
Proprietary Trading	12	11	1	9.1%
Mark-to-market gains	25	260	(235)	(90.4%)
Other(e)	49	(240)	289	(120.4%)
Total revenue net of purchased power and fuel expense	$3,489	$3,612	$ (123)	(3.4%)

(a) Includes results for Constellation beginning on March 12, 2012, the date the merger was completed.
(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.

(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date of $167 million and $341 million pre-tax for the three and six months ended June 30, 2013, and $414 million and $537 million pre-tax for the three and six months ended June 30, 2012.

Generation's supply sources by region are summarized below:

	Three Months Ended June 30,			
Supply source (GWh)	2013	2012	Variance	% Change
Nuclear generation(b)				
Mid-Atlantic	11,794	12,277	(483)	(3.9%)
Midwest	22,807	22,860	(53)	(0.2%)
Total Nuclear Generation	34,601	35,137	(536)	(1.5%)
Fossil and Renewables(b)				
Mid-Atlantic(b)(d)	2,796	2,316	480	20.7%
Midwest	318	228	90	39.5%
New England	3,132	2,755	377	13.7%
New York	—	—	—	—
ERCOT	1,617	2,177	(560)	(25.7%)
Other Regions(e)	1,431	1,923	(492)	(25.6%)
Total Fossil and Renewables	9,294	9,399	(105)	(1.1%)
Purchased power				
Mid-Atlantic(c)	2,616	7,111	(4,495)	(63.2%)
Midwest	1,503	1,558	(55)	(3.5%)
New England	1,365	3,905	(2,540)	(65.0%)
New York(c)	3,073	2,818	255	9.0%
ERCOT	4,269	6,686	(2,417)	(36.2%)
Other Regions(e)	4,998	6,012	(1,014)	(16.9%)
Total Purchased Power	17,824	28,090	(10,266)	(36.5%)
Total supply/sales by region(f)				
Mid-Atlantic(g)	17,206	21,704	(4,498)	(20.7%)
Midwest(h)	24,628	24,646	(18)	(0.1%)
New England	4,497	6,660	(2,163)	(32.5%)
New York	3,073	2,818	255	9.0%
ERCOT	5,886	8,863	(2,977)	(33.6%)
Other Regions(e)	6,429	7,935	(1,506)	(19.0%)
Total supply/sales by region	61,719	72,626	(10,907)	(15.0%)

	Six Months Ended June 30,			
Supply source (GWh)	2013	2012(a)	Variance	% Change
Nuclear generation(b)				
Mid-Atlantic	24,556	24,341	215	0.9%
Midwest	46,076	46,058	18	0.0%
Total Nuclear Generation	70,632	70,399	233	0.3%

Supply source (GWh)	Six Months Ended June 30, 2013	2012(a)	Variance	% Change
Fossil and Renewables(b)				
Mid-Atlantic(b)(d)	5,956	4,107	1,849	45.0%
Midwest	899	500	399	79.8%
New England	5,524	3,644	1,880	51.6%
New York	—	—	—	—
ERCOT	2,350	3,017	(667)	(22.1%)
Other Regions(e)	3,685	2,742	943	34.4%
Total Fossil and Renewables	18,414	14,010	4,404	31.4%
Purchased power				
Mid-Atlantic(c)	5,849	9,688	(3,839)	(39.6%)
Midwest	3,203	4,110	(907)	(22.1%)
New England	2,872	5,005	(2,133)	(42.6%)
New York(c)	6,584	3,753	2,831	75.4%
ERCOT	8,468	9,518	(1,050)	(11.0%)
Other Regions(e)	8,701	7,781	920	11.8%
Total Purchased Power	35,677	39,855	(4,178)	(10.5%)
Total supply/sales by region(f)				
Mid-Atlantic(g)	36,361	38,136	(1,775)	(4.7%)
Midwest (h)	50,178	50,668	(490)	(1.0%)
New England	8,396	8,649	(253)	(2.9%)
New York	6,584	3,753	2,831	75.4%
ERCOT	10,818	12,535	(1,717)	(13.7%)
Other Regions(e)	12,386	10,523	1,863	17.7%
Total supply/sales by region	124,723	124,264	459	0.4%

(a) Includes results for Constellation beginning on March 12, 2012, the date the merger was completed.
(b) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly owned generating plants and does not include ownership through equity method investments (e.g., CENG).
(c) Purchased power for the three months and six months ended June 30, 2013 includes physical volumes of 3,114 GWh and 5,702 GWh in the Mid-Atlantic and 2,655 GWh and 5,868 GWh in New York as a result of the PPA with CENG. Purchased power for the three months and six months ended June 30, 2012 includes physical volumes of 3,225 GWh and 3,544 GWh in the Mid-Atlantic and 2,817 GWh and 3,539 GWh in New York as a result of the PPA with CENG.
(d) Excludes 2012 activity related to generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger.
(e) Other Regions includes South, West and Canada, which are not considered individually significant.
(f) Excludes physical proprietary trading volumes of 1,995 GWh and 4,248 GWh for the three months ended June 30, 2013 and 2012, respectively, and 3,567 GWh and 6,077 GWh for the six months ended June 30, 2013 and 2012, respectively.
(g) Includes sales to PECO through the competitive procurement process of 1,242 GWh and 1,859 GWh for the three months ended June 30, 2013 and 2012, respectively, and 3,162 GWh and 3,488 GWh for the six months ended June 30, 2013 and 2012, respectively. Includes sales to BGE of 1,322 GWh and 1,076 GWh for the three months ended June 30, 2013 and 2012, respectively, and 2,857 GWh and 1,335 GWh for the six months ended June 30, 2013 and 2012, respectively.
(h) Includes sales to ComEd under the RFP procurement of 1,012 GWh and 865 GWh for the three months ended June 30, 2013 and 2012, respectively, and 1,012 GWh and 3,075 GWh for the six months ended June 30, 2013 and 2012, respectively.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the three and six months ended June 30, 2013 as compared to the three and six months ended June 30, 2012.

	Three Months Ended June 30,		
$/MWh	2013	2012	% Change
Mid-Atlantic(b)	$ 44.64	$ 40.68	9.7%
Midwest(c)	27.77	31.00	(10.4%)
New England	11.12	9.01	23.4%
New York	4.56	13.84	(67.1%)
ERCOT	19.03	13.43	41.7%
Other Regions(d)	9.18	4.28	114.4%
Electric revenue net of purchased power and fuel expense per MWh (e)(f)	27.33	26.15	4.5%

	Six Months Ended June 30,		
$/MWh (a)	2013	2012(a)	% Change
Mid-Atlantic(b)	$44.33	$43.35	2.3%
Midwest(c)	27.92	31.20	(10.5%)
New England	9.53	11.45	(16.8%)
New York	(1.22)	12.52	(109.7%)
ERCOT	19.69	12.21	61.3%
Other Regions(d)	8.48	4.56	86.0%
Electric revenue net of purchased power and fuel expense per MWh(e)(f)	27.28	28.82	(5.3%)

(a) Includes financial results for Constellation beginning on March 12, 2012, the date the merger was completed.

(b) Includes sales to PECO of $97 million (1,242 GWh) and $125 million (1,859 GWh) for the three months ended June 30, 2013 and 2012 respectively. Includes sales to PECO of $238 million (3,162 GWh) and $236 million (3,488 GWh) for the six months ended June 30, 2013 and 2012 respectively. Includes sales to BGE of $99 million (1,322 GWh) and $84 million (1,076 GWh) for the three months ended June 30, 2013 and 2012, respectively. Includes sales to BGE of $212 million (2,857 GWh) and $102 million (1,335 GWh) for the six months ended June 30, 2013 and 2012, respectively. Excludes compensation under the reliability-must-run rate schedule and the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the merger.

(c) Includes sales to ComEd of $37 million (1,012 GWh) and $32 million (865 GWh) and settlements of the ComEd swap of $84 million and $171 million for the three months ended June 30, 2013 and 2012, respectively. Includes sales to ComEd of $37 million (1,012 GWh) and $115 million (3,075 GWh) and settlements of the ComEd swap of $229 million and $336 million for the six months ended June 30, 2013 and 2012, respectively

(d) Other Regions includes South, West and Canada, which are not considered individually significant.

(e) Revenue net of purchased power and fuel expense per MWh represents the average margin per MWh of electricity sold during the three and six months ended June 30, 2013 and 2012 and excludes the mark-to-market impact of Generation’s economic hedging activities.

(f) Excludes Generation's other business activities not allocated to a region, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency, energy management and demand response. Also excludes Generation’s compensation under the reliability-must-run rate schedule, the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in Q4 2012 as a result of the merger, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the Exelon and Constellation merger of $167 million and $414 million, for the three months ended June 30, 2013 and 2012, respectively, and $341 million and $537 million, for the six months ended June 30, 2013 and 2012, respectively.

Mid-Atlantic

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012 . The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $115 million was primarily due to lower realized energy prices and increased nuclear fuel expense, partially offset by lower energy supply costs as a result of increased integration of Generation’s energy generation and load businesses.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $41 million was primarily due to lower realized energy prices and increased nuclear fuel expense, partially offset by higher capacity revenues and the addition of Constellation in 2012.

Midwest

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012 . The decrease in revenue net of purchased power and fuel expense in the Midwest of $80 million was primarily due to lower capacity revenues, lower realized energy prices, and increased nuclear fuel expense, partially offset by the early termination of certain contracts.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The decrease in revenue net of purchased power and fuel expense in the Midwest of $180 million was primarily due to lower capacity revenues, lower realized energy prices, and increased nuclear fuel expense, partially offset by the early termination of certain contracts and the addition of Constellation in 2012.

New England

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012 . The $10 million decrease in revenue net of purchased power and fuel expense in New England was primarily due to decreased load served and increased fuel expense.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The $19 million decrease in revenue net of purchased power and fuel expense in New England was primarily due to decreased load served and increased fuel expense, partially offset by the addition of Constellation in 2012. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

New York

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012 . The $25 million decrease in revenue net of purchased power and fuel expense in New York was primarily the result of decreased realized energy prices.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The $55 million decrease in revenue net of purchased power and fuel expense in New York was primarily a result of decreased realized energy prices, partially offset by the addition of Constellation in 2012. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

ERCOT

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012 . The $7 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of decrease in load served, offset by increased realized energy prices.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The $60 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the addition of Constellation in 2012.

Other Regions

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The $25 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of lower supply costs and increased integration of Generation's energy generation and load businesses.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The $57 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of lower supply costs, increased integration of Generation's energy generation and load businesses, and the addition of Constellation in 2012.

Mark-to-market

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012 . Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $428 million for the three months ended June 30, 2013 compared to gains of $200 million for the three months ended June 30, 2012. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012 . Mark-to-market gains on economic hedging activities were $25 million for the six months ended June 30, 2013 compared to gains of $260 million for the six months ended June 30, 2012. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012 . The $207 million increase in other revenue net of purchased power and fuel was primarily due to the decrease in amortization of the acquired energy contracts recorded at fair value at the merger date. This increase was also due to the addition of Constellation in 2012, which includes wholesale and retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities in 2012. In addition, other revenue net of purchased power and fuel for 2012 includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter 2012 as a result of the Exelon and Constellation merger. These positive factors were partially offset by a decrease in the compensation under the reliability-must-run rate schedule. See Note 4 – Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012 . The $289 million increase in other revenue net of purchased power and fuel was primarily due to the addition of Constellation in 2012, in addition to the decrease of the amortization of the acquired energy contracts recorded at fair value at the merger date. In addition, other revenue net of purchased power and fuel for 2012 includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter 2012 as a result of the Exelon and Constellation merger. These positive factors were partially offset by a decrease in the compensation under the reliability-must-run rate schedule. See Note 4 – Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for the three and six months ended June 30, 2013 as compared to the same periods in June 30, 2012, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor,

contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures comparatively to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Nuclear fleet capacity factor(a)	92.8 %	93.4 %	94.6 %	93.5 %
Nuclear fleet production cost per MWh(a)	$18.86	$18.48	$19.27	$19.27

(a) Reflects ownership percentage of stations operated by Exelon. Excludes Salem, which is operated by PSEG Nuclear, LLC, and Exelon's ownership in jointly owned generating plants through equity method investments (e.g. CENG).

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The nuclear fleet capacity factor decreased primarily due to more non-refueling outage days, partially offset by fewer refueling outage days, excluding Salem outages, during the three months ended June 30, 2013 compared to the same period in 2012. For the three months ended June 30, 2013 and 2012, non-refueling outage days totaled 31 and 16, respectively. During the same periods, refueling outage days totaled 47 and 51, respectively. Lower number of net MWhs generated and higher nuclear fuel costs resulted in a higher production cost per MWh for the three months ended June 30, 2013 as compared to the same period in 2012.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The nuclear fleet capacity factor increased primarily due to fewer refueling outage days, partially offset by more non-refueling outage days, excluding Salem outages, during the six months ended June 30, 2013 compared to the same period in 2012. For the six months ended June 30, 2013 and 2012, non-refueling outage days totaled 37 and 32, respectively. During the same periods, refueling outage days totaled 96 and 118, respectively.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and six months ended June 30, 2013 compared to the same period in 2012, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
FERC settlement(a)	$ —	$ (195)
Labor, other benefits, contracting and materials	(5)	151
Impairment and related charges of certain generating assets	92	113
Constellation merger and integration costs	(19)	(71)
Maryland commitments	—	(35)
Corporate allocations(b)	(19)	13
Pension and non-pension postretirement benefits expense	—	7
Nuclear refueling outage costs, including the co-owned Salem plant(c)	29	3
Bodily injury costs(d)	(14)	(12)
Plant retirements and divestitures(e)	(43)	(56)
Bad debt expense	7	23
Other	(17)	5
Increase (decrease) in operating and maintenance expense	$ 11	$ (54)

(a) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation's prior period hedging and risk management transactions.

(b) The increase in cost allocations during six months ended June 30, 2013 reflects the impact of an increased share of corporate allocated costs due to the merger, partially offset during the three months ended June 30, 2013 primarily as a result of merger synergy savings for Exelon's corporate operations and shared service entities.
(c) Reflects primarily increased nuclear fueling outage costs related to Generation's ownership interest in Salem for three months ended June 30, 2013 compared to same period in 2012.
(d) Reflects decreased asbestos-related bodily injury expense.
(e) Reflects the operating and maintenance expense associated with the generating assets retired or divested during 2012.

Depreciation and Amortization

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The increase in depreciation and amortization was primarily due to higher plant balances resulting from capital additions, increased nuclear fuel amortization costs, and the completion of wind and solar facilities placed into service in the second half of 2012 and in the first half of 2013.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The increase in depreciation and amortization was primarily due to higher plant balances resulting from the addition of Constellation's plant balances for full year to date 2013. The increase in depreciation and amortization expense was also due capital additions, increased nuclear fuel amortization costs, and the completion of wind and solar facilities placed into service in the second half of 2012 and in the first half of 2013.

Taxes Other Than Income

The increase in taxes other than income for the three and six months ended June 30, 2013 as compared to the three and six months ended June 30, 2012 was primarily due to higher property taxes. The increase in taxes other than income for the six months ended June 30, 2013 compared to six months ended June 30, 2012 was also due to addition of Constellation's financial results in 2012.

Equity in Loss of Unconsolidated Affiliates

The decrease in Equity in loss of unconsolidated affiliates for the three and six months ended June 30, 2013 was primarily due to higher net income generated from Generation's equity investment in CENG in 2013 compared to same period in 2012 and lower amortization of the basis difference of Generation's ownership interest in CENG recorded at fair value in connection with the Merger.

Interest Expense

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The increase in interest expense was primarily due to the reversal of previously capitalized interest expense related to power uprate projects that were cancelled during second quarter of 2013.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The increase in interest expense was primarily due to the increase in long-term debt as a result of the merger and the reversal of previously capitalized interest expense related to power uprate projects that were cancelled during second quarter of 2013.

Other, Net

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. Other, net primarily reflects the change in the net unrealized gains (losses) related to the NDT funds of the Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $43 million of credit facility termination fees recorded in 2012.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. Other, net primarily reflects the change in the net unrealized gains (losses) related to the NDT funds of the Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $30 million and $52 million of income in 2013 and 2012, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units and $42 million of credit facility termination fees recorded in 2012

The following table provides unrealized and realized gains and losses on the NDT funds of the Non-Regulatory Agreement Units recognized in other, net for the three and six months ended June 30, 2013 and 2012:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net unrealized gains (losses) on decommissioning trust funds	$ (40)	$ (35)	$ 24	$ 30
Net realized gains on sale of decommissioning trust funds	$ —	$ 3	$ 2	$ 40

Effective Income Tax Rate

The effective income tax rate was 31.2% and 32.3% for the three and three months ended June 30, 2013, respectively, compared to 26.0% and 46.5% for the same periods during 2012. See Note 12 of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

Results of Operations — ComEd

	Three Months Ended June 30,		Favorable (Unfavorable)	Six Months Ended June 30,		Favorable (Unfavorable)
	2013	2012	Variance	2013	2012	Variance
Operating revenues	$ 1,080	$ 1,281	$ (201)	$2,239	$2,670	$ (431)
Purchased power expense	248	587	339	630	1,208	578
Revenue net of purchased power expense(a)	832	694	138	1,609	1,462	147
Other operating expenses						
Operating and maintenance	359	331	(28)	687	650	(37)
Depreciation and amortization	170	152	(18)	337	300	(37)
Taxes other than income	71	69	(2)	145	144	(1)
Total other operating expenses	600	552	(48)	1,169	1,094	(75)
Operating income	232	142	90	440	368	72
Other income and (deductions)						
Interest expense, net	(76)	(74)	(2)	(429)	(156)	(273)
Other, net	6	3	3	11	7	4
Total other income and (deductions)	(70)	(71)	1	(418)	(149)	(269)
Income before income taxes	162	71	91	22	219	(197)
Income taxes	66	29	(37)	8	90	82
Net income	$ 96	$ 42	$ 54	$ 14	$ 129	$ (115)

(a) ComEd evaluates its operating performance using the measure of revenue net of purchased power expense. ComEd believes that revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended June 30, 2013, Compared to Three Months Ended June 30, 2012. ComEd's net income for the three months ended June 30, 2013, was higher than the same period in 2012, primarily due to the discrete impacts of the ICC's May 2012 Order in ComEd's 2011 formula rate proceeding under EIMA and the enactment of Senate Bill 9 in May 2013. The increase to net income was partially offset by unfavorable weather conditions in 2013 compared to the same period in 2012. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Six Months Ended June 30, 2013, Compared to Six Months Ended June 30, 2012. ComEd's net income for the six months ended June 30, 2013, was lower than the same period in 2012, primarily due to the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013 and unfavorable weather conditions in the second quarter of 2013 compared to the same period in 2012. The decrease to net income was partially offset by the discrete impacts of the ICC's May 2012 Order in ComEd's 2011 formula rate proceeding under EIMA and the enactment of Senate Bill 9 in May 2013. See Notes 5 — Regulatory Matters and 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Operating Revenues Net of Purchased Power Expense

There are certain drivers of revenue that are fully offset by their impact on purchased power expense, such as commodity procurement costs and customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on revenue net of purchased power expense. See Note 5 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

Electric revenues and purchased power expense are affected by fluctuations in customers' purchases from competitive retail electric suppliers. All ComEd customers have the choice to purchase electricity from an alternative retail electric supplier. The customers' choice of retail electric supplier does not impact ComEd's volume of deliveries, but does affect ComEd's energy revenue. The number of retail customers purchasing electricity from alternative retail electric suppliers was 2,593,064 and 668,209 at June 30, 2013, and 2012, respectively, representing 68% and 17% of total retail customers, respectively. Retail energy purchased from alternative electric suppliers represented 81% and 78% of ComEd's retail kWh sales for the three months and six months ended June 30, 2013, respectively, as compared to 62% and 61% for the three and six months ended June 30, 2012, respectively. During 2012, the City of Chicago and approximately 240 Illinois municipalities (which by reference also includes governmental entities such as townships and counties) approved referenda regarding electric supply aggregation. This approval allowed governmental officials to identify and sign contracts with alternative retail electric suppliers on behalf of the eligible retail customers in its community. Additionally, the referenda provided customers with the ability to opt-out of the municipal aggregation program. As of June 30, 2013, there are approximately 330 municipalities that have approved a municipal aggregation referendum in the ComEd service territory. As a result, approximately two-thirds of residential usage as of June 30, 2013 is being supplied by alternative retail electric suppliers and it is estimated that over 80% of that usage resulted from municipal aggregation activities. It is anticipated that as municipalities implement their aggregation programs throughout 2013, and as non-municipality aggregation switching continues to grow, that approximately three-quarters of total residential usage will be supplied by retail electric suppliers by the end of 2013.

The changes in ComEd's revenue net of purchased power expense for the three months and six months ended June 30, 2013, compared to the same periods in 2012 consisted of the following:

	Three Months Ended June 30, 2013 Increase (Decrease)	Six Months Ended June 30, 2013 Increase (Decrease)
Weather	$ (22)	$ (4)
Volume	5	1
Electric distribution revenues	53	77
Discrete impacts of the 2012 Distribution Rate Case Order	100	88
Senate Bill 9	10	10
Transmission revenues	3	3
Regulatory required programs	(2)	1
Uncollectible accounts recovery, net	(3)	(17)
Other	(6)	(12)
Total increase	$ 138	$ 147

Weather. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. Through June, ComEd's service territory experienced mild weather in 2013, compared to the warmest January through June period on record in 2012. For the three and six months ended June 30, 2013, the increase in revenue net of purchased power expense was offset by unfavorable weather conditions as a result of the mild weather in the second quarter of 2013, compared to the same period in 2012.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the three months and six months ended June 30, 2013 and 2012, consisted of the following:

				% Change	
Heating and Cooling Degree-Days	2013	2012	Normal	From 2012	From Normal
Three Months Ended June 30,					
Heating Degree-Days	778	544	765	43.0 %	1.7 %
Cooling Degree-Days	240	423	218	(43.3)%	10.1 %
Six Months Ended June 30,					
Heating Degree-Days	4,037	2,928	3,929	37.9 %	2.7 %
Cooling Degree-Days	240	462	218	(48.1)%	10.1 %

Volume. Revenue net of purchased power expense increased as a result of higher delivery volume, exclusive of the effects of weather, for the three months ended June 30, 2013, reflecting increased average usage per residential customer as compared to the same period in 2012.

Electric Distribution Revenues. EIMA provides for a performance-based formula rate tariff, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. During the three and six months ended June 30, 2013, ComEd recorded increased revenue net of purchased power expense of $53 million and $77 million, respectively, associated with the 2011 through 2013 reconciliations. These amounts exclude the discrete impacts of the May 2012 Distribution Rate Case Order and the enactment of Senate Bill 9, as discussed below. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Order. On May 30, 2012, the ICC issued its final Order related to ComEd's 2011 formula rate proceeding under EIMA, which resulted in a reduction to revenue net of purchased power expense of $100 million and $88 million, for the three and six months ended June 30, 2012. See Note 3 — Regulatory Matters of the Exelon 2012 Form 10-K for further information.

Senate Bill 9. On May 22, 2013, the Illinois General Assembly overrode the Governor's May 5, 2013 veto of Senate Bill 9, which became effective immediately. Revenue net of purchased power expense increased by $10 million for the three and six months ended June 30, 2013, as a result of the enactment of Senate Bill 9. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update, filed in April 2013, reflects 2012 actual costs plus forecasted 2013 capital additions. Transmission revenue net of purchased power expense vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. Revenues related to regulatory required programs are the recoveries from customers for costs of various legislative and/or regulatory programs on a full and current basis through approved regulated rates. Programs include ComEd's energy efficiency and demand response and purchased power administrative costs. An equal and offsetting amount has been reflected in operating and maintenance expense during the periods presented. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Represents recoveries under ComEd's uncollectible accounts tariff. Refer to the operating and maintenance expense discussion below for additional information on this tariff.

Other. Other revenues decreased during the three and six months ended June 30, 2013, compared to the same periods in 2012. Other revenues, which can vary period to period, include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of environmental costs associated with MGP sites.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2013	2012		2013	2012	
Operating and maintenance expense — baseline	$ 304	$ 274	$ 30	$ 593	$ 557	$ 36
Operating and maintenance expense — regulatory required programs(a)	55	57	(2)	94	93	1
Total operating and maintenance expense	$ 359	$ 331	$ 28	$ 687	$ 650	$ 37

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

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The changes in operating and maintenance expense for the three and six months ended June 30, 2013 compared to the same periods in 2012, consisted of the following:

	Three Months Ended June 30 Increase (Decrease)	Six Months Ended June 30 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials(a)	$ 10	$ 26
Pension and non-pension postretirement benefits expense	4	10
Storm-related costs(b)	11	9
Uncollectible accounts expense — provision(c)	(2)	(9)
Uncollectible accounts expense — recovery, net(c)	(1)	(8)
Other	8	8
	30	36
Regulatory required programs		
Energy efficiency and demand response programs	(2)	1
Purchased power administrative costs	—	—
	(2)	1
Increase in operating and maintenance expense	$ 28	$ 37

(a) The increase includes contracting costs resulting from new projects associated with EIMA. See Note 5 — Regulatory Matters of the Combined Notes to Financial Statements for additional information regarding EIMA.
(b) Under EIMA, ComEd may recover costs associated with certain one-time events, such as large storms, over a five-year period. During the second quarter of 2013, ComEd recorded a net reduction in operating and maintenance expense for costs related to one significant second quarter 2013 storm.
(c) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism.

Depreciation and Amortization

Depreciation and amortization expense increased during the three and six months ended June 30, 2013 compared to the same periods in 2012, primarily due to ongoing capital expenditures and increased regulatory asset amortization related to higher MGP remediation expenditures.

Taxes Other Than Income

Taxes other than income taxes increased for the three and six months ended June 30, 2013, compared to the same period in 2012, primarily due to increased Illinois electricity distribution taxes. Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes, and payroll taxes.

Interest Expense, Net

The changes in Interest Expense, net for the three and six months ended June 30, 2013, compared to the same period in 2012, consisted of the following:

	Three Months Ended June 30, 2013 Increase (Decrease)	Six Months Ended June 30, 2013 Increase (Decrease)
Interest expense related to uncertain tax positions(a)	$ —	$ 277
Interest expense on debt (including financing trusts)	2	(1)
Other	—	(3)
Increase in interest expense, net	$ 2	$ 273

(a) Primarily reflects the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013. See Note 12 of the Combined Notes to Financial Statements for additional information.

Effective Income Tax Rate

The effective income tax rate was 40.7% for the three months ended June 30, 2013 compared to 40.8% for the same period during 2012. The effective income tax rate was 36.4% for the six months ended June 30, 2013 compared to 41.1% for the same period during 2012. See Note 12 of the Combined Notes to Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	6,090	6,674	(8.8)%	1.1%
Small commercial & industrial	7,832	7,888	(0.7)%	2.2%
Large commercial & industrial	6,711	6,839	(1.9)%	(0.6)%
Public authorities & electric railroads	294	293	0.3%	4.0%
Total Retail Deliveries	20,927	21,694	(3.5)%	1.0%

Retail Deliveries to Customers (in GWhs)	Six Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)				
Residential	12,966	13,080	(0.9)%	0.5%
Small commercial & industrial	15,705	15,804	(0.6)%	(0.6)%
Large commercial & industrial	13,551	13,542	0.1%	(0.5)%
Public authorities & electric railroads	667	617	8.1%	11.6%
Total Retail Deliveries	42,889	43,043	(0.4)%	(0.2)%

Number of Electric Customers	As of June 30, 2013	2012
Residential	3,465,712	3,456,312
Small commercial & industrial	366,153	365,474
Large commercial & industrial	2,006	1,990
Public authorities & electric railroads	4,852	4,793
Total	3,838,723	3,828,569

Electric Revenue	Three Months Ended June 30, 2013	2012	% Change	Six Months Ended June 30, 2013	2012	% Change
Retail Delivery and Sales(a)						
Residential	$ 476	$ 720	(33.9)%	$1,060	$1,496	(29.1)%
Small commercial & industrial	315	306	2.9%	623	654	(4.7)%
Large commercial & industrial	113	94	20.2%	215	194	10.8%
Public authorities & electric railroads	12	9	33.3%	24	21	14.3%
Total Retail	916	1,129	(18.9)%	1,922	2,365	(18.7)%
Other Revenue(b)	164	152	7.9%	317	305	3.9%
Total Electric Revenues	$ 1,080	$ 1,281	(15.7)%	$2,239	$2,670	(16.1)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other items include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of environmental costs associated with MGP sites.

Results of Operations — PECO

	Three Months Ended June 30,		Favorable (Unfavorable)	Six Months Ended June 30,		Favorable (Unfavorable)
	2013	2012	Variance	2013	2012	Variance
Operating revenues	$ 672	$ 715	$ (43)	$1,567	$1,590	$ (23)
Purchased power and fuel	258	296	38	664	707	43
Revenue net of purchased power and fuel(a)	414	419	(5)	903	883	20
Other operating expenses						
Operating and maintenance	181	172	(9)	369	375	6
Depreciation and amortization	56	54	(2)	113	107	(6)
Taxes other than income	39	42	3	80	74	(6)
Total other operating expenses	276	268	(8)	562	556	(6)
Operating income	138	151	(13)	341	327	14
Other income and (deductions)						
Interest expense, net	(28)	(31)	3	(57)	(62)	5
Other, net	—	2	(2)	3	5	(2)
Total other income and (deductions)	(28)	(29)	1	(54)	(57)	3
Income before income taxes	110	122	(12)	287	270	17
Income taxes	32	42	10	87	93	6
Net income	78	80	(2)	200	177	23
Preferred security dividends and redemption	6	1	5	7	2	5
Net income attributable to common shareholders	$ 72	$ 79	$ (7)	$ 193	$ 175	$ 18

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income attributable to common shareholders

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The decrease in net income attributable to common shareholders was driven primarily by lower operating revenue net of purchased power and fuel expense and an increase in operating and maintenance expenses, partially offset by lower income tax expense.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The increase in net income attributable to common shareholders was driven primarily by higher operating revenue net of purchased power and fuel expense and decreases in operating and maintenance expenses and interest expense, partially offset by increases in depreciation and amortization expense and taxes other than income. The increase in revenue net of purchased power and fuel was the result of weather, which was partially offset by the impact of pricing.

Operating Revenues, Purchased Power and Fuel Expense

There are certain drivers to operating revenues that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and customer choice programs. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs.

PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenue net of purchased power and fuel expense.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenue net of purchased power and fuel expense. The number of retail customers purchasing electricity from a competitive electric generation supplier was 523,900 and 441,000 at June 30, 2013 and 2012, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 70% and 68% of PECO's retail kWh sales for the three and six months ended June 30, 2013, respectively, compared to 67% and 65% for the three and six months ended June 30, 2012. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 59,100 and 42,100 at June 30, 2013 and 2012, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 21% and 18% of PECO's mmcf sales for the three and six months ended June 30, 2013, respectively, compared to 18% and 14% for the three and six months ended June 30, 2012.

The changes in PECO’s operating revenues net of purchased power and fuel expense for the three months ended June 30, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ (2)	$ 2	$ —
Volume	(3)	—	(3)
Pricing	—	(2)	(2)
Regulatory required programs	6	—	6
Other	(6)	—	(6)
Total decrease	$ (5)	$—	$ (5)

The changes in PECO’s operating revenues net of purchased power and fuel expense for the six months ended June 30, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 16	$27	$ 43
Volume	(3)	(2)	(5)
Pricing	(9)	(5)	(14)
Regulatory required programs	4	—	4
Other	(9)	1	(8)
Total (decrease) increase	$ (1)	$21	$ 20

Weather

The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in

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increased deliveries of electricity and gas. Conversely, mild weather reduces demand. During the three months ended June 30, 2013 compared to the same period in 2012, electric and gas revenues net of purchased power remained relatively level compared to the same period in 2012.

During the six months ended June 30, 2013 compared to the same period in 2012, operating revenues net of purchased power and fuel expense were higher due to the impact of favorable 2013 winter weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the three and six months ended June 30, 2013 compared to the same periods in 2012 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Three Months Ended June 30,					
Heating Degree-Days	421	337	463	24.9 %	(9.1)%
Cooling Degree-Days	418	430	348	(2.8)%	20.1 %
Six Months Ended June 30,					
Heating Degree-Days	2,861	2,251	2,939	27.1%	(2.7)%
Cooling Degree-Days	418	434	348	(3.7)%	20.1%

Volume

The decrease in electric operating revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2013 compared to the same periods in 2012 reflected the impact of energy efficiency initiatives on customer usages offset by the oil refineries returning to full production in 2013.

Pricing

Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012. The decrease in gas revenues net of fuel expense as a result of pricing reflects the refund of the tax cash benefit resulting from the change in PECO's method of accounting for gas distribution repairs in 2012. The refund was reflected on customer bills as a credit beginning January 1, 2013. The accounting impact of the refund is completely offset by regulatory liability amortization recorded in income tax expense.

Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012. The decrease in electric operating revenues net of purchased power expense as a result of pricing reflects lower overall effective rates due to increased usage per customer across all customer classes. The decrease in gas revenue net of fuel expense as a result of pricing for the six months ended June 30, 2013, is driven by the refund of the tax cash benefit resulting from the change in PECO's method of accounting for gas distribution repairs in 2012. The refund was reflected on customer bills as a credit beginning January 1, 2013. The accounting impact of the refund is completely offset by regulatory liability amortization recorded in income tax expense.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other

The decrease in other electric revenues net of purchased power expense for the three and six months ended June 30, 2013 compared to the same periods in 2012 reflected a decrease in GRT revenue as a result of lower supplied energy service and wholesale transmission revenue earned by PECO due to increased participation in the customer choice program. There is an equal and offsetting decrease in GRT expense included in taxes other than income.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2013	2012		2013	2012	
Operating and Maintenance Expense — Baseline	$ 155	$ 151	$ 4	$ 329	$ 335	$ (6)
Operating and Maintenance Expense — Regulatory Required Programs(a)	26	21	5	40	40	—
Total Operating and Maintenance Expense	181	172	9	369	375	(6)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three and six months ended June 30, 2013 compared to the same periods in 2012, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 13	$ 9
Storm-related costs	(1)	—
Pension and non-pension postretirement benefits expense	(3)	(6)
Constellation merger and integration costs	(2)	(5)
Other	(3)	(4)
	4	(6)
Regulatory Required Programs		
Smart Meter	1	—
Energy Efficiency	4	—
	5	—
Increase (Decrease) in operating and maintenance expense	$ 9	$ (6)

Depreciation and Amortization Expense

The increase in depreciation and amortization expense for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to ongoing capital expenditures as well as increased depreciation and amortization expense related to the smart meter AMI infrastructure. An equal and offsetting amount for the depreciation and amortization expense related to the smart meter AMI infrastructure has been reflected in operating revenues during the periods represented.

Taxes Other Than Income

The decrease in taxes other than income for the three months ended June 30, 2013 compared to the same period in 2012 was primarily due to decreased GRT collections as a result of lower revenues. An equal and offsetting decrease in GRT has been reflected in operating revenues during the current period.

The increase in taxes other than income for the six months ended June 30, 2013 compared to the same period in 2012 is primarily due to a favorable sales and use tax reserve adjustment resulting from the completion of the audit of tax years 2005 through 2010 recorded in the first quarter of 2012. This increase was offset slightly by decreased GRT collections as a result of lower revenues. An equal and offsetting decrease in GRT has been reflected in operating revenues during the current period.

Interest Expense, Net

The decrease in interest expense, net for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to lower interest expense as a result of refinancing debt retired at lower interest rates during the second half of 2012.

Other, Net

The change in Other, net for the three and six months ended June 30, 2013 remained relatively level compared to the same period in 2012.

Effective Income Tax Rate

PECO's effective income tax rate was 29.1% and 34.4% for the three months ended June 30, 2013 and 2012, respectively, and 30.3% and 34.4% for the six months ended June 30, 2013 and 2012, respectively. The effective income tax rate for the three and six months ended June 30, 2013 reflects the impact of the tax benefit recognized in 2013 related to the gas repairs deduction and the gas repairs bill credit amortization which was not included in the second quarter of 2012. See Note 12 — Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change	Six Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)								
Residential	2,888	2,929	(1.4)%	(0.8)%	6,353	6,095	4.2%	(0.1)%
Small commercial & industrial	1,960	1,959	0.1%	0.9%	3,969	3,910	1.5%	(1.9)%
Large commercial & industrial	3,784	3,743	1.1%	1.9%	7,430	7,380	0.7%	1.7%
Public authorities & electric railroads	238	237	0.4%	0.4%	493	474	4.0%	4.0%
Total Electric Retail Deliveries	8,870	8,868	0.0%	0.8%	18,245	17,859	2.2%	0.4%

Number of Electric Customers	As of June 30, 2013	2012
Residential	1,419,977	1,417,346
Small commercial & industrial	148,723	148,837
Large commercial & industrial	3,109	3,107
Public authorities & electric railroads	9,672	9,680
Total	1,581,481	1,578,970

Electric Revenue	Three Months Ended June 30, 2013	2012	% Change	Six Months Ended June 30, 2013	2012	% Change
Retail Delivery and Sales(a)						
Residential	$ 354	$ 393	(9.9)%	$ 749	$ 800	(6.4)%
Small commercial & industrial	109	119	(8.4)%	215	237	(9.3)%
Large commercial & industrial	61	59	3.4%	120	113	6.2%
Public authorities & electric railroads	8	8	0.0%	16	16	0.0%
Total Retail	532	579	(8.1)%	1,100	1,166	(5.7)%
Other Revenue(b)	53	56	(5.4)%	108	112	(3.6)%
Total Electric Revenues	$ 585	$ 635	(7.9)%	$ 1,208	$ 1,278	(5.5)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change	Six Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales								
Retail sales(a)	6,919	6,228	11.1%	0.6%	35,357	28,655	23.4%	(0.2)%
Transportation and other	5,956	5,835	2.1%	3.5%	14,839	13,601	9.1%	2.3%
Total Gas Deliveries	12,875	12,063	6.7%	1.8%	50,196	42,256	18.8%	0.5%

Number of Gas Customers	As of June 30, 2013	2012
Residential	455,518	452,478
Commercial & industrial	41,648	41,383
Total Retail	497,166	493,861
Transportation	903	888
Total	498,069	494,749

Gas Revenue	Three Months Ended June 30, 2013	2012	% Change	Six Months Ended June 30, 2013	2012	% Change
Retail Delivery and Sales						
Retail sales(a)	$ 78	$ 73	6.8%	$ 338	$ 295	14.6%
Transportation and other	9	7	28.6%	21	17	23.5%
Total Gas Revenues	$ 87	$ 80	8.8%	$ 359	$ 312	15.1%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

Results of Operations — BGE

	Three Months Ended June 30,		Favorable (Unfavorable)	Six Months Ended June 30,		Favorable (Unfavorable)
	2013	2012	Variance	2013	2012	Variance
Operating revenues	$ 653	$ 616	$ 37	$1,533	$1,312	$ 221
Purchased power and fuel	288	285	(3)	713	670	(43)
Revenue net of purchased power and fuel(a)	365	331	34	820	642	178
Other operating expenses						
Operating and maintenance	160	161	1	303	356	53
Depreciation and amortization	82	71	(11)	175	150	(25)
Taxes other than income	54	47	(7)	109	95	(14)
Total other operating expenses	296	279	(17)	587	601	14
Operating income	69	52	17	233	41	192
Other income and (deductions)						
Interest expense, net	(32)	(34)	2	(66)	(75)	9
Other, net	4	7	(3)	9	13	(4)
Total other income and (deductions)	(28)	(27)	(1)	(57)	(62)	5
Income (loss) before income taxes	41	25	16	176	(21)	197
Income taxes	16	9	(7)	70	(7)	(77)
Net income (loss)	25	16	9	106	(14)	120
Preference stock dividends	3	3	—	6	6	—
Net income (loss) attributable to common shareholder	$ 22	$ 13	$ 9	$ 100	$ (20)	$ 120

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenue net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net income (loss) attributable to common shareholders

Three Months Ended June 30, 2013, Compared to Three Months Ended 2012. BGE's net income attributable to common shareholders for the three months ended June 30, 2013, was higher than the same period in 2012, primarily due to higher electric and gas distribution rates, effective February 23, 2013, pursuant to the MDPSC order in BGE's 2012 rate case.

Six Months Ended June 30, 2013, Compared to Six Months Ended 2012. BGE's net income attributable to common shareholders for the six months ended June 30, 2013, was higher than the same period in 2012, primarily due to decreased operating revenue net of purchased power and fuel expense in 2012 related to the accrual of the residential customer rate credit and the accrual of its portion of the charitable contributions which were conditions of the MDPSC's approval of Exelon's merger with Constellation. The increase in net income attributable to common shareholders was also driven by higher electric and gas distribution rates pursuant to the MDPSC order in BGE's 2012 rate case.

Operating Revenues, Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive electric generation supplier affects electric SOS revenues and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenues and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric generation supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive electric generation supplier was 389,400 and 338,400 at June 30, 2013 and 2012, respectively, representing 31% and 27% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 63% and 61% of BGE's retail kWh sales for the three and six months ended June 30, 2013, respectively compared to 62% and 61% for the three and six months ended June 30, 2012, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 161,900 and 125,300 at June 30, 2013 and 2012, respectively, representing 25% and 19% of total retail customers, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 63% and 51% of BGE's retail mmcf sales for the three and six months ended June 30, 2013, respectively, compared to 67% and 55% for the three and six months ended June 30, 2012, respectively.

The changes in BGE's operating revenues net of purchased power and fuel expense for the three months ended June 30, 2013 compared to the same period in 2012, consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Pricing	$ 18	$ 5	$ 23
Regulatory required programs	8	1	9
Other	1	1	2
Total increase	$ 27	$ 7	$ 34

The changes in BGE's operating revenues net of purchased power and fuel expense for the six months ended June 30, 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Residential customer rate credit(a)	$ 82	$31	$113
Pricing	24	8	32
Regulatory required programs	19	5	24
Other	7	2	9
Total increase	$ 132	$46	$178

(a) In accordance with the MDPSC order approving Exelon's merger with Constellation, the residential customer rate credit is not recoverable from BGE's customers. Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

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Revenue Decoupling. The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Volume. Heating degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the three and six months ended June 30, 2013 compared to the same period in 2012 consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Three Months Ended June 30,					
Heating Degree-Days	492	402	517	22.4 %	(4.8)%
Cooling Degree-Days	263	289	250	(9.0)%	5.2%
Six Months Ended June 30,					
Heating Degree-Days	2,943	2,275	2,902	29.4%	1.4%
Cooling Degree-Days	264	299	250	(11.7)%	5.6%

Residential Customer Rate Credit. The residential customer rate credit provided in 2012 as a result of the MDPSC's order approving Exelon's merger with Constellation decreased operating revenues net of purchased power and fuel for the six months ended June 30, 2013 compared to the same period in 2012.

Pricing. The increase in operating revenues net of purchased power and fuel expense as a result of pricing for the three and six months ended June 30, 2013 compared to the same period in 2012 primarily reflected the impact of the new electric and natural gas distribution rates charged to customers that became effective February 23, 2013 in accordance with the 2012 MDPSC approved electric and natural gas distribution rate case order. See Note 5 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs. This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the three and six months ended June 30, 2013 compared to the same period in 2012 was primarily due to the recovery of higher energy efficiency program costs.

Other. Other revenues increased during the three and six months ended June 30, 2013 compared to the same period in 2012. Other revenues, which can vary from period to period, include miscellaneous revenues such as late payment charge revenues and all base distribution revenues, which increased due to customer mix.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2013	2012		2013	2012	
Operating and Maintenance Expense — Baseline	$ 160	$ 161	$ (1)	$ 303	$ 356	$ (53)
Operating and Maintenance Expense — Regulatory Required Programs(a)	—	—	—	—	—	—
Total Operating and Maintenance Expense	$ 160	$ 161	$ (1)	$ 303	$ 356	$ (53)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three and six months ended June 30, 2013 compared to the same periods in 2012, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Baseline		
Charitable contributions accrual(a)	$ —	$ (28)
Merger costs(b)	(1)	(19)
Corporate Allocations	(3)	(5)
Storm-related costs	(3)	5
Labor, other benefits, contracting and materials	8	4
Other	(2)	(10)
	(1)	(53)
Regulatory Required Programs		
SOS	—	—
Decrease in operating and maintenance expense	$ (1)	$ (53)

(a) In accordance with the MDPSC order approving Exelon's merger with Constellation, the charitable contribution accrual is not recoverable from BGE's customers.

(b) BGE established a regulatory asset of $6 million at March 31, 2013 for certain 2012 other merger integration costs as part of the 2013 electric and gas distribution rate case order.

Depreciation and Amortization

The increase in depreciation and amortization expense for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to higher amortization expense related to energy efficiency and demand response programs, which are fully offset in revenues above. Furthermore, higher expense is also due to higher property, plant and equipment balances resulting from ongoing capital expenditures.

Taxes Other Than Income

The increase in taxes other than income for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to an increase in payroll taxes and increased GRT collections.

Interest Expense, Net

The decrease in interest expense, net for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to interest recorded in 2012 on prior year tax liabilities.

Other, Net

The decrease in other, net for the three and six months ended June 30, 2013 compared to the same periods in 2012 was primarily due to decreased AFUDC-Equity and investment income. See Note 19 – Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for further details of the components of other, net.

Effective Income Tax Rate

BGE's effective income tax rate was 39.0% and 36.0% for the three months ended June 30, 2013 and 2012, respectively, and 39.8% and 33.3% for the six months ended June 30, 2013 and 2012, respectively. See Note 12 – Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rate.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	% Change	Weather-Normal % Change	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(a)								
Residential	2,757	2,664	3.5%	n.m	6,293	5,865	7.3%	n.m
Small commercial & industrial	716	706	1.4%	n.m	1,492	1,435	4.0%	n.m
Large commercial & industrial	3,610	3,942	(8.4)%	n.m	7,164	7,582	(5.5)%	n.m
Public authorities & electric railroads	80	71	12.7%	n.m	161	158	1.9%	n.m
Total Electric Retail Deliveries	7,163	7,383	(3.0)%	n.m	15,110	15,040	0.5%	n.m

Number of Electric Customers	As of June 30, 2013	As of June 30, 2012
Residential	1,117,569	1,115,107
Small commercial & industrial	113,009	113,232
Large commercial & industrial	11,612	11,537
Public authorities & electric railroads	294	297
Total	1,242,484	1,240,173

Electric Revenue	Three Months Ended June 30, 2013	2012	% Change	Six Months Ended June 30, 2013	2012	% Change
Retail Delivery and Sales(a)						
Residential	$ 302	$ 295	2.4%	$ 667	$ 560	19.1%
Small commercial & industrial	60	60	0.0%	125	122	2.5%
Large commercial & industrial	112	99	13.1%	217	196	10.7%
Public authorities & electric railroads	8	7	14.3%	15	15	0.0%
Total Retail	482	461	4.6%	1,024	893	14.7%
Other Revenue	61	57	7.0%	124	114	8.8%
Total Electric Revenues	$ 543	$ 518	4.8%	$1,148	$1,007	14.0%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation suppliers as all customers are assessed delivery charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change	Six Months Ended June 30, 2013	2012	% Change	Weather-Normal % Change
Retail Delivery and Sales(b)								
Retail sales	14,951	15,535	(3.8)%	n.m.	55,212	49,466	11.6%	n.m.
Transportation and other	1,545	4,854	(68.2)%	n.m.	7,195	10,295	(30.1)%	n.m.
Total Gas Deliveries	16,496	20,389	(19.1)%	n.m.	62,407	59,761	4.4%	n.m.

Number of Gas Customers	As of June 30, 2013	2012
Residential	611,146	610,073
Commercial & industrial	44,059	44,011
Total	655,205	654,084

Gas Revenue	Three Months Ended June 30, 2013	2012	% Change	Six Months Ended June 30, 2013	2012	% Change
Retail Delivery and Sales						
Retail sales	$ 100	$ 84	19.0%	$ 345	$ 272	26.8%
Transportation and other(b)	10	14	(28.6)%	40	33	21.2%
Total Gas Revenues	$ 110	$ 98	12.2%	$ 385	$ 305	26.2%

(b) Transportation and other gas revenue includes off-system revenue of 1,545 mmcfs ($8 million) and 4,854 mmcfs ($12 million) for the three months ended June 30, 2013 and 2012, respectively, and 7,195 mmcfs ($32 million) and 10,295 mmcfs ($29 million) for the six months ended June 30, 2013 and 2012, respectively.

Liquidity and Capital Resources

Exelon and Generation prior year activity presented below includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through June 30, 2012. BGE prior year activity presented below includes its activity for the six months ended June 30, 2012.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. The Registrants' revolving credit facilities expire between 2017 and 2018. In addition, Generation has $0.4 billion in bilateral facilities with banks. The bilateral facilities at Generation have expirations in January 2015, December 2015 and March 2016. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 11 – Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

ComEd's, PECO's and BGE's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd's, PECO's and BGE's distribution services are provided to an established and diverse base of retail customers. ComEd's, PECO's and BGE's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 5 — Regulatory Matters and 18 – Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions

and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while others take effect in 2013. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to contribute $255 million to its qualified pension plans in 2013, of which Generation, ComEd, PECO and BGE will contribute $113 million, $115 million, $11 million and $0 million, respectively. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $81 million in 2013, of which Generation, ComEd, PECO, and BGE will make payments of $7 million, $1 million, $1 million, and $2 million, respectively.

To the extent interest rates decline or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase and such increases could be significant, especially in years 2015 and beyond. Additionally, the contributions above could change if Exelon changes its pension funding strategy.

Unlike qualified pension plans, other postretirement plans are not subject to regulatory minimum contribution requirements. Exelon's management considers several factors in determining the level of contributions to its other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). In 2013, Exelon anticipates funding its other postretirement benefit plans based on the funding considerations discussed above, with the exception of those plans previously sponsored by Constellation and AmerGen, which remain unfunded. Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $276 million in 2013, of which Generation, ComEd, PECO, and BGE expect to contribute $108 million, $112 million, $21 million, and $17 million, respectively.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- Exelon expects to receive a Federal refund of approximately $325 million between 2013 and 2014 which will be paid to ComEd, PECO, BGE and Generation of approximately $320 million, $10 million, $20 million, and $40 million, respectively.
- Given the current economic environment, state and local governments are facing increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the six months ended June 30, 2013 and 2012:

	Six Months Ended June 30,		
	2013	2012	Variance
Net income	$ 498	$ 490	$ 8
Add (subtract):			
Non-cash operating activities(a)	2,025	2,688	(663)
Pension and other postretirement benefit contributions	(284)	(90)	(194)
Income taxes	705	259	446
Changes in working capital and other noncurrent assets and liabilities(b)	(337)	(977)	640
Option premiums paid, net	(10)	(108)	98
Counterparty collateral (posted) received, net	(259)	451	(710)
Net cash flows provided by operations	$ 2,338	$ 2,713	$ (375)

(a) Represents depreciation, amortization and accretion, impairment of long-lived assets, mark-to-market gains and losses on derivative transactions, deferred income taxes, provision for uncollectible accounts, pension and other postretirement

benefit expense, equity in losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense and other non-cash charges.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Cash flows provided by operations for the six months ended June 30, 2013 and 2012 by Registrant were as follows:

	Six Months Ended June 30,	
	2013	2012
Exelon	$ 2,338	$ 2,713
Generation	1,150	1,866
ComEd	503	722
PECO	467	409
BGE	366	353

Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for the six months ended June 30, 2013 and 2012 were as follows:

Generation

- During the six months ended June 30, 2013 and 2012, Generation had net (payments) receipts of counterparty collateral of $(303) million and $443 million, respectively. Net (payments) receipts during the six months ended June 30, 2013 and 2012 were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.
- During the six months ended June 30, 2013 and 2012, Generation had net payments of approximately $(10) million and $(108) million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During the six months ended June 30, 2013 and 2012, ComEd's net payables to Generation for energy purchases related to its supplier forward contract, ICC-approved RFP contracts and financial swap contract settlements decreased by $14 million and $10 million, respectively. During the six months ended June 30, 2013 and 2012, ComEd's payables to other energy suppliers for energy purchases increased by $31 million and $22 million, respectively.
- During the six months ended June 30, 2013 and 2012, ComEd received $45 million and $7 million, respectively, of incremental cash collateral from PJM. ComEd's collateral posted with PJM has decreased due to lower PJM billings resulting from lower load being served by ComEd due to increased switching activity primarily driven by municipal aggregation. As of June 30, 2013 and 2012, ComEd had $8 million and $84 million, respectively, of collateral posted with PJM.

PECO

- During the six months ended June 30, 2013 and 2012, PECO's payables to Generation for energy purchases decreased by $11 million and increased by $21 million, respectively, and payables to other electric and gas suppliers for energy purchases increased by $26 million and decreased by $31 million, respectively.

BGE

- During the six months ended June 30, 2013 and 2012, BGE's payables to Generation for energy purchases increased by $8 million and $6 million, respectively, and payables to other electric and gas suppliers for energy purchases increased by $2 million and decreased by $7 million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2013 and 2012 by Registrant were as follows:

	Six Months Ended June 30,	
	2013	2012
Exelon	$(2,549)	$(1,968)
Generation	(1,378)	(1,284)
ComEd	(693)	(567)
PECO	(514)	(157)
BGE	(257)	(268)

Capital expenditures by Registrant for the six months ended June 30, 2013 and 2012 and projected amounts for the full year 2013 are as follows:

	Projected Full Year	Six Months Ended June 30,	
	2013 (d)	2013	2012
Exelon	$ 5,525	$ 2,518	$ 2,800
Generation(a)	2,775	1,277	1,820
ComEd(b)	1,450	711	585
PECO	575	254	179
BGE	650	264	266
Other(c)	75	12	30

(a) Includes nuclear fuel.
(b) The projected capital expenditures include approximately $267 million of expected incremental spending pursuant to EIMA, which ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology.
(c) Other primarily consists of corporate operations and BSC.
(d) Total projected capital expenditures do not include adjustments for non-cash activity.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 36% and 21% of the projected 2013 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy generation, including Antelope Valley construction costs, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Also included in the projected 2013 capital expenditures are a portion of the costs of a series of planned power uprates across Generation's nuclear fleet, adjusted during the second quarter of 2013 to reflect the cancellation of certain nuclear power uprate projects during 2013. See "EXELON CORPORATION—Executive Overview," for more information on nuclear uprates.

ComEd, PECO and BGE

Approximately 90%, 89% and 78% of the projected 2013 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and ComEd's, PECO's and BGE's construction commitments under PJM's RTEP. ComEd's capital expenditures includes smart grid/smart meter technology required under EIMA and for PECO and BGE capital expenditures related to its smart meter program and SGIG project, net of DOE expected reimbursements. The remaining amounts are for capital additions to support new business and customer growth.

In 2010, NERC provided guidance to transmission owners that recommends ComEd, PECO and BGE perform assessments of all their transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority lines by December 31, 2013. In compliance with this guidance, ComEd, PECO and BGE submitted their most recent bi-annual reports to NERC in July 2013. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2013 capital expenditures above reflect capital spending for remediation to be completed in 2013.

ComEd, PECO and BGE anticipate that they will fund their capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the six months ended June 30, 2013 and 2012 by Registrant were as follows:

	Six Months Ended June 30,	
	2013	2012
Exelon	$ (284)	$ (412)
Generation	(221)	(148)
ComEd	139	(360)
PECO	(259)	(174)
BGE	259	(81)

Debt

See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements.

Dividends

Cash dividend payments and distributions during the six months ended June 30, 2013 and 2012 by Registrant were as follows:

	Six Months Ended June 30,	
	2013	2012
Exelon	$ 716	$ 824
Generation	474	891
ComEd	110	85
PECO	167	174
BGE(a)	6	6

(a) Relates to dividends paid on BGE's preference stock.

Revised Dividend Policy

On February 6, 2013, the Exelon Board of Directors approved a revised dividend policy which contemplates a regular $0.31 per share quarterly dividend on Exelon's common stock payable beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis), subject to quarterly declarations by the Exelon Board of Directors.

First Quarter 2013 Dividend

On February 6, 2013, the Exelon Board of Directors declared a regular quarterly dividend, paid on March 8, 2013 of $0.525 per share on Exelon's common stock.

Second Quarter 2013 Dividend

On April 23, 2013, the Exelon Board of Directors declared a regular quarterly dividend, paid on June 10, 2013 of $0.310 per share on Exelon's common stock.

Short-Term Borrowings

During the six months ended June 30, 2013, ComEd issued $374 million of commercial paper and Generation issued $276 million of commercial paper and $12 million in short-term notes payable. During the six months ended June 30, 2012, Exelon issued $27 million of outstanding commercial paper, ComEd issued $178 million of commercial paper and Generation repaid $26 million in short-term notes payable.

Contributions from Parent/Member

During the six months ended June 30, 2013, there were no contributions from Parent/Member (Exelon). During the six months ended June 30, 2012, Exelon contributed $66 million to BGE to fund the after-tax amount of the residential customer rate credit as directed in the MDPSC order approving the merger transaction.

Other

For the six months ended June 30, 2013, other financing activities primarily consists of expenses paid related to the replacement of the Registrants' credit facilities. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

Credit Matters

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $8.4 billion in aggregate total commitments of which $6.4 billion was available as of June 30, 2013, and of which no financial institution has more than 8% of the aggregate commitments. Exelon, Generation, ComEd, PECO and BGE had access to the commercial paper market during the second quarter of 2013 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K for further information regarding the effects of uncertainty in the capital and credit markets or significant bank failures.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of June 30, 2013, it would have been required to provide incremental collateral of $1,878 million, which is well within its current available credit facility capacities of $4.1 billion, which includes $1,878 million of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements. If ComEd lost its investment grade credit rating as of June 30, 2013, it would have been required to provide incremental collateral of $18 million, which is well within its current available credit facility capacity of $626 million, which takes into account commercial paper borrowings as of June 30, 2013. If PECO lost its investment grade credit rating as of June 30, 2013, it would be required to provide collateral of $1 million pursuant to PJM's credit policy and could have been required to provide collateral of $31 million related to its natural gas procurement contracts, which, in the aggregate, are well within PECO's current available credit facility capacity of $599 million. If BGE lost its investment grade credit rating as of June 30, 2013, it would have been required to provide collateral of $2 million pursuant to PJM's credit policy and could have been required to provide collateral of $86 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of $600 million.

Exelon Credit Facilities

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 11 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information regarding the Registrants' credit facilities.

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at June 30, 2013:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size	Outstanding Commercial Paper at June 30, 2013	Average Interest Rate on Commercial Paper Borrowings for the Six Months Ended June 30, 2013
Exelon Corporate	$ 500	$ —	—
Generation	5,600	276	0.33%
ComEd	1,000	374	0.39%
PECO	600	—	—
BGE	600	—	—

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its commercial paper outstanding does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

Credit Agreements

Borrower	Facility Type	Aggregate Bank Commitment(a)	Facility Draws	Outstanding Letters of Credit	Available Capacity at June 30, 2013	
					Actual	To Support Additional Commercial Paper
Exelon Corporate	Syndicated Revolver	$ 500	$ —	$ 2	$ 498	$ 498
Generation	Syndicated Revolver	5,300	—	956	4,344	4,068
Generation	Bilaterals	375	—	374	1	1
ComEd	Syndicated Revolver	1,000	—	—	1,000	626
PECO	Syndicated Revolver	600	—	1	599	599
BGE	Syndicated Revolver	600	—	—	600	600

(a) Excludes $123 million of credit facility agreements arranged with minority and community banks at Generation, ComEd, PECO and BGE. These facilities expire on October 18, 2013, and are solely utilized to issue letters of credit. See Note 11 of the Combined Notes to the Consolidated Financial Statements for further information.

On March 14, 2013, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2018, and ComEd may request another one-year extension of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extension or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the registrants credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 27.5, 0.0 and 7.5 basis points for prime based borrowings and 127.5, 127.5, 127.5, 100.0 and 107.5 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreement also requires each entity to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of each entity.

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. The credit agreement expires in January 2015. This facility will solely be utilized by Generation to issue letters of credit.

On June 10, 2013, Exelon Corporate, Generation, PECO and BGE began the process of extending their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively. The transactions are expected to close and become effective in August 2013, with maturities of five years from the close of the transactions. The new covenants are expected to be substantially consistent with existing covenants. Generally, it is expected that costs incurred to amend and extend the facilities will be amortized over the newly extended lives of the facilities.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO and BGE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the six months ended June 30, 2013:

	Exelon	Generation	ComEd	PECO	BGE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At June 30, 2013, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	7.85	13.05	2.58	8.56	6.31

An event of default under any Registrant's credit facility will not constitute an event of default under any of the other Registrants' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit facility will constitute an event of default under the Exelon corporate credit facility.

Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant during the six months ended June 30, 2013, in addition to the net contribution or borrowing as of June 30, 2013, are presented in the following table:

Contributed (borrowed) as of June 30, 2013	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Generation	$ —	$ 417	$ (263)
PECO	298	—	263
BSC	—	194	(116)
Exelon Corporate	205	N/A	116

Investments in Nuclear Decommissioning Trust Funds

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's investment policy establishes limits on the concentration of holdings in any one company and also in any one industry. See Note 13 – Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements

On May 29, 2012, the Registrants filed a combined shelf registration statement unlimited in amount, with the SEC, which became immediately effective and remained effective as of June 30, 2013. The ability of each Registrant to sell securities off shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations

On March 1, 2013, ComEd received $470 million in long-term debt new money authority from the ICC and on February 27, 2012, ComEd received $1.3 billion in long-term debt refinancing authority from the ICC. As of June 30, 2013, ComEd had $1.3 billion available in long-term debt refinancing authority and $568 million available in new money long-term debt financing authority from the ICC. As of June 30, 2013, PECO had $1.9 billion available in long-term debt financing authority from the PAPUC. As of June 30, 2013, BGE had $850 million available in long-term financing authority from MDPSC.

As of June 30, 2013, ComEd and PECO had short-term financing authority from FERC, which expires on December 31, 2013, of $2.5 billion and $1.5 billion, respectively. BGE had short-term financing authority from FERC, which expires December 31, 2014, of $0.7 billion. Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

Contractual Obligations and Off-Balance Sheet Arrangements

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' commitments.

Generation, ComEd, PECO and BGE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd, PECO and BGE have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants' respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for further information.

For an in-depth discussion of the Registrant's contractual obligations and off-balance sheet arrangements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations and Off-Balance Sheet Arrangements" in the Exelon 2012 Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief executive officer, chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Risk Oversight Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of the Registrants' 2012 Annual Report on Form 10-K incorporated herein by reference.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2013 through 2015. Generation's energy contracts are accounted for under the accounting guidance for derivatives as further discussed in Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over the three years leading to the spot market. As of June 30, 2013, the percentage of expected generation hedged for the major reportable segments was 96%-99%, 78%-81% and 41%-44% for 2013, 2014 and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including sales to ComEd, PECO and BGE to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on June 30, 2013 market conditions and hedged position would be an immaterial change in pre-tax income for 2013 and a decrease in pre-tax net income of approximately $260 million and $690 million, respectively, for 2014 and 2015. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 1,995 GWhs and 3,567 GWhs for the three and six months ended June 30, 2013, respectively, and 4,248 GWhs and 6,077 GWhs for the three and six months ended June 30, 2012, respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the six months ended June 30, 2013 resulted in pre-tax gains of $12 million due to net mark-to-market gains of $5 million and realized gains of $7 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $ 1.2 million of exposure during the quarter. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for the six months ended June 30, 2013 of $3,489 million.

Fuel Procurement. Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2013 through 2017 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

ComEd

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd would be entitled to receive full cost recovery in rates. The change in fair value each period was recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expired on May 31, 2013. All realized impacts have been included in Generation's and ComEd's results of operations.

ComEd's RFP contracts are deemed to be derivatives that qualify for the normal purchases and normal sales exception under derivative accounting guidance. ComEd does not enter into derivatives for speculative or trading purposes. ComEd is permitted full recovery of its RFP contracts from retail customers with no mark-up.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Notes 5 and 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements. PECO has certain full requirements contracts and block contracts that are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Exelon's, Generation's, ComEd's and PECO's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's and ComEd's mark-to-market net asset or liability balance sheet position from December 31, 2012 to June 30, 2013. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 10 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for

additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of June 30, 2013 and December 31, 2012.

	Generation	ComEd	Intercompany Eliminations(b)	Exelon
Total mark-to-market energy contract net assets (liabilities) at December 31, 2012(a)	$ 1,505	$ (293)	$ —	$1,212
Total change in fair value during 2013 of contracts recorded in result of operations	44	—	(6)	38
Reclassification to realized at settlement of contracts recorded in results of operations	(14)	—	13	(1)
Reclassification to realized at settlement from accumulated OCI(c)	(459)	—	219	(240)
Changes in fair value — energy derivatives(d)	—	208	(226)	(18)
Changes in allocated collateral	297	—	—	297
Changes in net option premium paid/(received)	10	—	—	10
Option premium amortization(e)	(65)	—	—	(65)
Other balance sheet reclassifications	3	—	—	3
Total mark-to-market energy contract net assets (liabilities) at June 30, 2013(a)	$ 1,321	$ (85)	$ —	$1,236

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Amounts related to five-year financial swap between Generation and ComEd are eliminated in consolidation.
(c) For Generation, includes $ 219 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlement of the five-year financial swap contract with ComEd for the six months ended June 30, 2013.
(d) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of June 30, 2013, ComEd recorded an $85 million regulatory asset related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of June 30, 2013, this included $11 million of decreases in fair value and $215 million for reclassifications from regulatory asset to recognize cost in purchased power expense due to settlements of ComEd's five-year financial swap with Generation. As of June 30, 2013, ComEd also recorded $20 million of increases in fair value and $4 million of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(e) Includes $65 million of amounts reclassified to realized at the settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the six months ended June 30, 2013.

Fair Values. The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 9 – Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts(a)(b):							
Actively quoted prices (Level 1)	$ (20)	$ (50)	$ (30)	$14	$ 2	$ —	$ (84)
Prices provided by external sources (Level 2)	243	483	147	16	—	—	889
Prices based on model or other valuation methods (Level 3)(c)	106	175	102	45	23	(20)	431
Total	$329	$608	$219	$75	$25	$ (20)	$ 1,236

(a) Mark-to-market gains and losses on economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $328 million at June 30, 2013.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts(a)(b) :							
Actively quoted prices (Level 1)	$ (20)	$ (50)	$ (30)	$14	$ 2	$ —	$ (84)
Prices provided by external sources (Level 2)	243	483	147	16	—	—	889
Prices based on model or other valuation methods (Level 3)	122	184	119	61	37	(7)	516
Total	$345	$617	$236	$91	$39	$ (7)	$ 1,321

(a) Mark-to-market gains and losses on economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $328 million at June 30, 2013.

ComEd

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and beyond	Total Fair Value
Prices based on model or other valuation methods(a)	$(16)	$ (9)	$(17)	$(16)	$(14)	$ (13)	$ (85)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 10 – Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detail discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2013. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $41 million, $44 million and $33 million, respectively. See Note 22 – Related Party Transactions of the Exelon 2012 Form 10-K for further information.

Rating as of June 30, 2013	Total Exposure Before Credit Collateral	Credit Collateral(a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,744	$ 139	$ 1,605	1	$ 462
Non-investment grade	40	31	9	—	—
No external ratings					
Internally rated — investment grade	456	5	451	1	247
Internally rated — non-investment grade	62	1	61	—	—
Total	$ 2,302	$ 176	$ 2,126	2	$ 709

	Maturity of Credit Risk Exposure			
Rating as of June 30, 2013	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,235	$ 328	$ 181	$ 1,744
Non-investment grade	23	17	—	40
No external ratings				
Internally rated — investment grade	295	155	6	456
Internally rated — non-investment grade	62	—	—	62
Total	$ 1,615	$ 500	$ 187	$ 2,302

Net Credit Exposure by Type of Counterparty	As of June 30, 2013
Investor-owned utilities, marketers and power producers	$ 761
Energy cooperatives and municipalities	926
Financial institutions	386
Other	53
Total	$ 2,126

(a) As of June 30, 2013, credit collateral held from counterparties where Generation had credit exposure included $145 million of cash and $31 million of letters of credit.

ComEd

There have been no significant changes or additions to ComEd's exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K.

See Note 10 of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

PECO

There have been no significant changes or additions to PECO's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K.

See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

BGE

There have been no significant changes or additions to BGE's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2012 Annual Report on Form 10-K.

See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

Collateral (Exelon, Generation, ComEd, PECO and BGE)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 10 of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

As of June 30, 2013, Generation had $546 million cash collateral deposit payments being held by counterparties and Generation was holding $215 million of cash collateral deposits received from counterparties, of which $328 million in net cash collateral deposits was offset against mark-to-market assets and liabilities. As of June 30, 2013, $3 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives. See Note 18 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of June 30, 2013, ComEd held immaterial amounts of cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts. See Notes 5 — Regulatory Matters and 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of June 30, 2013, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 10 – Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for further information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of June 30, 2013, BGE was not required to post collateral under its natural gas procurement contracts, nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon and Generation)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's consolidated balance sheets, as of June 30, 2013, included a $683 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $1,465 million, less unearned income of $782 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange for a third party to bid on a service contract for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not

exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and, if the review indicates a fair value below the carrying value and the decline is determined to be other than temporary, must record an impairment charge in the period the estimate changed. Based on the review performed in the second quarter of 2013, the estimated residual value of one of Exelon's direct financing leases experienced an other than temporary decline in the net investment in direct financing leases of $14 million. See Note 7 of the Combined Notes to Consolidated Financial Statements for further information.

Interest Rate Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At June 30, 2013, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and $570 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper and PECO Accounts Receivables Facility) and fixed-to-floating swaps would result in less than $1 million decrease in Exelon Consolidated pre-tax income for the six months ended June 30, 2013.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of June 30, 2013, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $437 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the second quarter of 2013, each of Exelon's, Generation's, ComEd's, PECO's and BGE's management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by all Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon's management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of June 30, 2013, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd, PECO and BGE concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. All Registrants continually strive to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. In May 2013, the legacy-Constellation businesses transitioned to Exelon's enterprise-wide information technology networks and finance, supply chain and human resource systems, processes and controls; primarily impacting Exelon, Generation and BGE. Integration of Generation's commercial business platforms is being implemented in phases through mid-2014. Other than these changes, there have been no changes in internal control over financial reporting that occurred during the second quarter of 2013 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's and BGE's internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of Exelon's 2012 Form 10-K and (b) Notes 4, 5 and 18 of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

Item 1A. Risk Factors

Risks Related to Exelon

At June 30, 2013, the Registrants' risk factors were consistent with the risk factors described in Exelon's 2012 on Form 10-K.

Item 4. Mine Safety Disclosures

Exelon, Generation, ComEd, PECO and BGE

Not applicable to the Registrants.

Item 6. Exhibits

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
4.1	Form of 3.35% Senior Note due 2023. (File 1-1910, Form 8-K dated June 17, 2013, Exhibit 4.1)
101.INS*	XBRL Instance
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation
101.DEF*	XBRL Taxonomy Extension Definition
101.LAB*	XBRL Taxonomy Extension Labels
101.PRE*	XBRL Taxonomy Extension Presentation

* XBRL information will be considered to be furnished, not filed, for the first two years of a company's submission of XBRL information.

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2013 filed by the following officers for the following companies:

31-1 — Filed by Christopher M. Crane for Exelon Corporation

31-2 — Filed by Jonathan W. Thayer for Exelon Corporation

31-3 — Filed by Kenneth W. Cornew for Exelon Generation Company, LLC

31-4 — Filed by Bryan P. Wright for Exelon Generation Company, LLC

31-5 — Filed by Anne R. Pramaggiore for Commonwealth Edison Company

31-6 — Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company

31-7 — Filed by Craig L. Adams for PECO Energy Company

31-8 — Filed by Phillip S. Barnett for PECO Energy Company

31-9 — Filed by Kenneth W. DeFontes, Jr. for Baltimore Gas and Electric Company

31-10 — Filed by Carim V. Khouzami for Baltimore Gas and Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2013 filed by the following officers for the following companies:

32-1 — Filed by Christopher M. Crane for Exelon Corporation

32-2 — Filed by Jonathan W. Thayer for Exelon Corporation

32-3 — Filed by Kenneth W. Cornew for Exelon Generation Company, LLC

32-4 — Filed by Bryan P. Wright for Exelon Generation Company, LLC

32-5 — Filed by Anne R. Pramaggiore for Commonwealth Edison Company

32-6 — Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company

32-7 — Filed by Craig L. Adams for PECO Energy Company

32-8 — Filed by Phillip S. Barnett for PECO Energy Company

32-9 — Filed by Kenneth W. DeFontes, Jr. for Baltimore Gas and Electric Company

32-10 — Filed by Carim V. Khouzami for Baltimore Gas and Electric Company

SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON CORPORATION

/s/ CHRISTOPHER M. CRANE
Christopher M. Crane
President and Chief Executive Officer
(Principal Executive Officer)

/s/ JONATHAN W. THAYER
Jonathan W. Thayer
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ DUANE M. DESPARTE
Duane M. DesParte
Senior Vice President and Corporate Controller
(Principal Accounting Officer)

August 7, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON GENERATION COMPANY, LLC

/s/ KENNETH W. CORNEW
Kenneth W. Cornew
President and Chief Executive Officer
(Principal Executive Officer)

/s/ BRYAN P. WRIGHT
Bryan P. Wright
Chief Financial Officer
(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Chief Accounting Officer
(Principal Accounting Officer)

August 7, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

COMMONWEALTH EDISON COMPANY

/s/ ANNE R. PRAMAGGIORE
Anne R. Pramaggiore
President and Chief Executive Officer
(Principal Executive Officer)

/s/ JOSEPH R. TRPIK, JR.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

/s/ GERALD J. KOZEL
Gerald J. Kozel
Vice President and Controller
(Principal Accounting Officer)

August 7, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PECO ENERGY COMPANY

/s/ C RAIG L. A DAMS
Craig L. Adams
President and Chief Executive Officer
(Principal Executive Officer)

/s/ P HILLIP S. B ARNETT
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

/s/ S COTT A. B AILEY
Scott A. Bailey
Vice President and Controller
(Principal Accounting Officer)

August 7, 2013

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ K ENNETH W. D E F ONTES , J R .
Kenneth W. DeFontes, Jr.
President and Chief Executive Officer
(Principal Executive Officer)

/s/ C ARIM V. K HOUZAMI
Carim V. Khouzami
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

/s/ D AVID M. V AHOS
David M. Vahos
Vice President and Controller
(Principal Accounting Officer)

August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CHRISTOPHER M. CRANE
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JONATHAN W. THAYER
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ KENNETH W. CORNEW
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ BRYAN P. WRIGHT
Chief Financial Officer
(Principal Financial Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ANNE R. PRAMAGGIORE
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JOSEPH R. TRPIK, JR.
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ C RAIG L. A DAMS
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ P HILLIP S. B ARNETT
Senior Vice President, Chief Financial Officer
and Treasurer
(Principal Financial Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. DeFontes, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ KENNETH W. DEFONTES, JR.
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 7, 2013

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Carim V. Khouzami, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ C ARIM V. K HOUZAMI
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 7, 2013

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ CHRISTOPHER M. CRANE
Christopher M. Crane
President and Chief Executive Officer

Date: August 7, 2013

Exhibit 32-2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ JONATHAN W. THAYER
Jonathan W. Thayer
Executive Vice President and Chief Financial Officer

Date: August 7, 2013

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ KENNETH W. CORNEW
Kenneth W. Cornew
President and Chief Executive Officer

Date: August 7, 2013

Exhibit 32-4

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ BRYAN P. WRIGHT
Bryan P. Wright
Chief Financial Officer

Date: August 7, 2013

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ A NNE R. P RAMAGGIORE
Anne R. Pramaggiore
President and Chief Executive Officer

Date: August 7, 2013

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ J OSEPH R. T RPIK , J R .
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 7, 2013

Exhibit 32-7

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ C RAIG L. A DAMS
Craig L. Adams
President and Chief Executive Officer

Date: August 7, 2013

Exhibit 32-8

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ P HILLIP S. B ARNETT
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 7, 2013

Exhibit 32-9

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ KENNETH W. DEFONTES, JR.
Kenneth W. DeFontes, Jr.
President and Chief Executive Officer

Date: August 7, 2013

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended June 30, 2013, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ C ARIM V. K HOUZAMI
Carim V. Khouzami
Senior Vice President, Chief Financial Officer and Treasurer

Date: August 7, 2013

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Quarterly Period Ended June 30, 2014

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number	Name of Registrant; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definition of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
Exelon Corporation	☒			
Exelon Generation Company, LLC			☒	
Commonwealth Edison Company			☒	
PECO Energy Company			☒	
Baltimore Gas and Electric Company			☒	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The number of shares outstanding of each registrant’s common stock as of June 30, 2014 was:

Exelon Corporation Common Stock, without par value	859,197,443

S1-SSA-0009-19671

Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,914
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Antelope Valley	Antelope Valley Solar Ranch One
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively

Other Terms and Abbreviations

Note "—" of the Exelon 2013 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2013 Annual Report on Form 10-K
1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA
EE&C	Energy Efficiency and Conservation/Demand Response
EGS	Electric Generation Supplier
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste
LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

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FILING FORMAT

This combined Form 10-Q is being filed separately by the Registrants. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company and Baltimore Gas and Electric Company (Registrants) include those factors discussed herein, as well as the items discussed in (1) Exelon's 2013 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; (2) this Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors, (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants' websites at www.exeloncorp.com. Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions, except per share data)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Operating revenues	$ 6,024	$ 6,141	$13,261	$12,223
Operating expenses				
Purchased power and fuel	2,346	2,132	6,352	4,795
Purchased power and fuel from affiliates	66	287	400	605
Operating and maintenance	2,166	1,892	4,024	3,656
Depreciation and amortization	590	533	1,154	1,076
Taxes other than income	288	271	580	548
Total operating expenses	5,456	5,115	12,510	10,680
Equity in losses of unconsolidated affiliates	—	(21)	(20)	(30)
Gain on consolidation of CENG	261	—	261	—
Operating income	829	1,005	992	1,513
Other income and (deductions)				
Interest expense	(228)	(246)	(445)	(863)
Interest expense to affiliates, net	(10)	(6)	(20)	(13)
Other, net	243	(17)	348	155
Total other income and (deductions)	5	(269)	(117)	(721)
Income before income taxes	834	736	875	792
Income taxes	277	239	224	294
Net income	557	497	651	498
Net income attributable to non-controlling interests, preferred security dividends and redemption and preference stock dividends	35	7	39	12
Net income attributable to common shareholders	522	490	612	486
Comprehensive income, net of income taxes				
Net income	557	497	651	498
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(6)	—	(6)	1
Actuarial loss reclassified to periodic cost	38	50	72	100
Pension and non-pension postretirement benefit plans valuation adjustment	258	2	246	77
Deferred compensation unit valuation adjustment	—	10	—	10
Unrealized loss on cash flow hedges	(48)	(65)	(73)	(123)
Unrealized gain on equity investments	—	8	11	36
Unrealized gain (loss) on foreign currency translation	4	(5)	(1)	(6)
Unrealized gain (loss) on marketable securities	1	—	1	(1)
Reversal of CENG equity method AOCI	(116)	—	(116)	—
Other comprehensive income	131	—	134	94
Comprehensive income	$ 688	$ 497	$ 785	$ 592
Average shares of common stock outstanding:				
Basic	860	856	860	856
Diluted	864	860	863	859
Earnings per average common share:				
Basic	$ 0.61	$ 0.57	$ 0.71	$ 0.57
Diluted	$ 0.60	$ 0.57	$ 0.71	$ 0.57
Dividends per common share	$ 0.31	$ 0.31	$ 0.62	$ 0.84

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2014	2013
Cash flows from operating activities		
Net income	$ 651	$ 498
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	1,925	1,972
Gain on consolidation of CENG	(268)	—
Deferred income taxes and amortization of investment tax credits	133	(468)
Net fair value changes related to derivatives	751	(28)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(168)	(27)
Other non-cash operating activities	567	576
Changes in assets and liabilities:		
Accounts receivable	48	131
Inventories	(150)	(18)
Accounts payable, accrued expenses and other current liabilities	(358)	(583)
Option premiums received (paid), net	21	(10)
Counterparty collateral posted, net	(606)	(259)
Income taxes	(16)	705
Pension and non-pension postretirement benefit contributions	(499)	(284)
Other assets and liabilities	(280)	133
Net cash flows provided by operating activities	1,751	2,338
Cash flows from investing activities		
Capital expenditures	(2,501)	(2,518)
Proceeds from termination of direct financing lease investment	335	—
Proceeds from nuclear decommissioning trust fund sales	4,219	1,448
Investment in nuclear decommissioning trust funds	(4,238)	(1,565)
Acquisition of business	(66)	(3)
Proceeds from sale of long-lived assets	32	4
Cash consolidated from CENG	129	—
Change in restricted cash	(40)	22
Other investing activities	(57)	63
Net cash flows used in investing activities	(2,187)	(2,549)
Cash flows from financing activities		
Changes in short-term borrowings	293	662
Issuance of long-term debt	2,100	509
Retirement of long-term debt	(1,191)	(616)
Redemption of preferred securities	—	(93)
Distributions to non-controlling interest of consolidated VIE	(415)	—
Dividends paid on common stock	(533)	(716)
Proceeds from employee stock plans	18	32
Other financing activities	(83)	(62)
Net cash flows provided by (used in) financing activities	189	(284)
Decrease in cash and cash equivalents	(247)	(495)
Cash and cash equivalents at beginning of period	1,609	1,486
Cash and cash equivalents at end of period	$ 1,362	$ 991

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,362	$ 1,609
Restricted cash and investments	207	167
Accounts receivable, net		
Customer	2,973	2,981
Other	1,005	1,175
Mark-to-market derivative assets	629	727
Unamortized energy contract assets	264	374
Inventories, net		
Fossil fuel	409	276
Materials and supplies	1,041	829
Deferred income taxes	426	573
Regulatory assets	732	760
Other	775	666
Total current assets	9,823	10,137
Property, plant and equipment, net	51,747	47,330
Deferred debits and other assets		
Regulatory assets	5,545	5,910
Nuclear decommissioning trust funds	10,437	8,071
Investments	839	1,165
Investments in affiliates	22	22
Investment in CENG	—	1,925
Goodwill	2,674	2,625
Mark-to-market derivative assets	482	607
Unamortized energy contracts assets	593	710
Pledged assets for Zion Station decommissioning	402	458
Other	1,092	964
Total deferred debits and other assets	22,086	22,457
Total assets [(a)]	$ 83,656	$ 79,924

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 621	$ 341
Long-term debt due within one year	2,047	1,509
Accounts payable	2,633	2,484
Accrued expenses	1,382	1,633
Payables to affiliates	38	116
Deferred income taxes	17	40
Regulatory liabilities	368	327
Mark-to-market derivative liabilities	228	159
Unamortized energy contract liabilities	239	261
Other	994	858
Total current liabilities	8,567	7,728
Long-term debt	18,133	17,623
Long-term debt to financing trusts	648	648
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,192	12,905
Asset retirement obligations	7,054	5,194
Pension obligations	1,804	1,876
Non-pension postretirement benefit obligations	1,419	2,190
Spent nuclear fuel obligation	1,021	1,021
Regulatory liabilities	4,670	4,388
Mark-to-market derivative liabilities	262	300
Unamortized energy contract liabilities	260	266
Payable for Zion Station decommissioning	264	305
Other	2,133	2,540
Total deferred credits and other liabilities	32,079	30,985
Total liabilities [(a)]	59,427	56,984
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 894 shares and 857 shares outstanding at June 30, 2014 and December 31, 2013, respectively)	16,651	16,741
Treasury stock, at cost (35 shares at June 30, 2014 and December 31, 2013, respectively)	(2,327)	(2,327)
Retained earnings	10,435	10,358
Accumulated other comprehensive loss, net	(1,906)	(2,040)
Total shareholders' equity	22,853	22,732
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	1,183	15
Total equity	24,229	22,940
Total liabilities and shareholders' equity	$ 83,656	$ 79,924

(a) Exelon's consolidated assets include $7,765 million and $1,755 million at June 30, 2014 and December 31, 2013, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $3,111 million and $658 million at June 30, 2014 and December 31, 2013, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 3 — Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Non-controlling Interest	Preferred and Preference Stock	Total Equity
Balance, December 31, 2013	892,034	$16,741	$(2,327)	$10,358	$ (2,040)	$ 15	$ 193	$22,940
Net income	—	—	—	612	—	33	6	651
Long-term incentive plan activity	1,408	32	—		—		—	32
Employee stock purchase plan issuances	499	14	—	—	—	—	—	14
Allocation of tax benefit from member	—	(5)						(5)
Acquisition of non-controlling interest	—	—	—	—	—	2	—	2
Common stock dividends	—	—	—	(535)	—	—	—	(535)
Preferred and preference stock dividends	—	—	—	—	—	—	(6)	(6)
Fair value of financing contract payments	—	(131)	—	—	—	—	—	(131)
Non-controlling interest established upon consolidation of CENG	—	—	—	—	—	1,548	—	1,548
Consolidated VIE dividend to non-controlling interest	—	—	—	—	—	(415)	—	(415)
Reversal of CENG equity method AOCI, net of income taxes of $77	—	—	—	—	(116)	—	—	(116)
Other comprehensive income, net of income taxes of $(159)	—	—	—	—	250	—	—	250
Balance, June 30, 2014	893,941	$16,651	$(2,327)	$10,435	$ (1,906)	$ 1,183	$ 193	$24,229

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Operating revenues				
Operating revenues	$ 3,588	$ 3,718	$ 7,644	$ 6,859
Operating revenues from affiliates	201	352	535	744
Total operating revenues	3,789	4,070	8,179	7,603
Operating expenses				
Purchased power and fuel	1,766	1,656	4,774	3,503
Purchased power and fuel from affiliates	69	290	417	611
Operating and maintenance	1,255	1,041	2,194	2,007
Operating and maintenance from affiliates	158	148	305	295
Depreciation and amortization	254	210	466	424
Taxes other than income	118	101	223	194
Total operating expenses	3,620	3,446	8,379	7,034
Equity in losses of unconsolidated affiliates	(1)	(21)	(20)	(30)
Gain on consolidation of CENG	261	—	261	—
Operating income	429	603	41	539
Other income and (deductions)				
Interest expense	(74)	(77)	(147)	(142)
Interest expense to affiliates, net	(12)	(16)	(25)	(34)
Other, net	228	(33)	318	95
Total other income and (deductions)	142	(126)	146	(81)
Income before income taxes	571	477	187	458
Income taxes (benefit)	199	149	(1)	148
Net income	372	328	188	310
Net income (loss) attributable to noncontrolling interests	32	(2)	33	(1)
Net income attributable to membership interest	340	330	155	311
Comprehensive income, net of income taxes				
Net income	372	328	188	310
Other comprehensive income (loss), net of income taxes				
Unrealized loss on cash flow hedges	(45)	(137)	(70)	(267)
Unrealized gain on equity investments	—	8	11	36
Unrealized gain (loss) on foreign currency translation	4	(5)	(1)	(6)
Unrealized gain (loss) on marketable securities	2	—	(1)	(1)
Reversal of CENG equity method AOCI	(116)	—	(116)	—
Other comprehensive loss	(155)	(134)	(177)	(238)
Comprehensive income	$ 217	$ 194	$ 11	$ 72

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2014	2013
Cash flows from operating activities		
Net income	$ 188	$ 310
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	1,242	1,358
Gain on consolidation of CENG	(268)	—
Deferred income taxes and amortization of investment tax credits	(15)	(44)
Net fair value changes related to derivatives	760	(21)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(168)	(27)
Other non-cash operating activities	209	315
Changes in assets and liabilities:		
Accounts receivable	63	88
Receivables from and payables to affiliates, net	(20)	(29)
Inventories	(170)	(38)
Accounts payable, accrued expenses and other current liabilities	(273)	(426)
Option premiums received (paid), net	21	(10)
Counterparty collateral paid, net	(633)	(303)
Income taxes	72	265
Pension and non-pension postretirement benefit contributions	(210)	(120)
Other assets and liabilities	(56)	(168)
Net cash flows provided by operating activities	742	1,150
Cash flows from investing activities		
Capital expenditures	(1,103)	(1,277)
Proceeds from nuclear decommissioning trust fund sales	4,219	1,448
Investment in nuclear decommissioning trust funds	(4,238)	(1,565)
Acquisition of business	(66)	—
Proceeds from sale of long-lived assets	32	—
Change in restricted cash	(17)	(11)
Changes in Exelon intercompany money pool	44	—
Cash consolidated from CENG	129	—
Other investing activities	(14)	27
Net cash flows used in investing activities	(1,014)	(1,378)
Cash flows from financing activities		
Change in short-term borrowings	46	288
Issuance of long-term debt	300	209
Retirement of long-term debt	(538)	(458)
Changes in Exelon intercompany money pool	190	263
Distribution to member	(235)	(474)
Distributions to non-controlling interest of consolidated VIE	(415)	—
Other financing activities	(29)	(49)
Net cash flows used in financing activities	(681)	(221)
Decrease in cash and cash equivalents	(953)	(449)
Cash and cash equivalents at beginning of period	1,258	671
Cash and cash equivalents at end of period	$ 305	$ 222

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 305	$ 1,258
Restricted cash and cash equivalents	88	71
Accounts receivable, net		
Customer	1,733	1,689
Other	441	353
Mark-to-market derivative assets	629	727
Receivables from affiliates	67	108
Receivable from Exelon intercompany pool	—	44
Unamortized energy contract assets	264	374
Inventories, net		
Fossil fuel	328	164
Materials and supplies	872	671
Deferred income taxes	476	475
Other	524	505
Total current assets	5,727	6,439
Property, plant and equipment, net	23,743	20,111
Deferred debits and other assets		
Nuclear decommissioning trust funds	10,437	8,071
Investments	432	400
Investment in CENG	—	1,925
Goodwill, net	49	—
Mark-to-market derivative assets	464	600
Prepaid pension asset	1,888	1,873
Pledged assets for Zion Station decommissioning	402	458
Unamortized energy contract assets	593	710
Other	687	645
Total deferred debits and other assets	14,952	14,682
Total assets [(a)]	$ 44,422	$ 41,232

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 53	$ 22
Long-term debt due within one year	52	561
Long-term debt to affiliates due within one year	563	—
Accounts payable	1,508	1,322
Accrued expenses	819	976
Payables to affiliates	108	181
Borrowings from Exelon intercompany money pool	190	—
Deferred income taxes	1	25
Mark-to-market derivative liabilities	215	142
Unamortized energy contract liabilities	233	249
Other	473	389
Total current liabilities	4,215	3,867
Long-term debt	5,944	5,645
Long-term debt to affiliate	948	1,523
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,334	6,295
Asset retirement obligations	6,907	5,047
Pension obligations	125	—
Non-pension postretirement benefit obligations	941	850
Spent nuclear fuel obligation	1,021	1,021
Payables to affiliates	2,917	2,740
Mark-to-market derivative liabilities	135	120
Unamortized energy contract liabilities	260	266
Payable for Zion Station decommissioning	264	305
Other	761	811
Total deferred credits and other liabilities	19,665	17,455
Total liabilities [(a)]	30,772	28,490
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	8,895	8,898
Undistributed earnings	3,533	3,613
Accumulated other comprehensive income, net	37	214
Total member's equity	12,465	12,725
Noncontrolling interest	1,185	17
Total equity	13,650	12,742
Total liabilities and equity	$ 44,422	$ 41,232

(a) Generation's consolidated assets include $7,711 million and $1,695 million at June 30, 2014 and December 31, 2013, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $2,855 million and $362 million at June 30, 2014 and December 31, 2013, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 3 — Variable Interest Entities.

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

(In millions)	Member's Equity: Membership Interest	Member's Equity: Undistributed Earnings	Member's Equity: Accumulated Other Comprehensive Income, net	Non-controlling Interest	Total Equity
Balance, December 31, 2013	$ 8,898	$ 3,613	$ 214	$ 17	$12,742
Net income	—	155	—	33	188
Acquisition of non-controlling interest	—	—	—	2	2
Allocation of tax benefit from member	(3)	—	—	—	(3)
Distribution to member	—	(235)	—	—	(235)
Non-controlling interest established upon consolidation of CENG	—	—	—	1,548	1,548
Consolidated VIE dividend to non-controlling interest	—	—	—	(415)	(415)
Reversal of CENG equity method AOCI, net of income taxes of $77	—	—	(116)	—	(116)
Other comprehensive loss, net of income taxes of $35	—	—	(61)	—	(61)
Balance, June 30, 2014	$ 8,895	$ 3,533	$ 37	$ 1,185	$13,650

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Operating revenues				
Operating revenues	$ 1,128	$ 1,080	$ 2,261	$ 2,238
Operating revenues from affiliates	—	—	1	1
Total operating revenues	1,128	1,080	2,262	2,239
Operating expenses				
Purchased power	204	127	416	364
Purchased power from affiliate	65	121	173	266
Operating and maintenance	316	319	603	611
Operating and maintenance from affiliate	39	40	78	76
Depreciation and amortization	174	170	347	337
Taxes other than income	72	71	149	145
Total operating expenses	870	848	1,766	1,799
Operating income	258	232	496	440
Other income and (deductions)				
Interest expense	(76)	(72)	(153)	(422)
Interest expense to affiliates, net	(4)	(4)	(7)	(7)
Other, net	5	6	10	11
Total other income and (deductions)	(75)	(70)	(150)	(418)
Income before income taxes	183	162	346	22
Income taxes	72	66	137	8
Net income	111	96	209	14
Comprehensive income	$ 111	$ 96	$ 209	$ 14

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2014	2013
Cash flows from operating activities		
Net income	$ 209	$ 14
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	347	337
Deferred income taxes and amortization of investment tax credits	63	(226)
Other non-cash operating activities	99	39
Changes in assets and liabilities:		
Accounts receivable	(83)	18
Receivables from and payables to affiliates, net	(46)	(26)
Inventories	(4)	(11)
Accounts payable, accrued expenses and other current liabilities	27	20
Income taxes	5	240
Pension and non-pension postretirement benefit contributions	(236)	(119)
Other assets and liabilities	48	217
Net cash flows provided by operating activities	429	503
Cash flows from investing activities		
Capital expenditures	(747)	(711)
Proceeds from sales of investments	7	4
Purchases of investments	(3)	(3)
Change in restricted cash	(2)	(3)
Other investing activities	14	20
Net cash flows used in investing activities	(731)	(693)
Cash flows from financing activities		
Changes in short-term borrowings	314	374
Issuance of long-term debt	650	—
Retirement of long-term debt	(617)	(125)
Contributions from parent	112	—
Dividends paid on common stock	(153)	(110)
Other financing activities	(2)	—
Net cash flows provided by financing activities	304	139
Increase (Decrease) in cash and cash equivalents	2	(51)
Cash and cash equivalents at beginning of period	36	144
Cash and cash equivalents at end of period	$ 38	$ 93

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 38	$ 36
Restricted cash	4	2
Accounts receivable, net		
Customer	516	451
Other	428	584
Inventories, net	112	109
Regulatory assets	304	329
Other	32	29
Total current assets	1,434	1,540
Property, plant and equipment, net	15,121	14,666
Deferred debits and other assets		
Regulatory assets	850	933
Investments	1	5
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,606	2,469
Prepaid pension asset	1,626	1,583
Other	275	291
Total deferred debits and other assets	7,989	7,912
Total assets	$ 24,544	$ 24,118

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 498	$ 184
Long-term debt due within one year	260	617
Accounts payable	505	449
Accrued expenses	274	307
Payables to affiliates	37	83
Customer deposits	130	133
Regulatory liabilities	164	170
Deferred income taxes	117	16
Mark-to-market derivative liability	13	17
Other	82	72
Total current liabilities	2,080	2,048
Long-term debt	5,448	5,058
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,080	4,116
Asset retirement obligations	100	99
Non-pension postretirement benefits obligations	284	381
Regulatory liabilities	3,686	3,512
Mark-to-market derivative liability	121	176
Other	841	994
Total deferred credits and other liabilities	9,112	9,278
Total liabilities	16,846	16,590
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,304	5,190
Retained earnings	806	750
Total shareholders' equity	7,698	7,528
Total liabilities and shareholders' equity	$ 24,544	$ 24,118

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2013	$ 1,588	$ 5,190	$ (1,639)	$ 2,389	$ 7,528
Net income	—	—	209	—	209
Appropriation of retained earnings for future dividends	—	—	(209)	209	—
Common stock dividends	—	—	—	(153)	(153)
Contribution from parent	—	112	—	—	112
Parent tax matter indemnification	—	2	—	—	2
Balance, June 30, 2014	$ 1,588	$ 5,304	$ (1,639)	$ 2,445	$ 7,698

See the Combined Notes to Consolidated Financial Statements

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Operating revenues				
Operating revenues	$ 656	$ 672	$1,648	$1,567
Operating revenues from affiliates	—	—	1	—
Total operating revenues	656	672	1,649	1,567
Operating expenses				
Purchased power and fuel	193	161	570	426
Purchased power from affiliate	48	97	135	238
Operating and maintenance	160	155	416	319
Operating and maintenance from affiliates	24	26	48	50
Depreciation and amortization	59	56	117	113
Taxes other than income	38	39	80	80
Total operating expenses	522	534	1,366	1,226
Operating income	134	138	283	341
Other income and (deductions)				
Interest expense	(25)	(25)	(50)	(51)
Interest expense to affiliates, net	(3)	(3)	(6)	(6)
Other, net	1	—	3	3
Total other income and (deductions)	(27)	(28)	(53)	(54)
Income before income taxes	107	110	230	287
Income taxes	23	32	57	87
Net income	84	78	173	200
Preferred security dividends and redemption	—	6	—	7
Net income attributable to common shareholder	84	72	173	193
Comprehensive income	$ 84	$ 78	$ 173	$ 200

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2014	2013
Cash flows from operating activities		
Net income	$ 173	$ 200
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	117	113
Deferred income taxes and amortization of investment tax credits	6	25
Other non-cash operating activities	50	50
Changes in assets and liabilities:		
Accounts receivable	34	55
Receivables from and payables to affiliates, net	(21)	(18)
Inventories	22	27
Accounts payable, accrued expenses and other current liabilities	30	35
Income taxes	54	39
Pension and non-pension postretirement benefit contributions	(11)	(10)
Other assets and liabilities	(114)	(49)
Net cash flows provided by operating activities	340	467
Cash flows from investing activities		
Capital expenditures	(308)	(254)
Changes in intercompany money pool	—	(263)
Change in restricted cash	—	(1)
Other investing activities	6	4
Net cash flows used in investing activities	(302)	(514)
Cash flows from financing activities		
Dividends paid on common stock	(160)	(166)
Dividends paid on preferred securities	—	(1)
Redemption of preferred securities	—	(93)
Other financing activities	(2)	1
Net cash flows used in financing activities	(162)	(259)
Decrease in cash and cash equivalents	(124)	(306)
Cash and cash equivalents at beginning of period	217	362
Cash and cash equivalents at end of period	$ 93	$ 56

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 93	$ 217
Restricted cash and cash equivalents	2	2
Accounts receivable, net		
Customer	304	360
Other	107	107
Inventories, net		
Fossil fuel	34	60
Materials and supplies	25	21
Deferred income taxes	80	83
Prepaid utility taxes	78	3
Regulatory assets	29	17
Other	51	36
Total current assets	803	906
Property, plant and equipment, net	6,545	6,384
Deferred debits and other assets		
Regulatory assets	1,495	1,448
Investments	23	23
Investments in affiliates	8	8
Receivable from affiliates	490	447
Prepaid pension asset	359	363
Other	38	38
Total deferred debits and other assets	2,413	2,327
Total assets	$ 9,761	$ 9,617

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$ 250	$ 250
Accounts payable	298	285
Accrued expenses	167	106
Payables to affiliates	37	58
Customer deposits	50	49
Regulatory liabilities	88	106
Other	32	37
Total current liabilities	922	891
Long-term debt	1,947	1,947
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,545	2,487
Asset retirement obligations	30	29
Non-pension postretirement benefits obligations	292	286
Regulatory liabilities	671	629
Other	92	99
Total deferred credits and other liabilities	3,630	3,530
Total liabilities	6,683	6,552
Commitments and contingencies		
Shareholder's equity		
Common stock	2,415	2,415
Retained earnings	662	649
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,078	3,065
Total liabilities and shareholders' equity	$ 9,761	$ 9,617

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholder's Equity
Balance, December 31, 2013	$ 2,415	$ 649	$ 1	$ 3,065
Net income	—	173	—	173
Common stock dividends	—	(160)	—	(160)
Balance, June 30, 2014	$ 2,415	$ 662	$ 1	$ 3,078

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Operating revenues				
Operating revenues	$ 651	$ 649	$ 1,689	$ 1,525
Operating revenues from affiliates	2	4	18	8
Total operating revenues	653	653	1,707	1,533
Operating expenses				
Purchased power and fuel	183	189	592	501
Purchased power from affiliate	85	99	205	212
Operating and maintenance	163	139	326	266
Operating and maintenance from affiliates	25	21	50	37
Depreciation and amortization	89	82	197	175
Taxes other than income	53	54	113	109
Total operating expenses	598	584	1,483	1,300
Operating income	55	69	224	233
Other income and (deductions)				
Interest expense	(23)	(28)	(47)	(58)
Interest expense to affiliates, net	(4)	(4)	(8)	(8)
Other, net	5	4	9	9
Total other income and (deductions)	(22)	(28)	(46)	(57)
Income before income taxes	33	41	178	176
Income taxes	14	16	72	70
Net income	19	25	106	106
Preference stock dividends	3	3	6	6
Net income attributable to common shareholder	16	22	100	100
Comprehensive income	$ 19	$ 25	$ 106	$ 106

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2014	2013
Cash flows from operating activities		
Net income	$ 106	$ 106
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	197	175
Deferred income taxes and amortization of investment tax credits	47	98
Other non-cash operating activities	89	61
Changes in assets and liabilities:		
Accounts receivable	44	(58)
Receivables from and payables to affiliates, net	(12)	(11)
Inventories	—	4
Accounts payable, accrued expenses and other current liabilities	(74)	(28)
Counterparty collateral received, net	27	—
Income taxes	(14)	(33)
Pension and non-pension postretirement benefit contributions	(8)	(11)
Other assets and liabilities	8	63
Net cash flows provided by operating activities	410	366
Cash flows from investing activities		
Capital expenditures	(313)	(264)
Change in restricted cash	(30)	3
Other investing activities	11	4
Net cash flows used in investing activities	(332)	(257)
Cash flows from financing activities		
Changes in short-term borrowings	(65)	—
Issuance of long-term debt	—	300
Retirement of long-term debt	(35)	(33)
Dividends paid on preference stock	(6)	(6)
Other financing activities	12	(2)
Net cash flows (used in) provided by financing activities	(94)	259
Increase (decrease) in cash and cash equivalents	(16)	368
Cash and cash equivalents at beginning of period	31	89
Cash and cash equivalents at end of period	$ 15	$ 457

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 15	$ 31
Restricted cash and cash equivalents	58	28
Accounts receivable, net		
Customer	419	480
Other	102	114
Income taxes receivable	44	30
Inventories, net		
Gas held in storage	48	53
Materials and supplies	33	28
Deferred income taxes	11	2
Prepaid utility taxes	—	57
Regulatory assets	178	181
Other	8	7
Total current assets	916	1,011
Property, plant and equipment, net	6,030	5,864
Deferred debits and other assets		
Regulatory assets	499	524
Investments	4	5
Investments in affiliates	8	8
Prepaid pension asset	396	423
Other	24	26
Total deferred debits and other assets	931	986
Total assets [(a)]	$ 7,877	$ 7,861

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2014 (Unaudited)	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 70	$ 135
Long-term debt due within one year	72	70
Accounts payable	205	270
Accrued expenses	95	111
Deferred income taxes	39	27
Payables to affiliates	55	55
Customer deposits	87	76
Regulatory liabilities	63	48
Other	61	35
Total current liabilities	747	827
Long-term debt	1,904	1,941
Long-term debt to financing trust	258	258
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,814	1,773
Asset retirement obligations	17	19
Non-pension postretirement benefits obligations	215	217
Regulatory liabilities	202	204
Other	65	67
Total deferred credits and other liabilities	2,313	2,280
Total liabilities [(a)]	5,222	5,306
Commitments and contingencies		
Shareholders' equity		
Common stock	1,360	1,360
Retained earnings	1,105	1,005
Total shareholder's equity	2,465	2,365
Preference stock not subject to mandatory redemption	190	190
Total equity	2,655	2,555
Total liabilities and shareholders' equity	$ 7,877	$ 7,861

(a) BGE's consolidated assets include $31 million and $31 million at June 30, 2014 and December 31, 2013, respectively, of BGE's consolidated VIE that can only be used to settle the liabilities of the VIE. BGE's consolidated liabilities include $234 million and $269 million at June 30, 2014 and December 31, 2013, respectively, of BGE's consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note 3 — Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2013	$ 1,360	$ 1,005	$ 2,365	$ 190	$ 2,555
Net income	—	106	106	—	106
Preference stock dividends	—	(6)	(6)	—	(6)
Balance, June 30, 2014	$ 1,360	$ 1,105	$ 2,465	$ 190	$ 2,655

See the Combined Notes to Consolidated Financial Statements

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in millions, except per share data, unless otherwise noted)

1. Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses. On April 1, 2014, Generation assumed the operating licenses and corresponding operational control of CENG's nuclear fleet. As a result, Exelon and Generation consolidated CENG's financial position and results of operations into their businesses. Prior to April 1, 2014, Exelon and Generation accounted for CENG as an equity method investment. Refer to Note 6 — Investment in CENG for further information regarding the integration transaction.

The energy generation business includes:

- *Generation* : Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other regions.

The energy delivery businesses include:

- *ComEd* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Certain prior year amounts in the Exelon, Generation and BGE Consolidated Statement of Operations have been reclassified between line items for comparative purposes and correction of prior period classification errors identified in 2013. The reclassifications did not affect any of the Registrants' net income or cash flows from operating activities. Exelon corrected the presentation of Purchased power and fuel from affiliates of $287 million and $605 million on its Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2013, respectively. Generation corrected the presentation of Purchased power and fuel from affiliates of $290 million and $611 million on its Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2013, respectively. Generation also corrected the presentation of Interest expense to affiliates, net of $16 million and $34 million on its Statement of Operations and Comprehensive Income for the three and six months ended June 30, 2013, respectively. BGE corrected its presentation of Interest expense to affiliates, net of $4 million and $8 million on the Statement of Operations and Comprehensive Income for the three and six months ended June 30, 2013, respectively.

The accompanying consolidated financial statements as of June 30, 2014 and 2013 and for the six months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2013 Consolidated Balance Sheets were obtained from audited financial statements. Financial results for interim

periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2014. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. These notes should be read in conjunction with the Notes to Combined Consolidated Financial Statements of all Registrants included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA of their respective 2013 Form 10-K Reports.

2. New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

The following recently issued accounting standards were adopted by or are effective for the Registrants during 2014.

Presentation of Unrecognized Tax Benefits When Net Operating Loss Carryforwards, Similar Tax Losses or Tax Credit Carryforwards Exist

In July 2013, the FASB issued authoritative guidance requiring entities to present unrecognized tax benefits as a reduction to deferred tax assets for losses or other tax carryforwards that would be available to offset the uncertain tax positions at the reporting date. This guidance was effective for the Registrants for periods beginning after December 15, 2013 and was required to be applied prospectively. The adoption of this standard had an immaterial effect on the presentation of deferred tax assets at Exelon and Generation and no effect on ComEd, PECO and BGE. There was no effect on the Registrants' results of operations or cash flows.

The following recently issued accounting standards are not yet required to be reflected in the combined financial statements of the Registrants.

Revenue from Contracts with Customers

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. The new guidance replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing and uncertainty of revenue and the related cash flows. The guidance is effective for the Registrants for the first interim period within annual reporting periods beginning on or after December 15, 2016. Early adoption is not permitted. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their financial positions, results of operations, cash flows and disclosures as well as the transition method that they will use to adopt the guidance.

3. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

Under the applicable authoritative guidance, a VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have

the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly affect the entity's economic performance.

At June 30, 2014 and December 31, 2013, Exelon, Generation, and BGE collectively consolidated six and four VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary *(see detail by Registrant below)*. As of June 30, 2014 and December 31, 2013, the Registrants had significant interests in nine and eight other VIEs, respectively, for which the Registrants do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary.

Through March 31, 2014, CENG was operated as a joint venture with EDFI and was governed by a board of ten directors, five of which were appointed by Generation and five by EDF. CENG was designed to operate under joint and equal control of Generation and EDFI; therefore, CENG was not subject to VIE guidance. Accordingly, Generation's 50.01% interest in CENG was accounted for as an equity method investment. On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the NOSA pursuant to which Generation now conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDFI. As a result of executing the NOSA, CENG now qualifies as a VIE due to the disproportionate relationship between Generation's 50.01% equity ownership interest and its role in conducting the operational activities of CENG conveyed through the NOSA. Further, since Generation is conducting the operational activities of CENG, Generation qualifies as the primary beneficiary of CENG and, therefore, is required to consolidate the financial position and results of operations of CENG. On April 1, 2014, Exelon and Generation derecognized Generation's equity method investment in CENG and reflected all assets, liabilities, and the EDFI non-controlling interest in CENG at fair value on the consolidated balance sheets of Exelon and Generation, resulting in the recognition of a $261 million gain in their respective consolidated statements of operations and comprehensive income for the three and six months ended June 30, 2014. For additional information on this transaction refer to Note 6 — Investment in Constellation Energy Nuclear Group, LLC.

In March 2014, Generation began consolidating retail power VIEs for which Generation is the primary beneficiary as a result of energy supply contracts that give Generation the power to direct the activities that most significantly affect the economic performance of the entities. Generation does not have an equity ownership interest in these entities. These entities are included in Generation's consolidated financial statements and the consolidation of the VIEs did not have a material impact on Generation's financial results or financial condition.

Consolidated Variable Interest Entities

Exelon, Generation and BGE's consolidated VIEs consist of:

- BondCo, a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, and issue and service bonds secured by rate stabilization property,
- a retail gas group formed by Generation to enter into a collateralized gas supply agreement with a third-party gas supplier,
- a group of solar project limited liability companies formed by Generation to build, own and operate solar power facilities,
- several wind project companies designed by Generation to develop, construct and operate wind generation facilities,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

- certain retail power companies for which Generation is the sole supplier of energy, and
- Constellation Energy Nuclear Group, Inc. (CENG).

As of June 30, 2014 and December 31, 2013, ComEd and PECO do not have any material consolidated VIEs.

As of June 30, 2014 and December 31, 2013, Exelon, Generation, and BGE provided the following support to the consolidated VIEs:

- In the case of BondCo, BGE is required to remit all payments it receives from all residential customers through non-bypassable, rate stabilization charges to BondCo. During the three and six months ended June 30, 2014, BGE remitted $21 million and $42 million, respectively, to BondCo. During the three and six months ended June 30, 2013, BGE remitted $17 million and $39 million, respectively, to BondCo.
- Generation provides operating and capital funding to the solar entities for ongoing construction, operations and maintenance of the solar power facilities and provides limited recourse related to the Antelope Valley project.
- Generation and Exelon, where indicated, provide the following support to CENG (See Note 25 — Related Party Transactions of the Exelon 2013 Form 10-K and Note 6 — Investment in Constellation Energy Nuclear Group, LLC for additional information regarding Generation and Exelon's transactions with CENG).
  - under the Nuclear Operating Services Agreement (NOSA), Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF Inc. (EDFI) (a subsidiary of EDF),
  - under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management, and billing services to CENG fleet for the remaining life of the CENG nuclear plants,
  - under power purchase agreements with CENG, Generation will purchase 85% of the available output generated by CENG nuclear plants for the remainder of 2014 and 50.01% from 2015 through the end of the life of each respective plant under power purchase agreements with CENG,
  - Generation provided a $400 million loan to CENG,
  - Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity. (See Note 18 — Commitments and Contingencies for more details),
  - in connection with CENG's severance obligations, Generation has agreed to reimburse CENG for a total of approximately $6 million of the severance benefits paid or to be paid in 2013 through 2016. As of June 30, 2014, the remaining obligation is approximately $4 million (See Integration-Related Severance under Note 14 — Severance for additional details),
  - Generation and EDFI share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance (See Note 18 — Commitments and Contingencies for more details),

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

- Generation provides a $7 million guarantee associated with hazardous waste management facilities and underground storage tanks. In addition, EDFI executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,
- Generation and EDFI are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (See Note 18 — Commitments and Contingencies for more details), and
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

- Generation provides approximately $4 million in credit support for the retail power companies, and
- Generation provides a $75 million parental guarantee to the third-party gas supplier in support of its retail gas group.

For each of the consolidated VIEs, except as otherwise noted:

- The assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;
- Exelon, Generation and BGE did not provide any additional material financial support to the VIEs;
- Exelon, Generation and BGE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and
- the creditors of the VIEs did not have recourse to Exelon's, Generation's or BGE's general credit.

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in Exelon's, Generation's, and BGE's consolidated financial statements at June 30, 2014 and December 31, 2013 are as follows:

	June 30, 2014			December 31, 2013		
	Exelon [a][b]	Generation [b]	BGE	Exelon [a]	Generation	BGE
Current assets	$ 991	$ 956	$ 28	$ 484	$ 446	$ 28
Noncurrent assets	7,426	7,407	3	1,905	1,884	3
Total assets	$ 8,417	$ 8,363	$ 31	$ 2,389	$ 2,330	$ 31
Current liabilities	$ 815	$ 732	$ 76	$ 566	$ 481	$ 74
Noncurrent liabilities	2,911	2,738	158	774	562	195
Total liabilities	$ 3,726	$ 3,470	$234	$ 1,340	$ 1,043	$269

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total assets of $5.8 billion and total liabilities of $2.4 billion due to the consolidation of CENG begining April 1, 2014. See Note 6 — Investment in CENG for additional information.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of June 30, 2014 and December 31, 2013, these assets and liabilities primarily consisted of the following:

	June 30, 2014			December 31, 2013		
	Exelon	Generation	BGE	Exelon	Generation	BGE
Cash and cash equivalents	$ 126	$ 126	$ —	$ 62	$ 62	$ —
Restricted cash	75	47	28	80	52	28
Accounts receivable, net						
Customer	296	296	—	260	260	—
Other	133	133	—	—	—	—
Inventory						
Fossil fuel	103	103	—	2	2	—
Materials and supplies	165	165	—	—	—	—
Other current assets	61	54	—	53	42	—
Total current assets	959	924	28	457	418	28
Property, plant and equipment, net	4,603	4,603	—	1,171	1,171	—
Nuclear decommissioning trust funds	2,030	2,030	—	—	—	—
Goodwill	48	48	—	—	—	—
Other noncurrent assets	125	106	3	127	106	3
Total noncurrent assets	6,806	6,787	3	1,298	1,277	3
Total assets	$7,765	$ 7,711	$ 31	$1,755	$ 1,695	$ 31
Short-term borrowings	$ 40	$ 40	$ —	$ —	$ —	$ —
Long-term debt due within one year	84	5	72	85	5	70
Accounts payable	243	243	—	170	170	—
Accrued expenses	89	86	4	26	22	4
Mark-to-market derivative liabilities	24	24	—	29	29	—
Unamortized energy contracts	12	12	—	5	5	—
Other current liabilities	165	165	—	5	5	—
Total current liabilities	657	575	76	320	236	74
Long-term debt	258	84	158	298	86	195
Asset retirement obligations	1,731	1,731	—	—	—	—
Pension obligation [a]	133	133	—	—	—	—
Non-pension postretirement benefit	136	136	—	—	—	—
Unamortized energy contracts	18	18	—	12	12	—
Other noncurrent liabilities	178	178	—	28	28	—
Noncurrent liabilities	2,454	2,280	158	338	126	195
Total liabilities	$3,111	$ 2,855	$234	$ 658	$ 362	$269

(a) Includes the CNEG retail gas' pension obligation, which is presented as a net asset balance within the Prepaid Pension asset line item on Generation's balance sheet. See Note 13 — Retirement Benefits for additional details.

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected on Exelon's and Generation's Consolidated Balance Sheets in Investments in affiliates, Investments,

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(Dollars in millions, except per share data, unless otherwise noted)

and Other Assets. For the energy purchase and sale contracts and the fuel purchase commitments (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

The Registrants' unconsolidated VIEs consist of:

- Energy purchase and sale agreements with VIEs for which Generation has concluded that consolidation is not required.
- ZionSolutions, LLC asset sale agreement with EnergySolutions, Inc. and certain subsidiaries in which Generation has a variable interest but has concluded that consolidation is not required.
- Equity investments in energy development projects and energy generating facilities for which Generation has concluded that consolidation is not required.

As of June 30, 2014 and December 31, 2013, Exelon and Generation had significant unconsolidated variable interests in nine and eight VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity method investments and certain commercial agreements. The increase in the number of unconsolidated VIEs is due to an investment in another unconsolidated VIE and the execution of an energy purchase and sale agreement with an unconsolidated VIE, offset by the sale of Generation's ownership interest in one unconsolidated VIE. The following tables present summary information about Exelon and Generation's significant unconsolidated VIE entities:

June 30, 2014	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 119	$ 325	$444
Total liabilities [a]	2	120	122
Exelon's ownership interest in VIE [a]	—	63	63
Other ownership interests in VIE [a]	117	142	259
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	73	73
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning [b]	45	—	45

December 31, 2013	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 128	$ 332	$460
Total liabilities [a]	17	123	140
Exelon's ownership interest in VIE [a]	—	86	86
Other ownership interests in VIE [a]	111	123	234
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	7	67	74
Contract intangible asset	9	—	9
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning [b]	44	—	44

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.

(b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $402 million and $458 million as of June 30, 2014 and December 31, 2013, respectively; offset by payables to ZionSolutions LLC of $357 million and $414 million as of June 30, 2014 and December 31, 2013, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

For each of the unconsolidated VIEs, Exelon and Generation assess the risk of a loss equal to their maximum exposure to be remote and, accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no material agreements with, or commitments by, third parties that would affect the fair value or risk of their variable interests in these VIEs.

4. Mergers, Acquisitions and Dispositions

Proposed Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI's shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it purchased $90 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI, in the second quarter of 2014, with additional investments of $18 million to be made quarterly up to a maximum aggregate investment of $180 million. PHI has the right to redeem the preferred securities at its option for the purchase price paid plus accrued dividends, if any. The $90 million of PHI preferred securities are included in Other non-current assets on Exelon's Consolidated Balance Sheet as of June 30, 2014. Exelon expects total cash required to fund the acquisition of common stock and preferred securities plus other related acquisition costs to total approximately $7.2 billion.

The transaction must be approved by the shareholders of PHI. Completion of the transaction is also conditioned upon approval by the FERC, the District of Columbia Public Service Commission and several state commissions including Delaware Public Service Commission, MDPSC, the New Jersey Board of Public Utilities and the Virginia Department of Public Utilities. In addition, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), the transaction cannot be completed until Exelon has made required notifications and given certain information and materials to the Federal Trade Commission (FTC) and/or the Antitrust Division of the United States Department of Justice (DOJ) and until specified waiting period requirements have expired.

Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. Exelon intends to vigorously defend these suits. Exelon does not believe these suits will impact the completion of the transaction, and they are not expected to have a material impact on Exelon's results of operations.

Through June 30, 2014, Exelon has incurred approximately $25 million of expense associated with the transaction, primarily related to fees incurred as part of the acquisition. As part of the applications for approval of the merger, Exelon and PHI have proposed a package of benefits to PHI utilities' customers which results in a direct investment of more than $100 million. The Merger Agreement also provides for termination rights on behalf of both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the Merger

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Agreement does not close due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities (described above), by means of PHI redeeming the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock. The companies anticipate closing the transaction in the second or third quarter of 2015, subject to receipt of required regulatory approvals.

Merger Financing

Exelon intends to fund the all-cash transaction using a combination of approximately $3.5 billion of debt, up to $1.0 billion cash from asset sales primarily at Generation, and the remainder through issuance of equity (including mandatory convertible securities). On June 11, 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share in connection with forward sales agreements and $1.2 billion of junior subordinated notes in the form of 23 million equity units. In addition, Exelon signed a 364-day $7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing, which has subsequently been reduced to $4.2 billion as a result of the equity issuances. See Note 10 — Debt and Credit Agreements and Note 16 — Common Stock for more information.

Safe Harbor Water Power Corporation (Exelon and Generation)

On May 15, 2014, Generation entered into a Purchase and Sale Agreement with Brookfield Renewable Energy Partners L.P. to sell Generation's 67% economic equity interest in the 417 MW Safe Harbor Water Power Corporation hydroelectric facility on the Susquehanna River in Pennsylvania (Safe Harbor). The total purchase price for the transaction is approximately $613 million. The transaction, which is subject to customary closing conditions and regulatory approvals, is expected to be completed in the third quarter of 2014, at which time Generation anticipates recording a pre-tax gain of approximately $332 million. The after-tax net cash proceeds of $375 million are expected to be used to finance a portion of the acquisition of PHI and for general corporate purposes.

5. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

Regulatory and Legislative Proceedings (Exelon, Generation, ComEd, PECO and BGE)

Except for the matters noted below, the disclosures set forth in Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K appropriately represent, in all material respects, the current status of regulatory and legislative proceedings of the Registrants. The following is an update to that discussion.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd). Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. ComEd's earned rate of return on common equity is required to be within plus or minus 50 basis points ("the collar") of the target rate of return determined as the annual average rate on 30-year treasury notes plus 580 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on distribution revenue. In addition, ComEd's target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program. ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement

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(Dollars in millions, except per share data, unless otherwise noted)

expected to be approved by the ICC for that year's reconciliation. As of June 30, 2014, and December 31, 2013, ComEd had recorded a net regulatory asset associated with the distribution formula rate of $439 million and $463 million, respectively. The regulatory asset associated with the distribution true-up will be amortized as the associated amounts are recovered through rates.

On April 16, 2014, ComEd filed its annual distribution formula rate update with the ICC. The filing establishes the revenue requirement used to set the rates that will take effect in January 2015 after the ICC's review and approval, which is due by December 2014. The revenue requirement requested is based on 2013 actual costs plus projected 2014 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2013 to the actual costs incurred that year. ComEd's 2014 filing request includes a total increase to the net revenue requirement of $269 million, reflecting an increase of $174 million for the initial revenue requirement for 2014 and an increase of $95 million related to the annual reconciliation for 2013. The revenue requirement for 2014 provides for a weighted average debt and equity return on distribution rate base of 7.06% inclusive of an allowed return on common equity of 9.25%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2013 provided for a weighted average debt and equity return on distribution rate base of 7.04% inclusive of an allowed return on common equity of 9.20%, reflecting the average rate on 30-year treasury notes plus 580 basis points less a performance metrics penalty of 5 basis points.

EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. Participating utilities are required to file an annual update on their AMI implementation progress. On April 1, 2014, ComEd filed an annual progress report on its AMI Implementation Plan with the ICC. The ICC ruled that no investigation would be opened in regards to that April filing. In March, 2014, ComEd filed a petition with the ICC for approval to accelerate the deployment of AMI meters. On June 11, 2014, the ICC approved ComEd's accelerated deployment plan which allows for the installation of more than four million smart meters throughout ComEd's service territory by 2018, three years in advance of the originally scheduled 2021 completion date. To date, nearly 350,000 smart meters have been installed in the Chicago area.

Appeal of the 2012 Formula Rate Tariff (Exelon and ComEd) . On April 30, 2012, ComEd filed its annual distribution formula rate update. On December 20, 2012, the ICC issued its final order, which increased the revenue requirement by $73 million, in conformity with the formula rate structure provided in the ICC's May 2012 and Rehearing Orders. The $73 million reflected an increase of $80 million for the initial revenue requirement for 2012 and a decrease of $7 million for the annual reconciliation for 2011. The rate increase was set using an allowed return on capital of 7.54% (inclusive of an allowed return on common equity of 9.81%). The rates took effect in January 2013. ComEd and intervenors requested a rehearing on specific issues, which was denied by the ICC. ComEd and intervenors also filed appeals with the Illinois Appellate Court.

On June 30, 2014, the Illinois Appellate Court issued its opinion in the Appeal of the 2012 Formula Rate Tariff. Two of the three issues appealed (billing determinants and the use of certain allocators) were the same issues previously rejected by the Court in the Appeal of Initial Formula Rate Tariff (see Appeal of Initial Formula Rate Tariff discussed below). The Court re-affirmed the ICC's order and rejected ComEd's arguments. However, on the third issue (rate case expenses), the Court allowed for the possibility of future recovery. The Court's opinion has no accounting impact as ComEd recorded the distribution formula regulatory asset consistent with the ICC's final Order.

Appeal of Initial Formula Rate Tariff (Exelon and ComEd) . On March 26, 2014, the Illinois Appellate Court issued an opinion with respect to ComEd's appeal of the ICC's order relating to ComEd's initial formula rate tariff. The most significant financial issues under appeal related to ICC findings that were counter to the formula rate legislation and were clarified by subsequent legislation (Senate Bill 9). Therefore, only a subset of

the issues originally appealed remained. The Court found against ComEd on each of the remaining issues: compensation related adjustments, billing determinants and the use of certain allocators. The Court's opinion has no accounting impact as ComEd recorded the distribution formula regulatory asset consistent with the ICC's final Order.

ComEd has asked the Illinois Supreme Court to hear the issue of allocation between State and Federal regulatory jurisdictions. On June 4, 2014, ComEd filed a Petition for Leave to Appeal with the Illinois Supreme Court solely on the issue of allocation between FERC and ICC jurisdictional costs. On July 2, the ICC filed its Answer to the Petition, arguing that Supreme Court review is not necessary or appropriate. Under the rules, ComEd is not allowed to reply to the ICC filing. There is no set time by which the Court must decide rule on the Petition. ComEd cannot predict whether the Court will grant the appeal, or if it does, the ultimate outcome.

Advanced Metering Program Proceeding (Exelon and ComEd). As part of ComEd's 2007 electric distribution rate case, the ICC approved recovery of costs associated with ComEd's System Modernization Program (Rider SMP) for the limited purpose of implementing a pilot program for AMI. In October 2009, the ICC approved ComEd's AMI pilot program and associated rider (Rider AMP). ComEd collected approximately $24 million under Rider AMP and had no collections under Rider SMP through June 30, 2014. In ComEd's 2010 electric distribution rate case, the ICC approved ComEd's transfer of certain other costs from recovery under Rider AMP to recovery through electric distribution rates.

Several parties, including the Illinois Attorney General, appealed the ICC's orders on Rider SMP and Rider AMP. The Illinois Appellate Court reversed the ICC's approval of the cost recovery provisions of Rider SMP and Rider AMP on September 30, 2010 and March 19, 2012, respectively. In both cases, the Court ruled that the ICC's approval of the rider constituted single-issue ratemaking. ComEd filed Petitions for Leave to Appeal to the Illinois Supreme Court, which were denied.

In October 2013, the ICC opened an investigation on Rider AMP to determine if a refund is required and if so, to determine the appropriate refund amount. The ALJ presiding over the investigation requested each party provide a pre-trial memorandum describing their positions, which were submitted on April 10, 2014. The ICC Staff and the Illinois Attorney General proposed a refund of $14.6 million, representing the amount they claim was collected under Rider AMP since September 30, 2010, the date the Illinois Appellate Court reversed the ICC's approval of the cost recovery provisions of Rider SMP. ComEd believes no refund is appropriate and that any refund obligation associated with Rider AMP should be prospective from no earlier than the date of the Illinois Appellate Court's order on Rider AMP, or March 19, 2012, which would represent a refund of approximately $0.4 million. During the second quarter of 2014, ComEd reached a tentative proposed agreement to jointly resolve the disputed refund claim. Any joint agreement must ultimately be approved by the ICC through its investigation. At June 30, 2014, ComEd recorded a regulatory liability of approximately $9 million based on its assessment of the likely outcome of the matter. ComEd cannot predict the ultimate outcome of the ICC's investigation and therefore, actual refunds, if any, may differ from the estimated liability recorded at June 30, 2014.

Grand Prairie Gateway Transmission Line (ComEd). On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 57-mile, overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. Numerous stakeholders are participating in the proceeding and ComEd expects the ICC to rule on its request by October 27, 2014. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base.

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Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, as a result of the Illinois Settlement Legislation, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. On December 18, 2013, the ICC approved the IPA's procurement plan covering the period June 2014 through May 2019.

The Illinois Settlement Legislation requires ComEd to purchase an increasing percentage of the electricity for customer deliveries from renewable energy resources. Purchases by customers of electricity from competitive generation suppliers, whether as a result of the customers' own actions or as a result of municipal aggregation, are not included in this calculation and have the effect of reducing ComEd's purchase obligation. ComEd entered into several 20-year contracts with unaffiliated suppliers in December 2010 regarding the procurement of long-term renewable energy and associated RECs in order to meet its obligations under the state's RPS. Under the Illinois Settlement Legislation, all associated costs are recoverable from customers. The ICC did not require the acquisition of additional renewable resources for the period June 2014 through May 2015 due to ComEd expecting to exceed the renewable cost cap.

The IPA's 2014-2019 plan provides for two separate energy procurements during 2014 to address potential fluctuations in energy demand due to customer switching between ComEd and competitive electric generation suppliers. The ICC also approved the IPA's expansion of energy efficiency programs for both ComEd and Ameren. As of June 30, 2014, ComEd has completed the first ICC-approved procurement process for a portion of its energy requirements through the periods ending May 31, 2015, 2016 and 2017. See Note 18 — Commitments and Contingencies for additional information on ComEd's energy commitments.

During 2013, the ICC approved, and directed ComEd and Ameren (the Utilities) to enter into 20-year sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The sourcing agreement provides that the Utilities will pay FutureGen's contract prices, which are set annually pursuant to a formula rate. The contract prices are based on the difference between the costs of the facility and the revenues FutureGen receives from selling capacity and energy from the unit into the MISO or other markets, as well as any other revenue FutureGen receives from the operation of the facility. The order also directs the Utilities to recover (or pass along) these costs from the Utilities' distribution system customers, regardless of whether they purchase electricity from the utility or from competitive electric generation suppliers. In February 2013, ComEd filed an appeal with the Illinois Appellate Court questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers. On July 22, 2014, the Illinois Appellate Court issued its ruling re-affirming the ICC's order requiring ComEd to enter into the contract with FutureGen and allowing ComEd to recover the associated costs from retail customers purchasing electricity from both ComEd and competitive electric generation suppliers. ComEd is assessing the Court's order and is in process of determining the appropriate course of action.

On August 22, 2013, the Utilities executed the sourcing agreement with FutureGen in accordance with the ICC order. However, in the event the order is reversed as a result of the appeal, ComEd's obligations under the sourcing agreement would be suspended. In June 2014, ComEd filed a petition with the ICC seeking approval of a tariff allowing ComEd to recover its costs associated with the FutureGen contract from all of its delivery service customers. An order approving that tariff is expected before the end of 2014. Depending on the ultimate outcome of the outstanding appeals, and petitions, the eventual market conditions and the cost of the facility, the sourcing agreement could have a material adverse impact on Exelon's and ComEd's cash flows and financial positions.

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Pennsylvania Regulatory Matters

Pennsylvania Procurement Proceedings (Exelon and PECO). On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO's second DSP Program, which was filed with the PAPUC in January 2012. The program, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129.

In the second DSP Program, PECO is procuring electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes is served through competitively procured fixed price, full requirements contracts of two years or less. For the large commercial and industrial class load, PECO has competitively procured contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in June 2013. In September 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in December 2013. In January 2014, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small, medium, and large commercial classes that began in June 2014. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Statement of Operations and Comprehensive Income.

In addition, the second DSP Program includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to submit a plan to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs beginning April 2014. On May 1, 2013, PECO filed its CAP Shopping Plan with the PAPUC. By Order entered on January 24, 2014, the PAPUC approved PECO's plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court, claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On March 28, 2014, the Commonwealth Court issued the requested stay, pending a full review of the appeal. Pending the Commonwealth Court's review, PECO will not implement CAP Shopping. The Commonwealth Court's decision is expected in late 2014.

On March 10, 2014, PECO filed its third DSP Program with the PAPUC. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. A PAPUC ruling is expected in late 2014.

Smart Meter and Smart Grid Investments (Exelon and PECO). Pursuant to Act 129 and the follow-on Implementation Order of 2009, in April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million smart meters and an AMI communication network by 2020. The first phase of PECO's SMPIP, which was completed on June 19, 2013, included the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC which was approved without modification on August 15, 2013. The Joint Petition for Settlement supports all material aspects of PECO's universal deployment plan, including cost recovery, excluding certain amounts discussed below. Universal deployment is the second phase of PECO's SMPIP, under which PECO will deploy substantially all of the 1.6 million smart meters on an accelerated basis by the end of 2014. In total, PECO currently expects to spend up to $595 million, excluding the cost of the original meters (as further described below), on its smart meter infrastructure and approximately $120 million on smart grid investments through 2014 of which $200 million will be funded by SGIG as discussed

below. As of June 30, 2014, PECO has spent $480 million and $119 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO's existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of June 30, 2014, PECO has received $198 million, including $4 million for sub-recipients, of the $200 million in reimbursements. PECO's outstanding receivable from the DOE for reimbursable costs was $2 million as of June 30, 2014, which has been recorded in Other accounts receivable, net on Exelon's and PECO's Consolidated Balance Sheets.

On August 15, 2012, PECO suspended installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO has replaced the previously installed meters with an alternative vendor's meters. PECO is moving forward with the alternative meters during universal deployment and continues to evaluate meters from several vendors and may use more than one meter vendor during universal deployment.

Following PECO's decision, as of October 9, 2012, PECO will no longer use the original smart meters. For the meters that will no longer be used, the accounting guidance requires that any difference between the carrying value and net realizable value be recognized in the current period's earnings, before considering potential regulatory recovery. The cost of the original meters, including installation and removal costs, owned by PECO was approximately $17 million, net of approximately $16 million of reimbursements from the DOE and approximately $2 million of depreciation. PECO requested and received approval from the DOE that the original meters continue to be allowable costs and that any settlement with the vendor will not be considered project income. In addition, PECO remains eligible for the full $200 million in SGIG funds. On August 15, 2013, PECO entered into an agreement with the original vendor, which was part of the final agreement discussed below, under which PECO transferred the original uninstalled meters to the vendor and received $12 million in return. On January 23, 2014, PECO entered a final agreement with the vendor pursuant to which PECO will be reimbursed for amounts incurred for the original meters and related installation and removal costs, via cash payments and rebates on future purchases of licenses, goods and services primarily through 2017. PECO previously had intended to seek regulatory rate recovery in a future filing with the PAPUC of amounts not recovered from the vendor. As PECO believed such costs were probable of rate recovery based on applicable case law and past precedent on reasonably and prudently incurred costs, a regulatory asset was established at the time of the removals. As of December 31, 2013, $5 million was recorded on Exelon's and PECO's Consolidated Balance Sheets. Pursuant to the January 23, 2014, vendor agreement, PECO reclassified the regulatory asset balance as a receivable, which was fully collected as of June 30, 2014, with no gain or loss impacts on future results of operations.

Energy Efficiency Programs (Exelon and PECO). PECO's PAPUC-approved Phase I EE&C Plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I Plan set forth how PECO would meet the required reduction targets established by Act 129's EE&C provisions, which included a 3% reduction in electric consumption in PECO's service territory and a 4.5% reduction in PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013.

The peak demand period ended on September 30, 2012 and PECO filed its final compliance report on Phase 1 targets with the PAPUC on November 15, 2013. On March 20, 2014, the PAPUC issued its final report stating that PECO was in full compliance with all Phase I targets.

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On November 14, 2013, the PAPUC issued a Tentative Order on Act 129 demand reduction programs which seeks comments on a proposed demand response program methodology for future Act 129 demand reduction programs as well as demand response potential and wholesale prices suppression studies. In its February 20, 2014 Final Order, the PAPUC stated that it does not expect to make a decision as to whether it will prescribe additional demand response obligations until 2015. Any decision reached would affect PECO's EE&C Plan subsequent to its Phase II Plan.

On February 28, 2014, PECO filed a Petition for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers from June 1, 2014 to May 31, 2016. PECO proposed to fund the estimated $10 million annual costs of the program by modifying incentive levels for other Phase II programs. The costs of the DLC program will be recovered through PECO's Energy Efficiency Program Charge along with other Phase II Plan costs. In an April 23, 2014 Tentative Order, the PAPUC granted PECO's Petition. The Order became final on May 5, 2014.

Pennsylvania Retail Electricity Market (Exelon and PECO). The extreme weather experienced in early 2014 resulted in increased commodity costs causing certain shopping customers to receive unexpectedly high utility bills. In response to a significant number of customer complaints throughout Pennsylvania, on April 3, 2014, the PAPUC unanimously voted to adopt two rulemaking orders to address the issue. The first rulemaking order requires electric generation suppliers to provide more consumer education regarding their contract. The second rulemaking order requires electric distribution companies to enable customers to switch suppliers within three business days (known as accelerated switching). The improved customer education and accelerated switching are to be in place within 30 days and six months of approval of the orders, respectively. The Independent Regulatory Review Commission granted approval of the orders on May 22, 2014. The orders became final on June 14, 2014.

Maryland Regulatory Matters

2014 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 2, 2014, BGE filed an application for increases of $118 million and $68 million to its electric and gas base rates, respectively, with the MDPSC. The requested rates of return on equity in the application were 10.65% and 10.55% for electric and gas distribution, respectively. The new electric and gas distribution base rates are expected to take effect in late January 2015. BGE cannot predict the outcome of this proceeding or how much of the requested increases the MDPSC will approve.

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, BGE filed an application for increases of $101 million and $30 million to its electric and gas base rates, respectively, with the MDPSC. The requested rates of return on equity in the application were 10.50% and 10.35% for electric and gas distribution, respectively. In addition to these requested rate increases, BGE's application also included a request for recovery of incremental capital expenditures and operating costs associated with BGE's proposed short-term reliability improvement plan (the "ERI initiative") in response to a MDPSC order through a surcharge separate from base rates. On August 23, 2013, BGE filed an update to its rate request which altered the requested increase to electric base rates from $101 million to $83 million and the requested increase to gas base rates from $30 million to $24 million. On December 13, 2013, the MDPSC issued an order in BGE's 2013 electric and natural gas distribution rate case for increases in annual distribution service revenue of $34 million and $12 million, respectively. The electric distribution rate increase was set using an allowed return on equity of 9.75% and the gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved electric and natural gas distribution rates became effective for services rendered on or after December 13, 2013. As part of its December 13, 2013 decision granting BGE increases for its gas and electric distribution rates, the MDPSC also authorized BGE to recover through a surcharge mechanism costs associated with five ERI initiative

programs designed to accelerate electric reliability improvements. Such a decision, however, was premised upon the condition that the MDPSC approve specific projects scheduled for each year of the five-year program in advance of cost recovery through the surcharge mechanism. On March 31, 2014, after reviewing comments filed by the parties and conducting a hearing on the matter, the MDPSC approved all but one project proposed for completion in 2014 as part of the ERI initiative. As a result of the MDPSC's decision, BGE estimates 2014 capital and operating and maintenance costs associated with the ERI initiative of $14.8 million and a revenue requirement of $1.4 million. The ERI initiative surcharge became effective June 1, 2014. BGE is required to file an update on the 2014 work plan and reliability performance information for the specific projects, along with its work plan and cost estimates for 2015, on or before November 1, 2014.

In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE's 2013 electric and gas distribution rate cases. The nature of the appeal will not be known until further pleadings are filed by the residential consumer advocate. BGE cannot predict the outcome of this appeal.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million of which $200 million has been recovered through a grant from the DOE. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of June 30, 2014 and December 31, 2013, BGE recorded a regulatory asset of $94 million and $66 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. Additionally, the MDPSC has determined that the cost recovery for the non-AMI meters that BGE retires will be considered in a future depreciation proceeding.

On February 26, 2014, the MDPSC issued an Order authorizing BGE to impose a $75 upfront fee and an $11 recurring fee to customers electing to opt-out, effective the later of the first full billing cycle following July 1, 2014, or the AMI installation date in a customer's community. The fees authorized by the order will be reviewed after an initial 12 to 18 month period. The ultimate impact of opt-out could affect BGE's ability to demonstrate cost-effectiveness of the advanced metering system.

Overall, BGE continues to believe the recovery of smart grid initiative costs in future rates is probable as BGE expects to be able to demonstrate that the program benefits exceed costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE) . In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law, which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be included in gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and

surcharge. On March 26, 2014, the Maryland PSC approved as filed BGE's proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge that became effective April 1, 2014. BGE will defer the difference between the surcharge revenues and program costs as a regulated asset or liability, which was immaterial to Exelon and BGE as of June 30, 2014.

In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE's infrastructure replacement plan. The residential consumer advocate filed its related legal memorandum on July 7, 2014, claiming that the MDPSC did not apply the appropriate consideration in approving BGE's infrastructure replacement plan and associated surcharge. BGE has until August 7, 2014 to submit a response, and a hearing has been scheduled for September 5, 2014. BGE cannot predict the outcome of this appeal.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd's and BGE's transmission rates are each established based on a FERC-approved formula. ComEd and BGE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd's and BGE's best estimate of the revenue requirement expected to be approved by the FERC for that year's reconciliation. As of June 30, 2014, and December 31, 2013, ComEd had recorded a net regulatory asset associated with the transmission formula rate of $10 million and $17 million, respectively, and BGE had recorded a net regulatory asset associated with the transmission formula rate of $4 million and a net regulatory liability of $0 million, respectively. The regulatory asset associated with the transmission true-up will be amortized as the associated amounts are recovered through rates.

On April 16, 2014, ComEd filed its annual formula rate update with the FERC. The filing establishes the revenue requirement used to set rates that will take effect in June 2014, subject to review by the FERC and other parties, which is due by November 2014. The revenue requirement is based on 2013 actual costs plus forecasted 2014 capital additions as well as an annual reconciliation of the revenue requirement in effect starting in June 2013 to the actual cost incurred in 2013. The update resulted in a revenue requirement of $524 million plus an $11 million adjustment related to the reconciliation of 2013 actual costs for a total revenue requirement of $535 million. This compares to the 2013 revenue requirement of $488 million plus a $25 million adjustment related to the reconciliation of 2012 actual costs for a total revenue requirement of $513 million. The increase in the revenue requirement was primarily driven by increased capital investment and higher operating and maintenance costs.

ComEd's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.62%, inclusive of an allowed return on common equity of 11.50%, a decrease from the 8.70% average debt and equity return previously authorized. As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%.

On April 28, 2014, BGE filed its annual formula rate update with the FERC. The filings established the revenue requirement used to set rates that took effect in June 2014, subject to review by the FERC and other parties, which is due by October 2014. The revenue requirement is based on 2013 actual costs plus forecasted 2014 capital additions as well as an annual reconciliation of the revenue requirement in effect starting in June 2013 to the actual cost incurred in 2013. The update resulted in a revenue requirement of $167 million plus a $4 million adjustment related to the reconciliation of 2013 actual costs for a net revenue requirement of $171 million. This compares to the 2013 revenue requirement of $158 million offset by a $1 million reduction related

to the reconciliation of 2012 actual costs for a net revenue requirement of $157 million. The increase in the revenue requirement is primarily driven by higher depreciation expense and an increased level of return on investment associated with a higher equity ratio and increased rate base.

BGE's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.53%, an increase from the 8.35% average debt and equity return previously authorized. As part of the FERC-approved settlement of BGE's 2005 transmission rate case in 2006, the rate of return on common equity for BGE's electric transmission business for new transmission projects placed in service on and after January 1, 2006 is 11.3%, inclusive of a 50 basis point incentive for participating in PJM.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the PHI companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) for most investments included in its rate base and 11.3% for the remaining transmission investment (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the revenues subject to refund are limited to a fifteen month period, and the earliest date from which the base return on equity could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint. On June 19, 2014, FERC issued an order in another case involving New England Transmission Owners (NETOs), changing its methodology to determine ROE rates for public utilities. The result was a reduction in the NETO's ROE from 11.14% to 10.57%, with a possible further adjustment in either direction based on additional paper hearing submissions. On July 21, 2014, the NETOs filed a Request for Rehearing and Clarification with FERC of the June 19, 2014 order. Among other things, the NETOs assert that the 11.14% is reasonable based on the new methodology. As of June 30, 2014, BGE believes it is probable that BGE's base ROE rate will be subject to the revised methodology and may result in a potential refund to customers of transmission revenue for a maximum fifteen month period. In evaluating FERC's revised methodology, management believes it is reasonably possible no refunds will be required for BGE, and as such, no refund liability has been recorded as of June 30, 2014. If FERC were to order a reduction of BGE's base return on equity to 8.7% as sought in the complaint (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result would be a refund to customers of approximately $13 million, as well as an estimated ongoing annual reduction in revenues of approximately $10 million.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, that court issued its decision affirming FERC's order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On March 30, 2012, FERC issued an order on remand affirming the cost allocation in its April 2007 order. On March 22, 2013, FERC issued an order denying rehearing and made it clear

that the cost allocation at issue concerns only projects approved prior to February 1, 2013. A number of entities have filed appeals of the FERC orders. On June 25, 2014, the U.S. Court of Appeals for the Seventh Circuit issued a decision once again remanding to FERC the cost allocation of new facilities 500 kV and above. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent any rate design changes are retroactive to periods prior to January 1, 2011, there may be an impact on PECO's results of operations. BGE anticipates that all impacts of any rate design changes effective after the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE's results of operations, cash flows or financial position.

PJM Minimum Offer Price Rule (Exelon and Generation). PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The FERC orders approving the MOPR were upheld by the United States Court of Appeals for the Third Circuit in February 2014.

Exelon continues to work with PJM stakeholders and through the FERC process to implement several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts and capacity market speculators) cannot inappropriately affect capacity auction prices in PJM.

Demand Response Resource Order (Exelon, Generation, ComEd, PECO, BGE). On May 23, 2014, the D.C. Circuit Court issued an opinion vacating the FERC Order No. 745 ("D.C. Circuit Decision"). Order No. 745 established uniform compensation levels for demand response resources that participate in the day ahead and real-time wholesale energy markets. Under Order No. 745, buyers in ISO and RTO markets were required to pay demand response resources the full Locational Marginal Price when the demand response replaced a generation resource and was cost-effective.

In addition to invalidating the compensation structure established by Order No. 745, the D.C. Circuit Court, in broad language, explained that demand response is part of the retail market and FERC is restricted from regulating retail markets. The full implication of the D.C. Circuit Decision for both energy and capacity markets regulated by FERC is not yet known and will depend on how FERC and the RTOs and ISOs implement the decision. In addition, on July 7, 2014, FERC and several other parties sought rehearing of the D.C. Circuit Decision. Therefore, FERC will not be required to implement the D.C. Circuit Decision until at the earliest a determination is made on the rehearing request. If rehearing is denied, FERC or other parties will have an opportunity to appeal the decision to the United States Supreme Court. The final outcome of this litigation is therefore not expected for several months. Nonetheless, the final decision and its implementation by FERC and the RTOs and ISOs, could be material to Exelon, Generation, ComEd, PECO and BGE's results of operations and cash flows.

Reliability Pricing Model (Exelon, Generation and BGE). PJM's RPM Base Residual Auctions take place approximately 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2018 occurred in May 2014.

FERC Deficiency Letter Related to New England Capacity Market Results (Exelon and Generation). Each year, ISO New England, Inc. (ISO-NE) files the results of its annual capacity auction at the

FERC which is required to include documentation regarding the competitiveness of the auction. Consistent with this requirement, on February 28, 2014, ISO-NE filed the results of its eighth capacity auction (covering the June 1, 2017 through May 30, 2018 delivery period). On June 27, 2014, the FERC issued a letter to ISO-NE noting that ISO-NE's February 28, 2014 filing is deficient and that ISO-NE must file additional information before the FERC can process the filing. ISO-NE has 30 days to file the information and then FERC will determine how to proceed. Exelon cannot predict when the FERC will accept the capacity auction results for filing or what further action FERC may take concerning the results of that auction, but any FERC action could be material to Exelon's expected revenues from the capacity auction.

License Renewals (Exelon and Generation). On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively. In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. The temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear plants for up to 60 years beyond the original and renewed licensed operating life of the plants and that licensing renewal decisions do not require discussion of the environmental impact of spent fuel stored on site. In August 2012, the NRC placed a hold on issuing new or renewed operating licenses that depend on the temporary storage rule until the court's decision is addressed. In September 2012, the NRC directed NRC Staff to revise the temporary storage rule which is now not expected until October 3, 2014. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

On May 29, 2013, Generation submitted applications to the NRC to extend the operating licenses of Byron Units 1 and 2 and Braidwood Units 1 and 2 by 20 years. The current operating licenses for Byron Units 1 and 2 expire in 2024 and 2026, respectively. The current operating licenses for Braidwood Units 1 and 2 expire in 2026 and 2027, respectively. Generation does not expect the NRC to issue license renewals for Byron and Braidwood until 2015 at the earliest.

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively.

Generation is working with stakeholders to resolve water quality licensing issues with the MDE for Conowingo, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On January 30, 2014, Exelon filed a water quality certification application pursuant to Section 401 of the CWA with MDE for Conowingo, addressing these and other issues, although Generation cannot currently predict the conditions that ultimately may be imposed. Resolution of these issues relating to Conowingo may have a material effect on Generation's results of operations and financial position through an increase in capital expenditures and operating costs.

On June 3, 2014, PA DEP issued its water quality certificate for Muddy Run, which is a necessary step in the FERC licensing process and included certain commitments made by Generation. On July 3, 2014, PPL Holtwood, LLC, the owner of the next upstream dam from Muddy Run, filed an appeal of PA DEP's issuance of its water quality certificate. The financial impact associated with these commitments is estimated to be in the range of $25 million to $35 million, and will include both capital expenditures and operating expenses, primarily relating to fish passage and habitat improvement projects.

Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run's current license on August 31, 2014, and the expiration of Conowingo's

license on September 1, 2014. However, the stations would continue to operate under annual licenses until FERC takes action on the 46-year license applications. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. As of June 30, 2014, $36 million of direct costs associated with licensing efforts have been capitalized.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE each prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of June 30, 2014 and December 31, 2013. For additional information on the specific regulatory assets and liabilities, refer to Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K.

June 30, 2014	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 208	$ 2,510	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	13	1,495	1	68	—	1,358	12	69
AMI programs	7	222	7	56	—	72	—	94
Under-recovered distribution service costs	219	220	219	220	—	—	—	—
Debt costs	10	51	8	49	2	2	1	8
Fair value of BGE long-term debt [a]	7	198	—	—	—	—	—	—
Fair value of BGE supply contract [b]	6	—	—	—	—	—	—	—
Severance	4	11	—	—	—	—	4	11
Asset retirement obligations	1	110	1	73	—	26	—	11
MGP remediation costs	40	196	33	165	6	30	1	1
RTO start-up costs	1	—	1	—	—	—	—	—
Under-recovered uncollectible accounts	—	70	—	70	—	—	—	—
Renewable energy	13	121	13	121	—	—	—	—
Energy and transmission programs	17	4	12	—	—	—	5[f]	4
Deferred storm costs	3	1	—	—	—	—	3	1
Electric generation-related regulatory asset	13	24	—	—	—	—	13	24
Rate stabilization deferral	73	119	—	—	—	—	73	119
Energy efficiency and demand response programs	63	148	—	—	—	—	63	148
Merger integration costs	2	7	—	—	—	—	2	7
Conservation voltage reduction	—	1	—	—	—	—	—	1
Other	32	37	9	28	21	7	1	1
Total regulatory assets	$ 732	$ 5,545	$ 304	$ 850	$ 29	$ 1,495	$ 178	$ 499

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

June 30, 2014	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Other postretirement benefits	$ 53	$ 111	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	—	2,917	—	2,427	—	490	—	—
Removal costs	107	1,449	83	1,248	—	—	24	201
Energy efficiency and demand response programs	14	2	14	—	—	2	—	—
DLC Program Costs	1	9	—	—	1	9	—	—
Energy efficiency Phase 2	—	32	—	—	—	32	—	—
Electric distribution tax repairs	20	104	—	—	20	104	—	—
Gas distribution tax repairs	8	34	—	—	8	34	—	—
Energy and transmission programs	89	11	19	11	52[c]	—	18[f]	—
Over-recovered gas and electric universal service fund costs	5	—	—	—	5	—	—	—
Revenue subject to refund [d]	47	—	47	—	—	—	—	—
Over-recovered gas and electric revenue decoupling [e]	21	—	—	—	—	—	21	—
Other	3	1	1	—	2	—	—	1
Total regulatory liabilities	$ 368	$ 4,670	$ 164	$ 3,686	$ 88	$ 671	$ 63	$ 202

December 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits	$ 221	$ 2,794	$ —	$ —	$ —	$ —	$ —	$ —
Deferred income taxes	10	1,459	2	65	—	1,317	8	77
AMI programs	5	159	5	35	—	58	—	66
AMI meter events	—	5	—	—	—	5	—	—
Under-recovered distribution service costs	178	285	178	285	—	—	—	—
Debt costs	12	56	9	53	3	3	1	8
Fair value of BGE long-term debt [a]	—	219	—	—	—	—	—	—
Fair value of BGE supply contract [b]	12	—	—	—	—	—	—	—
Severance	16	12	12	—	—	—	4	12
Asset retirement obligations	1	102	1	67	—	25	—	10
MGP remediation costs	40	212	33	178	6	33	1	1
RTO start-up costs	2	—	2	—	—	—	—	—
Under-recovered uncollectible accounts	—	48	—	48	—	—	—	—
Renewable energy	17	176	17	176	—	—	—	—
Energy and transmission programs	53	—	52	—	—	—	1[f]	—
Deferred storm costs	3	3	—	—	—	—	3	3
Electric generation-related regulatory asset	13	30	—	—	—	—	13	30
Rate stabilization deferral	71	154	—	—	—	—	71	154
Energy efficiency and demand response programs	73	148	—	—	—	—	73	148
Merger integration costs	2	9	—	—	—	—	2	9
Other	31	39	18	26	8	7	4	6
Total regulatory assets	$ 760	$ 5,910	$ 329	$ 933	$ 17	$ 1,448	$ 181	$ 524

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

December 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Other postretirement benefits	$ 2	$ 43	$ —	$ —	$ —	$ —	$ —	$ —
Nuclear decommissioning	—	2,740	—	2,293	—	447	—	—
Removal costs	99	1,423	78	1,219	—	—	21	204
Energy efficiency and demand response programs	53	—	45	—	8	—	—	—
DLC Program Costs	1	10	—	—	1	10	—	—
Energy efficiency phase II	—	21	—	—	—	21	—	—
Electric distribution tax repairs	20	114	—	—	20	114	—	—
Gas distribution tax repairs	8	37	—	—	8	37		
Energy and transmission programs	78	—	9	—	58[c]	—	11[f]	—
Over-recovered gas and electric universal service fund costs	8	—	—	—	8	—	—	—
Revenue subject to refund [d]	38	—	38	—	—	—	—	—
Over-recovered electric and gas revenue decoupling [e]	16	—	—	—	—	—	16	—
Other	4	—	—	—	3	—	—	—
Total regulatory liabilities	$ 327	$ 4,388	$ 170	$ 3,512	$ 106	$ 629	$ 48	$ 204

(a) Represents the regulatory asset recorded at Exelon Corporate for the difference in the fair value of the long-term debt of BGE as of the merger date. The asset is amortized over the life of the underlying debt. See Note 10 — Debt and Credit Agreements for additional information.

(b) Represents the regulatory asset recorded at Exelon Corporate representing the fair value of BGE's supply contracts as of the close of the merger date. BGE is allowed full recovery of the costs of its electric and gas supply contracts through approved, regulated rates. The asset is amortized over a period of approximately 3 years.

(c) Includes $26 million related to the DSP program, $19 million related to the over-recovered natural gas costs under the PGC and $7 million related to over-recovered electric transmission costs as of June 30, 2014. As of December 31, 2013, includes $34 million related to the DSP program, $8 million related to the over-recovered electric transmission costs and $16 million related to the over-recovered natural gas costs under the PGC.

(d) Primarily represents the regulatory liability for revenue subject to refund recorded pursuant to the ICC's order in the 2007 Rate Case. See Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K for further information.

(e) Represents the electric and gas distribution costs recoverable from customers under BGE's decoupling mechanism. As of June 30, 2014, BGE had a regulatory liability of $3 million related to over-recovered electric revenue decoupling and $18 million related to over-recovered natural gas revenue decoupling. As of December 31, 2013, BGE had a regulatory liability of $7 million related to over-recovered electric revenue decoupling and $9 million related to over-recovered natural gas revenue decoupling.

(f) Relates to $1 million of under-recovered electric supply costs, $4 million associated with the transmission formula rate and $18 million of over-recovered natural gas supply costs as of June 30, 2014. As of December 31, 2013, includes $1 million of under-recovered electric supply costs, $0 million associated with the transmission formula rate and $11 million of over-recovered natural gas supply costs.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities' consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd and BGE purchase receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO and BGE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon's, ComEd's, PECO's and BGE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of June 30, 2014 and December 31, 2013.

As of June 30, 2014	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 270	$ 116	$ 75	$79
Allowance for uncollectible accounts [b]	(32)	(17)	(8)	(7)
Purchased receivables, net	$ 238	$ 99	$ 67	$72

As of December 31, 2013	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 263	$ 105	$ 72	$86
Allowance for uncollectible accounts [b]	(30)	(16)	(7)	(7)
Purchased receivables, net	$ 233	$ 89	$ 65	$79

(a) PECO's gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.

(b) For ComEd and BGE, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing (PORCB) tariff.

6. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation has historically had various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements, see Note 25 — Related Party Transactions of the Exelon 2013 Form 10-K.

On April 1, 2014, Generation and subsidiaries of Generation, EDF, EDF, Inc. (EDFI) (a subsidiary of EDF) and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI's rights as a member of CENG (the Integration Transaction). CENG will reimburse Generation for its direct and allocated costs for such services. As part of the arrangement, Nine Mile Point Nuclear Station, LLC, a subsidiary of CENG, also assigned to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with the co-owner. In addition, on April 1, 2014, the Power Services Agency Agreement (PSAA) was amended and extended until the permanent cessation of power generation by the CENG generation plants.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

In addition, on April 1, 2014, Generation made a $400 million loan to CENG, bearing interest at 5.25% per annum and payable out of specified available cash flows of CENG and, in any event, payable upon the settlement of the Put Option Agreement discussed below (if the put option is exercised) or payable upon the maturity date of April 1, 2034, whichever occurs first. Immediately following receipt of the proceeds of such loan, CENG made a $400 million special distribution to EDFI.

The parties also executed a Fourth Amended and Restated Operating Agreement for CENG on April 1, 2014, pursuant to which, among other things, CENG committed to make preferred distributions to Generation (after repayment of the $400 million loan and associated interest) quarterly out of specified available cash flows until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from April 1, 2014 (Preferred Distribution Rights).

Generation and EDFI also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDFI has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. The beginning of the exercise period will be accelerated if Exelon's affiliates cease to own a majority of CENG and exercise a related right to terminate the NOSA. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

On April 1, 2014, Generation also executed an Indemnity Agreement pursuant to which Generation indemnified EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity.

In addition, on April 1, 2014, Generation, EDFI, CENG and Nine Mile Point Nuclear Station, LLC entered into an Employee Matters Agreement (EMA) that provides for the transfer of CENG employees to Generation or one of its affiliates (the Generation Parties) and the assumption of the employee benefit plans and their related trusts by Exelon as the plan sponsor as of July 14, 2014. The EMA also generally requires CENG to fund the underfunded balance of the pension and other postretirement welfare benefit plans measured as of July 14, 2014 by making periodic payments to Generation. These payments will be made on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG.

As a condition to obtaining regulatory approval for the NOSA and related transactions from the NRC, Exelon executed a support agreement pursuant to which Exelon may be required under specified circumstances to provide up to $245 million of financial support to CENG (Exelon Support Agreement). The Exelon Support Agreement supersedes a previous support agreement under which Generation had agreed to provide up to $205 million of financial support for CENG. In addition, Exelon executed a Guarantee pursuant to which Exelon may be required under specified circumstances to provide up to $165 million in additional financial support for CENG. A previous support agreement executed by an affiliate of EDF remains in effect under which the EDF affiliate may be required to provide up to approximately $145 million of financial support for CENG under specified circumstances. The agreements were executed on April 1, 2014 when the NRC licenses were transferred to Generation. No liability has been recognized by Exelon for the guarantees.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. From January 1, 2014, through March 31, 2014, Generation recorded $19 million of equity in losses of unconsolidated affiliates related to its investment in CENG and recorded $17 million of

revenues from CENG. For the three and six months ended June 30, 2013, Generation recorded $19 million and $31 million, respectively, of equity in losses of unconsolidated affiliates related to its investment in CENG and $23 million and $34 million, respectively, of revenues from CENG. The book value of Generation's investment in CENG prior to the consolidation was $1.9 billion, and the book value of the AOCI related to CENG prior to consolidation was $116 million, net of taxes of $77 million.

As a result of the consolidation of CENG, there are several transactions included in Exelon's and Generation's Consolidated Financial Statements between CENG and EDF that are considered related party transactions to Generation. As further described in Note 25 — Related Party Transactions of the Exelon 2013 Form 10-K, EDF and Generation have a PPA with CENG under which they purchase 15% and 85%, respectively, of the nuclear output owned by CENG that is not sold to third parties under pre-existing PPAs. Beginning January 1, 2015 and continuing through the life of the respective plants, EDF and Generation will purchase 49.99% and 50.01%, respectively, of the nuclear output owned by CENG. Beginning April 1, 2014, sales to Generation are eliminated in consolidation. Sales to EDF of $38 million are included within Exelon's and Generation's Consolidated Statements of Operations for the three and six months ended June 30, 2014. See discussion above and Note 3 — Variable Interest Entities for additional information regarding other related party transactions, between CENG and EDF included within Exelon and Generation's financial statements.

See Note 3 — Variable Interest Entities for additional information about the Registrants VIEs.

Accounting for the Consolidation of CENG

The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's non-controlling interest in CENG at fair value on Exelon's and Generation's Consolidated Balance Sheets. As a result of the consolidation, Exelon and Generation recorded a net gain of $261 million within their respective Consolidated Statements of Operations and Comprehensive Income. This gain consists of approximately $136 million related to the step up to fair value basis of our ownership interest in CENG, and approximately $132 million related to the settlement of pre-existing transactions between CENG and Generation. The net gain on the consolidation of CENG of $261 million is net of a $7 million payment to EDF.

The fair value of CENG's assets and liabilities recorded in consolidation was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The valuations necessary to assess the fair values of certain assets and liabilities are considered preliminary as a result of the short time period between the execution of the NOSA and the end of the second quarter of 2014. The estimates of the fair value of assets and liabilities may be modified up to one year from April 1, 2014, as more information is obtained about the fair value of assets and liabilities. The principal items that are expected to be revised include the asset retirement obligation liabilities and related asset retirement costs. These items are expected to be updated with inputs from a third party engineering firm with corresponding adjustments recorded by the end of 2014. In the period of such revisions, these and any other material changes to the fair value assessments could result in adjustments to the amounts recorded upon consolidation, including the overall gain recorded by Generation. In addition, any asset or liability adjustments impacting depreciation and/or accretion expense recorded after the consolidation date would impact Generation's post-consolidation results of operations.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Generation recorded the assets and liabilities of CENG at fair value as of April 1, 2014. The following assets and liabilities of CENG were recorded within Generation's Consolidated Balance Sheets as of the date of integration:

Preliminary Fair Values	Exelon and Generation
Current assets	$ 499
Nuclear decommissioning trust fund	1,955
Property, plant and equipment	2,958
Nuclear fuel	482
Other assets	10
Total assets	5,904
Current liabilities	237
Asset retirement obligation	1,701
Pension and other employee benefit obligations	281
Unamortized energy contract liabilities	171
Other liabilities	114
Total liabilities	2,504
Total net assets	$ 3,400

Generation also recorded the fair value of the non-controlling interest on its Consolidated Balance Sheets of approximately $1.5 billion, net of the fair value of $152 million for certain specified additional distribution rights under the Operating Agreement. In addition, the non-controlling interest was further reduced by the $400 million special cash distribution to EDF.

Due to the Preferred Distribution Rights that Generation has on CENG's available cash, the earnings attributable to the non-controlling interest on the Statements of Operations and Comprehensive Income as well as the corresponding adjustment to Non-controlling interest on the Consolidated Balance Sheets will not be in proportion to Generation's and EDF's equity ownership interests. Rather, the attribution will consider Generation's Preferred Distribution Rights and allocate net income based on each owner's rights to CENG'S net assets. For the three months ended June 30, 2014, Generation reduced by $4 million the amount of Net income attributable to non-controlling interests on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. As a result of the consolidation, Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income includes CENG's incremental operating revenues of $98 million and CENG's net income, prior to any intercompany eliminations and any adjustments for non-controlling interest, of $76 million during the three and six months ended June 30, 2014.

During the three and six months ended June 30, 2014, Exelon and Generation incurred integration-related costs of $11 million and $18 million, respectively. The costs incurred are classified primarily within Operating and Maintenance Expense in Exelon's and Generation's respective Consolidated Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2014.

See Note 14 — Severance for integration-related severance costs incurred by Exelon and Generation during the three and six months ended June 30, 2014.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

7. Impairment of Long-Lived Assets (Exelon and Generation)

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the second quarter of 2014, updates to the long-term fundamental energy prices, which included a thorough evaluation of key assumptions including gas prices, load growth, plant retirements and renewable growth, suggested that the carrying value of certain merchant wind assets may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of twelve wind projects, primarily located in West Texas, were less than their respective carrying values at May 31, 2014. The fair value analysis was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result, long-lived assets held and used with a carrying amount of approximately $151 million were written down to their fair value of $65 million and a pre-tax impairment charge of $86 million was recorded during the second quarter in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Changes in the assumptions described above could potentially result in future impairments of Exelon's long-lived assets, which could be material.

Nuclear Uprate Program (Exelon and Generation)

Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted in both the first and second quarters of 2013 to cancel certain projects. During the first quarter of 2013, the Measurement Uncertainty Recapture (MUR) uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. For these cancelled projects, Generation recorded approximately $21 million to Operating and maintenance expense during the first quarter of 2013 to accrue remaining costs and reverse previously capitalized costs. During the second quarter of 2013, market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. For these cancelled projects, Generation recorded a pre-tax charge during the second quarter of 2013 to Operating and maintenance expense and Interest expense of approximately $92 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Like-Kind Exchange Transaction (Exelon)

Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in coal-fired generating station leases located in Georgia and Texas with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. See Note 11 — Income Taxes for further information. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessees to arrange for a third-party to bid on a service contract for a period following the lease term. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less

than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases.

On February 26, 2014, UII and the City Public Service Board of San Antonio, Texas (CPS) finalized an agreement to terminate the leases on the generating station located in Texas, as described above, prior to its expiration dates. As a result of the lease termination, UII received a net early termination amount of $335 million from CPS and wrote off the net investment in the CPS long-term lease of $336 million in Investments in the Consolidated Balance Sheet in the first quarter of 2014; resulting in a pre-tax loss of $1 million being reflected in Operating and maintenance expense in the Consolidated Statement of Operations and Comprehensive Income in the first quarter of 2014.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

Based on the annual reviews performed in the second quarter 2014 and 2013, the estimated residual value of Exelon's direct financing leases for the Georgia generating stations experienced other than temporary declines given reduced long-term energy and capacity price expectations. As a result, Exelon recorded a $24 million and $14 million pre-tax impairment charge in the second quarter of 2014 and 2013, respectively, for these stations. These impairment charges were recorded in Investments and Operating and maintenance expense in Exelon's Consolidated Balance Sheet and the Consolidated Statement of Operations and Comprehensive Income, respectively. Changes in the assumptions described above could potentially result in future impairments of Exelon's direct financing lease investments, which could be material.

At June 30, 2014 and December 31, 2013, the components of the net investment in long-term leases were as follows:

	June 30, 2014	December 31, 2013
Estimated residual value of leased assets	$ 685	$ 1,465
Less: unearned income	332	767
Net investment in long-term leases	$ 353	$ 698

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

8. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of June 30, 2014 and December 31, 2013:

Exelon

	June 30, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 624	$ 3	$ 621	$ —	$ 624
Long-term debt (including amounts due within one year)	20,180	1,150	19,373	1,135	21,658
Long-term debt to financing trusts	648	—	—	668	668
SNF obligation	1,021	—	814	—	814

	December 31, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 344	$ 3	$ 341	$ —	$ 344
Long-term debt (including amounts due within one year)	19,132	—	18,672	1,079	19,751
Long-term debt to financing trusts	648	—	—	631	631
SNF obligation	1,021	—	790	—	790

Generation

	June 30, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 53	$ —	$ 53	$ —	$ 53
Long-term debt (including amounts due within one year)	7,507	—	6,881	1,135	8,016
SNF obligation	1,021	—	814	—	814

	December 31, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 22	$ —	$ 22	$ —	$ 22
Long-term debt (including amounts due within one year)	7,729	—	6,586	1,062	7,648
SNF obligation	1,021	—	790	—	790

ComEd

	June 30, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 498	$ —	$ 498	$ —	$ 498
Long-term debt (including amounts due within one year)	5,708	—	6,452	—	6,452
Long-term debt to financing trust	206	—	—	211	211

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	December 31, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 184	$ —	$ 184	$ —	$ 184
Long-term debt (including amounts due within one year)	5,675	—	6,238	17	6,255
Long-term debt to financing trust	206	—	—	202	202

PECO

	June 30, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,197	$ —	$2,436	$ —	$2,436
Long-term debt to financing trusts	184	—	—	198	198

	December 31, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,197	$ —	$2,358	$ —	$2,358
Long-term debt to financing trusts	184	—	—	180	180

BGE

	June 30, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 73	$ 3	$ 70	$ —	$ 73
Long-term debt (including amounts due within one year)	1,976	—	2,206	—	2,206
Long-term debt to financing trusts	258	—	—	259	259

	December 31, 2013				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 138	$ 3	$ 135	$ —	$ 138
Long-term debt (including amounts due within one year)	2,011	—	2,148	—	2,148
Long-term debt to financing trusts	258	—	—	249	249

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2) and dividends payable (included in other current liabilities) (Level 1). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both

the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

The fair value of Generation's non-government-backed fixed rate project financing debt (Level 3) is based on market and quoted prices for its own and other project financing debt with similar risk profiles. Given the low trading volume in the project financing debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-backed fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value.

SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

Long-Term Debt to Financing Trusts. Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to access as of the reporting date. Financial assets and liabilities utilizing Level 1 inputs include active exchange-traded corporate units, equity securities and funds, certain exchange-based derivatives, and money market funds.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. Financial assets and liabilities utilizing Level 2 inputs include fixed income securities, derivatives, commingled and mutual investment funds priced at NAV per fund share and fair value hedges.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability. Financial assets and liabilities utilizing Level 3 inputs include infrequently traded securities and derivatives, and investments priced using an alternative pricing mechanism or third party valuation.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Transfers in and out of levels are recognized as of the end of the reporting period the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts. There were no transfers between Level 1 and Level 2 during the six months ended June 30, 2014 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations.

Exelon

The following tables present assets and liabilities measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2014 and December 31, 2013:

As of June 30, 2014	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 1,034	$ —	$ —	$ 1,034
Nuclear decommissioning trust fund investments				
Cash equivalents	151	66	—	217
Equity				
Individually held	2,572	—	—	2,572
Exchange traded funds	164	—	—	164
Commingled funds	—	2,529	—	2,529
Equity funds subtotal	2,736	2,529	—	5,265
Balanced funds — commingled funds	—	273	—	273
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	990	—	—	990
Debt securities issued by states of the United States and political subdivisions of the states	—	416	—	416
Debt securities issued by foreign governments	—	114	—	114
Corporate debt securities	—	2,059	181	2,240
Federal agency mortgage-backed securities	—	84	—	84
Commercial mortgage-backed securities (non-agency)	—	43	—	43
Residential mortgage-backed securities (non-agency)	—	3	—	3
Mutual funds	—	18	—	18
Commingled funds	—	325	—	325
Fixed income subtotal	990	3,062	181	4,233
Middle market lending	—	—	376	376
Private Equity	—	—	35	35
Other debt obligations	—	24	—	24
Nuclear decommissioning trust fund investments subtotal [b]	3,877	5,954	592	10,423
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	45	—	45
Equity				
Individually held	4	2	—	6
Equity funds subtotal	4	2	—	6
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	12	3	—	15
Debt securities issued by states of the United States and political subdivisions of the states	—	19	—	19
Corporate debt securities	—	172	—	172
Commingled funds	—	5	—	5
Fixed income subtotal	12	199	—	211
Middle market lending	—	—	133	133
Pledged assets for Zion Station decommissioning subtotal [c]	16	246	133	395

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of June 30, 2014	Level 1	Level 2	Level 3	Total
Rabbi trust investments [e]				
Cash equivalents	2	—	—	2
Mutual funds [d]	43	—	—	43
Rabbi trust investments subtotal	45	—	—	45
Commodity derivative assets				
Economic hedges	434	2,969	1,413	4,816
Proprietary trading	178	712	184	1,074
Effect of netting and allocation of collateral [f]	(569)	(3,119)	(1,127)	(4,815)
Commodity derivative assets subtotal	43	562	470	1,075
Interest rate and foreign currency derivative assets	24	40	—	64
Effect of netting and allocation of collateral	(21)	(7)	—	(28)
Interest rate and foreign currency derivative assets subtotal	3	33	—	36
Other investments	13	—	10	23
Total assets	5,031	6,795	1,205	13,031
Liabilities				
Commodity derivative liabilities				
Economic hedges	(434)	(2,803)	(1,465)	(4,702)
Proprietary trading	(182)	(707)	(176)	(1,065)
Effect of netting and allocation of collateral [f]	618	3,408	1,279	5,305
Commodity derivative liabilities subtotal	2	(102)	(362)	(462)
Interest rate and foreign currency derivative liabilities	(24)	(34)	—	(58)
Effect of netting and allocation of collateral	24	6	—	30
Interest rate and foreign currency derivative liabilities subtotal	—	(28)	—	(28)
Deferred compensation obligation	—	(104)	—	(104)
Total liabilities	2	(234)	(362)	(594)
Total net assets	$ 5,033	$ 6,561	$ 843	$12,437

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 1,230	$ —	$ —	$ 1,230
Nuclear decommissioning trust fund investments				
Cash equivalents	459	—	—	459
Equity				
Individually held	1,776	—	—	1,776
Exchange traded funds	115	—	—	115
Commingled funds	—	2,271	—	2,271
Equity funds subtotal	1,891	2,271	—	4,162
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	882	—	—	882
Debt securities issued by states of the United States and political subdivisions of the states	—	294	—	294
Debt securities issued by foreign governments	—	87	—	87
Corporate debt securities	—	1,753	31	1,784
Federal agency mortgage-backed securities	—	10	—	10
Commercial mortgage-backed securities (non-agency)	—	40	—	40
Residential mortgage-backed securities (non-agency)	—	7	—	7
Mutual funds	—	18	—	18
Fixed income subtotal	882	2,209	31	3,122
Middle market lending	—	—	314	314
Private Equity	—	—	5	5
Other debt obligations	—	14	—	14
Nuclear decommissioning trust fund investments subtotal [b]	3,232	4,494	350	8,076
Pledged assets for Zion decommissioning				
Cash equivalents	—	26	—	26
Equity				
Individually held	16	—	—	16
Equity funds subtotal	16	—	—	16

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	45	4	—	49
Debt securities issued by states of the United States and political subdivisions of the states	—	20	—	20
Corporate debt securities	—	227	—	227
Fixed income subtotal	45	251	—	296
Middle market lending	—	—	112	112
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal [c]	61	278	112	451
Rabbi trust investments [e]				
Cash equivalents	2	—	—	2
Mutual funds [d]	54	—	—	54
Rabbi trust investments subtotal	56	—	—	56
Commodity derivative assets				
Economic hedges	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761
Effect of netting and allocation of collateral [f]	(863)	(3,131)	(430)	(4,424)
Commodity derivative assets subtotal	(46)	766	577	1,297
Interest rate and foreign currency derivative assets	30	39	—	69
Effect of netting and allocation of collateral	(30)	(2)	—	(32)
Interest rate and foreign currency derivative assets subtotal	—	37	—	37
Other Investments	—	—	15	15
Total assets	4,533	5,575	1,054	11,162
Liabilities				
Commodity derivative liabilities				
Economic hedges	(540)	(1,890)	(590)	(3,020)
Proprietary trading	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral [f]	869	3,007	404	4,280
Commodity derivative liabilities subtotal	1	(139)	(305)	(443)
Interest rate and foreign currency derivative liabilities	(31)	(17)	—	(48)
Effect of netting and allocation of collateral	31	1	—	32
Interest rate and foreign currency derivative liabilities subtotal	—	(16)	—	(16)
Deferred compensation obligation	—	(114)	—	(114)
Total liabilities	1	(269)	(305)	(573)
Total net assets	$ 4,534	$ 5,306	$ 749	$10,589

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $14 million and $(5) million at June 30, 2014 and December 31, 2013, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $7 million at both June 30, 2014 and December 31, 2013, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) The mutual funds held by the Rabbi trusts include $42 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at June 30, 2014, and $53 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at December 31, 2013.
(e) Excludes $34 million and $32 million of the cash surrender value of life insurance investments at June 30, 2014 and December 31, 2013, respectively.
(f) Includes collateral postings to counterparties. Collateral posted to counterparties, net of collateral paid to counterparties, totaled $49 million, $289 million and $152 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2014. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $6 million, $(124) million and $(26) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2013.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2014 and 2013:

Three Months Ended June 30, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2014	$ 486	$ 137	$ 119	$ 10	$ 752
Total realized / unrealized gains (losses)					
Included in net income	2	—	(48) [a]	—	(46)
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	8	—	34	—	42
Included in payable for Zion Station decommissioning	—	4	—	—	4
Change in collateral	—	—	34	—	34
Purchases, sales, issuances and settlements					
Purchases	109	13	5	—	127
Sales	(1)	(21)	(4)	—	(26)
Settlements	(12)	—	—	—	(12)
Transfers into Level 3	—	—	(4)	—	(4)
Transfers out of Level 3	—	—	(28)	—	(28)
Balance as of June 30, 2014	$ 592	$ 133	$ 108	$ 10	$ 843
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended June 30, 2014	$ 2	$ —	$ 19	$ —	$ 21

Six Months Ended June 30, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2013	$ 350	$ 112	$ 272	$ 15	$ 749
Total realized / unrealized gains (losses)					
Included in net income	3	—	(360) [a]	—	(357)
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	11	—	59	—	70
Included in payable for Zion Station decommissioning	—	4	—	—	4
Change in collateral	—	—	178	—	178
Purchases, sales, issuances and settlements					
Purchases	249	42	15	2	308
Sales	(2)	(25)	(6)	—	(33)
Settlements	(19)	—	—	—	(19)
Transfers into Level 3	—	—	(30)	—	(30)
Transfers out of Level 3	—	—	(20)	(7)	(27)
Balance as of June 30, 2014	$ 592	$ 133	$ 108	$ 10	$ 843
The amount of total losses included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended June 30, 2014	$ 2	$ —	$ (427)	$ —	$(425)

(a) Includes the increase for the reclassification of $67 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three months ended June 30, 2014.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Three Months Ended June 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2013	$ 210	$ 104	$ 260	$ 9	$583
Total realized / unrealized gains (losses)					
Included in net income	1	—	158[a]	—	159
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	8	—	(10) [b]	—	(2)
Included in payable for Zion Station decommissioning	—	1	—	—	1
Change in collateral	—	—	10	—	10
Purchases, sales, issuances and settlements					
Purchases	35	11	13	2	61
Sales	(11)	(5)	(4)	—	(20)
Settlements	(3)	—	—	—	(3)
Transfers into Level 3	—	—	3	—	3
Transfers out of Level 3	—	—	1	—	1
Balance as of June 30, 2013	$ 240	$ 111	$ 431	$ 11	$793
The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities held for the three months ended June 30, 2013	$ 1	$ —	$ 187	$ —	$188

Six Months Ended June 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2012	$ 183	$ 89	$ 367	$ 17	$656
Total realized / unrealized gains (losses)					
Included in net income	2	—	31[a]	—	33
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	9	—	(18) [b]	—	(9)
Included in payable for Zion Station decommissioning	—	1	—	—	1
Change in collateral	—	—	43	—	43
Purchases, sales, issuances and settlements					
Purchases	67	33	8[c]	2	110
Sales	(13)	(12)	(8)	(8)	(41)
Settlements	(8)	—	—	—	(8)
Transfers into Level 3	—	—	7	—	7
Transfers out of Level 3	—	—	1	—	1
Balance as of June 30, 2013	$ 240	$ 111	$ 431	$ 11	$793
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the six months ended June 30, 2013	$ 1	$ —	$ 108	$ —	$109

(a) Includes the reclassification of $29 million and $77 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2013, respectively.
(b) Excludes decreases in fair value of $3 million and $11 million and realized losses reclassified due to settlements of $82 million and $215 million associated with Generation's financial swap contract with ComEd for the three and six months ended June 30, 2013. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(c) Includes $10 million which Generation was paid to enter into out of the money purchase contracts.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the six months ended June 30, 2014 and 2013:

	Operating Revenue	Purchased Power and Fuel	Other, net [a]
Total gains (losses) included in income for the three months ended June 30, 2014	$ (62)	$ 14	$ 2
Total gains (losses) included in income for the six months ended June 30, 2014	$ (330)	$ (30)	$ 3
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2014	$ (10)	$ 29	$ 2
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2014	$ (435)	$ 8	$ 2

	Operating Revenue	Purchased Power and Fuel	Other, net [a]
Total gains included in income for the three months ended June 30, 2013	$ 137	$ 21	$ 1
Total gains (losses) included in income for the six months ended June 30, 2013	$ (22)	$ 53	$ 2
Change in the unrealized gains relating to assets and liabilities held for the three months ended June 30, 2013	$ 156	$ 31	$ 1
Change in the unrealized gains relating to assets and liabilities held for the six months ended June 30, 2013	$ 39	$ 69	$ 1

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Generation

The following tables present assets and liabilities measured and recorded at fair value on Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2014 and December 31, 2013:

As of June 30, 2014	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 65	$ —	$ —	$ 65
Nuclear decommissioning trust fund investments				
Cash equivalents	151	66	—	217
Equity				
Individually held	2,572	—	—	2,572
Exchange traded funds	164	—	—	164
Commingled funds	—	2,529	—	2,529
Equity funds subtotal	2,736	2,529	—	5,265
Balanced funds — commingled funds	—	273	—	273
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	990	—	—	990
Debt securities issued by states of the United States and political subdivisions of the states	—	416	—	416
Debt securities issued by foreign governments	—	114	—	114
Corporate debt securities	—	2,059	181	2,240
Federal agency mortgage-backed securities	—	84	—	84
Commercial mortgage-backed securities (non-agency)	—	43	—	43
Residential mortgage-backed securities (non-agency)	—	3	—	3
Mutual funds	—	18	—	18
Commingled funds	—	325	—	325
Fixed income subtotal	990	3,062	181	4,233
Middle market lending	—	—	376	376
Private Equity	—	—	35	35
Other debt obligations	—	24	—	24
Nuclear decommissioning trust fund investments subtotal [b]	3,877	5,954	592	10,423
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	45	—	45
Equity				
Individually held	4	2	—	6
Equity funds subtotal	4	2	—	6
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	12	3	—	15
Debt securities issued by states of the United States and political subdivisions of the states	—	19	—	19
Corporate debt securities	—	172	—	172
Commingled funds	—	5	—	5
Fixed income subtotal	12	199	—	211
Middle market lending	—	—	133	133
Pledged assets for Zion Station decommissioning subtotal [c]	16	246	133	395
Rabbi trust investments [d]				
Cash equivalents	1	—	—	1
Mutual funds	14	—	—	14
Rabbi trust investments subtotal	15	—	—	15
Commodity derivative assets				
Economic hedges	434	2,969	1,413	4,816
Proprietary trading	178	712	184	1,074
Effect of netting and allocation of collateral [e]	(569)	(3,119)	(1,127)	(4,815)
Commodity derivative assets subtotal	43	562	470	1,075
Interest rate and foreign currency derivative assets	24	22	—	46
Effect of netting and allocation of collateral	(21)	(7)	—	(28)
Interest rate and foreign currency derivative assets subtotal	3	15	—	18
Other investments	13	—	10	23
Total assets	4,032	6,777	1,205	12,014

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of June 30, 2014	Level 1	Level 2	Level 3	Total
Liabilities				
Commodity derivative liabilities				
Economic hedges	(434)	(2,803)	(1,331)	(4,568)
Proprietary trading	(182)	(707)	(176)	(1,065)
Effect of netting and allocation of collateral [e]	618	3,408	1,279	5,305
Commodity derivative liabilities subtotal	2	(102)	(228)	(328)
Interest rate and foreign currency derivative liabilities	(24)	(28)	—	(52)
Effect of netting and allocation of collateral	24	6	—	30
Interest rate and foreign currency derivative liabilities subtotal	—	(22)	—	(22)
Deferred compensation obligation	—	(29)	—	(29)
Total liabilities	2	(153)	(228)	(379)
Total net assets	$ 4,034	$ 6,624	$ 977	$11,635

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 1,006	$ —	$ —	$ 1,006
Nuclear decommissioning trust fund investments				
Cash equivalents	459	—	—	459
Equity				
Individually held	1,776	—	—	1,776
Exchange traded funds	115	—	—	115
Commingled funds	—	2,271	—	2,271
Equity funds subtotal	1,891	2,271	—	4,162
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	882	—	—	882
Debt securities issued by states of the United States and political subdivisions of the states	—	294	—	294
Debt securities issued by foreign governments	—	87	—	87
Corporate debt securities	—	1,753	31	1,784
Federal agency mortgage-backed securities	—	10	—	10
Commercial mortgage-backed securities (non-agency)	—	40	—	40
Residential mortgage-backed securities (non-agency)	—	7	—	7
Mutual funds	—	18	—	18
Fixed income subtotal	882	2,209	31	3,122
Middle market lending	—	—	314	314
Private Equity	—	—	5	5
Other debt obligations	—	14	—	14
Nuclear decommissioning trust fund investments subtotal [b]	3,232	4,494	350	8,076
Pledged assets for Zion Station decommissioning				
Cash equivalents	—	26	—	26
Equity				
Individually held	16	—	—	16
Equity funds subtotal	16	—	—	16
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	45	4	—	49
Debt securities issued by states of the United States and political subdivisions of the states	—	20	—	20
Corporate debt securities	—	227	—	227
Fixed income subtotal	45	251	—	296
Middle market lending	—	—	112	112
Other debt obligations	—	1	—	1
Pledged assets for Zion Station decommissioning subtotal [c]	61	278	112	451
Rabbi trust investments [d]				
Mutual funds	13	—	—	13
Rabbi trust investments subtotal	13	—	—	13

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Commodity derivative assets				
Economic hedges	493	2,582	885	3,960
Proprietary trading	324	1,315	122	1,761
Effect of netting and allocation of collateral [e]	(863)	(3,131)	(430)	(4,424)
Commodity and foreign currency assets subtotal	(46)	766	577	1,297
Interest rate and foreign currency derivative assets	30	32	—	62
Effect of netting and allocation of collateral	(30)	(2)	—	(32)
Interest rate and foreign currency derivative assets subtotal	—	30	—	30
Other investments	—	—	15	15
Total assets	4,266	5,568	1,054	10,888
Liabilities				
Commodity derivative liabilities				
Economic hedges	(540)	(1,890)	(397)	(2,827)
Proprietary trading	(328)	(1,256)	(119)	(1,703)
Effect of netting and allocation of collateral [e]	869	3,007	404	4,280
Commodity derivative liabilities subtotal	1	(139)	(112)	(250)
Interest rate derivative liabilities	(31)	(13)	—	(44)
Effect of netting and allocation of collateral	31	1	—	32
Interest rate and foreign currency derivative liabilities	—	(12)	—	(12)
Deferred compensation obligation	—	(29)	—	(29)
Total liabilities	1	(180)	(112)	(291)
Total net assets	$ 4,267	$ 5,388	$ 942	$10,597

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net assets (liabilities) of $14 million and $(5) million at June 30, 2014 and December 31, 2013, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $7 million at both June 30, 2014 and December 31, 2013, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) Excludes $10 million of the cash surrender value of life insurance investments at both June 30, 2014 and December 31, 2013.
(e) Includes collateral postings to counterparties. Collateral posted to counterparties, net of collateral paid to counterparties, totaled $49 million, $289 million and $152 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2014. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $6 million, $(124) million and $(26) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2013.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2014 and 2013:

Three Months Ended June 30, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2014	$ 486	$ 137	$ 287	$ 10	$ 920
Total realized / unrealized gains (losses)					
Included in net income	2	—	(48) [a]	—	(46)
Included in noncurrent payables to affiliates	8	—	—	—	8
Included in payable for Zion Station decommissioning	—	4	—	—	4
Change in collateral	—	—	34	—	34
Purchases, sales, issuances and settlements					
Purchases	109	13	5	—	127
Sales	(1)	(21)	(4)	—	(26)
Settlements	(12)	—	—	—	(12)
Transfers into Level 3	—	—	(4)	—	(4)
Transfers out of Level 3	—	—	(28)	—	(28)
Balance as of June 30, 2014	$ 592	$ 133	$ 242	$ 10	$ 977
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended June 30, 2014	$ 2	$ —	$ 19	$ —	$ 21

Six Months Ended June 30, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2013	$ 350	$ 112	$ 465	$ 15	$ 942
Total realized / unrealized gains (losses)					
Included in net income	3	—	(360) [a]	—	(357)
Included in noncurrent payables to affiliates	11	—	—	—	11
Included in payable for Zion Station decommissioning	—	4	—	—	4
Change in collateral		—	178	—	178
Purchases, sales, issuances and settlements					
Purchases	249	42	15	2	308
Sales	(2)	(25)	(6)	—	(33)
Settlements	(19)	—	—	—	(19)
Transfers into Level 3	—	—	(30)	—	(30)
Transfers out of Level 3	—	—	(20)	(7)	(27)
Balance as of June 30, 2014	$ 592	$ 133	$ 242	$ 10	$ 977
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the six months ended June 30, 2014	$ 2	$ —	$ (427)	$ —	$(425)

(a) Includes an increase for the reclassification of $67 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2014, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Three Months Ended June 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of March 31, 2013	$ 210	$ 104	$ 420	$ 9	$ 743
Total realized / unrealized gains (losses)					
Included in net income	1	—	168[a][b]	—	169
Included in other comprehensive income	—	—	(95) [b]	—	(95)
Included in noncurrent payables to affiliates	8	—	—	—	8
Included in payable for Zion Station decommissioning	—	1	—	—	1
Changes in collateral	—	—	10	—	10
Purchases, sales, issuances and settlements					
Purchases	35	11	13	2	61
Sales	(11)	(5)	(4)	—	(20)
Settlements	(3)	—	—	—	(3)
Transfers into Level 3	—	—	3	—	3
Transfers out of Level 3	—	—	1	—	1
Balance as of June 30, 2013	$ 240	$ 111	$ 516	$ 11	$ 878
The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities held for the three months ended June 30, 2013	$ 1	$ —	$ 183	$ —	$ 184

Six Months Ended June 30, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2012	$ 183	$ 89	$ 660	$ 17	$ 949
Total realized / unrealized gains (losses)					
Included in net income	2	—	24[a][b]	—	26
Included in other comprehensive income	—	—	(219) [b]	—	(219)
Included in noncurrent payables to affiliates	9	—	—		9
Included in payable for Zion Station decommissioning	—	1	—	—	1
Changes in collateral	—	—	43	—	43
Purchases, sales, issuances and settlements					—
Purchases	67	33	8[c]	2	110
Sales	(13)	(12)	(8)	(8)	(41)
Settlements	(8)	—	—	—	(8)
Transfers into Level 3	—	—	7	—	7
Transfers out of Level 3	—	—	1	—	1
Balance as of June 30, 2013	$ 240	$ 111	$ 516	$ 11	$ 878
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the six months ended June 30, 2013	$ 1	$ —	$ 97	$ —	$ 98

(a) Includes the reclassification of $15 million and $73 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2013, respectively.

(b) Includes $3 million of decreases in fair value and $11 million of increases in fair value and realized losses due to settlements of $82 million and $215 million associated with Generation's financial swap contract with ComEd for the three and six months ended June 30, 2013, respectively. This position eliminates upon consolidation in Exelon's Consolidated Financial Statements.

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(c) Includes $10 million which Generation was paid to enter into out of the money purchase contracts.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the six months ended June 30, 2014 and 2013:

	Operating Revenue	Purchased Power and Fuel	Other, net [a]
Total gains (losses) included in net income for the three months ended June 30, 2014	$ (62)	$ 14	$ 2
Total losses included in net income for the six months ended June 30, 2014	$ (330)	$ (30)	$ 3
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2014	$ (10)	$ 29	$ 2
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2014	$ (435)	$ 8	$ 2

	Operating Revenue	Purchased Power and Fuel	Other, net [a]
Total gains included in net income for the three months ended June 30, 2013	$ 148	$ 20	$ 1
Total gains (losses) included in net income for the six months ended June 30, 2013	$ (28)	$ 52	$ 2
Change in the unrealized gains relating to assets and liabilities held for the three months ended June 30, 2013	$ 153	$ 30	$ 1
Change in the unrealized gains relating to assets and liabilities held for the nine months ended June 30, 2013	$ 29	$ 68	$ 1

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

ComEd

The following tables present assets and liabilities measured and recorded at fair value on ComEd's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2014 and December 31, 2013:

As of June 30, 2014	Level 1	Level 2	Level 3	Total
Assets				
Rabbi trust investments				
Mutual funds	$ 1	$ —	$ —	$ 1
Rabbi trust investments subtotal	1	—	—	1
Total assets	$ 1	$ —	$ —	$ 1
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities [a]	—	—	(134)	(134)
Total liabilities	—	(8)	(134)	(142)
Total net assets (liabilities)	$ 1	$ (8)	$(134)	$(141)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Rabbi trust investments				
Mutual funds	$ 5	$ —	$ —	$ 5
Rabbi trust investments subtotal	5	—	—	5
Total assets	5	—	—	5
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark-to-market derivative liabilities [(a)]	—	—	(193)	(193)
Total liabilities	—	(8)	(193)	(201)
Total net assets (liabilities)	$ 5	$ (8)	$(193)	$(196)

(a) The Level 3 balance includes the current and noncurrent liability of $13 million and $121 million at June 30, 2014, respectively, and $17 million and $176 million at December 31, 2013, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2014 and 2013:

Three Months Ended June 30, 2014	Mark-to-Market Derivatives
Balance as of March 31, 2014	$ (168)
Total realized / unrealized gains included in regulatory assets [(a)]	34
Balance as of June 30, 2014	$ (134)

Six Months Ended June 30, 2014	Mark-to-Market Derivatives
Balance as of December 31, 2013	$ (193)
Total realized / unrealized gains included in regulatory assets [(b)]	59
Balance as of June 30, 2014	$ (134)

(a) Includes $34 million decreases in the fair value partially offset by immaterial realized losses due to settlements recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended June 30, 2014.
(b) Includes $64 million of decreases in the fair value partially offset by realized gains due to settlements of $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the six months ended June 30, 2014.

Three Months Ended June 30, 2013	Mark-to-Market Derivatives
Balance as of March 31, 2013	$ (160)
Total realized / unrealized gains included in regulatory assets [(a)(b)]	75
Balance as of June 30, 2013	$ (85)

Six Months Ended June 30, 2013	Mark-to-Market Derivatives
Balance as of December 31, 2012	$ (293)
Total realized / unrealized gains included in regulatory assets [a][b]	208
Balance as of June 30, 2013	$ (85)

(a) Includes $3 million of increases in fair value and $11 million of decreases in fair value and realized gains due to settlements of $82 million and $215 million of associated with ComEd's financial swap contract with Generation for the three and six months ended June 30, 2013, respectively. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

(b) Includes $9 million and $20 million of increases in the fair value and realized losses due to settlements of $1 million and $4 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three and six months ended June 30, 2013, respectively.

PECO

The following tables present assets and liabilities measured and recorded at fair value on PECO's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2014 and December 31, 2013:

As of June 30, 2014	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 50	$ —	$ —	$ 50
Rabbi trust investments [a]				
Mutual funds	9	—	—	9
Rabbi trust investments subtotal	9	—	—	9
Total assets	59	—	—	59
Liabilities				
Deferred compensation obligation	—	(15)	—	(15)
Total liabilities	—	(15)	—	(15)
Total net assets (liabilities)	$ 59	$ (15)	$ —	$ 44

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 175	$ —	$ —	$175
Rabbi trust investments [a]				
Mutual funds	9	—	—	9
Rabbi trust investments subtotal	9	—	—	9
Total assets	184	—	—	184
Liabilities				
Deferred compensation obligation	—	(17)	—	(17)
Total liabilities	—	(17)	—	(17)
Total net assets (liabilities)	$ 184	$ (17)	$ —	$167

(a) Excludes $14 million of the cash surrender value of life insurance investments at both June 30, 2014 and December 31, 2013.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

PECO had no Level 3 assets or liabilities measured at fair value on a recurring basis during the six months ended June 30, 2014 and 2013.

BGE

The following tables present assets and liabilities measured and recorded at fair value on BGE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2014 and December 31, 2013:

As of June 30, 2014	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 53	$ —	$ —	$ 53
Rabbi trust investments				
Mutual funds	5	—	—	5
Rabbi trust investments subtotal	5	—	—	5
Total assets	58	—	—	58
Liabilities				
Deferred compensation obligation	—	(5)	—	(5)
Total liabilities	—	(5)	—	(5)
Total net assets (liabilities)	$ 58	$ (5)	$ —	$ 53

As of December 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 31	$ —	$ —	$ 31
Rabbi trust investments				
Mutual funds	6	—	—	6
Rabbi trust investments subtotal	6	—	—	6
Total assets	37	—	—	37
Liabilities				
Deferred compensation obligation	—	(6)	—	(6)
Total liabilities	—	(6)	—	(6)
Total net assets (liabilities)	$ 37	$ (6)	$ —	$ 31

BGE had no Level 3 assets or liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2014 and 2013.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE). The Registrants' cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds. Generation's and CENG's investment policies place limitations on the types and investment grade ratings of the securities that may be held by the trusts. These policies limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The fair values of private placement fixed income securities are determined using a third party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity, balanced and fixed income commingled funds and fixed income mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of fixed income commingled and mutual funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining equity commingled funds in which Exelon, Generation and CENG invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. Comingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities. See Note 12 — Nuclear Decommissioning for further discussion on the NDT fund investments.

Middle market lending are investments in loans or managed funds which invest in private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in middle market lending are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of June 30, 2014, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, private equity investments, and real estate investments of approximately $430 million. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The investments in the Rabbi trusts are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of mutual funds. These funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices.

Mark-to-Market Derivatives (Exelon, Generation, and ComEd) . Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' derivatives are predominately at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 9 — Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO and BGE). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd)

Mark-to-Market Derivatives (Exelon, Generation, ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Exelon Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at Exelon. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, certain transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price is generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $2.57 and $0.41 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 3. — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrant's mark-to-market derivative assets and liabilities.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 9 — Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk. The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at June 30, 2014 [c]	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Generation) [a]	$ 82	Discounted Cash Flow	Forward power price	$16 - $170(d)
			Forward gas price	$2.19 - $19.84(d)
		Option Model	Volatility percentage	8% - 260%
Mark-to-market derivatives — Proprietary trading (Generation) [a]	$ 8	Discounted Cash Flow	Forward power price	$13 - $168(d)
		Option Model	Volatility percentage	8% - 260%
Mark-to-market derivatives (ComEd)	$ (134)	Discounted Cash Flow	Forward heat rate [b]	8x - 9x
			Marketability reserve	3.5% - 8%
			Renewable factor	86% - 123%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
c) The fair values do not include cash collateral held on level three positions of $152 million as of June 30, 2014.
d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas economic hedges would be approximately $106 and $10.29, respectively, and would be approximately $93 for power proprietary trading.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Type of trade	Fair Value at December 31, 2013 [c]	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Generation) [a]	$ 488	Discounted Cash Flow	Forward power price	$8 - $176(d)
			Forward gas price	$2.98 - $16.63(d)
		Option Model	Volatility percentage	15% - 142%
Mark-to-market derivatives — Proprietary trading (Generation) [a]	$ 3	Discounted Cash Flow	Forward power price	$10 - $176(d)
		Option Model	Volatility percentage	14% - 19%
Mark-to-market derivatives (ComEd)	$ (193)	Discounted Cash Flow	Forward heat rate [b]	8x - 9x
			Marketability reserve	3.5% - 8%
			Renewable factor	84% - 128%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
c) The fair values do not include cash collateral held on level three positions of $26 million as of December 31, 2013
d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas would be approximately $100 and $5.70, respectively.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending, certain corporate debt securities, and private equity investments the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability, credit risk and relative performance.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its' Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations. For a sample of its' Level 3 investments, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

9. Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use derivative instruments to manage commodity price risk and interest rate risk related to ongoing business operations.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. The Registrants employ established policies and procedures to manage their risks associated with market fluctuations by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivative economic hedges for commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 22 — Commitments and Contingencies of the Exelon 2013 Form 10-K. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the

commodity price risk of its electric generation facilities, including power and gas sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and gas and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of June 30, 2014, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 75%-78%, and 46%-49% for 2014, 2015, and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including, Generation's sales to ComEd, PECO and BGE to serve their retail load.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts for energy and associated RECs were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved in March 2014. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 — Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts and block contracts. PECO has certain full requirements contracts and block contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation

capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2013 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2013 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE's price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. All of BGE's natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 2,629 GWhs and 5,123 GWhs for the three and six months ended June 30, 2014, respectively, and 1,995 GWhs and 3,567 for the three and six months ended June 30, 2013, respectively, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At June 30, 2014, Exelon and Generation had $1,550 million and $700 million of notional amounts of fixed-to-floating hedges outstanding, respectively, and $1,111 million and $411 million of notional amounts of floating-to-fixed hedges outstanding, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $4 million decrease in Exelon Consolidated pre-tax income for the six months ended June 30, 2014. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign currency hedges as of June 30, 2014.

	Generation					Other	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$ —	$ 2	$ 14	$ (18)	$ (2)	$ —	$ (2)
Mark-to-market derivative assets (noncurrent assets)	16	2	12	(10)	20	18	38
Total mark-to-market derivative assets	$ 16	$ 4	$ 26	$ (28)	$ 18	$ 18	$ 36
Mark-to-market derivative liabilities (current liabilities)	$ (1)	$ (4)	$ (15)	$ 19	$ (1)	$ —	$ (1)
Mark-to-market derivative liabilities (noncurrent liabilities)	(19)	(2)	(11)	11	(21)	(6)	(27)
Total mark-to-market derivative liabilities	$ (20)	$ (6)	$ (26)	$ 30	$ (22)	$ (6)	$ (28)
Total mark-to-market derivative net assets (liabilities)	$ (4)	$ (2)	$ —	$ 2	$ (4)	$ 12	$ 8

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2013:

	Generation					Other	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading [a]	Collateral and Netting [b]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$ —	$ 3	$ 15	$ (19)	$ (1)	$ —	$ (1)
Mark-to-market derivative assets (noncurrent assets)	26	3	15	(13)	31	7	38
Total mark-to-market derivative assets	$ 26	$ 6	$ 30	$ (32)	$ 30	$ 7	$ 37
Mark-to-market derivative liabilities (current liabilities)	$ (1)	$ (1)	$ (18)	$ 19	$ (1)	$ —	$ (1)
Mark-to-market derivative liabilities (noncurrent liabilities)	(10)	(1)	(13)	13	(11)	(4)	(15)
Total mark-to-market derivative liabilities	$ (11)	$ (2)	$ (31)	$ 32	$ (12)	$ (4)	$ (16)
Total mark-to-market derivative net assets (liabilities)	$ 15	$ 4	$ (1)	$ —	$ 18	$ 3	$ 21

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.
(b) Represents the netting of fair value balances with the same counterparty and any associated cash collateral.

Fair Value Hedges . For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

		Three Months Ended June 30,			
	Income Statement Location	2014	2013	2014	2013
		Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation	Interest expense [a]	$ (3)	$ (5)	$ 2	$ 2
Exelon	Interest expense	3	(6)	(3)	3

		Six Months Ended June 30,			
	Income Statement Location	2014	2013	2014	2013
		Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation	Interest expense [a]	$ (8)	$ (9)	$ 1	$ 1
Exelon	Interest expense	5	(12)	(7)	4

(a) For the three and six months ended June 30, 2014, the loss on Generation swaps included $4 million and $8 million realized in earnings, respectively, with an immaterial amount excluded from hedge effectiveness testing. For the three and six months ended June 30, 2013, the loss on Generation swaps included $4 million and $8 million realized in earnings, respectively, with an immaterial amount excluded from hedge effectiveness testing.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

During the first six months of 2014, Exelon entered into $50 million and $75 million of notional amounts of fixed-to-floating fair value hedges related to interest rate swaps, which expire in 2019 and 2020, respectively. At June 30, 2014, Exelon and Generation had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,400 million and $550 million, with unrealized gains of $33 million and $16 million, respectively. At December 31, 2013, Exelon and Generation had outstanding fixed-to-floating fair value hedges related to interest rate swaps of $1,275 million and $550 million, with unrealized gains of $26 million and $23 million, respectively. During the three and six months ended June 30, 2014, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $5 million and a $8 million gain, respectively. During the three and six months ended June 30, 2013, the impact on the results of operations as a result of ineffectiveness from fair value hedges was immaterial.

Cash Flow Hedges . In connection with the DOE guaranteed loan for the Antelope Valley project financings, as discussed in Note 13 — Debt and Credit Agreements of the Exelon 2013 Form 10-K, Generation entered into a floating-to-fixed forward starting interest rate swap with a notional amount of $485 million and a mandatory early termination date of September 30, 2014. The swap hedges approximately 75% of Generation's future interest rate exposure associated with the financing and was designated as a cash flow hedge. As such, the effective portion of the hedge is recorded in other comprehensive income within Generation's Consolidated Balance Sheets, with any ineffectiveness recorded in Generation's Consolidated Statements of Operations and Comprehensive Income. Net gains (or losses) from settlement of the hedges, to the extent effective, are amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

Every time Generation draws down on the loan, an offsetting hedge (fixed-to-floating) is executed and a portion of the cash flow hedge with a notional amount equal to the offsetting hedge, is de-designated and the related gains or losses going forward are reflected in earnings, which are largely offset by the losses or gains in the offsetting hedge.

Antelope Valley received its first loan advance on April 5, 2012, and a series of additional advances subsequently. Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $350 million, approximately 75% of the loan advance amount to offset portions of the original interest rate hedge, which are not designated as cash flow hedges. The remaining cash flow hedge has a notional amount of $135 million. At June 30, 2014, Generation's mark-to-market derivative liability relating to the interest rate swaps in connection with the loan agreement to fund Antelope Valley was $15 million.

During the third quarter of 2011, a subsidiary of Constellation entered into floating-to-fixed interest rate swaps to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Sacramento PV Energy. The swaps have a total notional amount of $27 million as of June 30, 2014 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At June 30, 2014, the subsidiary had a $2 million derivative liability related to these swaps.

During the third quarter of 2012, a subsidiary of Exelon Generation entered into a floating-to-fixed interest rate swap to manage a portion of the interest rate exposure of anticipated long-term borrowings to finance Constellation Solar Horizons. The swap has a notional amount of $26 million as of June 30, 2014 and expires in 2030. This swap is designated as a cash flow hedge. At June 30, 2014, the subsidiary had a $1 million derivative asset related to the swap.

During the first quarter of 2014, a subsidiary of Exelon Generation entered into floating-to-fixed interest rate swaps to manage a portion of the interest rate exposure with long-term borrowings to finance ExGen Renewables I, LLC. See Note 10 — Debt and Credit Agreements for additional information regarding the financing. The swaps have a notional amount of $223 million as of June 30, 2014 and expire in 2020. The swaps are designated as cash flow hedges. At June 30, 2014, the subsidiary had a $2 million derivative liability related to the swaps.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

During the first six months of 2014, Exelon entered into $400 million of floating-to-fixed interest rate hedges to refinance existing debt. The swaps are designated as cash flow hedges. At June 30, 2014, Exelon had a $6 million derivative liability related to the swaps.

During the three and six months ended June 30, 2014 and 2013, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Economic Hedges . During the second quarter of 2014, Exelon entered into $300 million of floating-to-fixed forward starting interest rate swaps to manage interest rate risks associated with anticipated future debt issuance related to the proposed merger with PHI. At June 30, 2014, Exelon had an immaterial derivative asset related to the swaps.

At June 30, 2014, Exelon and Generation had $150 million in notional amounts of fixed-to-floating interest rate swaps that are marked-to-market, with unrealized gains of $1 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the six months ended June 30, 2014 and 2013, the impact on the results of operations was immaterial.

At June 30, 2014, Generation had $257 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $121 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon, Generation, ComEd, PECO and BGE)

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation’s use of cash collateral is generally unrestricted unless Generation is downgraded below investment grade (i.e., to BB+ or Ba1). In the table below, Generation’s energy related economic hedges and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, is aggregated in the collateral and netting column. As of June 30, 2014 and December 31, 2013, $7 million of cash collateral held and $10 million of cash collateral posted, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd’s use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e., to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in a non affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of June 30, 2014:

	Generation				ComEd	Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting [a]	Subtotal [b]	Economic Hedges [c]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 3,422	$ 925	$ (3,716)	$ 631	$ —	$ 631
Mark-to-market derivative assets (noncurrent assets)	1,394	149	(1,099)	444	—	444
Total mark-to-market derivative assets	$ 4,816	$ 1,074	$ (4,815)	$ 1,075	$ —	$ 1,075
Mark-to-market derivative liabilities (current liabilities)	$ (3,354)	$ (900)	$ 4,040	$ (214)	$ (13)	$ (227)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,214)	(165)	1,265	(114)	(121)	(235)
Total mark-to-market derivative liabilities	$ (4,568)	$ (1,065)	$ 5,305	$ (328)	$ (134)	$ (462)
Total mark-to-market derivative net assets (liabilities)	$ 248	$ 9	$ 490	$ 747	$ (134)	$ 613

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $(126) million and $(56) million, respectively, and current and noncurrent liabilities are shown net of collateral of $(198) million and $(110) million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $490 million at June 30, 2014.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2013:

	Generation				ComEd	Exelon
Description	Economic Hedges	Proprietary Trading	Collateral and Netting [a]	Subtotal [b]	Economic Hedges [c]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,616	$ 1,476	$ (3,364)	$ 728	$ —	$ 728
Mark-to-market derivative assets (noncurrent assets)	1,344	285	(1,060)	569	—	569
Total mark-to-market derivative assets	$ 3,960	$ 1,761	$ (4,424)	$ 1,297	$ —	$ 1,297
Mark-to-market derivative liabilities (current liabilities)	$ (2,023)	$ (1,410)	$ 3,292	$ (141)	$ (17)	$ (158)
Mark-to-market derivative liabilities (noncurrent liabilities)	(804)	(293)	988	(109)	(176)	(285)
Total mark-to-market derivative liabilities	$ (2,827)	$ (1,703)	$ 4,280	$ (250)	$ (193)	$ (443)
Total mark-to-market derivative net assets (liabilities)	$ 1,133	$ 58	$ (144)	$ 1,047	$ (193)	$ 854

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $84 million and $72 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(12) million and $0 million, respectively. The total cash collateral received, net of cash collateral posted and offset against mark-to-market assets and liabilities was $144 million at December 31, 2013.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon and Generation). As discussed previously, effective prior to the merger with Constellation, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and is reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective changes in the fair value of these instruments through current earnings from the date of de-designation. Approximately $94 million of these net pre-tax unrealized gains within accumulated OCI are expected to be reclassified from accumulated OCI during the next twelve months by Generation. Generation expects the settlement of the majority of its cash flow hedges will occur during 2014.

The tables below provide the activity of accumulated OCI related to cash flow hedges for the three months ended June 30, 2014 and 2013, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended June 30, 2014	Income Statement Location	Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at March 31, 2014		$ 95[a]	$ 95
Effective portion of changes in fair value		—	(10)
Reclassifications from accumulated OCI to net income	Operating Revenues	(38) [b]	(38)
Accumulated OCI derivative gain at June 30, 2014		$ 57[a]	$ 47

(a) Excludes $6 million and $3 million of gains, net of taxes, related to interest rate swaps and treasury rate locks as of June 30, 2014 and March 31, 2014.

(b) Amount is net of related income tax expense of $25 million for the three months ended June 30, 2014.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Six Months Ended June 30, 2014	Income Statement Location	Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2013		$ 119[a]	$ 120
Effective portion of changes in fair value		—	(11)
Reclassifications from accumulated OCI to net income	Operating Revenues	(62) [b]	(62)
Accumulated OCI derivative gain at June 30, 2014		$ 57[a]	$ 47

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(a) Excludes $9 million of gains and $15 million of losses, net of taxes, related to interest rate swaps and treasury locks as of June 30, 2014 and December 31, 2013, respectively.
(b) Amount is net of related income tax expense of $40 million for the six months ended June 30, 2014.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended June 30, 2013	Income Statement Location	Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at March 31, 2013		$ 397[a][c]	$ 310
Effective portion of changes in fair value		—	21[d]
Reclassifications from accumulated OCI to net income	Operating Revenues	(142) [b][e]	(86)
Accumulated OCI derivative gain at June 30, 2013		$ 255[c]	$ 245

(a) Includes $58 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of March 31, 2013.
(b) Includes $58 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $11 million and $16 million of losses, net of taxes, related to interest rate swaps and treasury rate locks as of June 30, 2013 and March 31, 2013, respectively.
(d) Includes $18 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks at Generation for the three months ended June 30, 2013.
(e) Amount is net of related income tax expense of $94 million for the three months ended June 30, 2013.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Six Months Ended June 30, 2013	Income Statement Location	Energy-Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2012		$ 532[a][c]	$ 368
Effective portion of changes in fair value		—	21[d]
Reclassifications from accumulated OCI to net income	Operating Revenues	(277) [b][e]	(144)
Accumulated OCI derivative gain at June 30, 2013		$ 255[c]	$ 245

(a) Includes $133 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd, as of December 31, 2012.
(b) Includes $133 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to the settlements of the five-year financial swap contract with ComEd.
(c) Excludes $11 million of losses and $20 million of losses, net of taxes, related to interest rate swaps and treasury rate locks as of June 30, 2013 and December 31, 2012, respectively.
(d) Includes $22 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks.
(e) Amount is net of related income tax expense of $182 million for the six months ended June 30, 2013.

During the three and six months ended June 30, 2014 and 2013, Generation's former energy related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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earnings was a $63 million and a $102 pre-tax gain and a $236 million and a $459 pre-tax gain, respectively. Given that the cash flow hedges had primarily consisted of forward power sales and power swaps and did not include power and gas options or sales, the ineffectiveness of Generation's cash flow hedges was primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units.

The effect of Exelon's former energy-related cash flow hedge activity on pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $63 million and $102 million pre-tax gain for the three months ended June 30, 2014, and a $141 million and $240 million pre-tax gain for the three and six months ended June 30, 2013. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods as all energy-related cash flow hedge positions were de-designated prior to the merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps ("treasury") to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars. Exelon entered into floating-to-fixed forward starting interest rate swaps to manage interest rate risks associated with anticipated future debt issuance related to the proposed merger with PHI. For the three and six months ended June 30, 2014 and 2013, the following pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues, purchased, power and fuel expense, or interest expense. For the three and six months ended June 30, 2014 and 2013, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Generation				Intercompany Eliminations	HoldCo	Exelon
Three Months Ended June 30, 2014	Operating Revenues	Purchased Power and Fuel	Interest Expense	Total	Operating Revenues [a]	Interest Expense	Total
Change in fair value of commodity positions	$ (124)	$ 111	$ —	$(13)	$ —	$ —	$ (13)
Reclassification to realized at settlement of commodity positions	45	(42)	—	3	—	—	3
Net commodity mark-to-market gains (losses)	$ (79)	$ 69	$ —	$(10)	$ —	$ —	$ (10)
Change in fair value of treasury positions	$ (3)	$ —	$ (1)	$ (4)	$ —	$ —	$ (4)
Reclassification to realized at settlement of treasury positions	(1)	—	—	(1)	—	—	(1)
Net treasury mark-to-market gains (losses)	$ (4)	$ —	$ (1)	$ (5)	$ —	$ —	$ (5)
Net mark-to-market gains (losses)	$ (83)	$ 69	$ (1)	$(15)	$ —	$ —	$ (15)

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Six Months Ended June 30, 2014	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	Intercompany Eliminations Operating Revenues [a]	HoldCo Interest Expense	Exelon Total
Change in fair value of commodity positions	$ (975)	$ 282	$ —	$(693)	$ —	$ —	$(693)
Reclassification to realized at settlement of commodity positions	137	(183)	—	(46)	—	—	(46)
Net commodity mark-to-market gains (losses)	$ (838)	$ 99	$ —	$(739)	$ —	$ —	$(739)
Change in fair value of treasury positions	$ (4)	$ —	$ (1)	$ (5)	$ —	$ —	$ (5)
Reclassification to realized at settlementof treasury positions	(1)	—	—	(1)	—	—	(1)
Net treasury mark-to-market gains (losses)	$ (5)	$ —	$ (1)	$ (6)	$ —	$ —	$ (6)
Net mark-to-market gains (losses)	$ (843)	$ 99	$ (1)	$(745)	$ —	$ —	$(745)

Three Months Ended June 30, 2013	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	Intercompany Eliminations Operating Revenues [a]	HoldCo Interest Expense	Exelon Total
Change in fair value of commodity positions	$ 460	$ (77)	$ —	$ 383	$ (13)	$ —	$ 370
Reclassification to realized at settlement of commodity positions	44	1	—	45	3	—	48
Net commodity mark-to-market gains (losses)	$ 504	$ (76)	$ —	$ 428	$ (10)	$ —	$ 418
Change in fair value of treasury positions	$ —	$ —	$ (2)	$ (2)	$ —	$ —	$ (2)
Reclassification to realized at settlement of treasury positions	—	—	—	—	—	—	—
Net treasury mark-to-market gains (losses)	$ —	$ —	$ (2)	$ (2)	$ —	$ —	$ (2)
Net mark-to-market gains (losses)	$ 504	$ (76)	$ (2)	$ 426	$ (10)	$ —	$ 416

Six Months Ended June 30, 2013	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	Intercompany Eliminations Operating Revenues [a]	HoldCo Interest Expense	Exelon Total
Change in fair value of commodity positions	$ (26)	$ 69	$	$ 43	$ (6)	$ —	$ 37
Reclassification to realized at settlement of commodity positions	(56)	38		(18)	13	—	(5)
Net commodity mark-to-market gains (losses)	$ (82)	$ 107	$ —	$ 25	$ 7	$ —	$ 32
Change in fair value of treasury positions	$ —	$ —	$ (3)	$ (3)	$ —	$ —	$ (3)
Reclassification to realized at settlement of treasury positions	—	—	—	—	—	—	—
Net treasury mark-to-market gains (losses)	$ —	$ —	$ (3)	$ (3)	$ —	$ —	$ (3)
Net mark-to-market gains (losses)	$ (82)	$ 107	$ (3)	$ 22	$ 7	$ —	$ 29

(a) Prior to the merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value were recorded to operating revenues and eliminated in consolidation.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Proprietary Trading Activities (Exelon and Generation). For the three and six months ended June 30, 2014 and 2013, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on commodity derivative instruments entered into for proprietary trading purposes and interest rate derivative contracts to hedge risk associated with the interest rate component of underlying commodity positions. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. In the tables below, "Change in fair value" represents the change in fair value of the derivative contracts held at the reporting date. The "Reclassification to realized at settlement" represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	Three Months Ended June 30,		Six Months Ended June 30,	
		2014	2013	2014	2013
Change in fair value of commodity positions	Operating Revenues	$ 1	$ 5	$ —	$ 1
Reclassification to realized at settlement of commodity positions	Operating Revenues	(8)	(1)	(7)	5
Net commodity mark-to-market gains (losses)	Operating Revenues	$ (7)	$ 4	$ (7)	$ 6
Change in fair value of treasury positions	Operating Revenues	$ —	$ —	$ (1)	$ —
Reclassification to realized at settlement of treasury positions	Operating Revenues	1	(1)	1	(1)
Net treasury mark-to-market gains (losses)	Operating Revenues	$ 1	$ (1)	$ —	$ (1)
Net mark-to-market gains (losses)	Operating Revenues	$ (6)	$ 3	$ (7)	$ 5

Credit Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2014. The tables further delineate that exposure by credit rating of the

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counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below excludes credit risk exposure from individual retail counterparties, uranium procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of $6 million, $23 million and $36 million, respectively.

Rating as of June 30, 2014	Total Exposure Before Credit Collateral	Credit Collateral [a]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,095	$ 103	$ 992	1	$ 417
Non-investment grade	12	9	3	—	—
No external ratings					
Internally rated — investment grade	286	2	284	1	189
Internally rated — non-investment grade	21	4	17	—	—
Total	$ 1,414	$ 118	$ 1,296	2	$ 606

Net Credit Exposure by Type of Counterparty	As of June 30, 2014
Financial institutions	$ 185
Investor-owned utilities, marketers, power producers	360
Energy cooperatives and municipalities	729
Other	22
Total	$ 1,296

(a) As of June 30, 2014, credit collateral held from counterparties where Generation had credit exposure included $112 million of cash and $6 million of letters of credit.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of June 30, 2014, ComEd's net credit exposure to suppliers was approximately $2 million.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K for additional information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents PECO's net credit exposure. As of June 30, 2014, PECO had no net credit exposure with suppliers.

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PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 — Regulatory Matters for additional information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of June 30, 2014, PECO had credit exposure of $6 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 — Regulatory Matters for additional information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents BGE's net credit exposure. The seller's credit exposure is calculated each business day. As of June 30, 2014, BGE had a net credit exposure of $38 million to suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At June 30, 2014, BGE had credit exposure of $1 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third party suppliers.

Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e., NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested

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will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Feature	June 30, 2014	December 31, 2013
Gross Fair Value of Derivative Contracts Containing this Feature [(a)]	$(1,102)	$ (1,056)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements [(b)]	825	846
Net Fair Value of Derivative Contracts Containing This Feature [(c)]	$ (277)	$ (210)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk related contingent features ignoring the effects of master netting agreements.
(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of $623 million and letters of credit posted of $466 million and cash collateral held of $124 million and letters of credit held of $14 million as of June 30, 2014 for counterparties with derivative positions. Generation had cash collateral posted of $72 million and letters of credit posted of $364 million and cash collateral held of $206 million and letters of credit held of $34 million at December 31, 2013 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of $2.0 billion as of June 30, 2014 and December 31, 2013. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of June 30, 2014, Generation's swaps were in a liability position and Exelon's swaps were in an asset position, with a fair value of $(4) million and $8 million, respectively.

See Note 24 — Segment Information of the Exelon 2013 Form 10-K for further information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd's standard block energy contracts, collateral postings are

one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of June 30, 2014, ComEd held approximately $2 million from suppliers for the purpose of collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of June 30, 2014, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K for additional information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of June 30, 2014, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of June 30, 2014, PECO could have been required to post approximately $26 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of June 30, 2014, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of June 30, 2014, BGE could have been required to post approximately $73 million of collateral to its counterparties.

10. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool.

The Registrants had the following amounts of commercial paper borrowings outstanding as of June 30, 2014 and December 31, 2013:

Commercial Paper Borrowings	June 30, 2014	December 31, 2013
Exelon Corporate	$ —	$ —
Generation	—	—
ComEd	498	184
PECO	—	—
BGE	70	135

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Credit Facilities

Exelon had bank lines of credit under committed credit facilities at June 30, 2014 for short-term financial needs, as follows:

Type of Credit Facility	Amount [a] (In billions)	Expiration Dates	Capacity Type
Exelon Corporate			
Syndicated Revolver [b]	$ 0.5	May 2019	Letters of credit and cash
Generation			
Syndicated Revolver	5.1	May 2019	Letters of credit and cash
Syndicated Revolver	0.2	August 2018	Letters of credit and cash
Bilateral	0.3	December 2015 and March 2016	Letters of credit and cash
Bilateral	0.1	January 2015	Letters of credit
Bilateral	0.1	October 2014	Letters of credit and cash
ComEd			
Syndicated Revolver	1.0	March 2019	Letters of credit and cash
PECO			
Syndicated Revolver [b]	0.6	May 2019	Letters of credit and cash
BGE			
Syndicated Revolver [b]	0.6	May 2019	Letters of credit and cash
Total	$ 8.5		

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expire on October 18, 2014 and are solely utilized to issue letters of credit. As of June 30, 2014, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled $20 million, $18 million, $21 million and $1 million, respectively. Also, excludes the unsecured bridge credit facility of $7.2 billion to support the PHI transaction discussed below.

(b) Includes credit facilities for Exelon Corporate, PECO and BGE with aggregate commitments of $22 million, $27 million and $27 million, respectively, that expire in August 2018.

As of June 30, 2014, there were no borrowings under the Registrants' credit facilities, with the exception of CENG, see discussion below

On March 28, 2014, ComEd extended for an additional year the expiration date of its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2019. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

On April 1, 2014, as a result of the CENG integration, a $100 million bilateral CENG credit facility expiring October 2014 is now consolidated in Exelon's and Generation's consolidated financial statements. This facility will be utilized by CENG to fund working capital and capital projects and obtain letters of credit. As of June 30, 2014, CENG borrowed $40 million against its credit facility.

On May 30, 2014, Exelon, Generation, PECO and BGE extended for an additional year the expiration date of its unsecured revolving credit facility with aggregate bank commitments of $500 million, $5.3 billion, $600 million, $600 million, respectively into May 2019, with the exception of a cumulative amount of $300 million which expires in August 2018. Costs incurred to extend the facility were not material.

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Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular registrant's credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 7.5, 0.0 and 0.0 basis points for prime based borrowings and 127.5, 127.5, 107.5, 90.0 and 100.0 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

Credit Agreements

In May 2014, concurrently and in connection with entering into the agreement to acquire PHI, Exelon entered into a credit facility to which the lenders committed to provide Exelon a 364-day senior unsecured bridge credit facility of $7.2 billion to support the contemplated transaction and provide flexibility for timing of permanent financing. The bridge credit facility was subsequently reduced to $4.2 billion as a result of the June 2014 equity issuances discussed below. During the three and six months ended June 30, 2014, Exelon recorded $9 million to interest expense in connection with the bridge facility. It is not currently expected that Exelon will be required to draw upon this credit facility.

Long-Term Debt

Issuance of Long-Term Debt

During the six months ended June 30, 2014, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Junior Subordinated Notes	2.500%	June 1, 2024	$1,150	Used to finance a portion of the acquisition of PHI and for general corporate purposes
Generation	Nuclear Fuel Purchase Contract	3.350%	June 30, 2018	$ 38	Used for procurement of uranium
Generation	ExGen Renewables I Project Financing [(a)]	LIBOR + 4.250%	February 6, 2021	$ 300	Used for general corporate purposes
ComEd	Mortgage Bonds Series 115	2.150%	January 15, 2019	$ 300	Used to refinance existing mortgage bonds
ComEd	Mortgage Bonds Series 116	4.700%	January 15, 2044	$ 350	Used to refinance existing mortgage bonds

(a) See ExGen Renewables I Project Financing, non recourse debt, discussed below

Junior Subordinated Notes

Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Proceeds from the issuance were $1.11 billion, net of a $35 million underwriter fee. The net proceeds are expected to be used to finance a portion of the acquisition of PHI and for general corporate purposes.

Each equity unit represents an undivided beneficial ownership interest in Exelon's 2.5% junior subordinated notes due in 2024 and a forward equity purchase contract which settles in 2017. The junior subordinated notes are expected to be remarketed in 2017. In connection with the remarketing, Exelon may modify the maturity date of the notes to a date earlier than June 1, 2024 but not earlier than June 1, 2020, remove redemption provisions of

the notes, or change the interest rate on the notes, including changing the interest rate from fixed to floating. Investors that participate in the remarketing receive the remarketing proceeds and may use those funds to either settle the equity forward upon settlement date or invest in the remarketed debt and use other funds for the share purchase. Exelon intends to use the remarketing proceeds to repay debt issued or for other corporate purposes as soon as practical following such settlements. If the remarketing fails, holders of the notes will have the right to put their notes to Exelon for an amount equal to the principal amount plus accrued interest. The equity units carry a total annual distribution rate of 6.5%, which is comprised of a quarterly coupon rate of interest of 2.5% and a quarterly contract payment of 4.0% (contract payments).

Each purchase contract obligates the holder to purchase, and Exelon to sell, for $50.00 a number of shares of Exelon's common stock in accordance with the conversion ratios set forth below:

- If the market price equals or exceeds $43.7484, then 1.1429 shares.
- If the market price is less than $43.7484 but greater than $35.00, a number of shares of common stock having a value, based on the market price, equal to $50.00.
- If the market price is less than or equal to $35.00, then 1.4286 shares.

A holder's ownership interest in the notes is pledged to Exelon to secure the holder's obligation under the related forward equity purchase contract. If a holder of the forward equity purchase contract chooses at any time to no longer be a holder of the notes, such holder's obligation under the purchase contract must be secured by a U.S. Treasury security.

At the time of issuance, the $1.15 billion of junior subordinated notes were recorded within Long-term debt on Exelon's Consolidated Balance Sheet. Additionally, at the time of issuance, the present value of the contract payments of $131 million were recorded to Long-term debt, representing the obligation to make contract payments, with an offsetting reduction to Common stock. The obligation for the contract payments will be accreted to interest expense over the 3 year period ending in 2017 in Exelon's Consolidated Statement of Operations and Comprehensive Income. The Long-term debt recorded for the contract payments is considered a non-cash financing transaction that was excluded from Exelon's Consolidated Statements of Cash Flows. Until settlement of the equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method.

ExGen Renewables Energy I LLC

On February 6, 2014, ExGen Renewables I, LLC (EGR), an indirect subsidiary of Exelon and Generation, borrowed $300 million aggregate principal amount pursuant to a non-recourse senior secured loan, due February 6, 2021. The loan bears interest at a variable rate equal to LIBOR plus 4.25%. EGR indirectly owns Continental Wind LLC (Continental Wind). In addition to the financing, EGR entered into interest rate swaps with a notional amount of $240 million to manage a portion of the interest rate exposure in connection with the financing. The assets pledged as collateral related to EGR have a net book value of approximately $796 million as of June 30, 2014, See Note 9 — Derivative Financial Instruments for additional information regarding interest rate swaps.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

During the six months ended June 30, 2013, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Upstream Gas Lending Agreement	2.210%	July 22, 2016	$ 3	Used to fund Upstream gas activities
Generation	DOE Project Financing	2.535 - 2.922%	January 5, 2037	$ 197	Funding for Antelope Valley Solar Development
Generation	Energy Efficiency Project Financing	4.400%	August 31, 2014	$ 9	Funding to install energy conservation measures in Beckley, West Virginia
BGE	Senior Notes	3.350%	July 1, 2023	$ 300	Used to partially refinance Notes due July 1, 2013 and for general corporate purposes

Retirement and Redemptions of Current and Long-Term Debt

During the six months ended June 30, 2014, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	2003 Senior Notes	5.35%	January 15, 2014	$ 500
Generation	Pollution Control Loan	4.10%	July 1, 2014	$ 20
Generation	Continental Wind Project Financing	6.00%	February 28, 2033	$ 11
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 2
Generation	ExGen Renewables I	3mL + 4.25%	February 6, 2021	$ 3
Generation	AVSR	2.33% - 3.55%	January 5, 2037	$ 1
Generation	Clean Horizons Solar	2.56%	September 7, 2030	$ 1
Generation	Sacramento Solar	2.56%	December 31, 2030	$ 1
ComEd	Mortgage Bonds Series 110	1.63%	January 15, 2014	$ 600
ComEd	Pollution Control Series 1994C	5.85%	January 15, 2014	$ 17
BGE	Rate Stabilization Bonds	5.72%	April 1, 2017	$ 35

During the six months ended June 30, 2013, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	Kennett Square Capital Lease	7.830%	September 20, 2020	$ 1
Generation	Solar Revolver	1.950%	July 7, 2014	$ 6
Generation	Clean Horizons Solar	2.563%	September 7, 2030	$ 1
Generation [(a)]	Series A Junior Subordinated Debentures	8.625%	June 15, 2063	$ 450
ComEd	First Mortgage Bonds Series 92	7.625%	April 15, 2013	$ 125
BGE	Rate Stabilization Bonds	5.720%	April 1, 2017	$ 33

(a) Represents debt obligations assumed by Exelon as part of the merger on March 12, 2012 that became callable at face value on June 15, 2013. Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets. The debentures were redeemed and the intercompany loan agreements repaid on June 15, 2013.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

11. Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

For the Three Months Ended June 30, 2014	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	2.1	1.7	4.6	(0.5)	4.1
Qualified nuclear decommissioning trust fund income	4.1	6.0	—	—	—
Domestic production activities deduction	(2.0)	(2.9)	—	—	—
Health care reform legislation	—	—	0.2	—	0.2
Amortization of investment tax credit, net deferred taxes	(0.4)	(0.5)	(0.3)	(0.1)	(0.7)
Plant basis differences	(1.6)	—	(0.4)	(13.2)	5.1
Production tax credits and other credits	(0.8)	(1.1)	—	—	—
Noncontrolling interest	(2.0)	(2.9)	—	—	—
Other	(1.2)	(0.4)	0.2	0.3	(1.3)
Effective income tax rate	33.2%	34.9%	39.3%	21.5%	42.4%

For the Six Months Ended June 30, 2014	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(0.6)	(14.7)	5.0	0.4	5.0
Qualified nuclear decommissioning trust fund income	5.9	27.7	—	—	—
Domestic production activities deduction	(3.2)	(14.8)	—	—	—
Health care reform legislation	0.1	—	0.2	—	0.2
Amortization of investment tax credit, net deferred taxes	(1.2)	(4.9)	(0.3)	(0.1)	(0.3)
Plant basis differences	(3.0)	—	(0.5)	(10.8)	0.4
Production tax credits and other credits	(2.4)	(11.1)	—	—	—
Noncontrolling interest	(1.9)	(8.8)	—	—	—
Other	(3.1)	(8.9)	0.2	0.3	0.1
Effective income tax rate	25.6%	(0.5)%	39.6%	24.8%	40.4%

For the Three Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	4.1	3.5	5.6	2.9	5.6
Qualified nuclear decommissioning trust fund income	(1.8)	(2.7)	—	—	—
Domestic production activities deduction	0.1	0.2	—	—	—
Tax exempt income	(0.1)	(0.2)	—	—	—
Health care reform legislation	0.1	—	0.4	—	(0.3)
Amortization of investment tax credit, net deferred taxes	(1.8)	(2.5)	(0.3)	(0.1)	(0.6)
Plant basis differences	(1.4)	—	(0.4)	(8.6)	(0.7)
Production tax credits and other credits	(1.4)	(2.2)	—	—	—
Other	(0.3)	0.1	0.4	(0.1)	—
Effective income tax rate	32.5%	31.2%	40.7%	29.1%	39.0%

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

For the Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	8.6	0.4	4.1	2.9	5.7
Qualified nuclear decommissioning trust fund income	2.8	4.8	—	—	—
Domestic production activities deduction	—	(0.1)	—	—	—
Tax exempt income	(0.2)	(0.4)	—	—	—
Health care reform legislation	0.2	—	5.7	—	0.2
Amortization of investment tax credit, net deferred taxes	(3.5)	(5.6)	(4.9)	(0.1)	(0.3)
Plant basis differences	(3.1)	—	(8.7)	(7.5)	(0.6)
Production tax credits and other credits	(2.8)	(4.9)	(0.3)	—	—
Other	0.1	3.1	5.5	—	(0.2)
Effective income tax rate	37.1%	32.3%	36.4%	30.3%	39.8%

Accounting for Uncertainty in Income Taxes

Exelon, Generation, ComEd, PECO, and BGE have $1,871 million, $1,403 million, $153 million, $44 million, and $0 million, of unrecognized tax benefits as of June 30, 2014, respectively, and $2,175 million, $1,415 million, $324 million, $44 million, and $0 million, of unrecognized tax benefits as of December 31, 2013, respectively. The unrecognized tax benefits as of June 30, 2014 reflect a decrease at Exelon and ComEd primarily attributable to the like-kind exchange and the lease termination position discussed below.

Reasonably possible the total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Nuclear Decommissioning Liabilities (Exelon and Generation)

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and has disallowed the claims. In November 2008, Generation received a final determination from the Appeals division of the IRS (IRS Appeals) disallowing AmerGen's refund claims. Generation filed a complaint in the United States Court of Federal Claims on February 20, 2009 to contest this determination. During the first and second quarters of 2013, AmerGen and the DOJ completed and filed cross motions for summary judgment. On September 17, 2013, the Court granted the government's motion denying AmerGen's claims for refund. In the first quarter of 2014, Exelon filed an appeal of the decision to the United States Court of Appeals for the Federal Circuit.

Due to the possibility of final resolution through an appellate decision, Generation continues to believe that it is reasonably possible that the total amount of unrecognized tax benefits may significantly decrease in the next 12 months.

Settlement of Income Tax Audits

As of June 30, 2014, Exelon and Generation have approximately $225 million of unrecognized state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing federal and state audits and expected statute of limitation expirations that if recognized would decrease the effective tax rate. In January 2014, certain unrecognized tax benefits as of December 31, 2013 were effectively settled and thus resulted in reduced tax expense of $33 million at Generation in the first quarter of 2014.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Other Income Tax Matters

Like-Kind Exchange

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $1.2 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with this position and asserted that the entire gain of approximately $1.2 billion was taxable in 1999.

Exelon has been unable to reach agreement with the IRS regarding the dispute over the like-kind exchange position. The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately $87 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like-kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison's deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon's current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013 Exelon recorded a non-cash charge to earnings of approximately $265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $170 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the unpaid tax liabilities related to the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition, ComEd will continue to record non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. Exelon continues to believe that it is unlikely that the IRS's assertion of penalties will ultimately be sustained and therefore no liability for the penalty has been recorded.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

On September 30, 2013, the Internal Revenue Service issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue. The litigation could take three to five years including appeals, if necessary. Decisions in the Tax Court are not controlled by the Federal Circuit's decision in Consolidated Edison.

In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable as of June 30, 2014 may be as much as $830 million, of which approximately $310 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

In the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of $335 million. The termination will result in a 2014 tax payment of approximately $285 million by Exelon, including approximately $155 million by ComEd representing the remaining gain deferred pursuant to the like-kind exchange transaction. In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, Exelon will be required to pay the full amount of tax and after-tax interest discussed in the preceding paragraph but will ultimately be entitled to a refund of the 2014 tax payment. See Note 7 — Impairment of Long Lived Assets for further details.

Accounting for Final Tangible Property Regulations (Exelon, Generation, ComEd, PECO, and BGE)

On September 19, 2013, the Treasury Department and the IRS published final regulations regarding the tax treatment of costs incurred to acquire, produce, or improve tangible property. The Registrants have assessed the financial impact of this guidance and do not expect it to have a material impact. Any changes in method of accounting required to conform to the final regulations will be made for the Registrant's 2014 taxable year.

Accounting for Generation Repairs (Exelon and Generation)

On April 30, 2013, the IRS issued Revenue Procedure 2013-24 providing guidance for determining the appropriate tax treatment of costs incurred to repair electric generation assets. Generation will change its method of accounting for deducting repairs in accordance with this guidance beginning with its 2014 tax year. Generation has estimated that adoption of the new method will result in a cash tax detriment of approximately $100 - $120 million.

12. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets from December 31, 2013 to June 30, 2014:

Nuclear decommissioning ARO at December 31, 2013 [(a)]	$4,855
Consolidation of CENG [(b)]	1,701
Accretion expense	154
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at June 30, 2014 [(a)]	$6,707

(a) Includes $9 million as the current portion of the ARO at June 30, 2014 and December 31, 2013 which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.
(b) Includes the fair value of the CENG ARO liability as of April 1, 2014, the date of consolidation. See Note 6 — Investment in Constellation Energy Nuclear Group, LLC for additional information.

During the six months ended June 30, 2014, Generation's ARO increased by approximately $1.9 billion. The increase is largely driven by the consolidation of CENG. The fair value of CENG's assets and liabilities recorded in consolidation, including the ARO, was determined based on significant estimates and assumptions that are judgmental in nature. The valuation to assess the fair value of the ARO is considered an initial estimate and will be updated with inputs from a third party engineering firm with corresponding adjustments recorded by the end of 2014. For additional details on the consolidation of CENG, see Note 6 — Investment in Constellation Energy Nuclear Group, LLC.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with the former ComEd, former PECO, former AmerGen and the CENG units have been funded with amounts collected from ComEd customers, PECO customers, and the previous owners of the former AmerGen and the CENG plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of approximately $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. With respect to the former AmerGen and CENG units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts previously collected from ComEd and currently collected from PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third party (see

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Zion Station Decommissioning below) and the CENG units, where any shortfall is required to be funded by both Generation and EDF. Generation, through PECO, has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise Generation, will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen and CENG units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units and CENG units, Generation retains any funds remaining in the trust funds after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to nuclear decommissioning trust funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. Generation expects to comply with applicable regulations and timely commence and complete all required decommissioning activities.

At June 30, 2014 and December 31, 2013, Exelon and Generation had NDT fund investments totaling $10,437 million and $8,071 million, respectively.

The following table provides unrealized gains on NDT funds for the three and six months ended June 30, 2014 and 2013:

	Exelon and Generation			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net unrealized gains (losses) on decommissioning trust funds — Regulatory Agreement Units [a]	$ 172	$ (102)	$ 234	$ 92
Net unrealized gains (losses) on decommissioning trust funds — Non-Regulatory Agreement Units [b][c]	128	(40)	141	24

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.

(b) Excludes $10 million and $2 million of net unrealized gains related to the Zion Station pledged assets for the three months ended June 30, 2014 and 2013, respectively, and $20 million and $3 million of net unrealized gains related to the Zion Station pledged assets for the six months ended June 30, 2014 and 2013, respectively. Net unrealized gains (losses) related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.

(c) Net unrealized gains (losses) related to Generation's NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

See Note 3 — Regulatory Matters and Note 25 — Related Party Transactions of the Exelon 2013 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning. On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. See Note 15 — Asset Retirement Obligations of the Exelon 2013 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a payable to ZionSolutions in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately $85 million, which is included within the nuclear decommissioning ARO at June 30, 2014. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payable to ZionSolutions, and withdrawals by ZionSolutions at June 30, 2014 and December 31, 2013:

	Exelon and Generation	
	June 30, 2014	December 31, 2013
Carrying value of Zion Station pledged assets	$ 402	$ 458
Payable to Zion Solutions [a]	357	414
Current portion of payable to Zion Solutions [b]	93	109
Withdrawals by Zion Solutions to pay decommissioning costs [c]	575	498

(a) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(b) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.
(c) Cumulative withdrawals since September 1, 2010.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

NRC Minimum Funding Requirements . NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. On April 1, 2013, Generation submitted its NRC-required biennial decommissioning funding status report as of December 31, 2012. As of December 31, 2012, Generation provided adequate funding assurance for all of its units, including Limerick Unit 1, where Generation has in place a $115 million parent guarantee to cover the NRC minimum funding assurance requirements. On October 2, 2013, the NRC issued summary findings from the NRC Staff's review of the 2013 decommissioning funding status reports for all 104 operating reactors, including the Generation operating units. Based on that review, the NRC Staff determined that Generation provided decommissioning funding assurance under the NRC regulations for all of its operating units, including Limerick Unit 1. On March 26, 2014, in accordance with a NRC requirement with respect to units involved in a merger or acquisition, CENG submitted its NRC-required decommissioning funding status report as of December 31, 2013 and no additional financial assurance was required.

On March 31, 2014, Generation submitted its NRC required annual decommissioning funding report as of December 31, 2013 for shutdown reactors. This submittal also included the required updated financial tests for the Limerick Unit 1 parent guarantee. There was no change to the amount of the parent guarantee, or the funding status of these reactors. Adequate decommissioning funding assurance is in place for all reactors owned by Generation.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential "apparent violations" of its regulations because of alleged inaccuracies in the Decommissioning Funding Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation's status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. The January 31, 2013 letter from the NRC does not take issue with Generation's current funding status, and as reflected in Generation's April 1, 2013 decommissioning funding status report referenced above, Generation continues to provide adequate funding assurance for each of its units. Generation met with the NRC on April 30, 2013 for a pre-decisional enforcement conference to provide additional information to explain why Generation believes that it complied with the regulatory requirements and did not deliberately or otherwise provide incomplete or inaccurate information in its decommissioning funding status reports. On May 1, 2014, the NRC issued its final determination. Although the NRC determined that these historical status reports did not provide complete and accurate information, the violation of the regulatory requirements was not a deliberate violation. The NRC noted the low safety significance and Generation's corrective actions to satisfy the NRC Staff's expectations and issued a Severity Level IV violation, with no monetary penalty. A Severity Level IV violation is the lowest level of violation.

In addition, on June 24, 2013, Exelon received a subpoena from the SEC requesting that Exelon provide the SEC with certain documents generally relating to Exelon and Generation's reporting and funding of the future decommissioning of Generation's nuclear power plants. Exelon and Generation have cooperated with the SEC and provided the requested documents. On February 13, 2014, Exelon received a letter from the SEC confirming that it had concluded its investigation and that no further action was anticipated based on information provided by Exelon.

13. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees.

On April 1, 2014, as a result of the consolidation of CENG into Generation, the obligations associated with CENG's pension and other postretirement plans are reflected in the disclosures below based on an April 1, 2014 valuation. The plans include essentially all employees at CENG. Exelon will assume sponsorship of the CENG pension and other postretirement benefit plans in the third quarter of 2014.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2014, Exelon received an updated valuation of several of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2014. This valuation resulted in an increase to the pension obligation of $35 million and an increase to the other postretirement benefit obligation of $12 million. Additionally, accumulated other comprehensive loss increased by approximately $12 million (after tax), regulatory assets increased by approximately $34 million, and regulatory liabilities increased by approximately $5 million. During the second quarter of 2014, Exelon received an updated valuation for the remainder of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2014. This valuation resulted in an increase to the pension obligation of $13 million and an increase to the other postretirement benefit obligation of $3 million. Additionally, accumulated other comprehensive loss increased by approximately $1 million (after tax) and regulatory assets increased by approximately $15 million.

In April 2014, Exelon announced plan design changes for certain other postretirement benefit plans, which required an interim remeasurement of the benefit obligation for those plans using assumptions as of April 30, 2014, including updated discount rates and asset values. The remeasurement is expected to result in a decrease in the net periodic benefit costs for other postretirement benefits of approximately $149 million for the period May 2014 through December 2014 as compared to the net periodic benefit costs that were anticipated based on the January 1, 2014 valuation. The remeasurement resulted in a decrease in Exelon's non-pension postretirement benefit obligations, regulatory assets, and accumulated other compressive loss of approximately $790 million, $240 million, and $259 million (after tax), respectively, and an increase in regulatory liabilities of approximately $125 million.

The following tables present the components of Exelon's net periodic benefit costs for the three and six months ended June 30, 2014 and 2013. The 2014 pension benefit cost for Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 4.80%. The 2014 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.59% for funded plans and a discount rate of 4.90% for all plans. Certain of the other postretirement benefit plans were remeasured as of April 30, 2014 using an expected long-term rate of return on plan assets of 6.59% and a discount rate of 4.30%. Costs for the three and six months ended June 30, 2014 reflect the impact of this remeasurement. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets.

	Pension Benefits Three Months Ended June 30,		Other Postretirement Benefits Three Months Ended June 30,	
	2014(a)	2013	2014 (a)	2013
Service cost	$ 69	$ 79	$ 29	$ 40
Interest cost	184	163	45	49
Expected return on assets	(242)	(254)	(38)	(33)
Amortization of:				
Prior service cost (benefit)	4	4	(30)	(6)
Actuarial loss	104	141	12	21
Net periodic benefit cost	$ 119	$ 133	$ 18	$ 71

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Pension Benefits Six Months Ended June 30,		Other Postretirement Benefits Six Months Ended June 30,	
	2014(a)	2013	2014(a)	2013
Service cost	$ 138	$ 159	$ 61	$ 81
Interest cost	367	326	101	97
Expected return on assets	(483)	(508)	(76)	(66)
Amortization of:				
Prior service cost (benefit)	7	7	(34)	(10)
Actuarial loss	209	281	20	42
Net periodic benefit cost	$ 238	$ 265	$ 72	$ 144

(a) Excludes components of CENG's net periodic benefit costs for the period April 1, 2014 to June 30, 2014 as presented in the below table.

The following tables present the components of net periodic benefit costs for the CENG-sponsored benefit plans for the period April 1, 2014 to June 30, 2014 and reflect the valuation performed as of April 1, 2014. The 2014 pension benefit cost for CENG sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.75% and discount rates ranging from 3.60% — 4.30%. The 2014 other postretirement benefit cost is calculated using a discount rate of 4.55% for all plans.

	Pension Benefits	Other Postretirement Benefits
Service cost	$ 5	$ 1
Interest cost	6	2
Expected return on assets	(9)	—
Net periodic benefit cost	$ 2	$ 3

The amounts below represent Generation's, ComEd's, PECO's, BGE's and BSC's allocated portion of the pension and postretirement benefit plan costs, which were included in Capital expenditures and Operating and maintenance expense during the three and six months ended June 30, 2014 and 2013.

	Three Months Ended June 30,		Six Months Ended June 30,	
Pension and Other Postretirement Benefit Costs	2014	2013	2014	2013
Generation [a]	$ 63	$ 87	$ 139	$ 173
ComEd	40	77	96	154
PECO	9	10	21	21
BGE	17	14	33	27
BSC [b]	13	16	26	34

(a) Includes $5 million related to CENG for the period April 1, 2014 to June 30, 2014.
(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above.

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. Exelon expects to make qualified pension plan contributions of $317 million to its

qualified pension plans in 2014, of which Generation, ComEd, PECO and BGE will contribute $169 million, $119 million, $11 million and $0 million, respectively. Exelon's and Generation's expected qualified pension plan contributions above include $53 million and $51 million, respectively, related to CENG-sponsored plans for the period April 1, 2014 to December 31, 2014. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $18 million in 2014, of which Generation, ComEd, PECO and BGE will make payments of $9 million, $1 million, $0 million and $1 million, respectively. Exelon's and Generation's expected non-qualified pension plan benefit payments above include $3 million related to CENG-sponsored plans for the period April 1, to December 31, 2014.

Unlike qualified pension plans, other postretirement benefit plans are not subject to statutory minimum contribution requirements and certain plans are not funded. Exelon's management has historically considered several factors in determining the level of contributions to its funded other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued rate recovery). Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans and considering the impact of recent plan design changes, of approximately $290 million in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $128 million, $121 million, $4 million and $18 million, respectively. Exelon's and Generation's expected other postretirement benefit plan payments above include $5 million related to CENG-sponsored plans for the period April 1, 2014 to December 31, 2014.

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

CENG's investment strategy for its qualified pension assets is generally consistent with Exelon's investment strategy as outlined above.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
Savings Plan Matching Contributions	2014	2013	2014	2013
Exelon [a]	$ 19	$ 21	$ 48	$ 43
Generation [a]	10	10	24	21
ComEd	5	5	12	10
PECO	2	2	4	4
BGE	1	2	4	4
BSC [b]	1	2	4	4

(a) Includes $1 million of matching contributions to CENG's 401(k) defined contribution savings plan for the period April 1, 2014 to June 30, 2014.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO or BGE amounts above.

14. Severance (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

CENG Integration-Related Severance

In connection with the Master Agreement, Generation and CENG recorded a severance accrual in the fourth quarter of 2013 for the anticipated employee position reductions as a result of the integration. The majority of these positions are corporate and support positions at CENG. On April 1, 2014, the date the NOSA was executed, Generation consolidated the CENG severance liability pursuant to the Master Agreement. Generation adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. The estimated amount of severance payments associated with this plan is expected to be approximately $27 million. As of June 30, 2014, management recorded its best estimate of severance benefits, which could be adjusted through the completion of the integration process if additional employee position reductions are identified or if employees resign prior to their agreed upon service termination date. Estimated costs to be incurred after June 30, 2014 are not material.

Exelon and Generation recorded severance benefit costs associated with the employee reductions of $1 million and $2 million within Operating and maintenance expense for the three and six months ended June 30, 2014, respectively, in their Consolidated Statements of Operations and Comprehensive Income.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Amounts included in the table below represent the severance liability recorded by Exelon and Generation related to the CENG integration:

Six Months Ended June 30, 2014 Severance Liability	Exelon	Generation
Balance at December 31, 2013	$ 2	$ 2
Integration of CENG [(a)]	19	19
Severance charges	2	2
Payments	(3)	(3)
Balance at June 30, 2014	$ 20	$ 20

(a) Includes the fair value of the CENG integration-related obligation as of April 1, 2014, the date of consolidation. See Note 6 — Investment in CENG for additional information.

Cash payments under the severance plan began in the second quarter of 2014. Substantially all cash payments under the plan are expected to be made by the end of 2014.

Constellation Merger-Related Severance

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit.

The amount of severance expense associated with the post-merger integration recognized for the three and six months ended June 30, 2014 and 2013 is not material. Estimated costs to be incurred after June 30, 2014 are not material.

Amounts included in the table below represent the severance liability recorded by Exelon, Generation, ComEd, PECO and BGE for employees of those Registrants and exclude amounts billed through intercompany allocations:

Six Months Ended June 30, 2014 Severance Liability	Exelon	Generation	ComEd	PECO	BGE
Balance at December 31, 2013	$ 53	$ 10	$ —	$ —	$ 6
Payments	(20)	(2)	—	—	(3)
Balance at June 30, 2014	$ 33	$ 8	$ —	$ —	$ 3

Substantially all cash payments under the plan are expected to be made by the end of 2016.

Ongoing Severance Plans

The Registrants provide severance and health and welfare benefits under Exelon's ongoing severance benefit plans to terminated employees in the normal course of business, which are not directly related to the merger with Constellation or with the integration of CENG. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

For the three and six months ended June 30, 2014 and 2013, the Registrants recorded the following severance costs associated with these ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

	Exelon	Generation	ComEd	PECO	BGE
Three Months Ending					
June 30, 2014	$ 4	$ 2	$ —	$ —	$—
June 30, 2013	$ 1	$ 1	$ —	$ —	$—
Six Months Ending					
June 30, 2014	$ 6	$ 4	$ —	$ —	$—
June 30, 2013	$ 2	$ 1	$ 1	$ —	$—

The severance liability balances associated with these ongoing severance benefits as of June 30, 2014 and December 31, 2013 are not material.

15. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, and PECO)

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the six months ended June 30, 2014 and 2013:

For The Six Months Ended June 30, 2014	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon [a]						
Beginning balance	$ 120	$ 2	$ (2,260)	$ (10)	$ 108	$(2,040)
OCI before reclassifications	(11)	1	246	(1)	11	246
Amounts reclassified from AOCI [b]	(62)	—	66	—	(116)	(112)
Net current-period OCI	(73)	1	312	(1)	(105)	134
Ending balance	$ 47	$ 3	$ (1,948)	$ (11)	$ 3	$(1,906)
Generation [a]						
Beginning balance	$ 114	$ 2	$ —	$ (10)	$ 108	$ 214
OCI before reclassifications	(8)	(1)	—	(1)	11	1
Amounts reclassified from AOCI [b]	(62)	—	—	—	(116)	(178)
Net current-period OCI	(70)	(1)	—	(1)	(105)	(177)
Ending balance	$ 44	$ 1	$ —	$ (11)	$ 3	$ 37
PECO [a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See tables following changes in accumulated other comprehensive income tables for details about these reclassifications.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

For The Six Months Ended June 30, 2013	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
Exelon [a]						
Beginning balance	$ 368	$ —	$ (3,137)	$ —	$ 2	$(2,767)
OCI before reclassifications	24	(1)	87	(6)	31	135
Amounts reclassified from AOCI [b]	(147)	—	101	—	5	(41)
Net current-period OCI	(123)	(1)	188	(6)	36	94
Ending balance	$ 245	$ (1)	$ (2,949)	$ (6)	$ 38	$(2,673)
Generation [a]						
Beginning balance	$ 512	$ —	$ —	$ —	$ 1	$ 513
OCI before reclassifications	12	(1)	—	(6)	31	36
Amounts reclassified from AOCI [b]	(279)	—	—	—	5	(274)
Net current-period OCI	(267)	(1)	—	(6)	36	(238)
Ending balance	$ 245	$ (1)	$ —	$ (6)	$ 37	$ 275
PECO [a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI [b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in accumulated other comprehensive income.
(b) See tables following changes in accumulated other comprehensive income tables for details about these reclassifications

ComEd, PECO, BGE did not have any reclassifications out of AOCI to Net Income during the three and six months ended June 30, 2014 and 2013. The following tables present amounts reclassified out of AOCI to Net Income for Exelon and Generation during the three and six months ended June 30, 2014 and 2013.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Three Months Ended June 30, 2014

Details about AOCI components	Items reclassified out of AOCI [a] Exelon	Generation	Affected line item in the statement where Net Income is presented
Gains on cash flow hedges			
Energy related hedges	$ 63	$ 63	Operating revenues
	63	63	Total before tax
	(25)	(25)	Tax (expense)
	$ 38	$ 38	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs	$ 12	$ —	(b)
Actuarial losses	(61)	—	(b)
	(49)	—	Total before tax
	18	—	Tax benefit
	$ (31)	$ —	Net of tax
Equity investments			
Reversal of CENG equity method AOCI	$ 193	$ 193	Gain on consolidation of CENG
	193	193	Total before tax
	(77)	(77)	Tax benefit
	$ 116	$ 116	Net of tax
Total Reclassifications for the period	$ 123	$ 154	Net of Tax

Six Months Ended June 30, 2014

Details about AOCI components	Items reclassified out of AOCI [a] Exelon	Generation	Affected line item in the statement where Net Income is presented
Gains on cash flow hedges			
Energy related hedges	$ 102	$ 102	Operating revenues
Other cash flow hedges	—	—	Interest expense
	102	102	Total before tax
	(40)	(40)	Tax (expense)
	$ 62	$ 62	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs	10	—	(b)
Actuarial losses	$ (117)	$ —	(b)
	(107)	—	Total before tax
	41	—	Tax benefit
	$ (66)	$ —	Net of tax
Equity investments			
Reversal of CENG equity method AOCI	$ 193	$ 193	Gain on consolidation of CENG
	193	193	Total before tax
	(77)	(77)	Tax benefit
	$ 116	$ 116	Net of tax
Total Reclassifications for the period	$ 112	$ 178	Net of Tax

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Three Months Ended June 30, 2013

Details about AOCI components	Items reclassified out of AOCI [a] Exelon	Generation	Affected line item in the statement where Net Income is presented
Gains on cash flow hedges			
Energy related hedges	$ 141	$ 236	Operating revenues
Other cash flow hedges	—	1	Interest expense
	141	237	Total before tax
	(52)	(93)	Tax (expense)
	$ 89	$ 144	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs	$ (1)	$ —	(b)
Actuarial (losses)	(82)	—	(b)
	(83)	—	Total before tax
	32	—	Tax benefit
	$ (51)	$ —	Net of tax
Equity investments			
Capital activity	$ (5)	$ (5)	Equity in losses of unconsolidated affiliates
	(5)	(5)	Total before tax
	2	2	Tax benefit
	$ (3)	$ (3)	Net of tax
Total Reclassifications for the period	$ 35	$ 141	Net of Tax

Six Months Ended June 30, 2013

Details about AOCI components	Items reclassified out of AOCI [a] Exelon	Generation	Affected line item in the statement where Net Income is presented
Gains on cash flow hedges			
Energy related hedges	$ 240	$ 459	Operating revenues
Other cash flow hedges	(1)	1	Interest (expense) or benefit
	239	460	Total before tax
	(92)	(181)	Tax (expense)
	$ 147	$ 279	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs	$ (1)	$ —	(b)
Actuarial (losses)	(165)	—	(b)
	(166)	—	Total before tax
	65	—	Tax (expense)
	$ (101)	$ —	Net of tax
Equity investments			
Capital activity	$ (8)	$ (8)	Equity in losses of unconsolidated affiliates
	(8)	(8)	Total before tax
	3	3	Tax benefit
	$ (5)	$ (5)	Net of tax
Total Reclassifications for the period	$ 41	$ 274	Net of Tax

(a) All amounts are net of tax. Amounts in parenthesis represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see Note 13 — Retirement Benefits for additional details).

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Exelon				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$ 5	$ —	$ 5	$ 1
Actuarial loss reclassified to periodic cost	(23)	(32)	(46)	(66)
Pension and non-pension post retirement benefit plans valuation adjustment	(166)	(1)	(159)	(50)
Change in unrealized loss on cash flow hedges	28	45	48	77
Change in unrealized income on equity investments	77	(5)	70	(23)
Deferred compensation unit valuation adjustment	—	(6)	—	(6)
Total	$ (79)	$ 1	$ (82)	$ (67)
Generation				
Change in unrealized loss on cash flow hedges	$ 25	$ 89	$ 44	$175
Change in unrealized income on equity investments	77	(5)	70	(23)
Change in marketable securities	—	—	(2)	—
Total	$ 102	$ 84	$ 112	$152

16. Common Stock (Exelon, Generation, ComEd, PECO and BGE)

Equity Securities Offering

In June 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share. Concurrently, Exelon entered into forward sale agreements requiring Exelon to, at its election, prior to October 29, 2015; i) physically settle the transaction through the issuance of 57.5 million shares of its common stock in exchange for net proceeds at the forward price specified in the agreements of between approximately $1.85 billion and $1.95 billion, after consideration of underwriters discount of approximately $60 million and subject to certain adjustments as provided in the forward sales agreement, or ii) net settle the transaction either through the payment of cash or shares of its common stock based on the then current market value of the shares minus the value of the shares at the forward price, net of the underwriters discount and the daily accretion rate. No amounts have or will be recorded in Exelon's consolidated financial statements until settlement of the forward sale agreements occurs. At June 30, 2014, if Exelon had elected to net share settle the contract, the maximum number of common shares that would have been required to be issued is approximately 4 million shares at a forward price of $33.94. If Exelon elects to cash settle the contract, the transaction costs will be recorded as a charge to earnings in the period in which it becomes probable that Exelon will cash settle. Otherwise, all transaction costs will be reflected as a reduction to the value of the common stock issued in Exelon's Consolidated Balance Sheet. The net proceeds received upon settlement are expected to be used to finance a portion of the acquisition of PHI and for general corporate purposes. Until settlement, earnings per share dilution resulting from the forward sales agreement, if any, will be determined under the treasury stock method.

Concurrent with the forward equity transaction, Exelon also issued $1.15 billion of junior subordinated notes in the form of 23 million equity units. See Note 10 – Debt and Credit Agreements for further information on the equity units.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

17. Earnings Per Share and Equity (Exelon)

Earnings per Share (Exelon)

Diluted earnings per share is calculated by dividing Net income attributable to common shareholders by the weighted average number of shares of common stock outstanding adjusted to include the potentially dilutive effect of stock options, performance share awards, restricted stock outstanding under Exelon's LTIPs, and Exelon's equity forward sales agreement, which is further described in Note 10 — Debt and Credit Agreements. The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding (in millions) used in calculating diluted earnings per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income attributable to common shareholders	$ 522	$ 490	$ 612	$ 486
Average common shares outstanding — basic	860	856	860	856
Potentially dilutive effect of stock options, performance share awards, restricted stock, and Exelon's equity forward sales agreement	4	4	3	3
Average common shares outstanding — diluted	864	860	863	859

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 16 million for the three and six months ended June 30, 2014 and 17 million and 18 million for the three and six months ended June 30, 2013, respectively.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of June 30, 2014. In 2008, Exelon management decided to defer indefinitely any share repurchases.

Preferred Securities Redemption (Exelon and PECO)

On March 25, 2013, PECO announced that it issued a notice of redemption for all of its outstanding preferred securities with a redemption date of May 1, 2013. PECO had $87 million of cumulative preferred securities that were redeemable at its option at any time for the redemption price established when each series of securities were issued. The redemption premium of $6 million is treated as a reduction to Net income to arrive at Net income attributable to common shareholders utilized in the calculation of the earnings per share for Exelon. As a result of the redemption, PECO is now indirectly, wholly-owned by Exelon.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

18. Commitments and Contingencies (Exelon, Generation, ComEd, PECO and BGE)

The following is an update to the current status of commitments and contingencies set forth in Note 22 of the Exelon 2013 Form 10-K.

Commitments

Energy Commitments

As of June 30, 2014, Generation's commitments relating to its purchases from unaffiliated utilities and others of energy, capacity, transmission rights and RECs, are as indicated in the following table:

	Net Capacity Purchases [a]	REC Purchases [b]	Transmission Rights Purchases [c]	Total
2014	$ 208	$ 43	$ 13	$ 264
2015	353	163	13	529
2016	269	122	2	393
2017	208	59	2	269
2018	98	13	2	113
Thereafter	388	4	32	424
Total	$ 1,524	$ 404	$ 64	$1,992

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at June 30, 2014, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.
(b) The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

ComEd's, PECO's and BGE's electric supply procurement, curtailment services, REC and AEC purchase commitments, as applicable, as of June 30, 2014 are as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
ComEd							
Electric supply procurement [a]	$ 740	$217	$232	$151	$140	$—	$ —
Renewable energy and RECs [b]	1,548	32	73	76	77	78	1,212
PECO							
Electric supply procurement [c]	550	381	169	—	—	—	—
AECs [d]	13	1	2	2	2	2	4
BGE							
Electric supply procurement [e]	1,320	448	632	240	—	—	—
Curtailment services [f]	136	21	40	34	29	12	—

(a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. As of June 30, 2014, ComEd has completed the ICC-approved procurement process for a portion of its energy requirements through the periods ending May 31, 2015, 2016 and 2017.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(b) Primarily related to ComEd 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms.
(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2014 and 2016. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 5 — Regulatory Matters for additional information.
(d) PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. See Note 5 - Regulatory Matters for additional information.
(e) BGE entered into various contracts for the procurement of electricity that expire between 2014 through 2016. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 5 — Regulatory Matters for additional information.
(f) BGE has entered into various contracts with curtailment services providers related to transactions in PJM's capacity market. See Note 5 — Regulatory Matters for additional information.

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation. Beginning this quarter, all of CENG's nuclear fuel commitments are disclosed within the Generation line below, since CENG is now fully consolidated by Generation. PECO and BGE have commitments to purchase natural gas related to transportation, storage capacity and services to serve customers in their gas distribution service territory. As of June 30, 2014, these net commitments were as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Generation	$9,973	$694	$1,526	$1,230	$1,276	$929	$ 4,318
PECO	411	90	112	93	35	15	66
BGE	618	64	83	82	65	53	271

Other Purchase Obligations

The Registrants' other purchase obligations as of June 30, 2014, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	2014	2015	2016	2017	2018	2019 and beyond
Exelon	$568	$140	$171	$65	$55	$37	$ 100
Generation	474	110	155	52	47	31	79
ComEd [a]	53	16	8	5	5	5	14
PECO [a]	28	12	4	3	1	1	7
BGE [a]	12	1	4	5	2	—	—

(a) Purchase obligations include commitments related to smart meter installation. See Note 5 — Regulatory Matters for additional information.

Construction Commitments

Generation has committed to the construction of the Antelope Valley solar PV facility in Los Angeles County, California. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013. As of June 30, 2014, the facility was fully operational. Generation has no further remaining construction commitments for the project.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

On July 3, 2013, Generation executed a Turbine Supply Agreement to expand its Beebe wind project in Michigan. The estimated remaining commitment under the contract is $53 million and achievement of commercial operations is expected in the fourth quarter of 2014.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland generation site with 120 MW of new natural gas-fired generation to satisfy certain Exelon/Constellation merger commitments. The estimated remaining commitment under the contract is $84 million and achievement of commercial operation is expected in 2015. This project will satisfy a portion of Exelon's commitment to Maryland. See Note 4 — Mergers and Acquisitions of the Exelon 2013 Form 10-K for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Exelon/Constellation merger.

On December 27, 2013, Generation executed a Turbine Supply Agreement for construction of the 40 MW Fourmile Wind project in western Maryland. The estimated remaining commitment under the contract is $38 million and achievement of commercial operations is expected in the fourth quarter 2014. In the first quarter of 2014, Generation approved expansion of the Fourmile project to 40 MW. This project will satisfy a portion of Exelon's 125 MW Tier I land-based renewables commitment in Maryland. See Note 4 — Mergers and Acquisitions of the Exelon 2013 Form 10-K for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Exelon/Constellation merger.

Refer to Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K for information on investment programs associated with regulatory mandates, such as ComEd's Infrastructure Investment Plan under EIMA, PECO's Smart Meter Procurement and Installation Plan and BGE's comprehensive smart grid initiative.

Constellation Merger Commitments

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion.

The direct investment estimate includes $95 million to $120 million relating to the construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a 20 year lease agreement that was contingent upon the developer obtaining all required approvals, permits and financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. Generation's total commitments under the lease agreement are $0 related to 2014 and 2015, and $9 million, $12 million, $12 million, and $270 million related to 2016, 2017, 2018, and 2019 and thereafter.

The direct investment commitment also includes $600 million to $650 million relating to Exelon and Generation's development or assistance in the development of 285 — 300 MWs of new generation in Maryland, which is expected to be completed over a period of 10 years. The MDPSC Order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. If in the future Exelon determines that it is probable that it will make subsidy, compliance or liquidated damages payments related to the new generation development commitments, Exelon will record a liability at that time. As of June 30, 2014, it is reasonably possible that Exelon will be required to make subsidy

or liquidated damages payments of approximately $40 million rather than build one of the generation projects contemplated by the commitments, given that the generation build is dependent upon the passage of legislation and other conditions that Exelon does not control.

Contingencies

Commercial Commitments

The Registrants' commercial commitments as of June 30, 2014, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Letters of credit (non-debt) [a]	$1,514	$ 1,470	$ 19	$ 22	$ 1
Guarantees	4,706[b]	1,346[c]	206[d]	181[e]	259[f]
Nuclear insurance premiums [g]	3,559	3,559	—	—	—
Underwriters discount [h]	60	—	—	—	—
Total commercial commitments	$9,839	$ 6,375	$ 225	$203	$260

(a) Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.
(b) Primarily reflects parental guarantees issued on behalf of Generation to allow the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Also reflects guarantees issued to ensure performance under specific contracts, preferred securities of financing trusts, property leases, indemnifications, NRC minimum funding assurance requirements and miscellaneous guarantees. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $0.6 billion at June 30, 2014, which represents the total amount Exelon could be required to fund based on June 30, 2014 market prices.
(c) Primarily reflects guarantees issued to ensure performance under energy marketing and other specific contracts. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $0.3 billion at June 30, 2014, which represents the total amount Generation could be required to fund based on June 30, 2014 market prices.
(d) Primarily reflects full and unconditional guarantees of $200 million Trust Preferred Securities of ComEd Financing III, which is a 100% owned finance subsidiary of ComEd.
(e) Primarily reflects full and unconditional guarantees of $178 million Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.
(f) Primarily reflects full and unconditional guarantees of $250 million Trust Preferred Securities of BGE Capital Trust II, which is a 100% owned finance subsidiary of BGE.
(g) Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site, including CENG sites, under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.
(h) Represents the underwriters discount for Exelon's forward equity transaction. See Note 16 — Common Stock of the Combined Notes to Consolidated Financial Statements for further details of the equity securities offering.

Nuclear Insurance (Exelon and Generation)

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor

owners for such claims from any single incident. As of June 30, 2014, the current liability limit per incident was $13.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of June 30, 2014, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in an additional $13.2 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $127.3 million, payable at no more than $19 million per reactor per incident per year. Exelon's maximum liability per incident is approximately $2.7 billion, including CENG's related liability.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.6 billion limit for a single incident.

Generation is also required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member. Premiums paid to NEIL by its members are subject to assessment for adverse loss experience (the retrospective premium obligation). The maximum combined retrospective premium amount that Generation could be required to pay due to participation in the Price-Anderson Act retrospective rating plan for power reactors and the NEIL retrospective premium obligation is $3.6 billion, including CENG's obligation, which is included above in the Commercial Commitments table. See the Nuclear Insurance section within Note 22 — Commitments and Contingencies of the Exelon 2013 Form 10-K for additional details on Generation's nuclear insurance premiums.

As part of the execution of NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity. See Note 6 — Investment in CENG for additional information on Generation's operations relating to CENG.

Spent Nuclear Fuel Obligation (Exelon and Generation)

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation pays the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance will be delayed significantly. On November 19, 2013, the D.C. Circuit Court ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. On January 3, 2014, the DOE filed a petition for rehearing which was

denied by the D.C. Circuit Court on March 18, 2014. Also, on January 3, 2014, the DOE submitted a proposal to Congress to reduce the current SNF disposal fee to zero. On May 9, 2014, the DOE notified Generation that the SNF disposal fee will remain in effect through May 15, 2014, after which time the fee will be set to zero. For the six months ended June 30, 2014, and for the year ended December 31, 2013, Generation incurred expense of $49 million and $136 million, respectively, in SNF disposal fees, recorded in Purchased power and fuel expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income, including Exelon's share of Salem and net of co-owner reimbursements (not including such fees incurred by CENG). Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees.

Indemnifications Related to Sale of Sithe (Exelon and Generation)

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. Specifically, subsidiaries of Generation consummated the acquisition of Reservoir Capital Group's 50% interest in Sithe and subsequently sold 100% of Sithe to Dynegy, Inc. (Dynegy).

The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at December 31, 2013. The guarantee expired January 31, 2014. Generation was not required to make payments under the guarantee, and, therefore, has no further obligation related to this guarantee as of June 30, 2014.

Repurchase of Land Related to Master Agreement Closing (Exelon and Generation)

As a result of the closing of the transactions contemplated by the Master Agreement, EDF has the option to sell back to CENG the land adjacent to the Calvert Cliffs site, together with the rights associated with the land, at its fair market value. The option is exercisable for a period of five years, from April 1, 2014.

Environmental Issues

General. The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, ComEd, PECO or BGE is one of several PRPs that may be responsible for ultimate remediation of each location.

- ComEd has identified 42 sites, 16 of which have been approved for cleanup by the Illinois EPA or the U.S. EPA and 26 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2017.
- PECO has identified 26 sites, 16 of which have been approved for cleanup by the PA DEP and 10 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2020.

- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. BGE is authorized to and is currently recovering environmental costs for the remediation of former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. ComEd, PECO and BGE have recorded regulatory assets for the recovery of these costs. See Note 5 — Regulatory Matters for additional information regarding the associated regulatory assets.

As of June 30, 2014 and December 31, 2013, the Registrants had accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

June 30, 2014	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 323	$ 258
Generation	56	—
ComEd	222	217
PECO	44	41
BGE	1	—

December 31, 2013	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 338	$ 273
Generation	56	—
ComEd	234	229
PECO	47	44
BGE	1	—

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water Quality

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's and CENG's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. For Generation, those facilities are Clinton, Dresden, Eddystone, Fairless Hills, Gould Street, Handley, Mountain Creek, Mystic 7, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. For CENG, those facilities are Calvert Cliffs, Nine Mile Point Unit 1 and R.E. Ginna.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

On May, 19 2014, the U.S. EPA released the final Section 316(b) rule. The rule has not been published in the Federal Register, and will become effective 60 days after publication. The rule requires that a series of studies and analyses be performed to determine the best technology available, followed by an implementation period. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

The rule does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment. The rule provides the state permitting director with significant discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The rule also provides a number of flexible compliance options to reduce impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or other technology at the intake. A number of concerns raised by the electric generation industry about the proposed rule were resolved favorably in the final rule.

New York Facilities . In July 2011, the New York Department of Environmental Conservation (DEC) issued a policy regarding the best available technology for cooling water intake structures. Through its policy, the DEC established closed-cycle cooling or its equivalent as the performance goal for all existing facilities, but also provided that the DEC will select a feasible technology whose costs are not wholly disproportionate to the environmental benefits to be gained and allows for a site-specific determination where the entrainment performance goal cannot be achieved. Each of CENG's New York facilities has filed for its SPDES permit renewal in 2014 and the renewal applications are currently pending with the NYDEC.

Salem and Other Power Generation Facilities. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG, in July 2004 that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon's and Generation's share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $430 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment. However, it is unknown at this time whether implementation of the final EPA rule will result in a requirement to install closed cycle cooling at Salem.

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, Generation cannot estimate the effect that compliance with the rule will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows and financial position. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility's economic viability would be called into question. However, the likely impact of the rule has been significantly decreased since the final rule does not mandate cooling towers as a national standard, and the state permitting director is required to apply a cost-benefit test and can take into consideration site-specific factors.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. As of June 30, 2014, and December 31, 2013, Generation's remaining groundwater contamination reserve was $15 million and $14 million respectively. In addition, a private party asserted claims relating to groundwater contamination. In February 2014, Generation settled these private party claims for an amount that was not material to the financial condition of Generation.

Air Quality

Cross State Air Pollution Rule (CSAPR). On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of SO_2 and NO_x. The D.C. Circuit Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the D.C. Circuit Court's July 11, 2008 opinion. On July 7, 2011, the U.S. EPA published the final rule, known as the CSAPR. The CSAPR requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states.

Numerous entities challenged the CSAPR in the D.C. Circuit Court, and some requested a stay of the rule pending the Court's consideration of the matter on the merits. On December 30, 2011, the Court granted a stay of the CSAPR, and directed the U.S. EPA to continue the administration of CAIR in the interim. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. The Court's order was appealed to the U.S. Supreme Court, and on April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit Court decision and upheld CSAPR, and remanded the case to the D.C. Circuit Court to resolve the remaining implementation issues. On June 26, 2014, the U.S. EPA filed a motion with the D.C. Circuit Court seeking to have the stay of the CSAPR lifted, and proposed a three-year tolling of the effective dates under the rule so that the first phase of emission budgets would be implemented on January 1, 2015. The U.S. EPA believes that this would allow sufficient time to complete the remaining aspects of the rulemaking before the implementation of the more stringent second phase of emission budgets that, under the tolling proposal, would begin on January 1, 2017.

The CSAPR restricts entirely the use of pre-2012 allowances. Existing SO_2 allowances under the ARP would remain available for use. As of June 30, 2014, Generation had $64 million of emission allowances carried at the lower of weighted average cost or market.

EPA Mercury and Air Toxics Standards (MATS). The MATS rule became final on April 16, 2012. The MATS rule reduces emissions of toxic air pollutants, and finalized the new source performance standards for fossil fuel-fired electric utility steam generating units (EGUs). The MATS rule requires coal-fired EGUs to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that smaller, older, uncontrolled coal units will retire rather than make these investments. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. In addition, the new standards will require oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the

proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. On April 15, 2014, the D.C Circuit Court issued an opinion upholding MATS in its entirety. On July 14, 2014, three petitions for certiorari were filed with the U.S. Supreme Court seeking review of the D.C. Circuit Court decision upholding MATS.

Exelon, along with the other co-owners of Conemaugh Generating Station have improved the existing scrubbers and installed Selective Catalytic Reduction (SCR) controls to meet the requirements of MATS.

In addition, as of June 30, 2014, Exelon had a $353 million net investment in coal-fired plants in Georgia subject to long-term leases extending through 2028-2032. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, after the impairments recorded in the second quarter of 2013 and 2014, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material. See Note 7 — Impairment of Long-Lived Assets for additional information.

National Ambient Air Quality Standards (NAAQS). The U.S. EPA previously announced that it would complete a review of all NAAQS by 2014. Oral argument in the litigation (*State of Miss. v. EPA*) of the final 2008 ozone standard occurred in the D.C. Circuit Court in November 2012 and a final Court decision was issued on July 23, 2013 with the 2008 primary ozone standard upheld, but the secondary standard remanded to EPA for reconsideration. Concurrent with litigation of the 2008 ozone standard, the U.S. EPA continues its regular, periodic review of the ozone NAAQS and is expected to propose revisions in the fall of 2014, with preliminary indications that the U.S. EPA will likely propose a tightened standard. It is unclear at this point in time whether the U.S. EPA will be able to respond to the Court remand of the secondary 2008 ozone standard on a timeframe that would be any quicker than that of the U.S. EPA's current, periodic review schedule. In December 2012, the U.S. EPA issued its final revisions to the Agency's particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation. It is unclear if the vacatur of the CSAPR, one of the regulations that the U.S. EPA is relying on to assist with future PM reduction, would alter the U.S. EPA's view since either CAIR or a finalized CSAPR regulation would be in effect leading up to 2020. In March 2013, a number of industry coalitions filed a joint lawsuit challenging the new PM2.5 standard. Also during early 2013, the D.C. Circuit remanded several rules for implementation of earlier PM2.5 NAAQS to the U.S. EPA for revision of certain aspects of the rules, with a requirement that the U.S. EPA re-promulgate regulations in conformance with the correct subparts of the Clean Air Act.

In addition to these NAAQS, the U.S. EPA also finalized nonattainment designations for certain areas in the United States for the 2010 one-hour SO_2 standard on August 5, 2013, and indicated that additional nonattainment areas will be designated in a future rulemaking. U.S. EPA will require states to submit state implementation plans (SIPs) for nonattainment areas by April 2015. With regard to Texas and Maryland, no nonattainment areas were identified in EPA's final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. The U.S. EPA will follow the approach outlined in a February 2013 U.S. EPA strategy document that establishes a process and timeline for the Agency to address additional designations in states' counties under a future rulemaking. Nonattainment county compliance with the one-hour SO_2 standard is required by October 2018. While significant SO2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the requirements of pending states' SIPs to further reduce SO_2 emissions in support of attainment of the one hour SO_2 standard.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Notices and Finding of Violations and Midwest Generation Bankruptcy. In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

Under a supplemental agreement reached in 2003, Midwest Generation agreed to reimburse ComEd and Generation for 50% of the specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement.

On December 17, 2012 (Petition Date), EME and certain of its subsidiaries, including Midwest Generation, filed for protection under Chapter 11 of the U.S. Bankruptcy Code.

In 2012, the Bankruptcy Court approved the rejection of an agency agreement related to a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations incurred under the coal rail car lease. The rejection left Generation as the party responsible for making all remaining payments under the lease and performing all other obligations thereunder. In January 2013, Generation made the final $10 million payment due under the lease agreement which had been accrued at December 31, 2012.

On January 17, 2014, Midwest Generation filed a plan supplement to its bankruptcy filing that included a list of contracts to be rejected upon the effective date of the reorganization plan. This list included the sale agreement, including the environmental indemnity, and the asbestos cost-sharing agreement.

On March 11, 2014, the Bankruptcy Court for the Northern District of Illinois entered its Order Confirming Debtors' Joint Chapter 11 Plan of Reorganization. On April 1, 2014 (Effective Date), NRG Energy purchased EME's portfolio of generation, including Midwest Generation and the Joint Chapter 11 Plan of Reorganization (Plan) became effective. As part of the Plan, the sale agreement, including the environmental indemnity, and the asbestos cost-sharing agreement were rejected. Creditors were provided 30 days from the Effective Date to file rejection damages claims associated with contracts rejected under the Plan.

During the second quarter of 2013, Exelon filed proofs of claim for approximately $21 million with the Bankruptcy Court for amounts owed by EME and Midwest Generation for the coal rail car lease, ComEd utility payments and certain legal costs. Further, Exelon filed an environmental claim with an unspecified amount that listed the indemnifications that were in place pre-Petition Date and other factors associated with the remediation and a claim under the asbestos cost-sharing agreement with an unspecified amount. As of June 30, 2014, Exelon has not recorded a receivable for the filed proofs of claim because recovery of any amount cannot be assured at this point in the bankruptcy. Exelon will not record claim recoveries unless and until they are realized.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in Exelon's 2001 corporate restructuring to assume ComEd's rights and obligations associated with its former generation business)

could face liability (along with any other potentially responsible parties) for environmental conditions at the stations requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors. ComEd and Generation have reviewed available public information as to potential environmental exposures regarding the Midwest Generation station sites. Midwest Generation publicly disclosed in its March 31, 2014 Form 10-Q that (i) it has accrued a probable amount of approximately $9 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at two Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Crawford, Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted. For these reasons, ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations and as a result no liability has been recorded as of June 30, 2014. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Generation increased its reserve for asbestos-related bodily injury claims at December 31, 2013 by $25 million, as a result of Midwest Generation listing such agreement in the January 2014 plan supplement as an agreement to be rejected in connection with the Plan. As discussed above, the rejection became effective as part of the Plan. Subsequently, Generation increased its reserve by $15 million pursuant to the second quarter 2014 actuarial study of such claims, of which an estimated $6 million pertains to Midwest Generation's share. Midwest Generation publicly disclosed in its March 31, 2014 Form 10-Q that it had $53 million recorded related to asbestos bodily injury claims under the contractual indemnity with ComEd. Exelon and Generation may be entitled to damages associated with the rejection of the agreement. These amounts are considered to be contingent gains and would not be recognized until realized.

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the anticipated landfill cover remediation for the site is approximately $42 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the supplemental feasibility study, and subsequently requested additional analysis sampling and modeling that will be conducted throughout 2014 and into 2015. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment, but will likely be sometime in 2015 at the earliest. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2014 so that settlement discussions could proceed. Based on Generation's preliminary review, it appears probable that Generation has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the Exelon defendants) and Cotter. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the Exelon defendants' negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which were subsequently granted. Since May 30, 2012, several related lawsuits have been filed in the same court on behalf of various plaintiffs against Cotter and other defendants, but not Exelon. The allegations in these related lawsuits mirror the initially filed lawsuits. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price-Anderson Act. On July 8, 2013, the plaintiffs filed amended complaints under the Price-Anderson Act. Cotter moved to dismiss the amended complaints and has motions currently pending before the court. At this stage of the litigation, Exelon, Generation, and ComEd cannot estimate a range of loss, if any.

On April 11, 2014, a class action complaint was filed in the U.S. District Court for the Eastern District of Missouri against Cotter and six additional defendants. The complaint alleges that individuals living in the North St. Louis area within a three-mile radius of the West Lake Landfill suffered damage to property or loss of use of property due to the defendants' negligent handling of radioactive materials. Plaintiffs have asserted claims for monetary damages under the Price-Anderson Act. At this stage of the litigation, Exelon and Generation cannot estimate a range of loss, if any.

68 th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The PRP's submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be

allocated among all of the PRPs is in the range of $50 million to $64 million. On September 30, 2013, U.S. EPA issued the Record of Decision identifying its preferred remedial alternative for the site. The estimated cost for the alternative chosen by U.S. EPA is consistent with the PRPs estimated range of costs noted above. Based on Generation's preliminary review, it appears probable that Generation has liability and has established an appropriate accrual for its share of the estimated clean-up costs. A wholly owned subsidiary of Generation has agreed to indemnify BGE for most of the costs related to this settlement and clean-up of the site.

Rossville Ash Site. The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC (CPSG). In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately $6 million, which has been fully reserved as of June 30, 2014.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRP's signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRP's to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA's position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations (the Tailoring Rule) relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a CO_2 equivalent basis, and to modifications to existing sources that result in emissions increases greater than 75,000 tons per year on a CO_2 equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. On July 2, 2012 the U.S. EPA declined to lower GHG permit thresholds in its final "Step 3" Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per curium* decision, dismissed industry and state petitions challenging the U.S. EPA's "Tailpipe Rule" for cars and light duty trucks, the endangerment finding for GHG's from stationary sources, and the Tailoring Rule. On October 15, 2013, the U.S. Supreme Court granted industry petitions to review one aspect of the PSD permitting regulations. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case by case basis. Generation could be significantly affected by the regulations if it were to build new plants or modify existing plants.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

On June 25, 2013, President Obama announced "The President's Climate Action Plan," a summary of executive branch actions intended to: reduce carbon emissions; prepare the United States for the impacts of climate change; and lead international efforts to combat global climate change and prepare for its impacts. Concurrent with the announcement of the Administration's plan, the President also issued a Memorandum for the Administrator of the Environmental Protection Agency that focused on power generation sector carbon reductions under the Section 111 New Source Performance Standards (NSPS) section of the federal Clean Air Act. The memorandum directs the U.S. EPA Administrator to issue two sets of proposed rulemakings with regard to power plant carbon emissions under Section 111 of the Clean Air Act.

The first rulemaking, under Section 111(b) of the Clean Air Act, focuses on establishing carbon regulations for new fossil-fuel power plants. This rulemaking was proposed on September 20, 2013 and is to be finalized "in a timely fashion." In the proposed rule, U.S. EPA sets separate standards for fossil-fuel fired utility boilers and natural gas fired stationary combustion turbines.

The second rulemaking, under Section 111(d) of the Clean Air Act, focuses on modified, reconstructed and existing fossil power plants. The proposed rule was published in the Federal Register on June 18, 2014 and is open for public comment until October 16, 2014. The Climate Action Plan calls for the rule to be finalized no later than June 1, 2015, and requires that states submit to U.S. EPA their implementation plans no later than June 30, 2016. The proposed rule establishes emission reduction targets for each state and provides flexibility for each state to determine how to achieve its required reductions, including heat rate improvements at coal-fired power plants, fuel switching from coal to gas, renewable generation and new nuclear facilities, demand side energy efficiency, and the use of market-based instruments.

To the extent that the final Section 111(d) rule results in emission reductions from fossil fuel fired plants, and thereby imposes some form of direct or indirect price of carbon in competitive electricity markets, Exelon's overall low carbon generation portfolio results could benefit.

Litigation and Regulatory Matters

Except to the extent noted below, the circumstances set forth in Note 22 of the Exelon 2013 Form 10-K describe, in all material respects, the current status of litigation matters. The following is an update to that discussion.

Asbestos Personal Injury Claims (Exelon, Generation, PECO and BGE)

Exelon and Generation . Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At June 30, 2014 and December 31, 2013, Generation had reserved approximately $104 million and $90 million, respectively, in total for asbestos-related bodily injury claims. As of June 30, 2014, approximately $21 million of this amount related to 247 open claims presented to Generation, while the remaining $83 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary. During the second quarter of 2014, Generation increased its reserve by approximately $15 million, primarily due to increased actual and projected number and severity of claims.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee's disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee's last employment-based exposure, and that therefore the exclusivity provision of the Act does not preclude such employee from suing his or her employer in court. The Supreme Court's ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee's last employment-based exposure to asbestos. Currently, Exelon, Generation and PECO are unable to predict whether and to what extent they may experience additional claims in the future as a result of this ruling; as such no increase to the asbestos-related bodily injury liability has been recorded as of June 30, 2014. Increased claims activity resulting from this ruling could have a material adverse effect on Exelon's, Generation's and PECO's future results of operations and cash flows.

BGE . Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of "premises liability," alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

Approximately 486 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.

Discovery begins in these cases after they are placed on the trial docket. At present, only two of the pending cases are set for trial. Given the limited discovery in these cases, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

- the identity of the facilities at which the plaintiffs allegedly worked as contractors;
- the names of the plaintiffs' employers;
- the dates on which and the places where the exposure allegedly occurred; and
- the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

Continuous Power Interruption (ComEd)

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd's service territory, as well as for five other storm systems that affected ComEd's customers during June and July 2011 (Summer 2011 Storm Docket). In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket).

On June 5, 2013, the ICC approved a complete waiver of liability for five of the six summer storms and the February 2011 blizzard. The ICC held that for the July 11, 2011 storm, 34,559 interruptions were preventable and therefore no waiver should apply. As required by the ICC's Order, ComEd notified relevant customers that they may be entitled to seek reimbursement of incurred costs in accordance with a claims procedure established under ICC rules and regulations. In addition, the ICC found that ComEd did not systematically fail in its duty to provide adequate, reliable and safe service. As a result, the ICC rejected the Illinois Attorney General's request for the ICC to open an investigation into ComEd's infrastructure and storm hardening investments.

Following the ICC's June 26, 2013 denial of ComEd's request for rehearing, on June 27, 2013 ComEd filed an appeal of both the summer and winter storm dockets with the Illinois Appellate Court regarding the ICC's interpretation of Section 16-125 of the Illinois Public Utilities Act. On July 31, 2014, the Illinois Appellate Court reaffirmed the ICC's decision in the appeal of the Summer 2011 Storm Docket and dismissed the appeal of the February 2011 Blizzard Docket. The Illinois Appellate Court's opinion has no accounting impact as ComEd previously established a liability in connection with the June 5, 2013 ICC ruling discussed below.

As a result of the ICC's June 5, 2013 ruling, ComEd established a liability, which was not material, for potential reimbursements for actual damages incurred by the 34,559 customers covered by the ICC's June 5, 2013 Order. The liability recorded represents the low end of a range of potential losses given that no amount within the range represents a better estimate. ComEd's ultimate liability will be based on actual claims eligible for reimbursement as well as the outcome of the appeal. Although reimbursements for actual damages will differ from the estimated accrual recorded, at this time ComEd does not expect the difference to be material to ComEd's results of operations or cash flows.

ComEd has not recorded an accrual for reimbursement of local governmental emergency and contingency expenses as a range of loss, if any, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows.

Telephone Consumer Protection Act Lawsuit (ComEd)

On November 19, 2013, a class action complaint was filed in the Northern District of Illinois on behalf of a single individual and a presumptive class that would include all customers that ComEd enrolled in its Outage Alert text message program. The complaint alleges that ComEd violated the Telephone Consumer Protection Act ("TCPA") by sending approximately 1.2 million text messages to customers without first obtaining their consent to receive such messages. The complaint seeks certification of a class along with statutory damages, attorneys' fees, and an order prohibiting ComEd from sending additional text messages. Such statutory damages could range from $500 to $1,500 per text. On February 21, 2014, ComEd filed a motion to dismiss this class action complaint and intends to contest the allegations of this suit. On June 4, 2014, ComEd's motion to dismiss was denied. As of June 30, 2014, ComEd has a reserve, which is not material, representing its best estimate of probable loss associated with this class action complaint. As ComEd is unable to predict the ultimate outcome of this proceeding, actual damages may differ from the estimated amount recorded, which may be material to ComEd's results of operations, cash flows, and financial position.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Baltimore City Franchise Taxes (BGE)

The City of Baltimore claims that BGE has maintained electric facilities in the City's public right-of-ways for over one hundred years without the proper franchise rights from the City. BGE has reviewed the City's claim and believes that it lacks merit. BGE has not recorded an accrual for payment of franchise fees for past periods as a range of loss, if any, cannot be reasonably estimated at this time. Franchise fees assessed in future periods may be material to BGE's results of operations and cash flows.

General (Exelon, Generation, ComEd, PECO and BGE)

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Income Taxes (Exelon, Generation, ComEd, PECO and BGE)

See Note 11 — Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

19. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2014 and 2013:

Three Months Ended June 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a]					
Regulatory agreement units	$ 68	$ 68	$ —	$ —	$—
Non-regulatory agreement units	38	38	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	172	172	—	—	—
Non-regulatory agreement units	128	128	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	10	10	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(204)	(204)	—	—	—
Total decommissioning-related activities	212	212	—	—	—
Investment income (expense)	7	7	—	(1)	2[c]
Long-term lease income	10	—	—	—	—
Interest income (expense) related to uncertain income tax positions	(2)	3	—	—	—
AFUDC — Equity	5	—	—	1	3
Other	11	6	5	1	—
Other, net	$ 243	$ 228	$ 5	$ 1	$ 5

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a]					
Regulatory agreement units	$ 111	$ 111	$ —	$ —	$—
Non-regulatory agreement units	63	63	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	234	234	—	—	—
Non-regulatory agreement units	141	141	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	20	20	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(299)	(299)	—	—	—
Total decommissioning-related activities	270	270	—	—	—
Investment income (expense)	8	8	—	(1)	4[c]
Long-term lease income	17	—	—	—	—
Interest income related to uncertain income tax positions	7	17	—	—	—
AFUDC — Equity	11	—	3	3	6
Other	35	23	7	1	(1)
Other, net	$ 348	$ 318	$ 10	$ 3	$ 9

Three Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a]					
Regulatory agreement units	$ 47	$ 47	$ —	$ —	$—
Non-regulatory agreement units	16	16	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory agreement units	(102)	(102)	—	—	—
Non-regulatory agreement units	(40)	(40)	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	2	2	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	40	40	—	—	—
Total decommissioning-related activities	(37)	(37)	—	—	—
Investment income (expense)	2	—	—	(1)	2[c]
Long-term lease income	5	—	—	—	—
Interest expense related to uncertain income tax positions	(1)	(2)	—	—	—
AFUDC — Equity	5	—	3	1	2
Other	9	6	3	—	—
Other, net	$ (17)	$ (33)	$ 6	$ —	$ 4

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds [a]					
Regulatory agreement units	$ 84	$ 84	$ —	$ —	$—
Non-regulatory agreement units	30	30	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	92	92	—	—	—
Non-regulatory agreement units	24	24	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	3	3	—	—	—
Regulatory offset to decommissioning trust fund-related activities [b]	(148)	(148)	—	—	—
Total decommissioning-related activities	85	85	—	—	—
Investment income (expense)	5	(1)	—	(1)	5[c]
Long-term lease income	13	—	—	—	—
Interest income related to uncertain income tax positions	24	3	—	—	—
AFUDC — Equity	12	—	6	2	4
Other	16	8	5	2	—
Other, net	$ 155	$ 95	$ 11	$ 3	$ 9

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 15 — Asset Retirement Obligations of the Exelon 2013 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE's rate stabilization deferral. See Note 5 — Regulatory Matters for additional information regarding the rate stabilization deferral.

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the six months ended June 30, 2014 and 2013:

Six Months Ended June 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,015	$ 444	$ 290	$112	$142
Regulatory assets	117	—	57	5	55
Amortization of intangible assets, net	22	22	—	—	—
Amortization of energy contract assets and liabilities [a]	113	118	—	—	—
Nuclear fuel [b]	499	499	—	—	—
ARO accretion [c]	159	159	—	—	—
Total depreciation, amortization, accretion and depletion	$1,925	$ 1,242	$ 347	$117	$197

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 942	$ 402	$ 275	$109	$128
Regulatory assets	112	—	62	4	47
Amortization of intangible assets, net	22	22	—	—	—
Amortization of energy contract assets and liabilities [a]	306	344	—	—	—
Nuclear fuel [b]	454	454	—	—	—
ARO accretion [c]	136	136	—	—	—
Total depreciation, amortization, accretion and depletion	$1,972	$ 1,358	$ 337	$113	$175

(a) Included in Operating revenues or Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(c) Included in Operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Six Months Ended June 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 315	$ 139	$ 96	$ 21	$ 33
Loss from equity method investments	20	20	—	—	—
Provision for uncollectible accounts	59	8	(8)	28	30
Stock-based compensation costs	68	—	—	—	—
Other decommissioning-related activity [a]	(85)	(85)	—	—	—
Energy-related options [b]	63	63	—	—	—
Amortization of regulatory asset related to debt costs	5	—	4	1	—
Amortization of rate stabilization deferral	33	—	—	—	33
Amortization of debt fair value adjustment	(26)	(12)	—	—	—
Discrete impacts of EIMA [c]	9	—	9	—	—
Amortization of debt costs	19	6	(3)	1	1
Increase in inventory reserve	3	3	1	—	—
Impairment of investments in direct financing leases [e]	24	—	—	—	—
Impairment charges [f]	86	86	—	—	—
Other	(26)	(19)	—	(1)	(8)
Total other non-cash operating activities	$ 567	$ 209	$ 99	$ 50	$ 89
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 60	$ —	$ 61	$ (6)	$ 8
Other regulatory assets and liabilities	(25)	—	(30)	(13)	(49)
Other current assets	(157)	13	(5)	(89) [h]	51
Other noncurrent assets and liabilities	(158)	(69)	22	(6)	(2)
Total changes in other assets and liabilities	$ (280)	$ (56)	$ 48	$(114)	$ 8
Non-cash investing and financing activities:					
Fair value of net assets recorded upon CENG consolidation [j]	$3,400	$ 3,400	$ —	$ —	$ —
Issuance of equity units [k]	131	—	—	—	—
Uranium procurement [l]	38	38	—	—	—
Indemnification of like-kind exchange position [m]	—	—	2	—	—
Total non-cash investing and financing activities:	$3,569	$ 3,438	$ 2	$ —	$ —

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Six Months Ended June 30, 2013	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 409	$ 173	$ 154	$ 21	$ 27
Loss in equity method investments	30	30	—	—	—
Provision for uncollectible accounts	55	10	4	27	14
Stock-based compensation costs	70	—	—	—	—
Other decommissioning-related activity [a]	(62)	(62)	—	—	—
Energy-related options [b]	65	65	—	—	—
Amortization of regulatory asset related to debt costs	6	—	5	1	—
Amortization of rate stabilization deferral	29	—	—	—	29
Amortization of debt fair value adjustment	(22)	(22)	—	—	—
Discrete impacts from EIMA [c]	(126)	—	(126)	—	—
Amortization of debt costs	8	5	2	1	—
Merger integration costs [d]	(6)	—	—	—	(6)
Impairment of investments in direct financing leases [e]	14	—	—	—	—
Increase in inventory reserve	13	13	—	—	—
Impairment charges [g]	110	110	—	—	—
Other	(17)	(7)	—	—	(3)
Total other non-cash operating activities	$ 576	$ 315	$ 39	$ 50	$ 61
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ (24)	$ —	$ (61)	$ 19	$ 18
Other regulatory assets and liabilities	3	—	(28)	(5)	(82)
Other current assets	(123)	(134)	2	(62) [h]	99
Other noncurrent assets and liabilities	277	(34)	304[i]	(1)	28
Total changes in other assets and liabilities	$ 133	$ (168)	$ 217	$ (49)	$ 63
Non-cash investing and financing activities:					
Consolidated VIE dividend to non-controlling interest	$ 63	63	—	—	—
Indemnification of like-kind exchange position [l]	—	—	174	—	—
Total non-cash investing and financing activities	$ 63	$ 63	$ 174	$ —	$ —

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15 of the Exelon 2013 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 5 — Regulatory Matters for more information.
(d) Relates to integration costs to achieve distribution synergies related to the Constellation merger transaction. See Note 5 — Regulatory Matters for more information.
(e) Relates to an other than temporary decline in the estimated residual value of Exelon's direct financing leases. See Note 7 — Impairment of Long-Lived Assets for more information.
(f) Relates to the impairment of long-lived assets at Generation. See Note 7 — Impairment of Long-Lived Assets for additional information.
(g) Relates to the cancellation of uprate projects at Generation. See Note 7 — Impairment of Long-Lived Assets for additional information.
(h) Relates primarily to prepaid utility taxes.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(i) Relates primarily to interest payable related to like-kind exchange tax position. See Note 11 — Income Taxes for discussion of the like-kind exchange tax position.
(j) See Note 6 — Investment in Constellation Energy Nuclear Group, LLC for additional information.
(k) Relates to the present value of the contract payments for the equity units issued by Exelon. See Note 16 — Common Stock for additional information.
(l) Relates to the nuclear fuel procurement contract for the purchase of a fixed quantity of uranium, which was delivered to Generation on June 30, 2014. Generation is required to make payments starting June 30, 2016, with the final payment being due no later than June 30, 2018.
(m) See Note 11 — Income Taxes for discussion of the like-kind exchange tax position.

DOE Smart Grid Investment Grant (Exelon, BGE and PECO). For the six months ended June 30, 2014, PECO has included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $2 million and reimbursements of $3 million related to PECO's DOE SGIG programs. For the six months ended June 30, 2013, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $41 million, $12 million and $29 million, respectively, and reimbursements of $50 million, $16 million and $34 million, respectively, related to PECO's and BGE's DOE SGIG programs. See Note 5 — Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of June 30, 2014 and December 31, 2013.

June 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$14,369[a]	$ 7,397[a]	$3,325	$2,969	$2,781
Accounts receivable:					
Allowance for uncollectible accounts	293	56	71	124	42

December 31, 2013	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$13,713[b]	$ 7,034[b]	$3,184	$2,935	$2,702
Accounts receivable:					
Allowance for uncollectible accounts	272	57	62	107	46

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $2,411 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,371 million.

PECO Installment Plan Receivables (Exelon and PECO)

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $21 million as of June 30, 2014 and $19 million as of December 31, 2013. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology

discussed in Note 1 — Significant Accounting Policies of the Exelon 2013 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at June 30, 2014 of $20 million consists of $1 million, $4 million and $15 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2013 of $18 million consists of $1 million, $4 million and $13 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of June 30, 2014 and December 31, 2013 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1 — Significant Accounting Policies of the Exelon 2013 Form 10-K.

20. Segment Information (Exelon, Generation, ComEd, PECO and BGE)

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants.

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation's six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other regions not considered individually significant referred to collectively as "Other Regions"; including the South, West and Canada. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon's CODM evaluates the performance of and allocates resources to ComEd, PECO and BGE based on net income and return on equity.

The CODMs for ComEd, PECO, and BGE evaluate performance and allocate resources for their respective companies based on net income and return on equity for ComEd, PECO, and BGE each as single integrated businesses.

The foundation of Generation's six reportable segments is based on the geographic location of its assets, and is largely representative of the footprints of an ISO / RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

- Other Regions not considered individually significant:
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The CODMs for Exelon and Generation evaluate the performance of Generation's power marketing activities and allocate resources based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and sales to its affiliates, ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's own generation and fuel costs associated with tolling agreements. Generation's other business activities, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, and investments in energy-related proprietary technology are not allocated to regions. Further, Generation's other miscellaneous revenues, unrealized mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger with Constellation and the consolidation of CENG are also not allocated to a region.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three months ended June 30, 2014 and 2013 is as follows:

Three Months Ended June 30, 2014 and 2013

	Generation [a]	ComEd	PECO	BGE	Other [b]	Intersegment Eliminations	Exelon
Total revenues [c]:							
2014	$ 3,789	$ 1,128	$ 656	$ 653	$ 329	$ (531)	$ 6,024
2013	4,070	1,080	672	653	297	(631)	6,141
Intersegment revenues [d]:							
2014	$ 201	$ —	$ —	$ 2	$ 328	$ (531)	$ —
2013	329	—	—	4	298	(631)	—
Net income (loss):							
2014	$ 372	$ 111	$ 84	$ 19	$ (29)	$ —	$ 557
2013	328	96	78	25	(30)	—	497
Total assets:							
June 30, 2014	$ 44,422	$24,544	$9,761	$7,877	$ 8,769	$ (11,717)	$83,656
December 31, 2013	41,232	24,118	9,617	7,861	8,317	(11,221)	79,924

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the three months ended June 30, 2014

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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include revenue from sales to PECO of $49 million and sales to BGE of $87 million in the Mid-Atlantic region, and sales to ComEd of $65 million in the Midwest region. For the three months ended June 30, 2013 intersegment revenues for Generation include revenue from sales to PECO of $97 million and sales to BGE of $99 million in the Mid-Atlantic region, sales to ComEd of $121 million in the Midwest region, and $10 million related to the unrealized mark-to-market gains related to the ComEd swap, which eliminate upon consolidation.

(b) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.

(c) For the three months ended June 30, 2014 and 2013, utility taxes of $21 million and $18 million, respectively, are included in revenues and expenses for Generation. For the three months ended June 30, 2014 and 2013, utility taxes of $56 million and $56 million, respectively, are included in revenues and expenses for ComEd. For the three months ended June 30, 2014 and 2013, utility taxes of $30 million and $31 million, respectively, are included in revenues and expenses for PECO. For the three months ended June 30, 2014 and 2013, utility taxes of $19 million and $19 million, respectively, are included in revenues and expenses for BGE.

(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

Generation total revenues (three months ended):

	2014			2013		
	Revenues from external customers [a]	Intersegment revenues	Total Revenues	Revenues from external customers [a]	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 1,272	$ 5	$ 1,277	$ 1,220	$ 9	$ 1,229
Midwest	981	—	981	1,076	(5)	1,071
New England	211	1	212	209	(20)	189
New York	194	—	194	175	(1)	174
ERCOT	198	(1)	197	319	(4)	315
Other Regions [b]	314	(6)	308	246	(6)	240
Total Revenues for Reportable Segments	3,170	(1)	3,169	3,245	(27)	3,218
Other [c]	619	1	620	825	27	852
Total Generation Consolidated Operating Revenues	$ 3,789	$ —	$ 3,789	$ 4,070	$ —	$ 4,070

(a) Includes all electric sales to third parties and affiliated sales to ComEd, PECO and BGE.

(b) Other regions include the South, West and Canada, which are not considered individually significant.

(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the date of merger with Constellation and the consolidation of CENG in purchase accounting of $88 million and $234 million, for the three months ended June 30, 2014 and 2013, respectively, and elimination of intersegment revenues.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Generation total revenues net of purchased power and fuel expense (three months ended):

	2014			2013		
	RNF from external customers [a]	Intersegment RNF	Total RNF	RNF from external customers [a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 906	$ 14	$ 920	$ 770	$ (2)	$ 768
Midwest	604	1	605	687	(3)	684
New England	88	(24)	64	85	(35)	50
New York	142	6	148	—	14	14
ERCOT	117	(58)	59	143	(31)	112
Other Regions [b]	157	(82)	75	111	(52)	59
Total Revenues net of purchased power and fuel expense for Reportable Segments	2,014	(143)	1,871	1,796	(109)	1,687
Other [c]	(60)	143	83	328	109	437
Total Generation Revenues net of purchased power and fuel expense	$ 1,954	$ —	$ 1,954	$ 2,124	$ —	$ 2,124

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the date of merger with Constellation and the consolidation of CENG in purchase accounting of $50 million and $167 million for the three months ended June 30, 2014 and 2013, respectively, and the elimination of intersegment revenues.

Six Months Ended June 30, 2014 and 2013

	Generation [a][b]	ComEd	PECO	BGE	Other [c]	Intersegment Eliminations	Exelon
Total revenues [d]:							
2014	$ 8,179	$2,262	$1,649	$1,707	$ 619	$ (1,155)	$13,261
2013	7,603	2,239	1,567	1,533	615	(1,334)	12,223
Intersegment revenues [e]:							
2014	$ 517	$ 1	$ 1	$ 18	$ 618	$ (1,155)	$ —
2013	710	1	—	8	615	(1,334)	—
Net income (loss):							
2014	$ 188	$ 209	$ 173	$ 106	$ (25)	$ —	$ 651
2013	310	14	200	106	(132)	—	498

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the six months ended June 30, 2014 include revenue from sales to PECO of $137 million and sales to BGE of $207 million in the Mid-Atlantic region, and sales to ComEd of $173 million in the Midwest region. For the six months ended June 30, 2013 intersegment revenues for Generation include revenue from sales to PECO of $238 million in the Mid-Atlantic region and sales to BGE of $212 million in the Mid-Atlantic region, and sales to ComEd of $266 million in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation.
(b) Amounts include activity recorded at CENG from April 1, 2014, the date of integration, through June 30, 2014.
(c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
(d) For the six months ended June 30, 2014 and 2013, utility taxes of $45 million and $39 million, respectively, are included in revenues and expenses for Generation. For the six months ended June 30, 2014 and 2013, utility taxes of $119 million and $117 million, respectively, are included in revenues and expenses for ComEd. For the six months ended June 30, 2014 and 2013, utility taxes of $65 million and $64 million, respectively, are included in revenues and expenses for PECO. For the six months ended June 30, 2014 and 2013, utility taxes of $43 million and $41 million, respectively, are included in revenues and expenses for BGE.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(e) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with the Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

Generation total revenues (six months ended):

	2014			2013		
	Revenues from external customers [a]	Intersegment revenues	Total Revenues	Revenues from external customers [a]	Intersegment revenues	Total Revenues
Mid-Atlantic [b]	$ 2,713	$ (18)	$ 2,695	$ 2,551	$ 1	$ 2,552
Midwest	2,239	12	2,251	2,257	2	2,259
New England	756	5	761	600	(8)	592
New York [b]	384	(3)	381	350	(7)	343
ERCOT	441	(1)	440	612	(4)	608
Other Regions [c]	648	1	649	429	36	465
Total Revenues for Reportable Segments	7,181	(4)	7,177	6,799	20	6,819
Other [d]	998	4	1,002	804	(20)	784
Total Generation Consolidated Operating Revenues	$ 8,179	$ —	$ 8,179	$ 7,603	$ —	$ 7,603

(a) Includes all wholesale and retail electric sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Amounts include activity recorded at CENG from April 1, 2014, the date of integration, through June 30, 2014.
(c) Other regions include the South, West and Canada, which are not considered individually significant.
(d) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the date of merger with Constellation and the consolidation of CENG in purchase accounting of $180 million and $478 million, for the six months ended June 30, 2014 and 2013, respectively, and elimination of intersegment revenues.

Generation total revenues net of purchased power and fuel expense (six months ended):

	2014			2013		
	RNF from external customers [a]	Intersegment RNF	Total RNF	RNF from external customers [a]	Intersegment RNF	Total RNF
Mid-Atlantic [b]	$ 1,690	$ (75)	$1,615	$ 1,622	$ (10)	$1,612
Midwest	1,134	27	1,161	1,397	4	1,401
New England	242	(42)	200	103	(23)	80
New York [b]	113	14	127	(16)	8	(8)
ERCOT	272	(130)	142	255	(42)	213
Other Regions [c]	307	(127)	180	122	(17)	105
Total Revenues net of purchased power and fuel expense for Reportable Segments	3,758	(333)	3,425	3,483	(80)	3,403
Other [d]	(770)	333	(437)	6	80	86
Total Generation Revenues net of purchased power and fuel expense	$ 2,988	$ —	$2,988	$ 3,489	$ —	$3,489

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.

(b) Amounts include activity recorded at CENG from April 1, 2014, the date of integration, through June 30, 2014.
(c) Other regions include the South, West and Canada, which are not considered individually significant.
(d) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the date of merger with Constellation and the consolidation of CENG in purchase accounting of $92 million and $341 million, for the six months ended June 30, 2014 and 2013, respectively.

21. Subsequent Events (Exelon, Generation and PECO)

Summer storms during July 2014 interrupted electric service delivery in PECO's service territory. Restoration efforts included significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies. PECO estimates that restoration efforts will result in $10 million to $20 million of incremental operating and maintenance expense and $10 million to $20 million of incremental capital expenditures for the third quarter of 2014.

On July 29, 2014, Generation entered into a Stock Purchase Agreement (the Purchase Agreement) with Integrys Energy Group, Inc. (Integrys). Pursuant to the Purchase Agreement, Integrys agreed to sell its competitive retail electric and natural gas businesses through a sale of all of the stock of its wholly-owned subsidiary, Integrys Energy Services, Inc. (IES), to Generation for an all cash purchase price of $60 million plus adjusted net working capital at the time of the closing. IES's adjusted net working capital balance was approximately $183 million as of May 31, 2014. Pursuant to the Purchase Agreement, Generation has agreed to use its commercially reasonable efforts to replace the guarantees and other credit support currently being provided by Integrys for IES in support of the ongoing competitive retail businesses and to reimburse Integrys for any payments arising pursuant to such arrangements continuing for any post-closing period. The generation and solar asset businesses of IES are excluded from the transaction.

The transaction is expected to close in the fourth quarter of 2014 or the first quarter of 2015. The closing of the transaction is subject to certain conditions, included, among others, approval by the FERC and expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. Either party may terminate the Purchase Agreement if the transaction has not been consummated by the 6 month anniversary of the date of the Purchase Agreement, subject to an extension of up to 180 days, if necessary, to obtain regulatory approval. The Purchase Agreement also includes various representations, warranties, covenants, indemnification and other provisions customary for a transaction of this nature.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

(Dollars in millions except per share data, unless otherwise noted)

Exelon Corporation

General

Exelon, a utility services holding company, operates through the following principal subsidiaries:

- *Generation,* whose integrated business consists of owned, contracted and investments in electric generating facilities managed through customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities.
    - As a result of the Constellation merger, Generation owns a 50.01% interest in CENG. On April 1, 2014, Generation assumed the operating licenses and corresponding operational control of CENG's nuclear fleet. As a result, Exelon and Generation consolidate CENG's financial position and results of operations into their businesses.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Exelon has nine reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and other regions in Generation), ComEd, PECO and BGE. See Note 20 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

Exelon's consolidated financial information includes the results of its four separate operating subsidiary registrants, Generation, ComEd, PECO and BGE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO and BGE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Executive Overview

Financial Results. The following consolidated financial results reflect the results of Exelon for the three and six months ended June 30, 2014 compared to the corresponding periods in 2013. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended June 30,							Favorable (Unfavorable) Variance
	2014						2013	
	Generation [a]	ComEd	PECO	BGE	Other	Exelon	Exelon	
Operating revenues	$ 3,789	$1,128	$656	$653	$(202)	$6,024	$6,141	$ (117)
Purchased power and fuel	1,835	269	241	268	(201)	2,412	2,419	7
Revenue net of purchased power and fuel [b]	1,954	859	415	385	(1)	3,612	3,722	(110)
Other operating expenses								
Operating and maintenance	1,413	355	184	188	26	2,166	1,892	(274)
Depreciation and amortization	254	174	59	89	14	590	533	(57)
Taxes other than income	118	72	38	53	7	288	271	(17)
Total other operating expenses	1,785	601	281	330	47	3,044	2,696	(348)
Equity in losses of unconsolidated affiliates	(1)	—	—	—	1	—	(21)	21
Gain on consolidation of CENG	261	—	—	—	—	261	—	261
Operating income (loss)	429	258	134	55	(47)	829	1,005	(176)
Other income and (deductions)								
Interest expense, net	(86)	(80)	(28)	(27)	(17)	(238)	(252)	14
Other, net	228	5	1	5	4	243	(17)	260
Total other income and (deductions)	142	(75)	(27)	(22)	(13)	5	(269)	274
Income (loss) before income taxes	571	183	107	33	(60)	834	736	98
Income taxes (benefit)	199	72	23	14	(31)	277	239	(38)
Net income (loss)	372	111	84	19	(29)	557	497	60
Net income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	32	—	—	3	—	35	7	(28)
Net income (loss) attributable to common shareholders	$ 340	$ 111	$ 84	$ 16	$ (29)	$ 522	$ 490	$ 32

	Six Months Ended June 30, 2014						2013	Favorable (Unfavorable) Variance
	Generation [a]	ComEd	PECO	BGE	Other	Exelon	Exelon	
Operating revenues	$ 8,179	$2,262	$1,649	$1,707	$(536)	$13,261	$12,223	$ 1,038
Purchased power and fuel	5,191	589	705	797	(530)	6,752	5,400	(1,352)
Revenue net of purchased power and fuel [b]	2,988	1,673	944	910	(6)	6,509	6,823	(314)
Other operating expenses								
Operating and maintenance	2,499	681	464	376	4	4,024	3,656	(368)
Depreciation and amortization	466	347	117	197	27	1,154	1,076	(78)
Taxes other than income	223	149	80	113	15	580	548	(32)
Total other operating expenses	3,188	1,177	661	686	46	5,758	5,280	(478)
Equity in earnings (loss) of unconsolidated affiliates	(20)	—	—	—	—	(20)	(30)	10
Gain on consolidation of CENG	261	—	—	—	—	261	—	261
Operating income (loss)	41	496	283	224	(52)	992	1,513	(521)
Other income and (deductions)								
Interest expense, net	(172)	(160)	(56)	(55)	(22)	(465)	(876)	411
Other, net	318	10	3	9	8	348	155	193
Total other income and (deductions)	146	(150)	(53)	(46)	(14)	(117)	(721)	604
Income (loss) before income taxes	187	346	230	178	(66)	875	792	83
Income taxes	(1)	137	57	72	(41)	224	294	70
Net income (loss)	188	209	173	106	(25)	651	498	153
Net (loss) income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	33	—	—	6	—	39	12	(27)
Net income (loss) attributable to common shareholders	$ 155	$ 209	$ 173	$ 100	$ (25)	$ 612	$ 486	$ 126

(a) Includes the operations of CENG from April 1, 2014 through June 30, 2014.

(b) The Registrants' evaluate operating performance using the measure of revenue net of purchased power and fuel expense. The Registrants' believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013. Exelon's net income attributable to common shareholders was $522 million for the three months ended June 30, 2014 as compared to $490 million for the three months ended June 30, 2013, and diluted earnings per average common share were $0.60 for the three months ended June 30, 2014 as compared to $0.57 for the three months ended June 30, 2013.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, decreased by $110 million for the three months ended June 30, 2014 as compared to the same period in 2013. The quarter-over-quarter decrease in operating revenue net of purchased power and fuel expense was primarily due to the following unfavorable factors:

- Decrease in Generation's revenue net of purchased power and fuel expense of $442 million due to mark-to-market losses of $14 million in 2014 from economic hedging activities compared to $428 million in mark-to-market gains in 2013; and

The quarter-over-quarter decrease in operating revenue net of purchased power and fuel expense was partially offset by the following favorable factors:

- Increase in Generation's electric revenue net of purchased power and fuel expense of $184 million, primarily due to the inclusion of CENG's results for the full quarter ended June 30, 2014 and increased capacity prices related to the Reliability Pricing Model (RPM) for the PJM Interconnection, LLC (PJM) market, partially offset by lower realized energy prices, and lower generation volumes (excluding CENG);
- Decrease in Generation's amortization expense for the acquired energy contracts recorded at fair value at the date of the merger with Constellation and the integration with CENG of $117 million;
- Increase in BGE's revenue net of purchased power and fuel expense of $20 million, primarily due to increased distribution revenue as a result of 2013 electric and natural gas distribution rate case orders issued by the Maryland PSC; and
- Increase in ComEd's revenue net of purchased power expense of $27 million primarily due to higher electric distribution revenue resulting from increased capital investment and increased cost recovery associated with energy efficiency programs, partially offset by lower distribution formula rate revenue due to decreased pension and non-pension postretirement expense.

Operating and maintenance expense increased by $274 million for the three months ended June 30, 2014 as compared to the same period in 2013 primarily due to the following unfavorable factors:

- Increase in Generation's labor, contracting and materials costs of $126 million primarily due to the inclusion of CENG's results for the second quarter ended June 30, 2014;
- An increase of $61 million as a result of an increase in the number of planned nuclear refueling outage days at Generation during the second quarter;
- Long lived asset impairments of $110 million in 2014 compared to $106 million in 2013;
- An increase of $16 million in Generation's reserve for future asbestos-related bodily injury claims;
- Increased uncollectible accounts expense at BGE of $10 million; and
- Increase at ComEd of $18 million primarily relating to increased spend on energy and efficiency programs.

The year-over-year increase in operating and maintenance expense was partially offset by the following favorable factor:

- A decrease in pension and non-pension postretirement benefits expense of $57 million as a result of cost savings primarily at Exelon, Generation, and ComEd for plan design changes for certain OPEB plans, and the favorable impact of higher actuarially assumed pension and OPEB discount rates for 2014, partially offset by the inclusion of CENG's results for the second quarter of 2014.

Depreciation and amortization expense increased by $57 million primarily due to the inclusion of CENG's results for the full quarter ended June 30, 2014 and increased capital expenditures across all operating companies.

A $261 million gain recorded upon consolidation of CENG resulting from the difference in the fair value of CENG's net assets as of April 2014, and the equity method investment previously recorded on Generation's and Exelon's books and the settlement of pre-existing transactions between Generation and CENG.

Other, net increased by $260 million primarily as a result of the change in realized and unrealized gains and losses on NDT funds.

Exelon's effective income tax rates for the three months ended June 30, 2014 and 2013 were 33.2% and 32.5%, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. Exelon's net income attributable to common shareholders was $612 million for the six months ended June 30, 2014 as compared to net income attributable to common shareholders of $486 million for the six months ended June 30, 2013, and diluted earnings per average common share were $0.71 for the six months ended June 30, 2014 as compared to $0.57 for the six months ended June 30, 2013.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, decreased by $314 million for the six months ended June 30, 2014 as compared to the same period in 2013. The year-over-year decrease in operating revenue net of purchased power and fuel expense was primarily due to the following unfavorable factors:

- Decrease in Generation's revenue net of purchased power and fuel expense of $769 million due to mark-to-market losses of $744 million in 2014 from economic hedging activities compared to $25 million in mark-to-market gains in 2013.

  The year-over-year decrease in operating revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

- Increase in Generation's electric revenue net of purchased power and fuel expense of $22 million primarily due to inclusion of CENG's results for the quarter ended June 30, 2014 and increased capacity prices related to the Reliability Pricing Model (RPM) for the PJM Interconnection, LLC (PJM) market, partially offset by lower realized energy prices, higher procurement costs for replacement power, increased fossil fuel expense due to extreme cold weather during the first quarter of 2014, and lower generation volumes (excluding CENG);
- Decrease in Generation's amortization expense for the acquired energy contracts recorded at fair value at the date of the merger with Constellation and the integration with CENG of $249 million;
- Increase in BGE's revenue net of purchased power and fuel expense of $90 million, primarily due to increased distribution revenue as a result of the 2013 electric and natural gas distribution rate case orders issued by the Maryland PSC and increased cost recovery for energy efficiency and demand response programs;
- Increase in ComEd's revenue net of purchased power expense of $64 million primarily due to increased distribution revenue due to recovery of increased capital investments pursuant to ComEd's performance-based rate formula, favorable weather conditions in the first quarter of 2014, and increased cost recovery associated with energy efficiency programs, partially offset by lower distribution formula rate revenue due to decreased pension and non-pension postretirement expense; and
- Increase in PECO's revenue net of purchased power and fuel expense of $41 million, primarily due to favorable weather conditions in the first quarter of 2014.

Operating and maintenance expense increased by $368 million for the six months ended June 30, 2014 as compared to the same period in 2013 primarily due to the following unfavorable factors:

- Increase in Generation's labor, contracting and materials costs of $121 million primarily due to the inclusion of CENG's results for the second quarter ended June 30, 2014;
- An increase of $75 million as a result of an increase in the number of planned nuclear refueling outage days at Generation;
- An increase of $16 million in Generation's reserve for future asbestos-related bodily injury claims.
- An increase in storm costs at PECO and BGE of $84 million and $13 million, respectively;
- Increase at ComEd of $27 million primarily relating to increased spend on energy and efficiency programs; and
- Increased uncollectible accounts expense at BGE of $13 million.

The year-over-year increase in operating and maintenance expense was partially offset by the following unfavorable factors:

- A decrease in pension and non-pension postretirement benefits expense of $72 million as a result of cost savings primarily at Exelon, Generation, and ComEd for plan design changes for certain OPEB plans, and the favorable impact of higher actuarially assumed pension and OPEB discount rates for 2014, partially offset by the inclusion of CENG's results for the second quarter of 2014; and
- Long-lived asset impairments of $110 million in 2014 compared to $127 million in 2013.

Depreciation and amortization expense increased by $78 million primarily as a result of the inclusion of CENG's results for a full quarter in 2014, increased depreciation expense across the operating companies for ongoing capital expenditures, and higher costs related to energy efficiency and demand response program expenditures.

A $261 million gain recorded upon consolidation of CENG resulting from the difference in the fair value of CENG's net assets as of April 2014, and the equity method investment previously recorded on Generation's and Exelon's books and the settlement of pre-existing transactions between Generation and CENG.

Interest expense decreased by $411 million primarily as a result of a favorable settlement in 2014 of certain income tax positions on Constellation's 2009-2012 tax returns and the impacts of a 2013 unfavorable franchise tax settlement.

Other, net increased by $193 million primarily as a result of the change in realized and unrealized gains and losses on NDT funds.

Exelon's effective income tax rates for the six months ended June 30, 2014 and June 30, 2013 were 25.6% and 37.1%, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the three and six months ended June 30, 2014, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings. Exelon's adjusted (non-GAAP) operating earnings for the three months ended June 30, 2014 were $ 440 million, or $ 0.51 per diluted share, compared with adjusted (non-GAAP) operating earnings of $ 454 million, or $ 0.53 per diluted share, for the same period in 2013. Exelon's adjusted (non-GAAP) operating earnings for the six months ended June 30, 2014 were $970 million, or $1.12 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,056 million, or $1.23 per diluted share, for the same period in 2013. In addition to net income attributable to common shareholders, Exelon

evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three and six months ended June 30, 2014 as compared to the same period in 2013. The footnotes below the table provide tax expense (benefit) impacts:

	Three Months Ended June 30,			
	2014		2013	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 522	$ 0.60	$ 490	$ 0.57
Mark-to-Market Impact of Economic Hedging Activities (a)	8	0.01	(253)	(0.30)
Unrealized (Gains) Losses Related to NDT Fund Investments (b)	(76)	(0.09)	22	0.03
Merger and Integration Costs (c)	19	0.02	15	0.02
Amortization of Commodity Contract Intangibles (d)	23	0.03	115	0.13
Long-Lived Asset Impairment (e)	68	0.08	69	0.08
Gain on CENG integration (f)	(159)	(0.18)	—	—
PHI Acquisition Costs (g)	12	0.01	—	—
Non-Controlling Interest (h)	23	0.03	—	—
Amortization of the Fair Value of Certain Debt (i)	—	—	(4)	—
Adjusted (non-GAAP) Operating Earnings	$ 440	$ 0.51	$ 454	$ 0.53

	Six Months Ended June 30,			
	2014		2013	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 612	$ 0.71	$ 486	$ 0.57
Mark-to-Market Impact of Economic Hedging Activities [a]	451	0.52	(18)	(0.02)
Unrealized Gains Related to NDT Fund Investments [b]	(84)	(0.10)	(14)	(0.02)
Merger and Integration Costs [c]	28	0.03	43	0.05
Amortization of Commodity Contract Intangibles [d]	54	0.06	232	0.27
Long-Lived Asset Impairment [e]	68	0.08	82	0.10
Tax Settlements [j]	(35)	(0.04)	—	—
Gain on CENG integration [f]	(159)	(0.18)	—	—
PHI Acquisition Costs [g]	12	0.01	—	—
Non-Controlling Interest [h]	23	0.03	—	—
Plant Retirement and Divestitures [k]	—	—	(13)	(0.02)
Amortization of the Fair Value of Certain Debt [i]	—	—	(7)	(0.01)
Remeasurement of Like-Kind Exchange Tax Position [l]	—	—	265	0.31
Adjusted (non-GAAP) Operating Earnings	$ 970	$ 1.12	$1,056	$ 1.23

(a) Reflects the impact of losses (gains) for the three months ended June 30, 2014 and June 30, 2013 (net of taxes of $(6) million and $163 million, respectively), and six months ended June 30, 2014 and June 30, 2013 (net of taxes of $(293) million and $13 million, respectively), on Generation's economic hedging activities. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized (gains) losses for the three months ended June 30, 2014 and June 30, 2013 (net of taxes of $41 million and $(41) million, respectively), and six months ended June 30, 2014 and June 30, 2013 (net of taxes of $47 million and $27 million, respectively), on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 12 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Reflects certain costs incurred for the three months ended June 30, 2014 and June 30, 2013 (net of taxes of $3 million and $(10) million, respectively) and for the six months ended June 30, 2014 and June 30, 2013 (net of taxes of $(2) million and $(4) million, respectively), associated with the Constellation merger and CENG integration, including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses) integration initiatives and certain pre-acquisition contingencies.

(d) Reflects the non-cash impact for the three months ended June 30, 2014 and 2013 (net of taxes of $(26) million and $(73) million, respectively), and six months ended June 30, 2014 and June 30, 2013 (net of taxes of $(46) million and $(148) million, respectively), of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger date and at the CENG integration date.

(e) Reflects the 2014 charge to earnings for the three and six months ended June 30, 2014 primarily related to the impairment of certain wind generating assets (net of taxes of $(42) million). For the three and six months ended June 30, 2013, reflects a charge to earnings (net of taxes of $(44) million and $(53) million, respectively) related to Generation's cancellation of previously capitalized nuclear uprate projects.

(f) Reflects the non-cash gain recorded upon consolidation of CENG in accordance with the execution of the NOSA on April 1, 2014 (net of taxes of $103 million for the three and six months ended June 30, 2014).

(g) Reflects certain costs incurred associated with the Pepco Holdings Inc. acquisition, including professional fees and upfront credit facility fees (net of taxes of $(8) million).

(h) Represents adjustments to account for the CENG interest not owned by Generation, where applicable.

(i) Reflects the non-cash amortization of certain debt for the three and six months ended June 30, 2013 (net of taxes of $3 million and $5 million, respectively) recorded at fair value at the Constellation merger date which was retired in the second quarter of 2013.

(j) Reflects a benefit for the six months ended June 30, 2014, related to the favorable settlement in 2014 of certain income tax positions on Constellation's 2009-2012 tax returns (net of tax of $(18) million).

(k) Reflects the impact associated with the sale or retirement of generating stations (net of taxes of $5 million for the six months ended June 30, 2013).

(l) Reflects a non-cash charge to earnings resulting from the first quarter 2013 remeasurement of a like-kind exchange tax position taken on ComEd's 1999 sale of fossil generating assets (net of taxes of $(102) million for the six months ended June 30, 2013).

As discussed above, Exelon has incurred and will continue to incur costs associated with the Constellation merger, CENG transaction and PHI acquisition including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses), integration initiatives, and certain pre-acquisition contingencies.

For the three and six months ended June 30, 2014 and 2013, expense has been recognized for costs incurred to achieve the Constellation merger, CENG transaction and PHI acquisition as follows:

	Pre-tax Expense				
	Three Months Ended June 30, 2014				
Merger, Integration and Acquisition Costs:	Generation	ComEd	PECO	BGE	Exelon
Employee-Related [a]	$ 1	$ —	$ —	$—	$ 1
Other [b]	15	—	—	—	35
Total	$ 16	$ —	$ —	$—	$ 36

Merger and Integration Costs:	Pre-tax Expense Three Months Ended June 30, 2013 Generation	ComEd	PECO	BGE	Exelon
Employee-Related [a]	$ 7	$ —	$ —	$—	$ 7
Other [b]	13	—	2	1	18
Total	$ 20	$ —	$ 2	$ 1	$ 25

Merger, Integration and Acquisition Costs:	Pre-tax Expense Six Months Ended June 30, 2014 Generation	ComEd	PECO	BGE	Exelon
Employee-Related [a]	$ 5	$ —	$ —	$—	$ 5
Other [b]	25	—	—	—	45
Total	$ 30	$ —	$ —	$—	$ 50

Merger and Integration Costs:	Pre-tax Expense Six Months Ended June 30, 2013 Generation	ComEd	PECO	BGE	Exelon
Employee-Related [a]	13	—	1	—	14
Other [b]	30	—	4	(5) [c]	32
Total	$ 43	$ —	$ 5	$ (5)	$ 46

(a) Costs primarily for employee severance, pension and OPEB expense, and retention bonuses. ComEd established a regulatory asset of $1 million during the six months ended June 30, 2013. The majority of these costs are expected to be recovered over a five-year period. These costs are not included in the table above.

(b) Costs to integrate CENG and Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. For the three months ended June 30, 2014, includes professional fees at Exelon Corporate and upfront credit facility fees incurred at Exelon Corporate to acquire PHI. ComEd established a regulatory asset of $4 million and $7 million during the three and six months ended June 30, 2013, for certain other merger and integration costs, which are not included in the table above. BGE established a regulatory asset of $2 million during the six months ended June 30, 2013 for certain other merger integration costs, which are not included in the table above.

(c) BGE established a regulatory asset of $6 million at June 30, 2013 for certain 2012 other merger transaction costs as part of the 2013 electric and gas distribution rate case order which are not included in the table above.

As of June 30, 2014, Exelon projects incurring total additional PHI acquisition and integration related expenses of $265 million and $239 million, respectively, over the next five years. Exelon expects to incur total additional CENG and integration related costs of $35 million, primarily in 2014.

Pursuant to the conditions set forth by the MDPSC in its approval of the merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion. The direct investment estimate includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a twenty-year lease agreement that was contingent upon the developer obtaining all required approvals, permits and financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. The building is expected to be ready for occupancy in approximately 2 years. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information related to the lease commitments.

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Exelon's Strategy and Outlook for the remainder of 2014 and Beyond

Exelon's value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline.

Generation's electricity generation strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding Generation's regional and technological footprint. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results. Combined, the utilities plan to invest approximately $15 billion over the next five years in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Exelon's financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, and to return value to Exelon's shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

In pursuing its strategies, Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the power markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular, the prices of natural gas and coal, which drive the market prices that Generation can obtain for the output of its power plants, (2) the rate of expansion of subsidized low-carbon generation in the markets in which Generation's output is sold, (3) the effects on energy demand due to factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these market pricing issues.

Proposed Merger with Pepco Holdings, Inc. (Exelon)

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI's shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. Exelon intends to fund the all-cash transaction using a combination of approximately $3.5 billion of debt, up to $1 billion cash from asset sales primarily at Generation, and the remainder through issuance of equity (including mandatory convertible securities). In addition, Exelon entered into a 364-day $7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing, which has subsequently been reduced to $4.2 billion as a result of the equity issuances. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it purchased $90 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities in PHI, in the second quarter of 2014, with additional investments of $18 million to be made quarterly up to a maximum aggregate investment of $180 million.

The transaction must be approved by the shareholders of PHI. Completion of the transaction is also conditioned upon approval by the FERC, the District of Columbia Public Service Commission and several state

commissions including Delaware Public Service Commission, MDPSC, the New Jersey Board of Public Utilities and the Virginia Department of Public Utilities. In addition, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), the transaction cannot be completed until Exelon has made required notifications and given certain information and materials to the Federal Trade Commission (FTC) and/or the Antitrust Division of the United States Department of Justice (DOJ) and until specified waiting period requirements have expired. To date, Exelon and PHI have filed applications seeking approval of the proposed merger with the FERC, the Virginia State Corporation Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, and the New Jersey Board of Public Utilities. Exelon plans to make its filing under the HSR Act and the companies plan to file for merger approval with the MDPSC in August 2014. PHI has filed a preliminary proxy statement for a special meeting of shareholders to approve the proposed merger; a meeting date has not yet been set.

Through June 30, 2014, Exelon has incurred approximately $25 million of expense associated with the transaction, primarily related to fees incurred as part of the acquisition. Exelon currently estimates the total costs directly related to the closing of the transaction to be $265 million. As part of the applications for approval of the merger, Exelon and PHI have proposed a package of benefits to PHI utilities' customers which results in a direct investment of more than $100 million. The Merger Agreement also provides for termination rights on behalf of both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the Merger Agreement does not close due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities (described above), by means of PHI redeeming the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock.

Exelon has listed various potential risks relating to the pending merger with PHI (see Item 1A. Risk Factors), including difficulties that may be encountered in satisfying the conditions to completion of the merger and the potential for developments that might have an adverse effect on Exelon and the ability to realize the expected benefits of the merger. Exelon is taking steps to manage these risks and expects that the merger can be completed on a basis favorable to the company's shareholders and customers. Accordingly, Exelon anticipates closing the transaction in the second or third quarter of 2015. Refer to Note 4—Mergers, Acquisitions, and Dispositions for additional information on the merger transaction.

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Subsidized Generation . The rate of expansion of subsidized generation, including low-carbon generation such as wind and solar energy, in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have attempted to implement or propose legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices. For example, the New Jersey legislature enacted in to law in January 2011, the Long Term Capacity Pilot Program Act (LCAPP). LCAPP provides eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market. Under LCAPP, the local utilities in New Jersey are required to pay (or receive) the difference between the price eligible generators receive in the capacity market and the price guaranteed under the 15-year contract. New Jersey ultimately selected three proposals to participate in LCAPP and build new generation in the state. In addition, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under

which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. CPV has subsequently sought to extend that date. The CfD mandated that utilities (including BGE) pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others also challenged the selection of the three generation developers. On October 25, 2013, the U.S. District Court in New Jersey issued a judgment order finding that the New Jersey legislation violates the Supremacy Clause of the United States Constitution and the New Jersey (SOCA) contract is unenforceable. The non-prevailing parties have sought appeals in federal appellate court in the New Jersey proceeding. On October 23, 2013, the New Jersey state court dismissed the New Jersey state proceeding without prejudice, subject to the final outcome of the New Jersey federal litigation. Similarly, on October 24, 2013, the U.S. District Court in Maryland issued a judgment order finding that the MDPSC's Order directing BGE and two other Maryland electric distribution companies to enter into a CfD violates the Supremacy Clause of the United States Constitution, as described in Note 5 — Regulatory Matters of the combined Notes to Consolidated Financial Statements. However, on October 1, 2013, a Maryland State Circuit Court upheld the MDPSC Orders as being within the MDPSC's statutory authority under Maryland state law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD unenforceable under federal law. The federal judgment was affirmed on June 2, 2014, by the U.S Court of Appeals for the Fourth Circuit, and Exelon believes this judgment would prevent enforcement of the CfD even if the Maryland State Circuit Court decision stands. CPV filed for en banc review of the Fourth Circuit decision but its request was denied. CPV, one of the sellers under both a New Jersey and a Maryland contract, filed its two contracts at the FERC. Exelon believes such contracts to be void and is seeking to ensure that such contracts are not accepted by the FERC.

As required under their contracts, generator developers who were selected in the New Jersey and Maryland programs (including CPV) offered and cleared in PJM's capacity market auctions held in May 2012, 2013 and 2014. In addition, CPV has announced its intention to move forward with construction of its New Jersey plant, with or without the challenged state subsidy. Nonetheless to the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon's market driven position. While the U.S. District Court decisions in New Jersey and Maryland are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR) for future capacity auctions, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon's market driven position and could have a significant effect on Exelon's financial results of operations, financial position and cash flows.

PJM's capacity market rules include a MOPR, which is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. However, as described above, Exelon does not believe that the existing MOPR will work effectively with respect to generator developers who have a state-sponsored subsidy and has concerns with certain other aspects of PJM's rules related to the capacity auction. Accordingly, Exelon continues to work with other market stakeholders and through the FERC process to implement several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sponsored subsidy contracts and capacity market speculators) cannot inappropriately affect capacity auction prices in PJM.

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Maryland Order.

Exelon remains active in advocating for competitive markets, while opposing policies that require taxpayers and/or consumers to subsidize or give preferential treatment to specific generation providers or technologies, or that would threaten the reliability and value of the integrated electricity grid.

Energy Demand. Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for ComEd and PECO, and no projected growth for electricity for BGE. ComEd, PECO and BGE are projecting load volumes to increase by 0.8%, 0.7% and 0.0%, respectively, in 2014 compared to 2013.

Retail Competition. Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Recently, sustained low forward natural gas and power prices and low market volatility have caused retail competitors to aggressively pursue market share, and wholesale generators (including Generation) to use their retail operations to hedge generation output. These factors have adversely affected overall gross margins and profitability in Generation's retail operations.

Strategic Policy Alignment

Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's board of directors declared the second quarter 2014 dividend of $0.31 per share on Exelon's common stock. The second quarter dividend was paid on June 10, 2014 to shareholders of record on May 16, 2014. All future quarterly dividends require approval by Exelon's board of directors.

Exelon's board of directors declared the third quarter 2014 dividend of $0.31 per share on Exelon's common stock. The third quarter dividend is payable on September 10, 2014 to shareholders of record on August 15, 2014.

Exelon and Generation evaluate the economic viability of each of their generating units on an ongoing basis. Decisions regarding the future of economically challenged generating assets will be based primarily on the economics of continued operation of the individual plants. If Exelon and Generation do not see a path to sustainable profitability in any of their plants, Exelon and Generation will take steps to retire those plants to avoid sustained losses. Retirement of plants could materially affect Exelon's and Generation's results of operations, financial position, and cash flows through, among other things, potential impairment charges, accelerated depreciation and decommissioning expenses over the plants remaining useful lives, and ongoing reductions to operating revenues, operating and maintenance expenses, and capital expenditures.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2014 and 2015. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of June 30, 2014, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 75%-78% and 46%-49% for 2014, 2015, and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation's sales of energy to ComEd, PECO and BGE relating to their respective retail load obligations. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal, oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2014 through 2018 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position.

ComEd, PECO and BGE mitigate such exposure through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

Exelon is currently pursuing growth in both the utility and generation businesses focused primarily on smart meter and smart grid initiatives at the utilities and on renewables development and the nuclear uprate program at Generation. The utilities also anticipate making significant future investments in infrastructure modernization and improvement initiatives. Management continually evaluates growth opportunities aligned with Exelon's existing businesses in electric and gas distribution, electric transmission, generation, customer supply of electric and natural gas products and services, and natural gas exploration and production activities, leveraging Exelon's expertise in those areas.

Smart Meter and Smart Grid Initiatives.

ComEd's Smart Meter and Smart Grid Investments. ComEd plans to invest approximately $1.3 billion on smart meters and smart grid under EIMA, including $1.0 billion through the AMI Deployment Plan. On June 11, 2014, the ICC approved ComEd's request to accelerate the deployment, which allows for the installation of more than four million smart meters throughout ComEd's service territory by 2018, three years in advance of the originally scheduled 2021 completion date. To date, nearly 350,000 smart meters have been installed in the Chicago area by ComEd.

PECO's Smart Meter and Smart Grid Investments. In 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, under which PECO will install more than 1.6 million smart meters. PECO plans to spend up to a total of $595 million and $120 million on its smart meter infrastructure and smart grid investments, respectively, of which $200 million will be funded by SGIG.

BGE Smart Grid Initiative. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million electric and gas smart meters at an expected total cost of approximately $480 million, before considering the $200 million SGIG for smart grid and other related initiatives.

See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

Generation Renewable Development . On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar PV project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining

the project. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013 and the final two blocks coming online in 2014 making the facility fully operational. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA with Pacific Gas & Electric Company for the full output of the plant, which has been approved by the CPUC. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through June 30, 2014 were approximately $1.0 billion. In addition, Generation constructed and placed into service 400 MWs of additional wind generation in 2012 at a cost of $710 million and another 90 MW will be added to Generation's wind portfolio in 2014 with the 50 MW expansion of the Beebe project in Michigan, the output of which is fully contracted under a 20-year PPA, and the construction of the 40 MW Fourmile Wind project in Maryland to partially satisfy the Exelon-Constellation merger commitments to the State of Maryland.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Under the nuclear uprate program, Generation has placed into service projects representing 393 MWs of new nuclear generation at a cost of $1,021 million, which has been capitalized to property, plant and equipment on Exelon's and Generation's consolidated balance sheets. At June 30, 2014, Generation has capitalized $184 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 139 MWs of new nuclear generation, that are in the installation phase at two nuclear stations; Peach Bottom in Pennsylvania and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $225 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected not to be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest. See Note 7 — Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for further information.

Liquidity

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.5 billion. See Liquidity and Capital Resources — Credit Matters — Exelon Credit Facilities below.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets including European banks. Disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of June 30, 2014, approximately 29%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.3 billion was available as of June 30, 2014, due to outstanding letters of credit and commercial paper. There were no borrowings under the Registrants' credit facilities as of June 30, 2014, with the exception of CENG. See Note 10 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

Exelon supports the promulgation of certain environmental regulations by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to their low emission generation portfolios, Generation and CENG will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air Quality. In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a review of the current 2008 ozone NAAQS that is expected to result in a proposed revision of the ozone NAAQS sometime in fall 2014. These updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Until the U.S. EPA re-issues CSAPR, Exelon cannot determine the impacts of the rule, including any that would impact power prices. In June 2013, the U.S. Supreme Court granted the U.S. EPA's petition to review the D.C. Circuit Court's CSAPR decision, and on April 29, 2014, the U.S. Supreme reversed the D.C. Circuit Court decision and upheld CSAPR, and remanded the case to the D.C. Circuit Court to resolve the remaining implementation issues. On June 26, 2014, the U.S. EPA filed a motion with the D.C. Circuit Court seeking to have the stay of the CSAPR lifted, and proposed a three-year tolling of the effective dates under the rule so that the first phase of emission budgets would be implemented on January 1, 2015. The U.S. EPA believes that this would allow sufficient time to complete the remaining aspects of the rulemaking before the implementation of the more stringent second phase of emission budgets that, under the tolling proposal, would begin on January 1, 2017.

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. On April 15, 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety. On July 14, 2014, three petitions for certiorari were filed with the U.S. Supreme Court seeking review of the D.C. Circuit Court decision upholding MATS.

The cumulative impact of these air regulations could be to require power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO_2 and acid gases, and selective catalytic reduction technology for NO_x. Generation, along with the other co-owners of Conemaugh Generating Station have improved the existing scrubbers and installed Selective Catalytic Reduction (SCR) controls to meet the requirements of MATS. In addition, Keystone already has SCR and Flue-gas desulfurization (FGD) controls in place.

On January 15, 2013, EPA issued a final rule for NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE NESHAP/NSPS). The final rule allows diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but requires units that operate over 15 hours to burn low sulfur fuel and report key engine information. The final rule eliminates after May 2014 the 50 hour exemption for peak shaving and other non-emergency demand response that was included in the proposed rule and, therefore, is not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act. The U.S. EPA is addressing the issue of carbon dioxide (CO2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act. Pursuant to President Obama's June 25, 2013 memorandum to U.S. EPA, the Agency re-proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. The Climate Action Plan also required the U.S. EPA to propose by June 2014 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and to issue final regulations by June 2015. That proposed rule was published in the Federal Register on June 16, 2014 and is open for public comment until October 16, 2014. The proposed rule establishes emission reduction targets for each state and provides flexibility for each state to determine how to achieve its required reductions, including heat rate improvements at coal-fired power plants, fuel switching from coal to gas, renewable generation and new nuclear facilities, demand side energy efficiency, and the use of market-based instruments. While the nature and impact of the final regulations is not yet known, to the extent that the rule results in emission reductions from fossil fuel fired plants, imposing some form of direct or indirect price of carbon in competitive electricity markets, Exelon's overall low-carbon generation portfolio results would benefit.

Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On May, 19 2014, the U.S. EPA released the final Section 316(b) rule. The rule has not been published in the Federal Register, and will become effective 60 days after publication. The rule requires that a series of studies and analyses be performed at each facility to determine the best technology available, followed by an implementation period. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, the impact of compliance with the final rule is unknown. Should a state permitting director determine that a facility is required to install cooling towers to comply with the rule, that facility's economic viability would be called into question. However, the likely impact of the rule has been significantly decreased since the final rule does not mandate cooling towers as a national standard, and the state permitting director is required to apply a cost-benefit test and take into consideration site-specific factors.

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Generation's plants that would be affected by the proposed rules are the Keystone and Conemaugh generating stations in Pennsylvania, which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has entered into a Consent Decree which requires that a final rule be issued by December 19, 2014.

See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

Japan Earthquake and Tsunami and the Industry's Response. On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co.

In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events issued a report of its review of the accident, including tiered recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for the period from 2014 through 2018 is expected to be between approximately $500 million and $525 million of capital (including approximately $150 million for the CENG plants) and $75 million of operating expense (including approximately $25 million for the CENG plants). As Generation completes the design and installation planning for its actions, Generation will update these estimates. Further, Generation estimates incremental costs of $15 to $20 million per unit at thirteen Mark 1 and II units (including two CENG units) for the installation of filtered vents, if ultimately required by the NRC. Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Executive Overview of the Exelon 2013 Form 10-K, for additional information.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. Although the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing for certain categories of Swaps, incentives to shift swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. The Dodd-Frank Act, however, also preserves the ability of end users in the energy industry to hedge their risks without being subject to mandatory clearing. Exelon is conducting its commercial business in a manner that does not require registration as a swap dealer or major swap participant. There are additional rulemakings that have

not yet been issued, however, including the capital and margin rules, which will potentially have an impact on the Registrants' business. Depending on the substance of these final rules, the Registrants could be subject to additional new obligations.

In particular, the proposed regulations addressing collateral and capital requirements and exchange margin cash postings, when final, could require Generation to have increased collateral requirements or cash postings. Exelon had previously estimated that it could be required to make up to $1 billion of additional collateral postings under its bilateral credit lines.

Nonetheless, given that Generation is not a swap dealer or major swap participant and the majority of its wholesale portfolio is not comprised of Swaps, the actual amount of additional collateral postings that might be required as a direct result of Dodd-Frank could be lower than Exelon's previous expectations. The actual level of collateral required at any time will depend also on many other factors, including but not limited to market conditions, the extent of its trading activity in Swaps, and Generation's credit ratings. In addition, there will be minimal incremental costs associated with Generation's positions that are currently cleared and subject to exchange margin. Finally, as an end-user, Generation will not be subject to any of the proposed capital requirements that will apply to swap dealers and major swap participants.

Nonetheless, to the extent collateral costs increase as a result of the Dodd-Frank Act, Generation has adequate credit facilities and flexibility in its hedging program to meet any increase, including an increase of $1 billion.

Exelon and Generation continue to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on their results of operations, cash flows or financial position.

ComEd, PECO and BGE could also be subject to some additional Dodd-Frank Act requirements to the extent they were to enter into Swap transactions. However, at this time, management of ComEd, PECO and BGE continue to expect that their companies will not be materially affected by this legislation.

Energy Infrastructure Modernization Act . Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. In addition, ComEd's earned rate of return on common equity is required to be within plus or minus 50 basis points ("the collar") of the target rate of return determined as the annual average rate on 30-year treasury notes plus 580 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on distribution revenue. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation.

Formula Rate Tariff and Annual Reconciliation. On April 16, 2014, ComEd filed its annual distribution formula rate update with the ICC. The filing establishes the revenue requirement used to set the rates that will take effect in January 2015 after the ICC's review and approval, which is due by December 2014. The revenue requirement requested is based on 2013 actual costs plus projected 2014 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2013 to the actual costs incurred that year. ComEd's 2014 filing request includes a total increase to the net revenue requirement of $269 million, reflecting an increase of $174 million for the initial revenue requirement for 2014 and an increase of $95 million related to the annual reconciliation for 2013. The revenue requirement for 2014 provides for a weighted average debt and equity return on distribution rate base of 7.06% inclusive of an allowed return on common equity of 9.25%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2013 provided for a

weighted average debt and equity return on distribution rate base of 7.04% inclusive of an allowed return on common equity of 9.20%, reflecting the average rate on 30-year treasury notes plus 580 basis points less a performance metrics penalty of 5 basis points.

FERC Ameren Order. In July 2012, FERC issued an order to Ameren Corporation (Ameren) finding that Ameren had improperly included acquisition premiums/ goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. Ameren filed for rehearing of the July 2012 order, which was denied in June 2014. FERC and Ameren are in the process of determining the amount of any potential refund. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/ goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

FERC Order No. 1000 Compliance (ComEd, PECO and BGE). In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements of a right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners, including ComEd, PECO and BGE (collectively, the PJM Transmission Owners), submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC's " *Mobile-Sierra* " standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order on the PJM Compliance Filing and the filing of these PJM Transmission Owners (1) rejecting the arguments of those PJM Transmission Owners that changes to the PJM governing documents were entitled to review under the *Mobile-Sierra* standard, (2) accepting most of the PJM filing, removing the right-of-first refusal from the PJM tariffs, and (3) directing PJM to remove certain exceptions that it included in its compliance filing that FERC found did not comply with Order No. 1000. FERC's order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd's, PECO's and BGE's financial return on new investments in energy transmission facilities. Numerous parties sought rehearing of the FERC's March 22, 2013 order, including the PJM Transmission Owners who sought rehearing of the FERC's rejection of their Mobile-Sierra and related arguments. PJM's compliance filing was made on July 22, 2013. On May 15, 2014, FERC denied the rehearing requests except with respect to one issue on when PJM could consider state and local laws in evaluating projects. FERC generally accepted the July 22, 2013, Compliance Filing but required several minor additional changes. FirstEnergy and at least one other party filed an appeal of the May 15, 2014, Order upholding PJM's right of first refusal language in the DC Circuit. Exelon has intervened in the FirstEnergy appeal. Several parties have filed requests for rehearing or clarification concerning the changes set forth in the May 15, 2014, Order.

FERC Transmission Complaint. On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the PHI companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) for most investments included in its rate base and 11.3% for the remaining transmission investment (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the revenues subject to refund are limited to a fifteen month period, and the earliest date from which the base return on equity

could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint. On June 19, 2014, FERC issued an order in another case involving New England Transmission Owners (NETOs), changing its methodology to determine ROE rates for public utilities. The result was a reduction in the ROE from 11.14% to 10.57% for the NETOs, with a possible further adjustment in either direction based on additional paper hearing submissions. On July 21, 2014, the NETOs filed a Request for Rehearing and Clarification with FERC of the June 19, 2014 order. Among other things, the NETOs request on rehearing that the 11.14% is reasonable based on the new methodology. As of June 30, 2014, BGE believes it is probable that BGE's base ROE rate will be subject to the revised methodology and may result in a potential refund to customers of transmission revenue for a maximum fifteen month period. In evaluating FERC's revised methodology, management believes it is reasonably possible no refunds will be required for BGE, and as such, no refund liability has been recorded as of June 30, 2014. If FERC were to order a reduction of BGE's base return on equity to 8.7% (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result would be a refund to customers of approximately $13 million, as well as estimated ongoing annual reduction in revenues of approximately $10 million. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The Maryland Strategic Infrastructure Development and Enhancement Program. In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On March 26, 2014, the MDPSC approved as filed BGE's proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge becoming effective April 1, 2014. In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE's infrastructure replacement plan. The residential consumer advocate filed its related legal memorandum on July 7, 2014, claiming that the MDPSC did not apply the appropriate consideration in approving BGE's infrastructure replacement plan and associated surcharge. BGE has until August 7, 2014 to submit a response, and a hearing has been scheduled for September 5, 2014. BGE cannot predict the outcome of this appeal. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Employees

IBEW Local 15's collective bargaining agreements (CBAs) were set to expire in 2013 but were extended by agreement to February 28, 2014. A tentative agreement was reached prior to the expiration and on March 31, 2014, two CBA's with IBEW Local 15 (which represents approximately 5,250 of Exelon's employees) were ratified. The CBA's, one with ComEd and BSC and the other with Generation, extend through September 30, 2019 and April 30, 2019, respectively.

Critical Accounting Policies and Estimates

Management of each of the Registrants makes a number of significant estimates, assumptions and judgments in the preparation of its financial statements. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Policies and Estimates" in the Exelon's, Generation's, ComEd's, PECO's and BGE's combined 2013 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants' accounting for AROs, purchase accounting, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies and revenue recognition. At June 30, 2014, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2013.

Results of Operations

Net Income Attributable to Common Shareholders by Registrant

	Three Months Ended June 30,		Favorable (Unfavorable)	Six Months Ended June 30,		Favorable (Unfavorable)
	2014	2013	Variance	2014	2013	Variance
Exelon	$ 522	$ 490	$ 32	$ 612	$ 486	$ 126
Generation	340	330	10	155	311	(156)
ComEd	111	96	15	209	14	195
PECO	84	72	12	173	193	(20)
BGE	16	22	(6)	100	100	—

Results of Operations — Generation

	Three Months Ended June 30,		Favorable (Unfavorable)	Six Months Ended June 30,		Favorable (Unfavorable)
	2014 [a]	2013	Variance	2014 [a]	2013	Variance
Operating revenues	$ 3,789	$ 4,070	$ (281)	$ 8,179	$ 7,603	$ 576
Purchased power and fuel expense	1,835	1,946	111	5,191	4,114	(1,077)
Revenue net of purchased power and fuel [b]	1,954	2,124	(170)	2,988	3,489	(501)
Other operating expenses						
Operating and maintenance	1,413	1,189	(224)	2,499	2,302	(197)
Depreciation and amortization	254	210	(44)	466	424	(42)
Taxes other than income	118	101	(17)	223	194	(29)
Total other operating expenses	1,785	1,500	(285)	3,188	2,920	(268)
Equity in losses of unconsolidated affiliates	(1)	(21)	20	(20)	(30)	10
Gain on consolidation of CENG	261	—	261	261	—	261
Operating income	429	603	(174)	41	539	(498)
Other income and (deductions)						
Interest expense	(86)	(93)	7	(172)	(176)	4
Other, net	228	(33)	261	318	95	223
Total other income and (deductions)	142	(126)	268	146	(81)	227
Income before income taxes	571	477	94	187	458	(271)
Income taxes (benefit)	199	149	(50)	(1)	148	149
Net income	372	328	44	188	310	(122)
Net income (loss) attributable to noncontrolling interests	32	(2)	(34)	33	(1)	(34)
Net income attributable to membership interest	$ 340	$ 330	$ 10	$ 155	$ 311	$ (156)

(a) Includes the operations of CENG from April 1, 2014, through June 30, 2014.

(b) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Membership Interest

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013. Generation's net income attributable to membership interest for the three months ended June 30, 2014 increased compared to the same period in 2013 primarily due to the gain recognized as a result of the consolidation of CENG, and the increase in other income; partially offset by decreased revenue net of purchased power and fuel, increased operating and maintenance expense and increased depreciation and amortization expense. The decrease in revenue net of purchased power and fuel primarily relates to mark-to-market losses from economic hedging activities, lower realized energy prices, and, excluding CENG, generation volumes were lower, partially offset by the consolidation of CENG, higher capacity revenues, and a decrease in amortization expense for the acquired energy contracts recorded at fair value at the merger date with Constellation and consolidation of CENG. The increase in operating and maintenance expense is primarily related to the inclusion of CENG's results for a full quarter in 2014, and an increase in planned nuclear refueling outage days in 2014. The increase in other, net is primarily due to an increase in realized NDT fund gains.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. Generation's net income attributable to membership interest for the six months ended June 30, 2014 decreased compared to the same period in 2013 primarily due to decreased revenue net of purchased power and fuel expense, and increased operating and maintenance expense; partially offset by the gain recognized as a result of the consolidation of CENG and an increase in other operating income. The decrease in revenue net of purchased power and fuel primarily relates to mark-to-market losses from economic hedging activities, lower realized energy prices, higher procurement costs for replacement power, increased fossil fuel expense due to extreme cold weather during the first quarter of 2014 and, excluding CENG, generation volumes were lower, partially offset by the consolidation of CENG, higher capacity revenues, and a decrease in amortization expense for the acquired energy contracts recorded at fair value at the merger date with Constellation and consolidation of CENG. The increase in operating and maintenance expense is primarily related to the inclusion of CENG's results for a full quarter in 2014, and an increase in planned nuclear refueling outage days in 2014. The increase in other, net income is primarily due to an increase in realized NDT fund gains.

Revenue Net of Purchased Power and Fuel Expense

The foundation of Generation's six reportable segments is based on the geographic location of its assets, and are largely representative of the footprints of an ISO / RTO and/or NERC region. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within New York ISO, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:

- South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
- West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
- Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems and investments in energy-related proprietary technology. Further, the following activities are not allocated to a region, and are reported in Other: unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger with Constellation and the consolidation of CENG; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements.

For the three and six months ended June 30, 2014 and 2013, Generation's revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended June 30,			
	2014 [a]	2013	Variance	% Change
Mid-Atlantic [b]	$ 920	$ 768	$ 152	19.8%
Midwest [c]	605	684	(79)	(11.5%)
New England	64	50	14	28.0%
New York	148	14	134	n.m.
ERCOT	59	112	(53)	(47.3%)
Other Regions [d]	75	59	16	27.1%
Total electric revenue net of purchased power and fuel expense	1,871	1,687	184	10.9%
Proprietary Trading	7	3	4	n.m.
Mark-to-market gains (losses)	(14)	428	(442)	(103.3%)
Other [e]	90	6	84	n.m.
Total revenue net of purchased power and fuel expense	$ 1,954	$ 2,124	$ (170)	(8.0%)

	Six Months Ended June 30,			
	2014 [a]	2013	Variance	% Change
Mid-Atlantic [b]	$ 1,615	$ 1,612	$ 3	0.2%
Midwest [c]	1,161	1,401	(240)	(17.1%)
New England	200	80	120	n.m.
New York	127	(8)	135	n.m.
ERCOT	142	213	(71)	(33.3%)
Other Regions [d]	180	105	75	71.4%
Total electric revenue net of purchased power and fuel expense	3,425	3,403	22	0.6%
Proprietary Trading	20	12	8	66.7%
Mark-to-market gains (losses)	(744)	25	(769)	n.m.
Other [e]	287	49	238	n.m.
Total revenue net of purchased power and fuel expense	$ 2,988	$ 3,489	$ (501)	(14.4%)

(a) Includes the operations of CENG from April 1, 2014, through June 30, 2014
(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the date of the merger with Constellation and the consolidation of CENG in purchase accounting of $50 million and $92 million pre-tax for the three and six months ended June 30, 2014, and $167 million and $341 million pre-tax for the three and six months ended June 30, 2013.

Generation's supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended June 30, 2014	2013	Variance	% Change
Nuclear generation				
Mid-Atlantic [a]	14,912	11,794	3,118	26.4%
Midwest	22,719	22,807	(88)	(0.4%)
New York [a]	3,766	—	3,766	n.m.
Total nuclear generation	41,397	34,601	6,796	19.6%
Fossil and renewables [a]				
Mid-Atlantic	3,165	2,796	369	13.2%
Midwest	319	318	1	0.3%
New England	1,299	3,132	(1,833)	(58.5%)
New York	1	—	1	n.m.
ERCOT	1,553	1,617	(64)	(4.0%)
Other Regions [c]	2,041	1,431	610	42.6%
Total fossil and renewables	8,378	9,294	(916)	(9.9%)
Purchased power				
Mid-Atlantic [b]	810	2,616	(1,806)	(69.0%)
Midwest	520	1,503	(983)	(65.4%)
New England	2,290	1,365	925	67.8%
New York [b]	—	3,073	(3,073)	(100.0%)
ERCOT	2,518	4,269	(1,751)	(41.0%)
Other Regions [c]	3,654	4,998	(1,344)	(26.9%)
Total purchased power	9,792	17,824	(8,032)	(45.1%)
Total supply/sales by region [d]				
Mid-Atlantic [e]	18,887	17,206	1,681	9.8%
Midwest [e]	23,558	24,628	(1,070)	(4.3%)
New England	3,589	4,497	(908)	(20.2%)
New York	3,767	3,073	694	22.6%
ERCOT	4,071	5,886	(1,815)	(30.8%)
Other Regions [c]	5,695	6,429	(734)	(11.4%)
Total supply/sales by region	59,567	61,719	(2,152)	(3.5%)

Supply source (GWh)	Six Months Ended June 30, 2014	2013	Variance	% Change
Nuclear generation				
Mid-Atlantic [a]	27,048	24,556	2,492	10.1%
Midwest	45,844	46,076	(232)	(0.5%)
New York [a]	3,766	—	3,766	n.m.
Total nuclear generation	76,658	70,632	6,026	8.5%
Fossil and renewables [a]				
Mid-Atlantic	6,373	5,956	417	7.0%
Midwest	736	899	(163)	(18.1%)
New England	3,033	5,524	(2,491)	(45.1%)
New York	2	—	2	n.m.
ERCOT	3,208	2,350	858	36.5%
Other Regions [c]	3,670	3,685	(15)	(0.4%)
Total fossil and renewables	17,022	18,414	(1,392)	(7.6%)
Purchased power				
Mid-Atlantic [b]	4,043	5,849	(1,806)	(30.9%)
Midwest	1,231	3,203	(1,972)	(61.6%)
New England	4,360	2,872	1,488	51.8%
New York [b]	2,857	6,584	(3,727)	(56.6%)
ERCOT	5,958	8,468	(2,510)	(29.6%)
Other Regions [c]	7,009	8,701	(1,692)	(19.4%)
Total purchased power	25,458	35,677	(10,219)	(28.6%)
Total supply/sales by region [d]				
Mid-Atlantic [e]	37,464	36,361	1,103	3.0%
Midwest [e]	47,811	50,178	(2,367)	(4.7%)
New England	7,393	8,396	(1,003)	(11.9%)
New York	6,625	6,584	41	0.6%
ERCOT	9,166	10,818	(1,652)	(15.3%)
Other Regions [c]	10,679	12,386	(1,707)	(13.8%)
Total supply/sales by region	119,138	124,723	(5,585)	(4.5%)

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG). Nuclear generation for the three months and six months ended June 30, 2014 includes physical volumes of 3,780 GWh in Mid-Atlantic and 3,766 GWh in New York for CENG.

(b) Purchased power for the three months and six months ended June 30, 2014 includes physical volumes of 0 GWh and 2,489 GWh in the Mid-Atlantic and 0 GWh and 2,857 GWh in New York as a result of the PPA with CENG. Purchased power for the three months and six months ended June 30, 2013 includes physical volumes of 3,114 GWh and 5,702 GWh in the Mid-Atlantic and 2,655 GWh and 5,868 GWh in New York as a result of the PPA with CENG. As of the integration date of April 1, 2014, CENG volumes are included in nuclear generation.

(c) Other Regions includes South, West and Canada, which are not considered individually significant.

(d) Excludes physical proprietary trading volumes of 2,629 GWh and 1,995 GWh for the three months ended June 30, 2014 and 2013, respectively, and 5,123 GWh and 3,567 GWh for the six months ended June 30, 2014 and 2013, respectively.

(e) Includes affiliate sales to PECO and BGE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.

Mid-Atlantic

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013 . The $152 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to the consolidation of CENG, higher capacity revenues, and the cancellation of the DOE spent nuclear fuel disposal fee, partially offset by lower realized energy prices and lower generation volumes, excluding CENG.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. The $3 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to the consolidation of CENG, higher capacity revenues, and the cancellation of the DOE spent nuclear fuel disposal fees, partially offset by lower realized energy prices, higher procurement costs for replacement power, an increase in generation fuel prices, and lower generation volumes, excluding CENG.

Midwest

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013 . The $79 million decrease in revenue net of purchased power and fuel expense in the Midwest was primarily due to lower realized energy prices, partially offset by increased capacity revenue and the cancellation of the DOE spent nuclear fuel disposal fee.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. The $240 million decrease in revenue net of purchased power and fuel expense in the Midwest was primarily due to lower realized energy prices, partially offset by increased capacity revenue and the cancellation of the DOE spent nuclear fuel disposal fee.

New England

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013 . The $14 million increase in revenue net of purchased power and fuel expense in New England was primarily due to higher realized energy prices and favorable impacts from the restructuring of a fuel supply contract, partially offset by lower generation volume.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. The $120 million increase in revenue net of purchased power and fuel expense in New England was driven by higher realized energy prices and favorable impacts from the restructuring of a fuel supply contract, partially offset by lower generation volume.

New York

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013 . The $134 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the consolidation of CENG.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. The $135 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the consolidation of CENG.

ERCOT

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013 . The $53 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to higher procurement costs for replacement power and the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. The $71 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to increased generation fuel costs, higher procurement costs for replacement power in the second quarter of 2014, and the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest

entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013. The decreases were partially offset by higher realized energy prices and higher generation volume in the first quarter of 2014.

Other Regions

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013. The $16 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily due to higher generation volumes and higher realized energy prices, partially offset by increased generation fuel costs.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. The $75 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily due to higher realized energy prices, partially offset by increased generation fuel costs.

Mark-to-market

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013 . Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market losses on economic hedging activities were $14 million for the three months ended June 30, 2014 compared to gains of $428 million for the three months ended June 30, 2013. See Notes 8 – Fair Value of Financial Assets and Liabilities and 9 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013 . Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market losses on economic hedging activities were $744 million for the six months ended June 30, 2014 compared to gains of $25 million for the six months ended June 30, 2013. See Notes 8 — Fair Value of Financial Assets and Liabilities and 9 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013 . The $84 million increase in other revenue net of purchased power and fuel expense was driven by the reduction of amortization of the acquired energy contracts recorded at the date of merger with Constellation and the consolidation of CENG.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013 . The $238 million increase in other revenue net of purchased power and fuel was driven by the reduction of amortization of the acquired energy contracts recorded at fair value at the date of merger with Constellation and the consolidation of CENG.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for the three and six months ended June 30, 2014 as compared to the same periods in June 30, 2013, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures comparatively to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a

complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Nuclear fleet capacity factor [a]	91.8%	92.8%	92.9%	94.6%
Nuclear fleet production cost per MWh [a]	$20.31	$18.86	$20.50	$19.27

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. As of April 1, 2014, CENG is included.

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013. The nuclear fleet capacity factor decreased primarily due to the inclusion of the ownership share of CENG. In addition, there were more refueling and non-refueling outage days, excluding Salem outages, during the three months ended June 30, 2014 compared to the same period in 2013. For the three months ended June 30, 2014 and 2013, non-refueling outage days totaled 44 and 31, respectively. During the same periods, refueling outage days totaled 108 and 47, respectively. Inclusion of the ownership share of CENG resulted in higher production costs per MWh for the three months ended June 30, 2014 as compared to the same period in June 30, 2013.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013 . The nuclear fleet capacity factor decreased primarily due to the inclusion of the ownership share of CENG. In addition, there were more refueling and non-refueling outage days, excluding Salem outages, during the six months ended June 30, 2014 compared to the same period in 2013. For the six months ended June 30, 2014 and 2013, non-refueling outage days totaled 64 and 37, respectively. During the same periods, refueling outage days totaled 160 and 96, respectively. Inclusion of the ownership share of CENG resulted in higher production costs per MWh for the six months ended June 30, 2014 as compared to the same period in June 30, 2013.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and six months ended June 30, 2014 compared to the same period in 2013, consisted of the following:

	Three Months Ended June 30, Increase (Decrease) [a]	Six Months Ended June 30, Increase (Decrease) [a]
Labor, other benefits, contracting, materials	$ 126	$ 121
Impairment of certain wind generating assets [b]	86	86
Nuclear refueling outage costs, including the co-owned Salem plants [c]	61	75
Accretion expense	25	28
Regulatory fees and assessment	20	17
Increase in asbestos reserve	16	16
Nuclear uprate project cancellation [d]	(92)	(113)
Pension and non-pension postretirement benefits expense	(31)	(40)
Merger and integration cots	(5)	(12)
Other	18	19
Increase in operating and maintenance expense	$ 224	$ 197

(a) Includes the operations of CENG, from April 1, 2014 through June 30, 2014.
(b) Reflects the impact of the charge to earnings related to the impairment of certain wind generating assets.
(c) Reflects the impact of increased planned refueling outage days in 2014.
(d) Reflects the impact of the 2013 cancellation of previously capitalized nuclear uprate projects.

Depreciation and Amortization

The increase in depreciation and amortization expense for the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013 was primarily due the inclusion of CENG's results for a full quarter in 2014 and an increase in ongoing capital expenditures.

Taxes Other Than Income

The increase in taxes other than income for the three and six months ended June 30, 2014 as compared to the three and six months ended June 30, 2013 was primarily due to an increase in payroll taxes and real estate taxes.

Equity in Losses of Unconsolidated Affiliates

The favorable increase in Equity in losses of unconsolidated affiliates for the three and six months ended June 30, 2014 as compared to the three and six months ended June 30, 2013 was due to the decrease in non-cash amortization as a result of the second quarter 2013 non-cash amortization of the fair value basis difference recorded at the Constellation merger date, offset by equity in losses in CENG in 2013 which is now consolidated in 2014.

Interest Expense

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013.

Interest expense for three months ended June 30, 2014 compared to same period in 2013 remained relatively level.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013.

The decrease in interest expense primarily reflects a benefit recorded in 2014 related to the favorable settlement of certain income tax positions on Constellation's 2009-2012 tax returns.

Other, Net

The increase in Other, net for the three and six months ended June 30, 2014 compared to the three and six months ended June 30, 2013 primarily reflects the change in the realized and unrealized gains and losses related to the NDT funds of its Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $46 million and $(13) million for the three months ended June 30, 2014 and 2013, respectively, and $66 million and $30 million for the six months ended June 30, 2014 and 2013, respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 12 — for additional information regarding NDT funds.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014 [a]	2013	2014 [a]	2013
Net unrealized gains (losses) on decommissioning trust funds	$ 128	$ (40)	$ 141	$ 24
Net realized gains on sale of decommissioning trust funds	$ 12	$ —	$ 25	$ 2

(a) Includes results of CENG from April 1, 2014 through June 30, 2014.

Effective Income Tax Rate

The effective income tax rate was 34.9% and (0.5)% for the three and and six months ended June 30, 2014, respectively, compared to 31.2% and 32.3% for the same periods during 2013. See Note 11 of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

Results of Operations — ComEd

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2014	2013		2014	2013	
Operating revenues	$ 1,128	$ 1,080	$ 48	$2,262	$2,239	$ 23
Purchased power expense	269	248	(21)	589	630	41
Revenue net of purchased power expense [(a)]	859	832	27	1,673	1,609	64
Other operating expenses						
Operating and maintenance	355	359	4	681	687	6
Depreciation and amortization	174	170	(4)	347	337	(10)
Taxes other than income	72	71	(1)	149	145	(4)
Total other operating expenses	601	600	(1)	1,177	1,169	(8)
Operating income	258	232	26	496	440	56
Other income and (deductions)						
Interest expense, net	(80)	(76)	(4)	(160)	(429)	269
Other, net	5	6	(1)	10	11	(1)
Total other income and (deductions)	(75)	(70)	(5)	(150)	(418)	268
Income before income taxes	183	162	21	346	22	324
Income taxes	72	66	(6)	137	8	(129)
Net income	$ 111	$ 96	$ 15	$ 209	$ 14	$ 195

(a) ComEd evaluates its operating performance using the measure of revenue net of purchased power expense. ComEd believes that revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended June 30, 2014, Compared to Three Months Ended June 30, 2013. ComEd's net income for the three months ended June 30, 2014, was higher than the same period in 2013, primarily due to higher electric distribution revenue resulting from increased capital investment.

Six Months Ended June 30, 2014, Compared to Six Months Ended June 30, 2013. ComEd's net income for the six months ended June 30, 2014, was higher than the same period in 2013, primarily due to the interest expense and related income tax effects of the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013, as well as increased distribution revenue resulting from increased capital investment in 2014. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information on the like-kind exchange tax position.

Operating Revenues Net of Purchased Power Expense

There are certain drivers of revenue that are fully offset by their impact on purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on revenue net of purchased power expense. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries, but do affect ComEd's operating revenue related to supplied energy, which is fully offset in purchased power expense. Therefore, customer choice programs have no impact on revenue net of purchased power expense.

The number of retail customers participating in customer choice programs was 2,550,114 and 2,593,064 at June 30, 2014, and 2013, respectively, representing 66% and 68% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 81% and 80% of ComEd's retail kWh sales for the three months and six months ended June 30, 2014, respectively, as compared to 81% and 78% for the three and six months ended June 30, 2013, respectively.

The changes in ComEd's revenue net of purchased power expense for the three months and six months ended June 30, 2014, compared to the same periods in 2013 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Weather	$ 1	$ 16
Volume	—	6
Electric distribution revenues	(1)	39
Transmission revenues	3	2
Regulatory required programs	18	27
Uncollectible accounts recovery, net	7	(12)
Pricing and customer mix	14	4
Revenue subject to refund	(9)	(9)
Other	(6)	(9)
Increase in revenue net of purchased power expense	$ 27	$ 64

Weather. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the three months ended June 30, 2014, weather conditions were relatively consistent with the same period in 2013.

During the six months ended June 30, 2014 compared to the same period in 2013, operating revenues net of purchased power expense were higher due to the impact of favorable 2014 winter weather conditions in ComEd's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the three and six months ended June 30, 2014, and 2013, consisted of the following:

				% Change	
Heating and Cooling Degree-Days	2014	2013	Normal	From 2013	From Normal
Three Months Ended June 30,					
Heating Degree-Days	695	778	765	(10.7)%	(9.2)%
Cooling Degree-Days	259	240	218	7.9%	18.8%
Six Months Ended June 30,					
Heating Degree-Days	4,569	4,037	3,929	13.2%	16.3%
Cooling Degree-Days	259	240	218	7.9%	18.8%

Volume. Revenue net of purchased power expense increased as a result of higher delivery volume, exclusive of the effects of weather, reflecting increased average usage per residential customer as compared to the same six month period in 2013.

Electric Distribution Revenue. EIMA provides for a performance-based rate formula, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Distribution revenue varies from year to year based on fluctuations in the underlying costs, investments being recovered and other billing determinants. In addition, ComEd's earned rate of return on common equity is required to be within plus or minus 50 basis points ("the collar") of the target rate of return determined as the annual average rate on 30-year treasury notes plus 580 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on distribution revenue. During the three months ended June 30, 2014, ComEd recorded decreased electric distribution revenue primarily due to the one-time reduction for decreased expenses associated with OPEB plan design changes, mostly offset by increased costs and capital investment.

During the six months ended June 30, 2014, ComEd recorded increased electric distribution revenue primarily due to increased costs and capital investment, partially offset by the one-time reduction for decreased expenses associated with OPEB plan design changes. See Operating and Maintenance Expense below, and Note 5 — Regulatory Matters and Note 13 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's rate formula pursuant to EIMA and the OPEB plan design changes.

Transmission Revenues. ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update, filed in April 2014, reflects 2013 actual costs plus forecasted 2014 capital additions. Transmission revenue net of purchased power expense vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. Revenues related to regulatory required programs represents the recoveries from customers for costs of various legislative and regulatory programs on a full and current basis through approved regulated rates. Programs include ComEd's energy efficiency and demand response and purchased power administrative costs. An equal and offsetting amount has been reflected in operating and maintenance expense during the periods presented.

Uncollectible Accounts Recovery, Net. Represents recoveries under ComEd's uncollectible accounts tariff. See the operating and maintenance expense discussion below for additional information on this tariff.

Pricing and Customer Mix. The increase in revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes and change in customer mix for the three and six months ended June 30, 2014, as compared to the same periods in 2013.

Revenue Subject to Refund. ComEd records revenues subject to refund based upon its best estimate of customer collections that may be required to be refunded. As of the three and six months ended June 30, 2014 ComEd recorded $9 million of revenue subject to refund.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of environmental costs associated with MGP sites, for which an equal and offsetting amount is reflected in depreciation and amortization expense during the periods presented.

Operating and Maintenance Expense

	Three Months Ended June 30,		Increase (Decrease)	Six Months Ended June 30,		Increase (Decrease)
	2014	2013		2014	2013	
Operating and maintenance expense — baseline	$ 281	$ 304	$ (23)	$ 559	$ 593	$ (34)
Operating and maintenance expense — regulatory required programs [(a)]	74	55	19	122	94	28
Total operating and maintenance expense	$ 355	$ 359	$ (4)	$ 681	$ 687	$ (6)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three and six months ended June 30, 2014 compared to the same periods in 2013, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 4	$ 10
Pension and non-pension postretirement benefits expense	(27)	(38)
Storm-related costs	(11)	(6)
Uncollectible accounts expense — provision [(a)]	1	2
Uncollectible accounts expense — recovery, net [(a)]	6	(14)
Other	4	12
	(23)	(34)
Regulatory required programs		
Energy efficiency and demand response programs	18	27
Purchased power administrative costs	1	1
	19	28
Decrease in operating and maintenance expense	$ (4)	$ (6)

(a) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. During the three and six months ended June 30, 2014, ComEd recorded a net increase and reduction, respectively, in operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers as a result of municipal aggregation. An equal and offsetting increase and reduction, respectively, has been recognized in operating revenues for the periods presented.

Depreciation and Amortization

Depreciation and amortization expense increased during the three and six months ended June 30, 2014, compared to the same periods in 2013, primarily due to ongoing capital expenditures and increased regulatory asset amortization related to higher MGP remediation expenditures. An equal and offsetting amount for the amortization expense related to the MGP remediation expenditures is reflected in operating revenues during the periods presented.

Taxes Other Than Income

Taxes other than income taxes, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income taxes remained relatively flat for the three and six months ended June 30, 2014, compared to the same periods in 2013.

Interest Expense, Net

The changes in interest expense, net for the three and six months ended June 30, 2014, compared to the same period in 2013, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Interest expense related to uncertain tax positions [a]	$ —	$ 275
Interest expense on debt (including financing trusts)	(4)	(6)
Decrease in interest expense, net	$ (4)	$ 269

(a) Primarily reflects the remeasurement of Exelon's like-kind exchange tax position in the first quarter of 2013. See Note 11 — Income Taxes of the Combined Notes to Financial Statements for additional information.

Effective Income Tax Rate

The effective income tax rate was 39.3% for the three months ended June 30, 2014 compared to 40.7% for the same period during 2013. The effective income tax rate was 39.6% for the six months ended June 30, 2014 compared to 36.4% for the same period during 2013. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2014	2013	% Change	Weather-Normal % Change
Retail Deliveries [a]				
Residential	6,177	6,090	1.4%	1.1%
Small commercial & industrial	7,759	7,832	(0.9)%	(1.3)%
Large commercial & industrial	6,769	6,711	0.9%	0.5%
Public authorities & electric railroads	304	294	3.4%	5.7%
Total Retail Deliveries	21,009	20,927	0.4%	0.0%

Retail Deliveries to Customers (in GWhs)	Six Months Ended June 30, 2014	2013	% Change	Weather-Normal % Change
Retail Deliveries [a]				
Residential	13,587	12,966	4.8%	1.5%
Small commercial & industrial	16,090	15,705	2.5%	0.5%
Large commercial & industrial	13,864	13,551	2.3%	0.8%
Public authorities & electric railroads	701	667	5.1%	5.5%
Total Retail Deliveries	44,242	42,889	3.2%	0.9%

Number of Electric Customers	As of June 30, 2014	2013
Residential	3,487,337	3,465,712
Small commercial & industrial	367,354	366,153
Large commercial & industrial	2,025	2,006
Public authorities & electric railroads	4,827	4,852
Total	3,861,543	3,838,723

Electric Revenue	Three Months Ended June 30, 2014	2013	% Change	Six Months Ended June 30, 2014	2013	% Change
Retail Sales [a]						
Residential	$ 499	$ 476	4.8%	$ 1,007	$1,060	(5.0)%
Small commercial & industrial	340	315	7.9%	684	623	9.8%
Large commercial & industrial	113	113	0.0%	229	215	6.5%
Public authorities & electric railroads	12	12	0.0%	24	24	0.0%
Total Retail	964	916	5.2%	1,944	1,922	1.1%
Other Revenue [b]	164	164	0.0%	318	317	0.3%
Total Electric Revenues	$ 1,128	$ 1,080	4.4%	$ 2,262	$2,239	1.0%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other items include rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of environmental costs associated with MGP sites.

Results of Operations — PECO

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2014	2013		2014	2013	
Operating revenues	$ 656	$ 672	$ (16)	$1,649	$1,567	$ 82
Purchased power and fuel	241	258	17	705	664	(41)
Revenue net of purchased power and fuel [(a)]	415	414	1	944	903	41
Other operating expenses						
Operating and maintenance	184	181	(3)	464	369	(95)
Depreciation and amortization	59	56	(3)	117	113	(4)
Taxes other than income	38	39	1	80	80	—
Total other operating expenses	281	276	(5)	661	562	(99)
Operating income	134	138	(4)	283	341	(58)
Other income and (deductions)						
Interest expense, net	(28)	(28)	—	(56)	(57)	1
Other, net	1	—	1	3	3	—
Total other income and (deductions)	(27)	(28)	1	(53)	(54)	1
Income before income taxes	107	110	(3)	230	287	(57)
Income taxes	23	32	9	57	87	30
Net income	84	78	6	173	200	(27)
Preferred security dividends and redemption	—	6	6	—	7	7
Net income attributable to common shareholders	$ 84	$ 72	$ 12	$ 173	$ 193	$ (20)

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income attributable to common shareholders

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013. The increase in net income attributable to common shareholders was driven primarily by a decrease to income tax expense and redemption of preferred securities in May 2013, partially offset by an increase in operating expenses.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013. The decrease in net income attributable to common shareholders was driven primarily by higher operating and maintenance expenses, partially offset by higher operating revenue net of purchased power and fuel expense and a decrease to income taxes expense and redemption of preferred securities in May 2013.

Operating Revenues, Purchased Power and Fuel Expense

Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenue net of purchased power and fuel expense.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenue net of purchased power and fuel expense. The number of retail customers purchasing electricity from a competitive electric generation supplier was 538,800 and 523,900 at June 30, 2014 and 2013, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 72% and 70% of PECO's retail kWh sales for the three and six months ended June 30, 2014, respectively, compared to 70% and 68% for the three and six months ended June 30, 2013. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 74,800 and 59,100 at June 30, 2014 and 2013, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 24% and 21% of PECO's mmcf sales for the three and six months ended June 30, 2014, respectively, compared to 21% and 18% for the three and six months ended June 30, 2013.

The changes in PECO's operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2014 compared to the same period in 2013 consisted of the following:

	Three Months Ended June 30, Increase (Decrease)			Six Months Ended June 30, Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ (9)	$ 1	$ (8)	$ 10	$16	$ 26
Volume	2	1	3	7	2	9
Pricing	(2)	—	(2)	(6)	(3)	(9)
Regulatory required programs	5	—	5	13	—	13
Other	2	1	3	2	—	2
Total increase (decrease)	$ (2)	$ 3	$ 1	$ 26	$15	$ 41

Weather. The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. During the three months ended June 30, 2014 compared to the same period in 2013, operating revenues net of purchased power and fuel expense were lower due to unfavorable spring and summer weather conditions in PECO's service territory.

During the six months ended June 30, 2014 compared to the same period in 2013, operating revenues net of purchased power and fuel expense were higher due to the impact of favorable 2014 winter weather conditions, offset by unfavorable 2014 spring and summer weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the three and six months ended June 30, 2014 compared to the same periods in 2013 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	2014	2013	Normal	From 2013	From Normal
Three Months Ended June 30,					
Heating Degree-Days	393	421	463	(6.7)%	(15.1)%
Cooling Degree-Days	375	418	348	(10.3)%	7.8%
Six Months Ended June 30,					
Heating Degree-Days	3,237	2,861	2,939	13.1%	10.1%
Cooling Degree-Days	375	418	348	(10.3)%	7.8%

Volume. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and six months ended June 30, 2014 compared to the same period in 2013, primarily reflects the impact of moderate economic and customer growth and a shift in the volume profile across classes from lower priced classes to higher priced classes, partially offset by energy efficiency initiatives on customer usages.

Pricing. The decrease in operating revenues net of purchased power and fuel expense as a result of pricing is primarily attributable to lower overall effective rates due to increased usage per customer across all customer classes.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Operating and Maintenance Expense

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Increase (Decrease)	2014	2013	Increase (Decrease)
Operating and Maintenance Expense — Baseline	$ 155	$ 155	$ —	$ 415	$ 329	$ 86
Operating and Maintenance Expense — Regulatory Required Programs [(a)]	29	26	3	49	40	9
Total Operating and Maintenance Expense	$ 184	$ 181	$ 3	$ 464	$ 369	$ 95

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for the three and six months ended June 30, 2014 compared to the same periods in 2013, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 5	$ 6
Storm-related costs	5	84[a]
Injuries and Damages	(1)	(3)
Pension and non-pension postretirement benefits expense	(2)	—
Constellation merger and integration costs	(2)	(5)
Uncollectable Accounts Expense	(8)	1
Other	3	3
	—	86
Regulatory Required Programs		
Smart Meter	3	6
Energy Efficiency	—	3
	3	9
Increase (Decrease) in operating and maintenance expense	$ 3	$ 95

(a) Total storm-related costs include approximately $70 million of incremental storm costs incurred from the February 5, 2014 ice storm and other storms during the first half of 2014.

Depreciation and Amortization Expense

The increase in depreciation and amortization expense for the three and six months ended June 30, 2014 compared to the same periods in 2013 was primarily due to ongoing capital expenditures.

Taxes Other Than Income

The change in taxes other than income for the three and six months ended June 30, 2014 compared to the same period in 2013 remained relatively constant.

Interest Expense, Net

The decrease in interest expense, net for the three and six months ended June 30, 2014 compared to the same periods in 2013 remained relatively constant.

Other, Net

The change in Other, net for the three and six months ended June 30, 2014 remained relatively level compared to the same period in 2013.

Effective Income Tax Rate

PECO’s effective income tax rate was 21.5% and 29.1% for the three months ended June 30, 2014 and 2013, respectively.

The effective income tax rate was 24.8% and 30.3% for the six months ended June 30, 2014 and 2013, respectively. See Note 11 — Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	% Change	Weather-Normal % Change	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	% Change	Weather-Normal % Change
Retail Deliveries [a]								
Residential	2,801	2,888	(3.0)%	1.6%	6,649	6,353	4.7%	1.5%
Small commercial & industrial	1,947	1,960	(0.7)%	0.7%	4,002	3,969	0.8%	0.1%
Large commercial & industrial	3,741	3,784	(1.1)%	(0.6)%	7,518	7,430	1.2%	0.7%
Public authorities & electric railroads	222	238	(6.8)%	(6.8)%	481	493	(2.4)%	(2.4)%
Total Retail Deliveries	8,711	8,870	(1.8)%	0.2%	18,650	18,245	2.2%	0.8%

Number of Electric Customers	As of June 30, 2014	As of June 30, 2013
Residential	1,428,080	1,419,977
Small commercial & industrial	149,259	148,723
Large commercial & industrial	3,108	3,109
Public authorities & electric railroads	9,712	9,672
Total	1,590,159	1,581,481

Electric Revenue	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	% Change	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	% Change
Retail Sales [a]						
Residential	$ 338	$ 354	(4.5)%	$ 782	$ 749	4.4%
Small commercial & industrial	101	109	(7.3)%	212	215	(1.4)%
Large commercial & industrial	54	61	(11.5)%	117	120	(2.5)%
Public authorities & electric railroads	8	8	0.0%	16	16	0.0%
Total Retail	501	532	(5.8)%	1,127	1,100	2.5%
Other Revenue [b]	58	53	9.4%	109	108	0.9%
Total Electric Revenues	$ 559	$ 585	(4.4)%	$ 1,236	$ 1,208	2.3%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

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PECO Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2014	2013	% Change	Weather-Normal % Change	Six Months Ended June 30, 2014	2013	% Change	Weather-Normal % Change
Retail Delivery								
Retail sales [a]	7,424	6,919	7.3%	3.9%	40,594	35,357	14.8%	1.4%
Transportation and other	6,005	5,956	0.8%	(0.8)%	14,374	14,839	(3.1)%	(4.5)%
Total Gas Deliveries	13,429	12,875	4.3%	1.4%	54,968	50,196	9.5%	(1.6)%

Number of Gas Customers	As of June 30, 2014	2013
Residential	459,407	455,518
Commercial & industrial	42,042	41,648
Total Retail	501,449	497,166
Transportation	882	903
Total	502,331	498,069

Gas Revenue	Three Months Ended June 30, 2014	2013	% Change	Six Months Ended June 30, 2014	2013	% Change
Retail Sales						
Retail sales [a]	$ 88	$ 78	12.8%	$ 390	$ 338	15.4%
Transportation and other	9	9	0.0%	23	21	9.5%
Total Gas Revenues	$ 97	$ 87	11.5%	$ 413	$ 359	15.0%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

Results of Operations — BGE

	Three Months Ended June 30,		Favorable (Unfavorable) Variance	Six Months Ended June 30,		Favorable (Unfavorable) Variance
	2014	2013		2014	2013	
Operating revenues	$ 653	$ 653	$ —	$1,707	$1,533	$ 174
Purchased power and fuel	268	288	20	797	713	(84)
Revenue net of purchased power and fuel [(a)]	385	365	20	910	820	90
Other operating expenses						
Operating and maintenance	188	160	(28)	376	303	(73)
Depreciation and amortization	89	82	(7)	197	175	(22)
Taxes other than income	53	54	1	113	109	(4)
Total other operating expenses	330	296	(34)	686	587	(99)
Operating income	55	69	(14)	224	233	(9)
Other income and (deductions)						
Interest expense, net	(27)	(32)	5	(55)	(66)	11
Other, net	5	4	1	9	9	—
Total other income and (deductions)	(22)	(28)	6	(46)	(57)	11
Income before income taxes	33	41	(8)	178	176	2
Income taxes	14	16	2	72	70	(2)
Net income	19	25	(6)	106	106	—
Preference stock dividends	3	3	—	6	6	—
Net income attributable to common shareholder	$ 16	$ 22	$ (6)	$ 100	$ 100	$ —

(a) BGE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenue net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net income attributable to common shareholders

Three Months Ended June 30, 2014, Compared to Three Months Ended June 30, 2013. BGE's net income attributable to common shareholders for the three months ended June 30, 2014, was lower than the same period in 2013, primarily due to increases in operating and maintenance expense and depreciation expense, partially offset by an increase in revenue net of purchased power and fuel expense as a result of the December 2013 electric and gas distribution rate order issued by the MDPSC.

Six Months Ended June 30, 2014, Compared to Six Months Ended June 30, 2013. BGE's net income attributable to common shareholders for the six months ended June 30, 2014, was consistent with the same period in 2013, primarily due to an increase in revenue net of purchased power and fuel expense as a result of the 2013 electric and gas distribution rate orders issued by the MDPSC, offset by increases in operating and maintenance expense and depreciation expense.

Operating Revenues, Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive electric generation supplier affects electric SOS revenues and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenues and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric generation supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive electric generation supplier was 382,600 and 389,400 at June 30, 2014 and 2013, respectively, representing 31% of total retail customers at each date. Retail deliveries purchased from competitive electric generation suppliers represented 63% and 60% of BGE's retail kWh sales for the three and six months ended June 30, 2014, respectively, compared to 63% and 61% for the three and six months ended June 30, 2013, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 165,500 and 161,900 at June 30, 2014 and 2013, respectively, representing 25% of total retail customers at each date. Retail deliveries purchased from competitive natural gas suppliers represented 64% and 51% of BGE's retail mmcf sales for the three and six months ended June 30, 2014, respectively, compared to 63% and 51% for the three and six months ended June 30, 2013, respectively.

The changes in BGE's operating revenues net of purchased power and fuel expense for the three and six months ended June 30, 2014, compared to the same period in 2013, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)			Six Months Ended June 30, Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	$ 7	$ 3	$ 10	$ 35	$20	$ 55
Regulatory required programs	—	—	—	10	(1)	9
Commodity margin	—	1	1	1	8	9
Transmission revenues	3	—	3	8	—	8
Other	6	—	6	6	3	9
Total increase	$ 16	$ 4	$ 20	$ 60	$30	$ 90

Revenue Decoupling. The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the three and six months ended June 30, 2014 compared to the same period in 2013 consisted of the following:

Heating and Cooling Degree-Days	2014	2013	Normal	% Change From 2013	% Change From Normal
Three Months Ended June 30,					
Heating Degree-Days	497	492	513	1.0 %	(3.1)%
Cooling Degree-Days	233	263	252	(11.4)%	(7.5)%
Six Months Ended June 30,					
Heating Degree-Days	3,358	2,943	2,900	14.1 %	15.8%
Cooling Degree-Days	233	264	255	(11.7)%	(8.6)%

Distribution Rate Increase. The increase in distribution rates for the three and six months ended June 30, 2014, compared to the same periods in 2013, was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in December 2013 in accordance with the MDPSC approved electric and natural gas distribution rate case order. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the six months ended June 30, 2014 compared to the same period in 2013 was primarily due to the recovery of higher energy efficiency program costs.

Commodity Margin. The increase in commodity margin under BGE's market-based rate incentive mechanism for the three and six months ended June 30, 2014, compared to the same periods in 2013 was primarily due to the higher gas margins earned by BGE due to the extreme cold weather during the first quarter under BGE's MBR mechanism. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. The increase in transmission rates for the three and six months ended June 30, 2014, compared to the same periods in 2013, was primarily due to the impact of the new transmission rates charged to customers that became effective in June 2014. See Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other. Other revenues, which can vary from period to period, include miscellaneous revenues such as service application and late payment fees. Other revenues increased during the three and six months ended June 30, 2014 compared to the same periods in 2013.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and six months ended June 30, 2014 compared to the same periods in 2013, consisted of the following:

	Three Months Ended June 30, Increase (Decrease)	Six Months Ended June 30, Increase (Decrease)
Labor, other benefits, contracting and materials	$ 8	$ 25
Pension and non-pension postretirement benefits expense	2	4
Storm-related costs	(1)	13
Uncollectible accounts expense	10	13
Corporate allocations	5	7
Other	4	11
Increase in operating and maintenance expense	$ 28	$ 73

Depreciation and Amortization

The increase in depreciation and amortization expense for the three and six months ended June 30, 2014 compared to the same periods in 2013 was primarily due to higher amortization expense related to energy efficiency and demand response programs, which are fully offset in revenues above, and higher property, plant and equipment balances resulting from ongoing capital expenditures.

Taxes Other Than Income

The increase in taxes other than income for the three and six months ended June 30, 2014 compared to the same periods in 2013 was primarily due to increased gross receipts tax as a result of higher revenues.

Interest Expense, Net

The decrease in interest expense, net for the three and six months ended June 30, 2014 compared to the same periods in 2013 was primarily due to favorable interest rates in 2014 on long-term debt balances.

Effective Income Tax Rate

BGE's effective income tax rate was 42.4% and 39.0% for the three months ended June 30, 2014 and 2013, respectively, and 40.4% and 39.8% for the six months ended June 30, 2014 and 2013, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rate.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended June 30, 2014	2013	% Change	Weather-Normal% Change	Six Months Ended June 30, 2014	2013	% Change	Weather-Normal% Change
Retail Deliveries [a]								
Residential	2,639	2,757	(4.3)%	n.m	6,732	6,293	7.0%	n.m
Small commercial & industrial	704	716	(1.7)%	n.m	1,538	1,492	3.1%	n.m
Large commercial & industrial	3,593	3,610	(0.5)%	n.m	7,062	7,164	(1.4)%	n.m
Public authorities & electric railroads	79	80	(1.3)%	n.m	157	161	(2.5)%	n.m
Total Electric Retail Deliveries	7,015	7,163	(2.1)%	n.m	15,489	15,110	2.5%	n.m

Number of Electric Customers	As of June 30, 2014	2013
Residential	1,123,804	1,117,569
Small commercial & industrial	112,827	113,009
Large commercial & industrial	11,660	11,612
Public authorities & electric railroads	290	294
Total	1,248,581	1,242,484

Electric Revenue	Three Months Ended June 30, 2014	2013	% Change	Six Months Ended June 30, 2014	2013	% Change
Retail Sales [a]						
Residential	$ 293	$ 302	(3.0)%	$ 729	$ 667	9.3%
Small commercial & industrial	64	60	6.7%	136	125	8.8%
Large commercial & industrial	120	112	7.1%	243	217	12.0%
Public authorities & electric railroads	8	8	—%	16	15	6.7%
Total Retail	485	482	0.6%	1,124	1,024	9.8%
Other Revenue	67	61	9.8%	138	124	11.3%
Total Electric Revenues	$ 552	$ 543	1.7%	$ 1,262	$ 1,148	9.9%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended June 30, 2014	2013	% Change	Weather-Normal % Change	Six Months Ended June 30, 2014	2013	% Change	Weather-Normal % Change
Retail Deliveries [b]								
Retail sales	14,834	14,951	(0.8)%	n.m.	61,222	55,212	10.9%	n.m.
Transportation and other	875	1,545	(43.4)%	n.m.	7,204	7,195	0.1%	n.m.
Total Gas Deliveries	15,709	16,496	(4.8)%	n.m.	68,426	62,407	9.6%	n.m.

Number of Gas Customers	As of June 30, 2014	2013
Residential	612,202	611,146
Commercial & industrial	44,019	44,059
Total	656,221	655,205

Gas Revenue	Three Months Ended June 30, 2014	2013	% Change	Six Months Ended June 30, 2014	2013	% Change
Retail Sales [b]						
Retail sales	$ 92	$ 100	(8.0)%	$ 377	$ 345	9.3%
Transportation and other [c]	9	10	(10.0)%	68	40	70.0%
Total Gas Revenues	$ 101	$ 110	(8.2)%	$ 445	$ 385	15.6%

(b) Reflects delivery volumes and revenues from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.

(c) Transportation and other gas revenue includes off-system revenue of 875 mmcfs ($5 million) and 1,545 mmcfs ($8 million) for the three months ended June 30, 2014 and 2013, respectively, and 7,204 mmcfs ($58 million) and 7,195 mmcfs ($32 million) for the six months ended June 30, 2014 and 2013, respectively.

Liquidity and Capital Resources

Exelon's and Generation's current year activity presented below includes the activity of CENG from the integration date effective April 1, 2014 through June 30, 2014. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon Corporate, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Exelon Corporate, Generation, ComEd, PECO and BGE's revolving credit facilities expire in 2019. In addition, Generation has $0.5 billion in bilateral credit facilities. Generation's bilateral credit facilities have expirations in October 2014, January 2015, December 2015 and March 2016. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and issue letters of credit. See the "Credit Matters" section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

ComEd's, PECO's and BGE's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd's, PECO's and BGE's distribution services are provided to an established and diverse base of retail customers. ComEd's, PECO's and BGE's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 5 — Regulatory Matters and 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while the others took effect in 2013. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to make qualified pension plan contributions of $317 million to its qualified pension plans in 2014, of which Generation, ComEd, PECO and BGE will contribute $169 million, $119 million, $11 million and $0 million, respectively. Exelon's and Generation's expected qualified pension plan contributions above include $53 million and $51 million, respectively, related to CENG-sponsored plans for the period April 1, 2014 to December 31, 2014 (the period for which CENG is consolidated). Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $18 million in 2014, of which Generation, ComEd, PECO and BGE will make payments of $9 million, $1 million, $0 million and $1 million, respectively. Exelon and Generation's non-qualified expected pension plan benefit payments above include $3 million related to CENG-sponsored plans for the period April 1, 2014 to December 31, 2014.

To the extent interest rates decline significantly or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase, especially in years 2017 and beyond. Additionally, the contributions above could change if Exelon changes its pension funding strategy.

Unlike qualified pension plans, other postretirement benefit plans are not subject to statutory minimum contribution requirements and certain plans are not funded. Exelon's management has historically considered several factors in determining the level of contributions to its funded other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $290 million in 2014, of which Generation, ComEd, PECO and BGE expect to contribute $128 million, $121 million, $4 million and $18 million, respectively. Exelon and Generation's expected other postretirement benefit plan payments above include $5 million related to CENG-sponsored plans for the period April 1, 2014 to December 31, 2014 and contemplate reductions related to recent plan design changes.

During the first quarter of 2014, the Society of Actuaries issued an exposure draft with a proposed revised mortality table for use by actuaries, insurance companies, governments, benefit plan sponsors and others in setting assumptions regarding life expectancy in the United States for purposes of estimating pension and OPEB obligations, costs and required contribution amounts. The newly proposed mortality tables indicate substantial life expectancy improvements since the last study published in 2000 (RP 2000). Adoption of the new mortality table, if issued in its current form, would result in significantly increased future pension and OPEB plan obligations, costs and required contribution amounts for many plan sponsors, including Exelon. Exelon is currently evaluating the exposure draft and potential impacts to the December 31, 2014 valuation and future expected pension and OPEB plan contributions. The IRS has indicated the RP 2000 should be used for ERISA funding calculations impacting qualified pension plans in 2014 and 2015, meaning the earliest a new table would be required for determining those funding requirements is January 1, 2016.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- Exelon, Generation, ComEd, PECO and BGE expect to receive tax refunds of approximately $360 million, $60 million, $320 million, $10 million and $20 million, respectively, between 2014 and 2015.
- Given the current economic environment, state and local governments are facing increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes or the imposition, extension or permanence of temporary tax levies.
- In the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of $335 million. The termination will result in a 2014 tax payment of approximately $285 million by Exelon and its subsidiaries in 2014, including approximately $155 million by ComEd. Exelon intends to fund its portion of the tax payment using a portion of the net early termination amount. ComEd intends to fund its portion of the tax payment using a combination of debt and equity contributions from Exelon to substantially maintain its existing capital structure. See Note 11 — Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information.
- Under the Taxpayer Relief Act of 2012, 50% bonus depreciation expired on December 31, 2013. In the second quarter 2014, the Senate Finance Committee passed a two year extension of 50% bonus depreciation for 2014 and 2015. Further, on July 11, 2014, the House of Representatives passed H.R. 4718 permanently extending 50% bonus depreciation beginning with the 2014 tax year. If ultimately enacted for 2014 and 2015, 50% bonus depreciation legislation would generate incremental cash of approximately $1,175 million, $575 million, $375 million, $100 million, and $125 million, for Exelon,

Generation, ComEd, PECO, and BGE, respectively, primarily in 2015. The cash generated is an acceleration of tax benefits that Registrants would have received over the normal tax depreciable life of the qualifying property. Additionally, the extension of 50% bonus depreciation would result in a decrease to Generation's Domestic Production Activities Deduction, reducing cash tax benefits and increasing income tax expense by approximately $35 million and $25 million for 2014 and 2015, respectively. The potential extension of 50% bonus depreciation is not expected to result in a material impact on ComEd's, PECO's, or BGE's results of operations.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the six months ended June 30, 2014 and 2013:

	Six Months Ended June 30,		
	2014	2013	Variance
Net income	$ 651	$ 498	$ 153
Add (subtract):			
Non-cash operating activities [a]	3,208	2,025	1,183
Gain on consolidation of CENG	(268)	—	(268)
Pension and other postretirement benefit contributions	(499)	(284)	(215)
Income taxes	(16)	705	(721)
Changes in working capital and other noncurrent assets and liabilities [b]	(740)	(337)	(403)
Option premiums received (paid), net	21	(10)	31
Counterparty collateral posted, net	(606)	(259)	(347)
Net cash flows provided by operations	$ 1,751	$ 2,338	$ (587)

(a) Represents depreciation, amortization and accretion, impairment of long-lived assets, mark-to-market gains and losses on derivative transactions, deferred income taxes, provision for uncollectible accounts, pension and other postretirement benefit expense, equity in losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense and other non-cash charges.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Cash flows provided by operations for the six months ended June 30, 2014 and 2013 by Registrant were as follows:

	Six Months Ended June 30,	
	2014	2013
Exelon	$ 1,751	$ 2,338
Generation	742	1,150
ComEd	429	503
PECO	340	467
BGE	410	366

Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows provided by operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for the six months ended June 30, 2014 and 2013 were as follows:

Generation

- During the six months ended June 30, 2014 and 2013, Generation had net payments of counterparty collateral of $633 million and $303 million, respectively. Net payments during the six months ended June 30, 2014 and 2013 were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position and initial margin requirements on the exchanges. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.
- During the six months ended June 30, 2014 and 2013, Generation had net collections (payments) of approximately $21 million and $(10) million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During the six months ended June 30, 2014 and 2013, ComEd's payables for Generation energy purchases decreased by $33 million and $14 million, respectively, and payables to other energy suppliers for energy purchases increased by $55 million and $31 million, respectively.

PECO

- During the six months ended June 30, 2014 and 2013, PECO's payables to Generation for energy purchases decreased by $15 million and $11 million, respectively, and payables to other electric and gas suppliers for energy purchases (decreased) increased by $(4) million and $26 million, respectively.

BGE

- During the six months ended June 30, 2014 and 2013, BGE's payables to Generation for energy purchases increased by $9 million and $2 million, respectively, and payables to other electric and gas suppliers for energy purchases decreased by $16 million and $30 million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2014 and 2013 by Registrant were as follows:

	Six Months Ended June 30,	
	2014	2013
Exelon	$(2,187)	$(2,549)
Generation	(1,014)	(1,378)
ComEd	(731)	(693)
PECO	(302)	(514)
BGE	(332)	(257)

Capital expenditures by Registrant for the six months ended June 30, 2014 and 2013 and projected amounts for the full year 2014 are as follows:

	Projected Full Year 2014 [d]	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Exelon	$ 5,775	$ 2,501	$ 2,518
Generation [a]	2,625	1,103	1,277
ComEd [b]	1,775	747	711
PECO	675	308	254
BGE	600	313	264
Other [c]	100	30	12

(a) Includes nuclear fuel.
(b) The projected capital expenditures include approximately $442 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology.
(c) Other primarily consists of corporate operations and BSC.
(d) Total projected capital expenditures do not include adjustments for non-cash activity.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 38% and 10% of the projected 2014 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy generation, including Antelope Valley and wind construction costs, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages).

ComEd, PECO and BGE

Approximately 85%, 78% and 88% of the projected 2014 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and ComEd's, PECO's and BGE's construction commitments under PJM's RTEP. In addition to the capital expenditure for continuing projects, ComEd's total capital expenditures include smart grid/smart meter technology required under EIMA and for PECO and BGE, total capital expenditures related to their respective smart meter program and SGIG project.

In 2010, NERC provided guidance to transmission owners that recommends ComEd, PECO and BGE perform assessments of all their transmission lines. In compliance with this guidance, ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2014 capital expenditures above reflect capital spending in 2014 for remediation to be completed through 2017.

ComEd, PECO and BGE anticipate that they will fund their capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 5 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the six months ended June 30, 2014 and 2013 by Registrant were as follows:

	Six Months Ended June 30,	
	2014	2013
Exelon [a]	$ 189	$ (284)
Generation [a]	(681)	(221)
ComEd	304	139
PECO	(162)	(259)
BGE	(94)	259

(a) Includes $415 million of distributions to EDF.

Debt

See Note 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements.

Dividends

Cash dividend payments and distributions during the six months ended June 30, 2014 and 2013 by Registrant were as follows:

	Six Months Ended June 30,	
	2014	2013
Exelon [a]	$ 948	$ 716
Generation [a]	650	474
ComEd	153	110
PECO	160	167
BGE [b]	6	6

(a) Includes $415 million of distributions to EDF.
(b) Relates to dividends paid on BGE's preference stock.

First Quarter 2014 Dividend

On January 28, 2014, the Exelon Board of Directors declared a first quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on March 10, 2014, to shareholders of record of Exelon at the end of the day on February 14, 2014.

Second Quarter 2014 Dividend

On May 6, 2014, the Exelon Board of Directors declared a second quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on June 10, 2014, to shareholders of record of Exelon at the end of the day on May 16, 2014.

Third Quarter 2014 Dividend

On July 29, 2014, the Exelon Board of Directors declared a third quarter 2014 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on September 10, 2014 to shareholders of record of Exelon at the end of the day on August 15, 2014.

Short-Term Borrowings

During the six months ended June 30, 2014, ComEd and BGE issued(repaid) $314 million and $(65) million of commercial paper, respectively, and Generation issued $ 31 million in short-term notes payable. During the six months ended June 30, 2013, ComEd issued $374 million of commercial paper and Generation issued $276 million of commercial paper and $12 million in short-term notes payable.

Contributions from Parent/Member

During the six months ended June 30, 2014, ComEd received $112 million from Parent (Exelon). During the six months ended June 30, 2013, there were no contributions from Parent/Member (Exelon).

Distributions from Parent/Member

On April 1, 2014, Generation loaned $400 million to CENG, the proceeds of which were used to make a distribution to EDFI of $400 million. See Note 6 — Investment in Constellation Energy Nuclear Group, LLC for additional information on the integration of CENG.

Other

For the six months ended June 30, 2014, other financing activities primarily consisted of financing costs associated with the acquisition of PHI, other project financing and various debt issuance costs. See Notes 4, 10 and 16 for additional information.

Credit Matters

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $8.5 billion in aggregate total commitments of which $6.5 billion was available as of June 30, 2014, and of which no financial institution has more than 8% of the aggregate commitments. Exelon, Generation, ComEd, PECO and BGE had access to the commercial paper market during the second quarter of 2014 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See Part I. Item 1A. Risk Factors of Exelon's 2013 Annual Report on Form 10-K for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of June 30, 2014, it would have been required to provide incremental collateral of $2.0 billion to meet collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.3 billion. If ComEd lost its investment grade credit rating as of June 30, 2014, it would have been required to provide incremental collateral of $7 million, which is well within its current available credit facility capacity of $500 million, which takes into account commercial paper borrowings as of June 30, 2014. If PECO lost its investment grade credit rating as of June 30, 2014, it would not be required to provide collateral pursuant to PJM's credit policy and would have been required to provide collateral of $26 million

related to its natural gas procurement contracts, which, in the aggregate, are well within PECO's current available credit facility capacity of $599 million. If BGE lost its investment grade credit rating as of June 30, 2014, it would have been required to provide collateral of $4 million pursuant to PJM's credit policy and would have been required to provide collateral of $73 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of $530 million.

Exelon Credit Facilities

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 10 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information regarding the Registrants' credit facilities.

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at June 30, 2014:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size	Outstanding Commercial Paper at June 30, 2014	Average Interest Rate on Commercial Paper Borrowings for the Six Months Ended June 30, 2014
Exelon Corporate	$ 500	$ —	—
Generation	5,600	—	0.32%
ComEd	1,000	498	0.33%
PECO	600	—	—
BGE	600	70	0.27%

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its commercial paper outstanding does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

Credit Agreements

Borrower	Facility Type	Aggregate Bank Commitment [a]	Facility Draws	Outstanding Letters of Credit	Available Capacity at June 30, 2014	
					Actual	To Support Additional Commercial Paper
Exelon Corporate	Syndicated Revolver	$ 500	$ —	$ 2	$ 498	$ 498
Generation	Syndicated Revolver	5,300	—	1,161	4,139	4,139
Generation	Bilaterals	375	—	245	1	130
CENG	Bilaterals	100	40	—	60	—
ComEd	Syndicated Revolver	1,000	—	2	998	500
PECO	Syndicated Revolver	600	—	1	599	599
BGE	Syndicated Revolver	600	—	—	600	530

(a) Excludes $123 million of credit facility agreements arranged with minority and community banks at Generation, ComEd, PECO and BGE. These facilities expire on October 18, 2014, and are solely utilized to issue letters of credit. See Note 10 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information.

As of June 30, 2014, there were no borrowings under the Registrants' credit facilities, with the exception of CENG, see discussion below.

On March 28, 2014, ComEd extended its unsecured revolving credit facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement expires on March 28, 2019. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to extend the facility for ComEd were not material.

On April 1, 2014, as a result of the CENG integration, a $100 million bilateral CENG credit facility expiring October 2014 is now consolidated in Exelon's and Generation's consolidated financial statements. This facility will be utilized by CENG to fund working capital and capital projects and obtain letters of credit. As of June 30, 2014, CENG borrowed $40 million against its credit facility.

On May 30, 2014, Exelon, Generation, PECO and BGE extended for an additional year the expiration date of its unsecured revolving credit facility with aggregate bank commitments of $500 million, $5.3 billion, $600 million, $600 million, respectively into May 2019, with the exception of a cumulative amount of $300 million which expires in August 2018. Costs incurred to extend the facility were not material.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit facilities bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the registrants credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 7.5, 0.0 and 0.0 basis points for prime based borrowings and 127.5, 127.5, 107.5, 90.0 and 100.0 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO and BGE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the six months ended June 30, 2014:

	Exelon	Generation	ComEd	PECO	BGE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At June 30, 2014, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	10.63	11.73	5.99	7.95	8.53

An event of default under any Registrant's indebtedness will not constitute an event of default under any of the other Registrants' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation will constitute an event of default under the Exelon Corporate credit facility.

Security Ratings

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of June 30, 2014, are presented in the following table:

	During the three months ended June 30, 2014		As of June 30, 2014
Contributed (borrowed) as of June 30, 2014	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Generation	$ —	$ 405	$ (190)
PECO	129	—	—
BSC	—	329	(259)
Exelon Corporate	563	N/A	449

Investments in Nuclear Decommissioning Trust Funds

Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's and CENG's investment policies establish limits on the concentration of holdings in any one company and also in any one industry. See Note 12 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements

The Registrants have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in May 2017. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations

As of June 30, 2014, ComEd had $702 million available in long-term debt refinancing authority and $1.2 billion available in new money long-term debt financing authority from the ICC. As of June 30, 2014, PECO had $1.4 billion available in long-term debt financing authority from the PAPUC. As of June 30, 2014, BGE had $850 million available in long-term financing authority from MDPSC.

As of June 30, 2014, ComEd, PECO and BGE had short-term financing authority from FERC, which expires on December 31, 2015, of $2.5 billion, $2.5 billion, and $0.7 billion, respectively. Generation currently has blanket financing authority from FERC, which was granted in connection with its market-based rate authority.

Contractual Obligations and Off-Balance Sheet Arrangements

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' commitments.

Generation, ComEd, PECO and BGE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd, PECO and BGE have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants' respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for further information.

For an in-depth discussion of the Registrant's contractual obligations and off-balance sheet arrangements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations and Off-Balance Sheet Arrangements" in the Exelon 2013 Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief enterprise risk officer and includes the chief executive officer, chief financial officer, chief commercial risk officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Risk Oversight Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of the Registrants' 2013 Annual Report on Form 10-K incorporated herein by reference.

Commodity Price Risk (Exelon, Generation, ComEd, PECO and BGE)

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2014 through 2016.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over the three years leading to the spot market. As of June 30, 2014, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 75%-78% and 46%-49% for 2014, 2015 and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including sales to ComEd, PECO and BGE to serve their retail load.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on June 30, 2014 market conditions and hedged position would be a decrease in pre-tax net income of approximately $20 million, $270 million and $570 million, respectively, for 2014, 2015 and 2016. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting

from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 2,629 GWhs and 5,123 GWhs for the three and six months ended June 30, 2014, respectively, and 1,995 GWhs and 3,567 GWhs for the three and six months ended June 30, 2013, respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the six months ended June 30, 2014 resulted in pre-tax gains of $20 million due to net mark-to-market losses of $7 million and realized gains of $27 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $ 0.4 million of exposure during the quarter. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for the six months ended June 30, 2014 of $2,988 million.

Fuel Procurement. Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2014 through 2018 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

ComEd

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements in this report and Note 3 — Regulatory Matters of the Exelon 2013 Form 10-K for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements. PECO has certain full requirements contracts and block contracts which are considered derivatives and qualify for the normal purchases and normal

sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result, are accounted for on an accrual basis of accounting. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Exelon's, Generation's, ComEd's and PECO's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's and ComEd's commodity mark-to-market net asset or liability balance sheet position from December 31, 2013 to June 30, 2014. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 9 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of June 30, 2014 and December 31, 2013.

	Generation	ComEd	Exelon
Total mark-to-market energy contract net assets (liabilities) at December 31, 2013 [a]	$ 1,047	$ (193)	$ 854
Total change in fair value during 2014 of contracts recorded in result of operations	(693)	—	(693)
Reclassification to realized at settlement of contracts recorded in results of operations	(53)	—	(53)
Reclassification to realized at settlement from accumulated OCI	(102)	—	(102)
Changes in fair value — energy derivatives [c]	—	59	59
Changes in allocated collateral	634	—	634
Changes in net option premium paid/(received)	(21)	—	(21)
Option premium amortization [b]	(63)	—	(63)
Other balance sheet reclassifications	(2)	—	(2)
Total mark-to-market energy contract net assets (liabilities) at June 30, 2014 [a]	$ 747	$ (134)	$ 613

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Includes $63 million of amounts reclassified to realized at the settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the six months ended June 30, 2014.
(c) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of June 30, 2014, ComEd recorded a $134 million regulatory asset related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. As of June 30, 2014, ComEd also recorded $64 million of decreases in fair value and $5 million of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

Fair Values. The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 8 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts [a][b]							
Actively quoted prices (Level 1)	$ 22	$ (4)	$20	$ 2	$ 5	$ —	$ 45
Prices provided by external sources (Level 2)	159	253	52	(4)	—	—	460
Prices based on model or other valuation methods (Level 3) [c]	32	107	14	30	(17)	(58)	108
Total	$213	$356	$86	$28	$(12)	$ (58)	$ 613

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $490 million at June 30, 2014.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts [a][b]							
Actively quoted prices (Level 1)	$ 22	$ (4)	$ 20	$ 2	$ 5	$ —	$ 45
Prices provided by external sources (Level 2)	159	253	52	(4)	—	—	460
Prices based on model or other valuation methods (Level 3)	39	122	28	43	(5)	15	242
Total	$220	$371	$100	$41	$—	$ 15	$ 747

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $490 million at June 30, 2014.

ComEd

	Maturities Within						
	2014	2015	2016	2017	2018	2019 and beyond	Total Fair Value
Prices based on model or other valuation methods [a]	$ (7)	$(15)	$(14)	$(13)	$(12)	$ (73)	$ (134)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd, PECO and BGE)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2014. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers,

uranium procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of $6 million, $23 million and $36 million, respectively. See Note 25 — Related Party Transactions of the Exelon 2013 Form 10-K for additional information.

Rating as of June 30, 2014	Total Exposure Before Credit Collateral	Credit Collateral [a]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,095	$ 103	$ 992	1	$ 417
Non-investment grade	12	9	3	—	—
No external ratings					
Internally rated — investment grade	286	2	284	1	189
Internally rated — non-investment grade	21	4	17	—	—
Total	$ 1,414	$ 118	$ 1,296	2	$ 606

	Maturity of Credit Risk Exposure			
Rating as of June 30, 2014	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 709	$ 295	$ 91	$ 1,095
Non-investment grade	11	1	—	12
No external ratings				
Internally rated — investment grade	195	88	3	286
Internally rated — non-investment grade	21	—	—	21
Total	$ 936	$ 384	$ 94	$ 1,414

Net Credit Exposure by Type of Counterparty	As of June 30, 2014
Investor-owned utilities, marketers and power producers	$ 360
Energy cooperatives and municipalities	729
Financial institutions	185
Other	22
Total	$ 1,296

(a) As of June 30, 2014, credit collateral held from counterparties where Generation had credit exposure included $112 million of cash and $6 million of letters of credit.

ComEd

There have been no significant changes or additions to ComEd's exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2013 Annual Report on Form 10-K.

See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

PECO

There have been no significant changes or additions to PECO's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2013 Annual Report on Form 10-K.

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See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

BGE

There have been no significant changes or additions to BGE's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2013 Annual Report on Form 10-K.

See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

Collateral (Exelon, Generation, ComEd, PECO and BGE)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 10 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

As of June 30, 2014, Generation had cash collateral of $623 million posted and cash collateral held of $124 million for counterparties with derivative positions, of which $490 million and $2 million in net cash collateral deposits were offset against energy mark-to-market and interest rate and foreign exchange derivative assets and liabilities related to underlying energy contracts, respectively. As of June 30, 2014, $7 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives or as of the balance sheet date there were no positions to offset. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of June 30, 2014, ComEd held approximately $2 million of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements in this report and Note 3 — Regulatory Matters of the 2013 Exelon Form 10-K for additional information.

PECO

As of June 30, 2014, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of June 30, 2014, BGE was not required to post collateral under its natural gas procurement contracts. However, BGE did hold approximately $20 million of collateral from suppliers for both electric supply and natural gas procurement contracts as of June 30, 2014. See Note 9 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon and Generation)

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases (Exelon)

Exelon's Consolidated Balance Sheet, as of June 30, 2014, included a $353 million net investment in coal-fired plants in Georgia subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $685 million, less unearned income of $332 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessee does not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessee to arrange for a third party to bid on a service contract for a period following the lease term. Exelon will be subject to residual value risk if the lessee does not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

Exelon's Consolidated Balance Sheet, as of December 31, 2013, also included a net investment in a coal-fired plant in Texas subject to a long-term lease. In February 2014, Exelon and the City Public Service Board of San Antonio, Texas (CPS) finalized an agreement to terminate the leases prior to their expiration dates. As a result of the lease termination, Exelon received a net early termination amount of $335 million from CPS and wrote off the net investment in the CPS long-term lease of $336 million; resulting in a pre-tax loss of $1 million. See Note 11 — Income Taxes for the impact of the lease termination on income taxes.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At June 30, 2014, Exelon and Generation had $1,550 million and $700 million of notional amounts of fixed-to-floating hedges outstanding, respectively, and $1,111 million and $411 million of notional amounts of floating-to-fixed hedges outstanding, respectively. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $4 million decrease in Exelon Consolidated pre-tax income for the six months ended June 30, 2014. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of June 30, 2014, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $617 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the second quarter of 2014, each of Exelon's, Generation's, ComEd's, PECO's and BGE's management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by all Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon's management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include

the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of June 30, 2014, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd, PECO and BGE concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. All Registrants continually strive to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. There have been no changes in internal control over financial reporting that occurred during the second quarter of 2014 that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's and BGE's internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. Legal Proceedings

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of Exelon's 2013 Form 10-K and (b) Notes 5 and 18 of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

Item 1A. Risk Factors

In addition to the risk factors described in Part I, Item 1A. Risk Factors in Exelon's 2013 Form 10-K, Exelon faces the following additional risks:

Risks Related to the Pending Merger with PHI

Exelon and PHI may encounter difficulties in satisfying the conditions for the completion of the Merger and the Merger may not be completed within the expected timeframe or at all.

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (1) the approval of the Merger by the holders of a majority of the outstanding shares of the PHI common stock, (2) the receipt of regulatory approvals required to consummate the Merger, (3) the expiration or termination of the applicable waiting period under the HSR Act and (4) other customary closing conditions, including (a) the accuracy of each party's representations and warranties (subject to customary materiality qualifiers) and (b) each party's compliance with its obligations and covenants contained in the Merger Agreement. In addition, the obligation of Exelon to consummate the Merger is subject to the required regulatory approvals not, individually or in the aggregate, imposing terms, conditions, obligations or commitments that constitute a burdensome condition (as defined in the Merger Agreement)

Satisfying the conditions to completion of the Merger may take longer, and could cost more, than Exelon expects. Any delay in completing the Merger or any additional conditions imposed in order to complete the Merger may materially adversely affect the synergies and other benefits that Exelon expects to achieve from the Merger and the integration of the companies' respective businesses.

In addition, conditions to the completion of the Merger may fail to be satisfied. Exelon or PHI may terminate the Merger Agreement if the Merger is not completed by July 29, 2015 except that, under certain circumstances, the date may be extended by Exelon or PHI to October 29, 2015.

The Merger is subject to the receipt of consent or approval from governmental entities that could delay the completion of the Merger or impose conditions that could have a material adverse effect on the combined company or that could cause abandonment of the Merger.

Completion of the Merger is conditioned upon the receipt of consents, orders, approvals or clearances, to the extent required, from the FERC, the FCC, the District of Columbia Public Service Commission, and the public utility commissions or similar entities in certain states in which the companies operate, including the Delaware Public Service Commission, MDPSC, the New Jersey Board of Public Utilities and the Virginia Department of Public Utilities. The Merger is also subject to review by the DOJ Antitrust Division, under the HSR Act, and the expiration or earlier termination of the waiting period (and any extension of the waiting period) applicable to the Merger is a condition to closing the Merger. As of July 31, 2014, Exelon and PHI have made some, but not all, of the required regulatory filings, and the Merger remains subject to the approval or review of each of the regulatory agencies mentioned above.

Exelon and PHI have proposed conditions for approval in some of the regulatory filings that have been made and may subsequently propose or agree to further conditions, even if such conditions could have an adverse effect on Exelon, PHI or the combined company.

Exelon cannot provide assurance that all required regulatory consents or approvals will be obtained or that these consents or approvals will not contain terms, conditions or restrictions that would be detrimental to the combined company after the completion of the Merger. The Merger Agreement generally permits Exelon to terminate the Merger Agreement if the final terms of any of the required regulatory consents or approvals include burdensome conditions (as defined in the Merger Agreement). Any substantial delay in obtaining satisfactory approvals, receipt of proceeds from asset divestitures in an amount substantially lower than anticipated or the imposition of any terms or conditions in connection with such approvals could cause a material reduction in the expected benefits of the Merger.

Failure to obtain regulatory approval may result in Exelon's payment of a reverse termination fee.

If the Merger Agreement is terminated under certain circumstances due to the failure to obtain regulatory approvals or the breach by Exelon of its obligations in respect of obtaining regulatory approvals, Exelon will be required to pay PHI a reverse termination fee of up to $180 million, by means of PHI redeeming the outstanding nonvoting preferred securities purchased by Exelon for no consideration other than the nominal par value of the stock.

Failure to complete the Merger could negatively affect the share price and the future business and financial results of Exelon.

Completion of the Merger is not assured and is subject to risks, including the risks that approval of the transaction by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If the Merger is not completed, the ongoing businesses of Exelon may be adversely affected and Exelon will be subject to several risks, including:

- having to pay certain significant costs relating to the Merger without receiving the benefits of the Merger, including, in certain circumstances, a termination fee of up to $180 million payable by Exelon to PHI under some circumstances; and
- the share price of Exelon may decline if and to the extent that the current market prices reflect an assumption by the market that the Merger will be completed.

Exelon and PHI have and will incur significant transaction and Merger-related costs in connection with the Merger.

Exelon and PHI expect to incur a number of non-recurring costs associated with combining the operations of the two companies. Most of these costs will be transaction costs, including fees paid to financial and legal advisors related to the Merger and related financing arrangements, and employment-related costs, including change-in- control related payments made to certain PHI executives. In addition, if the closing of the Merger is materially delayed, Exelon may be required to pay financing costs without having realized any benefits from the Merger during the period of delay. Exelon will also incur transaction fees and costs related to formulating integration plans. Additional unanticipated costs may be incurred in the integration of the two companies' businesses. Although Exelon expects that the elimination of costs, as well as the realization of other efficiencies related to the integration of the businesses, will exceed incremental transaction and Merger-related costs over time, this net benefit may not be achieved in the near term, or at all.

Exelon may not realize the expected benefits of the Merger because of integration difficulties and other challenges.

The success of the PHI acquisition will depend, in part, on Exelon's ability to realize all or some of the anticipated benefits from integrating PHI's business with Exelon's existing businesses. The integration process may be complex, costly and time-consuming. The challenges associated with integrating the operations of PHI's business include, among others:

- delay in implementation of our business plan for the combined business;
- unanticipated issues or costs in integrating financial, information technology, communications and other systems;
- possible inconsistencies in standards, controls, procedures and policies, and compensation structures between PHI' s structure and our structure;
- unanticipated changes in applicable laws and regulations;
- difficulties in retention of key employees;
- operating risks inherent in PHI's business and our business; and
- unexpected regulatory requirements.

Exelon and PHI will be subject to various uncertainties while the Merger is pending that may adversely affect their ability to attract and retain key employees, and potentially affect the company's financial results.

Uncertainty about the effect of the Merger on employees, suppliers and customers may have an adverse effect on Exelon and/or PHI. These uncertainties may impair Exelon's and/or PHI's ability to attract, retain and motivate key personnel until the Merger is completed and for a period of time thereafter, as employees and prospective employees may experience uncertainty about their future roles with the combined company. In addition, current and prospective Exelon and PHI employees may determine that they do not desire to work for the combined company for a variety of possible reasons.

The Merger may divert attention of management at Exelon and PHI, which could detract from efforts to meet business goals.

The pursuit of the Merger and the preparation for the integration may place a burden on management and internal resources. Any significant diversion of management attention away from ongoing business concerns and any difficulties encountered in the transition and integration process could affect Exelon's and/or PHI's financial results. The process of integrating the operations of PHI may require a disproportionate amount of resources and management attention. Exelon's future operations and cash flows will depend to a significant degree upon Exelon's ability to operate PHI efficiently, achieve the strategic operating objectives for the business and realize cost savings and synergies. Exelon's management team may encounter unforeseen difficulties in managing the integration. In order to successfully integrate PHI, Exelon's management team will need to focus on realizing anticipated synergies and cost savings on a timely basis while maintaining the efficiency of operations. Any substantial diversion of management attention could affect Exelon's ability to achieve operational, financial and strategic objectives.

We are obligated to complete the Merger whether or not we have obtained the required financing.

Exelon intends to fund the cash consideration in the Merger using a combination of approximately $3.5 billion of debt, up to $1.0 billion cash from asset sales, and the remainder through issuance of equity (including mandatory convertible securities). Exelon has executed a $2.0 billion equity offering of 57.5 million shares of common stock in connection with forward sales agreements and $1.2 billion of junior subordinated

notes in the form of 23 million equity units. In addition, Exelon signed a 364-day $7.2 billion senior unsecured bridge credit facility to provide financing for the Merger pending the arrangement of permanent financing, which has subsequently been reduced to $4.2 billion as a result of the equity issuances. The unsecured bridge credit facility is subject to various conditions contained in the agreement and the issuance of long-term debt and sales of assets to finance the Merger will be subject to future market conditions.

The combined company's assets, liabilities or results of operations could be adversely affected by unknown or unexpected events, conditions or actions that might occur at PHI prior to the closing of the Merger.

The PHI assets, liabilities, business, financial condition, cash flows, operating results and prospects to be acquired or assumed by Exelon by reason of the merger could be adversely affected before or after the Merger closing as a result of previously unknown events or conditions occurring or existing before the Merger closing. Adverse changes in PHI's business or operations could occur or arise as a result of actions by PHI, legal or regulatory developments including the emergence or unfavorable resolution of pre-acquisition loss contingencies, deteriorating general business, market, industry or economic conditions, and other factors both within and beyond the control of PHI. A significant decline in the value of PHI assets to be acquired by Exelon or a significant increase in PHI liabilities to be assumed by Exelon could adversely affect the combined company's future business, financial condition, cash flows, operating results and prospects.

Exelon may record goodwill that could become impaired and adversely affect its operating results.

In accordance with GAAP, the Merger will be accounted for as an acquisition of PHI common stock by Exelon and will follow the acquisition method of accounting for business combinations. The assets and liabilities of PHI will be consolidated with those of Exelon. The excess of the purchase price over the fair values of PHI's assets and liabilities, if any, will be recorded as goodwill.

The amount of goodwill, which could be material, will be allocated to the appropriate reporting units of the combined company. Exelon is required to assess goodwill for impairment at least annually by comparing the fair value of reporting units to the carrying value of those reporting units. To the extent the carrying value of any of those reporting units is greater than the fair value, a second step comparing the implied fair value of goodwill to the carrying amount would be required to determine if the goodwill is impaired. Such a potential impairment could result in a material charge that would have a material impact on Exelon's future operating results and consolidated balance sheet.

Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could delay or prevent the completion of the Merger.

One of the conditions to the closing of the Merger is that no judgment (whether preliminary, temporary or permanent) or other order by any court or other governmental entity shall be in effect that restrains, enjoins or otherwise prohibits or makes illegal the consummation of the Merger.

PHI and its directors have been named as defendants in a purported class action lawsuits filed on behalf of named plaintiffs and other public stockholders challenging the proposed Merger and seeking, among other things, to enjoin the defendants from consummating the Merger on the agreed-upon terms. Exelon has been named as a defendant is some of these lawsuits.

If a plaintiff in this or any other litigation that may be filed in the future is successful in obtaining an injunction prohibiting the parties from completing the Merger on the terms contemplated by the Merger Agreement, the injunction may prevent the completion of the Merger in the expected timeframe or altogether. If completion of the Merger is prevented or delayed, it could result in substantial costs to Exelon. In addition, Exelon could incur significant costs in connection with the lawsuits, including costs associated with the indemnification of PHI's directors and officers.

Private parties who may believe they are adversely affected by the Merger and individual states may bring legal actions under the antitrust laws in certain circumstances or intervene in regulatory proceedings. Although Exelon and PHI believe the completion of Merger will not conflict with any antitrust law, there can be no assurance that a challenge to the Merger on antitrust grounds will not be made or, if a challenge is made, what the result will be. Under the Merger Agreement, Exelon and PHI have agreed to use their reasonable best efforts to obtain all regulatory clearances necessary to complete the Merger as promptly as practicable. In addition, in order to complete the Merger, Exelon and PHI may be required to comply with conditions, terms, obligations or restrictions imposed by regulatory agencies and any such conditions, terms, obligations or restrictions may have the effect of delaying completion of the Merger, imposing additional material costs on or materially limiting Exelon's revenues after the completion of the Merger, or otherwise reducing the anticipated benefits from the Merger. In addition, any such conditions, terms, obligations or restrictions could result in the delay or abandonment of the Merger.

The Merger may be completed on terms different from those contained in the Merger Agreement.

Prior to the completion of the Merger, Exelon and PHI may, by their mutual agreement, amend or alter the terms of the Merger Agreement, including with respect to, among other things, the Merger consideration to be received by PHI stockholders or any covenants or agreements with respect to the parties' respective operations pending completion of the Merger. In addition, Exelon may choose to waive requirements of the Merger Agreement, including some conditions to closing of the Merger. Any such amendments, alterations or waivers may have negative consequences to Exelon.

Item 4. Mine Safety Disclosures

Exelon, Generation, ComEd, PECO and BGE

Not applicable to the Registrants.

Item 6. Exhibits

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
1.1	Common Stock Underwriting Agreement, dated June 11, 2014, with Barclays Capital Inc. and Goldman, Sachs & Co., as representatives of the several underwriters (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 1.1)
1.2	Corporate Units Underwriting Agreement, dated June 11, 2014, with Barclays Capital Inc. and Goldman, Sachs & Co., as representatives of the several underwriters (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 1.2)
2.1	Agreement and Plan of Merger, dated as of April 29, 2014, by and among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp. (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit 2.1)
2.2	Subscription Agreement for Series A Non-Voting Non-Convertible Preferred Stock (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit 2.2)
2.3	Amended and Restated Agreement of Plan of Merger, dated as of July 18, 2014, among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp. (File No. 001-16169, Form 8-K dated July 21, 2014, Exhibit 2.1)

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Exhibit No.	Description
4.1	Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.1)
4.2	First Supplemental Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.2)
4.3	Form of 2.50% Notes due 2024 (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.3)
4.4	Purchase Contract and Pledge Agreement, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Purchase Contract Agent, Collateral Agent, Custodial Agent and Securities Intermediary (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.4)
4.5	Form of Remarketing Agreement (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.5)
4.6	Form of Corporate Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.6)
4.7	Form of Treasury Unit (File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.7)
10.1	Commitment Letter for $7.221 Billion Senior Unsecured Bridge Facility (File No. 001-16169, Form 8-K dated April 30, 2014, Exhibit 10.1)
10.2	364-Day Bridge Term Loan Agreement, dated as of May 30, 2014, among Exelon Corporation, as Borrow, the various financial institutions named therein, as Lenders, and Barclays Bank PLC, as Administrative Agent (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.1)
10.3	Amendment No. 4 to Credit Agreement, dated May 30, 2014, among Exelon Corporation, the Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.2)
10.4	Amendment No. 4 to Credit Agreement, dated May 30, 2014, among Exelon Generation Company, LLC, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.3)
10.5	Amendment No. 3 to Credit Agreement, dated May 30, 2014, among PECO Energy Company, as Borrower, the financial institutions signatory therein, as Lenders and JPMorgan Chase Bank, N.A., as Administrative Agent (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.4)
10.6	Amendment No. 2 to Credit Agreement, dated May 30, 2014, among Baltimore Gas and Electric Company, as Borrower, the financial institutions signatory therein, as Lenders and The Royal Bank of Scotland plc, as Administrative Agent (File No. 001-16169, Form 8-K dated June 4, 2014, Exhibit 10.5)
10.7	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Barclays Capital, Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.1)
10.8	Confirmation of Base Issuer Forward Transaction, dated June 11, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.2)
10.9	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Barclays Capital Inc., acting as Agent for Barclays Bank PLC (File No. 001-16169, Form 8-K dated June 17, 2014, Exhibit 10.3)
10.10	Confirmation of Additional Issuer Forward Transaction, dated June 13, 2014, between Exelon Corporation and Goldman Sachs & Co. (File No. 001-16169, Form 8-K dated June 17, 2014 Exhibit 10.4)
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema

Exhibit No.	Description
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014 filed by the following officers for the following companies:

31-1 — Filed by Christopher M. Crane for Exelon Corporation

31-2 — Filed by Jonathan W. Thayer for Exelon Corporation

31-3 — Filed by Kenneth W. Cornew for Exelon Generation Company, LLC

31-4 — Filed by Bryan P. Wright for Exelon Generation Company, LLC

31-5 — Filed by Anne R. Pramaggiore for Commonwealth Edison Company

31-6 — Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company

31-7 — Filed by Craig L. Adams for PECO Energy Company

31-8 — Filed by Phillip S. Barnett for PECO Energy Company

31-9 — Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company

31-10 — Filed by David M. Vahos for Baltimore Gas and Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014 filed by the following officers for the following companies:

32-1 — Filed by Christopher M. Crane for Exelon Corporation

32-2 — Filed by Jonathan W. Thayer for Exelon Corporation

32-3 — Filed by Kenneth W. Cornew for Exelon Generation Company, LLC

32-4 — Filed by Bryan P. Wright for Exelon Generation Company, LLC

32-5 — Filed by Anne R. Pramaggiore for Commonwealth Edison Company

32-6 — Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company

32-7 — Filed by Craig L. Adams for PECO Energy Company

32-8 — Filed by Phillip S. Barnett for PECO Energy Company

32-9 — Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company

32-10 — Filed by David M. Vahos for Baltimore Gas and Electric Company

SIGNATURES

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON CORPORATION

/ S / C HRISTOPHER M. C RANE
Christopher M. Crane
President and Chief Executive Officer
(Principal Executive Officer)

/ S / J ONATHAN W. T HAYER
Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/ S / D UANE M. D ES P ARTE
Duane M. DesParte
Senior Vice President and Corporate Controller
(Principal Accounting Officer)

July 31, 2014

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EXELON GENERATION COMPANY, LLC

/s/ K ENNETH W. C ORNEW
Kenneth W. Cornew
President and Chief Executive Officer
(Principal Executive Officer)

/s/ B RYAN P. W RIGHT
Bryan P. Wright
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ R OBERT M. A IKEN
Robert M. Aiken
Chief Accounting Officer
(Principal Accounting Officer)

July 31, 2014

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

COMMONWEALTH EDISON COMPANY

/s/ Anne R. Pramaggiore
Anne R. Pramaggiore
President and Chief Executive Officer
(Principal Executive Officer)

/s/ Joseph R. Trpik, Jr.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

/s/ Gerald J. Kozel
Gerald J. Kozel
Vice President and Controller
(Principal Accounting Officer)

July 31, 2014

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PECO ENERGY COMPANY

/s/ Craig L. Adams
Craig L. Adams
President and Chief Executive Officer
(Principal Executive Officer)

/s/ Phillip S. Barnett
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

/s/ Scott A. Bailey
Scott A. Bailey
Vice President and Controller
(Principal Accounting Officer)

July 31, 2014

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ Calvin G. Butler, Jr.
Calvin G. Butler, Jr.
Chief Executive Officer
(Principal Executive Officer)

/s/ David M. Vahos
David M. Vahos
Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

/s/ Matthew N. Bauer
Matthew N. Bauer
Vice President and Controller
(Principal Accounting Officer)

July 31, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CHRISTOPHER M. CRANE
President and Chief Executive Officer
(Principal Executive Officer)

Date: July 31, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JONATHAN W. THAYER
Senior Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: July 31, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ KENNETH W. CORNEW
President and Chief Executive Officer
(Principal Executive Officer)

Date: July 31, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ BRYAN P. WRIGHT
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: July 31, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ANNE R. PRAMAGGIORE
President and Chief Executive Officer
(Principal Executive Officer)

Date: July 31, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JOSEPH R. TRPIK, JR.
Senior Vice President, Chief Financial Officer
and Treasurer
(Principal Financial Officer)

Date: July 31, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ C RAIG L. A DAMS
President and Chief Executive Officer
(Principal Executive Officer)

Date: July 31, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ P HILLIP S. B ARNETT
Senior Vice President, Chief Financial Officer
and Treasurer
(Principal Financial Officer)

Date: July 31, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Calvin G. Butler, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ C ALVIN G. B UTLER , J R .
Chief Executive Officer
(Principal Executive Officer)

Date: July 31, 2014

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Vahos, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ D AVID M. V AHOS
Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: July 31, 2014

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended June 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ CHRISTOPHER M. CRANE
Christopher M. Crane
President and Chief Executive Officer

Date: July 31, 2014

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended June 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ JONATHAN W. THAYER

Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer

Date: July 31, 2014

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended June 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ KENNETH W. CORNEW
Kenneth W. Cornew
President and Chief Executive Officer

Date: July 31, 2014

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended June 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ BRYAN P. WRIGHT
Bryan P. Wright
Senior Vice President and Chief Financial Officer

Date: July 31, 2014

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended June 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ ANNE R. PRAMAGGIORE
Anne R. Pramaggiore
President and Chief Executive Officer

Date: July 31, 2014

Exhibit 32-6

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended June 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ JOSEPH R. TRPIK, JR.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Date: July 31, 2014

Exhibit 32-7

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended June 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ C RAIG L. A DAMS
Craig L. Adams
President and Chief Executive Officer

Date: July 31, 2014

Exhibit 32-8

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended June 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ P HILLIP S. B ARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Date: July 31, 2014

Exhibit 32-9

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended June 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ C ALVIN G. B UTLER , J R .
Calvin G. Butler, Jr.
Chief Executive Officer

Date: July 31, 2014

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended June 30, 2014, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ D AVID M. V AHOS
David M. Vahos
Vice President, Chief Financial Officer and Treasurer

Date: July 31, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Quarterly Period Ended June 30, 2015

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number	Name of Registrant; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
Exelon Corporation	☒			
Exelon Generation Company, LLC			☒	
Commonwealth Edison Company			☒	
PECO Energy Company			☒	
Baltimore Gas and Electric Company			☒	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

S1-SSA-0009-19928

The number of shares outstanding of each registrant's common stock as of June 30, 2015 was:

Exelon Corporation Common Stock, without par value	861,617,731

Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,973
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon's holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Antelope Valley, AVSR	Antelope Valley Solar Ranch One
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
ComEd Financing III	ComEd Financing III
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Energy Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
BGE Trust II	BGE Capital Trust II
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively

Other Terms and Abbreviations

Note "—" of the Exelon 2014 Form 10-K	Reference to a specific Combined Note to Consolidated Financial Statements within Exelon's 2014 Annual Report on Form 10-K
1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
DC Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA
EE&C	Energy Efficiency and Conservation/Demand Response
EGR	ExGen Renewables I, LLC
EGS	Electric Generation Supplier
EGTP	ExGen Texas Power, LLC
EIMA	Illinois Energy Infrastructure Modernization Act
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
Integrys	Integrys Energy Services, Inc.
IPA	Illinois Power Agency
IRC	Internal Revenue Code

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	New York Independent System Operator
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste
LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Standard Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody's	Moody's Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting including the CENG units (Calvert Cliffs, Nine Mile Point, and R.E. Ginna), Clinton, Oyster Creek, Three Mile Island, Zion (a former ComEd unit), and portions of Peach Bottom (a former PECO unit)
NOSA	Nuclear Operating Services Agreement
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
PPL	PPL Holtwood, LLC
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting including the former ComEd units (Braidwood, Bryon, Dresden, LaSalle, Quad Cities) and the former PECO units (Limerick, Peach Bottom, Salem)
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOA	Society of Actuaries
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
Upstream	Natural gas and oil exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

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FILING FORMAT

This combined Form 10-Q is being filed separately by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company and Baltimore Gas and Electric Company (Registrants). Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) Exelon's 2014 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; (2) this Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors, (b) Part 1, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 19; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants' websites at www.exeloncorp.com. Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions, except per share data)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Operating revenues	$ 6,514	$ 6,024	$15,345	$13,261
Operating expenses				
Purchased power and fuel	2,449	2,346	6,919	6,352
Purchased power and fuel from affiliates	—	66	—	400
Operating and maintenance	2,042	2,166	4,123	4,024
Depreciation and amortization	602	590	1,212	1,154
Taxes other than income	294	288	598	580
Total operating expenses	5,387	5,456	12,852	12,510
Equity in losses of unconsolidated affiliates	—	—	—	(20)
Gain on sales of assets	7	13	8	18
Gain on consolidation and acquisition of businesses	—	261	—	261
Operating income	1,134	842	2,501	1,010
Other income and (deductions)				
Interest expense, net	(145)	(228)	(480)	(445)
Interest expense to affiliates	(10)	(10)	(21)	(20)
Other, net	(17)	230	64	330
Total other income and (deductions)	(172)	(8)	(437)	(135)
Income before income taxes	962	834	2,064	875
Income taxes	327	277	690	224
Equity in losses of unconsolidated affiliates	(2)	—	(2)	—
Net income	633	557	1,372	651
Net income (loss) attributable to noncontrolling interest and preference stock dividends	(5)	35	41	39
Net income attributable to common shareholders	$ 638	$ 522	$ 1,331	$ 612
Comprehensive income, net of income taxes				
Net income	$ 633	$ 557	$ 1,372	$ 651
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(11)	(6)	(23)	(6)
Actuarial loss reclassified to periodic cost	55	38	110	72
Pension and non-pension postretirement benefit plans valuation adjustment	—	258	(29)	246
Unrealized gain (loss) on cash flow hedges	3	(48)	9	(73)
Unrealized gain on equity investments	—	—	—	11
Unrealized gain (loss) on foreign currency translation	3	4	(9)	(1)
Unrealized loss on marketable securities	—	1	—	1
Reversal of CENG equity method AOCI	—	(116)	—	(116)
Other comprehensive income	50	131	58	134
Comprehensive income	$ 683	$ 688	$ 1,430	$ 785
Average shares of common stock outstanding:				
Basic	863	860	862	860
Diluted	866	864	866	863
Earnings per average common share:				
Basic	$ 0.74	$ 0.61	$ 1.54	$ 0.71
Diluted	$ 0.74	$ 0.60	$ 1.54	$ 0.71
Dividends per common share	$ 0.31	$ 0.31	$ 0.62	$ 0.62

Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2015	2014
Cash flows from operating activities		
Net income	$ 1,372	$ 651
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	1,957	1,925
Impairment of long-lived assets	24	112
Gain on consolidation and acquisition of businesses	—	(268)
Gain on sales of assets	(8)	(18)
Deferred income taxes and amortization of investment tax credits	211	133
Net fair value changes related to derivatives	(507)	751
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(2)	(168)
Other non-cash operating activities	579	473
Changes in assets and liabilities:		
Accounts receivable	253	48
Inventories	159	(150)
Accounts payable, accrued expenses and other current liabilities	(668)	(358)
Option premiums received, net	22	21
Counterparty collateral received (posted), net	417	(606)
Income taxes	247	(16)
Pension and non-pension postretirement benefit contributions	(301)	(499)
Other assets and liabilities	214	(280)
Net cash flows provided by operating activities	3,969	1,751
Cash flows from investing activities		
Capital expenditures	(3,460)	(2,501)
Proceeds from nuclear decommissioning trust fund sales	3,314	4,219
Investment in nuclear decommissioning trust funds	(3,437)	(4,238)
Acquisition of businesses	(28)	(66)
Proceeds from sale of long-lived assets	145	32
Proceeds from termination of direct financing lease investment	—	335
Cash and restricted cash acquired from consolidations and acquisitions	—	129
Change in restricted cash	(3)	(40)
Other investing activities	(77)	(57)
Net cash flows used in investing activities	(3,546)	(2,187)
Cash flows from financing activities		
Changes in short-term borrowings	94	293
Issuance of long-term debt	5,907	2,100
Retirement of long-term debt	(1,708)	(1,191)
Distributions to noncontrolling interest of consolidated VIE	—	(415)
Dividends paid on common stock	(537)	(533)
Proceeds from employee stock plans	16	18
Other financing activities	(59)	(83)
Net cash flows provided by financing activities	3,713	189
Increase (decrease) in cash and cash equivalents	4,136	(247)
Cash and cash equivalents at beginning of period	1,878	1,609
Cash and cash equivalents at end of period	$ 6,014	$ 1,362

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 6,014	$ 1,878
Restricted cash and cash equivalents	274	271
Accounts receivable, net		
Customer	3,227	3,482
Other	1,304	1,227
Mark-to-market derivative assets	1,405	1,279
Unamortized energy contract assets	156	254
Inventories, net		
Fossil fuel and emission allowances	364	579
Materials and supplies	1,068	1,024
Deferred income taxes	173	244
Regulatory assets	785	847
Assets held for sale	1	147
Other	654	865
Total current assets	15,425	12,097
Property, plant and equipment, net	53,935	52,087
Deferred debits and other assets		
Regulatory assets	5,976	6,076
Nuclear decommissioning trust funds	10,607	10,537
Investments	607	544
Goodwill	2,672	2,672
Mark-to-market derivative assets	811	773
Deferred income taxes	2	—
Unamortized energy contracts assets	526	549
Pledged assets for Zion Station decommissioning	264	319
Other	1,388	1,160
Total deferred debits and other assets	22,853	22,630
Total assets [(a)]	$ 92,213	$ 86,814

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 543	$ 460
Long-term debt due within one year	226	1,802
Accounts payable	2,727	3,048
Accrued expenses	1,366	1,539
Payables to affiliates	8	8
Regulatory liabilities	409	310
Mark-to-market derivative liabilities	165	234
Unamortized energy contract liabilities	141	238
Other	941	1,123
Total current liabilities	6,526	8,762
Long-term debt	25,220	19,362
Long-term debt to financing trusts	648	648
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,309	13,019
Asset retirement obligations	7,550	7,295
Pension obligations	3,134	3,366
Non-pension postretirement benefit obligations	1,850	1,742
Spent nuclear fuel obligation	1,021	1,021
Regulatory liabilities	4,462	4,550
Mark-to-market derivative liabilities	595	403
Unamortized energy contract liabilities	166	211
Payable for Zion Station decommissioning	135	155
Other	2,528	2,147
Total deferred credits and other liabilities	34,750	33,909
Total liabilities [(a)]	67,144	62,681
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 862 shares and 860 shares outstanding at June 30, 2015 and December 31, 2014, respectively)	16,755	16,709
Treasury stock, at cost (35 shares at both June 30, 2015 and December 31, 2014)	(2,327)	(2,327)
Retained earnings	11,704	10,910
Accumulated other comprehensive loss, net	(2,626)	(2,684)
Total shareholders' equity	23,506	22,608
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	1,370	1,332
Total equity	25,069	24,133
Total liabilities and shareholders' equity	$ 92,213	$ 86,814

(a) Exelon's consolidated assets include $7,989 million and $8,160 million at June 30, 2015 and December 31, 2014, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $2,555 million and $2,723 million at June 30, 2015 and December 31, 2014, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 3 — Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interest	Preference Stock	Total Equity
Balance, December 31, 2014	894,568	$16,709	$(2,327)	$10,910	$ (2,684)	$ 1,332	$ 193	$24,133
Net income	—	—	—	1,331	—	35	6	1,372
Long-term incentive plan activity	1,252	29	—	—	—	—	—	29
Employee stock purchase plan issuances	790	16	—	—	—	—	—	16
Tax benefit on stock compensation	—	1	—	—	—	—	—	1
Changes in equity of noncontrolling interest	—	—	—	—	—	3	—	3
Common stock dividends	—	—	—	(537)	—	—	—	(537)
Preference stock dividends	—	—	—	—	—	—	(6)	(6)
Other comprehensive income, net of income taxes	—	—	—	—	58	—	—	58
Balance, June 30, 2015	896,610	$16,755	$(2,327)	$11,704	$ (2,626)	$ 1,370	$ 193	$25,069

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Operating revenues				
Operating revenues	$ 4,079	$ 3,588	$ 9,709	$ 7,644
Operating revenues from affiliates	153	201	365	535
Total operating revenues	4,232	3,789	10,074	8,179
Operating expenses				
Purchased power and fuel	1,848	1,766	5,274	4,774
Purchased power and fuel from affiliates	1	69	8	417
Operating and maintenance	1,149	1,255	2,311	2,194
Operating and maintenance from affiliates	159	158	308	305
Depreciation and amortization	255	254	509	466
Taxes other than income	124	118	246	223
Total operating expenses	3,536	3,620	8,656	8,379
Equity in losses of unconsolidated affiliates	—	(1)	—	(20)
Gain on sales of assets	7	12	6	18
Gain on consolidation and acquisition of businesses	—	261	—	261
Operating income	703	441	1,424	59
Other income and (deductions)				
Interest expense	(90)	(74)	(180)	(147)
Interest expense to affiliates, net	(9)	(12)	(21)	(25)
Other, net	(31)	216	62	300
Total other income and (deductions)	(130)	130	(139)	128
Income before income taxes	573	571	1,285	187
Income taxes (benefit)	181	199	407	(1)
Equity in losses of unconsolidated affiliates	(2)	—	(3)	—
Net income	390	372	875	188
Net (loss) income attributable to noncontrolling interests	(8)	32	34	33
Net income attributable to membership interest	$ 398	$ 340	$ 841	$ 155
Comprehensive income, net of income taxes				
Net income	$ 390	$ 372	$ 875	$ 188
Other comprehensive income (loss), net of income taxes				
Unrealized gain (loss) on cash flow hedges	2	(45)	(3)	(70)
Unrealized gain on equity investments	—	—	—	11
Unrealized gain (loss) on foreign currency translation	3	4	(9)	(1)
Unrealized gain (loss) on marketable securities	1	2	1	(1)
Reversal of CENG equity method AOCI	—	(116)	—	(116)
Other comprehensive income (loss)	6	(155)	(11)	(177)
Comprehensive income	$ 396	$ 217	$ 864	$ 11

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2015	2014
Cash flows from operating activities		
Net income	$ 875	$ 188
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	1,255	1,242
Impairment of long-lived assets	(1)	88
Gain on consolidation and acquisitions of businesses	—	(268)
Gain on sales of assets	(6)	(18)
Deferred income taxes and amortization of investment tax credits	65	(15)
Net fair value changes related to derivatives	(396)	760
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(2)	(168)
Other non-cash operating activities	134	139
Changes in assets and liabilities:		
Accounts receivable	291	63
Receivables from and payables to affiliates, net	(11)	(20)
Inventories	134	(170)
Accounts payable, accrued expenses and other current liabilities	(485)	(273)
Option premiums received, net	22	21
Counterparty collateral (posted) received, net	440	(633)
Income taxes	27	72
Pension and non-pension postretirement benefit contributions	(122)	(210)
Other assets and liabilities	203	(56)
Net cash flows provided by operating activities	2,423	742
Cash flows from investing activities		
Capital expenditures	(1,764)	(1,103)
Proceeds from nuclear decommissioning trust fund sales	3,314	4,219
Investment in nuclear decommissioning trust funds	(3,437)	(4,238)
Acquisition of businesses	(28)	(66)
Proceeds from sale of long-lived assets	144	32
Change in restricted cash	(16)	(17)
Changes in Exelon intercompany money pool	—	44
Cash and restricted cash acquired from consolidations and acquisitions	—	129
Other investing activities	(63)	(14)
Net cash flows used in investing activities	(1,850)	(1,014)
Cash flows from financing activities		
Change in short-term borrowings	15	46
Issuance of long-term debt	1,307	300
Retirement of long-term debt	(39)	(538)
Retirement of long-term debt to affiliate	(550)	—
Changes in Exelon intercompany money pool	638	190
Distribution to member	(2,262)	(235)
Distributions to noncontrolling interest of consolidated VIE	—	(415)
Other financing activities	(6)	(29)
Net cash flows used in financing activities	(897)	(681)
Decrease in cash and cash equivalents	(324)	(953)
Cash and cash equivalents at beginning of period	780	1,258
Cash and cash equivalents at end of period	$ 456	$ 305

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 456	$ 780
Restricted cash and cash equivalents	174	158
Accounts receivable, net		
Customer	2,045	2,295
Other	299	318
Mark-to-market derivative assets	1,405	1,276
Receivables from affiliates	103	113
Unamortized energy contract assets	156	254
Inventories, net		
Fossil fuel and emission allowances	305	465
Materials and supplies	860	847
Deferred income taxes	188	327
Assets held for sale	1	147
Other	451	658
Total current assets	6,443	7,638
Property, plant and equipment, net	23,766	22,945
Deferred debits and other assets		
Nuclear decommissioning trust funds	10,607	10,537
Investments	183	104
Goodwill	47	47
Mark-to-market derivative assets	790	771
Prepaid pension asset	1,699	1,704
Pledged assets for Zion Station decommissioning	264	319
Unamortized energy contract assets	526	549
Deferred income taxes	2	3
Other	798	731
Total deferred debits and other assets	14,916	14,765
Total assets [(a)]	$ 45,125	$ 45,348

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 40	$ 36
Long-term debt due within one year	89	58
Long-term debt to affiliates due within one year	—	556
Accounts payable	1,528	1,759
Accrued expenses	732	886
Payables to affiliates	98	107
Borrowings from Exelon intercompany money pool	638	—
Mark-to-market derivative liabilities	145	214
Unamortized energy contract liabilities	141	238
Other	453	605
Total current liabilities	3,864	4,459
Long-term debt	7,974	6,709
Long-term debt to affiliate	938	943
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,009	6,034
Asset retirement obligations	7,399	7,146
Non-pension postretirement benefit obligations	922	915
Spent nuclear fuel obligation	1,021	1,021
Payables to affiliates	2,832	2,880
Mark-to-market derivative liabilities	392	105
Unamortized energy contract liabilities	166	211
Payable for Zion Station decommissioning	135	155
Other	817	719
Total deferred credits and other liabilities	19,693	19,186
Total liabilities [(a)]	32,469	31,297
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	8,951	8,951
Undistributed earnings	2,382	3,803
Accumulated other comprehensive loss, net	(47)	(36)
Total member's equity	11,286	12,718
Noncontrolling interest	1,370	1,333
Total equity	12,656	14,051
Total liabilities and equity	$ 45,125	$ 45,348

(a) Generation's consolidated assets include $7,949 million and $8,119 million at June 30, 2015 and December 31, 2014, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $2,435 million and $2,507 million at June 30, 2015 and December 31, 2014, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 3 — Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interest	Total Equity
Balance, December 31, 2014	$ 8,951	$ 3,803	$ (36)	$ 1,333	$ 14,051
Net income	—	841	—	34	875
Changes in equity of noncontrolling interest	—	—	—	3	3
Distribution to member	—	(2,262)	—	—	(2,262)
Other comprehensive loss, net of income taxes	—	—	(11)	—	(11)
Balance, June 30, 2015	$ 8,951	$ 2,382	$ (47)	$ 1,370	$ 12,656

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Operating revenues				
Operating revenues	$ 1,147	$ 1,128	$ 2,331	$ 2,261
Operating revenues from affiliates	1	—	2	1
Total operating revenues	1,148	1,128	2,333	2,262
Operating expenses				
Purchased power	269	204	586	416
Purchased power from affiliate	6	65	15	173
Operating and maintenance	337	316	670	603
Operating and maintenance from affiliate	47	39	92	78
Depreciation and amortization	177	174	352	347
Taxes other than income	69	72	146	149
Total operating expenses	905	870	1,861	1,766
Operating income	243	258	472	496
Other income and (deductions)				
Interest expense, net	(78)	(76)	(158)	(153)
Interest expense to affiliates	(3)	(4)	(7)	(7)
Other, net	5	5	9	10
Total other income and (deductions)	(76)	(75)	(156)	(150)
Income before income taxes	167	183	316	346
Income taxes	68	72	127	137
Net income	99	111	189	209
Comprehensive income	$ 99	$ 111	$ 189	$ 209

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2015	2014
Cash flows from operating activities		
Net income	$ 189	$ 209
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	352	347
Deferred income taxes and amortization of investment tax credits	36	63
Other non-cash operating activities	222	99
Changes in assets and liabilities:		
Accounts receivable	(57)	(83)
Receivables from and payables to affiliates, net	(10)	(46)
Inventories	(19)	(4)
Accounts payable, accrued expenses and other current liabilities	(52)	27
Income taxes	239	5
Pension and non-pension postretirement benefit contributions	(125)	(236)
Other assets and liabilities	25	48
Net cash flows provided by operating activities	800	429
Cash flows from investing activities		
Capital expenditures	(1,061)	(747)
Proceeds from sales of investments	—	7
Purchases of investments	—	(3)
Change in restricted cash	—	(2)
Other investing activities	17	14
Net cash flows used in investing activities	(1,044)	(731)
Cash flows from financing activities		
Changes in short-term borrowings	199	314
Issuance of long-term debt	400	650
Retirement of long-term debt	(260)	(617)
Contributions from parent	45	112
Dividends paid on common stock	(150)	(153)
Other financing activities	(5)	(2)
Net cash flows provided by financing activities	229	304
Increase (decrease) in cash and cash equivalents	(15)	2
Cash and cash equivalents at beginning of period	66	36
Cash and cash equivalents at end of period	$ 51	$ 38

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 51	$ 66
Restricted cash	4	4
Accounts receivable, net		
Customer	522	477
Other	569	648
Receivables from affiliates	14	14
Inventories, net	144	125
Regulatory assets	276	349
Other	36	40
Total current assets	1,616	1,723
Property, plant and equipment, net	16,493	15,793
Deferred debits and other assets		
Regulatory assets	834	852
Goodwill	2,625	2,625
Receivables from affiliates	2,538	2,571
Prepaid pension asset	1,572	1,551
Other	283	277
Total deferred debits and other assets	7,852	7,876
Total assets	$ 25,961	$ 25,392

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 503	$ 304
Long-term debt due within one year	—	260
Accounts payable	580	598
Accrued expenses	291	331
Payables to affiliates	73	84
Customer deposits	128	128
Regulatory liabilities	154	125
Deferred income taxes	20	63
Mark-to-market derivative liability	20	20
Other	75	73
Total current liabilities	1,844	1,986
Long-term debt	6,099	5,698
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,579	4,498
Asset retirement obligations	103	103
Non-pension postretirement benefits obligations	262	263
Regulatory liabilities	3,622	3,655
Mark-to-market derivative liability	203	187
Other	1,049	889
Total deferred credits and other liabilities	9,818	9,595
Total liabilities	17,967	17,485
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,516	5,468
Retained earnings	890	851
Total shareholders' equity	7,994	7,907
Total liabilities and shareholders' equity	$ 25,961	$ 25,392

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2014	$ 1,588	$ 5,468	$ (1,639)	$ 2,490	$ 7,907
Net income	—	—	189	—	189
Appropriation of retained earnings for future dividends	—	—	(189)	189	—
Common stock dividends	—	—	—	(150)	(150)
Contribution from parent	—	45	—	—	45
Parent tax matter indemnification	—	3	—	—	3
Balance, June 30, 2015	$ 1,588	$ 5,516	$ (1,639)	$ 2,529	$ 7,994

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Operating revenues				
Operating revenues	$ 661	$ 656	$1,645	$ 1,648
Operating revenues from affiliates	—	—	1	1
Total operating revenues	661	656	1,646	1,649
Operating expenses				
Purchased power and fuel	189	193	565	570
Purchased power from affiliate	48	48	110	135
Operating and maintenance	166	160	363	416
Operating and maintenance from affiliates	26	24	51	48
Depreciation and amortization	69	59	131	117
Taxes other than income	39	38	80	80
Total operating expenses	537	522	1,300	1,366
Gain on sale of assets	—	—	1	—
Operating income	124	134	347	283
Other income and (deductions)				
Interest expense, net	(25)	(25)	(50)	(50)
Interest expense to affiliates	(3)	(3)	(6)	(6)
Other, net	1	1	3	3
Total other income and (deductions)	(27)	(27)	(53)	(53)
Income before income taxes	97	107	294	230
Income taxes	27	23	85	57
Net income attributable to common shareholder	70	84	209	173
Comprehensive income	$ 70	$ 84	$ 209	$ 173

See the Combined Notes to Consolidated Financial Statements

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2015	2014
Cash flows from operating activities		
Net income	$ 209	$ 173
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	131	117
Deferred income taxes and amortization of investment tax credits	4	6
Other non-cash operating activities	45	50
Changes in assets and liabilities:		
Accounts receivable	(18)	34
Receivables from and payables to affiliates, net	(2)	(21)
Inventories	21	22
Accounts payable, accrued expenses and other current liabilities	3	30
Income taxes	57	54
Pension and non-pension postretirement benefit contributions	(15)	(11)
Other assets and liabilities	(60)	(114)
Net cash flows provided by operating activities	375	340
Cash flows from investing activities		
Capital expenditures	(289)	(308)
Change in restricted cash	(1)	—
Other investing activities	9	6
Net cash flows used in investing activities	(281)	(302)
Cash flows from financing activities		
Change in Exelon intercompany money pool	41	—
Dividends paid on common stock	(139)	(160)
Other financing activities	—	(2)
Net cash flows used in financing activities	(98)	(162)
Decrease in cash and cash equivalents	(4)	(124)
Cash and cash equivalents at beginning of period	30	217
Cash and cash equivalents at end of period	$ 26	$ 93

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 26	$ 30
Restricted cash and cash equivalents	3	2
Accounts receivable, net		
Customer	301	320
Other	122	141
Receivables from affiliates	3	3
Inventories, net		
Fossil fuel	30	57
Materials and supplies	28	22
Deferred income taxes	69	69
Prepaid utility taxes	80	10
Regulatory assets	42	29
Other	36	31
Total current assets	740	714
Property, plant and equipment, net	6,957	6,801
Deferred debits and other assets		
Regulatory assets	1,552	1,529
Investments	28	31
Receivable from affiliates	477	490
Prepaid pension asset	341	344
Other	31	34
Total deferred debits and other assets	2,429	2,428
Total assets	$ 10,126	$ 9,943

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 319	$ 337
Accrued expenses	116	91
Payables to affiliates	50	52
Borrowings from Exelon intercompany money pool	41	—
Customer deposits	54	52
Regulatory liabilities	117	90
Other	41	31
Total current liabilities	738	653
Long-term debt	2,246	2,246
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,724	2,671
Asset retirement obligations	30	29
Non-pension postretirement benefits obligations	287	287
Regulatory liabilities	633	657
Other	93	95
Total deferred credits and other liabilities	3,767	3,739
Total liabilities	6,935	6,822
Commitments and contingencies		
Shareholder's equity		
Common stock	2,439	2,439
Retained earnings	751	681
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,191	3,121
Total liabilities and shareholder's equity	$ 10,126	$ 9,943

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholder's Equity
Balance, December 31, 2014	$ 2,439	$ 681	$ 1	$ 3,121
Net income	—	209	—	209
Common stock dividends	—	(139)	—	(139)
Balance, June 30, 2015	$ 2,439	$ 751	$ 1	$ 3,191

See the Combined Notes to Consolidated Financial Statements

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Operating revenue				
Operating revenue	$ 627	$ 651	$ 1,656	$ 1,689
Operating revenue from affiliates	1	2	8	18
Total operating revenues	628	653	1,664	1,707
Operating expenses				
Purchased power and fuel	143	183	493	592
Purchased power from affiliate	96	85	233	205
Operating and maintenance	120	163	276	326
Operating and maintenance from affiliates	29	25	55	50
Depreciation and amortization	87	89	192	197
Taxes other than income	54	53	111	113
Total operating expenses	529	598	1,360	1,483
Operating income	99	55	304	224
Other income and (deductions)				
Interest expense, net	(20)	(23)	(42)	(47)
Interest expense to affiliates	(4)	(4)	(8)	(8)
Other, net	4	5	8	9
Total other income and (deductions)	(20)	(22)	(42)	(46)
Income before income taxes	79	33	262	178
Income taxes	32	14	105	72
Net income	47	19	157	106
Preference stock dividends	3	3	6	6
Net income attributable to common shareholder	44	16	151	100
Comprehensive income	$ 47	$ 19	$ 157	$ 106

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Six Months Ended June 30, 2015	2014
Cash flows from operating activities		
Net income	$ 157	$ 106
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	192	197
Deferred income taxes and amortization of investment tax credits	54	47
Other non-cash operating activities	76	89
Changes in assets and liabilities:		
Accounts receivable	25	44
Receivables from and payables to affiliates, net	(2)	(12)
Inventories	23	—
Accounts payable, accrued expenses and other current liabilities	(49)	(74)
Counterparty collateral (posted) received, net	(23)	27
Income taxes	(6)	(14)
Pension and non-pension postretirement benefit contributions	(9)	(8)
Other assets and liabilities	51	8
Net cash flows provided by operating activities	489	410
Cash flows from investing activities		
Capital expenditures	(304)	(313)
Change in restricted cash	21	(30)
Other investing activities	8	11
Net cash flows used in investing activities	(275)	(332)
Cash flows from financing activities		
Changes in short-term borrowings	(120)	(65)
Retirement of long-term debt	(37)	(35)
Dividends paid on preference stock	(6)	(6)
Dividends paid on common stock	(77)	—
Other financing activities	(14)	12
Net cash flows used in financing activities	(254)	(94)
Decrease in cash and cash equivalents	(40)	(16)
Cash and cash equivalents at beginning of period	64	31
Cash and cash equivalents at end of period	$ 24	$ 15

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 24	$ 64
Restricted cash and cash equivalents	29	50
Accounts receivable, net		
Customer	360	390
Other	76	82
Inventories, net		
Gas held in storage	29	57
Materials and supplies	35	30
Deferred income taxes	12	6
Prepaid utility taxes	—	59
Regulatory assets	207	214
Other	4	5
Total current assets	776	957
Property, plant and equipment, net	6,373	6,204
Deferred debits and other assets		
Regulatory assets	486	510
Investments	13	12
Prepaid pension asset	344	370
Other	25	25
Total deferred debits and other assets	868	917
Total assets [(a)]	$ 8,017	$ 8,078

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 120
Long-term debt due within one year	77	75
Accounts payable	194	215
Accrued expenses	108	131
Deferred income taxes	48	52
Payables to affiliates	52	66
Customer deposits	97	92
Regulatory liabilities	91	44
Other	33	51
Total current liabilities	700	846
Long-term debt	1,828	1,867
Long-term debt to financing trust	258	258
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,930	1,865
Asset retirement obligations	18	17
Non-pension postretirement benefits obligations	209	212
Regulatory liabilities	185	200
Other	62	60
Total deferred credits and other liabilities	2,404	2,354
Total liabilities [(a)]	5,190	5,325
Commitments and contingencies		
Shareholders' equity		
Common stock	1,360	1,360
Retained earnings	1,277	1,203
Total shareholders' equity	2,637	2,563
Preference stock not subject to mandatory redemption	190	190
Total equity	2,827	2,753
Total liabilities and shareholders' equity	$ 8,017	$ 8,078

(a) BGE's consolidated assets include $27 million and $24 million at June 30, 2015 and December 31, 2014, respectively, of BGE's consolidated VIE that can only be used to settle the liabilities of the VIE. BGE's consolidated liabilities include $160 million and $197 million at June 30, 2015 and December 31, 2014, respectively, of BGE's consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note 3 — Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity	Preference Stock Not Subject To Mandatory Redemption	Total Equity
Balance, December 31, 2014	$ 1,360	$ 1,203	$ 2,563	$ 190	$ 2,753
Net income	—	157	157	—	157
Preference stock dividends	—	(6)	(6)	—	(6)
Common stock dividends	—	(77)	(77)	—	(77)
Balance, June 30, 2015	$ 1,360	$ 1,277	$ 2,637	$ 190	$ 2,827

See the Combined Notes to Consolidated Financial Statements

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in millions, except per share data, unless otherwise noted)

Index to Combined Notes to Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the registrants to which the footnotes apply:

Applicable Notes

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Exelon Corporation	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
Exelon Generation Company, LLC	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			.		.
Commonwealth Edison Company	.	.	.		.				.	.	.	.	.	.	.				.		.
PECO Energy Company	.	.	.		.				.	.	.	.		.	.	.			.		.
Baltimore Gas And Electric Company	.	.	.		.				.	.	.	.		.	.				.		.

1. Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses.

The energy generation business includes:

- *Generation* : Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

The energy delivery businesses include:

- *ComEd* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE* : Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Each of the Registrant's consolidated financial statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated. As a result of the Registrants' 2014 divestiture of certain unconsolidated affiliates considered integral to their operations and the consolidation of CENG during 2014, all Equity in earnings (losses) from unconsolidated affiliates have been presented below Income taxes in the Registrants' Consolidated Statements of Operations and Comprehensive Income starting in the first quarter of 2015.

The accompanying consolidated financial statements as of June 30, 2015 and 2014 and for the six months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

2014 Consolidated Balance Sheets were obtained from audited financial statements. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2015. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. These notes should be read in conjunction with the Combined Notes to Consolidated Financial Statements of all Registrants included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA of their respective 2014 Form 10-K Reports.

2. New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

The following recently issued accounting standards are not yet required to be reflected in the combined financial statements of the Registrants.

Simplifying the Measurement of Inventory

In July 2015, the FASB issued authoritative guidance that requires inventory to be measured at the lower of cost or net realizable value. The new guidance defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This definition is consistent with existing authoritative guidance. Current guidance requires inventory to be measured at the lower of cost or market where market could be replacement cost, net realizable value or net realizable value less an approximately normal profit margin. The guidance is effective for periods beginning after December 15, 2016 with early adoption permitted. The guidance is required to be applied prospectively. The Registrants are currently assessing the impacts this guidance may have on their financial positions, results of operations, cash flows and disclosures as well as the potential to early adopt the guidance.

Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share

In May 2015, FASB issued authoritative guidance that removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. Investments measured at net asset value per share using the practical expedient will be presented as a reconciling item between the fair value hierarchy disclosure and the investment line item on the statement of financial position. The guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient. Rather, those disclosures are limited to investments for which the entity has elected to measure the fair value using the practical expedient. The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015 with early adoption permitted. The guidance is required to be applied retrospectively to all prior periods presented. The Registrants are currently assessing the impacts this guidance may have on their disclosures as well as the potential to early adopt the guidance. There will be no impact to their financial position, results of operations or cash flows.

Customer's Accounting for Fees Paid in a Cloud Computing Arrangement

In April 2015, the FASB issued authoritative guidance that clarifies the circumstances under which a cloud computing customer would account for the arrangement as a license of internal-use software. A cloud computing arrangement would include a software license if (1) the customer has a contractual right to take possession of the software at any time during the hosting period without significant penalty and (2) it is feasible for the customer to either run the software on its own hardware or contract with another party unrelated to the vendor to host the software. If the arrangement does not contain a software license, it would be accounted for as a service contract.

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The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015. Early adoption is permitted. The guidance can be applied retrospectively to each prior reporting period presented or prospectively to arrangements entered into, or materially modified, after the effective date. The Registrants are currently assessing the impact this guidance may have on their financial positions, results of operations, cash flows and disclosures. The Registrants expect to apply the standard prospectively to arrangements entered into, or materially modified, after the standard becomes effective for the Registrants on January 1, 2016. The Registrants do not plan to early adopt the standard.

Simplifying the Presentation of Debt Issuance Costs

In April 2015, the FASB issued authoritative guidance that changes the presentation of debt issuance costs in financial statements. The new guidance requires entity's to present such costs in the balance sheet as a direct reduction to the related debt liability rather than as a deferred cost (i.e., an asset) as required by current guidance. The new standard does not change the recognition or measurement of debt issuance costs. The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015. Early adoption is permitted for financial statements that have not been previously issued. The guidance is required to be applied retrospectively to all prior periods presented. The Registrants are currently assessing the impact this guidance may have on their financial positions and disclosures. The standard will not impact the results of operations and cash flows of the Registrants. The Registrants expect to complete their assessment by the fourth quarter of 2015 and early adopt the standard at that time.

Amendments to the Consolidation Analysis

In February 2015, the FASB issued authoritative guidance that amends the consolidation analysis for variable interest entities (VIEs) as well as voting interest entities. The new guidance primarily (1) changes the assessment of limited partnerships as VIEs, (2) amends the effect that fees paid to a decision maker or service provider have on the VIE analysis, (3) amends how variable interests held by a reporting entity's related parties and de facto agents impact its consolidation conclusion, (4) clarifies how to determine whether equity holders (as a group) have power over an entity and (5) provides a scope exception for registered and similar unregistered money market funds. The guidance is effective for the Registrants for the first interim period within annual reporting periods beginning on or after December 15, 2015. Early adoption is permitted. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption (modified retrospective method). The Registrants are currently assessing the impact this guidance may have on their financial positions, results of operations, cash flows and disclosures as well as the transition method that they will use to adopt the guidance. The Registrants do not plan to early adopt the standard.

Revenue from Contracts with Customers

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. The new guidance replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing and uncertainty of revenue and the related cash flows. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to

retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their financial positions, results of operations, cash flows and disclosures as well as the transition method that they will use to adopt the guidance. As currently issued, the guidance is effective for the Registrants for the first interim period within annual reporting periods beginning on or after December 15, 2016; and early adoption would not be permitted. However, in July 2015, the FASB approved an amendment to provide a one year deferral of the effective date to annual reporting periods beginning on or after December 15, 2017, as well as an option to early adopt the standard for annual periods beginning on or after December 15, 2016. As of July 29, 2015, the amendment to defer the effective date and provide an option to early adopt had not been issued.

3. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)

A VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly affect the entity's economic performance.

At June 30, 2015 and December 31, 2014, Exelon, Generation, and BGE collectively consolidated seven and six VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary *(see Consolidated Variable Interest Entities below)* . As of June 30, 2015 and December 31, 2014, the Registrants had significant interests in eight and six other VIEs, respectively, for which the Registrants do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary (see Unconsolidated Variable Interest Entities below).

During the second quarter of 2015 Generation added a new group of consolidated VIEs named "a group of companies formed by Generation to build, own, and operate other generating facilities." The new group is comprised of a biomass fueled, combined heat and power facility and a backup generator company for which Generation is the primary beneficiary. Generation provides parental guarantees for up to $275 million in support of the payment obligations related to the Engineering, Procurement and Construction contract for Albany Green Energy, LLC (see Note 11 — Debt and Credit Agreements for additional details).

Consolidated Variable Interest Entities

Exelon, Generation and BGE's consolidated VIEs consist of:

- BondCo, a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, issue and service bonds secured by rate stabilization property,
- a retail gas group formed by Generation to enter into a collateralized gas supply agreement with a third-party gas supplier
- a group of solar project limited liability companies formed by Generation to build, own and operate solar power facilities,
- several wind project companies designed by Generation to develop, construct and operate wind generation facilities,
- a group of companies formed by Generation to build, own and operate other generating facilities,
- certain retail power and gas companies for which Generation is the sole supplier of energy, and
- CENG.

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As of June 30, 2015 and December 31, 2014, ComEd and PECO do not have any material consolidated VIEs.

As of June 30, 2015 and December 31, 2014, Exelon, Generation, and BGE provided the following support to their respective consolidated VIEs:

- In the case of BondCo, BGE is required to remit all payments it receives from all residential customers through non-bypassable, rate stabilization charges to BondCo. During the three and six months ended June 30, 2015, BGE remitted $21 million and $42 million to BondCo, respectively. During the three and six months ended June 30, 2014, BGE remitted $21 million and $42 million to BondCo, respectively.
- Generation provides operating and capital funding to the solar entities for ongoing construction, operations and maintenance of the solar power facilities and provides limited recourse related to the Antelope Valley project.
- Generation and Exelon, where indicated, provide the following support to CENG (see Note 6 — Investment in Constellation Energy Nuclear Group, LLC, and Note 25 — Related Party Transactions, of the Exelon 2014 Form 10-K for additional information regarding Generation's and Exelon's transactions with CENG):
  - under the NOSA, Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life and decommissioning of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF Inc. (EDFI) (a subsidiary of EDF),
  - under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management, and billing services to the CENG fleet for the remaining operating life of the CENG nuclear plants,
  - under power purchase agreements with CENG, Generation will purchase 50.01% of the available output generated by the CENG nuclear plants not subject to other contractual agreements from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs have been suspended during the term of the Reliability Support Services Agreement (RSSA) which Ginna entered into with Rochester Gas and Electric Corporation (RG&E) on February 13, 2015. The obligations under the RSSA commenced on April 1, 2015 and are effective through September 30, 2018 (see Note 5 — Regulatory Matters for additional details),
  - Generation provided a $400 million loan to CENG. As of June 30, 2015, the remaining obligation is $288 million plus accrued interest, which reflects the principal payment made in January 2015 (see Note 5 — Investment in Constellation Energy Nuclear Group, LLC of the Exelon 2014 Form 10-K for additional details),
  - Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. (See Note 19 — Commitments and Contingencies for more details),
  - in connection with CENG's severance obligations, Generation has agreed to reimburse CENG for a total of approximately $6 million of the severance benefits paid or to be paid in 2014 through 2016. As of June 30, 2015, the remaining obligation is approximately $2 million,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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- Generation and EDFI share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance (see Note 19 — Commitments and Contingencies for more details),
- Generation provides a guarantee of approximately $7 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDFI executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,
- Generation and EDFI are the members-insured with Nuclear Electric Insurance Limited (NEIL) and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (see Note 19 — Commitments and Contingencies for more details), and
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

- Generation provides approximately $8 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy, and
- Generation provides a $75 million parental guarantee to the third-party gas supplier in support of its retail gas group.

For each of the consolidated VIEs, except as otherwise noted:

- the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;
- Exelon, Generation and BGE did not provide any additional material financial support to the VIEs;
- Exelon, Generation and BGE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and
- the creditors of the VIEs did not have recourse to Exelon's, Generation's or BGE's general credit.

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in Exelon's, Generation's, and BGE's consolidated financial statements at June 30, 2015 and December 31, 2014 are as follows:

	June 30, 2015			December 31, 2014		
	Exelon [(a)]	Generation	BGE	Exelon [(a)]	Generation	BGE
Current assets	$ 924	$ 894	$ 24	$ 1,271	$ 1,242	$ 21
Noncurrent assets	7,731	7,723	3	7,580	7,566	3
Total assets	$ 8,655	$ 8,617	$ 27	$ 8,851	$ 8,808	$ 24
Current liabilities	$ 378	$ 292	$ 79	$ 611	$ 526	$ 77
Noncurrent liabilities	2,860	2,773	81	2,730	2,600	120
Total liabilities	$ 3,238	$ 3,065	$160	$ 3,341	$ 3,126	$197

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of June 30, 2015 and December 31, 2014, these assets and liabilities primarily consisted of the following:

	June 30, 2015			December 31, 2014		
	Exelon	Generation	BGE	Exelon	Generation	BGE
Cash and cash equivalents	$ 240	$ 240	$ —	$ 392	$ 392	$ —
Restricted cash	145	121	24	117	96	21
Accounts receivable, net						
Customer	179	179	—	297	297	—
Other	29	29	—	57	57	—
Mark-to-market derivatives assets	96	96	—	171	171	—
Inventory						
Materials and supplies	178	178	—	172	172	—
Other current assets	32	25	—	33	26	—
Total current assets	899	868	24	1,239	1,211	21
Property, plant and equipment, net	4,811	4,811	—	4,638	4,638	—
Nuclear decommissioning trust funds	2,096	2,096	—	2,097	2,097	—
Goodwill	47	47	—	47	47	—
Mark-to-market derivatives assets	45	45	—	44	44	—
Other noncurrent assets	91	82	3	95	82	3
Total noncurrent assets	7,090	7,081	3	6,921	6,908	3
Total assets	$7,989	$ 7,949	$ 27	$8,160	$ 8,119	$ 24
Long-term debt due within one year	$ 88	$ 5	$ 77	$ 87	$ 5	$ 75
Accounts payable	143	143	—	292	292	—
Accrued expenses	87	84	1	111	108	2
Mark-to-market derivative liabilities	8	8	—	24	24	—
Unamortized energy contract liabilities	9	9	—	22	22	—
Other current liabilities	13	13	—	25	25	—
Total current liabilities	348	262	78	561	476	77
Long-term debt	166	79	81	212	81	120
Asset retirement obligations	1,865	1,865	—	1,763	1,763	—
Pension obligation [(a)]	9	9	—	9	9	—
Unamortized energy contract liabilities	45	45	—	51	51	—
Other noncurrent liabilities	122	122	—	127	127	—
Noncurrent liabilities	2,207	2,120	81	2,162	2,031	120
Total liabilities	$2,555	$ 2,382	$159	$2,723	$ 2,507	$197

(a) Includes CNEG retail gas pension obligation, which is presented as a net asset balance within the Prepaid Pension asset line item on Generation's balance sheet. See Note 14 — Retirement Benefits for additional details.

Unconsolidated Variable Interest Entities

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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reflected on Exelon's and Generation's Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts and the fuel purchase commitments (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

The Registrants' unconsolidated VIEs consist of:

- Energy purchase and sale agreements with VIEs for which Generation has concluded that consolidation is not required.
- Asset sale agreement with ZionSolutions, LLC and EnergySolutions, Inc. in which Generation has a variable interest but has concluded that consolidation is not required.
- Equity investments in energy development projects, distributed energy companies, and energy generating facilities for which Generation has concluded that consolidation is not required.

As of June 30, 2015 and December 31, 2014, Exelon and Generation had significant unconsolidated variable interests in eight and six VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity method investments and certain commercial agreements. The increase in the number of unconsolidated VIEs is due to the execution of an energy purchase and sale agreement with a new unconsolidated VIE.

In June 2015, 2015 ESA Investco, LLC, a wholly owned subsidiary of Generation, entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of a distributed energy company. Equity will be contributed incrementally over an eighteen month period and will total approximately $250 million (see Note 19 — Commitments and Contingencies for additional details). Generation provides a parental guarantee of up to $275 million in support of 2015 ESA Investco, LLC's obligation to make equity contributions to the VIE. The investment was evaluated and it was determined to be a VIE for which Generation is not the primary beneficiary. Separate from the equity investment, Generation provided $27 million in cash to the other (10%) equity holder in the distributed energy company in exchange for a convertible promissory note. In July 2014, Generation entered into another arrangement with the same equity holder for the purchase of a 90% equity interest and 90% of the tax attributes of another distributed energy company. Generation's total equity commitment in this arrangement was $91 million and is paid incrementally over an approximate two year period (see Note 19 — Commitments and Contingencies for additional details). This arrangement did not meet the definition of a VIE and is recorded as an equity method investment. Both distributed energy companies are considered related parties.

The following tables present summary information about Exelon and Generation's significant unconsolidated VIE entities:

June 30, 2015	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 260	$ 127	$387
Total liabilities [a]	29	61	90
Exelon's ownership interest in VIE [a]	—	16	16
Other ownership interests in VIE [a]	231	51	282
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	19	19
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning [b]	23	—	23

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December 31, 2014	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets [a]	$ 114	$ 91	$205
Total liabilities [a]	3	49	52
Exelon's ownership interest in VIE [a]	—	9	9
Other ownership interests in VIE [a]	111	33	144
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	13	13
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning [b]	27	—	27

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs. Exelon corrected an error in the December 31, 2014 balances within Commercial Agreement VIEs for an overstatement of Total assets, Total liabilities and Other ownership interests in VIE of $392 million, $234 million and $158 million, respectively. The error is not considered material to any prior period.

(b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning include, gross pledged assets of $264 million and $319 million as of June 30, 2015 and December 31, 2014, respectively; offset by payables to ZionSolutions, LLC of $241 million and $292 million as of June 30, 2015 and December 31, 2014, respectively. These items are included to provide information regarding the relative size of the ZionSolutions, LLC unconsolidated VIE.

For each of the unconsolidated VIEs, Exelon and Generation has assessed the risk of a loss equal to their maximum exposure to be remote and, accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no material agreements with, or commitments by, third parties that would affect the fair value or risk of their variable interests in these VIEs.

4. Mergers, Acquisitions, and Dispositions (Exelon and Generation)

Proposed Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI's shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $162 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI as of June 30, 2015. The final investment of $18 million was paid on July 24, 2015 to reach the maximum aggregate investment of $180 million. The preferred securities are included in Other non-current assets on Exelon's Consolidated Balance Sheet. PHI has the right to redeem the preferred securities at its option for the purchase price paid plus accrued dividends, if any. Exelon expects total cash required to fund the acquisition of common stock and preferred securities plus other related acquisition costs to total approximately $7.2 billion.

On October 9, 2014, PHI and Exelon each received a request for additional information from the DOJ. The request had the effect of extending the DOJ review period until 30 days after PHI and Exelon each has certified that it had substantially complied with the request. On November 21, 2014, Exelon and PHI each certified that it had substantially complied with the request. Accordingly, the HSR Act waiting period expired on December 22,

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2014, and the HSR Act no longer precludes completion of the merger. Although the DOJ allowed the waiting period under the HSR Act to expire without taking any action with respect to the merger, the DOJ has not advised Exelon or PHI that it has concluded its investigation. Exelon and PHI have cooperated with the DOJ regarding the proposed merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU), the Delaware Public Service Commission (DPSC), the Maryland Public Service Commission (MDPSC) and the FERC have approved the merger of PHI and Exelon. The Federal Communications Commission has also approved the transfer of certain PHI communications licenses.

On February 13, 2015, Exelon and PHI announced that they had reached a settlement agreement in the proceeding before the DPSC to review the proposed merger. The settlement, which was amended on April 7, 2015, was signed and filed by Exelon, PHI, Delmarva Power & Light Company (DPL), the DPSC Staff, the Delaware Public Advocate, the Delaware Department of Natural Resources and Environment Control, the Delaware Sustainable Energy Utility, the Mid-Atlantic Renewable Energy Coalition and the Clean Air Council. As part of this settlement, Exelon and PHI proposed a package of benefits to DPL customers and the state of Delaware including the establishment of customer rate credits of $40 million for DPL customers in Delaware, $2 million of funding for energy efficiency programs for DPL low income customers, and $2 million of funding for workforce development. On June 2, 2015, the DPSC issued an order accepting the settlement and approving the merger between Exelon and PHI.

On March 17, 2015, Exelon and PHI announced that they had reached settlements with multiple parties in the Maryland proceeding to review the proposed merger after filing a Request for Adoption of Settlements with the MDPSC. The settlements were signed and filed by Exelon, PHI, Montgomery County, Prince George's County, The Alliance for Solar Choice, the National Consumer Law Center, National Housing Trust, the Maryland Affordable Housing Coalition, the Housing Association of Nonprofit Developers, and a consortium of recreational trail advocacy organizations led by the Mid-Atlantic Off-Road Enthusiasts. On May 15, 2015, the MDPSC approved the merger after modifying a number of the conditions in the settlements, resulting in total rate credits of $66 million, funding for energy efficiency programs of $43.2 million, a Green Sustainability Fund of $14.4 million, 20 MWs of renewable generation development, ring-fencing, financial reporting conditions and increased penalties related to reliability commitments. On May 18, 2015, Exelon and PHI accepted and committed to fulfill the conditions.

On June 11, 2015, the Maryland Office of People's Counsel (OPC), the Sierra Club, and the Chesapeake Climate Action Network filed Petitions for Judicial Review of the MDPSC's approval of the merger with the Circuit Court for Queen Anne's County. On July 1, 2015, Public Citizen, Inc. filed its Petition for Judicial Review with the Circuit Court for Queen Anne's County. On July 10, 2015, Exelon and PHI filed responses in opposition to the Petitions for Review. On July 21, 2015, the OPC filed a motion to stay the MDPSC order approving the merger and to set a schedule for discovery and presentation of new evidence. Exelon and PHI intend to vigorously oppose the motion.

The merger still requires approval by the public service commission of the District of Columbia. Exelon and PHI expect the merger to be completed in the third quarter of 2015.

Under the settlement terms and other conditions established in the merger approvals received to date and as proposed in the approval application in the District of Columbia, Exelon and PHI are required to expend in excess of $300 million, covering rate credits, funding for energy efficiency programs, sustainability funds, charitable contributions and other required commitments. Exelon and PHI anticipate substantially all of such amounts will be charged to earnings at the time of merger close and will be paid by the end of 2016.

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The actual nature, amount, timing and financial reporting treatment for these commitments may be materially impacted by terms and conditions set forth in any final District of Columbia approval order. Further, the settlements reached and commission orders received to date include a "most favored nation" provision which, generally speaking, requires allocation of merger benefits proportionately across all the jurisdictions.

Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. Exelon was also named in a federal court suit making similar claims. In September 2014, the parties reached a proposed settlement that would resolve all claims, which is subject to court approval. Final court approval of the proposed settlement is not anticipated until approximately 90 days after merger close. Exelon does not believe these suits will impact the completion of the transaction, and they are not expected to have a material impact on Exelon's results of operations.

Including 2014 and through June 30, 2015, Exelon has incurred approximately $205 million of expense associated with the proposed merger. Of the total costs incurred, $89 million is primarily related to acquisition and integration costs and $116 million of costs incurred to finance the transaction. The financing costs include a net loss of $64 million related to the settlement of forward-starting interest-rate swaps. These swaps were terminated in connection with the $4.2 billion issuance of debt, refer to Note 10 — Derivative Financial Instruments and Note 11 — Debt and Credit Agreements for more information.

The Merger Agreement also provides for termination rights for both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the Merger Agreement is terminated due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities of PHI described above, through the redemption by PHI of the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock, plus certain expenses.

Merger Financing

Exelon intends to fund the all-cash transaction using a combination of debt, cash from asset sales primarily at Generation, and through issuance of equity (including mandatory convertible securities). On June 11, 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share in connection with forward sales agreements and $1.2 billion of junior subordinated notes in the form of 23 million equity units. In addition, Exelon signed a 364-day $7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing. In June 2015, Exelon issued $4.2 billion of long-term debt which resulted in the termination of the remaining $3.2 billion bridge facility. Additionally, in July 2015, Exelon elected to settle the forward sales agreements resulting in net proceeds of approximately $1.87 billion. See Note 11 — Debt and Credit Agreements and Note 17 — Common Stock for more information.

Asset Divestitures (Exelon and Generation)

On January 21, 2015, Generation closed on the sale of the Quail Run generating facility. Including the sale of the Quail Run generating facility, Generation has sold generating assets for total pre-tax proceeds of $1.8 billion (after-tax proceeds of $1.4 billion) which are expected to be used primarily to finance a portion of the acquisition and related costs and expenses, of PHI.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

5. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)

Regulatory and Legislative Proceedings (Exelon, Generation, ComEd, PECO and BGE)

Except for the matters noted below, the disclosures set forth in Note 3 — Regulatory Matters of the Exelon 2014 Form 10-K appropriately represent, in all material respects, the current status of regulatory and legislative proceedings of the Registrants. The following is an update to that discussion.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd). Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities to modernize Illinois' electric utility infrastructure. EIMA was scheduled to sunset, ending ComEd's performance based rate formula and investment commitment, at December 31, 2017, unless approved to continue through 2022 by the Illinois General Assembly. On April 3, 2015, the Governor signed legislation extending the EIMA sunset from 2017 to 2019.

Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. As of June 30, 2015, and December 31, 2014, ComEd had recorded a net regulatory asset associated with the distribution formula rate of $275 million and $371 million, respectively. The regulatory asset associated with distribution true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

On April 15, 2015, ComEd filed its annual distribution formula rate with the ICC. The filing establishes the revenue requirement used to set the rates that will take effect in January 2016 after the ICC's review and approval, which is due by December 2015. The revenue requirement requested is based on 2014 actual costs plus projected 2015 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2014 to the actual costs incurred that year. ComEd's 2015 filing request includes a total decrease to the revenue requirement of $50 million, reflecting an increase of $92 million for the initial revenue requirement for 2016 and an decrease of $142 million related to the annual reconciliation for 2014. The revenue requirement for 2016 provides for a weighted average debt and equity return on distribution rate base of 7.05% inclusive of an allowed return on common equity of 9.14%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2014 provided for a weighted average debt and equity return on distribution rate base of 7.02% inclusive of an allowed return on common equity of 9.09%, reflecting the average rate on 30-year treasury notes plus 580 basis points less a performance metrics penalty of 5 basis points.

Participating utilities are also required to file an annual update on their AMI implementation progress. On June 11, 2014, the ICC approved ComEd's accelerated deployment plan which allows for the installation of more than 4 million smart meters throughout ComEd's service territory by 2018, three years in advance of the originally scheduled 2021 completion date. On April 1, 2015, ComEd filed an annual progress report on its AMI Implementation Plan with the ICC. To date, over 1.2 million smart meters have been installed in the Chicago area.

Grand Prairie Gateway Transmission Line (Exelon and ComEd). On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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DeKalb, Kane and DuPage Counties in Northern Illinois. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. The costs incurred for the project prior to May 21, 2014 were immaterial. On October 22, 2014, the ICC issued an order approving ComEd's Grand Prairie Gateway Project over the objection of numerous landowners and the City of Elgin. On January 15, 2015, the City of Elgin and other parties filed a Notice of Appeal in the Illinois Appellate Court. On April 8, 2015, the ICC issued a rehearing order denying the proposals filed by certain landowners to consider an alternate route for a three-mile segment of the transmission line. The rehearing order affirmed the route approved within the ICC's October 22, 2014 order. On July 8, 2015, the ICC approved ComEd's request for eminent domain to involuntarily acquire easements across 28 land parcels. ComEd began construction of the line during the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

Pennsylvania Regulatory Matters

2015 Pennsylvania Electric Distribution Rate Case (Exelon and PECO). On March 27, 2015, PECO filed a petition with the PAPUC requesting an increase of $190 million to its annual service revenues for electric delivery, which would reflect a 4.4% increase on the basis of total Pennsylvania jurisdictional operating revenue. The requested rate of return on common equity is 10.95%. The new electric delivery rates would take effect no later than January 1, 2016. The results of the rate case are expected to be known in the fourth quarter of 2015. PECO cannot predict how much of the requested increase the PAPUC will ultimately approve.

Pennsylvania Procurement Proceedings (Exelon and PECO). On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO's second DSP Program, which was filed with the PAPUC in January 2012. The program, which had a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129. In the second DSP Program, PECO entered into contracts with PAPUC-approved bidders, including Generation, to procure electric supply for its default electric customers through five competitive procurements.

In addition, the second DSP Program included a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to submit a plan to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs beginning in April 2014. In May 2013, PECO filed its CAP Shopping Plan with the PAPUC. By Order entered on January 24, 2014, the PAPUC approved PECO's plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, the Office of Consumer Advocate (OCA) and low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court (the Court), claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On July 14, 2015, the Court issued opinions on the OCA and low-income advocacy group appeal. Specifically, the Court remanded the issue to the PAPUC with instructions that it approve a rule revision to the PECO CAP Shopping Plan that would prohibit CAP customers from entering into contracts with an EGS that would impose early cancellation/termination fees. PECO does not have information at this time as to what action it may be required to take following remand to the PAPUC.

On December 4, 2014, the PAPUC approved PECO's third DSP Program. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. Under the program, PECO is procuring electric supply through four competitive procurements for fixed price full requirements contracts of two years or less for the residential classes and small and medium

commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. In March 2015, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential class and its small, medium, and large commercial classes which commenced in June 2015. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Statement of Operations and Comprehensive Income.

On March 12, 2015, PECO settled the CAP Design with the Office of Consumer Advocates (OCA) and Low Income Advocates, and filed the proposed plan with the PAPUC on March 20, 2015. The program design changes the rate structure of PECO's CAP to make the bills more affordable to customers enrolled in the assistance program. The CAP discounts continue to be recovered through PECO's universal service fund cost. On July 8, 2015, the CAP Design was approved by the PAPUC. PECO plans to implement the program changes in October 2016.

Smart Meter and Smart Grid Investments (Exelon and PECO). In April 2010, pursuant to Act 129 and the follow-on Implementation Order of 2009, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan (SMPIP). PECO is currently in the second phase of the SMPIP, under which PECO will deploy substantially all remaining smart meters, for a total of 1.7 million smart meters, on an accelerated basis by the end of 2015. In total, PECO currently expects to spend up to $591 million, excluding the cost of the original meters, on its smart meter infrastructure and approximately $155 million on smart grid investments through final deployment of which $200 million was primarily funded by SGIG. As of June 30, 2015, PECO has spent $574 million and $155 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received.

For further information on the SGIG and Smart Meter and Smart Grid program, see Note 3 — Regulatory Matters of the Exelon 2014 Form 10-K.

Pennsylvania Act 11 of 2012 (Exelon and PECO). In February 2012, Act 11 was signed into law, which seeks to clarify the PAPUC's authority to approve alternative ratemaking mechanisms, allowing for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems in Pennsylvania. Prior to recovering costs pursuant to a DSIC, the PAPUC's implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) approved by the Commission, which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure.

On May 7, 2015, the PAPUC approved PECO's modified natural gas LTIIP. In accordance with the approved LTIIP, PECO plans to spend $534 million through 2022 to further accelerate the replacement of existing gas mains and to relocate meters from indoors to outside in accordance with recent PAPUC rulemaking. In addition, on March 20, 2015, PECO filed a petition with the PAPUC for approval of its gas DSIC mechanism for recovery of gas LTIIP expenditures.

On March 27, 2015, PECO filed a petition with the PAPUC for approval of its proposed electric DSIC and LTIIP. In accordance with the LTIIP (System 2020 plan), PECO plans to spend $275 million over the next five years to modernize and storm-harden its electric distribution system, making it more weather resistant and less vulnerable to damage. If approved, the DSIC will allow PECO the opportunity to recover the costs, subject to certain criteria, incurred to repair, improve or replace its electric distribution property between rate cases.

Maryland Regulatory Matters

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, and as amended on August 23, 2013, BGE filed for electric and gas base increases with the MDPSC, ultimately

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requesting increases of $83 million and $24 million, respectively. In addition to these requested rate increases, BGE's application included a request for recovery of incremental capital expenditures and operating costs associated with BGE's proposed short-term reliability improvement plan (the ERI initiative) in response to a MDPSC order through a surcharge separate from base rates.

On December 13, 2013, the MDPSC issued an order in BGE's 2013 electric and natural gas distribution rate case for increases in annual distribution service revenue of $34 million and $12 million, respectively, and an allowed return on equity of 9.75% and 9.60%, respectively. Rates became effective for services rendered on or after December 13, 2013. The MDPSC also authorized BGE to recover through a surcharge mechanism costs associated with five ERI initiative programs designed to accelerate electric reliability improvements premised upon the condition that the MDPSC approve specific projects in advance of cost recovery. On March 31, 2014, after reviewing comments filed by the parties and conducting a hearing on the matter, the MDPSC approved all but one project proposed for completion in 2014 as part of the ERI initiative. The ERI initiative surcharge became effective June 1, 2014. On November 3, 2014, BGE filed a surcharge update including a true-up of cost estimates included in the 2014 surcharge, along with its work plan and cost estimates for 2015, to be included in the 2015 surcharge. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2014 annual report, 2015 work plan and the 2015 surcharge.

In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE's 2013 electric and gas distribution rate cases. The residential consumer advocate filed its related legal memorandum on August 22, 2014, challenging the MDPSC's approval of the ERI initiative surcharge. BGE submitted a response to the appeal on October 15, 2014, and a hearing was held on November 17, 2014. BGE cannot predict the outcome of this appeal. If the residential consumer advocate's appeal is successful, BGE could recover ERI expenditures through other regulatory mechanisms.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million of which $200 million was funded by SGIG. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of June 30, 2015 and December 31, 2014, BGE recorded a regulatory asset of $160 million and $128 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. As part of the settlement in BGE's 2014 electric and gas distribution rate case, the cost of the retired non-AMI meters will be amortized over 10 years.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE) . In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to recover promptly reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law; which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and

surcharge. On March 26, 2014, the MDPSC approved as filed BGE's proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge that became effective April 1, 2014. On November 17, 2014, BGE filed a surcharge update to be effective January 1, 2015 including a true-up of cost estimates included in the 2014 surcharge, along with its 2015 project list and cost estimates to be included in the 2015 surcharge. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2015 project list and the proposed surcharge for 2015, which included the true-up of the 2014 charge. As of June 30, 2015, BGE recorded a regulatory liability of $1 million, representing the difference between the surcharge revenues and program costs.

In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE's infrastructure replacement plan. On September 5, 2014, the Baltimore City Circuit Court affirmed the MDPSC decision on BGE's infrastructure replacement plan and associated surcharge. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court. The Court of Special Appeals (the Court) has issued a preliminary procedural schedule that sets oral argument in this matter for a date in the first two weeks of November 2015. On July 24, 2015, the residential consumer advocate's brief was filed. BGE's brief is due by August 24, 2015, and the residential consumer advocate's reply brief by September 15, 2015.

New York Regulatory Matters

Ginna Nuclear Power Plant Reliability Support Services Agreement (Exelon and Generation) . Ginna Nuclear Power Plant's (Ginna) prior period fixed-price PPA contract with Rochester Gas & Electric Company (RG&E) expired in June 2014. In light of the expiration of the agreement, Ginna advised the New York Public Service Commission (NYPSC) and ISO-NY that in absence of a reliability need, Ginna management would make a recommendation, subject to approval by the CENG board, that Ginna be retired as soon as practicable. A formal study conducted by the ISO-NY and RG&E concluded that the Ginna nuclear plant needs to remain in operation to maintain the reliability of the transmission grid in the Rochester region through 2018 when planned transmission system upgrades are expected to be completed. In November 2014, in response to a petition filed by Ginna, the NYPSC directed Ginna and RG&E to negotiate a Reliability Support Services Agreement (RSSA). On February 13, 2015, regulatory filings, including RSSA terms negotiated between Ginna and RG&E, to support the continued operation of Ginna for reliability purposes were made with the NYPSC and with FERC for their approval. Although the RSSA contract is still subject to regulatory approvals, on April 1, 2015, Ginna began delivering power and capacity into ISO-NY consistent with the provisions of the proposed RSSA contract. RG&E may terminate the RSSA contract upon providing 12-months' notice, which would require RG&E to make a specified termination payment to Ginna. The proposed RSSA contract extends through September 30, 2018. In the event that Ginna continues to operate beyond the RSSA term, Ginna would be required to make a specified refund payment to RG&E. The FERC issued an order on April 14, 2015, directing Ginna to make a compliance filing to ensure that the RSSA does not allow Ginna to receive revenues above its full cost-of-service and rejecting any extension of the RSSA beyond its initial term, rather requiring any extension be subject to the rules currently being developed by ISO-NY. The FERC order also set the RSSA for hearing and settlement procedures. In response to the FERC's April 14, 2015 order, on May 14, 2015, Ginna submitted a compliance filing to FERC containing proposed revisions to the RSSA addressing FERC's requirements and maintaining the April 1, 2015 proposed effective date. On July 13, 2015, FERC accepted Ginna's compliance filing effective April 1, 2015. The FERC accepted Ginna's proposal for market revenue sharing subject to a cap effective April 1, 2015, and rejected requests for rehearing by parties on a number of matters related to jurisdiction, the reliability need, RSSA term, and possible price suppression. While the FERC order supports Ginna's current agreement, it remains subject to FERC hearing and settlement procedures. These procedures may result in modifications to the agreement, however, Ginna is unable to predict the ultimate outcome of these proceedings. The effectiveness of the RSSA or any settlement among the parties at FERC remains contingent on approval by the NYPSC of RG&E's full and timely recovery of rates associated with the costs incurred under the RSSA.

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Until final regulatory approvals are received, Generation will recognize revenue based on market prices for energy and capacity delivered by Ginna into ISO-NY. Upon receiving regulatory approvals, under the RSSA contract terms, Generation would record an adjustment to recognize revenue based on the final approved pricing contained in the contract as of the April 1, 2015 effective date. While the RSSA is expected to receive regulatory approvals and, therefore, permit Ginna to continue operating through the RSSA term, there is still a risk that, for economic reasons, including adjustments to the revenue Ginna would be entitled to under the RSSA, Ginna could be retired before the end of its operating license period. In absence of such an agreement and in the event the plant is retired before the current license term ends in 2029, Exelon's and Generation's results of operations could be adversely affected by increased depreciation rates, impairment charges, severance costs, and accelerated future decommissioning costs, among other items. However, it is not expected that such impacts would be material to Exelon's or Generation's results of operations.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE) . ComEd's and BGE's transmission rates are each established based on a FERC-approved formula. ComEd and BGE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd and BGE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd's and BGE's best estimate of the revenue requirement expected to be approved by the FERC for that year's reconciliation. As of June 30, 2015 and December 31, 2014, ComEd had recorded a net regulatory asset associated with the transmission formula rate of $26 million and $21 million, respectively. BGE recorded a net regulatory asset associated with the transmission formula rate of $1 million as of June 30, 2015 and December 31, 2014 each. The regulatory asset associated with the transmission true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

On April 15, 2015 (and revised on May 19), ComEd filed its annual transmission formula rate update with the FERC. The filing establishes the revenue requirement used to set rates that took effect in June 2015, subject to review by the FERC and other parties, which is due by fourth quarter 2015. ComEd's 2015 annual update includes a total increase to the revenue requirement of $86 million, reflecting an increase of $68 million for the initial revenue requirement and an increase of $18 million related to the annual reconciliation. The revenue requirement provides for a weighted average debt and equity return on transmission rate base of 8.61%, inclusive of an allowed return on common equity of 11.50%, a decrease from the 8.62% average debt and equity return previously authorized.

In April 2015, BGE filed its annual transmission formula rate update with the FERC. The filing establishes the revenue requirement used to set rates that took effect in June 2015, subject to review by the FERC and other parties, which is due by October 2015. BGE's 2015 annual update includes a total increase to the revenue requirement of $10 million, reflecting an increase of $13 million for the initial revenue requirement and a decrease of $3 million related to the annual reconciliation. The revenue requirement provides for a weighted average debt and equity return on transmission rate base of 8.46%, inclusive of an allowed return on common equity of 11.30%, a decrease from the 8.53% average debt and equity return previously authorized.

FERC Transmission Complaint (Exelon and BGE) . On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and PHI companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) and a 50 basis point incentive for participating in PJM (the latter of which is conditioned upon

crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint.

On August 21, 2014, FERC issued an order in the BGE and PHI companies' proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013. BGE, the PHI companies and the parties began settlement discussions under the guidance of a FERC administrative law judge on September 23, 2014. On November 24, 2014, the Settlement Judge informed FERC and the Chief Judge that the parties had reached an impasse and determined that a settlement was not possible. On November 26, 2014, the Chief Judge issued an order terminating the settlement proceeding, designating a presiding judge at the hearings and directing that an initial decision be issued by November 25, 2015.

On December 8, 2014, various state agencies in Delaware, Maryland, New Jersey, and D.C. filed a second complaint against BGE regarding the base ROE of the transmission business seeking a reduction from 10.8% to 8.8%. The filing of the second complaint creates a second refund window. By order issued on February 9, 2015, FERC established a hearing on the second complaint with the complainants' requested refund effective date of December 8, 2014. On February 20, 2015, the Chief Judge issued an order consolidating the two complaint proceedings and established an Initial Decision issuance deadline of February 29, 2016. On March 2, 2015, the Presiding Administrative Law Judge issued an order establishing a procedural schedule for the consolidated proceedings that provides for the hearing to commence on October 20, 2015.

Based on the current status of the complaint filings, BGE believes it is probable that BGE's base ROE rate will be adjusted, and that a refund to customers of transmission revenue for the two maximum fifteen month periods will be required. However, BGE is unable to estimate the most likely refund amount for either complaint at this time, and has therefore established a reserve, which is not material, representing the low end of a reasonably possible estimated range of loss. Additionally, management is unable to estimate the maximum exposure of a potential refund at this time, which may have a material impact on BGE's results of operations and cash flows. The estimated annual ongoing reduction in revenues if FERC approved the ROEs requested by the parties in their filings is approximately $11 million. If FERC were to order a reduction of BGE's base ROE to 8.7% as sought in the first complaint (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result of the first fifteen month refund window would be a refund to customers of approximately $13 million. If FERC were to order a reduction in BGE's base ROE to 8.8% as sought in the second complaint (while retaining 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment) and the refund period extended for a full fifteen months, the result would be a refund to customers of approximately $14 million.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE) . PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. A number of parties appealed to the U.S. Court of Appeals for the Seventh Circuit.

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In August 2009, the court issued its decision affirming the FERC's order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above (Cost Allocation Issue) for further consideration by the FERC. On remand, FERC reaffirmed its earlier decision to socialize the costs of new facilities 500 kV and above. A number of parties filed appeals of these orders. In June 2014, the court again remanded the Cost Allocation Issue to FERC. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the Cost Allocation Issue. The hearing only concerns new facilities approved by the PJM Board prior to February 1, 2013. As of June 30, 2015, settlement discussions are continuing.

Because a new cost allocation had been adopted for projects approved by the PJM Board on or after February 1, 2013, this latest remand only involves the cost allocation for facilities 500 kV and above approved prior to that date. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent any rate design changes are retroactive to periods prior to January 1, 2011, there may be an impact on PECO's results of operations. BGE anticipates that all impacts of any rate design changes effective after the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE's results of operations, cash flows or financial position.

Demand Response Resource Order (Exelon, Generation, ComEd, PECO, BGE) . On May 23, 2014, the D.C. Circuit Court issued an opinion vacating the FERC Order No. 745 (D.C. Circuit Decision). Order No. 745 established uniform compensation levels for demand response resources that participate in the day ahead and real-time wholesale energy markets. Under Order No. 745, buyers in ISO and RTO markets were required to pay demand response resources the full Locational Marginal Price when the demand response replaced a generation resource and was cost-effective.

In addition to invalidating the compensation structure established by Order No. 745, the D.C. Circuit Court, in broad language, explained that demand response is part of the retail market and FERC is restricted from regulating retail markets. The FERC and several other parties sought rehearing of the D.C. Circuit Decision, which was denied in September 2014. In addition, on September 22, 2014, the FERC and another party sought to stay the issuance of the D.C. Circuit Court's mandate so that the FERC may appeal the decision to the U.S. Supreme Court. The stay was granted with respect to the FERC's request only. In January 2015, the FERC sought to appeal the decision to the U.S. Supreme Court. The U.S. Supreme Court agreed to consider the appeal. In addition, contemporaneously with the D.C. Circuit Court's decision on May 23, 2014, First Energy filed a complaint at the FERC asking the FERC to direct PJM to remove all PJM Tariff provisions that allow or require PJM to compensate demand response providers as a form of supply in the PJM capacity market effective May 23, 2014. FirstEnergy also asked the FERC to declare the results of PJM's May 2014 Base Residual Auction for the 2017/2018 Delivery Year, void and illegal to the extent that demand response resources cleared that auction. On November 14, 2014, the New England Power Generators Association, Inc. (NEPGA) filed a similar complaint at the FERC asking the FERC to disqualify demand response from the upcoming capacity auction in New England and to revise the New England tariff to remove demand response from participation in the capacity market. The FERC's response to the FirstEnergy complaint and the NEPGA complaint and its response to address the D.C. Circuit Court's decision in all markets could preclude demand response resources from receiving any future capacity market revenues and also subject such resources to refund obligations depending on how the U.S. Supreme Court resolves the matter. In addition, there is uncertainty as to how the FERC might treat already settled capacity market auctions as well as future auctions, both for demand response resources and generation

resources, again depending on the U.S. Supreme Court resolution. Due to these uncertainties, the Registrants are unable to predict the outcome of these proceedings, and the final outcome is not expected for several months. Nonetheless, the final decision and its implementation by FERC and the RTOs and ISOs, could be material to Exelon, Generation, ComEd, PECO and BGE's results of operations and cash flows.

New England Capacity Market Results (Exelon and Generation). Each year, ISO New England, Inc. (ISO-NE) files the results of its annual capacity auction at the FERC which is required to include documentation regarding the competitiveness of the auction. Consistent with this requirement, on February 27, 2015, ISO-NE filed the results of its ninth capacity auction (covering the June 1, 2018 through May 30, 2019 delivery period). On June 18, 2015, the FERC accepted the results of the ninth capacity auction.

On February 28, 2014, ISO-NE filed the results of its eighth capacity auction (covering the June 1, 2017 through May 30, 2018 delivery period). On June 27, 2014, the FERC issued a letter to ISO-NE noting that ISO-NE's February 28, 2014 filing was deficient and that ISO-NE must file additional information before the FERC can process the filing. ISO-NE filed the information on July 17, 2014, and the ISO-NE's filings became effective by operation of law pursuant to a notice issued by the secretary of FERC on September 16, 2014. Several parties sought rehearing of the secretary's notice which was effectively denied in October 2014 and have since appealed the matter to the D.C. Circuit Court. On April 7, 2015 the D.C. Circuit Court issued an order referring the matter to a merits panel where issues raised by parties challenging the FERC decision will be heard as well as FERC's Motion to Dismiss the challenges. It is not clear whether the court will decide ultimately on the merits of the case or whether it will dismiss the case as FERC urges based on the fact that there is no action by the FERC to be considered. Nonetheless, while any change in the auction results is thought to be unlikely, Exelon and Generation cannot predict with certainty what further action the court may take concerning the results of that auction, but any court action could be material to Exelon's and Generation's expected revenues from the capacity auction.

License Renewals (Exelon and Generation). On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Project (Muddy Run), respectively.

Generation is working with stakeholders to resolve water quality licensing issues with the MDE for Conowingo, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On January 30, 2014, Generation filed a water quality certification application pursuant to Section 401 of the CWA with MDE for Conowingo, addressing these and other issues, although Generation cannot currently predict the conditions that ultimately may be imposed. MDE indicated that it believed it did not have sufficient information to process Generation's application. As a result, on December 5, 2014, Generation withdrew its pending application for a water quality certification. FERC policy requires that an applicant resubmit its request for a water quality certification within 90 days of the date of withdrawal. Accordingly, on March 3, 2015, Generation refiled its application for a water quality certification. In addition, Generation has entered into an agreement with MDE to work with state agencies in Maryland, the U.S. Army Corps of Engineers, the U.S. Geological Survey, the University of Maryland Center for Environmental Science and the U.S. Environmental Protection Agency Chesapeake Bay Program to design, conduct and fund an additional multi-year sediment study. Generation has agreed to contribute up to $3.5 million to fund the additional study. Resolution of these issues relating to Conowingo may have a material effect on Exelon's and Generation's results of operations and financial position through an increase in capital expenditures and operating costs.

On June 3, 2014, and subsequently modified December 9, 2014, the PA DEP issued its water quality certificate for Muddy Run, which is a necessary step in the FERC licensing process and included certain commitments made by Generation. On March 2, 2015, Generation and US Fish and Wildlife Services (USFWS) submitted to FERC an executed settlement agreement resolving all outstanding issues related to Muddy Run. The

financial impact associated with these commitments is estimated to be in the range of $25 million to $35 million, and will include both capital expenditures and operating expenses, primarily relating to fish passage and habitat improvement projects.

The FERC licenses for Muddy Run and Conowingo expired on August 31, 2014 and September 1, 2014 respectively. Under the Federal Power Act, FERC is required to issue annual licenses for the facilities until the new licenses are issued. On September 10, 2014, FERC issued annual licenses for Conowingo and Muddy Run, effective as of the expiration of the previous licenses. If FERC does not issue new licenses prior to the expiration of annual licenses, the annual licenses will renew automatically. On March 11, 2015, FERC issued the final Environmental Impact Statement for Muddy Run and Conowingo.

The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. As of June 30, 2015, $42 million of direct costs associated with licensing efforts have been capitalized.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE each prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of June 30, 2015 and December 31, 2014. For additional information on the specific regulatory assets and liabilities, refer to Note 3 — Regulatory Matters of the Exelon 2014 Form 10-K.

June 30, 2015	Exelon	ComEd	PECO	BGE
Regulatory assets				
Pension and other postretirement benefits	$3,193	$ —	$ —	$ —
Deferred income taxes	1,574	65	1,432	77
AMI programs	349	119	70	160
Under-recovered distribution service costs [a]	275	275	—	—
Debt costs	51	49	2	8
Fair value of BGE long-term debt	177	—	—	—
Severance	11	—	—	11
Asset retirement obligations	121	76	26	19
MGP remediation costs	245	210	34	1
Under-recovered uncollectible accounts	50	50	—	—
Renewable energy	223	223	—	—
Energy and transmission programs [b] [c]	53	34	—	19
Deferred storm costs	2	—	—	2
Electric generation-related regulatory asset	25	—	—	25
Rate stabilization deferral	121	—	—	121
Energy efficiency and demand response programs	236	—	—	236
Merger integration costs	7	—	—	7
Conservation voltage reduction	2	—	—	2
Other	46	9	30	5
Total regulatory assets	6,761	1,110	1,594	693
Less: current portion	785	276	42	207
Total noncurrent regulatory assets	$5,976	$ 834	$1,552	$486

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

June 30, 2015	Exelon	ComEd	PECO	BGE
Regulatory liabilities				
Other postretirement benefits	$ 68	$ —	$ —	$ —
Nuclear decommissioning	2,831	2,354	477	—
Removal costs	1,563	1,351	—	212
Energy efficiency and demand response programs	41	39	2	—
DLC Program Costs	9	—	9	—
Energy efficiency phase II	38	—	38	—
Electric distribution tax repairs	102	—	102	—
Gas distribution tax repairs	33	—	33	—
Energy and transmission programs [b][c][d]	134	30	85	19
Over-recovered electric universal service fund costs	2	—	2	—
Over-recovered revenue decoupling [e]	40	—	—	40
Other	10	2	2	5
Total regulatory liabilities	4,871	3,776	750	276
Less: current portion	409	154	117	91
Total noncurrent regulatory liabilities	$4,462	$3,622	$633	$185

December 31, 2014	Exelon	ComEd	PECO	BGE
Regulatory assets				
Pension and other postretirement benefits	$3,256	$ —	$ —	$ —
Deferred income taxes	1,542	64	1,400	78
AMI programs	296	91	77	128
Under-recovered distribution service costs [a]	371	371	—	—
Debt costs	57	53	4	9
Fair value of BGE long-term debt	190	—	—	—
Severance	12	—	—	12
Asset retirement obligations	116	74	26	16
MGP remediation costs	257	219	37	1
Under-recovered uncollectible accounts	67	67	—	—
Renewable energy	207	207	—	—
Energy and transmission programs [b][c]	48	33	—	15
Deferred storm costs	3	—	—	3
Electric generation-related regulatory asset	30	—	—	30
Rate stabilization deferral	160	—	—	160
Energy efficiency and demand response programs	248	—	—	248
Merger integration costs	8	—	—	8
Conservation voltage reduction	2	—	—	2
Under recovered electric revenue decoupling	7	—	—	7
Other	46	22	14	7
Total regulatory assets	6,923	1,201	1,558	724
Less: current portion	847	349	29	214
Total noncurrent regulatory assets	$6,076	$ 852	$1,529	$510

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

December 31, 2014	Exelon	ComEd	PECO	BGE
Regulatory liabilities				
Other postretirement benefits	$ 88	$ —	$ —	$ —
Nuclear decommissioning	2,879	2,389	490	—
Removal costs	1,566	1,343	—	223
Energy efficiency and demand response programs	27	25	2	—
DLC Program Costs	10	—	10	—
Energy efficiency phase II	32	—	32	—
Electric distribution tax repairs	102	—	102	—
Gas distribution tax repairs	49	—	49	—
Energy and transmission programs [b][c][d]	84	19	58	7
Over-recovered electric universal service fund costs	2	—	2	—
Revenue subject to refund	3	3	—	—
Over-recovered revenue decoupling [e]	12	—	—	12
Other	6	1	2	2
Total regulatory liabilities	4,860	3,780	747	244
Less: current portion	310	125	90	44
Total noncurrent regulatory liabilities	$4,550	$3,655	$657	$200

(a) As of June 30, 2015, ComEd's regulatory asset of $275 million was comprised of $209 million for the applicable annual reconciliations and $66 million related to significant one-time events including $51 million of deferred storm costs and $15 million of Constellation merger and integration related costs. As of December 31, 2014, ComEd's regulatory asset of $371 million was comprised of $286 million for the applicable annual reconciliations and $85 million related to significant one-time events, including $66 million of deferred storm costs and $19 million of Constellation merger and integration related costs. See Note 4 — Mergers, Acquisitions, and Dispositions of the Exelon 2014 Form 10-K for further information.

(b) As of June 30, 2015, ComEd's regulatory asset of $34 million included $1 million related to under-recovered energy costs for non-hourly customers, $26 million associated with transmission costs recoverable through its FERC approved formulate rate, and $7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of June 30, 2015, ComEd's regulatory liability of $30 million included $10 million related to over-recovered energy costs for hourly customers and $20 million associated with revenues received for renewable energy requirements. As of December 31, 2014, ComEd's regulatory asset of $33 million included $4 million related to under-recovered energy costs for non-hourly customers, $22 million associated with transmission costs recoverable through its FERC approved formulate rate, and $7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2014, ComEd's regulatory liability of $19 million included $3 million related to over-recovered energy costs for hourly customers and $16 million associated with revenues received for renewable energy requirements.

(c) As of June 30, 2015, BGE's regulatory asset of $19 million included $1 million associated with transmission costs recoverable through its FERC approved formula rate and $18 million related to under-recovered electric energy costs. As of June 30, 2015, BGE's regulatory liability of $19 million related to $18 million of over-recovered natural gas supply costs and $6 million of over-recovered energy costs, offset by $4 million of Constellation merger and integration costs and $1 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2014, BGE's regulatory asset of $15 million included $10 million related to under-recovered electric energy costs, $4 million of Constellation merger and integration costs and $1 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2014, BGE's regulatory liability of $7 million related to over-recovered natural gas supply costs.

(d) As of June 30, 2015, PECO's regulatory liability of $85 million included $35 million related to the DSP program, $44 million related to the over-recovered natural gas costs under the PGC, $5 million related to over-recovered electric transmission costs and $1 million related to the Non-Bypassable service charge included in the DSP program. As of December 31, 2014, PECO's regulatory liability of $58 million included $39 million related to the DSP program, $16 million related to the over-recovered natural gas costs under the PGC and $3 million related to the over-recovered electric transmission costs.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(e) Represents the electric and gas distribution costs recoverable from customers under BGE's decoupling mechanism. As of June 30, 2015, BGE had a regulatory liability of $11 million related to over-recovered electric revenue decoupling and a regulatory liability of $29 million related to over-recovered natural gas revenue decoupling. As of December 31, 2014, BGE had a regulatory asset of $7 million related to under-recovered electric revenue decoupling and a regulatory liability of $12 million related to over-recovered natural gas revenue decoupling.

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers that participate in the utilities' consolidated billing. ComEd and BGE purchase receivables at a discount to recover primarily uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and permitted to recover uncollectible accounts expense from customers through its distribution rates. Exelon, ComEd, PECO and BGE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon's, ComEd's, PECO's and BGE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of June 30, 2015 and December 31, 2014.

As of June 30, 2015	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 275	$ 128	$ 80	$ 67
Allowance for uncollectible accounts [b]	(40)	(22)	(8)	(10)
Purchased receivables, net	$ 235	$ 106	$ 72	$ 57

As of December 31, 2014	Exelon	ComEd	PECO	BGE
Purchased receivables [a]	$ 290	$ 139	$ 76	$ 75
Allowance for uncollectible accounts [b]	(42)	(21)	(8)	(13)
Purchased receivables, net	$ 248	$ 118	$ 68	$ 62

(a) PECO's gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.

(b) For ComEd and BGE, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing tariff.

6. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation has historically had various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements, see Note 25 — Related Party Transactions of the Exelon 2014 Form 10-K.

As a result of the consolidation of CENG on April 1, 2014, there are several additional transactions included in Exelon's and Generation's consolidated financial statements between CENG and Exelon's affiliates that are considered related party transactions to Generation. As further described in Note 25 — Related Party Transactions of the Exelon 2014 Form 10-K, EDF and Generation had a PPA with CENG under which they purchased 15% and 85%, respectively, of the nuclear output owned by CENG that was not sold to third parties

under pre-existing PPAs through December 31, 2014. Beginning January 1, 2015 and continuing through the life of the respective plants, EDF and Generation will purchase 49.99% and 50.01%, respectively, of the nuclear output owned by CENG not subject to other contractual agreements. Beginning April 1, 2014, CENG's sales to Generation have been eliminated in consolidation. For the three and six months ended June 30, 2015, Generation had sales to EDF of $106 million and $288 million, respectively. See Note 3 — Variable Interest Entities for additional information regarding other transactions between CENG and EDF included within Exelon's and Generation's consolidated financial statements and for additional information about the Registrants VIEs.

Accounting for the Consolidation of CENG

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. From January 1, 2014, through March 31, 2014, Generation recorded $19 million of equity in earnings of unconsolidated affiliates related to its investment in CENG and $17 million of revenues from CENG. The book value of Generation's investment in CENG prior to the consolidation was $1.9 billion, and the book value of the AOCI related to CENG prior to consolidation was $116 million, net of taxes of $77 million.

The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014 resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interest in CENG at fair value on Exelon's and Generation's Consolidated Balance Sheets.

Generation and EDFI also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDFI has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return and the value of Generation's rights to other distributions. The beginning of the exercise period will be accelerated if Exelon's affiliates cease to own a majority of CENG and exercise a related right to terminate the NOSA. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Due to the Preferred Distribution Rights that Generation has on CENG's available cash, the earnings attributable to the noncontrolling interest on the Consolidated Statements of Operations and Comprehensive Income as well as the corresponding adjustment to Noncontrolling interest on the Consolidated Balance Sheets will not be in proportion to Generation's and EDF's equity ownership interests. Rather, the attribution considers Generation's Preferred Distribution Rights and allocates net income based on each owner's rights to CENG's net assets. For the three and six months ended June 30, 2015, Generation reduced by $4 million and $9 million, respectively, the amount of Net income attributable to noncontrolling interests on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. As a result of the consolidation, Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income includes CENG's incremental operating revenues of $109 million and $306 million and CENG's net (loss) income, prior to any intercompany eliminations and any adjustments for noncontrolling interest, of $(4) million and $93 million during the three and six months ended June 30, 2015, respectively.

7. Impairment of Long-Lived Assets (Exelon and Generation)

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the second quarter of each year, Generation updates

the long-term fundamental energy prices, which includes a thorough evaluation of key assumptions including gas prices, load growth, environmental policy, plant retirements and renewable growth.

In 2015, the year over year change in fundamentals did not indicate any impairments. In 2014, the year over year change in fundamentals suggested that the carrying value of certain merchant wind assets may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of twelve wind projects, primarily located in West Texas, were less than their respective carrying values at May 31, 2014. As a result, long-lived assets held and used with a carrying amount of approximately $151 million were written down to their fair value of $65 million and a pre-tax impairment charge of $86 million was recorded during the second quarter of 2014 in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

The fair value analysis was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. Changes in the assumptions described above could potentially result in future impairments of Exelon's long-lived assets, which could be material.

Like-Kind Exchange Transaction (Exelon)

Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in coal-fired generating station leases located in Georgia and Texas with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. See Note 12 — Income Taxes for further information. The leases for the generating stations located in Texas were terminated in 2014. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessees to arrange for a third-party to bid on a service contract for a period following the lease term. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Based on the annual reviews performed in the second quarters of 2015 and 2014, the estimated residual value of Exelon's direct financing leases for the Georgia generating stations experienced other than temporary declines given increases in estimated long-term operating and maintenance costs in the 2015 annual review and reduced long-term energy and capacity price expectations in the 2014 annual review. As a result, Exelon recorded $24 million pre-tax impairment charges in each of the second quarters of 2015 and 2014 for these stations. These impairment charges were recorded in Investments and Operating and maintenance expense in Exelon's Consolidated Balance Sheets and the Consolidated Statements of Operations and Comprehensive Income, respectively. Changes in the assumptions described above could potentially result in future impairments of Exelon's direct financing lease investments, which could be material.

At June 30, 2015 and December 31, 2014, the components of the net investment in long-term leases were as follows:

	June 30, 2015	December 31, 2014
Estimated residual value of leased assets	$ 639	$ 685
Less: unearned income	295	324
Net investment in long-term leases	$ 344	$ 361

8. Implications of Potential Early Plant Retirements (Exelon and Generation)

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation's nuclear plants. Factors that will continue to affect the economic value of Generation's nuclear plants include, but are not limited to: market power prices, results of the PJM capacity auction for the 2018/2019 delivery year, the effects of the new PJM "Capacity Performance" product, potential legislative solutions in Illinois such as the proposed Low Carbon Portfolio Standard (LCPS) legislation, the impact of final rules from the U.S. EPA requiring reduction of carbon and other emissions, and the outcome of the Ginna RSSA hearing and settlement procedures and the resulting contractual terms and conditions. Exelon and Generation have not made any decisions regarding potential plant closures at this time; however, various upcoming milestones could influence the timing of any such decisions, which could occur as soon as the third quarter of 2015. In September 2015, Generation has an obligation to inform PJM if any of its plants in the PJM region will not be participating in the May 2016 PJM capacity auction for delivery year beginning June 1, 2019. In December 2015, Generation must inform MISO if the Clinton plant will not be in operation during the next MISO resource adequacy planning year that begins June 1, 2016.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As a result of a decision to early retire one or more nuclear plants, certain changes in accounting treatment would be triggered and Exelon's and Generation's results of operations and cash flows could be materially affected by a number of items including: accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, accelerated amortization of plant specific nuclear fuel costs, severance costs, accelerated asset retirement obligation expense related to future decommissioning activities, and additional funding of decommissioning costs, among other items. In addition, any early plant retirement would also result in reduced operating costs, lower fuel expense, and lower capital expenditures in the periods beyond shutdown. While there are a number of Generation's nuclear plants that are at risk of early retirement, the following table provides the balance sheet amounts as of June 30, 2015 for significant assets and liabilities associated with the three nuclear plants currently deemed by management to be at the greatest risk of early retirement due to their current economic valuations and other factors:

(in millions)	Quad Cities	Clinton	Ginna	Total
Asset Balances				
Materials and supplies inventory	$ 48	$ 55	$ 30	$ 133
Nuclear fuel inventory	205	137	66	408
Completed plant, net	800	465	85	1,350
Construction work in progress	24	24	23	71
Liability Balances				
Asset retirement obligation	(450)	(287)	(611)	(1,348)
NRC License Renewal Term	2032	2046[a]	2029	

(a) Assumes Clinton seeks and receives a 20-year operating license renewal extension.

In the event a decision was made to early retire one or more nuclear plants, the precise timing of the retirement date, and resulting financial statement impact, is uncertain and would be influenced by a number of factors such as the results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity obligations and just prior to its next scheduled nuclear refueling outage date in that year.

9. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of June 30, 2015 and December 31, 2014:

Exelon

	June 30, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 546	$ 3	$ 543	$ —	$ 546
Long-term debt (including amounts due within one year)	25,446	1,043	24,011	1,349	26,403
Long-term debt to financing trusts	648	—	—	663	663
SNF obligation	1,021	—	838	—	838

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	December 31, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 463	$ 3	$ 448	$ 12	$ 463
Long-term debt (including amounts due within one year)	21,164	1,208	20,417	1,311	22,936
Long-term debt to financing trusts	648	—	—	648	648
SNF obligation	1,021	—	833	—	833

Generation

	June 30, 2015				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 40	$ —	$ 40	$ —	$ 40
Long-term debt (including amounts due within one year)	9,001	—	7,995	1,349	9,344
SNF obligation	1,021	—	838	—	838

	December 31, 2014				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 36	$ —	$ 24	$ 12	$ 36
Long-term debt (including amounts due within one year)	8,266	—	7,511	1,311	8,822
SNF obligation	1,021	—	833	—	833

ComEd

	June 30, 2015				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 503	$ —	$ 503	$ —	$ 503
Long-term debt (including amounts due within one year)	6,099	—	6,640	—	6,640
Long-term debt to financing trust	206	—	—	206	206

	December 31, 2014				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 304	$ —	$ 304	$ —	$ 304
Long-term debt (including amounts due within one year)	5,958	—	6,788	—	6,788
Long-term debt to financing trust	206	—	—	213	213

PECO

	June 30, 2015				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,246	$ —	$2,432	$ —	$2,432
Long-term debt to financing trusts	184	—	—	199	199

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	December 31, 2014				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,246	$ —	$2,537	$ —	$2,537
Long-term debt to financing trusts	184	—	—	199	199

BGE

	June 30, 2015				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 3	$ 3	$ —	$ —	$ 3
Long-term debt (including amounts due within one year)	1,905	—	2,086	—	2,086
Long-term debt to financing trusts	258	—	—	258	258

	December 31, 2014				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 123	$ 3	$ 120	$ —	$ 123
Long-term debt (including amounts due within one year)	1,942	—	2,178	—	2,178
Long-term debt to financing trusts	258	—	—	236	236

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of dividends payable (included in other current liabilities) (Level 1), short-term borrowings (Level 2) and third party financing (Level 3). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. The fair value of Exelon's equity units (Level 1) are valued based on publicly traded securities issued by Exelon.

The fair value of Generation's non-government-backed fixed rate project financing debt, including nuclear fuel procurement contracts, (Level 3) is based on market and quoted prices for its own and other project financing debt with similar risk profiles. Given the low trading volume in the project financing debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-backed fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value (Level 2).

SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

Long-Term Debt to Financing Trusts. Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts. There were no transfers between Level 1 and Level 2 during the six months ended June 30, 2015 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Exelon and Generation

The following tables present assets and liabilities measured and recorded at fair value on Exelon's and Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2015 and December 31, 2014:

	Generation				Exelon			
As of June 30, 2015	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents [a]	$ 134	$ —	$ —	$ 134	$ 5,486	$ —	$ —	$ 5,486
Nuclear decommissioning trust fund investments								
Cash equivalents	333	55	—	388	333	55	—	388
Equity								
Domestic	2,389	2,055	—	4,444	2,389	2,055	—	4,444
Foreign	696	—	—	696	696	—	—	696
Equity funds subtotal	3,085	2,055	—	5,140	3,085	2,055	—	5,140
Fixed income								
Corporate debt	—	1,860	250	2,110	—	1,860	250	2,110
U.S. Treasury and agencies	1,165	—	—	1,165	1,165	—	—	1,165
Foreign governments	—	83	—	83	—	83	—	83
State and municipal debt	—	405	—	405	—	405	—	405
Other	—	463	—	463	—	463	—	463
Fixed income subtotal	1,165	2,811	250	4,226	1,165	2,811	250	4,226
Middle market lending	—	—	417	417	—	—	417	417
Private Equity	—	—	100	100	—	—	100	100
Real Estate	—	—	19	19	—	—	19	19
Other	—	329	—	329	—	329	—	329
Nuclear decommissioning trust fund investments subtotal [b]	4,583	5,250	786	10,619	4,583	5,250	786	10,619
Pledged assets for Zion Station decommissioning								
Cash equivalents	—	17	—	17	—	17	—	17
Equities	5	1	—	6	5	1	—	6
Fixed income								
U.S. Treasury and agencies	7	2	—	9	7	2	—	9
Corporate debt	—	62	—	62	—	62	—	62
State and municipal debt	—	10	—	10	—	10	—	10
Other	—	3	—	3	—	3	—	3
Fixed income subtotal	7	77	—	84	7	77	—	84
Middle market lending	—	—	156	156	—	—	156	156
Pledged assets for Zion Station decommissioning subtotal [c]	12	95	156	263	12	95	156	263
Rabbi trust investments in mutual funds [d][e]	17	—	—	17	48	—	—	48
Commodity derivative assets								
Economic hedges	1,080	3,352	2,334	6,766	1,080	3,352	2,334	6,766
Proprietary trading	117	239	38	394	117	239	38	394
Effect of netting and allocation of collateral [f]	(1,364)	(2,753)	(872)	(4,989)	(1,364)	(2,753)	(872)	(4,989)
Commodity derivative assets subtotal	(167)	838	1,500	2,171	(167)	838	1,500	2,171
Interest rate and foreign currency derivative assets								
Derivatives designated as hedging instruments	—	1	—	1	—	22	—	22
Economic hedges	—	20	—	20	—	20	—	20
Proprietary trading	14	1	—	15	14	1	—	15
Effect of netting and allocation of collateral	(8)	(5)	—	(13)	(8)	(5)	—	(13)
Interest rate and foreign currency derivative assets subtotal	6	17	—	23	6	38	—	44
Other investments	—	—	30	30	1	—	30	31
Total assets	4,585	6,200	2,472	13,257	9,969	6,221	2,472	18,662

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of June 30, 2015	Generation				Exelon			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Liabilities								
Commodity derivative liabilities								
Economic hedges	(1,493)	(3,129)	(1,462)	(6,084)	(1,493)	(3,129)	(1,685)	(6,307)
Proprietary trading	(111)	(248)	(43)	(402)	(111)	(248)	(43)	(402)
Effect of netting and allocation of collateral [f]	1,641	3,296	1,026	5,963	1,641	3,296	1,026	5,963
Commodity derivative liabilities subtotal	37	(81)	(479)	(523)	37	(81)	(702)	(746)
Interest rate and foreign currency derivative liabilities								
Derivatives designated as hedging instruments	—	(14)	—	(14)	—	(14)	—	(14)
Economic hedges	—	(4)	—	(4)	—	(4)	—	(4)
Proprietary trading	(14)	—	—	(14)	(14)	—	—	(14)
Effect of netting and allocation of collateral	14	5	—	19	14	5	—	19
Interest rate and foreign currency derivative liabilities subtotal	—	(13)	—	(13)	—	(13)	—	(13)
Deferred compensation obligation	—	(26)	—	(26)	—	(88)	—	(88)
Total liabilities	37	(120)	(479)	(562)	37	(182)	(702)	(847)
Total net assets	$ 4,622	$ 6,080	$ 1,993	$12,695	$10,006	$ 6,039	$ 1,770	$17,815

As of December 31, 2014	Generation				Exelon			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents [a]	$ 405	$ —	$ —	$ 405	$ 1,119	$ —	$ —	$ 1,119
Nuclear decommissioning trust fund investments								
Cash equivalents	208	37	—	245	208	37	—	245
Equity								
Domestic	2,423	2,207	—	4,630	2,423	2,207	—	4,630
Foreign	612	—	—	612	612	—	—	612
Equity funds subtotal	3,035	2,207	—	5,242	3,035	2,207	—	5,242
Fixed income								
Corporate debt	—	2,023	239	2,262	—	2,023	239	2,262
U.S. Treasury and agencies	996	—	—	996	996	—	—	996
Foreign governments	—	95	—	95	—	95	—	95
State and municipal debt	—	438	—	438	—	438	—	438
Other	—	511	—	511	—	511	—	511
Fixed income subtotal	996	3,067	239	4,302	996	3,067	239	4,302
Middle market lending	—	—	366	366	—	—	366	366
Private Equity	—	—	83	83	—	—	83	83
Real Estate	—	—	3	3	—	—	3	3
Other	—	301	—	301	—	301	—	301
Nuclear decommissioning trust fund investments subtotal [b]	4,239	5,612	691	10,542	4,239	5,612	691	10,542
Pledged assets for Zion Station decommissioning								
Cash equivalents	—	15	—	15	—	15	—	15
Equities	6	1	—	7	6	1	—	7
Fixed income								
U.S. Treasury and agencies	5	3	—	8	5	3	—	8
Corporate debt	—	89	—	89	—	89	—	89
State and municipal debt	—	10	—	10	—	10	—	10
Other	—	3	—	3	—	3	—	3
Fixed income subtotal	5	105	—	110	5	105	—	110
Middle market lending	—	—	184	184	—	—	184	184
Pledged assets for Zion Station decommissioning subtotal [c]	11	121	184	316	11	121	184	316
Rabbi trust investments [d]								
Cash equivalents	—	—	—	—	1	—	—	1
Mutual funds [e]	16	—	—	16	46	—	—	46
Rabbi trust investments subtotal	16	—	—	16	47	—	—	47

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Generation				Exelon			
As of December 31, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivative assets								
Economic hedges	1,667	3,465	1,681	6,813	1,667	3,465	1,681	6,813
Proprietary trading	201	284	27	512	201	284	27	512
Effect of netting and allocation of collateral [f]	(1,982)	(2,757)	(557)	(5,296)	(1,982)	(2,757)	(557)	(5,296)
Commodity derivative assets subtotal	(114)	992	1,151	2,029	(114)	992	1,151	2,029
Interest rate and foreign currency derivative assets								
Derivatives designated as hedging instruments	—	8	—	8	—	31	—	31
Economic hedges	—	12	—	12	—	13	—	13
Proprietary trading	18	9	—	27	18	9	—	27
Effect of netting and allocation of collateral	(17)	(12)	—	(29)	(17)	(31)	—	(48)
Interest rate and foreign currency derivative assets subtotal	1	17	—	18	1	22	—	23
Other investments	—	—	3	3	2	—	3	5
Total assets	4,558	6,742	2,029	13,329	5,305	6,747	2,029	14,081
Liabilities								
Commodity derivative liabilities								
Economic hedges	(2,241)	(3,458)	(788)	(6,487)	(2,241)	(3,458)	(995)	(6,694)
Proprietary trading	(195)	(295)	(42)	(532)	(195)	(295)	(42)	(532)
Effect of netting and allocation of collateral [f]	2,416	3,557	729	6,702	2,416	3,557	729	6,702
Commodity derivative liabilities subtotal	(20)	(196)	(101)	(317)	(20)	(196)	(308)	(524)
Interest rate and foreign currency derivative liabilities								
Derivatives designated as hedging instruments	—	(12)	—	(12)	—	(41)	—	(41)
Economic hedges	—	(2)	—	(2)	—	(103)	—	(103)
Proprietary trading	(14)	(9)	—	(23)	(14)	(9)	—	(23)
Effect of netting and allocation of collateral	25	10	—	35	25	29	—	54
Interest rate and foreign currency derivative liabilities subtotal	11	(13)	—	(2)	11	(124)	—	(113)
Deferred compensation obligation	—	(31)	—	(31)	—	(107)	—	(107)
Total liabilities	(9)	(240)	(101)	(350)	(9)	(427)	(308)	(744)
Total net assets	$ 4,549	$ 6,502	$ 1,928	$12,979	$ 5,296	$ 6,320	$ 1,721	$13,337

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.
(b) Excludes net liabilities of $(12) million and $(5) million at June 30, 2015 and December 31, 2014, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $1 million and $3 million at June 30, 2015 and December 31, 2014, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) Excludes $36 million and $35 million of cash surrender value of life insurance investment at June 30, 2015 and December 31, 2014, respectively, at Exelon Consolidated. Excludes $13 million and $11 million and of cash surrender value of life insurance investment at June 30, 2015 and December 31, 2014, respectively, at Generation.
(e) The mutual funds held by the Rabbi trusts at Exelon include $47 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at June 30, 2015, and $45 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at December 31, 2014.
(f) Collateral posted to / (received from) counterparties totaled $277 million, $543 million and $154 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2015. Collateral posted to / (received from) counterparties totaled $434 million, $800 million and $172 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2014.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on the utility Registrants' Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2015 and December 31, 2014:

	ComEd				PECO				BGE			
As of June 30, 2015	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents	$ 5	$ —	$ —	$ 5	$ 5	$ —	$ —	$ 5	$ 46	$ —	$ —	$ 46
Rabbi trust investments in mutual funds [a]	—	—	—	—	8	—	—	8	5	—	—	5
Total assets	5	—	—	5	13	—	—	13	51	—	—	51
Liabilities												
Deferred compensation obligation	—	(7)	—	(7)	—	(10)	—	(10)	—	(3)	—	(3)
Mark-to-market derivative liabilities [b]	—	—	(223)	(223)	—	—	—	—	—	—	—	—
Total liabilities	—	(7)	(223)	(230)	—	(10)	—	(10)	—	(3)	—	(3)
Total net assets (liabilities)	$ 5	$ (7)	$(223)	$(225)	$ 13	$ (10)	$ —	$ 3	$ 51	$ (3)	$ —	$ 48

	ComEd				PECO				BGE			
As of December 31, 2014	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents	$ 25	$ —	$ —	$ 25	$ 12	$ —	$ —	$ 12	$ 103	$ —	$ —	$103
Rabbi trust investments in mutual funds [a]	—	—	—	—	9	—	—	9	5	—	—	5
Total assets	25	—	—	25	21	—	—	21	108	—	—	108
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(15)	—	(15)	—	(5)	—	(5)
Mark-to-market derivative liabilities [b]	—	—	(207)	(207)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(207)	(215)	—	(15)	—	(15)	—	(5)	—	(5)
Total net assets (liabilities)	$ 25	$ (8)	$(207)	$(190)	$ 21	$ (15)	$ —	$ 6	$ 108	$ (5)	$ —	$103

(a) At PECO, excludes $12 million and $14 million of the cash surrender value of life insurance investments at June 30, 2015 and December 31, 2014, respectively.

(b) The Level 3 balance includes the current and noncurrent liability of $20 million and $203 million at June 30, 2015, respectively, and $20 million and $187 million at December 31, 2014, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2015 and 2014:

	Generation					ComEd		Exelon
Three Months Ended June 30, 2015	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives [b]**	**Eliminated in Consolidation**	**Total**
Balance as of March 31, 2015	$ 715	$ 178	$ 1,066	$ 3	$ 1,962	$ (241)	$ —	$ 1,721
Total realized / unrealized gains (losses)								
Included in net income	2	—	(7) [a]	—	(5)	—	—	(5)
Included in noncurrent payables to affiliates	7	—	—	—	7	—	(7)	—
Included in payable for Zion Station decommissioning	—	(2)	—	—	(2)	—	—	(2)
Included in regulatory assets	—	—	—	—	—	18	7	25
Change in collateral	—	—	(30)	—	(30)	—	—	(30)
Purchases, sales, issuances and settlements								
Purchases	99	6	16	27	148	—	—	148
Sales	—	(26)	(5)	—	(31)	—	—	(31)
Settlements	(37)	—	—	—	(37)	—	—	(37)
Transfers into Level 3	—	—	11	—	11	—	—	11
Transfers out of Level 3	—	—	(30)	—	(30)	—	—	(30)
Balance as of June 30, 2015	$ 786	$ 156	$ 1,021	$ 30	$ 1,993	$ (223)	$ —	$ 1,770
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended June 30, 2015	$ 4	$ —	$ 175	$ —	$ 179	$ —	$ —	$ 179

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Generation					ComEd		Exelon
Six Months Ended June 30, 2015	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives [b]	Eliminated in Consolidation	Total
Balance as of December 31, 2014	$ 691	$ 184	$ 1,050	$ 3	$ 1,928	$ (207)	$ —	$ 1,721
Total realized / unrealized gains (losses)								
Included in net income	4	—	(39) [a]	—	(35)	—	—	(35)
Included in noncurrent payables to affiliates	15	—	—	—	15	—	(15)	—
Included in payable for Zion Station decommissionir	—	1	—	—	1	—	—	1
Included in regulatory assets	—	—	—	—	—	(16)	15	(1)
Change in collateral	—	—	(18)	—	(18)	—	—	(18)
Purchases, sales, issuances and settlements								
Purchases	146	11	57	27	241	—	—	241
Sales	(8)	(40)	(5)	—	(53)	—	—	(53)
Settlements	(66)	—	—	—	(66)	—	—	(66)
Transfers into Level 3	4	—	11	—	15	—	—	15
Transfers out of Level 3	—	—	(35)	—	(35)	—	—	(35)
Balance as of June 30, 2015	$ 786	$ 156	$ 1,021	$ 30	$ 1,993	$ (223)	$ —	$ 1,770
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the six months ended June 30, 2015	$ 5	$ —	$ 355	$ —	$ 360	$ —	$ —	$ 360

(a) Includes the reclassification of $(182) million and $(394) million of realized losses due to the settlement of derivative contracts for the three and six months ended June 30, 2015, respectively.

(b) Includes $14 million of increases in fair value and realized losses due to settlements of $4 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended June 30, 2015. Includes $22 million of decreases in fair value and realized losses due to settlements of $6 million for the six months ended June 30, 2015.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Generation					ComEd		Exelon
Three Months Ended June 30, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives [b]	Eliminated in Consolidation	Total
Balance as of March 31, 2014	$ 486	$ 137	$ 287	$ 10	$ 920	$ (168)	$ —	$ 752
Total realized / unrealized gains (losses)								
Included in net income	2	—	(48) [a]	—	(46)	—	—	(46)
Included in noncurrent payables to affiliates	8	—	—	—	8	—	(8)	—
Included in payable for Zion Station decommissioning	—	4	—	—	4	—	—	4
Included in regulatory assets	—	—	—	—	—	34	8	42
Change in collateral	—	—	34	—	34	—	—	34
Purchases, sales, issuances and settlements								
Purchases	109	13	5	—	127	—	—	127
Sales	(1)	(21)	(4)	—	(26)	—	—	(26)
Settlements	(12)	—	—	—	(12)	—	—	(12)
Transfers into Level 3	—	—	(4)	—	(4)	—	—	(4)
Transfers out of Level 3	—	—	(28)	—	(28)	—	—	(28)
Balance as of June 30, 2014	$ 592	$ 133	$ 242	$ 10	$ 977	$ (134)	$ —	$ 843
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended June 30, 2014	$ 2	$ —	$ 19	$ —	$ 21	$ —	$ —	$ 21